

**FortisBC Inc.**

**2014 Planning Reserve Margin Studies**

**Based on 2012 Planning Year**

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# Executive Summary

Planning Reserve Margin (PRM) is the dependable capacity above the expected peak demand and is measured in MW or percentage of the expected peak. PRM is required to ensure system resource adequacy. Utilities differ noticeably in their PRM practices, including how to define the dependability of their capacity resources, whether to rely on the external market or not, which reliability metric to target, and how to derive sufficient PRM to meet the resource adequacy requirements suitable for their operating environment. For example, neighboring utilities of FortisBC stated their PRM from 10% to 24%, but some of the numbers did not include Operating Reserves and at least one of the utilities did not include the market for PRM purposes. Utilities also differ widely in how PRM studies are conducted. The most widely accepted approach is to examine PRM from probabilistic studies using the LOLE (Loss-Of-Load-Expectation or the expected number of days in a year the generation capacity fails to meet load) metric. However, other approaches are the LOLP (Loss-Of-Load-Probability or the probability to fail to meet load), the PRM target originally set for the whole region by a NERC entity, or a simple deterministic rule.

Each utility should consider its own operating environment for PRM purposes since no two utilities are the same and there is really no one-size-fits-all solution here. For instance, FortisBC has four plants but its plants are operating under a special agreement in coordination with BC Hydro and other partners. The Company is expecting to have a new substantial capacity resource, Waneta Expansion (WAX), coming online in early 2015 and this is a source of additional uncertainty to the operating environment of the Company. FortisBC cannot use any other utilities’ existing results on PRM given all of its operating characteristics.

FortisBC believes that no additional resources are needed to meet resource adequacy requirements at the time of writing this PRM report (2014). The Company will review this report periodically and will update it as an appendix in the 2016 Long Term Electric Resource Plan (LTERP). The resource options portfolio modeling done as part of the LTERP will incorporate FortisBC’s approach to meeting resource adequacy requirements.

This report gives more detail on the findings of the Company’s Monte Carlo simulation PRM based approach. This approach is in accordance with the current best practices in the power industry and is expected to have lower rate impacts on customers. The Company adopted LOLE as the reliability metric in its PRM study, and targeted 1 day in 10 years or 0.1 day per year, used by most utilities, in its evaluation of resource adequacy. The resource stack to meet load consists of the Company’s own resources, its contracted capacity resources including 200MW from BC Hydro as per the recently approved New Power Purchase Agreement, and 150 MW of market access, subject only to transmission outages.

Cases investigated in this study include the base case, which assumes the Company’s expected operating environment, and a number of sensitivity cases that deviate from the base case. In the base case, the system meets the LOLE target without adding any capacity other than the capacity to meet expected capacity gaps, and the average winter PRM including Operating Reserves is around 24%. Further sensitivity cases conducted were classified into three main groups related to the load, the resources, and the market. For the majority of sensitivity cases, the system is capable of meeting the LOLE target without needing additional capacity as summarized below:

|  |  |  |
| --- | --- | --- |
| Case | Description | Meet LOLE Target? |
| Case 0 Base Case  | Yes |
| Load Sensitivity Analysis |  |
| Case 1 | 1-in-10 economic drivers | Yes |
| Case 2 | Industrial self-generating demand of 40MW | Yes |
| Case 3 | Time of seasonal peaks | Yes |
| Resource Sensitivity Analysis |  |
| Case 4 | WAX FORs | Yes |
| Case 5 | Double FORs  | Yes |
| Case 6 | Firming up additional WAX surplus sales | Yes |
| Case 7 | No additional capacity for gaps | No (expected gaps must be met) |
| Market Sensitivity Analysis |  |
| Case 8 | Market sizes at the base case FOR | Yes |
| Case 9 | No market access | No (alternative capacity is needed) |
| Case 10 | Market FORs at 150MW | Yes |

In the first group of load related sensitivity cases, when load increases can be anticipated (such as due to foreseeable higher rates of load growth) and additional capacity resources can be acquired to meet increased expected gaps in advance, the system is capable of meeting the LOLE target of 1 day in 10 years. Even when seasonal peaks cannot be anticipated in a timely manner due to weather, the system can still ensure the LOLE target. Second group of sensitivity cases on resources investigated higher than expected forced outage rates (FOR) of the Company’s own generators and its WAX resource, and also the unavailability of capacity surplus from WAX. Cases in this sensitivity group passed without requiring additional PRM capacity to meet the LOLE target. Finally, the market related sensitivity cases evaluated the size and availability of the market. At the transmission FOR of 0.74% as in the base case, approximately 75MW of market access is sufficient to reach the LOLE target, resulting in an average winter PRM of around 15%. Having a less reliable market will reduce market availability, and resource inadequacy will be observed when the unavailability of 150 MW market import exceeds 5%. If the Company has no access to the market, alternative capacity of up to 150 MW (at FOR 5%) will be required, resulting in an average winter PRM of around 23%. In any case, it is important to prepare dedicated resources rather than depending on market imports to meet expected capacity gaps.

In the sections that follow, section 1 reviews key concepts related to PRM including Operating Reserves, Planning Margins and resource adequacy metrics, then examines industry practices and explains the pros and cons of different methods to determine PRM for resource adequacy requirements. Section 2 gives an overview of the Company’s operating environment. Section 3 describes modeling techniques used to study PRM and presents results for the base case and further sensitivity scenarios. Finally, the conclusion is given in Section 4.

# Overview of Planning Reserve Margin

## Planning Reserve Margin Terminologies

Planning Reserve Margin (**PRM**) is conceptually the capacity above expected load necessary to maintain a certain resource adequacy level. PRM is calculated as the difference between system dependable generation capacity and peak demand, measured in either MW or percentage of peak demand:

PRM = ((Capacity – Peak Demand)/Peak Demand) \*100%

where the peak demand is the expected load while the generation capacity is dependable capacity. The FBC expected load is net of DSM and other savings. As described by NERC, PRM “*is designed to measure the amount of generation capacity available to meet expected demand in planning horizon*”[[1]](#footnote-2). PRM’s role is to ensure resource adequacy when dealing with unforeseen increases in demand and forced outages in the system. It serves the utilities’ ultimate goal of “keeping the lights on” over the planning horizon. Negative PRM indicates that the system capacity is not sufficient to meet the expected demand. PRM which is positive but falling below some targeted margin signals that additional capacity is needed to meet a resource adequacy target. Note that two other terms, Planning Reserve and Reserve Margin, are still being used quite interchangeably for the term PRM in the power utility industry.

The PRM concept is broader than Operating Reserves (**OR**) although it includes OR. OR is defined by NERC as “*capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserves*.”[[2]](#footnote-3) These spinning and non-spinning reserves[[3]](#footnote-4) are used to form two major functional OR components namely:

* Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard and other NERC and Regional Reliability Organization contingency requirements. It is for control under disturbance conditions and at least half of it must be spinning. It is available for only 60 minutes from the time of any contingency event; and
* Regulating Reserve: An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin. It is for control under normal conditions and consists of spinning reserve only

Utilities must hold capacity for OR to meet NERC (BAL-002[[4]](#footnote-5)) and further sub-regional reliability standards (WECC’s BAL-STD-002-0[[5]](#footnote-6) for FBC). Contingency reserve is not available to be used to meet end-use demand unless there is an unplanned outage event.

It is necessary to hold OR to ensure real-time reliable operation of the system. However, the OR requirement is also counted as part of the overall PRM requirement even though it does not directly contribute to PRM’s role of ensuring resource adequacy when dealing with unforeseen increases in demand and forced outages in the system. OR ensures hourly operational reliability while PRM must include a sufficient time period to ensure changes to the resource portfolio can be addressed as needed to ensure system resource adequacy. In other words, PRM includes the resource capacity reserved for OR to address uncertainties caused by hourly load and generation variations as well as any additional capacity needed on a longer term basis. This point is clearly indicated in WECC’s building block guideline to determine PRM[[6]](#footnote-7). In this guideline, PRM consists of the two obligatory blocks identified above: (1) contingency reserve and (2) regulating reserve, and two optional blocks: (3) reserve for 1-in-10 weather events and (4) reserve for other forced outages that are outside the 60 minute limit for contingency reserve. The first two blocks make up the OR requirement in most utilities’ practices.

Caution should be exercised when comparing PRM values stated by different utilities as they may differ in a number of dimensions, and are specific to the type of resources held by each utility and the nature of their loads. Utilities may also use non-firm capacity, and include or exclude market access as a source of capacity. Also, they may use different PRM calculation methods with markedly different results. Finally, although published PRM values frequently include OR, they may also exclude OR if a utility wants to make a clear differentiation between capacity requirements for OR and longer term planning margin. This is a practice proposed by Pacific Northwest Utilities Conference Committee (**PNUCC**) and which has been adopted by a number of Pacific Northwest utilities. PNUCC separated PRM into OR and “Planning Margin” (**PM**), which does not have the “reserved” capacity. Resources for PM might be used to meet end-use demand[[7]](#footnote-8). PNUCC recommends utilities to report both values of PM and PM with OR in their resource adequacy assessments. Table 1-1 below illustrates differences in PRM as reported by some of FBC’s neighboring utilities.

Table 1-1: PRM Stated by Neighbouring Utilities

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
|  | Avista | BC Hydro | Idaho Power | NorthWestern Energy | Pacific Corp | Portland General Electric | Puget Sound Energy |
| PRM  | 24% incl. OR15% excl. OR | 14%[[8]](#footnote-9) | 10% | PRM by Suppliers | 13% | 12% | 15.7% |
| OR Included? | Yes and No | Yes | Yes | N/A | Yes | Yes | No |
| Market Included? | Yes | No | Yes | Yes (100%) | Yes | No | Yes |
| Reference | 2011 Electric IRP[[9]](#footnote-10) | 2008 LTAP and 2013 IRP | 2011 IRP[[10]](#footnote-11) | 2011 IRP[[11]](#footnote-12) | 2011 IRP[[12]](#footnote-13) | 2009 IRP[[13]](#footnote-14) | 2011 IRP[[14]](#footnote-15) |

(**IRP**: Integrated Resource Plan)

There are currently no common NERC standards or requirements for PRM. NERC and its regional entities only strongly recommend PRM, but do not mandate it. Resource adequacy metrics and methodologies for PRM by NERC regional reliability councils are summarized in Table 1-2[[15]](#footnote-16).

Table 1-2: NERC’s Regional Metrics and Methods for PRM

|  | WECC | MRO£ | SPP | ERCOT | RFC\* | FRCC | NPCC | SERC |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| PRM Target | Not Specified | 15%, 10% if hydro system | 12%, 9% if 75% hydro  | 12.5% | 12% - 18% | 20% IOU, 15% others | 20%, Loss of Largest Unit | 10% - 15% |
| Regional Resource Adequacy Criteria | Not Specified | 1 day -in-10 yr LOLE# | 1 day -in-10 yr LOLE | 1 event -in-10 yr LOLP# | 1 day -in-10 yr LOLE | 1 day -in-10 yr LOLE | 1 day -in-10 yr LOLE | 1 day -in-10 yr LOLH |
| Methodology | Building Block | Probabilistic LOLE | Probabilistic LOLE | Probabilistic LOLP | Probabilistic LOLE | Probabilistic LOLE | Probabilistic LOLE | NERC Reference& |
| Notes: (£) MAPP before 2005;(\*) MAIN, ECAR, and MAAC were merged to form the ReliabilityFirst Co. in 2006; (#) LOLE and LOLP are discussed below.(&) NERC’s general reference levels are 10% of hydro and 15% for thermal dominant systems. Since SERC is an active member of NERC’s LOLP pilot group, its updated LOLP-based results are expected soon, |

WECC, the NERC regional entity monitoring FBC’s service area, does not impose a common target or method for PRM on its members. Meanwhile, NERC and WECC strictly require utilities to maintain their reliability standards for OR requirements. Because WECC only assesses and projects PRM but does not specify any adequacy threshold, NERC applies a baseline of 10% to WECC since WECC is hydro-generation predominant (see footnote 1). This serves only as a reminder to utilities in the WECC service area, however each utility should determine its own PRM requirement based on its own operational needs, including consideration of its resources, load requirements and access to the market. Nevertheless, all utilities must insure that any PRM must at least cover OR requirements for regulating and contingency reserves. FBC is a member of the North West Power Pool (**NWPP**) contingency reserve sharing group, and hence required to hold 5%[[16]](#footnote-17) of its capacity for contingency reserves, and under the Canal Plant Agreement FBC also holds 2% of its capacity for regulating reserves.

## Resource Adequacy Metrics

The utility industry uses a number of metrics (indices) to measure resource adequacy and determine PRM requirements. Most common metrics are described below:

* *Loss of Load Expectation* (**LOLE**, in days per year): LOLE is the expected number of days in a year when the aggregate resource is insufficient to meet load. It does not matter if there are single or multiple shortfall events in a day of resource inadequacy since the analysis is for the daily peak only. Resource capacity is assumed to remain constant throughout the day. This is the most commonly used metric in the industry. The traditional LOLE criterion is “1 day in 10 years”, or equivalently 0.1 day/year if annual analysis is required.
* *Loss of Load Hours* (**LOLH**, in hours per year): LOLH is the expected number of hours in a year when the aggregate resource is insufficient to meet load. This metric is very similar to the LOLE, but using hourly load and generation profiles rather than the daily peak and capacity profiles. It is useful when there are intermittent renewable resources like wind or solar in the resource mix. Conversion between LOLE and LOLH is, however, not straightforward. LOLE does not equal LOLH/24 because a shortfall event typically does not last for the whole day. If outages were to typically last for 8 hours, the LOLE criterion of 0.1 day/year would be closer to a LOLH criterion of (0.1 \* 8) or 0.8 hour/year. This uncertainty in the average outage time makes it very difficult to compare LOLE and LOLH numbers.
* *Expected Unserved Energy* (**EUE**, in MWh): EUE is the expected amount of energy not served per year. This metric gives some information of the aggregated magnitude of shortfalls.
* *Loss of Load Probability* (**LOLP**, in %): LOLP is the probability that at least one shortfall event will occur over the time period being evaluated. Common industry standards are 1-in-10 or 10% and 1-in-20 or 5%. This approach uses an annual measure. This metric does not reflect the frequency of events such as the LOLE or LOLH because it does not matter if there are one or more shortfall events in the bad year.

These resource adequacy metrics are sometimes referred to as reliability indices in the literature. Since cost consideration makes it practically impossible to have a system totally immune to shortage events, a target metric is chosen to reflect a tradeoff between reliability and cost, given a utility’s particular situation.

## Methods to Determine PRM

This section gives an overview of two main approaches to calculate the PRM capacity and the method chosen by FBC.

### Simple rule-based approach

This approach can be done in two ways. In the first way, the utility applies PRM as a certain percent of load. This percentage is taken directly from available study results published by its regional coordination organization on regional PRM. For example, a utility member in the Northwest Power and Conservation Council (**NWPCC**) can set its winter PRM at 24% and its summer PRM at 23% of net demand (inclusive of OR[[17]](#footnote-18)) based on the NWPCC’s calculations for its whole area. However, since the regional study’s methods typically take into account dispatching capability among different load serving entities with different load and capacity profiles, the regional organization warns utilities that the results should be interpreted for the whole region and should not be directly applied to any single utility.

The second way uses a simple deterministic formula to determine PRM. For example, prior to adopting the building block method described in Section 1.1 above, WECC used the following formula:

PRM = Most Severe Single Contingency + 5%\*Load Responsibility

The analytical methods above are simple to use, but their major disadvantage is that they do not directly address any resource adequacy metrics (LOLE, LOLH, EUE) and hence the utility cannot know the system risk level and whether the resource adequacy measure is appropriate for its individual situation.

### Probabilistic approach

Unlike methods in the simple rule-based approach, methods in the probabilistic approach, being deterministic or stochastic, directly target resource adequacy metrics. The first method is called the “Capacity Outage Probability Table” and was quite popular in the 1960s-1980s. In this method, the utility studies its generators’ forced outage rate (FOR), then builds up a complex table of capacity outage probabilities and compares values in this table to a forecast load duration curve to find LOLE. Appendix A gives an example of this calculation. There are two main disadvantages with this method. First, setting up the capacity outage probability table gets more cumbersome and intractable the more generators there are in the system. Second, this method cannot take into account both load variations and system outages at the same time.

To overcome these disadvantages, most utilities have switched to the stochastic method, which is based on a Monte-Carlo (**MC**) simulation. In this method, multiple uncertainties in the system are considered simultaneously and the output is obtained after a high number of sampling iterations. The main advantage of this method is to allow utilities to better approximate real operation of the system, which makes planning results much more useful. Utilities had limited access to computing power in the past to apply this method to obtain valid results, but current computing technologies have significantly reduced this obstacle.

The resource adequacy metrics mentioned in Section 1.2 are obtained in the MC simulation method as follows. Suppose a MC simulation for a year uses *n* sampling iterations. If there are *m* simulated years (m ≤ n) in which at least one shortfall event occurs (i.e. resource capacity in a day is less than the day’s peak demand if the daily load profile is used or resource capacity in an hour is less than this hour’s peak demand if the hourly load profile is used), then for this year:

*LOLP = m/n*, and *LOLE = Total number of days having shortfalls/n,* if the daily load profile is used (day/year), or

*LOLH = Total number of hours having shortfalls/n* (hour/year) if the hourly load and generation profiles are used.

In the latter case, EUE can also be estimated as *Total hourly capacity shortage/n* (MWh/year). As mentioned earlier, converting LOLH to the more traditional LOLE to compare to the default industry standard LOLE 0.1 day/year is not simple and still a subject of debate.

### FBC’s Method to Determine PRM

The Company believes a probabilistic approach employing a Monte Carlo simulation of its operating environment to assess the adequacy of its resources to meet a target performance provides the most balanced method. The Company has chosen the LOLE industry practice of 1 day in 10 years, or as it is more commonly expressed, 0.1 day/year as the target resource adequacy index as it is currently the industry standard and it is appropriate for the FBC resources. After the ReliabilityFirst Corporation, a NERC entity, approved this criterion in March 2011[[18]](#footnote-19), WECC remains the only NERC entity that has not endorsed this criterion. Details of the MC method that the Company employed are given in Section 3.

# Overview of THE FortisBC Operating Environment

The section presents in detail key features of the Company’s operating environment as they apply to Planning Reserve Margin. The normal operating environment constitutes the base case for the study to be presented in the next section while deviations from its expected condition are then examined in a number of sensitivity cases.

## FortisBC Resource Stack

### CPA Entitlement

The Company owns four existing hydro plants located on the Kootenay River between Nelson and Castlegar in this order: Corra Linn (three generators), Upper Bonnington (six generators), Lower Bonnington (three generators), and South Slocan (three generators). Since these facilities are operated under the Canal Plant Agreement (**CPA**), BCH directly dispatches the plants and FBC receives guaranteed entitlement energy and capacity provided the generating units are available to be dispatched. The Company’s usage of its plants to meet system requirements is therefore insulated from hydrology risks, but still subject to plant outages. In addition to its four plants, FBC has a long-term contract to purchase the whole output of the four generating units of the Brilliant Plant (**BRD**) belonging to the Brilliant Power Corporation (**BPC**), which are located close to the Company’s plants. Because BRD is also a CPA entitlement plant, the BRD output is also hydrology risk free, but subject to outages. Table B1 in Appendix B shows the entitlement capacity for the Company’s own and contracted generators. FBC has also contracted to purchase entitlement capacity from the Waneta Expansion (WAX) project, which is also a CPA entitlement plant that is expected to come into service by the second quarter of 2015. WAX is discussed further in section 2.1.3. In order to assess the availability of its generation units, FBC reviewed their historical performance. FBC’s Upgrade and Life Extension Program (**ULE**), completed in 2012, has extended the lives of 11 of the Company’s 15 generating units through its course of maintenance and refurbishment programs. Only four small (5 MW) units at the Upper Bonnington plant were not under the ULE. The majority of ULE work was done in the 1995-2008 period, therefore it is more reasonable to use historical outage data after 2008 to estimate the plants’ expected forced outage rates (FOR) [[19]](#footnote-20). Each generator’s average FOR from the 2008-2011 period is then used to set the expected FOR for that generator in the MC simulation. These generators’ average outages are found in Table B2 and their collective maintenance schedules are in Table B3.

The large majority of historical forced outage durations were less than one day as shown in Table B2. Two generators G1 and G3 in the Upper Bonnington plant, which are of small size (about 5 MW) and were not covered in the ULE, have a larger portion of forced outages lasting more than a day. However, due to their small size, for simulation purposes it was assumed that all generator forced outages will last for less than one day.

### Power Purchase Agreement, PowerEx, and Brilliant Expansion Capacity

In addition to the CPA entitlement capacity, the Company has also entered into a Power Purchase Agreement (**PPA**) with BCH. The recently approved New PPA (as per the Commission’s Order G-60-14 issued on May 6, 2014) ensures capacity purchases of up to 200MW at any time. Given the resources of BCH and the number of interconnection points, the 200MW PPA capacity is considered 100% available (i.e. FOR=0%). Because the PPA contract terminates in 2033 and significant changes in the Company’s resources may occur after that, this PRM study covers the period up to 2033 only.

Other capacity resources include two separate firm capacity block contracts (FOR 0%), from PowerEx for the winter months of 2012-2015 and 2013-2015, and entitlement capacity with energy from the Brilliant Expansion plant from January 2013 to December 2017 (with its assumed FOR calculated over the same 2008-2011 period).

### WAX Capacity

The Company receives capacity blocks from the Waneta Expansion (WAX) project which started in the spring of 2015. These blocks are CPA entitlement and are capacity only. The Company receives WAX entitlement capacity from two WAX units with a capacity of 165 MW each as shown in Appendix B, Table B-1. A 10-year overhaul for one unit is assumed in October 2024 and another one in October 2025. During these months, FBC will not have access to the whole WAX unit’s capacity. There are also projections of other maintenance for WAX as shown in Appendix B, Table B-3.

Since WAX is a new unit with no performance record, predicting WAX’s FOR is not straightforward. However, for the purposes of this simulation, it is assumed that the WAX unit performance will not be different from the performance of the units at the existing Waneta plant (P6) and therefore WAX’s FOR is assumed at 0.25%, close to P6’s average FOR of 0.24%. It was also assumed that the forced outage rate could be higher in the early years of operation of the new facility, hence the FOR in 2015-2019 is assumed to be two times higher than its expected long-term FOR, i.e. 0.5%. WAX’s forced outages are assumed to last for more than one hour but less than one day, similar to P6’s past forced outage record.

FBC has received approval of the Residual Capacity Agreement (RCA) to sell to BC Hydro unit-contingent[[20]](#footnote-21) WAX capacity blocks of up to 50MW for all months (i.e. typically 50 MW except in June where the WAX capacity available to FBC is less than 50MW) for the 2015-2024 period. As a result, for the purposes of the simulation, these monthly blocks are subtracted from the WAX entitlement capacity for FBC before any other usage. Appendix B, Table B-4 displays WAX capacity after the reduction for the 50 MW block capacity sale to BCH.

On a planning basis the remaining capacity is then used to meet the expected monthly load as the marginal (last) resource to dispatch (after FBC’s own and contracted resources, including the PPA). The remaining WAX capacity is surplus and is available to be sold as a monthly block.[[21]](#footnote-22) This sale is firm but it is also unit-contingent (i.e. there will be no surplus sales if the unit fails) such that it does not have to be made up from other resources in the event of a WAX outage. Since the sale is assumed to be for a month or more, it is not available for PRM but in the event of a longer term outage or unexpected heavy load growth, it would be available once the term of the sale is completed.

Additional amounts of WAX capacity may be available on non-peak days or in months when no block sale of surplus capacity was feasible. This additional capacity is available for PRM and Scenario 6 examines the case where this surplus capacity is not available for PRM.

### Market Access

FBC’s view is that reliance on market capacity to meet expected demand over the long term is not a prudent policy due to the uncertainty associated with both resource availability and market prices. This view is common among utilities. However, utilities that have access to market supply may consider market access as a supplemental resource to meet system requirements under unexpected conditions. This market capacity would only be called upon in case of contingencies where a utility’s own and contracted resources are not sufficient to meet load. Since peak loads only occur for a few hours of the month it is expected that any such market usage would be quite limited even if the shortfall occurred over a longer time frame. In practice, utilities’ opinions differ substantially on relying on market imports for resource adequacy purposes, as reported in the NERC 2011 Long-term Reliability Assessment[[22]](#footnote-23). Nevertheless, some of FBC’s neighboring utilities like AESO, Avista, Northwestern Energy, Idaho Power, and BCH (up to 2016) count market capacity as a supplemental resource.

FBC is able to import electricity from the Mid-C market via transmission line 71 connected to Teck’s Waneta plant, as well as through the BC Hydro transmission system. For the purposes of this PRM study, the conservative assumption is that only market capacity imported through line 71 is considered. Line 71 has a transmission capacity of 370 MW but Teck has priority over FBC for use of this line. Therefore, the Company only has reliable access to the market of about 150 MW over Line 71. Line 71 may also be inaccessible for the Company due to major maintenance. This maintenance can be for up to a month with a frequency of around once per ten years, and it was treated as a random variable in the MC simulation.

There are two types of risks associated with the market capacity: (1) transmission forced outages and (2) market availability. An internal study on forced outages of transmission lines in the 2000-2011 period shows that the average forced outage rate for transmission was very small, only 0.74% (Appendix B, Table B-2).

The market availability is much harder to evaluate. There is a risk of a competition among utilities for the market capacity during a cold snap and hence the Company might not be able to purchase on the spot market. There is also a risk of unreasonably high prices when the spot market is called for. While PRM does not consider price a factor in availability, prolonged prices at high levels can result in increased costs to customers. However, this is primarily an energy supply cost risk and is outside the scope of this study. Market unavailability has happened to the Company’s operation on a few rare occasions. This likelihood is considered quite small as the majority of WECC members are summer peaking utilities while FBC is a winter peaking utility. The Company believes it is acceptable to include limited access to market supply as an available resource when assessing resource adequacy at a risk of being unavailable of 0.74%, representing the risk of the transmission forced outage rate. This will be referred to as the market equivalent FOR. Impacts of possible higher market risks are discussed in the sensitivity analysis discussion in Section 3.

### Regulating Reserve and Contingency Reserve Obligations

The Company reserves a certain percentage of its capacity for regulating and contingency purposes. This reserved capacity cannot be counted on to meet expected load for planning purposes as discussed in Section 1.1.

FBC and BCH are both members in the Northwest Power Pool (**NWPP**), which is a contingency reserve sharing group for utilities in the northwest region.[[23]](#footnote-24) The NWPP pools all reserve contributions from its members according to their load and generation attributes and if a contingency is beyond the resources of the utility experiencing an event, reserves are allocated to them from the other members of the NWPP. The biggest advantage of the NWPP is that each individual utility member is not required to hold reserves to deal with its most severe single contingency. This is of great benefit to the Company after WAX comes online because of the high single unit capacity of each of WAX’s generators.

Under the CPA, the Company sets 2% of its generation capacity to regulate frequency. In addition, the Company’s contingency reserve obligation to the NWPP comprises 5% of its own and the BRD and WAX contracted capacity. The first 60 minutes of a contingency can be covered by contingency reserves. After 60 minutes the contingency reserves must be restored. Given the Company’s membership in the NWPP, forced outages lasting for less than one hour are not included in this analysis. The likelihood of the outage being less than an hour is set for each generator at its historical percentage of forced outages that lasted for less than one hour. For example, if a generator has a FOR of 0.5% and its forced outages have a likelihood of 30% of being less than one hour, then it will experience outages lasting for more than one hour for about 0.35% of the time.

### Peak Forecast

The PRM study used FBC’s peak demand forecast, after DSM and other savings, as filed in the 2012-2013 RRA and 2012 Long Term Resource Plan (LTRP) (the most recent FBC long term forecast approved by the BCUC), but with self-generating industrial customers load removed and only considered in a sensitivity case. This expected forecast of demand on FBC’s system with monthly and seasonal values is shown in Table C-1 in Appendix C. Since FBC’s winter peak has occurred in December more often than the other months in the past 20 years, this forecast assumes that the winter peak will occur in December and therefore it replaces the December peak in the peak forecast with the winter peak. The same argument is applied to replace the forecast July peak with the summer peak.

For the MC simulation, the peak profile should be on either a daily or hourly basis. The daily peak profile was chosen because:

* It fits the Company’s resource profile:
* WAX is a capacity-only resource;
* CPA only specifies monthly capacity and energy for entitlement resources;
* It is straightforward to compare the resultant LOLE to the industry practice of LOLE 0.1 day/year.

Twelve representative daily load curves for each month (in percentage of the month’s peak) were derived based on a study of peaks over the 2002-2011 period. These chronological curves were then assumed for the whole planning horizon. Monthly load profiles are shown in Table C-2. Figure 2-1 displays an example for July and December profiles. To forecast daily peaks (in MW) for a month, the month’s load curve (in %) is applied to the month’s forecast peak (in MW). For example, with a monthly peak of 700MW and the first day of the month set at 90% of the month’s peak, the peak on this first day is 630MW.

Figure 2-1: Load Profile Examples



## Capacity Gaps

Once the capacity resources and expected peak forecast are known, it is straightforward to calculate the WAX monthly capacity amounts needed to meet peaks, expected monthly capacity gaps, WAX total surplus capacity, WAX unit-contingent surplus capacity and WAX hourly surplus capacity. Table D-1 in Appendix D shows that there will be forecast capacity gaps in June as early as in 2018. All capacity gaps are expected to be supplied from other firm resources.

In this modeling work, it is assumed that if there is an expected capacity gap in a month then a firm capacity resource with FOR 5% to exactly meet the gap will be acquired in advance (see Table B-5 in Appendix B). Scenario 7 examines the case where additional capacity to meet expected capacity gaps is not acquired.

# Monte-Carlo Simulation Results

## Monte-Carlo Simulation and Assumptions in the Base Case

The Monte-Carlo (**MC**) simulation model for PRM was developed in-house using Microsoft Excel and its programming language VBA. There are off-the-shelf software packages for PRM planning, but they are more suitable for regional planning with economic dispatching capability. Furthermore, certain features of the Company’s operating environment, e.g. the CPA, are not present in the commercial models which would result in the need for additional customized programming.

The base case (Case 0) represents the Company’s expected operating environment, while sensitivity cases examine deviations from the expected operating environment. Assumptions for the base case are summarized below:

1. The peak forecast is the expected forecast with the winter and summer peaks to occur in December and July respectively. ;
2. The FBC’s own and contracted generators’ FORs are assumed as per column 3 in Appendix B, Table B-2;
3. WAX’s expected FOR in the 2015-2019 is 0.5% and after 2019 is 0.25%;
4. Forced outages last for less than one day and an outage on one day does not influence if the following day will have an outage as well;
5. Market access is 150MW and the transmission FOR is 0.74%;
6. Capacity to meet expected gaps is firm at FOR 5% and planned in advance as in Appendix B, Table B-5; and
7. WAX surplus capacity for unit-contingent sales is not available to meet system requirements while the remaining hourly WAX surplus capacity is.

Note that the model does not need to generate the duration of forced outages because daily peaks are used and outages are assumed to last less than one day. Simulation results are provided in the next section.

## Base Case Results

The MC simulation sampled 1,000 iterations for each year. This number of iterations tends to be common practice in the utility industry; for example, a recent NERC survey in July 2012 on pilot probabilistic assessment of resource adequacy shows that close to 50% of participants are adopting it[[24]](#footnote-25). The model was also tested at higher number of iterations (up to 5,000), but there were only immaterial variances from the results with 1,000 iterations. The convergence chart below, taken for 2033 as a randomly selected year, proves the sufficiency of 1,000 iterations since after 1,000 iterations the LOLE converges.

For presentation purposes, years 2014-2020, 2025, 2030, and 2033 were chosen for tables and charts in Section 3. LOLE results of the base case for these years are displayed in Table 3-1 below (see Table E-1 in Appendix E for more monthly LOLEs).

It is clear that in Case 0, or the base case, the system easily meets the industry benchmark of LOLE 0.1 day/year. There is no need to acquire further capacity for resource adequacy (other than the expected capacity to meet gaps as shown in Appendix D, Table D-1.)

Figure 3-1: Simulation Convergence



Table 3-1: LOLE in the Base Case (0.1 day per year as the target)

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual | Winter PRM |
| 2014 | 0.000 | 0.000 | 0.002 | 0.000 | 0.000 | 0.001 | 0.002 | 0.004 | 0.000 | 0.000 | 0.002 | 0.005 | 0.016 | 27% |
| 2015 | 0.002 | 0.000 | 0.015 | 0.000 | 0.000 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.006 | 0.024 | 26% |
| 2016 | 0.002 | 0.000 | 0.001 | 0.000 | 0.000 | 0.002 | 0.002 | 0.000 | 0.000 | 0.000 | 0.000 | 0.009 | 0.016 | 26% |
| 2017 | 0.002 | 0.000 | 0.001 | 0.000 | 0.000 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.005 | 0.009 | 26% |
| 2018 | 0.000 | 0.001 | 0.000 | 0.000 | 0.006 | 0.006 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.002 | 0.016 | 25% |
| 2019 | 0.002 | 0.000 | 0.000 | 0.000 | 0.003 | 0.005 | 0.003 | 0.000 | 0.000 | 0.000 | 0.000 | 0.007 | 0.020 | 25% |
| 2020 | 0.001 | 0.000 | 0.000 | 0.001 | 0.001 | 0.004 | 0.002 | 0.000 | 0.000 | 0.000 | 0.000 | 0.006 | 0.015 | 25% |
| 2025 | 0.000 | 0.001 | 0.001 | 0.001 | 0.000 | 0.012 | 0.003 | 0.000 | 0.000 | 0.000 | 0.000 | 0.003 | 0.021 | 24% |
| 2030 | 0.000 | 0.002 | 0.000 | 0.000 | 0.000 | 0.007 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.014 | 0.024 | 23% |
| 2033 | 0.001 | 0.002 | 0.000 | 0.000 | 0.000 | 0.003 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.023 | 0.030 | 23% |

The resultant PRM percentage value was calculated on a monthly basis for each year and the December PRM values (including OR) were then assumed for the winter as shown in the last column of the table above. Table E-2 in Appendix E further shows the seasonal PRM for the base case, including and also excluding OR. Table E-3 further explains the winter PRM calculations in the base case in detail.

## Sensitivity Analysis

Table 3-2 summarizes a number of sensitivity cases to assess impacts on LOLE when changing the modeling assumptions. In each scenario, only one assumption was changed while other components were kept intact. The scenarios were classified in three main groups related to load, resources, and the market. When it was necessary to add capacity to obtain the targeted LOLE of 0.1 day per year, this capacity was assumed to be from a resource with FOR 5% unless stated otherwise. In general, results from sensitivity cases show that the system is able to handle various scenarios, except for a few scenarios where additional capacity would be required to meet the LOLE target of 0.1 day per year.

Table 3-2: Cases for Sensitivity Analysis

|  |  |  |
| --- | --- | --- |
| Case | Description | Meet LOLE Target? |
| Load Sensitivity Analysis |  |
| Case 1 | 1-in-10 economic drivers | Yes |
| Case 2 | Industrial self-generating demand of 40MW | Yes |
| Case 3 | Time of seasonal peaks | Yes |
| Resource Sensitivity Analysis |  |
| Case 4 | WAX FORs | Yes |
| Case 5 | Double FORs  | Yes |
| Case 6 | No WAX surplus taken into account for PRM requirements | Yes |
| Case 7 | No additional capacity for gaps | No (expected gaps must be met) |
| Market Sensitivity Analysis |  |
| Case 8 | Market sizes at the base case FOR | Yes |
| Case 9 | No market access | No (alternative capacity is needed)  |
| Case 10 | Market FORs at 150MW | Yes |

### Load Sensitivity Analysis

Cases in this sensitivity group addressed peak demands higher than those in the base case. This includes the High load case due to economic drivers from the 2012 Resource Plan, industrial self-generating load included, and moving the time of the seasonal peaks.

Case 1. High Forecast due to Economic Drivers

This case addresses impacts on LOLE if the peak demand equals the High load scenario (90% percentile, or 1-in-10) in the 2012 Resource Plan due to economic strength. This High load forecast is shown in Table C-3, Appendix C of this report. Since there are typically indicators for stronger economic growth and it takes several years for load to build from load growth, additional peak demand can be anticipated with sufficient lead time for the Company to increase capacity in a timely manner to meet capacity gaps. As a result, LOLEs in this scenario still meet the target of 0.1 day/year as shown in Table 3-3 even though more load is subject to an assumed generation FOR of 5%.

Table 3-3: LOLE in Case 1 – High Load Forecast Due to Economic Drivers

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual | Winter PRM |
| 2014 | 0.000 | 0.000 | 0.005 | 0.000 | 0.000 | 0.001 | 0.001 | 0.004 | 0.000 | 0.000 | 0.001 | 0.000 | 0.012 | 25% |
| 2015 | 0.001 | 0.002 | 0.017 | 0.001 | 0.000 | 0.001 | 0.003 | 0.000 | 0.000 | 0.000 | 0.000 | 0.004 | 0.029 | 26% |
| 2016 | 0.005 | 0.000 | 0.002 | 0.001 | 0.000 | 0.002 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.009 | 0.019 | 26% |
| 2017 | 0.000 | 0.000 | 0.000 | 0.000 | 0.001 | 0.001 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.004 | 0.007 | 26% |
| 2018 | 0.004 | 0.000 | 0.000 | 0.002 | 0.001 | 0.005 | 0.003 | 0.000 | 0.000 | 0.000 | 0.000 | 0.001 | 0.016 | 25% |
| 2019 | 0.003 | 0.001 | 0.000 | 0.000 | 0.002 | 0.003 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.011 | 0.021 | 25% |
| 2020 | 0.002 | 0.000 | 0.002 | 0.003 | 0.002 | 0.012 | 0.004 | 0.000 | 0.000 | 0.000 | 0.000 | 0.012 | 0.037 | 24% |
| 2025 | 0.000 | 0.001 | 0.001 | 0.001 | 0.004 | 0.016 | 0.008 | 0.000 | 0.000 | 0.001 | 0.000 | 0.020 | 0.052 | 23% |
| 2030 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.019 | 0.004 | 0.000 | 0.000 | 0.000 | 0.001 | 0.020 | 0.044 | 22% |
| 2033 | 0.011 | 0.002 | 0.002 | 0.000 | 0.004 | 0.015 | 0.008 | 0.000 | 0.000 | 0.000 | 0.002 | 0.034 | 0.078 | 21% |

Case 2. Self-Generating Industrial Customer Load of 40MW

The base case excludes self-generating load from industrial customers. This load sensitivity case handles the situation in which self-generating load, assumed at 40 MW, is added to the current peak forecast and is to be met by resources in the base case. On a planning basis, the expected capacity gaps will increase in some months. This results in additional capacity to acquire in advance to meet the increased capacity gaps. Similar to Case 1, more load is subject to an assumed generation FOR of 5%. The system can still handle this additional peak capacity load with LOLEs meeting the target.

Table 3-4: LOLE in Case 2 – Self-generating Industrial Customer Load

| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual | Winter PRM |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| 2014 | 0.001 | 0.000 | 0.003 | 0.002 | 0.002 | 0.001 | 0.006 | 0.005 | 0.001 | 0.002 | 0.000 | 0.002 | 0.025 | 23% |
| 2015 | 0.003 | 0.001 | 0.018 | 0.002 | 0.001 | 0.003 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.002 | 0.030 | 31% |
| 2016 | 0.002 | 0.000 | 0.001 | 0.000 | 0.000 | 0.003 | 0.002 | 0.000 | 0.000 | 0.000 | 0.000 | 0.004 | 0.012 | 29% |
| 2017 | 0.000 | 0.000 | 0.004 | 0.000 | 0.003 | 0.004 | 0.003 | 0.000 | 0.000 | 0.000 | 0.000 | 0.006 | 0.020 | 28% |
| 2018 | 0.002 | 0.002 | 0.002 | 0.002 | 0.003 | 0.015 | 0.005 | 0.000 | 0.000 | 0.000 | 0.000 | 0.020 | 0.051 | 24% |
| 2019 | 0.002 | 0.004 | 0.000 | 0.002 | 0.003 | 0.022 | 0.004 | 0.000 | 0.000 | 0.000 | 0.000 | 0.021 | 0.058 | 24% |
| 2020 | 0.004 | 0.002 | 0.001 | 0.000 | 0.006 | 0.015 | 0.004 | 0.000 | 0.000 | 0.000 | 0.001 | 0.024 | 0.057 | 24% |
| 2025 | 0.003 | 0.001 | 0.002 | 0.000 | 0.006 | 0.019 | 0.018 | 0.000 | 0.000 | 0.003 | 0.000 | 0.020 | 0.072 | 23% |
| 2030 | 0.001 | 0.003 | 0.001 | 0.000 | 0.001 | 0.016 | 0.006 | 0.000 | 0.000 | 0.000 | 0.000 | 0.039 | 0.067 | 22% |
| 2033 | 0.003 | 0.000 | 0.000 | 0.000 | 0.004 | 0.021 | 0.008 | 0.000 | 0.000 | 0.000 | 0.000 | 0.021 | 0.057 | 22% |

Case 3. Time of Seasonal Peaks

The base case assumes the winter peak to occur in December and the summer peak in July. However, historical data in the past 23 years shows that the winter peak can also occur in November, December and January for 13%, 43.5%, and 43.5% of the time respectively. Therefore, this sensitivity case randomly assigns the winter peak to happen in November, December, and January at the probability equal to each month’s historical frequency of occurrences above. The same assumption was made for the summer peak in July and August with their probability of occurrence is 65% and 35% respectively. The resultant LOLEs (shown below) still meet the LOLE target of 0.1 day/year for most of the years in the planning horizon. In the 2022-2024 period toward the end of the RCA contract, the LOLEs are a bit higher because additional resources were acquired to meet expected gaps in December but in this scenario there is a chance the gaps occur in January. However, as this is such a short time period and the overall 1 day in 10 year metric is still met, the Company believes this is acceptable and no further resource is required.

Table 3‑5: LOLE in Case 3 – Time of Seasonal Peaks

| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual | Winter PRM |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| 2014 | 0.005 | 0.000 | 0.004 | 0.000 | 0.000 | 0.001 | 0.001 | 0.000 | 0.000 | 0.000 | 0.032 | 0.000 | 0.043 | 23% |
| 2015 | 0.025 | 0.002 | 0.016 | 0.000 | 0.000 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.003 | 0.047 | 26% |
| 2016 | 0.027 | 0.000 | 0.000 | 0.000 | 0.000 | 0.002 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.002 | 0.031 | 25% |
| 2017 | 0.021 | 0.000 | 0.001 | 0.000 | 0.000 | 0.002 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.002 | 0.027 | 25% |
| 2018 | 0.038 | 0.000 | 0.000 | 0.002 | 0.002 | 0.005 | 0.001 | 0.000 | 0.000 | 0.000 | 0.010 | 0.001 | 0.059 | 24% |
| 2019 | 0.057 | 0.000 | 0.000 | 0.000 | 0.000 | 0.005 | 0.002 | 0.000 | 0.000 | 0.000 | 0.008 | 0.003 | 0.075 | 24% |
| 2020 | 0.030 | 0.001 | 0.000 | 0.004 | 0.003 | 0.007 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.001 | 0.047 | 24% |
| 2021 | 0.047 | 0.000 | 0.000 | 0.000 | 0.001 | 0.009 | 0.001 | 0.000 | 0.000 | 0.000 | 0.010 | 0.005 | 0.073 | 23% |
| 2022 | 0.089 | 0.000 | 0.000 | 0.000 | 0.003 | 0.004 | 0.002 | 0.000 | 0.000 | 0.000 | 0.007 | 0.006 | 0.111 | 22% |
| 2023 | 0.133 | 0.000 | 0.001 | 0.002 | 0.002 | 0.004 | 0.000 | 0.000 | 0.000 | 0.000 | 0.008 | 0.010 | 0.160 | 22% |
| 2024 | 0.070 | 0.000 | 0.000 | 0.001 | 0.001 | 0.006 | 0.004 | 0.000 | 0.000 | 0.002 | 0.023 | 0.011 | 0.118 | 23% |
| 2025 | 0.052 | 0.001 | 0.003 | 0.000 | 0.004 | 0.003 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.063 | 26% |
| 2030 | 0.004 | 0.001 | 0.000 | 0.000 | 0.000 | 0.005 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.012 | 0.022 | 25% |
| 2033 | 0.030 | 0.000 | 0.000 | 0.000 | 0.000 | 0.005 | 0.001 | 0.000 | 0.000 | 0.000 | 0.004 | 0.008 | 0.048 | 25% |

### Resource Sensitivity Analysis

Cases in this sensitivity group investigated the impact of increasing the Forced Outage Rate (FOR) for WAX, BRD, BRX and FBC’s own generation resources. A case in which all WAX surplus is not available for PRM was also considered. Finally, the impact of requiring expected gaps to be met with no additional planned resources was addressed in both the presence and absence of the market.

Case 4. WAX’s Availability

Case 0 assumes WAX’s expected FOR is 0.5% in the first five years of the plant’s operation and 0.25% thereafter. This sensitivity case examines WAX’s expected FOR increased to 1% and 0.5% respectively. As expected, LOLE increased when the WAX FOR increased, but the impact was marginal and the LOLEs were within target.

Table 3-6: LOLE in Case 4 - WAX FOR Variations

|  |  |  |
| --- | --- | --- |
| Year | FOR 0.5% | FOR 1% |
|  | LOLE | Winter PRM | LOLE | Winter PRM |
| 2014 | 0.007 | 27% | 0.008 | 27% |
| 2015 | 0.020 | 27% | 0.052 | 27% |
| 2016 | 0.004 | 26% | 0.011 | 26% |
| 2017 | 0.002 | 26% | 0.016 | 26% |
| 2018 | 0.015 | 25% | 0.010 | 25% |
| 2019 | 0.005 | 25% | 0.024 | 25% |
| 2020 | 0.021 | 25% | 0.023 | 25% |
| 2025 | 0.008 | 24% | 0.015 | 24% |
| 2030 | 0.015 | 23% | 0.026 | 23% |
| 2033 | 0.026 | 23% | 0.036 | 23% |

Case 5. FOR of BRD, BRX and FBC’s Own Resources

Similar to the previous case, in this case FOR of FBC’s own generators, as well as contracted capacity from BRD and BRX, were doubled from their assumed value in Case 0. This case confirms that even at doubled FOR, these generators’ reliability is still high and the resultant LOLEs still meet the target.

 Table 3-7: Case 5 – FOR of Own Resources

| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual | Winter PRM |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| 2014 | 0.000 | 0.000 | 0.004 | 0.000 | 0.000 | 0.000 | 0.000 | 0.003 | 0.000 | 0.001 | 0.000 | 0.001 | 0.009 | 27% |
| 2015 | 0.004 | 0.001 | 0.015 | 0.000 | 0.000 | 0.002 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.003 | 0.026 | 27% |
| 2016 | 0.001 | 0.000 | 0.002 | 0.000 | 0.000 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.006 | 0.010 | 26% |
| 2017 | 0.001 | 0.000 | 0.001 | 0.000 | 0.000 | 0.005 | 0.000 | 0.000 | 0.000 | 0.001 | 0.000 | 0.006 | 0.014 | 26% |
| 2018 | 0.001 | 0.001 | 0.000 | 0.003 | 0.007 | 0.005 | 0.004 | 0.000 | 0.000 | 0.000 | 0.000 | 0.009 | 0.030 | 25% |
| 2019 | 0.003 | 0.000 | 0.000 | 0.001 | 0.004 | 0.005 | 0.003 | 0.000 | 0.000 | 0.000 | 0.000 | 0.011 | 0.027 | 25% |
| 2020 | 0.003 | 0.002 | 0.002 | 0.001 | 0.003 | 0.004 | 0.002 | 0.000 | 0.000 | 0.000 | 0.000 | 0.005 | 0.022 | 25% |
| 2025 | 0.003 | 0.004 | 0.001 | 0.000 | 0.004 | 0.006 | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.006 | 0.025 | 24% |
| 2030 | 0.003 | 0.002 | 0.002 | 0.000 | 0.000 | 0.005 | 0.001 | 0.000 | 0.000 | 0.000 | 0.001 | 0.018 | 0.032 | 23% |
| 2033 | 0.003 | 0.005 | 0.001 | 0.000 | 0.000 | 0.011 | 0.001 | 0.000 | 0.000 | 0.000 | 0.001 | 0.027 | 0.049 | 23% |

Case 6. Firming up WAX surplus

This case treated all WAX surplus as not available to assist meeting PRM requirements. The system was still able to meet the LOLE target.

Table 3-8: LOLE in Case 6 – Firming up WAX Surplus

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual | Winter PRM |
| 2014 | 0.000 | 0.000 | 0.003 | 0.000 | 0.000 | 0.001 | 0.003 | 0.008 | 0.000 | 0.000 | 0.000 | 0.002 | 0.017 | 27% |
| 2015 | 0.003 | 0.001 | 0.017 | 0.000 | 0.000 | 0.004 | 0.000 | 0.001 | 0.000 | 0.002 | 0.002 | 0.006 | 0.036 | 26% |
| 2016 | 0.004 | 0.005 | 0.003 | 0.000 | 0.000 | 0.002 | 0.001 | 0.002 | 0.000 | 0.001 | 0.002 | 0.000 | 0.020 | 26% |
| 2017 | 0.002 | 0.005 | 0.001 | 0.000 | 0.000 | 0.000 | 0.001 | 0.003 | 0.000 | 0.001 | 0.000 | 0.003 | 0.016 | 26% |
| 2018 | 0.002 | 0.001 | 0.003 | 0.002 | 0.003 | 0.004 | 0.000 | 0.004 | 0.000 | 0.000 | 0.000 | 0.006 | 0.025 | 25% |
| 2019 | 0.001 | 0.003 | 0.002 | 0.000 | 0.005 | 0.001 | 0.002 | 0.006 | 0.000 | 0.001 | 0.001 | 0.006 | 0.028 | 25% |
| 2020 | 0.002 | 0.003 | 0.003 | 0.001 | 0.002 | 0.005 | 0.001 | 0.001 | 0.000 | 0.000 | 0.002 | 0.006 | 0.026 | 25% |
| 2025 | 0.003 | 0.003 | 0.002 | 0.000 | 0.002 | 0.007 | 0.000 | 0.004 | 0.000 | 0.001 | 0.000 | 0.003 | 0.025 | 24% |
| 2030 | 0.004 | 0.002 | 0.001 | 0.001 | 0.002 | 0.006 | 0.000 | 0.002 | 0.004 | 0.001 | 0.002 | 0.024 | 0.049 | 23% |
| 2033 | 0.002 | 0.003 | 0.005 | 0.000 | 0.002 | 0.005 | 0.001 | 0.003 | 0.006 | 0.000 | 0.001 | 0.026 | 0.054 | 23% |

Case 7. No Additional Capacity for Expected Capacity Gaps

This case was included to demonstrate the importance of planning to meet expected loads. Strictly speaking, a utility should prepare to meet the expected gaps first as a part of its capacity planning process before preparing to meet any other resource adequacy metrics. If the Company does not acquire any additional capacity to meet the expected gaps, then depending on whether the market access is available or not, there are two subcases:

1. Without market access: This is the worst case scenario where the Company does not prepare to meet the expected gaps at all, even though it has no access to the market. As a result, not a single year can meet the LOLE target because the resources to meet the expected load are simply not in place.
2. With market access: This is a scenario in which the Company depends totally on the market to meet both the expected gaps and the LOLE target. Note that when market access is used for PRM purposes only, there will be no capacity shortages if market access is not available but the base resources are functioning well. However, if the market is also used as a base resource to meet expected gaps, then if the market is not available the backup market resource is also not available and there will be shortages. Reliance on the market as both a base and a backup resource is not a prudent approach in the long run as shown below with LOLE values failing the target after 2020, mainly due to high LOLE values in June and December.

In both cases, it is clear that the Company needs to explicitly address long term expected capacity gaps to avoid resource inadequacy. FBC will be addressing long term resource requirements and assessing various resource options portfolios within its next 2016 LTERP.

Table 3-9: Case 7 - No Additional Capacity for Expected Capacity Gaps

|  |  |  |
| --- | --- | --- |
| Year |  Without Market | With Market |
|  | LOLE | Winter PRM | LOLE | Winter PRM |
| 2014 | 15.531 | 6% | 0.214 | 27% |
| 2015 | 13.649 | 6% | 0.263 | 27% |
| 2016 | 0.429 | 6% | 0.007 | 26% |
| 2017 | 0.459 | 6% | 0.014 | 26% |
| 2018 | 4.839 | 6% | 0.088 | 25% |
| 2019 | 5.779 | 6% | 0.087 | 25% |
| 2020 | 5.868 | 6% | 0.089 | 25% |
| 2025 | 12.000 | 6% | 0.189 | 24% |
| 2030 | 21.342 | 3% | 0.255 | 21% |
| 2033 | 30.432 | 0% | 0.423 | 18% |

### Market Access Sensitivity Analysis

The base case assumes market access is limited to 150MW and will not be available for 0.74% of the time. This is similar to a FOR used to model generation resources and it can be considered a FOR equivalent. Cases in this sensitivity group address the limits to market supply and its availability.

Case 8. Market Access at the Base Case FOR

To evaluate the impact of market size access limits on LOLE, the MC simulation calculated LOLEs for different market limits at the base market FOR equivalent of 0.74%. Results below indicate that once WAX is operational, a market limit of around 75 MW[[25]](#footnote-26) is sufficient to reach the LOLE target of 0.1 day/year.

Table 3-10: Case 8- LOLE at Different Market Sizes

| Year | 0 MW | 50 MW | 75 MW | 100 MW | 150 MW |
| --- | --- | --- | --- | --- | --- |
| 2014 | 0.669 | 0.011 | 0.016 | 0.013 | 0.016 |
| 2015 | 1.387 | 0.251 | 0.159 | 0.084 | 0.024 |
| 2016 | 0.463 | 0.039 | 0.005 | 0.009 | 0.016 |
| 2017 | 0.441 | 0.052 | 0.011 | 0.007 | 0.009 |
| 2018 | 0.973 | 0.084 | 0.080 | 0.055 | 0.016 |
| 2019 | 0.995 | 0.092 | 0.073 | 0.057 | 0.020 |
| 2020 | 1.027 | 0.102 | 0.081 | 0.067 | 0.015 |
| 2025 | 1.443 | 0.185 | 0.100 | 0.052 | 0.021 |
| 2030 | 1.527 | 0.149 | 0.104 | 0.078 | 0.024 |
| 2033 | 2.062 | 0.179 | 0.105 | 0.083 | 0.030 |

Figure 3-2: LOLE at Different Market Sizes



PRM (in percentage) with a market size of 75 MW as the minimum market size are shown in Table E-4 in Appendix E.

Case 9. No Market Access

As mentioned in Section 2.1, utilities differ considerably in their practice to use market imports for resource adequacy requirements.

This sensitivity case tries to answer the question “What is the minimum additional capacity needing to be acquired to meet the resource adequacy target of LOLE 0.1 day/year if there is no market access?”

The preceding case showed that without market access (that is market access of 0 MW), LOLE would increase substantially and fail to meet the target of 0.1 day/year (see column 2 in Table 3-11). To return annual LOLEs to the target level, additional capacity resources at an assumed FOR of 5% (for example, an SCGT) are acquired on a monthly basis until the target levels are met. The required capacity values and the resultant LOLEs is displayed in Table 3.12 below. In this scenario, a minimum capacity increment of 50 MW was used to reflect physically adding capacity to the system. The size of the additional capacity resource can be reduced if it is more reliable with a lower FOR, for example at a FOR equivalent of 0.74% only 75MW of generation would be needed as it is then similar to the Case 8 example of 75 MW of market access being sufficient.

Table 3-11: Case 9 - Additional Planned Capacity (MW) to Reach LOLE Target with no Market

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Year | LOLE Before | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | LOLE After | Winter PRM |
| 2014 | 0.669 | 150 | 150 | 150 | 50 | 50 | 100 | 50 | 50 | 0 | 50 | 0 | 100 | 0.050 | 20% |
| 2015 | 1.387 | 150 | 150 | 150 | 50 | 50 | 100 | 50 | 0 | 0 | 0 | 0 | 100 | 0.091 | 20% |
| 2016 | 0.463 | 100 | 100 | 50 | 50 | 50 | 100 | 50 | 0 | 0 | 0 | 0 | 100 | 0.025 | 20% |
| 2017 | 0.441 | 100 | 100 | 50 | 50 | 50 | 100 | 50 | 0 | 0 | 0 | 0 | 100 | 0.028 | 19% |
| 2018 | 0.973 | 100 | 100 | 50 | 50 | 50 | 100 | 50 | 0 | 0 | 0 | 0 | 100 | 0.071 | 19% |
| 2019 | 0.995 | 100 | 100 | 50 | 50 | 50 | 100 | 50 | 0 | 0 | 0 | 0 | 100 | 0.096 | 19% |
| 2020 | 1.027 | 100 | 100 | 50 | 50 | 50 | 100 | 50 | 0 | 0 | 0 | 0 | 100 | 0.092 | 19% |
| 2025 | 1.443 | 100 | 100 | 50 | 50 | 50 | 100 | 100 | 0 | 0 | 0 | 0 | 150 | 0.086 | 24% |
| 2030 | 1.527 | 100 | 100 | 50 | 50 | 50 | 100 | 100 | 0 | 0 | 0 | 0 | 150 | 0.083 | 23% |
| 2033 | 2.062 | 100 | 100 | 50 | 50 | 50 | 100 | 100 | 0 | 0 | 0 | 0 | 150 | 0.056 | 23% |

The PRM (in %) associated with the additional capacity as given above is given in Appendix E, Table E-5. On average over the 20-year planning period, it is around 19% for the winter peaking month (December) and 18% for the summer peaking month (June) with OR included.

Case 10. Market Availability

There are risks that capacity on the market is not available when called for. For example, during a heavy cold snap utilities may be competing for market purchases and there can be both transmission and generation constraints. This case evaluates impacts of different levels of the market availability at the fixed market size of 150MW.

Table 3-12 and Figure 3-3 show that as long as the FOR equivalent for market access is less than 5%, the system is meeting the LOLE target for all years. At the FOR equivalent of 7% the system fails the LOLE target in the short period of 2022-2024 and by 2030. The further the market FOR equivalent increases, the earlier the system experiences resource inadequacy.

Table 3-12: LOLE at Different Market FOR Equivalent

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | 0.74 % | 3 % | 5 % | 7 % | 10 % |
| 2014 | 0.016 | 0.042 | 0.069 | 0.152 | 0.225 |
| 2015 | 0.024 | 0.053 | 0.083 | 0.093 | 0.151 |
| 2016 | 0.016 | 0.013 | 0.038 | 0.036 | 0.046 |
| 2017 | 0.009 | 0.021 | 0.023 | 0.032 | 0.062 |
| 2018 | 0.016 | 0.039 | 0.047 | 0.080 | 0.106 |
| 2019 | 0.020 | 0.032 | 0.078 | 0.087 | 0.105 |
| 2020 | 0.015 | 0.041 | 0.055 | 0.088 | 0.113 |
| 2025 | 0.021 | 0.059 | 0.087 | 0.093 | 0.152 |
| 2030 | 0.024 | 0.053 | 0.094 | 0.141 | 0.144 |
| 2033 | 0.030 | 0.074 | 0.110 | 0.167 | 0.216 |

Figure 3-3: LOLEs at Different Market FORs Equivalent



#

# Conclusion

FBC must ensure reliable power supply to its customers in a cost effective manner. To achieve this PRM resource adequacy requirements need to be met. FBC has determined that a Monte Carlo probabilistic approach to determine PRM requirements is the best approach. The most common measure to study PRM requirements is the Loss-Of-Load-Expectation (LOLE) of 1 day per 10 years or 0.1 day per year, which is an industry standard target for resource adequacy and has been adopted by FBC as well.

FBC believes additional resources must be acquired to meet any expected capacity gaps between existing resources and expected loads and this will be addressed as part of FBC’s ongoing Resource Planning activities and within its next 2016 LTERP. However, once this is accomplished, available resources combined with market access of 150 MW meets PRM requirements and no further resources beyond those required to meet expected loads are required at this time.

FBC evaluated its resource adequacy with respect to the LOLE target of 1 day in 10 years over a number of sensitivity scenarios where certain aspects of the operating environment deviated from the expected conditions. These scenarios are categorized in three groups related to load, resources, and market assumptions. The outcome of the studies are summarized below.

|  |  |  |
| --- | --- | --- |
| Case | Description | Meet LOLE Target? |
| Base |  |
| Case 0 | Expected operating environment | Yes |
| Load Sensitivity Analysis |  |
| Case 1 | 1-in-10 economic drivers | Yes |
| Case 2 | Industrial self-generating demand of 40MW | Yes |
| Case 3 | Time of seasonal peaks | Yes |
| Resource Sensitivity Analysis |  |
| Case 4 | WAX FORs | Yes |
| Case 5 | Double FORs  | Yes |
| Case 6 | Firming up additional WAX surplus sales | Yes |
| Case 7 | No additional capacity for gaps | No (expected gaps must be met) |
| Market Sensitivity Analysis |  |
| Case 8 | Market sizes at the base case FOR | Yes |
| Case 9 | No market access | No (alternative capacity is needed) |
| Case 10 | Market FORs at 150MW | Yes |

Further investigation showed that at the assumed transmission forced outage rate (FOR) of 0.74%, 75 MW of market access was enough to ensure the LOLE target. On the other hand, the transmission FOR could be as high as 5% if the market access size was kept at the available 150 MW. If market imports were replaced by another alternative resource at FOR 5%, this resource would need to be 100 MW until 2020 and 150 MW after that. The studies also demonstrated the importance of acquiring dedicated capacity to meet expected gaps since dependence on market imports to meet these gaps would fail to meet the LOLE target.

The resultant PRM percentage value was calculated on a monthly basis for each year, and the table below summarizes for each case the PRM values (including Operating Reserves) for selected years in December, when the winter peak was assumed to occur. Note that these values include the market import, if applicable.

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2025 | 2030 | 2033 |
| Case 0 | 27% | 26% | 26% | 26% | 25% | 25% | 25% | 24% | 23% | 23% |
| Case 1 | 25% | 26% | 26% | 26% | 25% | 25% | 24% | 23% | 22% | 21% |
| Case 2 | 23% | 26% | 25% | 25% | 24% | 24% | 24% | 23% | 22% | 22% |
| Case 3 | 23% | 33% | 33% | 33% | 33% | 25% | 25% | 31% | 30% | 23% |
| Case 4 | 27% | 26% | 26% | 26% | 25% | 25% | 25% | 24% | 23% | 23% |
| Case 5-1% | 27% | 26% | 26% | 26% | 25% | 25% | 25% | 24% | 23% | 23% |
| Case 6 | 27% | 26% | 26% | 26% | 25% | 25% | 25% | 24% | 23% | 23% |
| Case 7 with Market | 16% | 27% | 26% | 26% | 25% | 25% | 25% | 24% | 21% | 18% |
| Case 8 Market 75 MW | 20% | 16% | 16% | 16% | 16% | 15% | 15% | 15% | 14% | 14% |
| Case 9 Alternative Capacity 100-150 MW | 26% | 20% | 20% | 19% | 19% | 19% | 19% | 24% | 23% | 23% |
| Case 10 Market 95% | 27% | 26% | 26% | 26% | 25% | 25% | 25% | 24% | 23% | 23% |

The next PRM report will be released as an appendix to the 2016 Long Term Electric Resource Plan expected to be filed with the BCUC by June 30, 2016. The LTERP will incorporate the PRM approach recommended here within its resource options portfolio analysis as one of the main criteria in determining preferred resource portfolios to meet future customer load requirements in a reliable and cost effective manner.

# Appendices

Appendix A – An Example of Capacity Outage Probability Table

Appendix B – Capacity Resources

Appendix C – Peak Forecast

Appendix D – Capacity Gaps

Appendix E – Monte-Carlo Simulation Results

Appendix F – Comparison Between FBC and BCH Approaches for PRM

Appendix G – Glossaries & Acronyms

## Appendix A – An Example of Capacity Outage Probability Table



## Appendix B – Capacity Resources

Table B-1: Capacity Resources



Table B-2: Forced Outage Rates





Table B-4: Maintenance Schedule (MW)



Table B-4: WAX Capacity after RCA, Maintenances, and Operating Reserves (MW)



Table B-5: Planned Capacity to Meet Gaps (MW)



## Appendix C – Peak Forecast

**Table C-1: Expected Peak Demand Forecast (MW)**



**Table C-2: Monthly Load Curves (Percent of Peak Load)**



**Table C-3: High Peak Forecast due to Economic Drivers (MW)**



## Appendix D – Capacity Gaps

**Table D-1: Capacity Gaps (MW)**



## Appendix E – Monte-Carlo Simulation Results

**Table E-1: LOLE for the Base Case**



**Table E-2: PRM for the Base Case**

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| Year | LOLE (day) | Summer PRM excl. OR | Winter PRM excl. OR | Summer PRM incl. OR | Winter PRM incl. OR |
| 2014 | 0.016 | 26% | 23% | 31% | 27% |
| 2015 | 0.024 | 28% | 20% | 34% | 26% |
| 2016 | 0.016 | 27% | 20% | 33% | 26% |
| 2017 | 0.009 | 27% | 20% | 32% | 26% |
| 2018 | 0.016 | 25% | 20% | 31% | 25% |
| 2019 | 0.020 | 25% | 20% | 31% | 25% |
| 2020 | 0.015 | 25% | 19% | 30% | 25% |
| 2025 | 0.021 | 24% | 19% | 29% | 24% |
| 2030 | 0.024 | 27% | 18% | 32% | 23% |
| 2033 | 0.030 | 24% | 17% | 29% | 23% |

*Remarks:*

PRM values (%) were calculated for each month in each year in the planning horizon, taking into account both the inclusion and exclusion of OR. Winter and summer PRM values (%) will be presented as PRM values for December and July respectively. Being a winter peaking utility, the Company has a lower PRM in the winter. The high values of PRM were obtained largely due to the fact that 150MW of market import was used in the PRM calculation.

**Table E-3: Case 0 - Winter PRM Calculation Detail**

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Year | Winter Peak (1) | Total Resource Capacity without OR (2) | WAX Unit Contingent Surplus(3) | Acquired Capacity for Gaps (4) | Operating Reserve  (5) | Market Access (6) | PRM =((2)-(3)+(4)+(5)+(6)-(1))/(1) \*100% |
| 2014 |  733  |  749  | 0 |  -  |  29  |  150  | 27% |
| 2015 |  739  |  813  | 74 |  -  |  46  |  150  | 26% |
| 2016 |  743  |  813  | 69 |  -  |  46  |  150  | 26% |
| 2017 |  750  |  813  | 63 |  -  |  46  |  150  | 26% |
| 2018 |  756  |  774  | 18 |  -  |  43  |  150  | 25% |
| 2019 |  763  |  774  | 11 |  -  |  43  |  150  | 25% |
| 2020 |  770  |  774  | 4 |  -  |  43  |  150  | 25% |
| 2025 |  806  |  821  | 15 |  -  |  46  |  150  | 24% |
| 2030 |  843  |  821  | 0 |  23  |  46  |  150  | 23% |
| 2033 |  864  |  821  | 0 |  44  |  46  |  150  | 23% |

**Table E-4: Case 8 - PRM with Minimum Market Access**

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| Year | LOLE | Summer PRM excl. OR | Winter PRM excl. OR | Summer PRM incl. OR | Winter PRM incl. OR |
| 2014 | 0.016 | 13% | 12% | 18% | 16% |
| 2015 | 0.159 | 15% | 10% | 21% | 16% |
| 2016 | 0.005 | 14% | 10% | 20% | 16% |
| 2017 | 0.011 | 14% | 10% | 20% | 16% |
| 2018 | 0.080 | 13% | 10% | 18% | 16% |
| 2019 | 0.073 | 13% | 10% | 18% | 15% |
| 2020 | 0.081 | 13% | 10% | 18% | 15% |
| 2025 | 0.100 | 12% | 9% | 17% | 15% |
| 2030 | 0.104 | 15% | 9% | 21% | 14% |
| 2033 | 0.105 | 13% | 9% | 18% | 14% |

**Table E-5: Case 9 - PRM without Market and with Additional Capacity**

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| Year | LOLE After | Summer PRM excl. OR | Winter PRM excl. OR | Summer PRM incl. OR | Winter PRM incl. OR |
| 2014 | 0.050 | 9% | 16% | 13% | 20% |
| 2015 | 0.091 | 11% | 14% | 17% | 20% |
| 2016 | 0.025 | 10% | 13% | 16% | 20% |
| 2017 | 0.028 | 9% | 13% | 15% | 19% |
| 2018 | 0.071 | 8% | 13% | 14% | 19% |
| 2019 | 0.096 | 8% | 13% | 14% | 19% |
| 2020 | 0.092 | 8% | 13% | 14% | 19% |
| 2025 | 0.086 | 16% | 19% | 21% | 24% |
| 2030 | 0.083 | 19% | 18% | 24% | 23% |
| 2033 | 0.056 | 16% | 17% | 22% | 23% |

## Appendix F – Comparison Between FBC and BCH Approaches for PRM

Since BCH is the closest utility to FBC in terms of geographical proximity, energy policy, and direct partnerships in a number of agreements, it is useful to compare the two utilities’ PRM approaches. Appendix F presents a comparison.

|  |  |  |
| --- | --- | --- |
| Feature | FBC | BCH |
| Definition | Planning Reserve MarginPRM = (Dependable Capacity – Expected Peak)/Expected Peak | Capacity Reserve MarginCRM = (Dependable Capacity – Expected Peak)/ Dependable Capacity |
| Reference | 2014 PRM Study | 2013 IRP |
| Method | Probabilistic, StochasticMonte-Carlo simulation | Probabilistic, DeterministicCapacity Outage Probability Table |
| Reliability Metric | LOLE | LOLE |
| Reliability Target | 0.1 days/year | 0.1 days/year |
| Study Years | All years in the planning horizon (2014-2033) | Single year 2008/2009, then generalized |
| PRM Value | Vary by months and years | Vary at 14% of existing and committed resources, annually |
| Inclusion of OR | Can be stated with and without OR | Included |
| Market Reliance  | Yes (up to 150MW, transmission FOR 0.74%) | Yes (up to 400 MW) up to 2016 |
| Daily Peaks or Hourly Demands | Daily peaks | Daily peaks |
| Resource Profile | Daily capacity set at monthly entitlement values | Daily capacity set at monthly expected values |
| Role in Capacity Planning | Separated from capacity planning for expected capacity gaps | Included in capacity planning for expected capacity gaps. 14% of capacity is subtracted in order to calculate the load/resource balance. |

## Appendix G – glossaries & acronyms

**GLOSSARY**

**Adequacy:** The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

**Balancing Authority:** The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

**Balancing Authority Area:** The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

**Canal Plant Agreement (CPA):** The CPA aggregates the power production from multiple hydro generation facilities located upon the Kootenay and Pend d’Oreille Rivers, and apportions that production for the use of the owners of those hydro facilities in the form of entitlements of capacity and energy. This usage effectively eliminates the hydrological risk normally associated with individual hydroelectric generation facilities. In return for providing these CPA Entitlements, BC Hydro receives the right to dispatch plant generation to maximize the benefits to the overall Provincial system.

**Canal Plant Agreement Entitlement:** The average water year generation of the generating facilities included in the Canal Plant Agreement. Provided each unit is in-service, the related entitlements are provided by BC Hydro regardless of the actual generation dispatched by BC Hydro from the facilities.

**Capacity:**

(1) The instantaneous output of a power plant at any given time, normally measured in kilowatts (kW) or megawatts (MW).

(2) The instantaneous system electricity demand at any given time, normally measured in kilowatts (kW) or megawatts (MW).

(3) The amount of electrical power that can be safely transmitted by a transmission facility at any instant.

Related terms:

* **Maximum Capacity** - The highest generating plant output or transmission loading that can actually be achieved in situ.
* **Dependable Capacity** - The amount of megawatts of generation available assuming all units are in service for three peak hours per day during the coldest two-week period each year. In BC, system peak electrical demand typically occurs in December or January sometime between the hours of 5 pm and 9 pm. Factors external to the plant affect its dependable capacity. For example, stream flow conditions can restrict the dependable capacity of hydro plants and fuel supply constraints can impact thermal plant dependable capacity. Planned and forced outage rates are not included.
* **Installed Capacity** (Also referred to as Nameplate Rating) - The maximum rating of a generator or transmission station equipment as identified by the manufacturer under specified conditions.

**Capacity Purchase:** The purchase of capacity without energy.

**Contingency:** The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

**Contingency Reserve:** The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

**Contingency Reserve Obligation (CRO): T**he minimum amount of Contingency Reserve that must be carried by a particular Participating Balancing Authority or by the Reserve Sharing Group as a whole (as the context requires) to respond to Qualifying Events. A Participating Balancing Authority’s Contingency Reserve Obligation must be available for use as Internal Reserve if it experiences a Qualifying Event or to deliver as Assistance Reserve in response to a Reserve Sharing Request by another Participating Balancing Authority that has experienced a Qualifying Event.

**Demand:** 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.

**Demand Side Management (DSM):** Actions that modify customer demand for electricity, helping to defer the need for new utility energy and capacity supply additions.

**Energy:** The electricity produced or used over a period of time, usually measured in kWh, MWh or GWh.

**Firm Market Purchase:** The highest degree of reliable market power that can be purchased. It can only be curtailed due to the most severe contingencies such as the loss of the transmission path. See also Long-Term Firm Resource.

**Forced Outage:** 1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.

**Heavy Load Hours (HLH):** The time of day in which peak demand occurs. Heavy Load Hours are from 0600h through 2200h, Monday to Saturday, excluding holidays.

**Independent Power Producer (IPP):** A privately owned electricity generating facility that produces electricity for sale to utilities or other customers.

**Light Load Hours (LLH):** All hours that are not Heavy Load Hours. See Heavy Load Hours.

**Load:** The amount of electricity required by a customer or group of customers.

**Load Forecast:** The expected load requirements that an electricity system will have to meet in the future.

**Long-Term Firm Resource:** A generation facility, Market Energy Block purchase or other power contract intended to meet load more than five years in advance. See also Firm Market Purchase.

**Market:** The network of electricity trading options that allows the purchase of wholesale electricity.

**Medium-Term Purchase:** Energy Block market purchases made three to five years in advance.

**Non-spinning Reserve:**  1. Generating reserve that is not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.

**Off-Peak:** See Light Load Hours.

**Operating Reserve (OR):** The operating reserve is the generating capacity available to the system operator within a short interval of time to meet demand in case a generator is lost or there is another disruption to the supply. The operating reserve can be divided into two kinds of reserve power: the spinning reserve and the non-spinning or supplemental reserve. Generators that intend to provide either spinning or non-spinning reserve should be able to reach their promised capacity within ten or so minutes.

**Peak Demand:** 1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.

**Peaking Plant:** A generation plant that typically only runs at times of peak demand.

**Peaking Purchase:** The purchase of energy that is required to meet load due to system capacity constraints during peak load days.

**Planning Reserve Margin (PRM):** Planning margin is the difference between the electricity supply capacity available and the capacity required to serve the load over a planning period. Intended to protect against a 1 day in 10 year loss of load possibility, the planning margin typically is between 10–30 per cent over forecast load requirements, dependent upon the type and size of generation resources employed.

**Power:** The instantaneous rate at which electrical energy is produced, transmitted or consumed, typically measured in watts (W), kilowatts (kW), or megawatts (MW). See also Capacity.

**Regulating Reserve:** An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

**Reliability:** A measure of the adequacy and security of electric service. Adequacy refers to the existence of sufficient facilities in the system to satisfy the load demand and system operational constraints. Security refers to the system’s ability to respond to transient disturbances in the system.

**Reserve Sharing Group:** A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority’s use in recovering from contingencies within the group.

**Resource:** A source of electricity that is available to help meet or reduce electricity demand, including generation, purchases, demand-side management and transmission facilities.

**Resource Adequacy:** The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).

**Short-Term Purchase:** Energy Block market purchases made several months, up to a year, in advance.

**Spinning Reserve:** Unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve.

**Spot Market:** Real-time (hourly) and day-ahead market purchases and sales of electricity.

**Upgrade:** An improvement to an existing facility, which generally results in an increased performance of the integrated system.

**WAX CAPA:** The Waneta Expansion Capacity Purchase Agreement, a 40 year capacity purchase agreement with the Waneta Expansion Power Corporation to purchase all unused WAX-related capacity that remains after BC Hydro has acquired the energy entitlements associated with the plant (as defined by the CPA). The capacity entitlements obtained by FortisBC under WAX CAPA begin in 2015 and vary by month.

**ACRONYMS**

**BCH:** BC Hydro

**BRD**: Brilliant Plants

**BPC**: Brilliant Power Corporation

**CPA:** Canal Plant Agreement

**CRO**: Contingency Reserve Obligation

**DSM**: Demand Side Management

**EUE**: Expected Unserved Energy

**FBC**: FortisBC

**FOR**: Forced Outage Rate

**IRP**: Integrated Resource Plan

**HLH**: Heavy Load Hour

**LLH**: Light Load Hour

**LOLE**: Loss Of Load Expectation

**LOLH**: Loss Of Load Hour

**LOLP**: Loss Of Load Probability

**MC**: Monte-Carlo

MSSC: Most Severe Single Contingency

**NERC**: North American Electric Reliability Corporation

**NWPCC**: Northwest Power and Conservation Council

**NPP**: Northwest Power Pool

**OR**: Operating Reserve

**PPA**: Power Purchase Agreement

**PBR**: Performance Based Ratemaking Plan

**PRM**: Planning Reserve Margin

**RP**: Resource Plan

**RCA**: Residual Capacity Agreement

**RRA**: Revenue Requirements Application

**ULE**: Upgrade and Life Extension Program

**WAX**: Waneta Expansion

**WECC**: Western Electricity Coordinating Council

1. NERC website as of May 20, 2014: <http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx> [↑](#footnote-ref-2)
2. NERC, Glossary of terms used in NERC reliability standards, May 8, 2014, p.33 <http://www.nerc.com/files/Glossary_of_Terms.pdf> [↑](#footnote-ref-3)
3. Defined in the NERC glossary above under OR: Spinning and Supplemental (non-spinning) [↑](#footnote-ref-4)
4. <http://www.nerc.com/files/BAL-002-0.pdf> [↑](#footnote-ref-5)
5. <http://www.nerc.com/files/BAL-STD-002-0.pdf> [↑](#footnote-ref-6)
6. WECC 2011 Power Supply Assessment, p. 14, <http://www.wecc.biz/library/WECC%20Documents/Publications/Power%20Supply%20Assessments/2011%20Power%20Suppy%20Assessment.pdf> [↑](#footnote-ref-7)
7. Reserve in Capacity Planning – A Northwest Approach, p.2 <http://pnucc.org/sites/default/files/ReservesinCapacityPlanningFinal.pdf> [↑](#footnote-ref-8)
8. BC Hydro (**BCH**) uses capacity margin, defined as (Capacity-Peak Demand)/Capacity instead of PRM (App. F). [↑](#footnote-ref-9)
9. <http://www.avistautilities.com/inside/resources/irp/electric/Documents/2011%20Electric%20IRP.pdf>, p.2-21 [↑](#footnote-ref-10)
10. <http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2011/2011IRPFINAL.pdf>, p.115 [↑](#footnote-ref-11)
11. http://www.northwesternenergy.com/our-company/regulatory-environment/2013-electricity-supply-resource-procurement-plan/2011-electric-supply-resource-procurement-plan#1 [↑](#footnote-ref-12)
12. <http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-Appendices_Vol2-FINAL.pdf>, Appendix J. [↑](#footnote-ref-13)
13. <http://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/irp_nov2009.pdf>, p. 43 [↑](#footnote-ref-14)
14. <http://pse.com/aboutpse/EnergySupply/Documents/IRP_2011_chapters.pdf>, p. 5-3 [↑](#footnote-ref-15)
15. Adapted from Reserves in Capacity Planning – a Northwest Approach, p.13 <http://pnucc.org/sites/default/files/ReservesinCapacityPlanningFinal.pdf> [↑](#footnote-ref-16)
16. As of October 1, 2014 the contingency reserve requirement in WECC and the NWPP is changing to 3% of load and 3% of generation: http://www.wecc.biz/library/Documentation%20Categorization%20Files/Regional%20Standards/BAL-002-WECC-2.pdf. This change has not been incorporated into the current analysis as the differences are immaterial to the values in this analysis. [↑](#footnote-ref-17)
17. A probabilistic method to assess power supply adequacy for the Pacific Northwest (Fazio J., 2012) p. 18, [http://www.nwcouncil.org/energy/resource/Adequacy%20Standard%20Background%20(2008-07a).pdf](http://www.nwcouncil.org/energy/resource/Adequacy%20Standard%20Background%20%282008-07a%29.pdf) [↑](#footnote-ref-18)
18. <https://rsvp.rfirst.org/BAL502RFC02/default.aspx> [↑](#footnote-ref-19)
19. A forced outage is an unplanned/unexpected shutdown of a generating unit or an unexpected failure to start. Forced outage rate is the proportion of time the unit is on forced outage to its total service time. [↑](#footnote-ref-20)
20. Unit contingent sales are sales that require a particular unit to be available to support the sale. In this case, WAX. [↑](#footnote-ref-21)
21. The size of this surplus block is capped at 75 MW from 2015 to 2019, 50 MW from 2020-2024, 25 MW from 2025-2029 and zero thereafter. [↑](#footnote-ref-22)
22. <http://www.nerc.com/files/2011LTRA_Final.pdf> [↑](#footnote-ref-23)
23. <http://www.nwpp.org/>. FBC and BCH are NWPP’s Canadian members. [↑](#footnote-ref-24)
24. <http://www.nerc.com/files/2012_ProbA.pdf>, p.15 [↑](#footnote-ref-25)
25. Its PRM values (%) are shown in the Conclusion section. [↑](#footnote-ref-26)