British Columbia Transmission
CORPORATION™

# Interior to Lower Mainland Transmission Project Assessment of Need

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**Transmission System Planning**
**British Columbia Transmission Corporation**

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# LIST OF ABBREVIATIONS

| Abbreviation | Definition |
|---|---|
| ATC | Available Transfer Capability |
| BCTC | British Columbia Transmission Corporation |
| CBN | Clayburn Substation |
| CE | Canadian Entitlement |
| CKY | Cheekye Substation |
| CRP | Contingency Resource Plan |
| CU | Committed Use |
| DSM | Demand Side Management |
| EENS | Expected Energy Not Served |
| IEP | Integrated Electricity Plan |
| ILM | Interior to Lower Mainland |
| ISD | In-Service Date |
| KLY | Kelly Lake Substation |
| LM | Lower Mainland |
| LTAP | Long Term Acquisition Plan |
| MDN | Meridian Substation |
| NERC | North American Electric Reliability Council |
| NIC | Nicola Substation |
| NITS | Network Integration Transmission Service |
| TSCP | Transmission System Capital Plan |
| TTC | Total Transfer Capability |
| VI | Vancouver Island |
| WECC | Western Electricity Coordinating Council |

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# EXECUTIVE SUMMARY

The purpose of this report is to examine the need for the Interior to Lower Mainland (ILM) Transmission Project.

The ILM transmission grid (defined below) is the most critical transmission path in BC. In addition to transmitting electricity from the Interior to the Lower Mainland (LM) and Vancouver Island (VI), where almost 70% of provincial demand is located, the ILM grid is also a key transmission path for both firm and non-firm electricity trading activity.

A review of the results presented in this study leads to the following conclusions:

1. The majority of resource portfolios analyzed to date require an increase in the transfer capability of the ILM grid as early as 2014; and

2. Some portfolios indicate a deferral of the required increase by one to 9 years.

Without an increase in transfer capability, the existing ILM grid will not be adequate for the reliable transfer of future Interior generation resources to serve load in the LM and VI. By 2014, The system will not meet the NERC/WECC Planning Standards for most of the portfolios considered.

BCTC needs to plan the transmission system to meet those scenarios that require additional ILM transfer capability as early as 2014 as well as dealing with scenarios where the need for incremental capacity might arise later. Should greater Coastal Generation and/or Demand Side Management (DSM) materialize than the amounts forecast in those scenarios that require earlier ILM transfer capability additions, it would tend to defer the need for incremental ILM transfer capability. In that event, BCTC would be in a position to consider its impact on the timing of the ILM Project. However, because BCTC must be able to deal with scenarios that require earlier in service dates, proceeding with the approvals required to increase the transfer capability of the ILM grid and preserving an in-service date as early as 2014 is recommended.

# 1.0 INTRODUCTION AND PURPOSE

The purpose of this report is to examine the need for increasing the capacity of the ILM grid. The report is structured as follows;

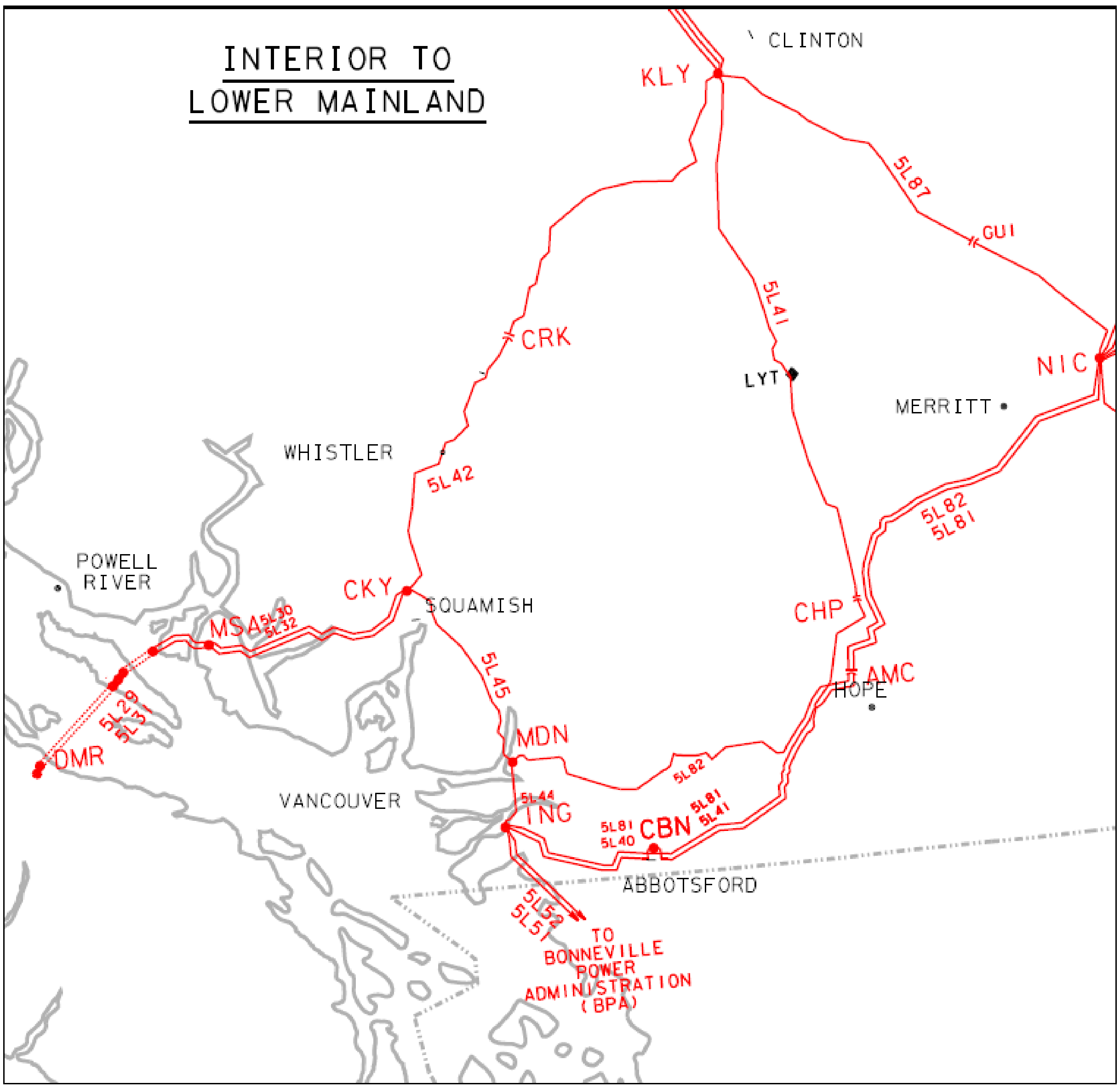
| | |
|---|---|
| Introduction and Purpose | (Section 1.0) |
| Description of the ILM grid | (Section 2.0), |
| Objectives and Planning Standards | (Section 3.0), |
| Limits of the Existing ILM Grid | (Section 4.0), |
| Drivers | (Section 5.0) |
| Probabilistic Reliability Analysis | (Section 6.0), and, |
| Conclusion | (Section 7.0). |

The study uses the BC Hydro 2006 Amended Long Term Acquisition Plan (LTAP) Portfolios including the two approved Contingency Resource Plans as described in Exhibit B-1E and amended by Exhibit B-55 and updated in Exhibit B-146A of BC Hydro's 2006 Integrated Electricity Plan (IEP)/LTAP proceeding. The study also documents the extensive portfolio analysis done in previous Network Integration Transmission Service (NITS) System Impact Studies and for the BC Hydro 2006 IEP filing in which the transmission implications of seventeen portfolios were analyzed. In addition, during the IEP proceedings, BCTC analyzed the transmission impact of re-powering Burrard and the return of the Canadian Entitlement (CE). In total 43 portfolios have been examined. The study results are discussed and evaluated and the need for the ILM Project is presented in the Conclusions section.

## 2.0 DESCRIPTION OF EXISTING ILM GRID

The ILM grid, shown in Figure 2-1, is the most critical transmission path in BC. The ILM grid transmits electricity from the Interior, where the majority of generation is located, to the LM and VI, which together comprise approximately 70% of provincial demand. The ILM grid is also a key transmission path for both firm and non-firm trading activity.

**Figure 2-1. Interior to Lower Mainland Grid Map**




The ILM grid comprises eight 500 kV transmission lines. The power transfer from the Interior to the LM and VI takes place over four of these lines:

- 5L81 and 5L82 connect Nicola (NIC) Substation in the South Interior to Ingledow (ING) and Meridian (MDN) substations in the LM; and
- 5L42 connects Kelly Lake (KLY) Substation in the Interior to Cheekye (CKY) Substation and 5L42 connects KLY to Clayburn (CBN) Substation in the LM.

Four additional lines allow for power sharing between the substations:

- 5L45 connects CKY and MDN substations in the LM;
- 5L44 connects MDN and ING substations in the LM;
- 5L40 connects CBN an ING substations in the LM; and
- 5L87 connects NIC and KLY substations in the Interior.

Five of the ILM lines (5L41, 5L42, 5L87, 5L81, and 5L82) are series compensated to increase transfer capability.

Usage of the ILM grid is a function of:

(a) LM and VI load (net of DSM),

(b) Firm exports/imports, and

(c) Generation resources in the coastal and interior regions.

Flexibility and economics dictate generation dispatch patterns. The transmission system should be able to accommodate the forecast generation output of the coastal and interior regions. Additional Independent Power Producers (IPPs) in the coastal region may partially compensate for the increase in load in the region and slow the growth in ILM usage. DSM options that provide capacity reductions when the demand is high will also reduce load growth and slow growth in ILM usage.

Dispatch of interior generation to either dependable or maximum levels also affects the usage of the ILM grid. For transmission planning studies that usually consider the heaviest coastal loads during the winter, the dependable generation capacities are usually modeled. These reflect the historical available generation capacities under winter peak conditions. Sensitivity studies are often performed using maximum generating capacities to stress the transmission system even further. These reflect how the system may be operated under emergencies or freshet conditions where the spring runoff is high at all the interior plants and power must be generated or water is spilled. A maximum dispatch pattern leads to a higher committed use (CU) on the ILM grid and therefore tend to require an earlier reinforcement of the when its transfer capability is exhausted.

When there is available capacity on the ILM grid it can play a role in enabling trade. When it is economic to do so, power can be exported from the Interior to the US and, conversely, power from the US and Alberta can be imported and delivered to loads via the ILM grid.

# 3.0 OBJECTIVES AND PLANNING STANDARDS

BCTC's planning objectives and standards are described in Sections 4.6.1 and 4.6.2 of Exhibit B-1 of BCTC's F2008-2017 Transmission System Capital Plan proceeding (F2008 TSCP), pages 50 to 59. The objectives are:

(a) Serving firm load,

(b) Enabling economic generation dispatch,

(c) Enabling point-to-point power transfers,

(d) Affordability,

(e) System performance,

(f) Community Impact, and

(g) Environmental compliance.

## 3.1 Application of Planning Standards and Objectives

Because of the complexity of the electric system, it is impossible to study all system operating conditions and permutations of equipment availability. For example, the load varies from 40 to 100% of peak. The generators are dispatched not only to serve the load but also to economically extract energy from the reservoirs. The transmission system requires planned maintenance during the year which requires equipment outages. The locations and sizes of future loads and resources are uncertain.

To manage this complexity and uncertainty, models of the future system are developed to test the system under maximum stressed conditions with the most critical element out of service. The results of these tests are compared to the planning standards. If the system meets the planning standards during reasonable worst-case scenarios, then it is likely that the CU will not exceed the total transfer capability (TTC) under less stressed conditions.

It is important to appreciate that capacity increases required for the most stressed cases provide reliability benefits under normal conditions. Increases in transfer capability that meet the planning standards but are only available for a short period of time provide little if any real reliability improvement to the system. For example, providing a load curtailment option or generation redispatch option that only is available for a few hours during the peak period will not provide the same level of reliability as a capacity increase that is available all year.

## 4.0 LIMITS OF THE EXISTING ILM GRID

Transmission systems are constrained by a number of single contingency limits.

Each of these limits is described in Section 4.6.2 of Exhibit B-1 of BCTC's F2008 TSCP, pages 55 to 59. Representative N-1 single contingency limits of the ILM grid are discussed below.

(a) Continuous Thermal Limits

For the ILM grid the continuous thermal limit is defined by the rating of the series capacitors banks in the ILM grid. This corresponds to a maximum continuous transfer of approximately 5000 MW.

(b) One-Hour Thermal Overload Limits

A one-hour thermal overload rating gives the operator time to redispatch available Coastal Generation or increase imports to reduce the ILM transfer to within the continuous thermal limit. The one-hour thermal overload limit for the existing ILM grid is approximately 6300 MW.

(c) Voltage Stability Limits

Voltage stability is the ability of a power system to maintain steady acceptable voltages at all buses in the system under normal operating conditions and after a contingency. A system enters a state of voltage instability when a disturbance, increase in load demand, or change in system condition causes a progressive and uncontrollable drop in voltage. The main factor causing instability is the inability of the power system to meet the demand for reactive power. Exceeding this limit could result in cascading system outages. The voltage stability limit of the existing ILM grid is approximately 5800 MW.

(d) Transient Stability Limits

Transient stability is a condition in which, following a system disturbance, a generator or group of generators will return to pre-disturbance rotational speed and will not lose synchronism with the integrated system.

After a disturbance, the generators' output in one area will oscillate against the generators' output in other parts of a large area interconnected system. An interconnected system must have sufficient damping so that power oscillations dissipate quickly.

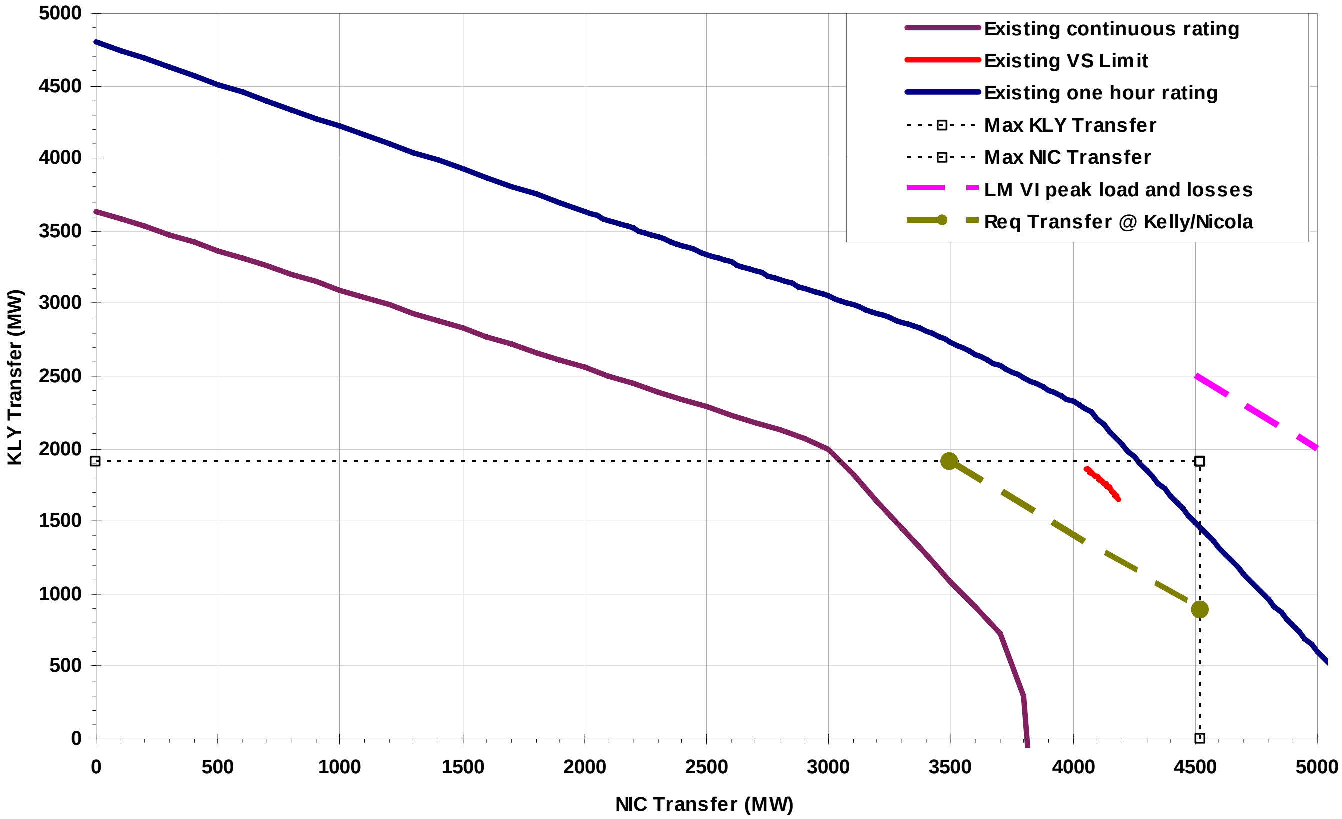
Transient stability simulations have confirmed that the power system remains transiently stable at transfer limits at or below the voltage stability limits of the ILM grid. Hence, voltage stability is the dominant constraint on the ILM grid relative to transient stability.

The full one-hour thermal overload rating cannot be used during peak load periods given the lower voltage stability rating. To the extent that the one-hour thermal overload rating can be used up to the voltage stability rating, if a single contingency outage lasts for more than one hour then Coastal Generation or imports would need to be re-dispatched to reduce the ILM grid loading to its continuous thermal rating.

## 4.1 Nomograms

The N-1 thermal and voltage stability limits described above are represented by single numbers for simplicity. Each limit is actually a range of values illustrated by a graphical plot known as a nomogram. The nomograms for continuous thermal limits, one-hour thermal overload limits, and voltage stability limits for the ILM grid are shown in Figure 4-1 and discussed below.

**Figure 4-1. ILM Nomograms**




The ILM nomograms help explain the relationship between the sources of generation and the TTC, CU and Available Transfer Capability (ATC) of the ILM grid. Figure 4-1 also displays the following:

(a) "LM & VI Load and Losses line" is a 45-degree locus of the winter peak load and losses to be served in the coastal region. This line moves upward and to the right if the load increases, and moves downward and to the left if the load decreases.

(b) "Required transfer at Kelly and Nicola line" is also a 45-degree locus of all the combinations of transfer from the NI and SI that meet the LM & VI Load and Losses requirement after the dispatch of Coastal Generation. As more Coastal

Generation is added, the line moves down to the left and, as more load is added, the line moves up to the right.

(c) The "Maximum KLY Transfer line" line defines the maximum amount of surplus NI generation flowing through KLY to the ILM grid. This dashed line is parallel to the horizontal axis.

(d) The "Maximum NIC Transfer line" defines the maximum amount of surplus SI generation flowing through NIC to the ILM grid. This dashed line is parallel to the vertical axis.

(e) ""Points A and B are the intersection of the Required Transfer at KLY and NIC line with the Maximum KLY Transfer line and the Maximum NIC Transfer line, respectively. Both these points must be below and to the left of the voltage and thermal ratings of the ILM grid for the system to be operated in an acceptable region of the nomogram while providing dispatch flexibility. For example, for the first hour after an outage, these points must be below and to the left of the voltage stability ratings and the one-hour thermal ratings. After the first hour, these points must be further moved below and to the left of the continuous thermal limit by re-dispatching additional Coastal Generation or imports if available. As the load grows and the Coastal Generation is fully utilized, these points will move beyond the limits of the ILM grid and transmission capacity increases must be added or additional imports scheduled to allow these points to continue to be below and to the left of the limits. From the example indicated in Figure 4-1, sufficient NI or SI coincident generation dispatch flexibility is not available in relation to the continuous rating of the ILM grid as the locus points are on the right side of the continuous rating nomogram. Whereas sufficient NI or SI coincident generation dispatch flexibility is available with the one hour rating as the locus points are on left side of the one hour rating nomogram.

# 5.0 DRIVERS

## 5.1 Demand and Supply Analysis

The ILM grid supplies the load in the coastal region from surplus power generated in the Interior. If resource additions to meet forecast load growth come from the Interior instead of from the coastal region, the usage of the ILM grid will increase. The LM and VI peak load forecasts and generation for the next 20 years are shown in Figures 5-1, 5-2, and 5-3 for the amended LTAP and Contingency Resource Portfolios. There is a growing imbalance between load and supply in the LM and VI regions. The 20-year incremental CU from Figure 5-1 (amended LTAP portfolio) is approximately 1600 MW from incremental load growth minus the net increase in Coastal Generation of about 200 MW for a total 20-year incremental CU of 1400 MW. Similarly, the 20-year incremental CU for Contingency Resource Plans (CRP) 1 and 2 in Figures 5-2 and 5-3 is approximately 1600 MW and 2000 MW, respectively.

**Figure 5-1. Total Generation and Load in LM and VI – 2006 Amended LTAP**

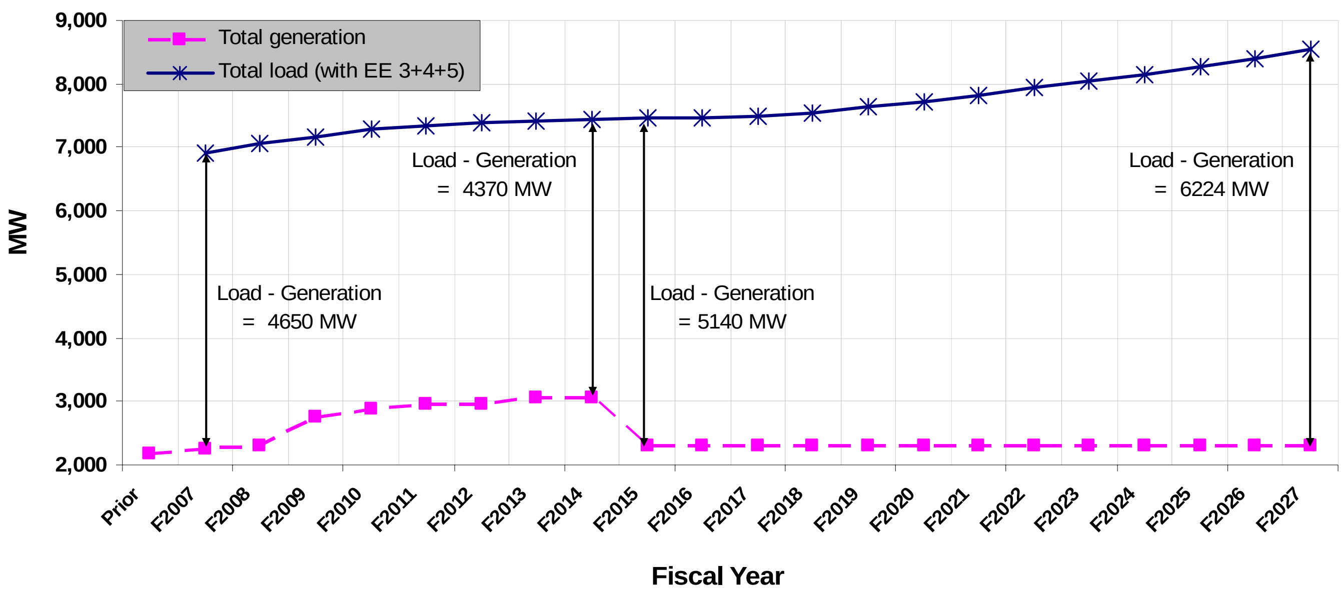


**Figure 5-2. Total Generation and Load in LM and VI – 2006 Contingency Resource Plan 1**

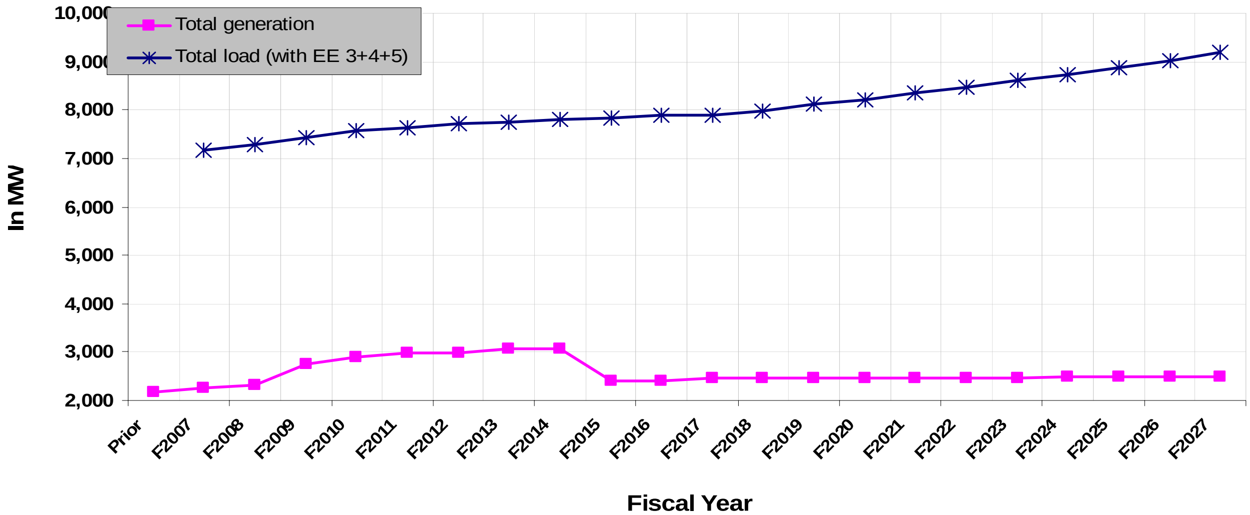
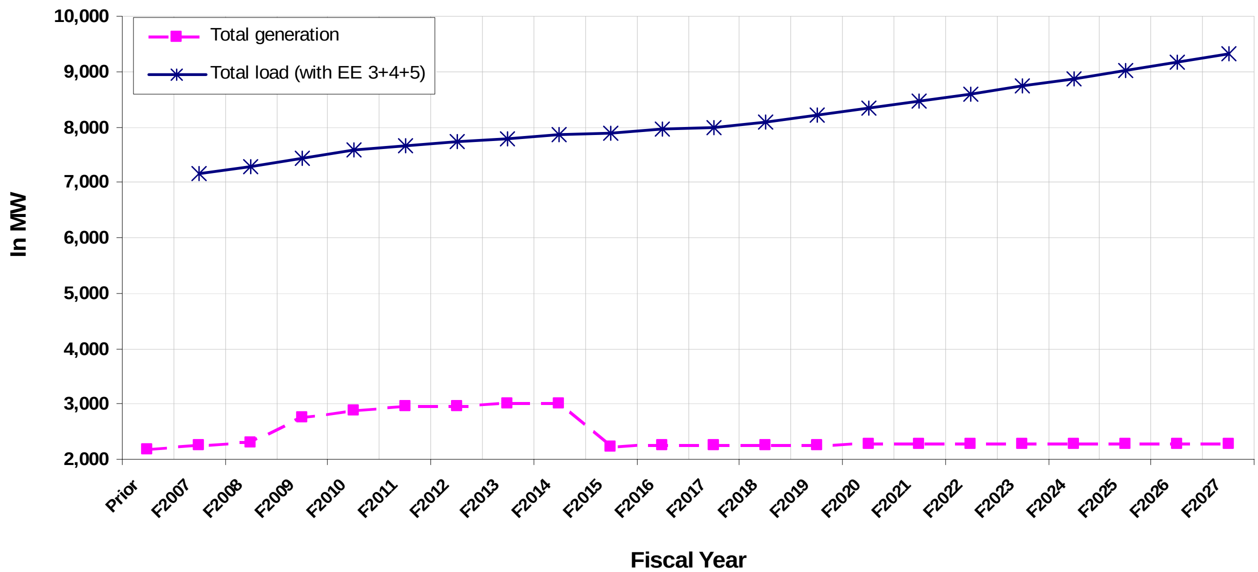



**Figure 5-3. Total Generation and Load in LM and VI – 2006 Contingency Resource Plan 2**




While demand is forecast to exceed supply in the coastal region, the opposite is true for the Interior. Figures 5-4, 5-5 and 5-6 show the forecast load and resources for each of the amended LTAP portfolio and CRPs. These figures show the Interior resource additions both in terms of their dependable and maximum capacities.

The Interior incremental dependable generation capacity exceeds the incremental demand by 2800 MW by F2027, while the incremental Interior maximum generation capacity exceeds the incremental demand by 4780 MW for the amended LTAP portfolio by F2027. For CRP1, the Interior region incremental dependable generation capacity exceeds the incremental demand by 3170 MW (F2027), while the incremental maximum generation capacity exceeds the incremental demand by 6460 MW (F2027). For CRP2, the Interior incremental dependable generation capacity exceeds the incremental demand by 3680 MW (F2027), while the incremental maximum generation capacity exceeds the incremental demand by 8000 MW (F2027).

**Figure 5-4. Total Generation and Load in Interior Regions – 2006 Amended LTAP**

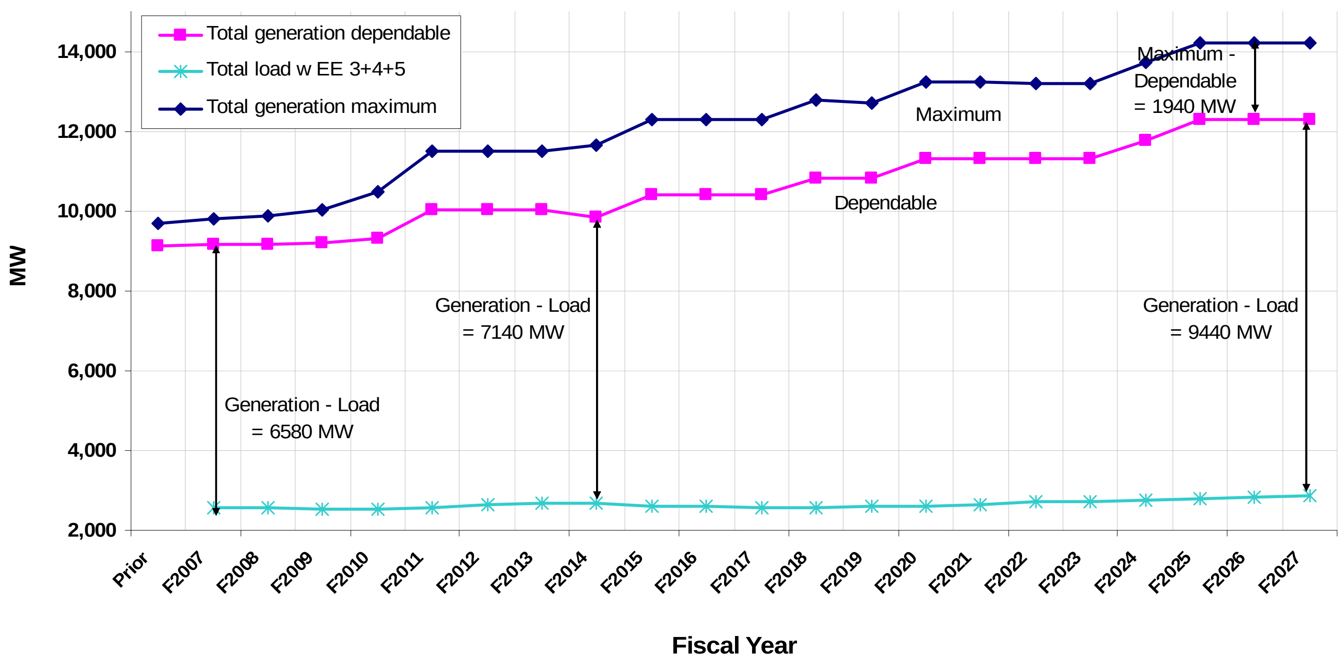


**Figure 5-5. Total Generation Additions and Load Growth in Interior Regions – 2006 Contingency Resource Plan 1**

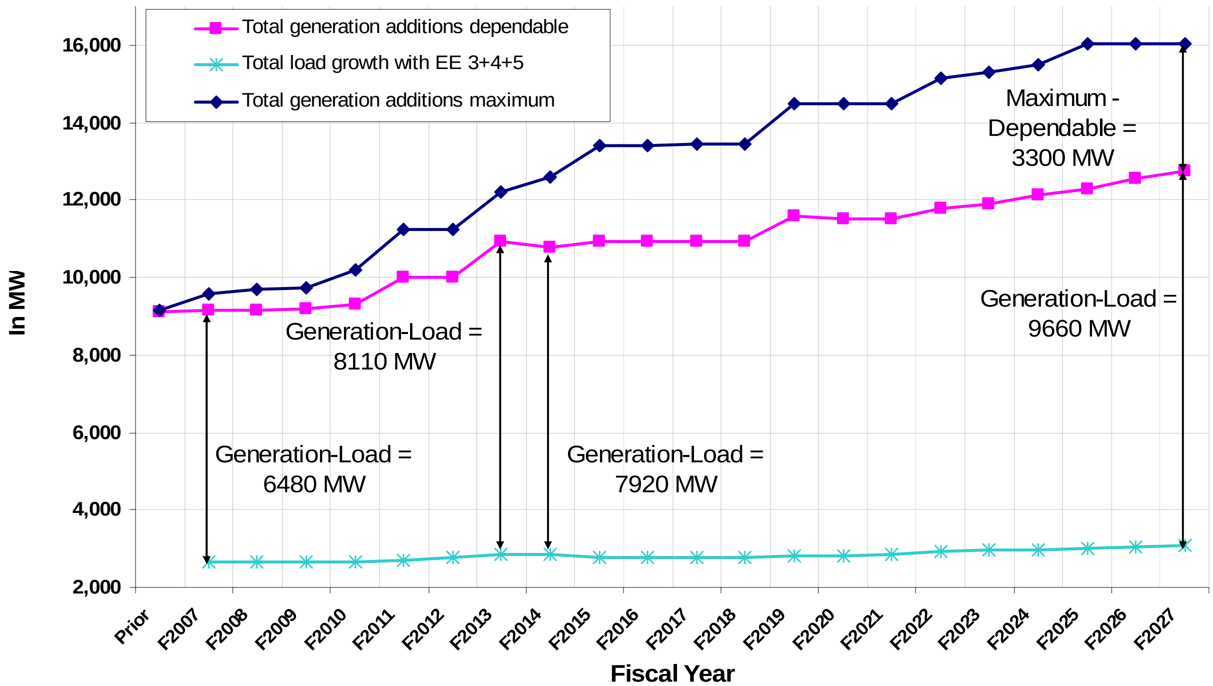
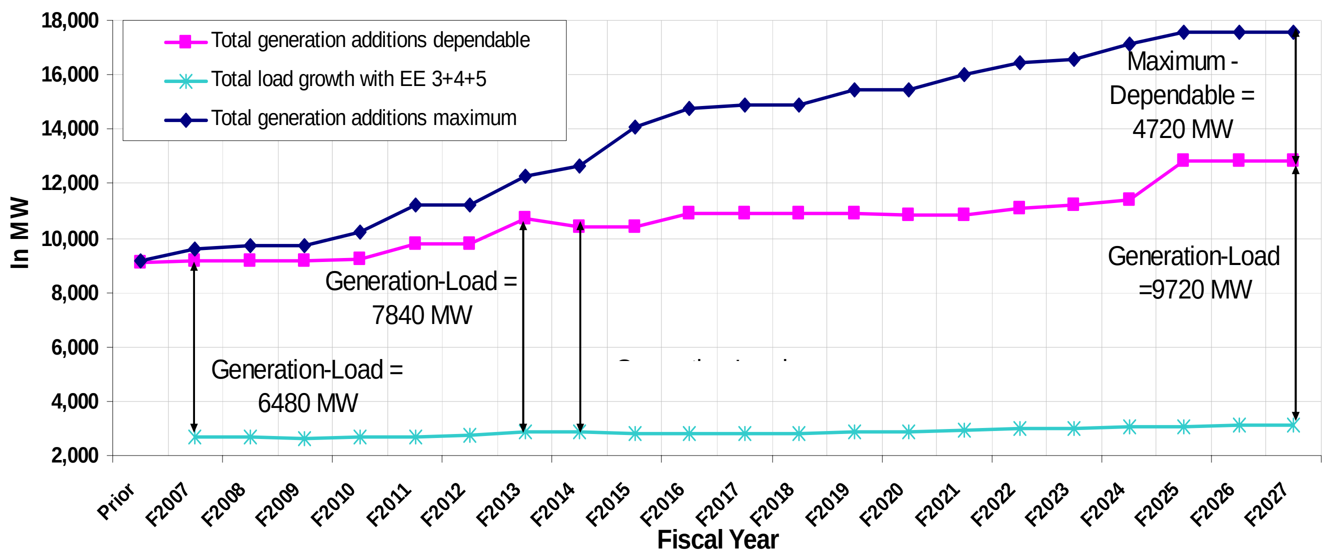



**Figure 5-6. Total Generation Additions and Load Growth in Interior Regions – 2006 Contingency Resource Plan 2**



## 5.2 Gap Analysis

### 5.2.1 Earlier Studies

Since 2004, BCTC has performed numerous studies to examine the need and timing of increased transfer capability on the ILM grid. These studies include:

(a) The NITS 2004 series of studies which examined eight alternative resource portfolios, and combinations of exports, each of which required increased transfer capability of the ILM grid at its earliest in-service date. These studies formed the basis of the Network Integrated Transmission Service contract which BCTC currently has with BC Hydro.

(b) The portfolio analysis conducted for BC Hydro's 2006 IEP Application in which seventeen portfolios were studied to determine their transmission implications. Thirteen of the portfolios showed a requirement to increase the transfer capability of the ILM grid as soon as possible, three portfolios showed a delay from 1 to 7 years, and one portfolio was constructed so as not to require any increased transfer capability on the ILM grid. This analysis can be found in Exhibit B-1C, Appendix H of the BC Hydro IEP/LTAP proceeding and is summarized in Appendix A of this report.

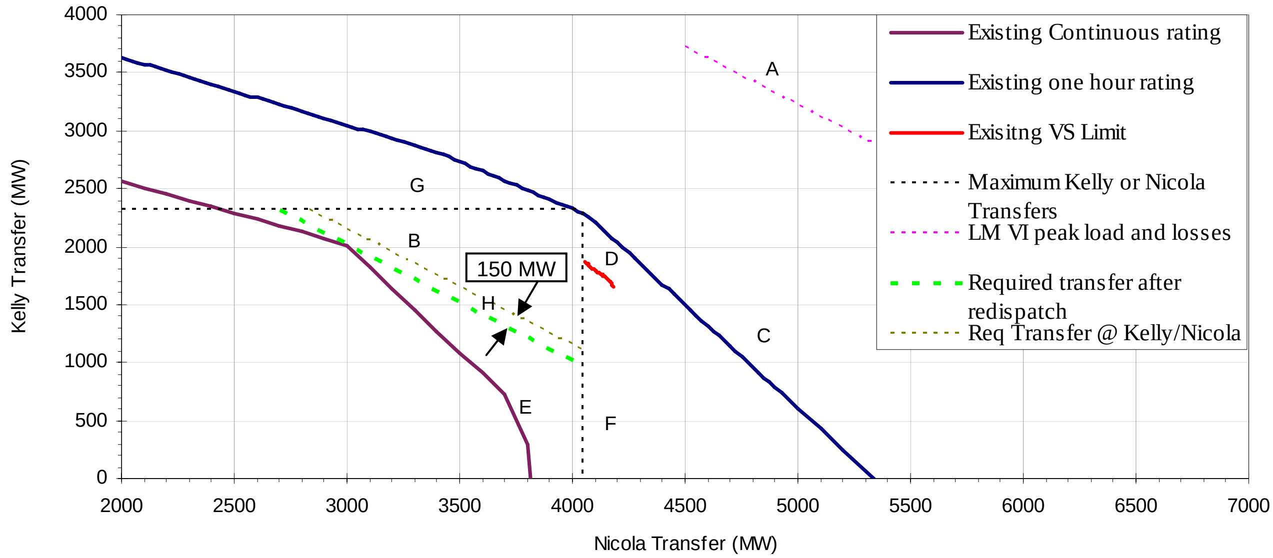
(c) 18 portfolios analyzed at the request of the Commission during the BC Hydro IEP/LTAP proceeding constituting variations on the capacity available from Burrard and the CE and combinations of maximum vs. dependable dispatch patterns. These portfolios showed that increased transfer capability on the ILM grid was required at its earliest date in 10 of the 18 portfolios, and that the increase could be delayed by 3 to 9 years with high dispatch levels of Burrard and the CE and by using Dependable Generation Capacities. This analysis was filed as Exhibit B-146A in the BC Hydro IEP/LTAP proceeding and is summarized in Appendix A of this report.

(d) Most recently, BCTC has studied the transmission implications of the Amended LTAP and Commission-approved CRPs to assess the need for and timing of increased transfer capability on the ILM grid. An explanation of methodology that went into this analysis is in the following sections.

### 5.2.2 ILM Cut-plane Single Contingency Nomogram Analysis

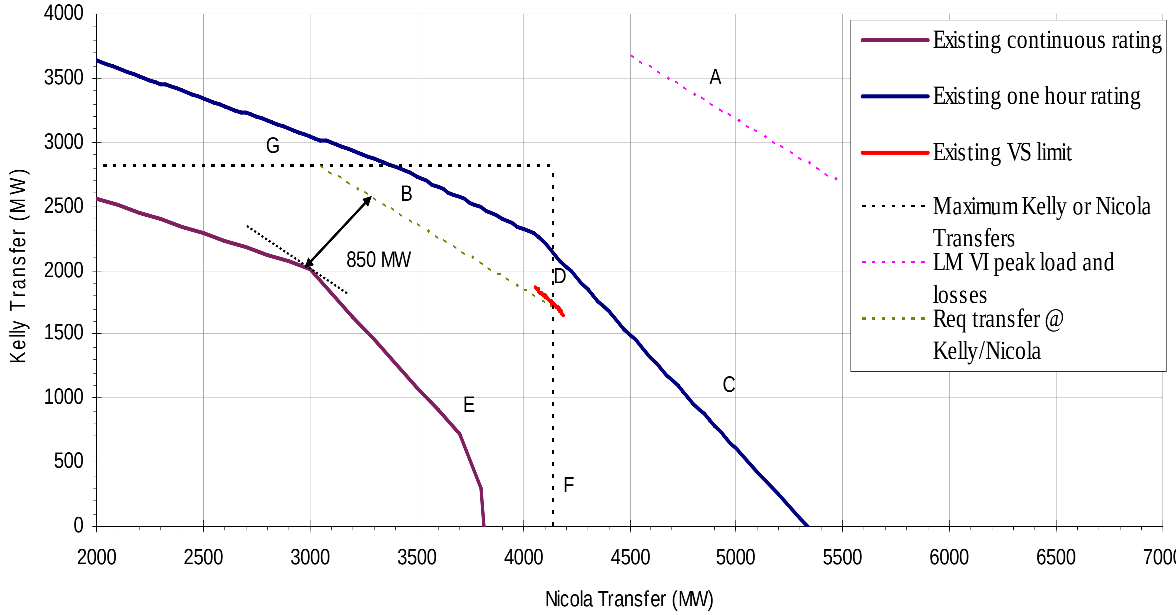
The single contingency analysis of thermal and voltage stability limit violations for the ILM grid during the peak load are analyzed using nomograms. These nomograms illustrate if sufficient ATC is available to meet the LM and VI load and losses. The ILM nomograms for the Amended LTAP for the years 2013\14 and 2014\15 are shown in Figures 5-7 and 5-8, respectively.

**Figure 5-7. ILM Nomogram for Amended LTAP Portfolio F2014**




In 2013\14, the LM and VI load and losses is shown as line A. The full dispatch of the dependable Coastal Generation, including Burrard Generating Station, is necessary to keep the required transfer at KLY and NIC (line B) within the one-hour thermal rating (line C) and the voltage stability rating (line D) of the ILM grid. After an hour, an additional 150 MW of the coastal resources or imports, such as the CE, is needed to keep the post one-hour required transfer at KLY and NIC (line H) within the continuous thermal rating of the system (line E). The dispatch of the SI generation (NIC transfer) would be restricted after an hour because the maximum dependable NIC transfer (line F) is larger than the continuous thermal rating (line E) even after full redispatch of coastal resources.

**Figure 5-8. ILM Nomogram for Amended LTAP Portfolio F2015**

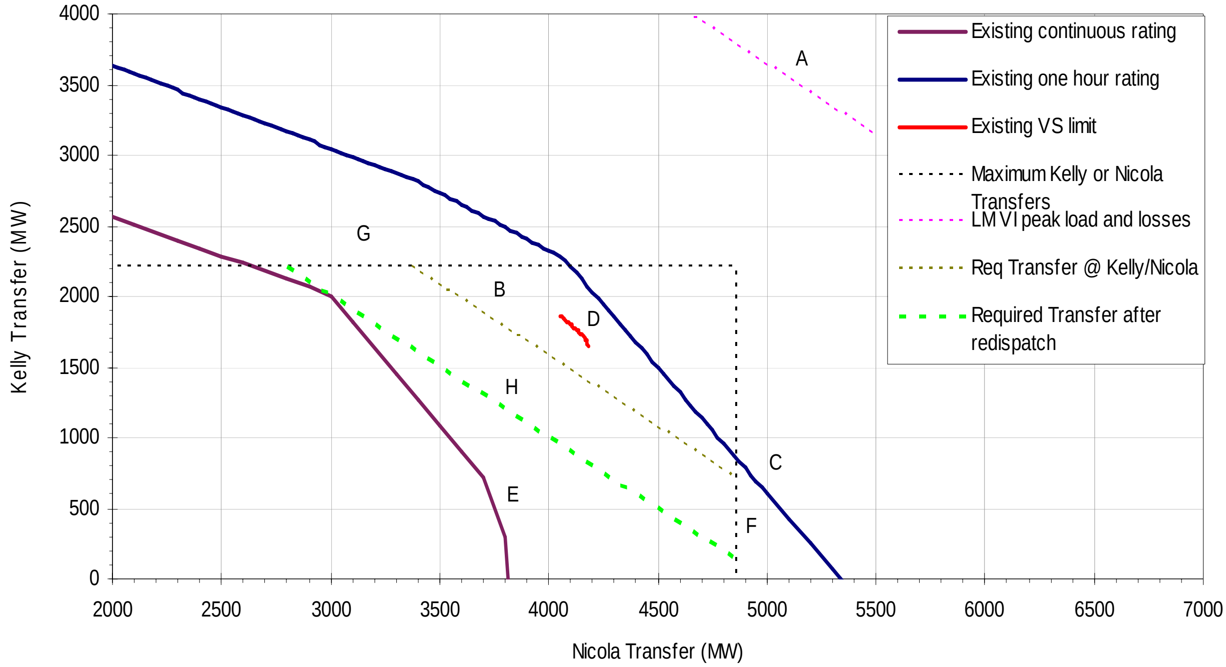



In 2014\15, Burrard Generating Station and the CE are no longer available for dispatch in the Amended LTAP portfolio. The dispatch of the remaining dependable Coastal Generation results in the required transfer at KLY and NIC (line B) to be above the continuous rating of the system (line E). This illustrates that under the Amended LTAP scenario, unless about 850 MW of increased transfer capability is provided on the ILM grid, or a similar amount of new coastal resources is found, the post contingency ILM transfers will be well above the continuous thermal limit by the winter of 2014. Unless increased transfer capability or additional coastal resources were put in place, this would result in load shedding to maintain the system within its thermal operating limits.

#### 5.2.2.1 ILM Nomogram for CRP 1

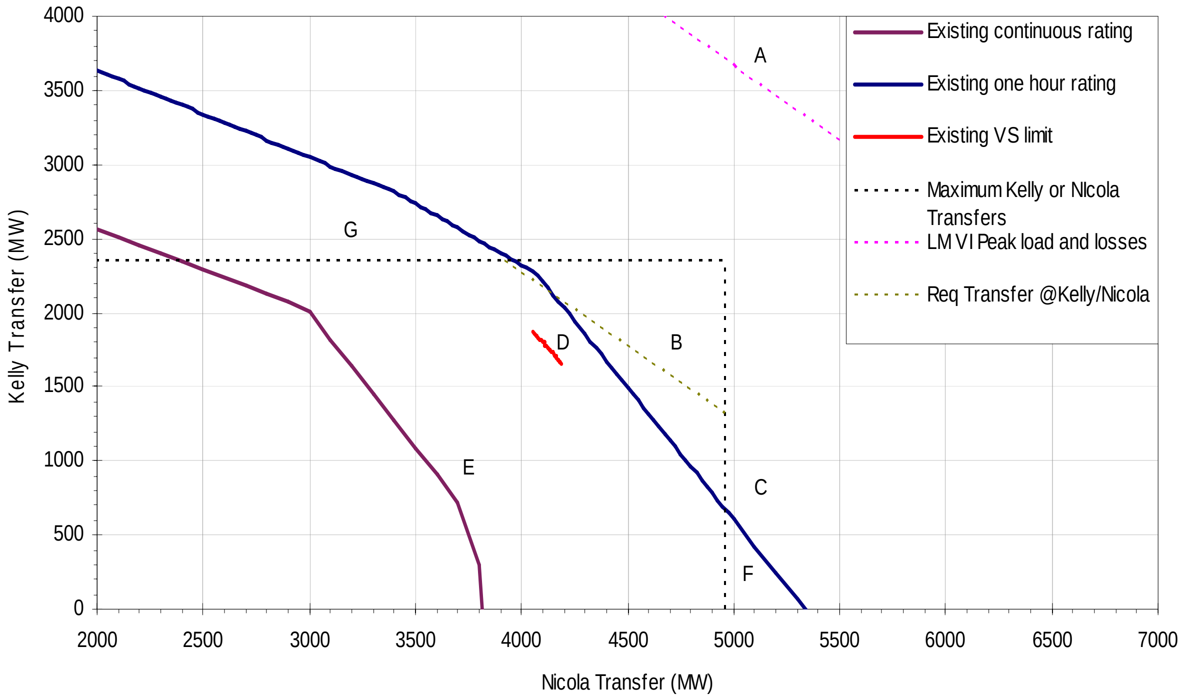
ILM transfers for CRP 1 for the years 2013\14 and 2014\15 are shown in Figures 5-9 and 5-10 respectively.

**Figure 5-9. ILM Nomogram for CRP1 F2014**




In 2013\14, the full dispatch of the dependable Coastal Generation, including Burrard Generating Station, is necessary to keep the KLY and NIC required transfer line (line B) within the one-hour thermal rating (line C) and the voltage stability rating (line D) of the ILM grid. After an hour, an additional 650 MW of coastal resources or imports, such as the CE, would need to be redispatched to keep the post one-hour required transfer at KLY and NIC (line H) within the continuous thermal rating of the system (line E). The continuous dispatch of SI generation (NIC transfer) would be restricted because the maximum dependable NIC transfer (line F) is larger than the continuous thermal rating (line E).

**Figure 5-10. ILM Nomogram for CRP1 F2015**

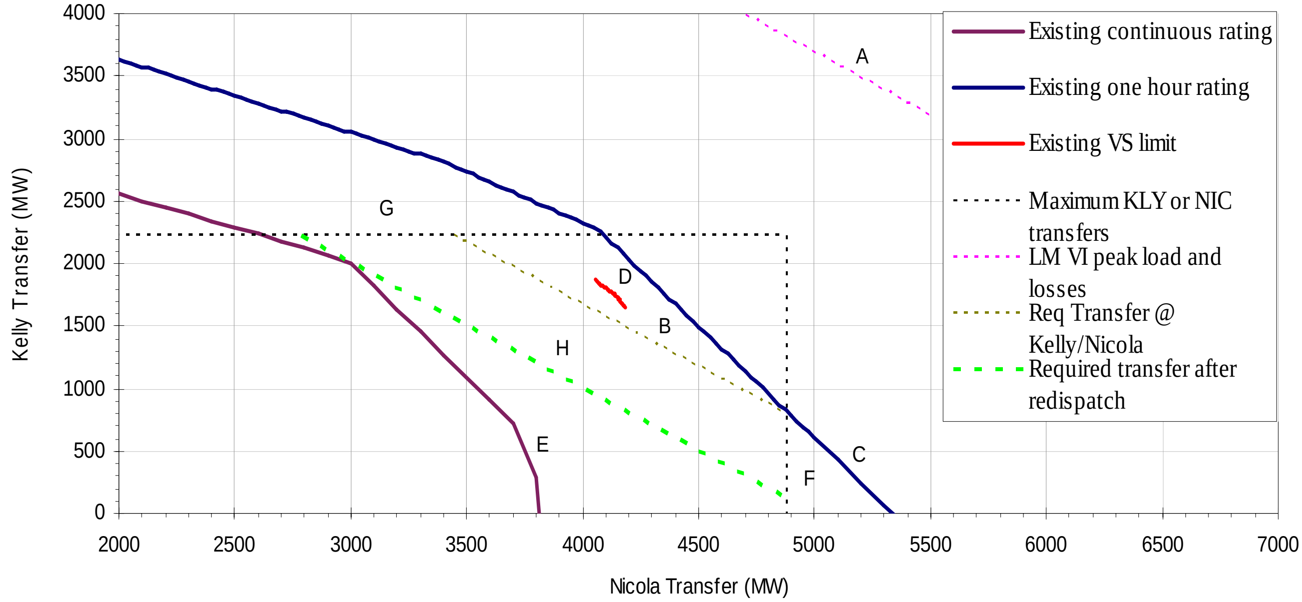



In 2014\15, Burrard Generating Station and the CE are no longer forecast to be available to be dispatched as Coastal Generation. The dispatch of the remaining dependable Coastal Generation results in the KLY and NIC transfer line (line B) being above the continuous rating of the system (line C) and the voltage stability limit (line D). Under this scenario, the ATC is negative by about 1250 MW and illustrates the need for increased transfer capability on the ILM grid in 2014.

### 5.2.2.2 ILM Nomogram for CRP 2

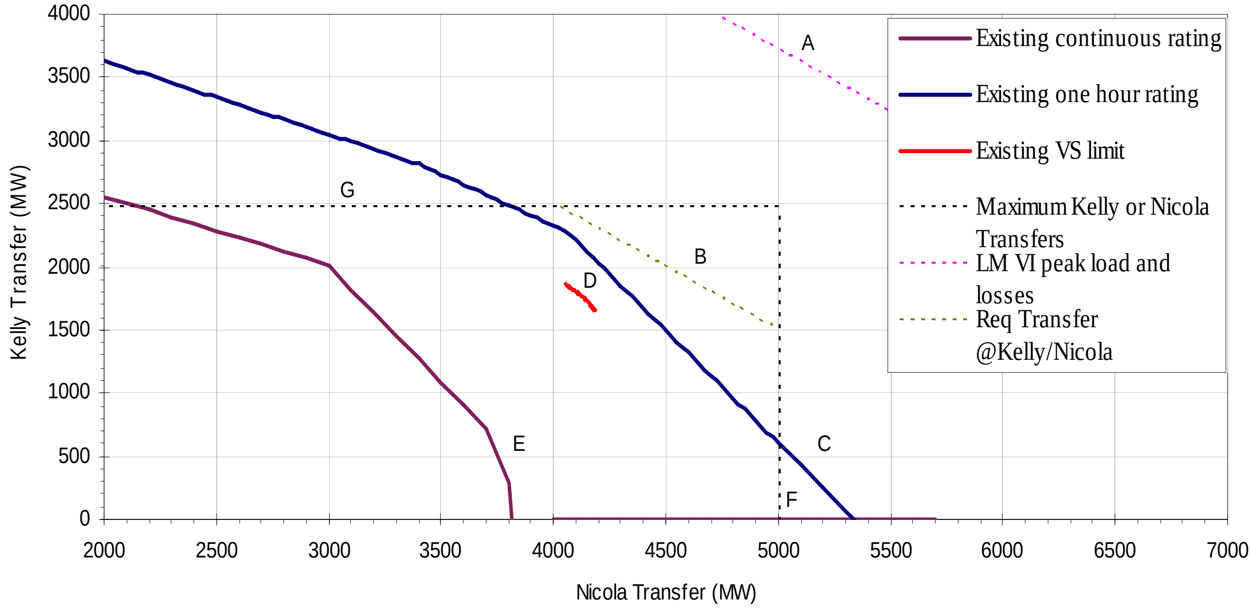
ILM transfers for CRP 2 for the years 2013 and 2014 are shown in Figures 5-11 and 5-12, respectively.

**Figure 5-11. ILM Nomogram CRP2 F2014**




In 2013\14, the full dispatch of the dependable Coastal Generation, including Burrard Generating Station, is necessary to keep the required transfer at KLY and NIC (line B) within the one-hour thermal rating (line C) and the voltage stability rating (line D) of the ILM grid. After an hour, an additional 750 MW of the CE would need to be redispatched to keep the KLY and NIC required transfers (line H) within the continuous thermal rating of the system (line E). The dispatch of SI generation (NIC transfer) is restricted because the maximum dependable NIC transfer (line F) is larger than the continuous thermal rating (line E).

**Figure 5-12. ILM Nomogram CRP2 F2015**




In 2014\15, Burrard Generating Station and the CE are no longer forecast to be available to be dispatched as coastal resources under CRP 2. The dispatch of the remaining Coastal Generation results in the KLY and NIC transfer line (line B) being above the continuous rating of the system (line C) and above the voltage stability limit (line D). The ATC of the ILM grid is negative by about 1500 MW and this illustrates the need for the ILM reinforcement in 2014.

#### 5.2.2.3 ILM Cut-Plane Observations for LTAP and Contingency Portfolios

(a) An increase in ILM transfer capability is needed at its earliest in-service date of 2014 for the Amended LTAP portfolio as well as for the Commission approved CRPs 1 and 2.

(b) In the absence of Burrard Generating station and the CE by 2014, all three portfolios exceed the existing continuous thermal limits of the existing ILM grid.

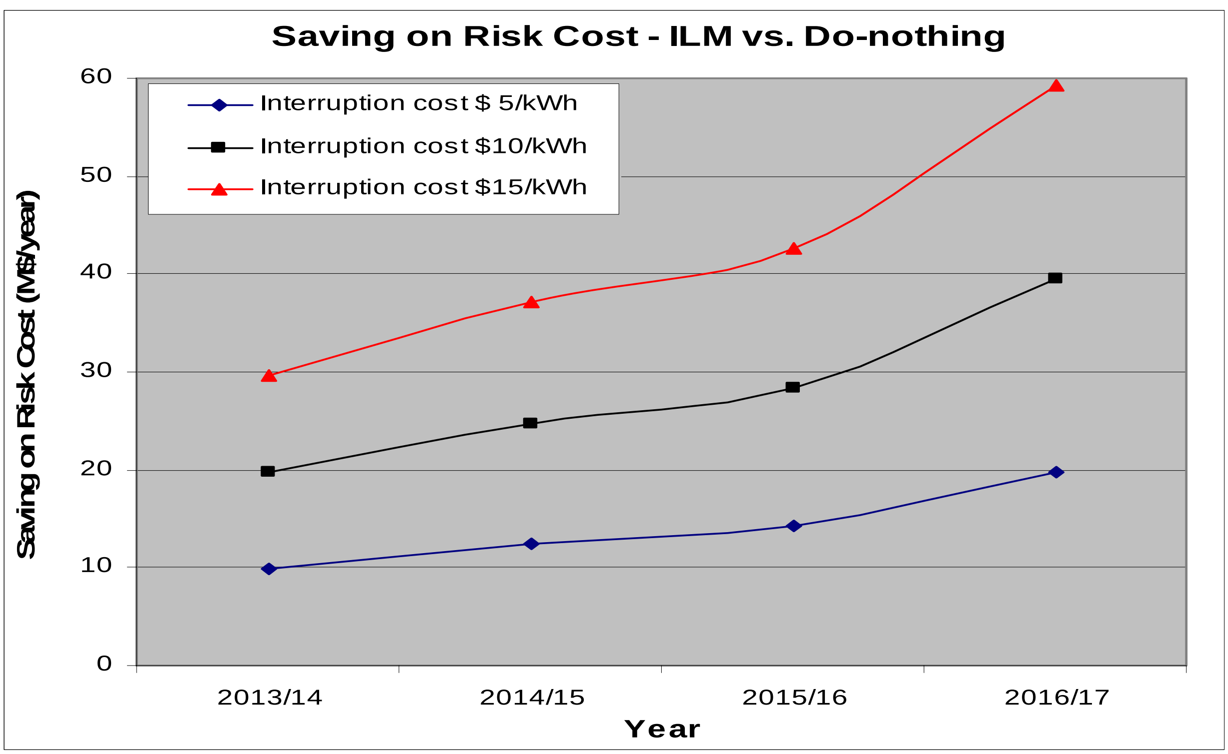
(c) All three portfolios exceed the existing voltage stability limits without Burrard Generating Station.

## 6.0 PROBABILISTIC RELIABILITY ANALYSIS

A probabilistic reliability analysis of a transmission system measures the adequacy of the system in terms of its ability to serve load. The analysis uses historical outage data to model the future random outage behaviour of system components under various loading conditions. The analysis calculates the likelihood of load being lost in terms of Expected Energy Not Served (EENS). This quantity can then be monetized by multiplying the EENS by a per unit customer damage function. The analysis does not determine the EENS if the system becomes insecure and cascades resulting in large amounts of load being lost. Nevertheless, the EENS analysis is a powerful tool for the decision-making process because it quantifies the unreliability of the system for various configurations assuming the system does not blackout.

An EENS analysis was completed in 2006 based on the NITS portfolios to determine the adequacy of the ILM grid with and without an increase in transfer capability of the ILM grid. The difference is shown in Figure 6-1. The difference in risk cost is the average value for the four years 2014 to 2018.

**Figure 6-1. Saving on Risk Cost – ILM vs. Do-nothing**



If the transfer capability of the ILM grid is not increased when it does not meet the single contingency criteria the unreliability of the system grows. Monetizing the impact of this unreliability using the per unit customer damage cost[1] of $10 per kWh results in an annual cost to the customer of $20 M per year in 2014 and increases to $ 40 M per year by 2016. Figure 6-1 also shows the annual cost of the “do nothing” option with higher and lower damage costs. The “do nothing option” can only be applied for four years, because for subsequent years, the load cannot be served during the peak period even under system normal conditions (i.e., with all equipment in service).

## 7.0 CONCLUSION

A review of the results leads to the following conclusions:

The transfer capability of the ILM grid must be increased to meet the single contingency outage requirement for the ILM cut-plane as early as the fall of 2014 for the Amended LTAP portfolio and the Commission approved CRP 1 and CRP 2.

The need for increased transfer capability on the ILM grid was also confirmed in the portfolio studies analyzed in the NITS 2004 studies, during the IEP studies, and during the course of BC Hydro’s 2006 IEP/LTAP proceeding. Depending upon which of these resource scenarios is considered, increased transfer capability on the ILM grid could be needed as early as the fall of 2014 or as late as 2023.[2] Almost all of the portfolios studied have indicated that increased transfer capability at the earliest in-service date is needed.

Resource portfolios that include a repowered Burrard and/or dispatch of the CE result in a deferral of the timing of the need for increased transfer capability on the ILM grid.

[1] This is the same approach that BCTC used in a series of five EENS studies (found at www. bctc.com/the_transmission_system/reliability_assessment/selected_tech_reports.htm) during the VITR proceeding. These studies used a benchmark interruption cost of $5/kWh and looked at sensitivities to other costs. $5/kWh as a benchmark comes from a study entitled “F. Turner, et al. Reliability Worth: Development of A Relationship with Outage Magnitude, Duration and Frequency. CEA paper, March 1994.” For an explanation of the sources of all of the costs, see section 6 of the fourth of the five EENS studies, “Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project, Part IV: Effects of Existing HVDC on VI Power Supply Reliability, Report BCTC-SPPA-R009D, January 9, 2006,” available at the weblink given above.

[2] This date is based on earlier studies that applied a one-hour thermal rating only and did not account for voltage stability limits.

Failure to increase the transfer capability of the ILM grid when needed will result in a violation of the ILM continuous thermal limits and the voltage stability limits due to a Coastal Generation capacity shortfall, for most of the generation resource portfolios. Failure to increase the transfer capability of the ILM grid when required will also increase the unreliability of the system from an adequacy point of view and will increase the risk of cascading outages and blackouts from a security point of view. Conversely, limiting the CU on the ILM grid to be within the existing ILM TTC will result in firm load not being served and inefficient operation of the system with restrictions on remote generation dispatch flexibility. Both outcomes are unacceptable consequences.

BCTC needs to plan the transmission system to meet those scenarios that require additional ILM transfer capability as early as 2014 as well as dealing with scenarios where the need for incremental transfer capability might arise later. Should greater Coastal Generation and/or DSM materialize than the amounts forecast in the above-identified portfolios, it would tend to defer the need for incremental ILM transfer capability. In that event, BCTC would be in a position to consider its impact on the timing of the ILM project. However, because BCTC must also be able to deal with scenarios that require earlier in service dates, proceeding with the approvals required to increase the transfer capability of the ILM grid and preserve an in-service date as early as 2014 is recommended.

# APPENDIX A

## IEP/ LTAP PORTFOLIO ANALYSIS

As part of BC Hydro's 2006 IEP application, BCTC analyzed the transmission implications of seventeen resource portfolios. A complete description of these portfolios can be found in the IEP application at:

http://www.bchydro.com/info/epi/epi43498.html

A summary of the incremental transmission facilities required for each portfolio was presented in Table H-1 of Appendix H in BC Hydro's 2006 IEP application and is included for reference below in Table A-1.

**Table A-1. 2006 IEP Incremental Transmission Facilities**

(Note: Burrard Replacement refers to an SVC device to provide voltage support in lieu of Burrard)

| Transmission Resources | Low Cost (mid-GHG) | Low Cost (GHG @ $10/tonne) | Coal | Low Air Impacts | Low Land Impacts | Diverse Technology | 100% Green | Low Air Impacts without EE 3, 4 or 5 | Low Cost without Site C | Low Cost without EE 3, 4 or 5 | Maintain Burrard | Maintain Burrard for Capacity | Burrard Repowering | Low Cost (up to 6,000 GWh Imports) | Low Cost (3,000 GWh Imports) | Security of Supply | Security of Supply with Insurance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mica G6 Transmission Reinforcement | | | | | | | October 2024 | October 2024 | | | | | | | | | |
| Nicola Substation 500 kV Reconfiguration | October 2012 | October 2011 | October 2011 | October 2012 | October 2011 | October 2012 | October 2012 | October 2010 | October 2012 | October 2010 | October 2012 | | October 2010 | October 2010 | October 2012 | October 2012 | October 2010 |
| Revelstoke G5 Transmission Reinforcement | October 2012 | October 2011 | October 2011 | October 2012 | October 2011 | October 2012 | October 2012 | October 2010 | October 2012 | October 2010 | October 2012 | | October 2010 | October 2010 | October 2012 | October 2010 | October 2010 |
| Revelstoke G6 Transmission Reinforcement | | | | October 2024 | | October 2024 | October 2024 | October 2023 | October 2024 | October 2024 | | | | | October 2024 | October 2024 | |
| Selkirk to Nicola/Ashton Creek Transmission Reinforcement | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 | October 2009 |
| Kelly Lake to Cheekye 500 kV line (5L46) | | October 2023 | October 2021 | | | | | | | October 2019 | | October 2022 | | | | | |
| Mica G5 Transmission Reinforcement | October 2024 | October 2024 | October 2024 | October 2024 | | October 2024 | October 2020 | October 2020 | October 2024 | October 2024 | October 2024 | | October 2024 | October 2024 | October 2024 | October 2014 | October 2024 |
| Nicola to Meridian 500 kV line (5L83) | October 2013 | October 2013 | October 2013 | October 2013 | | October 2013 | October 2013 | October 2013 | October 2013 | October 2013 | October 2013 | October 2013 | October 2020 | October 2013 | October 2013 | October 2014 | October 2016 |
| 2nd Vancouver Island 230 kV line | October 2023 | October 2020 | October 2020 | October 2024 | October 2024 | October 2022 | | October 2020 | October 2023 | October 2019 | October 2021 | October 2022 | October 2021 | October 2023 | October 2022 | | |
| Burrard Replacement | April 2014 | April 2014 | April 2014 | April 2014 | April 2014 | April 2014 | April 2014 | April 2014 | April 2014 | April 2014 | | | | April 2014 | April 2014 | April 2014 | April 2014 |

Thirteen of the seventeen portfolios required incremental facilities on the ILM grid (indicated as 5L83) by the earliest feasible in-service date. Three of the portfolios required in service dates from by 2014 to 2020, and one portfolio was constructed to require no incremental facilities on the ILM grid.

During BC Hydro's 2006 IEP hearings, BCTC conducted an analysis of the ILM requirements for the LTAP, CRP1, and CRP2 portfolios. The analysis was based on the December 2006 load forecast. It examined the impact of re-powering Burrard, applying the CE as a network resource, and dispatching maximum or dependable capacity of Interior generation resources on the timing of incremental facilities on the ILM grid. Results of the analysis are published and are summarized in Table A-2 for reference:

**Table A-2. Resource Portfolios Reviewed During 2006 IEP Hearings**

| | Resource Portfolios Reviewed During 2006 IEP Hearings | Required ILM In-Service Date |
|---|---|---|
| 1 | LTAP + Max Interior Dispatch | October 2014 |
| 2 | CRP1 + Max Interior Dispatch | October 2014 |
| 3 | CRP2 + Max Interior Dispatch | October 2014 |
| | | |
| 4 | LTAP + Re-powered BGS + Max Interior Dispatch | October 2014 |
| 5 | CRP1 + Re-powered BGS + Max Interior Dispatch | October 2014 |
| 6 | CRP2 + Re-powered BGS + Max Interior Dispatch | October 2014 |
| | | |
| 7 | LTAP + Re-powered BGS + CE + Max Interior Dispatch | October 2020 |
| 8 | CRP1 + Re-powered BGS + CE + Max Interior Dispatch | October 2017 |
| 9 | CRP2 + Re-powered BGS + CE + Max Interior Dispatch | October 2017 |
| | | |
| 10 | LTAP + Dependable Interior Dispatch | October 2018 |
| 11 | CRP1 + Dependable Interior Dispatch | October 2014 |
| 12 | CRP2 + Dependable Interior Dispatch | October 2014 |
| | | |
| 13 | LTAP + Re-powered BGS + Dependable Interior Dispatch | October 2023 |
| 14 | CRP1 + Re-powered BGS + Dependable Interior Dispatch | October 2014 |
| 15 | CRP2 + Re-powered BGS + Dependable Interior Dispatch | October 2014 |
| | | |
| 16 | LTAP + Re-powered BGS + CE + Dependable Interior Dispatch | October 2023 |
| 17 | CRP1 + Re-powered BGS + CE + Dependable Interior Dispatch | October 2019 |
| 18 | CRP2 + Re-powered BGS + CE + Dependable Interior Dispatch | October 2018 |

The need for increased transfer capacity on the ILM grid was also analyzed in the 2004 NITS studies, in studies prior to the submission of the BC Hydro's 2006 IEP application, and in studies during BC Hydro's 2006 IEP/LTAP proceeding. All of these studies used the N-1 thermal nomogram with one hour continuous thermal rating of the existing ILM grid to determine timing of the peak hour negative ATC of the grid. Each study was conducted based on the latest set of available load forecasts, the most likely resource scenarios, and the firm export possibilities at the time of study. The analysis data and assumptions are listed in Table A-3.

**Table A-3. Analysis Data and Assumptions**

| | Studies | Load Forecast | Resource Portfolios | Export Western Inter-tie |
|---|---|---|---|---|
| 1 | NITS2004<br>(8 scenarios) | October 2004 coincidental normal and high | Base resource plan, Alternative 1, Alternative 2, Alternative 3 | 230 MW<br>and<br>730 MW |
| 2 | Before 2006 IEP Submission<br>(17 scenarios) | December 2005 coincidental normal and high | Coal, Low air impacts, Low land impacts, Diverse technology, 100% Green, Low cost (mid GHG), Low cost (GHG@ $10/tonne), Maintain Burrard, Low cost (3000 GWh import), Maintain Burrard for capacity, Low cost without Site C, Burrard re-powering, Low cost (up to 6000 GWh imports), Security of supply with insurance, Low air impact w/o EE3 or 4 or 5, Security of Supply, Low cost impact w/o EE3 or 4 or 5 | 230 MW |
| 3 | During 2006 IEP Submission<br>(18 scenarios) | December 2006 coincidental normal and high | LTAP+Max Interior Dispatch, CRP1+Max Interior Dispatch, CRP2+Max Interior Dispatch, LTAP+Max Interior Dispatch+BGS repowering, CRP1+Max Interior Dispatch+BGS repowering, CRP2+Max Interior Dispatch+BGS repowering, LTAP+Max Interior Dispatch+BGS repowering+CE, CRP1+Max Interior Dispatch+BGS repowering+CE, CRP2+Max Interior Dispatch+BGS repowering+CE,<br>LTAP+Dep Interior Dispatch, CRP1+Dep Interior Dispatch, CRP2+Dep Interior Dispatch, LTAP+Dep Interior Dispatch+BGS repowering, CRP1+Dep Interior Dispatch+BGS repowering, CRP2+Dep Interior Dispatch+BGS repowering, LTAP+Dep Interior Dispatch+BGS repowering+CE, CRP1+Dep Interior Dispatch+BGS repowering+CE, CRP2+Dep Interior Dispatch+BGS repowering+CE | 230 MW |

The need for incremental facilities on the ILM grid was recognized in the eight NITS 2004 load/resource scenarios. In all of the NITS2004 scenarios, the ATC of the ILM grid would be depleted before a new ILM transmission line could be built. As a result, the earliest feasible in service date of a new transmission line was considered the earliest date for increasing the transfer capability of the ILM grid.

The need for the increased transfer capability on the ILM grid was confirmed in sixteen of the seventeen portfolios that BCTC reviewed prior to submission of the 2006 IEP. In terms of ILM's ISD, thirteen of the reviewed portfolios had 2013, one required a 2014, one a 2016, and one portfolio had a 2020. The only load/resource portfolio that did not require incremental facilities on the ILM transmission grid was based on the addition of approximately 1700 MW new thermal generation near the load center.