System Impact Study
For
BC Hydro Distribution
NITS 2004 – Stage 2 – Preliminary Results

Report # SP2005 – 05

March, 2005

System Planning and Performance Assessment

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Executive Summary

In February 2005, as a part of the System Impact Study Agreement between "BC Transmission Corporation" (BCTC) and "BC Hydro Distribution" (BCHD), BCTC released the "System Impact Study For BC Hydro Distribution NITS 2004 – Stage 1 – Preliminary Results, Report # SP2005-04". That report presented itemized lists of the required transmission network reinforcements for the eight different load / resource / export scenarios that BCHD provided. It also identified the amount of coastal generation that must be available to support system reliability under each scenario. In the report, the required coastal generation levels were referred to as the "Reliability Must Run (RMR) coastal generation levels".

This Stage 2 report of the NITS 2004 SIS expands on the preliminary results of Stage 1 and identifies the project phases and timelines associated with major Network Upgrades and Direct Assignment Facilities based on the reinforcements identified in Stage 1. In addition, BCTC has identified that the retirement of Burrard in 2014 will result in a reduction of import capability of approximately 600 MW unless the VAR support, reactive power and rotational energy are replaced. The RMR levels associated with Vancouver Island have also been revised to include the effect of transmission losses.

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1. Introduction

BCTC provides the following information under System Impact Study Stage 2 preliminary results for BCHD NITS 2004:

1. The significant phases of the proposed projects and associated timelines for major "Network Upgrades".
2. The significant phases of the proposed projects associated timelines for "Direct Assignment Facilities" that are required to start prior to 31 March 2007 .
3. The impact of retiring Burrard Generating Station in 2014 on import capability from the US.
4. The amount of RMR generation offset on Vancouver Island (VI) resulting from each Lower Mainland (LM) to VI cable reinforcement.

This report is a supplement to the SP2005-04 report entitled "System Impact Study for BC Hydro Distribution NITS 2004 Stage 1" completed by BCTC on February 28, 2005.

1.1 List of All Transmission Reinforcements

Report SP2005-04 reviewed eight different load, resource and export scenarios and identified the required Network Upgrades (NU) and Direct Assignment Facilities (DAF) for each scenario. NUs are for the general benefit of all users of the transmission system. DAFs describe the facilities that are constructed for the sole use/benefit of a particular transmission customer. Table 1.1.1 is a summary of all the transmission reinforcement projects identified in SP2005-04. This table can be used for quick reference. Included in the table are all "NU" and "DAF" identified in the Stage 1 report and their associated scenarios.

Table 1.1.1

ITEM	PROJECT DESCRIPTION	REGION	TYPE	SCENARIO
1	Nicola-Meridian 500 kV Line (5L83) 50% series compensation, at or near AMC, 3000 A.	Interior to Lower Mainland	NU	All
2	Kelly Lake-Cheekye 500 kV Line (5L46) 50% series compensation , at or near Creekside, 3000 A	Interior to Lower Mainland	NU	All
3	Ingledow SVC, -200/+300 MVAr	Lower Mainland	NU	All
4	Arnott-Vancouver Island Terminal 230 kV AC Cable Circuits (2L124 & 2L129) Each with a 600 MVA Phase Shifting Transformer at Vancouver Island Terminal	Lower Mainland to Vancouver Island	NU	All
5	Ingledow-Arnott 230 kV circuits (2L10 & 2L57) Upgrading	Lower Mainland	NU	All
6	Sahtlam 230 kV, 66.1 MVAr shunt reactors, two units.	Vancouver Island	NU	All
7	Generic third tie to Vancouver Island	Vancouver Island	NU	All
8	Series Compensation of Selkirk-Ashton Creek Line 5L91, 50% compensation, 2750 A	South Interior	NU	All
9	Series Compensation of Selkirk-Vaseux Lake Line 5L96, 50% compensation, 2750 A	South Interior	NU	All
10	Series Compensation of Vaseux Lake-Nicola Line	South Interior	NU	All

ITEM	PROJECT DESCRIPTION	REGION	TYPE	SCENARIO
	5L98, 50% compensation, 2750 A			
11	Series Compensation of Selkirk-Cranbrook Line 5L92, 50% compensation, 2750 A	South Interior	NU	4, 8
12	Series Compensation of Cranbrook-Langdon Line 5L94, 50% compensation, 2750 A	South Interior	NU	4, 8
13	Selkirk Transformer Bank Addition T4 (1200 MVA)	South Interior	NU	All
14	Selkirk 500 kV, 123 MVAr shunt Reactor	South Interior	NU	All
15	New 500 kV Selkirk - Vaseux Lake -Nicola lines 5L97 and 5L99	South Interior	NU	4, 8
16	Series compensation of the new Selkirk–Vaseux Lake-Nicola 500 kV lines, 50% compensation, 2750 A.	South Interior	NU	4, 8
17	The interconnection from East Kootenay Thermal (600 MW) to Cranbrook station	South Interior	DAF	4, 8
18	Series compensation of Mica – Nicola lines 5L71 and 5L72, each line 40% compensation and 3200 A	South Interior	DAF	All
19	Nicola 500 kV Station Reconfiguration	South Interior	NU	All
20	Nicola 500 kV 300 MVAr Shunt Capacitor #1	South Interior	NU	3, 7
21	Nicola 500 kV 300 MVAr Shunt Capacitor #2	South Interior	NU	3, 7
22	Nicola 500 kV SVC, -200/+300 MVAr	South Interior	NU	3, 7
23	Downie (DOW) 500 kV Switching Station	South Interior	NU	3, 7
24	Downie – Revelstoke 500 kV line 5L78	South Interior	NU	3, 7
25	Ashton Creek 250 MVAr Shunt Capacitor	South Interior	NU	2, 3, 4, 6, 7, 8
26	The interconnection from Kitimat_SCGT(180 MW) to Kitimat station	North Interior	DAF	1, 5
27	Upgrade Kennedy series capacitor station: Increase the series compensation from 50% to 65%. Increase the rated current of series capacitors from 2310 A to the minimum of 2500 A.	North Interior	NU	2, 6
28	Upgrade McLeese series capacitor station: Increase the series compensation from 50% to 65%. Increase the rated current of series capacitors from 1950 A to the minimum of 2500 A.	North Interior	NU	2, 6
29	Upgrade of GM Shrum to Williston lines 5L1, 5L2 and 5L3 from 2500 A to the minimum of 2750 A	North Interior	NU / DAF	2, 6
30	Upgrade Williston to Kelly Lake lines 5L11 and 5L12 from 2500 A to the minimum of 2750 A	North Interior	NU	2, 6
31	Williston 500 kV, 500 MVAr SVC or shunt Capacitor compensation	North Interior	NU	2, 6
32	Kelly Lake 500 kV, 500 MVAr SVC or shunt Capacitor compensation	North Interior	NU	2, 6
33	Two 500 kV circuits from Site C (900 MW) to Peace Canyon switchyard	North Interior	DAF	2, 6
34	The interconnection from NW_Wind (700 MW) to Skeena Substation	North Interior	DAF	2, 6
35	Apply Remedial Action Schemes (RAS)	All Regions	NU	All

2. Significant Project Phases for Reinforcements

This report identifies the significant project phases required for completing major NITS 2004 transmission reinforcements.

The time required for the Identification and Study phase of major upgrades varies depending on whether a required upgrade is driven by an internal BCTC planning process or by a formal customer request for service under the Tariff. A formal customer request will initiate a System Impact Study (SIS) and may lead to a Facilities Study (FS).

The Tariff defines timelines and deliverables for both the SIS and the FS. Given the short timeframes required under the Tariff, the level of detail and accuracy included in the studies can vary depending on the amount of new information and/or studies required.

2.1 "Identification and Study" Phase

The Identification and Study phase is the first phase in the process and is initiated when a potential shortfall in power transfer capability is first recognized. This is usually identified through an internal BCTC planning study or in response to a customer request.

During this phase, the implications of the potential shortfall are evaluated and options to address the system constraint are identified and evaluated. The Identification and Study phase is complete when reinforcement options to relieve the system constraint have been identified, scoped, and estimated.

Development of options to relieve constraints can take many months or even years to plan and develop and is dependent on the complexity of the reinforcement. Identification of reinforcement options before a formal customer request will allow time to fully develop the reinforcement options.

Phase Deliverables:

- Planning cost estimates (accuracy ± 30%) and proposed schedules for the potential reinforcement options with preliminary scoping documents to describe the project.
- A preliminary system planning report, which is an internal BCTC planning document describing the anticipated need for reinforcement, the alternative solutions identified, and the preferred option.
- A SIS report, which is the formal customer report provided under the Tariff that describes the recommended reinforcement to meet the customer requirements.
- A FS report that confirms, and describes in more detail, the recommended reinforcement, estimated cost and proposed schedule.

2.2 "Definition" Phase

The Project Definition Phase begins when a customer contract has been signed and/or BCTC management has given approval to proceed with a particular reinforcement project. The purpose of this phase is to fully define the project, refine project cost estimates, complete public consultation and obtain all required approvals. Approvals that may be required include a Certificate of Public Convenience and Necessity (CPCN) and other necessary authorizations from the BC Utilities Commission (BCUC) and/or other government agencies. This definition phase is completed when the required project approvals have been received.

Deliverables:

- Final system planning study report providing a detailed analysis of the selected project.

- A System Application report that describes the project in detail and its functional performance as well as associated network, protection, control, and telecommunication requirements
- A detailed Project Plan that includes equipment performance specifications, conceptual design, a list of project tasks and their associated costs and proposed schedule.
- An Expenditure Authorization Request (EAR) quality estimate of project cost (±10% accuracy level)
- Recommended site (for stations) or route (for transmission lines).
- CPCN and other financial and environmental approvals by BCUC or other government agencies.

2.3 "Implementation" Phase

The project Implementation phase begins once all approvals have been received and BCTC management have endorsed the project. It is completed when the project is commissioned and is accepted by BCTC Operations.

Deliverables:

- Final design, with station layout, equipment specifications, transmission line's centre-line, and detailed specifications ready for tendering.
- A constructed and commissioned project and the new and modified operating orders.

2.4 Possible Overlap of Definition and Implementation Phases

If necessary to secure a desired project in-service date, it may be possible to begin the implementation phase of the project before the approval portion of the definition phase is completed. BCTC and the transmission user purchasing the service need to recognize and understand the risks associated with the early start of the implementation phase. BCTC will not accept these implementation risks therefore any costs arising from the advancement will be borne by the customer.

2.5 Significant Project Phasing of Network Upgrades

Table 2.5.1 shows the different phases required for completion of the major NITS 2004 NU projects. Phasing duration and descriptions are based on the information available to BCTC at the time of this SIS. The information is approximate and should not be treated as project schedule. A more accurate account of project schedules will be provided in the FS.

In tables 2.5.1 and 2.6.1 each reinforcement project is listed only once, with the earliest of its potential in-service dates from the scenarios in the Stage 1 report.

Table 2.5.1

ITEM	NETWORK UPGRADE PROJECT DESCRIPTION	ID & STUDY PHASE	DEFINITION PHASE	IMPLEMENTATION PHASE
1	NIC-MDN 500 kV Line (5L83) 50% series compensation, at or near AMC, 3000 A.	Before Oct.’04	Oct.’04 – Aug.‘08	Sep.’08 – Oct.‘13
2	KLY-CKY 500 kV Line (5L46) 50% series compensation , at or near CRK, 3000 A	Feb.’05– Sep. ‘05	Oct.’05 – Aug.’09	Sep.’09 – Oct.’14
3	ING SVC, -200/+300 MVAr	Apr.’05 – Sep.’05	Oct.’05 – Sep.’06	Oct.’06 – Oct.’09
4	ARN-VIT 230 kV AC Cable Circuits (2L124 & 2L129). Each with a 600 MVA Phase Shifting Transformer at VIT	Before Apr.’04	Apr.’04 – Jul.’06	Dec.’05 – Oct.’08
5	ING-ARN 230 kV circuits (2L10 & 2L57) Upgrading	Oct.'05 - Mar.'06	Apr.'06 - Mar.'07	Apr.'07 - Oct.'08
6	SAT 230 kV, 66.1 MVAr shunt reactors, two units.	Before Apr.'04	Apr.'04 - Sep.'06	Oct.'06 - Oct.'08

ITEM	NETWORK UPGRADE PROJECT DESCRIPTION	ID & STUDY PHASE	DEFINITION PHASE	IMPLEMENTATION PHASE
7	Generic third tie to Vancouver Island	Oct.'06 - Sep.'07	Oct.'07 - Aug.'10	Sep.'10 - Oct.'14
8	Series Compensation of 5L91 50% compensation, 2750 A	Oct.'04 – Sep.'05	Oct.'05 – Apr.'07	May '07 – Oct.'09
9	Series Compensation of 5L96 50% compensation, 2750 A	Oct.'04 – Sep.'05	Oct.'05 – Apr.'07	May '07 – Oct.'09
10	Series Compensation of 5L98 50% compensation, 2750 A	Oct.'04 – Sep.'05	Oct.'05 – Apr.'07	May '07 – Oct.'09
11	Series Compensation of 5L92 50% compensation, 2750 A	Oct.'07 – Sep.'09	Oct.'09 – Sep.'11	Oct.'11 – Oct.'14
12	Series Compensation of 5L94 50% compensation, 2750 A	Oct.'07 – Sep.'09	Oct.'09 – Sep.'11	Oct.'11 – Oct.'14
13	SEL Transformer Bank Addition T4 (1200 MVA)	Oct.'04 – Jan.'05	Feb.'05 – Mar.'05	Apr.'05 – Nov.'06
14	SEL 500 kV, 123 MVAr shunt Reactor	Oct.'04 – Jan.'05	Feb.'05 – Mar.'05	Apr.'05 – Jul.'06
15	New 500 kV SEL-VAS-NIC lines 5L97 and 5L99	Feb.'05 – Sep.'06	Oct.'06 – Aug.'09	Sep.'09 – Oct.'14
16	Series Compensation of the new SEL-VAS-NIC 500 kV lines. 50% compensation, 2750 A	Feb.'05 – Aug.'10	Sep.'10 – Apr.'12	May '12 – Oct.'14
18	Series Compensation of 5L71 and 5L72 Each line 40% compensation and 3200 A	Oct.'04 – Sep.'05	Oct.'05 – Apr.'07	May '07 – Oct.'09
19	NIC 500 kV Station Reconfiguration	Oct.'04 – Mar.'06	Apr.'06 – Mar.'07	Apr.'07 – Oct.'09
20	NIC 500 kV, 300 MVAr Shunt Capacitor #1	Oct.'05 – Mar.'08	Apr.'08 – Jun.'09	Jul.'09 – Oct.'11
21	NIC 500 kV, 300 MVAr Shunt Capacitor #2	Oct.'08 – Mar.'11	Apr.'11 – Jun.'12	Jul.'12 – Oct.'14
22	NIC 500 kV SVC, -200/+300 MVAr	Oct.'09 – Mar.'11	Apr.'11 – Mar.'12	Apr.'12 – Oct.'14
23	DOW (Downie) 500 kV Switching Station	Oct.'06 – Sep.'08	Oct.'08 – Aug.'11	Sep.'11 – Oct.'14
24	DOW – REV 500 kV line 5L78	Oct.'06 – Sep.'08	Oct.'08 – Aug.'11	Sep.'11 – Oct.'14
25	ACK 250 MVAr Shunt Capacitor	Oct.'05 – Mar.'08	Apr.'08 – Jun.'09	Jul.'09 – Oct.'11
27	Upgrade KDY series capacitor station: Increase the series compensation from 50% to 65%. Increase the rated current of series capacitors from 2310 A to the minimum of 2500 A .	Oct.'09 - Sep.'11	Oct.'11 - Sep.'12	Oct.'12 - Oct.'14
28	Upgrade MLS series capacitor station: Increase the series compensation from 50% to 65%. Increase the rated current of series capacitors from 1950 A to the minimum of 2500 A.	Oct.'09 - Sep.'11	Oct.'11 - Sep.'12	Oct.'12 - Oct.'14
29	Upgrade 5L1, 5L2 and 5L3 from 2500 A to the minimum of 2750 A	Oct.'09 - Sep.'11	Oct.'11 - Sep.'12	Oct.'12 - Oct.'14
30	Upgrade 5L11and 5L12 from 2500 A to the minimum of 2750 A	Oct.'09 - Sep.'11	Oct.'11 - Sep.'12	Oct.'12 - Oct.'14
31	WSN 500 kV, 500 MVAr SVC or shunt Capacitor compensation	Oct.09 – Mar.'11	Apr.'11 – Mar.'12	Apr.'12 – Oct.'14
32	KLY 500 kV, 500 MVAr SVC or shunt Capacitor compensation	Oct.'09 – Mar.'11	Apr.'11 – Mar.'12	Apr.'12 – Oct.'14
35	Apply Remedial Action Schemes (RAS)	Oct.'05 - Sep.'06	Oct.'06 - Sep.'07	Oct.'07 - Oct.'24

2.6 Significant Project Phasing of Direct Assignment Facilities

Table 2.6.1 shows different phases for completion of the NITS 2004 DAF projects. Phasing durations and descriptions are based on the information available to BCTC at the time of SIS. The information is approximate and should not be treated as project schedule. A more accurate account of project schedules will be provided in the FS.

Table 2.6.1

ITEM	DIRECT ASSIGN. FACILITIES PROJECT DESCRIPTION	ID & STUDY PHASE	DEFINITION PHASE	IMPLEMENTATION PHASE
17	The interconnection from EKT (600 MW) to CBK station	Oct.'06 - Sep.'07	Oct.'07 - Sep.'10	Oct.'10 - Oct.'14

ITEM	DIRECT ASSIGN. FACILITIES PROJECT DESCRIPTION	ID & STUDY PHASE	DEFINITION PHASE	IMPLEMENTATION PHASE
18	Series Compensation of 5L71 and 5L72 Each line 40% compensation and 3200 A	Oct.'04 – Sep.'05	Oct.'05 – Apr.'07	May '07 – Oct.'09
26	The interconnection from KIT_SCGT(180 MW) to KIT station	Oct.'05 - Sep.'06	Oct.'06 - Sep.'07	Oct.'07 - Oct.'09
33	Two 500 kV circuits from Site C (900 MW) to PCN switch yard	Oct.'06 - Sep.'07	Oct.'07 - Sep.'10	Oct.'10 - Oct.'14
34	The interconnection from NW_Wind (700 MW) to SKA station	Oct.'06 - Sep.'07	Oct.'07 - Sep.'10	Oct.'10 - Oct.'14

3. Transmission Impact of Burrard Retirement

Retirement of Burrard will reduce the net import capability to BC by approximately 600 MW. The reduction in import capability is due to the loss of VAr support, dynamic reserves and rotational energy that Burrard currently provides. The most significant impact results from the loss of Burrard's VAr support which results in less control to prevent over-voltages during a double contingency event caused by the simultaneous loss of 5L51 and 5L52.
When the 5L51 and 5L52 double contingency occurs, with heavy flows into BC, controlled action is required to minimize the impacts on both the Alberta and US grids. The 5L51 and 5L52 contingency will trigger the Eastern Controlled Separation Remedial Action Scheme (ECS RAS), which will trip both the eastern BC–US tie(s) and the BC–Alberta ties. Islanding of BCTC system will occur with possible tripping of the Alcan tie due to excessive transient power.

After the separation, the under-frequency load shedding scheme and governor action will bring the islanded BC system back to a load and resource balance. At this stage, sufficient rotational inertia is required to prevent the frequency from dropping below 58.0 Hz, and there must be adequate absorbing dynamic reactive reserves to prevent over-voltages. This is especially true in the Lower Mainland Metro area where there are underground cables. Currently Burrard provides this capability.

Factors that limit the import of power from the US include the network load level, on-line generator inertia, and absorbing reactive reserves within the Lower Mainland. The total import capability, from all neighboring sources, into BC depends on the amount of on-line rotational energy in BC. Reactive requirements, to control over-voltages, are locality specific and are far more complex to analyze. When load shedding is required, its order and amount depends on the load level, load distribution, the electrical frequency at which each load is dropped, the status of transmission lines, and the overall rotational inertia of the BC system.

3.1 Impact of Burrard Retirement on Rotational Energy

The relative impact of retiring Burrard on the US import limits due to the reduction of rotational energy can be readily assessed. To control over-voltages caused by the loss of 5L51 and 5L52, the BCTC System Operating Order 7T22 requires a minimum of two Burrard units on-line during light load conditions. Each Burrard unit provides 500 MJ of inertia. This level of inertia is considered relatively light when compared to 1200 MJ for a GMS unit and 2865 MJ for a MCA unit. Interpolating the table in section 5.0 of the BCTC System Operating Order 7T64 it can be concluded, from the point of view of on-line inertia, retirement of Burrard will cause a reduction of about 30 MW in total import capability, assuming a 4000 MW BC Hydro load.

3.2 Reactive Reserve Impacts

Accurate determination of reactive reserves required to prevent over-voltages is difficult, even for the present day system. It requires detailed and accurate reactive modeling and simulations. Rough determination of reactive reserve requirements 10 years from now is very difficult, if not impossible. Planning uncertainty combined with modeling inaccuracies lead to even greater uncertainty in the results. The planned addition of 5L83 and 2L129 and the retirement of the HVDC increase the charging in the Lower Mainland area significantly and have to be compensated for.

Even though absolute accuracy cannot be achieved, an approximation of the relative effect of Burrard retirement, based on the previous studies of the current system, is possible. Previous studies indicated that, with BC Hydro loads below 5000 MW, reducing the number of on-line Burrard units from two to one will diminish the import limit from the US into BC by approximately 200 MW. The BCTC System Operating Order 7T22 requires removal of several 500 kV lines if there is only one Burrard unit on line. Reducing the number of Burrard units to zero will diminish the import limits non-linearly. A conservative estimate of the reduction in import capability from the US into BC, following Burrard retirement, is 600 MW.

If Burrard is retired in 2014 then replacement dynamic reactive reserves will be required to meet firm import commitments for NITS.

Retirement of Burrard not only impacts import capability, but also impacts the ability of the system to serve load during peak periods. Therefore simply accepting a lower import capability will not eliminate the need for the replacement of the Burrard reactive power capability.

4. Impact of LM-VI Reinforcements on RMR Generation on VI

The Preliminary Results of System Impact Study for BCHD NITS 2004 - Stage 1 Report SP2005-04 suggest the following reinforcements for Vancouver Island:

- Two new 230 kV submarine cable circuits between the Lower Mainland and Vancouver Island in October 2008,
- Two 66.1 MVAr shunt reactors at SAT to coincide with the in-service date of the cables,
- Upgrade of 2L10 and 2L57 to coincide with the in-service date of the cables.
- A generic third LM-VI tie in October 2014.

The proposed new tie will consist of an additional Ingledow transformer and a new transmission circuit from Ingledow substation to Vancouver Island Terminal substation via Arnott substation.

Without the stated transmission reinforcements, higher RMR generation on Vancouver Island will be required and the on-island transmission network may need to be reinforced depending on the amount and location of the proposed on-island generation. The impact of the suggested LM-VI upgrades on the amount of VI RMR generation is illustrated in tables 4.1 and 4.2. Table 4.1 lists the RMR generation levels for Study Scenarios 1 and 5 (1 in 2 year load forecast) over the next 20 years, and Table 4.2 is applicable to the Study Scenarios 2, 3, 4, 6, 7 and 8 (1 in 10 year load forecast). Tables 4.1 and 4.2 in this report are the revised version of Tables 10.5 and 10.6 in the Stage 1 report. The revision is based on a more accurate modeling of the transmission losses in the Stage 2 analysis.

The stated VI upgrades only cover the bulk transmission system. Significant regional transmission and VAr supply reinforcement on the island may still be required. The regional reinforcements will be identified in Stage 3 of the SIS for the selected scenarios.

Table 4.1: Vancouver Island RMR Generation (MW) for Study Scenarios 1 and 5

Year	No Additional Transmission to VI	One Cable in Service	2 Cables in Service	3 Cables in Service	Note
2004/05	724	724	724	724	
2005/06	728	728	728	728	
2006/07	743	743	743	743	
2007/08	997	997	997	997	Planning retirement of HVDC
2008/09	1025	425	0	0	1st/2nd LM-VI cables In-Service Date: October 2008
2009/10	1055	455	0	0	
2010/11	1112	512	0	0	
2011/12	1136	536	0	0	
2012/13	1171	571	0	0	
2013/14	1205	605	5	0	
2014/15	1239	639	39	0	Generic 3rd LM-VI cable In-Service Date: October 2014
2015/16	1277	677	77	0	
2016/17	1317	717	117	0	
2017/18	1357	757	157	0	
2018/19	1398	798	198	0	
2019/20	1440	840	240	0	
2020/21	1482	882	282	0	
2021/22	1525	925	325	0	
2022/23	1569	969	369	0	
2023/24	1613	1013	413	0	
2024/25	1658	1058	458	0	

Table 4.2: Vancouver Island RMR Generation (MW) for Study Scenarios 2, 3, 4, 6, 7 and 8

Year	No Additional Transmission to VI	One Cable in Service	2 Cables in Service	3 Cables in Service	Note
2004/05	845	845	845	845	
2005/06	851	851	851	851	
2006/07	868	868	868	868	
2007/08	1125	1125	1125	1125	Planning retirement of HVDC
2008/09	1156	556	0	0	1st/2nd LM-VI cables In-Service Date: October 2008
2009/10	1189	589	0	0	
2010/11	1248	648	48	0	Generic 3rd LM-VI cable In-Service Date: October 2010
2011/12	1274	674	74	0	
2012/13	1312	712	112	0	
2013/14	1348	748	148	0	
2014/15	1384	784	184	0	
2015/16	1425	825	225	0	
2016/17	1467	867	267	0	
2017/18	1510	910	310	0	
2018/19	1554	954	354	0	
2019/20	1598	998	398	0	
2020/21	1643	1043	443	0	
2021/22	1689	1089	489	0	
2022/23	1736	1136	536	0	
2023/24	1783	1183	583	0	
2024/25	1830	1230	630	30	

5. Conclusions

Stage 2 of the NITS 2004 SIS expands on the preliminary results of Stage 1 and identifies the project phases and timelines associated with major Network Upgrades and Direct Assignment Facilities based on the reinforcements identified in Stage 1. In addition, BCTC has identified that the retirement of Burrard in 2014 will result in a reduction of import capability of approximately 600 MW unless the VAR support, reactive power and rotational energy are replaced. The RMR levels associated with Vancouver Island have also been revised to include the effect of transmission losses.