

Chris Sandve
Chief Regulatory Officer
bchydroregulatorygroup@bchydro.com

December 20, 2024

Patrick Wruck
Commission Secretary and Manager
Regulatory Services
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Patrick Wruck:

**RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Application for Electric Tariff Supplement No. 110 – Load Curtailment
Agreement for Customers Served through Natal Substation**

BC Hydro writes to file the attached application for approval of Tariff Supplement No. 110 (**TS 110**).

TS 110 is a permanent load curtailment agreement for applicable customers that are, or would be, subject to the Natal Load Shedding Remedial Action Scheme which exists today on BC Hydro's system and has a low probability of occurrence. TS 110 will allow status quo service to be maintained for affected customers while avoiding the need for costly infrastructure investments to address a low probability event.

Concurrent with this filing and under separate cover, BC Hydro is also submitting an application for approval of Tariff Supplement No. 108 (**TS 108**). TS 108 is an interim, interruptible transmission service agreement for customers requesting new or increased load in the Dawson Creek area prior to the in-service date of a fourth transformer (currently expected to be March 2027), which is required to meet this load growth on a permanent basis. TS 108 will allow us to connect customers earlier than would otherwise be the case (i.e., prior to the fourth transformer entering service).

These applications will achieve compliance with Mandatory Reliability Standard TPL-001-4 (**TPL-001-4**), which does not permit Non-Consequential Load Loss or the interruption of Firm Transmission Service under certain system contingencies starting July 1, 2025.

Neither application imposes additional costs on ratepayers and both are supported by affected customers.

December 20, 2024
Patrick Wruck
Commission Secretary and Manager
Regulatory Services
British Columbia Utilities Commission
**Application for Electric Tariff Supplement No. 110 – Load Curtailment Agreement
for Customers Served through Natal Substation**

For further information, please contact Shiau-Ching Chou at
bchydroregulatorygroup@bchydro.com.

Yours sincerely,



Chris Sandve
Chief Regulatory Officer

jl/rh

Enclosure

**BC Hydro Application for Tariff Supplement
No. 110 – Load Curtailment Agreement for
Customers Served Through Natal Substation**

Chris Sandve
Chief Regulatory Officer
bchydroregulatorygroup@bchydro.com

December 20, 2024

Patrick Wruck
Commission Secretary and Manager
Regulatory Services
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Patrick Wruck:

**RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Application for Electric Tariff Supplement No. 110 – Load Curtailment
Agreement for Customers Served through Natal Substation**

BC Hydro writes pursuant to sections 58 to 61 of the *Utilities Commission Act* for approval of Electric Tariff Supplement No. 110 (**TS 110** or **Tariff Agreement**) for the provision of electricity service on a curtailable basis for applicable transmission voltage customers in the southern interior region of B.C. Subject to the terms of the Tariff Agreement, TS 110 will be required for any BC Hydro customer who takes, or proposes to take, electricity pursuant to an Electricity Supply Agreement (**ESA**) that is or would be subject to the Natal Load Shedding Remedial Action Scheme (**Natal Load Shedding RAS**).^{1,2}

BC Hydro has developed TS 110 to meet our compliance obligations associated with Mandatory Reliability Standard TPL-001-4 (**TPL-001-4**), made effective in B.C. through BCUC Order No. R-27-18A.³ As discussed further below, BC Hydro understands that the status quo (i.e., the Natal Load Shedding RAS) will not be compliant with TPL-001-4 after June 30, 2025. The proposed TS 110 resolves this issue and achieves compliance.

¹ RAS is defined by the North American Electric Reliability Corporation (**NERC**) Glossary of Terms as: "A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s)." The NERC Glossary of Terms is available at:
https://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf.

² The Natal Load Shedding RAS is as described in BC Hydro's operating order for the B.C.-Alberta Interconnection, System Operating Order 7T-17, as amended or replaced from time to time.

³ Available at:
<https://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/312044/index.do?q=R-27-18A>

There is one BC Hydro customer who would be immediately subject to TS 110, Elk Valley Resources Operations Limited (**EVR**), and currently one future transmission voltage customer with a project in BC Hydro's interconnection queue that would be subject to TS 110 once it is operational, NWP Coal Canada Ltd. (**NWP**). As described below, both EVR and NWP have been consulted and have provided letters of support for this Application.

The Application includes the following attachments:

1. Proposed TS 110 as Attachment 1;
2. Customer letters of support as Attachment 2; and
3. TPL-001-4 approved for adoption in B.C. as Attachment 3.

Background

TPL-001-4 was approved for adoption in B.C. by BCUC Order No. R-27-18A, dated June 28, 2018.⁴ In broad terms, and of most relevance for this Application, TPL-001-4 forbids the use of Non-Consequential Load Loss⁵ (**NCLL**) and/or the interruption of Firm Transmission Service to respond to many system contingency events.

More specifically, Table 1 of TPL-001-4 sets out a list of contingencies and related planning events and whether NCLL and/or interruption of Firm Transmission Service is allowed.⁶ Prior to TPL-001-4, there was no definition of NCLL that was tied to a performance standard and there was no prohibition on its use to respond to system contingency events.

TPL-001-4 includes a transition period for implementation, during which NCLL and interruption of Firm Transmission Service are still permitted.⁷ This transition period ends

⁴ With the exception of Requirement R7. TPL-001-4 R7 pertains to the Planning Coordinator (**PC**) function BC Hydro recommended that TPL-001-4 R7 be held in abeyance pending resolution of status of the PC function. The consideration and adoption of TPL-001-4 R7 is not relevant for the purposes of this Application.

⁵ Non-Consequential Load Loss is defined in the NERC Glossary of Terms as: "Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment". Refer to: https://www.nerc.com/pa/Stand/Glossary_of_Terms/Glossary_of_Terms.pdf

⁶ Refer to the last two columns of Table 1 in BCUC Order No. R-27-18A, which is provided as Attachment 3 to this Application.

⁷ Table 1 of Attachment A to BCUC Order No. R-27-18A specified the effective dates for TP-001-4 as July 1, 2020 for R2 through R6 and R8 and an 84 month period beginning the first day of the first calendar quarter following BCUC approval.

on June 30, 2025, after which NCLL and interruption of Firm Transmission Service are only permitted as set out in Table 1 of TPL-001-4.

BC Hydro's operating order for the B.C.-Alberta Interconnection, System Operating Order 7T-17 (**SOO 7T-17**), currently includes the Natal Load Shedding RAS, which is intended to avoid regional voltage collapse in the event of contingencies on the BES and heavy area load conditions.

If triggered, the Natal Load Shedding RAS will trip transmission line 1L274, which runs between BC Hydro's Natal substation and the Alberta Electric System Operator's (**AESO**) Pocaterra substation, and transmission line 60L288, which supplies EVR's EV1, PN6, and MCL substations from BC Hydro's Natal substation, and will cause NCLL and the interruption of Firm Transmission Service in circumstances that are not permitted in Table 1 of TPL-001-4.

While it is difficult to predict the likelihood of contingencies occurring that would trigger the Natal Load Shedding RAS, there have been no Natal Load Shedding RAS operations since it was placed in service in April 2013 and BC Hydro assesses it to be a low probability event. Based on current data, BC Hydro assesses that it has an annual probability of occurrence of approximately once every 60 years, but this may change over time as system loads and configuration change.

Proposed Load Curtailment Agreement

The purpose of the proposed load curtailment agreement, TS 110, is to allow BC Hydro to continue to provide service to customers with an ESA in the form of Tariff Supplement No. 5 or Tariff Supplement No. 87 (in the case of indirect customers) that is or would be subject to the Natal Load Shedding RAS, while ensuring compliance with TPL-001-4.

The key terms of TS 110 are summarized below:

- (a) **Applicability** – TS 110 will be required for any customer who takes, or proposes to take, electricity pursuant to an ESA in the form of Electric Tariff Supplement No. 5 or Electric Tariff Supplement No. 87, as applicable, for the supply of electricity to a Customer's Plant that is or would be subject to the Natal Load Shedding RAS (**Natal ESAs**).

At present, TS 110 is required for all known or expected Natal ESAs, but provision is made for certain Natal ESAs to be excluded if BC Hydro determines TS 110 is not required for them. This is intended to provide flexibility and ensure that TS 110 applies as minimally as necessary as the system changes over time;

- (b) **Suspension of Supply** – If the Natal Load Shedding RAS is triggered in the circumstances described in SOO 7T-17, BC Hydro may suspend or reduce the supply of electricity to the Customer's Plant(s) in accordance with the procedure set

out in SOO 7T-17 for as long as BC Hydro determines is necessary to ensure safe and reliable service;

- (c) Interruptible Load – BC Hydro and the customer agree that any load suspended or reduced under TS 110 will be considered Interruptible Load as defined by the NERC Glossary of Terms; and
- (d) Term – The Tariff Agreement shall commence on the Effective Date and will continue in force until all applicable ESAs have been terminated without replacement or BC Hydro provides written notice to the Customer that the agreement is no longer necessary.

BC Hydro submits that the Tariff Agreement is justified because it:

- Achieves compliance with TPL-001-4 while maintaining existing service levels;
- Is supported by affected customers; and
- Provides a timely and cost-effective alternative to expensive infrastructure investments.

TS 110 Achieves Compliance with TPL-001-4 While Maintaining Existing Service Levels

The purpose of TS 110 is to achieve compliance with TPL-001-4 through a curtailment agreement with the affected customers. TS 110 achieves compliance with TPL-001-4 because, if a customer's load is classified as "Interruptible Load", defined under the NERC Glossary of Terms as, "Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment" (underline added),⁸ then the loss of such load in the event of the relevant contingencies is acceptable under TPL-001-4.

TS 110 will allow BC Hydro to continue to serve current and future transmission voltage customers through the Natal substation after June 30, 2025 without a change in the service level that customers are receiving today, while meeting its compliance requirements under TPL-001-4. There are no changes to the rate that would otherwise apply, which remains the applicable transmission service rate.

TS 110 is Supported by Affected Customers

BC Hydro engaged with both customers that would be subject to the proposed Tariff Agreement in the immediate or near term regarding the need for TS 110: EVR (who would be immediately subject to TS 110) and NWP (who would be subject to TS 110 once their project is operational). This engagement has included meetings, emails and

⁸ Refer to: [https://www.nerc.com/pa/Stand/Glossary of Terms/Glossary of Terms.pdf](https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf)

phone calls. The potential for the customer's full load to be curtailed and the expected likelihood of curtailment formed part of our discussions with both customers.

The affected customers have provided letters of support for the Application, which are provided as Attachment 3 to this Application.

TS 110 Is a Timely and Cost-Effective Alternative to Expensive Infrastructure Investments

BC Hydro considered alternatives to meet our performance requirements under TPL-001-4 that were ultimately not pursued, in favour of the Tariff Agreement option. These included:

- Building a new 500 kV (180 km) transmission line in parallel with 5L92 from BC Hydro's Selkirk substation and BC Hydro's Cranbrook substation;
- Building a new 230 kV transmission line (250 km) from Selkirk substation to Natal substation;
- Working with the AESO to install a load and generation shedding RAS in Alberta; and
- Reducing existing B.C.-A.B. transfer limits during peak load operating periods.

The first two alternatives were dismissed as they would require significant capital expenditures and would not be in service until well after the implementation timeline of TPL-001-4. The third alternative was discussed with the AESO but dismissed as it would lead to significant technical challenges in Alberta. The fourth alternative was dismissed as it could adversely impact BC Hydro's Point-to-Point transmission customers with firm contracts under the Open Access Transmission Tariff.

Given the low probability of the contingencies occurring that would trigger the Natal Load Shedding RAS, and the expected minimal impact to affected customers, BC Hydro determined that a load curtailment agreement was the preferred approach for addressing the performance requirements of TPL-001-4 over the alternatives.

Under a load curtailment agreement, there are no costs to be recovered from affected customers or other ratepayers. Under the alternative infrastructure investments considered, significant costs would be borne by BC Hydro's ratepayers.

Proposed Regulatory Process and Order Sought

BC Hydro submits that a regulatory process is not required for the review of this application because the Tariff Agreement is supported by the affected customers who are the only parties who will be impacted by it for the foreseeable future.

December 20, 2024
Patrick Wruck
Commission Secretary and Manager
Regulatory Services
British Columbia Utilities Commission
**Application for Electric Tariff Supplement No. 110 – Load Curtailment Agreement
for Customers Served through Natal Substation**

BC Hydro respectfully requests that the BCUC issue an order approving TS 110 by April 30, 2025 such that BC Hydro can enter into agreements with customers, as applicable, prior to the TPL-001-4 implementation date of July 1, 2025.

For further information, please contact Shiau-Ching Chou at bchydroregulatorygroup@bchydro.com.

Yours sincerely,



Chris Sandve
Chief Regulatory Officer

jl/rh

Enclosure

**BC Hydro Tariff Supplement No. 110 –
Load Curtailment Agreement for Customers
Served Through Natal Substation**

Attachment 1

Tariff Supplement No. 110

NATAL LOAD CURTAILMENT

THIS SUPPLEMENTAL AGREEMENT is made as of

the ____ day of _____, 20____(the “**Effective Date**”)

BETWEEN:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY,

a Crown corporation continued under the laws of British Columbia having its
head office at

333 Dunsmuir Street, Vancouver, British Columbia V6B 5R3

(herein called “**BC Hydro**”)

OF THE FIRST PART

AND:

[**CUSTOMER LEGAL NAME**]

having an office in British Columbia at

[**CUSTOMER ADDRESS**], [**CITY**], British Columbia [**POSTAL CODE**]

(herein called the “**Customer**”)

OF THE SECOND PART

THIS AGREEMENT WITNESSES THAT BC Hydro and the Customer agree as follows:

ACCEPTED:_____

ORDER NO._____

COMMISSION SECRETARY

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ACCEPTED:_____

ORDER NO._____

COMMISSION SECRETARY

1.0 DEFINITIONS AND INTERPRETATION

1.1 In this Supplemental Agreement, the following terms shall have the following meanings:

- (a) “**Customer Electricity Supply Agreement(s)**” means, at any given time, all Natal ESA(s) then in effect[, **except the following Natal ESA(s):**

_____];

[Drafting Note: If BC Hydro determines that it is not necessary that this Supplemental Agreement apply to any one or more of the Natal ESAs, BC Hydro will include the square bracketed language in this definition and list the excluded Natal ESAs.]

- (b) “**Natal ESA**” means an agreement in the form of Electric Tariff Supplement No. 5 or Electric Tariff Supplement No. 87, as applicable, between BC Hydro and the Customer for the supply of Electricity to a Customer’s Plant that is or would be subject to the Natal Load Shedding RAS;
- (c) “**Natal ESA Customer**” means a BC Hydro customer who takes, or proposes to take, Electricity pursuant to a Natal ESA;
- (d) “**Natal Load Shedding RAS**” means the remedial action scheme of the same name described in the System Operating Order, as amended or replaced from time to time; and
- (e) “**System Operating Order**” means BC Hydro’s operating order for the B.C.-Alberta Interconnection, System Operating Order 7T-17 (SOO 7T-17), as amended or replaced from time to time.

ACCEPTED: _____

ORDER NO. _____

COMMISSION SECRETARY

1.2 All capitalized terms not otherwise defined in this Supplemental Agreement shall have the meaning set out in the Customer Electricity Supply Agreement(s).

1.3 This Supplemental Agreement is intended as a supplement to and should be read in conjunction with the Customer Electricity Supply Agreement(s). If there is any conflict between the provisions of this Supplemental Agreement and any Customer Electricity Supply Agreement(s), the provisions of this Supplemental Agreement shall prevail.

2.0 APPLICABILITY

2.1 Subject to section 5.0, this Supplemental Agreement will be required for any Natal ESA Customer.

3.0 SUSPENSION OF SUPPLY

3.1 If the Natal Load Shedding RAS is triggered in the circumstances described in the System Operating Order, BC Hydro may suspend or reduce the supply of Electricity to the Customer's Plant(s) in accordance with the procedure set out in the System Operating Order, for as long as BC Hydro determines is necessary to ensure safe and reliable service.

3.2 For greater certainty, BC Hydro's right to suspend or reduce the supply of Electricity to the Customer under section 3.1 is in addition to and does not limit any other right BC Hydro may have to discontinue, suspend or reduce the supply of Electricity to the Customer.

ACCEPTED: _____

ORDER NO. _____

COMMISSION SECRETARY

- 3.3 For the purposes of demonstrating BC Hydro's compliance with the mandatory reliability standard TPL-001-4 *Transmission System Planning Performance Requirements*, or any successor standard to the extent applicable, BC Hydro and the Customer agree that any load of the Customer's Plant(s) that is not served as a result of the suspension or reduction of the supply of Electricity pursuant to section 3.1 of this Supplemental Agreement will be considered Interruptible Load as defined in the North American Electric Reliability Corporation Glossary of Terms, as amended or replaced from time to time.

4.0 BILLING ADJUSTMENTS

- 4.1 A suspension or reduction, pursuant to section 3.1, for more than one hour shall be cause for Billing Adjustments to be made by BC Hydro under the Customer Electricity Supply Agreement(s).

5.0 TERM AND TERMINATION

- 5.1 The term of this Supplemental Agreement shall commence on the Effective Date and continue in force until all Customer Electricity Supply Agreement(s) have been terminated without replacement or BC Hydro provides written notice to the Customer that this Supplemental Agreement is no longer necessary.
- 5.2 If, at any given time, the Customer has more than one Customer Electricity Supply Agreement and BC Hydro determines that it is no longer necessary that this Supplemental Agreement apply to one or more of those Customer Electricity Supply Agreements, BC Hydro may replace this Supplemental Agreement with a Supplemental Agreement in the form of this Tariff Supplement No. 110 that applies only to certain Customer Electricity Supply Agreements as determined by BC Hydro.

ACCEPTED: _____

ORDER NO. _____

COMMISSION SECRETARY

6.0 COUNTERPARTS

- 6.1 This Supplemental Agreement may be executed in any number of counterparts, each of which when executed and delivered (by facsimile, pdf or otherwise) will be deemed to be an original, and all of which together shall constitute one and the same document.

ACCEPTED: _____

ORDER NO. _____

COMMISSION SECRETARY

IN WITNESS WHEREOF the duly authorized representative of each party has executed this Supplemental Agreement.

**BRITISH COLUMBIA HYDRO AND
POWER AUTHORITY**

[CUSTOMER LEGAL NAME]

By: _____
(signature)

By: _____
(signature)

Printed Name: _____

Printed Name: _____

Title: _____

Title: _____

ACCEPTED: _____

ORDER NO. _____

COMMISSION SECRETARY

**BC Hydro Tariff Supplement No. 110 –
Load Curtailment Agreement for Customers
Served Through Natal Substation**

Attachment 2

Customer Letters of Support



A GLENCORE COMPANY

December 9, 2024
Chris Sandve
Chief Regulatory Officer
BC Hydro
333 Dunsmuir St, 16th Floor
Vancouver, BC V6B 5R3

chris.sandve@bchydro.com

Dear Mr. Sandve,

**Re: EVR Operations
Application for Electric Tariff Supplement No. 110**

EVR Operations submits this letter in support of the British Columbia Hydro and Power Authority's (**BC Hydro**) application for approval of Electric Tariff Supplement No. 110 (**Tariff Agreement**) for Natal Load Curtailment (**Application**). We understand that BC Hydro will submit the Application, including this letter, to the British Columbia Utilities Commission.

The need for this RAS has been driven, in part, by our need to get more electricity. We understand that our increased demand at our 4 sites connected to Natal have make the system at Natal less stable. This RAS allows our sites to operate at higher loads without triggering costly system upgrades.

We have reviewed and acknowledge all terms and conditions as set out in the Tariff Agreement. In particular, we understand that the Tariff Agreement, if approved, will give BC Hydro the right to suspend or reduce electricity supply at our applicable sites in B.C. if the Natal Load Shedding Remedial Action Scheme (RAS) is triggered, for as long as BC Hydro determines is needed to ensure safe and reliable service.

If you have any questions about this letter of support, please contact me via email at jeff.sutherland@evr.com or telephone at 250-425-8447

Yours truly,

A handwritten signature in blue ink, appearing to read 'JS' followed by a stylized 'A'.

Jeff Sutherland, P. Eng
Energy Lead, EVR Operations

PO Box 399
Elkford, BC, Canada
V0B GH0

3 December 2024

Chris Sandve
Chief Regulatory Officer
BC Hydro
333 Dunsmuir St, 16th Floor
Vancouver, BC V6B 5R3

chris.sandve@bchydro.com

Dear Mr. Sandve,

Re: NWP Coal Canada Ltd – Crown Mountain Project
Application for Electric Tariff Supplement No. 110

NWP Coal Canada Ltd (**NWP**) is the proponent of the Crown Mountain Steemaking Coal Project in the Elk Valley in southeast British Columbia. In order to support development, NWP is seeking long term electricity supply from British Columbia Hydro and Power Authority's (**BC Hydro**) to supply the project.

NWP submits this letter in support of **BC Hydro's** application for approval of Electric Tariff Supplement No. 110 (**Tariff Agreement**) for Natal Load Curtailment (**Application**). We understand that BC Hydro will submit the Application, including this letter, to the British Columbia Utilities Commission.

We have reviewed and acknowledge all terms and conditions as set out in the Tariff Agreement. In particular, we understand that the Tariff Agreement, if approved, will give BC Hydro the right to suspend or reduce electricity supply at our future site in B.C. if the Natal Load Shedding Remedial Action Scheme (RAS) is triggered, for as long as BC Hydro determines is needed to ensure safe and reliable service.

If you have any questions about this letter of support, please contact me via email at michaelgray@jamesonresources.com.au or telephone at +61 417 736 461.

Yours sincerely,



Michael Gray
President
NWP Coal Canada Ltd

**BC Hydro Tariff Supplement No. 110 –
Load Curtailment Agreement for Customers
Served Through Natal Substation**

Attachment 3

Mandatory Reliability Standard TPL-001-4

A. Introduction

- 1. Title:** Transmission System Planning Performance Requirements
- 2. Number:** TPL-001-4
- 3. Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.
- 4. Applicability:**
 - 4.1. Functional Entity**
 - 4.1.1.** Planning Coordinator.
 - 4.1.2.** Transmission Planner.
- 5. Effective Date*:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

B. Requirements

- R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 1.1.** System models shall represent:
- 1.1.1.** Existing Facilities
 - 1.1.2.** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.
 - 1.1.3.** New planned Facilities and changes to existing Facilities
 - 1.1.4.** Real and reactive Load forecasts
 - 1.1.5.** Known commitments for Firm Transmission Service and Interchange
 - 1.1.6.** Resources (supply or demand side) required for Load
- R2.** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 2.1.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:
- 2.1.1.** System peak Load for either Year One or year two, and for year five.
 - 2.1.2.** System Off-Peak Load for one of the five years.
 - 2.1.3.** P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.
 - 2.1.4.** For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :
 - Real and reactive forecasted Load.
 - Expected transfers.
 - Expected in service dates of new or modified Transmission Facilities.
 - Reactive resource capability.
 - Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
 - Duration or timing of known Transmission outages.
- 2.1.5.** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.
- 2.2.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:
- 2.2.1.** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.
- 2.3.** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.
- 2.4.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part 2.6. The following studies are required:
- 2.4.1.** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.
- 2.4.2.** System Off-Peak Load for one of the five years.
- 2.4.3.** For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:
- Load level, Load forecast, or dynamic Load model assumptions.
 - Expected transfers.
 - Expected in service dates of new or modified Transmission Facilities.
 - Reactive resource capability.
 - Generation additions, retirements, or other dispatch scenarios.

- 2.5.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part 2.6 and shall include documentation to support the technical rationale for determining material changes.
- 2.6.** Past studies may be used to support the Planning Assessment if they meet the following requirements:
- 2.6.1.** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
- 2.6.2.** For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.
- 2.7.** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:
- 2.7.1.** List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:
- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
 - Installation, modification, or removal of Protection Systems or Special Protection Systems
 - Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
 - Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
 - Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
 - Use of rate applications, DSM, new technologies, or other initiatives.
- 2.7.2.** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.
- 2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner

or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

- 2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.
 - 2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:
 - 2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.
 - 2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.
 - R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
 - 3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.
 - 3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.
 - 3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:
 - 3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
 - 3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
 - 3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.
 - 3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.
 - 3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies

to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

- [illegible]

- 4.3.1.3.** Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

- 4.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

- 4.4.** Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

- 4.4.1.** Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

- 4.5.** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

- R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.
[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

- R7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

- R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- 8.1.** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

- a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
- b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
- c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
- d. Simulate Normal Clearing unless otherwise specified.
- e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

- f. Applicable Facility Ratings shall not be exceeded.
- g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
- h. Planning event P0 is applicable to steady state only.
- i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

- j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event ¹	Fault Type ²	BES Level ³	Interruption of Firm Transmission Service Allowed ⁴	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶	3Ø	EHV, HV	No ⁹	No ¹²
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault ⁷	N/A	EHV, HV	No ⁹	No ¹²
		2. Bus Section Fault	SLG	EHV	No ⁹	No
		3. Internal Breaker Fault ⁸ (non-Bus-tie Breaker)	SLG	HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) ⁸	SLG	EHV	No ⁹	No
				HV	Yes	Yes
				EHV, HV	Yes	Yes

Category	Initial Condition	Event ¹	Fault Type ²	BES Level ³	Interruption of Firm Transmission Service Allowed ⁴	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments ⁹	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶	3Ø	EHV, HV	No ⁹	No ¹²
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency (Fault plus stuck breaker ¹⁰)	Normal System	Loss of multiple elements caused by a stuck breaker ¹⁰ (non-Bus-tie Breaker) attempting to clear a Fault on one of the following:	SLG	EHV	No ⁹	No
		1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶ 5. Bus Section		HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker ¹⁰ (Bus-tie Breaker) attempting to clear a Fault on the associated bus		EHV, HV	Yes	Yes
P5 Multiple Contingency (Fault plus relay failure to operate)	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay ¹³ protecting the Faulted element to operate as designed, for one of the following:	SLG	EHV	No ⁹	No
		1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶ 5. Bus Section		HV	Yes	Yes
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by System adjustments. ⁹ 1. Transmission Circuit 2. Transformer ⁵ 3. Shunt Device ⁶ 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer ⁵ 3. Shunt Device ⁶	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event ¹	Fault Type ²	BES Level ³	Interruption of Firm Transmission ⁴ Service Allowed	Non-Consequential Load Loss Allowed
P7 Multiple Contingency (<i>Common Structure</i>)	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure ¹¹ 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability For all extreme events evaluated:	
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified.	
Steady State	Stability
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits.¹¹ b. Loss of all Transmission lines on a common Right-of-Way¹¹. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a generating station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. **British Columbia** Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
 - a. Date, time, and location for the meeting
 - b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
 - c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
 - a. System Load level and estimated annual hours of exposure at or above that Load level
 - b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
 - a. The estimated number and type of customers affected

- b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
 - a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
 - b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

- M1.** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.
- M2.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.
- M3.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.
- M4.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.
- M5.** Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.
- M6.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.
- M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.
- M8.** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits
Self-Certifications
Spot Checking
Compliance Violation Investigations
Self-Reporting
Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	