APPENDIX A AESO PLANNING REPORT

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Central East Transfer-out Transmission Development

Planning Report

AESO Project Number: P7001

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Executive Summary

The AESO performs system planning studies regularly in order to assess transmission system reliability. This Planning Report describes the planning studies conducted by the AESO to assess the need for transmission development in the South and Central East Planning Regions as well as the Preferred Transmission Development, which will enhance the transfer-out path in these Planning Regions.

The Study Area for the planning studies described in this Planning Report focuses on the east portion of the South and Central Planning Regions, i.e. South East (SE) sub-region and Central East (CE) sub-region (as further described in Section 1.1). The Study Area is an area rich in renewable resources and market interest. [1] Significant amounts of renewable generation could be developed and connected to the transmission system in the Study Area. To evaluate transmission system performance as renewable generation continues to develop, the AESO carried out deterministic planning studies, which are the primary focus of this Planning Report. The deterministic studies carried out in this report were used to establish the need for transmission development, evaluate the merits of the Transmission Development Options and select the Preferred Transmission Development. The AESO also conducted probabilistic assessments which are presented separately.[2] The probabilistic assessment re-affirms the planning recommendations made in this report.

Need Assessment

The AESO conducted generation integration capability studies to assess the performance of the system without transmission development (pre-development) in the Study Area. In consideration of the uncertainties associated with timing, volume and offer behavior with regards to the replacement of the existing thermal generation in the Study Area, the AESO considered two thermal dispatch scenarios in its planning studies. Scenario 1 represents a scenario where thermal generation has lower capacity and energy dispatch than the historical thermal fleet; and Scenario 2 represents a scenario where thermal generation has similar output as historical thermal fleet.

The 2023 study results indicated that in Scenario 1, the Category B capability in the Study Area is in the range of 450 MW to 565 MW and the Category A capability (enabled by generation remedial action scheme (RAS)) is in the range of 760 MW to 990 MW; in Scenario 2, the Category B capability in the Study Area is in the range of 120 MW to 280 MW; and the Category A capability (enabled by generation RAS) is in the range of 250 MW to 680 MW. The primary constraints are on the CE west transfer-out path (as defined in Section 1.2).

The AESO forecasts that by 2023, up to 900 MW new renewable generation, above the existing renewable generation and Renewable Electricity Program (REP) projects, will develop in Alberta. The renewable generation is forecast to continue to grow. By 2031, approximately 900 MW to 4,600 MW of

[1] This is discussed in further detail in Forecast Appendix filed under separate cover as Appendix B.

[2] Filed under separate cover as Appendix C.

incremental renewable generation is forecast to develop. It is anticipated that a significant amount of new renewable generation will be located in the Study Area and exceed the generation integration capability of the pre-development transmission system. In order to meet the forecasted renewable generation in the Study Area, the AESO has determined that transmission development is needed to alleviate constraints on the CE west transfer-out path, to meet Alberta Reliability Standards.

Transmission Development Options and Comparative Assessment

To alleviate the identified constraints on the CE sub-region west transfer-out path, the AESO considered additional transfer-out paths from the CE sub-region to adjacent load centers such as Red Deer (Area 35) planning area, and Edmonton, Northeast, and Calgary Planning Regions. The AESO's preliminary assessment indicated that a new transfer-out path from the CE sub-region to the Red Deer area would be the most effective transfer-out path, compared to the other considered paths. Therefore, different options for connecting the CE sub-region to the Red Deer area were developed and investigated. The Transmission Development Options are presented in Table E-1.

Table E-1: Transmission Development Options

Option	Description
1	Add two new 240 kV circuits between Tinchebray 972S and Gaetz 87S substations
2	Add two new 240 kV circuits between Tinchebray 972S and Wolf Creek 288S substations
3	Add one new 240 kV circuit between Tinchebray 972S and Gaetz 87S substations and upgrade existing 912L and 9L20
4	Add one new 500 kV circuit between Tinchebray 972S and Gaetz 87S substations
5	Convert EATL to bi-pole
6	Add one new 240 kV circuit between Cordel 755S and Gaetz 87S substations and add one new 240kV circuit between Tinchebray 972S and Gaetz 87S substations

The AESO performed generation integration capability studies to assess the incremental capability enabled by each option. Based on the study results, Options 3, 4 and 5 were not recommended for further consideration due to lower incremental capability and operational flexibility compared to Option 1. For Options 1, 2 and 6, +30/-30% cost estimates[3] and environmental and land use effects [4] were prepared. Option 1 is the Preferred Transmission Development Option for the following considerations:

- it is technically superior to other options in terms of generation integration capability and operational flexibility; and
- it has lower estimated cost.
- It has lower potential environmental and land use effects.

The Preferred Transmission Development includes the addition of two 240 kV circuits. To further assess the Preferred Transmission Development, the AESO undertook generation integration capability studies to evaluate the incremental capability enabled by each circuit. Results indicated that the Preferred Transmission Development first circuit enables approximately 400 MW to 600 MW of additional capability

[3] Filed under separate cover as Appendix E.

[4] Filed under separate cover as Appendix F.

(above the capability of pre-development transmission system) in the Study Area, and the Preferred Transmission Development second circuit enables approximately 300 MW additional capability (above the capability of the first circuit) in the Study Area.

Congestion Assessment

In addition to the deterministic studies described above, the AESO conducted hourly probabilistic assessment (the Congestion Assessment),[5] utilizing a market simulation tool to further assess transmission system performance. The congestion assessment established the relationship between the addition of generation in the Study Area and the likelihood of observing congestion using two scenarios in which the existence and operating patterns of thermal generation in the Study Area were varied.

The congestion assessment was performed both before and after the Preferred Transmission Development is in service. Results indicated that the amount of congestion depends on both thermal generation and renewable generation in the Study Area. Before the Preferred Transmission Development is in service, Category A congestion is projected to occur greater than 0.5% of the time annually when there is approximately 1,250 MW to 1,750 MW incremental generation (above the existing generation as of January 2020) in the Study Area. After the Preferred Transmission Development first circuit is in service, additional generation (total of approximately 1,900 MW to 2,350 MW of incremental generations above the existing generation as of January 2020) could develop in the Study Area before Category A congestion is projected to occur greater than 0.5% of the time annually. The Preferred Transmission Development second circuit further increases the amount of incremental generation that can be integrated in the Study Area.

In summary, the congestion assessment results re-affirm the need for transmission development in the CE sub-region. Once the Preferred Transmission Development is in service, the congestion on the CE sub-region west transfer-out path will be significantly reduced.

Recommended Transmission Development and Construction Milestone

The recommended Preferred Transmission Development comprises two stages:

Stage 1:

- Add one 240 kV circuit between the existing Tinchebray 972S and Gaetz 87S substations;
- Modify the Tinchebray 972S substation by adding circuit breakers and associated equipment;
- Modify the Gaetz 87S substation by adding circuit breakers and associated equipment.

Stage 2:

- Add one 240 kV circuit between the Tinchebray 972S and Gaetz 87S substations;
- Modify the Tinchebray 972S substation by adding circuit breakers and associated equipment;
- Modify the Gaetz 87S substation by adding circuit breakers and associated equipment.

The AESO proposes a construction milestone for each stage of the Preferred Transmission Development. A construction milestone will enable the AESO to manage uncertainty regarding the timing and impacts of thermal and renewable generation development in the Study Area by delaying construction as much as

[5] Filed under separate cover as Appendix C.

possible, while ensuring the Preferred Transmission Development can be constructed and energized before congestion arises.

The proposed milestones are based on the results of the congestion assessment indicating when the Category A congestion on the CE west transfer-out path is projected to occur greater than 0.5% of the time annually. Considering that it will take approximately 2 to 3 years to construct the Preferred Transmission Development after the Permit & Licence has been received and the construction milestone has been met, the milestone incorporates a 200 MW (i.e. an average sized wind farm) reduction of incremental generation into the analysis to align with generation construction timelines of 1 to 2 years as well as to avoid congestion on the transmission system.

The following construction milestone for the Preferred Transmission Development Stage 1 is proposed:

- The addition of approximately 1,050 MW to 1,550 MW of incremental generation (above the existing generation as of January 2020) that meets the AESO's certainty criteria (as described in Section 10.2) in the Study Area.

This is depicted in Figure E-1 below.

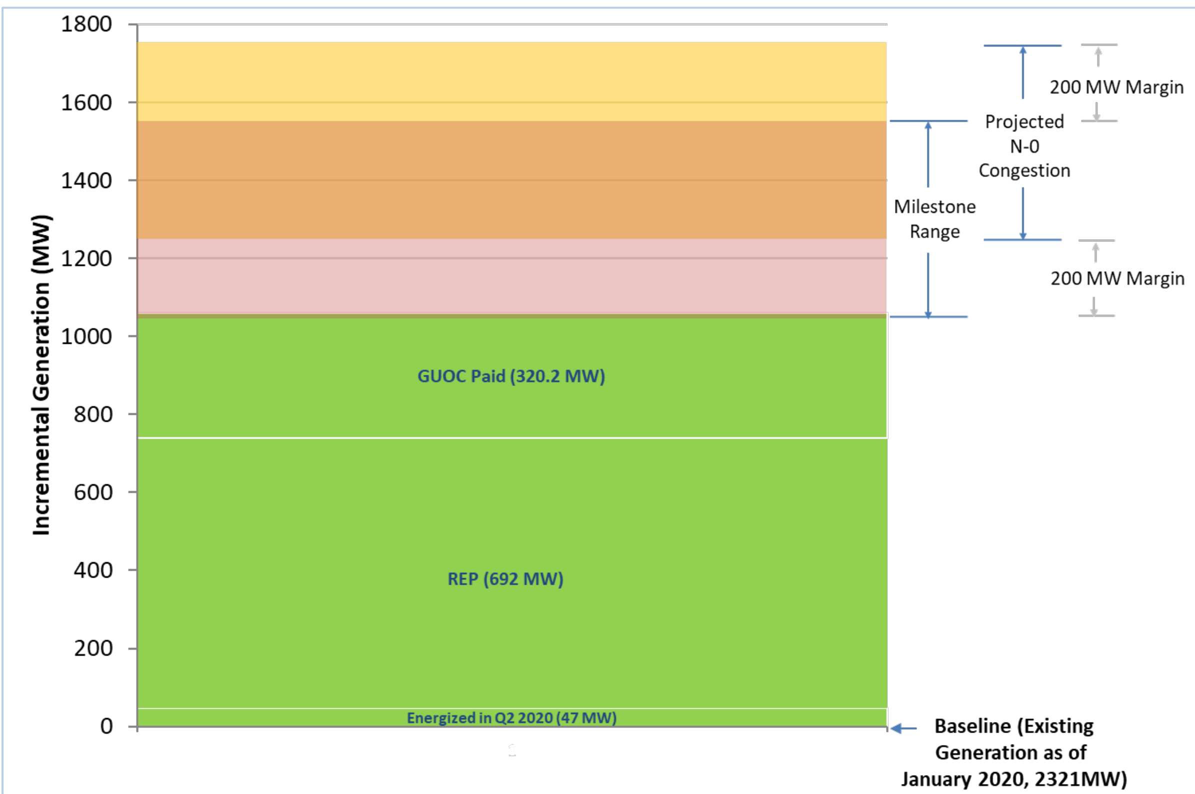

Figure E-1: Construction Milestone for the Preferred Transmission Development Stage 1

As part of this milestone approach, once incremental generation that meets the certainty criteria are within the range of 1,050 MW to 1,550 MW, the AESO would re-affirm that congestion is forecast to occur greater than 0.5% of the time annually during the Category A condition by performing congestion assessment studies that take into account the locations and sizes of the generation meeting the certainty criteria. In the event that these planning studies re-affirm that Category A congestion is forecast to occur greater than 0.5% of the time annually, the AESO will notify the Commission that the construction milestone has been met and advise the TFOs to commence construction for Stage 1.

Prior to filing this application, 1,059 MW of incremental generation has already met the certainty criteria. The AESO anticipates additional generation to reach the certainty criteria prior to the end of 2020. As such, the AESO expects to commence the congestion assessment studies prior to a Commission decision on the NID. Should the results re-affirm Category A congestion is forecast to occur greater than 0.5% of the time annually, the AESO would notify the Commission that the Stage 1 construction milestone has been met. If the Commission has already rendered a decision on the NID, the AESO will notify the Commission that the Stage 1 construction milestone has been met and advise the TFOs to commence construction for Stage 1.

The following construction milestone for the Preferred Transmission Development Stage 2 is proposed:

- The addition of approximately 1,700 MW to 2,150 MW of incremental generation (above the existing generation as of January 2020) that meet the AESO's certainty criteria in the Study Area.

For the Stage 2 construction milestone, once incremental generation is within the range of 1,700 MW to 2,150 MW, the AESO would re-affirm that congestion is forecast to occur greater than 0.5% of the time annually during the Category A condition by performing congestion assessment studies that take into account the locations and sizes of the generation meeting the certainty criteria. In the event that these planning studies re-affirm that Category A congestion is forecast to occur greater than 0.5% of the time annually, the AESO will notify the Commission that the Stage 2 construction milestone has been met and advise the TFOs to commence construction for Stage 2.

The AESO will use operational measures, as necessary, should congestion arise prior to the energization of the Preferred Transmission Development.

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Abbreviations

AESO	Alberta Electric System Operator
AC	alternating current
AIES	Alberta interconnected electric system
BC	British Columbia
DC	direct current
EATL	Eastern Alberta Transmission Line
ISD	in-service date
km	kilometer
kV	kilovolt
LTO	AESO's Long-term Outlook
LTP	AESO's Long-term Transmission Plan
MVA	megavolt ampere
MVAr	megavolt ampere reactive
MW	megawatt
NID	Needs Identification Document
RAS	Remedial Action Scheme
REP	Renewable Electricity Program
TFO	legal owner of a transmission facility
TPL	Transmission Planning Standards (part of the Alberta Reliability Standards)
VAr	volt ampere reactive
WATL	Western Alberta Transmission Line
WECC	Western Electricity Coordinating Council

1 Introduction

The AESO performs planning studies regularly in order to assess transmission system reliability. This Planning Report describes planning studies conducted by the AESO to assess the need for transmission development in the South and Central East Planning Regions, as well as the proposed transmission developments which will enhance the transfer-out path in these Planning Regions.

The Study Area for the planning studies described in this report focus on the east portion of the South and Central Planning Regions, as further described in Section 1.1. As indicated in Forecasting Appendix[6], the Study Area is an area rich in renewable generation. The number of requests for transmission system access service the AESO has received from market participants demonstrates high interest for generation development in the Study Area. It has the greatest proportion of proposed renewable development compared to the rest of Alberta. While the proposed generation connection projects currently in the AESO project list will not necessarily all proceed, the number and size of the proposed generation connection projects in the Study Area provides a strong indication of the interest in renewable development.

The AESO published its new corporate forecast, the 2019 LTO[7], in September 2019. The 2019 LTO forecasts that by year 2031, the new renewable generation in Alberta (above the existing installed renewable generation and the REP projects) is expected to be approximately 1,900 MW in the Reference Case and up to 4,600 MW in the Alternate Renewable Policy scenario (refer to Forecasting Appendix for further details). The generation is forecasted to continue to be developed in the Study Area where wind and solar resources are available in abundance.

In April 2019, the AESO published the *2019 Transmission Capability Assessment for Renewables Integration report* [8] (2019 Capability Report) which described system capability to integrate additional renewable generation. In this report, total renewable generation integration capability was determined to be approximately 470 MW in the South Planning Region and Central East sub-region which is based on thermal loading constraints under N-0[9] conditions. Optimal distribution of this capability is 340 MW in the SW, 130 MW in the SE and 0MW in the CE sub-regions. In addition, the development of the Provost to Edgerton and Nilrem to Vermilion (PENV) project and Nevis remedial action scheme (RAS) reconfiguration would provide an additional up to 360 MW to the overall capability in the South Planning Region and CE sub-region.

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6 Filed under separate cover as Appendix B.

7 Available on the AESO website.

8 Available on the AESO website.

9 Incremental capability under N-0 conditions in this report refers to the RAS-enabled maximum incremental capability to maintain reliable operation following the most critical single contingency.

The planning studies in this report further refine the generation integration capability assessment of all the three sub-regions referenced above using the AESO's latest 2019 LTO corporate forecast. To evaluate transmission system performance as renewable generation continues to develop in the Study Area, the AESO carried out the traditional deterministic studies that is the primary focus of this report and the probabilistic assessment that is presented in the Congestion Assessment Appendix[10]. The deterministic planning studies carried out in this report were used to establish the need of the transmission development, evaluate the merit of the proposed Transmission Development Options and select the Preferred Transmission Development. The congestion assessment undertaken in Appendix C was to further affirm the planning recommendations.

1.1 Study Area Definitions

The Study Area comprises the eastern portion of the South and Central Planning Regions. The following defines the spatial terminology used in this Planning Report.

- CE sub-region[11],[12]

  The CE sub-region is comprised of the following AESO planning areas: Lloydminster (Area 13); Wainwright (Area 32); Alliance/Battle River (Area 36); Provost (Area 37); Hanna (Area 42); and Vegreville (Area 56).

- SE sub-region

  The SE sub-region is comprised of the following AESO planning areas: Medicine Hat (Area 4); Sheerness (Area 43); Brooks (Area 47); Empress (Area 48); and Vauxhall (Area 52).

- Study Area

  The CE sub-region and SE sub-region are collectively referred as the Study Area.

- Southwest (SW) sub-region

  The Study Area is the focus of the study to assess the transmission system constraints to integrate the forecasted generation, and proposes a preferred transmission development option. In addition to the Study Area, the SW sub-region is also a renewable resource rich area and new renewable generation development is forecasted in the SW sub-region. Generation in the SW sub-region has an impact on the overall performance of the Study Area transmission system. To adequately assess the overall system impacts as new renewable generation is integrated into the transmission system, planning studies carried out in this Planning Report investigated the impact of the renewable development in the SW sub-region on the generation integration capability in the Study Area.

[10] Filed under separate cover as Appendix C.

[11] The AESO planning area of Cold Lake (Area 28) is not included in the CE sub-region in this assessment as it has lower potential and market interest for renewable generation.

[12] The AESO planning area of Red Deer (Area 35) is not part of the CE sub-region; however, it was included in the planning studies as described in Section 3.2.2.

The SW sub-region is comprised of the following AESO planning areas: Strathmore/Blackie (Area 45); High River (Area 46); Stavely (Area 49); Fort Macleod (Area 53); Lethbridge (Area 54), Glenwood (Area 55); and Calgary (Area 6).

1.2 Transmission Network in the Study Area

The Pre-Development[13] transmission system in the Study Area is shown in Figure 1-1. In the CE sub-region, the load is predominantly served through an extensive 138/144 kV transmission system supplied by a looped 240 kV transmission system (as shown in Figure 1-1). The surplus generation from the CE sub-region is transferred out to the rest of the AIES through the following three paths:

- **West transfer-out path**, connects the CE sub-region to the Red Deer and Edmonton Planning Region and consists of:
    - the 240 kV transmission lines 912L and 9L20 between the Cordel 755S substation and the Red Deer 63S substation; and
    - the 138 kV transmission line 174L between the Bardo 197S substation and the North Holden 395S substation.
- **North transfer-out path**, connects the CE sub-region to the Northeast Planning Region and consists of two 144 kV transmission lines, 7L92 in the Vegreville (Area 56) planning area and 7L53 in the Lloydminster (Area 13) planning area.
- **South transfer-out path**, connects the CE sub-region to the SE sub-region via Ware Junction 132S substation and consists of three 240 kV transmission lines, 933L, 934L/9L934, and 950L/9L950, between the Ware Junction 132S substation and the Anderson 801S substation, referred to as the South of Anderson (SOA) cut plane.

The approved Provost to Edgerton and Nilrem to Vermilion Transmission System Reinforcement [14] (the PENV development) is designed to alleviate the existing and anticipated constraints on the 138/144 kV transmission network (such as 7L50 in Wainwright planning area and 749L in the Provost Planning area), and to provide transmission system access for renewable generation in the area. The PENV development is expected to be in service in 2022.

In the SE sub-region, the existing 240 kV transmission system delivers power from the Medicine Hat and Empress planning areas to Brooks planning area. The 240 kV transmission system is designed to collect and provide transmission system access to geographically dispersed renewable generation sources and move power into load centres. As shown in Figure 1-1, the 240 kV transmission lines between Cassils 324S substation – Bowmanton 244S substation - Whitla 251S substation (CBW) and the 240 kV transmission lines between the Cypress 562S substation and the Jenner 275S substation serve as

[13] The Pre-Development transmission system is the existing transmission system with system and connection projects in service. The 2023 Pre-Development transmission system includes the approved PENV project (operating at 138 kV), REP projects, connection projects, and system projects. The 2031 Pre-Development transmission system includes the PENV project (operating at 240 kV), REP projects, connection projects, and system projects.

[14] The *Provost to Edgerton and Nilrem to Vermilion (PENV) Transmission System Reinforcement Needs Identification Document* was originally approved by the Commission on April 10, 2019 in Decision 23429-D02-2019.

integral transmission systems in the SE sub-region to collect and provide transmission system access to generation sources.

In addition, the 500 kV high-voltage direct current (HVDC) transmission line EATL runs through the CE sub-region and facilitates transmission of power between the Study Area and Northeast Planning Region.

Figure 1-1: Pre-Development Transmission System in the Study Area

1.3 Study Objectives

The study objectives are summarized below.

- Assess the need for transmission development in the Study Area.
- Develop Transmission Development Options to address the identified transmission constraints.
- Assess Transmission Development Options and compare performance of these options.
- Select the Preferred Transmission Development.
- Identify mitigation measures that may be required to ensure reliable transmission system performance.

1.4 Study Scope

The following planning studies were performed in the Study Area using the latest load and generation forecast as described in Forecast Appendix.

- **Need Assessment**

  Generation integration capability assessment was carried out for year 2023 for the Pre-Development transmission system. The system performance was compared against the requirement of the Reliability Criteria (see Section 2.1) to identify any transmission constraints under various stressed system conditions.

- **Transmission Development Options**

  Several different Transmission Development Options were considered to alleviate the identified constraints and to increase the generation integration capability in the Study Area.

- **Technical Assessment of the Transmission Development Options**

  The performance of each of the Transmission Development Options was evaluated by assessing additional generation integration capability provided by each of the options.

- **Selection of the Preferred Transmission Development**

  A number of factors were considered when selecting the Preferred Transmission Development including a comparison of generation integration capability, operational flexibility, cost, and environmental/land use effects.

- **Validation of Performance of the Preferred Transmission Development**

  The performance of the transmission system with Preferred Transmission Development included (Post-Development) was further evaluated through voltage stability and transient stability studies to ensure its performance fully complies with the Reliability Criteria as described in Section 2.1. Short circuit analyses of the transmission system were performed both before and after the Preferred Transmission Development is in service in different timeframes.

2 Reliability Standards, Criteria, Study Assumptions and System Model

This section discusses the applicable Reliability Standards, criteria, study assumptions and system model that were applied in the planning studies. The information used to create study cases, load and generation assumptions and system configuration reflects the most current information available to the AESO. While the AESO makes assumptions based on the latest available information, it is acknowledged that assumptions are subject to change over time. The AESO addresses the possible impact of changes in assumptions by monitoring active system and customer connection projects and performing regular system planning studies as part of its long-term planning process.

2.1 Transmission Reliability Standards and Criteria

The TPL Standards, which are part of the Alberta Reliability Standards[15], and *Transmission Planning Criteria – Basis and Assumptions*[16] (collectively, the Reliability Criteria) will be applied to evaluate system performance under Category A system condition (i.e., all elements in-service) and following Category B contingencies (i.e., single element outage), and Category C contingencies (i.e., multiple element outage).

Category A, often referred to as the N-0 condition, represents a normal system condition with all elements in service (N-0). All equipment must be within its applicable rating, voltages must be within their applicable range and the system must be stable with no cascading outages. Under Category A system condition, electric supply to load cannot be interrupted and generating units cannot be removed from service.

Category B events, often referred to as the N-1 conditions, results in the loss of any single element (N-1) under specified fault conditions with normal clearing. The specified elements are a generating unit, a transmission circuit, a transformer or a single pole of a direct current transmission line. The acceptable impact on the system is the same as Category A with the exception that radial customers or some local network customers, including loads or generating units, are allowed to be disconnected from the system if they are connected through the faulted element. The loss of opportunity load or opportunity interchanges is allowed. No cascading can occur.

Category C5 events results in loss of two circuits of a multiple circuit tower. All equipment must operate within its applicable rating, voltages must be within their applicable range, and the system must be stable with no cascading outages. For Category C5, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) transmission service electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

Category C3 events referred to as a Category B contingency, manual system adjustments, followed by another Category B contingency. All equipment must operate within its applicable rating, voltages must

[15] A complete description of these standards are given in https://www.aeso.ca/rules-standards-and-tariff/alberta-reliability-standards/

[16] Filed under separate cover as Appendix H.

be within their applicable range, and the system must be stable with no cascading outages. The controlled interruption of electric supply to customers (load shedding), the removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) transmission service electric power transfers is allowed both as a system adjustment and as a corrective action.

The TPL standards, TPL-001-AB-0, TPL-002-AB1-0, and TPL-003-AB-0, have referenced Applicable Ratings when specifying the required system performance under Category A, Category B, and Category C events. For the purpose of applying the TPL standards to the studies documented in this report, Applicable Ratings are defined as follows:

- Normal thermal rating of the line's loading limits for each season.
- The highest specified loading limits for transformers.
- For Category A conditions: Voltage range under normal operating condition per AESO Information Document #2010-007RS, *General Operating Practices – Voltage Control* (ID #2010-007RS). For the busses not listed in ID #2010-007RS, Table 2-1 in the *Transmission Planning Criteria – Basis and Assumptions* applies.
- For Category B and Category C contingency conditions: The extreme voltage range values per Table 2-1 in the *Transmission Planning Criteria – Basis and Assumptions.*

2.2 Study Years

Detailed deterministic planning studies were carried out for the years 2023 (near-term) and 2031 (mid-term). The year 2023 was selected based on anticipated need and the earliest possible in service year of transmission developments. The year 2031 was selected in consideration the existing coal-fired generation in the CE sub-region will be retired and assumed to be replaced with new combined cycle units.

The transmission system performance for the year 2039 (long-term) was assessed as part of the AESO's *2020 Long-term Transmission Plan* (2020 LTP) to ensure it meets the Reliability Criteria over the 20-year planning horizon.

2.3 Load Forecast

The load forecast used in the deterministic studies conducted as part of this planning report is based on the 2019 LTO. Please refer to Forecasting Appendix for further details on the load forecast.

2.4 Generation Assumptions

The generation assumptions used in the deterministic studies conducted as part of this planning report are based on the 2019 LTO. Please refer to the Forecasting Appendix for further details regarding the existing generation capacity and new generation projects in the Study Area.

Existing non-renewable generation is key to the system-wide generation integration capability studies. The thermal generation at the Battle River and Sheerness facilities impacts the Study Area generation integration capability. Generally, the existing non-renewable generation is dispatched based on its anticipated in-merit energy.

2.5 Transmission Developments

Table 2-1 lists the transmission developments included in the planning studies.

Table 2-1: Transmission Developments Included in the Planning Studies

AESO Project No.	Transmission Development Name	Planning Area	2023 Studies	2031 Studies
1456	Downtown Calgary Transmission Reinforcement	6	Yes	Yes
1784	Addition of Voltage Support at Rycroft 730S Substation	20	Yes	Yes
1381	807L Capacity Increase	33	Yes	Yes
1781	Provost to Edgerton and Nilrem to Vermillion (PENV) Transmission Development	32,37	Yes, operated at 138kV	Yes, operated at 240kV
7006	Alberta – British Columbia Intertie Restoration	6, 53	Yes	Yes
7064*	Chapel Rock to Pincher Creek Area (CRPC) Transmission Development	53	Yes	Yes
Note: * This project was not included in the Pre-Development transmission system in 2023 and 2031.				

It is noted that PENV Stage 1 development is anticipated to be in service in 2022. Therefore, the Stage 1 development was considered in this planning report. Construction for Stage 2 of the PENV development and the timing of when the developments will be energized at 240 kV is based on a milestone and not certain at this time. However, since the Stage 1 and Stage 2 PENV developments are primarily designed to alleviate the local 138 kV constraints in the PENV area, in order to maximize renewable generation integration capability, for purposes of this planning report, it was assumed that both stages of the PENV transmission developments are in service and operated at 138 kV in the 2023 studies; and the PENV transmission developments are assumed to be operated at 240 kV in the 2031 studies.

2.6 Customer Connection Projects

The load and generation connection projects included in the planning studies were as follows:

- Load projects and the load allocation to point-of-delivery (POD) substations was determined as per the 2019 LTO as further described in the Forecast Appendix[17].
- Generation projects and their dispatches are based on the methodology outlined in the Forecast Appendix.

Table 2-2 and Table 2-3 outline the generation and load connection projects that were included in this planning study.

[17] Filed under separate cover as Appendix B.

Table 2-2: Generation Connection Projects in Study Area

Project No.	Project Name	Planning Area	Anticipated In-Service Year	Capacity (MW)
1567	Sharp Hills Wind Farm	42	Pre-2023	248.4
1838	Suffield DG PV	4	Pre-2023	22.0
2122	Cypress Wind Power Project	4	Pre-2023	201.6
1853	Buffalo Atlee Wind Farm 1	48	Pre-2023	17.25
2199	Buffalo Atlee Wind Farm 2	48	Pre-2023	13.8
1892	Buffalo Atlee Wind Farm 3	48	Pre-2023	17.25
1533	Jenner Wind Power Project	48	Pre-2023	122.4
1698	Jenner Wind Power Project 2	48	Pre-2023	71.4

Table 2-3: Load Connection Projects in Study Area

Project No.	Project Name	Planning Area	Anticipated In-Service Year	Rate DTS (MW)
1782	Fortis Provost Reliability	37	2021	0
1410	ATCO Heartland Pump Station Connection	56	2020	20

2.7 Interties

The AIES is presently connected to British Columbia via WECC Path 1, which is the Alberta-British Columbia Intertie (AB-BC); to Saskatchewan via WECC Path 2 (AB-SK); and to Montana via the Montana Alberta Tie-Line (MATL) (WECC Path 83). In planning studies, various import and export flows were assumed in different study cases, as outlined further in Section 3.1.3.

2.8 Voltage Profile Assumptions

ID #2010-007RS was used to establish system normal (i.e., pre-contingency) voltage profiles for key area buses prior to commencing any of the planning studies. For the buses not included in ID #2010-007RS, Table 2-1 of the *Transmission Planning Criteria – Basis and Assumptions* applies. These voltages were used to set the voltage profile for the study base cases prior to the planning studies.

2.9 Transmission Facility Ratings

Transmission facility ratings in the Study Area were provided by the respective TFOs, which was the most recent information available when the planning studies commenced. All approved capital maintenance projects that are planned to be implemented by 2023 were included in the planning studies and are listed in Table 2-4.

Table 2-4: Capital Maintenance Projects Included in the Study

Line ID	Description	Voltage Class (kV)	Completed By / Anticipated Completion	Normal Rating (MVA)	
				Summer	Winter
7L42	Hill 751S to Lloydminster 716S	144	2020	114	145
7L65	Vegreville 709S to Vermilion 710S	144	2023	187	227
174L[a]	Bardo 197S to North Holden 395S	138	2023	96	96

Note: [a] As per information from AltaLink, there is an opportunity to restore 174L to its full conductor rating (120/145 MVA). In the generation integration capability studies undertaken in this report, if the 174L was the only element that limits the generation integration capability in the Study Area, a sensitivity study was carried out assuming a higher rating on this line.

2.10 Dynamic Data and Assumptions

In the planning studies, validated dynamic data was used for existing equipment in the AIES such as generators, wind farm turbines, motor loads, and static VAr compensators (SVCs) when available. If validated data was not available, generic dynamic models were adopted for existing equipment and for facilities planned to be in service within the timeline of the planning studies.

2.11 Protection Fault Clearing Times

The transient stability studies were performed using the protection fault clearing times provided by the TFOs. If the TFO did not specify the fault clearing times (e.g., for new transmission lines) for a selected contingency, then the studies for that contingency were performed using the standard fault clearing times that are specified in Table 2-3 of the AESO's *Transmission Planning Criteria – Basis and Assumptions*. Details protection faults clearing times for selected contingencies are provided in Attachment F.

2.12 HVDC Power Order Assumptions

WATL and EATL are HVDC transmission lines. The power orders of WATL and EATL were initially set to minimize transmission system loss in the base cases. If there were any transmission line constraints observed and these constraints could be alleviated by re-dispatching WATL and/or EATL, the power order for WATL and EATL was changed accordingly. During the course of the capability studies, HVDCs were dispatched to maximize the generation integration capability in the Study Area.

The reactive power limits of the MVAr exchanges between the HVDC terminals (WATL and EATL) and the connected AC transmission systems are shown in Table 2-5. These limits were maintained when performing the planning studies.

Table 2-5: HVDC to Adjacent AC System MVAr Exchange Limits

HVDC Facility	North Terminal Reactive Power Limit (MVAr)	South Terminal Reactive Power Limit (MVAr)
EATL	-85 to 75	-35 to 35
WATL	-75 to 75	-35 to 35

2.13 Existing RAS in Study Area

The existing transmission system in the Study Area is being operated with the help of RAS and automatic protection scheme (APS) that result in generation curtailment, reconfiguration of transmission lines, and HVDC re-dispatch to avoid thermal criteria violations and/or voltage violations during contingency conditions. Table 2-6 lists the existing RAS and APS (as of January 2020) in the Study Area that designed to operate automatically in real-time to protect the system from Reliability Criteria violations.

It is noted that the RAS and APS listed in Table 2-6 do not account for the generation projects that have been proposed in the Study Area nor the approved PENV development. As the system continues to evolve, the RAS and APS described in the table will be modified to maintain transmission system reliability. As a result of the PENV development, some of the existing RAS listed in Table 2-6 would not be required, such as RAS 138. RAS was implemented by the AESO if such scheme is effective in alleviating identified constraints. As new generation continues to develop in the Study Area, some of the RASs described in Table 2-6 would be modified to fully utilize the existing transmission system and planned transmission development, as further described in in Section 4.2.

Table 2-6: Existing RAS and APS in Study Area

RAS and APS No.	Scheme Name
20	Anderson 801S 240 kV Line 9L933, 9L934 and 9L950 Thermal Protection Scheme to Sheerness Plant
27	562S Cypress McNeil Power and Undervoltage Scheme
28	163S Amoco Empress Reverse Power and Undervoltage Scheme
29	McNeil (840s) Under Voltage Runback Scheme
32	Battle River 757S 7L50 and 7L701 Thermal Protection Scheme
33	Cypress (T562s) Reverse Power and Undervoltage Scheme
80	Anderson (801S) 9L59 Overvoltage Protection
106	Monitor Overvoltage Protection
112	Cypress 562s - Power/Under & Over Frequency Scheme
134	174L-395S North Holden Overload Mitigation Scheme
138	7L50 -526S Buffalo Creek Overload Mitigation Scheme

RAS and APS No.	Scheme Name
139	901T-766S Nevis Overload Mitigation Scheme
141	498S Voltage Instability Mitigation
149	EATL HVDC
150	WATL HVDC
151	223S Strome Low Voltage Mitigation
164	1034L and 1035L Contingency Mitigation

3 Planning Methodology

The methodology used to conduct the planning studies included the following:

- Develop credible study cases using various load conditions and generation dispatches for the planning studies.
- Conduct need assessment studies in the near-term by evaluating the generation integration capability of the transmission system prior to transmission development and identify potential system constraints in the Study Area.
- Develop Transmission Development Options to address the identified system constraints.
- Evaluate the performance of the proposed Transmission Development Options and select the Preferred Transmission Development.
- Assess the impact of CRPC and renewable generation in the SW sub-region on the generation integration capability in the Study Area.
- Evaluate the transmission system performance of the Preferred Transmission Development in the medium-term.
- Verify the performance of the Preferred Transmission Development through voltage stability, dynamic stability and system losses studies.
- Perform short-circuit analysis for the substations within and surrounding the Study Area, both before and after implementation of the Preferred Transmission Development.
- Develop milestone(s) for the construction of the Preferred Transmission Development.

3.1 Thermal Dispatch Scenarios

In consideration of the uncertainties associated with replacement or retirement of the existing thermal generation in the Study Area (Battle River and Sheerness), the AESO considered two thermal dispatch scenarios. Detailed descriptions of the two scenarios are provided in the Forecasting Appendix[18]. A brief summary of the two thermal dispatch scenarios are provided below.

3.1.1 Scenario 1

Scenario 1 assumes low thermal energy in the Study Area. It represents a potential outlook where the Battle River and Sheerness facilities have lower capacity and energy dispatch than the historical coal units assuming there would be no replacement for Battle River 3 and 4 (BR3, BR4) after their retirement and peaking behavior of the assumed conversion units.

[18] Filed under separate cover as Appendix B.

3.1.2 Scenario 2

Scenario 2 assumes high thermal energy in the Study Area. It represents a potential outlook where the Battle River and Sheerness facilities have similar capacity as historical thermal fleet.

Table 3-1 summarizes the status of the Battle River and Sheerness facilities under each dispatch scenario.

Table 3-1: Thermal Dispatch Scenarios [a]

<table>
<tr><th rowspan="2">Generating Unit Asset ID</th><th rowspan="2">Existing Capacity (MW)</th><th colspan="2">Scenario 1</th><th colspan="2">Scenario 2</th></tr>
<tr><th>2023</th><th>2031</th><th>2023</th><th>2031</th></tr>
<tr><td>BR3</td><td>149</td><td>Retired</td><td>Retired</td><td rowspan="2">New Simple Cycle</td><td rowspan="2">New Simple Cycle</td></tr>
<tr><td>BR4</td><td>155</td><td>Co-firing [b]</td><td>Retired</td></tr>
<tr><td>BR5</td><td>385</td><td>Conversion</td><td>New Combined Cycle (479MW)</td><td>Conversion</td><td>New Combined Cycle (479MW)</td></tr>
<tr><td>SH1</td><td>400</td><td>Conversion</td><td>Conversion</td><td>Conversion</td><td rowspan="2">New Combined Cycle (790MW)</td></tr>
<tr><td>SH2</td><td>390</td><td>Conversion</td><td>Conversion</td><td>Conversion</td></tr>
<tr><td>Total Capacity (MW)</td><td>1,479</td><td>1,330</td><td>1,269</td><td>1,479</td><td>1,573</td></tr>
</table>

Notes: [a] The future facility capacity is the same as the existing facility capacity if a capacity size is not specified in the table.

[b] Alterations to the Battle River Power Plant to allow additional natural gas as a supplemental fuel in the Battle River 4.

3.1.3 Study Cases

Study cases represent credible stressed operating conditions that includes various load conditions and generation dispatches. Generation dispatches were developed for the two thermal dispatch scenarios described above using both a statistical and a market simulation method (refer to Forecasting Appendix[19] for further details about generation dispatch methodology). As part of the market simulation, the power flow on the CE west transfer-out path was monitored. The operating conditions resulting in the highest flows on the CE west transfer-out path were selected to create the study cases. The study cases were then used to perform detailed deterministic studies.

For the year 2023, study cases were developed to include the generation dispatches based on both statistical and market simulation methods, which were used to perform the deterministic studies. For the year 2031, study cases were developed to include generation dispatch based on the market simulation method only, as it was determined that the historical statistics may not represent the generation fleet changes as forecasted in the 2019 LTO.

The list of study cases for 2023 and 2031 are provided in Table 3-2 and Table 3-3, respectively.

[19] Filed under separate cover as Appendix B.

Table 3-2: 2023 Study Cases

Case No.	Dispatch Method	Season	AIL Load (MW)[a]	Thermal Dispatch (MW)		Intertie Flow (MW)[b]			Wind Dispatched (% of Installed Capacity)		
				BR	SH	AB-BC	MATL	AB-SK	SW	SE	CE
Scenario 1											
M1	Statistical	SP	11,713	272	261	0	0	0	96	96	96
M2	Statistical	SL	8,358	97	199	0	0	0	96	96	96
M3	Statistical	SL	8,358	127	261	702	308	150	96	96	96
M4	Statistical	SP	11,713	448	720	42	0	0	42	95	75
M5	Statistical	SL	8,358	225	686	45	0	0	42	95	75
M6	Market Simulation (MS)	Summer	10,574	127	158	145	119	-154	95	99	92
M7	MS	Summer	10,167	134	158	0	0	-100	92	91	22
M8	MS	Winter	11,215	167	790	503	119	-73	97	99	94
M9	MS	Winter	10,920	167	790	199	119	52	92	97	82
Scenario 2											
H1	Statistical	SP	11,713	432	670	0	0	0	96	96	96
H2	Statistical	SP	11,713	520	792	0	0	0	96	96	96
H3	Statistical	SL	8,358	165	495	0	0	0	96	96	96
H4	MS	Summer	11,011	276	790	425	119	52	95	98	85
H5	MS	Summer	10,575	276	790	51	0	-153	78	96	85
H6	MS	Summer	10,586	276	375	0	0	152	94	93	49
H7	MS	Winter	11,161	316	790	384	119	-100	85	96	90
H8	MS	Winter	11,540	366	790	205	119	-100	69	99	97

Notes: [a] Alberta internal load

[b] negative indicates import into Alberta, positive indicates export out of Alberta

Table 3-3: 2031 Study Cases

Case No.	Dispatch Method	Season	AIL Load (MW) [a]	Thermal Dispatch (MW)		Intertie Flow (MW) [b]			Wind Dispatched (% of Installed Capacity)		
				BR	SH	AB-BC	MATL	AB-SK	SW	SE	CE
Scenario 1											
M10	MS	Summer	9,497	192	78	-14	-60	57	96	95	61
M11	MS	Summer	10,218	428	158	-255	37	152	76	98	91
M12	MS	Summer	10,051	428	158	220	59	64	70	95	97
M13	MS	Summer	10,212	428	158	-124	0	57	82	99	91
M14	MS	Summer	10,620	428	158	465	189	54	81	98	85
Scenario 2											
H9	MS	Summer	9,738	276	316	-390	-79	152	91	96	73
H10	MS	Summer	11,758	616	706	62	75	152	91	85	31
H11	MS	Summer	10,676	616	691	-107	259	152	76	95	94

Notes: [a] Alberta internal load

[b] negative indicates import into Alberta, positive indicates export out of Alberta

3.2 Generation Integration Capability Study Methodology

Generation integration capability is defined as the maximum amount of future generation that can be dispatched in a specific area without causing Reliability Criteria violations. Generation integration capability for this planning study was determined by optimally adjusting renewable generation capacity at pre-determined locations. The generation integration capability study was used to:

- Determine the generation integration capability of the Pre-Development transmission system and establish the need for future transmission capability enhancement.
- Evaluate the merit of various Transmission Development Options.

The generation integration capability study was carried out as follows:

- The optimized generation integration capability was determined by maximizing the overall generation integration capability in the Study Area and the SW sub-region. Future generation at each pre-defined generation connection location (provided in Section 3.2.1) was allocated in an optimal manner. During the course of the assessment, the amount of future generation at each of the pre-defined generation connection locations was varied independently, and the future generation was increased optimally until Reliability Criteria violations were observed.

- When future generation was added to the Study Area and SW sub-region, generation outside of these areas was adjusted based on the generic merit order to maintain the BC intertie flow at the level before any future generation was dispatched.
- The generation integration capability was first determined for reliable operation under Category B conditions (referred to throughout the document as the Category B capability). The Category B capability assessment identifies the maximum amount of future generation that could be dispatched in the Study Area and the SW sub-region without causing Reliability Criteria violations, or RAS requiring generation curtailment following a contingency. System re-configuration (such as transfer-tripping transmission lines post a Category B contingency) was considered if such an action could mitigate any Reliability Criteria violations and improve transmission system performance.
- After the Category B capability was determined, the Category A generation integration capability enabled by generation RAS (referred to throughout the document as the Category A capability enabled by generation RAS) was assessed to identify maximum amount of future generation that could be dispatched in the Study Area and the SW sub-region with the provision of generation RAS to curtail future generation in order to mitigate Reliability Criteria violations following a Category B contingency. The Category A capability study determined the theoretical amount of generation curtailment that would be required to alleviate Reliability Criteria violations. It must be noted that implementing RAS to curtail future generation may not be feasible, practical or most efficient from the real time operation and/or market perspective. For this planning study, the optimal minimum amount of generation curtailment to alleviate all the thermal violations for each of the Category B contingencies was determined, and the maximum amount of generation curtailment was assumed to be the current Most Severe Single Contingency (MSSC) limit which is 466 MW. [20] Generation RAS was assigned as follows for the generation integration capability assessment:
    - Only future generation was assigned to a generation RAS. Existing installed generation, and REP projects (assumed to be energized before 2023) were not assigned to a generation RAS.
    - Generators were curtailed based on location: if thermal criteria violations were observed in the Study Area, only future generation in the Study Area were assigned to a generation RAS. Similarly, only future generation in the SW sub-region were assigned to a generation RAS to alleviate thermal load criteria violations in the SW sub-region.
    - The order of generation curtailment was based on the effectiveness of the generator in mitigating the identified constraints.
- The limiting contingencies and limiting elements were identified for both the Category B capability and the Category A capability enabled by generation RAS. The limiting contingency is a Category B contingency that causes one or more elements in the transmission system reaching their thermal or voltage limits. The limiting element is the transmission element which reaches its thermal or voltage limit.

[20] MSSC refers to the most severe single contingency generator or supply loss on the AIES which may occur as a result of a generator trip or the loss of a transmission line that subsequently leads to the simultaneous loss of generation. The MSSC is currently at a value of approximately 466 MW under a normal transmission system configuration.

In the study, the identified generation integration capability was optimized towards the maximum system capability by adjusting the capacity at the new renewable generation injection point. However, future conditions may not reach the estimated optimal generation capability levels because actual project developments may not be sized or located optimally.

Although the generation integration capability in this planning study is designed for renewable integration, it is applicable to the connection of any type of generation. The AESO will review the impact of future generation projects on the transmission system through the assessments completed as part of the AESO's Connection Process.

3.2.1 Location of Future Renewable Generation

In order to efficiently utilize transmission system capability and minimize impact on local constraints, the future renewable generation was assumed to be primarily connected to major 240kV substations. Considering that the PENV development was designed to provide access to generation interconnection, it was assumed in the planning study that future renewable generation in the PENV area can be connected at 138 kV substations Drury 2007S and Edgerton 899S. The list of substations to which potential future renewable generation could connect to, as an assumption for this planning study are listed in Table 3-4.

The reactive power capability of the future renewable generating facilities shall comply with the Section 502.1 of the ISO rules, *Aggregated Generating Facilities Technical Requirements.*[21]

Table 3-4: Assumed Future Generation Connection Locations

Sub-region	Future Renewable Generation Connection Location
Central East (CE)	Hansman Lake 650S; Tinchebray 972S; Lanfine 959S; Nilrem 574S; Edgerton 899S; Drury 2007S
Southeast (SE)	Bowmanton 244S; Jenner 275S; Cypress 562S; Oakland 946S
Southwest (SW)	Castle Rock Ridge 205S; Goose Lake 103S; Windy Flats 138S; North Lethbridge 370S; Picture Butte 120S

3.2.2 Contingencies and Monitored Elements

Category B contingencies for generation integration capability studies include:

- 138 kV and above voltage class system elements in the Study Area, and all transmission elements connecting the Study Area to neighbouring planning areas.
- 138 kV and above voltage class system elements in the SW sub-region.
- 240 kV and above voltage class system elements in the following AESO planning areas: Wabamun (Area 40), Edmonton (Area 60), Red Deer (Area 35), and Didsbury (Area 39).
- WATL

[21] Available on the AESO website.

- EATL
- Outage of the AB-BC intertie and the MATL intertie was excluded as it is beyond the scope of this study.

Monitored elements included:

- 138 kV and above voltage class system elements in the Study Area, and all transmission lines connecting the Study Area to neighbouring planning areas.
- 138 kV and above voltage class system elements in the SW sub-region.
- 240 kV and above voltage class system elements in the following AESO planning areas: Wabamun (Area 40), Edmonton (Area 60), Red Deer (Area 35), and Didsbury (Area 39).

Category C5 contingencies for generation integration capability studies are listed in Table 3-5.

Table 3-5: List of Category C5 contingencies

Designation	Description
1035L_1088L	1035L (Bowmanton 244S - Newell 2075S) and 1088L (Cassils 324S - Newell 2075S)
1034L_1088L	1034L (Bowmanton 244S - Cassils 324S) and 1088L (Cassils 324S - Newell 2075S)
945L_1011L	945L (Cypress 562S - Jenner 275S) and 1011L (Cypress 562S - Empress 163S)
933L_934L	933L (Anderson 801S - Ware Junction 132S) and 934L (Anderson 801S - Ware Junction 132S)
945L_1002L	945L (Cypress 562S - Jenner 275S) and 1002L (Jenner 275S - Empress 163S)
1011L_1002L	1011L (Cypress 562S - Empress 163S) and 1002L (Jenner 275S - Empress 163S)
951L_944L	951L (Jenner 275S - Ware Junction 132S) and 944L (Jenner 275S - Ware Junction 132S)
931L_1075L	931L (West Brooks 28S - Ware Junction 132S) and 1075L (West Brooks 28S - Ware Junction 132S)
1035L_1034L	1035L (Bowmanton 244S - Newell 2075S) and 1034L (Bowmanton 244S - Cassils 324S)
1051L_1052L	1051L (West Brooks 28S - Cassils 324S) and 1052L (West Brooks 28S - Cassils 324S)
953L_1047L	953L (Nilrem 574S - Cordel 755S) and 1047L (Nilrem 574S - Hansman Lake 650S)
923L_1087L	923L (Milo 356S - Cassils 324S) and 1087L (Cassils 324S - Newell 2075S)
935L_1087L	935L (Cassils 324S - Milo 356S) and 1087L (Cassils 324S - Newell 2075S)
923L_935L	923L (Milo 356S - Newell 2075S) and 935L (Cassils 324S - Milo 356S)
924L_927L	924L (Langdon 102S - Milo 356S) and 927L (Langdon 102S - Milo 356S)
962L_986L	Proposed new 240kV circuits 962L/9L62 (Tinchebray 972S - Gaetz 87S) and 986L/9L86 (Tinchebray 972S - Gaetz 87S)

3.3 Voltage Stability Analysis

The objective of the voltage stability analysis was to determine the ability of the system to maintain voltage stability margin under Category A, Category B and Category C5 system conditions. The power-voltage (PV) curve is a representation of voltage change as a result of increased power transfer between two sub-systems. As the transfer between two sub-system increases, the voltage in the source system decreases and eventually voltage collapses at certain level of power transfer. The Study Area is generation rich area and excess generation is evacuated through transfer-out paths (as described in Section 1.2). Thus, an increase in power transfer between the Study Area and rest of the AIES can be simulated by increasing generation dispatch in the Study Area. The PV margin is defined as the minimum of the percentage increase in transfer to the point of voltage collapse for all the studied contingencies.

Voltage stability studies were carried out both before and after the Preferred Transmission Development systems is in service for 2023 and 2031 study years. Interface flow and voltages of the all the 240 kV buses in the Study Area were monitored and the voltage stability analysis was carried out for selected Category B and Category C5 contingencies in the Study Area

The new generators in the Study Area were simulated as source system and generators in the Wabamun (Area 40) and Fort McMurray (Area 25) planning areas were simulated as sink system. To increase the interface flow, the dispatch of future generation in the source system was increased and an equal amount of the generation in the sink system was reduced until voltage collapse.

The voltage stability criteria defined in Table 2-2 of the *Transmission Planning Criteria – Basis and Assumptions* was used to test if voltage stability margin can be met.

3.4 Transient Stability Analysis

The objective of the transient stability analysis is to determine the ability of the system to maintain rotor angle stability under Category B and Category C5 system conditions. In the transient stability analysis, three-phase-to-ground faults for Category B contingencies and single-phase-to-ground faults for Category C5 contingencies were applied to critical 240 kV and higher voltage class transmission elements in the Study Area to assess transmission system stability both before and after the Preferred Transmission Development is in service for both 2023 and 2031 study years. The faults were cleared by opening the near-end and far-end breakers according to the fault clearing times shown in Attachment F.

The Reliability Criteria was applied as outlined in Section 2.1 and a system dynamic response was considered acceptable if the following conditions were met after a disturbance:

- All the generators remained stable and connected to the AIES.
- The post-contingency voltage did not differ from the pre-fault voltage by more than 10%.
- All oscillations in the system were damped successfully.
- No uncontrolled separation of the interties is allowed.

3.5 Short-circuit Analysis

The objective of short-circuit analysis was to assess whether the maximum fault currents exceed the capability for the circuit breakers to clear faults and to ensure equipment in the area is capable of carrying the anticipated short-circuit flow. Short-circuit levels were analyzed under three-phase-to-ground faults and single-line-to-ground faults with all the generators in and around the Study Area dispatched.

The short-circuit analysis was carried out both before and after Preferred Transmission Development system is in service for both 2023 and 2031 study years.

3.6 Transmission System Losses Analysis

Transmission system loss analysis was conducted to assess the impact of the Preferred Transmission Development. The transmission system losses were evaluated using all Category B capability power flow cases for the 2023 and 2031 study cases with the assumption of CRPC in service. Transmission system losses were calculated using all the study cases with and without the Preferred Transmission Development. Average transmission system losses were estimated by taking the numerical average of transmission system losses for all the studied cases for a given thermal dispatch scenario for each study year.

4 Need Assessment

This section describes the assessment carried out to determine the need for transmission development.

4.1 Need Methodology

The following describes the methodology used to determine the need for transmission development in the Study Area.

1. Determine the generation integration capability of the Pre-Development transmission system in the Study Area.
2. Compare the generation integration capability of the Pre-Development transmission system with forecast new generation to determine the need for transmission development.

The generation integration capability of the transmission system was determined as described in Section 3.2. Generation integration capability studies were carried out for the Pre-Development transmission system in 2023 and 2031 for the two thermal dispatch scenarios, as described in Section 3.1. Detailed study results for 2023 are described below. Detailed study results for 2031 are described in Section 7.

In addition to identifying the optimized total generation integration capability in the Study Area and SW sub-region as described in Section 3.2, the following two sensitivity studies were performed in consideration of the impact of the distribution of future generation in three sub-regions on the total generation integration capability:

- Equally Distributed

  This assessment is to determine the generation integration capability in the Study Area and SW sub-region assuming that future generation developments among the SE, CE, and SW sub-regions were allocated in approximately equal amounts. The future generation developments were allocated among the pre-defined locations (as described in Section 3.2.1) within each sub-region in an optimal manner.

- Individual Sub-regions (SE sub-region and CE sub-region)

  This assessment is to determine the generation integration capability in each sub-region in the Study Area. It was assumed that future generation developments were concentrated in either the SE sub-region or the CE sub-region only; and future generation developments were allocated among the pre-defined locations (as described in Section 3.2.1) within each individual sub-region in an optimal manner.

4.2 Transmission Constraints and Mitigation Measures

During the course of the capability assessment, thermal criteria violations were observed on the 138 kV transmission system in the Study Area under Category B conditions. Thermal criteria violations observed in the Study Area[22] and the mitigation measures implemented in the assessment are as follows:

- Thermal criteria violations were observed on the 138 kV transmission lines 892L (Suffield 895S – Bowmanton 244S), 100L (Suffield 895S – Tilley 498S), and 610L (Fincastle 336S – Taber 83S) following the loss of 240kV transmission lines 1034L (Bowmanton 244S – Cassils 324S) or 1035L (Bowmanton 244S – Newell 2075S), when additional generation was connected to the 240 kV transmission lines 964L and 983L between Bowmanton 244S and Whitla 251S substations. Opening the Bowmanton 244S substation bus-tie breaker post-contingency mitigated these thermal criteria violations and improved transmission system performance.
- Nevis RAS re-configuration: thermal criteria violations were observed on the Nevis 766S substation transformer 901T following the loss of 240kV transmission line 9L20 (Nevis 766S – Cordel 755S). The existing RAS 139 manages this thermal criteria violation by curtailing the existing Halkirk wind power facility (HAL1). Once REP generators and other generation projects are connected in the area, revisions to RAS 139 will be required to manage the thermal criteria violations. In this assessment, RAS 139 was revised by transfer tripping the 144 kV transmission line 7L137 (Three Hills 770S – Rowley 768S) to mitigate the thermal criteria violations. This revised RAS mitigated the thermal criteria violations and improved transmission system performance.
- Thermal criteria violations were observed on the 138 kV transmission line 174L (North Holden 395S – Bardo 197S) following the loss of EATL, 912L (Red Deer 63S – Nevis 766S) or Nevis 766S transformer 901T). The existing RAS 134 opens 174L to mitigate thermal criteria violations and other reliability concerns in the area. In this capability assessment, RAS 134 was implemented when required to improve transmission system performance.

  Opening 174L may cascade thermal criteria violations to the CE sub-region 144 kV north transfer-out path (as defined in Section 1.2). In the approved PENV NID, the AESO proposed to open three lines, including 138 kV transmission line 174L (North Holden 395S – Bardo 197S), 144 kV transmission line 7L92 (Vegreville 709S – Vilna 777S), and 144 kV transmission line 7L53 (Irish Creek 706S – Lindberg 969S tap point), which would force the surplus power to be evacuated from the CE sub-region via the west and south transfer-out paths (as defined in Section 1.2). This scheme of transfer-tripping three lines was implemented in the capability studies when required to improve transmission system performance. The AESO acknowledges that opening three lines may introduce operational complexity under some unforeseen system conditions, such as planned or forced outages in the area. The AESO will continue to monitor the system as future generation develops in the Study Area and will propose and implement appropriate protection schemes to mitigate Reliability Criteria violations.

[22] 138 kV thermal criteria violations in the SW sub-region were also observed and thermal protection schemes were considered during the course of the capability assessment.

4.3 Generation Integration Capability in 2023

This section summarizes the generation integration capability study of the Pre-Development transmission system in 2023 for the two thermal dispatch scenarios described in Section 3.1. The study cases described in Table 3-2 were utilized for the capability assessment. Power flow single line diagrams (SLD) for this assessment are provided in Attachment A.

4.3.1 Category B Capability Assessment

The Category B capability was evaluated for the 2023 Pre-Development transmission system. The generation integration capability results for the two thermal dispatch scenarios are summarized as follows:

- Scenario 1
    - The optimal total generation integration capability is approximately 900 MW in which 535 MW is in the SE sub-region, 30 MW is in the CE sub-region, and 335 MW is in the SW sub-region.
        - The optimal total generation capability described above leads to several major 240 kV transfer paths in the Study Area and the SW sub-region reaching thermal limits simultaneously.
        - Of the optimized generation distribution, the CE sub-region is not an optimal location to connect future generation due to the limitation on the CE west transfer-out path (912L (Red Deer 63S – Nevis 766S) and 174L (Bardo 197S - North Holden 395S)) as indicated in Table 4-1. The impact of integrating higher amount of generation in the CE sub-region is discussed below.
    - Assuming future generation will be equally distributed among the SE, CE, and SW sub-regions, the total generation integration capability reduces to approximately 730 MW in which 245 MW is in the SE sub-region, 220 MW is in the CE sub-region, and 265 MW is in the SW sub-region. The 240 kV transmission line 912L (a component of the west transfer-out path) reaches its thermal limit for EATL contingency.
    - Assuming future generation will be concentrated in the SE sub-region only, (i.e., there is no future generation in the CE or SW sub-regions), there is approximately 570 MW of generation integration capability in the SE sub-region, and several 240 kV transmission lines in the SE sub-region reach their thermal limits under several Category B contingencies, which are listed in Table 4-1.
    - Assuming future generation will be concentrated in the CE sub-region only, (i.e., there is no future generation in the SE or SW sub-regions), there is approximately 450 MW of generation integration capability in the CE sub-region, and the 240 kV transmission line 912L (a component of the west transfer-out path) reaches its thermal limits for EATL contingency.
- Scenario 2
    - The optimal total generation integration capability is approximately 450 MW in which 120 MW is in the SE sub-region, 0 MW is in the CE sub-region, and 330 MW is in the SW sub-region.

- Due to the CE sub-region thermal generation dispatch being higher in Scenario 2 than in Scenario 1, the generation integration capability in the Study Area is reduced by approximately 400 MW compared to Scenario 1.
- Of the optimized generation distribution, the CE sub-region is not an optimal location to connect future generation due to the transfer-out limitation on the 240 kV transmission line 912L (Nevis 766S – Red Deer 63).

- Assuming future generation will be equally distributed among the SE, CE, and SW sub-regions, the total generation integration capability is approximately 275 MW in which 100 MW is in the SE sub-region, 75 MW is in the CE sub-region, and 100 MW is in the SW sub-region.
- Assuming future generation will be concentrated in the CE sub-region only, there is approximately 180 MW of generation integration capability in the CE sub-region.
- Assuming future generation will be concentrated in the SE sub-region only, there is approximately 275 MW of generation integration capability in the CE sub-region.
- For all Scenario 2 studies, the 240 kV transmission line 912L (a component of the west transfer-out path) is the limiting element following the loss of EATL.

The limiting contingencies and limiting elements for each thermal dispatch scenario are presented in Table 4-1.

Table 4-1: 2023 Category B Capability - Pre-Development

Thermal Dispatch Scenario	Capability Evaluation Basis	Study Area		SW (MW)	Total (MW)	Limiting Contingency	Limiting Elements	Loading (%)
		SE (MW)	CE (MW)					
Scenario 1	Optimized	535	30	335	900	1035L (Bowmanton 244S – Newell 2075S)	1087L (Cassils 324S – Newell 2075S)	98
						1088L (Cassils 324S – Newell 2075S) with EATL RAS	1087L (Cassils 324S – Newell 2075S)	100
						EATL	912L (Red Deer 63S – Nevis 766S)	100
						912L (Red Deer 63S – Nevis 766S) or Nevis 766S 901T	174L (Bardo 197S - North Holden 395S)	100
	Equally Distributed	245	220	265	730	EATL	912L (Red Deer 63S – Nevis 766S)	100
						1035L (Bowmanton 244S – Newell 2075S)	1087L (Cassils 324S – Newell 2075S)	96
	SE Sub-region Only	570	0	0	570	1035L (Bowmanton 244S – Newell 2075S)	1087L (Cassils 324S – Newell 2075S)	98
						EATL	912L (Red Deer 63S – Nevis 766S)	97
							174L (Bardo 197S - North Holden 395S)	100
							701L (North Holden 395S – Strome 223S)	99

Thermal Dispatch Scenario	Capability Evaluation Basis	Study Area		SW (MW)	Total (MW)	Limiting Contingency	Limiting Elements	Loading (%)
		SE (MW)	CE (MW)					
							7L701 (Strome 223S – Heisler 764S tap)	98
						923L (Milo 356S – Cassils 324S) with EATL RAS	1035L (Bowmanton 244S – Newell 2075S)	97
						935L (Milo 356S – Newell 2075S) with EATL RAS	923L (Milo 356S – Cassils 324S)	97
	CE Sub-region Only	0	450	0	450	EATL	912L (Red Deer 63S –Nevis 766S)	100
							174L (Bardo 197S - North Holden 395S)	100
						9L24 (Oakland 946S – Lanfine 959S)	7L760 (Oyen 767S - Amoco Empress 163S)	100
Scenario 2	Optimized	120	0	330	450	EATL	912L (Red Deer 63S –Nevis 766S)	100
	Equally Distributed	100	75	100	275	EATL	912L (Red Deer 63S –Nevis 766S)	100
	SE Sub-region Only	275	0	0	275	EATL	912L (Red Deer 63S –Nevis 766S)	100
	CE Sub-region Only	0	180	0	180	EATL	912L (Red Deer 63S –Nevis 766S)	100

4.3.2 Category A Capability (Enabled by Generation RAS) Assessment

The Category A capability enabled by generation RAS was evaluated for the 2023 Pre-Development transmission system. The generation integration capability results are for the two thermal dispatch scenarios are summarized as follows:

- Scenario 1
    - The optimized Category A capability enabled by generation RAS is approximately 1,440 MW in which 700 MW is in the SE sub-region, 55 MW is in the CE sub-region, and 685 MW is in the SW sub-region. The EATL contingency results in thermal criteria violations on 912L (Red Deer 63S – Nevis 766S), 9L20 (Nevis 766S – Cordel 755S), 174L (Bardo 197S – North Holden 395S), and 701L (North Holden 395S – Strome 223S), which would require approximately 460 MW of generation curtailment to mitigate the thermal criteria violations on these lines.
    - Assuming future generation is equally distributed within the SE, CE, and SW sub-regions, the total generation integration capability decreases marginally to 1,420 MW compared to the optimized Category A capability with approximately 500 MW in the SE sub-region, 485 MW in the CE sub-region, and 435 MW in the SW sub-region. The EATL contingency results in thermal criteria violations on 912L (Red Deer 63S – Nevis 766S), 9L20 (Nevis 766S – Cordel 755S), 174L (Bardo 197S – North Holden 395S), 701L (North Holden 395S – Strome 223S), and 7L701 (Strome 223S to Battle River 757S), which require would 460 MW of generation curtailment to mitigate the thermal criteria violations on these lines.

- Assuming future generation will be concentrated in the SE sub-region or CE sub-region only, the identified Category A capability in each sub-region is significantly lower than the optimal Category A capability (990 MW and 870 MW for each sub-region, respectively). The EATL contingency results in thermal criteria violations on 912L (Red Deer 63S – Nevis 766S), and 174L (Bardo 197S – North Holden 395S), which require generation curtailment of approximately 440 MW to mitigate the thermal criteria violations on these lines. The contingency of 912L (Red Deer 63S – Nevis 766S) or Nevis 766S 901T transformer cause thermal criteria violations on 174L (Bardo 197S – North Holden 395S), 701L (North Holden 395S – Strome 223S), and 7L701 (Strome 223S to Battle River 757S), which would require approximately 450 MW of generation curtailment to mitigate the thermal criteria violations on these lines.

- Scenario 2
  - The optimal total generation integration capability is approximately 830 MW in which approximately 250 MW is in the SE sub-region, 0 MW is in the CE sub-region, and 580 MW is in the SW sub-region. The EATL contingency results in thermal criteria violations on the 240 kV transmission lines 912L (Nevis 766S – Red Deer 63S), 9L20 (Nevis 766S – Cordel 755S), and 924L (Langdon 102S – Milo 356S), which would require all future generation in the SE sub-region to be curtailed to mitigate these thermal criteria violations under certain operating conditions.
  - Assuming future generation is equally distributed within the SE, CE, and SW sub-regions, this leads to the total generation integration capability of 830 MW in which approximately 275 MW is in the SE sub-region, 260 MW is in the CE sub-region, and 295 MW is in the SW sub-region. The EATL contingency results in thermal criteria violations on 912L (Red Deer 63S – Nevis 766S), 9L20 (Nevis 766S – Cordel 755S), 174L (Bardo 197S – North Holden 395S), 701L (North Holden 395S – Strome 223S), and 7L701 (Strome 223S to Battle River 757S), which would require approximately 460 MW of generation curtailment to mitigate the thermal criteria violations on these lines.
  - Assuming future generation will be concentrated in the SE or CE sub-regions only, the identified generation integration capability in each sub-region is lower than the optimal capability (675 MW and 580 MW for each sub-region, respectively). The EATL contingency results in thermal criteria violations on 912L (Red Deer 63S – Nevis 766S), 9L20 (Nevis 766S – Cordel 755S), and 174L (Bardo 197S – North Holden 395S), which would require approximately 460 MW of generation curtailment to mitigate the thermal criteria violations on these lines.

Table 4-2: 2023 Category A Capability Enabled by Generation RAS – Pre-Development

Thermal Dispatch Scenario	Capability Evaluation Basis	Study Area		SW (MW)	Total (MW)
		SE (MW)	CE (MW)		
Scenario 1	Optimized	700	55	685	1440
	Equally Distributed	500	485	435	1420
	SE Sub-region Only	990	0	0	990

Thermal Dispatch Scenario	Capability Evaluation Basis	Study Area		SW (MW)	Total (MW)
		SE (MW)	CE (MW)		
	CE Sub-region Only	0	870	0	870
Scenario 2	Optimized	250	0	580	830
	Equally Distributed	275	260	295	830
	SE Sub-region Only	675	0	0	675
	CE Sub-region Only	0	580	0	580

As explained in Section 3.2 that in the Category A capability assessment, it was assumed that only the future generation in the Study Area that are most effective to alleviate thermal criteria violations were curtailed first, and the existing installed generation as well as REP projects were not assigned to future generation RAS. Since renewable generation is developed in the areas of high resource potential, the location and size of future renewable generation developments within the Study Area are to be market driven. Depending on how the transmission capability is filled, the actual utilized generation integration capability may deviate from the optimized capability identified in this Planning Report.

For the reasons described above, the generation RAS enabled Category A capability identified throughout this section is subject to change. As future renewable generation projects develop and connect to the transmission system, additional studies will be performed to refine the required mitigation measures, RAS, or procedures.

4.4 Need Assessment Summary

Generation integration capability was assessed for the 2023 Pre-Development transmission system using the two thermal dispatch scenarios as described in Section 3.1. Thermal generation in the CE sub-region coincident with high renewable generation output impacts the available transmission system capability. Table 4-3 provides a summary for the Category B and Category A enabled by generation RAS capabilities in the Study Area. Following is the summary of the need assessment:

- In Scenario 1, the Category B capability in the Study Area is in the range of 450 MW to 565 MW; and the Category A capability enabled by generation RAS is in the range of 755 MW to 990 MW. The 240 kV transmission line 912L, a component of the CE sub-region west transfer-out path, is the main limiting element.
- In Scenario 2, the Category B capability in the Study Area is in the range of 120 MW to 280 MW; and the Category A capability enabled by generation RAS is in the range of 250 MW to 675 MW. The 240 kV transmission line 912L, a component of the CE sub-region west transfer-out path, is the main limiting element.

As indicated in the Forecasting Appendix[23], the AESO forecasts that by 2023, up to 900 MW new renewable generation, above the existing renewable generation and REP projects, will develop in Alberta. The renewable generation will continue to grow. By 2031, approximately 900 MW to 4,600 MW of incremental renewable generation is forecast to develop. The Study Area is a renewable resource rich area and it is anticipated that a significant portion of the forecasted new renewable generation would be developed in the Study Area, which would exceed the generation integration capability of the Pre-Development transmission system in 2023 and 2031 (as further described in Section 7).

Table 4-3: 2023 Generation Integration Capability Summary- Pre-Development

Thermal Dispatch Scenario	Capability Evaluation Basis	Category B (MW)		Category A Enabled by Generation RAS (MW)	
		Study Area	SW	Study Area	SW
Scenario 1	Optimized	565	335	755	685
	Equally Distributed	465	265	985	435
	SE Sub-region Only	570	0	990	0
	CE Sub-region Only	450	0	870	0
Scenario 2	Optimized	120	330	250	580
	Equally Distributed	175	100	535	295
	SE Sub-region Only	280	0	675	0
	CE Sub-region Only	180	0	580	0

In order to meet the forecasted renewable generation growth in the Study Area, the AESO has determined that transmission development is needed to alleviate thermal criteria violations on the CE sub-region west transfer-out path, in accordance with the Reliability Criteria. Without transmission development, the transmission system in the Study Area does not have sufficient capability to integrate the forecasted renewable generation in the 20-year planning horizon.

[23] Filed under separate cover as Appendix B.

5 Transmission Development Options

This section presents the Transmission Development Options considered to address the need identified in Section 4. The Transmission Development Options were formulated taking into account the type of violations, the geographical locations of the transmission system constraints, and the long-term forecast. Based on the Need Assessment, the existing CE sub-region west transfer-out path needs to be enhanced to ensure reliable evacuation of surplus generation in the Study Area.

The AESO considered additional transfer-out paths from the CE sub-region to adjacent load centers such as Red Deer (Area 35) planning area, Edmonton Planning Region, Northeast Planning Region, and Calgary Planning Region. The AESO’s preliminary assessment indicated that a new transfer-out path from the CE sub-region to the Red Deer (Area 35) area would be the shortest and most effective transfer-out path, compared to the other considered paths, therefore different options for connecting the CE sub-region to the Red Deer (Area 35) planning area were developed and investigated.

This section outlines six Transmission Development Options to connect the CE sub-region to the Red Deer (Area 35) planning area.

5.1 Option 1: Add Two 240 kV Circuits Between the Tinchebray 972S and Gaetz 87S Substations

Option 1 comprises the following components:

- Add two 240 kV circuits between the existing Tinchebray 972S and Gaetz 87S substations (approximately 130 km in length); and
- Modify the Tinchebray 972S substation by adding circuit breakers and associated equipment.
- Modify the Gaetz 87S substation by adding circuit breakers and associated equipment.

Figure 5-1 shows the simplified diagram for Option 1.

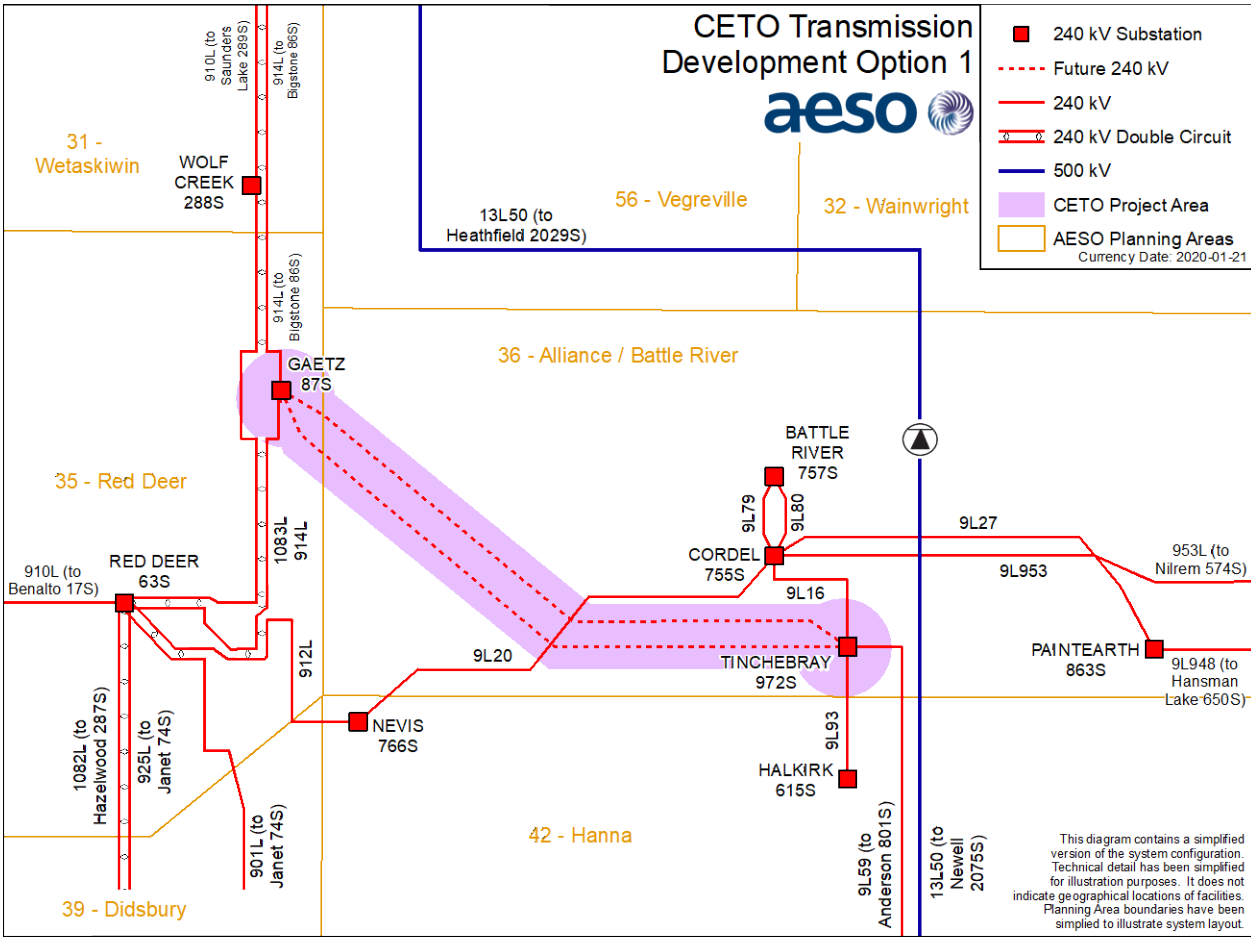

Figure 5-1: CETO Transmission Development Option 1

5.2 Option 2: Add Two 240 kV Circuits Between the Tinchebray 972S and Wolf Creek 288S Substations

Option 2 comprises the following components:

- Add two 240 kV circuits between the existing Tinchebray 972S and Wolf Creek 288S substations (approximately 130 km in length); and
- Modify the Tinchebray 972S substation by adding circuit breakers and associated equipment.
- Modify the Wolf Creek 288S substation by adding circuit breakers and associated equipment.

Figure 5-2 shows the simplified diagram for Option 2.

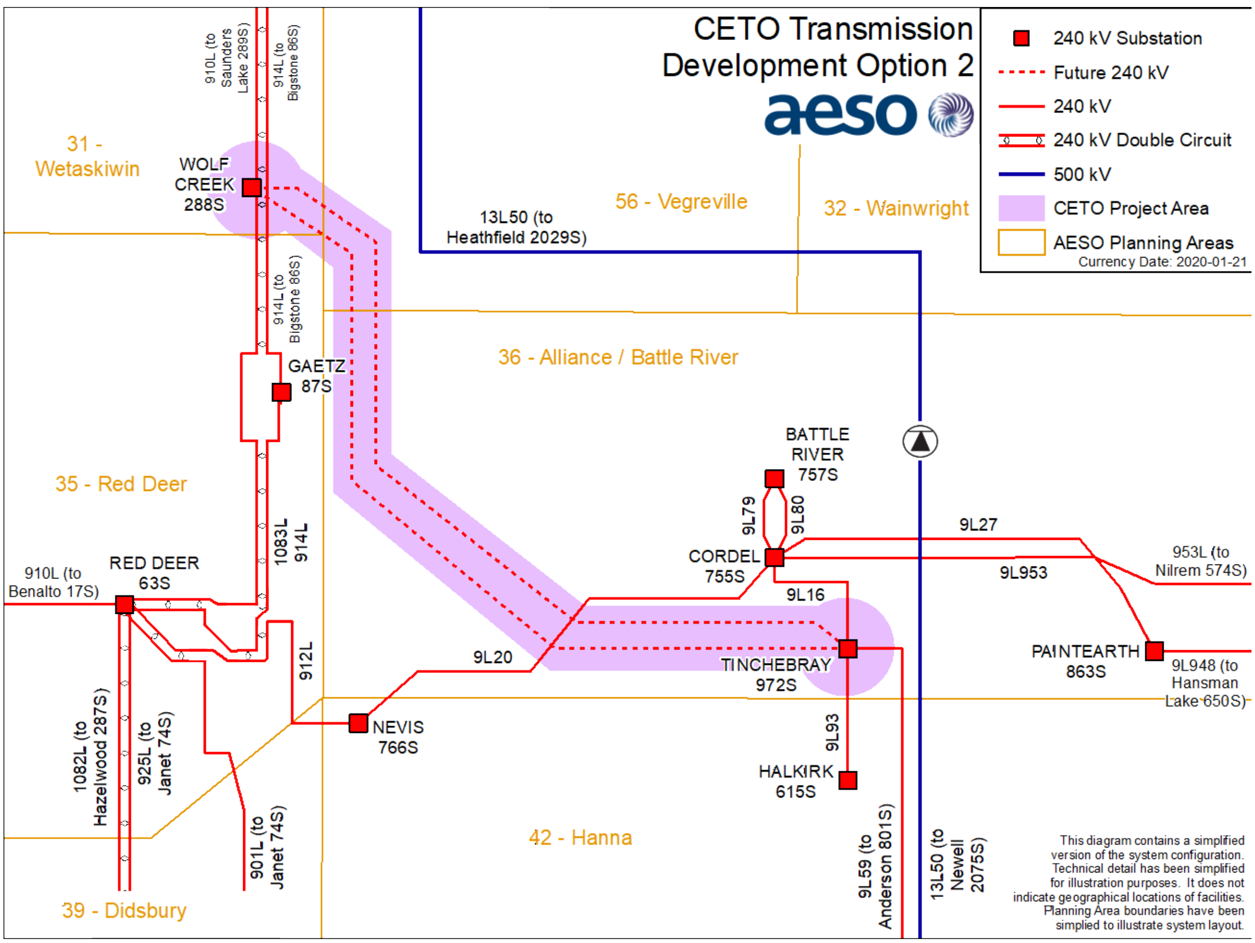

Figure 5-2: CETO Transmission Development Option 2

5.3 Option 3: Add One 240 kV Circuit Between the Tinchebray 972S and Gaetz 87S Substations and Upgrade 912L/9L20

Option 3 comprises the following components:

- Add one 240 kV circuit between the Tinchebray 972S and Gaetz 87S substations (approximately 130 km in length);
- Modify the Tinchebray 972S substation by adding circuit breakers and associated equipment;
- Modify the Gaetz 87S substation by adding circuit breakers and associated equipment; and
- Upgrade the existing 240 kV transmission lines 912L and 9L20 to a higher capacity.

Figure 5-3 shows the simplified diagram for Option 3.

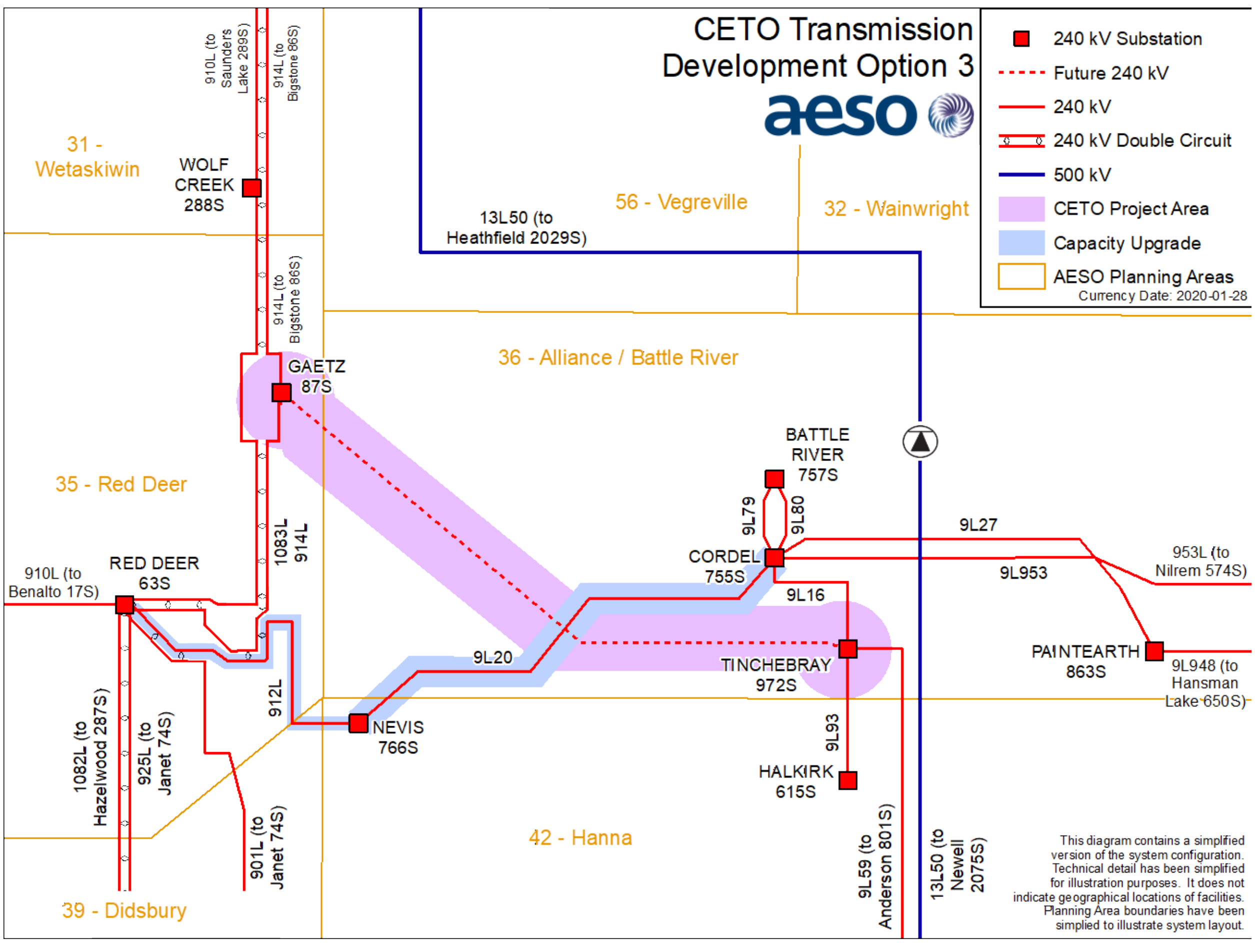

Figure 5-3: CETO Transmission Development Option 3

5.4 Option 4: Add one 500 kV Circuit Between the Tinchebray 972S and Gaetz 87S Substations

Option 4 comprises the following components:

- Add one 500 kV circuit between the Tinchebray 972S and Gaetz 87S substations (approximately 130 km in length);
- Modify the Tinchebray 972S substation by adding one 500/240 kV transformer, circuit breakers, and associated equipment;
- Modify the Gaetz 87S substation by adding one 500/240 kV transformer, circuit breakers, and associated equipment.

Figure 5-4 shows the simplified diagram for Option 4.

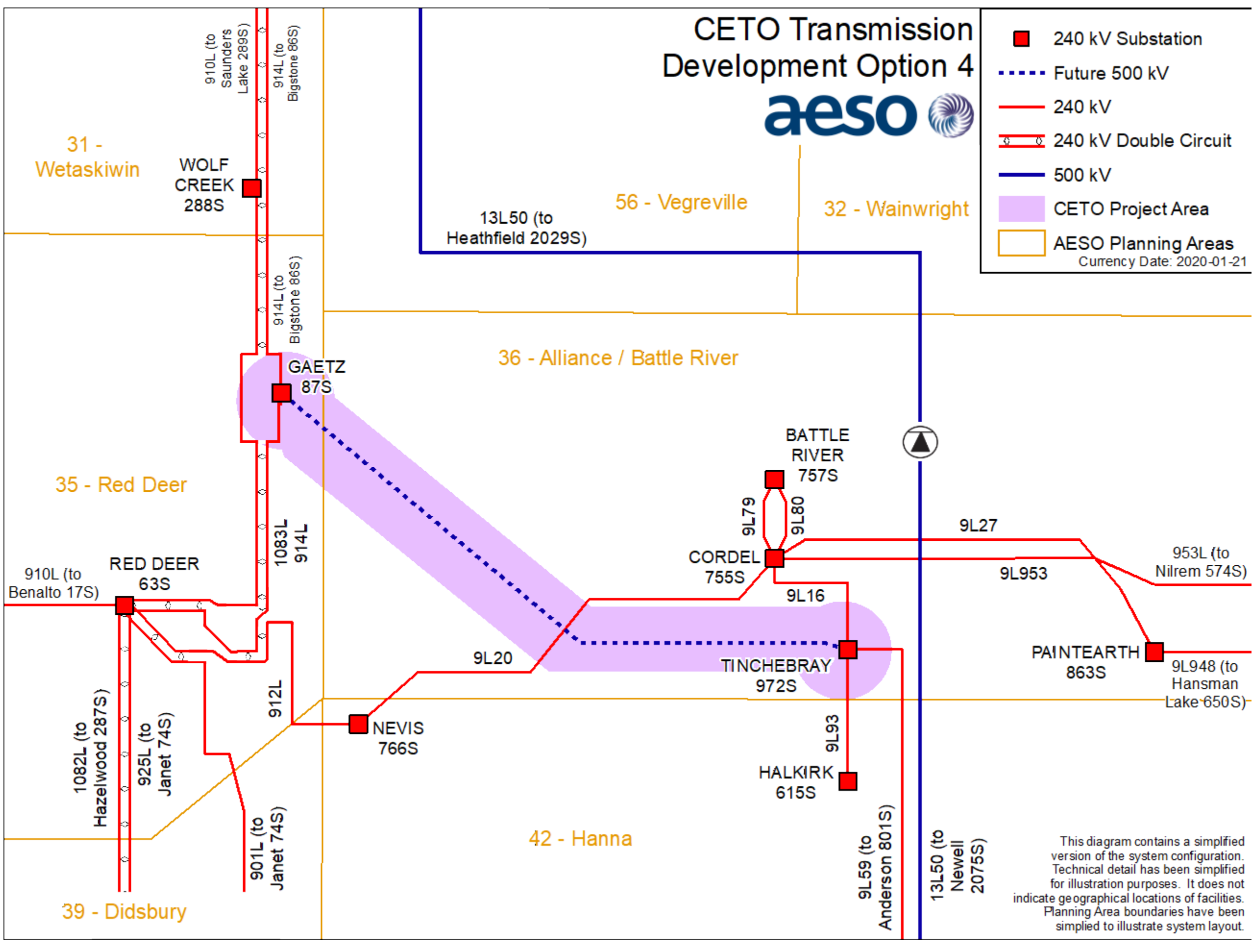

Figure 5-4: CETO Transmission Development Option 4

5.5 Option 5: Convert EATL to Bi-pole

Option 5 comprises the following components:

- Add one converter at each of the existing Newell 2075S and Heathfield 2029S substations to convert EATL to bi-pole to allow a total of up to 2,000 MW transfer capability on EATL. Each converter station includes AC/DC converters, converter transformer, filters, and associated station equipment and auxiliary equipment.

Figure 5-5 shows the simplified diagram for Option 5.

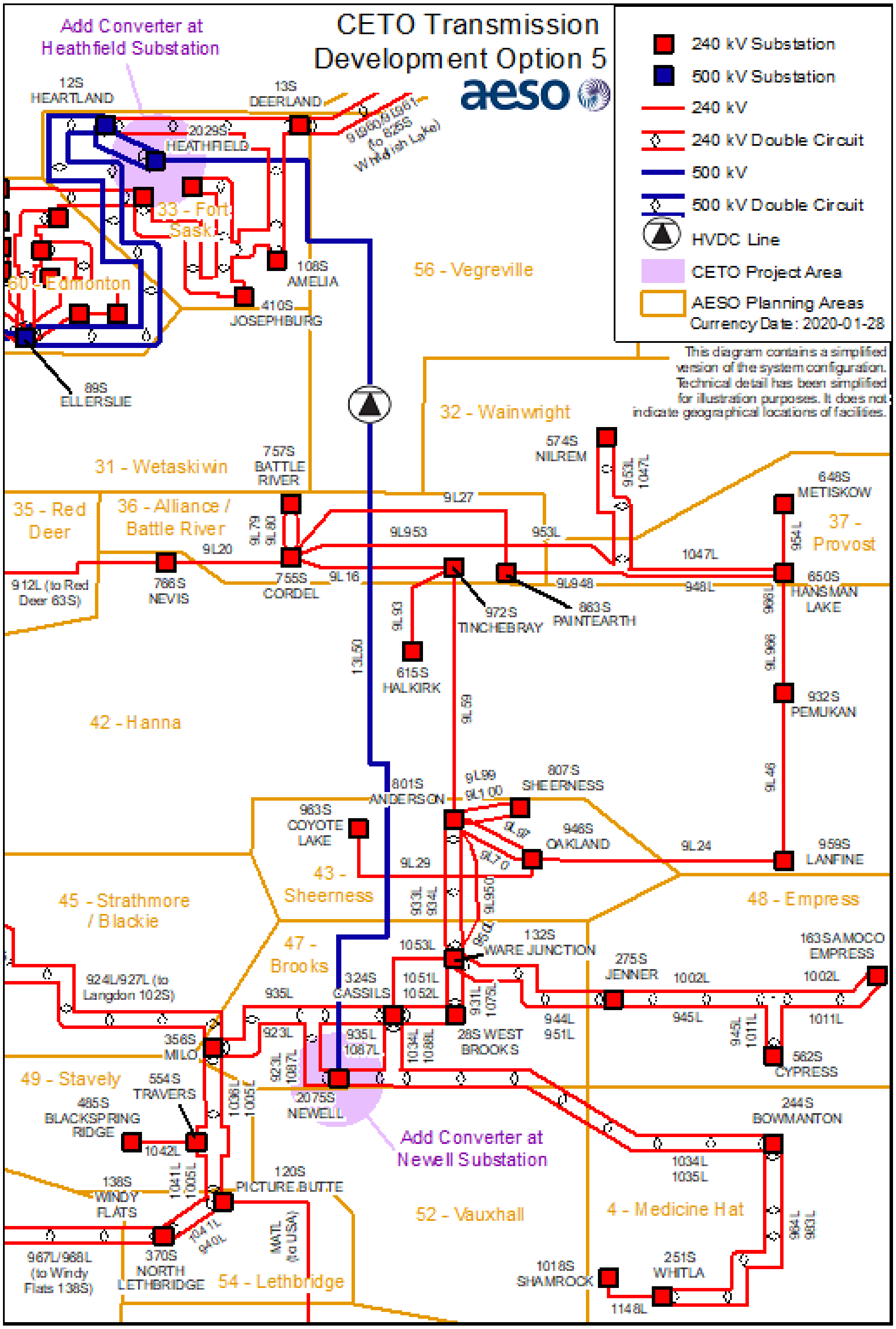

Figure 5-5: CETO Transmission Development Option 5

5.6 Option 6: Add one 240 kV Circuit Between the Gaetz 87S and Cordel 755S Substations and Add one 240 kV circuit Between the Gaetz 87S and Tinchebray 972S Substations

For Option 6, Cordel 755S was considered. However, the Cordel 755S substation has a single open bay available for the termination of a transmission circuit. The TFO has advised that due to physical constraints, an expansion to the Cordel 755S substation is not viable (see Attachment H). Therefore, the second 240 kV circuit must be terminated at a different substation (in this case the AESO has selected the Tinchebray 972S substation).

As a result, Option 6 comprises the following components:

- Add one 240 kV circuit between the Cordel 755S and Gaetz 87S substations (approximately 120 km in length);
- Add one 240 kV circuit between the Tinchebray 972S and Gaetz 87S substations (approximately 130 km in length);
- Modify the Tinchebray 972S substation by adding circuit breakers and associated equipment;
- Modify the Cordel 755S substation by adding circuit breakers and associated equipment; and
- Modify the Gaetz 87S substation by adding circuit breakers and associated equipment.

Figure 5-6 shows the simplified diagram for Option 6.

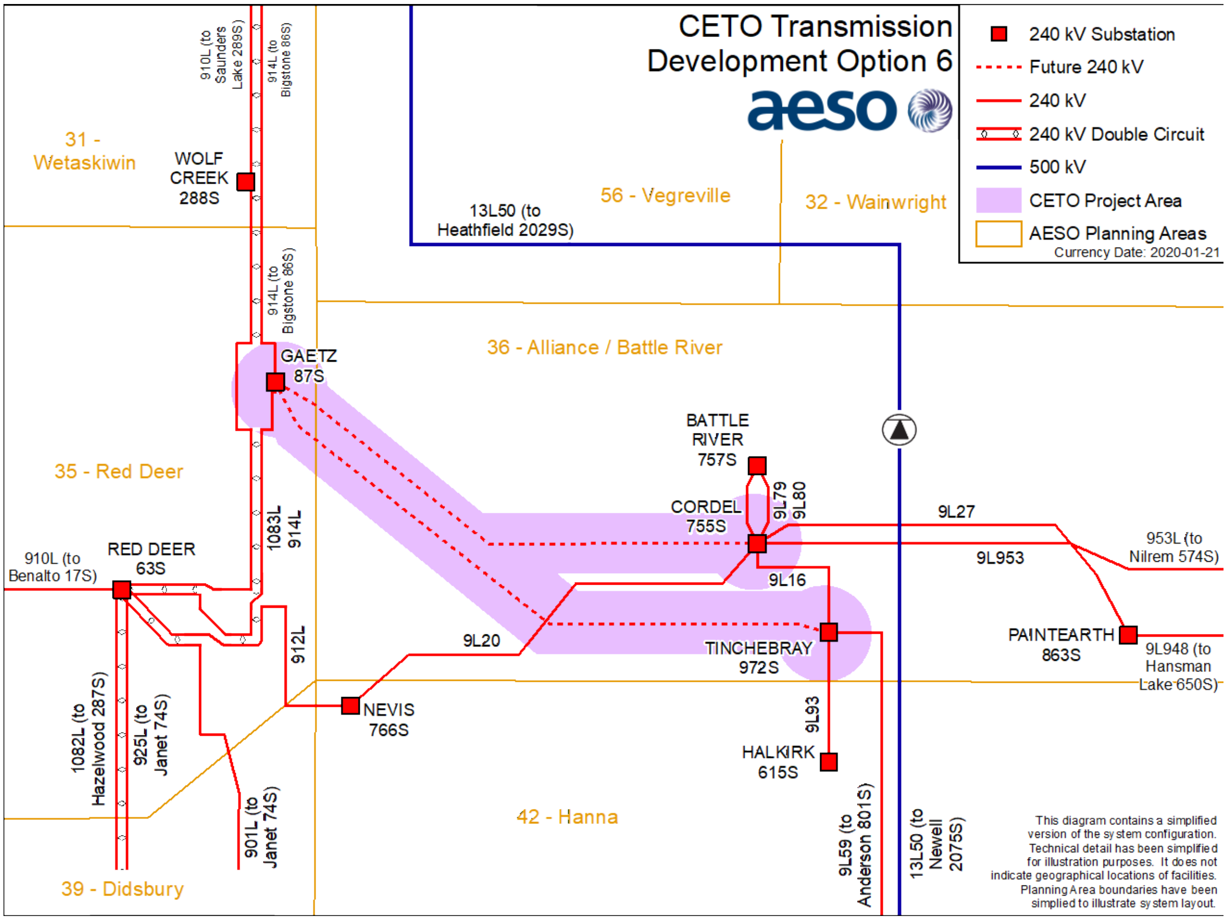

Figure 5-6: CETO Transmission Development Option 6

6 Selection of the Preferred Transmission Development

This section presents the evaluation and comparison of all Transmission Development Options described in Section 5, including the planning studies carried out to evaluate the transmission system performance of the Transmission Development Options. The Transmission Development Options were first evaluated based on technical merits including incremental generation integration enabled by the option and operational flexibility under outage conditions. Some options were ruled out if they are deemed technically inferior. For other options, cost estimate (+30/-30%), environmental and land use effects were developed and compared.

6.1 Technical Assessment of the Transmission Development Options

6.1.1 Category B Capability Assessment

The generation integration capability of the transmission system was determined as described in Section 3.2. Category B capability studies were carried out for the 2023 pre-Development transmission system using the thermal dispatch Scenario 2 as this is the most limiting scenario that places constraints on the CE sub-region transfer-out path. For the purpose of assessment of technical merits of the proposed options, the CRPC transmission development (as described in Section 2.5) was assumed to be in place so that all the options would be evaluated on a consistent basis. Generation integration capability was optimized towards the overall maximum capability in the Study Area and the SW sub-region. This approach is to ensure that the proposed plan aligns with the renewable integration plan as part of the 2020 LTP and provides the most benefits to the overall transmission system performance in the long term. It is noted that generation RAS can be implemented to obtain additional capability for each Transmission Development Option, however for the sake of comparison, the Category B Capability was the focus in this assessment.

The generation integration capability enabled by each Transmission Development Option was compared to the optimized Category B capability of 120 MW in the Study Area for the Pre-Development transmission system. Results indicated the following:

- Option 1 enhances the CE sub-region west transfer-out path by adding two 240 kV transmission circuits between the existing Tinchebray 972S substation and Gaetz 87S substation. The capability assessment indicates that Option 1 could enable approximately 820 MW of additional generation integration capability in the Study Area. Option 1 was considered further.
- Option 2 enhances the CE sub-region west transfer-out path by adding two 240 kV transmission circuits between the existing Tinchebray 972S substation and Wolf Creek 288S substation. The capability assessment indicates that Option 2 could enable approximately 660 MW of additional generation integration capability in the Study Area. Option 2 was considered further.
- Option 3 enhances the CE sub-region west transfer-out path by adding one 240 kV transmission circuit between the existing Tinchebray 972S substation and Gaetz 87S substation and upgrading the existing 240 kV transmission line 912L and 9L20. The capability assessment indicates that Option 3 could enable approximately 695 MW of additional generation integration capability in the Study Area. Option 3 was considered further.

- Option 4 enhances the CE sub-region west transfer-out path by adding one 500 kV transmission circuit between the existing Tinchebray 972S substation and Gaetz 87S substation. The capability assessment indicates that Option 4 could enable approximately 685 MW of additional generation integration capability in the Study Area. Option 4 was considered further.
- Option 5 converts EATL to bi-pole operation. Currently EATL is operated as mono-pole with 1,000 MW of transfer capability. The conversion of EATL to bi-pole will double the existing transfer capability to 2,000 MW, enabling additional generation integration in the Study Area. The capability assessment indicates that the incremental generation integration capability enabled by EATL bi-pole is limited to approximately 230 MW due to additional flow on EATL causing thermal criteria violations on the transmission lines connecting to the EATL south and north terminals, including 240 kV transmission lines 1087L, 1051L, 1052L, 909L, 908L, and 1056L. Option 5 was not considered further as it provides lowest amount of generation integration capability in the Study Area.
- Option 6 enhances the CE sub-region west transfer-out path by adding two 240 kV circuits, one circuit between the existing Cordel 755S substation and Gaetz 87S substation and one circuit between the existing Tinchebray 972S substation and Gaetz 87S substation. The capability assessment indicates that the incremental generation integration capability enabled by Option 6 is the same as Option 1 (approximately 800 MW). Option 6 was considered further.

Table 6-1 provides a summary of the Category B capability for each Transmission Development Option. Power flow SLDs for this assessment are provided in Attachment B.

Table 6-1: 2023 Category B Capability of the Transmission Development Options

Option	Study Area (MW)		SW (MW)	Total (MW)	Limiting Contingency	Limiting Elements	Loading (%)
	SE	CE					
1	505	435	985	1925	EATL	900L (Red Deer 63S-Benalto 17S)	100
						924L (Langdon 102S – Milo 356S)	100
					9L966/966L (Hansman Lake 650S – Pemukan 932S)	7L127 (Monitor 774S – Pemukan 932S)	100
2	580	200	935	1715	EATL	910L (Wolf Creek 288S - Saunders Lake 289S)	100
						9L59 (Tinchebray 972S – Anderson 801S)	100
3	385	430	980	1795	EATL	924L (Langdon 102S – Milo 356S)	100
						900L (Red Deer 63S – Benalto 17S)	99
					7L233 (Nilrem 574S -Drury 2007S)	7L50 (Buffalo Creek 526S –Jarrow 252S)	97
4	550	255	995	1800	EATL	924L (Langdon 102S –	100

Option	Study Area (MW)		SW (MW)	Total (MW)	Limiting Contingency	Limiting Elements	Loading (%)
	SE	CE					
						Milo 356S)	
						914L (Gaetz 87S – Bigstone 86S)	100
						9L59 (Tinchebray 72S – Anderson 801S)	100
						900L (Red Deer 63S – Benalto 17S)	97
					New 500 kV Tinchebray-Gaetz	912L (Nevis 766S - Red Deer 63S)	100
					7L205 (Drury 2007S – Vermilion 710S)	7L749 (Edgerton 899S - Bricker 880S tap)	99
5	260	90	940	1290	1035L (Bowmanton 244S – Newell 2075S)	1087L (Cassils 324S - Newell 2075S)	100
					935L (Cassils 324S –Milo 356S)	912L (Nevis 766S s-Red Deer 63S)	98
6	410	510	985	1905	EATL	900L (Red Deer 63S – Benalto 17S)	100
						924L (Langdon 102S – Milo 356S)	100
						912L (Nevis 766S - Red Deer 63S)	100
					WATL	7L701 (Strome 223S – Heisler 764S tap)	98
					9L966/966L (Hansman Lake 650S – Pemukan 932S)	7L127 (Monitor 774S – Pemukan 932S)	99
					7L205 (Drury 2007S – Vermilion 710S)	7L749 (Edgerton 899S – Bricker 880S tap)	99

Technical sensitivity assessment was performed on Options 1, 3, 4, and 6 to further evaluate their technical merits.

6.1.2 Termination Substation Assessment

The generation integration capability assessment described above indicated that incremental generation integration capabilities enabled by Option 1 and Option 6 are equivalent. Both provided the greatest amount of generation integration capability. Further analysis was undertaken to investigate the technical differences between Option 1, which has two 240 kV circuits that terminate at the Tinchebray 972S substation and Option 6, which has one 240 kV circuit terminate at Cordel 755S substation and one 240 kV circuit that terminates at the Tinchebray 972S substation. Both substations are located in west part of Hanna (Area 42).

This section presents the technical sensitivity assessment undertaken for Options 1 and 6. In consideration that there is significant renewable generation potential and market interest in the west Hanna area (i.e., at Tinchebray 972S substation and along the 240 kV transmission line 9L59 between the Tinchebray 972S and Anderson 801S substations). This is demonstrated by the fact that there are currently three proposed generation connection projects with a total of 430 MW[24] in the vicinity of the Tinchebray 972S substation. Generation integration capability studies were carried out focusing on the west Hanna area to further evaluate the flexibility of integrating higher amount of generation in this area.

Category B generation integration capability studies were carried out for Options 1 and 6 using 2023 Scenario 2 study cases described in Section 3.1.3. In this assessment, the generation integration capability assessment methodology as described in Section 3.2 was applied, with the exception of assuming that the future generation in CE sub-region was connected at Tinchebray 972S substation only.

Results indicated that generation integration capability in the west Hanna area is approximately 780 MW for Option 1. For Option 6, the Category B capability in the west Hanna area was limited to approximately 360 MW by 240 kV transmission line 9L16 (Cordel 755S – Tinchebray 972S) under a contingency of the proposed new 240 kV circuit between Gaetz 87S and Tinchebray 972S. Terminating both circuits at the Tinchebray 972S substation (Option 1) will allow more generation to be developed in the west Hanna area reliably compared to Option 6. Table 6-2 provides a summary of the Category B capability in west Hanna area for Option 1 and Option 6. Power flow SLDs are provided in Attachment B.

Table 6-2: 2023 Category B Capability in West Hanna Area

Option	Study Area (MW)		SW (MW)	Total (MW)	Limiting Contingency	Limiting Elements	Loading (%)
	SE	CE (West Hanna Area only)					
1	115	780	915	1800	EATL	912L (Red Deer 63S –Nevis 766S)	99
					Nevis 766S Transformer 901T	914L (Gaetz 87S – Red Deer 63S)	100
					912L (Red Deer 63S –Nevis 766S)	914L (Gaetz 87S – Red Deer 63S)	99
6	115	360	915	1380	New 240 kV circuit 962L/9L962 (Tinchebray 972S – Gaetz 87S)	9L16 (Tinchebray 972S – Cordel 755S)	100

[24] Three generation connection projects include: P1710 Halkirk 2 Wind Power Project Connection (Requested Rate STS 150 MW); P1909 Garden Plain Wind Power Project Connection (Requested Rate STS 130 MW); and P1704 Paintearth Wind Project Connection (Requested Rate STS 150 MW).

6.1.3 Category C3 Capability Assessment

Options 3 and 4 include the addition of one new circuit in comparison to the addition of two new circuits included in Option 1. This section presents a technical sensitivity assessment to compare Options 3 and 4 to Option 1. This comparison indicates the operational flexibility in consideration of planned or forced outages on the key transfer-out path in the CE sub-region for Options 1, 3, and 4.

In order to compare the operational flexibility of each option, the generation integration capability assessment of each option under Category C3 conditions were compared using 2023 Scenario 2 study cases described in section 3.1.3. The Category C3 results are then compared against the Category B capability. The difference between the Category B and C3 capabilities are the amount of generation that needs to be curtailed should the outage occur. Table 6-3 summarizes the comparison of the Category B and C3 capability results. Limiting contingencies and limiting elements are listed in Table 6-4. Power flow SLDs for Category C3 results are provided in Attachment B.

Study results are summarized as follows:

- For Option 1, the Category C3 capability in the Study Area is 610 MW which is 330 MW lower than Category B capability.
- For Option 3, the Category C3 capability in the Study Area is approximately 310 MW which is approximately 500 MW lower than Category B capability.
- For Option 4, the Category C3 capability in the Study Area is approximately 80 MW which is approximately 720 MW lower than Category B capability.

The above results indicate that under outage condition, the amount of generation in the Study Area that can still be connected for Option 1 is significantly higher than Option 3 and 4. Therefore, Option 1 provides more operational flexibility than the other two options.

Table 6-3: 2023 Generation Integration Capability Comparison for Options 1, 3, and 4

Option	Category	Outage	Study Area (MW)		SW (MW)	Total (MW)
			SE	CE		
1	B	None	505	435	985	1925
	C3	New 240 kV circuit 962L/9L962 (Tinchebray 972S - Gaetz 87S)	495	115	940	1550
3	B	None	385	430	980	1795
	C3	912L (Red Deer 63S – Nevis 766S)	190	120	980	1290
		New 240 kV circuit 962L/9L962 (Tinchebray 972S - Gaetz 87S)	245	85	980	1310
4	B	None	550	255	995	1800
	C3	New 500 kV circuit (Tinchebray 972S – Gaetz 87S)	80	0	910	990

Table 6-4: 2023 Category C3 Capabilities for Options 1, 3, 4 - Limiting Contingencies and Limiting Elements

Option	Outage	Limiting Contingency	Limiting Elements	Loading (%)
1	962L/9L962 (Tinchebray 972S - Gaetz 87S)	EATL	7L701 (Strome 223S –Heisler 764S Tap)	99
		966L/9L966 (Hansman 650S – 932S)	7L127 (Monitor 774S – Pemukan 932S)	100
3	912L (Red Deer 63S - Nevis 766S)	EATL	924L (Langdon 102S – Milo 356S)	100
			962L/9L962 (Tinchebray 972S – Gaetz 87S)	100
		7L233 (Nilrem 574S -Drury 2007S)	7L50 (Buffalo Creek 526S – Jarrow 252S)	98
	962L/9L962 (Tinchebray 972S - Gaetz 87S)	EATL	924L (Langdon 102S – Milo 356S)	100
			912L (Red Deer 63S - Nevis 766S)	100
4	New 500 kV line Tinchebray 972S - Gaetz 87S	EATL	912L (Red Deer 63S - Nevis 766S)	100

6.1.4 Technical Assessment Summary

This section describes the technical assessment carried out for the Transmission Development Options outlined in Section 5, considering that the need for transmission development is to alleviate thermal constraints on the CE west transfer-out path and enable additional generation to be connected in the Study Area without Reliability Criteria violations. Generation integration capability studies were performed to assess the incremental capability enabled by each option. The results indicated:

- Options 1 and 6 enable the greatest amount of incremental generation integration capability in the Study Area. Compared to Option 6, Option 1 provides flexibility to connect higher amount generation in west Hanna area, an area where there is significant market interest to develop renewable generation.
- The generation integration capability enabled by Options 2, 3, and 4 is approximately 130 MW – 170 MW lower than Option 1. In addition, under outage conditions, the amount of generation in the Study Area that can still be connected by Options 3 and 4 is significantly lower than Option 1. Therefore, Options 3 and 4 were not recommended for further consideration.
- Option 5 was not recommended for further consideration as it provides lowest amount of generation integration capability in the Study Area.

Based on the technical analysis described above, Options 3, 4, and 5 were not recommended for further consideration as they provides lower generation integration capability and operation flexibility than other options. Option 2 was further considered, as similar to Option 1 and 6, Option 2 offers operational flexibilities during outage conditions. The economic and environmental and land use effects of Options 1, 2, and 6 were assessed further. This assessment is presented in the following subsections.

6.2 Cost Estimate

The AESO prepared AACEi class 4 cost estimates (+30/-30%) for Options 1, 2, and 6. Detailed estimated cost for each option is provided in the AESO Cost Estimates Appendix[25]. Cost estimate results indicate that the total estimated cost of Option 1 is approximately $471 million, and the total estimated cost of Options 2 and 6 are higher than Option 1 by approximately $26 million and $9 million, respectively.

6.3 Environmental and Land Use Effects

The AESO directed the TFOs to prepare a report comparing Transmission Development Options 1, 2, and 6[26], according to the environmental and land use effects information contemplated in AUC Rule 007, Section 6.1, NID7(9).

As indicated in the Environmental and Land Use Effects Appendix[27], all three options are feasible and compared to Options 2 and 6, Option 1 has lower potential environmental and land use effects due to the presence of existing transmission lines to parallel.

6.4 Selection of the Preferred Transmission Development Option

Table 6-5 provides a summary of the performance comparison for the six considered Transmission Development Options.

In summary, Option 1 is the Preferred Transmission Development Option for the following reasons:

- it is technically superior to other options in terms of generation integration capability and operational flexibility;
- it is the most economic option when compared to Options 2 and 6; and
- it has a lower potential environmental and land use effects when compared to Options 2 and 6.

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[25] Filed under separate cover as Appendix E.

[26] The environmental and land use effects information was prepared by the TFOs for their respective service territories. AltaLink compared Transmission Development Options 1 and 2 and ATCO compared Transmission Development Options 1, 2, and 6.

[27] Filed under separate cover as Appendix G.

Table 6-5: Summary of Performance Comparison for the CETO Transmission Development Options

Option	Description	Technical Assessment		Cost Estimates	Environmental and Land Use Effects
		Generation Integration Capability in Study Area	Operational Limitations		
1	Add Two 240 kV Circuits Between the Tinchebray 972S and Gaetz 87S Substations	Provides approximately 820 MW incremental capability.	N/A	The estimated cost is lower than Options 2 and 6.	Lower potential land impact than Options 2 and 6.
2	Add Two 240 kV Circuits Between the Tinchebray 972S and Wolf Creek 288S Substations	Incremental capability is lower (~160 MW) than Option 1.	N/A	The estimated cost (+30/-30%) is higher (~$26M) than Option 1.	Higher potential land impact than Option 1.
3	Add One 240 kV Circuit Between the Tinchebray 972S and Gaetz 87S Substations and Upgrade 240 kV transmission lines 912L/9L20	Incremental capability is lower (~130 MW) than Option 1.	Line rebuilds generally would require lengthy outages. Therefore, this option is expected to require a lengthy outage on 912L and 9L20 resulting in operational complexity. Under outage of the new 240kV circuit, 912L, or 9L20, renewable generation can be dispatched for this option would be lower (~300 MW) than Option 1.	N/A	N/A
4	Add one 500 kV Circuit Between the Tinchebray 972S and Gaetz 87S Substations	Incremental capability is lower (~130 MW) than Option 1.	Under outage of the new 500 kV circuit, renewable generation dispatched for this option would be significantly (~500 MW) lower than Option 1.	N/A	N/A
5	Convert EATL to bi-pole	Incremental capability is significantly lower (~600 MW) than Option 1.	N/A	N/A	N/A
6	Add one 240 kV Circuits Between the Gaetz 87S and Cordel 755S Substations and	Provides similar level of integration capability as Option 1, however,	N/A	The estimated cost (+30/-30%) is higher (~$9M) than Option 1.	Higher potential land impact than Option 1.

Option	Description	Technical Assessment		Cost Estimates	Environmental and Land Use Effects
		Generation Integration Capability in Study Area	Operational Limitations		
	Add one 240 kV circuit Between the Gaetz 87S and Tinchebray 972S Substations	provides less flexibility to integrate generation in the west Hanna area where there is strong market interest for renewable development			

6.5 Preferred Transmission Development Capability

The Preferred Transmission Development includes the addition of two 240 kV circuits between Tinchebray 972S and Gaetz 87S, to be designated 962L/9L62 and 986L/9L86. The energization of the two circuits of the Preferred Transmission Development can be done in two stages (one circuit in each stage) to defer the capital expenditure of the second 240 kV circuit. Hence the following sections assess the generation integration capability enabled by the first and second circuit.

Category B and Category A enabled by generation RAS capabilities (as described in Section 3.2) were assessed for the first and second circuit of the Preferred Transmission Development. Generation integration capability studies were performed using the 2023 study cases listed in Table 3-2 for the two thermal dispatch scenarios described in Section 3.1. In consideration of the SW sub-region generation impacts on the overall performance of the CE sub-region transmission system, sensitivity studies were carried out for both with CRPC and without CRPC in the SW sub-region. Power flow SLDs are provided in Attachment C.

6.5.1 Category B Capability Assessment

Results for the Category B capability enabled by each circuit are summarized in Table 6-6. The limiting contingencies and limiting elements are listed in Table 6-7. To summarize the results:

- For Scenario 1, the incremental generation integration capability in the Study Area enabled by first circuit of the Preferred Transmission Development is in the range of 385 MW to 435 MW depending on the level of new renewable generation in the SW sub-region. The second circuit of the Preferred Transmission Development would enable approximately 300 MW of additional generation integration capability in the Study Area.
- For Scenario 2, the incremental generation integration capability in the Study Area enabled by first circuit of the Preferred Transmission Development is in the range of 495 MW to 650 MW depending on the level of new renewable generation in the SW sub-region. The second circuit of the Preferred Transmission Development would enable approximately 300 MW of additional generation integration capability in the Study Area.

The generation integration capabilities reported in this section are the maximum assuming optimal injection of incremental generation at optimal locations. If a generation project is connected at a non-optimal location, it may reduce the overall transmission system generation integration capability.

Table 6-6: 2023 Category B Capability of the Preferred Transmission Development

Thermal Dispatch Scenario	CRPC	CETO		Study Area (MW)		SW (MW)	Total (MW)
		First Circuit	Second Circuit	SE	CE		
1	No	No	No	535	30	335	900
	No	Yes	No	530	480	350	1360
	No	Yes	Yes	505	790	355	1650
	Yes	Yes	No	675	275	935	1885
	Yes	Yes	Yes	715	540	935	2190
2	No	No	No	120	0	330	450
	No	Yes	No	455	305	320	1090
	No	Yes	Yes	455	585	365	1405
	Yes	Yes	No	495	115	940	1550
	Yes	Yes	Yes	505	435	985	1925

Table 6-7: 2023 Preferred Transmission Development Category B Capability - Limiting Contingencies and Limiting Elements

Thermal Dispatch Scenario	CRPC	CETO		Limiting Contingency	Limiting Elements	Loading (%)
		First Circuit	Second Circuit			
1	No	Yes	No	EATL	174L (Bardo 197S - North Holden 395S)	100
					701L (North Holden 395S – Strome 223S)	97
				Proposed New 240 kV circuit 962L/9L962 (Tinchebray 972S - Gaetz 87S)	912L (Nevis 766S – Red Deer 63S)	100
				923L (Milo 356S – Cassils 324S) with EATL RAS	935L (Milo 356S – Newell 2075S)	98
				935L (Milo 356S – Newell 2075S) with EATL RAS	923L (Milo 356S – Cassils 324S)	98
				1035L (Bowmanton 244S – Newell 2075S)	1087L (Cassils 324S – Newell 2075S)	99
	No	Yes	Yes	912L (Nevis 766S – Red Deer 63S) or Nevis 766S901T	914L (Gaetz 87S – Red Deer 63S)	100
				923L (Milo 356S – Cassils 324S) with EATL RAS	935L (Milo 356S – Newell 2075S)	98

Thermal Dispatch Scenario	CRPC	CETO First Circuit	CETO Second Circuit	Limiting Contingency	Limiting Elements	Loading (%)
				1035L (Bowmanton 244S – Newell 2075S)	1087L (Cassils 324S – Newell 2075S)	98
				EATL	7L749 (Edgerton 899S – Briker 880S tap)	100
					174L (Bardo 197S - North Holden 395S)	100
					701L (North Holden 395S – Strome 223S)	97
				935L (Milo 356S – Newell 2075S) with EATL RAS	923L (Milo 356S – Cassils 324S)	98
				7L233 (Drury 2007S –Nilrem 574S)	7L749 (Edgerton 899S – Briker 880S tap)	98
	Yes	Yes	No	EATL	174L (Bardo 197S - North Holden 395S)	100
					701L (North Holden 395S – Strome 223S)	100
					7L701 (Strome 223S –Heisler 764S Tap)	98
					7L749 (Edgerton 899S – Briker 880S tap)	98
				Proposed New 240kV circuit 962L/9L962 (Tinchebray 972S - Gaetz 87S)	912L (Nevis 766S – Red Deer 63S)	100
				7L205 (Drury 2007S –Vermilion 710S)	7L749 (Edgerton 899S – Briker 880S tap)	100
				WATL	174L (Bardo 197S - North Holden 395S)	100
	Yes	Yes	Yes	1035L (Bowmanton 244S – Newell 2075S)	1087L (Cassils 324S – Newell 2075S)	98
				EATL	174L (Bardo 197S - North Holden 395S)	100
					701L (North Holden 395S – Strome 223S)	98
					914L (Gaetz 87S – Bigstone 86S)	97
					912L (Nevis 766S – Red Deer 63S)	98
				7L205 (Drury 2007S –Vermilion 710S)	7L749 (Edgerton 899S – Briker 880S tap)	97

Thermal Dispatch Scenario	CRPC	CETO		Limiting Contingency	Limiting Elements	Loading (%)
		First Circuit	Second Circuit			
2	No	Yes	No	Proposed New 240kV circuit 962L/9L962 (Tinchebray 972S - Gaetz 87S)	912L (Nevis 766S – Red Deer 63S)	100
				EATL	924L (Langdon 102S –Milo 356S)	100
					7L92 (Vegreville 709S – Vilna 777S)	100
				1035L (Bowmanton 244S – Newell 2075S)	1087L (Cassils 324S – Newell 2075S)	100
	No	Yes	Yes	EATL	900L (Red Deer 63S –Benalto 17S)	100
					924L (Langdon 102S –Milo 356S)	100
					912L (Nevis 766S – Red Deer 63S)	99
				1035L (Bowmanton 244S – Newell 2075S)	1087L (Cassils 324S – Newell 2075S)	100
				912L (Nevis 766S – Red Deer 63S) or Nevis 766S901T	914L (Gaetz 87S – Red Deer 63S)	100
	Yes	Yes	No	EATL	7L701 (Strome 223S –Heisler 764S Tap)*	99
				966L/9L966 (Hansman 650S – Pemukan 932S)	7L127 (Monitor 774S – Pemukan 932S)	100
	Yes	Yes	Yes	EATL	900L (Red Deer 63S –Benalto 17S)	100
					924L (Langdon 102S –Milo 356S)	100
				966L/9L966 (Hansman 650S – Pemukan 932S)	7L127 (Monitor 774S – Pemukan 932S)	100
Note: * Opening transmission line 174L to mitigate constraint on transmission line 701L will cascade overload to transmission lines 7L92 and 7L53 and opening these two lines leads to overloads on transmission lines 924L and 912L.						

6.5.2 Category A Enabled by Generation RAS Capability Assessment

Results for the Category A capability enabled by each circuit are summarized in Table 6-8. Power flow SLDs for the most limiting contingencies and generation curtailment required to alleviate thermal criteria violations are presented in Attachment C.

To summarize the results:

- For Scenario 1, the incremental generation integration capability in the Study Area enabled by first circuit of the Preferred Transmission Development is in the range of 265 MW to 505 MW depending on the level of new renewable generation in the SW sub-region. The second circuit of the Preferred Transmission Development would enable approximately 300 MW of additional generation integration capability in the Study Area.

- For Scenario 2, the incremental generation integration capability in the Study Area enabled by first circuit of the Preferred Transmission Development is in the range of 530 MW to 590 MW depending on the level of new renewable generation in the SW sub-region. The second circuit of the Preferred Transmission Development would enable an additional 155 MW to 265 MW of generation integration capability in the Study Area depending on the new renewable generation in SW sub-region. When CRPC is in place and new renewable generation in SW sub-region is high, the incremental generation integration capability enabled by the second circuit is limited to 155 MW. This is due to the limits outside of the Study Area (i.e., thermal criteria violations on the 240 kV transmission line 914L (Gaetz 87S - Bigstone 86S) and the 240 kV transmission line 900L (Red Deer 63S - Benalto 17S) for EATL contingency). In this assessment, it was assumed that future generation in the Study Area was curtailed to alleviate thermal violations on these two 240 kV lines. The generation RAS may not be the most effective way to mitigate this potential thermal violation. The AESO will continue to monitor the transmission system and, if necessary, propose other mitigation measures or system upgrades as appropriate to fully utilize the Preferred Transmission Development Second circuit.

Table 6-8: 2023 CETO Category A Enabled by Generation RAS Capability

CRPC	CETO		Scenario 1 (MW)				Scenario 2 (MW)			
	First Circuit	Second Circuit	Study Area		SW	Total	Study Area		SW	Total
			SE	CE			SE	CE		
No	No	No	700	55	685	1440	250	0	580	830
No	Yes	No	715	550	625	1890	550	340	715	1605
No	Yes	Yes	850	715	665	2230	575	580	700	1855
Yes	Yes	No	750	275	1140	2165	485	345	1145	1980
Yes	Yes	Yes	760	560	1025	2345	530	455	1110	2085*

* Integration capability is limited by other regions outside of the Study Area (thermal criteria violations on 914L (Gaetz 87S – Bigstone 86S) and 900L (Red Deer 63S – Benalto 17S)) for EATL contingency, which requires approximately 465 MW generation curtailment in the Study Area.

As was noted in the Category A capability assessment, it was assumed that only the future generation in the Study Area that are most effective to alleviate thermal criteria violations was curtailed first. As future generation is developed in the areas of high resource potential, the location and size of future generation developments within the Study Area are market driven. It is expected that the transmission capability may not be filled in the most optimized manner. As a result, the actual utilized generation integration capability may deviate from the optimized capability identified in this Planning Report.

For the reasons described above, the generation RAS enabled Category A capability identified throughout this section is subject to change. As future generation projects develop and connect to the transmission system, additional studies will be performed to refine the required mitigation measures, RAS, or procedures.

6.6 Summary

To accommodate future generation in the Study Area, transmission development is required to alleviate the thermal constraint on the CE sub-region west transfer-out path. Six Transmission Development Options to enhance the CE sub-region west transfer-out path were considered. Option 1 is recommended as the Preferred Transmission Development Option because it provides better system performance and has a lower estimated cost and environmental and land use effects than the other Options evaluated.

The Preferred Transmission Development includes two 240 kV circuits. The energization of the two circuits of the Preferred Transmission Development can be done in two stages (one circuit in each stage) to defer the capital expenditure. Generation integration capability studies were carried out to identify the capability enabled by each circuit of the Preferred Transmission Development. The Category B capability enabled by each circuit is summarized in Table 6-9. The first row of Table 6-9 shows the Category B capability for the Pre-Development transmission system (see Section 4.3.1 for further details). The incremental generation integration capability (compared to the Pre-Development transmission system) enabled by each circuit of the Preferred Transmission Development is presented in the subsequent rows.

Table 6-9: Summary of Category B Capability for the Preferred Transmission Development

CRPC	CETO		Scenario 1 (MW)		Scenario 2 (MW)	
	First Circuit	Second Circuit	Study Area	SW	Study Area	SW
No	No	No	565	335	120	330
No	Yes	No	+445	+0	+650	+0
No	Yes	Yes	+730	+0	+920	+0
Yes	Yes	No	+385	+600	+495	+610
Yes	Yes	Yes	+700	+600	+835	+640

To summarize, the first circuit of the Preferred Transmission Development would enable approximately 400 MW to 600 MW incremental generation integration capability in the Study Area. The second circuit of the Preferred Transmission Development would enable an additional approximately 300 MW incremental generation integration capability in the Study Area.

It is noted that the generation integration capability enabled by each circuit of the Preferred Transmission Development is dependent upon several factors including the CE sub-region thermal generation, new renewable generation in the SW sub-region, and location and size of new renewable generation in the Study Area. Depending on how renewable generation develops in the transmission system, the actual transmission system generation integration capability may deviate from the identified capability.

7 2031 Generation Integration Capability

Generation integration capability studies as described in Section 3.2 were carried out for the 2031 pre-Development and post-Development transmission system. The Category B and Category A enabled by generation RAS capability studies were performed for two thermal dispatch scenarios described in Section 3.1 using the 2031 study cases listed in Table 3-3. In consideration of the SW sub-region generation impacts on the overall performance of the CE sub-region transmission system, sensitivity studies were carried out for both with CRPC and without CRPC in the SW sub-region. Power flow SLDs are provided in Attachment C.

7.1 Category B Capability Assessment

The Category B capability results for Scenarios 1 and 2 are presented in Table 7-1 and Table 7-2. The limiting contingencies and limiting elements are also presented in the tables. The results are summarized as follows:

- Scenario 1
  - The optimal total generation integration capability of Pre-Development transmission system is approximately 960 MW in which 520 MW is in the SE sub-region, 35 MW in the CE sub-region, and 405 MW in the SW sub-region.
    - The 138 kV transmission line 174L (Bardo 197S – North Holden 395S) reaches its thermal limit for EATL contingency. If the 138 kV transmission line 174L can be restored to its conductor rating (120/145 MVA in summer/winter, as described in Section 2.9), the generation integration capability in the Study Area can be increased by approximately 100 MW, i.e., the SE sub-region generation integration capability would be increased to 575 MW and the CE sub-region capability would be increased to 100 MW. The 240 kV transmission line 912L, which is a component of CE sub-region west transfer-out path, reaches its thermal limit under a EATL contingency.
  - The Preferred Transmission Development first circuit could enable approximately 345 MW - 585 MW of additional capability in the Study Area depending on the future generation in the SW sub-region. The 240 kV transmission line 912L reaches its thermal limit under a EATL contingency.
  - The Preferred Transmission Development second circuit could add approximately 210 MW of generation integration capability (above the Preferred Transmission Development first circuit capability) in the Study Area.

- Scenario 2
  - The optimal total generation integration capability of Pre-Development transmission system is approximately 530 MW of which 50 MW is in the SE sub-region, 0 MW in the CE sub-region, and 480 MW in the SW sub-region.
    - The generation integration capability in the Study Area is extremely low. This is due to the assumption of combined cycle generation at Battle River and

Sheerness facilities which have higher energy output. The 240 kV transmission line 912L, which is a component of CE sub-region west transfer-out path reaches its thermal limit under a EATL contingency.

- The Preferred Transmission Development first circuit could enable approximately 605 MW - 695 MW of additional generation integration capability in the Study Area depending on the future generation in the SW sub-region. The 240 kV transmission line 912L reaches its thermal limit under the EATL contingency.
- The Preferred Transmission Development second circuit could enable an additional 365 MW above the Preferred Transmission Development first circuit capability in the Study Area.

Table 7-1: 2031 Category B Capability –Scenario 1

CRPC	CETO		Study Area (MW)		SW (MW)	Total (MW)	Limiting Contingency	Limiting Elements	Loading (%)
	First Circuit	Second Circuit	SE	CE					
No	No	No	520	35	405	960	EATL	174L (Bardo 197S - North Holden 395S)	100*
No	Yes	No	745	395	420	1560	EATL	912L (Red Deer 63S – Nevis 766S)	99
No	Yes	Yes	990	505	400	1895	EATL	912L (Red Deer 63S – Nevis 766S)	99
Yes	Yes	No	700	200	1000	1900	EATL	912L (Red Deer 63S – Nevis 76S)	100
Yes	Yes	Yes	820	290	1065	2175	EATL	174L (Bardo 197S –North Holden 395S)	100**
								701L (North Holden 395S – Strome 223S)	100**

*: 174L reaches its thermal limit in the Study Area. If the 174L can be restored to its conductor rating (120/145MVA summer/winter), the generation integration capability would be increased by approximately 100 MW, i.e. SE sub-region capability increased to 575 MW and CE sub-region capability increased to 100 MW. The 240 kV transmission line 912L (Red Deer 63S – Nevis 76S) reaches its thermal limit for EATL contingency.

**: If transmission line 174L (North Holden 395S – Bardo 197S) is opened then transmission line 7L92 (Vegreville 709S – Vilna 777S) will experience thermal criteria violations, opening transmission line 7L92 will result in thermal criteria violations on 7L117 (Vermilion 710S – Irish Creek 706S). Opening all three will result in thermal criteria violations on 914L (Gaetz 87S – Bigstone 86S).

Table 7-2: 2031 Category B Capability –Scenario 2

CRPC	CETO		Study Area (MW)		SW (MW)	Total (MW)	Limiting Contingency	Limiting Elements	Loading (%)
	First Circuit	Second Circuit	SE	CE					
No	No	No	50	0	480	530	EATL	912L (Red Deer 63S – Nevis 766S)	99
No	Yes	No	560	185	520	1265	New 240kV circuit 962L/9L962 (Tinchebray 972S –Gaetz 87S)	912L (Red Deer 63S – Nevis 766S)	99
							1035L (Bowmanton 244S – Newell 2075S)	1087L Cassils – Newell	100
No	Yes	Yes	865	330	500	1695	912L	174L Bardo-North Holden	97
Yes	Yes	No	400	255	1000	1655	912L (Red Deer 63S – Nevis 766S)	174L Bardo-North Holden	99
							New 240kV circuit 962L/9L962 (Tinchebray 972S -Gaetz 87S)	912L (Red Deer 63S – Nevis 766S)	100
							EATL	912L (Red Deer 63S – Nevis 766S)	99
Yes	Yes	Yes	760	260	1010	2040	EATL	912L (Red Deer 63S – Nevis 766S)	100

7.2 Category A Capability Enabled by Generation RAS

Results for the Category A enabled by generation RAS capability are summarized in Table 7-3. Power flow SLDs for the most limiting contingencies and generation curtailment required to alleviate thermal criteria violations are presented in Attachment D.

The results are summarized as follows:

- Scenario 1

- The optimal total generation integration capability of the 2031 Pre-Development transmission system is approximately 1,595 MW in which 775 MW is in the SE sub-region, 105 MW in the CE sub-region, and 720 MW in the SW sub-region.
- The Preferred Transmission Development first circuit could enable approximately 150 MW - 495 MW of additional capability in the Study Area depending on the future generation in the SW sub-region.
- The Preferred Transmission Development second circuit could enable an additional 250 MW (above the Preferred Transmission Development first circuit capability) in the Study Area.

- Scenario 2
  - The optimal total generation integration capability of the 2031 Pre-Development transmission system is approximately 725 MW in which 105 MW is in the SE sub-region, 30 MW in the CE sub-region, and 590 MW in the SW sub-region. The generation integration capability in the Study Area is extremely low. EATL contingency leads to thermal criteria violations on 912L which required all future generation in the Study Area to be curtailed to alleviate the thermal violation. Integrating more generation than the capability identified will result in thermal constraints that cannot be mitigated.
  - The Preferred Transmission Development first circuit could enable approximately 650 MW - 875 MW of additional generation integration capability in the Study Area depending on the future generation in the SW sub-region.
  - The Preferred Transmission Development second circuit could enable an additional 330 MW (above the Preferred Transmission Development first circuit capability) in the Study Area.

Table 7-3: 2031 Category A Enabled by Generation RAS Capability

CRPC	CETO		Scenario 1				Scenario 2			
	First Circuit	Second Circuit	Study Area		SW	Total	Study Area		SW	Total
			SE	CE			SE	CE		
No	No	No	770	105	720	1595	105	30	590	725
No	Yes	No	815	555	645	2015	745	265	670	1680
No	Yes	Yes	985	530	715	2230*	925	475	605	2005
Yes	Yes	No	785	230	1225	2240	465	320	1205	1990
Yes	Yes	Yes	815	450	1055	2315*	780	335	1045	2160

*: Cat A capability is limited by 914L (Gaetz 87S – Bigstone 86S). The AESO will continue to monitor the system and propose other mitigation measures or system upgrade as appropriate to fully utilize the Preferred Transmission Development second circuit.

7.3 Summary

Generation integration capability in the Study Area and SW sub-region was assessed for the 2031 pre-Development and post-Development transmission system. Generally, the capability identified for different transmission system configurations was consistent with the trend observed in 2023 (see Section 6.4).

The generation integration capability enabled by the Preferred Transmission Development is dependent upon the following factors: thermal generation in the Study Area, the level of new generation in the SW sub-region, and the location and size of new generation in the Study Area. Depending on where and how future generation develops in the Study Area and the SW sub-region, the actual transmission system capability may deviate from what was outlined above.

8 Additional Assessments for the Preferred Transmission Development

8.1 Generation Integration Capability under C5 System Conditions

Assuming the amount of new generation connected to the transmission system is as outlined in Table 6-6, there will be no Reliability Criteria violations in the Study Area following a Category B event. However, for Category C5 contingencies, the transmission system could experience Reliability Criteria violations. To ensure that the transmission system will operate reliably under C5 conditions, generation RAS needs to be in place to mitigate Reliability Criteria violations in the event of C5 contingencies.

In this section, generation integration capabilities for C5 contingencies were evaluated for the Preferred Transmission Development using power flow cases from the Category B capability assessment (see Section 6.1.1). Table 8-1 presents the maximum amount of future generation that needs to be curtailed in order to alleviate thermal criteria violations in the transmission system following a C5 contingency. Generation curtailments exceeding the current MSSC limit (466 MW) are highlighted.

Results indicated that the following Category C5 contingency events cause the most significant amount of generation to be curtailed: 1035L (Bowmanton 244S – Newell 2075S) and 1088L (Newell 2075S – Cassils 324S), 1034L (Bowmanton 244S – Cassils 324S) and 1035L (Bowmanton 244S – Newell 2075S), and the proposed new 240kV transmission lines 962L/9L62 and 986L/9L86 (Tinchebray 972S – Gaetz 87S).

Table 8-1: Maximum Future Generation Curtailment Under Category C5 Contingencies

Year	2023				2031			
CETO	One Circuit		Two Circuits		One Circuit		Two Circuits	
Contingency	Scenario 1 (MW)	Scenario 2 (MW)	Scenario 1 (MW)	Scenario 2 (MW)	Scenario 1 (MW)	Scenario 2 (MW)	Scenario 1 (MW)	Scenario 2 (MW)
1035L_1088L	-323	-453	-333	-451	-349	-408	-453	-535
951L_944L	-236	-175	-258	-214	-63	-160	0	-30
1034L_1035L*	-179	-72	-131	0	-74	0	0	0
953L_1047L	-152	0	-171	0	-15	0	-65	-15
1034L_1088L	-124	0	-118	0	0	0	0	0
923L_1087L	-70	0	-71	0	0	0	0	0
923L_935L	-101	0	-102	0	0	0	0	0
924L_927L	-312	0	-150	0	0	0	0	0
962L_986L	0	0	-498	-446	0	0	0	-431

*Additionally, all of the generation connected on the 240 kV path including 1034L, 1035L, 964L, and 983L were tripped by the existing RAS. The generation connected on these transmission lines were dispatched in the range 370 MW to 403 MW depending on the study cases.

8.2 Voltage Stability Analysis

The voltage stability analysis were carried out both before and after the Preferred Transmission Development is in service using the 2023 and 2031 power flow cases from the Category B capability assessment (see Section 6.1.1 and Section 7.1).

Detailed results of the PV analysis are presented in Attachment E. Results indicate that the voltage stability criteria of 5% margin for Category B contingencies and 2.5% margin for Category C5 contingencies can be met.

8.3 Transient Stability Analysis

Comprehensive transient stability studies were performed both before and after the Preferred Transmission Development is in service using the 2023 and 2031 power flow cases from the Category B capability assessment (see Section 6.1.1 and Section 7.1).

The results confirm that the transmission system remains stable under select Category B and Category C5 contingencies in the Study Area under normal clearing conditions. Detailed transient stability study results are provided in Attachment F.

8.4 Short-Circuit Analysis

Short-circuit analysis was performed using the 2023 and 2031 study cases to determine the maximum short-circuit current levels in the Study Area. Detailed short-circuit study results are presented in Attachment G.

The short-circuit fault levels for post Preferred Transmission Development were not significantly higher than the levels of pre Preferred Transmission Development and short-circuit levels were found to be within the designed capabilities of the nearby facilities.

8.5 Transmission System Losses Analysis

Transmission system loss analysis was conducted to assess the impact of the Preferred Transmission Development. The transmission system losses were evaluated using all Category B post-development capability power flow cases for the 2023 and 2031 study cases with the assumption that CRPC is in service (see Table 6-6 for 2023 and Table 7-1 and Table 7-2 for 2031). Transmission system losses were calculated for all the study cases with and without the Preferred Transmission Development. Average transmission system losses were estimated by taking the numerical average of transmission system losses for all the studied cases for a given CE sub-region generation scenario for each year. The average transmission system losses are summarized in Table 8-2. Results indicate that transmission system losses with the Preferred Transmission Development would be lower than without the Preferred Transmission Development.

Table 8-2: Transmission System Losses

Year	Preferred Transmission Development	Thermal Dispatch Scenario	Without Development (MW)	With Development (MW)
2023	First Circuit	Scenario 1	558.9	537.9
		Scenario 2	567.1	545.5
	Second Circuit	Scenario 1	596.9	583.4
		Scenario 2	619.4	603.9
2031	First Circuits	Scenario 1	516.2	497.6
		Scenario 2	549.8	524.5
	Second Circuit	Scenario 1	540.8	529.4
		Scenario 2	612.9	595.2

9 Congestion Assessment

In addition to the deterministic studies described in this Planning Report, the AESO also conducted hourly probabilistic analysis (referred to herein as "congestion assessment") utilizing a market simulation tool to further assess transmission system performance. The AESO conducted a congestion assessment to estimate potential congestion in the Study Area both before and after the Preferred Transmission Development is in service. The Congestion Assessment Appendix[28] provides further details including the methods of analysis, modeling assumptions, and results of the congestion assessment.

For the purpose of this Planning Report, the congestion assessment was used to:

- Provide an indication of the overall congestion trend as future generation continues to develop in the Study Area by correlating congestion to incremental levels of future generation development; and
- Inform the establishment and monitoring of milestones for commencing the construction of each stage of the Preferred Transmission Development, as described below.

The congestion assessment indicates that:

- The amount of congestion depends on both the thermal generation and renewable generation in the Study Area. If the thermal generation behave like baseload units, then more congestion on the CE sub-region west transfer-out path can be expected compared to peaking behaviour. As incremental generation continue to develop in the Study Area, the congestion on the CE sub-region west transfer-out path will increase.
- Prior to the Preferred Transmission Development being in service, the Category A congestion on the CE west transfer-out path is projected to occur greater than 0.5% of the time annually when there is approximately 1,250 MW to 1,750 MW incremental generation. Incremental generation includes REP projects and is above the existing installed generation as of January 2020 in the Study Area.[29]
- After the Preferred Transmission Development first circuit is in service, the Category A congestion on the CE west transfer-out path is projected to occur greater than 0.5% of the time annually when there is approximately 1,900 MW to 2,350 MW incremental generation. Incremental generation includes REP projects and is above the existing installed generation as of January 2020 in the Study Area.
- The Preferred Transmission Development second circuit further increases (over 300 MW) the amount of incremental generation that can be integrated in the Study Area.

In summary, the congestion assessment provided the correlation of the amount of incremental generation to the potential congestion on the CE west transfer-out path under different thermal generation dispatch scenarios. The congestion assessment results reaffirm the need for transmission development in the CE

[28] Filed under separate cover as Appendix C.

[29] The existing renewable generation assumption is outlined in Section 2.3 in Appendix B.

sub-region. Once the Preferred Transmission Development is in service, the congestion on the CE west transfer-out path will be significantly reduced.

10 Recommended Transmission Development and Construction Milestone

10.1 Recommended Transmission Development

The recommended Preferred Transmission Development comprises two stages:

Stage 1:

- Add one 240 kV transmission circuit, to be designated as 962L/9L62, between the existing Tinchebray 972S and Gaetz 87S substations.
- Modify the Tinchebray 972S substation by adding circuit breakers and associated equipment;
- Modify the Gaetz 87S substation by adding circuit breakers and associated equipment.

Stage 2:

- Add one 240 kV circuit, to be designated as 986L/9L86, between the Tinchebray 972S and Gaetz 87S substations;
- Modify the Tinchebray 972S substation by adding circuit breakers and associated equipment;
- Modify the Gaetz 87S substation by adding circuit breakers and associated equipment.

10.2 Construction Milestone

The AESO is proposing a construction milestone for each stage of the Preferred Transmission Development. The milestone process enables the AESO to manage uncertainty regarding the timing and impacts of thermal and renewable generation development in the Study Area. A milestone approach accepts incremental risk by delaying construction as much as possible while ensuring the Preferred Transmission Development can be constructed and energized prior to congestion occurring on the transmission system, therefore delaying costs for ratepayers. The use of milestones is proposed in accordance with section 11(4) of the *Transmission Regulation*.

The proposed milestones are based on the results of the congestion assessment indicating when the Category A congestion on the CE west transfer-out path is projected to occur greater than 0.5% of the time annually.[30]

It will take approximately 2 to 3 years to construct the Preferred Transmission Development after the Permit & Licence (P&L) has been received and the construction milestone has been met. To avoid congestion on the transmission system, the milestone incorporates a 200 MW (i.e., an average sized

[30] The AESO does not plan to have Category A congestion on the transmission system, it is rather an indication of when the Category A congestion would occur.

wind farm) reduction of incremental generation. This would allow one typical wind farm to be constructed concurrently [31] with the Preferred Transmission Development.

The following construction milestone for the Preferred Transmission Development Stage 1 is proposed:

- The addition of approximately 1,050 MW [32] to 1,550 MW [33] of incremental generation [34] (above the existing generation as of January 2020) that meet the AESO's certainty criteria[35] in the Study Area.

This is depicted in Figure 10-1 below. In the figure, the Y-axis represents the incremental generation in the Study Area. The existing installed generation as of January 2020 was considered as the baseline value [36] which represents 0 MW on the Y-axis. The green zone represents new generation in the Study Area including the projects energized as of July 2020 and the projects meet the AESO's certainty criteria.

As part of this milestone approach, once incremental generation that meets the certainty criteria are within the range of 1,050 MW to 1,550 MW, the AESO would re-affirm that congestion is forecast to occur greater than 0.5% of the time annually during the Category A condition by performing congestion assessment studies that take into account the locations and sizes of the generation meeting the certainty criteria. In the event that these planning studies re-affirm that Category A congestion is forecast to occur greater than 0.5% of the time annually, the AESO will notify the Commission that the construction milestone has been met and advise the TFOs to commence construction for Stage 1.

Prior to filing this application, 1,059 MW of incremental generation has already met the certainty criteria. The AESO anticipates additional generation to reach the certainty criteria prior to the end of 2020. As such, the AESO expects to commence the congestion assessment studies prior to a Commission decision on the NID. Should the results re-affirm Category A congestion is forecast to occur greater than 0.5% of the time annually, the AESO would notify the Commission that the Stage 1 construction milestone has been met. If the Commission has already rendered a decision on the NID, the AESO will notify the Commission that the Stage 1 construction milestone has been met and advise the TFOs to commence construction for Stage 1.

The following construction milestone for the Preferred Transmission Development Stage 2 is proposed:

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[31] The generation construction timelines for wind farm is typically 1 to 2 years.

[32] Calculated as 1,250 MW (the Category A congestion is expected to occur in the thermal generation baseload scenario) minus the 200 MW margin.

[33] Calculated as 1,750 MW (the Category A congestion is expected to occur in the thermal generation peaking scenario) minus the 200 MW margin.

[34] For the milestone calculation, incremental generation could be renewable or thermal. For the thermal, anything beyond 1,479 MW of installed thermal generation capacity would be considered incremental. This 1,479 MW is the highest level of installed thermal generation capacity in the baseload scenario.

[35] The AESO's certainty criteria for purposes of meeting the milestone will include awarded REP projects and all generation projects that have paid their Generating Unit Owner's Contribution (GUOC).

[36] This aligns with the existing renewable generation assumption outlined in Section 2.3 in Appendix B.

- The addition of approximately 1,700 MW [37] to 2,150 MW [38] of incremental generation (above the existing installed renewable generation as of January 2020) that meet the AESO's certainty criteria in the Study Area.

For the Stage 2 construction milestone, once incremental generation is within the range of 1,700 MW to 2,150 MW, the AESO would re-affirm that congestion is forecast to occur greater than 0.5% of the time annually during the Category A condition by performing congestion assessment studies that take into account the locations and sizes of the generation meeting the certainty criteria. In the event that these planning studies re-affirm that Category A congestion is forecast to occur greater than 0.5% of the time annually, the AESO will notify the Commission that the Stage 2 construction milestone has been met and advise the TFOs to commence construction for Stage 2.

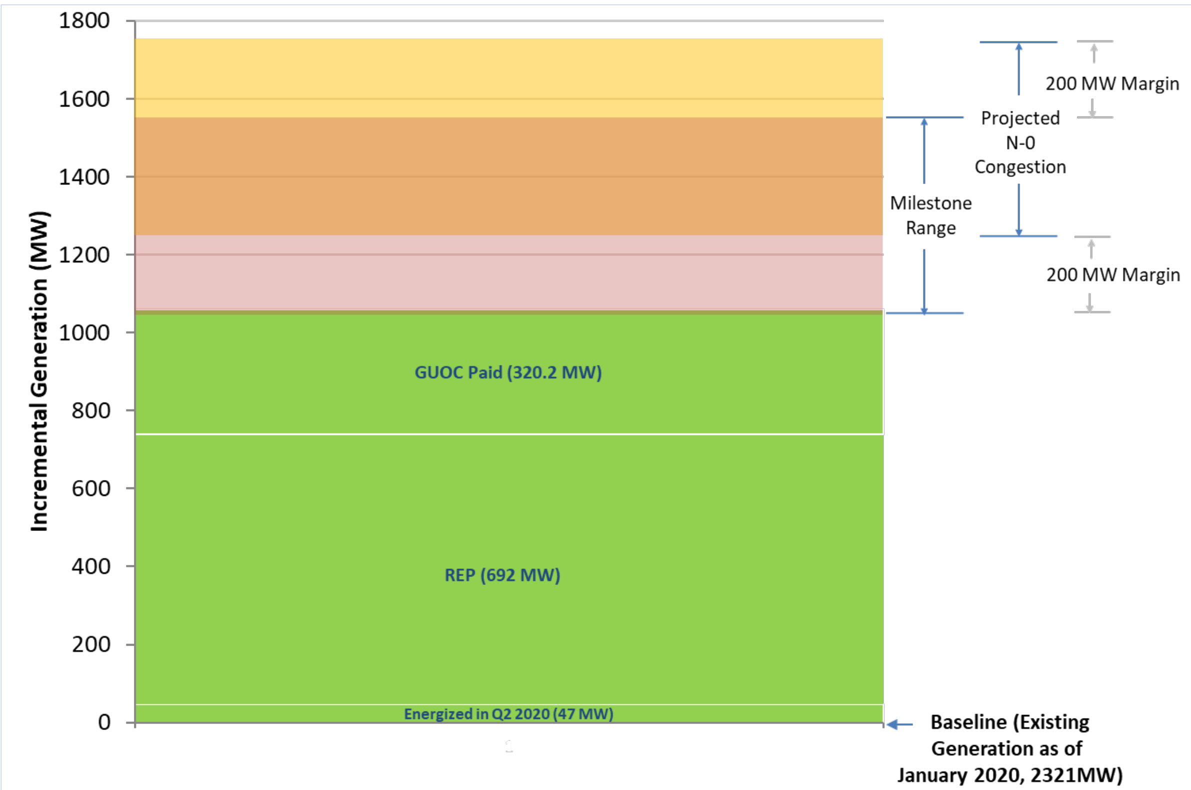

Figure 10-1: Construction Milestone for the Preferred Transmission Development Stage 1

The AESO will use operational measures, as necessary, should congestion arise prior to the energization of the Preferred Transmission Development.

[37] Calculated as 1,900 MW (the Category A congestion is expected to occur in the thermal generation baseload scenario) minus the 200 MW margin.

[38] Calculated as 2,350 MW (the Category A congestion is expected to occur in the thermal generation peaking scenario) minus the 200 MW margin.

11 Alignment with AESO's Long Term Plan

The AESO's long-term transmission system plans are high-level assessments of transmission capability and required transmission system development in Alberta focusing on broad technical aspects. More detailed studies are performed in preparation of a needs identification document application to ensure that the AESO's Preferred Transmission Development will address the identified reliability violations in the most efficient manner.

The Preferred Transmission Development proposed by the AESO in this Application is aligned with the *AESO 2020 Long-term Transmission Plan* (2020 LTP) in that transmission development in the CE sub-region is recommended

12 Project Interdependencies

The Preferred Transmission Development is not dependent on other transmission developments that are currently planned within the AIES in this timeframe. However, to achieve the maximum generation integration capability of the Preferred Transmission Development, the approved PENV development which was designed to alleviate the local 138 kV constraints in the PENV area is required.

13 Summary and Conclusions

The AESO conducted planning studies to assess the need for transmission development in the CE sub-region. Planning study results demonstrate that the Pre-Development transmission system does not have sufficient capacity to reliably integrate the forecast incremental renewable generation in the Study Area. This is primarily due to the thermal constraints on the CE sub-region west transfer-out path. Therefore, there is a need for transmission development in the CE sub-region to alleviate the identified constraints. The driver of the need for transmission system development is the forecast incremental renewable generation in the Study Area.

Transmission Development Options and Performance Assessment

To alleviate the identified constraints on the CE sub-region west transfer-out path and to increase the generation integration capability in order to accommodate future renewable generation in the Study Area, the AESO considered six Transmission Development Options presented in Table 13-1.

Table 13-1: Transmission Development Options

Option	Description
1	Add two new 240 kV circuits between Tinchebray 972S and Gaetz 87S substations
2	Add two new 240 kV circuits between Tinchebray 972S and Wolf Creek 288S substations
3	Add one new 240 kV circuit between Tinchebray 972S and Gaetz 87S substations and upgrade existing 912L and 9L20
4	Add one new 500 kV circuit between Tinchebray 972S and Gaetz 87S substations
5	Convert EATL to bi-pole
6	Add one new 240 kV circuit between Cordel 755S and Gaetz 87S substations and add one new 240 kV circuit between Tinchebray 972S and Gaetz 87S substations

Table 13-2 provides a summary of the performance comparison for the six considered Transmission Development Options.

Table 13-2: Summary of Performance Comparison for the Transmission Development Options

Option	Description	Technical Assessment		Cost Estimates	Environmental and Land Use Effects
		Generation Integration Capability in Study Area	Operational Limitations		
1	Add Two 240 kV Circuits Between the Tinchebray 972S and Gaetz 87S Substations	Provides approximately 820 MW incremental capability.	N/A	The estimated cost is lower than Options 2 and 6.	Lower potential land impact than Options 2 and 6.
2	Add Two 240 kV Circuits Between the Tinchebray 972S and Wolf Creek 288S	Incremental capability is lower (~160 MW) than	N/A	The estimated cost (+30/-30%) is higher (~$26M) than	Higher potential land impact than

Option	Description	Technical Assessment		Cost Estimates	Environmental and Land Use Effects
		Generation Integration Capability in Study Area	Operational Limitations		
	Substations	Option 1.		Option 1.	Option 1.
3	Add One 240 kV Circuit Between the Tinchebray 972S and Gaetz 87S Substations and Upgrade 240 kV transmission lines 912L/9L20	Incremental capability is lower (~130 MW) than Option 1.	Line rebuilds generally would require lengthy outages. Therefore, this option is expected to require a lengthy outage on 912L and 9L20 resulting in operational complexity. Under outage of the new 240kV circuit, 912L, or 9L20, renewable generation can be dispatched for this option would be lower (~300 MW) than Option 1.	N/A	N/A
4	Add one 500 kV Circuit Between the Tinchebray 972S and Gaetz 87S Substations	Incremental capability is lower (~130 MW) than Option 1.	Under outage of the new 500 kV circuit, renewable generation dispatched for this option would be significantly (~500 MW) lower than Option 1.	N/A	N/A
5	Convert EATL to bi-pole	Incremental capability is significantly lower (~600 MW) than Option 1.	N/A	N/A	N/A
6	Add one 240 kV Circuits Between the Gaetz 87S and Cordel 755S Substations and Add one 240 kV circuit Between the Gaetz 87S and Tinchebray 972S Substations	Provides similar level of integration capability as Option 1. Provides less flexibility to integrate renewable generation in the west of the Hanna (Area 42) planning area.	N/A	The estimated cost (+30/-30%) is higher (~$9M) than Option 1.	Higher potential land impact than Option 1.

In summary, Option 1 is the Preferred Transmission Development for the following reasons:

- it is technically superior to other options in terms of generation integration capability and operational flexibility;
- it is the most economic option when compared to Options 2 and 6; and
- It has lower potential environmental and land use effects when compared to Options 2 and 6.

Based on the deterministic studies described in this Planning Report and probabilistic assessment outlined in Congestion Assessment Appendix[39], the AESO recommends the Preferred Transmission Development comprising the following two stages:

Stage 1:

- Add one 240 kV circuit between the existing Tinchebray 972S and Gaetz 87S substations;
- Modify the Tinchebray 972S substation by adding circuit breakers and associated equipment;
- Modify the Gaetz 87S substation by adding circuit breakers and associated equipment.

Stage 2:

- Add one 240 kV circuit between the existing Tinchebray 972S and Gaetz 87S substations;
- Modify the Tinchebray 972S substation by adding circuit breakers and associated equipment;
- Modify the Gaetz 87S substation by adding circuit breakers and associated equipment.

The AESO proposes a construction milestone for each stage of the Preferred Transmission Development. A construction milestone will enable the AESO to manage uncertainty regarding the timing and impacts of generation development in the Study Area and to delay construction as much as possible, while ensuring the Preferred Transmission Development can be constructed and energized before congestion arises.

The proposed milestones are based on the results of the congestion assessment indicating when the Category A congestion on the CE west transfer-out path is projected to occur greater than 0.5% of the time annually. Considering that it will take approximately 2 to 3 years to construct the Preferred Transmission Development after the Permit & Licence has been received and the construction milestone has been met, the milestone incorporates a 200 MW (i.e., an average sized wind farm) reduction of incremental generation into the analysis to align with generation construction timelines of 1 to 2 years as well as to avoid congestion on the transmission system.

The following construction milestone for the Preferred Transmission Development Stage 1 is proposed:

- The addition of approximately 1,050 MW to 1,550 MW of incremental generation (above the existing generation as of January 2020) that meets the AESO's certainty criteria (as described in Section 10.2) in the SE and CE sub-regions.

As part of this milestone approach, once incremental generation that meets the certainty criteria are within the range of 1,050 MW to 1,550 MW, the AESO would re-affirm that congestion is forecast to occur greater than 0.5% of the time annually during the Category A condition by performing congestion assessment studies that take into account the locations and sizes of the generation meeting the certainty criteria. In the event that these planning studies re-affirm that Category A congestion is forecast to occur

[39] Filed under separate cover as Appendix C.

greater than 0.5% of the time annually, the AESO will notify the Commission that the construction milestone has been met and advise the TFOs to commence construction for Stage 1.

Prior to filing this application, 1,059 MW of incremental generation has already met the certainty criteria. The AESO anticipates additional generation to reach the certainty criteria prior to the end of 2020. As such, the AESO expects to commence the congestion assessment studies prior to a Commission decision on the NID. Should the results re-affirm Category A congestion is forecast to occur greater than 0.5% of the time annually, the AESO would notify the Commission that the Stage 1 construction milestone has been met. If the Commission has already rendered a decision on the NID, the AESO will notify the Commission that the Stage 1 construction milestone has been met and advise the TFOs to commence construction for Stage 1.

The following construction milestone for the Preferred Transmission Development Stage 2 is proposed:

- The addition of approximately 1,700 MW to 2,150 MW of incremental generation (above the existing generation as of January 2020) that meet the AESO's certainty criteria in the SE and CE sub-regions.

For the Stage 2 construction milestone, once incremental generation is within the range of 1,700 MW to 2,150 MW, the AESO would re-affirm that congestion is forecast to occur greater than 0.5% of the time annually during the Category A condition by performing congestion assessment studies that take into account the locations and sizes of the generation meeting the certainty criteria. In the event that these planning studies re-affirm that Category A congestion is forecast to occur greater than 0.5% of the time annually, the AESO will notify the Commission that the Stage 2 construction milestone has been met and advise the TFOs to commence construction for Stage 2.

The AESO will use operational measures, as necessary, should congestion arise prior to the energization of the Preferred Transmission Development.

Attachment A: Power Flow SLDs – Pre-Transmission Development 2023

Attachment B: Power Flow SLDs – Assessment of Transmission Development Options

Attachment C: Power Flow SLDs – Preferred Transmission Development Capability

Attachment D: Power Flow SLDs – Medium-term (2031) Assessment

Attachment E: Voltage Stability (PV) Analysis

Attachment F: Transient Stability Analysis

Attachment G: Short-Circuit Analysis

Attachment H: Letter from ATCO Re: Cordel 755S: Inability to add more than one (1) 240kV transmission line