ALBERTA UTILITIES COMMISSION

IN THE MATTER OF THE NEED FOR REINFORCEMENT OF THE TRANSMISSION SYSTEM IN THE HANNA REGION

AND IN THE MATTER OF THE *ELECTRIC UTILITIES ACT*, SA 2003, C. E-5.1, THE *ALBERTA UTILITIES COMMISSION ACT*, SA 2007, C. A-31.2, THE *TRANSMISSION REGULATION*, AR 86/2007 AND ALBERTA UTILITIES COMMISSION RULE 007

APPLICATION of the ALBERTA ELECTRIC SYSTEM OPERATOR for APPROVAL of its HANNA REGION TRANSMISSION DEVELOPMENT NEEDS IDENTIFICATION DOCUMENT

Overview

1. Pursuant to Section 34 of the Electric Utilities Act (EUA) and in accordance with the further legislative provisions set out in the recital to this application, the Alberta Electric System Operator (AESO) applies for approval from the Alberta Utilities Commission (AUC) of the attached Hanna Region Transmission Development Needs Identification Document (HR NID), as more specifically described therein.[1]

2. The HR NID identifies and describes necessary reinforcements and enhancements of the transmission system in southeastern Alberta, including Wainwright, Hardistry, Castor, Provost, Stettler, Drumheller, Hanna, Monitor, Oyen, Empress, Ware Junction and Brooks.[2] The AESO has determined, in accordance with its statutory mandate, that this development is required to meet Alberta's need and is in the public interest, specifically to alleviate conditions that affect the ability of the Hanna Region to provide safe, reliable and economic electricity service to local area load and to facilitate interconnection of wind power projects in the region.

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[1] The HR NID consists of the NID itself, and Appendices A to H, inclusive.

[2] And which includes the following transmission planning areas: Hanna (Area 42), Wainwright (Area 32), Alliance/Battle River (Area 36), Provost (Area 37), and Sheerness (Area 43). See HR NID, Figures 1-1 and 1-2, pages 2 and 3.

Background

3. The AIES is a vital component of Alberta's electric industry and provides a platform for its competitive electricity market. The AESO is responsible for the safe, reliable operation of the AIES, as well as its future development. The AESO is charged with planning the transmission elements of the AIES, and strives to ensure that it keeps pace with growing consumer demand, meets the needs of generation development to satisfy that demand, and provides safe, reliable and economic service.

4. The Hanna Region comprises five (5) transmission-planning areas as described in paragraph 2 above. Local area load in the Hanna Region is primarily served by a 138/144 kV network and two (2) 240 kV substations. However, given load growth in the Hanna Region and the forecast development of wind generation, the current transmission system in the Hanna Region requires reinforcement.

Analysis and Evaluation of the Existing Hanna Region Transmission System

5. Applying its Transmission Reliability Criteria, and using reasonable load forecast and generation assumptions, the AESO has tested the existing Hanna Region transmission system for acceptable performance and to determine its present and future adequacy.

6. As more specifically set out in the HR NID, the AESO's analysis identifies capacity constraints/conditions that affect the operation, safety and reliability of the transmission system in the Hanna Region. As such, the Hanna Region transmission system requires reinforcement and enhancement to ensure adequate capacity and reliability of supply to growing area load, address forecast development of wind generation, and assure compliance with the AESO's Transmission Reliability Criteria.

Proposed Hanna Region Transmission Reinforcement

7. The AESO's primary objective is to plan the transmission system in the Hanna Region to provide for the safe, reliable and efficient delivery of electricity.

8. The HR NID reflects the AESO's considered analysis, assessment and evaluation of three (3) alternatives in order to address the performance concerns described earlier. Such analysis was undertaken having regard to: transmission technologies/facility options;

planning alternatives; load forecast; available capacity; forecast development of wind generation; power flows; reactive power supply; transient stability; land impact assessment; and high level economic analysis. In light of the various factors taken into account by the AESO, and as required by paragraph 11(3)(h) of the *Transmission Regulation*, the AESO's preferred alternative for the Hanna Region transmission system development was determined.

Participant Involvement Program

9. Consistent with the requirements of Commission Rule 007, the AESO has conducted a comprehensive and varied participant involvement program (PIP) over the course of its development of the HR NID. A variety of forums have been utilized in order to provide notice of the proposal and offer opportunities for consultation and discussion with the public generally, as well as residents, occupants, landowners, businesses, industry, and others having an interest in the Hanna Region. Further detail concerning the AESO's PIP may be found in Section 6.8 and Appendix H of the HR NID.

The AESO's Preferred Alternative

10. The AESO's preferred alternative is set out in detail in Section 8.0 and Figure 8-1 in the HR NID. Stage I of the preferred alternative is recommended to proceed immediately and Stage II is required by 2017.

Costs and Benefits

11. The estimated total cost of Stage I of the AESO's preferred alternative is $849 million (+/-30%, $2009, inclusive of capital cost, AFUDC, Engineering & Supervision, and Contingency). The estimated total cost of Stage II of the AESO's preferred alternative is $157 million (+/-30%, $2009, inclusive of capital cost, AFUDC, Engineering & Supervision, and Contingency). The total cost of both stages is approximately $1.006 billion (+/-30%, $2009, inclusive of capital cost, AFUDC, Engineering & Supervision, and Contingency).

12. As set out in the HR NID, the AESO believes that the recommended enforcement and enhancement will benefit Alberta by:

(i) improving the reliability of the AIES in the Hanna Region;

(ii) increasing the capacity of the transmission system to serve future area load; and

(iii) facilitating the interconnection of proposed wind power projects in the region.

Relief Requested

13. For all of the reasons set out herein and in the HR NID, the AESO requests that the Alberta Utilities Commission approve the Hanna Region Reinforcement Needs Identification Document or grant such further and other relief in addition to, or in substitution for, that applied for by the AESO, as may appear to the Alberta Utilities Commission to be just and appropriate.

All of which is respectfully submitted this 14th day of August, 2009.

ALBERTA ELECTRIC SYSTEM OPERATOR

William Strongman P.Eng.
Director, Regional System Planning

ALBERTA ELECTRIC SYSTEM OPERATOR

Hanna Region

Transmission Development

Needs Identification Document

Application Number: ______________

Date: August 14, 2009

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APEGGA Permit to Practice P-08200

Executive Summary

As a part of its mandate, the Alberta Electric System Operator (AESO) is responsible for planning the transmission system within the province of Alberta as set out in the Electric Utilities Act, SA 2003 c E-5.1. As prescribed in the Transmission Regulation (“Regulation”), the AESO issued the Long-Term transmission System Plan in June 2009. In the context of the Transmission System Plan, the AESO has engaged in the planning process to facilitate the preparation of this Needs Identification Document (NID) for the Hanna region of Alberta.

The need for transmission reinforcement in the Hanna region is driven predominantly by load growth and the forecast development of wind generation. The regional load is forecast to increase more than double from approximately 420 MW in 2008 to approximately 970 MW in 2017. It is forecasted that up to 3,900 MW of wind generation will be operating in Alberta within the next 10 years, including the 500 MW currently in operation in southern Alberta. Of that generation, it is anticipated that up to 700 MW of the province’s total will be located in the Central region of Alberta.

The AESO has received over 12,000 MW of wind interest of which approximately 2,300 MW is located in the Hanna region of Alberta. However, the AESO recognizes that in the competitive electricity wholesale market, more wind projects may be pursued by developers than the market can absorb, and that the competitive electricity wholesale market serves both to attract new generation when required, and also to send appropriate signals to limit excess supply.

The AESO’s system studies indicate that the Hanna region transmission system is near its capacity and will not be able to supply additional loads in the region or interconnect any major wind project. A number of system constraints have been identified that indicate substantial system improvements are required to supply projected new load and accommodate proposed wind generation in the Hanna region. Accordingly, the AESO has developed its plan for transmission reinforcement, set out in this NID, in a staged approach.

The first stage of the proposed development is designed to supply forecast regional load of 820 MW and enable about 500 MW of wind generation by 2012. The AESO projected about 3,400 MW of new wind projects would be developed in the South and Central regions of Alberta by 2017. Of this 3400 of MW wind projects, the Central region share is 175 MW in 2012 and 700 MW in 2017. Although the forecast is for 175 MW of wind by 2012, stage I of the system as proposed can accommodate about 500 MW of wind potential. The total cost[1] of stage I is estimated at approximately $849 million (+/- 30%, 2009$).

[1] The total cost includes capital cost, Allowance for Funds Used During Construction (AFUDC), Engineering and Supervision (E&S), and contingency.

The second stage of the proposed development will supply forecast load of at least 970 MW and enable 700 MW of forecast wind generation to be operational in the Hanna region in 2017. The total cost of this stage is currently estimated at approximately $157 million (+/-30%, 2009$).

Three major transmission development alternatives were identified and studied to supply the forecast load and integrate 700 MW wind in the Hanna region by 2017. They are:

- Alternative 1: Double 240 kV AC looped system
- Alternative 2: Single reinforced 240 kV AC looped system
- Alternative 3: Single extended 240 kV AC looped system

For each transmission alternative, technical and economic analysis was carried out using two conductor types, the 477 kcmil ACSR (Hawk), and 795 kcmil ACSR (Drake). Given the possibility that more than 700 MW of wind integration could materialize beyond 2017 and the expected increase in load growth in the Hanna region, the 600 MVA rating of the twin bundle 477 kcmil ACSR conductors was considered to be a limiting factor. Hence large sized conductor was selected.

The AESO identified a set of reinforcements that are common to all three alternatives and are outlined in Section 5. Detailed capital costs for each of the alternatives are presented in Appendix G.

The AESO's recommended transmission plan consists of Alternative 3 and the set of common system reinforcements described in Section 5.1. The recommended proposal in the Hanna region is shown in Figure EX-1.

In all the alternatives considered, the 240 kV lines were based on double circuit towers with one side strung (unless otherwise specified). Capacity can be added at a later date by stringing the second 240 kV circuit if and when required, without the need for new right-of- ways.

All of the alternatives are viable from a land impact perspective, and none have potential impacts that would cause any to be rejected. Alternative 3 has the least overall impact for the majority of measurable indicators assessed.

The AESO conducted a Participant Involvement Program (PIP) throughout the development of its NID and used a variety of methods for public consultation. The AESO has not received any preference for any of the three alternatives from the public.

The economic analysis was carried out for all the alternatives considered in this NID. The net present value (NPV) of capital costs and relative value of losses for the three alternatives are as follows:

Table EX-1: Comparison of Net Present Value (+/- 30%, 2009$)

Alternatives[2]	NPV
Alternative 1: Double 240 kV AC looped system	$1,371
Alternative 2: Single reinforced 240 kV AC looped system	$1,366
Alternative 3: Single extended 240 kV AC looped system	$1,250

As indicated, the AESO is adopting a staged approach for implementation of the recommended proposal. Stage I is recommended to proceed immediately upon regulatory approval, as all of the components in this stage are required for supplying projected load and for integrating a minimum of 175 MW of wind generation. The details of each stage are outlined below:

Stage I:

1. 240 kV Oakland 946S switching station and a double circuit 240 kV line connecting it to Anderson 801S.
2. 240/144 kV substation at Coyote Lake 963S (for wind collection) and a 240 kV double circuit line with single side strung connecting it to Oakland 946S.
3. One 300 MVA 240/144 kV transformer at Coyote Lake 963S and 144 kV line from Coyote Lake 963S to Michichi Creek 802S.
4. 240 kV double circuit line with single side strung from Ware Junction 132S to West Brooks 28S.
5. 240/144 kV substation at Lanfine 959S with one 300 MVA 240/144 kV transformer and a 240 kV double circuit line with single side strung from Oakland 946S to Lanfine 959S.
6. 240/144 kV substation at Pemukan 932S with one 300 MVA 240/144 kV transformer and a 240 kV double circuit line with single side strung from Lanfine 959S to Pemukan 932S.
7. 240 kV double circuit line with single side strung from Hansman Lake 650S to Pemukan 932S.
8. 240/138 kV substation at Nilrem 574S with two 400 MVA 240/138 kV transformer and a 240 kV double circuit line from 9L953/953L to Nilrem 574S.

[2] Pertain to twin bundle 795 kcmil conductors, or Option B.

9. 138 kV double circuit line from Nilrem 574S to Tucuman 478S.

10. 144 kV double circuit line with single side strung from Pemukan 932S to Monitor 774S.

11. 144 kV double circuit line with single side strung from Lanfine 959S to Oyen 767S.

12. 144 kV single circuit line from Lanfine 959S to Excel 910S.

13. Build new 144 kV Cornish Lake 954S substation (replaces existing Rowley 768S) and connect it in-and-out on 7L25 from Three Hills 770S to Michichi Creek 802S.

14. Convert existing 72 kV Stettler 769S to a 144 kV substation and new 144 kV line from Nevis 766S to upgraded Stettler 769S.

15. Build new 144 kV Heatburg 948S substation (replaces existing Delburne 760S) and connect it in-and-out on 7L16 from Three Hills 770S to Nevis 766S.

16. Capacitor banks at Hardisty 377S, Pemukan 932S, Lanfine 959S, Three Hills 770S, Stettler 769S, Youngstown 772S and Battle River 757S.

17. Three Static VAr compensators (+/-200 MVAr) each at Hansman Lake 650S, Pemukan 932S, and Lanfine 959S.

The total cost for Stage I is approximately $849 million (+/- 30%, 2009$).

Stage II:

1. 240 kV double circuit line with single side strung from Cordel 755S to Halkirk switching station.

2. Second side strung on the 240 kV double circuit line from Oakland 946S to Coyote Lake 963S.

3. Second side strung on the 240 kV double circuit line from Oakland 946S to Lanfine 959S.

4. Convert existing 72 kV Hanna 763S to a 144 kV substation and new 144 kV line from Coyote Lake 963S to upgraded Hanna 763S.

5. Second 200 MVA 240/138 kV transformer at Hansman Lake 650S.

6. Second 300 MVA 240/144 kV transformer at Pemukan 932S.

7. Second 300 MVA 240/144 kV transformer at Lanfine 959S.

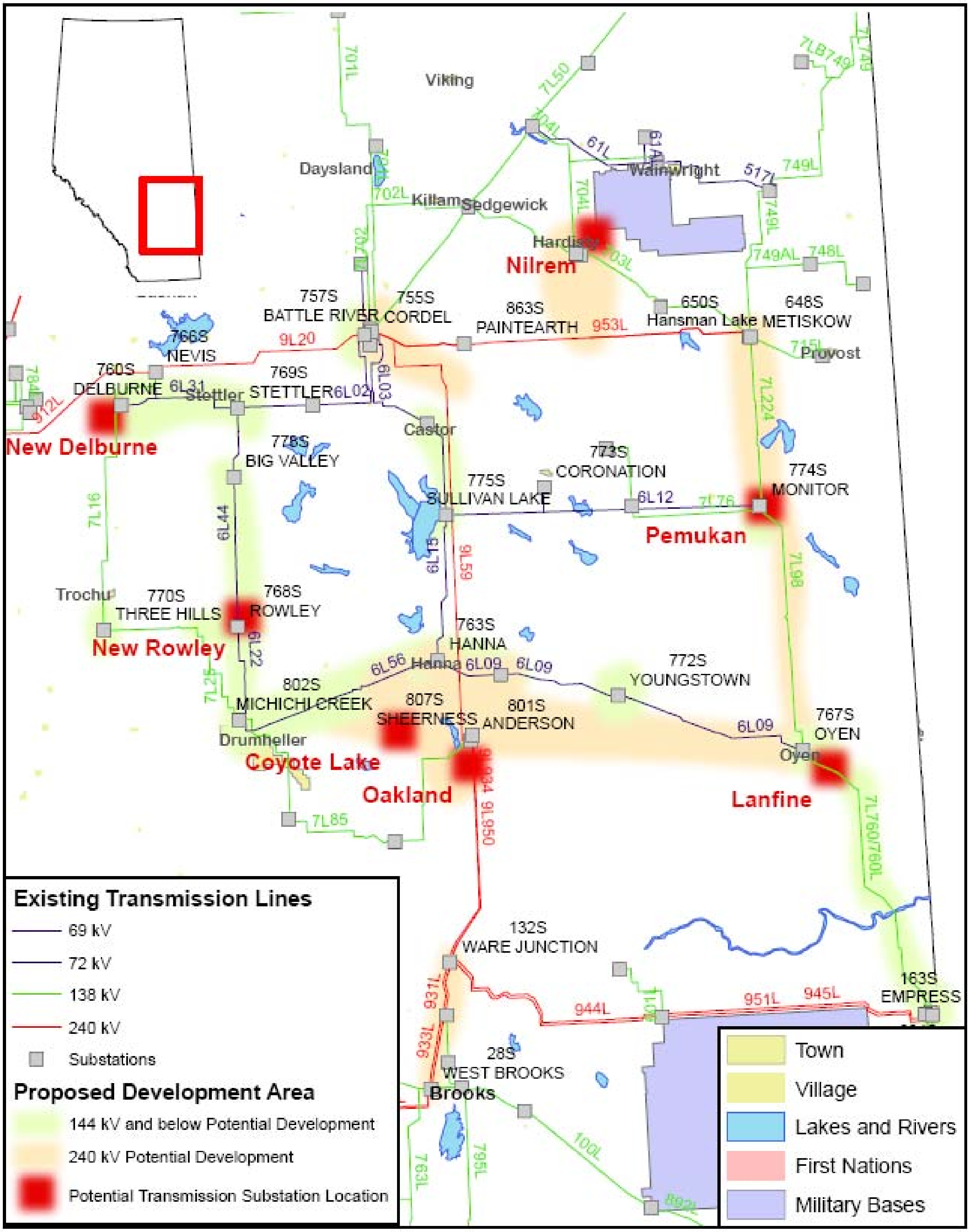
8. Second side strung on the 144 kV double circuit line from Pemukan 932S to Monitor 774S.

9. Second side strung on the 144 kV double circuit line from Lanfine 959S to Oyen 767S.

10. Capacitor banks at Nilrem 574S, Hansman Lake 650S, Metiskow 648S, Youngstown 772S, and Coronation 773S.

The total cost for Stage II is approximately $157 million (+/-30%, 2009$).

Figure EX- 1: Hanna Region Transmission Development Proposed Alternative



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1 Description of the Hanna Region Transmission System

The Alberta Interconnected Electric System (AIES) is a vital component of the electric industry and provides a platform for a competitive wholesale electricity market. The AIES connects generators to load over a large and diverse geographic area and is designed to deliver electric energy to Alberta customers reliably and efficiently under a wide variety of system operating conditions and continuously changing customer demands.

The Hanna region encompasses the southeast portion of the Alberta central planning region. It borders Saskatchewan to the east, Strathmore, Brooks and Empress planning areas to the south, Airdrie, Didsbury and Red Deer planning areas to the west and Fort Saskatchewan, Vegreville and Lloydminster planning areas to the north. This study region includes the following Alberta Electric System Operator (AESO) planning areas: Hanna (Area 42), Wainwright (Area 32), Alliance/Battle River (Area 36), Provost (Area 37) and Sheerness (Area 43). Figures 1-1 and 1-2 show the geographical map and schematic representation of the Hanna transmission system, respectively.

The region is primarily served by a 138/144 kV and 69/72 kV network and two 240 kV substations. Currently, there are three major 240 kV interconnections from the Hanna region to the AIES bulk system. These three 240 kV lines are 912L from Red Deer 63S to Nevis 766S, 9L933/933L from Anderson 801S to West Brooks 28S and 931L from Ware Junction 132S to West Brooks 28S. The two major thermal power plants in the Hanna region are the Sheerness and Battle River coal-fired power plants. They are connected by the 240 kV line 9L59 from Anderson to Cordel. The generation is connected to load centres in the Wainwright and Provost areas by two 240 kV lines from Cordel 755S to Hansman Lake 650S and also to a load centre in the Empress area by two other 240 kV lines, 951L and 944L/945L from Ware Junction 132S to Empress 163S. The east Hanna area loads are supplied by two 138/144 kV sources, one from Hansman Lake 650S and one from Empress 163S. The west Hanna area is supplied by two 144 kV sources, one from Nevis 766S and one from Anderson 801S. Under the west Hanna 144 kV system, there is a 72 kV network that supplies remote loads. This 72 kV system is also connected back to Oyen 767S in the east and Battle River in the northeast.

Figure 1-1: Existing Hanna Region Transmission System

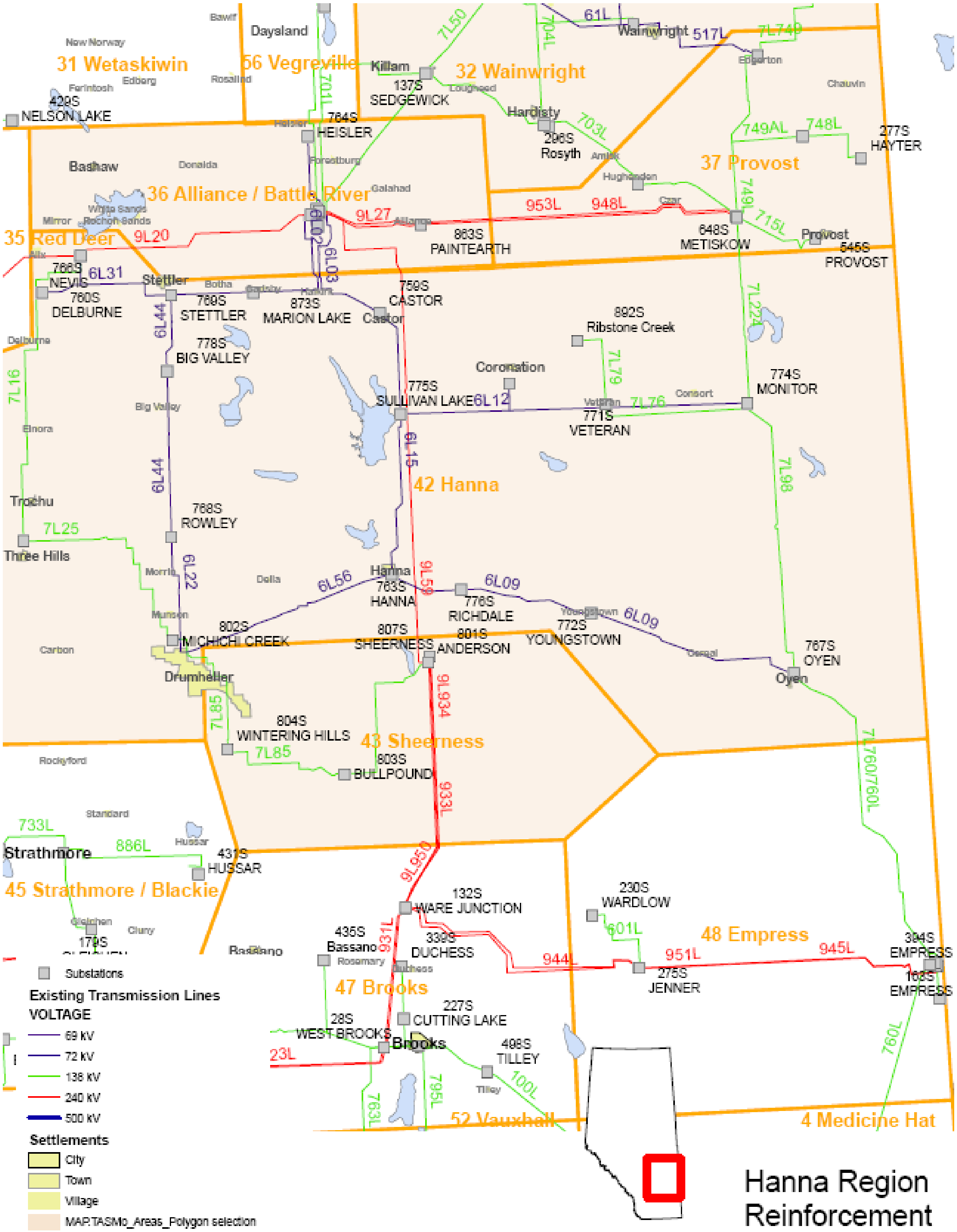
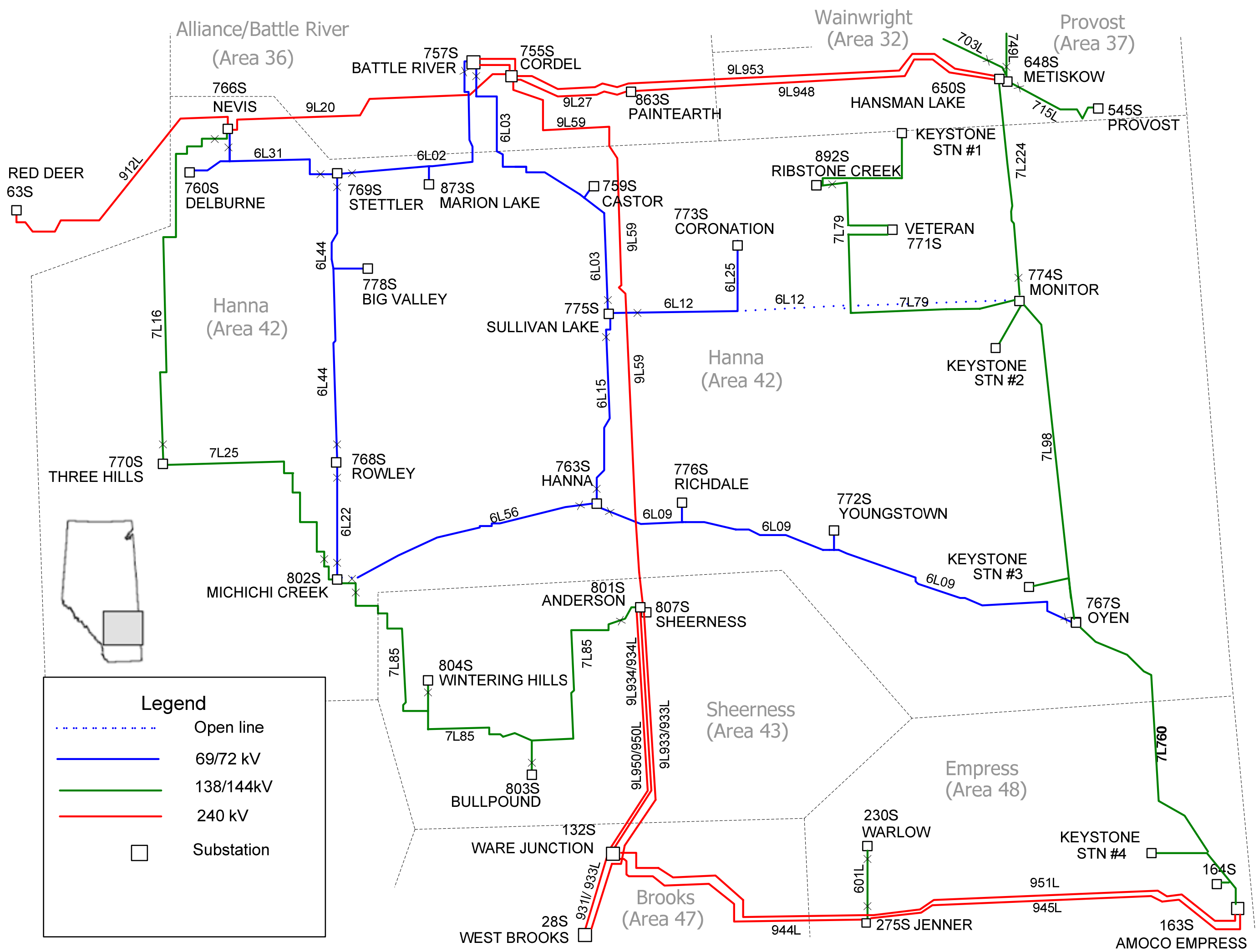


Figure 1-2: Schematic of Existing Hanna Region Transmission System



2 Criteria and Assumptions

To identify the need to reinforce transmission in the Hanna region, the AESO tests the present and future adequacy of the existing transmission system by applying the AESO Transmission Reliability Criteria (Reliability Criteria). The Hanna region transmission system was tested under certain load forecasts and future generation assumptions. The following sections describe the Reliability Criteria and assumptions in further detail.

2.1 Reliability Criteria

The AESO performs technical studies to assess transmission supply and reliability needs in Alberta. These technical studies test the transmission system for adequacy, security, system operability and maintenance management.

The Reliability Criteria was applied to determine the load supply and wind power integration adequacy of the planned transmission system in the Hanna region. That is, the existing transmission system along with the proposed alternatives were tested to see if the proposed alternatives were capable of supplying the forecast peak demand and capable of integrating projected wind generation under both Category A (i.e. all elements in service) and Category B (i.e. an element out of service, N-1 and N-G-1) contingencies. The three alternatives were put through an iterative planning process to ensure that the planned transmission system, with any one of the three alternatives, conform with the Reliability Criteria.

Category B contingencies also cover single element outage events while the most critical generator is out of service for maintenance or for commercial reasons (N-G-1), and the remaining generators in the system are dispatched according to the forecast merit order. All equipment must operate within its acceptable thermal and voltage limits.

Category C and D events are studied for the recommended alternative. The system performance is evaluated to ensure no system cascading occurs. Special Protection Schemes (SPS) will be proposed if required.

Table 2.1-1 presents the acceptable steady state and contingency state voltage ranges for the AIES.

Table 2.1-1: Acceptable Range of Steady State Voltage (kV)[3]

Nominal Voltage	Extreme Minimum	Normal Minimum	Normal Maximum	Extreme Maximum
240	220	240	264	264
144	130	137	151	155
138	124	135	145	150
72	65	71	75	78
69	62	65	72	74

The voltage stability criterion that was used to test the system performance is provided in Table 2.1-2.

[3] For details, see Table 5.1-1 on Page 11 of "AESO Transmission Reliability Criteria – Part II System Planning."

Table 2.1-2: Voltage Stability Criteria[4]

Performance Level	Disturbance Initiated by: Fault or No fault DC Disturbance	MW Margin (P-V method)	MVAr Margin (V-Q method)
A	Any element such as: One generator One circuit One transformer	≥ 5%	Worst Case Scenario[5]
B	Bus section	≥ 2.5%	50% of margin requirement in Level A
C	Any combination of two elements such as: A line and a generator A line and a reactive power source Two generators Two circuits Two transformers	≥ 2.5%	50% of margin requirement in Level A
D	Any combination of three or more elements, such as: Three or more circuit on ROW Entire substation	> 0	> 0

[4] For details, see Table 5.2-1 Voltage Stability Criteria on Page 15 of the AESO Transmission Reliability Criteria – Part II System Planning

[5] The most reactive deficient bus must have adequate reactive power margin for the worst single contingency to satisfy either of the following conditions, whichever is worst: (i) a 5% increase beyond maximum forecasted loads or (ii) 5% increase beyond maximum allowable interface flows. The worst single contingency is the one that causes the largest decrease in the reactive power margin.

2.2 Input Assumptions

Primary assumptions that were considered in the Hanna region planning study consist of the area load forecast, generation scenarios, bulk transmission system and transfers on interconnections with other jurisdictions. The assumptions on bulk transmission system and transfers are described in section 6.

2.2.1 Load Forecast

The Hanna region study is based on the AESO 2007 corporate load forecast. Table 2.2-1 provides the planning area average annual growth rates over a historical six year period and the next nine year forecast.

Table 2.2-2 provides the historical and forecast area and regional summer and winter peak loads in MW for the Hanna region.

The load in the Hanna region peaks in the winter period[6]. Therefore, the winter peak case is the worst case for the load adequacy study. The recorded Hanna winter regional peak load was approximately 420 MW in 2008. The Hanna region winter peak load is forecasted to grow from 420 MW in 2008 to approximately 820 MW by the year 2012 and to 970 MW by 2017. Load growth in the region is primarily driven by oil and gas pipelines that require a significant amount of power to operate pumping facilities. Other contributors to the load in the region include power required for developing coal bed methane.

The average load growth in the Hanna, Wainwright and Provost areas over the next nine years is expected to exceed the provincial average load growth rate of approximately 3 per cent/annum by more than three times. The peak load growth rates in the Battle River and Sheerness areas are relatively low compared to the Hanna, Wainwright and Provost areas, as there is no major industrial development foreseen at this time.

[6] Winter period is defined as the period from November 01 to April 30; Summer period from May 01 to October 30. Winter peak is denoted as ‘win’; summer peak is denoted as ‘sum’.

Table 2.2-1: Hanna, Wainwright, and Provost Areas Load Growth Rates

Area	Winter peak load growth rate (%)	
	Historical (2002-2008)	Forecast (2008-2017)
Hanna	1.9	10.3
Wainwright	2.5	14.3
Provost	1.7	5.9

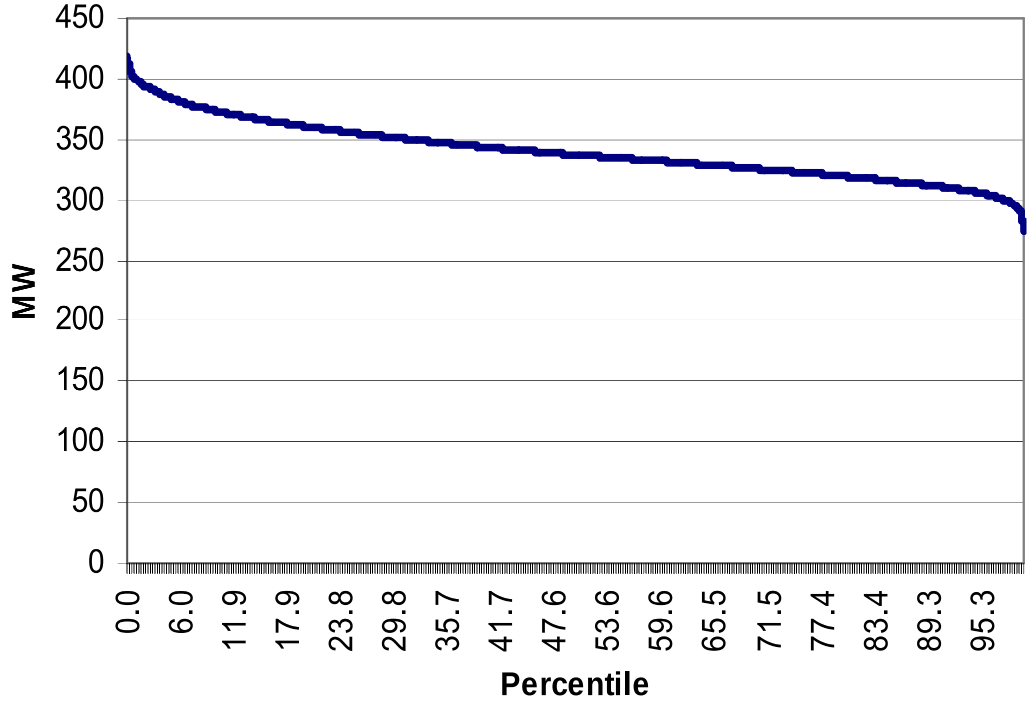
Table 2.2-2: Hanna Region Historical and Forecast Area Peak Load

	Year	Area Peak										Regional Peak	
		Hanna		Wainwright		Battle River		Provost		Sheerness			
		win	sum	win	sum	win	sum	win	sum	win	sum	win	sum
Historical Peak Load (MW)	2002	140.2	127.5	81.3	77.0	40.1	39.3	113.4	108.2	22.6	25.3	381.3	355.4
	2003	141.1	120.9	87.2	80.0	40.8	38.6	117.1	108.9	40.0	37.0	399.8	358.3
	2004	144.5	121.3	89.1	85.2	38.5	40.2	114.6	105.4	42.7	25.1	395.2	353.3
	2005	152.8	125.0	92.6	82.7	37.4	37.9	120.1	106.2	33.2	39.9	410.2	354.7
	2006	156.9	138.8	92.5	87.5	45.0	39.7	118.9	112.8	40.7	38.4	415.9	388.7
	2007	159.7	140.6	92.2	84.8	34.7	33.3	123.0	112.2	20.9	32.8	419.6	384.2
	2008	156.6	132.8	94.4	84.6	34.6	32.4	125.5	108.6	25.1	28.8	419.6	372.7
Forecast Peak Load (MW)	2009	212.5	197.5	162.4	154.0	51.6	37.9	150.0	112.7	44.8	38.2	605.6	514.2
	2010	235.7	220.7	186.8	178.4	51.6	38.0	151.5	113.4	45.0	38.4	653.6	560.3
	2011	239.2	223.9	204.1	195.6	51.6	38.0	153.1	117.2	45.2	38.6	675.8	583.6
	2012	300.2	284.5	266.1	257.4	51.6	38.0	178.0	141.3	45.4	38.8	820.0	723.2
	2013	303.0	287.2	268.4	259.5	51.6	38.0	179.4	141.4	45.6	39.0	826.6	728.1
	2014	306.1	290.1	270.7	261.7	51.6	38.0	181.1	139.5	45.8	39.2	833.7	731.3
	2015	309.3	293.1	273.2	264.0	51.6	38.0	183.1	140.2	46.0	39.4	841.4	737.3
	2016	314.6	298.2	275.6	266.2	51.6	38.1	185.2	144.4	46.2	39.6	851.2	748.4
	2017	377.0	360.4	314.1	304.5	51.6	38.1	210.5	168.6	46.4	39.8	974.3	867.3
	2018	378.7	361.7	316.7	306.8	51.7	38.1	212.3	169.4	46.6	40.0	980.5	871.7

Table A-1 in Appendix A provides the historical summer and winter peak substation loads for the last five years.

Figure 2.2-1 provides the load duration curve for the Hanna region for the year 2008. It presents the variation of the Hanna region load over a one-year period. The peak load is approximately 420 MW and the minimum load is slightly less than 300 MW. The annual load curve is relatively flat, signifying that the load is predominantly industrial in nature, which does not vary significantly from day to day or season to season like residential and/or commercial loads. The annual load factor is 81 per cent.

Figure 2.2-1: Hanna Region 2008 Load Duration Curve



2.2.2 Potential Generation Scenarios

Generation development in Alberta is driven by commercial business decisions within a competitive wholesale market, and it is not possible to definitively describe the timing and location of generation facilities in the future. Accordingly, the AESO creates a range of generation scenarios against which the transmission system can be tested to identify where future reinforcements are required. The generation scenarios are based on the transmission policy and market structure that is currently in place and the assumption that transmission is not a constraint in locating new generation.

There are many factors that affect generation developers' decisions regarding when and where to build new power plants in Alberta. These include resource availability, the state of technology development, relative generation costs, environmental constraints, market structure, intertie capacity and the ability to finance projects in a competitive marketplace.

The amount of generation developed in the province is determined by market participants based on market signals. There is no adequacy reserve margin requirement defined by an authoritative body in Alberta. For the purpose of developing reasonable generation scenarios a 10 per cent effective reserve margin is used as a proxy for the amount of generation that will be developed in the province due to market signals. The term effective reserve margin is used to denote the effective capacity above peak load. The effective capacity is determined by taking the maximum continuous rating of generation and derating wind and hydro capacity. Wind and irrigation hydro are derated to 20 per cent of total capacity, legacy hydro is derated to 67 per cent of total capacity and new hydro is derated to 50 per cent of capacity. Wind is derated to a level that approximates the capacity of other generation technologies that will not be installed in the competitive market due to the addition of the wind generation. As an example, if 100 MW of wind capacity is added to the system it is assumed that 20 MW of other generation will not be built. The effective capacity attempts to capture the behavior of the market in making generation development decisions.

Based on this effective reserve margin and forecasted Alberta internal load, effective generation capacity in Alberta will increase from 11,500 MW today to 15,500 MW by 2017 and 20,700 MW by 2027. Taking generation retirements into account, this translates into the expectation that 5,000 MW of effective capacity will be added to the Alberta system by 2017 and 11,500 MW by 2027.

Given this amount of expected additions, information on potential generation resources and the relative costs of generation, five generation scenarios were created, as shown in Table 2.2-3. These scenarios represent a reasonable range of future expansion to comprehensively test the transmission system for planning purposes.

As a basis for developing the scenarios, it was assumed that within the next 10 years, significant generation additions are expected to be comprised of coal-fired plants, combined cycle gas units, simple cycle gas units, cogeneration units and wind power. This assumption stems from the commercial availability of the technologies and the long lead time for other existing technologies such as nuclear and large hydro.

Two different electricity futures were considered in the creation of the generation scenarios, a business-as-usual case (Scenarios A1 and A2) and an environmentally driven case (Scenarios B4 and B5). Each case has unique characteristics which increase the likelihood of a particular generation scenario developing in Alberta. These characteristics include greenhouse gas (GHG) emission constraints, technology development, future natural gas prices, oil sands development and other environmental constraints.

Table 2.2-3: Generation Scenarios for 2008-2017 (MW)

Scenario	A1	A2	A3	B4	B5
Coal	1,950	1,500	1,500	1,050	1,050
Cogeneration	1,760	2,260	1,760	1,760	1,760
Combined Cycle	90	90	720	1,230	1,230
Hydro (Installed)	100	100	100	100	100
(Effective)	50	50	50	50	50
Other Small Additions	100	100	100	100	100
Simple Cycle	800	800	620	620	430
Wind (Installed)	1,600	1,600	1,600	1,600	3,400
(Effective)	320	320	320	320	680
Total Effective Additions	**5,070**	**5,120**	**5,070**	**5,130**	**5,300**

In the business-as-usual case, generation development over the next 10 years continues in a manner similar to what has occurred in the past in Alberta. Large coal plants are added to the system with gas-fired, wind and other generation added as required to fill the supply gaps between the large additions. This case could occur under three possibilities:

1) GHG costs remain relatively low,
2) natural gas costs are high enough to offset the GHG costs for coal, or
3) clean coal technologies make significant advancements.

These possibilities allow for the continued development of Alberta's coal resource for power generation. Scenarios A1 and A2 would both be developed in this type of situation. In the first 10 years Scenarios A1 and A2 both include the addition of three large coal plants, cogeneration, simple cycle and wind. They differ in the fact that Scenario A1 includes the addition of a fourth large coal unit, whereas Scenario A2 includes the development of a gasification cogeneration plant near oil sands operations. The technology that will be applied in the development of the coal resources will depend on the maturity of the technologies and the associated costs at the time of construction.

In the environmentally driven cases, GHG costs are high enough that in the interim, as clean coal technologies continue to develop; minimal new coal-fired generation is developed in Alberta. Instead, gas-fired combined cycle and more wind generation are developed. Either Scenario B4 or B5 would be developed in this case. They both include additional combined cycle and wind generations in place of the coal plants included in Scenarios A1 and A2.

The one additional scenario, A3, represents a blend of the two electricity futures, falling in between business-as-usual and environmentally driven.

For the Hanna region study, Scenario B5 was used for the purpose of determining transmission reinforcement in the region as this scenario stresses the Hanna transmission system the most. This is mainly due to the concentration of generation in the southern portion of Alberta.

The coal additions in Scenario B5 include the Keephills 3 project and a number of project upgrades, accounting for 600 MW of coal additions. One additional 450 MW unit located in the northern part of the province is also included in Scenario B5.

The cogeneration capacity included in Scenario B5 is additions to support behind-the-fence load, with the bulk occurring within the oil sands industry in the northeast area of the province. The 1,760 MW of cogeneration capacity added exceeds growth in behind-the-fence load, by 500 MW.

Scenario B5 also includes the development of 1,230 MW of combined cycle generation prior to 2017. This combined cycle generation is assumed to be developed near Calgary based on project announcements made by ENMAX and TransCanada.

The hydro project included in the scenario represents the 100 MW Dunvegan project on the Peace River. The 100 MW of other small additions are included to capture the future development of biomass generation and other small projects, such as solar, micro generation, and geothermal developments.

The characteristics of simple cycle generation allow it to provide peaking capability in Alberta's base load heavy generation mix to manage the load and supply fluctuations. Scenario B5 includes 430 MW of additional simple cycle generation.

Large amounts of wind generation are planned for the province. Scenario B5 includes the addition of 3,400 MW of wind capacity to the system by 2017. Including the existing capacity of 497 MW, this will amount to 3,900 MW of wind generation in Alberta by 2017. The amount of wind added to the system over the next 10 years is assumed to be determined by market factors, and not transmission or market policy. The factors affecting wind generation additions are assumed to be the pace at which the wind farms can be constructed, the economic viability of the projects as the amount of wind on the system increases, and the ability of the system to integrate variable wind generation. The additions of wind generation were proportionally split throughout the province based on the wind applications in the AESO's interconnection queue as of February 2008, with 80 per cent being developed in southern Alberta and the remaining 20 per cent developing in central Alberta. This leads to Scenario B5 forecasting the addition of approximately 700 MW of wind generation in the central region by 2017, of this, 175 MW is forecasted to be installed by 2012. In this study, AESO assumed all wind generation in the central region would develop in the Hanna region.

Additional information on the development of the generation scenarios is available in Appendices E, F and G of the 2009 AESO Long-Term Transmission System Plan[7].

2.2.3 Existing and Proposed Generation in the Hanna Region

Table 2.2-4 summarizes the existing coal and proposed wind generations in the Hanna region.

There are two coal-fired generating plants in the Hanna region. Battle River has three generating units and Sheerness has two generating units. All of these units produce power at their respective Supply Transmission Service (STS) contract levels most of the time. The AESO has received applications from the owners of Battle River Unit #5 and Sheerness Units 1 and 2 to increase STS levels which are currently under review. The new STS levels of these units, though not yet approved, are assumed in the 2012 and 2017 case models.

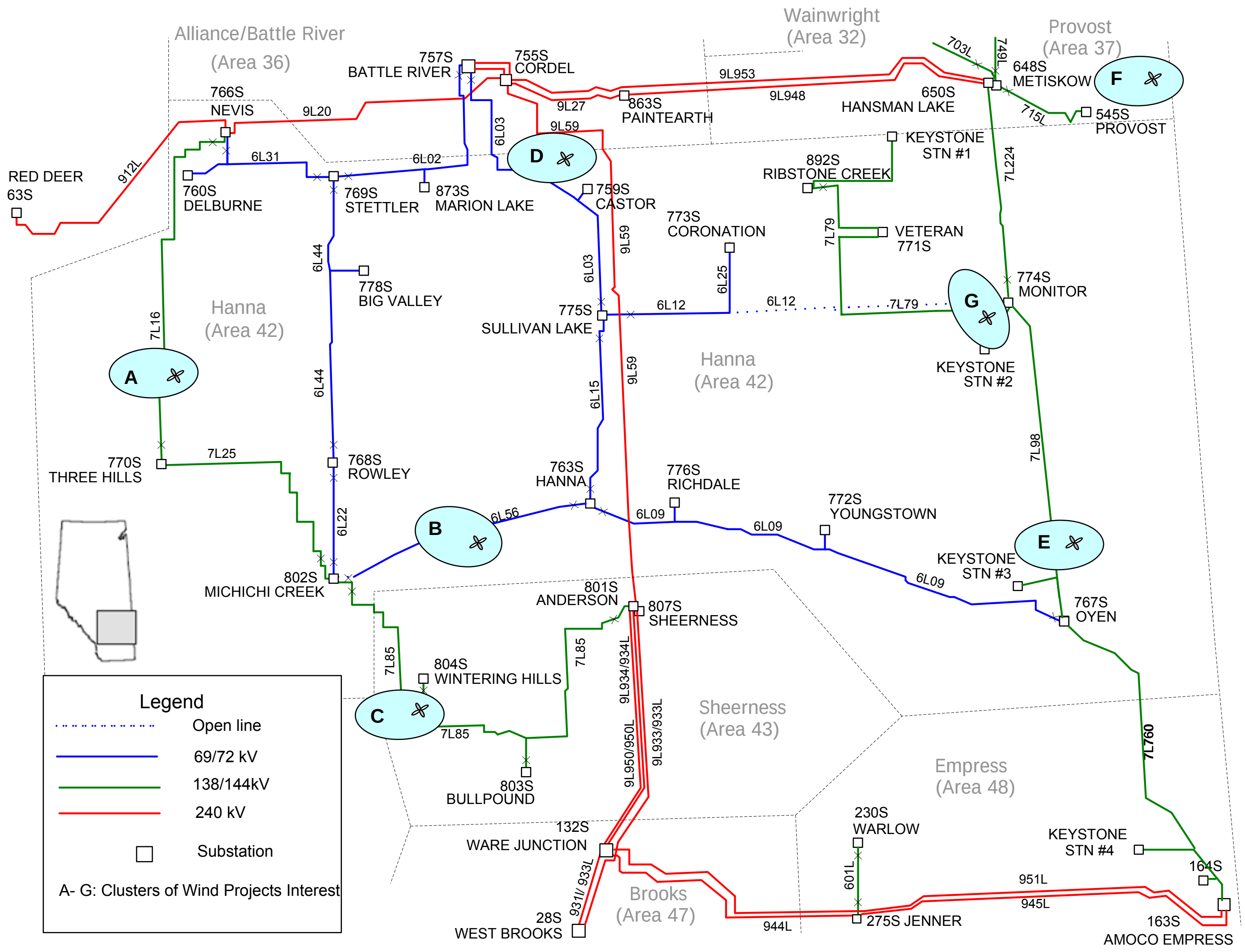
As of the beginning of 2009, the AESO received nineteen system access applications from wind developers in the Hanna region, for a total wind generation capacity of 2283.5 MW by 2017. Figure 2.2-2 shows the location of wind interest in the Hanna region as clusters A to G.

[7] The 2009 AESO Long-Term Transmission System Plan can be found on the AESO website at: http://www.aeso.ca/downloads/AESO_LTTSP_Final_July_2009.pdf

Table 2.2-4: Hanna Region Generation Summary

Name	Location	Requested in-service date	Capacity (STS) 2008/2012 (MW)	
Existing			**Existing**	**Proposed**
Battle River Unit #3	Battle River area	Existing	147	
Battle River Unit #4	Battle River area	Existing	147	
Battle River Unit #5	Battle River area	Existing	367	378
Sheerness Unit #1	Sheerness area	Existing	378	390
Sheerness Unit #2	Sheerness area	Existing	378	390
Total existing generation			**1,417**	**1,452**
Group 1 - Wind Projects with Executed Customer Commit Agreements				
Wind Farm Project 518	NW of Three Hills 770S (Cluster A)	Q4 2010	81	
Group 2 - Wind Projects with System Access Applications				
Wind Farm Project 634	Wintering Hills (Cluster C)	Pending	99	
Wind Farm Project 635	Hand Hills (Cluster B)	Pending	79.5	
Wind Farm Project 678	Hand Hills (Cluster B)	Q4 2009	80	
Wind Farm Project 718	Wintering Hills (Cluster C)	Q3 2010	150	
Wind Farm Project 723	West of 9L59 near Castor (Cluster D)	Q3 2010	150	
Wind Farm Project 753	Hand Hills (Cluster B)	Pending	130	
Wind Farm Project 759	Hand Hills (Cluster B)	Q1 2010	102	
Wind Farm Project 763	Near Monitor (Cluster E)	Q4 2010	200	
Wind Farm Project 764	Hand Hills (Cluster B)	Q4 2010	150	
Wind Farm Project 789	East of Provost (Cluster F)	Q4 2010	130	
Wind Farm Project 796	Hand Hills (Cluster B)	Q4 2010	150	
Wind Farm Project 798	Near Monitor (Cluster G)	Q4 2010	120	
Wind Farm Project 805	West of 9L59 near Castor (Cluster D)	Q3 2012	150	
Wind Farm Project 845	NW of Wintering Hills (Cluster C)	Q1 2010	102	
Wind Farm Project 847	Hand Hills (Cluster B)	Q2 2010	60	
Wind Farm Project 875	Near Monitor (Cluster G)	Q4 2012	100	
Wind Farm Project 876	Hand Hills (Cluster B)	Q4 2012	100	
Wind Farm Project 935	North of Monitor (Cluster G)	Q1 2013	150	
Total proposed wind generation			**2,283.5**	
Total existing and proposed generation			**3,700.5**	**3,735.5**

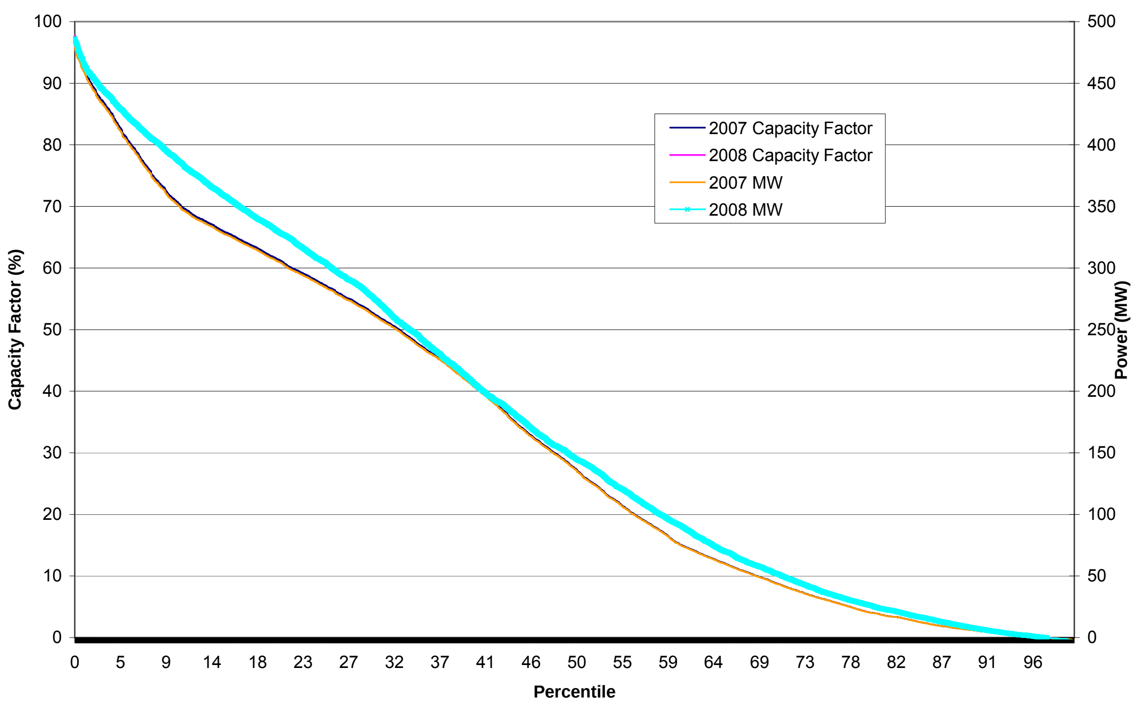
Figure 2.2-2: Potential Wind Power Generation Facilities in Hanna Region



In terms of the characteristic of the existing wind generation, Figure 2.2-3 provides both the wind power production (MW) and the aggregate hourly capacity factor (%) for the existing wind generation in Alberta. It is produced using Energy Management System (EMS) data for the years 2007 and 2008. The total maximum continuous rating (MCR) of these wind farms is 497.3 MW.

The data indicates that the total wind generation output varies from 0% to 98% of the total MCR and has an average annual capacity factor of about 35%.

Figure 2.2-3: Installed Wind Generation Duration Curve and Capacity Factor



The power output from wind projects can vary from zero to their rated capacity in a relatively short period of time. The wind farms cannot be dispatched like conventional units. Since the fuel cost of wind power is zero, they are known to be price takers and when wind blows, they are included in the merit order dispatch. Recognizing the random nature of generation availability from wind, the AESO plans the system under two extreme scenarios: without wind and with wind at its peak (all wind farms generate at their rated installed capacity). The Hanna region plan is based on the above extreme scenarios and thus, the transmission plan will be able to meet all other intermediate wind operating conditions.

3 Need Analysis for Transmission in the Hanna Region

An assessment of the existing system was undertaken to determine the need for system upgrades to accommodate expected load growth and wind integration in the Hanna region. Several voltage and thermal violations were identified for certain contingency conditions.

3.1 Existing System Analysis

In 2009, the Hanna region transmission system experiences low voltages at several locations in the Hanna and Battle River areas under a number of Category B contingencies and is susceptible to voltage collapse under certain critical contingencies. The 144 kV system in the western part of the Hanna area (from Nevis 766S to Three Hills 770S to Michichi Creek 802S and to Anderson 801S via Wintering Hills 804S and Bullpound 803S) is at capacity and several contingencies cause thermal overloads in this part of the system. The system also experiences a shortage of available transformation capacity in the Wainwright, Provost and west Hanna areas (240/144 kV).

By 2012, as the region is subject to significant forecast load growth, the low voltage profile problem becomes more severe. The Hanna region system will not satisfy the Reliability Criteria even with all facilities in service. The system will be prone to voltage collapse under several contingencies due to lack of reactive power sources and transmission capacities. The system also develops new overloading problems on 144 kV and 72 kV lines in the west Hanna transmission system.

Analysis of the 2012 winter peak condition with the integration of approximately 175 MW of wind generation indicates that a number of transmission system elements are projected to be loaded to near their limits, with several transmission elements being overloaded under normal operating conditions. Most of the contingencies will also result in a number of overloads across all transmission voltage levels in several locations.

Analysis of the 2012 summer peak condition for the same level of wind integration shows that almost the same overloads exist as well, though less severe. In addition, voltage violations in the Hanna area are observed under both normal operating conditions and under contingency conditions.

Due to the lack of reactive power compensation in 2012, the transmission system will experience voltage collapse for several critical contingencies.

It is not feasible to connect 175 MW of wind generation reliably by 2012 without reinforcements to the regional grid. This study did not investigate the application of interim measures such as Special Protection Schemes (SPS) in order to allow wind projects to precede transmission system reinforcements.

In summary, the existing transmission facilities in the Hanna region will not meet the Reliability Criteria. Transmission reinforcements are therefore required in the region to meet projected load growth and the interconnection of proposed wind generation.

Appendix A contains the power flow diagrams of the existing system analysis for both load adequacy and wind integration studies.

3.2 Transfer Out Capability Assessment

The purpose of the transfer out analysis is to identify the levels of wind generation capacity within the Hanna region that can be delivered to the loads outside the Hanna region via the 240 kV lines that connect Hanna area with the bulk system. Siemens MUST Version 9 software was used to perform the transfer out analysis.

The transfer out analysis was based on the following assumptions:

- The 2009, 2012, and 2017 Summer Light and Winter Peak cases;
- The existing Sheerness and Battle River generation is fully dispatched prior to any additional transfer;
- The generation source is wind generator located in the Hanna region;
- Wabamun area generation was assumed to be the sink location. When Hanna area wind generation is increased, a similar amount of generation in the Wabamun area is reduced to keep the system in balance;
- All the AIES facilities were monitored; and
- Category B contingencies for the entire AIES bulk system were examined.

During summer light conditions, the Hanna region generation exceeds its load and the balance will be transferred out of the Hanna region to the bulk system via three 240 kV lines which are 912L from Red Deer 63S to Nevis 766S, 9L933/933L from Anderson 801S to West Brooks 28S and 931L from Ware Junction 132S to West Brooks 28S. The available transfer capability during summer light condition is lower than that during winter peak conditions and thus summer light condition was selected as the limiting condition for determining the Hanna region transfer out capacity.

The transfer analysis carried out for the recommended system indicates that: under the proposed Generation Scenario B5, the three proposed alternatives are adequate to integrate at about 500 MW of wind generation by 2012 and 700 MW by 2017. The results of the transfer out analysis for the summer light and winter peak load conditions are presented in Appendix B.

4 Hanna Region Transmission Alternatives

There are several potential options that can be considered in combination to fully address the transmission development requirements in the Hanna region. The broad categories of options include:

i. New transmission lines:
   - 765 kV and 500 kV AC(Alternating Current);
   - High Voltage Direct Current (HVDC) Classic (overhead);
   - HVDC Voltage Source Control VSC (underground);
   - 240 kV AC; and
   - 144 kV AC.

ii. Upgrades to existing transmission lines:

iii. Reactive power support:
   - Switched capacitors; and
   - Dynamic reactive power resources such as Static VAr Compensator (SVC); and

iv. Operational measures.

The following sections discuss the potential applicability of the above options for the Hanna region transmission development.

4.1 New AC Transmission Lines

Power systems around the globe use a variety of transmission technology options to meet their needs. These include Extra High Voltage 765 kV, 500 kV AC & HVDC technologies in addition to 240 kV and 138/144 kV voltage levels. In Alberta, both 500 kV AC and HVDC technologies are being considered as potential options for development of the bulk system.

4.1.1 765 kV, 500 kV AC and HVDC technologies

The 765 kV, 500 kV AC and HVDC technologies are well suited to situations where large quantities of power (above 1000 MW) need to be transported over long distances (400 km or longer). Both the amount of power transfers and the transmission distances in the Hanna region are far below the aforementioned typical parameters, and therefore, these technologies are not suitable for the Hanna region transmission plan and were not pursued further.

4.1.2 240 kV and 144 kV AC options

The transmission system in the Hanna region mainly consists of 240 kV 144 kV AC transmission lines. Therefore, these voltages form a prudent choice for new transmission system in this area because they meet the forecasted load and generation projections. When considering new transmission lines, single-circuit as well as double circuit designs were explored as potential options for the area.

4.2 Upgrades to Existing Transmission Lines

This option is feasible for transmission lines which presently have low ratings with relatively small conductor size. Increasing the size of the conductors can increase the power carrying capability of the line without needing new rights-of-way. This can be achieved at a relatively lower cost than building a new transmission line and will be considered when the incremental increase in the capacity of the line is adequate.

4.3 Reactive Power Support

Addition of reactive power sources (e.g. capacitor banks and static VAr compensators) were considered to address voltage magnitude and stability concerns. The extensive use of large induction motors for pumping loads in eastern Hanna requires significant amount of reactive power support to these loads during contingency events. Switched shunt capacitors and dynamic VAr sources, such as SVC, present potential options to provide reactive power support in the Hanna region.

4.4 Operational Measures

Operational measures do not present an option where there is a clear violation of the Reliability Criteria. These operational measures are interim and would be considered until the transmission system is reinforced in the area. Use of operational measures, however, may be considered for maintenance-related thermal overload, or voltage drop concerns, where the risk can be addressed by existing SPS.

5 Development of Transmission Alternatives

The following sections identify possible alternative solutions that can be considered to address each of the constraints identified in Section 3. This section provides alternatives to address the system performance issues identified and aims to:

- Create a system that will meet load supply adequacy requirements up to and beyond 2017 and
- Provide adequate capacity for integrating up to 700 MW of wind generation in the Hanna region by 2017.

The following sections provide the alternative development study results for meeting load requirements and integration of wind generation.

In order to provide adequate transmission for wind generation in the Hand Hills and Wintering Hills areas, it is proposed to build a new 240 kV 963S substation at Coyote Lake and connect it to Oakland 946S via two new 240 kV 9L29/9L31 lines. In addition, another 240 kV line from Ware Junction 132S to West Brooks 28S is required to transport Hanna wind generation to the load centre. The details are discussed further in the Wind Power Integration Requirements in Section 5.5. This proposed development for wind generation is common to all three alternatives and hence is not repeated in the discussion of alternatives.

5.1 Load Supply Adequacy Requirements

In order to supply the Hanna region's forecast load growth, a number of alternatives were considered and subsequently narrowed to three transmission reinforcement alternatives. In addition to these three alternatives, there are two additional system reinforcement plans required for the load supply adequacy which are common to all three alternatives. There is one in the Hardisty area and one in the West Hanna area. As well, there is a need for reactive power support that is also common to all three alternatives. The first part of this section explains the system reinforcement in the Hardisty and West Hanna areas and the reactive power support. The subsequent three sections present the three proposed alternatives, applicable specifically in the east Hanna area.

5.1.1 Hardisty Area System Reinforcement

As per the *AESO's Future Demand and Energy Outlook (2007-2027),* the Wainwright area's load has been projected to grow at an average annual growth rate of 14% from 2008 to 2017. Presently the majority of transmission lines in this area are rated at 138 kV. Due to the load growth, the existing area 138 kV transmission system will be unable to supply the increased load. The existing area transmission system lacks both transmission/transformation capacity and VAr support. A new 240 kV source substation is required to support the Hardisty area forecasted load. Because the Hardisty area is known as the “oil hub” for pipelines and becomes the pumping stations’ load centre, a 240 kV substation close to Tucuman 478S is considered to be a preferred location for this new substation. The proposed 240/138 kV substation is named as Nilrem 574S.

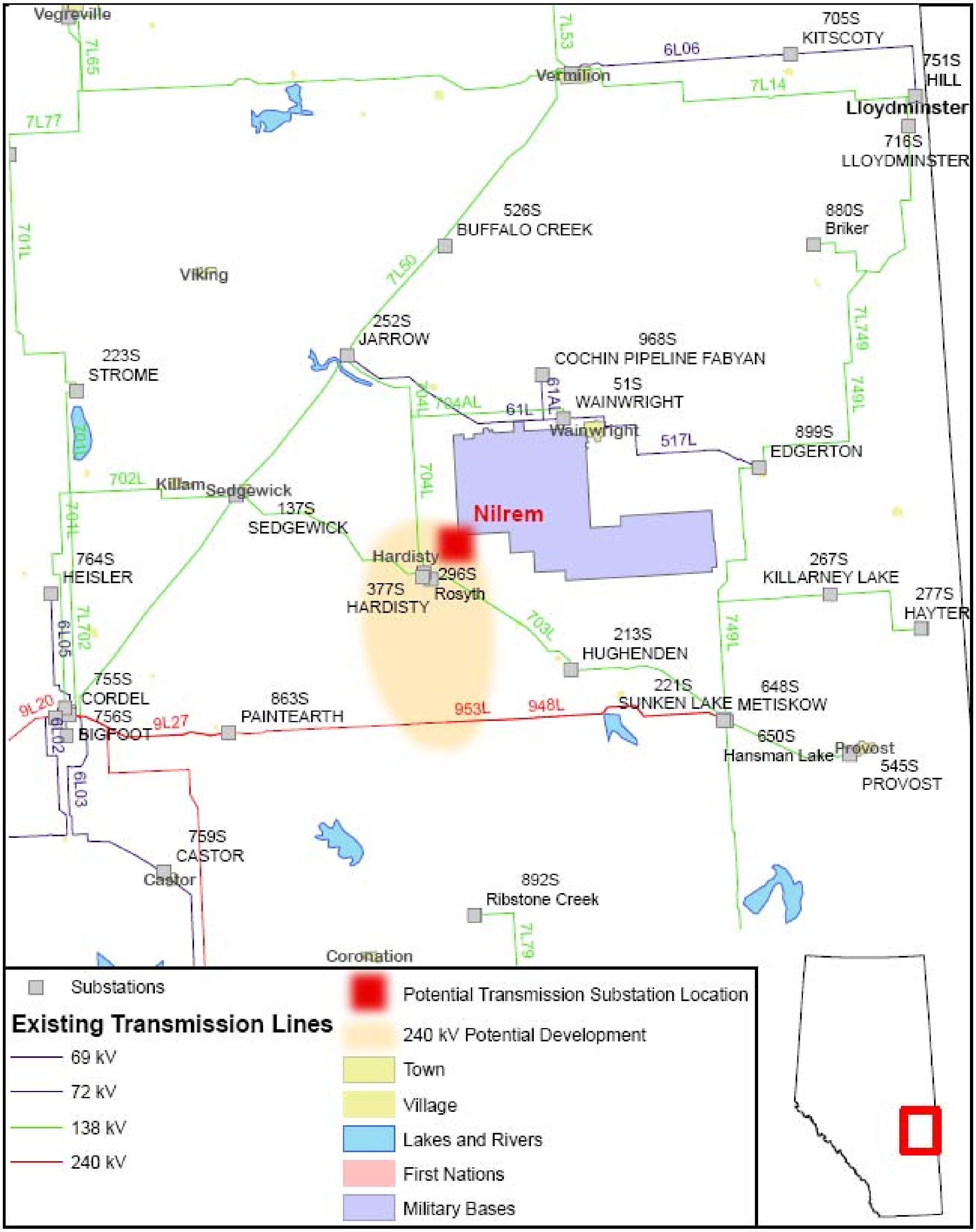
The existing 240 kV substations and lines in the area are as follows:

- 240 kV substations: Cordel 755S, Hansman Lake 650S and Metiskow 648S and
- 240 kV lines: 9L953/953L, 9L27 and 9L948/948L.

The direct distances from Tucuman 478S to Cordel 755S or Hansman Lake 650S are approximately 60 to 70 km. However, the distance from Tucuman to the existing 240 kV line 9L953/953L or 9L948/948L is approximately 30 km. Therefore it is economical and practical to connect the proposed Nilrem 574S to the 240 kV line nearby, rather than to the distant 240 kV substations. Because Paintearth Creek 863S has already been connected to 9L948/948L from Cordel 755S to Hansman Lake 650S, the only available 240 kV line is 9L953/953L. Hence the connection of Nilrem 574S to 240 kV 9L953/953L via an in-and-out scheme with a double circuit 240 kV line is the most economic option.

The detailed recommended reinforcement plan for the Hardisty area system is presented in Appendix C. Figure 5.1-1 presents the area for the Hardisty reinforcement.

Figure 5.1-1: Hardisty Area System Reinforcement



5.1.2 West Hanna Area System Reinforcement

The existing west Hanna area contains both 144 kV and 72 kV systems which supply local loads. The 144 kV system has two supply sources, namely 240/144 kV transformers at Nevis 766S and Anderson 801S. Loss of one of these two 240/144 kV transformers will cause overloads on the other one. Therefore an additional 144 kV source is required to supply the forecast load.

The local 72 kV system is supplied by four 144/72 kV system transformers, which are located at Battle River 757S, Nevis 766S, Michichi Creek 802S and Oyen 767S. Similar to the 144 kV system, the 72 kV system is constrained due to the 72 kV system load growth. Loss of Battle River 144/72 kV transformer will cause voltage collapse on the 72 kV system.

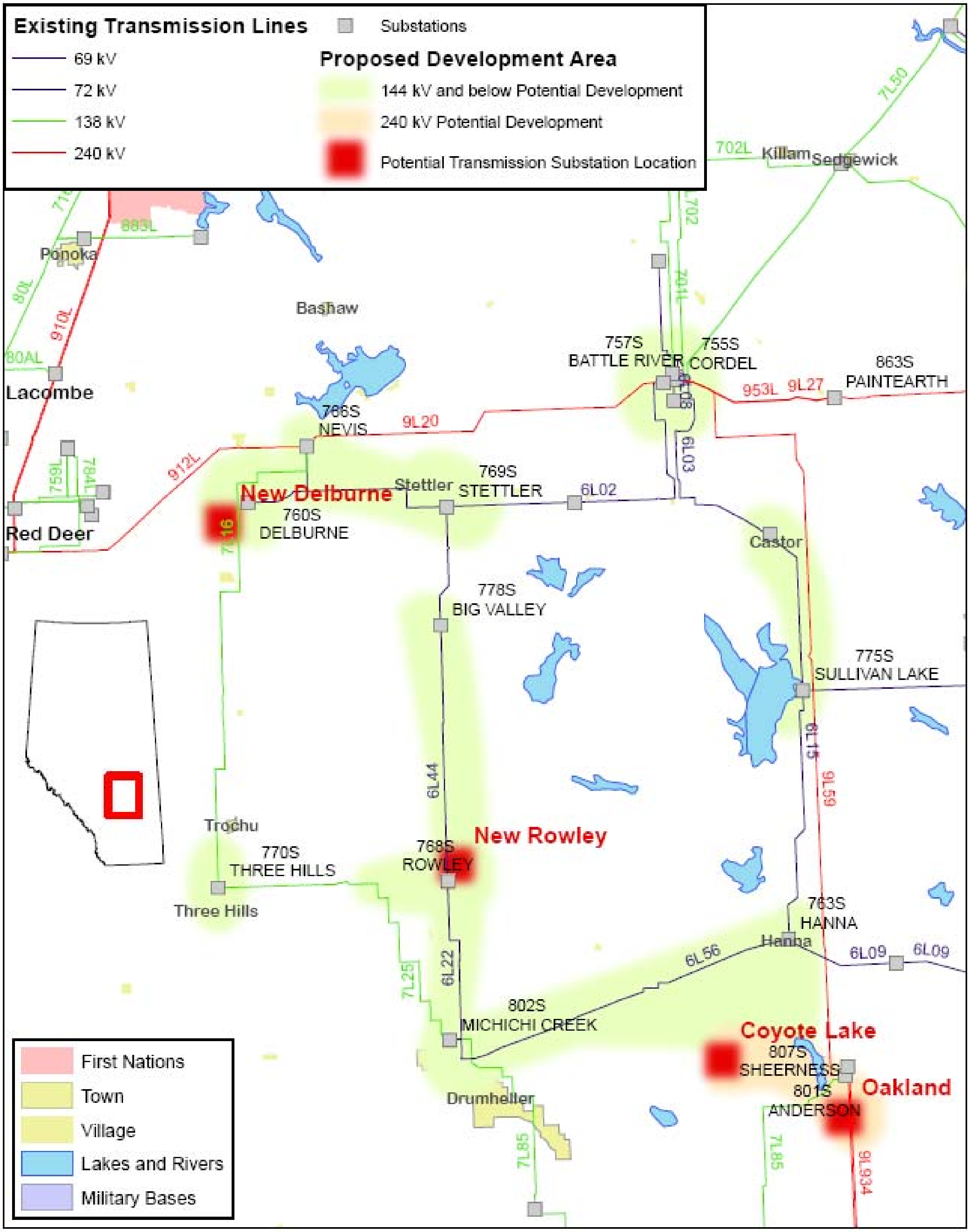
In order to address the above issues, the following is recommended:

- Convert the existing 72 kV Stettler, Delburne and Rowley substations into 144 kV substations;
- Connect the new Delburne and new Rowley substations via in-and-out schemes to 7L16 and 7L25 respectively; and
- Build a 144 kV line from Nevis to the new Stettler substation.

In order to meet the additional load from the 72 kV system, a new 144 kV source is required in the area. Hence a new 144 kV source is proposed at the wind collector Coyote Lake 963S. A new 144 kV line will be built from Coyote Lake 963S to Michichi Creek 802S in 2012 and another one from Coyote Lake 963S to Hanna 763S in 2017.

Figure 5.1-2 presents the area of development for the west Hanna system reinforcement.

Figure 5.1-2: West Hanna Reinforcement



5.1.3 Reactive Power Support in East Hanna Area

As indicated in the load forecast section, the major load additions in the region are concentrated in Wainwright, Provost and Hanna areas. Virtually all these are pipeline pumping motor loads. The dynamic model for the motor was developed based on customer supplied motor performance data. The detailed dynamic performance of these large induction motors was carried out using the PSS/E 'CIM5BL' induction motor model. Based on the study results, local dynamic VAr compensation is required at the eastern Hanna area to maintain local and system stability after critical N-1 contingencies. This reactive power support is required regardless of which alternative is selected. Three SVCs are proposed at:

- Hansman Lake 650S (+/- 200 MVAr)
- Pemukan 932S (+/- 200 MVAr)
- Lanfine 959S (+/- 200 MVAr)

The SVCs are required to fulfill two functions:

- Maintain acceptable voltage levels in the eastern Hanna region during normal operation by absorbing/delivering VArs required; and
- Deliver a substantial amount of dynamic reactive power after critical fault conditions to supply increased reactive demand from the induction motors that drive the pumping loads. This support is needed to avoid short term voltage instability caused by lack of dynamic VAr in the immediate area.

The sizes of the SVCs recommended in this application are adequate to maintain voltage under steady state and dynamic conditions. However, the final sizes will be determined through technical studies during the facility application stage.

5.2 Alternative 1: Double 240 kV AC Looped system in Hanna Area

The load growth in the Hanna region is expected to occur in the Wainwright and Provost areas and also along the existing east 138/144 kV transmission corridor from the Provost to Empress area. This load growth is mainly due to the construction of new pipelines that start from Hardisty and run through the eastern part of Hanna area.

Presently, loads in the Wainwright and Provost areas are largely supplied by two 240/138 kV transformers, one at Hansman Lake 650S and the other at Metiskow 648S with the associated area 138/144 kV transmission lines through these two transformers.

The existing single 138/144 kV transmission lines from Hansman Lake 650S to Monitor 774S to Empress 163S were built using 266.8 kcmil ACSR and hence rated at about 109 MVA in summer at 138 kV. The expected pump stations along this line will increase the load to approximately 153 MW by the summer of 2012. The existing single 138/144 kV transmission line cannot supply this load.

The Hanna area needs new transmission lines and transformation capacities, upgrading the existing 144 kV lines will not suffice. Therefore one solution is to build new 240 kV transmission lines from the generation source to the load area. In the Hanna region, the generation sources are coal fired plants at Sheerness and Battle River with a combined generation capacity of approximately 1500 MW. There are two 240 kV lines from Battle River to the Hansman Lake and Metiskow area. The Sheerness plant is located approximately 90 km south of Battle River plant in the Sheerness area. It is connected to the Hanna region load centre through 240 kV 9L59 line from Anderson to Cordel 755S. Even though there are two other 240 kV lines that run south from Anderson 801S to Ware Junction 132S and then to the Empress area, they do not provide strong enough support to Hanna area load due to the weak connection between the Empress and Hanna areas. As such, there is no existing direct or strong connection from Sheerness generation to the Hanna area load centre.

In order to supply growing load in both the Wainwright and Provost areas as well as in the east 138/144 kV transmission corridor, Alternative 1 proposes two new 240 kV loops in the Hanna area, as explained in Sections 5.2.1 and 5.2.2. With the addition of these two 240 kV transmission loops, the system will meet the Reliability Criteria under Category B events since at least one loop will be available to serve the area load. This is because in the remaining loop, there will still be two direct 240 kV supplies from the generation source to the load centre. This helps to maintain sufficient transmission capacity and provides voltage support capability as well.

This study assumed a 0.9 lagging power factor for the pipeline loads which are expected to be large induction motors. Such inductive loads demand significant VAr support to maintain proper voltages and voltage stability during system disturbances.

Alternative 1 would be developed in two stages, the first stage by 2012 and the second one by 2017. Most of the aforementioned facilities except for Clement 988S and the associated 240 kV lines, 9L06 and 9L14 will be constructed by 2012. It should be noted that Alternatives 1 and 3 are identical after completion of Stage I. The sections below describe the facilities of each stage of Alternative 1, further details can be found in Appendix C.

5.2.1 Alternative 1: 2012 Development

The proposed 240 kV lines consist of:

- 240 kV line from Hansman Lake 650S to Pemukan 932S

- 240 kV line from Pemukan 932S to Lanfine 959S
- 240 kV line from Lanfine 959S to Oakland 946S

These proposed lines, along with the existing 240 kV lines form an outer loop (Oakland-Cordel-Hansman Lake-Pemukan-Lanfine-Oakland).

A single 240/144 kV transformer would be added at Pemukan 932S and Lanfine 959S. The 144 kV line 7L98 between Monitor 774S and Oyen 767S would be opened to alleviate the 240/144 kV parallel flow issue. Any tapped load on 7L98 would be supplied radially.

In Alternative 1, Oyen area loads are supplied from two sources. One source is the 240/144 kV transformer at Lanfine 959S and the other one is the 138/144 kV 7L760/760L from Empress 163S. Monitor area loads, including all the substations on 144 kV 7L79 would also be supplied from two sources. That is, one source from the 240/144 kV transformer at Pemukan 932S and the other one from the 138/144 kV 7L224 from Hansman Lake 650S.

Figure 5.2-1 shows the development for Alternative 1 in 2012.

5.2.2 Alternative 1: 2017 Development

The proposed 240 kV lines consist of:

- 240 kV line from Clement 988S to Oakland 946S
- 240 kV line from Clement 988S to Pemukan 932S

These proposed lines, along with the existing 240 kV lines form two inner loops (Oakland-Clement-Pemukan-Lanfine-Oakland and Clement-Cordel-Hansman Lake-Pemukan-Clement).

An additional 240/144 kV transformer would be added at both Pemukan 932S, Lanfine 959S and Hansman Lake 650S substations. With these new transformers, both Oyen and Monitor areas will have two sources from the 240 kV system. Meanwhile, due to load increase in the area the parallel flow issue will become significant on both 7L224 and 7L760. As such, the existing 138/144 kV 7L760 and 7L224 would be opened in 2017 to alleviate the parallel flows on the 144 kV lines when one of the parallel 240 kV line is out of service. The tapped-off loads on these two lines would be supplied radially from Hansman Lake 650S or Empress 163S substation.

Figure 5.2-2 shows the development for Alternative 1 in 2017.

Figure 5.2-1: Hanna Region Transmission System Development Alternative 1 – 2012

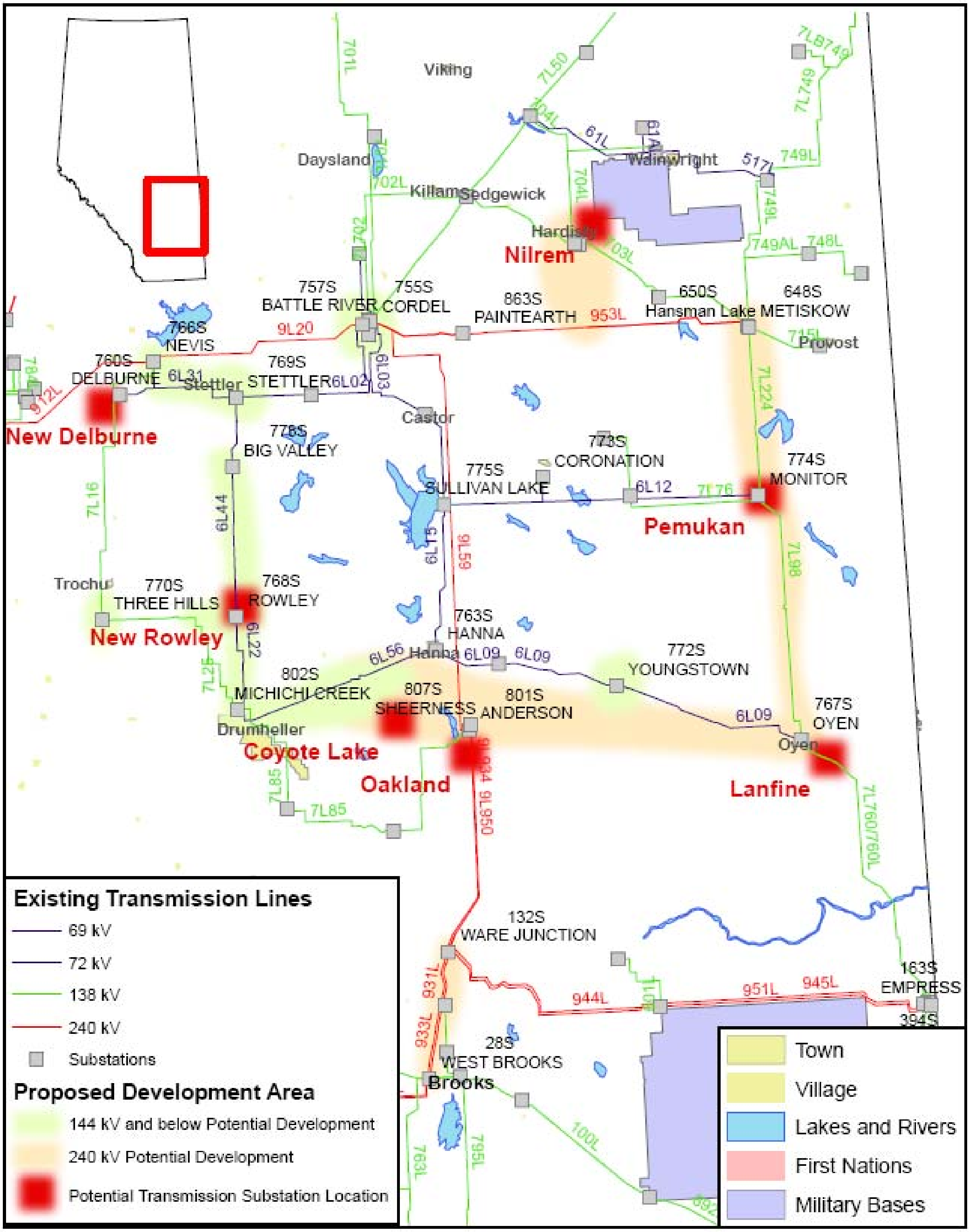
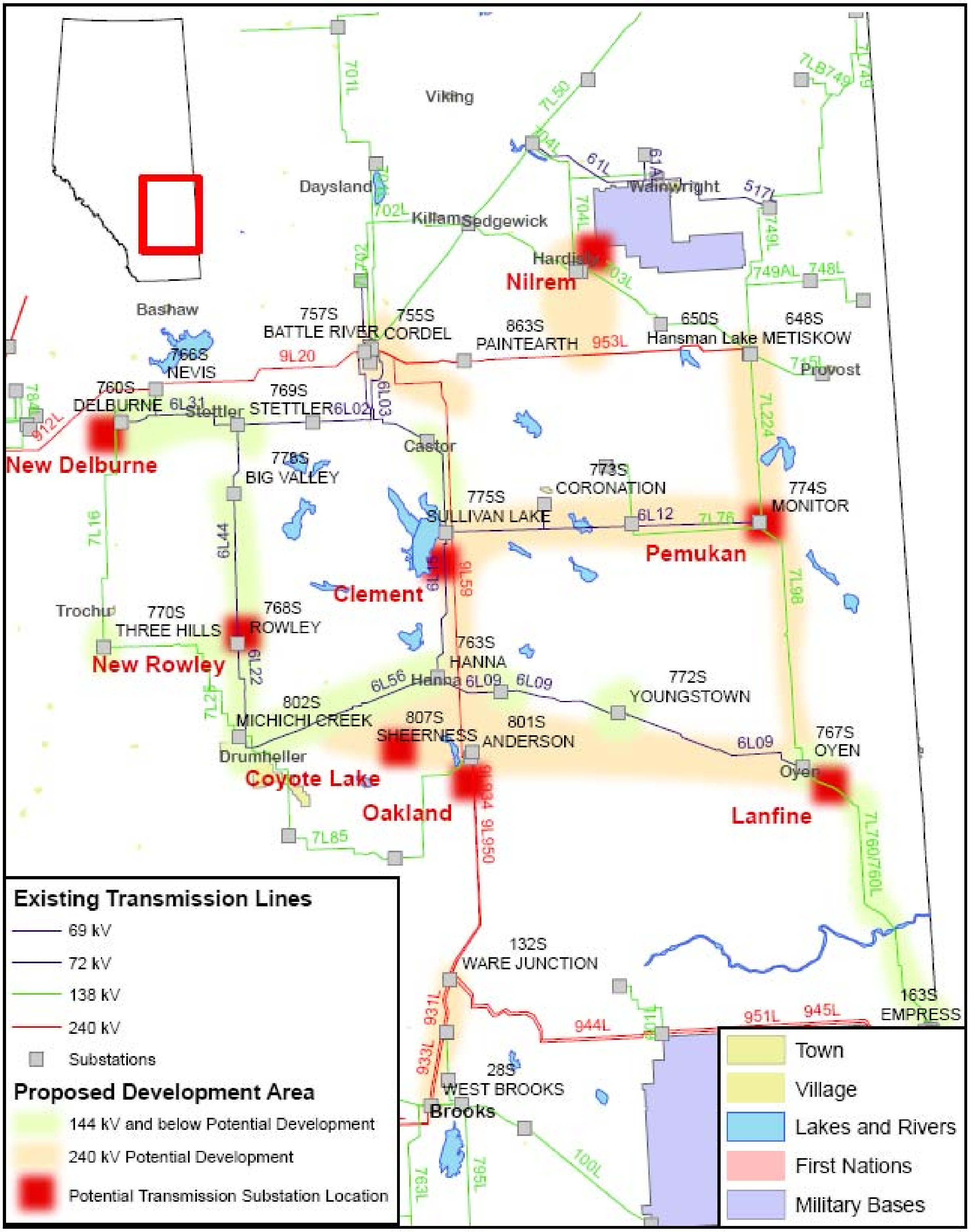


Figure 5.2-2: Hanna Region Transmission System Development Alternative 1 – 2017



5.3 Alternative 2: Single Reinforced 240 kV AC Loop in Hanna Area

A new 240 kV Clement 988S substation would be created in the Sullivan Lake area. One 240 kV double circuit line would be built from Clement 988S to Oakland 946S and another double circuit line would be built from Clement 988S to Pemukan 932S in the east. This forms a reinforced 240 kV loop from Clement 988S to Pemukan 932S to Hansman Lake 650S to Cordel 755S and back to Clement 988S. The double circuit line from Clement 988S to Pemukan 932S would provide a reliable supply source from Sheerness generation to the east Hanna area load. At the same time, the two existing 240 kV lines from Cordel 755S to Hansman Lake 650S and Metiskow 648S provide the strong connection from the Battle River generation source to the Wainwright and Provost area loads.

Furthermore, Alternative 2 also provides a strong connection between the two generation sources at Battle River and Sheerness. In this configuration, with potential future 240 kV development from Clement 988S to Cordel 755S, a central Hanna 240 kV transmission corridor can be created. Any major generation addition in Battle River area can be transferred to the south.

In Alternative 2, the Oyen area will only have one 240 kV source in 2017, compared to two sources in Alternative 1. The existing 144 kV 7L98 would be the second source for the Oyen area load. This would save the cost of one 240/144 kV transformer at Oyen in 2017.

One of the main differences between Alternatives 1 and 2 is that no line is required between Oakland 946S and Lanfine 959S. Instead, the new 240 kV lines from Oakland 946S to Clement 988S and from Clement 988S to Pemukan 932S would serve a similar purpose as the single line in Alternative 1. Alternative 2 thus requires fewer transmission right-of-ways compared to Alternative 1.

Like Alternative 1, Alternative 2 will also be developed in two stages. The double circuit 240 kV lines will be single side strung in 2012. In 2017, the 240 kV line from Oakland 946S to Clement 988S and the 240 kV line from Clement 988S to Pemukan 932S will be double circuit with second side strung. The sections below describe the facilities of each stage of Alternative 2, further details can be found in Appendix C.

5.3.1 Alternative 2: 2012 Development

The proposed 240 kV line consists of:

- 240 kV line from Hansman Lake 650S to Pemukan 932S
- 240 kV line from Pemukan 932S to Lanfine 959S
- 240 kV line from Pemukan 932S to Clement 988S
- 240 kV line from Clement 988S to Oakland 946S

These proposed lines, along with the existing 240 kV lines form a loop (Oakland-Clement-Pemukan-Lanfine-Oakland).

Only a single 240/144 kV transformer will be installed at Pemukan 932S and Lanfine 959S. The 144 kV 7L760/760L between Oyen 767S and Empress 163S would be opened to eliminate the 240/144 kV parallel flow issue. The tapped loads on 7L760/760L would be served radially from Empress 163S.

In Alternative 2, Oyen area loads would be supplied from two sources, one from the 240/144 kV transformer at Lanfine 959S and other one from the 144 kV line 7L98. In order to increase the service reliability of 144 kV 7L98, the north terminal of 7L98 would be relocated from Monitor 774S to Pemukan 932S. Monitor area loads, including all the substations on 144 kV 7L79 would also be supplied from two sources, one from the 240/144 kV transformer at Pemukan 932S and the other from the 138/144 kV 7L224 from Hansman Lake 650S.

Figure 5.3-1 shows the development for Alternative 2 in 2012.

5.3.2 2017 Development

The proposed 240 kV line consists of:

- 240 kV line from Hansman Lake 650S to Pemukan 932S
- 240 kV line from Pemukan 932S to Lanfine 959S

Both the 240 kV lines from Oakland 946S to Clement 988S and from Clement 988S to Pemukan 932S would be converted to double circuit by stringing the second line on these towers. An additional 240/144 kV transformer would be added at Pemukan 932S and Hansman Lake 650S. With the second 240/144 kV transformer at Pemukan 932S, loss of the 240 kV line exacerbates the parallel flow issue on 138/144 kV 7L224 from Hansman Lake 650S to Monitor 774S. To mitigate this parallel flow, the existing 138/144 kV 7L760 would be opened in 2017. The tapped-off loads on this line would be supplied radially from Hansman Lake 650S. Oyen area load would still be supplied by one Lanfine 959S 240/144 kV transformer and 144 kV 7L98 from Pemukan 932S.

Figure 5.3-2 shows the development for Alternative 2 in 2017.

Figure 5.3-1: Hanna Region Transmission System Development Alternative 2 – 2012

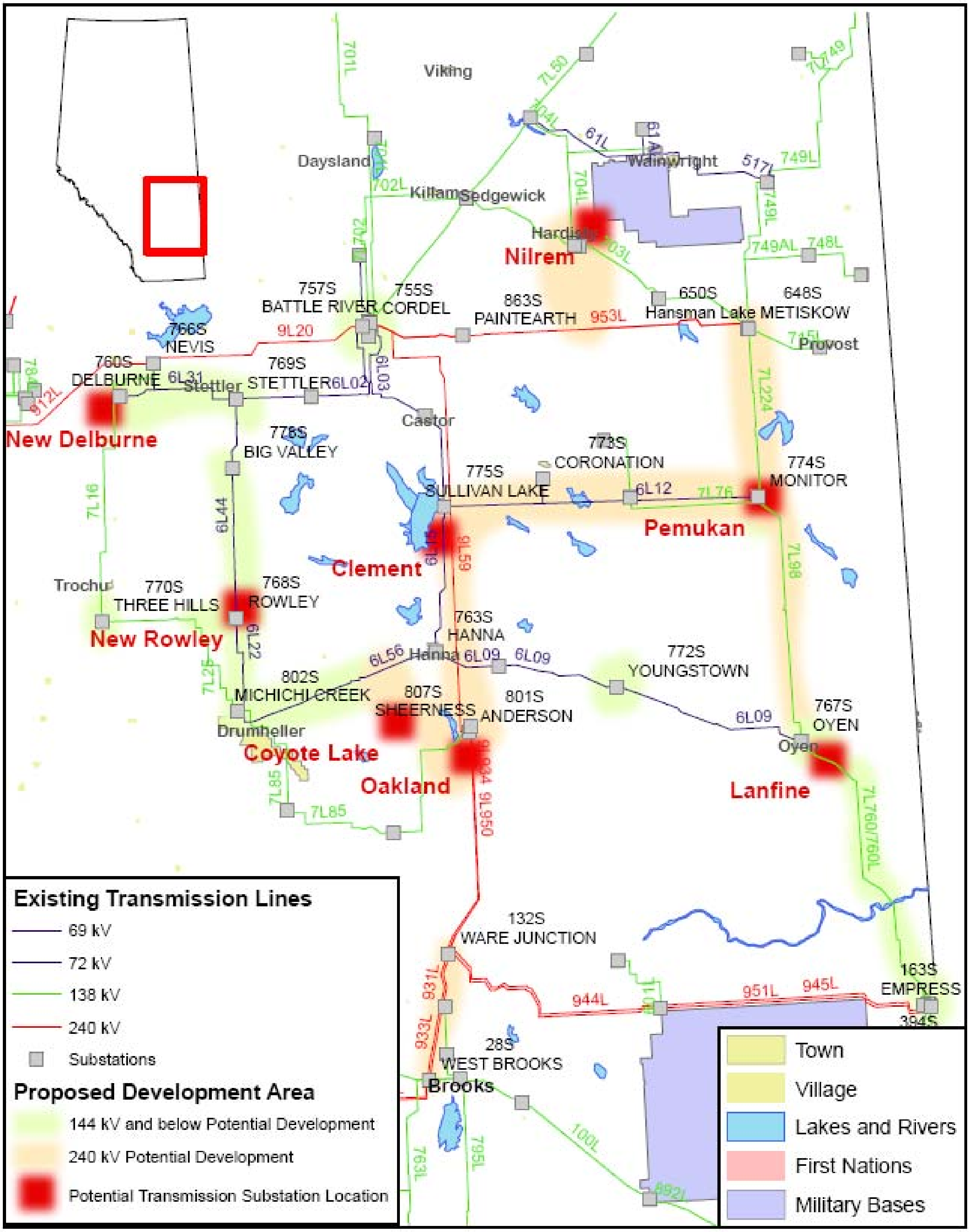
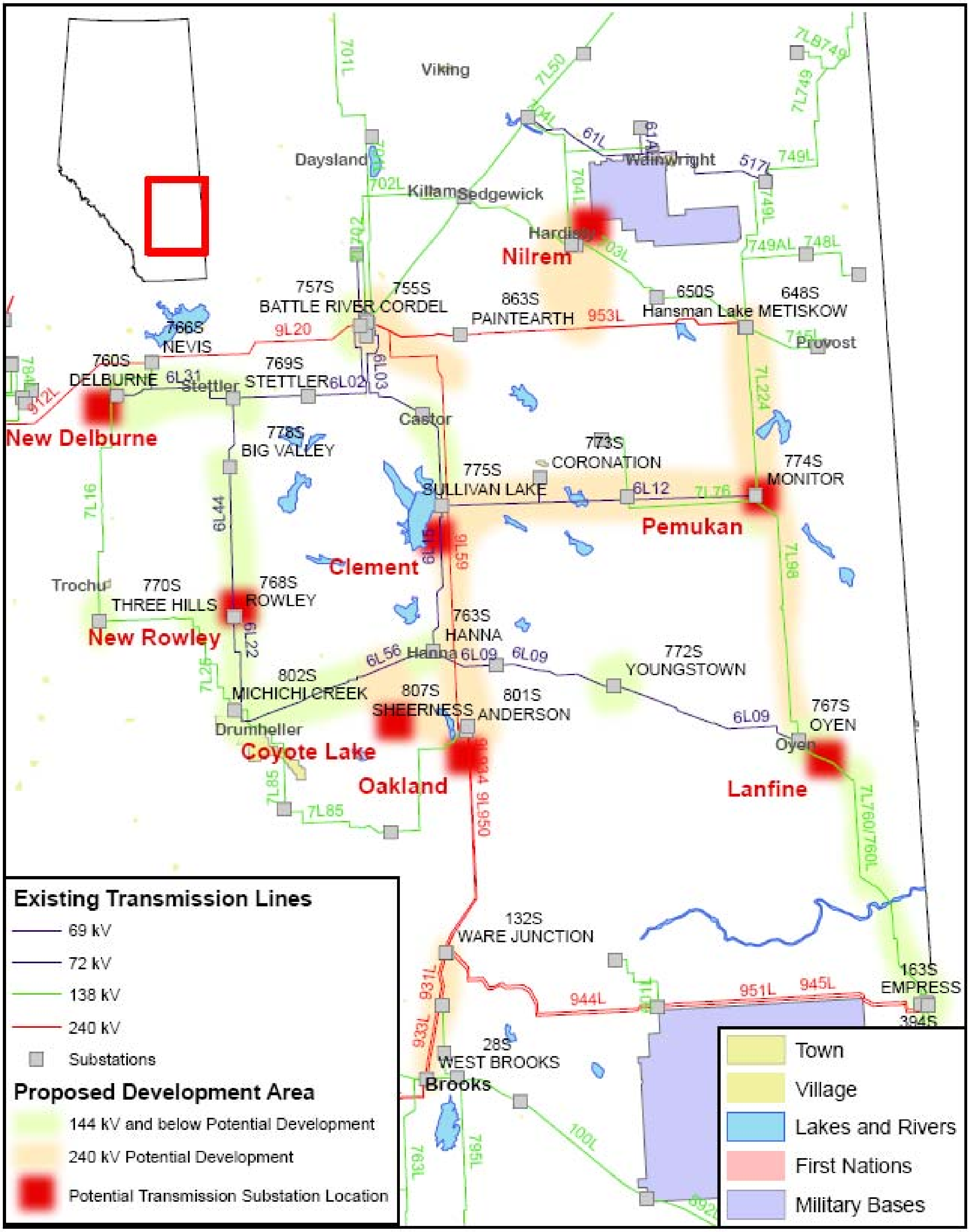


Figure 5.3-2: Hanna Region Transmission System Development Alternative 2 – 2017



5.4 Alternative 3: Single Extended 240 kV AC loop in Hanna area

Alternative 3 introduced a single large 240 kV loop in the Hanna region that includes all the load centres from Metiskow to Oyen in the south east. This alternative contains a minimal number of substations and 240 kV lines while meeting the load supply requirements. This large 240 kV transmission loop would run from Oakland 946S in the south to Lanfine 959S in the east and then to Pemukan 932S to Hansman Lake 650S to Cordel 755S to Anderson 801S and back to Oakland 946S.

This alternative is bound by two 240 kV lines from Cordel 755S to Hansman Lake 650S in the north which connect the Battle River area generation directly to Wainwright and Provost area loads. While in the south, a double circuit line from Oakland 946S to Lanfine 959S connects Sheerness area generation directly to east Hanna area loads. Thus this loop provides direct supply paths from generation sources to load centres in the Hanna area.

Due to the introduction of this large 240 kV transmission loop in the Hanna region, all the original 144 kV transmission lines in the eastern corridor would be opened to avoid potential 240/144 kV parallel flow issues in the region. Similar to Alternatives 1 and 2, the 144 kV 7L98 would be opened in 2012. The existing tapped-off load on 7L98, which is Excel 910S, would be supplied radially from the south, as it is closer to the south substation than the north substation. In order to improve the service reliability, the south terminal of 7L98 would be relocated from Oyen 767S to Lanfine 959S. The 138/144 kV lines, namely 7L224 and 7L760/760L would be opened to avoid 240/138 kV parallel flow issues in 2017. Consequently, existing loads on 7L224 and 7L760/760L would be supplied radially from Hansman Lake 650S and Empress 163S in 2017.

Similar to the other alternatives, Alternative 3 transmission facilities will be developed in two stages. The sections below describe the facilities of each stage of Alternative 3, further details can be found in Appendix C.

5.4.1 Alternative 3: 2012 Development

The 240 kV line from Oakland 946S to Lanfine 959S would be single side strung in 2012 and the second side would be strung in 2017. As noted earlier in the description of Alternative 1, Alternative 3 and Alternative 1 are identical in 2012.

Only a single 240/144 kV transformer would be added at Pemukan 932S and Lanfine 959S substations. The 144 kV 7L98 between Monitor 774S and Oyen 767S would be opened to eliminate the 240/144 kV parallel flow issue. Any tapped-off load on 7L98 would be supplied radially.

Oyen area loads would be supplied from two sources, one from the 240/144 kV transformer at Lanfine 959S and the other one from the 138/144 kV 7L760/760L from Empress 163S. Monitor area loads, including all the substations on 144 kV line 7L79 would also be supplied from two sources, one from the 240/144 kV transformer at Pemukan 932S and the other from the 138/144 kV 7L224 line from Hansman Lake 650S. Alternative 3 development in 2012 is the same as that of Alternative 1 and is replicated in Figure 5.4-1.

5.4.2 Alternative 3: 2017 Development

Additional 240/144 kV transformers would be added at Pemukan 932S, Lanfine 959S and Hansman Lake 650S substations. With these new transformers, both Oyen and Monitor areas would have two sources of supply from 240 kV systems. Meanwhile, due to load increase in the area, the parallel flows on both 7L224 and 7L760/760L will pose significant problems when the parallel 240 kV line is out of service. Therefore, the existing 138/144 kV 7L760 and 7L224 would be opened to alleviate this overload issue. The tapped-off loads on these two lines will be supplied radially from Hansman Lake 650S or Empress 163S. Figure 5.4-2 shows the development for Alternative 3 in 2017.

Figure 5.4-1: Hanna Region Transmission System Development Alternative 3 – 2012

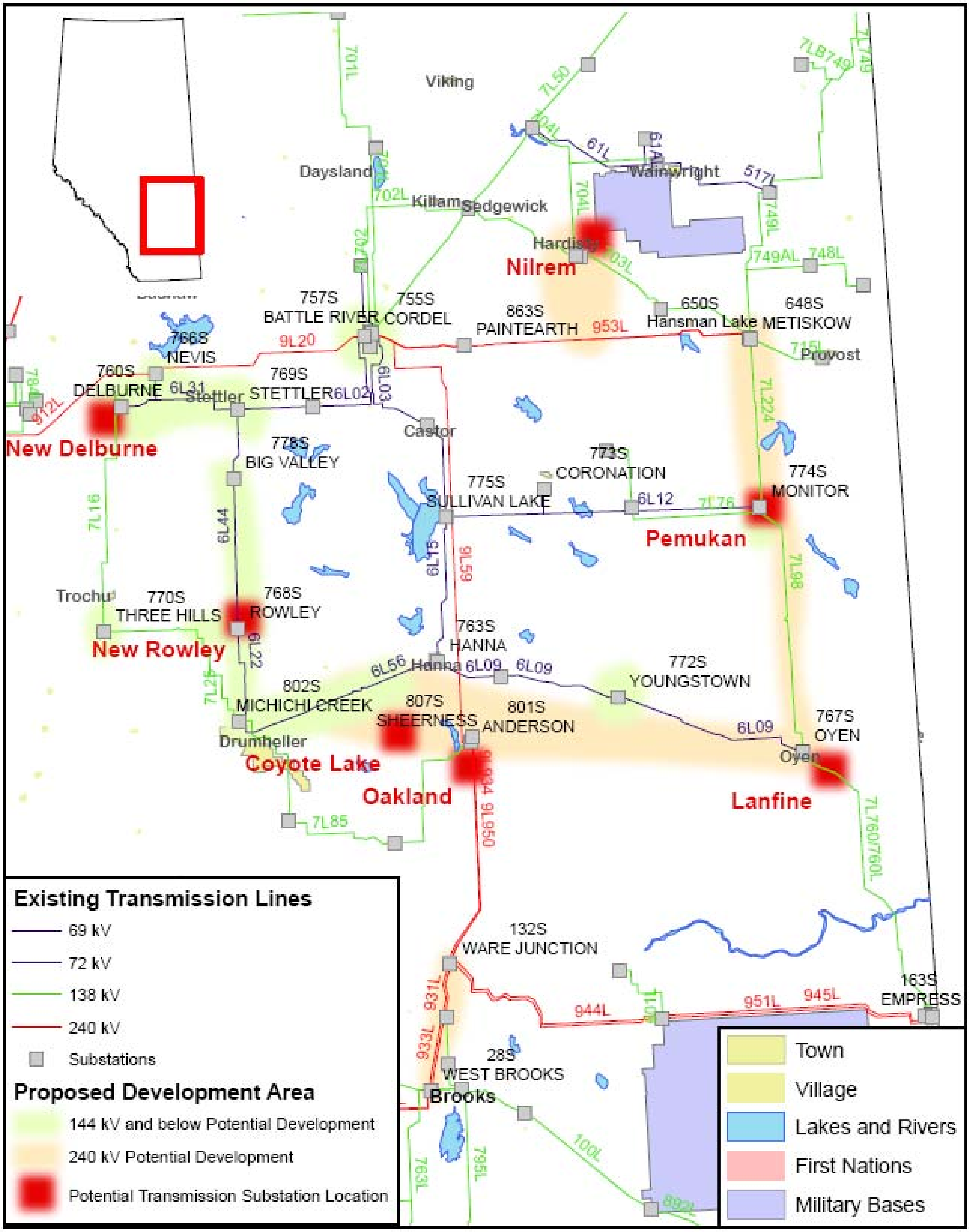
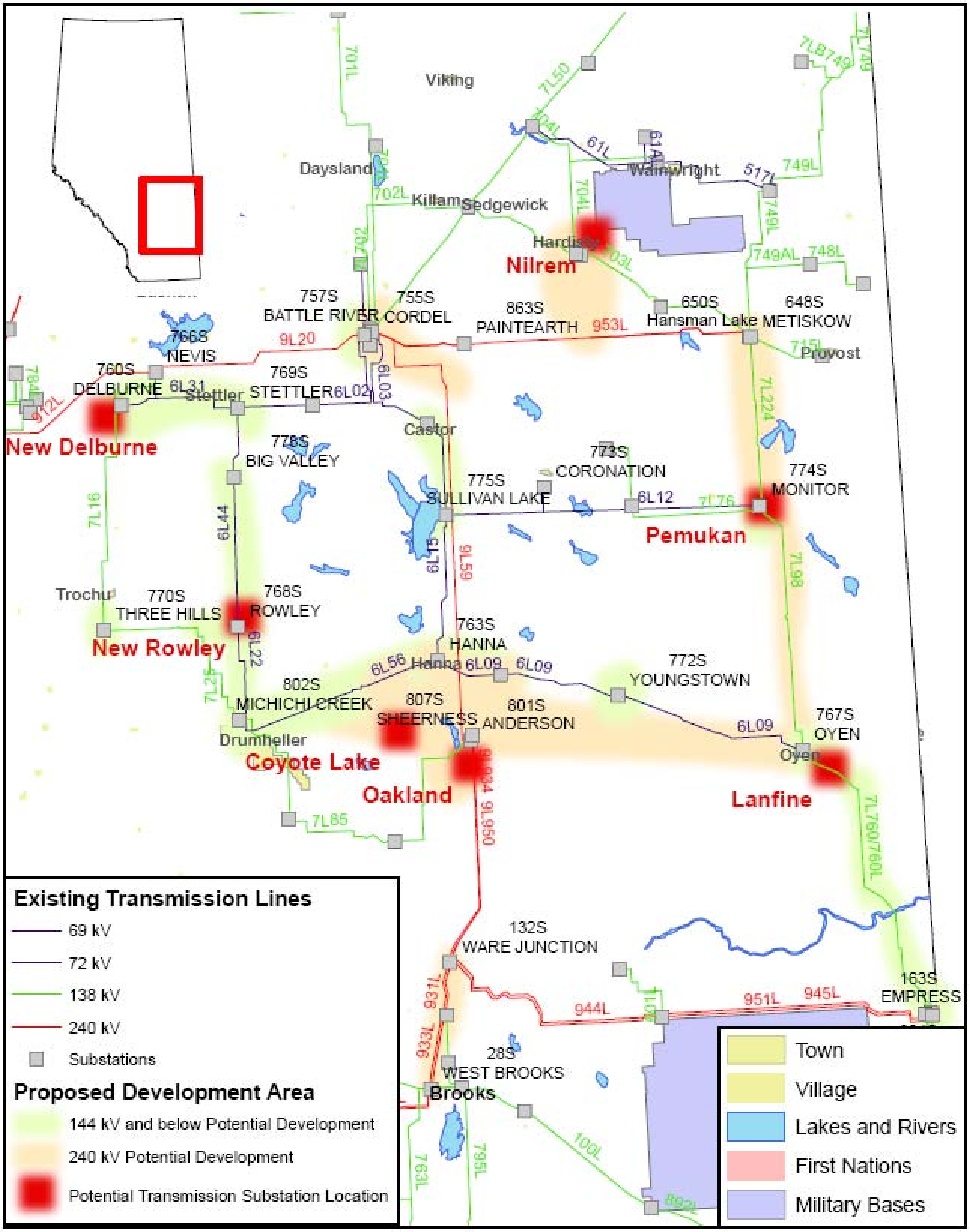


Figure 5.4-2: Hanna Region Transmission System Development Alternative 3 – 2017



5.5 Wind Power Integration Requirements

The previous sections discussed the development of alternatives to meet the forecast load. This section discusses the incremental transmission requirements to integrate wind generation in the Hanna region.

It can be seen in Figure 2.2-2 and Table 2.2-4 that there is significant interest in wind development in the Hand Hills and Wintering Hills areas. However, the existing transmission facilities are insufficient to accommodate the projected wind generation in these areas.

The following transmission requirements are proposed by 2012 to facilitate integration of wind projects in these areas:

- A new 240 kV collector substation Coyote Lake 963S; and
- A new 240 kV line 9L29 from Coyote Lake 963S to the bulk system via Oakland 946S.
- New 240 kV line (Ware Junction 132S - West Brooks 28S). This line will strengthen the capability of the south corridor from Anderson 801S to Ware Junction 132S to West Brooks 28S. In addition to increasing the Available Transfer Capability out of Hanna area, it will help strengthen the system dynamic stability by providing an extra path between Sheerness generation and the bulk system. This will provide extra security for sheerness generation against severe contingency events.
- 240 kV line between Halkirk switching station and Cordel 755S. This line will be required to avoid potential overload on the 9L59 section between Halkirk and Cordel which may appear under 2017 peak loading conditions when Battle River Unit #5 is out of service.
- When the total installed wind capacity in the Hand Hills and Wintering Hills areas exceeds the capacity of the largest generating unit in the AIES, a second side will need to be strung on the 240 kV line from Oakland to Coyote Lake. From a reliability perspective, this avoids creating a larger equivalent generating unit in the AIES. It also provides the transmission capacity to accommodate more generation to be connected to Coyote Lake substation.

6 Evaluation of Transmission Alternatives

Alternatives 1, 2, and 3 were evaluated based on technical, economic, land impact and social factors. Power flow analysis was completed for all alternatives to evaluate their ability to serve high load growth and integrate 700 MW of wind generation in the Hanna region. Transient stability, reactive power margin and short circuit analysis were performed only for Alternative 3.

6.1 Model Development

6.1.1 Bulk System Assumptions

In order to conduct technical studies and evaluate alternatives, it is necessary to consider the transmission development in Alberta outside of the local study region. The following assumptions include upgrades or additions that are expected to be in place by 2012 on Alberta's bulk system:

- 240 kV line from Brintnell to Wesley Creek;
- New 1x 240 kV line to the Thickwood substation;
- New Cache Creek Substation located between the Ruth Lake and Kinosis substations;
- 240 kV line from the Thickwood substation to Cache Creek;
- 240 kV 600 MVA phase shifting transformer at Keephills;
- 946L/947L with 1 x 240 kV from Ellerslie to Clover Bar and 1 x 240 kV line from Ellerslie to East Edmonton;
- 240 kV double circuit line from Ellerslie to the new Eastwood substation;
- Edmonton Region 240 kV line upgrades[8];
- New 2 x 477 kcmil 240 kV lines from Keephills to new 904L-908L-909L confluence point;
- 908L (Ellerslie-Sundance) re-termination from its existing location at Sundance to the new 904L-908L-909L confluence point;
- Swap the connections of 904L (Jasper-Wabamun) and 908L at the confluence point so that the 904L termination at Wabamun can be moved to Sundance; and
- New 240 kV 600 MVA phase shifting transformer located at the new Livock substation and on 9L57 (Livock-Dover) and the new 240 kV line to the Fort McMurray 240 kV substation.

The following assumptions include upgrades or additions that are expected to be in place by 2017 on the bulk system:

[8] The Edmonton Region 240 kV Line Upgrade NID can be found on the AESO website: http://www.aeso.ca/transmission/17452.html

- 500 kV, 2000 MW, Bipole HVDC line from Genesee to Langdon with associated static VAr compensators (SVC), and
- 500 kV, 2000 MW, Bipole HVDC line from new Heartland 500 kV substation to the existing 240 kV West Brooks with associated SVCs.
- 500 kV Heartland substation; and
- 500 kV Thickwood substation.
- 500 kV AC from Ellerslie to Thickwood via Heartland;
- 500 kV AC from Ellerslie to Heartland; and
- 240 kV Southern Alberta Transmission Reinforcement - Looped System.

6.1.2 Southern Alberta System Assumptions

The following assumptions include upgrades or additions that are expected to be in place by 2012 in the southern Alberta system:

- Replace the existing 240 kV 911L (Janet 74S to Peigan 59S) by Calgary South-Peigan 240 kV double circuit line with 50% series compensation;
- New 200 MVAr SVC at Peigan substation;
- Milo Junction upgrade to Switching Station to tie in 924L, 927L, 923L and 933L;
- New 120 MVA Phase Shifting Transformer on 170L Coleman to Natal;
- New 240 kV substation Sub D close to the Burdette substation;
- New 240/138 kV Medicine Hat 2 substation;
- Sub D-Medicine Hat 2 240 kV double circuit line;
- New 240 kV double circuit line from West Brooks to the new Sub D substation;
- New 100 MVAr SVC at new Sub D substation; and
- Medicine Hat 138 kV changes/upgrades.

The following assumptions include upgrades or additions that are expected to be in place by 2017 in the southern Alberta system:

- 500 kV Crowsnest substation located on the existing 500 kV 1201L with two 500/240 kV 1200 MVA transformers and one 240 kV 400 MVAr SVC;
- 240 kV double circuit line from Crowsnest to Goose Lake;
- 240 kV single circuit line from Goose Lake to Sub C;
- 240 kV single circuit line from Sub C to MATL substation; and
- 240 kV single circuit line from Sub C to Sub D.

6.1.3 Intertie flow assumptions

There are two major interties from Alberta, one to British Columbia (B.C.) in the southwest and the other to Saskatchewan (SK) in the east. Based on historical Alberta-B.C. intertie load flow, considering Generation Scenario B5 with full dispatch of southern wind, this intertie is set at the low export level

(200 MW) from Alberta to B.C. for the peak cases. For the Summer Light case, due to the large amount of wind in the south system, the Alberta-B.C. intertie is set at a high export level (750 MW). The Alberta-SK intertie is a back-to-back DC system and is set at 0 MW for all cases.

6.1.4 Conductor Sizes

In developing the model data for each alternative, different conductor types were compared to determine the suitable size of conductor for the transmission plans. The two conductor types studied for 240 kV alternatives were the twin bundle 477 kcmil ACSR (Hawk), and twin bundle 795 kcmil ACSR (Drake). Table 6.1-1 below shows the thermal ratings and line parameters for each conductor for a single circuit.

Table 6.1-1: Conductor Parameters

Conductor Type	Impedance (pu/km)		Admittance (pu/km)	Summer Rating	Winter Rating
	R	X	B	MVA	
240 kV Twin-bundle 477 kcmil ACSR (Hawk) – Single Circuit	0.000104	0.000628	0.002628	600	744
240 kV Twin-bundle 795 kcmil ACSR (Drake) – Single Circuit	0.000063	0.000611	0.002704	874	1103

Given the possibility that more than 700 MW of wind generation could materialize beyond 2017, and with the expected increase in load in the Hanna region, the 600 MVA rating of the 477 kcmil ACSR conductors was considered to be a limiting factor for future growth. The twin bundle 795 kcmil ACSR is proposed for most of the new 240 kV lines.

6.1.5 Wind Interconnection Assumptions

By 2012, 175 MW of wind generation is projected to be developed in the Hanna region and increases to approximately 700 MW by 2017. Additional information on the wind forecast was presented in Section 2.2.3. The exact location of the wind generation that will come online in the next ten years cannot be predicted accurately at this time. The location of wind additions which stresses the system the most is when the wind develops in the western Hanna area since loads are concentrated in the eastern Hanna region. This assumption was used in the technical analysis.

6.2 Power Flow Analysis

Power flow analysis for each alternative was completed for the 2012 and 2017 scenarios. The following scenarios were created for Alternatives 1, 2, and 3:

- 2012 Winter Peak Load
- 2012 Summer Peak Load
- 2012 Summer Light Load
- 2017 Winter Peak Load
- 2017 Summer Peak Load
- 2017 Summer Light Load

6.2.1 Power Flow Results for 2012

Power Flow Analysis: 2012 Load Supply Adequacy

Both Category A and B contingency events were simulated for each alternative for the 2012 winter peak and summer peak load conditions.

Battle River Unit #5 is the critical generating unit in the area for the load supply adequacy study, as it is the largest generator close to the Hanna region load centre. When Battle River Unit #5 is out of service, the 240 kV loop in Hanna area transfers approximately 430 MW of power from the Sheerness power plant to the Hanna region loads, which are in the Wainwright and Provost areas and along the east Hanna transmission corridor from Hansman Lake 650S to Oyen 767S. Since wind generation in the south system is dispatched at its maximum output, the power transferred from the Sheerness plant to the south is at a relatively low level. The three 240 kV lines connecting Anderson 801S to the south (9L934/934L, 9L950/950L (801S-132S), and 9L933/933L (801S-28S)) are loaded between 80 to 90 MW to south in 2012. The 240 kV 912L (766S-63S) from Red Deer imports approximately 60 MW of power to partially compensate for the loss of Battle River Unit #5.

The simulation results reveal that all three 240 kV alternatives satisfy voltage range requirements without any thermal overloads for both Category A and B events. Thus, the proposed transmission development alternatives meet the Reliability Criteria for 2012 forecasted load as shown in Table 6.2-1.

Table 6.2-1: Power Flow Analysis Results – Load Supply Adequacy

Alternative	Thermal Loading Violations	Voltage Range Violations
Alternative 1	None	None
Alternative 2	None	None
Alternative 3	None	None

Power Flow Analysis: 2012 Integration of Hanna Wind Generation

The power flow analysis was repeated with the addition of approximately 175 MW of wind capacity in the Hanna region in 2012. Both Category A and B events were simulated for each alternative for the 2012 winter peak, summer peak and summer light load conditions.

The simulation results indicate the transmission system is free of both voltage range violations and facility thermal overloading issues under both Category A and B events for all the load scenarios as set out in Table 6.2-2.

Table 6.2-2: Power Flow Analysis Results – Integration of Hanna Wind Generation

Alternative	Thermal Loading Violations	Voltage Range Violations
Alternative 1	None	None
Alternative 2	None	None
Alternative 3	None	None

6.2.2 Power Flow Results for 2017

Power Flow Analysis: 2017 Load Supply Adequacy

The power flow analysis for 2017 was completed for each alternative. The same simulation was produced for the year 2017 by modeling the three alternatives in the study cases. Both Category A and B contingency events were simulated for each alternative for the 2017 winter peak and summer peak load conditions.

Battle River Unit #5 remains the critical generating unit in the area for the 2017 load supply adequacy study. Since wind generation in the south is modeled at its maximum output, the power transferred from Sheerness plant to the south is at a relatively low level. Three 240 kV lines that connect Anderson 801S to the south (9L934/934L, 9L950/950L (801S-132S), and 9L933/933L (801S-28S)) will be lightly loaded in 2017.

The system in 2017 is free of both voltage range violation and facility thermal overloading issues for both Category A and B events. The results indicate that these transmission development plans meet the Reliability Criteria under the 2017 forecast load as set out in Table 6.2-3 below.

Table 6.2-3: Power Flow Analysis Results – Load Supply Adequacy

Alternative	Thermal Loading Violations	Voltage Range Violations
Alternative 1	None	None
Alternative 2	None	None
Alternative 3	None	None

Power Flow Analysis: 2017 Integration of Hanna Wind Generation

Approximately 700 MW of wind capacity in the Hanna region was included in the 2017 system base cases in each of the three alternatives studied. Both Category A and B contingency events were simulated for each alternative for the 2017 winter peak, summer peak and summer light load conditions.

As noted previously, Battle River Unit #5 remains the critical generating unit in the summer peak power flow study with 700 MW of wind generation integration. When Battle River Unit #5 is out of service, the 240 kV loop in Hanna area transfers approximately 400 MW of power from the Sheerness plant to loads, mainly through the 240 kV line from Oakland 946S to Lanfine 959S along the east Hanna transmission corridor to Hansman Lake and to the Hardisty area. In order to transfer excess wind generation in Hanna and southern Alberta, east HVDC line is dispatched at 1200 MW from south to north. Three 240 kV lines that connect Anderson 801S (9L934/934L, 9L950/950L (801S-132S), and 9L933/933L (801S-28S)) will be loaded to about 200 MW each. In each of these alternatives, the system is free of voltage range violation and facility thermal overloading issues for both Category A and B events. Thus these alternatives meet the Reliability Criteria as shown in Table 6.2-4.

Table 6.2-4: Power Flow Analysis Results – Integration of Hanna Wind Generation

Alternative	Thermal Loading Violations	Voltage Range Violations
Alternative 1	None	None
Alternative 2	None	None
Alternative 3	None	None

6.2.3 System Performance under Category C and D Events

The system performance for the recommended plan was tested using power flow analysis for a variety of Category C and D events.

The power flow plots for category C and D for year 2012 and 2017 are presented in Appendix D. Tables D-2012-8 to Table D-2012-12 in Appendix D summarizes the system performance under various Category C and D events for 2012. Tables D-2017-8 to Table D-2017-14 summarizes the system performance under Category C and D events for 2017.

The overall performance of the planned system was found to be satisfactory and met the Reliability Criteria for all 2012 and 2017 cases. In some extreme contingency conditions, shedding of the load or tripping some generation were found to be necessary to alleviate overloads observed under these circumstances. This is accomplished in compliance with AESO and NERC reliability standards.

6.3 Reactive Power Margin Analysis

Voltage stability (P-V and V-Q) analyses were also carried out for Alternative 3 in order to calculate the reactive power margins available under Category B conditions as well as to ensure that the reactive power compensation recommended is adequate under normal and contingency conditions. The results of the analysis are included in Appendix D and show that Alternative 3 meets the AESO Voltage Stability Criteria.

6.4 Transient Stability Analysis Results

Given the nature of the generation and loads in the Hanna region, transient stability analysis was performed with the recommended plan in place. Three-phase–to-ground faults were simulated for Category B and selected Category C and D events throughout the Hanna region. This is to ensure that under Category C and D conditions, there are no uncontrolled or cascading outages in the system. Several Category C and D events were simulated in the Hanna region. The study used GE 1.5 MW wind turbine generator models for dynamic analysis.

Initial simulation which was carried out without the three SVCs at Hansman Lake 650S, Pemukan 932S, and Lanfine 959S showed that the system is prone to voltage instability caused by increased reactive power requirements by pumping motor loads following several Category B contingencies in the Hanna area. The implementation of sufficient resources which can supply dynamic VAr in eastern the Hanna region was proven a necessity to ensure system stability following system disturbances.

Category B fault analysis was performed on the recommended plan. Category B faults are defined as three-phase faults of a transmission line or transformer with normal fault clearing time. Transient simulation plots for Category B contingencies can be found in Appendix E for 2012 Winter Peak, Summer Light, 2017 Winter Peak and 2017 Summer Light load conditions. A summary of event descriptions and observations on the dynamic simulation outcomes is presented in Table E-1 and E-4 for Summer Light and Winter Peak conditions respectively. Figure E-1 displays the location of category B events studied.

Category C3 faults are defined as a category B event followed by manual system adjustment then followed by another category B event. This category is referred to as (N-1-1) contingency. Appendix E presents the simulation results of those combinations of Category C3 faults, which stress the system most. The loss of any one of 946L, 9L24, 9L59 and 9L53, will affect the dynamic reactive power supply to eastern Hanna area where large pump loads are assumed to be concentrated, the system will be prone to voltage instability if one of the above line outage is followed by another critical line outage. To make the system ready for the next contingency following the loss of any one of lines mentioned above, an Under Voltage Load Shedding (UVLS) scheme will be needed to maintain the stability of the system. Further studies are required to determine the exact design of the scheme.

Category C5 faults are defined as double line-to-ground faults of a double-circuited transmission tower with normal fault clearing time. Figures in Appendix E-2 show the locations where the Category C5 faults were applied to the system. The impedances of the double line–to-ground faults were calculated at the faulted locations on the system. Table E-2 and Table E-5 summarize the fault descriptions and results for the Category C5 fault analysis for Summer Light and Winter Peak respectively. Transient simulation plots for Category C5 contingencies can also be found in Appendix E.

Category C7 faults are defined as single line-to-ground faults of transmission lines with delayed clearing time (stuck breaker condition). Figures E-4 to E-13 show the locations where the Category C7 faults were applied at each substation. The stuck breaker conditions simulated are identified by breaker number labels in these Figures. Breakers without labels were not simulated for stuck breaker conditions. Tables E-2 and E-5 in Appendix E summarize the fault descriptions and results for the Category C7 fault at each substation for 2012 Summer Light and 2012 Winter Peak respectively. Transient simulation plots for Category C7 contingencies can also be found in Appendix E.

Category D events include all the extreme events that would result in simultaneous outage of two or more (multiple) elements. The following D events were simulated:

- D7: Loss of all transmission lines on a common corridor
- D8: Loss of a substation (one voltage level plus transformers)
- D9: Loss of a switching station (one voltage level plus transformers)
- D10: Loss of all generating units at a substation

Figure E-3 displays the location of the D events studied. Tables E-3, E-6, E-9 and E-12 summarize the fault descriptions and results for the Category D7, D8, D9, and D10 faults for 2012 and 2017 years. Specific transient simulation plots for Category D contingencies can also be found in Appendix E.

The transient stability analysis results indicate that:

- Three (+/-200 MVAr) SVCs, one each at Hansman Lake 650S, Pemukan 952S and Lanfine 959S are essential to maintain system stability;
- With the addition of these SVCs, the system was found to be stable under Category B events with good voltage recovery for both summer light and winter peak load conditions in 2012;
- In 2017, the system was found to be stable for all of the Category B contingencies except for three faults, two near Empress 163S and one near Nilrem 574S. In the case of Empress area, under the loss of any one of 240 kV line from Ware Junction to Empress, there is not enough dynamic VAr support for the induction motor loads. Similarly, loss of 9L953 from Cordell to Nilrem results in deficiency of dynamic VAr to the Hardisty area. The analysis of these specific contingencies showed that instability is primarily due to the induction motor loads. Changes in assumptions associated with motor locations, sizes, or connections provided stable solutions for the above mentioned cases. Given this uncertainty, the AESO will address this issue once sufficient information regarding the exact type of loads and their interconnection to the system are known; and
- The system will also sustain all the simulated Category C and D events for 2012 and 2017 without causing cascading outages – SPS are required for some outages.

Thus, the proposed system meets the Reliability Criteria.

6.5 Short Circuit Analysis

A short circuit analysis was performed based on AESO data for the Hanna region to determine the impact of Alternative 3 improvements on the Hanna region short circuit levels. Short circuit current levels were calculated for two cases: the existing system and the Alternative 3 system for 2017. Three-phase faults and single line-to-ground faults were applied at the existing and proposed 240 kV and 138/144 kV substations. The three-phase and single-phase fault currents observed at each substation for both scenarios are compared and presented in Table 6.5-1. The fault current levels at the existing substations are higher in 2017 than in the existing system since Alternative 3 improvements include major system reinforcements and the integration of about 700 MW of wind generation. The results indicate that there is no need to change any existing breakers in the study region.

Table 6.5-1 Existing and Future (2017) Fault Current Levels

Substation Name (Fault Location)	Base Voltage (kV)	Existing System		Alternative 3 with 3900 MW of South and Hanna Area Wind Generation	
		3 Phase Fault Current (kA)	1 Phase Fault Current (kA)	3 Phase Fault Current (kA)	1 Phase Fault Current (kA)
Metiskow 648S	240	4.6	3.0	6.1	6.5
	138	6.5	4.6	8.6	9.3
Hansman Lake 650S	240	4.7	3.0	6.1	6.6
	138	6.5	4.6	8.6	9.3
PaintEarth Creek 863S	240	6.1	4.6	7.0	5.8
Nevis 766S	240	7.9	5.7	8.4	6.0
	138	5.2	5.2	5.6	5.5
Three Hills 770S	138	2.2	1.8	2.9	2.1
Michichi Creek 802S	138	2.2	2.0	4.5	3.1
Battle River 757S	240	9.7	9.1	10.6	11.5
	138	11.9	9.6	12.1	10.3
Monitor 774S	138	3.2	2.2	6.1	5.6
Oyen 767S	138	2.6	1.6	7.3	6.6
Anderson 801S	240	10.6	11.5	13.2	9.5
	138	4.2	4.6	4.9	5.0
Cordel 755S	240	9.7	9.2	10.7	11.2
Pemukan 932S	240	N/A	N/A	5.5	4.9
	138	N/A	N/A	6.8	6.7
Lanfine 956S	240	N/A	N/A	7.3	6.2
	138	N/A	N/A	8.3	8.1
Oakland 946S	240	N/A	N/A	12.4	8.9
Ware Junction 132S	240	9.2	6.7	12.4	9.4
Jenner 275S	240	6.3	3.6	7.8	6.2
Amoco Empress 163S	240	5.3	2.6	6.5	7.6
	138	7.8	4.2	8.7	9.8
Cypress 562S	240	5.3	2.6	6.5	7.9
	138	7.9	4.2	8.8	8.9
Nilrem 574S	240	N/A	N/A	5.6	6.4
	138	N/A	N/A	8.9	11.4
Tucuman 478S	138	3.6	2.0	8.8	10.8

6.6 Land Impact Assessment

A Land Impact Assessment (LIA) was completed for all the alternatives to evaluate the potential impacts of each alternative. The detailed LIA for the studied alternatives are presented in four separate documents and are included in Appendix F. The main reasons for four separate LIA documents are:

i) Proposed developments in the Wainwright and Brooks areas are common to all alternatives and these lie in AltaLink's service territories.

ii) The alternatives studied traverse through non contiguous service territories of both AltaLink and ATCO TFOs.

Each TFO undertook the preparation of LIAs for the segments that are contained in their own service territory. The first three documents included in Appendix F were prepared by AltaLink and the last document was prepared by ATCO.

In the first document, AltaLink presented the results of LIA for the proposed 240 kV double circuit line midway between Paintearth Creek 863S and Hansman Lake 650S to the new 240 kV Nilrem 574S substation. These proposed double circuit lines and Nilrem substation lie entirely within the AltaLink's service territory of the Wainwright area.

The second LIA document presents the results for the AltaLink's portion of the proposed 240 kV line from Hansman Lake 650S to the new proposed Pemukan 932S. This short line is part of the three alternatives.

The third document presents the results for the 240 kV line from Ware Junction 132S to West Brooks 28S. This line lies entirely in AltaLink's service territory.

The last document contains the detailed LIA for ATCO's portion of the three alternatives. Except for a short line segment from Hansman Lake to the service boundaries of AltaLink and ATCO, the rest of the proposed alternatives lie entirely in ATCO's service territory. This document contains the bulk of LIA for all the three alternatives.

The main conclusions of the LIA are:

- All of the alternatives including developments common to all the alternatives are viable from a land impact perspective. None have potential impacts that would cause any to be rejected.
- All three alternatives are comparable in terms of the amount of infrastructure and linear features (e.g. transmission lines, highways, railway lines, and pipelines) potentially paralleled by new transmission lines.

- Alternative 3 has the least overall impact for the majority of the measurable indicators assessed.

For comparative purpose, ATCO's "metrics" for measurable indicators for all alternatives were examined as most of the new lines are in ATCO's service territory. The following describes individual categories of impacts assessed for the three alternatives in ATCO's service territory. A detailed comparison of "metrics" is given in Table 6.6-1.

Agricultural

- Alternative 3 has the least potential impact.
- Alternative 1 has the highest potential impact.
- All three alternatives pass primarily through CLI Capability Classes 4 and 5 soil capability for agriculture.

Residential

- All three alternatives impact almost equally the residences within 150 m of centerline.
- Alternative 3 has the least potential impact to residences within 800 m of the potential right-of-way.
- Alternative 1 has the highest potential impact to residences within 800 m of the potential right of way.

Environment

- None of the three alternatives crosses rivers, military bases, airfields, or Indian Reserves.
- Alternatives 1 and 2 potentially have greater impacts compared to Alternative 3 in terms of metrics /indicators such as proximity to water bodies, oil and gas facilities native grass lands and Historical Resources.

Electrical Considerations

- All three alternatives have potential for paralleling existing linear disturbances and transmission lines (144 kV and 240 kV).
- All three alternatives have similar potential to cross 2 highways and 3 pipelines.

Visual Impacts

- None of the route concepts considered for the three Alternatives lie within 800 m of protected areas even though they do cross through Environmentally Sensitive Areas (ESAs).
- All three alternatives have about the same impact on residences within 150 m.

- Alternative 1 has the greatest potential impact to residences within 800 m.

Special Constraints

- Alternative 3 has the least potential impact on special constraints.
- Alternative 1 has the greatest potential impact on special constraints.
- Alternative 3 has the least potential impact on Historical Resources
- None of the Alternatives cross military lands or facilities, airfields or Indian Reserves.
- Alternatives 1 and 2 have potential to be within 800 m of urban areas.
- Alternative 3 potentially crosses the least amount of privately owned land while Alternative 1 potentially crosses the most.

The comparison of alternatives for those sections of line within the AltaLink service territories are similar and can be found in Appendix F.

Table 6.6-1: Summary of Comparison of Metrics for Three Alternatives

Major Aspects and Considerations		Technical Components		
		Alternative 1	Alternative 2	Alternative 3
		7L143, 7L128, 7L108, 7L159/7L16, 7L137/7L25, 7L116, 7L141/7L132, 7L151/7L127, 9L97/9L70, 9L29/9L31, 9L06, 9L24, 9L14, 9L966, 9L46	7L143, 7L128, 7L108, 7L159/7L16, 7L137/7L25, 7L116, 7L141/7L132, 7L151/7L127, 9L97/9L70, 9L29/9L31, 9L06/9L52, 9L14/9L25, 9L966, 9L46	7L143, 7L128, 7L108, 7L159/7L16, 7L137/7L25, 7L116, 7L141/7L132, 7L151/7L127, 9L97/9L70, 9L29/9L31, 9L24/9L65, 9L966, 9L46
		Total	Total	Total
ROW Length (km)		**578**	**491**	**406**
Agricultural Impact				
Agricultural Land Crossed (km)	Crop land	140	127	117
	Forage Land	20	20	9
	Total	160	147	126
Land Capability for Agriculture (km crossed)	Agricultural Capability Class 1	4	4	4
	Agricultural Capability Class 2	48	48	48
	Agricultural Capability Class 3	49	49	37
	Agricultural Capability Class 4	231	185	164
	Agricultural Capability Class 5	197	164	114
	Agricultural Capability Class 6	44	37	35
	Agricultural Capability Class 7	4	4	3
	Agricultural Capability Class 8	0	0	0
	Agricultural Capability Class O	0	0	0
Residential Impacts				
Residences (#)	Within 150 m of centreline	8	7	7
	Within 800 m of ROW	119	112	104
Environmental Impacts				
Amount of Environmentally Significant Areas Crossed (km)		137	98	120
Number of Protected or Designated Areas in or within 800m of ROW edge		0	0	0
Number of Grazing Reserves, Community Pastures within 800m ROW edge		5	4	4
Native Grasslands Crossed (km)		249	189	160
Major River Crossings (#)		0	0	0
Surface Water (hectares) in or within 800m of ROW edge		2739	1943	1898
Electrical Considerations				
Amount of Existing Linear Disturbances Paralleled (km)	Existing Transmission Lines >= 240 kV	6	6	6
	Existing Transmission Lines = 144 kV	26	26	26
	Primary / Secondary Highways	2	2	2
	Railways	0	0	0
	Pipelines	3	3	3
Total Amount of Existing Disturbances (km)		37	37	37
Number of Telecommunications Towers (>25m) within 800m of ROW (#)		5	5	5
Number of Gas Facilities Within 800m of ROW (#)		3	3	1
Number of Wells within 40m of ROW (#)		61	59	50
Visual Impacts				
see "*Residences (#)*" *in Residential Impacts*				
see "*Proximity to Protected or Designated Areas in or within 800 m of ROW edge (#)*" *in Environmental Impacts*				
Special Constraints				
Proximity to Historical Resources in or within 800 m of ROW (#)		107	106	73
Urban Areas within 800m of ROW (#) (Cities, Towns, Villages, Hamlets,		4	4	0
Cemeteries within 800m of ROW (#)		3	3	3
Airfields within 800m of ROW (#)		2	2	2
Special Area Lands Crossed (km)		221	161	141
Municipal Lands Crossed (km)		0	0	0
Crown Lands Crossed (km)		13	13	13
Private Lands Crossed (km)		343	316	252

6.7 Economic Evaluation

Selection of a preferred alternative by the AESO is based on the totality of its analysis, with economics being one factor that is considered together with technical and social factors. In terms of economic assessment, all things being equal, the alternative with the lowest discounted capital cost and losses is the preferred one.

Two conductor sizes were studied for each alternative, resulting in a total of six alternatives (i.e., 1A, 2A, 3A, 1B, 2B, and 3B). Alternatives 1A, 2A, and 3A are based on smaller 477 kcmil ACSR conductor size while Alternatives 1B to 3B are based on larger 795 kcmil ACSR conductor size. The AESO has performed an economic comparison of alternatives using a net present value approach. The analysis considered capital costs and the cost of losses and in turn the total net present value of the proposed transmission system reinforcements and expansions. Net present value calculations were performed to derive a single number that can be used to compare alternatives. A before-tax weighted average cost of capital discount rate (before-tax WACC) was used for net present value calculations. Before-tax WACC has been used since a July 2004 EUB Generic Cost of Capital decision acknowledged that TFOs may possibly pay tax. Before-tax WACC is calculated as follows:

Before-tax WACC (%) = Debt (%) x Debt Cost (%) + Equity (%) x After-tax ROE (%)
/
(1 - Tax Rate (%))

Where:

a) Equity percentage: 33% is based on EUB Decision 2004-052 (Generic Cost of Capital, Pages 44 and 51) in which the EUB concluded that an appropriate common equity ratio for fully taxable electric transmission companies, with no preferred shares, is 33%;

b) Debt percentage: 67% is calculated as: (1 – Equity(%) presented in a) above);

c) A Debt Cost of 4.91% is calculated as: 1% + June, 2009 Long-term BOC bond rate (Bank of Canada benchmark bond yields, CANSIM series V122544).

d) After-tax ROE of 8.75% is based on EUB Order U2007-347 (2008 Generic Return on Equity Formula Result, p. 2). The percentage approximates the amount a TFO is allowed to earn after taxes are paid.

e) The federal corporate tax rate of 19% is based on rates listed on the Canadian Revenue Agency website.

f) The provincial corporate tax rate of 10% is based on the Alberta Corporate Tax Act, section 21 (o).

The economic model used for the economic assessment is included in Appendix G to this application.

6.7.1 Capital Costs

Appendix G contains capital cost estimates for the facilities included in each alternative. Cost estimates provided by incumbent TFOs have an accuracy of +/- 30%. Capital cost estimates include costs related to design, construction, land, regulatory activities, Allowance for Funds Used During Construction (AFUDC), Engineering and Supervision (E&S), contingency and escalation.

Table 6.7-1 summarizes capital cost estimates for the assumed project stages, 2012 and 2017 (+/- 30%, 2009$, Million). Alternatives 3A and 3B have lower capital costs than the other alternatives. Alternatives 1A and 1B have the highest capital costs due to longer transmission line length.

Table 6.7-1: Capital Cost Estimates for Each Stage (+/-30%, 2009$, Million)

	Alternative 1A	Alternative 1B	Alternative 2A	Alternative 2B	Alternative 3A	Alternative 3B
Stage 1 2012	$811	$834	$922	$951	$820	$849
Stage 2 2017	$327	$344	$161	$173	$150	$157
Total	$1,138	$1,178	$1,084	$1,124	$970	$1,006

Capital cost estimates were escalated to targeted in-service dates using escalation rates provided by the incumbent TFOs. Table 6.7-2 summarizes capital cost estimates in dollars of the year in which costs are planned to be incurred.

Table 6.7-2: Capital Cost Estimates (+/-30%, In-service Date$, Million)

	Alternative 1A	Alternative 1B	Alternative 2A	Alternative 2B	Alternative 3A	Alternative 3B
Stage 1 2012	$939	$965	$1,068	$1,101	$950	$983
Stage 2 2017	$483	$508	$239	$255	$221	$231

6.7.2 Revenue Requirement

The AESO has performed revenue requirement calculations that approximate the amount TFOs would likely seek to recover in return for constructing, operating and maintaining transmission facilities identified. Calculations consider operating expenses, depreciation, income taxes, debt costs and return on equity. The economic model contains comments with explanations of the variables that were used in the revenue requirement calculations.

Table 6.7-3 summarizes the net present value of annual revenue requirement calculations for each alternative.

Table 6.7-3: Net Present Value of Annual Revenue Requirement Discounted over a 20 year period to 2012 (Million)

Alternative 1A	Alternative 1B	Alternative 2A	Alternative 2B	Alternative 3A	Alternative 3B
$1,370	$1,416	$1,350	$1,399	$1,206	$1,250

Alternatives 3A and 3B have the lowest revenue requirement as a result of lower capital cost estimates.

The depreciation rate of 2.88% used in the revenue requirement calculation is based on depreciation rates from the AltaLink 2007-2008 General Tariff Application (Appendix K-1 - Depreciation Study, p. III-11) and ATCO Electric's 2009-2010 General Tariff Application (Schedule 6-3).

The Operating expense factor of 1.5% used to approximate Operating and Maintenance cost is an approximation based on discussions with TFOs.

6.7.3 Cost of System Losses

The AESO has used the following methodology to estimate losses for each alternative, which are necessary inputs for completing the economic analysis.

For each alternative, hourly system losses for the years 2009, 2012 and 2017 were calculated using PSS/E software. The ‘UPLAN’ software was used to produce the hourly generation dispatches which are used in PSS/E software for estimating the losses. For each of the aforementioned three simulated years, a power flow case was run for each hour in the year to determine system loss. These 8760 hourly system losses for each alternative were averaged over one year to obtain an average hourly loss for that year. Table 6.7-4 summarizes average hourly losses for the three simulated years.

Table 6.7-4: Average Hourly Losses (MW) for Simulated Years (2009, 2012 and 2017)

Year	Alternative 1A	Alternative 1B	Alternative 2A	Alternative 2B	Alternative 3A	Alternative 3B
2009	303	303	303	303	303	303
2012	362	361	362	361	362	361
2017	385	384	385	385	388	387

Hourly losses for each year of the study period were estimated using a linear regression model. Table 6.7-5 summarizes estimated hourly losses for years 2009 to 2031. As a result of the regression analysis, estimated losses in Table 6.7-5 differ from the original data points shown in Table 6.7-4.

Table 6.7-5: Estimated Hourly Losses (MW)

Year	Alternative 1A	Alternative 1B	Alternative 2A	Alternative 2B	Alternative 3A	Alternative 3B
2009	315	315	315	314	314	314
2010	324	324	324	324	324	324
2011	334	334	334	334	334	334
2012	344	343	344	343	344	344
2013	353	353	353	353	354	354
2014	363	362	363	363	364	364
2015	373	372	373	372	374	374
2016	382	381	382	382	384	384
2017	392	391	392	391	394	394
2018	402	400	402	401	404	404
2019	411	410	412	411	414	414
2020	421	419	421	420	424	424
2021	431	429	431	430	434	434
2022	440	438	441	440	444	444
2023	450	448	450	449	455	454
2024	460	457	460	459	465	464
2025	469	467	470	468	475	474
2026	479	476	479	478	485	484
2027	489	486	489	488	495	494
2028	498	495	499	497	505	504
2029	508	505	509	507	515	514
2030	518	514	518	517	525	524
2031	528	524	528	526	535	534

In order to compare differences in losses for each alternative, the AESO has calculated the amount of incremental losses of each alternative relative to

Alternative 3B. The AESO then multiplied the incremental loss volume of each alternative relative to Alternative 3B by forecasted annual Alberta power prices provided to the AESO by EDC Associates Ltd. in July 2009.

Table 6.7-6 summarizes the present value of incremental annual loss values for each of the alternatives.

Table 6.7-6: Present Value of Annual Loss Values Relative to Alternative 3B Discounted over a 20 year period to 2012 ($Million)

Alternative 1A	Alternative 1B	Alternative 2A	Alternative 2B	Alternative 3A	Alternative 3B
-$26	-$45	-$25	-$33	$6	$0

Results indicate that the incremental cost of losses for Alternatives 1 and 2 are lower than the cost of losses for Alternative 3B by up to $45 million. However, the benefit of lower loss costs is outweighed by the higher capital costs of Alternatives 1 and 2. Hence the lower incremental loss cost is not a deciding factor in the final selection of a preferred alternative.

6.7.4 Net Present Value of Each Alternative

Table 6.7-7 summarizes the net present value of each alternative.

Table 6.7-7: Net Present Value Discounted over a 20 year period to 2012 ($Million)

	Alternative 1A	Alternative 1B	Alternative 2A	Alternative 2B	Alternative 3A	Alternative 3B
Net Present Value Revenue Requirement	$1,370	$1,416	$1,350	$1,399	$1,206	$1,250
Net Present Value Losses Relative to Alternative 3B	-$26	-$45	-$25	-$33	$6	$0
Total Net Present Value	**$1,344**	**$1,371**	**$1,325**	**$1,366**	**$1,212**	**$1,250**

The ranking of alternatives, in term of economic assessment, is shown in Table 6.7-8.

Table 6.7-8: Economic Assessment Ranking of Alternatives

Relative Ranking of Alternatives	
1	Alternative 3A
2	Alternative 3B
3	Alternative 2A
4	Alternative 1A
5	Alternative 2B
6	Alternative 1B

6.7.5 Conclusions

Results of economic analysis indicate the following:

1. Alternative 3A has the lowest net present value. Net present values for Alternatives 1A and 2A are higher than Alternative 3A by $132 million and $113 million respectively.

   The net present value of Alternative 3B is $38 million higher than the net present value of Alternative 3A. Net present values for Alternatives 1B and 2B are higher than the Alternative 3B net present value by $121 and $116 million, respectively.

2. The estimated capital cost (+/- 30%, 2009$) for Alternative 3A is 10% lower than Alternative 1A and 8% lower for Alternative 2A.

   The estimated capital cost (+/- 30%, 2009$) for Alternative 3B is 9% lower for Alternative 1B and 8% lower for Alternative 2B.

3. The cost of incremental losses for Alternatives 1 and 2 are lower than that of Alternative 3. However, the benefit of lower losses is outweighed by higher capital costs and thus will not be a deciding factor in selecting a preferred alternative.

4. Even though Alternative B is slightly more costly than the least cost Alternative 3A, the AESO recommends Alternative 3B because it can accommodate long term growth and minimize land use impacts. This is in line with AESO's vision for long-term development.

6.8 Participant Involvement Program

The AESO conducted a Participant Involvement Program (PIP) throughout the development of its Needs Identification Document (NID) for major transmission reinforcement in the Hanna region (east central Alberta). A variety of methods were used to notify, consult with and engage residents, occupants, landowners, businesses, industry, First Nations, advocacy groups as well as elected and administrative municipal and provincial officials with interests in east central Alberta.

Throughout the PIP, the AESO:

- Delivered presentations at nine meetings with elected and administrative government officers and another two presentations to the industry stakeholders
- Hosted public information sessions (12 open houses);
- Mailed information by postal code (unaddressed mail through Canada Post) and directly (addressed mail) to approximately 66,990 residences, farms and businesses throughout the study area;
- Posted information on the AESO web site;
- Advertised in 13 local newspapers;
- Corresponded with stakeholders by mail, email and telephone; and
- Published information in the AESO's weekly stakeholder newsletter.

The AESO's PIP provided the opportunity for all stakeholders with interest in transmission development in the Hanna region:

- To be fully informed about the AESO NID process for reinforcing the transmission system in east central Alberta; and
- To share their feedback about the need for reinforcement and about alternatives the AESO proposed to meet this need.

The PIP also allowed the AESO to identify stakeholders (and their concerns) and to take measures to address these concerns where reasonable.

The AESO has responded to all concerns regarding potential reinforcements in the Hanna region received as a result of the PIP in a reasonable and appropriate manner.

A detailed description of the PIP is provided in Appendix H.

7 Alternative Comparison

The following section compares the Hanna transmission alternatives based on technical, economic and societal factors**.** Table 7-1 provides a summary of the comparison.

7.1 Technical Performance

7.1.1 Meeting Reliability Criteria

Section 6 of the NID presents the results of detailed technical analysis carried out for all the alternatives. A summary of the results are presented in Section 6.2 to Section 6.4 and the corresponding power flow plots, PV and QV analysis and transient stability plots are included in Appendix D and E. These results demonstrate that all alternatives meet the Reliability Criteria.

7.1.2 Future Expandability

The ranking of the alternatives, based on potential for future expandability, was contingent on using existing right-of-way. In Alternatives 1 and 3, all the 240 kV transmission lines (except a short 240 kV line from the existing Cordel 755S substation to one wind farm switching station in the area) use double circuit towers, and most of these lines initially will have only one circuit strung. Therefore, the system capacity of lines in Alternatives 1 and 3 can be increased by stringing a second circuit on to the double circuit towers when required, without the need for any new right-of-ways. However, Alternative 2 can only be expanded by the acquisition of additional right-of-way. This makes Alternative 2 less attractive with regard to future expandability compared to Alternatives 1 and 3. Alternative 3 requires fewer transmission lines compared to Alternative 1 and hence has lower capital cost.

7.2 Economic Factors

Results from the economic comparison of alternatives are included in Tables 6.7-7 and 6.7-8. The analysis compared alternatives based on the net present value of a stream of annual capital cost and loss values. Section 6.7 describes the methodology used for economic evaluation and the results of the analysis.

7.2.1 Capital Costs

Total estimated capital cost (+/-30%, 2009$) for the three alternatives, including common developments, is provided in Table 6.7-1 of Section 6.7. As indicated in this table, Alternative 3 requires the least amount of capital. Alternative 1 has the highest capital cost and the capital cost for Alternative 2 is between Alternatives 1 and 2.

7.2.2 System losses

The assumptions and methodology adopted for estimating the average hourly system losses for all the alternatives is described in Section 6.7.3. The average system losses of all three alternatives for either low capacity or high capacity conductor are comparable. Average hourly losses of the three alternatives were found to be within 10 MW of each other by 2031. Considering the narrow range, Alternative 3 has relatively high system losses compared to other alternatives.

The difference between the A series and the B series alternatives is the size of 240 kV line conductor. The summer ratings of twin bundle 477 kcmil ACSR and twin bundle 795 kcmil ACSR conductors are 600 and 874 MVA respectively. Thus the large size conductor can carry nearly 45 percent of more power than the smaller conductor. The higher capacity line can accommodate any unforeseen large load and/or generation additions in the area more than a low capacity line. Therefore, use of this large sized conductor can defer the need for additional lines and associated right-of-ways. The benefits realized by this choice of conductor are estimated to be much higher than the difference in cost introduced by choosing larger conductor size. High capacity lines (i.e. with larger sized conductor) also means less future requirement of land for transmission line right-of-way. Another benefit for larger sized conductor is less system losses compared to low capacity lines.

7.3 Societal Factors

Societal factors such as land impact, including environment, and stakeholder/pubic feedback were also considered in the comparison of the alternatives.

7.3.1 Land Impact Assessment

The detailed land impact assessment reports are included in Appendix F. A summary of the results of LIA for all the alternatives are summarized in Section 6.6, Table 6.6-1. All three alternatives are viable and Alternative 3 appears to have the least overall impact.

7.3.2 Stakeholder/Public Feedback

The AESO met with major municipal districts, towns and special interest groups and made presentations to these groups on the Hanna region development. The AESO has not received any preference for any of the three alternatives from the public. Appendix H contains details of the participant involvement program, with a summary given in Section 6.8.

7.4 Summary

Based on the overall results of the alternative comparison as summarized below, Alternative 3 is preferred.

Table 7.4-1: Comparison of Alternatives[9]

Alternative	Alternative 1	Alternative 2	Alternative 3
Technical Factors			
Meets Reliability Criteria	Yes	Yes	Yes
Future Expandability (Using Existing ROW)	Offers excellent opportunity	Limited opportunity	Offers very good opportunity
Economic Factors			
Capital Cost	Very High	High	Low
System Losses	Low	Lowest	High
Societal Factors			
Land Impact Assessment	Impacts most	Impacts moderately	Impacts less
Stakeholder/Public Feedback	No preference	No preference	No preference

[9] Pertain to twin bundle 795 kcmil conductors, or option B.

8 Recommended Proposal

Based on the results presented in Section 7, Alternative 3 with larger conductor is recommended for the Hanna region system development to accommodate forecast loads and wind farms in the Hanna region. The recommended proposal is shown in Figure 8-1 along with the wind interest zones. The total estimated cost for the recommended proposal is $1.0 billion (+/-30%, 2009$). Once the recommended proposal is approved, the AESO will be adopting a staged approach for implementation as shown in Tables 8-1 and 8-2.

Stage I is recommended to proceed immediately, as some of the components are needed to address reliability concerns in the existing transmission system. Although the generation forecast anticipates 175 MW of wind generation by 2012, the plan will allow approximately 500 MW of wind generation to operate in the Hanna area.

Stage II is required by year 2017 to meet the additional forecast loads and wind farm projects in the region.

Figure 8-1: Recommended Plan (Alternative 3) with Wind Interest Zones

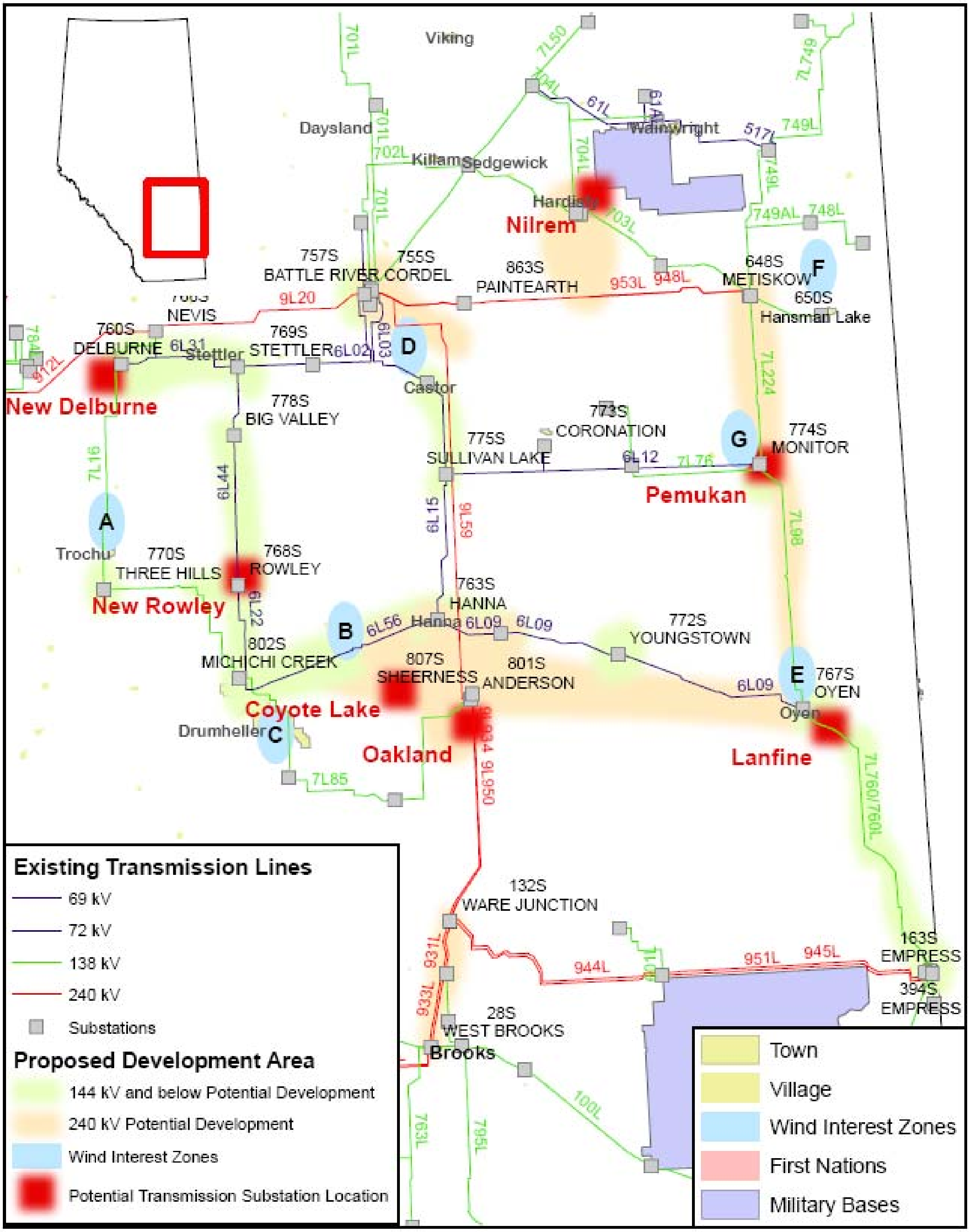


Table 8-1: Stage I Components of the Recommended Proposal (Alternative 3B)

Item #	Recommended Proposal	Description
I-1	Nilrem substation and build a 240 kV D/C line from 9L953 to Nilrem (in-and-out scheme); 138 kV D/C line from Nilrem to Tucuman.	Two 400 MVA 240/138 kV transformers, 2X477 kcmil ACSR 240 kV D/C line (30 km), 1X477 kcmil ACSR 138 kV D/C line (3km).
I-2	Hardisty 138 kV cap banks	One 138 kV 27 MVAr, and Restore existing 20.4 MVAr to its full size 44.9 MVAr
I-3	Hansman Lake SVC	One 138 kV +/-200 MVAr SVC
I-4	Pemukan substation	One 300 MVA 240/144 kV transformer, One 144 kV +/-200 MVAr SVC and Two 144 kV 30 MVAr cap banks
I-5	Lanfine substation	One 300 MVA 240/144 kV transformer, One 144 kV +/-200 MVAr SVC and Two 144 kV 30 MVAr cap bank
I-6	Oakland substation	240 kV switching station
I-7	Oakland to Anderson 240 kV lines	2X795 kcmil ACSR D/C line (7 km)
I-8	Coyote Lake substation	One 300 MVA 240/144 kV transformer
I-9	Oakland to Coyote Lake 240 kV lines	2X795 kcmil ACSR D/C line with single side strung (38 km)
I-10	Coyote Lake to Michichi Creek 144 kV line	1X477 kcmil ACSR single circuit line (42 km)
I-11	Hansman Lake to Pemukan 240 kV line	2X795 kcmil ACSR D/C line with single side strung (60 km)
I-12	Pemukan to Lanfine 240 kV line	2X795 kcmil ACSR D/C line with single side strung (68 km)
I-13	Oakland to Lanfine 240 kV line	2X795 kcmil ACSR D/C line with single side strung (87 km)
I-14	New 144 kV Cornish Lake	266.8 kcmil ACSR D/C line (12 km) and one

Item #	Recommended Proposal	Description
	(replaces Rowley) and in-and-out on 7L25 line	25 MVA 144/25 kV transformer
I-15	New 144 kV Heatburg substation (replaces Delburne) and in-and-out on 7L16 line	266.8 kcmil ACSR D/C line (1.6 km) and one 25 MVA 144/25 kV transformer
I-16	Convert Stettler to 144 kV sub with 144 kV line from Nevis	1X477 kcmil ACSR single circuit line (35 km) with 25 MVA 144/25 kV load transformer, 33.3 MVA 144/72 kV tie transformer and 144 kV 10 MVAr and 5 MVAr cap banks
I-17	Three Hills cap banks	Two 144 kV 10 MVAr
I-18	72 kV Cap banks at Battle River, Youngstown	10 MVAr at Battle River, 5 MVAr at Youngstown
I-19	Ware Junction to West Brooks 240 kV line	240 kV double circuit line with single side strung from Ware Junction 132S to West Brooks 28S
I-20	Pemukan to Monitor 144 kV line	2x477 kcmil ACSR D/C line with single side strung
I-21	Lanfine to Oyen 144 kV line	2x477 kcmil ACSR D/C line with single side strung

Table 8-2: Stage II Components of the Recommended Proposal (Alternative 3B)

Item #	Recommended Proposal	Description
II-1	Nilrem substation cap banks	Two 138 kV 27 MVAr
II-2	Hansman Lake cap banks	One 138 kV 27 MVAr Two 240 kV 36 MVAr
II-3	Metiskow cap bank	One 138 kV 27 MVAr
II-4	Second side Strung on the 240 kV line from Oakland to Lanfine	Second side strung on the existing 2X795 kcmil ACSR D/C tower lines (87 km)
II-5	Convert Hanna to 144 kV sub	Relocate Michichi Creek 144/72 kV 33 MVA tie transformer to Hanna
II-6	Coyote Lake to Hanna 144 kV line	1X477 kcmil ACSR single circuit line (40 km)
II-7	Oakland to Coyote Lake 240 kV lines	Second side strung on the existing 2X795 kcmil ACSR D/C tower lines (38 km)
II-8	Second transformer at Pemukan substation	Second 300 MVA 240/144 kV transformer
II-9	Second transformer at Lanfine substation	Second 300 MVA 240/144 kV transformer
II-10	Second transformer at Hansman Lake substation	Second 200 MVA 240/138 kV transformer
II-11	Second side strung on 144 kV line from Pemukan to Monitor	Second side strung on the 2x477 kcmil ACSR D/C tower lines
II-12	Second side strung on 144 kV line from Lanfine to Oyen	Second side strung on the 2x477 kcmil ACSR D/C tower lines
I-13	Cordel to Halkirk switching station 240 kV line	2X795 kcmil ACSR D/C line with single side strung (17 km)

8.1 Rationale for Components of the Recommended Plan

The rationale for each component of the recommended plan is discussed in the following sections. The rationale briefly reviews why each major component was needed in terms of staging.

8.1.1 240 kV Nilrem Substation and Hardisty Area Cap Banks Additions (Items I-1 and I-2)

The winter peak load in the Wainwright and Provost areas is projected to be more than double from 220 MW (2008) to approximately 444 MW (2012) in the next three years. The major sources of supply to these areas are the 144 kV 7L50 from the Battle River plant and two 240/138 kV transformers at Hansman Lake 650S and Metiskow 648S. The combined capacity of the above three sources is not adequate to supply the peak load in 2012, even under a Category A event. Hence a new 240 kV source station is deemed necessary to meet AESO reliability criteria. The Nilrem site was chosen to be close to the load centre in the Wainwright area, which happens to be next to the Tucuman substation. Two 240/138 kV transformers are recommended to ensure that an outage of one transformer at Nilrem does not cause overloads on the existing 240/138 kV transformers at Hansman Lake and Metiskow. A short new 138 kV D/C line needs to be built from 240 kV Nilrem substation to the existing 138 kV Tucuman substation to provide supply to the Tucuman loads.

8.1.2 144 kV SVCs at Hansman Lake, Pemukan and Lanfine (Items I-3, I-4 and I-5)

The SVCs are required to fulfill two objectives. The first objective is to maintain system voltage in eastern the Hanna region in the acceptable range during normal operation by absorbing/delivering VArs required. The second objective is to deliver a substantial amount of dynamic reactive power (for a few seconds) after critical fault conditions to supply reactive demand during transients by the induction motors that drive the pumping loads. This support is needed to avoid short term voltage instability caused by lack of local dynamic VAr in the region.

8.1.3 240 kV Substations – Pemukan and Lanfine (Items I-4 and I-5)

Due to the significant load growth along the eastern Hanna transmission corridor, the existing 144 kV system can not supply the loads. Hence 240 kV supply sources to the area are required. In order to coordinate the supply of loads at the existing Monitor and Oyen substations, the new 240 kV Pemukan and Lanfine substations will be located close to the existing Monitor and Oyen substations respectively.

8.1.4 240 kV Oakland Switching Station and 240 kV Line to Anderson (Items I-6 and I-7)

It is not feasible to expand the existing Anderson substation to connect a proposed wind collector substation at Coyote Lake and also add more 240 kV lines from it eastwards to Oyen substation. This necessitated building of a new 240 kV switching station at Oakland approximately seven kilometres south of Anderson substation. This new Oakland switching station becomes a hub for this area to integrate wind farms in the Hand Hills and Wintering hills area, and also provide space to add new transmission lines to supply the pipeline loads in the eastern Hanna transmission corridor. A double circuit tower line is proposed to connect Oakland to Anderson substation.

8.1.5 240 kV Coyote Lake Substation and 240 kV Line from Oakland to Coyote Lake (Items I-8 and I-9)

Based on the wind applications to date, the AESO grouped wind interest in the Hand Hills and Wintering Hills areas into seven clusters. The total proposed wind capacity is about 2300 MW. About 1200 MW of proposed wind farms are located west of the existing Anderson substation in Clusters B and C. The AESO, in consultation with stakeholders, identified a collector station near Coyote Lake. The Coyote Lake collector station is about 38 km west of Oakland switching station and will be located at the centre of proposed wind farms in these two clusters. Coyote Lake substation will be connected to the bulk system by a new 240 kV line (Coyote Lake 963S – Oakland 946S).

8.1.6 144 kV Line from Coyote Lake to Michichi Creek (Item I-10)

At present, the West Hanna 144 kV system is supplied by two 240/144 kV transformers located at Nevis 766S and Anderson 801S substations. The transfer of some 72 kV loads to 144 kV level, coupled with projected load growth, will result in overloads on the existing 144 kV system. Hence, new transmission facilities are required to supply area load as per reliability criteria. Moreover, a new 144 kV interconnection is also required to export wind generation on the 144 kV system in the west Hanna area under contingencies. A new 144 kV line from the wind collector Coyote Lake substation to the existing Michichi Creek substation, plus a 240/144 kV transformer at Coyote Lake are proposed. This 144 kV source complements the aforementioned two existing two sources in the west Hanna area. The new 144 kV source is close to the area load centre. In addition, it is the best location to handle export of power from two proposed wind farms in west Hanna area during N-1 contingencies.

8.1.7 240 kV Lines from Oakland to Lanfine, from Lanfine to Pemukan, and from Pemukan to Hansman Lake (Items I-11, I-12 and I-13)

The proposed 240 kV lines from Hansman Lake to Pemukan to Lanfine and then to Oakland along with the existing lines (9L59 from Anderson to Cordel and two lines from Cordel to Hansman Lake) will form a 240 kV loop in the Hanna planning area. These three proposed 240 kV lines are essential to serve the pipeline loads along the eastern Hanna area transmission corridor in a reliable manner. These three lines are the minimum transmission development required to meet the planning criteria.

8.1.8 Conversion of Rowley, Stettler, Delburne to 144 kV Substations and 144 kV Line from Nevis to Stettler (Items I-14, I-15 and I-16)

Presently, the Western Hanna area 72 kV system is subject to low voltages under a number of contingences, particularly with the loss of any one of the 144/72 kV tie transformers at Battle River, Nevis or Anderson substations. The voltage violations become worse with load growth in the 72 kV system at Stettler, Delburne and Rowley substations, as outlined in the need assessment section. In order to supply projected load growth while meeting reliability criteria, it is recommended to transfer area loads from the local 72 kV system to 144 kV system. Thus the three substations will be upgraded from the 72 kV to 144 kV level. Due to space restrictions at the existing Rowley 768S and Delburne 760S substations, new substations Cornish Lake 954S (near existing Rowley 768S) and Heatburg 948S (near existing Delburne 760S) will be built. A new 144 kV line will be built from the Nevis substation to upgraded 144 kV Stettler substation. New 144 kV Heatburg 948S substation will be connected to the existing 7L16 via an in-and-out scheme. Similarly, the new 144 kV Cornish Lake 954S substation will be connected to the 7L25 line via an in-and-out scheme.

8.1.9 Cap Bank Additions in West Hanna Area (Items I-16, I-17 and I-18)

Due to the load growth in the west Hanna area, both the 144 kV and 72 kV systems have voltage violations under Category B contingencies. Additional cap banks are required to maintain area voltage in the acceptable ranges. New cap banks are proposed at two 144 kV locations, which are Three Hills and Stettler substations and two 72 kV locations, which are Battle River power plant and Youngstown substation.

8.1.10 240 kV Line from Ware Junction to West Brooks (Item I-19)

The increased implementation of wind generation in the Hanna region will result in loading of the interties between the Hanna region and the bulk system south of Anderson. When the wind generation in the area exceeds 500 MW, the loss of either intertie 9L933/933L (801S-28S) or 931L (132S-28S) will cause overloading of the other intertie. The new 240 kV line (132S-28S) is required to facilitate the integration of potential wind in the region in excess of 500 MW. This line will strengthen the south corridor from Anderson 801S to Ware Junction 132S to West Brooks 28S.

8.1.11 Cap Bank Additions in East Hanna Area (Items II-1, II-2 and II-3)

Due to the load growth in the Wainwright and Provost areas in 2017, the 144 kV system will lack the required VAr support to maintain area voltage in compliance with AESO reliability criteria. Additional cap banks are required to maintain area voltage within the acceptable ranges. New cap banks are proposed at three 144 kV locations: Hansman Lake 650S, Metiskow 648S and Nilrem 574S.

8.1.12 Second Side Strung on the 240 kV Line from Oakland to Lanfine (Item II-4)

The increasing load in the east Hanna transmission corridor, and also in the Wainwright and Provost areas, requires stronger supply from generation sources. Second side strung on the 240 kV line from Oakland 946S to Lanfine 959S creates another strong support from generation to load area.

8.1.13 Conversion of Existing 72 kV Hanna Substation to 144 kV Substation (Items II-5 and II-6)

Due to the load growth in the west Hanna 72 kV system, the area 72 kV system is overloaded during Category B contingencies in 2017. It is proposed to open the area 72 kV system and supply the 72 kV loads radially from different sources. Hanna substation is supplied mainly from Michichi Creek via 72 kV line 6L56 line. In order to maintain area supply reliability, it is proposed to convert Hanna substation to a 144 kV substation and receive 144 kV supply from Coyote Lake 963S.

8.1.14 Second Side Strung on the 240 kV Line from Oakland to Coyote Lake (Item II-7)

When total generation connected to Coyote Lake and tapped on the 240 kV line from Coyote Lake to Oakland is more than 500 MW, a second side strung on the 240 kV line from Oakland to Coyote Lake is required. Without the second strung, it creates the largest capacity generating unit in the AIES. The second side strung on the 240 kV line from Coyote Lake to Oakland can avoid any potential issue caused by creating the largest generating unit in the AIES. It also provides the transmission capacity to accommodate more generation to be connected to Coyote Lake substation.

8.1.15 Second Transformers at Pemukan and Lanfine (Items II-8 and II-9)

In Stage I plan, Monitor and Pemukan loads are supplied by Pemukan 240/144 kV transformer and 144 kV 7L224 line from Hansman Lake. Oyen and Lanfine loads are supplied by Lanfine 240/144 kV transformer and 144 kV 7L760 line from Empress. With the load growth in the east Hanna transmission corridor, 7L224 and 7L760 lines will be overloaded when the local 240/144 transformer is out of service. The second 240/144 kV transformer is required for Category B contingencies in Stage II.

8.1.16 Second Transformer at Hansman Lake (Item II-10)

Due to the load growth in the Wainwright and Provost areas, additional 240/138 kV transformation capacity is require to supply area load. The second Hansman Lake 240/138 kV transformer is proposed to ensure that area 240/138 kV transformers are free of overloading issue during N-1 contingencies.

8.1.17 144 kV Lines from Pemukan to Monitor and from Lanfine to Oyen (Items I-20, I-21, II-11, and II-12)

These short 144 kV lines from the new 240 kV substations (i.e. Pemukan and Lanfine) to the existing 144 kV Monitor and Oyen substations, respectively, are required to supply loads at Monitor and Oyen substations. Without these 144 kV lines, the existing Monitor and Oyen substations will be isolated from the system and hence loads at Monitor and Oyen cannot be served.

8.1.18 240 kV Line from Halkirk to Cordel (Item II-13)

A new 240 kV line is required between Halkirk switching station 401S and Cordel 755S. The new line would facilitate mitigating potential overload which would appear on the 9L59 line section between Halkirk Switching Station 401S and Cordel 755S, as a result of the outage of either 240 kV 9L966 Hansman Lake 650S to Pemukan 932S or 240 kV 9L46 (Lanfine 959S to Pemukan 932S) when Battle River Unit #5 is out of service under summer peak conditions.

8.2 Advancement of Expenses

In order to advance Stage I project development to meet the projected in-service dates and enable the interconnection of a number of wind power projects, the AESO intends to direct both AltaLink and ATCO to proceed with certain activities as preparatory activities in advance of approval of the NID, and in advance of approval of the subsequent TFOs facility applications for permit and license.

Stage I of the development is estimated at $849 million (+/-30%, 2009$) .It is assumed that the NID will be approved by mid February 2010.

With the above assumptions and in order to maintain project schedule, it is estimated that approximately $47 million and $50 million will be incurred by the AltaLink and ATCO respectively prior to the need being approved.

These cost estimates are based on order-of-magnitude estimates and actual cost flows will be refined later.