Electric Light & Power Department

STUDY FOR
THE CITY OF RED DEER,
EL&P TRANSMISSION SYSTEM
2011-2025 MASTER PLAN

May 30, 2011

	Name	Signature	Date
EL&P PLANNING	Mark Krukowski, P.Eng. Leo Britos, P.Eng. Randy Ferrier, C.E.T.		
EL&P MANAGER	Ligong Gan, P.Eng.		

DEFINITIONS, ACRONYMS AND ABBREVIATIONS

“The City” or **“CoRD”**	The City of Red Deer
“**ELP**”	The Electric Light & Power Department of The City of Red Deer
“TFO	Transmission Facility Owner
“DFO”	Distribution Facility Owner
“AESO”	Alberta Electrical System Operator
“AIES”	Alberta Interconnected Electrical System.
“AltaLink”	AltaLink Management Ltd.
“DTS”	Demand Transmission Service defined by AESO.
“OPP”	Operating Policies and Procedures defined by AESO.
“**POD**”	Point Of Delivery, i.e. point of interconnection with transmission system.
“NID”	Need Identification Document
“SCADA”	Substation Control And Data Acquisition
“ROW”	Right Of Way

Contents

LIST OF FIGURES AND TABLES

1.0 INTRODUCTION

Purpose

The primary purpose of this 2011 – 2025 Transmission Master Plan is to develop a long-term view of the electric power transmission and bulk distribution requirements to meet the expected load growth in the City of Red Deer ("City").

The objectives of this report are:

- To provide a rational basis for the City to make technical and financial decisions on various transmission and bulk distribution projects.
- To assess land and right of way requirements.
- To coordinate expansion of transmission and distribution system in new annexed areas and service territories to ensure that all capital investments are part of a long term structured plan.
- To assist the AESO in the development of transmission systems in and around Red Deer area.

Planning Area

The planning area encompasses the City's existing and future boundaries over the period to 2025 shown in Figure 1.0-1. In 2007 the City and Red Deer County adopted the Inter-municipal Development Plan (City of Red Deer Bylaw No. 3393/2007) describing the City's Growth Area. In 2009, the City has been given the green light to expand its boundary by 3,000 hectares following provincial approval of an application to annex land from Red Deer County. The future annexations are expected to be completed in 2017-2020 timeline.

It is important to note that all annexed areas, except Queens Business Park, are still served by Fortis Alberta. ELP expects successive acquisitions of Fortis' service areas and this has been taken into account in forecasting the future load.

Planning Horizon

The overall planning horizon is the years 2011 to 2025. However, for convenience, the load forecasting and transmission system assessment for this horizon has been divided into the following three parts:

- Years 2011 to 2015
- Years 2016 to 2020
- Years 2021 to 2025

All short-term (2-year) and medium-term (5-year) system development plans shall take into account the future long-term (10, 15-year) requirements for electric power transmission and bulk distribution in the City as outlined in this Master Plan.

Planning Criteria

For transmission system development the AESO "Transmission System Planning Criteria" as posted by the AESO on March 10, 2005 has been used.

For distribution system the following Distribution Point-of-Delivery Interconnection Process Guideline published by the AESO has been used:

- ***Standards of Service (revision 0: March 22, 2005).*** The Red Deer TFO and DFO planning methodology has been applied to the analysis of this report (refer to tables in sections 2.2 and 3.3 of the AESO Guideline).

2.0 LOAD FORECAST (2010-2025) SUMMARY

The City of Red Deer's long-term demand and energy forecast is a study of past energy use patterns, future economic indicators, planned electrical service boundary expansion, emerging alternative energy technologies and spatial analysis that are combined to produce a future demand and energy forecast. The Electric Light and Power Department (ELP) annually monitor performance and updates the 15-year outlook with Red Deer's electricity consumption and peak demand. The 15-year outlook is revised every third year performing detailed studies in each of its customer sectors and research segments that may offer enhancements or insight to its 15-year outlook.

The 15-years outlook recognizes future electrical service boundary expansion in regards to timing, size, zoning and number of quarter sections added to its electrical service territory in five year increments. The timing and size of area added to the City's electrical service boundary was aligned to the initiatives and future outlook of the City's environmental and engineering departments extending their services according to their 2011 departmental budgets. Noteworthy, extending electrical service boundary will heavily depend on the facility to service these areas.

The 15-year outlook also reflects future economic growth, the continually expanding trade area, and adoption of emerging alternative energy technologies including the "Smart Grid". "Smart Grid" will enable electric energy consumer to make better decision regarding their electrical energy consumption. It is in ELP's view that full scale "Smart Grid" integration will improve energy load factor which on average from 1997 to 2010 is 65 per cent with subtle changes year-over-year. The energy load factor will be significantly improved with the implementation of "Smart Grid" devices, adaptation to energy efficient appliances, and conversion of traffic and streetlights to higher efficiency lighting technology. Load factor improvement would increase the uniformity and efficiency with which electric energy is being used. Moreover, the need to increase system capacity for absorbing climatic peak demands will be reduced.

Figure 2.0-1 shows The City of Red Deer's system long-term electrical demand forecast with five per cent confidence band. Figure 2.0-2 shows The City of Red Deer's system long-term electrical energy forecast.

Figure 2.0-1 15-Year System Electrical Demand Forecast with Five per cent Confidence Band

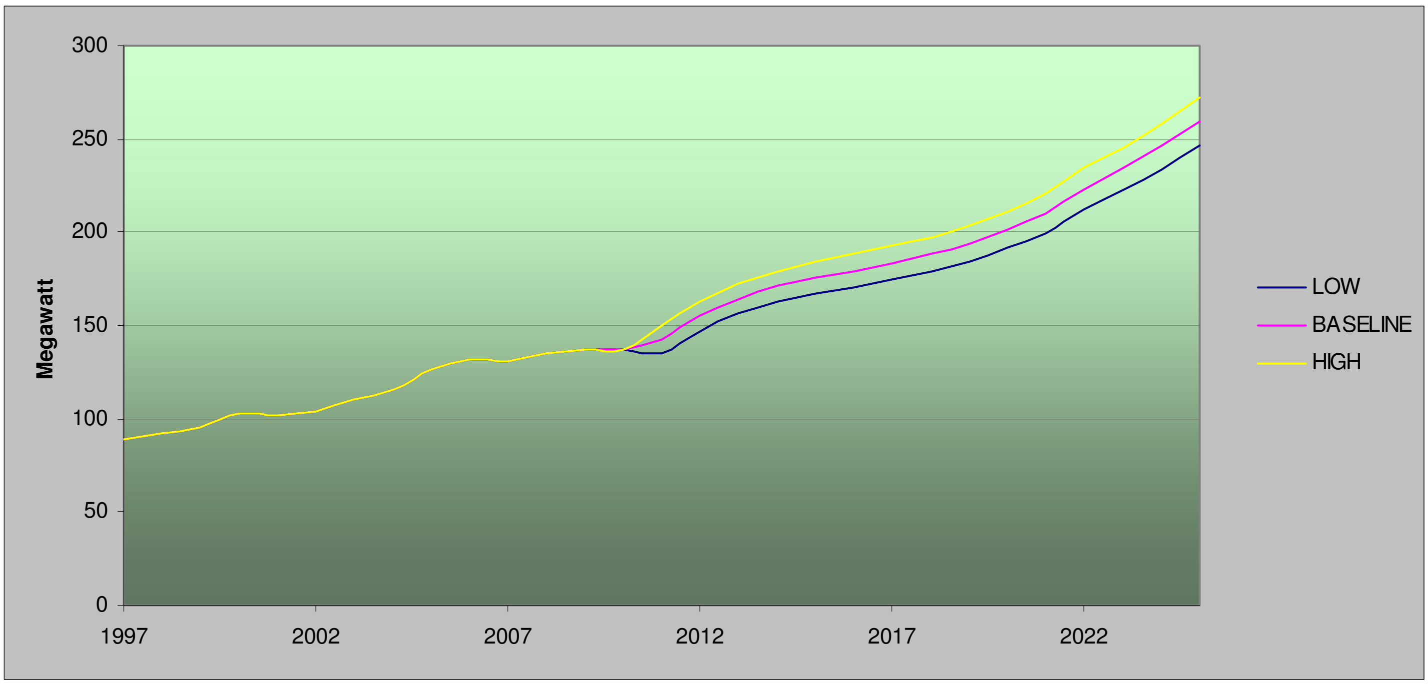


Figure 2.0-2 15-Year System Electrical Energy Forecast

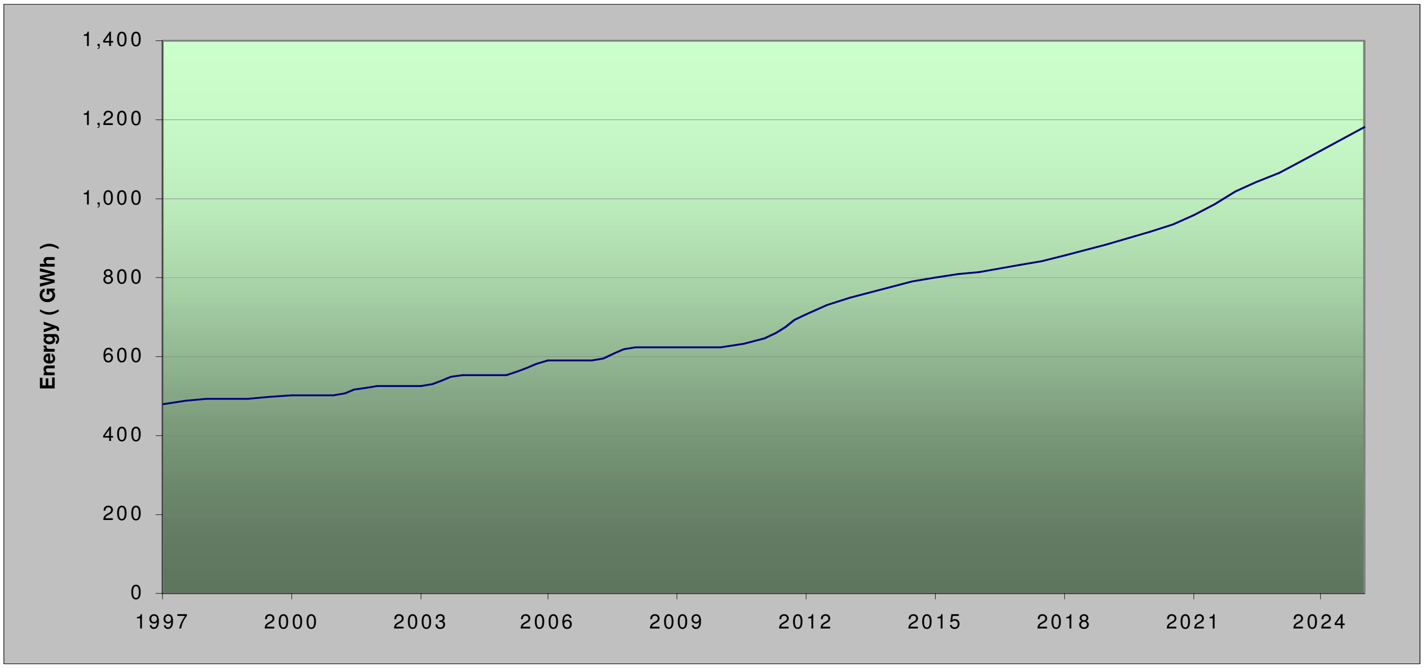


Table 2.0-1 shows increasing peak demand requirements relative to the existing electrical substation service area.

Table 2.0-1: System Year-Over-Year Forecast Percent Growth and Electrical Facility Supply Requirements

		Mega-Watts														
Service Area	**Substation**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
North	RD14S	44	50	55	58	60	62	64	67	70	75	80	88	93	98	105
South-Central	RD15S	58	64	68	71	73	74	75	77	78	80	82	86	91	96	101
South-East	RD17S	40	41	41	42	42	43	44	45	46	47	48	49	50	51	53
System	TOTAL (% year over year)	4.17	8.82	6.08	3.95	2.7	2.13	2.29	2.61	3.17	3.8	4.31	6.25	4.84	5.05	5.45

The supply requirement of major City of Red Deer electrical substation facilities indicated in Table 2.0-1 will depend to a large extent on the process and timing in which existing and new underground and overhead 25kV distribution feeder cables are installed and routed. Consequently, Table 2.0-1 reflects supply requirements based on current practices to service territory expansion without the addition of new facilities.

For more detail on methodology and processes that ELP employs to assess Red Deer's future demand and electric energy requirements refer to accompanying document Electric Light & Power Future Demand and Energy Outlook (2010-2025).

3.0 EXISTING TRANSMISSION and BULK DISTRIBUTION

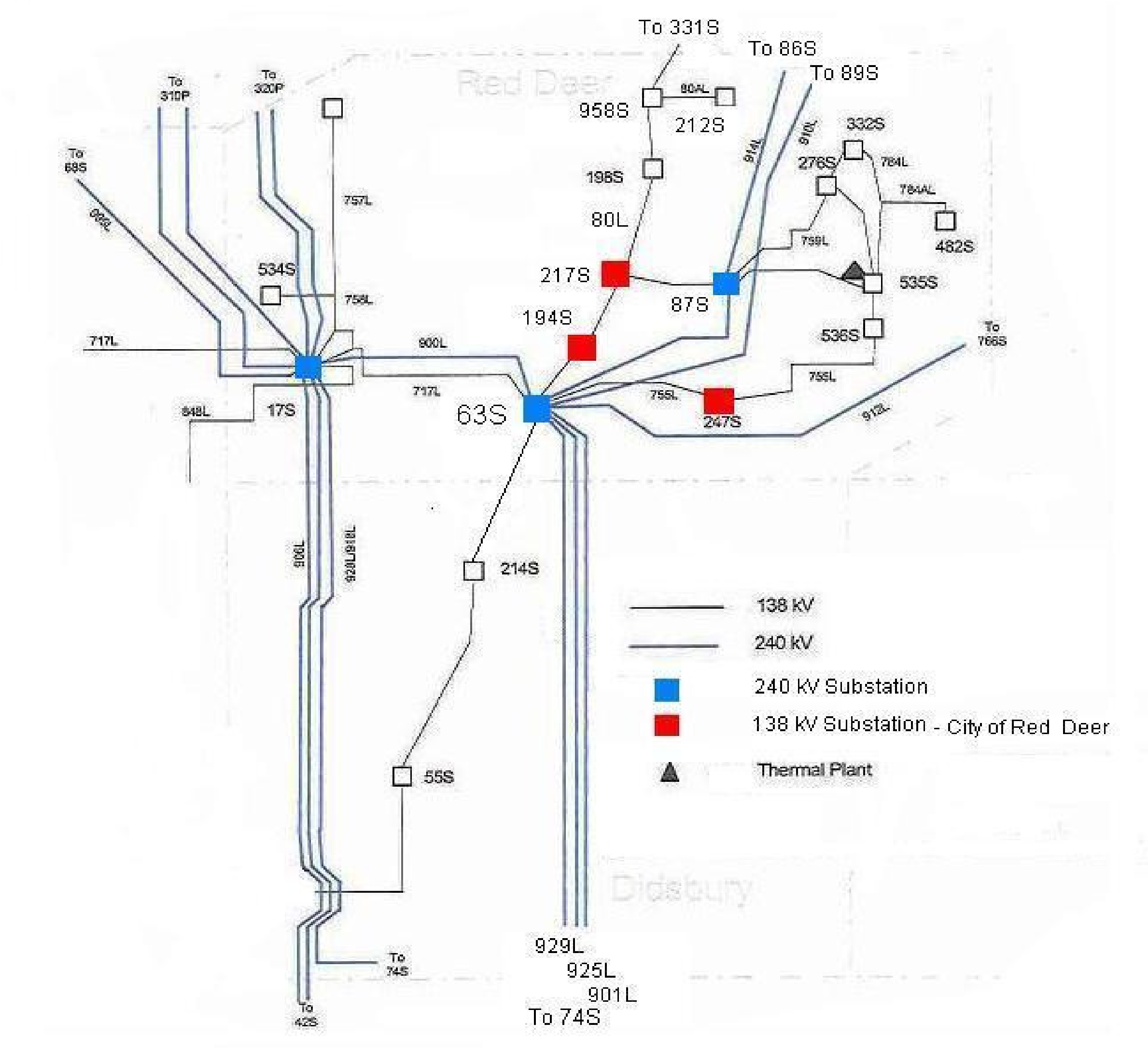
3.1 Existing Transmission System

The City of Red Deer is currently served by a 138 kV network fed by AltaLink 240/138 kV substations (Red Deer 63S, Gaetz 87S) and Nova generation at the Joffre plant (Joffre 535S). Geographically, this network is included in the AIES Regional Transmission Area 35. The 240 kV lines supplying 63S and 87SS form part of the AIES transmission path known as the SOK (South of Keephills) cut-plane. The 138 kV lines 755L (off 63S) and 759L, 793L, 756L (off 87S) form the Joffre area inflow cut-plane. The outgoing 138 kV lines off 535S form the Joffre area out-flow plane. Figure 3.1-1 shows the Red Deer Area Transmission System. Transformer ratings and generation levels at substations 63S, 87S and 331S are shown in Table 3.1-1.

Table 3.1-1 In-City 138 kV Transmission Network Sources

Substation	Transformation	Generation
63S Red Deer	240/138 kV, 2 x 200 MVA	
87S Gaetz	240/138 kV, 2 x 200 MVA	
330S Nova - 535S Joffre	18/138 kV, 3 x 185 MVA	470 MW

Figure 3.1-1 Red Deer (Area 35), AIES Regional Transmission



Currently, ELP (as a TFO and a DFO) operates (along with AltaLink) three substations:

- 194S - South Red Deer, City of Red Deer #15 Substation (RD15S)
- 217S – North Red Deer, City of Red Deer #14 Substation (RD14S)
- 247S – Piper Creek, City of Red Deer #17 Substation (RD17S)

For each of the above substations, all 138 kV equipment, except 138 kV power transformers and 138 kV motor operated disconnects (MODs), are owned and operated by AltaLink. The City owns the substation land and all site property. These substations are supplied by 138 kV lines 80L, 778L, 755L from substations 63S (Red Deer), 87S (Gaetz) and 535S (Joffre) as shown in Figures 3.1-2 and 3.1-3. All existing transmission lines feeding ELP substations are owned by AltaLink. Transformer ratings at ELP substations RD14S, RD15S and RD17S are shown in Table 3.1.2

Table 3.1-2 Transmission/Distribution Substation Capacity

Substation	Transformation/Winter	Transformation/Summer
217S/RD14S	100 MVA	100 MVA
194S/RD15S	100 MVA	100 MVA
247S/RD17S	70 MVA	60 MVA

3.1.1 Constraints

Transmission Lines

The study completed by AESO in 2009 [1] showed that the capacity constraints of the of transmission lines supplying City's substations result in the following problems:

1. The 2012 Winter Peak case with Nova generation off-line would result in:

   a. Voltage range violations under normal operating conditions and shortage of reactive power required to support voltage profile.
   b. Overloading 80L (North Red Deer 217S/RD14S through South Red Deer 194S/RD15S to Red Deer 63S).
   c. Overloading 755L (Red Deer 63S to Piper Creek 247S/RD17S) under 80L (South Red Deer 194S/RD15S to Red Deer 63S) outage.
   d. Overloading autotransformers at Gaetz 87S (104 % of its winter peak rating) after outage of another autotransformer in the Gaetz 87 substation.

2. If high SOK cut-plane flows are experienced during the 2012 summer with Nova generation at 434 MW, the following local transmission issues are:

    a. Overloading 80L (South Red Deer 194S/RD15S to North Red Deer 217S/RD14S) from 102% to 207% under certain contingencies.
    b. Overloading 755L (Joffre 535S to Piper Creek 257S) under 80L (South Red Deer 194S/RD15S to North Red deer 217S/RD14S).
    c. Overloading 80L (South Red Deer 194S/RD15S under 914L (Red Deer 63S to Gaetz 87S) outage.

Because of the Joffre outflow and inflow constrains, AESO Operating Policies and Procedures (OPP) 502 [4] limits power transfer into and out of the Joffre area. As a result, the City's substation RD17S is currently affected by OPP 502 requirements, which means compulsory load curtailment at substation's POD (based on DTS contracted with AESO) when Nova generation is offline.

The City Substations

ELP is concerned about:

- Limitation of substation capacities.
- Reliability.

Substations RD15S and RD17S transformation capacities are insufficient to meet the single element outage (N-1) criterion. Furthermore, because a number of transformers are approaching the end of their useful life, the probability and consequence of their failures are high.

The need for increased capacity of substations is addressed in Section 4 of this master plan as part of the medium (2011-2015) and long term (2016-2025) strategic planning of the City's transmission system.

The need for increasing system reliability (in 2018-2023) is the main driver for planning replacement of existing transformers as shown in Table 3.1.1-1.

Table 3.1.1-1 ELP Power Transformers Replacement Plan

Transformer	Voltage kV	Size MVA	Built Year	Replacement Year
14T1	138/25 kV	36.4/40/50	1978	2018-2019
14T2	138/25 kV	30/40/50	1984	2022-2023
15T1	138/25 kV	36.4/40/50	1978	2017-2018
15T2	138/25 kV	30/40/50	1982	2021-2022

ELP short term plan (2011-2013), which is closely coordinated with the medium and long term planning, includes the “like for like” replacement of aged facilities and equipment to enhance the system reliability. This short term plan includes the following projects:
:

- In 2011, the obsolete protection and control building at the RD14S substation will be replaced with new building including IED protection, control and communication equipment, and LAN supporting the IEC-61850 standard and allowing substation automation.

- In 2012, the two 25 kV breakers will be replaced at the RD14S substation.

- By 2013, the RD15S 25 kV switchgear will be replaced with new switchgear complete with busbars, breakers, protection and control, communications, SCADA, and other equipment. Transformer–breaker 25 kV incomer cables will be replaced to avoid overloading (existing 3 – Cu 500 kcmil per phase C/N cables have insufficient ampacity and 3 - Cu 750 kcmil per phase C/N cables are proposed).

3.2 Existing Bulk Distribution System

ELP bulk distribution system is comprised of 25 kV feeder trunks (or just feeders) emanating from each substation. Each feeder is connected to the adjacent feeder through a normally open load break tie switch. All substations are interconnected by feeders forming open loops, i.e. during normal operations all feeders are configured as radial. The existing distribution system topology is shown in Figure 3.2-1. By closing a tie switch between adjacent feeders, the load transfer is possible between substation transformers. ELP practices so called "hot feeder switching" allowing uninterruptible load transfers between substations. It means temporary paralleling the distribution system with the transmission system before opening a particular feeder breaker at the substation. All ELP tie switches are capable of interrupting up to 600 A at 25 kV. These switches must have enough interruption capacity, taking into account possible circular flows, to allow the break back to radial service.

3.2.1 Constraints

Insufficient Feeder Ampacities

The existing feeders are comprised of sections of 1 - Cu 350 kcmil per phase C/N underground cables and typically 4 – ACSR 336 kcmil (including neutral) overhead sections. Feeder ampacities are limited by the maximum allowable current of cables, which depends on the installation method, cable configuration, soil thermal resistivity, and load profile.

According to the ELP Standards of Service the maximum feeder loading under normal operation is limited to 8 MVA at 25 kV (185A), which provides 16 MVA at 25 kV (or 370A) capacity to supply entire loads of two feeders (in case of a breaker failure, its maintenance, or required load transfer between substations). Taking into account technical, economic and handling aspects, Cu 750 kcmil cable was selected as the optimal option. As this cable meets the Standard of Service requirements, ELP will successively replace all feeder cables with Cu 750 kcmil C/N cables.

4.0 DEVELOPMENT PLANS

4.1 Transmission System

4.1.1 Need for Red Deer Region System Reinforcement

AESO identified [5] the need for transmission system development in the region using the following key drivers:

- Load growth of 3.5 per cent expected over next ten year period.
- Providing access to the transmission network for proposed ~400 MW of wind generation.
- Mitigating the existing constraints in the Joffre area (OPP 502).

4.1.2 Transmission System Development Proposed by AESO

AESO has considered the following development alternatives:

- Alternative 1 includes:

  a. Upgrading the Didsbury 152S substation to 240 kV.
  b. Upgrading the 80L line (double circuit) from Didsbury 152S through the City of Red Deer to Ponoka 331S (higher ampacity required).
  c. Upgrading 755L and other transmission lines in the area (higher ampacity required due to constraints in the Joffre area).

- Alternative 2 includes:

  a. Upgrading Didsbury 152S, Innisfail 214S, and Ponoka 331S to 240 kV.
  b. Salvaging sections of the 80L lines from Innisfail to Red Deer and from Lacombe 958S to Ponoka 331.
  c. Upgrading other sections of the 80L line (higher ampacity but double circuit not required).
  d. Upgrading 755L and other transmission lines in the area (higher ampacity required related to constraints in the Joffre area).
  e. Adding a 138 kV transmission line between the Lacombe 212S and Ellis 332S substations.

The final NID document (including determination of preferred alternative) will be completed by AESO in November 2011. From the City's perspective, alternative 2 is more attractive since it provides required flexibility in the future in-city transmission network development.

4.1.3 Need for In-City System Expansion

The key drivers for the need for transmission development in the City are:

- Territorial and demographic expansion and growing demand for electricity.
- Inability of existing substations (due to their locations and capacity constraints) to supply new electrical service areas.
- Limited options available for upgrading existing substations.

Tables 4.1.3-1 and 4.1.3-2 show that:

1) By 2022 90% of the available transmission supply capacity will be exhausted. At that point regular overloading on the transformers will be unavoidable.

2) By 2017, there is a possibility of load being at risk since 91% of the available transmission supply capacity would be exhausted, when failure of a transmission element occurs (N-1 contingency).

Table 4.1.3-1 The City Load as Percentage of Total Capacity of Existing Substations RD14S, RD15S, RD17S

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
System Load /Sub. Capacity [%](1) (2)	57	62	66	69	71	72	73	76	78	81	84	89	94	98	104

Notes:
(1) Substation total transformation capacity (all transformers in operation) = 260MVA
(2) Assumed power factor = 0.96

Table 4.1.3-2 The City Load as Percentage of N-1 Capacity of Existing Substations RD14S, RD15S, RD17S

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
System Load/ S_{N-1} Sub. Capacity [%] (1) (2)	70	77	81	85	87	89	91	94	96	100	104	111	116	122	128

Notes:
(1) Capacity S_{N-1} = 260 MVA – 50 MVA (largest transformer)=210 MVA
(2) Assumed power factor = 0.96

4.1.4 In-City System Expansion Proposed by the City

The City proposes the following system development within its boundaries:

- Adding two 138/25 kV substations and upgrading the existing substation RD15S as listed in Table 4.1.4-1.
- Construction of transmission lines as shown in Table 4.1.4-2.

Table 4.1.4-1 New 138/25 kV Substation Installations and Upgrades

Substation	Location	TFO	Project Cycle
E. Red Deer RD1S – New Sub.	¼ Section 23-38-27 NW (1)	CoRD	2011 – 2015 (2)
S. Red Deer RD15S - Upgrade (4)	Downtown	CoRD	2017 - 2018
W. Red Deer RD10S	¼ Section 25-38-28 SE (1)	CoRD	2022 – 2026 (3)

Notes:
(1) Land owned by the City.
(2) Funds to purchase land allocated in 2011 ELP budget.
(3) Funds to purchase land to be allocated in 2012 ELP budget.
(4) Adding a third 50 MVA transformer.

ELP proposes two transmission line options to supply the new substation E. Red Deer RD1S as shown a shown in Table 4.1.4.2. The lines supplying the proposed W. Red Deer RD10S substation are listed in Table 4.1.4-3.

The Substation Land Acquisition and Transmission Line ROW

- Substation E. Red Deer RD1S & Transmission Lines

  ELP has initiated the process working with the City's Land services to acquire the land for the new substation as well as on the right of way agreement for the transmission lines (see Figures 4.1.4-1a and 4.1.4-1b).

- Substation W. Red Deer RD10S & Transmission Lines

  ELP has teamed up with the City's Land Service to acquire the land for the new substation by 2012.

The City intends to have annexation of the City Growth Area completed in 2017-2020. By this time, it is advisable for the City Planning to consider establishing a Transportation and Utility Corridor (TUC), which would be used for new power and bulk distribution lines as well as major roads and other utilities. Having such a TUC would streamline the plan, design and construction process of the new transmission line required in 2022-2025 period (as shown in Table 4.1.4-3).

Table 4.1.4-2 In-City 138 kV Transmission Lines, 2012-2020

Transmission Line - Option 1 (see Figures 4.1.4-2a and 4.1.4-2b)				
From	**To**	**TFO**	**Comments**	**Project Cycle**
Gaetz 87S	N. Red Deer RD1S	AltaLink/ CoRD	Upgrading 768L/778L; Additional breakers required at 87S and 217S	2012 – 2015 (Phase 1)
E.Red Deer RD1S	Line 778L	AltaLink/ CoRD	Double circuit in-and-out on existing 778L	2012 – 2015 (Phase 1)
Red Deer 63S	910L and 914 NS ROW	AltaLink	Upgrading existing 755L – double circuit with single side strung	2012 – 2015 (Phase 1)
Red Deer 63S	Piper Creek RD17S	AltaLink/ CoRD	Stringing second circuit. Additional breaker required at 63S	2018-2020 (Phase 2)
Piper Creek RD17S	E.Red Deer RD1S	AltaLink/ CoRD	New line	2018 – 2020 (Phase 2)
Red Deer RD1S	Line 778L	AltaLink/ CoRD	Salvaging second circuit	2018 -2020 (Phase 2)
Transmission Line - Option 2 (see Figure 4.1.4-3)				
Line 778L	E. Red Deer RD1S	AltaLink	Double circuit line in-and-out on existing 778L	2012 – 2015
E. Red Deer RD1S	Line 778L	AltaLink		2012 - 2015

Table 4.1.4-3 In-City 138 kV Transmission Lines, 2022-2025

Transmission Line - Option 1 (see Figure 4.1.4-4)				
From	**To**	**TFO**	**Comments**	**Project Cycle**
Red Deer 63S	W. Red Deer RD10S	AltaLink/ CoRD	Additional breaker required at 63S	2022 - 2025
W. Red Deer RD10S	N. Red Deer RD14S	AltaLink/ CoRD	Additional breaker required at 217S	2022 - 2025
Transmission Line - Option 2 (see Figure 4.1.4-5)				
Line 80L	W. Red Deer RD10S	AltaLink/ CoRD	Double circuit line in-and-out on existing 80L	2024 - 2025
W. Red Deer RD10S	Line 80L	AltaLink/ CoRD		2024 - 2025

4.2 Planning Procedure

The proposed system reinforcement and expansion described in section 4.1.4 is based on the planning procedure, which includes:

(1) Forecast of long-term load distribution
(2) Determination of required substation capacities (under N-0 and N-1 conditions)
(3) Determination of number of substations
(4) Determination of new substation sites
(5) Verification of new and existing substation service areas
(6) Specifying standards for new substations
(7) Proposing in-City transmission system configuration options
(8) Upgrading bulk distribution system tying the City's substations.

Although, the above tasks are presented in a linear sequence, there area many loops in this basic planning procedure, because the system features cannot be set independently of each other. Therefore, the planning staff always has to loop back certain tasks to optimize the system performance. For instance, the final substation service areas are determined at the end of the planning process during the fine tuning of the system by changing the position of the open points of the feeders tying different substations. The following sections briefly explained the basic planning procedure.

Forecast of Long-Term Load Distribution

A necessary element of effective power system planning is the knowledge of the future load levels and its geographic locations. The spatial load forecasting, described in “Electric Light & Power Future Demand and Energy Outlook (2010 – 2025) provides information about the future load densities inside the existing and future City boundaries. Thanks to departmental geographic information system, the existing and future electricity demands can be coupled with geographic locations and supply areas can be established. Thereafter, the distribution and transmission can be modeled in Cyme (a network calculation program, owned by ELP) for steady state and short circuit calculations.

Substation Capacities

Calculation of required substation capacities in the City areas includes consideration of normal conditions (all elements in service or “N-0”) and “N-1” conditions, i.e. the largest transformer in the system being out of service. The substation capacities are influenced by substation configurations (number of transformers) and the short circuit withstand capability of 25 kV distribution switchgear. To limit the available short circuit currents, the ELP standards require the transformer power rating shall not exceed 50/56 MVA, with a minimum short circuit impedance of 10%.

Table 4.2.1 shows proposed substation options, including typical power transformer MVA ratings and cooling systems.

Table 4.2-1 Capacities of New and Upgraded Substations [1] [2] [3]

Table 4.2.1 Option A			
Year	**Proposed RD1S**	**Existing RD15S**	**Proposed RD10S**
2015	New 3-18/24/30 MVA S_{N-0} =90 MVA S_{N-1} =60 MVA	Existing 2 – 36.4/40/50 MVA S_{N-0} = 100 MVA S_{N-1} = 50 MVA	
2017		Add 1-30/40/50 MVA S_{N-0} = 150 MVA S_{N-1} = 100 MVA	
2024	Add 1-18/24/30 MVA S_{N-0} = 120 MVA S_{N-1} = 90 MVA		
2026			New 2-18/24/30 MVA S_{N-0} = 60 MVA S_{N-1}= 30 MVA

Table 4.2.1 Option B			
Year	**Proposed RD1S**	**Existing RD15S**	**Proposed RD10S**
2015	New 2-25/33/41 MVA S_{N-0} = 82 MVA S_{N-1} = 41 MVA	Existing 2 – 36.4/40/50 MVA S_{N-0} = 100 MVA S_{N-1} = 50 MVA	
2017		Add 1-30/40/50 MVA S_{N-0} = 150 MVA S_{N-1} = 100 MVA	
2020	Add 1-25/33/41 MVA S_{N-0} = 123 MVA S_{N-1} = 41 MVA		
2026			New 2-25/33/41 MVA S_{N-0} = 82 MVA S_{N-1} = 41 MVA

Table 4.2.1 Option C			
Year	**Proposed RD1S**	**Existing RD15S**	**Proposed RD10S**
2015	New 2-30/40/50 MVA S_{N-0} = 100 MVA S_{N-1} = 50 MVA	Existing 2 – 36.4/40/50 MVA S_{N-0} = 100 MVA S_{N-1} = 50 MVA	
2017		Add 1-30/40/50 MVA S_{N-0} = 150 MVA S_{N-1} = 100 MVA	
2024	Add 1-30/40/50 MVA S_{N-0} = 150 MVA S_{N-1} = 100 MVA		
2026			New 2-30/40/50 MVA S_{N-0} = 100 MVA S_{N-1} = 50 MVA

NOTES:

(1) RD 14S and RD17S capacities remain unchanged:

RD14S:	RD17S:
S_{N-0} = 100 MVA S_{N-1} = 50 MVA	S_{N-0} = 60MVA S_{N-1} = 30 MVA

(2) S_{N-0} denotes the substation MVA capacity when all power transformers of each substation supply load at their nominal MVA.

(3) S_{N-1} denotes the substation MVA capacity when the largest power transformer of each substation is shut down and other transformers supply load at their nominal MVA.

Determination of Number of Substations

In general, the total number of substations in the City boundary depends on the total demand in the area under consideration and N-0 and N-1 capacities of substations (See Tables 4.1.3-1 and 4.1.3-2). Ideally, the N-1 capacity of each substation shall match expected power demand.

Based on the past ELP's experience, the ratio of the City peak demand to total N-0 capacity of all substations should not exceed 60%, assuming that additional reserve is available from adjacent substations. According to Table 4.2-2, in 2012-2014 this ratio is higher by 2%...9%, and therefore in 2015 ELP plans to commission the new RD1S.

By 2025/2026 the above ratio may again exceed 60%, and therefore the new RD10S substation is proposed in the North-West part of the City. According to current available planning data, by 2026 five (5) should be available to match the expected load growth.

For optional capacities of new substations see Table 4.2.1.

Table 4.2-2 The City Peak Demand as Percentage of Total Capacity of Existing, New and Upgraded Substations

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Peak MW	142	155	164	171	175	179	183	189	194	202	210	223	234	245	259	267
Peak MVA	148	161	171	178	182	186	191	197	202	210	219	232	244	255	270	278
OPTION 1 Peak MVA / S_{N-0} [%] (1) (2)	57	62	66	69	52	53	48	49	51	53	55	58	61	59	63	57
OPTION 1 Peak MVA / S_{N-1} [%] (1) (2)	70	77	81	85	61	62	54	56	58	60	63	66	70	67	71	63
OPTION 2 Peak MVA / S_{N-0} [%] (1) (2)	57	62	66	69	53	55	49	50	52	49	51	54	56	59	62	53
OPTION 2 Peak MVA / S_{N-1} [%] (1) (2)	70	77	81	85	62	64	56	58	59	55	57	61	64	67	70	59
OPTION 3 Peak MVA / S_{N-0} [%] (1) (2)	57	62	66	69	51	52	46	48	49	51	53	57	59	55	59	50
OPTION 3 Peak MVA / S_{N-1} [%] (1) (2)	70	77	81	85	59	60	53	55	56	58	61	65	68	62	66	54

Notes:
(1) Assumed power factor=0.96
(2) S_{N-0} denotes the MVA capacity of all substations (all transformers can supply the load at their nominal MVA).
(3) S_{N-1} denotes the MVA capacity of all substations when only one the largest power transformer of all substations is shut down and other transformers can supply the load at their nominal MVA.

Determination of Substation Sites and Service Areas

The substation service areas in years 2015, 2020 and 2025/2026 are depicted in Figures 4.4-1, 4.4-2 and 4.4-3.

The substation capacities vs. anticipated load in 2014-2026 are shown in Table 4.2-3.

Table 4.2-3 Substation Loading

Table 4.2-3 RD14S Service Area				
Service Area Peak Demand				
Year 2014	Year 2015	Year 2020	Year 2025	Year 2026
58 MW Cos fi = 0.94 S=62 MVA	37 MW Cos fi = 0.94 S=39 MVA	46 MW Cos fi = 0.94 S=49 MVA	62 MW Cos fi = 0.94 S=66 MVA	47 MW Cos fi = 0.94 S=50 MVA
S/S_{N-0} Capacity Ratio				
S_{N-0}=100MVA 62%	S_{N-0}=100MVA 39%	S_{N-0}=100MVA 49%	S_{N-0}=100MVA 66%	S_{N-0}=100MVA 50%
S/S_{N-1} Capacity Ratio				
S_{N-1}=50MVA 123%	S_{N-1}=50MVA 79%	S_{N-1}=50MVA 98%	S_{N-1}=50MVA 132%	S_{N-1}=50MVA 100%

Table 4.2-3 RD15S Service Area				
Service Area Peak Demand				
Year 2014	**Year 2015**	**Year 2020**	**Year 2025**	**Year 2026**
71 MW Cos fi = 0.95 S=75 MVA	56 MW Cos fi = 0.95 S=59 MVA	62 MW Cos fi = 0.95 S=65 MVA	85 MW Cos fi = 0.95 S=89 MVA	76 MW Cos fi = 0.95 S=80 MVA
S/S_{N-0} Capacity Ratio				
S_{N-0} =100MVA 75%	S_{N-0} =100MVA 59%	S_{N-0}=150MVA 44%	S_{N-0}=150MVA 60%	S_{N-0}=150MVA 53%
S/S_{N-1} Capacity Ratio				
S_{N-1}=50MVA 149%	S_{N-1}=50MVA 118%	S_{N-1}=100MVA 65%	S_{N-1}=100MVA 89%	S_{N-1}=100MVA 80%

Table 4.2-3 Service Area RD17S				
Service Area Peak Demand				
Year 2014	**Year 2015**	**Year 2020**	**Year 2025**	**Year 2026**
42 MW Cos fi = 0.98 S=43 MVA	36 MW Cos fi = 0.98 S=37 MVA	42 MW Cos fi = 0.98 S=43 MVA	44 MW Cos fi = 0.98 S=45 MVA	46 MW Cos fi = 0.98 S=47 MVA
S/S_{N-0} Capacity Ratio				
S_{N-0}=60MVA 72%	S_{N-0}=60MVA 62%	S_{N-0}=60MVA 72%	S_{N-0}= 60MVA 75%	N-0 =60MVA 78%
S/S_{N-1} Capacity Ratio				
		S_{N-1}=30MVA 143%	S_{N-1}=30MVA 150%	S_{N-1}=30MVA 157%

Table 4.2-3 Service Area RD1S				
Service Area Peak Demand				
Year 2014	**Year 2015**	**Year 2020**	**Year 2025**	**Year 2026**
n/a	46 MW Cos fi = 0.97 S=47 MVA	52 MW Cos fi = 0.97 S=54 MVA	67 MW Cos fi = 0.97 S=69 MVA	69 MW Cos fi = 0.98 S=71 MVA
Substation Option A - S/S_{N-0} Capacity Ratio				
n/a	S_{N-0}=90MVA 52%	S_{N-0}=90MVA 60%	S_{N-0}=120MVA 58%	S_{N-0}=120MVA 59%
Substation Option A - Load / Capacity (N-1) Ratio				
	N-1=60MVA 79%	N-1=60MVA 89%	N-1=90MVA 77%	N-1=90MVA 79%
Substation Option B - S/S_{N-0} Capacity Ratio				
n/a	S_{N-0}=82MVA 58%	S_{N-0}=123MVA 44%	S_{N-0}=123MVA 56%	S_{N-0}=123MVA 58%
Substation Option B - S/S_{N-1} Capacity Ratio				
n/a	S_{N-1}=41MVA 116%	S_{N-1}=82MVA 65%	S_{N-1}=82MVA 84%	S_{N-1}=82MVA 87%
Substation Option C - S/S_{N-0} Capacity Ratio				
n/a	S_{N-0}=100MVA 47%	S_{N-0}=150MVA 54%	S_{N-0}=150MVA 46%	S_{N-0}=150MVA 47%
Substation Option C - S/S_{N-1} Capacity Ratio				
n/a	S_{N-1}=50MVA 95%	S_{N-1}=50MVA 107%	S_{N-1}=50MVA 69%	S_{N-1}=50MVA 71%

Table 4.2-3 Service Area RD10S				
Service Area Peak Demand				
Year 2014	Year 2015	Year 2020	Year 2025	Year 2026
n/a	n/a	n/a	n/a	46 MW Cos fi = 0.98 S=80 MVA
Substation Option A - S/S_{N-0} Capacity Ratio				
n/a	n/a	n/a	n/a	S_{N-0}=60MVA **29%**
Substation Option A - S/S_{N-1} Capacity Ratio				
n/a	n/a	n/a	n/a	S_{N-1}=30MVA **88%**
Substation Option B - S/S_{N-0} Capacity Ratio				
n/a	n/a	n/a	n/a	S_{N-0}=82MVA **32%**
Substation Option B - S/S_{N-1} Capacity Ratio				
n/a	n/a	n/a	n/a	S_{N-1}=41MVA **64%**
Substation Option C - S/S_{N-0} Capacity Ratio				
n/a	n/a	n/a	n/a	S_{N-0}=100MVA **26%**
Substation Option C - S/S_{N-1} Capacity Ratio				
n/a	n/a	n/a	n/a	S_{N-1}=50MVA **53%**

Verification of New and Existing Substation Service Areas

In order to balance the load between substation service areas, the final adjustment of 25 kV normally open points on feeders interconnecting substations may be required. This fine tuning would slightly change new and existing substation service areas.

Specifying Standards for New Substations

See Section 4.3

Proposing in-City Transmission System Configuration Options

See Section 4.1

Upgrading Bulk Distribution System Tying the City's Substations

See Section 4.4

4.3 New Substation Standard Specifications

New standards will be developed for new substations. At this stage, ELP considers the following factors influencing the design of RD1S substation:

- Due to the proximity to the residential subdivision, the substation should be blended with the environment, which affects a building, fencing, and other facilities.
- The compact substation design concept should be considered to allow reduction in space requirements and number of foundations and civil works and allow efficient engineering and shorter project time.

From a technical point of view the requirements include:

- A substation design that allows for future expansion, e.g. additional power transformer installation.
- Bus/switching configuration flexibility.
- Long equipment life expectancy with minimal maintenance.
- Electrical and mechanical ratings of equipment which are sufficient to match steady and transient states of the transmission system.

All of the above technical requirements will be provided at the interconnection study and proposal stage as required by AESO.

4.4 Bulk Distribution System Expansion

The existing bulk distribution system of the City described in Section 3.2 and illustrated by Figure 3.2-1, is configured as an open loop network normally operated with radial topology. A number of feeders interconnect substations to allow load transfer under contingency conditions. Due to this requirement, ELP will upgrade, in the period of 2010-2025, all its 25 kV feeders increasing their continuous capacity to 16 MVA.

However, in spite of upgrading the existing feeders will be not able to handle the forecast load. For instance, by 2015 seven (7) feeders would be overloaded under contingency conditions, and this number would grow every year reaching twelve (12) feeders by 2018. Therefore, ELP has to expand its distribution network to include new loops between new and existing substation as shown in Figures 4.4-1, 4.4-2 and 4.4-3. Table 4.4-1 shows existing feeder breakers normally energized at each substation. At present, there are total 29 feeders in the City's open loop distribution network. ELP plans to increase this number by 8 new feeders having total 37 feeders in 2015 and continue systematic upgrade of the bulk distribution system in consecutive years. By 2026, a total of 48 feeders is expected to be in the system which will enhance its reliability and flexibility.

The projected cost of bulk distribution system expansion in 2011-2025 is shown in Appendix C, Table C2.

Table 4.4-1 Existing and New Energized Feeder Breakers

Sub. Year	RD14S		RD15S		RD17S		RD1S		RD10S	
	Total Brkrs.	New Brkrs.	Total Brkrs.	New Brkrs.	Total Brkrs.	New[(1)] Brkrs.	Total Brkrs.	New Brkrs.	Total Brkrs.	New Brkrs.
2010	10	--------	12	----------	7	---------	0	----------	0	----------
2011	10	--------	12	----------	7	---------	0	----------	0	----------
2012	10	--------	12	----------	7	---------	0	----------	0	----------
2013	10	--------	13	15.B.90	7	---------	0	----------	0	----------
2014	10	--------	14	15.B.91	8	1.B.76	0	----------	0	----------
2015	10	--------	14	----------	8	---------	5	1.B.101 1.B.102 1.B.107 1.B.109 1.B.110	0	----------
2016	10	--------	14	----------	8	---------	5	---------	0	----------
2017	10	--------	14	----------	8		8	1.B.103 1.B.104 1.B.108	0	----------
2018	10	--------	15	15.B.93	8	---------	8	----------	0	----------
2019	10	--------	15	----------	8	---------	8	----------	0	----------
2020	10	0	15	----------	8	---------	9	1.B.106	0	----------
2021	10	0	15	---------	8	---------	9	----------	0	
2022	10	0	16	15.B.92	8	---------	9	----------	0	
2023	10	0	16	----------	8	---------	9	----------	0	
2024	10	0	16	----------	8	---------	9	----------	0	
2025	10	0	16	----------	8	---------	9	----------	0	
2026	10	0	16	----------	8	---------	9	----------	5	10.B.200 10.B.201 10.B.206 10.B.207 10.B.208

Note: [(1)] Vacant feeder breakers available at RD17S.

5.0 EVALUATION OF IN-CITY TRANSMISSION SYSTEM ALTERNATIVES

The purpose of this evaluation is to compare alternative options of transmission account certain quantitative and qualitative criteria as described in the following sections. The proposed new transmission facilities, including two new substations and new 138 kV transmission lines supplying these substations, are listed in Table 5.0-1.

Table 5.0-1 Proposed New Transmission Facilities

Project (1)	Project Name	Options	Start-Completion	Project Description	Need Description
I	New Substation East Red Deer – RD1S	A B C	2011-2015	New 138/25 kV Substation – **Option A:** Total 4-30MVA transformers: 3-30MVA (2015) 4-30MVA (2024) **Option B:** Total 3- 41MVA transformers: 2-41MVA (2015) 3-41MVA (2020) **Option C:** Total 3-50MVA Transformers: 2-50MVA (2015) 3-50MVA (2024)	Transmission/ distribution capacity improvement
II	New Substation West Red Deer-RD10S	A B C	2024-2026	New 138/25 kV Substation – **Option A:** 2-30MVA (2026) **Option B:** 2-41MVA (2026) **Option C:** 2-50MVA (2026)	Transmission/ distribution capacity improvement

III, IV	Transmission Lines supplying RD1S	1, 2	**Option 1:** 2012-2015 (phase 1) 2018-2020 (phase 2) **Option 2:** 2012-2015	Options 1 and 2 are described in Table 4.1.4-2	Transmission/ distribution capacity improvement
V	Transmission Lines supplying RD10S	1, 2	**Option 1:** 2022-2025 **Option 2:** 2024-2025	Options 1 and 2 are described in Table 4.1.4-3	Transmission/ distribution capacity improvement

(1) It should be noted that the City also plans to replace or add new equipment at existing substations including:

VI. RD15S, Replacement of Breakers, Busbars, and P&C	in 2011-2013
VII. RD15S, Addition of Incomer and Feeder Breakers	in 2013-2015
XII. RD15S, Addition of 3rd Transformer	in 2016-2017
VIII. RD15S, Replacement of 15T1	in 2017-2018
IX. RD14S, Replacement of 14T1	in 2018-2019
X. RD15S, Replacement of 15T2	in 2021-2022
XI. RD15S, Replacement of 14T2	in 2020-2021

Costs of the above projects are shown in Appendix C, Table C1.

5.1 Comparison of Options of Proposed Substations

Proposed Substation RD1S

Three options were considered. All three options meet normal and single contingency criteria as well as reliability and operational flexibility. Option A has slightly higher N-1 MVA capacity than Options B and C. Capital investment costs for all three options including transformers, pads, oil spill containments, circuit breakers and MODs (net present value - NPV with an annual discount rate of 8%) are shown below:

$NPV (2011) Transformer Substation Options:

- Option A: $7,859,00
- Option B $3,014,00
- Option C $3,150,00

Presuming Option B for the new substation RD1S with 2- 41 MVA transformers by 2015 and the provisions for the future capacity increase to 3- 41 MVA, the estimated investment cost in 2011-2015 is shown in Table 5.1

Table 5.1-1 RD1S Substation Projected Capital Cost (x 1000)

Year	2011	2012	2013	2014	2015
Cost		$700	$3,100	$7,200	$7,300
Cost of Land	$600				
Cost + Inflation	$600	$713.720	$3,222.711	$7,631.712	$7,889.367

Proposed Substation RD10S

Three options were considered. Each of them meets normal and single contingency criteria as well as reliability and operational flexibility. Option A has slightly higher N-1 MVA capacity than Options B and C. Taking into account capital investments cost similarly to calculations of RD1S substation options, installing 2-41 MVA transformers (with a provision for future upgrade to 3-41 MVA) seems to be the preferable substation configuration. It should be noted that determining the required substation capacity beyond 2026 is not possible due to lack of forecasted load.

Presuming Option B for the new substation RD1S with 2- 41 MVA transformers by 2015 and the possible provisions for the future capacity increase to 3- 41 MVA, the estimated investment cost in 2016-2026 is shown in Table 5.1-2.

Table 5.1-2 RD10S Substation Projected Capital Cost (x 1000)

Year	2016	2023	2024	2025	2026
Cost		$700.00	$3,000.0	$8,000.0	$6,000.0
Cost of Land	$600				
Cost + Inflation	$661.15	$3,861.08	$10,498.0	$8,027.84	$7,889.367

5.2 Comparison of In-City Transmission Line Options

Two options of new 138 kV transmission lines for each of the new substations RD1S and RD10S have been compared in the following tables.

Transmission Lines Supplying RD1S Substation

Tables 5.2-1, 5.2-2 and 5.2-3 present qualitative and quantitative comparisons of alternatives of transmission lines supplying the new RD1S substation.

Table 5.2-1 RD1S Transmission Lines, Qualitative Comparison of Options

Description	Options	
	1	2
Number of 138 kV Transmission Developments	New Lines: 2 (9.3 km) Line Upgrades: 1 (15.5 km)	New Lines: 1 (2.0 km) Line Upgrades: 2 (15.5 km)
240/138 kV Substation Upgrades	138 kV Breaker Additions: 2	138 kV Breaker Additions: 2
Reliability Criteria	Satisfied	Satisfied
Operational Flexibility	Yes	Yes
City-Owned Transmission Network Expansion Feasibility	High	Low
Available Capacity to Accommodate Future Growth	Further load flow calculations required	Further load flow calculations required

Table 5.2-2 Option 1 of RD1S Transmission Lines, Capital Cost (x 1000)

From	To	L (km)	1000$/km	Cost	Constr. Year	Cost + Inflation	Notes	TFO
87S	217S	n/a	n/a	2,000.00	2013	2,079.17	(1)	AltaLink
87S	217S	6	90	540.00	2013	561.38	(2)	AltaLink
RD1S	778L	2	610	1,220.00	2013	1,268.29	(3)	CoRD
63S	RD17S	9.5	540	5,130.00	2013-2014	5,385.33	(4)	AltaLink
63S	RD17S	9.5	90	855.00	2018-2020	998.76	(5)	CoRD
RD17S	RD1S	7.8	280	2,184.00	2018-2020	2,551.21	(6)	CoRD

Notes:
(1) 2 – 138 kV circuit breakers additions at 87S and 217S
(2) Existing line upgrade
(3) New double circuit in-and-out tapped off existing 778L
(4) Double circuit one side strung
(5) Double circuit second circuit strung
(6) New CoRD line

Table 5.2-3 Option 2 of RD1S Transmission Lines, Capital Cost (x 1000)

From	To	L (km)	1000$/km	Cost	Constr. Year	Cost + Inflation	Notes	TFO
87S	217S	n/a	n/a	2,000.00	2013	2,079.17	(1)	AltaLink
87S	217S	6	90	540.00	2013	561.38	(2)	AltaLink
RD1S	778L	2.0	610	1,220.00	2013	1,268.29	(3)	CoRD
63S	RD17S	9.5	280	2,660.00	2013-2014	2,792.39	(4)	CoRD

Notes:
(1) 2 – 138 kV circuit breakers additions at 87S and 217S
(2) Existing line upgrade
(3) New double circuit in-and-out tapped off existing 778L
(4) Double circuit one side strung
(5) Double circuit string second circuit

Transmission Lines Supplying RD10S Substation

Tables 5.2-4, 5.2-5 and 5.2-6 present qualitative and quantitative comparisons of alternatives of transmission lines supplying the new RD1S substation.

Table 5.2-4 RD10S Transmission Lines, Qualitative Comparison of Options

Description	Options	
	1	2
Number of 138 kV Transmission Developments	New Lines: 2 (26.5 km)	New Lines: 1 (10.7 km – double circuit line)
240/138 kV Substation Upgrades	138 kV Breaker Additions: 2	138 kV Breaker Additions: 2
Reliability Criteria	Satisfied	Satisfied
Operational Flexibility	Yes	Yes
City-Owned Transmission Network Expansion Feasibility	High	Low
Available Capacity to Accommodate Future Growth	Further load flow calculations required	Further load flow calculations required

Table 5.2-5 Option 1 of RD10S Transmission Lines, Capital Cost (x 1000)

From	To	L (km)	1000$/km	Cost	Constr. Year	Cost + Inflation	Notes	TFO
63S	217S	xxxxxxxx		2,000.00	2024	2,574.05	(1)	AltaLink
63S	RD10S	12.6	280	3,528.00	2023-2024	4,496.99	(2)	CoRD
RD10S	217S	9.2	280	2,576.00	2022-2023	3,220.40	(3)	CoRD
80L	217S	3.2	540	1,728.00	2022-2023	2,160.27	(4)	CoRD
TAP TO	RD10S	1.5	540	810.00	2025	1,062.92		CoRD

Notes:
(1) 2 – 138 kV circuit breakers additions at 63S and 217S
(2) New CoRD line
(3) New CoRD line
(4) Double circuit upgrade
(5) Double circuit

Table 5.2-6 Option 2 of RD10S Transmission Lines, Capital Cost (x 1000)

From	To	L (km)	1000$/km	Cost	Constr. Year	Cost + Inflation	Notes	TFO
RD10S	217S	xxxxxxxx		2,000.00	2024	2,574.05	(1)	AltaLink
80L	RD10S	10.7	540	5,778.00	2024-2025	3,718.22	(2)	CoRD

Notes:
(1) 2 – 138 kV circuit breakers additions at 87S and 217S
(2) New CoRD line

6.0 SUMMARY AND KEY FINDINGS

Bulk Distribution System

The anticipated electrical load in the next 15 years would require the reinforcement of the distribution system within the existing and future ELP service areas. The proposed distribution topology in years 2015, 2020 and 2025 is depicted in Figures 4.4-1, 4.4-2 and 4.4-3 showing the distribution system network comprised of new feeders interconnected with existing feeders as well as existing and new substations. This network, normally operated as radial, can be reconfigured by opening or closing tie switches allowing load transfer between adjacent feeders and substations.

To accomplish the bulk distribution system objectives, ELP would consider constructing nineteen (19) new feeders including:

eight (8) feeders in 2011-2015,
five (5) feeders in 2016-2020,
one (1) feeder in 2020-2025,
and five (5) feeders in 2026.

Ultimately, by 2026 the City distribution network would be comprised of forty eight (48) feeders. The costs of installing new feeders are summarized in Appendix C, Table C2.

Except for RD17S, the existing substations lack vacant feeder breakers to accommodate new feeders. The RD15S substation, currently with two (2) incomers (2-50 MVA) and twelve (12) feeders can be upgraded to (3) incomers (3-50 MVA) and eighteen (18) feeders. This option has been considered in this report. There is no possibility of upgrading the RD14S substation within existing substation boundaries.
Connecting new outgoing feeders to RD15S and RD17S substations, located in densely populated areas, poses a great challenge to the distribution system development. Owing to lack of space in road allowances, it is practically impossible to construct new overhead feeders in these areas; therefore, a number of new underground circuits have been proposed instead.

The alternative of uprating the existing feeders to allow for connecting of new loads have been considered. The ACSR 336 kcmil conductors are already in use or being installed on the overhead circuits. Likewise, most of the existing underground feeders are already in the process of uprating or are scheduled for uprating from Cu 350 kcmil to Cu 750 kcmil (installing cables larger than 750 kcmil are considered impractical from a handling perspective). Simply extending and connecting new loads to these existing feeders would exceed their ampacities and violate acceptable voltage levels on the system (which must be consistent with CSA CAN3 C235-83).

For the reasons described above, the only realistic option is to supply new loads from new outgoing feeders connected to the new (RD1S and RD10S) and upgraded (RD15S) substations.

Transmission System

The following new transmission facilities and new equipment additions at the existing substations has been proposed in 2011-2025/2026.

- New 138/25 kV substations :

  1) RD1S, East Hill – Timberland neighbourhood, 2011-2015
  2) RD10S, Queens Business Park area, 2016, 2023-2026

- New Transmission lines:

  1) Lines supplying RD1S, 2013-2014, 2018-2020
  2) Lines supplying RD10S, 2024-2025

- Addition of incomer and feeder breakers at the existing substation RD15S, 2013-2015

- Addition of a third transformer at the existing substation RD15S, 2016-2017

New Substation RD1S

As a general rule, in order to meet the planning objectives of minimizing the costs of investment and electrical losses, a substation shall be placed as near as possible to the expected centre of the load in a particular service area.

The proposed location of the new RD1S substation, shown in Figures 4.1.4-1a and 4.1.4-1b, is near the expected centre of a high-load density, relatively close to the 87S 240/138 kV substation, near to the existing 138 kV transmission line and distribution feeders allowing easy integration with the existing distribution system.

The substation is expected to be energized with 2– 41 MVA transformers by 2015, and upgraded to 3- 41 MVA by 2020.

New Substation RD10S

The RD10S substation will be a key piece of infrastructure in the Queens Business Park area, and therefore its location shall be strictly coordinated with City's Land & Economic Development, Planning, Engineering Services and other departments. Although the substation is expected to be energized by 2026, ELP shall commence the process of acquiring land as soon as possible to avoid any difficulties in situating the substation in the rapidly developing area.

Initially the substation would be energized with 2- 41 MVA transformers with a provision for the future upgrade to 3- 41 MVA.

New In-City Transmission Network

The following three scenarios of new transmission network supplying new RD1S and RD10S substations have been considered.

The first scenario assumes that 138 kV transmission lines supplying new substations RD1S and RD10S would be built according to Option 1 as described in section 5.2. In that case, these new transmission lines would form a ring around the City (as shown in Figures 1.0-1 and 4.1.4-4) being fed from AltaLink 240/138 kV transmission substations 87S (Gaetz) and 63S (Red Deer).

The second scenario assumes 138 kV lines feeding new substations RD1S and RD10S would be built according to Option 2 as described in section 5.2. In that case, the new in-and-out double-circuit transmission line tapped off the existing 778L would be connected to the new RD1S substation. Similarly, the new in-and-out double-circuit line taped off existing 80L would be connected to the new RD10S substation. This scenario is depicted in Figure 4.1.4-5.

The third scenario assumes the new 138 kV in-and-out double-circuit line taped off 778L would supply substation RD1S from (as shown in Figure 4.1.4-5) and the new 138 kV lines would supply substation RD10S from 87S and 63S (as shown in Figure 4.1.4-4).

Comparative Assessment of Scenarios

- **Under the first scenario:**

1. The following 138 kV transmission lines would be constructed or upgraded in 2012-2020:

a) New double-circuit construction, in-and-out line to RD1S tapped off 768L (CoRD Project - Phase 1, 2012-2015).

b) 755L double-circuit upgrade, from 63S to 240kV-910L/914L South/North-ROW (AltaLink Project 2013-2014).

c) Second circuit stringing (755L), from 63S to 247/RD17S and from 247/RD17S to 240kV-910L/914L-South/North-ROW and new line construction as per 2.d) - (CoRD Project– Phase 2, 2018-2020).

d) New line construction to RD1S along 240kV-910L/914L-South/North-ROW (CoRD Project– Phase 2, 2018-2020).

e) Double-circuit line - 1.a) - would be reconfigured to single-circuit.

2. The following 138 kV transmission lines would be constructed or upgraded in 2022-2025:

   a) New line construction, from 217S to RD10S (CoRD, 2022-2025).

   b) New line construction, from 63S to RD10S (CoRD, 2023-2025).

3. After completion above listed projects, clear demarcation lines could be established between the in-City transmission system and the whole AIES network.

4. Between 2014 and 2025, the City would gradually acquire new transmission lines listed in 1.a), 1.c), 1d), 2a), 2b). As a result, the City would own these transmission lines and new RD1S and RD10S substations including their 138 kV bus-works, circuit breakers and all other equipment.

5. If there is a consensus between the City, AESO, and AltaLink, the City may consider purchasing 194S, 217S and 247S 138 kV equipment as well as 80L and 768L/778L transmission lines.

- **Under the second scenario:**

1. The new 138 kV new double-circuit transmission line, in-and-out to RD1S tapped off 768L, would be constructed in 2013-2015.

2. The new 138 kV new double-circuit transmission line, in-and-out to RD10S tapped off 80L, would be constructed in 2023-2025.

3. The City may own exclusively 138 kV and 25 kV sides of new RD1S and RD10S substations.

4. There would not be a clear demarcation between in-City and AIES transmission systems.

5. Upon an agreement between the City, AESO and AltaLink, the City may own some new section of transmission lines. Also, the City may consider purchasing 194S, 217S and 247S 138 kV equipment as well as 80L and 768L/778L transmission lines.

6. Beyond 2026, the City may consider extending these sections to supply additional new substations if required.

- **Under the third scenario:**

  1. The new 138 kV new double-circuit transmission line, in-and-out to RD1S tapped off 768L, would be constructed in 2013-2015.
  2. The following 138 kV transmission lines would be constructed:

     a) New line from 217S to RD10S (CoRD, 2022-2025).

     b) New line from 63S to RD10S (CoRD, 2023-2025).
  3. The City may own exclusively 138 kV and 25 kV sides of new RD1S and RD10S substations.
  4. Upon an agreement between the City, AESO and AltaLink, the City may own the transmission line section supplying RD1S. Subsequently, the City may consider future line extension to 247S/RD17S, which would require upgrading 755L to double circuit. Also, the City may consider purchasing 194S, 217S and 247S 138 kV equipment as well as 80L and 768L/778L transmission lines.

Key Findings

- Preliminary plans for the future in-City transmission and distribution systems, which would be required to meet the forecast load, have been developed and have been discussed in this report. These plans are based on the expected load growth in the existing and future annexed areas as well as in the existing and future ELP service areas. This report assumes that future annexation would be completed in 2017-2020 time frame and that certain areas, currently serviced by Fortis, would be serviced by ELP as shown in Appendix B.

- The routing of transmission lines supplying the new RD1S substation have been proposed according to the right-of-ways of the existing transmission lines, which possibly would be widen to accommodate the new transmission lines. In the east part of the City, ATCO Gas company intends to expand its facilities by installing more pipelines along the existing transmission right-of-ways; and therefore, ELP has started the process of coordinating the future locations of its and ATCO facilities.

- To facilitate infrastructure development in the new annexed areas a transportation /utility corridor encompassing the City may be considered as part of the long term municipal planning, which would accommodate power transmission lines (including new substation sites), transportation routes, municipal water, sever lines, and other utilities. Such a corridor would streamline tasks of developing new transmission facilities in the west and north City areas. For instance, at this stage it has been impossible to plan the new transmission lines supplying the new RD10S substation and consequently, these lines have been shown schematically without representing future right-of-ways yet.

- The proposed location of the new substations RD1S and RD10S has been based on anticipated spatial load allocation in the areas by 2015-2025. The land acquisition process for these substations shall be coordinated with Land & Economic Development and other City's departments. The future substation shall be integrated into the surrounding urban environment in an esthetically pleasing manner.

- As all transmission development plans must be endorsed by AESO and ultimately by AUC, the in-City transmission system development shall be in sync with the AESO plan of transmission system reinforcement in Red Deer/Didsbury regions. In general, both plans, proposed by the City and AESO, are coherently related to each other. For instance, the transmission lines supplying the RD1S substation (presented in this report as Option 1) would significantly increase the transmission capacity between Joffre generation and 63S, 87S transmission/transmission substations eliminating so called Joffre outflow and inflow constrains.

- To date, ELP has advised AESO of its objectives set forth in this report and intends to proceed soon with the formal application process to build the new RD1S substation and necessary transmission lines as it is recommended in the next section of this report.

- It is recommended the future prospect of City owning transmission facilities including in-City transmission line be based on a further cost and benefit analysis.

7.0 RECOMMENDATIONS

To accomplish objectives of this master plan it is recommended to proceed with the following tasks:

- Continue working with other City departments on land impact assessment related to the in-City transmission system development. Determine preferred locations of future transmission facilities proposed in this report.

- By November 2011, acquire land for the RD1S substation in the East Hill-Timberland area.

- By December 2011, start the process of acquiring land for the RD10S substation in the Queens Business Park area.

- By July 2011, submit to AESO the System Access Request to start the RD1S substation and its transmission lines connection process to include:

    1. July 2011-September 2011, develop connection study report.

    2. September 2011-April 2012, prepare connection proposal including:

        a. Load forecast (10 year outlook),
        b. Transmission options,
        c. Engineering study report together with power flow, short circuit, and any other applicable analyses deemed necessary to assess transmission system performance.

    3. April 2012-May 2013, prepare the Need Identification Document and Prepare Facility Application including public consultations.

    4. 2013-2015, construct, commission and energize transmission lines and the RD1S substation.

- Between 2011-2021, proceed with projects related to capital replacement or equipment additions to existing transmission facilities as planned in this master plan unless the verified load forecast indicates the need for project deferral.

- Between 2018-2020, if the first scenario of the in-City transmission system is endorsed by AESO, proceed with the phase 2 of transmission system development.

- Between 2016-2025/2026, progress with steps to construct the new substation RD10S and its transmission lines; adjust the project accordingly to the verified load forecast.

REFERENCES

[1] AESO, Red Deer/Didsbury Transmission Development – Need Assessment, September 8, 2009. Available @ www.aeso.ca/transmission/19147.html

[2] AESO, Transmission System Planning Criteria March 10, 2005

[3] AESO, Distribution Point-of-Delivery Interconnection Process Guideline, March 22, 2005

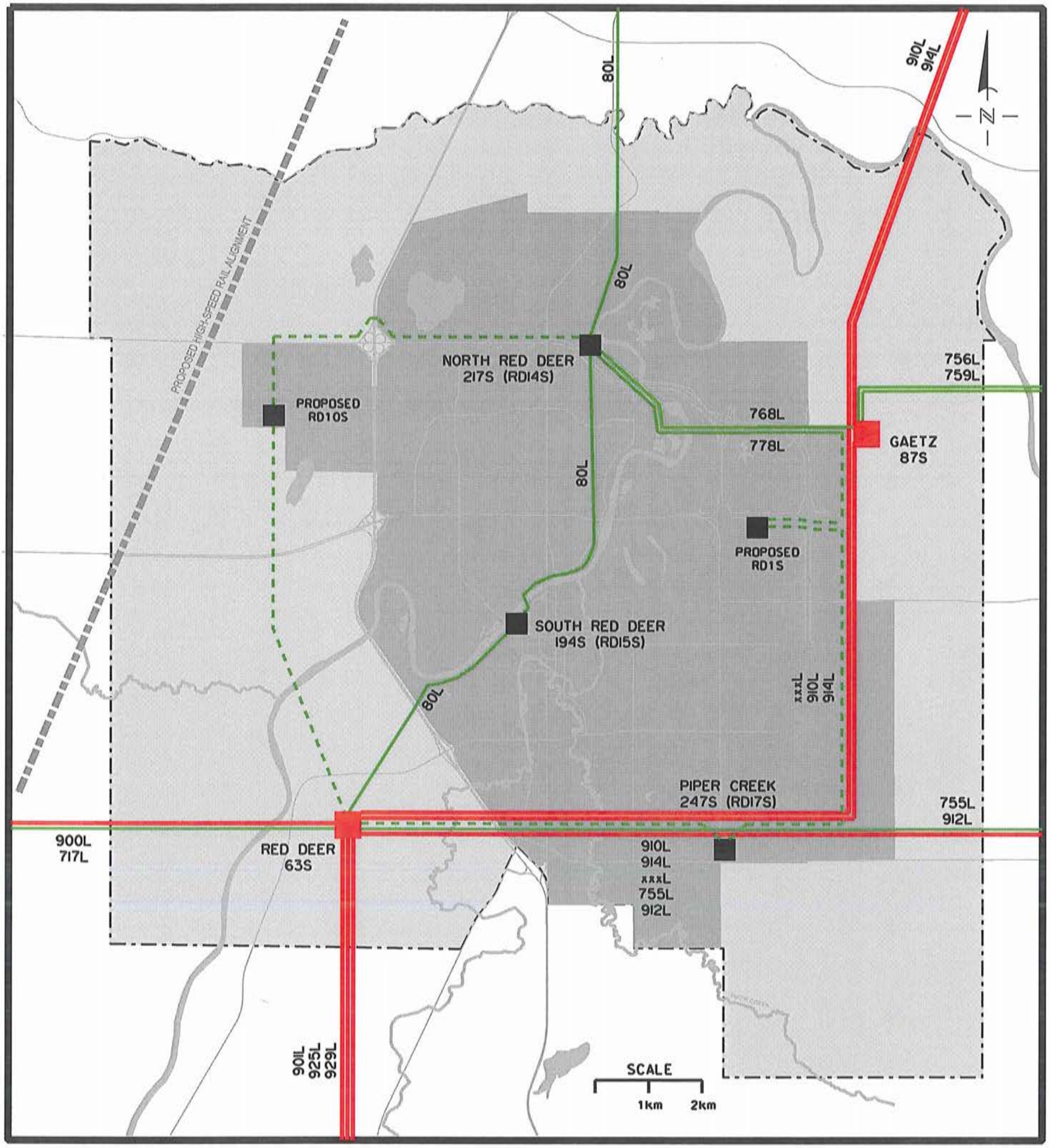
[4] AESO Website http://www.aeso.ca/rulesprocedures/8778.html

[5] AESO, Red Deer Didsbury Region Transmission Development & Transmission Project Delivery South - Presented by Ramaiah Divi, P.Eng and Steve Kanerva, P.Eng. – Red Deer, ELP Office, December 15, 2010

APPENDIX A

FIGURES

Figure: 1.0-1 The City of Red Deer Planning Area



LEGEND

FUTURE CITY GROWTH AREA

2010 CITY BOUNDARY AREA

PROPOSED 138kV TRANSMISSION LINE

138 KV

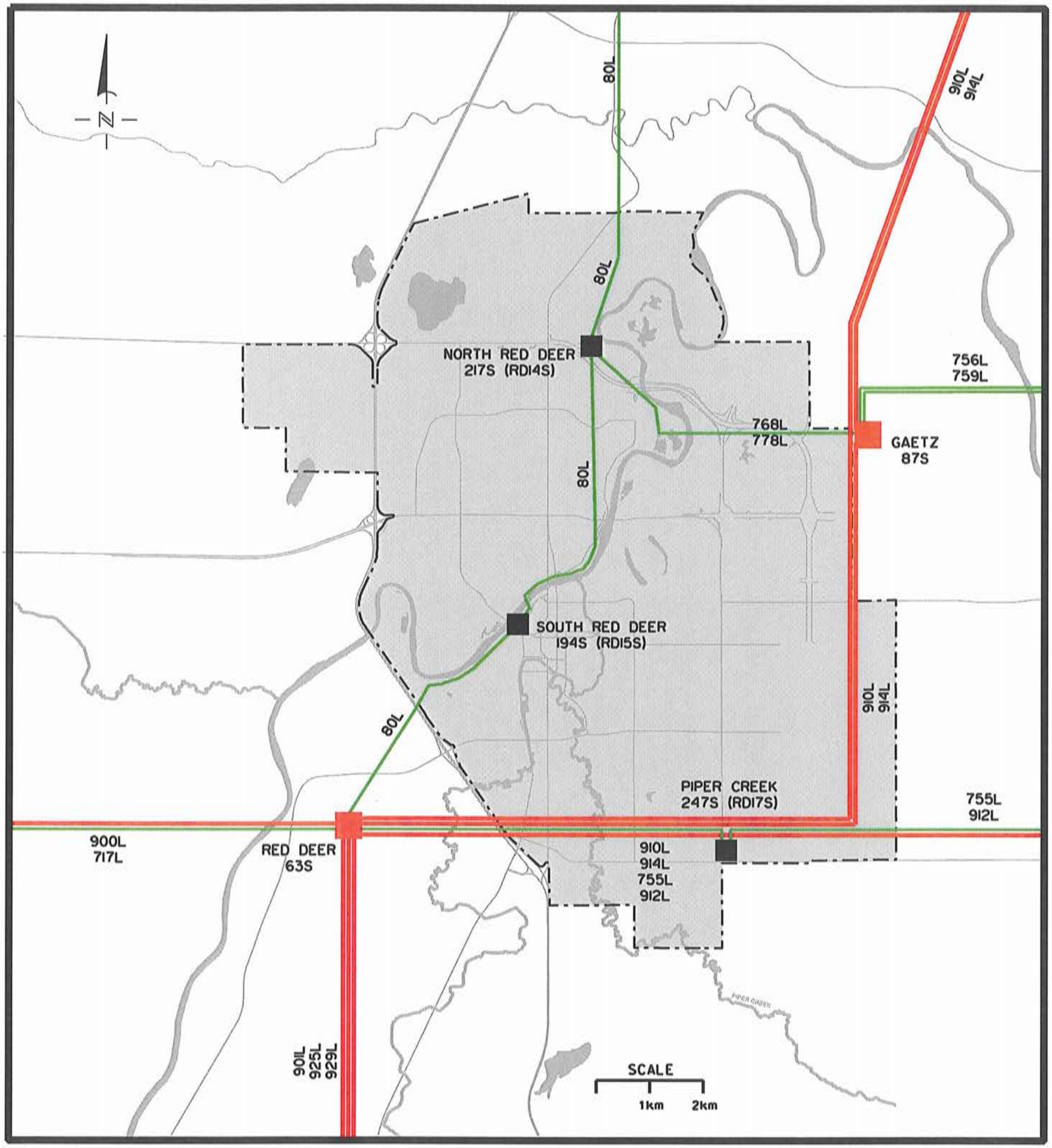
240V

THE CITY OF Red Deer
ELECTRIC LIGHT & POWER

Proposed 2025
Transmission System
Red Deer (Area 35)

DATE: May 30, 2011

Figure: 3.1-2 Existing Transmission System - Red Deer City Area



LEGEND

EXISTING CITY BOUNDRY (2010)

138 KV

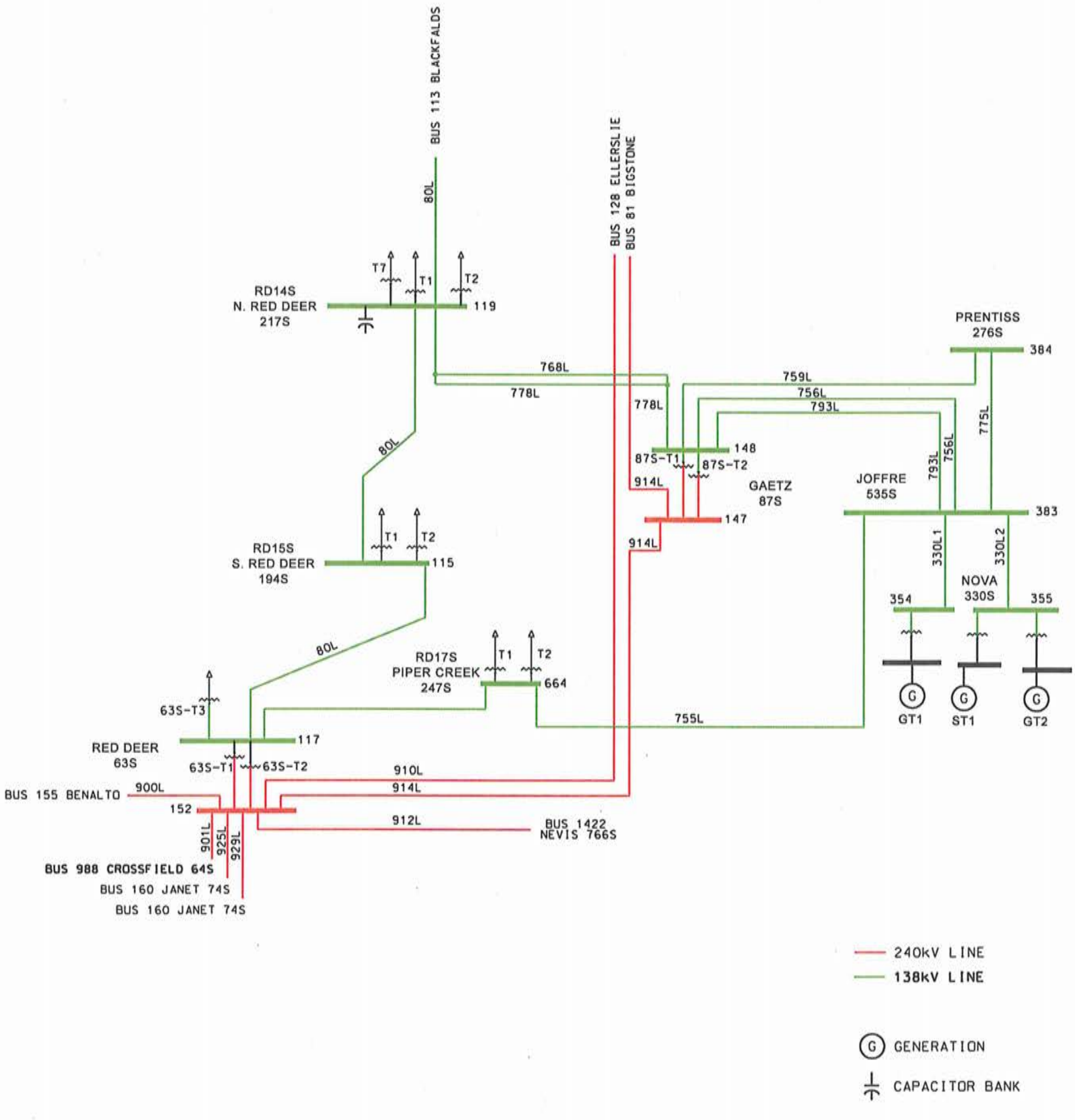
240V

THE CITY OF Red Deer
ELECTRIC LIGHT & POWER

2010
Transmission System
Red Deer (Area 35)

DATE: JANUARY 14, 2011

Figure: 3.1-3 Existing In-City Transmission System Single Line Diagram

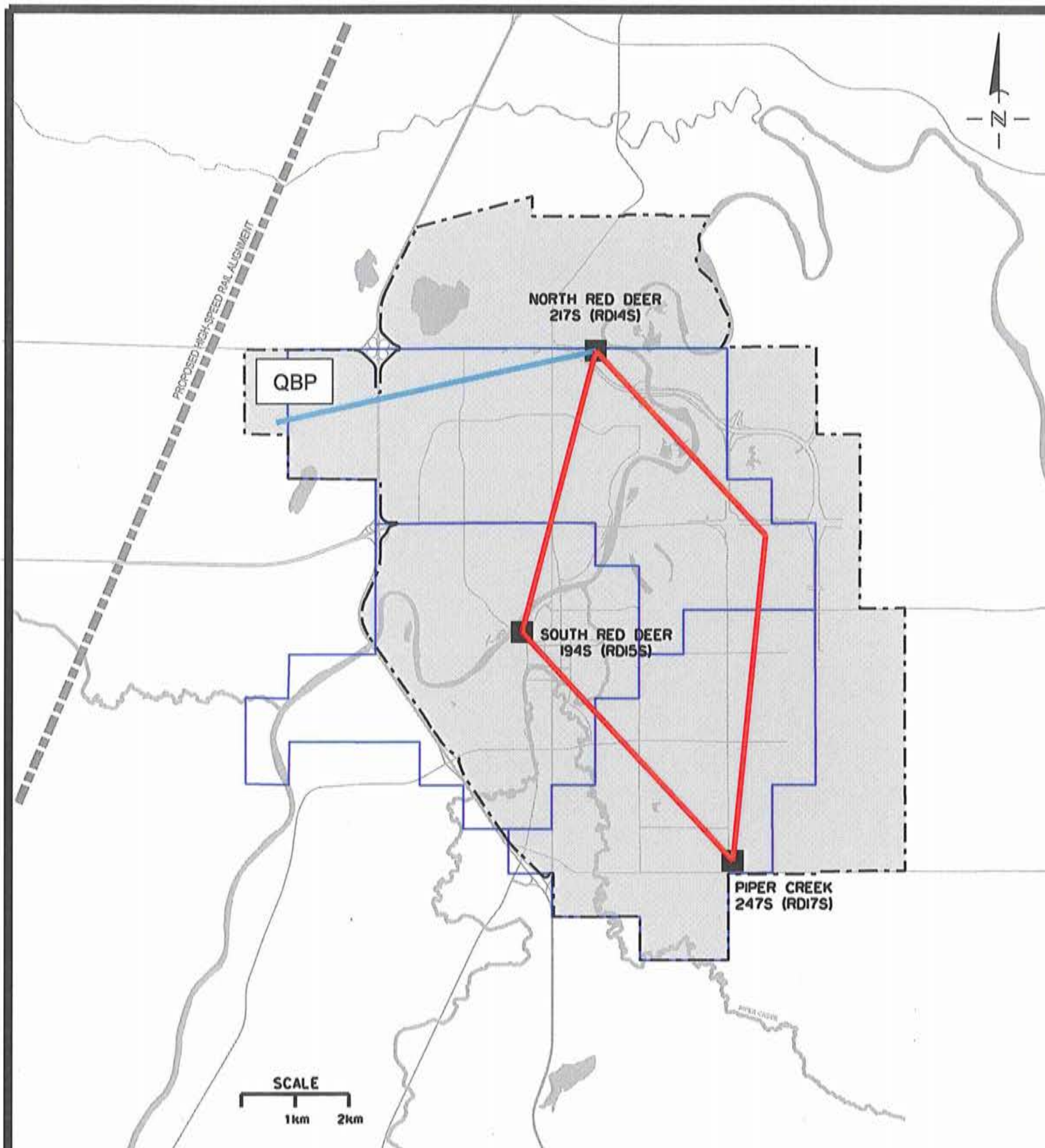


NOTES:

1. THIS DIAGRAM REPRESENTS THE IN-CITY TRANSMISSION SYSTEM CURRENT (2010) CONFIGURATION.

THE CITY OF Red Deer ELECTRIC LIGHT & POWER	Date: Dec 16, 2010 EXISTING TRANSMISSION SYSTEM PORTION OF RED DEER (AREA 35)	SLD - 2010

Figure: 3.2-1 Existing Distribution System Topology



RD15S - RD14S

15-B-16 --> 14-B-30
15-B-19 --> 14-B-13
15-B-32 --> 14-B-34
15-B-46 --> 14-B-18

RD15S - RD17S

15-B-25 --> 17-B-25
15-B-26 --> 17-B-63
15-B-23 --> 17-B-26

RD14S - RD17S

14-B-30 --> 17-B-75
14-B-35 --> 17-B-61
14-B-36 --> 17-B-72

QBP

14-B-38

LEGEND

- CITY BOUNDARY (2010)
- SUBSTATION SERVICE AREAS
- 3 OR MORE EXISTING 25kV FEEDER TIES
- 2 EXISTING 25kV FEEDER TIES
- 1 EXISTING 25kV FEEDER TIE

THE CITY OF Red Deer
ELECTRIC LIGHT & POWER

2010
Substation Interconnection
TOPOLOGY

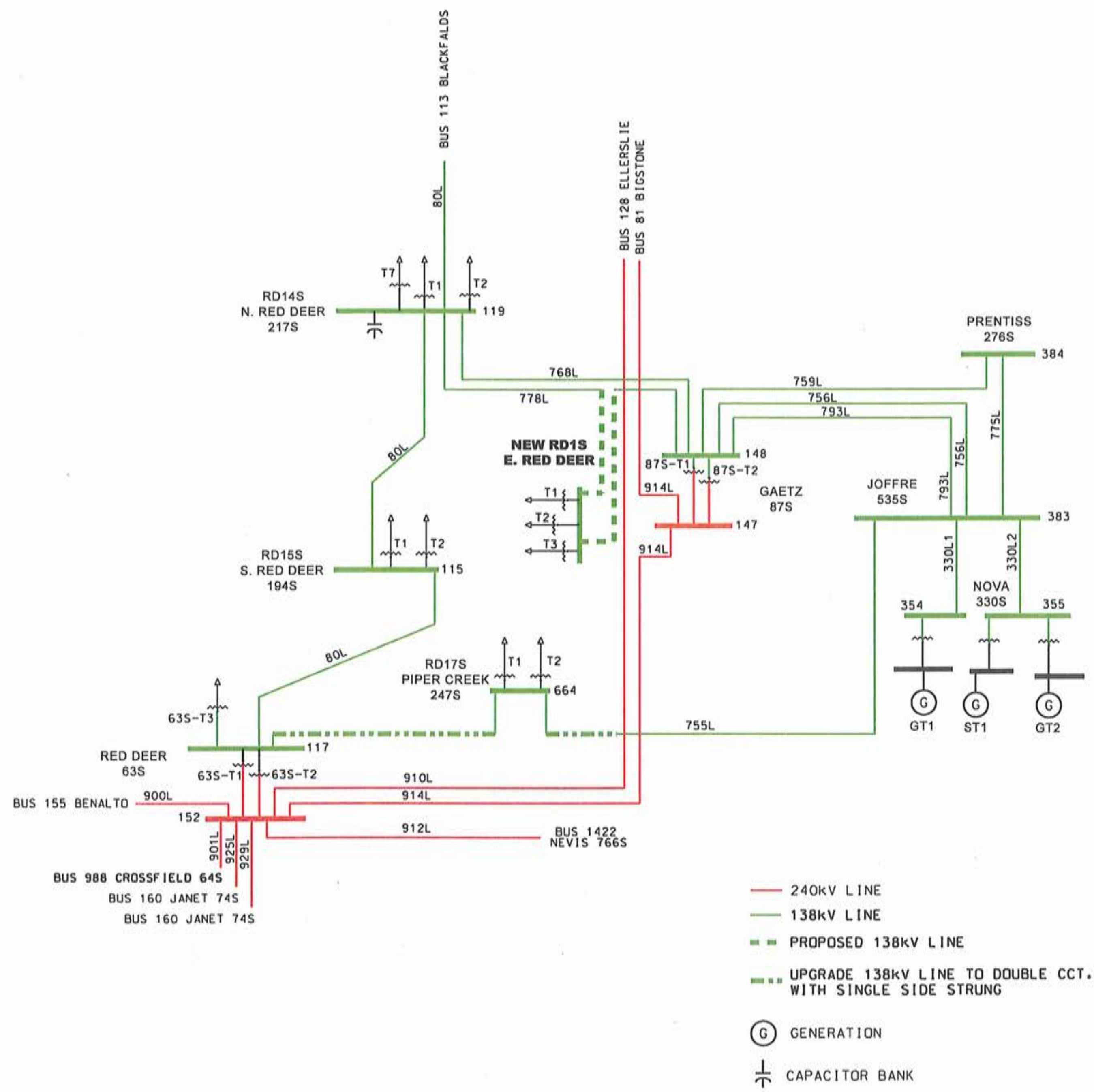
DATE: JANUARY 20, 2011

...\2010 Bulk Distribution System TOPOLOGY.dgn 20/01/2011 1:48:02 PM

Figure: 4.1.4-1a New Substatiion E. Red Deer RD1S
Proposed Siting and Transmission R/W - Stage 1

Figure: 4.1.4-1b New Substatiion E. Red Deer RD1S
Proposed Siting and Transmission R/W - Stage 2

Figure: 4.1.4-2a In-City Transmission System Concept 2015 - Option 1

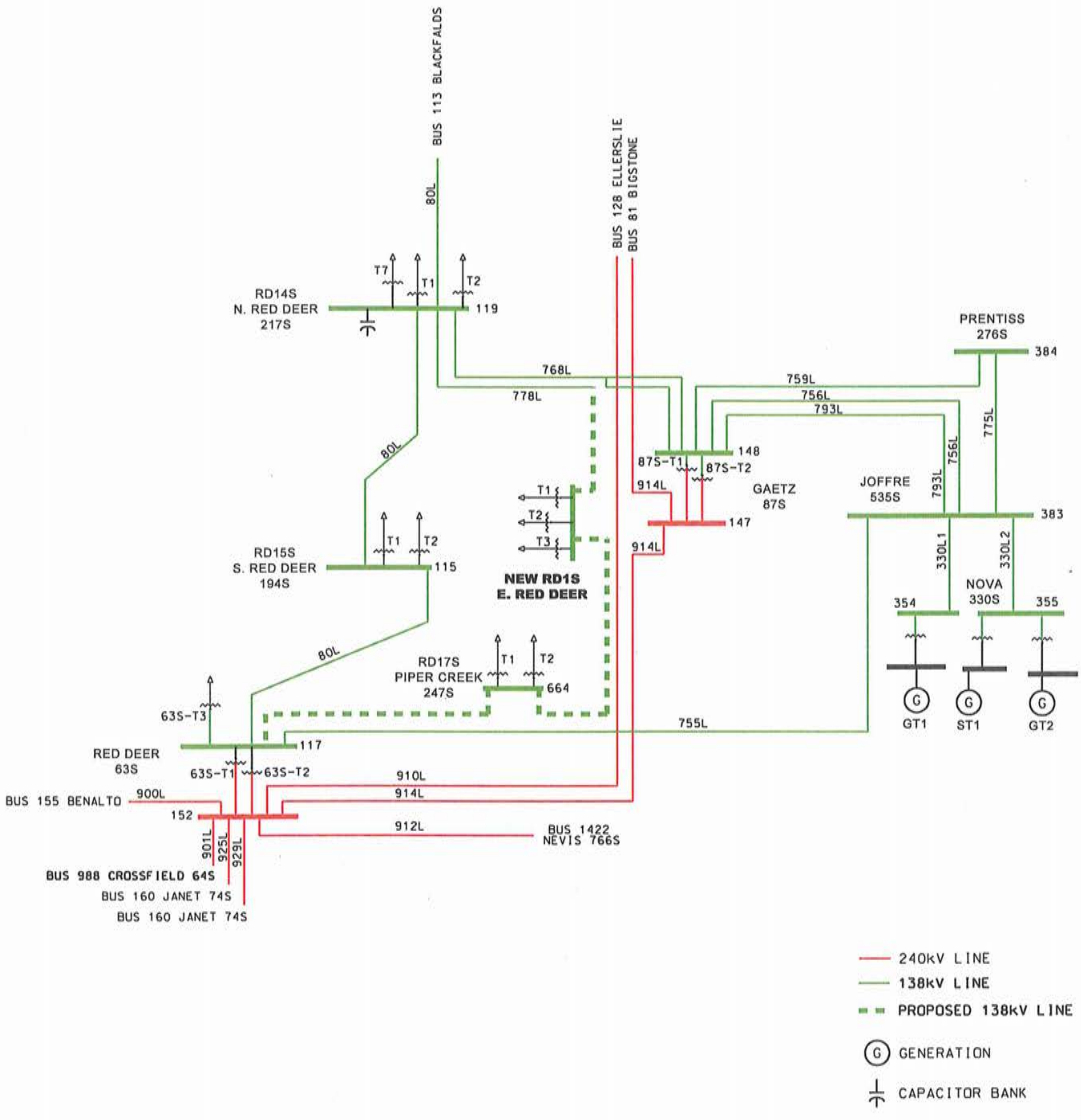


NOTES:

1. THIS DIAGRAM REPRESENTS A PRELIMINARY CONCEPT OF THE IN-CITY TRANSMISSION SYSTEM CONFIGURATION BY 2015.
2. OPTIONAL CONFIGURATION IS SHOWN ON DWG. #SLD - 2015 - OPTION 2 (FIGURE: 4.1.4-3)
3. TRANSMISSION LINE CONFIGURATION, SUBSTATION SITING AND POWER TRANSFORMER SIZING MUST BE ENDORSED WITH AESO AND ALTALINK.
4. LOAD FLOW AND SHORT CIRCUIT CALCULATIONS SHALL BE COMPLETED TO SELECT ADEQUATE EQUIPMENT AND CONDUCTOR RATINGS.

THE CITY OF Red Deer ELECTRIC LIGHT & POWER	Date: Jan 20, 2011 TRANSMISSION SYSTEM CONCEPT PORTION OF RED DEER (AREA 35)	SLD - 2015 - OPTION 1

Figure: 4.1.4-2b In-City Transmission System Concept 2020 - Option 1

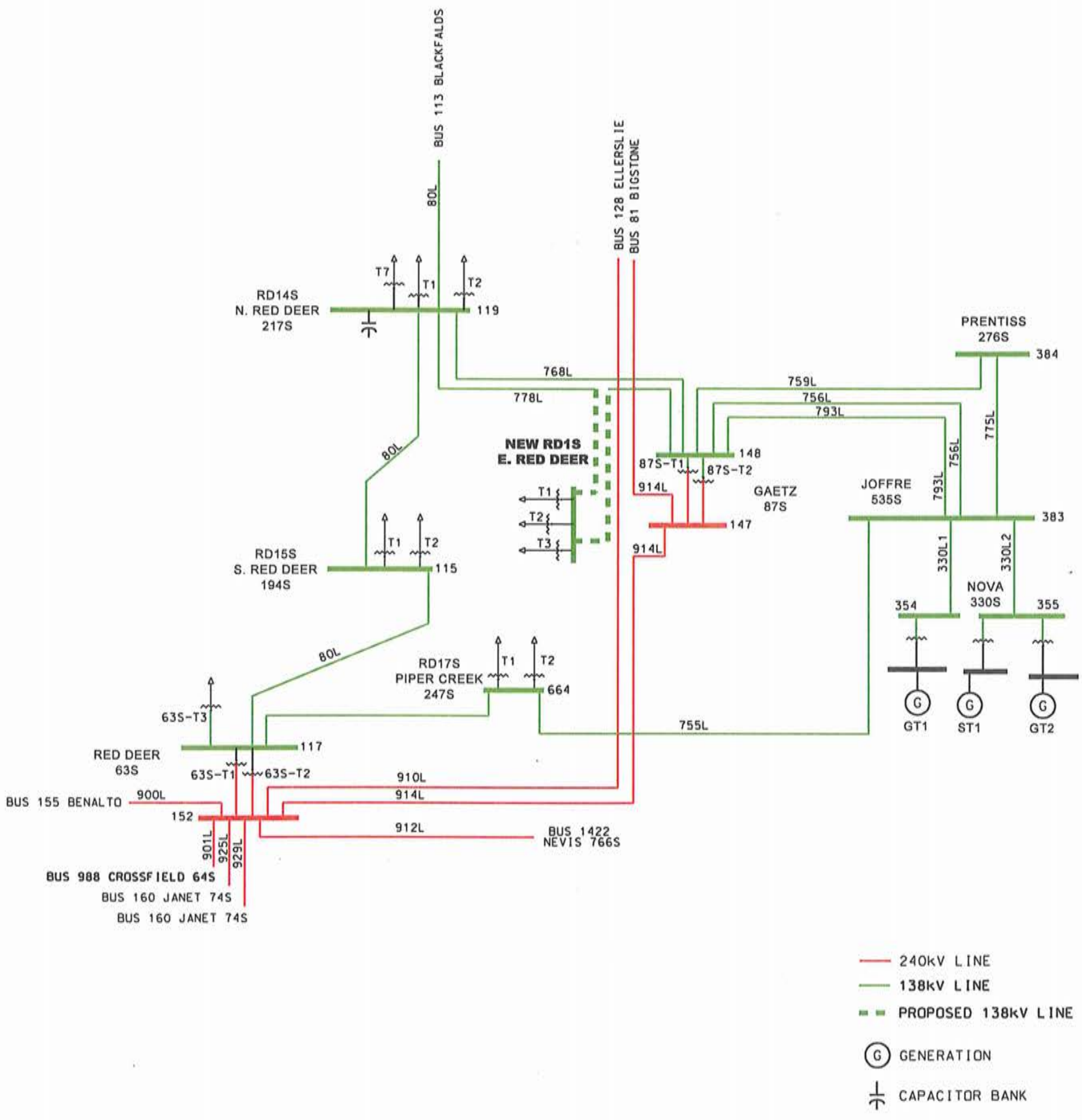


NOTES:

1. THIS DIAGRAM REPRESENTS A PRELIMINARY CONCEPT OF THE IN-CITY TRANSMISSION SYSTEM CONFIGURATION BY 2020.
2. OPTIONAL CONFIGURATION IS SHOWN ON DWG. #SLD - 2015 - OPTION 2 (FIGURE: 4.1.4-3)
3. TRANSMISSION LINE CONFIGURATION, SUBSTATION SITING AND POWER TRANSFORMER SIZING MUST BE ENDORSED WITH AESO AND ALTALINK.
4. LOAD FLOW AND SHORT CIRCUIT CALCULATIONS SHALL BE COMPLETED TO SELECT ADEQUATE EQUIPMENT AND CONDUCTOR RATINGS.

THE CITY OF Red Deer ELECTRIC LIGHT & POWER	Date: Jan 20, 2011 TRANSMISSION SYSTEM CONCEPT PORTION OF RED DEER (AREA 35)	SLD - 2020 - OPTION 1

Figure: 4.1.4-3 In-City Transmission System Concept 2015 - Option 2

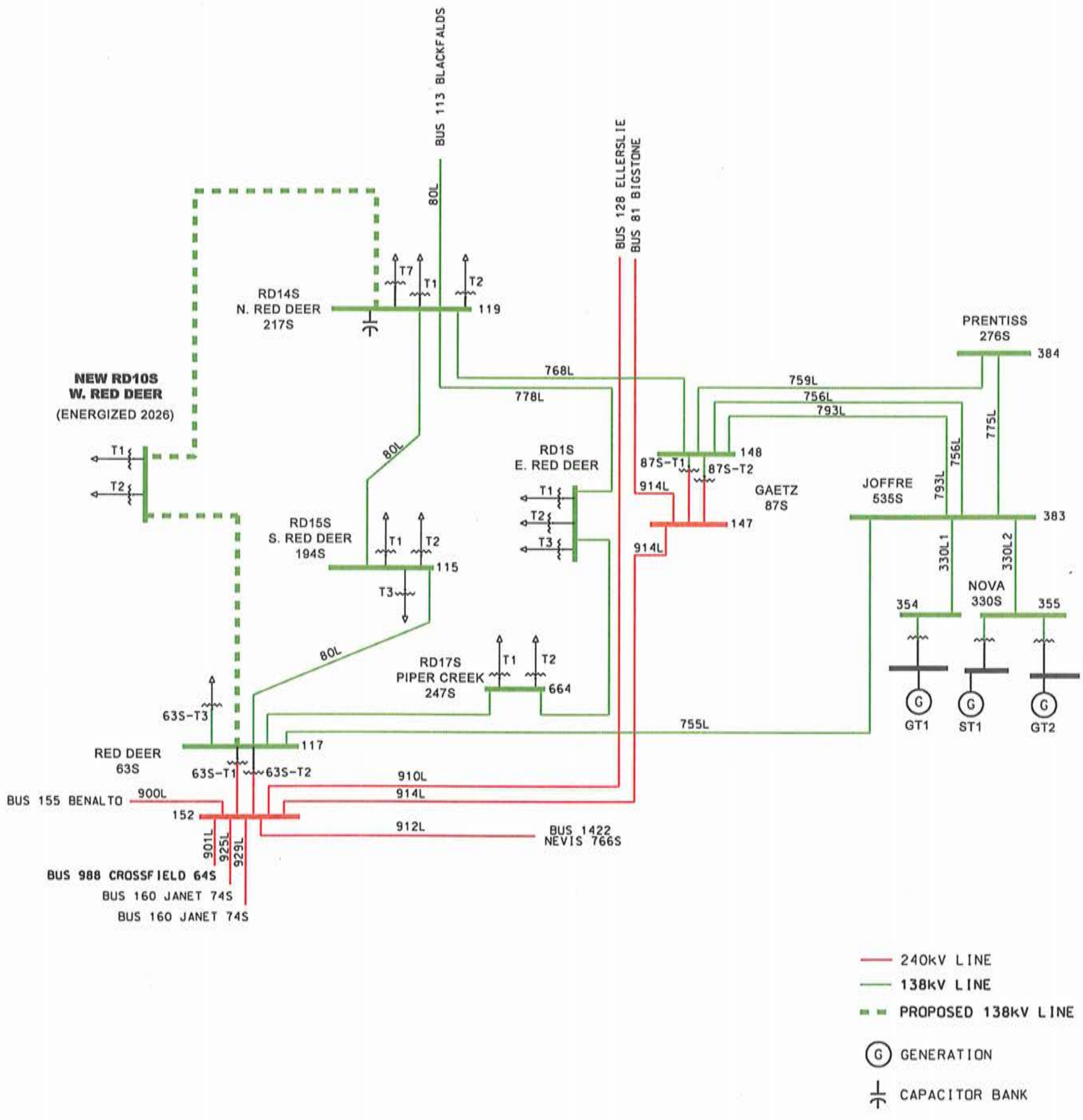


NOTES:

1. THIS DIAGRAM REPRESENTS A PRELIMINARY CONCEPT OF THE IN-CITY TRANSMISSION SYSTEM CONFIGURATION BY 2015.
2. OPTIONAL CONFIGURATION IS SHOWN ON DWG. #SLD - 2015 - OPTION 1 (FIGURE: 4.1.4-2a)
3. TRANSMISSION LINE CONFIGURATION, SUBSTATION SITING AND POWER TRANSFORMER SIZING MUST BE ENDORSED WITH AESO AND ALTALINK.
4. LOAD FLOW AND SHORT CIRCUIT CALCULATIONS SHALL BE COMPLETED TO SELECT ADEQUATE EQUIPMENT AND CONDUCTOR RATINGS.

THE CITY OF Red Deer ELECTRIC LIGHT & POWER	Date: Jan 20, 2011 TRANSMISSION SYSTEM CONCEPT PORTION OF RED DEER (AREA 35)	**SLD - 2015 - OPTION 2**

Figure: 4.1.4-4 In-City Transmission System Concept 2025 - Option 1

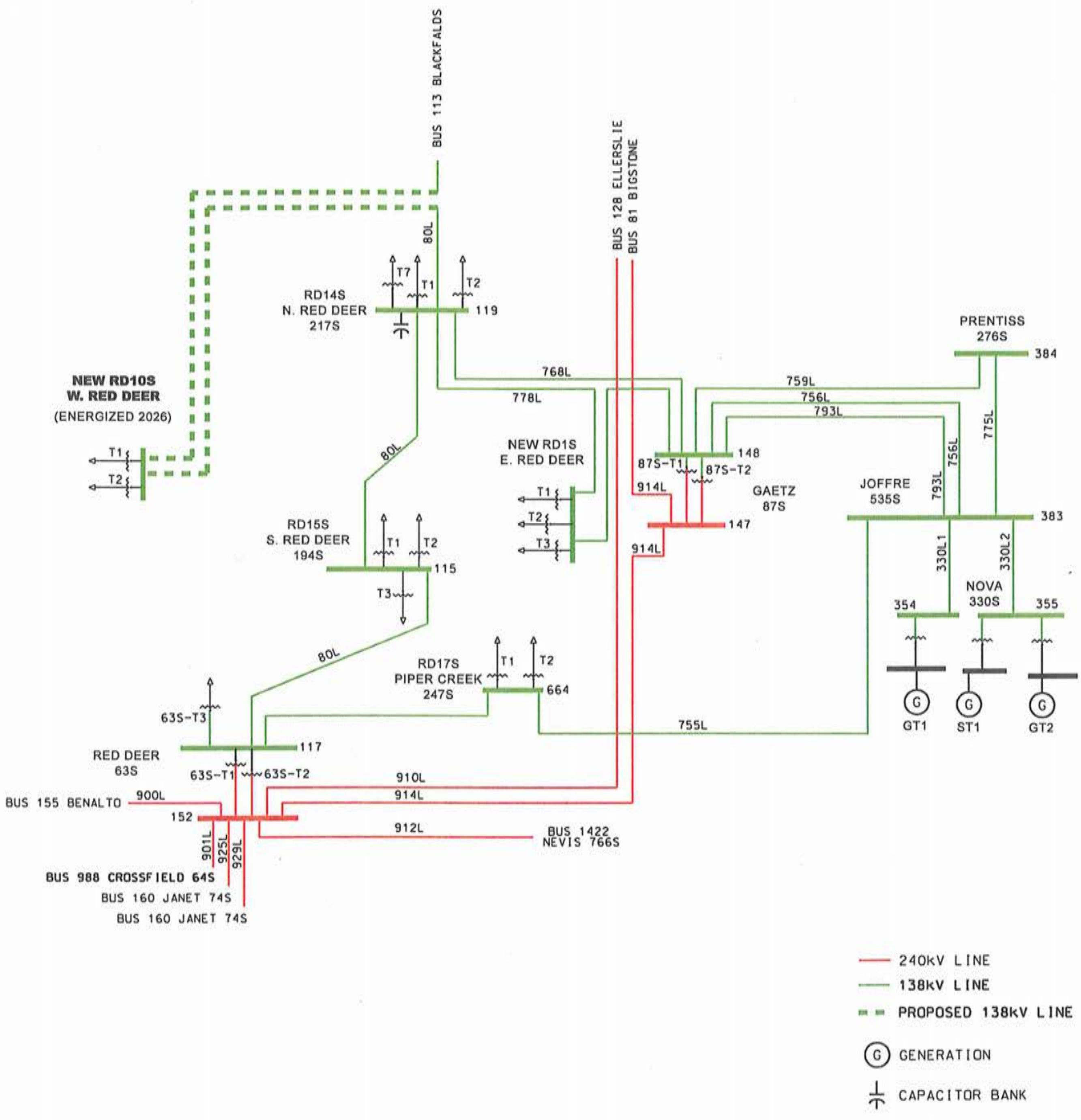


NOTES:

1. THIS DIAGRAM REPRESENTS A PRELIMINARY CONCEPT OF THE IN-CITY TRANSMISSION SYSTEM CONFIGURATION BY 2025.
2. OPTIONAL CONFIGURATION IS SHOWN ON DWG. #SLD - 2025 - OPTION 2 (FIGURE: 4.1.4-5)
3. TRANSMISSION LINE CONFIGURATION, SUBSTATION SITING AND POWER TRANSFORMER SIZING MUST BE ENDORSED WITH AESO AND ALTALINK.
4. LOAD FLOW AND SHORT CIRCUIT CALCULATIONS SHALL BE COMPLETED TO SELECT ADEQUATE EQUIPMENT AND CONDUCTOR RATINGS.

THE CITY OF Red Deer ELECTRIC LIGHT & POWER	Date: Jan 20, 2011 TRANSMISSION SYSTEM CONCEPT PORTION OF RED DEER (AREA 35)	SLD - 2025 - OPTION 1

Figure: 4.1.4-5 In-City Transmission System Concept 2025 - Option 2

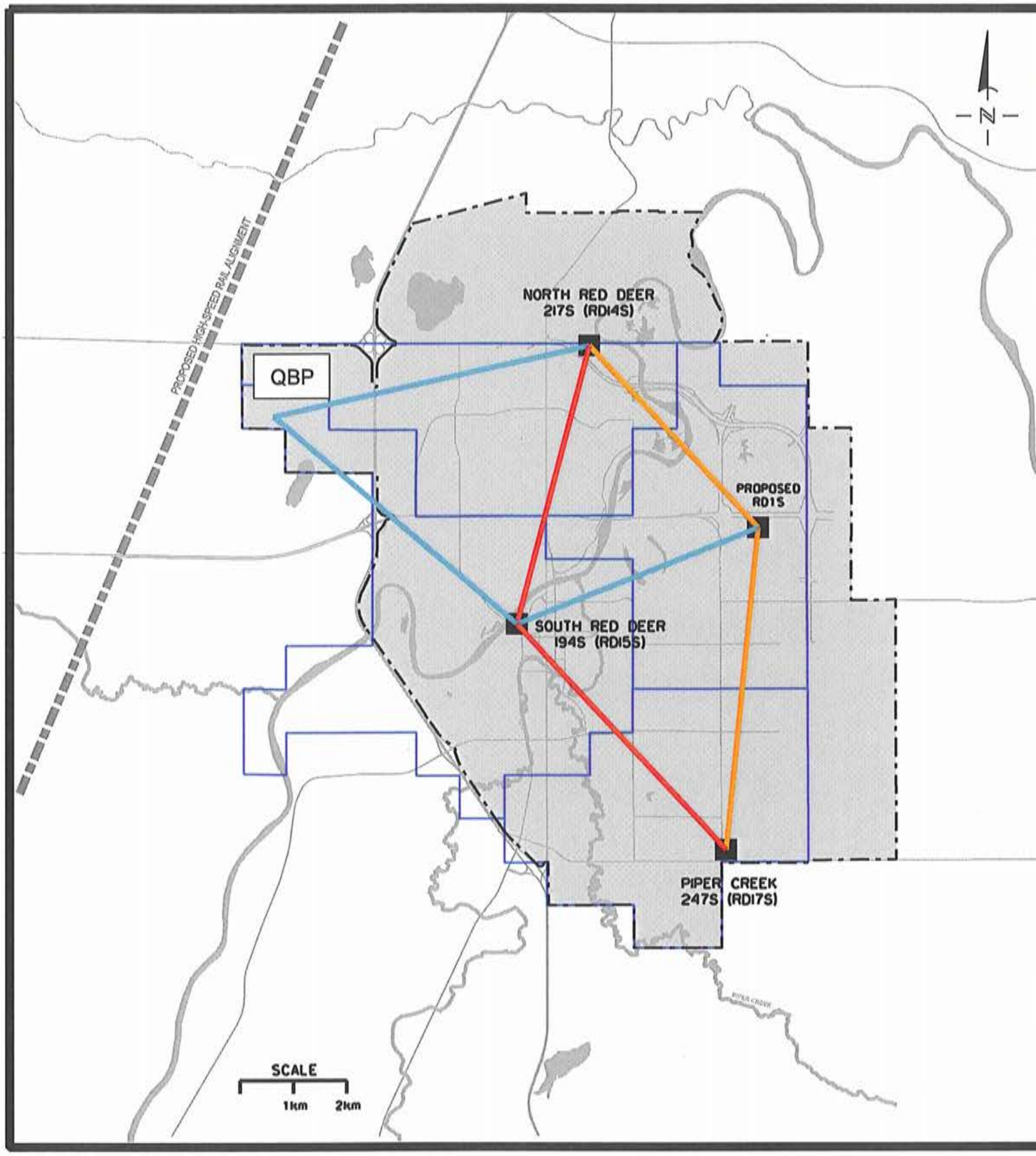


NOTES:

1. THIS DIAGRAM REPRESENTS A PRELIMINARY CONCEPT OF THE IN-CITY TRANSMISSION SYSTEM CONFIGURATION BY 2025.
2. OPTIONAL CONFIGURATION IS SHOWN ON DWG. #SLD - 2025 - OPTION 1 (FIGURE: 4.1.4-4)
3. TRANSMISSION LINE CONFIGURATION, SUBSTATION SITING AND POWER TRANSFORMER SIZING MUST BE ENDORSED WITH AESO AND ALTALINK.
4. LOAD FLOW AND SHORT CIRCUIT CALCULATIONS SHALL BE COMPLETED TO SELECT ADEQUATE EQUIPMENT AND CONDUCTOR RATINGS.

THE CITY OF Red Deer ELECTRIC LIGHT & POWER	Date: Jan 20, 2011 TRANSMISSION SYSTEM CONCEPT PORTION OF RED DEER (AREA 35)	SLD - 2025 - OPTION 2

Figure: 4.4-1 Proposed 2015 Distribution System Topology



RD15S - RD14S
15-B-19 --> 14-B-12
15-B-32 --> 14-B-34
15-B-16 --> 14-B-36
15-B-46 --> 14-B-80

RD15S - RD17S
15-B-25 --> 17-B-73
15-B-26 --> 17-B-63
15-B-91 --> 17-B-25
15-B-20 --> 17-B-26

RD15S - RD1S
15-B-90 --> 1-B-110

RD14S - RD1S
14-B-35 --> 1-B-102
14-B-30 --> 1-B-101

RD17S - RD1S
17-B-61 --> 1-B-109
17-B-72 --> 1-B-107

QBP
14-B-18 --> 15-B-23

LEGEND

- CITY BOUNDARY (2010)
- SUBSTATION SERVICE AREAS
- 3 OR MORE PROPOSED 25kV FEEDER TIES
- 2 PROPOSED 25kV FEEDER TIES
- 1 PROPOSED 25kV FEEDER TIE

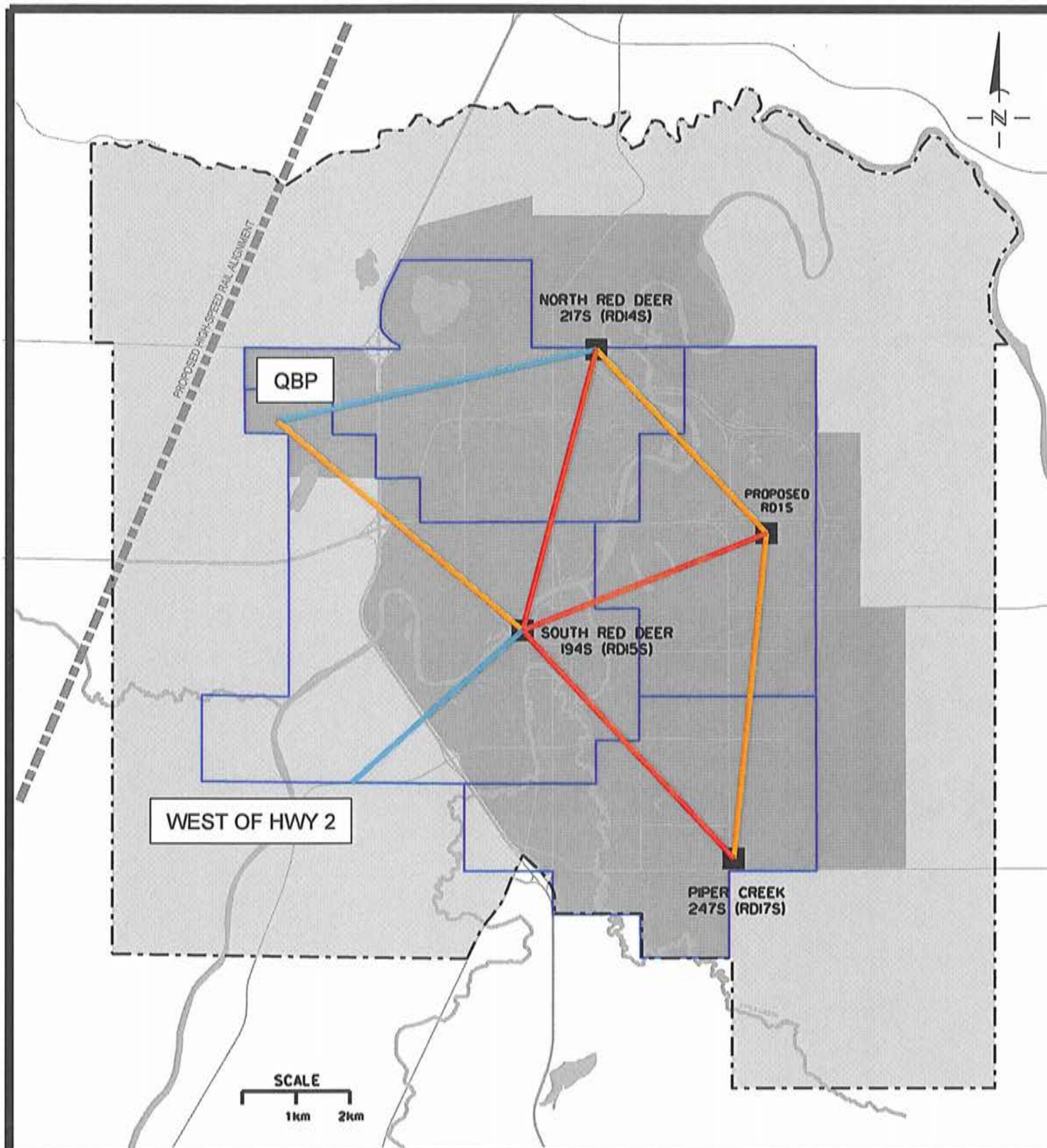
THE CITY OF Red Deer
ELECTRIC LIGHT & POWER

2015
Substation Interconnection
TOPOLOGY

DATE: JANUARY 14, 2011

...\2015 Bulk Distribution System TOPOLOGY.dgn 14/01/2011 1:24:20 PM

Figure: 4.4-2 Proposed 2020 Distribution System Topology



RD15S - RD14S
15-B-19 --> 14-B-12
15-B-32 --> 14-B-34
15-B-16 --> 14-B-36

RD15S - RD17S
15-B-25 --> 17-B-73
15-B-26 --> 17-B-63
15-B-91 --> 17-B-25
15-B-20 --> 17-B-26

RD15S - RD1S
15-B-21 --> 1-B-108
15-B-22 --> 1-B-103
15-B-90 --> 1-B-110

RD14S - RD1S
14-B-35 --> 1-B-102
14-B-12 --> 1-B-104

RD17S - RD1S
17-B-61 --> 1-B-109
17-B-72 --> 1-B-107

QBP
14-B-18 --> 15-B-23
15-B-46

WEST OF HWY 2
15-B-92

LEGEND
- FUTURE CITY GROWTH AREA
- 2010 CITY BOUNDARY AREA
- SUBSTATION SERVICE AREAS
- 3 OR MORE PROPOSED 25kV FEEDER TIES
- 2 PROPOSED 25kV FEEDER TIES
- 1 PROPOSED 25kV FEEDER TIE

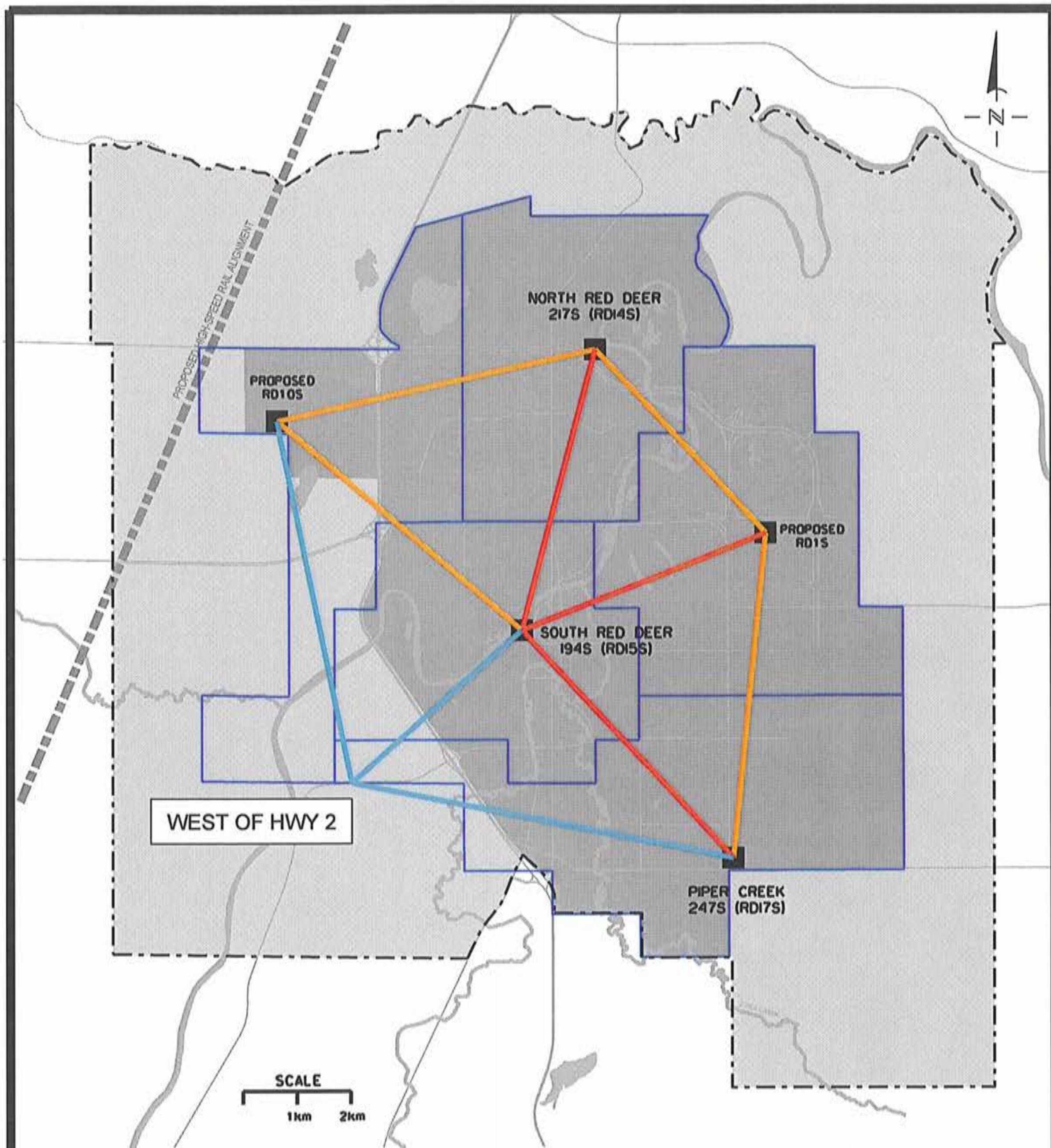
THE CITY OF Red Deer
ELECTRIC LIGHT & POWER

2020
Substation Interconnection
TOPOLOGY

DATE: JANUARY 14, 2011

...\2020 Bulk Distribution System TOPOLOGY.dgn 14/01/2011 11:32:24 AM

Figure: 4.4-3 Proposed 2025 / 2026 Distribution System Topology



RD15S - RD14S

15-B-19 --> 14-B-12
15-B-32 --> 14-B-34
15-B-16 --> 14-B-36

RD15S - RD17S

15-B-25 --> 17-B-73
15-B-26 --> 17-B-63
15-B-91 --> 17-B-25

RD15S - RD1S

15-B-21 --> 1-B-108
15-B-22 --> 1-B-103
15-B-90 --> 1-B-110

RD15S - RD10S

15-B-23 --> 10-B-206
15-B-46 --> 10-B-207

RD14S - RD1S

14-B-35 --> 1-B-102
14-B-12 --> 1-B-104

RD14S - RD10S

14-B-18 --> 10-B-201
14-B-13 --> 10-B-200

RD17S - RD1S

17-B-61 --> 1-B-109
17-B-72 --> 1-B-107

WEST OF HWY 2

15-B-92 --> 10-B-208
17-B-26

LEGEND

- FUTURE CITY GROWTH AREA
- 2010 CITY BOUNDARY AREA
- SUBSTATION SERVICE AREAS
- 3 OR MORE PROPOSED 25kV FEEDER TIES
- 2 PROPOSED 25kV FEEDER TIES
- 1 PROPOSED 25kV FEEDER TIE

THE CITY OF Red Deer
ELECTRIC LIGHT & POWER

2025 / 2026
Substation Interconnection
TOPOLOGY

DATE: JANUARY 14, 2011

...\2025 Bulk Distribution System TOPOLOGY.dgn 14/01/2011 11:34:55 AM

APPENDIX B

ELECTRIC LIGHT & POWER FUTURE ENERGY OUTLOOK (2010-2025)

THE CITY OF
Red Deer

Electric Light & Power
Future Demand and Energy Outlook
(2010 – 2025)

Table of Contents

1.0 INTRODUCTION

The City of Red Deer's long-term demand and energy forecast is based on a study of past energy use patterns, future economic indicators, planned electrical service boundary expansion, emerging alternative energy technologies and spatial analysis that are combined to produce a future demand and energy forecast. The Electric Light and Power Department (ELP) monitors and updates annually its 15-year outlook of Red Deer's electric energy consumption and peak demand. Furthermore, the 15 year outlook is revised every third year by performing detailed studies for each of its customer sectors and investigating issues that may offer enhancements or insight to its 15-year outlook.

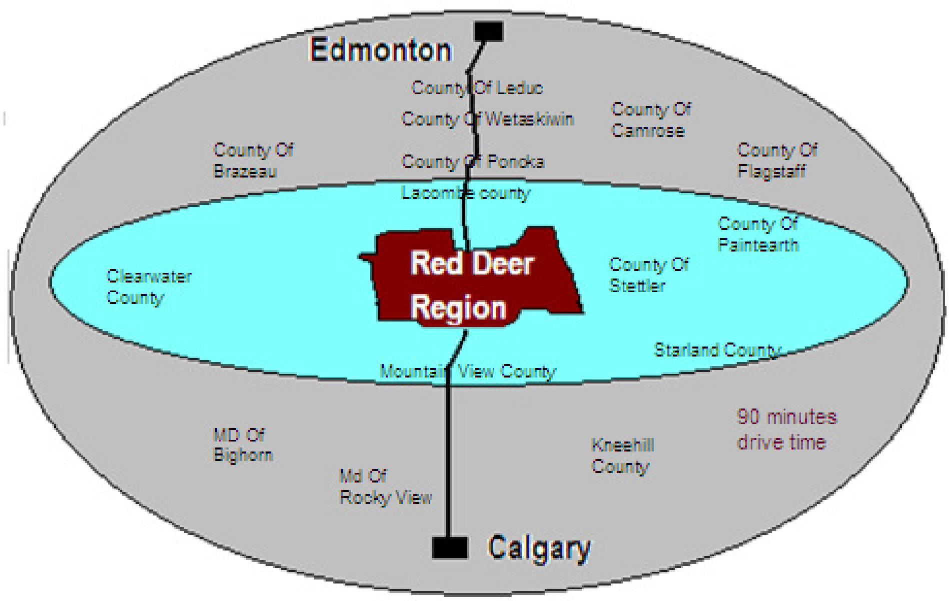
This Future Demand and Energy Outlook (2010-2025) Report describes the methodology and processes that ELP has employed to assess Red Deer's future demand and electric energy requirement for the next 15 years.

The 15-year outlook recognizes future electrical service boundary expansion in regards to timing, size, zoning and number of quarter sections of land to be added to its service territory in five year increments. It also reflects future economic growth, the continually expanding trade area, and adoption of emerging alternative energy technologies.

2.0 ECONOMIC OUTLOOK

The City of Red Deer's electricity demand and energy forecast is closely dependent on the economic outlook in the Red Deer Region. According to the Red Deer Regional Economic Development, Annual Stakeholders Report [10] the Red Deer corridor remains as an attractive place to work and conduct business. Powering its economy is its geographic setting, namely a central location on Highway 2 corridor, which gives the local merchants and service provider's access to a trade area of about 230,000 people and distribution capabilities to over 2.4 million people within 90 minutes drive. Figure 2.1-1 show the Red Deer Region's Trade Area within a 90 minute drive time.

Figure 2.1-1: Red Deer Region's Trade Area



2.1 RED DEER REGION ECONOMIC GROWTH

The Region's population continues to grow at approximately 1% per year and retail sales increased 11.1% in 2009 during the economic downtown. However the region did experience a tough economic time in 2009 with no significant increase in Real GDP growing only 0.1% from 2007.

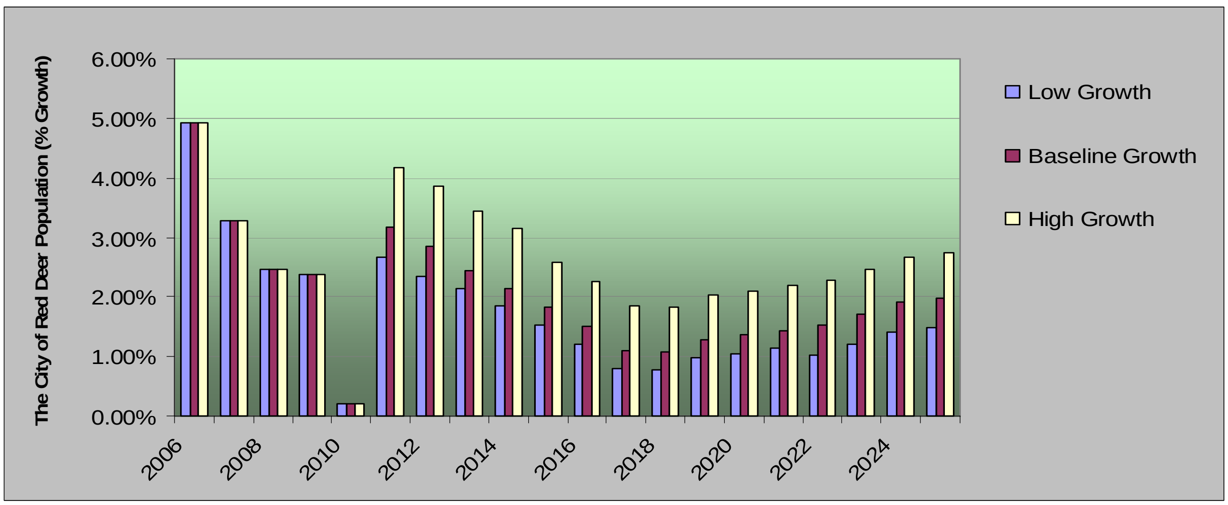
Also noted in the Annual Stakeholders Report [10] the growth anomalies of 2006 and 2007 indicate an unbalanced economy due to excess demand for goods and services and that 2008 marked a return to attainable development initiatives indicating long term economic growth in the future. In 2011 growth is expected to increase to levels seen in 2008 in the Red Deer Region. The anticipated Real GDP growth is about 1.5 per cent in 2011 and 2.4 per cent in the subsequent years.

In summary, over the next decade The City of Red Deer electricity demand will continue to grow as infrastructure improvements and new developments continue and trade areas expand.

2.2 RED DEER REGION POPULATION GROWTH

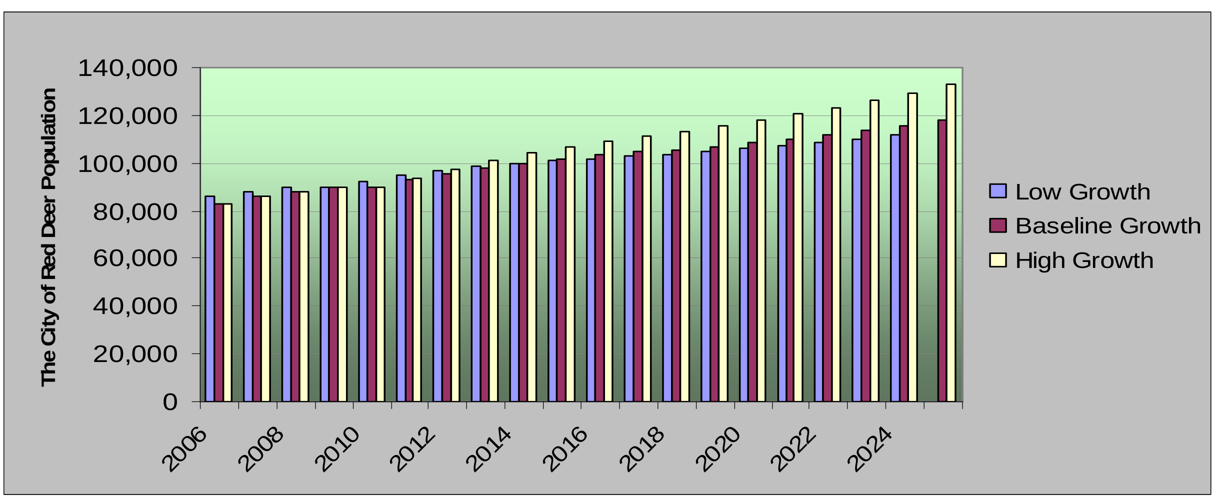
According to the Parkland Community Planning Services Population Projections [15] the City's population grew by 31.9 per cent from 2001 to 2010. Figure 2.3-1 and Figure 2.3-2 show yearly low, baseline and high projections of population growth in per cent and total population respectively. Data for 2010 and prior years are based on actual numbers. Population growth is expected to remain steady above one per cent on a year-over-year basis.

Figure 2.3-1: The City of Red Deer Population Per cent Growth Forecast



Source: Parkland Community Planning Services Population Projections **[15]**

Figure 2.3-2: The City of Red Deer Population Growth Forecast

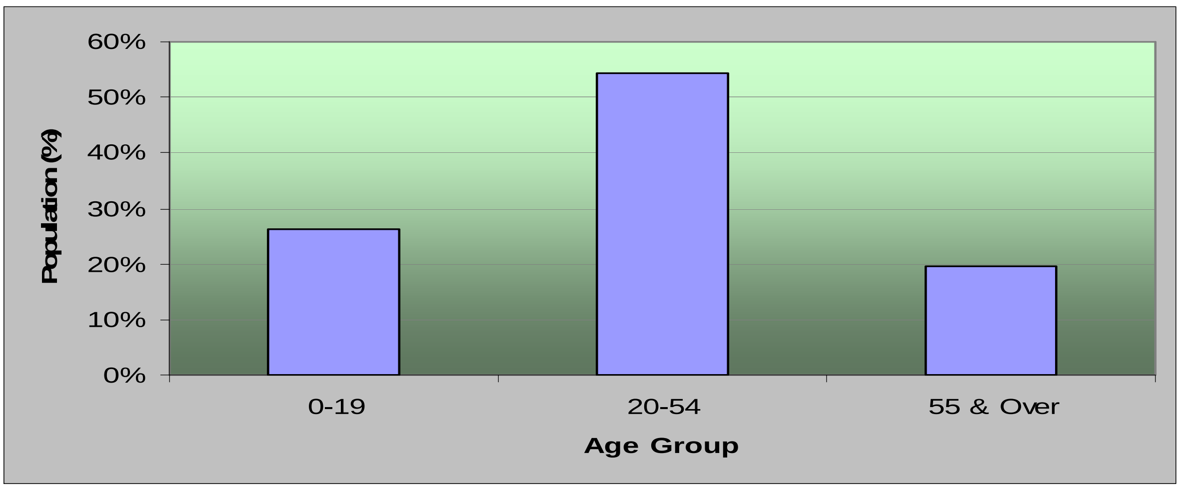


Source: Parkland Community Planning Services Population Projections **[15]**

In addition to the City's population growth, the greater Red Deer region, which account for roughly forty per cent of the cities workforce, is also expected to grow at 1 per cent year over-year.

Figure 2.3-3 shows the City of Red Deer population age structure obtained from the City of Red Deer, 2010 Municipal Census Report [9]. The average population age is 34 years with 23 years being the most frequently occurring age. According to the National Bureau of Economic Research Working Paper [4] the demographics of a population's age group structure gives significance to its economic prosperity and details how the combined effect of this large working-age population can create virtuous cycles of wealth creation. Most of the City's population falls within the working ages and the productivity of this group can produce a "demographic dividend" of economic growth.

Figure 2.3-3: The City of Red Deer Population Age Structure



Source [9]

In summary, the population projections shown in Parkland Community Report [15] were adopted as an element in forecasting electrical energy consumption for the residential customer sector. An average of 2 per cent was used to project yearly Real GDP growth.

3.0 METHODOLOGY

The City of Red Deer Electric Light and Power Department uses an econometric approach to estimating future demand and electricity usage. This methodology provides a consistent approach to demand forecasting through the use of a combination of fitted statistical models, historical data, and electrical energy spatial analysis over the geographic areas of the City.

The long-term demand forecast is developed by considering the six factors listed below:

- Industrial Sector
- Commercial Sector
- Residential Sector
- Smart Grid Development

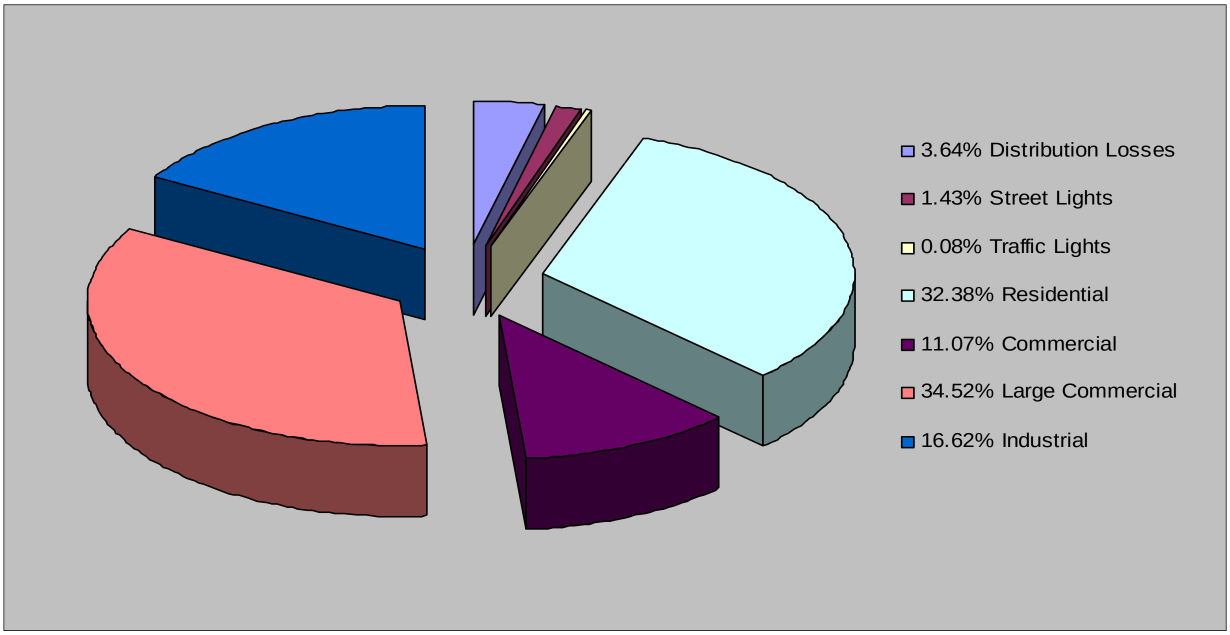
- Electric Propulsion Vehicles
- Distribution Generation (DG)

➢ Climate Dependencies

➢ Spatial Analysis

Figure 3.0-1 shows distribution of load segments as a percentage of the total electrical energy consumed in the City of Red Deer.

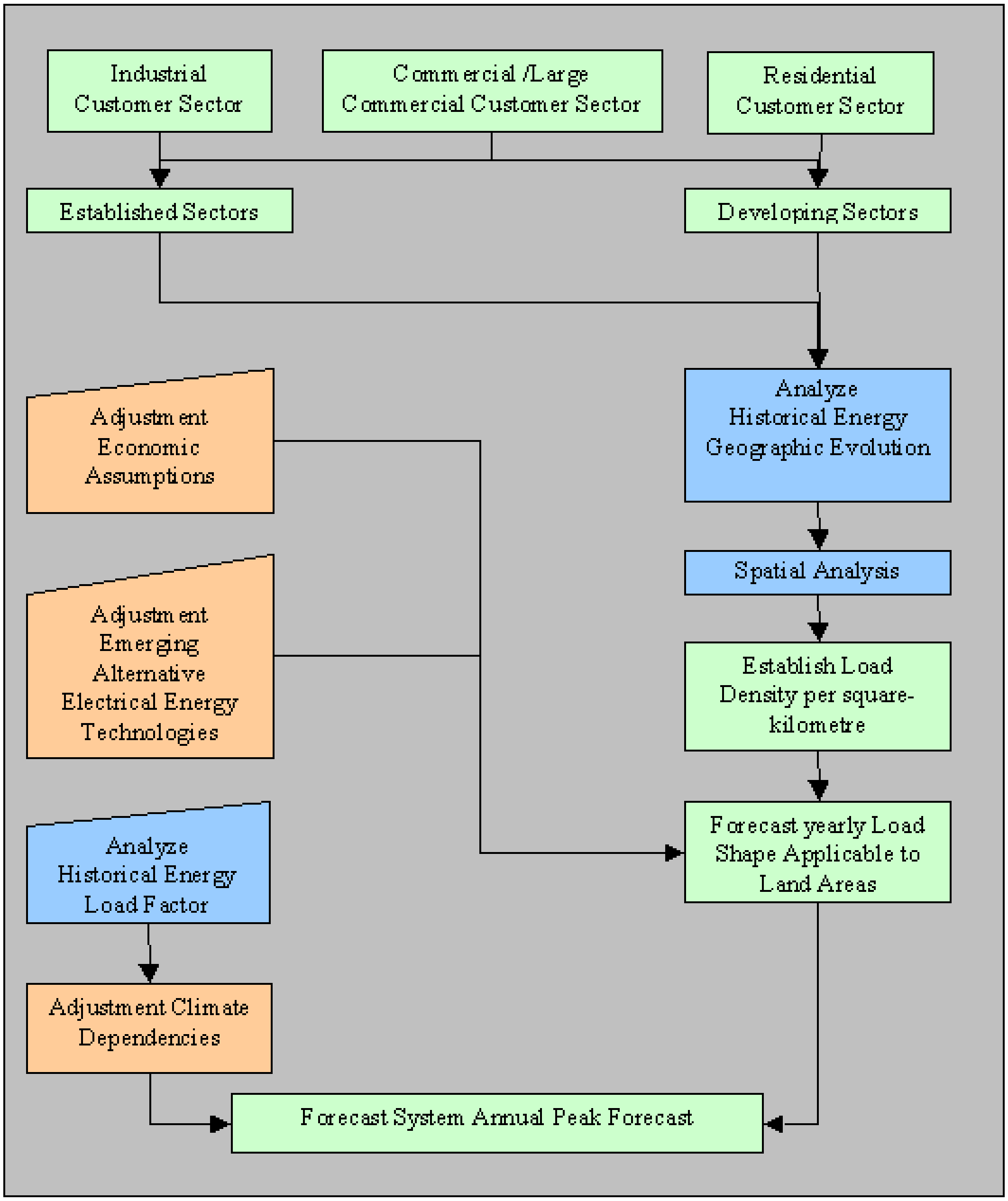
Figure 3.0-1: Customer Sectors as Percentage of Total Electrical Energy (2009)



3.1 RED DEER DEMAND FORECAST METHODOLOGY DIAGRAM

A high-level overview of Red Deer's long-term demand forecasting methodology is shown in Figure 3.1-1: and details for each sector are discussed in the sections that follow

Figure 3.1.-1: Red Deer Demand Forecast Methodology Flow Diagram



3.2 COMMERCIAL CUSTOMER SECTOR

The commercial sectors comprising commercial and large commercial sectors are the largest consumers in terms of demand and energy consumption.

Figure 3.2-1 shows commercial sector electrical energy use from 1997 to 2009. Although there has been a steady 1.8 per cent average growth from 1997 to 2009 in the commercial sector there has been a slight decline in 2009 which indicate a changing pattern of growth characterized by a stagnant year-over-year growth.

Figure 3.2-1: Historical Commercial (Comm. and Lg. Comm.) Electrical Energy

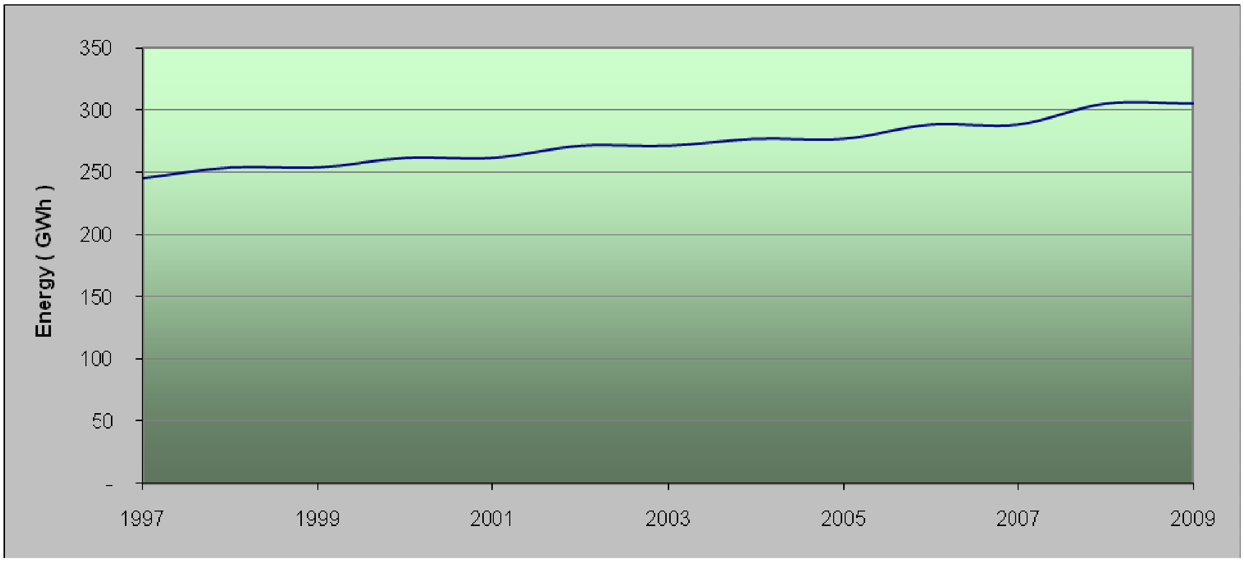
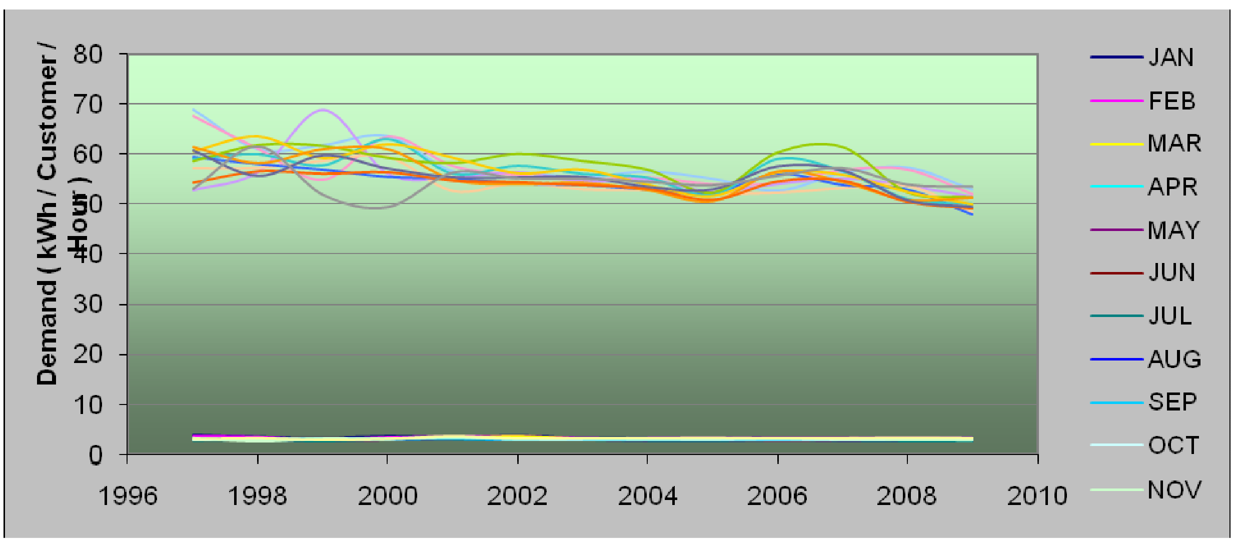


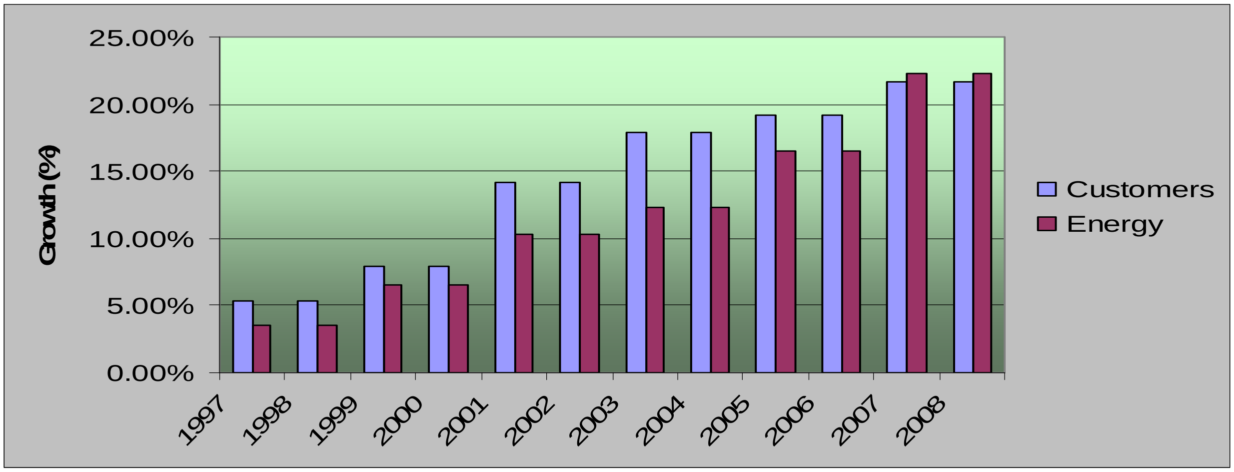
Figure 3.2-2 shows the hourly average electrical demand from 1997 to 2009 per customer per month for the commercial and large commercial sector. While the historical commercial electrical energy consumption shows a steady increase Figure 3.2-2 shows that the increase in electrical demand is not attributable to increase in consumption per customer.

Figure 3.2-2 Hourly Average Commercial and Lg. Commercial Electrical Demand per Customer per Month



Noteworthy, Figure 3.2-2 also illustrates energy deviations between months for a given year. The sources of these deviations are explained under the Climate Dependencies section. Various economic indicators were looked at to find the best fit to predict the future demand of this sector. The correlation between electrical energy growth and number of customer connections stands out as the best fit. Figure 3.2-3 shows per cent commercial electrical energy demand growth since 1997 versus customer connections

Figure 3.2-3: Growth of Commercial Electrical Energy vs. Customer Connections Since 1997

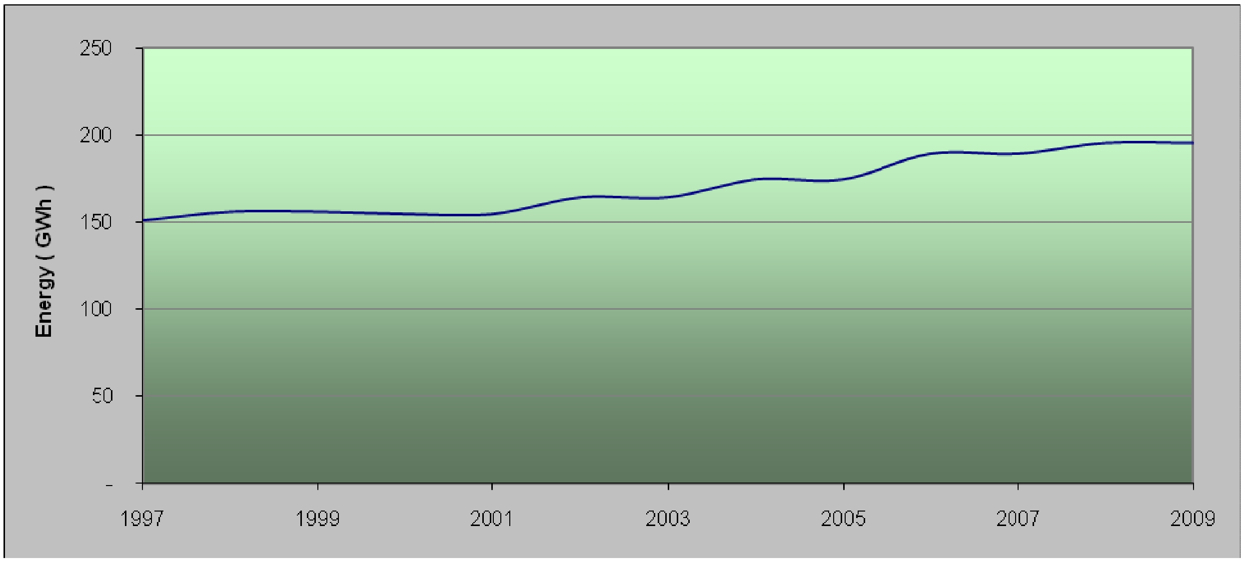


In Red Deer System, electrical energy consumption tends to lag the customer time of connection. This can be attributed to the development of the establishment and business rollout. To an extent this can be seen on figure 3.2-3 in that the increases in electrical energy consumption follow the increasing number of customer connections from 1997 to 2009. The slowdown from 2009 to 2010 reduces the electrical energy demand indicating a possible stagnant growth period in 2011 in this sector. A similar decline was found in 2009 between new subdivision developments and building development permits issued resulting in a declining rate of development of commercial land.

3.3 RESIDENTIAL CUSTOMER SECTOR

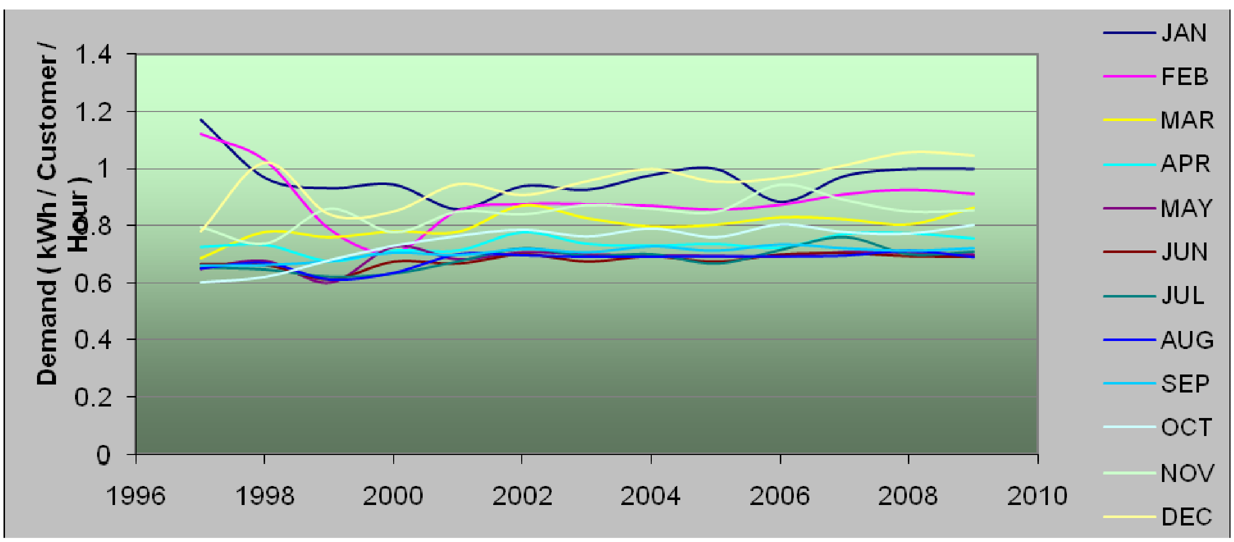
The residential sector is the second largest consumer in terms of demand and energy consumption. The residential model for the 2011 – 2025 electrical energy forecast uses the population, disposable income per person, and labour market conditions for its projection. The residential sector accounts for almost 33 per cent of Red Deer's total electrical energy consumption. Figure 3.3-1 shows residential sector electrical energy use from 1997 to 2009.

Figure 3.3-1: Historical Residential Electrical Energy



The growth in this sector will change with population and disposable income per person. The growth rate in this sector will depend on improvements in world commodity prices and the pace of Canadian and global economic recovery. As seen on Figure 3.3-2, the increase in electrical demand in the forecast will largely depend on new housing developments with only minor increases in electrical demand per customer.

Figure 3.3-2: Hourly Average Residential Electrical Demand per Customer per Month



The historical trend of increase of electrical energy requirements for the residential sector is expected to continue in the 2011-2025 period.

3.4 INDUSTRIAL CUSTOMER SECTOR

Figure 3.4-1 shows industrial sector electrical energy use from 1997 to 2009. Historically there has been consistent industrial electrical energy growth with a declining growth pattern in 2009.

The industrial sector is the smallest consumer in terms of demand and electricity consumption. However, as seen on Figure 3.4-2 the rate at which electrical energy consumption has grown in this sector is greater than those of all other sectors.

Figure 3.4-1: Historical Industrial Electrical Energy

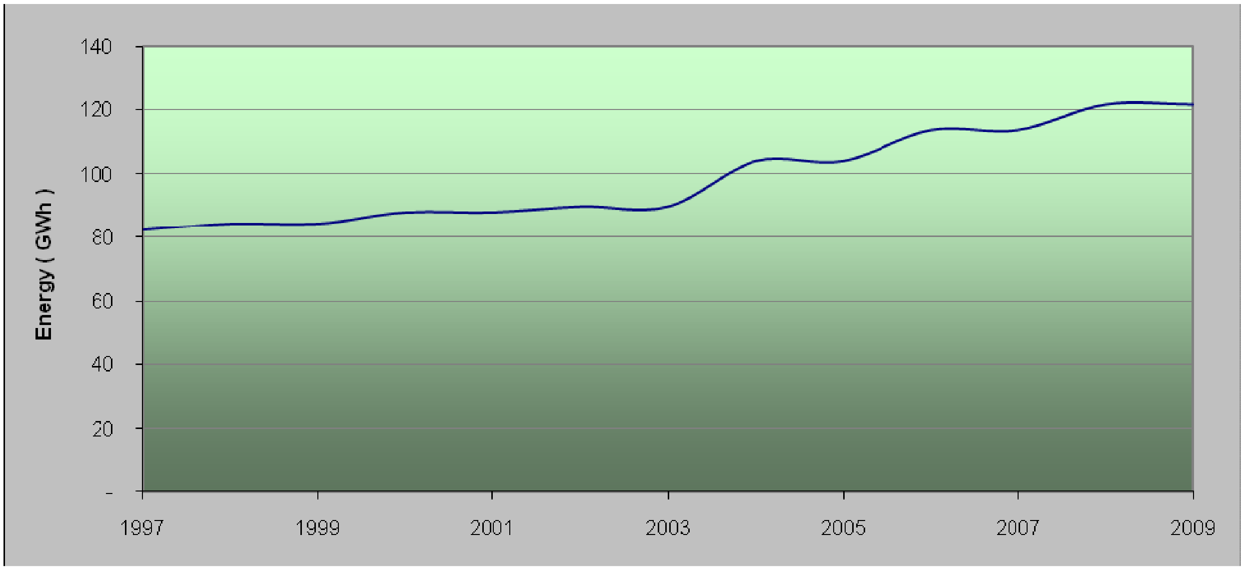
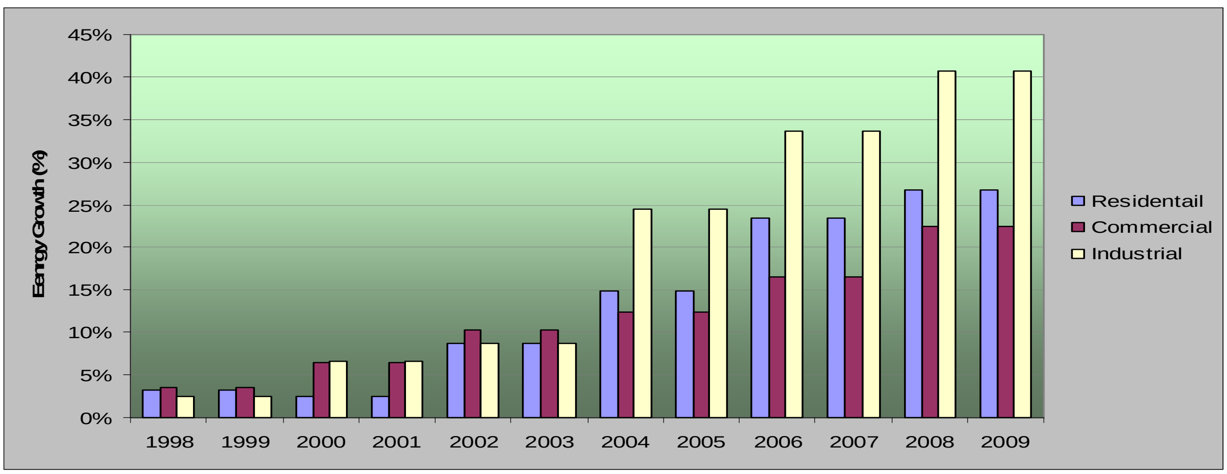


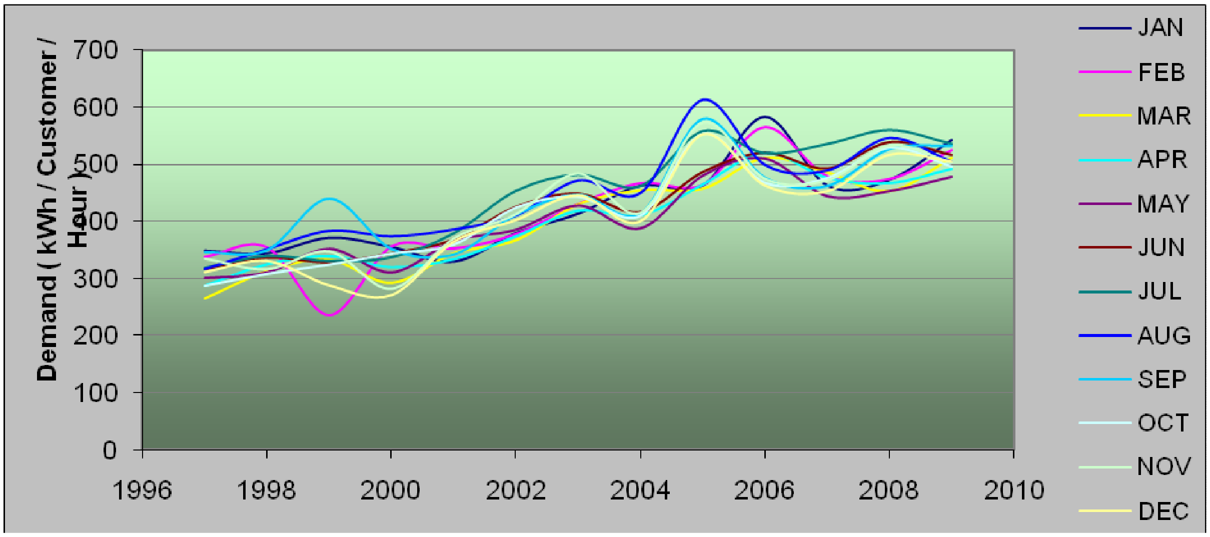
Figure 3.4-2: Electrical Energy Growth Since 1997



The electrical energy use in the industrial sector is expected to continue to grow partly as a result of the City's recent industrial land annexation of approximately 289 ha. It is also noteworthy that Red Deer Region's combined tax and utility rates are among the lowest in Canada and municipalities in the Red Deer Region do not have business taxes [12].

Figure 3.4-3 shows that unlike the residential and commercial per customer growth patterns the industrial electrical demand is attributable both to new industrial land developments and the expansion of existing industry.

Figure 3.4-3: Hourly Average Industrial Electrical Demand per Customer per Month



3.5 SMART GRID DEVELOPMENT

"Smart Grid" is a collective of power systems devices equipped with intelligence and networked to share information and control systems to allow near real-time management of electrical energy exchange between energy consumers and suppliers for the purpose of providing efficient transfer of electrical energy, minimize power outages and their duration, and assist in electrical energy peak shaving to avoid electric energy shortfalls.

Full-scale integration of "Smart Grid" devices will take some time which will depend on the adoption of these technologies through consumer demand and government incentives facilitating its development. Governments are encouraging improved fuel economy either implicitly by regulating it or by charging high fuel taxes or setting limits on vehicle emissions. In addition before a "Smart Grid" can begin to materialize, electrical utilities will need to undergo various infrastructure modifications at a substantial cost to the utility.

3.5.1 ELECTRIC VEHICLES

The battery electric vehicle (BEV) and plug-in electric vehicle (PEV) were not considered in the electrical energy forecast because they only have an electrical propulsion system and penetration of these vehicles in the Canadian market is very slim according to an assessment which explains that the "Canadian climate imposes additional constraints compared to a milder climate. There are other barriers to entry, such as Canadian-specific regulations on bumpers and running lights" [3]. The majority of BEV and PEV vehicles in production to be available by 2011 favor a dense metropolitan setting due to limitations in vehicle size, top speed, and range.

A plug-in hybrid electric vehicle (PHEV) has both a conventional internal combustion engine (ICE) propulsion system and an electric propulsion system which offers a reliable solution to these Canadian barriers.

According to Pike Research PHEV programs will initially focus on the small car market and small SUV market reaching a target of 80 per cent and 10 per cent of sales by 2015 respectively in United States, an estimated 640,000 PHEV vehicles.

Using an approach similar to that outlined in an IEEE report [5] to estimating penetration of PHEV vehicles, based on production and consumer base, results in a penetration of 186 PHEV or 1 PHEV vehicle for every 500 homes in the City of Red Deer by 2015.

Figure 3.5.1-1 and Figure 3.5.1-2 show projections of PHEV market penetration and kWh capacities as PHEV vehicles evolve to meet the demands in all customer sectors. The PHEV statistics were developed using the information and analysis from the IEEE report [5] and a U.S. Department of Energy report on Plug-in Hybrid Electric Vehicle Market Penetration [8].

Figure 3.5.1-1: PHEV Vehicles Market Penetration (%)

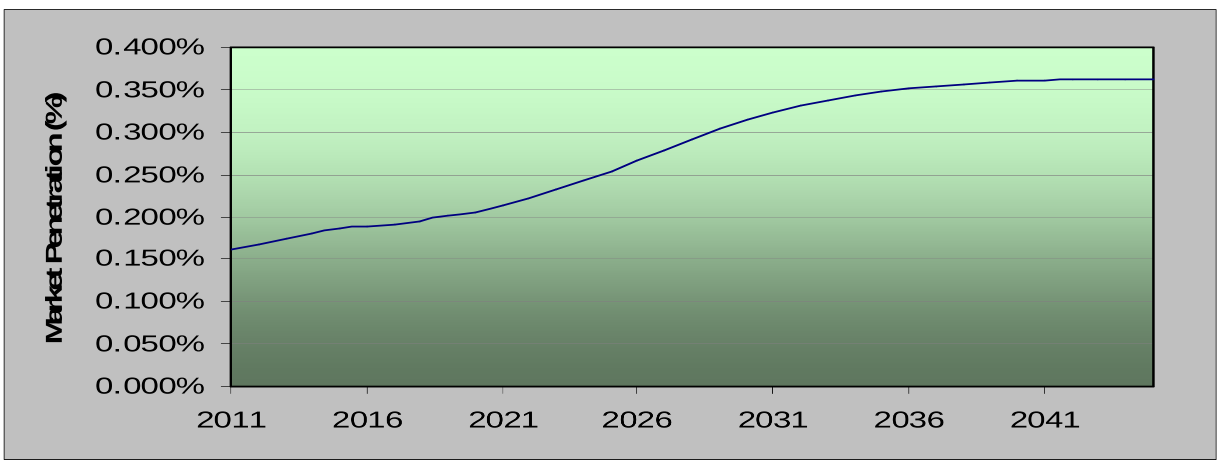
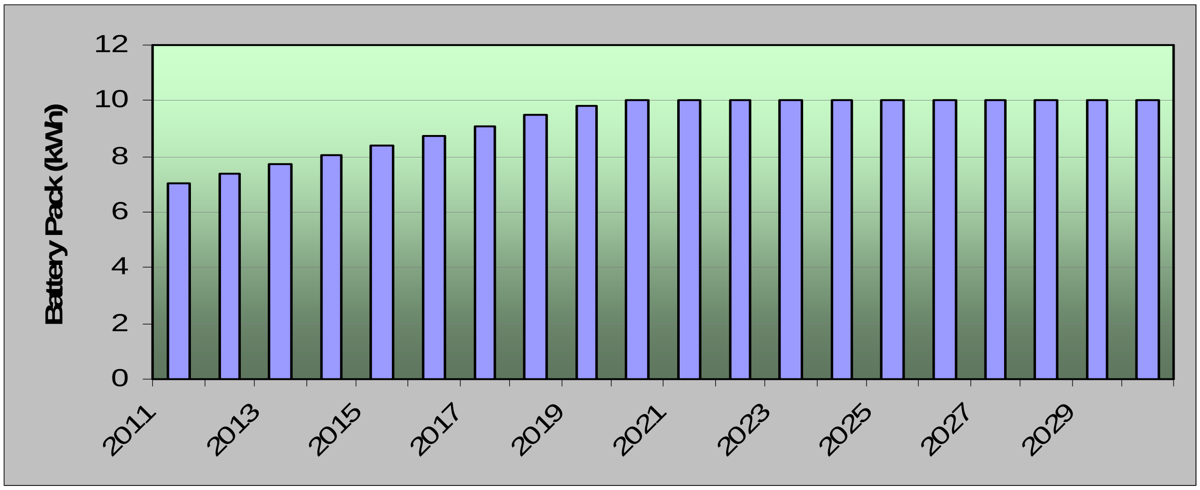


Figure 3.5.1-2: PHEV Battery Pack Capacity (kWh)



Apart from having a successful deployment of PHEV vehicles, the synergy among "Smart Grid" devices will be essential to achieve a reliable electrical energy exchange between PHEV vehicles and other electrical energy consumers and suppliers. For the current forecast, PHEV vehicles were considered only as an electrical consumer with some potential to assist during electrical energy shortfalls and demand peak shaving. However, until their potential to supply electricity can be quantified these are not being classified as an electrical energy generation entity.

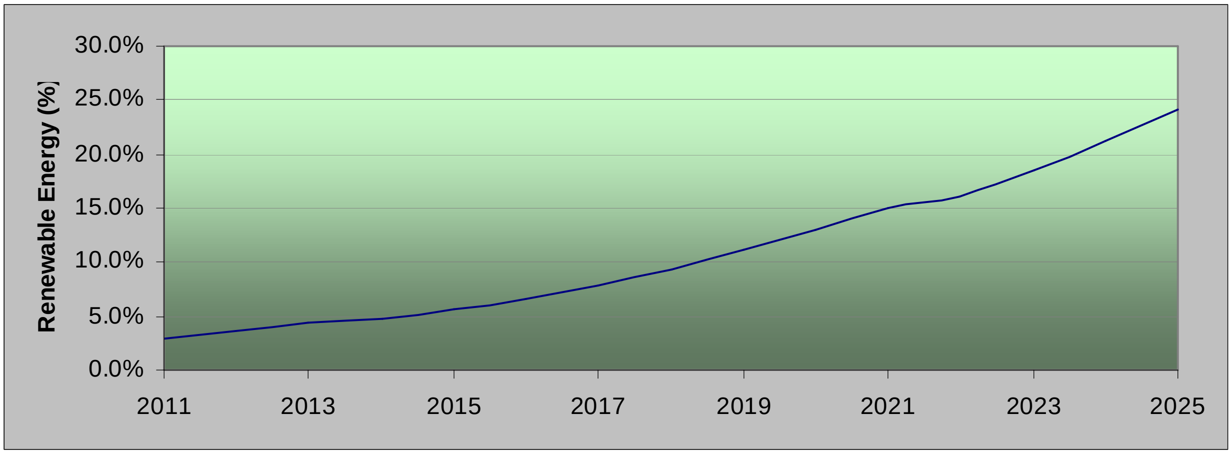
3.5.2 DISTRIBUTION GENERATION

In 2010, 20,111 kWh of electrical energy representing about 46kW of generation capacity has been recorded to have been supplied to the electrical distribution grid by commercial and residential customers in the City. The lack of electrical energy generation at the distribution grid in the form of solar, wind, biomass, micro-cogeneration, power electronics, and fuel cells may be attributed to long-term payback, building permits, bylaw restrictions, and the availability of reasonably priced electrical energy.

However it is generally expected that electrical generation at the distribution level will grow as electrical energy prices increase owing to capital investments necessary to maintain and replace aging infrastructure along with building new facilities to keep up with electrical energy demand. Moreover, fuelling the demand for distributed generation and energy price increases are geopolitics, government regulations, subsidies and financial incentives enforcing the need for greener technologies. "Smart Grid" devices such as smart electrical meters will allow consumers to make better and conscious decisions for their electrical energy usage to reduce their environmental footprint and participate in energy conservation. These governing regulations are expected to become effective by 2012 according to the Department of Energy Alberta and utilities will be required to comply with these new regulations shortly thereafter. Consequently, emerging distribution generation technologies are considered as an electrical energy generation segment in developing the electrical energy demand forecast.

Figure 3.5.2-1 shows a projection of installed distributed generation versus Red Deer's residential sector electrical demand based on a cost per watt affordability time curve, take-up, and demand and supply side barriers.

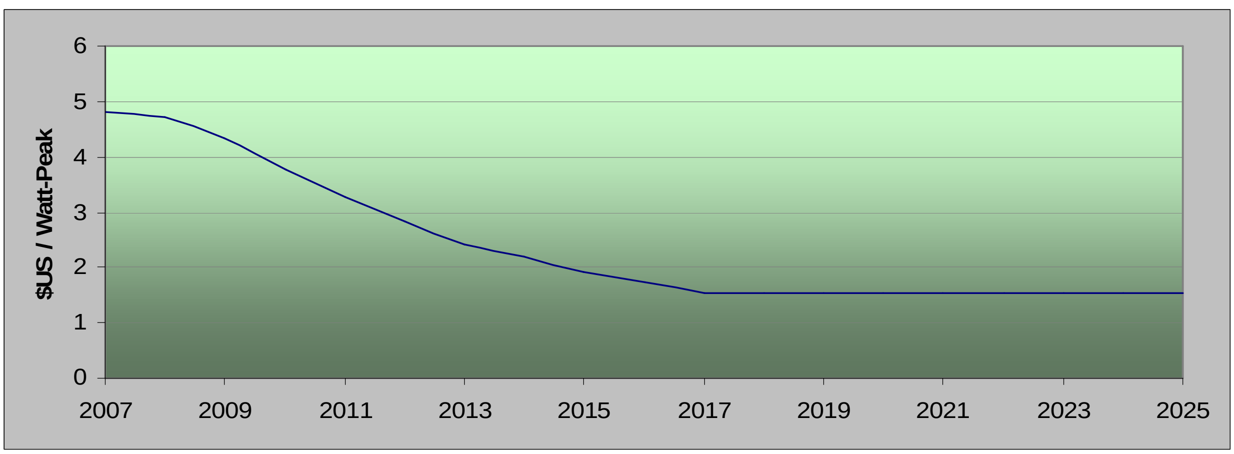
Figure 3.5.2-1: Distribution Generation as a per cent of Residential Electrical Demand



Source: EU 2020 Renewable Energy Target [16]

Figure 3.5.2-2 and Figure 3.5.2-3 show for the projected generation at the distribution level.

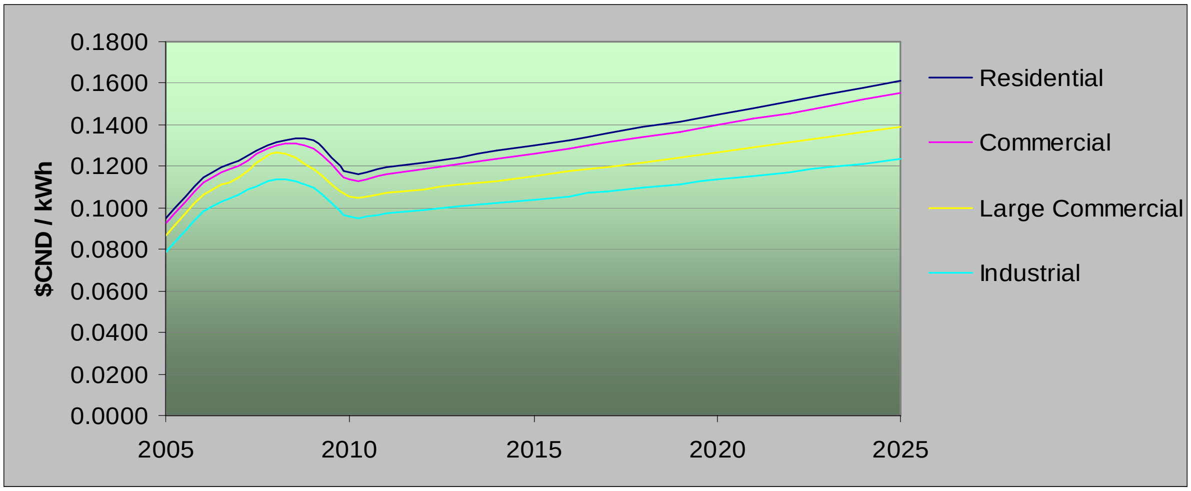
Figure 3.5.2-2: Retail Price per Watt-Peak Projection



Source: Solarbuzz Consultancy Reports [2]

It is generally expected that electric energy prices will continue to increase due to increases in energy consumption, cost to build and maintain infrastructure, and deliver energy to the end user. Figure 3.5.2-3 depicts projected normalized CND$/kWh historical regulated rate pricing combining energy and delivery charges using linear approximation. Figure 3.5.2-3 is shown here for illustrative purposes only as electricity bills will depend on the intricacies of rate structures and contract details offered by energy retailers

Figure 3.5.2-3: Customer Sector Energy Price Projection

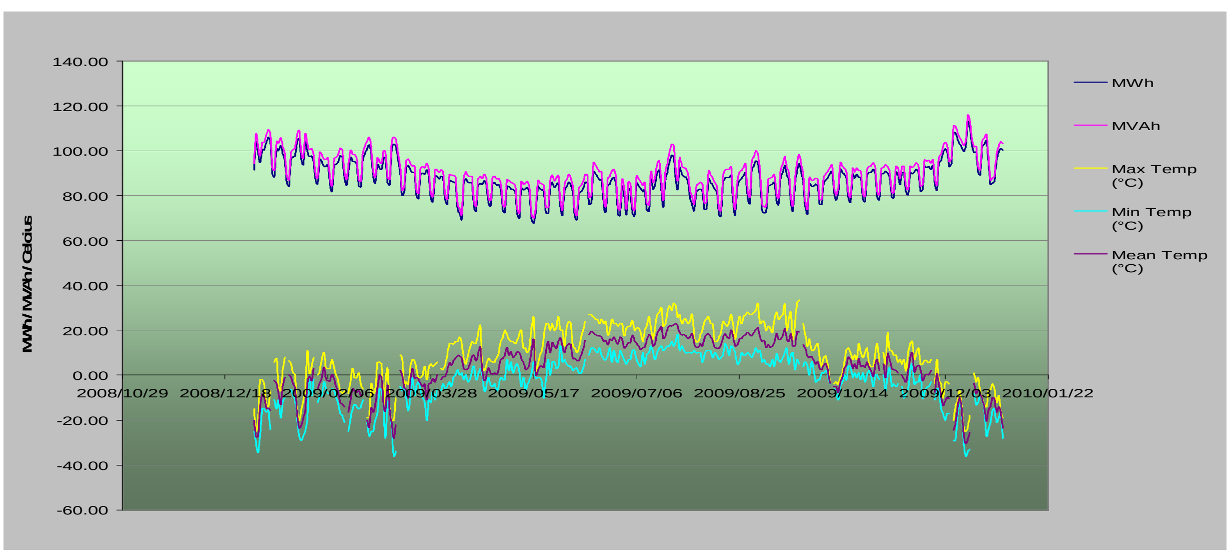


3.6 CLIMATE DEPENDENCY

Equally important to the development of the energy demand forecast is the climate driven segment responsible for energy peak demand cycles. Although these cycles are short lasting it is crucial that the electrical system is able to supply these energy demand spikes to ensure a reliable system and avoid overstressing equipments that will shorten their life expectancy.

Figure 3.6-1 shows the entire energy peak demand profile for 2009. Studies from 1997 through 2009 show similar patterns marking distinctive demand spikes during winter and summer temperature extremes with consistent concave up and concave down patterns following climate anomalies.

Figure 3.6-1: System Energy Demand vs. Climate (2009)

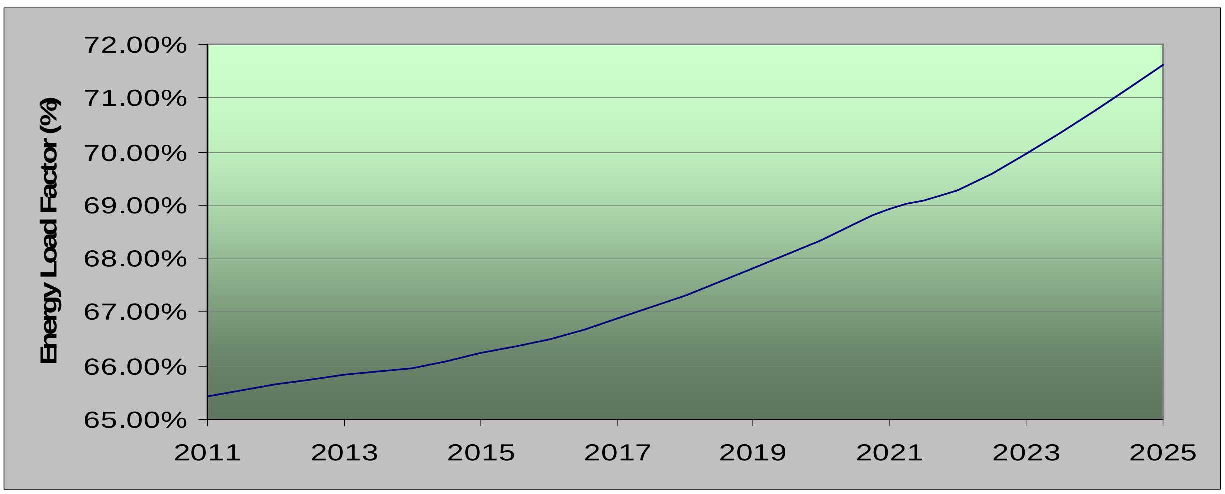


Source Environment Canada National Climate Data and Information Archive

Figure 3.6-1 elucidates the monthly variances seen on Figure 3.2-2, Figure 3.3-2 and Figure 3.4-3 in which they are partly driven by climate.

Using statistical methods to measure climate effects on baseline electrical demand found that peak demands are directly attributed to climate extremes and the shortening of daylight hours largely accounts for the gradual increase in electrical energy usage during the winter months. The system average load factor from 1997 to 2010 is 65 per cent with subtle changes year-over-year. The load factor will be significantly improved with the implementation of "Smart Grid" devices, adaptation to energy efficient appliances, and converting traffic and streetlights to higher efficiency lighting technology. Load factor improvement would increase the uniformity and efficiency with which electric energy is being used. Moreover, increase in system capacity requirements for absorbing climatic peak demands can be reduced. Figure 3.6.3 shows the projected energy load factor correction based partly on implementation of "Smart Grid" devices, distributed generation, and adaptation of energy efficient technologies.

Figure 3.6-3: Projected System Load Factor

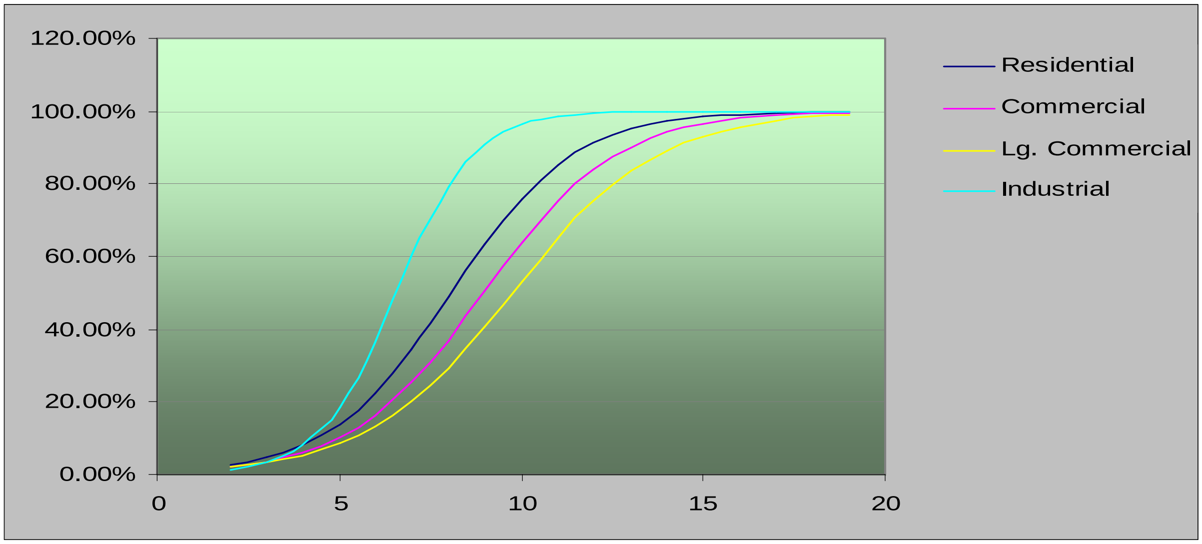


3.7 SPATIAL ANALYSIS

Developing the electric energy and demand forecast also requires the identification of the geographical locations where electrical facilities upgrade would be required to deliver electrical energy reliably and efficiently. Spatial analysis offers an insight to the best suited location of these facility capacity improvements.

To forecast demand for each customer sector within a small area, the logistic S-curves [6], which showed to be consistent and provide good results when applied to small areas have been used. The characteristic S-curve represents three main parts. The dormant or initial period that accounts for about 10% of the growth. The ramp period, that accounts for nearly 80% of the growth and finally the saturation period, which accounts for the remaining 10% growth. Figure 3.7-1 shows the logistic S-curves used to forecast growth for each customer sector in both saturated and non-saturated small areas.

Figure 3.7-1: Logistic S-curve representing the growth of a small area



For Red Deer a small area boundary condition was defined as a quarter section. A utilization factor was assigned based on available and prohibited land to each quarter section. The timing, size, zoning and number of quarter sections added to the electrical service boundary was aligned to the City's phase one annexation [14] and environmental and engineering departments initiatives to extend services as set out in their 2011 departmental budgets. However, because most service departments aim for a 10-year outlook, preferential factor (i.e. distance to highways, to educational institutions, etc) were used to extend the electrical service boundary to the 15-year outlook.

The available geographical information system (GIS) proved to be a useful tool to extract installed transformer sizes and quantities within each quarter section. Each transformer was grouped according to a service size and given a load classification. The transformer service size load classification range was derived from customer sector energy usage and 2010 City of Red Deer distribution tariff energy rate class with results shown in Table 3.7-1.

Table 3.7-1: Transformer Size Load Classification Range

Sector	Rate Class	kVA (<=)
Residential	E61	5
Commercial	E63	50
Lg. Commercial	E64	1,000
Industrial	E78	2,000
Industrial	E78	>2,000

Using Table 3.7-1 each quarter section was allotted a customer sector per cent according to their weighted average to avoid skewing the allotment due to the significant variation between transformer service sizes. Table 3.7-2 represents load density ranges obtained from AESO Ultimate Load Density Table [13] with minor adjustments to reflect actual findings. Using the load density table a saturation factor was assigned per customer sector to identify its position relative to the appropriate sector S-curves to forecast demand.

Table 3.7-2: The City of Red Deer Ultimate Load Density

Classification of Load	Load Density (MVA/Quarter Section)		
	LOW	AVG	HIGH
Residential	1	1.75	2.5
Light Commercial / Industrial	2	3.5	5
Heavy Commercial / Industrial	5	7.5	10
Downtown Area	5	7.5	10

Key electrical demand projections occurred at the substation main 25kV feeder level. Quarter sections were clustered according to main feeder service route with slight adjustments to the customer sector load density scale to reflect actual 2010 electrical demand figures. Tracing the logistic S-curve equations based on utilization and saturation factor assigned to each quarter section combined with economic indicators and emerging alternative energy technologies formed the system long-term electrical demand forecast. Figure 3.7-1 shows The City of Red Deer's system long-term electrical demand forecast with five per cent confidence band. Figure 3.7-3 shows The City of Red Deer's system yearly average long-term electrical energy forecast.

Figure 3.7-1: 15 Year System Electrical Demand Forecast with Five per cent Confidence Band

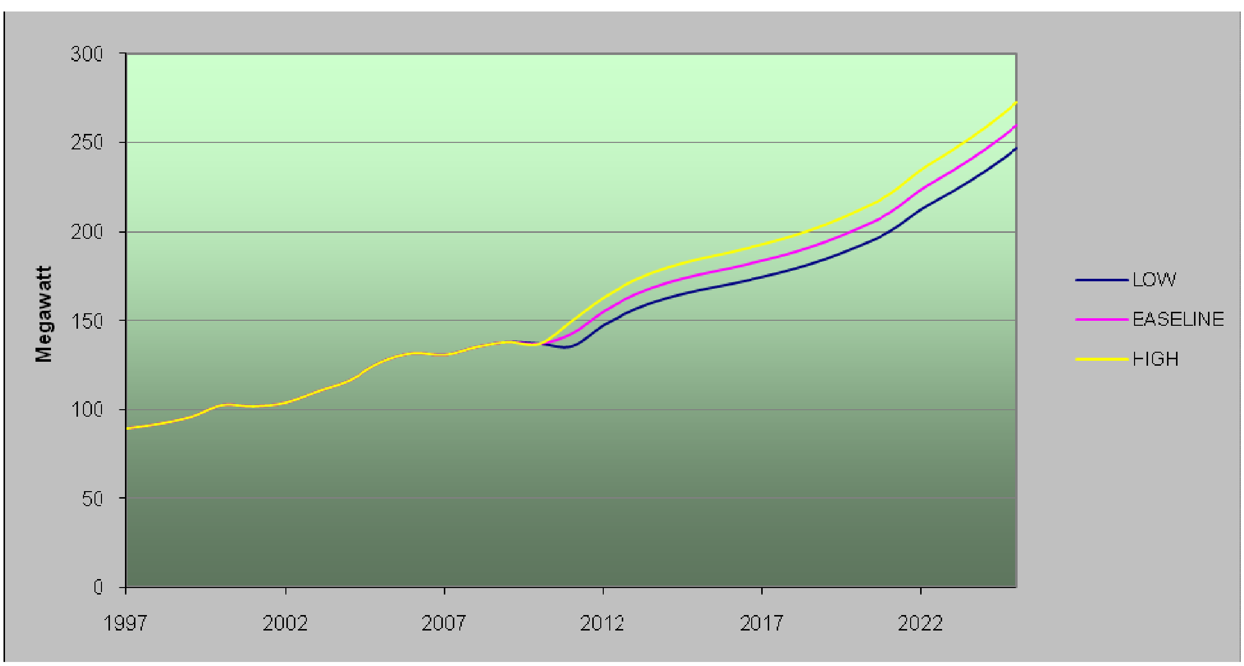


Table 3.7-3 shows increasing peak demand requirements relative to electrical substation service area outlined in Figure 3.7-2. Figure 3.7-2 depicts a successive five-year expansion of the electrical service boundary and major electrical substation service territory with ultimate energy density mapping to year 2025. Darker shaded areas represent higher electrical demand.

Table 3.7-3: Electrical Substations Peak Demand Forecast

		Mega-Watts														
Service Area	**Substation**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
North	RD14S	44	50	55	58	60	62	64	67	70	75	80	88	93	98	105
South-Central	RD15S	58	64	68	71	73	74	75	77	78	80	82	86	91	96	101
South-East	RD17S	40	41	41	42	42	43	44	45	46	47	48	49	50	51	53

The supply requirement of major City of Red Deer electrical substation facilities mentioned in Table 3.7-3 will heavily depend on the process and timing in which existing and new underground and overhead 25kV distribution feeder cables are installed and routed. Consequently, Table 3.7-3 reflects supply requirements based on current practices to service territory expansion without the addition of new facilities.

Figure 3.7-2: Electrical Service Boundary Expansion with Identified Electrical Substation Service Territory

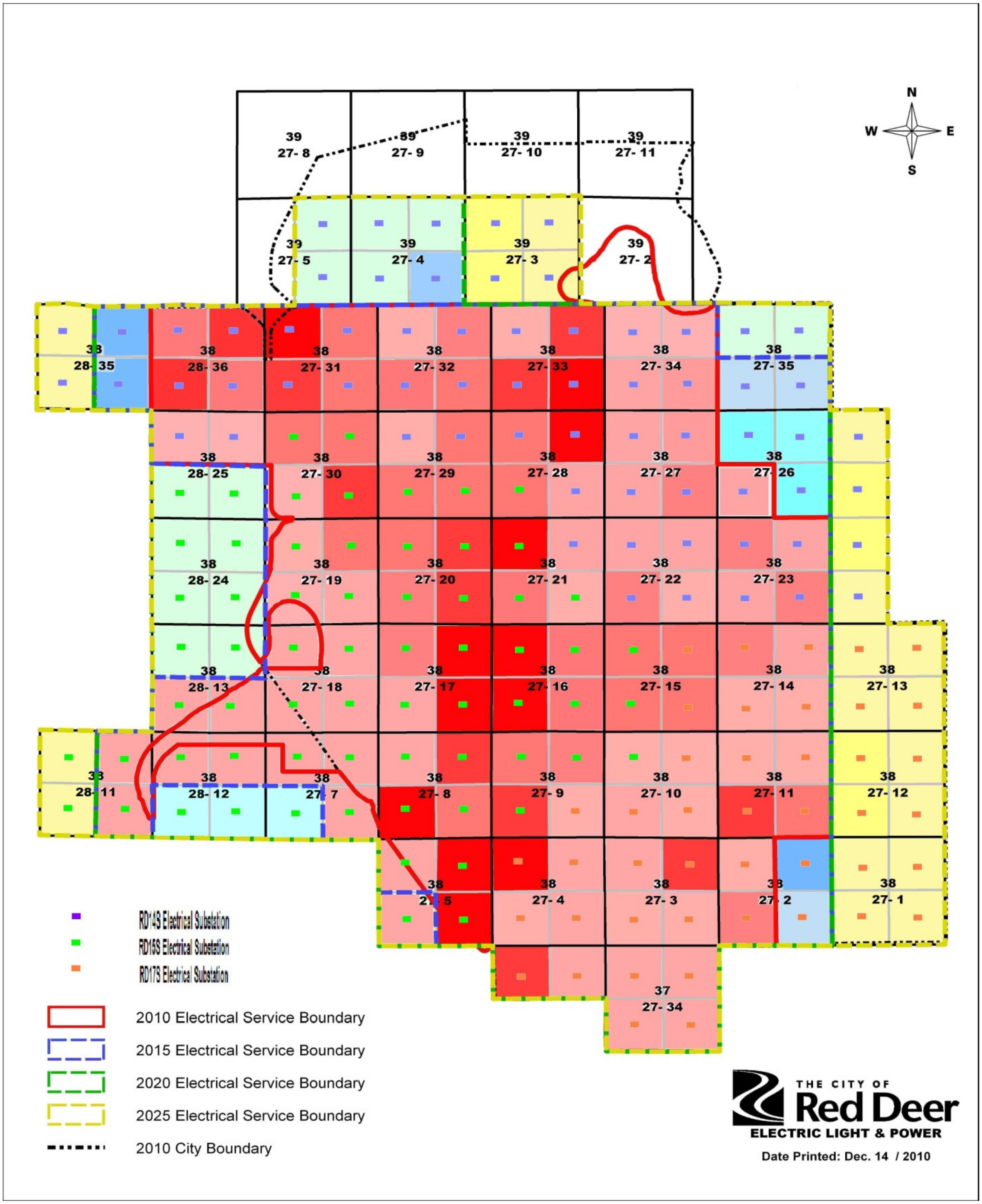
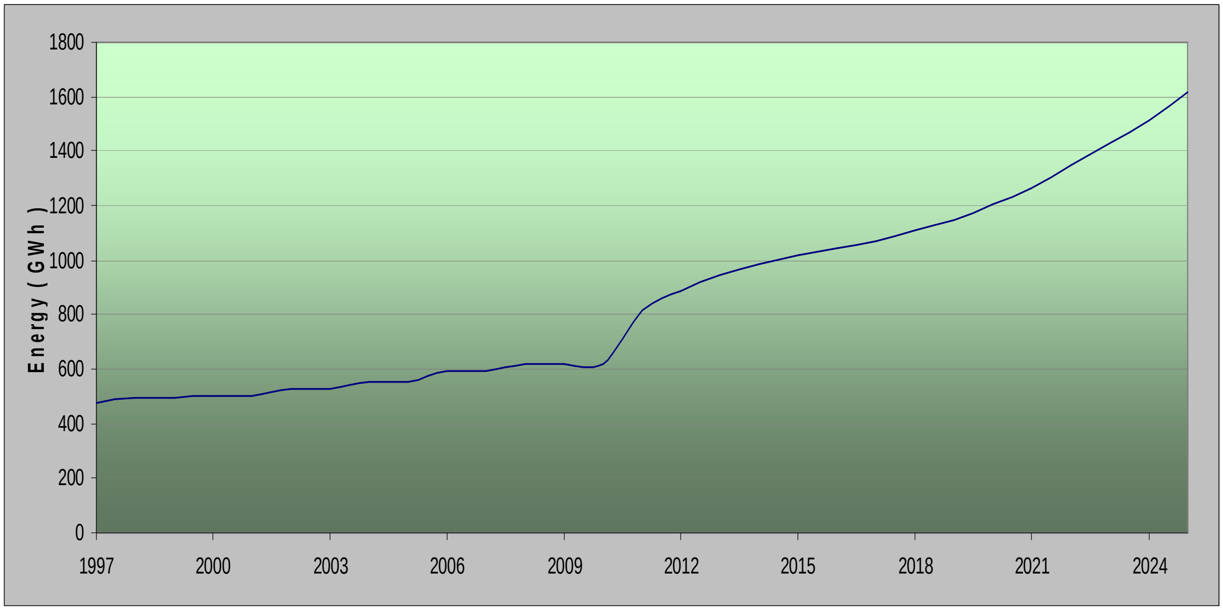


Figure 3.7-3: 15 Year System Yearly Average Electrical Energy Forecast



List of Reference Documents

[1] Environment Canada, Canada's National Climate Archive
http://www.climate.weatheroffice.gc.ca/

[2] Solarbuzz Consultancy Reports, Solar Module Retail Price Environment
http://www.solarbuzz.com/ModulePrices.htm

[3] Electric Mobility Canada (EMC), Demonstrating electric Vehicles in Canada (March 2010)

[4] National Bureau Of Economic Research, Economic Growth And The Demographic Transition (December 2001), Working Paper 8685
http://www.nber.org/papers/w8685

[5] IEEE, Electric Vehicles: Holy Grail or Fool's Gold (2009)

[6] IEEE, A Methodology for Electrical Energy Forecast and its Spatial Allocation over Developing Boroughs (2008)

[7] Energy Service, Improving Load Factor and Power Factor to Reduce Demand

[8] US Department of Energy (DOE), Plug-in Hybrid Electric Vehicle Market Penetration Scenarios (September 2008)

[9] The City of Red Deer, 2010 Municipal Census Report (July 2010)

[10] Red Deer Regional Economic Development, Annual Stakeholders Report (February 2010)

[11] Pembina Institute for Appropriate Development, The Alberta GPI: Economy, GDP, and Trade (March 2002)

[12] The City of Red Deer, Demographics and Socio-Economic Trends of Red Deer Research Report (November 2008)

[13] Alberta Electric System Operator (AESO), Distribution Point-of-Delivery Interconnection Process Guideline – Standard of Service (2005)

[14] The City of Red Deer / Red Deer County Report on Negotiations Regarding a Proposed Annexation

[15] Parkland Community Planning Services Population Projections (PCPSP) 2007 -2031 Final Report

[16] The EU's Target for Renewable Energy: 20% by 2020 - 27th Report of Session 2007–08

APPENDIX C

INVESTMENT and REPLACEMENT COST

ELP MAJOR DISTRIBUTION CAPITAL PROJECTS, BREAKDOWN OF PROJECT COST (x $ 000)

Line	Project	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	Extend Feeder to QBP via Hwy 11A (14B18)	$290.0														
5	Kentwood Feeder, S14 to Taylor (14B80)	$900.0														
	Downtown back-up (14B36 - 15B16)	$210.0														
9	Extend line on 20 Ave, 55 St to 67 St (17B75)		$250.0													
13	New feeder to offload 15B16 (15-B-EAST)			$700.0												
17	Split feeder 15B23 add new feeder (15-B-SPNT)				$500.0											
21	Extend feeder along 67 St to QBP (15B23)				$650.0											
27	Rebuild to 2C on 20 Ave and 55 St (14B36)				$150.0											
30	1,2 circuit along 67 St, S1 to 30 Ave					$600.0										
36	Downtown backup (1-B-108 tie to 15-B-21)						$250.0									
33	Extend feeder along 67 St to QBP (15B46)						$400.0	$400.0								
36	3,4 circuit along 67 St, S1 to 30 Ave							$1,100.0								
36	1,2 circuit along 67 St, 30 Ave to River								$400.0							
39	New feeder for Riverlands / Railyards (15-B-DNTN)								$800.0							
	Rerouting for Edgar Industrial (14B38)								$500.0							
39	Hwy 2 UG road crossing (14B13)									$150.0						
39	2-CCT into Chiles and North (14B13 & 14B80)										$800.0	$800.0				
39	New feeder along Northlands Drive, S14 to S1									$1,000.0						
39	New feeder along 22 St, S17 to 20 Ave (17B64)									$400.0	$500.0					
45	Branches into Annex Ph.1 East Res. (14B13 &14B18)										$200.0					
42	Branches into Annex Ph.1 East Commercial (14B80)										$250.0					
48	Extend feeder to Annex Ph.1 East Industrial (14B30)											$300.0				
48	New feeder Westlake across HWY2 to QBP (15-B-90)											$800.0	$400.0			
48	Extend feeder to West of SPJ across HWY 2 (17B26)													$400.0		
48	Extend feeder to West 15-B-SPNT (17B26)														$475.0	
	TOTAL	**$1,400.0**	**$250.0**	**$1,200.0**	**$1,650.0**	**$1,000.0**	**$650.0**	**$1,500.0**	**$1,700.0**	**$1,550.0**	**$1,750.0**	**$1,900.0**	**$400.0**	**$400.0**	**$475.0**	**$0.0**
	Annual Inflation	0.00%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%
	Inflation from Base Year	100.00%	101.96%	103.96%	106.00%	108.07%	110.19%	112.35%	114.55%	116.80%	119.09%	121.42%	123.80%	126.23%	128.70%	131.23%
	NOTES: annual inflation rate was calculated using Bank of Canada Rate and Statistics available at www.bankofcanada.ca/en/rates/inlation_calc.html															
	TOTAL Cost with Inflation	**$1,400.0**	**$254.9**	**$1,247.5**	**$1,748.9**	**$1,080.7**	**$716.2**	**$1,685.3**	**$1,947.4**	**$1,810.4**	**$2,084.0**	**$2,307.0**	**$495.2**	**$504.9**	**$611.3**	**$0.0**

ELP EXISTING SUBSTATION CAPITAL PROJECTS, BREAKDOWN OF PROJECT COST (x $ 000)

Line	Project	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
21	**VI. RD15S, Replacement of Breakers, Busbars and P&C**															
22	Total Construction Cost in Year	$800.00	$2,100.00	$800.00												
23	Total Cost with Inflation (*)	$800.0	$2,141.2	$831.7												
24	**VII. RD15S, Addition of Feeder Breakers**															
25	Total Construction Cost in Year			$1,000.0	$1,500.0	$500.0										
26	Total Cost with Inflation (*)			$1,039.6	$1,589.9	$540.4										
39	**XII. RD15S, Addition of 3rd Transformer**															
40	Total Construction Cost in Year						$600.0	$1,600.0								
41	Total Cost with Inflation (*)						$661.15	$1,797.62								
27	**VIII. RD15S, Replacement of 15T1**															
28	Total Construction Cost in Year							$600.0	$1,600.0							
29	Total Cost with Inflation (*)							$674.1	$1,832.9							
30	**IX. RD14S, Replacement of 14T1**															
31	Total Construction Cost in Year								$600.0	$1,600.0						
32	Total Cost with Inflation (*)								$687.3	$1,868.8						
33	**X. RD15S, Replacement of 15T2**															
34	Total Construction Cost in Year											$600.0	$1,600.0			
35	Total Cost with Inflation (*)											$728.53	$1,980.83			
36	**XI. RD14S, Replacement of 14T2**															
37	Total Construction Cost in Year										$600.0	$1,600.0				
38	Total Cost with Inflation (*)										$714.53	$1,942.76				
	Annual Inflation	0.00%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%
	Inflation from Base Year	100.00%	101.96%	103.96%	106.00%	108.07%	110.19%	112.35%	114.55%	116.80%	119.09%	121.42%	123.80%	126.23%	128.70%	131.23%
	NOTES: annual inflation rate was calculated using Bank of Canada Rate and Statistics available at www.bankofcanada.ca/en/rates/inlation_calc.html															
	TOTAL Cost with Inflation	**$800.0**	**$2,141.2**	**$1,871.3**	**$1,589.9**	**$540.4**	**$661.2**	**$2,471.7**	**$2,520.2**	**$1,868.8**	**$714.5**	**$2,671.3**	**$1,980.8**	**$0.0**	**$0.0**	**$0.0**