City of Edmonton Transmission Reinforcement

Load and Generation Forecast

Date: September 15, 2023

Prepared by: Mehdi Salamati
Forecast Analyst

Classification: Public

Table of Contents

1. Introduction

This document describes the load and generation forecasts used as an input for the City of Edmonton Transmission Reinforcement Planning Report (Planning Report).[1]

Section 2 describes historical and forecast load estimates. Given the proximity of Kennedale and Namao substations to each other and the historical evidence of load transferring between them, this report presents both historical and forecast insights for both substations. This approach ensures a holistic understanding of the load dynamics in these areas. The AESO conducted several meetings with EPCOR Distribution & Transmission Inc. (EDTI) to enhance understanding of load dynamics in the Edmonton area especially within the Study Area which is comprised of the service areas of Kennedale and Namao substations. These discussions covered critical topics, including the closure of Northlands Coliseum, historical and anticipated load transfers, the impact of the 2021 heatwave, and future transportation and residential projects in the service areas.

This report commences with the presentation of historical data related to annual peaks in the Edmonton Planning Area (Area 60)[2], encompassing both the Kennedale and Namao substations, as well as the individual annual peaks of the Kennedale and Namao substations. The inclusion of Area 60 serves the purpose of providing a broader perspective of the area in which the Kennedale substation is located, offering valuable insights into the general load growth trends in that vicinity. This approach is deemed essential as historical growth and peaks at the substation level may not always accurately reflect the overall load patterns due to factors such as temporary or permanent load transfers and potential incidents impacting substation peaks.

In the load forecasting section, our forecast model will present output data for both Namao and Kennedale substations which aligns with the AESO's preliminary 2024 Long-term Outlook (preliminary 2024 LTO).[3] In addition to the main case, the report includes three other forecasts as sensitivities. Our main forecast, accompanied by two sensitivities, investigates different Electric Vehicle (EV) adoption rates and charging profiles. A third sensitivity, the 'Area 60 Trend-Based ' utilizes Edmonton area growth rates to predict annual peaks in Kennedale and Namao. The 'Area 60 Trend-Based' primarily focuses on assessing near-term load growth within other sensitivities, and since it doesn't consider the impact of electrification on long-term demand, its long-term forecast isn't directly comparable.

Section 3 describes the existing and forecast generation capacity in the Edmonton Planning Area, as well as the methodology that was used to develop the generation dispatches used in the Planning Report studies.

2. Load

2.1 Historical Load

In Table 1, the summer and winter peaks are presented, along with the 5-year (2017-2022) Compound Annual Growth Rate (CAGR), for Area 60. Annual peaks occurring in summer are highlighted in orange, while those in winter are marked in blue. Notably, the data reveals that the summer peaks are exhibiting a

[1] Filed as Appendix A.

[2] Edmonton is identified as Area 60 on the AESO transmission planning areas map, accessible at https://www.aeso.ca/assets/Uploads/Planning-Regions.pdf for reference.

[3] AESO's preliminary 2024 LTO materials are available here: https://www.aesoengage.aeso.ca/34307/widgets/141824/documents/118661

more rapid rate of growth compared to the winter peaks in Area 60. The most recent 5-year CAGR for Area 60, standing at 1.3% for summer peaks and 0.8% for winter peaks, will be utilized in one of the forthcoming sensitivity analyses in the forecasting section.

Table 1: Historical Summer and Winter Peak Loads (MW) for Area 60

Year	Area 60	
	Summer peak (MW)	Winter peak (MW)
2011	1,132.2	1,140.7
2012	1,205.6	1,158.9
2013	1,293.4	1,203.4
2014	1,278.8	1,181.9
2015	1,280.3	1,213.2
2016	1,205.3	1,199.7
2017	1,214.7	1,192.2
2018	1,285.4	1,210.7
2019	1,244.6	1,174.4
2020	1,249.3	1,240.2
2021	1,405.8	1,200.6
2022	1,298	1,242.2
CAGR (2017-2022)	**1.3%**	**0.8%**

Table 2 presents data on both winter and summer peaks at the Kennedale and Namao substations, encompassing the years from 2011 to 2022. In this table, annual peaks occurring during the summer months are highlighted in orange, while those in winter are indicated in blue. The data reveals that the summer peaks are exhibiting a more rapid rate of growth compared to the winter peaks in both Kennedale and Namao.

The peaks in Namao consistently occurred during the winter season, with the highest recorded peak reaching 57.5 MW in the year 2022. Over the past decade (2013-2022), Namao has seen average summer peaks of 50.4 MW and winter peaks of 53.3 MW. According to EDTI, there was a permanent load transfer of 4.7 MW from Kennedale to Namao in 2021. To assess the growth rates while mitigating the impact of load transfers, the year 2022 has been excluded from the CAGR in Table 2. When looking at a 5-year (2016-2021) CAGR for Namao, it indicates a 2% rise in summer peaks and a 1% increase in winter peaks.

Kennedale recorded its highest historical peak at a level of 63.3 MW in 2021, with the heat wave that occurred during that year being one of the contributing factors to this record peak. The 10-year averages (2013-2022) for summer peaks and winter peaks stand at 56.1 MW and 56.7 MW for Kennedale, respectively. In the most recent 5-year period (2018-2022), the average summer peak is 55.5 MW, while the average winter peak is 54.3 MW.

The mentioned 4.7 MW load transfer coupled with a notably cooler summer in 2022, contributed to a 12 MW decrease in the summer peak at Kennedale in 2022 compared to 2021. In Table 2, a 5-year CAGR (2016-2021) is presented for Kennedale, revealing a 3% increase for summer peaks and a -1% decrease for winter peaks. The decline in the winter peak load of Kennedale may be attributed to a combination of factors, including load transfer to Namao in 2021 and the ongoing influence of Covid-19.

Based on the data in Table 2, it's apparent that Kennedale annual peaks are alternating between winter and summer seasons. Our analysis on Kennedale shows that seasonal peaks closely correlate with the maximum and minimum temperatures recorded each year. Elevated summer temperatures are associated with higher summer peaks, while lower winter temperatures contribute to higher winter peaks. Examining the day types for annual peaks in Kennedale reveals a distinct pattern. Specifically, every annual peak during the summer months coincides with a working day, while all the annual peaks in winter occur on weekends, except for one occurrence in 2012. Hence, the oscillation of annual peaks between summer and winter appears to be influenced by both temperature levels and the day types on which these peaks occur.

Table 2: Historical Summer and Winter Non-Coincident Peak Loads (MW) for the Study Area

Year	Kennedale Substation		Namao Substation	
	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
2011	49.3	57	52.2	52.9
2012	54.2	57.8	46	52.8
2013	55.9	59.6	48.5	51
2014	55.6	60.4	47.4	50
2015	59.7	59.4	46.1	46.6
2016	54.1	60.3	48.8	53.6
2017	58.8	55.8	48.9	56.3
2018	57.1	53.7	51.1	53.3
2019	52.3	54.9	49.4	53.5
2020	53.3	55.7	53.6	55
2021	63.3	56.2	54.5	56
2022	51.3	50.9	55.8	57.5
CAGR 2016-2021	**3%**	**-1%**	**2%**	**1%**

2.2 Load Forecast

In this section, we introduce the Main Case and three sensitivities: the Main Case, Moderate EV Penetration, High-EV Penetration, and the Area 60 Trend-Based. While the Main Case and two of sensitivities consist of two primary components—the 'Base Load' and 'Load Modifiers,' detailed in the following paragraphs—the third sensitivity, Area 60 Trend-Based, takes a different approach. It leverages the most recent 5-year Compound Annual Growth Rate (CAGR) for Area 60 as a basis for predicting future growth for the Kennedale and Namao substations.

The 'Base Load' is predicted using an econometric model designed to capture the intricate relationships between the electricity load and various crucial socioeconomic, environmental, and calendar-related variables. The model utilizes a composite index reflecting real GDP, employment figures, and population estimates of Edmonton sourced from the Conference Board of Canada's (CBoC) metropolitan economic forecast reports[4]. Additionally, the model employs a typical weather year data as the temperature input for

[4] Major City Insights: Edmonton—October 2022 - The Conference Board of Canada

the forecast horizon. This typical weather year was generated through a probabilistic analysis of 21 years of weather data in Alberta, providing a robust foundation for weather-related projections.

The 'Load modifiers' represent evolving load drivers that were not present in the past but are projected to play a significant role in the future. These loads encompass a spectrum of factors, including the integration of electric vehicles, building heating electrification, energy efficiency and distributed energy resources, and more. The final forecast is derived by aggregating the 'Base load' with these 'Load modifiers'. Of paramount importance among these 'Load modifiers' is the Electric Vehicle (EV) load component. While the 'Base load' remains consistent across the Main Case as well as the Moderate EV Penetration and High EV penetration sensitivities, the variations in assumptions regarding EV load have resulted in distinct forecasts, which are elaborated upon in the following sections.

Main Case: In this scenario, the EV model assumes modest levels of EV adoption in line with the federal government's proposed zero-emission vehicle sales target for light-duty vehicles. In this scenario, the charging profile for Electric Vehicles (EVs) is categorized as 'Unmanaged'. This designation implies that EVs are being charged without any coordinated effort or control mechanism in place to avoid coincidental EV and base load peaks.

Moderate EV Penetration Sensitivity: Similar to the Main Case, the Moderate EV Penetration Sensitivity also assumes modest levels of EV adoption. However, the key difference lies in how EV charging is managed. In this sensitivity, we implement a Managed EV charging profile, where we strategically shift the peak of the charging profile. This adjustment of charging behavior reduces strain on the grid during peaking conditions.

High EV Penetration Sensitivity: we evaluate a more ambitious EV penetration in Alberta. Here, we project EV adoption rates that align with the policy goals announced in the federal 2030 emission reduction plan (ERP). Notably, the charging profile for EVs is Managed, similar to the Moderate EV Penetration Sensitivity.

The Area 60 Trend-Based Sensitivity: This projection takes a distinct approach compared to the others mentioned. It assumes that the future year-over-year growth of Kennedale and Namao substations mirrors the most recent 5-year CAGR for Area 60. By doing so, this scenario allows us to analyze the broader trend in Area 60's growth, thus avoiding the intricacies of intra-substation load transfers. Primarily, this scenario focuses on evaluating near-term load growth within various sensitivities. It is essential to note that this scenario does not account for the impact of electrification on long-term demand. Consequently, its long-term forecast isn't directly comparable to the other sensitivities. The 5-year CAGR for Area 60 for the summer and winter peaks currently stand at 1.3% and 0.8%, respectively. These numbers are used as the year-over-year growth rates to predict the future peaks for Kennedale and Namao substations. The forecasted annual peaks for all the scenarios are presented in Table 3 (Kennedale) and Table 4 (Namao), offering a comprehensive view of the peak load predictions across these four scenarios.

Table 3: Kennedale Substation Forecast

	Main Case		Moderate EV Penetration		High EV Penetration		Area 60 Trend-Based	
Year	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
2023	49.1	53.4	49.1	53.4	49.1	53.4	51	52
2024	49.6	53.9	49.6	53.9	49.7	53.9	52	53
2025	50.2	54.5	50.2	54.4	50.2	54.5	52	53
2026	50.7	55.0	50.7	55.0	50.9	55.0	53	54
2027	51.3	55.4	51.3	55.3	51.6	55.5	53	55
2028	52.3	56.0	52.2	55.8	52.7	56.1	53	56
2029	53.1	56.7	52.9	56.5	53.6	56.9	54	56
2030	53.9	57.1	53.6	56.6	54.6	57.2	54	57
2031	54.8	58.1	54.5	57.4	55.8	58.2	55	58
2032	56.4	59.6	55.9	58.7	57.5	59.7	55	59
2033	57.7	60.8	57.1	59.7	58.9	60.8	56	59
2034	59.3	61.9	58.5	60.5	61.1	61.7	56	60
2035	61.4	64.1	60.5	62.4	64.2	63.6	56	61
2036	63.2	65.0	62.1	63.8	67.0	65.3	57	62
2037	65.3	66.9	63.8	65.3	69.9	66.8	57	63
2038	67.4	68.5	65.5	66.5	73.1	69.0	58	64
2039	69.7	70.3	67.4	68.0	76.4	71.3	58	64
2040	72.1	72.3	69.3	69.6	79.9	73.5	59	65
2041	74.7	73.7	71.4	70.9	83.4	75.8	59	66
2042	77.8	76.0	74.4	72.9	87.1	78.3	60	67
2043	80.7	78.3	77.1	74.7	90.5	81.1	60	68
CAGR (2023-2028)	**1.3%**	**0.9%**	**1.3%**	**0.9%**	**1.4%**	**1.0%**	**0.8%**	**1.3%**

Table 4: Namao Substation Forecast

	Main Case		Moderate EV Penetration		High EV Penetration		Area 60 Trend-Based	
Year	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
2023	57.6	54.5	57.7	54.5	57.7	54.6	58.0	56.5
2024	58.3	55.0	58.3	55.0	58.3	55.0	58.4	57.3
2025	58.9	55.5	58.9	55.4	59.1	55.5	58.9	58.0
2026	59.6	55.9	59.6	55.8	59.8	55.9	59.4	58.8
2027	60.4	56.2	60.3	56.1	60.7	56.3	59.8	59.5
2028	61.7	56.6	61.4	56.5	62.1	56.8	60.3	60.3
2029	62.7	57.0	62.2	56.6	63.3	57.3	60.8	61.1
2030	64.0	58.1	63.0	57.5	64.8	58.5	61.3	61.9
2031	65.5	59.0	64.2	58.0	66.5	59.6	61.8	62.7
2032	67.7	60.6	66.0	59.3	68.8	61.5	62.3	63.5
2033	69.9	62.9	67.7	61.3	72.0	64.2	62.8	64.3
2034	72.4	63.7	69.8	61.8	76.1	67.1	63.3	65.2
2035	75.6	66.0	72.7	63.7	81.0	70.6	63.8	66.0
2036	78.5	68.6	75.1	65.9	85.8	73.9	64.3	66.9
2037	81.7	70.2	77.6	67.5	90.7	77.8	64.8	67.7
2038	85.0	72.8	80.2	69.8	95.9	81.5	65.3	68.6
2039	88.5	75.2	82.8	72.1	101.4	85.2	65.8	69.5
2040	92.2	77.5	86.4	74.5	107.1	89.1	66.4	70.4
2041	96.1	80.2	90.1	77.0	112.6	92.8	66.9	71.3
2042	100.4	83.4	94.4	79.8	118.2	96.5	67.4	72.2
2043	104.5	85.7	98.2	82.7	123.3	100.4	68.0	73.2
CAGR (2023-2028)	**1.4%**	**0.8%**	**1.2%**	**0.7%**	**1.5%**	**0.8%**	**0.8%**	**1.3%**

Public

3. Generation

3.1 Existing Generation

Several generation facilities are located within the Edmonton Planning Area (Area 60). They include gas-fired and solar generating units. Total existing generation capacity is 366 MW. Table 5 summarizes the existing generation capacity in the Study Area as of September 2023.

Table 5: Existing Generation in the Edmonton Planning Area

Asset Name	Asset MPID	Type	Planning Area	Maximum Capability (MW)
Cloverbar #1	ENC1	Simple Cycle	60	48
Cloverbar #2	ENC2	Simple Cycle	60	101
Cloverbar #3	ENC3	Simple Cycle	60	101
South Edmonton Terminal	SET1	Simple Cycle	60	20
Strathcona	IOR4	Cogeneration	60	43
University of Alberta	UOA1	Cogeneration	60	39
kisikaw-pisim 1	KKP1	Solar	60	7
kisikaw-pisim 2	KKP2	Solar	60	7
Total Generation Capacity				**366**

3.2 Generation Forecast

As mentioned previously, the CETR Planning Studies used the assumptions of the preliminary 2024 LTO. In addition to the above facilities, the generation forecast for the Edmonton Planning Area in the preliminary 2024 LTO includes potential new hydrogen-fueled generation. For more information, please refer to the preliminary 2024 LTO document.

Table 6 summarizes the forecast generation capacity in the Edmonton Planning Area.

Table 6: Forecast Generation in the Study Area

Technology	Existing (MW)	2026 (MW)	2033 (MW)	2043 (MW)
Cogeneration	82	82	82	82
Simple Cycle	270	270	250	250
Solar	14	14	14	14
Hydrogen	0	93	93	93
Total Capacity	**366**	**459**	**439**	**439**

3.3 Generation Dispatch

The AESO developed deterministic generation dispatch scenarios using a market simulation method in order to create hourly dispatches for the entire study years. The simulations were evaluated to select study cases for the Planning Studies based on area- and region-level load and generation that could lead to stressed power flow conditions.

The market simulation software used is AuroraXMP[5]. This software incorporates the latest market assumptions adopted in the preliminary 2024 LTO generation outlook[6].

The market simulation model incorporates bidding strategies and generating unit characteristics to build an economic dispatch. This method uses market simulation to forecast hourly merit orders and considers uncertainties in load and generation facility development and availability, dynamics in market conditions, intermittent generation output, as well as power flows on the interties. The market simulation model used the hourly system-level load forecast of the preliminary 2024 LTO and uses a probabilistic approach to incorporate uncertainty of variable generation and firm generation availability. This allows the AESO to consider the dynamic relationship between the supply and demand in an integrated manner to create generation dispatches.

[5] See Energy Exemplar website.

[6] AESO's preliminary 2024 LTO materials are available here: https://www.aesoengage.aeso.ca/34307/widgets/141824/documents/118661