Forecast Renewable Generation and Electric Vehicle Load Requirements, a System Analysis of Alberta Canada

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***Abstract*—This paper presents a system analysis of the Alberta Electric System Operator's 2021 Long Term Outlook data, comparing forecast electric vehicle load data against renewable electricity generation.**

***Index Terms*—Electric vehicles, internal combustion engine, combined cycle, compressed air energy storage, Alberta Electric System Operator, Alberta Interconnected Electric System, Zero emissions vehicle, renewable generation, wind, solar**

I. INTRODUCTION

A. Motivation

Global warming is arguably the greatest modern threat humanity faces. Over the past decade anthropogenic contributions to GHG emissions have continued to rise, putting into jeopardy humanity's ability to limit global warming to the accepted 1.5 degrees required to mitigate the climate crisis [1]. The 26th Conference of the Parties (COP26) outcomes maintained that this 1.5 degree goal requires quickly moving away from coal power while aggressively increasing the speed at which our global society switches to electric vehicles (EVs) [2]. However, switching from internal combustion engines (ICEs) to EVs still results in significant GHG emissions when fossil fuel sourced electricity is used [3].

The influx of EVs required to replace fossil fuel transportation is expected to increase electricity grid demand profiles, presenting many challenges for transmission and distribution planners [4]. Peak EV charging has been shown to naturally coincide with existing peak load demand, potentially leading to reduced lifespan of existing distribution transformers and more customer outages due to blown fuses [5], [6]. EV charge controlling strategies seeking to minimize peak load have been shown to reduce system upgrade requirements when compared with strategies minimizing charge cost [7]. Exploring distribution limits EVs will place on grid systems will be outside the scope of this paper, system impacts of EVs will be revewed here.

With significant unit costs of wind and solar generation decreasing [1] it seems natural to compliment increasing EV load requirements with renewable power generation while reducing fossil fuel power reliance. Market penetration potential of renewable generation is expected to be jurisdiction specific and dependent on environmental, policy, and techno-economic factors; including carbon pricing [8]. In the Canadian province of Alberta's energy jurisdiction, the nature of its real time energy market, where generated electricity is sold through a competitive power pool system [9], make the province an attractive option for renewable generation development [10].

Due to the intermittency of renewables, installation of enough wind and solar in the province to meet base load requirements would require far too costly battery storage installations [11]. The current strategy for meeting base load demand is to replace or convert coal fired generation with natural gas combined cycle (CC) capacity [11]. Although several energy storage options have been considered for Alberta, including compressed air energy storage (CAES) and pumped hydro storage (PHS) [12], the only current utility scale energy storage in the province is the WindCharger 10 MW battery facility, which required heavy subsidies to bring online [13]. Clearly the province currently lacks storage capacity to support the intermittency of wind and solar.

The Alberta Electric System Operator (AESO) ensures the Alberta Interconnected Electric System (AIES) – commonly known as the grid – has reliable, safe, and economic operation [9]. The AESO publicly publishes long-term outlook (LTO) electricity plans bi-yearly for stakeholder review and this paper will utilize the AESO's 2021 LTO data for analysis [14]. Although Alberta's electricity generation has potential for a variety of renewable energy sources, such as hydro electric and proposed geothermal [15], this paper will discuss renewables in terms of wind and solar generation where:

$$renewable = wind + solar \tag{1}$$

B. Problem

This paper will seek to understand the following:

- From a system perspective, will renewable power generation hold the potential to meet projected EV loading demand under the AESO's 2021 LTO?
- Where projected EV loading requirement and renewable energy generation deficiencies exist, what type of solutions may be considered to manage these deficiencies?

– How could adding additional nameplate capacity affect projected demand issues?
– How could load shifting EVs help mitigate loading concerns?
– What renewable energy daily energy surplus is expected that could be combined with energy storage technology to meet EV load requirements?

II. Methods

A. Data used

Two AESO data sets were used for this paper's analysis. One data set with actual historical generation data and the second data set containing forecast generation and EV information.

The generation history (GH) data was obtained from the web address located within cited reference, where hourly granularity was used under tab *Generation* [16]. The GH data provided historical hourly generation from midnight January 1, 2015 to midnight March 1, 2022, including nameplate capacity and actual capacity factors for each hour.

The AESO's 2021 LTO forecast data was obtained from the Excel file web address located within cited reference [14]. Three Excel sheets within the LTO file were utilized:

- Electric Vehicle Forecast (EVF)
- Generation data by fuel type (GFT)
- Reference Case Hourly AIL (RCH)

B. Tools

Excel was used to open the GH data for the purpose of combining and eliminating excess title heading rows before exporting the file as a csv.

All further analysis was done within Jupyter Notebook using Python code. The code and modified GH data file is available on the author's public GitHub at the web address located within cited reference [17].

C. AESO Scenario Choice

The AESO's 2021 LTO includes four scenarios used to describe Alberta's future energy market: Reference Case, Clean-Tech, Robust Global Oil and Gas Demand, and Stagnant Global Oil and Gas Demand [18]. The Robust and Stagnant scenarios are largely dependent on fossil fuel market conditions [18], and therefore ignored in analysis here. Reference Case makes assumption of a \$50-per-tonne carbon price for 2022 followed by a yearly percentage increase, whereas the Clean-Tech scenario follows the federal carbon pricing plan with a yearly percentage increase after reaching \$170-per-tonne in 2030 [18], [19]. The Clean-Tech scenario assumes faster EV adoption than for the Reference Case [18], which agrees with COP26 EV goals [2] and further supported through the Canadian Federal Government's Zero Emissions Vehicle (ZEV) program [20]. Although the Reference Case is typically what industry and planners will follow, the Clean-Tech scenario presents the case most aligned with current Alberta energy market conditions and will be the focus of analysis here.

D. Data Analysis

All generation and load requirements presenting in this analysis are assumed constant across the given hour.

1) Renewable Capacity Factor Creation: The AESO's GH data was used to create hourly renewable capacity factors (CFs) that were then used, alongside LTO renewable nameplate capacity, to project hourly renewable generation 20 years forward.

Several steps were taken in cleaning and preparing the GH data for analysis. All NaN elements in GH were replaced with numeric zero values. NaN values existed in the original file where capacity was non-existent and therefore could be replaced with numeric zeros without affecting data integrity. Applicable CF columns were reformatted to decimal form. From here the GH data was ready for renewable CF extrapolation.

Four defined CFs were extrapolated from the GH data to give 8784 different CFs in each category; representing each hour of a year while including leap year hours: an average CF (CF_{avg}), a minimum CF (CF_{min}), a maximum CF (CF_{max}), and the CFs from the year 2020 (CF_{2020}). CF_{avg} was calculated using the basic average formula:

$$CF_{avg} = \frac{1}{n}\sum_{i=1}^{n} a_i \tag{2}$$

with n the number of years starting in year 2015, and a_i the data set value for the particular hour of each year. CF_{min} and CF_{max} are respective minimum and maximum CFs from GH. CF_{2020} is simply the CFs for each hour of year 2020, and chosen to define a typical year's hourly renewable CFs. 2020 was also chosen for describing a typical year since it was the most recent year of GH data which was also a leap year.

Additional considerations were given when calculating solar CFs that were not necessary with wind. Solar capacity in the province did not come online until late 2017, resulting in a data column zero values with potential to negatively affect data integrity of solar's CF_{min}, CF_{max}, and CF_{avg}. To mitigate this concern all zero values regarding solar CFs were removed before calculating applicable solar CF_{min}, CF_{max}, and CF_{avg}. This was done under assumption that zero values in the data column either represented times where there was no nameplate solar capacity or night hours where the solar CF will always be zero regardless of nameplate capacity. The additional assumption that year-over-year nighttime hours did not change was also made.

Two additional assumptions were made while using the methods here to create future renewable CFs. First is that renewable CFs are entirely dependent on the intermittency of the renewable source, wind or solar. This assumption is considered valid since renewable energy in Alberta is typically dispatched through the power pool onto the grid at \$0, since fuel cost is zero, to ensure all generated power enters the AIES. Second is that new installed renewable generation will have no geographic dependence, and follow the same weather patterns as current installations. Authors acknowledge that some geographic differences will exists for new capacity, however, this simplification was not considered to significantly affect results.

2) Clean-Tech Electric Vehicle Load Data: The AESO provided hourly EV load requirements for their Reference Case ($\mathrm{EVload_{RC}}$) within the RCH data, which was used with EVF data to create hourly EV load requirements for the AESO's Clean-Tech scenario ($\mathrm{EVload_{CT}}$). EV numbers for Clean-Tech ($\mathrm{EVnum_{CT}}$) and EV numbers for Reference Case ($\mathrm{EVnum_{RC}}$) were given for each forecast year in EVF data and assumed constant through the respective year. EV load requirements were assumed directly proportional to the number of EVs in the market at the time, therefore:

$$EVload_{\mathrm{CT}} = b_i \cdot EVload_{\mathrm{RC}} \tag{3}$$

where,

$$b = \frac{EVnum_{\mathrm{CT}}}{EVnum_{\mathrm{RC}}} \tag{4}$$

for each *i* year. It was assumed daily loading patterns do not change under the EV increase, where $\mathrm{EVload_{CT}}$ follows (3) proportionally related to the increase in EVs using b_i (4).

3) Forecast Renewable Generation and Hourly Generation Output: Authors used the *Capacity Begin Year (MW)* column from GFT data, for each year, as renewable nameplate capacity and assumed this capacity constant throughout the respective year. New generation capacity was assumed to come online January 1 of each year, inline with the *Capacity Begin Year (MW)* column. Although this does not account for generation capacity that comes online throughout the year, the assumption was considered a good approximation.

Wind and solar nameplate capacity was given for both the Reference Case and Clean-Tech scenario in GFT data, with applicable data extracted from GFT data and combined into EVH columns.

Next wind and solar CFs from GH were joined into the EVH data set. Combining CFs into EVH allowed calculation of actual expected renewable output based on the following:

$$RenewableOuput = RenewableCapacity \cdot CF_{\mathrm{x}} \tag{5}$$

where *x* represents one of the CFs described above (*avg, min, max, 2020*) and *Renewable* being either wind or solar. However, before calculating (5) a daylight savings issue within the data had to be managed.

Each November there is one morning that contains two 2am times due to daylight savings, and one spring morning that skips an early morning hour (i.e. time goes from 1am to 3am). To address the issue of a fall double hour count under EVH data column *Hour Ending* the double counted hours in *Hour Ending* were identified as string *02X*, then replaced with 2.5 entries. These double hour entries also resulted in null CF column entries when CFs were previously joined into EVH. An assumed hourly capacity factor identical to the previous hour (i.e. 2am) replaced null CF entries using a forward fill method. This allowed yearly hour total to remain 8760 in a year, with 8784 for a leap year, while preventing a double hour count during November. Since daylight savings only affected two hours in the year making the above modifications to mitigate the issue was not considered to have a significant impact on data integrity. Equation (5) was then used to calculate wind and solar under all $\mathrm{CF_x}$ conditions.

4) Annual Data: Yearly EV numbers and renewable capacity were combined into a single data frame (EVRC) for Reference Case and Clean-Tech scenarios, ready for analysis.

5) Transmission Losses: During analysis all renewable output was assumed to incur a 2.8% transmission loss, $\mathrm{t_{loss}}$, inline with the AESO transmission assumption [18]. Distributed renewable was calculated using:

$$Distributed = (1 - t_{\mathrm{loss}}) \cdot Renewable\ Output \tag{6}$$

with $\mathrm{t_{loss}}$ in fraction form.

E. Load Modifications and Considerations

The analysis presented here first reviews the data under assumptions that all renewable generation would be theoretically available to charge EVs, nameplate generation follows the AESO's 2021 LTO projections, and EV loading profile does not change with an increase of EVs within the Alberta market; this was treated as a base scenario for analysis. Clearly, some renewable generation will have other end uses within the AIES, however this assumption allows a base point for study. Modifications were applied to data during analysis to consider renewable generation used elsewhere in the AIES, increasing installed nameplate renewable capacity on a compounded annual basis, and a shift of EV load requirements off of peak demand hours to other hours within the same day.

1) Renewable Available: Available distributed renewable was adjusted by removing a percentage from availability using,

$$Available = c \cdot Distributed \tag{7}$$

where *c* is the fraction of renewable to be used elsewhere in the grid. The analysis here considers the modified case where 50% of generated renewable power is assumed to be used elsewhere within the grid.

2) Additional Nameplate Capacity: Renewable generation capacity was adjusted through a compounded percentage of additional capacity using the following:

$$C_{\mathrm{i}} = \begin{cases} Generation\ Capacity \cdot d & i = 2021 \\ (Generation\ Capacity + C_{i-1}) \cdot d & i > 2021 \end{cases} \tag{8}$$

where *i* gives the respective year, starting in 2021. In (8), *C* is the additional capacity for the respective year, with *d* the fractional percent of capacity added. The analysis considers the modified case with 10% annual renewable nameplate capacity added.

3) Electric Vehicle Load Shifting: EV load peaking occurs in evening hours alongside typical residential peak load [18]. Here the assumption is made that peak EV loading is the result of vehicle owners returning home where they plug in their EV to receive a full charge prior to the next morning.

EV load shifting was considered under assumption a percentage of vehicle owners would take advantage of charging infrastructure that could be installed at places of employment. This assumption is quantified by taking a percent of EV load between the hours of 3pm and midnight of each day and shifting that load to be added onto existing EV load 9 hours earlier. The 9 hour load shift was selected on the basis of the typical Alberta work days being 8 hours with a 30 minute assumed commute. The same EV load shifting assumptions were made for weekends and holidays. EV load shifting was done, on the applicable hours, using the following:

$$D_i = EVload_{\mathrm{CT}.i} \cdot g \tag{9}$$

where D is the respective load to be shifted on the i^{th} hour, with g the fractional percent of load to be shifted. D_{i} is then subtracted from the applicable evening hour and added to the corresponding hour 9 hours earlier. The analysis here considers the modified case where 20% of forecast EV load was shifted.

III. Results and Discussion

A. Annual Electric Vehicles with Renewable Generation Forecast

Annual EV units and nameplate renewable generation for each forecast year are summarized in Table I, for Reference Case and Clean-Tech scenarios. Starting in 2034 through to end of forecast, EV numbers for Clean-Tech are a magnitude higher than Reference Case. Renewable generation in 2034 was 17.2% higher in Clean-Tech compared to Reference Case; for 2041 the same comparison showed Clean-Tech at 36.0% higher than Reference Case.

TABLE I: Annual Electric Vehicle and Renewable Generation, Reference Case (RC) and Clean-Tech scenarios (CT) given.

	Electric Vehicles		Capacity (MW)			
Year	EV RC	EV CT	Solar RC	Wind RC	Solar CT	Wind CT
2021	15131	15131	236	1781	236	1781
2022	16256	24385	796	2450	820	2450
2023	17466	34931	954	3327	954	3407
2024	18765	75060	954	3327	1104	3507
2025	20161	100806	1004	3327	1104	3707
2026	21661	129966	1004	3327	1104	3907
2027	23272	139635	1004	4007	1204	4167
2028	25004	175027	1004	4457	1354	4207
2029	26864	188048	1004	4607	1524	4467
2030	31699	253596	1004	4607	1704	4497
2031	37405	299243	1004	4607	1784	4497
2032	44138	397245	1054	4617	1964	4497
2033	52083	468749	1054	4667	1964	4647
2034	61458	614582	1104	4667	2114	4647
2035	72521	725206	1104	4717	2114	4797
2036	85574	855744	1154	4747	2344	4997
2037	100978	1009777	1154	4807	2424	5147
2038	119154	1191537	1204	4726	2654	5066
2039	140601	1406014	1204	4857	2704	5297
2040	165910	1659097	1254	4857	2934	5297
2041	195773	1957734	1254	4907	2934	5447

Table I data for the Clean-Tech scenario is displayed in Figure 1, presenting annual comparison of EV numbers against renewable capacity. Renewable energy has been stacked in annual bars, showing wind and solar capacity differences while providing the renewable sum. EV unit numbers are shown along the right vertices with generation capacity along the left of Figure 1. An exponential increase in EVs can be observed starting in year 2028. Figure 1 shows the Clean-Tech scenario having linear growth in renewable generation from 2024 to end of forecast, with more modest linear solar growth from 2027 to the end of forecast relative to the Reference Case.

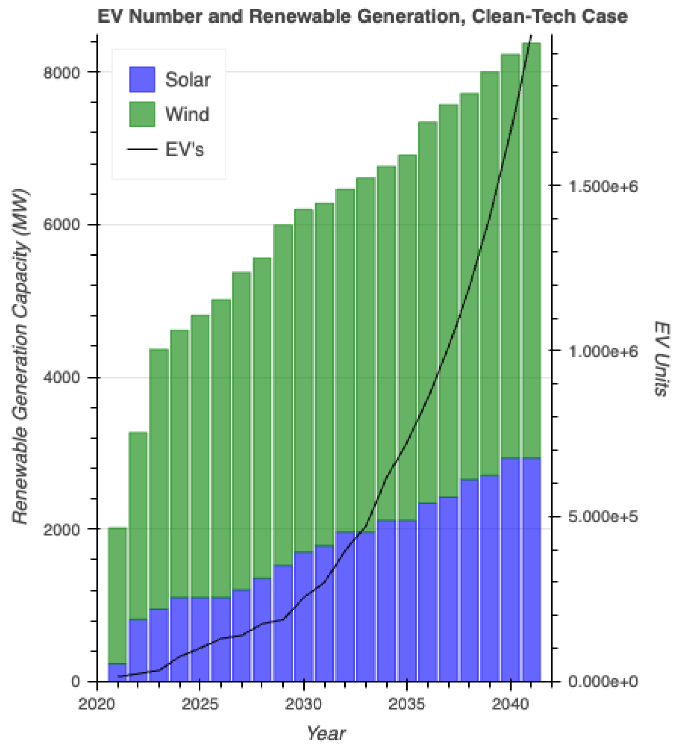


Fig. 1: Yearly EV numbers and renewable generation for the Clean-Tech scenario. Renewable generation units are given along the left, while EV numbers are given along the right.

Although results presented here are not a direct power comparison, results clearly indicate EV growth is forecast to outpace renewable generation capacity. The Clean-Tech scenario sees exponential increase in EV units coming into market with only modest linear renewable growth across the same time period.

B. Renewable Generation and Electric Vehicle Load Difference and Deficiencies, Snapshot

The notebook program will output hourly plots displaying renewable generation and EV load difference for anytime within the 20 year forecast using Clean-Tech data. A 48 hour sample period starting September 1, 2030, is shown in Figure 2 for the base scenario. Figure 2 displays the difference of renewable generation with required EV load subtracted while independently displaying only EV load. CF_{avg}, CF_{min}, CF_{max}, and CF_{2020} were used with (5) in obtaining the Figure 2 data points. CF_{min} and CF_{max} give the error bar extremes, while

CF_{avg} and CF_{2020} results are displayed in green and brown lines respectively, with stand alone EV load represented by the red line. Observed in Figure 2 is that a more typical year, represented by CF_{2020} and (5), give data both above and below average projections while intermittently hitting extrema. Several deficient hours, defined as:

$$\mathit{Power\ Difference} < 0, \tag{10}$$

where,

$$\mathit{Power\ Difference} = \mathit{Renewable\ Generation} - \mathit{EV\ load}, \tag{11}$$

are seen in the sample period along the error bar's lower extrema.

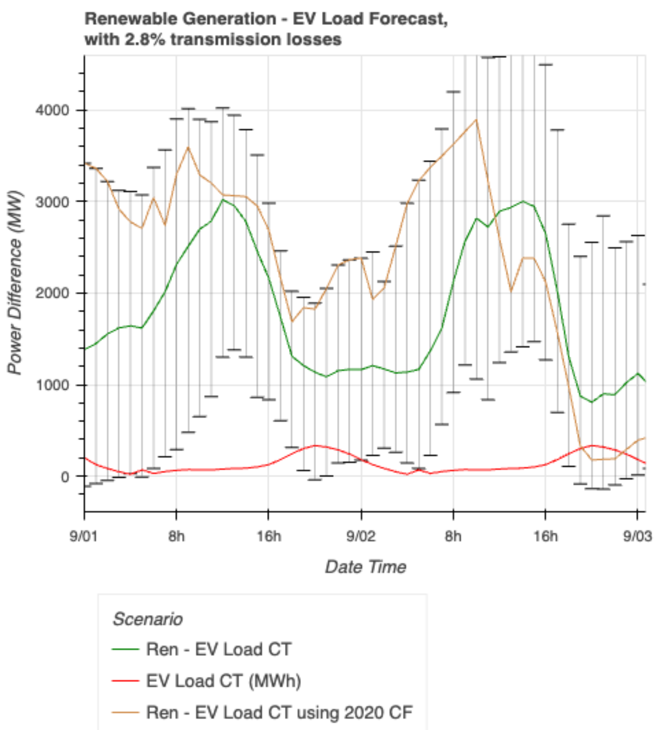


Fig. 2: Power difference (10) for a 48 hour sample period beginning September 1, 2030 for the Clean-Tech base scenario.

The profiles created under this section merely reflect a snapshot in time from the forecast period. Error bars in Figure 2 show that actual renewable has high potential to deviate from the average created here – CF_{2020} was used to represent a typical year – and likely to fluctuate well to either side of projected averages.

C. Daily Power Surplus/Deficiency Analysis

Results presented in this section are limited to the Clean-Tech scenario where renewable generation is obtained from (5) using CF_{avg}. Figure 3 and Figure 4 each consist of four sub-figures – *(a-d)* – representative of the four scenarios described in the *Load Modifications and Considerations* section.

1) Hour of Day Deficiency Frequency Histogram: The histogram of Figure 3 displays how frequently each hour of the day incurred a power deficiency. Against the base scenario, *EV load shifting* and *additional nameplate* modifications resulted in a decrease of peak hours having power deficiency, whereas *renewable used elsewhere* increased deficiency frequency across all hours.

2) Power Deficiency Magnitude Histogram: Power deficiency magnitude frequency is shown in Figure 4, grouping magnitudes into 125 MW ranges. Against the base scenario, *EV load shifting* and *additional renewable nameplate* modifications can be seen reducing the number of hours where each range of power deficiency occurred, whereas *renewable used elsewhere* significantly increased power deficiency occurrence across all ranges.

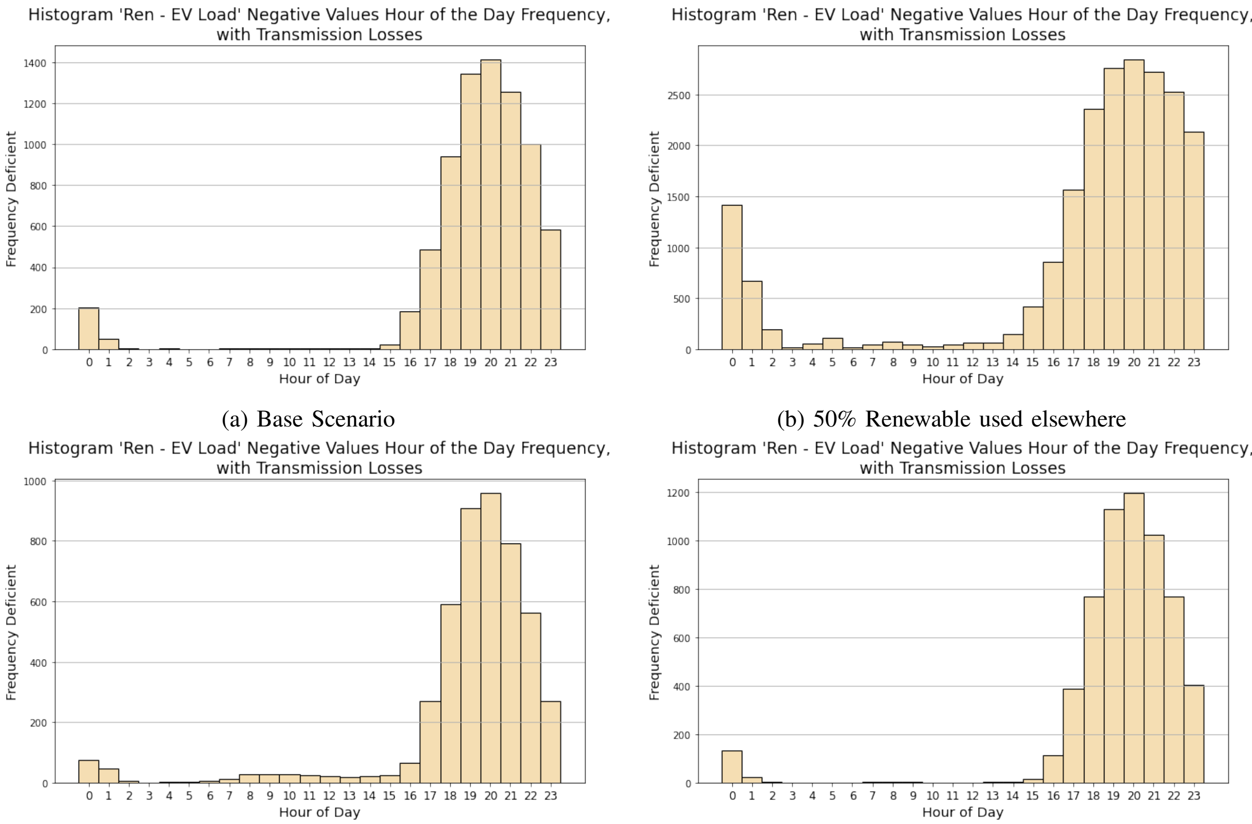
3) Power Deficiency Summary: Table II provides deficiency summary data for the four load modification scenarios. The most common deficient hour of the day was 8pm for all scenarios. The *Hours* column of Table II provides the total number of deficient hours across the forecast period in accordance using (10) and (11), with the *First Occurrence* column showing dates of initial deficiency occurrence. The *Average* and *Most Negative* columns of Table II provide applicable power deficiency results across the forecast period for each scenario.

TABLE II: Renewable Generation Difference with Electric Vehicle Load, Deficiency Summary.

	Renewable – Electric Vehicle Load Deficiency			
Scenario	Hours	First Occurrence	Average (MW)	Most Negative (MW)
Base	7509	2030-12-25	-775	-3991
Renewable Elsewhere	21163	2025-12-25	-824	-4310
EV Load Shift	4758	2031-12-25	-562	-3065
Nameplate Added	5987	2031-12-25	-755	-3920

A summary of daily deficient power differences in accordance with (10) and (11) is presented in Table III providing forecast deficient days, initial deficiency dates, average energy deficiency, and greatest energy deficiency under the four assumed *Load Modifications and Considerations* scenarios, with all CF_x considered (*average, minimum, maximum, 2020*). Initial deficiency dates for data obtained from (5) using CF_{avg}, in Table III, are observed to coincide with December 25th of the respective year.

Results presented in this section demonstrate power deficiencies are expected within the forecast period base scenario. Load modifications show varying effects on forecast power deficiency. For the *additional renewable nameplate* modification, a reduction in deficient hour frequency is observed in



(a) Base Scenario

(b) 50% Renewable used elsewhere

(c) 20% Electric Vehicle Load Shift

(d) 10% Additional Renewable Nameplate

Fig. 3: Frequency of deficient hour, in accordance with (11), for each hour of the day across forecast period: *(a)* Base Scenario; *(b)* 50% Renewable used elsewhere; *(c)* 20% Electric Vehicle Load Shift; *(d)* 10% Additional Renewable Nameplate.

Figure 3d, with Figure 4d showing a decrease in the frequency of each deficient power range. *EV load shifting* modifications are shown to increase midday deficient power frequency while decreasing evening deficient hour frequency in Figure 3c, while also reducing occurrence in each deficiency range in Figure 4c. Table III results further extrapolate that the load modifications have the same system wide effect regardless of the CF considered. Overall, *renewable used elsewhere* has the negative effect of increasing power deficiency, *additional renewable nameplate* results in power deficiency mitigation, and *EV load shifting* mitigates evening peak hour concerns while increasing daytime power deficiency occurrence and magnitudes.

D. Annual Power Surplus/Deficiency

Daily renewable generation and EV load differences are shown in Figure 5. The distinct curve of outliers seen near the bottom of Figure 5 occur once each year on December 25th due to relatively high forecast EV load for that day. This suggests that the *Greatest Deficiency* dates and magnitudes categories in Table III are heavily skewed because of outlier data.

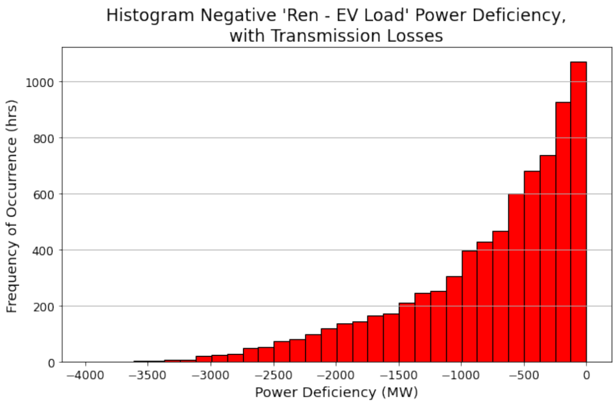
Annual energy surplus or deficiency are given in *Fig. 7* using:

$$NetAnnualEnergy_f = \sum_{i=1}^{8760 or 8784} PowerDifference_i.f \tag{12}$$

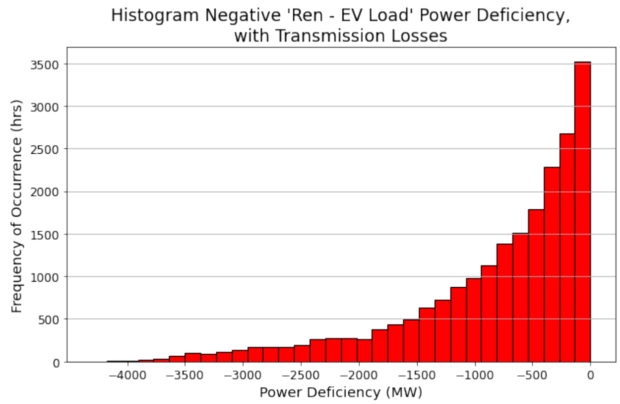
where i is the respective hour of each year, *f*, and *Power Difference* is found using (12).

The four *Load Modifications and Considerations* scenarios are shown in Figure 6 (a-d), providing annual power difference surplus or deficiency using (11) and (12) with renewable generation projected using each CF considered in this analysis: CF_{avg}, CF_{min}, CF_{max}, and CF_{2020}. Against the base scenario the load modifications; *renewable used elsewhere* reduced surplus (or increased deficiency), *EV load shift* had no effect on surplus or deficiency, and *additional nameplate* increased surplus (or reduced deficiency).

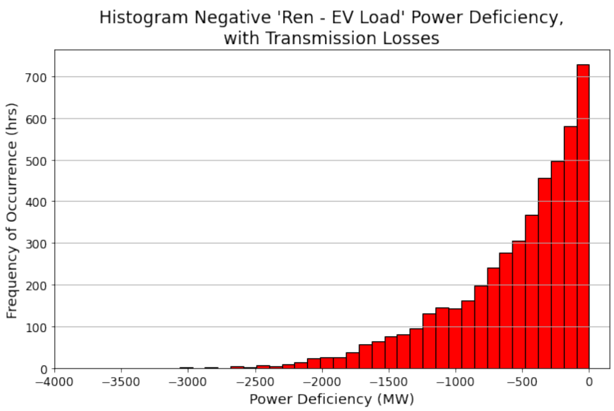
Results in this section indicate annual energy surplus in accordance with (11) for the base scenario using all but the worst case CF, CF_{min}, where annual deficiency begins in year 2035. Only when the *renewable used elsewhere* modification is applied are annual deficiencies observed using CF_{avg}, CF_{max}, and CF_{2020} starting year 2040. A typical year – CF_{2020} data – shows energy surplus across the forecast period with the exception of the *renewable used elsewhere* modification deficiency starting year 2040. Results suggest incorporating



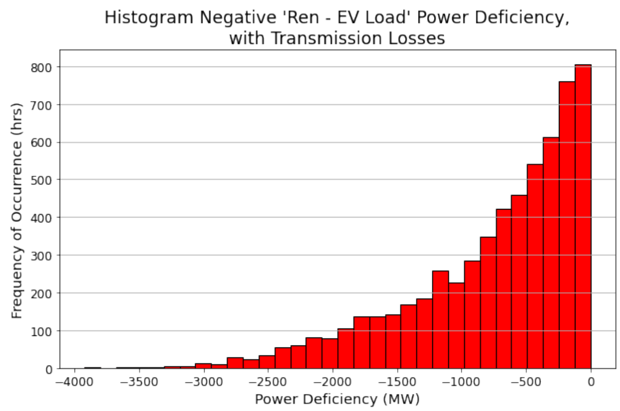
(a) Base Scenario



(b) 50% Renewable used elsewhere



(c) 20% Electric Vehicle Load Shift



(d) 10% Additional Renewable Nameplate

Fig. 4: Frequency across forecast period, in number of hours, of power deficiency broken into 125 MW ranges: *(a)* Base Scenario; *(b)* 50% Renewable used elsewhere; *(c)* 20% Electric Vehicle Load Shift; *(d)* 10% Additional Renewable Nameplate.

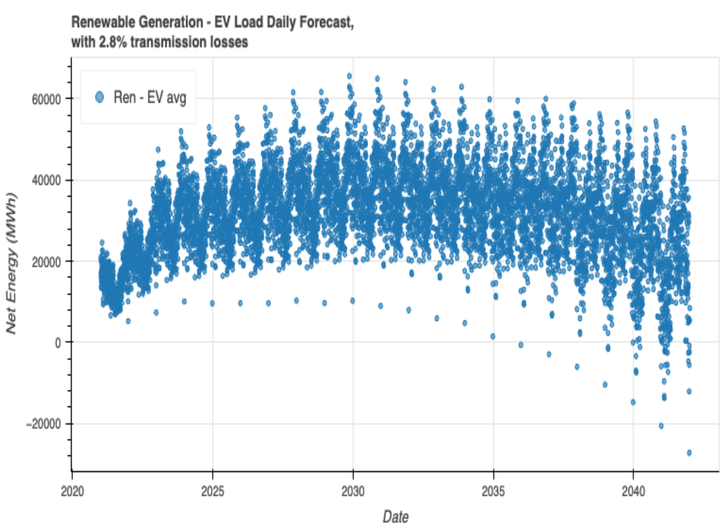


Fig. 5: Daily net power difference (5) energy scatter plot for forecast period's Clean-Tech scenario under base conditions.

energy storage options into the grid could theoretically allow renewable energy to supply all EV load requirements across the forecast period for all but worst case CFs.

IV. Conclusions

EV units in the Alberta electricity market are set to outpace renewable generation capacity installation. As a result, from a system level over the long term, renewable generation will not be capable of meeting EV load demand under the conditions set out in this paper. Furthermore, this paper makes the far reaching assumption that all renewable generation would be available for EV charging, an assumption that is clearly impractical from an application standpoint. Increasing nameplate renewable installation and promoting consumer behaviour that encourages EV charging to off evening hours are suggested to help alleviate future power deficiency concerns. Since the Alberta grid meets its internal load demands over and above renewable generation using thermal generation, system planners should should remain aware of these forecast power deficiencies while working towards non-GHG emitting solutions while continuing to support renewable installation.

Intermittency is a well known concern for renewable power generation. This paper has shown that although periods exist where renewable power cannot meet EV loading requirements,

TABLE III: Daily Renewable Generation Difference against Electric Vehicle Load Deficiency Summary.

Deficiency Type	Scenario	Capacity Factor Used Average	Minimum	Maximum	2020
Number of Deficient Days	Base	34	2819	0	322
	Renewable Elsewhere	728	4260	15	947
	EV Load Shift	34	2818	0	322
	Nameplate Added	18	2581	0	279
Initial Deficiency Date	Base	2035-12-25	2021-01-02	n/a	2025-01-15
	Renewable Elsewhere	2041-12-25	2021-01-02	2038-12-25	2024-01-13
	EV Load Shift	2035-12-25	2021-01-02	n/a	2041-12-25
	Nameplate Added	2036-12-25	2021-01-08	n/a	2025-01-15
Average Deficiency (MWh)	Base	-5985	-11221	n/a	-21615
	Renewable Elsewhere	-8743	-10785	-39359	-21201
	EV Load Shift	-5985	-11225	n/a	-21615
	Nameplate Added	-6717	-11415	n/a	-21300
Greatest Deficiency (MWh)	Base	-27177	-44710	n/a	-44235
	Renewable Elsewhere	-36139	-44906	-44107	-44906
	EV Load Shift	-27177	-44710	n/a	-44235
	Nameplate Added	-25190	-44666	n/a	-44139

periods exist where renewable generation exceeds required EV load. Implementation of energy storage to harness this power surplus holds potential to meet EV load requirements with renewable generation and is recommended. Therefore, system planning should incorporate an energy storage strategy and policy makers should be encouraged to create policy in support of such strategy.

A. *Future Research*

This paper has analysed the Alberta electricity market LTO data from a system level on meeting EV load requirements with renewable energy. Ignored here has been costs associated with any suggested mitigation technique or policy requirements to support such mitigation. Future research is required that incorporates cost variables for industry stakeholders to understand the viability of addressing forecast power deficiencies before they come to term.

Additionally, authors suggested mitigation techniques were independently reviewed on their potential to alleviate forecast power deficiency. A combination of techniques is likely more appropriate, and future research could expand on results here to find an optimized approach that combines mitigation strategies while also incorporating costs.

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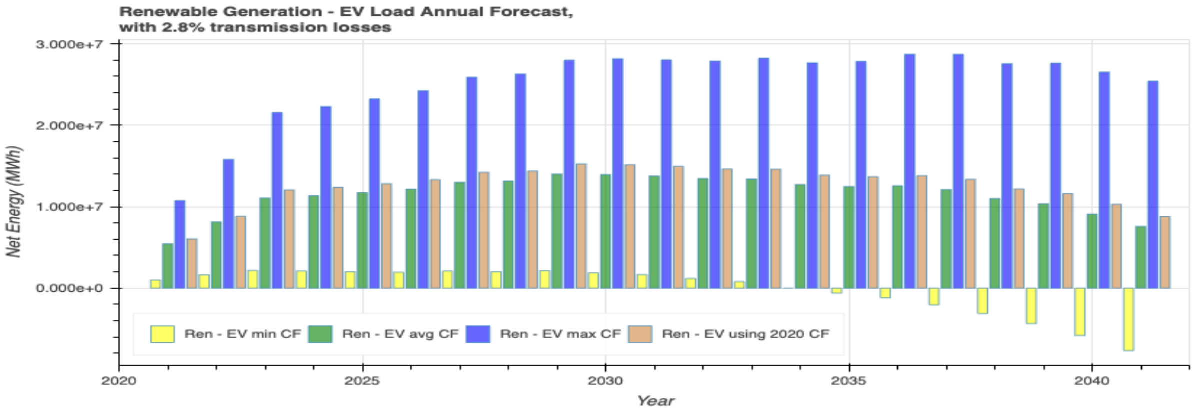
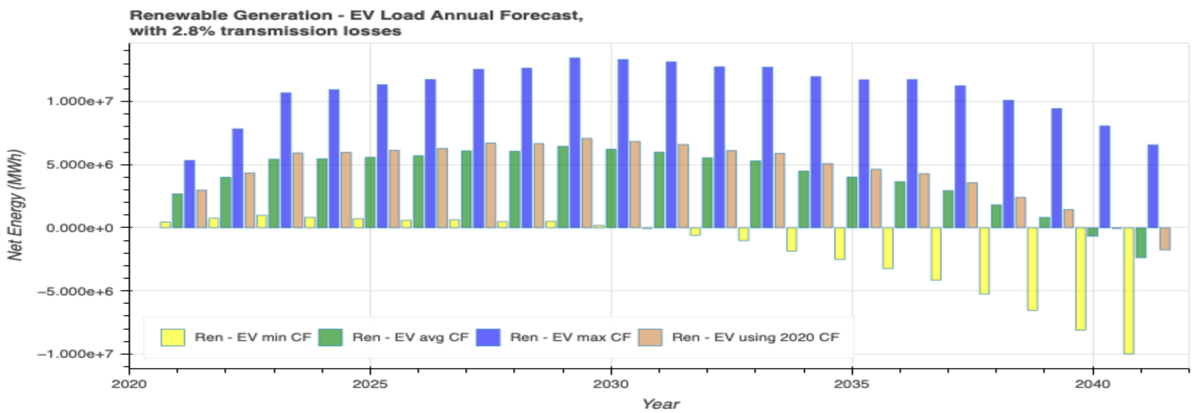
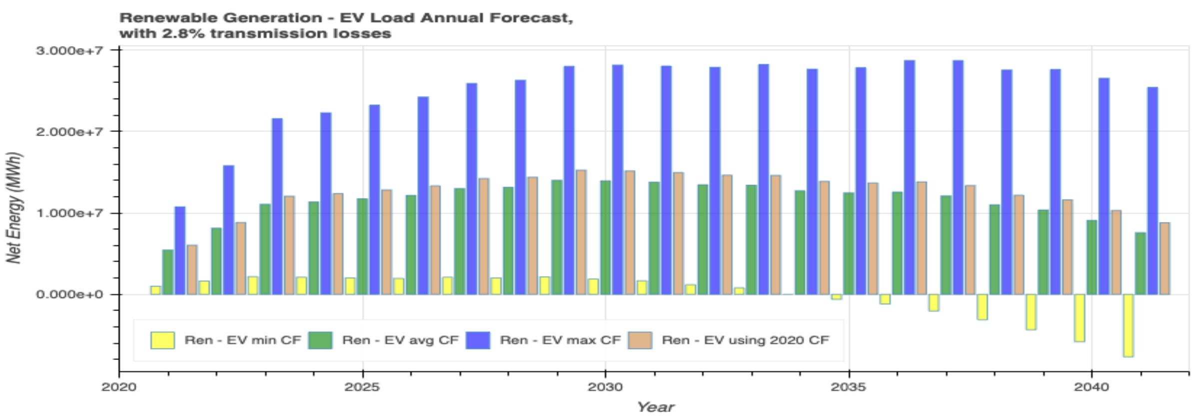


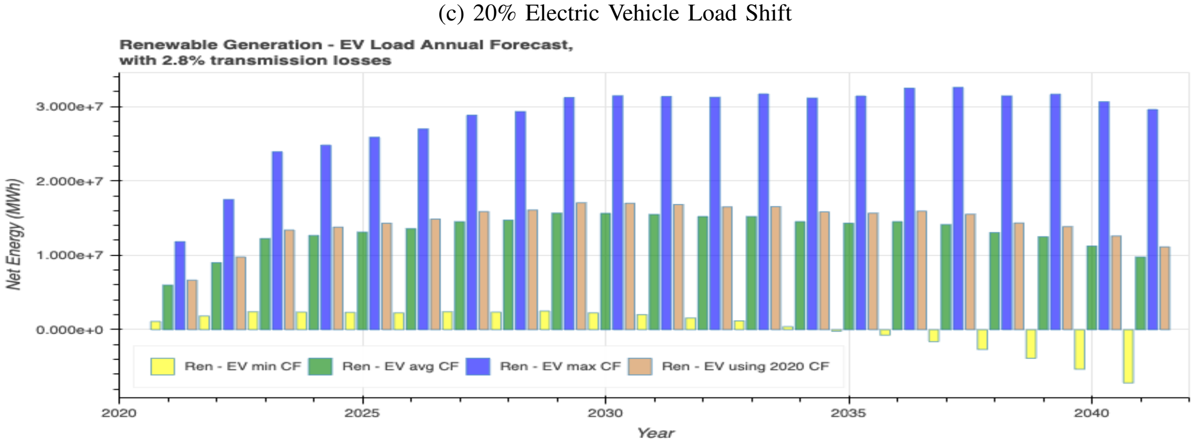
(a) Base Scenario



(b) 50% Renewable used elsewhere



(c) 20% Electric Vehicle Load Shift



(d) 10% Additional Renewable Nameplate

Fig. 6: Annual energy surplus using specified capacity factors to project renewable generation: *(a)* Base Scenario; *(b)* 50% Renewable used elsewhere; *(c)* 20% Electric Vehicle Load Shift; *(d)* 10% Additional Renewable Nameplate.