WECC

Year 20 Compound Load Impacts Study

May 2024

Executive Summary

The Western Interconnection (WI) is experiencing and is expected to continue experiencing a major change with how and when electricity is consumed. Electrification presents challenges and creates questions that have not been experienced or answered before. Commercial buildings, residential appliances, industrial processes, and electrical vehicles are expected to not only change the magnitude of electricity being consumed, but also challenge our expectations of when demand is at its peak. Along with these changes come opportunities for encouraging specific consumer usage behaviors, or "use patterns," through technology and programs that we may not even be aware of yet.

The goal of this study was to answer two questions:

1. Could the anticipated demand due to electrification cause any reliability concerns in the West?
2. Would shifting demand due to electrification help to alleviate any reliability concerns?

To study these questions, electricity demand was increased from the Year 20 Foundational Case (Y20 FC) loads to account for additional demand due to electrification. Electrification demand was broken into four sections: Commercial, Industrial, Residential, and Transportation. The demand response assumptions were limited to programs or technology that would shift load from one hour to another; this study did not consider other demand response possibilities such as peak-shaving programs.

The modeling for this study consisted of using a nodal production cost model (PCM) to compare the results of the reference case with the four sensitivity scenarios. The reference case, Y20 FC set in 2042, is a business-as-usual possible future scenario with no unserved load. Each sensitivity scenario included shocked assumptions relative to the respective sensitivity. Since this study is focused on identifying possible reliability risks, the intent was not to study the expected future but to understand the impacts of the sensitivities with changing demand patterns.

Four scenarios were included in this study; two looked at varying the magnitudes of increased load due to electrification (without load shifting), and the remaining two scenarios looked at shifting the electrification load to different times of the day.

1. High Electrification—a possible future with a high amount of electrification adoption. No demand shifting.
2. Extreme Electrification—an increase in electrification above the High Electrification assumptions. No demand shifting.
3. Extreme Electrification with Midday Demand Response—Extreme Electrification assumptions with electrification demand shifted to off-peak hours.
4. Extreme Electrification with Off-Peak Demand Response—Extreme Electrification assumptions with electrification demand shifted to midday hours.

This study found that business-as-usual assumptions, with a reasonable forecast of high electrification in the future, did create a reliability concern. Both the High Electrification and the Extreme

Electrification scenarios saw unserved load in all the modeled subregions. This study was a first step in understanding the potential impact across the WI if resource plans and transmission plans are not updated to appropriately account for the increase in demand due to electrification.

Both scenarios with shifted-load due to demand response (DR) experienced some relief of unserved load in the peak energy hours. Unfortunately, the increased load in the shifted period created more unserved load. The industry should continue discussing what shifting load can, and should, look like and what opportunities exist to make the best use of the available energy.

As we anticipate increased electrification, we also expect to see other changes in the system, such as resource mix. A careful balance between changing demand shapes and strategies to take advantage of excess renewable energy in certain times of the day will be important to mitigate reliability risks. Additional studies should be considered for looking at further load-shifting or demand response opportunities to relieve reliability risks in peak load hours. Combining the effects of electrification with other anticipated grid changes should also be considered.

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Purpose

Electrification in the Western Interconnection is driving a major change in how and when electricity is consumed. Large portions of major economic sectors such as transportation are expected to shift toward electrification over the next 20 to 30 years. Electrification brings new reliability challenges. Commercial buildings, residential appliances, industrial processes, and electric vehicles are expected to not only change the magnitude of electricity being consumed, but also change hourly demand patterns, potentially causing peak demand to occur at hours not experienced in the past. Along with these challenges come opportunities to encourage specific charges or use-patterns through technology and programs that may not have been conceived yet, to address reliability risks.

In the Year 20 Compound Load Impacts study, WECC seeks to better understand how changes to electricity consumption due to electrification could affect load, as well as how shifting that electricity consumption to different times of the day could help relieve reliability risks. This study is set in 2042 with conservative forecasts for capacity additions and no transmission expansion. That means this study could be used to identify areas for improvement or highlight potential gaps in resource or transmission planning. WECC encourages stakeholders to use these results as a starting point for their own studies to identify the specific gaps or reliability concerns for their area of interest.

The scope of the Year 20 Compound Load Impacts study was assessing the impacts of electrification and demand response to reliability in the year 2042 using the Year 20 Foundational Case (Y20 FC) as the starting point. This study focused on four scenarios that increased the magnitude of loads and shifted the hourly shape for each subregion. The study broke electrification demand into four sections: Commercial, Industrial, Residential, and Transportation. The demand response assumptions were limited to programs or technology that would shift load from one hour to another; this study did not consider other demand response possibilities such as peak-shaving programs.

Background

Electrification generally refers to switching from a non-electric energy source, such as natural gas, to electricity supplied by the grid as the source of energy. More specifically, the goal of electrification is to move toward sustainable energy by electrifying power consumption, while simultaneously moving to replace fossil fuels in the electric grid with renewable sources (i.e., clean energy). The target sectors for electrification are far and wide, including:

- Transportation
    - Producing vehicles which can plug into the electric grid and require less, or zero, gasoline. This not only includes passenger vehicles but also trucking, shipping, ferries, and other modes of transportation.
- Heating

    - Switching commercial and residential gas heating sources to electric heat pumps or electric heaters.
- Residential Appliances
    - Switching appliances such as stoves or grills to using electricity rather than natural gas.
- Commercial and Industrial Processes
    - Making a switch from gas-powered systems, processes, and equipment in commercial and industrial processes to electrically powered.

The push toward electrification brings up new unknowns for the bulk power system (BPS) that can bring into question the reliability and resiliency of the grid. The transportation sector, for example, is expected to grow rapidly. As emphasized in a report by the North American Electric Reliability Corporation (NERC), California Mobility Center (CMC), and WECC, a

> …dramatic increase in demand [due to the growth of EVs] will challenge the electric power system in many ways. [The growth is] unprecedented, and is taking place at the same time electricity system operators and planners are also focused on integrating rapidly growing levels of inverter-based generation resources, extreme weather impacts, and increasingly malicious security threats.[1]

NERC Reliability Risk Priorities

In the 2023 ERO Reliability Risk Priority Report[2], NERC identified five key reliability risks to the BPS that deserve attention:

1. Energy Policy
2. Grid Transformation
3. Resilience to Extreme Events
4. Security Risks
5. Critical Infrastructure Interdependencies

Electrification introduces reliability risks into 4 out of 5 of NERC's Reliability Risk Priorities. Electrification is a heavy topic in policy discussions, with many states, provinces, and local jurisdictions enacting, or proposing, strong electrification policies. The effects of electrification on demand magnitude and shape must be considered in coordination with the resource mix moving from capacity-limited to fuel/energy-constrained, in addition to the occurrence of extreme weather events. Policy makers also need to keep reliability at the forefront when proposing new policies or legislation.

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[1] Grid_Friendly_EV_Charging_Recommendations.pdf (nerc.com)

[2] 2032 ERO Reliability Risk Priorities Report (nerc.com)

Policies, Goals, and Incentives

Transportation Electrification

The Infrastructure and Jobs Act of 2021 invested $7.5 billion in building a national network of 500,000 electric vehicle (EV) chargers; $10 billion for electric buses for school and public transportation; and $7 billion for EV battery components. The law also provided:

- Investments in transmission: $110 billion for modernization. Particularly important for the WI, which has an aging and congested transmission system.
- Tax credits for EVs: extends federal tax credit for electric vehicles.
- Support for grid modernization: includes $10 billion in investments for grid modernization, which will help make the grid more resilient and efficient.

Table 1 indicates the types of programs that the states or provinces within the WI are offering as of August 2023. See Appendix A for more details on the specific state and local goals and policies within the WI as of August 2023.

Table 1: Transportation Electrification Incentives and Offerings by State/Province (As of August 2023)

State/Province	Tax incentives	Charging infrastructure programs	Fleet Electrification efforts
Alberta	√	√	√
Arizona	√	√	√
British Columbia	√	√	√
California	√	√	√
Colorado	√	√	
Idaho	√		
Montana	√		
New Mexico	√	√	
Nevada	√		
Oregon	√	√	√
Utah	√	√	
Washington	√	√	√
Wyoming	√	√	

Building and Residential Electrification

All the states and provinces in the West have offerings and incentives for building electrification as indicated in Table 2. See Appendix B for additional information on state or local goals and policies.

Table 2. Building Electrification Incentives and Offerings by State/Province (As of August 2023)

State/Province	Tax incentives	Government-wide Building Initiatives
Alberta	√	

State/Province	Tax incentives	Government-wide Building Initiatives
Arizona	√	
British Columbia	√	
California	√	√
Colorado	√	
Idaho	√	
Montana	√	
New Mexico	√	
Nevada	√	
Oregon	√	√
Utah	√	√
Washington	√	
Wyoming	√	

Potential Reliability and Security Impacts

The addition or conversion of technologies and processes to electricity can introduce a number of reliability or security concerns that require monitoring and collaborative effort to address.

- Grid reliability: EVs and other electrified technologies increase electricity demand. Without proper planning and infrastructure upgrades, a surge in demand could strain the grid. In addition, the generation portfolio needs to be adaptive to shifts in peak demand through days and seasons.
- Energy security: EV charging stations must remain resilient to disruptions, such as cyber-attacks or natural disasters, to prevent potential energy shortages.
- Innovation and investment: Stakeholders in technology, energy storage, and grid management are more likely to invest in solutions that support growth of electrified transportation when they can rely on the stability and security of the grid.
- Infrastructure planning: Utility companies and infrastructure planners need to account for the impact of EV charging on grid capacity and distribution. Proper planning and investment in grid upgrades ensure that infrastructure can meet the needs of EV charging and other energy demands.

Demand Response

Demand response (DR), demand-side management (DSM), or flexible demand is the ability of an electrical load to either shed load or change its power profile. A 2017 study by Berkeley Lab[3] defined a taxonomy for describing DR services with the four methods described in Table 3.

Table 3. Demand Response Categories

Method	Description
Shape	Load modification through user responses to price or other signals.
Shift	Change load timing from peaks to times of surplus renewable generation.
Shed	Loads that can be curtailed to reduce peaks with sufficient notice.
Shimmy	Dynamic load adjustment to manage disturbances in the seconds-hour timescale.

Figure 1, from [RMI The Economics of Electrifying Buildings](), shows how demand flexibility in residential spaces could be used to shift loads into times of high renewable output.

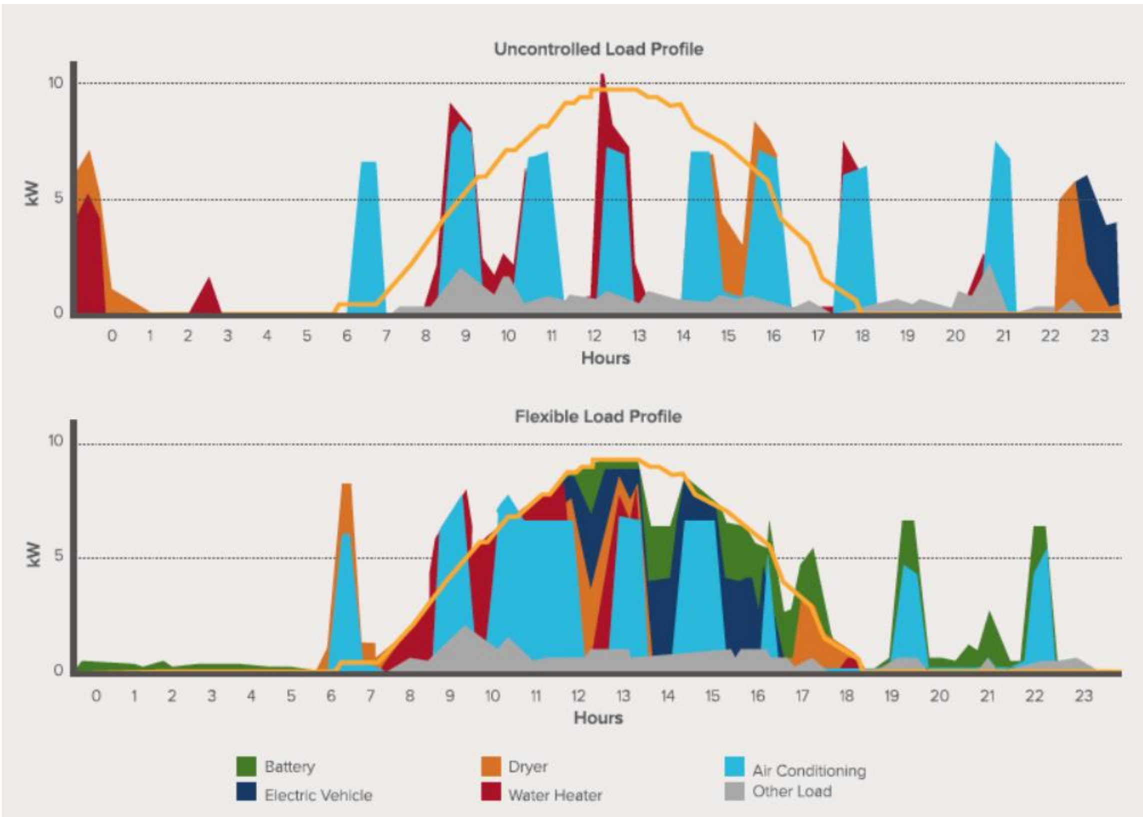

Figure 1. Demand Flexibility in Residential Buildings

[3] 2025 California Demand Response Potential Study - Charting California's Demand Response Future: Final Report on Phase 2 Results (lbl.gov)

Approach

The modeling for this study used a nodal production cost model (PCM) to compare the results of the reference case against the four sensitivity scenarios. The reference case, 2042 Foundational Case (Y20 FC), is a business-as-usual possible future scenario with no unserved load. Each sensitivity scenario included adjusted assumptions relative to the respective sensitivity. Since this study is focused on identifying possible reliability risks, the intent was not to study the expected future but to understand the impacts of the sensitivities; from there, other changes to load, generation, transmission, etc. could be used to relieve potential reliability risks.

This study included four scenarios:

1. High Electrification
2. Extreme Electrification
3. Extreme Electrification with Midday Demand Response
4. Extreme Electrification with Off-peak Demand Response

The first two scenarios looked at varying the magnitudes of increased load due to electrification, and other two looked at shifting the electrification load to different times of the day.

High Electrification

The High Electrification (HE) scenario is used to evaluate the impact on reliability of the possible future with a high amount of electrification adoption. This scenario uses incremental growth from the NREL Electrification Futures Study (EFS)[4] between the Reference Slow scenario and the High Slow scenarios.[5] In the NREL EFS scenario names, "Reference" and "High" refer to the technology adoption, while "Slow" indicates the rate of technology advancement in cost and performance.

Extreme Electrification

The Extreme Electrification (XE) scenario seeks to answer the question. "What if electrification increases more than we anticipate?" If the HE scenario is a reasonable approximation of a high level of electrification, the XE scenario acknowledges that electrification could be higher than we anticipate.

Extreme Electrification with Off-peak Demand Response

The Extreme Electrification with Off-peak Demand Response (XE OP) case shows whether shifting the electrification demand to off-peak, or overnight, hours would help alleviate reliability risks of the XE

[4] Electrification Futures Study: A Technical Evaluation of the Impacts of an Electrified U.S. Energy System | Energy Analysis | NREL

[5] Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States (nrel.gov)

demand. The XE OP case uses the same magnitude of load as the XE case but shifts the demand attributed to electrification to hours of the day that are considered off-peak.

Extreme Electrification with Midday Demand Response

Similar to the XE OP case, the Extreme Electrification with Midday Demand Response (XE MD) case examined whether shifting the electrification demand to midday hours would help alleviate reliability risks of the XE demand. The XE MD case also uses the same magnitude of load as the XE case while shifting the demand attributed to electrification to hours of the day when the energy generation of solar and wind are the highest. The catalyst for this scenario is the Stanford study[6] that suggests a shift to daytime charging for transportation loads to minimize cost and grid-level electricity storage needs for off-peak charging.

Key Assumptions

In addition to the assumptions in the Y20 FC, the following assumptions were made for all scenarios in this study:

- The study horizon was limited to the year 2042.
- The area of focus was the Western Interconnection.
- The transmission topology modeled was from the 2032 Heavy Summer Power Flow.[7]
- All batteries are considered to have a four-hour dispatch time and are optimized for each 24-hour period only (See Model Limitations for details).
- The study divided the WI into seven subregions with inputs and results shown at the corresponding level.

In addition to these assumptions, the following sections outline the specific assumptions for each of the four study scenarios.

HE Scenario Assumptions

The HE scenario uses the load assumptions from the NREL EFS[8] High Slow case to create a reasonable expected future with a high rate of adoption of electrification in four categories: Commercial, Industrial, Residential, and Transportation. The NREL EFS High Slow case represents a high level of electrification adoption with slow progress in technological advancements that would reduce cost and/or improve performance. Due to the nature of this study, the High Slow case was chosen as a

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[6] Stanford study warns against overnight charging of electric cars at home (thebrighterside.news)

[7] Reliability Modeling Base Cases (wecc.org)

[8] Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States (nrel.gov)

conservative estimate of a possible future. If technology increases at a more rapid rate, the impacts to the WI BPS could be lessened.

Since this study and the NREL EFS use different starting points for demand and hourly shape, the delta between the NREL EFS Ref Slow case and the NREL EFS High Slow case was applied to the Y20 FC using one of two growth methods for each hour: percentage or absolute.

- Percentage—growth is based on initial value.
  - Ex: base = 50, increase is 5, therefore growth is 10%.
- Absolute—growth is indifferent to initial value.
  - Ex: base = 50, increase is 5, therefore growth is 5 units.

The growth method used for each sector is shown in Table 4. A growth method of percentage is used in the sectors where demand already exists and an increase in demand could be considered an incremental change: i.e., a residence already had a demand, therefore, the electrification of appliances could reasonably be considered a percentage increase of the existing demand. Transportation, specifically, is assumed to be an absolute growth since it is generally new load being added to the system. The formula to build each hour of the HE scenario for the two methods is shown in Table 5, while Table 6 shows an example of the calculation for a single hour for all four sectors.

Table 4. Growth Method by Sector

Sector	Method	Reasoning
Commercial	Percentage	Increase in demand is based on existing demand
Industrial	Percentage	Increase in demand is based on existing demand
Residential	Percentage	Increase in demand is based on existing demand
Transportation	Absolute	Demand is new and therefore NOT based on existing demand

Table 5. Growth Method Formula

Method	Demand Formula
Percentage	$\{HighElec\} = \{2042FC\} \times (1 + \frac{\{NREL\ EFS\ High\ SLow\} - \{NREL\ EFS\ Ref\ Slow\}}{\{NREL\ EFS\ Ref\ Slow\}})$
Absolute	$\{HighElec\} = \{2042FC\} + (\{NREL\ EFS\ High\ Slow\} - \{NREL\ EFS\ Ref\ Slow\})$

Table 6. Single Hour High Electrification Example

Sector	Y20 FC Total MWh (A)	NREL EFS Ref Slow MWh (B)	NREL EFS High Slow MWh (C)	Method (D)	NREL EFS MWh from Electrification (E)	HE MWh from Electrification (F)	HE Total MWh (G)
					$(C) - (B)$	$\frac{(A) \times (E)}{(B)}$ or (E) based on (D)	$(A) + (F)$
Commercial	7,583	6,436	6,722	Percentage	286	337	7,920
Industrial	3,353	2,846	2,891	Percentage	45	53	3,406
Residential	8,565	7,269	8,059	Percentage	790	931	9,496
Transportation	302	256	4,117	Absolute	3,861	3,861	4,163
Total Demand	**19,803**	**16,807**	**21,789**		**4,982**	**5,182**	**24,985**

XE Scenario Assumptions

To identify reliability risks, the XE scenario stresses the electrification levels beyond the HE scenario. This was done by taking the NREL EFS High Slow adoption rate assumptions and increasing them as indicated in Table 7. Since the NREL EFS High Slow scenario does not include 2042, the values in Table 7 are reasonable approximations based on the 2050 values in the NREL EFS. Table 8 shows an example of the calculation for a single hour for all four sectors. The final column, Weighted ExtremeElec % Increase, is an average of the different technology options when more than one exists. For Transportation, the Weighted ExtremeElec % Increase is used to come up with one rate of increase based on the individual components.

Table 7. Assumed Technology Adoption Rates

Sector	Technology	2042 Approx Adoption Rate	ExtremeElec % increase	Weighted ExtremeElec % Increase
Commercial	ASHP	95%	25%	25%
Industrial	Electrotechnologies	5%	50%	50%
Residential	ASHP	95%	25%	25%
Transportation	PEV—LD cars	95%	25%	23%
	PEV—LD trucks	86%	25%	
	MDV	58%	50%	
	HDV	39%	50%	

Where ASHP—Air Source Heat Pumps; PEV—Plug-In Electric Vehicles; LD—Light Duty; MDV—Medium Duty Vehicles; HDV—Heavy Duty Vehicles

Table 8. Single Hour Extreme Electrification Example

Sector	Y20 FC Total MWh (A)	HE MWh from Electrification (B)	HE Total MWh (C)	Weighted XE % Increase MWh (D)	XE MWh from Electrification (E)	XE Total MWh (G)
			$(A)+(B)$		$(B)\times(1+(D))$	$(A)+(E)$
Commercial	3,652	157	3,809	25%	196	3,848
Industrial	1,422	24	1,446	50%	36	1,455
Residential	4,767	850	5,617	25%	1,063	5,830
Transportation	115	2,213	2,328	23%	2,722	2,837
Total Demand	**9,956**	**3,244**	**13,200**		**4,017**	**13,973**

Figure 2 demonstrates how the seasonal XE scenario demand curves compare to the Y20 FC demand curves for the CAMX subregion. You can see how the demand peak for each season can be shifted from the initial Y20 FC seasonal hourly peak. See Appendix C for the seasonal demand comparisons for each subregion.

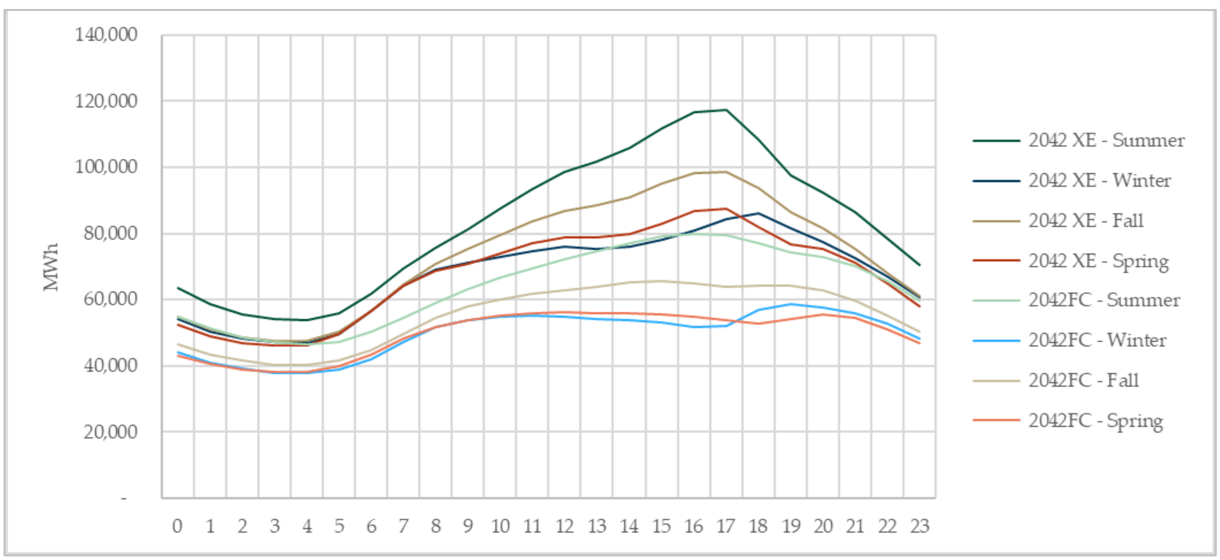


Figure 2. Example of CAMX XE and Y20 FC Demand Curves

Demand Response Assumptions

The DR assumed in this study is limited to load-shifting technology or programs. While the other types of DR could benefit the system, they fall outside the scope of this study. In addition, the load-shifting approximates what may be available in the future; however, this study makes no claims about which technology or programs could achieve the desired results. Table 9 shows the amount of assumed electrification load from each sector in each subregion. The amount of electrification demand assumed to be shaped via programs or technology is informed by the NREL EFS Analysis for Demand-Side Flexibility[9] and the amount of flexible load for each subregion and sector is shown in Table 10.

Table 9. Electrification Load by Sector and Area

Sector	AB	BC	BS	CAMX	NW	RM	SW
Commercial	8%	8%	4%	9%	8%	5%	6%
Industrial	4%	4%	2%	14%	4%	5%	2%
Residential	10%	10%	7%	7%	10%	8%	8%
Transportation	94%	94%	92%	94%	94%	91%	94%

Table 10. Flexible Load Percentages by Sector and Area

Sector	Flexible Load as % of Total Load	AB	BC	BS	CAMX	NW	RM	SW
Commercial	5%	0%	0%	0%	0%	0%	0%	0%
Industrial	3%	0%	0%	0%	0%	0%	0%	0%
Residential	12%	1%	1%	1%	1%	1%	1%	1%
Transportation	51%	49%	49%	49%	48%	49%	49%	49%

XE OP Scenario Assumptions

In the XE OP scenario, the shaping of electrification demand to off-peak hours, defined in Table 11, is assumed to be the same for all subregions and for all seasons. Figure 3 shows the shaping of the electrification demand to fall predominantly in the off-peak hours. The weighted curve assumes the programs or technology will not match the off-peak hours exactly and that some level of demand will fall outside the period as the programs or technology take effect.

[9] Electrification Futures Study: Operational Analysis of U.S. Power Systems with Increased Electrification and Demand-Side Flexibility (nrel.gov)

Table 11. Time of Day Assumptions

Hours	TOD
HE 1-6	Off-peak
HE 7-22	On-peak
HE 23-24	Off-peak

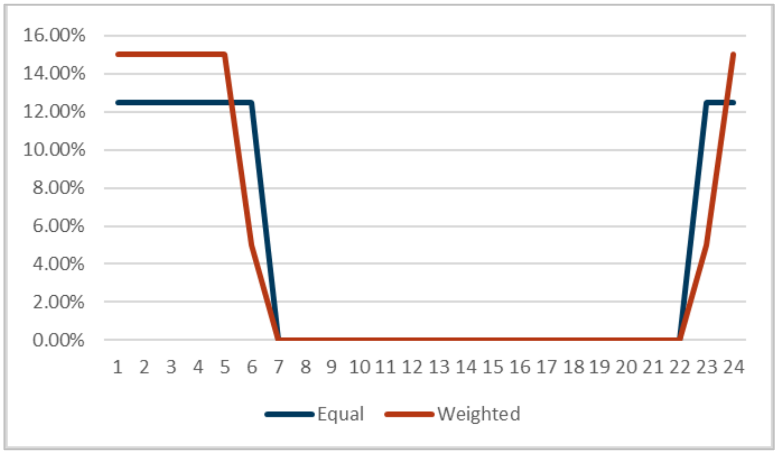


Figure 3. Off-peak Demand Response Hourly Distribution

XE MD Scenario Assumptions

In the XE MD scenario, the shaping of electrification demand for midday is focused on the hours with the highest amount of wind and solar energy generation, by subregion and by season. Figure 4 demonstrates the midday shaping for the winter season in CAMX. The blue line is the percentage of the daily total wind plus solar energy generation that is occurring in each seasonal hour. The purple line is how the demand attributed to electrification is shaped in the XE MD scenario to focus the demand into the middle of the period. See Appendix D for the seasonal midday shaping for all subregions.

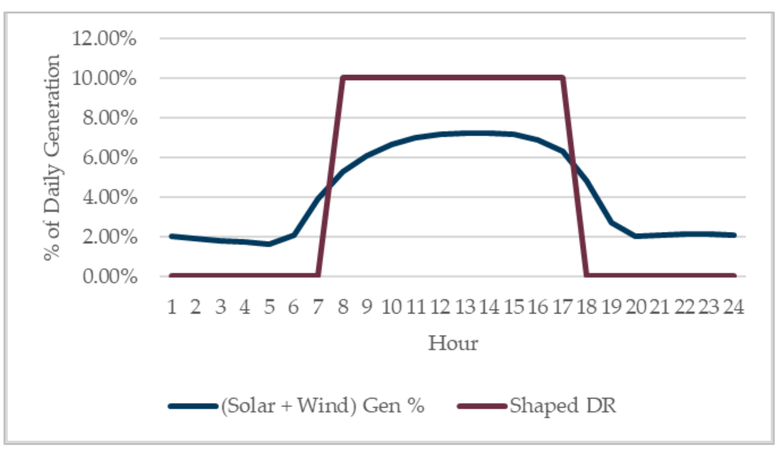


Figure 4. Example of Midday Demand Shaping by Season for CAMX

Scenario Demand Comparisons

Seasonal Net Demand Comparison

Figure 5 shows a comparison of net demand for each of the four scenarios, where net demand = total demand—(solar generation + wind generation), by season for the CAMX subregion. See Appendix E for the net demand comparisons for each of the WECC subregions.

The HE and XE demand curves show an increase in net demand for all hours over the Y20 FC, as well as a stronger, or shifted, peak (depending on the subregion and season). The HE scenario saw the greatest increase in demand magnitude across all hours, while the XE scenario saw a greater peak demand

The XE MD and XE OP net demand curves indicate a strong shift in time of use from the XE curve. The XE MD curve demonstrates a shift in demand to periods of high renewable penetration while the XE OP shows higher demand in the off-peak period.

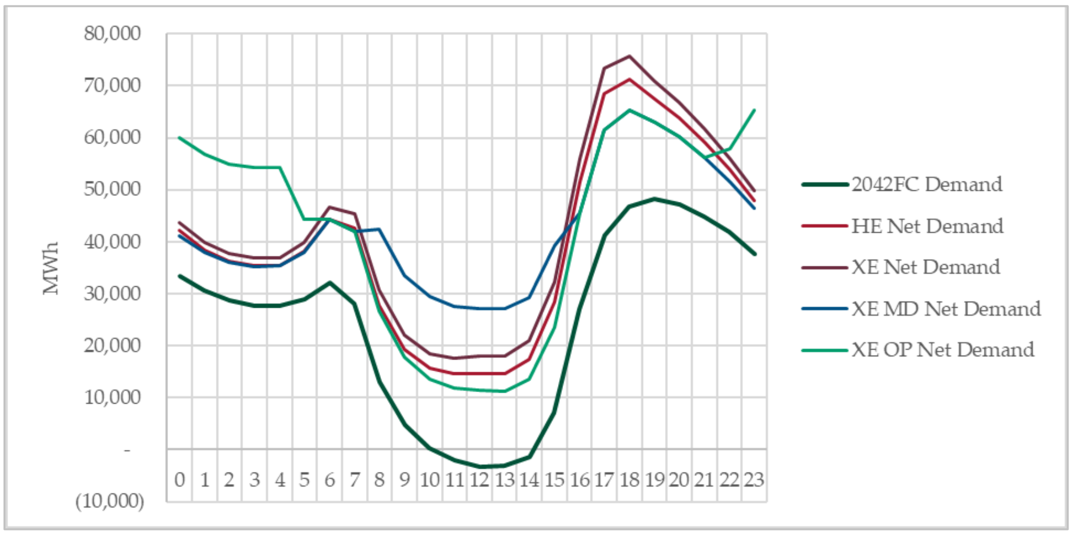


Figure 5. Example of Net Demand by Season for CAMX

48-Hour Demand Shape Comparison

In addition to the seasonal view, it is helpful to look at an hourly comparison to visualize the hour-by-hour demand changes between the four study scenarios. Figure 6 shows this over a 48-hour period beginning 04/02/2042. The bars in Figure 6 show the breakdown of the XE demand by the four sectors: Transportation, Residential, Industrial, and Commercial. The total Y20 FC demand is shown as the reference line, with the total HE, XE OP, and XE MD demand lines shown as well. The solar and wind generation forecasts are also shown on the other axis.

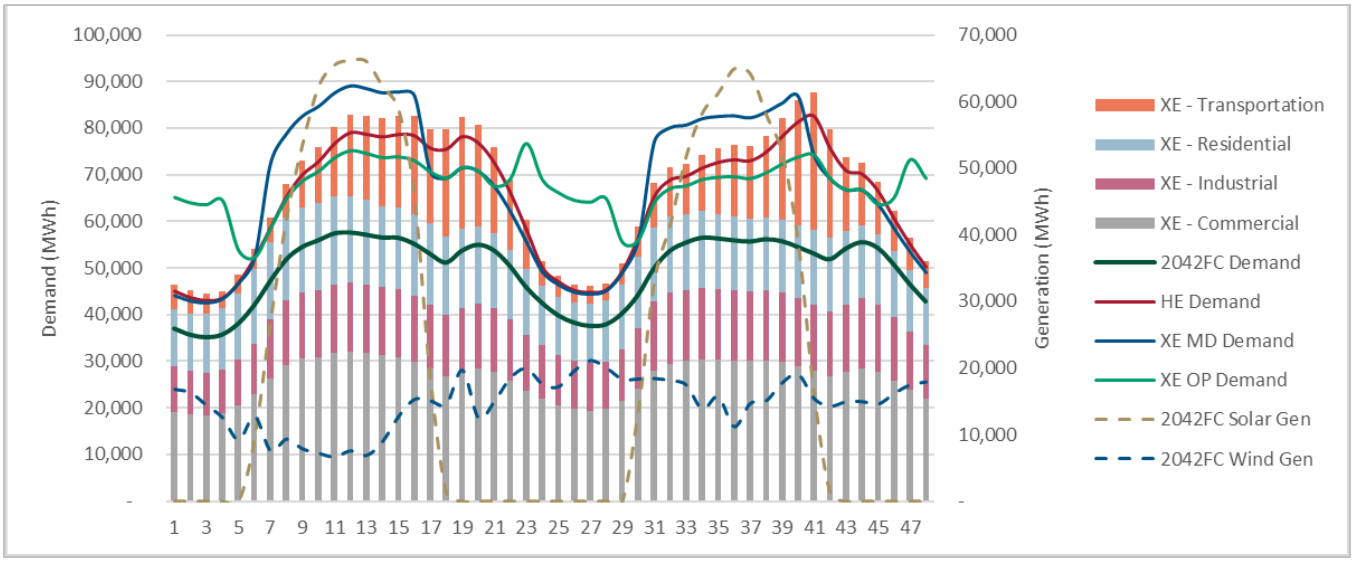


Figure 6. Example of Hourly Demand 48-hours in CAMX

Model Limitations

The scope and timeline for this study prohibited the creation of a full expansion capacity plan or transmission expansion plan. The new generators assumed to be available during 2042 are distributed by area, meaning they were not placed on a specific bus. If the assumed capacity comes to fruition, it likely will be placed in a different area than how the software distributed it.

The ABB PCM GridView Version 10.3.62 was the sole modeling software used in this study. As with all software, there are limitations of GridView worth noting:

- Upon testing, batteries and energy storage both operated on daily charge and discharge cycle of 24 hours such that none of the modeled storage is considered long-duration.
- The addition of generation for a 20-year forecast was distributed by area, which required the model to not consider transmission losses.
    - This potential is working in our favor, however, as some loss models may unnecessarily move energy to minimize spillage.

Observations and Findings

The goal of this study was to answer two questions:

1. Could the anticipated demand due to electrification cause any reliability concerns in the West?
2. Would shifting of the demand due to electrification help to alleviate any reliability concerns?

Reliability Risk Due to Electrification Demand

When business-as-usual capacity addition assumptions were used with a reasonable forecast of high electrification, unserved energy was found. Figure 7 shows how the increase in demand in the HE scenario creates unserved load in each of the subregions.

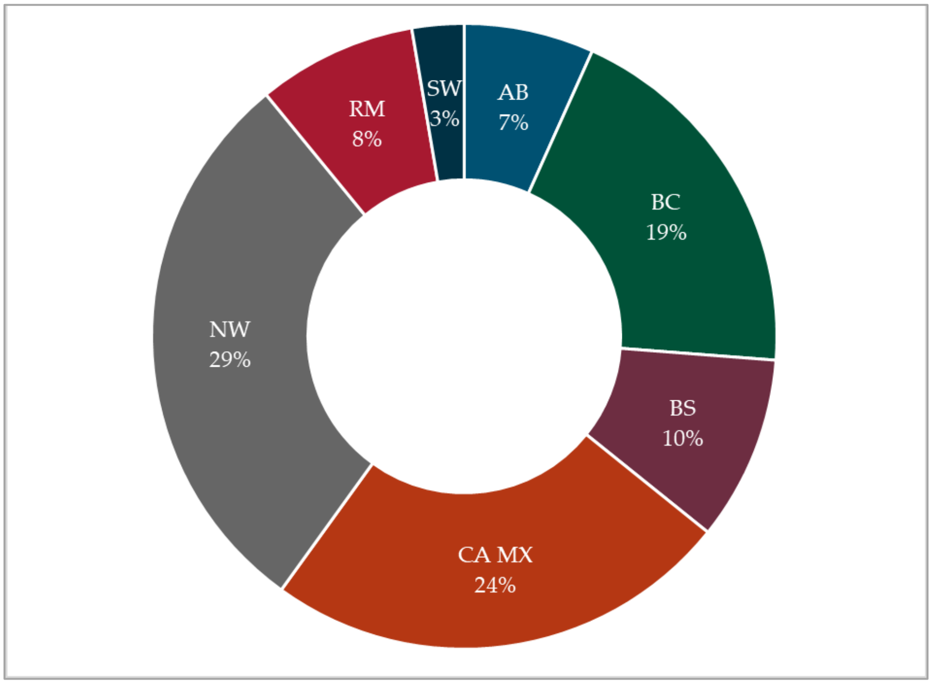


Figure 7. 2042 Unserved Load by Subregion in HE Scenario

As mentioned in the Year 20 Foundational Case report, CAISO provided its 20-year generation forecast to be used in the reference case; yet, even with the increase in generators, the HE scenario still showed unserved load in California.

Figure 8 shows the subregions most stressed by the XE demand. These results indicate that the BPS in the WI is susceptible to fairly small changes in demand leading to greater reliability risk. (see Appendix E for a seasonal demand comparison).

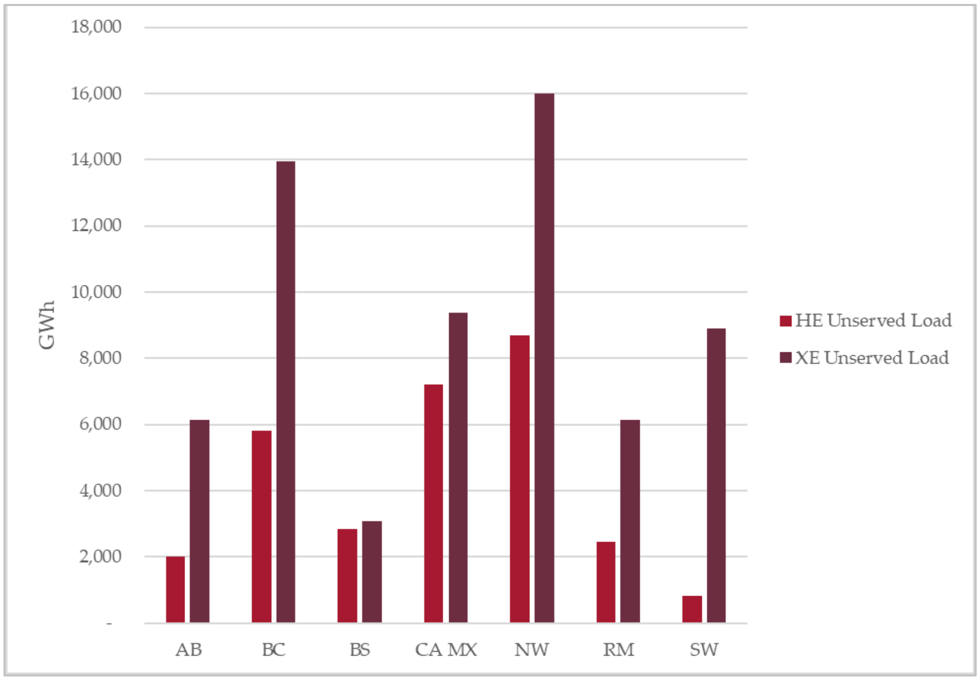


Figure 8. 2042 Unserved Load Comparison by Subregion

Figure 9 shows a high stress hour in the HE case with a visualization for both the amount of unserved load in each subregion, as well as an indicator for key transmission path utilization. Figure 9 indicates that many of the key paths are reaching 75% utilization in the hour, and that the paths with lower utilization are in areas with no additional energy available to send across the path(s). Another phenomenon observed with transmission paths was that, even in hours in which excess energy was available to send across a path, if there was no room on the connecting path, the system did not utilize the first path. An example of this is Path 27 (P27) to Path 28 (P28)—with P28 fully utilized, it limited the ability to utilize P27.

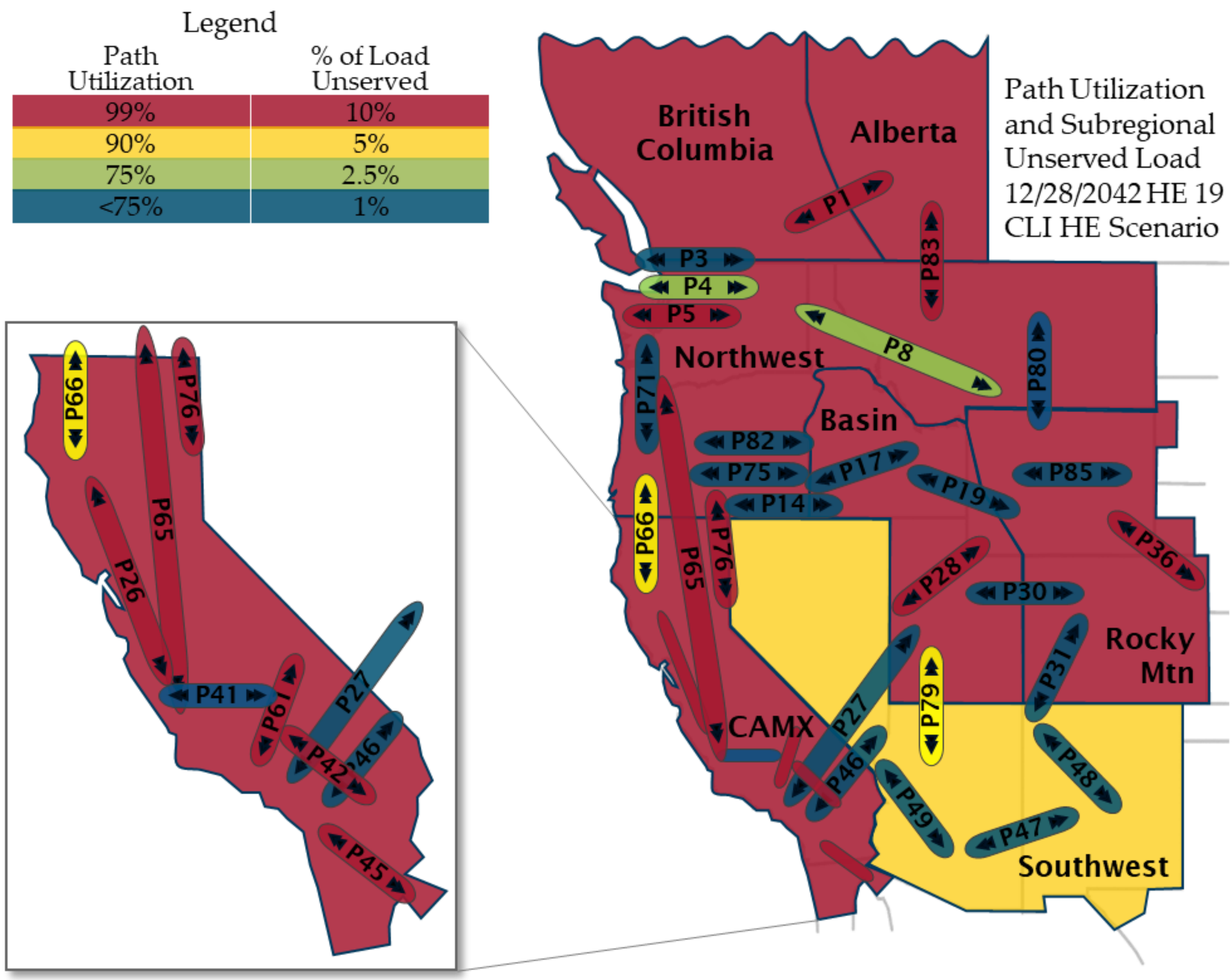


Figure 9. Key Path Utilization and Subregional Unserved Load Heat Map in CLI HE Scenario

The net subregional transfers for the entire WI over the year are shown in Figure 10. With the CAISO-provided resource plan, it stands to reason that the CA subregion is a large net exporter of energy to surrounding subregions.

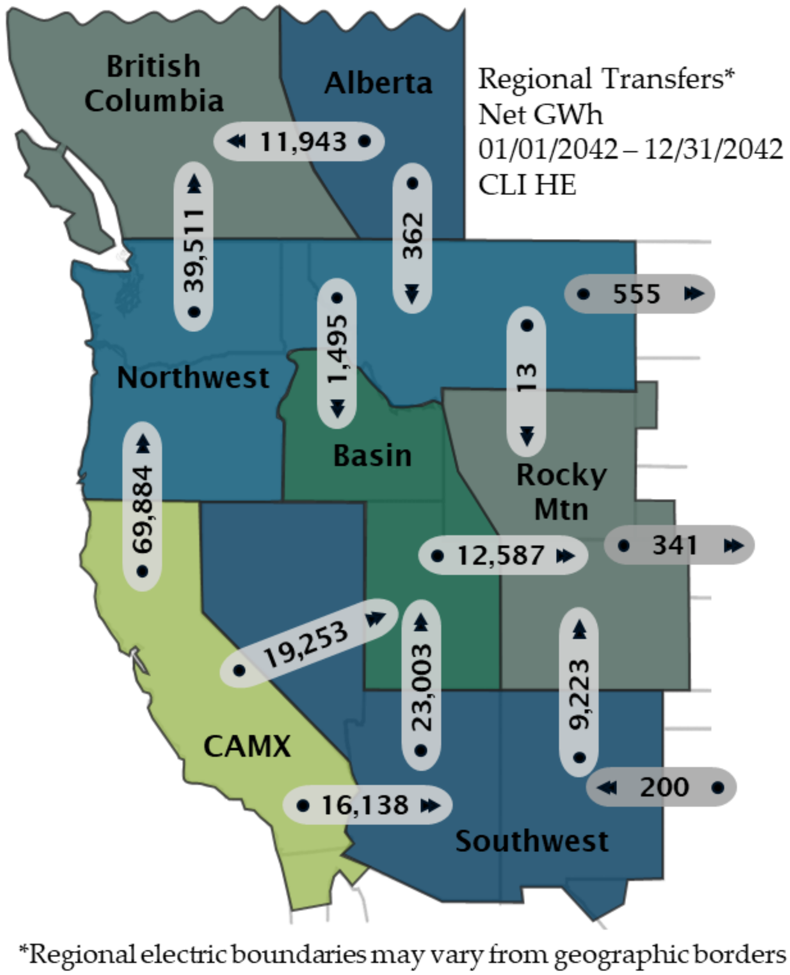


Figure 10. 2024 Net Subregional Transfers

The load magnitude and shape used in this study is a forecast with inherent error and will not be the actual demand seen in 2042; however, the HE and XE scenarios indicate that if utilities and load-serving entities do not adapt their resource and transmission expansion plans to account for future electrification, there will be a very real reliability risk.

Demand Response Impact on Reliability Risks

The impact of demand response on reliability risk from electrification is less straight forward but arguably more interesting. This study was limited in the number of scenarios and therefore is limited in what it can reveal. However, the results do indicate that some load-shifting could help to reduce the burden that electrification is expected to add to certain hours of the day in many subregions. Figure 11 shows that different subregions benefit from different load shifting; the NW is the only subregion that did not realize a net benefit from either.

While the NW subregion saw hourly benefits in both the XE OP and XE MD scenarios, the unserved load relief in the traditionally peak demand hours of the day could not outweigh the unserved load increase in the period of load-shifting (off-peak or midday). The CAMX subregion also showed an obvious outcome: an extreme increase in unserved load when load was shifted to the off-peak. Because the CAISO-provided capacity expansion plan leans heavily toward solar and wind generation, it is not surprising that the off-peak has little ability to meet the increased needs in the XE OP scenario.

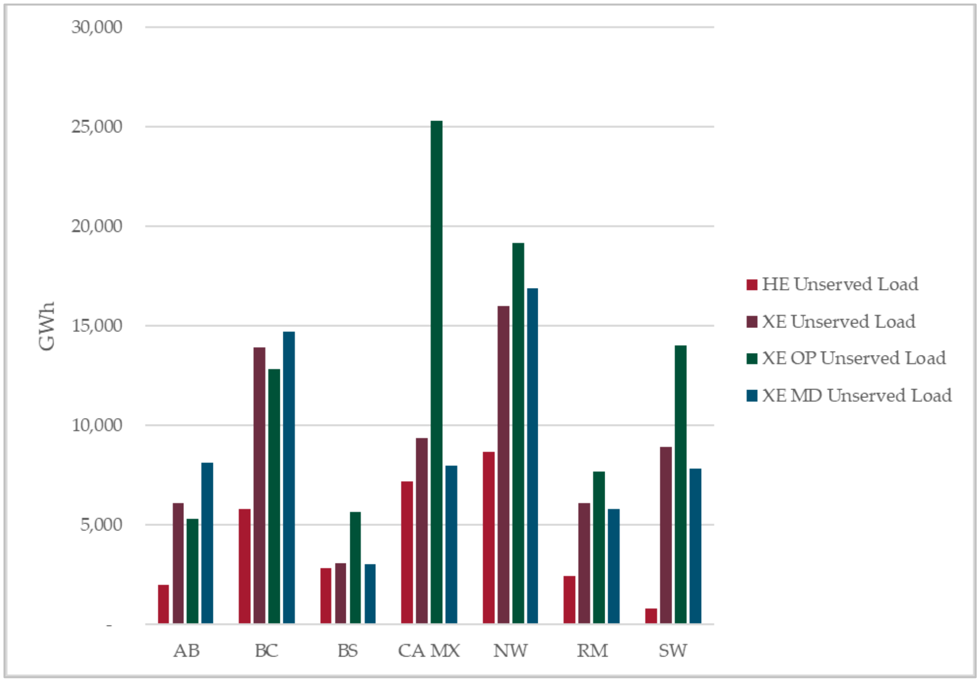


Figure 11. Unserved Load Comparison by Subregion

Results of Off-Peak Demand Response

One of the leading ideas for relieving the pressure of the peak demand in the on-peak hours of the day is to shift load to the off-peak hours when many people are asleep and commercial and industrial work is less active. As seen in Figure 11, in the XE OP scenario, the U.S. subregions saw an annual increase in unserved load, while the Canadian provinces had an overall drop in unserved load.

Figure 12Figure 13 are hourly visualizations of the Alberta (AB) and Southwest (SW) subregions over a seven-day, high-risk period in December. These figures reveal the delta between the XE and XE OP scenarios for net load, energy storage generation, and unserved load. The Unserved Load Delta line highlights how the unserved load changed when the electrification demand was shifted to the off-peak hours. A positive value means the respective variable increased in the XE OP scenario. The grey sections show the on-peak hours for each day.

Figure 12 reveals that the AB subregion experienced a decrease in unserved load in the on-peak hours due to the demand decrease modeled during that time. Conversely, the unserved load increased in the off-peak hours when the modeled demand was increased.

Figure 12. Example of Change in Unserved Load for Alberta Subregion in XE OP

Figure 13 demonstrates that the SW subregion experienced the same thing as the AB subregion in Figure 12, however, the daily total increase in unserved load in the off-peak was greater than the total decrease in unserved load in the on-peak. The Storage Delta line also reveals that when energy storage exists in the subregion, it helps to serve the load later in the day. Much of the unserved load is occurring the morning hours when the energy storage is not generating. This is most likely due to the limitation with 24-hour optimization in the model. Hypothetically, the unserved load in the morning hours could also be served with energy storage when optimized over a larger period.

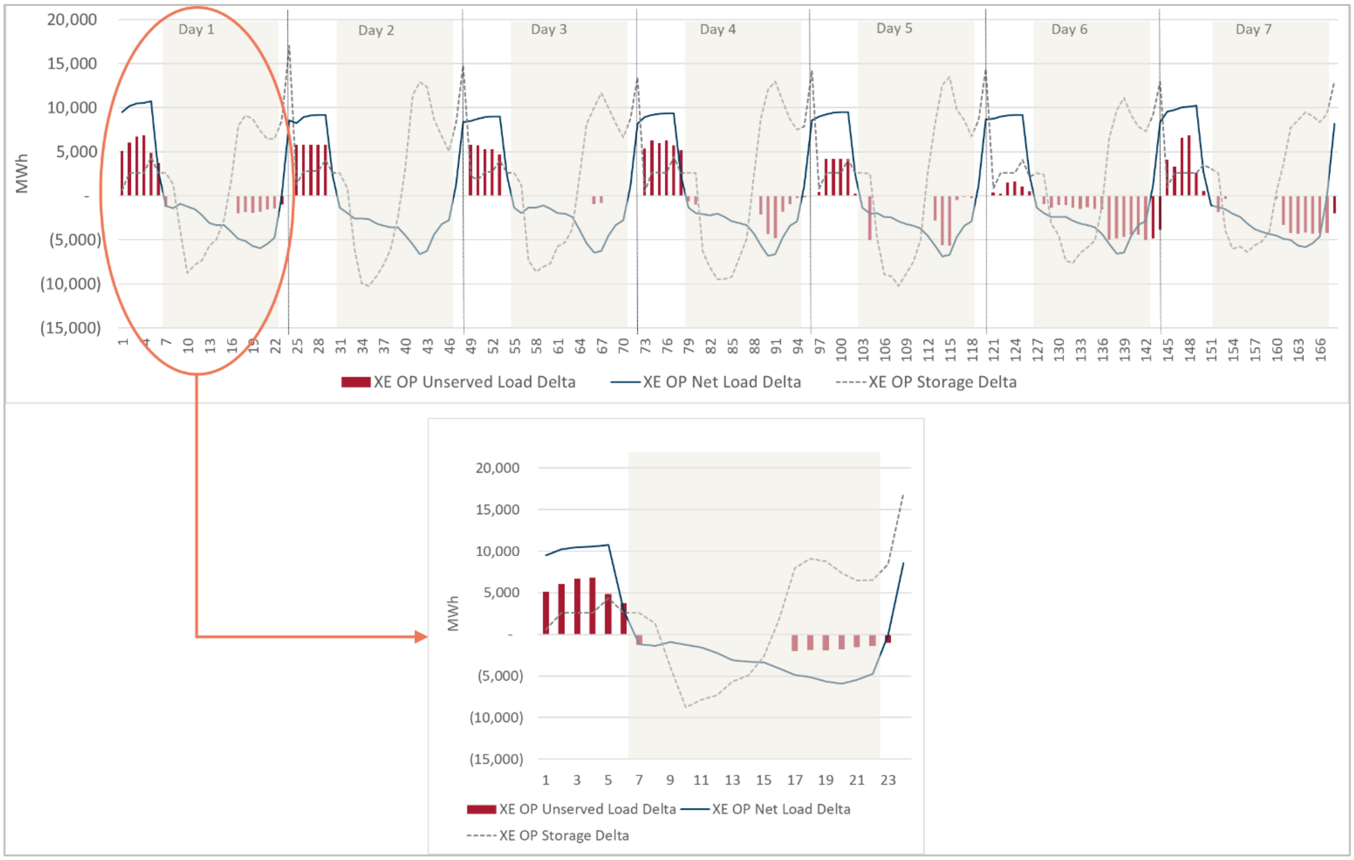


Figure 13. Example of Change in Unserved Load for Southwest Subregion in XE OP

Both figures indicate that, while a load shift to off-peak creates a benefit by decreasing unserved load in certain hours, other opportunities can be explored. Combining expanded resource plans and transmission plans with demand response for load shifting could eliminate the reliability risks. All of the subregions saw similar results. See Appendix G for the XE OP changes in unserved load for all subregions.

Results of Midday Demand Response

With a more generation being provided by resources that produce more generation in the on-peak hours, namely solar, the middle of the day provides an opportunity to serve additional load. As seen in Figure 11, the unserved load is reversed from the XE OP scenario; the U.S. subregions saw an annual decrease in unserved load, while the Canadian provinces experienced an increase in unserved load in the XE MD scenario.

Figure 14 and Figure 15 are hourly visualizations similar to the XE OP scenario in Figure 12Figure 13; they also look at the AB and SW subregions over the same seven-day, high-risk period in December. Figure 14 shows that the XE MD scenario overall increases the unserved load from the XE scenario in the AB subregion. Figure 14 indicates that the designation of midday for AB (defined in Appendix D) may be too narrow to realize the true benefit of midday load shifting.

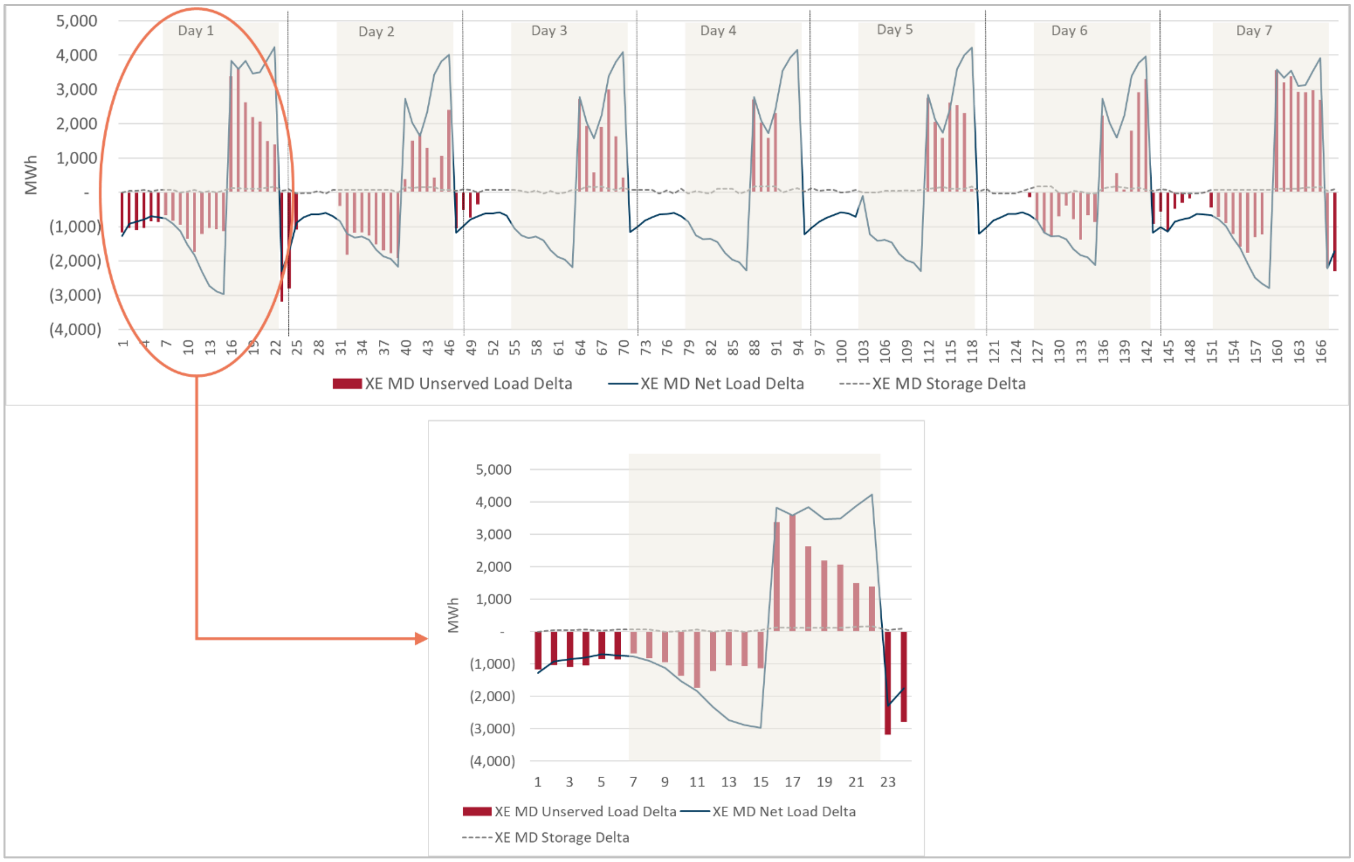


Figure 14. Example of Change in Unserved Load for Alberta Subregion in XE MD

The XE MD scenario for the SW subregion, Figure 15, with all the available wind and solar in the middle of the day, has additional capacity available to serve the increase in demand due to electrification.

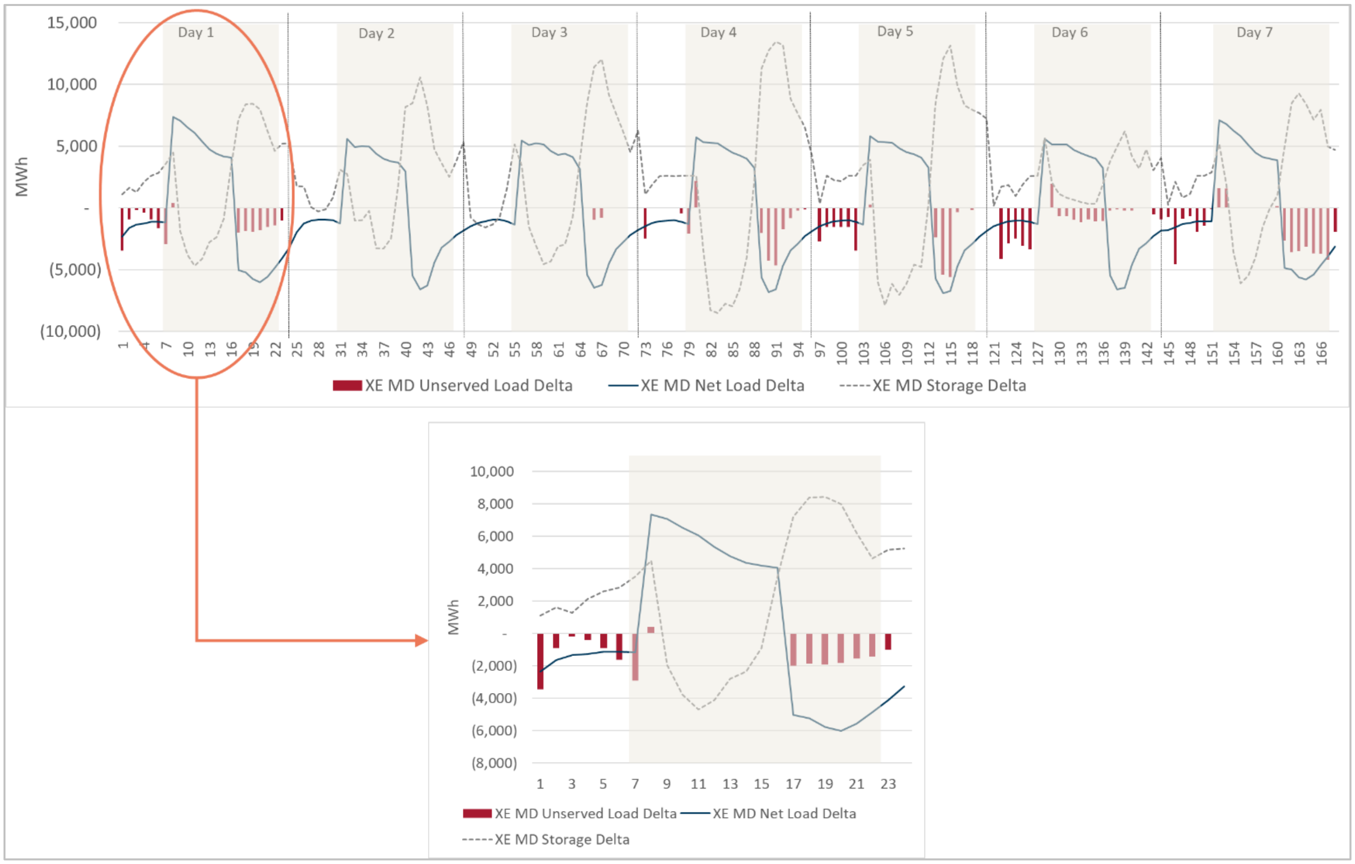


Figure 15. Example of Change in Unserved Load for Southwest Subregion in XE MD

Unlike the XE OP scenario, the subregions with energy storage in the XE MD scenario are less affected by the 24-hour energy storage optimization horizon.

The BC and NW subregions did not see the same decreased unserved load in the XE MD scenario as AB and SW (Figure 14 and Figure 15). This may be, in large part, because these subregions have the lowest ratios of (solar + wind) generation to gross demand, as shown in Figure 16. Since the XE MD scenario attempts to serve the increased load due to electrification with wind and solar generation in the middle of the day, it makes sense that without large amounts of wind and solar generation, the XE MD scenario would not realize a benefit from the midday load shift. See Appendix H for the XE MD scenario change in unserved load for each of the subregions.

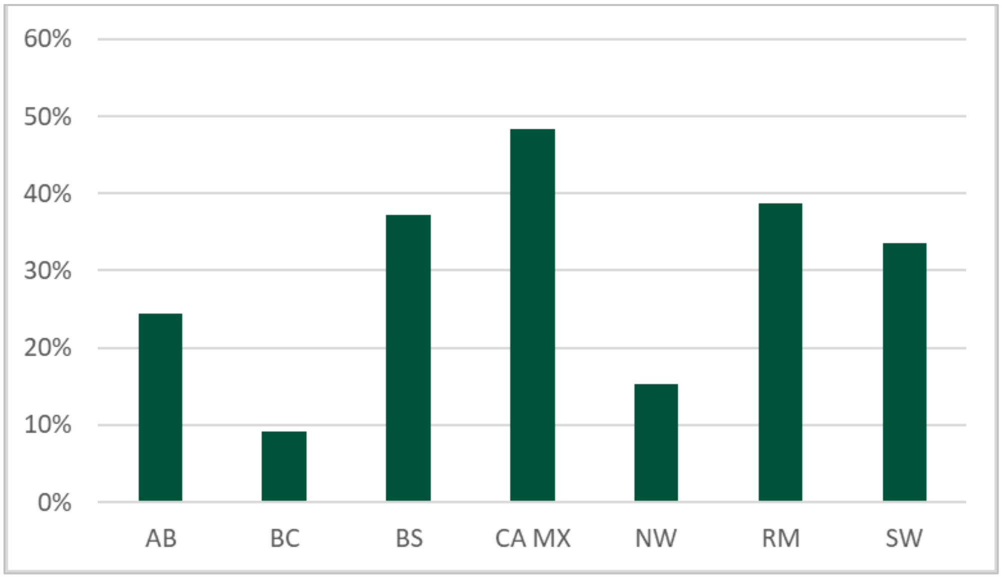


Figure 16. Ratio of Renewable Energy to Demand

Recommendations

From this study of electrification and the impacts of different demand response options, there are two types of recommendations: response to the study, and future study considerations.

Response to the Study

When looking 20 years out, the combinations of unknowns become almost incomprehensible. That said, there are some clear opportunities for moving into an unknown future: in this case, electrification. There are two perspectives that should be considered: supply-side and demand-side.

This study was a good first step in understanding the potential supply-side impact across the WI if considerations in creating resource plans and transmission plans are not updated to appropriately account for the increase in demand due to electrification and changing resource mix. It is critical that the electric industry continue to look at electrification in terms of policies and goals, adoption rates, technology advancements, and demand impacts. Resource and transmission plans need to account for not only an increase in demand, but also a change in the demand shape from what has been observed in the past.

There should also be continued demand-side assessments on what shifting load patterns could look like and how they could be adjusted for reliability benefits. Previous assumptions about DR may no longer meet the needs of the changing grid. Electrification will not occur outside of other grid changes, such as changing resource mix; taking advantage of excess renewable energy in certain times of the day may be an untapped opportunity. As energy storage becomes a more viable and scalable option, it can also play a major role in adjusting demand patterns to allow electric generators to more easily satisfy the need.

Future Study Considerations

There have been many studies and reports focused on how electrification could affect the BPS. This study was an attempt at understanding the potential impact on the WI and possible DR solutions for reliability concerns. This study provides a jumping-off point; from the observations, there are two additional questions that arise that could be examined:

- Could a more customized DR profile for different subregions better address the reliability risks?
- How could more robust energy storage modeling affect the observations?

The GridView storage modeling limitations, which constrain the optimization to a single day, could be unfairly diminishing the value of storage on the BPS. Since the batteries in this study were limited to short-duration batteries optimized over each 24-hour period, it is possible that broadened energy storage or battery options could help alleviate the observed unserved load.

As mentioned, this study used the business-as-usual Y20 FC as the reference, but there are more expected grid changes that could be worth combining with electrification, including:

- Increases in distributed generation,
- Additional renewable energy sources,
- Nuclear resources playing a larger role in future resource plans,
- Expansion of the transmission infrastructure,
- A change in retirement of fossil fuel generation, either more or less aggressive,
- More or less aggressive assumptions around electrification adoption, and
- Electrification combined with extreme events.

Appendix A. Transportation State and Local Goals and Policies

While goals and policies are constantly changing, the following are some of the existing policies and goals for transportation electrification in the Western Interconnection as of August 2023.

Alberta

- Alberta is offering a $5,000 rebate for purchasing or leasing a new electric, hydrogen fuel cell, or plug-in hybrid vehicle.
- Additionally, the province committed 30% of new light-duty vehicle sales to be electric, plug-in hybrid, or hydrogen fuel cell vehicles by 2030.

Arizona

- Arizona offers a tax credit of up to $75 for residents who install commercial electric vehicle charging equipment.
- In December 2021, the Arizona Corporation Commission (ACC) approved a plan (Docket no. no. E-00000A-21-0104) for comprehensive transportation electrification. The plan includes a "moderate" electric vehicle adoption scenario, anticipating 1,076,000 EVs on Arizona roads by 2030.
- Phoenix offers tax incentives for installing electric vehicle charging infrastructure and has invested in building charging stations.
- Phoenix's Valley Metro Agency also has a Zero Emissions Bus initiative to make all diesel buses electric by 2025.

British Columbia

- British Columbia offers a Clean Energy Vehicle Program with rebates for purchasing and installing Level 2 charging stations for residential and commercial use.
- Committed to having new light-duty vehicle fleet be zero-emissions vehicles by 2040.
- Vancouver set a target for all new cars and trucks to be 100% zero-emission vehicles by 2030.
- Victoria has set target for 30% of all passenger vehicle trips within the city to be made on electric or other zero-emission vehicles by 2030.

Oregon

- Oregon has also set targets for adopting electric vehicles, with a goal of reaching 50,000 registered electric vehicles by 2020.
- Portland has adopted a goal of having 25% of all new car sales be electric vehicles by 2030.

California

- California has set ambitious targets for adopting electric vehicles, with 5 million zero-emission vehicles on the road by 2030.

- On September 23, 2020, the Executive Order (N-79-20) stated that by 2035 all new passenger cars, trucks, and SUVs sold in California would be zero emission.
- Los Angeles has committed to transitioning to an all-electric vehicle fleet by 2035 and has invested in building a network of charging stations throughout the city.
- San Francisco has also committed to transitioning to an all-electric vehicle fleet to have all city vehicles powered by renewable energy by 2035.

Colorado

- $5,000 tax credits for the purchase of electric vehicles and has invested in developing a statewide network of charging stations.
- The City of Denver offers tax credits of up to $5,000 for the purchase of electric vehicles and has invested in building a network of charging stations.

Idaho

- Idaho provides a tax credit of up to $750 for purchasing a new or used electric vehicle.

Montana

- $500 tax credit to purchase a new or used electric vehicle. Montana's Energy Technology Program also manages a Clean Energy Grant Program.

New Mexico

- New Mexico offers an income tax credit of 30% of the cost of purchasing or converting a vehicle to run on alternative fuel, including electric vehicles.
- Santa Fe offers tax credits of up to $5,500 for the purchase of electric vehicles and has invested in building a charging station network.

Nevada

- Nevada provides a sales tax abatement of up to $1,500 for individuals who purchase or lease an electric vehicle in the state.
- Las Vegas offers free public charging for electric vehicles and has invested in building a network of charging stations throughout the city.
- Reno installed several electric vehicle charging stations throughout city.

Oregon

- Oregon set targets for adopting EVs to reach 50,000 registered electric vehicles by 2020.
- Portland has adopted a goal of having 25% of all new car sales be electric vehicles by 2030. The city offers tax credits and rebates to purchase electric vehicles and has invested in building a charging station network.

Utah

- Utah offers tax credits of up to $1,500 for the purchase of electric vehicles and has invested in building a network of charging stations.
- Salt Lake City offers free public charging for electric vehicles and has invested in building a network of charging stations throughout the city.

Washington

- Washington offers tax exemptions for purchase of EVs and charging infrastructure. On March 25, 2022, SB 5974 became law. It states that all vehicles of the model year 2030 or later that are sold, purchased, or registered in the state must be electric.
- Seattle offers EV owners free street parking and has invested in network of charging stations throughout the city.

Wyoming

- Wyoming offers exemptions from sales and uses taxes on the purchase of EVs.
- Wyoming has five charging stations and partnered with subregional groups to help expand EV infrastructure throughout state.

Appendix B. Building/Residential State and Local Goals and Policies

Alberta

- Heat Pump Rebate: Up to $2,000 for the purchase and installation of a new electric heat pump.
- On November 23, 2020, Alberta's Bill 36 created clear policies and regulations for the "emerging industry" to encourage investment in geothermal resource development.

Arizona

- Solar tax credit: 25% for the installation of solar PV systems.
- Arizona has set a goal of achieving 100% clean energy by 2050 and has programs to promote building electrification, including incentives for installing solar systems and heat pumps.
- Scottsdale recently began implementing commercial green building codes to boost energy efficiency.

British Columbia

- Home energy rebate: Up to $5,000 for the installation of energy efficient home improvements, such as insulation, windows, and appliances.
- Heat pump rebate: Up to $1,500 for the purchase and installation of a new electric heat pump.
- In March 2021, British Columbia significantly reduced the greenhouse gas (GHG) emissions attributable to British Columbia's building sector and achieved the following vision:
  - By 2030, nearly all new and most replacement space heating and domestic hot water systems in British Columbia's homes and buildings will be high-efficiency electric in pursuit of a province-wide shift to low-carbon buildings.

California

- Solar tax credit: 25% tax credit for the installation of solar PV systems.
- On December 23, 2022, the California Energy Commission released its Building Energy Efficiency Standards.

Colorado

- Heat pump rebate: Up to $1,000 for the purchase and installation of a new electric heat pump.
- Colorado has set a goal of 100% renewable energy by 2050.
- On June 21, 2021, SB 21-246 became law. It encourages electrification [RV1] and directs the public utilities commission and Colorado Utilities to promote compliance with current environmental and labor standards.

Idaho

- Solar tax credit: 25% tax credit for the installation of solar PV systems.

Nevada

- 25% tax credit for the installation of solar PV systems.
- Nevada has set a goal to achieve 100% renewable energy by 2050 and has implemented several programs to promote building electrification, including solar systems.

New Mexico

- Solar Tax Credit: 25% tax credit for the installation of solar PV systems.
- New Mexico has implemented several programs to promote building electrification, including offering incentives for installing solar systems.

Oregon

- 50% tax credit for the installation of solar PV systems.
- The Oregon Department of Energy released a Building Decarbonization Strategy that outlines a plan to reduce greenhouse gas emissions from buildings in the state.

Utah

- Solar tax credit: 30% tax credit for the installation of solar PV systems.
- Utah has set a goal of reducing greenhouse gas emissions to 25% below 2005 levels by 2025 and has implemented several programs to promote building electrification, including offering incentives for installing solar systems.

Washington

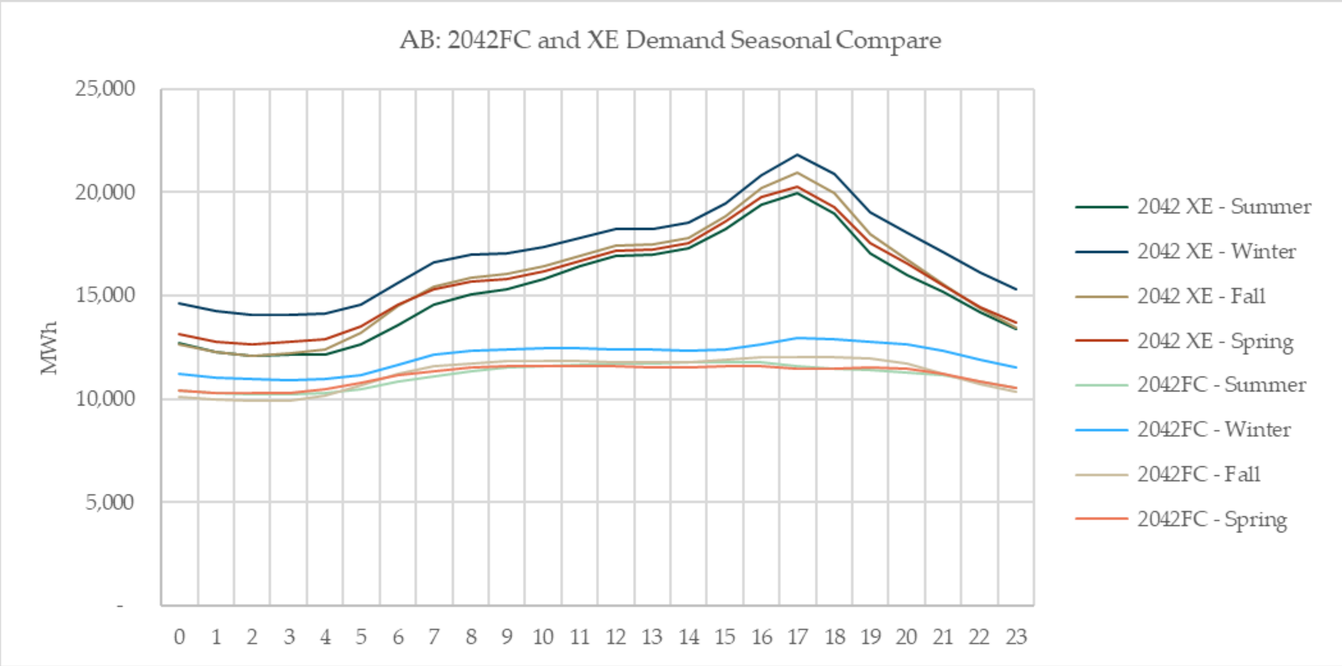
- Solar tax credit: 50% tax credit for the installation of solar PV systems.
- Washington has set goals of reducing greenhouse gas emissions to 95% below 1990 levels by 2050 and has implemented several programs to promote building electrification.

Wyoming

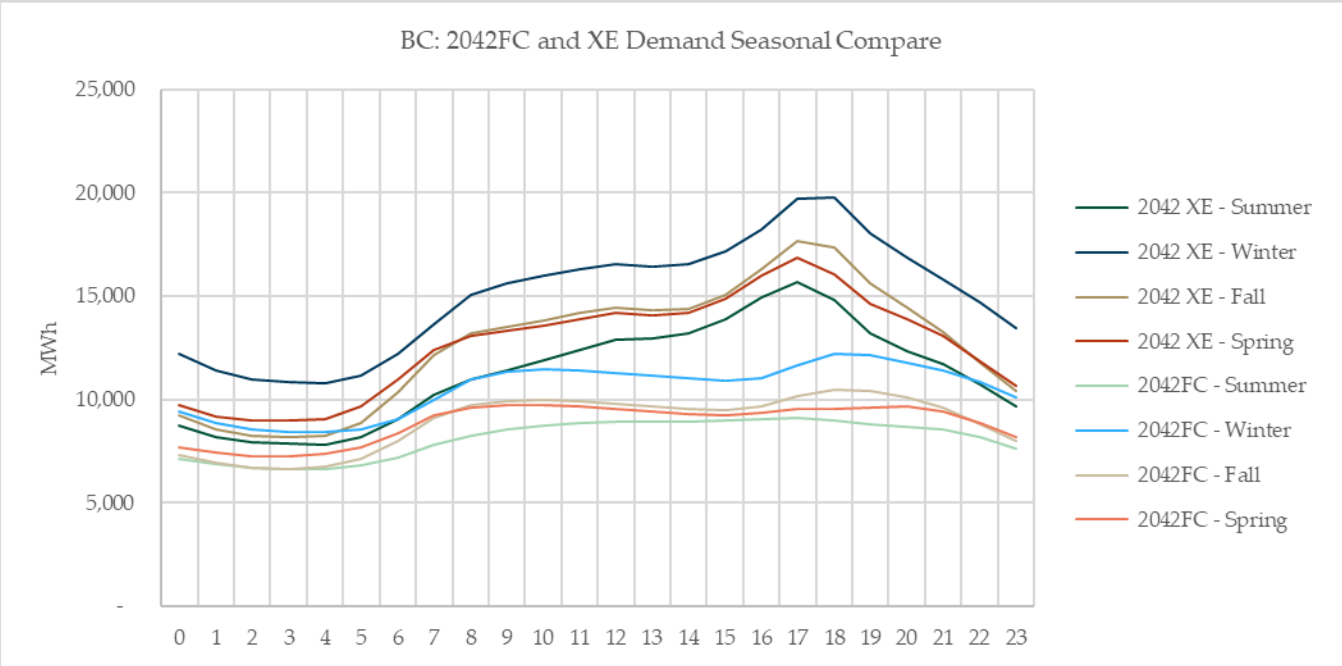
- Heat pump rebate: Up to $500 for the purchase and installation of a new electric heat pump.

Appendix C. Extreme Electrification (XE) Demand Shapes

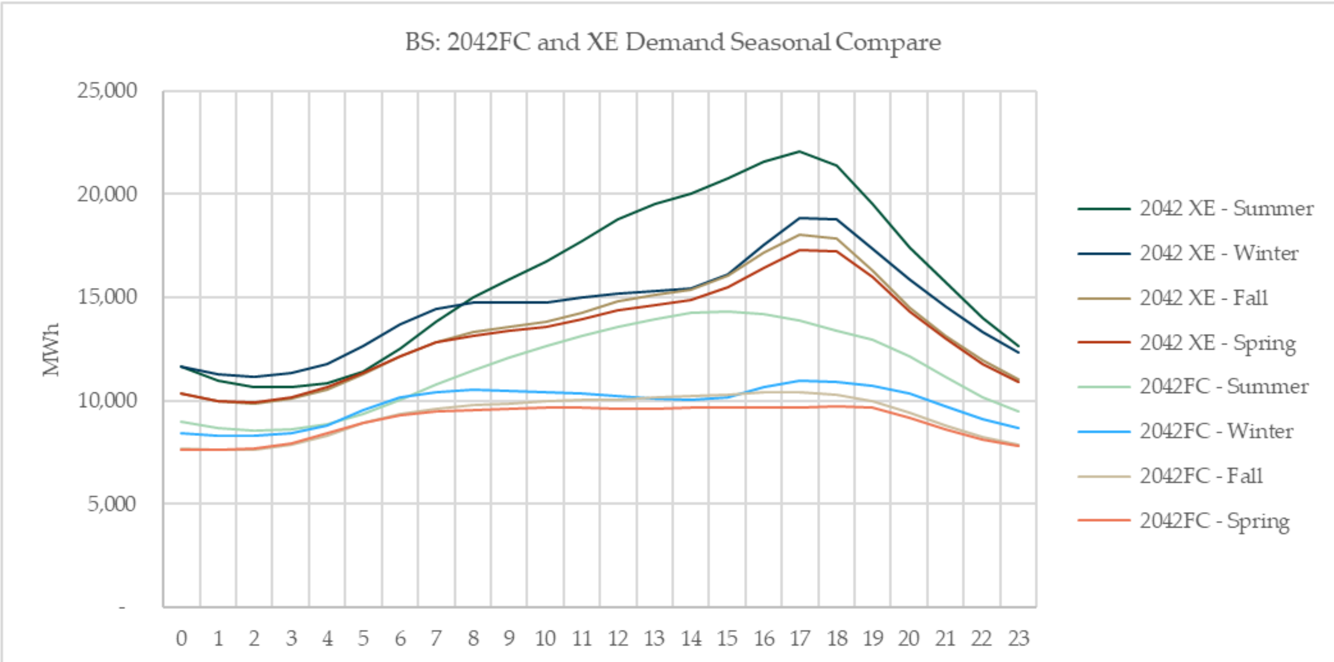
Alberta (AB)



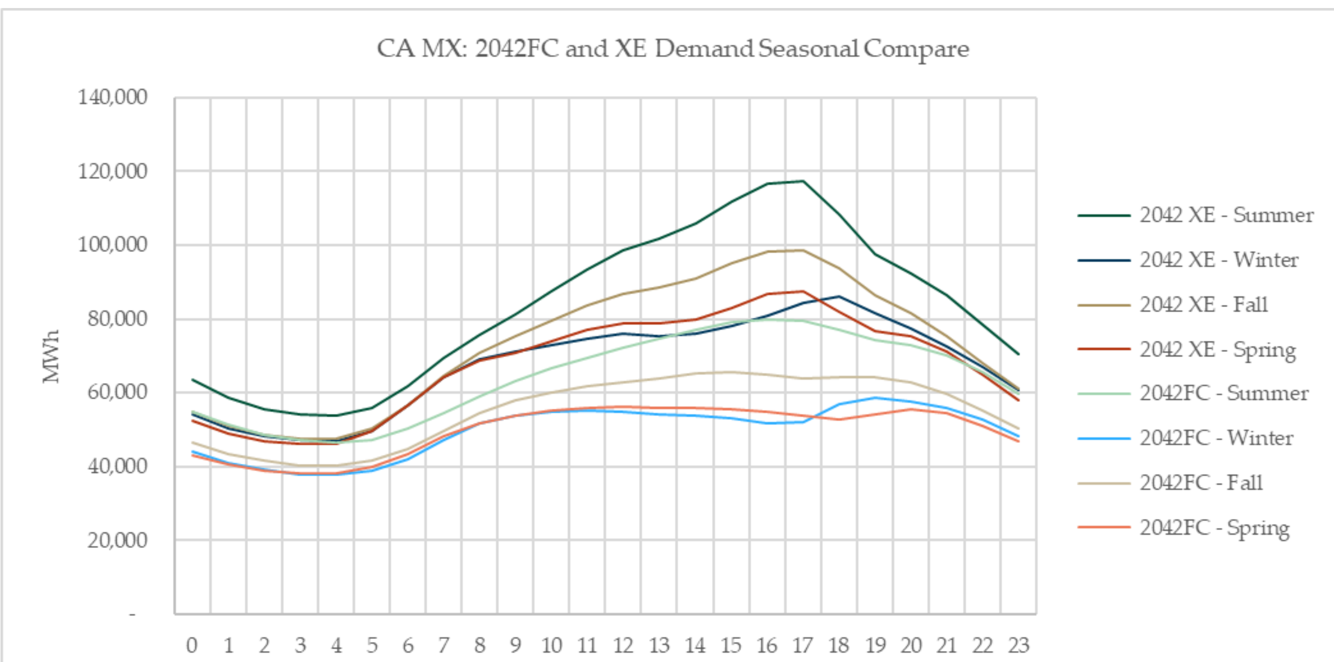
British Columbia (BC)



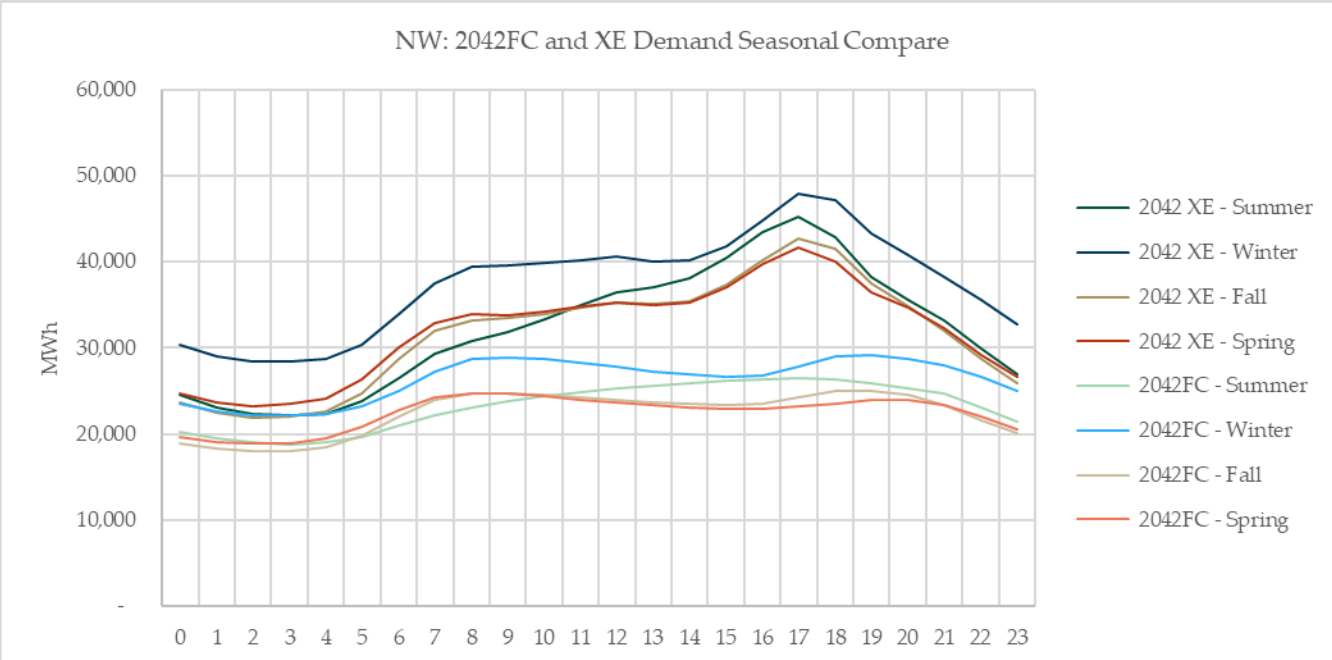
Basin (BS)



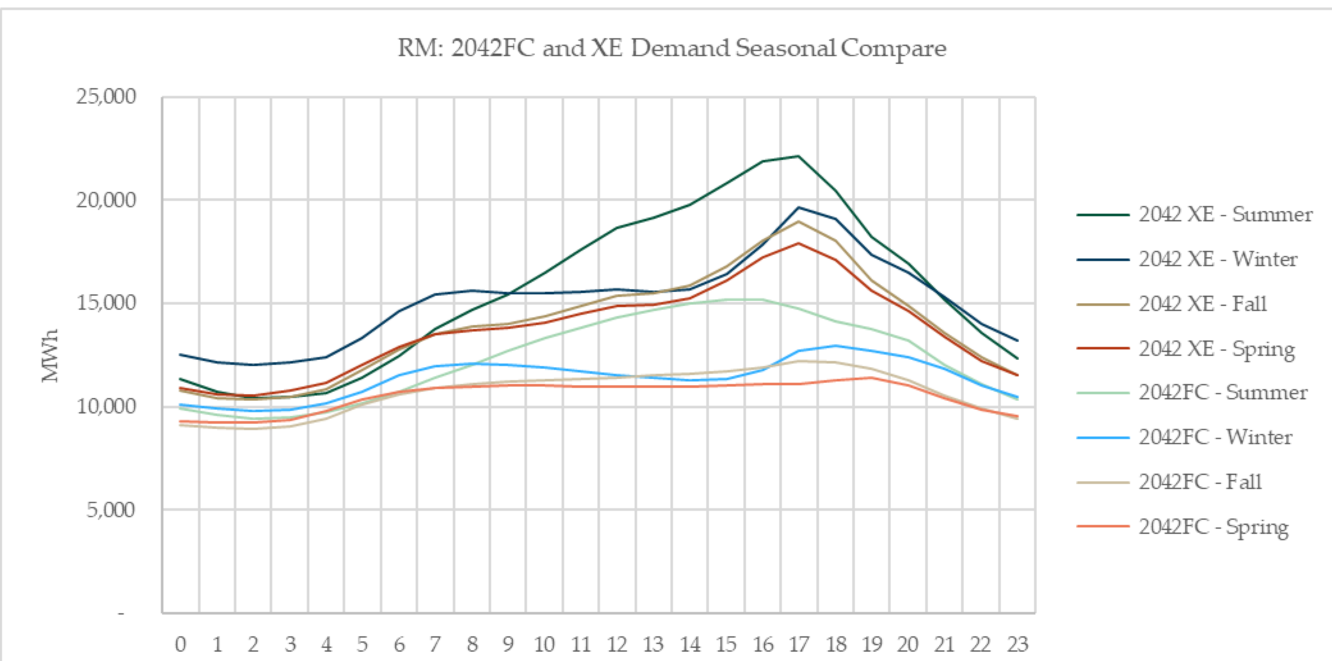
California/Mexico (CAMX)



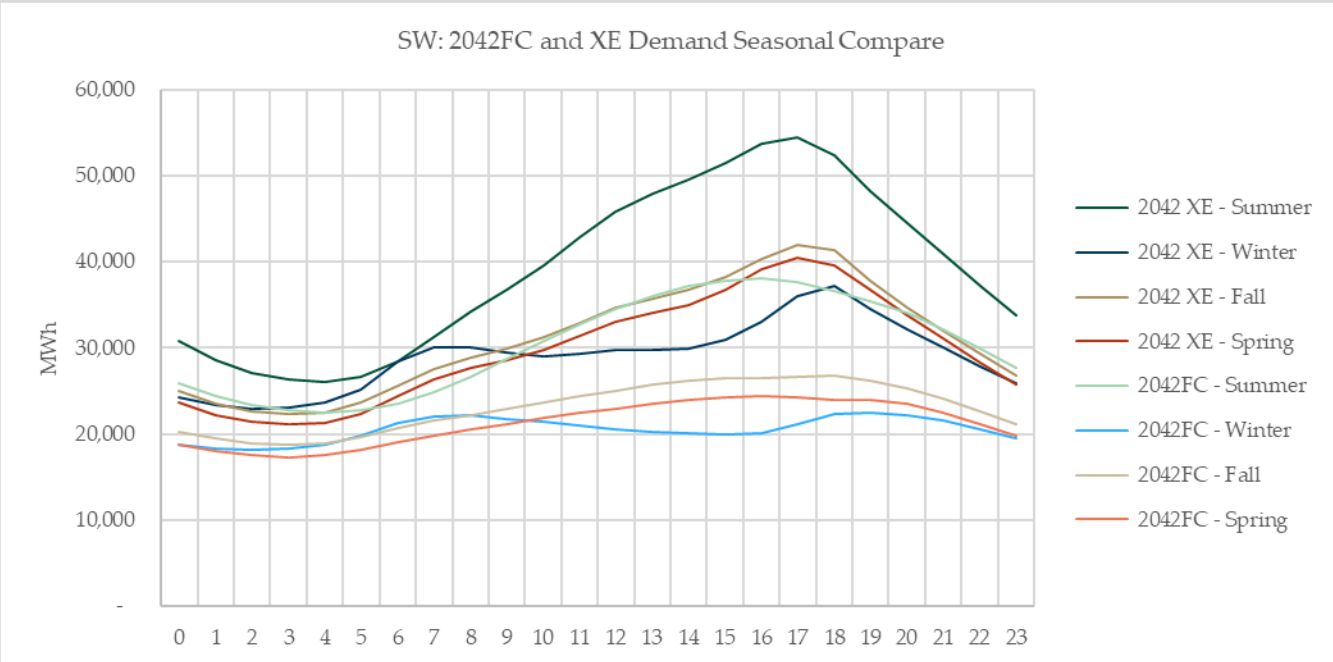
Northwest (NW)



Rocky Mountain (RM)

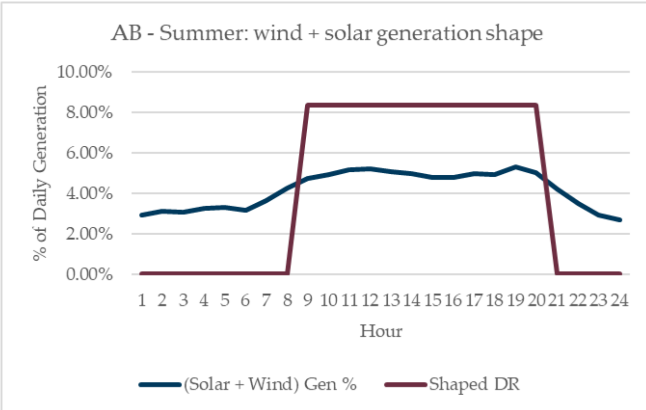


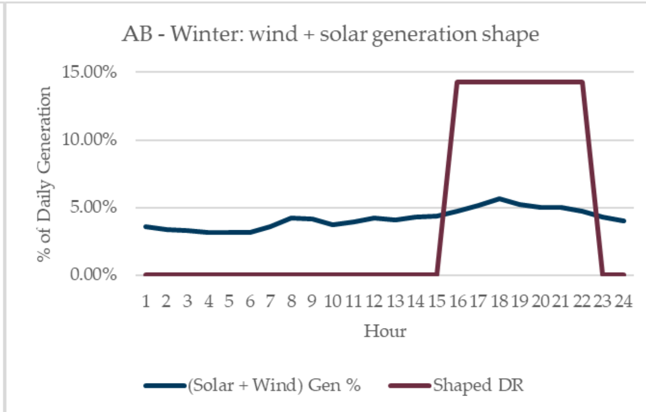
Southwest (SW)

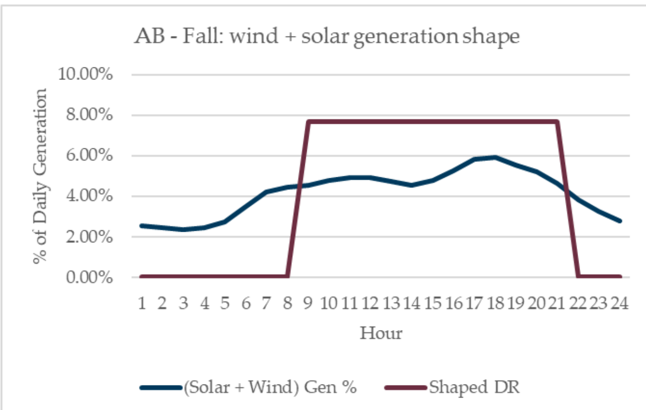


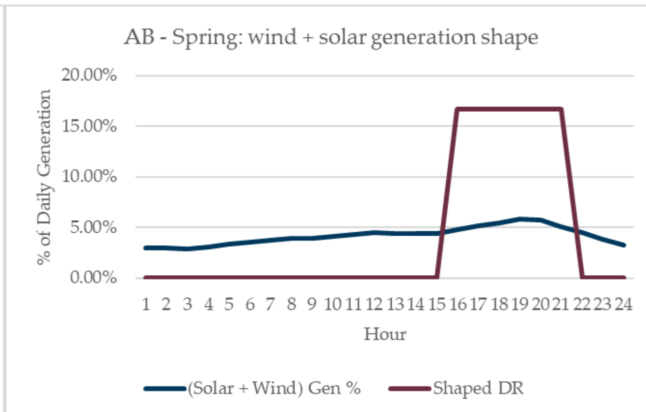
Appendix D. Midday Demand Response Shaping by Season

Alberta (AB)

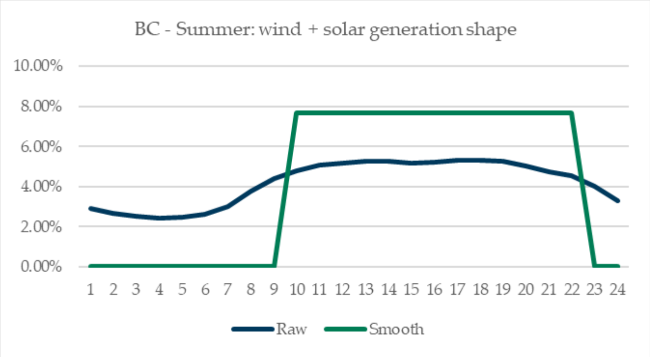


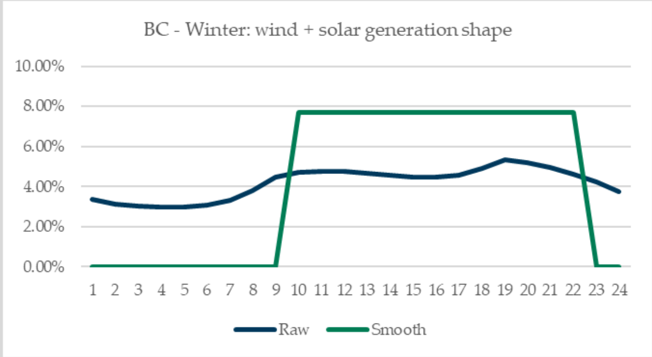


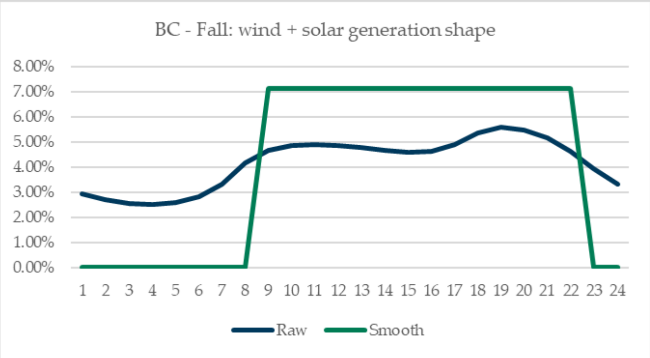


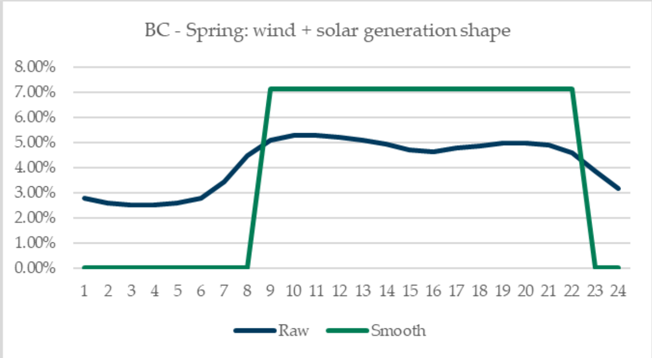


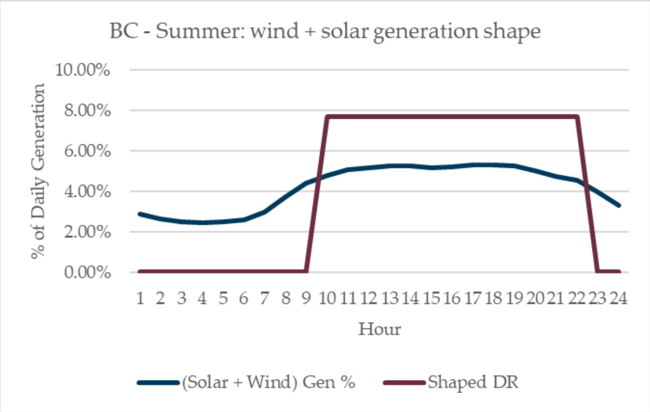
British Columbia (BC)

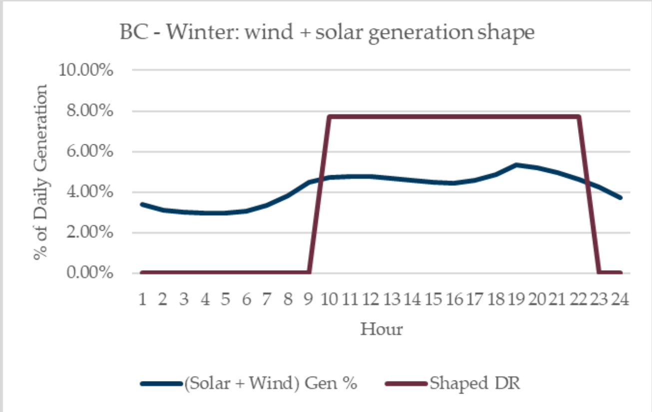


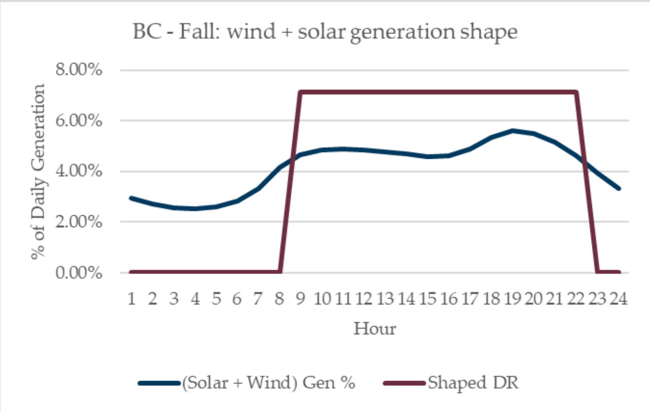


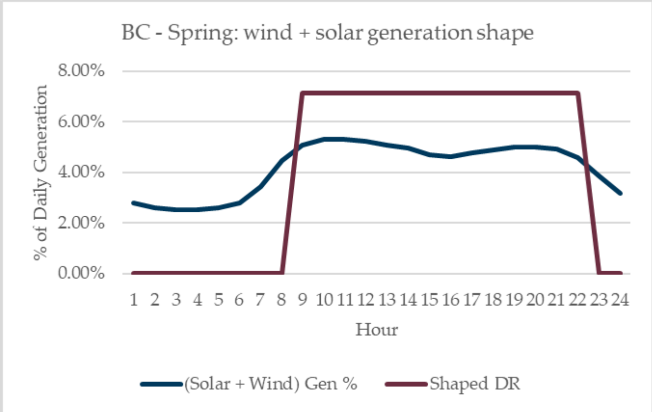




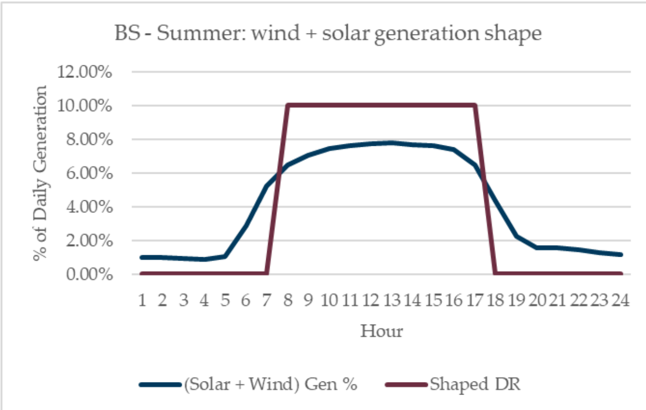


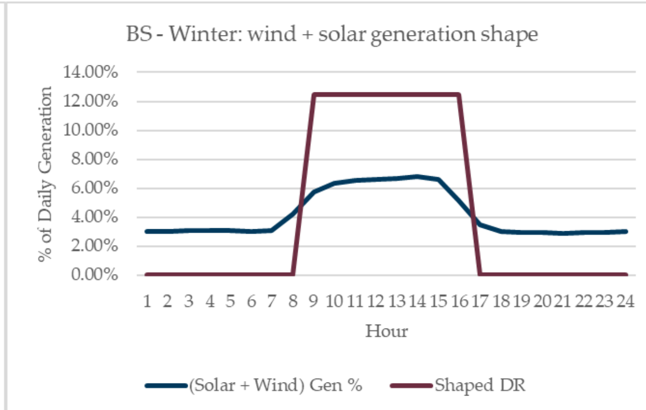


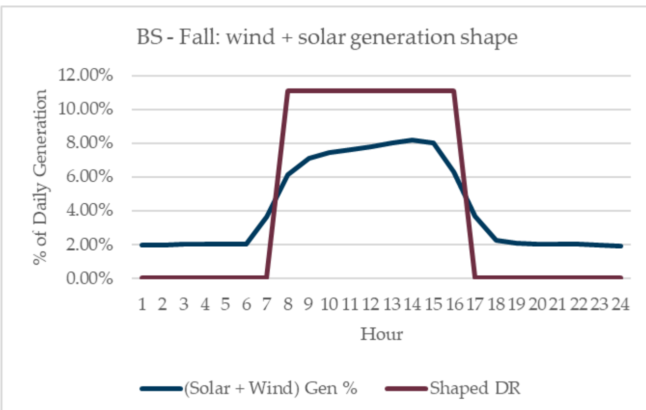


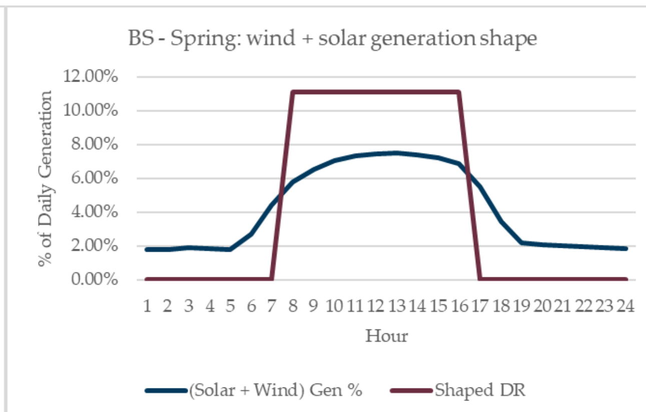


Basin (BS)

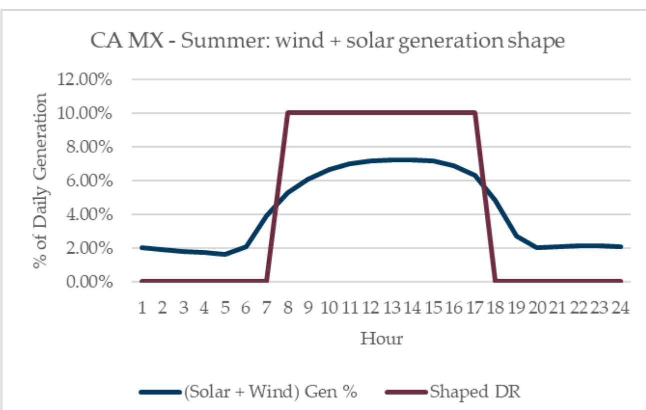


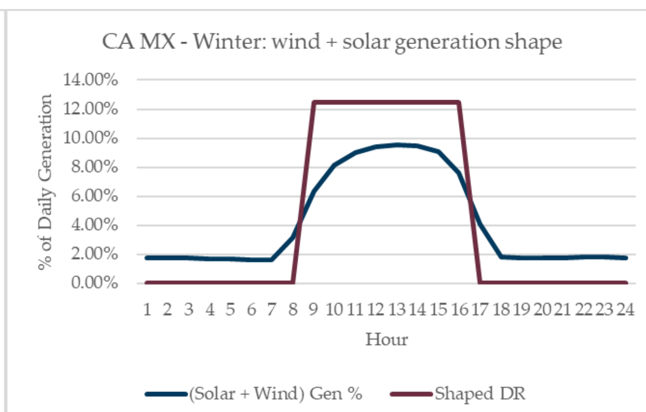


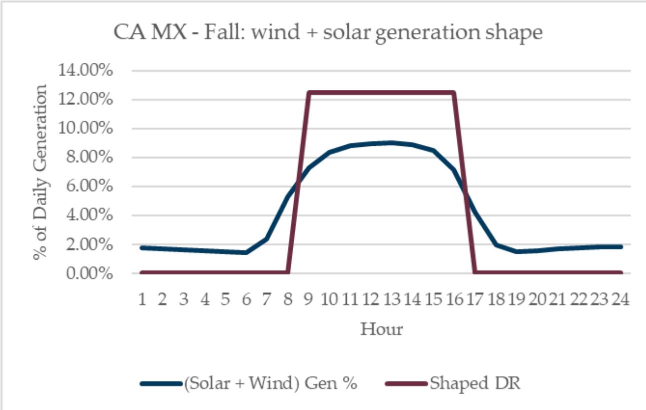


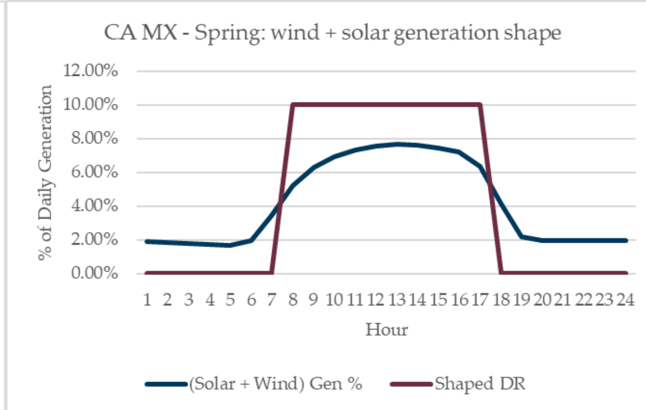


California/Mexico (CAMX)









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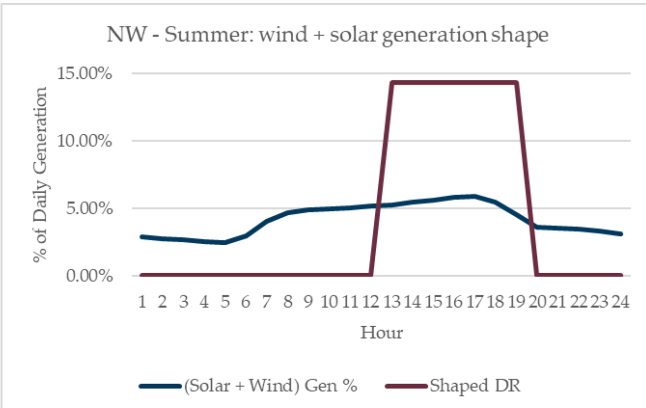
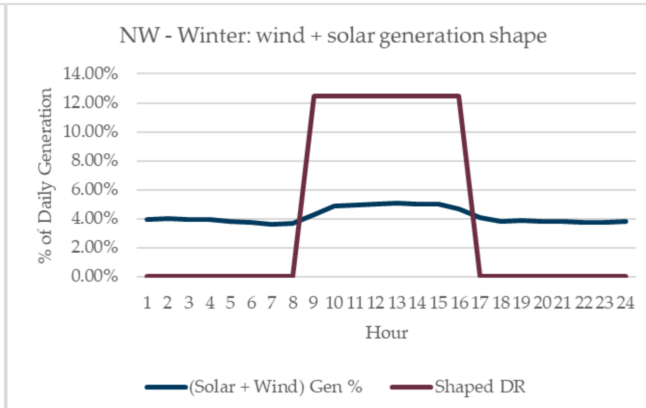
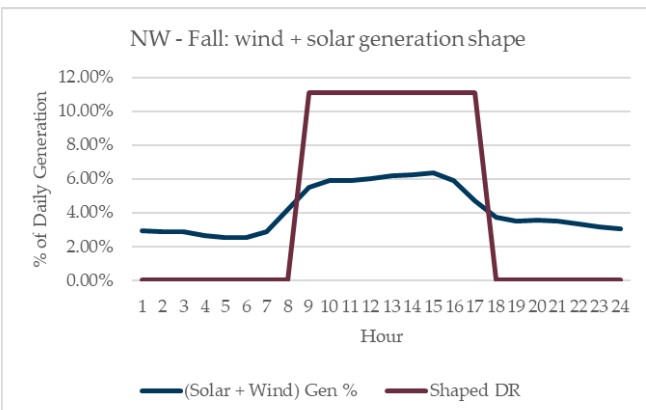
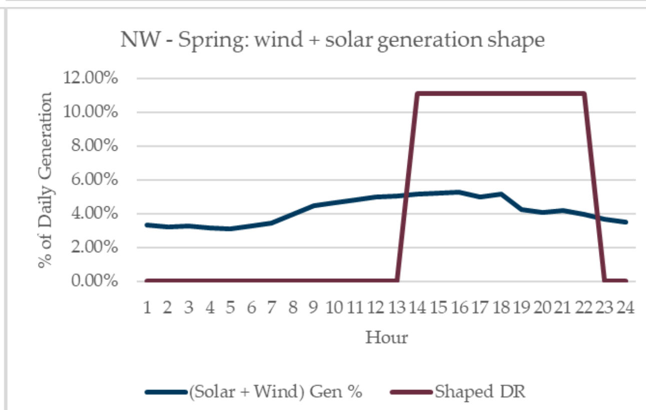
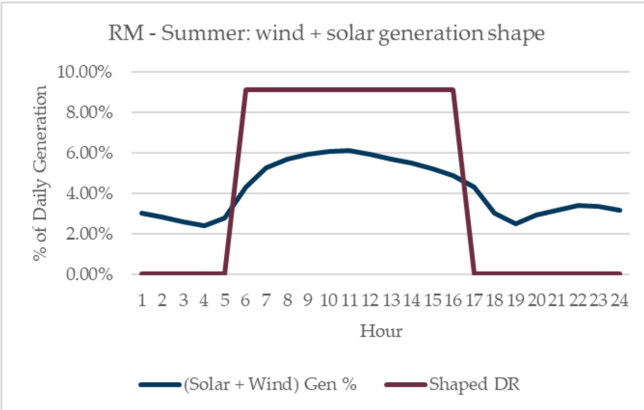


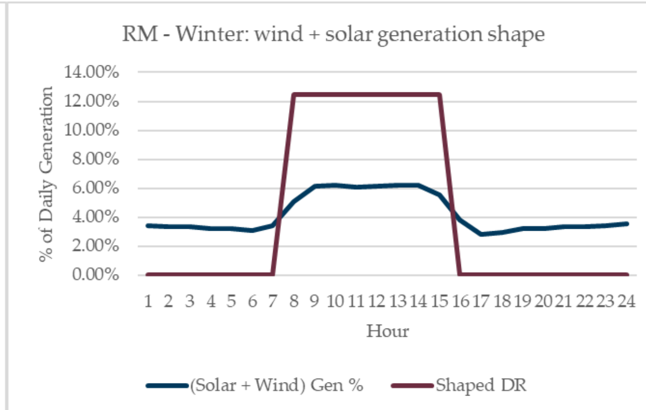


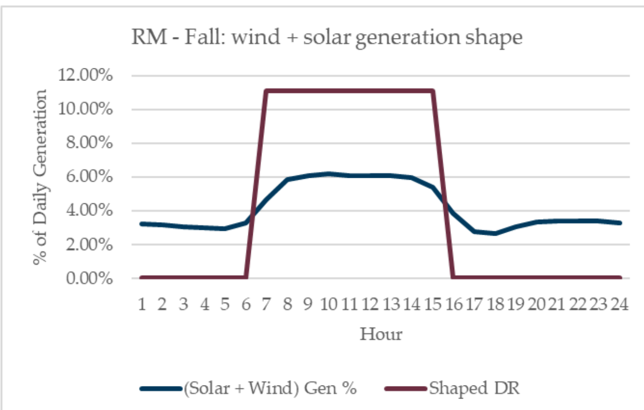


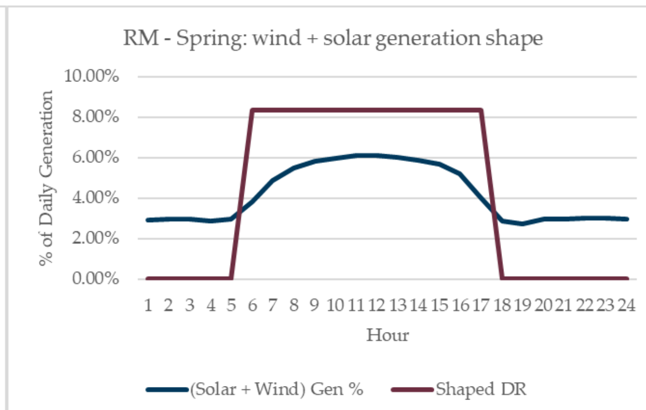


Rocky Mountain (RM)

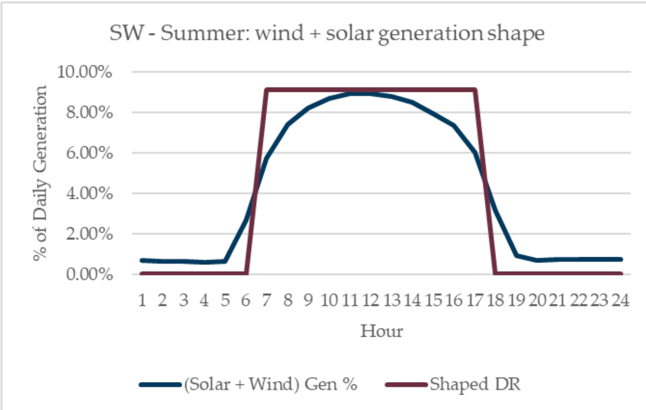


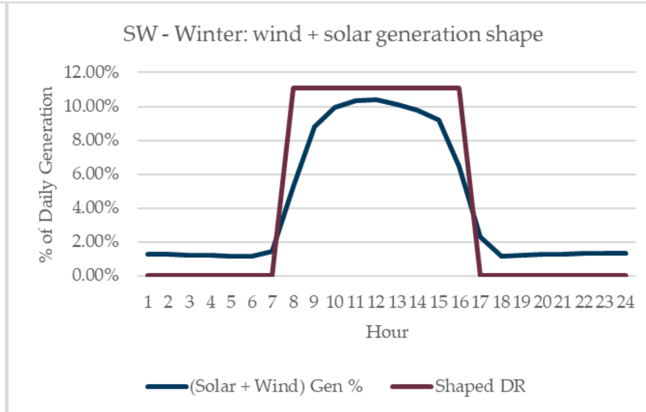


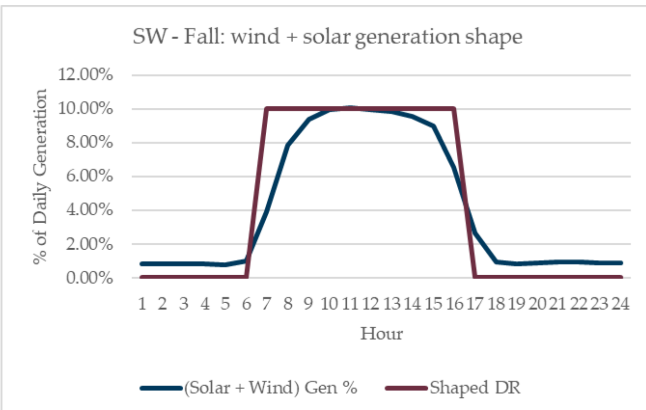


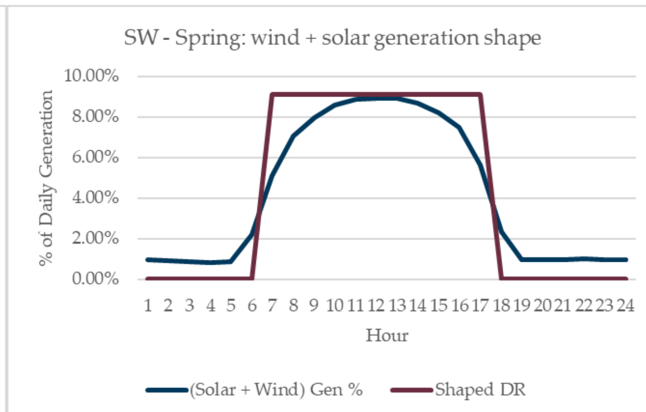


Southwest (SW)



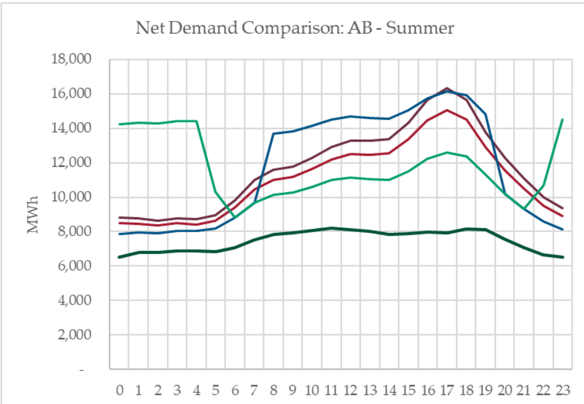


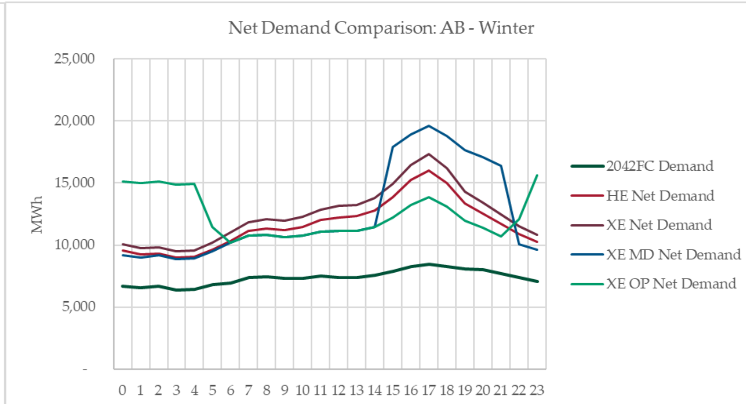


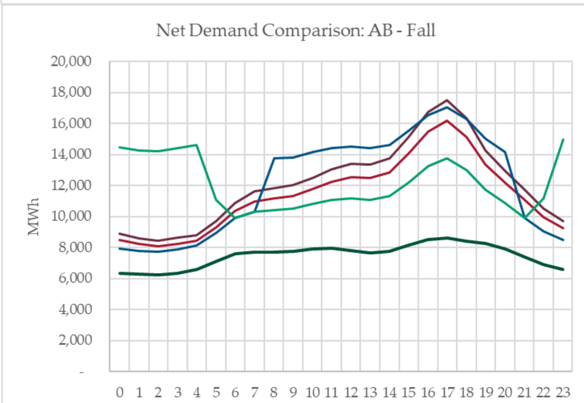


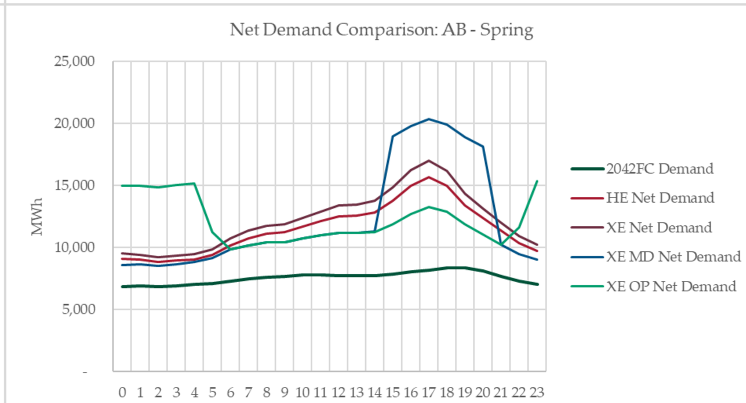
Appendix E. Comparison of Net Demand by Season

Alberta (AB)

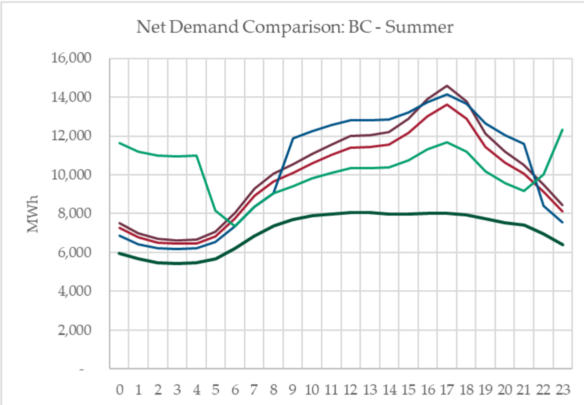


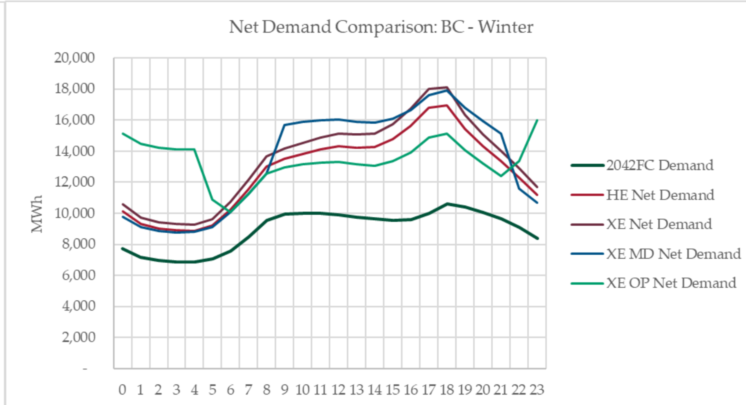


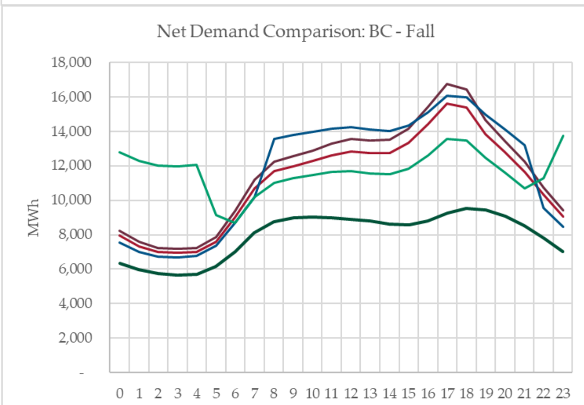


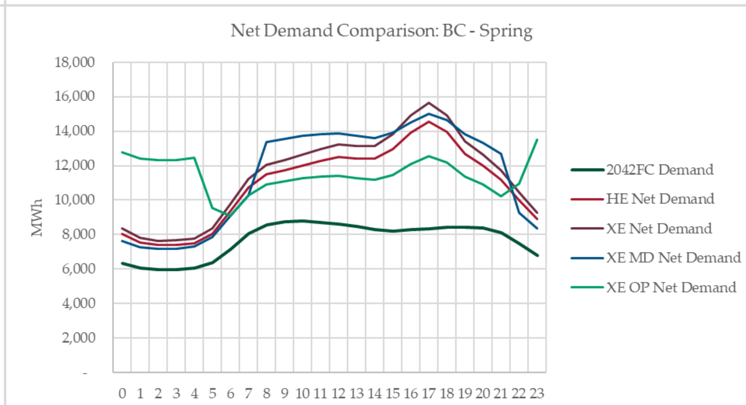


British Columbia (BC)

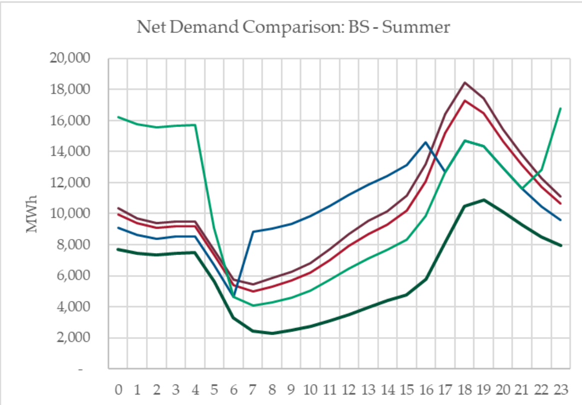


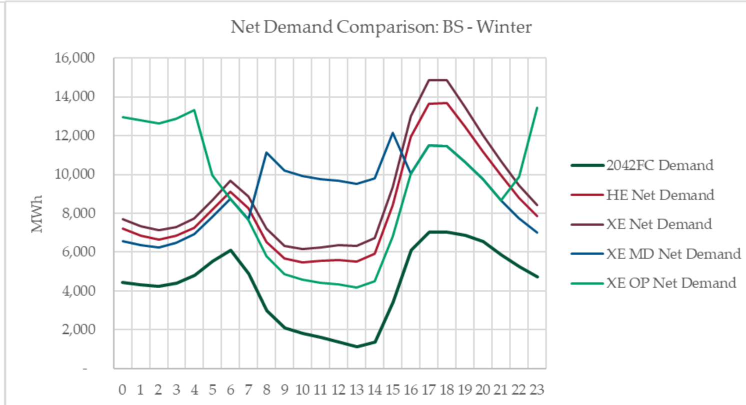


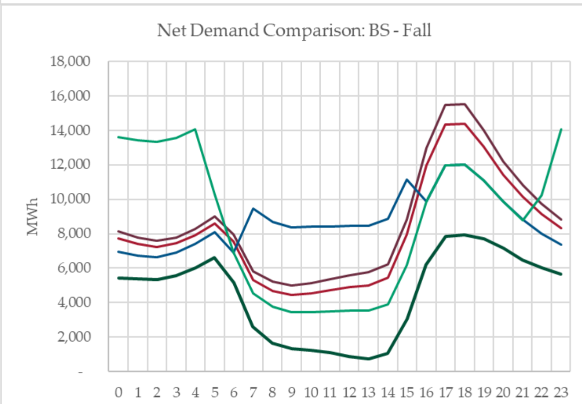


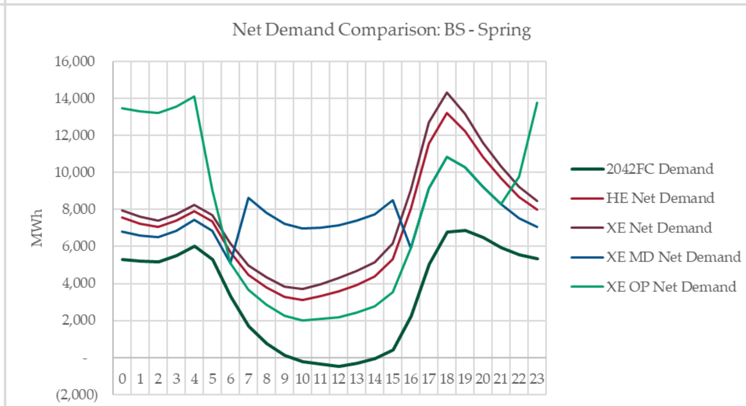


Basin (BS)

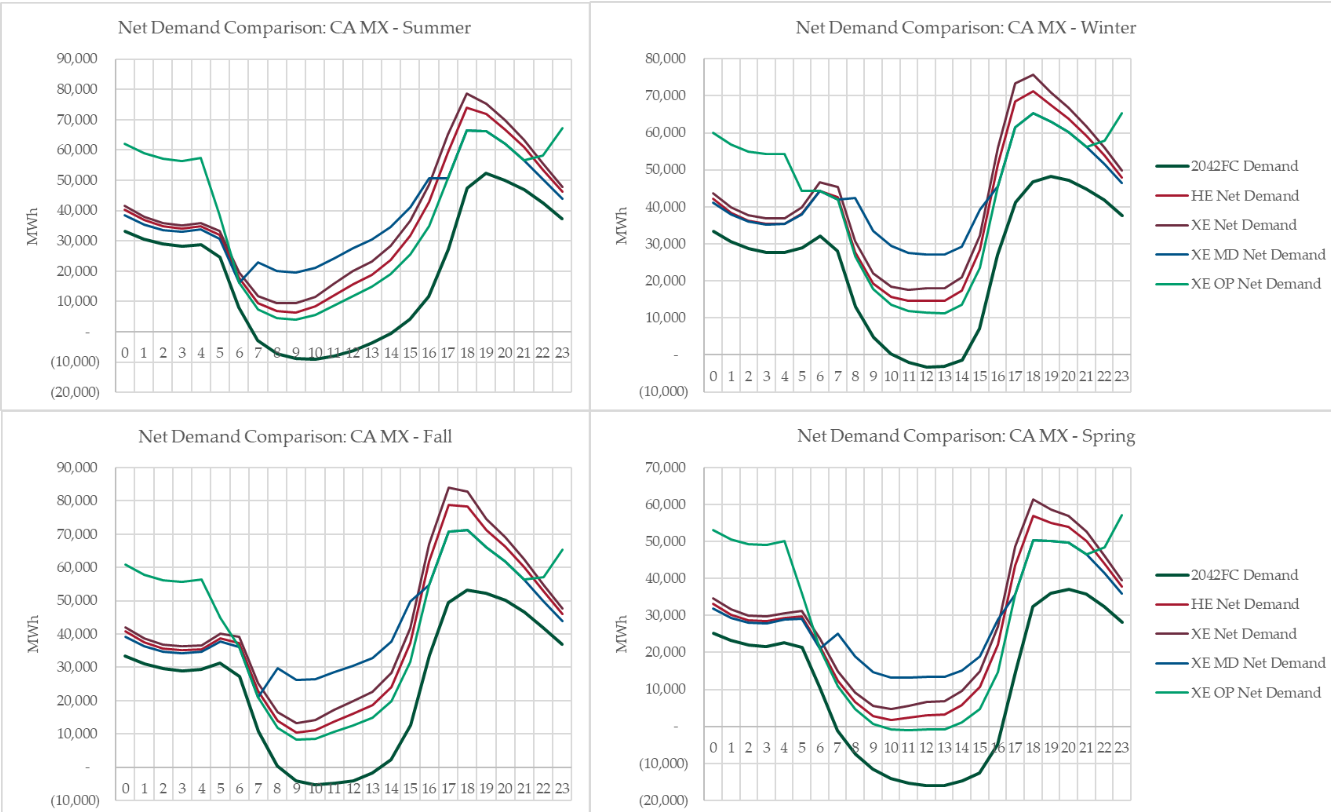

Net Demand Comparison: BS - Summer
MWh
20,000 18,000 16,000 14,000 12,000 10,000 8,000 6,000 4,000 2,000 -
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23


Net Demand Comparison: BS - Winter
MWh
16,000 14,000 12,000 10,000 8,000 6,000 4,000 2,000 -
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
2042FC Demand
HE Net Demand
XE Net Demand
XE MD Net Demand
XE OP Net Demand

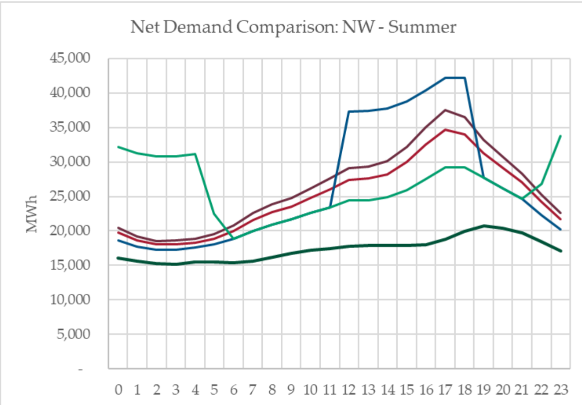

Net Demand Comparison: BS - Fall
MWh
18,000 16,000 14,000 12,000 10,000 8,000 6,000 4,000 2,000 -
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23

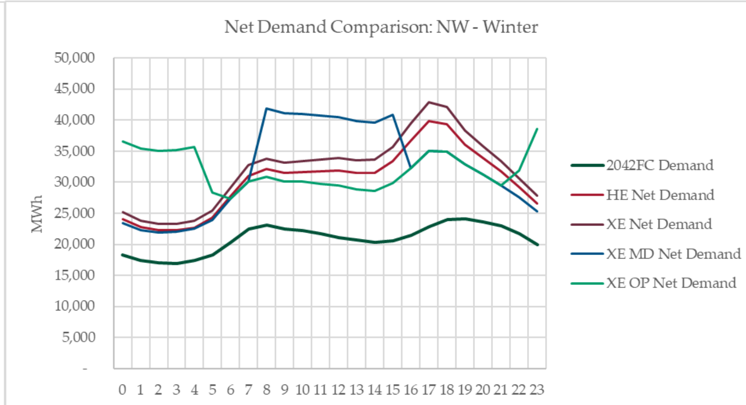

Net Demand Comparison: BS - Spring
MWh
16,000 14,000 12,000 10,000 8,000 6,000 4,000 2,000 - (2,000)
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
2042FC Demand
HE Net Demand
XE Net Demand
XE MD Net Demand
XE OP Net Demand

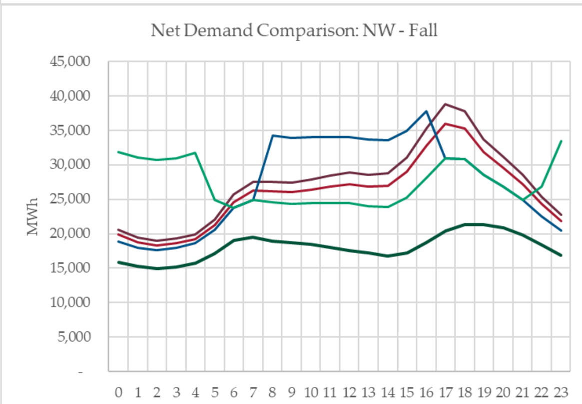
California/Mexico (CAMX)

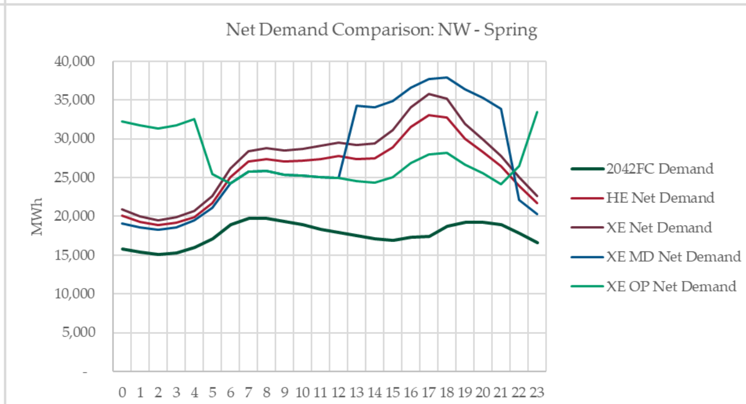


Northwest (NW)

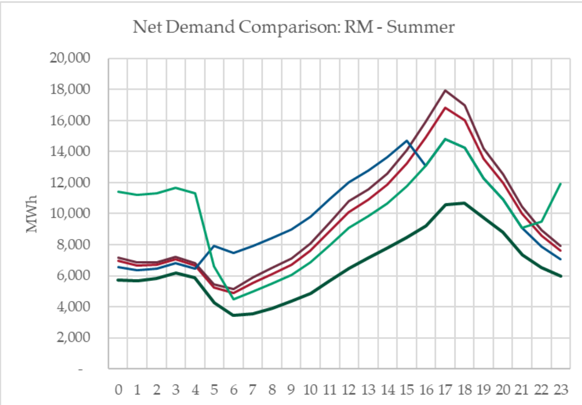


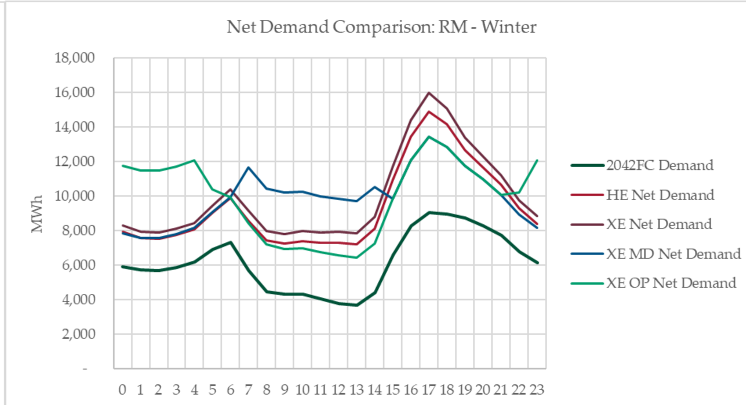


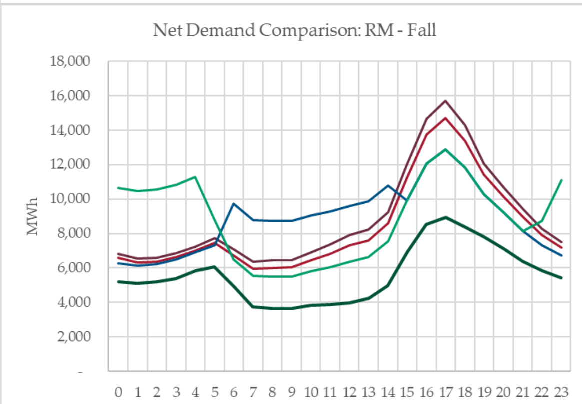


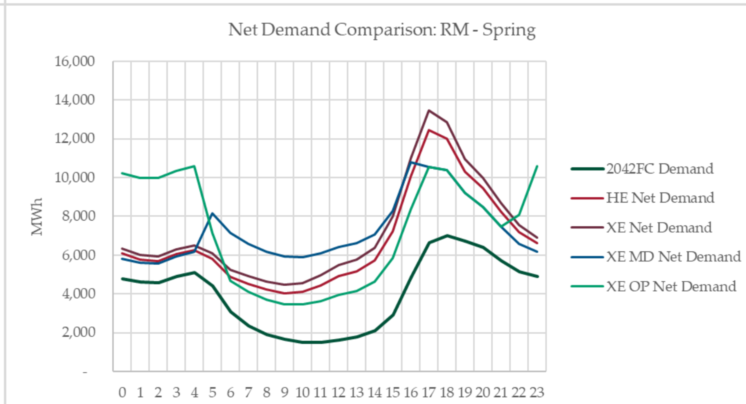


Rocky Mountain (RM)

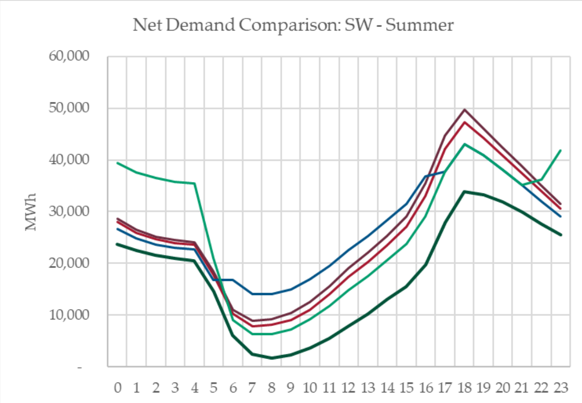


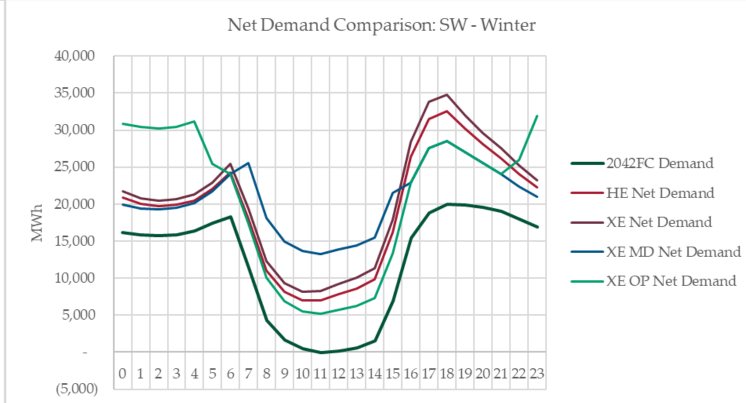


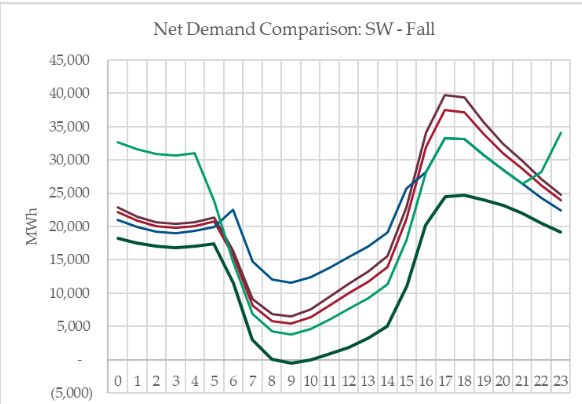


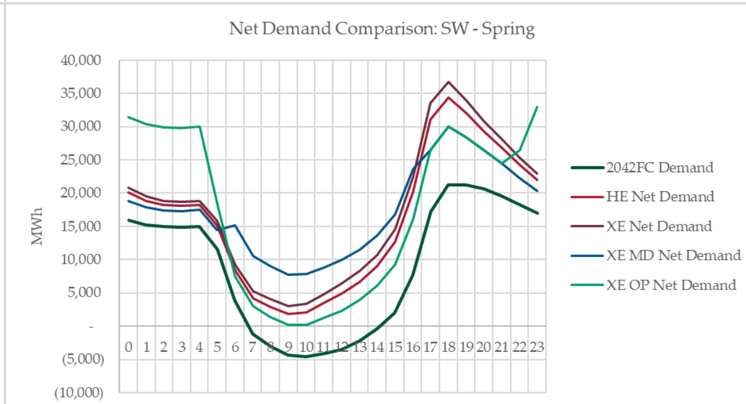


Southwest (SW)



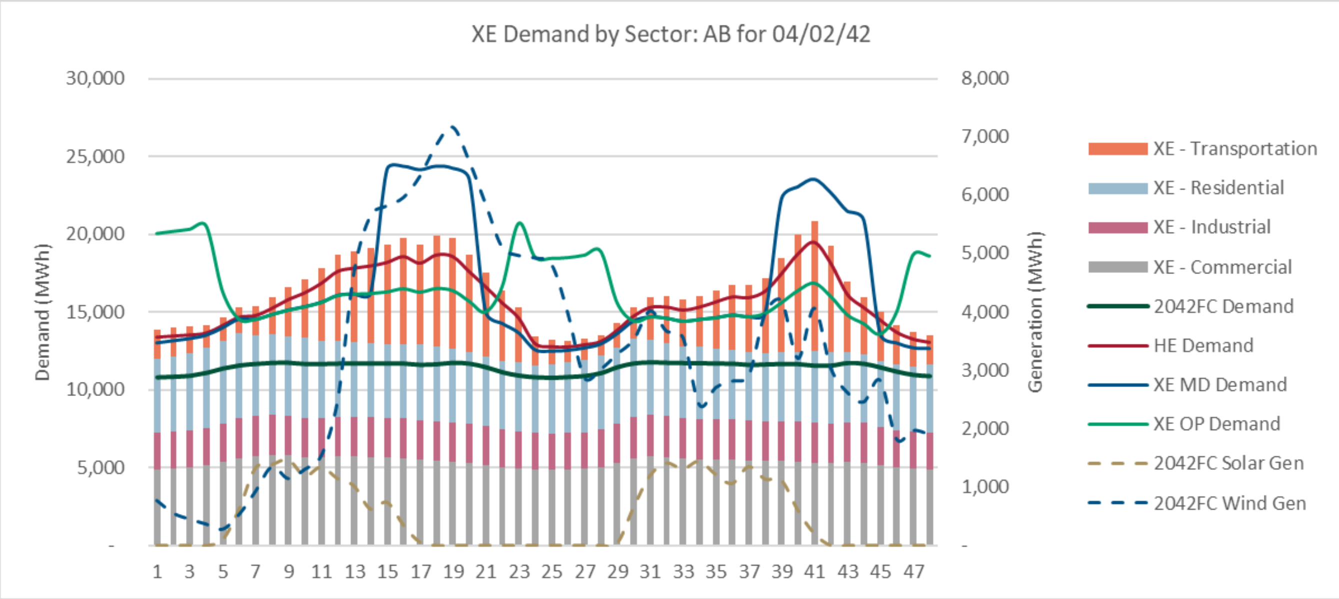


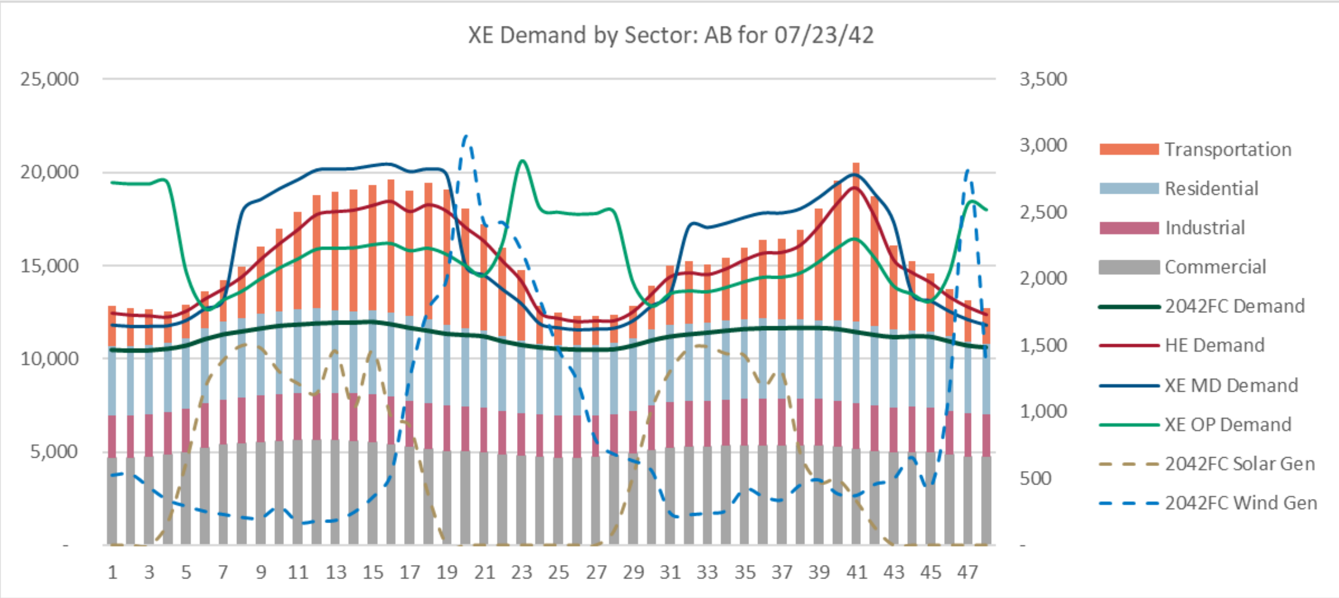




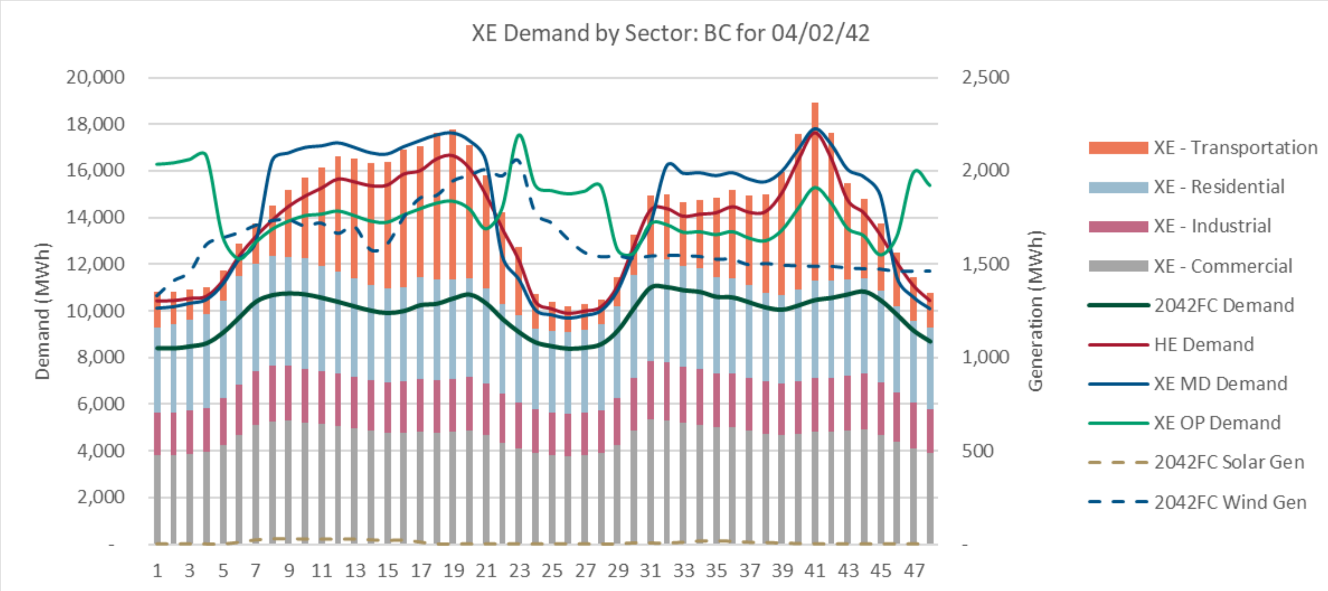
Appendix F. 48-Hour Load Shape Examples

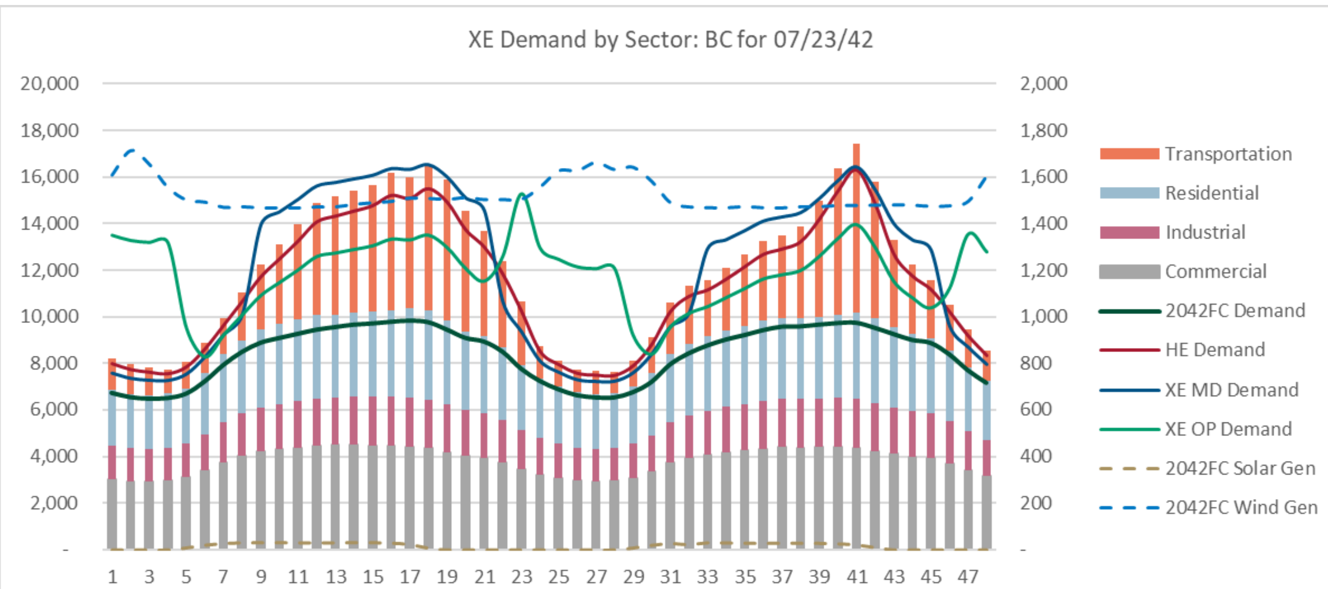
Alberta (AB)



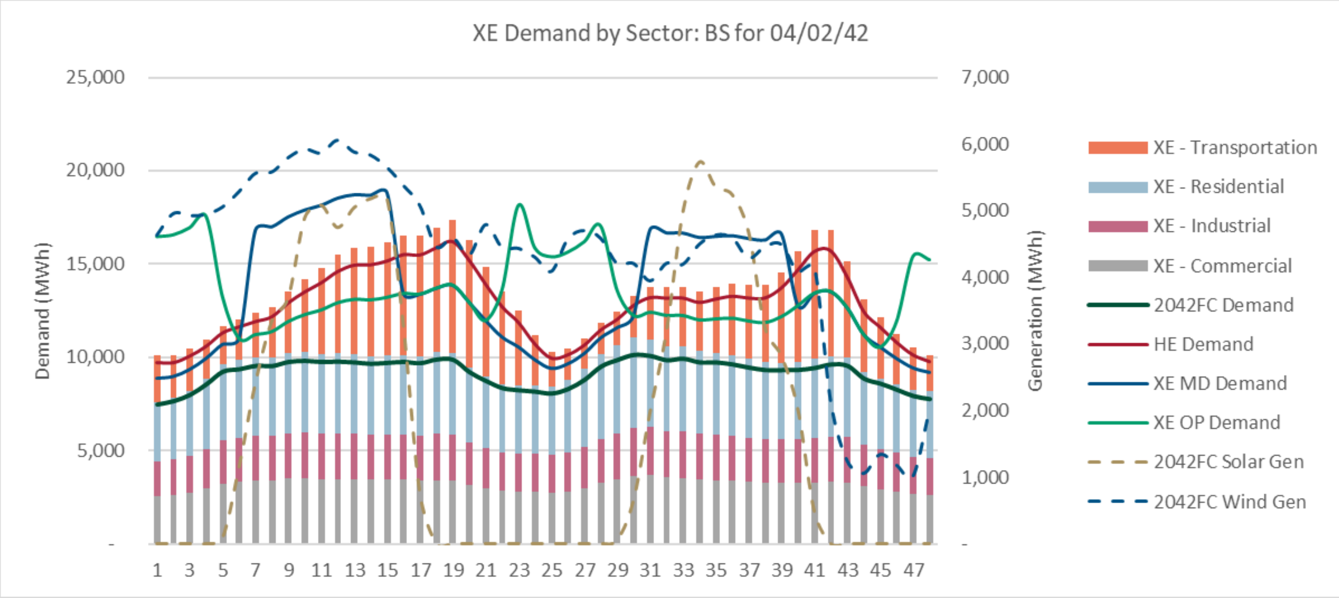


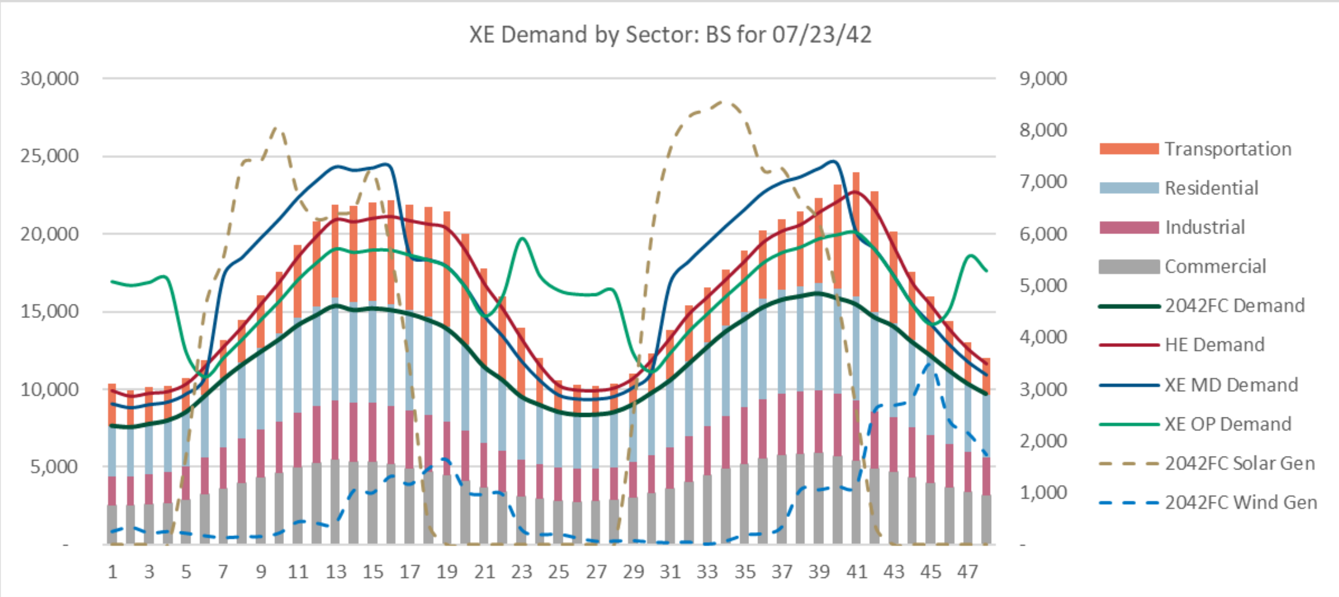
British Columbia (BC)



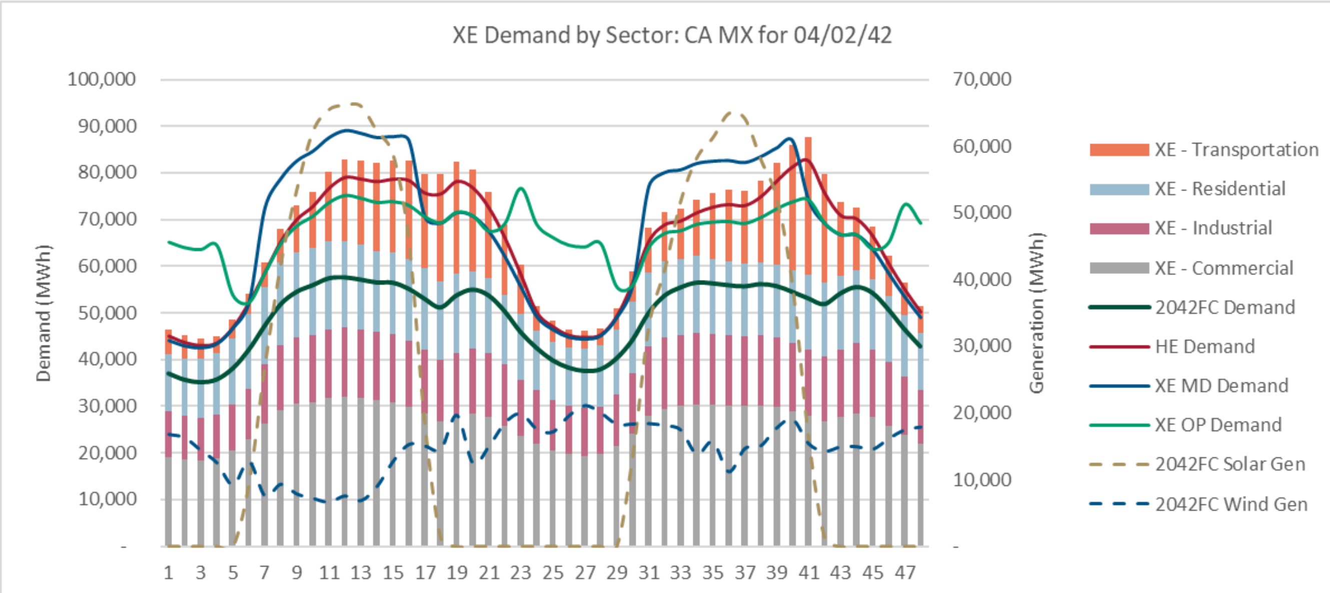


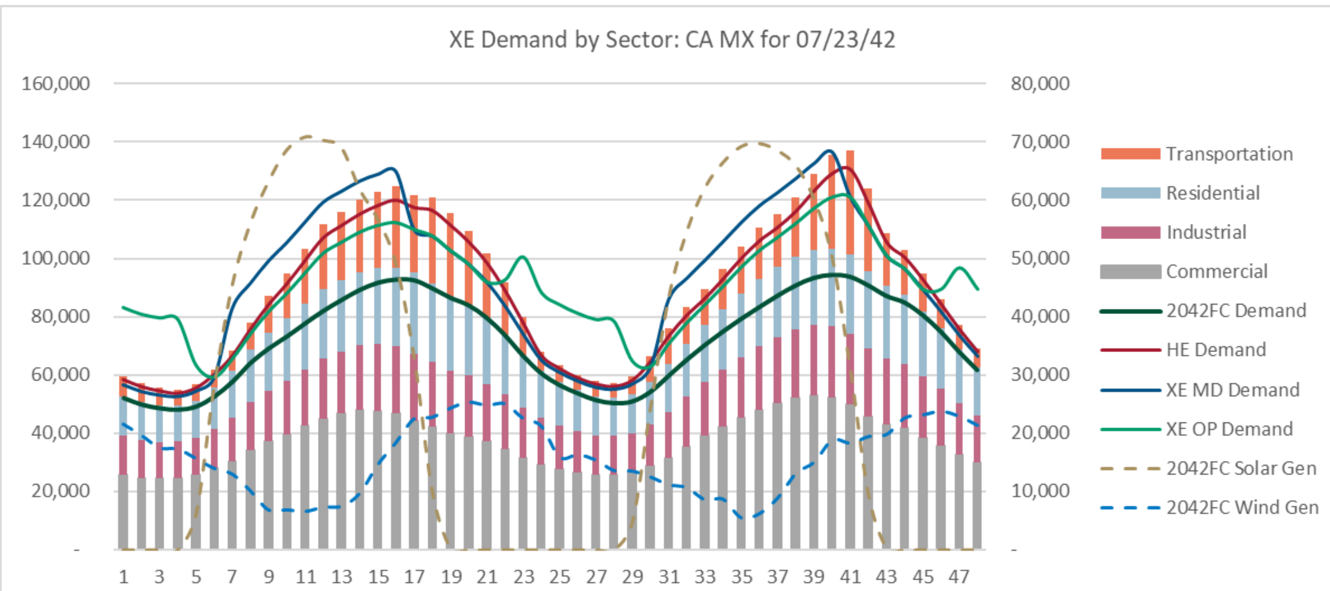
Basin (BS)


XE Demand by Sector: BS for 04/02/42
Demand (MWh)
Generation (MWh)
25,000
20,000
15,000
10,000
5,000
-
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47
XE - Transportation
XE - Residential
XE - Industrial
XE - Commercial
2042FC Demand
HE Demand
XE MD Demand
XE OP Demand
2042FC Solar Gen
2042FC Wind Gen

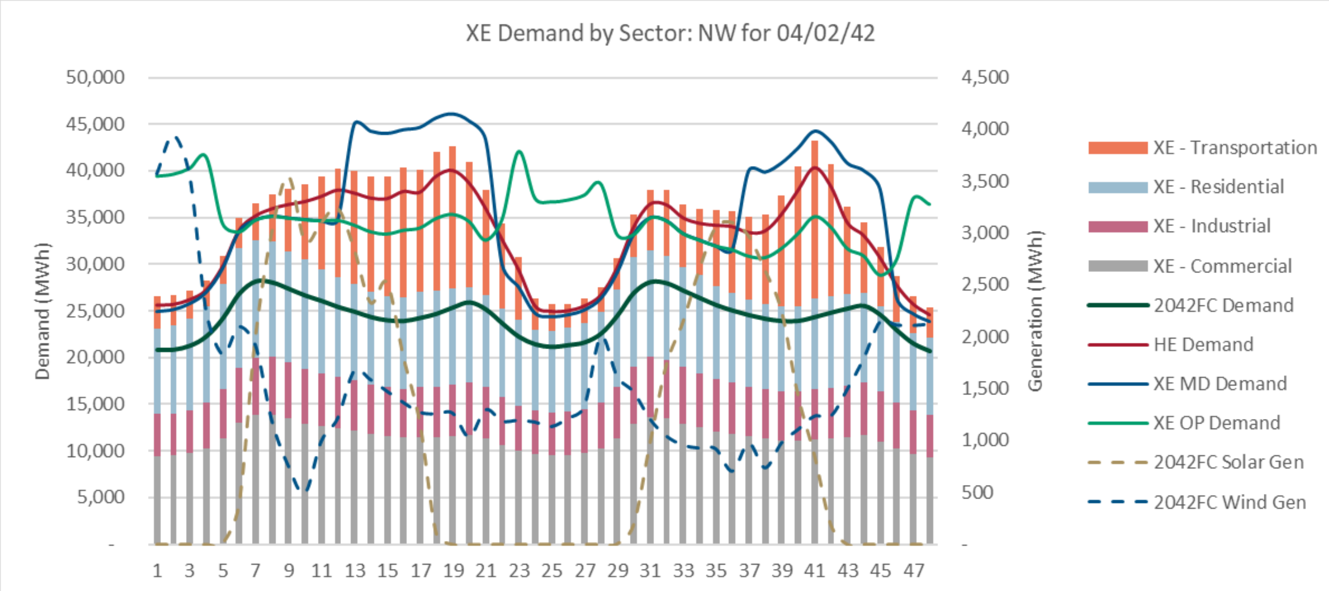

XE Demand by Sector: BS for 07/23/42
30,000
25,000
20,000
15,000
10,000
5,000
-
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47
Transportation
Residential
Industrial
Commercial
2042FC Demand
HE Demand
XE MD Demand
XE OP Demand
2042FC Solar Gen
2042FC Wind Gen

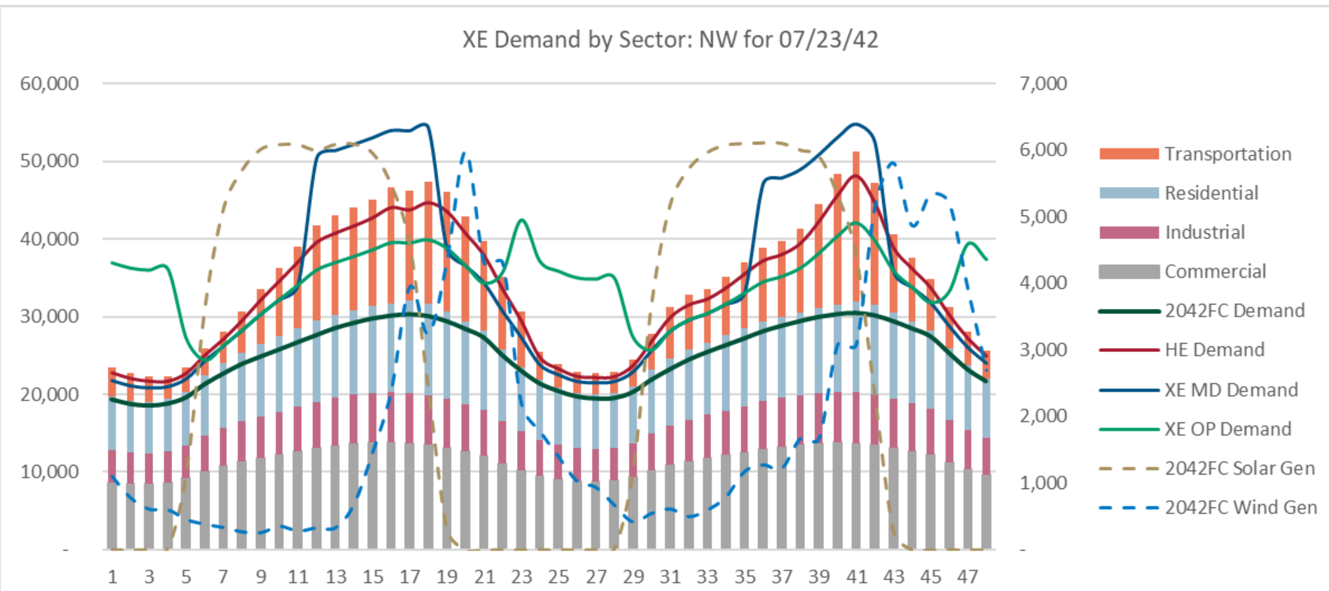
California/Mexico (CAMX)



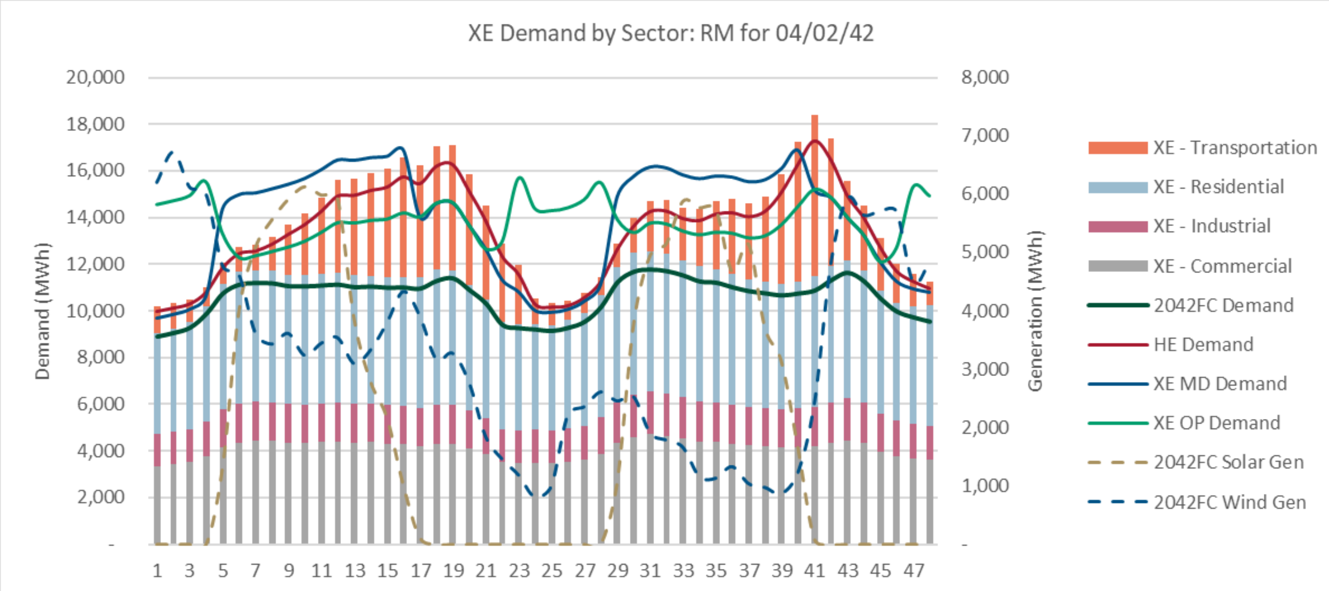


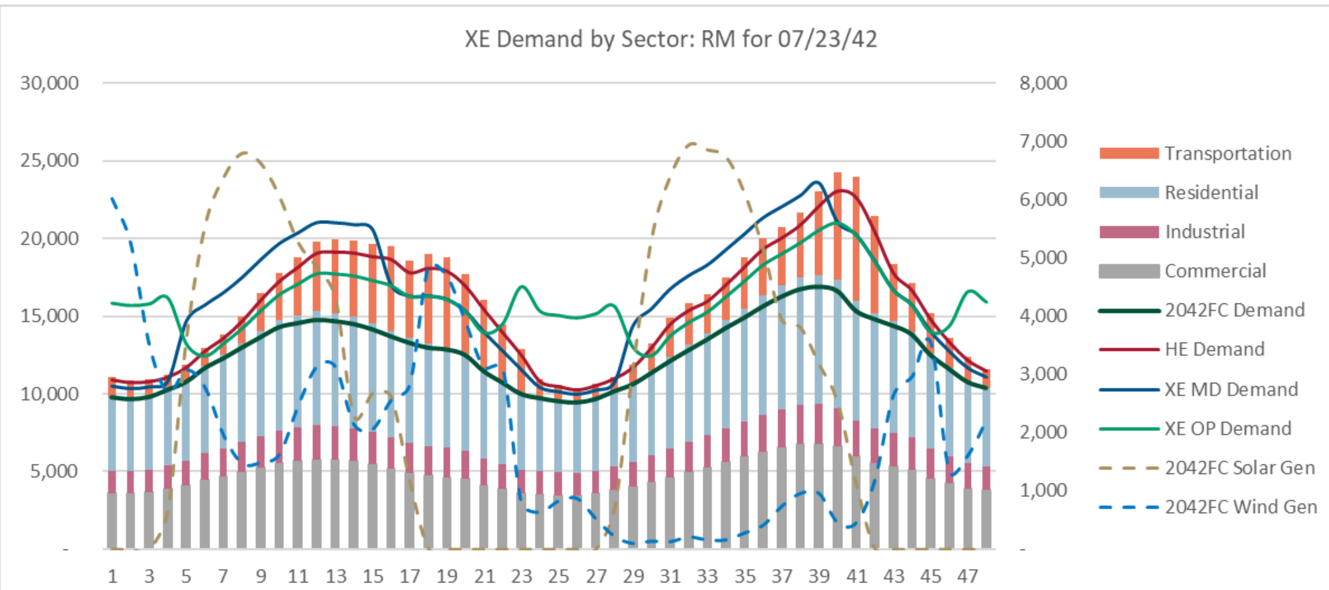
Northwest (NW)



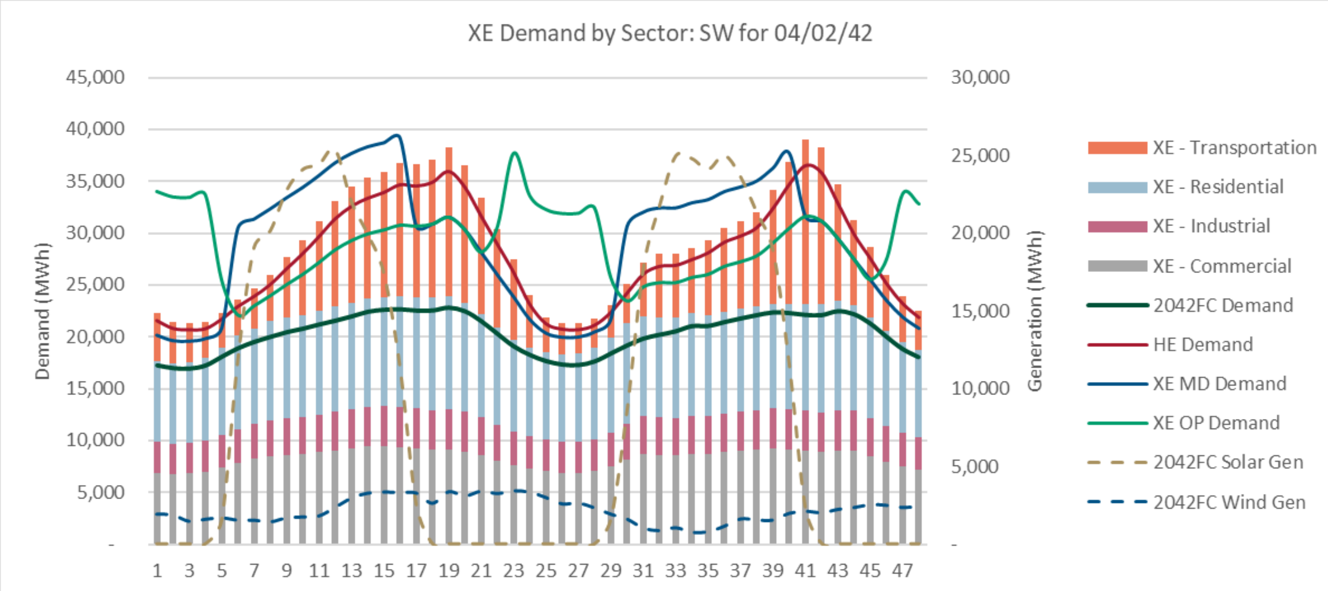


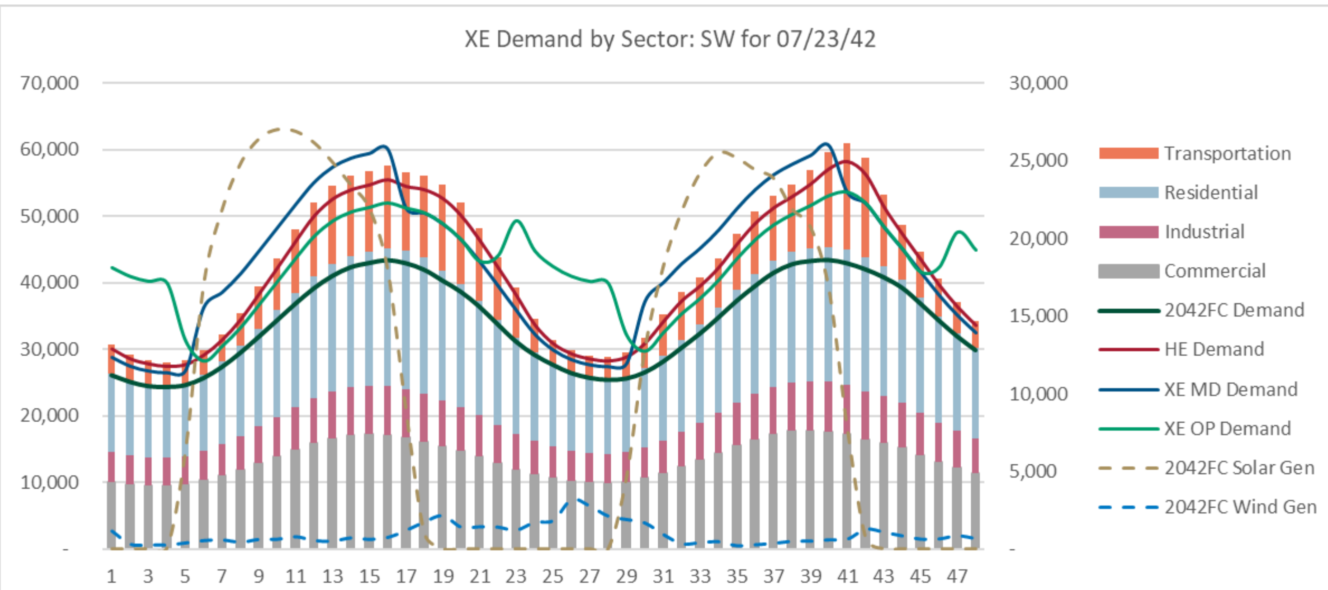
Rocky Mountain (RM)





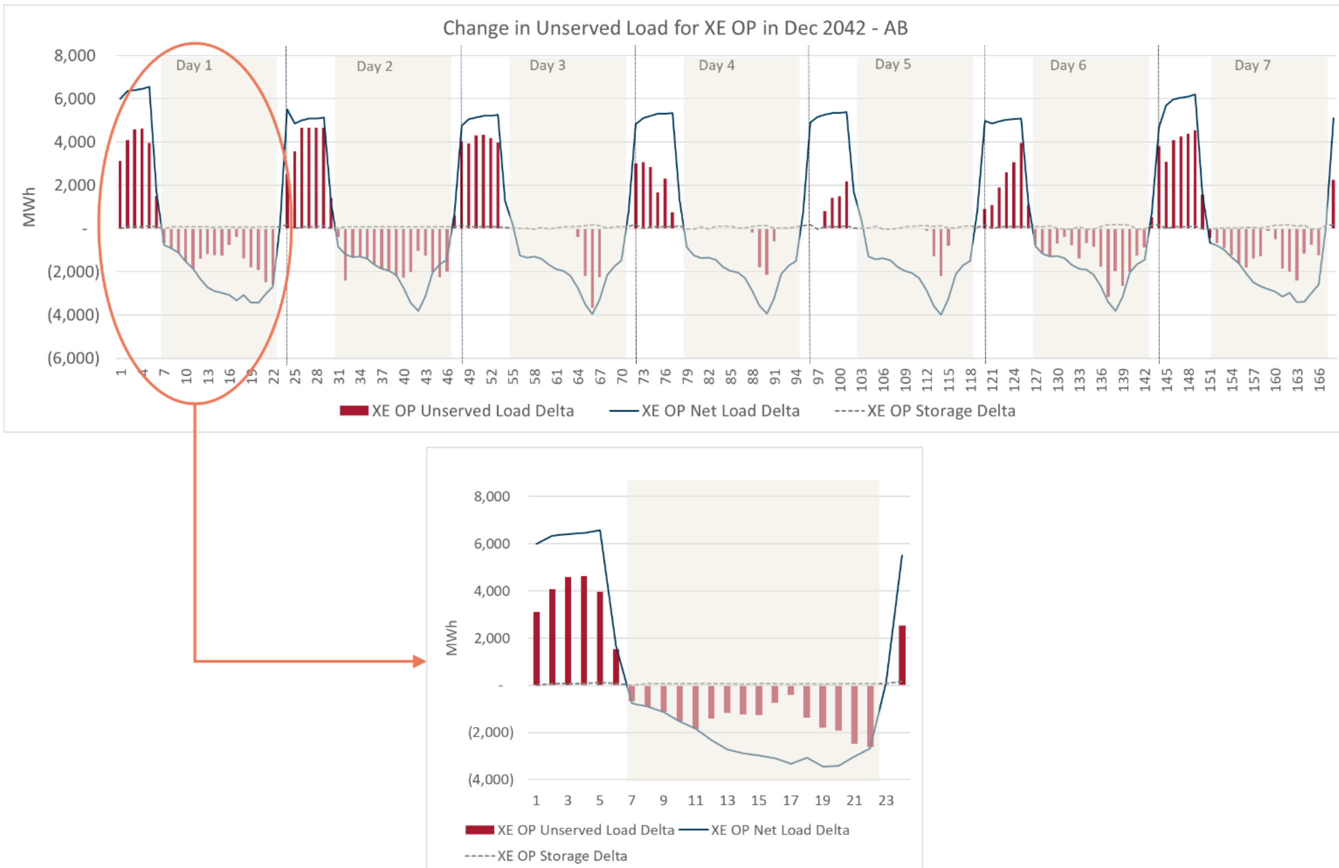
Southwest (SW)



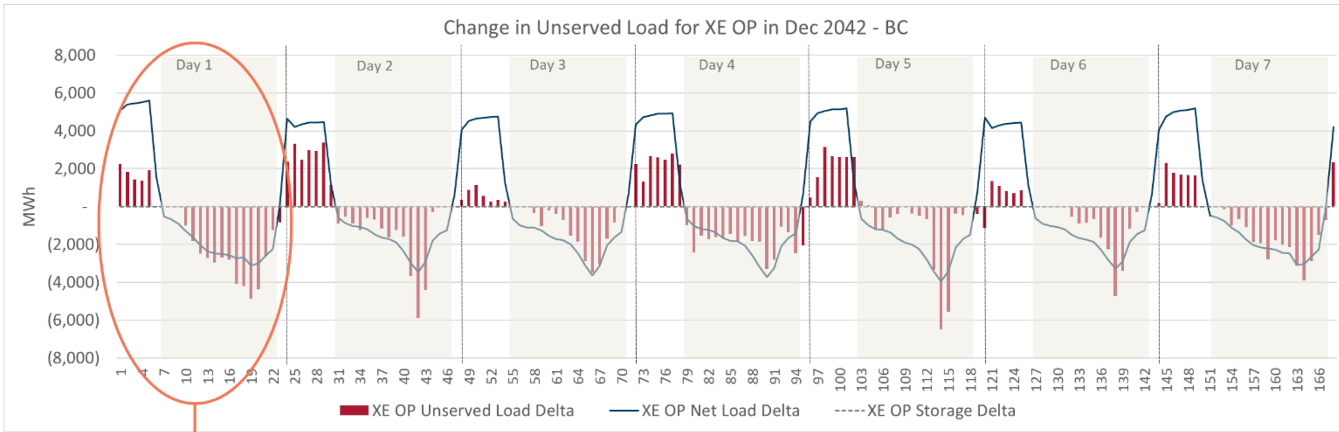


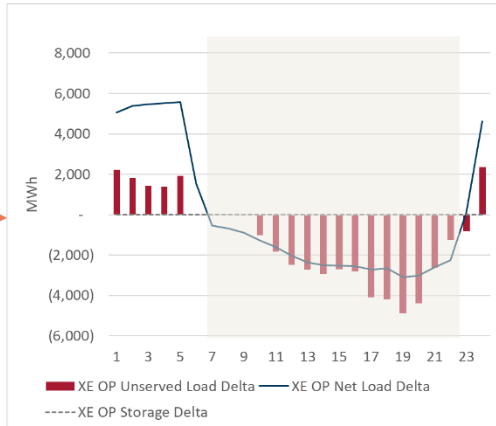
Appendix G. Change in Unserved Load in XE OP Scenario

Alberta (AB)

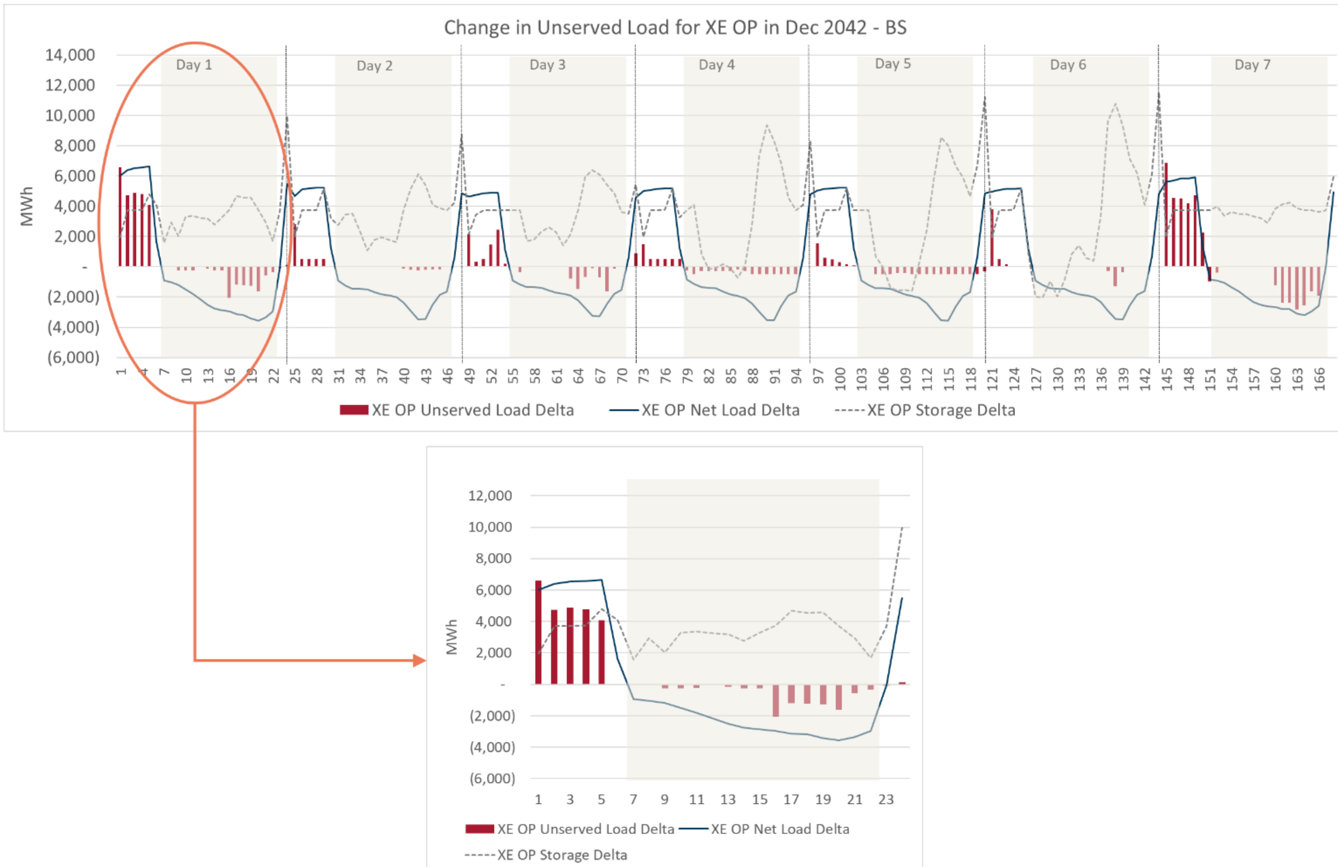


British Columbia (BC)

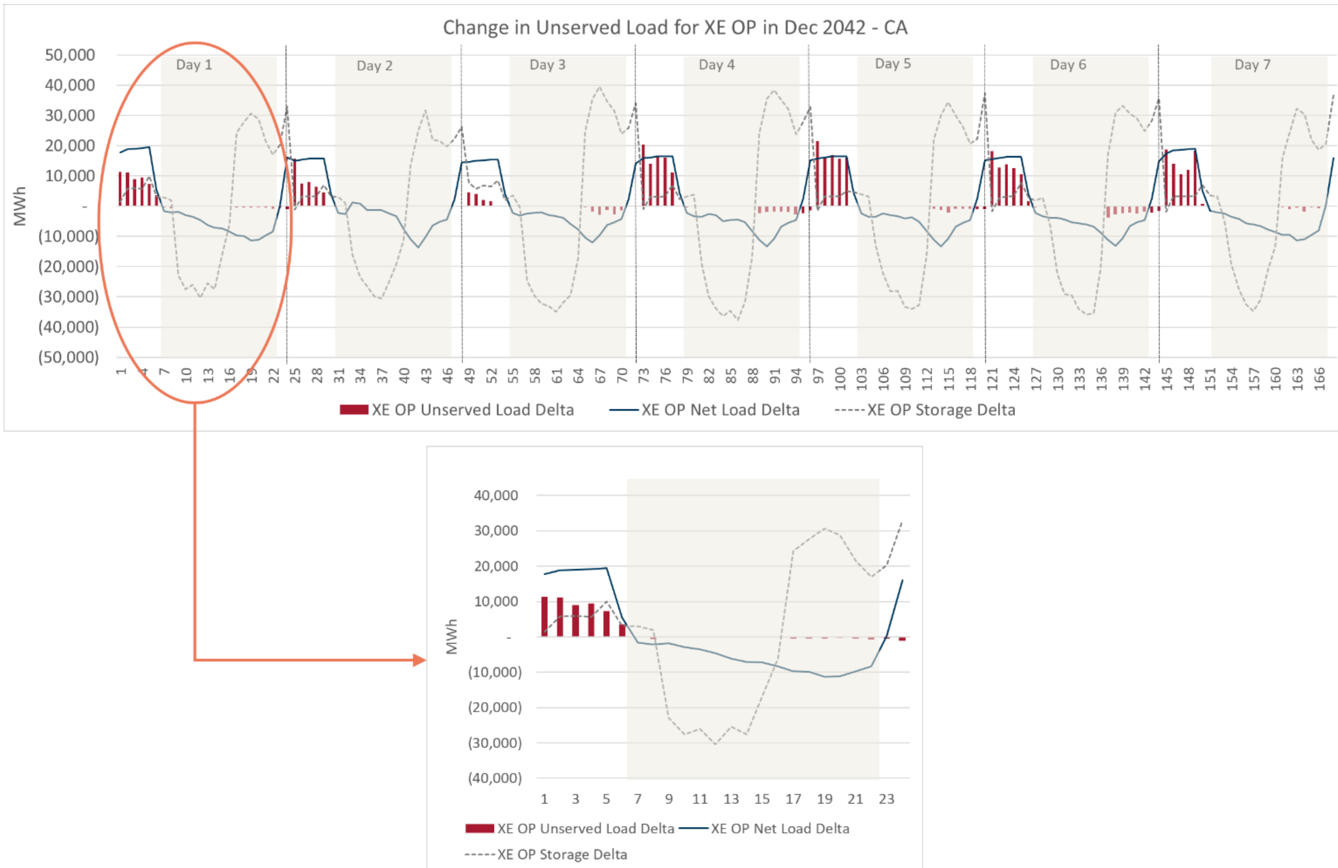




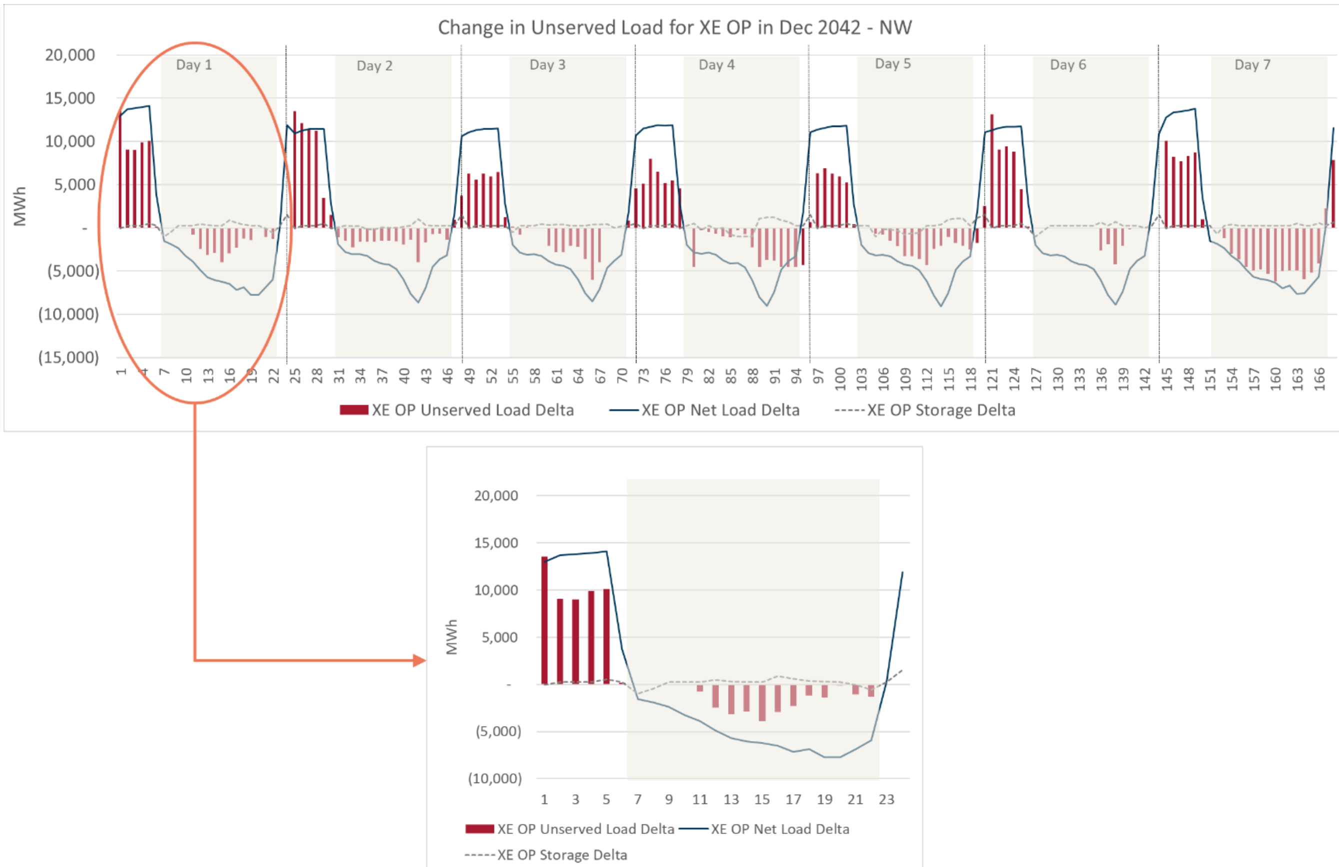
Basin (BS)


Change in Unserved Load for XE OP in Dec 2042 - BS
MWh
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
(2,000)
(4,000)
(6,000)
Day 1
Day 2
Day 3
Day 4
Day 5
Day 6
Day 7
XE OP Unserved Load Delta
XE OP Net Load Delta
XE OP Storage Delta
1
3
5
7
9
11
13
15
17
19
21
23

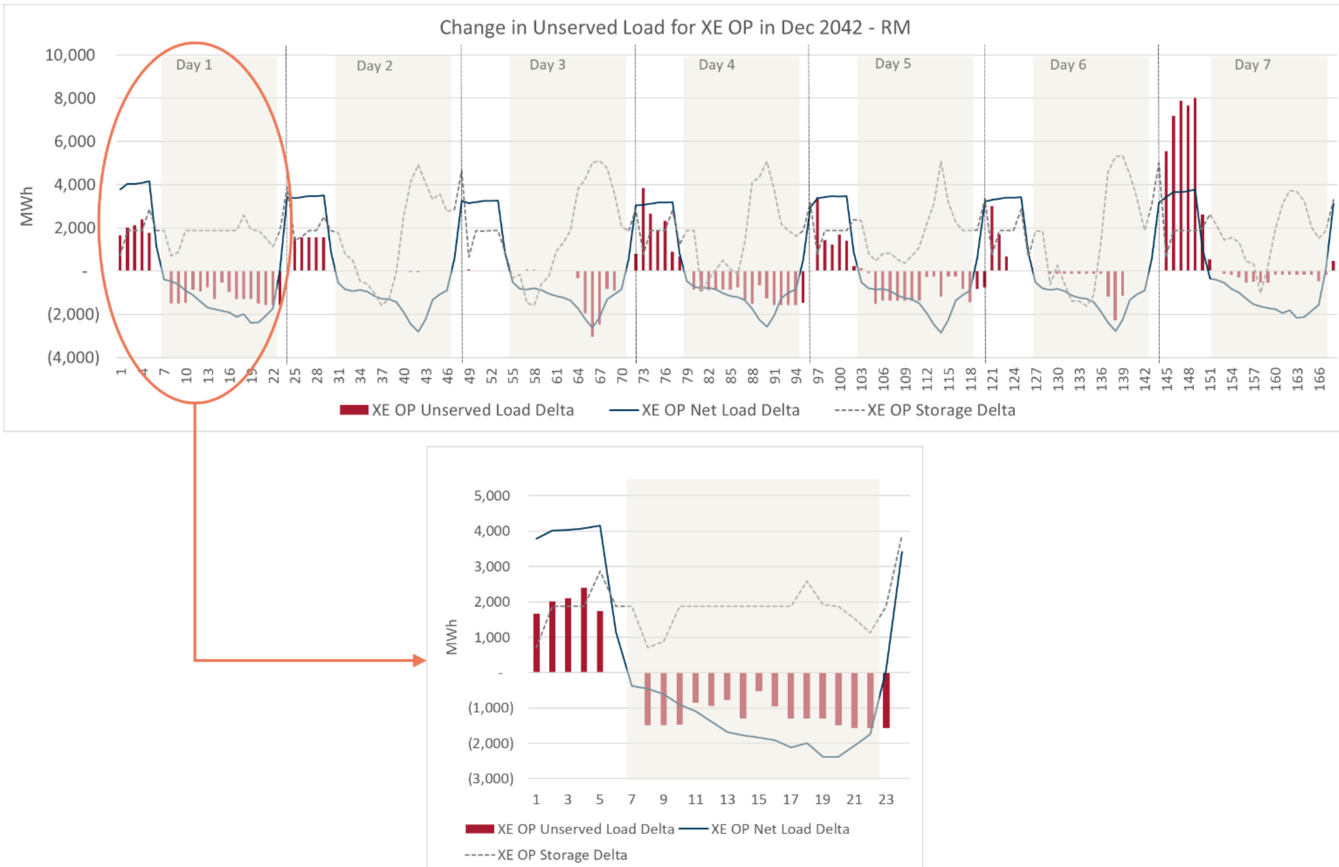
California/Mexico (CAMX)



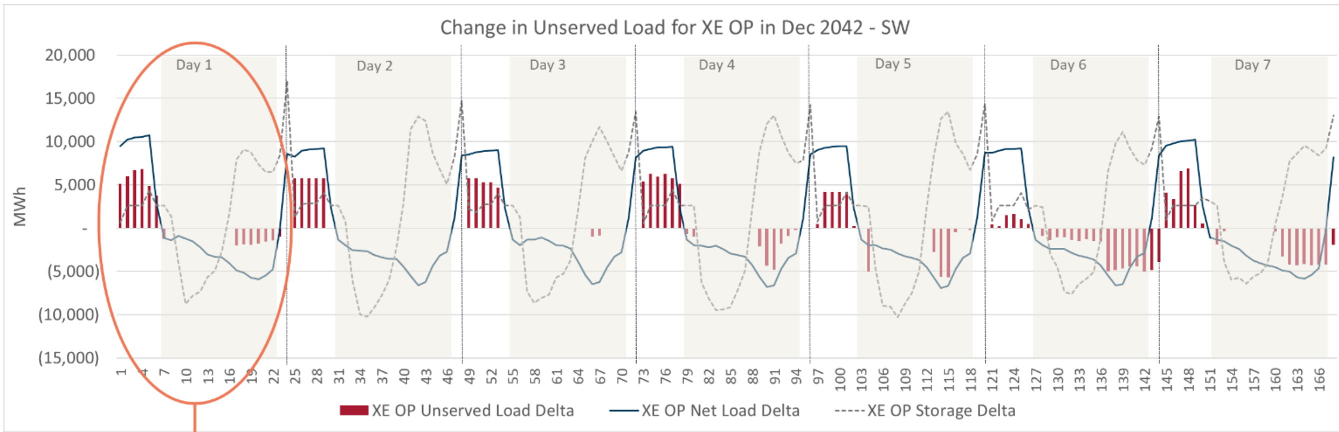
Northwest (NW)

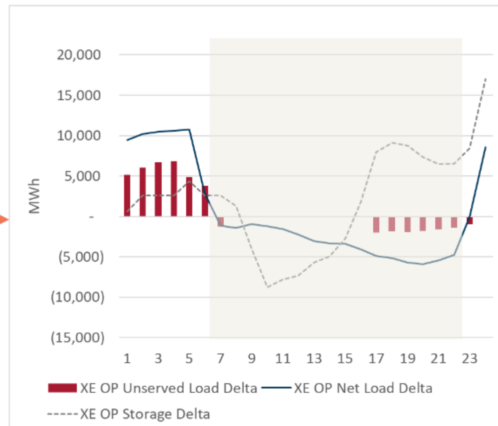


Rocky Mountain (RM)



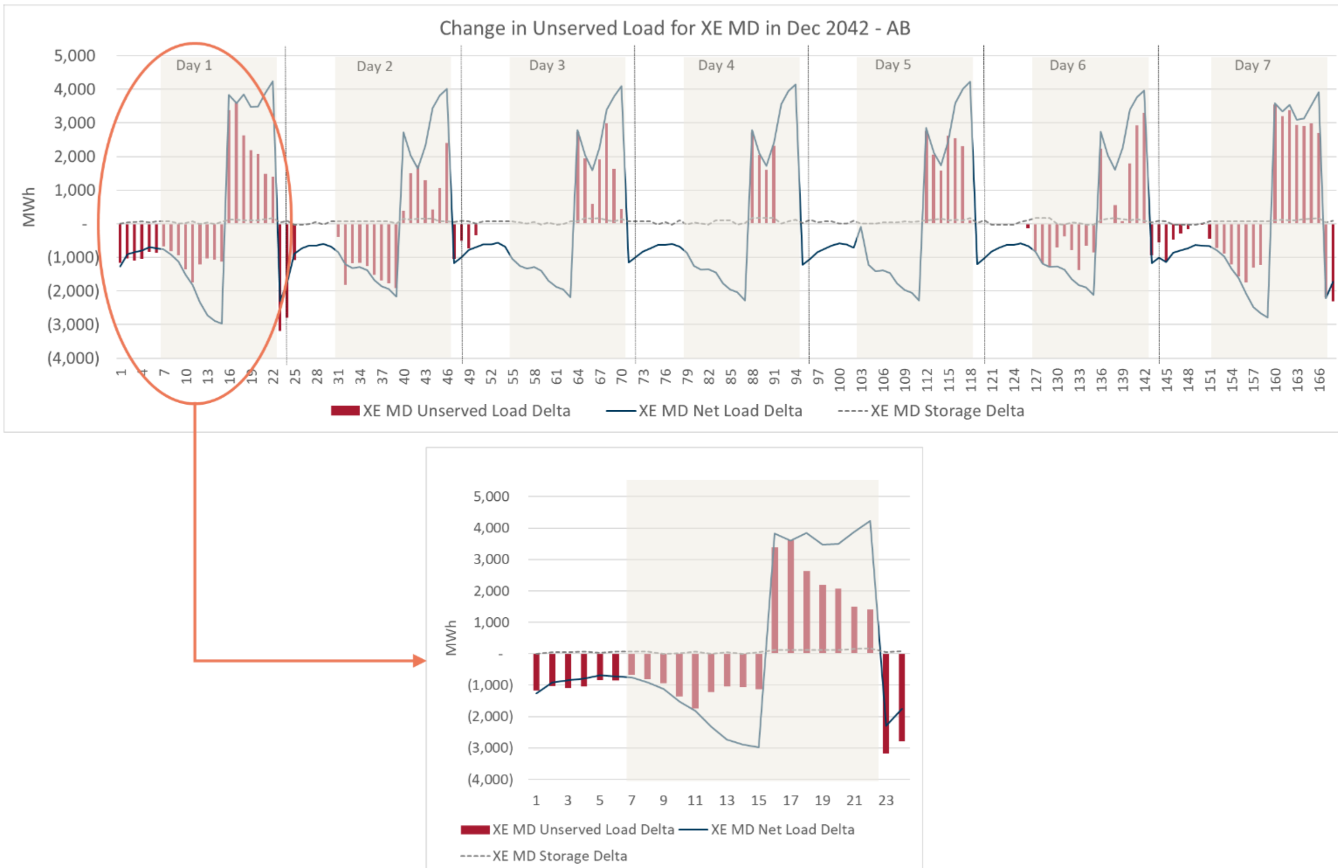
Southwest (SW)



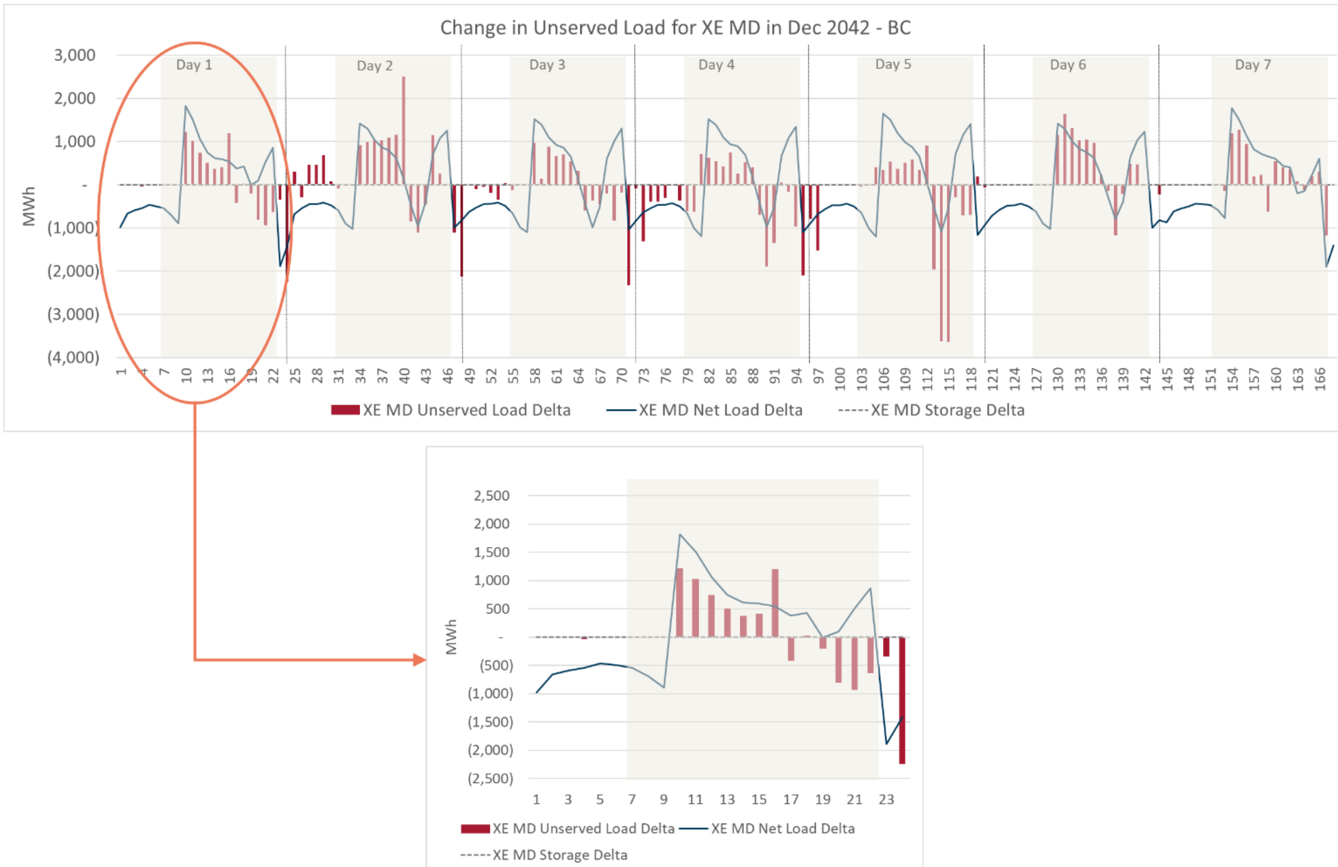


Appendix H. Change in Unserved Load in XE MD Scenario

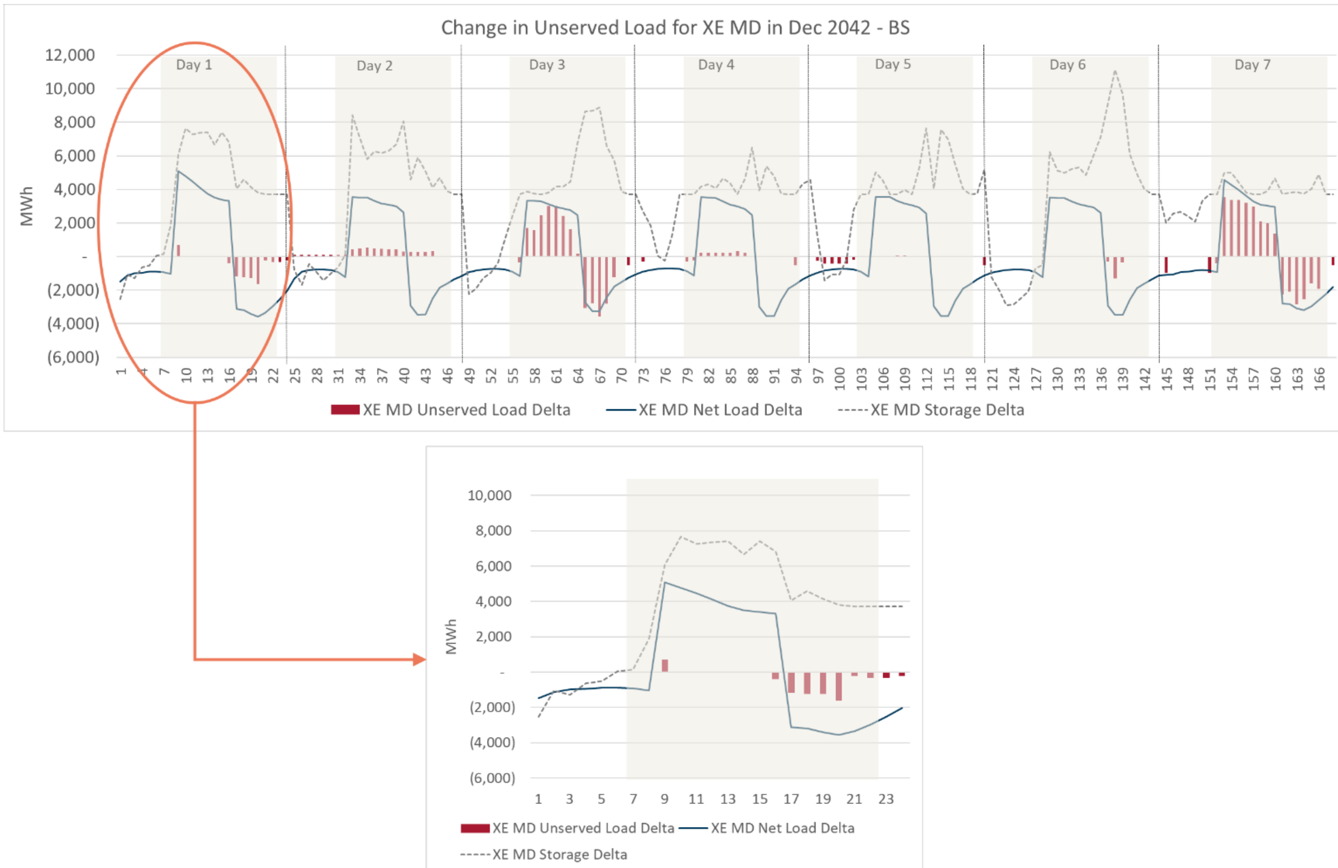
Alberta (AB)



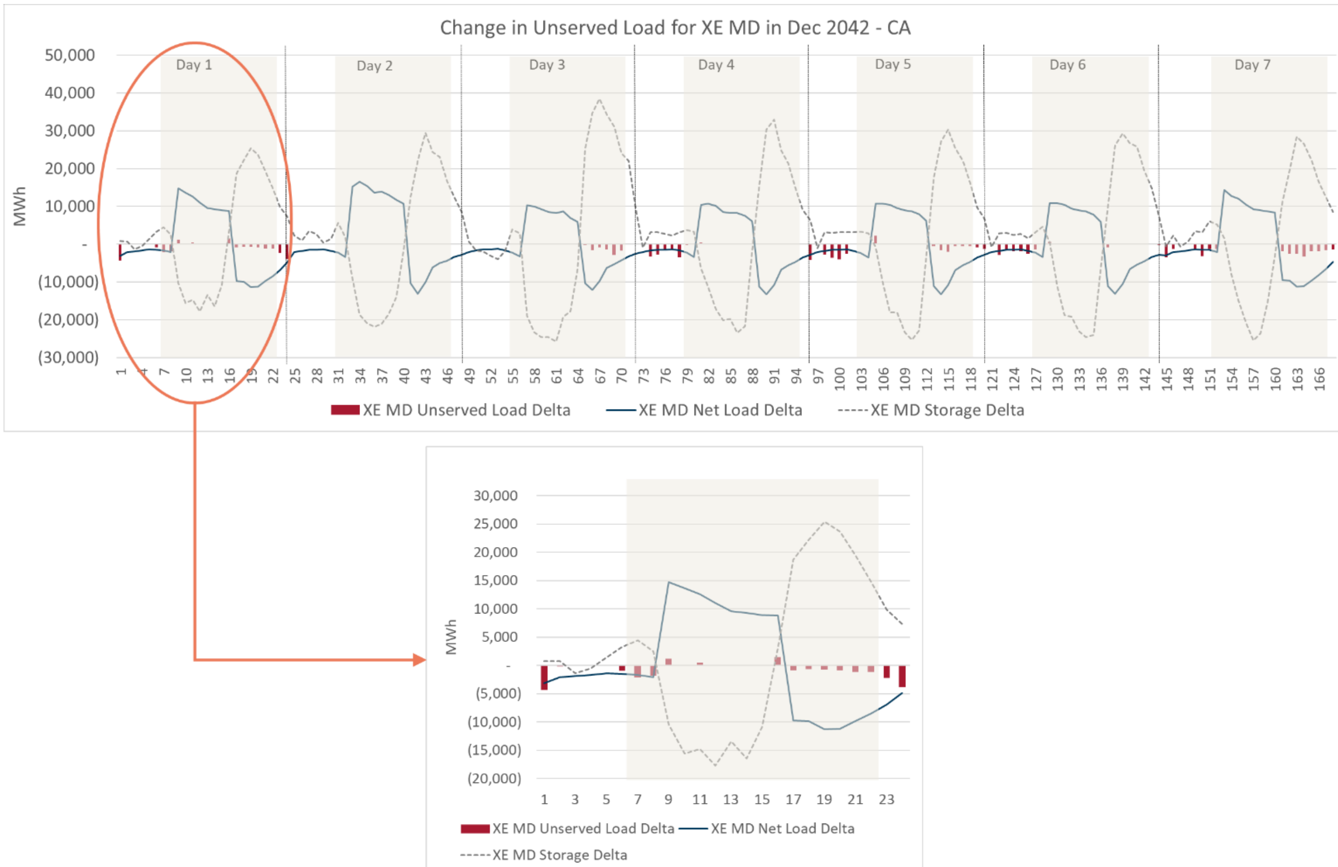
British Columbia (BC)



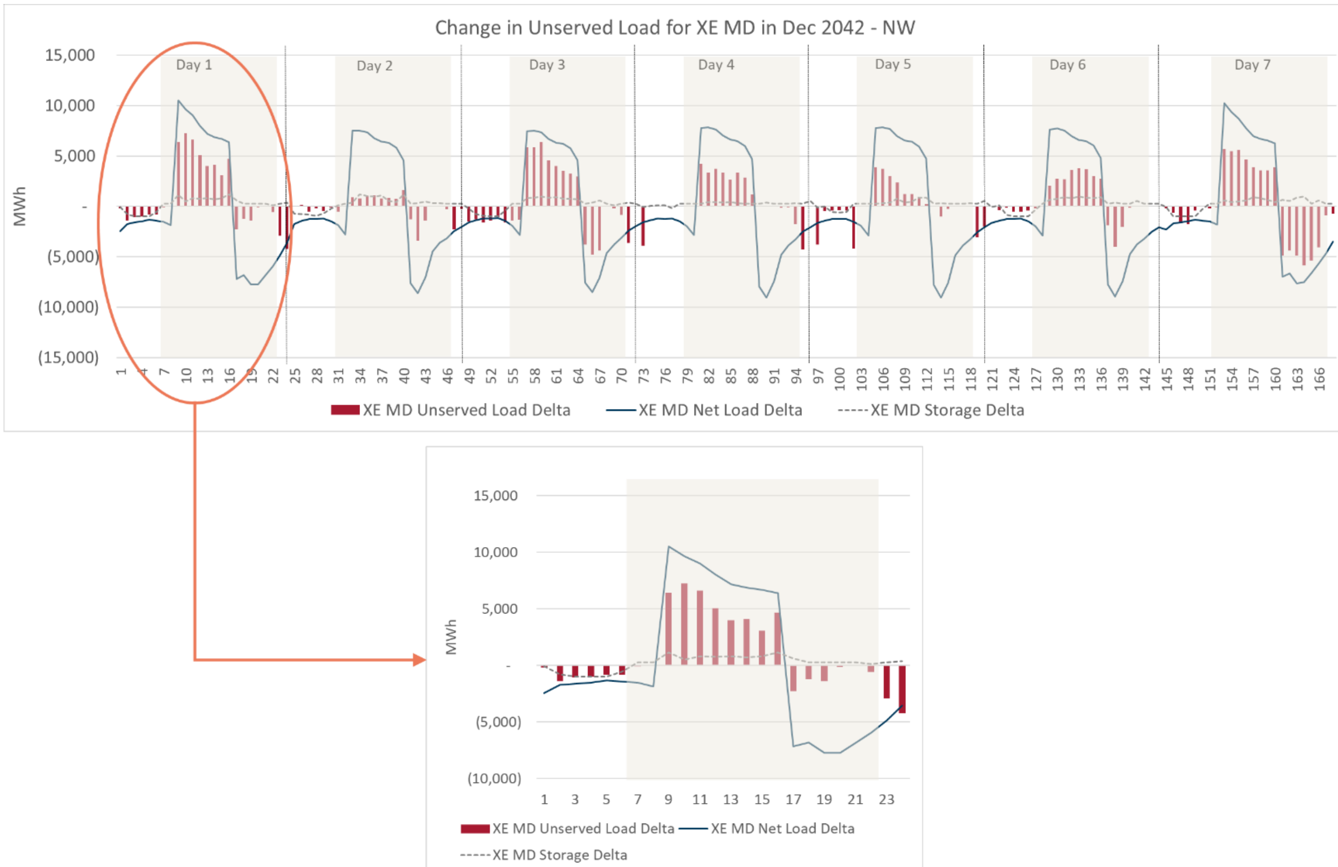
Basin (BS)


Change in Unserved Load for XE MD in Dec 2042 - BS
MWh
Day 1
Day 2
Day 3
Day 4
Day 5
Day 6
Day 7
XE MD Unserved Load Delta
XE MD Net Load Delta
XE MD Storage Delta

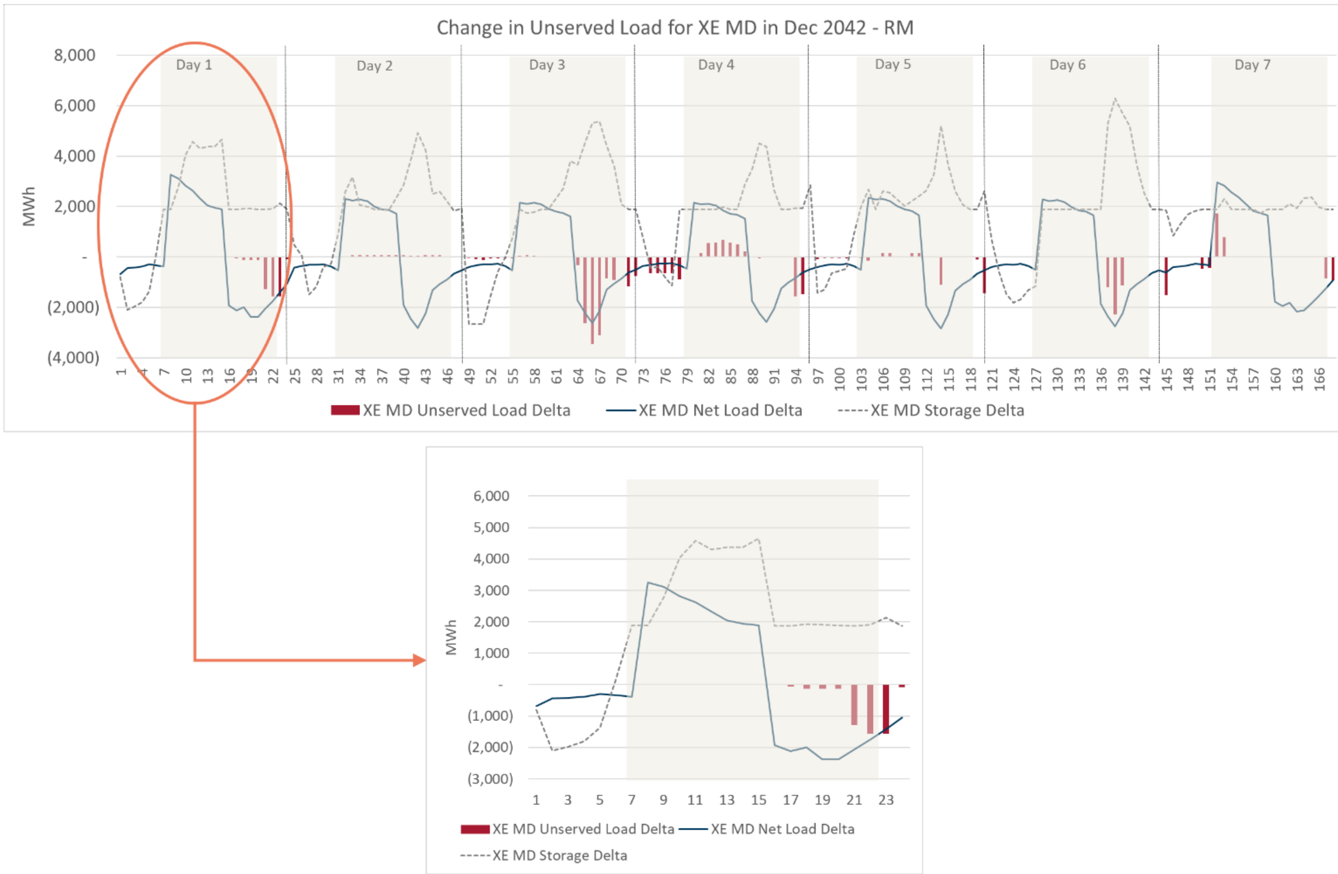
California/Mexico (CAMX)



Northwest (NW)



Rocky Mountain (RM)



Southwest (SW)