WECC

Load, Resource, and Transmission Trends in the Year 20 Future

March 31, 2024

Executive Summary

WECC assesses system performance under a range of future scenarios that may present reliability risks. Historically, WECC has studied potential risks in the Year 10 time frame. In 2023, WECC began developing its capability to assess risks in a Year 20 time frame. WECC started by building a Year 20 Foundational Case (Y20 FC), which provides a reasonable set of business-as-usual assumptions as an analytical baseline against which WECC tested three risk-based scenarios set in 2042:

- Year 20 Extreme Cold Weather Event
- Year 20 Extreme Hot Weather Event
- Year 20 Compound Load Impacts

This developing work has provided important insights into potential future risks to the Western Interconnection and revealed opportunities to continue improving WECC's modeling capabilities.

Year 20 Extreme Cold Weather Event Study

Compared to WECC's [Year 10 Extreme Cold Weather Event Study](), the system in this Year 20 study was more sensitive to cold weather impacts as load loss occurred under less stressed conditions.

Sufficient availability of natural gas generation was critical to serve load in this study. Reduced solar and wind output and increased load caused the Western Interconnection to rely heavily on natural gas generation. Natural gas units ran at maximum capacity but were unable to keep up, eventually leading to unserved load.

Transmission flows increased going to the northern part of the Western Interconnection on several major WECC paths.

Figure 1: WECC Modeling Subregions

Year 20 Extreme Hot Weather Event Study

When the solar and wind output and load data from the August 2020 heat event were extrapolated to 2042, there were nearly 1 million MWh of unserved load. Eliminating the unserved load required a simulated load reduction of more than 15% below the actual load during the August 2020 heat event.

Unserved load occurred in all subregions except Alberta and British Columbia. Canada remained unaffected by unserved load despite the increased loads and decreased energy availability.

Year 20 Compound Load Impacts

In the model, the Western Interconnection was sensitive to fairly small changes in demand.

Electrification resulted in unserved load in WECC's simulation and could create reliability risk in the Year 20 future, particularly if utilities and load-serving entities do not adapt their resource and transmission expansion plans to adequately account for it.

Load shifting helped alleviate some of the increased demand burden caused by electrification in the model. In the simulations, when WECC shifted the load to off-peak hours (at night), the demand burden decreased.

Transmission Trends

Most of the subregions required increased imports during both the extreme cold and heat events. Transfers from British Columbia to the Northwest subregion increased substantially. For the CAMX subregion the simulations indicated a continued need for imports to the subregion during extreme events, despite large capacity additions over the next 20 years.

Transmission path utilization increased on several paths in the 2042 study cases, compared to the 2032 Anchor Dataset (2032 ADS). In some cases, the flow on a path reversed directions as power was moved in different ways in the simulation. The results were highly sensitive to the season, month, time of the day, or extreme weather event.

Analytical Challenges

To address the lack of an interconnection capacity expansion plan, WECC synthesized capacity expansion assumptions by combining information from several sources, creating a useable but simplified capacity expansion dataset. WECC considers the preparation of longer-term capacity expansion plans a best practice and urges entities to begin building their capability to develop 20-year forecasts and planning processes immediately.

The way WECC's model optimizes battery storage heavily influenced the results. The model used for these studies optimizes (charges and dispatches) battery storage in a manner that is not consistent with actual practice. In the model, batteries are charged and discharged over a 24-hour cycle. This optimization pattern allowed battery storage to help cover peak load in the late afternoon; however, it caused more unserved load in the morning.

In this first attempt at Year 20 modeling, WECC simplified its approach and focused on only load magnitude and resource capacity in building the Y20 FC. In its future work, WECC will expand its considerations to better reflect the range of changes likely to exist in the 20-year time frame, including new transmission lines.

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Introduction

As part of its work to identify, understand, and help mitigate risks to the reliability of the bulk power system in the Western Interconnection, WECC assesses system performance under a range of future scenarios using advanced modeling and analytics, as well as detailed datasets. Historically, WECC has studied potential risks in the Year 10 time frame. In recent years, it has become clear that the risks facing the Western Interconnection extend beyond the 10-year horizon. Drivers of change like energy policies and clean energy goals are being planned beyond 10 years, with many policies setting targets near the middle of the century. In addition, planning and building or updating system elements can take a long time, in some cases more than a decade. To ensure critical elements are built or updated by the time they are needed, they must be planned long in advance. To account for these factors, in 2023, WECC began developing its capability to assess risks in a Year 20 time frame.

WECC used its existing 2032 Anchor Dataset (2032 ADS) model as a starting point to create a Year 20 Foundational Case (Y20 FC). It compared three alternate futures to the Y20 FC to identify changes in loads and resources and examine trends in transmission use across the four potential futures. This work, while still under development, has provided important insights into future risks to the Western Interconnection and revealed opportunities to continue improving WECC's modeling capabilities.

Approach

The Year 20 future of the interconnection is impossible to predict, which makes drawing absolute conclusions from any Year 20 analysis illogical. Because of this, WECC performed an analysis comparing the results of hypothetical scenarios to a baseline. The resulting trends represent potential areas for further analysis or possible risks. For the baseline, WECC developed the Y20 FC. Next, WECC created three alternate future cases, each representing a major risk or change in the Western Interconnection that WECC anticipates will create challenges for the industry over the next 20 years (See Figure 2):

- Extreme Cold Weather Event—examines system performance under an extreme, protracted, cold weather event in 2042, with data extrapolated from the December 2022 cold weather event.
- Extreme Heat Event—examines system performance under an extreme, protracted, heat event in 2042, with data extrapolated from the August 2020 heat event.
- Compound Load Impacts—examines system performance given changes in load resulting from differing amounts of electrification as well as possible demand response programs.

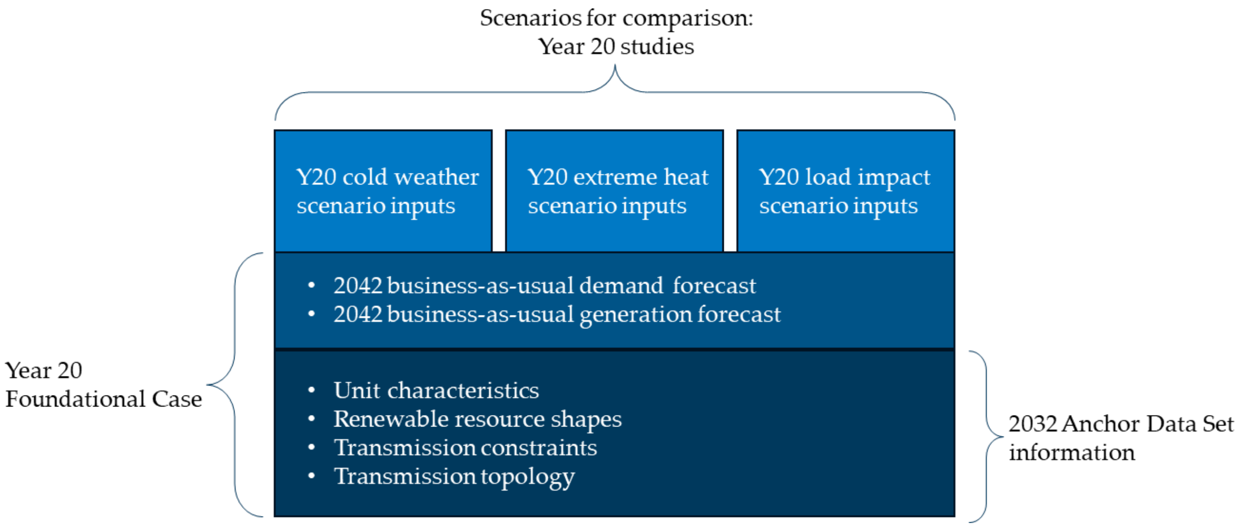

Figure 2: Building the Year 20 Study Cases

WECC used a deterministic approach for this analysis, meaning it studied and compared a small number of discrete future scenarios. WECC does not intend for any scenario it studies to reflect or fully encompass every aspect of the system in 20 years. The value in running deterministic studies is in comparing the results across multiple cases to identify areas where additional focus and study may be useful in identifying potential future risks. WECC uses information from studies like this to inform stakeholders of potential risks and scope future analytical work.

Year 20 Foundational Case

The Y20 FC represents a business-as-usual future scenario set in 2042.[1] WECC started with its 2032 ADS, which is a stakeholder-vetted compilation of load, resource, and transmission forecasts for 2032. From there, WECC extended the load and resource forecasts to reflect 10 more years of business-as-usual growth, meaning growth without any major changes or course corrections. The resulting assumptions in the Y20 FC reflect a future in which no major action is taken beyond 2032 to affect or account for load and resource growth, i.e., growth would proceed linearly toward 2042. This means the transmission infrastructure, technology types, and pricing assumptions are the same in the Y20 FC as the 2032 ADS.

WECC made limited changes from the 2032 ADS to help ensure the Y20 FC represented a business-as-usual situation. The changes WECC did make included:

- Load magnitude was grown linearly from the load magnitude in the 2032 ADS.

[1] A full description of the Year 20 Foundational Case is available here: https://www.wecc.org/Administrative/Year%2020%20Foundational%20Case.pdf.

- Resource retirements as of 2032 were included. Although some state policies aim to achieve more aggressive retirement schedules, WECC only included those retirements accounted for in the 2032 ADS.
- Resource additions were limited to wind, solar, and battery assumptions received from the California ISO, as it is one of the only entities with available 20-year resource plans. New resources had the same profiles as similar resources in the 2032 ADS. New resources were placed near load centers so new transmission was not needed. No new transmission was added beyond what was included in the 2032 ADS.

Year 20 Extreme Cold Weather Event Study

To build the Year 20 Extreme Cold Weather Event (Y20 Cold Event) study, WECC applied load profiles from Winter Storm Elliott to the Y20 FC.[2] Winter Storm Elliott occurred from December 21 through December 26, 2022. The storm was the result of an extratropical cyclone that created blizzard conditions, high snowfall, and record cold temperatures across most of the U.S. and parts of Canada. From there, WECC made the following additional assumptions to shape the scenario to reflect an extreme cold weather event in 2042:

- Increased all load by an additional 10% to represent more extreme cold temperatures;
- Used low wind and solar output shapes to reflect worst-case scenarios for those resources;
- Doubled the forced outage rate for generation resources to reflect increased generation loss due to cold weather; and
- Included natural gas derates to mimic natural gas fuel disruptions.

Year 20 Extreme Heat Event Study

WECC built the Year 20 Extreme Heat Event (Y20 Heat Event) case in a similar way as the Y20 Cold Event case.[3] WECC started with the Y20 FC and applied load and resource profiles from the western heat wave event that occurred August 14 through 19, 2020. The heat wave affected the entire Western Interconnection, causing a new peak demand record of just over 162,000 MW on August 18, 2020.

WECC created a base scenario that extrapolated the wind and solar patterns and increased load from the August 2020 heat wave to the year 2042. WECC also created four sensitivity scenarios to study the impacts of compounding heat wave conditions, such as limited thermal generation, limited water, and transmission constraints. The base scenario resulted in unserved load in the simulation. So, WECC then

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[2] A full description of the Year 20 Extreme Cold Weather Event Study is available here: https://www.wecc.org/Administrative/Year%2020%20Cold%20Weather%20Event%20Study.pdf?Web=1.

[3] A full description of the Year 20 Extreme Heat Event Study is available here: https://www.wecc.org/Administrative/Year%2020%20Extreme%20Heat%20Event%20Study.pdf.

created three additional sensitivity scenarios in which it reduced the load by different amounts to determine what level of load reduction would eliminate the unserved load.

- Extreme heat event base scenario: applied the year 2020 heat wave load shape to 2042. WECC extrapolated the wind and solar generation by comparing actual hourly production data for the August 2020 heat wave to WECC's forecast data.
- Extreme heat event with various compounding effects: in addition to the load, wind, and solar profiles from the base scenario, WECC added transmission constraints and derated thermal and hydro generation to varying degrees across multiple scenarios.
- Extreme heat event with 5% load reduction: base scenario with the load decreased by 5%.
- Extreme heat event with 10% load reduction: base scenario with the load decreased by 10%.
- Extreme heat event with 15% load reduction: base scenario with the load decreased by 15%.

Year 20 Compound Load Impacts Study

The Year 20 Compound Load Impacts (Y20 Compound Load) study examined the potential reliability impacts of demand changes anticipated from electrification of transportation, residential, and commercial sectors as well as the potential to relieve reliability risk through load shifting for the entire year of 2042.[4] The Y20 FC was the starting point for the Y20 Compound Load case. From there, WECC examined two different outlooks of future electrification with changes in load magnitude and load shape as well as two scenarios that looked at potential load shifting through demand response:

- High Electrification (HE): uses assumptions from NREL's Electrification Futures Study High Slow case and incrementally grows load out to 2042 for an expected future with a high level of electrification adoption.
- Extreme Electrification (XE): represents electrification assumptions beyond the High Electrification case.
- Extreme Electrification with Mid-Day Demand Response (XE MD): examines how shifting electrification demand to mid-day hours could affect reliability, based on load values from the extreme electrification case.
- Extreme Electrification with Off-Peak Demand Response (XE OP): examines how shifting electrification demand to off-peak hours could affect reliability, based on load values from the extreme electrification case.

In this study, demand response was limited to load-shifting technology or programs. The study simulates the possible amounts of demand response but does not identify the type of technology or

[4] Additional information about the Year 20 Compound Load Impacts Study, including electrification assumptions can be found here: https://www.wecc.org/Administrative/Year%2020%20Compound%20Load%20Impacts%20Study.pdf.

programs necessary to achieve that level of demand response. Figure 3 shows an example of the Net Demand shapes for each scenario for the California–Mexico (CAMX) subregion for the winter season.

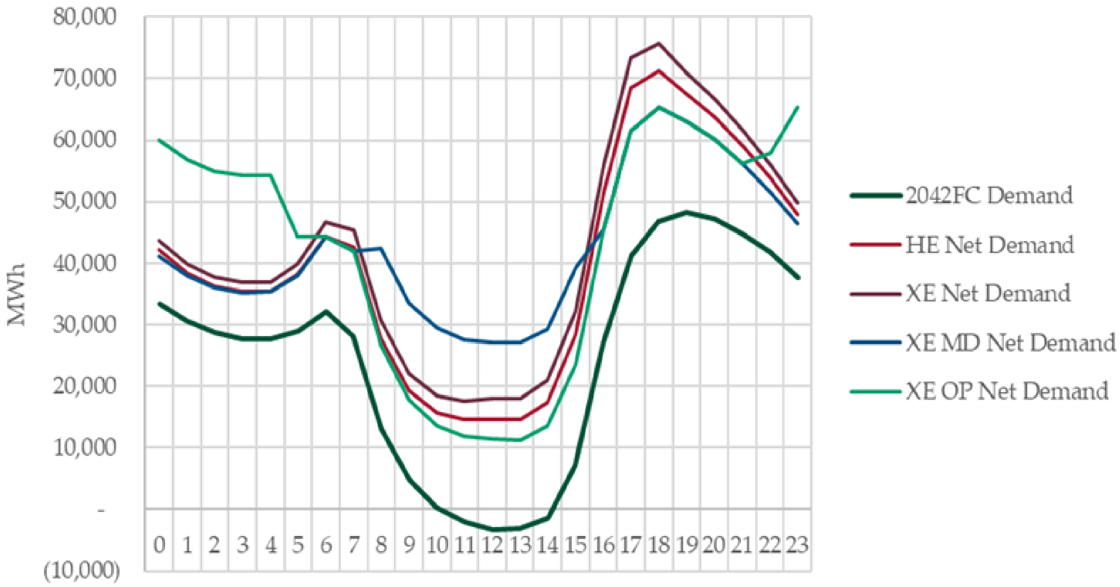

Figure 3: Example of Net Demand by Season for CAMX

Transmission Trends

WECC compared the results from the Year 20 studies to identify trends in transmission use. WECC did not attempt to model specific future transmission additions because it lacked forecast information for transmission topology in the Year 20 time frame. Therefore, the value of this assessment is in the relative changes in transmission use across the Year 20 studies, rather than the transmission use patterns of any single study. Identifying trends in transmission use can provide insight into areas of potential risk in need of further study.

WECC's production cost model simulates thousands of lines in the interconnection. For this trend assessment, WECC chose 18 transmission paths that comprise the subregion-to-subregion flow in the interconnection. WECC measures the utilization of the transmission paths with three metrics: U75, U90, and U99. These metrics capture the percentage of time that the flow on a path meets or exceeds the respective rating of that path. For example, U75 represents the percentage of time that

Figure 4: WECC Year 20 Modeling Subregions

the path flows meet or exceed 75% of the path rating in the respective direction.

Modeling Subregions

WECC divided the Western Interconnection into seven subregions for all the Year 20 studies. (See Figure 4.)

Load and Resource Findings

Year 20 Extreme Cold Weather Event Study

In the Y20 Cold Event case study, WECC stressed the system by applying three cold-weather-related conditions: high loads, low wind and solar output, and increased generation outages. WECC applied the conditions individually, then combined them and added different levels of natural gas derates. WECC ran each of these Y20 Cold Event scenarios for a single month: December 2042. When the system was stressed with only one of these conditions, regardless of which condition it was, no unserved load occurred. When more than one of the cold-weather-related conditions was combined, there was unserved load. The unserved load increased as WECC added more cold weather conditions and natural gas derates. (See Figure 5.)

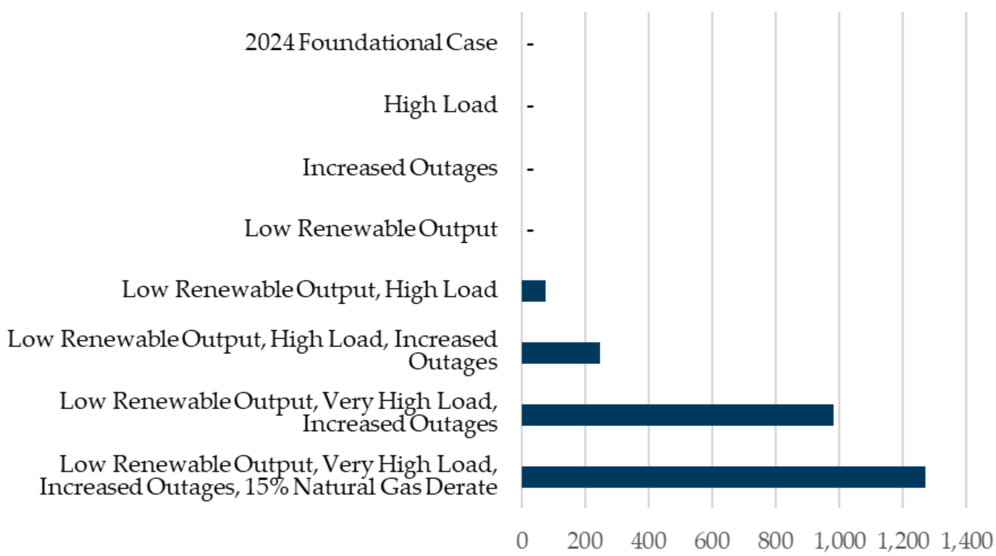

Figure 5: Unserved Load (GWh) for Year 20 Extreme Cold Weather Event Study

Compared to WECC's Year 10 Cold Event Study, which used the same approach as the Y20 Cold Event study, the system in the Y20 Cold Event was more sensitive to cold weather impacts—load loss occurred under less stressed conditions than in the Year 10 study. In the Year 10 Cold Event Study, unserved load occurred only after WECC applied all three cold-weather-related conditions and a 15% natural gas derate. The sensitivity of the system in the Y20 Cold Event case was due to the characteristics of the new resource mix WECC modeled, which included large increases in wind and solar generation and decreases in resources like coal and natural gas.

Hours with Unserved Load

WECC modeled the cold weather event over seven days (December 18–24, 2042). Figure 6 shows the generation and load over this time in the most extreme scenario WECC examined, i.e., all three cold-weather-related conditions and a 15% natural gas derate (2042EC_15%NG Derate scenario). The white space between the black load line and the colored generation stack is the unserved load.

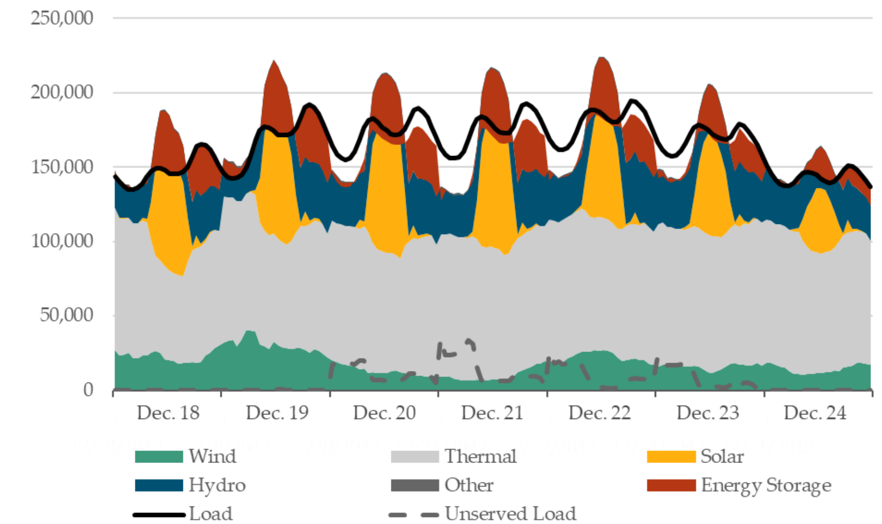

Figure 6: Load and Generation for 2042EC_15%NG Derate Scenario (MW)

Some hours of the day were more susceptible to unserved load. For the most extreme scenario, the worst hour of unserved load was Hour 1 on December 21, 2042. During this hour, approximately 21% of load was unserved. (See Figure 7.) Hour 7 was very similar with 20% of the load unserved. This load pattern occurred in all the study scenarios. WECC's model optimizes battery storage on a 24-hour cycle, meaning it charges and discharges the batteries in the model every day. This schedule does not reflect realistic battery charging and discharging, which typically occur over multiple days. The timing of the unserved load was heavily influenced by the battery storage optimization schedule in the model.

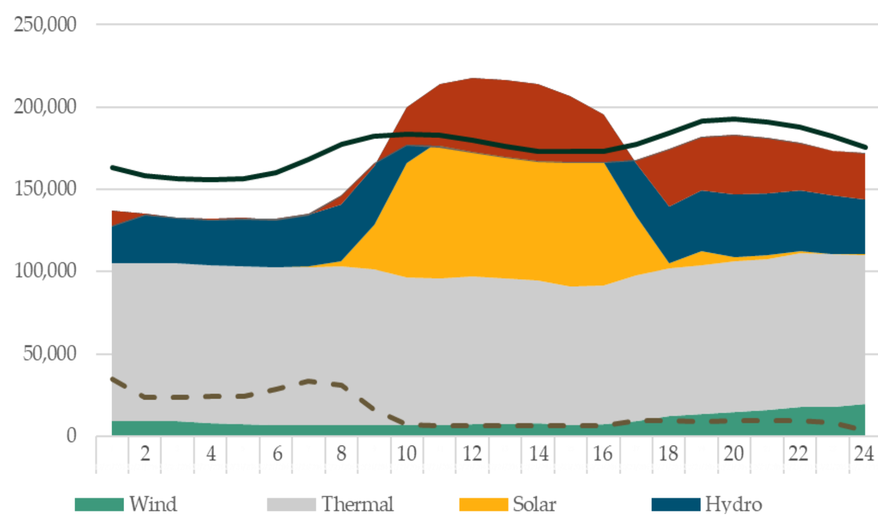

Figure 7: Hourly Load and Generation for 2042EC_15%NG Derate Scenario (MW) – December 21, 2042

Reliance on Natural Gas

Sufficient availability of natural gas generation was critical to serve load in the Y20 Cold Event, as solar and wind output decreased while load increased. Natural gas units ran at maximum capacity but were unable to keep up, leading to unserved load. With much less wind and solar generation, gas was primarily used to make up the deficit until the gas generation ran out. This finding is particularly revealing because cold weather events can cause gas supply interruptions or derates of gas generation capacity, making heavy reliance on natural gas resources during these events risky.

Year 20 Extreme Heat Event Study

In the Y20 Heat Event case study, WECC applied various heat event conditions for a two-week period in mid-August 2042. In its base scenario, WECC extrapolated August 2020 load, wind, and solar shapes to August 2042, and the simulation showed nearly 1 million MWh of unserved load. (See Figure 8.) The situation worsened when WECC derated thermal resources by 10%, which increased the unserved load to over 1.5 million MWh. WECC ran three sensitivities on the case scenario to determine what level of load reduction—5%, 10%, and 15%—might alleviate the unserved load. While reducing the load lowered the amount of unserved load in the simulation, it did not eliminate it. Loads would need to be reduced more than 15% below what the interconnection experienced in the August 2020 heat wave to minimize the risk of unserved load.

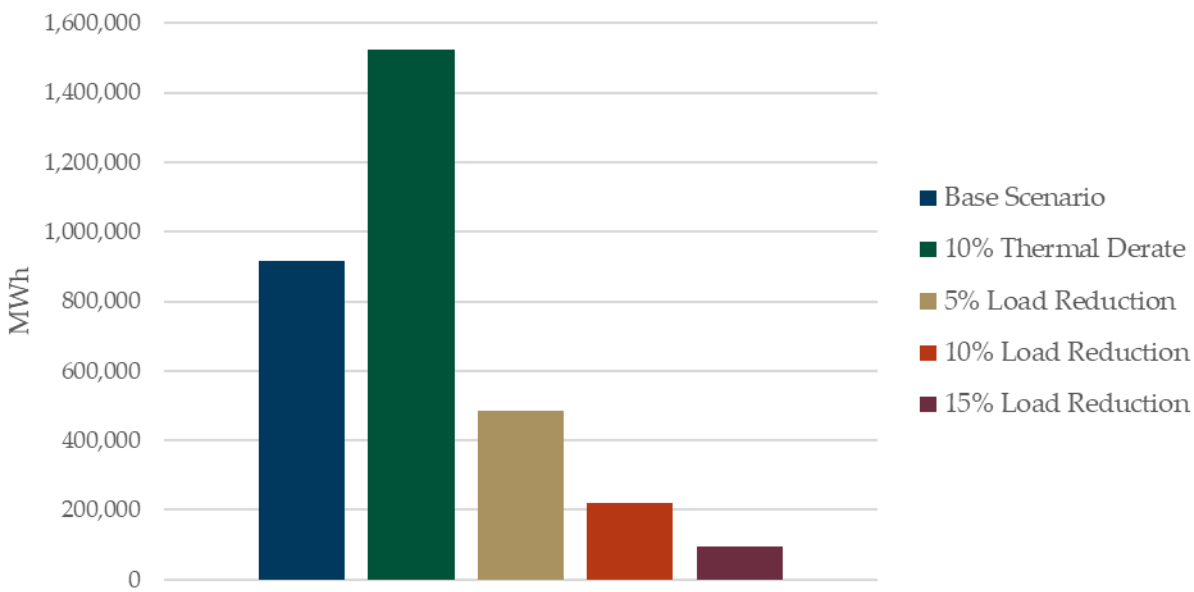

Figure 8: Unserved Load (MWh)

Unserved load was greatest in the CAMX subregion. Canada was unaffected by unserved load despite the increased loads and decreased energy availability. (See Figure 9.) The role of hydro generation and storage in reducing reliability risk during extreme weather merits further analysis.

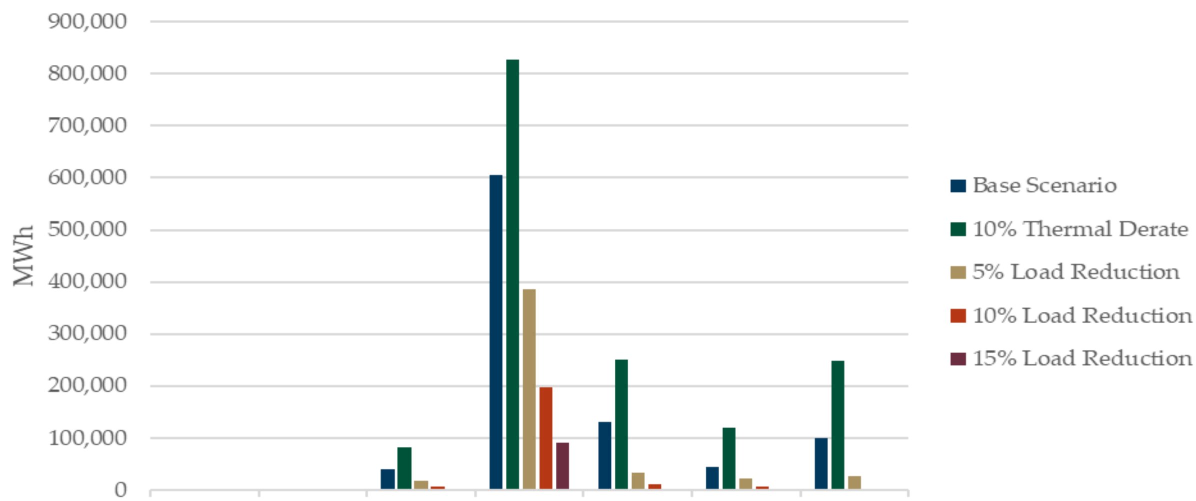

Figure 9: Unserved Load by Subregion (MWh)

Most of the unserved load occurred at night when battery storage was charging in the model; however, this charging pattern is atypical. Batteries usually charge during the day when there is renewable energy available and dispatch or discharge in the evening or at night to help with ramping and peak load. WECC's model optimizes battery storage on a 24-hour cycle, meaning it charges and discharges over a single day. When the day starts over at midnight, the batteries are depleted and begin charging. WECC is looking at ways to adjust the battery optimization in the model, though it is not clear what effect an adjustment in the battery charging schedule would have made in this study. Whether an adjustment would have been sufficient to alleviate all the hours of unserved load or shift the unserved load to other hours remains an open question.

Year 20 Compound Load Impacts Study

The Y20 Compound Load study demonstrated the potential for electrification to create reliability risk in the Year 20 future, particularly if utilities and load-serving entities do not adapt their resource and transmission expansion plans to adequately account for it. Figure 10 shows the unserved load in the High Electrification (HE) and Extreme Electrification (XE) scenarios. In the simulation, the Western Interconnection was sensitive to fairly small changes in demand, leading to greater reliability risk

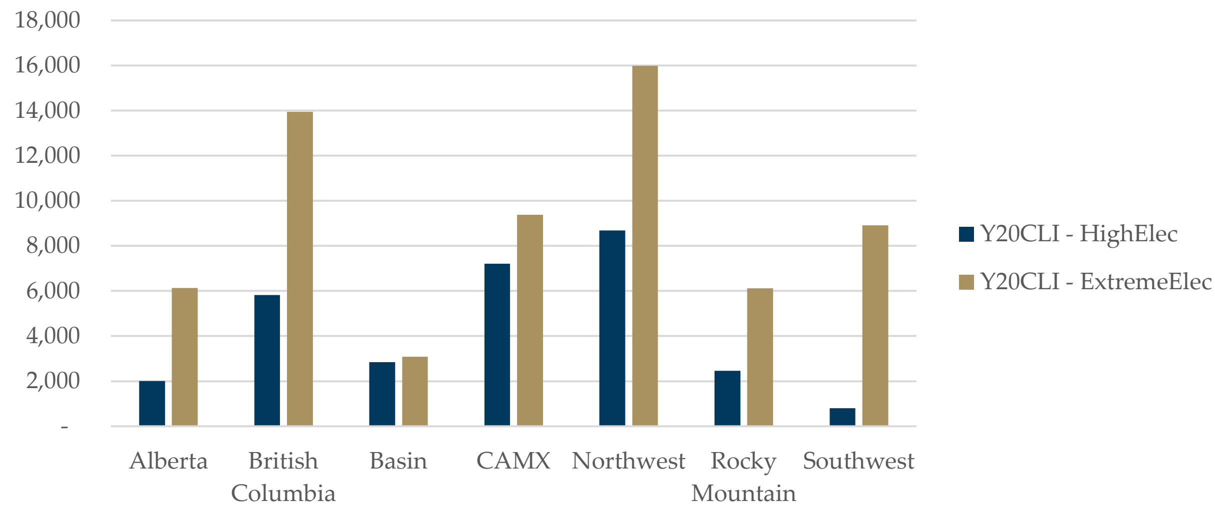

Figure 10: Unserved Load Comparison by Region

Load Shifting Demand Response

WECC added load shifting demand response to the simulation to help reduce the demand burden that electrification added during parts of the day. Load shifting is one type of demand response where load from peak hours is shifted to other hours of the day. The hours to which demand is shifted determines how load shifting may affect reliability. Figure 11 shows that, when WECC shifted load from peak hours to off-peak or night hours, there was an increase in unserved load in the U.S. portions of the interconnection. This occurred because there was a lot of solar generation in the simulation that did not generate during off-peak times. Figure 11 also shows that, when WECC shifted the load to midday hours, the simulation showed that a load shift could help reduce the demand burden caused by electrification for the U.S. subregions.

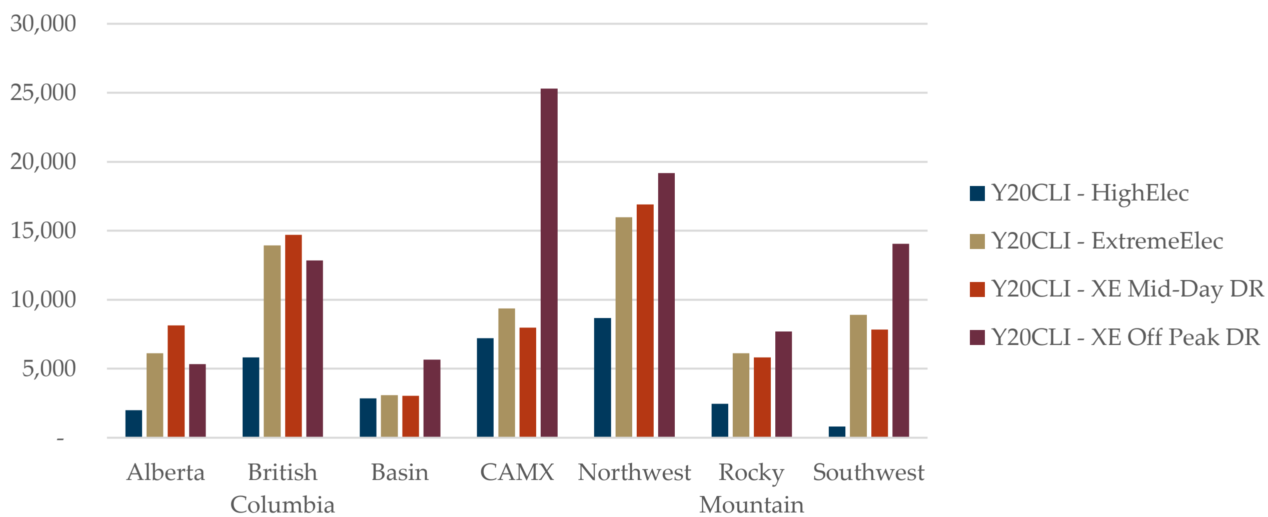

Figure 11: Comparison of Unserved Load by Subregion for the Y20 Compound Load Scenarios

Load shifting affects subregions differently. The Northwest is the only subregion that did not show a net benefit from either scenario. There were hourly benefits in the Northwest subregion in both the Extreme Electrification with off-peak load shifting (XE OP) and Extreme Electrification with midday load shifting (XE MD) scenarios. However, the unserved load relief during the peak demand hours could not outweigh the unserved load increase in the period of load-shifting (off-peak or midday).

In WECC's simulations, the CAMX subregion showed a large increase in unserved load when load was shifted to off-peak times. California's resource 2042 portfolio will likely contain large amounts of solar and wind generation, which provide the most generation during peak hours. Without increased capacity during the off-peak hours, the CAMX subregion was not able to avoid unserved load during those times given the increased demand in the XE OP scenario.

The results of the Y20 Compound Load study bring up additional questions about how the combination of demand response programs or technology that shift load to both midday and off-peak hours might alleviate unserved load. In addition, as with the other studies, the battery storage optimization in WECC's model affected the results and could have grossly impeded the ability of storage to alleviate unserved load during off-peak hours.

Transmission Trends

WECC compared the subregional transfers and transmission line utilization across each of the studies in this assessment to identify trends and potential areas of future risk.

Subregional Transfers

WECC's comparison of the subregional net transfers focused on how energy moved in the simulation between subregions. The analysis did not look at specific transmission lines or paths. To make the comparison of net transfers, WECC selected a single resource-stressed scenario from each of the studies in the assessment. Each scenario was compared to the net transfers in the Y20 FC, and major changes were noted. From there, WECC compared the changes in net transfers between the scenarios. Figure 12 and Figure 13 show comparisons of the subregional transfers between the Y20 FC and one scenario from each of the extreme event studies for a single month of 2042: December for the Y20 Cold Event and August for the Y20 Heat Event.

Most of the subregions required increased imports during both the extreme cold and heat events. In both extreme weather scenarios, transfers from British Columbia to the Northwest subregion increased substantially. For the CAMX subregion, despite large capacity additions in the Y20 FC, analysis of the net transfers suggests a continued need for imports into the subregion during extreme events.

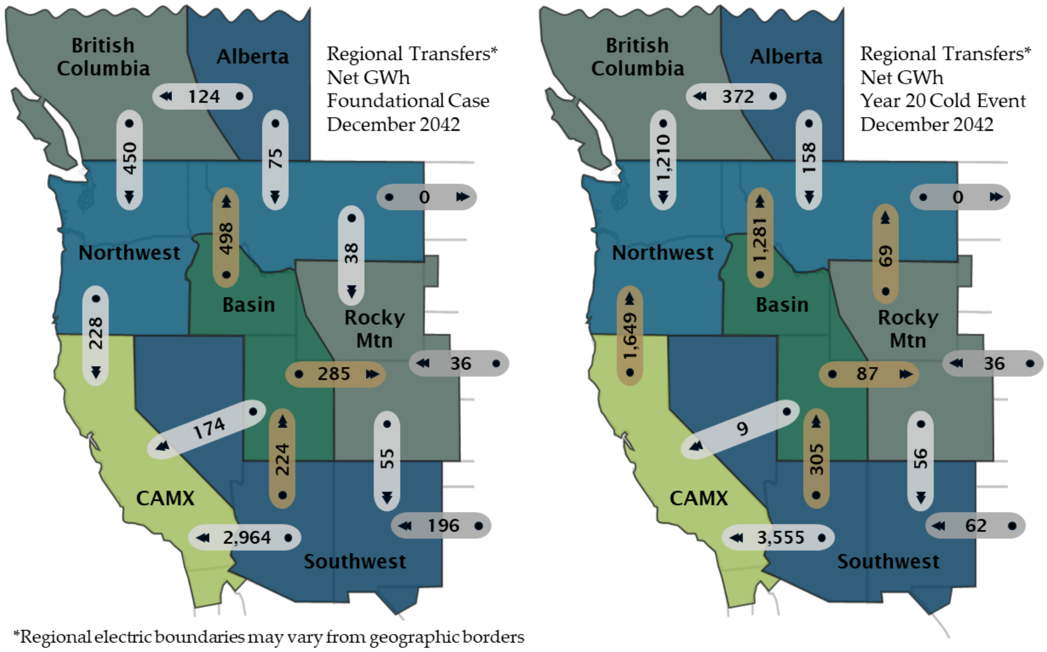

Figure 12: Comparison of Net Subregional Transfers between 2042 Foundational Case and Year 20 Cold Event

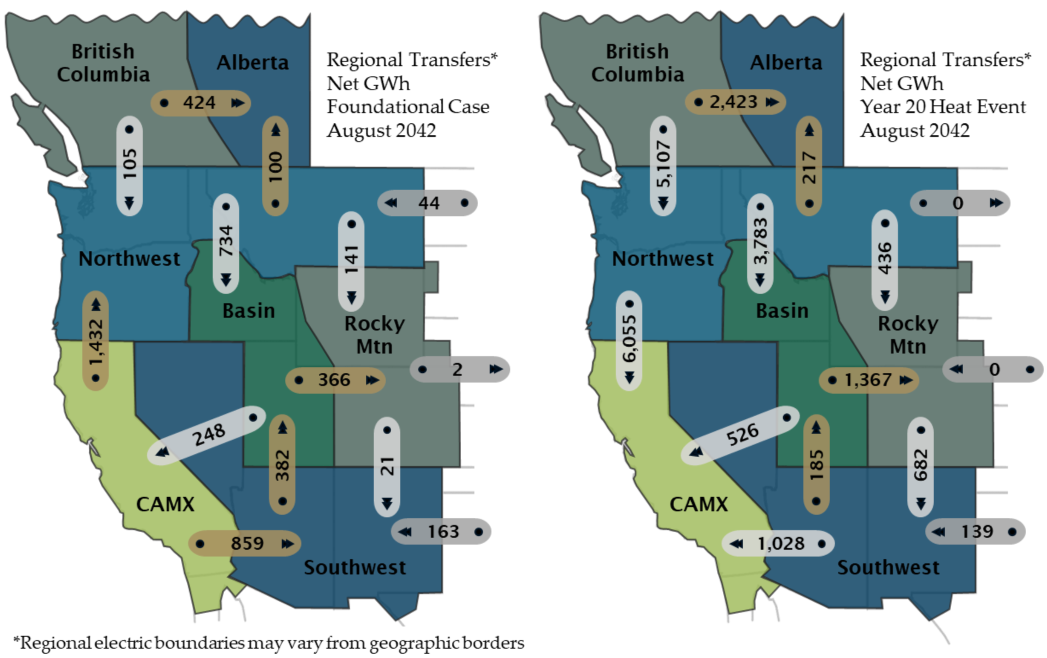

Figure 13: Comparison of Net Subregional Transfers between 2042 Foundational Case and Year 20 Extreme Heat Event

Figure 14 shows the results for all of 2042, the time frame for the Y20 Compound Load study. Under the high-load conditions caused by electrification in the Y20 Compound Load study, the CAMX subregion became a heavy exporter annually. The large amount of wind and solar that California entities plan to build allows the CAMX subregion to be a net exporter in this scenario. However, in the Y20 Heat Event regional transfers comparison above, the CAMX subregion is a net importer, meaning there are times when the CAMX subregion will need imports, despite being a net exporter over the year. The same is true for the Alberta subregion: in the Y20 Compound Load scenario, it is a net exporter, but in the Y20 Heat Event scenario, it relied on imports.

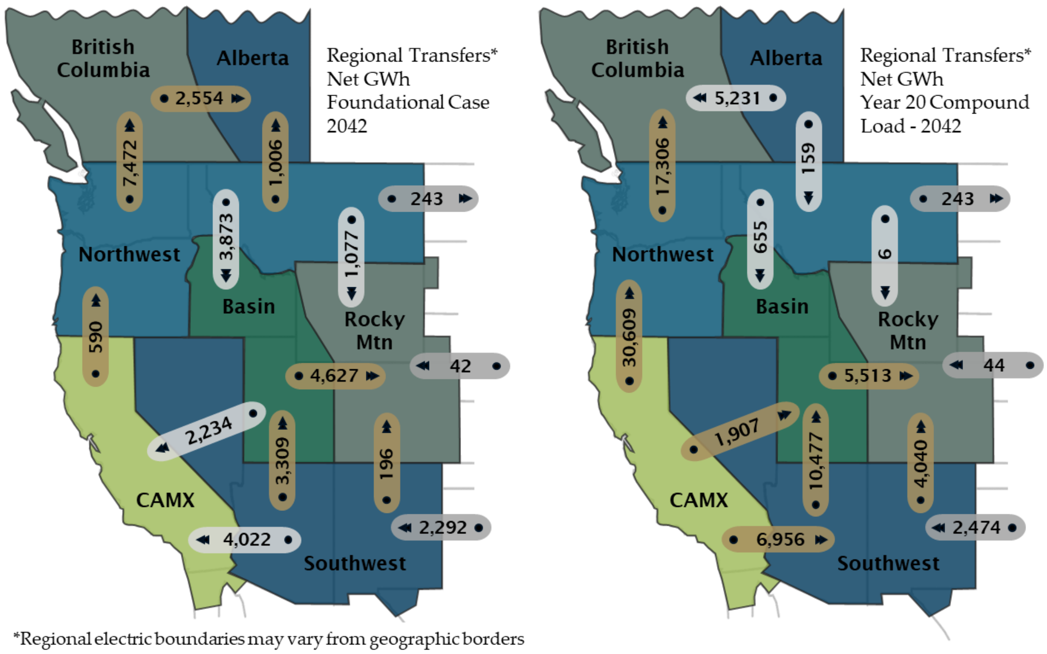

Figure 14: Comparison of Net Regional Transfers between 2042 Foundational Case and Year 20 Compound Load Case

Transmission Path Utilization

The path utilization analysis compared the path utilization in the 2032 ADS to the path utilization in each of the studies in this assessment. The Y20 FC and Y20 Compound Load included the entire year while Y20 Heat Event and Y20 Cold Event looked at a single month, August and December, respectively. Figure 15 compares seven notable paths. There are two types of utilization changes shown: increases in the predominant flow direction (positive or negative) and increases in utilization with potential directional switching. For example, utilization on Paths 36 and 47 increased in the positive direction, the same direction as the Y20 FC. This indicates that these paths may experience increased utilization in 20 years, including during times of high system stress like extreme events. While the utilization on these paths increased, their characteristic flow pattern did not. Paths 14 and 35 show the same behavior in the negative flow direction.

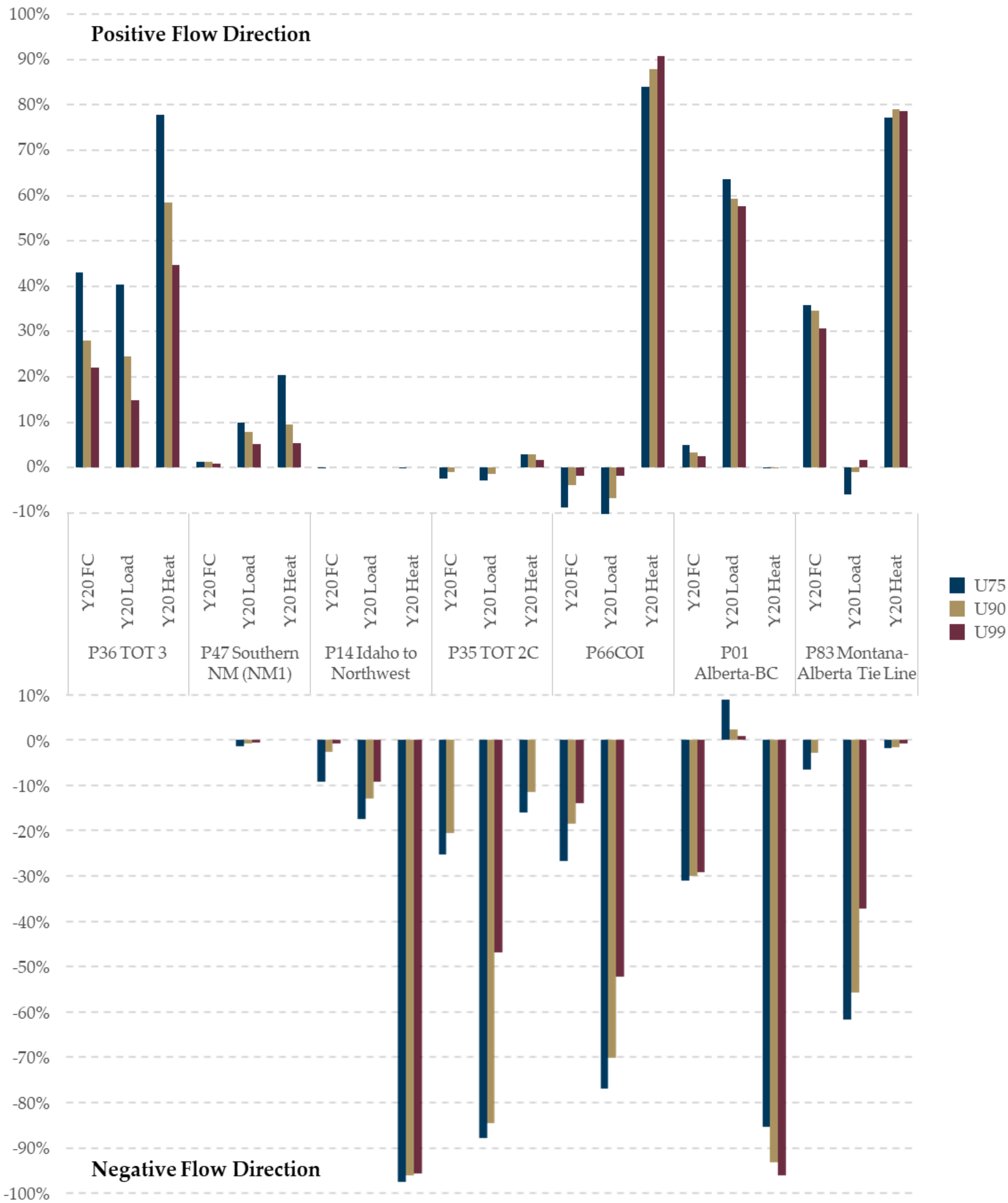

Figure 15: Path Utilization Change from 2032 ADS to 2042 Study Cases (MW)

The other paths (1, 66, and P83) showed increases in utilization but in the opposite direction from the Y20 FC in some scenarios. This means that in some scenarios the predominant flow on these paths changed directions. Under some circumstances, not only might these paths be more heavily used, but they may also be used in an uncharacteristic flow pattern. This comports with the regional transfers results, in which, under certain conditions, some subregions switch from being net importers to exporters or vice versa.[5]

These results show that each path is used differently in each season, month, and time of the day, as well as during extreme weather events. The location of high loads and resource availability drive the different flow directions and magnitudes. Entities in the West cannot assume that the direction of flows on paths today will be the same in the Year 20 future, nor that the predominant flow direction will be the same across all system conditions.

Year 20 Analytical Challenges

The inaugural creation of the Y20 FC and other Year 20 study cases posed analytical and modeling challenges. WECC learned valuable lessons from this process and intends to apply them to future analyses.

Lack of a Capacity Expansion Plan

The lack of a capacity expansion plan was a challenge in building the Y20 FC. In lieu of a plan, WECC synthesized capacity expansion assumptions by combining information from several sources, creating a useable but simplified capacity expansion dataset. To remedy this in future study work, WECC may request that Balancing Authorities submit their own Year 20 forecasts to help build the Y20 FC. While some entities produce expansion plans beyond the 10-year time frame, this is not common practice. WECC considers the preparation of longer-term capacity expansion plans a best practice and urges entities to begin building their capability to develop 20-year forecasts and planning processes immediately.

Modeling Limitations

WECC pushed the boundaries of the GridView Production Cost Model software. Among the issues that WECC addressed were anomalies that occurred when the 2042 loads and resources were added to the simulation. Through a version upgrade, many of these anomalies were resolved; however, this is a consideration WECC will need to address in future studies.

[5] It is worth noting that some paths do not have a path rating defined in one of the flow directions. The utilization changes for these paths is not included in this analysis as there is no path rating from which to calculate a U75, U95, or U99 amount.

One issue WECC was unable to resolve was the way the model optimizes resources, particularly battery storage. The model optimizes energy storage on a 24-hour cycle, which means the energy storage charges and discharges each day. Because the day starts at midnight, energy storage units start out the day discharged, because they discharged completely the previous day. Because of this, energy storage cannot effectively contribute as load increases in the morning. In late morning and early afternoon, battery storage begins to charge. The stored energy is then discharged in the late afternoon and evening when load is highest. This optimization pattern allows battery storage to help cover peak load in the late afternoon; however, it causes more unserved load in the morning. This modeling limitation does not accurately reflect typical operational practices where batteries are charged and discharged over several days. This skews the results with different energy storage operation and cycling—the unserved load pattern would likely change. If the model had optimized energy storage over a span greater than one day, the pattern of energy storage charging and discharging may have been represented over many days, depending on how the model optimized load serving versus energy storage charging. This issue affected all four of the Year 20 study cases, meaning the results from any single case should be considered with this modeling behavior in mind. However, because the issue affected each study case in the same way, comparisons between the cases may still reveal useful information on risks to reliability.

To address this critical modeling issue, WECC will work to refine the model to help ensure the cost-optimized decisions better reflect real-world decisions. In addition, WECC is evaluating modeling software options that simulate battery storage in a more realistic way.

Limited Considerations Modeled

As this was its first attempt at Year 20 modeling, WECC narrowed its focus to a small number of considerations and focused only load magnitude and resource capacity when it transformed the 2032 ADS into the Y20 FC. To better account for the range of changes in the Year 20 time frame, additional considerations should be included, for example, transmission additions. WECC will examine and add or update additional elements in future Y20 FC development.

Transmission Projects not Included

The transmission topology was the same for all cases and studies used. The modeled topology came from the 2032 Heavy Summer Power Flow; however, there are questions about when to include a known project in the model. The current known transmission projects not included in any of the studies include:

- Boardman to Hemmingway: 500 kV transmission from Idaho (Hemmingway) to Oregon (Boardman);
- Crosstie: 500 kV transmission from Utah (Clover) to Nevada (Robinson Summit);
- Southline: 345 kV transmission line from El Paso to Tucson;

- SunZia: 500+ HVDC transmission line from New Mexico (SunZia East) to Arizona (Pinal);
- Southwest Intertie Project:
  - North 500 kV transmission line from Idaho (Midpoint) to Nevada (Robinson Summit),
  - South 500 kV line from Nevada (Robinson Summit) to Harry Allen;
- Transwest Express: High voltage DC Transmission line from Wyoming to Utah and 500 kV transmission line from Utah to Nevada; and
- Ten West Line: 500 kV transmission line from Arizona (Delaney) to California (Colorado River).