WECC

Significant Electrification Assessment

May 27, 2020

Executive Summary

This assessment investigates the impacts of increased electrification on the reliability of the Western Interconnection. Electrification is the conversion or addition of end-use technologies that increase the load or demand on the electric grid. This study considers various trends in load changes, including electrification of buildings and transportation for the highest stressed conditions. The study also includes stability impacts of an increased percentage of power electronic loads like drives and chargers.

The scope of this study is to assess the system stability and system adequacy of a Year 10 future with a significant electrification scenario. Starting with the 2028 Heavy Summer Anchor Data Set, the load values were taken from a similar study by the Department of Energy's National Renewable Energy Laboratory (NREL) called the Electrification Futures Study. The NREL load assumptions were imported to the WECC Production Cost Model (PCM) to evaluate the impacts of high loads over an entire year and export the peak hour for reliability analysis with the power flow model.

The PCM shows there was 0.187% of unserved energy compared to the total load growth due to electrification in the extreme scenario. There was zero unserved energy in the original 2028 Anchor Data Set Production Cost Model. When a small portion of the increased load (1.62% of total load) is modeled as dispatchable load (DER-EV) the amount of unserved energy drops by 50%.

The steady-state and dynamic stability were evaluated for the system summer peak under this high electrification scenario. Peak load increased from 185.4 GW in the ADS Power Flow case to 189.2 GW in the electrification scenario. The steady-state power flow had one major path overload and one area that experienced low voltages under the high electrification scenario. Various disturbances and contingencies were run on this case and show no imminent instability issues compared to the original case.

The task force members conducted additional transient stability studies to understand the impact of increased power electronic load percentage on delayed voltage recovery and voltage dip. Although there were no reports of WECC criteria violation, the transient voltage dip was lower in cases with a larger percentage of power electronic loads.

Analyzing several cases with significant electrification showed that, although there are some issues under the extreme conditions, the assessment did not reveal any major reliability risks.

This study was the first coordinated effort to understand the reliability impact of increased electrification and increased percentage of electronically connected loads. We recommend the studies continue with greater focus on regional issues. On the PCM side, the assessment team recommends studying in more depth the dispatch prices at which DER-EV optimally affects the system to mitigate unserved energy in the case. On the reliability side, we recommend expanding the scope to other seasons and generation dispatch scenarios.

1. Introduction

This report analyzes potential risks to the Western Interconnection's (WI) reliability as electric load in the West transforms through 2028. Many factors drive the change in electric load in the WI; for example, state policy, customer preferences, and technology innovations. This change is transitioning other energy sources, like automobile fuel, to electrical energy. As more of the Western load transitions to electric-power, the impacts on the WI could be drastic. The Department of Energy (DOE) predicts that the electric load in the U.S. could increase by nearly 40% by 2050 from electric vehicles (EV) alone.

Not only will load increase in the future, but other load characteristics will change, including daily and yearly shapes. For example, EVs will increase total load but will change the time at which the load is used depending on the end users' charging patterns. Increased use of heat pumps for space heating and water heating will increase electricity consumption in the winter months which alters the seasonal load.

Various factors will affect the level of electrification, including how aggressively customers adopt technologies and how rapidly technology advances. EVs have the most potential for electrification and the highest potential impact on the electric grid. Depending on how extensively customers use EVs, the size and time of the total load could vary significantly. Technology advancement will determine the efficiency of EVs and could also offset increased system load.

With increased electrification, many factors contributing to the total load will affect the reliability of the grid. This study assumed a high projected level of electrification to create an extreme scenario and develop an understanding of potential outcomes. Implicit in this scenario is that the increase in loads was unanticipated and additional generation resources were not added to meet the higher loads. The highest electrification scenario in 2028 assumed there was high customer adoption of electrification technologies and slow technology advancement.

In addition to increased electrification of buildings, a higher percentage of load becomes electronically-connected to the power grid. The DOE estimates that, by 2030, 80% of all U.S. electricity will flow through power electronics.[1] Variable-frequency drives are increasingly used, not only in manufacturing processes, but also for energy efficiency. Just as inverter-based generators have different characteristics from synchronous machines, so do variable frequency drives and rectifiers from motors during grid disturbances.

This report analyzes the system's resource adequacy and stability with electrification in buildings and transportation in the 10-year horizon. Reliability risks to the WI's bulk power system (BPS) were analyzed for unserved energy, overloads on major transmission paths, increased ramp rates for generators to serve the increasing load curves, and transient and voltage stability during contingencies.

[1] https://www.energy.gov/eere/amo/power-america

2. Participants

The following Significant Electrification Task Force (SETF) members were involved in this assessment.

Member	Organization
Elena Melloni	WECC
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Hassan Baklou	San Diego Gas and Electric
Simrit Basrai	Pacific Gas and Electric Company
Thomas Carr	Western Interstate Energy Board
Charles Cheung	California Independent System Operator
Jonathan Cichosz	Portland General Electric Company
Jared Ellsworth	Idaho Power Company
Irina Green	California Independent System Operator
Fred Heutte	NW Energy Coalition
Peter Mackin	GridBright, Inc.
Eepsita Priye	Puget Sound Energy, Inc.
Andreas Schmitt	Bonneville Power Administration–Transmission
Angela Tanghetti	California Energy Commission
Berhanu Tesema	Bonneville Power Administration–Transmission

3. Assessment Approach

This assessment consisted of two parallel tracks to answer the following questions:

1. How does an increased load due to electrification impact the resource adequacy of the interconnection without resource portfolio changes?
2. How does an increased load due to electrification affect the system stability of the interconnection?

3.1. Data

Both the PCM and power flow cases were based on the 2028 Heavy Summer 1 Anchor Data Set (ADS) case. This base case was vetted through the typical WECC power flow base case compilation process and was used to provide topology for the ADS compilation of the PCM case.

The 2028 ADS PCM Phase 2 V2.0 was the starting case to model all the electrification scenarios. This case included California Independent System Operator (CAISO) 50% Renewable Portfolio Standard (RPS) resources. The Phase 2 PCM case contains additional generation resources over the Phase 1 ADS PCM and, therefore, the original 28 HS1 power flow. All Phase 2 generation changes included transmission topology to integrate additional resources. All the changes made to the ADS Phase 1 were based on feedback from the data owners. Phase 2 included 3,276 MW of retired thermal generation and 4,906 MW of added generation, compared to the Phase 1 case.[2]

The original approach for data collection involved sending a survey to all the Balancing Authorities (BA) in the WI to request electrification forecasts. According to multiple sources, including the Loads and Resources Task Force, it was determined the BAs' electrification data was not as detailed as was needed for this study. The California Energy Commission (CEC), however, provided an electrification forecast for California.

The source of load data with a high electrification future came from the Demand-Side Scenarios (DSS) developed as part of the Electrification Futures Study (EFS), a multi-year study effort led by the DOE's National Renewable Energy Laboratory (NREL). NREL and its research partners—Electric Power Research Institute, Evolved Energy Research, Lawrence Berkeley National Laboratory, Northern Arizona University, and Oak Ridge National Laboratory—are using multiple analytic tools and models to develop and assess electrification scenarios designed to quantify potential energy, economic, and environmental impacts to the U.S. power system and broader economy. NREL provided WECC the hourly, state-level load profiles for each DSS. Section 3.3 discusses the scenarios selected for this study from the DSS. The selected DSS state-level hourly load profiles were used to create hourly load profiles for each of the 40 BAs modeled in the WECC study cases. Tom Carr from the Western Interstate Energy Board provided the load breakdowns between WECC BAs and states for the 2028 ADS. You can find them here. BAs in a given state boundary were created by normalizing to the BA's percentage share of annual load energy to that of the State DSS profile based on the BA to State load breakdowns. As a sanity check, the DSS profiles were confirmed to be aligned with WECC load models for 2016. Relative to the year 2016, the DSS load scenarios have compound annual growth rates (CAGR) between 0.65% (Reference) to 1.6% (High), as described in the EFS-DSS report which can be found here. For those BAs with service territories span across multiple state boundaries, hourly profiles were weighted by percentage shares of the DSS state profiles. The DSS state profiles provided to WECC from NREL were further broken down by static and variable electrification load. Variable electrification load, in this context, represents the hourly electrification load that can be committed and dispatched in the PCM. This variable load comprises DER EV load (variable DER-EV).   This variable DER-EV was modeled in the

[2] For details, see Changes to 2028 ADS PCM from Phase 1 V1.0 to V2.2 and Phase 2 V2.0.

case as an hourly resource and assigned various price points for commitment and dispatch in the PCM as described in Section 4.2.

3.2. Work with other assessment teams

The SETF worked with the WECC Scenarios Task Force (WSTF). Like the SETF, the WSTF considered the effects of customer adoption of new technologies, advancement in technology availability and their effects on the BPS. This coincided with the WSTF's electrification projections as customer choice can have a significant impact on future load values and profiles. For the customer adoption axis in the WECC Scenarios, the electrification load assumptions were the same between studies and, therefore, the SETF and WSTF developed load shapes. Detailed information is included in Section 3.3.

One other demonstration of collaboration to highlight is the collaboration with the Year-10 Task Force (Y10TF). The electrification analysis included reviewing load-shedding values and Interconnection Frequency Response Obligation (IFRO) for seven standard disturbances described below. The Y10TF ran the same disturbances on the original ADS base case. The increased electrification case results could then be compared to a base line for determining specifically how electrification impacted these results.

3.3. Production Cost Model Resource Adequacy

Multiple sources, including the Loads and Resources Task Force advised that BAs might not have electrification data detailed enough for this study. However, the California Energy Commission (CEC) has provided the electrification forecast for BAs in California.

NREL's EFS used nine scenarios to study electrification looking at customer adoption rates and sensitivity to technology advancement. The customer adoption axis was broken out into three scenarios—a reference, medium, and high adoption—while the technology advancement axis was broken down into slow, moderate, and rapid levels. Table 1 shows the sensitivity cases.

Table 1

	Slow Technology Advancement	Moderate Technology Advancement	Rapid Technology Advancement
Reference Customer Adoption	Reference Adoption, Slow Technology Advancement	Reference Adoption, Moderate Technology Advancement	Reference Adoption, Rapid Technology Advancement
Medium Customer Adoption	Medium Adoption, Slow Technology Advancement	Medium Adoption, Moderate Technology Advancement	Medium Adoption, Rapid Technology Advancement

High Customer Adoption	High Adoption, Slow Technology Advancement	High Adoption, Moderate Technology Advancement	High Adoption, Rapid Technology Advancement

PCM simulations were run on the reference and medium customer adoption scenarios and the results concluded that the WI had no unserved load or any overloaded major transmission paths. Therefore, the current resource portfolio as modeled in the ADS Phase 2 V2.0 could serve the increased electrification load in these scenarios. The highest level of load growth occurred with the combination of the high customer adoption and slow technology advancement scenario. These assumptions were adopted for this study as highlighted in Table 1.

For example, the highest load growth occurs when consumers adopt more electric vehicles and the technology has not advanced enough to reduce the amount of energy it takes to charge them. Once the SETF applied the load changes based on the NREL data, total system energy increased by 20% and the overall system peak increased by 21.83%, when compared to the original ADS PCM case, as shown in Figures 1 and 2.

Figure 1

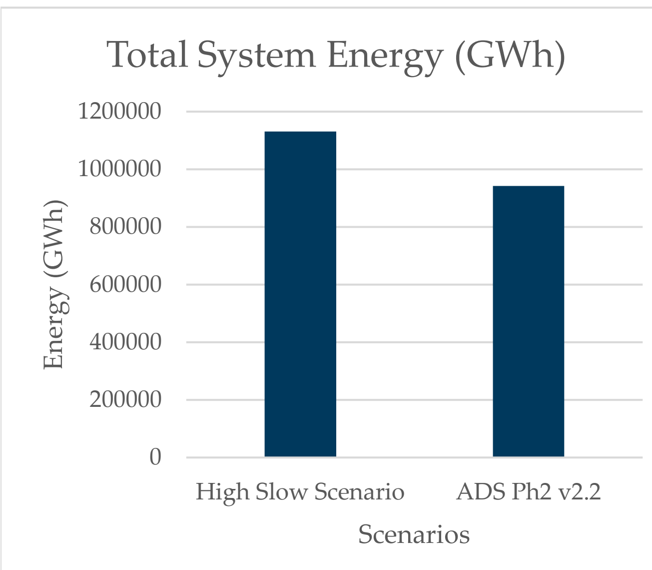


Figure 2

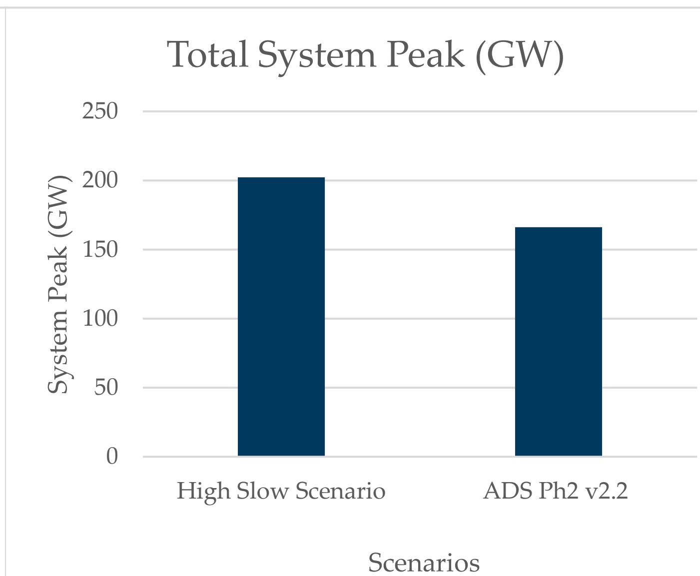


Figure 3 shows the total load (MWh) increase in all the BAs across the WI compared to the ADS Phase 2 V2.0 case based on the data as provided by NREL and the CEC. This load forecast shows areas with the highest electrification potential are BCHA, BPAT and most areas in California. Areas with comparatively lower impacts from electrification include AZPS, GCPD, NWMT, and WACM.

Figure 3

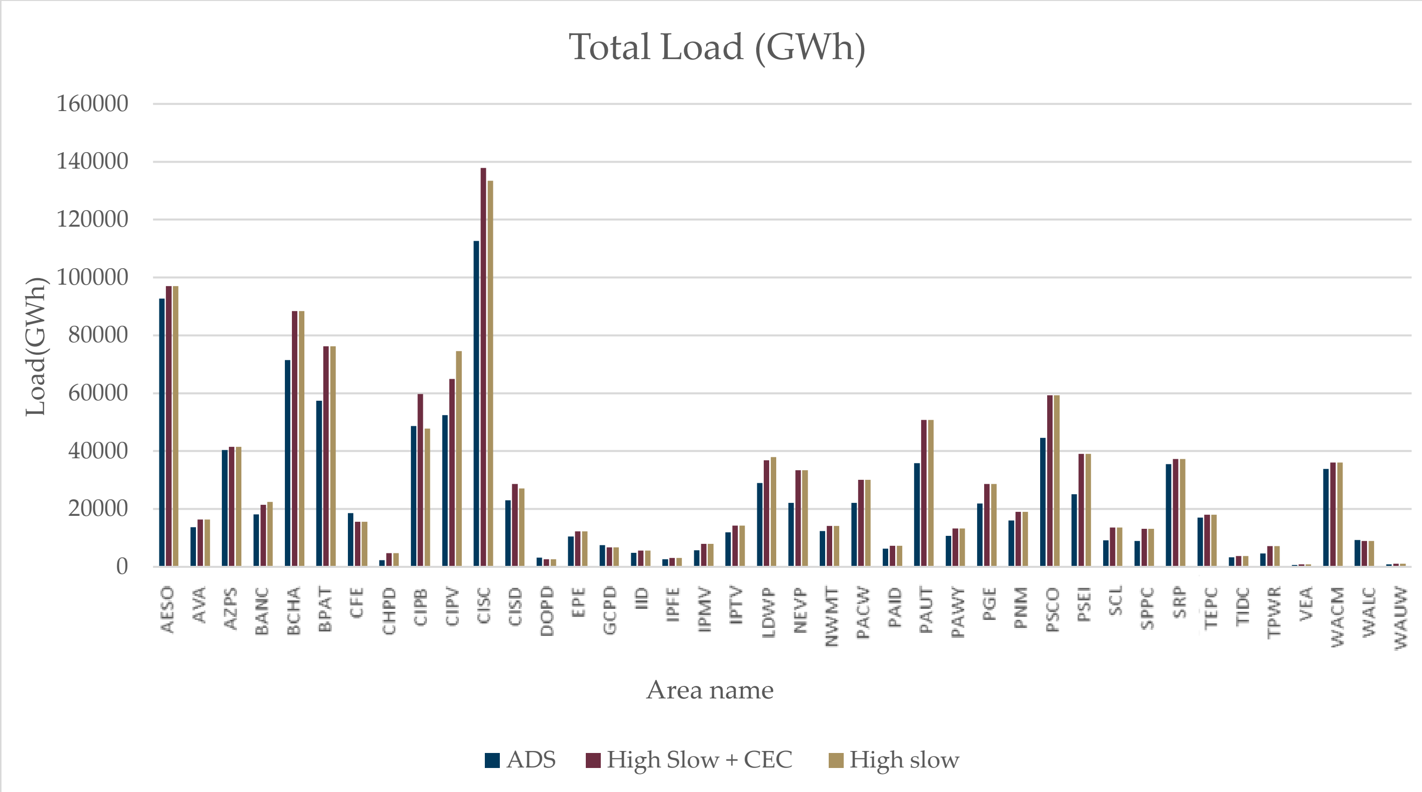
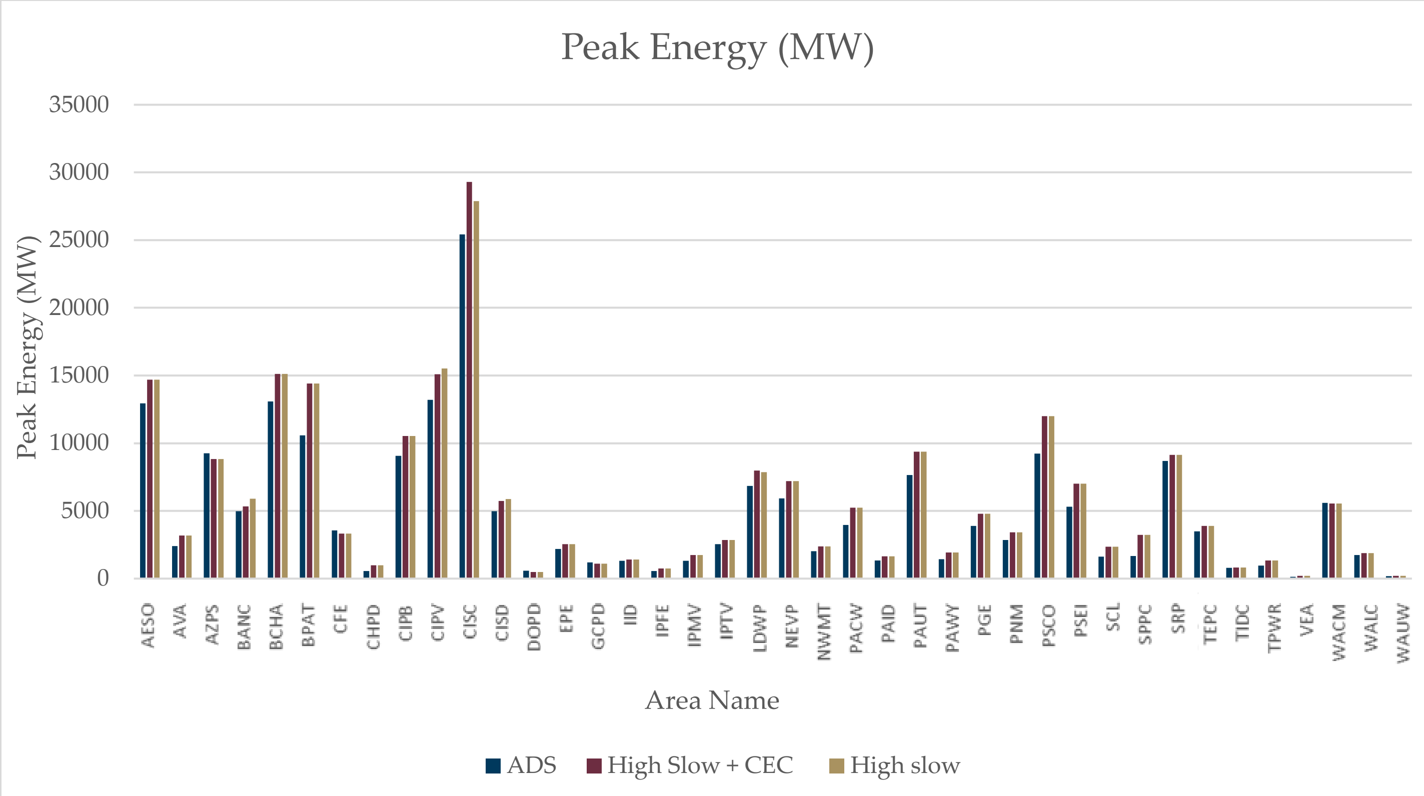


Figure 4 shows the peak load (MW) increase in all the BAs across the WI when compared to the ADS Phase 2 V2.0 case and with the addition of the CEC forecast for California. When the SETF compares the peak loads across all the BAs in the WI, the results show a similar trend to the total load comparison. Areas like BCHA, BPAT, PSCO, and most areas in California, have the highest increase in their peak loads compared to areas like AZPS, GCPD, NWMT, and WACM.

Figure 4



In addition to these scenarios, the SETF analyzed other sensitivities given that EVs and commercial building energy use can be used as a flexible load. The SETF modeled this flexible load as a variable portion of the total load, in the that it could potentially decrease the peak value (depending on the price) at which EVs would stop charging or buildings would decrease end-use at a certain time of day. This flexible load, although not a generation source, is modeled in the PCM software as a Distributed Energy Resource that would offset the EV charging load (DER-EV) or building electrification load depending on the dispatch cost of the DER-EV. Currently, the PCM software cannot model a demand response that would have the same effects.

Price points for dispatching the DER-EV range from $0 to $200/MWh, in $50/MWh increments, to best show how the DER-EV is dispatched; for example, the price at which charging these EVs would not be encouraged. The average system locational marginal price was $75.09/MWh.

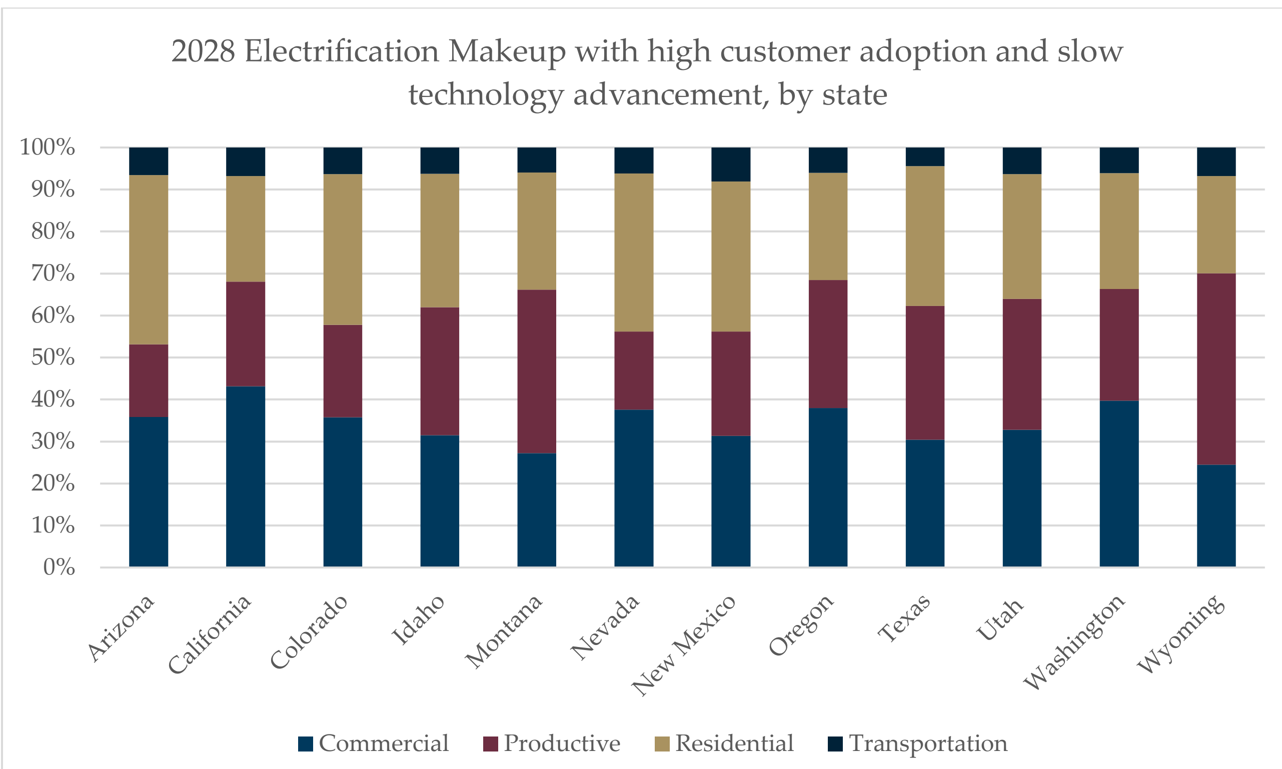
3.4. Power Flow System Stability

The SETF used the 28HS1 ADS power flow case as a starting point and adjusted to model the system's stability. To adjust the loads for electrification, a peak hour was exported from the 2028 ADS PCM Phase 2 V2.0 with the loads adjusted to their highest potential (high customer adoption with slow technology advancement scenario). The hour that had the highest load value was August 13th, 2028, at 6:00 pm PST (hour 5417). This hour had 189.2 GW of load compared to the original case that had 185.4 GW of load.

The high customer adoption and slow technology advancement was the only scenario of the nine that was higher than the ADS loads. The differences in loads and generation between the 28HS1 power flow and the exported PCM case were then compared by area. The load in the 28HS1 base case was incrementally adjusted by area to match the exported load values from the PCM case.

Once the case was solved, the task force members reviewed the changes in load and recommended necessary revisions. Changes were applied to the case for a more accurate representation. The task force verified the values against a metric developed using the NREL energy source data available with NREL's EFS report. The percentages of load that NREL published in the energy source data showed hourly use by state for the year 2028 and for the scenario that was analyzed (high customer adoption and slow technology advancement). This data was averaged over the year and broken out to show the percentage of each type of load over the total load for each state. The types of load included are transportation, commercial, residential, and productive (industrial). Figure 5 shows the makeup of electrified load in 2028, by state, in the WI. It is important for this study to increase not just the total load in the power flow case but the specific type of load. The type of load will determine the composite load model. In dynamics simulations, the various types will behave differently.

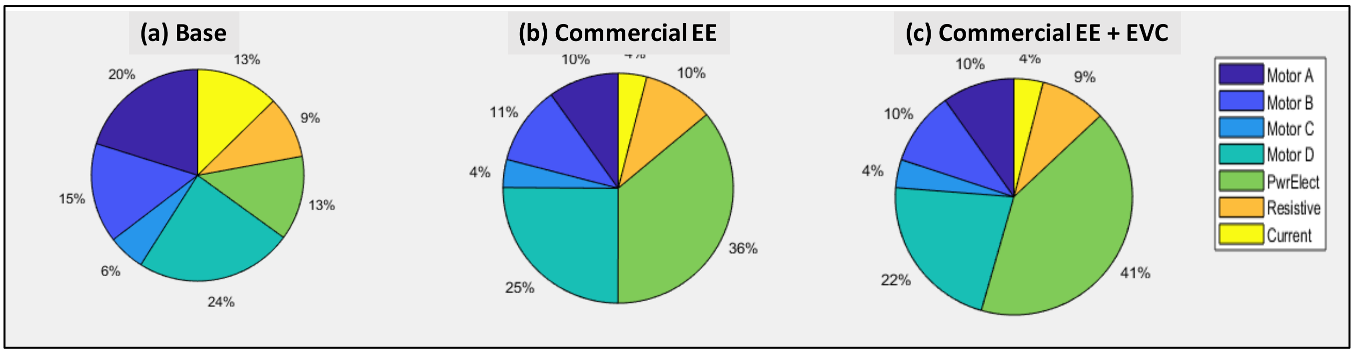
Figure 5



Once the load was in a range that the task force deemed reasonable for each type and area, the task force developed a dynamics data set for the power flow simulations. The SETF started with the 28HS11 dynamics file, as this was the dynamics file published with the base case development. A new composite load model was generated for the case for a hot summer season at 1800 PST. The task force developed two alternative composite load models to test different load compositions and the impacts on dynamics. One was generated with an expected increase in power electronic loads (drives, lights, etc.) in commercial buildings, and the other with the commercial load increase and a 20% EV charging increase in residential buildings.

Pie charts in Figure 6, compare dynamic load composition percentages for Northern California loads for (a) base scenario, (b) "Commercial Energy Efficiency" (CEE) scenario with increased power electronic drives and loads in commercial buildings, and (c) 20% of residential electric vehicles added to scenario (b).

Figure 6



3.5. Assumptions

The NREL energy data was broken out by load types, the task force assumed that the average of the total energy over the year has the same percentage breakdown by total load type contribution. For example, in Arizona, the task force assumed that 40% of the load is from residential demand because that is the average for the year. At the peak hour, however, this may not hold true.

A field in the base cases (climate zone) was used to determine the region and type of load used to develop the composite load model for that load. Almost 97% of the climate zone field is populated in the 28HS1 power flow case. The base case area definitions also do not align exactly with the state data in the energy source data, therefore, the energy data and base case data do not completely map to each other.

NREL provides the electrification forecast data by state in the U.S. The SETF mapped the states to the BAs in the 2028 ADS PCM Phase 2 V2.0 with help from the WSTF. Since there was no electrification forecast data for provinces in Canada, it was assumed that British Columbia had the same load growth rate as Washington state and Alberta had the same rate as Montana. Table 2 shows a sample of the load data. The generation portfolio was the same as 2028 ADS PCM Phase 2 V2.0 for all the sensitivity cases except when modeling the flexible portion of the load.

Table 2

Index	Area 1 2028 Static Load (MWh)	Area 1 2028 Flexible Load (MWh)	Area 1 2028 Total Load (MWh)
1	11052.57	88.11	11140.68
2	10835.82	78.96	10914.78
3	10758.95	61.69	10820.64
4	10716.91	55.13	10772.03
5	10710.75	52.53	10763.28
6	10796.1	50.50	10846.81
…			

Current PCM software cannot model the dispatchable load as demand response on the load side with a dispatch cost, so it models dispatchable load as behind-the-meter hourly generators (DER-EV) with a fixed generation profile, distributed to all the buses in the area.

4. Analytical Results

4.1. Stability Results

Disturbances Performed

Seven standard disturbances were run on the case with the three different composite load models—reference, commercial increase, and residential and commercial increase. These standard disturbances create potentially high impacts to the system throughout the interconnection and are run on each base case when being developed. The results from each disturbance simulation were checked for oscillations and other deviations from standard behavior.

The seven standard disturbances are:

1. 30-cycle insertion of Chief Joseph braking resistor ("Ringdown");
2. Three-phase fault at Comanche and loss of the Daniels Park-Comanche 1 & 2 345-kV lines;
3. Three-phase fault at Colorado River and loss of Colorado River-Red Bluff 1 & 2 500-kV lines;
4. Three-phase fault at Hells Canyon and loss of Brownlee-Hells Canyon 230-kV line;
5. Three-phase fault at Midway and loss of Gates-Midway #1 & Diablo-Midway #2 500-kV lines;
6. Loss of two Palo Verde generating units; and
7. Bi-pole Pacific DC Intertie (PDCI) outage.

The SETF found that:

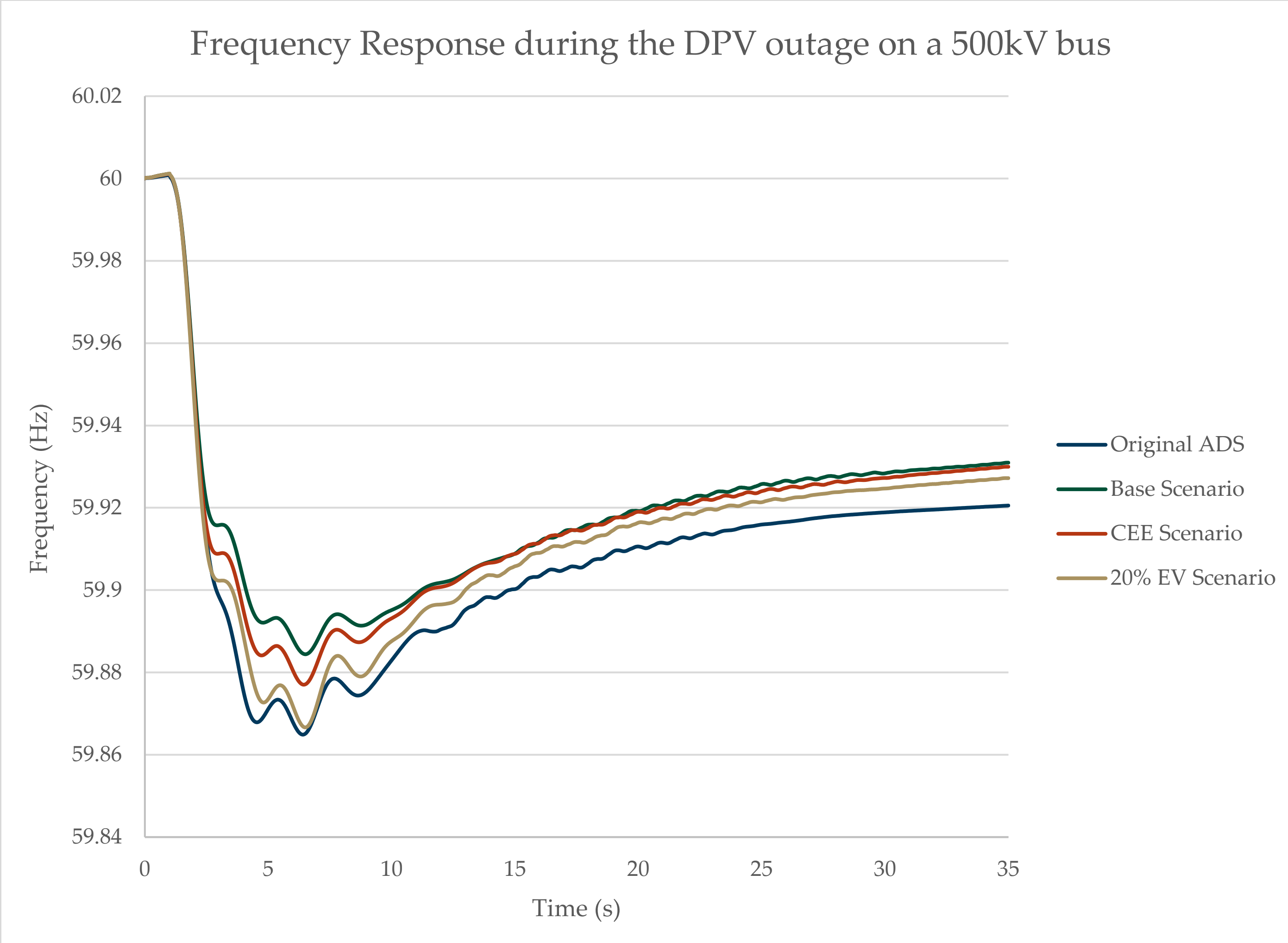
- The lowest frequency seen was 59.856 Hz during the Double Palo Verde outage;
- TPL-001 WECC CRT 3.1 WR1.3 voltage violations occurred at both ends of the PDCI during the loss of the bi-pole PDCI. These violations were present in the original 28HS1 power flow case;
- TPL-001 WECC CRT 3.1 WR1.3 voltage violations occurred on one bus in Northern California during the Midway-Diablo outage causing the bus to reach a voltage below its limit. Similarly, these violations were present in the original 28HS1 power flow case; and
- No other voltage violations were present.

The composite load models in the three scenarios discussed in Section 3.4 showed the following load tripping:

- The Brownlee-Hells Canyon outage had 4.34 MW of load tripped in the base scenario;
- The Brownlee-Hells Canyon outage had 6.12 MW of load tripped in the CEE scenario;
- The Brownlee-Hells Canyon outage had 6.52 MW of load tripped in the CEE and 20% EV increase scenario; and
- No load was shed for any of the other disturbances in the three scenarios.

One common measure of frequency response is the IFRO. It is calculated by dividing the total generation lost (in MW), by the difference in frequency (in 0.1 Hz) between the initial frequency and the recovery frequency ($\frac{\mathrm{MW}}{0.1\mathrm{Hz}}$). The minimum IFRO for the WI is 858 MW/.1 Hz. Figure 7 shows the frequency response of the Double Palo Verde outage at one high-voltage bus for various scenarios. The scenarios include the original ADS power flow case and the three composite load model compositions discussed in Section 3.4. According to this plot, the frequency response for the base scenario would be calculated as the generation lost (2,747 MW) divided by the delta frequency (.1156Hz) times 0.1. Therefore, the frequency response would be 2,376$\frac{\mathrm{MW}}{0.1\mathrm{Hz}}$; well above the WI obligation. The IFRO for the WI was satisfied for all scenarios. One observation from Figure 7 is that the changes to the load characteristics made for the scenarios developed for this assessment made the frequency dip less severe. A potential cause for this change is that generation changes were made in the electrification scenario and therefore increased the frequency response of the system.

Figure 7



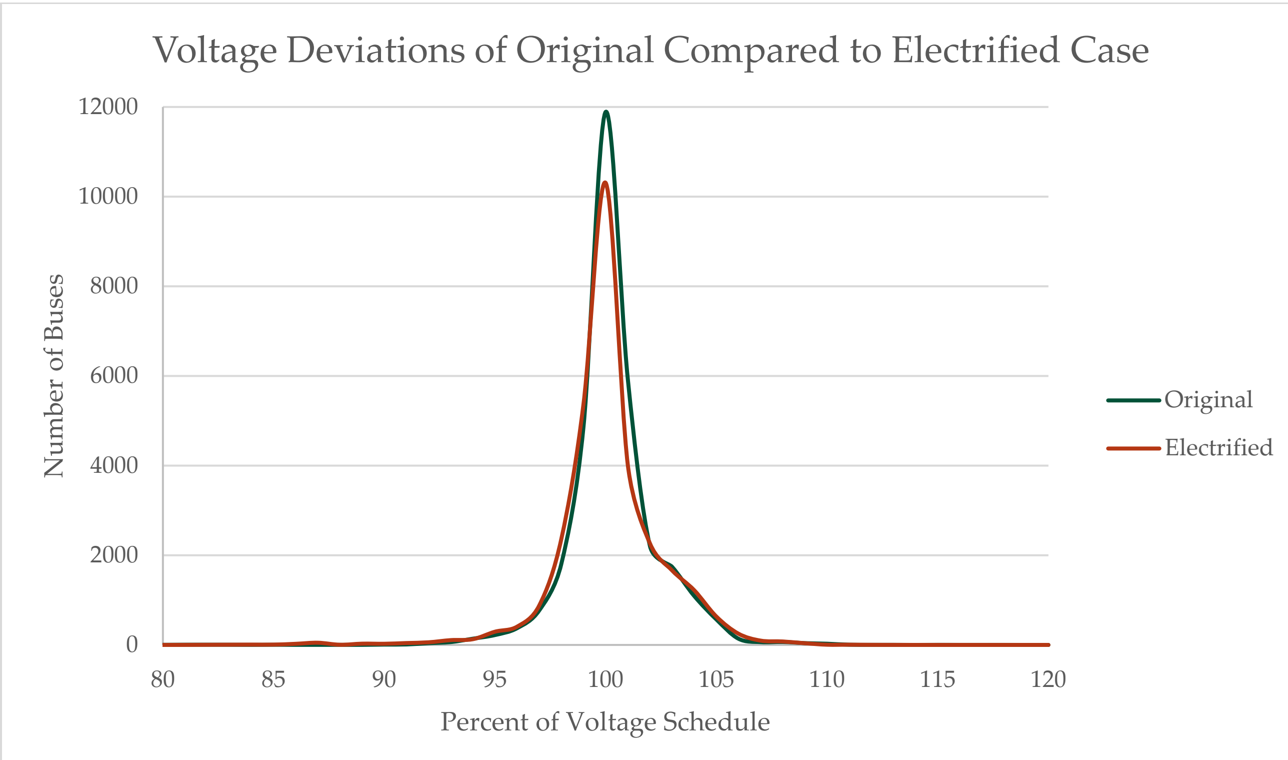
Path Use and Overloads

One of the major paths was overloaded in the steady-state power flow case. This path was overloaded by almost double the branch rating in the highly stressed electrification scenario. Section 4.2 discusses similar observations in the PCM evaluation of path overloads. Other branches were overloaded in the adjusted case compared to the original 28HS1 case. Overloads occurred on 18 branches over 100 kV in the case, compared to five in the original. Four of the five overloads in the original case contribute to the 18 seen in the adjusted case and occur throughout the system.

Voltage Violations

The case was checked for voltage violations and compared to the original starting case. Any bus was flagged with a violation if its voltage was greater than 105% or less than 95% of the voltage schedule. Figure 8 shows that the number of buses on their voltage schedule has decreased slightly, but overall, few buses are significantly higher or lower than their schedule compared to the original case. It is important to note that there were two areas in which the there was a large number of buses outside their limits: one area had approximately 190 buses lower than the minimum voltage limit, and another had approximately 60 buses above the maximum voltage limit in the electrified case. Unfortunately, the task force did not have a representative to review the base case from the area that showed lower voltages.

Figure 8



Contingencies

Typically, N-1 contingencies are not run on 10-year cases, partly due to the uncertainties of Remedial Action Schemes (RAS) that would be in place in the future and could alleviate unstable contingencies. N-1 contingencies were run on this case primarily to identify any egregious issues that needed to be analyzed further. The SETF observed the following results:

- No cascaded RAS and relay action;
- One relay action event;
- No cascaded RAS;
- No interface flow violations;
- 315 of 5,028 (6.2%) contingencies solved with a P/Q mismatch greater than 1; and
- 28 of 315 unsolved contingencies corrected with RAS, resulting in 5.7% unsolved. Further investigation should be done on these unsolved contingencies, but the small percentage indicates electrification of the system does not create significant instability.

Post-Transient Simulation

The post-transient simulation assesses the system's stability following a double Palo Verde outage or a bi-pole PDCI outage. After the event, the voltages are compared to initial conditions and can identify possible instabilities that could lead to load shedding. The loss of PDCI outage case showed no buses having greater than 5.2% deviation. One of the base case areas experienced instability when redispatching generation during the loss of Palo Verde units. This may be due to preexisting voltage profiles or generator models causing issues in the area. When this area is excluded during the redispatching process, the post-transient solves and produces no buses with a voltage deviation greater than 5%.

SETF Member Studies

SETF members performed sensitivity studies with respect to load composition assumptions. Peak transfers occur when one area has peak demand and another area has lighter loads and surplus low-cost generation. The SETF developed scenario cases to represent peak transfers on the California-Oregon Intertie using operating cases. These cases do not model increase in demand due to electrification, they only represent change in load composition due to increased share of power electronic loads.

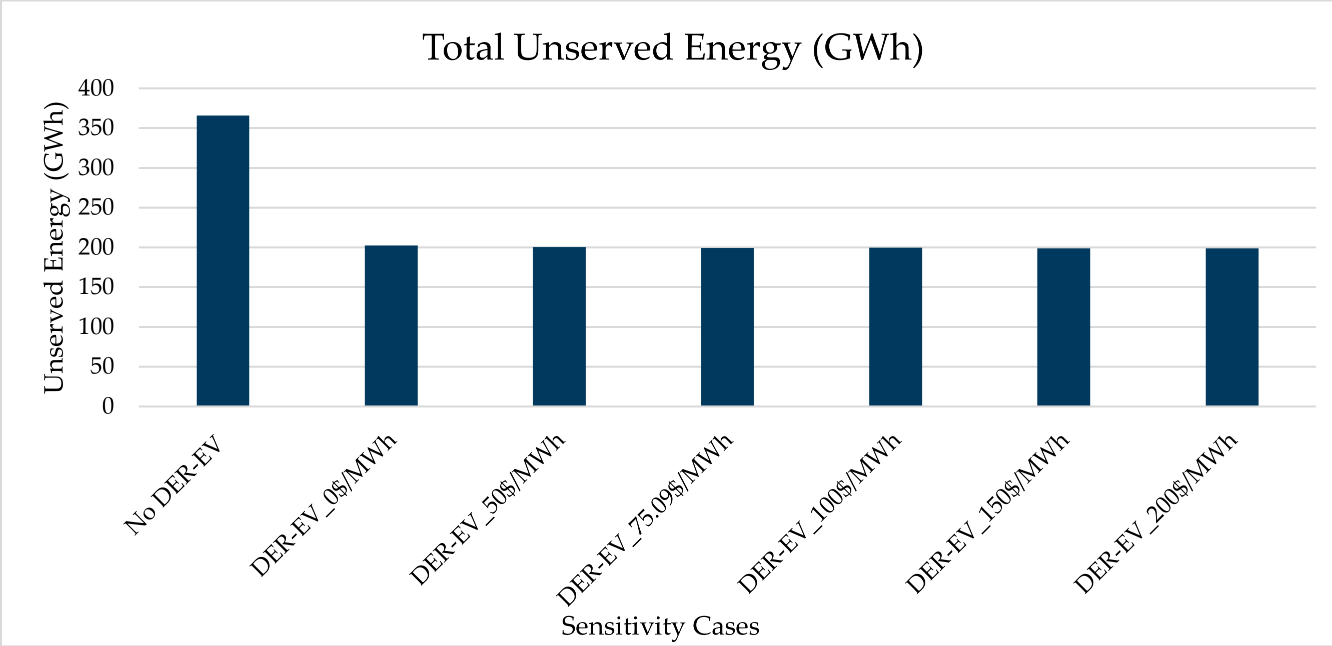
The SETF members simulated a wide range of NERC TPL planning contingencies. Transient voltage dip and transient voltage recovery were comparable for most contingencies. However, one of the study cases had a lower transient voltage dip with a higher percentage of power electronic loads.

4.2. Resource Adequacy Results

Unserved Energy

To analyze the unserved energy, seven PCM cases were run on the scenario with high customer adoption and slow technology advancement. This included cases modeling the variable load as DER-EV with price points ranging from $0 to $200/MWh in $50/MWh increments, and an average system locational marginal price (LMP) of $75.09/MWh in the sensitivity case without modeling DER-EV. The case was also run without the use of the variable load potential. Of these seven runs, the highest unserved energy occurred when all load was modeled as static and no portion was dispatched as DER-EV. In Figure 9, it is evident that nearly 370 GWh of the increased electrification load is unserved in this scenario. This also shows that the variable load capabilities serve the increased load due to electrification, reducing the unserved energy by half (nearly 200 GWh of load). Most of this unserved energy occurs during the evening peak in August.

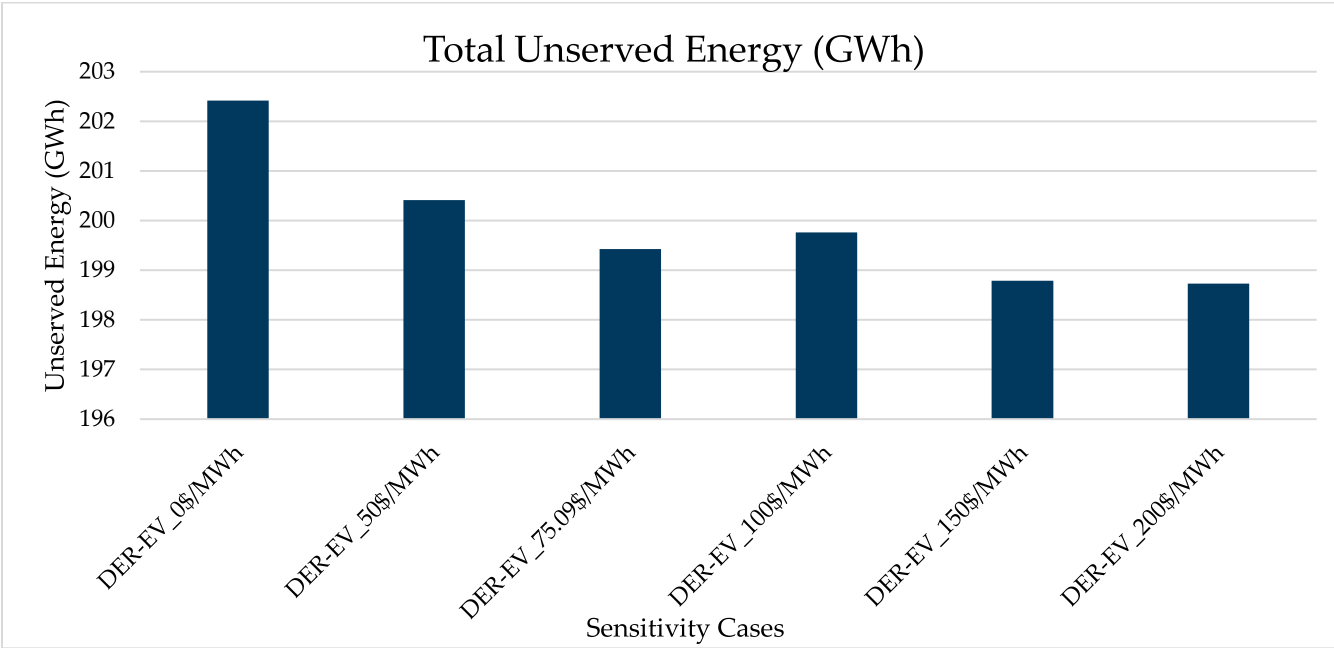
Figure 9



Excluding the case without modeling the variable load, Figure 10 shows the minor differences between dispatch costs while using the variable load as DER-EV. Figure 10 shows that the highest unserved energy occurs when the DER-EV is set to $0/MWh. This is unexpected, as it would make sense that the more expensive the DER-EV was to dispatch, the less DER-EV would be dispatched. Less dispatched DER-EV would result in an increase in unserved energy. However, the opposite occurred.

All the available DER-EV capacity is already dispatched for serving the baseload and no added variable load capacity is available to serve the evening peak load or to meet the ramping requirements of the evening load. Also, this lower-priced DER-EV displaces combined cycle units, combustion turbines, and some baseload coal units. Therefore, DER-EV at lower dispatch costs negatively affects the system by reducing capacity to meet ramping requirements and increasing total dispatch cost. At a higher dispatch cost, $200/MWh, DER-EV is dispatched last, compared to less expensive units, to meet the peak load and ramping needs. This could also be due to transmission constraints that stop generation from serving load during certain times of the year.

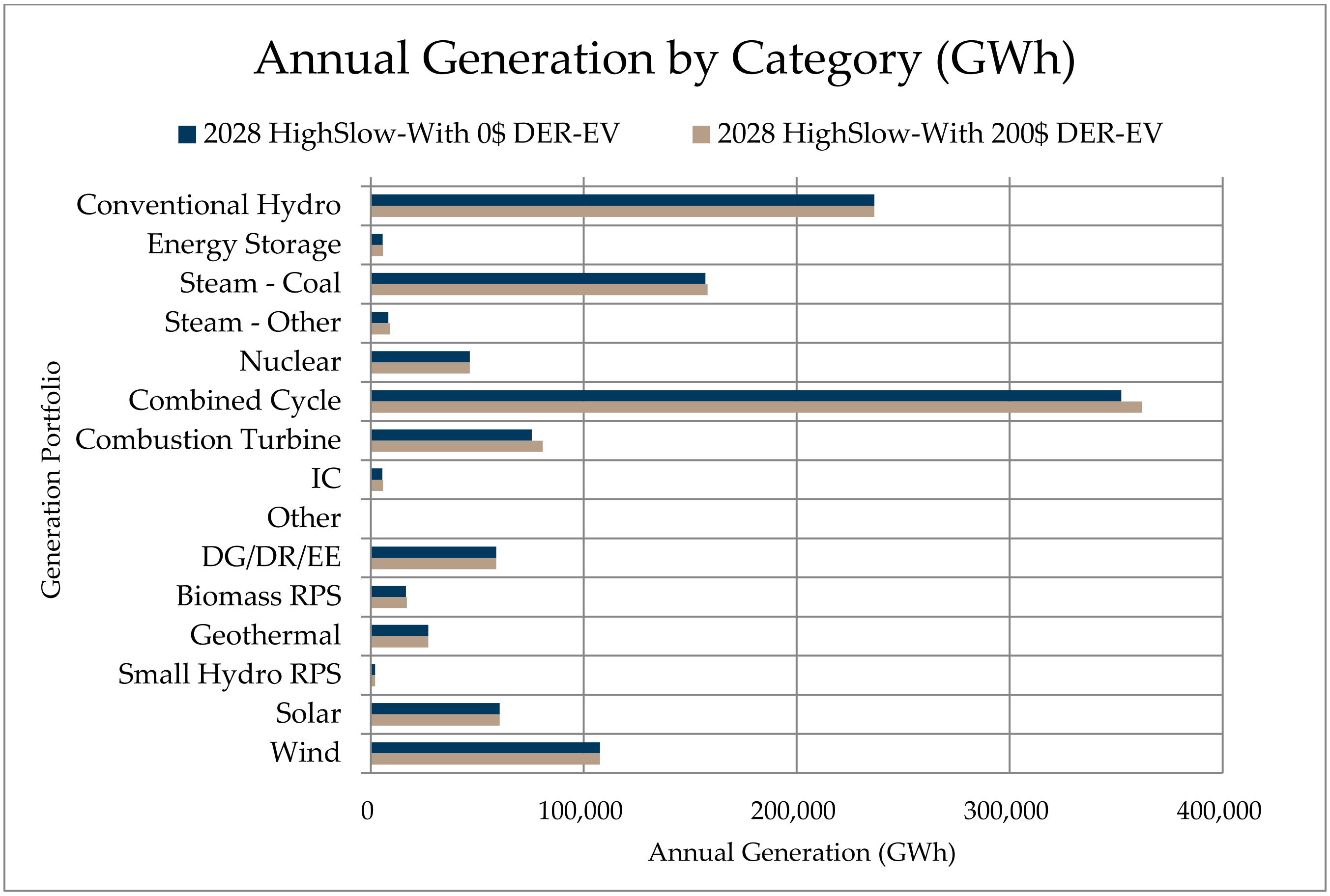
Figure 10



Change in Generation Dispatch

After determining the price point at which unserved energy is at a minimum, the generation portfolio was analyzed and the SETF came to the conclusions stated above. Figure 11 shows the generation mix when the DER-EV is priced at $0/MWh and at $200/MWh flex. This report notes that the combustion cycle and combustion turbine generation has been displaced by the lower DER-EV costs. The DER-EV has displaced 9,833 GWh of combined-cycle generation and 5,219 GWh of combustion turbine generation between $0/MWh and $200/MWh.

Figure 11



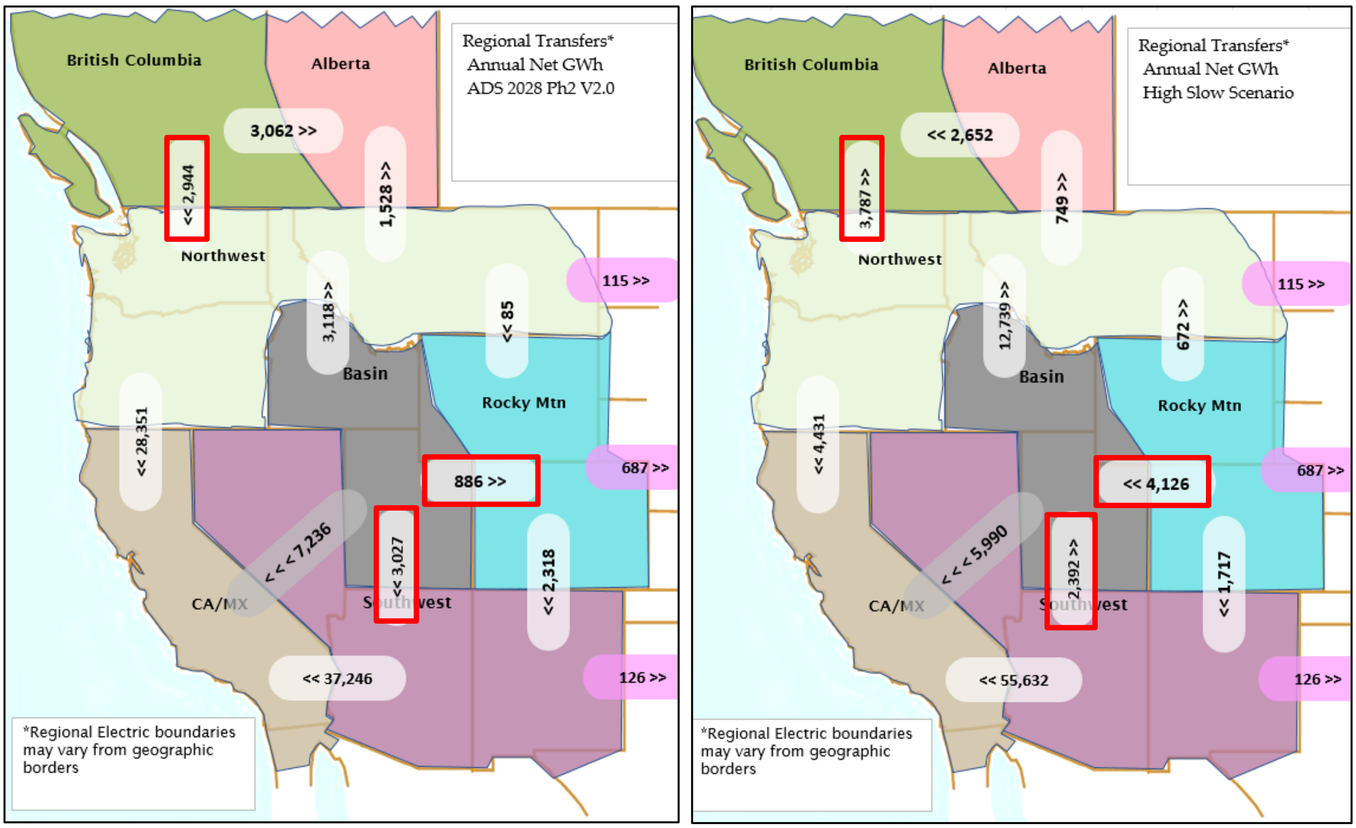
Inter-area Flows

Figure 12 shows how much the inter-regional transfers have changed with the inclusion of the electrification loads compared to the ADS PCM case. The major takeaways from analyzing the inter-regional transfers are:

- The California net imports are relatively constant between the original 10-year ADS PCM case and the adjusted electrification scenario case.
- The Rocky Mountain area has 4,364 GWh of annual surplus generation after serving its regional load, including electrification load and losses.
- The Southwest has 28,041 GWh of surplus generation after serving its 181,900 GWh of regional load, including electrification load.
- It appears the Northwest (NW) has become a net energy importer when compared to the total inter-regional flows for the ADS PCM case. The NW has 1,817 GWh of surplus generation after serving its electrification load, including losses. This is because energy is flowing into British Columbia (BC) from the NW and Alberta. As per the assumptions stated in Section 3.5, BC would require 4,455 GWh more to serve its demand.

- Flows on the ties from NW-BC, BC-Alberta, and Southwest (SW)-Basin are reversed relative to the ADS case. Building electrification load and EV load growth forecasted in the Northwest lead to this shift in energy transfers.

Figure 12



Original ADS PCM Case *Adjusted Electrification Scenario Case*

Path Utilization

WECC uses the following metrics to identify paths that are "highly utilized":

- U75 means paths that are utilized at 75% or more of their rated capacities for 50% or more of the hours in the year;
- U90 means paths that are utilized at 90% or more of their rated capacities for 20% or more of the hours in the year; and
- U99 means paths that are utilized at 99% or more of their rated capacities for 5% or more of the hours in the year.

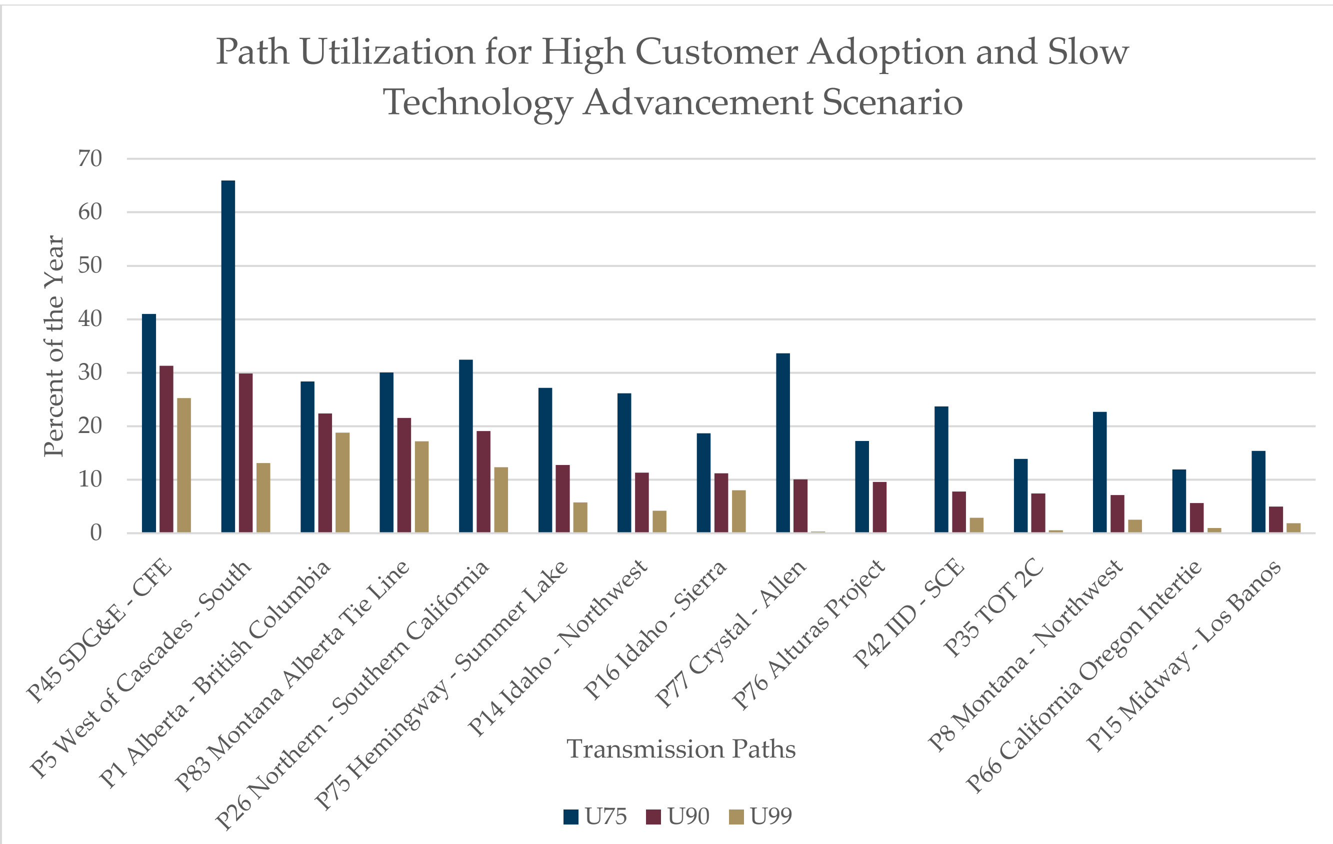
Any path that meets one or more of these criteria is identified as "highly utilized." The PCM results for path utilization mimic the results observed in the power flow analysis. Figure 13 shows the most heavily utilized paths in the PCM case and the percentage of the year they are utilized at 75%, 90% and 99% of their rated capacity.

Path 45 (SDG&E-CFE) is the most heavily utilized path. This path was utilized more than 75% of its rated capacity for over 40% of the year, at 90 % of its rated capacity for over 30% of the year, and at 99% of its rated capacity for almost 25% of the year.

Path 5 (West of Cascades-South) was also being heavily utilized. The results showed this path was utilized 75% of its rated capacity for over 65% of the year, 90% of its rated capacity for over 30% of the year, and at 99% of its capacity for 10% of the year.

Path 1 (Alberta-British Columbia Tie line) and Path 83 (Montana Alberta Tie-Line) are the next heavily utilized transmission paths.

Figure 13



Load and Generation Balance

In the high electrification scenario, without modeling dispatchable load, the WI had the highest unserved energy on August 13 at 6:00 p.m. The load-generation balance is analyzed for a 10-day snapshot, from August 12 to August 21. Figure 14 shows how the available generation portfolio is dispatched to meet the total load in the northwestern region of the WI in the ADS Phase 2 case. For most hours during this time, available generation in this area meets all the load, and, for several days, total generation in the area is higher than the total load; i.e., Area 1 is exporting to adjacent areas in the WI.

Figure 14

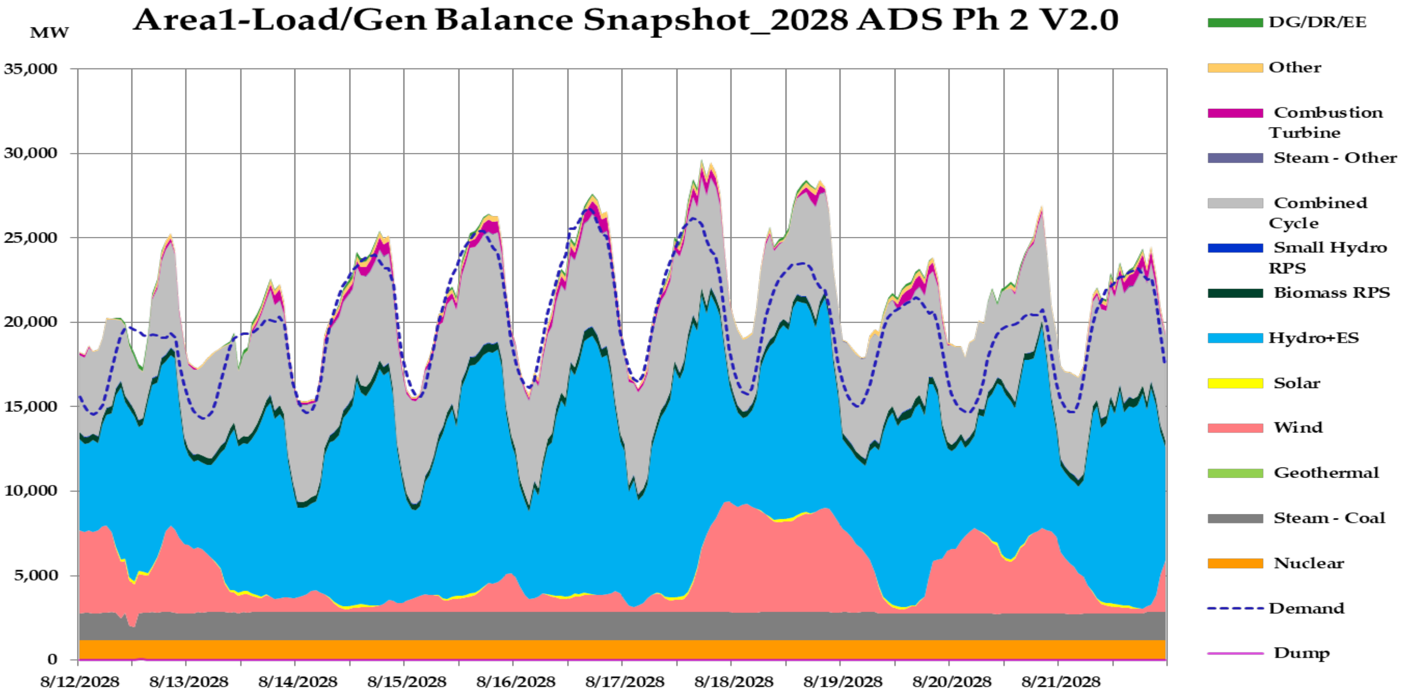
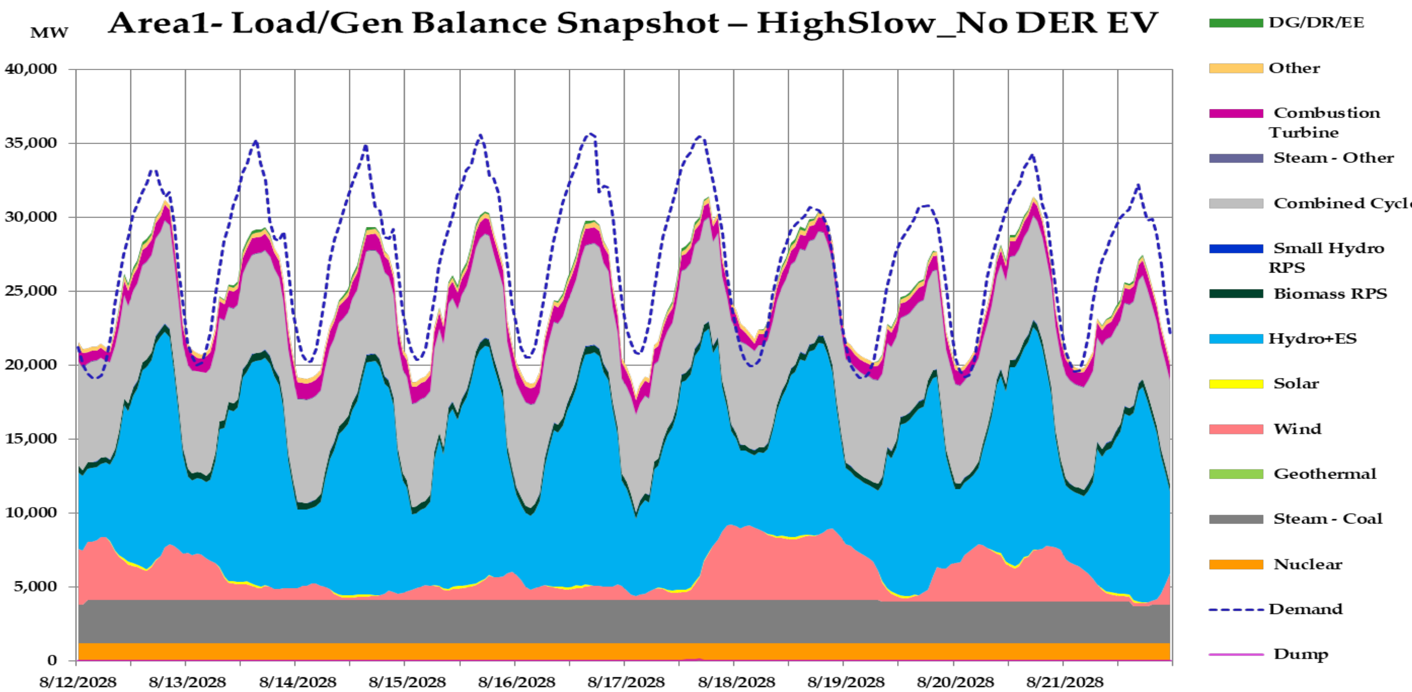


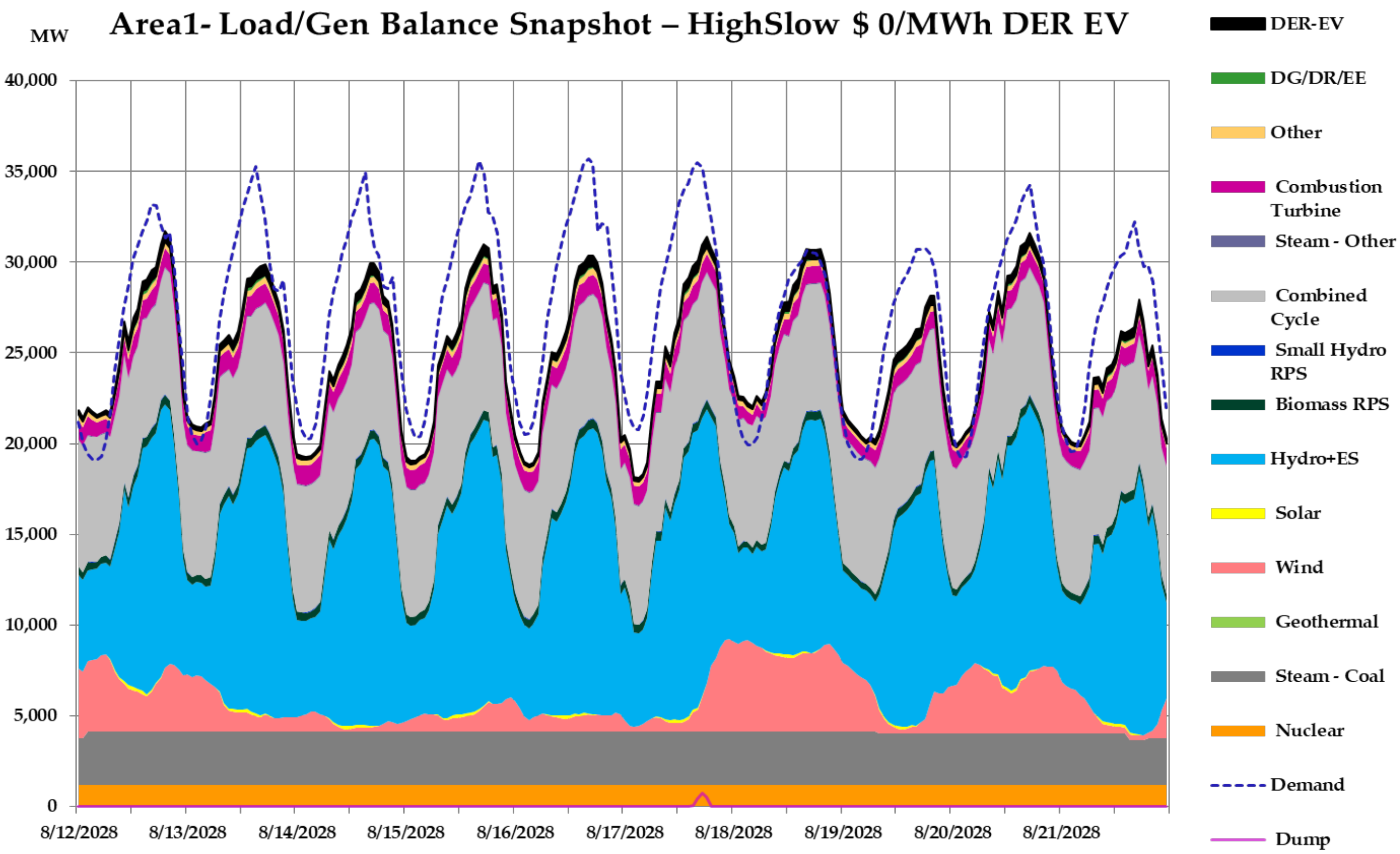
Figure 15 shows the increased electrification demand for the same area. For most days, the demand is much higher than committed generation. On average, daily peaks are 20% higher than the ADS PCM case, which resulted in unserved load. Dispatchable load is not modeled as DER-EV in this scenario.

Figure 15



In this next scenario, dispatchable load is modeled as behind-the-meter DER EV, with a dispatch cost of $0/MWh. Figure 16 shows how DER-EV is being committed to minimize unserved energy during this 10-day period for the same area. By showing just one area in these examples, it is easier to see how DER-EV is being dispatched to offset the unserved energy. A similar trend is seen in the entire WI.

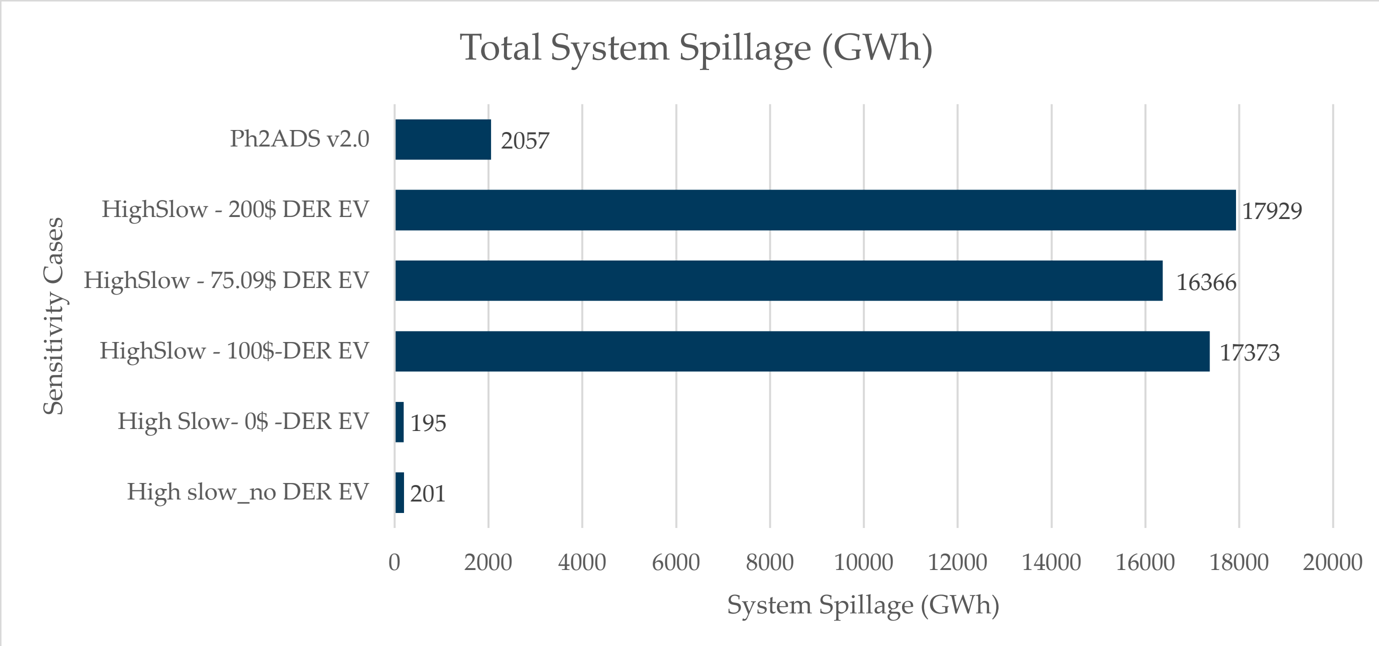
Figure 16



System Spillage

System spillage occurs when hourly resources are curtailed due to lower demand compared to the available hourly generation or due to transmission constraints in a particular hour. Figure 17 shows the total system spillage in the different sensitivity cases. Since the variable load is modeled as DER-EV, an hourly resource with a fixed generation profile, at higher prices, these resources are not dispatched, often leading to increased and high spillage in the sensitivity cases with the DER-EV dispatch cost of $100/MWh or more. In sensitivity cases with no DER-EV modeled, all the hourly resources already present in the ADS Phase 2 V2.0 PCM case are dispatched to serve the increased load. In the sensitivity cases with a low dispatch cost for the DER-EV, these resources are dispatched to serve the increased electrification load, reducing the system spillage.

Figure 3



5. Observations and Conclusions

After running several analyses to determine the stability of the electrified 2028 case, the SETF determined that the electrification did not significantly increase any reliability risks. Stability issues were already present in the original ADS case, and there were minor sensitivities when the load was increased in certain areas. Depending on the generation used to serve the load increase, low voltages were seen in one area. These low voltages could be mitigated by more accurate assumptions about generation redispatching or topology updates that were not present in the original 28HS1 case. Also note that a major path was overloaded due to the increase load. Overall, the electrification in the 10-year horizon presents no major reliability risks, as this study looked at the maximum load forecast during a scenario that involved high customer adoption and a slow technology advancement. It is more likely that electrification will be somewhere in between a reference case and this forecast, suggesting the interconnection generation supply and stability will be stable during this period.

After running several PCM studies, the SETF saw:

1. During this high-stress condition, the system had higher amounts of unserved energy and system spillage. With electrification, there were significant changes in inter-regional energy transfers, especially between BC-NW-Alberta, SW-Basin, and Rocky Mountain-Basin.
2. The dispatchable load or DER-EV is essential to reduce the size of the unserved energy by half. Though the DER-EV dispatch cost had minimal impact on the entire WECC system, when being dispatched at very low costs (0$/MWh), this DER-EV is displacing the peaking combined cycle and combustion turbine units, causing higher unserved energy compared to DER-EV being

dispatched at higher cost (~$200/MWh). Although the most unserved energy was seen during August, a typical summer-peaking month, a couple of major paths were heavily utilized throughout the entire year.

3. In the sensitivity runs with lower DER-EV dispatch costs, and with no DER-EV used, the least system spillage occurred. This is because all the hourly resources were being committed to meet the increased electrification load.

6. Recommendations

This study was the first coordinated effort to assess the reliability impact of electrification in the Western Interconnection. Such studies should continue as more information becomes available. There are several regional and national efforts under way that will provide more information on the impacts of the electrification of the grid.

The peak load value for 2028 occurred in the summer. However, the task force recommends studying a winter peak power flow case. During the winter, heat pumps for water and space heating will convert more typically non-electric utilities to electric load, affecting the colder and more northern areas in the WI. The total load for the interconnection will be less in the winter compared to the summer, but it will change the path flows due to higher loads in the northern part of the system.

Modeling DER-EV as dispatchable load with an associated cost would more accurately represent the flexibility of the electrification load. Having a flexible portion of DER-EV helps serve the most unserved energy, but more studies should be conducted to assess the value of the DER-EV. Studying various levels of dispatchable load availability, at varying dispatch costs, would produce some interesting results, and this would even offset the need for adding more generation to meet the increased electrification load.

The task force also recommends studying generation changes in the Year 10 future. By strategically adding generation to meet the increased load, the generation portfolios could better adapt to the needs in the load scenario. Inverter-based resources can be dispatched differently than conventional generation and could serve a large part of the ramping load due to electrification and decrease unserved energy.

This study used the most extreme load scenario to evaluate the potential outcomes. The task force recommends studying other scenarios to analyze more realistic implications for increased electrification. Modeling the electrification load forecast using the utilities' Integrated Resource Plans would create a more realistic scenario that might produce different results, including the threshold at which the system starts to experience unserved energy and transmission utilization constraints.

While PCM studies show reduction in the total energy transfers on certain paths, further assessment of path flows, variability, and ramp rates must be conducted to ensure the transmission system can reliably accommodate them.

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