National Transmission Planning Study

Chapter 4:

AC Power Flow Analysis for 2035 Scenarios

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Context

The National Transmission Planning Study (NTP Study) is presented as a collection of six chapters and an executive summary, each of which is listed next. The NTP Study was led by the U.S. Department of Energy's Grid Deployment Office, in partnership with the National Renewable Energy Laboratory and Pacific Northwest National Laboratory.

- The **Executive Summary** describes the high-level findings from across all six chapters and next steps for how to build on the analysis.
- **Chapter 1: Introduction** provides background and context about the technical design of the study and modeling framework, introduces the scenario framework, and acknowledges those who contributed to the study.
- **Chapter 2: Long-Term U.S. Transmission Planning Scenarios** discusses the methods for capacity expansion and resource adequacy, key findings from the scenario analysis and economic analysis, and High Opportunity Transmission interface analysis.
- **Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios** summarizes the methods for translating zonal scenarios to nodal-network-level models, network transmission plans for a subset of the scenarios, and key findings from transmission planning and production cost modeling for the contiguous United States.
- **Chapter 4: AC Power Flow Analysis for 2035 Scenarios (this chapter)** identifies the methods for translating from zonal and nodal production cost models to alternating current (AC) power flow models and describes contingency analysis for a subset of scenarios.
- **Chapter 5: Stress Analysis for 2035 Scenarios** outlines how the future transmission expansions perform under stress tests.
- **Chapter 6: Conclusions** describes the high-level findings and study limitations across the six chapters.

As of publication, there are three additional reports under the NTP Study umbrella that explore related topics, each of which is listed next.[1] For more information on the NTP Study, visit https://www.energy.gov/gdo/national-transmission-planning-study.

- **Interregional Renewable Energy Zones** connects the NTP Study scenarios to ground-level regulatory and financial decision making—specifically focusing on the potential of interregional renewable energy zones.

[1] In addition to these three reports, the DOE and laboratories are exploring future analyses of the challenges within the existing interregional planning landscape and potential regulatory and industry solutions.

- **Barriers and Opportunities To Realize the System Value of Interregional Transmission** examines issues that prevent existing transmission facilities from delivering maximum potential value and offers a suite of options that power system stakeholders can pursue to overcome those challenges between nonmarket or a mix of market and nonmarket areas and between market areas.

- **Western Interconnection Baseline Study** uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on best available data.

List of Acronyms

AC	alternating current
ADS	Anchor Dataset
API	application programming interface
BA	balancing authority
BESS	battery energy storage systems
BTM	behind the meter
CAISO	California Independent System Operator
C-PAGE	Chronological AC Power Flow Automated Generation
CDF	cumulative distribution function
DC	direct current
DOE	U.S. Department of Energy
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GDAL	Geospatial Data Abstraction Library
GIS	geographical information system
GW	gigawatt
HVDC	high-voltage direct current
ID	identification
IDW	inverse distance weighting
ISO	independent system operator
km	kilometer
KS	Kolmogorov–Smirnov
KS-D	Kolmogorov–Smirnov distance
kV	kilovolt

LHSD	Latin hypercube sampling with dependence
MW	megawatt
NREL	National Renewable Energy Laboratory
NTP Study	National Transmission Planning Study
PCM	production cost model
PNNL	Pacific Northwest National Laboratory
PSLF	Positive Sequence Load Flow
PSS/E	Power System Simulator for Engineering
PV	photovoltaic
ST	steam turbine
TRC	technical review committee
VRE	variable renewable energy
WECC	Western Electricity Coordinating Council

Chapter 4 Overview

This chapter presents the National Transmission Planning Study (NTP Study) alternating current (AC) power flow analysis methods and key findings, in line with key NTP Study goals to identify interregional and national strategies to accelerate decarbonization while maintaining system reliability. Power flow studies are vital for determining how best to operate current transmission systems and plan for system expansion.

This chapter evaluates the reliability of transmission expansion options using power flow analyses of two specific transmission expansion scenarios that were developed for the Western Interconnection in support of the NTP Study: 1) the Western Interconnection 2035 Limited (Lim) scenario and 2) the Western Interconnection 2035 Alternating Current (AC) scenario.[2] The specific assumptions used for these scenarios are high demand growth[3] and the 90% decarbonization by 2035 emissions constraint. Though the NTP Study team used power flow software and methods accepted by industry transmission planners to conduct contingency analyses, the team's analysis neither simulated the full scope of contingencies that transmission planners customarily perform nor considered monitoring criteria or operating procedures specific to each utility. This chapter analyzes the most critical and impactful contingencies recognized by the transmission planning community to test the overall robustness of the transmission expansion scenarios and demonstrates the associated method of power flow case development, which can be adopted for further detailed reliability analyses.

Key Findings

Using tools refined in the NTP Study, power flow cases with different generation mixes can be extracted from production cost model simulations.

Intelligent sampling methods, such as those applied in this chapter, should be used to select representative hours from the production cost model for the power flow analysis as planning engineers face significantly varying load, wind, solar, and online generation mixes within the same scenario. Thus, the linkage between the production cost model and the power flow model is critical for investigating the reliability of future scenarios.

Power grids with large transmission buildouts and clean energy penetration can be planned to withstand contingencies.

New transmission lines associated with the scenarios can be planned to avoid voltage or thermal loading risks to the system, even when they are highly loaded. Utility-scale

[2] The power flow analysis study examined only the Lim and AC scenarios within the Western Interconnection footprint because of study timeline limitations. Future areas recommended for study include conducting additional stress analyses for combined Eastern and Western Interconnection scenarios expanding transmission scenarios (e.g., multiterminal high-voltage direct current [HVDC]).

[3] An increase in peak demand of 21% relative to the 2030 Industry case. For more information regarding the load assumptions, refer to Chapter 1: Introduction (Appendix D), earlier (Round 1) ReEDS Scenario. The nodal realization is explained in Section 4 of Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios.

storage can play a key role in providing the primary frequency response for large power plant contingencies. However, a full reliability analysis is necessary for new grid infrastructure.

Advanced data analytics developed in this study can help industry understand grid behavior for many AC power flow hourly snapshots and contingencies.

The database management system and interactive visualization developed in this study can help planning engineers understand and analyze system behavior for many AC power flow hourly snapshots and contingencies

Table of Contents

Chapter 4 Overview....vii

1 Introduction 1

2 Methodology 3

2.1 Importance of the Linkage Between the Production Cost Model and Power Flow Model 3

2.2 Chronological AC Power Flow Automated Generation (C-PAGE) 3

2.2.1 Stage 1: Prepare the DC power flow cases using production cost model results 4

2.2.2 Stage 2: DC-to-AC convergence process 5

2.2.3 Stage 3: Reactive power planning for voltage improvement 5

2.3 Intelligent Sampling.... 5

2.3.1 Method for intelligent sampling of representative hours.... 5

2.4 Descriptions of the Transmission Expansion Scenarios 7

2.5 Contingency Analysis.... 11

3 Key Findings for AC Power Flow Analysis 13

3.1 Using Tools Refined in the NTP Study, Power Flow Cases With Different Generation Mix Can Be Extracted From Production Cost Model Simulations 13

3.1.1 The linkage between the production cost model and the power flow model is critical for investigating the reliability of future scenarios 13

3.1.2 Intelligent sampling is necessary when developing power flow models to account for the increasing variability of generation and load.... 13

3.2 Power Grids With Large Transmission Buildouts and Clean Energy Penetration Can Be Planned To Withstand Contingencies 14

3.2.1 Outage of highly loaded new transmission buildouts do not introduce reliability risk in the developed scenarios 14

3.2.2 Utility-scale battery storage plays a critical role in providing governor response during the outage of large power plants 21

3.3 Advanced Data Analytics Developed in This Study Can Help Industry Understand Grid Behavior for Many AC Power Flow Hourly Snapshots and Contingencies.... 26

4 Conclusions 27

References 29
Appendix A. Compatibility Issues Between the Production Cost Model and the Power Flow Model 31
Appendix B. Procedure for Preparing AC Power Flows Based on Production Cost Model Data for Power Flow Case Creation 45
Appendix C. Visualization of Simulation Results Using a Geographic Information System 51
Appendix D. Western Interconnection Transmission Modeling Assumptions 56

List of Figures

Figure 1. The NTP Study modeling framework consists of incorporating datasets and assumptions, performing capacity expansion modeling (Chapter 2), translating capacity expansion modeling results into nodal production cost modeling (Chapter 3), and conducting power flow modeling (this chapter) 2

Figure 2. C-PAGE AC power flow three-stage convergence process 4

Figure 3. Process of disaggregating generation and load from production cost model simulation results to power flow cases 4

Figure 4. Sampling design that explicitly accounts for the seasonal and diurnal variations of renewable energy sources 7

Figure 5. Transmission expansion in the 2035 Lim scenario from the 2030 ADS: 500-, 230-, and 345-kilovolt (kV) circuits are added or updated; new high-voltage direct current (HVDC) circuits are added 8

Figure 6. Transmission expansion in the 2035 AC scenario from the 2030 ADS: 500-, 230-, and 345-kV circuits are added or updated; new HVDC circuits are added 9

Figure 7. Seven WECC subregions (excluding Alberta, British Columbia, and Northern Baja California Mexico): Basin (BASN), California North (CALN), California South (CALS), Desert Southwest (DSW), Northwest United States (NWUS), and Rocky Mountain (ROCK) 10

Figure 8. (a) Gen mix Lim vs. AC at interconnection level; (b) Gen mix Lim vs. AC at region level; (c) Gen mix difference Lim vs. AC at interconnection level; (d) Gen mix difference Lim vs. AC at region level.. 11

Figure 9. Distribution of the representative hours for the NTP 2035 AC case; the color scheme corresponds to different times of the day: blue signifies nighttime, yellow indicates transition periods, and green represents daytime 14

Figure 10. Generation mix at 4 p.m. MST on August 2, 2035 15

Figure 11. Single-circuit flow of the selected three parallel lines on August 2, 2035: Maximum loading time east to west 16

Figure 12. Lim contingency scenario: (a) pre- and (b) postcontingency line flows; some flow changes between southern New Mexico and Arizona; some flows reverse direction 17

Figure 13. Lim AC contingency scenario: (a) pre- and (b) postcontingency system voltages; no significant voltage change following the contingency 18

Figure 14. Generation mix at 10 p.m. MST on August 2, 2035: Natural gas and wind are the dominant generation 19

Figure 15. Single-circuit flow of the selected double-circuit 500-kV line on August 2, 2035: Nearly maximum loading time during high wind penetration 19

Figure 16. AC contingency scenario: (a) pre- and (b) postcontingency line flows; some flow changes in New Mexico as power was diverted north before it was sent to the West.. 20

Figure 17. AC contingency study: System voltages before (left) and after (right) the contingency; there is not a significant voltage change following the contingency 21

Figure 18. (a) Precontingency generation mix for the 2030 ADS case as a reference industry case, 2035 Lim scenario, and 2035 AC scenario: The NTP Study evaluated scenarios that have more renewable generation than the Baseline case, especially high solar penetration; (b) generation dispatch difference by type in the 2035 Lim and AC scenarios from the 2030 ADS case 22

Figure 19. Generation redispatch after the loss of 2,600 MW of generation: BESS, Hydro, Natural Gas, PS-Hydro dispatch; Hydro accounts for the greatest contribution in the ADS case redispatch; BESS has the greatest contributions in both NTP AC and Lim scenarios 23

Figure 20. Voltage heatmaps (a) pre- and (b) postcontingency for the loss of 2,600 MW of generation at a nuclear power plant for the 2030 ADS case: No significant voltage changes following the contingency 24

Figure 21. Voltage heatmaps (a) pre- and (b) postcontingency for the loss of 2,600 MW of generation at a nuclear power plant for the Lim scenario: No significant voltage changes following the contingency 25

Figure 22. Voltage heatmaps (a) pre- and (b) postcontingency for the loss of 2,600 MW of generation at a nuclear power plant for the AC scenario: No significant voltage changes following the contingency 26

Figure A-1. Same generators modeled at different buses in the (a) power flow and (b) production cost models 33

Figure A-2. Generators modeled as one lumped unit versus several distributed units at the same bus in the (a) power flow and (b) production cost models 33

Figure A-3. Interface flow for Path P4 on July 19 (2035 AC scenario) 35

Figure A-4. Interface flow for Path P4 on July 19 (2035 AC scenario) 36

Figure A-5. Interface flow for Path P65 on July 19 (2035 AC scenario) 36

Figure A-6. Interface flow for Path P66 on July 19 (2035 AC scenario) 37

Figure A-7. Interface flow for Path P4 on July 29 (2035 Lim case) 38

Figure A-8. Interface flow for Path P16 on July 29 (2035 Lim case) 38

Figure A-9. Interface flow for Path P65 on July 29 (2035 Lim case) 39
Figure A-10. Interface flow for Path P66 on July 29 (2035 Lim case) 39
Figure A-11. Boxplots of the transmission line (a) flow error and (b) percentage error between the power flow and production cost models.... 40
Figure A-12. Boxplots of the transmission interface (a) flow error and (b) percentage error between the power flow and production cost models 41
Figure A-13. Conversion of an HVDC line to two generators, a sending terminal, and a receiving terminal.... 44
Figure B-1. Process of disaggregating generation and load from the production cost model simulation results to power flow cases 47
Figure B-2. Procedure to convert a converged DC power flow case from the production cost model results to a converged AC power flow case.... 48
Figure B-3. Reactive power planning to improve voltage profiles.... 49
Figure C-1. Flowchart showing the automated process for analyzing and visualizing simulation results 52
Figure C-2. Voltage heatmap and visualization of the transmission line flows 54
Figure C-3. Visualization of the major loading paths and transmission line flows 55

List of Tables

Table 1. Contingency Limit Monitoring Settings 12
Table A-1. Redispatched Hydropower Units Considering the Loading Distribution and Modified Capacity Limits 42
Table A-2. Redispatched Hydropower Units Considering Prioritization and Different Unit Capacity Limits.... 42

1 Introduction

This chapter describes the power flow analysis of two specific transmission expansion scenarios that were developed for the Western Interconnection in support of the NTP Study:**Error! Bookmark not defined.**

1. **Western Interconnection 2035 Limited (Lim) Scenario**
   Transmission is developed only within Federal Energy Regulatory Commission (FERC) Order No. 1000 planning regions; no interregional transmission is included.

2. **Western Interconnection 2035 Alternating Current (AC) Scenario**
   Transmission is developed between adjacent FERC Order No. 1000 regions in the Western Interconnection; no transmission is built between the Western and Eastern Interconnections.

The specific assumptions used for these scenarios are high demand growth[4] and a 90% decarbonization by 2035 emissions constraint. To reliably plan for a high penetration of wind and solar generation, grid planners perform steady-state voltage and thermal contingency analyses of numerous AC power flow models that bracket the range of the varying dispatch characteristics through all hours of the year.

The AC power flow models in this chapter are based on industry-provided data with significant additions of new wind, solar, and storage resources and transmission expansions based on capacity expansion modeling results (Chapter 2). The study team translated the capacity expansion model results, through zonal-to-nodal translation (Chapter 3), into a nodal production cost model. The production cost model simulations provided chronological hourly dispatch of generation and load. As described in this chapter, the study team fed this hourly dispatch from the production cost model into the AC power flow models to perform a steady-state contingency analysis.

Figure 1 summarizes how the power flow cases referenced in this chapter were created in relation to the initial datasets, capacity expansion modeling, and zonal-to-nodal realization found in other chapters. Grid planners can use this strong functional framework and the associated datasets to accelerate the analysis and development of new transmission.

[4] An increase in peak demand of 21% relative to the 2030 Industry case. For more information regarding the load assumptions, please refer to Chapter 1: Introduction (Appendix D), earlier (Round 1) ReEDS Scenario. The nodal realization is explained in Section 4 of Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios.

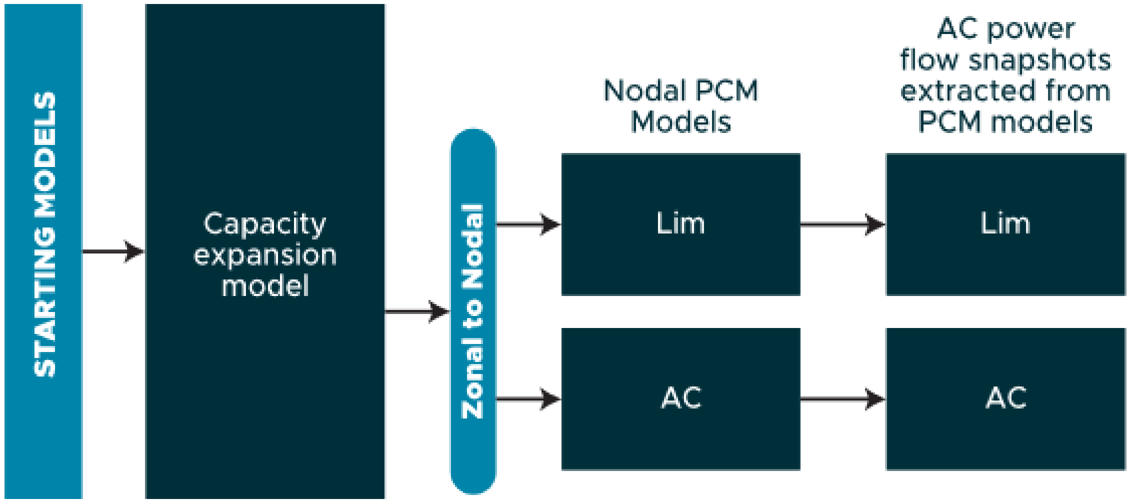


Figure 1. The NTP Study modeling framework consists of incorporating datasets and assumptions, performing capacity expansion modeling (Chapter 2), translating capacity expansion modeling results into nodal production cost modeling (Chapter 3), and conducting power flow modeling (this chapter)

PCM = production cost model

2 Methodology

This section provides a brief description of the methods used to create AC power flow cases from the production cost model. It conveys the evolution of the power flow from the production cost model, why it is necessary to advance the state of the art in power flow analytics, and the benefits that industry can gain from this analysis in the NTP Study to replicate the process for detailed transmission planning studies.

2.1 Importance of the Linkage Between the Production Cost Model and Power Flow Model

Grid planners need enhanced power grid reliability studies to prepare the transmission network for the increasing penetration of variable generation and the growing variability and volume of electric demand. Grid planning at the interconnection level currently requires only a small number of system snapshots to manage today's grid. As transmission expands, however, planners will need greater numbers of system snapshots for reliable grid planning, especially interregional transmission, as intricate transactions among balancing authorities (BAs) become more common and as variable renewable energy (VRE) penetration increases. Grid planners will need datasets, tools, and models that provide the ability to examine solutions across thousands of chronological power flow cases to understand the operational impacts of increased penetrations of VRE and changing load patterns (Hitachi ABB 2024; Western Electricity Coordinating Council [WECC] 2020a). Chronological power flow is valuable in transmission planning to calculate performance indices for systems with high renewables penetration, such as the optimal combination of network reinforcements to reduce energy spillage and the cost-effectiveness of equipment investments (WECC 2020b).

The process to create a single, operable AC power flow model takes a substantial amount of time because it involves production cost modeling, convergence of the AC power flow, and reactive power planning (da Silva et al. 2012; Hitachi ABB 2024; Independent System Operator [ISO] New England 2019; WECC 2020a, 2021). To address these challenges, the Pacific Northwest National Laboratory (PNNL) developed a chronological AC power flow automated generation (C-PAGE) tool (Vyakaranam et al. 2021) to bring system dispatch time series from the PCM into time-sequenced power flow runs for reliability analysis. The study team used C-PAGE to convert nodal PCM outputs to AC power flow cases for selected scenarios in this chapter.

2.2 Chronological AC Power Flow Automated Generation (C-PAGE)

The analysis in this chapter used the C-PAGE tool (Vyakaranam et al. 2021) to convert system dispatch time series from a PCM into time-sequenced power flow runs for a reliability study. C-PAGE includes procedures for translating datasets between production cost models and power flow models, creating chronological AC power flow instances and automating the process with choices for delivering results in a variety of formats. The study team used C-PAGE to generate AC power flow cases. Figure 2 depicts the three-stage C-PAGE procedure for preparing AC power flow cases. Each step is described in more detail next.

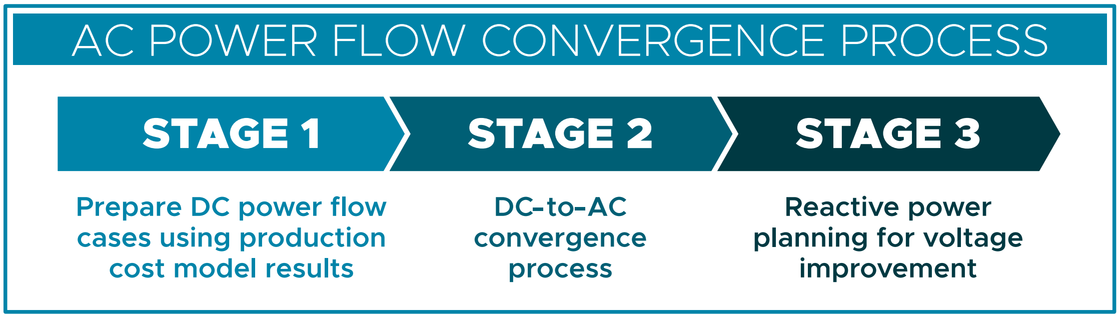


Figure 2. C-PAGE AC power flow three-stage convergence process

DC = direct current

2.2.1 Stage 1: Prepare the DC power flow cases using production cost model results

For C-PAGE to successfully prepare the DC power flow case using the PCM generation dispatch, the system topologies of the production cost model and power flow model must match. The PCM outputs consist of the load at the BA level along with load distribution factors to distribute loads at each node and generation aggregated at the power plant level. Figure 3 shows the process of disaggregating generation and load from the power plant and BA levels, respectively, to the nodal level for use in a power flow model. Appendix A presents detailed data mappings and validation of the production cost model and power flow model.

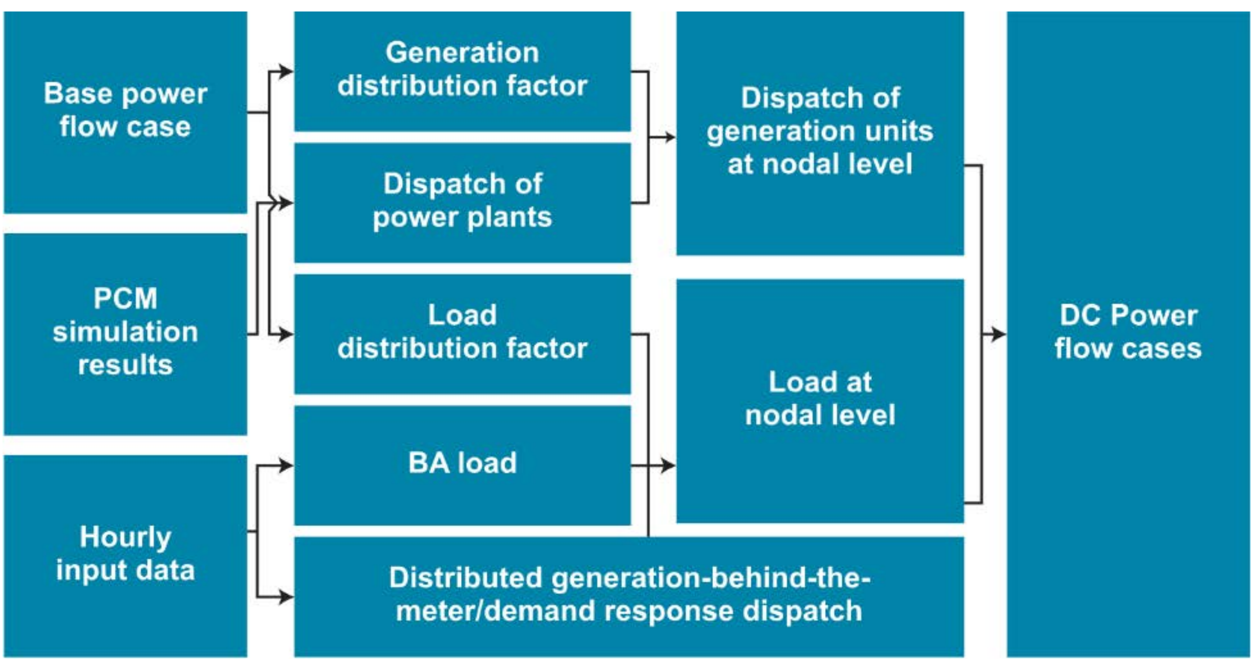


Figure 3. Process of disaggregating generation and load from production cost model simulation results to power flow cases

2.2.2 Stage 2: DC-to-AC convergence process

A production cost model uses a DC power flow, where transmission line losses are zero. Thus, the total generation in the resulting DC power flow case is equal to the total load, which is reflective of the forecasted substation load plus the estimated transmission line losses. However, the transmission line losses are inherently calculated in the AC power flow solution. Therefore, when converting the DC power flow case to an AC power flow case to ensure generation, load, and losses are equal, either nodal load reduction or increases in total generation are required to compensate for the transmission losses. In this chapter, the study team lowered the loads in C-PAGE to compensate for the losses to ensure the PCM generation outputs remain unchanged. Accordingly, in Step 2 of the procedure, the nodal loads must be iteratively reduced before an AC power flow solution is found. A detailed procedure for converting a converged DC power flow case from the production cost model results to a converged AC power flow case is presented in Appendix B.

2.2.3 Stage 3: Reactive power planning for voltage improvement

After achieving a converged AC power flow case, the priority shifts to improving the bus voltage profile. This is a crucial step because a good voltage profile at one timestep directly affects the possibility of achieving a converged AC power flow solution in subsequent timesteps. In this stage, C-PAGE scans all bus voltages to identify voltage violations and adjusts or adds local reactive devices to mitigate bus voltage violations. Appendix B presents a detailed reactive power planning procedure to improve the voltage profile. The final converged AC power flow case for the current timestep is the resulting power flow case after improving the voltage profile using existing and additional shunts.

2.3 Intelligent Sampling

As a result of the transitioning power grid, rather than using the traditional approach of assessing a select number of operating situations (usually based on engineering judgment and experience), grid planners should evaluate a variety of operating situations that are representative of most operating conditions in a year. However, the industry lacks a statistical method for determining the number of representative hourly power flow cases that represents the entire year. To address this, the study team developed an intelligent sampling approach for scenario reduction to find a small number of hourly cases that are statistically representative of the whole year appropriate for power flow analysis. The approach accounts for the seasonal and diurnal variability of renewable energy sources, using a hierarchical design followed by a slicing/Latin hypercube sampling method to select a statistically representative subset of hours.

2.3.1 Method for intelligent sampling of representative hours

Considering the substantial role of VRE in the planning scenarios, it is critical to account for the multi-timescale variability of renewable energy sources. To ensure the sampling results are statistically representative, the intelligent sampling method used a multiscale hierarchical sampling strategy, as depicted in Figure 4. This innovative approach builds on the foundation laid by the flexible smart sampling framework introduced in Chen et al. (n.d.) and Sun et al. (2021, 2023), expanding its capabilities by explicitly incorporating crucial multi-timescale information embedded in VRE.

The first step in creating the intelligent sampling method is to create joint cumulative distribution functions (CDFs) of the generator profiles of each generator fuel type. To mitigate the complexity of the sampling problem and efficiently capture critical aspects of different power generation hourly profiles, the study team classified generation profiles by fuel type. Following that, with the assistance of hourly mean and standard deviation statistics for generation, this approach ensures a reduced dimension while preserving the key features of the original generation data. The study team employed the Kolmogorov–Smirnov (KS) test to examine the representativeness of the samples concerning statistical properties, particularly the marginal distributions. The study team measured the distance between the two distributions using the KS distance (KS-D). In addition, the study team performed a statistical test of the KS-D to ensure the difference between the sampled and original distributions is statistically significant. This approach ensures a lower dimension problem while keeping the key characteristics of the original generation data.

Next, the study team used a two-level hierarchical structure to capture the natural variability in VRE. To account for such natural variability, the framework of the method included seasonal and diurnal cycles that govern the generation production of VRE:

- The four meteorological seasons represent the seasonal cycle: winter (December, January, and February), spring (March, April, and May), summer (June, July, and August), and fall (September, October, and November). Solar generation production is the only generation affected by the diurnal cycle, which is determined by daylight availability, which is dependent on both season and location.
- Three categories comprise the diurnal cycle: daytime, transition, and nighttime. The study team used solar penetration as a criterion for categorizing diurnal cycles, which naturally accommodates the seasonal and location-dependent variation in daytime length.

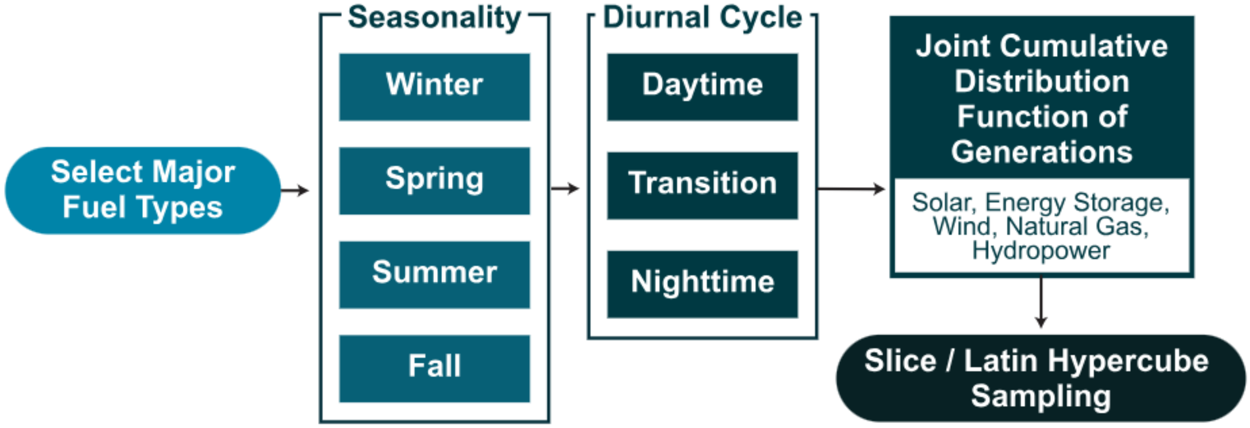


Figure 4. Sampling design that explicitly accounts for the seasonal and diurnal variations of renewable energy sources

As an example, for the AC scenario, the study team developed a dataset that contains the simulation results for 1 full year, e.g., 8,760 hours of the production cost model run. Statistical analysis of this dataset shows solar, energy storage (mainly utility-scale batteries), wind, natural gas, and hydropower account for more than 90% of the variance and overall contribution to the total generation. As such, the study team considered these five fuel types and the system load when sampling and validating representative hours.

The last step in the intelligent sampling method is to divide these data into 12 seasonal–diurnal bins. The Latin hypercube sampling with dependence (LHSD) method performed this division within each bin based on their respective joint CDF.

The study team identified representative hours for a variety of scenarios in this work but did not perform analyses for every representative hour. However, the study team conducted a contingency analysis on a subset of operating conditions chosen from the representative hours, and the results are detailed in the results section next. As a follow-up to this chapter, the study team recommends performing a detailed analysis of all representative hours.

2.4 Descriptions of the Transmission Expansion Scenarios

This section briefly describes the scenarios and datasets used to create the power flow scenarios. It provides context to the transmission and generation included in the power flow scenarios discussed in the rest of this report.

The NTP Study used the WECC 2030 Anchor Dataset (ADS) production cost model dataset as the starting nodal PCM case for the Western Interconnection. The ADS (WECC 2020a, 2020b) is the most reliable forecast for upcoming developments in new generation, generation retirements, transmission assets, and load growth, providing 10-year predictions from specified reference years.

The study team added transmission projects to the 2030 ADS that are either under construction or have significantly progressed through the permitting process and thus are deemed both plausible and likely to materialize. The capacity expansion modeling process of the NTP Study identified additional transmission capacity for the year 2035 (Chapter 2). The study team then converted the zonal models from the capacity expansion results to spatially detailed nodal production cost models for year 2035: the 1) Limited and 2) AC scenarios (Chapter 3).

These two scenarios have the same demand estimate from the capacity expansion model, which assumes 2.4% load growth per year until 2035 (as described in Chapter 1) and achieves 90% decarbonization by the year 2035, albeit through divergent transmission and generation capacity expansion strategies. The 2035 AC scenario facilitates expansion between transmission planning regions (i.e., FERC Order No. 1000) whereas the 2035 Limited scenario permits transmission buildouts solely within these planning regions, with few exceptions for projects.

Figure 5 and Figure 6 show an overview of transmission expansion.

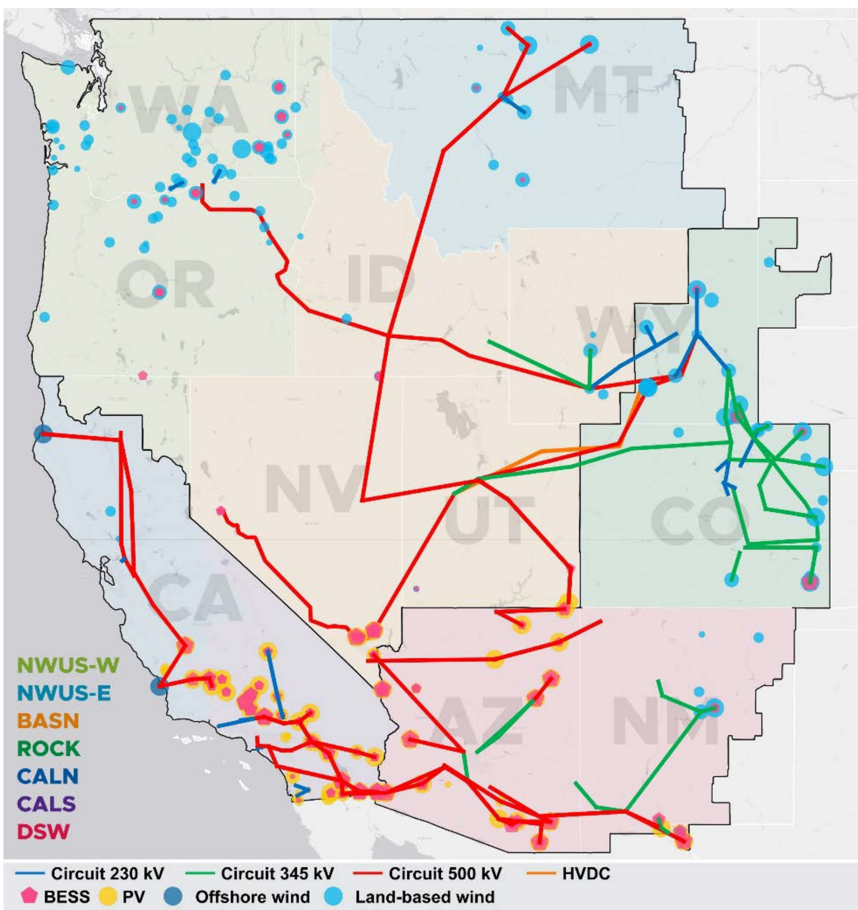


Figure 5. Transmission expansion in the 2035 Lim scenario from the 2030 ADS: 500-, 230-, and 345-kilovolt (kV) circuits are added or updated; new high-voltage direct current (HVDC) circuits are added

BESS = battery energy storage system; PV = photovoltaic

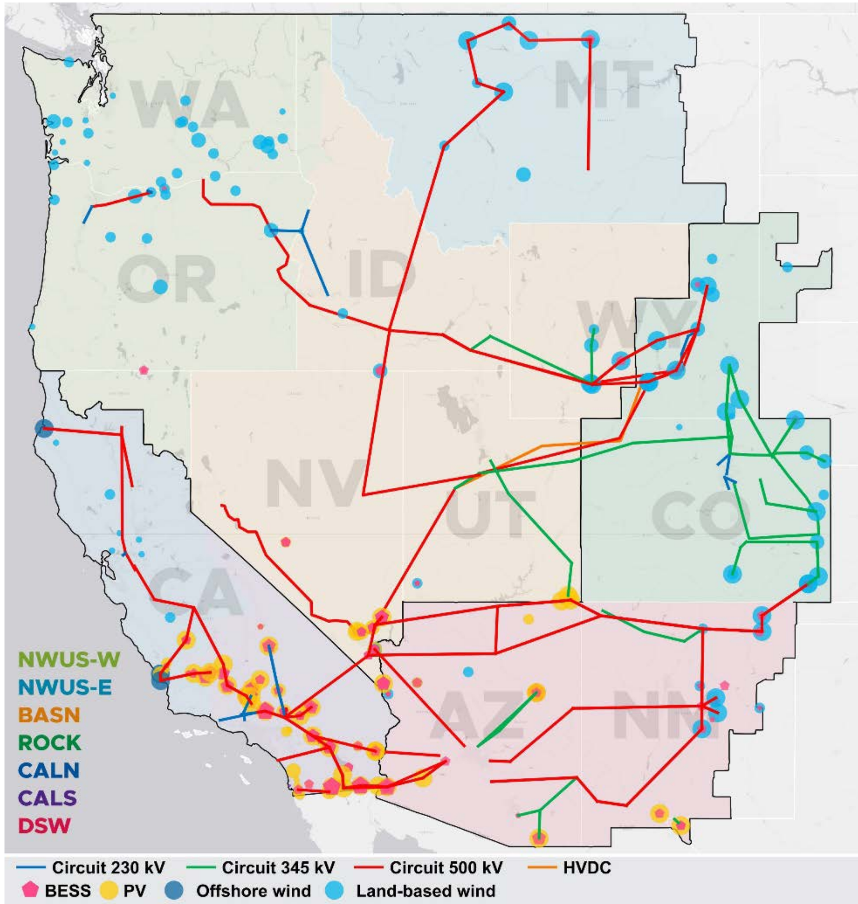


Figure 6. Transmission expansion in the 2035 AC scenario from the 2030 ADS: 500-, 230-, and 345-kV circuits are added or updated; new HVDC circuits are added

The 2035 AC scenario facilitates expansion between transmission planning regions (i.e., FERC Order No. 1000) whereas the 2035 AC Limited scenario permits transmission buildouts solely within these planning regions. For the Western Interconnection, the FERC Order No. 1000 regions consist of the California Independent System Operator (CAISO), WestConnect, and NorthernGrid—whose borders are displayed in Figure 7.

Figure 7. Seven WECC subregions (excluding Alberta, British Columbia, and Northern Baja California Mexico): Basin (BASN), California North (CALN), California South (CALS), Desert Southwest (DSW), Northwest United States (NWUS), and Rocky Mountain (ROCK)

Figure 8 shows the additional generation capacity mix for the two transmission expansion scenarios (i.e., 2035 AC and Lim). Solar, wind, and storage are the largest capacity resources. The solar and storage capacity is mostly located in the California South and Desert Southwest regions for both derivative AC scenarios whereas the wind capacity is mostly located in the Northwest and Rocky Mountain regions.

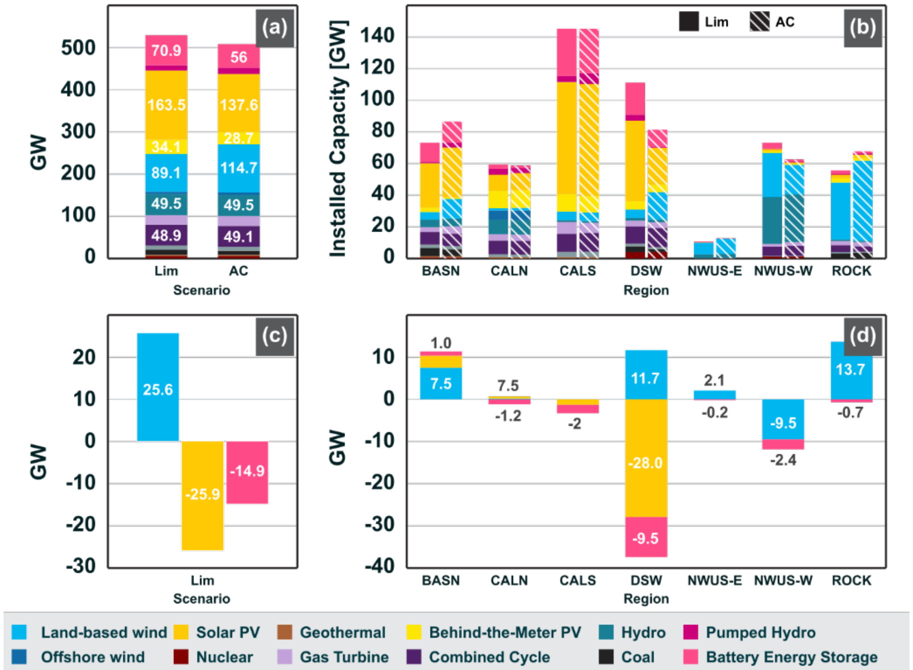


Figure 8. (a) Gen mix Lim vs. AC at interconnection level; (b) Gen mix Lim vs. AC at region level; (c) Gen mix difference Lim vs. AC at interconnection level; (d) Gen mix difference Lim vs. AC at region level

GW = gigawatts

2.5 Contingency Analysis

The purpose of the contingency analysis is to test the nodal transmission expansion scenarios' overall robustness and demonstrate the power flow case development method, which can also enhance more detailed reliability analysis. This contingency analysis is limited to the most critical and impactful contingencies recognized by the transmission planning community and does not begin to approach a full reliability planning study. For NTP Study purposes, the criteria for the selected contingencies are as follows:

- Make sure the new lines, mainly 500-kV lines, do not introduce new critical contingencies that negatively impact the reliability of the grid system. The study team selected individual outages of the newly added transmission and neighboring lines.
- Select large power plants 500 megawatts (MW) or above to understand the availability of the pseudo-governor response.

Table 1 lists the contingency limit monitoring settings only for buses and lines with a nominal voltage greater than or equal to 230 kV.

Table 1. Contingency Limit Monitoring Settings

	Voltage Levels (kV)	Low (P.U.)	High (P.U.)
Voltage limits	230	0.9	1.1
	345	0.9	1.1
	500	0.9	1.1

	Normal	Contingency
Line flow limits	100% of normal rating	Minimum of 130% of normal rating or 100% of emergency rating (if available)

The analysis in this chapter evaluated three contingencies. Contingency #1 is the outage of two parallel lines that deliver power from a wind farm to load centers. These two lines carry 3,300 MW in the precontingency condition. The AC scenario uses this contingency. Contingency #2 is the outage of two of three parallel lines that connect 2,500 MW energy storage to the grid. These two lines deliver 2,000 MW in the precontingency condition. The Limited scenario uses this contingency. Contingency #3 is the outage of 2,600 MW of generation from a power plant. Both scenarios use this contingency.

3 Key Findings for AC Power Flow Analysis

This section provides the key findings based on the results of the power flow activities described in the methodology above.

3.1 Using Tools Refined in the NTP Study, Power Flow Cases With Different Generation Mix Can Be Extracted From Production Cost Model Simulations

3.1.1 The linkage between the production cost model and the power flow model is critical for investigating the reliability of future scenarios

The study team successfully created the two power flow scenarios described in this report using the 2035 AC and 2035 Limited production cost models. The study team selected power flow snapshot cases for the 2035 AC scenario based on the intelligent sampling results next. The analysis in this chapter employed 24 of all the cases sampled. For these cases, the study team developed AC power flow models, including peak load models for different seasons, models that correlate to high solar penetrations, and models that show peak wind flow during the day. The linkage between the production cost model and the power flow model is critical for investigating the reliability of nodal scenarios with high penetrations of wind, solar, and battery storage—that is, the future decarbonized grid. Normally, this entire process may take a few weeks to months to create a base AC converged power flow case because it involves production cost modeling, AC convergence, and reactive power planning. C-PAGE enables power planners to generate many power flow cases in a matter of minutes per production cost model. The savings in staff time, ability to run time series data, and number of samples selected justify tools such as C-PAGE for becoming a standard in industry transmission planning. Linking power flow samples from one hour to the next is necessary to adequately evaluate the effects of shared ramping and variability hours across all scenarios. Thus, the linkage between the production cost model and the power flow model is critical for investigating the reliability of future scenarios.

3.1.2 Intelligent sampling is necessary when developing power flow models to account for the increasing variability of generation and load

Each day of the year and each hour of the day exhibit even distributions of significantly varying load, wind, solar, and online generation mixes within the same scenario. Figure 9 shows the final LHSD down-selected representative hours for the NTP Study 2035 AC scenario. Each day of the year and each hour of the day have even distributions for the 214 hours chosen by LHSD (sample size: 2.5%). This is the direct and desired outcome of regular interval slicing of the experimentally established CDF for all major fuel types. The definition of diurnal bins naturally divides a day into three groups while accounting for seasonal variations in daylight hours. This feature is observable in the seasonal variation of the vertical extension of the daytime and transition bins. This approach minimizes the computational cost and time expenses during AC power flow case conversion and accurately maintains statistical properties while accommodating the inherent natural variability among VRE sources and demand.

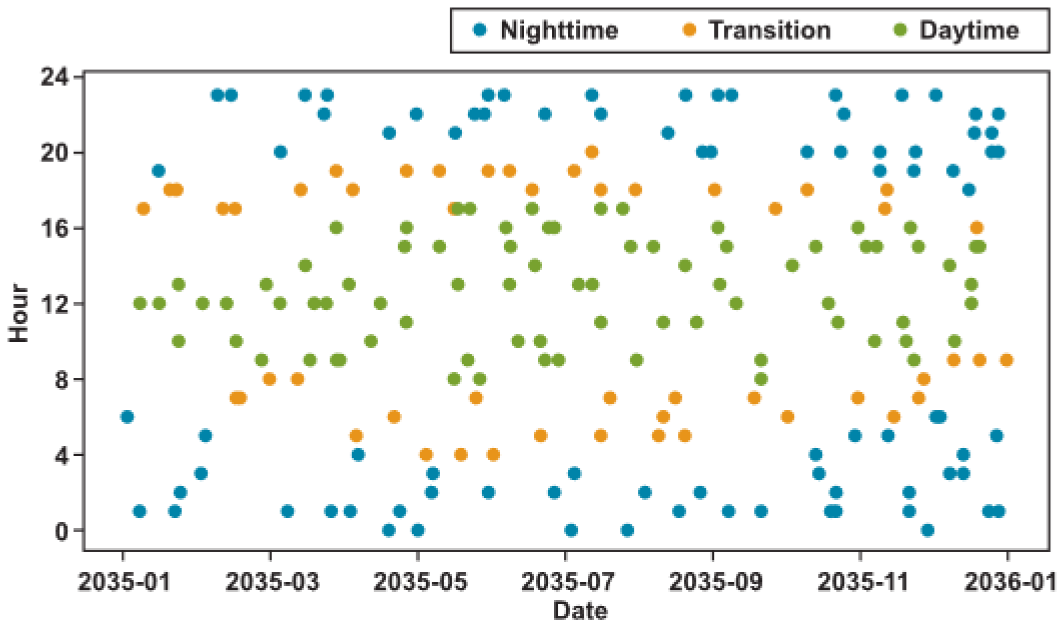


Figure 9. Distribution of the representative hours for the NTP 2035 AC case; the color scheme corresponds to different times of the day: blue signifies nighttime, yellow indicates transition periods, and green represents daytime

3.2 Power Grids With Large Transmission Buildouts and Clean Energy Penetration Can Be Planned To Withstand Contingencies

3.2.1 Outage of highly loaded new transmission buildouts do not introduce reliability risk in the developed scenarios

The contingency analyses presented in this chapter are only a preliminary indication of the robustness of the 2035 Limited and AC scenarios. The new transmission lines associated with the scenarios can be planned to avoid voltage or thermal loading risks to the system, even when they are highly loaded (closer to their normal ratings). Additional reliability studies are still needed to comprehensively assess the reliability in systems with large buildouts of high-voltage transmission lines, VRE and BESS, and changing load profiles. Providing the same level of voltage support as conventional power plants to prevent voltage instability and ensure proper power transfer to meet system reliability requirements will require new wind and solar projects.

Contingencies for new lines in the Western Interconnection Limited scenario

The study team evaluated the steady-state reliability of new transmission lines for the Limited scenario by simulating the contingency of two of three parallel, highly loaded transmission lines. The chosen line was to be highly loaded before the outage because this would have a huge influence on the line flows of the surrounding transmission lines. The study team analyzed the power flow at 4 p.m. mountain standard time (MST) on August 2, 2035, because high solar penetration caused the selected line to have the most loading on that day. After factoring in compensation from behind-the-meter (BTM) resources, the total load in the Western Interconnection amounted to 172 GW. Figure 10 shows the generation mix. Generation type “Other” represents the sum of several small generators of different types such as geothermal, steam turbine-oil, bio-steam turbine, bio-internal combustion, combustion turbine-oil distillate, and bio-combined cycle. This corridor has three lines with a combined total normal rating of 6,500 MW and combined total real power flow of 2,700 MW before the contingency. Figure 11 displays the daily single-circuit flow of the selected line. The contingency trips two of the three circuits, resulting in an adjusted real power flow of about 1,900 MW through the single remaining line. This post-contingency loading of the remaining line is 88% of its normal rated capacity and 65% based on its emergency rating.

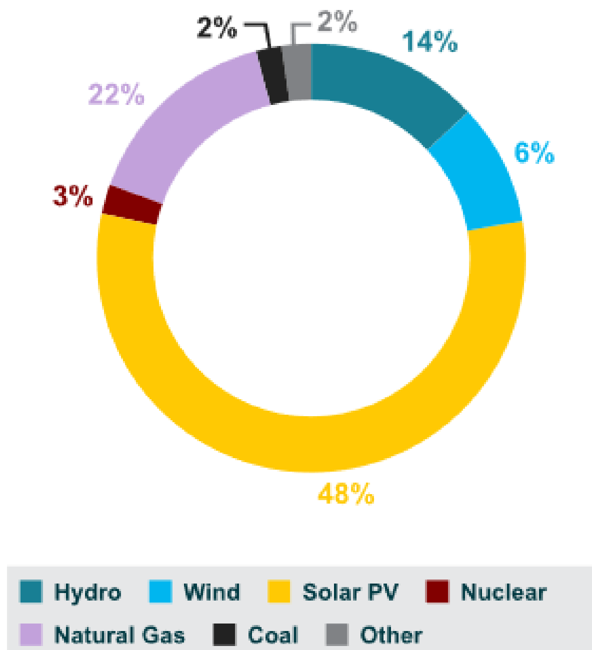


Figure 10. Generation mix at 4 p.m. MST on August 2, 2035

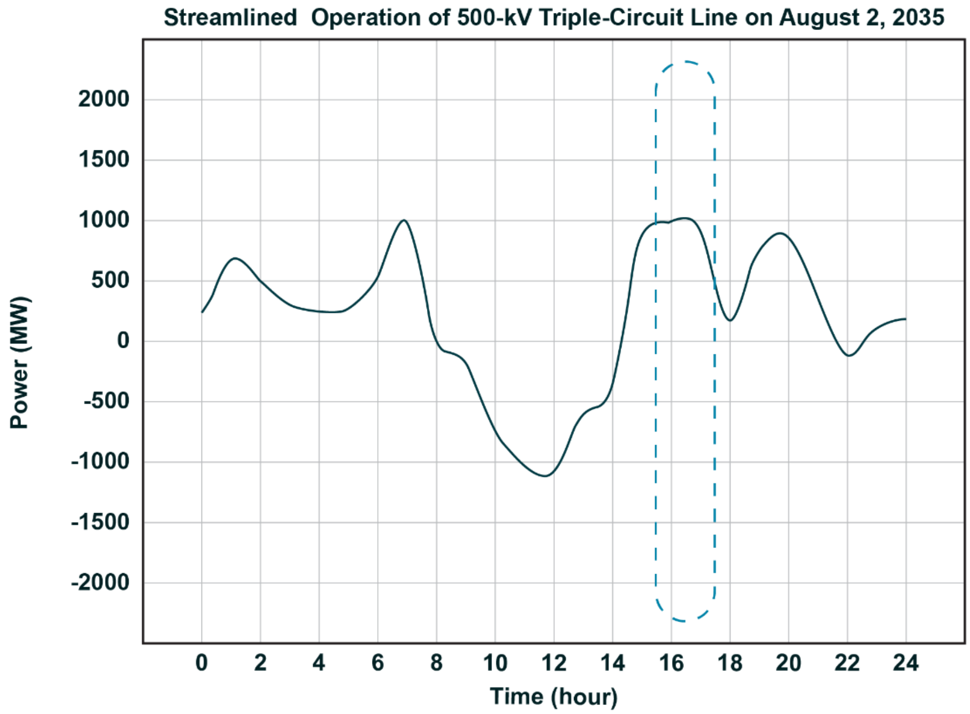


Figure 11. Single-circuit flow of the selected three parallel lines on August 2, 2035: Maximum loading time east to west

Figure 12 shows the changes to the transmission line power flows following the outage of the double-circuit transmission line. Lines with red, yellow, and green arrowheads show the power flow within the line exceeds 90% of its rated capacity, represents 50% to 90% of its rated capacity, and is less than 50% of its rated capacity, respectively. Figure 12(a) and (b) show the line flows pre- and postoutage, respectively. Two of the three parallel lines enclosed by the red cylinder in (a) are not operational. The contingency increases the load on the circuit that remains. This causes the flow on a line in New Mexico to revert to the north before sending power to Arizona and the West, as shown in (b).

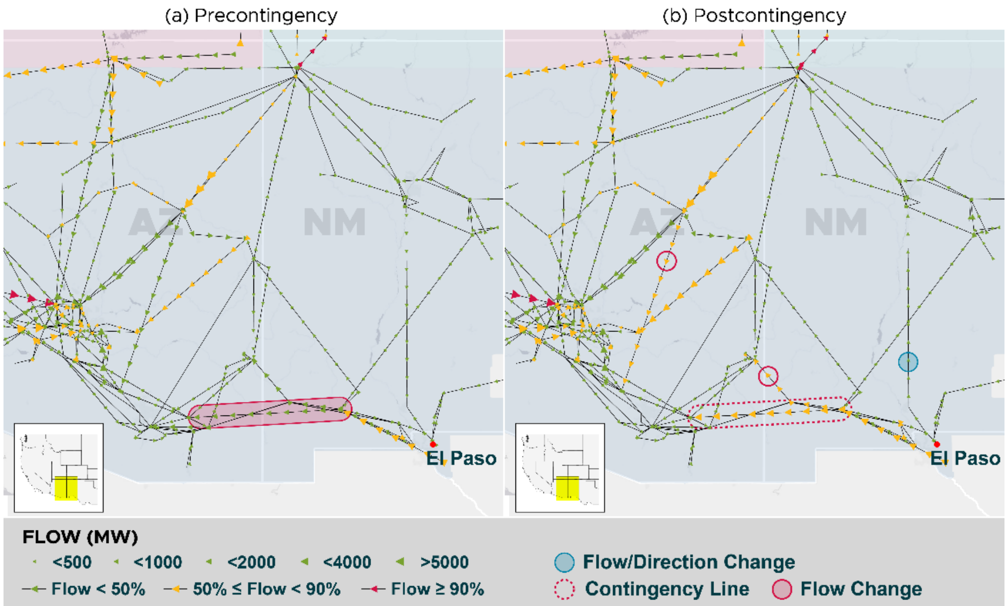


Figure 12. Lim contingency scenario: (a) pre- and (b) postcontingency line flows; some flow changes between southern New Mexico and Arizona; some flows reverse direction

A comparison of Figure 12(a) and (b) demonstrates 1) the channel from the El Paso Electric solar hub to the west is limited; thus, the flow is redirected north before moving west, and 2) the north-south flow reverses direction. Figure 13(a) and (b) depict the voltage magnitudes before and after the contingency, respectively. They also depict the flow of the Western Interconnection’s high-voltage lines. Figure 12(b) shows some of the major variations in flow and flow direction close to the contingency line. Figure 13 shows there are not more voltage violations in the postcontingency situation beyond those observed in the precontingency condition.

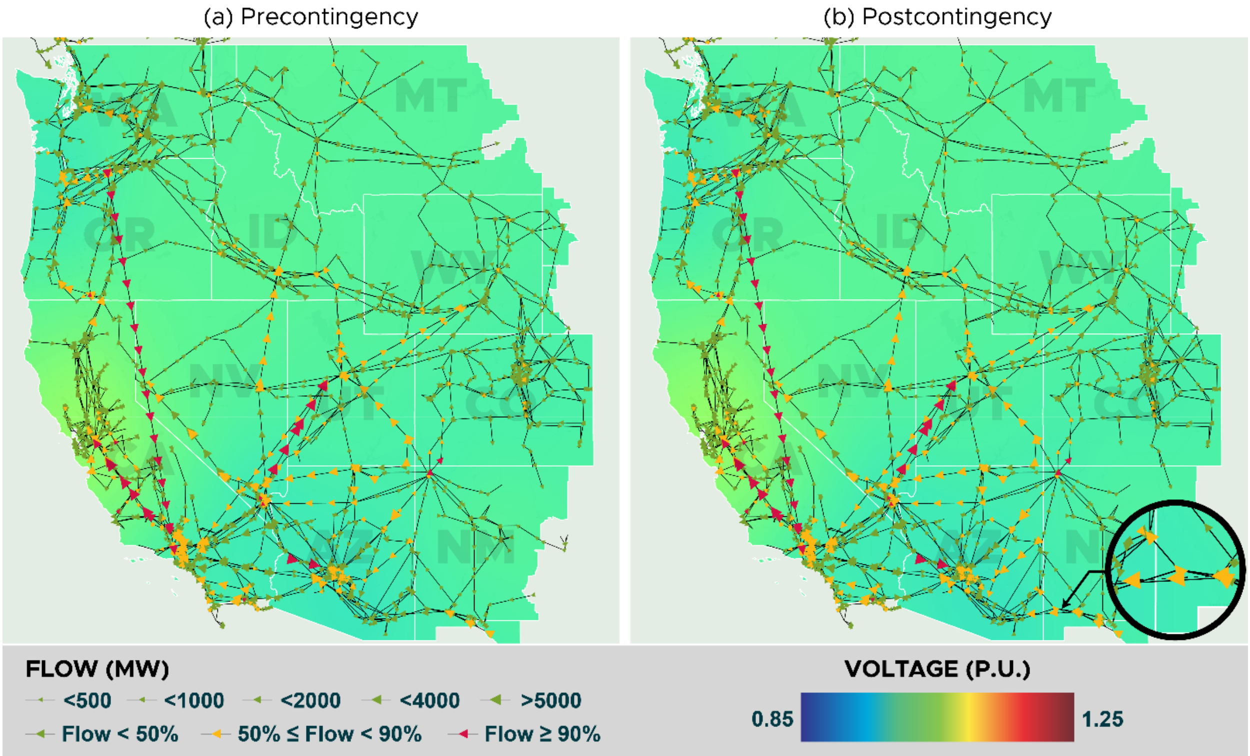


Figure 13. Lim AC contingency scenario: (a) pre- and (b) postcontingency system voltages; no significant voltage change following the contingency

Contingencies for new lines in the Western Interconnection AC scenario

The study team evaluated the steady-state reliability of the new transmission lines within the AC scenario by performing a contingency analysis at 10 p.m. MST on August 2, 2035. The flow on the chosen contingency line—two 500-kV lines in parallel based in New Mexico—is at its peak during the day's high wind penetration levels at that hour. The total load in the Western Interconnection for the selected hour is 163 GW. Figure 14 displays the generation mix for this hour. Figure 15 shows the flow in one line of the two parallel 500-kV lines. Before the contingency, 2,600 MW flows through the selected line (two circuits). Postcontingency, when both lines are unavailable, power is rerouted.

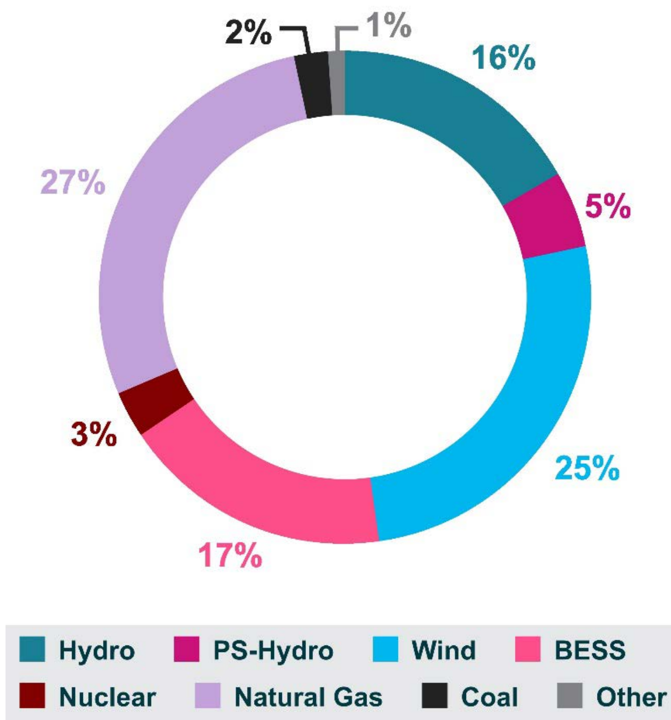


Figure 14. Generation mix at 10 p.m. MST on August 2, 2035: Natural gas and wind are the dominant generation

PS = pumped storage

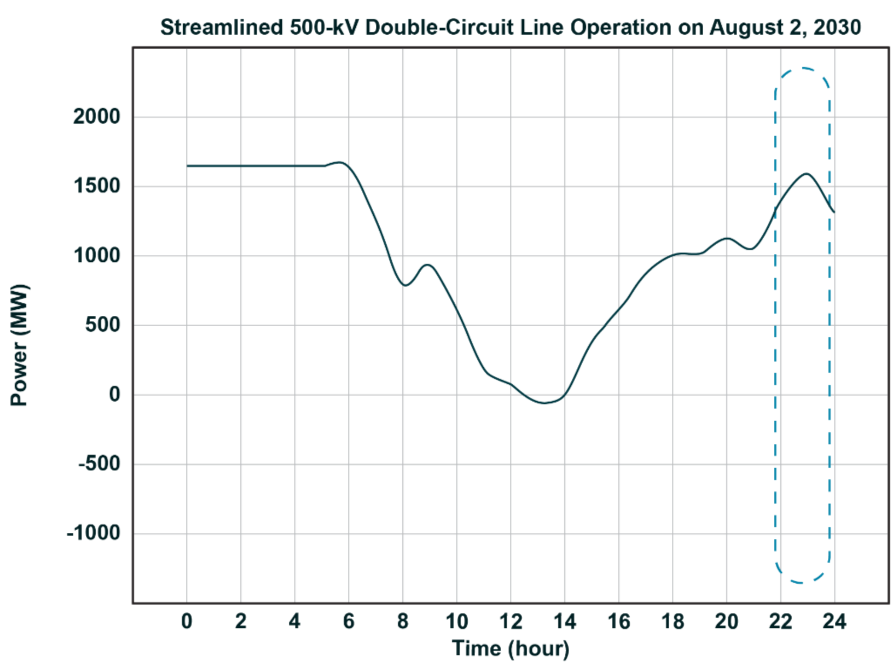


Figure 15. Single-circuit flow of the selected double-circuit 500-kV line on August 2, 2035: Nearly maximum loading time during high wind penetration

Figure 16(a) and (b) depict the pre- and postcontingency transmission power flows, respectively. The line surrounded by the red cylinder in (a) is the contingency. As a result of the contingency, more power is redirected to the north in New Mexico before being transferred to the west via Arizona and Utah. The contingency does not cause overloading on any other lines on the redirected paths, as shown in (b).

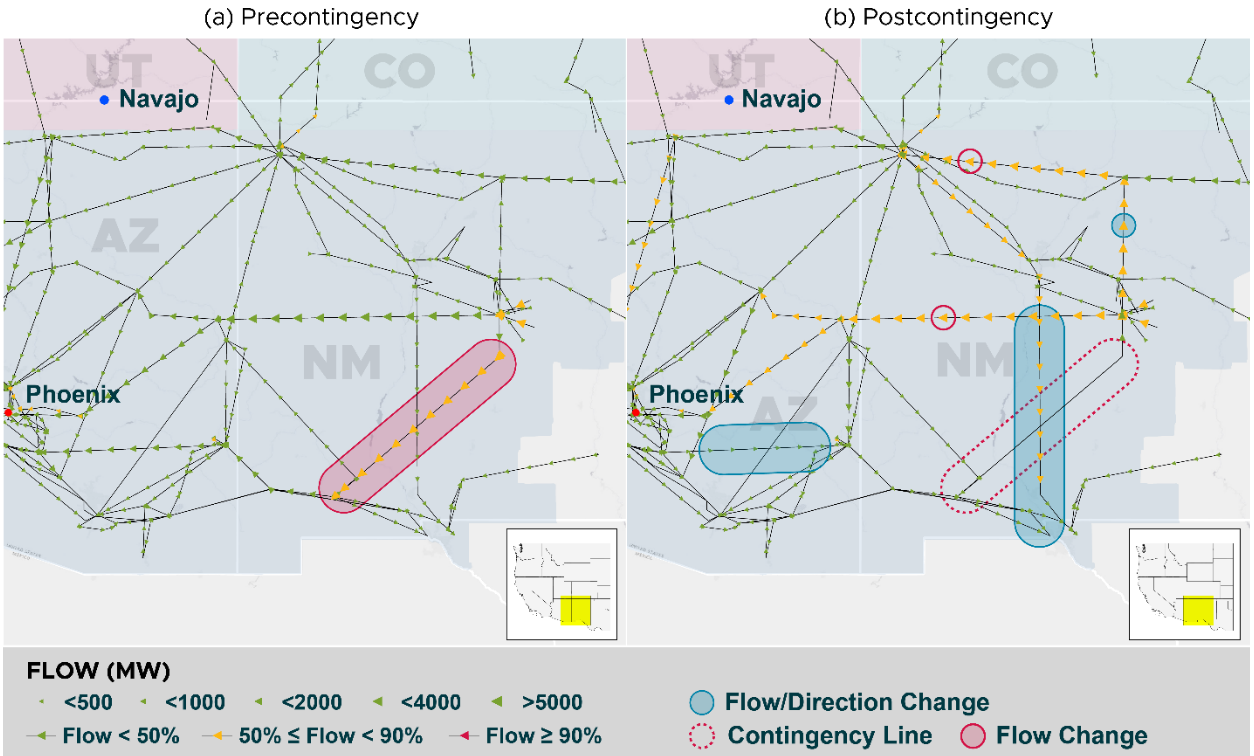


Figure 16. AC contingency scenario: (a) pre- and (b) postcontingency line flows; some flow changes in New Mexico as power was diverted north before it was sent to the West

A comparison of pre- and postcontingency power flows reveals 1) the flow into southeast New Mexico increases or reverses, 2) the flow from the central New Mexico wind hub increases through the western and northern paths (Coronado and Four Corners), and 3) the increased flow from Navajo replaces the flow received by Phoenix from southern New Mexico, as shown in (b). Figure 17(a) and (b) show heatmaps of the voltage magnitudes and line flows before and after the contingency, respectively. Figure 17 indicates no noticeable change in the voltage violation postcontingency beyond what is observed in precontingency. Figure 16 shows the alterations to the line flow after the contingency.

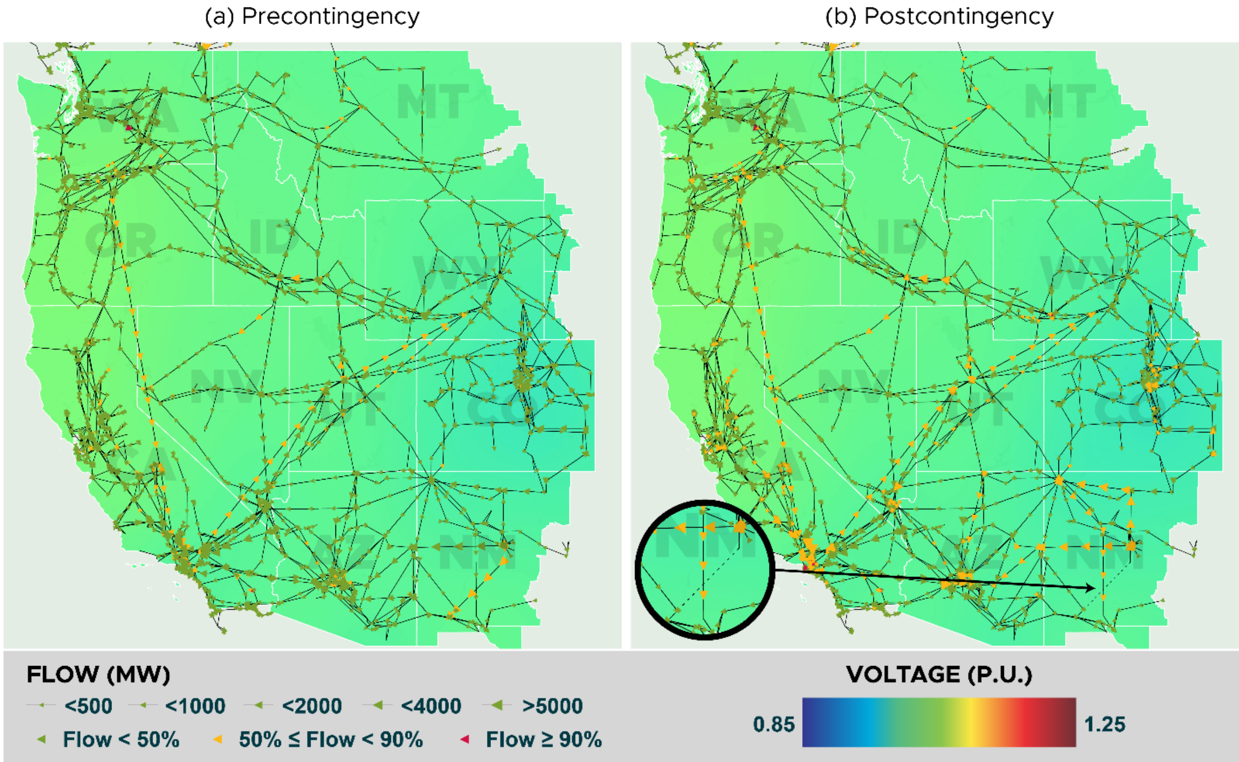
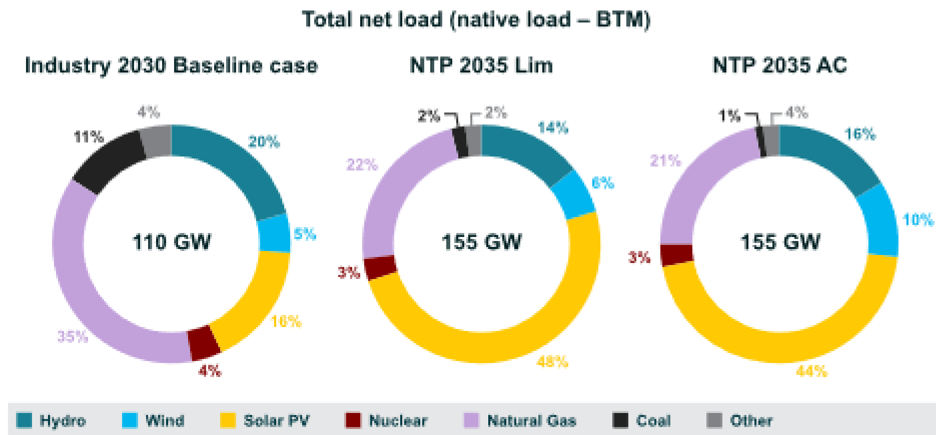


Figure 17. AC contingency study: System voltages before (left) and after (right) the contingency; there is not a significant voltage change following the contingency

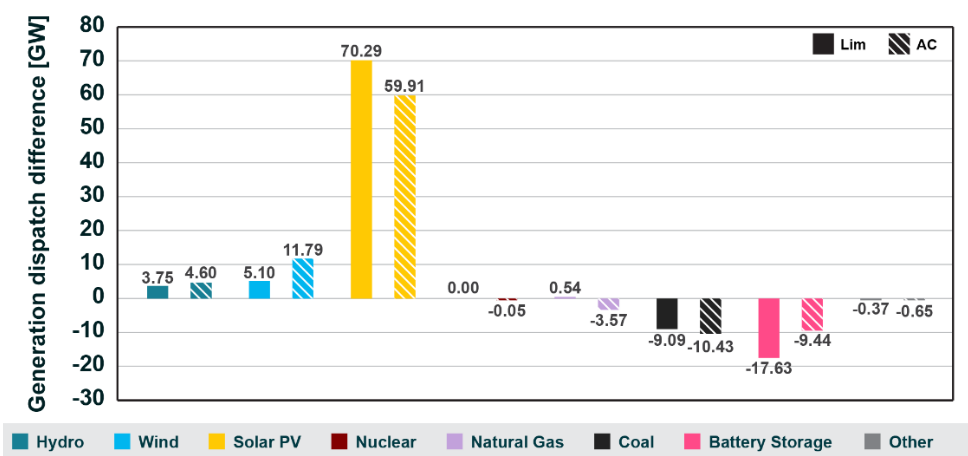
3.2.2 Utility-scale battery storage plays a critical role in providing governor response during the outage of large power plants

In highly interconnected transmission grids with high penetrations of VRE, this chapter shows large utility-scale BESS can play a key role in maintaining frequency response reserves. After the loss of a large generator, BESS can quickly either cease charging or increase generation (if there is sufficient headroom) faster than other types of generators to provide the necessary power to recover grid frequency.

As part of the contingency analysis, the analysis in this chapter evaluated the pseudo-governor response following the loss of a large generator in the two power flow scenarios. In this pseudo-governor response simulation, the generation redispatch compensates for an imbalance between generation and load at a predefined set of generators in the system in which the contribution of each generator is proportional to its capacity while respecting headroom limitations. For this analysis, the study team evaluated both power flow scenarios (Limited and AC) at the same hour—8 a.m. MST on July 21, 2035—and compared them to a power flow case exported from the 2030 ADS for 8 a.m. MST on July 21, 2030. The analysis in this study applied the same large generator outage to all power flow cases to assess the effects of the pseudo-governor response across each scenario. The contingency in this chapter is the loss of two nuclear generators at a single power plant with a total output of approximately 2,600 MW. Figure 18(a) shows the generation mix of the three scenarios, precontingency. Note all BESSs are charging, and the analysis considers them as loads at this chosen hour in the three scenarios. Therefore, they do not contribute to the generation mix in the charts in this figure. Figure 18(b) shows the difference in generation dispatch in the NTP 2035 Limited and NTP 2035 AC scenarios from the industry 2030 Baseline by type. Solar dispatch is dominant in the Limited and AC scenarios because the solar capacity is much greater in the two scenarios compared with that in the Baseline scenario. The battery storage capacity in the Limited and AC scenarios is also much higher than that in the Baseline case. Note the negative value for battery storage in Figure 18(b) indicates they are charging (operated as load) during the hour of consideration.



(a)



(b)

Figure 18. (a) Precontingency generation mix for the 2030 ADS case as a reference industry case, 2035 Lim scenario, and 2035 AC scenario: The NTP Study evaluated scenarios that have more renewable generation than the Baseline case, especially high solar penetration; (b) generation dispatch difference by type in the 2035 Lim and AC scenarios from the 2030 ADS case

Figure 19 shows the generation redispatch by type to make up for the loss of 2,600 MW of generation. Notice solar and wind do not participate in the redispatch because they have no headroom—nor coal because its governors are typically slow to react or are disabled. At the time of the generator loss, BESS devices in the system are charging, and BESS has enough reserved energy to cease charging and ramp up its generation to participate in the pseudo-governor response process. BESS devices are also dispatchable at any stage of their operation. A positive BESS redispatch after the contingency means it charges at a lower level to decrease its consumption.

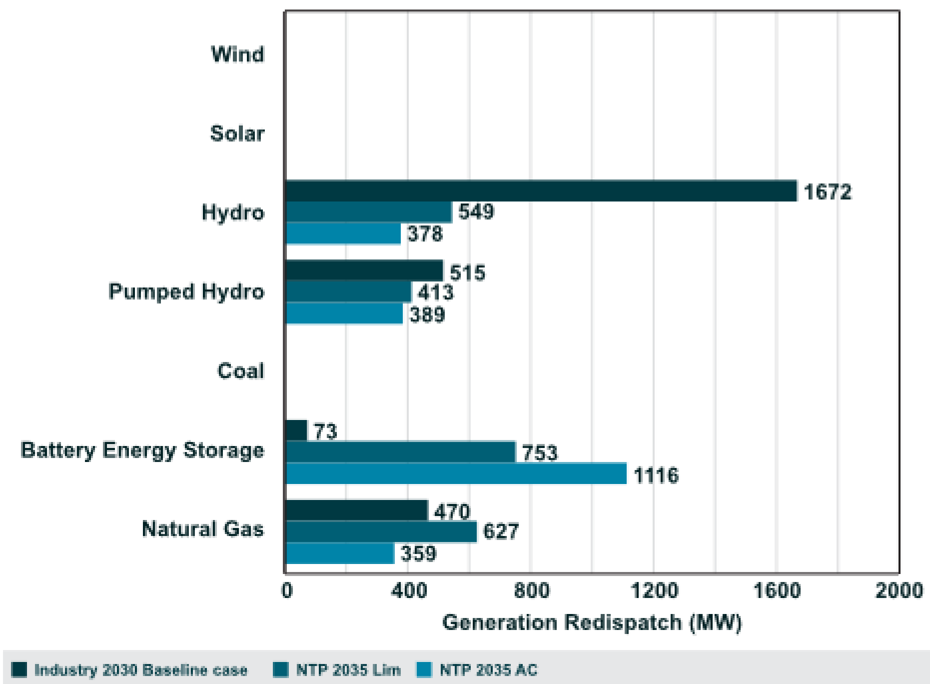


Figure 19. Generation redispatch after the loss of 2,600 MW of generation: BESS, Hydro, Natural Gas, PS-Hydro dispatch; Hydro accounts for the greatest contribution in the ADS case redispatch; BESS has the greatest contributions in both NTP AC and Lim scenarios

Figure 20, Figure 21, and Figure 22 show the pre- and postcontingency voltage heatmaps and transmission line power flows for all three scenarios.

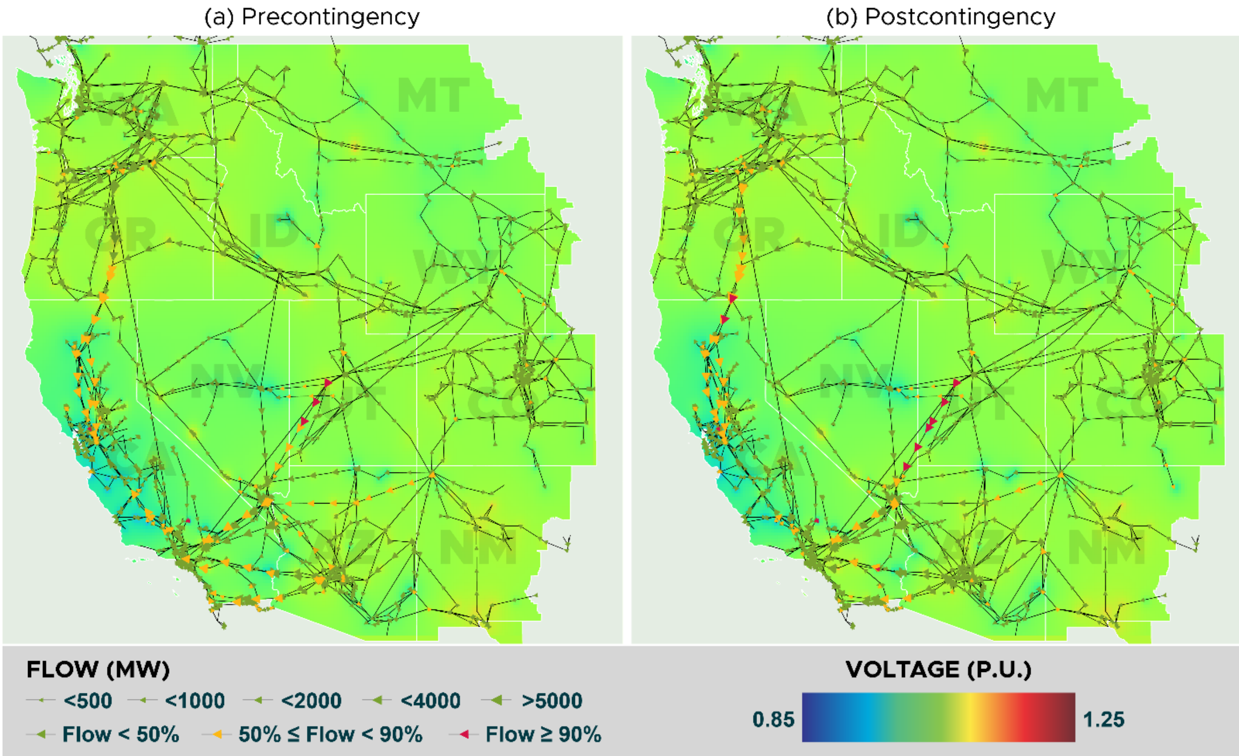


Figure 20. Voltage heatmaps (a) pre- and (b) postcontingency for the loss of 2,600 MW of generation at a nuclear power plant for the 2030 ADS case: No significant voltage changes following the contingency

For the Limited scenario, as seen from Figure 21, there are no significant changes in the voltage profile, and the line flows overload because of the loss of 2,600 MW. Therefore, the study team assessed the scenario as robust and relevant for further study and analysis.

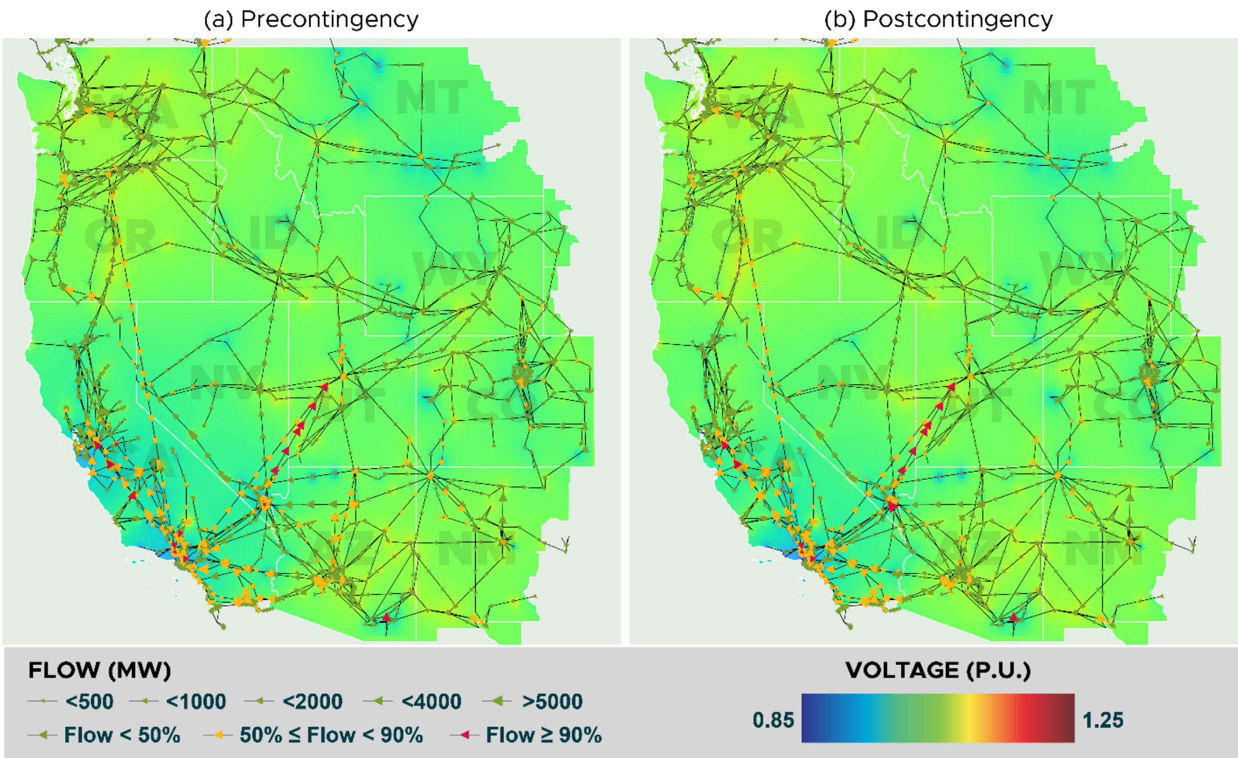


Figure 21. Voltage heatmaps (a) pre- and (b) postcontingency for the loss of 2,600 MW of generation at a nuclear power plant for the Lim scenario: No significant voltage changes following the contingency

For the AC scenario, as seen from Figure 22, there are no significant changes in the voltage profile because of the loss of 2,600 MW. The loss of power delivered to California from Arizona is primarily compensated by Utah and Las Vegas, Nevada. The changes in power delivery pattern help reduce the overload on the path from Southern to Northern California.

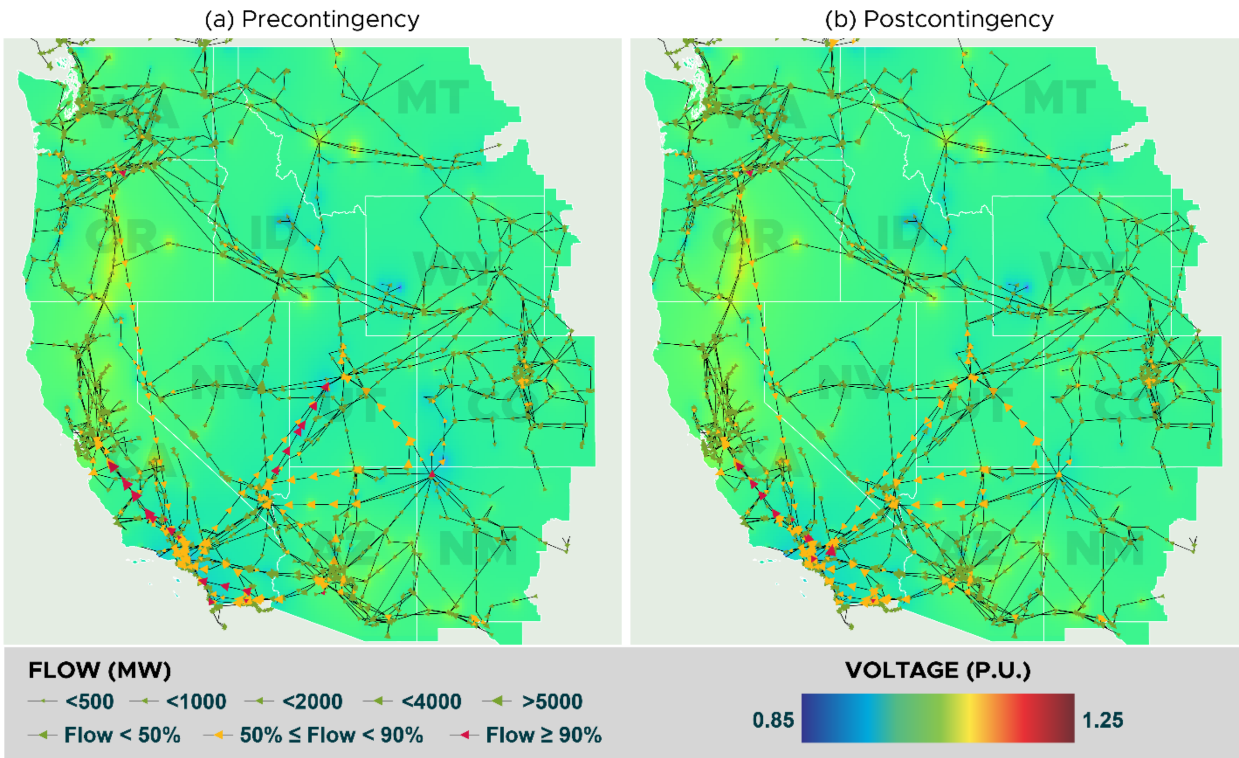


Figure 22. Voltage heatmaps (a) pre- and (b) postcontingency for the loss of 2,600 MW of generation at a nuclear power plant for the AC scenario: No significant voltage changes following the contingency

3.3 Advanced Data Analytics Developed in This Study Can Help Industry Understand Grid Behavior for Many AC Power Flow Hourly Snapshots and Contingencies

The study team needed and used the interactive visualization and a database management system throughout the NTP Study to visually explore and analyze system behavior. The study team developed advanced data analytics to handle a large set of results, analyzing several power flow cases with contingencies and comparing grid performance between several capacity expansion scenarios for future studies.

The study team developed Python automation scripts that enable the efficient handling of large-scale power flow datasets produced by production cost model, power flow, and contingency analysis tools. These scripts use QGIS to facilitate the automated generation of detailed, interactive maps that display power flow information, such as the transmission grid topography, voltage profiles, and transmission line loading. Full back-to-back automation allows users to extract power flow information from solvers (usually stored in binary files), process it, and upload it to the database server to generate GIS visualizations (QGIS layers) and unique QGIS projects for specific power flow cases or scenarios. The analytics module ranks all simulated contingencies across all events and situations, allowing the user to choose where to zoom in for more extensive analysis. This module supports future integration with industry-standard Big Data analytical and interactive visualization tools. Appendix C describes the specifics of these components, which are exemplified in some of the graphics within this report.

4 Conclusions

Through the development and contingency analyses of two transmission power flow scenarios—the Limited and AC high-demand scenarios both with 90% decarbonization by 2035—the analysis in this chapter verified the robustness of certain transmission expansion scenarios developed in the capacity expansion modeling and production cost model portions of the NTP Study. During the NTP Study, the study team developed an automated conversion tool that exports generator dispatch from a production cost model to an AC power flow model. The methods outlined in this chapter will enable planning engineers to perform detailed transmission planning studies on large interregional systems with high penetrations of VRE and BESS.

This chapter shows large, interregional systems can maintain voltages within acceptable ranges, given careful reactive power planning. The conversion tool the study team developed and used in this chapter is complemented by an intelligent statistical sampling method to select a representative range of dispatch conditions throughout a year for power flow analysis. Finally, in this chapter, the study team has designed an interactive visualization and database management system to assist transmission planning engineers in visually exploring and analyzing system behavior.

Key takeaways of this chapter include the following:

- **Using tools refined in the NTP Study, power flow cases with different generation mixes can be extracted from production cost model simulations.** Intelligent sampling methods, such as those applied in this chapter, should be used to select representative hours from the production cost model for the power flow analysis because planning engineers face significantly varying load, wind, solar, and online generation mixes within the same scenario. Thus, the linkage between the production cost model and the power flow model is critical for investigating the reliability of future scenarios.
- **Power grids with large transmission buildouts and clean energy penetration can be planned to withstand contingencies.** New transmission lines associated with the scenarios can be planned to avoid voltage or thermal loading risks to the system, even when they are highly loaded. Utility-scale storage can play a key role in providing the primary frequency response for large power plant contingencies. However, a full reliability analysis is necessary for new grid infrastructure.
- **Advanced data analytics developed in this study can help industry understand grid behavior for many AC power flow hourly snapshots and contingencies.** The database management system and interactive visualization developed in this study can help planning engineers understand and analyze system behavior for many AC power flow hourly snapshots and contingencies.

Future areas of recommended study include additional contingency analyses for combined Eastern and Western Interconnection scenarios under many single and multiple contingencies and several different operating conditions. In addition, future research should include contingency analyses using dynamic simulation to examine the developed grid models for characteristics such as the frequency response and voltage ride-through during grid disturbances.

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Appendix A. Compatibility Issues Between the Production Cost Model and the Power Flow Model

A.1 Linkage Between the Production Cost Model and the Power Flow Model (test and validation)

To ensure consistency between the production cost model (PCM) and power flow model, the study team conducted a componentwise (bus, generator, bus load, and transmission line/transformer, high-voltage direct current [HVDC] interface) comparison between the two models' databases. Note each component in one model must have the same or an equivalent component in the other model. If one component exists in one model but not in the other, the study team normalized the models by either adding the component or removing it from a model to maintain equivalency. Appendix B includes examples of how compatibility issues between the two models for specific network components were handled.

The analysis in this chapter used Python scripts to modify all models. To verify the validity of the model, the study team gradually performed test runs for the modified production cost model along with the model modifications.

Model modifications

1. **Buses:** A comparison of the buses from the power flow model and the production cost model revealed the study team identified 27 buses in the production cost model that were absent from the power flow model and 8 buses in the power flow model that were also absent from the production cost model. The study team added those buses to the corresponding model to ensure they matched.

2. **Loads:** A comparison identified nine bus loads in the power flow model but not in the production cost model. The study team added them to the production cost model to match those in the power flow model.

3. **Transmission lines/transformers:** An initial comparison of the lines/transformers in the two models resulted in many mismatches. A detailed investigation of the mismatches identified each mismatch is because of one or more of the following reasons:

    - The three-winding transformers in the power flow and production cost models are modeled differently.
    - The lines/transformers have the same from bus and to bus but different circuit IDs.
    - Several lines/transformers exist in one model but not in the other.

    After addressing these mismatches, the study team identified 18 lines/transformers that still exist in the power flow model but not in the production cost model and 42 lines that exist in the production cost model but not in the power flow model. The study team added those lines/transformers to the corresponding models.

4. **Generators:** A comparison of the generators in the production cost and power flow models identified many differences. Several hundred generators exist in one model but not in the other. There are several reasons for these differences:

   - One model added new variable renewable energy generators but not the other.
   - One model removed some retired generators but not the other.
   - The same generator is present but connected to the system at different voltage levels in the two models.
   - The same generator is present with different IDs in each model.
   - The same generator is present but connected to different buses in each model (i.e., the bus was renumbered).
   - One model modeled the power plant at the plant level (“lumped” unit) versus several generators at the bus level in the other model.
   - There were duplicated generators at the same bus (several generators with the same identification [ID] connected at the same bus).
   - The production cost model contained generators that were connected at buses that do not exist in the system.
   - The power flow model modeled generators as a synchronous condenser, and these generators do not exist in the production cost model.

   Figure A-1 and Figure A-2 show examples of generator mismatches between the two models.

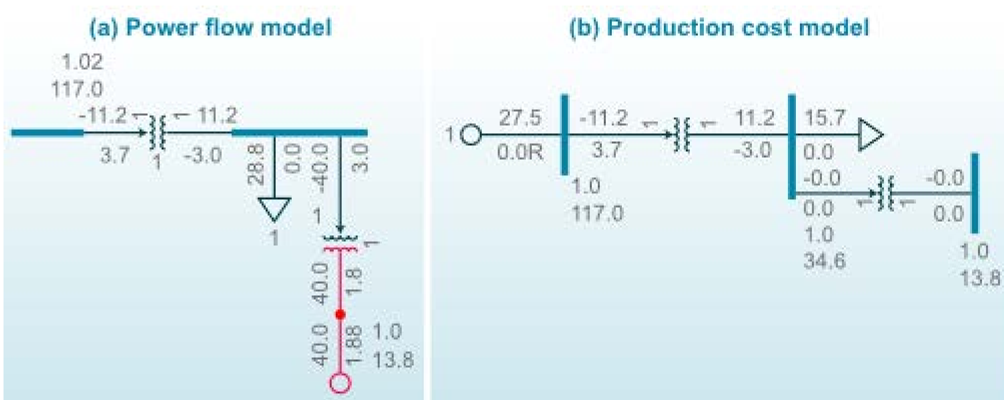

Figure A-1. Same generators modeled at different buses in the (a) power flow and (b) production cost models

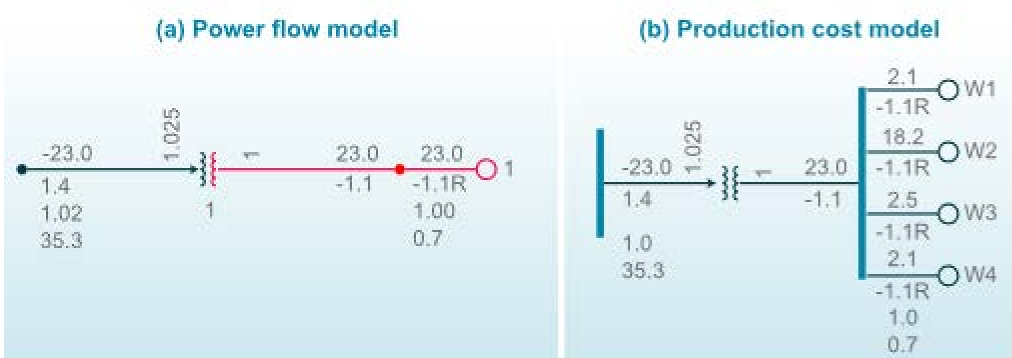

Figure A-2. Generators modeled as one lumped unit versus several distributed units at the same bus in the (a) power flow and (b) production cost models

After considering all the factors mentioned previously, the comparison identified 112 generators that exist in the power flow model but not in the production cost model and 650 generators that exist in the production cost model but not in the power flow model. Because the generator datasets in the power flow model do not provide enough information (fuel price, heat rate, startup/shutdown cost for thermal units, hourly profile for renewable units, and so on) to implement in the production cost model, the study team removed generators that exist in the power flow model but not in the production cost model. For generators that exist in the production cost model but not in the power flow model, the study team added them to the power flow model. To reduce the complexity of the dynamics model later, the study team removed the units with a capacity less than 20 megawatts (MW) from the production cost model instead of adding them to the power flow model. With this simplification, the power flow model now includes only 320 generators.

5. **HVDC:** The high-voltage direct current is modeled to allow power flow in only one direction in the power flow model whereas in the production cost model, power is allowed to flow in either direction. Hence, when importing the scheduled power for an HVDC with the flow direction reversed, users must reverse the converters' functionality (rectifier vs. inverter) at both ends.

6. **Interface definition checks and modifications:** The two models have different definitions of several interfaces. The reasons for the differences are as follows:
    - The interfaces comprise different numbers of transmission lines in both models.
    - The interfaces comprise the same number of transmission lines but are defined in opposite directions in the two models.

The study team identified and corrected all differences along with their corresponding flow limits in one or both models to match them.

After the study team addressed all inconsistencies between the component datasets of the two models, components in the two models were added or removed via the following steps:

1. Add new generators: After the new buses are added, add the required number of new generators.
2. Add new buses.
3. Add new lines/transformers.
4. Remove generators in the power flow model but not in the production cost model.

The study team developed several EPCL scripts to add components to the power flow model. To maintain the converged power flow case, the study team solved the power flow model after each modification.

Steps to add/remove components to/from the production cost model database:

1. Add new buses.
2. Add new lines.
3. Add new loads.
4. Remove generators that do not exist in the power flow model and with a capacity less than 20 MW.

Model validation

The study team imported the dispatch results from the production cost model into the power flow and obtained a solution for the DC power flow. A comparison of the line/interface flows validated the mapping between the two models. Temporal snapshots showed the closeness of the power flow pattern between power flow cases and the production cost model. In addition, the study team performed a statistical analysis to measure the goodness-of-fit of the modeling transformation.

Production cost model vs. DC flow comparison for the 2035 Alternating Current (AC) scenario

For the 2035 AC scenario, the study team created 24-hour cases on the peak load day (July 29) and compared them with the production cost model, as shown in Figure A-3 to Figure A-6.

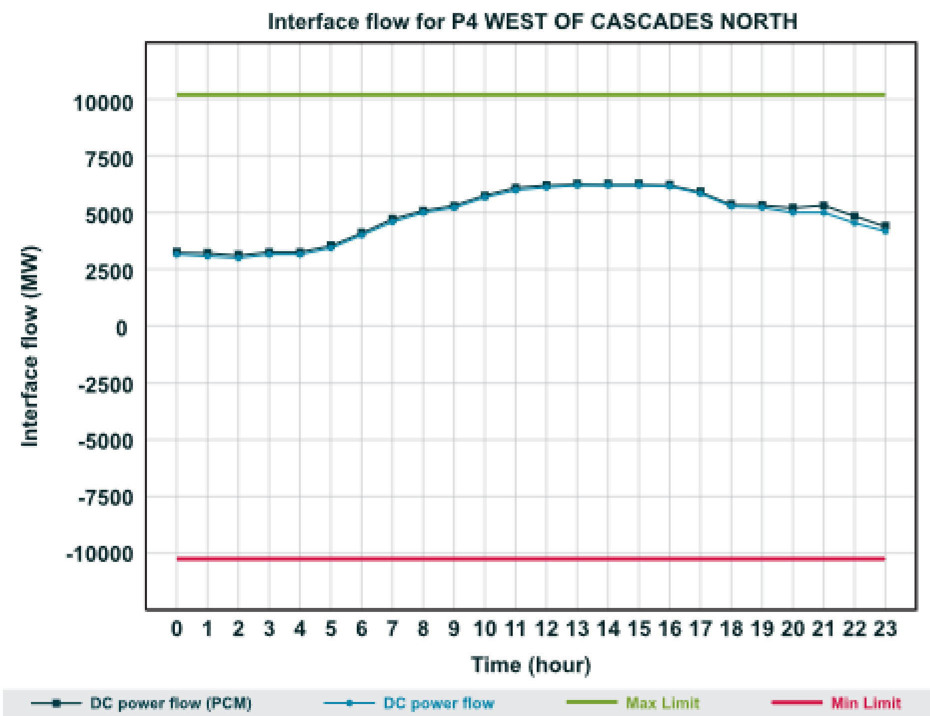

Figure A-3. Interface flow for Path P4 on July 19 (2035 AC scenario)

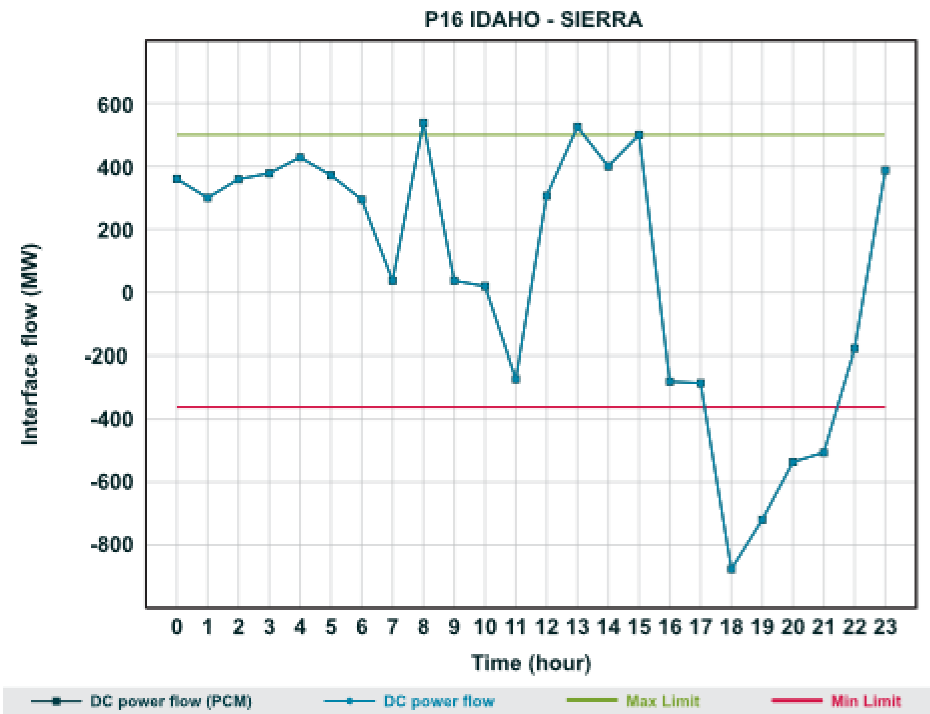

Figure A-4. Interface flow for Path P4 on July 19 (2035 AC scenario)

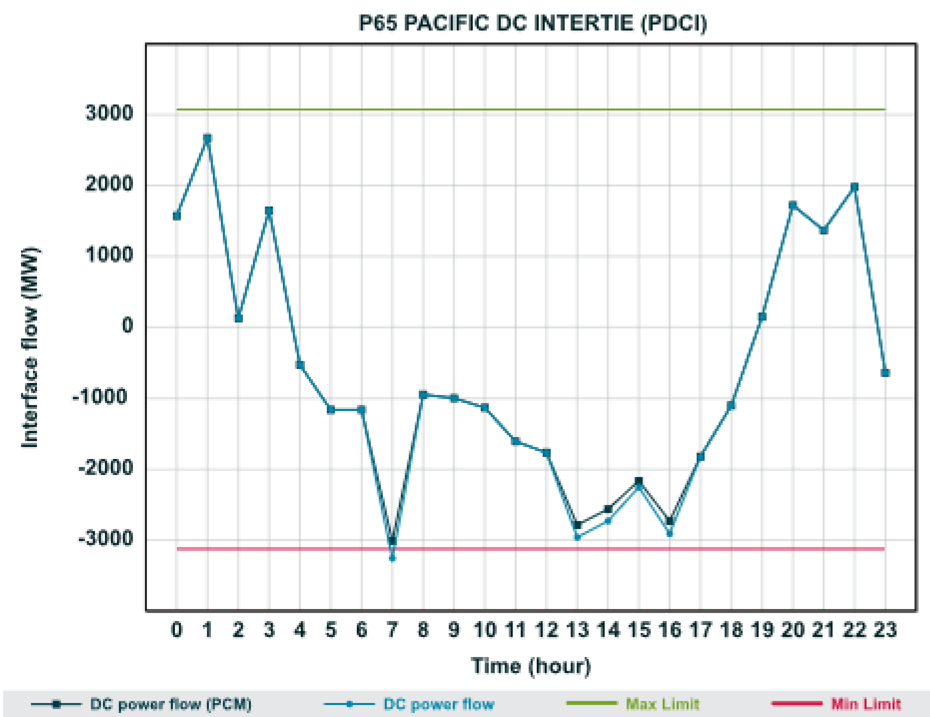

Figure A-5. Interface flow for Path P65 on July 19 (2035 AC scenario)

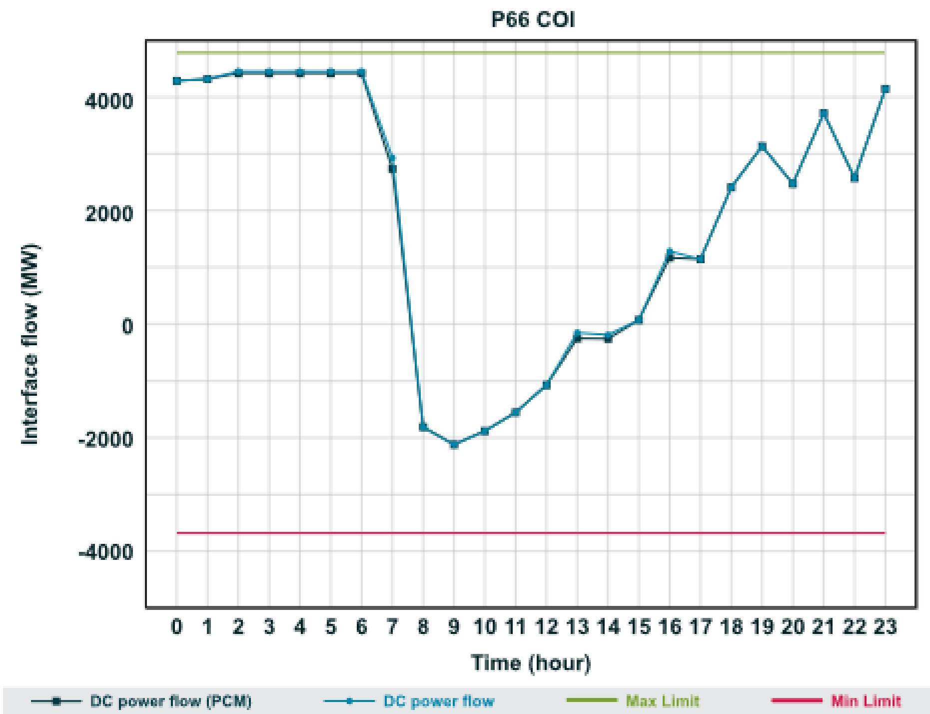

Figure A-6. Interface flow for Path P66 on July 19 (2035 AC scenario)

Production cost model vs. DC flow comparison for the 2035 Limited (Lim) scenario

For the 2035 Limited scenario, the study team created 24-hour cases on the peak load day (July 29) and compared them with the production cost model, as shown in Figure A-7 through Figure A-10.

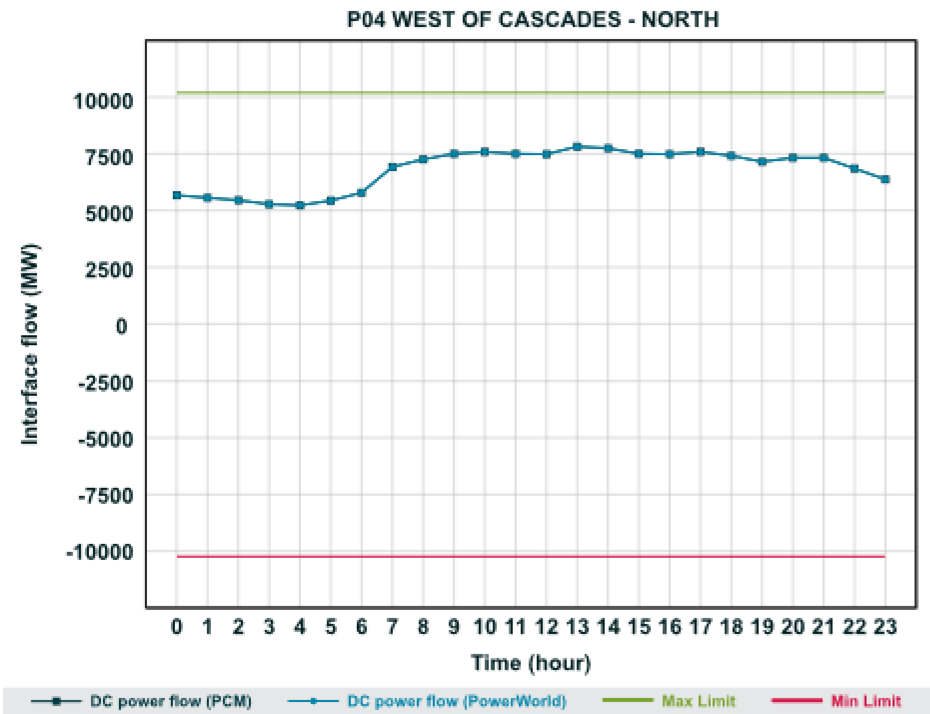

Figure A-7. Interface flow for Path P4 on July 29 (2035 Lim case)

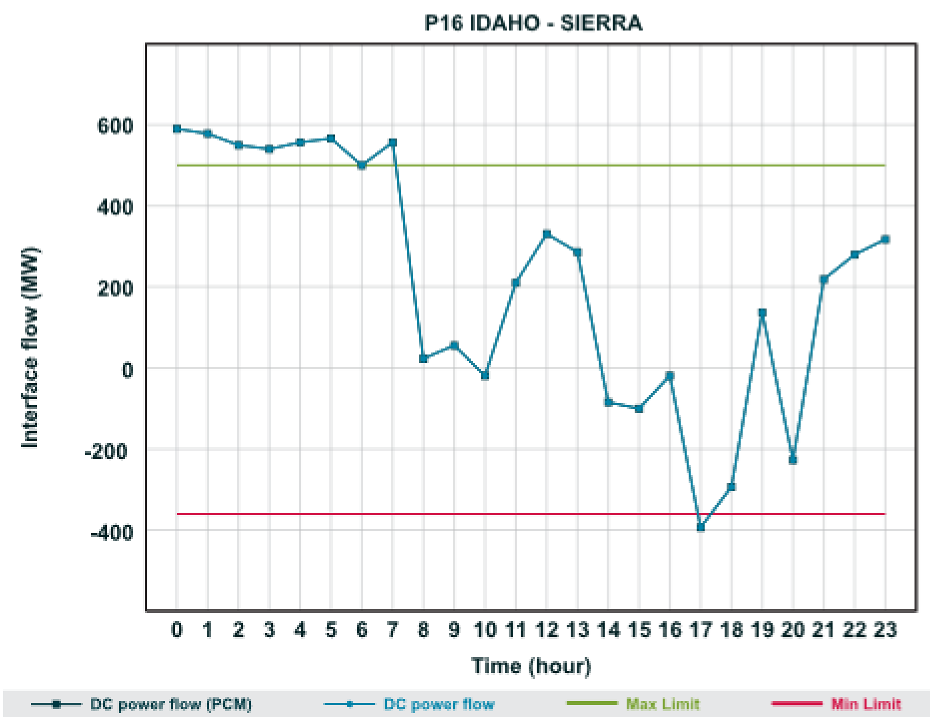

Figure A-8. Interface flow for Path P16 on July 29 (2035 Lim case)

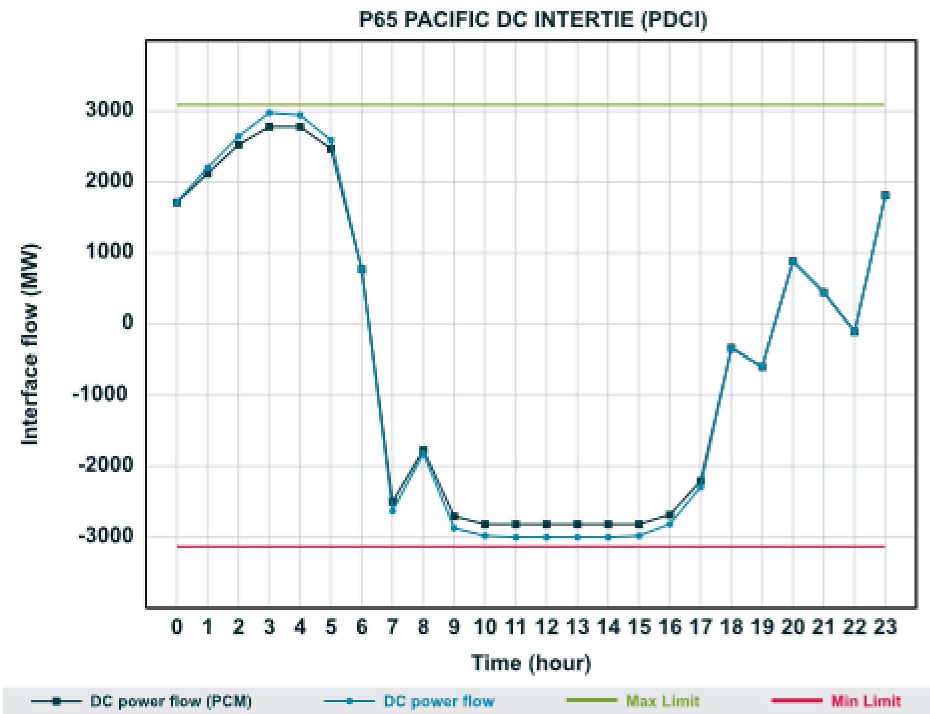

Figure A-9. Interface flow for Path P65 on July 29 (2035 Lim case)

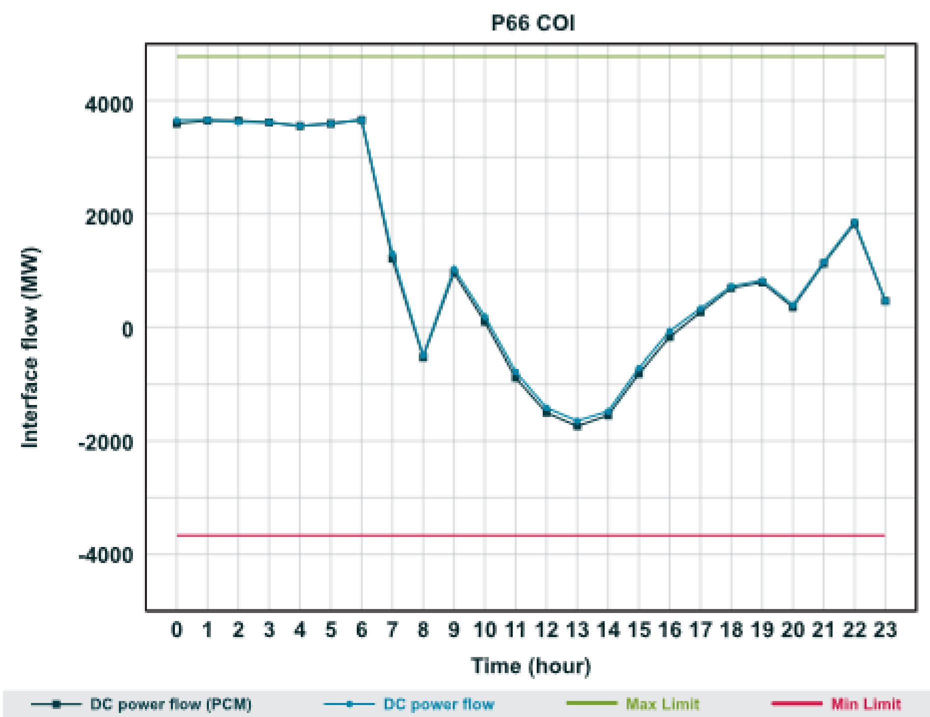

Figure A-10. Interface flow for Path P66 on July 29 (2035 Lim case)

In general, the results show acceptable consistency in the interface and branch flows for the production cost model and the exported power flow case.

The study team performed a statistical analysis of the exported power flow cases for the entire year to capture the accuracy and deviation from the PCM. This analysis computed the differences in the power flows on system transmission lines and at interfaces. The study team normalized the magnitudes of these differences by the component rating to quantify the deviation in the error between the power flow and production cost models. In the boxplots that follow, the positive error means the flow in the power flow model is higher than that in the production cost model.

Figure A-11(a) shows the error between flows from the power flow and production cost models on transmission lines categorized by voltage level whereas Figure A-11(b) shows the percentage error of the normalized transmission line flows. The average errors on the 230-, 345-, and 500-kilovolt (kV) lines are −6.3, 11.2, and 34 MW, respectively. Though the 230-kV transmission lines have a smaller error compared to the 500-kV transmission lines, the percentage error is slightly wider because the number of monitored 230-kV transmission lines is much larger than that of 500-kV lines. Moreover, the average percentage errors are −0.4%, 2.4%, and 2.8% for the 230-, 345-, and 500-kV lines, respectively. These are very small errors for the transformation of the PCM into power flow cases.

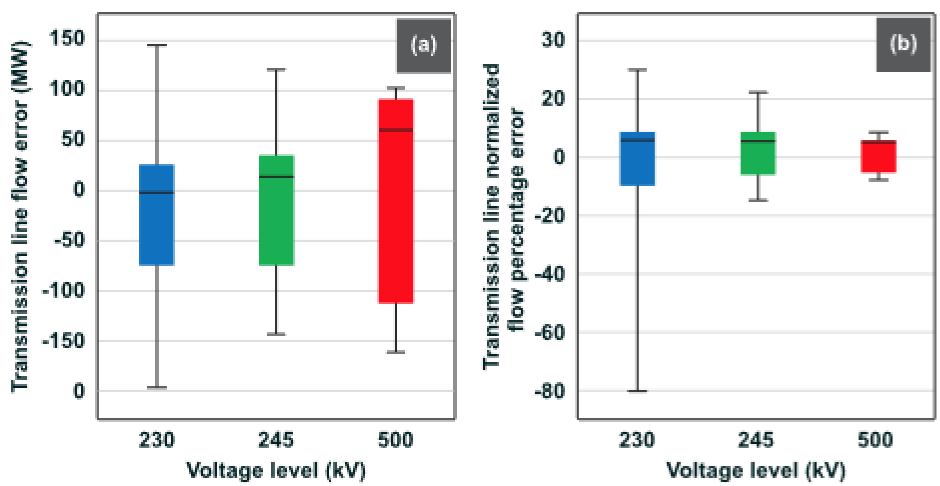

Figure A-11. Boxplots of the transmission line (a) flow error and (b) percentage error between the power flow and production cost models

Figure A-12(a) and (b) show the error and percentage error between flows from the power flow and production cost models on the interfaces defined in the system, respectively. The average error and average percentage error on the interfaces are −26.8 MW and −12.4%, respectively.

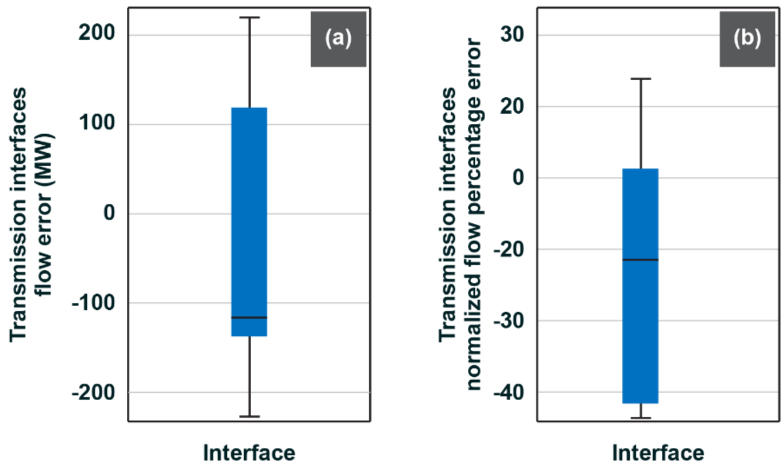

Figure A-12. Boxplots of the transmission interface (a) flow error and (b) percentage error between the power flow and production cost models

A.2 Production Cost Model Postprocessing Redispatch Procedure

The results generated by the PCM require additional analysis and data processing to prepare for the power flow and contingency analyses. The PCM postprocessing procedure comprises three main phases: a) redispatch hydropower plants, b) redispatch variable renewable energy (VRE), and c) make system-specific modifications. The following describes these phases:

1. **Redispatch hydropower plants:** GridView (Hitachi ABB 2024) models the hydropower generation at a given hydropower plant as several units. It conducts hydropower generation dispatch globally at the plant scale. Then, it computes the amount of generation from each unit within a hydropower plant based on the unit rating. In other words, GridView splits the total hydropower plant generation among all hydropower units in proportion to their rating; e.g., a total hydropower dispatch of 10 MW is split equally across 10 hydropower units—assuming all units have the same rating. If the capacity rating of each hydropower unit is 2 MW, each unit is 50% loaded. In this way, all hydropower units have the same participation (loading) factor. However, in real systems, not all hydropower units run simultaneously. Determining the number of active (running) hydropower units requires knowing 1) the ratio of the amount of generation dispatch to the total power capacity and 2) a given priority list. For the previously mentioned example, assuming the hydropower units have the same priority, the number of active units is five (50% of the number of plant units). This is calculated by dividing the amount of dispatch (10 MW) by the total power plant capacity (20 MW), resulting in five fully loaded units, with the remaining units unloaded.

   On the other hand, the capacity limit of each hydropower unit varies seasonally and is not fixed across the whole year. This variation impacts the number of dispatchable hydropower units at a particular time instant. If the summer limit for the previous example is reduced to 1.5 MW per unit, for the same scenario, seven hydropower units are dispatchable [10/(1.5 × 10) = 0.67% → 70% of the number of units]. In this case, the resulting capacity mix includes six fully loaded units with a total generation of 9 MW, one unit generating 1 MW, and three unloaded units. The GridView model considers seasonal changes, and power flow cases should preserve these considerations. Table A-1 and Table A-2 summarize the differences in hydropower dispatch accounting for prioritization, loading distribution, and seasonal limits.

Table A-1. Redispatched Hydropower Units Considering the Loading Distribution and Modified Capacity Limits

Unit Number	1	2	3	4	5	6	7	8	9	10
Power generation profile from GridView	1	1	1	1	1	1	1	1	1	1
Redispatched power considering loading distribution	2	2	2	2	2	0	0	0	0	0
Redispatched power considering reduced unit limits to 1.5 MW	1.5	1.5	1.5	1.5	1.5	1.5	1	0	0	0

Table A-2. Redispatched Hydropower Units Considering Prioritization and Different Unit Capacity Limits

Unit Number	1	2	3	4	5	6	7	8	9	10
Capacity limit (MW)	1	2	1	2	0.5	0.5	2.5	2.5	1	1
Priority	3	2	7	6	4	10	1	5	8	9
Power generation profile from GridView	1	1	1	1	1	1	1	1	1	1
Power generation profile from GridView	1	2	0	1.5	0.5	0	2.5	2.5	0	0

To address these challenges, the study team prepared a two-step Python-based script to redispatch hydropower generation. First, the script extracts the results from GridView and computes the total generation of each hydropower plant by aggregating the power generated by each unit within the power plant. Then, it uses a priority list of each power plant to commit individual units. The script redispatches hydropower units sequentially until the total amount dispatched equals the precalculated aggregation generation plus the required reserve generation. In this step, the script adopts the capacity limit of each unit from the

GridView results and assumes the status of unloaded units is “off” and should not contribute to power flow cases.

2. **Redispatch VRE:** GridView conducts renewable energy generation globally on the plant level. This results in distributing the total plant dispatch value equally across all connected units. However, for a particular renewable power plant (solar, wind, and battery storage), the number of units in GridView is usually different from the number of installed units in power flow cases. Generally, the study team observed fewer units in GridView because the GridView model aggregates very-small-scale units at nearby geographical locations into a single point of interconnection. Accordingly, the amount of unit dispatch will change according to the ratio between the amount of plant dispatch and the corresponding number of units in power flow cases. Moreover, it is important to enforce the status of battery storage units to “on,” even those with zero power contribution. This ensures such devices can contribute to reactive power stability when solving power flow cases. In renewable redispatch, GridView does not preserve priority across units of the same power plant.

   To address these challenges, the study team prepared a Python-based script to redispatch VRE including solar, wind, and battery storage. The script applies the same procedure adopted for redispatching hydropower with slight modifications. It properly maps VRE between the GridView and power flow cases prior to redispatching. For each renewable power plant, the script computes the total generation by aggregating the generated power of all units from the GridView results. It then splits the computed total generation equally across all corresponding units for the corresponding renewable power plant in the power flow case.

3. **Make system-specific modifications:** Some components require special handling between the GridView and power flow models. In the Western Interconnection model, a few more issues required external intervention. These methods are described next.

   - *HVDC transmission lines:* The study team modeled HVDC lines as generators in power flow cases. Two generators, a sending terminal, and a receiving terminal replace each HVDC line. The real power of the generator at the sending terminal corresponds to the power flow injected into the HVDC line. In other words, the generator at the sending terminal will have a negative real power value. On the other hand, the real power of the generator at the receiving terminal corresponds to the amount of power flow from the HVDC line to the rest of the network. The direction of the power flow on the HVDC link determines the sending and receiving terminals. Figure A-13 illustrates the conversion of an HVDC line to two generators.

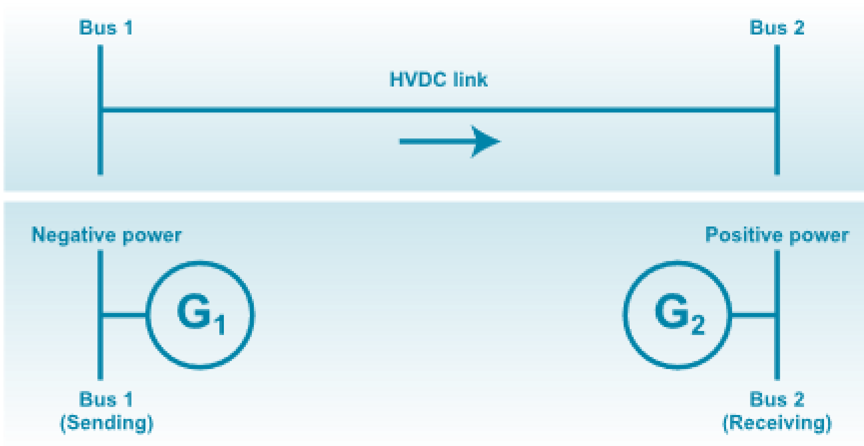

Figure A-13. Conversion of an HVDC line to two generators, a sending terminal, and a receiving terminal

- *Generator IDs:* After completing the previously mentioned processes, it is found at several buses the same generator is identified by a different ID in PF and PCM. This creates an issue when passing the data to the Chronological AC Power Flow Automated Generation (C-PAGE) platform to prepare the power flow cases. It is essential to ensure this data discrepancy is handled properly during the data processing.
- *Nuclear power plant:* The study team aggregated multiple steam turbine (ST)-nuclear generators at a single bus as a single ST-nuclear power plant and lumped them as a carbon-free nuclear generator at a nearby bus into the power flow model.

Appendix B. Procedure for Preparing AC Power Flows Based on Production Cost Model Data for Power Flow Case Creation

There are some differences between direct current (DC) and alternating current (AC) power flow modeling. Because the production cost model (PCM) employs a DC model and linear solver, the study team did not consider the bus voltages in the initial stage of the optimization procedure. The system loss is another element that has an impact on the solution. Unlike AC power flows, where the loss is calculated as part of the power flow solution, a production cost model estimates the loss and adds it to the load. In addition, solving the chronological power flow models requires assumptions regarding the reactive power load and generation because the production cost model neglects them but the AC power flow does not. The research team used a reference power flow case to determine load distribution factors once, and then they applied those factors to all hours. Though this is acceptable in a production cost model because bus voltages are not considered, it is typically not the case in an AC power flow model because of the significant seasonal differences in the bus load distribution and voltage profiles.

Another significant distinction is the production cost model data do not include information concerning the reactive power dispatch of generators. In a power system, the solution for the power flow traditionally determines the actual reactive power dispatch of generators. The starting point for power flow algorithms such as the Newton–Raphson method is either a flat start or the operational point of a converged power flow case. Obtaining convergence for the power flow in a large-scale power system, such as the Western Interconnection, is difficult. It is challenging from the perspective of the power system to develop a dispatch for each generator that offers adequate reactive power while preserving a stable voltage profile for all buses in the system. Mathematically, the power flow in a system of this size is typically unconditioned, meaning a small change in demand can result in a large change in the system's state or voltage profile. Therefore, if the solution of the prior converged power flow case is far from the solution of the present power flow case, using a flat start or the solution of that case may be inefficient. Furthermore, if voltage violations occur on multiple buses, the algorithm is likely to converge to an unstable solution. This makes it difficult to import production cost model data and solve the chronological AC power flow problem.

Creating a basic converged AC power flow case normally takes a few hours to days because it involves production cost modeling, convergence of the AC power flow, and reactive power planning. With the use of the Chronological AC Power Flow Automated Generation (C-PAGE) tool created in the NTP Study, any large, interconnected system—including the Western Interconnection, the Eastern Interconnection, and the Electric Reliability Council of Texas (ERCOT)—may produce a converged AC power flow automatically and in a matter of minutes.

This modeling activity evaluated the engineering feasibility of a future system scenario. Although the study team used the same tools transmission planners use to test safe and reliable operations for future grid expansions, the full and large scope of contingency analyses transmission planners customarily perform was not applied. Given the significant numbers of power flow models available for analysis, the study team focused on smaller sets of contingencies that represent the most critical and impactful issues recognized by the transmission planning community. This is because of the large number of power flow scenarios that must be examined. The technical review committee (TRC) discussed the prioritization of contingency cases for exploration.

The Pacific Northwest National Laboratory (PNNL)-developed C-PAGE tool translated the production cost model outputs of selected operating conditional cases to AC power flow models. C-PAGE uses a three-stage process to translate datasets between the production cost and power flow models.

B.1 Stage 1: Data Mapping and Model Validation of the Production Cost Model and Power Flow Cases

B.1.1 System topologies of the production cost and power flow models

A seamless transition from production cost model simulation findings to power flow instances is necessary for transmission design studies. Therefore, it is important to understand how the production cost model results are exported to a power flow case, how to validate the process of updating the production cost model results to the power flow case, and the similarities and differences between the production cost model and power flow model. Consistency between production cost and power flow model system topologies is required to correctly feed the production cost model dispatch to power flow models, necessitating rectifying any differences. For example, any transmission lines in the two models must have a one-to-one match for transmission line identification (ID), status, and rating.

B.1.2 Exporting production cost model simulation results to the power flow case

The C-PAGE produces nodal-level updates to the power flow model after receiving the results of the production cost model simulation. The unit commitment and economic dispatch for generation units, high-voltage direct current (HVDC) dispatch, transformer phase angles, and transmission line status are all provided to all equipment. A power plant in a production cost model is comparable to one or more distinct units in the power flow situation, as mentioned in Appendix A. The state of each of these units is comparable to that of the power plant in the production cost model result when the results are exported to a power flow case. Figure B-1 depicts the process of disaggregating generation and load from the power plant and balancing authority (BA) levels to the nodal level. Appendix A.2 details the production cost model postprocessing redispatch procedure.

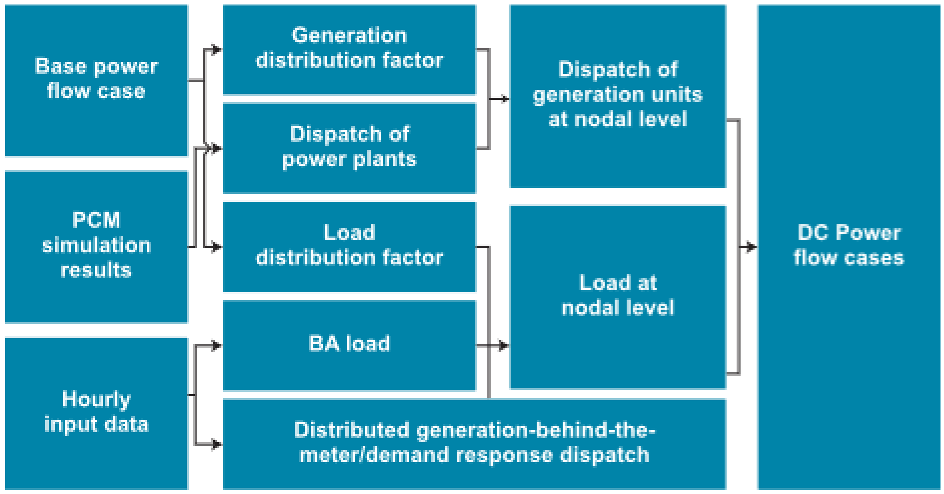

Figure B-1. Process of disaggregating generation and load from the production cost model simulation results to power flow cases

B.2 Stage 2: DC-to-AC Convergence Process

The approach begins with Step 1 in Figure B-2, which updates the new production cost model result to a converged AC power flow case derived from the preceding timestep. The reasoning is the loading conditions for two consecutive power flow instances are frequently near one another; therefore, the voltage of the prior timestep in the converged AC power flow case is a useful starting point for solving for the power flow in the new power flow case.

Because the production cost model employs a DC power flow, the total generation equals the total load in the new power flow condition. In this approach, it is assumed the dispatch of all generation units—including the unit at the slack bus—is fixed, as in the production cost model results. Therefore, when converting from a DC power flow scenario to an AC power flow scenario, decreasing the nodal loads accounts for transmission losses.

As a result, Step 2 of the process progressively reduces the nodal loads prior to solving for the AC power flow. This step reduces the load further if the power flow does not converge. If the power flow converges, this step compares the resulting real power generation P_{slack} at the slack bus to P^0_{slack} in the production cost model result. This step reduces the load further if the difference at iteration *k* exceeds a certain tolerance δ; otherwise, the load-reducing process is complete. It is worth noting this step uses an adaptive step size μ^{k+1} at iteration (*k* + 1) based on the slack generation difference Δ^k at time *k* to iteratively lower the load as follows:

$$\mu^{k+1} = \Delta^k \sigma = | P^k_{slack} - P^0_{slack} | \sigma , \qquad \text{Eq. B-1}$$

where σ is a constant coefficient.

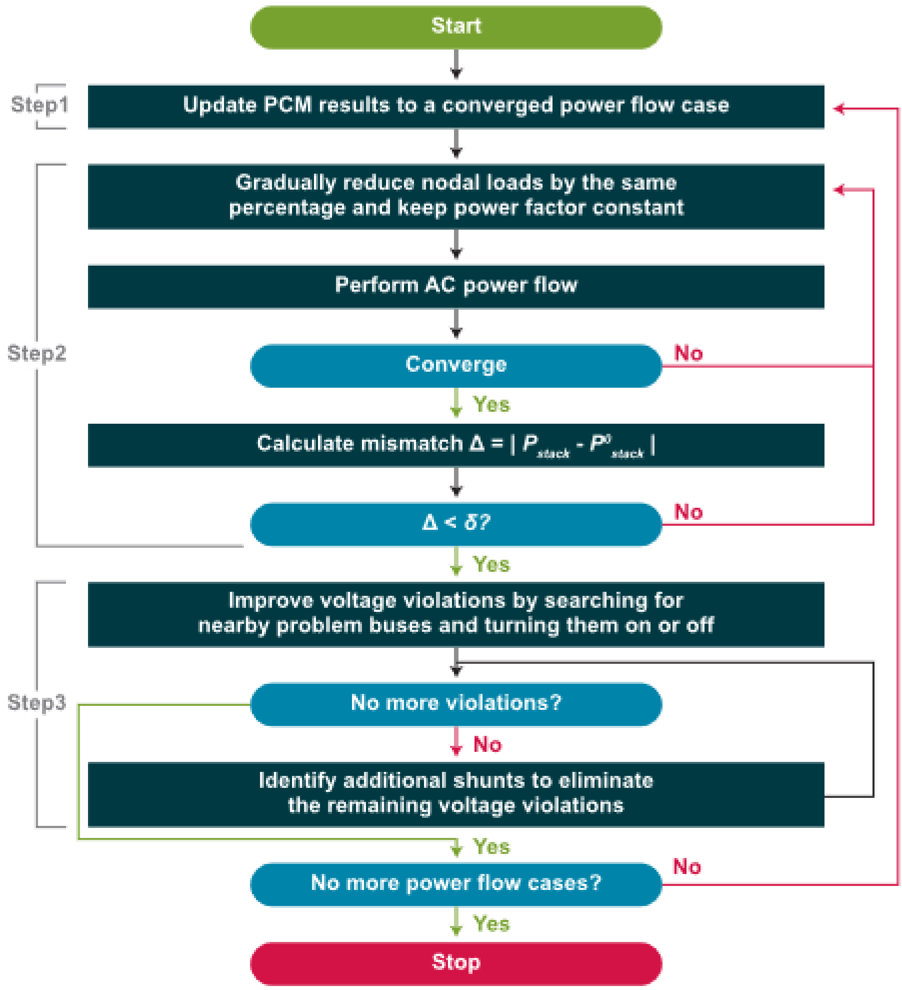

Figure B-2. Procedure to convert a converged DC power flow case from the production cost model results to a converged AC power flow case

B.3 Stage 3: Reactive Power Planning for Voltage Improvement

After attaining a converged AC power flow situation, the focus moves to improving the bus voltage profile. Improving the voltage after attaining convergence of the AC power flow is critical because a good voltage profile at one timestep has a direct impact on the potential to achieve convergence of the AC power flow in succeeding timesteps. As a result, Step 3 in Figure B-2 examines all bus voltages to look for voltage violations. The next step is to process each bus that has a voltage violation and identify any current shunts on that bus or any surrounding buses. The level of voltage violation and the shunt step sizes determine whether to turn on, turn off, or change the dispatch of these shunt devices.

After a bus voltage violation is mitigated using the system's existing shunts, Step 3 checks for voltage violations again to discover any remaining violations. If a voltage violation is not completely rectified, this step performs another voltage improvement process based on a *Q*-*V* analysis to identify the locations and sizes of shunts to add to the system. The resulting power flow scenario is regarded as the final converged AC power flow case for the current timestep after enhancing the voltage profile using existing and additional shunts. This step repeats the conversion of the DC power flow from the production cost model findings to a converged AC power flow case (Figure B-3) until all timesteps are processed.

Transition planning should include ample reactive power resources to meet reliability requirements under a wide variety of feasible contingencies. The reactive power is a critical reliability service for bulk power systems. Generators, capacitors, transmission lines, and loads all contribute to its supply; transformers, loads, and transmission lines all use it. The reactive power and voltage magnitude are closely related. Ensuring voltage remains within a reasonable range is achievable with careful reactive power planning.

At Stage 2, the voltage profiles of each converged AC power flow case require mitigation to address any voltage breaches. C-PAGE can improve voltage profiles by performing a *Q-V* analysis, which displays the sensitivity and volatility of bus voltages with respect to reactive power injections or absorptions. As depicted in Figure B-3, the strategy is to gradually improve a voltage profile while using suitable reactive power support devices.

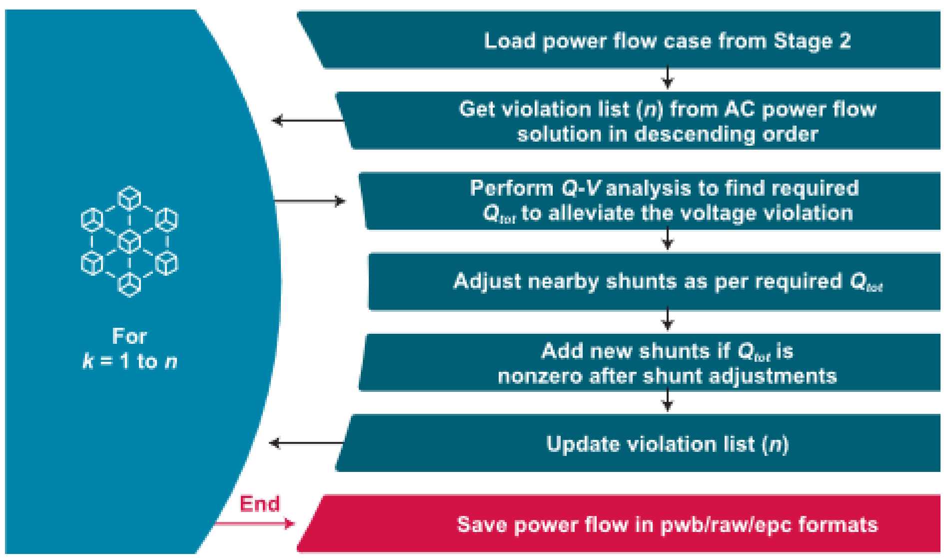

Figure B-3. Reactive power planning to improve voltage profiles

The reactive power planning algorithm starts by loading the power flow case from Stage 2 and extracting voltage-out-of-range violations for higher voltages. In this work, the focus is on base voltages of more than 230 kV, but the concept applies to any voltage level. The algorithm carries out a *Q-V* analysis of the bus with the highest voltage violation in the first stage to determine the necessary reactive power support (Q_{tot}) to reduce the voltage violation. This stage also involves sorting the violation list in descending order of voltage. If any shunts, such as capacitors or reactors, are found close to the bus being most violated, the simulator adjusts them to the needed Q_{tot} value and updates Q_{tot}. The simulator inserts a new shunt if Q_{tot} is still nonzero after the shunt changes. Then, it resolves the power flow and derives a list of violations. When the simulator cannot converge at a specific transfer level throughout this process, that bus is skipped. If not, this procedure is repeated until there are no violations left on the list. With reasonable reactive power support devices, this algorithm incrementally improves a voltage profile, which can partially correct flow violations. Performing generation redispatch reduces power flow violations, but this was not done because the study team did not want to change the PCM generation dispatch at any time. Finally, the algorithm saves the power flow case with the better voltage profile in formats such as PowerWorld's pwb, PSS/E's raw, and PSLF's epc.

Appendix C. Visualization of Simulation Results Using a Geographic Information System

C.1 Introduction

For efficient analysis of the simulation results, there is a need for various graphs, including geographic information system (GIS)-based plots. Given the size of the generated dataset, the process of data processing, analysis, and visualization must be automated.

The use of QGIS in conjunction with the Python automation scripts enables advanced visualization and analysis of power flow results in the GIS domain. QGIS, an advanced open-source GIS platform, provides extensive tools for spatial data manipulation and visualization, efficient for representing electrical grid components and their operating conditions geographically. Integrating Python, a programming language with powerful libraries and scripting capabilities, enables the automation of complex data processing tasks. This integration facilitates the efficient handling of large-scale power flow datasets produced by production cost model, power flow, and contingency analysis tools—allowing the automated generation of detailed, interactive maps that display power flow information such as the transmission grid topography, voltage profiles, and transmission line loading. To achieve this goal, the study team implemented full back-to-back automation to extract power flow information from solvers (typically stored in binary files), process this information, and upload it to the database server, generating GIS visualizations (QGIS layers) and creating new, self-contained QGIS projects for specific power flow cases or scenarios.

C.2 Features

Figure C-1 displays a flowchart of the visualization automation process. An on-premises server is used for simulation and data extraction. Subsequently, the process uploads the information to an AWS cloud-hosted PostgreSQL database server, which also incorporates GIS infrastructure information. A script to automatically generate a QGIS project and visualize the results is executable on a user's workstation computer. The following subsections provide more details about each block in the flowchart.

C.2.1 Simulation and data extraction

An on-premises server hosts simulation applications (such as DCAT, PowerWorld, and GridView) and stores their outputs as binary files. It is crucial to eliminate redundancies and convert key information from binary format files into a database. Therefore, the process designed to extract, process, and upload data plays a pivotal role in effective data management.

The developed data processing automation facilitates user-friendly access and aids in data-driven decision making and optimal data use, as shown in Figure C-1. The data extraction procedure entails parsing data sources using simulator application programming interfaces (APIs) such as SimAuto or PSSPY, consolidating and organizing data spread across various systems, and subsequently uploading them into a centralized data repository, e.g., MongoDB or AWS S3, for enhanced secure storage.

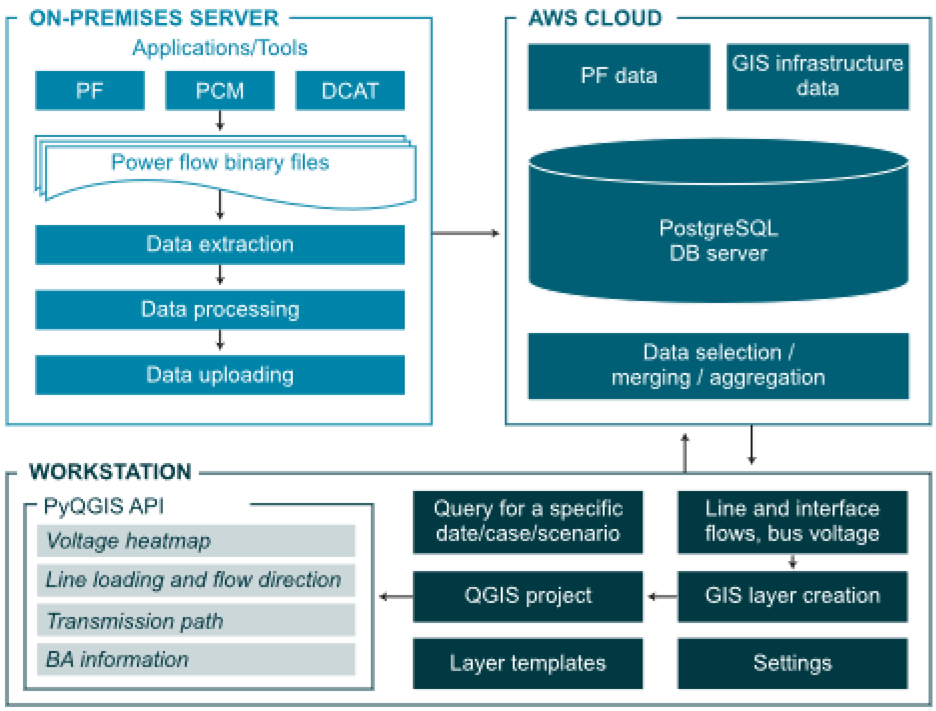

Figure C-1. Flowchart showing the automated process for analyzing and visualizing simulation results

C.2.2 Cloud-based GIS database

The study team developed a cloud-based GIS database architecture to leverage the robust and scalable infrastructure provided by AWS cloud services. This architecture uses a PostgreSQL database, a sophisticated object-relational database system known for its robust data management capabilities.

To enhance the GIS functionality of the PostgreSQL database, the study team integrated the PostGIS add-in. PostGIS expands the capabilities of PostgreSQL to include support for geographic objects, enabling the execution of location-based queries in SQL. This enhancement is crucial for conducting spatial data analysis and for operations within GISs.

The study team sourced various publicly available and commercial GIS information regarding electricity infrastructure. This includes the locations of buses, lines, substations, power plants, and more, providing a comprehensive overview of the electrical grid’s structure and components.

In addition, the database stored the simulation results from the production cost model, power flow, and contingency analyses and systematically indexed these results with specific identifiers such as scenario, case, and date, facilitating efficient data retrieval and organization.

The strength of the PostgreSQL database on AWS allows efficient data manipulation capabilities, enabling rapid data retrieval, aggregation, and the merging of datasets (e.g., joining power flow data with bus locations).

C.2.3 QGIS visualization

The study team designed a user-centric and interactive power flow analysis visualization that is executable using a Python script from any workstation machine. The user must specify input parameters in a settings file, which includes the date, case, scenario, and the type of basemap desired (such as a geographical map, satellite map, or gray/dark map). With these inputs configured, the user executes the Python script, which queries the database based on the user's specified criteria. The server processes this query and returns the required power flow information, such as line flows, bus voltages, and interface flows—all linked with their respective location data.

Once the relevant data are retrieved, the script uses PyQGIS, the Python API for QGIS, to create QGIS layers. It applies predesigned QGIS layer templates to the data, enabling the visualization of flows as arrows showing directions. They also vary in color and width to represent different flow sizes and line loadings relative to their limits. The script further enhances the visual representation by generating a voltage heatmap using the inverse distance weighting (IDW) method. This method provides a graphical representation of voltage levels across the network. IDW, a type of deterministic method for spatial interpolation, assigns values to unknown points based on the values of known points, weighted by the inverse of their distance. This function is available in the Geospatial Data Abstraction Library (GDAL), which is part of the QGIS package. The created heatmap is a raster layer and uploaded to the server using the pg_raster_upload plugin. To improve visualization, the study team added some layers to the project such as balancing authority (BA) boundaries, state boundaries, and major cities.

Finally, the script compiles all the elements into a QGIS project, which is then saved for subsequent use. QGIS can open the resulting project, where users can interact with the map, zooming in on areas of interest and gaining insights through the visual representation of the system's operating conditions.

C.3 Visualization Examples

Figure C-2 presents an example of voltage profile visualization using a heatmap along with the power flows through the transmission lines. It also depicts the borders of U.S. states and major cities. The inclusion of U.S. state borders and major cities in the visualization adds a geographical context, enabling viewers to understand the physical locations of infrastructure elements. Figure C-3 provides another example visualization of simulation results, illustrating the power flows in the grid, the loading of major Western Interconnection paths, and the boundaries of the BAs.

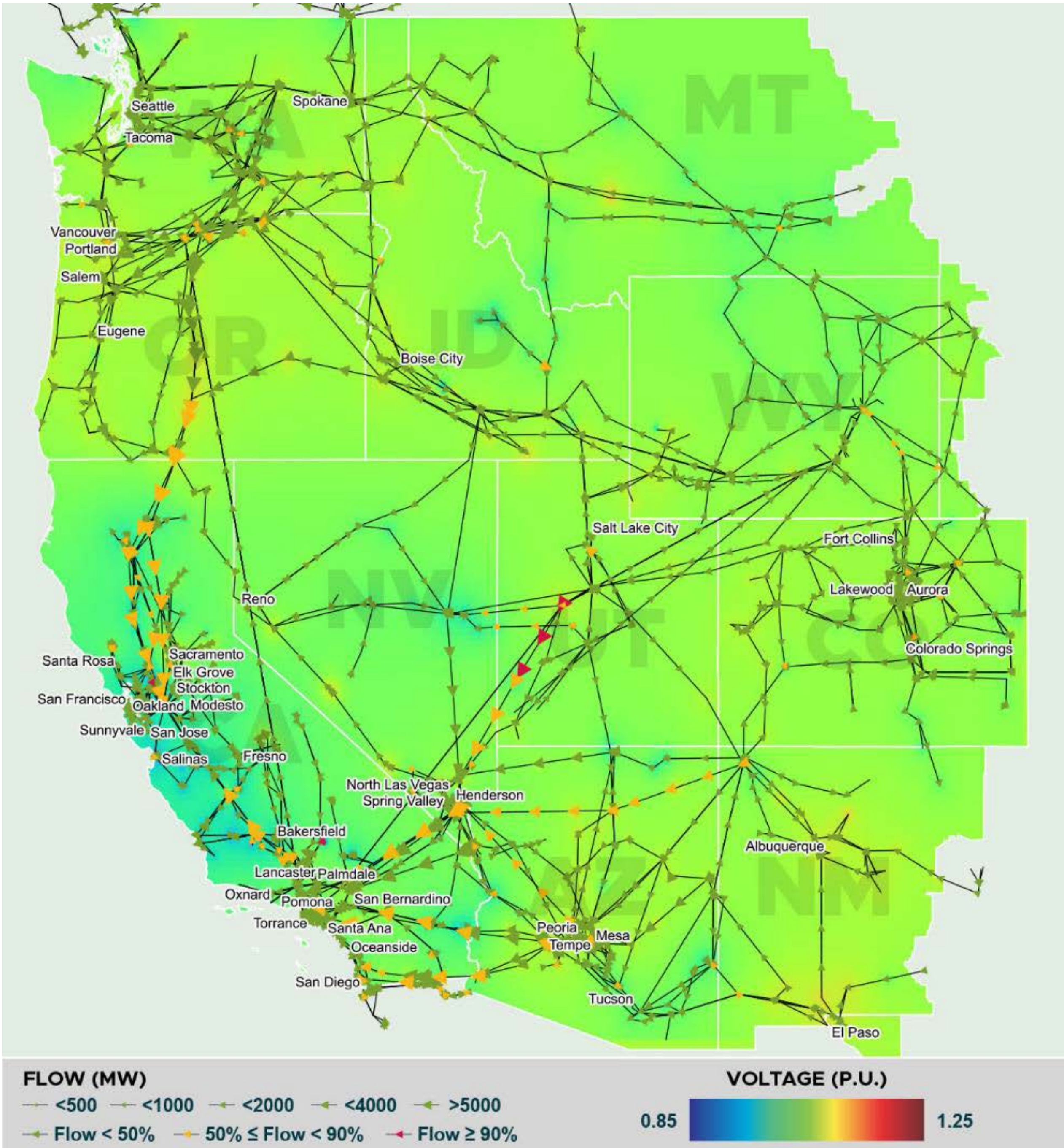

Figure C-2. Voltage heatmap and visualization of the transmission line flows

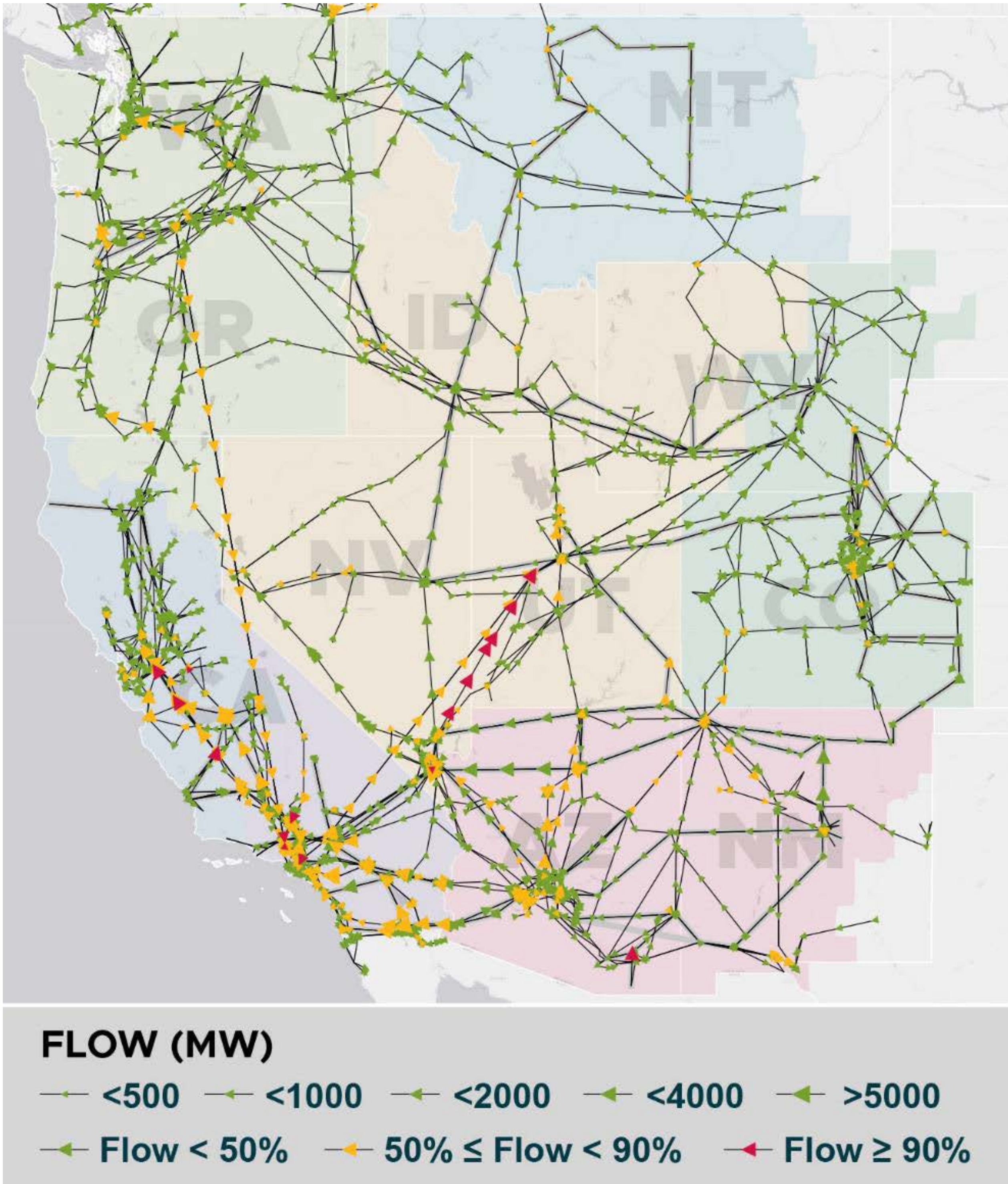

Figure C-3. Visualization of the major loading paths and transmission line flows

Appendix D. Western Interconnection Transmission Modeling Assumptions

For the fixed shunt line reactors of new lines (new corridors only; not for duplicates of existing ones), the study team made the following assumptions for shunt compensation:

- Total fixed line compensation:
  - Length < 100 kilometers (km) – 0% of the line susceptance
  - 100 km ≤ length < 150 km – 40% of the line susceptance
  - 150 km ≤ length < 200 km – 45% of the line susceptance
  - Length ≥ 200 km – 50% of the line susceptance
- Distribution of the fixed line compensation:
  - 50% of the total fixed shunt compensation at the “from” terminal
  - 50% of the total fixed shunt compensation at the “to” terminals.

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