Modeling the Effects of Distributed Generation on Transmission Infrastructure Investment

A WESTERN CASE STUDY

A Report of the
Energy Systems Integration Group's
DER-Transmission Project Team

Updated May 2024

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Modeling the Effects of Distributed Generation on Transmission Infrastructure Investment: A Western Case Study

A Report by the Energy Systems Integration Group's DER-Transmission Project Team

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May 2024 Update

The updated May 2024 version reflects a rerun of the PLEXOS ST production simulation model with corrected settings. Minor changes were made to some graphics and tables, with the largest change in Figure 20 transmission flows between WACM and APS. Study conclusions remain the same. There were no updates or changes made to the PLEXOS LT capacity expansion model results.

Contents

Abbreviations Used

BESS	Battery energy storage system
DG	Distributed generation
DGR	Distributed generation resource
EFS	Electrification Futures Study
IRA	Inflation Reduction Act
LT	Long term
LTCE	Long-term capacity expansion
NREL	National Renewable Energy Laboratory
PV	Photovoltaic
ST	Short term
WECC	Western Electricity Coordinating Council

Executive Summary

Within the rapidly transforming energy industry, the increasing adoption of distributed generation technologies—such as rooftop solar and batteries installed behind the meter at homes and businesses—has the potential to transform the way we plan and operate energy systems. While ample research has been conducted on the relationship between distributed generation and distribution wires, transformers, and other equipment used to get electricity to homes and businesses, the impact of distributed generation on the high-voltage bulk transmission systems that connect major cities, planning areas, and states has received limited attention. This study explores how increasing distributed generation deployments—namely, distributed solar photovoltaic (PV) generation often paired with storage—impact zonal transmission flows and the need for transmission investment. It also investigates potential synergies between transmission and resource expansion under distributed- and utility-scale-generation–dominant futures. Given that distributed generation is anticipated to play an important role in the ongoing energy transition, this study seeks to bridge this research gap and provide insights into the transmission use and planning implications of distributed generation to help grid planners ensure a more efficient and reliable grid.

While ample research has been conducted on the relationship between distributed generation and distribution wires, transformers, and other equipment used to get electricity to homes and businesses, the impact of distributed generation on the high-voltage bulk transmission systems that connect major cities, planning areas, and states has received limited attention.

Study Scenarios

The study compared three long-term futures of the United States' Western Interconnection simulated with varying levels of distributed generation. The study assumed that the Western system follows a common trajectory for generation and transmission builds from present-day through 2030. This 2030 reference case was used as the starting point for three divergent futures, or scenarios, which were centralized, hybrid, and distributed. For a study horizon spanning 2031 to 2040, each scenario featured a unique set of inputs, variables, and results.

Two of the three futures, the centralized and hybrid scenarios, were simulated with varying levels of distributed generation defined as an input. The centralized and hybrid scenarios included distributed generation adoption rates equal to 100% and 200%, respectively, of the 2022 National Renewable Energy Laboratory's Standard Scenarios future projections.[i] The third future, the distributed scenario, represented a theoretical "information-only" bookend case in which distributed generation resources were simulated as the primary method of meeting long-term planning objectives. Distributed generation resources represented in the study included many combinations of solar and battery project configurations with a range of tariff assumptions that impact distributed generation operating paradigms.

i See https://www.nrel.gov/analysis/standard-scenarios.html.

Modeling Framework

Each of the three futures was modeled in the PLEXOS software using both long-term capacity expansion (LTCE) and short-term (ST) dispatch functionalities. The basis for the study's zonal topology and many key assumptions was the PLEXOS WECC 2023 Zonal Dataset, released by Energy Exemplar in January 2023. This dataset includes a baseline of existing and planned generation resources, zonal load forecasts, and zonal line limits representing the transfer capability between zones in the Western Interconnection. We expanded the dataset to align with the study methodology, including adding candidates for transmission expansion as well as sophisticated representation of distributed generation operations.

For each of the three scenarios, long-term capacity expansion modeling was used to identify generation and transmission investment during the 2031–2040 study period, with all scenarios starting from the common 2030 reference case. The model's objective was to find the least-cost generation and transmission expansion plan accounting for both capital costs and production costs for the 10-year study horizon. The long-term capacity expansion optimization solved for a variety of constraints including energy balance, resource adequacy, and clean energy policy constraints such as state renewable portfolio standards and other clean energy targets.

All three scenarios were able to select zonal transmission upgrades from a list of over 80 transmission expansion candidates compiled during the study process. In the centralized and hybrid scenarios, which incorporated distributed generation build trajectories as an input, the long-term capacity expansion model selected additional resources from a set of utility-scale generation technologies. In the distributed scenario, the model was limited to selecting only distributed generation during the study horizon.

Using the generation and transmission build selections from the long-term capacity expansion model, the PLEXOS short-term dispatch stage was used to simulate each scenario's hourly operations in a full-year chronological simulation for a 2035 study year. The short-term functionality incorporated operating reserves, which were not included in the long-term capacity expansion modeling to reduce computational complexity. The short-term dispatch model enabled an acute focus on hourly interzonal transmission flows, utilization, and congestion.

Key Findings

This study framework provided unique insights into the implications of distributed generation on the bulk transmission system. Findings were derived by comparing the scenario results of both the long-term capacity expansion and short-term simulations. Comparisons

of the simulated futures led to the following findings.

Distributed generation can significantly impact inter-zonal transmission flows.

The scenarios investigated in this study exhibited a range of transmission flow and congestion patterns resulting from varying distributed generation build-out assumptions and operational constraints. The modeled adoption of distributed solar and batteries across the Western Interconnection changed diurnal transmission flow and generation patterns. Specifically, it tended to create a midday nadir in net load, and a need for morning and evening flexibility that must be served by storage and other generators on the system. These shifts in generation dispatch had corresponding impacts on zonal transmission flows as power is moved from where it is generated to where it is needed in response to this new system dynamic.

The operational limitations of these generators and zonal lines drove divergent transmission flow patterns between scenarios. The timing and magnitude of distributed generation adoption changed flow and congestion patterns and demonstrated the potential to similarly impact the timing and size of transmission needs. This result is sensitive to the location, capacity, design, and participation behavior of distributed generators and batteries.

At moderate levels, distributed generation adoption could cause certain inter-zonal transmission investments to be delayed or avoided.

The three study scenarios differed significantly from each other in terms of transmission, generation, and battery capacities at the end of the study horizon in 2040. The results from the long-term capacity expansion modeling indicated that significant additional inter-zonal transmission capacity will be needed in addition to projects planned in the near-term under all future scenarios.

Relative to the centralized scenario, the hybrid scenario, which has a distributed generation adoption rate doubling our study's status quo (centralized) trajectory from 2031 onward, required about 30% less inter-zonal transmission in terms of both GW and GW-miles as shown in Table ES-1.

TABLE ES-1
Summary of Capacity Expansion Results Through 2040

	Centralized Scenario	Hybrid Scenario	Distributed Scenario
Zonal transmission expansion candidates	11 projects totaling 18 GW (238 GW-miles)	8 projects totaling 12 GW (166 GW-miles)	11 projects totaling 16 GW (526 GW-miles)
Generation nameplate capacity	431 GW	418 GW	537 GW
Total storage capacity	252 GWh	328 GWh	1,090 GWh

Inter-zonal transmission builds, generation nameplate capacity, and energy storage capacity—all results of long-term capacity expansion modeling—illustrate the key differences between the studied scenarios.

Source: Energy Systems Integration Group.

The hybrid scenario also exhibited a lower overall generation nameplate capacity but required about 30% more storage capacity than the centralized scenario. These comparisons between the centralized and hybrid scenarios support the finding that distributed generation above present-day trajectories could cause certain inter-zonal transmission to be delayed or avoided. However, the results also indicated that significant inter-zonal transmission expansion was required under all scenarios, and that high levels of distributed generation may result in higher GW-miles of inter-zonal transmission investments.

The status-quo (centralized) and accelerated (hybrid) distributed generation adoption scenarios shared many common inter-zonal transmission investments.

Notably, the eight inter-zonal transmission candidates selected in the hybrid scenario were also all selected in the centralized scenario, though often in different years. The centralized scenario required three additional inter-zonal transmission projects—for a total of 11 projects—that were not required in the hybrid scenario. These three projects were avoided in the hybrid scenario during the study horizon because of the increased distributed generation levels in this scenario. It is important to note that distributed generation adoption rates and locations were fixed as an input, and that distributed generation capacity in the hybrid scenario was scaled in the same relative locations as the centralized scenario. Therefore, the sensitivity of this finding to the relative locations of distributed generation was not explored.

The commonality between the selected inter-zonal transmission candidates in the centralized and hybrid scenarios indicates the opportunity for "least-regrets" transmission investments in futures with distributed generation adoption rates near or above status-quo trajectories.

The commonality between the selected inter-zonal transmission candidates in the centralized and hybrid scenarios indicates the opportunity for "least-regrets" transmission investments in futures with distributed generation adoption rates near or above status-quo trajectories.

In contrast, the distributed scenario displayed significantly less commonality, featuring unique projects and timings for its transmission portfolio. Consideration of the distributed scenario leads to the study's final finding.

High levels of distributed generation could increase the need for inter-zonal transmission investment.

While significant inter-zonal transmission is selected in all three study scenarios, the transmission built in the distributed scenario was almost double that of the centralized scenario as measured by GW-miles. The large increase in transmission GW-miles in the distributed scenario illustrates the need for longer lines to help transport high levels of solar and balance the system between regions where existing inter-zonal capacity is limited. The distributed scenario also required more than four times the storage capacity of the centralized scenario, including small amounts of long-duration storage in each zone, although these two scenarios met the same system planning and policy requirements over the study horizon.

Therefore, distributed generation and storage alone may not reduce the need for transmission investments. Much of the transmission built in the distributed scenario was

built later in the study horizon—when clean energy policy constraints forced the model to serve an increasing percentage of system load with non-emitting resources.

Unlike the other two scenarios, the distributed scenario was free to build distributed solar and storage in locations determined by the model. Thus, the location, timing, and magnitude of both distributed generation and transmission builds differed significantly from the centralized and hybrid scenarios. **Our examination of the distributed scenario results highlighted that the need for transmission investment was sensitive to the location, timing, and magnitude of distributed generation builds.**

Study Takeaways

In aggregate, these findings highlight the complex trade-offs between investments in distributed generation, storage, and bulk transmission in the Western Interconnection. Indeed, distributed generation resources could change flows on inter-zonal transmission infrastructure and even potentially defer or eliminate certain future inter-zonal transmission infrastructure investments, but the need for such investments is sensitive to many other factors. The findings also make clear that while moderate levels of distributed generation could help to reduce bulk-scale transmission investment, the need for such investment is not eliminated or significantly reduced.

This study highlights the critical nature of forecasted capacities, locations, and operational behaviors of distributed generation and storage as part of integrated transmission planning efforts. The results suggest the potential benefits of simultaneously planning for transmission, distributed generation resources, and utility-scale resources in order to optimize power planning outcomes.

Finally, this study reinforces the perspective that there is no single solution in the pursuit of achieving long-term system needs and clean energy policy goals, only trade-offs. More detailed engineering and economic assessments should be performed to explore these trade-offs in specific contexts. This study is intended to be illustrative and exploratory in nature; the scenarios considered were approximations of future outcomes relating to different levels of distributed generation. While many realistic system constraints were included in this modeling, much more analysis including a nodal topology would be required to inform investment decisions.

Introduction

The efficient integration of distributed generation resources (DGRs) is an increasingly important task for power system operators and planners. DGRs, typically solar that is often paired with battery storage, represent one of many steps toward increasing customer choice and reducing carbon emissions in the power system. In the last decade, electricity customers have chosen to adopt distributed generation (DG) as a means of reducing metered electricity consumption, reducing carbon emissions, and increasingly with storage technologies, as a means of backup power. Distributed solar and battery storage are incentivized by the U.S. government, and many utilities have structured tariff policies that enable their adoption by homeowners and businesses.

According to the U.S. Energy Information Administration, installed distributed solar capacity has increased at a rate of approximately 3.5 GW per year in the United States since 2014, and this adoption rate has been steadily increasing (U.S. EIA, 2023). As DG deployment grows, it is critical for the energy industry to understand how DGRs impact both distribution and transmission systems.

Distributed Generation Resources' Impacts on the Distribution System

Because DG is often co-located with electrical loads and interconnected into low-voltage power distribution systems, most analyses considering the impact of DG on the power system have focused on the distribution level (69 kV or lower). These analyses typically indicate that DG has the potential to alter flows on elements of power distribution, especially in metering agreements that allow distributed generation to be injected back onto the grid. The implications of DG are wide-ranging even when limiting analysis to the distribution system. In many cases, DG can change flow patterns enough to require investments in distribution-level upgrades, such as transformers or conductors. Distribution network upgrade costs are recovered by utilities via a variety of mechanisms either from the individual customer or more broadly across its rate base.

As distributed generation deployment grows, it is critical for the energy industry to understand how distributed generation resources impact both distribution and transmission systems.

There are many cases in which utilities recognize the potential for DG, or more broadly distributed energy resources (a broader set of distributed and highly flexible resources not considered comprehensively in this study),

to defer or eliminate the need for distribution system upgrades that would have otherwise been necessary due to increasing electrical loads. In 2021, publicly owned utilities in the state of California released databases regarding the ability of distributed resources to defer distribution upgrades per the California Public Utilities Commission's rulemaking 21-06-017 (CPUC, 2021).

Overall, DGRs' impacts on distribution systems vary widely depending on the locations and configurations of the resources. Research suggests that the benefit-cost impacts of DG on proximate low-voltage distribution systems are context dependent, and that these impacts are likely to change with improvements in technology and communications (Horowitz et al., 2019).

Distributed Generation Resources' Impacts on Transmission Flows and Investment

If widespread adoption of DG has the potential to change flow patterns and the need for or deferral of capital investments on distribution systems, it is likely that the same potential may exist on the higher-voltage power system as well (Clack et al., 2020). While recent literature has begun to shed some light on these impacts, no study has explored the relationships between DG adoption and future transmission flows and the quantity of capital investments. Neither have any studies assessed the ability of the high-voltage transmission system to accommodate future levels of DG, or conversely, the ability of DG to defer or eliminate the need for future high-voltage transmission investments.

On one hand, extrapolating what is known about the relationship between DGRs and the distribution system to what might be true about DGRs and transmission networks suggests that the localized nature of DGRs and their power production could *offset* the need for some material transmission infrastructure, by reducing system net loads and increasing system flexibility through changes at the distribution level. DG expansion can provide value to the system where low load growth or tail-end load events drive the need for large capital investment over planning horizons that are long enough for the deployment of the necessary distributed capacity (Frick et al., 2021). If DGRs can help reduce the amount of total load that the transmission system must manage, it is reasonable to posit that at least some inter-zonal transmission infrastructure could be avoided, delayed, or reduced in scale.

On the other hand, energy output from present-day DG technologies is usually not sufficient to offer the combination of sufficient energy production and flexibility to shift energy to times when it is most needed, such as early morning or evening hours. DG output to service loads is typically limited for rooftop or commercial-scale solar resources and co-located distributed storage devices with limited duration (two to four hours with current technology), which may not offer sufficient flexibility to shift enough energy to times when it is most needed. Given this challenge, high levels of DG often still need transmission investment to address local area generation deficiencies in certain hours. Based on this perspective, it is assumed that DGRs, compared to a broad mix of non-emitting utility-scale resources like wind, solar, and geothermal, will offer fewer diversity benefits and flexibility at a regional scale.

However, on the third hand, regional flexibility is a key driver of transmission utilization and expansion needs, and improving regional connectivity can help to enhance the availability and benefits of DG by allowing excess DG in one zone of the grid to be shared with another zone during a time of need. Therefore, there will likely be a material need for an expanded regional transmission system under a future with high DG adoption so that reliability can be maintained, and power can be delivered to zones with power scarcity.

Given the lack of information associated with these trade-offs, this study aimed to characterize the impacts on the power transmission system between load zones resulting from futures with varying levels of DGRs. Characterizing these relationships may assist planners to better understand both the opportunities and barriers toward widespread DG adoption.

Key Questions

This study sought to answer the following questions.

QUESTION 1: Do increasing levels of distributed generation resources impact high-voltage transmission system flows?

The study investigated the effects of varying levels of DGRs on inter-zonal transmission system flows. By modeling and comparing the results of three scenarios, the study examined how the integration of various levels of DG capacity influenced the movement of power through the bulk-scale transmission grid.

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This investigation aimed to provide insights into future transmission usage and congestion as DG and utility-scale renewable adoption continue to grow, using a detailed analysis of hourly transmission flows and congestion on transmission paths across the system.

QUESTION 2: Can distributed generation resources reduce, defer, or eliminate investment in inter-zonal transmission projects?

This analysis investigated the ability of future modeled scenarios to rely on DG to reduce or avoid investments in transmission by utilizing distributed power generation closer to the point of consumption.

Each of the three study scenarios was simulated in a long-term capacity expansion (LTCE) phase in which the model algorithm made a least-cost selection from a variety of transmission candidates to meet system planning requirements. A comparison of the transmission build decisions across the three study scenarios indicated the potential for avoided or delayed transmission investments at moderate levels of DG and the potential for additional transmission investments at high levels of DG.

QUESTION 3: Is there synergy between transmission investments driven by distributed generation resources vs. utility-scale resources?

Here, the research delved into the potential synergy—or commonality—between transmission investments required by DGRs compared to those required by utility-scale resources, recognizing that it is likely that scenarios featuring each of these resource types will require some transmission investment over the study horizon.

The study analyzed whether the infrastructure upgrades necessitated by DG integration aligned with or diverged from those required for utility-scale power generation projects, given their diverse production profiles and geographical concentrations across the West. Understanding this transmission synergy—or lack thereof—can help to identify the potential for least-regrets transmission investment decisions for a more efficient grid.

Study Design and Approach

A Western Case Study

This study was a forward-looking case study of the United States' Western Interconnection (Figure 1, p. 5). The Western Interconnection is characterized by its unique mix of generation resources, large geographical scale, and high potential for renewable energy development. It spans more than 1.8 million square miles and serves a population of over 80 million people, making it one of the largest and most complex power systems in the world.

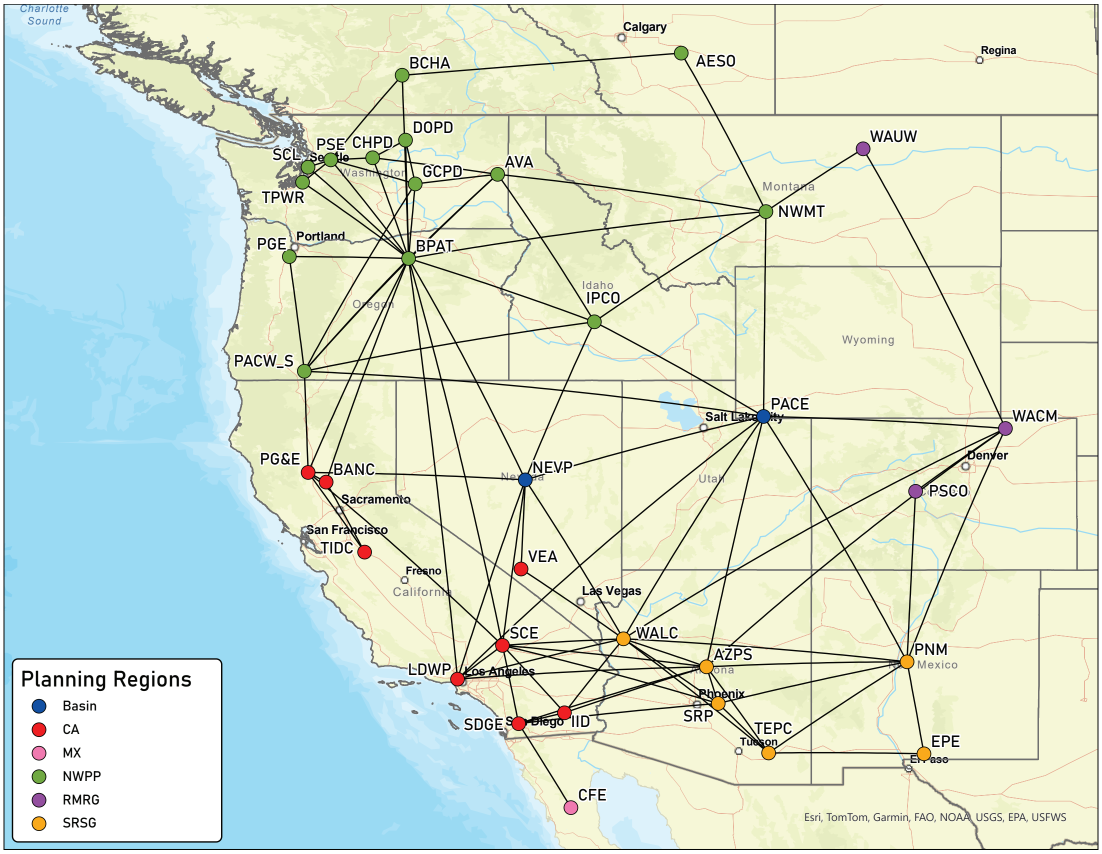
With a diverse mix of generation resources and development potential—including large-scale wind and solar projects, hydroelectric facilities, geothermal resources, off-shore wind, and natural gas–fired power plants—the Western U.S. presents a dynamic and challenging environment for the planning of transmission infrastructure.

Defining Distributed Generation

Distributed generators in this study included solar, battery, and solar-plus-battery hybrid facilities at residential and nonresidential (e.g., commercial or industrial) installation sites, illustrated in Figure 2 (p. 5). DGRs are unique among power generation resources in their dispatch variability, points of interconnect, and lack of detailed

FIGURE 1

Geographical Scope of the Study



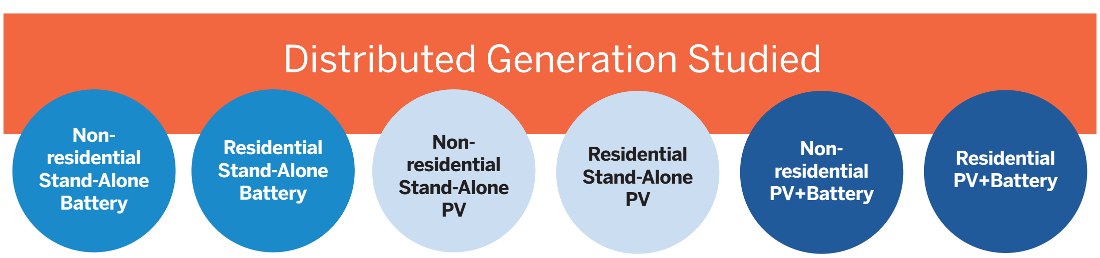
The model's zonal topology shows the model's 34 zones and 102 zonal lines and indicates zones' membership in planning regions.

Notes: CA = California; MX = Mexico; NWPP = Northwest Power Pool; RMRG = Rocky Mountain Reserve Group; SRSG = Southwest Reserve Sharing Group.

Source: Energy Systems Integration Group.

FIGURE 2

Types of Distributed Generation Resources Considered in the Study



The study modeled combinations of residential and nonresidential solar and battery resources as distributed generators. Other distribution-level generation resources or load modifiers were not considered.

Source: Energy Systems Integration Group.

planning and operational coordination. Most DGRs have little to no supervisory monitoring, control, or coordination to optimize their operation with respect to the bulk power system.

Despite these characteristics, the increasing levels of DGRs offer opportunities to serve load locally and help decarbonize the power system. This study explored the implications of DG on the transmission system and did not model the distribution system itself. But although the distribution system was not explicitly modeled, the study approach attempted to capture many of the interactions among DGRs, the distribution system, and the transmission grid. The study assumed that distribution systems are sufficiently robust to integrate the levels of DGRs simulated and that transmission-distribution interfaces are sufficient to allow excess DG generation to flow onto the bulk transmission system (as needed). As such, DGRs were represented as generators in the model's zones alongside utility-scale resources, serving as a key part of the hour-to-hour energy balance maintained in study simulations. However, in this study, distributed generation and storage had unique assumptions to reflect their unique nature as generation resources. The assumptions that differentiate DGRs from utility-scale resources are further outlined in the "DG Representation" section.

PLEXOS Modeling

The study was performed using PLEXOS, a power system modeling software used for market analysis, power planning, and operational studies. The software is customizable and capable of modeling an approximated representation of the bulk power system.

PLEXOS is particularly useful for analyzing the impacts of large-scale renewable energy integration on the power grid. For this study, PLEXOS was used to simulate the Western U.S. power system using both long-term capacity expansion (LTCE) and short-term dispatch (ST) modeling functionalities. The results of each scenario in these two stages provided for an evaluation of DG's impact on the transmission system over the study horizon. PLEXOS is well suited for the study because its cost-minimization algorithm can simultaneously optimize for both DG expansion and transmission infrastructure needs within a single objective function.

Zonal Transmission Topology

The PLEXOS WECC 2023 Zonal Dataset, released by Energy Exemplar in January 2023, was the basis for the study topology and many key assumptions.[1] All study simulations in both the LTCE and ST functionalities were completed using this zonal topology. The zonal topology for this study consisted of 34 zones and 102 zonal lines representing an approximation of the Western Interconnection.[2] Zonal transmission modeling aggregates generators, loads, and transmission lines into a simplified topology to provide a high-level perspective of zonal transmission needs and flows. The zonal topology considered in this study is shown in Figure 1 (p. 5).

Generation and load were sited at each zone with zonal lines facilitating economic interchange and power flows among zones. These aggregations make feasible optimized dispatch, resource expansion, and transmission expansion solutions over long time horizons and large geographical regions, consistent with the aims of the study. However, such simplifications obfuscate the presence and influence of distribution and intra-zonal transmission limitations. Given the challenges of integrated transmission and

1 https://www.energyexemplar.com/power-datasets#north-america.

2 The terms "zone" and "zonal" are used in this report to refer to the nodes and edges in a PLEXOS zonal model.

distribution modeling, this study did not endeavor to model transmission and distribution systems within zones or evaluate their costs and benefits.

The WECC 2023 Zonal Dataset was expanded to align with the study methodology and best available data regarding the state of the system. This effort included the addition of conceptual inter-zonal transmission upgrades to the model that were considered alongside generation expansion candidates in the LTCE. A set of over 80 conceptual transmission projects was developed as a part of this study. All transmission projects represent increased capacity on inter-zonal lines and include estimates of incremental capacity, cost, and the earliest available in-service date.

Long-Term Capacity Expansion Modeling

The PLEXOS LTCE functionality was used to forecast a mix of generation and transmission resources in the Western Electricity Coordinating Council (WECC), above and beyond what was assumed to be built through 2030, such that each scenario was sufficient to meet policy, capacity, and energy-related planning requirements. We performed a thorough review and update of planned retirement date assumptions for all coal power plants in the Western system consistent with publicly available planning documentation. The software was populated with both generation (including DGRs) and transmission expansion options, as appropriate, for each of the scenarios considered.

The long-term (LT) model was set up with a "sampled" hour-to-hour chronology for a subset of representative days in each study year. This chronology decision allowed the model to capture the operational dynamics of the system in considering long-term capital investments, while also keeping the computational requirements manageable. The LT model was used to establish unique resource portfolios and transmission build-outs for each of the three scenarios.

Short-Term Dispatch Modeling

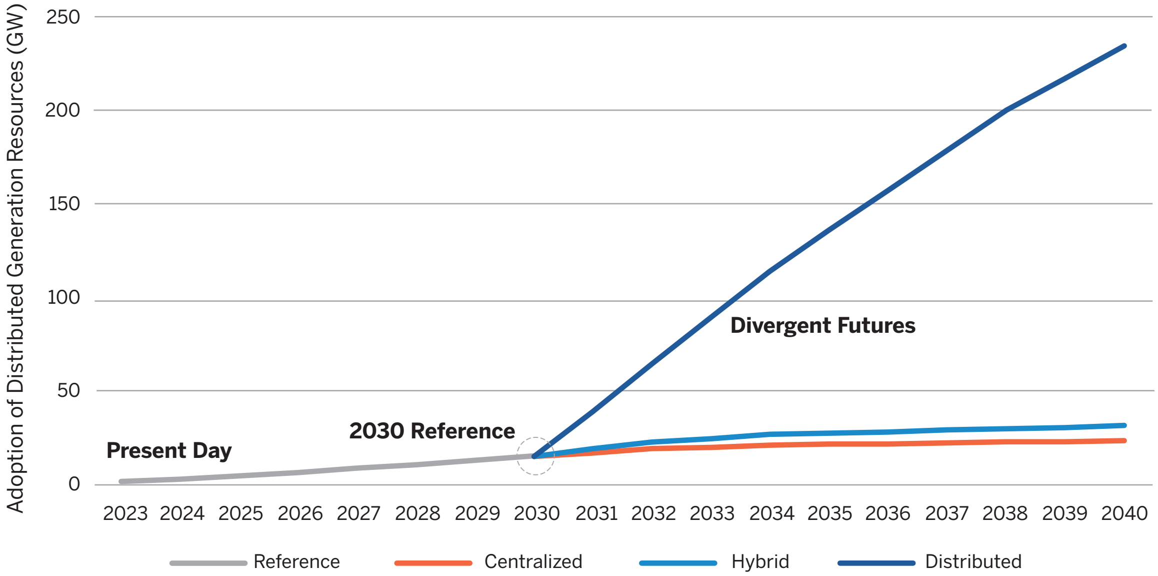
The build decisions identified in the LTCE model were used as inputs for an ST dispatch assessment performed across each scenario for a 2035 study year. Although any year considered in the study horizon could have been modeled in the ST phase, 2035 was selected because it represents a nearer-term study year that still exhibits noticeable differences between the scenarios studied. The ST model is a detailed hourly production cost simulation that finds the least-cost dispatch for every hour of the year given a set of generators, transmission lines, loads, and operating constraints. The ST model was used to capture detailed operational dynamics (including operating reserves), variability, and hour-to-hour transmission flows over the course of each study year. Employing both LTCE and ST models helps to translate planning considerations into hourly operations.

Overview of Scenarios

This study compared three long-term futures with varying levels of distributed generation. It assumed that the Western system follows a deterministic trajectory for generation and transmission builds and retirements from the present day through 2030. A common reference through 2030 was modeled to be consistent with near-term utility generation and transmission planning efforts, and the ability of the model to diverge after 2030 reflected the expectation that significant divergence in futures would likely occur after a near-term investment cycle of approximately seven years. This 2030 reference was determined via an initial LTCE simulation, which incorporated a baseline outlook of the Western system and could add additional utility-scale generation and battery resources as necessary to meet planning constraints. Build decisions made by 2030 were used as the starting point for the three different future scenarios.

FIGURE 3

Study Scenario Divergence After 2030



The study established a reference trajectory for load, generation, and transmission from the present day to 2030. Beyond 2030, the study modeled three distinct trajectories representing centralized, hybrid, and distributed futures.

Source: Energy Systems Integration Group.

For the study horizon from 2031 to 2040, each future was assessed in detail with a unique set of inputs, variables, and results. The three futures in this study were the centralized, hybrid, and distributed scenarios and represented a wide range of study bookends. All three scenarios simulated varying levels of widespread DG adoption across the Western Interconnection.

The reference scenario assumed DG adoption rates consistent with the National Renewable Energy Laboratory's (NREL's) Standard Scenarios future projections for the Western states, a suite of forward-looking scenarios of the U.S. power sector that are updated annually.[3] The base build trajectory of DG was fixed and could not be altered in the LTCE model. In a similar way, the reference and all three scenarios included a set of fixed transmission upgrades consistent with known near-term planned projects. The reference LTCE model was not allowed to build any other transmission upgrades through 2030.

From 2031 onward, the centralized scenario continued the same DG adoption trajectory as the reference scenario, which is consistent with the NREL Standard Scenarios future projections. The hybrid scenario assumed a doubling of this DG adoption rate—representing a future in which DG adoption is accelerated. In both the centralized and hybrid scenarios, DG capacities were fixed inputs to the model and could not be altered by the LTCE.

The third future, the distributed scenario, represented a theoretical high bookend in which DGRs were selected during the simulation process as the primary method of achieving long-term planning objectives, including policy and energy drivers. In the distributed scenario, the LTCE model could build as much DG, distributed battery, and long-duration (10-hour) storage as was necessary to meet its planning constraints, but it could not build any utility-scale resources. The distributed scenario was the only scenario in which the model had long-duration storage as a candidate resource to enable more efficient storage of highly coincident distributed solar generation. See Figure 3.

3 See https://www.nrel.gov/analysis/standard-scenarios.html.

- **Reference case:** A **baseline** trajectory for the Western system through 2030 that included near-term planned generation and transmission. An LTCE model was run from 2023 through 2030 and could build additional utility-scale generation above and beyond planned resources but could not build any of the study's transmission candidates since candidates were intended to reflect economic decisions made by the model after the 2030 reference. DG adoption rates followed the NREL Standard Scenarios for Western states. The reference case established a 2030 starting point for all future scenarios in the study.
- **Centralized future:** A **status-quo** future scenario representing continued DG adoption rates consistent with the NREL Standard Scenarios. This scenario built combinations of utility-scale generation and transmission expansion candidates to meet long-term planning constraints from 2031 through 2040.
- **Hybrid future:** A future representing **accelerated DG adoption rates** at twice the rates predicted by NREL Standard Scenarios from 2031 onward. Other than different DG adoption rates, all other assumptions remained the same as for the centralized future.
- **Distributed future:** A future representing a **high bookend for DG**. This scenario had to meet its planning constraints through a combination of DG and the study's transmission candidates. Unlike the other future scenarios, this scenario could not build utility-scale generation after 2030.

Thermal generation expansion decisions from the centralized future were fixed as an input into all other scenarios, such that the thermal generation assumptions were consistent among all study scenarios. In all scenarios, the LTCE model added the necessary resources and transmission available in the scenario to meet load growth and policy requirements—the primary planning constraints considered in the study. An overview of key future scenario assumptions is given in Table 1.

DG Representation

Distribution-level generation alters the magnitude and shape of the loads served by the transmission system and cleared by wholesale markets (Prasanna et al., 2021). Broadly, DGRs are uncoordinated in their operation and do not consider real-time wholesale market conditions. Distributed solar PV systems generate power in accordance with local solar irradiance and without supervisory control. Distributed battery storage facilities primarily charge and discharge to serve local, on-site demands. The non-optimal dispatch of DG generation paired with its increasing deployment introduces uncertain risks and opportunities that may materially impact transmission systems, distribution systems, and market operations. Absent the introduction of advanced distribution

TABLE 1
Summary of Study Scenarios

Scenario	Started at 2030 Reference	Could Build Transmission	Could Build Utility-Scale Thermal Generators	Could Build Utility-Scale Renewable Generators	Could Build Distributed Generators	Could Build Long-Duration Storage
Centralized	✓	✓	✓	✓	No; fixed at 1x NREL Standard Scenario rate	
Hybrid	✓	✓	No; fixed to centralized builds	✓	No; fixed at 2x NREL Standard Scenario rate	
Distributed	✓	✓	No; fixed to centralized builds		✓	✓

The futures modeled varied from one another in their ability to build utility-scale generation, distributed generation, and long-duration storage during the 2031–2040 study horizon.

Source: Energy Systems Integration Group.

management systems and markets that directly consider DG participation, the dispatch of these DGRs will be influenced by tariff design.

This study considered only solar PV, battery storage, and paired PV+battery facilities as residential and nonresidential DG candidates. Their dispatch was designed to mimic the dispatch expected under various existing and future tariff structures. Demand-side management was not included as a resource candidate but was considered in all scenarios via load shape adjustments.

DG Capacity Expansion

The study scenarios considered pre- and post-2030 timelines for resource expansion. Across the study horizon, the model adopted a baseline DG capacity expansion trajectory according to the 2022 NREL Standard Scenarios. In the second decade of the study horizon, 2031–2040, certain scenarios allowed the model to choose to build additional DG capacity to meet energy and capacity demands subject to system constraints. The 2022 Standard Scenarios represent state-level forecasts for installed generation capacity by resource type through 2050. The 2022 vintage includes the core influences of the Inflation Reduction Act (IRA) including increased loads due to electrification, changes to production tax credits, investment tax credits, and CO_2 capture incentives, and new credits for existing nuclear generation.

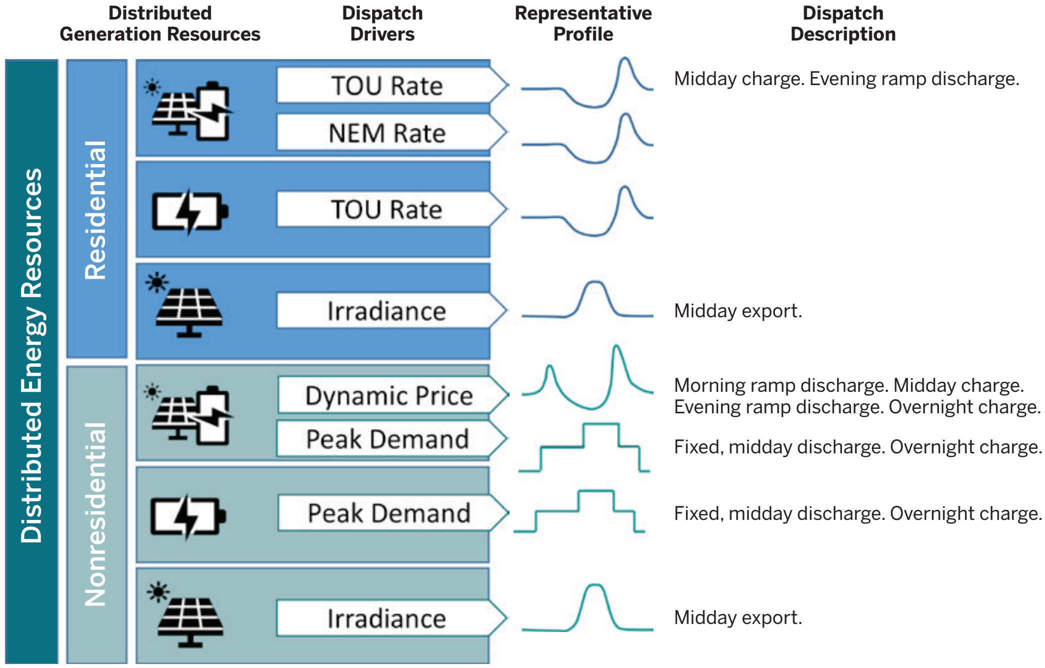
Of the DG facilities considered, the 2022 Standard Scenarios provide only distributed solar PV capacity forecasts. Distributed batteries and distributed hybrid facilities are not included due to a lack of supporting data. Therefore, this study leveraged supporting literature to develop state-level distributed battery and distributed hybrid facility forecasts with respect to anticipated state-level solar PV capacity expansion. First, state-level distributed solar PV capacity trajectories were disaggregated to individual zones according to utility energy sales in each balancing area and state as presented in EIA Form 861 (U.S. EIA, 2021). Zonal distributed solar PV capacity trajectories were then split across residential and nonresidential sites according to the Energy Information Administration's 2022 *Annual Energy Outlook* and assigned to their corresponding zone in the PLEXOS model (U.S. EIA, 2022). The adoption of batteries, either as hybrid or stand-alone facilities, was then calculated as a percentage of each balancing area's distributed PV capacity trajectory as described in Prasanna et al. (2021) and Barbose et al. (2022). Beyond the base trajectory defined here, the model optimally built candidate DGRs according to energy, capacity, and policy demands.

DG Dispatch Profiles

Excluding non-dispatchable, stand-alone PV facilities, the dispatch of DG batteries is driven by one of four common tariff structures. Since the study was executed in an optimally dispatched production cost modeling environment, the adoption of these tariff-based dispatch strategies effectively achieved a sub-optimal dispatch, from the perspective of the wholesale market, of DG units that reflects the unique operating constraints of DG facilities (summarized below). Dispatch profile shapes were partially informed by work presented to the California Public Utilities Commission (Aydin and Aydin, 2023). Figure 4 (p. 11) provides a high-level illustration of how the DG resource types were designed to dispatch in the model.

FIGURE 4

Distributed Generator and Battery Dispatch Profile Summary



The study defined distributed generation profiles according to site type, resource type, and dominant tariff structure. The tariff structures create an economic incentive for distinct dispatch characteristics presented here and implemented in the model by temporal battery operation constraints.

Notes: NEM = net-energy metering; TOU = time-of-use.

Source: Energy Systems Integration Group.

Residential facilities dispatch batteries under a time-of-use tariff or net-energy metering tariff. In the time-of-use tariff (TOU), it was assumed that the stand-alone battery or hybrid facility was subject to daily peak and non-peak pricing periods wherein the battery facility charges during the midday solar PV generation peak and discharges during the afternoon to evening peak period. The time-of-use dispatch profile was achieved by introducing daily temporal properties to offer (discharge) or bid (charge) into the market during the peak and pre-peak periods. In the net-energy metering (NEM) tariff, it was assumed that the value of distribution-level PV generation will continue to decline beyond 2030, and therefore net-energy-metering hybrid facilities will prioritize the charging of their on-site battery over the export of PV generation (St. John, 2021). The net-energy metering dispatch profile was achieved by introducing an explicit modeling constraint that restricts battery charging to its paired solar PV system.

Nonresidential facilities dispatch batteries under dynamic price and demand charge tariffs. In the dynamic pricing tariff, it was assumed that the host site for the DG facility is exposed to a price signal with a morning peak and evening peak reflective of a net load shape driven by solar PV penetration. The dynamic price dispatch profile was achieved by introducing daily temporal model properties to offer (discharge), bid (charge), and offer again into the market during a morning ramp period, midday solar PV generation period, and evening ramp period, respectively. In the demand charge tariff, it was assumed that the host site for the DG facility is subject to a demand charge and therefore seeks to minimize its peak load during mid-afternoon facility operation. The demand charge dispatch profile was achieved by introducing daily temporal properties to encourage the dynamic price facility to discharge during the mid-afternoon period and recharge overnight.

DG Dispatch Profile Allocation

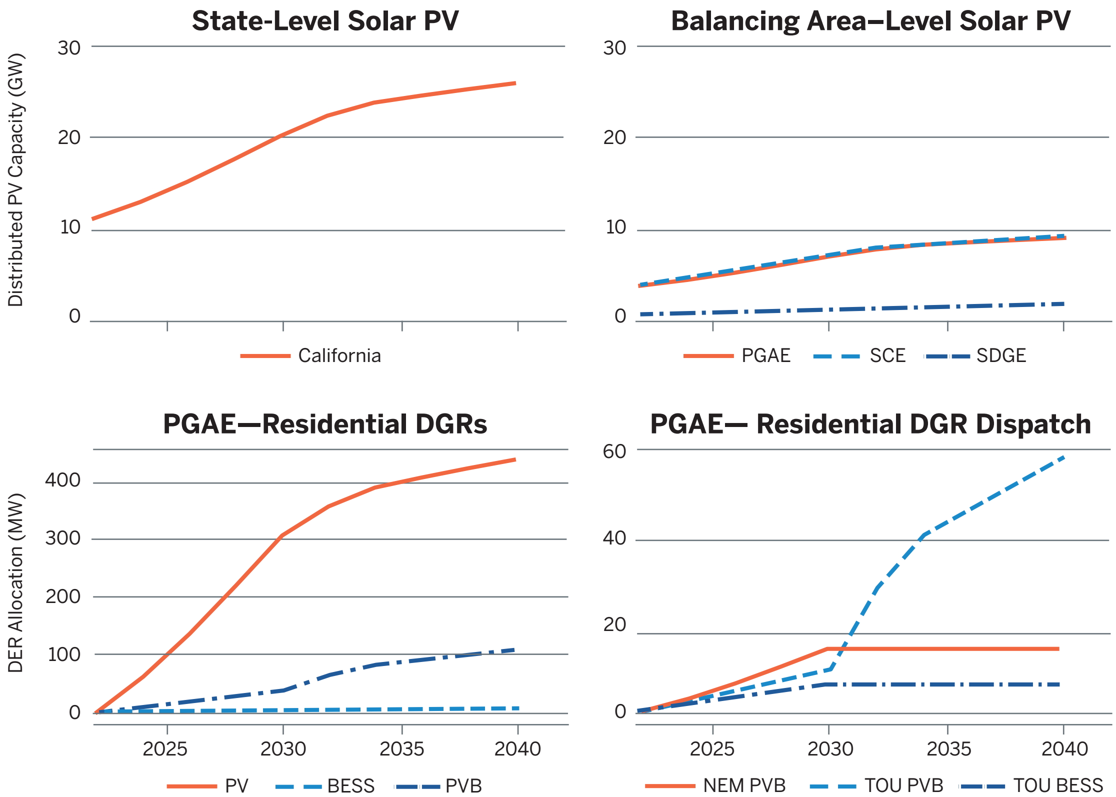
The adoption of these dispatch profiles served to model the sub-optimal, uncoordinated dispatch of DG facilities within an optimized dispatch production-cost modeling framework. The installed capacity of each dispatch profile was allocated according to known and anticipated trends in DG adoption in the pre- and post-2031 horizons (Prasanna et al., 2021; Barbose et al., 2022). The literature reviewed reflects increasing sophistication among dispatchable DG facilities with respect to wholesale market prices. At present, only a few blunt tariff structures exist to shape net load, but going forward DG facilities will likely shift toward operating regimes that more closely align with wholesale market prices and grid services. Note, this study limited itself to existing tariff structures and avoided speculation regarding future distributed locational marginal pricing, peer-to-peer transactions, or other distribution market developments that could enable coordinated supervisory control of DG facilities.

The evolution of DG sophistication was modeled in this study by a shift in tariff structure participation toward those strategies that are better aligned with pricing dynamics. Due to increasing levels of solar PV, real-time prices are anticipated to be lowest during midday with elevated prices during the early evening ramp-down period and, to a lesser extent, the morning ramp-up period when solar irradiance is more volatile. This daily shape is expected to deepen in the coming years. For residential sites, this study assumed that battery and hybrid facilities will transition away from net-energy metering, or a net billing tariff, toward time-of-use rate tariffs. For nonresidential sites, the study assumed that battery and hybrid facilities will transition away from demand charge, peak-shaving regimes toward dynamic pricing–responsive strategies. The transition to more responsive dispatch strategies was assumed to occur in 2031, and this change was represented by a shift in DG allocation after that year in the PLEXOS model. Given the DG capacity forecasts described above in the "DG Capacity Expansion" subsection, this study split battery and hybrid facilities among residential and nonresidential dispatch profiles and corresponding zones in the model. Figure 5 (p. 13) illustrates the allocation of residential battery energy storage system (BESS) and hybrid (PVB) capacity to dispatch profiles for the Pacific Gas & Electric (PGAE) zone over the study horizon, as an example of the adopted modeling technique.

The upper-left panel displays the distributed solar PV capacity forecasted by the NREL 2022 Standard

FIGURE 5

Allocation of Distributed Generation Resources and Dispatch Profiles from State-Level Distributed PV Forecasts



Each zone of the model was allocated distributed generation capacity according to the state's total distributed solar PV capacity trajectory and its constituent balancing areas, or zones. Zonal distributed solar PV capacity trajectory was then further disaggregated among the distributed generation profile types previously discussed.

Notes: BESS = battery energy storage systems; DER = distributed energy resources; NEM = net-energy metering; PGAE = Pacific Gas & Electric; PVB = (solar) photovoltaic and battery; SCE = Southern California Edison; SDGE = San Diego Gas and Electric; TOU = time of use.

Source: Energy Systems Integration Group.

Scenarios for the state of California. The upper-right panel disaggregates the state-level capacity among the three largest balancing areas (the zonal resolution of the model). The lower panels illustrate how this capacity was further disaggregated among residential DG facilities and dispatch profiles. Note the change in DG dispatch allocation after the 2030 study year. Beyond 2030, it was assumed that residential hybrid facilities will no longer participate in net-energy metering and will instead operate under a time-of-use tariff. The process of disaggregation from state-level DG capacity forecasts to balancing area–level dispatch profiles was repeated for all 34 zones in the WECC model and provided the base DG capacity expansion trajectory input for the study horizon.

Transmission Expansion Model

The study used a long-term capacity expansion formulation in which both generation and transmission were candidates for future build decisions. To inform candidates for future transmission upgrades, conceptual inter-zonal transmission projects were developed via an engineering review of WECC power flow cases and other documentation. The resulting set of over 80 transmission expansion candidates included options to uprate existing lines or to build new transmission lines between WECC zones. Each transmission expansion candidate was developed as part of the study process with estimates of cost and approximate MW capacity that were reflected in model inputs. Build costs for transmission candidates considered approximate costs, specific to each zonal corridor, based on a variety of data sources including WECC's Transmission Expansion Planning Policy Committee's 2019 Transmission Capital Cost Calculator and the Midcontinent Independent System Operator's (MISO's) Transmission Cost Estimation Guide for the MISO Transmission Expansion Plan 2022.[4] Zonal transmission expansion candidates were not defined for any of the inter-zonal corridors connected to the three non-U.S. zones (Alberta, British Columbia, and CFE in Baja Mexico) in order to keep zonal flow capabilities on the edges of the Western U.S. system consistent with present-day limits.

The model considered transmission candidates alongside generation to determine a least-cost capacity expansion solution. Transmission candidates were selected to minimize the overall cost objective (production cost plus capital cost) of the capacity expansion formulation over its study horizon.

In the model, two primary constraints were considered, representing prudent transmission expansion principles. First, only one upgrade could be installed on each inter-zonal transmission path per year, reflecting the reality that it is unlikely that transmission owners would build two lines increasing the same zonal path simultaneously. Second, a maximum of three major transmission projects could be completed and placed into service per study year. This constraint forced the model to prioritize a steady transmission build-out over time and produced transmission expansion solutions in line with trajectories projected through 2030.

There are many reasons why the least-cost objective function would choose to select transmission candidates over other expansion options. First, additional transmission

capacity increases the transfer capability between two model zones, which can make for greater interchange and a lower-cost dispatch across the system. Second, transmission lines built by the model allow shared firm capacity between planning regions in the model.[5] Third, the model may use transmission lines to reduce the curtailment of excess renewable generation across the system, thereby allowing the model to meet its clean energy requirement more efficiently.

Thus, differences in transmission build decisions over the study horizons reflected the timing and magnitude of transmission capacity necessary to accommodate economic transfers and firm capacities of the various study scenarios.

4 See https://www.wecc.org/Administrative/TEPPC_TransCapCostCalculator_E3_2019_Update.xlsx and https://cdn.misoenergy.org/20220208%20PSC%20Item%2005c%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP22_Draft622733.pdf.

5 U.S. planning regions represented in the model include Basin, California (CA), Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), and Southwest Reserve Sharing Group (SRSG).

Key Assumptions

To further describe the approach and assumptions adopted in this study, here we describe our reference case, DG modeling approach, and transmission expansion model, and address technical limitations of the study.

Reference Case

The model reference case established an eight-year trajectory of the Western power system in the U.S. based on best-available references for generation, load, transmission, policy, and economic assumptions. The starting point for the development of the reference case was the WECC 2023 Zonal Dataset created by PLEXOS. Base generation resources, forecasted loads, system topology, and zonal transmission limits were drawn from the U.S. Energy Information Administration, Federal Energy Regulatory Commission (FERC), WECC, and other public data sources.

For each zone in the model, the dataset provided a set of candidate utility-scale generation resources including advanced natural gas, biomass, geothermal, solar, wind, and energy storage. Through the course of an LTCE study, the model elected to build generation and storage from candidate resources, subject to system constraints, while minimizing total system cost.

In support of study goals, the dataset was augmented to include DG and transmission line expansion candidate resources. Each zone in the model was populated with a set of residential and nonresidential stand-alone solar PV, stand-alone battery storage, and hybrid solar-plus-storage DG expansion candidates. Multiple expansion candidates were defined for each unique zonal transmission interface. Generic transmission line candidates represented line uprates and new single- and double-circuit line expansions. The study case included several model enhancements rectifying the base dataset with the latest utility integrated resource plans, load electrification forecasts, clean energy policy targets, and the influence of the IRA on generator capital costs.

Zonal load data were adapted to represent a high level of electrification in the future. Where the PLEXOS model load is informed by utility-submitted FERC-714 load forecasts, we adopted the NREL Electrification Futures Study (EFS) (Murphy et al., 2021) to realize loads reflective of a higher electrification future. The NREL EFS scenarios quantify the impact of future electrification, demand response, and efficiency changes on electricity consumption nationally and represent a key benchmark for the loads and load shapes adopted in this study. Specifically, EFS load shapes reflect sharper peaks and increased ramps in demand corresponding to load electrification, technology advancement, and energy efficiency. All study scenarios included the same amount of demand response as defined by the EFS load forecasts. Demand-side management was assumed in all scenarios and was not considered as a candidate resource in the study.

The following sections summarize these model enhancements, their influence, and their source data.

Generation

The LT and ST models considered a common baseline generation fleet based on the July 2022 release of EIA-860[6] and the WECC 2032 ADS Seed Case.[7] These data

6 https://www.eia.gov/electricity/data/eia860/

7 https://www.wecc.org/ReliabilityModeling/Pages/AnchorDataSet.aspx

sources informed a baseline representation of existing generation resources, planned builds, and planned retirements. We reviewed the retirement dates of existing conventional resources and updated these retirement assumptions with the latest public information sourced primarily from utility integrated resource plans.

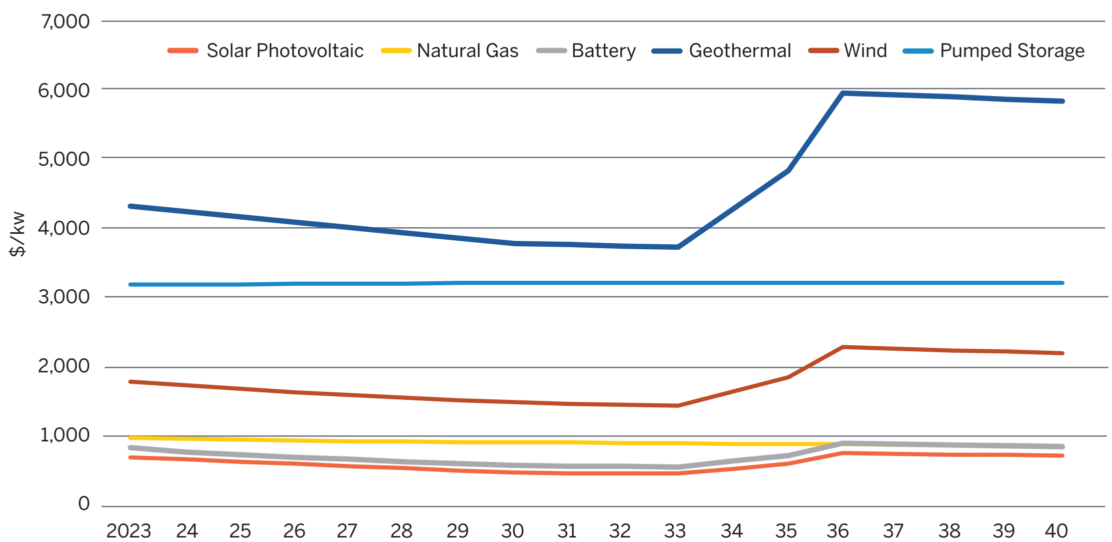
For the centralized and hybrid future scenarios, candidate utility-scale resource types were made available according to the PLEXOS dataset. Technology types included solar PV, onshore wind, offshore wind, geothermal, biomass, natural gas[8] (simple-cycle and combined-cycle combustion turbines), paired PV-plus-battery energy storage system, and stand-alone battery energy storage system. For weather-dependent resources (solar and wind), zonal hourly shapes were used, and economic curtailment of those resources was allowed in every hour of the simulation.

To better reflect distributed PV generation, as distinct from the PLEXOS' utility-scale solar PV resources, we defined new DG PV–specific capacity shapes. Location coordinates were extracted for the centroid of each balancing area zone and fed to the NREL PySAM module assuming fixed, non-tracking PV arrays to represent the DG PV facilities. All candidate resources were modeled with operating constraints, and fuel off-take parameters were sourced from the PLEXOS dataset. Candidate hybrid PV-plus-battery energy storage system resources were defined as a 1:1 nameplate capacity ratio for the PV and battery generators.

Capital, fixed, and variable costs for all expansion candidate generation resources were sourced from the NREL ATB 2023 with adjustments to account for the IRA.[9] Overnight build costs assumed in the model for candidate generators and batteries are shown in Figure 6.

FIGURE 6

Average Overnight Build Costs by Resource Class over the Study Horizon



Overnight build costs by resource class provide context regarding the model's decision-making around generation resource expansion. Derived from the NREL ATB 2023 and adjusted for the Inflation Reduction Act, these build costs incorporated IRA adjustments and further zone-specific scaling that is not represented in the figure.

Source: Energy Systems Integration Group.

8 Natural gas builds added in the centralized scenario from 2031–2040 were fixed in the other two scenarios.

9 https://atb.nrel.gov/electricity/2023/data

We assumed capital costs for eligible candidate resources benefit from both the IRA's base and domestic content bonus for 95% of capital costs.

In general, solar, battery storage, and natural gas represented the three lowest-cost resources depending on the year, followed by wind, pumped storage, and geothermal, in that order. Overnight build costs were one of many assumptions that the model considered when selecting resource candidates, and the values implemented in the model differed from these averages regionally.

Topology and Transmission

The study model adopted the WECC zonal system from the PLEXOS WECC 2023 Zonal Dataset as the starting point for scenario development, execution, and analysis. Zonal models are commonly employed to explore LTCE studies for their simplified, but efficient, depiction of large power systems. The study zonal system topology comprised 34 zones and 102 zonal transmission lines. Generators and loads were aggregated up to each zone. Accordingly, expansion of candidate generation resources occurred within zones, and expansion of transmission resources occurred between zones. Since all transmission candidates in the model are zonal lines, the model was unable to directly account for transmission inside of zones.

Zonal lines represented aggregations of physical transmission infrastructure and estimated the total transfer capability between zones in the Western system. From a modeling standpoint, zonal lines provide increased energy transfer capability (flow) and firm capacity to a connected zone. The model was initialized with zonal lines and limits representing present-day transfer capabilities as of 2022. Beyond the present day, seven transmission projects with likely completion outcomes were assumed to be installed at in-service dates between 2024 and 2033 as shown in Table 2 and Figure 7 (p. 18).

TABLE 2

Assumed Transmission Upgrade

Inter-zonal Project	Date	Transfer Impact (MW)[10]
Ten West Link	**2024**	Assumes 1050 MW additional capacity between Southern California Edison (SCE) and AZ Public Service (AZPS) and 550 MW additional capacity between AZPS and LA Dept. of Water and Power (LDWP) [based on approximate application of Path 46 and Path 49 increases]
Boardman to Hemingway (B2H)	**2026**	Assumes 1000 MW total of new bi-directional capacity, split between PacifiCorp East (PACE) and PacifiCorp West (PACW), and Idaho Power (IPCO) and Bonneville Power Authority (BPA)
TransWest Express	**2027**	Assumes 750 MW additional capacity between PACE and LDWP, and 750 MW between PACE and SCE [date and total capacity per CAISO PTO Application (+1 year)]
SunZia	**2028**	Assumes 3000 MW increase on Public Service of NM (PNM)-to-SCE zonal line
SWIP North	**2028**	Assumes an addition of 2000 MW of bi-directional capacity between Nevada (NVE) and IPCO
Gateway West Segment E	**2030**	Assumes 500 MW of additional capacity between PACE and IPCO
Upgrades to Montana Export Path (Path 8)	**2033**	Assumes a 500 MW bi-directional increase between NorthWestern Energy (NWMT) and BPA

This study assumed, and hard coded into the reference transmission build-out, seven transmission upgrades with in-service dates estimated between 2024 and 2033. The basis for assumptions is given in brackets. Transfer impacts were estimated in Spring 2023.

Source: Energy Systems Integration Group.

10 Transfer impacts estimated in Spring 2023.

FIGURE 7
Assumed Transmission Upgrades

Note that in some cases a single transmission project can contractually represent increased transfer capability between multiple zones. This graphic does not intend to be geospatially accurate to the physical assets themselves, but only to illustrate which zonal corridors are assumed to be impacted by the planned transmission upgrades in this study.

Source: Energy Systems Integration Group.

Loads

The NREL EFS database provides scenarios that explore the influence of increasing electrification, technology advancement, and increasing efficiency on hourly loads by state. We disaggregated state-level load data down to constituent balancing areas, represented in the model as PLEXOS zones, according to historical EIA-861 energy sales shares.

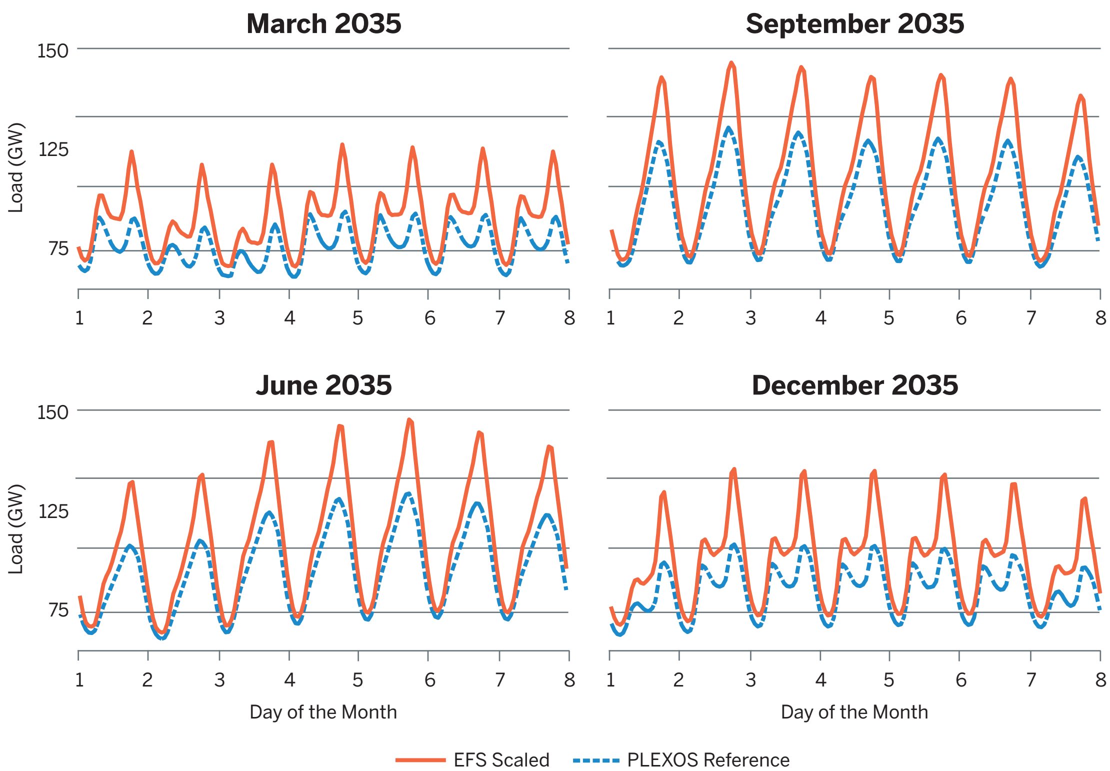
We integrated load electrification into the model by scaling the PLEXOS dataset load by an EFS scalar, defined for each zone, across all years in the study horizon. The EFS scalar we introduced is a month-hour (12x24) comparison of the EFS Medium-Moderate Scenario to the EFS Reference-Moderate Scenario. This EFS scalar was calculated for each year and zone in the study and multiplied by the corresponding PLEXOS dataset load to define a load shape and growth magnitude reflective of electrification trends for each zone in the model. At the WECC-wide level, this EFS scalar approach increased total peak load and energy demand by 21% and 12%, respectively, for the 2035 study year, illustrated in Figure 8 (p. 19).

Planning Constraints

The reference case and all study scenario cases contained planning constraints that ensured that each case met

FIGURE 8

Total WECC Load Under the Medium EFS Scalar Approach



The study assumed a future increase in total load due to electrification programs. Accordingly, system load, as modeled in PLEXOS, was scaled up to align with expectations outlined in the NREL Electrification Futures Study.

Notes: WECC = Western Electricity Coordinating Council; EFS = NREL Electrification Futures Study.

Source: Energy Systems Integration Group.

energy, capacity, and policy requirements. The LTCE model was incentivized to select the combination of generation, storage, and transmission builds and retirements that minimized the net present value of the total costs of the system over a long-term planning horizon.

The LTCE model used a simplified hour-to-hour chronology to reduce problem size and computation time. For each hour of this modeled chronology, energy constraints were enforced using an energy balance equation that ensured that generation met or exceeded load for any given hour in the study time frame. Load shedding was not enabled for the LT simulations, so if the existing build decisions were not sufficient to serve load, additional generators or zonal transmission lines were able to be selected by the solver. Build decisions for all generators were linearized, such that the model could choose to build a fraction of a candidate generator. However, transmission build decisions were set up to be integer decisions ("build" or "no build").

Capacity constraints ensured that the firm capacity of all generators in a zone met or exceeded that planning region's peak load plus a planning reserve margin sourced from the 2021 WECC Western Assessment of Resource Adequacy.[11] We used the firm capacity assumptions for existing generation and battery resources consistent with the PLEXOS WECC 2023 Zonal Dataset but implemented a custom framework for candidate resources. This included a diminishing firm capacity framework

11 https://www.wecc.org/Administrative/WARA%202021.pdf.

that reduced the firm capacity contribution, or effective load-carrying capability (ELCC), of a certain resource type or location based on penetration level (build decisions) for each planning region. This implementation accounted for present-day levels of applicable resources and incentivized the model to build resources in diverse locations and in reasonable proportions around the Western system.

Recent renewable portfolio standard policies were compiled to create estimated annual clean energy policy target forecasts for each state and each year. Table 3 shows these targets for four of the forecasted years to illustrate how they were assumed to change from 2025 through 2040. Biomass, geothermal, solar PV, solar thermal, and wind generators were allowed to contribute to these targets in all states, and additional types (mostly nuclear and hydro) were allowed in certain states depending on their local policies. These policy targets were implemented in the LTCE phase of the simulation as custom constraints requiring a certain percentage of a region's load to be served by a subset of qualifying clean generators—including existing, planned, or new-build generators.

Ultimately, due to limitations in the ability to represent state-level constraints in the zonal model, we replaced state-level constraints with a single clean energy constraint across the Western system that achieved the same outcome across the entire system—shown in the "West-wide" column of Table 3.

The model implemented a carbon price in California initialized in the PLEXOS WECC 2023 Zonal Dataset that was based on the California Air Resources Board's May 2022 Joint Auction #31 mean carbon price and was escalated annually.[12] In the LTCE phase of the simulation, a carbon price across the Western system was implemented consistent with the White House Social Cost of Carbon, starting in 2030 (IWGSCGG, 2021). The purpose of this price was to reflect the externalities associated with carbon emissions that are considered in

TABLE 3
Clean Energy Policy Targets Assumed in This Study

Year	CA	OR	WA	ID	NV	CO	NM	AZ	Other States	West-Wide
2025	44%	50%	30%	24%	34%	40%	25%	45%	—	34%
2030	60%	80%	55%	44%	50%	60%	50%	57%	—	52%
2035	75%	90%	80%	64%	63%	80%	65%	71%	—	68%
2040	88%	100%	90%	82%	75%	100%	80%	79%	—	78%

Targets drive the adoption of non-emitting generation capacity. Individual states across the West have passed legislation formalizing their clean energy targets. While state-level constraints cannot be represented within the context of the study's zonal model, a single West-wide clean energy constraint was implemented.

Source: Energy Systems Integration Group.

12 https://ww2.arb.ca.gov/sites/default/files/2022-05/nc-may_2022_summary_results_report.pdf.

Western resource planning. However, no WECC-wide carbon price was included in the ST dispatch phase—consistent with present-day policies.

Operational Constraints

Each scenario's LTCE build decisions for generators, batteries, and zonal lines were fed as an input to scenario-specific PLEXOS ST simulations for the year 2035. The ST simulations executed an optimal hourly dispatch whereas the LT simulations featured a simplified dispatch appropriate for capacity expansion planning but not for evaluating line flows and system operations. ST models were allowed to shed load if operational constraints could not be met; however, load shed was not observed in any of the completed ST simulations.

The ST stage included modeling of regulation and spinning reserves, which were not considered in the LTCE for computational efficiency. These operating reserves were reflected in the model by holding headroom in dispatchable (or curtailable) generators and batteries. Regulation reserves reflected the need for balancing areas to address moment-to-moment changes in generation and load and were calculated as 1% of load applied at the zone level. Spinning reserves were modeled consistent with BAL-002-WECC 2 and captured reserve sharing within WECC reserve-sharing groups.[13] Regulation and spinning reserves were assumed to be mutually exclusive such that each MW of headroom held could only contribute to one operating reserve type. Some DG and battery types were assumed to be able to contribute operating reserves as outlined in Table 4 (p. 22).

13 https://www.wecc.org/Reliability/BAL-002-WECC-2%20-%20Guidance%20Document.pdf.

TABLE 4

Summary of Operational and Planning Assumptions for Generators Considered in the Study

Site Type	Unit Type	Dispatch Driver	Contributes Toward Clean Energy Constraints	Contributes Firm Capacity	Regulation Up	Regulation Down	Spin Up Reserve
Utility-scale	Gas/coal	Wholesale price		✓	✓	✓	✓
	Nuclear	Wholesale price	✓	✓	✓	✓	✓
	Biomass/ geothermal	Wholesale price	✓	✓	✓	✓	✓
	Hydro	Load-following	✓	✓	✓	✓	✓
	Wind	None; fixed profile	✓	Partial; diminishing	✓	✓	✓
	Stand-alone PV	None; fixed profile	✓	Partial; diminishing	✓	✓	✓
	PV+battery (PV)	None; fixed profile	✓		✓	✓	✓
	PV+battery (battery)	Wholesale price		✓	✓	✓	✓
	Stand-alone battery	Wholesale price		✓	✓	✓	✓
Residential	Stand-alone PV	None; fixed profile	✓	Partial; diminishing	✓	✓	✓
	Stand-alone battery	Time-of-use		✓	✓	✓	✓
	PV+battery (PV)	Net-energy metering	✓		✓	✓	✓
	PV+battery (battery)	Net-energy metering		✓	✓	✓	✓
	PV+battery (PV)	Time-of-use	✓				
	PV+battery (battery)	Time-of-use		✓	✓	✓	✓
Non-residential	Stand-alone PV	None; fixed profile	✓	Partial; diminishing	✓	✓	✓
	Stand-alone battery	Demand charge		✓	✓	✓	✓
	PV+battery (PV)	Demand charge	✓				
	PV+battery (battery)	Demand charge		✓	✓	✓	✓
	PV+battery (PV)	Demand pricing	✓		✓	✓	✓
	PV+battery (battery)	Demand pricing		✓	✓	✓	✓

This table shows the assumptions made by the model regarding each resource's ability to contribute toward regulation, capacity, and clean energy needs.

Source: Energy Systems Integration Group.

Results

The intent of the study was to explore transmission implications for futures with increasing levels of DGRs. In doing so, we highlight how transmission flows, investment, and need changed under the three study scenarios. Our results focus primarily on the analysis of transmission-related simulation data. However, we also present results related to resource mix, generation dispatch, and production costs as they help to inform and explain transmission-related study results.

Generation Capacity Expansion

During the study horizon the WECC generation fleet experienced significant change under the three future scenarios. The results below summarize how the fleet evolved over the study horizon, with a focus on the 2035 study year for operational analysis.

The PLEXOS LT simulations established a policy-compliant, cost-minimized resource and transmission plan for the West under each scenario. Figure 9 (p. 24) summarizes the total installed capacity of generation and battery resources established for the three study scenarios. As of the start of 2031, the system portfolio included 322 GW of generation capacity and 35 GW of storage capacity. All scenarios began in 2030 at the reference starting point and diverged subject to their unique constraints and assumptions. By 2040, the scenarios featured the installed capacities in the WECC region seen in Table 5.

Resource additions in the model were the result of firm capacity and energy needs in one or more of the planning regions through 2036. In 2036, the clean energy policy constraint across the Western system became binding for the distributed scenario and remained binding for the rest of the study horizon. For the centralized and hybrid scenarios, this constraint began binding in 2037. This indicates that renewable portfolio standards' goals were, in part, responsible for generator build decisions in the later years of the study horizon. By the end of the study horizon in 2040, all three scenario simulations reached equilibriums in one or more planning regions where a combination of firm capacity needs and clean energy

TABLE 5
Summary of Built Generation and Storage Capacity by 2040

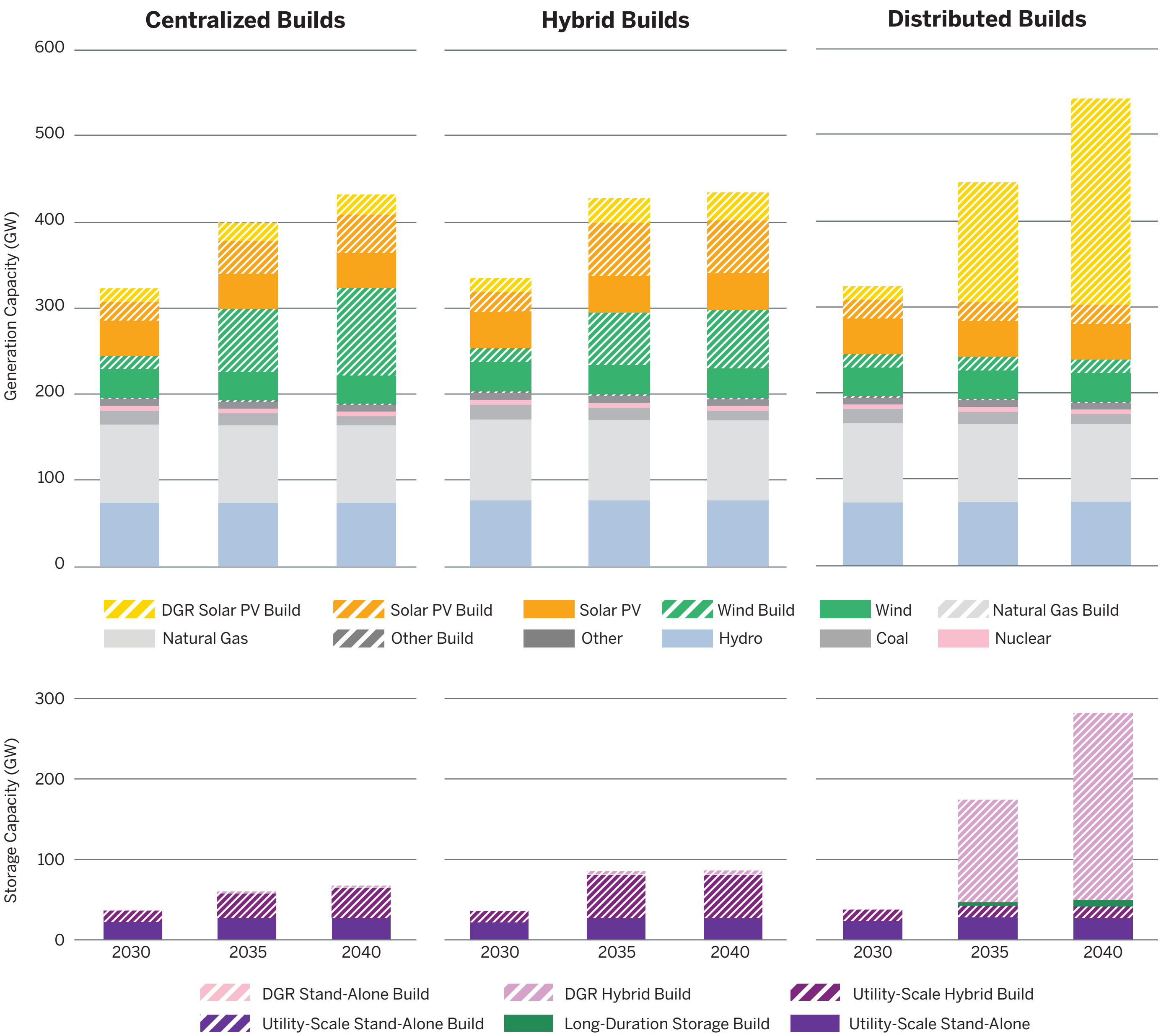
	Centralized Scenario	Hybrid Scenario	Distributed Scenario
Generation nameplate capacity	431 GW	418 GW	537 GW
4-hour storage nameplate capacity	63 GW	82 GW	255 GW
10-hour storage nameplate capacity			7 GW
Total storage capacity	252 GWh	328 GWh	1,090 GWh

Cumulative generation and storage capacity built by 2040 including existing resources, planned resources, and resources selected by the long-term capacity expansion model.

Source: Energy Systems Integration Group.

FIGURE 9

Study Scenario Installed Generation and Battery Capacities



The installed capacity across all three futures illuminates the influence of each scenario on generation and battery capacity expansion. Bar segments denoted with "build" in the legend refer to capacity that may be built in the 2023–2030 reference.

Notes: DGR = distributed generation resource; PV = photovoltaic.

Source: Energy Systems Integration Group.

policy constraints drove resource builds. By the end of the study horizon, the centralized scenario ended up with more wind capacity than the hybrid scenario, whereas the hybrid scenario had more solar and battery capacity—partially as a result of the increased DG adoption.

In general, the reason why installed capacities differed between scenarios was because some scenarios allowed a more diverse resource mix than others, and a diverse set of resources contributed better to more efficient and clean economic dispatch and firm capacity than a more limited set of resources.

Offsetting a lack of resource diversity and generator flexibility requires more paired or stand-alone storage—which can shift power generation to times when it is needed to serve load. The significant additional build-out of storage capacity in the distributed scenario, three to four times greater than in the other two scenarios, illustrates the important role of storage to meet capacity and energy needs in a DG-heavy future. The ability of the distributed scenario to build long-duration storage was critical to serving load in such a future. The 7 GW of long-duration (10-hour) storage built in the distributed scenario was built across the Western system, with slightly more being built in the Northwest Power Pool (NWPP) than elsewhere.

Despite the "sampled" chronology adopted in this model, which required the LTCE model to inform build decisions based on a subset of days each year, the model identified diverse resource mixes reflecting unique aspects among the future scenarios. In addition to significant builds of renewable resources, all three scenarios retained the same level of dispatchable thermal resources, which helped to provide the flexibility to the system that enabled it to meet its clean energy constraints.

Comparing battery builds between scenarios, we observed that the hybrid scenario built 19 GW (30%) more nameplate 4-hour battery capacity than the centralized scenario by 2040. This difference was mostly the result of the model choosing to build utility-scale PV+storage resources in the hybrid scenario. The distributed scenario installed more than four times as much 4-hour battery capacity as the centralized scenario. This suggests that the lack of resource diversity and dispatchability provided by a broad range of utility-scale resources forced the model to build more storage capacity to meet its system planning constraints.

Finally, as part of this modeling effort, coal units not planned to be retired through the end of the study horizon were made available to the LTCE algorithm to be considered as candidates for retirement. Retirement costs of these units were included at approximately $129,000/MW. No coal retirements above and beyond planned retirements occurred in any of the studied scenarios.

Transmission Expansion

This section is an exploration into the relationship between DG deployment and the timing and magnitude of inter-zonal transmission investment needs (Table 6). The intent of this study was not to perform an investment-grade analysis, or to identify specific inter-zonal corridors that should be considered for development. Accordingly, the locations or modeled capital costs of investment candidates are not explicitly discussed. Note that this study considers only inter-zonal upgrades. There are many more upgrades within zones that would be needed to facilitate the generators modeled in study scenarios, but such upgrades were not captured in this model.

Figures 10 through 12 (pp. 26–28) summarize the transmission capacity added across scenarios during the 2031–2040 study horizon. Multiple transmission expansion candidates were available for selection between each unique zone-to-zone pair, and these maps show only the cumulative capacities built through the end of the study horizon in 2040.

TABLE 6

Built Inter-Zonal Transmission, 2031–2040

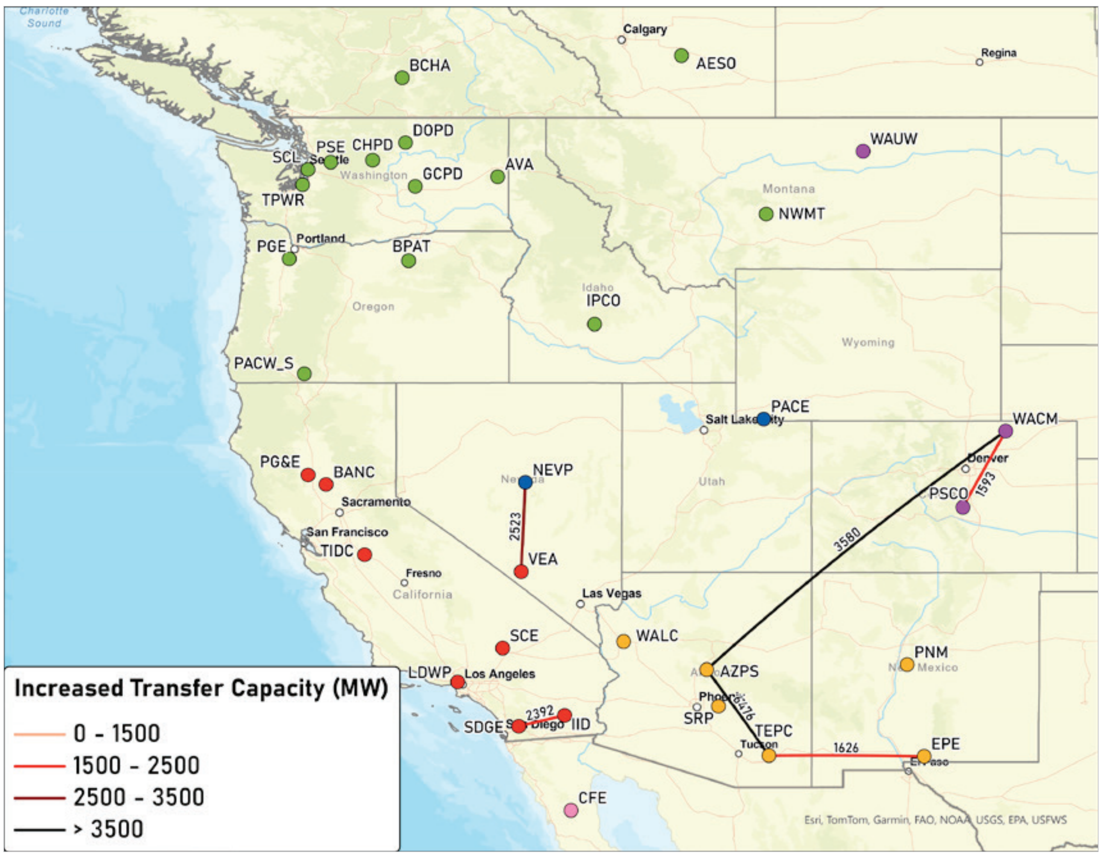
Scenario	Projects Built	Sum of GW-Miles Added	Sum of GW Added
Centralized	11	238 GW-miles	18 GW
Hybrid	8	166 GW-miles	12 GW
Distributed	11	526 GW-miles	16 GW

Summary of built inter-zonal transmission for the three study scenarios.

Source: Energy Systems Integration Group.

FIGURE 10

Centralized Scenario Transmission Additions

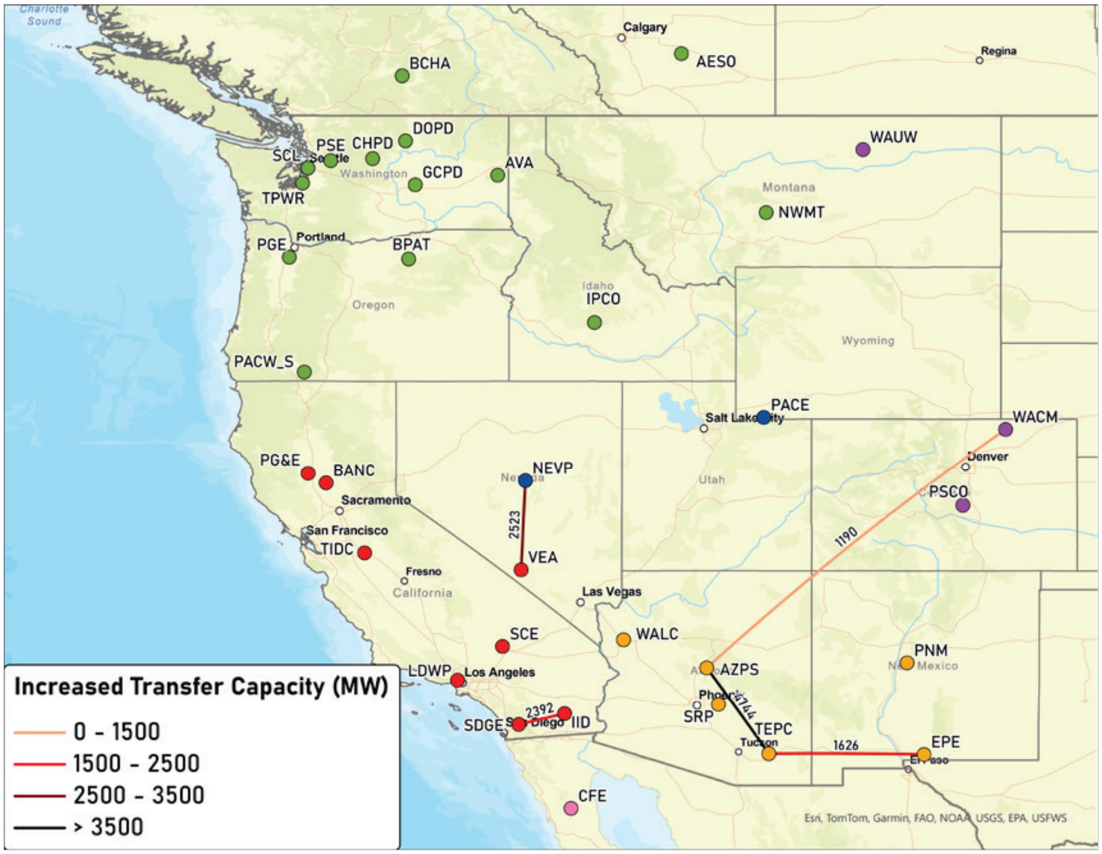


Zonal line capacity added by the long-term capacity expansion model in the centralized scenario.

Source: Energy Systems Integration Group.

FIGURE 11

Hybrid Scenario Transmission Additions



Zonal line capacity added by the long-term capacity expansion model in the hybrid scenario.

Source: Energy Systems Integration Group.

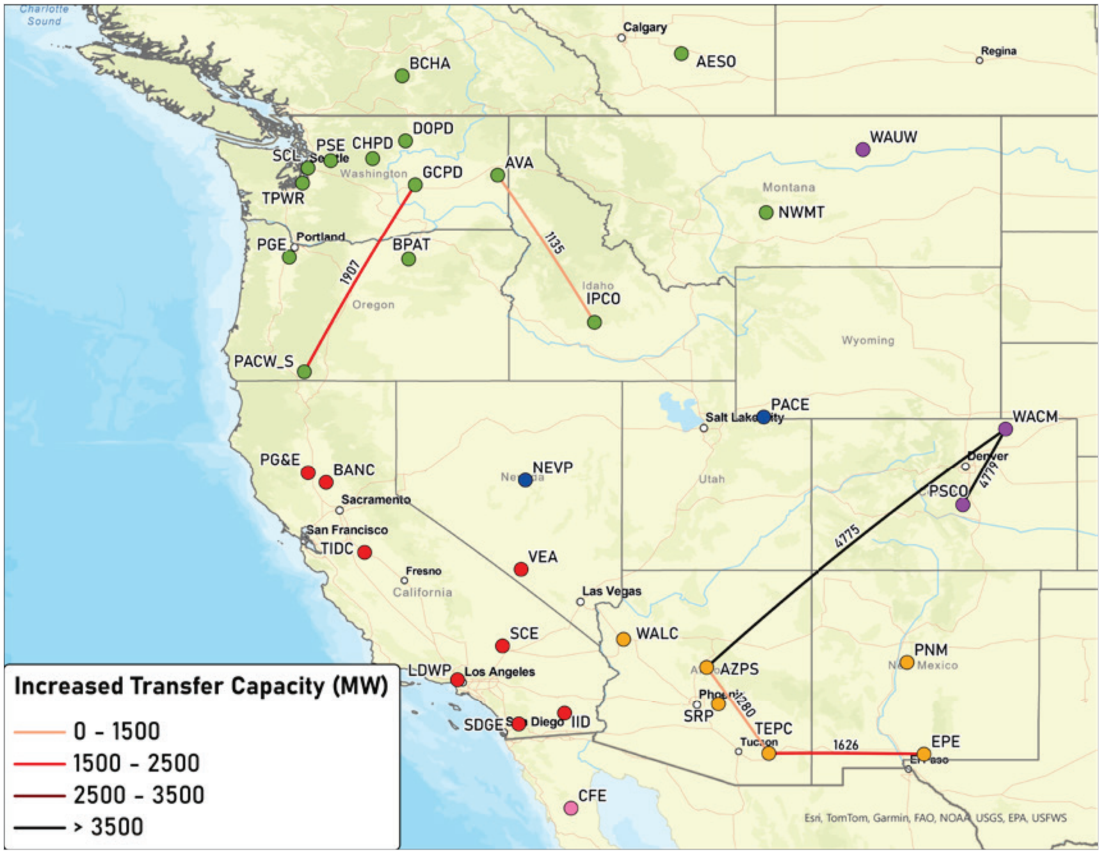
Both centralized and distributed resource futures required significant inter-zonal transmission expansion to support future loads and electrification. The hybrid scenario resulted in the lowest expansion among the scenarios, a transmission capacity build-out that was 33% smaller than in the centralized scenario and nearly 25% smaller than in the distributed scenario. This finding points to the complementary nature of utility-scale generation with moderately higher levels of DG. Reliance on DG expansion in high levels did not result in reduced transmission expansion and capital costs. Still, the results of the distributed and hybrid scenarios' transmission builds illustrated the role that DG plays in reducing transmission expansion need at moderate levels, though this trend did not hold for very high levels of DG.

While all futures required transmission expansion, and DGRs helped to avoid some investment in the hybrid scenario, these results also indicated that a DG-heavy future drove different transmission builds. This finding points to the complementary nature of DG and transmission in that transmission (and storage) enables a high-DG future.

In the distributed scenario, the model was free to build DG resources in locations with high resource quality and/or low cost. The DG resources built in the distributed scenario differed significantly in both capacity and location from the DG trajectories included as an input in the other two scenarios, and these differences had an impact on the transmission build of the distributed scenario. Interestingly, the distributed scenario built transmission

FIGURE 12

Distributed Scenario Transmission Additions



Zonal line capacity added by the long-term capacity expansion model in the distributed scenario.

Source: Energy Systems Integration Group.

lines that were almost twice as long as in the other scenarios. So, while all futures required transmission expansion, and DGRs helped to avoid some investment in the hybrid scenario, these results also indicated that a DG-heavy future drove different transmission builds. This finding points to the complementary nature of DG and transmission in that transmission (and storage) enables a high-DG future.

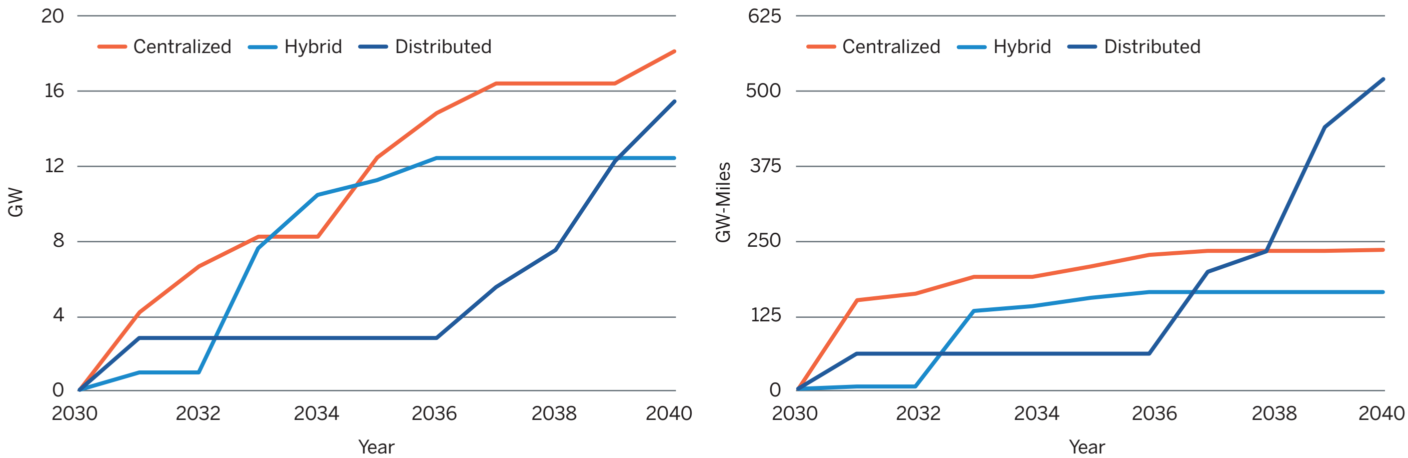
Chronological transmission expansion data for inter-zonal line candidates are outlined for each of the three scenarios in Figure 13 (p. 29). All three scenarios built significant transmission on the order of 166 to 526 GW-miles but arrived at these cumulative values along distinct build trajectories. The centralized build followed a nearly linear path comparable to the pre-2030 reference build. The hybrid scenario deferred some transmission expansion for the first couple of years, then steeply accelerated builds before leveling off. The distributed scenario deferred transmission expansion until approximately 2036, when expansion nearly doubled over the last few years of the horizon to satisfy system planning needs, including clean energy policies.

Transmission expansion occurred when the annualized cost-savings of the system exceeded the annualized costs associated with the candidate transmission line within the study horizon. Candidate transmission capacity was deferred when, among other things, system operating costs were low enough that the investment cost was not justified (i.e., would not result in a lower system cost according to the cost-minimizing objective function).

Another important area of investigation for the study was any synergy or commonality between transmission upgrades identified in each of the three transmission

FIGURE 13

Inter-Zonal Transmission Expansion, 2030–2040



Graphs show the total GW and GW-miles of inter-zonal transmission selected by the long-term capacity expansion model during the 2031–2040 study horizon. The build trajectories of the three future scenarios depicted a common need for transmission capacity regardless of distributed generation trajectories.

Source: Energy Systems Integration Group.

expansion scenarios. Table 7 summarizes the number of shared and unique lines for combinations of scenarios.

Transmission upgrades between the distributed and other scenarios were distinct: just 29% and 19% overlapped with the centralized and hybrid scenarios, respectively. Further, the unique lines built in the distributed scenario tended to be very long lines not included by the centralized builds. The hybrid and centralized futures, both featuring prominent builds of utility-scale resources, exhibited the most resemblance in their transmission builds, with a 73% overlap. Notably, all eight of the lines built in the hybrid future were also present in centralized future. The centralized future built an additional three lines to meet energy and capacity needs beyond the transmission need exhibited in the hybrid scenario. That certain transmission upgrades were consistently identified across scenarios indicates the potential persistence of specific drivers for transmission investments irrespective of the energy resource mix considered.

TABLE 7

Shared and Unique Lines for Scenario Pairs

Compare	Lines Built*	Shared Lines	Unique Lines	GW Shared	GW Unique	% Shared	% Unique
Distributed vs. centralized	17	5	12	8 GW	18 GW	29%	71%
Distributed vs. hybrid	16	3	13	4 GW	20 GW	19%	81%
Centralized vs. hybrid	11	8	3	12 GW	6 GW	73%	27%

Overlap among the transmission build-outs in each scenario indicates some common geographical transmission needs. The build-outs in the centralized and hybrid scenarios were mostly alike.

* Counts the total number of unique lines among the two cases compared.

Source: Energy Systems Integration Group.

TABLE 8

Transmission Upgrades in the Hybrid and Distributed Scenarios, Compared to Upgrades in the Centralized Scenario

ID	Hybrid Scenario	Distributed Scenario
1	Deferred	Deferred
2	Avoided	Avoided
3	Installed sooner	Avoided
4	Deferred	Deferred
5	Same in-service date	Avoided
6	Same in-service date	Avoided
7	Same in-service date	Avoided
8	Installed sooner	Avoided
9	Deferred	Installed sooner
10	Avoided	Deferred
11	Avoided	Same in-service date
12		Added
13		Added
14		Added
15		Added
16		Added
17		Added

The deferral or outright avoidance of transmission builds observed in the hybrid and distributed scenarios point to distributed generation's benefit to the system.

Source: Energy Systems Integration Group.

Table 8 illustrates the impact of DG expansion on transmission expansion with regard to the centralized future. Namely, the table identifies how specific upgrades were unchanged, installed sooner, deferred (delayed in their installation date), or avoided all together. This analysis is presented relative to the centralized scenario, and also lists upgrades (starting at #12) that were not in the centralized scenario but were added in the distributed scenario. Since this study did not endeavor to discuss individual transmission expansion candidates selected by the model, these candidates were assigned an ID number in Table 8.

In aggregate, the hybrid scenario had a smaller transmission build than the centralized scenario in terms of both number and capacity of lines built. Compared to the centralized scenario, the hybrid scenario showed two transmission projects that were installed sooner, three deferred projects, and three projects that were avoided altogether. The distributed scenario, in contrast, avoided six transmission projects built in the centralized scenario but added six projects that were not built in the centralized or hybrid scenarios. One line was installed sooner, one line had the same in-service date, and three lines were deferred.

Although the aggregate transmission capacity expansion in the distributed and centralized scenarios may exhibit comparable totals, the specific network topologies and geographical distribution of new infrastructure differed substantially. While significant transmission expansion remained crucial for accommodating DG-heavy futures, the transmission expansion results indicated that the network build-out pattern could deviate markedly from traditional generation–driven approaches.

Generation Operations in Short-Term Model

In each hour of the study simulation, the system had to solve a feasible and cost-minimized dispatch solution subject to system constraints and requirements. This hourly economic dispatch reflected the capabilities and costs associated with each generator, as well as the need to hold operating reserves and adhere to operational constraints.

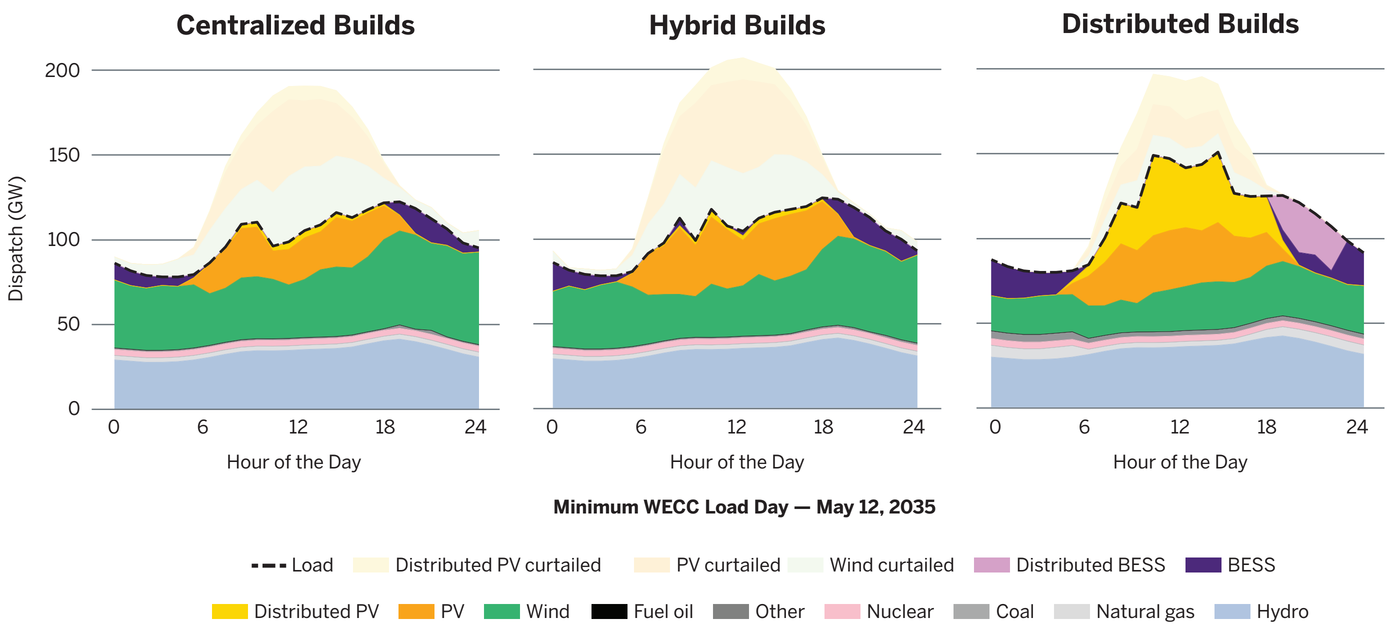
The Western system currently has a significant base load capacity composed of nuclear, coal-, and natural gas–fueled resources. There are several technologies used to turn these fuels into electricity on the system, each of which has different operational capabilities and costs. Operational capabilities considered in this study were modeled consistent with the PLEXOS WECC 2023 Zonal Dataset and included generator-specific heat rates (efficiencies), minimum stable factors, minimum up and down time for unit commitments, and planned and forced outage rates. Generator costs considered by the ST model included fuel costs, variable operations and maintenance (O&M) costs, fixed costs, and start costs. Hydro units in the model were assumed to be load-following and were constrained with monthly maximum energy constraints consistent with a unit-specific historical analysis of hydro generation in the study footprint.

All three studied scenarios retained some level of dispatchable resources, which helped to provide the flexibility to the system that enabled it to meet its clean energy constraints by cycling and adjusting dispatch around variable renewable generation.

As previously noted, clean energy policy constraints and carbon prices across the Western system were implemented only in the LTCE stage of modeling. The absence of these factors in the ST allowed the system to dispatch lowest-cost resources as available from a scenario-specific

FIGURE 14

Minimum WECC Load Day Dispatch



The system dispatch, by resource type, illustrates the operational decision-making of the model to serve hour-to-hour load demands. Here, on the minimum WECC load day, substantial curtailment occurs as more non-dispatchable generation is available than is demanded by WECC in total.

Notes: BESS = battery energy storage systems; PV = photovoltaic; WECC = Western Electricity Coordinating Council.

Source: Energy Systems Integration Group.

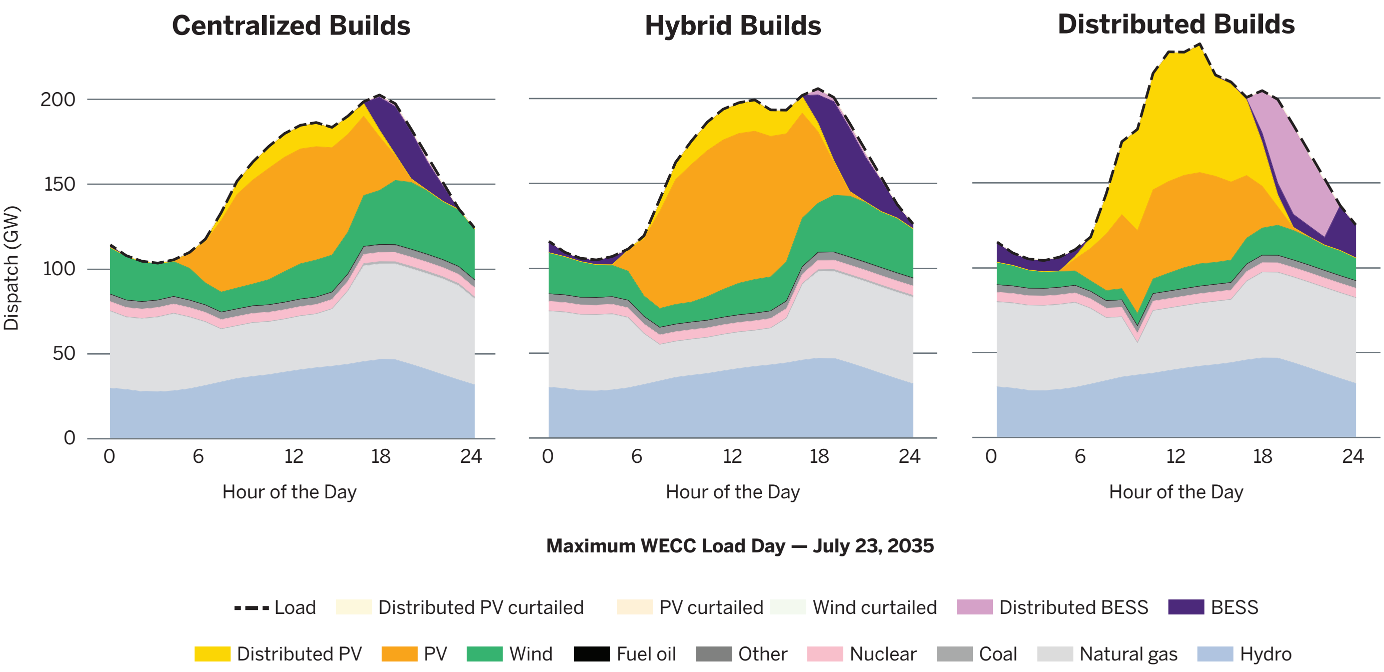
list of available resources. Above the "baseline" resources outlined above, onshore wind candidates assisted in providing intermittent around-the-clock power, whereas solar PV technologies saturated the system and shifted the net peak load later into the evening. Increased solar PV capacities required greater levels of storage technologies to shift generation to meet demands.

Figures 14 and 15 (p. 33) illustrate the hourly total system dispatch and weather-dependent resource curtailment for the minimum load day (Figure 14), May 12, and maximum load day (Figure 15), July 23, across the three scenarios. The solid-colored areas represent the hourly generation of each resource, the dashed line identifies the total system load, and the light-colored areas illustrate the curtailed generation of weather-dependent resources (wind and solar PV).

Load on the minimum load day was largely supplied by hydro, wind, and solar generation. After saturating battery storage charging demands, the system curtailed significant generation to maintain system stability. Curtailment was smallest in the distributed scenario due to the additional battery storage charging demand, as it had three to four times the storage capacity of the centralized and hybrid scenarios. Long-duration storage, in the distributed scenario only, followed a diurnal charge-discharge pattern and was responsible for much of the load served during nighttime hours. In the afternoon peak period, where solar generation falls during sunset hours, the battery storage that had previously charged during peak solar generation periods was available to discharge energy and support evening load. It is this complementary operation between solar generation and storage that enables a DG-heavy future to provide firm capacity in the absence of dispatchable, emitting generating resources.

On the maximum load day—the peak operating condition for the system—no generation was curtailed.

FIGURE 15
Maximum WECC Load Day Dispatch



The system dispatch, by resource type, illustrates the operational decision-making of the model to serve hour-to-hour load demands. Here, on the maximum WECC load day, zero curtailment occurs. Maximum load days such as this are precisely what the system is built up to efficiently support.

Notes: BESS = battery energy storage systems; PV = photovoltaic; WECC = Western Electricity Coordinating Council.

Source: Energy Systems Integration Group.

The overbuild of solar capacity and storage of the distributed scenario was demonstrated by the larger peak generation and load shown in Figure 15. Again, storage played a significant role in the distributed scenario in serving evening load as solar generation ramps down. The centralized and hybrid scenarios relied more heavily on utility-scale wind generation during this period to serve load. The presence of utility-scale wind contributed to greater overall resource diversity and consequently offset natural gas–fueled generation, particularly in the summer. Hydro and natural gas resources provided significant baseload support throughout all scenarios, with wind and storage generation contributing in the shoulder periods.

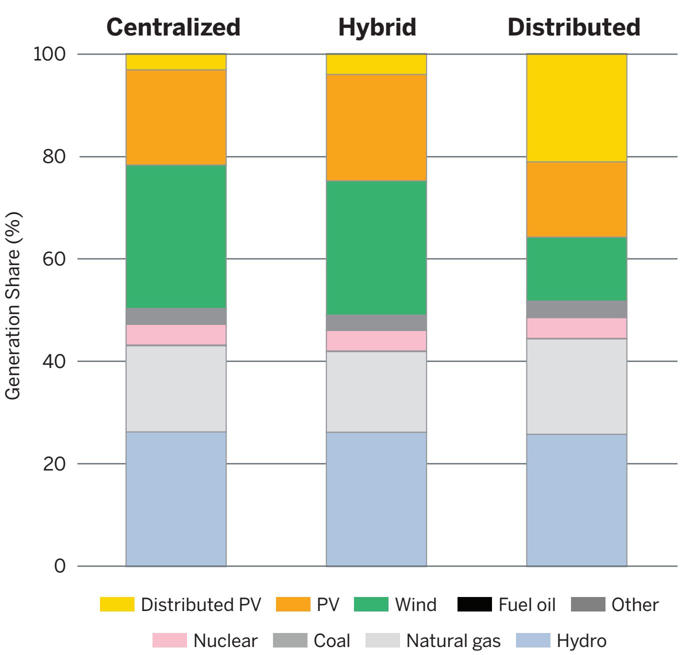
The shift of daytime solar generation to evening peaks through battery storage played a significant role in meeting evening demand across all scenarios. Even the baseline battery capacity installed in the centralized scenario served an important role in meeting peak demand. The high offtake of solar generation into storage, especially among distributed battery storage facilities, indicated a demand for storage to complement a deeply decarbonized generation portfolio.

In general, we observed a varying dependence on DG energy among the scenarios, illustrated in Figure 16. In the 2035 study year, DG provided 3%, 4%, and 21% of total energy in the centralized, hybrid, and distributed scenarios, respectively. Still, without utility-scale wind capacity, as was present in the centralized and hybrid scenarios, the distributed scenario had to rely more heavily on emitting resources than did other scenarios.

Table 9 shows the percentage of generation from non-emitting resources in the 2035 short-term simulations. Note that the clean energy polices enforced as a constraint in the LTCE models shown in Table 3 (p. 20) were not enforced in the 2035 short-term simulations. Rather, these resources were dispatched according to their unit economics and characteristics.

FIGURE 16

Total Energy Delivered by Resource Type



Total generation share, for the 2035 study year, illustrates the energy contribution of each resource type.

Source: Energy Systems Integration Group.

TABLE 9

2035 Percent Generation by Non-emitting Resources

Scenario	% Non-emitting Resources
Centralized	82.7%
Hybrid	85.1%
Distributed	80.7%

Resources considered in this metric include solar PV (distributed and utility-scale), wind, nuclear, hydro, geothermal, and biomass-fueled resources.

Source: Energy Systems Integration Group.

As noted above, all three scenarios were subject to the same West-wide clean energy target. The changes in energy delivered by resource type resulted in changes to the total CO_2 emissions of each of the study scenarios, shown in Table 10. In the hybrid scenario the combination of distributed non-emitting resources and utility-scale wind resulted in the lowest emission of CO_2 and, consequently, the smallest social cost as calculated consistent with White House estimates (IWGSCGG, 2021). Similarly, the lack of utility-scale wind capacity and the (slightly) heavier reliance on natural gas–fueled generation present in the distributed scenario resulted in the highest total CO_2 emissions.

Total curtailed energy provides a measure of the system's ability to deliver weather-dependent generation to load via the provided transmission system. Aggregate curtailment

TABLE 10

2035 WECC CO_2 Emissions by Scenario

Scenario	CO_2 Emissions (million metric tons)	Social Cost of CO_2
Centralized	57.7 mmT	$1,269 million
Hybrid	49.7 mmT	$1,093 million
Distributed	67.3 mmT	$1,481 million

Future scenario resource and transmission expansion significantly impact total WECC CO_2 emissions. Relative to the centralized scenario, the hybrid scenario emits 14% fewer and the distributed scenario emits 17% more emissions.

Source: Energy Systems Integration Group.

TABLE 11

Summary of Renewable Generation Curtailment

Scenario	Generation Potential	Curtailment	Percent Curtailed	Peak Curtailment Hour (MST)
Centralized	555.78 TWh	26.00 TWh	4.6%	5/12/2035 11:00
Hybrid	589.75 TWh	30.35 TWh	5.1%	5/12/2035 12:00
Distributed	538.81 TWh	17.45 TWh	3.2%	5/12/2035 12:00

Renewable generation curtailment quantifies the system's inability to accept generation from wind and solar resources. Here, the Distributed scenario results in the lowest curtailment due to its higher battery storage capacity and the inclusion of long-duration storage.

Source: Energy Systems Integration Group.

TABLE 12

WECC Production Costs in the 2035 Study Year

Scenario	Production Costs
Centralized	$11.90 billion
Hybrid	$10.52 billion
Distributed	$13.77 billion

Total WECC system production costs yielded a 16% increase in the distributed scenario over the centralized future. The hybrid scenario resulted in 12% lower production costs.

Source: Energy Systems Integration Group.

values for the 2035 study year are presented in Table 11. Of the three study scenarios, the hybrid scenario exhibited the highest percentage of renewable energy curtailed. Despite the distributed scenario's overbuild of generation resources and reliance on distributed, non-dispatchable resources, it resulted in significantly less curtailment than the centralized and hybrid scenarios. However, the distributed scenario's ability to avoid curtailment can be attributed to its significantly high build of storage and its ability to use long-duration storage—which was not available in the other two study scenarios.

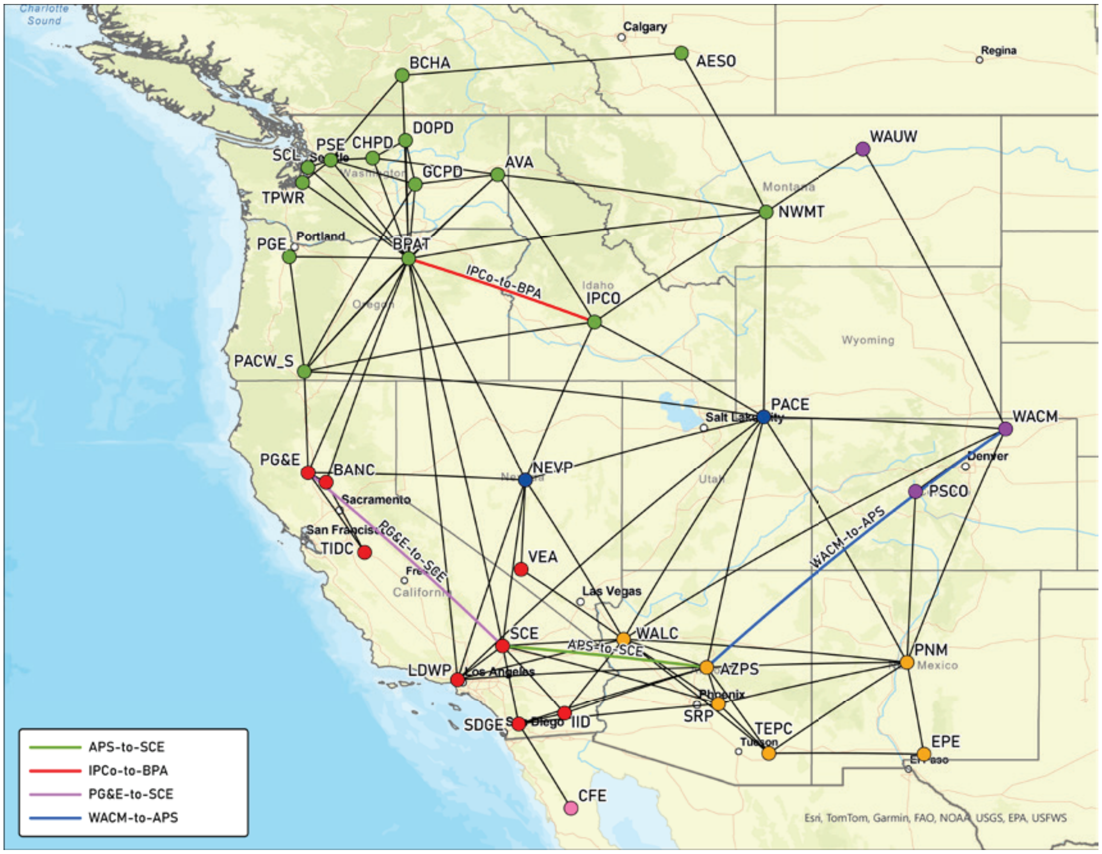
Total system production costs are presented in Table 12. The hybrid scenario, representing accelerated DG adoption, had the lowest production cost, 12% less than the centralized scenario. In contrast, the distributed scenario cost 16% and 31% more than the centralized and hybrid scenarios, respectively. This analysis suggests economic benefits, though not unlimited, of accelerated DG adoption in the Western system.

Transmission Flows and Utilization in Short-Term Model

This section investigates zonal transmission in the 2035 ST models. In this section, we explore the broader

FIGURE 17

Lines Investigated in Short-Term Results



Impacts of distributed generation vary widely on zonal lines across the Western system. This report investigates the flows of four zonal lines in detail: APS-to-SCE, IPCo-to-BPA, PG&E-to-SCE, and WACM-to-APS.

Source: Energy Systems Integration Group.

impacts on the system as a whole and investigate four lines specifically to illustrate differences in impacts in different geographical areas of the Western system. Figure 17 shows the zonal topology of this study and highlights the four lines specifically investigated in this section.

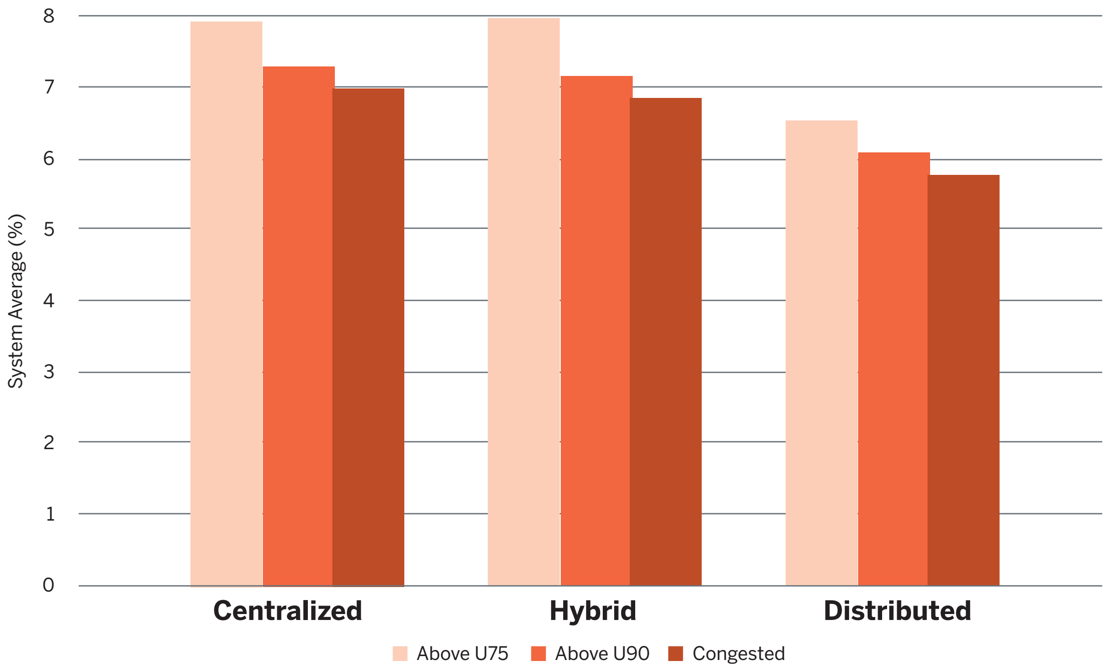
Average Transmission System Operation

Figure 18 (p. 37) presents the average transmission system operation, expressed as the percentage of lines (e.g., zonal links) for which flows are at or above the given utilization or congestion.

To help quantify the flows and utilization of inter-zonal transmission links in the study, we used a handful of utilization metrics, including:

FIGURE 18

Average System Congestion in 2035 Study Year



Transmission line congestion averaged across all lines in the system suggests a modest decrease in congestion because of expanded distributed generation.

Source: Energy Systems Integration Group.

- **U75:** Percentage of time that flows on the line are 75% of the limit or higher
- **U90:** Percentage of time that flows on the line are 90% of the limit or higher
- **Congestion:** Percentage of time that flows on the line are at 100% of the limit

For example, in the centralized scenario the average congestion among all lines was approximately 7% for the 2035 study year.

The results indicate that transmission utilization, as established by these metrics, was generally comparable across the scenarios. For context, the 2018 WECC *State of the Interconnection* report identified average, across all system lines, U75 and U90 metrics of 6.2% and 1.3%, respectively (WECC, 2018). Given these 2035 results, the Western system can expect increased line utilization and congestion in the coming years. Utilization and congestion metrics were comparable across all three futures, but the hybrid and distributed scenarios did present slightly lower congestion. We infer from these results that local generation and increased storage capacity can reduce transmission system congestion in a DG-heavy future. Regardless of the resource future, transmission flows will play a critical role in servicing load and may be more highly utilized more often than historically observed.

Drivers of Transmission Line Flows

The drivers of transmission line flows are numerous and complex. Broadly, transmission flows are driven by imbalances in load and generation within and among zones, the diversity of constituent resources, and transmission line and generator capacity limits. Deep levels of variable renewable energy and load electrification add to the variability of transmission flows observed.

To better understand the drivers of transmission flows in these scenarios, we present a selection of results focused on individual, inter-zonal links connecting zones with various resource mixes and loads. We selected the following lines to get a broad geographical view of transmission flows occurring across the study scenarios. We also surveyed additional lines, and many of them exhibited similar behavior, although no two lines had the exact same performance due to the broad geography and diversity of the Western grid. For each line, the name indicates the positive flow direction: for example, for "Idaho Power to BPA," positive flow values indicate flow from the system's Idaho Power zone to its BPA zone.

IPCo-to-BPA

On the path from Idaho Power (IPCo) to Bonneville Power Authority (BPA) approximately on the border between Oregon and Idaho (Figure 19), flow duration in each direction was balanced, suggesting a bi-directional benefit to resource sharing for each of these two zones. On average, IPCo's reliance on BPA imports (seen as negative flows which are represented by lines beneath the zero point on the y axis in the right panel of the figure) was greatest during early morning hours of the distributed scenario. The hybrid scenario yielded negative flows in both the early morning and late evening hours. The reduction of evening imports in the distributed scenario was likely due to evening battery discharge provided by the large battery storage fleet. Among the three scenarios, utility-scale wind capacity was greatest in the centralized scenario. This wind capacity helps to make IPCo a net exporter into BPA on average, as seen in the positive average day flows in the centralized scenario.

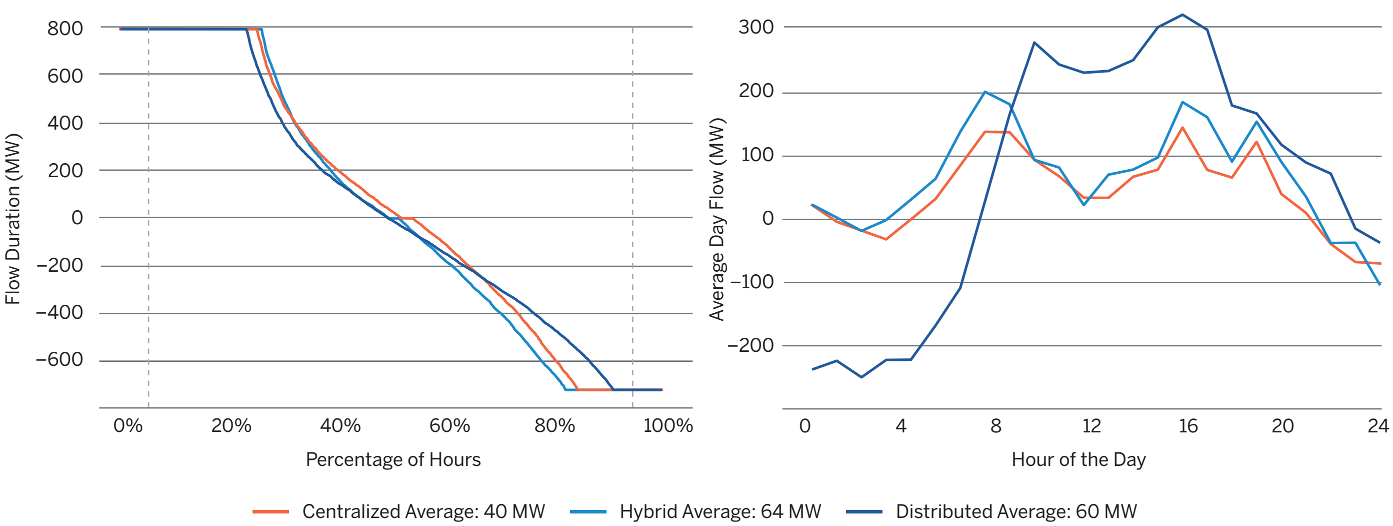
Seasonal hydro availability in the Pacific Northwest (PNW) is a significant supply of firm capacity that can influence net imports into IPCo. In the scenarios with less firm capacity, greater imports into IPCo were observed. Still, the flow on this line demonstrated a diurnal shape suggesting that some solar energy either was sourced from or was traversing the IPCo system into the PNW. This positive flow was greatest in the distributed scenario, where solar capacity was overbuilt relative to the other scenarios.

WACM-to-APS

In the physical transmission system, flows between the Western Area Power Administration–Colorado Missouri region (WACM) and Arizona Public Service in the Phoenix area (APS) occur mainly in the Four Corners area, with both zones holding substantial capacity at this location. Figure 20 (p. 39) shows the flows exhibited on these lines in the ST model. In the distributed scenario, flows were predominantly from APS to WACM. Flows from WACM to APS peaked in the hybrid and centralized scenarios in the overnight periods, implying the

FIGURE 19

IPCo-to-BPA Zonal Line Flow During the 2035 Study Year

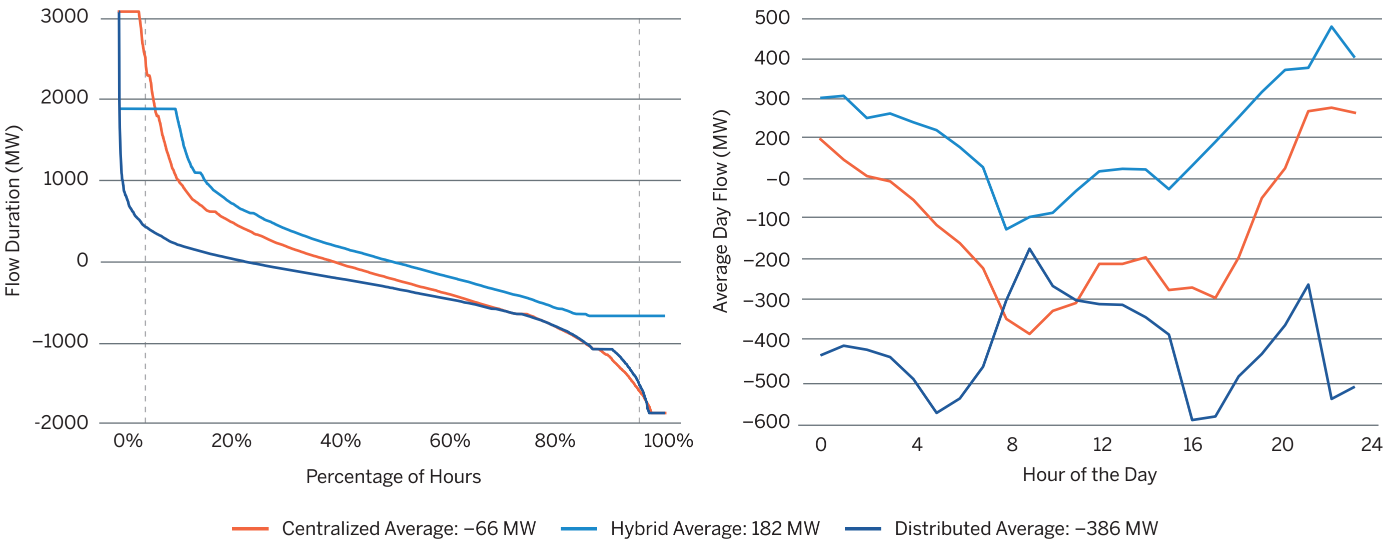


These flows illustrate bi-directional flows and a diurnal swing in positive flow indicating midday solar generation moving from Idaho and onto the BPA system.

Source: Energy Systems Integration Group.

FIGURE 20

WACM-to-APS Zonal Line Flow During the 2035 Study Year



These flows depict a divergence between the distributed and other cases. The distributed case, with significantly less wind in WACM and more solar in APS, results in flows predominantly from APS and into WACM.

Source: Energy Systems Integration Group.

transfer of wind energy from Colorado/Wyoming into Arizona. Average day flows in the distributed scenario, in which wind generation expansion was limited, did not yield positive flow in the WACM to APS direction. It is worth mentioning the divergent average day flow between the distributed scenario and other two. This observation highlights the impact of a DG-heavy future on power flow patterns and resource exchange between zones under the varying scenarios.

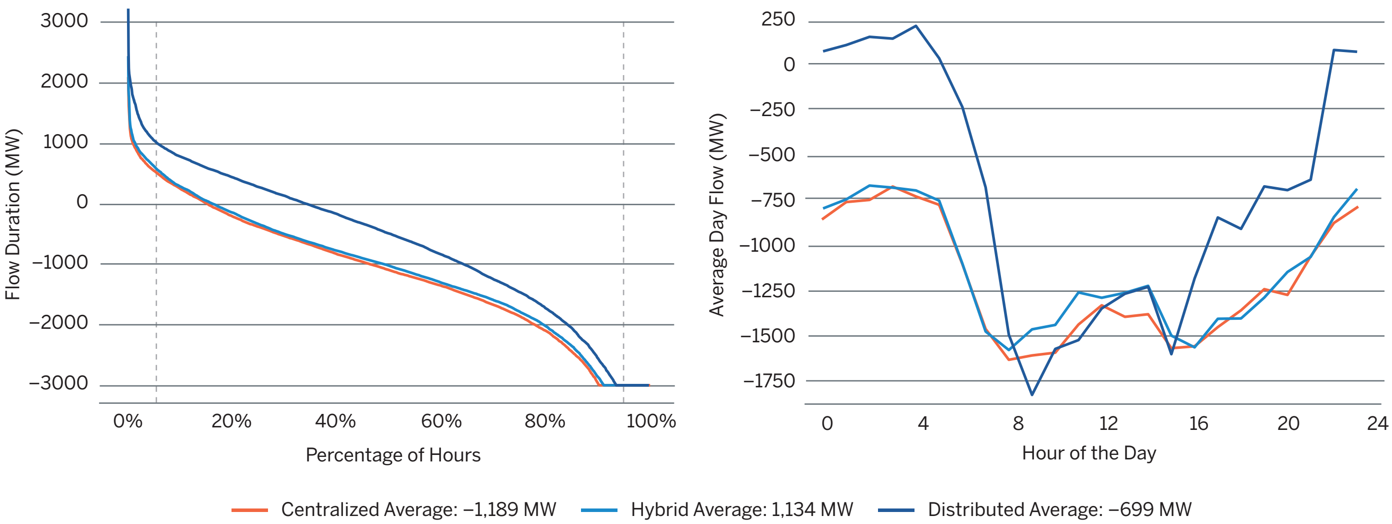
PG&E-to-SCE

For the path from northern to southern California (PG&E to SCE) (Figure 21, p. 40), power flows primarily moved from south to north (negative direction), mirroring common flow patterns observed on Path 15 and Path 26, which connect California's northern and southern reaches.[14] Congestion was observed in the SCE-to-PG&E direction in all scenarios but was most common in the hybrid scenario, wherein no line upgrades had been selected for this interface by 2035. Overnight flows in the SCE-to-PG&E direction (negative flow) in the centralized scenario may have been due to the additional utility-scale wind generation available, at zero marginal cost, on the system. The PG&E-to-SCE line flows were largely consistent among model scenarios, indicating a flow demand that persisted between two zones despite varying zonal capacity build-outs. This is an excellent

14 For information on WECC paths, see https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/2023%20Path%20Rating%20Catalog%20Public.pdf&action=default&DefaultItemOpen=1.

FIGURE 21

PG&E-to-SCE Zonal Line Flow During the 2035 Study Year



Flows on the PG&E-to-SCE transmission line were predominantly negative flow, from SCE to PG&E. Flow was remarkably consistent across all three future scenarios, indicating persistent flow demand regardless of distribution resource build-outs.

Source: Energy Systems Integration Group.

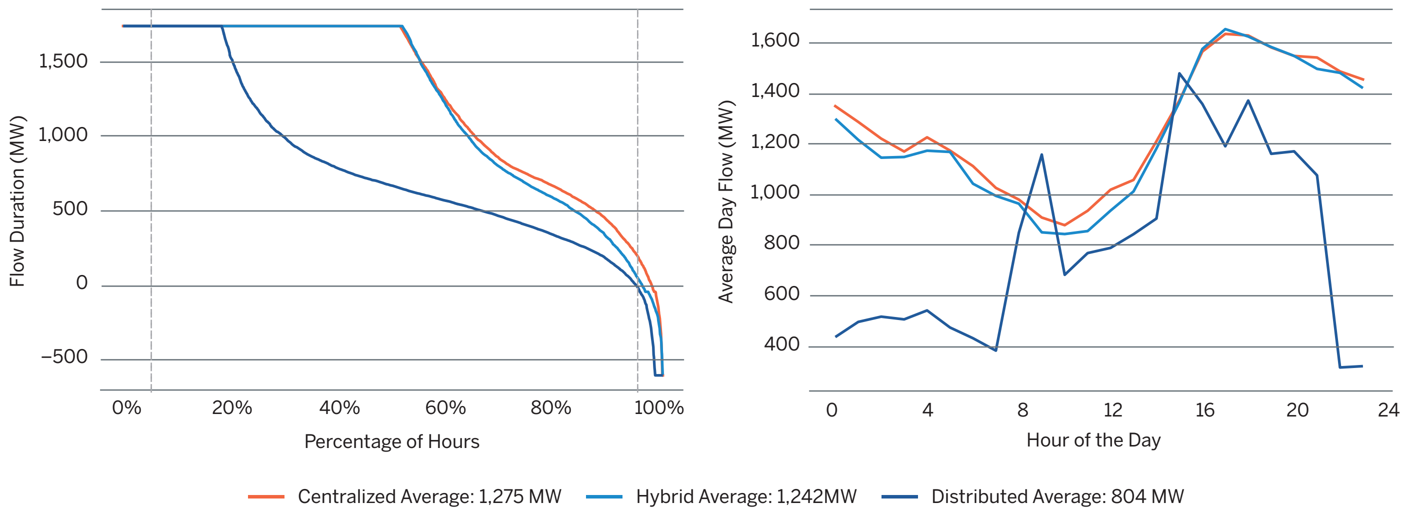
example of demand on the transmission system regardless of the resource future.

APS-to-SCE

Out of all the scenarios studied, congestion was observed primarily in the positive direction connecting the Phoenix area with southern California (APS and SCE) (Figure 22, p. 41). However, the centralized and hybrid scenarios stood out with the highest average flows from APS to SCE—both scenarios demonstrated significant congestion, nearly 50% of all hours. Notably, the average day flow plot reveals a significant drop in imports into California during midday with an increase during the afternoon shoulder period as loads peak and solar PV generation declines. Where the centralized and hybrid scenarios presented the well-known "duck curve," the distributed scenario illustrated the volatility that can be observed with such a heavy reliance on distributed solar generation. The distributed scenario lacked the wind capacity to support early morning imports to SCE and demanded steeper ramping as the sun set. Comparing the centralized and distributed average flows in Figure 22 (p. 41) highlights the benefits of resource diversity in supporting the robust utilization of transmission capacity.

FIGURE 22

APS-to-SCE Zonal Line Flow During the 2035 Study Year



In the APS-to-SCE transmission line, flow congestion was observed in the positive direction, APS to SCE, across all future scenarios, as load in southern California draws in generation from the solar-rich desert southwest.

Source: Energy Systems Integration Group.

Discussion of Key Transmission Metrics

Transmission Flow

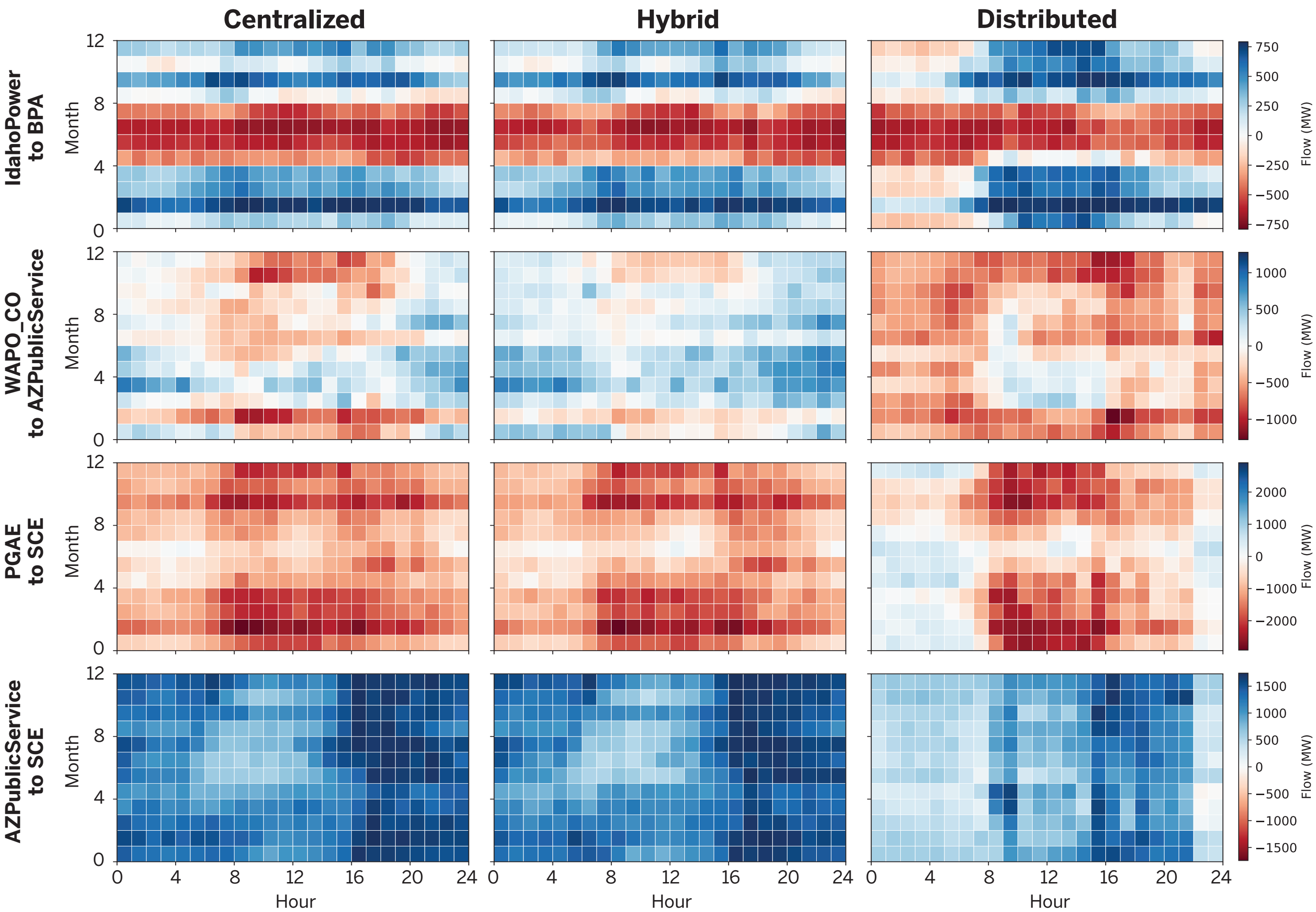
The varying flow patterns and congestion in different scenarios demonstrate how high levels of DGRs can have major impacts on transmission flows. This observation is further supported by the flow heat maps presented in Figure 23 (p. 42) for the transmission links discussed above. The heat maps are in month-hour 12x24 format and show positive and high directional flows as dark blue and negative direction high flows as dark red, with lower flows as lighter colors of each.

The flow heat maps are useful for exploring how flow intensities and directions change across the scenarios. In almost all cases, flows were dramatically different in certain hours for the centralized vs. distributed scenarios. Depending on the path, the distributed scenario could have higher daytime flows (due to solar PV output) or could have higher shoulder-hour flows to make up for a lack of solar production in each zone (with imports being sourced from neighboring zones). The seasonal availability of hydropower generation was evident in the IPCo-to-BPA path results, where high negative flows, shown in red, were dominant during the summer after the winter snow melts. Flows from WACM to APS

illustrated the greatest sensitivity to the distributed vs. centralized generation portfolios. In the distributed scenario, generation predominantly flowed from APS to WACM. Net flows were more balanced in the centralized and hybrid scenarios. On the PG&E-to-SCE path, power flowed most often from south to north with higher magnitude during midday in the winter across all scenarios. Flows on this path were lowest during the summer months when cooling load in SCE reduced the availability of surplus generation to send up to PG&E.

FIGURE 23

12x24 Flow Heat Maps



The flows depicted in the heat map are color-scaled according to the minimum and maximum flows observed on each line across all three future scenarios. Dark blue cells indicate month-hours with highly positive flow, while dark red cells indicate month-hours with highly negative flow.

Source: Energy Systems Integration Group.

Similarly, the APS-to-SCE path flows demonstrated the regularity with which SCE relied on imports from APS to supply load. Across all scenarios, this need grew in the evening as solar generation ramped down.

Congestion

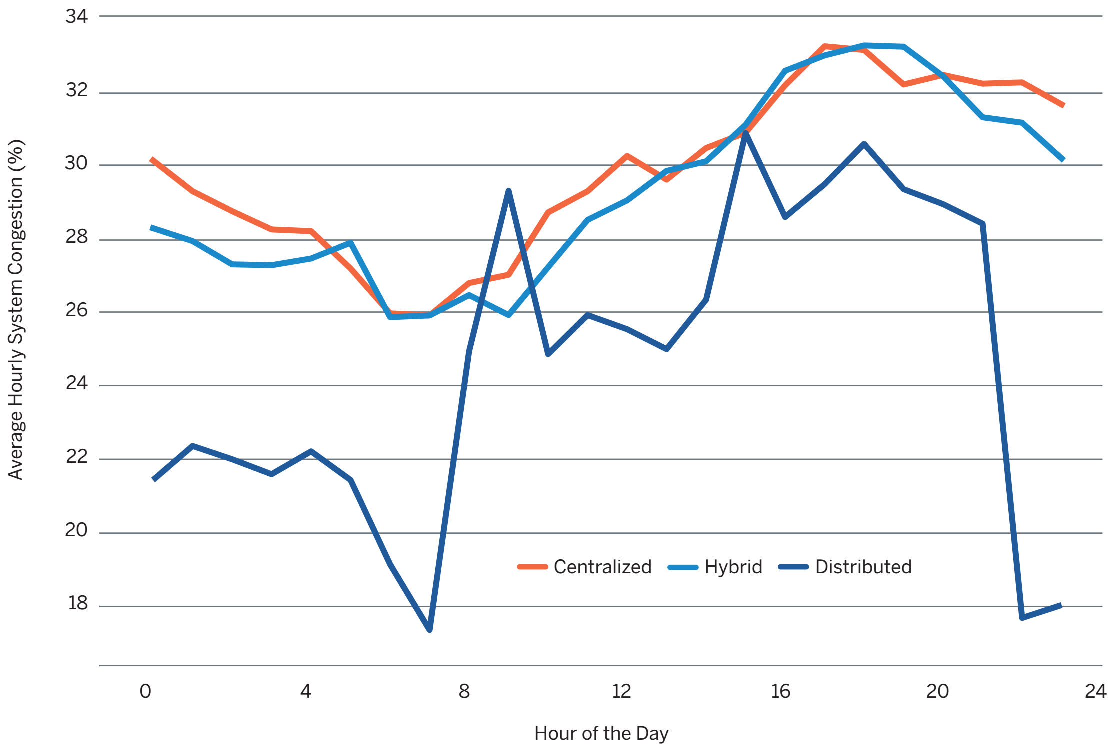
Differences in transmission congestion across the scenarios was another telling metric for how DGRs impact the transmission system. Figure 24 (p. 43) shows when congestion (as a percentage of yearly hours) occurred across all transmission links in the study scenarios. This figure captures the cumulative sum of congestion hours per daily hour across the system.

The centralized and hybrid scenarios demonstrated similar patterns of congestion, peaking during the evening shoulder period. Here, increased DG in the hybrid scenario made a clear positive impact on congestion.

Overall, the distributed scenario experienced the lowest system congestion at sunrise, with afternoon peaks in congestion resulting from the utilization of the transmission system to supply load as solar generation was

FIGURE 24

Transmission Congestion by Hour for All Paths (All Scenarios)



Average hourly system congestion summarizes the influence of future resource scenarios on transmission flows. While the resulting transmission system for each scenario is unique, this average hourly system congestion illustrates the likelihood of congestion on the system and its predominant daily shape.

Source: Energy Systems Integration Group.

ramping up or down. During overnight hours, congestion leveled off in the distributed scenario. This drop in congestion during the sundown hours was likely a consequence of DG battery operation shifting daytime generation into the early evening hours when net demand peaks. These results demonstrate how significant changes in transmission congestion can occur as a result of varying DG levels.

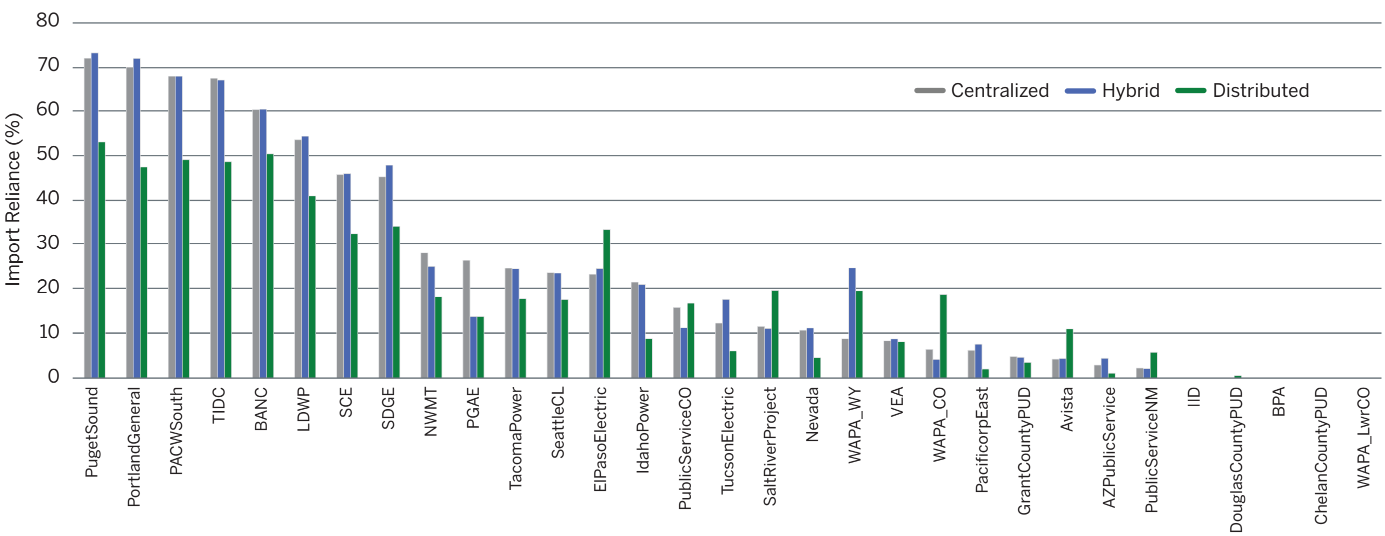
Transmission Import Reliance

An additional metric—transmission import reliance—was calculated to measure the degree to which a zone (or balancing area) was reliant on imports to serve loads, shown in Figure 25 (p. 44). The metric was calculated as imported energy divided by total load in the zone during periods of net import. The rank order of zones by transmission import reliance was comparable across all three scenarios. In general, import reliance was lower in the distributed scenario. A comparison between the centralized and hybrid scenarios reveals the beneficial influence of incremental DG capacity in addition to centralized generation. Notably, due to the locational diversity of their resource mixes, the centralized scenario and the hybrid scenario had zones relying on more imports than the distributed scenario (which featured more local generation). Despite the significant expansion of local DG, the distributed scenario still required load zones to import significant amounts of power during non-solar production times. Load zones' net reliance on imports decreased but was not eliminated by having high levels of DGRs. From this finding we concluded that transmission is still needed to deliver energy under high-DG futures.

Based on the analysis of the results, it is clear that high levels of DGRs reduce but do not eliminate zonal reliance on imports from the transmission system to serve load. High levels of DGRs have a significant impact on the nature of transmission flows in terms of magnitude, direction, and seasonality. High levels of coincident weather-dependent generation resources impact the timing and magnitude of transmission flows and congestion, and these impacts manifest very differently based on the unique attributes and topology of each zone across the Western system. Transmission expansion, selected by the model in the long-term capacity expansion phase, takes this into account to reduce congestion and result in annualized cost-savings for the system at large.

FIGURE 25

Transmission Reliance by Zone and Scenario



Transmission reliance calculates the share of a zone's load that was served by imports. Broadly, the distributed scenario illustrated the lowest import reliance across model zones.

Source: Energy Systems Integration Group.

Key Findings

This study framework provided unique insights into the implications of DG on the bulk transmission system. Findings were derived by comparing the scenario results of both the LTCE and ST simulations. Comparisons of the simulated futures led to the following findings.

Distributed generation can significantly impact inter-zonal transmission flows.

The scenarios investigated in this study exhibited a range of transmission flow and congestion patterns resulting from varying DG build-out assumptions and operational constraints. The modeled adoption of distributed solar and batteries across the Western Interconnection changed diurnal transmission flow and generation patterns. Specifically, it tended to create a midday nadir in net load, and a need for morning and evening flexibility that must be served by storage and other generators on the system. These shifts in generation dispatch had corresponding impacts on zonal transmission flows as power was moved from where it was generated to where it was needed in response to this new system dynamic.

The operational limitations of these generators and zonal line limits drove divergent transmission flow patterns between scenarios. Changing flow and congestion patterns

TABLE 13

Summary of Capacity Expansion Results Through 2040

	Centralized Scenario	Hybrid Scenario	Distributed Scenario
Zonal transmission expansion candidates	11 projects totaling 18 GW (238 GW-miles)	8 projects totaling 12 GW (166 GW-miles)	11 projects totaling 16 GW (526 GW-miles)
Generation nameplate capacity	431 GW	418 GW	537 GW
Total storage capacity	252 GWh	328 GWh	1,090 GWh

Inter-zonal transmission builds, generation nameplate capacity, and energy storage capacity—all results of long-term capacity expansion modeling—illustrate the key differences between the studied scenarios.

Source: Energy Systems Integration Group.

resulting from the timing and size of DG adoption has the potential to similarly impact the timing and size of transmission needs. This result is sensitive to the location, capacity, design, and participation behavior of distributed generators and batteries.

At moderate levels, distributed generation adoption could cause certain inter-zonal transmission investments to be delayed or avoided.

The three study scenarios differed significantly from each other in terms of transmission, generation, and battery capacities at the end of the study horizon in 2040. The results from the LTCE modeling indicated that, although DG above present-day trajectories could cause certain inter-zonal transmission to be delayed or avoided, significant additional inter-zonal transmission capacity will be needed in addition to projects planned in the near-term under all future scenarios.

Relative to the centralized scenario, the hybrid scenario, which has a DG adoption rate double that of the study's status quo (centralized) trajectory from 2031 onward, required about 30% less inter-zonal transmission in terms of both GW and GW-miles as shown in Table 13. The hybrid scenario also exhibited a lower overall generation nameplate capacity than the centralized scenario but required about 30% more storage capacity. These comparisons between the centralized and hybrid scenarios support the finding that DG above present-day trajectories could cause certain inter-zonal transmission to be delayed or avoided. However, the results also indicated that significant inter-zonal transmission expansion was required under all scenarios, and high levels of DG actually resulted in higher GW-miles of inter-zonal transmission investments.

Results from the LTCE modeling indicated that, although DG above present-day trajectories could cause certain inter-zonal transmission to be delayed or avoided, significant additional inter-zonal transmission capacity will be needed in addition to projects planned in the near-term under all future scenarios.

The status-quo (centralized) and accelerated (hybrid) distributed generation adoption scenarios shared many common inter-zonal transmission investments.

Notably, the eight inter-zonal transmission candidates selected in the hybrid scenario were also all selected in the centralized scenario, though often in different years. The centralized scenario required three additional inter-zonal transmission projects—for a total of 11 projects—that were not required in the hybrid scenario. These three projects were avoided in the hybrid scenario during the study horizon because of the increased DG levels in this scenario. It is important to note that DG adoption rates and locations were fixed as an input; however, DG capacity in the hybrid scenario was scaled in the same relative locations as the centralized scenario. Therefore, the sensitivity of this finding to the relative locations of DG was not explored.

The commonality between the selected inter-zonal transmission candidates in the centralized and hybrid scenarios indicates the opportunity for "least-regrets" transmission investments in futures with DG adoption rates near or above status-quo trajectories.

In contrast, the distributed scenario displayed significantly less commonality, featuring unique projects and timings for its transmission portfolio. Consideration of the distributed scenario leads to the study's final finding.

High levels of distributed generation could increase the need for inter-zonal transmission investment.

While significant inter-zonal transmission is selected in all three study scenarios, the transmission built in the distributed scenario was almost double that of the centralized scenario as measured by GW-miles. The large increase in transmission GW-miles in the distributed scenario illustrates the need for longer lines to help transport high levels of solar and balance the system between regions where existing inter-zonal capacity is limited. The distributed scenario also required more than four times the storage capacity of the centralized scenario, although these two scenarios met the same system planning and policy requirements over the study horizon.

Therefore, distributed generation and storage alone may not reduce the need for transmission investments. Much of the transmission built in the distributed scenario was built later in the study horizon—when clean energy policy constraints forced the model to serve an increasing percentage of system load with non-emitting resources.

The commonality between the selected inter-zonal transmission candidates in the centralized and hybrid scenarios indicates the opportunity for "least-regrets" transmission investments in futures with distributed generation adoption rates near or above status-quo trajectories.

Unlike the other two scenarios, the distributed scenario was free to build distributed solar and storage in locations determined by the model. Thus, the location, timing, and magnitude of both distributed generation and transmission builds differed significantly from the centralized and hybrid scenarios. Our examination of the distributed scenario results highlighted that the need for transmission investment was sensitive to the location, timing, and magnitude of distributed generation builds.

In aggregate, these findings highlight the complex trade-offs between investments in distributed generation, storage, and bulk transmission in the Western Interconnection. Indeed, DGRs could change flows on inter-zonal transmission infrastructure and even potentially defer or eliminate certain future inter-zonal transmission infrastructure investments, but the need for such investments is sensitive to many other factors. The findings also make clear that while moderate levels of DG could help to reduce bulk-scale transmission investment, the need for such investment is not eliminated or significantly reduced.

This study highlights the critical nature of forecasted capacities, locations, and operational behaviors of DG and storage as part of integrated transmission planning efforts. The results suggest the potential benefits of simultaneously planning for transmission, DGRs, and utility-scale resources in order to optimize power planning outcomes.

There is no single solution in the pursuit of achieving long-term system needs and clean energy policy goals, only trade-offs. More detailed engineering and economic assessments should be performed to explore these trade-offs in specific contexts.

Finally, this study reinforces the perspective that there is no single solution in the pursuit of achieving long-term system needs and clean energy policy goals, only trade-offs. More detailed engineering and economic assessments should be performed to explore these trade-offs in specific contexts. This study is intended to be illustrative and exploratory in nature; the scenarios considered were approximations of future outcomes relating to different levels of DG. While many realistic system constraints were included in this modeling, much more analysis including a nodal topology would be required to inform investment decisions.

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PHOTOS

Modeling the Effects of Distributed Generation on Transmission Infrastruture Investment: A Western Case Study

A Report of the Energy Systems Integration Group's DER-Transmission Project Team

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The report is available at https://www.esig.energy/distributed-generation-impact-on-transmission/.

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