# Better Together: The Benefits of Coordination in the Development of Transmission and Distributed Energy Resources

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# Table of Contents

# Executive Summary

For jurisdictions across the United States to deeply decarbonize their grids, achieve their policy goals, and meet the climate challenge, an energy transformation of unprecedented speed and scale will be needed. The United States must increase the pace of clean energy development and build the infrastructure to deliver that energy where it is needed. Expanding the high-voltage transmission system, coupled with large-scale generation and energy storage, has been widely discussed as a central strategy for doing so. Across the country, however, the pace of new transmission development has not kept up with the expansion in clean energy generation, resulting in existing renewable resources being curtailed and ever-growing interconnection queues for new clean resources looking to connect to the grid. This reality poses a serious threat to achieving clean energy goals, with multiple expert studies indicating the United States will need to rapidly accelerate the pace of transmission development to meet both near-term and midcentury goals. However, progress is being made to build much-needed transmission. On May 13, 2024, the Federal Energy Regulatory Commission (FERC) released FERC Order No. 1920, which directs Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to conduct long-term, scenario-based regional transmission planning that expands consideration of the drivers of needed transmission and evaluates a wider range of benefits. Additionally, the order reforms the process by which states agree on cost allocation for transmission projects and requires consideration of advanced transmission technologies in Long-Term Regional Transmission Planning.

Even as large-scale resources remain critical to the energy transition, distributed energy resources (DER) – resources connected to the distribution system close to the load, such as distributed photovoltaics, small-scale wind, combined heat and power, microgrids, energy storage, and diesel generators, amongst others – continue to gain in popularity for their ability to meet customer needs, reduce customer energy costs, and contribute to clean energy goals while encouraging customer participation in the energy system. As DER deployment grows, it also has the effect of reducing net loads and relieving grid constraints. In fact, in some cases, DERs have been able to successfully defer or completely avoid the need for new transmission investments. Customer interest in DERs, evidenced by a growing number of distributed solar and storage systems and the expansion of innovative aggregation models like virtual power plants, drives home the vital role they are playing in the clean energy transition.

Historically, because transmission and DERs exist on opposite ends of the electricity system, they have often been planned, developed, and operated in siloes. Moreover, conversations on the interplay between transmission and DERs often focus on these resources as substitutes for each other rather than acknowledging the ways they can work in concert to achieve clean energy goals. At a time of rapid grid evolution, reimagining the relationship between transmission and DERs is needed to help strengthen grid reliability and resilience, increase efficiencies in grid planning and operations, and advance progress toward clean energy goals. This report explores the need for, and benefits of, both transmission and DER development. It then focuses on the need for coordination between transmission and DERs and demonstrates the many ways these resources can complement each other to meet the growing need for clean energy. This report uses both qualitative and quantitative case studies from regions at the center of the transmission-DER nexus—Australia, Hawaii, and Southern California—to demonstrate real-world examples of the coordination between these resources. In addition, the Southern California case study presents the results of a forward-looking, scenario-based analysis, which demonstrates the interdependence between transmission and DERs that will be necessary as DER deployment in Southern California increases between 2024 and 2035. Across this analysis and the case studies, Strategen finds the following:

- Research, policy frameworks, grid planning approaches, and public discourse on the interplay between DERs and transmission typically focus on the ability of DERs to reduce, defer, or completely avoid the need for transmission investment by acting as "non-wires alternatives" or "non-transmission alternatives." Other elements of the transmission-DER nexus are comparatively underexplored and underappreciated.

- Multiple states, including Hawaii, have established frameworks to explore the potential of DERs to function as non-transmission alternatives to conventional transmission projects. DERs have already successfully played this role in multiple proposed transmission projects. Still, their ability to do so depends significantly on reducing load both at the right time and the right place. It should not always be assumed that DERs can substitute for transmission, meaning large transmission investments are still needed to meet clean energy goals.

- The discourse on the transmission-DER nexus typically leaves out the ways that the transmission system can support DER growth. With a growing number of DERs, proactive investments in transmission infrastructure and the transmission-distribution interface (e.g., substations) can increase the distribution grid's hosting capacity for additional DERs and enable the export of distributed renewable energy onto the transmission grid. Without such investment, continuing DER deployment may result in negative safety or reliability impacts on local systems.

- Novel approaches to DER management are needed to mitigate any safety and reliability risks and provide transmission system operators with greater visibility into DERs on their system. DER management systems and aggregation mechanisms, which are well established in regions including Australia, can enable more seamless consideration of DERs in transmission-level planning and operations.

- In regions with high DER deployment and limited spare transmission capacity, renewable energy generated by DERs may be wasted if no incremental transmission investments are made to transport this energy during times of overgeneration.

- In Southern California, which has an increasingly large amount of customer rooftop solar, modeling for this report by Strategen demonstrates that a substantial portion of the region's rooftop solar energy could be curtailed in the future absent new transmission capacity to export that energy elsewhere.

- Strategen's modeling shows the potential for local DER overgeneration to surpass available transfer capability out of Southern California by 2035 under the baseline DER deployment assumptions, and as early as 2030, assuming more aggressive DER deployments are realized.

- The analysis shows that using transmission to link load centers together can be critical to transform DERs from a local energy source that is prone to overgeneration, to assets that can provide energy beyond their neighborhoods, adding flexibility to the overall system.

- The potential for distributed energy to be exported across the transmission grid calls for a rethinking of grid planning approaches. The transmission discussion, as it relates to increasing renewables deployment, has typically focused on connecting remote generation sources to load centers, rather than thinking of the ways that load centers can themselves be generation hubs via DERs. Using transmission to connect load centers can help mitigate the risk of DER overgeneration and enable DERs to provide energy beyond their immediate neighborhoods, contributing to overall grid flexibility.

Based on these findings, the following conclusions for policymakers, regulators, and market operators are meant to strengthen investment in both transmission and DERs and enhance the coordination between these two vital resources:

- **Engage in comprehensive planning:** Market operators, transmission owners, and distribution system operators should work to establish comprehensive planning efforts that enable coordination between DERs and transmission, including consideration of non-wires alternatives to meet transmission needs.

- **Consider the benefits that transmission may create for DERs within the transmission approval process:** Consider requiring transmission approval processes to assess, when applicable, the broader benefits of new transmission on DERs, such as increased DER utilization and regional reliability gains.

- **Proactively plan for new transmission development:** When evaluating areas for transmission development, market operators, transmission owners, and state agencies should consider prioritizing linking load centers to areas with significant variable renewable energy potential and to each other.

- **Improve DER visibility and control:** Distribution system operators, regulators, and policymakers should consider the development of requirements to promote better visibility of DERs, automatic grid-responsiveness[1], safety, and system operator control.

- **Bolster aggregation frameworks that allow DER participation in wholesale energy markets:** To leverage the capabilities and benefits of DERs, market operators, policymakers, and regulators should build upon, and expedite meeting, the requirements of FERC Order 2222 by way of enhanced collaboration to develop workable market participation schemes that support DER aggregation, allowing them to participate unencumbered in wholesale electricity markets. In delaying their implementation of FERC Order 2222 (e.g., Midcontinent Independent System Operator (MISO) until 2029, California Independent System Operator (CAISO) the earliest with partial implementation in late 2024), ISOs and RTOs argued that Order 2222 implementation is a long and complicated process. Early implementation proposals by ISOs/RTOs have seen third-party aggregator criticism around state jurisdictional challenges in the Midwest and that proposals favor existing distribution utilities.

[1] Automatic grid-responsiveness is the use of smart inverters to automatically react to grid conditions, injecting or absorbing reactive power (volt/VAR control) or real power (volt/watt control).

# Introduction: The Growing Need for Clean Energy

As the impacts of climate change become more widespread and severe, the need for a transition to a zero-carbon economy has never been more urgent. In the United States, the rapid deployment of zero-carbon electricity generation and energy storage will be among the most critical steps toward economy-wide decarbonization. The power sector plays a central role in decarbonization due both to its significant greenhouse gas emissions (the second-largest emitting sector in 2021) and its contribution to the decarbonization of other sectors of the economy through the rise of end-use electrification.[2] With the electrification of transportation, industry, and commercial and residential building systems, the power sector faces two key challenges: producing and delivering *more* electricity than ever before and doing so *cleaner* than ever before.

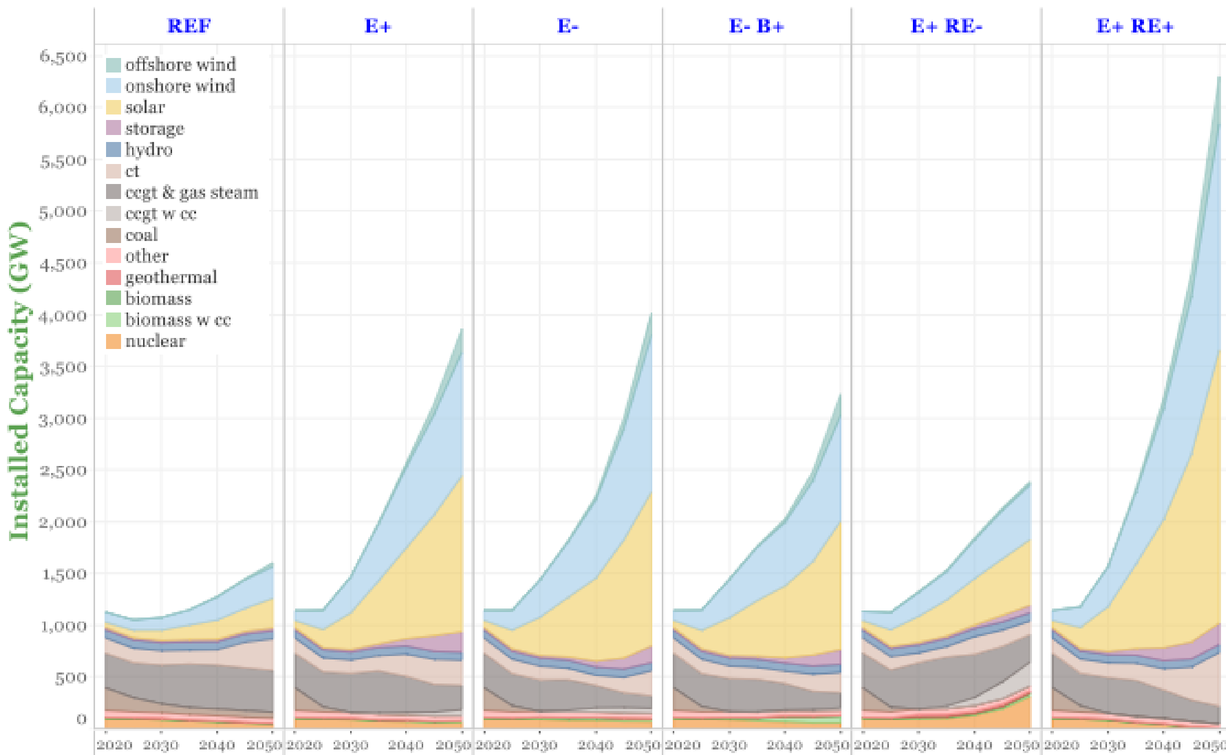
The Energy Information Administration's (EIA) 2023 Annual Energy Outlook documents the expected increase in electric demand across sectors in the coming decades. Between 2022 and 2050, EIA estimates consumption of purchased electricity will increase by 14% to 22% in the residential sector; 3% to 38% in the industrial sector; and an astounding 892% to 2,028% in transportation.[3] As a result of this increasing demand for electricity, EIA predicts that the United States' total installed power capacity will close to double between 2022 and 2050 across nearly all scenarios analyzed.[4] Solar photovoltaic (PV) generation, in particular, is expected to increase significantly, with generating capacity skyrocketing from 325% to 1,019% by 2050. Wind capacity is also expected to grow rapidly, with nameplate deployments increasing from 138% to 235% in the same period.

While the anticipated growth across the scenarios presented above is substantial, it is important to underscore that these figures assume current policy; they do not necessarily explore futures that align with economywide decarbonization, which will require even greater amounts of incremental zero-carbon generation and energy storage. To achieve President Biden's goal of a zero-carbon grid by 2035, the National Renewable Energy Laboratory (NREL) predicts that total electricity generation (for both direct use and for hydrogen production) would need to increase by 95% to 135% between 2020 and 2035.[5] Overall generation capacity would have to grow even more, roughly by a factor of three. The result is 43-90 GW of

[2] "Sources of Greenhouse Gas Emissions," U.S. Environmental Protection Agency, last modified November 16, 2023, https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions#t1fn3; "FAQ: What Is U.S. Electricity Generation by Energy Source?," U.S. Energy Information Administration, last modified October 20, 2023, https://www.eia.gov/tools/faqs/faq.php?id=427&t=3#.
[3] EIA.gov, "Annual Energy Outlook 2023," U.S. Energy Information Administration, 2023, https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Narrative.pdf.
[4] Ibid.
[5] Denholm, P. Brown, P. Cole, W. Sergi, B. "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035," National Renewable Energy Laboratory, 2022, https://www.nrel.gov/docs/fy22osti/81644.pdf.

new solar development required annually by the end of the decade, with 70-145 GW/year of wind—a roughly quadrupling of current deployment levels.[6] Looking out to 2050, the Princeton University Net-Zero America report estimates installed solar capacity will need to be 9-39 times larger than 2020 and installed wind capacity 6-28 times larger to meet net-zero goals.[7] While the amount of incremental capacity needed to reach clean energy goals varies slightly by study (depending on their methods and the scenarios analyzed), it is clear that the challenge of decarbonizing the grid will require thousands of megawatts deployed across the country at an unprecedented pace.

**Figure 1. Estimates of Installed Power Capacity Required to Reach Net-Zero by 2050.**




*This shows the expansion in installed power capacity required to meet net-zero emissions by 2050 in the United States, estimated by the Princeton University Net-Zero America report. In this figure, "CT" refers to combustion turbines, "CCGT" refers to combined cycle gas turbines, "CC" refers to carbon capture, "E" refers to electrification, "B" references biomass supply, and "RE" refers to renewable energy. The leftmost column (REF) displays the reference case (based on the EIA's 2019 Annual Energy Outlook), while the five columns to the right display various pathways to net zero, with differing assumptions around end-use*

[6] EIA.gov, "Annual Energy Outlook 2023," U.S. Energy Information Administration, 2023, https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Narrative.pdf.

[7] Larson, E. Greig, C. Jenkins, J. Mayfield, E. Pascale, A. Zhang, C. Drossman. J. Williams, R. Pacala, S. Socolow, R. "Net-Zero America: Potential Pathways, Infrastructure, and Impacts," Princeton University, 2020, https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf.

*electrification, biomass availability, and renewable energy supply. Importantly, all scenarios would require significant expansion of solar and wind capacity by 2050. The rightmost scenario assumes aggressive end-use electrification and excludes any new nuclear, carbon dioxide capture and sequestration, or fossil fuel use in 2050, resulting in the most aggressive wind and solar buildout.*

*Source: Eric Larson et al., Net-Zero America: Potential Pathways, Infrastructure, and Impacts, 2021.*

While the need for incremental capacity in the coming decades may seem daunting, renewable energy generation is already rapidly expanding to meet this challenge. In 2023, solar represented half of the U.S. generating capacity added to the grid, with wind following as the second largest resource contributing to new capacity.[8] Electricity generation from renewables overall (including hydropower, biomass, and geothermal) now surpasses both coal-fired generation and nuclear generation.[9]

Accelerating the deployment of renewable generation and energy storage across the United States to meet climate goals necessitates using every tool in the toolbox, including both large-scale and distributed approaches. At the bulk system level, transmission infrastructure is a vital component of getting increasing amounts of renewable energy from the places in which the sun shines and the wind blows to load centers where most people live and work. Transmission has been described as the linchpin to the United States being able to meet its clean energy goals, with experts noting that a lack of sufficient transmission investment could make achieving the country's climate goals virtually impossible.[10] Distributed energy resources (DER)—such as distributed solar and storage, energy efficiency, demand response, and electric vehicles— sit on the other end of the electricity system, close to load centers, and are seeing significant growth, driven in part by federal and state incentives, but also by ever-improving cost and performance.[11] DERs have strong potential to accelerate renewable energy generation absent new transmission and can also reduce loads while giving customers more agency in the clean energy transition.

At present, transmission and DERs are typically discussed and planned for within their own siloes. This separation has created the perception that transmission and DERs are independent goods or strategies. In extreme cases, they are even viewed as being in tension with each

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[8] Beth Anton, "Solar Was Half of US Capacity Additions in 2023," *Renewable Energy Magazine*, February 20, 2024, https://www.renewableenergymagazine.com/pv_solar/solar-was-half-of-us-capacity-additions-20240220.

[9] Katherine Antonio, "Renewable Generation Surpassed Coal and Nuclear in the U.S. Electric Power Sector in 2022," *U.S. Energy Information Administration*, March 27, 2023, https://www.eia.gov/todayinenergy/detail.php?id=55960.

[10] Diana DiGangi, "US Won't Reach Net Zero Emissions Without Transmission Buildout: DNV," *Utility Dive*, September 25, 2023, https://www.utilitydive.com/news/net-zero-transition-clean-energy-north-america-transmission-buildout/694621/; Jesse Jenkins et al., *Electricity Transmission is Key to Unlock the Full Potential of the Inflation Reduction Act* (Princeton, NJ: REPEAT Project, 2022), https://repeatproject.org/docs/REPEAT_IRA_Transmission_2022-09-22.pdf.

[11] Ben Hertz-Shargel, "Distributed Energy Is Poised to Take Center Stage in 2022, but Policymakers and Regulators Must Step Up," *Utility Dive*, February 4, 2022, https://www.utilitydive.com/news/distributed-energy-is-poised-to-take-center-stage-in-2022-but-policymakers/618331/.

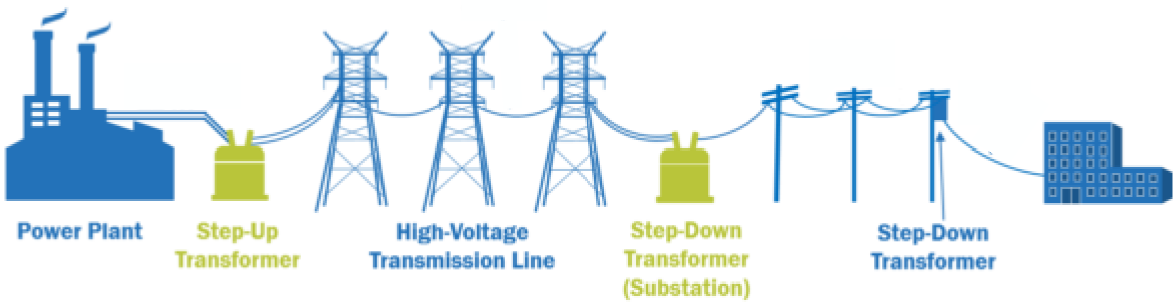
other. While some voices in the energy sector argue the development of DERs can reduce or eliminate the need for new transmission buildout, others insist on the necessity of transmission and overlook the potential of DERs' contribution to a decarbonized grid. Because energy planning today rarely addresses these two critical resources in tandem, this serves to reinforce said siloes.

To address this issue, this report aims to demonstrate that transmission and DER deployments are complementary solutions. It also seeks to capture the need for, and promise of, transmission and DER investments and explores strategies for these resources' mutual development and coordination. The report is divided into three parts. First, it introduces both transmission and DERs, outlining the need for investment in both these resources, the benefits they offer, and the challenges that must be overcome to maximize their role in the clean energy transition. Then, the report offers case studies from regions with diverse approaches to planning for the transmission-DER nexus: Australia, Hawaii, and Southern California. The Southern California case study also details findings from a Strategen analytical modeling exercise that explored the benefits of increased coordination between transmission and DERs in the region. Finally, the report concludes with recommendations and best practices to enable deeper planning coordination between DER and transmission investments in support of the country's clean energy goals.

# Transmission and the Value It Presents

In the electric power sector, the transmission system is responsible for moving electricity over long distances, from where power is produced to close to where it is used (see Figure 2). Transmission lines operate at high voltages, typically 100 kilovolts (kV) or higher, and connect to substations where the electricity's voltage is stepped down before it passes through the distribution system and to customers connected to the local distribution grid. The transmission system uses high voltages to minimize losses, thus reducing costs for ratepayers and ensuring energy access across great distances.

Figure 2. The transmission of electricity




*Source: "Line Losses: Overlooked and Often Misunderstood," Constellation, June 30, 2020, https://blogs.constellation.com/energy-management/line-losses-overlooked-and-often-misunderstood/.*

In some regions of the United States, the transmission system is controlled by regional organizations called independent system operators (ISOs) or regional transmission organizations (RTOs), which, despite distinct names, occupy virtually identical roles. These ISOs and RTOs are overseen by the Federal Energy Regulatory Commission (FERC), which also regulates rates for transmitting electricity across state lines and can permit the siting of transmission lines in areas designated as being in the national interest, provided certain conditions are met.

The need for additional transmission capacity has been a central topic of conversation at the federal level recently, with regulatory agencies and Congress taking multiple actions to expand and accelerate transmission development.[12] The Infrastructure Investment and Jobs Act (IIJA) and Inflation Reduction Act (IRA) both included significant financing to facilitate

[12] "FACT SHEET: The Biden-Harris Administration Advances Transmission Buildout to Deliver Affordable, Clean Electricity," The White House, November 18, 2022, https://www.whitehouse.gov/briefing-room/statements-releases/2022/11/18/fact-sheet-the-biden-harris-administration-advances-transmission-buildout-to-deliver-affordable-clean-electricity/.

transmission investments.[13] In this context, the time is ripe to consider how transmission investments can be better coordinated with other energy infrastructure, including the deployment of DERs.

## The Need for Transmission Investment

As the United States has accelerated its pace of renewable energy buildout, it has become increasingly clear that meeting clean energy goals will require a corresponding buildout in the nation's transmission infrastructure. A considerable portion of the country's most viable wind and solar resources are situated far from existing transmission infrastructure and major population centers, requiring the construction of new transmission lines to fully utilize the best solar and wind resources in these areas.[14] Despite this, the number of newly constructed high-voltage transmission lines has decreased over the past decade. According to the U.S. Department of Energy (DOE), the annual average of newly built transmission lines declined from 2,000 miles between 2012 and 2016 to 700 miles between 2017 and 2021.[15]
The impact of this stalled transmission investment is evident in the growing backlog of renewable energy and energy storage projects waiting to come online in interconnection queues. Interconnection is the process whereby grid operators require projects seeking to connect to the grid to undergo impact studies to ensure the grid's safety, stability, and reliability when integrating new assets. This process determines the transmission upgrades necessary before a project can connect, and it assigns the costs associated with any required transmission interconnection upgrades to the applicable project owner.

As of 2023, interconnection queues across the country held more than 1,570 gigawatts (GW) of solar, wind, hydropower, geothermal, and nuclear capacity, along with 1,030 GW of energy storage.[16] These figures represent roughly the entire installed capacity of the existing U.S. generation fleet and, if built, would exceed the amount needed to reach a 90% zero-carbon grid by 2035.[17]

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[13] Richard Campbell, *IIJA: Efforts to Address Electric Transmission for Reliability, Resilience, and Renewables* (Washington, D.C.: Congressional Research Service, 2021), https://crsreports.congress.gov/product/pdf/IN/IN11821; Ashley Lawson, *Electricity Transmission Provisions in the Inflation Reduction Act of 2022* (Washington, D.C.: Congressional Research Service, 2022), https://crsreports.congress.gov/product/pdf/IN/IN11981.
[14] Nadia Christakou et al., "Renewable-Energy Development in a Net-Zero World: Land, Permits, and Grids," *McKinsey & Company*, October 31, 2022, https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/renewable-energy-development-in-a-net-zero-world-land-permits-and-grids.
[15] *Queued Up... But in Need of Transmission* (Washington, D.C.: U.S. Department of Energy, 2022), https://www.energy.gov/sites/default/files/2022-04/Queued%20Up%E2%80%A6But%20in%20Need%20of%20Transmission.pdf.
[16] Joseph Rand et al., *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2023* (Berkeley, CA: Lawrence Berkeley National Laboratory, 2023), https://emp.lbl.gov/publications/queued-2024-edition-characteristics.
[17] Ibid.

The interconnection queue backlog demonstrates the private sector's enthusiasm for further renewable energy and energy storage development, underscoring the readiness of these technologies and their cost-effectiveness. Nevertheless, the size of these queues is also a symptom of a more significant problem for the United States: insufficient transmission lines supporting the transition from a fossil fuel-based electricity system to a decarbonized one. Numerous studies indicate the country will have to rapidly accelerate its pace of transmission investment to reach climate goals. The Princeton University REPEAT Project, for instance, estimates that the pace of transmission expansion needs to double compared to the last decade to meet the need for renewable resource interconnection and electrification, with the emissions reduction potential of the IRA being dependent on expanding transmission capacity.[18]

## Transmission Benefits

Transmission infrastructure is not only crucial for reaching climate goals. The transmission system offers numerous other important benefits for the U.S. grid and consumers by connecting regions of the country together for lower cost, cleaner, and more reliable power.

Central benefits associated with transmission include:

- **Providing reliability and resilience:** By facilitating power transfer across regions, transmission infrastructure can allow states to access additional generation during events where local generation is insufficient or unavailable. In 2019, for instance, a polar vortex affecting the Midwest led to high demand for power and natural gas, necessitating electricity imports from other regions to meet local system needs. Power imports via transmission from other regions ultimately supplied 9% of the load in a single day and offered essential relief to local systems.[19] In the event of wide-area blackouts, transmission can also help with system restoration and recovery using generating resources located far from the disruption.[20] Conversely, a lack of transmission infrastructure can have severe consequences. Minimal interregional transmission capacity connecting Texas to neighboring states in the Southeast was identified as a significant factor in the grid outages triggered by Winter Storm Uri in 2021. One analysis found that each additional gigawatt of transmission capacity

[18] Jesse Jenkins et al., *Electricity Transmission is Key to Unlock the Full Potential of the of the Inflation Reduction Act*.
[19] *Report on Barriers and Opportunities for High Voltage Transmission* (Washington, D.C.: Federal Energy Regulatory Commission, 2020), https://www.congress.gov/116/meeting/house/111020/documents/HHRG-116-II06-20200922-SD003.pdf.
[20] *Report on Barriers and Opportunities for High Voltage Transmission.*

between Texas and surrounding states could have kept the heat on for approximately 200,000 Texas homes during the storm and saved nearly $1 billion.[21]

- **Maximizing renewable energy penetration:** Without sufficient transmission capacity, transmission lines can become congested by the amount of generation resources attempting to access them, much like traffic on a busy road. This issue is of particular concern for variable resources such as wind and solar, given the fact that these resources are not dispatchable and are generated only when the sun shines or the wind blows. As a result, wind and solar projects that are interconnected to congested nodes may need to curtail their output at certain times. Renewable curtailment is anticipated to increase in many locations without additional transmission capacity. For example, a lack of long-distance transmission lines connecting renewable energy projects to load centers in Texas results in roughly 1.5-5% of all wind and solar generation in the state being curtailed as of 2021.[22] Concerningly, a 2022 study predicted this number will grow to 20-28% by 2030 absent transmission upgrades.[23] In addition, multiple studies have shown that interstate transmission investments will result in significant cost savings in achieving a high clean energy grid, relative to state-by-state approaches or business-as-usual.[24]

- **Creating jobs:** Investment in transmission infrastructure can expand the clean energy workforce by providing quality jobs. A 2020 study by Americans for a Clean Energy Grid found that significantly expanding renewable energy and accompanying transmission infrastructure in the Eastern Interconnection (one of two main grids in the North American power transmission grid, synchronized at 60 Hz, roughly everything east of the Midwest U.S., not including Texas ) would provide 1.5 million net new jobs in the transmission sector alone.[25] The job potential from a nationwide transmission buildout would be even greater, with benefits concentrated in the construction and manufacturing sectors.

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[21] Michael Goggin, *Transmission Makes the Power System Resilient to Extreme Weather* (Washington, D.C.: ACORE, 2021), https://acore.org/resources/transmission-makes-the-power-system-resilient-to-extreme-weather/.
[22] Derek Stencilik and Ryan Deyoe, *Multi-Value Transmission Planning for a Clean Energy Future* (Reston, VA: Energy Systems Integration Group, 2022), https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf.
[23] Derek Stencilik and Ryan Deyoe, Multi-Value Transmission Planning for a Clean Energy Future.
[24] Patrick Brown and Audun Botterud, "The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System," Joule 5, no. 1: 115-134, (January 2021), https://doi.org/10.1016/j.joule.2020.11.013; Christopher Clack, "The Role of Transmission in Deep Decarbonization" (presentation, Energy Systems Integration Group webinar, March 22, 2021), https://vibrantcleanenergy.com/wp-content/uploads/2021/03/VCE-ESIG03222021.pdf.
[25] It is important to note the report does not distinguish between short-term and more permanent jobs and accordingly, this number may be an overestimate of long-term employment gains. Christopher Clack et al., Consumer, Employment and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S. (Arlington, VA: Americans for a Clean Energy Grid, 2020), https://cleanenergygrid.org/wp-content/uploads/2020/11/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S.pdf.

- **Minimizing consumer costs:** The transmission system helps lower consumers' energy costs by allowing regions to source electricity from where power is cheapest. For instance, a hypothetical transmission line that connects California with low-cost wind resources in the Rocky Mountains was found to offer California consumers significant savings on utility bills in a 2020-modeled study. The line was projected to result in $500 million in consumer savings the year operations began, ramping up to $1.5 billion in annual savings by 2035.[26] Unfortunately, the constraints in transmission capacity today result in unnecessary costs to consumers. In 2022, market congestion from insufficient transmission was estimated to cost U.S. ratepayers $20.8 billion, a 56% increase from 2021.[27]

Overall, the combination of cost savings, reliability benefits, and societal gains associated with transmission development mean that ratepayers often get a high return on transmission investments. For instance, the Midcontinent Independent System Operator (MISO) estimated that investing $10.4 billion in new transmission projects through the first round of its Long-Range Transmission Planning (LRTP) process would provide $37 billion in financially quantifiable benefits over 20 years.[28]

## Transmission Challenges

While the transmission system offers numerous benefits to consumers and society, developing transmission infrastructure is a notoriously challenging process. The slowing pace of transmission development in recent years is unmistakable evidence of this difficulty. Many of the challenges with transmission projects stem from their large size and footprint, meaning projects often require significant regional coordination, financing, community outreach, environmental analysis, and time to complete. Some of the central challenges associated with transmission include:

- **Costs and cost allocation:** Transmission projects are capital-intensive, often costing millions of dollars per mile.[29] Who exactly should bear the costs of a transmission upgrade or expansion has been a topic of contention. Historically, a key principle in transmission cost allocation has been that whoever benefits should pay, what is known

[26] Julia Frayer et al., How Does Electric Transmission Benefit You? (Washington, D.C.: WIRES, 2018), https://wiresgroup.com/wp-content/uploads/2020/06/2018-01-08-London-Economics-Intl-How-Does-Electric-Transmission-Benefit-You.pdf.
[27] Richard Doying, Michael Goggin, and Abby Sherman, Transmission Congestion Costs Rise Again in U.S. RTOs (Washington, D.C.: GridStrategies LLC, 2023), https://gridstrategiesllc.com/wp-content/uploads/2023/07/GS_Transmission-Congestion-Costs-in-the-U.S.-RTOs1.pdf.
[28] Midcontinent Independent System Operator, "LRTP Tranche 1 Portfolio Detailed Business Case" (presentation, LRTP workshop, March 29, 2022), https://cdn.misoenergy.org/20220329%20LRTP%20Workshop%20Item%2002%20Detailed%20Business%20Case623671.pdf.
[29] Cara Marcy, "EIA Study Examines the Role of High-Voltage Power Lines in Integrating Renewables," *U.S. Energy Information Administration*, June 28, 2018, https://www.eia.gov/todayinenergy/detail.php?id=36393.

as FERC's "beneficiary pays" principle. While seemingly straightforward, this rationale gets complicated when considering the wide array of beneficiaries—often geographically dispersed—who could benefit from new transmission, especially if that transmission provides widespread social benefits like reduced greenhouse gas emissions. As a result, attributing costs across the range of actors involved in transmission projects can be contentious.[30] In some RTOs and ISOs, for instance, transmission upgrade costs are assigned nearly exclusively to the project developer responsible for triggering those costs, even if others would benefit from such upgrades.[31] Federal action may help address this challenge. In April 2022, FERC began a rulemaking process to consider changes to the way it evaluates the benefits of transmission and accordingly allocates cost.[32] As of the time of writing, this rulemaking was still ongoing.

- **Siting challenges:** Siting a transmission line and getting the required approvals from impacted parties and permits from local, state, and federal agencies are often the most challenging and time-consuming parts of developing transmission projects. Projects can require permission from hundreds of affected landowners, many of whom may be concerned about reductions to property value, the need for fair compensation, visual impacts, perceived health impacts, loss of land use, and other factors.[33] Transmission projects may also impact communities that have already been disproportionately burdened by the energy system; effective planning, environmental justice analyses, and early community engagement are needed to ensure transmission siting does not exacerbate these burdens.[34] Siting concerns are not just limited to community impacts. Projects must also consider potential environmental impacts, including impacts to water, species, and historic land, all of which can influence where a project is proposed and if it is permitted.[35]

- **Regional coordination:** Transmission projects are often regional by their nature and can necessitate coordination across different RTOs/ISOs, state utility commissions,

[30] Catherine Clifford, "Why It's So Hard to Build New Electrical Transmission Lines in the U.S.," *CNBC*, February 22, 2023, https://www.cnbc.com/2023/02/21/why-its-so-hard-to-build-new-electrical-transmission-lines-in-the-us.html.
[31] Vish Sankaran, Himali Parmar, and Ken Collison, Just and Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits (Washington, D.C.: ACORE, 2021), https://acore.org/wp-content/uploads/2021/10/Just_and_Reasonable.pdf.
[32] Ethan Howland, "FERC Proposes Expanded State Role in Effort to Spur Transmission Development," *Utility Dive*, April 22, 2022, https://www.utilitydive.com/news/ferc-state-transmission-planning-cost-allocation/622532/.
[33] Lucas Davis, Catherine Hausman, and Nancy Rose, "Transmission Impossible? Prospects for Decarbonizing the US Grid," *Journal of Economic Perspectives* 37, no. 4 (Fall 2023): 155-80, https://doi.org/10.1257/jep.37.4.155https://haas.berkeley.edu/wp-content/uploads/WP338.pdf; Samantha Gross, *Renewables, Land Use, and Local Opposition in the United States* (Washington, D.C.: Brookings Institution, 2020), https://www.brookings.edu/wp-content/uploads/2020/01/FP_20200113_renewables_land_use_local_opposition_gross.pdf.
[34] Christine Powell et al., "Environmental Justice and Electric Transmission Development," (presentation, State Energy & Environmental Impact Center webinar, May 31, 2023), https://stateimpactcenter.org/news-events/events/environmental-justice-transmission-development.
[35] Lucas Davis, Catherine Hausman, and Nancy Rose, "Transmission Impossible? Prospects for Decarbonizing the US Grid."

utilities, and agencies, making complete consensus on projects a significant challenge.[36] Not all states may benefit equally from transmission development; projects may pass through states with low population density to connect renewable resources to load centers in other states. Those states that do not benefit from the power may have little incentive to support a project.[37] The patchwork of legal frameworks across states can also create complications. For instance, some states allow the use of eminent domain for transmission projects while others do not,[38] and states also differ in how they evaluate whether a transmission project is in the public interest.[39] While regional coordination on transmission is a challenge, there are positive examples of state-to-state collaboration. MISO's LRTP process, for instance, involved state governments from across the region, in addition to other stakeholders, to develop a slate of high-priority transmission investments across nine states.[40]

- **Time to project completion:** The combination of the challenges detailed above means that transmission projects often take upwards of a decade from ideation to completion, in the event they are completed at all. In extreme cases, projects can take far longer; the TransWest Express project connecting Wyoming wind with demand centers in Nevada, Arizona, and California, for instance, was initiated in 2005, entered the permitting pipeline in 2007, and will finish construction in 2027.[41] These years-long processes must be sped up to achieve the rapid decarbonization of the U.S. power grid.

Given these myriad challenges, the search for alternatives to transmission infrastructure has become increasingly appealing. Distributed energy resources (DERs) have emerged as an attractive option to add renewable energy to the grid while minimizing the need for costly and time-intensive transmission projects.

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[36] Lucas Davis, Catherine Hausman, and Nancy Rose, "Transmission Impossible? Prospects for Decarbonizing the US Grid."
[37] Samantha Gross, *Renewables, Land Use, and Local Opposition in the United States.*
[38] Samantha Gross, *Renewables, Land Use, and Local Opposition in the United States.*
[39] *Report on Barriers and Opportunities for High Voltage Transmission.*
[40] Jeff Dennis, "Lessons from MISO on Transmission Planning for a Changing Grid," *Advanced Energy United*, August 24, 2022, https://blog.advancedenergyunited.org/lessons-from-miso-on-transmission-planning-for-a-changing-grid.
[41] "Schedule and Timeline," TransWest Express, accessed August 8, 2023, https://www.transwestexpress.net/about/timeline.shtml.

# Distributed Energy Resources and the Value They Present

Distributed energy resources encompass a range of technologies located near or at the point of electricity use, typically behind the meter on customer premises. DERs include energy efficiency and demand response resources, distributed generation resources (e.g., rooftop solar or other small-scale solar arrays), distributed energy storage resources (e.g., home battery systems, battery electric vehicles), and microgrids. While many of these resources, such as in-home batteries, are located behind-the-meter (BTM), others, such as community solar farms, connect directly to the distribution grid. The term virtual power plant (VPP) has emerged more recently to describe DERs and aggregations of DERs that are controllable and that can respond to price or other signals in order to provide capacity and other valuable grid services.

The distribution system was designed for the one-way flow of electricity, from centralized generation facilities to load. With the growth of distributed generation resources like rooftop solar, electricity generation is becoming more decentralized and dynamic. Customers can generate and use electricity on site, and export excess production to the distribution grid. Other DERs, like community solar, supply electricity directly to the distribution system. In the event of grid outages, local generation and storage resources can be completely islanded from the grid in self-sustaining microgrids. While the integration of DERs has significant promise with regard to reliability, resilience, decarbonization, and cost-reduction, the shift away from a centralized, one-way grid necessitates updated approaches to planning and operations of the distribution grid as well as coordination between distribution and transmission systems.

DERs have experienced significant growth in recent years, especially distributed solar. In 2023, the residential solar market experienced its sixth consecutive record year, growing more than 55 percent compared to 2021.[42] The EIA estimates there is nearly 40 GW of distributed solar installed in the United States.[43] While much of this deployment has been in California, distributed solar is expanding across the country. New York and New Jersey, for instance, have the second and third most distributed solar capacity in the country.[44]

As with transmission, federal agencies are paying increased attention to DER. A 2020 order by FERC, Order No. 2222, allows DERs to play a more significant role in regional wholesale energy

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[42] "Solar Industry Research Data," Solar Energy Industries Association, accessed August 8, 2023, https://www.seia.org/solar-industry-research-data.

[43] Elesia Fasching and Katherine Antonio, "Record U.S. Small-Scale Solar Capacity Was Added in 2022," *U.S. Energy Information Administration*, September 11, 2023, https://www.eia.gov/todayinenergy/detail.php?id=60341.

[44] Fasching and Antonio, "Record U.S. Small-Scale Solar Capacity."

markets by removing barriers to participation, enabling DERs to be aggregated and bid into markets alongside traditional resources.[45] As a result, ISOs and RTOs across the country have been actively working on the development of new pathways to enable DERs to provide energy, capacity, and ancillary services. Unfortunately, citing challenges to meeting Order 2222's requirements, ISOs and RTOs are in different stages of the compliance process, with the California Independent System Operator (CAISO) having the earliest partial implementation date scheduled as the end of 2024, and MISO not implementing Order 2222 requirements until 2029.[46] Highlighted by these long implementation timeframes, there are several challenges that must be worked through, and proposed rules have been identified by grid experts as continuing to present DER participation barriers. These include minimum DER size requirements for participation, DER aggregation limitations to single nodes, and individual DER asset monitoring and visibility requirements, amongst others. Accordingly, despite the potential presented by Order 2222, questions remain as to its long-term effectiveness at enabling DER market participation.[47]

## The Need for DER Investment

In a transmission-constrained environment, DERs have emerged as a necessary complement to deliver clean energy to customers. DERs can help meet the growing need for power while potentially deferring, minimizing, or even obviating the need for larger generation, transmission, or distribution system investments.

It is important to note that DERs are not a monolith and that different resources will play distinct functions in the grid in the future. Energy efficiency and demand response programs can ease strains on the grid that would otherwise occur with growing power demand. Distributed solar can reduce a load-serving entity's overall load obligation and provide new sources of clean generation to meet clean energy goals, while distributed energy storage can play a role in grid resilience and support increased renewable energy penetration by helping to safely integrate local variable renewable resources.

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[45] "FERC Order No. 2222: Fact Sheet," *Federal Energy Regulatory* Commission, September 17, 2020, https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet.

[46] "FERC Order No. 2222 Explainer: Facilitating Participation in Electricity Markets by Distributed Energy Resources." Federal Energy Regulatory Commission. Accessed April 4, 2024. https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy.

[47] For example, demand response is not permitted under state law to be aggregated and bid into wholesale markets in many midwestern states. *See,* Walton, Robert. "Uneven Pace of FERC Order 2222 Implementation Continues as Grid Operators Face Challenges." Utility Dive. Utility Dive. Accessed April 4, 2024. https://www.utilitydive.com/news/grid-operators-face-technology-finance-and-policy-challenges-FERC-2222/696392/. *and* "FERC Order 2222 Implementation Plans Create Risks, Challenges, and Opportunities for Market Players." Guidehouse. Accessed April 4, 2024. https://guidehouseinsights.com/reports/ferc-order-2222-implementation-plans-create-risks-challenges-and-opportunities-for-market-players.

Consumer interest is a significant factor driving new investment in DERs. For rooftop solar, polling conducted by the Pew Research Center in 2022 showed that saving money is the most important driver for homeowners considering installing solar panels.[48] This polling was conducted prior to the passage of the IRA, which both increased and extended tax credits for homeowners who go solar. These revamped federal incentives are likely to further accelerate the already-booming distributed solar market.

While rooftop solar has dominated the DER market for years, the distributed battery storage market is quickly gaining steam. From 2020 to 2023, residential energy storage installations increased by five times, and Wood Mackenzie forecasts that distributed storage will grow twice as fast as grid-scale storage through 2027.[49] As with rooftop solar, federal tax incentives through the IRA are likely to spur consumer interest in distributed energy storage with the addition of a new standalone energy storage investment tax credit.[50] State policy can also be an important driver of distributed storage growth. In California, for instance, Assembly Bill 2868 required the three investor-owned utilities to propose programs and investments to accelerate the deployment of distributed energy storage systems with a total capacity not to exceed 500 MW.[51] California now leads the country in distributed storage installations, with the result that the state nearly doubled its installed residential storage capacity from Q2 to Q3 2023 alone.[52] Changes to California's net metering rules are anticipated to temper the state's distributed solar and storage market in the near term, though.[53]

These trends in consumer adoption mean that the DER market is anticipated to nearly double in capacity between 2022 and 2027, according to Wood Mackenzie.[54] The firm anticipates 262 GW of new DER and demand flexibility capacity installed from 2023-2027 in the United States, which rivals the 272 GW of utility-scale resource installations it expects during the same time period.

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[48] Rebecca Leppert and Brian Kennedy, "Home Solar Panel Adoption Continues to Rise in the U.S.," *Pew Research Center*, October 14, 2022, https://www.pewresearch.org/short-reads/2022/10/14/home-solar-panel-adoption-continues-to-rise-in-the-u-s/.

[49] Jason Finkelstein, "Residential Energy Storage" (presentation, Better Buildings Residential Network Peer Exchange Call Series, November 9, 2023), https://www.energy.gov/sites/default/files/2023-11/bbrn-peer-110923.pdf; Vanessa Witte and Hanna Nuttall, *US Energy Storage Monitor* (Wood Mackenzie, 2023), https://go.woodmac.com/usesmq42023execsum.

[50] Marc Nickel et al., "Inflation Reduction Act Creates New Tax Credit Opportunities for Energy Storage Projects," *McGuireWoods*, December 27, 2022, https://www.mcguirewoods.com/client-resources/Alerts/2022/12/inflation-reduction-act-creates-new-tax-credit-opportunities-for-energy-storage-projects.

[51] "Energy Storage," *California Public Utilities Commission*, accessed February 7, 2024, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-storage.

[52] *Battery Storage in the United States: An Update on Market Trends* (Washington, D.C.: U.S. Energy Information Administration, 2021), https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf.

[53] Dan Gearino, "U.S. Battery Storage Had a Record Quarter. Here's Why It Could Have—and Should Have—Been Much Better," *Inside Climate News*, September 28, 2023, https://insideclimatenews.org/news/28092023/inside-clean-energy-battery-storage-growth-record/.

[54] Sonia Kerr et al., "US Distributed Energy Resource Market to Almost Double by 2027," Wood Mackenzie, June 20, 2023, https://www.woodmac.com/press-releases/us-distributed-energy-resource-market-to-almost-double-by-2027/.

## DER Benefits

As discussed, DERs offer a host of benefits to the grid, customers, the environment, and society more broadly. Aggregating multiple types of DERs together in VPPs can enhance the benefits associated with DERs: DOE estimates that tripling the current deployment of VPPs would save $10 billion in grid costs annually and could address between 10-20% of peak demand.[55] DERs also offer value to a grid that is increasingly strained by climate change. In California, for instance, the risk of heatwave- and wildfire-induced grid outages has caused DERs such as microgrids and distributed storage to gain steam among utilities and their customers.[56]

Numerous states have methodologies to account for the value and benefits of DERs, typically used in cost-benefit analyses when comparing DERs to conventional investments in generation, transmission, or distribution. Table 1 outlines several benefits and value streams DERs can provide that are widely recognized by states.

**Table 1. Value Streams and Benefits of Distributed Energy Resources**

| DER Value Category | Value or Benefit |
|---|---|
| **Generation** | Avoided energy<br>Avoided fuel hedge<br>Avoided capacity and reserves<br>Avoided ancillary services<br>Avoided renewable procurement<br>Market price reduction |
| **Transmission** | Avoided or deferred transmission investment<br>Avoided transmission congestion and losses<br>Avoided transmission O&M |
| **Distribution** | Avoided or deferred distribution investment<br>Avoided distribution losses<br>Avoided distribution O&M<br>Avoided or net avoided reliability costs<br>Avoided or net avoided resiliency costs |

[55] Jennifer Downing et al., *Pathways to Commercial Liftoff: Virtual Power Plants* (Washington, D.C.: U.S. Department of Energy, 2023), https://liftoff.energy.gov/wp-content/uploads/2023/09/20230911-Pathways-to-Commercial-Liftoff-Virtual-Power-Plants_update.pdf.

[56] Garrett Hering and Jeff Stanfield, "In Summer of Darkness, Distributed Energy Offers Brighter Future for US West," *S&P Global Market Intelligence*, September 18, 2020, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/in-summer-of-darkness-distributed-energy-offers-brighter-future-for-us-west-60369551.

| | |
|---|---|
| **Environment** | Avoided land area converted or developed<br>Greenhouse gas emission reductions<br>Criteria air pollutant emission reductions<br>Avoided water impacts |
| **Society or Customer** | Societal economic benefits (e.g., jobs)<br>Customer cost savings<br>Monetized health benefits<br>Increased resiliency<br>Increased energy security |

*Source: Natalie Mims Frick et al., Locational Value of Distributed Energy Resources (Berkeley, CA: Lawrence Berkeley National Laboratory, 2021), https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf; Paul De Martini and Lorenzo Kristov, Distribution Systems in a High Distributed Energy Resources Future (Berkeley, CA: Lawrence Berkeley National Laboratory, 2015), https://eta-publications.lbl.gov/sites/default/files/lbnl-1003797.pdf.*

## DER Challenges

Numerous challenges come along with DER adoption. To be clear, these are not challenges with the DERs themselves, but rather with the grid's ability to integrate them. Most central is that there are limits to how many DERs can be connected to the grid—as it currently exists—before DERs begin to strain it. As mentioned previously, the U.S. grid was designed for one-way power flow, meaning increasing volumes of exports from distributed generation on the grid can create challenges. A grid's ability to accommodate new DERs is referred to as its "hosting capacity." As a local grid's ability to accommodate additional DERs decreases, unanticipated power flows from DERs can disturb voltage and frequency and result in system imbalances, which can impact the safety and reliability of the grid.[57]

In areas with high DER penetrations, another challenge is the lack of visibility that often accompanies them and their operation, making it harder to know how DERs will affect the net load that must be served by the bulk power system. This, once again, relates to the way the grid was designed decades ago. When the grid only had to account for one-way power flow, there was little need for significant investments in power flow monitoring equipment beyond the transmission system. As such, grid operators, for example, do not have the ability to map and predict DER behavior. In many cases, DERs are often only evident to grid operators when

[57] Craig Boice, *Grid Impacts from Distributed Energy Resources: Research & Development Priorities* (Palo Alto, CA: Electric Power Research Institute, 2020), https://www.dret-ca.com/wp-content/uploads/2021/03/Grid-Impacts-from-Distributed-Energy-Resources.pdf.

they alter demand curves. A cloudy day, for instance, can lead to increased load when customers with rooftop PV systems draw more from the grid. 58 Conversely, a lack of DER visibility can also *decrease* loads relative to grid operators' expectations. In the summer of 2023, MISO reported it over-forecasted its load on several extremely hot days, potentially because it did not properly account for power production from a growing fleet of residential DERs.[59] Both over- and under-forecasting can be costly to grid operators and consumers. Tools including advanced metering, DER management systems, and VPPs can help overcome this barrier and allow both distribution and transmission system operators to coordinate in the development and deployment of DERs to maximize their value.

Finally, DER potential is currently constrained by a lack of comprehensive integration into utility regulation, planning, and operations. DOE reports that utility regulators across the country remain relatively unfamiliar with DER aggregation approaches like VPPs.[60] Despite emerging methodologies for DER cost-benefit analysis (as referenced above), both utilities and regulators may undervalue the services DERs can provide to the grid, making it less likely that DERs will be integrated into utility plans. In fact, only twenty states require that regulated utilities address the integration and utilization of DERs in their distribution plans, creating a significant gap in utility planning.[61]

[58] Aaron Larson, "How are Distributed Energy Resources Affecting Transmissions System Operators?," *POWER Magazine*, May 1, 2016, https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf.
[59] Ethan Howland, "Residential DER Surges 63% in MISO, Pushing Distributed Resources to 12.5 GW: Report," *Utility Dive*, September 26, 2023, https://www.utilitydive.com/news/residential-der-miso-distributed-energy-resources-oms/694695/.
[60] Jennifer Downing et al., *Pathways to Commercial Liftoff: Virtual Power Plants.*
[61] Jennifer Downing et al., *Pathways to Commercial Liftoff: Virtual Power Plants.*

# The Interplay Between Transmission and Distributed Energy Resources

As evident from the prior section, transmission, and DERs offer their own distinct advantages and challenges and occupy unique roles in the energy system. Up to now, these resources have been planned for, developed, and managed independently, in part due to innate separations between the transmission and distribution systems. Given the multiplicity of authorities engaged in grid development and management and the fact that power flow has historically been unidirectional, the transmission and distribution systems operate largely in silos, both in organized and unorganized market environments. In organized markets, bulk system operators (ISOs and RTOs) manage the dispatch of large-scale generation and ensure their nondiscriminatory access to the transmission lines within their footprint. Distribution system operators (DSOs) connect to this transmission network but operate their distribution systems with limited coordination with ISOs and RTOs.[62] Similarly, in unorganized market environments, i.e., states or regions that are not part of an ISO or RTO, power planning and operations departments within vertically integrated utilities manage bulk generation and transmission, and their distribution system counterparts manage utility distribution system operations. Despite both departments being in the same organization, communication is limited and coordination rare, as this has seldom been warranted since the initial development of the grid.

In recognition of the traditionally siloed relationship between transmission and DERs, this section focuses on how transmission and DERs can work in concert to provide reliable, clean, and affordable power. It begins with descriptions of the ways these resources can mutually support each other, then provides real-world case studies from three regions at the forefront of transmission-DER coordination: Australia, Hawaii, and Southern California. The Southern California case study includes the results of a quantitative modeling exercise Strategen undertook for this report, which demonstrates the interdependence between transmission and DERs that will be necessary as DER penetration increases in the region through 2035.

## How Can DERs Support Transmission?

The most widely recognized interplay between DERs and transmission is in the way DERs can complement, support, or replace transmission services. There is a growing body of evidence demonstrating their ability to reduce transmission network congestion and defer or completely avoid the need for new transmission investments. Given challenges with developing new transmission, DERs can often be cheaper and easier to deploy, helping get more clean energy

[62] This report uses DSO to refer to the entities that own and operate distribution systems and is not intended to imply a specific market structure or business model in use outside of the U.S.

on the grid faster. 63 In 2018, for instance, the (CAISO) canceled 18 transmission projects and modified another 21 projects that had been previously approved due to changes in local load forecasts driven by energy efficiency and residential solar increases.[64] The result was $2.6 billion in avoided costs.

While the potential of DERs to defer or avoid transmission investments is often touted, it should not be assumed that DERs will always be able to play this role. The ability of DERs to do so depends on the transmission system's topology and utilization, as well as the ability of DERs to deliver load reductions at both the right location and time (when the transmission system experiences its peak load).[65] Even assuming DERs can deliver load reductions where and when they are needed, in some cases, their economic value proposition may not be that competitive with a traditional transmission investment. In the case of the Bonneville Power Administration's (BPA's) Kangley-Echo Lake transmission project in the early 2000s, for instance, an economic analysis determined that the value of deferring the transmission investment for three years using DERs was minor compared to the value the transmission line would offer the region in additional load to be served and reduced energy losses. 66 The line was ultimately constructed to improve the region's power reliability.

In other cases, though, DERs have been successful at avoiding the need for transmission projects that may have been unnecessary. In 2017, BPA successfully leveraged DERs to eliminate the need for a new transmission project along the Interstate 5 corridor that would have increased power transfer from southern Washington State to northern Oregon. Following a pilot program, BPA determined it could use demand response and energy efficiency measures to decrease generation in the northern part of its line while ramping up distributed generation in the south to balance power flows and eliminate the need for investment.[67]

Another often cited example is ConEd's Brooklyn Queens Demand Management (BQDM) project, intended to defer $1.2 billion of sub-transmission investment to address forecasted overload conditions at two separate substations Brooklyn and Queens. Approved by the NY P-ublic Service Commission, ConEd worked with community organizations, universities, businesses, and technology developers to develop an energy efficiency, demand response, and DER deployment strategy consisting of 17 MW of utility demand reduction solutions (including conservation voltage optimization and energy storage) and 52 MW of customer-side DER solutions (including energy efficiency, distributed generation, and energy storage) to defer the

[63] Natalie Mims Frick et al., Locational Value of Distributed Energy Resources.
[64] Robert Walton, "Efficiency, DERs Saving $2.6B in Avoided Transmission Costs, CAISO Says," Utility Dive, March 26, 2018, https://www.utilitydive.com/news/efficiency-ders-saving-26b-in-avoided-transmission-costs-caiso-says/519935/.
[65] Natalie Mims Frick et al., Locational Value of Distributed Energy Resources.
[66] Natalie Mims Frick et al., Locational Value of Distributed Energy Resources.
[67] Natalie Mims Frick et al., Locational Value of Distributed Energy Resources.

developme-nt of major sub-transmission substation upgrades. Following the initial success of the program, ConEd requested and obtained approval for an extension.[68] By the end of 2023, ConEd achieved more than 42 MW of customer-side load reduction and another 18.5 MW of utility load reduction solutions, with a total spend of $132.16 million.[69]

In recognition of DERs' potential role to defer or avoid transmission investments, multiple states have laws or regulatory requirements mandating that utilities explore non-wires alternatives (including DERs) for transmission and distribution (T&D) system upgrades. Maine, for instance, passed a law in 2013 that requires examination of non-transmission alternatives for proposed transmission projects.[70] Since the late 1990s, New York has required utilities to evaluate DERs as alternatives to T&D capital projects. In 2016, it established a benefit-cost analysis framework for utilities to evaluate the cost-effectiveness of infrastructure proposals, considering economic, environmental, and broader social costs and benefits in their T&D investments.[71] Such policies drive home the important role that DERs can play in deferring or avoiding potentially unnecessary transmission investments.

## How Can Transmission Support DERs?

While not traditionally thought of as a necessary enabler of DERs, the transmission system can provide essential functions that help facilitate the buildout of DERs, reduce some of the challenges associated with a high-DER future, and bolster the benefits of DER deployment. This potential is most salient in locations with high DER penetration, where the volume of DERs on the distribution system (especially distributed generation resources such as rooftop solar) may generate electricity in excess of local load on certain feeders or substations. This, in turn, may adversely affect power quality or reliability, even triggering costly infrastructure upgrades. In this context, proactive coordination across the distribution and transmission systems can help minimize these impacts, expand the grid's hosting capacity for additional DERs, and enable DERs to serve loads beyond the local area in which they were deployed. For instance, advanced inverters and upgrades to both substation transformers and voltage regulators to enable bidirectional power flows can help to allow safe reverse power flow from distributed generation resources onto the grid.[72] Putting this infrastructure in place allows the transmission system to better support high volumes of DERs, while also enabling DERs to use the distribution and transmission systems to supply power to loads across the grid. While most

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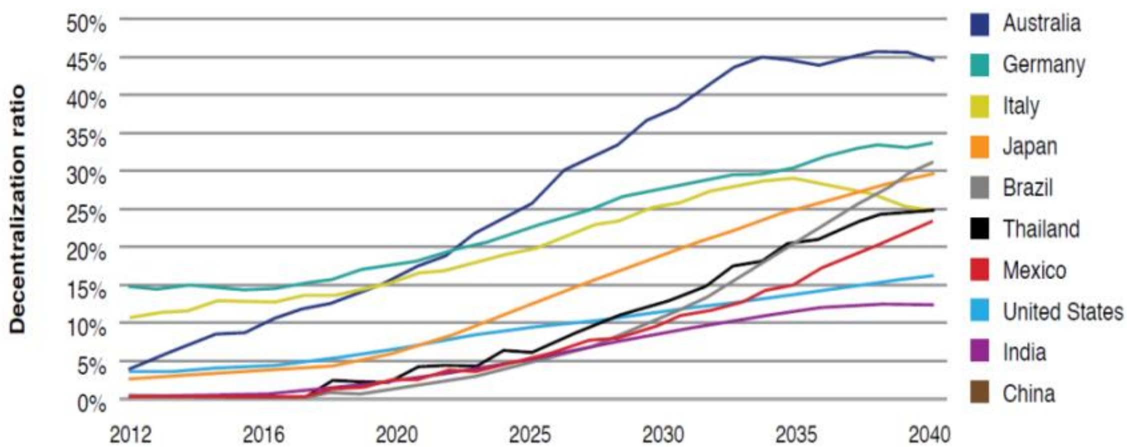
[68] "Brooklyn Queens Demand Management Program, Implementation and Outreach Plan." January 31, 2023. Consolidated Edison Company of New York, Inc.
[69] "Internal BQDM Quarterly Expenditures & Program Report: Fourth Quarter 2023." February 29, 2024. Consolidated Edison Company of New York, Inc.
[70] Natalie Mims Frick et al., *Locational Value of Distributed Energy Resources.*
[71] Natalie Mims Frick et al., *Locational Value of Distributed Energy Resources.*
[72] Kelsey Horowitz et al., *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions.*

places have not reached levels of DER penetration that necessitate this coordination, proactively preparing transmission-level infrastructure for a high-DER future can still be advantageous, particularly considering the global trend towards electricity decentralization bolstered by falling renewable generation costs, as seen in Figure 3, below.

**Figure 3. Decentralization ratio of electricity generation by country**




*Source: The Distributed Energy Resources Revolution: A Roadmap for Australia's Enormous Rooftop Solar and Battery Potential (Melbourne, Australia: Clean Energy Council, 2019),* *https://assets.cleanenergycouncil.org.au/documents/advocacy-initiatives/the-distributed-energy-resources-revolution-paper.pdf*.

Transmission infrastructure can also play a key role in supplying power to distributed energy storage resources. In locations with insufficient distributed generation, transmission infrastructure may be needed to fully charge distributed storage resources and maximize their value to the grid. For instance, the municipal utility in Glendale, California (which is in a transmission-constrained load pocket), found in its 2019 Integrated Resource Plan that adding new batteries to its system failed to get the city to a 100% clean energy portfolio because behind-the-meter renewable resources were not sufficient to fully charge them. The city concluded that, in addition to expanding distributed renewable generation, additional transmission capacity would be necessary to supply the batteries with clean electricity from outside the city, enabling the batteries to be a local capacity resource and reduce reliance on local natural gas generation.[73] Transmission capacity can therefore be a vital complement to distributed generation resources when it comes to storing clean energy on the grid.

[73] *2019 Integrated Resource Plan* (Glendale, CA: City of Glendale Water & Power, 2019), https://www.glendaleca.gov/home/showpublisheddocument/51814/638258694171330000.

## Case Studies of Transmission and DER Challenges, Mutual Benefits, and Coordination

This section outlines three case studies that highlight real-world interactions between transmission and DERs, including both benefits and challenges with these interactions. Brief case studies are presented for Australia and Hawaii, underscoring the challenges these systems face in integrating DERs and transmission and lessons learned from their experiences with comprehensive planning methods. This section then concludes with a more in-depth case study of Southern California, which includes the results of a quantitative analysis undertaken for this report to illustrate the interdependence between transmission and DERs that becomes necessary as DER deployment increases in the region, with a focus on the timeframe of 2024 to 2035.

The first case study highlights the leading role DERs play in Australia's energy system and the innovative ways these resources are being developed to meet clean energy goals, provide access to power, and bolster grid reliability. The Australian case study shows that proactively embracing and planning for DER integration in local grids can lead to widespread benefits that ripple across both the distribution and transmission systems, while avoiding some of the DER integration challenges and growing pains that manifest in the bulk transmission systems in other regions are experiencing as DERs see increasing deployment worldwide. Australia's approach to DER development and management (which includes piloting both grid-connected and remote microgrids, virtual power plants, and dynamic distributed solar exporting mechanisms) shows that, with creative intentional efforts, DERs can play an important part in national power systems and be complementary to traditional infrastructure, like transmission, and centralized generation.

The next case study explores the islands of Hawaii, where distance and deep water limit mainland and inter-island transmission interconnections and where DERs are playing a key role in moving the islands to cleaner resources, but reliance on bulk system renewables is still necessary to meet demand. This results in a need for parallel deployment and an ultimate tying together of the resources through the transmission system. Recognizing this relationship, Hawaiian Electric and the Hawaii Public Utilities Commission (HIPUC) have shifted their planning approach to a more holistic perspective, with the intent to co-evaluate and co-optimize generation, distribution, and transmission requirements. Hawaiian Electric filed its first Integrated Grid Plan (IGP) with the HIPUC in 2023.[74] The IGP includes recommendations for a mix of customer-scale and large-scale renewables, highlighting the importance of customer participation in the clean energy transition.

[74] "Integrated Grid Planning." Hawaiian Electric. Accessed April 4, 2024. http://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning

The final case study covers Southern California. California is a leader in the clean energy transition and has used aggressive policies, mandates, and incentives to dramatically increase the deployment of renewable resources, and more recently, energy storage to integrate these renewables. As with Australia and Hawaii, California has a robust mix of DER and large-scale resources. However, Southern California is transmission constrained. Accordingly, operating DERs in concert with the larger grid will become increasingly necessary to meet load, ensure day-to-day reliability, and address resilience against extreme weather events. As DER deployment continues, its benefits will diminish unless supporting infrastructure investments are made to continue realizing its full value. This situation presents a question around what resources will be available to serve load while meeting climate targets and maintaining system reliability and resilience. To better illustrate the interplay between transmission investments and DER deployment in Southern California, this case study presents the results of quantitative modeling that Strategen undertook as part of this report. The analysis considers grid DER and transmission deployment scenarios that show negative net load values more than the assumed available transfer capability out of Southern California, underscoring the need for incremental transmission investments in the region. The discussion around transmission in the Southwest region often focuses on importing remote large-scale renewable resources, but this analysis shows that transmission can also play a critical role in local DER growth by taking advantage of periods of DER overgeneration. Using transmission to link load centers together can be critical to transforming DERs from a local energy resource that is prone to overgeneration, to assets that can provide energy beyond their neighborhoods, adding flexibility and enhancing reliability of the overall system.

## Australia

Given Australia's low overall population density and sprawling geography, the country has the most decentralized grid in the world.[75] This innate grid decentralization, coupled with high electricity prices and grid reliability concerns, has made DERs, particularly rooftop solar, popular among consumers. The country has 20 GW of rooftop solar capacity, with rooftop solar slated to overtake coal as the country's largest source of electricity generation following coal retirements in 2023.[76] For context, total installed solar capacity in Australia is 34.2 GW.[77] The Australia Energy Market Commission predicts that, by 2050, more than half of all houses in Australia will have solar PV, with one-third of residential buildings having energy storage.[78]

The growing decentralization of its grid and high consumer interest in DERs have required Australia to become an innovator in effective management and operations of DERs. In 2020,

[75] The Distributed Energy Resources Revolution: A Roadmap for Australia's Enormous Rooftop Solar and Battery Potential.
[76] Will Norman, "Australian Rooftop PV Passes 20GW of Capacity, Utility-Scale Forecast Less Sunny – SunWiz," PV Tech, March 2, 2023, https://www.pv-tech.org/australian-rooftop-pv-passes-20gw-of-capacity-utility-scale-forecast-less-sunny-sunwiz/.
[77] "Australian Photovoltaic Institute • Market Analyses." Accessed April 30, 2024. https://pv-map.apvi.org.au.
[78] *The Distributed Energy Resources Revolution: A Roadmap for Australia's Enormous Rooftop Solar and Battery Potential.*

the Australian Energy Market Operator (AEMO) launched a DER Register, which aimed to increase the visibility of installed DER devices in its National Electricity Market by cataloging the number of DERs at a postcode level, allowing AEMO to better understand and manage the grid.[79] The interface of DERs with the grid is also aided by the widespread use of smart inverters on residential solar systems, allowing for both greater and more flexible exports of energy to local distribution systems. Australia's Clean Energy Regulator reported that roughly 96 percent of all inverters installed in 2019 were "smart," meaning that they are capable of autonomously sensing grid conditions and modulating their output, as well as providing voltVAR, voltwatt, or other grid s-ervices as needed.[80] The widespread deployment of smart inverters allows for roughly twice as much distributed solar to be hosted on the country's grid, relative to a scenario where regular inverters are deployed.[81] In addition, DSOs are also making necessary investments to accommodate greater PV adoption. SA Power Networks, the DSO in the state of South Australia, plans to invest more than $50 million between 2020 and 2025 to modernize its network for a high-DER future; this includes upgrades to 140 major substations to address voltage issues in high-solar areas and increase the capacity of those substations to receive distributed solar energy. [82]

Australia is also a pioneer in aggregating DERs, such as rooftop solar for grid services. Microgrids, which often couple rooftop solar, battery storage, and other DERs, have been piloted for years in both grid-connected applications (often at the "edge-of-grid") and off-grid applications to provide power to remote areas that have poor or no grid interconnection that would be challenging to upgrade or connect with traditional transmission and distribution infrastructure solutions.[83] Results often include increased access to clean energy, improved reliability, and lowered energy bills.[84] VPPs are also well established in Australia, particularly in the population-dense Southeast. In the state of New South Wales, for instance, a 200 MW VPP by Origin Energy, along with 700 MW of batteries, are working in conjunction to replace the

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[79] "About the DER Register," AEMO, accessed February 7, 2024, https://aemo.com.au/energy-systems/electricity/der-register/about-the-der-register. and

[80] *The Distributed Energy Resources Revolution: A Roadmap for Australia's Enormous Rooftop Solar and Battery Potential.* https://assets.cleanenergycouncil.org.au/documents/advocacy-initiatives/the-distributed-energy-resources-revolution-paper.pdf.

[81] *The Distributed Energy Resources Revolution: A Roadmap for Australia's Enormous Rooftop Solar and Battery Potential.* https://assets.cleanenergycouncil.org.au/documents/advocacy-initiatives/the-distributed-energy-resources-revolution-paper.pdf.

[82] *Distributed Energy Transition Roadmap 2020-2025* (Kenswick, Australia: SA Power Networks), https://www.sapowernetworks.com.au/public/download.jsp?id=319084.

[83] Daniel Hilson and Max Zaporoshenko, *Delivering Higher Renewable Penetration in New Land and Housing Developments Through Edge-of-Grid Microgrids* (Sydney, Australia: Flow Systems, 2016), https://arena.gov.au/assets/2015/04/Delivering-higher-renewable-penetration-new-land-housing-developments-microgrids.pdf; ARENA, "Microgrids: Cheaper, cleaner, reliable energy for remote communities," August 28, 2023, https://arena.gov.au/blog/microgrids-cheaper-cleaner-reliable-energy-for-remote-communities/.

[84] Khaled Al Khawaldeh, "Micro Grids Pilot Fund to Promote 'Energy Sovereignty' in Remote Queensland Communities," *The Guardian*, December 28, 2022, https://www.theguardian.com/australia-news/2022/dec/29/micro-grids-pilot-fund-to-promote-energy-sovereignty-in-remote-queensland-communities.

Eraring coal power plant.[85] The company aims to grow this already large VPP to roughly two GW in the future and use it to shift load from times of high demand to times of low demand through demand response approaches. In South Australia, a project marketed as the country's largest virtual power plant launched in 2018 and has installed thousands of solar and battery systems on homes, with the goal of connecting to 50,000 homes in the future.[86] This VPP has already provided critical support to the grid during fires, grid interruptions, and other events.[87]

While Australia has proven to be a leader in developing, aggregating, and monetizing DERs, the country's high DER penetration does not come without challenges. Insufficient visibility of DERs, a lack of interoperability between DER devices, potential cybersecurity issues, constraints on local network hosting capacity, and other challenges are all present in Australia.[88] At the bulk power system level, the impacts of DERs are not well understood, but research and pilot projects are ongoing to better understand the way DERs affect, or contribute to, the country's bulk system reliability and security.[89]

The impact of DERs at the transmission level is likely to increase in the future, as demonstrated when analyzing areas of the country at risk of reverse power flows due to high rooftop solar adoption. While this reverse power flow most centrally affects the distribution system, transmission will also be impacted. The red dots in Figure 4 below represent substations at the transmission-distribution interface anticipated to experience reverse power flow this decade, most of which are concentrated in South Australia, where rooftop solar adoption is highest.[90] This problem is anticipated to spread across the country over the next three decades, indicating a need for strategies to avoid grid strain at both the distribution and transmission levels.

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[85] Andy Colthorpe, "Australia's Origin Energy to Replace Coal with Energy Storage and Virtual Power Plant," *Energy Storage News*, March 9, 2022, https://www.energy-storage.news/australias-origin-energy-to-replace-coal-with-energy-storage-and-virtual-power-plant/.

[86] "South Australia's Virtual Power Plant," Government of South Australia Department for Energy & Mining, accessed February 7, 2024, https://www.energymining.sa.gov.au/consumers/solar-and-batteries/south-australias-virtual-power-plant.

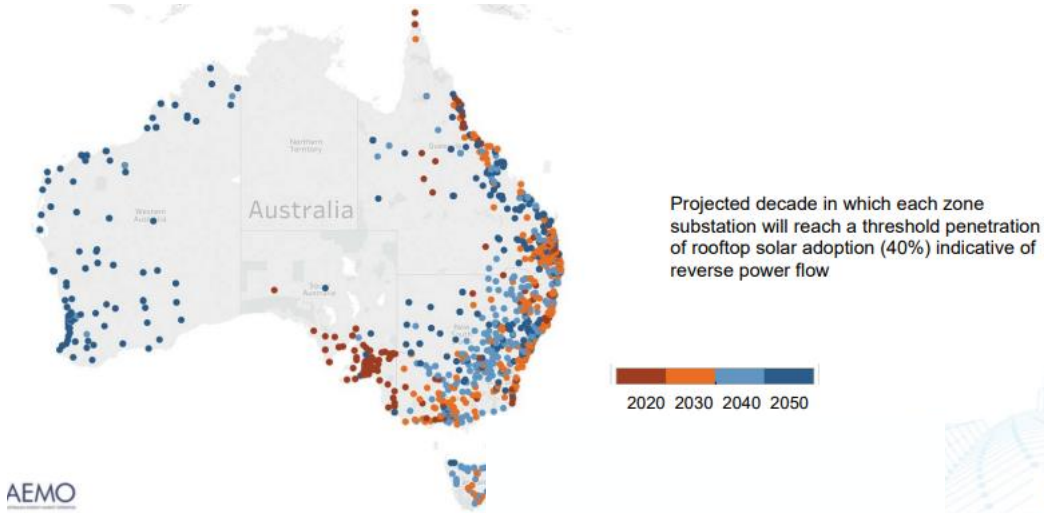
[87] "South Australia's Virtual Power Plant," Government of South Australia Department for Energy & Mining.

[88] *State of Distributed Energy Resources Technology Integration Report* (Canberra, Australia: Australian Renewable Energy Agency, 2021), https://arena.gov.au/assets/2021/02/state-of-distributed-energy-resources-technology-integration-report.pdf.

[89] *State of Distributed Energy Resources Technology Integration Report.*

[90] "Open Energy Networks Project: How Best to Transition to a Two-Way Grid That Allows Better Integration of DER to Deliver Better Outcomes for All Customers" (presentation, Energy Networks Australia & Australian Energy Market Operator workshop, July 2018), https://www.energynetworks.com.au/assets/uploads/open_energy_networks_workshop_slidepack.pdf.

**Figure 4. Projection of substations anticipated to experience reverse power flow due to rooftop solar penetration of 40+%.**




*Source: "Open Energy Networks Project: How Best to Transition to a Two-Way Grid That Allows Better Integration of DER to Deliver Better Outcomes for All Customers" (presentation, Energy Networks Australia & Australian Energy Market Operator workshop, July 2018),* *https://www.energynetworks.com.au/assets/uploads/open_energy_networks_workshop_slidepack.pdf.*

To avoid potentially negative impacts on distribution systems (for instance, voltage instability), some distribution operators have imposed "zero-export" policies, which restrict or completely prevent excess solar energy from being exported onto local grids.[91] This practice, however, is becoming less common, and a ruling by the Australian Energy Regulator in April 2023 now only permits static zero-export limits in "exceptional circumstances," requiring DSOs to explore alternative options before imposing such limits.[92] This ruling could lead to greater investment in dynamic DER management systems, helping increase the grid's DER hosting capacity while minimizing potentially negative grid strains that DERs can create at both distribution and transmission levels. This regulatory development, and the associated steps DSOs will take to comply with it, can offer lessons learned for other jurisdictions managing growing amounts of distributed solar on local grids; with creative and dynamic solutions for DER management, DERs can play an important role in grid reliability and resilience with minimized risk to both distribution and transmission infrastructure.

The Australia case study is a lesson in the value of proactive visioning and planning for DERs. Despite some challenges associated with high DER penetration (for instance, network voltage constraints leading to the need for zero-export limits), Australia's distribution and transmission

[91] *The Distributed Energy Resources Revolution: A Roadmap for Australia's Enormous Rooftop Solar and Battery Potential.*
[92] Bella Peacock, "Zero Solar Export Limits Soon to Be Heavily Restricted," *PV Magazine*, April 12, 2023, https://www.pv-magazine-australia.com/2023/04/12/zero-solar-export-limits-to-soon-be-heavily-restricted/.

system operators and government agencies repeatedly emphasize the significant role that customer resources can play in Australia's energy transition and set goals around DER adoption and integration. SA Power Networks' Distributed Energy Transition Roadmap, for instance, lays out a vision that, by 2030, much of its energy will be produced locally, with the entire network capable of running in reverse to supply customers' surplus solar energy to large industries, and even export it to other states.[93] In this context, the utility is actively making investments to achieve that vision. At the national level, the Electricity Network Transformation Roadmap, produced by a governmental science agency and the trade group representing Australia's distribution and transmission networks, is bullish on DERs and has set goals and milestones for developing consumer compensation and incentive regimes, effective DER forecasting approaches, and network intelligence and visibility strategies, among other targets. The roadmap aims to have one-third of all Australian customers selling DER services to networks "on a dynamic, locational basis" by 2027 and estimates that, by 2050, DERs could provide up to 45 percent of Australia's electricity supply.[94]

As is clear from the Australia case study, the benefits of DERs can be significant on a national scale, leading to greater clean energy penetration, access to power for remote communities, and grid reliability and resilience, with benefits rippling across both the distribution and transmission levels. Conversely, though, DER impacts can also extend beyond the transmission-distribution interface, pointing to the need for innovation in DER deployment, aggregation, and dynamic integration in local grids.

### Hawaii

Unlike mainland U.S. grids, Hawaii's power system is composed of small island grids that are self-contained and isolated, meaning each island is unable to turn to neighboring grids for support when pushed beyond normal operational limits. Traditionally, Hawaii has relied heavily on fuel oil to fuel its power plants.[95] However, the state's drive to meet clean energy targets, coupled with the simple fact that imported oil leads to very high electric rates, has caused renewable generation to nearly triple since 2010.[96] Customer deployment of solar (and, more recently, solar and storage) has been a significant and primary component of this growth. Figure 5 presents Hawaiian Electric's renewable energy sources in 2022, with customer DER being the utility's largest renewable resource.

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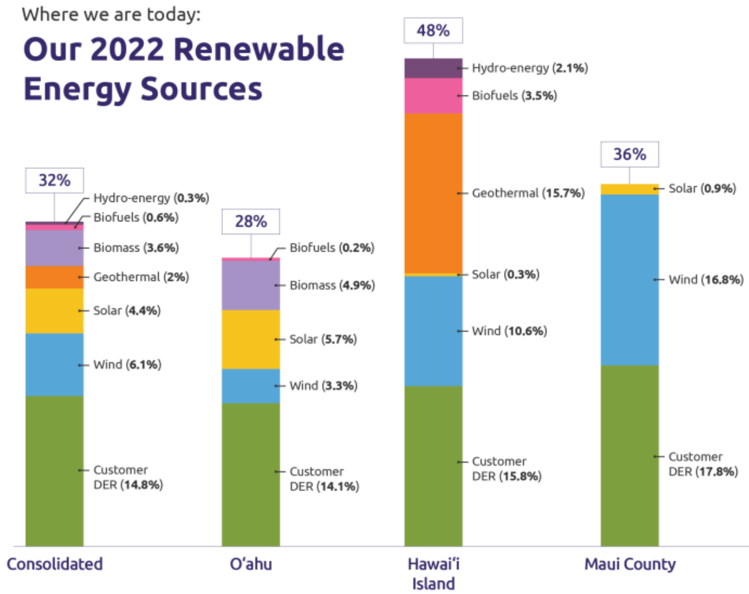
[93] *Distributed Energy Transition Roadmap 2020-2025*, SA Power Networks.
[94] Garth Crawford et al., *Electricity Network Transformation Roadmap: Final Report* (Canberra, Australia: CSIRO & Energy Networks Australia, 2017), https://www.energynetworks.com.au/assets/uploads/entr_final_report_april_2017.pdf.
[95] "Hawaii: Profile Analysis," U.S. Energy Information Administration, last modified March 16, 2023, https://www.eia.gov/state/analysis.php?sid=HI#.
[96] "Clean Energy Hawaii," Hawaiian Electric, accessed February 7, 2024, https://www.hawaiianelectric.com/clean-energy-hawaii.

**Figure 5. The significance of DER in Hawaiian Electric's renewable resources.**




*Source: Hawai'i Powered: Integrated Grid Plan (Honolulu, HI: Hawaiian Electric, 2023),* *https://hawaiipowered.com/igpreport/IGP-Report_Final.pdf*

Because of its unique system and limited land and large-scale resources, Hawaii has had to take innovative approaches to meeting its energy needs, especially its clean energy targets. Both state and utility incentives have played a key role in these approaches. Enabled by Hawaii's unique geography, needs, and regulatory framework, utility programs in the state enable DERs to provide bulk system services, leveraging customer solar and storage to deliver frequency response, capacity, and replacement (i.e., operating) reserves. These programs, such as Hawaii's Battery Bonus Program, incentivize customer installations by paying customers to permit Hawaiian Electric to control their resources to deliver grid services.[97] The heavy use of DERs is expected to continue, deferring the need for transmission and generation solutions to deliver capacity as fossil power plants retire.

At present, consideration of grid services provided by DERs in Hawaii has been limited to generation services, but there has been a drive to value other services and benefits DERs can provide to the bulk power system, specifically as non-wires alternatives (NWA) for transmission. In recent years, the Hawaii Public Utilities Commission (HIPUC) has reiterated its expectation that Hawaiian Electric considers both non-transmission alternatives (NTA) and non-distribution alternatives in evaluating system T&D upgrades, including analyzing locational

[97] "Battery Bonus," Hawaiian Electric, accessed February 7, 2024, https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/rooftop-solar/battery-bonus.

benefits associated with customer DER as a part of T&D upgrade analyses.[98] In response to this directive, Hawaiian Electric has developed a Non-Wires Opportunity Evaluation Methodology to identify NWA opportunities, evaluate sourcing options, and deploy NWAs across the Hawaiian islands.[99] As part of its methodology, Hawaiian Electric identified two primary T&D grid services that it believes NWAs can provide: T&D capacity deferral and distribution reliability (i.e., system support during contingency operations, including voltage support and resilience services).

While the establishment of this NWA framework is a positive development, Hawaiian Electric has so far had mixed results with successfully deploying DERs as NWAs. In two different requests for proposals (RFPs) for NWAs—one in the Ho'opili area of O'ahu and the other in the North Kohala area of Hawaii Island—the utility was unable to find bidders to complete the planned projects. The Ho'opili NWA project was originally intended to address anticipated overloads of substation transformers and distribution circuits while deferring the need for both circuit extension and substation projects. Due to insufficient response to the RFP from the market, which may be partially explained by the cost of doing business on Oahu, Hawaiian Electric ultimately decided to move forward with this traditional solution instead of pursuing an NWA.[100] The North Kohala project would entail developing a microgrid as a deferral of a sub-transmission line.[101] While Hawaiian Electric did receive bids for the primary component of this project (a battery storage system), the utility ultimately determined the bids did not meet its RFP criteria.[102] A final report from the independent RFP observer is pending and will provide an overall assessment of the process and a discussion of key issues impacting the RFP process outcome. Despite both RFP processes not resulting in successful outcomes, the utility indicates it intends to continue to evaluate NWA opportunities across its system as required by the HIPUC as part of its expectation for the utility to evolve and move to consider Integrated Grid Planning (IGP). [103]

Recognizing the relationship between distribution and DER, transmission, and bulk scale generation, Hawaiian Electric and the HIPUC have shifted their planning approach to a more holistic perspective, with the intent to co-evaluate and co-optimize generation, distribution, and transmission requirements. Hawaiian Electric filed its IGP with the HIPUC in 2023, which aims to decarbonize and fortify the grid while ensuring affordability and reliability for

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[98] *Non-Wires Opportunity Evaluation Methodology* (Honolulu, HI: Hawaiian Electric, 2020), https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20200602_dpwg_non_wires_opportunity_evaluation_methodology.pdf.
[99] *Non-Wires Opportunity Evaluation Methodology*, Hawaiian Electric.
[100] *Non-Wires Opportunity Evaluation Methodology*, Hawaiian Electric.
[101] *Hawai'i Powered: Integrated Grid Plan*, Hawaiian Electric.
[102] "North Kohala Microgrid," Hawaiian Electric, last modified September 6, 2023, https://www.hawaiianelectric.com/about-us/our-vision-and-commitment/investing-in-the-future/north-kohala-microgrid.
[103] Order No. 40645 Terminating the North Kohala BESS RFP and Closing the Docket, No. 2022-0012 (Public Utilities Commission of the State of Hawaii March 6, 2024).

customers.[104] The IGP is also intended to support the company's climate change action plan and state decarbonization goals, which aim to generate 100% of all electricity from renewable energy sources by 2045, while maintaining energy choices and stable rates for customers.[105] Hawaiian Electric's IGP included recommendations for growing the marketplace through a mix of customer-scale and large-scale renewables, highlighting the importance of customer participation in the clean energy transition. The implementation of customer programs and incentives would increase participation in areas including rooftop solar, energy storage, vehicle charging, and energy efficiency. By 2030, it is estimated that over 125,000 residential and commercial private rooftop solar and energy storage systems (1,186 MW) will be needed across service territories to meet decarbonization targets.[106] As of Q1 2024, Hawaii has 108,482 solar PV systems, with a cumulative installed capacity of 1,268 MW, and as of Q2 2023, 17,462 PV and battery systems on Oahu, with an estimated installed capacity of 88MW and another 8 MW on Maui.[107]

To move to a more sophisticated utility business model and operations process, the HIPUC has implemented a Performance Based Regulation (PBR) framework that intends to focus and tie utility financial performance to actual performance and achievement of legislative and regulatory desired outcomes. As part of this PBR framework that took effect in 2021, Hawaiian Electric is subject to financial incentives and penalties targeting State clean energy goals, with a specific DER Asset Effectiveness category that includes metrics measuring DER capability, enrollment, utilization, and curtailment in the delivery of grid services, tying utility performance to DER solutions that complement transmission and the bulk system.[108]

## Southern California

The Southern California bulk power system is composed of 500 kV transmission facilities in the Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) territories, interconnected with 230 kV infrastructure. The California Independent System Operator (CAISO) operates the bulk of the system as the state's ISO and one of the balancing authorities within California. In the last decade, robust state policies and incentives have encouraged significant DER buildout, with Southern California being particularly attractive for DER

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[104] "Integrated Grid Planning." Hawaiian Electric. Accessed April 4, 2024. http://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning.
[105] *Hawai'i Powered: Integrated Grid Plan*, Hawaiian Electric.
[106] *Hawai'i Powered: Integrated Grid Plan*, Hawaiian Electric.
[107] "Battery Bonus." Hawaiian Electric Company. 2024. http://www.hawaiianelectric.com/products-and-services/customer-incentive-programs/battery-bonus; "Bring Your Own Device." Hawaiian Electric Company. 2024. https://www.hawaiianelectric.com/products-and-services/customer-incentive-programs/bring-your-own-device; "Solar PV Battery Installations in Honolulu: 2022 Update." Research and Economic Analysis Division. Department of Business, Economic Development and Tourism. State of Hawaii. May 2023. https://files.hawaii.gov/dbedt/economic/data_reports/reports-studies/Solar_PV_Battery_Installation_2023May.pdf.
[108] "Performance Based Regulation (PBR)." Hawaiian Electric Company. Accessed April 4, 2024. https://puc.hawaii.gov/energy/pbr/.

deployment given the quality of its solar resources and high electricity prices. While distributed solar deployment has been strong, there also exists a need for bulk resources to meet clean energy goals and transmission to bring these bulk resources to load. In this context, CAISO's 20-Year Transmission Outlook identifies $30.5 billion in new transmission needed to reach the state's 2045 net-zero clean energy goals.[109]

As California advances towards meeting its decarbonization targets, growing coordination across the grid will be required. California's ambitious clean energy targets—coupled with ongoing electrification efforts—present challenges in maintaining power system reliability, resilience, and cost efficiency, requiring an unprecedented expansion of the state's clean energy generation. Currently, California, and Southern California in particular, has achieved progress through significant DER deployment, specifically customer solar resources, which now account for 14,048 MW of installed capacity across the state (in 2022) and are expected to increase to 24,721 MW by 2030. 110 For comparison, the peak load for CAISO in 2022 was 52,061 MW.[111] The state's DERs are complemented by large-scale solar and some large-scale wind brought from inland California to load centers via transmission; natural gas power plants located much closer to load centers, often within cities in Southern California; a recent build-out of energy storage resources;  and imports of hydroelectric generation from the Pacific Northwest (PNW) and renewables from other Southwestern states. Given the monumental scale of California's decarbonization goals, operating DERs in concert with the larger grid will become increasingly necessary to ensure day-to-day reliability. Further, DERs will be critical in helping to maintain- resilience against extreme weather events as well as to help customers keep their lights on during Public Safety Power Shutoffs, with many of these challenges centered around transmission outages in extreme conditions.[112]

Widespread deployment of DERs in California has brought about considerable progress in meeting clean energy targets and has avoided, or at least reduced, the need for large-scale transmission development to deliver distantly located renewable energy to customers. Nevertheless, as DER deployment continues, its benefits will diminish unless supporting infrastructure investments are made to continue realizing its full value. This is because, as more distributed solar PV is added to the grid, daytime net load will continue to drop to lower and lower levels, exacerbating grid ramping requirements as the sun sets while load peaks. At

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[109] *20-Year Transmission Outlook* (Sacramento, CA: California Independent System Operator, 2022), https://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf.

[110] *2021 Integrated Energy Policy Report* (Sacramento, CA: California Energy Commission, 2021), https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report.

[111] "California ISO Peak Load History 1998 through 2023," California Independent System Operator, accessed February 7, 2024, https://www.caiso.com/documents/californiaisopeakloadhistory.pdf.

[112] Public Safety Power Shutoffs are California investor-owned utility actions to cut power to electrical lines in the case of last resort if there is an imminent and significant weather-related risk of those lines causing wildfires. This practice has expanded to other western states. *See* "Public Safety Power Shutoffs." California Public Utilities Commission. Accessed April 4, 2024. https://www.cpuc.ca.gov/psps/.

the same time, the differential between total load and net load will continue to increase, that is, DERs will provide the bulk of energy needs during sunlight hours, limiting grid-scale resource needs during the day. On top of this, it is expected that dispatchable fossil resources will retire soon to meet state climate targets.[113]

This situation presents a question around what resources will be available to serve load while meeting climate targets and maintaining system reliability and resilience. Recent modeling of the existing energy system across California, but particularly in Southern California, shows that in the absence of dispatchable large-scale generation (i.e., natural gas generation) the region will struggle to meet energy and reliability needs.[114] This is driven by significant transmission constraints across the system, limiting the ability to add local capacity within load pockets. For example, the Los Angeles Basin has limited transmission capacity to CAISO and neighboring regions. It relies on in-basin natural gas power plants to meet reliability requirements and energy needs. Deploying distributed or grid-scale storage may help but given transmission constraints and limited in-basin energy resources, there is currently not enough generation to charge these storage resources.

As DER penetration increases in Southern California, net load will continue to decrease in the middle of the day, potentially into negative territory. Given transmission constraints, the question then arises: what will the grid do with vast amounts of renewable energy generated across its load centers during periods of comparatively low demand? How can these resources be utilized, and their value maximized? Under the status quo, the value of DERs is limited because they are constrained to only serving local loads. This inability to serve needs across greater distances lies at the heart of the complementary nature of DERs and transmission development. Of course, an analogous situation is being faced in Australia and Hawaii, where as discussed, significant DER deployments are driving net load into negative territory, challenging utilities to maintain system reliability.

The development of new transmission capacity with the intent of bringing additional bulk energy to the CAISO system is attractive, but such an approach would overlook another critical benefit said transmission capacity could potentially unlock: the ability to further and better utilize existing DERs to meet load on a regional basis (rather than just local). This potential could be achieved, if, for example, Arizona or New Mexico had load profiles better coincident with California's solar resource. In this case, California's installed DER base could support Arizona and New Mexico load during daytime hours, while Arizona and New Mexico resources support California during other hours. This of course assumes that generation and load across

[113] Hudson Sangree, "California to Keep Old Gas Plants Operating for Reliability," *RTO Insider*, August 9, 2023, https://www.rtoinsider.com/52446-california-energy-commission-gas-plants/.
[114] Cochran, Jaquelin, and Paul Denholm, eds. 2021. The Los Angeles 100% Renewable Energy Study. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-79444. https://maps.nrel.gov/la100/.

states match up well and does not fully address ramping needs as the sun sets. Nonetheless, considering this additional benefit contextualizes the need for transmission as not just related to the development of new resources in neighboring states to serve California load, but as an investment to get more regional reliability and minimize costs by leveraging existing resources. The next section presents a high-level analysis of this potential opportunity.

## The Transmission-DER Nexus in Southern California: Exploring Future Scenarios

To better illustrate the interplay between transmission investments and DER deployment in Southern California, this section presents the results of a quantitative analysis Strategen undertook as part of this report that explores the impacts of increasing DER penetration in the region, including how transmission infrastructure can evolve to support DER growth. The analysis focuses on 2024 to 2035, imagining multiple future scenarios of DER deployment and load. The goal of this assessment was to answer pivotal questions about systemic limitations, such as identifying the upper threshold of DERs that the existing Southern California grid can sustain and the instances that may merit significant grid upgrades. Furthermore, Strategen's analysis also contemplates potential outcomes stemming from imagined transmission expansion scenarios, illuminating the benefits of bolstering transmission systems to host a larger share of DER assets.

This analysis sought to identify periods of concern and potential transmission solutions that could enable further DER integration and utilization. Strategen's analysis examined anticipated trends regarding demand, DER (in this case for simplicity and because they make up much of installed DER capacity, solar PV, and battery storage), and transmission deployment in Southern California. Considering these elements, Strategen's analysis sought to pinpoint potential barriers that might impede the full realization of DER capabilities, especially during peak midday hours. Overall, the analysis found that absent proper transmission infrastructure, these barriers can result in energy curtailments and the underutilization of vital resources, potentially contributing to the area's continued reliance on fossil-fueled resources.[115]
For details on Strategen's data collection efforts, modeling methodology, and research limitations, see Appendix I.

[115] Importantly, the analysis presented here is not extensive production cost or capacity expansion analysis. As such, this analysis does not model the system in detail and is instead intended to provide directional and indicative guidance regarding the interplay between DER deployment and future transmission development in Southern California.

# Analysis and Results

Using the hourly load forecasts prepared by the CEC as part of their 2021 Integrated Energy Policy Report (IEPR), described further detail in Appendix I, Strategen constructed a spreadsheet-based model to identify periods of negative demand where energy generated by DERs (in this case, solar and storage) could be exported outside their local area across a range of future scenarios (see Table 2Table 2).[116] This, in tandem with the information Strategen collected regarding transmission utilization, allows for the identification of factors that could lead to suboptimal utilization of DERs unless transmission constraints are removed.

Table 2. Summary of Studied Futures

| Hourly Load and Net Load Forecast (from CEC)[117] | Associated DER Forecast (from CEC) | DER Future Variants (Scaled from CEC data as % of total DER forecast materialized)[118] |
|---|---|---|
| **Low** | Higher DER deployment anticipated relative to the Mid hourly load forecast | 100%, 125%, 150%, 200%, 250%, and 300% |
| **Mid** | - | 100%, 125%, 150%, 200%, 250%, and 300% |
| **High** | Lower DER deployment anticipated relative to the Mid hourly load forecast | 100%, 125%, 150%, 200%, 250%, and 300% |

An overview of the forecasted load for the SCE and SDG&E areas over the next 12 years shows that, even without considering incremental DER deployment relative to CEC's baseline forecast, or the role of large-scale resources, the net load will continue to drop as time goes on, particularly during the middle of the day. Figure 6 shows the forecasted hourly load for April 1 across a series of years, under the baseline (i.e., 100% forecasted DER) Mid load scenario. Throughout this section, Strategen focused on April 1 as spring months exhibit overgeneration conditions due to favorable solar irradiation and low cooling loads. The figure

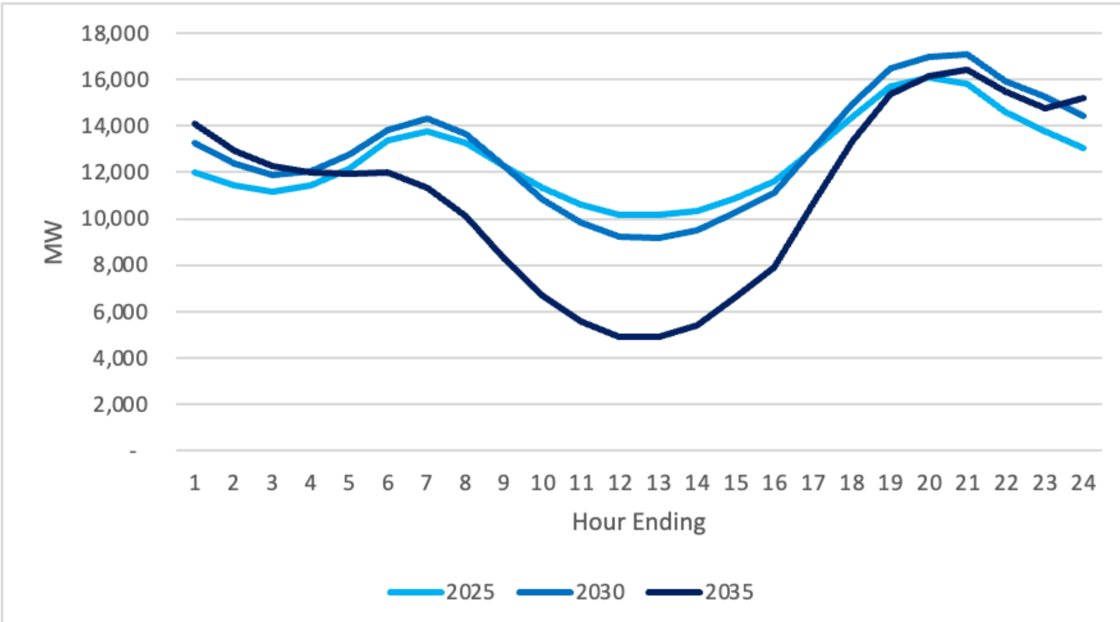
[116] Specifically, Strategen leveraged six data sets that cover hourly load forecasts for SCE and SDG&E under low, mid, and high load conditions. Hourly load data for SCE and SDG&E was added to represent a single Southern California region. *See* California Energy Commission. "2023 Integrated Energy Policy Report," https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report.

[117] Includes assumptions around electrification of transportation and industry as well as new load growth and energy efficiency.

[118] Future variants were selected to represent sensitivities to forecasts. At the high end, it is unlikely DER deployment could increase by 300% without significant infrastructure development at the distribution and transmission level to enable reliable hosting of this capacity.

below captures the effects of expected DER deployment on net load, highlighting the fact that the hours of greatest solar generation have the most material impact on net load, especially as time goes on.

**Figure 6. Comparison of aggregate SCE and SDG&E net load for April 1 across select years (Mid Load, at 100% Forecasted DER).**

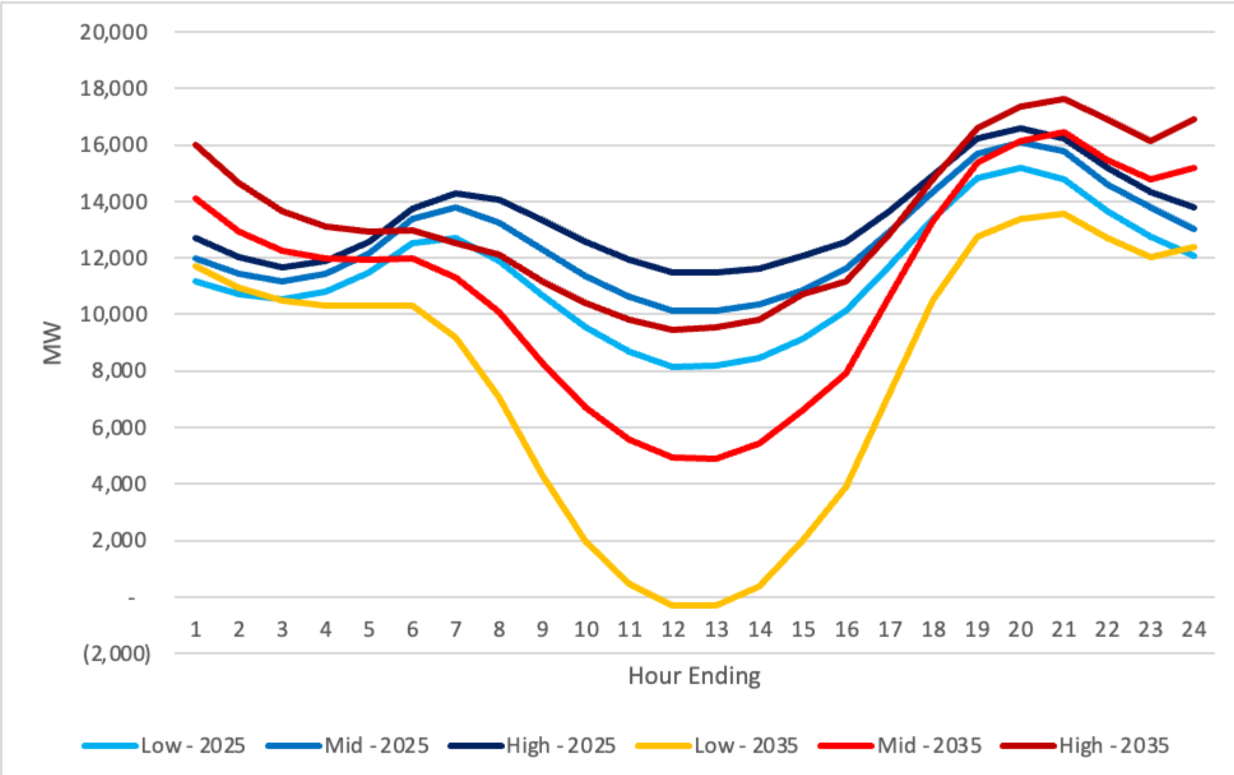



*Source: Prepared by Strategen using data from the CEC* California Energy Demand *(CED0 2021 Hourly Forecasts for SCE and* SDG&E *and the SCE and* SDG&E *2022* Integrated Resource Plan (*IRP) Preferred Portfolio*[119]

While the Mid load scenario shows the growing impact of DER development on net load, it does not identify hours of negative net load during April 1 under baseline (i.e., 100% realization of the forecast) DER deployment assumptions. This changes when considering the three load scenarios for which the CEC developed hourly load forecasts. As shown in Figure 7, the Low load scenario shows a greater potential for periods with negative net load due to said scenario's increased baseline DER deployment assumptions.

[119] California Energy Commission. "2023 Integrated Energy Policy Report." and California Public Utilities Commission. "LSE 2022 Integrated Resource Plans." https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/lse-2022-integrated-resource-plans.

Figure 7. Comparison of aggregate SCE and SDG&E net load for April 1 across select years (All Load Scenarios, at 100% Forecasted DER).



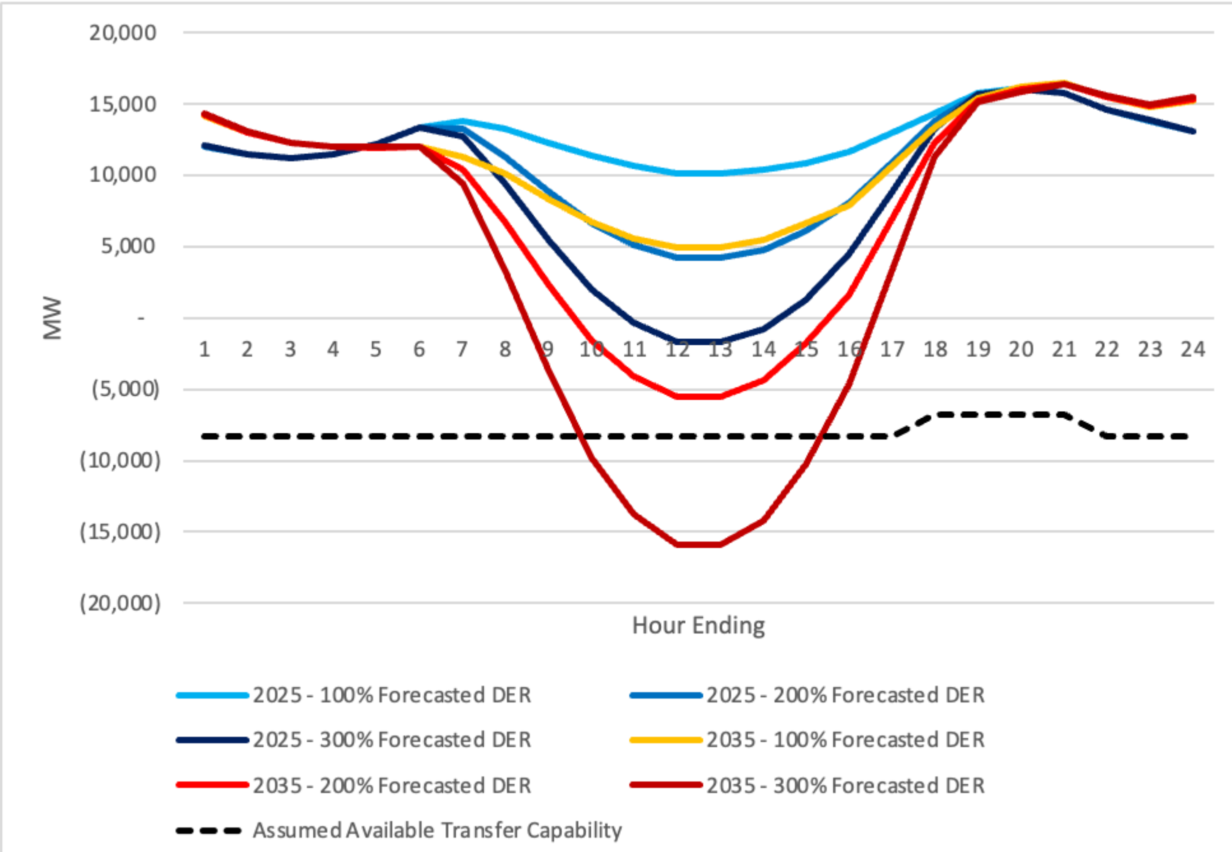

*Source: Prepared by Strategen using data from the CEC CED 2021 Hourly Forecasts for SCE and* SDG&E *and the SCE and* SDG&E *2022 IRP Preferred Portfolio*[120]

To assess the potential for periods of negative net load, Strategen developed a series of alternative futures that scale the deployment of DERs upwards, to identify the upper limit of DER deployment that the system could currently sustain. Figure 8 below shows the effects of incremental (i.e., above-baseline) DER deployment on the net load, under the Mid load scenario. As noted previously, applying baseline DER development assumptions to the Mid load scenario does not result in negative net load on April 1 through 2035; nevertheless, when scaling DER deployment to 200% (i.e., double) of the forecasted value, a period of negative net load manifests from hour ending (HE) 10 through HE 15 by 2035. When scaling DER deployment to 300%, periods of negative net load become apparent as early as 2025 and reach a net load minimum below -15,000 MW by 2035. It is important to note that Strategen scaled the capacity of DER deployment (BTM solar PV and energy storage) as well as their hourly impacts on the forecasted load, thus accurately capturing the effects of incremental deployment based on the CEC forecasts. Starting with Figure 8, Strategen has also added a data trend to illustrate the available transfer capability out of the region. Those values are

[120] California Energy Commission. "2023 Integrated Energy Policy Report" and California Public Utilities Commission. "LSE 2022 Integrated Resource Plans."

represented with negative numbers to more clearly show how transmission can enable sustainable management of periods of negative net load.

**Figure 8. Comparison of aggregate SCE and SDG&E net load for April 1 across select years and levels of DER forecast realization (Mid Load).**



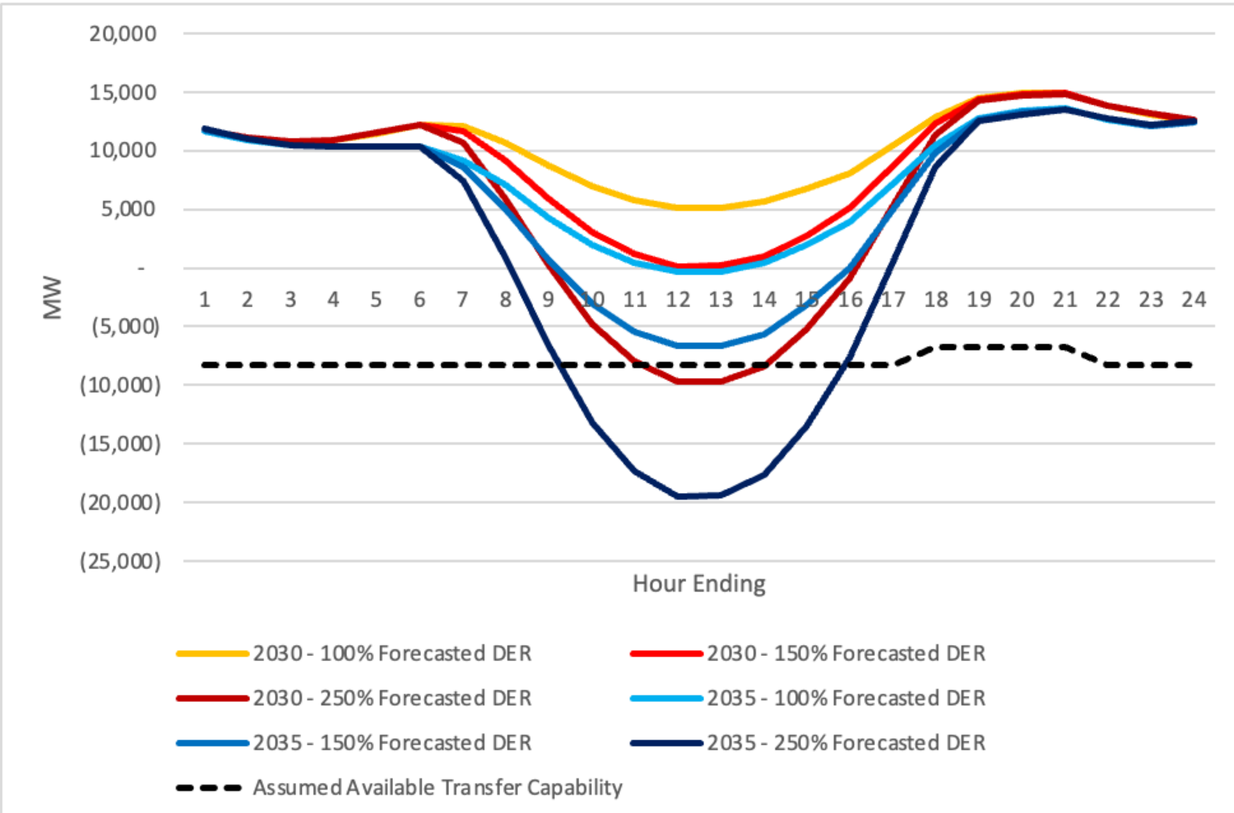

*Source: Prepared by Strategen using data from the CEC CED 2021 Hourly Forecasts for SCE and* SDG&E *and the SCE and* SDG&E *2022 IRP Preferred Portfolio*[121]

For the Low load scenario, which exhibited some negative net load periods under baseline DER deployment assumptions, even more modest levels of incremental DER development materially impact net load minima. As shown in Figure 9 below, assuming realization of 150% of the DER forecast for this scenario results in a negative net load period from hour ending (HE) 10 through HE 16 by 2035, with a minimum of approximately -10,000 MW. If 250% (i.e., 2.5 times) of the DER forecast were to materialize, a similar period of negative net load would manifest as early as 2030, with the system reaching a net load minimum of about -20,000 MW by 2035. Notably, some of these scenarios result in negative net load in excess of the assumed transfer capability out of Southern California, indicating that, even without consideration of

[121] California Energy Commission. "2023 Integrated Energy Policy Report" and California Public Utilities Commission. "LSE 2022 Integrated Resource Plans."

large-scale resources, significant DER development might merit incremental transmission investments in order to fully leverage what would otherwise be a significant period of local PV overgeneration.

Figure 9. Comparison of aggregate SCE and SDG&E net load for April 1 across select years and levels of DER forecast realization (Low load).



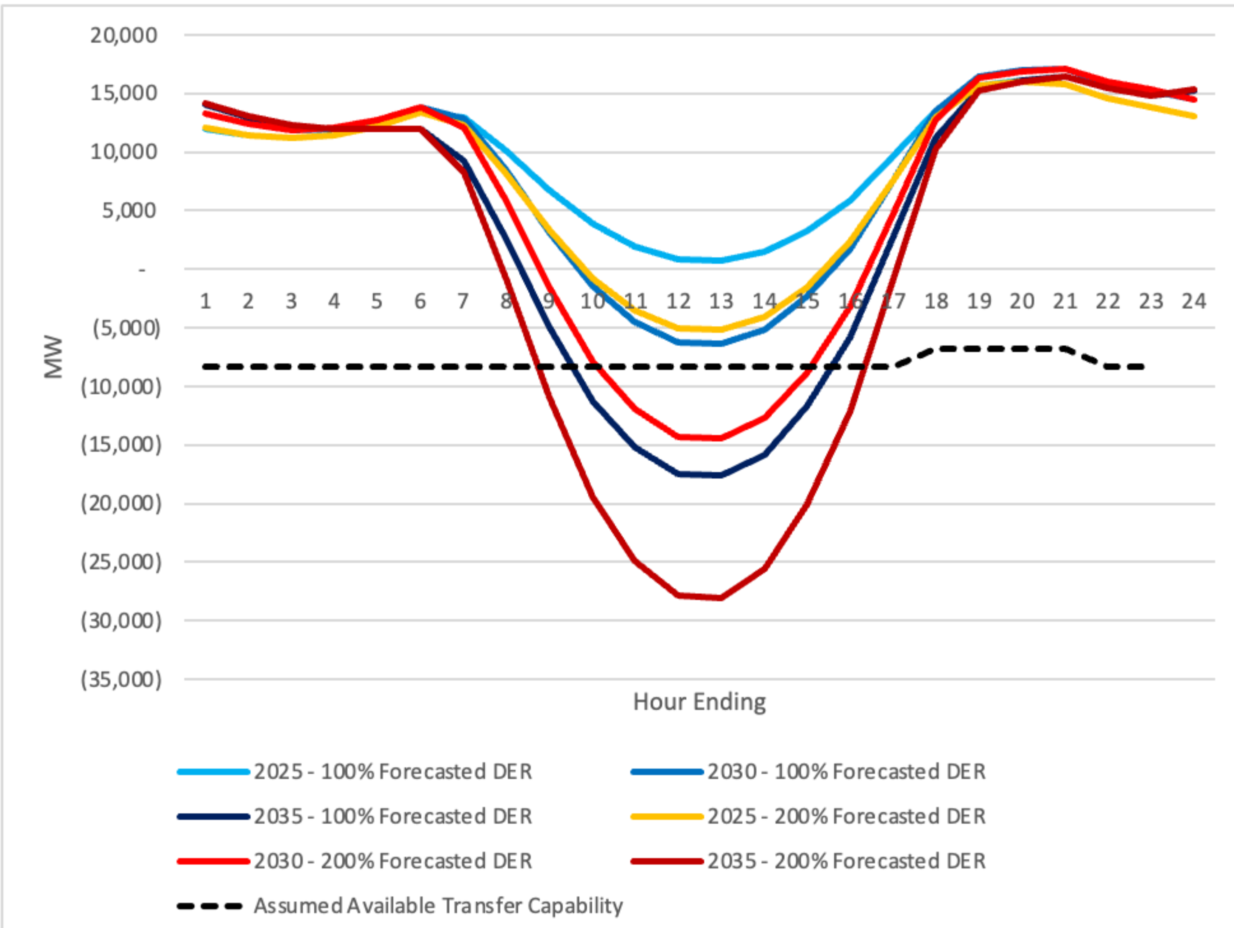

*Source: Prepared by Strategen using data from the CEC CED 2021 Hourly Forecasts for SCE and* SDG&E *and the SCE and* SDG&E *2022 IRP Preferred Portfolio*[122]

It is clear, based on Strategen's assumptions and modeling, that increased DER deployment would materially affect net load trends in Southern California, particularly during the middle of the day; however, distributed generation is not the only variable source of power in the systems analyzed herein. Figure 10 captures the effects of large-scale solar resources, existing and forecasted, on net load. Notably, Figure 10 focuses on the mid load scenario, which, without assuming incremental DER deployment, did not experience negative net load intervals during April 1 through 2035. When considering the effects of large-scale solar generation on net load shapes, the mid load scenario exhibits periods of negative net load as early as 2030, even under baseline (100%) DER forecast assumptions, reaching a minimum of about -17,000

[122] California Energy Commission. "2023 Integrated Energy Policy Report" and California Public Utilities Commission. "LSE 2022 Integrated Resource Plans."

MW by 2035. If 200% (double) of the DER forecast were to materialize, when considering the impact of local large-scale solar PV, the mid load scenario would experience significant periods of negative net load from HE 10 to HE 16 in 2025 (minimum of about -5,500 MW). Under said assumptions, by 2035, negative net load conditions would be prevalent from HE 8 to HE 17 (minimum of approximately -28,000 MW), covering every hour with significant solar electricity production. The significant deployment of other resources, such as large-scale deployment of energy storage, for example, could alter this picture.

**Figure 10. Comparison of aggregate SCE and SDG&E net load for April 1 across select years and levels of DER forecast realization, including effects of existing and expected large-scale solar development in Southern California (Mid Load).**




*Source: Prepared by Strategen using data from the CEC CED 2021 Hourly Forecasts for SCE and* SDG&E *and the SCE and* SDG&E *2022 IRP Preferred Portfolio*[123]

[123] California Energy Commission. "2023 Integrated Energy Policy Report" and California Public Utilities Commission. "LSE 2022 Integrated Resource Plans."

## Discussion

These results show that, when considering the impact of both DER and large-scale solar, even baseline load and DER deployment assumptions result in significant periods and magnitudes of negative net load. This results in the potential for local DER overgeneration to surpass available transfer capability out of Southern California by 2035 under the baseline DER deployment assumptions, and as early as 2030, assuming a doubling of DER deployments is realized.

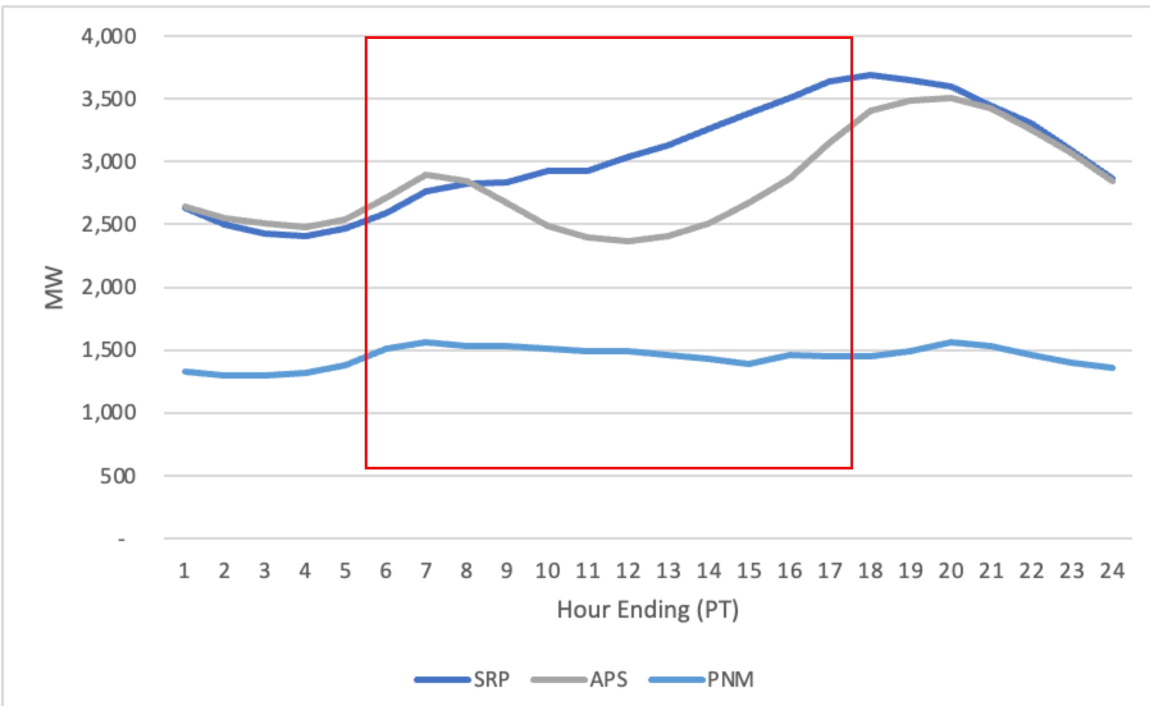
Given the likelihood of DER generation exceeding local load under these assumptions, it is crucial to consider regional load patterns to better understand the potential of exporting this excess generation to deliver more clean energy to other neighboring balancing authority areas (BAAs). Southern California is electrically tied to other BAAs in the Southwest, such as the Los Angeles Department of Water & Power (LADWP) and the Imperial Irrigation District (IID) within California, and the Western Area Power Administration (WAPA), Salt River Project (SRP), and the Arizona Public Service Company (APS) in neighboring states, among others. Some of these neighboring entities have less ambitious clean energy commitments than California, and thus, measures to enhance clean energy exports from Southern California to southwestern states can have an outsized impact on displacing fossil fuels. Not having as ambitious clean energy goals may also mean these entities do not have some of the net load issues faced by California, and accordingly may be good candidates to receive daytime energy imports.

To assess the potential to export DER generation to neighboring regions, Strategen utilized data from the US Energy Information Administration's (EIA) Hourly Electric Grid Monitor, which collects demand and total interchange data per BAA on an hourly basis. The data used is for 2022 and thus is intended to illustrate the potential synergies given the overall load shapes of the neighboring BAA and the Southern California net load profile.

The analysis presented below focuses on APS, Salt River Project (SRP), and the Public Service Company of New Mexico (PNM), three BAAs outside of California. Figure 11 presents the load managed by these BAAs on April 1, 2022. Notably, these areas were selected given the time difference relative to the Southern California grid, a distinction that enhances synergy due to the timing of loads. As shown in Figure 11, all BAAs experience significant load in the periods where DER overgeneration in Southern California would exceed transfer capabilities in future years. This is particularly noticeable for SRP and PNM, but still relevant for APS despite the latter having its own to manage. These hours are denoted in Figure 11 by the red box. Notably, several of the hours with potential DER exports from CA during the late afternoon coincide with the peak load hour for SRP. This coincidence will increase over time as more of the DERs installed in California include not only rooftop solar but also additional battery storage, which could extend DER generation output into the evening hours.

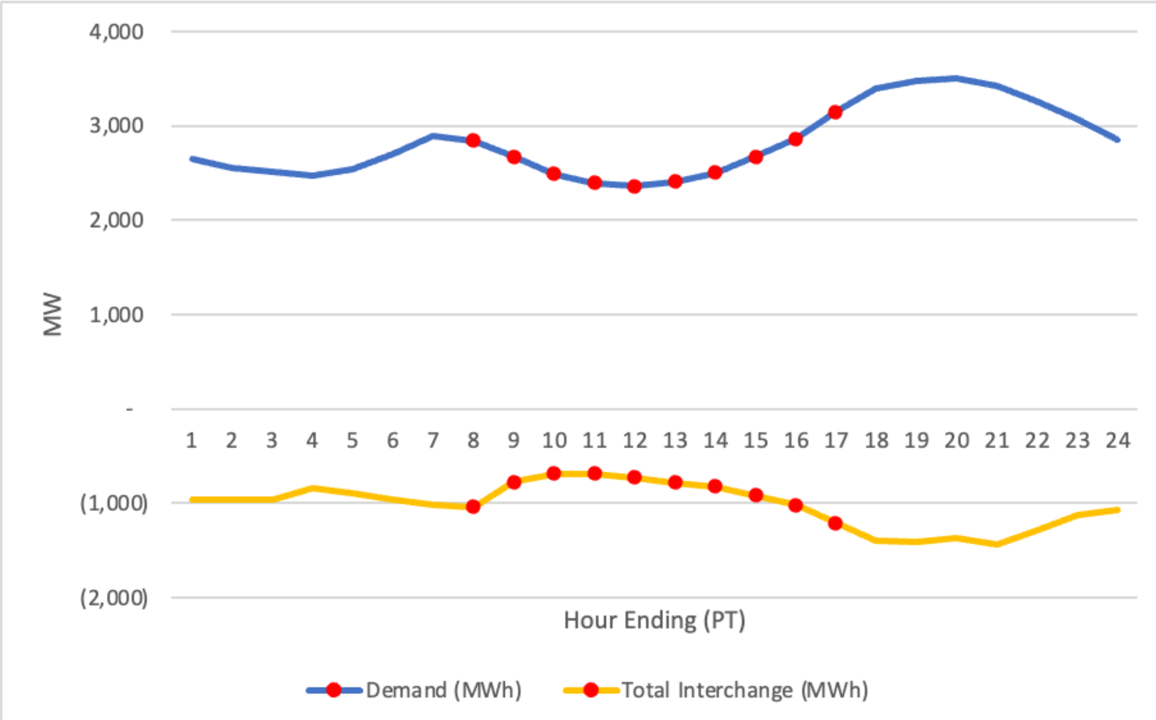
While APS' peak load hour does not coincide with the hours of potential DER exports from CA, it is important to note that APS continued to rely on imports to meet its load during the hours marked in red (albeit at a reduced rate relative to other hours), as shown in Figure 12, below. This shows that, provided there is sufficient available transfer capability, even APS, whose load shape is less complementary than that of SRP and PNM, could still make use of potential DER overgeneration in Southern California given its load and transfer patterns.

Figure 11. Demand of APS, SRP, and PNM on April 1, 2022 (MW)




*The red box denotes the hours of the day that Southern California experiences overgeneration. Source: Prepared by Strategen using data from the EIA Hourly Electric Grid Monitor*

Figure 12. Demand and Total Interchange of APS on April 1, 2022 (MW).




*The red dots represent hours during which APS relies on energy imports.*
*Source: Prepared by Strategen using data from the EIA Hourly Electric Grid Monitor*

In summary, several scenarios presented in this section show negative net load values in excess of the assumed available transfer capability out of Southern California, underscoring the need for incremental transmission investments in the region. The discussion around transmission in the Southwest region often focuses on importing remote large-scale renewable resources, but this analysis shows that transmission can also play a critical role in local DER growth by taking advantage of periods of DER overgeneration. Using transmission to link load centers together can be critical to transforming DERs from a local energy source that may soon likely be prone to overgeneration, to assets that can provide energy beyond their neighborhoods, adding flexibility and enhancing reliability to the overall system. Importantly, doing so will require not only transmission infrastructure development, but enabling infrastructure to accommodate a transfer of energy from DER to the transmission system. Further, given that Arizona and New Mexico may themselves face overgeneration issues in the future with continued solar deployment (albeit at a slower pace than California), in the longer term, there may be value in, and a need to, export solar overgeneration from all of these states even further away, particularly to those regions of lower solar potential.

# Implications for Decision-Makers

A clean energy future will require the use of every tool in the toolbox, meaning that both transmission and distributed energy resources have a vital role to play in the energy transition. But while investment is needed on both these fronts—and transmission and DER infrastructure can complement and reinforce each other—there is not yet an established framework to consider these two necessary components of the clean energy transition in tandem.

A segmented approach to DER and transmission planning can result in inefficient grid operations, costly equipment upgrades, or risks to power reliability. For instance, failing to accurately consider DER adoption and DER benefits in bulk power system planning can result in either the overbuilding or underbuilding of generation and transmission assets, with potentially significant ramifications for electricity costs and reliability.[124] Given the complementary nature of DERs and transmission, and considering the lessons learned from the case studies of Australia, Hawaii, and Southern California, the following takeaways should serve as guidance for regulators, policymakers, and market operators seeking to properly align these siloed domains.

1. **Engage in comprehensive planning:** Market operators, transmission owners, and DSOs should work to establish comprehensive planning efforts that enable coordination between DERs and transmission. Ensuring planning alignment and coordination necessitates effective DER adoption forecasts. Adequate forecasting is essential for accurately projecting peak demand at the bulk power system level and planning for resource procurement decisions.[125] It is important that DER forecasts be locationally granular (corresponding to particular transmission-distribution substations) so that DER growth can be considered in transmission infrastructure planning.[126] Given the importance of this information, regulators and market operators should consider setting requirements for information sharing regarding DER forecasting and development for DSOs. Said information transfer should be done on a regular basis to limit delays in the already laborious transmission planning process. This should be incorporated into a regular planning process between DSOs, market operators, and applicable agencies and authorities, as underscored in Hawaii's experience with holistic planning within its Integrated Grid Planning process. Notably, this type of comprehensive planning also allows for the adequate consideration of different

[124] Kelsey Horowitz et al., *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions.*
[125] Paul De Martini and Lorenzo Kristov, *Distribution Systems in a High Distributed Energy Resources Future.*
[126] Paul De Martini and Lorenzo Kristov, *Distribution Systems in a High Distributed Energy Resources Future.*

solutions to reliability challenges, such as the evaluation of DERs as NWAs for transmission needs.

2. **Consider DER benefits within the transmission approval process:** Today, ISOs and RTOs within organized markets seldom consider the impact that transmission investments will have on the utilization of DERs. This is due to their jurisdiction being limited to resources that are directly interconnected to high-voltage transmission lines, or that participate in their wholesale markets. As a result, the benefits that transmission may offer to DERs are not considered during planning. While incorporating consideration of these benefits in the planning process could be complex given timing, jurisdictional concerns, and challenges in quantifying them, the siting approval process, a step required in many states, offers another opportunity to capture the impact that transmission investments would have on DER utilization. Today, several states require a final approval process once a transmission project is recommended for development. These approval processes usually take the form of proceedings at the applicable utility or siting commission where interested parties can weigh in on the pertinence of proposed transmission investments. In this context, regulators and policymakers could require the consideration of the broader benefits that deploying incremental transmission can provide, such as increased DER utilization and regional reliability gains. Enshrining the need to account for these potential benefits in statute could assist in bolstering the record regarding the interdependence and complementary nature of DER and transmission solutions.

3. **Proactively plan for incremental transmission development:** Historically, the development of additional transmission capacity has been laborious and time-consuming. In addition, due to the capital-intensive nature of transmission development, projects have rarely been undertaken in a proactive manner, prior to when the need for the upgrades is manifest. As noted earlier in this report, the slow pace of transmission deployment has left hundreds of GW of incremental clean generation and storage capacity awaiting interconnection in queues across the nation. In this context, proactive planning, such as the aforementioned 20-Year Transmission Outlook prepared by CAISO, will be essential to ensure timely identification and completion of future projects. When evaluating areas for proactive transmission development, market operators, transmission owners, and state agencies should consider prioritizing linking load centers to areas with significant variable renewable potential and to each other, so as to allow for the sharing of DER generation across them. In considering proactive transmission opportunities, jurisdictions should consider a wide set of future conditions regarding DER deployment, load growth, and other conditions, as exemplified in Strategen's analysis of Southern California, which identified significant need for additional transfer capability as early as 2030 under

different load and DER development scenarios. A particular emphasis should be placed on connecting areas with significant DER development, load growth, and limited local resource diversity to bolster reliability and minimize costs.

4. **Improve DER visibility and control:** As noted earlier in this report, jurisdictions across the globe have adopted policies to better understand the behavior and impact of DERs, as well as to leverage them to improve safety and bolster reliability. Learning from the Australian experience, LSEs, regulators, and policymakers should consider development of a DER registry and establishment of smart inverter requirements to promote enhanced awareness of DERs and increased DER grid responsiveness, safety, and control. In addition, before imposing static 'no-export limits' in regions with high DER adoption, regulators and utilities should first seek to maximize dynamic DER management. These steps can materially improve the hosting capacity of the distribution system and enable DERs to reliably support power quality and stability efforts at a local level, maintaining adequate voltage for end-users.

5. **Bolster aggregation frameworks that allow DER participation in wholesale energy markets:** To leverage the capabilities and benefits of DERs, market operators, policymakers, and regulators should build upon, and expedite meeting, the requirements of FERC Order 2222 by way of enhanced collaboration to develop workable market participation schemes that support DER aggregation, allowing them to participate unencumbered in wholesale electricity markets. VPPs, as deployed successfully in Australia, are one example of a potential aggregation approach. This level of market integration will allow DERs to serve load across the grid, not solely in the area in which they have been deployed. Development of these market participation pathways should also consider the necessary steps to allow for these resources to provide capacity in markets where such a product is available.

While breaking the siloes that separate DERs and transmission will require intentional effort, a coordinated approach to planning and deploying these resources would benefit ratepayers and accelerate the clean energy transition. Linking these increasingly interrelated resources would allow for more efficient resource deployment, better utilization of all potential services from DERs, and more efficient use of transmission capacity. Expanding the use of DERs and developing transmission lines that connect renewable generation to load centers, and load centers to each other, will allow for more rapid and deep decarbonization across the country, enabling both large-scale and distributed renewable energy generation. In sum, as demonstrated by the analysis and case studies presented here, DER and transmission investments must be thought of as complementary—rather than competing—resources. Deploying them in tandem, and effectively coordinating between them, will be essential to achieving the clean energy transition and maximizing the benefits it will provide.

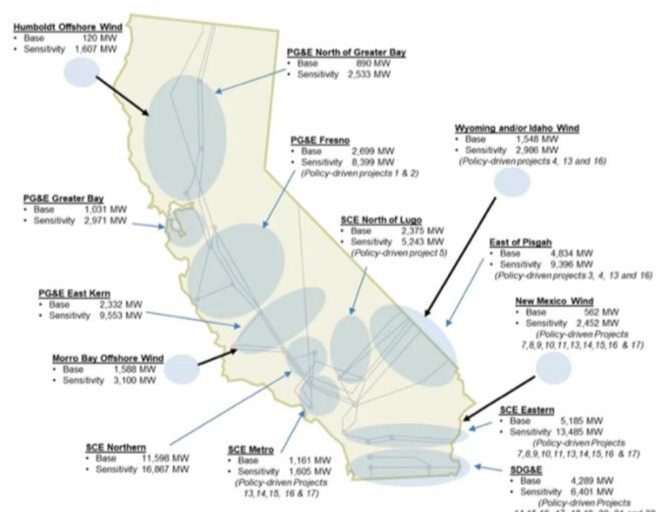
# Appendix I: Southern California Case Study Methodology

## Additional Background

As noted previously, California has historically relied on energy imports of hydroelectric power from the PNW transmitted across HVDC power lines. In recent years, interest in the significant renewable potential in neighboring southwest states, including Arizona, Nevada, and New Mexico, has grown, but existing transmission capacity between the states is limited and fully subscribed.

To address California's need for clean energy, CAISO unveiled a $7.3 billion plan in May 2022 to develop "thousands of miles of new high-voltage transmission lines the state needs to hit its climate goals."[127] This plan aims to tackle the lack of transmission available to connect the vast amount of potential clean energy resources available in remote regions of California and the southwest. With an estimated 8-to-10-year lead time for transmission projects, the plan has been coined a "least-regrets investment" to address grid instability and the clean energy transition. Three of the largest transmission projects are open to competitive bidding from independent developers; however, most of the forty-five total projects will be led by California's major utilities (SCE, PG&E, SDG&E), as noted in Figure I-1, below.[128]

Figure I-1. California transmission planning zones and capacity.




*Source: '20-Year Transmission Outlook,' CAISO, 2023*

[127] Jeff St. John, "California Has a New $7.3B Plan to Fix Its Transmission Problems," *Canary Media*, May 22, 2023, https://www.canarymedia.com/articles/transmission/california-has-a-new-7-3b-plan-to-fix-its-transmission-problems.
[128] *20-Year Transmission Outlook,* California Independent System Operator.

Beyond new transmission infrastructure, SCE, the largest utility in the region, has also taken proactive measures for transmission and DER coordination through the release of its next-generation Grid Management System (GMS). The GMS aims to provide more visibility of DER impacts on the circuit to help operators take actions to maintain reliability of operations. More awareness of DER on circuits would allow SCE to utilize DERs to support distribution system operations – SCE has noted the vast number of DERs in the region are "presently unmonitored and controlled," limiting its ability to integrate additional DER and potentially utilize DER to mitigate stability issues at the transmission level.[129] SCE is actively looking at applications to utilize DER to support both distribution and transmission system operations.

## Data Collection

Strategen's analysis has been developed to be in line with California's planning and forecasting practices. Strategen's modeling approach is based on publicly available data from California's load-serving entities (LSEs), regulators, energy agencies, and market operators regarding load and DER forecasts, the deployment of large-scale renewables, and issues pertaining to regional transmission infrastructure. The below sections outline Strategen's data collection approach to several central modeling inputs.

## Hourly Load Forecast Data

In California, load forecasts are prepared by the state's foremost energy agency, the California Energy Commission (CEC). For these analyses, Strategen utilized hourly load forecasts prepared by the CEC as part of their 2021 Integrated Energy Policy Report (IEPR). Specifically, Strategen leveraged six data sets that cover hourly load forecasts for SCE and SDG&E under low, mid, and high load conditions. These forecasts, which are also used to inform long-term planning activities by LSEs and the California Public Utilities Commission (CPUC), were used to inform the baseline and net load for every hour through 2035. Given the fact that net load is mostly driven by the availability of solar generation, Strategen's analysis focuses on periods where the oversupply of solar generation is most significant, the spring and early summer months. Hourly load data for SCE and SDG&E was added to represent a single Southern California region.[130]

[129] Anthony Johnson, "SCE's Next-Generation Grid Management System," (presentation by Southern California Edison, 2019), https://www.energy.gov/oe/articles/ferc2johnsonsce.

[130] Specifically, Strategen used the following SCE and SDG&E hourly load forecasts for the analyses contained herein: CED 2021 Hourly Forecast - Low Baseline AAEE Scenario 5 - AAFS Scenario 2; CED 2021 Hourly Forecast - Mid Baseline - AAEE Scenario 2 - AAFS Scenario 4; and CED 2021 Hourly Forecast - High Baseline - AAEE Scenario 1 - AAFS Scenario 4.

## DER Deployment Forecasts

The CEC's load forecasts are inclusive of expected BTM solar and storage development since California agencies view DERs as demand modifiers given the fact that they are not fully deliverable. As such, hourly load forecasts directly capture the expected effect of BTM solar PV and storage assets. In addition, the CEC hourly load forecasts also capture differentiated adoption effects across these load scenarios, as noted in the tables below. In addition to modeling these deployment cases, Strategen used the CEC's DER deployment forecasts to further explore the potential effects of increased and aggressive DER deployment, building upon the data included in the CEC forecasts by adding DER deployment multipliers, allowing Strategen to consider a wide set of potential futures. The scenarios, Low Demand, Medium Demand, and High Demand, are indicated in Table I-1, Table I-2, and Table I-3, respectively.

Table I-1. BTM PV and Energy Storage System (ESS) Deployment Scenarios (Low Demand, MW).

| Year | SCE PV | SCE ESS | SDG&E PV | SDG&E ESS |
|---|---|---|---|---|
| **2024** | 5,685 | 472 | 2,297 | 164 |
| **2025** | 6,295 | 560 | 2,509 | 194 |
| **2026** | 6,948 | 652 | 2,719 | 224 |
| **2027** | 7,444 | 745 | 2,878 | 255 |
| **2028** | 7,961 | 841 | 3,034 | 287 |
| **2029** | 8,499 | 939 | 3,186 | 319 |
| **2030** | 9,053 | 1,040 | 3,335 | 352 |
| **2031** | 9,616 | 1,143 | 3,480 | 385 |
| **2032** | 10,231 | 1,249 | 3,628 | 418 |
| **2033** | 10,842 | 1,357 | 3,771 | 452 |
| **2034** | 11,448 | 1,469 | 3,910 | 486 |
| **2035** | 12,047 | 1,582 | 4,046 | 520 |

Table I-2. BTM PV and ESS Deployment Scenarios (Mid Demand, MW).

| Year | SCE PV | SCE ESS | SDG&E PV | SDG&E ESS |
|---|---|---|---|---|
| 2024 | 4,896 | 456 | 2,044 | 158 |
| 2025 | 5,243 | 535 | 2,180 | 184 |
| 2026 | 5,607 | 617 | 2,323 | 211 |
| 2027 | 5,986 | 700 | 2,469 | 238 |
| 2028 | 6,380 | 784 | 2,616 | 266 |
| 2029 | 6,789 | 869 | 2,764 | 294 |
| 2030 | 7,213 | 956 | 2,913 | 322 |
| 2031 | 7,653 | 1,045 | 3,062 | 350 |
| 2032 | 8,104 | 1,135 | 3,210 | 379 |
| 2033 | 8,564 | 1,227 | 3,356 | 408 |
| 2034 | 9,031 | 1,321 | 3,500 | 438 |
| 2035 | 9,501 | 1,416 | 3,642 | 467 |

Table I-3. BTM PV and ESS Deployment Scenarios (High Demand, MW).

| Year | SCE PV | SCE ESS | SDG&E PV | SDG&E ESS |
|---|---|---|---|---|
| 2024 | 4,412 | 440 | 1,797 | 152 |
| 2025 | 4,617 | 511 | 1,860 | 175 |
| 2026 | 4,819 | 583 | 1,924 | 199 |
| 2027 | 5,020 | 655 | 1,990 | 222 |
| 2028 | 5,220 | 727 | 2,055 | 246 |
| 2029 | 5,420 | 800 | 2,122 | 269 |
| 2030 | 5,623 | 874 | 2,191 | 293 |
| 2031 | 5,829 | 948 | 2,262 | 317 |

| | | | | |
|---|---|---|---|---|
| **2032** | 6,040 | 1,023 | 2,335 | 341 |
| **2033** | 6,255 | 1,098 | 2,411 | 365 |
| **2034** | 6,476 | 1,174 | 2,488 | 390 |
| **2035** | 6,705 | 1,250 | 2,568 | 415 |

*Source: Prepared by Strategen using data from the CEC CED 2021 Hourly Forecasts for SCE and SDG&E and the SCE and SDG&E 2022 IRP Preferred Portfolio*

## Large-Scale Resource Development

To further tune the load shapes derived from Strategen's analysis of the CEC's hourly load forecasts, Strategen considered the expected development of additional large-scale renewables, particularly solar PV. For many years, California has been among the leading states in deployment of large-scale renewable and storage resources. Given the state's decarbonization goals, this trend is expected to continue and intensify, as has been documented in the California Public Utilities Commission's (CPUC) IRP proceeding, the CEC's Senate Bill (SB) 100 modeling, and other planning venues. In this context, Strategen relied on filings made by SCE and SDG&E before the CPUC and CEC to model expected deployments through the study period. Specifically, Strategen used the CPUC's baseline portfolio data for its IRP proceeding to determine the existing solar resources in SCE and SDG&E territory. To assess future deployments in the same territories, Strategen used the preferred portfolio filings made by SCE and SDG&E in 2022 under the CPUC's IRP proceeding to develop the projections in Table I-4.

Table I-4. Large-Scale Solar PV Capacity Projections (MW).

| IOU | 2025 | 2030 | 2035 |
|---|---|---|---|
| **SCE** | 10,791 | 18,378 | 26,649 |
| **SDG&E** | 1,391 | 1,818 | 2,620 |

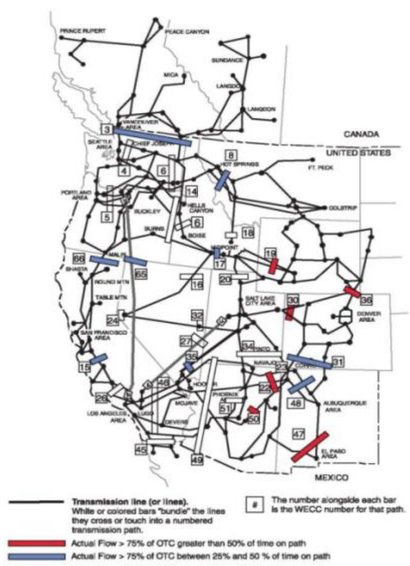
*Source: Prepared by Strategen using data from the CEC CED 2021 Hourly Forecasts for SCE and SDG&E and the SCE and SDG&E 2022 IRP Preferred Portfolio*

## Transmission Utilization

To analyze transmission capacities and usage within Southern California, Strategen collected transmission and DER penetration data from several sources. For transmission capacity usage in Southern California, Strategen focused specifically on Pathways 26, 27, and 46 of the Western Interconnection. These three pathways were chosen due to being the key intertie paths in and out of Southern California (see Figure I-2).[131]

Path 26 is composed of three 500 kV SoCal Edison (SCE) power lines located in Los Angeles County (as well as parts of Kern and Ventura counties). The north-to-south transfer limit is 4,000 MW, while the south-to-north transfer limit is 3,000 MW.[132] Path 27, also known as the Intermountain or the Southern Transmission System (STS), is an overhead power line running from Utah's coal-fired Intermountain Power Plant to Adelanto Converter Station in the Southwestern United States. This pathway is designated to carry power generated from Utah to areas throughout Southern California, with a transfer capacity of 2,400 MW.[133] Path 46, also known as AZ-CA West of the River Path (WOR), is a set of fourteen 500 kV and 230 kV transmission lines in southeast California and Nevada up the Colorado River. With a 10,600 MW east-to-west transfer limit, the pathway delivers power to the population centers of Los Angeles and San Diego.[134] These three paths can be seen in the southwest area depicted in Figure 9, below, which also depicts historical congestion on transmission lines across the region.

**Figure I-2. Western interconnection transmission paths.**




*Source: National Electric Transmission Congestion Study (Washington, D.C.: U.S. Department of Energy, 2006),*[*https://www.energy.gov/sites/default/files/oeprod/DocumentsandMedia/Congestion_Study_2006-9MB.pdf*](https://www.energy.gov/sites/default/files/oeprod/DocumentsandMedia/Congestion_Study_2006-9MB.pdf).

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[131] *2023 Path Rating Catalog – Public Version* (Salt Lake City, UT: Western Electricity Coordinating Council, 2023), https://www.wecc.org/Reliability/2023%20Path%20Rating%20Catalog%20Public.pdf.
[132] *WSCC Path 26: Midway-Vincent Rating Increase Study Plan* (Sacramento, CA: California Independent System Operator, 2001), https://www.caiso.com/Documents/2001121316394010577.pdf.
[133] *2023 Path Rating Catalog – Public Version*, Western Electricity Coordinating Council.
[134] *2023 Path Rating Catalog – Public Version*, Western Electricity Coordinating Council.

While these three paths total approximately 16,600 MW of transfer capability out of Southern California, the amount of available transfer capability varies on an hourly basis due to demand and supply patterns. Moreover, this estimation of transfer capability is approximate as it is historically rated for going into the Southern California system, not out of it, given historical load patterns. To better understand the capability of the Southern California system to export power, entities like WECC are likely to be required to perform additional studies. In addition, it is likely that actual flow limits may be subject to other constraints within WECC, like stability requirements. Furthermore, the total transfer capability of the three paths may not be additive due to Kirchhoff's laws.

To better approximate available transfer capability, Strategen used the transmission utilization data provided by the Western Electricity Coordinating Council (WECC). WECC's transmission utilization data uses 2018 information to provide two values regarding the availability of transfer capacity per path: the U75 and U90 metrics. These metrics communicate the percentage of time in which power flow within a line was above 75 or 90 percent of the path's operating limit, respectively.

For paths 26 and 27, the U75 value is around 18%. For Path 46, the U75 value is around 0.3%. The U90 value for all paths considered is below 1%. While these metrics communicate how often lines are close to full utilization, they do not communicate it on an hourly basis (i.e., which hours see the highest utilization). As a result, Strategen's analysis assumes that available transfer capability out of the Southern California area is 50% of the rated capability for all hours for all paths, with the exception of HE 18 through HE 21 for Paths 26 and 27, where available transfer capability is assumed to be 25% to reflect WECC's U75 metric.[135]

## Research Limitations

This analysis must be understood as indicative rather than exhaustive, as it is intended to be used as a high-level illustration of the interplay between DER and transmission deployment in Southern California. As such, this research has several limitations. First, there are constraints related to the usage of utility-specific load forecasts from 2022-2035, which are likely to vary given load migration and future technological developments. In addition, it is important to underscore that future large-scale solar PV deployments are likely to be determined by the pace of interconnection, a variable that is not captured in the present analysis. Instead, this analysis assumed timely deployment of the large-scale renewables identified in the state's planning venues.

[135] HE 18 through 21 were selected as California planning agencies have routinely modelled limited Path 26 transfers for peak periods within their IRP and Resource Adequacy proceedings. *See* "Summer Reliability," California Energy Commission, accessed February 7, 2024, https://www.energy.ca.gov/data-reports/california-energy-planning-library/reliability/summer-reliability.

While this report considers many types of DERs, Strategen's technical analysis focused extensively on large-scale solar output and BTM solar and storage. For these reasons, concentrated solar, wind, biomass, and other renewables are not featured extensively in this technical analysis. Further, significant data availability constraints prevented Strategen from using the most up-to-date data on the utilization of WECC's transmission pathways. This obstacle was partially mitigated by combining WECC's 2018 Path Utilization data with inferences informed by WECC literature review and background research.[136] While Strategen considers the assumptions included in the present analysis to be sound, there exists some margin of error that could only be mitigated if utilization information was disclosed publicly with more granularity and frequency. In this context, more visible, recent, and accessible data is necessary to further understand WECC transmission utilization and its relationship with projected DER load growth and deployment.

Finally, and importantly, when considering the ability of DER to take advantage of available transmission capacity even before getting to transfer limits on the high-voltage transmission system, there are other factors that limit DER export. Indeed, this has been a factor widely cited as a challenge to DER deployment in the U.S. and across the -world.[137] Although there are existing situations where enabling infrastructure is present to enable DER exports that exceed local demand with export beyond a local substation, in many instances, this is not the case. Typically, substation protection measures such as circuit protection relays that prevent reverse power flows would need to be upgraded with devices that permit it, and additional power quality or voltage control devices to maintain protection may be required. Absent these modifications, the ability of DER energy to transfer to other regions on transmission lines is limited. While not quantified in this study, a significant amount of energy generated from DERs would be unavailable for meeting regional clean energy needs unless these transmission upgrades are made to enable reverse power flows.

[136] "Transmission Adequacy," Western Electricity Coordinating Council, accessed February 7, 2024, https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Transmission-Adequacy.aspx.

[137] *See, for example: Distributed Energy Transition Roadmap 2020-2025*, SA Power Networks; Laurel Varnado and Michael Sheehan, *Connecting to the Grid: A Guide to Distributed Generation Interconnection Issues* (Albany, NY: Interstate Renewable Energy Council, 2009), https://www.energy.gov/eere/amo/articles/connecting-grid-guide-distributed-generation-interconnection-issues-6th-edition.