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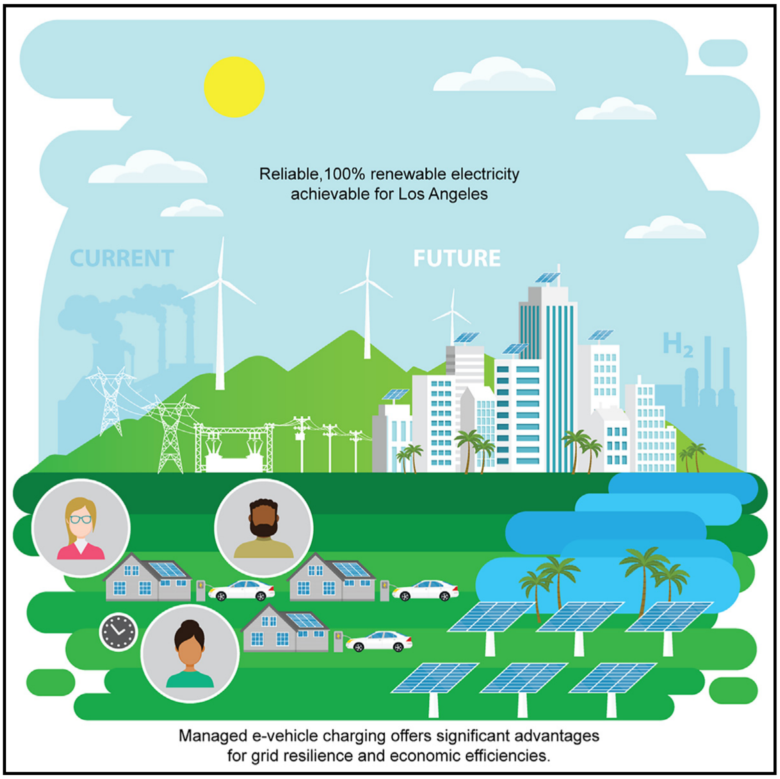
Integrated multimodel analysis reveals achievable pathways toward reliable, 100% renewable electricity for Los Angeles

Graphical abstract



Highlights

- Los Angeles' plan to supply all its electricity with clean energy by 2045 is viable
- Solar, wind, energy storage, fuel cell, and grid solutions are vital to meeting goals
- The system will yield billions of dollars in health and climate benefits

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In brief

Although communities and businesses nationwide have announced ambitious plans to combat climate change with electricity from carbon-free or renewable energy sources, there has been no comprehensive analysis of the pathways needed to power the largest US cities using only clean energy. Cochran et al. present findings from the Los Angeles 100% Renewable Energy Study, using detailed models to explore the interplay of factors, including supply, demand, infrastructure, and operational practices, in reliably delivering electricity to more than 4 million residents.

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Integrated multimodel analysis reveals achievable pathways toward reliable, 100% renewable electricity for Los Angeles

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SCIENCE FOR SOCIETY Communities and businesses nationwide have set ambitious goals to combat climate change by generating 100% of their electricity from carbon-free or renewable energy sources. Until now, there has been no comprehensive analysis of the possible pathways to achieve these goals on the scale needed to power the largest US cities. Here, we present findings from the Los Angeles 100% Renewable Energy Study (LA100), a thorough and wide-reaching assessment of the factors needed to make a fully renewable utility system operate reliably and deliver adequate electricity to more than 4 million residents. Our analysis uses detailed models of the city's power grid to examine not just renewable resource options and technical solutions related to generation, transmission, and distribution systems but also the balance of supply and demand, variability and reliability, and affordability and viability—all through the lens of changing demographics and climate conditions.

SUMMARY

Climate change has prompted many communities to set targets for carbon-free power supplies, but they often lack data-driven strategies to achieve them. We present a comprehensive analysis of an entirely renewable electric power system that can maintain operating reliability and resource adequacy using detailed models of the city of Los Angeles power grid. In consultation with the operating utility, the Los Angeles Department of Water and Power (LADWP), and the local community, we develop four supply scenarios across three demand projections to analyze which types of infrastructure and operational changes would achieve reliable electricity at least cost. We find that a reliable, 100%-renewable power system yielding more than $1 billion annually in health and climate co-benefits is achievable. Solar can supply most future energy needs, while combustion turbines that use renewable, storable carbon-neutral fuels are key to maintaining reliability. This study provides a replicable methodology that other jurisdictions globally can follow.

INTRODUCTION

Hundreds of communities and corporations have set targets for 100% carbon-free or renewable energy (RE) supplies to combat climate change.[1,2] However, until now, no major US utility or electricity provider had performed a comprehensive analysis of the possible pathways to achieve a 100% RE system, where supply and demand are balanced across all timescales and resource adequacy and operational reliability are maintained across both the transmission and distribution systems in the face of changing demand patterns, risks from climate change, and supply-side resource variability and uncertainty.

Here, we present a first-ever comprehensive analysis of an entirely renewable electric utility system that can maintain operating reliability and resource adequacy at a large metropolitan scale. Performed for the Los Angeles (LA) Department of Water and Power (LADWP), which serves more than 4 million residents, our analysis used detailed models of the city's power grid to evaluate four supply scenarios across three demand projections. The LA 100% Renewable Energy Study (LA100) examined which types of infrastructure and operational changes, where and when, would achieve reliable electricity at least cost, as agreed to by LADWP and the local community.

Through the integration of more than a dozen models at an unprecedented geographic and temporal scale, we find that a reliable, 100% renewable power system is achievable following multiple pathways. The comparison across scenarios offers quantitative insights for technology options, speed of the transition, and sectoral goals. Pursuing a faster transition with a tightly defined set of qualifying technologies has higher power-sector costs but also is associated with earlier and more substantial health and climate benefits.

A rapid transition of an energy system to 100% renewable (or 100% clean or zero-carbon) resources has implications for every citizen. The evolving perspective on energy justice is being further evaluated as a crucial next step.[3] This study charts a replicable methodology that other jurisdictions can use and improve upon to provide rigorous science-based insights for translating ambitious goals into programmatic and technology implementation plans.

Our analysis includes an extensive representation of residential and commercial building end-use electrification, light-duty electric mobility, and electrification of the city and school bus fleets. However, it does not factor in other possible electric loads that may become increasingly material to further planning, such as electrification of industry, fuel production for industry (such as renewable natural gas, methanol, ammonia, or other hydrocarbons), or medium- and heavy-duty vehicle electrification.

The goal of our study is not to predict outcomes or to provide a detailed plan that identifies specific project sites and their costs, but to allow Angelenos to make long-term policy goals informed by a better understanding of both feasibility and costs and benefits.

RESULTS AND DISCUSSION

Viability of 100% RE by 2045

This comprehensive technical evaluation identifies the LADWP's 100% RE goal as achievable, with hydrogen, RE fuels, and network robustness playing critical roles. In summary, we find that LADWP can achieve its target of 100% RE through multiple pathways by 2045—or sooner.

Consistent with other deep-decarbonization studies, solar and wind—enabled by batteries—provide most of the energy needed to meet future demand: 69%–87%, depending on the scenario, with resources sited on both the transmission grid and the distribution grid.[4–8] To serve the last ~10%–20% of demand and maintain reliability, our models build new renewably fueled combustion turbines located within the LA Basin that use storable carbon-neutral fuels such as hydrogen (see experimental procedures for details). Because this type of resource is not yet widely deployed, it represents a significant uncertainty in the cost of the transition to 100% renewable power and an important focus of technology development (including non-combustion alternatives such as fuel cells). Our analysis also explores tradeoffs between locally sited versus remote assets in terms of resource costs and the difficulties of delivering power through limited transmission corridors under contingency conditions.

Although power system costs increase compared with the 2017 Integrated Resource Plan, reflecting both increased load and generation capacity requirements, the system designs yield billions of dollars in health and climate co-benefits, and costs are small compared with the $200 billion/annum LA economy (less than 0.5%). Electrification, particularly of transportation, contributes significantly to the overall reduction in emissions across all neighborhoods, offering health benefits that can exceed $1 billion in 2045 alone.

Importantly, the study does not present recommendations. The goals and specific implementation pathways are decisions that LADWP will make with input from community members after reviewing the study findings. For example, the study does not recommend or evaluate alternative retail rate structures, customer incentives, or efficiency programs to identify policies or programs that could be needed to realize LA100's electrification, efficiency, or demand-response projections. Without identifying these programs, the study cannot analyze the cost or rate design implications of such programs. However, the National Renewable Energy Laboratory (NREL) has provided information to LADWP on the overall amount of assumed electrification, energy efficiency, and demand response. This information will enable LADWP to assess the potential costs associated with various programs. Similarly, the study does not address tradeoffs in electricity rates and the rate of electrification.

Future growth in demand and distribution-connected generation and storage

For the LA100 study, we developed three electricity demand projections—moderate demand, high demand, and stress demand—that vary in the rates of electrification of end-use demands assumed across the transportation, buildings, and industrial sectors, as well as by the rate of energy efficiency and demand-response deployment.

Figure 1 shows both the evolution of the annual energy consumption and annual peak load under the multiple scenarios. For reference, the figure also includes LADWP projections from its 2017 Integrated Resource Plan.[9] By 2045, compared with a 2020 baseline, annual energy demand increases by 45% with the moderate-demand projection, while peak demand increases by 30%. Growth in energy consumption in the residential and commercial sectors is driven by a hotter climate, population growth, and electrification, offset by significant energy efficiency measures. About 31% of the annual load growth results from the 1 million electric vehicles assumed to be deployed by 2045.

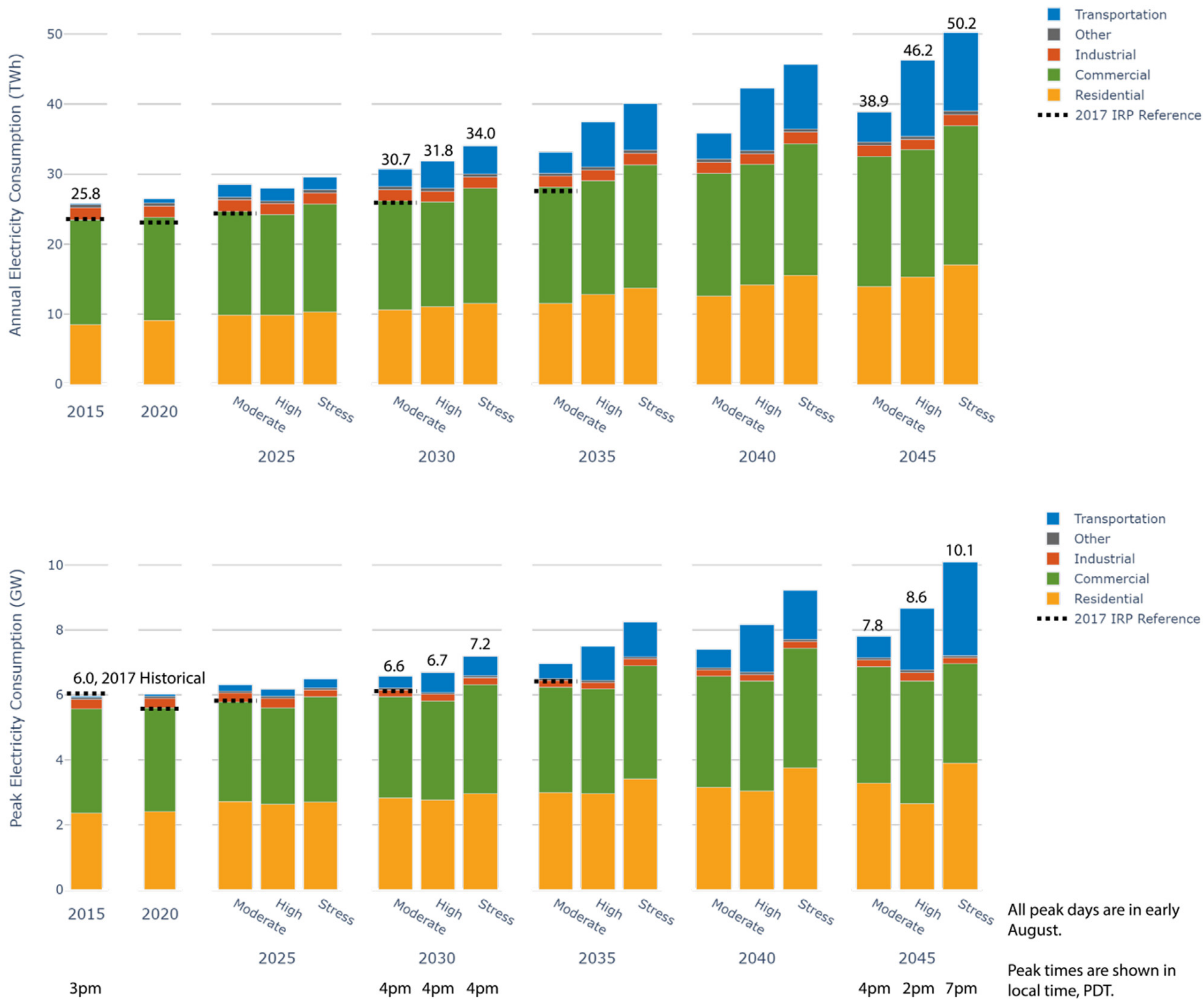

Figure 1. Peak electricity consumption and annual customer demand projections by sector
The figure is based on customer demand at the meter, not including losses. Totals are for periods before shifts in timing due to customer demand flexibility.

With the high-demand projection, more widespread adoption of electric vehicles (2.8 million vehicles by 2045), combined with more aggressive electrification of building end uses (e.g., cooking, heating, and cooling), produces a 74% overall increase in annual electricity demand by 2045, but more aggressive efficiency and demand-response measures mitigate the increase in peak demand. Electric vehicle charging can influence the timing of the peak. The high-demand projection assumes more workplace charging relative to home charging, resulting in charging earlier in the day (which is better aligned with solar generation).

The stress-demand projection, in which load nearly doubles relative to pre-2020 values, assumes (1) higher levels of electrification and electric vehicle adoption, but with limited deployment of efficiency measures, and (2) a greater fraction of residential electric vehicle charging starting in the evening hours. This scenario results in a peak demand at 7 p.m., reducing the effectiveness of solar photovoltaics (PV) to meet demand peak.

Simulations of demand also produce flexibility profiles or the amount of load that can be shifted over various timescales. Overall, 900–1,400 MW of load (9%–16% of peak) is shifted during periods of peak demand, and up to 12% of annual demand is shifted within the diurnal periods, resulting in a better alignment of RE supply and demand.

Deployment of distributed resources

Distribution-connected solar and energy storage were found to be a key part of meeting this demand. Using high-spatial-resolution data, least-cost analysis identified locations for solar (and solar plus storage) that would be economically viable. Depending on the scenario, 2.8–3.9 GW of customer-sited PV would be deployed, with variations being influenced by assumed compensation for electricity exported to the grid from

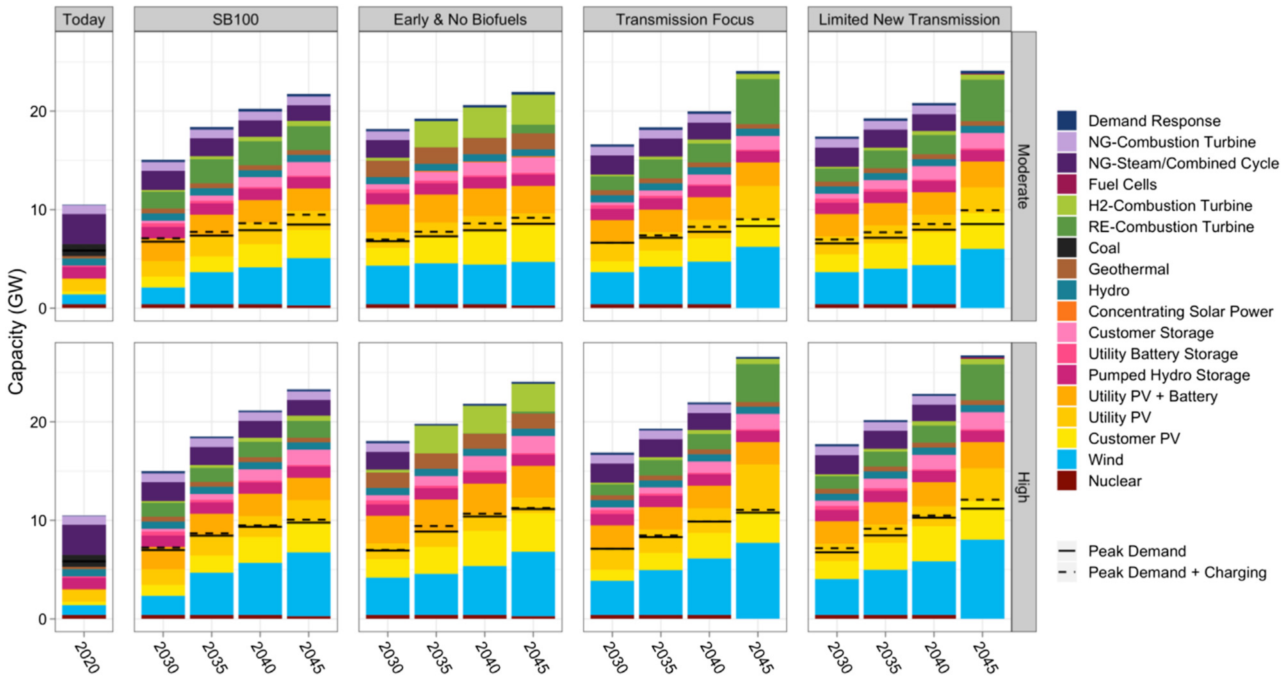

Figure 2. Capacity mix over time
The top row shows moderate-demand projections for each scenario, and the bottom row shows high-demand projections. NG is natural gas, and H2 is hydrogen.

behind-the-meter systems. As illustrated later in Figure 2, this customer-sited PV provided 8%–12% of LADWP's annual electricity demand in 2045. The technical and economic potential of rooftop PV is widespread across the city, including in disadvantaged communities. Further analysis and policy actions would be required to ensure that all customers can access the economic benefits by addressing barriers related to homeownership, access to financing, and rooftop quality.

Resources within the LADWP service territory and also within the LA Basin are referred to as "in-basin." For non-rooftop PV deployments within the city, the study estimates a total of 5.7 GW of in-basin technical potential, meaning the capacity that could be deployed on parking lots, in brownfield locations, at water treatment facilities, or along developable service corridors (such as along water canals). Subsequently, after evaluating the economics of each location, the system-wide least-cost capacity expansion model (CEM) (see experimental procedures for details) determined the actual level deployed in each scenario (0.3–1.0 GW), where these resources had to compete against cheaper, but more distant, resources. Costs include bulk power system investment and operations, customer rooftop solar installation, and distribution system upgrades (to accommodate load growth and distributed energy resources [DERs]), but do not include debt payments on assets installed prior to 2021, distribution maintenance costs, or costs associated with energy efficiency or demand-response programs. The capacity expansion pathways also favored PV locations that could be paired with storage, which was assumed to not be available in carports or with floating solar.

The production from this distributed solar and storage was combined with load estimates and disaggregated to individual electrical nodes to simulate the impacts on the entire distribution system and estimate the cost of corresponding required upgrades. About 80% of the 4.8 and 34.5 kV network was analyzed. Overall, by 2045, the increased annual demand of 13–20 TWh (nearly all of which is delivered via the LADWP distribution network) is partially offset by the generation from distributed generation PV (greater than 6 TWh). However, differences in temporal and geographic matching drives a need for distribution upgrades to avoid overloads. Many of the required upgrades were changes to control schemes or upgrades to smaller service transformers, as opposed to more expensive upgrades such as reconductoring. However, some cases could require more substantial upgrades, which may be challenging due to space limitations. It should be noted that these upgrades would be required to accommodate anticipated load growth, including vehicle electrification, and are not necessarily needed for a 100% RE system.

The supply side: Renewably, reliably serving future demand

Across the load projections and with the iterative feedback from distributed energy options, we developed four scenarios in an extensive consultative process with LADWP and representatives from the local community:

- The SB100 scenario approximated the requirements of the California Senate Bill No. 100,[10] with the goal of achieving net zero emissions by 2045. Allowing a portion of the target to be satisfied with unbundled RE credits (RECs) enables limited natural gas use offset. The use of RECs was included based on extensive discussion with community

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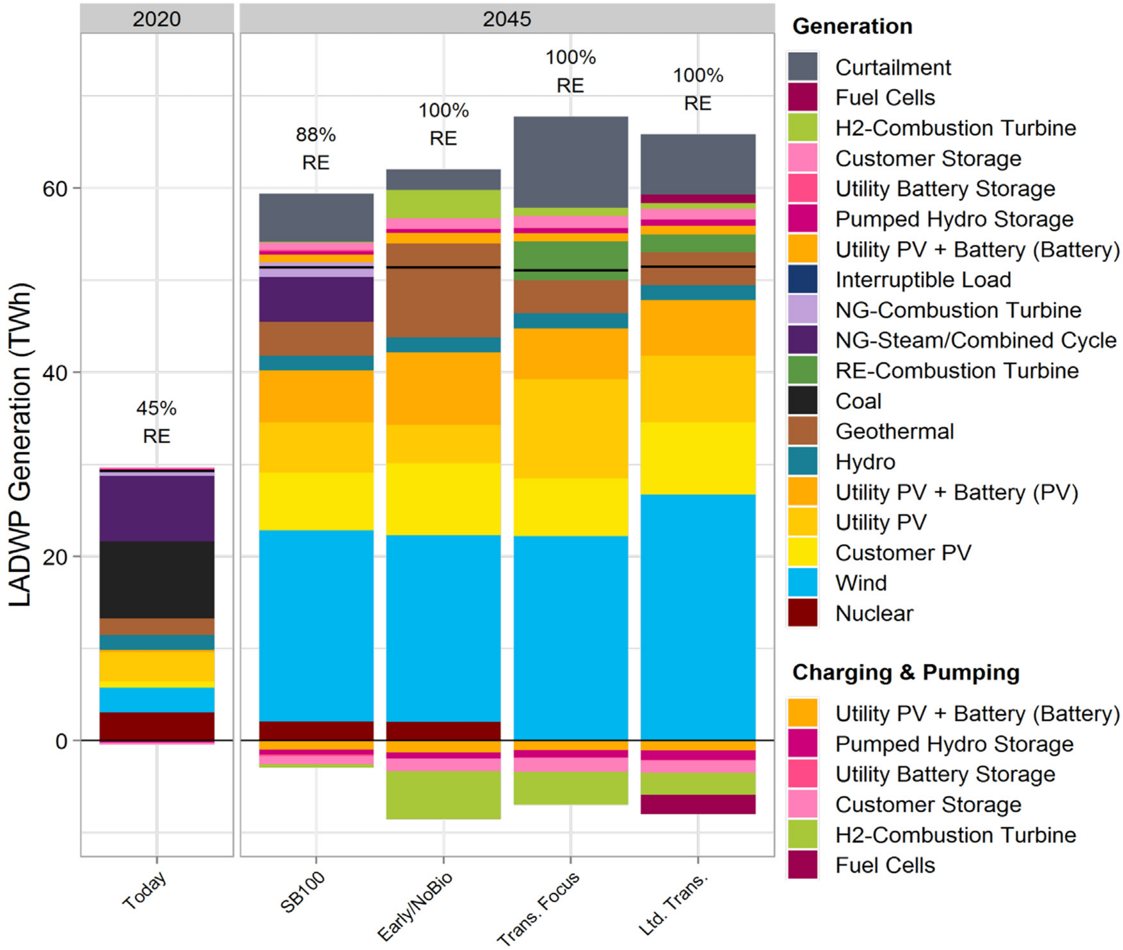

Figure 3. Annual generation mix in 2045 for all high-demand projections compared with 2020

The percent RE at the top of each bar includes nuclear. For SB100, the gap from 88% to 100% RE is met through RECs. Negative generation values indicate the amount of electricity consumed by storage or hydrogen production. Load (solid line) is customer electricity consumption.

stakeholders to reflect their agreed-upon approach for this scenario.

- The "early & no biofuels" scenario prohibited the use of biofuels, reflecting community concerns about their sustainability and direct emissions. The scenario achieves 100% RE supply by 2035—10 years earlier than the SB100 case.
- The transmission focus scenario explored a future in which LADWP is assumed to build a new transmission backbone for the city, and other transmission infrastructure improvements are assumed to be available at lower cost.
- Finally, the limited new transmission scenario did not allow any new transmission or transmission upgrades beyond those already planned by LADWP, and it assumed greater incentives for deployment of rooftop PV.

The early & no biofuels, transmission focus, and limited new transmission scenarios also all prohibited the use of unbundled RECs and thus represent physical compliance with the 100% RE target.

We applied least-cost optimization methods in combination with a suite of reliability assessments (see experimental procedures) to determine a deployment mix of renewable resources for each scenario that met the load requirements, generation profiles, and rigorous reliability conditions.

Figure 2 illustrates the resulting evolution of the capacity mix over time in each of the scenarios against two demand projections.

All scenarios include significant deployment of renewable and zero-carbon energy by 2035: 84%–100% of energy in 2035 compared with 45% in 2020. Wind and solar resources provide most of the energy required to meet load: 69%–87% of total energy generation by 2045 (Figure 3).

Diurnal storage resources (resources with storage durations of less than 12 h) increase the utilization of wind and solar assets by shifting surplus energy from midday to other hours.

New in-basin renewable firm capacity resources—that use renewably produced and storable fuels, can come online within minutes, and can run for hours to days—are key elements in maintaining reliability at the least cost (given the assumed retirement of natural gas generators, existing transmission constraints, and challenges in upgrading existing or developing new transmission infrastructure). This capacity is represented in Figure 3 as hydrogen- and renewably fueled combustion turbines (RE-CTs) and fuel cells. Electrolytic hydrogen production is modeled as a load. The produced hydrogen is then stored as a generation fuel (for combustion turbines and fuel cells), with adequate deliverability to ensure reliable service for several days. Fuels labeled RE are market-purchased and could include biofuels (except in the early & no biofuels scenario), ammonia, or hydrogen. As noted in the experimental procedures, this analysis did not extend to the development and economics of these RE fuel markets, per the scope agreed upon with LADWP and the stakeholder community. These carbon-neutral fuels, which act as a form of very long-duration storage, can address seasonal mismatches in supply and demand as well as replace various services currently provided by in-basin natural gas generators that are expected to retire.

Achieving a 100% renewable or clean power system requires rapid and sustained deployment of variable generation (wind and solar), diurnal storage (resources with storage durations of less than 12 h), and firm capacity technologies. Across scenarios, the average annual deployment for combined wind, solar, and batteries ranges from ~470 to 730 MW/year over the LA100 study period (2021–2045), representing a substantial and sustained acceleration of new resource procurement. These deployment rates for capital expansion would be significantly higher than recent historical LADWP rates for wind and batteries, but moderate compared with recent (2017) solar PV installations of more than 600 MW/year. The increased deployment rates for wind and batteries reflect historically moderate expansion of generation capacity and limited new demand. The installation rates increases are comparable with those anticipated for California under SB100, which were estimated to increase by three times the current rates for PV and eight times that for batteries.

Resource adequacy, operational reliability, and the role of firm and local resources

All modeled scenarios, including the transmission outage stress tests, achieve the 100% renewable or clean energy targets while maintaining resource adequacy, although experiencing an expected loss of load of 2.4 h or less per year (based on an evaluation using 7 years of historical weather data and including cooling demand adjusted for hotter climates).

A key finding of the LA100 study is the relative role of resources within and outside the LA Basin. Overall, the LA100 study relies on out-of-basin resources for most of the energy (74%–89% of total energy generation by 2045, with 67% of renewable generation coming from the Western Interconnection) due to resource availability and cost.

Because LA relies on an extensive transmission network to bring in electricity generated out of basin, the study employs in-basin resources to provide a large fraction of firm capacity, especially to manage transmission outages. Figure 4 shows the source of both firm capacity (top) and operating reserves (bottom). Consistent with previous work,[11] the LA100 study demonstrates the need for firm capacity resources, not only for addressing limitations of seasonal RE supply but also for addressing limitations of the transmission network. LADWP has an extensive transmission network, including both AC and long-distance high-voltage direct current (HVDC) lines that are used to tap into valuable energy resources throughout the West. However, most of this network delivers energy into the north side of the city, and historically, coastal natural-gas-fired power plants have been used to address some of the limitations in delivering energy further south, particularly during periods of peak demand where southbound transmission capacity is constrained. Furthermore, simulations of extended transmission outages (reflecting possible increased occurrences of wildfires under climate change) demonstrated that delivery of energy from out-of-basin resources may be restricted. This ultimately limits the potential for firm out-of-basin renewable resources, such as geothermal or nuclear energy, to provide resource adequacy and can also limit the ability of in-basin storage systems (such as batteries) to be sufficiently recharged. If most of the West achieves closer to 80%–100% renewables by 2045, there will be greater competition for renewable resources, potentially resulting in cost increases as well as changes in resource locations, associated transmission rights, upgrades, and builds to access those resources.

Given the limitations to the transmission network, the RE-CTs in particular are key to maintaining resource adequacy. RE-CTs produce local emissions of oxides of nitrogen (NOx). However, with planned transmission upgrades and in-basin RE and storage, these units can be operated less frequently than current in-basin generators.

An important element of reducing in-basin combustion is the use of energy storage and other resources for operating reserves and transmission reliability. Storage systems can reduce the operation of thermal generators often used for spinning reserve to address contingency events. Storable, zero-carbon fuels are used in each scenario to improve reliability, including to address the seasonal and annual variability of wind and solar, which cannot be mitigated through spatial diversity alone. Although wind and solar technologies provide a large fraction of the energy needs, all scenarios rely heavily on diurnal storage, demand response, and renewably fueled generators to provide operational flexibility and operating reserves. In addition, renewably fueled generators capable of operating for extended periods over multiple sequential days ensure load balancing on consecutive days or weeks with low wind and solar resource availability. Storage technologies, such as pumped storage hydropower and batteries, provide fast-response services (Figure 4) and address most of the daily mismatch of supply and demand. The use of storage introduces new complications in guaranteeing that the system can respond to both routine and extreme events. Also essential to this operation are improved transmission operations, allowing lines to be used closer to their thermal limits, which is enabled by advanced transmission monitoring (e.g., dynamic line rating) and technologies such as flexible AC transmission systems.

Emissions and air quality benefits

The modeled scenarios produce a reduction of 76%–100% in greenhouse gas (GHG) emissions from power plant operations in 2035 compared with 2020. Figure 5 (top) illustrates the GHG emissions trajectories across the various scenarios. The scenarios factor in both direct combustion and life-cycle impacts associated with power plant construction and operation,

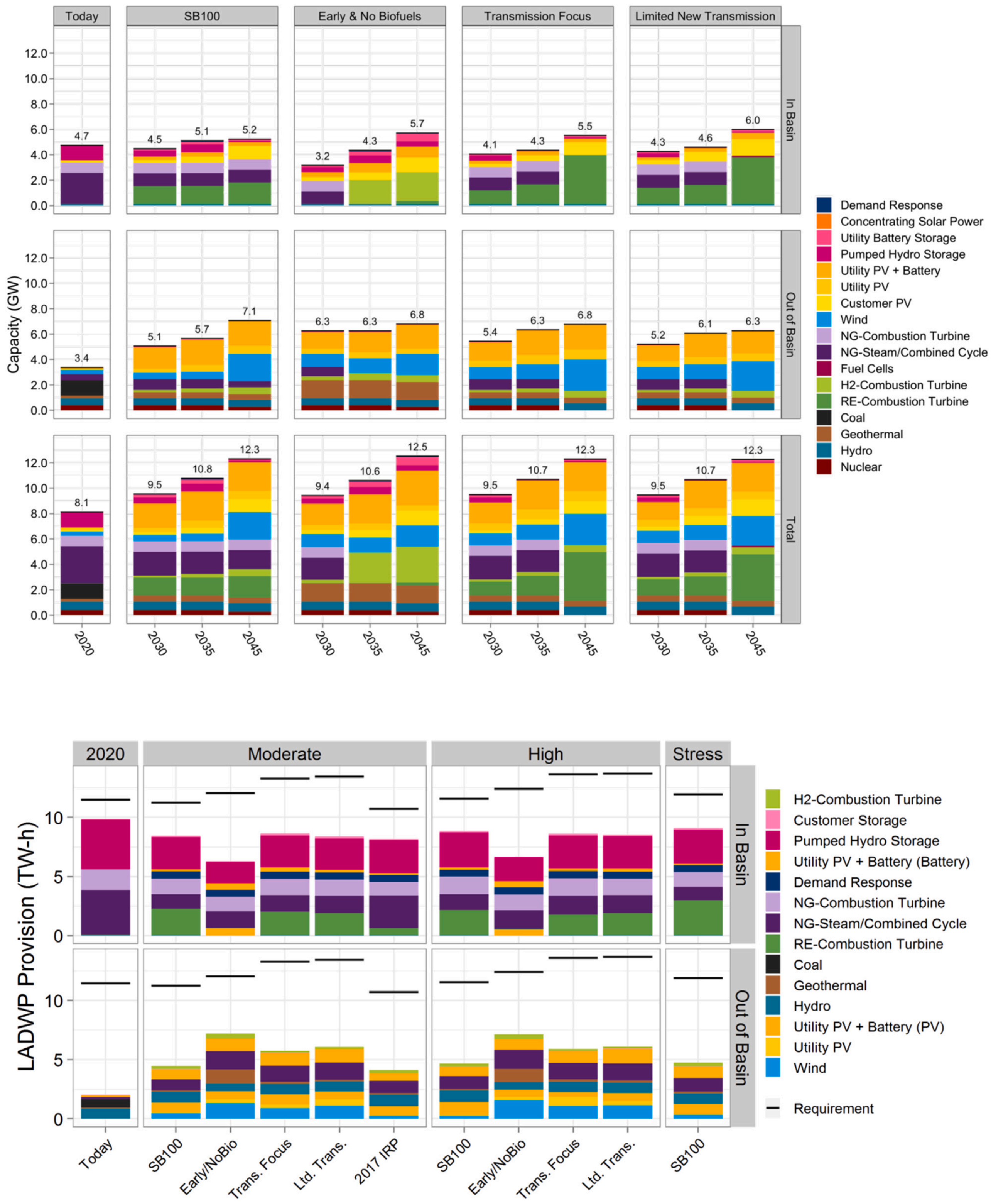

Figure 4. Sources of firm capacity (top) and operating reserves (bottom) show significant contribution from in-basin resources, including renewably fueled combustion turbines

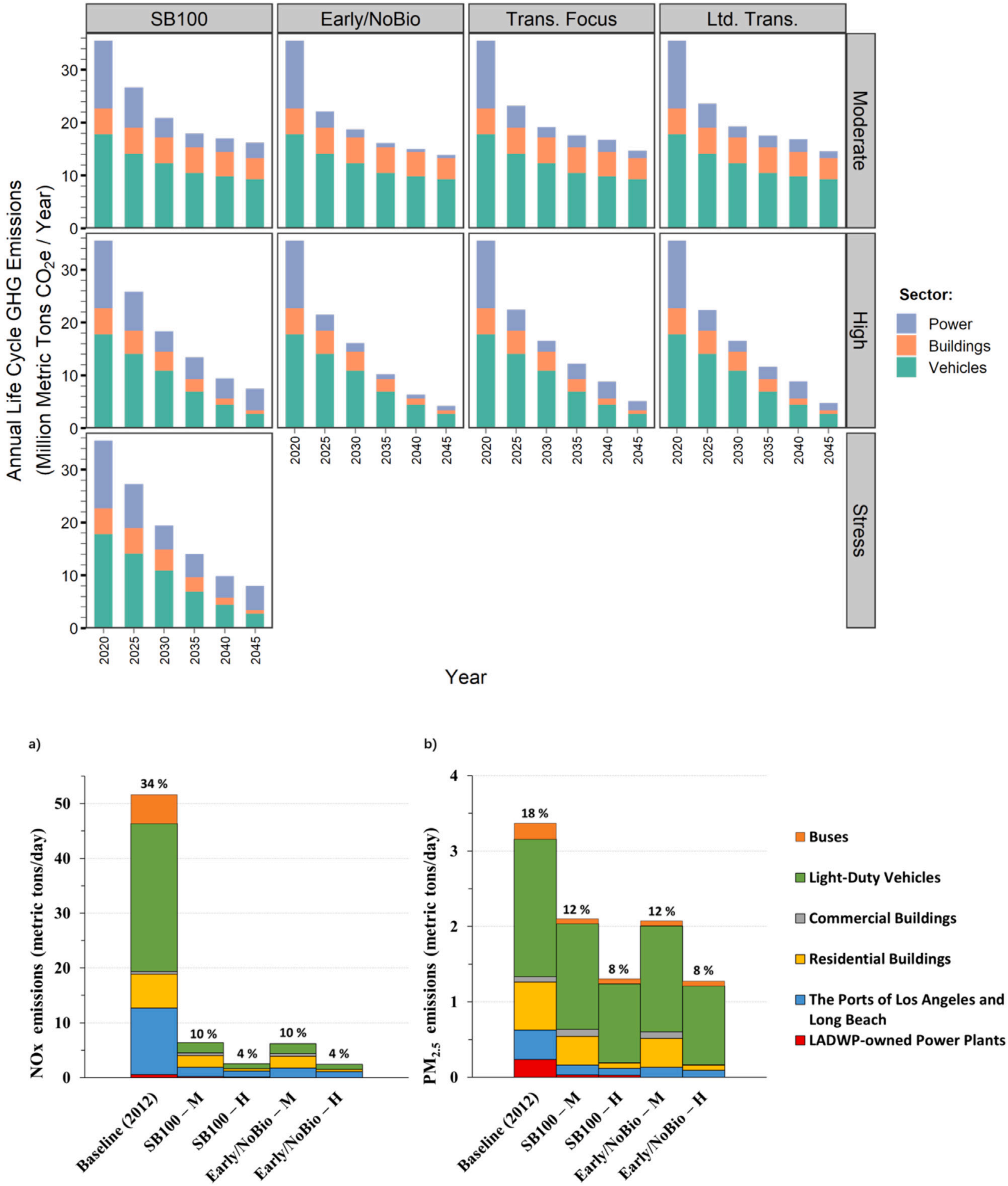

Figure 5. Emissions reductions: annual GHG by sector (top) and NOx/PM (bottom)

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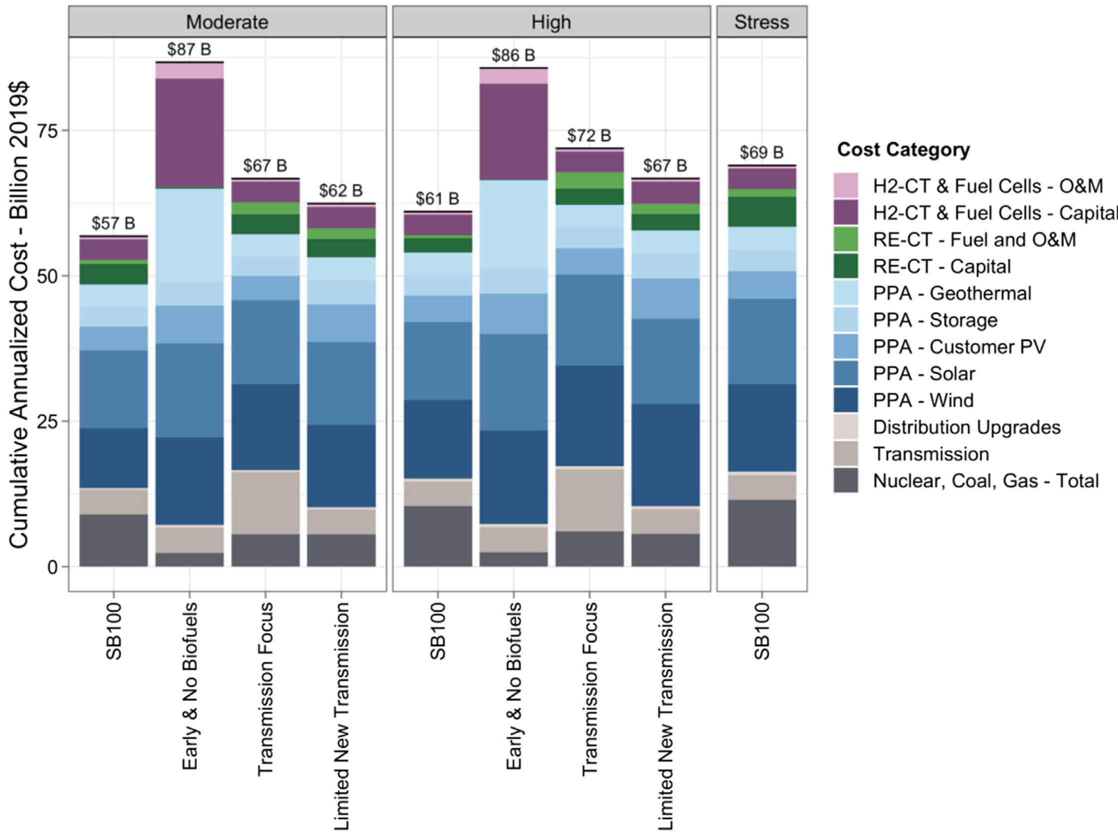

Figure 6. Cumulative annualized system costs incurred from 2021 to 2045 by scenario, load level, and cost type

including fossil fuel extraction and transport. The primary difference in GHG emissions among the scenarios is due to the significant electrification of buildings and transportation end uses in the high-demand projections, especially when coupled with the accelerated 100% RE target of the early & no biofuels scenarios.

Sources that emit GHGs can also emit other air pollutants that impact air quality and public health. Figure 5 (bottom) compares NO_x and particulate-matter ($PM_{2.5}$) emissions in the baseline case (using historical 2012 rates) with 2045 estimates. As with GHGs, a key factor in improving air quality is the electrification of buildings and transportation. Changes to the power sector reduce NO_x emissions by 0.8%–1.0% and PM emissions by 10%–18% compared with 2012 (the base year for the air quality data).[12]

Although disadvantaged and non-disadvantaged communities continue to experience disparities in exposure to pollutant concentrations, all communities experience overall reductions in exposure to fine PM, 6%–8% compared with 2012.

The reduction in PM concentration results in $1.5 billion in health savings in 2045 alone due to reductions in deaths, cardiovascular disease, and other diseases caused by this pollutant.

What will it cost?

The estimated cumulative costs of expanding and operating the power system—to service new demand, replace retired power plants, and decarbonize the electricity supply—range from $57 billion to $87 billion (2019$), depending on the scenario and load projection. These include costs for new bulk system generation, transmission, customer-sited solar PV installations, and the distribution system upgrades required to accommodate load growth and DERs. Importantly, these costs do not include the cost of servicing debt on any assets installed before 2021, future costs of distribution systems operation and maintenance, or costs of energy efficiency and demand-response programs.

Costs increase over time across all scenarios due to the accumulation of costs of procured capacity and generation directly or via power purchase agreements (PPAs), increasing load, and increased stringency of the RE targets (Figure 6). Crucially, these annual per-megawatt-hour costs are a measure of the evolution of average costs of generation, and they do not represent the incremental cost of achieving a 100% renewable system. Rather, they explicitly represent the revenue required (per unit of generation) to cover the annualized costs associated with the accumulated debt service on capital investment, PPA obligations, and operation and maintenance costs.

The cost of achieving the 100% target depends highly on which technologies are assumed to qualify as renewable, among other factors, such as the availability of financial compliance mechanisms such as RECs, the speed at which the target is achieved, and the evolution of load (Figure 7). For example, the early & no biofuels scenario has the highest costs due to both earlier deployment of capital (the same fleet of renewables deployed earlier will

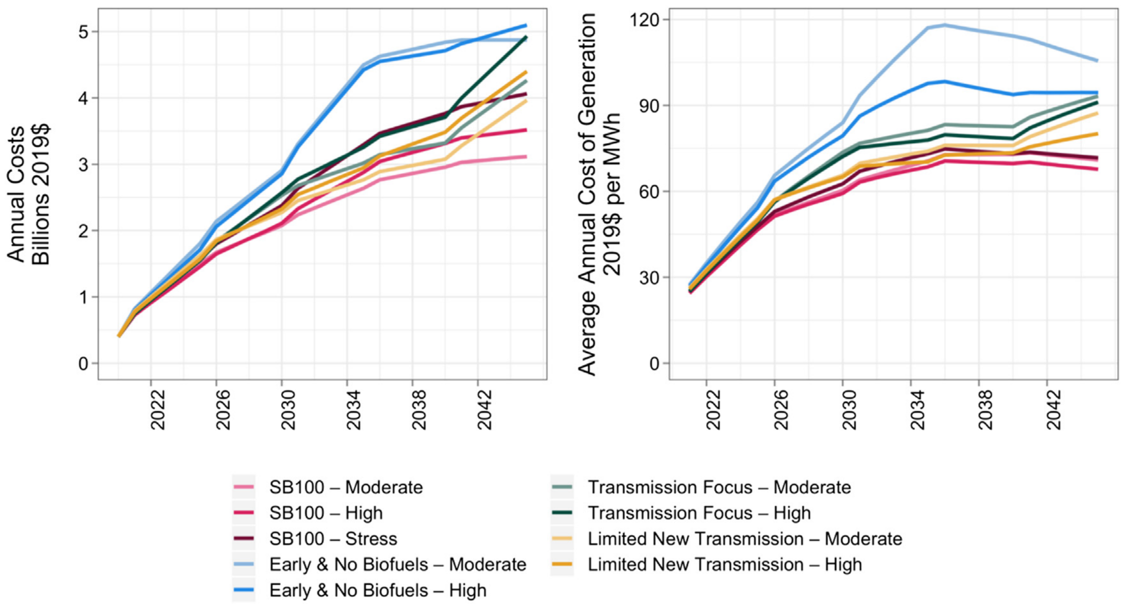

Figure 7. Annual and average annual costs of generation over time

Annual costs (left) represent the total costs observed in a given year (operations, capital, and PPA payments from LA100 resources installed in current and earlier years). Average annual costs of generation (right), dividing annual costs by annual generation.

have higher per unit costs because costs decline over time) and the elimination of biofuels and RECs, preventing larger GW-scale deployments of wind, solar, batteries, and hydrogen. These higher costs are mitigated, but not eliminated, by that scenario's inclusion of some continued nuclear generation from existing facilities. None of the scenarios included evaluations of either expanded nuclear or carbon capture and storage, as determined by LADWP, SB100, and the community stakeholders.

The RE investments alone are not anticipated to notably impact LA's economy. The power-related industry is small relative to the overall size of LA's economy, which includes 3.9 million jobs and $200 billion annual output. Between 2026 and 2045, the LA100 scenarios support an average of 8,600 jobs due to construction and installation and 2,000 jobs due to operations and maintenance. Solar supports, on average, 58% of the positions, followed by transmission at 14%.

No-regrets pathways and the challenge of the last ~10%–20% of energy demand

The scenarios show similar cost increases through deployment of approximately 80%–90% RE and suggest that there are no-regrets options for pursuing deep decarbonization, not only for LADWP but also for other jurisdictions pursuing clean energy goals. All scenarios demonstrate the value of large-scale deployment of new wind, solar, storage, transmission, and demand-side measures, including energy efficiency plus incentivized load flexibility. These options can be deployed while analyzing options to supply the final 10%–20% of RE.

Beyond 80%–90%, the scenarios diverge in the technologies deployed to meet the last 10%–20% of energy demand that cannot be easily served by wind, solar, and conventional storage technologies—and to maintain reliability in the face of extreme events. The costs, which are highly dependent on technology choices that vary in their maturity today, point to an important need for research and development to improve and demonstrate technologies needed to address the seasonal mismatch of RE supply and demand. Today, the lowest-cost option for this type of seasonal storage/peaking capacity is likely a storable renewable fuel used in modified versions of combustion turbines[13] and reciprocating engines—or ultimately fuel cells if capital costs are competitive or there are strict limits on combustion-based emissions. Renewably fueled combustion generators may also provide fuel flexibility to serve as backup in emergencies or as a hedge against uncertainty related to prices and market availability of fuels. Although carbon-neutral biofuel could be used as a transition fuel, supply limits likely will require fuel with a larger potential supply, such as renewably produced hydrogen or hydrogen-derived fuels. These are not yet commercially available at scale and will require development in volumes beyond requirements of individual utilities, necessitating collaboration and development across industry and/or much larger regions.

Finally, while the LA100 study largely emphasizes a traditional supply-oriented approach to maintaining reliability, there may be opportunities for further use of demand-side options, particularly demand response that can be sustained over multiple days, such as to manage the impact of extreme weather events. By contrast, LA100 included demand-response options that are of a short duration (e.g., shifting cooling demand or vehicle charging to earlier in the day). To implement a multi-day demand-response option, further research is needed on investments required for development of information and communication technologies, related customer education and outreach, and pilots that could measure reliability during an actual event.

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Table 1. Modeling tools and datasets used

Topic	Modeling tools
Electricity demand projections	ResStock, https://www.nrel.gov/buildings/resstock.html ComStock, https://www.nrel.gov/buildings/comstock.html EVI-Pro, https://afdc.energy.gov/evi-pro-lite dsgrid, https://www.nrel.gov/analysis/dsgrid.html
Customer-adopted rooftop solar and storage	distributed generation market demand (dGen), https://www.nrel.gov/analysis/dgen/
Renewable energy resource data	renewable energy potential (reV), https://www.nrel.gov/gis/renewable-energy-potential.html
Utility options for local solar and storage	resource planning model (RPM), https://www.nrel.gov/analysis/models-rpm.html dGen, https://www.nrel.gov/analysis/dgen/
Renewable energy investments and operations	RPM, https://www.nrel.gov/analysis/models-rpm.html PLEXOS, https://www.energyexemplar.com/plexos probabilistic resource adequacy suite (PRAS), https://nrel.github.io/PRAS/ positive sequence load flow (PSLF), https://www.geenergyconsulting.com/practice-area/software-products/pslf
Distribution system analysis	distribution transformation tool, https://github.com/NREL/ditto HELICS, https://helics.org/ integrated grid modeling system: Transmission & Distribution application, https://www.nrel.gov/grid/modeling-tools.html OpenDSS (distribution system simulator), https://github.com/tshort/OpenDSS PyDSS, https://github.com/NREL/PyDSS
Greenhouse gas emissions	Life cycle assessment harmonization project data, https://www.nrel.gov/analysis/life-cycle-assessment.html
Air quality and health	weather research and forecasting (WRF) model, https://www.mmm.ucar.edu/models/wrf chemistry (WRF-Chem), https://www2.acom.ucar.edu/wrf-chem environmental benefits mapping and analysis program—community edition (BenMAP-CE), https://www.epa.gov/benmap
Environmental justice	No new modeling tools were employed, but they aligned as closely as possible with CalEnviroScreen, https://oehha.ca.gov/calenviroscreen
Economic impacts and jobs	JEDI, https://www.nrel.gov/analysis/jedi/models.html IMPLAN, https://implan.com/

EXPERIMENTAL PROCEDURES

Resource availability

Lead contact

Any requests for further information should be directed to Jaquelin Cochran (jaquelin.cochran@nrel.gov).

Materials availability

This study did not generate new, unique materials.

Data and code availability

The data that support the findings of this study are available at https://maps.nrel.gov/la100/#home-1 or from the public domain resources listed in Table 1. Non-proprietary code is available from the links listed in Table 1.

Overview of methods

By integrating more than a dozen models, we examine a transition to a 100% renewable supply by 2045 at an unprecedented geographic and temporal scale. Figure 8 shows the model integration and data flows.

Stakeholder input

The study began with extensive discussions with key stakeholders of LADWP. Stakeholder input shaped the scenarios, assumptions, questions addressed, and how material was presented. For example, the incorporation of impacts of hotter temperatures due to climate change was added in response to stakeholder feedback.

Modeling methods

Detailed modeling began with the two critical steps of data acquisition and defining the scenarios to be evaluated. The workflow then shifted to CEM input modeling (e.g., projections of customer demand, rooftop solar generation, and RE resource availability), which served as exogenous inputs for the CEM. The CEM produced the generation mixes needed to achieve the RE targets, as defined in the scenarios, as well as some key performance metrics. However, as discussed further below, the CEM does not have the temporal and spatial resolution to capture all elements of system operational reliability. Several additional validation modeling steps were used to ensure that the CEM solution produced a reliable power system. If these validation steps found violations, generation and/or transmission were adjusted in the CEM to produce revised results. This is represented by the iterative loop in Figure 8. There was also a set of output modeling steps that generated additional results, including economic and environmental impacts.

The analysis included detailed, bottom-up projections of customer electricity demand over time, including impacts of building and vehicle electrification and customer-owned solar and storage. The study used a highly resolved, bottom-up modeling approach referred to as the demand-side grid model (dsgrid, see Figure 8) to project, compile, and geospatially distribute sector-level demand estimates. The dsgrid model is composed of multiple detailed models that each represent one major electricity load sector. The addition of gap models and other adjustments allow dsgrid to deliver a complete, time-synchronized, and spatially resolved electricity load dataset. The detailed models provide hourly or subhourly load profiles at a fine geographic resolution and with end-use specificity.

We coupled these projections with detailed simulations of generation, storage, transmission, and distribution assets, developing four scenarios in which we evaluated the infrastructure and operational changes required to achieve a reliable, 100% renewable electricity system at least cost. Key to our LA100 study[14] was the evaluation of the reliability of the system (1) under normal conditions, (2) during and following contingency events, such as short-term generation or transmission outages, and (3) over extended outages. This approach may help ensure that the future systems studied can meet load under all but the most rare and extreme conditions. Finally, we evaluated the impacts of the 100% renewable system on local air quality, human health, and the regional economy.

Datasets and modeling tools

Because of the large scope of the LA100 study, no single existing model could perform all the analysis the study required. Instead, about a dozen individual tools or models of various types were used in the study,

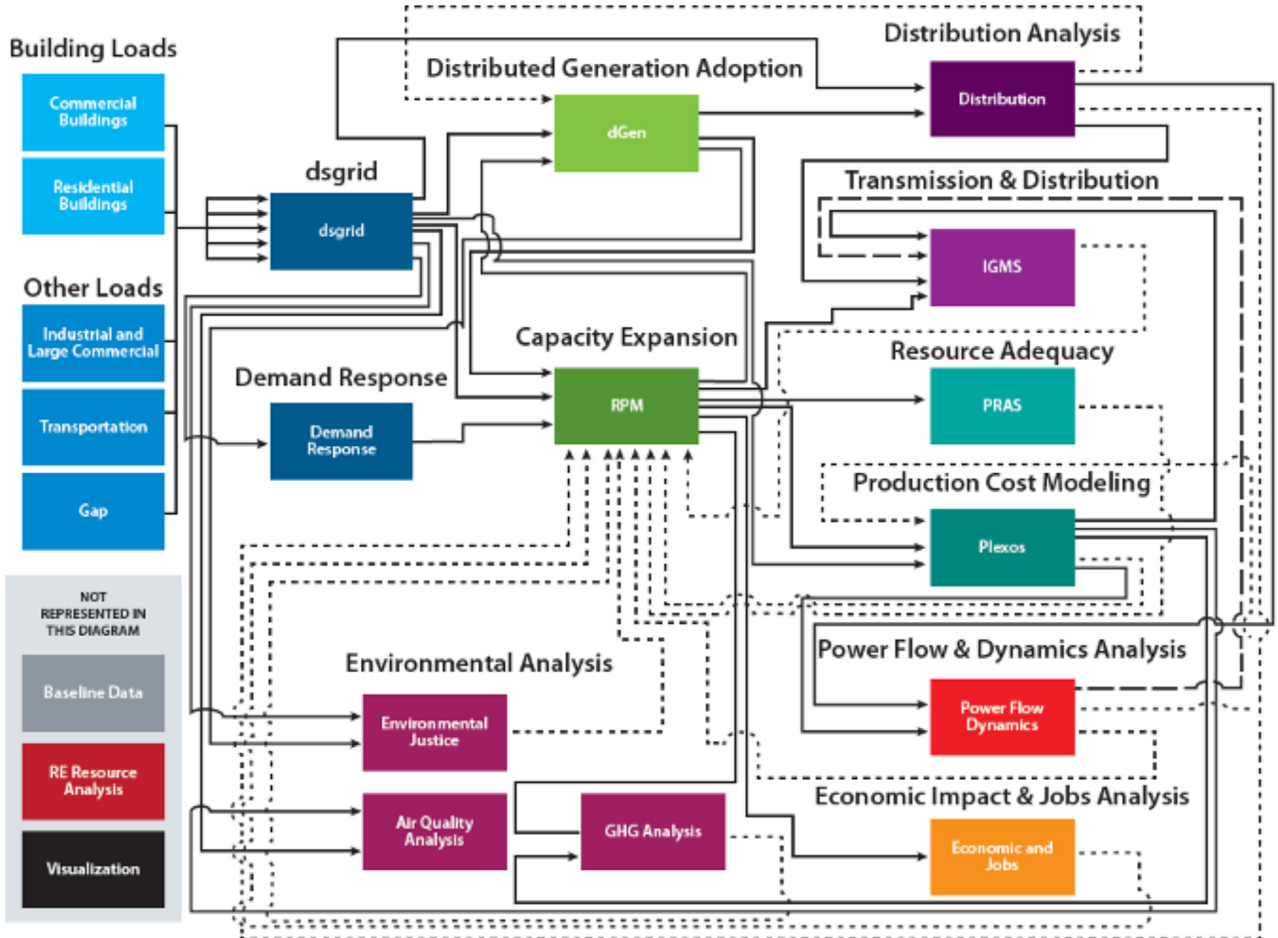

Figure 8. Model integration, including load models (left), power systems modeling, and complementary analysis of environmental, economic, and jobs impact

Solid lines represent data flow, and dashed lines represent feedback to inform the modeling.

including both NREL-developed and commercial tools. The large set of tools was dictated by the large scope of topical elements as well as the scale of geographic and temporal evaluation. The study examined factors ranging from the performance of individual distribution circuits to the entire Western Interconnection and from the timescales of subsecond dynamic grid performance to build decisions with decades-long impact on transmission and generation capacity. Models were generally run sequentially, but significant iteration was needed between models in several key steps to arrive at a viable system solution. Demand models (buildings, electric vehicles, municipal water system, etc.) were evaluated initially to provide gross demand. Distributed generation adoption models, which were run to evaluate the economic options for rooftop and other local PV and storage, subsequently reduced bulk load requirements and also were included in overall system operational assessments. Bulk system capacity and transmission configurations (including storage) were initially determined via least-cost optimization methods, and those configurations were then evaluated by a suite of detailed production costs, resource adequacy, and reliability models. All system balancing and reliability challenges were assessed, and we used these findings to adjust the capacity expansion optimization methods or data. The whole cycle repeated until all reliability requirements were fully articulated and met. Table 1 lists the main models used in the study and URLs for the tools, many of which are publicly or commercially available. Application of each of these tools to the LA100 study is discussed in the following subsections.

Underlying load projections

The initial step was generating the underlying load projections, simulating the hourly demand for electricity over the coming decades. Residential and commercial buildings were simulated using physics-based models. Building stock data for the LADWP service territory and other regions were used to create probability distributions of about 100 building characteristics (e.g., age, insulation, size, and heating and cooling systems). Data were sampled 50,000 times for residential buildings and 25,000 times for commercial buildings, then translated into building energy models on the OpenStudio EnergyPlus platform. These results were then scaled to represent the region's millions of buildings and aggregated electricity demand for each of the simulated years out to 2045 (in 5-year increments).

Demand simulations

Simulations performed for the study considered building stock evolution, including appliance turnover, retrofits, and new construction. Variation of these energy efficiency and electrification assumptions were used to produce the moderate-, high-, and stress-demand profiles. Simulations of air conditioning and heating demand relied on 2012 weather conditions. However, to address impacts of hotter temperatures due to climate change, the LA100 study captured expected changes in air-conditioning demand based on projected increases in average and peak temperatures. Higher daily maximum temperatures were estimated using the Intergovernmental Panel on Climate Change (IPCC) representative concentration pathway (RCP) 8.5 scenario.

The use of RCP 8.5 was determined by the study advisory group. Historical correlations between temperature and load were then used to estimate increased cooling and decreased heating loads.

The LA100 analysis was performed based on electricity demand projections generated before the COVID-19 pandemic. It did not account for changes that occurred during the pandemic nor did it consider potentially longer-lasting impacts, such as changes in work patterns. Our simulated 2020 total electricity demand under non-COVID conditions of 26.5 TWh was about 31% higher than actual demand in that year (21.0 TWh).[15] Initial explanations attributed this difference to changes in commercial building loads (predominantly air conditioning) due to reduced use during the COVID-19 pandemic.

Electric vehicle charging and load profiles

Light-duty electric vehicle charging profiles were generated based on travel data and charging preference assumptions (i.e., residential, workplace, or public charging). Bus charging loads were developed assuming 100% electrification by 2030 of all school, LA Metro, and LA Department of Transportation buses serviced or charged overnight within the LADWP service territory. Electrification of medium- and heavy-duty vehicles was not included in the modeling due to insufficient data when the study began. Industrial loads profiles relied on a historical customer billing dataset, which we adjusted using projections from existing sources.

Demand-response estimate

Demand-response resource was estimated using the detailed demand projections combined with information on current LADWP demand-response programs[16] and plans,[9,17] plus a demand-response participation rate model.[18] The moderate-, high-, and stress-demand projections had varying levels of demand-response resource based on assumptions about technology automation, program marketing, and incentive levels. The latter were roughly aligned with estimates of demand-response value by end use.

Renewable resource potential and generation profiles

The next step was to produce the necessary datasets for renewable resource potential and generation profiles. Regional wind and solar generation profiles for locations throughout the Western Interconnection were obtained from the RE potential (reV) tool, using underlying data from the National Solar Radiation Database[19] and the Wind Integration National Dataset.[20] A total of 23 resource clusters were generated for utility-scale PV inside the LADWP service territory and another 53 for locations outside, while 59 clusters were generated for wind resources. The base meteorological data were for 2012, and data for 2007–2014 were used for sensitivity analysis. These datasets were not adjusted based on possible climate change impacts. Siting availability for these and other resources, including geothermal, was adjusted based on land exclusions and other siting restrictions as determined by LADWP and with the agreement of the study advisory group.

Cost and reliability analyses

After completing these steps, we began the iterative process of generating a least-cost, reliable system for each of the four scenarios. The core model in this step was a CEM, NREL's Resource Planning Model (RPM). It has a mixed-integer linear programming formulation with the objective function of minimizing life-cycle costs while meeting adequacy and reliability constraints, including meeting load. The RPM also features a reserve margin, enforcing operating reserve constraints, including contingency, flexibility, and regulating reserve. Transmission was modeled using linearized DC power flow for AC lines and pipe flow for DC lines and inter-regional connections. Some scenarios allowed development of new transmission lines, and reserves were required to ensure sufficient headroom on transmission lines to get generation from reserved capacity to load. Dispatch modeling within RPM was conducted using hourly time steps sampled from select days throughout a year, and the model considered energy balance, reserves, and many generator constraints. The model was run in 5-year time steps, beginning 2020 and running through 2045, selecting a resource mix (i.e., generation, transmission, and storage) under each scenario and estimating the total system costs associated with each pathway. New generation builds were allowed starting 2025, with new transmission starting 2030.

RPM selects from a mix of generator and storage types by considering the capital and operating costs of each over the planning horizon, along with technical capabilities such as ability to meet peak demand or provide operating reserves. Generation and storage technology cost and performance assumptions came from NREL's 2019 Annual Technology Baseline,[21] while fuel price assumptions were based on a compilation of the US Energy Information Administration's Annual Energy Outlook 2019[22] and projections from LADWP. The LA100 study did not consider obtaining resources from a wholesale electricity market, meaning that for planning (investment) decision-making, RPM assumed all energy, capacity, and operating reserve requirements needed to be met with either LADWP-owned and LADWP-contracted assets or customer-sited distributed PV. This constraint also limited new transmission to only serving LADWP assets and loads.

As a CEM, RPM can select from resources throughout the Western Interconnection, while considering the availability of existing transmission or the ability to build new transmission (with associated costs). LADWP's once-through cooling (OTC) units were identified as retired before 2030 in all scenarios, except in a reference case that extends only until 2036 (and is not included in the LA100 scenario results). Non-OTC investments identified in the 2017 Integrated Resource Plan Recommended Case[9] were included for consideration in all scenarios.

Scenarios

The supply-related constraints established by the four scenarios were implemented largely in the CEM stage. Scenarios were based on stakeholder input, with the four scenarios reflecting two main themes of community priorities that could be evaluated: (1) the speed of the transition (in relation to both the RE targets and electrification of end uses) and (2) the eligibility of generation technology options to meet the RE target.

The SB100 scenario most closely complies with existing California Senate Bill 100[10] and meets all requirements associated with it (60% RE by 2030 and 100% zero-carbon energy by 2045). In keeping with the legislation, clean energy targets were based on a fraction of load, meaning that the scenario did not require transmission and distribution energy losses to be covered by renewable generation. Unbundled RECs were allowed to contribute toward compliance in the final year of only the SB100 scenario. Together, these aspects of the scenario allowed for approximately 10%–15% of generation to be derived from fossil fuels. Existing nuclear generation was allowed, in compliance with the zero-carbon target of the legislation.

The transmission focus scenario assumed lower barriers to new transmission, the development of a new multiterminal DC backbone connecting key locations in and around the city, and prohibited fossil fuels and nuclear energy. The limited new transmission scenario prohibited new transmission capacity that is not already planned, prohibited new nuclear energy, and assumed higher levels of customer rooftop solar adoption. In each of these three scenarios, biofuels were allowed as a transition fuel, and the 100% target is met in 2045.

By contrast, the early & no biofuels scenario has the earliest compliance (2035 instead of 2045), prohibiting fossil and biofuels and assuming higher levels of customer rooftop solar adoption. Existing nuclear generation was allowed in order to contribute to the earlier decarbonization target.

Supplemental modeling methods

Like most CEMs, RPM does not include consumer adoption of DERs or detailed distribution system representation. Also, computational tractability prevents simulation of full AC optimal power flow (ACOPF) or contingency events. Evaluation of these factors for the LA100 study required supplemental models. First, the CEM was run in parallel with a customer adoption model. We used NREL's Distributed Generation Market Demand (dGen) model to generate projections of rooftop solar adoption.

In dGen, market diffusion of distributed generation PV technologies was simulated in 5-year intervals from 2020 through 2050 using an agent-based approach. For the LA100 study, agents (i.e., potential customers) were assigned attributes (e.g., building area, building value, and zoning type) based on data provided by LADWP, LA County tax assessor records, and other building-level fields. Rooftop potential of 800,000 buildings with about 13 GW of technical potential within the city was estimated using lidar scans to assess roof suitability for PV based on shading, fire code compliance, tilt, orientation, and minimum area (but not including roof structural suitability or age).

Economic calculations in dGen were performed for each agent and included costs, prevailing retail rates, incentives (e.g., net metering), and cost of financing. Ultimate adoption or market share of distributed PV technologies was determined by simulating adoption based on Bass-style adoption and other considerations of consumer behavior. This allowed the combined model to consider a wide range of consumer preferences, as opposed to a CEM, which considers the financial parameters and objectives of a single entity (i.e., LADWP). For the LA100 study, we generated five projections based on the assumed solar compensation policy and demand projections. A high compensation scheme was applied to the early & no biofuels and limited new transmission scenarios, which assumed continuation of net metering at the retail electricity rate. The SB100 and transmission focus scenarios assumed net billing, where electricity exported to the grid was valued at wholesale rates, partially reflecting the declining value of solar (particularly during periods of low net demand). This basis for adoption was applied to all communities, including those classified as disadvantaged, and for multifamily buildings. For multifamily buildings, compensation was based on the retail rate from the building owner's perspective. Though we modeled the potential for adoption from disadvantaged communities and multifamily buildings, the explicit policy changes needed to enable adoption in these sectors were not considered.

The net billing case depended on determining the time-varying value of grid electricity, which relies on the overall mix of resources and system demand patterns. Therefore, this value was generated using an initial run of the RPM model. This time series value was then used as an input to the dGen model, which generated the customer PV adoption scenario. Because this case changed the need for other resources, the build scenario was then fed back to the RPM model to produce a final mix of resources.

Adoption of distributed storage was not explicitly modeled in dGen and was based on an assumption that a fraction of new rooftop solar systems would be combined with energy storage systems, similar to the approach for electric vehicle adoption. For the LA100 study, the fraction was based on historical trends of storage co-adoption with solar in LADWP and increased linearly through 2045, again following trends in historical attachment rate. By 2045, 91% of residential solar adopters and 64% of nonresidential adopters co-adopted storage.

The second set of factors considered outside the CEM was the impact on and cost associated with the distribution system. In coordination with the dGen scenario analysis, we performed a parallel analysis to evaluate the impacts of increased load and distributed generation PV deployment on the distribution system. This analysis also provided an estimate of upgrade costs. The analysis considered how the distribution system was being upgraded while simultaneously considering how both load and DERs might provide cost savings relative to sequentially upgrading for load followed by DERs.

The combination of RPM and dGen produced a build scenario consisting of a generation fleet and transmission network, which we then validated using three additional models. First, resource adequacy analysis was performed using NREL's Probabilistic Resource Adequacy Suite (PRAS) to analyze 100,000 random hourly draws of generator and transmission outages for each of 7 weather years. Next, a commercial unit commitment and economic dispatch model (PLEXOS) was used to evaluate operational reliability in detail. PLEXOS performed hourly simulations a full year at each of the 5-year timesteps modeled in RPM (2020–2045), monitoring storage stage of charge, unit ramp rates, availability of operating reserve, and transmission system thermal limits. This set of simulations was used to confirm that the mix of generation resources could actually maintain supply-demand balance. For each LA100 study scenario, we simulated the system, assuming LADWP must meet energy and operating reserve solely with LADWP-owned or LADWP-contracted assets. Distributed PV generation was assumed to be visible to LADWP for system scheduling. Behind-the-meter, customer-sited storage was dispatched according to its highest value to grid operations, on the presumption that LADWP would create a tariff to incentivize these storage systems.

We did not simulate forecast error for renewables or load, but we required multiple operating reserve products, established at levels that could accommodate any energy needs associated with error in load or renewable resource forecasts. These included non-spinning contingency reserve, spinning contingency reserve, flexibility reserve, and regulation reserve. Contingency reserve requirements were established by LADWP's share of the flow on one of two large DC lines, which was shown to reach 1,428 MW. Half of the contingency requirement needed to be provided by fast-response resources. Regulation and flexibility reserve varied as a function of renewable resource supply.

To evaluate the ability of the system to provide reliable service under extended outages, we evaluated year-long outage of each 213 LADWP-provided contingencies plus several contingency events created by NREL. Although it is highly unlikely that any outage evaluated would last for an entire year, outages lasting weeks or even months are common, and, therefore, this conservative assumption allowed us to evaluate the system across a variety of conditions. This was performed for both 2020 and 2045 to ensure that the future system does not have a significant decrease in overall reliability.

Power flow modeling

Finally, we used a positive sequence load flow (PSLF) power flow model to evaluate steady-state and dynamic performance under normal and post-contingency events. For the LA100 study, we evaluated system stability for the time instant with the highest likelihood of reliability criteria violations (i.e., highest bus load in LADWP) in two scenarios: 2030 SB100 (stress demand) and 2045 early & no biofuels (high demand). We used established PSLF models of the Western Electricity Coordinating Council (WECC) system obtained from LADWP that included, for example, detailed data on transmission/distribution lines, transformers, and loads. Based on results from the production cost model, we selected the hour with the highest total bus load (i.e., net of positive load left at all load buses after subtracting co-located generation) for the two cases that underwent detailed power flow and stability analysis with PSLF. Simulations considered contingencies (such as the loss of the largest generating unit or major transmission lines in the system) to evaluate the LADWP power system against the applicable reliability criteria. Three sensitivities were also performed for each of the two scenarios. These sensitivities attempted to identify system constraints under high northern imports, monsoon, and high-flow conditions on the Victorville-LA path. Only steady-state power contingency analysis was performed for the sensitivities. Because of the focus on LADWP's power system, we did not identify the upgrades required in the adjacent areas to ensure feasibility of power flows in these areas based on the RPM/PLEXOS defined load and generation mix. Identification of the impacts of changes in one Western Interconnection region on the reliability of the other regions would require a complete Western Interconnection-wide power flow and stability analysis study using detailed network models of the entire WECC.

The three models were used primarily to validate the overall generation mix and refine the production cost and/or CEMs. During this process, deficiencies identified in the solution (e.g., transmission or reserve violation) were used to inform changes and improve the modeling approach via an iterative loop process. Examples included improving the power flow representation in the RPM model and energy storage capacity credit estimation. Because of this refinement loop, the actual modeling effort required multiple iterations before the desired level of resource adequacy and operational reliability was achieved.

Socio-economic and environmental modeling

Once a reliable and adequate solution was identified, we used four additional models to evaluate social, economic, and environmental aspects of each scenario. First, direct GHG emissions were estimated for all fossil fuel sources in the LA100 study region, including all fossil-fueled electric generators; natural gas used for space and water heating and cooking in buildings (both commercial and residential); gasoline used in light-duty vehicles; and diesel, natural gas, and propane used in urban transit and school buses. The GHGs considered for each fuel were carbon dioxide (CO_2), methane (CH4), nitrous oxide (N_2O), volatile organic compounds (VOCs), carbon monoxide (CO), and sulfur hexafluoride (SF6). Estimates were also generated for life-cycle-related GHG emissions in the electric sector, including emissions related to plant construction; non-combustion activities such as plant operation and maintenance; acquisition, treatment, and transport of fuels; and plant decommissioning and disposal. The GHG emissions accounting approach we used quantified

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all relevant GHG emissions from all generators and technologies, across all years and life-cycle phases. Monetization factors for the social costs of GHGs were applied using standard estimates from the literature.[23]

Next, we evaluated air quality and human health impacts. We used a regional meteorology and chemistry model, the weather research and forecasting model, coupled with chemistry version 3.74. The model used emissions from a historical year (2012) as a point of comparison and emissions estimated from four LA100 2045 scenarios (SB100 and early & no biofuels, with both moderate and high load electrification). For each selected scenario, we simulated representative months per season-January (winter), April (spring), July (summer), and October (autumn)—in Southern California based on meteorology in the year 2012.

We used the benefit mapping and analysis program-community edition (BenMAP-CE) to estimate the health impacts and economic valuation, from exposure changes to fine particulate and ozone pollution.[24] Census-tract-level population data from BenMAP was regridded to the 2 km by 2 km WRF-Chem modeling grid using the PopGrid tool. The output from PopGrid was used as the modeling domain population input for BenMAP, with population projected to 2045. BenMAP contains health impact functions for several different health endpoints. For the LA100 study, we considered premature mortality, cardiovascular hospital admissions, nonfatal heart attacks, and asthma emergency department visits. These were translated into economic effects using cost of illness and value of statistical life values from the literature. Although BenMAP output used 2015 US dollars for calculating the monetized benefits, our results for all health endpoints are presented in 2019 US dollars to be consistent with other LA100 results (such as bulk and distribution costs).

The analysis of net economic impacts within LA employed a computable general equilibrium model,[25] which reflected both expenditures for new infrastructure as well as how to pay for them. An increase in cost of electricity would typically correspond to reduced purchasing power for other services and acquisitions, which in turn exhibited a ripple effect across the economy.[26,27]

Gross workforce impacts inside and outside of LA—capturing the full western US—were estimated using the jobs and economic development impacts (JEDI) suite of models and IMPLAN. These models used expansion and operations data from the CEM to estimate gross jobs impacts due to LADWP investments. These results were specific to power generation and did not include jobs associated with energy efficiency or with electrification demand, such as installing electric water heaters. Jobs shown for solar, for example, may include a combination of onsite installers, supply chain wholesale workers, hardware manufacturers, and retail or health care workers supported by installer and supply chain worker spending.

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AUTHOR CONTRIBUTIONS

All authors contributed to the analysis and writing. J.C., P.D., E.H., B.P., and D.A. edited the paper.

DECLARATION OF INTERESTS

The authors declare no competing interests.

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