The Los Angeles 100% Renewable Energy Study

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Advisory Group Meeting #14
December 10 & 17, 2020

Meeting Summary[1]
Meeting Notes Compiled by Kearns & West

Table of Contents

Virtual Session #1

Thursday, December 10, 2020, 10:00 a.m. to 12:00 p.m.

Location

Virtual Meeting

Virtual Meeting #14.1 Attendees

Advisory Group Members

Adam Lane, Los Angeles Business Council
Allison Smith, Southern California Gas
Andrea Rojas, Sierra Club
Andy Shrader, Council District 5
Bonny Bentzin, University of California, Los Angeles
Bruce Tsuchida, The Brattle Group
Camden Collins, Office of Public Accountability (Ratepayer Advocate)
Christos Chrysiliou, Los Angeles Unified School District
Dan Kegel, Neighborhood Council Sustainability Alliance
Duane Muller, University of California, Los Angeles
Fred Pickel, Office of Public Accountability (Ratepayer Advocate)
Jack Humphreville, DWP Advocacy Committee
Jasmin Vargas, Food & Water Action
Jim Caldwell, Center for Energy Efficiency and Renewable Technologies
Kendal Asuncion, Los Angeles Chamber of Commerce
Liz Crosson, Office of Mayor Eric Garcetti
Loraine Lundquist, California State University, Northridge

[1] This summary is provided as an overview of the meeting and is not meant as an official record or transcript of everything presented or discussed. The summary was prepared to the best of the ability of the note takers.

Los Angeles Department of Water & Power
NREL Transforming ENERGY

Priscila Kasha, City of Los Angeles Attorney
Rebecca Rasmussen, Office of Mayor Eric Garcetti
Sergio Dueñas, California Energy Storage Alliance
Tony Wilkinson, Neighborhood Council

LADWP Staff

Ann Santilli
Armen Saiyan
Ashkan Nassiri
Carol Tucker
Dawn Cotterell
Faranak Sarbaz
Greg Huynh
James Barner
James Lin
Jason Rondou
Jay Lim
Jeremiah Valera
Julie Van Wagner
LeiLani Johnson
Louis Ting
Nicholas J. Matiasz
Paul Habib
Robert Dang
Scott Moon
Stephanie Spicer
Steve Ruiz
Steve Swift

Project Team

Bryan Palmintier, NREL
Doug Arent, NREL
Garvin Heath, NREL
Jaquelin Cochran, NREL
Kelsey Horowitz, NREL
Paul Denholm, NREL
Ramin Faramarzi, NREL
Scott Haase, NREL
Alyson Scurlock, Kearns & West
Joan Isaacson, Kearns & West
Taylor York, Kearns & West

Observers

Erin Berger, Southern California Gas
Jovy Kroh, Southern California Gas
Lauren Harper, Los Angeles Cleantech Incubator
Mayte Sanchez, Los Angeles Cleantech Incubator

Call to Order and Agenda Overview

Joan Isaacson, LA100 Advisory Group meeting facilitator from Kearns & West, welcomed the virtual meeting attendees to the first of two virtual sessions for Meeting #14 of the Advisory Group for the City of Los Angeles 100% Renewable Energy Study (LA100 study). Isaacson noted that the Advisory Group has been meeting over the previous 3 years to provide essential input, knowledge, and insights to the project team to help guide the LA100 study. This session's focus was the distribution grid analysis.

Welcome Remarks

Greg Huynh, LADWP Manager of the 100% Clean Energy Innovation Group, welcomed Advisory Group members and wished them all continued safety and good health during this challenging year. He reflected on the progress made despite COVID-19 and thanked NREL, LADWP, Kearns & West, and the Advisory Group members for their continued flexibility and level of engagement in transitioning to a virtual meeting format. He highlighted additional LADWP progress over the last year, including the approval of the Red Cloud Wind Project, expansion of the Feed-In Tariff program and the Bring Your Own Thermostat program, and completion of the Boulder Canyon Feasibility Study. He noted that the people in the City of Los Angeles are resilient and will continue to face any challenges that may come. He thanked all for a great year.

Doug Arent, NREL Deputy Associate Lab Director, reiterated the sense of gratitude for all parties adjusting and adapting to continue the good work of the Advisory Group. He expressed excitement about the results and the questions coming from the Advisory Group as the project team enters the final phase of the LA100 study. He noted that in several conversations with incoming federal administration advisors, they are incredibly enthusiastic to hear about the leadership of the City of Los Angeles and LADWP, and the engagement in the Advisory Group process. He identified the Advisory Group as somewhat iconic for the change that will occur at a more rapid scale across the country. He thanked the Advisory Group members for continuing to engage in the LA100 study and said that he is looking forward to its completion and moving into the next phases of implementation.

Jaquelin Cochran, NREL LA100 Study Principal Investigator, reviewed the meeting agenda, noting that the current (December 10) session would cover early results from the distribution grid analysis. The following session (December 17) will address final updates to the bulk power modeling in addition to general LA100 updates and an open question and answer session on any LA100 topic. She explained that bulk power modeling results are available on the website, and that distribution grid results will be available soon.

Distribution Grid Analysis

Bryan Palmintier, Principal Research Engineer and Grid-Connected Energy System Modeling Group Manager at NREL, provided an overview of the distribution grid analysis. He noted that the discussion would focus on the costs and upgrades associated with the 4.8 kV local distribution system and 34.5 kV sub-transmission system, incidental deferments, and reflections on findings for considering LA100 scenarios. He reviewed what the project team has learned so far (recapped again at the end of his presentation) and then presented new results. New results include final estimates for both parts of the distribution system (4.8 and 34.5 kV systems). He noted that some of the inputs changed due to revisions made to bulk power expansion planning. In addition, NREL now has cost estimates for all LA100 scenarios and non-rooftop solar integration costs. He emphasized that the distribution analysis was completed on an unprecedented scale, capturing greater than 80% of the system.

Costs and Impacts of Change to Load, Solar, and Storage to Required Infrastructure

Palmintier provided an overview of the costs and impacts of change to load, solar, and storage to the required infrastructure and explained why distribution is important. He detailed the different aspects of LADWP's distribution system, focusing on the 34.5 kV sub-transmission system and the 4.8 kV distribution system. Bulk generation connects to transmission through a switching station whereas transmission connects to sub-transmission through a receiving station. He noted that the 34.5 kV sub-transmission system is where utility-scale distributed solar, fast charging stations, and industrial users connect. Next, the sub-transmission system connects to the local 4.8 kV distribution system through a distributing station and then a secondary system. Large commercial users are connected to the distribution system whereas residential/small commercial users are connected to the secondary system. He highlighted that the distribution system is important for ensuring that electricity can reach a customer as well as accommodating distributed generation.

Palmintier described the different categories of renewable resources in-basin. Utility-scale resources are broken into two types of resource locations: resources located at existing once-through cooling (OTC) sites that are connected to the transmission system and "non-rooftop" solar and storage that will be built based on systemwide needs. He noted that non-rooftop solar and storage is connected to the 34.5 kV distribution system and is located based on GIS analysis that considers physical aspects and land ownership. Additionally, rooftop solar and customer-adopted storage is connected to both the 4.8 kV and 34.5 kV distribution systems based on customer-adopted models. He noted that resources located at existing OTC sites would not be discussed at this session.

Palmintier reviewed the changes to distribution analysis when transitioning to a 100% renewable energy system. The size of traditional and low renewable energy systems is based on a single peak load planning time point, and regulation is designed to manage only voltage drop. The size of a 100% renewable energy system will consider multiple design points that use different combinations of load, electric vehicles, and load vs. solar, as well as regulation to manage voltage drops (load) and rises (generation) and non-traditional sources of voltage control (advanced inverters).

Palmintier recapped the methods for conducting the distribution cost analysis. The first step was to build electric models using GIS input data to reflect where components were located within LADWP's current system. Second, loads were allocated and local solar and storage were attached. Third, power flow modeling was used to identify overloads or voltage problems. Palmintier highlighted that the core analysis focused on the overloads or voltage problems identified by the power flow modeling and noted that these would be discussed in this session. The fourth step identified the upgrades needed to solve these problems, and the fifth step estimated the corresponding costs.

Palmintier posed the following key research question that the NREL team explored in their analysis: How do changes in load and deployment of distributed solar and storage associated with 100% renewable energy pathways affect LADWP's electrical distribution system? He identified overloads (lines and transformers) and voltage challenges (overvoltage and undervoltage) as two prominent issues that would be explored in the distribution system.

Major Themes from Advisory Group Member Questions and Discussion

- How has NREL tested sensitivities to distribution costs for different load patterns? For example, if 50% of electric vehicle charging is assumed at home, how would increases in electric vehicle charging beyond this assumption impact the system?

LA100 Upgrades and Costs

Palmintier provided an overview of the distribution upgrades that will be needed for implementation of a 100 percent renewable system. He noted that before upgrades, overloads occur on 80% of feeders in the city, but typically with only a few (of hundreds) pieces of equipment needing changes. After upgrades, problems such as maximum transformer and line loading are reduced with previously overloaded equipment under 75% loading post upgrade and other non-upgraded equipment below the threshold of 125% of loading.

Palmintier explained impacts to costs and needed upgrades. He provided an example of implications for the distribution system if it is not upgraded to resolve existing issues. Currently, a distribution transformer may occasionally be overloaded at 115%, but without upgrades the same distribution transformer could be overloaded to more than 145% with added solar and electric vehicle charging. He noted that the solution is to upgrade the transformer so that they are loaded at 75% allowing for future expansion.

Palmintier described the flow of core distribution upgrade analysis. He explained that circuits with known overloading or voltage challenges are assumed to be upgraded in order to isolate effects of new load and solar growth. Upgrades would then be made to load (electric vehicle adoption, energy efficiency, and other growth) and to distributed solar and storage by 2030 and again by 2045.

Palmintier posed the following key research question that the NREL team explored in their analysis: What are the costs associated with distribution system upgrades to accommodate these changes? He discussed several caveats prior to providing cost results:

- The results do not include the cost to resolve any existing issues in distribution or the cost for routine maintenance and capital costs unrelated to load growth or solar and storage deployment.
- The analysis considers only autonomous advanced solar inverter functions and traditional infrastructure upgrades and control changes.
- System-wide upgrades and/or the use of emerging solutions could result in different costs, such as upgrading from a 4.8 kV to a 12.5 kV system or coordinating efforts of a Distributed Energy Management System (DERMS) and Advanced Distribution Management System (ADMS). He noted that these were beyond the scope of analysis.
- NREL's data is not perfect and the results should be considered the best estimate for purposes of evaluating LA100 study pathways and cost drivers.

Palmintier reviewed the key findings for distribution system costs across the LA100 scenarios, noting that 75-90% of costs are incurred in the 4.8 kV system. According to Palmintier, costs are generally strongly influenced by load electrification because higher loads lead to higher costs for upgrading the system. Additionally, costs are somewhat higher with greater deployment of rooftop solar and customer-adopted storage. He noted that distribution upgrade costs are much lower than bulk system costs. The distribution system costs address upgrades only and not the cost of the solar panels or other equipment. Palmintier shared that NREL's analysis also considered several adoption patterns for rooftop solar and storage and that the costs and trends remained consistent (within a 10% range). Costs are largely driven by investments between 2030 to 2045 as compared to 2020 to 2030. He noted that a lot of investment in upgrades is needed to support the renewable energy transition. Upgrading transformers and lines is the biggest driver of these costs.

Major Themes from Advisory Group Member Questions and Discussion

- There was interest in data on distribution upgrade costs needed outside of the renewable energy transition process.
- What is replaced during upgrades? Do upgrades include just replacement of the transformers, or would the lines and other equipment be replaced as well?
- Upgrading some or all of the 4.8 kV system to a 12.5 kV rating was discussed as potential mitigation, with a suggestion that this could be critical for addressing on peak distribution losses. Does NREL's analysis indicate areas of the 4.8 kV system that might provide good candidates for upgrade to 12.5 kV?
- Has LADWP engaged SB100 Author and City of Los Angeles Council Member Kevin De Leon to invite his staff to participate in the LA100 process?
- Does analysis consider switching loads to a 34.5 kV system rather than upgrading the 4.8 kV system?
- Has NREL estimated job creation for each scenario?

- Why do the 34.5 kV system costs go down with higher load in the LA Leads and Distributed Energy Future scenarios as compared to moderate load?
- Are there any efficiencies to upgrading the transformers and is that taken into consideration?
- Because the distribution system relies on the OTC sites, how does the model address these sites after 2030? This is important for determining relevant costs for upgrading the distribution system.

Deployment of Non-Rooftop Local Solar

Palmintier discussed geographic deployment of non-rooftop solar within Los Angeles on sites with the lowest distribution system costs in 2045. He described the flow of distribution analysis for additional costs to add non-rooftop solar. Analyses were conducted for select years 2020 to 2045 and considered load and customer-adopted solar. Storage and additional analyses for select years 2020 to 2045 were conducted, adding possible non-rooftop solar for comparison. Palmintier noted that only about 5–20% of potential capacity gets built for non-rooftop solar (parking canopies, floating solar, and ground mount solar). He explained that there is a lot of rooftop solar in all of the LA100 study scenarios. Non-rooftop solar holds significant potential at parking canopies, which have fewer space options to pair with storage. Additionally, the build-out of non-rooftop solar is not uniform across the city. In some scenarios, cross-basin congestion and other factors increase the value of non-rooftop solar.

Palmintier reviewed how distribution-level grid integration costs change with capacity, noting that total costs increase as more kilowatts of solar are installed. For the distribution grid upgrade cost per system-wide non-rooftop solar capacity, built capacities are generally in the low range of system-wide upgrade costs. Key findings for non-rooftop solar integration indicate that distribution integration does not add significant cost to utility-scale solar. Non-customer local solar capacity that is built represents a small fraction of the technical potential. Most regions can accommodate a significant amount of solar with no 34.5 kV upgrades. Lastly, integration costs for the LA100 study scenarios are low compared to the cost of generation (solar panels and storage).

Palmintier posed the final key question: Does increased distributed solar and storage deployment in a 100% renewable energy future provide an opportunity for deferring distribution system upgrades? He provided the caveat that only incidental deferment was considered. The grid was designed to support load and distributed generation and the generation location was not optimized for grid value. Additionally, not all value streams were included for deferment. For example, for substation expansion, only equipment costs and labor were included, not land costs or other stakeholder considerations.

Summary

Palmintier provided a recap of themes from this analysis. Some distribution upgrades are required for load and solar, though few upgrades are needed per feeder. These upgrades are fairly simple (mostly service transformers) and they represent only about 1% of bulk system costs. The cost of distribution upgrades for larger non-rooftop solar varies with location but is generally low. In addition, the 100% pathways use a fraction of the available in-basin solar/storage capacity. Lastly, there are synergies between upgrades for load and solar.

Major Themes from Advisory Group Member Questions and Discussion

- Do costs for capacity of non-rooftop solar and grid integration include storage?
- Has NREL estimated the cost of solar and storage to customers?
- What assumptions are made for customer-adopted storage that may reduce distribution system loads?

Wrap-up and Next Steps

In wrapping up the meeting, Isaacson reminded the Advisory Group members that the next session will cover the bulk power modeling and will take place on Thursday, December 17. She wished the Advisory Group members a good afternoon.

Virtual Session #2

Thursday, December 17, 2020, 10:00 a.m. to 12:00 p.m.

Location

Virtual Meeting

Virtual Meeting #14 Attendees

Advisory Group Members

Aaron Ordower, Council District 2
Allison Smith, Southern California Gas
Andrea Rojas, Sierra Club
Andy Shrader, Council District 5
Bonny Bentzin, University of California, Los Angeles
Bruce Tsuchida, The Brattle Group
Camden Collins, Office of Public Accountability (Ratepayer Advocate)
Christos Chrysiliou, Los Angeles Unified School District
Dan Kegel, Neighborhood Council Sustainability Alliance
Danielle Mills, American Wind Energy Association California
Duane Muller, University of California, Los Angeles
Ernie Hidalgo, Neighborhood Council Sustainability Alliance
Fred Pickel, Office of Public Accountability (Ratepayer Advocate)
Jack Humphreville, DWP Advocacy Committee
Jasmin Vargas, Food & Water Action
Jean-Claude Bertet, City of Los Angeles Attorney
Jin Noh, California Energy Storage Alliance
Rebecca Rasmussen, Office of Mayor Eric Garcetti
Stuart Waldman, Valley Industry Commerce Association
Tony Wilkinson, Neighborhood Council

LADWP Staff

Ann Santilli
Ashkan Nassiri
Carol Tucker
David Rahimian
Dawn Cotterell
Doug Tripp
James Barner
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Jason Rondou

Jay Lim
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Julie Van Wagner
LeiLani Johnson
Louis Ting
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Nicholas J. Matiasz
Paul Lee
Paul Schultz
Scott Moon
Stephanie Spicer
Steve Ruiz
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Project Team

Daniel Steinberg, NREL
Jaquelin Cochran, NREL
Paul Denholm, NREL
Ramin Faramarzi, NREL
Scott Haase, NREL
Alyson Scurlock, Kearns & West
Joan Isaacson, Kearns & West
Taylor York, Kearns & West

Observers

Bill Engels, Water and Power Associates
Dan Reeves
Kayla Koerting, Valley Industry Commerce Association
Kevin Barker, California Energy Commission
Lauren Harper, Los Angeles Cleantech Incubator
Mayte Sanchez, Los Angeles Cleantech Incubator
Sarah Wiltfong, Los Angeles County Business Federation
Zelinda Welch, University of Southern California

Call to Order and Agenda Overview

Joan Isaacson, LA100 Advisory Group meeting facilitator from Kearns & West, welcomed the virtual meeting attendees. She explained that this was the second and final virtual session for Meeting #14 of the Advisory Group for the City of Los Angeles 100% Renewable Energy Study (LA100). This session provided an update on the bulk power modeling as well as general LA100 study updates.

Welcome Remarks

Ashkan Nassiri, LADWP Manager of Strategic Initiatives, welcomed Advisory Group members and wished them well. He noted that this was the last virtual meeting of 2020 and acknowledged that this journey started over 3 years ago. He shared that LADWP and NREL are preparing for the last Advisory Group meeting, which will occur in early 2021. Advisory Group Meeting #15, noted Nassiri, will include a presentation detailing rate impacts associated with a 100% renewable energy system. He thanked the NREL, Kearns & West, and LADWP teams for their involvement in this groundbreaking study for the City of Los Angeles and acknowledged Advisory Group members for providing their honest feedback. The LA100 study is more comprehensive and complete due to Advisory Group members' contributions, concluded Nassiri, and he wished everyone a safe holiday.

Jaquelin Cochran, NREL LA100 Principal Investigator, welcomed everyone and reviewed the meeting agenda, noting that today's session would include final updates on the bulk power modeling. The session would conclude with general LA100 study updates and include an open question and answer session on LA100 study topics.

Final Results: LA100 Investment Pathways

Dan Steinberg, NREL Economics and Forecasting Group Manager, provided an overview of the final results for the LA100 investment pathways. He began by recapping the sensitivity analyses and reliability topics discussed in the Advisory Group Meeting #13 sessions. The sensitivity analyses focused on the effects of varying 100% renewable energy definitions, how the speed of transition to 100% renewable energy affects system costs, the impacts of different load levels, what happens with varying availability of key technologies such as transmission, and the effect of changes in renewable energy technology costs. Steinberg's review of meeting #13 on reliability highlighted that the pathways identified in the draft results were highly robust for simulated outages, and that NREL examined the implications of potential reductions in capacity expansion investments to reduce costs.

Steinberg highlighted the progress that NREL has made since Advisory Group Meeting #13 and gave an overview of the topics to be covered in the current session. NREL first revised the methods used to assess the capacity credit of renewable and storage resources at very high penetrations and ran a new analysis using these methods. NREL then re-simulated the pathways to evaluate how the resource mix changed as a result of changes in methods. Next the resource adequacy of the resulting lower cost systems were then evaluated to ensure that adequacy thresholds were met. Steinberg noted that instances of unserved energy are more likely but only in the most extreme events. Steinberg explained that in this meeting he would cover the final results for the renewable energy investment pathways including what gets built, how the target is met, the composition of the generation mix, how the results compare to the previous version, and how the revised scenario buildouts hold up under extreme events.

Steinberg presented the capacity results by technology for the core LA100 scenarios (SB100, LA Leads, Transmission Renaissance, and High Distributed Energy Future) in the year 2045. He began with the moderate load capacity mix for each scenario and described the final results as compared to the draft results presented in Advisory Group Meeting #13, noting the changes. He noted that the results were consistent with the AG13 version of results, with small changes to firm capacity assets. He reviewed the general themes across scenarios. He explained that the SB100 scenario allows electricity certificates, which results in natural gas being used for a portion of the capacity and energy needs. He emphasized that there is a tradeoff in assets between the LA Leads scenario and Transmission Renaissance scenario in that LA Leads does not allow renewable energy combustion turbine assets prior to 2045, causing the LA Leads scenario to rely on hydrogen combustion turbines. On the other hand, the Transmission Renaissance scenario and High Distributed Energy Future scenario rely on renewable energy combustion turbine assets in the near term. He noted that hydrogen combustion turbines assume fuel is produced on site, while renewable energy combustion turbines assume that fuel is supplied by the market.

Steinberg then presented the capacity mixes under the High Load scenarios in the year 2045. He noted that although the total amount of capacity is increased slightly, overall the technologies deployed and their uses did not change under the revised scenarios. He explained that generally, the high load scenarios exhibited increased wind and solar assets and decreased firm capacity assets. He then reviewed in more detail the deployment of non-variable generation and non-diurnal storage assets. Overall, the most significant changes are seen in the firm capacity assets. He noted that there are major changes in the level of investment and these assets are used to provide reliable resources to meet energy demands when wind and solar have low output.

Major Themes from Advisory Group Member Questions and Discussion

- This analysis seems to focus on the solution for 2045, as well as methods for getting to 2045. To inform policy decisions, LADWP engineers should be provided access to projections created before reserves were reduced. It is important to consider actions between now and 2045, rather than just what the system will look like in 2045.

Generation

Steinberg provided an overview of the monthly generation mix in 2045 for the SB100 and LA Leads High Load scenarios. He noted that the generation in each month encompasses the energy produced by all technologies and curtailed energy. Additionally, energy used for charging and pumping is used to calculate the net generation per month. He highlighted patterns of change in generation mix throughout the year for each scenario. For the SB100 High Load scenario, most energy needs are met with renewable generation during the first half of the year, while natural gas is used to supplement energy needs during the second half of the year when renewable generation declines. This helps to meet energy demands during a time when renewable energy availability is relatively low and load conditions are relatively high. Steinberg noted that the LA Leads High Load scenario follows a similar pattern, the difference being that hydrogen combustion turbines are substituted for natural gas turbines during the second half of the year because the LA Leads scenario does not allow the use of natural gas. He noted that the hydrogen fuel is modeled as seasonal storage during the first part of the year to produce hydrogen generation during the latter part of the year.

Steinberg reviewed the annual generation mix for all the LA100 scenarios for moderate and high load levels, comparing these results to the previous draft results. He noted that the generation mix is fairly consistent for meeting moderate loads across the scenarios, but that more substantial changes in the generation mix are necessary to meet loads during high load scenarios. In the Transmission Renaissance High Load scenario, hydrogen combustion turbine assets decrease while renewable energy combustion turbine assets increase from draft to final results. Curtailed energy in that scenario also increases substantially as a result of more wind and solar resources and less reliance on hydrogen combustion turbines. He noted that there is also less charging and dispatching from hydrogen combustion turbines in the final results. He explained that the High Distributed Energy Future High Load scenario displays similar behavior with decreases in hydrogen combustion turbines and fuel cell technologies.

Steinberg reviewed the changes in the overall in-basin and out-of-basin generation mix for all the scenarios, highlighting the Transmission Renaissance scenario. The out-of-basin generation and charging show decreases in geothermal and wind assets and an increase in curtailed energy in the final results as compared to the draft results.

Major Themes from Advisory Group Member Questions and Discussion

- Curtailed energy saves money when compared to the cost of adding storage and makes more energy available for later uses.
- How are the results split between residential and commercial/industrial with regard to customer photovoltaic and storage?
- Do results consider net metering?

Costs

Steinberg provided an overview of the cumulative bulk system, distribution upgrades, and distributed resource costs for 2021 through 2045. He noted that the costs are not inclusive of existing debt or power purchase agreements executed prior to 2021, costs associated with future distribution operation and maintenance, or energy efficiency and demand response programs. He explained that the themes around the total costs have not changed when comparing the draft and final results. The required bulk system investment is for key energy assets including wind, solar, storage, and geothermal. Additionally, firm capacity makes up some of the costs. He noted that the LA Leads scenario requires considerably more investment in hydrogen combustion turbine technologies and geothermal assets to meet targets because the scenario does not allow use of renewable energy combustion turbines. Steinberg reviewed the cost savings for the moderate load scenarios. When comparing draft and final results, there is a slight change in overall required capacity, which is reflected in the costs. Cost savings across scenarios range from $1 to 2 billion, with LA Leads resulting in a $3 billion cost reduction in the final results.

Steinberg next reviewed the costs for the high load scenarios, noting that these scenarios have more significant changes. Under the high load scenarios, the need for more capacity resources is greater. He explained that the costs still see a 2–5% reduction in savings across all scenarios, noting that a substantially higher cost savings is seen in the LA Leads scenario comparing final to draft results.

Steinberg reviewed what would happen if every scenario achieved 100% renewable energy by 2035. He noted that the LA Leads scenario has a compliance year of 2035 while all other scenarios have a compliance year of 2045. Costs for all of the high load scenarios increase when the compliance year is shifted to 2035, with LA Leads having the highest costs due to biofuel restrictions. The key takeaway is that an earlier compliance year drives up costs. The LA Leads scenario is also restricted to available technologies because it does not allow the use of renewable energy combustion turbines, resulting in higher costs.

Major Themes from Advisory Group Member Questions and Discussion

- Is it relatively easy to switch between renewable energy combustion turbines and hydrogen combustion turbines before a plant is constructed?
- Is it fair to assume that new system assets are less labor intensive than traditional generation, and can this be quantified?
- How much are residential ratepayers being asked to invest in customer photovoltaic? How much of this investment is expected to occur in single-family residential?
- Residential ratepayers will likely bear the costs of the transition, and there will be little bonding capacity for this transition.
- There was a concern that operations and maintenance were not considered in the analysis.
- Is it true that the incremental cost of choosing the SB100 scenario over the Transmission Renaissance scenario is only 5–10%? Does the incorporation of hydrogen combustion turbines contribute to cost savings?
- How many miles of transmission and distribution are required in the latter scenarios, and how likely is it this level of infrastructure could be built by 2035?
- The study needs to consider feasibility. How will that be addressed in the report? It would be helpful if, to provide perspective, NREL could provide reference numbers comparing the current system to the modeled system.
- Please follow up on the feasibility of 2035 for the various scenarios.

Reliability

Steinberg provided an overview of reliability, including a comparison between resilience to extreme transmission events in revised and draft scenarios. NREL developed methods to explore the impacts of large-scale transmission outages on the operation of systems, analyzing the amount of energy that would be unserved by extreme events and the point during the year when that would occur. He compared the current 2020 system to the 2045 system in the LA Leads High Load scenario. Overall, the level of unserved energy is significantly less in the 2045 system. Draft results had shown a system that was more robust to system outages than the current one, a main indicator that the 2045 system was overbuilt. In the revised and final version, the performance of the 2045 system is not as robust as in the draft results but remains consistently robust and reliable with the current 2020 system in extended outage scenarios.

Summary

Steinberg provided a summary of core conclusions from the final results. He noted that wind and solar are crucial energy sources for achieving 100% renewable energy, and that diurnal storage assets are key to increasing utilization and the value of wind and solar resources. In-basin firm capacity assets are the lowest cost option for maintaining sufficient in-basin energy supply during times of system stress. Costs are highly sensitive to assumed technologies and are impacted by the timing of the target year. Options for cost mitigation include renewable energy credits or other alternative compliance options, broader technology and/or fuel-type eligibility, cross-sectoral coordination, and modernization of load.

Major Themes from Advisory Group Member Questions and Discussion

- There was a request for clarification of results from the worst of the failure scenarios that were modeled.
- Did you model loss of a big transmission line for 5 months, or similar situations?
- Would the High Distributed Energy Future scenario improve our resilience to severe transmission outages since it has more local generation?
- Climate change considerations such as higher temperatures at night and higher power demand in the summer should be included in the standard assumptions.
- The final report should define extreme events or failure scenarios.
- Is there an estimate of cost for rooftop solar that is already deployed?
- It may be hard for some to understand the costs presented for this analysis without an understanding of current system costs.

LA100 Updates

Community Outreach

Cochran provided updates on the upcoming community outreach, Advisory Group Meeting #15, the LA100 website, and final report. She outlined the two rounds of community outreach for the LA100 study. In the first round scheduled for January 2021, community outreach will focus on introducing the LA100 study, including a high-level explanation of the scenarios. In the second round scheduled for March 2021, community outreach will focus on the LA100 study results, including an explanation of the key insights. She noted that both rounds of community outreach will include opportunities for community feedback and Q&A. She then noted LADWP's path to 100% clean energy, which LADWP presented in the Advisory Group Meeting #13 sessions. This plan includes the LA100 study and Clean Grid LA, and both efforts feed into the Strategic Long-Term Resource Plan. She explained that outreach for the Strategic Long-Term Resource Plan will begin in Spring 2021. Cochran next provided an overview of the proposed agenda for community meetings. The first round will take place January 20 to February 6, and will include morning, afternoon, and evening timeslots. All community outreach meetings will be held virtually using the WebEx platform combined with Facebook Live streaming, which will include an option for Spanish translation. Resources are available for promoting participation in community outreach meetings, including the LA100 study website, a fact sheet that is drafted and will be added to the website soon, and an introductory video. Dates for the second round of community outreach meetings in March have yet to be determined.

Major Themes from Advisory Group Member Questions and Discussion

- It is exciting to hear that public outreach is starting soon.
- The presentation slides should be kept simple to support wider understanding.
- The LA100 study team should coordinate with potential outreach and community partners on the content of community outreach.
- The impact of the transition on ratepayers is likely to be a concern for many.
- The community outreach effort should remain neutral and be designed to solicit feedback and not to sell the project to the community.
- Will the slides from all LA100 Advisory Group meetings remain accessible after completion of the study?
- Can you provide a preview of the outreach slides?
- When will the results website be made public?
- The focus should be on engaging the general public and those who may not be aware of the study, rather than neighborhood councils or other groups. However, neighborhood council presentations in environmental justice communities would be beneficial.
- What steps are you taking to reach out to environmental justice communities?
- The Advisory Group should receive notice of all public meetings.

Advisory Group Meeting #15

Cochran reviewed the topics for Advisory Group Meeting #15, the final meeting. The session will focus on the final results for the LA100 study including job and economic impacts, air quality, health, environmental justice, monetization of benefits, and a synthesis across the entire study. There will also be a summary of the community outreach discussions and LADWP will present on rate impact analysis.

LA100 Website and Final Report

Cochran presented information on the two final products of the study: the LA100 website and LA100 final report. The LA100 website will be publicly accessible, and the final report will be available both as a PDF from NREL and on the website. She noted that the report will provide more detailed results, whereas the website content will be higher level and likely used more frequently for outreach.

Cochran gave an overview of updates to the LA100 website, including the addition of Spanish translation for the two LA100 study videos. There have also been updates to key findings by scenario including final results for generation, capacity, and greenhouse gas emissions. She noted that the distribution results are coming soon. Key findings by topic have been updated to include final results for renewable energy pathways, greenhouse gas emissions, and local solar. Cochran explained that a bulk layer was added to the data viewer and updates are still being made. The remaining results for the key findings will be available in January to March.

Cochran reviewed the anticipated schedule for the final report. In January, draft chapters for the introduction, electricity demand, and customer solar and storage will be posted to the LA100 website. The remaining draft chapters will be posted in early February before the final report is published in March. She invited Advisory Group members to provide feedback on the draft chapters.

Major Themes from Advisory Group Member Questions and Discussion

- How long will the report be?

- Will the report be presented to the LADWP Board of Commissioners, and if so, when? The public should have an opportunity to provide input before the Board reviews the study.
- When will the LA100 study website be available to the public?
- Breaking the report into chapters is a good way to provide digestible chunks of complex information.
- Will a community engagement process be conducted for Clean Grid LA? If so, can LADWP provide details?
- A community meeting dry run would be beneficial.
- In general, people need a base understanding about how the power system works to understand the proposed changes, including an understanding of in-basin, out-of-basin, and transmission resources.
- The reality is that storage costs significantly more than renewable energy.
- There was a request for more information about costs for achieving the last 10%.

Wrap-up and Next Steps

Isaacson wished the Advisory Group members a happy holiday and hoped that they had time to rest and unplug. She thanked everyone and wished the Advisory Group members a good afternoon.