LA100 PLAN

ADVISORY GROUP MEETING #7

(LA100 PLAN, NREL STUDY, AND TRANSMISSION SYSTEM ASSESSMENT)

PRESENTED BY:

Power System Planning Division

Resource Planning

MARCH 20, 2025

NEXT MEETING
May 2025 (TBD); Public Meetings targeted for June 2025

LOCATION
In-person, LADWP Wall Street

AGENDA

9:00 – 9:05 AM	Welcome and Introductions
9:05 – 9:10 AM	Meeting Purpose, Agenda Overview, Guide for Productive Meetings
9:10 – 10:10 AM	LA100 Plan Results – Risks and Modeled Sensitivities
10:10 – 10:15 AM	*Break*
10:15 – 10:50 AM	NREL Presentation on Scattergood Modernization Project Alternatives
10:50 – 11:25 AM	Transmission System Planning Assessment
11:25 – 11:30 AM	Wrap Up and Next Meeting

Note: Q&A and discussion will follow presentations

ADVISORY GROUP ROLES (1/2)

Provide input and feedback based on the expertise, knowledge, and resources of the organizations, institutions, and constituent groups represented by the Advisory Group Members

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Provide Perspectives. Discuss major issues that LADWP will face in the next 10-20 years. Provide input and review of strategic scenarios that are used in the resource analysis and final recommendations for near-term actions.

Continue the Collaborative Dialogue. Build upon the momentum from the LA100 Equity Strategies Study and 2022 SLTRP Process.

Conduct Outreach to Respective Constituent Groups. Bring diverse input into the process and keep constituents informed of the SLTRP process.

Consider Broader Community Input. During Advisory Group discussions think of the various communities and considerations throughout the City of Los Angeles.

Provide Technical Information & Perspectives. Add value through your areas of expertise.

ADVISORY GROUP ROLES (2/2)

Provide input and feedback based on the expertise, knowledge, and resources of the organizations, institutions, and constituent groups represented by the Advisory Group Members

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Read Pre-Meeting Materials. Prior to each meeting materials and agendas will be distributed and you are expected to be prepared for the meeting. This includes reading and reviewing the 2022 SLTRP and LA100 Equity Strategies Study Report.

Participate in All Meetings. A total of eight (8) meetings are anticipated between March 2024 and May 2025. Meetings are expected to alternate between in-person and virtual. Each meeting will be conduced in 2-3 hours segments.

Alternate Representatives. If you cannot attend a meeting, then please send an alternate on your behalf.

Balancing Perspectives. To maintain stakeholder balance – only one representative per member organization in meeting discussions.

READ MATERIALS

PARTICIPATE

REPRESENTATIVES

BALANCE

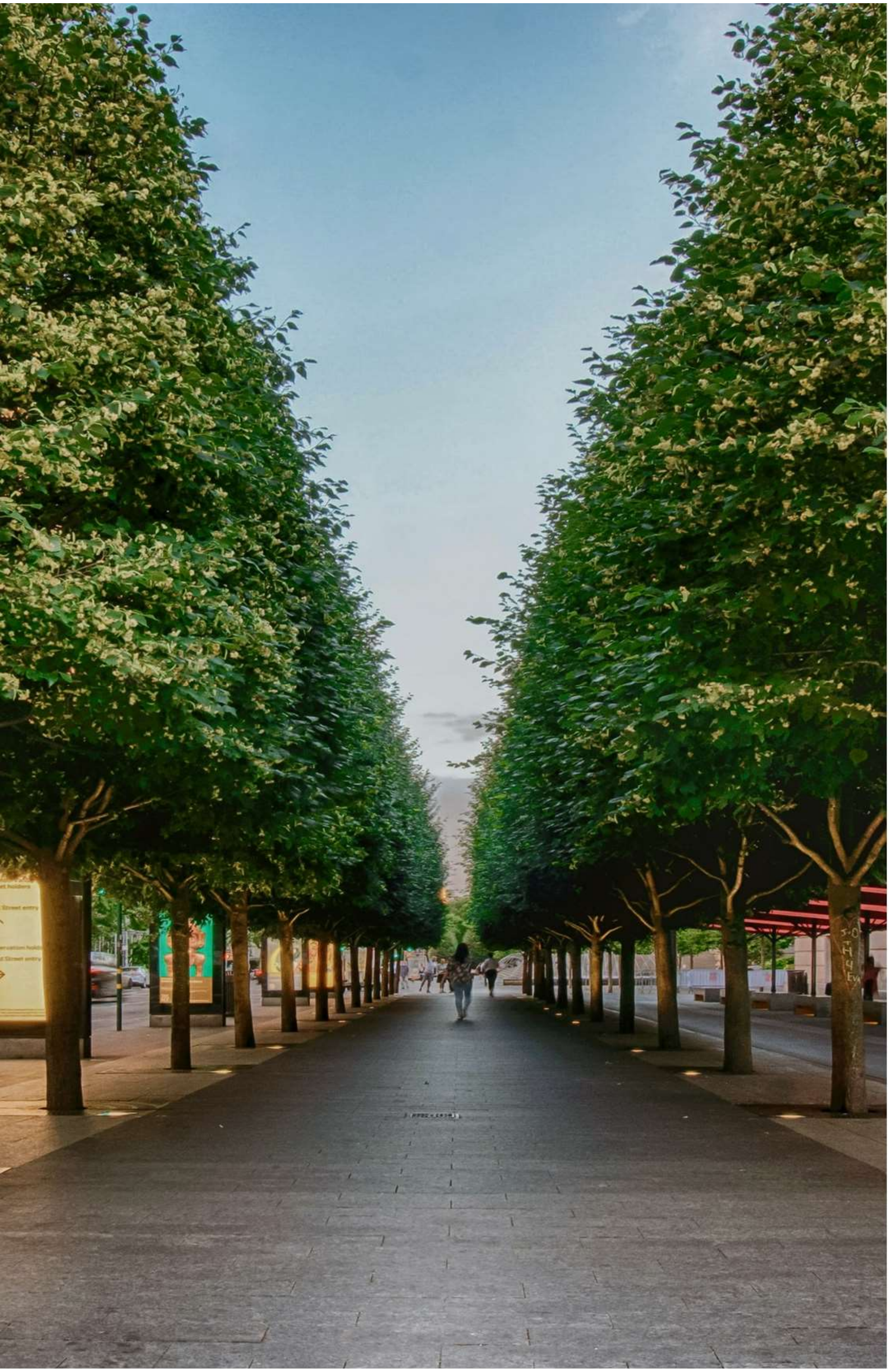
2024 ADVISORY GROUP MEMBERS

90 Members Total

NOTE:

LA100 Equity Strategies Steering Committee has been integrated into the SLTRP Advisory Group Roster

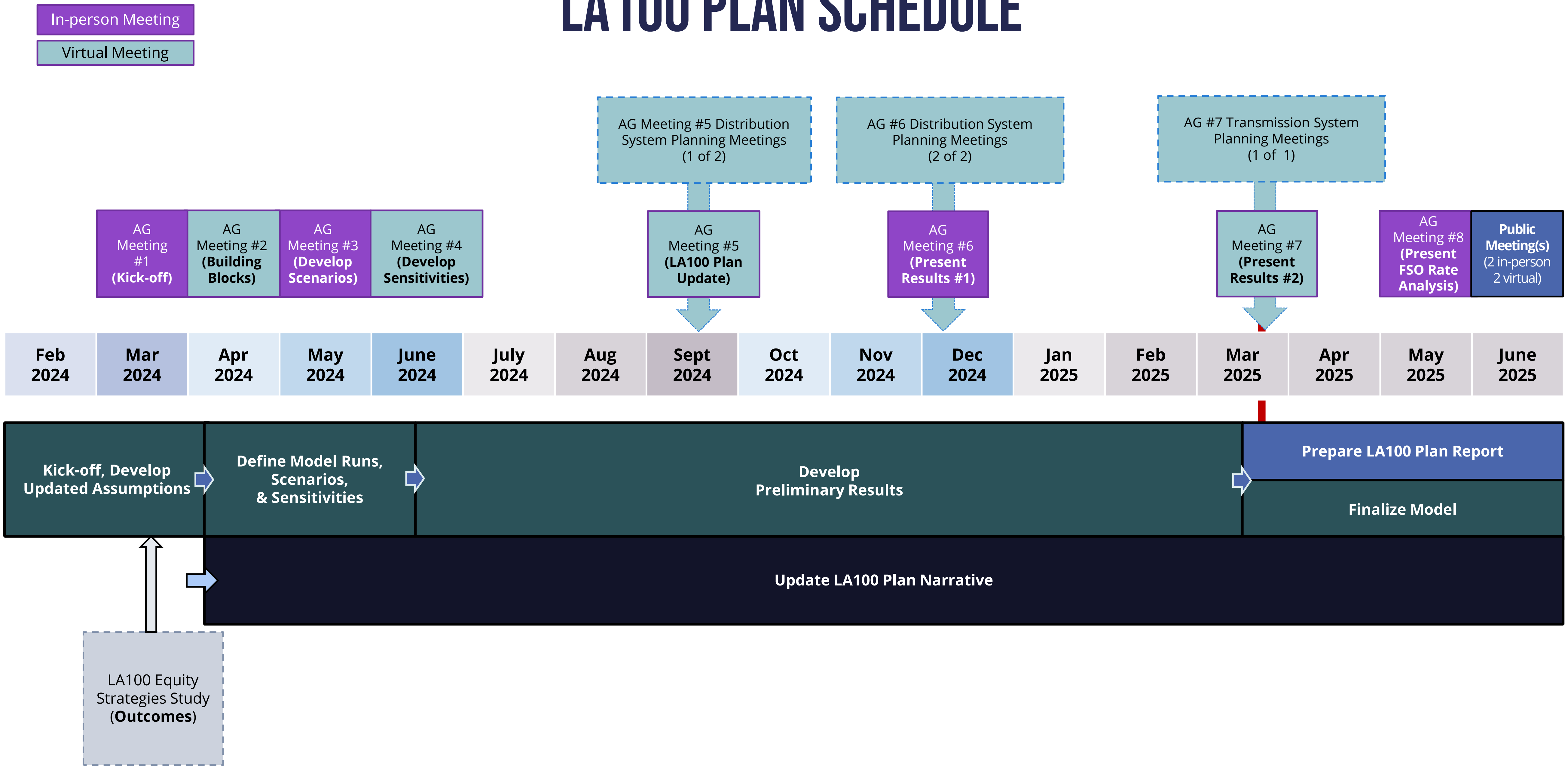
# of Representatives	Stakeholder Category	Organization(s)
6	ACADEMIA	CSUN, UCLA, USC
17	BUSINESS & WORKFORCE	CEERT, Center for Sustainable Energy, Central City Assoc, IBEW – Local 18, LABC, LA Chamber, VICA, LABC
26	CITY GOVERNMENT	CLA, City Attorney, Council Districts, Rate Payer Advocate, Mayor's Office, Civil & Human Rights and Equity Dept., CEMO, Housing Authority, LA City Planning, LADOT
5	NEIGHBORHOOD COUNCIL	DWP Advocacy Committee, DWP MOU Oversight Committee, Neighborhood Council Sustainability Alliance, SLAANC
20	ENVIRONMENTAL COMMUNITY	CBE, EDF, Food and Water Watch, NRDC, LAANE, Sierra Club, Climate Resolve, Community Build, Enterprise Community Partners, Esperanza Community Housing, LA Cleantech Incubator, Move LA, PACE, Pacoima Beautiful, RePower, SLATE-Z, So. Cal. Association of Non-Profit Housing; SCOPE
10	PREMIER ACCOUNTS & KEY CUSTOMERS	LAUSD, LAWA, Metro, POLA, Valero Wilmington Refinery
6	UTILITIES	Southern California Gas, SCPPA, Water and Power Associates



GUIDELINES

1. **EQUAL TIME** — Everyone commits to all members having equal time to contribute input and perspectives
2. **CONCISE** — Keep input concise so all members have time to participate
3. **ACTIVELY LISTEN** — Actively listen to others, seek to understand perspectives
4. **OFFER IDEAS** — Offer ideas to address questions and concerns raised by others
5. **RAISING NAME TENT or RAISING HAND** — Participate by using the Raising Name Tent or Raising Hand

LA100 PLAN SCHEDULE



Note: Specific dates and meetings are subject to change.

LA100 PROGRESS

Renewable & Clean Energy

2024 Mix: **49% Renewables, 66% Carbon Free Energy**

2030 Goal: 80% Renewables, 97% Carbon Free

Eland Solar Battery Project

- COD on Nov 18, 2024 (Phase 1)
- April 7, 2025 (Phase 2)
- 400 MW of Solar; 1200 MWHr battery

Transmission Upgrades

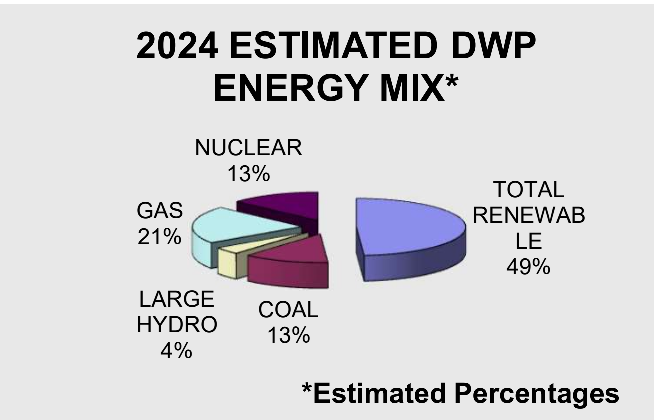
- 33 projects completed since 2018
- 41 Current Transmission Projects
- 5 new lines on existing corridors proposed
- Approx. 20 GW increase in rating
- RFI issued for new transmission corridors
- Estimated cost of planned projects: $5.3B

Energy Storage

- 1.5 GW of energy storage
- 55.1 MW of behind-the-meter
- Target additional 2 GW by 2035

Energy Efficiency

- Achieved 15% EE through customer programs
- Targeting 30% by 2035
- Inverting $1B in next decade



Dispatchable Generation

The Intermountain Power Project (IPP)

- <u>Complete divesture from coal & transition to renewable clean fuel</u>
- 840 MW green hydrogen ready units
- Commissioning in mid-2025

Scattergood Modernization Project

- <u>Transition to renewable clean fuel</u>
- 346 MW green hydrogen ready units
- EIR/RFP Phase
- Commissioning in 2029

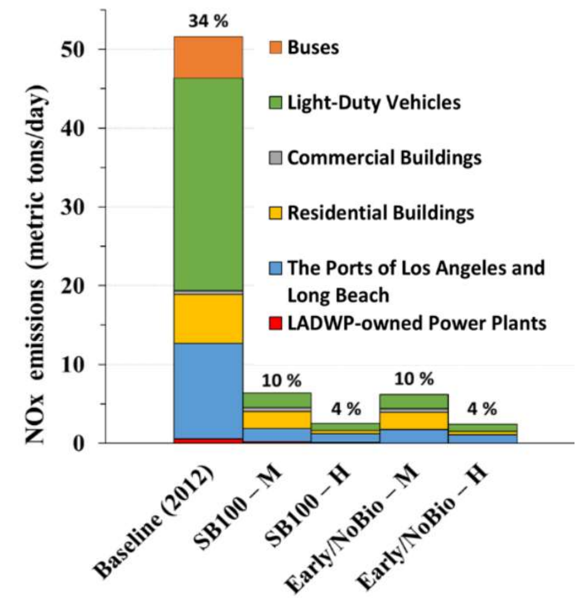
Electrification

POLA, LAWA, BE & EV Commercial EV Charging Targets:

- 45,000 charging stations by 2025 including 1,000 DC Fast Chargers
- 120,000 charging stations by 2030 including 3,000 DC Fast Chargers

City of LA EV Adoption Targets:

- 250,000 Light Duty EVs by 2025
- 750,000 Light Duty EVs by 2030



Local Solar

- Total local solar of approx. 778 MW
- Target of 926 MW by 2025
- 1500 MW by 2030; 2220 MW by 2035

Distribution Upgraded

- Pacific Palisades rebuilding
- Upgrades for system resiliency
- Future Growth

Demand Response (DRs)

Residential Thermostat DR

- 50,000 customers, 41 MW of Capacity

Commercial and Industrial DR:

- 78 customers, 38 MW of capacity
- Target: 815 MW by 2035.
- RFP in the process

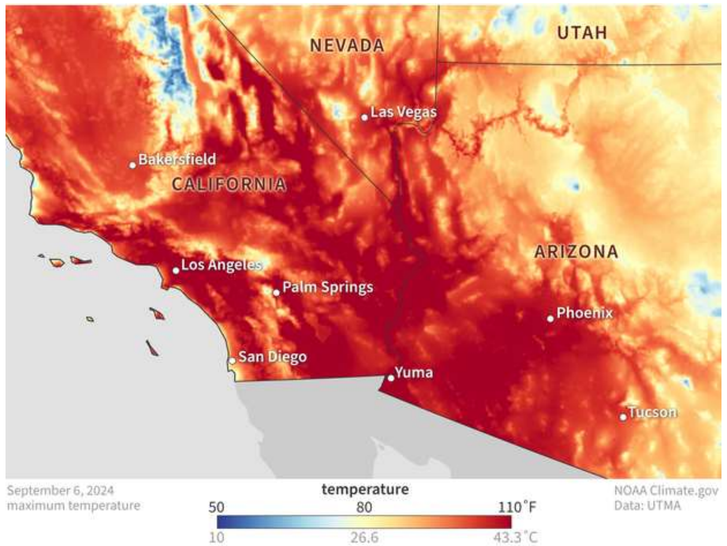
Distributed Energy Resources (DERs)

- 226 MW local solar PV, 387 MWh energy storage, 8,840 EV chargers.
- Estimated $1.9 billion investment in expanding DERs/ RFP in process

IN-BASIN DISPATCHABLE GENERATION IS REQUIRED FOR RELIABILITY

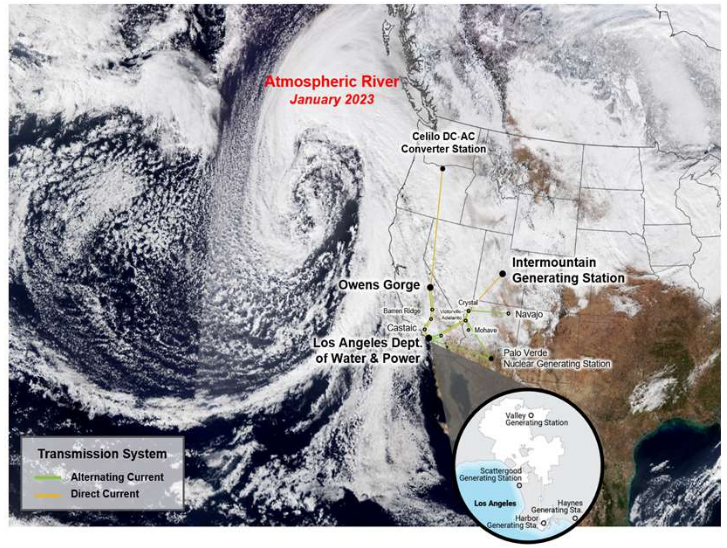
In-basin dispatchable generation is critical to avoid load shedding during stressed condition

Heat Wave



- **In-basin generation** provided more than 60% of demand during the 2024 heat storm, avoiding blackouts. LADWP avoided load shed due to in-basin generation
- **The 2020 California heat wave** resulted in rolling blackouts that affected over 300,000 Californians, LADWP's service territory avoided blackouts
- **Heat storms** are expected to occur more often due to climate change

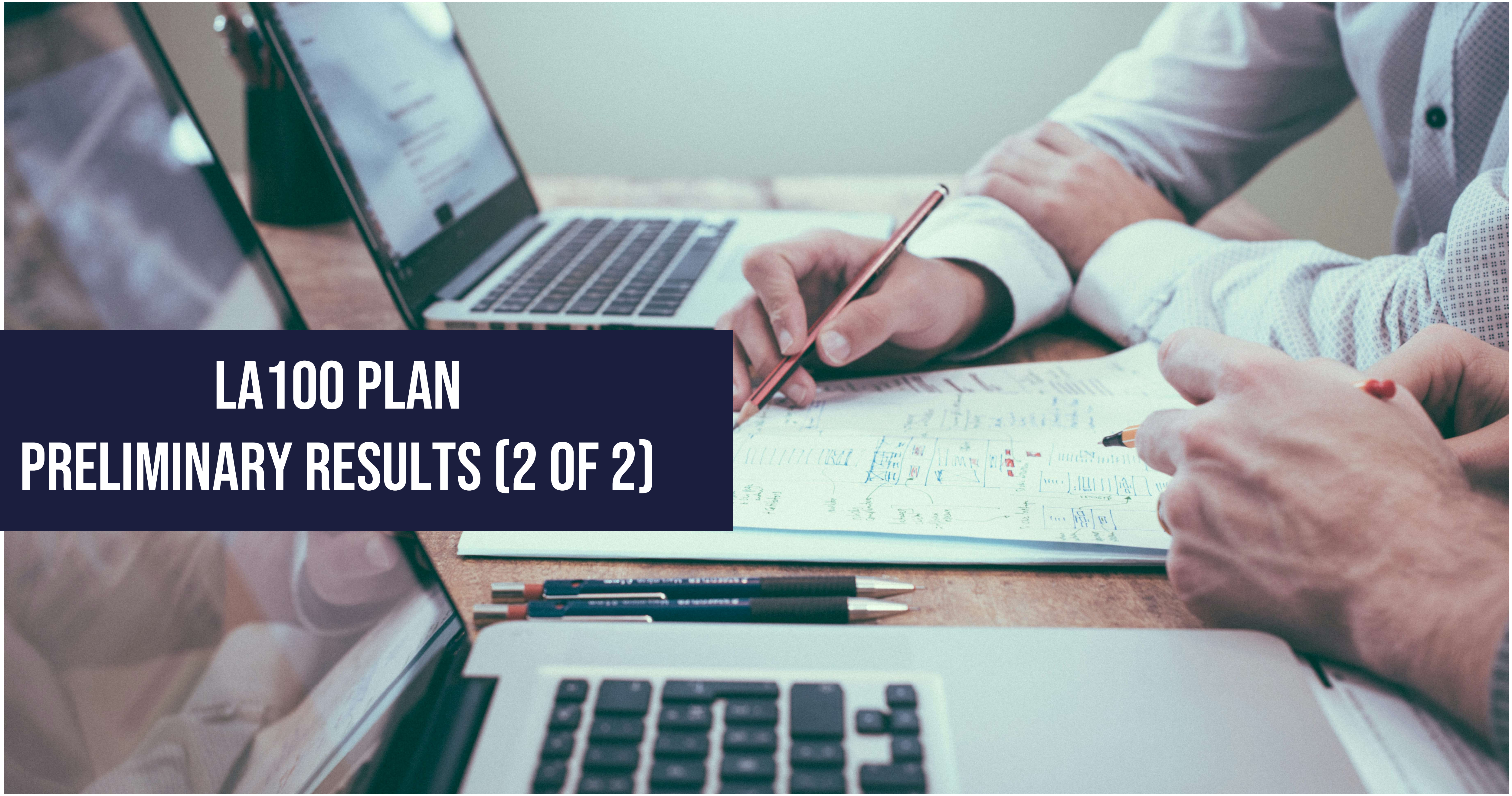
Atmospheric River



- **Renewables** mostly unavailable during the 10-day atmospheric river rainstorm in 2023. LADWP will be significantly increasing reliance on renewable energy
- **Short-Duration Energy Storage** not sufficient for prolonged periods of stressed conditions.
- **Intermittency** of renewables cannot respond to long duration outages or significant weather events
- **Dispatchable generation** is a key to long duration reliability

Wildfire

- **The 2019 Saddle Ridge Fire** led long-lasting outages over multiple transmission corridors, and LADWP's in-basin generation was relied on to avoid blackouts
- **The 2025 windstorm** and wildfires in Los Angeles caused significant transmission outages, and in-basin generation was used as backup. Scattergood played critical role in supporting the grid.



LA100 PLAN
PRELIMINARY RESULTS (2 OF 2)

Ascend Analytics

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Model Results for LA100

Modeling Work

- The IRP team considered two primary scenarios:
    - LA100 – Mandated plan by City Council to reach 80% RPS by 2030 and 100% carbon free by 2035
    - SB100 – Mandated by the State of California to reach 60% RPS by 2030 and 100% carbon free for retail load by 2045
- SB100 represents the reference case to benchmark LA100 outcomes

- **This presentation will briefly recap LA100 and cover sensitivity analysis**

LA100 Plan

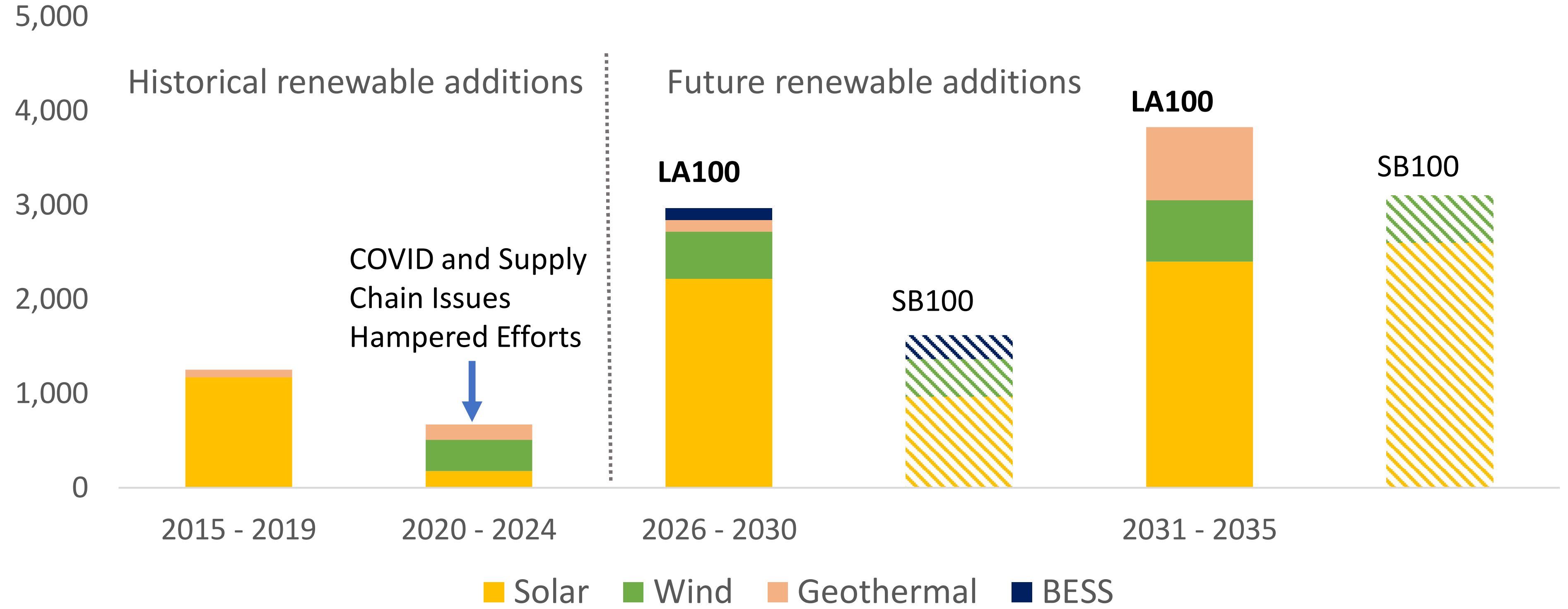
Ascend Analytics
Better models. Better decisions.

LA100 Plan

- 100% clean energy by 2035
- 80% renewables by 2030

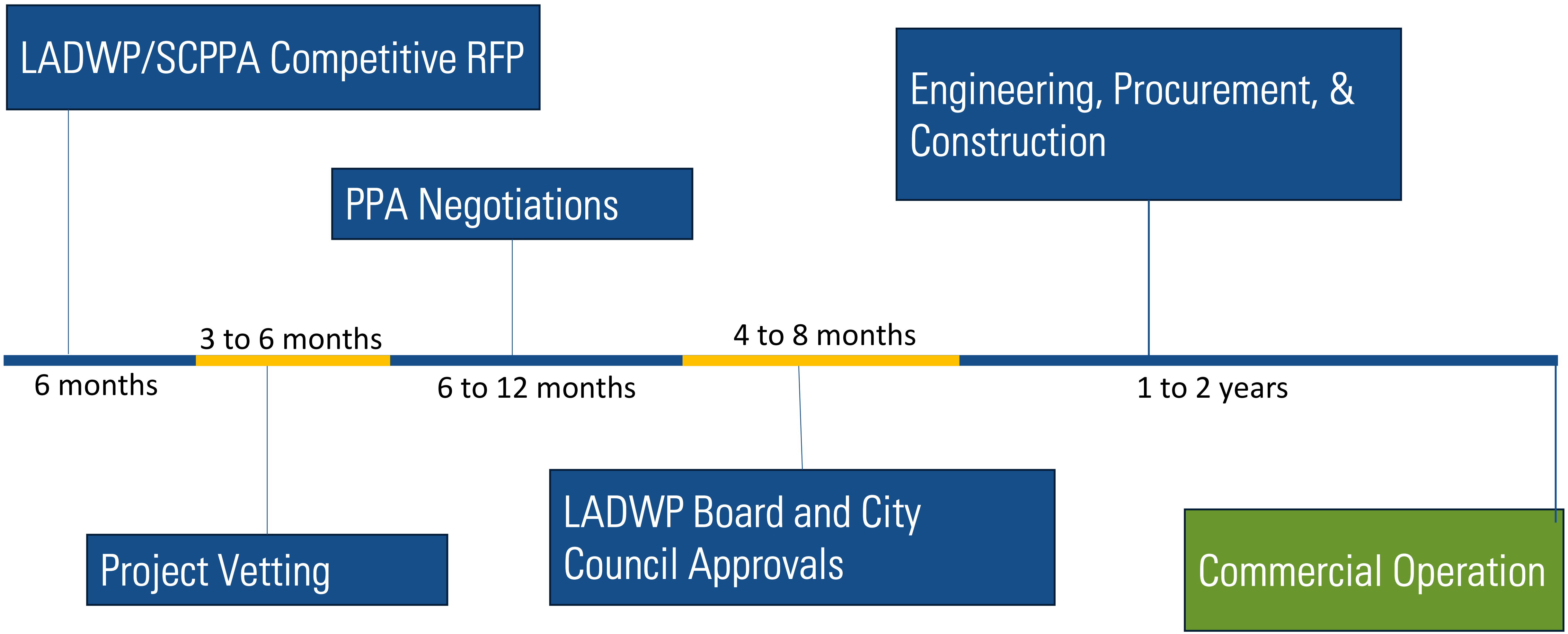
From 2015 to 2024, LADWP acquired **1921 MW** of clean energy resources; averaging 192 MW per year

From 2026 to 2035, LA100 Plan calls for **6792 MW** of clean energy resources; averaging 679 MW per year



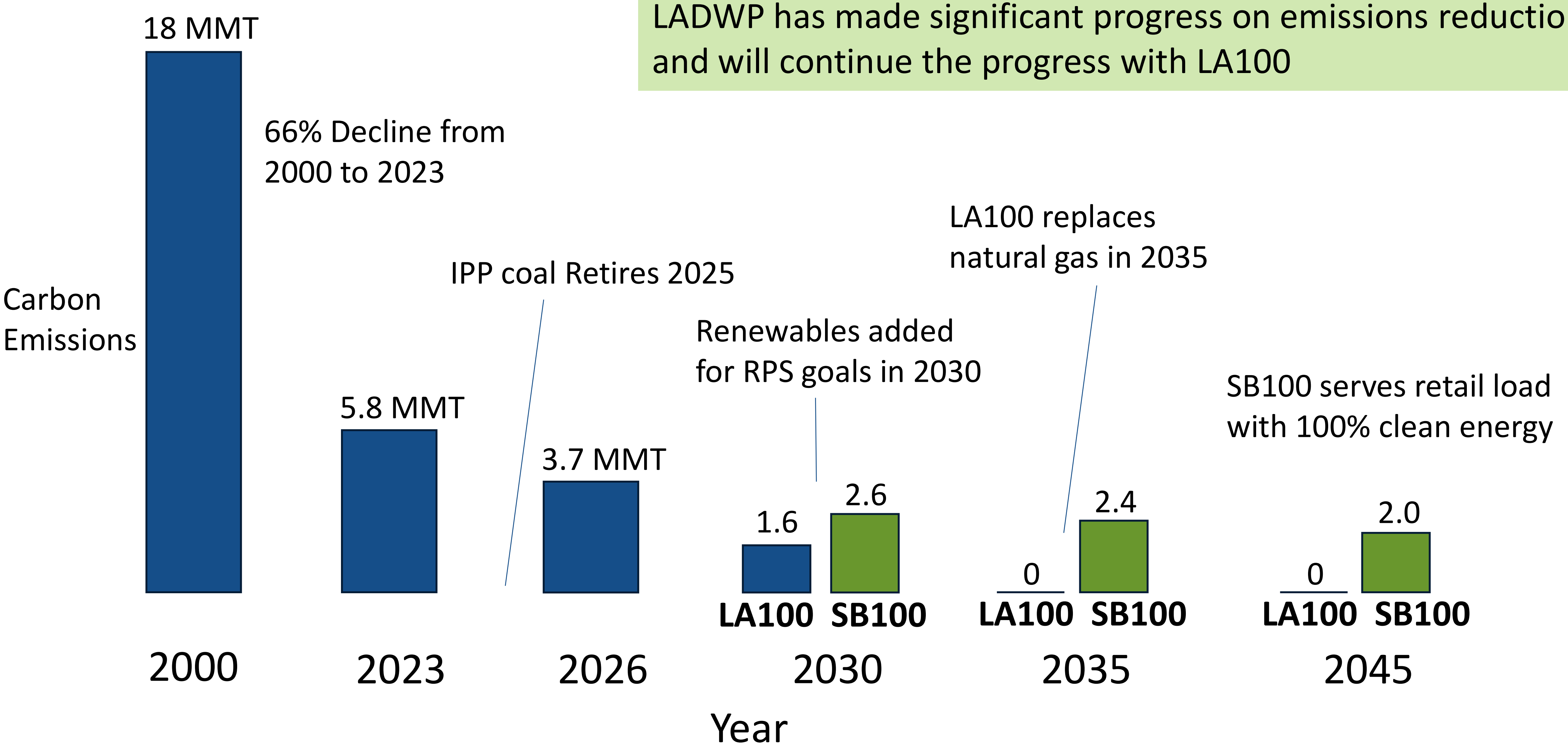
Note: Hydrogen generation efforts not shown in the future additions

New Renewables Project Development Takes up to 3 Years



Carbon Emission Reduction

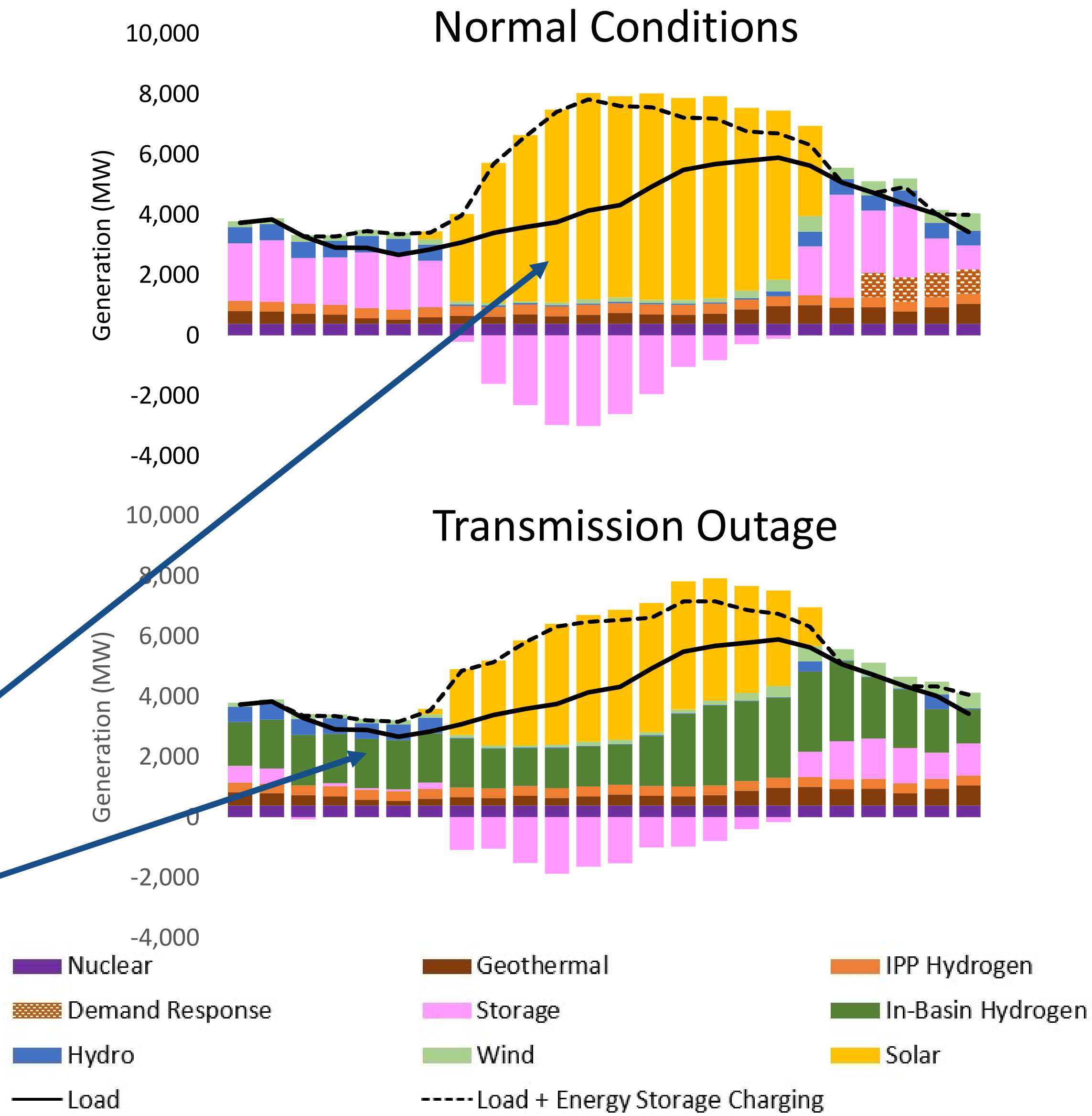
LADWP has made significant progress on emissions reduction and will continue the progress with LA100



In-basin Firm Generation

- In-basin generation provides support during
  - Low renewable generation
  - Grid contingencies such as transmission outages
- Modeling transmission outages based on recent fires shows the need for firm generation in-basin
- Top graphs to the left show dispatch under normal conditions where solar and storage supplies most of the load
- Bottom graph shows system with transmission outages where solar and storage are not available so in-basin resources must be used

Transmission losses due to natural disasters reduce access to renewables in the transmission grid. In basin resources must fill the gap.



Sensitivities

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Sensitivity Overview

- Sensitivity analysis investigates future uncertainty by making adjustment to input assumptions
  - Models include several assumptions that need to be tested against the future uncertainty
- Sensitivity runs evaluate future planning risk due to uncertain model assumptions
  - The outputs show us what might happen if assumptions deviate
- LA100 was tested with a set of sensitivity studies
  - All studies satisfied reliability requirements (Loss of Load Expectation (LOLE) < 0.1 days per year)
  - 11 studies provided a range of potential futures
- Key Outputs
  - Costs – Net present value (NPV) of total supply costs
  - Emissions

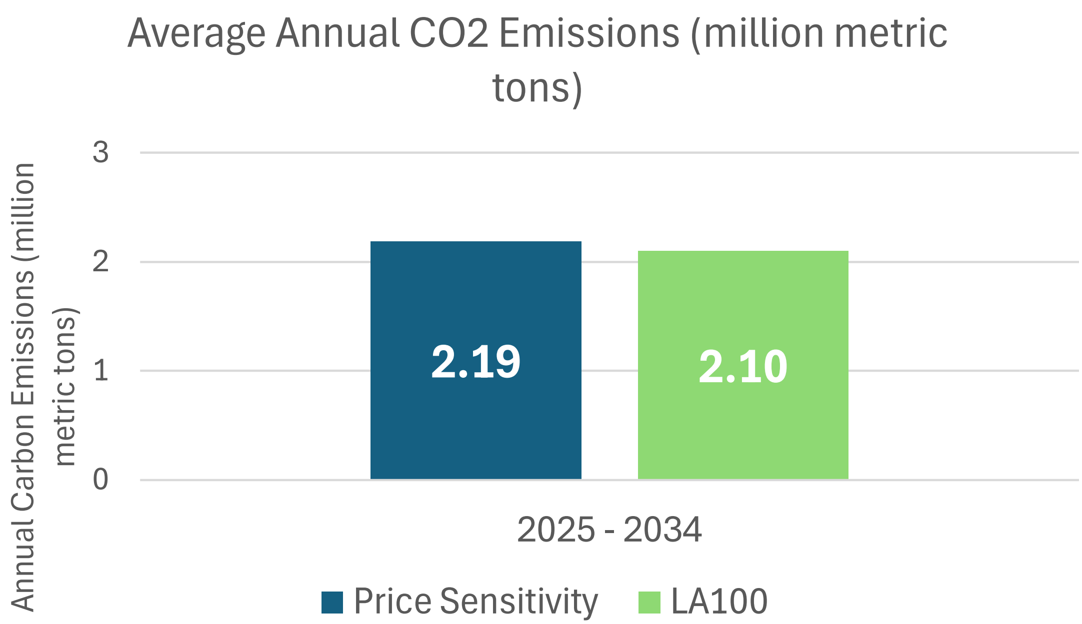
Sensitivity Model Descriptions

Model Name	Risk Analysis
LA100 Plan	
1. LA100 - Price Sensitivity	High cost of clean energy
2. LA100 - Low Load	Load growth is lower than expected leading to overspending on resources
3. LA100 - High Load	Load growth is higher than expected leading to higher costs for resource procurement
4. LA100 - Low DER	DER adoption will be low compared to projections
5. LA100 - High DER	DER adoption will be high compared to projections
6. LA100 - No In-basin Combustion	Alternatives to in-basin combustion to be evaluated
7. LA100 - No In-basin H2 Supply	Market conditions restricts fuel available for clean, firm in-basin generation
8. LA100 – Limited H2 Supply	Market conditions limit the amount of fuel available for clean, firm in-basin generation
9. LA100 - Resource Constrained	Market conditions and resource limitations may delay buildouts
10. LA100 - Climate Change	Run LA100 with amplified effects from climate change
SB 100	
11. SB 100 - Price Sensitivity	Lower clean energy costs

Developed with input from the LA100 Advisory Group.

1. LA100 – Price Sensitivity

- **Risk Evaluated:** Higher prices for renewables and storage with lower prices for fuel and GHG allowances.
- Assumed lower natural gas and GHG allowance pricing resulted in carbon emissions that are slightly higher due to the model favoring natural gas a bit more before 2035



Renewables and storage cost 28.5% more than LA100 on average

Total Supply Cost (2025 to 2045)
$105.6 billion

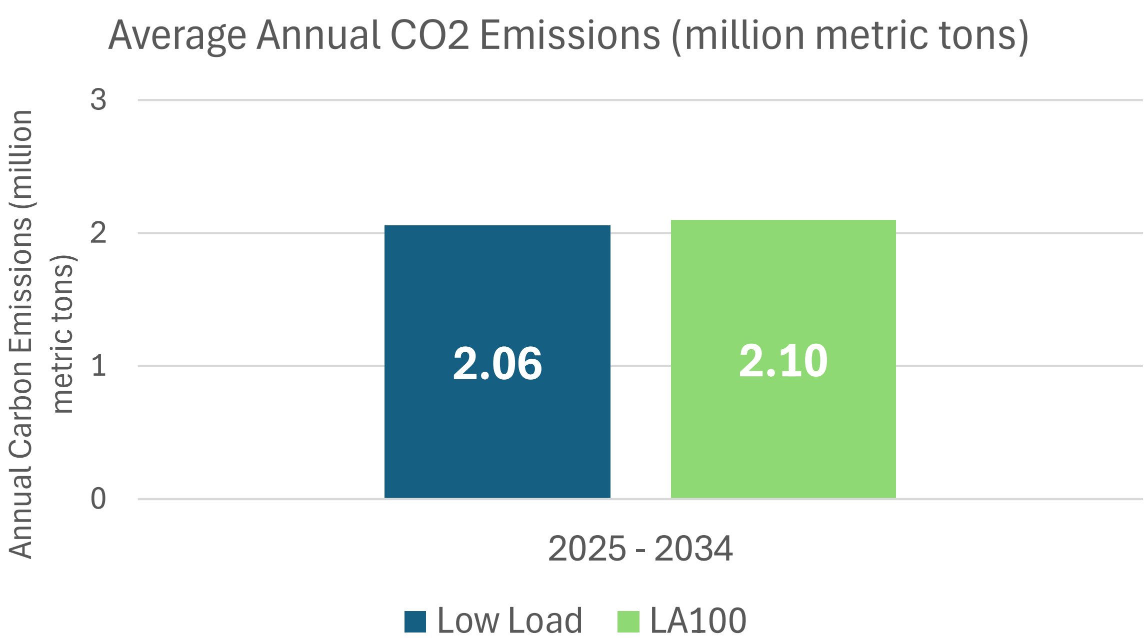
3% Higher than LA100

Average capacity factor (2035 to 2045)
In-basin dispatchable units

3%

2. LA100 – Low Load Sensitivity

- **Risk Evaluated:** Does lower load growth lead to potential overbuilding of resources?
- Reduced load growth leads to less use of in-basin generation and lower emissions overall
- Costs are lower with less load to serve and less resources needed to build
- Lower retail sales likely to result in higher retail rates



Customer demand grows 0.6% annually on average (versus 1.06% for LA100)

Total Supply Cost (2025 to 2045)
$98.5 billion

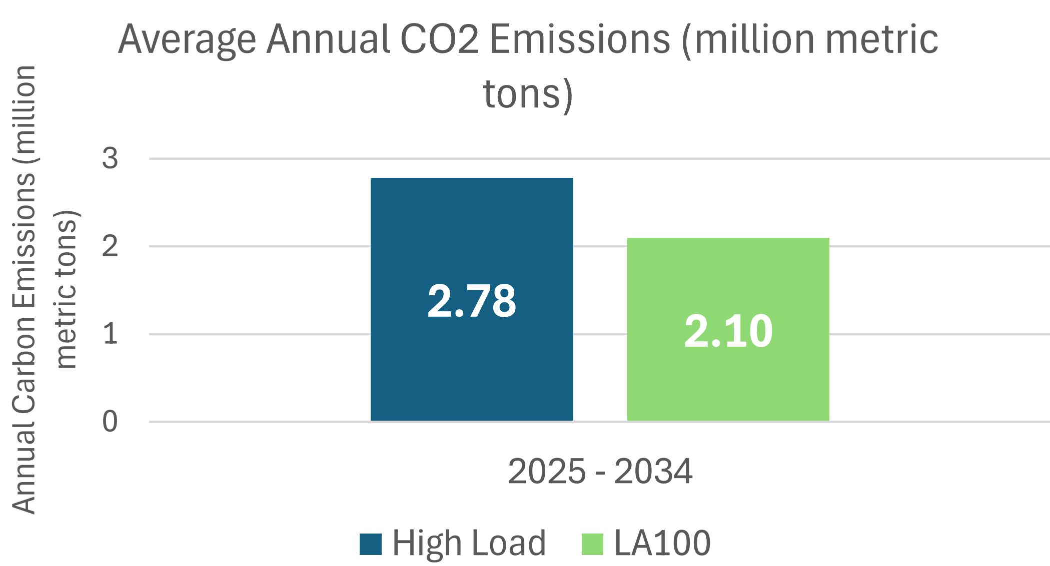
4% Lower than LA100

Average capacity factor (2035 to 2045)
In-basin dispatchable units

3%

3. LA100 – High Load Sensitivity

- **Risk Evaluated:** Does increased load growth impact reliability?
- System will maintain reliable operations and achieve the 100% clean energy target by 2035
- Overall cost increases to meet higher load needs
- If load growth occurred at this rate, we would need to invest in additional clean resources; however, it takes a minimum of 3 years to secure a renewable project
- Increased load may put downward pressure on rates



Customer demand increases at 2.06% annually on average (versus 1.06% for LA100)

Total Supply Cost (2025 to 2045)
$104.4 billion

7% Higher than LA100

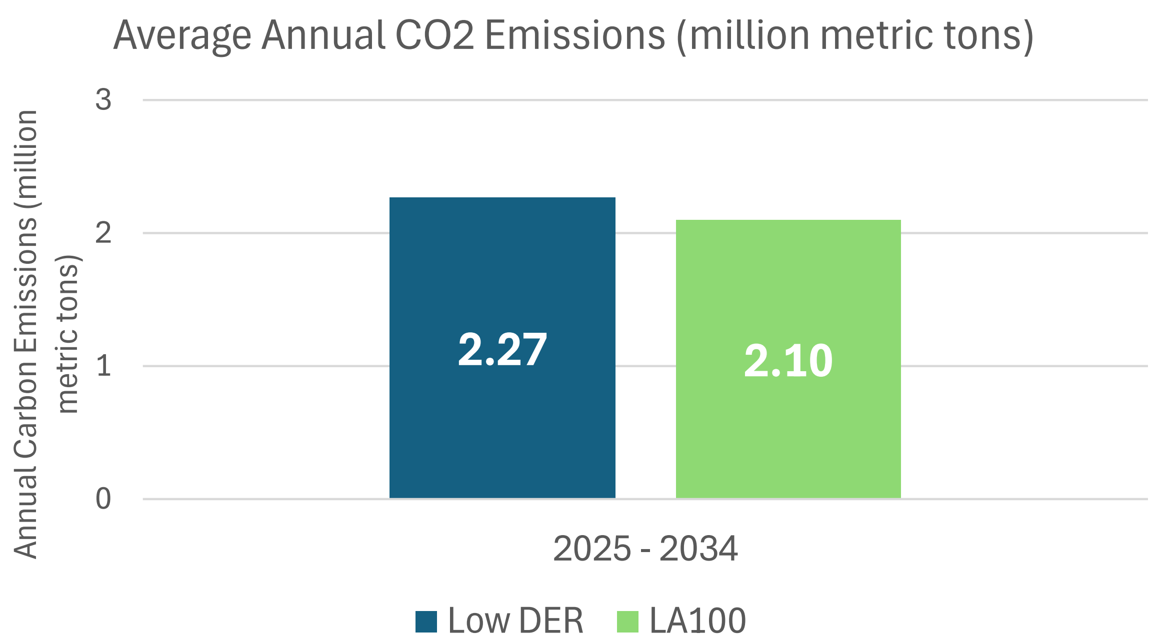
Average capacity factor (2035 to 2045)
In-basin dispatchable units

17%*

*Note: If load trends higher than expected, LADWP would plan for additional renewable

4. LA100 – Low DER Sensitivity

- **Risk Evaluated:** Does low DER adoption impact reliability?
- Less DER adoption leads to marginally more dispatch of in-basin generation
- Emissions marginally increase with more use of natural gas prior to 2035
- Costs decrease slightly driven by less spending on rooftop solar, Feed-in Tariff (FiT), and DWP-built solar, which have a cost premium
- LADWP maintains reliability throughout the modeling horizon



DER adoption grows at 5.24% annually on average (versus 6.85% for LA100)

Total Supply Cost (2025 to 2045)
$99.5 billion

3% Lower than LA100

Average capacity factor (2035 to 2045)
In-basin dispatchable units

5%

5. LA100 – High DER Sensitivity

- **Risk Evaluated:** Does high DER adoption lead to overbuilding of other resources?
- High DER adoption leads to higher in-basin resiliency as it reduces load
- Emissions marginally decrease with less use of natural gas prior to 2035
- Costs increase very slightly with more spending on rooftop solar, FiT, and DWP-built solar, due to cost premium

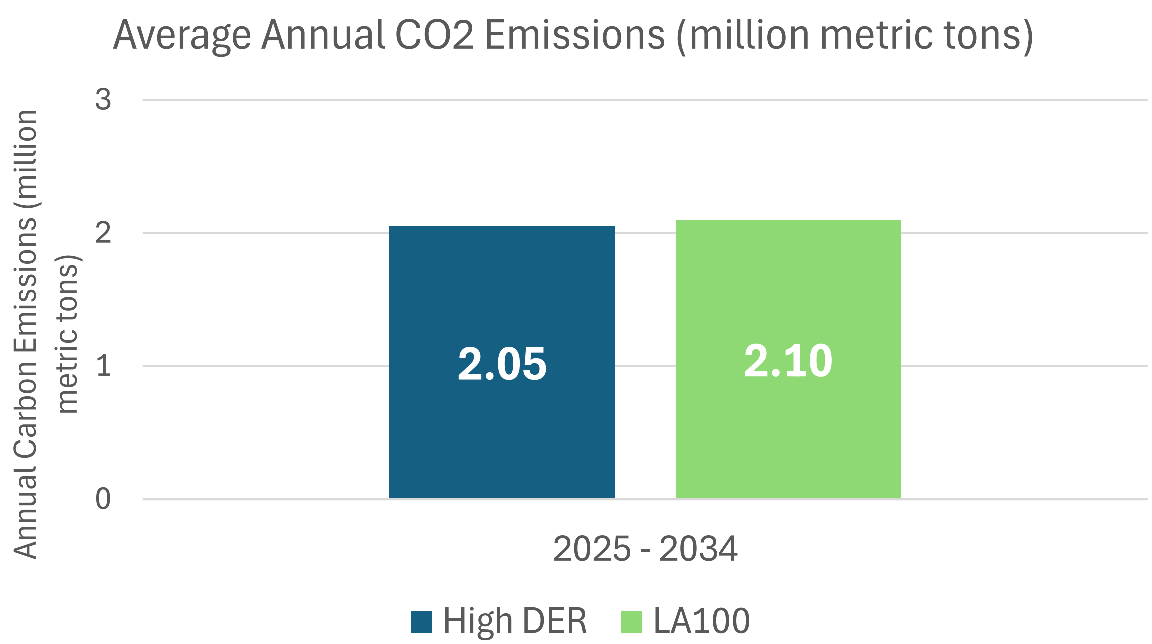
DER adoption grows at 8.45% annually on average (versus 6.85% for LA100)

Total Supply Cost (2025 to 2045)
$103.3 billion

1% Higher than LA100

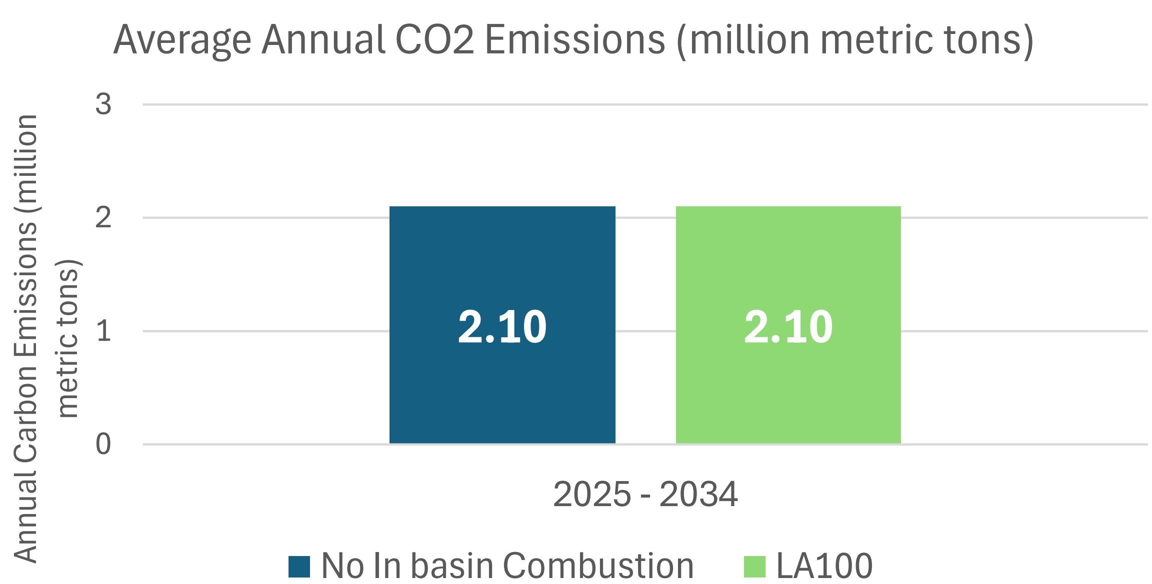
Average capacity factor (2035 to 2045)
In-basin dispatchable units

3%



6. LA100 – No In-Basin Combustion Sensitivity

- **Risk Evaluated:** Technologies other than combustion turbines may be necessary
- The chosen alternative to hydrogen combustion for this sensitivity was fuel cell generation due to its long duration dispatchability.
- **Currently, this technology is not available at scale.** NREL Study evaluated alternatives to combustion.
- Emissions are on-par with LA100 (no emission benefit)
- Costs increase significantly from the higher cost of fuel cells



Several alternatives considered, but fuel cells were chosen to replace in-basin combustion turbines.

Total Supply Cost (2025 to 2045)
$119.0 billion

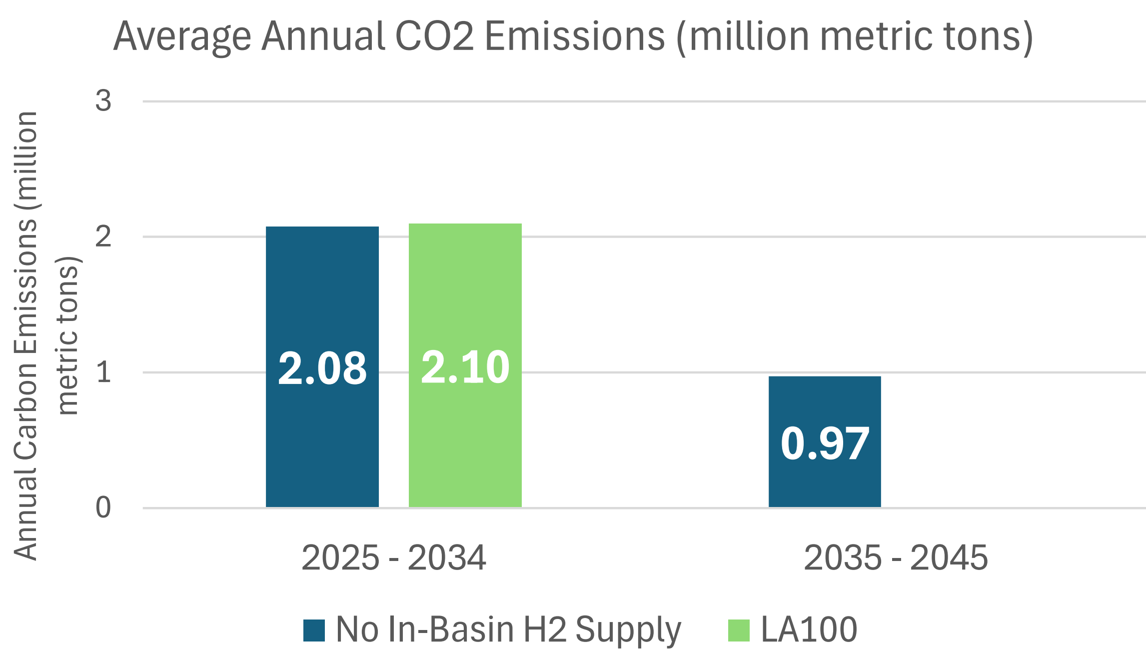
16% Higher than LA100

Average capacity factor (2035 to 2045)
In-basin dispatchable units

3%

7. LA100 – No In-Basin H2 Supply Sensitivity

- **Risk Evaluated:** Market for H2 fuel does not exist
- Without in-basin hydrogen, the model kept natural gas generation online, but used sparingly for backup
- Emissions marginally increase with fossil fuels remaining online
- Costs decline due to not replacing in-basin resources with hydrogen generation (last 5% decarbonization)
- LADWP still achieves significant GHG reductions



No H2 market exists, so gas-fired turbines retained but used sparingly

Total Supply Cost (2025 to 2045)
$91.4 billion

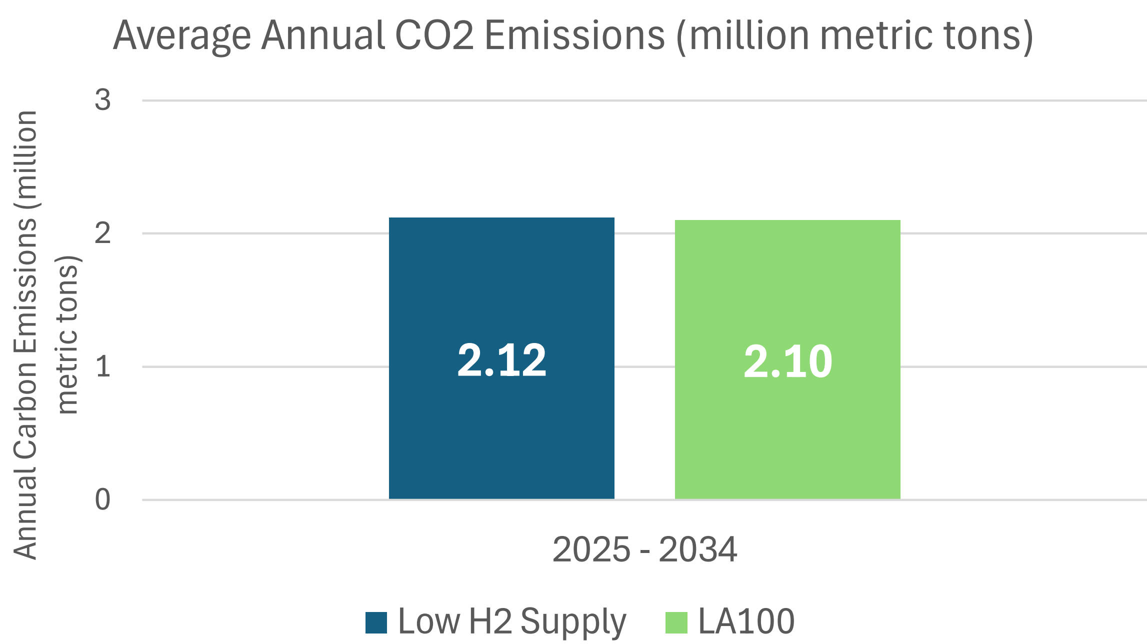
10% Lower than LA100

Average capacity factor (2035 to 2045)
In-basin dispatchable units

8%

8. LA100 – Limited H2 Supply Sensitivity

- **Risk Evaluated:** Market for H2 fuel supplies less fuel than anticipated
- Limited fuel for in-basin resources requires more acquisition of renewables and storage; however, it takes at least 3 years to secure a renewable project
- Carbon emissions increase slightly since natural gas runs a bit more
- Costs increase due to the need to build more resources
- LADWP maintains reliability throughout study horizon.



Less H2 is available on the market than anticipated, leading to increased need for renewables and storage.

Total Supply Cost (2025 to 2045)
$102.8 billion

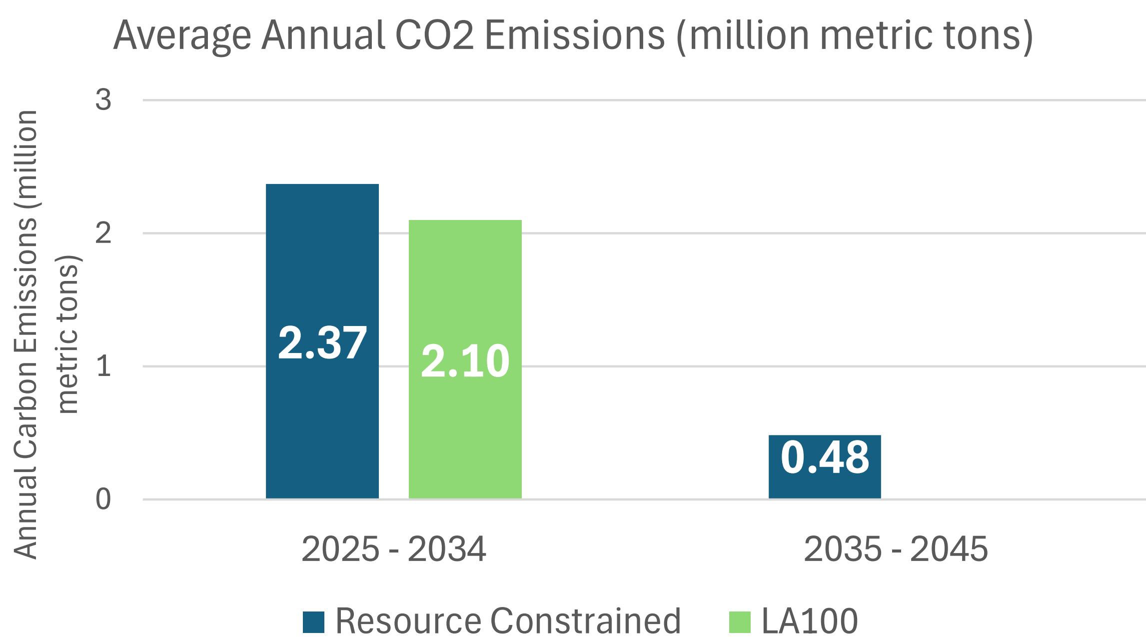
3% Higher than LA100

Average capacity factor (2035 to 2045)
In-basin dispatchable units

2%

9. LA100 – Resource Constrained Sensitivity

- **Risk Evaluated:** Market for renewables and storage is undersupplied and H2 technology is delayed
- A lack of needed resources leads to delays achieving carbon free energy
- Emissions marginally increase due to the more gradual timeline in building out renewables
- Costs are slightly higher with more reliance on in-basin resources



Market for renewables and storage is undersupplied and H2 technology is delayed. No more than 500 MW can be procured annually.

Total Supply Cost (2025 to 2045)
$104.9 billion

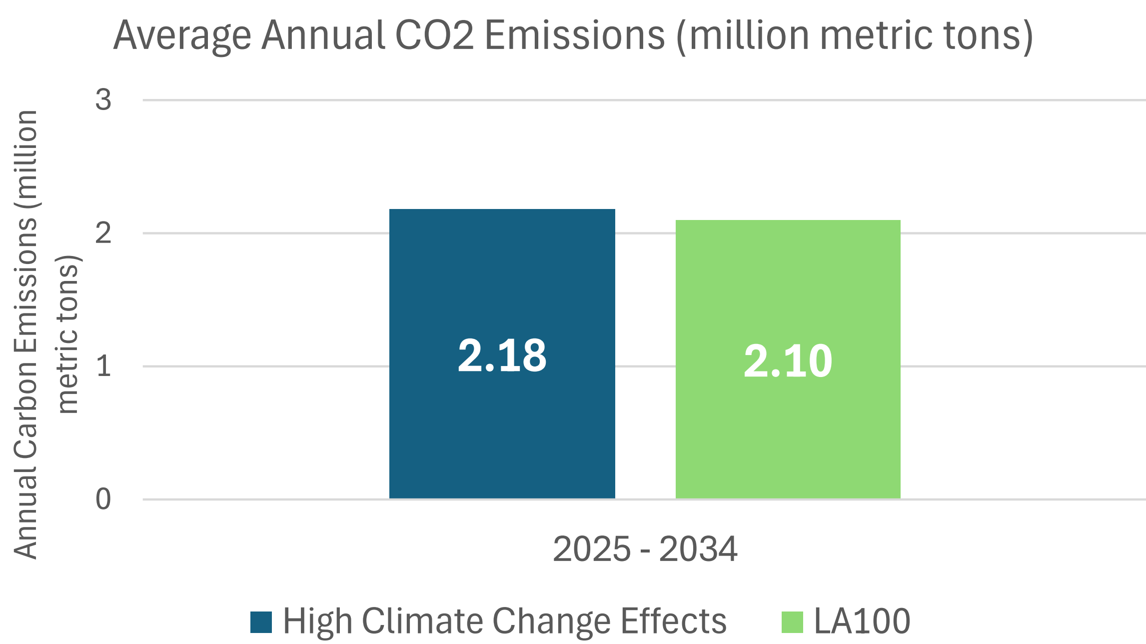
2% Higher than LA100

Average capacity factor (2035 to 2045)
In-basin dispatchable units

7%

10. LA100 – Climate Change Sensitivity

- **Risk Evaluated:** Does climate change impact reliability?
- Increased climate change drives higher load and more forced outages of thermal generation
- LADWP maintains reliability throughout the study horizon.
- In-basin dispatchable generation is used to ensure reliability during stress conditions. **Planned LA100 Portfolio is robust enough to manage climate change**



Customer demand grows 1.23% annually on average (versus 1.06% for LA100)

Total Supply Cost (2025 to 2045)
$105.6 billion

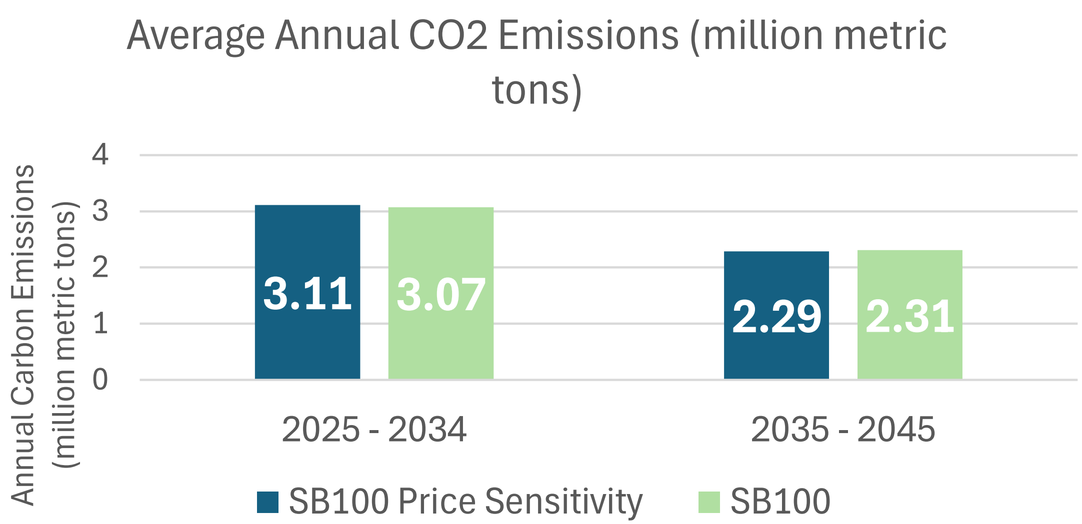
3% Higher than LA100

Average capacity factor (2035 to 2045)
In-basin dispatchable units

5%

11. SB100 – Price Sensitivity

- **Risk Evaluated:** Low renewable and storage costs with high fuel and GHG allowance cost
- This sensitivity meets state of California mandates for renewables and clean energy
- Costs are slightly lower than SB100 and much lower than LA100
- Emissions are close to SB100, much higher than LA100



Costs for renewables and storage are 26.8% lower than SB100 on average

Total Supply Cost (2025 to 2045)
$84.6 billion

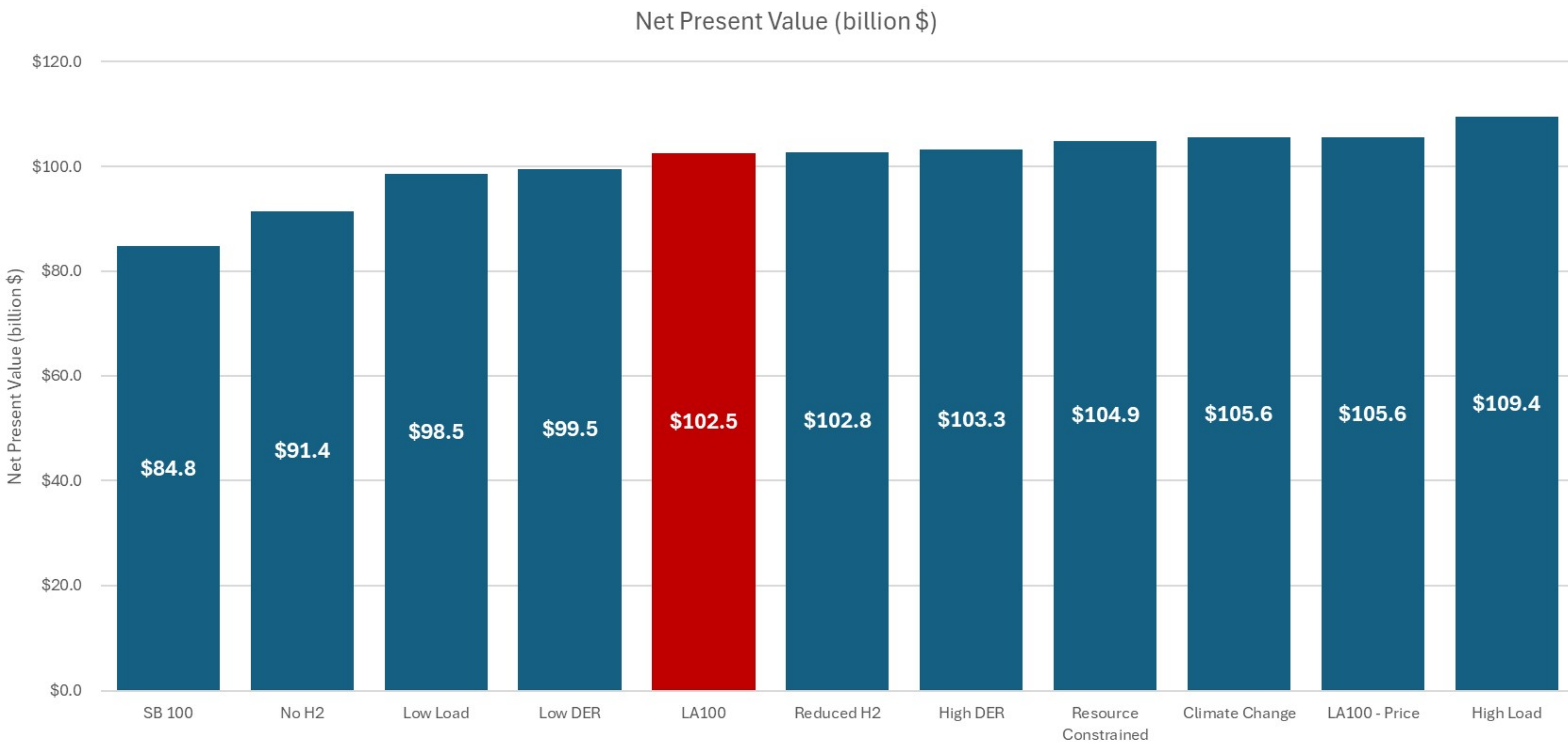
17% Lower than LA100
1% Lower than SB100

Average capacity factor (2035 to 2045)
In-basin dispatchable units

7%

Summary of Costs - Net Present Value

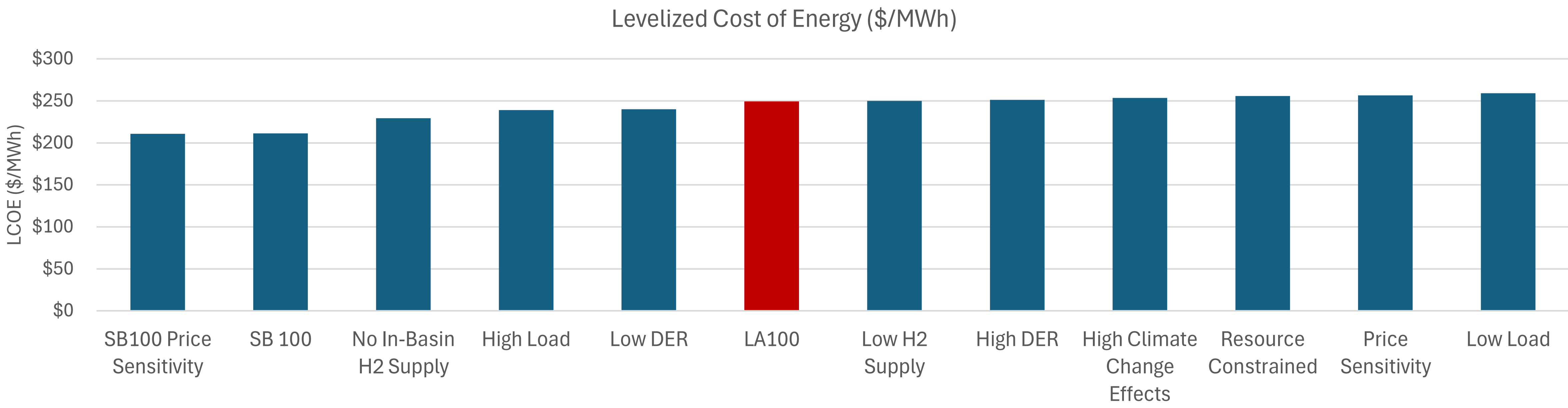
- Net present value includes both fixed and variable costs summed and discounted to their present value



Note: 2022 SLTRP's recommended case cost was approximately $80 billion net present value. Updated cost for LA100 plan has increased due to various factors such as inflation.

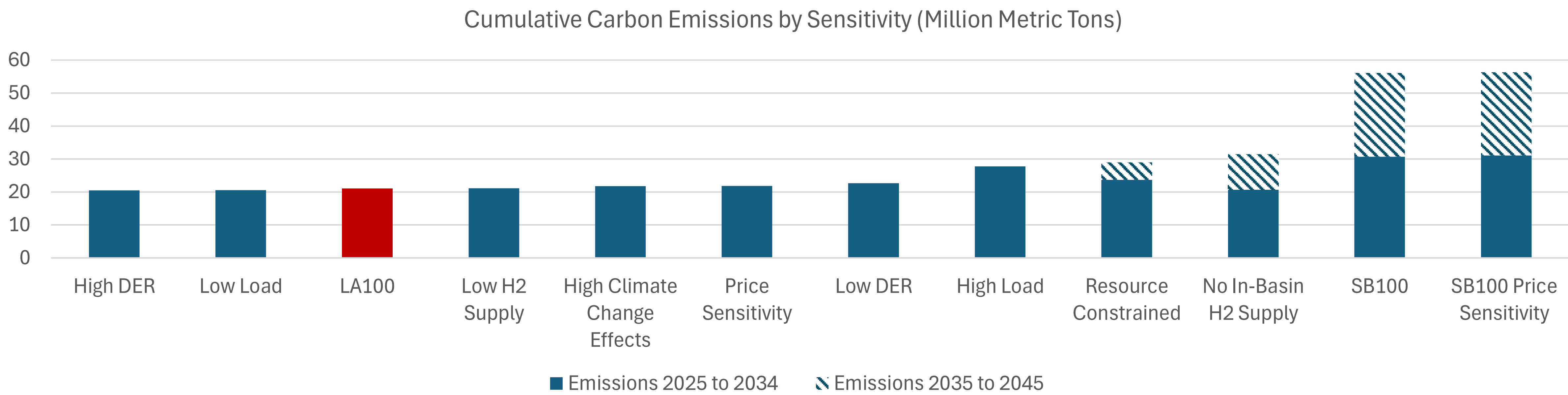
Summary of Costs - LCOE

- Levelized cost of energy shows the cost per unit of load including both fixed and variable costs
  - Total supply costs are spread over the total load
  - Costs does not include all inputs for rates



Summary of Carbon Emissions

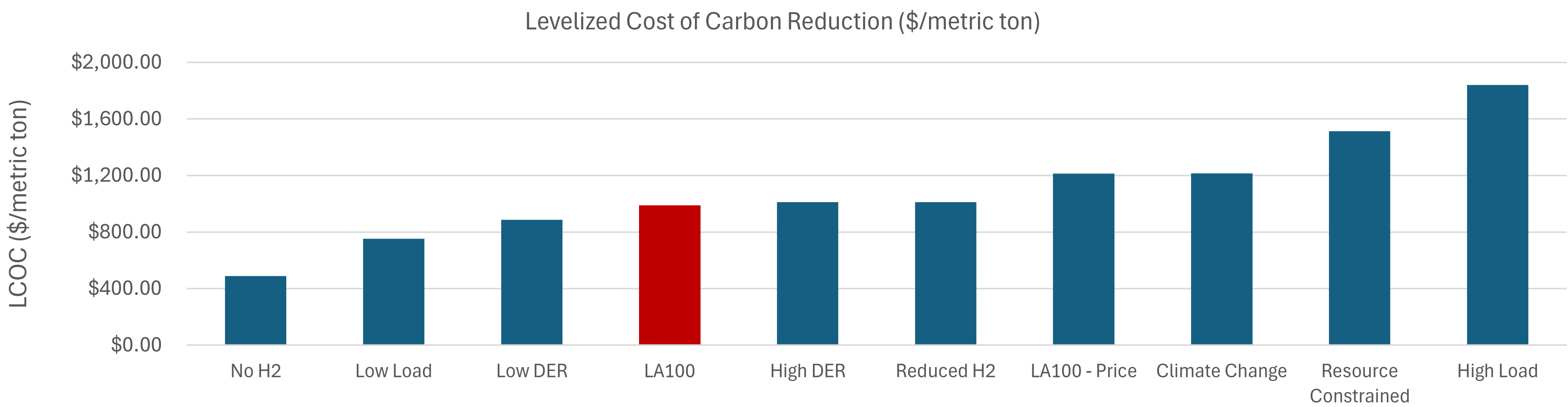
- Most sensitivity models have cumulative carbon emission below 25 million metric tons with three exceptions
  - "High Load" requires most use of fossil fuels before the transition away from natural gas
  - "No In-basin H2 Supply" has higher emissions due to the continuation of in-basin natural gas
  - "Resource constrained" has higher emissions due to the slower growth of renewables and delayed transition away from natural gas



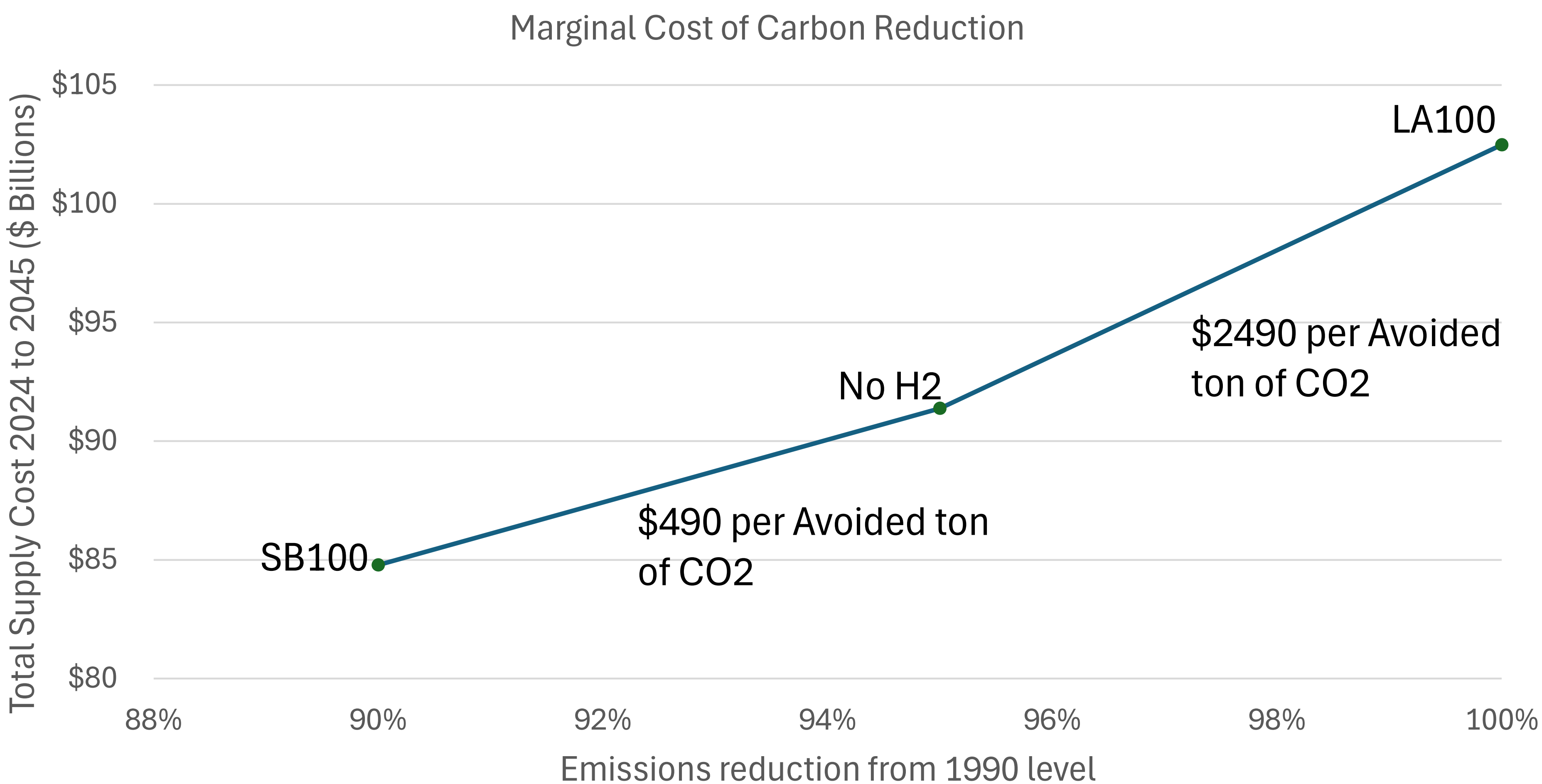
Note: Forecasted carbon emissions for each sensitivity were estimated as a modeling exercise to gain insights into various factors that are outside of LADWP's control, and do not represent any specific scenario in which LADWP would pursue.

Cost of Carbon Reduction

- Levelized cost of carbon reduction (LCOC) compares sensitivities to SB100 for costs and emissions
  - LCOC is the cost difference from SB100 divided by the carbon reduction beyond SB100
  - Metric shows how efficiently sensitivities reduce carbon



Marginal Emission Costs Increase Along the Path to 100%



Key Takeaways

- The LA100 portfolio is robust enough to maintain reliability under several stress cases including climate change, higher-than-expected load growth, technology availability, and price fluctuations for fuel and technologies
- High-level investments in solar, wind, and storage are required to meet the 2030 80% RPS target and 2035 100% clean target
- On average, LADWP will need to procure 1,065 MW annually of renewables, storage, and hydrogen capacity between 2025 and 2035
- Firm, dispatchable generation is required for reliability
- No In-Basin Combustion sensitivity was found to be infeasible due to unavailability of fuel cells at scale
- LA100 is approximately $18 billion more costly than SB100 on a net present value basis.
- Even if hydrogen is not available, LADWP would still reduce carbon emissions to 5% of 1990 levels
- A plan based on SB100 would reach 89% carbon reductions from the 1990 level by 2045.

Q&A

Scattergood Modernization Project Alternatives Study: Summary of Key Findings

Briefing to LA100 Advisory Committee
March 20, 2025

Scope – City Council Directive

“Conduct a new or updated assessment of **non-combustion alternatives** to the project Scattergood Modernization Project (SMP), including the use of green-hydrogen powered fuel cells, high levels of energy storage, large-scale multi-day demand response programs, new and upgraded transmission lines to import higher levels of renewable energy, and others that considers the public health benefits, safety risks, and costs and benefits.”

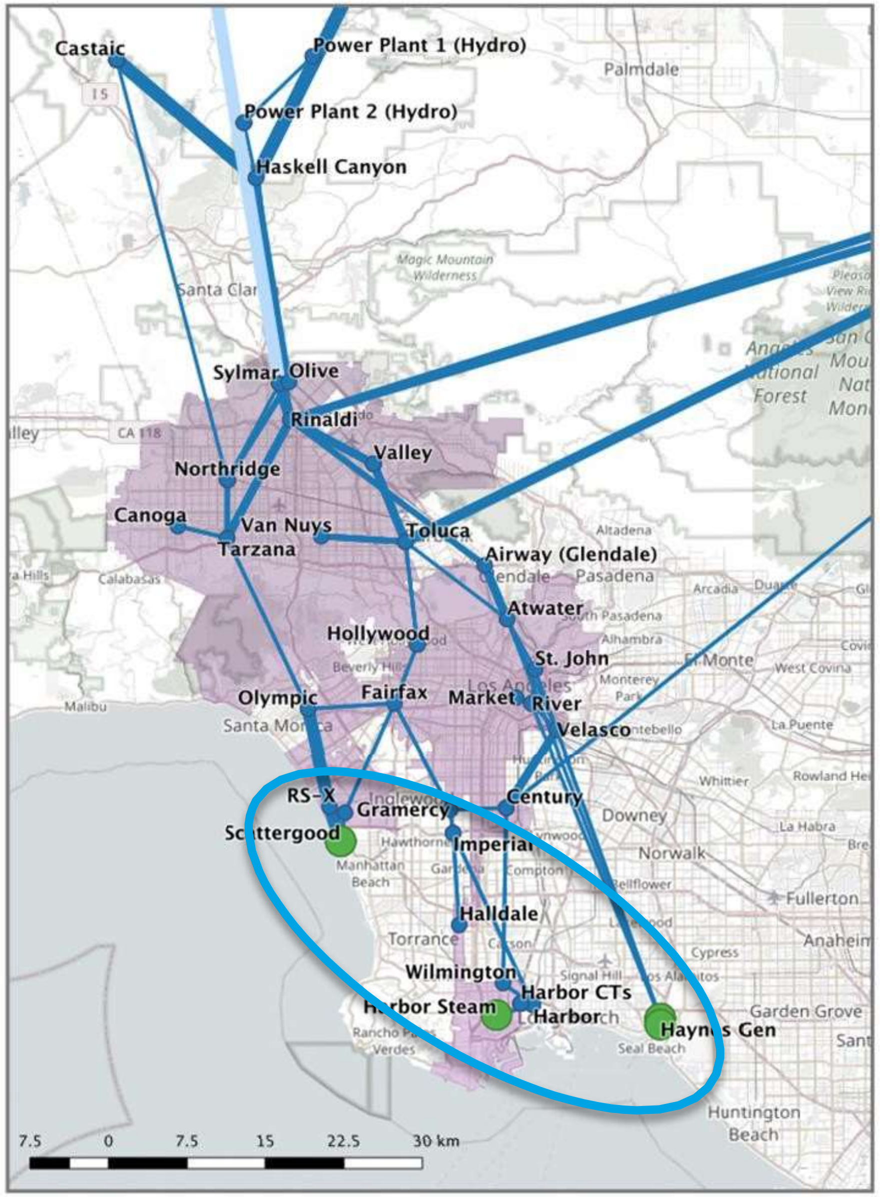
The analysis and findings in this study are solely related to the specific potential for the alternatives to replace the retiring Scattergood once-through cooling (OTC) units **by the end of 2029**.

Context: LA100 Findings and the Need for Dispatchable Capacity

The Los Angeles 100% Renewable Energy Study (LA100) found a continued need for "dispatchable" capacity (generation) located in the LA basin, *including at the Scattergood site,* that can operate for extended periods of time and provide system reliability and resilience against transmission failures, including during periods of extremely high demand and/or low renewable output.

Dispatchable capacity refers to power sources that can be adjusted on demand by grid operators to match supply with electricity demand. It plays a fundamental role in grid reliability by ensuring that fluctuations in demand can be met in real-time, which is critical in maintaining uninterrupted power supply and avoiding outages.

The Transmission Challenge



Transmission from the north

- The LADWP transmission network was designed in part around power plants at specific locations in the basin.
- When there **isn't enough renewable energy.** (On a cloudy day for example, but it's more of a system issue.)
- The bigger issue is when we cannot get renewable energy it to the **right places** in basin due to transmission limitations.
- Transmission limits/outages can be addressed by running generators in the southern part of the system (at OTC sites)

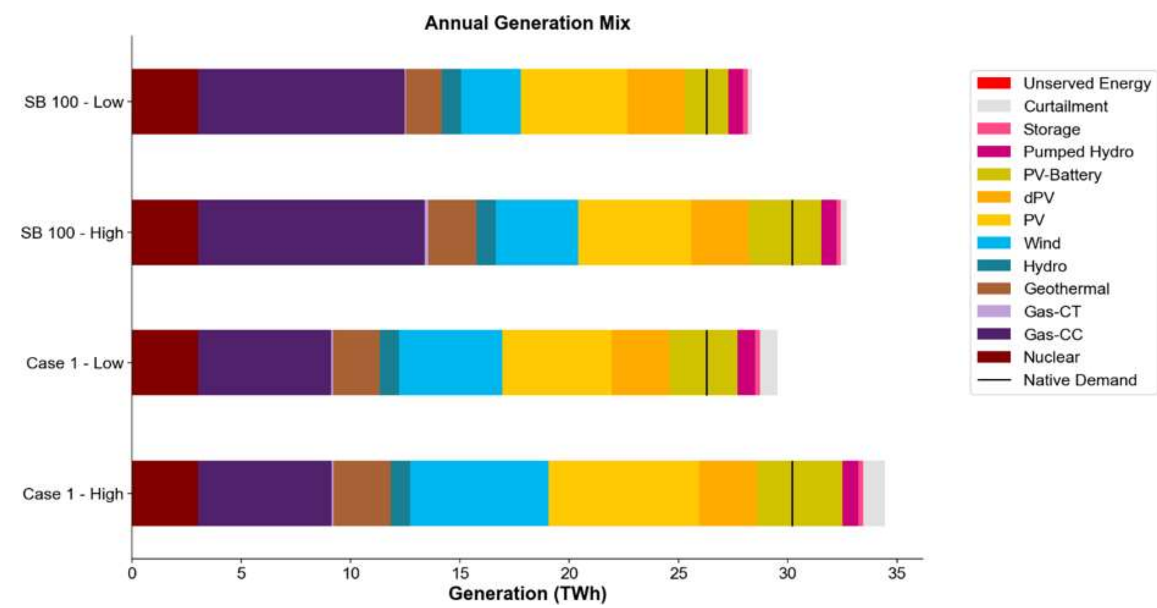
Existing generators in the south

Takeaway

It may be difficult to deliver energy to all points within the basin without **new transmission or in-basin generation at specific locations such as Scattergood.**

Technical Approach

- Evaluated costs of each alternative that passed screening criteria (slide 8) compared to the Scattergood Modernization Project (SMP) over 30-year period from 2030—2060
- Based scenarios largely on the 2022 Strategic Long-Term Resource Plan (SB100 and Case 1)
- Evaluated system operation during all hours of the year in 2030, 2035, and 2040 (assumes years after 2040 have the same generation mix)
- Evaluated system reliability under stress conditions including multiple line outages and including a case that resembles the impact of the Saddleridge fire.



Example of 2030 generation mix

New In-Basin Capacity Is Needed

- This study also confirms the LA100 findings that new in-basin capacity is needed to replace the retiring OTC units at Scattergood.
- Without this new capacity there is a significantly increased risk of unserved energy (outages) especially during periods of hot summer weather, and with the increased risk of transmission outages due to wildfires.
- This new capacity has specific requirements:
    - Some of this capacity **must** be located at or near to the Scattergood location.
    - It must be capable of reliably serving load for multiple hours in a row (often at least 10, particularly in cases of transmission failures), for multiple days in a row, primarily during late summer afternoons and into the evenings (past sunset).

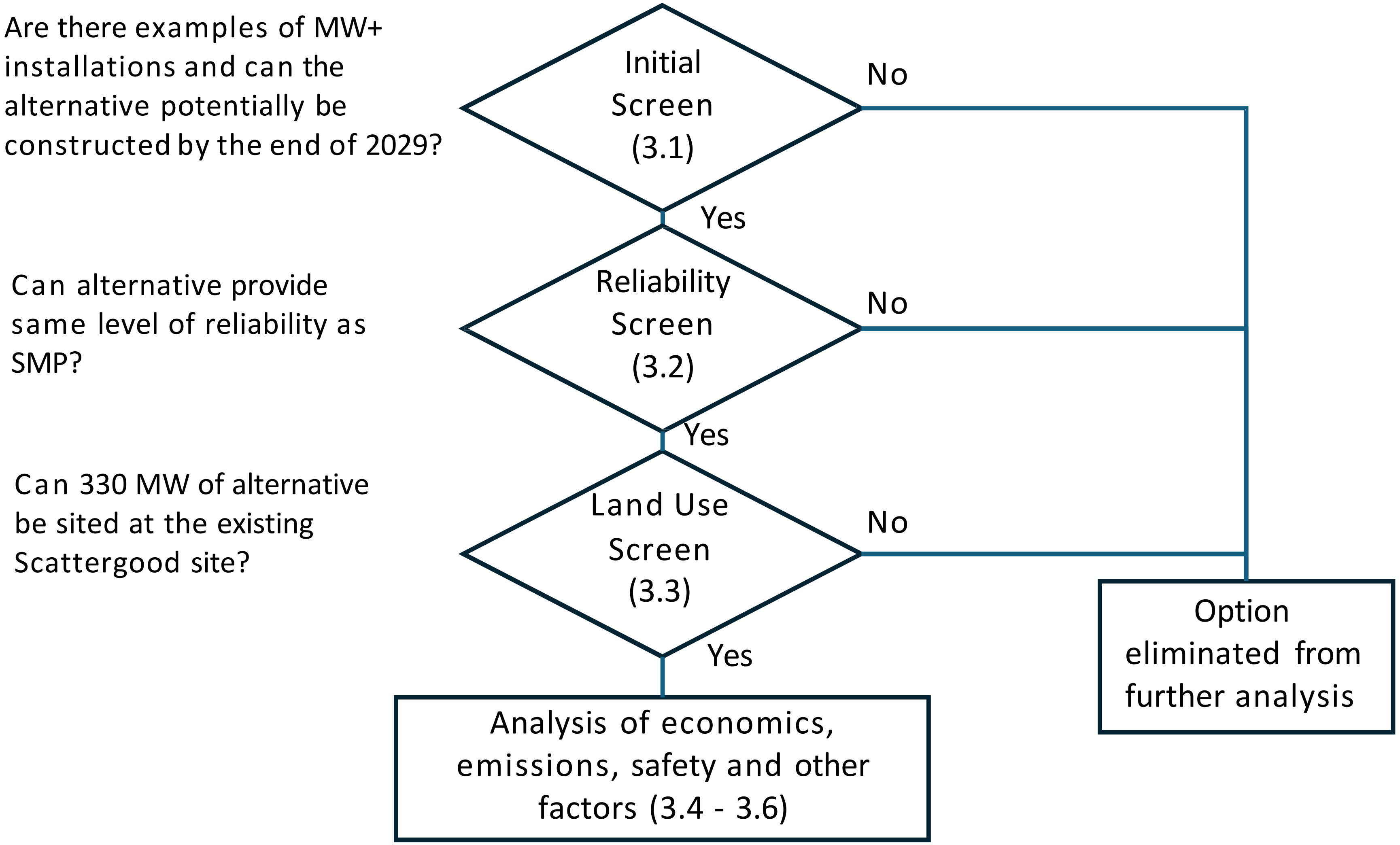
Alternative Options Considered

1. Transmission
2. Energy Storage
3. Fuel Cells
4. Demand Response
5. Combination options

Summary of Findings

1. **Transmission:** Not a viable alternative due to time required to develop.
2. **Energy storage:** Not a viable alternative due to insufficient space available for duration required to maintain reliability (at least 10 hours).
3. **Fuel cells:**
    - Running on 100% green hydrogen: Not a viable alternative due insufficient fuel supply, technology scale-up challenges, and infrastructure requirements for **100% H2** fuel by the end of 2029.
    - Running on natural gas/hydrogen blend (same as SMP): May be technically feasible, but at a much higher cost, higher system emissions, technology and constructability risk.
3. **Demand response:** Not a viable alternative due to insufficient resource (both duration and location) needed to maintain reliability.
5. **Combination options:** Can reduce the cost premium of the alternatives but are still likely more expensive and do not eliminate significant technology risks.

Screening Process



1: Transmission

New transmission does not appear to be a viable alternative by the 2030 requirement.

- There is **insufficient time** to develop new transmission to the specific locations required by the end of 2029.
- Building new transmission near Scattergood has **land acquisition challenges**.

2: Energy Storage

Energy storage faces barriers to serve as an alternative due to long duration requirements.

- Li-ion batteries are likely the only storage technology feasible to be deployed in basin at a large scale.
- Energy storage durations required to achieve reliable service are at least 10 hours.
- Important to note that storage will have significant charging from natural gas. Charging with only renewable energy is **not a feasible alternative.**
- Overnight charging may stress existing transformers and other infrastructure, causing increased costs due to accelerated replacement. NREL doesn’t have enough information to evaluate the impact of this.
- To achieve the same level of reliability, the amount of batteries needed (using at least 16 acres) **exceeds space available** at the Scattergood site (about 9 acres).
- Based on the requirement that the entire energy storage plant be sited at the Scattergood location, battery storage is not considered a viable alternative.

3a: Fuel Cells Using Only Green Hydrogen

Fuel cells using only green hydrogen do not appear to be a viable alternative by 2030.

- The city council language is "the use of green-hydrogen powered fuel cells."
- This means to "**solely utilize hydrogen that is produced using new, dedicated renewable energy resources or excess renewable energy resources**."
- This would require production of very large quantities of green hydrogen fuel, and some combination of H2 pipelines, H2 storage, and electrolyzers.
- **If required to operate on 100% green hydrogen** starting in 2030, then fuel cells are **not a feasible option**:
    - A sufficient amount of Hydrogen fuel and infrastructure **to produce and deliver 100% H2 fuel** currently does not exist near Scattergood and is still in early stages of development and not likely to be completed by 2030.
    - This finding is only pertinent to the option to use 100% green hydrogen

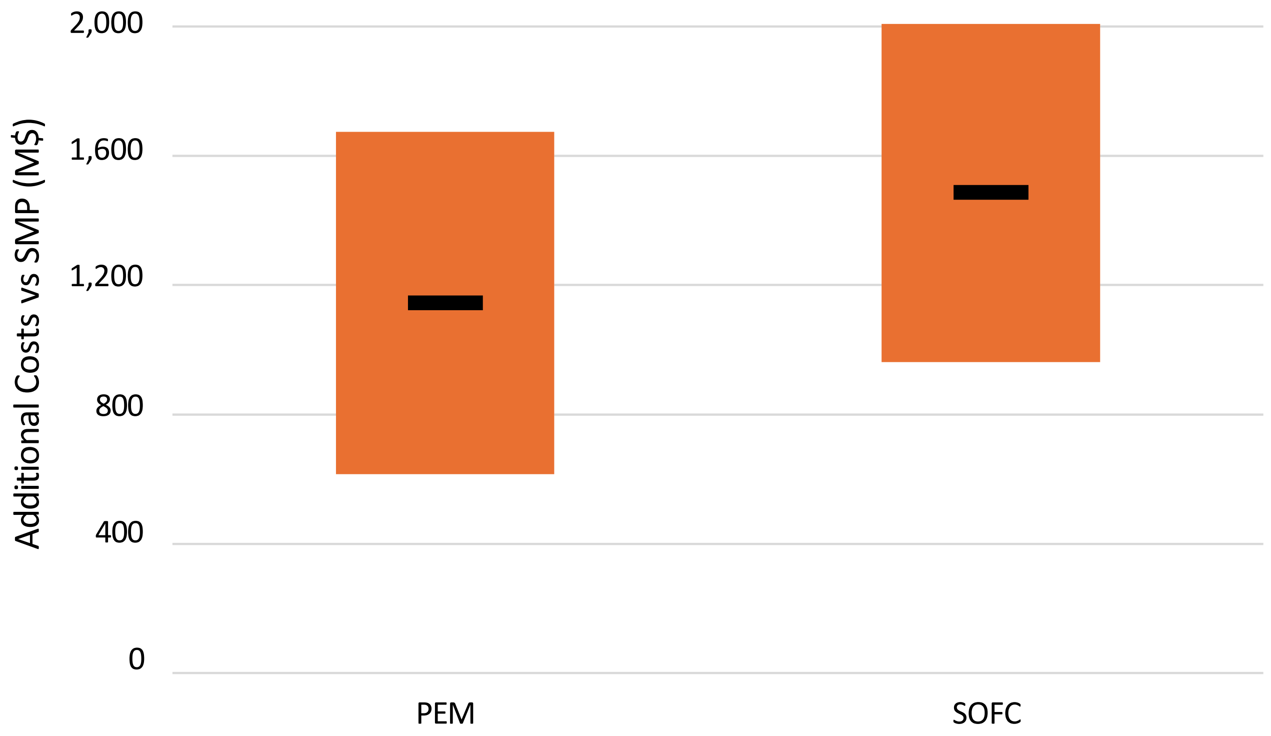
3b: Natural Gas/Hydrogen Blend Fuel Cell Alternative

- To provide a more direct comparison of SMP—burning mostly natural gas in the initial years—we also considered a case where fuel cells use **natural gas** or **natural gas/hydrogen** blends the same as SMP.
- Of the four types considered, only proton-exchange membrane (PEM) fuel cells and solid-oxide fuel cells (SOFC) appear to be viable candidates.

3b: Natural Gas/Hydrogen Blend Fuel Cell Alternative

Fuel cells using blended fuel have a **significant cost premium**.

- Both technologies have higher capital and operating costs than SMP.
- When using natural gas, the fuel cells will not be eligible for the federal Investment Tax Credit (ITC).



3b. Natural Gas/Hydrogen Blend Fuel Cell Alternative

There are **no emissions benefits** with fuel cells using blended fuel.

- PEM fuel cells have much lower efficiency when using natural gas compared to SMP. The efficiency of SOFC is about the same, but with much lower operating flexibility.
- Net result is that systemwide emissions of CO_2 are about 1% **higher** with a fuel cell alternative in 2030.
- Total systemwide emissions of NO_x are about the same to about 1% **higher** with a fuel cell alternative in 2030.
    - The NO_x penalty decreases beyond 2035, but there is never a significant NO_x benefit with the fuel cell alternative.

3b. Natural Gas/Hydrogen Blend Fuel Cell Alternative

Fuel cells using blended fuel face **considerable challenges** including higher cost and large uncertainties.

- The cost premium for a fuel cell alternative using a blended fuel is likely to be over $1 billion over a 30-year period.
- There is considerable uncertainty in these cost estimates, and significant technology risk, as SMP is about 20 times the size of the single largest fuel cell installation in the United States.

4: Demand Response

Demand response by itself cannot provide a viable alternative.

- There is likely an insufficient amount of economic demand response at the location, and with the right characteristics, to provide the required level of reliability by 2030.
- Demand response deployable by 2030 has **insufficient duration** and is **not at the right location** to provide an alternative.
    - Demand response would require shifting/deferring about 5% of system-wide load for at least 10 hours. (*Example: Five percent of all LADWP customers would defer or shift all of their demand or 10% of customers would shift 50% of demand for 10 hours on multiple days.)* Most demand response potential does not have this capability.
    - To provide an alternative, most of the demand response would need to be located in the region around the Scattergood site, and insufficient potential was identified in this region.

5: Combination Options

We considered the following combinations:

1) Fuel cells plus storage
   - Constrained by space, so requires a SOFC fuel cell on the main three-acre site, plus storage on the site south of Grand Avenue.
   - Evaluated a 230 MW SOFC fuel cell plus 100 MW eight-hour battery.

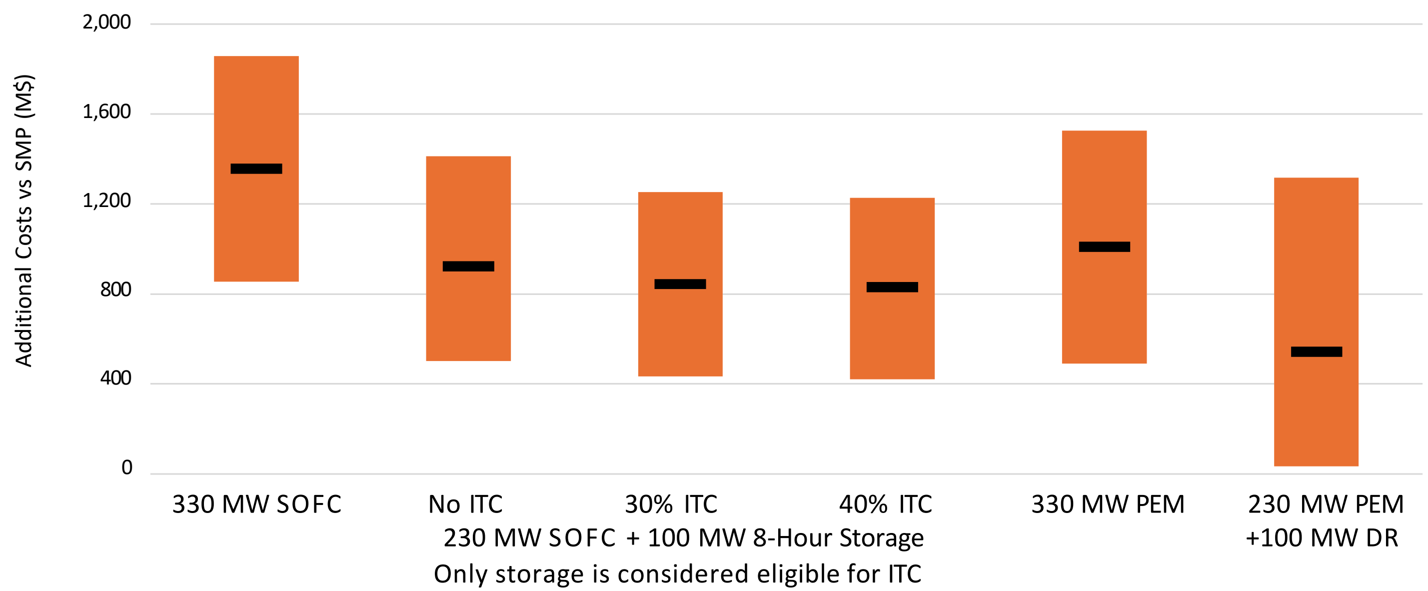
2) Fuel cells plus demand response
   - Limited by the availability of long-duration demand response of about 100 MW.
   - Evaluated a 230 MW PEM fuel cell plus 100 MW of DR.

3) Storage plus demand response
   - Limited by DR availability, space, and long duration requirements.
   - Scattergood site limited to about 180 MW of ten-hour storage so remaining DR requirements exceeds identified DR potential.
   - **Combination not considered viable, so not evaluated further.**

5: Combination Options

Combination options can reduce the cost premium of the alternatives but are still likely more expensive and **do not eliminate significant technology risk**. This study found that:

- The median cost premium for fuel cell/storage combinations is above $800 million
- The median cost premium for fuel cell/demand response combinations is about $500 million
- Combinations still rely on fuel cell installations that greatly exceed the largest installation in the United States (more than 10 times larger) and have associated technology risks.



Additional costs associated with replacing SMP with only fuel cells, or a combination of fuel cells plus energy storage or demand response over the 30-year evaluation period.

Conclusions

In the years since the LA100 analysis, there have been no fundamental changes in the LADWP power system that alter the conclusion that new dispatchable capacity is needed to replace the retiring OTC units at Scattergood. This analysis found that:

- Transmission is not viable due to the 2030 requirement.
- Storage is not viable due to duration and the requirement that all 330 MW be sited at Scattergood. There is uncertain timing and risk of additional land acquisition.
- Demand response is not viable due to the location and duration requirements.
- Green hydrogen fuel cells are not viable due to the infrastructure requirements for 100% hydrogen fuel that is unlikely to be available by 2029.
- Natural gas/hydrogen blend fuel cells have an extremely large cost premium, no significant emissions reductions, and considerable uncertainty around large-scale deployments.
- Combination options can reduce the cost premium of the alternatives but are still likely more expensive and do not eliminate the significant technology and implementation risk.

Q&A

TRANSMISSION SYSTEM ASSESSMENT

Los Angeles Department of Water & Power

2024 LONG TERM TRANSMISSION ASSESSMENT

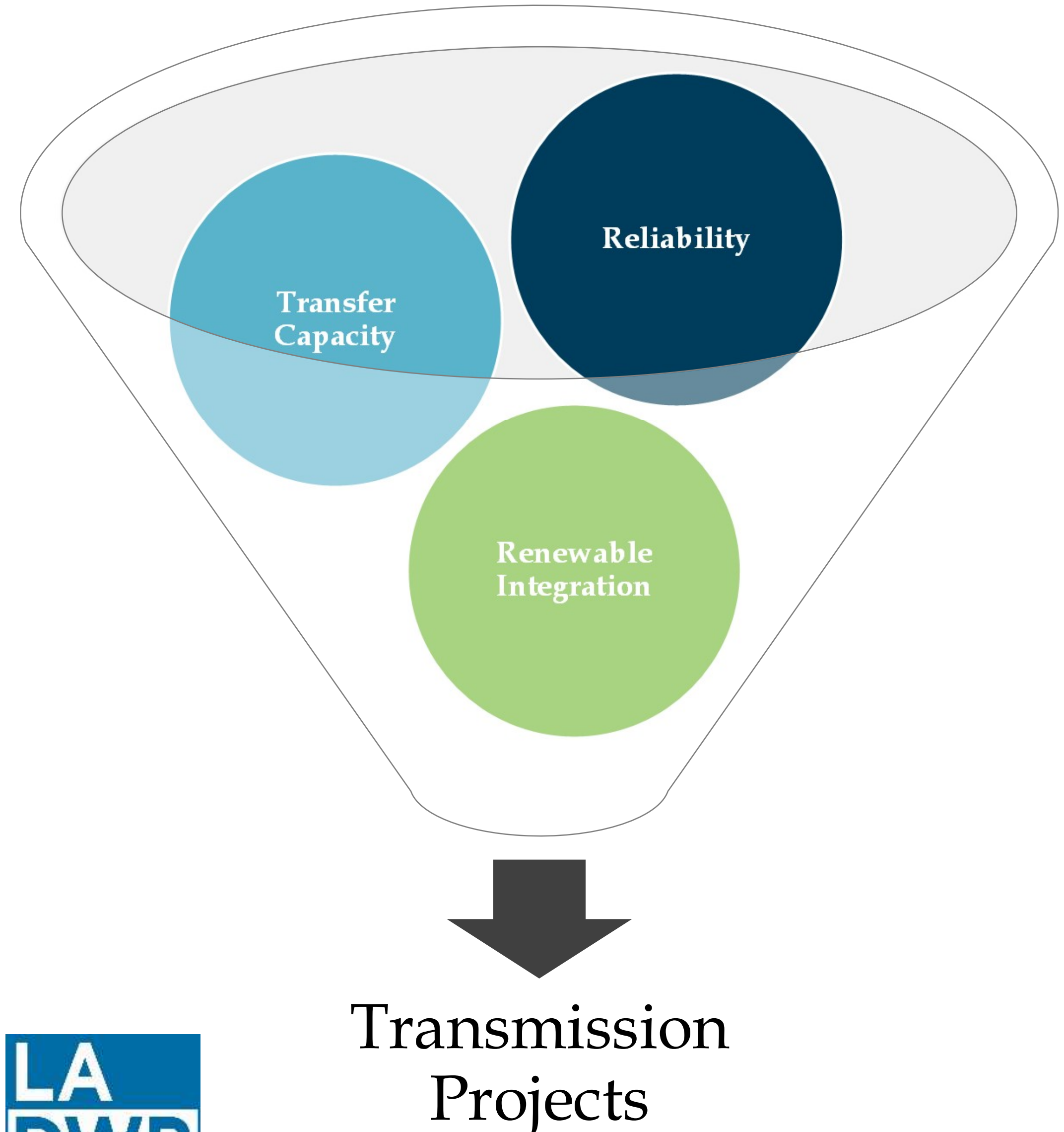
LA100 Briefing

PRESENTED BY:

TRANSMISSION PLANNING

3/19/2025

Transmission Planning Function



Ensure Reliability of the Transmission System

- **NERC Reliability**
  - Facilities must be operated within the System Operating Limits (SOL)
    - Facility Ratings, Voltage limits, & Stability Limits
  - Event Analysis
    - What if a transformer fails? A Line trips? Generator Trips? Multiple elements?

Transfer Capacity

- Evaluate Transfer Capacity on various paths that energy is scheduled on.

Interconnection Studies

- Integration of potential renewable projects into the Department's power system

LADWP's Challenges and Opportunities

Challenges

Maintaining System Reliability & Resiliency

LADWP Transmission system was designed to operate with local generation due to geographic location

Meeting Renewable Portfolio Standards Goals & Load Growth

100% carbon free by 2035,
Once Through Cooling (OTC) requirements,
Building electrification,
EV charging,
Which leads to Increase imports

2024 Long Term Transmission Assessment
Ensuring Reliability of the Transmission System

- **System Reliability Assessment**
  - Required on an Annual basis by North American Electric Reliability Corporation (NERC) TPL-001-5.1
  - Iterative plan designed to ensure reliability is maintained as plans change
    - Load Forecasts
    - Project in service dates
    - Available Generation
- **Study Scope**
  - Near-Term (year 2 and 5) 2026 and 2029
  - Long-Term (year 10) 2034
  - year 2030 and 2035 added as sensitivity analysis
- **Results are needed for other WECC and other NERC Compliances:**
  - FAC-014-2, IROL-017-1, PRC-023-4, and PRC-026

Study Assumptions

Study Assumptions

Updated 2022 SLTRP Case 1

2023 FSO Aggregate
Load Forecast

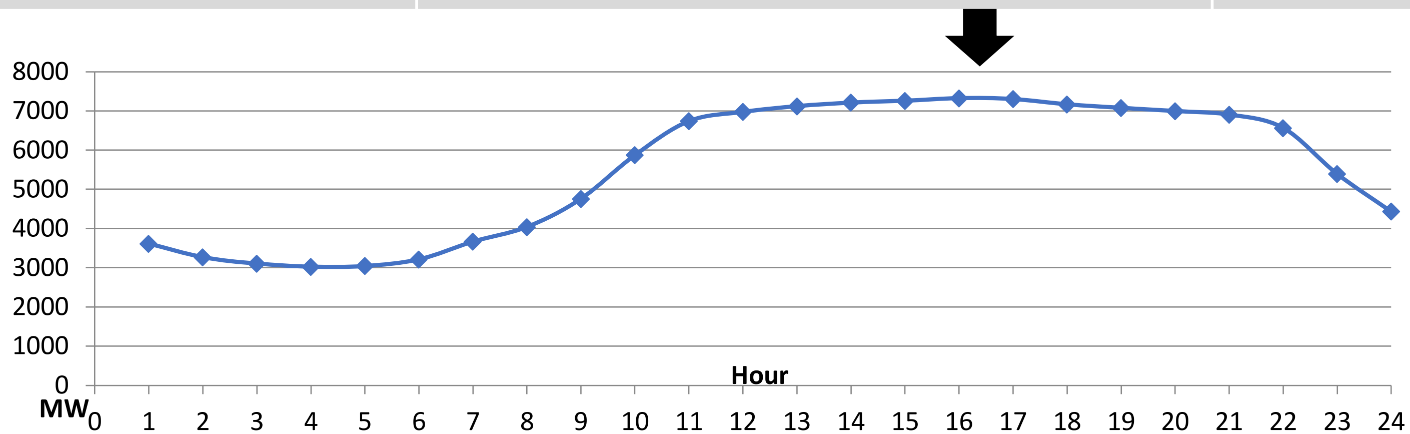
2023 Distribution
Load Forecast

2024 Long-Term Transmission Assessment

2024 Planning Cycle Information – Base cases

- Base cases intended for use in the local transmission planning study

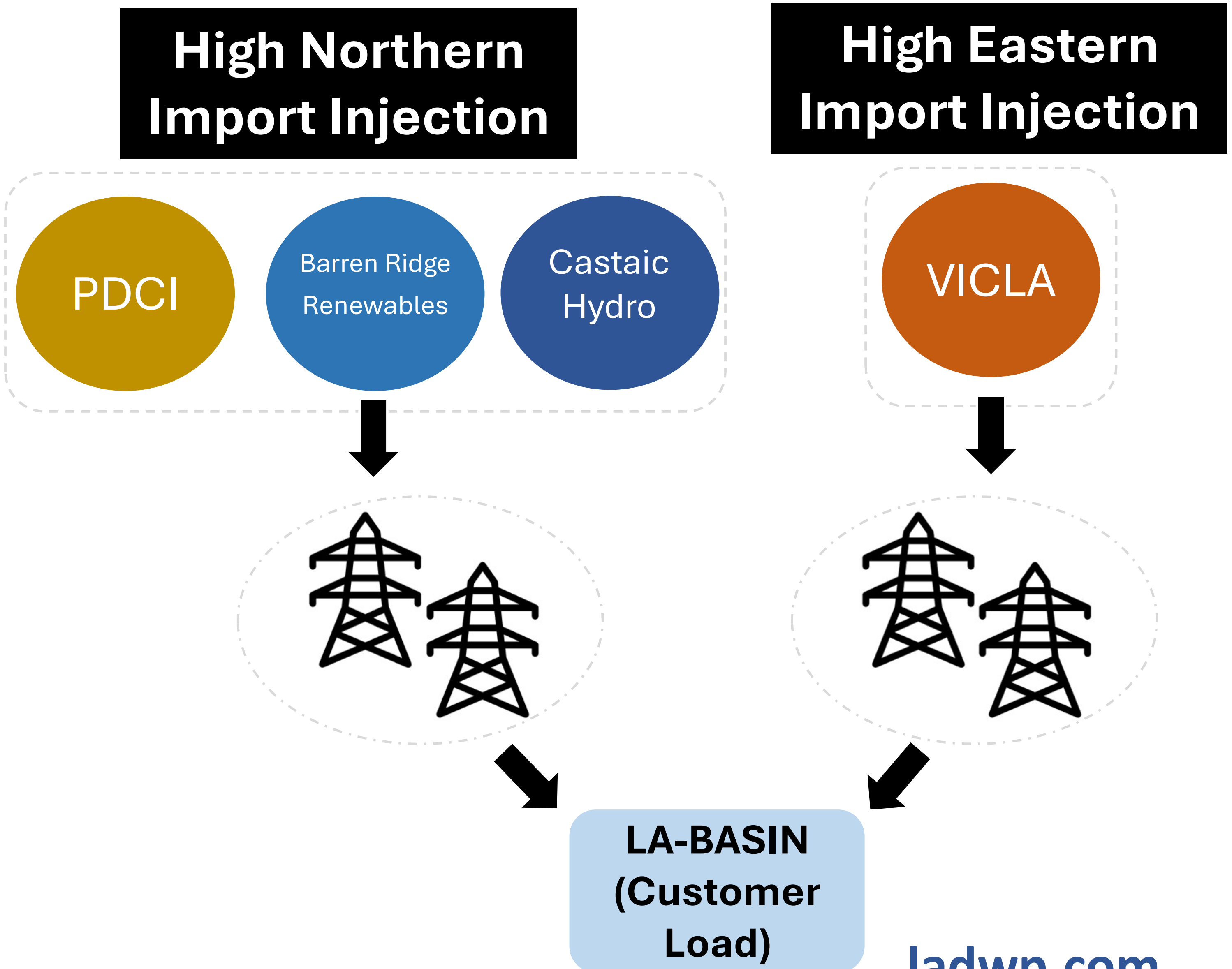
Model Year	WECC Base Case	System Condition
2025	25HW3a1	Heavy Winter
2026	24HS3b1	Heavy Summer
2029	29HS2a1	Heavy Summer
2029	29HW2a1	Heavy Winter
2029	25LW1a1	Light Winter
2030	29HS2a1	Heavy Summer
2034	34HS1a1	Heavy Summer
2035	34HS1a1	Heavy Summer



2024 Planning Cycle Information – Sensitivity

– Sensitivity Scenarios :

Sensitivity
High Vic-LA
5 % Load Growth
Maximum PDCI (3210MW) + High Castaic (1250MW)* + High Wind
Maximum PDCI (3210MW) + Normal Castaic + High Solar Output
Maximum PDCI (3210MW) + High Castaic (1250MW)* + Maximum Renewable Output



* Reserve Transmission Capacity for operation Requirement

2024 Planning Cycle Information – Load Assumptions

- System Load Assumptions:

Year	Net Aggregate Load Forecast (MW)
2026 Heavy Summer	6923
2029 Heavy Summer	6757
2030 Heavy Summer	6859
2034 Heavy Summer	7324
2035 Heavy Summer	7467
2025 Heavy Winter	3675
2029 Heavy Winter	3829
2029 Light Winter	1749

2024 Planning Cycle Information – Generation Assumptions

- Internal Generation Assumptions:

Resource Type	2024 MW Net Max Capacity
Pumped Storage	1265
Natural Gas (Basin Thermal)	3373
Wind (Pine Tree)	135
Solar (Pine Tree, Beacon, Adelanto, RE-Cinco, SpringBok(1, 2, & 3)	678
Hydroelectric (Owens Gorge, PP1 & PP2, Small Hydro)	205
TOTAL INTERNAL GENERATION	5656
% of Total Generation	56%

LA DWP

2024 Planning Cycle Information - External Generation

- External Generation Assumptions:

Resource Type	2024 MW Net Max Capacity
Hydroelectric (Hoover)*	496
Wind (Milford, Red Cloud and Pacific Northwest Imports)	1071
Solar (Copper Mtn3, Moapa)	460
Coal (Intermountain)*	1202
Geothermal	259
Nuclear (Palo Verde)*	387
Natural Gas	578
TOTAL EXTERNAL GENERATION & PURCHASES	4453
% of Total Generation	44%

*LADWP Entitlement Share

2024 Planning Cycle Information – Existing Renewable Energy (MW)

Project	Type	Capacity*	Status	Location	2025	2026	2029	2030**	2034	2035**
Linden	Wind	50	Existing	NOB	50	50	50	50	50	50
Pebble Springs	Wind	69	Existing	NOB	69	69	x	x	x	x
Pine Tree	Wind	135	Existing	Barren Ridge	135	135	135	135	135	135
WindyPoint	Wind	262	Existing	NOB	262	262	262	262	262	262
Milford1	Wind	185	Existing	IPP	185	185	185	185	185	185
Milford2	Wind	102	Existing	IPP	102	102	102	102	102	102
Red Cloud	Wind	334	Existing	Navajo	334	334	334	334	334	334
Copper Mountain	Solar	210	Existing	Marketplace	210	210	210	210	210	210
Pine Tree	Solar	9	Existing	Barren Ridge	9	9	9	9	9	9
Adelanto	Solar	10	Existing	Adelanto	10	10	10	10	10	10
Springbok1	Solar	105	Existing	Barren Ridge	105	105	105	105	105	105
Springbok2	Solar	155	Existing	Barren Ridge	155	155	155	155	155	155
Springbok3	Solar	90	Existing	Barren Ridge	90	90	90	90	90	90
Recinco	Solar	60	Existing	Barren Ridge	60	60	60	60	60	60
Moapa	Solar	250	Existing	Crystal	250	250	250	250	250	250
Beacon1	Solar	56	Existing	Barren Ridge	56	56	56	56	56	56
Beacon2	Solar	45	Existing	Barren Ridge	45	45	45	45	45	45
Beacon3	Solar	56	Existing	Barren Ridge	56	56	56	56	56	56
Beacon4	Solar	50	Existing	Barren Ridge	50	50	50	50	50	50
Beacon5	Solar	37	Existing	Barren Ridge	37	37	37	37	37	37
Geo_DonCamb	Geo	14	Existing	Mead	14	14	14	14	x	x
Geo_DonCamb2	Geo	16	Existing	Mead	16	16	16	16	16	16
Geo_Herber1	Geo	36	Existing	Mead	36	36	x	x	x	x
Geo_Ormesa	Geo	30	Existing	Mead	30	30	30	30	30	30
Geo_PPA_NNV_E	Geo	164	Existing	Crystal	164	164	164	164	164	164

*Represents LADWP's capacity
**Additional Studies with Power Flow Analysis only

x - Generation capacity not modeled in study year

2024 Planning Cycle Information – New Renewable Energy (MW)

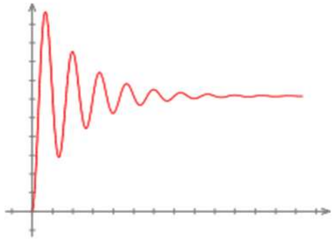
Project	Type	Capacity*	Status	Location	2025	2026	2029	2030**	2034	2035**
HandDesign_Geo_Victorville	Geo	500	New	Victorville	x	x	x	x	400	500
HandDesign_Geo_McCullough	Geo	225	New	McCullough	x	x	x	x	180	225
HandDesign_Geo_Crystal	Geo	150	New	Crystal	x	x	x	x	120	150
Solar_PPA_Eland1	Solar + BESS	175	New	Barren Ridge	175	175	175	175	175	175
Solar_PPA_Eland2	Solar + BESS	200	New	Barren Ridge	200	200	200	200	200	200
Solar_PPA_2025_B	Solar + BESS	170	New	Rosamond	x	170	170	170	170	170
Solar_PPA_2025_U	Solar + BESS	250	New	IPP	x	250	250	250	250	250
Solar_PPA_2027_Generic_RA	Solar + BESS	300	New	Navajo	x	x	300	300	300	300
Solar_PPA_2027_Generic_A	Solar + BESS	300	New	Mohave	x	x	300	300	300	300
Candidate_Solar+Storage_Marketplace_Case1	Solar + BESS	325	New	Marketplace	150	200	200	325	325	325
Candidate_Solar+Storage_Haskell_Case1	Solar + BESS	325	New	Rosamond	x	x	x	x	x	325
Wind_PPA_2027_Generic_LS	Wind	300	New	Mona	x	x	300	300	300	300
Candidate_Wind_IPP	Wind	350	New	IPP	x	x	x	350	350	350
Wind_PPA_STS	Wind	600	New	IPP	x	x	x	x	600	600
HandDesign_Wind_Navajo	Wind	313	New	Navajo	x	x	x	x	x	313
HandDesign_Wind_Marketplace	Wind	313	New	Marketplace	x	x	x	x	x	313

*Represents LADWP's capacity
**Additional Studies with Power Flow Analysis only

x - Generation capacity not modeled in study year

2024 Planning Cycle Information – Study Plan

Study plan to guide the local transmission planning study for the LADWP Bulk Electric System



- Steady State – Power Flow Analysis
- Transient Stability
- Voltage Stability
- Short circuit analysis
- Identify mitigations to alleviate issues, if possible

Study Criteria – Reliability Criteria: NERC-TPL-001-5.1

Steady State and Stability Performance Planning Events

- **P0** – All elements in service
- **P1/2** – Loss of one element
- **P3** – Loss of a Generator, followed by the loss of another element
- **P4** – Loss of multiple elements due to a stuck breaker
- **P5** – Loss of multiple elements due to a non-redundant protection component
- **P6** – Loss of a Circuit, followed by the loss of another element
- **P7** – Loss of two elements on a common structure
- **EXT** – Loss of multiple elements on a common right-of-way

FINDINGS – MITIGATION & RECOMMENDATIONS

2024 Long-Term Transmission Assessment Results in development process

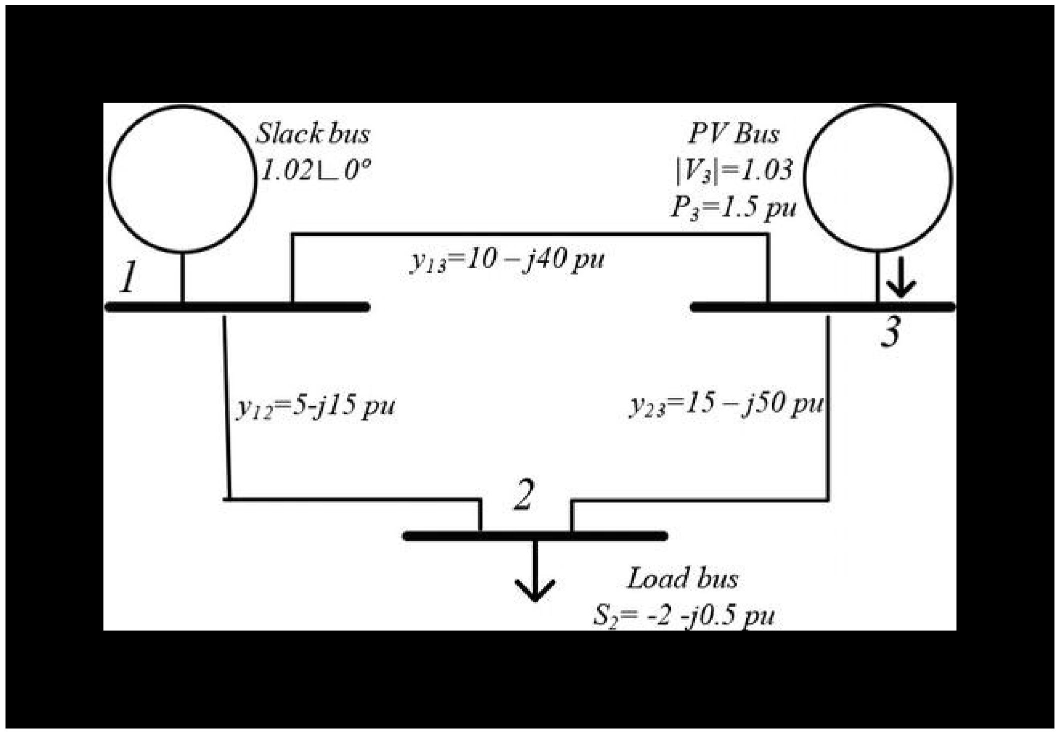
High Voltage in lightly loaded conditions	**Install reactive equipment in various locations throughout the LA System**
High Fault current caused by increased Renewable Energy	**Upgrade Circuit breakers and develop short mitigation strategies**
Modify Remedial Action Schemes	**Owens Valley and Scattergood**
Transmission line upgrades	**Castaic – Haskell 230kV Line 1** **Victorville 287 AC to DC conversion**
Further evaluate Longer-Term Horizon Beyond 10 years	**Transmission Planning issued an RFI to survey information on new potential corridors**

Project Development And Challenges

LA DWP

Transmission Project – Development

System Model Recommendation



Physical Equipment

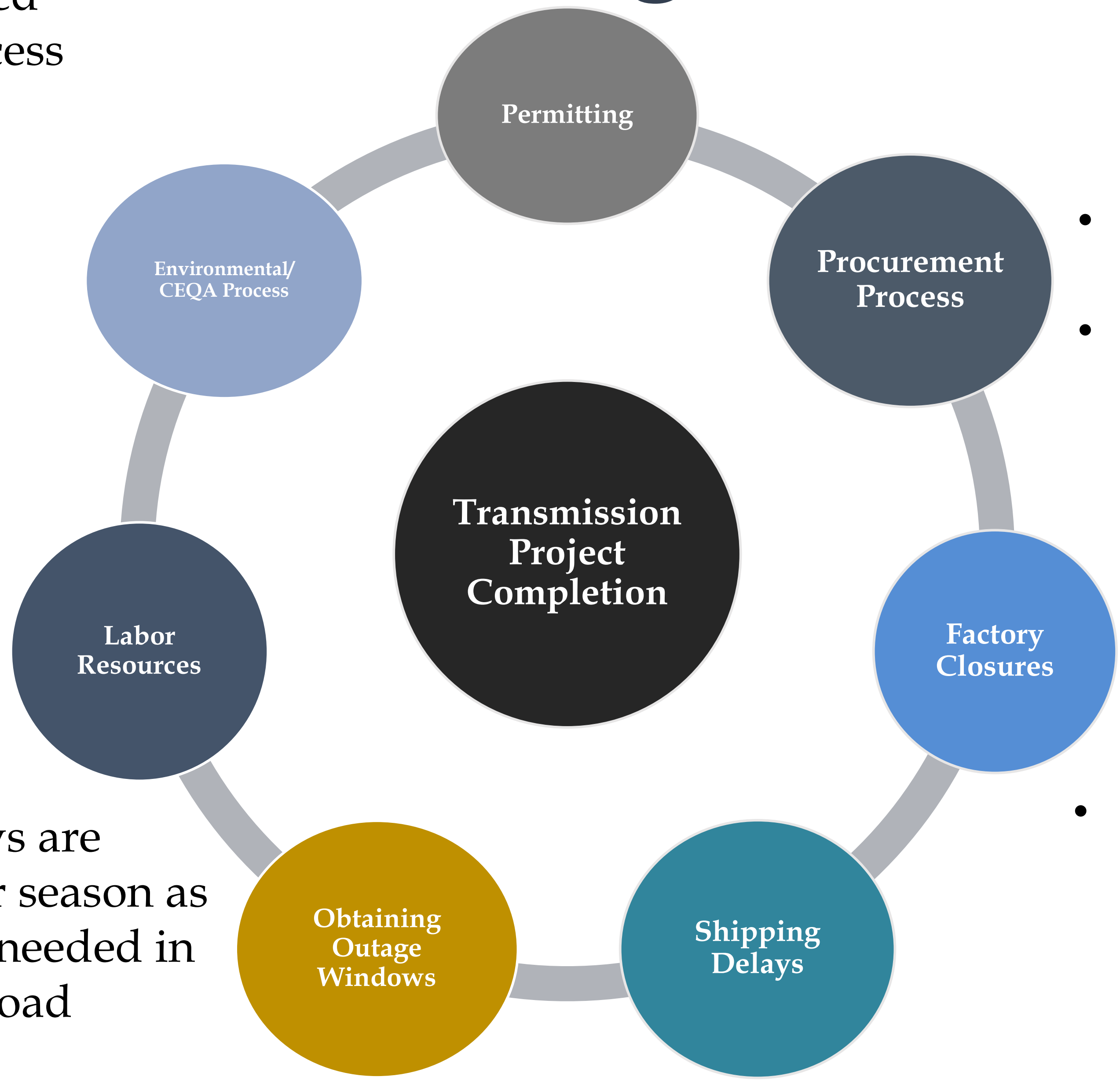
Multi-Year Process

- Coordinate with Design team
- Evaluate sizing, cost, rating, spare strategy
- Alternate Options

- Project Approval
- Design/ Permitting /Engineering
- Procurement/ Testing and commissioning

Transmission Project – Implementation Challenges

- Many Groups are involved with this multi-step process



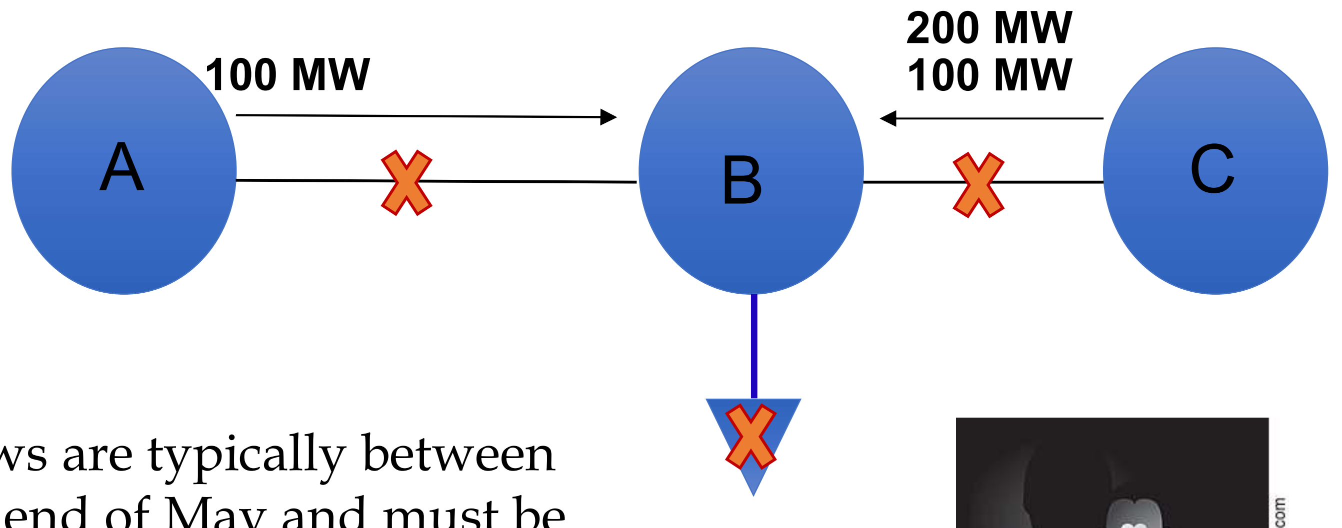
- Much of the equipment comes outside of US
- Manufactures are quoting up to 5-year lead times in some cases

- On Average transmission Projects can take 7-10 years

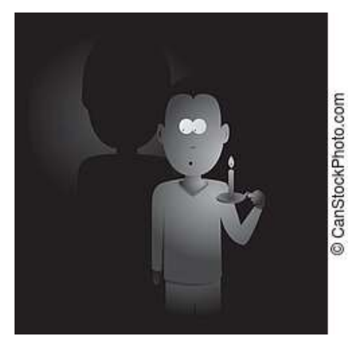
- Outages windows are limited to Winter season as all equipment is needed in service for high load conditions

Outage Coordination – Challenges

- Many lines are critical and cannot be taken out of service without causing reliability constraints
- Generation resources are also critical and may not be able to taken out of service in combination with some transmission outages



- Outage Windows are typically between November and end of May and must be strategically staggered



Scattergood – Olympic Line A

Project Scope: New 12-mile Underground cable from Scattergood to Olympic

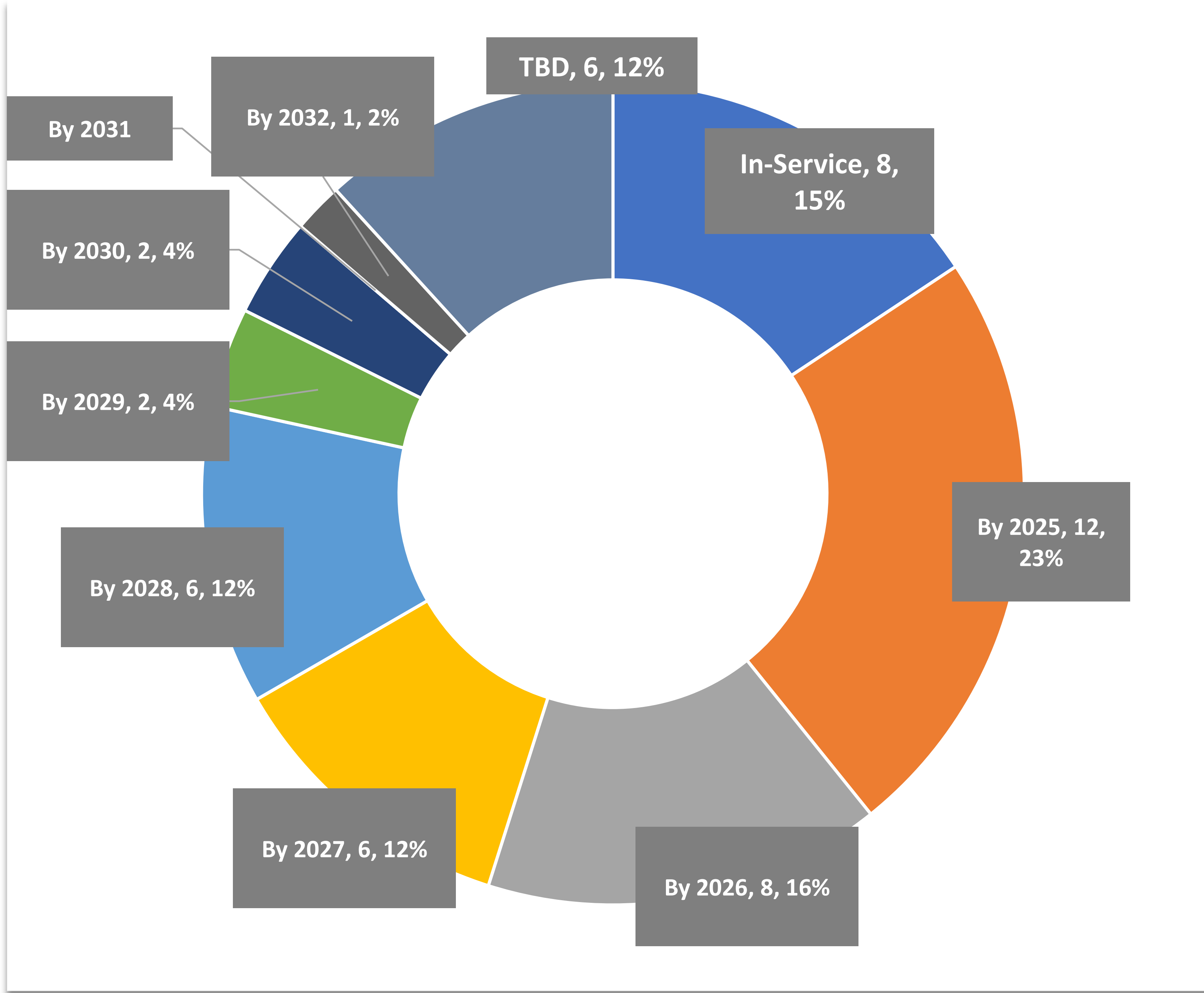
Timeline:

- Proposal for the project: 2006
- Environmental Process: 5 years
- Construction starts: 2012
- Caltrans Permit to cross Ballona Creek on the Lincoln Bridge took 4 years to obtain
- Placed into service: 2018

LADWP – Existing Project Statistics

Total Number of Projects presented at Q4 2024 Stakeholder Process = **51 Projects**

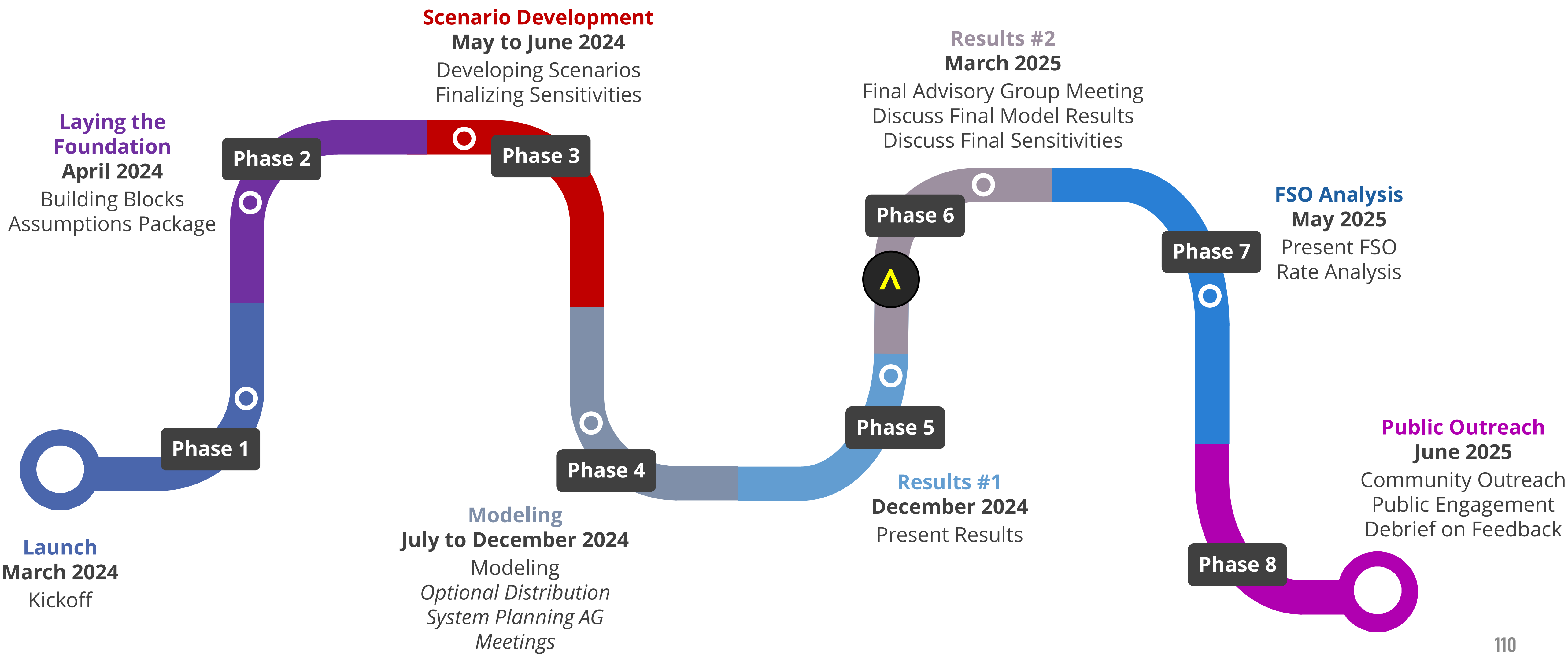
In service means projects completed between Dec 2023 and Dec 2024



Local Transmission Process – https://www.oasis.oati.com/LDWP/

Q&A

NEXT STEPS – MEETING MAP



LA100 Plan Advisory Group Draft Meeting Plan
Please note that dates are tentative and subject to change based on needs of the LA100 Plan process.