BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	R.20-11-003

OPENING TESTIMONY AND PROPOSALS OF DR. KARL MEEUSEN
ON BEHALF OF WÄRTSILÄ NORTH AMERICA, INC.

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September 1, 2021

A. Introduction

My name is Dr. Karl Meeusen, Ph.D. I am currently employed by Wärtsilä North America, Inc. (Wärtsilä) at 900 Bestgate Rd. #300, Annapolis, MD 21401. I work in the Growth and Development group of the Energy Business as the Director – Markets, Legislative and Regulatory Policy. I have held this position since May 2021. In this role, I represent Wärtsilä's Energy Business interests in federal and state regulatory matters and identify and communicate the commercial, operational, and business process impacts of regulatory matters. Additionally, I serve as the California-lead on the Path to 100% initiative for Wärtsilä. The Path to 100% initiative utilizes detailed production simulations of electric systems around the world to identify the optimal path towards a clean energy future.

Prior to joining Wärtsilä, I worked for the California Independent System Operator Corporation (CAISO). I was at the CAISO from 2011 through April 2021. At the CAISO I was in the Markets and Infrastructure Policy group as the Senor Advisor – Infrastructure and Regulatory Policy. Among other things, I was responsible for evaluating and developing new wholesale electricity market designs related to the CAISO's ongoing efforts to integrate renewable resources into the CAISO electricity market and electric grid. I have assessed changing resource adequacy needs resulting from the increased presence of renewable resources and the need to maintain sufficient flexible capacity resources for renewable resource integration.

Prior to joining the CAISO, I served as Energy Advisor to California Public Utilities Commission (CPUC) President Michael Peevey, advising on issues such as resource adequacy, long-term resource procurement, demand response, and FERC-related issues. While at the Commission, I also worked in the Energy Division on Demand Response, Federal Energy Regulatory Commission (FERC) proceedings, and Resource Adequacy. My experience prior to joining the Commission included research positions at the National Regulatory Research Institute, the U.S. Department of Justice, Antitrust Division, and independent consulting. I hold a Ph.D. in Agricultural, Environmental, and Development Economics and an M.A. in Economics from The Ohio State University, and a Bachelor's of Science in Philosophy and Economics from the State University of New York, College at Brockport. My qualifications are attached at Appendix A.

The primary objective of the proceeding can be stated as follows: Ensure new clean, firm, dependable capacity is installed in California as quickly as possible. The emergency actions directed in the Governor's Emergency Proclamation on July 30, 2021, opens the door for numerous short-term solutions, including supporting on-site back-up generation regardless of fuel efficiency or air emissions profile and the state paying for penalties when generators exceed their air emissions limits. While these solutions may help ensure reliability in the short term, they run contrary to the state's long-term environmental goals and should be in place only until better, cleaner solutions can be put in place. The CPUC's Energy Division has provided a set of proposals aimed at addressing the immediate needs identified by the California Energy Commission (CEC). These proposals focus on 1) demand reduction, 2) smart thermostats, and 3) utility scale storage, imports, and generation.

My testimony focuses on generation options that can 1) be in place for the 2022 and/or 2023 summer seasons and 2) also be consistent with D.21-06-035 and the August 17, 2021 ruling seeking comments on the new preferred system plan (PSP) and assessing the existing thermal fleet in R.20-05-003. In summary, my testimony shows the following:

1) New thermal capacity additions can help ensure reliability for summer 2022 and 2023; however, the window of opportunity for 2022 is very narrow and requires prompt action.

2) It is possible to add new thermal capacity while maintaining consistency with decisions and ruling from R.20-05-003.

3) The addition of fast, flexible balancing capacity will help meet short-term reliability needs, enhance renewable integration, and allow for retirement of less efficient thermal resources as new capacity comes on-line.

4) Any thermal capacity procured through this proceeding should have the demonstrated capability to run on hydrogen-based fuels.

5) Several of Energy Division's proposals have merit but are unlikely to provide significant incremental MWs to fulfill the CEC's forecasted shortfalls.

There are currently three CPUC regulatory processes attempting to forge a path to 100 percent renewable generation by 2045 in California. Specifically, D.21-06-035 has directed the procurement of 11,500 MW of new capacity, including 1,000 MW of long-duration storage resources and 1,000 MW of generation resources with at least an 80 percent capacity factor, which have zero on-site emissions or otherwise qualify under the RPS program eligibility rules, by 2028.[1] Additionally, R.20-05-003 has recently kicked off its next phase, seeking comments on the proposed Preferred System Portfolio (PSP). Included in the proposed PSP are the forced integration of 1,000 MW of both pumped hydro and geothermal resources and consideration for the optimal transition for the thermal fleet and hydrogen generation to achieve the state's 2045 emissions goals.[2] Finally, there is the present proceeding that seeks immediate solutions that can be put in place for the summers of 2022 and 2023 in response to the CEC's recently completed stack analysis that identified potential shortfalls up to 5,274 MW.[3]

Additionally, Wärtsilä, as part of the Path to 100% initiative, has conducted extensive production simulation models of the California system using Plexos. The inputs used in these models are based on the PSP used in the 2019 IRP process, with two differences: 1) differentiation between peaking and balancing thermal resources (described more below); and 2) the inclusion of power-to-gas, a process that utilizes excess renewable generation to produce green hydrogen-based fuels for thermal combustion. The most recent draft of the California Path to 100% results are provided in the Appendix B of my testimony.[4]

B. Proposals and recommendations

1. New thermal capacity additions can help ensure reliability for summer 2022 and 2023, but the window of opportunity for 2022 is very narrow and requires prompt action.

In order to meet the immediate reliability needs, all capacity options must be considered. This includes new thermal capacity. However, as discussed in greater detail below, new thermal resources should reflect the needs not just of 2022 or 2023, but of 2032, 2045, and beyond. As shown in the Path to 100% study, installation of new efficient, flexible, and convertible thermal resources now can actually accelerate the path to California's 2045 carbon goals.

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[1] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF, p. 90-91
[2] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M399/K450/399450008.PDF
[3] https://efiling.energy.ca.gov/GetDocument.aspx?tn=239251&DocumentContentId=72701
[4] Additional details and studies beyond California study can be found at https://www.pathto100.org/.

In the context of the current proceeding, new capacity would need to be online in near record time to provide benefits for 2022, making the logistics critically important. Wärtsilä has approximately 200 – 400 MW of reciprocating internal combustion engines (RICE) available to meet California's near-term capacity needs. Wärtsilä engines can be installed in 12-16 months in many locations, including identifying sites, permitting a resource, and construction and commissioning. However, the standard California requirements would typically extend that timeline much further. Therefore, when assessing the opportunities for adding thermal resources, there must a clear path with expedited processes.

Perhaps the most significant challenge to adding new thermal capacity for summer 2022 and 2023 is determining whether or not a thermal facility can even be brought online to meet these deadlines using the traditional processes for project development and permitting. The CEC, in Order Nos. 21-0817-01 and 21-0817-02, approved streamlining the citing and permitting processes for facilities capable of reducing the energy shortfall by October 31, 2021.[5] The importance of this decision cannot be overstated. Extension of these streamlined processes is necessary to ensure that new capacity can be brought online by 2023 but could also allow for new capacity in 2022 if the CPUC takes immediate action.

An additional step that must be addressed is the need for interconnection studies for resources that are not already in the CAISO's interconnection queue. The CAISO must be able to study new resources to ensure they are able to reliably integrate into the system. The CAISO's interconnection process assesses resources in clusters. Currently, there are 373 interconnection requests in the CAISO cluster 14,[6] comprised mostly of storage and solar/storage hybrids. If the commission identifies a need for and benefit from additional thermal capacity, then it is likely that the CAISO will have to seek a waiver from FERC of its existing tariff to conduct any interconnection studies for any new capacity that must be procured and brought online.

Between the waiver request and the interconnection study process, new thermal capacity for summer 2022 will be challenging, though not impossible if immediate and decisive action is taken. However, the opportunities for new thermal capacity for 2023 are very achievable. Finally, in addition to providing immediate reliability benefits, adding fast, flexible, and

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[5] https://efiling.energy.ca.gov/GetDocument.aspx?tn=239400&DocumentContentId=72859
[6] http://www.caiso.com/Documents/FinalProposal-SuperclusterInterconnectionProcedures.pdf, p. 6.

convertible thermal capacity now can actually accelerate carbon reductions, allowing California to reach its carbon goals even sooner. This is discussed in greater detail below.

Many of the global supply lines needed to provide critical elements for all types of electric generation are currently experiencing significant shortages, backlogs and delays. In light of global supply chain risks, the Commission should act quickly to procure the necessary capacity to maintain mid-term reliability. There are two major ways in which supply chain risks are currently threatening procurement: 1) delays to project deliveries due to the impacts of the COVID-19 pandemic; and 2) scarce resource availability due to competitive global markets for energy storage and firm capacity. Examples of the former risk include previously announced delays by Pacific Gas & Electric and San Diego Gas & Electric to battery storage projects scheduled to come online by August 1, 2021.[7] As noted by Mr. Jin Noh of the California Energy Storage Association during the CEC's August 30, 2021 Workshop on Midterm Reliability ("MTR Workshop"), energy storage is a globally competitive market that requires advanced procurement: battery storage developers have already sold all their capacity for 2022.[8]

Furthermore, the global demand for firm and flexible resources is growing in the face of extreme weather events and ambitious decarbonization goals. For example, extreme drought conditions have jeopardized hydropower reserves in the United States, Brazil, and China.[9] As such, the Commission should view its procurement decisions in the context of a global marketplace with limited supply. The Commission cannot treat procurement as a "wait-and-see" decision. Delays in decision making could mean that scarce inventory is procured in other markets and therefore no longer available to California.

The Commission should consider the risks associated with heavy reliance on a single solution source. Although the CEC studies showed storage can provide comparable reliability in

[7] https://www.utilitydive.com/news/california-governor-moves-to-free-up-electricity-supply-amid-projected-35/604344/

[8] https://energy.zoom.us/rec/play/CG32EAEmNy0gZPWwyn5YDvo01oc9QWVnEztjGC5RItQ-_Dm2FeOAQGmoxnXoLtOUScepwUeQc_RuFz84.Ygl0vVglZeSnMlmp?continueMode=true&_x_zm_rtaid=cWBzsoSRS0eSH9NO8OoNqA.1630420208774.e560275afbc9814bdb92dd09c3ebd250&_x_zm_rhtaid=718 at 01:45:18 - 01:45:52

[9] https://www.reuters.com/business/sustainable-business/inconvenient-truth-droughts-shrink-hydropower-pose-risk-global-push-clean-energy-2021-08-13/

the short run,[10] it can only do so if the supply chain constraints do not affect the resource development. The Commission should consider diversifying the fleet they are relying on to provide these solutions. Rather than relying on manufacturers and developers to have available inventory in the future, for example, the Commission should consider taking a proactive approach towards procurement by diversifying the procured fleet to avoid the risk of capacity shortages posed by uncertain supply chains.

2. It is possible to add new thermal capacity while maintaining consistency with decisions and ruling from R.20-05-003.

As noted above, new thermal capacity must be capable of addressing the short-, medium-, and long-term needs of the system. The CEC has identified a need for as much as 5,274 MW. Additionally, the August 17, 2021 ruling in R.20-05-003 asks for comments on the need for fossil-fueled generation resources, the definition of renewable hydrogen, and the feasibility and cost of transitioning from a blend of renewable hydrogen to full renewable hydrogen combustion by 2036.[11] Moreover, D.21-06-035 directs LSEs to procure 1,000 MW of long-duration storage. These paths can all be simultaneously achieved by procuring the convertible, flexible thermal resources today.

To alleviate the projected 5,274 MW capacity shortfall in Summer 2022 and beyond, the Commission should have a rethink of flexibility and the resulting emissions. Currently flexibility focuses on the ability to start, stop, and ramp quickly without regard to impact on emission rates by technology. In reality, depending on the technology, starts can have different emissions values and different minimum operating levels which can greatly affect the overall emittance and operational profile capabilities of a resource. Particularly in the long run, the Commission should consider these attributes when determining the costs and benefits of building additional thermal capacity or continuing to rely on existing resources. For example, some thermal resources that are well suited for peaking needs may not be as well suited balancing renewable resources' variability at the lowest carbon impact due to high start-up emissions to get to minimum operating levels. However, flexible resources with efficient start-ups and low minimum

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[10] The CEC staff analysis on midterm reliability did not assess the cost impacts of maintaining mid-term reliability. As shown in the Path to 100% initiative, reliability does not have to come at a greater system cost. Instead, new flexible, convertible thermal resources can provide accelerated emissions reductions and reliability at lower cost.
[11] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M399/K450/399450008.PDF, p. 52-53

operating levels can both balance renewable variability and meet peak load when needed with an overall minimum emissions impact when all relevant factors are considered.

To differentiate between these two types of resources, I will introduce the concept of balancing resources (hereafter referred to as “balancers”). Balancers are resources that are designed to be operationally and economically flexible (i.e., fast-ramping with low start-up and minimum costs associated with operating throughout the load profile, especially low-load operations) while producing the lowest emissions needed to balance variable resources. For example, Wärtsilä’s RICE units have high thermal efficiencies and can run at minimum loads close to ten percent on any engine. Additionally, because Wärtsilä’s engines are modular in nature, a 50 MW facility could be comprised of three to five engines, allowing that 50 MW resource to operate as low as one or two MW without significantly sacrificing fuel efficiency or emission rates. Additionally, RICE units can go from full output to off-line in less than one minute with a minimum down time of five minutes. Such flexibility provides carbon reductions relative to reliance on a typical peaking plant.

In contrast to traditional “peaker” units that provide firm capacity during peak load periods, balancers also offer a variety of other grid services, such as 5-minute start-up to 100 percent load with no impact on maintenance costs, fast ramp rates, and other ancillary services that “balance” the intermittent generation of variable renewable energy resources. Wärtsilä balancer RICE units also promote resiliency under extreme weather conditions: they offer superior open-cycle efficiency and do not suffer from thermal de-rates from high ambient conditions, require minimal water (approximately 1 gallon per engine per week), have black-start capability, and provide built-in redundancy in the event of an outage due to their modular block configuration. As such, balancers can respond almost instantly to any alerts, warnings, or emergencies.

Another consideration in the August 17, 2021 ruling in R.20-05-003 is the ability to utilize hydrogen as a fuel source. As noted in greater detail further below, any resource procured as part of this proceeding should have the ability to utilize green (synonymously, renewable) hydrogen or another green hydrogen-based fuel. Over time, these resources should also be capable of being converted to burn 100 percent renewable hydrogen-based carbon neutral fuels. Wärtsilä’s balancer Reciprocating Internal Combustion Engines (RICE) are currently capable of running on hydrogen blends of up to 25 percent, and Wärtsilä expects that by 2025 existing balancer RICE units can be converted to burn 100 percent hydrogen while maintaining much of the current balance of plant equipment. With supporting infrastructure such as electrolyzers and hydrogen storage in place, convertible balancers could provide additional decarbonization benefits. As the focus of the present proceeding is immediate capacity needs, it need not be required that the supporting hydrogen infrastructure be in place at the time of construction, however, as discussed below, real demonstrations of the technology's ability to utilize hydrogen or hydrogen-based fuels should be a precondition of procurement.

Procurement of thermal generators that can be converted to run on 100 percent carbon neutral fuels could also lower the cost of mid-term reliability. In the ruling issued by ALJ Fitch in R.20-05-003 on August 17, 2021, Commission staff included 1,000 MW net qualify capacity of long-duration storage provided by pumped hydro in the PSP to maintain reliability through 2032. This is done without regard to the costs of pumped hydro as a long-duration storage solution, meaning that the cost to ratepayers is not necessarily cost-optimal. Procurement of convertible thermal resources in the near term would provide an alternative pathway to meeting California's long-duration storage needs. Burning renewable hydrogen-based carbon neutral fuels (e.g., renewable hydrogen, ammonia, methanol, and synthetic methane) is currently uneconomical. However, the momentum for 100 percent renewable hydrogen is rapidly accelerating and, by the time long-duration storage is called upon (in the 2026 – 2028 timeframe according to D.21-06-035), renewable hydrogen-based carbon neutral fuels could present a cheaper alternative to pumped hydro. At the CEC's MTR Workshop, Mr. Gabe Murtaugh expressed that the need for storage beyond 4-hour batteries will evolve, with 6–8-hour storage resources becoming more important in the near term and seasonal storage resources necessary for long-term reliability. [12] Although CEC staff analysis indicates that no additional thermal capacity is necessary from a mid-term reliability perspective, new flexible thermal resources provide multiple benefits to the system. These benefits include lower emissions profiles compared to existing resources, the ability to run on hydrogen blends, and the flexibility to be

[12] https://energy.zoom.us/rec/play/CG32EAEmNy0gZPWwyn5YDvo01oc9QWVnEztjGC5RItQ-_Dm2FeOAQGmoxnXoLtOUScepwUeQc_RuFz84.Ygl0vVglZeSnMlmp?continueMode=true&_x_zm_rtaid=cWBzsoSRS0eSH9NO8OoNqA.1630420208774.e560275afbc9814bdb92dd09c3ebd250&_x_zm_rhtaid=718 at 02:00:44 - 2:01:17

converted to long-duration (multi-day to seasonal) storage resources that combust 100 percent hydrogen-based carbon neutral fuels in the future.

At the same time, if the definition of renewable hydrogen proposed in the August 17th ruling is adopted, renewable hydrogen-based carbon neutral fuels would also offer emissions savings compared to pumped hydro. Whereas the electricity used to store these fuels would be guaranteed to come from 100 percent renewable energy under the definition of renewable hydrogen, no such guarantee exists for the electricity used to store pumped hydro. Thus, procurement of convertible generators, such as Wärtsilä's balancer RICE units would double as both an investment in near-term reliability and a down-payment on future long-duration storage needs. Therefore, procurement of convertible resources will incrementally decarbonize California's grid and promote near-term reliability in a cost-effective manner.

3. The addition of fast, flexible balancing capacity will help meet short-term reliability needs, enhance renewable integration, and allow for retirement of less efficient thermal resources as new capacity comes on-line.

If new balancing resources are procured now, then this will allow less flexible resources to retire more quickly, accelerating carbon reductions while helping to maintain system reliability. ALJ Fitch's August 17, 2021 ruling in R.20-05-003 also identifies this issue as a consideration for capacity expansion. The addition of balancers to the California grid can also maximize renewable energy generation from existing resources. Due to the inflexibility of the existing gas capacity in California's supply stack, variable renewable energy resources are often curtailed when supply exceeds demand. Due to operational limitations such as minimum down time or start-up times, inflexible resources may be held on-line through midday solar peaks to address forecasted ramps. This inflexible resource results in lower solar production and higher carbon emission. By way of contrast, balancing resources like Wärtsilä's RICE unit can start and stop efficiently in minutes without impact to maintenance schedules and maintain minimum operating levels at ten percent per engine. Greater capacity of flexible balancers allows grid operators to dispatch renewable energy at greater levels and adjust balancer output as necessary to match load and lower the need for curtailment of the renewable generation mix.

In the Commission's current production simulations, peakers and balancers are treated as though they are the same resources. They are not. They have different cost structures, operational capabilities, and emission profiles and thus should be treated as distinct resource types. In the Path to 100% initiative, Wärtsilä has modeled these resources using cost structures that reflect Wärtsilä's real-world experience with its RICE units. This differentiated cost structure shows that balancers are cost-competitive with peakers from a CAPEX standpoint, but much less costly from an OPEX and carbon standpoint. For example, Equivalent Operating Hours (EOH) starting costs are additional maintenance required by the prime mover due to every start. For many technologies, increasing the number of starts can result in accelerating the need for major maintenance and increase costs borne by rate payers.[13] Wärtsilä's RICE units can manage these frequent starts and stops with impacting maintenance schedule. As a result, the Path to 100% study shows a transition to solar, wind, and battery storage paired with balancing resources creates a reliable system and reduces overall carbon levels sooner and at lower cost than simply maintaining the existing resources or expanding the amount of peakers on the system.

4. **Any thermal capacity procured through proceeding should have the demonstrated capability to run flexibly on a variety of hydrogen-based fuels.**

As noted above, developing the supporting hydrogen infrastructure may not be feasible in time to meet the reliability and capacity needs of the system. However, the Commission should not be asked to expand thermal capacity based on the hope that a resource will be able to utilize hydrogen-based fuels when the hydrogen infrastructure is in place. Therefore, any thermal capacity approved here should be able to point to specific technology demonstrations where hydrogen or hydrogen-based fuels are currently being utilized to demonstrate more than a hypothetical outcome.

Further, as the hydrogen infrastructure is developed, fuel flexibility must be considered. For example, green hydrogen-based fuels such as green ammonia and green methanol can currently be produced and stored at relatively low costs compared to hydrogen in the immediate-term. Additionally, the storage for green ammonia and green methanol is easily scalable and can be expanded on site at low cost, providing additional long duration storage. Therefore, the Commission should maintain focus on hydrogen-based fuel flexibility. Put differently, the

[13]For example, starting and stopping frequently, can result in the need for major overhauls after just 15000 hours instead of 25,000 hours. These costs increase the Levelized Cost of Energy.

Commission need not focus only on green hydrogen, but allow flexibility for a variety of green hydrogen-based fuels.

5. Several of Energy Division's proposals have merit but are unlikely to provide significant incremental MWs to fulfill the CEC's forecasted shortfalls.

While demand reduction via demand response and energy efficiency from smart thermostats are necessary tools for ensuring system reliability, the stochastic nature of consumer behavior and load makes the effectiveness of such tools uncertain. As noted in the Staff Concepts document, persistent extreme weather may cause consumer fatigue that diminishes the effectiveness of voluntary and compensated customer load reduction. [14] Accordingly, the Load Impact Protocols should factor in the long-run effects of consumer fatigue. Specifically, Qualifying Capacity should reflect the demand reduction during conditions of maximum consumer fatigue (i.e., the minimum demand reduction during the relevant historical interval) rather than some averaged value, for example. Doing so would avoid situations in which expected demand response does not "show up". Furthermore, the Commission should exercise prudence when quantifying the load reduction potential of demand reduction mechanisms, as customer enrollment in multiple programs could result in double counting of demand response contributions. Therefore, Wärtsilä believes that other mechanisms, namely, procurement of flexible, convertible thermal generation resources should complement any demand reduction efforts utilized to meet projected capacity shortfalls.

With respect to incentives for expediting procurement, although monetary penalties (or rewards) could potentially incentivize timely online dates of new generation resources, many questions exist regarding how and whether they can be effective. For example, due to unprecedented circumstances (e.g., COVID-19 pandemic, semiconductor chip shortages, etc.), many supply chains simply do not have the capacity to be expedited, regardless of potential penalties or payments. Power systems across the world, ranging from those in the Pacific Northwest to Brazil, are facing similar capacity shortfalls and are seeking to procure additional resources. Globally, new generation capacity is a scarce resource; any penalties due to delayed procurement should be reflective of this scarcity. However, if penalties are not substantial

[14] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M399/K449/399449984.PDF, p. 9

enough for load serving entities (LSEs) to procure additional capacity, such penalties would not bring additional reliability to the system and would have a purely punitive effect. As such, further research should be conducted to understand the economic and logistical feasibility of avoiding delays and expediting deliveries before a determination is made regarding the proposed incentives.

C. Conclusions

I recommend that the Commission consider all capacity available to address any identified shortfalls for summer 2022 and 2023. This includes expediting procurement of fast, flexible balancing capacity that currently has renewable hydrogen capabilities and can be converted to 100 percent renewable hydrogen-based fuels over the long run. I am not recommending that the Commission take any action that would be contrary to the directions outlined in the Commission's Integrated Resource Planning Process, R.20-05-003. To the contrary, the recommendations made here seek to stay consistent with the Integrated Resource Planning Process and even also accelerate California's path to a 100 percent renewable future. However, it will be necessary to establish streamlined processes in conjunction with the CEC and CAISO.

It is important to recognize that not all starts from thermal resources are economically or environmentally equal. Procurement of balancing resources can help accelerate California's environmental goals. Procuring balancing resources with low minimum operating levels and low start-up emission that can rely on hydrogen-based fuels will reduce costs and carbon emissions in both the short- and long-run. Immediate action to procure convertible balancer technology can not only alleviate upcoming summer capacity shortfalls, but also reduce costs and carbon emissions. Such resources fulfill a need for firm capacity that cannot be met by demand reduction programs and smart thermostats, while providing cost and emissions benefits over peaker alternatives. Additionally, diversifying the solutions utilized to alleviate capacity shortfalls will help ensure supply chain constraints do not prevent all of the capacity needed from coming on-line when needed.

VERIFICATION

I, Dr. Karl Meeusen, am authorized to make this verification on behalf of Wärtsilä North America, Inc. I declare under penalty of perjury that the statements in the foregoing Testimony and Proposals are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters, I believe them to be true.

Executed on September 1, 2021, at Annapolis, Maryland.

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APPENDIX A

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RELEVANT EXPERIENCE

WÄRTSILÄ NORTH AMERICA, INC.
Director – Markets, Legislative and Regulatory Policy (4/2021 to present)

- California-lead on the Path to 100% initiative, overseeing production simulation models and results to determine optimal decarbonization path for California's utility sector
- Represent Wärtsilä's Energy Business interests in federal and state regulatory matters and identifying and communicating the commercial, operational, and business process impacts of regulatory matters
- Coordinate with management to identify, strategically enhance and prioritize Wärtsilä's state regulatory and legislative efforts to enhance Wärtsilä's portfolio, while supporting project acquisition and diligence efforts as they arise
- Direct North America Market Development team identifying and communicating the commercial, operational, and business process impacts of regulatory matters

CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO)
Senior Advisor – Infrastructure and Regulatory Policy (12/2015 to 4/2021)

- Designed long-term vision, policy objectives, strategies, and proposals for Resource Adequacy including rules and metrics for determining sufficient capacity procurement
- Served as CAISO subject matter expert in regulatory proceedings and provided expert witness testimony on Resource Adequacy and Integrated Resource Planning
- Directed cross-departmental team and oversaw all public and regulatory processes that improved the accuracy of the compliance assessment of a settlement system that allocates $50 million of performance incentives annually
- Developed, facilitated, and led company-wide projects, initiatives, and regulatory filings on numerous topics, including Resource Adequacy, Integrated Resource Planning, transmission planning, and energy storage to ensure all proposed policy designs were implemented consistently with Federal Energy Regulatory Commission (FERC) tariff

Market Design and Regulatory Policy Lead (6/2011 to 12/2015)

- Successfully managed the first-ever flexible capacity procurement requirements for both the CAISO and California Public Utilities Commission (CPUC), including designing a flexible capacity product and proposal, developing regulatory strategy and outreach for federal, state, and municipal agencies, and directing the CAISO research teams
- Negotiated CAISO market design and regulatory policy agreements with municipal and investor-owned utility executives, CPUC commissioners and staff, thermal, renewable, and battery technology generation developers, and environmental groups
- Designed analytical models to determine operational requirements needed to meet state renewable resource integration goals and used results to support effective revisions to market design and infrastructure policies

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC)
Energy Advisor to Commissioner Michael Peevey, President (2/2010 to 6/2011)

- Provided strategic and technical advice to the commissioner on resource adequacy and energy procurement, rate design, demand response, smart grid, and energy storage
- Oversaw Commission proceedings and negotiations between CPUC Energy Division staff, parties to Commission proceedings, and members of the state legislature to ensure Commission objectives and timelines were achieved
- Wrote, edited, and modified rulings, proposed decisions, and alternate proposed decisions for Commission vote and implementation based on assessment of the record established in proceedings and consultations with the commissioner and administrative law judges

Senior Public Utilities Regulatory Analyst (8/2007 to 2/2010)

- Evaluated demand response programs and budgets filed by investor-owned utilities and provided recommendations to administrative law judges to determine if the proposed projects were cost effective, viable, and consistent with CPUC policy objectives
- Led FERC team analysis of the economic and policy implications of CAISO market design proposals, liaising with other Energy Division teams to develop consistent and functional CPUC positions on procurement programs in CAISO stakeholder processes, particularly around resource adequacy and demand response
- Negotiated and collaborated with CAISO staff and stakeholders, including investor-owned and municipal utilities, members of the generation community, and environmental groups, to create market enhancements that were consistent with CPUC programs
- Drafted and edited CPUC comments filed at CAISO and FERC

ELECTRICITY MARKETS RESEARCH CONSULTANT
Private Consultant (7/2005 to 8/2007)

- Produced reports for state public utility commissions and electricity trade organizations detailing the findings of market research
- Analyzed Public Utilities Regulatory Policies Act (PURPA) amendments of the Energy Policy Act of 2005 and produced guidelines for state commissions and industry trade groups
- Conducted primary research and analysis on U.S. wholesale electricity markets

NATIONAL REGULATORY RESEARCH INSTITUTE
Graduate Research Assistant (9/2002 to 12/2002; 6/2003 to 7/2005)

- Researched, generated, and edited reports for publication on market monitoring, resource adequacy, and Locational Marginal Pricing
- Performed statistical analysis of primary data from consumer benchmarking survey on utility quality of service
- Evaluated the public availability and accessibility of wholesale electricity markets and its usefulness in performing market analysis by state and local regulatory authorities

U.S. DEPARTMENT OF JUSTICE, ANTITRUST DIVISION, ECONOMIC ANALYSIS GROUP
Statistician and Research Assistant Coordinator (7/2000 to 8/2002)

- Managed staff of nine research assistants on economic analysis and litigation projects, assigning researchers specific duties based on individual skills and project requirements
- Coordinated with senior economists and attorneys to develop and implement litigation

strategies while directing research teams

- Identified relevant markets for utilities' mergers and performed statistical and econometric analyses including cost-benefit, regression, and unit competition analyses, as well as cost/fuel, load, and bid curves

EDUCATION

Doctor of Philosophy in Agricultural, Environmental, and Development Economics
The Ohio State University (12/2011)

Master of Arts in Economics
The Ohio State University (12/2003)

Bachelor of Science in Economics and Philosophy
State University of New York, College at Brockport (5/1998)

APPENDIX B

WÄRTSILÄ

Path to 100% Renewables for California

WÄRTSILÄ WHITE PAPER

Meeting California's goal of 100% renewable electricity by 2045 while also ensuring affordable and reliable power is a tremendous challenge. This white paper explores a new path that would enable California to meet its goal of 100% clean electricity by 2040 — five years ahead of schedule — slashing greenhouse gas emissions and air pollution along the way. Compared to current plans, this path optimizes the number of wind farms and solar installations built in the state, saving billions of dollars and alleviating land-use and grid construction pressures. The proposed pathway features flexible thermal generation that can run on carbon-neutral fuel produced with excess solar and wind energy. Together with energy storage, flexible generation can ensure affordable, reliable electricity supply and a net-zero-carbon future.

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Executive Summary

California has ambitious goals for decarbonization, including a Renewable Portfolio Standard (RPS) that relies heavily on solar, wind and battery storage. The RPS requires that by 2045 at least 60% of electricity will come from solar, wind and other carbon free sources, while the remainder can be supplied from carbon neutral sources. Yet the RPS still allows for fossil-thermal generation in 2045 and beyond to cover grid losses. This study explores an Optimal Path for California to decarbonize the electricity sector completely, and compares it to alternatives, including the current Integrated Resource Plan (IRP).

The Optimal Path builds out renewables and battery storage faster than the IRP, or California's Current Plan, and during the final years of the study period leverages power to gas (PtG) to produce renewable fuels using excess solar and wind energy that would otherwise be curtailed. As fossil fuels are phased out, thermal assets convert to renewable fuel to form a large, distributed long-term energy storage system with durations of weeks, not hours, providing seasonal balancing and security of supply during extreme weather events. Benefits of this approach include reaching RPS goals by 2040, five years ahead of schedule, and net-zero carbon by 2045. The Optimal Path leveraging power-to-methane is accompanied by the following features relative to the current (IRP) plan;

- Reach RPS target by 2040, and fully decarbonize by 2045
- 124 Million tons less CO2 emitted during 2020-2045
- 8 BUSD lower cost
- Significantly less NOx and particulate emissions (2020-2045)
- Requires 2/3 of the land for solar and wind development relative to the current RPS plan
- Allows for consideration of flexible thermal capacity today on a strategic basis, while respecting the falling share of fossil generation in accordance with the goals of decarbonization
- Enables closing of the OTC plants in 2023
- Avoids GW's of thermal capacity (and natural gas infrastructure) from becoming "climate stranded" while maintaining reliability in a cost-effective manner

An alternate Optimal Path was also considered leveraging power to hydrogen instead of methane. Many of the advantages listed for power to methane hold true for power to hydrogen. A hydrogen alternative has allure because it is truly carbon free, but still faces challenges. Challenges include lack of hydrogen infrastructure.

For the state of California to realize the benefits of power to gas as defined in this study the following policy recommendations are required;

- Formal recognition of all renewably sourced carbon-neutral and carbon-free fuels as "renewable fuels" for RPS compliance purposes (beyond just biofuels).
- Close OTC plants according to original retirement schedules (no extensions)
- Deployment of the optimal mix of new generation sources, described as the Optimal Path throughout the study, which includes solar, wind and energy storage as well as strategic amounts of fast-start flexible thermal generation (Table 5).

Introduction

California is a global leader in clean energy. Current plans include a renewable portfolio standard (RPS) that sets a 60% carbon-free target by 2030, then transitioning to 100% clean energy by 2045. The 2045 goal requires all MWh for retail sales within the state to be met with zero or net-zero carbon energy sources.

California (CA) has set ambitious goals but several key challenges exist that are addressed throughout this study. These challenges are primarily related to minimizing the cost of power while maintaining security of supply with the increased variability in energy production from clean energy sources such as solar, wind and hydro. California has amazing solar potential, but the solar output varies during the day and is zero at night. In order to maintain reliability through the coming years legacy thermal plants (once-through cooling, or OTC facilities) have already been given retirement extensions, allowing them to emit carbon beyond their original retirement dates.

Seasonally solar production is maximized in summer months and minimized in winter due to differences in solar intensity and day length. Wind in California also follows seasonal patterns with maximum output occurring in mid-year (Figure 1). Unlike solar, wind also generates at night. Hydro power is also available, but has seasonal patterns related to rainfall and is subject to multi-year patterns related to drought conditions (Figure 1).

California is reliant on these three dominant carbon-free energy sources (solar, wind, hydro) to meet it's clean energy targets, and must carefully consider how to build out its electrical system to optimize utilization of these resources, maintain reliability, and to minimize both cost and environmental impact along the way. Key to this process is the design and implementation of storage systems, both short-term and seasonal (e.g. Jenkins et al. 2018).

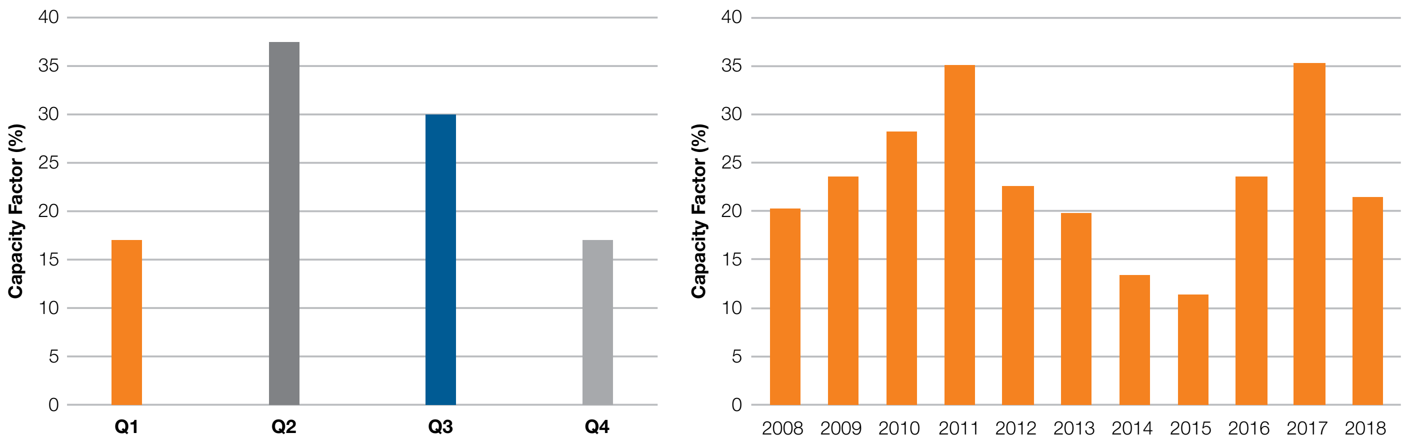

Figure 1. Wind capacity factors by quarter for California, left (CEC, 2019a), Annual California hydro capacity factor, right (CEC, 2020).

California hydro production is dependent on drought conditions. A multi-year drought left hydro production in 2015 at less than one third of peak year productions in 2011 and 2017. This emphasizes that the power system needs to be dimensioned so that it can handle these dry years.

This study compares three potential pathways for CA to meet its climate goals in the electric utility sector, with a focus on energy storage systems, cost and environmental impact.

The **first pathway**, called **Current Plan**, follows the existing Integrated Resource Plan (IRP) process through 2030 and extrapolates to 2045 under the assumptions and guidelines of the RPS (high electrification scenario). This pathway is heavy on solar and some wind, and traditional energy storage, and as per the RPS does not reach full carbon-neutrality by 2045. It does not reach carbon neutrality because the RPS allows fossil-generation to cover grid losses, which are approximately 8% of the total annual load for the state of California.

The **second pathway**, called **Optimal Path**, optimizes the entire system until 2045, and explores the power-to-gas (PtG) process as a long-term storage alternative, both power-to-methane (PtM) and power-to-hydrogen (PtH) - read more on this later in the Power-to-Gas section. The Optimal Path achieves RPS goals five years ahead of schedule (2040 instead of 2045) and reaches total carbon-neutrality by 2045.

In the **third** pathway called **Current Plan without Fossil Thermal,** California reaches carbon-neutrality by 2045 without any combustion of fuels other than biomass and biogas.

Following the current RPS, all scenarios ensure that by 2030 at least 60% of energy provided to consumers in California is carbon-free and provided directly by solar, wind and hydro.

Analytical Approach

This power system Study has been conducted utilizing PLEXOS® Energy Simulation Software. Plexos has a robust simulation capability across electric, water and gas systems focusing on full user control, transparency and accuracy across numerous constraints and uncertainties. This software is widely used by system operators (including CAISO), utilities and consultants for power system analysis as well as system planning and dispatch optimization.

Plexos is capable of long-term capacity expansion optimization applied in this study. Capacity expansion models find the least cost generation capacity mix for a power system for the future. That is, the software selects the best fit technologies among the given candidates to satisfy the future electricity demand while respecting real-life constraints related to power plant operations and transmission. To properly calculate costs and emissions, the software solves the hourly dispatch of power plants throughout the studied period while making new capacity additions.

The model used in this study is based on the Plexos model used by the California Independent System Operator (CAISO) and Western Electricity Coordinating Council (WECC) to support the 2019 IRP as well as the IRP 2019 modelling datasets (CPUC 2019a, b). These sources provide necessary inputs for the expansion optimization, including existing generation capacity with their parametrization, system demand now and in the future as well as financial inputs from fuel prices to the investment cost of new generation capacity.

The modelled power system covers California, North-West (Oregon, Washington, Idaho etc.) region, and South-West (Arizona, Nevada, New Mexico etc.) region, with their load, generation capacity and transmission constraints being accounted for between the regions. The neighbouring states are important to incorporate in the model because of California's dependency on imported electricity. More information regarding demand and capacity can be found in the Appendix.

The software can select new generation capacity additions from several potential technologies during the expansion optimization. These include solar, wind, biomass, geothermal, Reciprocating Engines, Gas Turbines (GT), Combine Cycle Gas Turbine (CCGT), Lithium-Ion storage, pumped hydro, and Power to Gas (PtG) fuel synthesis systems. Performance, cost and parameterization of all potential new-build decisions are presented in the Appendix.

This expansion optimization approach was applied to all studied future scenarios. Each scenario was modelled across a 25-year horizon by explicitly solving 2022, 2026, 2030, 2035, 2040 and 2045 dispatch. The model optimizes the capacity needed and the power system operation for these years. Selecting specific model years as opposed to every year across the horizon made the simulation tractable, while within each year the model was run at two-hour time resolution.

For accurate insights in California, the reported results are isolated for the state of California even though the neighbour states were also modelled and optimized. Results include capacity additions, costs, generation across all fuel classes, overgeneration or curtailed renewable energy, CO_2 emissions, other air pollutant emissions such as NO_X and particulates, and land-use.

NEIGHBOURING STATES HAVE RENEWABLE TARGETS OF THEIR OWN

At present California is reliant on neighbouring states for approximately 32% of all electricity used by Californians (CEC, 2019b). Neighbouring states can absorb excess energy (overgeneration) from Californian renewable energy sources (RES) such as wind and solar and provide needed flexibility to California via the Energy Imbalance Market (EIM). Questions arise over the ability and willingness of neighbours to provide this flexibility service when they are all moving towards similar RPS standards as California (Figure 2). In this study it was assumed that all the neighbouring states would decarbonize their power systems by 2045 and thereby large quantities of fossil fuel based balancing power would not be available for California from them.

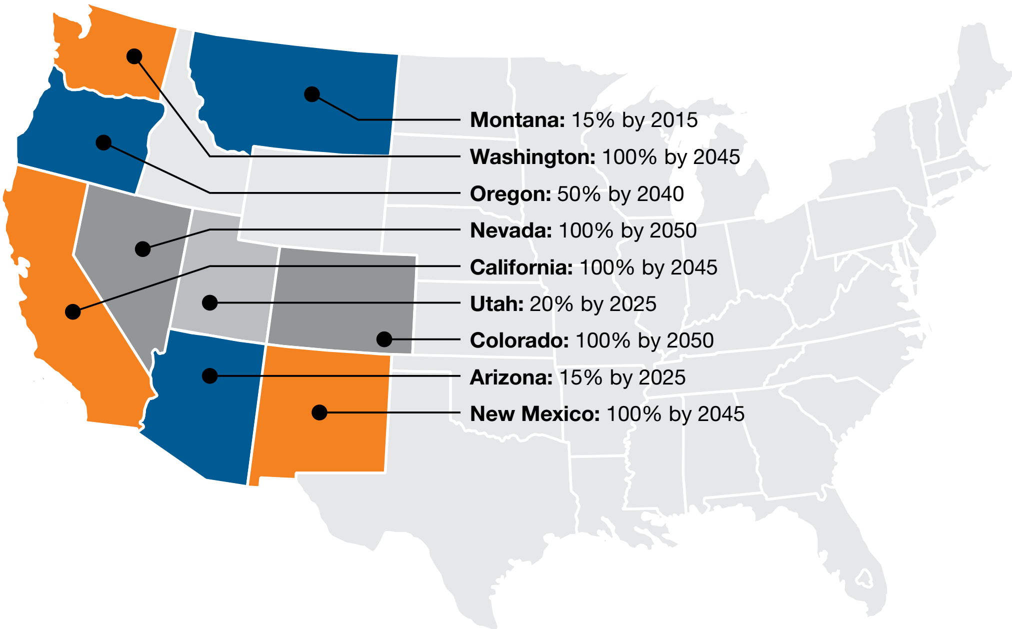

Figure 2. Current clean energy targets for States in the Western United States. These are expected to continue to become more and more stringent.

Summary of Scenarios

The scenarios – or pathways – are summarized in Table 1

	Current Plan – the state's current plan	Optimal Path	Current Plan without Fossil Thermal
Full RPS compliance date	2045	2040	2045
Fossil fuels in use after 2045?	Yes	No	No
Net-Zero carbon by 2045?	No	Yes	Yes
OTC retirement date extensions?	Yes	No	Yes
Thermal investments limited	Yes (selected OTC capacity replacement with thermal and peakers for firm capacity)	No (thermal added as per system optimization but still respecting other RPS constraints)	Yes (selected OTC capacity replacement with thermal and peakers for firm capacity). No fossil fuel thermal allowed in 2045
Existing CCGTs retire at the age of 35 years	Yes	Yes	Yes

Table 1. Main features of the scenarios.

Power-to-Gas (Power-to-Methane, PtM)

Unique to the Optimal Path (Table 1) is allowance for power-to-gas (PtG), which here is defined as the process of using excess RES energy, MWh that would otherwise be curtailed, to produce renewable fuels. The first such fuel to consider is methane, produced through the power-to-methane, or PtM process. PtM produces carbon-neutral CH4 (methane) via a three-step process.

1. Direct Air Capture (DAC) of CO_2 from the atmosphere as a source of carbon
2. Electrolysis of water as a source of hydrogen
3. Methanation to combine carbon and hydrogen into CH4

The final molecule, CH4 (methane) can be stored and transported in existing natural gas infrastructure and used in households, industries and power plants by any thermal technology that can burn natural gas. Carbon is recycled from air, so combustion of PtG methane is net-zero, or carbon-neutral, with no increase in atmospheric CO_2 levels.

While PtM, or power to fuels in general, is not currently used at mass-scale, they are a major avenue for deep decarbonization, particularly in the transportation sector. The processes of electrolysis and methanation are decades old technologies with numerous commercial applications. Direct air capture (DAC) of carbon is the newest technology involved with the PtG process, with several large-scale projects under development. For example Carbon Recycling International is developing a large DAC facility in China that will produce 180,000 tons per year of liquefied natural gas (LNG) and methanol (Carbon Recyling International, 2019). Carbon Engineering is actively developing a 1 million ton per year DAC carbon capture plant in Texas for enhanced oil recovery, where CO_2 taken from the air will be pumped into the ground for permanent sequestration, and help to enhance oil production (Rathi, 2019). The California Low Carbon Fuel Standard (LCFS) was amended in 2019 to include DAC, allowing companies to net carbon sequestered from air from the carbon footprint of fuels sold into the California market.

Power-to-Gas (Power-to-Hydrogen, PtH)

Power-to-hydrogen is an alternate PtG pathway. Power-to-hydrogen requires only electrolysis, where electrolyzers use excess renewable energy to produce hydrogen (from water) for direct use as a fuel. Hydrogen production with PtH is less expensive than PtM and more efficient as there is no need for carbon DAC or methanation. In addition, hydrogen as a fuel is carbon free. Complexities arise as there is, unlike the existing infrastructure for methane, no comparable hydrogen infrastructure. Thermal power plants designed to burn methane typically cannot burn 100% hydrogen. Existing gas storage facilities, pipelines, compressor stations and distribution lines typically cannot handle 100% hydrogen without expensive upgrades, if not complete replacement. Still, hydrogen is an efficient and carbon-free alternative to renewable synthetic hydrocarbons and is worth investigating. Power plant technology manufacturers seem to understand this as many of them are in the process of developing technologies that are fuelled by 100% hydrogen.

Why Power-to-Gas?

Renewable fuels from PtM or PtH processes are not economic relative to low-cost fossil fuels prevalent in the United States. However, in a 100% carbon-neutral power system, where fossil fuels are banned, PtG and its use in existing or new built thermal power plants is considered a form of long-term storage (e.g., (Blanco & Faaj, 2018)). The thermal fleet coupled with gas storage and delivery systems becomes a gigantic distributed "battery". Fuel produced by PtG can be stored indefinitely and is the equivalent of fully charged "cells" in a Li-Ion battery storage system. Thermal power plants become the "inverters", taking stored renewable energy and converting it to MWh. In power system operations renewable energy will serve the majority of load, traditional storage (e.g., batteries) will handle day to day balancing, and PtG coupled with the thermal fleet provides longer term balancing (e.g., seasonal) and reliability (e.g., generating MWh when unforeseen weather leads to days or weeks of little to no solar that cannot be managed with traditional, shorter term storage).

Scenario findings

The first portion of findings will observe and compare the results of California's Current Plan and the Plexos optimized Optimal Path for the state. The third scenario, Current Plan without Fossil Thermal, is further studied in a separate section.

Optimal Path minimizes capacity buildout

"Our grid needs to go on a diet and get leaner and greener" - NRDC (Chen, 2017)

The installed generation and storage capacity for California is depicted in Figure 3 for the Current Plan and the Optimal Paths. All three scenarios meet the RPS target of 60% energy from clean energy sources by 2030 and meet load and other requirements of the High Electrification scenario all through the period. Old CCGT´s retire at age of 35. For the Current Plan the capacity additions are mainly solar and battery storage, although wind and small amounts of geothermal and biomass are added as well.

The Current Plan requires 263 GW of capacity in 2045 while in the Optimal Paths with PtM and PtH require 237 and 231 GW of capacity respectively. (Figure 3). The Optimal PtH pathway installs almost twice as much power to gas capacity than the PtM pathway, an artefact of PtH production capacity being less expensive, and the PtH fuel production being more efficient than PtM.

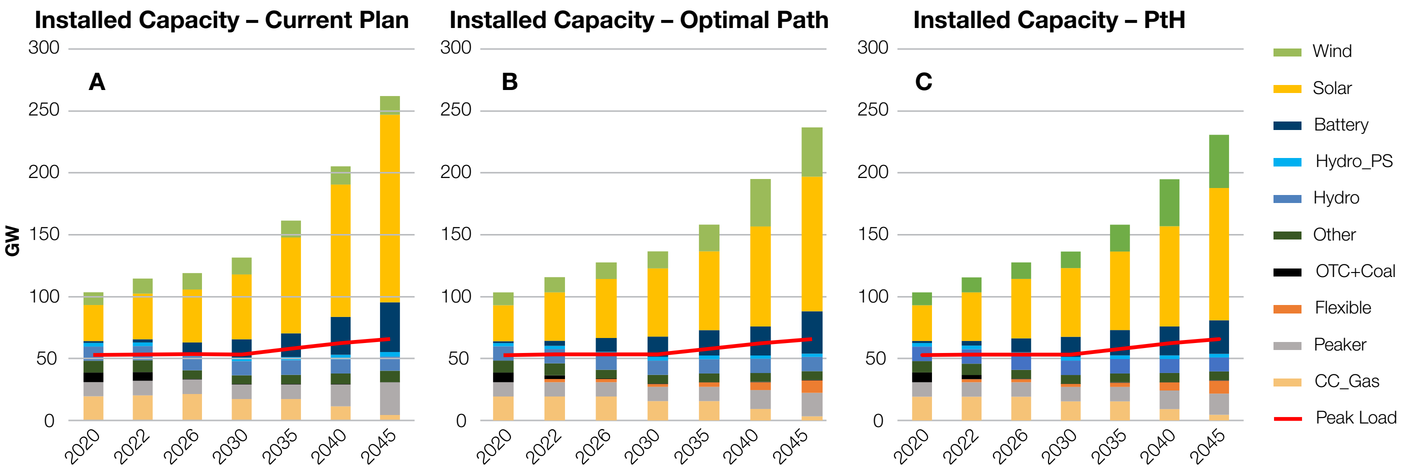

Figure 3. Capacity mix for Current Plan (A), Optimal Path PtM (B) and PtH (C) 2020-2045.

Optimal Path minimizes carbon emissions and reaches net-zero by 2045

"The report finds that limiting global warming to 1.5°C would require…'net zero' around 2050." (The Intergovernmental Panel on Climate Change, 2018)

The Optimal Path has a reduced carbon footprint across the entire horizon relative to the Current Plan (Figure 4). This is due to OTC retirements occurring on schedule (no delays) and earlier replacement of inefficient, inflexible thermal capacity with a wider array of clean energy sources, storage and flexible thermal. The addition of greater amounts of wind in the Optimal Path (Figure 3B & 3C vs. 3A) also allows for additional renewable generation at night, displacing MWh that would otherwise be generated with thermal in the Current Plan.

In the Optimal Path carbon emissions reach net-zero in 2045, while the Current Plan does not reach zero at all (as per the IRP). This is because the IRP allows for grid losses to be produced with fossil fuels even in 2045. The cumulative carbon reduction with the Optimal Path, using either PtM or PtH, is approximately 125 million tons of CO_2 (Figure 4) compared to the Current Plan, corresponding to annual equivalent CO_2 emissions of approximately 27,000,000 cars (assuming 4.6 tons per year of CO_2 from a vehicle as per the EPA, 2020a)

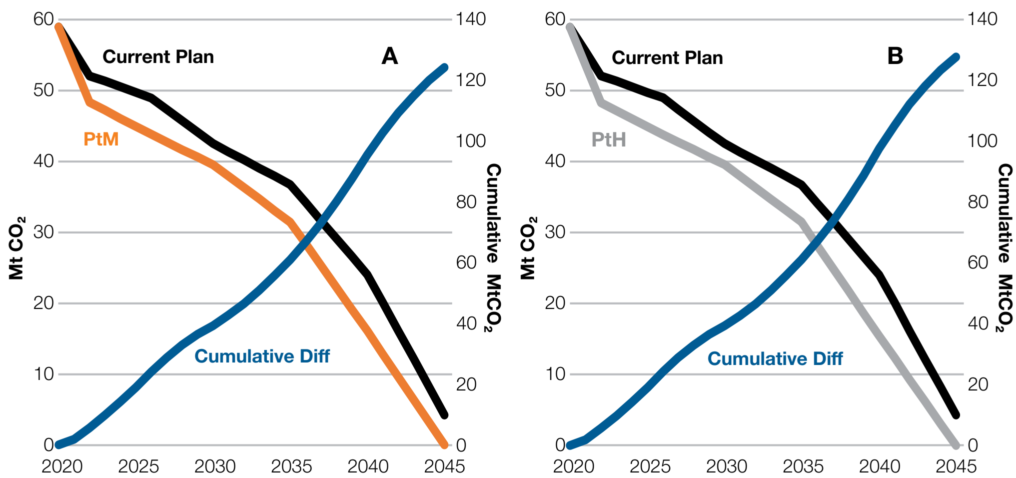

Figure 4. Annual CO_2 emissions for Current Plan and Optimal Path PtM (A) and PtH (B) across 2020-2045, and the cumulative emissions savings with Optimal Path.

Optimal Path minimizes emissions of NO_X and Particulates

"NO_2 along with other NO_X reacts with other chemicals in the air to form both particulate matter and ozone. Both of these are also harmful when inhaled due to effects on the respiratory system." US EPA (2020b)

Fuel combustion emits hazardous pollutants independent of CO_2 generation. To that end it is of interest to understand the contribution of PtG in 2045 in the Optimal Path to emissions of Nitrogen Oxides (NO_X) and particulate matter (PM10), and to explore the trajectories of these emissions across scenarios.

Annual flow rates were calculated using thermal generation (MWh by year) and the following rates on a "per MWh" basis for modern gas plants.

NO_X (as NO_2) 0.08 Lb/MWh

PM10 0.10 Lb/MWh

These values are indicative of gas generation in general and not meant to represent any specific technology.

All pollutants in 2045 are significantly reduced relative to 2020 (Figure 5). In both the Current Plan and Optimal Path thermal generation is all gas and provides less than 10% of all electricity in 2045. Current Plan NO_X and PM10 levels are reduced by 86% relative to 2020 levels. In comparison the Optimal Path levels are reduced 82% relative to 2020 levels. The emissions reductions are similar except for one major difference: The Optimal Path is net-zero carbon and in compliance with IPCC recommendations related to climate change in 2045, the Current Plan is not.

Values in Figure 5 are for the PtM pathway but are assumed similar for the PtH pathway. A lack of publicly available emission rates from CTs or ICEs on 100% hydrogen makes calculation difficult, but hydrogen burns hotter than CH4 and produces greater amounts of NO_X per unit of fuel burned. Therefore, the values presented for PtH pathway are assumed at a minimum to be similar to that from PtM.

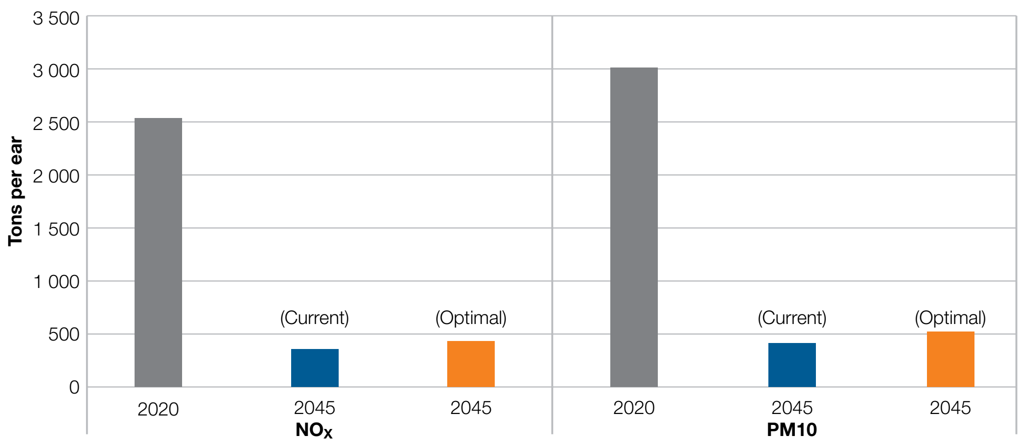

Figure 5. NO_X and PM10 emission rates (metric tons/year) in 2020 and 2045 for Current Plan and Optimal Path.

Optimal Path minimizes curtailment of solar and wind

"Solar and wind developers need to be able to sell nearly all the electricity they produce to repay their investors and make money."- NRDC (Kwatra, 2018)

A major difference between the Current Plan and Optimal Path is a dramatic reduction in curtailment of solar and wind across the horizon and in particular at the end of the period when the Optimal Path becomes 100% carbon-neutral (Figure 6). In the middle phase of the transition, more flexible thermal capacity is available in the Optimal Path to support renewables and to reduce curtailment. Towards the end of the horizon (2045) the PtG capacity acts as additional load to be served specifically by over-generation of solar and wind. Therefore, by design the Optimal Path maximises the use of renewables.

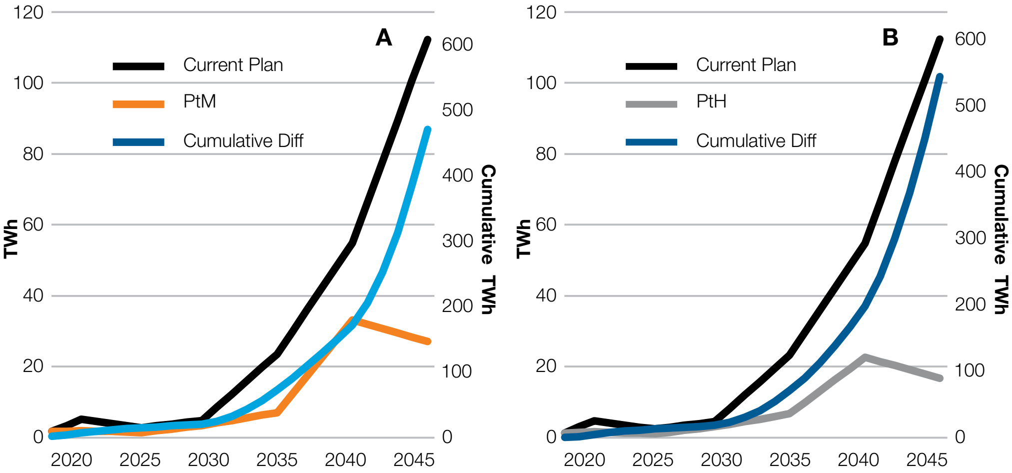

Figure 6. Annual curtailment (overgeneration) of solar and wind for the Current Plan and Optimal Path (left scales), and cumulative difference of curtailment (right scales), for PtG (A) and PtH (B).

Optimal Path minimizes land use

"Habitat loss—due to destruction, fragmentation, or degradation of habitat—is the primary threat to the survival of wildlife in the United States." (National Wildlife Federation, 2020)

Deep decarbonization by necessity means large volumes of solar and wind capacity to provide energy, either directly or indirectly through storage mechanisms. Solar and wind, however, require a lot of land. Solar on average needs approximately 5 acres per MW (Green Coast, 2019) while wind requires roughly 0.75 acres per MW (Gaughan, 2018). Every solar or wind project will have to undergo rigorous environmental impact assessments, permitting and grid connection. The more sites and land needed for renewable development, the greater the risk of delays. The Optimal Path using either PtM or PtH requires approximately 300 square miles less land for renewable development (Table 2).

	Optimal Path PtM	Optimal Path PtH	Current Plan
GW Solar (Residential)	34	34	34
GW Utility-Scale Solar	76	73	118
GW Wind	40	43	16
Land Use (Utility-Scale Solar), sq. miles	594	570	922
Land Use (Wind), sq. miles	47	50	19
Total Land Use utility-scale solar & wind (sq. miles)	641	621	941
Additional Land needed vs Optimal Path	-300	-320	

Table 2. Calculated land use for the Optimal Path and Current Plan.

Optimal Path minimizes total cost to decarbonize the electric utility sector in California

"Californians are paying Billions for power they don't need" - LA Times (Penn & Menezes, 2017)

At present Californians pay some of the highest prices for electricity in the nation (Daniels, 2017). As California moves towards aggressive decarbonization, the state faces the challenge of doing so in the most cost-effective manner. As with any optimization problem, adding more choices, or more degrees of freedom, often results in better solutions than those obtained with a narrower range of choices. The results for the Optimal Path and especially the introduction of PtG demonstrate this concept, as the Optimal Path allows the simulation to unlock the value of thermal capacity in a 100% carbon-neutral future. The Optimal Path PtM provides lower cost than the Current Plan across the horizon 2020-2045 (Figure 7), yielding a net savings of 8 Billion USD. The Optimal Path PtH provides initial savings but then added costs towards 2045 as all thermal capacity in CA must be retired and replaced with new capacity capable of burning 100% hydrogen, in order to be in line with CA clean energy goals. Total saving is however 3 Billion USD compared to Current Plan, excluding the cost of the hydrogen grid.

Total generation cost includes OpEx (fuel and other variable costs), CapEx (capital costs and other fixed costs), interchange costs (costs of purchased imports, revenues from exports, and associated wheeling charges), and estimated transmission expansion costs. The costs do not include any carbon taxes. In the year 2045, the levelized cost of electricity for the Optimal Path is 50 $/MWh (PtM) and 54 $/MWh (PtH), in comparison to 51 $/MWh for the Current Plan. Note: CapEx of the existing power system (in 2020) is not included, but CapEx of all new plants installed during the period is included. This gives a false impression of costs increasing rapidly.

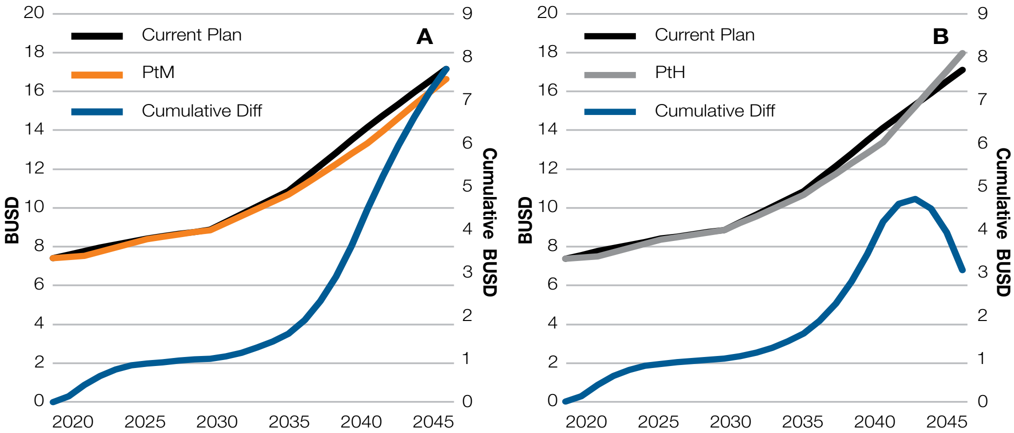

Figure 7. Annual total generation cost of Optimal Path and Current Plan, and cumulative savings of Optimal Path versus Current Plan via PtM (A) and PtH (B). Note: 2020 cost is only OpEx while the cost after 2020 includes both CapEx and OpEx of the new investments.

Optimal Path maximizes storage capacity through use of power-to-gas

"The optimised mix of short-term battery storage and long-term power-to-gas (PtG) storage leads to the least cost system solution for 100% RE" (Breyer, Fasihi, & Aghahosseini, 2019)

The major differentiating factor of the Optimal Path is the use of PtG as a long-term storage, to manage weather periods during which solar, wind and possibly hydro output are out of phase with demand. Traditional energy storage systems, ranging from Li-Ion batteries to pumped hydro, rarely exceed durations of 12 hours while seasonal weather-related events in renewable dominated systems can easily lead to far longer periods of diminished renewable outputs. Storage must cover the differences, and a diversified portfolio of storage optimized for different timescales is an optimal choice as shown in the cost, carbon trajectory and land use considerations outlined in previous sections.

Some advocate for pumped hydro as a long-term storage solution. Pumped hydro was included as a capacity choice in the simulations that the model could choose if it was an optimal candidate for new-build. Price and performance for pumped hydro was provided by the IRP documentation. Across all four scenarios pumped hydro was installed between 285 GWh (same in optimal path PtM and PtH pathways) and 333 GWh (Current plan without thermal). Therefore, pumped hydro is included as new build capacity in all scenarios. However, in the current plan without thermal, the majority of energy storage selected by the model was battery storage (1624 GWh). This is due to batteries having a lower cost ($/kW) and higher round trip efficiency than pumped hydro. For the Optimal path (both PtM and PtH) the model selects renewable fuels as the preferred long-term storage option.

POWER-TO-GAS PRODUCTION AND USE IN OPTIMAL PATH

Throughout the year excessive wind and solar electricity is used to power the direct air capture (DAC), electrolysis and methanation (collectively "PtM") for production of renewable methane. Production is maximized in mid-year when solar and wind outputs typically peak. Thermal generation using this carbon-neutral fuel is used mostly in the winter months (December through February) with some sporadic generation in late summer and fall (Figure 8). The renewable gas storage (Figure 8) is charged with gas during spring and early summer to provide fuel for fall (Sept-October) and winter (Dec through Feb) carbon-neutral thermal generation.

The renewable capacity and PtG process are dimensioned so that enough carbon neutral fuel can be produced for Californian power system annual needs. In the Optimal Path California is therefore self-sufficient on carbon neutral fuel for power system balancing.

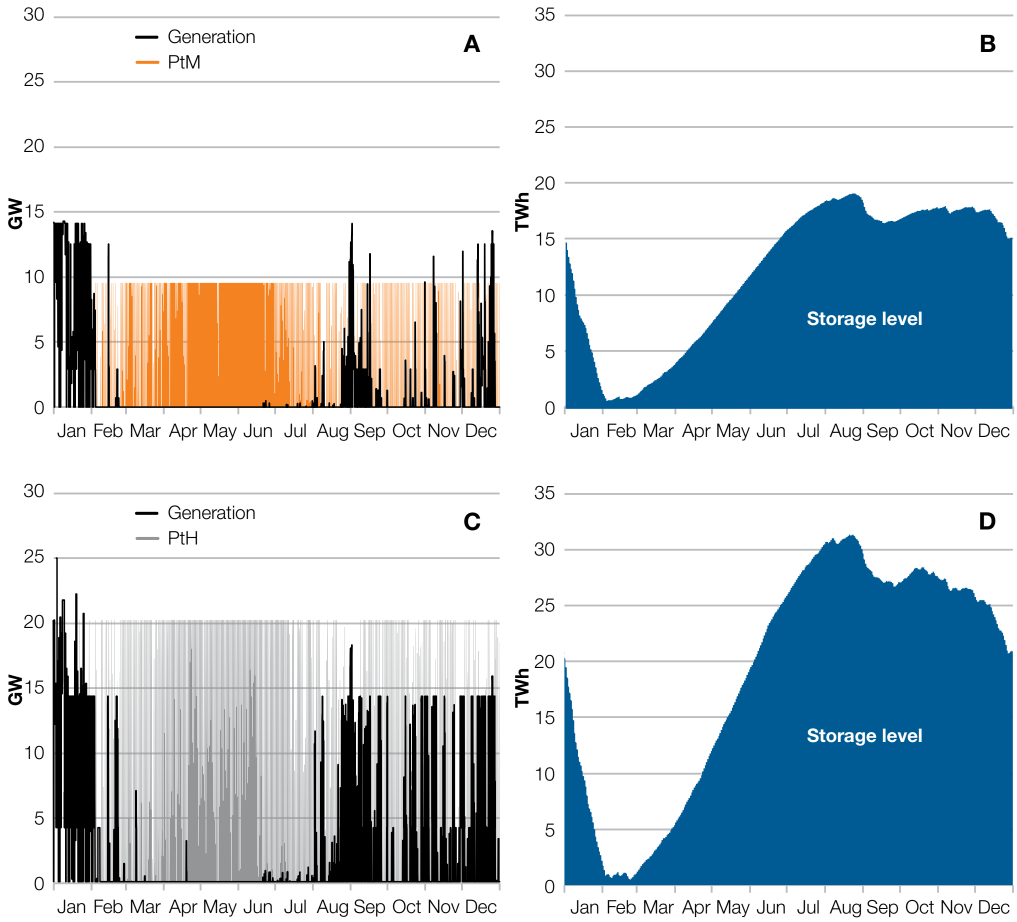

Figure 8. Power-to-gas (PtG) utilization in 2045, Optimal Path. Annual hourly thermal generation and electricity consumption (GW) of PtM and PtH (panels A & C respectively); Annual storage levels of renewable gas from PtM and PtH (Panels B & D respectively).

RENEWABLE GAS VOLUMES RELATIVE TO EXISTING UNDERGROUND GAS STORAGE FACILITIES IN CALIFORNIA

The simulation model could generate and store renewable methane without any limitations. Results (Figure 8 A, B) showed a difference between upper and lower bounds of gas volumes in the storage to be approximately 18 TWhfuel which is equivalent to 61 billion cubic feet of gas. The underground gas storage capacity serving California, as of 2017, consisted of 12 facilities with a total capacity just shy of 400 billion cubic feet of gas, designed to store methane "over daily to seasonal time scales" (California Council on Science and Technology, 2018). Therefore, under the Optimal PtM pathway the renewable methane capacity required for 100% carbon-neutrality would use roughly 15% of existing long-term underground gas storage capacity in the state. Hydrogen storage (TWh) is approximately 80% greater than methane by volume (Figure 8 D vs B) and should also fit within the underground storage capacity in the state of California, but further research is needed to determine if these chambers can safely store hydrogen. Even if they can store hydrogen there is a lack of infrastructure (pipelines) to convey this fuel to distributed generation assets.

RENEWABLE GAS AND EXISTING THERMAL AS LONG-TERM ENERGY STORAGE

In 2045 in the Optimal Path, the accumulation of methane through the PtM process across the spring/summer months leads to an 18 TWh "bank" of stored, renewable energy (Figure 8B). Assuming a generic thermal plant heat rate of 8 MBtu/MWh (42.5% efficiency), 18 TWhfuel x 42.5% = 7.65 TWhelectric. That is, the 32 GW of thermal capacity installed in California in 2045 in the Optimal Path PtM would be able to generate 7,650 GWh of electricity, giving a full power duration of approximately 240 hours (10 days). The amount of stored hydrogen in Optimal Path PtH is 32 TWh

(Figure 8D), 80% greater than the TWh in Optimal Path PtM. Therefore, the same 32GW of installed thermal capacity using hydrogen would have a duration of approximately 18 days.

The PtM fuel storage need is approximately 15% of the total underground gas storage in California, or rather the existing storage capacity is 6.7 times greater than the fuel volumes needed for the Optimal Path. If the existing underground gas storage capacity in California was filled with renewable gas from the PtG process, the 32 GW x 240 hours would instead have a duration of 1,600 hours (67 days). There is potential for California to optimize stored gas volumes for reliability purposes. Similar can be envisioned for hydrogen, assuming hydrogen infrastructure is in place to move hydrogen from storage facilities to power plants.

Overall the combination of long-term renewable carbon neutral fuel storage coupled with thermal capacity has direct parallels with battery storage (Figure 9).

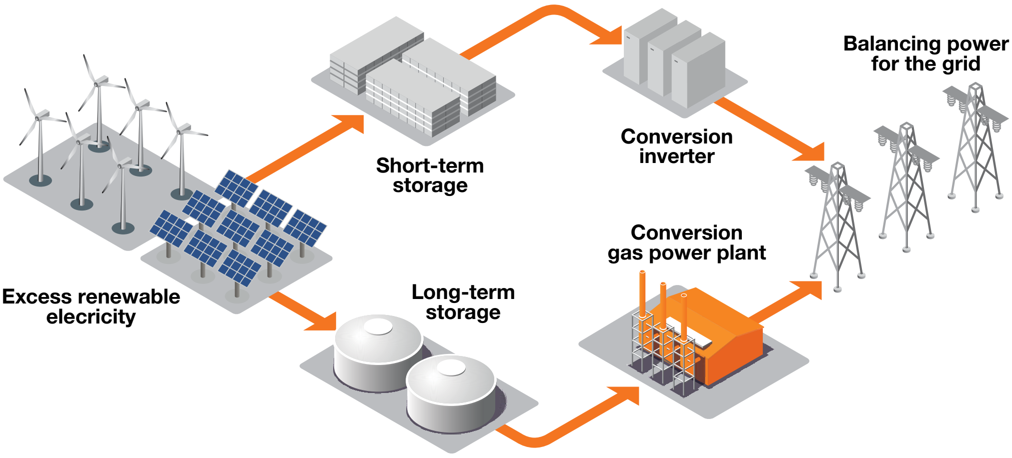

Figure 9. Renewable energy can be stored in short term batteries or converted to renewable PtG fuels for long term storage.

THERMAL GENERATION IN 2045

In 2045 in the Optimal Path, gas-fired generation remains in the system but operates in short bursts using renewable fuels. This capacity not only acts as long-term energy storage but also provides flexibility and firm capacity. The contribution to system reliability is an essential role for this capacity minimizing overbuild of wind, solar and battery storage (which all have low effective load carrying capabilities).

The gas-fired capacity and the electricity generation is presented in Table 3A for the Optimal Path PtM. There are three types of gas capacity in the system. Firstly, some older inflexible CCGTs that provide electricity for longer stretches during low renewable winter months. Keeping these older assets in the systems makes sense as permitting new ones can be challenging and the cost of building new ones is relatively high. Secondly, peakers, mostly simple cycle CTs, which ensure adequate firm capacity for system reliability, but rarely operate due to their poor efficiency. Thirdly, flexible gas fired generation participates in daily and seasonal renewable balancing while providing firm capacity for system reliability. Flexible gas generation is here considered as medium speed reciprocating engines, which have start times of 1 to 5 minutes, minimum down times of 5 minutes and no restrictions on minimum run time, and unlimited starts per day with no maintenance penalties. Combined with high efficiency (heat rates on the order of 8000 Btu/kWh), flexible thermal generation can provide balancing power as needed with the least amount of operational restrictions relative to any other form of thermal capacity. Similar trends are shown for the Optimal Path PtH case (Table 3B), only the capacity factor of CCGTs and flexible generation are increased due to the lower cost of synthetic renewable hydrogen versus methane (both in terms of capital cost to install hydrogen production assets, and the higher efficiency of electrolysis alone versus that of electrolysis plus DAC and methanation).

	CCGT	Peaker	Flexible
Generation GWh	4698	593	6716
Installed Capacity MW	3168	19075	10143
Capacity Factor %	16.9	0.4	7.6

Table 3A. Methane thermal capacity operational data for Optimal Path in 2045.

	CCGT	Peaker	Flexible
Generation GWh	9906	1573	11101
Installed Capacity MW	4504	17193	10606
Capacity Factor %	25.1	1.0	11.9

Table 3B. Hydrogen thermal capacity operational data for Optimal Path in 2045.

Current Plan without Fossil Thermal

The final studied scenario assumes that fossil gas-fired generation is forbidden and must retire from the system by 2045. This is an alternative way to decarbonize the system instead of using PtG, and currently the mainstream political approach in many areas, including California. Furthermore, one should note that the fossil gas-fired capacity cannot be retained for reliability purposes in this case as there is no acceptable fuel available.

The installed capacity for 2045 is depicted in Figure 10 together with the Current Plan and Optimal Path. Removing gas-fired capacity from Current Plan leads to major battery storage additions that are needed for two purposes: to provide long-term storage and to maintain system capacity reserve margins for security of supply. As battery storage is added to the system it initially has high effective load carrying capability (ELCC). When battery storage capacity exceeds 50% of the peak load it flattens net load peaks cross longer durations, in which case it is difficult to ensure every storage device is fully charged at critical peak times with enough duration to sustain the peak. As more storage is added to the system, it's marginal ELCC is reduced, leading to much larger storage for provision of adequate capacity margin.

This scenario is relying on solar and battery storage, both heavily overbuilt, in order to provide security of supply during all types of weather conditions. Much of the storage capacity is added for ensuring system reliability. The capacity factor of storage is 3% versus 17% and 15% for the Optimal Path with PtM and Current Plan respectively. Consequently, the generation cost of the system increases dramatically: the levelized cost of electricity in 2045 is 128 USD/MWh, which is more than double compared to the Current Plan and the Optimal Path. Nevertheless, the system reaches zero carbon in 2045 by utilizing mainly solar and batteries, so it is technically possible. Other studies have reported that complete removal of thermal capacity in California would lead to dramatic cost increases (Energy and Environmental Economics, Inc., 2019).

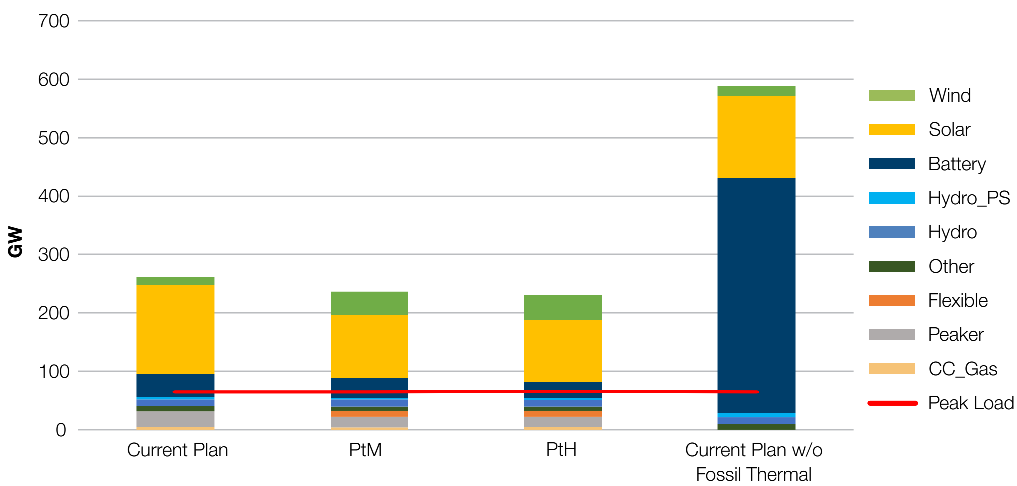

Figure 10. Installed capacity in 2045 for all scenarios. Note: the necessary overbuilding of battery storage if thermal generation is banned from the system.

Optimal Path maximizes generation from carbon-free sources

The generation by technology type for each scenario is presented in Figure 11, including the generation of storages and electricity exchange with other states. The total load includes state-wide electricity demand with grid losses, as well as pump & battery storage charging and PtG loads with their losses. Thus, this graph shows the annual generation balance.

The figure also depicts the actual Californian electricity demand, including the state-wide electricity demand and storage and PtG losses. In 2045, electricity demand is higher in the Optimal Path as the PtG process consumes electricity. Excess renewable energy that would have been curtailed in the alternate scenarios is utilized by the PtG process and stored as long-term energy in the form of fuel. Figure 11 clearly indicates how the Optimal Path has a greater diversity of energy sources, and the fact that the thermal power plants do not run much but enable construction of a smaller and more efficient power system.

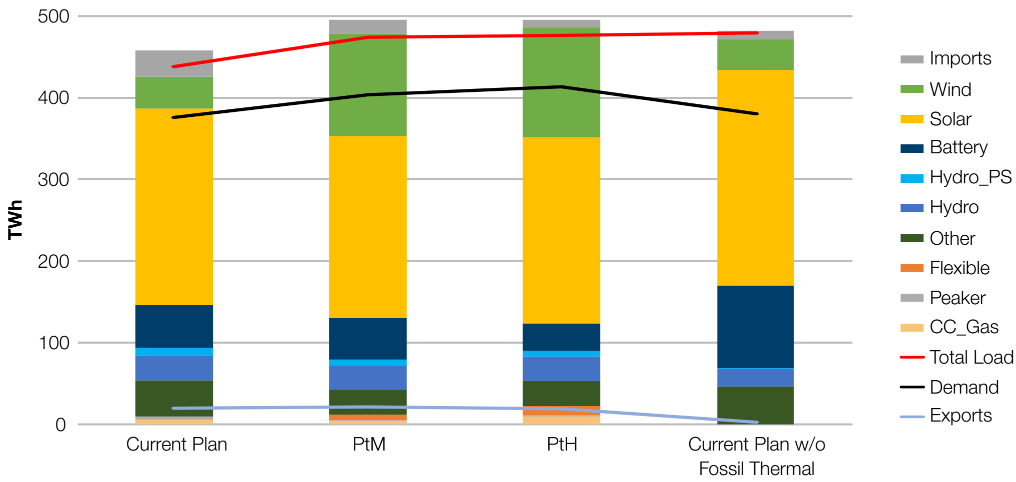

Figure 11. Generation (TWh) in 2045 for the scenarios.

Summary and Final Recommendations

California is leading the world in environmental stewardship by embarking on an aggressive path of decarbonization. Decarbonizing the electric power sector will require new ways of thinking and new approaches to simultaneously meet carbon goals and minimize land use, emissions and cost. The California IRP meets some but not all these goals. Through consideration of carbon-neutral pathways utilizing renewable power to gas, this analysis shows that net-zero carbon can be reached by 2045 while simultaneously minimizing land use, emissions and costs (Table 4).

		Optimal Path		Current Plan	
		PtM	PtH	IRP	w/o Fossil Thermal
Capacity	GW Solar	109	107	152	141
	GW Wind	40	43	15	16
	GW Storage	37	30	44	410
	GW Thermal Old	14	0	14	0
	GW Thermal New	18	32	17	0
	GW Other	7	7	9	9
	GW Hydro	12	12	12	12
	Total GW (Capacity)	**237**	**231**	**263**	**588**
	PtM GW (load)	**10**	**0**	**0**	**0**
	PtH GW (load)	**0**	**20**	**0**	**0**
Storage	GWh Pumped Hydro	285	285	326	333
	GWh Batteries	158	108	189	1624
	GWh Renewable Fuels	7650	13 617	0	0
	Total GWh storage in system	**8093**	**14 010**	**515**	**1957**
Curtailment	Curtailed Wind (TWh)	4	4	4	7
	Curtailed Solar (TWh)	23	13	108	61
	Total Curtailment (TWh)	**27**	**17**	**112**	**68**
Carbon	Mton (2020-2045)	824	820	948	935
	Mton CO_2 in 2045	0	0	4	0
Cost	**2045 Energy Cost ($/MWh)**	**50**	**54**	**51**	**128**
Land	Land for Utility-Scale Solar (Sq. miles)	594	570	922	806
	Land for Wind (Sq. miles)	47	50	19	18
	Land needed for Solar & Wind (Sq. miles)	**641**	**620**	**941**	**824**

Table 4. Summary of results from scenarios.

THE OPTIMAL PATHWAY EXHIBITS THE FOLLOWING FEATURES:

The Optimal Pathway (both PtM and PtH) have the following common attributes;

- Meets current RPS compliance 5 years ahead of schedule and full net-zero compliance in 2045
- Enables closure of OTC plants by 2023
- Minimizes cumulative CO2 emissions between now and 2045
- Minimizes the needs to permit and build new grid connections to renewable generation sites
- Reduce land use requirements for renewable development by hundreds of square miles
- Dramatically reduce solar & wind curtailment and maximize value of renewables
- Maximizes reliability by providing weeks of long-term energy storage

In both the PtM and PtH pathways early closure of the OTC plants allows for early installation of more than 10 GW each of solar and battery storage, supplemented by approximately 2.5 GW of flexible thermal. This ensemble of flexible capacity and carbon-free solar provides a greater carbon reduction across the whole modelling horizon as well as lower cost than the current IRP plan.

The PtM pathway provides 8 BUSD savings over the Current Plan and uses off the shelf technology for power generation. Flexible thermal can be installed as needed without fear of the assets being stranded in 2045, as they can transition at any time from fossil gas to renewably sourced methane from the PtM process. The PtM pathway leverages existing gas storage and pipeline/distribution systems, and provides for 8 TWh of reliable, fully dispatchable renewable energy storage. The Optimal Pathway with PtM reaches true carbon-neutrality for the state of California by 2045.

The Optimal PtH pathway has allure because hydrogen production is more efficient than PtM and hydrogen fuel is truly carbon free. The results indicate greater energy storage potential with hydrogen relative to methane and a 3 BUSD savings over the Current Plan. The savings are reduced relative to PtM because all thermal generation installed in CA to run on gas (methane) must be retired and replaced with all new thermal generation designed to burn 100% hydrogen. The costs/savings reported for PtH do not include the cost of modification of existing gas infrastructure or the need for new build hydrogen infrastructure such as pipelines, compressor stations and distribution systems needed to support hydrogen power generation.

The path to the decarbonized power system for California in 2045 is dependent on decisions made now. For example, the passage of Senate Bill (SB) 100 that led to the current RPS, is already guiding how utilities invest today. Investors and power system planners need assurance that technologies necessary to reach the goals will have support at the policy and legislative levels. Elements of renewable PtG are being planned or already in use to decarbonize the residential and transportation fuel supplies for the state of CA. But there is no policy level mechanism through which electric utilities can be assured that California will recognize carbon-neutral renewable methane (from PtG process) coupled with flexible thermal assets as “renewable generation”. Such a policy would allow utilities to strategically install flexible thermal as needed while also assuring these assets would contribute positively towards the ideal net-zero power system and enable California to follow the Optimal Path outlined in the study.

Flexible thermal should center around technologies that allow for distributed installation, with project sizes under 100 MW in most cases, without starting costs and restrictions on the number of starts per day, start times of 5 minutes or less, minimal to no restrictions on minimum run or down times, low gas pressure requirements to avoid compressor losses, zero water consumption, and minimum unit turndown of 10-20%. These flexibility features – used by Plexos for flexible gas generation in the study – allow units to thrive in energy markets exhibiting high net load and price volatility, such as California, in ways less flexible thermal cannot. Flexible generation can immediately shut down when renewables are available, minimizing overgeneration, use of fuels and carbon emissions.

POLICY RECOMMENDATIONS:

The Optimal Pathway as described in this work, either through power to methane or power to hydrogen, enables California to achieve its clean energy goals faster than currently planned and at a lower cost than currently projected, while also ensuring reliability. For the state to take full advantage of these benefits, the following policy considerations must be addressed.

- California must formally recognize thermal plant operation on renewable fuels, including synthetic methane and hydrogen produced with excess renewable energy, as renewable generation for the purposes of meeting clean electricity mandates. This would provide regulatory certainty which in turn will encourage research, development and deployment of power-to-methane and power-to-hydrogen technologies, enabling the fastest, least-cost Optimal Path to 100% clean electricity.
- Retirement of once-through-cooling power plants by 2023. To ensure adequate firm capacity over the next few years, the California Water Control Board is considering extending the licenses for some of the state's once-through-cooling power plants. However, the addition of flexible thermal along with renewables can replace the legacy thermal assets while ensuring reliability and adherence to California's clean power goals.
- California should allow for replacement of legacy thermal capacity with optimal proportions of renewable, lithium-ion and other forms of traditional energy storage, as well as strategic amounts of fast-start, flexible thermal capacity. This is outlined in the Optimal Path scenario of this study, capacity additions for Optimal Path displayed in Table 5. Flexible thermal is critical for reliability and will transition to renewable fuels in the future.

	Unit	2021	2022	2023	2024	2025
Solar	MW	2165	2165	2165	2165	2165
Wind	MW	519	519	519	519	519
Battery storage	MW	1692	1692	1692	1692	1692
Battery storage	MWh	6768	6768	6768	6768	6768
Flexible gas	MW	0	2421	0	0	0

Table 5. Annual capacity additions by technology type for Optimal Path

The policy goals above allow for and facilitate the Optimal Path outcomes provided in this work, allowing California to meet RPS goals five years ahead of schedule and reach true carbon neutrality by 2045, with decreased emissions and lower costs the entire way.

Appendix 1

California's Capacity Shortfall of August 2020

California and Western USA experienced a record-breaking heat wave in August 2020. As a consequence, electricity demand exceeded supply, and 2 million Californians were impacted by rolling blackouts. California has been able to rely on neighboring states and utilities for more power, but as the heat wave covered the whole South West, the bordering states reserves were also in short supply. There was not enough power generation available to cover the need locally in California, and the shortfall of power reached nearly 5,000 MW.

The shortfall and rolling blackouts lasted several days. Challenges for gas turbine technologies in hot climates, transmission line issues, sudden forced shutdowns of generating units, incapability of neighbors to supply electricity to California, and the recent retirement of 9 GW of in-state gas capacity all contributed to the chaos. Obviously, the current plan for decarbonization does not address these issues properly, and the heat wave gave us a glimpse into the future, allowing us to see how the system can serve load when the ratio between local firm dispatchable capacity and peak net load continues to change.

MODIFYING OPTIMAL PATH TO MITIGATE RELIABILITY ISSUES

The purpose of this additional scenario is to study how California can move optimally towards 100% renewable power system while maintaining system reliability in a future with potentially higher peak loads and more volatility in generation and imports.

In order to ensure the system can withstand a similar heat wave, the peak electricity demand forecast on August 18, 2020 is assumed to be the new system peak load. The weather events in August can happen more often in the future, and the system should be able to cope with them without blackouts. Such extreme heat wave week was not present in the load data used in this study originally, so it was added after the heat wave.

The peak demand of the heat wave week was inserted into the Plexos model. Table 1 summarizes the previously used peak demand in Optimal Path and the new estimated peak demand for CAISO's area and all of California. The scenario with the new, higher peak load is called Optimal Path+. One should note that the actual load in August 2020 did not reach 50 GW level mainly because it was actively reduced by load shedding i.e. rolling blackouts, so the peak demand is an estimate.

The power system must be capable of providing security of supply even during the new peak demand, without load shedding. Owing to the higher peak load in the model, Plexos dimensions the system to maintain its load serving reliability in the future even during similar heat waves experienced as in 2020. No other changes were made to the model and scenarios.

	Peak demand in 2020 in Optimal Path (GW)	Peak demand in 2020 in Optimal Path+ (GW)
CAISO	46	50
California	53	57

Table A1-1. CAISO and California peak loads in the Optimal Path and Optimal Path+ scenarios.

OPTIMAL PATH+ FOR RELIABLE CALIFORNIAN POWER SYSTEM

This section summarizes the modelling results – how the California power system's Optimal Path for decarbonizing needs to be modified in order to enable it to provide reliable power also during an extreme heat wave.

The cumulative system capacity additions until 2030 are presented in Figure A1-1 for the Optimal Path, and the Optimal Path+ scenario with higher peak load. Compared to the Optimal Path, the key differences to note in Optimal Path+ are the increased flexible gas capacity, and a small reduction in battery storage. The exact capacity additions are presented in Table A1-2.

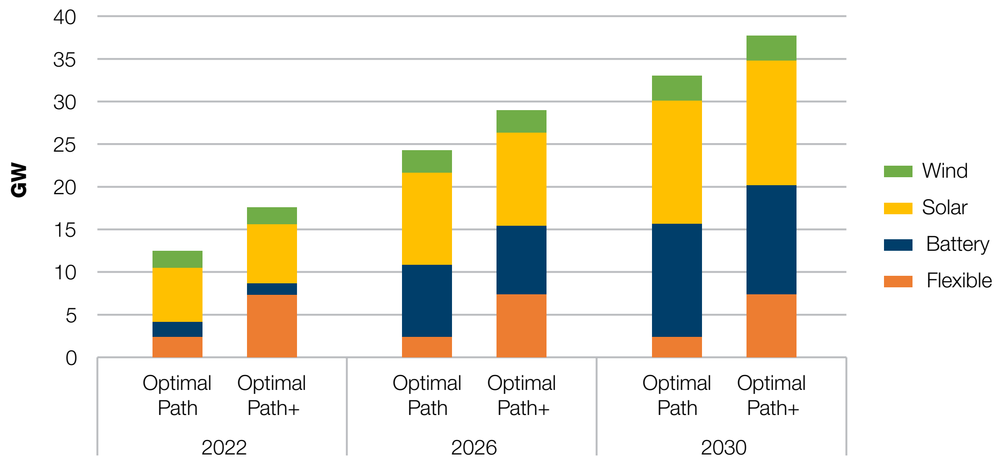

Figure A1-1. Cumulative capacity additions by 2030 to meet RPS target.

With the capacity additions in Figure A1-1. and Table A1-2, the system is prepared for the higher peak demand caused by a heat wave, increased variability and uncertainty due to wind and solar additions, and reduced imports from neighbours. There is no unserved energy (black-outs) in the system dispatch based on the simulation. As seen, the Optimal Path+ suggests the installation of 7.4 GW of flexible gas-fired capacity instead of 2.4 GW in the Optimal Path. At the same time, the quantity of battery storage is slightly reduced. No other significant changes.

	Flexible		Battery		Solar		Wind	
	Optimal Path	Optimal Path+	Optimal Path	Optimal Path+	Optimal Path	Optimal Path+	Optimal Path	Optimal Path+
2022	2.4	7.3	1.7	1.4	6.3	6.9	2.0	2.0
2026	2.4	7.4	8.5	8.0	10.8	11.0	2.6	2.6
2030	2.4	7.4	13.2	12.8	14.5	14.6	2.9	2.9

Table A1-2. Comparison of cumulative capacity additions between Optimal Path and Optimal Path+.

One reason for the model to build new firm capacity is to enable early retirement of OTC power plants. California's options to ensure capacity adequacy are to add 7.3 GW of new flexible capacity, or as we saw in August 2020, additional flexible gas capacity is needed even if the OTCs remain in the system. Without new firm and dispatchable capacity, the state must be prepared for blackouts during heat waves and other extreme weather conditions.

An important aspect to note is that the new flexible gas generation takes a much different role in the power system than the inflexible OTCs. New flexible generation can be started and stopped in minutes, several times a day, so they provide a fast way to safeguard system reliability. And by being able to go off-line fast at any time, they will not burn any fuel – and generate emissions – when it is not necessary. And later, they can and need to be converted to carbon neutral fuels.

Flexible, firm gas capacity is an important component in a decarbonized power system to provide security of supply, and to avoid major overbuilding of the system with solar and storage.

The modifications necessary to enable the power system to operate reliably through major heat waves do not have a significant impact on the system size and capacity mix compared to the Optimal Path, see Table A1-3. It compares the capacity mix of the Optimal Path and the Optimal Path+ in 2045. The main difference is the increase in dispatchable thermal capacity which replaces some battery storage. It should be noted that the addition of more thermal capacity requires slightly more carbon neutral PtM fuel production in 2045. The costs of this are included in the results.

With more capacity in the system to provide security of supply, the generation cost of electricity increases slightly from 50 USD/MWh to 51 USD/MWh in 2045. Additionally, over the modelled time span 2020 to 2045, the emissions are largely the same, rising just .4% due to the higher peak load.

		Optimal Path	Optimal Path+
Capacity	GW Solar	109	109
	GW Wind	40	40
	GW Storage	37	36
	GW Thermal Old	14	14
	GW Thermal New	18	24
	GW Other	7	7
	GW Hydro	12	12
	Total GW (Capacity)	**237**	**242**
	PtM GW (load)	10	10
Carbon	**Mton (2020-2045)**	**824**	**828**
Cost	**2045 Energy Cost ($/MWh)**	**50**	**51**

Table A1-3. System capacity and generation cost in 2045 in fully carbon neutral system, and cumulative carbon emissions over the study period 2020-2045.

The main difference between the Optimal Path and Optimal Path+ scenarios is that to ensure a reliable system even during heat waves, and to be able to close down the OTC power plants as planned by 2023, 7.3 GW of flexible gas generation capacity needs to be built instead of the Optimal Path's 2.4 GW by 2023. This corresponds to 4.9 billion USD of additional investment, which is the cost of avoiding future rolling blackouts during heat waves. As the previous paragraph stated, this has only minimal impact on cost of power and system emissions.

The issues in California in Aug 2020 have already resulted in actions on demand response programs which can cut the system peak load and improve the reliability. Reducing demand will help during times of need but is only a partial solution to the problem. These can be included in the modelling and scenarios as soon as numbers are published.

CONCLUSION

CAISO's concerns were made evident in August of 2020 as the systems vulnerabilities to variable weather conditions became a reality. As the State has decreased the amount of firm thermal capacity and increased variable renewable energy, the room for errors in keeping the lights on has become smaller and smaller.

This Path to 100 study shows how the Californian power system can be optimally structured to provide reliable supply of electricity to all households even during extreme weather conditions, with similar emissions, and just slightly higher costs compared to the Optimal Path.

KEY TAKEAWAYS

- There is a very practical way for California to decarbonize its power sector and reach RPS targets
- The power system needs to be designed and structured for peak demands taking place during heat waves
- California needs to ensure it has under its own command adequate firm generation capacity to enable security of supply
- Having an optimally balanced combination of battery storage and dispatchable flexible gas generation in California – or under the direct command of CAISO without grid restrictions – is the optimal way to provide adequate firm capacity
- Adding 7.3 GW of flexible gas generation gradually by 2030 enables:
  - Closure of the inflexible OTCs by 2023
  - The transition to clean electricity
    - With minimal emissions as these plants can go offline & stop using fossil fuels at any moment when they are not needed
    - Without security of supply issues as these plants start in minutes, and provide adequate firm capacity to CAISO
  - Finalize decarbonization by converting the plants to use hydrogen or synthetic methane – as preferred by California – at a suitable moment in the future

Appendix 2

Model inputs and Node information

In this study, the model contains three nodes, California, North-West (Oregon, Washington, Idaho etc.), and South-West (Arizona, Nevada, New Mexico etc.). Each of these nodes have their generation technologies modelled by several aggregated power plants. The technologies include solar PV, wind, geothermal, bio, hydro (reservoir, run-of-river), combined cycle and open cycle gas turbines, engines, steam turbines (coal and gas-fired), nuclear, pump storage, and battery storage. Initial capacity mixes for NW and SW regions are presented in Figure A2-1.

For the technologies, several characteristics are modelled, including size of plant, minimum stable generation, heat rate at 100% and 50%, fuel price, VO&M, FO&M, start cost, ramp rates, maintenance and forced outages, and firm capacities. These metrics are well-established and documented for both existing thermal assets and new-builds. For the Optimal path with hydrogen, it was assumed that the same new build technologies are available as for gas (methane) with the same costs and performance. Variable renewable generation (wind and solar) are represented by their hourly generation profiles for a full year in order to capture their variability and low and high generation periods.

The model has capacity reserve margin requirements as well as an operational reserves requirement that captures the additional reserve requirements for wind and solar PV balancing. The requirements are due to the weather forecast error and its impact on predicting wind and solar generation as well as the short-term variability of these resources. The technologies are modelled with a constant firm capacity except battery storage, of which effective load carrying capacity decreases when the amount of installed battery capacity increases.

According to the IRP (CPUC 2019a,b) solar and wind have low marginal ELCC when the states penetration is high, i.e., installing additional capacity adds only a little new firm capacity. The same applies to battery storage: once the installed 4-hour battery capacity is approximately 50% of peak load, ELCC drops down to 7%. This low ELCC necessitates buildout of significantly more capacity than is needed to serve load and showcases the need for dramatic overbuild of capacity to meet load and reliability without firm, dispatchable resources.

The demand for each node is modelled as hourly profiles for a full year. For the future years, the load growth follows CEC Pathways High Electrification load forecast, which assumes, for example, increasing electrification in transportation sector and buildings. The forecast also assumes additions in behind the meter solar generation that is included in the model with solar PV profiles. Annual demand assumption without storage load and losses and rooftop solar for California and the neighbour regions are depicted in Figure A2-1.

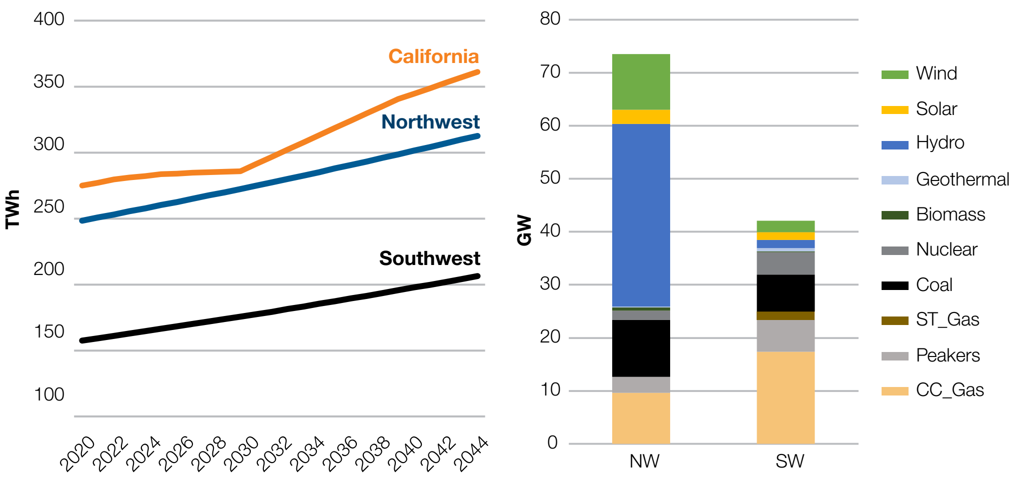

Figure A2-1. Electricity demand by regions (left) and Initial Installed capacity in NW and SW Regions (right).

California's RPS targets are modelled by gradually increasing the target so that it reaches 60% in 2030 and 100% in 2045. Up until the end of 2030, RPS eligible sources are wind, solar, bio, geothermal and small-scale hydro. After 2030, nuclear and large-scale hydro are also considered RPS eligible.

To meet future demand and RPS targets, the model can choose the technologies to add to the power system. The potential technologies with their price assumptions are given in Figure A2-2 Table A2-1. Battery storages have also FO&M that is 1.5% of CapEx and PtG has a FO&M that is 4% of CapEx. The software can also add 12-hour pump hydro with a CapEx of 2879 USD/kW and a FO&M of 14.64 USD/kW-year. Economic life and WACC assumptions are in Table A2-2.

Transmission expansion is not optimized in the study. Instead, the cost of expansion is estimated after the generation expansion optimization using CAISO's transmission capability and cost estimates produced for the IRP modelling. The estimation assumes that location with available transmission capacity is utilized first, after which renewable generation additions are done by starting from locations with the lowest transmission expansion cost.

Renewable Energy Sources (RES) and storage technology price learning curves used in this study are displayed in Figure A2-2 in more detail.

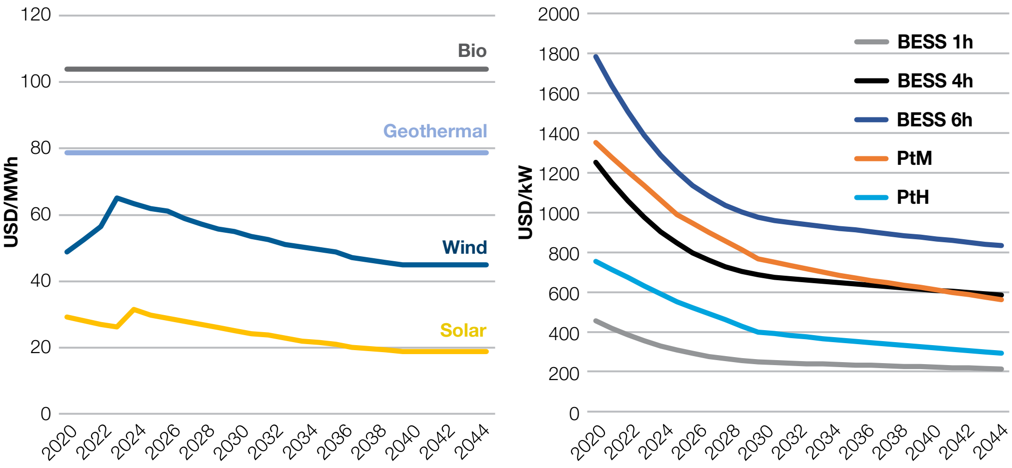

Figure A2-2. Levelized Cost of Energy for Renewable Energy Sources (left) and storage technology price (right) learning curves. Source: IRP dataset, Bloomberg NEF Source: IRP dataset, LUT.

	Heat Rate MMBtu/ MWh	VO&M Charge $/MWh	Start Cost $/MW	FO&M $/kW,a	CapEx $/kW
Open Cycle Gas Turbine (CT)	9.92	3	70	13.7	950
Combine Cycle Gas Turbine (CCGT)	6.98	2.65	60	11.1	1250
Reciprocating Internal Combustion Engine (ICE)	8.02	5	0	13.7	1250

Table A2-1. Inputs for new build thermal candidates (assumed to be the same for methane and for hydrogen).

	Renewables	Battery Storage	Pump Hydro	Thermal
WACC, %	6.4	9.13	9.13	5.84
Economic Life, years	20	20	50	20

Table A2-2. Economic life for generation/storage and WACC assumptions.

The fuel and carbon price for this study are those used in the CAISO IRP. California's fuel and carbon price in 2020 are displayed in Table A2-3. Based on market forecast a gradual increase for gas and carbon prices are assumed.

Fuel	Price
Coal	2 USD/MMBtu
Gas	4.3 USD/MMBTu
Uranium	0.7 USD/MMBtu
Carbon Price	15.2 USD/t CO_2

Table A2-3. Fuel and carbon price inputs for the study. Source: CAISO IRP dataset.

The Modelling Software

Plexos is a simulation software for studying and dispatching of a power system. The software uses mathematically based optimization techniques to realistically represent the operation of a real-life power system.

Plexos is an optimal tool for the capacity expansion studies of high variable renewable generation system because it is able to:

- Modelling the variability of wind and solar in detail is important for representing the low solar and wind periods required to properly model the system reliability
- Including the technical parameters needed to capture the inflexibilities of thermal generation. Such parameters include ramp rates, starts costs and profiles, minimum stable generation and minimum up and down times.
- Allowing the representation of weather forecast uncertainty in operational reserve provision

A Plexos model is a combination of power system data and advanced mathematical formulation, which captures the characteristics of the studied system. Figure A2-3 shows the power system data used in a model. This data, combined with the mathematical formulation, is a Plexos model, representing the power system with each of its techno-economic detail. The formulation basically models system features, such as the characteristics of power plants (e.g. efficiencies, dynamic features), the nodes and lines in the electrical grid, ancillary service requirements, and supply-demand balance.

The model is fed to a solver that produces the results shown in the figure (right side of Figure A2-3). The solver optimizes the power system. In a long-term expansion model, the optimization objective is to find the optimal (lowest cost) generation capacity additions to supply the future electricity demand. Due to the complex nature of the power system capacity optimization modelling some simplifications and compromises are typically needed. But it is noteworthy to mention that these simplifications should not severely impact the end results, which means that all compromises need to be carefully investigated and chosen.

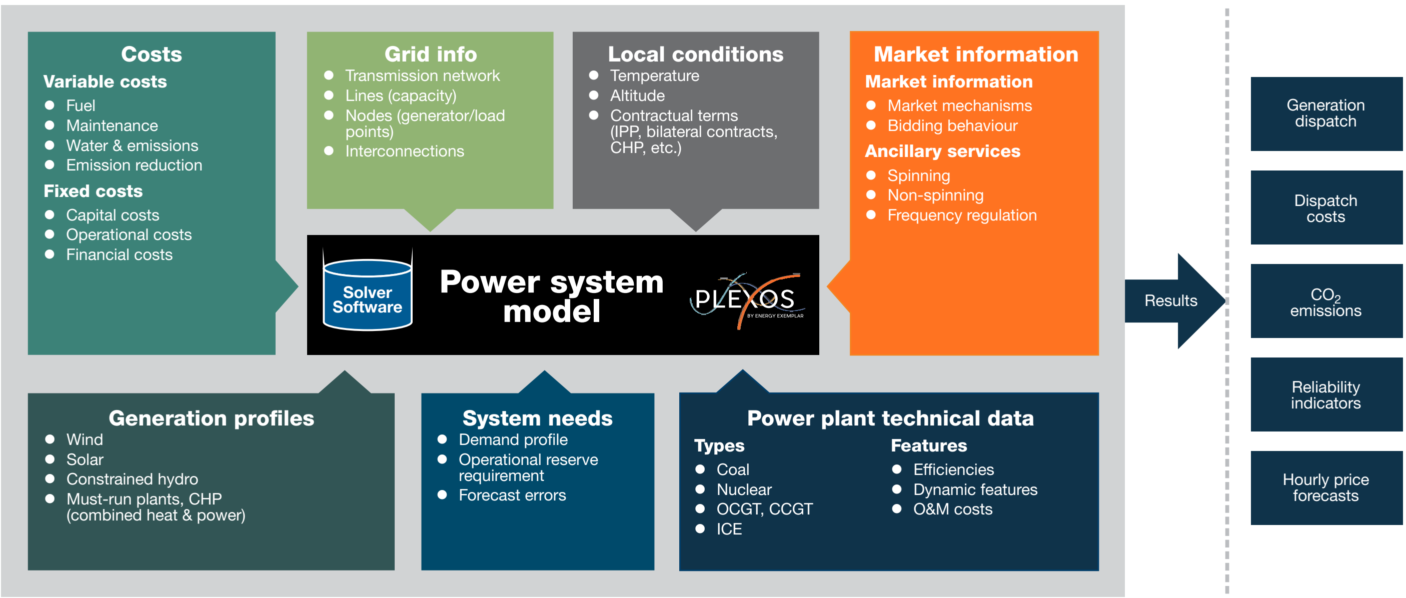

Figure A2-3. Plexos power system model (requires major computing power).

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