BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

DIRECT TESTIMONY OF HART GILCHRIST

EXHIBIT 1200

November 2025

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Hart Gilchrist and my business address is 8113 West Grandridge Boulevard, Kennewick, Washington 99336.

Q. By whom are you employed, for how long, and in what capacity?

A. I am employed by Cascade Natural Gas Corporation ("Cascade" or "Company"), a wholly owned subsidiary of MDU Resources Group, Inc. ("MDU Resources"), as Vice President of Business Development and External Affairs. In this capacity, I am responsible for the external affairs functions at Cascade and the business development function, which works with new and potential residential, commercial, and industrial gas customers.

Q. Please briefly describe your educational background and professional experience.

A. I am a graduate of the University of Idaho with a Bachelor of Science degree in Finance and Marketing. I have participated in several executive education programs, including attending executive utility education at the University of Idaho Utility Executive Course. I am a director of the Northwest Gas Association, Gas Technology Institute Operations Technology Development, Association of Washington Business, Idaho Association of Commerce and Industry, Associated Taxpayers of Idaho, and Boise Metro Chamber of Commerce.

I served as Vice President, Safety, Process Improvement, and Operations Systems from 2018 to 2024. From 2015 to 2018, I was Vice President, Operations for Intermountain Gas Company.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this docket?

A. My testimony will address high-level considerations related to the regulatory and policy landscape into which Cascade is filing this rate case. Particularly, this marks Cascade's first rate case filing since the adoption of the Climate Protection Program ("CPP") rules, which were promulgated by the Oregon Department of Environmental Quality ("DEQ"). The aim of the CPP rules is to, among other things, reduce greenhouse gas ("GHG") emissions in Oregon by establishing a declining limit on emissions from fossil fuels used by certain regulated entities, including natural gas utilities. The limit on emissions is reduced over time, with the goal of reaching a 50 percent reduction in emissions from 2017-2019 averages by 2035, and a 90 percent reduction in emissions by 2050. I provide a high-level overview of the steps Cascade will take and costs it will incur to comply with the CPP in the near- and long-term.

My testimony will highlight the Company's ongoing efforts to support Oregon's GHG emissions reduction goals and comply with the CPP while also meeting its duty to serve customers in Cascade's Oregon service territory. I will demonstrate that Cascade understands its role as a contributor to the achievement of the state's GHG emissions reduction commitments, and that the Company is dedicated to utilizing its existing assets and deploying new assets to support statewide decarbonization efforts. Cascade commits to continue to explore opportunities to decarbonize the Company's operations and to support customers in decarbonizing their energy usage in the most cost-effective and equitable manner possible.

Q. Please outline the content of your testimony.

A. First, I provide a high-level overview of Cascade's historic decarbonization efforts and the steps Cascade is taking to further decarbonize. Second, I discuss the current policy and regulatory landscape for gas utilities in Oregon, explain the CPP, and describe how the CPP will impact Cascade. Third, I discuss new decarbonization measures that Cascade will be undertaking in the future. I describe the strategy that Cascade will pursue to meet CPP compliance obligations, including direct investments in durable decarbonization measures and purchasing Community Climate Investments (“CCIs”). Finally, I provide testimony supporting decarbonization measures that are requested for cost recovery in this case. I provide testimony supporting Cascade’s request for recovery of $100,000 for decarbonization testing and demonstration activities that will assist Cascade in complying with state law. I also discuss the Company’s proposal to embed in base rates the incremental labor costs related to CPP compliance for employees who perform activities that will assist Cascade in complying with state law.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I sponsor the following exhibits:

- Exhibit CNGC/1201 – Designs for Net-Zero Energy Systems: Meta-Analysis of U.S. Economy-Wide Decarbonization Studies, February 2024.
- Exhibit CNGC/1202 – E3 Report – *Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results*, Docket UE-210096, PowerPoint presentation to the Washington Utilities and Transportation Commission and the Washington Department of Commerce (Sept. 22, 2025).
- Exhibit CNGC/1203 – Pacific Northwest Utilities Conference Committee, *2025 Northwest Regional Forecast of Power Loads and Resources* (Apr. 2025).
- Exhibit CNGC/1204 – Cascade 2023 Integrated Resource Plan Excerpt (pages 4-5 to 4-17).
- CNGC/1205 – Order Approving Natural Gas Innovation Plan with Modifications, *In re CenterPoint Energy’s Natural Gas Innovation Plan*,

Minnesota Public Utilities Commission Docket No. G-008/M-23-215 (Oct. 9, 2024).

- CNGC/1206 – SoCalGas – Clean Fuels Application, August 2022

III. CASCADE'S DECARBONIZATION EFFORTS

Q. Please describe Cascade's history with respect to decarbonization efforts.

A. Cascade has a long-standing commitment to reducing carbon emissions and delivering decarbonization solutions for our customers. For more than a decade, the Company has actively implemented energy efficiency programs via Community Action agencies and the Energy Trust of Oregon to help customers lower energy use and costs. As evidenced by Figure 1 and Figure 2 below, from 2007 through 2024 Cascade's programs achieved 6,081,590 therms of energy savings across all customer segments: 35.5 percent of savings were realized by residential customers, 63.9 percent by commercial and industrial customers, 0.6 percent through low-income weatherization initiatives. These efforts reflect Cascade's ongoing leadership in promoting energy efficiency and supporting the transition to a cleaner energy future.

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Figure 1 - Energy Efficiency Savings – Low Income Weatherization (2007-2012)

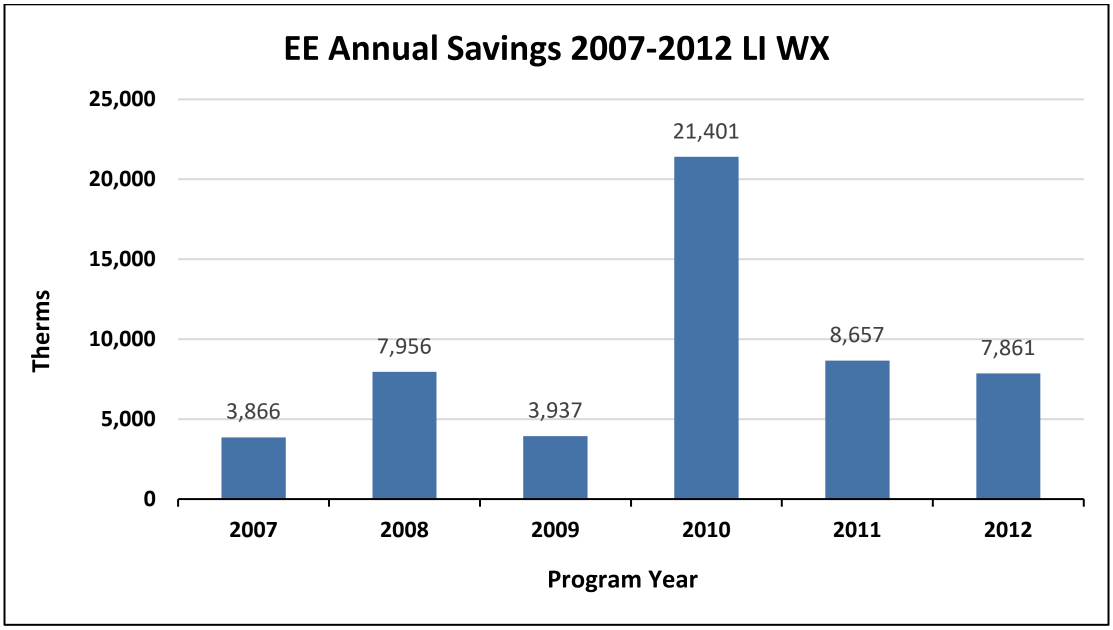
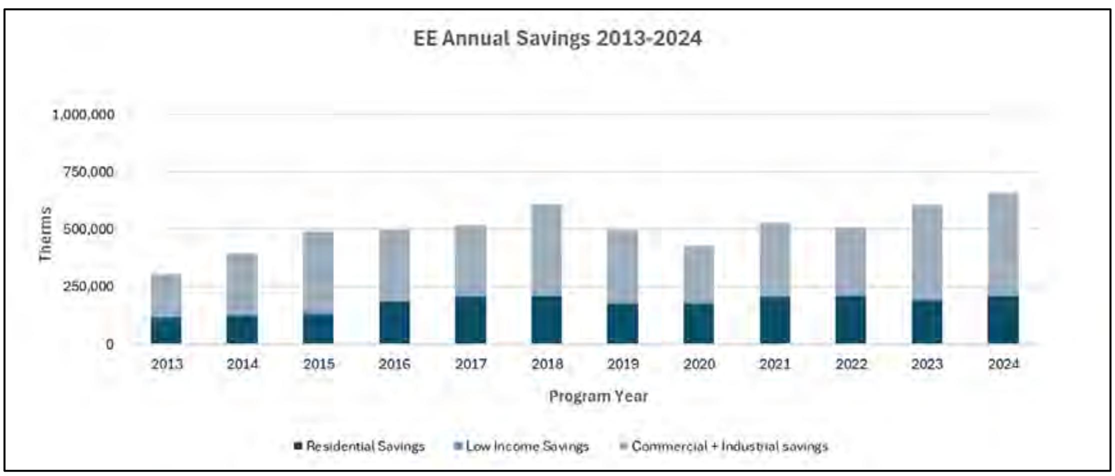


Figure 2 – Energy Efficiency Savings by Rate Class (2013-2024)



Q. Are there other decarbonization efforts being undertaken?

A. Yes. In 2023, Cascade's parent company MDU Resources set a methane emissions reduction target of 30 percent by 2035, compared to 2022 levels, across the entirety of its natural gas utility segment.

Q. What steps is Cascade taking to support Oregon's GHG reduction goals?

A. As discussed in more detail below, Cascade is currently analyzing how best to utilize its knowledge and assets to support Oregon in achieving statewide GHG emissions reduction targets. Cascade's intent is to proactively formulate a plan for making durable, direct capital investments in decarbonization measures that could prove more economic and impactful than CCI purchases over the long term. Early results from this analysis are already informing projects that the Company could invest in to support statewide decarbonization efforts as we move through 2025. Examples of potential capital investment initiatives Cascade is analyzing to support system decarbonization, in no order of preference, include:

1) Developing low-carbon fuel production;
2) Encouraging the deployment of hybrid heating systems;
3) Delivering hydrogen to large customers; and
4) Developing thermal energy networks (in Washington).

These decarbonization measures are described in more detail later in my testimony.

Q. Please describe the value that the gas delivery system provides to Oregonians.

A. Cascade's gas delivery system is an integral part of the energy system in the Pacific Northwest. In a recent study, clean energy consulting firm E3 reported that, because of accelerated load growth and continued coal plant retirements, the Pacific Northwest will experience a resource gap of nearly nine GW by 2030, which is approximately the same as the load of the state of Oregon.[1] The Pacific Northwest Utilities Conference Committee ("PNUCC") reported similar findings in its 2025 Northwest Regional Forecast—that winter peak load is projected to rise by about 9,100 MW by 2034—and existing and planned resources currently will not meet that resource need.[2] The

[1] CNGC/1202, Gilchrist/7.
[2] CNGC/1203, Gilchrist/5, 7-8.

resource gap has implications for the ability of the electric system to accommodate demands placed upon it. Critically, the electric demands in the winter heating season will be most acute when renewable energy sources are less available to meet that need, as wind and solar generation may be substantially limited or unavailable due to environmental conditions during those times.

As PNUCC points out in its 2025 report, "[t]he region is dangerously close to experiencing significant energy supply disruption, which could lead to blackouts during peak demand events."[3] The report finds that meeting peak energy demand during extreme weather events like a winter cold snap will continue to require careful coordination between natural gas and electricity providers.[4]

While decarbonization of the statewide energy system may ultimately involve some amount of electrification of end uses, it is also important to recognize that the natural gas energy system provides significant benefits for Oregon's transition to reduce emissions in its energy system, including inherent storage capabilities and significant investment in the transportation and delivery system.

As some energy use in the state is electrified to meet decarbonization goals, there will still be a need for gas and other fuels, as part of a comprehensive energy portfolio, to provide overall reliability and resilience benefits to the energy system to meet the highest peak loads. As the Meta-Analysis describes, "[a]lthough pipeline gas consumption decreases for net-zero scenarios, peak gas demands can remain relatively high."[5] For these reasons, it will be in the interest of the state to maintain the viability of the gas utility business in Oregon, including using supportive regulatory tools such as Cascade's proposed Renewable Natural Gas ("RNG") Cost Recovery

[3] CNGC/1203, Gilchrist/8.
[4] CNGC/1203, Gilchrist/8.
[5] CNGC/1201, Gilchrist/24-25.

Mechanism, which is discussed in greater detail in the Direct Testimonies of Travis R. Jacobson and Zachary L. Harris.

IV. OVERVIEW OF THE CPP AND CASCADE'S COMPLIANCE APPROACH

Q. Please provide a brief description of the CPP.

A. The CPP was developed by the Oregon DEQ to, among other things, reduce GHG emissions in Oregon by establishing a declining limit on emissions from fossil fuels used by certain regulated entities, including natural gas utilities. The limit on emissions is reduced over time, with the goal of reaching a 50 percent reduction in emissions from 2017-2019 averages by 2035, and a 90 percent reduction in emissions by 2050.

Q. When is the first compliance period?

A. The first compliance period started January 1, 2025, and covers emissions through the end of 2027. The first demonstration of compliance for this period will be in December 2028. All subsequent compliance periods will be two years.

Q. How do regulated entities demonstrate compliance with the CPP?

A. Every year, DEQ provides regulated companies with a set number of free compliance instruments, equal to the given year's emissions cap. For every metric ton of GHG emissions a regulated entity is responsible for, it must submit either a compliance instrument or a CCI credit to DEQ. If an entity's emissions are below the allowance during a given compliance period, the entity can choose to "bank" its compliance instruments or trade them to other regulated entities.

Q. How do regulated entities earn CCI credits?

A. Regulated entities earn CCI credits by contributing funds to third-party projects approved by DEQ that aim to reduce GHG emissions in Oregon ("CCI projects"). CCI projects typically will prioritize environmental justice communities and involve actions that reduce GHG emissions resulting from transportation or maintenance and development of residential, industrial, or commercial structures and processes.

Q. In what ways is the CPP changing the way Cascade serves its customers?

A. By quantifying the cost of GHG emissions associated with the use of energy across the state, the CPP is changing the way Cascade serves customers. While not every investment will reduce GHG emissions, Cascade aims to make investment decisions that serve customer interests, comply with policy and regulatory imperatives, further equity, and enhance the affordability, safety, and resilience of the energy system.

As Cascade strives to satisfy its CPP requirements and serve its customers equitably, the Company is currently developing a diversified portfolio of decarbonization measures to achieve compliance. While purchasing CCIs represents the least-cost compliance option at the present time, going forward Cascade intends to seek an optimal balance between CCI purchases and durable, direct capital investments in decarbonization measures that deliver environmental, social, and customer benefits while managing the cost impact to Cascade customers over the long term.

As described in "Designs for Net-Zero Energy Systems: Meta-Analysis of U.S. Economy-Wide Decarbonization Studies" ("Meta-Analysis"), local distribution companies like Cascade and their pipeline infrastructures will need to be leveraged to enable a sustainable and equitable decarbonization of Oregon's energy system.[6]

As part of this transition to a decarbonized energy system, Cascade firmly believes that targeted investments to: (a) utilize existing assets more efficiently; (b) decarbonize the Company's fuel supply; and (c) deploy new low-carbon assets, will be in the best interests of customers and all Oregon residents. Executing an equitable

[6] CNGC/1201, Gilchrist/29.

transition to a decarbonized system will result in changes to the ways all customers interact with their energy service providers. As such, we expect that customers' service needs will change, and Cascade will need to respond dynamically and flexibly to provide new solutions that serve all customers' changing needs and expectations.

Q. Has Cascade presented an updated Integrated Resource Plan ("IRP") analysis detailing its plans for CPP compliance?

A. No, not yet. In docket LC 83, Cascade requested an extension of the deadline to file its next IRP, in part based on needing additional time to re-assess compliance plans based on the new CPP rules, among other reasons. The Commission granted Cascade's request, and the deadline for filing the next IRP is May 2027.

Q. What decarbonization strategies will Cascade deploy to meet the requirements of the CPP?

A. To meet the CPP targets, Cascade must reduce GHG emissions associated with its facilities, purchase CCIs, and/or utilize Renewable Thermal Credits ("RTCs"). Cascade expects it will primarily achieve near-term compliance through CCI purchases. In the long term, Cascade currently projects that a mix of RTCs procured from direct capital investment and offtake-only contracts will primarily drive the Company's emissions reduction strategy. Plans to pursue energy efficiency and make capital investments to reduce emissions across Company facilities will also help to reduce reliance on CCIs.

Q. Why is it important for Cascade to seek to balance its CPP compliance portfolio with CCIs and other direct decarbonization tools?

A. First, at the time of filing this testimony, it is not yet possible to purchase CCIs. DEQ has plans to make them available in Q3 2026 at the earliest, however, there remain a number of tasks that DEQ must complete before CCIs will become available for purchase. Cascade remains optimistic that a CCI program will be established and

CCIs will be available for purchase prior to the end of Cascade's first compliance window. Second, even when CCIs become available, CCIs cannot be used to meet 100 percent of Cascade's compliance obligations, as there is a limit on the number of CCIs that can be used for compliance. Without a mix of resources beyond CCIs, if Cascade were to plan around maximizing the use of CCIs based on expected weather and then face a stretch of consecutive years of below average winter temperatures, the Company may be forced to procure expensive short-term resources to meet compliance obligations that result from higher throughput. To avoid that risk to customers, it is critical that Cascade pursue a suite of options in its CPP compliance portfolio.

V. CASCADE IS PLANNING DECARBONIZATION MEASURES THAT COMPLEMENT CCI PURCHASES

Q. Please describe the decarbonization planning approach Cascade applies to fulfill CPP compliance and address the business and financial impacts to Cascade.

A. Driven by the current state energy policy described above, Cascade is continuously evaluating ways to manage the financial impact of meeting the state climate goals on our customers and our business. Cascade's planning experts and leadership meet regularly to develop and adjust the Company's strategy to best meet the emissions reduction targets of the CPP through a combination of CCI purchases and durable, direct capital investments.

Q. Why is it important for Cascade to invest in capital projects and programs in addition to CCIs?

A. Investing directly in durable, targeted decarbonization measures alongside CCI purchases will transform the role of the natural gas utility. While CCI purchases provide a near term compliance pathway, long term compliance cannot be achieved with CCIs alone, and they do not directly mitigate the natural gas utility's GHG emissions. By meeting the CPP obligations through durable, direct investments in targeted decarbonization measures, Cascade will continue to provide vital energy services to customers while being an important part of Oregon's decarbonized energy solution.

Q. How does Cascade's decarbonization planning support the financial resiliency of Cascade's utility operations while complying with the State of Oregon's policy and regulatory mandates?

A. Cascade believes that rigorous planning is needed to achieve least-cost, least-risk decarbonization while also maintaining the Company's financial strength. The outcome of the Company's planning effort provides Cascade with a trajectory that enables the continued financial strength and stability of the business while also complying with existing policy mandates. The stability of the business is of high importance for both Cascade and its customers. Cascade has a duty to serve customers in its service territory, and customers depend on Cascade to meet their energy needs. Cascade must be financially stable to meet customers' energy needs while also investing in the decarbonization of its system. Future business planning will align with solutions that support Oregon's decarbonization policy efforts while taking into account customer impacts.

Q. What categories of decarbonization measures is Cascade exploring?

A. The primary solutions Cascade is exploring as part of this process include the following four decarbonization measure categories:

1. **Developing Low-Carbon Fuel Production:** Low-carbon fuels ("LCF"), such as RNG and hydrogen, offer decarbonization benefits while leveraging existing natural gas distribution infrastructure and limiting the burden on customers to make significant investments in replacing end-use equipment. As described in greater detail below, Cascade is currently participating in several RNG-related

projects, including one production facility. Cascade continues to explore opportunities to make additional direct investments in LCF production facilities. By owning the facilities, Cascade can secure long-term access to LCF supply and limit exposure to long-term risk of LCF price volatility, providing more security in costs for our customers.

2. **Piloting the Deployment of Hybrid Heating Systems:** Hybrid heating systems, such as dual fuel heat pumps, may offer decarbonization benefits over traditional fossil fuel systems while also improving system resilience. In March 2025, Cascade obtained approval for a new Hybrid System Pilot in Oregon, which commenced on April 1, 2025, and will continue through December 31, 2026.[7] The pilot will evaluate how three hybrid system technologies and advanced control systems can coordinate electric and gas service, support demand-side management, reduce gas usage, and affect overall affordability. Hybrid heating systems have the potential to provide viable avenues to support system decarbonization and reduce impacts to customers. As the Meta-Analysis describes, efficiency improvements across all sectors will be critical to meet decarbonization goals while still allowing for economic growth.[8]

3. **Delivering Hydrogen to Large Customers:** Many large commercial and industrial customers have processes that are difficult to electrify and will require access to low-carbon fuels to decarbonize. Cascade is exploring the opportunity and interest of large customers in the region to move to a hydrogen supply. In addition, the Company is exploring the business case to develop

[7] Cascade Tariff PUC Or No. 10, Original Sheet 810.3 (filed Feb. 21, 2025); *Cascade Advice No. O25-02-01 Schedule 810 Hybrid System Pilot*, Docket No. ADV 1710, Letter from ALJ Lackey Approving Utility Filing at 1, Item No. CA4 at 1 (Mar. 27, 2025).
[8] CNGC/1201, Gilchrist/5.

projects that supply hydrogen fuels to large customers by deploying new pipeline or modifying existing pipeline.

4. **Developing Thermal Energy Networks (in Washington):** Community geothermal and thermal energy networks (“TENs”) may offer an efficient way for customers to meet heating and cooling needs while curtailing GHG emissions at the point of use. Although geothermal heating systems can offer very low operating costs, the underground pipe infrastructure can be overly costly to serve a single customer. Cascade is exploring opportunities to leverage its capabilities as a regulated utility with knowledge of underground pipe infrastructure to develop TENs, and to explore whether it is possible to achieve economies of scale that make TENs a more economical solution for low-carbon heating and cooling. Cascade is currently evaluating a potential TEN pilot project in Washington in accordance with a recently enacted Washington law that provides local distribution companies with the authority to pursue TEN pilots in that state. The law gives gas utilities priority for developing TEN pilot projects in the gas utility’s service territory and provides the opportunity for local distribution companies to apply for grant funding for such pilots through the Washington State Department of Commerce. Cascade anticipates taking advantage of this opportunity in Washington and expects that the study results from the Washington pilot would inform Cascade’s assessment of whether this technology may be scaled up.

Cascade is currently exploring each of the decarbonization solutions described above to evaluate the market opportunity, understand the interest of customers, and to build the financial case, particularly in comparison to the purchase of CCIs. Cascade is committed to pursuing capital projects and programs that result in a reduction of GHG emissions. To meet the objectives of the CPP, Cascade believes incremental capital project investments and programs that reduce emissions are necessary to leverage the Company's infrastructure, which has been heavily invested in by Oregon ratepayers. A diverse portfolio of decarbonization solutions will ensure that Cascade will be a part of reducing energy-related GHG emissions across the state, help meet the CPP requirements, and manage the impacts of the transition to a low-carbon energy system equitably and cost-effectively for Cascade's customers and energy users across the state.

Q. With respect to low-carbon fuel production discussed above, describe Cascade's ongoing and planned RNG development efforts as part of the Company's CPP compliance.

A. Cascade believes that RNG is a critical resource in the portfolio to be deployed to meet CPP GHG emissions reduction targets. RNG is an established supply option that brings many benefits; chief among them being emissions reductions. RNG is a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anerobic digesters. Cascade provides a deeper discussion of RNG in its 2023 IRP.[9] An excerpt is provided as Exhibit CNGC/1204.

Cascade is currently progressing on RNG projects at varying stages of development. There are three types of RNG projects with which Cascade is involved: "Purchase Projects," "Transport Projects," and "Production Projects."

Purchase Projects are defined as projects where Cascade invests in the infrastructure required to on-board or flow the RNG produced by a third party into the Company's distribution system and purchase the environmental attributes or RTCs to

[9] *In re Cascade Nat. Gas Corp., 2023 Integrated Res. Plan*, Docket No. LC 83, Cascade Natural Gas Corporation's Draft 2023 Integrated Resource Plan at 63-65 (June 2, 2023).

be utilized for compliance obligations or voluntary RNG tariffs. The Company's investment in the infrastructure influences the negotiated price to purchase the RNG.

In Transport Projects, RNG produced by a third party is injected into Cascade's distribution system, and Cascade transports the customer's RNG so that the customer may market the environmental attributes to other parties. Cascade is not the purchaser of the environmental attributes of Transport Projects because they are already committed to another customer. The third-party producer will normally be placed on Cascade's transportation Schedule 800 Biomethane Receipt Services, and Cascade will make an investment in the infrastructure required to flow the gas into the distribution system in accordance with Schedule 800. Although Cascade plays an essential role in enabling Oregon's emissions reductions through its facilitation of RNG Transport Projects, under current rules, Cascade receives no credit for the emissions reductions accorded to the RNG production entity.

The third type of RNG projects, called Production Projects, are defined as projects where Cascade invests in the RNG production facility as well as the infrastructure required to flow the RNG into the distribution system. Cascade will ultimately produce and own the RNG, including the associated environmental attributes. Cascade plans to grow its portfolio of RNG Production Projects over time to support Oregon's GHG emissions reduction goals.

Q. Please describe the contracts that Cascade has executed for RNG projects.

A. Cascade has signed contracts for several RNG projects. Those contracts include agreements with third-party producers where the gas will be injected into Cascade's distribution system. Most of those are Purchase Projects where Cascade will be purchasing some or all of the environmental attributes. Cascade has also contracted with a third-party producer for a Transport Project where Cascade is only facilitating the transportation of RNG on its distribution system. Cascade also has a Production

Project where Cascade will own and operate the production facility and retain both the biomethane and RTCs for use by its customers. Additional contracts are likely in the near future. The projects Cascade is requesting to recover in this case are listed below and discussed in more detail in the Direct Testimony of Patrick C. Darras.[10]

VI. CASCADE'S APPROACH FOR RECOVERY OF DECARBONIZATION MEASURES

Q. What types of cost recovery mechanisms are appropriate for costs associated with CPP compliance?

A. Cascade believes that regulatory cost recovery mechanisms for CPP compliance investments and programs should be flexible, principled, and based on cost causation. The Commission should be open-minded to multiple cost recovery mechanisms and customer cost allocations that align with the way Cascade deploys capital while achieving policy objectives and managing customer equity.

Cascade anticipates using future regulatory proceedings—both general rate cases and annual recovery mechanisms—to request cost recovery for decarbonization investments and customer solutions. Cascade is sensitive to the impacts that decarbonization compliance will have on customers' energy costs and is mindful of the need to balance decarbonization mandates and customer energy affordability.

Q. Is Cascade seeking approval of direct investments in decarbonization measures in this case?

A. Yes, Cascade is seeking cost recovery of three distinct items in this case: RNG capital additions; testing and demonstration funding; and embedding labor costs associated with decarbonization efforts into base rates.

[10] CNGC/901, Darras.

Q. What RNG capital plant additions is Cascade seeking to recover in this case?

A. Exhibit CNGC/901 accompanying the Direct Testimony of Patrick C. Darras presents information on RNG interconnection plant additions that are being requested for cost recovery, including the following:

- Horn Rapids Landfill RNG Project – Purchase Project
- Lamb Weston RNG Project – Purchase Project
- Pasco Process Water Reuse Facility RNG Project – Purchase Project

Q. Will technology testing and demonstration be warranted to implement the solutions required to meet Oregon's decarbonization goals?

A. Yes. Providing the deep decarbonization envisioned in the CPP while still maintaining safe and reliable energy for Oregon customers will only be possible through the expanded use and accelerated availability of new or emerging technologies. In the Meta-Analysis of five different U.S. economy-wide, net-zero studies, all studies relied on large-scale deployment of new technologies. The study goes on to state, "Innovation in a variety of forms—technologies, operating models, market frameworks, and beyond—will be central to enabling the transition to net-zero economies."[11]

Q. Please explain the technology testing and demonstration proposed in this case.

A. Cascade is proposing to collect $100,000 annually from customers through base rates to fund technology testing and demonstrations related to the decarbonization measures outlined earlier in my testimony. Potential options for providing this type of testing and demonstration include Operations Technology Development ("OTD") and Utilization Technology Development NFP ("UTD"). These collaborative, not-for-profit organizations are managed by GTI Energy and would allow the Company to direct

[11] CNGC/1201, Gilchrist/6.

funding to projects that directly support Cascade's decarbonization efforts, providing meaningful benefits to customers.

Participation in these not-for-profit organizations will allow Cascade to benefit from leveraging the collective intelligence and experience of other participating companies from across North America as well as outside funders to bring innovative solutions to Oregon. The requested technology testing and demonstration funding can also be used to fund specific pilot projects related to Cascade's decarbonization strategies. This targeted funding will allow Cascade to develop and apply innovative near-term and long-term solutions to address Oregon's energy transition goals. Cascade would develop a technology testing and demonstration plan after the decarbonization solutions are selected. The technology testing and demonstration plan would be updated each year with spending capped at $100,000 annually.

Q. Please describe OTD's work and how Cascade and its customers could benefit from working with OTD.

A. OTD directs a research, development, and deployment program of near-term applied research to develop, test, and implement new technologies that enhance system safety, improve operating efficiencies, reduce operating costs, and maintain system reliability and integrity. Examples of OTD projects that will assist Cascade in implementing decarbonization solutions include research on improved leak detection technology to improve customer safety and meet decarbonization goals; research to better understand and safely incorporate lower carbon gases like hydrogen and RNG; and research into new thermal energy delivery systems such as community geothermal.

Q. Please describe UTD's work and how Cascade and its customers could benefit from working with UTD.

A. UTD directs a research, development, and deployment program of near-term applied research to expand innovative customer solutions that maximize the environmental performance, affordability, efficiency, and safety of equipment and processes that use natural gas and renewable energy resources, including the integration of hydrogen or electricity derived from renewable energy. Oregon's technology interests and needs, like other states, are based on building types, venting safety, specific codes and standards, weather, and other localized factors. One major benefit of participating in UTD is that projects can be tailored to specific issues within a state or service territory. Working with UTD, the utility can engage UTD's staff and technology developers to ensure that the technologies being developed can address any specific state or local issues and best perform for Oregon consumers. Additionally, any add-ons or optimization of a specific technology can potentially be tested through demonstration projects in Cascade's service territory to verify performance, to measure environmental benefits, and to learn any specific barriers to future deployment. Local contractors involved in the demonstration project learn about installing new pre-commercial emerging technologies which can help to identify and overcome any potential local barriers.

Q. Is there regulatory precedent in other jurisdictions that support testing and demonstration of decarbonization solutions?

A. Yes, state regulatory commissions in other states are considering or have approved utility spending to test and demonstrate decarbonization solutions within the regulated gas industry. In Minnesota, the Natural Gas Innovation Act creates a regulatory framework for natural gas utilities to invest in renewable energy resources and innovative technologies that aim to reduce the state's GHG emissions. In June 2023, CenterPoint Energy ("CenterPoint") proposed the first five-year innovation plan under Minnesota's Natural Gas Innovation Act. Within the proposal, CenterPoint proposed several research and development projects aimed at better understanding various pathways to achieving net-zero carbon emissions. The Minnesota Public Utilities Commission approved CenterPoint's research and development proposals with limited modifications.[12]

In California, Southern California Gas ("SoCalGas") has applied for and received cost recovery from the California Public Utilities Commission ("CPUC") across four main research areas including "Clean & Renewable Energy Resources," "Gas Operations," "Clean Transportation," and "Clean Energy Applications."[13] SoCalGas's Research, Development, and Deployment Program tracks and evaluates projects based on a set of six potential ratepayer benefits: safety, reduced GHG emissions, improved air quality, improved affordability, operational efficiency, and reliability.

Q. Please explain the request to add labor and benefits related to CPP compliance to base rates.

A. Cascade currently defers labor costs incurred to comply with the CPP in accordance with the orders issued in docket UM 2257.[14] Specifically, Cascade added personnel to

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[12]CNGC/1205, Gilchrist (*In re CenterPoint Energy's Nat. Gas Innovation Plan*, Minn. Pub. Util. Comm'n. Docket No. G-008/M-23-215, Order Approving Natural Gas Innovation Plan with Modifications at 24, 36, (Oct. 9, 2024) (approving CenterPoint's research and development proposals with modifications (1) to CenterPoint's Minnesota Net Zero Study to include "a description of how the plan, as a whole, helps CenterPoint reduce its greenhouse gas emissions to support the economy-wide timeline and incremental goals established by the legislature;" and (2) to require CenterPoint to "receive [Commission] approval to invest in any R&D projects that were not previously filed and approved" to address commenter concerns about unallocated research and development budget)).

[13] CNGC/1206, Gilchrist (Southern California Gas Company (U 904 G), 2024 General Rate Case, Application No. A.22-05-015, Exhibit SCG-12-R ("Revised Prepared Direct Testimony of Armando Infanzon (Clean Energy Innovations (CEI))") at AI-55 (Aug. 2022)).

[14] *In re Cascade Nat. Gas Corp., Application for Auth. to Defer Cost of Compliance with the Climate Prot. Plan*, Docket No. UM 2257, Order No. 23-230 at 1, App. A at 1 (Jun. 30, 2023); Order No. 24-292 at 1, App. A at 1 (Aug. 8, 2024); and Order No. 25-062 at 1, App. A at 1 (Feb. 19, 2025).

assist with the efforts to develop and interconnect RNG projects, to develop voluntary RNG customer programs, to manage overall decarbonization compliance, and to effectively participate in allowance auctions. Incremental labor and benefit costs related to these positions or partial positions are currently being deferred.

In this case, Cascade is requesting these labor and benefits costs be embedded in base rates. This request is included in the Company's Revenue Requirement model provided as part of the Direct Testimony of Matthew Larkin (Exhibit CNGC/700), through an adjustment made to incorporate labor costs related to the administration of the CPP into the revenue requirement for recovery through base rates. The Company will stop recording CPP labor costs in the deferral when base rates become effective to ensure the costs are not recovered twice.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

DESIGNS FOR NET-ZERO ENERGY SYSTEMS: META-ANALYSIS OF U.S. ECONOMY-WIDE DECARBONIZATION STUDIES

EXHIBIT 1201

November 2025

CNGC/1201
Gilchrist/1

GTI ENERGY

LCRI
LOW-CARBON
RESOURCES INITIATIVE

NOVEMBER 2023

Designs for Net-Zero Energy Systems: Meta-Analysis of U.S. Economy-Wide Decarbonization Studies

CNGC/1201
Gilchrist/2

DESIGNS FOR NET-ZERO ENERGY SYSTEMS: META-ANALYSIS OF U.S. ECONOMY-WIDE DECARBONIZATION STUDIES (Meta NZ)

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Executive Summary

This report provides a detailed meta-analysis of U.S. economy-wide net-zero studies, enabling like-for-like comparisons among different studies and scenarios. This study was performed through a process of collaboration among the authors of each of the five studies evaluated. This meta-analysis brings together a diversity of perspectives, analytical frameworks, and datasets to offer a comprehensive look at designs for net-zero energy systems.

Informing the Designs of Net-Zero Systems

Transitioning to net-zero requires an informed view of net-zero energy system designs. What pathways and technologies might be deployed? How might these systems be integrated? What infrastructure is critical to achieve that integration? What investments might be needed? Economy-wide net-zero modeling efforts are helping to answer these questions.

Energy system models offer an analytically informed means for evaluating the potential evolution of energy systems. These models leverage economic optimization to balance energy supply and demand under different scenarios, assumptions, and inputs. Historically, the scope of these models was limited to a particular sector (e.g., the power sector) and/or focused on less stringent emissions targets (e.g., 50% reduction). It has only been within recent years that modeling teams have taken on the complex task of evaluating the full U.S. economy under net-zero conditions. By looking across sectors, value chains, and energy carriers, these modeling efforts provide some of the most in-depth assessments available for informing the design of net-zero energy systems.

This report presents a comparison of five publicly accessible comprehensive U.S. economy-wide net-zero studies.[1,2] This meta-analysis is built upon a collaborative effort among the team members from each of these studies aimed at ensuring accurate interpretation of model information and results. The harmonized set of results presented in this report offers fresh insight into the design of net-zero systems—the common approaches, the range of possibilities, and the areas of differentiation.

Table ES-1: Studies Evaluated in this Meta-Analysis

Study	Team	Date Published	Scenarios Evaluated
Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis (report)	Low-Carbon Resources Initiative (LCRI)	September 2022	3 net-zero 1 business as usual 0 other
An Open Energy Outlook: Decarbonization Pathways for the USA (report)	Open Energy Outlook (OEO)	September 2022	1 net-zero 1 business as usual 2 other
Annual Decarbonization Perspective: Carbon-Neutral Pathways for the United States 2022 (report)	Evolved Energy Research (EER)	August 2022	7 net-zero 1 business as usual 0 other
Net-Zero America: Potential Pathways, Infrastructure, and Impacts (report)	Princeton University	October 2021	5 net-zero 1 business as usual 0 other
Pathways to Net-Zero Emissions (report)	Decarb America	February 2021	7 net-zero 1 business as usual 1 other

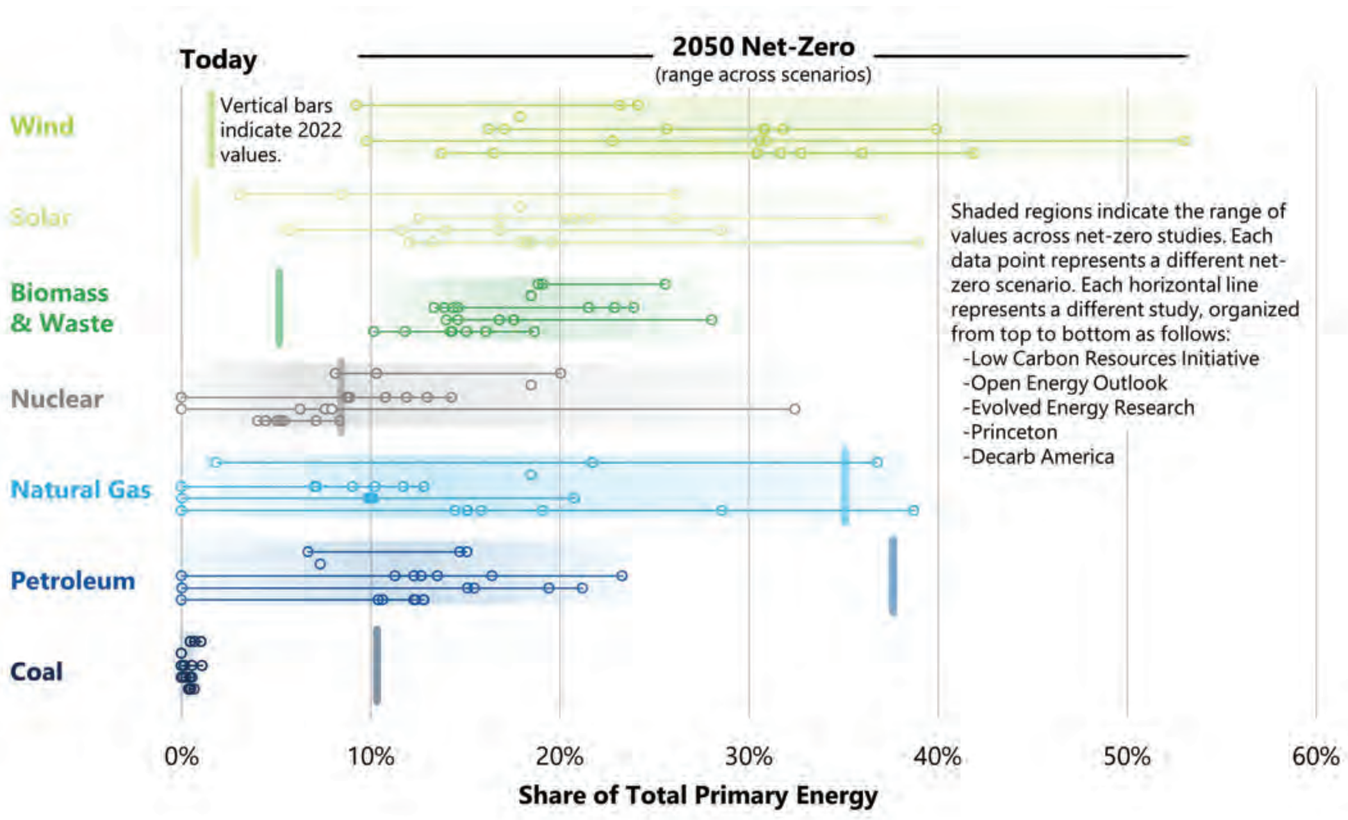
Commonalities Across U.S. Economy-Wide, Net-Zero Studies

Renewables grow the supply of low-carbon energy. Wind and solar deployments increase considerably from today's levels (Figure ES-1), contributing a large share of electricity generation. Bioenergy resources, such as cellulosic biomass, grow substantially to serve a range of markets, including low-carbon fuels production. Altogether, these studies project that renewables could supply the majority of energy in a net-zero U.S. economy.

Electricity expands across sectors. Today, 18% of energy supplied to end-use customers is in the form of electricity —the remainder is in the form of a gaseous, liquid, or solid fuel. This share grows to between 36 and 59% of all final energy under these net-zero scenarios (Figure ES-2). Electricity generation is dominated by wind and solar across most scenarios, with other forms of generation deployed to balance the inherent variability of these resources. Energy storage technologies, predominantly batteries, are deployed to balance short-duration variability (hourly, intraday). Fuel-based generation, chiefly from pipeline gas, is leveraged to balance long-duration (multiday, seasonal) renewables and demand variations, with total installed capacity comparable to today in most net-zero scenarios.

Fuels diversify and serve multiple markets. Fuels continue to have a sizeable role in these net-zero systems, accounting for between 41 and 64% of final energy (Figure ES-2). In all net-zero scenarios, fuels are used across all end-use sectors—transportation, industry, and buildings. Liquid fuels and pipeline gas are increasingly produced via low-carbon approaches, such as bioenergy and synthetic fuel production, where hydrogen and carbon dioxide are used as feedstocks to produce fuels.[3,4] Hydrogen grows considerably from today's levels, though is below 10% of final energy in 2050 across most scenarios, with production through a variety of low-carbon pathways including electrolysis, natural gas with carbon capture and sequestration, and bioenergy with carbon capture and sequestration.

Figure ES-1: Share of Total Primary Energy by Source



Renewables grow the supply of low-carbon energy, with nuclear and fossil fuels contributing to the energy mix in most net-zero scenarios. Geothermal and hydro energy, not shown in this figure, account for 2% or less of primary energy consumption across net-zero scenarios.

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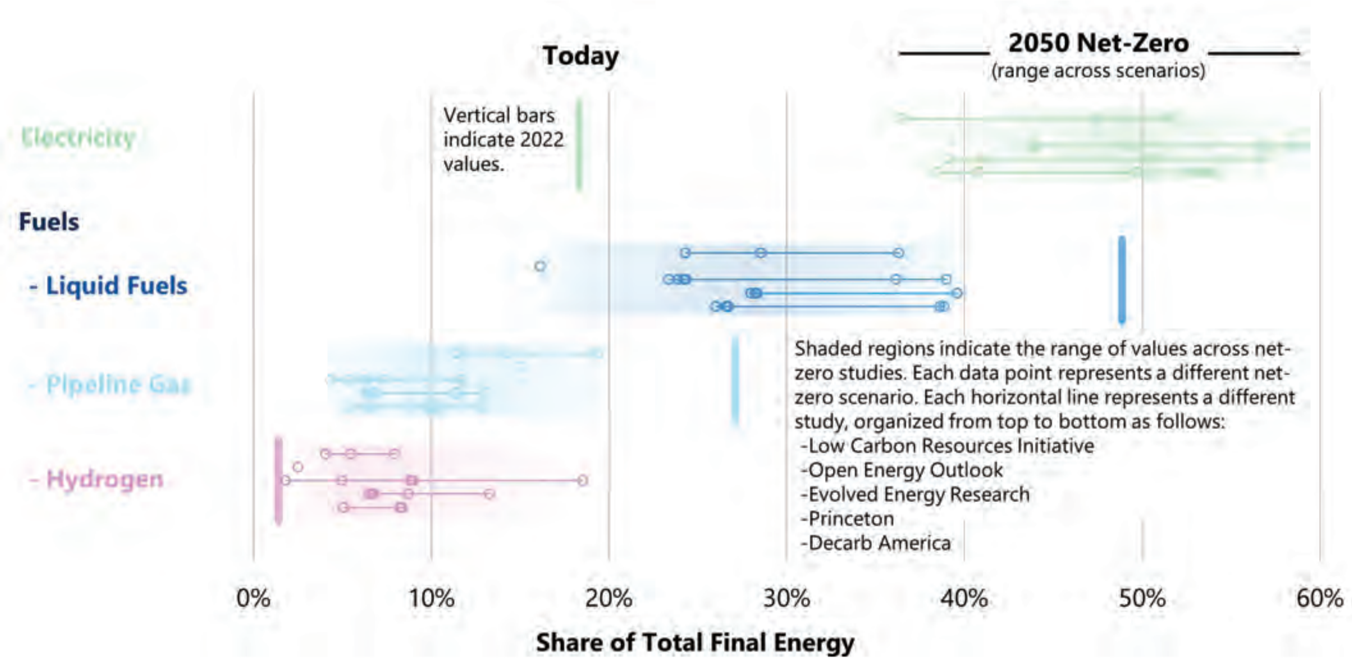
Figure ES-2: Share of Total Final Energy by Carrier



Final energy, the form of energy used by end-use customers in the buildings, transportation, and industrial sectors, transforms in net-zero scenarios relative to today. The share of final energy supplied by electricity grows in all scenarios. Gaseous and liquid fuels continue to serve across sectors, with growing shares of hydrogen. Coal and biomass, not shown in this figure, provide less than 2% and 4% of final energy across net-zero scenarios, respectively. These final energy results include both energy and non-energy use of fuels.[5]

Efficiency reduces energy consumption while enabling economic growth. All of these studies target net-zero emissions in 2050. These net-zero studies assume continued economic growth over the next three decades, leveraging projections from the U.S. Energy Information Agency for future energy service demands (e.g., vehicle miles driven, square footage of buildings heated and cooled, etc.). Even with growing service demand, final energy consumption is reduced from 81 EJ today to between 40 and 62 EJ in 2050 across net-zero scenarios. Similarly, primary energy consumption is reduced from 100 EJ today to between 52 and 88 EJ in 2050. These reductions are achieved through efficiency improvements across sectors, including increased adoption of electric vehicles and heat pumps which have substantial efficiency gains relative to conventional combustion vehicles and gas-fired furnaces respectively.[6]

Carbon dioxide removal balances remaining emissions. The net-zero scenarios evaluated in these studies achieve deep emissions reductions relative to today; yet all scenarios indicate some level of positive emissions remaining from costly-to-abate activities. These positive emissions are balanced by negative emissions approaches where carbon dioxide is removed from the atmosphere and durably stored. This can include technologies such as direct air carbon capture and sequestration, or bioenergy with carbon capture and sequestration. Carbon dioxide removal can also be achieved by incrementally increasing the carbon land sink through changing land use practices and other means. In these net-zero systems, carbon dioxide removal pathways account for total negative emissions flows of between −0.3 and −1.9 $GtCO_2$/year (Figure ES-3) versus total positive greenhouse gas emissions of 6.3 $GtCO_{2e}$/year today.

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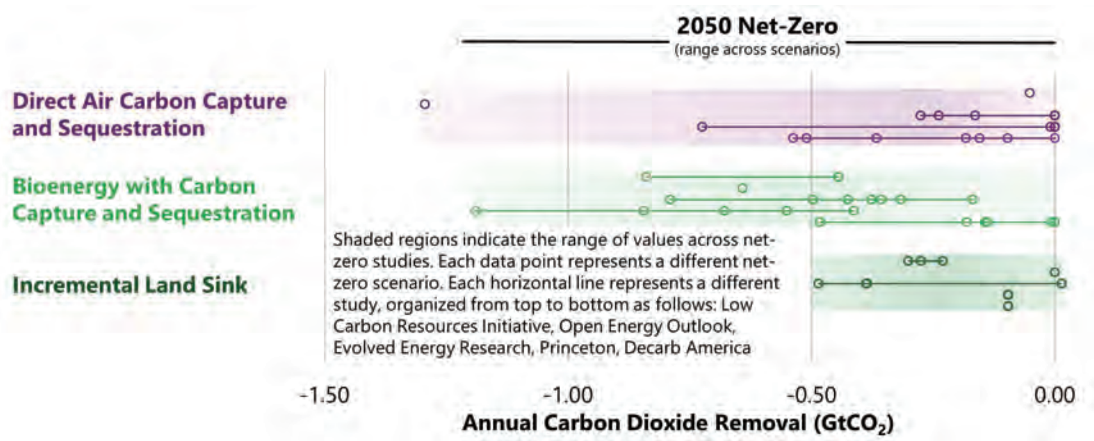
Figure ES-3: Annual Carbon Dioxide Removal by Approach



Carbon dioxide removal is deployed across net-zero scenarios to offset positive emissions from difficult-to-abate activities. Incremental land sink characterizes the change in the carbon land sink from today's levels (Updated February 2024).[7]

Implications for Transitioning to Net-Zero

There is no single design for net-zero energy systems. Each of these studies points to a wide array of energy carriers, technologies, and regionally specific solutions to meet the energy demands of an expanding U.S. economy. The range of results across these studies highlights a range of perspectives and possibilities for the design of net-zero systems. This range stems partly from intentioned efforts within these studies to evaluate corner point scenarios as a means for highlighting the dynamics and tradeoffs of different net-zero designs. Despite their differences, these studies are consistent in finding that constrained scenarios—where certain technologies or pathways are explicitly excluded or limited—have higher costs than unconstrained scenarios. There is value in considering a range of options to reach net-zero, particularly in these early stages of energy transitions when there is a lot of learning yet to come. At the same time, the insights shared across these studies can inform the decisions made today.

Net-zero systems entail net-zero infrastructure. Large-scale investment in energy infrastructure is needed to achieve the unprecedented level of transformation projected across these studies. These models point to expansion of the electric grid to accommodate increasing wind and solar deployments and growing electricity demands. Infrastructure to move and store gaseous molecules at scale is required to employ hydrogen as a versatile low-carbon energy carrier and to enable carbon dioxide removal and sequestration. The existing liquid hydrocarbons and pipeline gas infrastructure will need to be leveraged where it supports the net-zero system designs envisioned in these studies.

Innovation is a foundation for transformation. The net-zero designs envisioned in these studies all rely on large-scale deployment of new technologies. This includes investing in innovations already proven out at scale, such as wind, solar, and battery technologies. It also includes investing in a broad portfolio of nascent solutions, such as hydrogen, bioenergy, carbon capture, and sequestration. The net-zero systems projected in these studies are based on the information available today. The understanding of these systems is certain to evolve as progress is made towards net-zero. Innovation in a variety of forms—technologies, operating models, market frameworks, and beyond—will be central to enabling the transition to net-zero economies.

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U.S. Economy-Wide, Net-Zero Analyses

More than 90 countries have committed to reaching net-zero by the end of this century,[8] with the United States targeting economy-wide net-zero emissions by 2050. The list of countries with net-zero pledges expands every year. **Delivering on these net-zero commitments requires an informed view of the design of net-zero systems**—the technologies, the infrastructure, and the associated investments to deploy, integrate, and operate these systems.

A growing number of researchers, modelers, and analysts are working to inform the design of energy systems capable of achieving economy-wide, net-zero emissions by mid-century. These emerging efforts consider a range of sectors, value chains, and energy carriers, offering detailed assessments and insights on least-cost pathways to reach net-zero. An increasing number of U.S. economy-wide, net-zero studies have been performed in recent years. To draw upon the collective wisdom of these analyses, a framework for comparing and contextualizing studies relative to one another is needed.

This study provides a comprehensive assessment of U.S. economy-wide analyses performed to date, enabling like-for-like comparisons of results, scenarios, and approaches. This meta-analysis—study of studies—has been performed through a collaborative effort among team members from each of the studies evaluated to ensure accurate interpretation of model information and results. The harmonized set of results presented in this report offers fresh insight into the design of net-zero systems—the common approaches, the range of possibilities, and the areas of differentiation.

Economy-Wide Models

The economy-wide energy systems models evaluated here encompass a comprehensive set of sectors, technologies, and energy carriers, applying economic optimization to solve for pathways to **source, make, move, store,** and **use** energy. When exploring net-zero scenarios, these models solve for systems that achieve economy-wide carbon neutrality under assumptions about technologies, markets, and policies. While the results from these models point to deep reductions in greenhouse gas (GHG) emissions, the economy-wide framing of these analyses is such that negative emissions activities can be deployed in one part of the economy to balance remaining positive emissions elsewhere in the economy.

These models apply economic optimization to balance energy supply and demand under different scenarios and assumptions. Demand projections are typically defined in terms of energy services: for example, the vehicle miles driven for a given vehicle class, or the square footage of buildings heated and cooled in a given climate zone. These service demands can be met in a variety of ways. For example, internal combustion vehicles, battery electric vehicles, or hydrogen fuel cell vehicles could all be used to satisfy vehicle service demands. Determining which demand-side options will help realize the net-zero target requires additional supply-side information. Namely, the associated cost and emissions of supplying liquid fuels, electricity, and hydrogen to these vehicles. There are multiple ways to produce and deliver these energy carriers, each with their own cost, performance, and emissions profiles. The economy-wide models evaluated in this study incorporate this information to solve for least-cost pathways to supply energy across the economy.

The scope of technologies included in these models is extensive (Figure 1). A comprehensive set of primary energy resources is considered—renewable, fossil, nuclear—all of which can be leveraged to generate electricity. Hydrogen can be produced from electricity via electrolysis or through conversion processes that leverage fossil or bioenergy resources. Liquid and gaseous hydrocarbon fuels can be produced through conventional fossil-based routes, or bioenergy and synthetic pathways. These synthetic fuels pathways leverage hydrogen and captured carbon dioxide (CO_2) as feedstocks. Carbon dioxide can be captured from power generation, hydrogen production, biofuels processing, or other industrial facilities, as well as directly from the air via direct air capture (DAC) technologies. While CO_2 can be used as a feedstock, it can also be sequestered to abate emissions from fossil sources or to achieve negative emissions flows when captured from bioenergy sources or the air.[9] Negative emissions flows can also be achieved through activities aimed at expanding the land sink to enhance the terrestrial uptake of CO_2. These negative emissions activities can offset positive emissions from activities elsewhere in the economy.

In addition to how energy is **sourced** and **made**, these models characterize the ways in which energy carriers are **moved**, **stored**, and **used**. The existing electric grid and fuels infrastructure are represented. These models also characterize the build-out of new infrastructure to support growing demand, including electricity transmission and distribution infrastructure, and transport and storage

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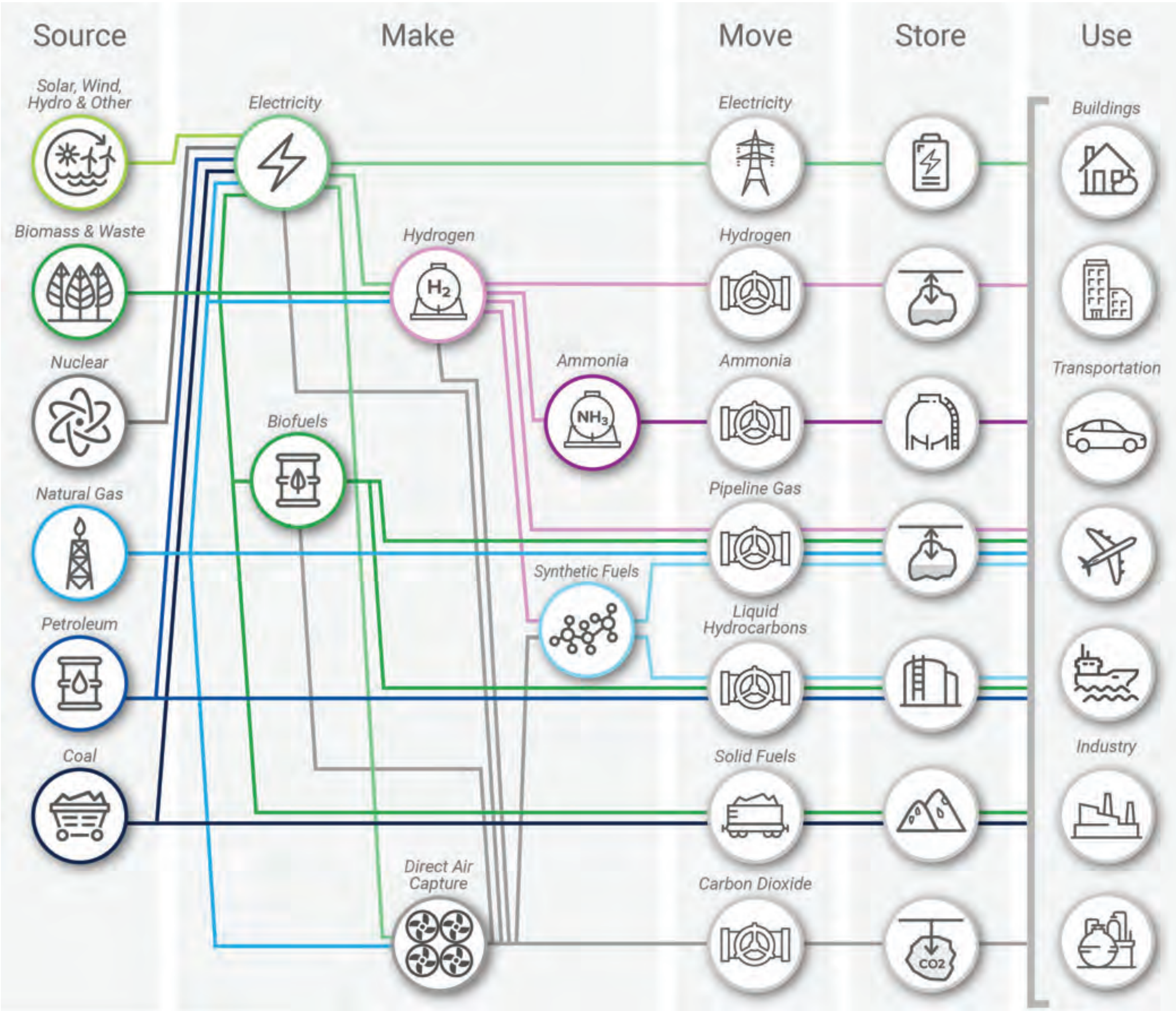
Figure 1: Illustrative Technology Pathways Considered in Economy-Wide, Net-Zero Analyses



A broad set of sectors, technologies, and energy carriers are considered in economy-wide, net-zero analyses. The potential designs of net-zero systems involve a diverse array of energy value chains with a high degree of integration for how to source, make, move, store, and use energy.

networks for hydrogen, ammonia, and captured carbon dioxide. Once energy carriers are delivered to end-use markets, these models consider a range of end-use technology options to meet energy service demands—vehicles, appliances, and equipment.

Economy-wide, net-zero models include several low-carbon technologies that are still at relatively early stages of development and deployment, which carry uncertainty regarding their cost, performance, and emissions. These models apply forward-looking estimates for these early-stage technologies based on the information available today. This information—the costs and performance of these technologies, and the energy sources they leverage—will evolve in progressing towards net-zero. Technological breakthroughs and other disruptions could significantly alter the net-zero energy system designs projected by these models. Nonetheless, these modeling approaches provide some of the most comprehensive and analytically grounded tools available to inform the designs of net-zero systems.

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Table 1: Studies Considered in this Meta-Analysis

Study	Team	Date Published	Primary Energy	Final Energy	Transportation	Industry	Buildings	Electricity Capacity	Electricity Generation	Hydrogen Production	Pipeline Gas Supply	Liquid Fuel Supply	GHG Emissions
New Energy Outlook U.S. (report)	Bloomberg New Energy Finance	August 2023											
BP Energy Outlook 2023[10] (report)	BP	July 2023											
Net-zero CO_2 by 2050 scenarios for the United States in the Energy Modeling Forum 37 study (report)	Energy Modeling Forum (EMF)[11]	April 2023											
Shell Scenarios Sketch: A U.S. Net-Zero CO_2 Energy System by 2050 (report)	Shell	March 2023											
Pathways to Net-Zero for the U.S. Energy Transition (report)	Energy Pathways USA[12]	November 2022											
LCRI Net-Zero 2050: U.S. Economy-wide Deep Decarbonization Scenario Analysis (report)	Low-Carbon Resources Initiative (LCRI)[13]	September 2022											
An Open Energy Outlook: Decarbonization Pathways for the USA (report)	Open Energy Outlook (OEO)[14]	September 2022											
Annual Decarbonization Perspective: Carbon-Neutral Pathways for the United States (report)	Evolved Energy Research (EER)	August 2022											
Navigating America's net-zero frontier: A guide for business leaders (report)	McKinsey Sustainability	May 2022											
The Long-Term Strategy of The United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050 (report)	U.S. Executive Office of the President	November 2021											
Net-Zero America: Potential Pathways, Infrastructure, and Impacts (report)	Princeton University	October 2021											
Pathways to Net-Zero Emissions (report)	Decarb America (DA)[15]	February 2021											

Data publicly available *Data partially publicly available* *Data not publicly available*

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Studies Considered

Several U.S. decarbonization studies have been considered in this meta-analysis, as summarized in Table 1 below. The studies considered here align with the following criteria: (1) the study is focused on the U.S. economy; (2) at least one scenario in the study is targeted at achieving economy-wide, net-zero emissions; and (3) the results of the study are freely and publicly available.[16] To the authors' knowledge, Table 1 contains all such studies published to date.[17,18,19]

The scope of results reported varies across these studies. At present, this meta-analysis focuses on the five studies with the most comprehensive set of publicly available results. Future efforts, extending beyond the publication of this study, will seek to perform a detailed evaluation of a broader subset of the studies listed in Table 1.

Two studies listed in Table 1 are comparative in nature. The Energy Pathways USA study compared the results of two 2050 analyses—U.S. Energy Information Administration (EIA)'s Annual Energy Outlook (AEO) and the Princeton study—similar to this meta-analysis. The EMF 37 study investigated how different energy systems modeling platforms perform when given the same objective and guidelines for evaluating U.S. economy-wide deep decarbonization, providing granular insights into the impact of analytical methodology on model results. The meta-analysis presented here offers a broad comparison across five U.S. economy-wide, net-zero studies, encompassing different modeling approaches, input assumptions, and scenario definitions.

Studies Evaluated

Five of the 12 considered studies were evaluated in detail in this meta-analysis (Table 2). All five studies set a target of achieving U.S. economy-wide, net-zero emissions by 2050. These studies assumed continued economic growth over the next three decades, with increasing energy service demands. Projections of these energy service demands—such as the number of miles driven by given vehicle class, or the square footage of buildings heated and cooled in a given region—were based on estimates from the EIA's AEO for all five studies.

Table 2: Studies Evaluated in this Meta-Analysis

Study	Team	Net-Zero Target	Model	Service Demands	Demand Decisions	Supply Decisions	Scenarios
Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis (report)	Low-Carbon Resources Initiative (LCRI)	net-zero CO_2 by 2050	US-REGEN	AEO 2020	model output	model output	3 net-zero 1 BAU 0 other
An Open Energy Outlook: Decarbonization Pathways for the USA (report)	Open Energy Outlook (OEO)	net-zero CO_2 by 2050	TEMOA	AEO 2022	model output	model output	1 net-zero 1 BAU 2 other
Annual Decarbonization Perspective 2022 (report)	Evolved Energy Research (EER)	net-zero GHGs by 2050	Energy PATHWAYS	AEO 2022	user input	model output	7 net-zero 1 BAU 0 other
Net-Zero America: Potential Pathways, Infrastructure, and Impacts (report)	Princeton University	net-zero GHGs by 2050	Energy PATHWAYS	AEO 2019	user input	model output	5 net-zero 1 BAU 0 other
Pathways to Net-Zero Emissions (report)	Decarb America (DA)	net-zero GHGs by 2050	Energy PATHWAYS	AEO 2019	user input	model output	7 net-zero 1 BAU 1 other

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There are key differences across these studies, such as the way the net-zero target is defined. The LCRI and OEO studies targeted net-zero CO_2 emissions, whereas the EER, Princeton, and DA studies targeted net-zero emissions of several GHG emissions, including activities not directly associated with energy (e.g., agricultural livestock production).[20] This difference in definition has a meaningful impact on the total emissions burden to be abated.

All studies analyzed a multitude of technology options and pathways across sectors, solving for energy systems designs that achieve economy-wide net-zero emissions. All studies applied cost-optimization as part of the analytical framework, although the methodology applied varied across different studies.

The EER, Princeton, and DA studies used Evolved Energy Research's EnergyPATHWAYS model, and Evolved Energy Research participated in all three studies. In the EnergyPATHWAYS model, the demand-side technology mix is defined as based upon user-defined values. For example, the share of light-duty vehicle types—gasoline internal combustion vehicle, battery electric vehicle, hydrogen fuel cell vehicle, etc.—is defined by the user. The supply-side technology mix is optimized within the EnergyPATHWAYS model to achieve the lowest possible cost while satisfying the economy-wide emissions target. That is, the mix of technologies for making, moving, and storing electricity, hydrogen, and other fuels is optimized to provide the least cost set of supply-side technologies to meet energy demands, while satisfying the net-zero target.

The LCRI and OEO studies also optimize the supply-side technology mix. Additionally, these studies incorporate the demand-side technology mix and associated costs into the analytical framework. In these models the technology decisions at the point of end-use—for example, whether to heat a building with an electric heat pump, a gas-fired unit, or a hybrid electric-gas system—are solved as a model output, rather than being defined as a user input.

A wide range of scenarios were evaluated across these five studies.[21] These scenarios evaluate the trajectory of energy systems under different sets of assumptions and constraints, characterizing the impacts of various parameters on possible future outcomes. This range stems partly from intentioned efforts within these studies to evaluate corner point scenarios as a means for highlighting the dynamics and tradeoffs of different net-zero designs. Each study included a business-as-usual (BAU) scenario to evaluate the possible trajectory of the U.S. energy system under current policies. None of the studies evaluated incorporated the Inflation Reduction Act (IRA) incentives because the modeling activities were completed before the legislation passed.[22] Some studies, such as OEO and DA, included 'other' scenarios, which introduced emissions targets, but not net-zero targets. While these 'other' scenarios offer useful insights, they are not incorporated into the results of this meta-analysis. Rather, this meta-analysis primarily focuses on the results of net-zero scenarios.

Comparison of Net-Zero Results

The economy-wide, net-zero studies evaluated here differed in their reporting of results, making it difficult to make direct comparisons across studies. In this meta-analysis, the results of these different studies have been harmonized through a process of collaboration with the teams from each of the five studies to ensure accurate interpretation and representation. The results have been aligned to a consistent reporting basis across the following metrics: **total energy consumption, end-use sectors, energy carriers, greenhouse gas emissions,** and **cost**.

This meta-analysis seeks to identify insights when comparing across economy-wide, net-zero conditions. Thus, this report highlights the results of net-zero scenarios, specifically the 2050 end point of these scenarios—**the designs of U.S. economy-wide, net-zero energy systems**. The results presented here enable like-for-like comparisons of these net-zero designs, both across different studies and scenarios, and relative to today's energy systems.[23]

Total Energy Consumption
primary and final energy

End-Use Sectors
transportation, industry, and buildings

Energy Carriers
electricity, hydrogen, pipeline gas, and liquid fuels

Greenhouse Gas Emissions
positive and negative emissions

Cost
total cost of deploying and operating future energy systems

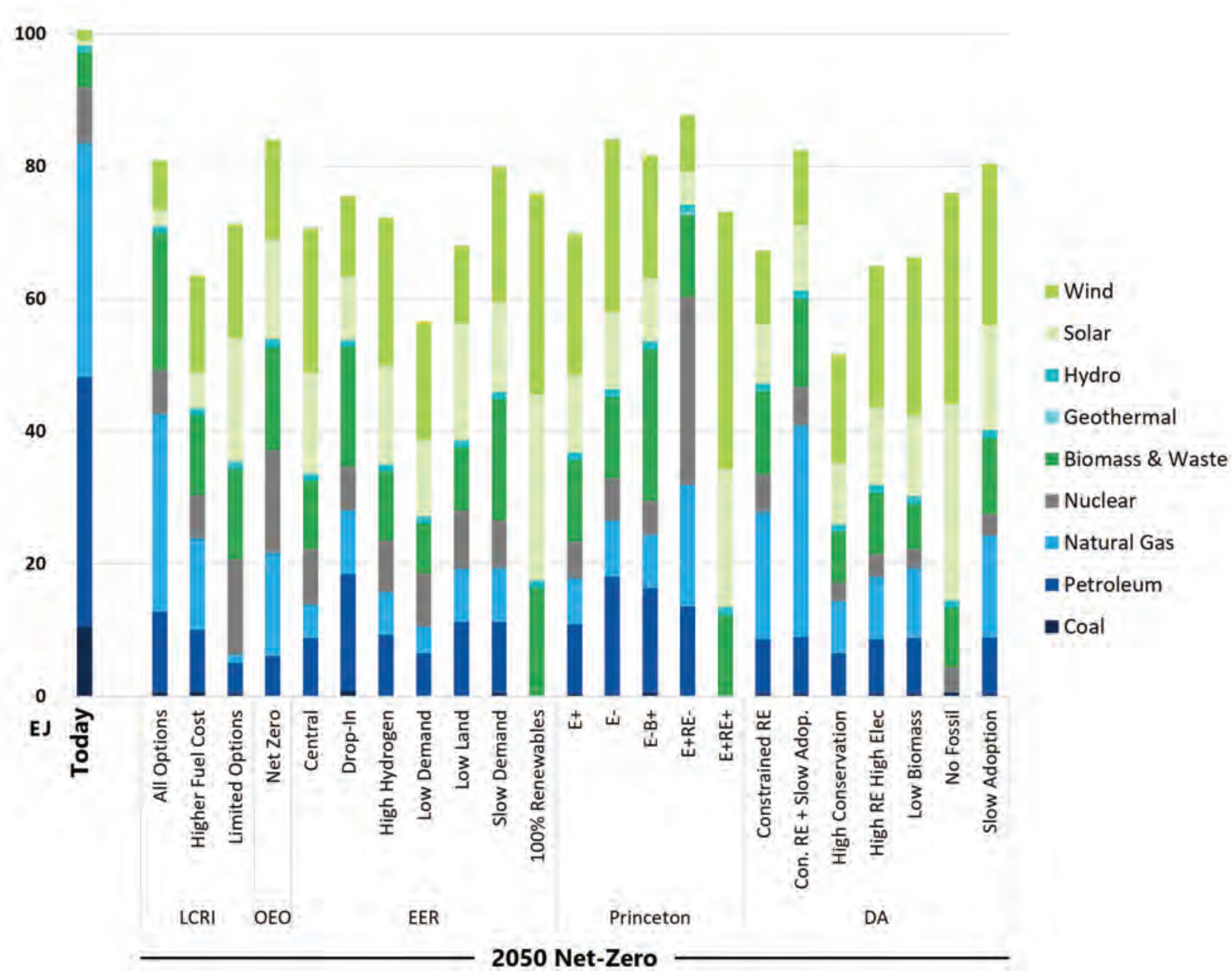
Total Energy Consumption

The net-zero studies evaluated here all assume continued economic growth from now until reaching net-zero in 2050, leveraging information from the EIA to project future energy service demands (e.g., vehicle miles driven of a given vehicle class, building square footage heated and cooled, etc.). Even with growing service demand, final energy consumption is reduced from 81 EJ today to between 40 and 62 EJ in 2050 across net-zero scenarios.[24,25] Similarly, primary energy consumption is reduced from 100 EJ today to between 52 and 88 EJ in 2050 (Figure 2). These reductions are achieved through efficiency improvements across sectors. The reported reduction in primary energy consumption is also an artifact of the reporting convention employed here for wind and solar technologies, where the produced energy is directly reported (e.g., the electricity generated from a solar panel) rather than the available energy (e.g., the sunlight energy impinging on a solar panel).

Many net-zero scenarios suggest that renewables could supply the majority of energy in a net-zero U.S. economy. Wind and solar deployments increase considerably from today's levels, contributing to large shares of electricity generation. Wind contributes more primary energy than solar in most scenarios. Energy from biomass and waste increases from 5% today to 10–28% in 2050. Bioenergy resources, such as cellulosic biomass, grow substantially to serve a range of markets, especially low-carbon fuels production. Hydro energy is similar to today across scenarios. Geothermal energy is nearly zero in all but two scenarios.

Fossil energy resources continue to play a role across these net-zero systems. Coal is largely eliminated, other than for uses in heavy industrial applications like steel and cement. Consumption of petroleum and natural gas decreases but is non-zero unless it is explicitly excluded under the constraints of a given scenario. Petroleum contributes 7–23% of primary energy and natural gas contributes 7–39% in net-zero scenarios where fossil fuels and carbon sequestration are allowed within the scenario definition. Carbon capture and sequestration (CCS) is deployed to abate fossil emissions across many scenarios. Unabated use of fossil fuels is also present

Figure 2: Annual Primary Energy Consumption by Source (EJ)



Primary energy consumption decreases relative to today in all net-zero scenarios as a result of efficiency improvements across energy value chains. Renewable energy deployment grows considerably. Fossil fuel consumption decreases but remains, except for scenarios that explicitly prohibit their use.

across all scenarios where fossil fuels are allowed, with associated emissions offset by carbon dioxide removal (CDR) approaches to achieve the economy-wide, net-zero target. Fossil resources also continue to be leveraged for non-energy purposes as feedstock for production of chemicals and materials.

Nuclear energy is used for power generation in all scenarios unless it is explicitly excluded under the constraints of a given scenario.[26] Some net-zero scenarios point to declines in nuclear energy relative to today, whereas other scenarios point to increases in nuclear energy through growing deployment of small modular reactors.

Final energy also decreases in all scenarios relative to today due to efficiency improvements across end-use sectors. Electricity use expands, with increasing shares in transportation, buildings, and industry. Electric vehicles and heat pumps particularly arise as cost-competitive technologies with substantial efficiency gains, driving increases in electricity consumption and decreases in overall final energy consumption. Today, 18% of energy supplied to end-use customers is in the form of electricity. This share grows to between 36 and 59% of all final energy under these net-zero scenarios, serving an even larger share of energy service demands as a result of the relatively higher efficiencies achieved for electricity-based equipment.

Solid, liquid, and gaseous fuels continue to be supplied to end-use markets in these net-zero systems, accounting

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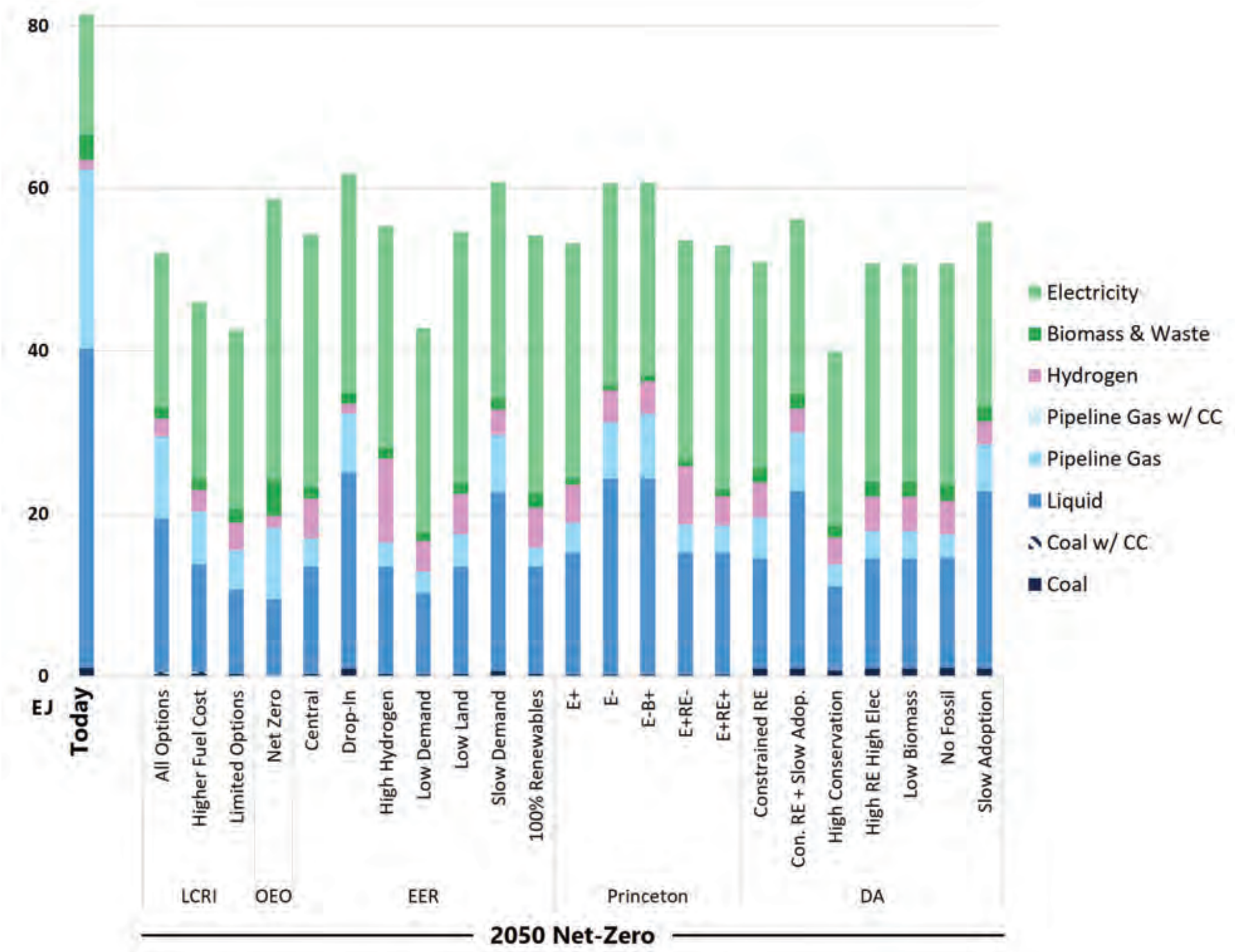
Figure 3: Annual Final Energy Consumption by Energy Carrier (EJ)



Final energy supplied to end-use consumers decreases in all net-zero scenarios relative to today as a result of efficiency improvements in vehicles, appliances, and other equipment. Electricity expands across sectors, with total consumption growing considerably from today's levels. Energy delivered to consumers as a fuel decreases but still makes up roughly half of final energy consumed in most net-zero scenarios.

for between 41 and 64% of final energy. Fuels are used across all end-use sectors—transportation, industry, and buildings—in all net-zero scenarios. Liquid fuels and pipeline gas are increasingly produced via low-carbon approaches such as bioenergy and synthetic fuel production, where hydrogen and carbon dioxide are used as feedstocks to produce fuels.[27,28] Hydrogen grows considerably from zero today to 2–19% of final energy in 2050, with production through a variety of low-carbon pathways including electrolysis, natural gas with carbon capture and sequestration (CCS), and bioenergy with carbon capture and sequestration (BECCS).[29] Liquid fuels, particularly petroleum-derived liquids, are also leveraged as feedstocks for non-energy uses and included in the results reported in Figure 3.[30]

End-Use Sectors

Energy systems are built to serve the myriad of end-use customer needs across the economy. In the transition to net-zero energy systems, energy **use** will also evolve to meet the needs of the evolving U.S. economy. Across the net-zero energy system designs envisioned in these studies, increasing shares of electric and hydrogen-fueled vehicles, appliances, and equipment are adopted, while hydrocarbon fuels continue to serve end-use markets.

Transportation

In the transportation sector (Figure 4), electric vehicle adoption increases considerably relative to today in all net-zero scenarios, especially in the light-duty, on-road market. Given the efficiency gains of electric vehicles

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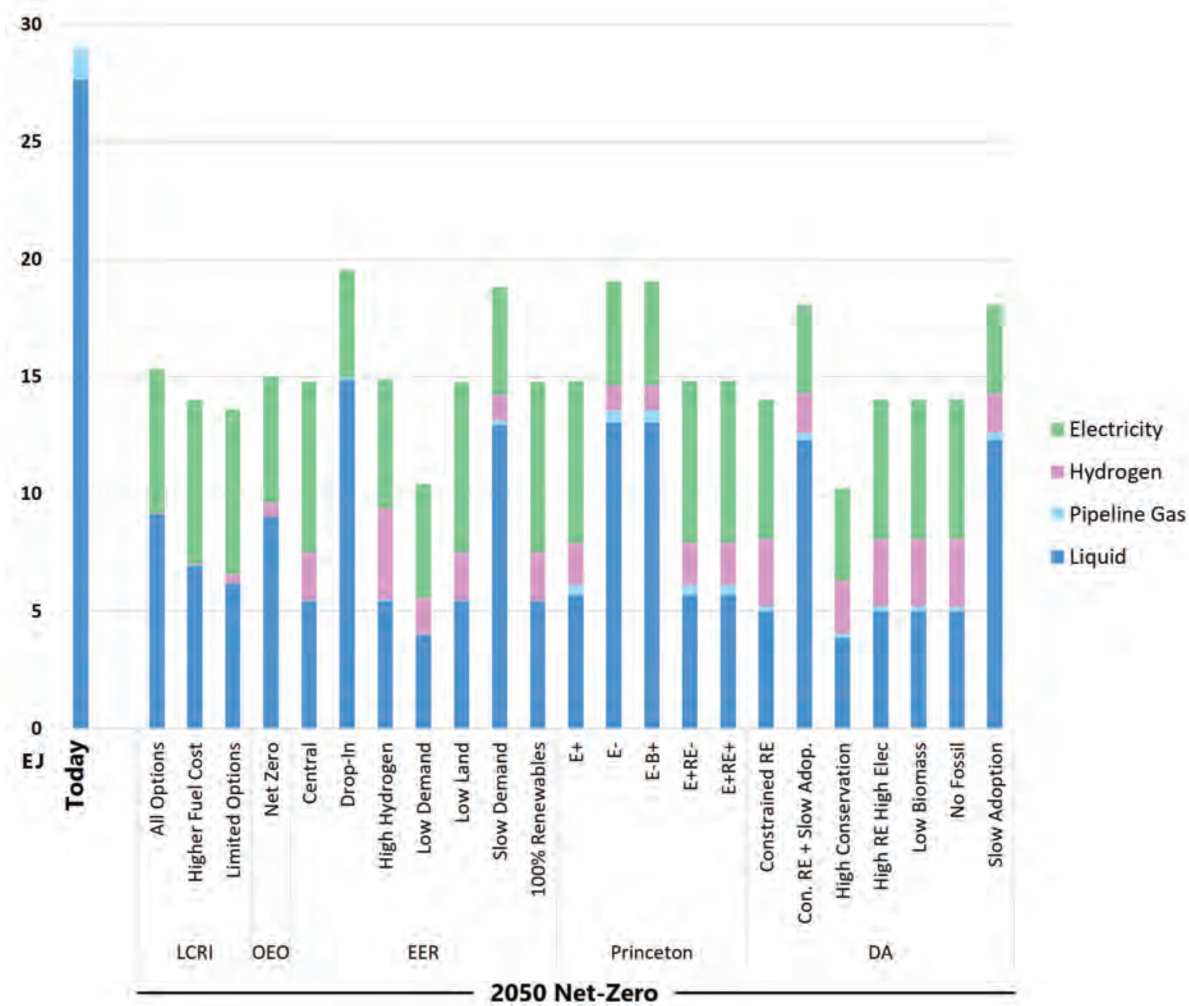
Figure 4: Annual Transportation Energy Consumption by Energy Carrier (EJ)



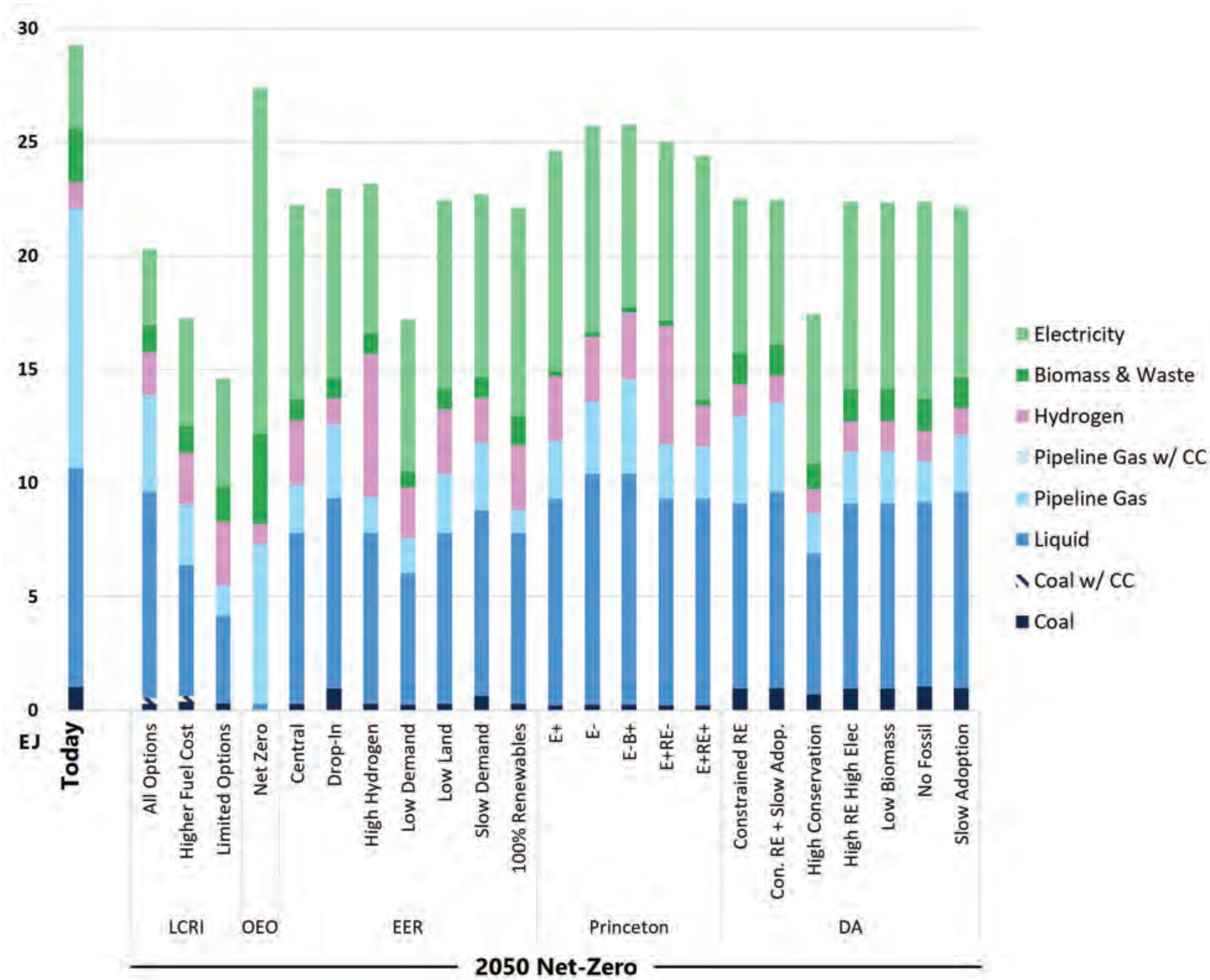
Increased deployment of efficient electric vehicles drives rising electricity consumption and falling energy consumption relative to today. Hydrogen vehicles are adopted across all net-zero scenarios, while liquid fuels continue to serve long-haul and heavy-duty sectors.

as compared to conventional fuels-based vehicles, this increased adoption drives steep declines in total energy consumption in the transportation sector, even as the total number of vehicle miles traveled per year rises from now to 2050. Note that these efficiencies for transport electrification mean that electricity's share of service demand exceeds its share of final energy. Fuels—which are capable of storing large quantities of energy per unit weight and volume—continue to serve, especially in sectors with more stringent on-board storage requirements. Liquid fuels remain a large share of the energy supply, particularly for aviation, maritime, and heavy-duty sectors. Hydrogen is also adopted in the transport sector, with a range of potential deployments across studies and scenarios. Hydrogen vehicle deployment is lower in the LCRI and OEO studies, as compared to the EER, Princeton, and DA studies. In the LCRI and OEO studies the demand-side decisions regarding which vehicle type to deploy were incorporated as part of the overall cost optimization, whereas the vehicle types were provided as user-defined inputs in the other studies. Ammonia is adopted as a fuel for the maritime sector in the LCRI, EER, and DA studies. Pipeline gas continues to serve a small share of the transportation sector in some net-zero scenarios, primarily for medium- and heavy-duty vehicles.

Industry

Industrial energy consumption falls across net-zero scenarios (Figure 5), driven by efficiency improvements. For example, the LCRI Limited Options scenario—where

Figure 5: Annual Industrial Energy Consumption by Carrier (EJ)



Electricity and hydrogen expand across industry relative to today. Fuels comprise a large share of industrial energy consumption under net-zero conditions, with liquid fuels continuing to serve as feedstocks for non-energy uses.

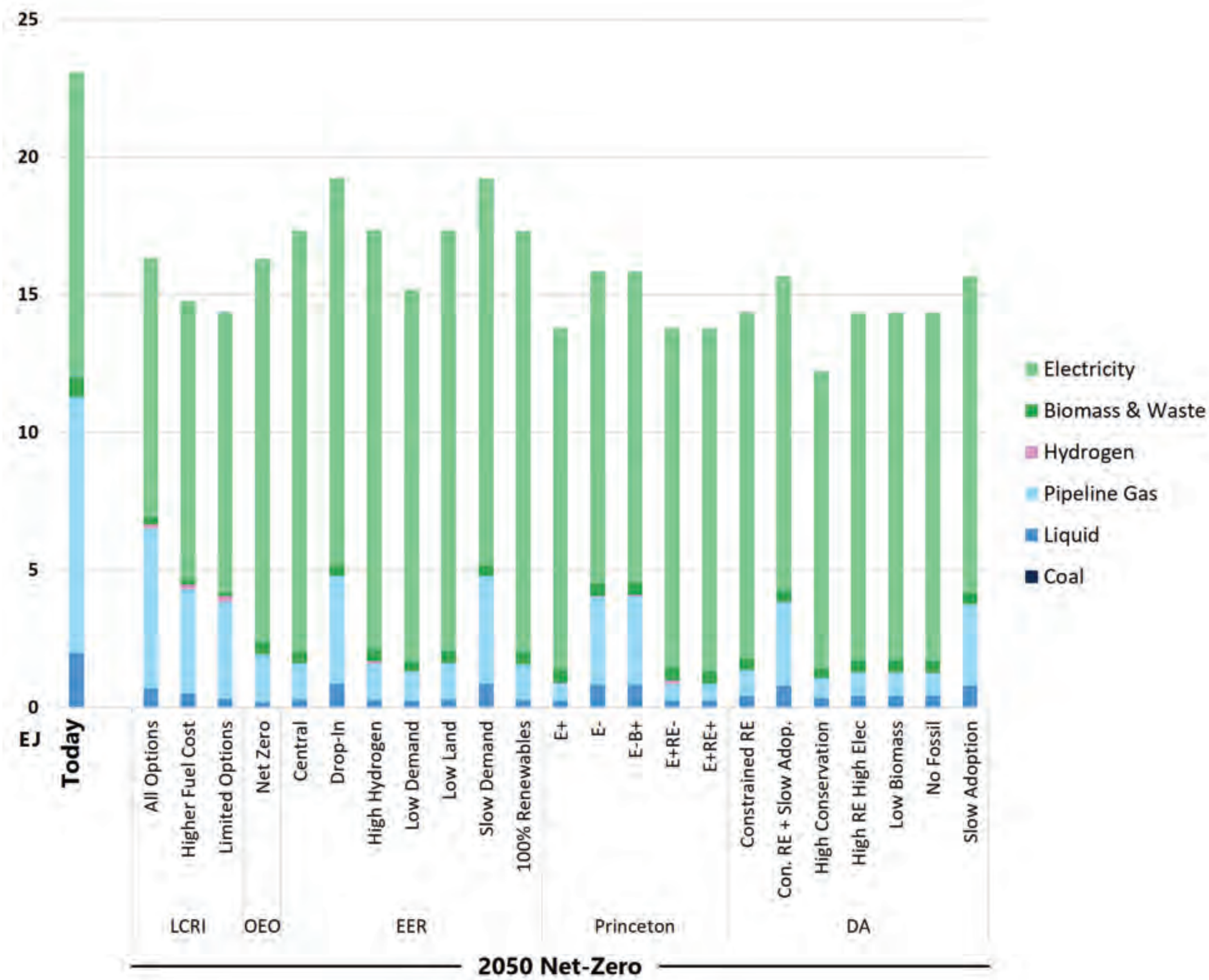
there were constraints on the technology options available—adopted higher efficiency technologies as part of the least-cost solution, driving down overall energy consumption in the industrial sector. EER's Low Demand scenario and DA's High Conservation scenario assumed lower energy service demand in general, which also led to lower industrial energy consumption.

Electricity grows considerably relative to today, comprising more than a third of energy consumption in most net-zero scenarios. Fuels continue to have a significant role, accounting for more than half of industrial energy consumption in all net-zero scenarios. Hydrogen grows from today's levels where it continues to serve as a non-energy feedstock for chemicals production, as well as a fuel for process heating.[29] Pipeline gas usage declines but remains non-zero in all scenarios. Liquid fuel consumption remains similar to today's levels, in part, because these fuels continue to serve as feedstocks for non-energy uses.[30] Coal declines across most scenarios but continues to serve the steel and cement industry with carbon capture and sequestration deployed in some scenarios.

Buildings

In the buildings sector (Figure 6), as with the transportation and industrial end-use sectors, electricity expands to provide a large share of energy consumption. A range of electric appliances and equipment are adopted, with substantial deployment of electric heat pumps for space

Figure 6: Annual Building Energy Consumption by Energy Carrier (EJ)



Electric appliance adoption expands throughout the buildings sector as compared to today. Pipeline gas and liquid fuels decline but continue to supply energy to buildings in all net-zero scenarios.

heating. The high efficiencies of these technologies lead to reductions in the total energy consumed in the buildings sector, even as the total square footage of buildings is projected to increase from today to 2050. The LCRI and EER studies allowed the option to deploy electric heat pumps as part of a hybrid approach in which a fuel-fired heating unit is coupled with the electric heat pump, particularly in cooler climate zones. This hybrid approach avoids the need to size the electric heat pump to satisfy peak heating demands on the coldest degree days, offering a cost-competitive approach for reducing emissions.[31] Whether as part of a hybrid electric-gas heating system or a standalone gas-fired unit, pipeline gas continues to serve the buildings sector across all net-zero scenarios, particularly for cooler climate regions with peak winter space heating demands.

Liquid fuels, including propane, decrease drastically across scenarios but are never eliminated. They—along with biomass resources like firewood—continue to be used for cooking and heating in places where it may be costly to build or upgrade distribution infrastructure, such as in rural communities.

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Energy Carriers

While energy systems are built to serve customer needs, much of the energy infrastructure is built to **make**, **move**, and **store** the energy carriers supplied to end-use markets. Today, electricity is made in a variety of ways, whereas the liquid and gaseous fuels leveraged are primarily linked to petroleum and natural gas, respectively. These economy-wide net-zero studies open the aperture, considering a diverse set of pathways for producing low-carbon liquid and gaseous fuels relative to other potential decarbonization options. The cost-optimized net-zero energy system designs in these studies point towards increased production of low-carbon electricity coupled with a mix of fuels that is increasingly produced through low-carbon pathways.

Electricity

Electricity generation capacity significantly increases relative to today in all net-zero scenarios to meet the demands of increased electrification across sectors (Figure 7). Wind and solar power dominate new capacity in all scenarios, increasing four to 26 times that of today's level. New solar deployments outpace wind in all but two scenarios. Hydropower capacity remains largely unchanged relative to today's levels across all scenarios. Geothermal installations remain at their current levels, increasing only in OEO's Net Zero scenario and Princeton's E+RE- and E+RE+ scenarios.

Electric storage technologies, including batteries, pumped hydro, compressed air energy storage, and other storage systems are available as deployable options across these net-zero studies. Batteries dominate the share of new storage capacity across all scenarios, while other storage technologies have relatively little to no new deployment. The substantial increase in battery capacity complements the substantial increase in wind and solar capacity, serving to balance the short-duration (hourly, intraday) variability of these resources.

Fuels-based generation—fossil, nuclear, biomass, and hydrogen—provides firm capacity to balance long-duration (multiday, seasonal) renewables and demand variations. Total fuels-based power capacity varies across net-zero scenarios, ranging from 40% to 117% of today's fuels-based generation capacity. Coal power capacity is largely retired across net-zero scenarios. Limited levels of biomass power capacity are deployed in some scenarios, and in some cases with carbon capture.

Gas-fired capacity ranges from roughly 200 to 800 GW across net-zero scenarios, spanning a wide range as compared to the 500 GW installed today. The majority of gas-fired capacity in net-zero scenarios is deployed as peaking plants without carbon capture, providing firm, flexible operation to meet peak load demands. It is noteworthy that gas-fired generation without carbon capture is leveraged even in net-zero scenarios that exclude fossil fuels. A low-carbon pipeline gas fuel blend is used for gas-fired power plants in EER's 100% Renewables scenario, Princeton's E+RE+ scenario, and DA's No Fossil scenario.

Gas-fired power generation units with carbon capture are deployed in several scenarios. These units operate at higher capacity factors as compared to gas-fired units without carbon capture, offering firm, low-carbon power capacity. Correspondingly, higher deployment levels of carbon-capture enabled gas-fired generation tends to occur in scenarios with lower deployment levels of wind and solar generation. The relative competitiveness of carbon-capture enabled gas-fired generation depends on a multitude of factors, including the costs of the power plant and CO_2 transport and sequestration, as well as the ability of these systems to flexibly operate in response to fluctuations in renewables availability and load demand.

Nuclear power capacity is present in all net-zero scenarios except those that explicitly exclude it (EER's 100% Renewables scenario and Princeton's E+RE+ scenario). In scenarios that allow nuclear, a sizeable share of the existing capacity is maintained through 2050. New nuclear capacity buildout tends to leverage advanced technologies like small modular reactors. The highest level of nuclear deployment occurs in scenarios where other options are constrained.

Hydrogen-fired power capacity is only deployed in the LCRI study, predominately in the Limited Options scenario.[32] These units leverage hydrogen as a form of long-duration energy storage (multiday, seasonal), dispatching to meet peak demands when other generation is insufficient: for example, when wind and solar availability is limited.

Electricity production increases significantly in these net-zero systems, with total generation of between two- and three-times today's levels across most scenarios (Figure 8). This generation serves the increased electricity demands across end-use sectors, as well as electrolysis-based hydrogen production, and the synthetic fuels derived from that hydrogen.

Wind and solar contribute the majority of power generation in nearly all net-zero scenarios, providing more than two-thirds of total generation in most scenarios. In net-zero scenarios where fossil fuels and nuclear are allowed, wind and solar account for as much as 90% of all primary generation. This share increases to as high as 98% in scenarios where fossil and nuclear resources are excluded. When generation from these units exceeds

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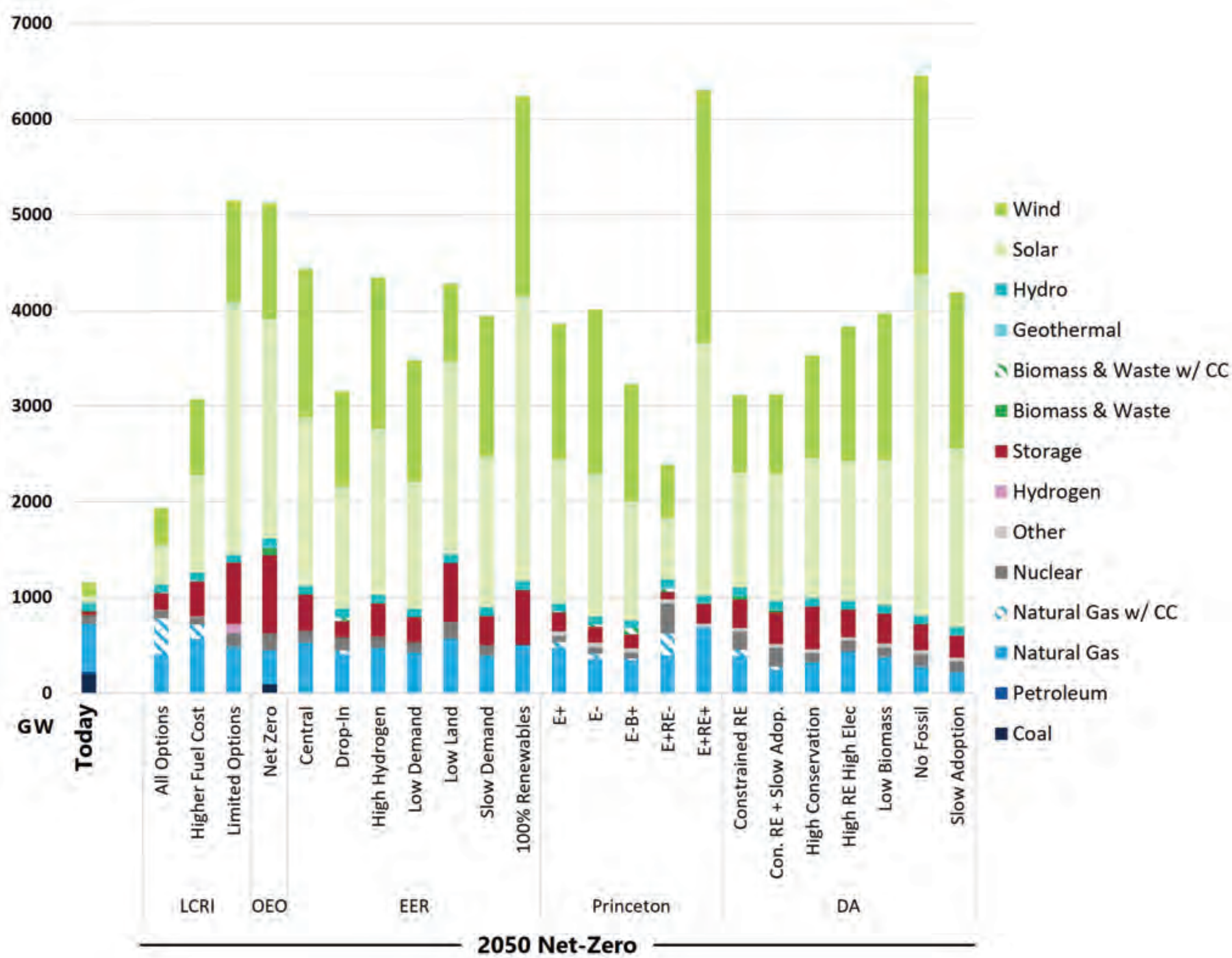
Figure 7: Electricity Generation Capacity by Source (GW)



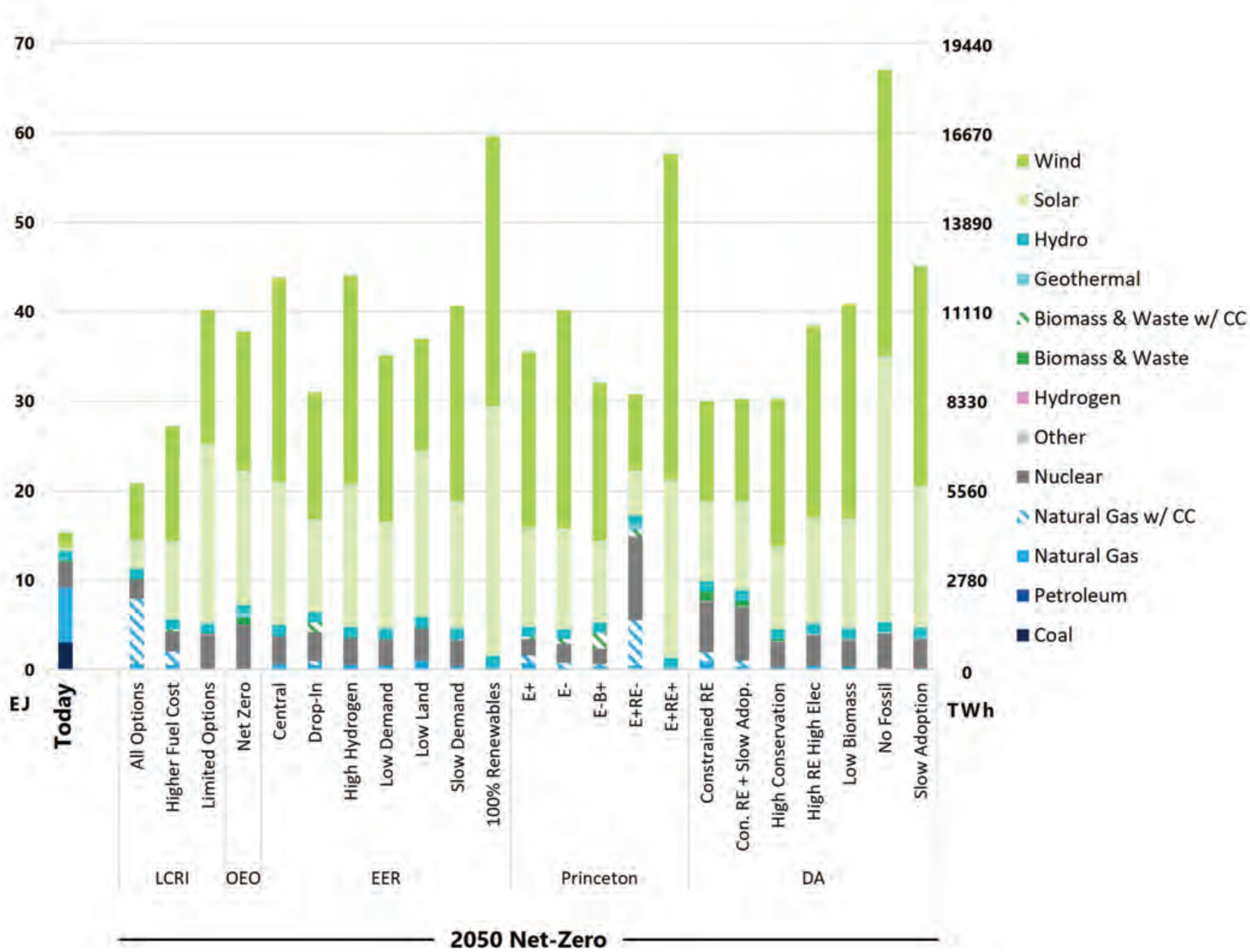
Electricity generation capacity grows multifold relative to today and is dominated by wind and solar across most net-zero scenarios, with storage and fuels-based capacity deployed to balance the variability of these renewable resources.

end-use electricity demands, this excess energy is either stored for dispatch at a later time, leveraged to produce hydrogen via electrolysis, curtailed or used to support direct air capture in some scenarios.

Nuclear energy provides the largest share of electricity after wind and solar in most scenarios (Figure 8). Nuclear-based generation contributes between 5 and 20% of total generation in all scenarios where nuclear is allowed. The Princeton E+RE-scenario is an exception, where nuclear contributes 30% of total generation. While the total installed capacity is relatively small (Figure 7), these units operate as baseload generation, providing a meaningful contribution to total electricity production.

Gas-fired generation contributes only a small amount of electricity across most net-zero scenarios, despite the relatively large capacity deployed (Figure 7). Natural gas-fired generation without carbon capture accounts for less than 3% of generation across all scenarios. These generators operate as peaking plants, with fleet-average capacity factors of roughly 2–5% for most scenarios.[33] Although used infrequently, the firm, flexible capacity offered by these units serves to provide high rates of power production to address peak events when renewables availability is low (e.g., low wind speeds due to atypical weather conditions) and/or demand is high (e.g., peak building cooling loads associated with a heat wave). In scenarios where

Figure 8: Annual Electricity Generation by Source (EJ)



The substantial wind and solar capacity deployed in these net-zero systems is leveraged to provide the vast majority of power generation in most net-zero scenarios.[34] The variability of these resources is balanced by low-carbon dispatchable generation—batteries, hydro, and carbon-captured enabled gas generation—and gas-fired peaking plants. Nuclear, and to a lesser extent biomass-fueled power, provide baseload generation.

fossil fuels are excluded, these 'natural gas' units are fueled by a mix of low-carbon fuels. Hydrogen-fired generation is also leveraged to meet peak demands in the LCRI Limited Options scenario.

Carbon-captured enabled natural gas generation contributes a small share of power production in several net-zero scenarios, accounting for at least 1% of total generation in seven scenarios (Figure 8). These units operate with fleet-average capacity factors of roughly 30 to 70% across scenarios, offering dispatchable power to balance renewables intermittency and load demands. Carbon-capture enabled gas-fired units tend to generate more electricity in scenarios where wind and solar generation is lower.

Hydropower generation is dispatched in all net-zero scenarios, leveraging a fleet of generation units with total installed capacity similar to today. In most scenarios, these units are leveraged at somewhat higher capacity factors in 2050, producing roughly 10–20% more power as compared to today. These units serve as a dispatchable source of power to balance grid demands, with fleet-average capacity factors of 40–45% in most scenarios.

Deployment of biomass-fueled power generation capacity is relatively small across net-zero scenarios (Figure 7). However, these plants tend to operate with high-capacity factors, making them a relevant share of the total generation mix. Biomass-fueled electricity accounts for at

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least 2% of total generation in six of the net-zero scenarios, spanning all studies except LCRI. Biomass-fuel power generation offers a source of low-carbon power. When coupled with carbon capture and sequestration, biomass-fueled power generation provides a pathway for achieving carbon dioxide removal (see Greenhouse Gas Emissions section). In some scenarios, carbon captured from these facilities provides a source of biogenic CO_2 feedstock for synthetic fuels production.

Geothermal generation is near zero in all scenarios except OEO's Net Zero scenario and Princeton's E+RE- scenario, which account for 1.5% and 1.8% of total generation, respectively. Geothermal units are leveraged as baseload power in those two scenarios.

The way electricity is **made** and **stored** in net-zero energy systems is central to delivering a robust supply of low-carbon electricity to end-use sectors: so too is the infrastructure required to **move** that electricity from where it is made and stored, to where it is used. Each of these studies incorporated the cost of expanding the electric grid as part of the overall analytical framework. The electricity generation capacity (Figure 7) offers a proxy for the electric grid infrastructure required in these net-zero scenarios. The grid must be sized to capture the peak output of wind and solar resources, as well as that of batteries and other firm generation. In some scenarios, this can include buildout of long-distance transmission infrastructure to move electricity from regions with high production to regions with high demand. In all net-zero scenarios where electric transmission results were reported, the transmission infrastructure is expanded relative to today. Distribution infrastructure must also be expanded considerably to meet growing demands across end-use sectors. With increased electrification of space heating, peak electric grid loads can grow considerably in cooler regions, with peak demands shifting from the summer cooling season to the winter heating season.

Hydrogen

Hydrogen has been part of the U.S. economy for decades, primarily for non-energy uses as a feedstock in petroleum refining and chemical production. Hydrogen offers great potential as a low-carbon energy carrier in that it offers the intrinsic storability and transportability characteristics of fuels, while emitting no CO_2 emissions at point of end-use. There are multiple pathways for producing low-carbon hydrogen, including electrolysis coupled with low-carbon electricity, natural gas conversion coupled with CCS, and biomass conversion with or without carbon capture. These low-carbon production pathways, as well as the systems and equipment required for moving, storing, and using hydrogen at scale, are still in the early stages of development and deployment.

Hydrogen production increases sharply in all net-zero scenarios, growing three to 20 times relative to today (Figure 9). The wide range of production levels across scenarios is driven, in part, by the nascency of the low-carbon hydrogen industry and the associated uncertainty of technology costs and performance assumptions.[35] It is noteworthy that the LCRI and OEO studies tend to have lower levels of hydrogen production and consumption, relative to the other three studies.[36] This may be attributed in part to the fact that demand side decisions—for example, whether to deploy a battery electric vehicle versus a hydrogen-fueled vehicle—are solved for as part of the overall cost optimization in the LCRI and OEO studies, whereas these decisions are framed as part of the input assumptions in the other studies.

In addition to differences in production levels, there is a range of results across net-zero studies and scenarios regarding the type of hydrogen production deployed. Electrolysis—where electricity is used to produce hydrogen from water—is leveraged across a wide range of production levels, with deployment in all net-zero scenarios except LCRI's All Options scenario. Electrolysis, and hydrogen production overall, becomes especially pronounced in scenarios where fossil resources are constrained such as LCRI's Limited Options scenario,[37] EER's 100% Renewables scenario, Princeton's E+RE+ scenario, and DA's no-fossil scenario. Across net-zero scenarios, electrolysis leverages generation from intermittent wind and solar, such that these hydrogen production facilities are considered to operate with a high degree of flexibility to utilize the variable supply of electricity from these resources.

Hydrogen production from biomass and/or waste with carbon capture and sequestration arises across many scenarios, in part, as this provides means for both producing hydrogen and for achieving negative carbon emissions flows. By capturing and sequestering the carbon in the biomass—carbon which was removed from the atmosphere during the biomass growth cycle—atmospheric CDR can be achieved. Additionally, biomass conversion with carbon capture and utilization is adopted in some scenarios, where the captured carbon is utilized as a feedstock to produce drop-in hydrocarbon fuels via synthetic fuel production pathways (hydrogen and carbon dioxide converted to hydrocarbon fuels).

Today, there is a limited level of hydrogen pipeline and underground storage infrastructure, with installations centralized in the U.S. gulf refining region. To leverage hydrogen as an energy carrier at the scale envisioned in these net-zero scenarios, the infrastructure required to **store** and **move** hydrogen must be deployed in parallel with the facilities to **make** hydrogen. These studies evaluated blending hydrogen in natural gas pipelines along with the deployment of dedicated hydrogen

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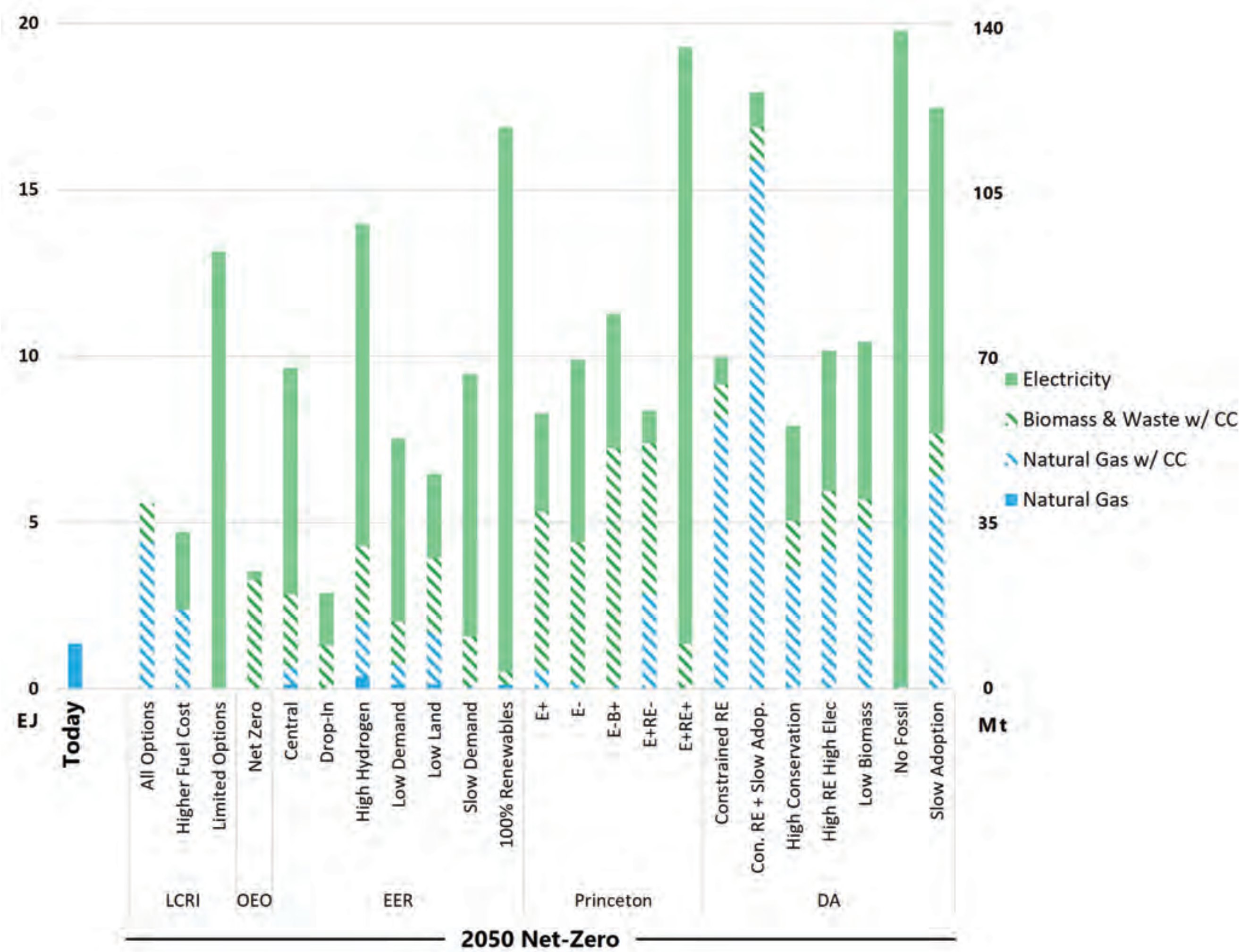
Figure 9: Annual Hydrogen Production by Production Pathway (EJ)



Low-carbon hydrogen grows considerably from today's levels, with a range of projections for production levels and pathways across net-zero studies and scenarios.

pipeline networks and large-scale underground storage, incorporating the costs of these facilities into the overall cost optimization analysis. Additionally, options for trucking hydrogen and above-ground storage tanks were also evaluated. Scenarios that leverage high levels of wind- and solar-based electrolytic hydrogen production tend to deploy higher levels of hydrogen storage to balance the variability of production with demand.

Pipeline Gas

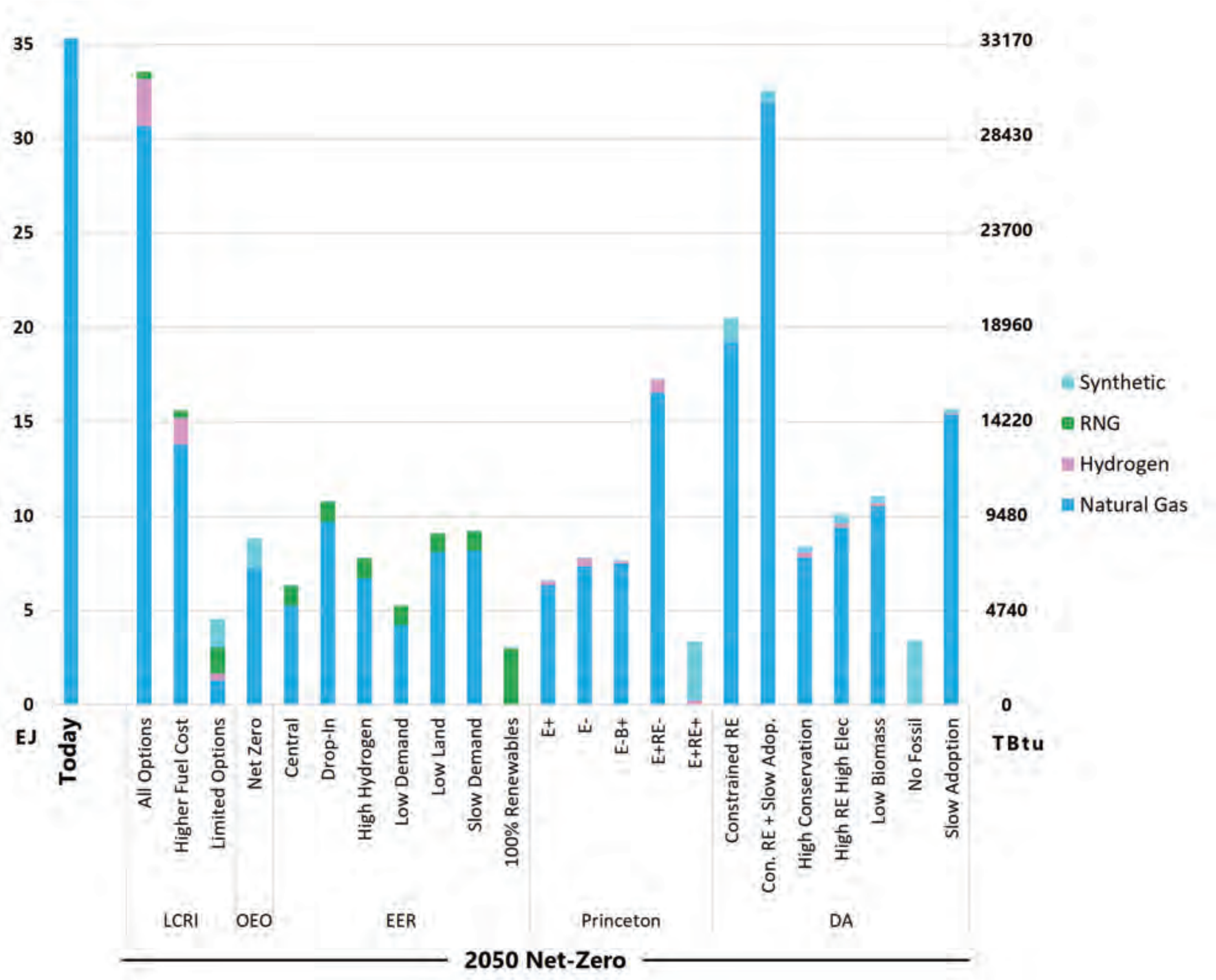
Large quantities of energy are stored and moved within the U.S. natural gas pipeline infrastructure today, supplying both power generation as well as end use customers. As energy systems transition towards net-zero, there is the potential to leverage this infrastructure for use with low-carbon gas molecules including renewable natural gas (RNG), synthetic natural gas (SNG), and blended hydrogen.

Pipeline gas continues to serve in all net-zero scenarios, but consumption declines to less than a third of today's levels across most scenarios (Figure 10). The steepest declines arise where fossil resources are constrained such as LCRI's Limited Options scenario,[37] EER's 100% Renewables scenario, Princeton's E+RE+ scenario, and DA's No Fossil scenario. Gas consumption remains the highest in scenarios where pipeline gas is leveraged with higher levels carbon capture and sequestration, such as in LCRI's All Options scenario and DA's Con. RE + Slow Adoption scenario.

Fossil natural gas remains the dominant share of pipeline gas supply in all net-zero scenarios except for those in which fossil resources are constrained either directly or indirectly.[37] RNG and SNG pathways provide a means for producing gas with a nearly identical composition to fossil natural gas.[38] They supply a small share of gas across all net-zero scenarios, with the highest shares present in net-zero scenarios where fossil fuel resources are constrained. Hydrogen is blended into the pipeline gas supply at low levels in the LCRI, Princeton, and DA studies.

The way pipeline gas is **made** in these net-zero systems evolves relative to today, whereas the way it is **moved** and **stored** is similar to today, i.e., by leveraging the existing natural gas infrastructure. These net-zero studies include the transport and storage capacity of pipeline gas infrastructure in the analysis, incorporating the costs to operate and maintain this infrastructure as part of the overall cost optimization. Although pipeline gas consumption

Figure 10: Annual Pipeline Gas Consumption by Production Pathway (EJ)



Pipeline gas consumption decreases relative to today but continues to serve in all net-zero scenarios—particularly for peak electric and winter heating demands—with increasing shares of gas produced through low-carbon pathways.

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decreases for net-zero scenarios, peak gas demands can remain relatively high. For example, gas-fired power generation capacity is deployed across all net-zero scenarios (Figure 7), but these generation assets only account for a small level of total generation (Figure 8). In many scenarios, these gas-fired generation units are only used during periods when variable renewable energy resources (e.g., wind and solar) or other generators are insufficient to meet electric demands. Hence, these gas-fired generators are used infrequently, but when called upon, they may operate at high loads, requiring a relatively high rate of pipeline gas delivery. This operating characteristic—infrequent use of pipeline gas infrastructure at relatively high throughput capacity—also arises for hybrid electric-gas heat pump systems that leverage gas-fired heating for peak heating demands during the coldest days and weeks of the year (see Buildings section in End-Use Sectors). These net-zero studies leverage the seasonal storage capacity and gas throughput capacity of gas infrastructure at relatively high levels as compared to the lower levels of pipeline gas consumption.

Liquid Fuels

Liquid hydrocarbon fuels dominate today's energy systems, both as a primary energy source and as a final form of energy to serve end-use markets. These fuels are energetically dense, enabling relatively low-cost storage and transport of these molecules—characteristics which have led to widespread adoption of these fuels in the transportation sector (where vehicle on-board energy storage is required) and large-scale deployment of pipeline and distribution networks to move these energy carriers to market. Low-carbon drop-in fuels capable of substituting petroleum-derived fuels provide a means to leverage these networks as part of an economy-wide net-zero energy system.

Liquid fuels serve multiple markets, especially transportation, across all net-zero scenarios, but at much lower levels of consumption relative to today. In terms of the energy uses for liquid fuels, as shown in Figure 11 here,[39] consumption levels drop to roughly a quarter of today's levels across most scenarios. Higher levels of liquid fuels consumption tend to occur in scenarios with lower levels of transportation electrification (Figure 4).

Conventional petroleum-based fuels comprise a large share of the liquid fuel mix across net-zero scenarios, albeit with significant decreases relative to today. Advanced biofuel technologies capable of converting a variety of cellulosic biomass materials into drop-in liquid hydrocarbon fuels—especially low-carbon aviation and diesel fuels—expand across net-zero scenarios, substituting petroleum fuels and first-generation biofuels, such as corn-based ethanol.[39] Synthetic fuel technologies, which utilize carbon dioxide and hydrogen as feedstocks for low-carbon fuel production, also expand across net-zero scenarios. These pathways tend to leverage CO_2 originally absorbed from the atmosphere, including CO_2 from direct air capture and CO_2 captured from biofuels production processes. Deployment of biofuels and synthetic fuels technologies is most prevalent in net-zero scenarios where fossil fuels are constrained, either directly within the definition of the scenario, or indirectly as a result of other aspects of the scenario definition.[37]

Ammonia is produced through low-carbon pathways in all net-zero scenarios to serve non-energy purposes, such as fertilizer and chemical applications. In the LCRI,[40] EER, and DA studies ammonia is leveraged as a low-carbon fuel to serve end-use energy needs—specifically as a fuel for marine sectors.

Today's liquid fuels are delivered to market through widespread pipeline and distribution networks. Many of the low-carbon liquid fuels **made** in these net-zero systems can leverage the existing infrastructure and networks to **move** and **store** these energy carriers. Drop-in liquid hydrocarbon fuels are energetically dense, making them relatively inexpensive to move and store as compared to other energy carriers. Given this, and the availability of existing infrastructure, the costs of moving and storing liquid hydrocarbon fuels has a relatively low impact on the results of the studies. Where ammonia production grows to accommodate a larger share of final energy as a transportation fuel, the buildout of associated storage and transport infrastructure is included in the overall cost optimization.

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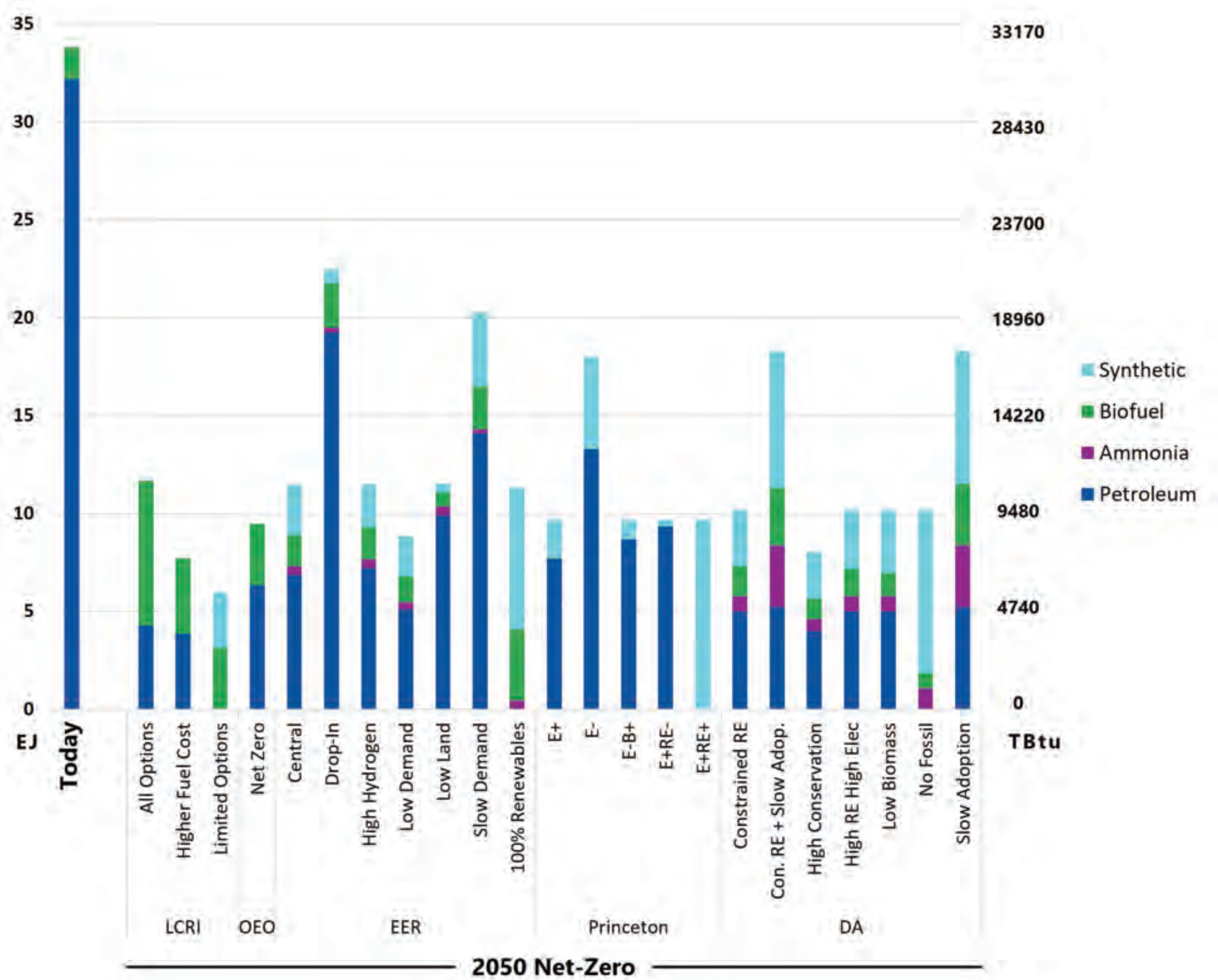
Figure 11: Annual Liquid Fuel Consumption by Production Pathway (EJ)



Liquid fuels continue to serve energy uses in all net-zero scenarios,[41] but at much lower levels of consumption as compared to today. Drop-in liquid hydrocarbons produced through bioenergy and synthetic fuels pathways increasingly serve as substitutes for petroleum-based fuels. Ammonia arises as a fuel for the maritime sector in some net-zero scenarios.

Greenhouse Gas Emissions

Getting to net-zero across the U.S. economy entails sharp declines from today's emissions levels. In addition to deeply reducing positive emissions, economy-wide, net-zero analyses consistently point to expanding negative emissions approaches, CDR, as a part of the cost-optimal design for achieving net-zero. Across the studies evaluated here, the net-zero target has been framed differently. In the LCRI and OEO studies, the net-zero target encompasses only CO_2 emissions. In the EER, Princeton, and DA studies, several greenhouse gas emissions across the economy are balanced out as part of the net-zero target.[20] Therefore, non-CO_2 emissions are only reported for the EER, Princeton, and DA in Figure 12.

Total positive emissions levels include unabated CO_2 and non-CO_2 emissions. Fossil-based emissions that are abated through CCS are also shown in Figure 12 below to illustrate the relative scale of these activities. However, these abatements do not contribute to the total positive emissions level. Positive emissions are balanced by negative emissions approaches, where CO_2 is removed from the atmosphere and durably stored. CDR can be achieved through adjustments in agriculture, forestry, and other practices that further expand the natural land sink, i.e., terrestrial absorption of atmospheric CO_2 into the land. The existing U.S. land sink absorbs 0.75 $GtCO_2$ from the atmosphere each year. This land sink grows in net-zero scenarios relative to today.[42]

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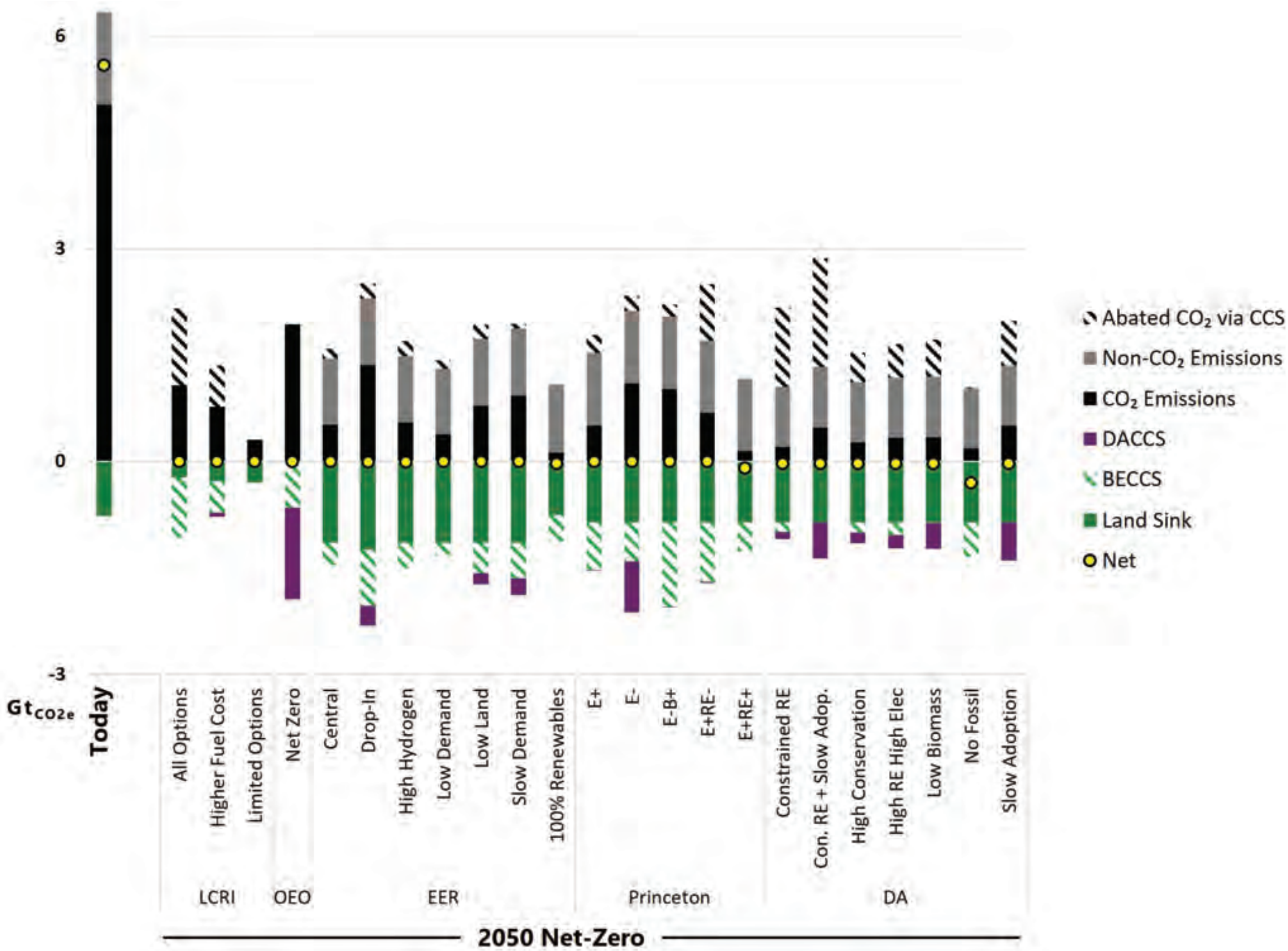
Bioenergy pathways combined with carbon capture and sequestration (BECCS) also provide a means for achieving CDR. As bioenergy feedstocks are leveraged for energy purposes, such as power production or fuels generation, CO_2 is typically emitted. By capturing this CO_2—which was originally absorbed from the atmosphere during the biomass growth cycle—and durably sequestering it, negative emissions flows can be achieved. These BECCS pathways are leveraged in every study and every net-zero scenario, except for the LCRI Limited Options scenario, where carbon sequestration was explicitly excluded as part of the scenario definition. The level of BECCS deployment varies across studies.

Direct air capture systems, energy-consuming technologies that extract CO_2 directly from the atmosphere, are also leveraged across net-zero scenarios. Coupling direct air capture with carbon sequestration (DACCS) provides another pathway for achieving negative emissions flows.

Although DACCS is a relatively costly approach for abating emissions, it offers a pathway to offset positive emissions from the most difficult-to-abate activities elsewhere in the economy. Given this, DACCS tends to arise as a backstop in these net-zero scenarios. DACCS technologies tend to be deployed later in the time horizon (i.e., closer to 2050) and the costs of these systems tend to ultimately set the marginal cost of CO_2 emissions under net-zero conditions in 2050. Given the multitude of factors that converge around the DACCS deployment decision within these optimization analyses, as well as the uncertainties in the costs and performance of this nascent technology, there is a wide range of estimates for the level of DACCS deployed across these net-zero studies.

To realize the BECCS, DACCS, and CCS-based abatements envisioned in these net-zero systems, infrastructure to **move** and **store** CO_2 at scale must be deployed. These studies include the costs associated with building new

Figure 12: Annual Greenhouse Gas Emissions ($GtCO_{2e}$)



Deep emissions reductions are achieved relative to today across all net-zero scenarios, with remaining positive emissions balanced by carbon dioxide removal (Updated February 2024).

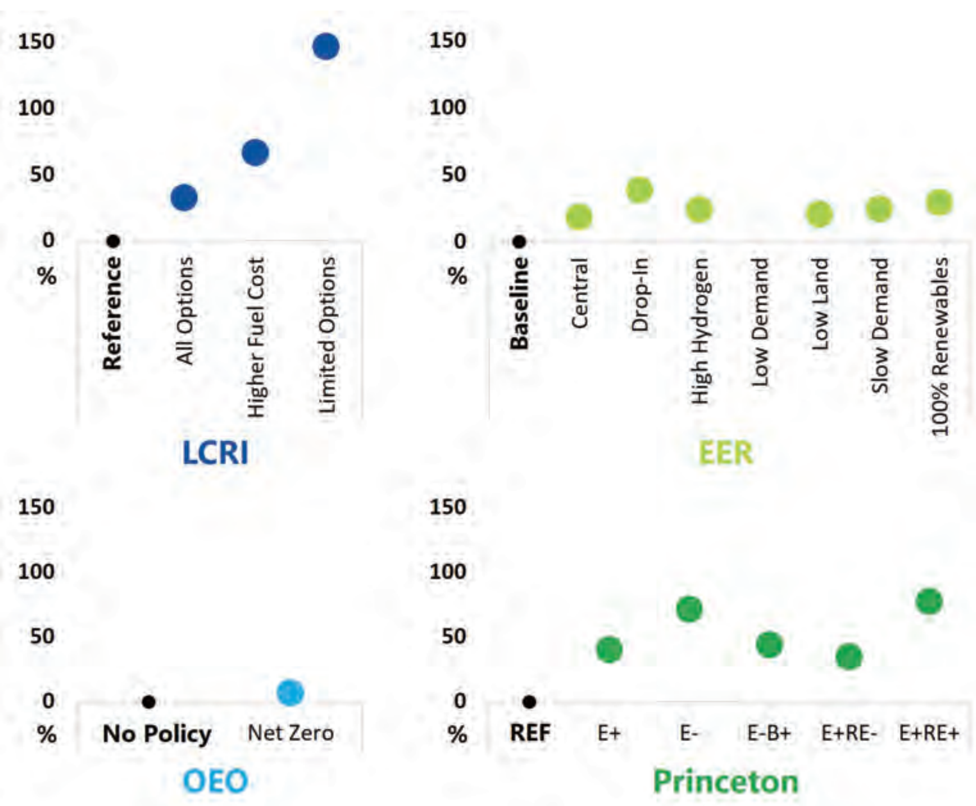
CO_2 transport networks and sequestration facilities as part of the overall cost-optimization analysis. Additionally, for scenarios that leverage CO_2 utilization, these studies include buildout of the networks for transporting CO_2 from the places where it is captured to the places where it is used, such as synthetic fuels production facilities.

Costs

All evaluated studies solved for least-cost pathways to achieve U.S. economy-wide, net-zero emissions by 2050. While each of the energy system designs envisioned across these studies reach net-zero targets, the total cost associated with transitioning to these systems varies as a function of input assumptions and scenario constraints. These studies differ in their framing and approach to characterizing the total cost of deploying these future energy systems.[43] It is thus tenuous to attempt to directly compare costs between different studies. Nonetheless, insights can be attained by comparing relative changes in cost across different scenarios within a single study. To this end, net-zero scenario costs for a given study are shown relative to that study's business as usual (BAU) scenario in Figure 13. For example, the LCRI All Options scenario costs 33% more than the LCRI BAU scenario, and the EER 100% Renewables scenario costs 29% more than the EER BAU scenario. In all studies and scenarios, achieving net-zero by 2050 results in higher cost as compared to continuing under business-as-usual conditions.[44]

The relative costs of reaching net-zero can vary across scenarios for a multitude of reasons. This can include changes in projected resource supply assumptions for a given scenario. For example, LCRI's Higher Fuel Cost and Limited Options scenarios assume lower biomass supply relative to the All Options scenario leading to higher costs, whereas Princeton's E-B+ scenario assumes higher biomass supply relative to other scenarios leading to lower costs. This can also include variations in technology assumptions such as higher CCS costs as in LCRI's Higher Fuel Cost scenario. In general, the highest costs tend to correspond to scenarios which introduce the most constraints. Examples of such constraints are: LCRI's Limited Options scenario does not allow CO_2 to be sequestered, EER's 100% Renewables scenario and Princeton's E+RE+ scenarios only allow renewable energy sources to be used, and EER's Drop-In scenario and Princeton's E- scenario constrain the adoption of electric technologies.

Figure 13: Cost of Net-Zero Systems Relative to Business as Usual (%)[45]



The total cost of deploying and operating these net-zero energy systems increases as compared to proceeding on a business-as-usual trajectory. The relative costs vary depending on the assumptions and constraints of a given net-zero scenario. The highest costs tend to correspond to scenarios with the most constraints.

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Designs for a Net-Zero U.S. Economy

Transitioning to net-zero requires an informed view of net-zero energy system designs. In recent years, a growing number of researchers, modelers, and analysts have begun to evaluate energy system designs capable of achieving economy-wide, net-zero emissions by mid-century. The energy system models leveraged in these studies consider a comprehensive set of sectors, value chains, and energy carriers, offering detailed assessments of least-cost pathways to deep decarbonization—the technologies, infrastructure, investments, and integration needed to enable a growing, net-zero U.S. economy.

The designs envisioned in these economy-wide, net-zero studies point to a transformation in the way energy is sourced, made, moved, stored, and used. These net-zero designs are built on the energy systems of today, deploying new technologies and expanding the energy infrastructure with an increasing degree of integration across electricity, fuels, and carbon management value chains. These economy-wide studies point to a common set of features in the design of net-zero energy systems. While these studies were performed prior to passage of the Inflation Reduction Act, the commonalities across these studies are consistent with the incentives in this legislation. These common approaches, now further supported by the IRA, can inform decision-making and planning efforts to drive the transition to a net-zero U.S. economy.

- **Renewables grow the supply of low-carbon energy.** Wind and solar electricity generation expands dramatically from today's levels, while biomass resources are increasingly leveraged for low-carbon fuels production.
- **Electricity expands across sectors.** Increasing numbers of electric vehicles, equipment, and appliances are adopted across sectors, with total electricity generation doubling or more than tripling today's levels.
- **Fuels diversify and serve multiple markets.** Fuels continue to supply roughly half of all energy delivered to end-use customers, with growing shares of hydrogen, and increased deployment of bioenergy and synthetic fuels technologies for producing liquid fuels and pipeline gas.
- **Efficiency reduces energy consumption while enabling economic growth.** Efficiency gains across energy value chains, particularly for electric vehicles and heat pumps, drive reductions in total energy consumption while satisfying the growing demands of an expanding U.S. economy.
- **Carbon dioxide removal balances remaining emissions.** Emissions are greatly reduced, with remaining positive emissions balanced by negative emissions approaches, such as growing the land sink, or deploying bioenergy and/or direct air capture technologies with carbon sequestration.

There is no single design for net-zero energy systems. Each of these studies points to a wide array of energy carriers, technologies, and regionally specific solutions to meet the energy demands of an expanding U.S. economy. The range of results across these studies highlights a range of perspectives and possibilities for the design of net-zero systems. This range stems partly from intentioned efforts within these studies to evaluate corner point scenarios as a means for highlighting the dynamics and tradeoffs of different net-zero designs. Despite their differences, these studies are consistent in finding that constrained scenarios—where certain technologies or pathways are explicitly excluded or limited—have higher costs than unconstrained scenarios. There is value in considering a range of options to reach net-zero, particularly in these early stages of energy transitions when there is a lot of learning yet to come. At the same time, the insights shared across these studies can inform the decisions made today.

Net-zero systems entail net-zero infrastructure. Large-scale investment in energy infrastructure is needed to achieve the unprecedented level of transformation projected across these studies. These models point to expansion of the electric grid to accommodate increasing wind and solar deployments and growing electricity demands. Infrastructure to move and store gaseous molecules at scale is required to employ hydrogen as a versatile low-carbon energy carrier and to enable carbon dioxide removal and sequestration. The existing liquid hydrocarbons and pipeline gas infrastructure will need to be leveraged where it supports the net-zero system designs envisioned in these studies.

Innovation is a foundation for transformation. The net-zero designs envisioned in these studies all rely on large-scale deployment of new technologies. This includes investing in innovations already proven out at scale, such as wind, solar, and battery technologies. It also includes investing in a broad portfolio of nascent solutions, such as hydrogen, bioenergy, carbon capture, and sequestration. The net-zero systems projected in these studies are based on the information available today. The understanding of these systems is certain to evolve as progress is made towards net-zero. Innovation in a variety of forms—technologies, operating models, market frameworks, and beyond—will be central to enabling the transition to net-zero economies.

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Acronyms

AEO	Annual Energy Outlook
BAU	Business As Usual
BECCS	Bioenergy with Carbon Capture and Sequestration
CC	Carbon Capture
CCS	Carbon Capture and Sequestration
CDR	Carbon Dioxide Removal
CO_2	Carbon Dioxide
DA	Decarb America
DAC	Direct Air Capture
DACCS	Direct Air Capture with Carbon Sequestration
EER	Evolved Energy Research
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
GHG	Greenhouse Gas
IRA	Inflation Reduction Act
LCRI	Low-Carbon Resources Initiative
OEO	Open Energy Outlook
RNG	Renewable Natural Gas
SNG	Synthetic Natural Gas

Units

EJ	exajoule
GW	gigawatt
Gt	gigatonne (billion metric tons)
Mt	megatonne (million metric tons)
TBtu	trillion British thermal units
TWh	terawatt-hour

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Endnotes

1 See Table 1 in the main report for the complete list of studies considered.

2 The Evolved Energy Research, Princeton University, and Decarb America studies all employed a common analytical framework—the EnergyPATHWAYS model, developed by EER.

3 Liquid fuels include ammonia and hydrocarbon fuels derived from petroleum, bioenergy, and synthetic pathways.

4 Pipeline gas includes fossil natural gas, renewable natural gas, synthetic natural gas, and blended hydrogen.

5 Three exceptions are: (1) the Open Energy Outlook study did not report non-energy uses of fuels, hence the results shown here are for energy uses only, (2) the hydrogen data for today is based on 2020 data, rather than 2022, and (3) the Open Energy Outlook Net-Zero scenario had 7% of final energy as biomass.

6 The reported reduction in primary energy consumption is also an artifact of the reporting convention employed here for wind and solar technologies, where the produced energy is directly reported (e.g., the electricity generated from a solar panel) rather than the available energy (e.g., the sunlight energy impinging on a solar panel).

7 Land sinks were not included in the Open Energy Outlook analysis.

8 As based on government commitments tracked by Climate Watch.

9 Facilities that leverage bioenergy resources for power generation or fuel production may emit CO_2 released from carbon that was originally within the bioresource. The carbon in these bioresources was absorbed from the atmosphere during growth. By capturing and sequestering this CO_2 from bioenergy facilities, this creates an overall negative flow of CO_2 from the atmosphere.

10 The BP study, despite being global in scope, was still considered for this meta-analysis because it had a section with U.S. data.

11 The Energy Modeling Forum (EMF), coordinated by Stanford, brings together experts and decisionmakers to study important energy and environmental issues. Each EMF study is organized through a working group to design the study, compare each model's results, and discuss key conclusions.

12 Energy Pathways USA is a partnership between Duke Nicholas Institute for Energy, Environment & Sustainability and Energy Transitions Commission.

13 The Low-Carbon Resources Initiative (LCRI) is a joint collaboration between GTI Energy and Electric Power Research Institute (EPRI) focused on accelerating the development and deployment of low-carbon energy technologies required for deep decarbonization.

14 The Open Energy Outlook is joint initiative between the Wilton E. Scott Institute for Energy Innovation at Carnegie Mellon University and North Carolina State University to examine U.S. energy futures to help inform energy and climate policy efforts.

15 The Decarb America Research Initiative is a collaboration between the Bipartisan Policy Center, Clean Air Task Force, and Third Way to analyze policy and technology pathways for the United States to reach net-zero greenhouse gas emissions by 2050.

16 The data assessment in Table 1is based on an evaluation of publicly and freely available data. It is possible that additional data is available behind a paywall for some studies.

17 As of September 2023. Some teams publish studies on an annual basis, such as BP, Shell, and EER. Only the most recent publication has been considered here.

18 Pathways to 2050 by the Center for Climate and Energy Solutions was initially considered for this meta-analysis but ultimately not included because none of its scenarios targeted net-zero emissions. The most aggressive scenario stopped at an 80% reduction in GHG emissions.

19 Many global net-zero studies have been published over the past few years, such as the International Energy Agency's *Net Zero Roadmap*. However, these studies sometimes lack publicly available U.S.-specific data. Comparisons of global decarbonization studies have been published by Resources for the Future (report) and others (report, report).

20 Non-CO_2 greenhouse gases in the EER, Princeton, and DA studies include methane, oxides of nitrogen, fluorinated gases, and others and are represented as carbon dioxide equivalent (CO_{2e}).

21 A more detailed summary of studies and scenarios is provided in the Supporting Material.

22 A recent multimodal study provides a comparison of how the Inflation Reduction Act could shape energy systems and emissions (report).

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23 Information for the current U.S. energy system was derived from EIA; current U.S. emissions data was obtained from the Environmental Protection Agency (EPA). Detailed discussion on the methodologies applied in this meta-analysis are provided in the Supporting Material.

24 Final energy is calculated by summing the energy consumption of the three end-uses: transportation, industry, and buildings. It does not show energy consumed in direct air capture or in interim stages like electricity and fuel production.

25 Energy values for fuels are reported on a higher heating value (HHV) basis in this report.

26 The EER study also used heat from thermal nuclear power plants for direct air capture systems.

27 Liquid fuels include ammonia and hydrocarbon fuels derived from petroleum, bioenergy, and synthetic pathways.

28 Pipeline gas includes fossil natural gas, renewable natural gas, synthetic natural gas, and blended hydrogen.

29 Hydrogen is reported as a final energy carrier when it is used directly as an end-use fuel or as a non-energy feedstock for chemicals production (including non-energy uses of ammonia). Hydrogen is reported in pipeline gas when it is blended into the pipeline gas supply. Hydrogen is reported in liquid fuels when it is used to produce synthetic fuels or ammonia used as an end-use fuel.

30 The OEO study did not include non-energy uses of fuels.

31 Air-source heat pump efficiencies decrease as outside air temperatures become colder. To meet the heating requirements with a heat pump alone, the heating unit would need to be sized larger than a unit sized for a hybrid mode. This standalone heat pump approach is more costly in terms of the heating equipment itself, but also in terms of the associated infrastructure requirements. Electrification of space heating can increase and shift peak annual electric loads to the coldest winter days, such that additional electric transmission and distribution capacity is required, along with additional electric generation capacity. This cost stacking through the electric value chain for standalone heat pumps can lead to higher overall costs for achieving economy-wide net-zero targets in comparison to hybrid electric-gas heating systems. This complex set of cost tradeoffs is incorporated into the analyses of the LCRI and EER studies, which allow for this hybrid heating option. The results of these studies point to broad adoption of hybrid electric-gas heating systems in net-zero scenarios.

32 Although hydrogen is blended into the pipeline gas mixture used for gas-fired power generation in some scenarios across studies, pure hydrogen is only leveraged as a fuel for power generation in the LCRI study.

33 Capacity factor is a measure how intensively a generating unit is operated. Capacity factors are calculated here by dividing the electricity generated in 2050 by the maximum possible electrical energy that could have been produced if the generator were continuously operated at maximum capacity. A capacity factor of 100% indicates that a generating unit is continuously operated at its maximum output.

34 Figure 8 reports the primary source of generation from wind and solar, rather than the secondary generation from storage, which originally stored power from excess wind and solar capacity. This is consistent with the reporting convention of all five studies evaluated here.

35 Electrolysis costs in 2050 were assumed to be lower in the Princeton and EER studies as compared to the LCRI study, and correspondingly, the Princeton and EER studies trend towards higher deployment of electrolytic hydrogen production. Regarding natural gas with carbon capture pathways, Princeton and EER assumed higher costs in 2050 than LCRI, and correspondingly the Princeton and EER studies trended towards lower deployment of natural gas-based hydrogen production. LCRI assumed a 55% carbon capture rate for biomass pathways, whereas Princeton assumed an 87% capture rate.

36 For OEO, the lower level of hydrogen could be attributed to the study excluding non-energy uses of resources.

37 LCRI's Limited Options scenario does not explicitly exclude fossil fuels, but it explicitly excludes carbon sequestration. This constraint ultimately translates to substantial reductions in fossil fuel consumption in the LCRI Limited Options scenario.

38 There are differences in how certain low-carbon pipeline gas pathways are labeled across different studies. In all studies, landfill gas and anaerobic digestion-based gas are considered as sources for renewable gas. Similarly, across all studies, pipeline gas generated through conversion of captured CO_2 and hydrogen is treated as synthetic natural gas. For gas produced via biomass gasification this is treated as RNG in the LCRI study, whereas it is treated as SNG in EER, Princeton, and DA. OEO did not include RNG but included SNG.

39 The Princeton study included biofuels as part of the production of liquid fuels and pipeline gas. However, in the Princeton dataset utilized for this meta-analysis, biofuels are reported as synthetic fuels. Hence, the synthetic fuels results in Figure 10 and Figure 11 are indicative of both biofuels and synthetic fuels.

40 For LCRI, ammonia is used as a transportation fuel at very low levels (0.04 EJ) in the Limited Options scenario.

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41 Figure 11 shows energy uses of liquid fuels, such as heating buildings and fueling vehicles. Non-energy use of liquid fuels as feedstock chemicals and materials is not shown here but is included in the total final energy values reported in Figure 3.

42 The land sink values reported for LCRI scenarios only include the incremental land sink change relative to the 2020 level evaluated in that study. Hence these values appear smaller in magnitude as compared to the 2022 levels shown in Figure 12. In the EER 100% Renewables scenario, the 2050 land sink is slightly lower than the 2022 level, but the overall net-zero target is still achieved despite this slight land sink reduction. OEO did not include the land sink in their analysis.

43 The cost information reported here is described in greater detail in the Supporting Material.

44 Costs for the EER Low Demand scenario are not reported here as based on guidance from the authors of the EER study. The framing for the Low Demand scenario is such that it is tenuous to compare costs for this scenario relative to other EER scenarios.

45 Decarb America did not report cost information.

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About GTI Energy

GTI Energy is a leading technology development organization. Our trusted team works to scale impactful solutions that shape energy transitions by leveraging gases, liquids, infrastructure, and efficiency. We embrace systems thinking, innovation, and collaboration to develop, scale, and deploy the technologies needed for low-carbon, low-cost energy systems.

About Low-Carbon Resources Initiative (LCRI)

GTI Energy and EPRI are together addressing the need to accelerate development and demonstration of low- and zero-carbon energy technologies.

The Low-Carbon Resources Initiative (LCRI) will focus on large-scale deployment to 2030 and beyond. Fundamental advances in a variety of low-carbon electric generation technologies and low-carbon chemical energy carriers—such as clean hydrogen, bioenergy, and renewable natural gas—are needed to enable affordable pathways to economy-wide decarbonization.

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E3 REPORT – *RESOURCE ADEQUACY AND THE ENERGY TRANSITION IN THE PACIFIC NORTHWEST: PHAST 1 RESULTS, DOCKET UE-210096*

EXHIBIT 1202

November 2025

Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results

Washington Utilities and Transportation Commission
Washington Department of Commerce

Resource Adequacy Meeting, RCW 19.280.065, Docket UE-210096

September 22, 2025

Lacey, Washington

Energy+Environmental Economics

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Overview of Phase 1

E3 was retained by regional utilities and generation owners to evaluate the state of resource adequacy in the Pacific Northwest today and into the future. Key findings of Phase 1:

1. **Accelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to <u>*9 GW by 2030*</u>**
   - 9 GW is approximately the load of the state of Oregon
2. **Preferred resources such as wind, solar and batteries make only <u>*small contributions*</u> to meeting resource adequacy needs**
3. **<u>*Timely development of all resources is extremely challenging*</u> due to permitting and interconnection delays, federal policy headwinds, and cost pressures**

STUDY SPONSORS

- Puget Sound Energy
- Public Generating Pool
  - Chelan Public Utility District
  - Clark Public Utility District
  - Cowlitz Public Utility District
  - Eugene Water & Electric Board
  - Grant Public Utility District
  - Lewis Public Utility District
  - Seattle City Light
  - Snohomish Public Utility District
  - Tacoma Power
- Avista Corporation
- Benton Public Utility District
- Douglas Public Utility District
- Emerald People's Utility District
- Franklin Public Utility District
- Idaho Power
- Klickitat Public Utility District
- Mason Public Utility District No. 3
- Northwest & Intermountain Power Producers Coalition
- NorthWestern Energy
- Okanogan Public Utility District
- Pacific Public Utility District
- Portland General Electric

Who is E3?

Our Practice Areas

+ **E3 is the largest consulting firm focused on the clean energy transition in North America**
+ **E3 is a recognized thought leader on decarbonization and clean energy transition topics**
+ **E3 has three major practice areas covering energy systems from bulk grid to behind the meter**

Climate Pathways / Policy Analysis

- Climate and energy policy analysis
- Long-term energy & climate scenarios
- Electrification and low-carbon fuels
- Future of gas

Asset Valuation & Strategy

- Asset valuation and due diligence
- Strategic advisory
- Energy market price forecasting
- Market design
- Transmission planning

Integrated System Planning

- Integrated resource planning for electric systems: reliability and resource mix
- Planning for utility and state RPS + GHG targets
- Utility planning and procurement decisions

Economy-wide energy systems | Bulk grid power systems | Grid edge & behind-the-meter

E3 has extensive experience planning for deeply-decarbonized power systems for a wide range of clients

+ State agencies

- **California:** E3 provides technical support and advisory services to the CPUC in administration of the state's IRP program, to CARB in implementation of AB32 "cap-and-trade" program, and to the CEC on a variety of research topics including compliance with SB100
- **New York State Climate Act Scoping Plan:** E3 supports NYSERDA with technical analysis of pathways to achieve economy-wide carbon neutrality by 2050 including 100x40 in the power sector
- **Illinois:** E3 supports the Illinois Power Authority and Commerce Commission on a variety of topics including resource adequacy, procurement, and renewable energy transmission studies
- **Massachusetts Department of Energy Resources:** Evaluating the benefits of long-duration energy storage and other topics

+ Utilities

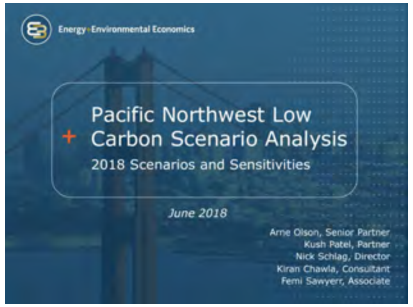
- **E3 has provided IRP support to dozens of utilities** including Puget Sound Energy, Eugene Water and Electric Board, Sacramento Municipal Utilities District, Arizona Public Service, Salt River Project, NV Energy, Public Service Company of New Mexico, El Paso Electric, Xcel Energy, Black Hills Energy, Hawaiian Electric Company, Omaha Public Power District, Florida Power & Light, Tampa Electric Company, Nova Scotia Power, New Brunswick Power, and others

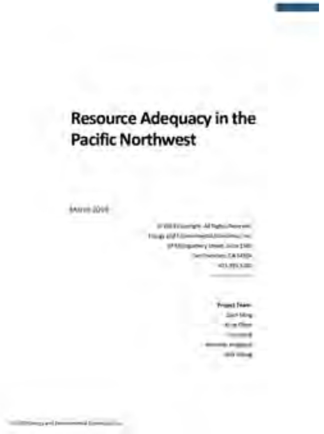
+ Non-profits

- E3 has advised **environmental advocacy organizations** including the Natural Resources Defense Council, Environmental Defense Fund, The Nature Conservancy, Clean Air Task Force, EarthJustice, World Resources Institute, Climate Solutions, and others

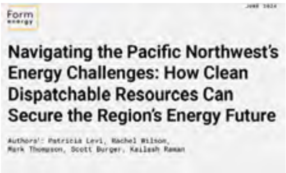
Resource Adequacy and the Energy Transition: Project Background

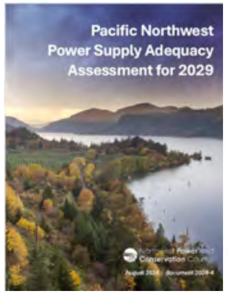
Prior E3 Studies in the Pacific Northwest

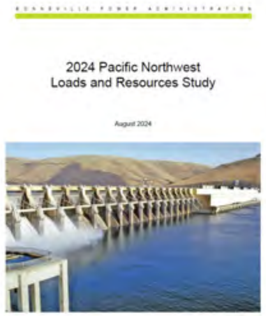




Recent PNW Regional Studies and Forecasts



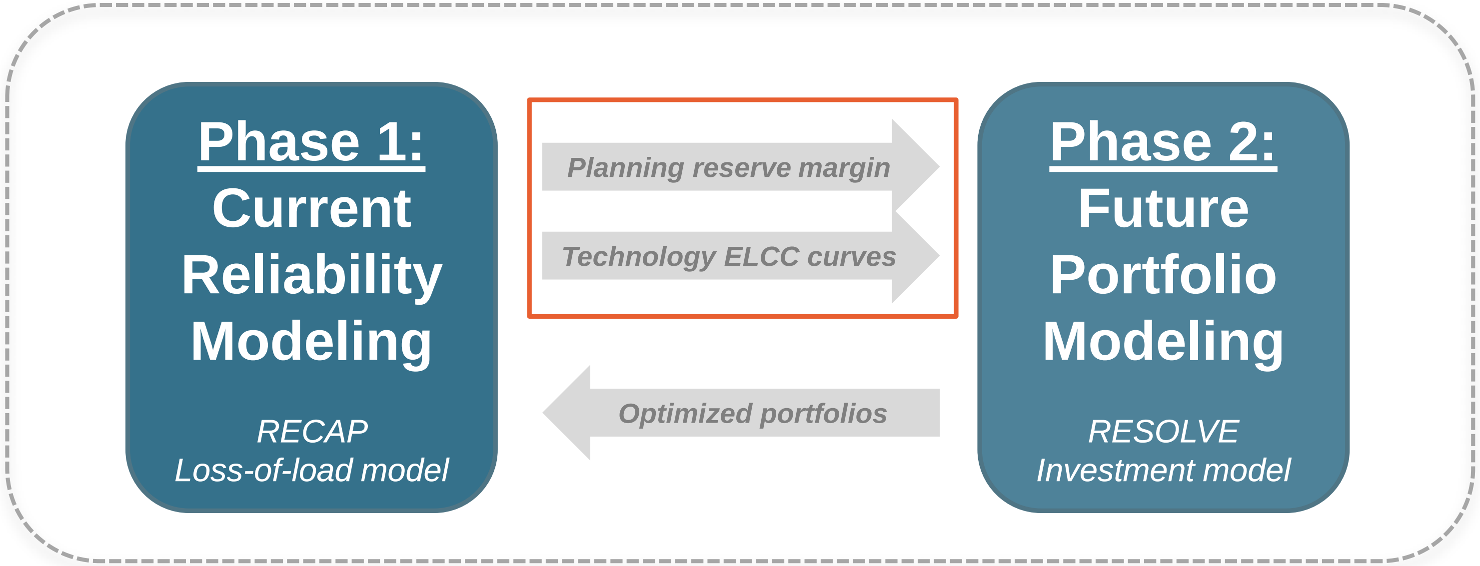




- **Prior E3 studies found that the Pacific Northwest faces *immediate and growing* resource adequacy challenges**
- **Much has happened over the past six years that might change the regional resource adequacy picture**
- **Current study objectives:**
  - Evaluate current load-resource balance
  - Examine the role of various technologies including flexible loads and firm generation for ensuring reliability
  - Identify potential barriers that may prevent the region from meeting its goals in the future

Study uses a two-phased modeling approach

+ **The modeling approach pairs detailed loss-of-load-probability modeling with capacity expansion modeling to provide a robust perspective on system reliability and cost under aggressive clean energy targets**

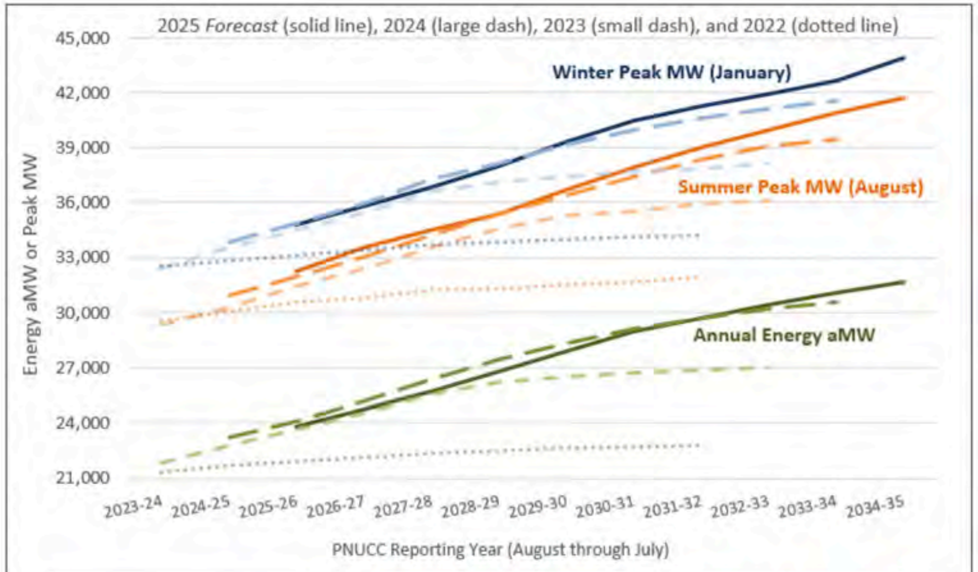


Key Study Topics:

1. Near-term resource adequacy picture
2. Barriers to new resource development
3. How to maintain long-term resource adequacy on a transitioning grid
4. Potential role for DSM and emerging "clean firm" resources
5. Stranding risk for near-term capacity resources

Regional load forecasts continue to increase due to AC adoption, electric vehicles, and data centers

PNUCC 2025 Northwest Regional Forecast
Energy aMW or Peak MW Forecast



Growth Rates

Energy	10 year
2025 Forecast	3.2%
2024 Forecast	3.1%
2023 Forecast	2.4%
2022 Forecast	0.9%

Summer Peak	10 year
2025 Forecast	2.9%
2024 Forecast	2.7%
2023 Forecast	2.3%
2022 Forecast	1.0%

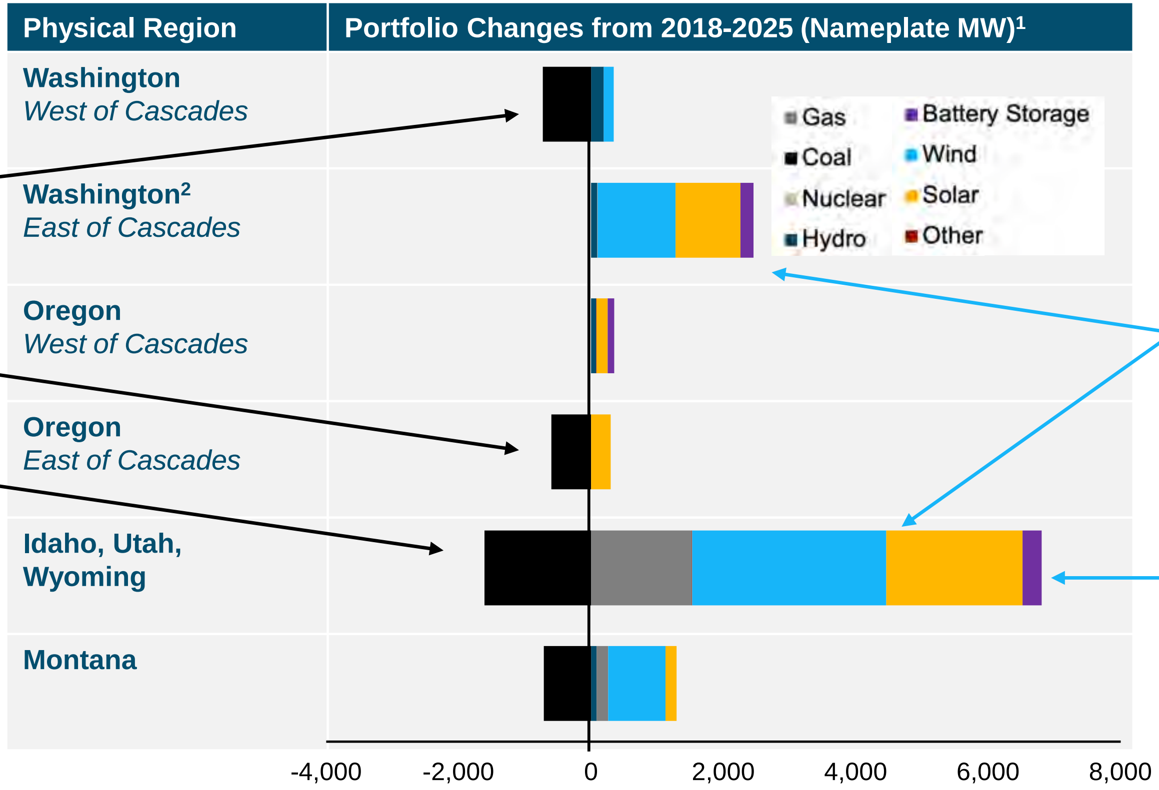
Winter Peak	10 year
2025 Forecast	2.6%
2024 Forecast	2.3%
2023 Forecast	1.8%
2022 Forecast	0.7%

+ **Load growth acceleration is attributable to multiple distinct drivers, despite impact of energy efficiency**

Driver	Near-term Impact
Economywide **energy efficiency**	Small load reductions in both seasons
Higher-than-expected **air conditioning adoption** after recent heat waves	Small-medium peak load growth in the summer
Policy-driven **electric vehicle adoption**	Medium peak load growth in both seasons
Population growth and new building construction	Medium peak load growth in both seasons
Anticipated **data center** interconnection	Large average and peak load growth in both seasons

New resource additions have been slow, and located primarily outside of Washington and Oregon

Coal retirements are reducing the quantity of firm capacity available in the region



Almost all new resources have been wind and solar

New resources are mostly being built in Wyoming and Utah

1. Based on WECC 2034 ADS and recent retirements)

The Greater Northwest faces a supply deficit in 2026 which grows to 8,700 MW by 2030

- **Load growth and retirements mean the region faces a power supply shortfall in 2026**
  - The region currently relies on imports to maintain reliability
- **Nearly 9,000 MW of new capacity is needed by 2030**
- **Projects currently in active development account for only 3,000 MW of new capacity**
  - 850 MW are coal-to-gas conversions
  - 260 MW are hydro upgrades

Greater Northwest
Total Resource Need and Effective Capacity Contribution from Planned Resources (MW)

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

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Greater Northwest
Total Resource Need and Effective Capacity Contribution from Planned Resources (MW)

System Needs (MW)	2025	2026	2027	2028	2029	2030
Total Resource Need*	49,245	50,737	52,499	54,184	55,879	57,195
Existing Portfolio w/ Retirements	46,716	45,666	45,395	45,388	45,098	44,757
Firm Imports	3,750	3,750	3,750	3,750	3,750	3,750
Reliability Position Surplus (+) / Shortfall (-)	**+1,221**	**-1,321**	**-3,354**	**-5,046**	**-7,031**	**-8,689**
ELCC from “In-Development” Firm Resources	-	296	407	580	770	1,114
ELCC from “In-Development” Wind, Solar and Battery projects	-	645	1,015	1,316	1,508	1,934

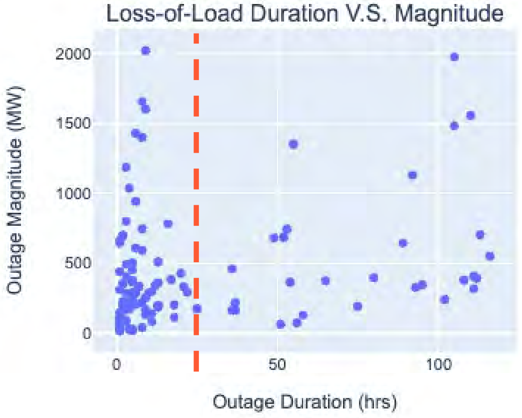
** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

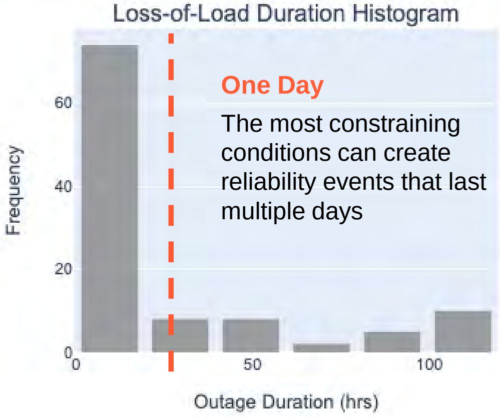
The most constraining reliability conditions are extended wintertime cold weather events during very low water years

- **Most loss-of-load events occurring during the coldest winter months**
- **Many events exceed 50 hours in duration with some exceeding 100 hours due to energy shortfalls in dry years**

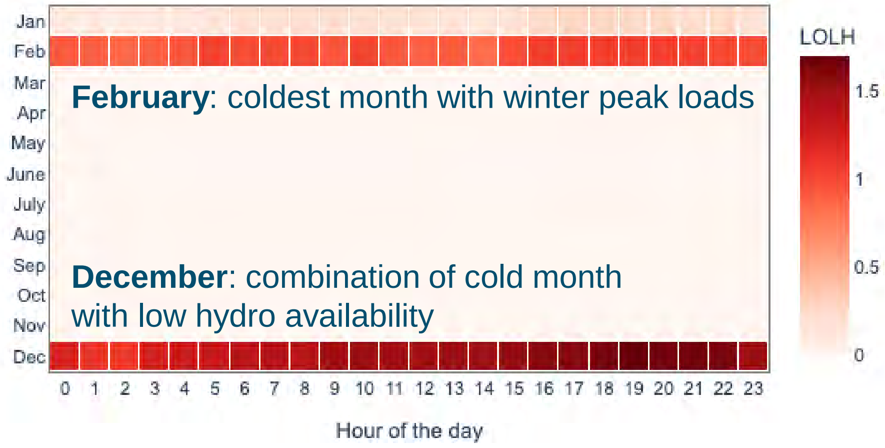
Greater Northwest, tuned to 1-day-in-10-year standard

Distribution of Loss-of-Load Events across over 2,500 years of simulated load, hydro, and renewable conditions





Average Loss-of-Load Hours (LOLH) by Month x Hour*



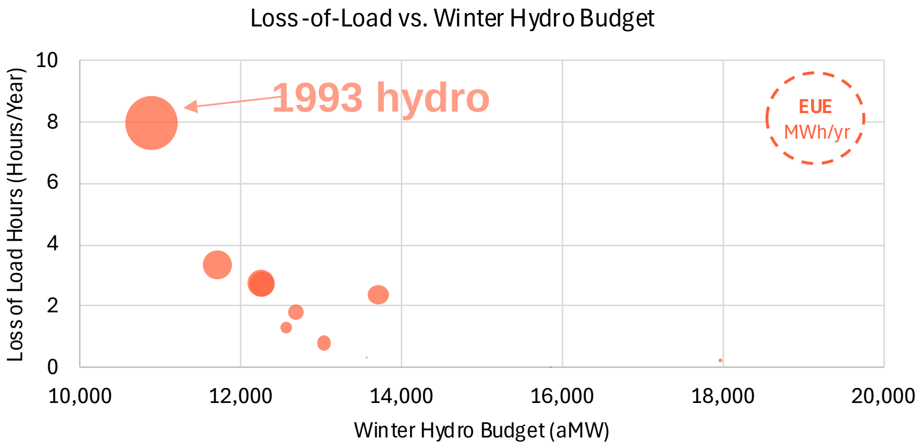
* Metrics + heatmap shown without firm imports

Addressing these events requires resources that can deliver energy over long periods of time

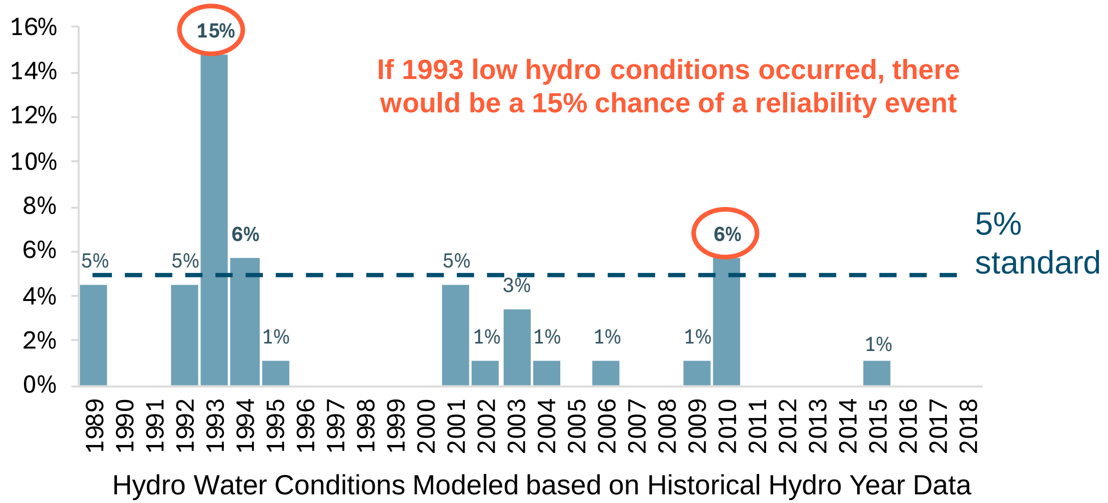
Energy shortfalls that occur during low hydro years contribute significantly to resource adequacy events

- **Loss of load events are concentrated during the lowest hydro years (1989, 1990, 1992, 1993, 1994, 2001, 2010)**
- **January 2024 conditions were consistent with the very low hydro years simulated here**

2025 Average Loss-of-Load Hours (LOLH) and Expected Unserved Energy (EUE) by Hydro Year



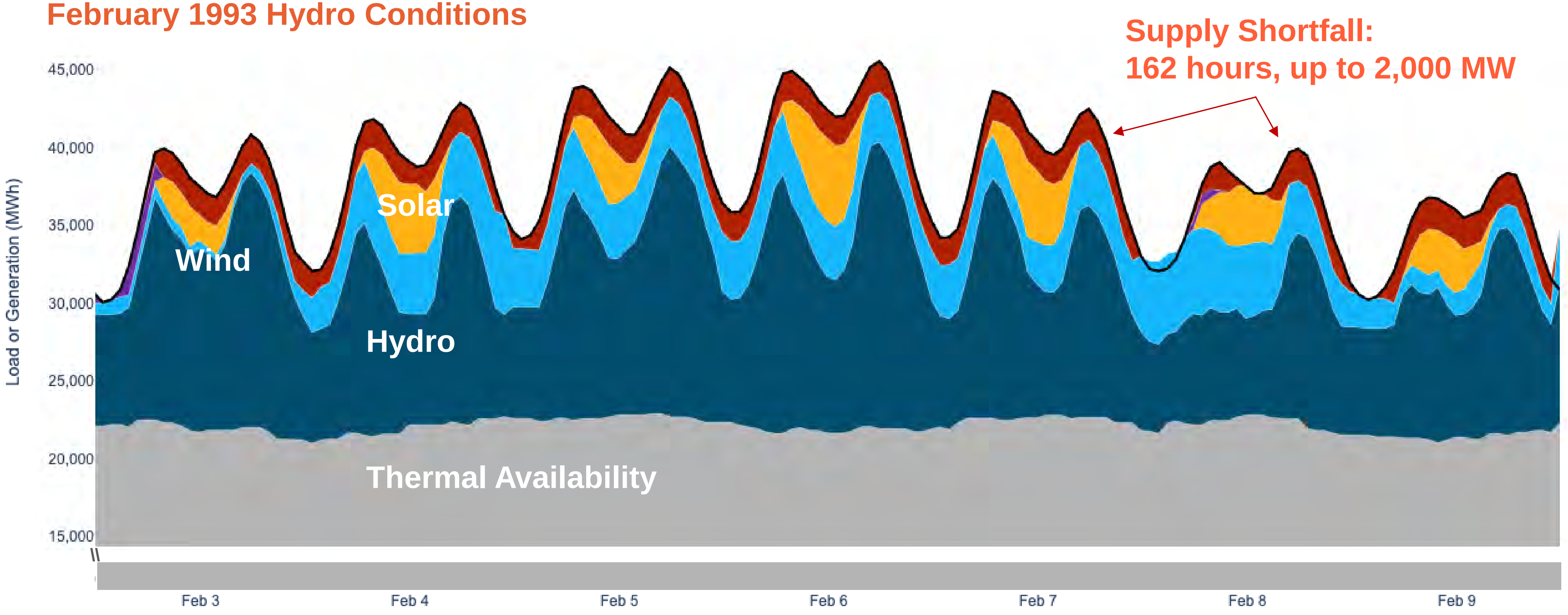
2025 Loss-of-Load Probability (LOLP) by Hydro Year



Resource availability example: February 2014 load conditions combined with 1993 hydro conditions

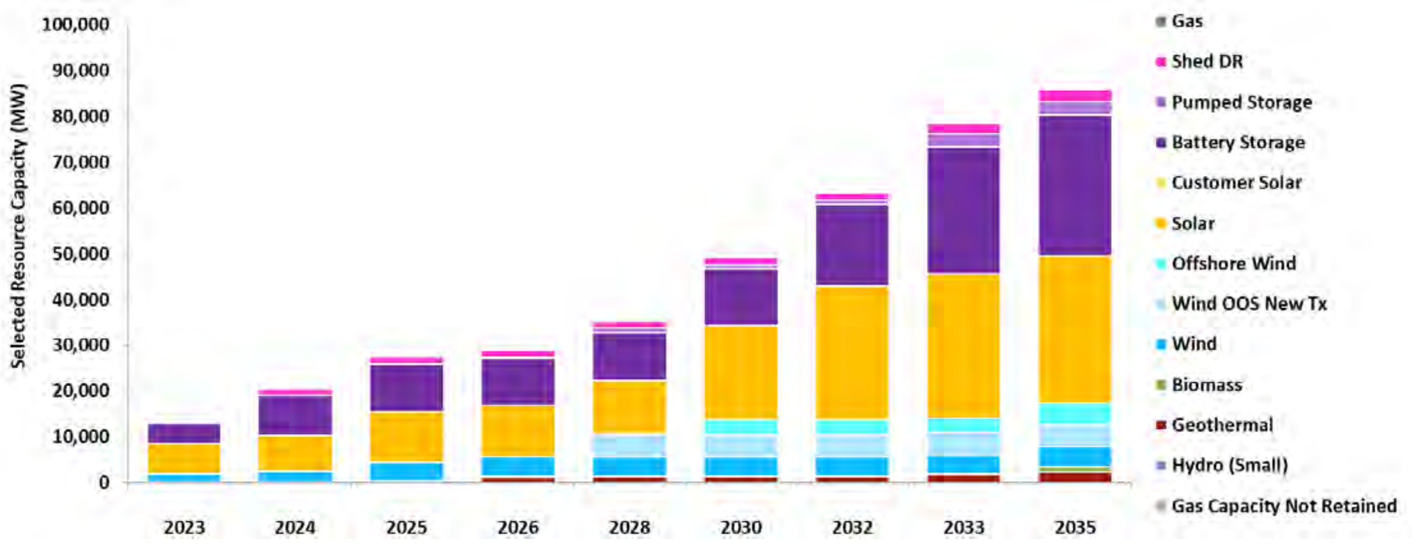
Greater Northwest 2025, RECAP simulated energy-limited event

February 1993 Hydro Conditions

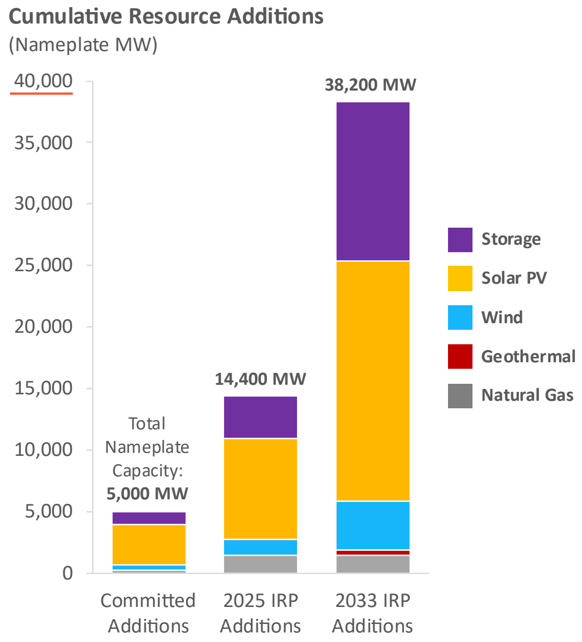


Regional comparison: solar and batteries provide high capacity value in summer-peaking regions like the Southwest

California is planning to build 50 GW of solar and storage resources by 2035 and 100 GW by 2040 (on top of 50 GW installed in 2025)

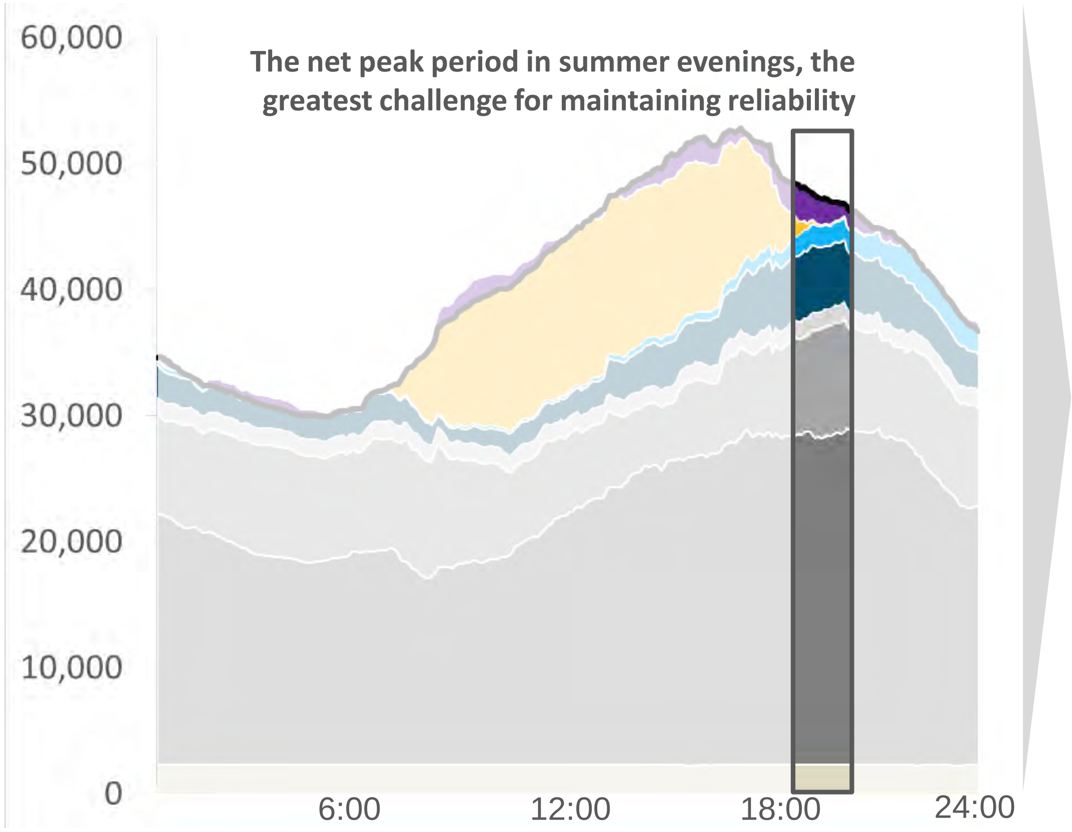


Desert Southwest is planning to build 30 GW of solar and storage resources through 2033

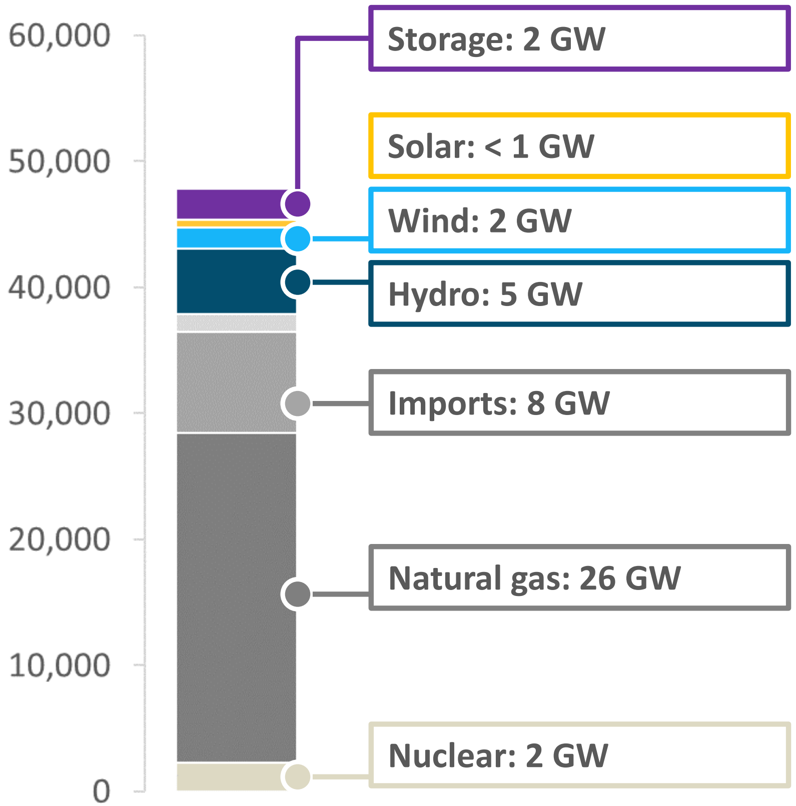


Regional comparison: California's most recent near reliability event was during a historic heatwave in September 2022

CAISO System Operations on September 6, 2022
(MW)

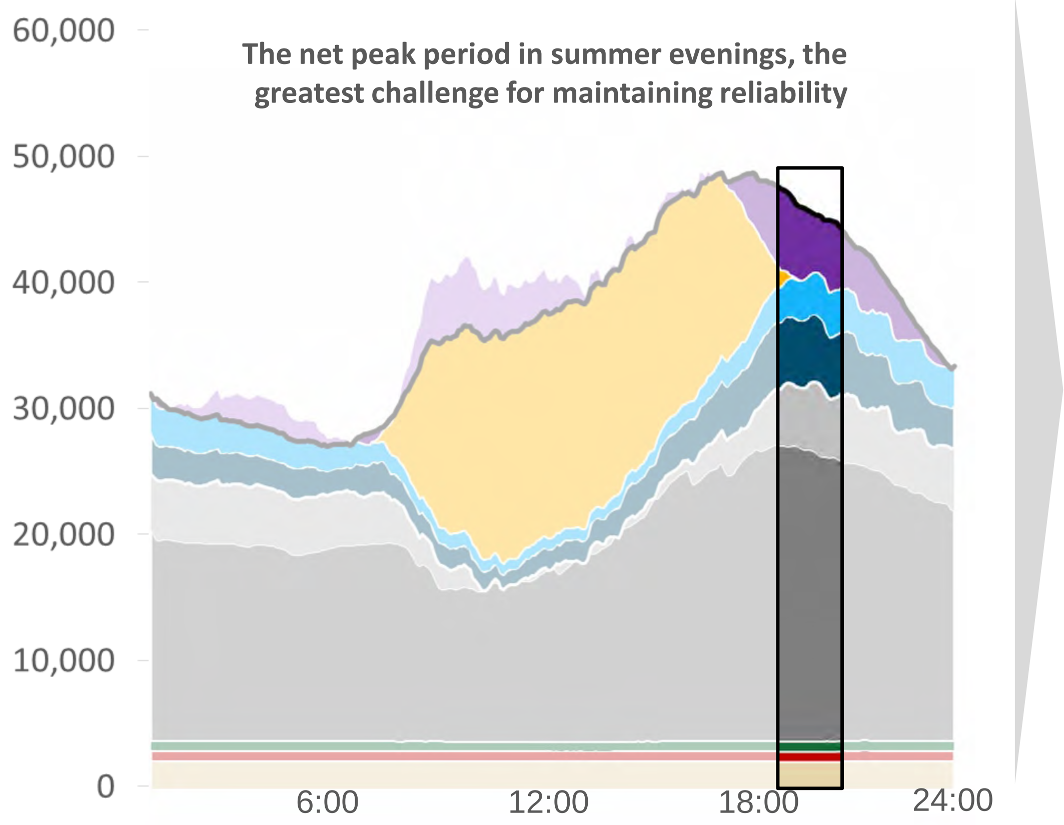


Generation During Hour of Highest Net Load
(MW)

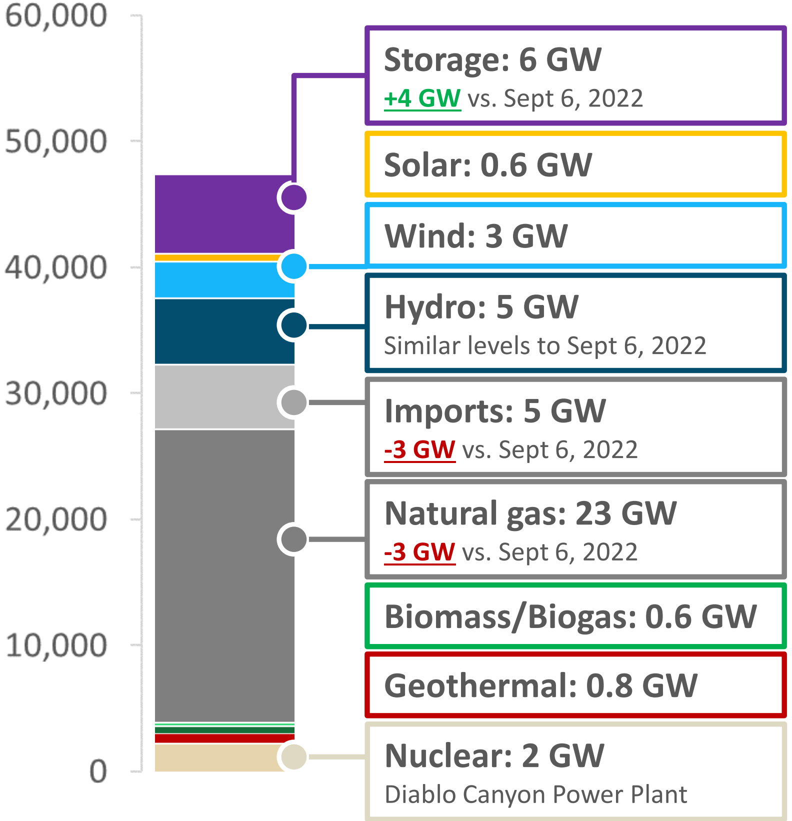


Regional comparison: Significant additions of batteries helped make the next September heatwave in 2024 a non-event

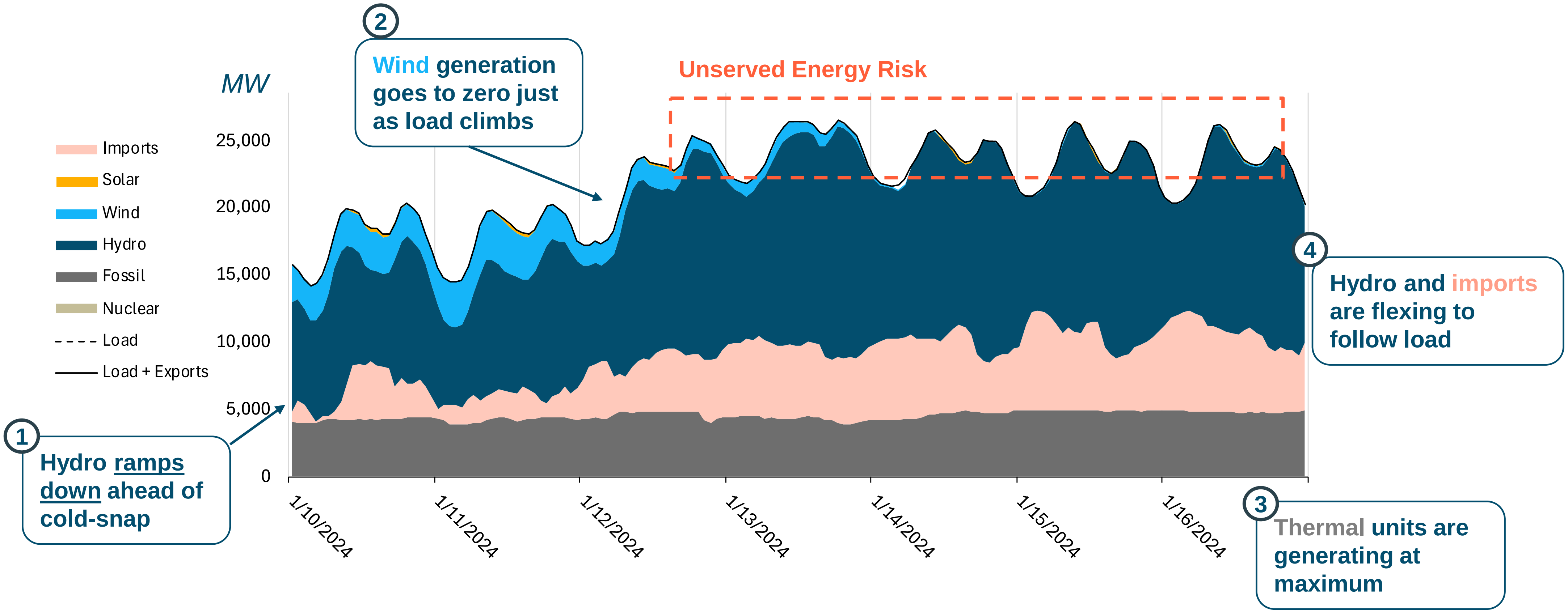
CAISO System Operations on September 5, 2024
(MW)



Generation During Hour of Highest Net Load
(MW)



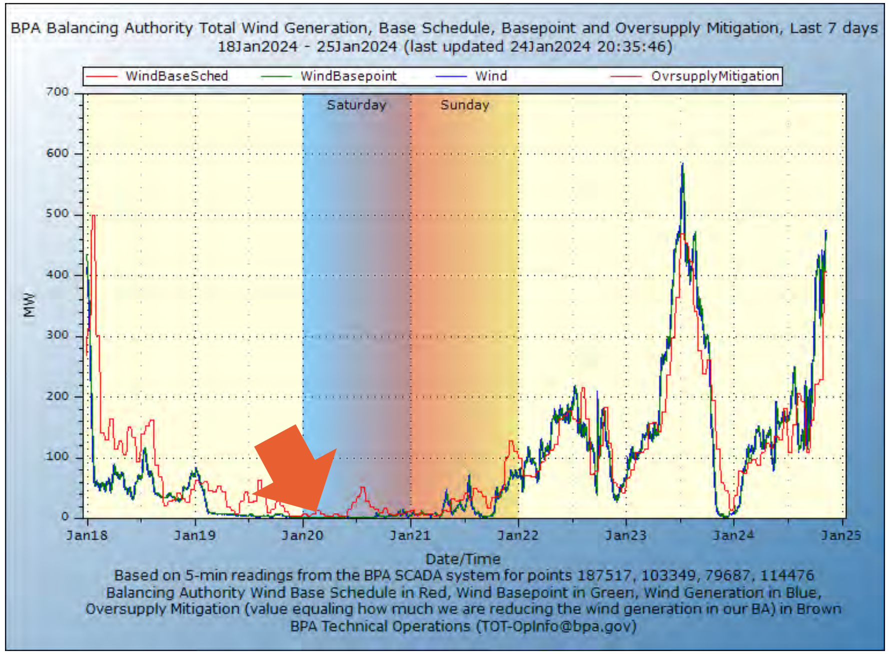
Regional comparison: The Northwest's most recent near reliability event was the multi-day January 2024 cold snap



Source: EIA, BPA

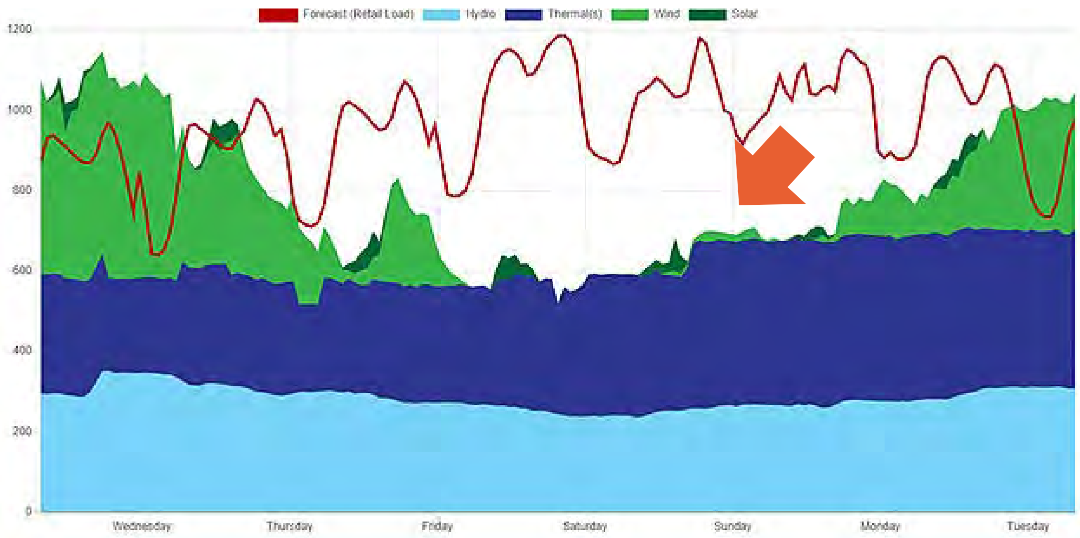
Northwest wind produced at very low levels during most of the January 2024 cold weather event

BPA: Almost no wind production on January 15-17 and 19-21



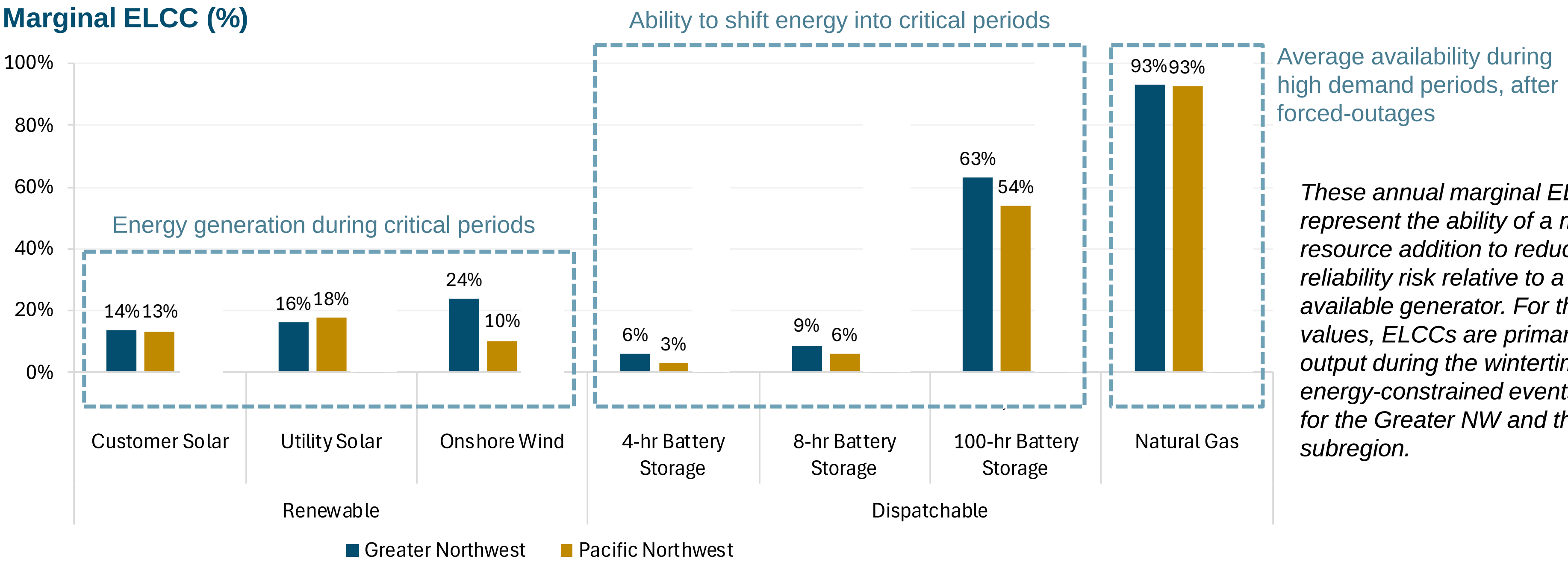
Average Jan 13: **567 MW**
Average Jan 15 5:00 AM – Jan 17 10:00 AM: **8 MW**

NorthWestern Energy: Almost no wind production on January 12-14



Low temperature records set on January 13 in Portland (12 degrees) and Seattle (16 degrees)

Resource reliability value depends on ability to supply energy during multi-day cold snaps under low hydro conditions



These annual marginal ELCC values represent the ability of a marginal resource addition to reduce region-wide reliability risk relative to a firm, always available generator. For these 2025 values, ELCCs are primarily a function of output during the wintertime multi-day energy-constrained events that define risk for the Greater NW and the PNW subregion.

- **Solar and wind have low capacity factor during reliability events → 10-24% of nameplate**
- **Short-duration energy storage cannot charge during most energy-constrained events → 3-9%**
- **Natural gas plants with firm fuel can run when needed → 93%**

Energy storage and flexible loads can be valuable if matched to the duration of the reliability event

- **Short-duration storage and demand response solutions do not have high reliability value**
- **Multi-day response is valuable but more difficult to source**

	Duration (hours)	# of Calls per year	2030 Marginal ELCC
Energy Storage	4		6%
	8		9%
	100		**63%**
Load-shed Demand Response	6	12	18%
	12	10	30%
	24	8	44%
	48	6	**54%**
	72	4	**57%**
	120	2	**61%**

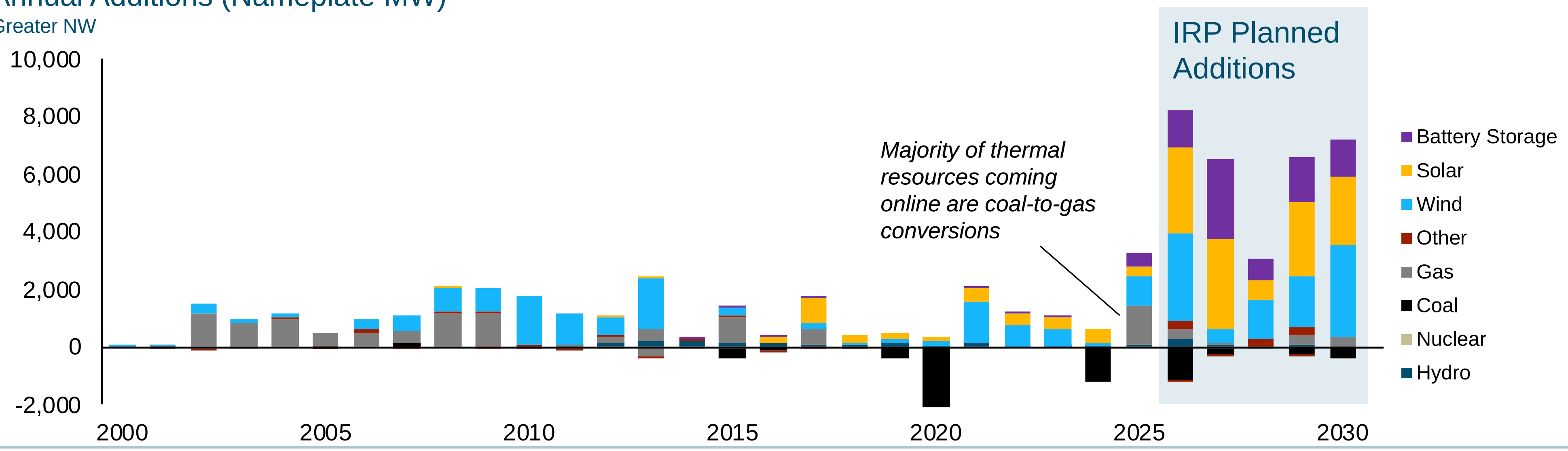
The rate of new resource additions required to meet resource adequacy needs in the next five years is unprecedented

- **Meeting the pace of growth anticipated in utility IRPs would require annual resource additions equal to 4-5x historical levels**
- **Project development is currently experiencing significant headwinds due to changes in federal policy and higher costs**

Retirements and New Installed Capacity Additions by Year

Annual Additions (Nameplate MW)

Greater NW



Utility + developers identified transmission, accreditation uncertainty, and new firm capacity barriers as key challenges

Key challenge	Findings from stakeholder interviews	Potential Solutions
1. Transmission access faces physical and institutional constraints	• Separate procurement and transmission planning processes leading to chicken-and-egg challenges • Lack of firm transmission rights for new resources • Difficult terrain and siting challenges	• **Improve regional transmission planning and interconnection processes**
2. Uncertain capacity accreditation metrics	• **WRAP is voluntary** and has not yet become binding • **Accreditation metrics are uncertain**	• **Strengthen the WRAP program with fundamentals-based capacity accreditation**
3. Barriers to building new RA capacity	• Utilities are likely to be challenged by the **sheer volume** of new resources in their IRPs • Existing clean resources make limited contributions to resource adequacy and **"clean firm" options are not yet commercially available** • Natural gas is the only viable near-term firm capacity option, yet siting new gas plants is extremely challenging and may create **stranded asset risks**	• **New firm resources may be needed** if they do not set the region back on long-term carbon reduction goals • **"Clean firm" resources may need policy support to** speed commercialization

Key findings of Phase 1:

1. **Accelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to *9 GW by 2030***
   - 9 GW is approximately the load of the state of Oregon
2. **Preferred resources such as wind, solar and batteries make only *small contributions* to meeting resource adequacy needs**
3. ***Timely development of all resources is extremely challenging* due to permitting and interconnection delays, federal policy headwinds, and cost pressures**

Phase 2 will evaluate resource options for meeting near-term and long-term resource adequacy and clean energy needs

	Scenario	RA contributions	Additional considerations
Mature	Solar	Low and declining ELCCs	Variable energy resource
	Onshore wind	Declining ELCCs	Variable energy resource
	Natural gas	Firm	Carbon emitting, requires pipeline infrastructure
	Biomass/biodiesel	Firm	Uncertain fuel availability and cost
	Short-duration storage (4-8 hr li-ion)	Declining ELCCs	ELCC saturation impacted by hydro fleet interactions
	Long duration storage (10-12 hr pumped hydro)	Declining ELCCs	ELCC saturation impacted by hydro fleet interactions
	Geothermal	Limited potential	High cost per kWh and limited PacNW sites
	Energy efficiency	Limited potential vs. cost	Can reduce new load but cannot serve existing load
	Demand response	Declining ELCCs	Duration and use limited
Emerging	Floating offshore wind	Declining ELCCs	High enabling infrastructure costs + long timelines
	Natural gas to H2 retrofits	Firm	High enabling infrastructure costs + long timelines
	New dual fuel gas + H2-ready plants	Firm	High enabling infrastructure costs
	New H2-only plants	Firm	High enabling infrastructure costs + long timelines
	Gas w/ 90-100% carbon capture and storage	Firm	High enabling infrastructure costs + long timelines
	Nuclear small modular reactors	Firm	Uncertain costs + long timelines
	Enhanced geothermal	Firm	Uncertain costs and potential
	Multi-day storage (100 hr)	Slower declining ELCCs	Uncertain costs, high round-trip energy losses
	Direct air capture	n/a	Can offset emitting gas that serves RA needs

Note: emerging technologies face cost uncertainty, unclear commercialization timelines, and/or high enabling infrastructure needs

Thank you!

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Energy+Environmental Economics

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

PACIFIC NORTHWEST UTILITIES CONFERENCE COMMITTEE, *2025 NORTHWEST REGIONAL FORECAST OF POWER LOADS AND RESOURCES*

EXHIBIT 1203

November 2025

Northwest Regional Forecast

of Power Loads and Resources

August 2025 through July 2035

PNUCC

April 2025

Special thanks to the utility staff who provided us with this information. The input from the PNUCC Board members, guidance from the Communications Task Force and contributions from the System Planning Committee are also appreciated.

Electronic copies of this report are available on the

PNUCC website

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Table of Contents

2025 Northwest Regional Forecast

Executive Summary

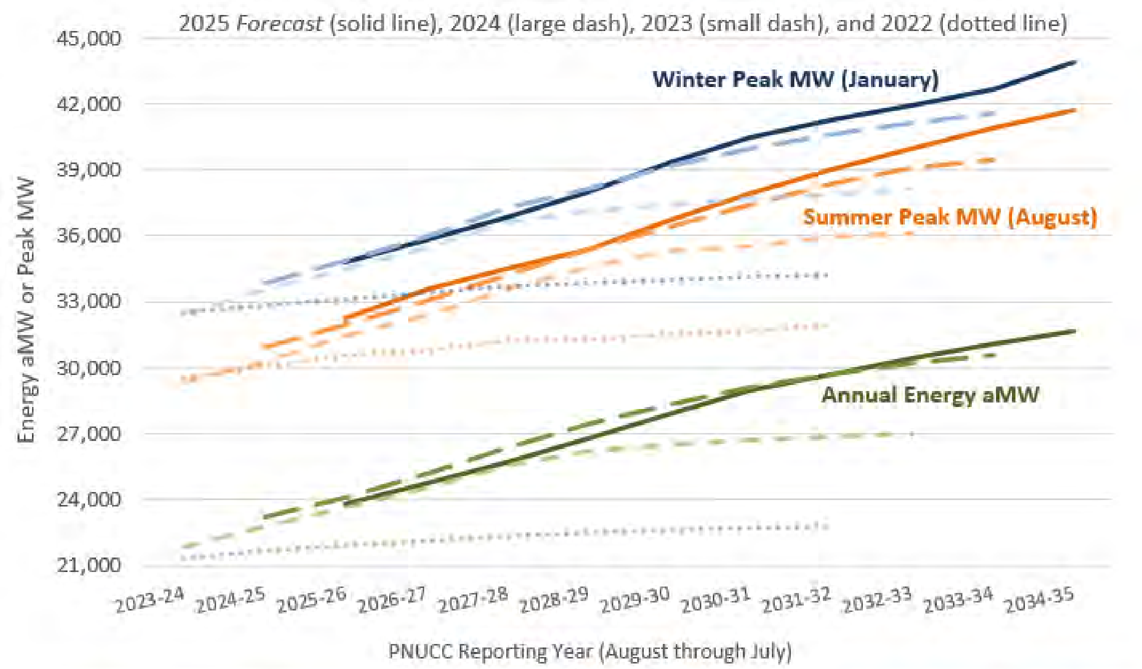
Utilities in the Pacific Northwest are facing growing uncertainty and mounting pressure to add generating resources to bolster the grid and serve a projected increase in demand for electricity. Meeting the region's energy needs has become an urgent concern, requiring immediate attention. While there is convincing evidence that demand for electricity is clearly rising, plans for new large loads and the energy transition may be delayed due to challenges in expanding energy infrastructure. Addressing these difficulties is critical to ensuring a reliable, affordable and resilient power supply for the region.

Each year, the Pacific Northwest Utilities Conference Committee (PNUCC) collects and aggregates data provided by individual utilities, PNGC Power and the Bonneville Power Administration to assess the state of the electric utility industry in the region. The *Northwest Regional Forecast* (*Forecast*) is the sum of utilities' forecast of loads and resources within the Northwest Power Act footprint, which primarily includes utilities in Washington, Oregon, Idaho and Montana (see Planning Area on page 20). This longstanding resource tracks power system trends, including shifts in demand, resource changes and emerging technologies from a regional utility perspective.

Projected Load Forecast Aligns with Last Year's Outlook

The *2025 Forecast* indicates that anticipated regional load growth is consistent with the *2024 Forecast*, reflecting a continued rise in projected demand for electricity. Figure 1 on page 5 shows aggregated utility-reported load projections, accounting for transmission and distribution losses and reductions from energy efficiency measures.

Figure 1: 2025 Load Forecast Compared to Previous Forecasts



Growth Rates

Energy	10 year
2025 *Forecast*	3.2%
2024 *Forecast*	3.1%
2023 *Forecast*	2.4%
2022 *Forecast*	0.9%

Summer Peak	10 year
2025 *Forecast*	2.9%
2024 *Forecast*	2.7%
2023 *Forecast*	2.3%
2022 *Forecast*	1.0%

Winter Peak	10 year
2025 *Forecast*	2.6%
2024 *Forecast*	2.3%
2023 *Forecast*	1.8%
2022 *Forecast*	0.7%

The solid lines represent the 2025 load forecast, while the lighter dashed lines depict previous years' forecasts. The annual energy projections shown in green suggest that regional loads could grow by approximately 7,800 average megawatts (aMW) over the next decade—an increase of more than 30%. The data starts at around 23,800 aMW in 2025 and rises to roughly 31,600 aMW by 2034.

Seasonal peaks in demand are shown in orange and blue, representing expected peak load under normal weather conditions (not extreme events). The summer peak (orange) could rise by nearly 9,400 megawatts (MW), from about 32,200 MW to nearly 41,600 MW. The winter peak (blue) is projected to rise by around 9,100 MW, from around 34,700 MW to nearly 43,800 MW. Although both summer and winter peaks are trending upward, summer demand has been rising more quickly in recent years, mostly because hotter weather is increasing the need for air conditioning.

Power demand, which was stagnant for decades, could grow swiftly over the next decade. One cause of this significant growth in demand across the country is the increasing reliance on digital technologies, cloud computing and Artificial Intelligence (AI). Money from technology companies, government and venture capitalists is being invested in AI at unprecedented levels. This technology is shifting away from conventional large language models (LLMs) toward reasoning models and AI agents. Reasoning models, which are based on LLMs, are different in that their actual operation consumes many times more resources, in terms of both microchips and electricity. AI reasoning models can require over 100 times as many computing resources for challenging queries compared to conventional LLMs. [1] While the growth in AI creates challenges, these advances could be the foundation for many new scientific discoveries and technological breakthroughs.

More than a decade ago, technology companies started developing data centers in the Northwest to accommodate customer demand for computing capacity. These companies have actively invested in local communities, created jobs and stimulated economic growth in the region.

Another reason for this forecasted increase in demand is the trend toward electrification, with electric vehicle adoption being the first to show up in the load growth projections. When asked specifically, Northwest utilities that serve about 60% of the regional load reported they are forecasting how much energy and capacity could be needed for the electrification of buildings, transportation, and commercial and industrial applications. The overall amount of new electrification from electric vehicles included in this regional forecast is small and gradual (around 3% by year 10), but for some individual utilities, it is a large piece of their forecasted load growth. Utilities are raising awareness that an economy that is more dependent on electricity will be much different than the past and will require significant investment in new generation, distribution and transmission.

Ambitious Resource Acquisitions

Regional utilities face growing pressure to meet ambitious resource acquisition plans, but the success of these plans depends on many factors including coordinated regional action. No single utility can implement these substantial changes alone as neighboring utilities' decisions influence the viability of individual resource strategies.

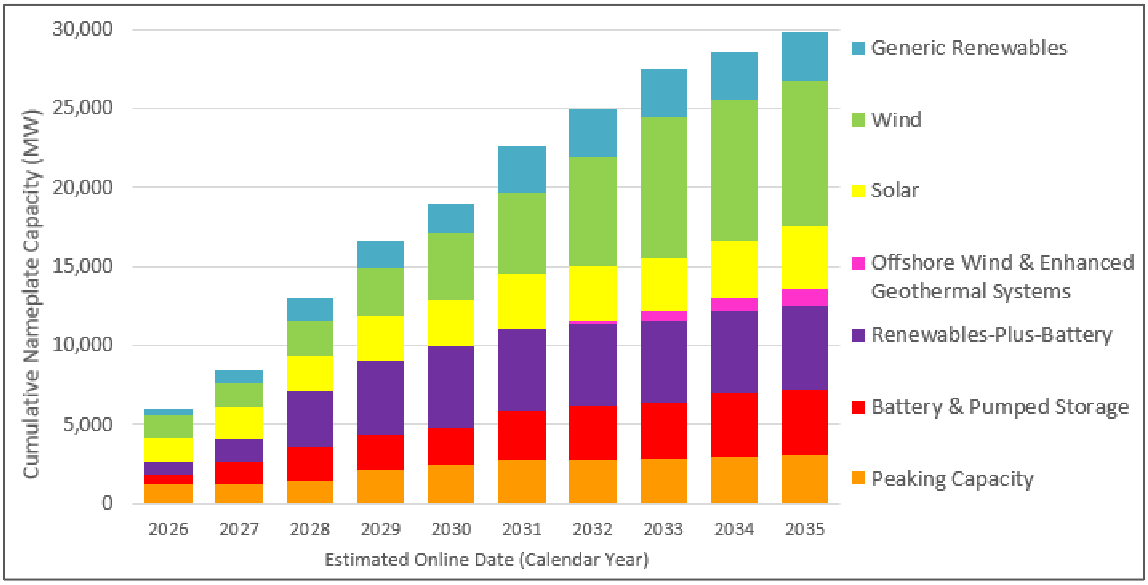
The *Forecast* shows aggregated utility-reported needed future resources, including specific projects and generic resources identified in the latest integrated resource plans and planning studies. Needed future resources are not yet under construction, are not part of the regional analysis and remain speculative.

Utilities anticipate new utility-scale wind and solar resources will be developed either in-region or delivered via high-voltage transmission from resource-rich areas. However, project development timelines are getting longer. Local opposition has led to complex permitting and state-level siting processes. At the same time, transmission interconnection queues are congested and shifting federal energy policies have introduced even more planning uncertainty. These challenges underscore the growing disconnect between renewable energy ambitions and the infrastructure needed to deliver them.

Resource plans undergo regular review and updates through comprehensive analysis and stakeholder input. As a result, these plans, particularly the longer-term projections, evolve over time.

[1] https://blogs.nvidia.com/blog/ai-scaling-laws/

Figure 2: Cumulative Needed Future Resources



In Figure 2 above the stacked bars amount to the cumulative nameplate capacity for needed future resources by resource type for each year of the *Forecast*. The data adds up to an unprecedented number of about 30,000 MW nameplate capacity in the next 10 years. This is an extraordinary number of added resources to develop in 10 years. Many utility plans rely heavily on wind, solar and battery. Since wind and solar generation are variable and weather-dependent, they do not always produce power when demand is highest. To maintain resource adequacy and system reliability, especially during peak demand periods, significantly more wind and solar nameplate capacity needs to be installed than would be needed if these resources were more available. For utilities that have not been specific about the kind of renewable resources included in their plans, the resources are identified as generic renewables.

The data in the graph does not include committed resources for 2025 and 2026 and coal to natural gas conversions because they are part of the Northwest utility generating resources in the load and resource balance picture (see Figure 5). Further, this graph does not reflect any uncommitted resources in the West with which utilities or large customers may acquire or enter contracts.

Regional assessments rely on resource additions that are at risk of not being deployed

The *Forecast* is not a resource adequacy assessment—that work is conducted by others—nor is it a prediction of the future. Instead, it explores what *could* happen, offering insights into potential challenges facing the region. It serves as a complementary resource to other assessments, helping to validate trends by providing a utility perspective and a more detailed focus on Pacific Northwest utilities. Through this finer lens, the *Forecast* enhances understanding of emerging issues and supports more informed decision-making.

Individually, a utility's resource acquisition plans may seem achievable, but in a constrained energy system where multiple utilities are competing for the same resources, securing those resources has become increasingly challenging. The risk of developing plans in isolation can be severe. For example, if every utility independently pursues the same technologies the effectiveness of those resources could diminish. Likewise, if too many utilities wait and buy from the market, reliability risks increase and impacts on affordability can be significant.

The Western Electricity Coordinating Council (WECC) looks at risks to the power system throughout the Western Interconnection to help stakeholders target specific areas and topics for deeper evaluation and mitigation. WECC observes that generation has never been built in the West at the rate called for in many current resource plans.

WECC warns if demand grows as expected and industry experiences delays and cancellations in building added resources over the next decade, the West will face potentially severe resource adequacy challenges. According to WECC over the last six years, 76% of planned resource additions came online in the year scheduled, and in 2023, that number was only 53%[2]. Resource margins are shrinking, leaving less buffer for cancelled and delayed projects. If the resource build-out over the next 10 years mimics the last five years, by 2034, the West will have hundreds of hours each year when demand is at risk. WECC observes risks to planned resource additions include supply chain disruptions, uncertainty in the interconnection process, siting delays and increased costs.

Increasing threats to reliability

With natural gas serving as the region's second-largest power source after hydro, its role will persist as electricity demand rises. The region is relying on natural gas for dependable power generation, demanding more from the existing constrained pipeline capacity network and highlighting the need for adequate storage.

The region is dangerously close to experiencing significant energy supply disruption, which could lead to blackouts during peak demand events. Energy emergencies during extreme weather events are increasing in frequency and threatening reliability. The multi-day cold snap in January 2024 is the most recent in a string of examples. Meeting peak demand during the cold snap required execution of emergency operations and procedures, careful coordination between natural gas and electricity providers, customer response to energy conservation requests and significant electricity imports from the Desert Southwest and the Rockies.

Natural gas used to generate electricity plays an increasingly critical role in the reliable operation of the region's power system. The region's electric and natural gas delivery system (transmission and pipelines) are almost fully subscribed with limited excess capacity for serving increasing peak loads. When combined with unplanned infrastructure curtailments and depleted underground gas storage inventories, prolonged events test the system. While the Pacific Northwest has endured cold weather events by rapid emergency response coordination, these situations demonstrate how close the region is to severe disruptions. The

[2] https://feature.wecc.org/wara/

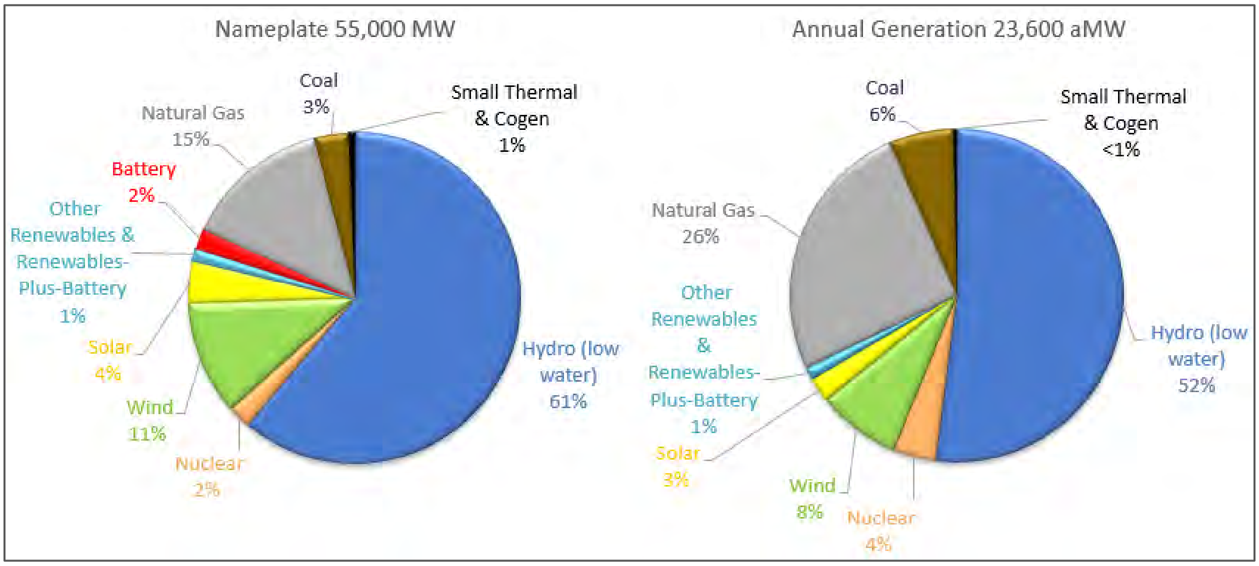
electrification of natural gas uses can have the biggest impact at the times which are becoming the most challenging for the electric system.

Furthermore, siloed planning in natural gas and electric systems can have a detrimental effect on overall energy reliability and the transition to cleaner energy. The increasing interdependence between natural gas and electricity providers demands greater awareness and enhanced coordination to mitigate serious risks to the region's energy system.[3] For example, on the natural gas side, in 2027 the Woodfibre LNG export facility in British Columbia will come online and will require a significant amount of gas capacity, which will further strain the region's energy system capacity until any new contemplated capacity becomes available.[4]

Energy system failures are a public health and safety issue. They also drive up costs for consumers—both through exposure to high market prices and the need to procure emergency or unplanned capacity. These preventable expenses make the energy transition more costly for ratepayers. To manage these growing risks, the region must work together to remove barriers and build a more diverse, resilient and reliable system.

Northwest Utility Generating Resources

Figure 3: Northwest Utility Generating Resources in 2026



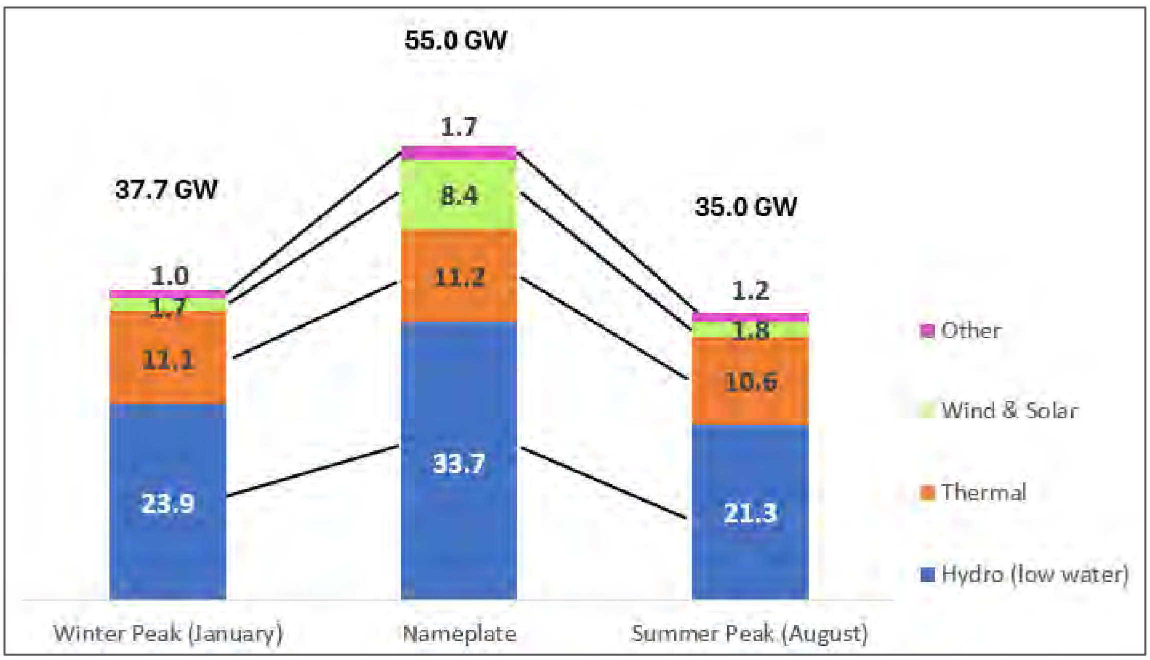
Most of the Northwest's power supply is carbon-free, with hydropower serving as the foundation of the region's resource mix. Figure 3 above shows the regional Northwest utility generating resources. Resources move clockwise around the charts from carbon-free to carbon-emitting. Total installed nameplate capacity is about 55,000 MW. In the annual generation chart, hydropower provides over half

[3] https://www.pnucc.org/wp-content/uploads/Guidehouse-analysis-of-regional-energy-reports-2025.pdf
[4] https://www.nwga.org/_files/ugd/054dfe_da78848821a448c1b897a5a32d94cbd8.pdf

of total utility generation on an energy basis even under low water conditions. Carbon-free energy resources make up almost 70 percent of the total annual generation. The charts include utility-reported resources (whether owned or contracted). The annual generation output will vary. Energy generation for natural gas resources represents the energy available for the Northwest. Natural gas generation does not reflect dispatch for expected economic conditions or compliance with clean energy policies.

With the growth of wind and solar power, utilities are relying on technologies that can store surplus energy and deliver it to the grid when needed. Standalone battery systems are expected to make up a growing share of the resource mix. Even as the overall mix evolves, hydropower remains a critical contributor to reliability thanks to its unmatched storage capacity and operational flexibility.

Figure 4: Winter and Summer Capacity Contributions of Northwest Utility Generating Resources in 2026



To explain and illustrate how different resources contribute to meeting peak hour capacity needs, the nameplate pie's slices in Figure 3 are aggregated into four layers in Figure 4 above. Categories include resources with similar characteristics. The blue block is only hydro. Coal, natural gas, nuclear and cogeneration are thermal resources in orange. Thermal resources are more readily available and use fuels that can be stored in large quantities. Wind and solar are combined in the lime green block because both have variable and weather dependent. The pink block is a combination of resource types that are smaller in their role, including battery, renewables-plus-battery systems, biomass, landfill gas and geothermal.

The region's resource mix can be thought of as a layer cake, with each layer representing different types of resources. The cake is illustrated in the middle bar of Figure 4, which shows the nameplate capacity in MWs. The left bar shows how well these layers meet the projected winter peak hour (January) , while the right bar shows how well these layers meet the projected summer peak hour (August) as reported by utilities. Think of those bars as the “taste tests” or reliability standards. The Northwest’s resource mix—a carefully balanced, multi-layered cake—has reliably met the region’s needs and passed those seasonal tests.

In the last few years, utilities have modified the “ingredients”, particularly adding battery and new natural gas as the region relies less on coal. These changes show up in the thermal (orange) and other (pink) layers.

The region’s layer cake has a solid reputation for being low-cost, carbon-free and able to meet reliability standards. Northwest utilities have been developing plans for needed future resources (Figure 2). To meet new demand, under current conditions, the region will need to either scale up the layers or add new ones—all while keeping the cake affordable and reliable. The Northwest’s power supply is evolving as utilities decarbonize their resource mix. A diverse resource mix will keep the grid stable and mitigate the risks of being overdependent on a single energy source. Additionally, a mix of resources can contribute to lower energy costs and reduce greenhouse gas emissions.

Load/Resource Balance

Total energy system view informs better decision-making

One way to understand the energy system is a comparison that is called a load/resource balance. Figures 5 and 6 on page 12 illustrate gaps between what utilities have (existing and committed resources) and what utilities project they may need (requirements) in future years. The colored stack bars represent the utility’s view of how existing and committed resources contribute to annual energy (Figure 5) and peak-hour demand (Figure 6) during low water conditions. The stack does not include needed future resources. It does include contracted imports and demand response. In Figure 5 the solid line shows the expected load plus any long-term contractual exports to other regions.

Figure 6 shows available capacity during the highest demand hours of the year (expanding the winter and summer contributions data shown in Figure 4 for all 10 years of the forecast). The solid line shows the sum of peak hour loads, exports and a 16% planning reserve margin (PRM). The PRM is the need for extra capacity meant to cover uncertainties like extreme weather, outages or forecasting errors. The dashed line in Figure 6 shows the forecasted peak load. In the *Forecast*, the PRM is set to 16% of the peak load for every year of the planning horizon.

Monitoring energy and capacity deficits helps illuminate the evolving balance between the region’s available resources and what’s needed to meet demand. A projected gap in the *Forecast* does not necessarily signal an inability to serve load—utilities frequently rely on short-term market purchases. But as system constraints tighten during peak demand events and load grows across the interconnected grid, the reliability of those external supplies becomes more uncertain. Figures 5 and 6 offer a snapshot of shifting conditions and highlight where attention and action may soon be needed. The *Forecast* provides a utility view that adds up utility data and is not the result of a model. Other regional assessments (from

WECC, Western Power Pool and the Northwest Power and Conservation Council) are important sources of additional information for understanding the bigger picture.

Figure 5: Annual Energy Picture

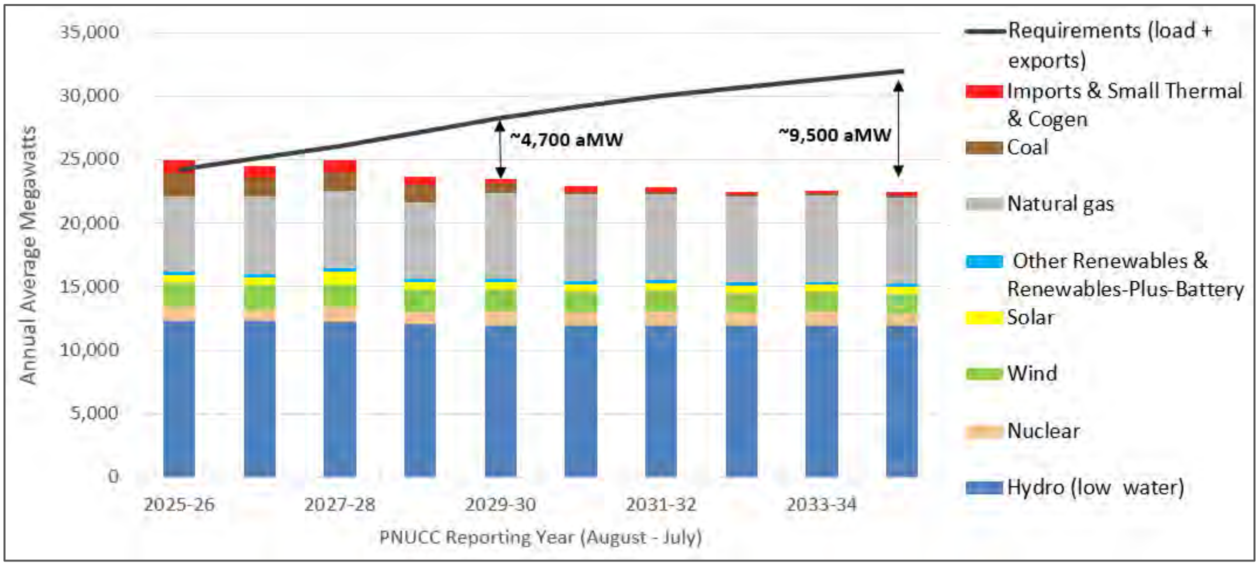
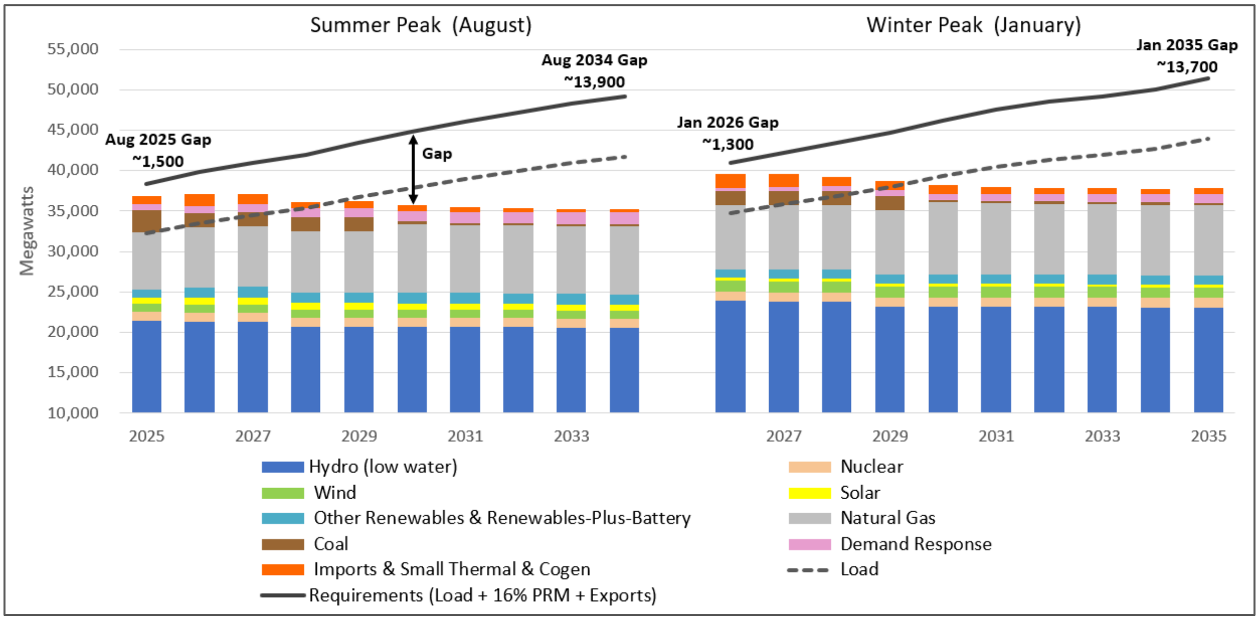


Figure 6: Summer and Winter Peak Hour Picture

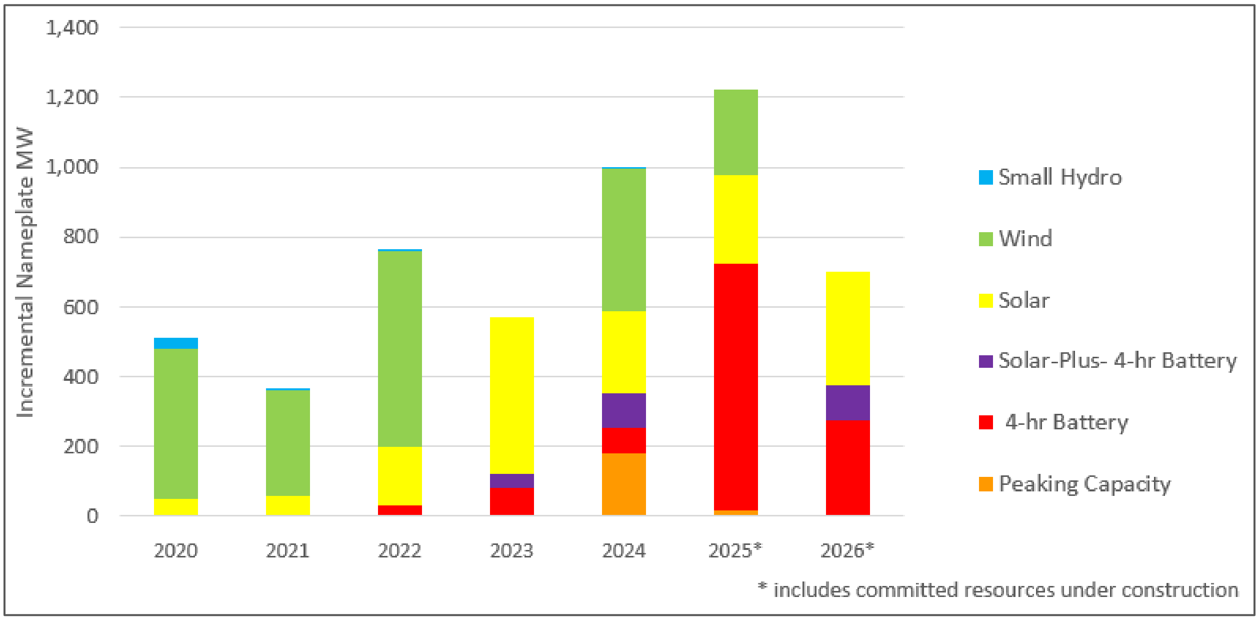


The energy system is constrained, and it is getting harder to build and buy new generating resources and rely on other entities' surplus power during peak events. Recent events like the January 2024 cold snap show that shortages can be expensive and risky. Planners need to consider a lot more than just building power plants—like transmission availability, fuel delivery, permitting, resource development timelines, costs and policy. Connecting a new power plant can take more than a decade from inception to when it is able to deliver power. The comparison of resources to requirements demonstrates that to meet projected energy load and peak-hour demand, the region needs resources and delays can be detrimental to meeting projected load growth.

An evolving mix of long-term acquisitions

Utilities have added 5,100 MW nameplate capacity of new resources since 2020 as shown in Figure 7 below. Wind and solar have dominated new resource additions. Combined with small hydro, wind and solar total 3,500 MW. Most recently, new natural gas generation, battery and solar-plus-battery systems are being deployed in recognition of capacity needs all while supporting the transition to carbon-free energy.

Figure 7: Incremental Nameplate Capacity 2020-2026 New Build Acquisitions



A significant regional milestone came in 2022 with the introduction of 4-hour battery storage systems (marked in red), enabling energy to be shifted to different times of the day. In 2023, the addition of solar-plus-battery systems (shown in purple) further enhanced the ability to store and dispatch solar energy during evening peak demand periods.

In 2024, the region added new peaking capacity fueled by natural gas (highlighted in orange) to reliably meet peak power demands. Additional peaking capacity is expected to be online by the end of 2025 fueled by natural gas plants that can transition to use hydrogen or other clean fuel in the future. Combined peaking capacity, standalone battery and solar-plus-battery systems are becoming an increasingly prominent part of the energy mix, with about 1,600 MW now dedicated to supporting peak demand and optimizing renewable generation.

When looking back at the *2024 Forecast* for comparison, utilities projected adding approximately 4,400 MW of committed and needed future resources in 2025. However, actual new builds for 2025 currently only total to about 1,200 MW—falling far short of the forecasted need.

Despite this uncertainty, one promising trend from the *2024 Forecast* is that all 2024 and 2025 (940 MW) committed resources are on track to serve load by the end of 2025 at the latest. This suggests that utilities report high-confidence projects under the committed category. In comparing recently acquired and committed resources to the future resources needed, the pace of resource additions needs to accelerate if the region is to maintain an adequate system through the projected load increases.

Natural gas expected to provide dependable capacity

The increasing interdependence between natural gas and electricity in the Pacific Northwest presents a critical challenge that demands immediate attention. As coal declines, natural gas is being leaned on to provide dependable power supply. Industry leaders stress the urgency of enhanced coordination, improved risk assessment and strategic investment in both natural gas infrastructure and alternative resources.

Figure 8: NW Utility Coal and Natural Gas Plant Availability

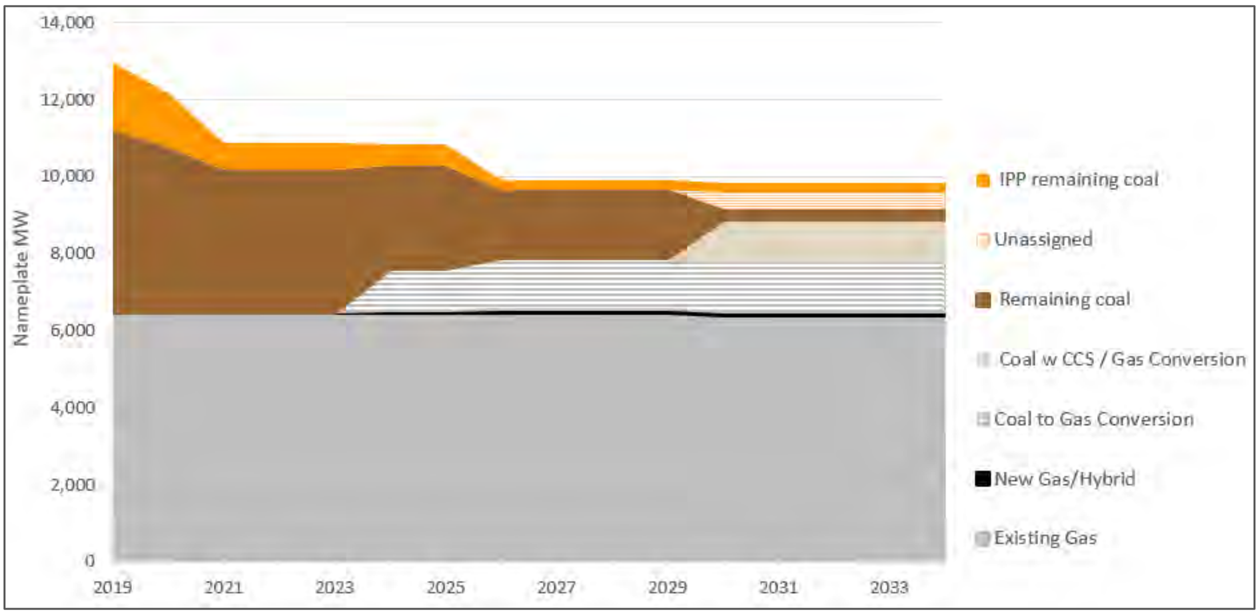


Figure 8 above shows the expected changes for coal and natural gas resources in the region. It begins with the picture in 2019. State laws require that coal-fueled resources be eliminated from Oregon's electricity resources by January 1, 2030, and from Washington rates by December 31, 2025. The decline in coal shows up in the *Forecast* as retirements, coal-to-natural gas conversions and the potential for coal with carbon capture and sequestration (CCS) or coal-to-gas conversion. A portion of coal generation remains in the *Forecast* that is owned by independent power producers and not assigned to serve regional load. By 2030, another small amount of regional coal is also shown as unassigned with no future owner identified.

The combined natural gas and coal outlook closely mirrors last year's picture, with only minor differences. The changes include the addition of a new 18 MW natural gas peaker in 2026 (black) and the potential 62 MW retirement of an existing peaker in 2030 (gray). Minor differences in the remaining coal (brown) include changes in ownership that result in more coal staying in the region under utility operations as opposed to being assigned to independent power producers. While utilities actively consider options to comply with environmental rules, including retrofit with carbon capture or coal-to-natural gas conversion (tan), for simplicity the *Forecast* assumes coal-to-natural gas conversion instead of coal with carbon capture.

Energy efficiency and demand response growing

Utilities are actively supporting energy efficiency and demand response programs. By incentivizing customers to reduce energy use and manage peak demand, these initiatives help ensure a more efficient and resilient power supply for the region. Energy efficiency and demand response are valuable resources to meet demand now and in the future, as well as a strategy to mitigate risk due to the challenges in building new power supply.

Figure 9: Cumulative Energy Efficiency Projections

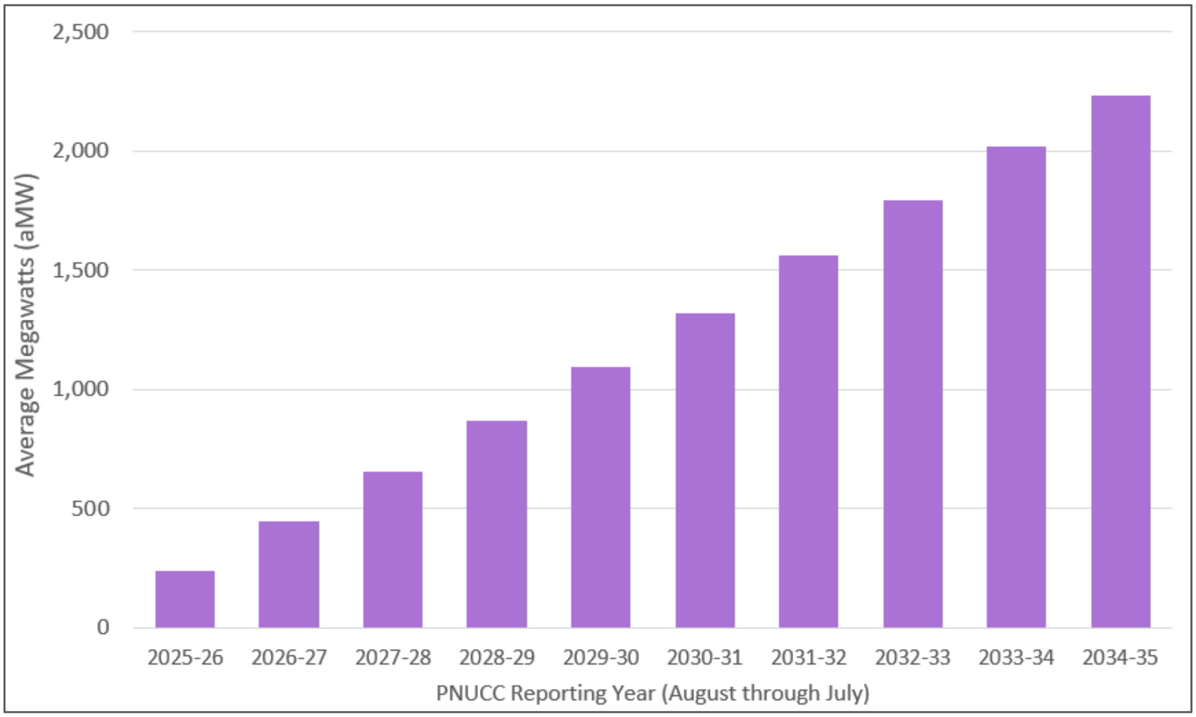


Figure 9 above shows projected cumulative energy efficiency savings of around 2,200 aMW over the next 10 years – approximately 200 aMW higher this year than last year. Energy efficiency has provided over 7,865 aMW of savings since 1978,[5] reducing the need for new generation and the dependence on carbon-emitting resources. Utility efficiency programs have been the key driver of energy savings in the region, with the Northwest Energy Efficiency Alliance's (NEEA) market transformation work emerging in recent years as a significant contributor of regional savings.

[5] https://rtf.nwcouncil.org/about-rtf/conservation-achievements/2023/

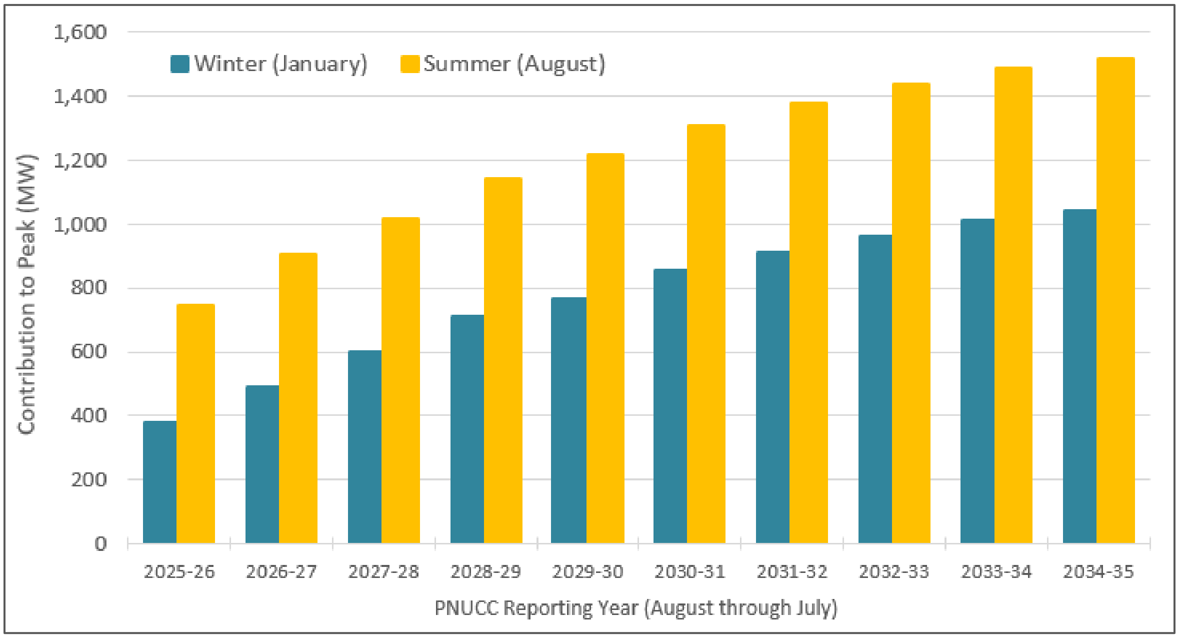
Demand response programs are designed to help balance electricity supply and demand by incentivizing customers to reduce or shift energy use during peak periods. For example, during peak demand events, some utilities send customers notifications to reduce their energy usage, earning financial benefits based on how much electricity they save. Some utility customers with eligible smart thermostats may enroll in programs that allow their utility to automatically adjust the thermostat's temperature set point by a few degrees during a peak demand event. Portland General Electric's (PGE) demand response initiatives have demonstrated significant success. For instance, during a heatwave in July 2024, customer participation in these programs reduced electricity demand by nearly 109 MW during peak hours on July 8 and 100 MW on July 9. PGE activated its entire portfolio of energy-shifting programs to help alleviate strain on the grid due to record-breaking hot weather.[6]

Agriculture customers who allow Idaho Power to remotely turn off enrolled irrigation pumps during high-demand periods between June 15 and September 15 receive financial incentives based on the amount of load they agree to reduce and the duration of interruptions. New in 2025, the program will offer an early interruption option with event hours from 3 p.m. to 9 p.m., alongside existing options.[7]

Figure 10 on page 17 shows the utilities' active and projected summer (August) and winter (January) demand response programs. The *Forecast* projects summer demand response to double, reducing the region's one hour peak by about 740 MW in 2025 to over 1,500 MW in 2034. While summer demand response programs continue to provide more peak load reduction in comparison to winter demand response programs, the *Forecast* projects the winter demand response to also more than double from nearly 400 MW in 2026 to over 1000 MW in 2035.

[6] https://portlandgeneral.com/news/2024-07-customer-actions-resulted-in-largest-electricity-demand-shift
[7] https://www.idahopower.com/energy-environment/ways-to-save/savings-for-your-business/irrigation-programs/irrigation-peak-rewards/

Figure 10: Cumulative Active and Projected Demand Response



Regional Collaboration is Essential

Utilities are focused on fostering open communication, joint planning efforts and shared investments in infrastructure and resource adequacy to ensure a resilient and reliable power system that serves the needs of customers and communities across the Pacific Northwest. Regional collaboration is not just beneficial, it is essential.

Transmission expansion critical

Transmission is the backbone of the electric power system. It moves resources from generation to loads. Much of the high-voltage transmission in the Pacific Northwest was constructed in the 1960s, 1970s and 1980s, providing the region with ample capacity to accommodate power generation and demand. However, after four decades of limited new expansion, existing transmission has reached its capability for interconnecting new resources and serving new demands.

There are a range of significant transmission-related issues that need to be addressed. Presently, the unprecedented volume of transmission service requests poses risks to bringing additional resources online as expected. Coordination with federal, state and local planning jurisdictions to improve siting and permitting is key to successful transmission expansion.

Utilities are increasingly focused on enhancing the efficiency, capacity and flexibility of the transmission grid to maximize the performance of existing infrastructure and meet growing energy demands. Some utilities are including transmission builds in their integrated resource plans as a critical component of accessing new generation sources and electricity markets outside of the region and Western

Interconnection. These investments bring capacity benefits that are defined in utilities' plans and utilities should receive credit and cost recovery for transmission that provides access to long-distance resources.

Creative partnerships lead to innovative solutions

Large energy consumers are working directly with utilities on new agreements to bring energy projects to the grid. For example, Amazon Web Services (AWS) is partnering with Umatilla Electric Cooperative in eastern Oregon to create an innovative solution to reliably power its data centers in the region. The agreement provides AWS with greater involvement in choosing its power supply.

Another promising development in the West is Google's partnership with NV Energy on a Clean Transition Tariff, which is a rate structure designed to facilitate the procurement of clean firm energy for large consumers. Under the unique tariff, NV Energy plans to procure 115 MW of enhanced geothermal energy from Fervo Energy's geothermal project in the Southwest and supply this energy directly to Google's data centers. The hope is this type of tariff can be used as a framework for advancing the development of clean firm capacity in other regions.

Energy Northwest, a PNUCC industry partner, is at the forefront of exploring innovative solutions to the region's energy challenges. In October 2024, Energy Northwest, Amazon and X-Energy announced a groundbreaking collaboration to develop a 320 MW advanced nuclear power project. Energy Northwest plans to license and permit 12 modular reactors initially, with the potential for expansion to additional modules. This particular project features four 80 MW small modular reactors (SMRs) that will be located near Energy Northwest's Columbia Generating Station in Washington state.

As the largest corporate purchaser of renewable energy, Amazon is helping shoulder the substantial upfront costs and risks of early-stage nuclear development, paving the way for utilities to follow suit with fewer barriers. This investment aligns with Amazon's commitment to powering its data centers and operations with carbon-free energy. The goal is to have the first modules operational between 2032 and 2035. This innovative approach not only addresses the immediate needs of Amazon but also establishes a scalable framework for utilities to access clean, reliable energy, ensuring the region can meet future demands.

In the broader energy landscape, most utilities have limited means on their own to invest in emerging technologies—including long-duration energy storage, next-generation nuclear and geothermal, clean fuels and fossil fuel generation with carbon capture and storage. These promising technologies are still in the early stages of development and commercialization and are extremely expensive. The size of the investment needed will require utilities to partner to bring these technologies to fruition.

The region is fortunate to have institutional frameworks that support collective action. Coalitions, an expanding generation and transmission (G&T) cooperative and joint operating agencies are already working together to be part of the solution. By banding together, utilities can accelerate progress and drive meaningful, regional outcomes.

Conclusion

Obstacles to bringing new resources online and meeting projected demand are mounting—permitting and siting delays, local opposition, transmission interconnection bottlenecks, shifting federal energy policies and more are slowing progress. If these delays continue, the Northwest could face severe resource adequacy challenges. At the same time, siloed planning in natural gas and electric sectors can have a detrimental effect on overall energy reliability and the transition to cleaner energy. Natural gas and electric systems are increasingly interdependent, necessitating enhanced coordination and planning to mitigate reliability risks.

Pacific Northwest utilities alone cannot expand the region's energy infrastructure. The collective will and effort of the Northwest is required to make acquiring and delivering resources possible. To ensure a reliable, affordable and resilient energy future, the region needs to eliminate scarcity and build a mix of abundant resources.

Overview

Each year the *Northwest Regional Forecast* aggregates utilities' 10-year projections of electric loads and resources to provide information about the region's need to acquire new power supply. The *Forecast* is a comprehensive look at the capability of existing and new electric generation, long-term firm contracts, expected savings from demand side management programs and other components of electric supply and demand in the Northwest.

This report presents estimates of annual average energy, seasonal energy and winter and summer peak capability in Tables 1 through 4 of the Northwest Region Requirements and Resources section. These metrics provide a multidimensional look at the Northwest's need for power and underscore the growing complexity of the power system. The information is intended to identify regional trends and general themes based on utilities' resource planning assessment results, rather than provide a precise metric of resource adequacy.

Northwest new and existing generating resources are shown by fuel type. Existing and committed resources are listed in Tables 5, 6 and 10. Table 5, Recently Acquired Resources, highlights projects and supply that became available most recently. Table 6, Committed New Supply, lists projects where construction has started or supply is firmly committed, as well as contractual arrangements that have been made for providing power at a future time. Table 10, Northwest Utility Generating Resources, is a comprehensive list of generating resources that make up the electric power supply for the Pacific Northwest that are utility-owned or utility-contracted.

In addition, utilities have demand side management programs in place to reduce the need for generating resources. Table 7, Demand-Side Management Programs, provides a snapshot of expected savings from these programs for the next 10 years. Lastly, Tables 8 and 9, Needed Future Resources, compile what utilities have reported in their individual resource planning assessments to meet future need.

Planning Area

The Northwest Regional Planning Area is the area defined by the *Pacific Northwest Electric Power Planning and Conservation Act*. It includes: the states of Oregon, Washington, and Idaho; Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming that lie within the Columbia River drainage basin; and any rural electric cooperative customer not in the geographic area described above but served by BPA on the effective date of the *Act*.

Northwest Region Requirements and Resources

Table 1. Northwest Region Requirements and Resources – Annual Energy shows the sum of the individual utilities' requirements and firm resources for each of the next 10 years. Expected firm load and exports make up the total firm regional requirements.

Average Megawatts	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Firm Requirements										
Load 1/	23,819	24,772	25,689	26,792	27,908	28,944	29,716	30,429	31,049	31,650
Exports	352	352	352	352	325	272	272	272	273	273
Total	24,171	25,124	26,041	27,144	28,233	29,216	29,988	30,701	31,322	31,923
Firm Resources										
Hydro 2/	12,316	12,290	12,271	12,046	11,968	11,968	11,968	11,968	11,942	11,923
Natural Gas3/	5,947	6,049	6,050	5,952	6,694	6,834	6,782	6,782	6,782	6,781
Coal	1,820	1,481	1,450	1,456	743	197	197	183	189	197
Nuclear	1,116	994	1,116	994	1,116	994	1,116	994	1,116	994
Small Thermal	29	29	29	19	11	11	11	11	11	11
Cogeneration	55	40	17	14	14	14	14	14	14	14
Imports	883	883	878	551	395	382	263	177	176	176
Solar	541	564	576	578	566	558	550	536	534	504
Wind	1,937	1,907	1,807	1,746	1,708	1,651	1,615	1,575	1,556	1,559
Renewables -Plus-Battery	34	64	72	72	72	72	72	72	72	72
Other Renewables	241	228	223	216	214	211	198	188	186	185
Total	24,918	24,530	24,488	23,643	23,502	22,892	22,787	22,500	22,579	22,418
Surplus (Deficit)	747	(595)	(1,553)	(3,502)	(4,731)	(6,324)	(7,201)	(8,201)	(8,743)	(9,505)

1/ Load net of energy efficiency
2/ Firm hydro for energy is the generation expected assuming low water conditions
3/ Reflects energy available from natural gas power plants not dispatch for economic conditions or clean energy policies

Table 2. Northwest Region Requirements and Resources – Monthly Energy shows the monthly energy values for the 2025-2026 reporting year.

Average Megawatts	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
Firm Requirements												
Load 1/	23,375	21,408	21,478	23,763	26,547	26,612	25,817	23,973	22,640	22,116	23,154	24,940
Exports	490	465	306	306	306	305	305	305	305	305	383	447
Total	23,865	21,873	21,784	24,069	26,853	26,917	26,122	24,278	22,945	22,421	23,537	25,387
Firm Resources												
Hydro 2/	12,405	10,849	8,872	11,793	12,743	13,364	12,732	13,003	12,140	14,784	13,738	11,413
Natural gas	5,805	5,818	5,869	6,025	6,160	6,396	6,343	6,037	5,970	4,946	5,969	6,034
Coal	2,383	2,312	2,231	2,382	2,373	1,561	1,537	1,593	1,352	1,258	1,329	1,525
Nuclear	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116
Small Thermal	31	26	25	30	31	32	32	32	32	30	25	25
Cogeneration	53	51	48	58	55	62	62	56	54	52	51	55
Imports	571	560	731	936	1,024	1,073	1,072	996	907	905	908	911
Solar	790	631	433	240	177	185	335	507	667	760	856	907
Wind	1,773	1,620	1,867	2,055	1,967	1,886	1,955	2,051	2,146	1,954	2,092	1,886
Renewables-Plus-Battery	49	38	29	18	10	14	16	31	39	48	55	55
Other Renewables	242	246	251	255	253	249	249	250	227	220	218	225
Total	25,218	23,268	21,472	24,908	25,909	25,938	25,449	25,672	24,649	26,074	26,357	24,152
Surplus (Deficit)	1,352	1,395	(311)	839	(944)	(979)	(673)	1,393	1,704	3,652	2,820	(1,235)

1/ Load net of energy efficiency
2/ Firm hydro for energy is the generation expected assuming low water conditions
3/ Reflects energy available from natural gas power plants not dispatch for economic conditions or clean energy policies

Table 3. Northwest Region Requirements and Resources – Winter Peak

The sum of the individual utilities' firm requirements and resources for the peak hour in January for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Firm Requirements										
Load 1/	34,764	35,843	36,834	37,996	39,297	40,482	41,307	41,903	42,692	43,888
Exports	660	660	660	660	590	573	565	558	550	550
Planning Margin 2/	5,562	5,735	5,893	6,079	6,288	6,477	6,609	6,704	6,831	7,022
Total	40,986	42,238	43,387	44,736	46,175	47,533	48,482	49,165	50,073	51,460
Firm Resources										
Hydro 3/	23,862	23,767	23,767	23,146	23,139	23,139	23,139	23,139	23,047	23,047
Natural Gas	7,928	7,928	7,928	7,928	8,926	8,790	8,790	8,790	8,790	8,790
Coal	1,771	1,771	1,771	1,771	270	270	270	270	270	270
Nuclear	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178
Small Thermal	173	170	171	153	154	155	156	158	159	159
Cogeneration	66	36	16	16	16	16	16	16	16	16
Imports	1,578	1,313	923	898	898	693	543	543	543	543
Battery	278	259	259	260	260	256	235	223	223	223
Solar	328	336	336	336	336	329	322	307	305	293
Wind	1,404	1,382	1,360	1,356	1,355	1,348	1,339	1,331	1,330	1,330
Renewables -Plus-Battery	592	720	720	720	720	720	720	720	720	720
Other Renewables	109	187	187	187	187	187	187	187	187	187
Demand Response	376	486	599	711	761	855	908	958	1,011	1,042
Total	39,640	39,533	39,213	38,660	38,201	37,938	37,805	37,820	37,779	37,797
Surplus (Need)	(1,346)	(2,705)	(4,174)	(6,075)	(7,974)	(9,595)	(10,677)	(11,345)	(12,294)	(13,663)

1/ Expected (1-in-2) load net of energy efficiency

2/ Planning margin is 16% of load (this assumption was updated and set with the *2018 Northwest Regional Forecast*)

3/ Firm hydro for capacity is the generation expected assuming sustained low water

Table 4. Northwest Region Requirements and Resources – Summer Peak

The sum of the individual utilities' firm requirements and resources for a peak hour in August for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Firm Requirements										
Load 1/	32,263	33,527	34,502	35,386	36,663	37,903	38,985	39,954	40,893	41,684
Exports	961	960	960	960	890	873	865	858	850	850
Planning Margin 2/	5,162	5,364	5,520	5,662	5,866	6,064	6,238	6,393	6,543	6,669
Total	38,386	39,852	40,982	42,008	43,419	44,840	46,087	47,204	48,286	49,203
Firm Resources										
Hydro 3/	21,365	21,272	21,272	20,651	20,651	20,651	20,651	20,651	20,558	20,558
Natural Gas	7,194	7,473	7,473	7,473	7,473	8,499	8,371	8,371	8,371	8,371
Coal	2,663	1,762	1,762	1,762	1,762	267	267	267	267	267
Nuclear	1,163	1,163	1,163	1,163	1,163	1,163	1,163	1,163	1,163	1,163
Small Thermal	169	168	168	169	153	153	154	155	157	157
Cogeneration	66	66	36	17	17	17	17	17	17	17
Imports	838	1,185	1,020	630	590	590	385	235	235	235
Battery	486	863	863	863	863	863	863	863	863	863
Solar	819	821	868	870	872	829	829	804	803	770
Wind	989	992	976	953	942	938	929	925	918	918
Renewables -Plus-Battery	123	123	211	211	211	211	211	211	211	211
Other Renewables	283	258	258	252	259	259	245	224	222	217
Demand Response	743	904	1,014	1,139	1,217	1,305	1,376	1,437	1,483	1,517
Total	36,902	37,051	37,086	36,153	36,173	35,745	35,460	35,323	35,268	35,263
Surplus (Need)	(1,483)	(2,801)	(3,896)	(5,855)	(7,245)	(9,095)	(10,627)	(11,881)	(13,018)	(13,940)

1/ Expected (1-in-2) load net of energy efficiency

2/ Planning margin is 16% of load (this assumption was updated and set with the *2018 Northwest Regional Forecast*)

3/ Firm hydro for capacity is the generation expected assuming sustained low water

Northwest New and Existing Resources

Table 5. Recently Acquired Resources highlights projects that have recently become available.

Project	Fuel/Tech	Nameplate (MW)	Utility/Owner
Clearwater Wind III	Wind	98	Avista
Yellowstone County Generating Station	Natural Gas	175	NorthWestern Energy
Bakeoven	Solar	60	Portland General Electric
Coffee Creek Battery	Li Ion Battery	34	Portland General Electric
Constable	Li Ion Battery	75	Portland General Electric
Daybreak	Solar	140	Portland General Electric
Seaside	Li Ion Battery	200	Portland General Electric
Troutdale	Li Ion Battery	200	Portland General Electric
Beaver Creek	Wind	248	Puget Sound Energy
Vantage Wind	Wind	90	Puget Sound Energy
Prineville	Solar	40	Seattle City Light
25 MW 100MWh BESS	Li Ion Battery	25	Snohomish PUD
Total (Nameplate)		1,385	

Table 6. Committed Resources details firm contracts and generating projects that are committed to come online. All supply listed in this table is included in the regional analysis of power needs.

Project	Year	Fuel/Tech	Nameplate (MW)	Utility/Owner
Palouse Junction	2026	Solar	10	Franklin PUD
Idaho Falls Peak Generation Plant	2025	Peaking Capacity	17.5	Idaho Falls Power
Blacks Creek	2027	Solar	320	Idaho Power
Boise Bench BESS	2026	Li Ion Battery	150	Idaho Power
Boise Bench BESS Expansion 2	2026	Li Ion Battery	50	Idaho Power
Crimson Orchard Solar + BESS	2026	Solar-Plus-Battery	100	Idaho Power
Happy Valley BESS	2025	Li Ion Battery	80	Idaho Power
Hemingway Battery Expansion 2	2026	Li Ion Battery	50	Idaho Power
Jackalope Wind	2027	Wind	600	Idaho Power
Kuna BESS	2025	Li Ion Battery	150	Idaho Power
Pleasant Valley Solar	2025	Solar	3	Idaho Power
Pleasant Valley Solar 2	2026	Solar	125	Idaho Power
Canyonville Solar 1 LLC	2026	Solar	1	PACW
Canyonville Solar 2 LLC	2026	Solar	2	PACW
Farmers Irrigation District (Copper Dam Plant)	2026	Hydro	4	PACW
Pilot Rock Solar 1, LLC	2025	Solar	2	PACW
Pilot Rock Solar 2, LLC	2025	Solar	3	PACW
Tutuilla Solar, LLC	2025	Solar	2	PACW
Appaloosa	2026	Solar	142	Puget Sound Energy
Fort Rock	2026	Solar	47	Seattle City Light
Total (Nameplate)			1,858	

Table 7. Demand-Side Management Programs is a snapshot of the regional utilities' efforts to manage demand. The majority of the energy efficiency savings are from utility programs and included in the regional analysis of power needs. This table also shows cumulative existing plus new demand response programs reported by utilities.

	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Energy Efficiency (aMW)										
Incremental	242	208	207	212	227	226	241	231	229	212
Cumulative	242	450	657	868	1,095	1,321	1,562	1,793	2,022	2,234
Demand Response (MW) existing + forecast[1]										
Winter (January)	376	486	599	711	761	855	908	958	1011	1042
Summer (August)	743	904	1,014	1,139	1,217	1,305	1,376	1,437	1,483	1,517

[1] Values are program effectiveness, nameplate values are higher.

Table 8. Needed Future Resources catalogues future resources that utilities have identified to meet their own needs. These resources are subject to change and are not included in the regional analysis of power needs.

Project	Year	Fuel/Tech	Nameplate	Utility
Stand Alone Storage	2026	Battery	274	OR Utility
Distributed Storage	2026	Battery	25	WA Utility
Solar and Wind	2026	Generic Renewables	331	OR Utility
Community-Based Renewables	2026	Generic Renewables	66	OR Utility
Generic Capacity	2026	Peaking Capacity	253	OR Utility
Generic Capacity	2026	Peaking Capacity	698	OR Utility
Frame Peaker Biodiesel	2026	Peaking Capacity	237	WA Utility
Montana Pumped Hydro Energy Storage	2026	Pumped Storage	200	WA Utility
WA/OR Pumped Hydro Energy Storage	2026	Pumped Storage	200	WA Utility
Renewables-Plus-Battery	2026	Renewables-Plus-Battery	75	OR Utility
Wind-Plus-Battery	2026	Renewables-Plus-Battery	150	WA Utility
Wind-Plus-Solar-Plus-Battery	2026	Renewables-Plus-Battery	250	WA Utility
Solar	2026	Solar	300	OR Utility
Solar	2026	Solar	600	OR Utility
Solar	2026	Solar	80	OR Utility
Solar	2026	Solar	41	OR Utility
Ponderosa Solar PPA	2026	Solar	200	Multi-State Utility
Distributed Solar	2026	Solar	30	WA Utility
SE Oregon Solar	2026	Solar	75	WA Utility
E Washington Solar	2026	Solar	300	WA Utility
Solar	2026	Solar	250	OR Utility
Wind	2026	Wind	110	OR Utility
Wind	2026	Wind	151	OR Utility
Wind	2026	Wind	24	OR Utility
Columbia River Gorge Wind	2026	Wind	275	WA Utility
Montana Wind	2026	Wind	100	WA Utility
Wind	2026	Wind	350	OR Utility
Wind	2026	Wind	350	OR Utility
RFP Battery	2027	Battery	200	WA Utility
Distributed Storage	2027	Battery	25	WA Utility
Li Ion 4hr	2027	Battery	300	WA Utility
Battery 8hr	2027	Battery	100	WA Utility
Battery 4hr	2027	Battery	100	WA Utility
25 MW 100 MWh BESS	2027	Battery	25	WA Utility
Solar and Wind	2027	Generic Renewables	410	OR Utility
Community-Based Renewables	2027	Generic Renewables	19	OR Utility
Pumped Storage	2027	Pumped Storage	27	Multi-State Utility

Project	Year	Fuel/Tech	Nameplate	Utility
Renewables-Plus-Battery	2027	Renewables-Plus-Battery	260	Multi-State Utility
E Washington Solar + Battery	2027	Renewables-Plus-Battery	50	WA Utility
Solar	2027	Renewables-Plus-Battery	400	OR Utility
Passage Solar	2027	Solar	74	WA Utility
Utility-Scale Solar	2027	Solar	322	Multi-State Utility
Distributed Solar	2027	Solar	30	WA Utility
Stateline Wind PPA	2027	Wind	90	Multi-State Utility
Generic Wind	2027	Wind	25	WA Utility
4hr Storage	2028	Battery	5	Multi-State Utility
Stand Alone Battery	2028	Battery	21	Multi-State Utility
Distributed Storage	2028	Battery	25	WA Utility
Solar and Wind	2028	Generic Renewables	400	OR Utility
Community-Based Renewables	2028	Generic Renewables	25	OR Utility
Frame Peaker Biodiesel	2028	Peaking Capacity	237	WA Utility
Pumped Storage	2028	Pumped Storage	400	OR Utility
Renewables-Plus-Battery	2028	Renewables-Plus-Battery	64	Multi-State Utility
Wind-Plus-Battery	2028	Renewables-Plus-Battery	150	WA Utility
Solar-Plus-Battery	2028	Renewables-Plus-Battery	500	OR Utility
Solar-Plus-Battery	2028	Renewables-Plus-Battery	400	OR Utility
Utility Solar	2028	Solar	64	Multi-State Utility
Distributed Solar	2028	Solar	30	WA Utility
WA East Solar	2028	Solar	200	WA Utility
Solar	2028	Solar	1,000	OR Utility
Wind	2028	Wind	100	Multi-State Utility
Wind	2028	Wind	315	WA Utility
RFP Battery	2028	Wind	200	WA Utility
Wind	2028	Wind	350	WA Utility
4hr Storage	2029	Battery	5	Multi-State Utility
Stand Alone Battery	2029	Battery	137	Multi-State Utility
Distributed Storage	2029	Battery	25	WA Utility
Solar and Wind	2029	Generic Renewables	306	OR Utility
Community-Based Renewables	2029	Generic Renewables	23	OR Utility
IRP Resource - CT	2029	Peaking Capacity	50	Multi-State Utility
Generic Capacity	2029	Peaking Capacity	635	OR Utility
Hybrid (Solar + Battery)	2029	Renewables-Plus-Battery	429	OR Utility
Solar-Plus-Battery	2029	Renewables-Plus-Battery	300	WA Utility
Wind-Plus-Battery	2029	Renewables-Plus-Battery	300	WA Utility
Solar	2029	Solar	76	WA Utility
Solar	2029	Solar	200	Multi-State Utility
Distributed Solar	2029	Solar	30	WA Utility
WA East Solar	2029	Solar	400	WA Utility
Northwest Wind	2029	Wind	200	Multi-State Utility

Project	Year	Fuel/Tech	Nameplate	Utility
Wind	2029	Wind	400	Multi-State Utility
Generic Wind	2029	Wind	50	WA Utility
Wind	2029	Wind	90	OR Utility
4hr Storage	2030	Battery	5	Multi-State Utility
Distributed Storage	2030	Battery	25	WA Utility
25 MW 100 MWh BESS	2030	Battery	25	WA Utility
Walker Ranch Geothermal Project PPA	2030	Generic Renewables	15	ID Utility
Solar and Wind	2030	Generic Renewables	10	OR Utility
Community-Based Renewables	2030	Generic Renewables	22	OR Utility
Natural Gas CT	2030	Peaking Capacity	90	Multi-State Utility
Generic Capacity	2030	Peaking Capacity	265	OR Utility
Hybrid (Solar + Battery)	2030	Renewables-Plus-Battery	571	OR Utility
Distributed Solar	2030	Solar	30	WA Utility
Northwest Wind	2030	Wind	200	Multi-State Utility
Wind	2030	Wind	400	Multi-State Utility
Wind	2030	Wind	75	Multi-State Utility
WA Wind	2030	Wind	400	WA Utility
Generic Wind	2030	Wind	225	WA Utility
4hr Storage	2031	Battery	55	Multi-State Utility
Stand Alone Battery	2031	Battery	431	Multi-State Utility
Stand Alone Storage	2031	Battery	315	OR Utility
Distributed Storage	2031	Battery	25	WA Utility
Capacity	2031	Peaking Capacity	36	OR Utility
Generic Capacity	2031	Peaking Capacity	225	OR Utility
Solar and Wind	2031	Generic Renewables	1,155	OR Utility
Hybrid (Solar + Battery)	2031	Renewables-Plus-Battery	10	OR Utility
Solar	2031	Solar	500	Multi-State Utility
Distributed Solar	2031	Solar	30	WA Utility
Northwest Wind	2031	Wind	100	Multi-State Utility
Montana Wind	2031	Wind	100	Multi-State Utility
Wind	2031	Wind	400	Multi-State Utility
Wind	2031	Wind	5	Multi-State Utility
WY East Wind	2031	Wind	200	WA Utility
Generic Wind	2031	Wind	75	WA Utility
4hr Storage	2032	Battery	5	Multi-State Utility
Stand Alone Battery	2032	Battery	10	Multi-State Utility
Li Ion 4hr	2032	Battery	100	WA Utility
Nevada Enhanced Geothermal	2032	Enhanced Geothermal Systems	50	WA Utility
Offshore Wind	2032	Offshore Wind	237	OR Utility
IRP Resource - CT	2032	Peaking Capacity	50	Multi-State Utility
IRP Resource - Pumped Hydro	2032	Pumped Storage	100	Multi-State Utility
Distributed Solar	2032	Solar	30	WA Utility

Project	Year	Fuel/Tech	Nameplate	Utility
Wind	2032	Wind	1,401	Multi-State Utility
Montana Wind	2032	Wind	100	Multi-State Utility
Wind	2032	Wind	100	Multi-State Utility
WY East Wind	2032	Wind	100	WA Utility
4hr Storage	2033	Battery	55	Multi-State Utility
Li Ion 6hr	2033	Battery	100	WA Utility
Nevada Enhanced Geothermal	2033	Enhanced Geothermal Systems	50	WA Utility
Offshore Wind	2033	Offshore Wind	233	OR Utility
Capacity	2033	Peaking Capacity	72	OR Utility
Distributed Solar	2033	Solar	30	WA Utility
Wind	2033	Wind	1,765	Multi-State Utility
Northwest Wind	2033	Wind	157	Multi-State Utility
WY East Wind	2033	Wind	100	WA Utility
4hr Storage	2034	Battery	55	Multi-State Utility
Stand Alone Battery	2034	Battery	1	Multi-State Utility
Li Ion 4hr	2034	Battery	300	WA Utility
Li Ion 6hr	2034	Battery	100	WA Utility
4hr Storage	2034	Battery	55	Multi-State Utility
Nevada Enhanced Geothermal	2034	Enhanced Geothermal Systems	50	WA Utility
Offshore Wind	2034	Offshore Wind	250	OR Utility
IRP Resource - RECIP	2034	Peaking Capacity	18	Multi-State Utility
Capacity	2034	Peaking Capacity	97	OR Utility
WA East Solar	2034	Solar	200	WA Utility
Distributed Solar	2034	Solar	30	WA Utility
Offshore Wind	2035	Offshore Wind	254	OR Utility
Capacity	2035	Peaking Capacity	139	OR Utility
East Solar	2035	Solar	300	WA Utility
Distributed Solar	2035	Solar	30	WA Utility
East Wind	2035	Wind	200	WA Utility
Broadview QF	TBD	Renewables-Plus-Battery	80	Multi-State Utility
Meadowlark QF	TBD	Renewables-Plus-Battery	20	Multi-State Utility
Trident QF	TBD	Renewables-Plus-Battery	80	Multi-State Utility
Jawbone QF	TBD	Wind	80	Multi-State Utility
TOTAL			29,798	

Table 9. Needed Future Resources Timeline displays the cumulative supply-side resource additions over time, combining the nameplate MW values of resources from Table 8 (NW utility owned/contracted only, IPP additions not included).

Nameplate MW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Wind	1,360	1,475	2,440	3,180	4,480	5,360	7,061	9,083	9,083	9,363
Solar	1,876	2,302	3,596	4,302	4,332	4,862	4,892	4,922	5,152	5,482
Generic Renewables	397	826	1,251	1,580	1,627	2,782	2,782	2,782	2,782	2,782
Offshore Wind & Enhanced Geothermal Systems	-	-	-	-	-	-	287	570	870	1,124
Renewables-Plus-Battery	475	1,185	2,299	3,328	3,899	3,909	3,909	3,909	3,909	4,089
Battery	299	1,049	1,100	1,267	1,322	2,148	2,263	2,418	2,929	2,929
Pumped Storage	400	427	827	827	827	827	927	927	927	927
Peaking Capacity	1,188	1,188	1,425	2,110	2,465	2,726	2,776	2,848	2,963	3,102
TOTAL	5,995	8,452	12,938	16,594	18,952	22,614	24,897	27,459	28,615	29,798

Table 10. Northwest Utility Generating Resources is a comprehensive list of utility-owned and utility contracted generating resources that make up those utilities electric power supply. The table reflects full plant nameplate and can be larger than the resource share assigned to meet regional load. This table includes recently acquired and committed resources – some of the resources listed may not currently be operating. Needed future resources are not included in the table.

Project	Owner	NW Utility	Nameplate (MW)
HYDRO			33,663
Albeni Falls	US Corps of Engineers	Federal System (BPA)	43
Alder	Tacoma Power	Tacoma Power	50
American Falls	Idaho Power	Idaho Power	92
Anderson Ranch	US Bureau of Reclamation	Federal System (BPA)	40
Arena Drop	PURPA	Idaho Power	1
Arrowrock Dam	Clatskanie PUD/Irr Dist	Clatskanie PUD	20
Astoria	QF	PacifiCorp	0.03
Baker City Hydro	PURPA	Idaho Power	0.2
Barber Dam	PURPA	Idaho Power	4
Bend - Unit 1	PacifiCorp	PacifiCorp	0.2
Bend - Unit 2	PacifiCorp	PacifiCorp	0.3
Bend - Unit 3	PacifiCorp	PacifiCorp	1
Big Cliff	US Corps of Engineers	Federal System (BPA)	18
Big Sheep Creek	Everand Jensen	Avista Corp.	0.1
Bigfork - Unit 1	PacifiCorp	PacifiCorp	2
Bigfork - Unit 2	PacifiCorp	PacifiCorp	2
Bigfork - Unit 3	PacifiCorp	PacifiCorp	1
Birch Creek	PURPA	Idaho Power	0.1
Black Canyon	US Bureau of Reclamation	Federal System (BPA)	10
Black Canyon #3	PURPA	Idaho Power	0.1
Black Canyon Bliss Dam	PURPA	Idaho Power	0.03
Black Creek Hydro	Black Creek Hydro, Inc.	Puget Sound Energy	4
Black Eagle	NorthWestern Energy	NorthWestern Energy	23
Blind Canyon	PURPA	Idaho Power	2
Bliss	Idaho Power	Idaho Power	75
Bogus Creek	QF	PacifiCorp	0.2
Boise River Diversion	US Bureau of Reclamation	Federal System (BPA)	2
Bonneville	US Corps of Engineers	Federal System (BPA)	1,102
Boundary	Seattle City Light	Seattle City Light	1,119
Box Canyon	Pend Oreille County PUD	Pend Oreille County PUD	90
Box Canyon-Idaho	PURPA	Idaho Power	0.4
Briggs Creek	PURPA	Idaho Power	1
Broadwater Dam	Dept. of Natural Res. & Cons.	NorthWestern Energy	10
Brownlee	Idaho Power	Idaho Power	585
Bypass	PURPA	Idaho Power	10
C. J. Strike	Idaho Power	Idaho Power	83
Cabinet Gorge	Avista Corp.	Avista Corp.	265
Calispel Creek	Pend Oreille County PUD	Pend Oreille County PUD	1
Calligan Creek	Snohomish County PUD	Snohomish County PUD	6
Canyon Springs	PURPA	Idaho Power	0.1
Carmen-Smith	Eugene Water & Electric Board	Eugene Water & Electric Board	105
Cascade	US Bureau of Reclamation	Idaho Power	12
C-Drop	QF	PacifiCorp	1
Cedar Draw Creek	PURPA	Idaho Power	2
Cedar Falls, Newhalem	Seattle City Light	Seattle City Light	33
Chandler	US Bureau of Reclamation	Federal System (BPA)	12

Project	Owner	NW Utility	Nameplate (MW)
Chelan	Chelan County PUD	Chelan County PUD	59
Chief Joseph	US Corps of Engineers	Federal System (BPA)	2,457
Clackamas	Portland General Electric	Portland General Electric	96
Clear Lakes	Idaho Power	Idaho Power	3
Clear Springs Trout	PURPA	Idaho Power	1
Clear Water 1	PacifiCorp	PacifiCorp	18
Clear Water 2	PacifiCorp	PacifiCorp	31
Cochrane	NorthWestern Energy	NorthWestern Energy	62
Coleman Hydro	PURPA	Idaho Power	1
Cougar	US Corps of Engineers	Federal System (BPA)	25
Cowlitz Falls	Lewis County PUD	Federal System (BPA)	70
Crystal Springs	PURPA	Idaho Power	2
Curry Cattle Company	PURPA	Curry Cattle Company	0.2
Cushman 1	Tacoma Power	Tacoma Power	43
Cushman 2	Tacoma Power	Tacoma Power	81
Deep Creek	Gordon Foster	Avista Corp.	1
Derr Creek	Jim White	Avista Corp.	0.3
Deschutes Valley	QF	PacifiCorp	6
Detroit	US Corps of Engineers	Federal System (BPA)	100
Dexter	US Corps of Engineers	Federal System (BPA)	15
Diablo	Seattle City Light	Seattle City Light	182
Dietrich Drop	PURPA	Idaho Power	5
Dorena	QF	PacifiCorp	6
Dworshak	US Corps of Engineers	Federal System (BPA)	400
Dworshak/ Clearwater		Federal System (BPA)	3
Eagle Point	PacifiCorp	PacifiCorp	3
East Side (Klamath River System)	PacifiCorp	PacifiCorp	3
EBD	QF	PacifiCorp	3
Ebey Hill	Ebey Hill Hydroelectric, Inc.	Snohomish County PUD	0.2
Eight Mile Hydro	PURPA	Idaho Power	0.4
Elk Creek	PURPA	Idaho Power	3
Eltopia Branch Canal	SEQCBID	Multiple Utilities	2
Esquatzel Small Hydro	Green Energy Today, LLC	Franklin County PUD	1
Fall Creek - Unit 1	PacifiCorp	PacifiCorp	1
Fall Creek - Unit 2	PacifiCorp	PacifiCorp	0.5
Fall Creek - Unit 3	PacifiCorp	PacifiCorp	1
Falls River	PURPA	Idaho Power	9
Faraday	Portland General Electric	Portland General Electric	27
Fargo Drop Hydro	PURPA	Idaho Power	1
Farmers Irrigation District	QF	PacifiCorp	4
Faulkner Ranch	PURPA	Idaho Power	1
Fish Creek	PacifiCorp	PacifiCorp	10
Fisheries Development Co.	PURPA	Idaho Power	0.3
Foster	US Corps of Engineers	Federal System (BPA)	20
Galesville Dam	QF	PacifiCorp	2
Gem State Hydro 1	IdahoFalls-ID	Other Publics (BPA)	23
Geo-Bon #2	PURPA	Idaho Power	1
Gorge	Seattle City Light	Seattle City Light	207
Grand Coulee	US Bureau of Reclamation	Federal System (BPA)	6,494
Green Peter	US Corps of Engineers	Federal System (BPA)	80
Green Springs	US Bureau of Reclamation	Federal System (BPA)	16
Hailey CSPP	PURPA	Idaho Power	0.1
Hancock Creek	Snohomish County PUD	Snohomish County PUD	6

Project	Owner	NW Utility	Nameplate (MW)
Hauser	NorthWestern Energy	NorthWestern Energy	19
Hazelton A	PURPA	Idaho Power	8
Hazelton B	PURPA	Idaho Power	8
Head of U Canal	PURPA	Idaho Power	1
Hells Canyon	Idaho Power	Idaho Power	392
Hills Creek	US Corps of Engineers	Federal System (BPA)	30
Holter	NorthWestern Energy	NorthWestern Energy	50
Hood Street Reservoir	Tacoma Power	Tacoma Power	1
Horseshoe Bend	PURPA	Idaho Power	9
Hungry Horse	US Bureau of Reclamation	Federal System (BPA)	428
Hydro Contracts (Outside Region)	Various	Multiple Utilities	110
Ice Harbor	US Corps of Engineers	Federal System (BPA)	603
Idaho Falls - City Plant		Federal System (BPA)	8
Idaho Falls - Lower Plant #1		Federal System (BPA)	8
Idaho Falls - Lower Plant #2		Federal System (BPA)	3
Idaho Falls - Upper Plant		Federal System (BPA)	8
Jackson (Sultan)	Snohomish County PUD	Snohomish County PUD	112
Jim Ford Creek	Ford Hydro	Avista Corp.	2
Jim Knight	PURPA	Idaho Power	0.3
John Day	US Corps of Engineers	Federal System (BPA)	2,160
John Day Creek	Dave Cereghino	Avista Corp.	1
Juniper Ridge	QF	PacifiCorp	5
Koma Kulshan	Koma Kulshan Associates	Puget Sound Energy	12
Koyle Small Hydro	PURPA	Idaho Power	1
La Grande	Tacoma Power	Tacoma Power	64
Lacomb Irrigation	QF	PacifiCorp	1
Lake Oswego Corp.		Portland General Electric	1
Lake Siskiyou (Box Canyon)	QF	PacifiCorp	5
Lateral #10	PURPA	Idaho Power	2
Lemolo 1	PacifiCorp	PacifiCorp	32
Lemolo 2	PacifiCorp	PacifiCorp	39
Lemoyne	PURPA	Idaho Power	0.1
Libby	US Corps of Engineers	Federal System (BPA)	525
Little Falls	Avista Corp.	Avista Corp.	32
Little Goose	US Corps of Engineers	Federal System (BPA)	810
Little Mac	PURPA	Idaho Power	1
Little Wood River Ranch II	PURPA	Idaho Power	1
Little Wood Rvr Res	PURPA	Idaho Power	3
Little Wood/Arkoosh	PURPA	Idaho Power	1
Long Lake	Avista Corp.	Avista Corp.	70
Lookout Point	US Corps of Engineers	Federal System (BPA)	120
Lost Creek	US Corps of Engineers	Federal System (BPA)	49
Low Line Canal	PURPA	Idaho Power	8
Low Line Midway	PURPA	Idaho Power	3
Lower Baker	Puget Sound Energy	Puget Sound Energy	115
Lower Granite	US Corps of Engineers	Federal System (BPA)	810
Lower Malad	Idaho Power	Idaho Power	14
Lower Monumental	US Corps of Engineers	Federal System (BPA)	810
Lower Salmon	Idaho Power	Idaho Power	60
Lower Swift Creek	Lower Valley Energy, Inc.	Other Publics (BPA)	0.4
Lowline #2	PURPA	Idaho Power	3
Lucky Peak	US Corps of Engineers	Seattle City Light	113
Lucky, Paul	QF	PacifiCorp	0.1
Madison	Northwestern Energy	NorthWestern Energy	8

Project	Owner	NW Utility	Nameplate (MW)
Magic Reservoir	PURPA	Idaho Power	9
Main Canal Headworks	SEQCBID	Multiple Utilities	26
Malad River	PURPA	Idaho Power	1
Mayfield	Tacoma Power	Tacoma Power	162
MC6 Hydro	PURPA	Idaho Power	2
McNary	US Corps of Engineers	Federal System (BPA)	980
McNary Fishway	US Corps of Engineers	Other Publics (BPA)	10
Meyers Falls	Hydro Technology Systems	Avista Corp.	1
Middlefork Irrigation	QF	PacifiCorp	1
Mile 28	PURPA	Idaho Power	2
Milner	Idaho Power	Idaho Power	118
Minidoka	US Bureau of Reclamation	Federal System (BPA)	28
Mitchell Butte	PURPA	Idaho Power	2
Monroe	QF	PacifiCorp	0.3
Monroe Street	Avista	Avista Corp.	15
Mora Drop	PURPA	Idaho Power	2
Morony	NorthWestern Energy	NorthWestern Energy	49
Mossyrock	Tacoma Power	Tacoma Power	300
Mount Tabor	City of Portland	Portland General Electric	0.2
Moyie River 1	BonnersFerry-ID	Other Publics (BPA)	1
Moyie River 2	BonnersFerry-ID	Other Publics (BPA)	2
Moyie River 3	BonnersFerry-ID	Other Publics (BPA)	2
Mud Creek/S&S	PURPA	Idaho Power	1
Mud Creek/White	PURPA	Idaho Power	0.2
Mystic	NorthWestern Energy	NorthWestern Energy	12
N-32 Canal (Marco Ranches)	PURPA	Idaho Power	1
Nine Mile	Avista Corp.	Avista Corp.	26
Nooksack	Puget Sound Hydro, LLC	Puget Sound Energy	4
North Fork	Portland General Electric	Portland General Electric	27
North Fork Sprague	QF	PacifiCorp	1
North Gooding Main Hydro		Idaho Power	1
Noxon Rapids	Avista Corp.	Avista Corp.	466
Oak Grove	Portland General Electric	Portland General Electric	27
Owyhee Dam Cspp	PURPA	Idaho Power	5
Oxbow	Idaho Power Company	Idaho Power	190
Packwood	Energy Northwest	Other Publics (BPA)	28
Palisades	US Bureau of Reclamation	Federal System (BPA)	177
PEC Headworks	SEQCBID	Avista Corp.	7
Pelton	Portland General Electric	Multiple Utilities	110
Pelton Reregulation	Warm Springs Tribe	Portland General Electric	10
Pigeon Cove	PURPA	Idaho Power	2
Port Townsend Mill 2	PortTownsend Paper	Other Publics (BPA)	0.4
Portland Hydro-Project	City of Portland	Portland General Electric	36
Portland Water Bureau	QF	PacifiCorp	0.03
Post Falls	Avista Corp.	Avista Corp.	15
Potholes East Canal 66 Headworks	SEQCBID	Seattle City Light	2
Priest Rapids	Grant County PUD	Multiple Utilities	956
Pristine Springs #1	PURPA	Idaho Power	0.1
Pristine Springs #3	PURPA	Idaho Power	0.2
Prospect 1	PacifiCorp	PacifiCorp	5
Prospect 2 - Unit 1	PacifiCorp	PacifiCorp	18
Prospect 2 - Unit 2	PacifiCorp	PacifiCorp	18
Prospect 3	PacifiCorp	PacifiCorp	8
Prospect 4	PacifiCorp	PacifiCorp	1

Project	Owner	NW Utility	Nameplate (MW)
Quincy Chute	SEQCBID	Multiple Utilities	9
R.D. Smith	SEQCBID	Multiple Utilities	6
Rainbow	NorthWestern Energy	NorthWestern Energy	64
Reynolds Irrigation	PURPA	Idaho Power	0.3
River Mill	Portland General Electric	Portland General Electric	15
Rock Creek #1	PURPA	Idaho Power	2
Rock Creek #2	PURPA	Idaho Power	2
Rock Island	Chelan County PUD	Multiple Utilities	629
Rocky Reach	Chelan County PUD	Multiple Utilities	1,300
Ross	Seattle City Light	Seattle City Light	450
Round Butte	Portland General Electric	Multiple Utilities	338
Roza	US Bureau of Reclamation	Federal System (BPA)	13
Ryan	NorthWestern Energy	NorthWestern Energy	72
Sagebrush	PURPA	Idaho Power	0.4
Sahko	PURPA	Idaho Power	1
Schaffner	PURPA	Idaho Power	1
Sheep Creek	Glen Phillips	Avista Corp.	2
Shingle Creek	PURPA	Idaho Power	0.2
Shoshone #2	PURPA	Idaho Power	1
Shoshone CSPP	PURPA	Idaho Power	0.4
Shoshone Falls	Idaho Power	Idaho Power	14
Skookumchuck		Puget Sound Energy	1
SLATE CREEK	QF	PacifiCorp	4
Slide Creek	PacifiCorp	PacifiCorp	18
Smith Creek	Smith Creek Hydro, LLC	Eugene Water & Electric Board	0.1
Snake River Pottery	PURPA	Idaho Power	0.1
Snedigar Ranch	PURPA	Idaho Power	1
Snoqualmie Falls	Puget Sound Energy	Puget Sound Energy	54
Soda Springs	PacifiCorp	PacifiCorp	12
South Fork Tolt	Seattle City Light	Seattle City Light	17
Spokane Upriver	City of Spokane	Avista Corp.	16
St. Anthony	QF	PacifiCorp	1
Stone Creek	Eugene Water & Electric Board	Eugene Water & Electric Board	12
Strawberry Creek Wyoming 1	Lower Valley Energy	Other Publics (BPA)	2
Summer Falls	SEQCBID	Multiple Utilities	92
Swalley	QF	PacifiCorp	1
Swan Falls	Idaho Power	Idaho Power	25
Swift 1	PacifiCorp	Multiple Utilities	264
Swift 2	Cowlitz County PUD	Multiple Utilities	86
Sygitowicz	Cascade Clean Energy	Puget Sound Energy	0.4
The Dalles	US Corps of Engineers	Federal System (BPA)	1,807
The Dalles North Fishway	Northern Wasco County PUD	Other Publics (BPA)	5
Thompson Falls Dam	Northwestern Energy	NorthWestern Energy	94
Thousand Springs	Idaho Power	Idaho Power	9
Three Sister	QF	PacifiCorp	0.3
Toketee - Unit 1	PacifiCorp	PacifiCorp	15
Toketee - Unit 2	PacifiCorp	PacifiCorp	15
Toketee - Unit 3	PacifiCorp	PacifiCorp	15
Trail Bridge	Eugene Water & Electric Board	Eugene Water & Electric Board	10
Trout Co	PURPA	Idaho Power	0.2
TSID Watson-Mcr1	QF	PacifiCorp	1
TSID Watson-Mcr2	QF	PacifiCorp	0.2
Tunnel #1	PURPA	Idaho Power	7
Turnbull Hydro		NorthWestern Energy	13

Project	Owner	NW Utility	Nameplate (MW)
TW Sullivan	Portland General Electric	Portland General Electric	15
Twin Falls	PURPA	Puget Sound Energy	53
Twin Falls	PURPA	Puget Sound Energy	20
Upper Baker	Puget Sound Energy	Puget Sound Energy	105
Upper Falls	Avista Corp.	Avista Corp.	10
Upper Malad	Idaho Power	Idaho Power	8
Upper Salmon A	Idaho Power	Idaho Power	18
Upper Salmon B	Idaho Power	Idaho Power	17
Upper Swift Creek	Lower Valley Energy	Other Publics (BPA)	1
Walla Walla 1	Columbia REA	Other Publics (BPA)	2
Wallowa Falls	PacifiCorp	PacifiCorp	1
Walterville	Eugene Water & Electric Board	Eugene Water & Electric Board	8
Wanapum	Grant County PUD	Multiple Utilities	934
Weeks Falls	So. Fork II Assoc. LP	Puget Sound Energy	5
Wells	Douglas County PUD	Multiple Utilities	774
West Side (Klamath River System)	PacifiCorp	PacifiCorp	1
White Water Ranch	PURPA	Idaho Power	0.2
Whitefish Hydro		Flathead Electric Cooperative	0.2
Wilson Lake		Other Publics (BPA)	8
Woods Creek	Snohomish County PUD	Snohomish County PUD	1
Wynoochee	Tacoma Power	Tacoma Power	13
Yakama Drop 2	Yakama Power	Other Publics (BPA)	3
Yakama Drop 3	Yakama Power	Other Publics (BPA)	2
Yakima Cowiche	QF	PacifiCorp	1
Yakima Orchard	QF	PacifiCorp	1
Yale - Unit 1	PacifiCorp	PacifiCorp	82
Yale - Unit 2	PacifiCorp	PacifiCorp	82
Yelm 1		Other Publics (BPA)	12
Youngs Creek	Snohomish County PUD	Snohomish County PUD	8
COAL			2,525
Colstrip #3	PP&L Montana, LLC	Multiple Utilities	740
Colstrip #4	NorthWestern Energy	Multiple Utilities	740
Jim Bridger #3	PacifiCorp / Idaho Power	Multiple Utilities	521
Jim Bridger #4	PacifiCorp / Idaho Power	Multiple Utilities	524
NUCLEAR			1,230
Columbia Generating Station	Energy Northwest	Federal System (BPA)	1,230
NATURAL GAS			8,586
Basin Creek	Basin Creek Acquistion LLC	NorthWestern Energy	52
Beaver	Portland General Electric	Portland General Electric	509
Bennett Mountain	Idaho Power	Idaho Power	179
Boulder Park	Avista Corp.	Avista Corp.	25
Carty	Portland General Electric	Portland General Electric	437
Chehalis Generating Facility	PacifiCorp	PacifiCorp	477
Coyote Springs I	Portland General Electric	Portland General Electric	252
Coyote Springs II	Avista Corp.	Avista Corp.	287
Danskin	Idaho Power	Idaho Power	90
Danskin 1	Idaho Power	Idaho Power	179
Dave Gates Generating Station	NorthWestern Energy	NorthWestern Energy	150
Encogen	Puget Sound Energy	Puget Sound Energy	166

Project	Owner	NW Utility	Nameplate (MW)
Ferndale	Puget Sound Energy	Puget Sound Energy	244
Frederickson Generation Station	EPCOR Power L.P./PSE	EPCOR Power L.P./PSE	258
Fredonia 1 & 2	Puget Sound Energy	Puget Sound Energy	234
Fredonia 3 & 4	Puget Sound Energy	Puget Sound Energy	108
Fredrickson 1 & 2	Puget Sound Energy	Puget Sound Energy	149
Goldendale Generating Station	Puget Sound Energy	Puget Sound Energy	280
Hermiston Generating Project	PacifiCorp/Hermiston Generating Co.	PacifiCorp/Hermiston Generating Co.	468
Idaho Falls Peak Gen. Plant	Idaho Falls Power	Idaho Falls Power	18
Jim Bridger #1-Conversion	PacifiCorp / Idaho Power	Multiple Utilities	528
Jim Bridger #2-Conversion	PacifiCorp / Idaho Power	Multiple Utilities	536
Kettle Falls CT	Avista Corp.	Avista Corp.	7
Lancaster Power Project	Avista Corp.	Avista Corp.	270
Langley Gulch	Idaho Power	Idaho Power	321
Mint Farm Energy Center	Puget Sound Energy	Puget Sound Energy	276
Northeast A&B	Avista Corp.	Avista Corp.	62
Port Westward	Portland General Electric	Portland General Electric	411
Port Westward Unit 2	Portland General Electric	Portland General Electric	225
Rathdrum 1 & 2	Avista Corp.	Avista Corp.	167
River Road Generating Project	Clark Public Utilities	Clark Public Utilities	248
Sumas Energy	Puget Sound Energy	Puget Sound Energy	129
Valmy #1	NV Energy / Idaho Power	Multiple Utilities	254
Valmy #2	NV Energy / Idaho Power	Multiple Utilities	267
Whitehorn #2 & 3	Puget Sound Energy	Puget Sound Energy	149
Yellowstone County Generating Station	NorthWestern Energy	NorthWestern Energy	175
COGENERATION			88
Hampton Lumber	Hampton Lumber Mills	Snohomish County PUD PPA	5
International Paper Energy Center	Eugene Water & Electric Board	Eugene Water & Electric Board	26
Port Townsend Mill (non-hydro cogen)	Port Townsend Paper	Other Publics (BPA)	8
Simplot-Pocatello	PURPA	Idaho Power	12
Tasco-Nampa	Tasco	Idaho Power	2
Wauna	Georgia-Pacific	Clatskanie PUD	36
OTHER RENEWABLES			383
Bannock County Landfill	PURPA	Idaho Power	3
BioOne	QF	PacifiCorp	33
Bloks Evergreen Dairy	Puget Sound Energy	Puget Sound Energy	0.2
City of Spokane Waste to Energy	City of Spokane	Avista Corp.	26
Columbia Ridge Landfill Gas	Waste Management	Seattle City Light	13
Emerald City I		Puget Sound Energy	5
Emerald City II		Puget Sound Energy	5
Farm Misty Meadows	QF	PacifiCorp	1
Farm Power Rexville		Puget Sound Energy	1
Fighting Creek Landfill Gas to Energy Station	PURPA	Idaho Power	3
Flathead County Landfill	Flathead Electric Cooperative	Flathead Electric Cooperative	3
H. W. Hill Landfill	Allied Waste Companies	Multiple Utilities	37
Interfor Pacific-Gilchrist	Midstate Electric Co-op	Midstate Electric Co-op	2
Kettle Falls	Avista Corp.	Avista Corp.	51
Neal Hot Springs	U.S Geothermal	Idaho Power	33
OIT	QF	PacifiCorp	0.3
PGE Other QF		Portland General Electric	31
Plum Creek NLSL	Plum Creek MDF	Flathead Electric Cooperative	6
Pocatello Wastewater	PURPA	Idaho Power	0.5

Project	Owner	NW Utility	Nameplate (MW)
Port of Tillamook Digester		Tillamook PUD	1
Qualco Dairy Digester		Snohomish PUD	1
Raft River 1	US Geothermal	Idaho Power	16
Rainier Biogas		Puget Sound Energy	1
RES Ag-Oak Lea BG	QF	PacifiCorp	0.2
River Bend Landfill	McMinnville, OR (City of)	McMinnville, OR (City of)	5
Roseburg Forest Products Company - Dillard	QF	PacifiCorp	20
Roseburg LFG	QF	PacifiCorp	2
Roseburg_Weed	QF	PacifiCorp	10
Seneca	Seneca Sustainable Energy, LLC	Eugene Water & Electric Board	20
Short Mountain		Emerald PUD	3
Sierra Pacific Industries		Grays Harbor PUD	18
SPI Biomass		Puget Sound Energy	17
Stimson Lumber	Stimson Lumber	Avista Corp.	7
Stoltze Biomass	F.H. Stoltze Land & Lumber	Flathead Electric Coop	3
Tamarack	PURPA	Idaho Power	5
TMF Biofuels (Three Mile Digester)	QF	PacifiCorp	5
SOLAR			2,386
7_Mile_Solar	QF-CSP (OR Sch 126)	PacifiCorp	1
Adams	QF	PacifiCorp	10
American Falls Solar	PURPA	Idaho Power	20
American Falls Solar II	PURPA	Idaho Power	20
Antelope_Creek_Solar	QF-CSP (OR Sch 126)	PacifiCorp	2
Appaloosa	Puget Sound Energy	Puget Sound Energy	142
Bakeoven Solar	Avangrid	Portland General Electric	60
Baker Solar	PURPA	Idaho Power	15
BearCreek	QF	PacifiCorp	10
Bellevue Solar	EDF Renewable Energy	Portland General Electric	1
Black Cap		PacifiCorp	2
Black Cap II	QF	PacifiCorp	8
Black Eagle Solar		NorthWestern Energy	3
Blackwell Creek Solar	QF-CSP (OR Sch 126)	PacifiCorp	1
Bly	QF	PacifiCorp	9
Brush Solar	PURPA	Idaho Power	3
Buckaroo Solar 1	QF-CSP (OR Sch 126)	PacifiCorp	2
Buckaroo Solar 2	QF-CSP (OR Sch 126)	PacifiCorp	3
Canyonville Solar 1	QF-CSP (OR Sch 126)	PacifiCorp	1
Canyonville Solar 2	QF-CSP (OR Sch 126)	PacifiCorp	2
Cherry_Creek_Solar	QF-CSP (OR Sch 126)	PacifiCorp	0.4
Chiloquin	QF	PacifiCorp	10
Cleanera Apex I		NorthWestern Energy	80
Daybreak Solar	Avangrid	Portland General Electric	138
Durkee Solar	PURPA	Idaho Power	3
Elbe	QF	PacifiCorp	10
Ewauna	QF	PacifiCorp	1
Ewauna II	QF	PacifiCorp	3
Finn Hill Solar (Lake Washington School District		Puget Sound Energy	0.4
Goose Prairie	Goose Prairie, LLC	Grant Co. PUD	80
Grand View Solar	PURPA	Idaho Power	80
Great Divide Solar		NorthWestern Energy	3
Green Meadows Solar		NorthWestern Energy	3
Green Solar	QF-CSP (OR Sch 126)	PacifiCorp	3

Project	Owner	NW Utility	Nameplate (MW)
Grove Solar	PURPA	Idaho Power	6
Hay_Creek_Solar	QF-CSP (OR Sch 126)	PacifiCorp	1
Horn Rapids		Energy Northwest	3
Hyline Solar Center	PURPA	Idaho Power	9
ID Solar 1 (formerly Boise City Solar)	Boise City Solar, LLC	Idaho Power	40
IKEA Solar		Puget Sound Energy	1
Jackpot Solar	Jackpot Holdings, LLC	Idaho Power	120
King Estate Solar	Lane Co. Electric Cooperative	Lane Co. Electric Cooperative	1
Linkville_Solar	QF-CSP (OR Sch 126)	PacifiCorp	3
Lund Hill	Lane Co. Electric Cooperative	Puget Sound Energy	150
Magpie Solar		NorthWestern Energy	3
Morgan Solar	PURPA	Idaho Power	3
Moyer-Tolles Solar	Umatilla Electric Coop	Umatilla Electric Coop	1
Mt. Home Solar 1	PURPA	Idaho Power	20
MTSun LLC			80
Murphy Flat Power	PURPA	Idaho Power	20
Neilson Solar		Avista	19
NW2_Neff	QF	PacifiCorp	10
NW4_Bonanza	QF	PacifiCorp	5
NW7_EaglePoint	QF	PacifiCorp	10
NW9_Pendleton	QF	PacifiCorp	6
Old Mill		PacifiCorp	5
Ontario Solar Center	PURPA	Idaho Power	3
Open Range Solar Center	PURPA	Idaho Power	10
OR2_AgateBay	QF	PacifiCorp	10
OR3_TurkeyHill	QF	PacifiCorp	10
OR5_Merril	QF	PacifiCorp	8
OR6_Lakeview	QF	PacifiCorp	10
OR8_Dairy	QF	PacifiCorp	10
Orchard Ranch Solar	PURPA	Idaho Power	20
Orchard_Knob_Solar	QF-CSP (OR Sch 126)	PacifiCorp	2
Oregon Community Solar Program	Various	Portland General Electric	56
OSLHCollier	QF	PacifiCorp	10
Pachwáywit Solar		Portland General Electric	162
PGE Solar QF		Portland General Electric	398
Pilot Rock Solar 1	QF-CSP (OR Sch 126)	PacifiCorp	2
Pilot Rock Solar 2	QF-CSP (OR Sch 126)	PacifiCorp	3
Pine_Grove_Solar	QF-CSP (OR Sch 126)	PacifiCorp	1
Pleasant Valley Solar		Idaho Power	3
Pleasant Valley Solar 2		Idaho Power	125
PSE Small Solar (5 projects)		Puget Sound Energy	15
Railroad Solar Center	PURPA	Idaho Power	5
River Bend Solar		NorthWestern Energy	2
Round_Lake_Solar	QF-CSP (OR Sch 126)	PacifiCorp	1
Simcoe Solar	PURPA	Idaho Power	20
Skysol	QF	PacifiCorp	55
Solar Energy Project		PacifiCorp	100
Solorize_Rogue	QF-CSP (OR Sch 126)	PacifiCorp	0.1
South Mills Solar 1		NorthWestern Energy	3
Sunset_Ridge_Solar	QF-CSP (OR Sch 126)	PacifiCorp	2
Thunderegg Solar Center	PURPA	Idaho Power	10
Tumbleweed	QF	PacifiCorp	10
Tutuilla Solar	QF-CSP (OR Sch 126)	PacifiCorp	2
Vale Air Solar	PURPA	Idaho Power	10

Project	Owner	NW Utility	Nameplate (MW)
Vale I Solar	PURPA	Idaho Power	3
Wallowa_County	QF-CSP (OR Sch 126)	PacifiCorp	0.4
Wheatridge Solar	Portland General/Nextera Energy	Portland General Electric	50
Whisky_Creek_Solar	QF-CSP (OR Sch 126)	PacifiCorp	0.2
Wild Horse Solar Project	Puget Sound Energy	Puget Sound Energy	1
Wocus_Marsh_Solar	QF-CSP (OR Sch 126)	PacifiCorp	1
Wood River Solar	QF-CSP (OR Sch 126)	PacifiCorp	0.4
Woodline	QF	PacifiCorp	8
Yamhill Solar	EDF Renewable Energy	Portland General Electric	1
WIND			6,566
3Bar Wind		Puget Sound Energy	0.1
71 Ranch LP		NorthWestern Energy	3
Beaver Creek Wind	Puget Sound Energy	Puget Sound Energy	248
Bennett Creek	PURPA	Idaho Power	21
Benson Creek Wind	PURPA	Idaho Power	10
Big Timber Wind		NorthWestern Energy	25
Big Top		PacifiCorp	2
Biglow Canyon - 1	Portland General Electric	Portland General Electric	125
Biglow Canyon - 2	Portland General Electric	Portland General Electric	163
Biglow Canyon - 3	Portland General Electric	Portland General Electric	161
Broadview East Wind		NorthWestern Energy	2
Burley Butte Wind Farm	PURPA	Idaho Power	21
Butter Creek Power		PacifiCorp	5
Camp Reed Wind Park	PURPA	Idaho Power	23
Cassia Wind Farm	PURPA	Idaho Power	11
Chopin Wind		PacifiCorp	10
Chopin Wind (Schumann Wind)		PacifiCorp	8
Clearwater Wind	NextEra	Multiple Utilities	759
Coastal Energy Project			6
Cold Springs	PURPA	Idaho Power	23
Combine Hills I	Eurus Energy of America	Clark Public Utilities	41
Combine Hills II	Eurus Energy of America	Clark Public Utilities	63
Condon Wind	Condon Wind Power, LLC	Seattle City Light	50
Cycle Horseshoe Bend Wind		NorthWestern Energy	9
DA Wind Investors		NorthWestern Energy	3
Desert Meadow Windfarm	PURPA	Idaho Power	23
Durbin Creek	PURPA	Idaho Power	10
Elkhorn Wind	Telocaset Wind Power Partners	Idaho Power	101
Fairfield Wind		NorthWestern Energy	10
Fossil Gulch Wind	PURPA	Idaho Power	11
Four Corners Windfarm		PacifiCorp	8
Four Mile Canyon Windfarm		PacifiCorp	10
Golden Hills	Puget Sound Energy	Puget Sound Energy	200
Golden Valley Wind Farm	PURPA	Idaho Power	12
Goodnoe Hills	PacifiCorp	PacifiCorp	94
Gordon Butte Wind		NorthWestern Energy	10
Greenfield Wind		NorthWestern Energy	25
Hammett Hill Windfarm		Idaho Power	23
Harvest Wind	Summit Power	Multiple Utilities	99
Hay Canyon Wind	Hay Canyon Wind Project LLC (Iberdrola)	Snohomish County PUD	101
High Mesa Wind	PURPA	Idaho Power	40
Hopkins Ridge	Puget Sound Energy	Puget Sound Energy	157

Project	Owner	NW Utility	Nameplate (MW)
Horseshoe Bend	PURPA	Idaho Power	9
Hot Springs Wind	Hot Springs Wind	Idaho Power	21
Jett Creek	PURPA	Idaho Power	10
Judith Gap	Invenergy Wind, LLC	NorthWestern Energy	135
Klondike II	Portland General Electric	Portland General Electric	75
Klondike III	PPM Energy	Multiple Utilities	221
Knudson Wind		Puget Sound Energy	0.1
Leaning Juniper	PPM Energy	PacifiCorp	100
Lime Wind Energy	PURPA	Idaho Power	3
Lower Snake River 1	Puget Sound Energy	Puget Sound Energy	343
Mainline Wind Farm	PURPA	Idaho Power	23
Marengo	Renewable Energy America	PacifiCorp	156
Marengo II	PacifiCorp	PacifiCorp	78
Milner Dam Wind Farm	PURPA	Idaho Power	20
Musselshell Wind 1		NorthWestern Energy	10
Musselshell Wind 2		NorthWestern Energy	10
Nine Canyon	Energy Northwest	Multiple Utilities	96
Orchard Wind Farm 1		PacifiCorp	10
Orchard Wind Farm 2		PacifiCorp	10
Orchard Wind Farm 3		PacifiCorp	10
Orchard Wind Farm 4		PacifiCorp	10
Oregon Trail Windfarm		PacifiCorp	10
Oregon Trails Wind Farm	PURPA	Idaho Power	14
Oversight Resources		NorthWestern Energy	3
Pacific Canyon Windfarm		PacifiCorp	8
Palouse Wind	Palouse Wind, LLC	Avista Corp.	105
Paynes Ferry Wind Park	PURPA	Idaho Power	21
Pilgrim Stage Station Wind Farm	PURPA	Idaho Power	11
Prospector Wind	PURPA	Idaho Power	10
Rattlesnake Flat Wind		Avista Corp.	146
Rockland Wind	PURPA	Idaho Power	80
Ryegrass Windfarm	PURPA	Idaho Power	23
Salmon Falls Wind Farm	PURPA	Idaho Power	22
Sand Ranch Windfarm		PacifiCorp	10
Sawtooth Wind	PURPA	Idaho Power	22
Skookumchuck	Puget Sound Energy	Puget Sound Energy	137
South Peak Wind		NorthWestern Energy	80
Spion Kop Wind		NorthWestern Energy	40
Stateline Wind	NextEra	Multiple Utilities	275
Stillwater Wind		NorthWestern Energy	80
Thousand Springs Wind Farm	PURPA	Idaho Power	12
Threemile Canyon Wind I		PacifiCorp	10
Tuana Gulch Wind Farm	PURPA	Idaho Power	11
Tuana Springs Expansion Wind	PURPA	Idaho Power	36
Tucannon	Portland General Electric	Portland General Electric	267
Two Dot Wind		NorthWestern Energy	11
Two Ponds Windfarm	PURPA	Idaho Power	23
Vansycle Ridge	Portland General Electric	Portland General Electric	24
Vantage	Invenergy Wind NA, LLC	Puget Sound Energy	90
Wagon Trail		PacifiCorp	3
Ward Butte Windfarm		PacifiCorp	7
Wheat Field Wind Project	Wheat Field Wind LLC (Horizon Energy/EDP)	Snohomish County PUD	97
Wheatridge Wind Project	Portland General Electric/Nextera	Portland General Electric	300

Project	Owner	NW Utility	Nameplate (MW)
White Creek	White Creek Wind I LLC	Multiple Utilities	205
Wild Horse	Puget Sound Energy	Puget Sound Energy	273
Willow Spring Windfarm	PURPA	Idaho Power	10
Yahoo Creek Wind Park	PURPA	Idaho Power	21
SMALL THERMAL			280
Bangor Base 1&2	U.S. Naval Submarine Base, Bangor	Other Publics (BPA)	18
Colstrip Energy LP Coal		Puget Sound Energy	42
Crystal Mountain	Puget Sound Energy	Puget Sound Energy	3
PGE DSG	Various	Portland General Electric	140
Puget Sound Shipyard	USNavy-Everett	Other Publics (BPA)	12
Yellowstone Energy LP		Northwestern Energy	65
BATTERY			1,128
Boise Bench BESS		Idaho Power	150
Boise Bench BESS Expansion 1		Idaho Power	50
Constable Battery		Portland General Electric	75
Happy Valley BESS		Idaho Power	80
Hemingway Battery		Idaho Power	80
Hemingway Battery Expansion 1		Idaho Power	36
Hemingway Battery Expansion 2		Idaho Power	50
KUNA BESS		Idaho Power	150
Oregon Institute of Technology BESS		PacifiCorp	2
Seaside Battery		Portland General Electric	200
SnoPUD 25 MW Battery		Snohomish County PUD	25
Sundial Battery		Portland General Electric	200
Wheatridge battery		Portland General Electric	30
RENEWABLE -PLUS- BATTERY			240
Black Mesa Solar + Battery		Idaho Power	40
Crimson Orchard Solar + BESS		Idaho Power	100
Franklin Solar + Battery		Idaho Power	100
TOTAL GENERATING RESOURCES			57,075

Report Description

This report provides a comparison that is called load/resource balance over the ten-year period for annual energy (August through July, *Table 1*), monthly energy (*Table 2*), winter peak-hour (*Table* 3) and summer peak-hour (*Table 4*) during low water conditions. The load/resource balance illustrates gaps between what utilities have (existing and committed resources) and what utilities project they may need (requirements) in future years. The monthly energy picture is provided to underscore the variability of the power need. The peak need reflects information for January and August, as they present the greatest risk for their respective seasons. These metrics provide a multi-dimensional look at the Northwest's need for power and underscore the growing complexity of the power system.

This information reflects the summation of individual utilities' load forecasts and generating resources expected to meet their load, as well as the total of utilities' recently acquired, committed and needed future resources to meet resource adequacy and policy requirements. Needed future resources are identified in the utilities' latest integrated resource plans and planning studies. Individual utilities, PNGC Power and the Bonneville Power Administration (BPA) provide information in a response to a request from PNUCC. This section includes procedures used in preparing the load resource comparisons, a list of definitions, and a list of the utilities summarized by this report (*Table 11*).

Load Estimate

Regional loads are the sum of demand estimated by the Northwest utilities and BPA for its federal agency customers and certain non-generating public utilities. Direct service industrial customers are no longer a significant part of regional load. Utilities are asked to provide their native load forecast. Load projections include network transmission and distribution losses and are net of existing and forecasted energy efficiency savings (including codes & standards). Demand response program savings are not reflected in loads, rather they are included on the supply side in this report. Since the *Forecast* is completed annually, utilities may provide load forecasts that are updated and out of sync with their last resource plan.

Energy Loads

Northwest firm energy loads are provided for each month of the ten-year forecast period. This forecast reflects normal (1-in-2) weather conditions.

Peak Loads

Northwest regional peak loads are provided for each month of the ten-year forecast period. The tabulated loads for winter and summer peak are the highest estimated hourly loads for that month, assuming normal (1-in-2) weather conditions. The regional firm peak load is the sum of the individual utilities' peak loads and does not account for a utility potentially experiencing a peak load at a different day/hour than other Northwest utilities. Hence the regional peak load is considered non-coincident. The federal system (BPA) firm peak load is adjusted to reflect a federal coincident peak among its many utility customers.

Federal System Transmission Losses

Federal System (BPA) transmission losses for both firm loads and contractual obligations are embedded in federal load. These losses represent the difference between energy generated by the federal system (or delivered to a system interchange point) and the amount of energy sold to customers. System transmission losses are calculated by BPA for firm loads utilizing the federal transmission system.

Planning Margin

In the derivation of regional peak requirements, a planning margin is included. The planning margin is set to 16 percent of the total peak load for every year of the planning horizon.[1]

This planning margin is intended to cover, for planning purposes, operating reserves and all elements of uncertainty not specifically accounted for in determining loads and resources. These include forced-outage reserves, unanticipated load growth, temperature variations and plant maintenance.

Demand-Side Management Programs

Savings from demand-side management (*Table 7*) are for the ten-year study period and include data provided by utilities such as utility energy efficiency programs, some market transformation, and other efforts that reduce the demand for electricity. These estimates reflect savings from programs that utilities fund directly, or through a third-party, such as the Northwest Energy Efficiency Alliance and Energy Trust of Oregon.

Demand response programs are also tallied on *Table 7* showing the programs' winter peak and summer peak contributions to need. The regional demand response data is from the cumulative sum of all utilities' agreements with their customers (for both existing and future programs). Each program has its own characteristics and limitations that are reflected in the data provided.

Generating Resources

This report catalogues existing resources, committed new supply (including resources under construction), and needed future resources. For the load/resource balance, only the existing and committed resources are reflected in the regional tabulations. In addition, only those generating resources (or shares) that are firmly committed to meeting Northwest loads are included in the load/ resource balance. A list of all resources included in the report load/resource tabulations is in *Table 10*.

[1] When making comparisons to *Northwest Regional Forecasts* prior to 2018, be aware that the planning margin was previously set at 12 percent for the first year of the report and grew a percent a year until it reached 20 percent and remained at 20 percent thereafter. This escalation was in part to address uncertainty of planning for generating resources with long planning and construction lead times.

Hydro

Major hydro resource capabilities are estimated from a regional analysis using computer models that simulate reservoir operation of past hydrologic conditions with today's operating constraints and requirements. Beginning this year, the bulk of the hydro modeling used in this report is provided by BPA and/or project owners/sponsors because of a switch to using BPA for hydro energy modeling instead of the US Army Corps of Engineers. This means the historical stream flow record used covers the 30-year period August 1989 through July 2019 instead of the 90-year period from August 1928 through July 2018.

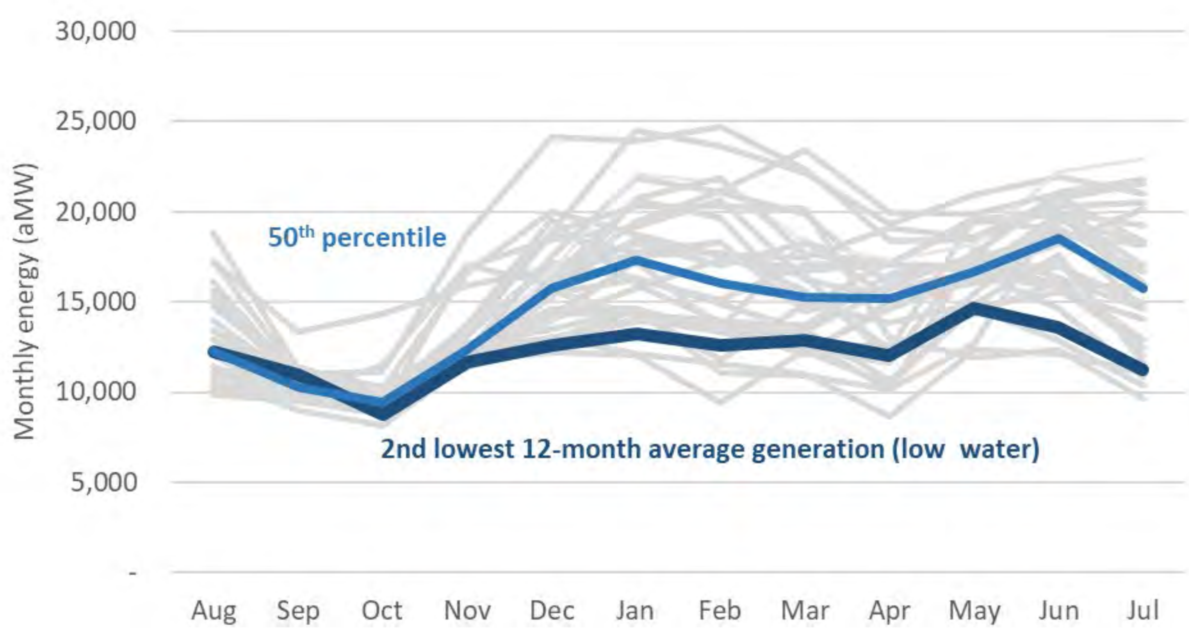
Annual and Monthly Energy

The bulk of the hydro energy data in this report comes from BPA. The firm energy capability of hydro plants (low water) is the amount of energy produced during the operating year with the second lowest 12-month average generation using the 30-year historical river flow given today's operating criteria (August 1994 through July 1994). Generation for projects that are influenced by downstream reservoirs reflects the reduction due to encroachment. This provides an updated view of the critically low value for planning.

Variability of Hydro

The variability of hydro generation is due to the hydrology of the river systems in the Northwest. Monthly hydro energy generation estimates from the major projects in the coordinated hydro system are shown for each of the 30 different river flow conditions using current system operating criteria in Figure 11. For perspective, the 50th percentile and 2nd lowest 12-month average generation (low water) are identified.

Figure 11. Monthly Hydro Generation Across 30-Year Historical Record



Peak Capability

For this report the peak capability of the hydro system represents maximum sustained hourly generation available to meet peak demand during the period of heavy load. Hydro-project owners submit a sustained peak capability for each project.[2] The bulk of the peak data in this report come from BPA. BPA's critical peak planning is the 10th percentile from the most recent 30-year historical record for water conditions.

The peaking capability of the hydro system maximizes available energy and capacity associated with the monthly distribution of streamflow. The peaking capability is the hydro system's ability to continuously produce power for a specific time period by utilizing the limited water supply while meeting power and non-power requirements, scheduled maintenance, and operating reserves.

Columbia River Treaty

Since 1961 the United States has had a treaty with Canada that outlines the operation of U.S. and Canadian storage projects to increase the total combined generation. Hydropower generation in this analysis reflects the firm power generated by coordinating operation of three Canadian reservoirs, Duncan, Arrow and Mica with the Libby reservoirs and other power facilities in the region. Canada's share of the coordinated operation benefits is called Canadian Entitlement. BPA and each of the non-Federal mid-Columbia project owners are obligated to return their share of the downstream power benefits owed to Canada. The delivery of the Entitlement reflected in this analysis has been updated for the Agreement In Principle reached in July 2024 between the two nations and makes up the bulk of the region's exports in this year's report.

Downstream Fish Migration

Another requirement incorporated in the hydro modeling are modified river operations to provide for the downstream migration of anadromous fish. These modifications include adhering to specific flow limits at some projects, spilling water at several projects, and augmenting flows in the spring and summer on the Columbia, Snake and Kootenai rivers. Specific requirements are defined by various federal, regional and state mandates, such as project licenses, biological opinions and state regulations.

Thermal

Thermal resources are reported in a variety of categories including coal, natural gas, nuclear, cogeneration and small thermal includes diesel and oil.

Renewable

Renewable resources are categorized as solar, wind and other renewables and are each totaled and reported separately. Other renewables include energy from biomass, geothermal, municipal solid waste projects, and other projects.

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[2] Historically, a 50-hour sustained peak (10 hours/day for 5 days) was reported. Project owners/sponsors use a variety of peak capability metrics today.

Battery

Rechargeable batteries store surplus energy and deliver it to the grid when needed. Battery shows up as standalone and in combination with renewables. Battery is reflected as supply during the peak hour of the month.

All existing non-hydro generating plants, regardless of size, are included in amounts submitted by each utility that owns or is purchasing the generation. The energy and peaking capabilities of plants are submitted by the projects' owners and take into consideration scheduled maintenance (including refueling), forced outages, and other expected operating constraints. Energy generation for thermal resources represents the energy available for the Northwest. It does not reflect dispatch for expected economic conditions or compliance with clean energy policies. Some small thermal plants and combustion turbines are included as peaking resources and their reported energy capabilities are only the amounts necessary for peaking operations.

New and Future Resources

The latest activity with new and future resource developments, including expected savings from demand-side management actions, are tabulated in this report. These resources are reported as recently acquired, committed new supply, and needed future resources to reflect the different stages of development.

Recently Acquired Resources

The Recently Acquired Resources reported in *Table 5* have been acquired and will be serving Northwest utility loads as of December 31, 2025. They are reflected as part of the regional load/resource balance.

Committed Resources

Committed Resources reported in *Table 6* includes projects under construction or firmly committed to meet Northwest load that are not delivering power. These resources are included in the regional load-resource analysis. Future energy efficiency and demand response programs are included in the load-resource analysis as well (see *Table 7*).

Needed Future Resources

Needed Future Resources presented in *Table 8* includes specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans and planning studies. Projects in *Needed Future Resources* are not yet under construction, are not part of the load/resource balance, and are subject to change until the time for acquiring them is closer. As the resource build date nears, more information about these resources will likely become available, and they typically move into the *Committed Resources* category prior to coming online. Often, the utility will undergo a request for proposal process before moving a resource from *Needed Future Resources* to *Committed.* Please note, resources in this category have been *referred to as Planned or Potential Resources* in previous *Forecasts*.

Contracts

Imports and exports include firm arrangements for trade with systems outside the region, as well as with third-party developers/owners within the region. These arrangements comprise firm contracts with utilities to the East, in California and Canada. Contracts to and from these areas are amounts delivered at the area border and include transmission losses associated with deliveries.

Long-term intraregional contracts between Northwest utilities net to zero in the regional picture and consequently are not tallied for this report. In addition, short-term and/or spot purchases from Northwest independent power producers and from out-of-region are not reflected in the tables that present the load/resource balance comparisons in this report.

Non-Firm Resources

The *Forecast* omits from the load/resource balance non-firm power supply that may be available to utilities to meet needs. These non-firm sources include generation from uncommitted Northwest independent power producers (IPPs), imports from power plants located outside the region, uncommitted hydro generation owned by Northwest utilities and hydro generation likely available when water supply is greater than the assumed critical levels. Power from these resources may be available to the Northwest from the market, during high need hours, or it may have been already sold to a higher bidder outside the Northwest.

Non-firm imports depend on several factors including availability of out-of-region resources, availability of transmission and market efficiency. The trend of large thermal resource retirements in the Western Interconnection could impact power available for import into the Northwest in the coming years. Looking at hydropower, the *Forecast* assumes low water during peak hours for the monthly peak calculations. Most months the water supply for the hydro system is not at critical levels. During a median water month, the region will have more water available for energy and peak needs.

Climate Change

More utilities and organizations are incorporating the impacts of a changing climate into their long-range planning. Two areas where climate change may impact utility planning is the influence of temperatures on loads and water supply for hydrogeneration. As more utilities account for changing temperature trends in their forecasting models the impact on utility loads becomes incorporated into the *Forecast*. Increasing temperatures in the summer can result in higher summer load (due to air conditioning, for example) and moderately warmer temperatures in the winter can reduce winter load (reduced need for heating loads), on average across the region. The differences in geography for utilities across the Northwest means individual utilities can have varying degrees of climate change effects.

The *2025 Forecast* does not explicitly account for the impact of climate change on hydroelectric generation. Any consideration of climate change is limited to what may be reflected in a hydro project owners or sponsor's submitted peak capability for their project. For the most part, the hydroelectric data in the *Forecast* rely on the historical records of river flows.

Table 11. Utilities Included in the Northwest Regional Forecast

Albion, City of
Alder Mutual
Ashland, City of
Asotin County PUD #1
Avista Corp.
Bandon, City of
Benton PUD
Benton REA
Big Bend Electric Co-op
Blachly-Lane Electric Co-op
Blaine, City of
Bonners Ferry, City of
Bonneville Power Administration
Burley, City of
Canby Utility
Cascade Locks, City of
Central Electric
Central Lincoln PUD
Centralia, City of
Chelan County PUD
Cheney, City of
Chewelah, City of
City of Port Angeles
Clallam County PUD #1
Clark Public Utilities
Clatskanie PUD
Clearwater Power Company
Columbia Basin Electric Co-op
Columbia Power Co-op
Columbia REA
Columbia River PUD
Consolidated Irrigation Dist. #19
Consumers Power Inc.
Coos-Curry Electric Co-op
Coulee Dam, City of
Cowlitz County PUD
Declo, City of
Douglas County PUD
Douglas Electric Co-op
Drain, City of
East End Mutual Electric
Eatonville, City of
Ellensburg, City of
Elmhurst Mutual P & L
Emerald PUD
Energy Northwest
Eugene Water & Electric Board
Fall River Rural Electric Co-op
Farmers Electric Co-op
Ferry County PUD #1
Fircrest, Town of
Flathead Electric Co-op
Forest Grove Light & Power
Franklin County PUD
Glacier Electric
Grant County PUD
Grays Harbor PUD
Harney Electric
Hermiston, City of
Heyburn, City of
Hood River Electric
Idaho County L & P
Idaho Falls Power
Idaho Power
Inland Power & Light
Jefferson County PUD
Kittitas County PUD
Klickitat County PUD
Kootenai Electric Co-op
Lakeview L & P (WA)
Lane Electric Co-op
Lewis County PUD
Lincoln Electric Co-op
Lost River Electric Co-op
Lower Valley Energy
Mason County PUD #1
Mason County PUD #3
McCleary, City of
McMinnville Water & Light
Midstate Electric Co-op
Milton, Town of
Milton-Freewater, City of
Minidoka, City of
Missoula Electric Co-op
Modern Electric Co-op
Monmouth, City of
Nespelem Valley Elec. Co-op
Northern Lights Inc.
Northern Wasco Co. PUD
NorthWestern Energy
Ohop Mutual Light Company
Okanogan Co. Electric Co-op
Okanogan County PUD #1
Orcas Power & Light
Oregon Trail Co-op
Pacific County PUD #2
PacifiCorp
Parkland Light & Water
Pend Oreille County PUD
Peninsula Light Company
Plummer, City of
PNGC Power
Port of Seattle – SEATAC
Portland General Electric
Puget Sound Energy
Raft River Rural Electric Co-op
Ravalli Co. Electric Co-op
Richland, City of
Riverside Electric Co-op
Rupert, City of
Salem Electric Co-op
Salmon River Electric Co-op
Seattle City Light
Skamania County PUD
Snohomish County PUD
Soda Springs, City of
Southside Electric Lines
Springfield Utility Board
Steilacoom, Town of
Sumas, City of
Surprise Valley Electric Co-op
Tacoma Power
Tanner Electric Co-op
Tillamook PUD
Troy, City of
Umatilla Electric Co-op
Umpqua Indian Utility Co-op
United Electric Co-op
US Corps of Engineers
US Bureau of Reclamation
Vera Water & Power
Vigilante Electric Co-op
Wahkiakum County PUD #1
Wasco Electric Co-op
Weiser, City of
Wells Rural Electric Co.
West Oregon Electric Co-op
Whatcom County PUD
Yakama Power

Definitions

Annual Energy

Energy value in megawatts that represents the average output over the period of one year. Expressed in average megawatts.

Average Megawatts

(aMW) Unit of energy for either load or generation that is the ratio of energy (in megawatt-hours) expected to be consumed or generated during a period of time to the number of hours in the period.

Battery

Rechargeable batteries store surplus energy and deliver it to the grid when needed. Battery shows up as standalone and in combination with renewables.

Biomass

Any organic matter which is available on a renewable basis, including forest residues, agricultural crops and waste, wood and wood wastes, animal wastes, livestock operation residue, aquatic plants, and municipal wastes.

Canadian Entitlement

Canada is entitled to downstream power benefits resulting from Canadian storage as defined by the Columbia River Treaty. Canadian entitlement returns estimated by Bonneville Power Administration.

Coal Resource

This category of generating resources includes the region’s coal-fired plants.

Cogeneration

Cogeneration is the technology of producing electric energy and other forms of useful energy (thermal or mechanical) for industrial and commercial heating or cooling purposes through sequential use of an energy source.

Combustion Turbines

These are plants with combined-cycle or simple-cycle natural gas-fired combustion turbine technology for producing electricity.

Committed Resources

These projects are under construction and/or committed resources and supply confirmed to meet Northwest load, but not delivering power.

Conservation

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with energy efficiency.

Demand Response

Control of load through customer/utility agreements that result in a temporary change in consumers' use of electricity.

Demand-side Management

Peak and energy savings from conservation/energy efficiency measures, distribution efficiency, market transformation, demand response, fuel conversion, fuel switching, energy storage and other efforts that that serve to reduce electricity demand.

Dispatchable Resource

A term referring to controllable generating resources that are able to be dispatched for a specific time and need.

Direct Service Industry (DSI) customer

Historically, large industrial customers such as aluminum smelters and other energy-intensive manufacturing facilities were major power consumers in the Pacific Northwest and purchased electricity directly from BPA rather than through a local utility. Many DSI customers shut down operations in the early 2000s. Only one DSI customer remains operating – Port Townsend Paper.

Distribution Efficiency

Infrastructure upgrades to utilities' transmission and distribution systems that save energy by minimizing losses.

Electrification

Electrification is the process of converting technologies that run on fossil fuels to technologies that run on electricity. This shift is most seen in transportation (e.g., electric vehicles), buildings (e.g., electric heat pumps, stoves and water heaters) and industrial processes. The goal of electrification is to reduce greenhouse gas emissions.

Emerging Technologies

A term used to describe future resource technologies such as advanced nuclear, offshore wind, renewable hydrogen and long-duration storage.

Encroachment

A term used to describe a situation where the operation of a hydroelectric project causes an increase in the level of the tailwater of the project that is directly upstream.

Energy Efficiency

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with conservation.

Energy Load

The demand for power averaged over a specified period of time.

Energy Storage

Technologies for storing energy in a form that is convenient for use at a later time when a specific energy demand is greater.

Exports

Firm interchange arrangements where power flows from regional utilities to utilities outside the region or to non-specific, third-party purchasers within the region.

Federal System (BPA)

The federal system is a combination of BPA's customer loads and contractual obligations, and resources from which BPA acquires the power it sells. The resources include plants operated by the U.S. Army Corps of Engineers (COE), U.S. Bureau of Reclamation (USBR) and Energy Northwest. BPA markets the thermal generation from Columbia Generating Station, operated by Energy Northwest.

Federal Columbia River Power System (FCRPS)

Thirty-one federal hydroelectric projects constructed and operated by the U.S. Corps of Engineers and the U.S. Bureau of Reclamation, and the Bonneville Power Administration transmission facilities.

Firm Energy

Electric energy intended to have assured availability to customers over a defined period.

Firm Load

The sum of the estimated firm loads of private utility and public agency systems, federal agencies and BPA industrial customers.

Firm Losses

Losses incurred on the transmission system of the Northwest region.

Historical Streamflow Record

A database of unregulated streamflows for 30 years (1989 to 2018). Data is modified to take into account adjustments due to irrigation depletions, evaporations, etc. for the particular operating year being studied.

Hydro Maintenance

The amount of energy lost due to the estimated maintenance required during the critical period. Peak hydro maintenance is included in the peak planning margin calculations.

Hydro Regulation

A study that utilizes a computer model to simulate the operation of the Pacific Northwest hydroelectric power system using the historical streamflows, monthly loads, thermal and other non-hydro resources, and other hydroelectric plant data for each project.

Imports

Firm interchange arrangements where power flows to regional utilities from utilities outside the region or third-party developer/owners of generation within the region.

Independent Power Producers (IPPs)

Non-utility entities owning generation that may be contracted (fully or partially) to meet regional load.

Investor-Owned Utility (IOU)

A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders.

Market Transformation

A strategic process of intervening in a market to accelerate the adoption of cost-effective energy efficiency.

Megawatt (MW)

A unit of electrical power equal to 1 million watts or 1,000 kilowatts.

Nameplate Capacity

A measure of the approximate generating capability of a project or unit as designated by the manufacturer.

Natural Gas-Fired Resources

This category of resources includes the region's natural gas-fired plants, mostly single-cycle and combined-cycle combustion turbines. It may include projects that are considered cogeneration plants.

Needed Future Resources

These resources include specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans and planning studies. These projects are not yet under construction, are not part of the load/resource balance, and are in some ways speculative.

Non-Firm Resources

Electric energy acquired through short term purchases of resources not committed as firm resources. This includes generation from hydropower in better than critical water conditions, independent power producers and imports from outside the region.

Non-Utility Generation

Facilities that generate power whose ownership by a sponsoring utility is 50 percent or less. These include PURPA-qualified facilities (QFs) and non-qualified facilities of independent power producers.

Nuclear Resources

The region's only nuclear plant, the Columbia Generating Station, is included in this category.

Other Publics (BPA)

Refers to the smaller, non-generating public utility customers whose load requirements are estimated and served by Bonneville Power Administration as referred to in *Table* 10.

Other Renewables

A category of resources that includes projects that produce power from such fuel sources as geothermal, biomass (includes wood, municipal solid-waste facilities) and pilot level projects including tidal and wave energy.

Peaking Capacity

Resources that can be dispatched to meet short-term spikes in electricity demand, including dispatchable resources such as peaker plants fueled by natural gas, biodiesel and generic capacity. Some peaking capacity can transition to use hydrogen or another clean fuel in the future.

Peak Load

In this report the peak load is defined as one-hour maximum demand for power.

Planning Margin

A component of regional requirements that is included in the peak load/resource balance to account for various planning uncertainties. In the 2018 *Forecast* the planning margin changed to a flat 16% of the regional load for each year of the study. Earlier reports included a growing planning margin that started at 12% of load, increasing 1% per year until it reached 20%.

Private Utilities

Same as investor-owned utilities.

Publicly-Owned Utilities

One of several types of not-for-profit utilities created by a group of voters and can be a municipal utility, a public utility district, or an electric cooperative.

Pumped Hydro

Pumped hydro facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station.

PURPA

Public Utility Regulatory Policies Act of 1978. The first federal legislation requiring utilities to buy power from qualifying independent power producers.

Renewables

Renewable power generation in this report primarily includes variable, weather-dependent wind and solar power. Renewables play a critical role in the transition to a clean energy system.

Renewables-Plus-Battery

Refers to the combination of renewable resources—such as solar and wind power—with battery systems. This pairing helps balance the variability of renewable generation by storing excess electricity when production is high (e.g., sunny or windy periods) and discharging the power when it’s needed.

Reporting Year

Twelve-month period beginning on August 1 of any year and ending on July 31 of the following year. For example, reporting year 2025 is August 1, 2025 through July 31, 2026.

Requirements

Include for each year, a utility's projected loads, exports and contracts out. Peak requirements also include the planning margin.

Small Thermal & Miscellaneous Resources

This category of resources includes small thermal generating resources such as diesel generators used to meet peak and/or emergency loads.

Solar Resources

Resources that produce power from solar exposure. This includes utility scale solar photovoltaic systems but does not include distributed solar generation.

Storage

Storage resources (i.e., batteries, pumped hydro,) store energy for release at a later time. They help shift energy from periods of low value to peak high value hours. Due to efficiency losses, they are a net consumer of energy. They are usually defined by their maximum discharge rate in MW, and their total storage capacity in MWh.

Thermal Resources

Resources that burn coal, natural gas, oil, diesel or use nuclear fission to create heat which is converted into electricity.

Wind Resources

This category of resources includes the region's utility-scale wind powered projects.

Western Energy Imbalance Market (WEIM)

A real-time energy market launched in 2014, operated by the California Independent System Operator.

Western Resource Adequacy Program (WRAP)

A regional reliability and compliance program in the West. It delivers a region-wide approach for assessing and addressing resource adequacy.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

CASCADE 2023 INTEGRATED RESOURCE PLAN EXCERPT (PAGES 4-5 TO 4-17)

EXHIBIT 1204

November 2025

In the Community to Serve®

2023
Integrated Resource Plan Draft

June 2, 2023

resources in that they are more volatile, both in terms of availability and price, and are largely influenced by the laws of supply and demand.

In general, spot market supplies (also called day gas) are provided from gas supplies not under any long-term firm contract. Therefore, as firm market demand decreases, more gas becomes available for the spot market. Prices for spot market supplies are market driven and may be either lower or higher than prices under firm supply contracts. In warmer weather, as firm market demand requirements decrease, usually more gas becomes available for the spot market, resulting in lower prices. In colder weather, as firm markets demand their gas supplies, the remaining spot market supplies can carry higher prices.

The role for spot market gas supply in the core market portfolio is based on economics. Spot market supplies may be used to supplement firm contracts during periods of high demand or to displace other volumes when it is cost effective to do so. Depending upon availability and price, spot market volumes may be used in place of storage withdrawal volumes to meet firm requirements on a given day or for mid-heating season refills of storage inventory during periods of moderate weather.

While Figure 4-1 provides a general overview of regional gas flows to Cascade's distribution system, supporting detail is included in Appendix E.

Renewable Natural Gas

Renewable natural gas (RNG) is an emerging supply option that brings many benefits, chief among them emissions reduction. Since submitting its last IRP, Cascade has made significant strides in analyzing, planning, and acquiring RNG. In this section and elsewhere in this IRP, issues unique to RNG are found in the inset box to the right.

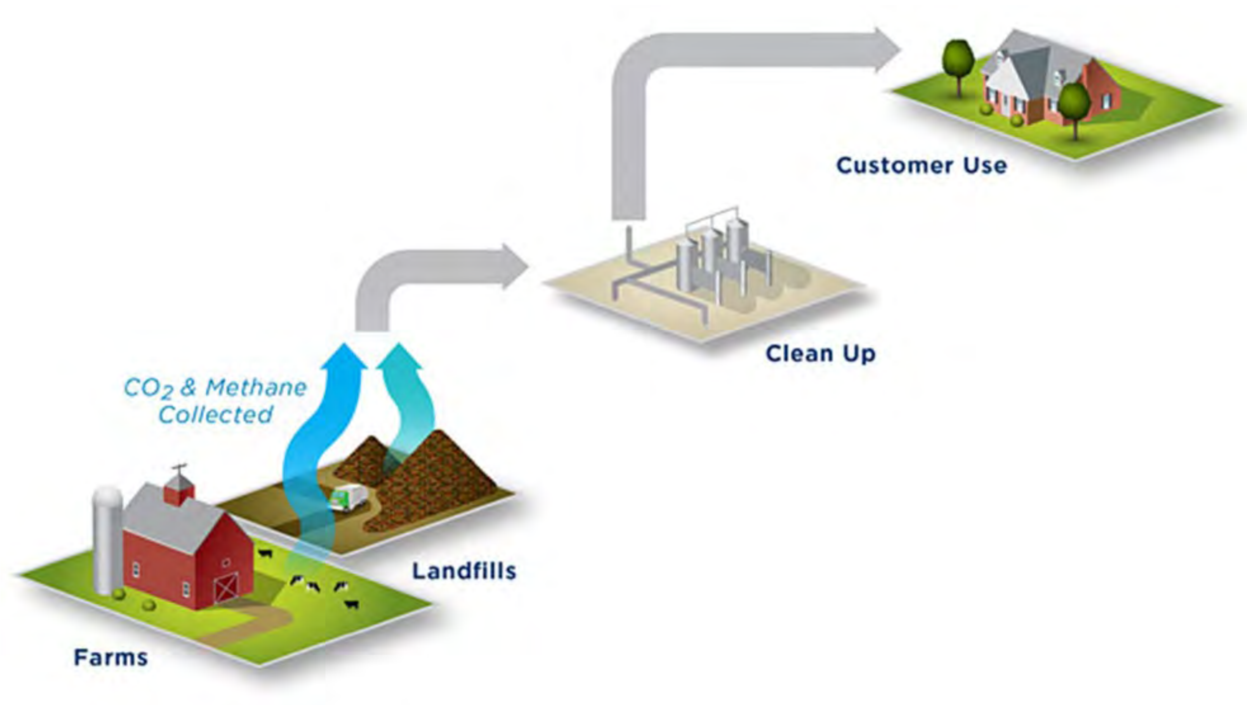
<u>QUICK REFERENCE TO RNG LOCATIONS IN IRP</u>

RNG, as defined in RCW 54.04.190,[3] is a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters. Cascade is committed to developing programs that allow the Company to acquire RNG under guidelines and rules stated in Washington HB 1257 and Oregon SB 98.

[3] *See* https://app.leg.wa.gov/rcw/default.aspx?cite=54.04.190

Figure 4-2,[4] provides an example of a general RNG process from landfill to end-user.

Figure 4-2: Example of RNG process from landfill to end user



Renewable natural gas, biomethane and biogas are sometimes used interchangeably but they are different biofuel products along the value chain:

- Biogas is a mixture of carbon dioxide and hydrocarbons, primarily methane gas, from the biological decomposition of organic materials.
- Biomethane is a biogas-derived, high BTU gas that is predominately methane after the biogas is upgraded to remove contaminants.
- Renewable natural gas is biomethane upgraded to natural gas pipeline-quality standards so it can substitute or blend with conventional natural gas.[5]

Examples of RNG sources include:

- Biogas from Landfills
    - o Collect waste from residential, industrial, and commercial entities.
    - o Digestion process takes place in the ground, rather than in a digester.
- Biogas from Livestock Operations
    - o Collects animal manure and delivers to anaerobic digester.
- Biogas from Wastewater Treatment

[4] U.S. Department of Energy, Alternative Fuels Data Center, Renewable Natural Gas
[5] American Natural Gas.com

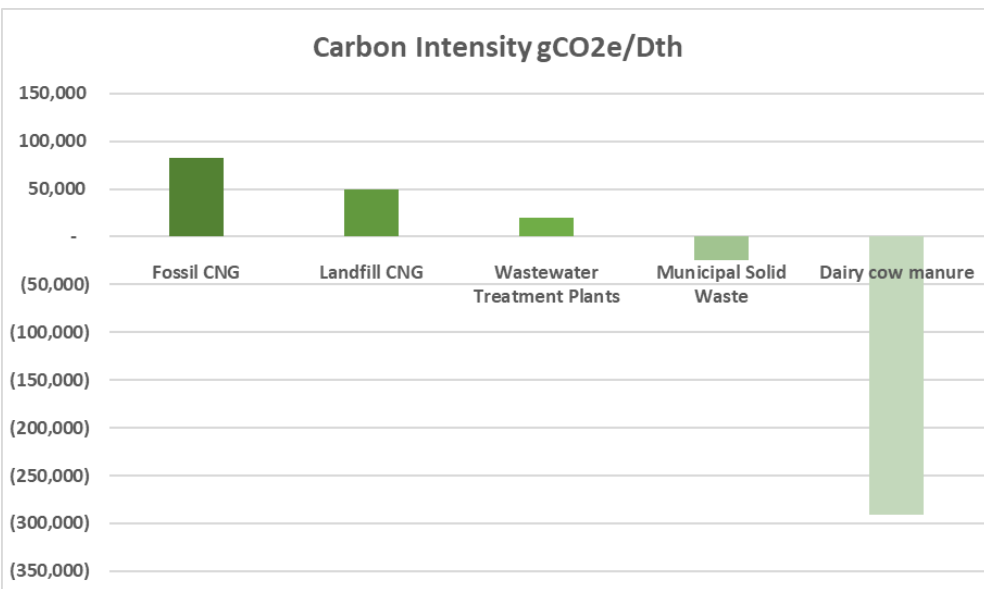
   - o Produced during digestion of solids that are removed during the wastewater treatment process.
- Other sources include organic waste from food manufacturers and wholesalers, supermarkets, restaurants, hospitals, and more.[6]

Biofuel estimates vary, for example, E3 estimates 25 million dry tons of biomass supply available to Washington and Oregon, compared to Washington State's deep decarbonization study which assumed 23.8 million dry tons available to the state.[7]

Carbon Intensity

One of the major driving forces behind investment in RNG is the potential to mitigate the carbon footprint of the natural gas industry. For some types of projects such as compressed natural gas (CNG) from landfills, this means RNG is the utilization of a resource that still emits carbon into the environment, but at a lower intensity. For others like gas from solid waste and dairy cow manure, this means preventing the escape of gas with such high carbon intensity that the net impact to the environment by redirecting this gas to end-users would be positive. Figure 4-3 highlights the different impact of five different types of natural gas[8].

Figure 4-3: Carbon Intensity of Natural Gas by Source



[6] U.S. Department of Energy, Alternative Fuels Data Center, Renewable Natural Gas.
[7] Energy + Environmental Economics, Pacific NW Pathways to 2050: Achieving an 80% reduction in economy-wide greenhouse gases by 2050.
[8] https://ww2.arb.ca.gov/sites/default/files/classic//research/apr/past/13-307.pdf

According to the Climate Protection Program and the Climate Commitment Act, all RNG is treated equally when determining the CO_2e offset to traditional natural gas. However, in the LCFS program, Carbon Intensity is used to determine the offset to CO_2e, which make dairy projects much more attractive in California.

Applicable Regulations

On January 14, 2019, SB 98 was introduced in Oregon legislation. SB 98 requires the Oregon Public Utility Commission (OPUC) to adopt by rule renewable natural gas program for natural gas utilities to recover prudently incurred qualified investments in meeting certain targets for including renewable natural gas in gas purchases for distribution to retail natural gas customers. On June 23, 2019, SB 98 was signed into law effective September 29, 2019.

On August 27, 2019, the OPUC initiated docket UM 2030, an investigation into the use of Northwest Natural's RNG evaluation methodology. The Company is an active participant in UM 2030. Cascade has developed its own potential Cost Effectiveness Evaluation Methodology which can be seen in the next subsection.

On October 1, 2019, the OPUC Staff initiated docket AR 632, in the matter of rulemaking regarding the 2019 SB 98 RNG programs. Cascade has participated in multiple meetings regarding this docket. On February 20, 2020, the OPUC provided informal draft rules for the docket. On April 28, 2020, the OPUC held a hearing to discuss formal comments to the rules in AR 632. On July 16, 2020, OPUC adopted the initial rules to implement 2019 SB 98.

Below, Cascade lists key portions of the preliminary rule followed by the Company's compliance:

(1) According to rule 860-150-100 of AR 632, each large natural gas utility and small natural gas utility must, as part of an integrated resource plan (IRP) filed after August 1, 2020, include information relevant to the RNG market, prices, technology, and availability that would otherwise be required under the Commission's IRP guidelines, by order of the Commission, or by administrative rules.

Cascade has provided information relative to the RNG market, prices, technology, and availability throughout this IRP narrative.

(3) In addition to the information required under section (1), each small natural gas utility must also include in its IRP:

(a) An indication whether and when the utility expects to make a filing with the Commission, pursuant to OAR 860-150-0400, of its intent to begin participating in the RNG program described in these rules, if the utility has not already started to participate in the RNG program;

Cascade is currently preparing the petition to be filed with OPUC around the time of the filing of the 2023 IRP.

(b) Information about opportunities, challenges, perceived barriers, and the natural gas utility's strategy for participation in the RNG program described in these rules; and

The Company has met with several individuals and companies within the RNG industry such as producers, municipalities, wastewater treatment plants, biodigesters, and landfills. During these conversations, Cascade has gathered market intelligence around RNG. Some of the Company's findings include:

- Options for securing RNG will involve purchase and/or participation in infrastructure.
- No "spot market" for RNG at this point due to long off-take commitments.
- Lead times on new RNG projects up to 36 months.
- Landfill projects are typically the largest RNG opportunity at 300-600 dth/day and usually require lowest capital investment.
- Dairy projects, due to higher carbon intensity, do very well in the Renewable Identification Numbers (RINs) market and run 50-500 dth/day (expensive to operate).
- Food waste/Industrial wastewater treatment projects are seen as an ideal option for utilities as they have low RINs and Low Carbon Fuel Standards (LCFS) potential and can typically be online within 24 months of contracting. Municipal & County wastewater treatment plants can also be good utility partnerships although lead times can be substantially longer.
- $13-$30/dth long-term off-take deals.

Specific near-term opportunities are provided later in this chapter.

(c) The cost effectiveness calculation that the utility will use, pursuant to OAR 860-150-0200, to evaluate RNG resources, if the utility has not already filed this with the Commission pursuant to OAR 860-150-0400.

Cascade's cost effectiveness calculation is described in the following section.

Cascade Project Cost Effectiveness Evaluation Methodology

Several departments within the Company have collaborated to create a model that allows Cascade to evaluate the cost-effectiveness of all potential RNG projects before entering into an agreement with potential suppliers. Similar to the Company's PLEXOS® modeling, the results of this calculation help inform final acquisition decisions, but ultimately must be combined with qualitative analysis from RNG subject matter experts. This subsection will present the model notes, a discussion of the static and dynamic inputs to the model and provide an understanding of how the results should be interpreted.

Cost Effectiveness Evaluation Model Notes

$$\boldsymbol{C_{RNG} = I_{RNG} - AC_U - AC_D + \sum_{T=1}^{365}(P_{RNG} + VC - CIF) * Q}$$

$$\boldsymbol{C_{Conventional} = \sum_{T=1}^{365}(P_{Conventional} + VC) * Q}$$

Where:

C_{RNG} = The all-inclusive annual cost of a proposed RNG project
I_{RNG} = The annual required investment to procure a proposed RNG resource. If Cascade is simply buying the gas and/or environmental attributes, this value is zero.
AC_U = Avoided upstream costs
AC_D = Avoided distribution system costs
P_{RNG} = Daily price of renewable natural gas being evaluated
Q = Daily quantity of gas being evaluated
VC = Variable cost to move one dekatherm of gas to Cascade's distribution system. This value can be zero if a project connects directly to the Company's system.
CIF = Carbon Intensity Factor. This is calculated by multiplying the Company's expected carbon compliance cost by 1 minus the ratio of a proposed project's carbon intensity to conventional gas' carbon intensity. For the purpose of compliance with the CCA and CPP, the CIP factor is just Cascade's expected carbon compliance cost in the various jurisdictions, as these rules do not account for the variable carbon intensities of various sources of RNG.
$C_{Conventional}$ = The all-inclusive annual cost of conventional natural gas.
If $C_{Conventional} \geq C_{RNG}$, a project can be considered cost effective, and should be acquired. If not, the project may still be considered under the regulatory exceptions discussed earlier in this chapter.

Static Versus Dynamic Inputs

Inputs to Cascade's model can be classified as either static or dynamic. Static inputs are ones that are not project specific, but rather related to the Company's system as a whole. They include Cascade's avoided costs, costs associated with the price of conventional gas, and regulatory factors that are used to calculate the impact to revenue requirement. Dynamic inputs on the other hand, are ones that need to be updated on a project by project basis. These include the price and quantity of the RNG, initial investment required, and carbon intensity of the project.

Purchase Versus Build

Cascade utilizes different proprietary models based on whether the Company is evaluating the purchase of RNG or the building and ownership of an RNG generating facility. While philosophically the same, the models are calibrated to account for slight differences in the various decision-making processes. The build decision model allows for more detailed inputs and evaluation of overhead variables related to ownership, such as tax impacts of ownership and depreciation of assets. The purchase model, on the other hand, allows for analysis of variable purchase structures, where Cascade may only purchase a fraction of the RNG quantity that will ultimately be flowed from an RNG deal, which also allows the model to consider revenue that the Company would earn from transportation agreements related to the volumes of RNG that Cascade would not own, but would still flow on its system.

Based on results from Chapter 9, Resource Integration, Cascade states a need for RTCs/RNG/etc to meet environmental compliance needs, specifically under the CPP. The Company's model is used to compare the market value and revenue requirement per dekatherm per year for a project vs. other alternatives. Cascade does not have enough on system projects to provide the volumes needed for compliance, so acquiring RTCs/RNG/etc with off system contracts is necessary. Cascade compares the market value and revenue requirement per dekatherm per year of potential on system projects to off system contract opportunities via a model. If the on-system projects project favorably vs. off system opportunities based on the model results, the Company will consider other risks and factors:

- There is more risk with the assumptions made for on system projects vs. off system projects, specifically with estimates for the cost of capital investment, RNG production volume, timing for start of production. The values Cascade uses for these are estimates, and the actual costs, volumes, and timing could have variances. With off system contracts these values are more certain.

- On system projects may be viewed as more favorable than off system projects because the RNG environmental attributes as well as the molecules can be purchased as a bundle, and the RNG is injected directly into the Company's system and consumed by Cascade's customers.

- In Cascade's opinion, the pros and cons of on system projects vs. off system projects offset and Cascade considers any on system project that has a favorable market value and revenue requirement per dekatherm per year vs. known off system opportunities to be attractive because it will reduce the need to purchase RTCs/RNG/etc via more expensive means.

- Cascade's RNG Cost-Effectiveness model currently accounts for timing risks by recognizing the value of certainty in longer term deals versus uncertainty. The model evaluates costs in real dollars, so any opportunity to amortize investments over a longer period of time is valued appropriately in the model. Additionally, alternative costs for carbon compliance such as CCIs will increase over time, allowing the model to favorably evaluate a project that contains fixed prices for the environmental attributes associated with RNG. If a deal being considered is not a fixed price deal, the model will evaluate how any escalating factors compare to increases in cost for alternative compliance costs.

- One additional risk that will be important as the Company continues to evaluate build versus purchase decisions will be the uncertainty around investment costs for build projects. Since Cascade does not have data regarding the variance of potential build costs this variable is currently being evaluated deterministically, but the Company looks forward to being able to perform stochastic analyses around these costs to mitigate risk to ratepayers in future IRPs.

Model Results

Once all inputs are populated, the model provides three main pieces of information: The potential enterprise value of the project over its lifetime, the first year dollar impact to revenue requirement, and the first year percentage impact to revenue requirement. As discussed in the model notes, if the cost of conventional gas is greater than or equal to the cost of

RNG, the project can be considered cost effective. If not, the impact to revenue requirement provides a valuable insight as to whether the project is attractive from a regulatory perspective.

RNG Projects

Cascade is currently progressing with twenty-one on-system RNG projects at varying stages of development. Ten of these projects are what Cascade refers to as Purchase Projects, where Cascade would on-board the RNG onto the Company's distribution system and purchase the environmental attributes to be utilized for the CPP, CCA, and voluntary RNG tariffs in Washington and Oregon. These types of RNG projects are Cascade's highest RNG priority.

Currently, Transport Projects only occur where Cascade cannot cost effectively purchase the environmental attributes or where the nature of the projects financial development involves prior commitment of the attributes. One example of this is dairy projects where the current attribute values can be $60-$83/MMBtu because of the value it provides in the LCFS market. Some Transport Projects also come to Cascade with the attributes pre-sold as a part of the financing package to fund the facility. In these cases, if Cascade is capable of on-boarding the RNG, a business decision can be made to allow an RNG Transport Project. These projects are very similar to a normal non-core customer except that an interconnection facility with gas quality testing is constructed in addition to the interconnecting pipeline. Currently, these RNG customers would take service under Cascade's Rate Schedule OR800 in Oregon or Rate Schedule 663 in Washington. They only ship their fuel on Cascade's system and pay to transport that fuel, just as a typical non-core customer does. In most cases, these attributes are being transported for use in the LCFS market or they may also be used to produce green hydrogen for renewable diesel, aviation fuels, etc. These projects do not play a role in Cascade's compliance but do represent the evolving use of the Cascade's natural gas system for use in decarbonizing the transportation sector.

Cascade is now pursuing a middle ground on non-dairy RNG Transport Projects which provides greater benefits for core-customers. There are food waste, landfill, and industrial WWTF transport projects where Cascade has been able to provide a competitive offer that enables a partial purchase of attributes in return for a partial facilities investment. Early modeling and experience has shown that these purchases can be more cost effective than other off-system environmental attribute purchases in some cases. In these "Partial Purchase" RNG projects, the percentage of environmental attributes and physical biomethane which cannot be purchased are transported and treated as typical RNG Transport customer. This approach has created cost effective on-system attribute purchase opportunities where they did not exist previously, and Cascade is continuing to learn and evolve on applying this approach to procure new compliance attributes.

There are two different design and construction paths based on the type of RNG project.

- RNG Plant – Cascade is the producer of the RNG. RNG Plant projects include the development of the entire biogas processing plant to bring the biogas to pipeline quality standards. This entails analysis of the biogas itself, flowrates, and connected feed systems to enable determination of the most effective type of biogas scrubbing system(s) to be utilized. Other ancillary equipment must be designed such as the compressors to bring the RNG to pipeline operating conditions. In some cases, other upstream improvements are made to maximize the efficiency and cost effectiveness of the biogas collection such as adding additional gas wells in a landfill or improving air sealing on digester-based gas processing. Depending on the type, size, and scrubber technology, a project may have either skid mounted, containerized equipment or it may require constructing a building to house the processing, compression, and other ancillary equipment. These projects have much more extensive engineering needs. Cascade utilizes an outside engineering firm in these cases but is also supported by internal engineering and development resources. Additionally, these projects would require most of the work in the second type of project listed below.

- RNG System Interconnection & Related Infrastructure – This type of project generally has the RNG Plant constructed by the producer directly. Once contracted, Cascade's portion of the work includes the design and construction of the Interconnection Facility and the pipeline interconnecting with the existing distribution or transmission system. The pipeline portion of the project is designed and constructed in the manner of traditional construction protocols. The Interconnect Facility has additional design and construction but is essentially a small gate station similar to interconnections with interstate pipelines. In addition to typical regulation and metering systems, the facility also requires design of automated valving connected to gas quality measurement systems, odorant system, SCADA system, and two small buildings which contain the gas testing equipment and electrical & SCADA equipment. The Interconnect Facility design and construction has a more interactive project management requirement to resolve the numerous details which enable it to be interwoven with the larger project and site utilities. To date, these projects have been supported directly with Cascade's internal engineering resources.

Of the Purchase Projects in development, four projects are either under contract or at very advanced stages of contracting as detailed here:

City of Richland – Horn Rapids Landfill & Lamb Weston RNG Project – Richland, Washington

Source - 3rd party developer has rights to raw biogas from two sources in close proximity to each other.

1. Landfill Gas from the City of Richland's Horn Rapids Landfill
2. Food Waste from potatoes at Lamb Weston's Richland Processing Plant.

Scope of Cascade Work

- Design and construct interconnect facilities
- Design and construct pipeline from interconnect facility to local distribution system

Status & Terms

- Under contract, engineering in progress
- 1,860,000 therm/yr or ~ 9,880mtCO2e
- 15-year term
- Projected in-service date late Q4 2023

Deschutes County Landfill RNG Project - Bend Oregon

Source - Cascade/Jacobs Engineering Team was successful candidate chosen through RFP process to own and operate processing facilities to convert landfill gas to RNG

Scope of Cascade Work

- Build, own, operate, and maintain the gas processing plant
- Design and construct interconnect facilities
- Design and construct pipeline from interconnect facility to local distribution system

Status & Terms

- Working through final contact terms with Deschutes County
- Plant engineering and design in progress
- 3,100,000 therm/yr or ~ 16,460 mtCO2e
- 20-year term
- Projected in-service date Q4 2024

City of Pasco Process Water Reuse Facility - Pasco, Washington

Source – Expanding Industrial wastewater processing facility currently serving several aggregated industrial food processors & growers.

Scope of Cascade Work

- Design and construct interconnect facilities
- Design and construct pipeline from interconnect facility to local distribution system

Status & Terms

- Under contract and advancing system design progressing
- 3,400,000 therm/yr or ~ 18,060 mtCO2e
- 20-year term
- Projected in-service date late Q4 2024

Landfill RNG Project under Non Disclosure Agreement- Washington

Scope of Cascade Work

- Design and construct interconnect facilities
- Design and construct pipeline from interconnect facility to local distribution system

Status & Terms

- Partial Purchase Project
- Terms reached and progressing through contract language
- Total volume 4,000,000 therm/yr
- Purchase volume 600,000 therm/yr or ~ 3,186 mtCO2e
- 20-year term
- Projected in-service date mid-year 2025

The following two projects are Transport Projects either under contract or at advanced stages of contracting as detailed below:

Divert, Inc. RNG Project – Longview, Washington

Source – Aggregated food waste from approximately 100 chain grocery outlets in Washington and Oregon

Scope of Cascade Work

- Design and construct interconnect facilities
- Design and construct pipeline from interconnect facility to local distribution system

Status & Terms

- Under contract, engineering in progress, project has 6 month customer-side delay for unexpected site Geotech work
- 1,800,000 therm/yr (mtCO2e not applicable as Cascade is not receiving the attributes)

- 10-year term
- Projected in-service date early Q3 2024

Diary RNG Project – Snohomish County, Washington

Source – Manure from 3,500 head dairy operation

Scope of Cascade Work
- Design and construct interconnect facilities
- Design and construct pipeline from interconnect facility to local distribution system

Status & Terms
- Interconnect Agreement terms reached, final contract draft in review
- 815,000 therm/yr (mtCO2e not applicable as Cascade is not receiving the attributes)
- 10-year term
- Projected in-service date TBD, developer is currently negotiating a purchase of the project and revised in-service date is not yet known

Cascade has several RNG projects that are at different levels of advancement in terms of Cascade's procurement of the project. The following projects include a list of the type of projects Cascade is either near advancement, or at the early stages of discussion.

5 Key Advancing Projects

Waste Source	Project Type	Volumes (therm/year)	Compliance Volumes (therm/year)
Food Waste WWTF, Landfill	Purchase or Partial Purchase	16,165,000	13,315,000 (~70,725 mtCO2e)
Dairy	Transport	1,370,000	0

Other Active Projects

Purchase	2 Projects
Transport	8 Projects

Renewable Thermal Certificates

The Oregon Department of Environmental Quality (DEQ) has adopted M-RETS as the tracking platform to validate and track environmental attributes from RNG and hydrogen in the CCP. M-RETS utilize Renewable Thermal Certificates (RTCs) to track the production, transfer and retirement of these qualified environmental

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

ORDER APPROVING NATURAL GAS INNOVATION PLAN WITH MODIFICATIONS, IN REGARDS TO CENTERPOINT ENERGY'S NATURAL GAS INNOVATION PLAN

EXHIBIT 1205

November 2025

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Valerie Means	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of CenterPoint Energy's Natural Gas Innovation Plan

ISSUE DATE: October 9, 2024

DOCKET NO. G-008/M-23-215

ORDER APPROVING NATURAL GAS INNOVATION PLAN WITH MODIFICATIONS

PROCEDURAL HISTORY

On June 28, 2023, CenterPoint Energy Corp. d/b/a CenterPoint Energy Minnesota Gas (CenterPoint) filed a petition for approval of its first Natural Gas Innovation Plan.

By January 17, 2024, the Commission received initial comments from:

- Office of the Attorney General—Residential Utilities Division (OAG)
- Center for Energy and Environment (CEE)
- Coalition for Renewable Natural Gas (RNG Coalition)
- Clean Energy Organizations (CEOs)[1]
- Geothermal Exchange Organization
- International Union of Operating Engineers Local 49 (Local 49)
- Citizens Utility Board of Minnesota (CUB)
- Department of Commerce (Department)
- City of Minneapolis

By March 15, 2024, the Commission received reply comments from:

- CEE
- Laborers' International Union of North America–Minnesota and North Dakota (LIUNA)
- RNG Coalition
- CenterPoint
- CEOs

[1] The CEOs consist of Minnesota Center for Environmental Advocacy, Fresh Energy, and Sierra Club.

By May 15, 2024, the Commission received supplemental comments from:

- LIUNA
- City of Minneapolis
- Department
- CUB
- CEOs
- OAG
- CenterPoint
- Local 49

By May 16, 2024, numerous members of the public filed comments.

On July 22, 2024, the Department filed additional comments.

On July 25, 2024, CenterPoint, CEE, LIUNA, and Local 49 jointly filed proposed decision options.

On July 23 and 25, 2024, this matter came before the Commission.

FINDINGS AND CONCLUSIONS

I. Background

On June 26, 2021, Governor Walz signed the Natural Gas Innovation Act (NGIA) into law.[2] The NGIA allows natural gas utilities to file innovation plans with the Commission that detail the innovative resources they plan to implement to contribute to meeting Minnesota's greenhouse gas (GHG) and renewable energy goals. The term "innovative resource" is defined as "biogas, renewable natural gas, power-to-hydrogen, power-to-ammonia, carbon capture, strategic electrification, district energy, and energy efficiency."[3]

As part of their innovation plans, utilities are allowed to propose pilot programs and research and development (R&D) investments that implement innovative resources. The NGIA imposes numerous requirements on what a utility must include in a plan. Some requirements dictate what information must be included in a plan while others affect how the plan is crafted, such as by setting a cap on cost recovery or by requiring utilities to allocate a percentage of a plan's budget to certain innovative resources. Of particular importance is the requirement that fifty percent or more of a plan's costs are for the procurement and distribution of RNG, biogas, hydrogen produced via power-to-hydrogen, and ammonia produced via power-to-ammonia (the fifty-percent cost requirement).[4]

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[2] The NGIA is codified in statute as Minn. Stat. §§ 216B.2427 and 216B.2428.

[3] Minn. Stat. § 216B.2427, subd. 1(h).

[4] Minn. Stat. § 216B.2427, subd. 2(d)(1).

After the NGIA was enacted, the Commission issued an order establishing two frameworks: (1) a general framework to compare the lifecycle GHG emissions intensities of each innovative resource, and (2) a cost-benefit analytic framework to compare the cost-effectiveness of innovative resources and plans.[5] The Commission issued its frameworks order pursuant to Minn. Stat. § 2428.

II. CenterPoint's Natural Gas Innovation Plan

A. Overview of the Plan

CenterPoint is the first natural gas utility to file an innovation plan since the NGIA was enacted. The plan includes seventeen pilots that will utilize six, and possibly seven, of the innovative resources listed in the NGIA and seven R&D pilots, some of which explore the eighth innovative resource, power-to-ammonia.[6] CenterPoint estimated that the pilots will reduce or avoid nearly 1.2 million metric tons of carbon dioxide equivalent emissions—comparable to the energy use of approximately 150,000 homes for one year—and create 3,000 full-time equivalent jobs in Minnesota. The proposed five-year cost of the plan is $105,701,515.

In addition to the pilot and R&D proposals, the plan includes a request for budget flexibility, a cost-recovery proposal, proposed cost-effectiveness objectives, and a proposal on what information CenterPoint should include in its annual status reports.

1. Comments

While some commenters encouraged the Commission to approve CenterPoint's plan outright, others recommended modifying portions of the plan by, for example, rejecting or altering certain pilot proposals or adjusting the plan's budget. No commenter recommended rejecting the plan in its entirety. After the first day of oral argument on the plan, CenterPoint, CEE, LIUNA, and Local 49 filed a list of proposed decision options that they jointly supported.

2. Commission Action

After consideration of the record and the proceedings in this matter, the Commission is persuaded that CenterPoint's innovation plan should be approved—including all the proposed pilots and R&D projects—as modified in this order. Decarbonizing the natural gas sector requires a different approach than decarbonizing the electricity sector, and CenterPoint has crafted a plan that uses innovative resources to reduce GHG emissions and natural gas throughput. The plan marks an important first step in an iterative process in which CenterPoint and stakeholders learn the most effective way to implement these resources. CenterPoint's plan

[5] Order Establishing Frameworks for Implementing Minnesota's Natural Gas Innovation Act, Docket No. G-999/CI-21-566 (June 1, 2022).

[6] CenterPoint's plan originally included eighteen pilots, but one of the pilots—Pilot A—is no longer feasible. Under Pilot A, CenterPoint intended to purchase renewable natural gas from an anaerobic digestion facility that Hennepin County was developing. Hennepin County informed CenterPoint that it was no longer pursuing the facility.

is consistent with the NGIA and relevant Commission orders, and the Commission finds that the plan meets the criteria under Minn. Stat. § 216B.2427, subd. 2(b).[7]

When reviewing CenterPoint's innovation plan, the Commission was particularly mindful of the following considerations.

First, the NGIA encourages utilities to learn. Utilities with innovation plans must implement innovative resources, some of which they may not have much, or any, experience using. As utilities learn what works and what doesn't, they will become better positioned to develop programs that more effectively contribute to meeting Minnesota's GHG and renewable energy goals.

Second, approval of CenterPoint's innovation plan does not set the plan in stone. The NGIA requires a utility to file annual reports on various aspects of an approved plan, such as costs incurred, reductions or avoidance of GHG emissions, and the economic impact of the plan, among others.[8] When evaluating such reports, the Commission has the authority to make modifications or even to disapprove the continuation of a pilot program or plan.[9] The Commission's review will provide an important check on CenterPoint's innovation plan and help ensure that only useful projects continue.

Third, to recover costs under its plan, CenterPoint must demonstrate to the satisfaction of the Commission that the costs it incurs are reasonable.[10] This requirement helps protect ratepayers and incentivizes CenterPoint to be prudent when incurring costs.

With these considerations in mind, the Commission is confident that CenterPoint's plan will help Minnesota move closer to achieving its GHG and renewable energy goals. The Commission appreciates CenterPoint's efforts in developing the first innovation plan under the NGIA as well as stakeholders' involvement. Stakeholders' comments have been extremely valuable as the Commission considers this novel proposal.

Below, the Commission will address the following: (1) pilot modifications, (2) R&D project modifications, (3) CenterPoint's request for budget flexibility, (4) cost recovery, (5) cost-effectiveness objectives, (6) annual status reports, (7) other plan modifications, and (8) requirements for future NGIA plans.

B. Pilot Modifications

As discussed above, the Commission is approving CenterPoint's plan, including all the proposed pilots, as modified in this order. Commenters made numerous recommendations on

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[7] To approve an innovation plan, the NGIA requires the Commission to find that the criteria under Minn. Stat. § 216B.2427, subd. 2(b) are met.

[8] Minn. Stat. § 216B.2427, subd. 2(f).

[9] Minn. Stat. § 216B.2427, subd. 2(g).

[10] Minn. Stat. § 216B.2427, subd. 2(c).

CenterPoint's seventeen pilot proposals. This section includes a brief description of each pilot, a discussion of relevant comments, and any pilot modifications.

1. Pilot B – Renewable Natural Gas (RNG) Produced from Ramsey and Washington Counties' Organic Waste

Under Pilot B, CenterPoint proposed purchasing RNG from Dem-Con HZI Bioenergy LLC's anaerobic digestion facility, which is currently under development. This new anaerobic digester facility will process source-separated food waste from Twin Cities metro area counties, including Washington and Ramsey Counties' organics recycling programs and a smaller quantity of yard waste.

a. Comments

Several commenters addressed Pilot B and supported its approval with modifications. The City of Minneapolis highlighted the potential benefits of the pilot, including a marketable biochar product to sequester carbon, reducing methane emissions from landfills, and creating a new local fuel source that supports local economic development. But the City of Minneapolis conditioned its support of the pilot on acceptable air quality impacts for local residents, and it encouraged CenterPoint to find a local offtaker for the RNG, a recommendation the CEOs echoed.

The Department recommended including Pilot B in the competitive bidding process and draft request for proposals in Pilot C to ensure a fair price for the project. By the time this matter came before the Commission, however, CenterPoint had already released its request for proposals. In light of the changed circumstances, the Department made a modified recommendation to require CenterPoint to request a bid from Dem-Con HZI Bioenergy LLC prior to plan approval.

In response to the City of Minneapolis's concerns about air quality, CenterPoint stated that, according to the developer, the facility would meet stringent federal and state air quality standards. The developer also informed CenterPoint that using a local offtaker for the project was not feasible or desirable. In response to the Department, CenterPoint explained that it would use available market benchmarks and information gained from the request for proposals in Pilot C to determine the reasonableness of pricing for Pilot B.

b. Commission Action

The Commission agrees with commenters that Pilot B should be approved. As the City of Minneapolis observed, the pilot has several potential benefits, and because it involves purchasing RNG, it contributes to the plan meeting the fifty-percent cost requirement.

In the interest of keeping the costs of Pilot B as low as possible, the Commission will require CenterPoint to obtain from Dem-Con HZI Bioenergy, LLC the information that was required for the bidders for Pilot C.

2. Pilot C – RNG Request for Proposal Purchase

Under Pilot C, CenterPoint proposed issuing a request for proposals to purchase an additional amount of RNG to complete its RNG portfolio and help satisfy the fifty-percent cost requirement. CenterPoint would potentially procure RNG from four different feedstocks: food waste, dairy, wastewater treatment, and landfill. As proposed, Pilot C has the largest budget in CenterPoint's innovation plan.

a. Comments

Commenters widely acknowledged that the Commission would need to approve some version of Pilot C to meet the NGIA's fifty-percent cost requirement, but commenters did not agree on all aspects of the pilot and raised issues concerning four main topics: (1) Pilot C's budget, (2) bundled RNG purchases, (3) geographic limitations on RNG purchases, and (4) the appropriate feedstocks for RNG purchases.

i. Pilot C's Budget

The CEOs, CUB, the Department, the OAG, and the City of Minneapolis all recommended reducing the budget for Pilot C. These commenters were concerned about the substantial size of Pilot C's budget and ensuring that CenterPoint makes economical RNG purchases. As an additional measure to contain Pilot C's costs, the OAG and the Department recommended imposing a pilot-specific budget cap.

In response, CenterPoint asserted that the budget for Pilot C was appropriate and consistent with the legislature's intent as reflected by the NGIA's cost cap on innovation plans and the permissible level of spending on RNG relative to that cap. CenterPoint did not support a budget cap specifically for Pilot C.

ii. Bundled RNG Purchases

RNG can be separated into two component parts: commodity gas and environmental attributes. RNG producers can sell those parts together (i.e., bundled) or they can sell them separately (i.e., unbundled). If natural gas utilities purchase only the environmental attributes of RNG—referred to in this context as Renewable Thermal Certificates—without the associated commodity gas, they can apply the environmental attributes to their conventional natural gas supply and claim an environmental benefit.

Under Pilot C, CenterPoint proposed giving a preference to purchasing bundled RNG but stated that it would also consider purchasing some amount of the environmental attributes of RNG without the associated commodity gas. CenterPoint asserted that the NGIA does not allow utilities to purchase unbundled commodity gas because it requires that environmental benefits produced under an innovation plan not be claimed for any other program.[11]

In contrast, the OAG and CUB argued that the NGIA only allows CenterPoint to purchase bundled RNG and recommended prohibiting CenterPoint from buying only the environmental attributes of RNG. CenterPoint asserted in response that the NGIA supports purchasing environmental attributes of RNG without the associated commodity gas because such purchases would be tied to gas coming onto the system in Minnesota or in a neighboring state and could support increased production of RNG. For example, if a potential RNG producer has a buyer for its commodity gas but not for the associated environmental attributes, CenterPoint's purchase of

[11] Minn. Stat. § 216B.2427, subd. 2(a)(10)(i).

those attributes could provide an avenue for facilitating RNG production and further the goals of the NGIA.

iii. Geographic Limitations on RNG Purchases

The CEOs and the City of Minneapolis recommended requiring CenterPoint to buy RNG only from Minnesota sources, and CUB recommended CenterPoint prioritize Minnesota-made RNG over RNG produced elsewhere. CenterPoint agreed that it should prioritize buying RNG from Minnesota sources to promote in-state economic development and ultimately supported a related modification to Pilot C. But CenterPoint disagreed that it should limit its RNG purchases to Minnesota sources because there are other relevant factors, such as GHG reductions and cost, that affect purchasing decisions.

iv. Feedstocks for RNG purchases

The CEOs recommended eliminating investments in dairy manure feedstocks because, the CEOs argued, there are environmental concerns associated with that type of feedstock. CenterPoint opposed eliminating dairy-manure feedstocks from Pilot C and noted that each type of feedstock provides a different learning opportunity.

b. Commission Action

The Commission is persuaded that Pilot C should be approved because it presents learning opportunities related to RNG procurement and distribution, offers significant reductions in GHG emissions, and supports local RNG producers. The importance of RNG and other alterative fuels to the legislature is evident in the NGIA's requirement that fifty percent *or more* of a utility's costs under an innovation plan are for these fuels.[12] The legislature also understood how much might be spent on RNG and other alternative fuels relative to the overall cost cap it established for the NGIA. Accordingly, the Commission is persuaded that Pilot C's budget is reasonable to explore the benefits of using RNG to reduce GHG emissions and natural gas throughput. With the NGIA's overall cost cap on CenterPoint's plan and a prudency review for all cost recovery, the Commission does not consider it necessary to impose a cost cap specifically on Pilot C at this time.

The Commission also agrees with CenterPoint that the NGIA allows utilities to purchase environmental attributes without the associated commodity gas because such purchases support RNG production and further the goals of the NGIA.

Regarding geographic considerations, the Commission concurs with commenters that CenterPoint should prioritize purchasing RNG produced in Minnesota. Accordingly, the Commission will modify Pilot C to prioritize geographic preferences as follows:

- RNG interconnected with CenterPoint's Minnesota distribution system;
- RNG within Minnesota; and

[12] Minn. Stat. § 216B.2427, subd. 2(d)(1).

- RNG in neighboring regions.[13]

Turning to the issue of feedstocks, the Commission is not persuaded that it should limit the types of feedstocks for Pilot C as the CEOs recommended. The CEOs may be correct that some methods of RNG production are preferable to others for various reasons, but at this early stage of NGIA implementation, CenterPoint should be allowed to purchase RNG from all the proposed types of feedstocks. This will give CenterPoint the opportunity to learn more about the various sources of RNG and possibly allow CenterPoint to buy more of its RNG from Minnesota-based producers.

Additional information on the size of dairy farms that participate in RNG production would be useful for future innovation plan proceedings. To that end, the Commission will require CenterPoint to collect data on dairy cow herd size for RNG purchases from dairy farms and provide that data in its annual status reports. Through its annual status reports, CenterPoint must provide an analysis that compares the farm sizes participating in Pilot C to the statewide average, and range, of herd sizes.

3. Pilot D – Green Hydrogen Blending into Natural Gas Distribution System

Under Pilot D, CenterPoint proposed to own and operate a one-megawatt green hydrogen plant at an existing CenterPoint facility in Mankato. CenterPoint would install dedicated solar panels, an electrolyzer, a hydrogen storage system, and other necessary systems and equipment to generate, store, and blend hydrogen into the natural gas distribution system.

a. Comments

Commenters were divided on Pilot D. The Department stated that there is inherent value in studying the implementation of hydrogen blending but expressed concerns, which other commenters also voiced, due to the allegedly poor performance of an existing hydrogen blending facility that CenterPoint operates. The Department recommended reviewing the causes of the poor performance at the existing facility before moving forward with Pilot D. Commenters also expressed concerns about Pilot D's cost, the safety of hydrogen blending, and the effects of hydrogen blending on the integrity of the natural gas distribution system.

CenterPoint disagreed with commenters' assertions that CenterPoint's existing hydrogen blending facility has performed poorly, noting that production has increased significantly over time and that operating the facility has created valuable learning opportunities. In response to safety concerns, CenterPoint stated that it consulted with the Minnesota Office of Pipeline Safety and would follow all applicable safety regulations. CenterPoint acknowledged that there is an upper threshold on how much hydrogen can be safely blended into the system, but explained that even a five-percent hydrogen blend would reduce a substantial amount of GHG emissions.

[13] For purposes of this program, neighboring regions would be participants injecting in an interstate pipeline system that delivers to Minnesota or a distribution system connected to an interstate pipeline that delivers to Minnesota within the states of Iowa, North Dakota, South Dakota, Iowa, Wisconsin and the upper peninsula of Michigan and participants injecting gas in the Northern interstate pipeline in Nebraska and Kansas, north of Demarc.

b. Commission Action

The Commission understands commenters' concerns about Pilot D but is persuaded that the pilot should be approved. Pilot D presents an opportunity for CenterPoint to learn more about blending hydrogen with natural gas at a facility that is being powered, at least in part, by onsite renewable energy. CenterPoint expects the reduction in geologic gas throughput and GHG emissions to be significant, which furthers the goals of the NGIA. With the experience CenterPoint has already gained from operating its existing hydrogen blending facility, the new facility under Pilot D is more likely to be successful and provide even more learning opportunities. CenterPoint should further explore implementing this innovative technology.

To ensure that carbon-free electricity is being used for Pilot D, the Commission will require CenterPoint to specify the source of additional power that it will use for the pilot, including any green tariff or power purchase agreement that it will use to procure the power.

4. Pilot E – Industrial or Large Commercial Hydrogen and Carbon Capture Incentives[14]

Under Pilot E, CenterPoint would identify a small number of large commercial or industrial customers interested in installing either power-to-hydrogen or carbon-capture demonstration projects and support their projects by providing financial assistance towards feasibility studies and project costs. The pilot contains an initial scoping study to aid with customer identification. To incentivize customer participation, CenterPoint would pay 100 percent of capital costs for project installation up to a maximum of $1.5 million for a single project.

a. Comments

Commenters broadly supported Pilot E. The CEOs and CUB both recommended that CenterPoint prioritize hard-to-electrify customers, and CUB encouraged enrolling industrial customers. The CEOs also recommended imposing a minimum amount of natural gas savings that customers would need to achieve to qualify for the power-to-hydrogen project.

CenterPoint was amenable to imposing a minimum amount of natural gas savings for the power-to-hydrogen project and suggested 136,000 dekatherms over the lifetime of the project. Regarding prioritizing hard-to-electrify customers, CenterPoint said that it was not aware which of its customers are industrial as opposed to commercial, and it was not able to determine which customers are hard to electrify. But CenterPoint thought it was likely that customers would not incur the substantial costs to participate in Pilot E if they were able to electrify easily. CenterPoint supported a decision option in which it would describe in its annual filings how it is working with its customers to identify opportunities to work on a hydrogen project for an industrial process customer in Pilot E.

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[14] CenterPoint states that Pilot E satisfies the requirement in Minn. Stat. § 216B.2427, subd. 7, that the "first innovation plan filed under this section […] must include a pilot program to provide innovative resources to industrial facilities whose manufacturing processes, for technical reasons, are not amendable to electrification."

The Department supported the power-to-hydrogen proposal but recommended classifying the proposed carbon-capture scoping study as an R&D project. The Department recommended that any other budget allocations for carbon capture should be removed until CenterPoint has identified at least one potential customer and provided additional information on the cost effectiveness of carbon-capture technology. The Department made a similar recommendation for other pilots where CenterPoint had not preidentified participants.

CenterPoint disagreed with the Department's general position that pilot participants must be identified before receiving budget approval. CenterPoint argued that such an approach is unreasonable because it would require CenterPoint to incur significant marketing and outreach costs before stakeholders and the Commission had a chance to review pilots. Also, pilot designs may change during the regulatory process, which could affect customer interest, and predetermining customers for each pilot could force other interested customers to wait to join a pilot until the innovation plan can be modified.

CenterPoint also opposed changing the scoping study proposal to an R&D expense because it does not satisfy the R&D criteria in CenterPoint's petition. CenterPoint asserted that the scoping study is an integral part of implementing Pilot E, and as the pilot with the fourth largest estimated GHG reductions, CenterPoint argued that the Commission should approve the full budget proposal. CenterPoint explained that even though the budget is based on one hydrogen participant and one carbon-capture participant, it would be flexible in allowing multiple participants for either program depending on interest and available funds.

The City of Minneapolis recommended requiring customers participating in Pilot E to pay fifty percent of the costs. CenterPoint responded that a large upfront incentive would better motivate customers who need to invest time and effort in the pilot and bear the ongoing operating costs.

b. Commission Action

The Commission agrees with commenters that Pilot E should be approved. The pilot presents the opportunity to reduce GHG emissions from industrial customers that are not amenable to electrification. To ensure a minimum amount of savings in the power-to-hydrogen project, the Commission will adopt the requirement that a customer must reduce 136,000 dekatherms of natural gas over the life of the project to qualify. The Commission will also require CenterPoint to describe in its annual filings how it is working with its customers to identify opportunities to work on a hydrogen project for an industrial process customer within the Pilot E power-to-hydrogen archetype. This reporting requirement will help inform the Commission and stakeholders about whether Pilot E is helping to decarbonize hard-to-electrify manufacturing processes.

The Commission will not reduce Pilot E's budget as the Department proposed or direct CenterPoint to pursue the carbon-capture scoping study as an R&D project. Both the power-to-hydrogen and carbon-capture projects present learning opportunities and the possibility of significant reductions in GHG emissions. CenterPoint should have the flexibility to work with customers in either project as interest and funding allows. The Commission also declines to require customers to pay fifty percent of the upfront costs to participate in Pilot E as the City of Minneapolis proposed. The pilots in CenterPoint's innovation plan will only yield results if customers participate, and the Commission views the incentive in Pilot E as a reasonable means of encouraging participation.

5. Pilot F – Industrial Methane and Refrigerant Leak Reduction

Under Pilot F, CenterPoint would hire a vendor to conduct surveys of participating industrial and large commercial facilities for methane and refrigerant leaks behind the customer gas meter. CenterPoint would also offer incentives to partially offset the cost of leak repair.

a. Comments

No commenters opposed this pilot. CEE observed that the findings from Pilot F will help mitigate environmentally damaging leaks across CenterPoint's system. The City of Minneapolis voiced its support for the pilot but recommended that contractors be solicited from in-state to support the local economy.

The Department supported Pilot F but recommended reducing the budget to accommodate ten participants instead of twenty-five because CenterPoint only identified one potential participant. The CEOs advocated for several modifications to the pilot, including, among others, evaluation of both piping and appliances, which CenterPoint supported. Lastly, the OAG questioned the accuracy of CenterPoint's estimates of how much methane savings would result from Pilot F and recommended reducing the estimates before the Commission assessed the pilot's benefits.

In response to the Department, CenterPoint restated its position that it was not seeking participants for all its pilots before approval of its innovation plan. But CenterPoint noted that it expected to reach the planned twenty-five participants for Pilot F based on its experience implementing customer programs. In response to the OAG, CenterPoint acknowledged uncertainty in its methane-savings estimates but reiterated its view that the estimates are conservative. CenterPoint asserted that even if the methane savings were four times lower than estimated, Pilot F would still be cost effective.

b. Commission Action

The Commission agrees with commenters that Pilot F should be approved. As the OAG observed, preventing methane from entering the atmosphere is an important part of addressing climate change, and Pilot F will further this effort by repairing methane leaks.

The Commission will not reduce Pilot F's budget as the Department proposed. As with Pilot E, the Commission is not persuaded that it was necessary for CenterPoint to identify all its pilot participants before approval of its innovation plan. If CenterPoint does not find the expected twenty-five participants for the pilot, it will likely not use the entire budget, which protects ratepayers' interests. Regarding the OAG's concerns about the methane-savings estimates, the Commission understands there is uncertainty in the estimates but is persuaded that the pilot should be approved given its cost effectiveness even if the methane savings ends up being significantly lower than expected.

As to the City of Minneapolis's recommendation to use in-state labor, the Commission will encourage participants in Pilot F, and other pilots, to employ contractors that maximize opportunities for residents of communities CenterPoint serves and local workers to the extent feasible. The Commission will also require that Pilot F include the evaluation of both indoor piping and appliances to the extent feasible, as the CEOs recommended, and impose several annual filing requirements specific to the pilot.

6. Pilot G – Urban Tree Carbon Offsets

Under Pilot G, CenterPoint proposed to purchase carbon offsets from local non-profit, Green Cities Accord. Green Cities Accord works with local tree-planting partners across the seven-county Twin Cities Metro area to plant trees in urban areas and funds their work by selling carbon offsets.

a. Comments

Commenters were divided on Pilot G. The City of Minneapolis supported the pilot and highlighted its environmental justice benefits and cost effectiveness. Conversely, the Department, the CEOs, CUB, and the OAG recommended rejecting it. The Department opposed the project because purchasing carbon offsets would result in carbon being captured by trees that have already been planted. Unless new trees were planted, the Department asserted, there would be no new emissions reductions. The Department expressed interest in a pilot that included planting new trees. CenterPoint responded that the money used to purchase carbon offsets from Green Cities Accord would go towards the planting of new trees and the upkeep of existing trees.

The OAG, the CEOs, and CUB opposed Pilot G as inconsistent with the NGIA. They based their arguments on the statutory definition of "carbon capture" and asserted that trees do not capture GHG "emissions that would otherwise be released into the atmosphere."[15] Rather, trees remove GHG emissions that have already been released. CenterPoint disagreed with this interpretation of the NGIA and stated that trees capture carbon that would otherwise remain released in the atmosphere.

In addition to capturing carbon, CenterPoint highlighted the benefits of planting trees in urban areas, including the reduction of stormwater runoff, air pollution, urban heat effects, and heating and cooling costs. CenterPoint also noted that Green Cities Accord targets tree planting in areas of limited tree coverage, which have a high correlation with areas of concentrated poverty.

b. Commission Action

The Commission is persuaded that Pilot G should be approved. Trees play an important role in combatting climate change by absorbing—or capturing—carbon dioxide from the air and releasing oxygen. In winter, trees can shelter homes from wind that causes heat loss, thereby reducing the need to operate gas-fired furnaces as often. In that way, planting trees could reduce natural gas throughput, a goal of the NGIA.[16] Also, as CenterPoint observes, trees planted in urban areas benefit populations that are often most impacted by the negative effects of climate change.

[15] Minn. Stat. § 216B.2427, subd. 1(c).

[16] Minn. Stat. § 216B.2427, subd. 10.

CenterPoint addressed the Department's concerns about new trees being planted under the pilot. For purposes of oversight, the Commission will require CenterPoint to provide information about the number of new trees planted and the average cost of the new trees in its annual status reports.

And while there are reasonable and differing interpretations of the NGIA's approach to carbon capture, the Commission is unpersuaded that this first application of the statute calls for its narrowest reading. Other approaches to carbon capture may be more reasonable in future iterations of innovation plans, but those will be explored upon reflection of the pilot's effectiveness and continuing examination of the issues, which will facilitate careful consideration of possible program refinements or changes. The Commission simultaneously recognizes the importance of minimizing ratepayer impacts and is satisfied that the level of spending/budget allocation related to this pilot is reasonably minimal, while furthering important public policy goals, and the Commission will therefore approve this pilot.

7. Pilot H – Carbon Capture Rebates for Commercial Buildings

Under Pilot H, CenterPoint proposed to provide rebates to commercial customers that install CarbinX carbon capture systems manufactured by Canadian company CleanO2. These units connect to existing natural gas heating equipment, capture CO_2, and convert it into chemicals that are resold for commercial uses.

a. Comments

Commenters were divided on Pilot H. The City of Minneapolis expressed support for the pilot as did public commenters from the University of Minnesota, Bloomington Public Schools, and Minneapolis Public Schools. Commenters emphasized how the technology could help their organizations meet their decarbonization goals.

In contrast, the Department recommended rejecting Pilot H. The Department stated that CenterPoint has an existing CarbinX pilot in its Energy Conservation and Optimization (ECO) program and asserted that CenterPoint failed to adequately explain why Pilot H could not proceed through ECO.[17] Similarly, CUB and the CEOs questioned the need for a CarbinX pilot in CenterPoint's innovation plan when there is already a similar ECO pilot.

CenterPoint responded that the primary focus of its CarbinX pilot in ECO is on energy savings and noted that the pilot is fully subscribed. Through Pilot H, CenterPoint proposed emphasizing the carbon capture savings of CarbinX units and focusing on deploying units to a larger number of customers.

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[17] A program approved through ECO is administered by a utility with regulatory oversight by the Department. ECO portfolios promote energy efficient technologies and practices by providing rebates, marketing, and technical assistance to utility customers. The Department reviews and approves ECO regulatory filings. In 2021, the governor signed the Minnesota ECO Act into law, which modernized the existing Conservation Improvement Program (CIP). Commenters often used the acronyms "ECO" and "CIP" interchangeably in their filings. For simplicity's sake, the Commission will use "ECO" throughout this order, except as otherwise noted.

The Department ultimately proposed an alternative in which the Commission would approve Pilot H but direct CenterPoint to begin pilot implementation after the completion of the ECO CarbinX project.

b. Commission Action

The Commission is persuaded that Pilot H should be approved. The CarbinX units reduce GHG emissions and provide revenue opportunities for customers. Even though CarbinX technology is already being explored in an ECO pilot, a larger number of customers using CarbinX units would increase learning opportunities and environmental benefits.

As with some other pilots in CenterPoint's innovation plan, the Department is not satisfied with CenterPoint's explanation for why Pilot H cannot be administered through ECO because a similar program already exists in ECO. The NGIA provides that "energy efficiency" and "strategic electrification" do not include investments that the Commissioner of Commerce determines could reasonably be included in a natural gas utility's ECO plan.[18] The Commissioner of Commerce has not made such a determination for any of the pilots included in CenterPoint's plan. In its initial filing in this docket, CenterPoint discussed the pilots that include energy efficiency or strategic electrification and explained why those pilots were appropriately included in its plan instead of ECO.[19] The Commission is persuaded by CenterPoint's explanations for why these pilots should be included in its innovation plan and will therefore approve pilots that meet the requirements of the NGIA and further the state's GHG and renewable energy goals.

Concerning Pilot H specifically, the NGIA does not require the pilot to proceed through ECO. The language in Minn. Stat. § 216B.2427, subd. 1(f) pertains to energy efficiency resources, but Pilot H utilizes both energy efficiency and carbon capture resources. The NGIA does not require carbon capture pilots to be included in ECO programs, and the Commission is unpersuaded that the NGIA mandates that the pilot be included in ECO simply because a portion of the pilot involves energy efficiency.

The Commission will adopt the Department's alternative decision option. Waiting until completion of the ECO CarbinX project will allow CenterPoint to maximize learning opportunities from the ECO pilot before implementing Pilot H.

8. Pilot I – New Networked Geothermal Systems

Under Pilot I, CenterPoint proposed to develop a new networked geothermal system to provide building heating and cooling for a neighborhood currently served by CenterPoint. This pilot starts with a study phase to identify the location, technologies, and business model for the system.

a. Comments

Commenters generally supported CenterPoint pursuing a networked geothermal system, but some advocated for a more cautious approach. The Department asserted that CenterPoint did not

[18] Minn. Stat. § 216B.2427, subd. 1(f) and (q).

[19] Petition by CenterPoint Energy for Approval of its First Natural Gas Innovation Plan, Exhibit I.

provide enough information to determine the reasonableness of the pilot and recommended requiring CenterPoint to file a modified version of Pilot I that funds a feasibility study for a networked geothermal system for new construction. The OAG agreed with the Department but recommended allowing CenterPoint to request modification of the pilot for approval of additional costs after providing information from the feasibility study.

The CEOs supported approving Pilot I, and along with CUB, recommended requiring CenterPoint to install a networked geothermal system in a low-income or environmental justice area and requiring CenterPoint to file additional information with its first annual status report about how it will facilitate stakeholder and community engagement for the pilot.

CenterPoint was receptive to commenters' feedback and ultimately supported several decision options that addressed their recommendations.

b. Commission Action

The Commission agrees with commenters that networked geothermal system technology could potentially provide substantial environmental and financial benefits for customers. Accordingly, the Commission will approve Pilot I with the modifications that CenterPoint supported.

Generally, the modifications require CenterPoint to, among other things, (1) include certain information in the feasibility study, (2) request approval from the Commission prior to implementation if the feasibility study indicates that total costs will exceed plan estimates by more than ten percent, (3) file additional information about how CenterPoint will facilitate stakeholder and community engagement, (4) issue a request for interest (RFI) to solicit feedback from communities and developers interested in the pilot, and (5) provide information related to the RFI process in its annual status reports.

9. Pilot J – Decarbonizing Existing District Energy Systems

Under Pilot J, CenterPoint proposed to help existing district energy systems that currently use geologic gas to identify opportunities to reduce the lifecycle GHG impact of their systems via funding for feasibility studies and financial support for following through with study recommendations.

a. Comments

The CEOs and the City of Minneapolis supported Pilot J. The CEOs recommended that Pilot J not count toward the NGIA's twenty-percent district energy cap unless the resulting system meets the definition of "district energy."[20] The CEOs also recommended that the feasibility studies include a full electrification/decarbonization scenario.

[20] Minn. Stat. § 216B.2427, subd. 2(d)(2) limits a utility's cost recovery for district energy pilots to twenty percent of the costs the Commission approves for recovery under the plan.

The Department initially recommended rejecting Pilot J because, in the Department's view, it does not meet the statutory definition of "district energy."[21] The Department also asserted that insofar as Pilot J could qualify as an energy efficiency or strategic-electrification pilot, CenterPoint had not explained why the pilot could not be included in ECO. Ultimately, the Department proposed approving Pilot J subject to the application of screening criteria that would allow the Department to remove the pilot from CenterPoint's plan if projects within the pilot do not satisfy the screening criteria.[22]

CenterPoint responded that even though projects implemented within Pilot J may not meet the definition of district energy, the pilot should still be approved. Pilot J involves two parts for any given participant: a feasibility-study phase and an implementation phase. CenterPoint explained that after the feasibility-study phase, CenterPoint would support participants in implementing GHG reduction projects that utilize any of the innovative resources in the NGIA. CenterPoint stated that it would screen all energy efficiency and strategic electrification projects for inclusion in ECO before pursuing NGIA funding. Even though there may be possible overlap, CenterPoint asserted that Pilot H goes significantly beyond what is possible in ECO.

b. Commission Action

The Commission is persuaded that Pilot J should be approved. The pilot provides the opportunity for CenterPoint to assist participants in decarbonizing existing district energy systems using any of the innovative resources identified in the NGIA. Because participants may elect to use resources other than district energy to reduce GHG emissions, the Commission agrees with the CEOs that Pilot J should not count toward the NGIA's twenty-percent cost recovery cap unless the project meets the statutory definition of "district energy."

The Commission also agrees with the CEOs that it is important to include a full electrification/ decarbonization scenario in feasibility studies, but the Commission will not require inclusion of such a scenario. Participants will bear the majority of the costs of the feasibility study, and the Commission does not want to deter participation by imposing an additional requirement. Instead, the Commission will require CenterPoint to offer customers the option to include a full electrification/decarbonization scenario in the feasibility study, and CenterPoint will include in its annual status reports the number of customers who choose to study such a scenario.

As to the Department's position on Pilot J, the Commission is not convinced that the pilot should be rejected because it does not neatly fit into the definition of one of the innovative resources. It remains to be seen which innovative resources participants will use to reduce their GHG emissions in Pilot J. If participants choose energy efficiency or strategic electrification, CenterPoint will pursue including the project in ECO. If that is not possible, the project will proceed through the NGIA. ECO and the NGIA should not interfere with one another, but rather

[21] The term "district energy" is defined under the NGIA as "a heating or cooling system that is solar thermal powered or that uses the constant temperature of the earth or underground aquifers as a thermal exchange medium to heat or cool multiple buildings connected through a piping network." Minn. Stat. § 216B.2427, subd. 1(e).

[22] The Department made a similar recommendation for Pilots K, L, M, O, and R.

both be used to implement programs that benefit utilities' customers and further the state's GHG and renewable energy goals.

The Commission is unpersuaded that it should adopt the Department's proposal to approve Pilot J, or any other pilots, subject to an additional screening process by the Department. Imposing an additional screening process would likely impede CenterPoint's ability to explore several pilot programs and is unnecessary since the Commission has determined that CenterPoint's proposed pilots are appropriately included in its innovation plan.

10. Pilot K – New District Energy System

Under Pilot K, CenterPoint proposed a pilot to help current natural gas customers considering developing district energy systems by providing funding for feasibility studies and financial support to follow through with feasibility-study recommendations.

a. Comments

Commenters' positions on Pilot K were essentially the same as they were for Pilot J. The CEOs supported the pilot and recommended that the pilot not count toward the twenty-percent statutory district energy cap unless the resulting system meets the definition of "district energy." The City of Minneapolis also supported the pilot.

The Department initially recommended rejecting the pilot because CenterPoint had not established that any of the potential participants' projects would meet the definition of "district energy." In response, CenterPoint clarified that it expects most participant projects in Pilot K to meet the definition of "district energy," but one possible project would meet the definition of "strategic electrification." Ultimately, the Department made a modified recommendation similar to the one it made for Pilot J in which Pilot K would be approved subject to additional screening criteria.

b. Commission Action

The Commission is persuaded that Pilot K should be approved as a means of exploring implementation of district energy systems and possibly a strategic electrification system. The Commission also agrees with the CEOs that Pilot K should not count toward the statutory twenty-percent district energy cap unless the resulting system meets the statutory definition of "district energy." As with Pilot J, the Commission will not adopt the Department's proposed screening process for this pilot because it would unnecessarily delay implementation of the pilot.

11. Pilot L – Industrial Electrification Incentives

Under Pilot L, CenterPoint would support industrial customers to electrify low-to-medium heat processes using heat-pump technologies. This pilot begins with a study phase to identify promising heat-pump technologies and potential industrial applications.

a. Comments

Commenters generally supported Pilot L. The CEOs recommended approving Pilot L with modifications, including (1) ensuring the pilot is not limited to hybrid heating systems, (2) prioritizing investments in electric heating equipment rather than the installation of new gas backup in hybrid heating systems, (3) requiring CenterPoint to study geothermal heat pumps, and (4) requiring CenterPoint to collect data on how often gas backups are needed in hybrid heat-pump systems.

CenterPoint supported the CEOs' modifications except for prioritizing investments in electric heating equipment instead of the installation of new gas backup in hybrid heating systems. In CenterPoint's view, the definition of "strategic electrification" in the NGIA reflects a policy goal of ensuring that participants remain CenterPoint customers while participating in the pilot. CenterPoint explained that if participants remain customers, they will continue to pay a portion of the pilot costs through their ongoing gas service. Participants continuing to be CenterPoint customers also avoids the possibility that other CenterPoint customers would end up subsidizing pilot participants discontinuing their gas service.

b. Commission Action

The Commission is persuaded that Pilot L should be approved. Pilot L utilizes strategic electrification to reduce natural gas usage for a small number of CenterPoint's industrial customers. If CenterPoint is able to help industrial customers successfully implement electric heating technologies, the broader adoption of such technologies could lead to substantial reductions in GHG emissions. The pilot is therefore consistent with the goals of the NGIA and should be approved.

The Commission will also adopt the modifications to Pilot L that the CEOs proposed and CenterPoint supported. The Commission is persuaded that it should not require CenterPoint to prioritize investments in electric heating equipment to help ensure that pilot participants remain CenterPoint customers.

12. Pilot M – Commercial Hybrid Heating

Under Pilot M, CenterPoint proposed to provide support for small-to-medium commercial buildings interested in replacing heating, ventilation, and air conditioning systems with hybrid systems using electric heat pumps and gas backup.

a. Comments

Commenters generally supported Pilot M. The CEOs recommended the same modifications for Pilot M that they proposed for Pilot L. The City of Minneapolis noted the importance of including a diverse group of participants and encouraged CenterPoint to offer a greater participation incentive for small businesses in environmental justice areas.

b. Commission Action

The Commission is persuaded that Pilot M should be approved because it provides an opportunity to reduce carbon emissions in small-to-medium commercial buildings and encourages the use of emerging commercial hybrid heating technologies.

The CEOs' recommended modifications are not all appropriate for Pilot M because CenterPoint's proposal involves using hybrid rooftop units that use electric heat pumps and gas backup. These units make consideration of non-hybrid systems, prioritization of electric heating equipment, or geothermal heat pumps impracticable. The Commission will, however, require CenterPoint to collect data on how often gas backups are needed in the subset of hybrid heat pump systems included in CenterPoint's measurement and verification plan.

The Commission agrees with the City of Minneapolis on the importance of having small businesses in environmental justice areas participate in Pilot M. The Commission will therefore require CenterPoint to monitor the type of customers that enroll in Pilot M, report its findings, and discuss whether pilot modifications are warranted if a disproportionately low number of participants are located in environmental justice areas.

13. Pilot N – Residential Deep Energy Retrofits and Electric Air Source Heat Pumps

Under Pilot N, CenterPoint would provide support for residential customers interested in retrofitting their homes to significantly improve energy efficiency and installing air source heat pumps with gas backup. This pilot starts with a study phase to identify appropriate measures and home characteristics for deep energy retrofits.

a. Comments

Commenters supported Pilot N but recommended various modifications. The Department recommended reducing the budget for Pilot N to align with the participation level reflected in the responses to the RFI. CenterPoint argued that its proposed budget for Pilot N was appropriate because the RFI responses did not include multi-family buildings, which would be included in the pilot, and that cost and participation estimates were not based entirely on RFI responses. CEE agreed with CenterPoint that its proposed participation goal was attainable and the budget appropriate.

The City of Minneapolis noted the benefits of deep energy retrofitting and recommended that Pilot N make up a much larger share of CenterPoint's innovation plan. In response, CenterPoint stated that Pilot N has the second largest pilot budget in its innovation plan, and even though it does not intend to increase the budget at this time, participation estimates may warrant refinement in the future.

The CEOs suggested that CenterPoint (1) not limit Pilot N to hybrid heating systems and prioritize electric heating equipment, (2) examine the impact of retrofit levels on gas backup demand in different types of homes, and (3) pursue the goal that up to 100% of residences participating in the phase 2 field testing portion of Pilot N are low-income residences.

Regarding prioritizing electric heating equipment, CenterPoint opposed that modification for the same reasons it gave in Pilots L and M. As to the CEOs' second recommendation, CenterPoint supported examining the impact of retrofit levels on gas backup demand and expressed its intent to collect and analyze such information as part of the pilot. Finally, CenterPoint agreed with the CEOs that it is important to provide program access to low-income residents but resisted a 100% goal noting that it is also important to take advantage of learning opportunities from a wide variety of home types.

b. Commission Action

The Commission agrees with commenters that Pilot N should be approved. The pilot meets the NGIA requirement that the first innovation plan filed must include a pilot program that facilitates deep energy retrofits and the installation of cold climate electric air-source heat pumps.[23] CenterPoint's anticipated participation level is reasonable, and the Commission therefore declines to modify the budget as the Department and the City of Minneapolis proposed.

As to the CEOs' recommendations, the Commission appreciates CenterPoint's willingness to collect and analyze information on the impact of retrofit levels on gas backup demand. The Commission agrees with CenterPoint that Pilot N should not be limited to electric heating equipment for the reasons discussed in Pilot L, and that phase 2 field testing should not be limited exclusively to low-income residences so that CenterPoint has a wider variety of learning opportunities. The Commission will approve Pilot N without pilot-specific modifications.

14. Pilot O – Small/Medium Business Greenhouse Gas Audit

Under Pilot O, CenterPoint proposed to expand its existing Conservation Improvement Program (CIP) Natural Gas Energy Analysis project to include identification of non-CIP GHG reducing opportunities for small- and medium-sized businesses. Recommendations may include measures available under the pilots for Carbon Capture Rebates for Commercial Buildings (Pilot H) and Commercial Hybrid Heating (Pilot M).

a. Comments

CUB, the CEOs, and the City of Minneapolis expressed support for Pilot O. The CEOs recommended prioritizing weatherization and energy efficiency over carbon capture technologies, and the City of Minneapolis advocated a similar modification.

b. Commission Action

The Commission is persuaded that Pilot O should be approved because it provides an opportunity for more small- and medium-sized businesses to reduce their GHG emissions. It also satisfies the NGIA requirement that the first innovation plan filed "must include a pilot program to provide thermal energy audits to small- and medium-sized businesses in order to identify opportunities to reduce or avoid greenhouse gas emissions from natural gas use."[24]

The Commission appreciates the CEOs' and the City of Minneapolis's proposed modifications but is not persuaded that some innovative resources should be prioritized over others in Pilot O. Prioritization of certain innovative resources may be appropriate in the future, but at this early stage of plan implementation, CenterPoint should be allowed to use innovative resources that align with participant interest.

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[23] Minn. Stat. § 216B.2427, subd. 8.

[24] Minn. Stat. § 216B.2427, subd. 6.

15. Pilot P – Residential Gas Heat Pumps

Under Pilot P, CenterPoint proposed to fund the development and testing of a small number of combi-space and water heating gas-heat-pump systems in Minnesota homes.

a. Comments

While some commenters supported Pilot P, several strongly opposed it. The Department recommended rejecting Pilot P because, it asserted, electric-air-source heat pumps are more efficient and cost effective than gas heat pumps. And since the technologies serve the same function, the Department argued, there is no reason for CenterPoint to pursue gas-heat-pump technology. If the Commission approved the pilot, however, the Department recommended that CenterPoint maximize the tax incentives available under the federal Inflation Reduction Act (IRA).

The CEOs also recommended rejecting Pilot P. They argued that gas heat pumps do not provide a pathway to full decarbonization and asserted that electric heat pumps are a more scalable, mature, and cost-effective technology. Similarly, the City of Minneapolis opposed the pilot and asserted that gas heat pumps are an expensive technology for reducing emissions compared to other technologies. The City of Minneapolis also noted that installing gas heat pumps would transition electric cooling to gas and argued that Pilot P is inconsistent with the state's goal of reducing GHG emissions. Many public commenters opposed Pilot P for these same reasons and expressed a strong preference for electrification.

In response to comments in opposition to Pilot P, CenterPoint argued that it should be allowed to explore both gas and electric heat pumps in its innovation plan. CenterPoint explained that the technologies have some fundamental differences that could make installation of gas heat pumps preferrable depending on building types or customer preference. CenterPoint also emphasized that gas heat pumps are more efficient than standard gas equipment and could improve gas efficiency, which is consistent with the goals of the NGIA.

CenterPoint disagreed with the assertion that gas heat pumps could not be compatible with a fully decarbonized future. If used with zero or negative GHG fuels, such as certain kinds of RNG, gas heat pumps would emit zero emissions, CenterPoint argued.

Regarding tax incentives available under the IRA, CenterPoint agreed with the Department that it is important to maximize such incentives but argued that it was inappropriate for Pilot P because pursuing the incentives could discourage participation. CenterPoint explained that the total incentive available under Pilot P would be $12,000, but to get that amount, participants would need to pay $4,600 each and have a large enough tax liability to take advantage of the tax credit. Since gas heat pumps are an emerging technology that is not widely adopted, CenterPoint viewed covering 100 percent of participants' costs as the best way to encourage participation.

b. Commission Action

The Commission is persuaded that Pilot P should be approved. Through the pilot, CenterPoint will explore implementing gas heat pumps, an emerging technology, and learn what role these pumps could play, if any, in achieving the NGIA's goals. If CenterPoint is correct that there are building types where gas heat pumps would be preferrable to electric heat pumps, then the technology will likely prove helpful. At the very least, emissions will be reduced for customers that are unwilling to install electric heat pumps because gas heat pumps are more efficient than standard gas equipment. CenterPoint expects Pilot P to involve just six systems, which makes it a comparatively modest pilot proposal that could provide important learning opportunities for an emerging technology.

Regarding the Department's recommendation that CenterPoint be required to maximize IRA tax incentives, the Commission agrees with CenterPoint that requiring participants to pay $4,600 towards installation may deter participation. The Commission will therefore not impose that requirement.

To ensure that the Commission and stakeholders are informed about the pilot, the Commission will require CenterPoint to report on continuous field performance monitoring, bill savings, equipment costs, and installation costs for Pilot P in its annual status reports.

16. Pilot Q – Gas Heat Pumps for Commercial Buildings

Under Pilot Q, CenterPoint proposed to fund the development and testing of a small number of gas-heat-pump systems in commercial buildings.

a. Comments

Pilot Q is similar to Pilot P in that it utilizes gas-heat-pump technology. The CEOs and the City of Minneapolis recommended rejecting Pilot Q for the same reasons they gave for rejecting Pilot P (i.e., the technology does not provide a pathway to full decarbonization and is not cost effective). The Department, however, took a different position on Pilot Q and recommended approving the pilot with a modification to maximize utilization of IRA tax incentives to cover installation costs for participants. CenterPoint opposed the modification and stated that there is uncertainty about whether projects under Pilot Q would be eligible for IRA benefits. But even if they were, the dollar amount of any benefits would be a fraction of the participant copay.

b. Commission Action

The Commission is persuaded that Pilot Q should be approved. As with Pilot P, CenterPoint will utilize a relatively modest budget to explore the benefits of emerging gas-heat-pump technology. This technology has the potential to reduce GHG emissions in buildings where the use of other technology is impracticable or undesirable for building owners. The Commission will not require CenterPoint to attempt to maximize possible IRA benefits for the project because doing so could deter customer participation.

17. Pilot R – Industrial and Large Commercial Greenhouse Gas Audit

Under Pilot R, CenterPoint proposed to expand its existing CIP Process Efficiency and Commercial Efficiency projects to include identification of non-CIP GHG reduction measures and payment of incentives for the installation of identified non-CIP measures.

a. Comments

Few commenters specifically addressed Pilot R. The City of Minneapolis supported the pilot, but given its small size, questioned how well it would demonstrate the potential benefits of GHG audits on a bigger scale. The Department recommended approving the pilot, subject to additional screening criteria, but asserted that CenterPoint's proposed incentive level for the pilot was unreasonably high.

In response, CenterPoint argued that the proposed incentive level is necessary to drive customer action and noted that even with that incentive level, Pilot R will result in some of the lowest-cost GHG savings in the innovation plan. As to the City of Minneapolis's point about size of the pilot, CenterPoint responded that if its request for budget flexibility is approved, it would endeavor to increase resources for pilots with higher customer demand.

b. Commission Action

The Commission is persuaded that Pilot R should be approved because expanding upon CenterPoint's CIP programs for industrial and large commercial customers will provide learning opportunities for reducing GHG emissions from these types of customers. The Commission is also persuaded that CenterPoint's proposed incentive level is appropriate to encourage customer participation, and as discussed above, the Commission is not adopting the Department's recommendation to approve certain pilots subject to additional screening criteria.

C. R&D Project Modifications

CenterPoint's innovation plan includes seven R&D pilot proposals for the first two years of the plan. The R&D pilots include:

- **CenterPoint Minnesota Net Zero Study:** CenterPoint proposed to conduct a study to help it and interested parties better understand the different pathways for CenterPoint to reach net zero emissions by 2050.

- **Weatherization Blitzes**: CenterPoint proposed to test intensive, novel, and community-based marketing and outreach approaches to increase participation in CenterPoint's CIP/ECO weatherization offerings.

- **High Performance Commercial New Construction Building Envelope Initiative:** CenterPoint proposed to test a multi-prong strategy to address barriers to integrating high-performance commercial building envelopes in new commercial construction.

- **Assessing Next-Generation Micro-Carbon Capture for Commercial Buildings:** This proposed R&D pilot will investigate the carbon-capture effectiveness and heat-recovery efficiency of CleanO2's next generation CarbinX units (version 4.0). This pilot complements the full pilot Carbon Capture Rebates for Commercial Buildings (Pilot H) which will incentivize installation of version 3.0 units.

- **Green Ammonia Novel Technology:** This pilot will support testing of a Modular One Vessel Ammonia Production System for green ammonia, which has the potential to improve production efficiency and reduce costs for green ammonia production.

- **RNG Potential Study:** CenterPoint will study three regions in its Minnesota service territory for potential development of an RNG production facility. Regions will be selected based on the potential for production of RNG feedstock and the feasibility of accepting substantial quantities of RNG into CenterPoint's system.

- **Utilization of Green Ammonia for Thermal Energy Applications:** CenterPoint proposes to support research into how green ammonia may be used in industrial-scale burner applications. The primary goal is to determine operating ranges and burner concepts that can be applied to industrial burners used in grain drying and boilers used for district heating.

CenterPoint proposed to allocate a portion of its R&D budget to these seven pilots over the first two years of the plan and use the remainder of the R&D budget for future R&D projects. CenterPoint stated that by reserving some of the R&D budget until after it begins implementing its innovation plan, it will be able to use what it has learned about deploying innovative resources to create more effective R&D projects.

1. Comments

Commenters supported, with limited exceptions and suggested modifications, CenterPoint's proposed R&D projects. The Department and the CEOs raised concerns about the unallocated portion of the R&D budget and opposed the project that would explore next generation CarbinX units. As with Pilot H, the Department argued that the CarbinX R&D project should proceed through ECO.

The CEOs and CUB suggested modifying the first R&D project, the Minnesota Net Zero Study, to include an estimation of CenterPoint's GHG emissions from providing natural gas service and a description of how the innovation plan, as a whole, helps CenterPoint reduce GHG emissions to support the economy-wide timeline and incremental goals established by the legislature. CenterPoint supported this modification.

To assuage commenters' concerns about the unallocated portion of the R&D budget, the CEE advocated for requiring CenterPoint to propose R&D projects in its annual status reports and receive Commission approval to invest in any such projects. CenterPoint and the Department supported this recommendation.

2. Commission Action

The Commission is persuaded that CenterPoint's proposed R&D projects should be approved. The projects are designed to yield useful information about innovative resources and provide further insights into how CenterPoint might decarbonize its natural gas service.

The Commission agrees with commenters that it would be helpful for CenterPoint to modify its Minnesota Net Zero Study to include a description of how the innovation plan will help

CenterPoint reduce its GHG emissions. Also, requiring CenterPoint to receive Commission approval for additional R&D projects is appropriate. The Commission will adopt both modifications.

For the same reasons given for Pilot H, the Commission is unpersuaded by the Department's argument that the CarbinX R&D project should proceed through ECO.

D. Request for Budget Flexibility

CenterPoint requested budget flexibility to spend up to twenty-five percent more than budgeted for pilots with higher-than-expected expenditures without seeking additional approval from the Commission. CenterPoint modeled this proposal on the flexibility provided in ECO. Instead of increasing its innovation plan budget, CenterPoint would reallocate funding from pilots with lower-than-expected expenditures, which could be caused by various factors including low pilot participation. CenterPoint stated that its proposal for budget flexibility would not cause the innovation plan, as a whole, to exceed the statutory cost cap.

1. Comments

Commenters were initially divided on CenterPoint's budget flexibility proposal. Those opposed raised various concerns and suggested modifications. For example, the OAG argued that approving budget flexibility would allow CenterPoint to spend up to the statutory cost cap, which would be more than the approved NGIA budget. In recognition of this concern, CenterPoint supported a modification that would require CenterPoint to not exceed the approved budget for its NGIA plan.

CenterPoint also agreed to several modifications based on CUB's recommendations. After stating that it was reasonable for CenterPoint to request some flexibility in describing budgeted costs, CUB recommended against allowing too much flexibility. CUB's concern was that large shifts in budgets could alter the size and cost effectiveness of pilot programs. As an alternative to denying CenterPoint's request, CUB recommended modifications—such as requiring CenterPoint to explain in annual review filings how budgets were modified and why such modifications were warranted—that it argued would ensure CenterPoint's budget flexibility was reasonably limited. CenterPoint supported many of CUB's proposed modifications.

Like CUB, the Department acknowledged that there would be some fluctuation in pilot budgets throughout the plan's implementation but argued that twenty-five percent budget flexibility was too high. The Department asserted that CenterPoint had a financial incentive to shift funding from some pilots to others, a concern the OAG also expressed, and recommended denying CenterPoint's request.

To address this concern, CenterPoint agreed to a modification that would require it to notify the Department and the OAG when it exercises budget flexibility. If the Department or the OAG objected to the use of budget flexibility, CenterPoint would have to seek approval through filing a request in this docket or through its annual status reports.

The OAG raised an additional issue concerning fair cost allocation for pilot programs among customer classes. CenterPoint agreed to a modification that would require it to ensure its cost recovery mechanism trues up customer class allocations to match actual pilot spending.

CenterPoint clarified that approving budget flexibility would not constitute an advanced determination of prudence. To recover costs under the NGIA, CenterPoint must establish that those costs were prudently incurred.

2. Commission Action

The Commission is persuaded that CenterPoint's request for budget flexibility should be approved as modified in the ordering paragraphs below. With budget flexibility, CenterPoint will be able to reallocate some funding to bolster pilot programs that are performing better than expected. The Commission agrees with CenterPoint that waiting for budget approval through filing an annual plan modification could disrupt successful pilot delivery, but imposing conditions on CenterPoint's use of the flexibility is also warranted to ensure that any reallocation is consistent with the NGIA. The Commission appreciates commenters' suggestions on this proposal and CenterPoint's willingness to adopt them.

E. Cost Recovery Proposal

The NGIA provides that prudently incurred costs under an approved plan are recoverable in three ways:

- via the utility's purchased gas adjustment (PGA);
- in the utility's next general rate case; or
- via annual adjustments.[25]

CenterPoint proposed to use all three methods of recovery. To recover certain fuel costs—such as for RNG and for purchasing electricity under Pilot D—CenterPoint proposed using the PGA mechanism but noted that a rule variance to the applicable PGA rules would be needed to use that method of recovery. CenterPoint explained that the Commission's rules define "cost of purchased gas" and "cost of fuel consumed in manufacture of gas" in such a way that RNG purchases and electricity purchases for Pilot D do not meet the respective definitions.[26]

For its remaining innovation plan costs, CenterPoint proposed using the other two cost recovery methods in a manner similar to how it recovers its ECO costs. Certain costs would be included in CenterPoint's rate case, and it would use the annual rider mechanism to match actual NGIA expenses with recoveries.

1. Comments

Commenters supported or did not take a position on CenterPoint's cost recovery proposal, including granting CenterPoint a variance to the applicable PGA rules. CUB recommended that

[25] Minn. Stat. § 216B.2427, subd. 2(c).

[26] Minn. R. 7825.2400, subparts 10 and 12.

CenterPoint include relevant information from monthly PGA filings and annual automatic adjustment (AAA) reports in its annual status reports to allow for comprehensive review of the cost recovery mechanism. CenterPoint supported this modification.

CUB also recommended that CenterPoint be required to recover the costs of upgrading equipment for RNG pilots, if any, in a rate case. CUB argued that reviewing recovery of these costs as part of a rate case would ensure that such investments are only recovered if prudent and cost effective. CenterPoint opposed this recommendation and noted that all three methods of recovery in the NGIA include a prudency review.

In support of its variance request, CenterPoint explained that the Commission's rules require the Commission to make three determinations before granting a variance, including:

- enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;
- granting the variance would not adversely affect the public interest; and
- granting the variance would not conflict with standards imposed by law.[27]

CenterPoint asserted that the first requirement is satisfied, because if it is not able to recover certain fuel costs through the PGA mechanism, its cost recovery would be delayed and thus its cost of doing business would increase significantly. Intergenerational inequalities would also result, CenterPoint argued, because customers who receive the benefits of the RNG purchases might not be the same customers who pay the costs associated with those resources. Accordingly, CenterPoint argued, not granting the variance would impose an excessive burden on it and its customers.

Regarding the second requirement, CenterPoint stated that its proposed recovery structure is similar to how it already recovers costs from customers, and it is not seeking to recover more costs than are reasonable or permitted by the NGIA. CenterPoint asserted that granting the variance would therefore not adversely affect the public interest.

Finally, CenterPoint argued that the third requirement is met because the variance does not conflict with standards imposed by law. On the contrary, CenterPoint asserted, granting the variance would allow it to recover costs in accordance with the NGIA and as permitted by Minn. Stat. § 216B.16, subd. 7.

2. Commission Action

The Commission is persuaded that CenterPoint's proposed method of cost recovery is consistent with the NGIA and should be approved. The Commission also agrees with CUB that information from monthly PGA filings and CenterPoint's AAA reports would be helpful for review of the PGA cost-recovery mechanism, and the Commission will therefore require CenterPoint to include that information in its annual status reports.

[27] Minn. R. 7829.3200, subpart 1.

The Commission will not require CenterPoint to pursue recovery through a rate case for the potential purchase of upgrading equipment for RNG pilots. All three methods of cost recovery include a prudency review, which ensures that CenterPoint will only recover prudently incurred costs.

As to CenterPoint's variance request, the Commission agrees with CenterPoint that the requirements to grant a variance are met for purposes of recovering certain fuel costs. First, enforcing the rule would impose an excessive burden on CenterPoint and its customers by delaying cost recovery and potentially causing some customers to pay for fuel costs that they did not benefit from. Second, granting the variance will not adversely affect the public interest. Third, granting the variance will not conflict with standards imposed by law. The Commission will therefore grant the variance.

To prevent CenterPoint from potentially over recovering for capital expenditures that may not occur, the Commission will require CenterPoint to incorporate in its annual filings a true-up adjustment that reconciles revenues recovered to actual costs.

F. Cost-Effectiveness Objectives

The NGIA directs the Commission to establish cost-effectiveness objectives for innovation plans based on the cost-benefit test for innovative resources developed in the Commission's frameworks order.[28] CenterPoint's proposed cost-effectiveness objectives fall into four categories: perspectives, environment, socioeconomic, and innovation. Below are excerpts from the proposal:[29]

> **Perspectives**
> - Overall GHG savings achieved by all approved pilots is achieved at a cost of no more than $200/MTCO2e.[30] For this objective, costs are measured on a lifetime basis using the utility cost test and GHG savings are also measured on a lifetime basis.
> - At least 40 percent of residential units served by the Residential Deep Energy Retrofit and Electric Air Source Heat Pumps Pilot and the Weatherization Blitzes R&D Pilot qualify as low-income, as that term is defined in CIP/ECO, or are located in a disadvantaged community, as that term is defined for the Inflation Reduction Act programs.
> - Over the course of the five-year Plan, CenterPoint Energy supports the development of four new sources of low-carbon fuels produced in Minnesota. This may include one or more anaerobic digesters that produces RNG, projects that produce hydrogen via power-to-hydrogen, biogas projects, or projects that create ammonia via power-to-ammonia.

[28] Minn. Stat. § 216B.2427, subd. 2(e).

[29] The entire updated cost-effectiveness objectives proposal can be found in Exhibit B of CenterPoint's reply comments dated March 15, 2024.

[30] Metric tons of carbon dioxide equivalent.

Environment

- The Plan achieves overall lifetime GHG emissions reductions equivalent to 13 percent of emissions from CenterPoint Energy's 2020 sales. For purposes of this objective, CenterPoint Energy's 2020 sales include only sales to non-exempt customers and no transport volumes.
- Over the five-year term of the Plan, the Plan achieves annual, first-year GHG emissions reductions equal to one percent of emissions from CenterPoint Energy's 2020 sales. For purposes of this objective, CenterPoint Energy's 2020 sales include only sales to non-exempt customers and no transport volumes. Annual, first-year GHG emissions reductions are the sum of GHG reductions expected to be achieved by all projects implemented under the Plan in the first full year of their operation.
- In year five of the Plan, CenterPoint Energy has reduced annual emissions from sales of natural gas by 51,000 metric tons as a result of low-carbon fuels included in the NGIA Plan. This goal includes reductions from RNG, power-to-hydrogen, biogas, and power-to-ammonia provided to non-exempt sales customers.
- To support the state's renewable energy goal, CenterPoint Energy procures 610,000 dekatherms of sales gas from renewable resources. This goal includes RNG, biogas, power-to-hydrogen, and power-to-ammonia provided to non-exempt sales customers.
- To support the state's economy-wide net zero GHG emissions goal, CenterPoint Energy completes an analysis of pathways that would allow it to achieve net zero emissions by 2050. CenterPoint Energy anticipates satisfying this goal through the proposed R&D pilot, CenterPoint Energy Minnesota Net Zero Study.

Socioeconomic

- The Plan supports 4 projects that satisfy Inflation Reduction Act requirements around prevailing wages and support for apprenticeships.

Innovation

- The Plan supports projects using at least six of the eight innovative resources.
- 100 percent of completed R&D projects result in a report summarizing learnings and suggesting next steps that will be filed with the Commission and the Company take action on learnings that are within CenterPoint Energy's control and reasonable to pursue, such as incorporating insights into a subsequent NGIA plan or other Company initiative.

The NGIA provides for an increase in budget for subsequent innovation plans if the Commission determines the utility has successfully achieved a plan's cost-effectiveness objectives.[31] To determine whether it has been successful, CenterPoint proposed that the Commission approve additional funding if CenterPoint achieves a majority of its cost-effectiveness objectives.

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[31] Minn. Stat. § 216B.2427, subd. 3(c) and (d).

1. Comments

Commenters took various positions on CenterPoint's cost-effectiveness objectives. The Department recommended against adopting CenterPoint's majority test for determining whether it should receive additional funding because, the Department argued, approving a majority test could incentivize CenterPoint to focus on the success of some pilots at the expense of others. Instead, the Department advocated for pilot-level and plan-level criteria, including a GHG-reduction evaluation for each pilot. CUB and the CEOs also recommended evaluating pilots individually.

Like the Department, CUB, the CEOs, and the City of Minneapolis opposed a majority test. As an alternative, CUB advocated for a holistic approach to plan evaluation to allow the Commission to give greater weight to certain metrics or variables. CenterPoint ultimately supported adopting a holistic evaluation methodology.

CUB asserted that the plan the Commission ultimately approves could impact the cost-effectiveness objectives. For example, modifications to CenterPoint's proposed innovation plan could affect estimates of emissions reductions and geologic-gas savings, which could make some cost-effectiveness objectives unreasonable. CUB initially argued that the Commission should wait until it has established the parameters of the plan to render a decision on cost-effectiveness objectives.

But to avoid administrative inefficiency, CUB ultimately recommended that the Commission establish cost-effectiveness objectives when it approves the plan but require CenterPoint to make a subsequent compliance filing with updated objectives. The subsequent filing would be subject to a thirty-day negative check-off period in which commenters may raise concerns about the updated objectives. If no parties object, the cost-effectiveness objectives would go into effect. CenterPoint agreed with CUB that a subset of the proposed objectives would need to be recalibrated or modified to account for any changes to the plan and supported the modification.

2. Commission Action

The Commission will approve CenterPoint's proposed cost-effectiveness objectives as modified in the ordering paragraphs below. The Commission is persuaded that a holistic evaluation methodology is preferrable to a majority test for determining whether CenterPoint has successfully achieved its cost-effectiveness objectives. A holistic approach gives the parties and the Commission more flexibility in subsequent evaluations and helps ensure that CenterPoint does not inappropriately prioritize some pilots over others.

The Commission will require CenterPoint to make a compliance filing within thirty days with updated cost-effectiveness objectives and give commenters an additional thirty days to file any objections. This filing requirement will make certain that the plan and its cost-effectiveness objectives are appropriately aligned.

Finally, in recognition of the NGIA's throughput goal, the Commission will require CenterPoint to include an additional cost-effectiveness objective as follows:

The plan as a whole achieves material reductions to the overall amount of natural gas produced from geologic sources delivered to CenterPoint customers compared to the amount that would have been delivered absent CenterPoint's plan.

G. Annual Status Reports

As discussed above, the NGIA requires utilities with an approved innovation plan to file annual reports on work completed under the plan.[32] CenterPoint proposed to file its annual reports on June 1 each year and include in the reports plan activity that occurred in the prior calendar year.

1. Comments

No commenters opposed CenterPoint's annual reporting proposal, and CUB and the CEOs expressly supported it. CUB recommended that CenterPoint include in its annual reports updates on IRA implementation and pilot-specific data on reductions in GHG emissions. CenterPoint agreed to include this information in its annual reports.

2. Commission Action

The Commission agrees with commenters that CenterPoint's annual reporting proposal should be approved. The proposal is consistent with the NGIA and will provide valuable information to the Commission and stakeholders on how the various pilots and programs in the innovation plan are progressing. The Commission also agrees with CUB's recommendations and will require CenterPoint to provide updates on IRA implementation and pilot-specific data on GHG emissions reductions.

To further clarify what information CenterPoint should include in its annual status reports, the Commission will require CenterPoint to propose reporting requirements within thirty days and will delegate authority to the Executive Secretary to approve the compliance filing via notice if no objections are filed within thirty days of CenterPoint's filing.

The Commission will also require CenterPoint to update its list of reporting requirements for new or modified pilots or R&D projects and require CenterPoint to include a similar list of reporting requirements for future NGIA innovation plans. The Commission will delegate authority to the Executive Secretary to update the approved reporting requirements list consistent with decisions made in this and subsequent NGIA-related dockets.

H. Other Plan Modifications

The Commission will direct three additional modifications, which CenterPoint supported, to the innovation plan. First, the Commission will require CenterPoint to purchase and retire the full environmental attributes associated with innovative fuel purchases made through its innovation plan to ensure that environmental benefits resulting from the plan are not claimed for any other program.

[32] Minn. Stat. § 216B.2427, subd. 2(f).

Second, since RNG production could provide an opportunity for Minnesota's small family farms, the Commission will require CenterPoint to consult with the Minnesota Department of Agriculture regarding the possibility of incentivizing more Minnesota small family agricultural operations to participate in the development and sale of RNG. With its first annual status report, CenterPoint shall report on its discussions with the Minnesota Department of Agriculture, and depending on the results of those discussions, propose an R&D project that explores incentives to encourage Minnesota small family farms to participate in RNG markets.

Finally, the Commission will require CenterPoint to prioritize the creation of high-quality jobs and registered apprenticeship opportunities for residents of communities served by CenterPoint, Minnesota residents, and local workers in the implementation of all approved pilot programs as detailed in the relevant ordering paragraph below. This modification furthers the NGIA's goal of "maximiz[ing] the availability of construction employment opportunities for local workers[.]"[33]

I. Future NGIA Plans

1. Comments

For future NGIA plans, the CEOs recommended requiring Center Point to:

- define clear learning objectives and metrics of success for all proposed pilots;
- articulate how the plan will help meet its fair share of state GHG emission reductions; and
- prioritize district energy pilots that meet the statutory definition of this resource.

In response, CenterPoint expressed its support for the CEOs' first recommendation but opposed the other two. CenterPoint agreed that reducing GHG emissions is an important goal of the NGIA but noted that the NGIA is not singularly focused on GHG reduction, and it does not provide all the tools needed to achieve aggressive GHG reduction goals. CenterPoint also generally opposed prioritizing one GHG reducing option, such as district energy, over another to avoid limiting customers' options.

2. Commission Action

It would be helpful for CenterPoint to include clear learning objects and metrics of success for pilots in future NGIA plans, and the Commission will therefore order CenterPoint to include that information. But the Commission is not persuaded that it should adopt the CEOs' other two recommendations.

The CEOs' recommendations are rooted in their broader argument that in the coming years, CenterPoint's reductions in GHG emissions should essentially follow a line trending downward, which ends at zero GHG emissions by 2050. To meet this target, the CEOs advocated for a thirty-percent reduction in CenterPoint's 2020 emissions by 2029, which is far beyond the expected GHG reductions under CenterPoint's plan. The Commission appreciates the CEOs' position but agrees with CenterPoint that the NGIA does not require such reductions.

[33] Minn. Stat. § 216B.2427, subd. 2(a)(11).

Instead of mandating a level of emissions reductions, the NGIA encourages natural gas utilities to explore how to use innovative resources to meet the state's GHG and renewable energy goals. It makes sense that GHG emissions reductions will be more modest under utilities' initial innovation plans as they learn which pilots and innovative resources are most effective. Once CenterPoint knows more about pilot effectiveness and scalability, it will be better positioned to more aggressively reduce its GHG emissions.

The Commission will also not require CenterPoint to prioritize district energy pilots in future NGIA plans at this time. Prioritization of certain innovative resources may be appropriate in the future, but a decision on prioritization should be made after CenterPoint has had an opportunity to implement its plan and share what it learns with the Commission and stakeholders.

ORDER

1. The Commission approves CenterPoint's 2023 Natural Gas Innovation Plan as described by CenterPoint in its reply comments filed March 15, 2024, with the modifications identified below.

Pilot Modifications

2. CenterPoint must obtain the information that was required for the bidders for Pilot C from Dem-Con HZI Bioenergy, LLC.

3. The Commission modifies Pilot C such that the express geographic preferences are as follows:

    a. RNG interconnected with CenterPoint's Minnesota distribution system;
    b. RNG within Minnesota; and
    c. RNG in neighboring regions.

    For purposes of this program, neighboring regions would be participants injecting in an interstate pipeline system that delivers to Minnesota or a distribution system connected to an interstate pipeline that delivers to Minnesota within the states of Iowa, North Dakota, South Dakota, Iowa, Wisconsin and the upper peninsula of Michigan and participants injecting gas in the Northern interstate pipeline in Nebraska and Kansas, north of Demarc.

4. CenterPoint must collect data on dairy cow herd size for RNG purchases from dairy farms and provide that data in their annual status reports. Through its annual status reports, CenterPoint must provide an analysis that compares the farm sizes participating in Pilot C to the statewide average, and range, of herd sizes.

5. CenterPoint must specify the source of additional power, including any green tariff or power purchase agreement that it will use to procure the power, that it will use for Pilot D in a compliance filing after issuance of final Treasury regulations.

6. The Commission modifies Pilot E to require a minimum amount of dekatherms of natural gas savings of at least 136,000 dekatherms over the lifetime of the project for customers to qualify for the Pilot E Power-to-Hydrogen Archetype.

7. CenterPoint must include in its annual filings a description of how it is working with its customers to identify opportunities to work on a hydrogen project for an industrial process customer within the Pilot E Power-to-Hydrogen Archetype.

8. CenterPoint must include in its annual filings information on environmental benefits of Pilot F including, but not limited to, the review period of the annual filing, the number of customers determined to have zero leaks, the average leak rate per screened customer, the maximum leak rate for screened customers, and the minimum leak rate for screened customers.

9. The Commission modifies Pilot F to include the evaluation of both indoor piping and appliances to the extent feasible to be determined by CenterPoint in consultation with the vendor selected for the pilot.

10. As part of its annual status report, CenterPoint must provide information on the number of carbon offsets purchased by CenterPoint as part of Pilot G. Beginning with CenterPoint's second annual status report, CenterPoint must provide, to the best of its ability, the number of new trees planted by Green Cities Accord in the previous year and the average cost of those new trees.

11. The Commission approves Pilot H and directs CenterPoint to begin pilot implementation after the completion of the ECO R&D CarbinX project.

12. The Commission approves Pilot I as proposed but requires CenterPoint to file the results of its feasibility study for Pilot I in an annual report or in a separate filing in Docket No. 23-215 for Commission review and approval prior to implementation if the feasibility study indicates that the total costs will exceed plan estimates by more than ten percent or lifetime greenhouse gas reductions will be less than 90 percent of what was estimated in the approved plan. Pilot I's feasibility study results must include, but are not limited to, at least the following information:

    a. a description of the geothermal system's characteristics (including assumed heating capacity, location, and lifespan), the type of geothermal technology to be installed, the suitability of the proposed location for the installation, the number and types of buildings to be connected, and the customers that would be served by the system;

    b. a description of the project costs, broken down by installation, equipment, and operation and maintenance costs while taking into account any incentives, rebates, and tax credits assumed to reduce these costs; and

    c. a description of the estimated benefits of the project, including throughput reduction, efficiency gains, load management possibilities, and customer financial benefits.

13. The Commission approves Pilot I with the requirement to develop monitoring and evaluation plans to track system performance, emissions reductions, identify potential issues, and optimize operations.

14. CenterPoint must file additional information with its first annual status report about how it will facilitate stakeholder and community engagement for Pilot I. This discussion must detail how CenterPoint will engage with potential host communities to inform decisions about the project location, as well as a description of stakeholder and community engagement CenterPoint has engaged in to date.

15. CenterPoint must issue a request for interest (RFI) to solicit feedback from communities and developers interested in installing and/or operating a networked geothermal system and include RFI responses and the corresponding sites in CenterPoint's feasibility study for Pilot I.

16. CenterPoint must provide information and updates on the RFI process and responses in annual NGIA status reports, including how CenterPoint considered opportunities to install a networked geothermal system in a low-income and/or environmental justice area and in areas of its system with upcoming pipe replacements and upgrades along with other considerations including the suitability of sites from an engineering and technological perspective and customer preferences.

17. Pilot J does not count toward the statutory 20% district energy cap unless the resulting district energy system meets the statutory definition.

18. CenterPoint must offer customers the option to include a full electrification/decarbonization scenario in the feasibility study for Pilot J and include the number of customers who choose to study a full decarbonization/electrification scenario in the annual status report filing.

19. Pilot K does not count toward the statutory 20% district energy cap unless the resulting district energy system meets the statutory definition.

20. The Commission modifies Pilot L as follows:

    a. Pilot L must not be limited to hybrid heating systems.
    b. CenterPoint must consider including geothermal heat pumps.
    c. CenterPoint must collect data on how often gas backups are needed in any hybrid heat pump systems included.

21. CenterPoint must modify Pilot M to collect data on how often gas backups are needed in the subset of hybrid heat pump systems included in CenterPoint's measurement and verification plan.

22. CenterPoint must monitor the number and type of customers that enroll in Pilot M and report its findings in annual status reports. If CenterPoint finds that a disproportionately low number of participants are small businesses or are located in environmental justice areas, CenterPoint must include a discussion in its annual status report of the potential causes of lower participation by small businesses and businesses located in environmental justice areas and discuss whether program modifications are warranted to increase participation by those groups.

23. CenterPoint must report on continuous field performance monitoring, bill savings, equipment costs, and installation costs for Pilot P in its annual status reports.

Research and Development (R&D) Project Modifications

24. CenterPoint's R&D project #1, "CenterPoint Energy Minnesota Net Zero R&D Study," must include an estimation of CenterPoint's greenhouse gas emissions resulting from providing natural gas service to end-use customers in Minnesota based on the NGIA measure of lifecycle greenhouse gas emissions and a description of how the plan, as a whole, helps CenterPoint reduce greenhouse gas emissions to support the economy-wide timeline and incremental goals established by the legislature.

25. CenterPoint must propose R&D projects to the Commission in its annual status reports and receive approval to invest in any R&D projects that were not previously filed and approved as part of CenterPoint's 2023 Natural Gas Innovation Plan.

Request for Budget Flexibility

26. The Commission approves CenterPoint's request for budget flexibility with the following conditions:

    a. Prohibit using budget flexibility to increase the budget of any pilot or pilots in such a way that there is insufficient remaining funding available to enable CenterPoint to fund other pilots up to at least 75% of their approved five-year budgets.
    b. Require any budget increases exceeding 25 percent of the total five-year pilot budget to go through the annual review process or be filed for comment and approval in Docket No. 23-215. CenterPoint's filing must identify any avenues that could be taken to increase enrollment or improve performance of any pilots not achieving quantitative or qualitative expectations and provide a justification for why these options are not reasonable.
    c. Require CenterPoint to describe any use of budget flexibility in annual review filings and explain why the use of budget flexibility was warranted. CenterPoint's justification should include an analysis of pilot performance that takes into account both participation levels and realized cost-effectiveness.
    d. Prohibit any use of budget flexibility until the third year of the plan in order to provide sufficient time for pilots to reach maturity and enroll participants.
    e. Prohibit CenterPoint from using budget flexibility in a way that leaves insufficient funding to fund the full five-year approved budgets of any pilots that are achieving plan expectations in terms of total lifecycle GHG emissions reductions at a cost equal to or less than estimated in the plan at the time that the budget flexibility is used.
    f. Require CenterPoint to ensure the cost recovery mechanism trues up customer class allocations to match actual pilot spending.
    g. Segment CenterPoint's exercise of budget flexibility between renewable natural gas, biogas, hydrogen produced via power-to-hydrogen, and ammonia produced via power-to-ammonia investments and all other investments and only allow exercises of budget flexibility within each segmented category. Budget flexibility can only be used to reallocate funding within pilots in the segment.

h. Require CenterPoint to notify the Department and the Office of the Attorney General–Residential Utilities Division when it exercises budget flexibility without a modification. If no written response is received from the Department or an Assistant Attorney General in the Residential Utilities Division within 30 days, CenterPoint shall be authorized to engage in budget flexibility subject to the modified terms. If either the Department or an Assistant Attorney General in the Residential Utilities Division objects to the use of budget flexibility, CenterPoint must make a filing with the Commission to seek approval of budget flexibility in Docket No. 23-215 or may seek a modification to the pilot in question through annual review filings.

i. Any budget flexibility shall not allow CenterPoint to exceed its approved budget for the full NGIA plan.

Cost Recovery Proposal

27. The Commission approves CenterPoint's cost recovery proposal, including the requested five-year variance to recover renewable natural gas costs and the costs associated with electricity used to create hydrogen through the purchased gas adjustment (PGA).

28. CenterPoint must include relevant information from monthly PGA filings and annual automatic adjustment (AAA) in its innovation plan annual reports.

29. CenterPoint must incorporate, in its annual filing, a true-up adjustment that reconciles revenues recovered to actual costs.

Cost-Effectiveness Objectives

30. The Commission approves CenterPoint's proposed cost-effectiveness objectives.

31. The Commission will adopt a holistic evaluation methodology for reviewing plan cost effectiveness and determining whether CenterPoint's next innovation plan may utilize the increased incremental cost cap for the Company's next innovation plan under Minn. Stat. § 216B.2427, subd. 3(c).

32. CenterPoint must file a compliance filing with updated cost-effectiveness objectives within 30 days of this order, subject to a 30-day negative check-off. If no parties raise disagreements with the updated objectives within 30 days of CenterPoint's filing, the comment period will close and the cost-effectiveness objectives will go into effect. If any filed comments raise contested issues, the Commission will issue a notice of comment period and the matter will be brought to an agenda meeting.

33. The Commission modifies CenterPoint's first cost-effectiveness objective under the "environment" category of objectives to be based on a total lifetime greenhouse gas emissions reduction goal. In its compliance filing with updated cost-effectiveness objectives, CenterPoint must propose a revised goal based on total estimated lifetime greenhouse gas emissions reductions of the plan as approved.

34. CenterPoint must include the following cost-effectiveness objective that supports the NGIA's throughput goal (Minn. Stat. § 216B.2427, subd. 10) in its compliance filing updating its cost-effectiveness objectives:

> The plan as a whole achieves material reductions to the overall amount of natural gas produced from geologic sources delivered to CenterPoint customers compared to the amount that would have been delivered absent CenterPoint's NGIA plan.

Annual Status Reports

35. The Commission approves CenterPoint's proposed plan for filing its annual status reports with the program year beginning on the date of this order, and annual reports submitted each year on June 1, reflecting the activity occurring in the prior calendar year.

36. CenterPoint must provide updates on IRA implementation and pilot-specific data on greenhouse gas emissions reductions in annual status report filings.

37. Within 30 days of this order, CenterPoint must propose reporting requirements for its NGIA innovation plan's annual status reports. The proposed list of reporting requirements shall include content required by the NGIA and relevant Commission Orders, and shall clearly articulate what information will be provided for each individual pilot and research and development project (including updates on progress, project results, project cost and budget impacts, and relevant updates to cost-benefit metrics using project data), and the plan in aggregate. CenterPoint may file earlier as a joint filing with relevant stakeholders in this Docket, including the Department. The Commission delegates authority to the Executive Secretary to approve the compliance filing via notice if no objections are filed within 30 days of the Company's filing.

    Additionally:

    a. CenterPoint must propose updates to its list of reporting requirements when proposing new, or modified, pilots and/or research and development projects.
    b. CenterPoint must file a similar list of reporting requirements for its NGIA annual status reports with future NGIA innovation plans.
    c. The Commission delegates authority to the Executive Secretary to update the approved reporting requirements list consistent with decisions made in this and subsequent NGIA-related dockets.

Other Plan Modifications

38. CenterPoint must purchase and retire on behalf of its Minnesota customers the full environmental attributes associated with innovative fuel purchases made through its NGIA plan.

39. CenterPoint must consult with the Minnesota Department of Agriculture regarding the possibility of incentivizing more Minnesota small family agricultural operations to participate in the development and sale of RNG. With its first annual status report, CenterPoint shall report on its discussions with the Minnesota Department of Agriculture and, depending on the results of these discussions, propose an R&D project that explores incentives to encourage Minnesota small family farms to participate in RNG markets.

40. CenterPoint must prioritize the creation of high-quality jobs and registered apprenticeship opportunities for residents of communities served by the utility, Minnesota residents and local workers in the implementation of all approved pilot programs as follows:

   a. Require that the RNG producer identified in Pilot B (Dem-Con HZI Bioenergy LLC) demonstrate that the facility will maximize creation of high-quality jobs and registered apprenticeship opportunities for residents of communities served by the utility and local workers to the extent feasible (see Minn. Stat. § 216B.2422 Subd. 1(h) for definition of local workers).
   b. Give preference to Pilot C bidders that commit to maximizing creation of high-quality jobs and registered apprenticeship opportunities for residents of communities served by the utility and local workers in construction of RNG production and associated facilities including pipelines.
   c. Employ contractors to build Pilots D and I that commit to maximizing creation of high-quality jobs and registered apprenticeship opportunities for residents of communities served by the utility and local workers.
   d. Encourage participants in Pilots E, F, H, J, and K-R to employ contractors that maximize creation of high-quality jobs and registered apprenticeship opportunities for residents of communities served by the utility and local workers to the extent feasible and prioritize financial support for participants that commit to do so.

Future NGIA Plans

41. In future NGIA plans, CenterPoint must define clear learning objectives and metrics for success for all proposed pilots.

This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Will Seuffert
Executive Secretary

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CERTIFICATE OF SERVICE

I, Mai Choua Xiong, hereby certify that I have this day, served a true and correct copy of the following document to all persons at the addresses indicated below or on the attached list by electronic filing, electronic mail, courier, interoffice mail or by depositing the same enveloped with postage paid in the United States mail at St. Paul, Minnesota.

Minnesota Public Utilities Commission
ORDER APPROVING NATURAL GAS INNOVATION PLAN WITH MODIFICATIONS

Docket Number **G-008/M-23-215**
Dated this 9th day of October, 2024

/s/ Mai Choua Xiong

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

SOCAL GAS – CLEAN FUEL APPLICATION AUGUST 2022

EXHIBIT 1206

November 2025

Company: Southern California Gas Company (U 904 G)
Proceeding: 2024 General Rate Case
Application: A.22-05-015
Exhibit: SCG-12-R

REVISED

PREPARED DIRECT TESTIMONY

OF ARMANDO INFANZON

(CLEAN ENERGY INNOVATIONS (CEI))

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

August 2022

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APPENDICES

SUMMARY

Clean Energy Innovations (In 2021 $, in 000s)			
	2021 Adjusted-Recorded	**TY2024 Estimated**	**Change**
Total Non-Shared Services	28,461	47,223	18,762
Total Shared Services (Incurred)	0	0	0
Total O&M	**28,461**	**47,223**	**18,762**

Summary of Requests

Southern California Gas Company (SoCalGas or Company) is requesting $47.223 million for Test Year (TY) 2024 Operations and Maintenance (O&M) costs associated with Clean Energy Innovations (CEI), an increase of $18.762 million over Base Year (BY) 2021 levels. In sum, CEI's O&M costs cover a variety of workstreams aiming to promote and innovate transformational clean energy products and technologies, including:

- Implementation of SoCalGas's sustainability strategy to advance California's climate goals and align with the United Nations' Sustainable Development Goals;
- Development of Clean fuels infrastructure, which accelerates the transition to clean energy and supports SoCalGas's sustainability strategy in alignment with the State's climate objectives;
- Creation of the Clean Energy Innovations Project Management Office (PMO) to support the expected growth in clean energy-related projects and tasks, including project governance and implementation to facilitate continued project portfolio alignment with CEI's goals; and
- Research Development & Demonstration (RD&D) Program and related activities that advance and champion technologies and that support widespread access to clean, affordable, and reliable energy for all Californians, including those living and working in environmental and social justice (ESJ) communities.[1,2]

Additional details regarding CEI's O&M requests, including forecast methodology and cost drivers, are discussed below in this testimony.

[1] SoCalGas, "Research, Development, and Demonstration Program 2020 Annual Report," June 2021, available at: https://www.socalgas.com/sites/default/files/2021-06/2020-SoCalGas-RDD-Annual-Report.pdf.

[2] CPUC, "Environmental and Social Justice Action Plan, Version 2.0," April 7, 2022, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/esj-action-plan-v2jw.pdf.

REVISED PREPARED DIRECT TESTIMONY OF
ARMANDO INFANZON
(CLEAN ENERGY INNOVATIONS (CEI))

I. INTRODUCTION

A. Summary of Clean Energy Innovations (CEI) Costs and Activities

My testimony supports the Test Year 2024 forecasts for O&M costs for non-shared services, associated with the four following groups: (1) Sustainability, (2) Clean Fuels Infrastructure Development, (3) Clean Energy Innovations Project Management Office (PMO), and (4) Research Development and Demonstration (RD&D) Program. My testimony also identifies activities associated with capital expenditures for the [H2] Hydrogen Home Project and Hydrogen Refueling Stations related to CEI project development. The capital expenditure forecasts for these projects are referenced in other SoCalGas testimonies, including witness Brenton Guy's Real Estate and Facility Operations testimony (Ex. SCG-19) and witness Michael Franco's SoCalGas Fleet Services testimony (Ex. SCG-18).

As discussed in detail below, CEI supports the development and implementation of innovative technologies that support California's climate policy goals, including the continued use and increased adoption of clean fuels,[3] such as renewable natural gas, hydrogen, and synthetic natural gas, as well as carbon management in support of the State's carbon neutrality goals.[4] Development of clean energy solutions helps customers to adopt low carbon products and services and supports a variety of statewide clean policy commitments,[5] as discussed in detail by witness Naim Jonathan Peress in his Sustainability and Climate Policy testimony (Ex.

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3 "Clean fuels" in this testimony are gases such as clean hydrogen (H_2), renewable natural gas (also referred to as biogas and RNG), synthetic natural gas (also referred to as syngas and SNG), and biofuels, the production and combustion of which can be carbon-neutral or even carbon negative. (*See* , SoCalGas, "Role of Clean Fuels Summary," October 2021, available at: https://www.socalgas.com/sites/default/files/2021-10/Role_Clean_Fuels_Summary.pdf, at p.1.)

4 State of California, Executive Department, EO B-55-18 "Achieve Carbon Neutrality," available at: https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

5 Reducing GHG emissions to 40% below 1990 levels by 2030 (Senate Bill (SB) 32, California Global Warming Solutions Act of 2006), to 80% below 1990 levels by 2050 (State of California, Executive Department, Executive Order (EO) S-03-05); 100% carbon-free electricity by 2045 (SB 100, The 100 Percent Clean Energy Act of 2018); attaining carbon neutrality by 2045 (EO B-55-18), and reducing emissions of short-lived climate pollutants, such as methane, and reducing organic waste disposal by 75% by 2025 (SB 1383).

SCG-02, Chapter 1). CEI also provides support to enhance clean energy system and operational readiness and assists with system resiliency.

Table AI-1 below summarizes my sponsored costs for CEI's groups: Sustainability, Clean Fuels Infrastructure Development, CEI PMO, and RD&D. Additional details regarding these costs, including forecast methodology and support, are discussed in Section IV below.

Table AI-1
Test Year 2024 Summary of Total Costs[6]

Clean Energy Innovations (In 2021 $, in 000s)			
Categories of Management	**2021 Adjusted-Recorded**	**TY2024 Estimated**	**Change**
Sustainability	1,930	1,982	52
Clean Fuels Infrastructure Development	8,195	20,400	12,205
Clean Energy Innovations Project Management Office	297	1,592	1,295
Research Development and Demonstration	18,039	23,249	5,210
Total Non-Shared Services	**28,461**	**47,223**	**18,762**

B. Support To and From Other Witnesses

In addition to sponsoring CEI's costs, my testimony also references the testimony and workpapers of several other witnesses, either in support of their testimony or as cross-referential support for this testimony. Other testimony includes: Naim Jonathan Peress and Michelle Sim's SoCalGas Sustainability and Climate Policy testimony (Ex. SCG-02: Chapter 1 (Climate) and Chapter 2 (Sustainability)); R. Scott Pearson and Gregory S. Flores' RAMP to GRC Integration testimony (Ex. SCG/SDG&E-03, Chapter 2); Maria T. Martinez's SoCalGas Gas Engineering testimony (Ex. SCG-07); Daniel J. Rendler's SoCalGas Customer Services – Field and Advanced Meter Operations testimony (Ex. SCG-14); Brian C. Prusnek's SoCalGas Customer Services – Information testimony (Ex. SCG-16); Michael Franco's SoCalGas Fleet Services testimony (Ex. SCG-18); Brenton Guy's SoCalGas Real Estate and Facility Operations (Ex. SCG-19); and Rae Marie Yu's Regulatory Accounts (Ex. SCG-38).

[6] As described in the Angeles Link Application, costs associated with the Angeles Link application are excluded from the request in this GRC.

C. Organization of Testimony

My testimony focuses primarily on non-shared service costs addressing key activities for the four following areas: (1) Sustainability, (2) Clean Fuels Infrastructure Development, (3) Clean Energy Innovations Project Management Office, and (4) RD&D.

My testimony is organized as follows:

- Introduction
- Risk Assessment and Mitigation Phase Integration
- Sustainability And Safety Culture
- Non-Shared Costs
  - Sustainability
  - Clean Fuels Infrastructure Development
    - Business Development
    - Clean Fuels Power Generation
    - Carbon Capture, Utilization and Sequestration (CCUS) Front End Engineering Design (FEED) Study Program
    - Clean Fuels Operational Readiness Program
    - Clean Fuels Transportation Program
  - Clean Energy Innovations Project Management Office (PMO)
  - Research Development & Demonstration (RD&D) Refundable Program
- Capital
  - [H2] Hydrogen Home
  - H2 Refueling Stations
- Conclusions
  - Witness Qualifications

D. Organization Overview

As part of SoCalGas's sustainability strategy and in support of California's goal to deliver increasing amounts of renewable energy and support economy-wide decarbonization, SoCalGas aims to accelerate the energy transition by increasing the delivery of clean fuels, adapting its system for hydrogen, and supporting customer decarbonization.[7] CEI supports a

[7] Michelle Sim's Sustainability testimony (Ex. SCG-02, Chapter 2).

comprehensive portfolio of clean energy solutions that enhances SoCalGas's role as a long-term leader in California's clean energy future. As mentioned above, the groups discussed in this testimony are Sustainability, Clean Fuels Infrastructure Development, CEI PMO, and RD&D. To more clearly present this testimony, a brief overview of these areas is discussed here, with further details provided in Section IV below.

The forecasts in this testimony have been structured to address the costs related to specific functions and programs in the four aforementioned groups under the CEI umbrella. For example, the Clean Fuels Infrastructure Development group supports specific business functions and programs. These functions support a diverse portfolio of activities, whereas these programs support a specific set of activities to meet specific goals for the Company. All activities within CEI support the State's climate policy goals and sustainability plan, as noted in Naim Jonathan Peress and Michelle Sim's Sustainability and Climate Policy testimonies (Ex. SCG-02, Chapters 1 and 2).[8]

E. Sustainability

The Sustainability group is responsible for planning, developing, and tracking near and long-term environmental, social, and governance (ESG) business strategies, with a focus on implementing sustainable business practices to optimize operational activities, while serving customers safely, reliably, and affordably. It works across business units within the Company to facilitate ongoing discussions, workshops, and cross-functional collaboration, in its efforts to implement various sustainability-related initiatives and goals.

The group also monitors and assesses the rapidly changing ESG market, priorities, and requirements, and engages with external stakeholders including community advisory councils, customers, business partners, and ESG community members. The group tracks, monitors, and reports on sustainability goals and Key Performance Indicator (KPI) metrics. Specific projects and tasks performed by Sustainability that drive its costs include:

8 As stated in Michelle Sim's Sustainability testimony (Ex. SCG-02, Chapter 2, at p. 35), "as part of SoCalGas's sustainability strategy and in support of California's goal to deliver increasing amounts of renewable energy and support economy-wide decarbonization, SoCalGas aims to accelerate the energy transition by increasing the delivery of clean fuels, adapting its system for hydrogen, and supporting customer decarbonization."

1. Coordination and execution of ASPIRE 2045[9] sustainability strategy goals through development of procedures, controls, internal communications, governance, and coordination across business units;
2. Continuous assessment and development of sustainable business practices that create near-term emissions reduction benefits and help to meet long-term climate objectives while creating opportunity and equity for employees, customers, and communities;
3. Continuous development and implementation of tools to track progress of sustainability strategies and KPIs for transparency and accountability; and
4. Continuous engagement with external stakeholders and ESG communities to shape sustainability strategies to develop science, policy, and best management practices.

Additional details regarding cost drivers and the funding request for Sustainability are discussed in Section IV.A., below.

1. Clean Fuels Infrastructure Development

The Clean Fuels Infrastructure Development group includes two functions: Business Development and Clean Fuels Power Generation as well as the three following programs: CCUS FEED Study Program, Clean Fuels Operational Readiness Program, and Clean Fuels Transportation Program. Details for each of these functions and programs are described below.

a. Business Development Function

The Business Development function supports development and deployment of cost-effective and environmentally sustainable clean energy solutions, including clean fuels and carbon management, to serve SoCalGas's customers. This function's activities include identifying, analyzing, selecting, and prioritizing clean energy and decarbonization initiatives and projects (including outside of RD&D) to advance the Company's sustainability goals. Business Development plays a vital role in the creation of a strategic long-term planning framework for the clean fuels infrastructure network that can provide customers with increasing amounts of clean energy, as well as developing carbon management solutions, to facilitate the

[9] SoCalGas, "ASPIRE 2045 Climate Commitment," available at: https://www.socalgas.com/sites/default/files/2022-01/SoCalGas_Sustainability_Strategy-final.pdf.

decarbonization of California's energy systems. With active engagement in the State's energy initiatives and working with multiple agencies – including the California Public Utilities Commission (CPUC), California Energy Commission (CEC), California Air Resources Board (CARB), and the California Independent System Operator (CAISO), municipal agencies, universities, national laboratories, and national and international partnership/associations – the Business Development function works with key industry stakeholders in the clean energy sector to initiate and/or collaborate on projects to advance the development of hydrogen, RNG, syngas (SNG), biofuels, and carbon management solutions across multiple end-use applications. The Business Development function also includes RNG infrastructure development activities to facilitate the development and utilization of biogas resources to support the State's policy goals for the growth of renewable gas resources. The function also conducts market research and engages in financial and business analytics activities to collect and analyze information on external clean energy trends, support the long-term capital planning process, and develop and maintain analytical and collaboration tools.

b. Clean Fuels Power Generation Function

This function is responsible for facilitating the adoption of clean fuel power generation resources in alignment with the State's environmental goals[10] and SoCalGas's ASPIRE 2045 and other clean fuels analysis.[11] The team works with various business units and evaluates project feasibility by bringing together operational, permitting, regulatory, financing, and other requirements to create a set of foundational practices that support clean fuels power generation projects. This function provides support to various business units (both customer-facing and operational) within the Company. The Clean Fuels Power Generation's additional activities include clean fuels market transformation (through active collaboration with different areas in the Company, including the RD&D program), development of education and communication

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[10] Reducing GHG emissions to 40% below 1990 levels by 2030 (SB 32) and to 80% below 1990 levels by 2050 (EO S-03-05); 100% carbon-free electricity by 2045 (SB 100); attaining carbon neutrality by 2045 (EO B-55-18); reducing emissions of short-lived climate pollutants, such as methane, and reducing organic waste disposal by 75% by 2025 (SB 1383).

[11] SoCalGas, "The Role of Clean Fuels and Gas Infrastructure in Achieving California's Net Zero Climate Goal," October 2021, available at: https://www.socalgas.com/sites/default/files/2021-10/SCG_Whitepaper_Full-Report.pdf.

materials specific to clean fuel power generation technologies (with respect to tariffs, gas rates, safety considerations, regulatory and technical requirements), and policy support with regards to regulatory, legislative, local, and other policies that may impact clean fuel power generation technologies.

c. CCUS Feed Study Program

The CCUS FEED Study Program will work on activities to develop a CO2 pipeline to support the development of carbon management solutions in Southern California. The CCUS FEED Study Program will address scope, design, and technical specifications, and identify related environmental attributes so that all aspects of the project evaluation undergo a "due diligence" process to help finalize the project scope, technical specifications, and the project's capital investment estimates.

d. Clean Fuels Operational Readiness Program

The Clean Fuels Operational Readiness Program activities will include assessment of the current infrastructure, processes and standards for operational readiness, and identifying gaps in technological, material, operational, safety, workforce, and training standards, with the purpose of achieving safe, effective, and efficient adoption of clean fuels infrastructure into our operations to deliver clean fuels and help California achieve its carbon neutrality goal.

e. Clean Fuels Transportation Program

The Clean Fuels Transportation Program provides information, education, and training regarding Clean Transportation to a variety of stakeholders, including owners of hydrogen fuel cell vehicles (FCVs) and renewable natural gas vehicles (RNGVs), operators of hydrogen and RNGV refueling stations, vehicle and equipment manufacturers, government agencies, policymakers, and others. In response to customer demand, SoCalGas facilitates market adoption of hydrogen and renewable natural gas as transportation fuels in support of California's climate neutrality goals.[12]

Additional details regarding cost drivers and funding requests for Clean Fuels Infrastructure Development are discussed in section IV.B, below.

[12] State of California, Executive Department, EO B-55-18 "Achieve Carbon Neutrality," available at: https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

2. Clean Energy Innovations Project Management Office

The PMO works to establish uniform project management and reporting standards across CEI's project portfolio. The team is responsible for developing and implementing project controls including scope, schedule, financials, risk analysis, and change management with the goal of mitigating risks and increasing the likelihood of project success. Specific activities performed by the PMO that drive costs include development and implementation of: (1) project governance standards for scope, schedule, and cost management; (2) tools for project monitoring and portfolio reporting; and (3) the management of project initiatives. The PMO also implements project management methodologies to align with SoCalGas's clean energy vision, strategy, and goals.[13,14] Additional details regarding cost drivers and funding request for the PMO are in section IV.C.

3. Research Development & Demonstration Refundable Program

SoCalGas's RD&D Program is a refundable program that plays a key role in the research, development, and demonstration of transformational products and technologies that promote decarbonization across the energy delivery value chain and a diversified portfolio of clean energy sources, distributed networks, tools, and applications.[15] The RD&D activities "offer reasonable probability of providing benefit to ratepayers," and support one or more RD&D objectives, including to "improve operating efficiency and reliability and otherwise reduce operating costs."[16]

The RD&D Program collaborates with customers, businesses, manufacturers, academic researchers, and other stakeholders to identify and test potential projects or technologies that will save energy and reduce carbon emissions. The four program areas of focus within the RD&D Program are: Clean & Renewable Energy Resources, Gas Operations, Clean Transportation, and

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13 SoCalGas, "The Role of Clean Fuels and Gas Infrastructure in Achieving California's Net Zero Climate Goal," October 2021, https://www.socalgas.com/sites/default/files/2021-10/SCG_Whitepaper_Full-Report.pdf.

14 SoCalGas, "ASPIRE 2045 Climate Commitment," January 2022, available at: https://www.socalgas.com/sites/default/files/2022-01/SoCalGas_Sustainability_Strategy-final.pdf.

15 SoCalGas, "Research, Development, and Demonstration Program 2020 Annual Report," available at: https://www.socalgas.com/sites/default/files/2021-06/2020-SoCalGas-RDD-Annual-Report.pdf.

16 Pub. Util. Code § 740.1(e)(5).

Clean Energy Applications. Additional details regarding cost drivers and funding request for RD&D Program are addressed in section IV.D, below.

II. RISK ASSESSMENT MITIGATION PHASE INTEGRATION

Certain costs supported in my testimony are driven by activities described in SoCalGas and SDG&E's respective 2021 Risk Assessment Mitigation Phase (RAMP) Reports (the RAMP Report).[17] The RAMP Reports presented assessments of the key safety risks for SoCalGas and proposed plans for mitigating those risks. As discussed in R. Scott Pearson and Gregory S. Flores' RAMP to GRC Integration testimony (Ex. SCG-03/SDG&E-03, Chapter 2), the costs of risk mitigation projects and programs were translated from the RAMP Report into the individual witness areas.

In the course of preparing the CEI GRC forecasts, SoCalGas continued to evaluate the scope, schedule, resource requirements, and synergies of RAMP-related projects and programs. Therefore, the final presentation of RAMP costs may differ from the ranges shown in the RAMP Report. TABLE AI-2 below provides a summary of the RAMP-related costs supported in my testimony.

TABLE AI-2
Summary of RAMP O&M Costs*

Report Cross-Functional Factor (CFF) Chapter	BY 2021 Embedded Costs (in 000s)	TY 2024 Estimated Total (in 000s)	TY 2024 Estimated Incremental (in 000s)
SCG-CFF-2 Energy Resilience	$0	$9,155	$9,155
Sub-Total			
Total RAMP O&M Costs	**$0**	**$9,155**	**$9,155**

* CFF-related information, in accordance with the March 30, 2022, Assigned Commissioner Ruling in A.21-05-011/-014 (cons.), is provided in R. Scott Pearson and Gregory S. Flores' RAMP to GRC Integration testimony (Ex. SCG-03/SDG&E-03, Chapter 2).

[17] Application (A.) 21-05-011/-014 (cons.) (RAMP Proceeding). Please refer to R. Scott Pearson and Gregory S. Flores' RAMP to GRC Integration testimony (Ex. SCG-03/SDG&E-03, Chapter 2) for more details regarding the 2021 RAMP Reports.

F. RAMP Cross-Functional Factor Overview

As summarized in Table AI-3 below, my testimony includes costs to help evaluate cross-functional factors (CFFs) included in the 2021 RAMP Report.[18] The applicable CFF is further described in below:

Table AI-3
RAMP CFF Chapter Description

SoCalGas (SCG-CFF-2) – Energy System Resilience [19]	This chapter addresses the energy resilience spanning multiple lines of business within SoCalGas and helps to mitigate several RAMP risks including transition to clean fuels.

The testimony of RAMP-to-GRC Integration witnesses Gregory Flores and Scott Pearson[20] describe all the risks and factors included in the RAMP report and the processes utilized for RAMP-to-GRC integration. While developing the GRC forecasts, SoCalGas evaluated the scope, schedule, resource requirements, and synergies of RAMP-related projects and programs to determine costs already covered in the base year and those that are incremental increases expected in the test year. Messrs. Pearson and Flores' testimony discuss all of the risks and CFFs included in the 2021 RAMP Reports and the RAMP to GRC integration process.[21]

G. GRC CFF Activities

Table AI-4 below summarizes the TY 2024 forecast by workpaper associated with the RAMP activities. For additional details, please refer to my workpaper (SCG-12-WP, 2RD000.001).

18 Unless otherwise indicated, references to the 2021 RAMP Report refer to SoCalGas's respective RAMP Report.

19 SoCalGas, "Risk Assessment and Mitigation Phase Cross-Function Factor (SCG-CFF-2) Energy System Resilience," May 2021, available at: https://www.socalgas.com/sites/default/files/SCG-CFF-2_RAMP-Cross-Functional-Chapter-Climate_Change_62.pdf; R. Scott Pearson and Gregory S. Flores' RAMP to GRC Integration testimony (Ex. SCG-03/SDG&E-03, Chapter 2).

20 R. Scott Pearson and Gregory S. Flores' RAMP to GRC Integration testimony (Ex. SCG-03/SDG&E-03, Chapter 2).

21 Id.

Table AI-4
Summary of Safety Related Risk Mitigation Costs by Workpaper
(In 2021 $, in 000s)

Workpaper	RAMP ID	Activity	2021 Embedded-Recorded	TY 2024 Estimated	Change	GRC RSE*
2RD000.001	SCG-CFF-2 Energy Resilience	Carbon Capture, Utilization and Sequestration Front End Engineering Design (FEED) Study Program		6,655		
2RD000.001	SCG-CFF-2 Energy Resilience	Clean Fuels Operational Readiness Program		2,500		
		Sub-Total		**9,155**		

* No RSE was calculated for this activity.

The activities, forecast method, and cost drivers associated with RAMP-related expenses shown in Table AI-4 above are identified in the Clean Fuels Infrastructure Development section of this testimony under CCUS FEED Study Program (see Section IV.B.2, below) and Clean Fuels Operational Readiness Program (see Section IV.B.3, below).

H. Changes from RAMP Report

As discussed in more detail in R. Scott Pearson and Gregory S. Flores' RAMP to GRC Integration testimony (Ex. SCG-03/SDG&E-03, Chapter 2), in the RAMP Proceeding, the Commission's Safety Policy Division (SPD) and intervenors provided feedback on the RAMP Report. Appendix B in Ex. SCG-03/SDG&E-03, Chapter 2 provides a complete list of the feedback and recommendations received and the Company's responses.

Changes from the 2021 RAMP Report presented in my testimony, including updates to forecasts and the amount and timing of planned work, extend to the CCUS FEED Study Program and the Clean Fuels Operational Readiness Program as activities associated with the SCG-CFF-2 Energy Resilience Cross-Functional Chapter.

III. SUSTAINABILITY AND SAFETY CULTURE

Sustainability at SoCalGas focuses on continuous improvement, innovation, and partnerships to advance California's climate objectives incorporating holistic and sustainable business practices and approaches. SoCalGas's sustainability strategy, ASPIRE 2045, integrates five key focus areas across the Company's operations to promote the public interest and the wellbeing of utility customers, employees, and other stakeholders.

The five key identified focus areas that provide a framework for integrating sustainability across the Company's business, guide investment decisions, and drive the sustainability-related proposals and programs of the SoCalGas TY 2024 GRC Application are:

a. Accelerating the transition to clean energy;
b. Protecting the climate and improving air quality;
c. Increasing clean energy access and affordability;
d. Advancing a diverse, equitable, and inclusive culture; and
e. Achieving world-class safety.

Each of these five focus areas are discussed in detail in Michelle Sim and Naim Jonathan Peress's Sustainability and Climate Change Policy testimony (Ex. SCG-02, Chapters 1 and 2).

CEI supports the Company's sustainability strategies. For example, the activities described in this CEI testimony support the advancement of the State's climate goals and align with SoCalGas's sustainability priorities. Specifically, CEI's proposal aims to drive progress in accelerating the transition to clean energy, protecting the climate, and improving air quality in our communities by increasing access to affordable and clean energy.[22] CEI is uniquely positioned to accelerate the energy transition by increasing the delivery of clean fuels such as renewable natural gas and hydrogen. CEI also supports the development of CCUS and SNG and support customer decarbonization through a portfolio of energy technology innovation and infrastructure.[23]

CEI also participates in supporting important sustainability initiatives, including some of the groundwork for developing what would be the largest green hydrogen energy infrastructure system in the United States (the "Angeles Link") to deliver clean and reliable renewable energy

[22] *See* Michelle Sim and Naim Jonathan Peress's Sustainability and Climate Change Policy testimony (Ex. SCG-02, Chapters 1 and 2) for additional detail on SoCalGas's Sustainability Strategy.

[23] "The Role of Clean Fuels and Gas Infrastructure in Achieving California's Net Zero Climate Goal," SoCalGas, October 2021, https://www.socalgas.com/sites/default/files/2021-10/SCG_Whitepaper_Full-Report.pdf, p.75.

to the Los Angeles region.[24] As currently envisioned, Angeles Link would support the integration of more renewable electricity resources like solar and wind and could significantly reduce greenhouse gas emissions from electric generation, industrial processes, heavy-duty trucks, and other hard-to-electrify sectors of the Southern California economy. The proposed Angeles Link could also significantly decrease demand for natural gas, diesel, and other fossil fuels in the LA Basin, helping accelerate California's and the region's climate and clean air goals.[25]

CEI's clean fuels and carbon management activities are also integral to the State reaching its clean electricity and carbon neutrality goals.[26] Specifically, CEI functions support many activities to decarbonize hard-to-electrify sectors of the economy like heavy-duty transportation and industrial activities, as well as supporting the reliability of the electric grid by providing flexible and dispatchable power and developing comprehensive carbon management infrastructure.

In addition, safety is foundational to SoCalGas and SoCalGas's sustainability strategy. As the nation's largest gas distribution utility, with over 7,800 employees serving 22 million customers, safety is foundational to our business. SoCalGas's safety culture includes: (1) standardizing policies and procedures; (2) complying with applicable laws, regulations, and internal policies; (3) building and operating a system that supports the safe and reliable delivery of gas; (4) communicating with stakeholders; and (5) using data and data analysis to help make informed decisions. CEI engages in the safety culture by supporting clean energy policies and technologies that help reduce the environmental impacts, improve safety of the existing and new clean fuels infrastructure, and contribute to the carbon neutrality 2045 climate goals of the

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[24] As described and explained in the Angeles Link Project Memorandum Account Application (A.22-02-007), certain costs related to that Application and work included therein is being tracked separately and is not included in this GRC.

[25] PRNewswire, "SoCalGas Proposes to Develop United States' Largest Green Hydrogen Energy Infrastructure System to Help Decarbonize LA Basin and Accelerate California's Climate Goals," SoCalGas Newsroom, February 17, 2022, available at: https://newsroom.socalgas.com/press-release/socalgas-proposes-to-develop-united-states-largest-green-hydrogen-energy.

[26] Senate Bill 100, The 100 Percent Clean Energy Act of 2018; State of California, Executive Department, EO B-55-18 "Achieve Carbon Neutrality"; see also SoCalGas, "ASPIRE 2045, Sustainability and Climate Commitment to Net Zero," available at: https://www.socalgas.com/sites/default/files/2021-03/SoCalGas_Climate_Commitment.pdf

state.[27] In addition to the external environmental impacts, CEI also promotes safety amongst our employees and contractors. This includes safety messages in staff meetings, regular ergonomics training, building emergency planning and safety training, and participation in other Company safety programs.

IV. NON-SHARED COSTS

"Non-Shared Services" are activities that are performed by a utility solely for its own benefit. Corporate Center provides certain services to the utilities and to other subsidiaries. For purposes of this general rate case, SoCalGas treats costs for services received from Corporate Center as Non-Shared Services costs, consistent with any other outside vendor costs incurred by the utility.

A. Sustainability

Below are activities and associated O&M costs for sustainability, which are non-shared. The costs are summarized in Table AI-6 below.

Table AI-6
Sustainability Cost Summary

Sustainability (in 2021$, in 000s)			
O&M	**2021 Adjusted-Recorded**	**Estimated TY 2024**	**Change**
Labor	$994	$1,382	$388
Non-Labor	$936	$600	($336)
Total O&M	$1,930	$1,982	$52

1. Description of Costs and Underlying Activities

Sustainability is responsible for planning, developing, and tracking near and long-term environmental, social, and governance (ESG) business strategies. This function also implements sustainable business practices to optimize operational activities while serving customers safely, reliably, and affordably. It works across the Company's organizations to facilitate ongoing discussions, workshops, and cross-functional collaboration, review, implementation of sustainability-related initiatives and goals.

Sustainability also monitors and assesses rapidly changing ESG markets, priorities, and requirements, inclusive of engaging with external stakeholders like community advisory

[27] State of California, Executive Department, EO B-55-18 "Achieve Carbon Neutrality," available at: https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

councils, customers, business partners, and ESG community members. With a goal to be transparent with all stakeholders, the Sustainability function also includes the review, utilization, and implementation of technologies to effectively track, monitor, and report on sustainability goals and KPI metrics.

The Company's sustainability strategy, ASPIRE 2045, is an important driver of this function, setting sustainable business priorities, goals to achieve its vision, and key performance indicators to track progress. The sustainability strategy aims to advance California's climate goals, align with the United Nations Sustainable Development Goals, and serve the public interest with increasing clean energy options safely, reliably, and affordably.[28]

2. Forecast Method

The forecast method developed for this cost category for labor and non-labor expenses is the base year method. Incremental adjustments to the base year were made to include additional expenses anticipated in TY 2024. This method is most appropriate because no historic costs exist for the sustainability group prior to its formation in January 2021. The only full year of cost data available is for calendar year 2021.

3. Cost Drivers

Sustainability's total adjusted-recorded expenditures of $1.930 million in base year (BY) 2021 consisted of $0.994 million in labor and $0.936 million in non-labor costs. Collectively, these expenditures provided a foundational-level sustainability strategy, governance framework, and sustainability tracking capabilities. The costs for this area include employee labor and expenses, software license fees, and external contractor support.[29]

For TY 2024, SoCalGas is requesting a total of $1.982 million for Sustainability. This amount reflects forecasted reduction of $0.336 million in non-labor costs because there was a one-time non-labor cost that will not be seen in the future years. In addition, during BY 2021, two full-time Program Managers were hired into the group mid-year. Since these are full-time positions, the full-year labor costs (prorated estimated expense of $0.103 million), is added to the

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[28] For a more detailed discussion on the Company's sustainability strategy and initiatives see Michelle Sim's Sustainability testimony (Ex. SCG-02, Chapter 2 (Sustainability))

[29] For additional details, please refer to workpaper (SCG-12-WP, 2RD003.000).

TY 2024 labor cost totals. Finally, to support the roll-out of the sustainability strategy and expansive integration of sustainability across the Company's business units (as highlighted in the activities listed below), Sustainability will require an increase of $0.285 million to hire two Full Time Equivalent (FTEs): one Sustainability Manager and one Project Manager II/Programs Advisor. In summary, this forecast is based on the recorded expense in BY 2021 with a net incremental funding request of $0.052 million above the base year to accomplish the following activities:

1. Supporting execution and coordination of the ASPIRE 2045 sustainability strategy goals through the development of procedures, controls, internal communications, governance, and iterative coordination across business units;

2. Updating the existing sustainability strategy to incorporate the latest developments in science, policy, and best management practices, and develop additional goals and KPIs;

3. Deploying and managing sustainability performance tracking software to support progress against goals and enhance transparency and reporting on sustainability areas; and

4. Increasing sustainability communications and engagement on climate initiatives, through increased engagement with external stakeholders and ESG communities.

B. Clean Fuels Infrastructure Development

Activities and associated O&M costs for Clean Fuels Infrastructure Development, which are non-shared, are set forth below. The costs are summarized in Table AI-7 below.

Table AI-7
Clean Fuels Infrastructure Development

Clean Fuels Infrastructure Development (in 2021$, in 000s)			
O&M	**2021 Adjusted-Recorded**	**Estimated TY 2024**	**Change**
Labor	$3,975	$4,832	$857
Non-Labor	$4,220	$15,568	$11,348
Total O&M	$8,195	$20,400	$12,205

Clean Energy Infrastructure Development total adjusted-recorded expenditures of $8.195 million in BY 2021 consisted of $3.975 million in labor and $4.220 million in non-labor costs. For TY 2024, SoCalGas is requesting a total of $20.400 million. This amount reflects $12.205 million incremental increase from the base year, which includes $0.857 million in labor and $11.348 million in non-labor to support an expected increase in project activity associated with clean fuels infrastructure development. The costs drivers include both labor and non-labor related expenses. Pertinent cost drivers are identified in the subsequent sub-sections of clean fuels infrastructure development activities. All O&M expenses related to Clean Fuels Infrastructure include the two following functions: Business Development and Clean Fuels Power Generation as well as the three following programs: CCUS FEED Study Program, Clean Fuels Operational Readiness Program, and Clean Fuels Transportation Program.

1. Forecast Method

The forecast method developed for this cost category (and all the sub-sections below) for labor and non-labor expenses is the base year method. Incremental adjustments to the base year were included to represent the expense requirements anticipated in TY 2024. This method is most appropriate because trends, multi-year averages, or other methods would not accurately reflect the fact that some costs associated with Clean Fuels Infrastructure Development are new and include functions under CEI that consolidated several pre-existing functions, while also adding new functions not included in the predecessor organizations.

2. Description of Costs and Underlying Activities

The costs associated with the Clean Fuels Infrastructure Development activities directly support the Company's goals of developing clean fuels infrastructure to meet SoCalGas's sustainability strategy and climate commitments[30] and California's decarbonization goals. The costs described in this section include both labor and non-labor costs.

SoCalGas will continue to lead the transition to a resilient and decarbonized clean fuel infrastructure in California. The word "clean" in clean fuels is defined as alternative fuels and/or carbon management solutions resulting in a net-zero carbon footprint.[31] Innovation and rapid development of new technologies will be essential to reach decarbonization goals set by the

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[30] SoCalGas, "ASPIRE 2045 Climate Commitment," January 2022, available at: https://www.socalgas.com/sites/default/files/2022-01/SoCalGas_Sustainability_Strategy-final.pdf.

[31] SoCalGas, "The Role of Clean Fuels and Gas Infrastructure in Achieving California's Net Zero Climate Goal," October 2021, available at: https://www.socalgas.com/sites/default/files/2021-10/SCG_Whitepaper_Full-Report.pdf.

federal government,[32] State, and SoCalGas. The development and deployment of clean energy solutions is achievable through active collaborations to lead the transition to an affordable and resilient clean energy solutions at scale. The functions and programs under Clean Fuels Infrastructure Development are further described below.

3. Business Development

As described previously in Section I.D.2.i., above, under "Organization Overview," Business Development performs many key functions including identifying, analyzing, selecting, and prioritizing clean energy and decarbonization initiatives and projects to advance the Company's sustainability goals. Business Development also assists in accelerating the transition to a Clean Fuels Infrastructure, through development of hydrogen and carbon management projects to support multiple end use applications,[33] demonstrating the technical and operational readiness of the existing gas infrastructure to safely deploy, and managing clean fuels as part of SoCalGas's clean energy transition.

RNG is one area of recent development and emphasis in the state that Business Development is actively engaged in to identify projects to meet the State's renewable gas procurement goals. The recent decision by the CPUC to establish a Renewable Gas Standard (RGS),[34] is an important step toward decarbonizing the gas system and reducing short-lived climate pollutant emissions. Under the new RGS ruling, SoCalGas will be required to replace 12.2 percent of the traditional gas it delivers to core customers with renewable gas by 2030.[35] The RGS also sets an interim goal of procuring approximately 3 percent renewable gas by 2025.[36] Efforts by Business Development will help SoCalGas meet the RGS goals for RNG to

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[32] H.R. 3684 "Infrastructure Investment and Jobs Act," last modified November 15, 2021, available at: https://www.congress.gov/bill/117th-congress/house-bill/3684/text.

[33] Includes industries, transportation, thermal generation, residential and commercial building decarbonization, and distributed energy resources.

[34] CPUC Rulemaking R13-02-008; D.22-02-025.

[35] D.22-02-025 at 32, 60 (Ordering Paragraph 18).

[36] *Id.* at 10, 60 (Ordering Paragraph 14); see also SoCalGas Newsroom, PRNewswire, "SoCalGas Applauds Establishment of First Renewable Gas Standard in the United States," February 24, 2022, available at: https://newsroom.socalgas.com/press-release/socalgas-applauds-establishment-of-first-renewable-gas-standard-in-the-united-states.

core customers by 2030.[37] The Renewable Gas Customer Outreach group is specifically focused on pursuing these goals by supporting customer implementation of renewable gas projects.

Hydrogen opportunities are also advancing, and the Business Development group is actively engaged in SoCalGas's transition to a Clean Fuels Infrastructure. This includes the development of conceptual hydrogen infrastructure solutions (as part of a response to a request for information (RFI) from Los Angeles Department of Water and Power (LADWP)) to support an integrated vision and best practices that will help the LADWP to plan, design, and deploy in-basin 100% green hydrogen in the LA basin.[38] In many nations, hydrogen has been increasingly treated as a tool in the fight against climate change. Many utilities, energy companies, and nations are prioritizing the development of hydrogen infrastructure as an integral component of large scale decarbonization.[39] The European Union (EU) has unveiled REPowerEU, by increasing renewable energy development and quadrupling its 2030 targets for renewable hydrogen supply needs.[40] The EU plan also includes a Hydrogen Accelerator program to develop an additional 15 million tons of renewable hydrogen by 2030 and will fast-track reforms that promote hydrogen projects.[41] Australia's national hydrogen strategy has launched the "H2 under 2" target, which sets a production cost of below AU $2/kg (approximately USD $1.50) for green hydrogen sourced from solar and wind.[42]

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[37] SoCalGas, "ASPIRE 2045 Climate Commitment," January 2022, available at: https://www.socalgas.com/sites/default/files/2022-01/SoCalGas_Sustainability_Strategy-final.pdf at p. 8.

[38] LADWP, "Green Hydrogen Pathways for Supporting 100% Renewable Energy, RFI Number: 8.5.21-Power-SA," August 5, 2021, available at: https://www.ammoniaenergy.org/wp-content/uploads/2021/09/Green_Hydrogen_RFI_-_8.5.21-Power-SAL.pdf.

[39] Bloomberg Finance, "2H 2021 Hydrogen Market Outlook: A Defining Year Ahead," available at: https://about.bnef.com/new-energy-outlook/ [report behind a subscription paywall].

[40] International Renewable Energy Agency, "Green Hydrogen Needs Industrial Policy Making and Certification," March 11, 2022, available at: https://www.irena.org/newsroom/articles/2022/Mar/Green-Hydrogen-Needs-Industrial-Policy-Making-and-Certification.

[41] Recharge News, "'Bloody Hard – but possible': EU plots renewables and green hydrogen dash from Russian gas," March 8, 2022, available at: https://www.rechargenews.com/energy-transition/bloody-hard-but-possible-eu-plots-renewables-and-green-hydrogen-dash-from-russian-gas/2-1-1181308.

[42] S&P Global Commodity Insights, "Analysis: Asia's 'H2 at $2' Green Hydrogen Target is a Mission Not Impossible," January 14, 2021, available at: https://www.spglobal.com/platts/en/market-

Domestically, the Department of Energy's (DOE) Earthshot-Hydrogen Shot program seeks to reduce the cost of "clean hydrogen"[43] by 80 percent to $1 per 1 kilogram in 1 decade ("1 1 1") by 2030.[44] Similarly, the HyDeal LA initiative is aiming to achieve $1.5/kg of delivered green hydrogen to off-takers in the LA basin.[45] The recently passed Infrastructure Investment and Jobs Act (IIJA) allocates $9.5 billion for clean hydrogen programs including: $8 billion dollars in funding for the development of at least four regional clean hydrogen hubs addressing hydrogen feedstock, end-use, and geographic diversity;[46] $1 billion for research, development, demonstration, commercialization, and deployment of hydrogen electrolysis program for commercialization to improve efficiency, durability, and reduce the cost of producing clean hydrogen using electrolyzers; and $500 million to support a clean hydrogen supply chain.[47] In 2020, Energy and Environmental Economics, Inc. modeled three different scenarios to achieve carbon neutrality in California by 2045. All three scenarios, including a high-electrification scenario, include the use of hydrogen.[48]

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insights/latest-news/electric-power/011421-analysis-asias-h2-at-2-green-hydrogen-target-is-a-mission-not-impossible.

43 "Clean hydrogen," refers to the phrase as used and interpreted with respect to the DOE, and the Infrastructure Investment and Jobs Act.

44 US DOE, Office of Energy Efficiency and Renewable Energy, "Hydrogen Shot," available at: https://www.energy.gov/eere/fuelcells/hydrogen-shot.

45 Green Hydrogen Coalition, "HyDeal LA: Architecting a Scalable Model for Green Hydrogen Hubs, Starting With Los Angeles," July 7, 2021, available at: https://static1.squarespace.com/static/5e8961cdcbb9c05d73b3f9c4/t/60ef84fb65edb26c8618d579/1626309884328/GHC+HyDeal_H2+Earthshots+RFI+response_July2021_HyDealSupporters.pdf at p. 5.

46 H.R. 3684 "Infrastructure Investment and Jobs Act," last modified November 15, 2021, available at: https://www.congress.gov/bill/117th-congress/house-bill/3684/text. Feedstock diversity implies hydrogen produced using multiple feedstocks (fossil fuels, nuclear, and renewable energy); end-use diversity implies hydrogen uses across multiple end-use applications including electric power generation, industries, residential and commercial heating, and transportation; geographic diversity implies no hydrogen hub in the same region as another.

47 *Id.*

48 Energy and Environmental Economics, Inc. "PATHWAYS Scenario Achieving Carbon Neutrality in California," October 2020, available at: https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf at p. 79; see also National Renewable Energy Laboratory (NREL), "LA100: The Los Angeles 100% Renewable Energy Study Executive Summary," March 2021, available at: https://www.nrel.gov/docs/fy21osti/79444-ES.pdf at p. 12.

Activities under Business Development include market research, financial and business analytics associated with tracking of clean energy market trends, the techno-economic outlook, and decarbonization trends in the energy and utility sectors. These activities provide analysis support, guidance, and direction to the business development initiatives as part of the clean fuels infrastructure development, thereby improving the effectiveness of these efforts. To promote optimal deployment of capital to benefit our customers, the market research, financial and business analytics activities focus on collecting and analyzing information on external trends, assisting with financial and technical analysis related to clean fuels infrastructure development projects, supporting the long-term capital planning process, and developing and maintaining analytical and data collaboration tools.

To this end, the Business Development function and its activities incur both labor and non-labor related expenses to perform the key functional activities as described above.

4. Cost Drivers

For TY 2024, SoCalGas is requesting an incremental increase of $2.333 million for Business Development from the 2021 BY costs. This is part of the overall incremental request of $12.205 million for the Clean Fuels Infrastructure Development group as shown in Table AI-7. The $2.333 million incremental increase for Business Development includes $0.333 million in labor and $2.0 million in non-labor related expenses to accomplish the following:

- Labor expenses required to backfill 2 FTEs: two business development managers to support clean fuels development;
- Increase in non-labor expenses to conduct feasibility assessments related to the clean fuel infrastructure value chain to meet the SoCalGas's sustainability strategy. This cost includes consulting services support for the clean fuels infrastructure assessments including identifying, analyzing, selecting, and prioritizing clean energy project portfolio;
- Non-labor expenses related to the development of strategic initiatives including roadmaps and vision documents to advance the clean fuels infrastructure goals; and
- Non-labor expenses related to the increased engagement in the State's energy initiatives and working with multiple agencies, partners, research laboratories, and universities.

For additional details, please refer to workpaper (SCG-12-WP, 2RD000.000).

5. Carbon Capture, Utilization and Sequestration Front End Engineering Design (CCUS FEED) Study Program

SoCalGas is requesting $6.655 million for a CCUS FEED study program (as described in the cost drivers section below) to support the development of carbon management solutions in Southern California. The proposed CCUS FEED Study Program would identify a Carbon Dioxide (CO_2) pipeline route in Southern California to follow, to the extent possible, existing pipeline corridors and/or leverage existing rights-of-way to help optimize project development and reduce environmental disturbance and siting concerns while connecting the CO_2 source to the CO_2 sink for storage. The CCUS FEED study program would also address scope, design, and technical specifications and identify related environmental attributes so that all aspects of the project evaluation undergo a "due diligence" process to help finalize the project's scope, technical specifications, capital investment estimates.

CCUS is a set of technologies that remove CO_2 either from the atmosphere or from point sources. The captured CO_2 is then compressed and transported for various end-use utilization, or injected[49] into deep underground geological formations (that may include depleted oil and gas reservoirs or saline formations) for permanent storage. As stated in S.799 of the Storing CO_2 and Lowering Emissions (SCALE) Act, "Congress finds that carbon dioxide transport infrastructure and permanent geological storage are proven and safe technologies with existing Federal and State regulatory frameworks."[50] CCUS is a means to abate CO2 emissions from energy-intensive industries[51] where CO_2 emissions are inherent to current production processes and cannot be eliminated solely by switching to low-carbon electricity or clean fuels

The recently passed IIJA in the United States include substantial carbon management provisions and funding of $12.1 billion over the next five years including the funds to build out large-scale pilot projects, development of commercial CO_2 transport and storage infrastructure, authorizations to support commercial-scale demonstrations, and FEED (front-end engineering

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[49] S.799 "Storing CO2 And Lowering Emissions Act (SCALE Act)," last modified March 17, 2021, available at: https://www.congress.gov/bill/117th-congress/senate-bill/799/text.

[50] *Id.* at 3 (findings).

[51] Includes power generation and industrial facilities such as refineries, cement, iron, steel manufacturing, etc.

and design) studies as part of the carbon capture technology and utilization activities.[52] The SCALE Act (as part of the IIJA) also supports the buildout of critical regional CO_2 transport and storage infrastructure networks through several other programs including financing and innovation, carbon storage validation and testing, and geologic storage permitting activities.[53]

CCUS would be an essential technology solution needed to meet California's 2045 decarbonization targets. This is evident from the ongoing actions being taken within the State's governing entities. In 2006, Assembly Bill 1925 (Blakeslee, Chapter 471) required the California Energy Commission, in coordination with the Department of Conservation's Geologic Energy Management Division (CalGEM) and the California Geological Survey to prepare a report recommending how California could facilitate the adoption of geologic carbon sequestration…."[54] In 2021, the California Governor signed SB 27 into law, requiring the California Natural Resources Agency to establish the "Natural and Working Lands Climate Smart Strategy" creating a framework to advance California climate goals and specified carbon removal targets for 2030 and beyond. SB 27 also requires the Natural Resources Agency to track projects that remove carbon in a registry, with the projects reporting updates on status, benefits, and outcomes.[55]

As explained in the testimony of Naim Jonathan Peress and Michelle Sim (Ex. SCG-02, Chapters 1 and 2), AB 32, SB 32, and Executive Order B-55-18 promote the development and examination of CCUS solutions. CARB's 2022 Scoping Plan Update is being informed through

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[52] Great Plains Institute (GPI), "An Atlas of Carbon and Hydrogen Hubs for United States Decarbonization," February 2022, available at: https://scripts.betterenergy.org/CarbonCaptureReady/GPI_Carbon_and_Hydrogen_Hubs_Atlas.pdf at p.77.

[53] *Id.* at p.78.

[54] AB 1925, Chapter 471, September 26, 2006, available at: http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_1901-1950/ab_1925_bill_20060926_chaptered.pdf; CalGEM, "Carbon Capture and Geological Sequestration," available at: https://www.conservation.ca.gov/calgem/Pages/CarbonDioxideCaptureandStorage.aspx.

[55] SB-27, Chapter 237, "Carbon sequestration: state goals: natural and working lands: registry of projects," last modified September 24, 2021, available at: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220SB27.

the development of decarbonization scenario modeling efforts.[56] All of the four alternative scenarios currently proposed in the 2022 Scoping Plan scenario modeling framework include the role of CO_2 removal from the atmosphere and the development of carbon capture and sequestration technologies to help capture carbon emissions from industrial facilities in California. In 2018, CARB expanded the Low Carbon Fuel Standards (LCFS) program to include carbon capture and sequestration into the regulation with the goal to incentivize and enable these technologies to scale more widely.[57]

California possesses a sizeable carbon emissions market as well as ample and conducive geologic storage potential for safe and permanent CO_2 storage. According to the Lawrence Livermore National Laboratory, the previously estimated storage capacity of onshore geologic saline formations in California's ten largest basins range from 75 to 300 billion tons of CO_2 capacity.[58]

California currently lacks CO2 transport infrastructure to support CCUS development. Los Alamos National Laboratory, in its assessment of CCUS at a DOE workshop on April 19, 2022, has stated "Regional CO2 transport infrastructure connecting regional sources to geologic sinks is a critical need[.]"[59] A CO_2 transport pipeline infrastructure network in California, connecting hard to electrify industrial sources of emissions to the geologic CO_2 storage sites, is essential to spur the development and deployment of large-scale CCUS infrastructure solutions.

56 California Air Resources Board (CARB), "PATHWAYS Scenario Modeling 2022 Scoping Plan Update," December 15, 2021, available at: https://ww2.arb.ca.gov/sites/default/files/2021-12/Revised_2022SP_ScenarioAssumptions_15Dec.pdf.

57 The federal 45Q tax credits can be combined with California's LCFS carbon capture and sequestration credits.

58 Lawrence Livermore National Laboratory, "Getting to Neutral: Options for Negative Carbon Emissions," January 30, 2020, available at: https://livermorelabfoundation.org/2019/12/19/getting-to-neutral/; see also Energy Futures Initiative and Stanford University Center for Carbon Storage, "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions," October 22, 2020, Rev. 2, December 11, 2020, available at: https://sccs.stanford.edu/california-projects/opportunities-and-challenges-for-CCS-in-California (a collaborative study between the California Energy Commission (CEC) and the U.S. Department of Energy (DOE) that estimated the CO_2 storage capacity of saline formations in the state's 10 largest basins ranged from 150 to 500 gigatons (Gt)).

59 Los Alamos National Laboratory, "CCS Pipeline Infrastructure Development in the Gulf Coast and Southeast US," April 19, 2022, p.2, https://usea.org/sites/default/files/event-/Rajesh%20Pawar%2C%20Bailian%20Chen.pdf at 2.

Los Alamos also noted "CCS [(carbon capture and sequestration)] infrastructure is a long term investment" and "strategic development of infrastructure could help address large number of sources and help save on costs[.]" [60]

As part of the Communities Local Energy Action Program grants, the DOE has recently pledged technical assistance to two communities in SoCalGas's service territory, Kern County and Bakersfield, to support these energy overburdened communities in making a clean energy transition, including the development of carbon capture, utilization, and sequestration solutions.[61]

With SoCalGas's extensive experience in engineering, constructing, operating, inspecting, safety, and maintaining pipelines in the backcountry and urban settings, the Company is well-positioned to play a key role in the development of a region-critical CO_2 pipeline network that would benefit ratepayers and the state by advancing California's net-zero goals, reducing emissions from the hard to electrify economic sectors in the LA Basin, and creating new jobs and economic benefits.

SoCalGas has analyzed publicly available research on CCUS by Stanford[62], Lawrence Livermore[63], and others, as well as EPA data[64] on emissions to assess Southern California's potential for carbon capture, transport, and a storage network and its subsequent implementation for a wide-scale CCUS development. SoCalGas is planning to conduct additional Pre-FEED evaluations prior to a comprehensive FEED study[65] for the CO_2 pipeline transport infrastructure necessary to enable the deployment of carbon capture, utilization, and storage technologies in Southern California.

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[60] *Id*.

[61] Kern County News, "Kern County Awarded U.S. Department of Energy Communities LEAP Technical Assistance Grant for Development of Clean Energy & Carbon Management Business Park," March 29, 2022, available at: https://www.kerncounty.com/Home/Components/News/News/660/34810.

[62] EFI and Stanford University, "An Action Plan," October 2020, Rev. 2, Dec. 11, 2020.

[63] Lawrence Livermore National Laboratory, "Getting to Neutral."

[64] "Environmental Protection Agency Facility Level Information on Greenhouse Gases Tool," last modified August 7, 2021, available at: http://ghgdata.epa.gov/ghgp.

[65] A FEED study is the basic engineering work required to produce a quality process in documenting engineering and project requirements prior to a capital investment. FEED studies are commonly performed after a conceptual or feasibility study but before any detailed engineering work is conducted for the EPC stage (Engineering, Procurement, and Construction).

a. Cost Drivers

For TY 2024, SoCalGas is requesting an incremental increase of $6.655 million for the CCUS FEED Study program from the 2021 BY costs. This is part of the overall incremental request of $12.205 million for the Clean Fuels Infrastructure Development group as shown in Table AI-7.

The $6.655 million non-labor incremental increase is to support the activities related to the development of a CCUS FEED study program. The non-labor estimate is based on industry guidance of FEED studies for large, first of its kind infrastructure projects, and based on previous costs for studies of this nature. The associated cost for the FEED study is part of the RAMP activities as identified in Table AI-4 of this testimony (see Section II). Cost drivers include non-labor expenses to accomplish the following activities:

- Conduct a FEED study to evaluate the development of a CO_2 pipeline transport infrastructure system necessary to enable the deployment of carbon capture, utilization, and storage technologies in Southern California;
- Identification of routes in Southern California to follow, to the extent possible, existing pipeline corridors and/or leverage existing right of ways to help optimize project development and reduce environmental disturbance and siting concerns while connecting the CO_2 sources to the CO_2 sink for storage; and
- Development of a final scope, design, and technical specifications for the CO_2 pipeline as a precursor to the evaluation of the project's capital investment estimates.

For additional details, please refer to workpaper (SCG-12-WP, 2RD000.000).

6. Clean Fuels Operational Readiness Program

Development of a clean fuels operational readiness program will be pivotal to demonstrate and deploy clean fuels technologies as part of the clean fuels' infrastructure transition. The clean fuels operational readiness program is intended to help SoCalGas develop a strategic framework for operational and system readiness to help accelerate the Company towards new clean fuels infrastructure.

Assessment of the current processes, standards, systems, and infrastructure for operational readiness and identifying gaps in technological, material, operational, safety, workforce, Information Technology (IT), Operational Technology (OT) systems, training standards, regulatory and compliance protocols, and fleets and facilities will promote an effective and efficient deployment of the clean fuels infrastructure. The clean fuels operational readiness program will also evaluate current transmission and distribution integrity standards, operational tools, and management practices to optimize transmission, distribution, storage, IT/OT, & metering systems that would assist in integrating systems operations with the clean fuels infrastructure.

Transitioning to a balanced and diversified portfolio of clean fuels delivery network in California can enhance system-wide energy resilience to meet energy demands. Innovation and rapid development of new technologies requires evaluating not only the key benefits, but also the associated risks to the overall energy system. Currently, data is either limited or unavailable (both internally at SoCalGas or available in the public domain) to evaluate asset-related risks as part of the RAMP requirements to integrate emerging clean fuel technologies into the energy ecosystem in California to address system resiliency. As discussed in the RAMP Integration section of this testimony, the clean fuels operational readiness program will also evaluate the overall benefits and risks to the energy system to address system resiliency with the adoption of clean fuels infrastructure.

a. Cost Driver

For TY 2024, SoCalGas is requesting an incremental increase of $2.500 million for Clean Fuels Operational Readiness Program from the 2021 BY costs. This is part of the overall incremental request of $12.205 million for the Clean Fuels Infrastructure Development group as shown in Table AI-7. The $2.500 million non-labor incremental increase is to support the activities related to the development and implementation of the Clean Fuels Operational Readiness Program. The costs associated with the Clean Fuels Operational Readiness Program is part of the RAMP activities as identified in Table AI-4 of this testimony (see Section II). Cost drivers include non-labor expenses to accomplish the following activities:

- Assessment of current processes, standards, systems, and infrastructure for operational readiness to embrace clean fuels infrastructure, identifying gaps in technological, material, operational, safety, workforce, and training standards, etc.;
- Evaluation of current transmission and distribution integrity standards, operational tools, and management practices to optimize transmission, distribution, storage, IT/OT, and metering systems for clean fuels delivery;
- Integration of research, testing, and demonstration results as part of the operational readiness plan; and
- Identification of risk drivers and mitigation strategies to address clean fuels system resiliency.

For additional details, please refer to workpaper (SCG-12-WP, 2RD000.000). Cost drivers related to expenses required to support hydrogen blending operational readiness activities are identified separately in Maria T. Martinez's Gas Engineering testimony (Ex. SCG-07) and is not part of this testimony.

7. Clean Fuels Transportation Program

The SoCalGas's Clean Transportation Program supports customer demand for renewable natural gas and the market adoption of hydrogen as transportation fuels in support of California's regional and state air quality and GHG emission reduction goals. The Clean Fuels Transportation Program provides information, education and training related to Clean Transportation a variety of stakeholders, including owners of hydrogen fuel cell vehicles (FCVs) and renewable natural gas vehicles (RNGVs), operators of hydrogen and RNGV refueling stations, vehicle and equipment manufacturers, government agencies, policymakers, and others.

This testimony provides background information and support for several other testimony areas that seek costs relating to Clean Transportation. Direct customer contact activities (Customer Outreach) for Clean Transportation customers are handled by Customer Energy Solutions (CES), and those associated costs and underlying activities are included in Brian Prusnek's Customer Services – Information testimony (Ex. SCG-16).[66] Indirect customer support activities (Customer Support) for Clean Transportation customers, including product and service development, public access station management, and regulatory and legislative support for Clean Transportation customers are handled by CEI. This testimony (both non-shared costs and capital costs) is also referenced by Brenton Guy's Real Estate and Facility Operations testimony (Ex. SCG-19) as well as the Rae Marie Yu's Regulatory Accounts testimony (Ex. SCG-38) related to the associated costs and underlying activities for utility-owned and operated hydrogen refueling stations.

The Clean Transportation Program (Customer Support) includes costs related to the development and management of new and existing Clean Transportation-related products and services, including customer outreach tools and materials, grant funding tracking and reporting, the truck loan program, fleet financial analysis tools, utility public access refueling station

[66] Direct customer contact activities include, but are not limited to, customer information, education, and training, as well as utility new business and existing account management services.

management (customer credit card sales, development of monthly retail pricing and LCFS credit revenue return) and offering subject matter expertise regarding Clean Transportation-related local, state, and federal regulations. These products and services are provided to the Clean Transportation (Customer Outreach) team for direct use with customers.

b. Background

i. Existing Stations

As of March 22, 2022, thirty (30) retail hydrogen FCV stations were in operation in the SoCalGas's service territory.[67] Most of these retail hydrogen FCV stations serve light-duty FCVs. As described below, it is expected that more medium-duty and heavy-duty FCVs will be introduced into the market, including in maritime and rail applications, and adopted by commercial fleets.

SoCalGas serves 349 RNGV refueling stations dispensing 154 million therms of natural gas or over 123 million gasoline gallon equivalents to G-NGV customers.[68] As of the end of 2019, over 98% of the natural gas dispensed by RNGV refueling stations in California and reported to CARB's Low Carbon Fuel Standard (LCFS) Program was renewable natural gas.[69] SoCalGas owns and operates 27 RNGV refueling stations dispensing 100% renewable natural gas to the utility fleet and general public. Most Clean Transportation customers own and operate both RNGVs and RNGV refueling stations, but some customers operate "public access" fueling stations to serve the general public and nearby fleets. RNGV customers vary significantly in terms of the number and type of RNGVs operated, including commuter vehicles, transit buses, school buses, waste haulers, street sweepers, airport fleets (taxis, shuttles), goods movement trucking, and port drayage trucking.

[67] California Fuel Cell Partnership, "California Fuel Cell Partnership Hydrogen Station List," March 25, 2022, available at: https://cafcp.org/sites/default/files/h2_station_list.pdf.

[68] Source is G-NGV billing data. Data based on actual 2021 volumes and stations.

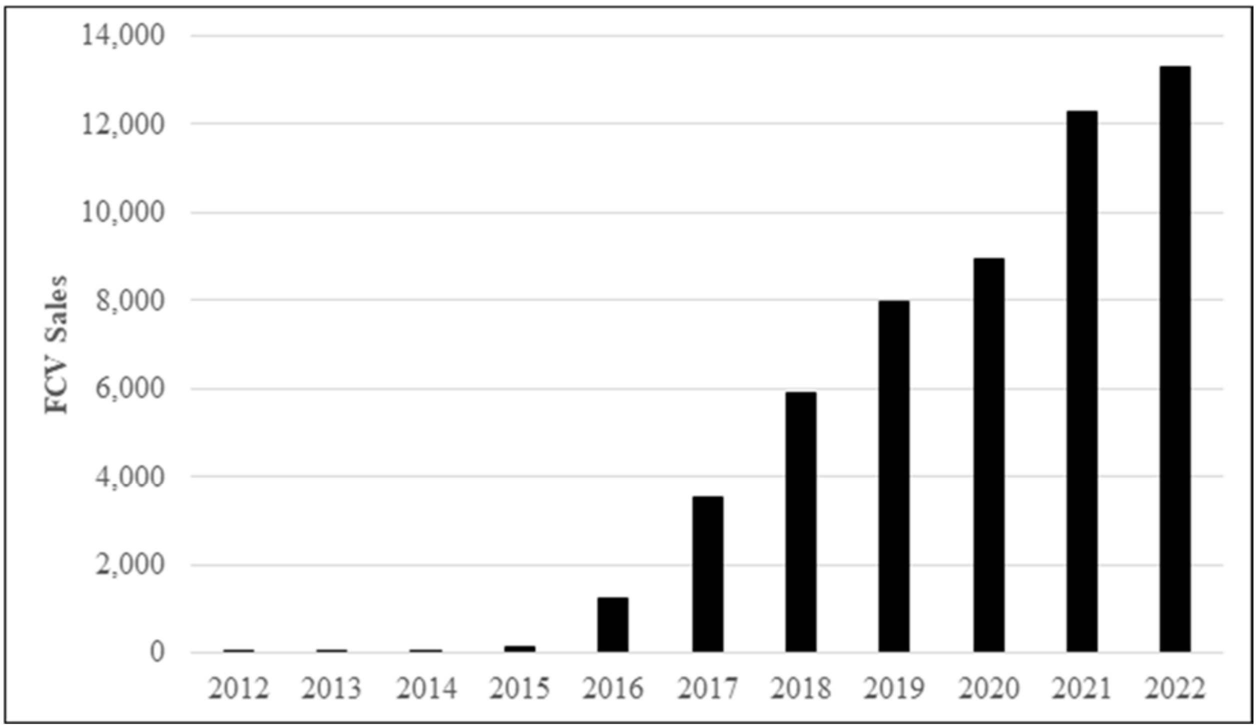
[69] California Air Resources Board and LCFS Data Dashboard, "Alternative Fuel Volumes and Credit Generation," April 30, 2021, available at: https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm at Figure 2.

ii. Customer Demand

The primary cost driver for an increase in Clean Transportation utility services is based on the increasing demand for hydrogen FCVs and hydrogen refueling stations to support transition into Zero Emissions Vehicles (ZEV). This increase in utility service demand will occur due to: (a) increasing industry and customer interest in and sales of hydrogen FCVs, (b) regulatory requirements mandating the use of zero emission vehicles, including hydrogen FCVs, and (c) the steadily increasing price competitiveness of hydrogen compared to petroleum fuels.

According to the California Fuel Cell Partnership, FCV sales in the United States have been steadily increasing since 2016, as shown in Figure AI-1
Cumulative FCV Sales in the United States).

Figure AI-1
Cumulative FCV Sales in the United States [70]



[70] FCV sales data, California Fuel Cell Partnership (CAFCP), available at: https://cafcp.org/sites/default/files/FCEV-Sales-Tracking.pdf.

There is also a significant number of off-road FCVs, as evidenced by the over 20,000 hydrogen FCV forklifts in operation throughout the United States.[71]

SoCalGas has also observed an increase in customer interest and requests for hydrogen station natural gas utility service. For example, in 2020, SoCalGas received a single request to evaluate a location for hydrogen station natural gas utility service. In 2021, this figure jumped to sixteen requests.

In March 2022, SoCalGas commissioned a market research study to quantify customer interest in proposed utility hydrogen-related products and services, including customer information, education, and training programs as well as utility-owned public access hydrogen stations.[72] Ninety-four percent (94%) of respondents stated SoCalGas's proposed hydrogen products and services would be beneficial. Eighty-one percent (81%) of respondents stated SoCalGas' proposed hydrogen products and services would motivate them or their company to adopt the use of hydrogen vehicles sooner. Respondents ranked the need for more hydrogen fueling stations as well as affordable hydrogen fuel as the most appealing aspects of SoCalGas's proposed hydrogen products and services. These findings are consistent with the most recent CEC AB 8 report on hydrogen refueling stations, which states "general barriers … to overall widespread FCEV commercialization and deployment remain" and include "high hydrogen fuel and FCEV prices, hydrogen station downtime due to equipment failures and other factors, and the lack of vehicle models and consumer options…. The need for a reliable hydrogen supply and reliable stations also presents a barrier to widespread FCEV commercialization and deployment, as does expanded geographic coverage of the stations. FCEV adoption may increase at a higher pace when these barriers are addressed."[73]

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[71] U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, Hydrogen and Fuel Cells Program Record #18002, "Fact of the Month November 2018: There are Now More Than 20,000 Hydrogen Fuel Cell Forklifts in Use Across the United States," November 2018, available at: https://www.energy.gov/eere/fuelcells/fact-month-november-2018-there-are-now-more-20000-hydrogen-fuel-cell-forklifts-use.

[72] "Clean Air Intercept Study", Q-Insights, March 2022.

[73] California Energy Commission Joint Agency Staff Report on Assembly Bill 8: 2021 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California, CEC-600-2021-040, December 2021, available at: https://www.energy.ca.gov/sites/default/files/2021-12/CEC-600-2021-040.pdf at p. 55.

iii. ZEVs for Addressing Climate Change

To aggressively address climate change, state policies are increasingly mandating the use of zero emission vehicles, including hydrogen FCVs. As an example, the CARB Innovative Clean Transit (ICT) regulation approved in 2019 requires that "Starting January 1, 2029, all new bus purchases must be zero-emission buses" where a zero emission bus is defined as "a bus with zero tailpipe emissions and is either a battery electric bus or a fuel cell electric bus."[74,75] Since hydrogen fuel cell electric buses can fuel faster and often have greater range than battery electric bus counterparts, many transit agencies throughout the state plan to procure, fuel and operate hydrogen fuel cell bus fleets. As of September 2, 2021, 60% of the SoCalGas transit agencies that have submitted ICT implementation plans to CARB intend to operate hydrogen fuel cell buses.[76] Similar regulations have been approved for other types of vehicles, such as the CARB Advanced Clean Truck regulation that requires a portion of all heavy-duty trucks sales from each manufacturer to be a zero-emission truck starting in 2024. The proposed CARB Advanced Clean Car II regulations requires 100% of all light-duty new vehicle sales from each manufacturer to be zero emission by 2035.[77] Other regulations are currently under development, such as the draft Advanced Clean Fleets (ACF) regulation, that will require a transition to zero emission medium- and heavy-duty vehicle fleets "performing drayage operations, public agencies, federal governments, and high-priority fleets that own, operate or direct vehicles with a gross vehicle weight rating (GVWR) greater than 8,500 lbs."[78] Collectively, these regulations will result in additional ZEV adoption, including hydrogen FCVs, within the state of California. This increased adoption, in turn, will result in increasing demands for utility Clean Transportation products and services.

[74] Title 13, California Code of Regulations, §§ 2023.1(a)(1)(A)(3) and (a)(1)(B)(2).

[75] Title 13, California Code of Regulations, § 2023(b)(54).

[76] Title 13, California Code of Regulations, § 2023.1(d); see also "The Innovative Clean Transit (ICT) regulation, last modified December 16, 2021, available at: https://ww2.arb.ca.gov/our-work/programs/innovative-clean-transit/ict-rollout-plans.

[77] CARB, "Advanced Clean Cars II Staff Report: Initial Statement of Reasons," April 12, 2022, available at: https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2022/accii/isor.pdf. at p. 9

[78] CARB, "Advanced Clean Fleets Fact Sheet," last modified August 17, 2021, available at: https://ww2.arb.ca.gov/our-work/programs/advanced-clean-fleets/advanced-clean-fleets-fact-sheets

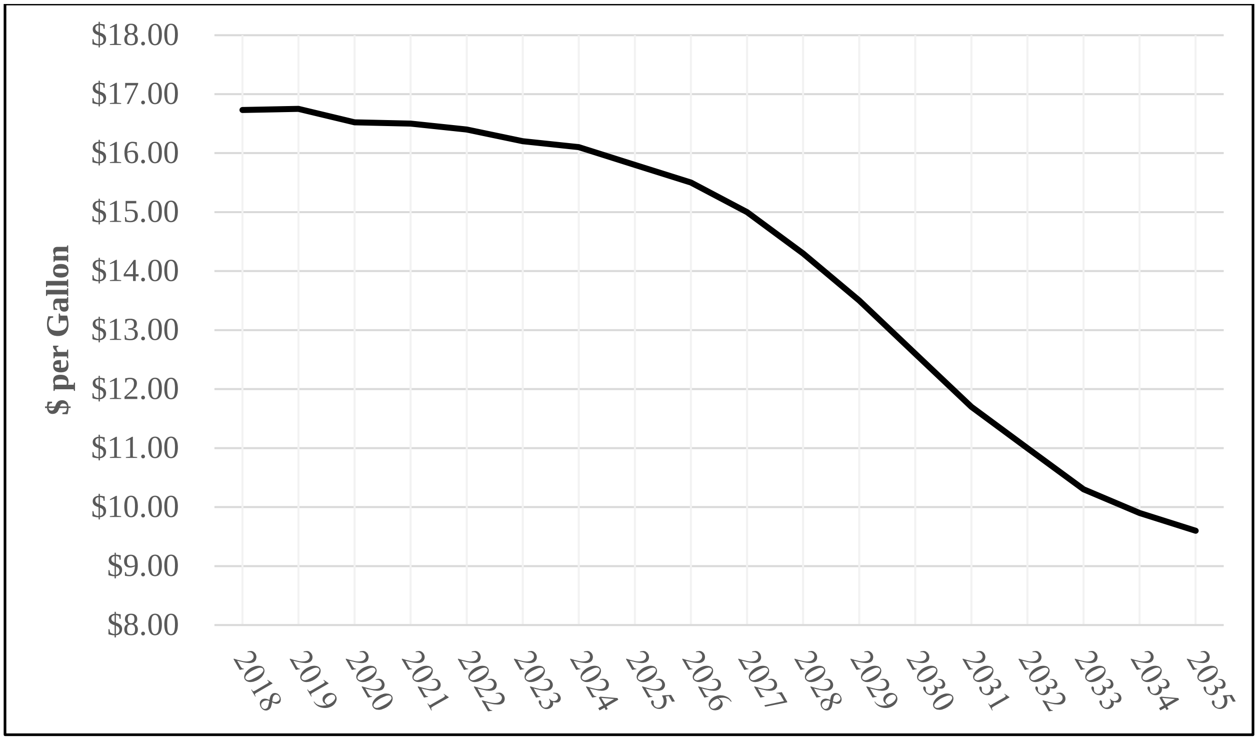
As the cost of hydrogen fuel drops, demand for hydrogen to fuel hydrogen FCVs would likely increase. A 2021 Bloomberg NEF forecast states "the costs of producing green hydrogen from renewable electricity should fall by up to 85% from today to 2050, leading to costs below $1/kg ($7.4/MMBtu) by 2050 in most modeled markets."[79] Since 1 kg of hydrogen is approximately equal to a gallon of gasoline [80] and hydrogen FCVs are expected to be more efficient than internal combustion engines, this forecast indicates renewable hydrogen will be less costly than petroleum fuels in the next thirty years. Declining hydrogen prices are also reflected in fuel price forecasts used in the California Energy Commission 2020 IEPR and shown below in Figure AI-2
CEC Hydrogen Fuel Price Forecast.

Figure AI-2
CEC Hydrogen Fuel Price Forecast [81]

[79] Bloomberg NEF, Green Car Congress, "BloombergNEF Forecasts Green Hydrogen Should be Cheaper Than Natural Gas by 2050 in Some Markets; Falling Costs of Solar PV Key," April 7, 2021, available at: https://www.greencarcongress.com/2021/04/20210407-bnef.html.

[80] RMI, "Run on Less with Hydrogen Fuel Cells," October 2019, available at: https://rmi.org/run-on-less-with-hydrogen-fuel-cells/

[81] Hydrogen Fuel Price Forecasts provided by Ysbrand van der Werf, California Energy Commission Transportation Energy Forecasting Unit, November 19, 2021.



Increasing demand for hydrogen FCVs will result in an increased demand for public and private hydrogen refueling infrastructure, customer information, education, and training. The Company team will support customers by providing the necessary hydrogen refueling infrastructure, information, education, and training.

iv. Market Activity

In the past few years, there has been increasing market activity related to third-party hydrogen FCV products and services including the production of Original Equipment Manufacturer (OEM) vehicles, hydrogen refueling stations, and associated equipment and hydrogen production capability. Customers seeking to operate hydrogen FCVs and hydrogen refueling stations will require information and education on third-party Clean Transportation products and services available and have traditionally sought such information from utilities.

Prominent OEMs, including Toyota, Honda, and Hyundai, have already begun producing hydrogen FCVs for the consumer market.[82] Heavy-duty FCVs are under development for eventual commercialization. For example, the CARB Zero Emissions for California Ports

[82] As of January 1, 2022, consumer fuel cell vehicles were available for sale/lease from Toyota (Mirai), Honda (Clarity), and Hyundai (Nexo).

project started in 2019 will be validating "the commercial viability of zero-emissions hybrid fuel cell-electric yard trucks operating in a demanding, real-world cargo-handling application at the Port of Los Angeles."[83] As of June of 2021, two zero-emissions fuel cell-electric yard trucks began operating as part of this demonstration.

As stated earlier, 30 retail hydrogen refueling stations are currently in operation within the SoCalGas service territory. These stations produce or procure hydrogen in a variety of ways, including gaseous transport, liquid transport, on-site electrolysis, and hydrogen pipelines. These production and procurement methods require different types of products and services. As the portfolio of hydrogen refueling stations grow within California, the demand for these products and services will grow as well.

New hydrogen FCV products and services will benefit and impact the transportation fleets of many of our largest commercial and industrial customers. The Clean Transportation team will support our customers by helping them understand new and evolving hydrogen FCV products and services through information, education, and training.

v. Regulatory and Legislative Activity

Federal, state, and local air quality and climate change related programs, regulations, and legislation directly impact individual and fleet customers that operate or could benefit from operating hydrogen FCVs and/or hydrogen refueling stations. Customers seeking information on Clean Transportation regulatory and legislative requirements and opportunities (grant funding) have traditionally sought such information and education from the utilities. The Clean Transportation team will also support our customers by helping customers understand both existing and new hydrogen fuel quality, measurement, and safety regulations and standards.

Any increase in the associated regulation and legislation will increase the demand on utility resources to adapt to those changes.

These numerous laws, regulations and policies include:

- In 2018, Governor Brown issued Executive Order B-48-18 that states, in part, "It is further ordered that all State entities work with the private sector and all

[83] CARB, "Zero Emissions for California Ports ZECAP," March 2020, available at: https://ww2.arb.ca.gov/sites/default/files/movingca/pdfs/zecap.pdf.

appropriate levels of government to spur the construction and installation of 200 hydrogen fueling stations...by 2025."[84]

- In 2020, Governor Newsom issued Executive Order N-79-20 that states, in part, "It shall be a goal of the State that 100 percent of in-state sales of new passenger cars and trucks will be zero-emission by 2035. It shall be a further goal of the State that 100 percent of medium-and heavy-duty vehicles in the State be zero-emission by 2045 for all operations where feasible and by 2035 for drayage trucks. It shall be further a goal of the State to transition to 100 percent zero-emission off-road vehicles and equipment by 2035 where feasible."[85]

- The CARB 2020 Mobile Source strategy states, "a key focus of the 2020 Strategy is advancing the use of zero-emission technologies wherever feasible," and "deployment of approximately 1.4 million medium and heavy-duty zero-emission vehicles (ZEVs) in California by 2045" and for "on-road light-duty vehicles … 100 percent of sales will be ZEVs by 2035.…"[86]

- In November 2021, the U.S. Department of Energy announced it "awarded $199 million to fund 25 projects aimed at putting cleaner cars and trucks on America's roads [that] align with DOE's commitment to reaching President Biden's goals of having zero-emission vehicles make up half of all vehicles sold in America by 2030 and achieving net zero emissions economy-wide by 2050."[87]

- In 2018 and 2019, CARB updated the Low Carbon Fuel Standard (LCFS) program, which now mandates a 20% reduction in the carbon intensity of transportation fuels used in California by 2030. Hydrogen, when used as a motor vehicle fuel, has GHG emissions that are up to 228% lower than diesel fuel.[88]

- In response to California's clean energy goals and Governor Newsom's Executive Order N-79-20, SoCalGas has observed the California Legislature introducing

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84 State of California, Executive Department, EO B-48-18, available at: https://www.library.ca.gov/wp-content/uploads/GovernmentPublications/executive-order-proclamation/39-B-48-18.pdf.

85 State of California, Executive Department, EO N-79-20, available at: https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf.

86 CARB, "Proposed 2020 Mobile Source Strategy," September 28, 2021, available at: https://ww2.arb.ca.gov/sites/default/files/2021-09/Proposed_2020_Mobile_Source_Strategy.pdf. at p. 4.

87 U.S. Department of Energy, "DOE Announces Nearly $200 Million to Reduce Emissions in Cars and Trucks," November 1, 2021, available at: https://www.energy.gov/articles/doe-announces-nearly-200-million-reduce-emissions-cars-and-trucks.

88 CARB, "Current LCFS Regulation," modified July 2020, available at: https://ww2.arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf at p. 54, Table 1 and p. 73, Table 5.

legislation to increase the adoption of zero emission vehicles, including hydrogen fuel cell vehicles and associated refueling infrastructure.[89]

- The California Department of Food and Agriculture is "responsible for overseeing the fuel quality, dispenser accuracy, and advertising of fuels sold at retail, including hydrogen" and has adopted the SAE International hydrogen fuel quality standard J2719.[90]
- CARB also has adopted hydrogen fuel quality regulations.[91]
- Many municipalities use the National Fire Protection Association (NFPA) to establish refueling station permitting and safety standards, including NFPA 2, "Hydrogen Technologies Code".

At the local level, the two largest regional air basins within the SoCalGas service territory, South Coast and San Joaquin Valley, are in extreme non-attainment for ozone and both must achieve significant reductions in particulate matter (PM) for National Ambient Air Quality Standards under the Federal Clean Air Act.[92] More than 85% of the region's emissions come from mobile sources.[93] With heavy-duty diesel trucks as the single largest contributor to these emissions, the widespread deployment of near-zero and zero emission heavy-duty trucks, including hydrogen FCV trucks, is the single most impactful emission reduction strategy.[94]

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89 SoCalGas monitors state legislative activity impacting both the utility and customers. Over the past three legislative sessions, the number of bills addressing natural gas and hydrogen mobility has increased from 2 bills in the 2018-2019 legislative session, to 6 bills in the 2019-2020 legislative session, and to 9 bills in the 2020-2021 legislative session.

90 California Department of Food and Agriculture, "Division of Measurement Standards," available at: https://www-test.cdfa.ca.gov/dms/hydrogenfuel/hydrogenfuel.html.

91 California Code of Regulations, Title 13, Division 3, Chapter 5, Article 3, Sub-Article 1, § 2292.7, "Specifications for Hydrogen."

92 South Coast Air Quality Management District, "Final 2016 Air Quality Management Plan," March 2017, available at: https://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2016-air-quality-management-plan/final-2016-aqmp/final2016aqmp.pdf?sfvrsn=15 at ES-1-2; see also San Joaquin Valley Air Pollution Control District, "2016 Ozone Plan for 2008 8-hour Ozone Standard," June 16, 2016, available at: http://valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/Adopted-Plan.pdf at 1-6.

93 South Coast Air Quality Management District, "Final 2016 Air Quality Management Plan," available at: https://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2016-air-quality-management-plan/final-2016-aqmp/final2016aqmp.pdf?sfvrsn=15 at ES-7; see also San Joaquin Valley Air Pollution Control District, "2016 Ozone Plan," available at: http://valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/ES.pdf at ES-5.

94 South Coast Air Quality Management District, "Final 2016 Air Quality Management Plan," available at: https://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2016-

Further, in November 2017, the San Pedro Bay Ports (Los Angeles, Long Beach) approved a Clean Air Action Plan that includes a goal "to transition the current drayage truck fleet to near-zero technologies in the near-term and ultimately zero-emissions technologies by 2035."[95]

Significant air quality and climate change policy developments at the federal, state, and local levels are likely to impact the transportation fleets of many of our largest commercial and industrial customers. The Clean Transportation team will support our customers by helping them understand new and evolving regulatory and legislative requirements through information, education and training.

c. Cost Drivers

For TY 2024, SoCalGas is requesting an incremental increase of $0.357 million for Clean Fuels Transportation Program from the 2021 BY costs. This is part of the overall incremental request of $12.205 million for the Clean Fuels Infrastructure Development group as shown in Table AI-7.

The $0.357 million incremental increase for Clean Fuels Transportation Program includes $0.224 million in labor and $0.133 million in non-labor to support an expected increase in demand for Clean Transportation services (Customer Support) associated with hydrogen-related customer demand, market activity, and regulatory and legislative activity.[96] The increase in labor and non-labor expenses is to support the following:

- Labor expense for 2 FTEs (two project managers) to support the development and management of new hydrogen-related Clean Transportation customer information, education, and training products and services.
- Non-labor expenses will support the FTEs engaged in the development and management of new hydrogen-related Clean Transportation customer information, education and training products and services.

For additional details, please refer to my workpaper (SCG-12-WP, 2RD000.000).

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air-quality-management-plan/final-2016-aqmp/final2016aqmp.pdf?sfvrsn=15 at 3-32; see also San Joaquin Valley Air Pollution Control District, "2016 Ozone Plan," available at: http://valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/ES.pdf at ES-6.

95 Port of Los Angeles, "San Pedro Bay Ports Clean Air Action Plan 2017 Final," November 2017, at 33.

96 As stated above, other costs related to clean transportation are captured in other testimony areas.

8. Clean Fuels Power Generation

The primary goal of this group is to strategically manage policy, technology, compliance, and operational requirements relevant to the deployment of clean fuel power generation projects in efforts to achieve the State's carbon neutrality goals and SoCalGas's vision as described by the ASPIRE 2045 and clean fuels analysis.

The major activities of the clean fuels power generation teams consist of providing policy, technical, and economic feasibility analyses to internal and external facility operators advising in areas that pertain to regulatory, tariffs, contracts, air quality, legislation, market transformation, and education and training specific to clean fuel power generation. This group is a highly cross-functional team that works in collaboration with Customer Energy Solutions Account Representatives to provide customer support in the deployment of clean fuel power generation to all customer segments as described in Brian Prusnek's Customer Services-Information testimony (see Ex. SCG-16, Table BP-14).

Clean fuel power generation projects are subject to many operational, permitting, and safety requirements set forth by the many regulatory and legislative policies. Over the last several years, the number of policies related to clean fuel power generation projects has increased. SoCalGas assists customers in their deployment of clean fuel power generation by answering questions relating to policies that may impact the deployment of the projects. The clean fuels power generation team will also inform customers of the environmental and financial benefits of adopting microgrids. For example, the Clean Fuels Power Generation group provides assistance to customers looking to maximize microgrid benefits by integrating a multitude of Distributed Energy Resources (DER) such as photovoltaics, CHP, energy storage, fuel cells, and linear generators, along with clean fuels such as renewable gas and hydrogen to increase resiliency and reliability as well as economic benefits.[97] Ultimately, customers are looking to deploy microgrids that will yield the best financial outcome, which requires a full understanding of the numerous programs, tariffs, credits, and subsidies. Increasing customer support is not only

[97] U.S. Department of Energy, "The US Department of Energy's Microgrid Initiative," The Electricity Journal, Volume 25, Issue 8, October 2012, available at: https://www.energy.gov/sites/prod/files/2016/06/f32/The%20US%20Department%20of%20Energy's%20Microgrid%20Initiative.pdf.

in alignment with state goals, but it is also necessary to increase customer awareness and education.

Furthermore, climate change and extreme weather events are putting electric system resiliency and reliability at risk, posing serious safety and financial risks to California's people and electric utilities. Extreme weather in and outside of California has significant impacts on the planned operation of California's electric and gas grids making power system resiliency and reliability increasingly important. While the intent of planned outages in the electric system is to avoid greater loss or damage from the extreme climate events, the planned outages still have significant economic and health impacts on many customers.[98] Despite the efforts to reduce the related capacity shortfall due to climate-related events, customers remain vulnerable to unplanned power outages. According to the US Environmental Protection Agency's (EPA) assessment of indoor air quality and climate change, power outages may occur with more frequent extreme weather, making it more difficult to maintain comfortable indoor temperatures and healthy indoor air quality, and leading to more frequent use of portable generators."[99] SoCalGas's clean fuels power generation activities can potentially drive a zero-carbon resiliency solution as traditional gas is displaced with clean fuels for power generation.

The Clean Fuels Power Generation team will increase education, outreach and project support to customers who are looking to adopt clean fuel generation technologies. The intent is to provide customer support in the deployment of projects that meet or exceed expected environmental goals of the State with clean fuels such as renewable natural gas and hydrogen, and technologies such as fuel cells, electrolyzers, combined heat and power, and linear generators.

a. Cost Drivers

For TY 2024, SoCalGas is requesting an incremental increase of $0.360 million for Clean Fuels Power Generation from the 2021 BY costs. This is part of the overall incremental request

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[98] California Governor's Office, Emergency Services, "FY 2019-20 Public Safety Power Shutoff Legislative Report," available at: https://www.caloes.ca.gov/GrantsManagementSite/Documents/Public%20Safety%20Power%20Shutoff%20Legislative%20Report%20FY%202019-20.pdf.

[99] U.S. Environmental Protection Agency, "Indoor Air Quality and Climate Change," December 16, 2021, available at: https://www.epa.gov/indoor-air-quality-iaq/indoor-air-quality-and-climate-change.

of $12.205 million for the Clean Fuels Infrastructure Development group as shown in Table AI-7. The $0.360 million incremental increase for Clean Fuels Power Generation includes $0.300 million in labor and $0.060 million in non-labor to support increased workload to address growing interests in clean fuel power generation projects, and to increase resiliency, reliability, decarbonization, air quality benefits and new technology adoption. The increase in labor and non-labor expenses is to support the following:

- Labor expenses to account for 3 FTEs (two project managers and one administrative assistant) to support clean fuels power generation objectives through research and data gathering efforts, document review, customer outreach, education, and admin support;
- Non-labor expenses required to support clean fuel power generation projects, including feasibility analysis of clean fuel power generation with the intent to transition to clean fuels such as hydrogen and adoption of CCUS; and
- Non-labor expenses required for the development and ongoing maintenance of clean fuel power generation feasibility tool, as well as providing outreach and education to customers transitioning to clean fuels such as renewable gas, hydrogen, or carbon reduction.

For additional details, please refer to workpaper (SCG-12-WP, 2RD000.000).

C. Clean Energy Innovations Project Management Office (PMO)

Included in this section of the testimony are activities and associated O&M costs for PMO, which are non-shared. The costs are summarized in Table AI-8 below.

TABLE AI-8
Clean Energy Innovations PMO Cost Summary

Clean Energy Innovations Project Management Office (PMO) (in 2021$, in 000s)			
O&M	**2021 Adjusted-Recorded**	**Estimated TY 2024**	**Change**
Labor	$293	$1,523	$1,230
Non-Labor	$4	$69	$65
Total O&M	$297	$1,592	$1,295

1. Description of Costs and Underlying Activities

The complexity of projects and activities executed as part of CEI's project portfolio and the integration between them and other existing enterprise systems and organizations requires the institution of formal project management processes and procedures to mitigate risks and increase the likelihood of project success. To accomplish this, the CEI PMO is responsible for the establishment and implementation of a project governance and management framework to reduce risks through checks and balances during the project life cycle. The governance processes are guided by industry standards and best practices, designed to standardize project execution across the project portfolio, and to provide leadership with clear, timely, and accurate portfolio information and allow management to assess whether projects follow scope and schedule, meet quality expectations, and are on target to achieve established goals.

The project management framework includes:

1. Defining project and portfolio management standards including common templates and documentation standards, project staging guidelines, processes for ending project activities, and transition project outcomes to operations;
2. Establishing a common methodology for tracking and reporting project scope, project risk, project changes, scheduling strategy and execution, and project communications;
3. Implementing monitoring tools to provide timely and accurate project reporting to aid leadership in ensuring continued portfolio alignment with clean energy strategies, and best allocation of resources;
4. Establishing Organizational Change Management (OCM) processes and methodologies for introducing changes driven by project results to the organization;
5. Developing and executing a process to help achieve project benefits;
6. Facilitating tracking of project plans; and
7. Establishing and staffing an organization with experienced management staff in each of the core PMO control areas.

The CEI PMO is comprised mainly of two focus areas: (1) the PMO Portfolio Management Group that is responsible for the establishment and implementation of project management standards and reporting across the entire portfolio of CEI projects, and (2) the PMO Special Initiatives Group that is responsible for project management of specific initiatives and established based on the initiatives’ changing needs. PMO functions are aligned to support project activities while providing the Company leadership with visibility of the project portfolio through project lifecycles. In support of a lean organization, cross-training is performed whenever feasible.

2. Forecast Method

The forecast method developed for this cost category for labor and non-labor expenses is the base year method. Incremental adjustments represent the anticipated expense requirements in TY2024. This method is most appropriate because the CEI PMO group was formed in January 2021 and no historic cost information exists prior to this date.

3. Cost Drivers

Clean Energy Innovations Project Management Office's total adjusted-recorded expenditures of $0.297 million in BY 2021 consisted of $0.293 million in labor and $0.004 million in non-labor costs. For TY 2024, SoCalGas is requesting a total of $1.592 million. This amount reflects $1.295 million incremental increase from the base year. The incremental increase includes $1.230 million in labor and $0.065 million in non-labor to support an expected growth in activity associated with clean energy-related projects and activities that help deliver future products and services to customers. The increase in labor and non-labor expenses is to support the following:

- Labor expenses include PMO project managers and project advisors.
- Non–Labor expenses include project management software acquisition and maintenance.

For additional details, please refer to workpaper (SCG-12-WP, 2RD002.000).

D. Research Development & Demonstration (RD&D) Refundable Program

TABLE AI-9
Research Development & Demonstration Cost Summary

Research Development & Demonstration Refundable Program (in 2021$, in 000s)			
O&M	**2021 Adjusted-Recorded**	**Estimated TY 2024**	**Change**
Labor	$2,111	$2,608	$497
Non-Labor	$15,929	$20,641	$4,712
Total O&M	$18,040	$23,249	$5,209

1. Description of Costs and Underlying Activities

The RD&D Program is a statutorily authorized program that identifies and supports new technologies and research activities.[100] The mission and values of the RD&D Program align with SoCalGas's mission to build the cleanest, safest, and most innovative energy company in America. The RD&D Program's mission, which is to "Identify transformational energy Solutions. Build them. Share them with the world," is supported by three core values: (1) Science – Our experts in science, engineering, energy systems, and environmental policy seek to answer some of today's most pressing energy questions; (2) Synergy – We work with the world's finest researchers in universities, nation labs, and industry to develop transformational technologies that support decarbonizations, energy security, and economic development; and (3) Equity – We champion technologies that support affordable access to clean, safe, and reliable energy.

The RD&D Program cost forecast for TY2024 of $23.249 million is driven by the need to develop and deploy technologies that: (1) reduce GHG emissions, (2) increase safety, and (3) improve energy reliability for all Californians.

As in prior GRC cycles, the RD&D Program costs will be tracked in a one-way balancing account and all RD&D Program funding is refundable. Costs incurred and tracked in the RD&D Program balancing account include direct project expenditures and all project related management and administration costs.[101] This includes non-labor costs used for the direct

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[100] Pub. Util. Code § 740.1.

[101] Balancing account is further described in Rae Marie Yu's Regulatory Accounts testimony (Ex. SCG-38).

execution of RD&D projects by third parties under contract to SoCalGas, as well as labor and non-labor costs used in planning, directing, managing, and administering these projects.

2. Forecast Method

The forecast method developed and used for this cost category is the zero-based method. This method is most appropriate because specific RD&D needs and activities evolve over time as technologies progress and new public policies and goals are established. Additionally, a zero-based methodology is more forward-looking as it considers funding for projects that are being planned rather than projects that have already been completed. The zero-based method has been utilized for this workpaper in SoCalGas's last two GRCs and has been previously approved by the Commission. To provide additional support for the zero-based method, technology gaps and needs were assessed in each RD&D program area based on the current state of technology and then compared to the performance required to meet safety and reliability enhancements, energy efficiency goals, criteria pollutant and GHG emission reductions, and other cost and performance goals (more detail on the technology needs assessment is provided in Appendix B – "Technology Needs Assessment Summary"). The identified technology needs were combined with prior experience on project cost and co-funding requirements to develop target project funding requirements in each program area. To manage larger and more complex research initiatives, policy directives, and reporting requirements, two additional FTE are needed to manage these efforts. The TY2024 forecast reflects increased RD&D activity in hydrogen production and utilization, building decarbonization, energy reliability and resilience, carbon capture, zero-emission transportation, and gas transmission and distribution system safety and reliability.

3. Cost Drivers

The RD&D Program costs support the State's climate policy goals, including the continued use and adoption of clean fuels such as renewable natural gas and hydrogen, as well as carbon management in support of the State's carbon neutrality goals.[102] Additionally, the RD&D Program costs support the Company's goals of reducing emissions, improving performance, reducing cost across the full range of gas applications, and improving the safety and reliability of

[102] State of California, Executive Department, EO B-55-18 "Achieve Carbon Neutrality."

utility operations, all of which are aligned to SoCalGas's mission, strategy, safety, and sustainability plan.[103]

As explained in previous sections, SoCalGas is intent on leading the transition to a resilient and decarbonized clean fuels infrastructure in California.[104] Innovation and rapid development of new technologies will be essential to reach the decarbonization goals set by the State and SoCalGas. The development and deployment of clean energy solutions including hydrogen, renewable natural gas, synthetic fuels, and carbon management is made more achievable through active research, development, and demonstration of technologies that lead to increased affordability and adoption of resilient clean energy solutions at scale.

Additional cost drivers for this forecast include efforts to increase equity consideration and program transparency:

- SoCalGas, in consultation with the Commission and Energy Division Staff, is working to increase consideration of Environmental and Social Justice in RD&D funding decisions and to track and report efforts towards these considerations and to quantify their benefits. Additional resources are required to develop new policies and procedures, educate RD&D Program staff and research partners, and track and report progress.
- The RD&D Program began development of a multi-year, public-facing Equity Engagement Roadmap that seeks to include face-to-face encounters aimed at building trust, gathering and disseminating critical information, reporting, synthesizing data, and responding to ESJ needs appropriately.
- SoCalGas continues its efforts to increase transparency in the RD&D Program by providing research webinars on recently completed projects and compiling an annual report that both summarizes the RD&D Program's structure, objectives, and accomplishments and provides project level detail on each of the active and completed projects within the RD&D Program's portfolio.

Furthermore, additional RD&D resources are required to track and identify relevant funding opportunities that will result from the recently passed IIJA.[105] Some of the objectives of the IIJA that are relevant to the RD&D Program include: (1) to advance research and development to demonstrate and commercialize the use of clean hydrogen in the transportation,

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[103] SoCalGas, "ASPIRE 2045 SoCalGas Sustainability Strategy," available at: https://www.socalgas.com/sites/default/files/2022-01/SoCalGas_Sustainability_Strategy-final.pdf.

[104] *Id*.

[105] H.R. 3684 "Infrastructure Investment and Jobs Act," last modified November 15, 2021, available at: https://www.congress.gov/bill/117th-congress/house-bill/3684/text.

utility, industrial, commercial, and residential sectors; and (2) to demonstrate a standard of clean hydrogen production in the transportation, utility, industrial, commercial, and residential sectors by 2040. To help accomplish these goals, the IIJA has appropriated $500 million to advance clean hydrogen manufacturing and recycling research and development and $1 billion toward research, development, demonstration, commercialization, and deployment of hydrogen electrolysis program. The RD&D Program, along with project partners will develop proposals and seek to secure federal funding for these projects within California generally and specifically within SoCalGas's service territory.

For additional details, please refer to workpaper (SCG-12-WP, 2RD001.001).

E. The RD&D Program Supports California's Environmental, Health, Safety, and Reliability Policy Goals

The RD&D Program tracks and evaluates projects based on a set of six potential ratepayer benefits: safety, reduced GHG emissions, improved air quality, improved affordability, operational efficiency, and reliability. These six benefits were identified based on the project objectives outlined in CPUC Section 740.1 as well as some of California's environmental, health, safety, and reliability policy goals, including SB 32 (Reduce carbon dioxide emissions 40% below 1990 levels by 2030), Executive Order B-55-18 (Carbon-neutral California economy by 2045), AB 3232 (Reduce GHG emissions from residential and commercial buildings by 40% below 1990 levels by 2030), Executive Order N-79-20 (100% of MHDs be zero emission by 2045 for all operations where feasible), and CPUC General Order No. 112F (Rules governing design, testing, operation, and maintenance of gas transmission and distribution systems).

1. RD&D Projects Target Specific Ratepayer Benefits

Benefits are identified for each project funded by the RD&D Program. For example, in 2021, the RD&D Program supported 379 active projects. Of those projects, 177 contributed to safety, 203 supported improved reliability, and 211 had the potential to reduce GHG emissions. In accordance with CPUC Resolution G-3586, the RD&D Program is working with Energy Division staff to develop a framework to better quantify and report the specific benefits of funded projects.

SoCalGas's internal processes and stakeholder outreach promote relevant, non-duplicative, and effective RD&D, as set forth below.

2. A Rigorous Review Process Checks RD&D Projects Against CPUC Section 740.1 Standards

When identifying promising projects and evaluating them for potential funding, RD&D Program staff take a comprehensive yet flexible approach that enables them to: (1) identify potential projects that are most in alignment with RD&D Program goals, state and federal environmental policy, and industry demand; (2) assess the likelihood of potential projects to succeed; (3) work with proven partners and technologies over time; and (4) respond nimbly to changing market, technology, and policy drivers. In addition—remembering that some technologies will not result in concrete benefits until implemented at scale—RD&D Program staff consider the overall development and implementation process and research life cycle of a given technology or product.

RD&D Program staff relies primarily on CPUC Code Section 740.1 in developing project evaluation criteria. Key project evaluation criteria are customer benefit, alignment with California policy, lead investigator/team, technical feasibility, co-funding collaborators, commercialization potential, and equity considerations. SoCalGas's RD&D Program staff follow a rigorous approach to project identification and selection. In this process, program staff: (1) identify potential areas for research, development, and demonstration and collaborate with researchers to develop project proposals; (2) prepare or receive project proposals; (3) review project proposals with the RD&D Program team and SMEs, considering a wide range of inputs, including the current CPUC approved RD&D Research Plan, California policies and targets, project evaluation criteria, and the overall portfolio strategy; (4) refine scopes of work for approved projects, if necessary; (5) review funding sources following SoCalGas accounting policies; and (6) execute the project contract and initiate project research. Projects that do not receive internal approval or sufficient funding may be directed to adjust the project scope and re-start that approval process at Step 2.

3. Annual Report, Public Workshop, and Research Plan Process Promote Public Engagement

Following the requirements of D.19-09-051, there is a robust annual process for presentation and approval of SoCalGas's RD&D plans. Each year, the SoCalGas RD&D program produces and submits to Energy Division an Annual Report that includes a summary of ongoing and completed projects; funds expended, funding recipients, and leveraged funding; and an explanation of the process used for selecting RD&D project areas as well as the structure of SoCalGas's RD&D portfolio. These reports are also posted on the SoCalGas RD&D website[106] for public access.

In addition, each year, the RD&D Program hosts a public workshop to present the results of the previous year's RD&D activities and obtain input regarding its intended spending for the following calendar year. Prior to the workshop, the RD&D Program directly engages key stakeholders in the R&D community, including DOE, CEC, and GTI Energy. In 2020, the online workshop was attended by 148 individuals from organizations, including CPUC, CEC, CARB, CalState LA, and Orange County Hispanic Chamber of Commerce. The 2021 workshop was attended by 165 individuals from organizations including CPUC, California Governor's Office of Business and Economic Development, GTI, SCAQMD, Earthjustice, and Latino Chamber of Commerce of Compton. Public comments during and after the workshops have proven valuable in providing guidance to RD&D staff in research planning efforts. Many comments have also highlighted the value that SoCalGas RD&D brings to the broader research landscape.

After considering stakeholder comments during the workshop, SoCalGas files a Tier 3 Advice Letter with its research plan for the following calendar year. The research plan includes budgets broken down by Sub-program, a description of how RD&D projects help improve reliability, safety, environmental benefits, or operational efficiencies, and a discussion of the ways RD&D staff incorporates feedback from workshop stakeholders and Commission staff.

Overall, this review process has proven to be extremely valuable, through incorporation of stakeholder input, sharing the results of the RD&D Program's research projects with them, and better connecting the members of the clean energy research community through various workshops.

4. Proposal to Modify Advice Letter Requirement

Although the newer, robust process for RD&D Program approval has resulted in more engagement and feedback from interested parties, the requirement of a Tier 3 Advice Letter

106 https://www.socalgas.com/sustainability/research-development-demonstration-rdd.

filing presents the Commission with an enormous review and approval burden. Therefore, SoCalGas is respectfully requesting that the process be modified to a Tier 2 Advice Letter to streamline and improve the program approval process.

In 2021, SoCalGas submitted the 2022 Research Plan (Advice No. 5824) on June 21st, 2021. Resolution G-3586, which approved the Research Plan in its entirety, was voted on and approved on March 17, 2022.

For almost the entire 1st quarter of 2022, the RD&D Program could not issue payment to research teams. As such, we respectfully request to modify the Advice Letter requirement from Tier 3 to Tier 2 to help reduce the administrative burden on the Commission and ED staff. A Tier 2 Advice Letter is appropriate for matters such as “A tariff change that is consistent with authority the Commission previously has granted to the Utility submitting the advice letter, such as a rate change within a price floor and ceiling previously approved by the Commission for that Utility.”[107] Since RD&D Program funding is authorized by the Commission through the GRC process and approval of the RD&D Annual Research Plan simply allows the RD&D Program to adapt to an ever-changing research landscape, a Tier 2 Advice Letter is appropriate. A Tier 2 Advice Letter requires approval of Commission Staff, who are actively engaged throughout the process described in the proceeding section. Furthermore, all Advice Letter filings include a 20-day protest period, further ensuring public oversight and transparency, and allowing the same opportunity for the public to be heard. SoCalGas is committed to working closely with the Commission, Energy Division Staff, and our public stakeholders to ensure that the RD&D Program provides the greatest possible benefit to our ratepayers.

5. The RD&D Program’s Equity Engagement Activities Improve Deployment of Clean Energy Benefits to Historically Underserved Communities

The RD&D Program seeks to advance and champion technologies that support widespread access to clean, affordable, and reliable energy for all Californians, including those living and working in ESJ communities. Equity is one of the Program’s core values that is considered in every funding allocation decision.

[107] CPUC, General Order 96-B, Industry Rule 5, § 5.2(2) (“Matters Appropriate to Tier 2”).

In 2021, the RD&D Program, in coordination with SoCalGas Regional Public Affairs (RPA) group, conducted five community outreach sessions to facilitate a dialogue with leaders from community-based organizations (CBOs) from across the SoCalGas service territory. Participants included El Concilio Family Services, Black Voice Foundation, Asian Youth Center, Community Action Partnership of Kern, UC Riverside, and CSU Los Angeles. Based on these conversations, the RD&D Program launched the development of an Equity Engagement Roadmap to identify specific activities that the RD&D Program will undertake to enhance the equity component of the program.

Furthermore, the RD&D Program works with the SoCalGas Supplier Diversity group to identify resources available to help diverse and minority-owned businesses connect and work with the RD&D Program. Supplier Diversity can help diverse business owners navigate the paperwork required to obtain certification by the CPUC as a Diverse Business Entity (DBE).

Finally, the RD&D Program seeks out underserved communities to identify host sites for demonstration projects. In 2021, the RD&D Program supported 27 projects located in SB535 disadvantaged communities including the cities of Compton, West Sacramento, and Riverside.

6. The RD&D Program Supplements and Complements Other R&D Programs

The RD&D Program is an important element of a larger technology funding ecosystem that includes federal, state, and regional public agencies, and a variety of gas industry research entities. RD&D Program staff works with leading industry professionals and SMEs from these organizations, as well as from universities, national labs, and businesses, to maximize the impact of their investments in promising technologies and products with high commercialization potential. These relationships enable SoCalGas to engage science and technology experts, other utilities, and industry stakeholders in open dialogues to effectively identify and close knowledge and research gaps, avoid duplication of previous and ongoing research, and mitigate technical, economic, and commercialization risks. Engagement with these groups help facilitate development of products and technologies that reduce customer costs, save energy, increase safety and reliability, improve air quality, and reduce GHG emissions. Together, information and research concepts are exchanged, project collaborations are developed, partnerships are established, and public and private funding opportunities are actively sought, with the goals of securing additional co-funding for projects as well as assembling the most capable and impactful team of SMEs to work on any particular project.

Within this rich state and national funding ecosystem, the RD&D Program plays a unique role. Whereas many other funding programs focus on national and statewide needs, the RD&D Program concentrates on the needs of its many residential, commercial, and industrial customers in Southern California. This focus enables the RD&D Program to better serve its customers by driving the scope of research sponsored by entities like DOE, ARPA-E, and EPA to concentrate on California's specific energy transition needs.

The SoCalGas RD&D Program also has many strengths of its own. First, SoCalGas is dedicated to engaging with and supporting the communities it serves, providing energy, time, and financial support in areas where it can make a difference. Because SoCalGas serves residential, commercial, and industrial gas customers in Southern California as its primary line of business, RD&D Program staff have access to the existing infrastructure, information, and expertise of the entire Company, including an intimate knowledge of customer challenges, needs, and desired benefits. In addition, the Company's existing infrastructure—as well as the relationships the Company has built with its customer base and regional public agencies—also provides access to a rich base of potential demonstration sites within the region. Importantly, the RD&D Program can act nimbly, providing funding to innovative new products and technologies that federal, state, and regional agencies cannot support due to slower funding cycles. Finally, the RD&D Program is positioned to supplement[108] and complement[109] the work of other organizations, by stepping in to fund early-stage research or middle- to late-stage technology

[108] D.19-09-051 at 377 ("SoCalGas provided evidence that their RD&D programs complement other R&D programs such as solicitations, host sites, and co-funding projects that complement the CEC's Natural Gas R&D program as well as projects that supplement programs by the Environmental Protection Agency and Air Resource Board.…The above shows that SoCalGas' RD&D program is not duplicative of and actually supplements other R&D projects by government agencies and other groups.")

[109] SoCalGas Advice Letter 5652, July 25, 2020, Appendix C at C-8 ("SoCalGas' RD&D program can complement the CEC's R&D efforts to help meet the state's clean energy goals…. Historically, the CEC has successfully partnered with SoCalGas on projects spanning residential and commercial end use appliances, industrial process energy improvements, and transportation with high- efficiency low-emission CNG heavy-duty engines. These collaborative projects have delivered important deployments (e.g., Hyperlight, GTI on food processing) and commercialization achievements (e.g., Cummins Westport)").

development that other organizations cannot support.

7. Recent Accomplishments Demonstrate the Effectiveness of the RD&D Program

In 2020 and 2021, SoCalGas RD&D projects resulted in the production of 95 publications, reports, and technology briefs. The RD&D Program's research work also produced four patents and patent applications. A major goal of the RD&D Program is to bring technology from lab to market. In 2020 and 2021, organizations across California and throughout the nation deployed numerous products and technologies for real-world use. Examples include a method for measuring fracture toughness via in-ditch, non-destructive testing; real-time visualization and notification of gas utility threats; an in-line inspection tool for gas storage piping; and a method to protect tracer wires from corrosion.

In 2020, 19 research proposals supported by the SoCalGas RD&D Program were awarded funding by government agencies including CEC, DOE, NSF, and ARPA-E. These awards represented over $38M of additional funding to support SoCalGas RD&D research initiatives. In 2021, 11 research proposals were awarded funding by public agencies including CEC, DOE, and PHMSA. These awards represent over $48M of additional funding to support SoCalGas RD&D research initiatives. Examples of such research initiatives include collaboration with DOE to demonstrate a technology that captures carbon dioxide from the air while simultaneously collecting water that can then be reused for irrigation[110]; funding from CEC to support SoCalGas, Sierra Northern Railway, Gas Technology Institute (GTI), and other technical experts to develop and test a zero-emission hydrogen fuel cell engine for a switcher locomotive;[111] and funding from CEC to support SoCalGas and Zero Emission Industries (ZEI)

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[110] SoCalGas, "SoCalGas to Fund Testing of First-of-its-Kind Direct Air Capture Technology," November 16, 2021, available at: https://newsroom.socalgas.com/press-release/socalgas-to-fund-testing-of-first-of-its-kind-direct-air-capture-technology.

[111] SoCalGas, "SoCalGas Partners with Sierra Northern Railway to Fund Development of Hydrogen Fuel Cell Switcher Rail Locomotive," July 28, 2021, available at: https://newsroom.socalgas.com/press-release/socalgas-partners-with-sierra-northern-railway-to-fund-development-of-hydrogen-fuel.

to develop a zero emissions solution for small commercial marine vessels by modifying a commercial boat with a hydrogen fuel cell in place of a combustion engine.[112]

Finally, numerous RD&D Program alumni companies have received significant following their participation in the RD&D Program. For example, Electrochaea's biomethanation technology was demonstrated at NREL with support from the RD&D Program. In 2021, Baker Hughes, a $20B industrial services company,[113] purchased a 15% stake[114] in Electrochaea, backing a technology intended to address concerns about greenhouse gas emissions. Also in 2021, electrochemical carbon dioxide reduction startup, Twelve (formerly Opus 12), which received early technology development support from the SoCalGas RD&D Program, raised $57 million in Series A[115] funding from lead investors Capricorn Technology Impact Fund and Carbon Direct Capital Management. These examples show the RD&D Program's ability to identify promising technology early, but also show the impact that SoCalGas's support can have in advancing those technologies to commercialization.

8. Funding Detail

The RD&D Program supports projects in four main research domains:

a. Clean & Renewable Energy Resources RD&D

The primary goal of the Clean & Renewable Energy Resources program area is to decarbonize the gas supply while maintaining its affordability and reliability. To accomplish this

[112] SoCalGas, "SoCalGas & California Energy Commission to Provide Funding to Test Hydrogen Fuel Cell Technology for Marine Vessels," April 27, 2021, available at: https://newsroom.socalgas.com/press-release/socalgas-california-energy-commission-to-provide-funding-to-test-hydrogen-fuel-cell.

[113] Baker Hughes Company Profile, available at: https://craft.co/baker-hughes.

[114] Bloomberg News, "Baker Hughes Takes a Stake in Synthetic Natural Gas Startup." June 28, 2021, available at: https://www.bloomberg.com/news/articles/2021-06-28/baker-hughes-takes-a-stake-in-synthetic-natural-gas-startup.

[115] Yahoo Finance, "Twelve, Formerly Opus 12, Secures $57 Million in Series A Funding Led by Capricorn and Carbon Direct," July 8, 2021, available at: https://finance.yahoo.com/news/twelve-formerly-opus-12-secures-120000904.html?guccounter=1&guce_referrer=aHR0cHM6Ly93d3cuYmluZy5jb20v&guce_referrer_sig=AQAAAKBIzUQYylBtZ5HUE8pbgBHCQ2h837FsthpVLnGtb2_OIg09pJ_c_PhNY9FAwxfkg-1eT0NjnCFUNWFRM2dmRFookOUFDJ8Huutl80EREhLiL5UahF5EIK08OH9nFBeRSs1pvWQ8W9kwdshvf9YNV4rPhNKcJHtrmqTlIJ69fcUe.

goal, program staff members develop, promote, and advance new technologies aimed at increasing and expanding the production of renewable gas to displace conventionally sourced pipeline gas, while aggressively eliminating GHG emissions.

b. Gas Operations RD&D

The Gas Operations RD&D program supports pipeline transportation and storage operations through innovations that enhance pipeline and employee safety, maintain system reliability, increase operational efficiency, and minimize GHG impacts to the environment.

c. Clean Transportation RD&D

The Clean Transportation RD&D program supports activities that minimize environmental impacts related to the transportation sector through the development of low-carbon fuels, zero and near-zero-emissions drivetrains, refueling infrastructure, and on-board storage technologies.

d. Clean Energy Applications RD&D

The Clean Energy Applications RD&D program supports the development and demonstration of highly efficient low-emission technologies associated with the stationary utilization of gaseous fuels for power generation and thermal applications. This program seeks to improve efficiencies, reduce emissions, lower costs, and improve reliability for residential, commercial, and industrial customers.

9. RD&D Program Cost Forecast

The RD&D Program cost forecast is a small fraction of the total GRC request. This level of RD&D funding as a proportion of annual authorized GRC base margin revenues is also consistent with the historical range over recent last program cycles.

TABLE AI-10
TY 2024 RD&D Program Funding Forecast
In Thousands of (In 2021 $, in 000s)

Program	Sub-Program	TY 2024 Forecast
Clean & Renewable Energy Resources	Renewable Gas Production	$ 3,701
	Carbon Management	$ 3,701
	Subtotal	**$ 7,402**
Gas Operations	Environmental & Safety	$ 784
	Operations Technology	$ 587
	System Design & Materials	$ 1,568

	System Inspection & Monitoring		$	980
		Subtotal	**$**	**3,919**
Clean Transportation	Off-Road		$	1,970
	On-Road		$	1,970
	Refueling Infrastructure		$	470
		Subtotal	**$**	**4,410**
Clean Energy Applications	Energy Reliability		$	1,970
	Residential & Commercial		$	1,470
	Industrial Operations		$	1,470
		Subtotal	**$**	**4,910**
Total			**$**	**20,641**

V. CAPITAL

Included in this section of the testimony are descriptions of activities associated with capital expenditures for the [H2] Hydrogen Home and Hydrogen Refueling Stations related to CEI. The capital expenditure forecasts and the actual costs for these projects are referenced in other SoCalGas testimonies including in witness Brenton Guy's Real Estate and Facility Operations testimony (Ex. SCG-19) and Mike Franco's SoCalGas Fleet Services testimony (Ex. SCG-18).

A. [H2] Hydrogen Home

In TY2024, SoCalGas is forecasting $4.573 million to support the capital expenditure activities to build the [H2] Hydrogen Home project, a state-of-the-art clean energy project to showcase the role hydrogen could play in attaining California's decarbonization goals. Included in this section of the testimony is the overview and the associated scope of the non-shared project. Refer to the Real Estate and Facility Operations testimony of Brenton Guy's Real Estate and Facility Operations testimony (Ex. SCG-19) for the detailed capital expenditure forecast for the [H2] Hydrogen Home project.

1. Description

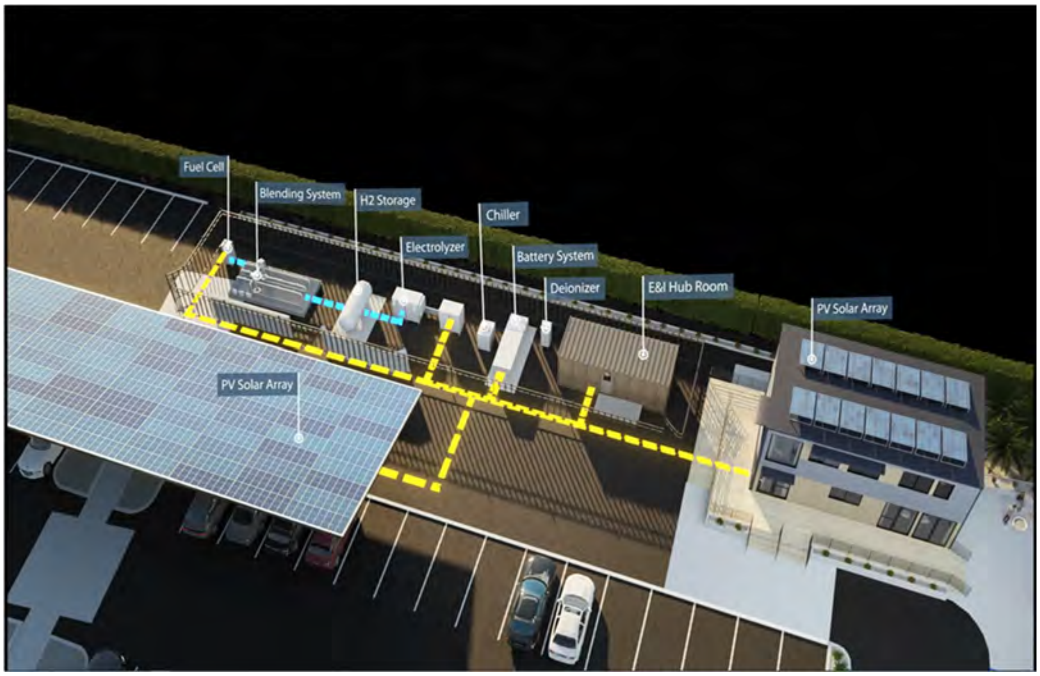
As part of SoCalGas's clean energy solutions to help its 22 million customers enjoy a more sustainable future, the CEI is currently building the [H2] Hydrogen Home project, a state-of-the-art clean energy project to showcase the role hydrogen could play in attaining California's decarbonization goals. The [H2] Hydrogen Home project is one of first of its kind clean energy projects that incorporates solar panels, battery storage, green hydrogen production, hydrogen fuel cell, hydrogen storage, and hydrogen blending into the natural gas system for a less carbon-intensive energy source to be used in the home's appliances, including the heat pump, heating and air conditioning unit, water heater, clothes dryer, and gas stove.

Being the first of its kind in the U.S., the [H2] Hydrogen Home project will create an islanded microgrid that includes a home, solar arrays, a home battery, and an electrolyzer to convert solar energy into green hydrogen. It will also include a fuel cell to convert the hydrogen back to electricity. The home will function and feel exactly like a regular home but use reliable and clean energy 24 hours a day, 7 days a week, 365 days a year. The [H2] Hydrogen Home project has been named one of Fast Company's 2021 World-Changing Ideas in the North America category because of its impact on climate goals, design, scalability, and ingenuity in innovation.[116]

The [H2] Hydrogen Home project integrates renewable hydrogen production and fuel cell technology with a renewable energy stand-alone-power-system in a "living lab" microgrid setup. The [H2] Hydrogen project will have renewable energy generated from the 65 kW cart port and 7 kW rooftop solar photovoltaics, which will also be used to produce renewable hydrogen from a 62 kW electrolyzer. Excess renewable energy will also be stored for non-sunshine hours-usage in 230 kWh capacity as onsite battery energy storage. Green hydrogen will be stored in a 30-bar high-pressure storage vessel on-site and will either be distributed within the microgrid as a blended fuel with natural gas (20% hydrogen by volume) for use as a direct fuel for home appliances or as direct power to the home via a 100% hydrogen fuel cell. The [H2] Hydrogen Home design is a two story 1,920 square foot, pre-engineered sustainable modular home. The [H2] Hydrogen Home is being designed for Platinum LEED certification upon its completion.

[116] SoCalGas Newsroom, PRNewswire, "SoCalGas' H2 Hydrogen Home Named a Fast Company 2021 World-Changing Idea," June 15, 2021, available at: https://newsroom.socalgas.com/press-release/socalgas-h2-hydrogen-home-named-a-fast-company-2021-world-changing-idea.

Figure AI-3
[H2] Hydrogen Home Scope



The [H2] Hydrogen Home project is currently under construction and scheduled to be completed in 3rd quarter of 2022.

The research, testing, and showcase efforts as part of the [H2] Hydrogen Home project would inform the viability assessments and to further innovate and adopt future hydrogen technologies at scale. The [H2] Hydrogen Home project aims to accelerate the clean energy transition by increasing the delivery of clean fuels such as green hydrogen and to meet SoCalGas' sustainability goals[117] and California's decarbonization goals. The results from the [H2] Hydrogen Home project will help advance SoCalGas's clean energy and sustainability endeavors with a focus on protecting California's communities with the goal to achieve net zero greenhouse gas emissions and helping to improve local air quality and to increase access to clean and more affordable energy for all energy customers.

[117] SoCalGas, "ASPIRE 2045 SoCalGas Sustainability Strategy" available at: https://www.socalgas.com/sites/default/files/2022-01/SoCalGas_Sustainability_Strategy-final.pdf.

B. Hydrogen Refueling Stations

1. Description

SoCalGas plans to construct and operate public access Hydrogen Refueling Stations (HRS) at utility operating bases, as sponsored in Brenton Guy's Real Estate and Facility Operations testimony (Ex. SCG-19). These HRS will be designed to serve the utility fleet located at the bases in question as well as the general public. The general public will be offered hydrogen fuel once a retail rate for hydrogen vehicle fuel is approved in the next applicable Triennial Cost Allocation Proceeding. See Section IV.B.7, above for more detail on hydrogen transportation.

2. Low Carbon Fuel Standard

Since SoCalGas is seeking authority to construct and operate HRS, it will now be possible to begin generating hydrogen related green credits, including but not limited to CARB Low Carbon Fuel Standard (LCFS) credits. As a result, SoCalGas requests the authority to sell and disburse hydrogen related green credits generated by utility owned, public access hydrogen vehicle refueling stations to customers, consistent with the treatment of natural gas vehicle related green credits described in D.14-05-021, D.14-12-083 and Advice Letter 5295-G. The green credit revenue will be placed in the Hydrogen Refueling Station Balancing Account (HRSBA) as described in the Rae Marie Yu's Regulatory Accounts testimony (Ex. SCG-38).

VI. CONCLUSION

My testimony covers a variety of functions and activities that supports innovative clean energy technologies and pathways to create a portfolio of clean energy solutions, which is foundational to the energy transition for California and to meet SoCalGas' sustainability goals.

The incremental funding requests in my testimony are driven by SoCalGas's sustainability strategy and in support of California's goal to meet the States' decarbonization goals. The CEI's activities are carried out to protect the interests and safety of our customers and our community that we serve and to ensure that State's decarbonization goals are achieved cost-effectively.

This concludes my prepared direct testimony.

VII. WITNESS QUALIFICATIONS

My name is Armando Infanzon. My business address is 555 West 5th Street, Los Angeles, California 90013. I am employed by Southern California Gas Company as Director of Business Development. My present responsibilities are the project development of clean fuels infrastructure including hydrogen, carbon capture, utilization and sequestration and distributed energy resources. I also manage the Federal Energy Retrofit Program (FERP) for SoCalGas.

Between 2011-2014, I served as Smart Grid Policy Manager for San Diego Gas and Electric (SDG&E) representing the company on regulatory and legislative issues at state and federal level. I served as a witness for SDG&E's Energy Storage Procurement Application (A. 14-02-006).

I have been employed by Sempra Energy, SDG&E and/or SoCalGas since 1998 and have held various management level positions covering an array of different areas including business development, regulatory and energy policy, economic analysis, financial planning, corporate finance, and asset management. I received a bachelor's degree in accountancy from the Autonomous University of Baja California in 1997 and a master's degree in business administration from San Diego State University in 2000.

APPENDIX A

Glossary of Terms

Appendix A
Glossary of Terms

Acronym	Definition
ACF	Advanced Clean Fleets
BNEF	BloombergNEF
BY	Base Year
CAISO	California Independent System Operator
CARB	California Air Resources Board
CBO	Community-based organizations
CCUS	Carbon Capture, Utilization, and Storage
CDFA	California Department of Food and Agriculture
CEC	California Energy Commission
CEI	Clean Energy Innovations
CES	Customer Energy Solutions
CFF	Cross-Functional Factor
CFR	Code of Federal Regulations
CO2	Carbon dioxide
CoRE	Consequence of Risk Event
CPUC	California Public Utilities Commission
DBE	Diverse Business Entity
DOE	Department of Energy
DOT	Department of Transportation
E3	Energy and Environmental Economics, Inc.
EO	Executive Order
EPC	Engineering, Procurement, and Construction
EPIC	Electric Program Investment Charge
ESJ	Environmental & Social Justice
FCVs	Fuel Cell Vehicles
FEED	Front-End Engineering and Design
FERP	Federal Energy Retrofit Program
FTE	Full-Time Equivalent
GFO	Grant Funding Opportunity
GHG	Greenhouse Gas
Gt	Gigatons
GTI	Gas Technology Institute
GVWR	Gross Vehicle Weight Rating
HRSBA	Hydrogen Refueling Station Balancing Account
ICT	Innovative Clean Transit
IIJA	Infrastructure Investment and Jobs Act
IT	Information Technology
kg	Kilogram

Acronym	Definition
KPI	Key performance indicator
LADWP	Los Angeles Department of Water and Power
LCFS	Low Carbon Fuel Standard
LoRE	Likelihood of Risk Event
NFPA	National Fire Protection Association
NGVs	Natural gas vehicles
NOx	Nitrogen oxides
O&M	Operations and Maintenance
OCM	Organizational Change Management
OEM	Original Equipment Manufacturer
OIR	Order Instituting Rulemaking
OT	Operational Technology
PM	Particulate matter
PMO	Project Management Office
RAMP	Risk Assessment Mitigation Phase
RD&D	Research Development & Demonstration
RGS	Renewable Gas Standard
RNG	Renewable Natural Gas
RPA	Regional Public Affairs
RSE	Risk spend efficiency
SB	Senate Bill
SCALE	Storing CO2 and Lowering Emissions
SCG	SoCalGas
SDG&E	San Diego Gas and Electric
SNG	Synthetic Natural Gas also referred to as Syngas
SoCalGas	Southern California Gas Company
T&D	Transmission and distribution
TY	Test Year
ZEI	Zero Emission Industries
ZEVs	Zero-Emission Vehicles

APPENDIX B

Technology Gap Assessment

APPENDIX B

Technology Gap Assessment

Technology Gap Assessment Summary

Program	Sub-Program	TY2024 Forecast ($,000)
Clean & Renewable Energy Resources	Renewable Gas Production	3,701
	Carbon Management	3,701
	Subtotal	**7,402**
Gas Operations	Environmental & Safety	784
	Operations Technology	587
	System Design & Materials	1,568
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Clean Transportation	Off-Road	1,970
	On-Road	1,970
	Refueling Infrastructure	470
	Subtotal	**4,410**
Clean Energy Applications	Energy Reliability	1,970
	Residential & Commercial	1,470
	Industrial Operations	1,470
	Subtotal	**4,910**

Total	**20,641**

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Clean & Renewable Energy Resources Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
Renewable Gas Production	EO B-55-18: 2045 Carbon-neutral California economy AB 3232: Building decarbonization Clean Air Act: Air quality standards for NOx and PM	Reliability: Increase in-state production of renewable hydrogen and methane. Safety: These technologies can help	Electrochemical Methods	Baseline: The current cost of producing hydrogen gas through electrolysis pathways is between $5 and $6/kg-H2. Mass adoption of electrolyzers to produce hydrogen has high cost barriers due, mostly associated with the use of rare materials and the need of a balance of plan. Source: https://www.hydrogen.energy.gov/pdfs/20004-cost-electrolytic-hydrogen-production.pdf	1) Explore alternatives to traditional electrolyzer designs for the production of renewable hydrogen. Promising approaches include: a) novel electrolyzer geometries, b) development of next-generation membrane technology, and c) integrated photoelectrochemical

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	SB 32: Regulating and monitoring GHG emission sources AB 32: GHG emission reduction targets SB 1383: Methane (CH4) emissions from organic waste LCFS: Reduce carbon intensity of transportation fuels AB 8: Development of 100 hydrogen Refueling Infrastructure in California EO B48-18: 200 hydrogen	promote the safe production of hydrogen. Operational Efficiency: The CCNTP (Catalytic Non Thermal Plasma)system enhances operational efficiency through reduced capital costs and energy requirements, both on the front end and post-production. Improved Affordability: The ability to		Gap: The DOE's goal for hydrogen production is to produce hydrogen via net-zero-carbon pathways and reduce the cost of clean hydrogen to $1/kg in one decade. Deployment at scale may require identifying and leveraging earth-abundant materials for use in catalysis or other electrochemical processes. Source: https://www.energy.gov/policy/energy-earthshots-initiative	water splitting devices 2) Develop and scale-up production of earth-abundant catalysts to enable alternatives to the relatively scarce platinum group metals used in current state-of-the-art applications. 3) Support development and demonstration of electrochemical hydrogen pumping, separation, compression, and storage technologies due to their potential to maximize the efficiency of the hydrogen production chain while reducing costs and systemic carbon footprint.
			Renewable Hydrocarbon Conversion	Baseline: The current cost of producing hydrogen gas through traditional SSMR (Steam Methane Reforming) pathways is around $2.27/kg. The cost to produce renewable hydrogen from net-zero-carbon pathways is even more expensive, upwards of 2.5x more than traditional methods.	1) Identify technologies to enable efficient production of renewable hydrogen from renewable hydrocarbon feedstocks. 2) Explore alternatives to traditional SMR for the production of renewable hydrogen via non-

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	Refueling Infrastructure in California by 2025	sell valuable carbon from methane pyrolysis will lower the production cost of renewable hydrogen gas. Environmental: Reduced GHG Emissions Environmental: Improved Air Quality		Gap: The DOE's goal for hydrogen production is to produce hydrogen via net-zero-carbon pathways and reduce the cost of clean hydrogen to $1/kg in one decade. Meeting these goals in systems generating hydrogen from hydrocarbon feedstocks requires improvements in conversion efficiency and appropriate management or leveraging of any byproducts. Source: https://www.energy.gov/policy/energy-earthshots-initiative ——— Gap: Biogas upgrading technologies that can reduce RNG production costs may drastically reduce GHG emissions from live feedstock agriculture. To achieve California state target and company goals of net carbon neutrality by 2045, SoCalGas needs to remove fossil sourced natural gas from its system, cumulatively reducing approximately 2 million tons of carbon dioxide per year over the next 20 years. https://www.socalgas.com/sites/default/files/2022-01/SoCalGas_Sustainability_Strategy-final.pdf	conventional pathways with high potential for scale-up. Promising approaches include: advanced SMR or pyrolysis solutions such as: a) inductively heated microchannel reactors, b) catalytic non-thermal plasma technology applications, c) membrane reactors, and d) renewable methane pyrolysis. 3) Explore technological advancements in hydrogen production from biomass streams through biomass gasification and biomass pyrolysis.

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Technology Gap Assessment

<table>
<tr>
<td rowspan="2">Carbon Manageme nt</td>
<td rowspan="2">EO B-55-18: 2045 Carbon-neutral California economy

AB 3232: Building decarbonization Clean Air Act: Air quality standards for NOx and PM

LCFS: Reduce carbon intensity of transportation fuels

AB 8: Development of 100 hydrogen Refueling Infrastructure in California

EO B48-18:</td>
<td rowspan="2">Environmental: Reduced GHG Emissions and potentially create pathways to achieve negative emissions. Improved Affordability: Reduced operating and capital costs. Operational Efficiency: Direct conversion of CO2 to materials, increase conversion rate.</td>
<td rowspan="2">Point-Source Carbon Capture</td>
<td>Baseline: Commercial systems for post-combustion carbon capture. At scale ($400-$500 million per unit), the current cost is $40-$100 per ton of carbon dioxide captured.

https://www.pnnl.gov/news-media/cheaper-carbon-capture-way</td>
<td rowspan="2">1) Identify technologies involving flue gas/tailgas processing for CO2 capture and conversion to reduce cost and improve capture efficiency.

2) Develop new solvent, sorbent, or membrane technologies to increase capture efficiency.

3) Explore modularization of carbon capture devices to enable fast adoption at a wide range of industrial scales.

4) Perform fundamental research and pre-commercial development to advance carbon capture technologies, including microchannel devices, supersonic compression, cryogenic modular processes, and flue gas aerosol pretreatment.</td>
</tr>
<tr>
<td>Gap: Cheap and rapidly deployable small-scale carbon capture technology to meet or beat current large-scale carbon capture costs. DOE has funded research targeting $30 per ton of carbon dioxide captured at point-sources by 2030. In order for California to achieve its goal of net carbon neutrality by 2045, carbon capture technology must be developed and deployed at scale.

Sources:
https://netl.doe.gov/projects/project-landing-page-list.aspx

https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf</td>
</tr>
</table>

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	200 hydrogen Refueling Infrastructure in California by 2025	Environmental: Improved Air Quality	Carbon Dioxide Removal (CDR)	Baseline: Commercial carbon dioxide sorbents capture carbon dioxide from the atmosphere. The projected cost for direct air capture (DAC) using current technologies ranges from \$100 to \$1,000 per ton of carbon dioxide captured. Sources: Nisbet (2019) THE CARBON REMOVAL DEBATE. Asking Critical Questions About Climate Change Futures, Carbon Removal Briefing No. 2, Institute for Carbon Law Removal and Policy, American University, 24 pages, https://www.american.edu/sis/centers/carbon-removal/upload/carbon-removal-debate.pdf Fuss, et al. (2018) Negative emissions-Part 2: Costs, potentials and side effects, in: Environmental Research Letters, Vol 13(6): 063002, https://iopscience.iop.org/article/10.1088/1748-9326/aabf9f	1) Develop/improve high-efficiency sorbents and optimize device design to bring total direct air capture system costs down. 2) Explore carbon capture from ocean and other systems with increased carbon concentrations relevant to atmospheric levels. 3) Develop technology to capture carbon dioxide while simultaneously co-producing clean water. 4) Develop electrodialysis technology to efficiently extract carbon dioxide from oceanwater sources. 5) Identify other technology to accomplish mineralization or conversion-to/capture-as other solid products for sequestration on a geologically relevant time scale.
				Gap: DOE goal is <\$100 per ton CO_2 captured (DOE 10-year target, Earthshot goal). In order for CA to achieve its goal net carbon neutrality by 2045, carbon capture technology must be deployed at scale.	

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				Source: https://www.energy.gov/policy/energy-earthshots-initiative https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf	
			Carbon Conversion/Recycling	Baseline: The current market size for carbon-dioxide-based products is $10.67 billion, with a compound annual growth rate of 4.0%. The global petrochemical market is $556 billion with a compound annual growth rate of 6.4%.	1) Explore the conversion of sequestered or captured carbon to useful, durable products and to improve the emissions outlook on the ~50-100 year time-scale vs. unconverted carbon material through life cycle assessment (LCA) analysis. 2) Identify carbon recycling opportunities, including synthesis of building materials from captured carbon dioxide; electrochemical reduction; conversion of carbon dioxide to industrially useful chemicals; and extraction, conversion, and recycling of carbon compounds from waste/wastewater streams for the production of
				Gap: Diversion from fossil-based to carbon-dioxide-based synthesis of durable carbon-based products and an increased market share of carbon-dioxide-based products to reduce emissions from newly-extracted fossil sources.	

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					biologically-sourced and industrially-relevant precursors (i.e. biocrude oil and renewable fuels). 3) Explore further opportunities for diversion and conversion of waste streams to mitigate organic decay emissions and reduce/replace fossil extraction.

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
Environmental and Safety	EO B-55-18: 2045 Carbon-neutral California economy Clean Air Act: Air quality standards for NOx and PM SB 32: Regulating and monitoring GHG emission sources AB 32: GHG emission reduction targets SB 1383: Methane emissions from organic waste	Reliability: Pipeline safety management system and high consequence area assessment tools improve public safety and pipeline reliability. Safety: Accurate asset-locating technology prevents mechanical damage caused by excavation and construction activities. Ratepayers experience increased safety through avoiding accidental damage to	Systems Emissions	**Gap #1: Technology to Reduce Combustion GHG and Criteria Emissions from Transmission and Storage**	**How we are planning to address Gap #1**
				1. Continuous efficiency performance monitoring for turbochargers 2. Improved catalyst regeneration process 3. Reciprocating engine exhaust methane slip reduction 4. Precombustion chamber design 5. Engine controller design solutions to address variable fuel composition of lean-burn engines--field based evaluation 6. Low-cost sensors for	1) Efficiency monitoring technology for compressor station equipment 2) Technology to retrofit existing equipment to improve efficiency and reduce GHGs 3) Diagnostic technology to provide real-time monitoring of facility to improve operating performance 4) Low-cost and accurate sensors for measuring criteria pollutants 5) Alternatives to natural gas-powered equipment 6) Control algorithms for

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
	LCFS: Reduce carbon intensity of transportation fuels AB 8: Development of 100 hydrogen Refueling Infrastructure in California EO B48-18: 200 hydrogen Refueling Infrastructure in California by 2025 Cal/OSHA Title 8 CC: Injury and Illness Prevention Program	pipelines. Remote monitoring technology to alert operators of mechanical damage also enhances safety by enabling operators to respond to accidents. Operational Efficiency: Decreases in operating costs benefit ratepayers with reliable and affordable energy. Improved Affordability: Increases in operating		accurate sensors for measuring criteria pollutants	criteria pollutant reduction in equipment 7) Reciprocating engine exhaust methane slip reduction 8) Improve precombustion chamber for GHG reduction
				Gap #2: Technology to Reduce Combustion GHG from Transmission and Storage Using Hydrogen or Alternative Fuels	**How we are planning to address Gap #2**
				1. Fuel reforming and segregation as alternative for compressor fuels 2. Alternative fuels for combustion equipment	1) Non-carbon fuels for compressors to reduce GHGs 2) Renewable Natural Gas 3) Alternatives to natural-gas-powered devices

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
		efficiency not only reduce GHG emissions, criteria pollutants, and toxics, but also decrease operating costs. Environmental: Reduced GHG Emissions: Non-carbon fuel source eliminates CO2, criteria pollutants, and some toxic byproducts. Ratepayers		**Gap #3: Develop and improve Pipeline Repair Technology to Reduce GHG Emissions**	**How we are planning to address Gap #3**
				1. Evaluate in-situ repair techniques 2. Centrifugal compressor dry gas seal reliability enhancement 3. Methods to reduce pipeline blowdowns to effectuate inspection and repair	1) In-situ valve repair techniques 2) Alternative pipeline repair methods 3) Energy recovery 4) Low-cost instruments to detect/quantify leaks from seals, packings, and valves 5) Alternative technology to reduce blowdowns
				Gap #4: Explore Paths to Abating GHG Emissions	**How we are planning to address Gap #4**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
		benefit from elimination of GHG emissions and better air quality. Environmental: Improved Air Quality: Technology reducing criteria pollutants and toxics improves air quality for ratepayers.		1. Methane oxidation catalysts for reduction of emissions in flaring 2. Classification of methane emissions at regulator stations	1) Better air pollution control technology 2) Better leak detection and monitoring technology 3) Certified renewable natural gas 4) Preparing relief valves for emissions control which includes a—detection of leakage through valve; b—technology to sense overflow; and c—technology to capture emissions 5) Study of ability to reduce emissions after commissioning of new pipeline by pickling 6) Pilot study assessment of reductions from certified natural gas
			Environment	**Gap #1: Identify potential sources for emissions and the**	**How we are planning to address Gap #1**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				impact to the environment	
				1. Development and evaluation of high-resolution historical climate dataset over California 2. Stanford Natural Gas Initiative Program 3. Center for Methane Research 4. PRCI (Pipeline Research Council International) GHG strategic research priorities	1) Participate in industry-led organization to focus on new fuels to reduce GHG 2) Leverage research funding to benefit ratepayers
				Gap #2: Determine research gaps that need to be studied supporting decarbonization efforts	**How we are planning to address Gap #2**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				1. LDC (Local Distribution Company) focused gap analysis and SOTA (state of the art) study on decarbonization	1) Preparation of RNG market (sources and regions, development over last 10 years and market projection, US and Canadian production capacity and example North American and European projects) 2) Identification and evaluation of RNG treatment technologies and technology readiness levels 3) Assessment of pipeline-quality specifications for RNG (by country, regions and example specifications) 4) Overview of available credits for environmental attributes (e.g., RINs, LCFS, and others)
			Safety	**Gap #1: Determine Hydrogen Impact on Pipeline Infrastructure**	**How we are planning to address Gap #1**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				1. Gap identification between hydrogen and natural gas pipelines 2. Study of natural gas dispersion with blended hydrogen in residential structures 3. Center for Hydrogen Safety 4. In service welding onto methane/hydrogen mixture pipelines 5. Impact of blended hydrogen on threaded connections	1) Explore paths to carbon neutrality and conversion of infrastructure 2) Impact of blended hydrogen on CGI leak detection instruments
				Gap #2: Damage Prevention: Develop sensors that monitor and alert operators of third-party excavation activities, encroachment, and other natural events	**How we are planning to address Gap #2**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				1. Smart shutoff technology for commercial and residential buildings 2. Subsurface multi-utility asset location detection 3. Advanced computed tomography for pipeline inspection 4. Recommended practice for post-construction geohazard management	1) Technology to prevent accidental mechanical damage from excavations 2) Technology to accurately inventory asset locations for use in avoiding excavation damage 3) IT technology to assist inspection of pipelines for safety 4) Best practices for construction activities to avoid mechanical damage 5) Remote monitoring technology to locate mechanical damage
				Gap #2a: Damage Prevention: Improve locating technologies to reduce or prevent damages	**How we are planning to address Gap #2a**
				1. Aboveground service tee identification and mapping system 2. ORFEUS obstacle	1) Reduce cross bore intrusions caused by horizontal boring, independent of the operator

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				detection technology for horizontal directional drilling 3. Selecting locating and excavation technologies	2) Improve and develop new locating technology for identifying asset locations 3) Technology to locate PE pipes with accuracy
				Gap #3: Explore new technologies to improve worker safety and explore innovative training approaches	**How we are planning to address Gap #3**
				1. B31Q Training Documentation Portal 2. Virtual Reality (VR) Training: emergency response situations 3. Work zone intrusion detection and warning system 4. Clothing performance guidelines to reduce heat stress for natural gas workers	1) Effective training methods and technology, interactive technology 2) Protective equipment technology 3) Ergonomic technology/equipment
				Gap #4: Develop systems to support more real-time data to	**How we are planning to address Gap #4**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				support safety management systems	
				1. A process-based approach to pipeline safety management system 2. Tracking software development for pipeline safety management system 3. Improving HCA (High Consequence Area) classification methods	1) Tools to implement and benchmark API (American Petroleum Institute) 1173 Pipeline Safety Management System for continuous improvement to pipeline operations 2) High consequence area assessment tools
				Gap #5: Explore Means to Use Predictive Analytics to increase Proactive Decision-making	**How we are planning to address Gap #5**
				1. Airborne automated threat detection system-monitoring and surveillance of imminent threats through remote sensing	1) Cybersecurity and pipeline component security (Smart)

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				2. Optimal approach to cost-effective, multi-source, satellite surveillance of river crossings, slope movements, and land use threats to buried pipelines	
Operations Technology	DOT 49 CFR Part 192: Federal pipeline safety regulations PUC General Order 112F: Gas Transmission & Distribution rule AB 32: GHG emission reduction targets AB 1900: Biomethane	Reliability: Improved evaluation methods and testing standards adapting the use of new technologies will benefit ratepayers with more reliable gas services. Safety: Accuracy in locating buried assets avoids mechanical damage resulting in accidents.	Equipment and Tool Evaluation	**Gap #1: Develop and maintain industry standards for Equipment & Tool Evaluations (New or Revised)**	**How we are planning to address Gap #1**
				1. Uniform frequency code 2. Update ASTM standard on soil compaction control using the DCP	1) Improve evaluation methods for equipment and tools 2) Improve equipment and testing standards adapting new technologies
			Mapping and Locating Technologies	**Gap #1: Technology to locate underground assets to prevent mechanical damage from construction and pipeline repair**	**How we are planning to address Gap #1**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
	quality standards D.14-06-007: Approved SoCalGas's Pipeline Safety Enhancement Program	Operational Efficiency: Locating technology improves operational efficiency by decreasing labor hours in locating buried assets. Improved Affordability: New technologies will also improve efficiency and reduce costs. Environmental: Reduced GHG Emissions:		1. 3D visualization software for mapping underground pipelines and improving pipeline asset management 2. Enhanced locating technologies for underground pipelines with better accuracy 3. GIS portal data quality improvement	1) Investing in research and development in the technology to accurately locate buried assets 2) Improve GIS and mapping processes to manage locations of buried assets 3) Locating "unlocatable" pipe (PE pipe, congested urban areas) 4) Standardized locator frequencies for industry
			Measurement & Regulation Operations Technologies	**Gap #1: Evaluate new meter and regulator technology to enhance performance and determine viable options with decarbonization**	**How we are planning to address Gap #1**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
		Reliable meters help reduce GHG emissions through the capability to self-monitor their reliability and enabling repairs to be conducted as soon as		1. Continuation of single-path ultrasonic meter long-term performance testing and monitoring 2. Determine impact of hydrogen on meter accuracy and performance	1) Install single-path ultrasonic residential meters on live gas distribution systems and conduct long-term performance and accuracy testing over an 18-month period.
			Steel and Plastic Pipeline	**Gap #1: Develop more cost-effective methods for repairing pipe**	**How we are planning to address Gap #1**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
		problems are detected.	Construction, Operations, and Repair Technologies	1. Automation of the Explorer series of robotic platforms 2. Data logger evaluation project 3. PE systems research program 4. Composite repair wrap for PE 5. Update of PRCI repair manual 6. Evaluate in situ valve repair techniques	1) Develop autonomous operating capability in the Explorer robot that can collect a large amount of data in the field 2) Reduce operational complexity 3) Increase capability 4) Improve data quality 5) Increase robustness 6) Alternative pipeline repair methods to reduce GHG emissions 7) Repair leaks using composite technologies
System Design & Materials	DOT 49 CFR Part 192: Federal pipeline safety	Reliability: Understanding the properties of hydrogen within	Gas Composition and Quality	**Gap #1: Explore Paths to Carbon Neutrality and Conversion of Infrastructure**	**How we are planning to address Gap #1**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
	regulations PUC General Order 112F: Gas Transmission & Distribution rule AB 32: GHG emission reduction targets AB 1900: Biomethane quality standards D.14-06-007: Approved SoCalGas' Pipeline Safety Enhancement Program	the gas system improves reliability. Safety: Safety training of workers result in safer and more reliable energy services. New safety training methods also reduce training costs and improve affordability for ratepayers. Operational Efficiency: Better technology and assessment tools increase operational efficiency and reduce operating		1. Biomethane justification study for improved/accepted gas quality standards 2. Study on the impact of trace constituents in RNG on natural gas grids and consumer appliances 3. Trace constituent database 4. Identification and development of an analyzer for siloxane measurement 5. On-line biomethane gas quality monitoring 6. PRCI emerging fuels institute 7. Universal analytical technique for siloxane	1) Study impacts of properties in RNG and traditional pipeline gas, such as TC on gas network infrastructure 2) Common (standardized) RNG skid development for utilities (est. start 1/22, est. completion 12/22) 3) Study on changing accuracy and variability of thermal zones affecting metering of new gas supplies 4) Address hydrogen, RNG, carbon capture and sequestration (CCS), ammonia, and biofuels with emphasis on integrity of pipeline system steel and non-steel components, compressor stations and facilities, pressure control and over-pressure safety devices, design requirements for electrical classification

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
		costs, leading to more affordable energy. Improved Affordability: Low-cost meters and regulators improve ratepayer affordability. Environmental: Reduced GHG Emissions: Utilization of hydrogen reduces GHG emissions.			and fire safety, and downhole reservoir and cavern storage
				Gap #2: Explorer Paths to Carbon Neutrality and Conversion of Infrastructure - Hydrogen	**How we are planning to address Gap #2**
				1. Blending modeling (hydrogen) 2. Hydrogen blend into natural gas, metallic materials 3. Hydrogen embrittlement and crack growth 4. Impact of	1) Analyze and report data on the impacts of hydrogen blending at higher percentages in the natural gas system

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				hydrogen/natural gas blends on LDC infrastructure integrity 5. Microstructural characterization of pipe steels exposed to hydrogen blends 6. Expansion of NYSEARCH range model, to include hydrogen test data 7. Living lab for hydrogen 8. HyBlend collaborative research partnership	
				Gap #3: Identify and update industry standards for Odorants as new constituents are introduced to the pipeline system	**How we are planning to address Gap #3**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				1. Odor detection threshold study 2. Impact of trace constituents on odor masking 3. Effects of odor masking agents 4. Trace constituents from gas processing plants as masking agents	1) Odorant masking agent studies 2) Odor threshold studies 3) Operational safety training
				Gap #3a: Identify and update industry standards for Odorants as new constituents are introduced to the pipeline system - Hydrogen	**How we are planning to address Gap #3a**
				1. Odor detection study for blended hydrogen	1) Odorant threshold studies using natural gas-hydrogen blends and investigate whether hydrogen is a masking agent

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
			Materials & Equipment	**Gap #1: Assess the effects of metering designs, operating conditions and other variables that impact metering accuracies (Evaluate field operation tools and equipment)**	**How we are planning to address Gap #1**
				1. Review and evaluation of the Utonomy smart regulator 2. In-situ ultrasonic meter flow verification	1) Research and develop to produce more accurate, safer and more reliable regulators and meters
				Gap #1a: Assess the effects of metering designs, operating conditions and other variables that impact metering accuracies. - Hydrogen (Evaluate field operation tools and Equipment)	**How we are planning to address Gap #1a**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				1. Effect of hydrogen blended natural gas on performance of gas meters and diaphragm type service regulators	1) Examine the effect of hydrogen-blended natural gas on the performance of domestic gas meters in terms of measurement accuracy and intrinsic safety through extensive, long-duration testing 2) Examine the effect of hydrogen-blended natural gas on the normative performance of diaphragm-type service regulators, specifically addressing materials compatibility and gas leak concerns 3) Consider other meter set assembly (MSA) components for evaluation in the long-duration testing
				Gap #2: Develop new Materials and construction methods that are cost effective and support Tracking	**How we are planning to address Gap #2**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				and Traceability requirements	
				1. Alternative caps for pe service tees 2. MAOP & materials verification 3. Product & process validation program 4. Tracking & traceability counterfeit detection, 2-way production communication using GS1 standards 5. Tracking and traceability for transmission, pipe materials 6. Tracking and traceability marking standard for transmission components 7. Automate field data collection to reduce human error and duplicative work	1) Improve methods for tracking materials using modern technology 2) Improve QA/QC processes and programs

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				Gap #3: Develop new Materials and operating parameters that will reduce O&M costs and extend the service life of PE piping and components	**How we are planning to address Gap #3**
				1. NDE material strength verification for an index of long seam fracture toughness of ERW Pipes 2. ARPA-E Repair Program (TTSP)	1) ARPA-E research deliverables
			System Design	**Gap #1: Assessing risk on the infrastructure by unforeseen events**	**How we are planning to address Gap #1**
				1. Seismic risk assessment and management of natural gas storage and pipeline structure - 2 Projects Slate/Berkeley & UCLA 2. Hot tap branch connections	1) Improve risk and management assessment tools

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				3. Investigate CLSM to manage axial soil loads on buried pipelines 4. Enhance risk assessment tools for decision making	
			Design, Materials, and Construction	**Gap #1: Develop new test methods for materials used in construction of pipelines and processes, and improve procedures in pipeline construction**	**How we are planning to address Gap #1**
				1. Full thickness weld tensile round robin 2. Evaluate higher strength consumables for manual root bead in x70 girth welds 3. Evaluation of semi-automatic FCAW-S welding process and implications to pipeline girth weld integrity	1) Low-cost alternatives to stress relieving pipelines undergoing axial strain due to ground movement 2) Revise and update testing and construction standards 3) PRCI guidance document on API welding standard 1104 4) Field performance of coatings exposed to soil

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				4. Revision of the PRCI hot-tap model to include two different base metals	5) PRCI guidance document on fatigue assessment procedures for pipeline girth welds 6) Improve tensile strength capacity estimation tool for vintage pipes 7) Shielded metal arc welding best practices
			Mechanical Damage	**Gap #1: Develop improved methods for detection and mitigation of mechanical damage**	**How we are planning to address Gap #1**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				1. Validate in-line inspection capabilities to detect/characterize mechanical damage 2. Improve dent/cracking assessment methods 3. Performance evaluation of in-line inspection systems for detecting and discriminating metal loss, cracks and gouges in geometric anomalies 4. Remaining life model and assessment tool for dents and gouges 5. Pipeline mid-wall defect and fitness for service assessment 6. Improvements to mechanical engineering assessment tools	1. Database of bursting pressure tests for corrosion, cracking, dent, and interacting defects 2) Improve mechanical damage engineering assessment tools 3) Methods for analyzing remaining fatigue life prediction of cracks in dents 4) Investigating and identifying failure modes between cracks in pipes and in dents to better understand which mode dominates failure 5) Strain-based design methods
			Corrosion and Crack Management	**Gap #1: Address technical gaps in corrosion control from**	**How we are planning to address Gap #1**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				conventional corrosion and environmental cracking	
				1. Guidelines on the selection and applications of cathodic protection coupons 2. Review of plausible corrosion assessment model 3. Understanding why cracks fail 4. Improve dent/cracking assessment methods 5. CT fundamentals with calibration and reference standards for pipeline anomaly detection 6. Effect of pressure fluctuations on growth rate of near neutral PH SCC-phase iii	1) Material property database, corrosion and crack performance of materials 2) Autogenous weld defects and weld corrosion 3) Reliability models to assess cracks to mitigate pipeline failure 4) Improve models for improved assessment and prioritizing of stress corrosion cracking threats 5) Improve predictive model for assessing pipeline service life with corrosion 6) Acquisition of real-time pipe defects 7) Metal-loss assessment tools 8) Prevention of crack growth

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
					9) Development of guidelines for rehabilitation of corroded pipes 10) Development of primer sets for microbiologically influenced corrosion analysis 11) Assessment of stress corrosion cracking using machine learning methods/AI 12) Improve assessment methods of axial cracks and weld seams with in-line inspection data 13) Improve assessment method of fitness for service for cracks within corrosion 14) Crack management for low-toughness pipes
System Inspection & Monitoring	AB 32: Reducing GHG emissions CPUC General	Reliability: Effective monitoring technology of cathodic	**Corrosion Inspection & Monitoring**	**Gap #1: Develop new technologies to improve Corrosion Inspection & Monitoring**	1. Guidelines on the selection and applications of cathodic protection coupons 2. Review of plausible corrosion assessment model

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
	Order 112F: Gas Transmission & Distribution rule DOT 49 CFR Part 192: Federal pipeline safety regulations Clean Air Act: Air quality standards for NOx and PM	protection prevents corrosion and improves reliability. Safety: This work improves ratepayer safety because it enables the advanced determination of the condition of polyethylene pipeline without excavation. Operational Efficiency: This work improves reliability because it enables robotic operations to be performed			3. Impact of drag reducing agents on corrosion management 4. Water wetting tools for pipeline integrity 5. Understanding why cracks fail 6. Improve dent/cracking assessment methods
				1. Monitoring solution for pipeline A/C interference 2. Evaluation and mitigation of selective seam weld corrosion in the field 3. Comprehensive metal-loss assessment criterion 4. ILI-based generic external corrosion growth rate distribution for buried pipes 5. Pipeline CP monitoring using real-time current measurement 6. Validate the accuracy	1) Remote monitoring technology for cathodic protection for pipelines 2) Inspection technology for assessing corrosion damage 3) Development of real-time detection of pipeline defects

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
		without excavation and interruption of flow. Affordability: The application of modern technology will also decrease costs and lead to reduced costs in energy for ratepayers.		of cathodic protection effective modeling 7. Selective seam weld corrosion detection with in-line inspection technologies	
			Pipeline Systems Inspection Technologies - Inline and	**Gap # 1: Improve Operational Effectiveness for all NDE Pipeline Inspection**	**How we are planning to address Gap #1**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
			Non-Destructive Examination (NDE)	1. Xray and terahertz development for NDE of pe pipe (study for the application of x-rays in the inspection of plastic pipe and fittings) 2. Eclipse scientific red/green light tool for NDE of PE pipe butt fusion joints 3. Standard library of PE joint samples with embedded defects for NDE tool validation 4. NJIT advanced terahertz (THz) imaging and spectroscopy for non-destructive evaluation of polyethylene pipes 5. Validation of NDT technology for PE pipe	1) Determine pros/cons of X-ray & THz techniques for field use 2) Develop an automated tool to be operated by properly trained but non-NDE expert gas industry workers using PAUT & NYSEARCH established acceptance criteria to create NDE interrogation algorithm 3) Produce a PE pipe BF joint sample library of known defects 4) Advance THz NDE technology with enhancement of techniques to interpret PE BF joint defects & stress related to established acceptance criteria 5) Evaluate/validate claims of commercially available NDT for PE pipe & fitting joints

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
					6) Review and evaluation of pipe stress inspection techniques for pipelines 7) Ultrasonic crack size detection
				Gap #2: Expand Understanding and Assure Integrity of Gas Pipelines	**How we are planning to address Gap #2**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				1. Alternate crack sensor 2. Electromagnetic time domain reflectometry (EM-TDR) for pipeline integrity 3. Modeling and assessing PE assets with 3D scanning technology	1) Use an integrated onboard system on Explorer Robot to find and scan long-seam weld in a more diverse set of live pipelines 2) Wireless accessibility 3) Refinement of MFL sensor to detect defects in the pipeline 4) Innovative probes and/or remote inspection techniques for PE pipe (est. start 09/22, est. completion 06/25)
				Gap #3: Expand Understanding and Assure Integrity of Gas Pipelines - Internal Inspection	**How we are planning to address Gap #3**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				1. Energy harvesting in gas industry applications 2. Explorer wireless range extender 3. Extending energy harvesting to other explorer sizes - a feasibility study 4. High resolution MFL for Explorer series of robotic platforms - feasibility study (feasibility study for robotic platform and suite of sensor to ID degradation in non-conforming Driscopipe 8000) 5. Pipeline cleaning tool for liquids with flow 6. Low flow EMAT ILI tool demonstration 7. Energy harvesting for recharging of explorer robotic platforms	1) Develop a robotic module that can be integrated with Explorer to harvest energy from the pipeline gas flow 2) Energy harvesting and on-board rechargeability 3) Robotic/visual inspection for 2" plastic pipe 4) Robotic inspection for large-diameter plastic pipe

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				Gap #4: Mechanical Damage, Pipeline Infrastructural Integrity	**How we are planning to address Gap #4**
				1. Heat affected zone susceptibility testing development 2. Practical girth weld evaluation criteria considering weld strength mismatch and haz softening 3. Integrity impact of HAZ softening on type-B sleeves and hot tap on modern steel 4. Guidance on the use, specification, and anomaly assessment of modern line pipes	1) New testing methods and standards 2) New predictive models for mechanical properties prediction to prevent corrosion and mechanical damage 3) Better pipeline construction methods
			Remote Pipeline Monitoring Systems	**Gap #1: Develop new technologies to improve remote monitoring and data collection to**	**How we are planning to address Gap #1 non-intrusive technologies include satellite, aerial (manned and unmanned),**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				support Corrosion management programs	**and aboveground measurement of ground subsidence, methane emissions, distressed or dead vegetation, pipeline coating condition, and corrosion.**
				1. Remote monitoring of pipe-to-soil readings, AMI network integration 2. AC stray current monitoring system evaluation 3. Corrosion logging tool	1. Improve and develop new remote monitoring technology
			Data Analytics	**Gap #1: Develop technologies**	**How we are planning to address Gap #1 Leveraging machine learning, AI, image recognition, virtual and augmented reality technologies, neural networks, and advanced connectivity through social networks and the Internet of Things (IoT)**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				1. Digitalize system information and advance the use of data analytics to improve system safety, reliability, and integrity in addition to being a pathway for achieving operational efficiency and emissions reductions.	1. Develop AI using existing and new data sensors to address the safety, reliability, and integrity of pipelines and to improve efficiency and emission reductions
			Geohazard Threat Inspection and Monitoring	**Gap #1: Develop technologies to monitor environmental threats, such as weather-related landslides and floods, as well as seismic ground faults impacting pipeline integrity providing continuous real-time measurement of strain imposed onto the pipeline and alert pipeline operators to take mitigative measures to avoid pipeline failures.**	**How we are planning to address Gap #1**

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Gas Operations Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
				1. Modernize the assessment of pipeline water crossings 2. UCLA Fault Displacement Hazard Initiative	1. Modernize the assessment of pipeline water crossings 2. Satellite-based early warning systems for pipelines for threat inspection and monitoring 3. Develop slope monitoring methods using remote sensing techniques and in-situ instrumentation 4. Sensors for measuring pipeline strains caused by geohazards 5. Enhancement of strain capacity of pipelines subjected to geohazards

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Clean Transportation Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
Off-Road	EO N-79-20: 100% zero-emission off-road vehicles and equipment by 2035 where feasible. CARB Clean Fleets Rule: Establishes a medium- and heavy-duty zero-emission fleet regulation with the goal of achieving a zero-emission truck and bus California fleet by 2045 where feasible CARB At-Berth Regulations:	Environmental: Reduced GHG Emissions: Increasing adoption of hydrogen fuel for zero-emission vehicles provides an environmental benefit by reducing the reliance on fossil fuels and, therefore, the associated CO2 emissions. Environmental: Improved Air Quality: Increasing adoption of hydrogen fuel cell, zero-emission vehicles provides	Zero-Emission Technology for Rail	Baseline: Typical freight and passenger locomotives are powered by a diesel engine that drives an electrical generator or alternator. This is referred to as a “diesel-electric” locomotive. There are three major groups of locomotives categorized by ARB: • Interstate line haul – (>4,000 hp); • Medium horsepower (MHP) – (2,301 to 3,999 hp); • Switch (yard) – (1,006 to 2,300 hp) Newest diesel-electric freight interstate line haul locomotives can	1) Develop and demonstrate zero-emission hydrogen fuel cell switcher and line haul locomotives. 2) Develop and demonstrate liquid hydrogen tender cars to extend the range of line-haul locomotives. 3) Develop higher-efficiency fuel cell systems that take advantage of lower projected costs and modularity to reduce fuel cell system costs from $285/kW to *$130/kw and, ultimately, *$60/kW to achieve TCO cost parity with diesel.

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	Reduce diesel PM and NOx emissions from the auxiliary engines of ocean-going vessels while they are docked at California ports IMO 2020: from 1 January 2020, marine sector emissions in international waters will have to reduce Sulphur emissions by over 80% by switching to lower Sulphur fuels	an environmental benefit by reducing NOx and PM emissions.		have engine efficiencies of up to 40 to 50 percent. In California, UP and BNSF primarily operate newer or remanufactured locomotives. These locomotives are subject to the federal emissions standards (Tier 4 NOx: LH/SW-1.3 g/bhp-hr) during their specified useful life. Under the federal definition, the useful life for a freight interstate line haul locomotive can be between 30,000 and 40,000 megawatt-hours (MWh), which typically translates to about seven to ten years of operation, before replacement or remanufacture.	4) Develop and demonstrate advanced materials, system controls, and optimized operating conditions. 5) Pursue development of fuel cell stacks capable of operating beyond current ambient operating temperature limits to prevent overheating or freezing (extreme temperature ranges). 6) Seek to reduce storage costs from *$1130/kg to *$500/kg and, ultimately, *$266/kg.

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			Zero-Emission Technology for Aviation	Baseline: Aviation fuel (Jet-A kerosene, Gasoline, Diesel) for low-range, regional, and long-range flights.	1) Develop and demonstrate zero-emission hydrogen fuel cell aircraft (under 30 passengers and 1,000 miles). 2) Explore the use of hydrogen for sustainable aviation fuels (SAF) in the aviation sector. This will include prototype/proof-of-concept aircraft and demonstrations; higher-efficiency fuel cell systems that take advantage of lower projected costs; and advanced materials, system controls, and optimized systems capable of operating in challenging conditions (high/low temperatures, pressure changes, etc.).

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			Advanced On-Board Storage for Off-Road Applications	Baseline: Gaseous hydrogen tanks currently operate at 350 bar or 700 bar at a temperature of -40°C. Costs for these systems can be in excess of $1,000/kg for off-road applications. This is a new area of focus and will require significant research for larger applications that operate in challenging environments.	1) Develop and demonstrate advanced storage systems for off-road applications. Examples include: 1) liquid hydrogen boil-off management and advanced gaseous and liquid hydrogen tanks; 2) advanced storage systems for gaseous and liquid hydrogen storage in aviation, marine, and challenging environments; 3) methods for meeting and exceeding the critical target of $4/kg-H2 at the pump; and 4) H2 tender for line haul locomotives to achieve longer ranges sufficient for interstate routes.
				Gap: Onboard storage systems for gaseous and liquid hydrogen to operate at lower pressures, with reduced footprints, or increased storage space for onboard off-road applications. On-board storage systems that can operate efficiently in various challenging environments such as aviation where ambient temperatures can vary significantly or the	

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				marine space where systems can be impacted by high salt content or corrosion. Reduce storage system costs to \$300/kg by 2030 and \$266/kg beyond 2030 and 10kg/min refueling.	
On-Road	EO B-48-18: 5 million ZEVs by 2030; 200 hydrogen Refueling Infrastructure by 2025 EO N-79-20: Eliminate new internal combustion engine vehicles by 2035; 100% light-duty vehicles and	Environmental: Reduced GHG Emissions: Increasing adoption of hydrogen fuel for zero-emission vehicles provides an environmental benefit by reducing the reliance on fossil fuels and, therefore, the associated CO2	Hydrogen Fuel Cell Development for MHD Trucks	Baseline: MHD vehicles include a wide variety of vocational, drayage, buses, and long-haul trucks that currently use diesel. These trucks are capable of hauling anywhere from 1-20 tons of goods (Class 4-8), can operate on a range of 300-1,000 miles on a full tank, and can last upwards of 1 million miles.	1) Develop and demonstrate zero-emission hydrogen MHD trucks to serve in hard-to-electrify vocations and on longer routes. 2) Target increasing fuel cell efficiency to 68% and 72% by 2030 and beyond. 3) Achieve an ultimate fuel economy of 17 mpkg/19.4mpgde for

	drayage trucks sold will be zero emission by 2035; 100% MHD vehicles sold and operated are zero-emission by 2045 CARB Clean Truck Rule: 100% ZEV where feasible for drayage, public fleets, last-mile delivery by 2045 CARB Clean Fleet Rule: 100% zero-emission trucks and buses where feasible by 2045	emissions. Environmental: Improved Air Quality: Increasing adoption of hydrogen fuel cell, zero-emission vehicles provides an environmental benefit by reducing NOx and PM emissions.		Current diesel MHD trucks achieve an average fuel economy of 6-12 MPG, depending on duty cycle. Gap: Current fuel cell electric vehicle (FCEV) MHD trucks are limited on usable range (up to 300 miles) and have a lifespan of up to 6-8 years. Future FCEV MHD trucks need to reach 25,000 hours or 10 years/1,000,000 miles, and achieve at least 1.9x fuel economy improvements and a total cost of ownership reduction of at least 30%.	fuel cells vs 15.6 mpgde for diesel.

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			Hydrogen Fuel Cell Development for LD Fleet Trucks	Baseline: Current developments in the light-duty vehicle truck space are limited to battery-electric vehicles and conventional gasoline and diesel. Such trucks operate on shorter ranges compared to MHD vehicles, but account for over 1 million of the total truck population in California.	1) Develop, demonstrate, and commercialize light-duty fuel cell electric vehicle trucks to meet the demands of utility fleets and emergency services such as SoCalGas and Caltrans that serve communities in rural areas and diverse climate regions.
				Gap: Currently, there are no hydrogen fuel cell light-duty vehicle trucks that fall in the Class 2a, 2b, and 3 categories. These categories will eventually need to be zero-emissions to comply with CARB and California mandates. Over 50% of SoCalGas' fleet falls in the class 2b category and needs to be available and operational 24/7/365 to	

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				respond to customers and emergency events.	
			Advanced On-Board Storage for On-Road Applications	Baseline: High-pressure non-conformable tanks for hydrogen (350 bar and 700 bar, temperature of -40C).	1) Develop and demonstrate advanced storage systems for MHD trucks and off-road applications. Examples include: 1) conformable hydrogen storage; 2) low-pressure hydrogen storage; and 3) advanced materials for hydrogen storage for on-road applications. 2) Support development of liquid hydrogen boil-off management and advanced gaseous and liquid hydrogen tanks. 3) Develop advanced materials for gaseous and liquid hydrogen storage in aviation,
				Gaps: Increased storage of gaseous and liquid hydrogen at lower pressures that require less space to be packaged in a vehicle (lower pressures and temperatures above -40C). Reduce storage system costs to \$300/kg by 2030 and \$266/kg beyond 2030.	

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					marine, and challenging environments. 4) Develop methods for meeting and exceeding the critical target of $4/kg-H2 at the pump.
			Advanced Innovation and Connected Vehicles	Baseline: Level 0 Autonomous Vehicles	The RD&D Program should develop and demonstrate advanced vehicles, autonomous vehicles, or advanced routing solutions to reduce emissions and increase safety and reliability.
				Gaps: Level 2 and above autonomous vehicles, connected vehicles for fleets, and advanced fleet monitoring/tracking to reduce emissions.	
Refueling Infrastructure	AB 8: 100 Hydrogen Refueling Infrastructure in California EO B-48-18: 5 million ZEVS by 2030; 200 hydrogen Refueling Infrastructure by 2025	Reliability: Advancing refueling technologies and the hydrogen supply chain will help promote sustainable and reliable fuel for transportation and other sectors. Safety: As technology	Hydrogen Refueling Infrastructure Optimization and Safety	Baseline: Current hydrogen fill technology limits fueling to 1-5 kg/min @ 40°C. One of the many challenges for the hydrogen industry is the efficiency, reliability, and availability of hydrogen supply and Refueling Infrastructure for on-	1) Develop and demonstrate fast-fill and hydrogen refueling technologies to achieve hydrogen fill rates of 8kg/min by 2030 and 10kg/min beyond 2030 for transportation. 2) Develop advanced cooling systems.

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	Low Carbon Fuel Standard: Reduce carbon intensity in transportation fuels as compared to conventional petroleum fuels, such as gasoline and diesel	advances and is adopted widely throughout California, safety protocols and monitoring efforts need to be increased to enable the hydrogen ecosystem across off-road and on-road applications Operational Efficiency: Reducing refueling time and effort across multiple transportation sectors. Improved Affordability: Advancing refueling technologies can help reduce the cost of equipment, reduce refueling time, and increase energy storage. Environmental: Reduced GHG Emissions:		road and off-road applications. Gaps: Increase fueling reliability and safety to allow higher fill rates to meet DOE targets of 8kg/min by 2030 and 10kg/min beyond 2030 for transportation. Fueling stations and infrastructure for on-road MHD trucks, rail, marine, and construction.	3) Develop integrated fueling systems. 4) Explore development of liquid hydrogen boil-off management. 5) Develop hydrogen bunkering for marine applications. 6) Develop advanced materials, system controls, and optimized operating conditions. 7) Explore methods for meeting and exceeding the critical target of $4/kg-H2 at the pump. 8) Explore co-location of light-duty and MHD Refueling Infrastructure. 9) Explore the use of multi-modal Refueling Infrastructure for off-road and on-road applications.

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		Improving Refueling Infrastructure can reduce auxiliary electrical loads to compress and store hydrogen for transportation. Environmental: Improved Air Quality: Increasing the availability of hydrogen by expanding the hydrogen refueling network will promote the adoption of hydrogen fuel for transportation, thus reducing NOX and PM emissions.			

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Clean Energy Applications Program					
Sub-Program	**Policy Drivers for Technical Development Work**	**Ratepayer Benefits**	**Research Area**	**Technology Gap between current performance and required performance**	**RD&D Development Activities**
Energy Reliability	CPUC R.19-09-009: Microgrids and resiliency proceeding AB 3232: Building decarbonization SB 32: Reduce CO2 emissions Clean Air Act: Air quality standards for NOx and PM SB 100: Zero-carbon electricity by 2045 EO B-55-18: Carbon-neutral	Reliability: Distributed generation improves customer electrical reliability and resilience, both in areas prone to wildfire-related outages as well as "regular" grid disturbances. Enabling and simplifying the integration of gas fueled distributed generation with solar and battery improves power reliability and resilience for customers. Safety: Distributed generation can also improve customer safety by providing the reliability and resilience mentioned above (required for critical infrastructure and life saving/sustaining devices). Enabling the integration of gas-fueled distributed generation can improve	Small Scale (less than 50 kilowatt) Fuel Cell Development	Baseline: There are currently no commercially available small scale fuel cells available in the US. However, these technologies exist in other countries at various scales. Current alternative forms of resilient distributed generation are gas/diesel engines, either stationary or mobile. Gap: Fuel cells for the residential and small commercial sectors that can meet US and California safety and emissions requirements. A pathway to being cost-	1) Identify commercially available technologies from overseas and demonstrate their ability to function as expected, comply with all safety requirements, yield the desired benefits, and meet California market needs. 2) Support lab testing and demonstrations, which will be needed to confirm performance and understand how systems work prior to installing in real homes and businesses. 3) Support field

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	California economy by 2045 SB 1298: Established DG Certification Standard requirement SGIP: Self-Generation Incentive Program SB 1339: Microgrids for increased electricity reliability CA Title 24: Buildings Energy Efficiency	customer safety by providing the reliability and resilience mentioned above (required for critical infrastructure and life saving/sustaining devices). Operational Efficiency: Projects in this sub-program aim to develop technologies that can optimize onsite energy production and consumption, potentially improving customer energy efficiency. Improved Affordability: Projects in this area aim to develop distributed generation technologies that provide customer cost savings compared to alternatives (solar, battery, grid power). Microgrids are still typically very customized and therefore costly. Projects in this area aim to simplify gas distributed generation integration and showcase the ability of gas-supported microgrids to meet societal and customer needs, potentially increasing adoption and driving down		competitive with solar/battery, although there is no agreed upon metric to value resilience.	demonstrations. They will range from a few units to larger-scale pilots, depending on the technology readiness and funding availability.
			Hydrogen Blending in Existing Power Generation Technologies	Baseline: Most OEMs seem to indicate an ability for existing systems to accept blends of <20%, although this has not yet necessarily been demonstrated in the field. OEMs are also working on systems that can accept 100% hydrogen.	1) Support projects ranging from fundamental combustion lab scale research and OEM system design to field demonstrations. 2) Identify blending limits, increase blending thresholds, and demonstrate blending capabilities. 3) Explore a wide range of technologies and project types in this space.
				Gap: Need to demonstrate capability for systems to actually accept 20% hydrogen blends in the field for sustained durations. Need to identify cost-effective (retrofit) pathways to bridge the gap between 20% and	

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		prices. Environmental: Reduced GHG Emissions: Projects in this area aim to develop technologies with reduced GHG emissions, either indirectly through improved efficiencies or directly through hydrogen integration and/or carbon capture. Environmental: Improved Air Quality: Projects in this area aim to develop technologies that meet or exceed CARB-DG certification standards, which regulate NOx, CO, VOCs, and PM.		100%. Ability to eventually operate on 100% hydrogen safely, while performing similar to or better than current technology.	
			Backup Generation Development	Baseline: Current backup generation typically consists of gas and diesel engines. Backup generation is not CARB-DG, and sometimes flies under air board regulations based on supposed low operating hours. Gap: Need low-emissions options across all sizes to compete with diesel and un-regulated gas technologies. Target emissions to meet CARB-DG certification requirements.	1) Target lab evaluations to confirm emissions performance. 2) Target field demonstrations to showcase real-world benefits of the new technologies.

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			Fuel Cell Integration	Baseline: Current microgrid integration hardware (controllers, inverters, etc.) is typically tailored to solar + battery, without specific ability to integrate fuel cells. Fuel cell integration and control is usually specific to OEMs, aside from inverters. Gap: Need technologies that simplify the integration of fuel cells with solar, battery, and grid energy.	1) Work with technology developers and research institutions to identify and evaluate the performance of integration hardware and control platforms. Evaluation will range from paper studies and lab testing to field demonstrations.
			Backup Power Integration	Baseline: Similar to above, integration of backup generation is either non-existent (manual switch) or very costly. Backup generation has different operating constraints from baseline production, which is what fuel cells	1) Work with technology developers and research institutions to identify and evaluate the performance of integration hardware and control platforms. Evaluations will

				mentioned above typically provide.	range from paper studies and lab testing to field demonstrations.
				Gap: Should be simple and seamless. Should also be cost-comparative to solar / battery systems.	
			CHP Efficiency Improvements	Baseline: This area covers technologies that optimize "waste" heat utilization, such as heat-driven cooling processes that offset electrical consumption.There are a wide range of technologies, but most have low penetration due to relative novelty or high costs.	1) Support a broad range of project types, from early-stage prototype development to field demonstrations of almost commercialized systems.
				Gap: Fuel-cell-based CHP systems offer ~30% increase in system efficiency when heat is utilized. Maximizing the value of that utilized heat to offset energy-intensive (and therefore	

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				costly) processes is the goal.	
			Cybersecurity of Integrated Energy Systems	Baseline: Since the integration technologies mentioned in prior research areas are fairly novel, this is a new challenge/opportunity for research. Presumably more active connections can/will lead to potential security threats at various scales (customer or grid/pipeline side of meter).	1) Support projects ranging from or progressing from paper studies and prototype development to field testing (possibly in conjunction with other research areas).
				Gap: Need to develop technologies that ensure customer and infrastructure security.	

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			Hydrogen Based Energy Storage	Baseline: The primary baseline technology is battery storage, which is poorly suited for long-duration storage. There are some other emerging options for long duration, such as pumped hydro and compressed air, but these are early stage and not necessary "baseline." Gap: Need sufficient storage capacity to bridge both daily and seasonal gaps in renewable power production.	1) Address hydrogen storage integration in front of and behind the meter. 2) Develop and/or demonstrate the capabilities for various hydrogen storage technologies to integrate with the grid, on-site renewable production, fuel cells, and site loads (both hydrogen and electric).
Residential & Commercial	2016 Air Quality Management Plan: NOx and PM emissions regulationCA Title 24: Buildings Energy EfficiencyCA Title 20: Appliance Energy EfficiencyAB 3232: Reduce	Operational Efficiency: Increasing energy efficiency and burner performance for CFS appliances provides improved operational efficiency for customers by reducing cooking time, increasing food output, and reducing fuel cost.Improved Affordability: Increased energy efficiency improves cost savings and ensures that energy is affordable and equitable. Additionally, near-term improvements on	Hydrogen in Residential Homes	Baseline: In the last three years, several projects have been completed to evaluate the impact of low blends of hydrogen on residential appliances. Research has validated that residential appliances can consume blends containing up to 30% hydrogen with no modification and major consequences. Generally, there were	1) Conduct equipment testing. 2) Pursue near-term modifications to increase hydrogen tolerance. 3) Develop design guidelines. 4) Test and compare older vintage appliances with new. 5) Test less-common appliances. 6) Perform material durability testing.

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	the emissions of greenhouse gases from the state's residential and commercial building stock by at least 40% below 1990 levels by 2030AB 32: Reduce CO2 emissions 40% below 1990 levels by 2030EO B-55-18: Carbon-neutral	energy efficiency can aid in the energy transition to low-carbon fuels such as hydrogen. Increased energy efficiency improves cost savings. This reduces overhead expenditures for businesses and delivers an attractive ROI for adoption of high-efficiency technologies.Environmental: Reduced GHG Emissions: Projects in this sub-program seek to increase energy efficiency and burner performance, which provides GHG benefits by reducing emissions from		few notable variations in process temperatures or emissions. For partially-premixed-type combustion equipment, which is prevalent in North America, the dominant impact of hydrogen blending is an increase in excess air, often resulting in lower NOx emissions and reduced surface temperatures. Therefore, hydrogen blending in residential space at low blends seems somewhat well understood.	7) Gain experience with blending in the field to assess the potential impact/challenge on the customer base. 8) Conduct field demonstrations to help end-users become comfortable with hydrogen.

	California economy by 2045AB 617: DACs for air quality improvements	CFS equipment. Developing advanced appliances that are compliant with RNG and hydrogen provides an environmental benefit by reducing GHG emissions from residential and commercial buildings.Environmental: Improved Air Quality: The CFS sector is a highly energy-intensive sector. Improved burner performance and energy efficiency significantly reduce GHG and NOx emissions. Increasing energy efficiency and burner performance for residential and commercial appliances provides an environmental benefit by reducing NOx and PM emissions.		Gap: 1) Increase residential appliance tolerance of hydrogen blends by up to 50%. Design should consider efficiency, emissions, safety, and performance issues. Ideally, the solution should allow for easy modification to existing appliances in service through a form of a retrofit kit. 2) Examine the long-term material durability impact due to hydrogen blends. 3) For high blends of hydrogen, explore additives to colorize hydrogen flame for safety. 4) Explore technologies that have synergies between short-term needs such as energy efficiency and emissions reduction and hydrogen compatibility. 5) Field-demonstrate hydrogen-compatible appliances.	

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			Commercial Development of Gas Heat Pump	Baseline: Several European manufacturers have commercialized residential gas heat pump water heaters that offer a coefficient of performance of > 1.2. Gas heat pumps could provide an immediate step-change increase in gas appliance efficiency and facilitate achievement of the state's building decarbonization goals.	1) Streamline the North American Gas Heat Pump Water Heater field demonstration and turn field results into actionable steps towards market entry. 2) Explore other gas heat pump variants such as combi and space heating.
				Gap:This research area will focus on coordination efforts by U.S. manufacturers and distributors to modify those products for extensive deployment in the U.S., particularly in the SoCalGas service territory.1) Implement residential gas heat pump demonstrations extensively.2) Support development of commercially available, consumer-focused gas heat pumps.	

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			Burner Development for Auxiliary Gas Appliances (i.e., Patio Heaters, Barbeques, Range Tops, Pool Heaters) With Focus on Energy Efficiency	Baseline: Since auxiliary gas appliances do not have any efficiency criteria or testing requirements to be sold in the marketplace, they have traditionally lagged behind in technological advancement (i.e., efficiency gains and emissions reduction). As a result, the appliance class represents an easy win for significant energy and emissions savings opportunities for building decarbonization. Similar to issues faced by the gas-fired food service appliance classification, auxiliary gas appliances use relatively simple and inexpensive technology.	1) Identify promising new burner designs. 2) Support burner testing, prototyping, collaboration with manufacturers, commercialization activities, and collaboration with customer programs on incentivizing the adoption of new technologies.
				Gap: Focus on energy efficiency improvements in this research area and strive for 50-100% efficiency improvements from the current	

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				appliance performance level.	
			Catalytic Burner for Near-Zero Emission in Residential Water and Space Heating	Baseline: This technology has been utilized extensively in industrial boilers due to the increasingly challenging emission regulations imposed on these systems. Research is currently being done to utilize these types of burners for water heating and space heating in both residential and commercial settings. The benefit of this technology is that it allows operation at much leaner fuel conditions, resulting in lower temperatures that discourage the formation of NOx and the reduction of fuel consumption.	1) Pursue prototyping. 2) Conduct field demonstrations. 3) Work with customer programs to incentivize consumer adoption.
				Gap: Commercialization in the next three years since this technology has	

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				the potential to achieve near-zero emissions.	
			Hydrogen Blends in Commercial Equipment	Baseline:Research into residential hydrogen blending will also close the knowledge gap in commercial buildings. The unique challenge will be creating an expansive dataset to allow for extrapolation across the diverse ranges of equipment and appliance types in the commercial end-use space. Similar to the residential space, there are limited data from North America on hydrogen blending in commercial buildings. Thus, researchers typically cite European studies. Special consideration should also be given to commercial foodservice. Hydrogen will most likely have a larger impact on this customer segment An additive may need to be	1) Pursue equipment testing and near-term modifications to increase hydrogen tolerance, production of design guidelines, and material durability. 2) Expand datasets in order to extrapolate to many other potential end-uses.

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				considered in order to safely cook with hydrogen since hydrogen flame is more difficult to see. Additionally, the reduced heat output due to hydrogen could affect cooking time and food quality.	
				Gap: Additional studies on the lower blends of hydrogen (up to 30%) covering a range of commercial-grade end-uses are still worthwhile because commercial equipment typically has a higher output/throughput compared to residential appliances. However, other projects also make strategic sense, including pursuing increased appliance tolerance of	

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				hydrogen blends up to 50%, assessing material durability, and gaining experience blending hydrogen in commercial buildings.	
			Advanced Building Equipment	Baseline: Condensing technologies have brought traditional, direct-fired natural gas equipment efficiencies to the upper 90% range, so few additional opportunities exist for incremental performance increases without embracing transformative technologies like gas heat pumps. Stakeholders have broad interest in improving natural gas system efficiency through system-level improvements, not just through improved combustion efficiency. Areas of interest include waste-heat recovery, innovative controls, and low-cost sensors that enable data-driven	1) Pursue new product development, system design, and integration through AI, controls, sensors, gas heat pumps, waste heat recovery, HVAC, phase change, combi systems, and building retrofits.

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				operations. Interest in low-cost, innovative multi-function natural gas products is increasing, including the more common combined space heat and hot water systems, as well as more exotic products such as combined cooling, heating, and power systems (CCHP, or trigeneration).	
				Gap: Late-stage development of gas heat pumps, waste heat recovery, catalytic burners, smart technologies, advanced building construction technologies, machine learning, and block-chain.	

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			Solar and Ground-Source Heating in Commercial Applications	Baseline:This program will focus on the technology development and application of solar and ground-source heating as a form of renewable energy to decarbonize gaseous end-users. The technologies being pursued includes solar water and space heating and district heating and cooling through ground-source. Increasing the use of geothermal energy for U.S. heating and cooling can significantly contribute to the Biden-Harris Administration's decarbonization goals to cut U.S. emissions in half by 2030. Gap: Technology development and the application of the following technologies: flat-plate solar collectors, evacuated tube solar collectors, concentrating solar	1) Focus on early wins for this new research area to gain experience and insight. 2) Participate with industry experts to understand and develop technologies that can improve the energy efficiency of gaseous technologies in order to decarbonize the commercial market segment. 3) Actively seek to participate with technology experts to pursue the most competitive grant funding opportunities. Based on recent publications by the DOE and NREL, there may be more opportunities to collaborate with researchers in pursuing government grants

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				systems, ground source heat pumps, direct use of geothermal, and deep and enhanced geothermal systems.	in the geothermal space.
Industrial Operations	2016 Air Quality Management Plan: NOx and PM emissions regulation CA Title 24: Buildings Energy Efficiency CA Title 20: Appliance Energy Efficiency AB 3232: Reduce the emissions of greenhouse gases from the state's residential and commercial building stock	Operational Efficiency: Increasing energy efficiency and burner performance for industrial equipment also provides operational efficiency improvements for industrial customers by reducing fuel costs associated with high-temperature processes and improving throughput. Improved Affordability: Developing solutions that can be implemented as modifications or retrofits to existing equipment allows for cost-effective and energy efficient decarbonization of industrial end-uses. Environmental: Reduced GHG Emissions: Developing advanced industrial equipment that is compliant with RNG and hydrogen reduces GHG emissions from industrial	Advanced Combustion System & Thermal Management for Heavy Industrial Process Equipment	Baseline: Industrial processes are the second-largest contributor to GHG emissions in California and one of the most difficult sectors to decarbonize. There is a large technical potential for GHG emissions reductions from a range of mitigation options that can help decarbonize the industry sector. Given the complexity and diverse nature of many industrial processes, however, an effective decarbonization strategy will require tailored solutions that take into account the unique challenges and opportunities in each industrial subsector.	1) Pursue continued technology development and demonstration in equipment energy efficiency, waste heat recovery, and the other technologies outlined in the GAP strategy. 2) Focus on the 15 key subsectors that account for 95% of all energy-use: chemicals, petroleum refining, forest products, food & beverage, iron & steel, plastics, fabricated metals, transportation equipment, electronics, aluminum, cement, glass, machinery,

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	by at least 40% below 1990 levels by 2030 AB 32: Reduce CO2 emissions 40% below 1990 levels by 2030 EO B-55-18: Carbon-neutral California economy by 2045 AB 617: DACs for air quality improvements	processes that are difficult and costly to electrify.		Waste heat losses are a major consideration in process heating, especially for higher-temperatures process such as steelmaking and glass melting. Some R&D opportunities include integrated manufacturing control systems, waste heat recovery systems, high-efficiency industrial boilers, and new catalyst and reaction process to improve yields of process conversion.	textiles, and foundries. 3) Conduct a market assessment to gain valuable insight into which areas and/or activities offer the highest decarbonization potential.
				Gap: Some areas that RD&D program is focusing on in this area include: smart energy management systems, advanced Combustion System (e.g., immersion tube burner, surface burner, radiant tube heaters, ribbon burners), waste heat and water recovery systems, emissions control systems and catalytic material to enhance	

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				process yield, and thermal energy storage.	
			Hydrogen Blends in Process Heat	Baseline: No substantial interrelated research in North America--other than a few pockets of independent projects--currently exists to integrate hydrogen into industrial processes.	1) Target applications that are difficult to decarbonize for hydrogen blending which includes processes requiring combustion-based heat (e.g., blast

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				Gap:Recently, the CEC issued a grant funding opportunity to fund a technical study to identify the impact of the potential use of hydrogen and hydrogen-natural gas blends on existing equipment as a potential decarbonization strategy for large commercial buildings and the industrial sector. The study will identify operating parameters such as the maximum concentration of hydrogen that can be handled by existing equipment with and without modification. This study will inform policymakers and the private sector of the potential for hydrogen and hydrogen-natural gas blends as a decarbonization strategy for industrial and large commercial building applications. Some of the objectives of the	furnace for iron production), ethylene crackers, chemicals and fuels refining, feedstock, reducing agents, cement kilns, and high-temperature process heat requirements that are complementary to applications that cannot be electrified. 2) Address customer concerns, including: a) Metal forming - Metal forming and working companies are sensitive to changes in the gas composition and many have in-line gas chromatographs to monitor the heating value and composition. Since hydrogen is not a standard component measured by typical commercial in-line gas chromatographs, equipment upgrades are necessary to

				study include: market characterization report, equipment testing, equipment simulation to identify "safe" limits for hydrogen-natural gas blends, and exploration of modifications to enable higher hydrogen blends.	monitor for hydrogen. b) Ferrous metal working - Natural gas is used to create endothermic and exothermic atmospheres and for carburizing processes. According to literature, the typical atmospheres used in carburizing processes contain significant quantities of hydrogen, thus the 5 vol% hydrogen blend may be tolerable. However, these customers will have to work with the equipment manufacturers to assure proper modifications are made when necessary. c) Glass manufacturers - Glass manufacturers are sensitive to changes in the

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					heating value. The 5 vol% hydrogen gas blend is at the low end of the acceptable range. Thus, if the value fell much, it might become unacceptable. RD&D program will pursue activities that address these concerns. The program has identified UCI's Advanced Casting Research Center as a potential strategic partner in addressing these customer needs.

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			Point-of-Use Carbon Capture and Utilization	Baseline:Commercial systems for post-combustion carbon capture. At scale ($400-$500 million per unit), current cost is $40-$100 per ton of carbon dioxide captured.Current capture capacity is at just 44 million tons per annum (Mtpa), or 0.1% of global emissions. Very few large projects have come online in the last five years, and only 0.2Mtpa were added in 2021. Last year broke records for CCS announcements, and the industry is set to expand faster than ever. Capture capacity could grow at a compound annual rate of 18% to reach 225 Mtpa by 2030, according to BNEF's CCUS database. The power, gas processing, and hydrogen industries were first to implement CCS projects, but now industries such as cement, chemicals, and	1) Focus on point-of-use carbon capture & utilization, enhanced weathering for agricultural customers. California's state rock, serpentinite, naturally absorbs carbon dioxide. 2) Explore less carbon-intensive ways to make cement through carbon capture and utilization. 3) Demonstrate cement production technologies and processes that may be able to sequester carbon dioxide. 4) Explore application to metals customers.

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				direct air capture are also announcing large facilities. The U.K., U.S., Canada and the Netherlands have the most ambitious CCS plans.	

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				Gap: Cheap and rapidly deployable small-scale carbon capture technology to meet or beat current large-scale carbon capture costs. DOE has funded research targeting $30 per ton of carbon dioxide captured at point-source by 2030. In order for California to achieve its goal of net carbon neutrality by 2045, carbon capture technology must be developed and deployed at scale. This program will focus on distributed point-of-use capture that would scale in size for commercial and industrial end-users.	

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			Solar and Ground-Source Heating in Industrial Process Heat	Baseline: This program will focus on the technology development and application of solar and ground-source heating as a form of renewable energy to decarbonize gaseous end-users. The technology being pursued includes solar water and space heating and district heating and cooling through ground-source. Increasing the use of geothermal energy for U.S. heating and cooling can significantly contribute to the Biden-Harris Administration's decarbonization goals to cut U.S. emissions in half by 2030.	1) Focus on early wins for this research area because it is a new program to gain experience and insight. 2) Participate with industry experts to understand and develop technologies that can improve the energy efficiency of gaseous technologies in order to decarbonize the industrial market segment. 3) Actively seek to participate with technology experts to pursue the most competitive grant funding opportunities. Based on recent publications by the DOE and NREL, there may be more opportunities to collaborate with researchers in
				Gap:Technology development and the application of the following technologies: flat-plate solar collectors, evacuated tube solar collectors, concentrating solar systems, ground source	

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				heat pumps, direct use of geothermal, and deep and enhanced geothermal systems.	pursuing government grants in the geothermal space.

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SoCalGas 2024 GRC Testimony Revision Log –August 2022

Exhibit	Witness	Page	Line or Table	Revision Detail
SCG-12	Armando Infanzon	AI-iii	Summary of O&M Costs	Revised values in table and revised TY 2024 O&M cost from "$47,251 million" to "$47,223 million."
SCG-12	Armando Infanzon	AI-2	Table AI-1	Revised values in table.
SCG-12	Armando Infanzon	AI-16	Table AI-7	Revised values in table.
SCG-12	Armando Infanzon	AI-16	Lines 23-26	Revised adjusted-recorded expenditures from "$8.223 million" to "$8.195 million," BY 2021 from "$4.003 million" to "$3.975 million," and TY 2024 request from "20.428 million" to "$20.400 million."

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

DIRECT TESTIMONY OF ROXANNE ROERICK

EXHIBIT 1300

November 2025

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Roxanne Roerick. My business address is 1200 West Century Avenue, Bismarck, North Dakota 58503.

Q. By whom are you employed and in what capacity?

A. I am employed by MDU Resources Group, Inc. ("MDU Resources"), as a Director of Human Resources. My primary responsibilities include leading and administering MDU Resources' and its various subsidiaries, including Cascade Natural Gas Corporation's ("Cascade" or the "Company") compensation philosophy, the active employee and retiree health and welfare benefit plans, 401(k) retirement plan, and frozen pension plans.

Q. Please describe your educational background and other qualifications.

A. I graduated from Minnesota State University Moorhead in 1999 with a bachelor's degree in business administration. I have been a certified Human Resources Professional by the Society of Human Resources Management since 2014, as well as a Professional in Human Resources by Human Resources Certification Institute, and a Certified Plan Sponsor Professional by the American Retirement Association and the Plan Sponsor Council of America.

Q. Please describe your work experience.

A. I have worked in the human resources field for 25 years and have held a variety of positions of increasing responsibility since joining MDU Resources in 2009. My career at MDU Resources and Montana-Dakota Utilities Co. has included the roles of Benefits Analyst, Senior Human Resources Generalist, Senior Compensation Analyst, and Manager of Human Resources. Currently, as Director of Human Resources, I lead the Company's compensation and benefits strategy, ensuring competitive and equitable total rewards.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I discuss Cascade's labor-related issues, including employee retention, compensation, and benefits.

Q. Please summarize your testimony.

A. My testimony covers many aspects of how the Human Resources Department ensures that Cascade maintains an excellent workforce. I describe the current labor market in Oregon and how MDU Resources addresses recruitment, retention, and engagement challenges. I also address how MDU Resources, the MDU Utilities Group, and Cascade are controlling costs and managing open positions while maintaining safe and reliable service for customers. Next, I share MDU Resources' compensation philosophy and how it effectively utilizes a combination of base pay and at-risk pay to attract, retain, and engage employees, thus providing safe and reliable service that is also affordable for customers. Finally, I describe the benefit plans provided to employees and how they effectively attract, retain, and engage employees.

Q. Do you sponsor any exhibits in support of your testimony?

A. No.

III. CASCADE LABOR MARKET

Q. What are the key labor market issues Cascade is facing?

A. The key labor market challenges Cascade is facing include recruitment, retention, and recognition of qualified employees, as well as the labor and housing market in certain locations.

Q. Has the current labor market impacted the Company's goal of hiring qualified employees?

A. Yes, the current labor market has made it more challenging for the Company to hire qualified employees. Cascade provides an essential service to its customers and must maintain high-quality, safe, and reliable service regardless of the economics existing in the industry or labor market. Cascade has reinforced its goal to attract and retain highly skilled employees despite current and recent economic conditions and continues to significantly invest in employees' training and development for both professional and technical teams. The labor costs included in this filing are necessary to maintain a highly qualified workforce that can provide a safe and reliable gas system.

Q. How does the Company keep costs low while managing open positions caused by employee turnover?

A. When an employee's resignation or retirement results in an open position, the first step is for local leadership to assess whether the work done by that position could be permanently transferred to other positions within the organization, whether because of technological advancements or other factors. If the answer is "yes," then the position will not be replaced. If the answer is "no," local leadership will work with senior leadership and human resources to replace the role. If the answer is "maybe" or "temporarily," then the position will be held for up to six months to determine if long-term needs require the position to be replaced.

Q. How is the Company ensuring that it provides safe, reliable, and affordable service while attracting and retaining qualified employees and encouraging employee engagement?

A. In 2025, the Company introduced the CORE strategy, which includes four focus areas: Customers and Communities, Operational Excellence, Returns Focused, and Employee Driven. The CORE strategy is central to guiding business priorities and culture. Each element works together to ensure the Company provides safe, reliable, and affordable service.

For customers, this means a continued emphasis on delivering best-in-class customer satisfaction, maintaining rates below the national average, and supporting the vitality of local communities. The CORE Strategy also prioritizes safety—for both employees and systems—and reinforces operational efficiency by keeping operations and maintenance costs below peer utility averages.

A key driver of CORE's success is the "Employee Driven" component, which underscores the importance of attracting, retaining, and developing a high-performing workforce. By investing in employees through compensation, benefits, and development opportunities, the Company increases engagement and performance—directly contributing to service quality and reliability. As part of this strategy, a new short-term incentive plan was implemented with metrics directly aligned to CORE goals for employees, except the bargained employees of Cascade. In particular, the "Employee Driven" focus area reflects the Company's commitment to be an employer of choice. This includes fostering a workplace culture defined by collaboration, creativity, respect, and strong employee engagement.

To meet this goal, the Company has enhanced its total compensation offerings, including expanded use of sign-on bonuses, up-front vacation banks to recruit new employees, when needed, and increased Company 401(k) plan match from a maximum contribution of three percent of salary to four percent of salary. Ongoing research into employee preferences ensures that compensation and benefits programs continue to evolve with workplace needs. These initiatives are not only competitive but also strategic, as they are designed to attract and retain top talent while promoting engagement and performance—all in alignment with the CORE strategy.

Ultimately, the CORE Strategy supports a cycle of continuous improvement that benefits customers, employees, and the communities the Company serves.

IV. CASCADE'S COMPENSATION PROGRAM

Q. Please describe the Total Rewards philosophy and Cascade's general approach to managing total compensation for employees.

A. The Company's approach to employee compensation is designed to minimize costs while allowing it to attract and retain the qualified employees necessary to deliver safe and reliable service to its customers. To do this, the Company applies three basic principles:

First, the Company has adopted a Total Rewards philosophy, which provides employees with a Total Rewards package. The Total Rewards package includes both total cash compensation and benefits. The two key components of total cash compensation are base pay and incentive compensation.

Second, the Company compares its base pay and at-risk incentive compensation with the relevant labor market and seeks to set total cash compensation at the market average for comparable jobs. As previously mentioned, the market for employees with the skills and experience required is very competitive in the industry, and therefore Cascade must provide the same general total cash compensation and benefits as are included in the packages provided by the Company's competitors for labor.

Third, the Company believes that a certain percentage of each employee's market compensation should be "at-risk" to encourage employee engagement and reward employees for their role in effectively operating the business. Accordingly, in addition to base wages, employees have the opportunity to receive total cash compensation at the market average under the short-term incentive plan.

Q. Please explain how the market average for the base pay and pay-at-risk components of total cash compensation is determined.

A. The Company researches and obtains industry salary data when market pricing individual positions. This data comes from many reliable sources, including the American Gas Association, Mercer, Willis Towers Watson, and Kenexa Compensation Analyst. Specifically, the Company analyzes the median base pay and target incentive compensation from these sources to determine an appropriate market wage.

Q. How are non-bargained employee annual base pay increases determined?

A. The Company allocates a share of its annual salary budget for merit-based compensation increases. Managers and supervisors are provided guidelines by Human Resources for how to allocate individual employee salary increases, taking into consideration performance appraisals, pay equity, retention concerns, and other factors. In the second quarter of each year, the Company reviews available external salary budget surveys and resources to project the salary budget for the following year. The Company also reviews internal needs and historical data when information is limited early in the year. In the third quarter of each year, the Company finalizes the salary increase budget by reviewing the external survey data for any updates or changes from the second quarter. MDU Resources' Chief Human Resources, Administration & Safety Officer ("Chief Human Resources Officer") publishes guidelines for MDU Resources and its various subsidiaries to follow in allocating the following year's pay increases for non-bargained employees. Managers and supervisors are responsible for allocating this budget in accordance with the guidelines.

Q. How does the Company ensure it is not paying or incentivizing more than necessary to attract and retain a qualified workforce?

A. In addition to the internal market review described above, approximately once every five years the Company retains an outside, independent consultant to review its compensation practices and programs. In 2022, the Company engaged Mercer to conduct a robust competitive market study on multiple aspects of the Company's compensation program. This outside review assures reasonable and appropriate compensation packages are being implemented to attract and retain quality employees, who in turn allow the Company to continue providing a safe and reliable service to its customers.

The Company's pay philosophy is to pay employees at the 50th percentile of the identified salary grade for base salary and total cash compensation, but Mercer's study found the Company was positioned between the 25th and 50th percentiles. Thus, a new pay structure was identified and implemented where warranted.

Mercer also found that the Company's pay levels under this new structure were within a competitive market range of +/- 10 percent for base salary and +/- 15 percent for total cash compensation.

The Company analyzed options to position a more favorable compensation package for current and potential employees, as the talent market continues to be very competitive overall, and extremely competitive for certain positions. Options available for consideration and which may be utilized to successfully recruit new employees include frontloading vacation time for new hires as well as utilizing sign-on bonuses and relocation assistance, which is used on a limited basis. Incentives that help attract new employees as well as retain current employees include changes to the Company's 401(k) plan match that increase the amount of funds contributed to employees' retirement accounts, an increase in the number of paid holidays starting in 2024, and the restructuring of the Company incentive plan program to align more closely with employee contributions to the Company's success.

Q. How was Cascade's 2025 and 2026 non-bargained employee compensation determined?

A. In the second quarter of each year, the Company creates a budget for non-bargained employee pay increases. MDU Resources' Chief Human Resources Officer provides a recommendation for the subsequent calendar year, subject to approval by MDU Resources' President and Chief Executive Officer. The salary budget recommendation considers competitive pay, economics, and industry-specific salary budget projections. The recommendation is presented as an all-inclusive percentage that includes merit increases for performance, equity and competitive pay adjustments, and promotions.

In October of 2024, the Chief Human Resources Officer published guidelines for the Company's officers to follow in allocating 2025 pay increases for non-bargained employees. The guidelines provided managers a 4.5 percent merit-based wage increase budget, plus an additional 0.5 percent to be used during 2025 to address pay equity, wage compression, and promotions through a mid-year salary increase process. The Chief Utilities Officer approved 2025 salary recommendations submitted by officers for non-bargained employees effective on December 16, 2024, which resulted in a total increase of approximately 4.3 percent. The energy industry's labor market published from Mercer Pulse Survey in July 2025 supports a 2026 salary budget increase total of 5.0 percent, inclusive of merit, promotional, and off-cycle increases for its non-bargained workforce. This increase will be effective in December of 2025.

The 2027 compensation budget will be similar to previous years, and will be at least 5 percent, inclusive of merit, promotions, and off-cycle increases.

Q. Please explain the rationale for bargained employee compensation.

A. The bargained employees at Cascade are represented by the International Chemical Workers' Union ("Union") under a collective bargaining agreement ("CBA"). Hourly pay rates and total compensation make up one portion of the CBA. The current CBA for the group has been effective since June 3, 2024. The annual wage increases for the Union are provided in Table 1 below:

Table 1 – Union CBA Wage Increases

Bargained Group	2024 Wage Increase	2025 Wage Increase	2026 Wage Increase	2027 Wage Increase
International Chemical Workers' Union	8.50%	6.00%	4.00%	3.50%

The cost of labor has increased in recent years to attract and retain individuals in bargained roles with the skills required to operate and maintain our systems.

Q. Does Cascade propose inclusion of allocated wage increases from affiliate companies to Cascade's overall wage expense?

A. Yes. Since 2018, the Company has been consolidating functions within its affiliate utility companies to be efficient at providing safe, reliable, and affordable service to customers. This consolidation resulted in many non-bargained positions transferring from Cascade's headcount to an affiliate's headcount. A percentage of these positions continue to contribute to Cascade's business either directly or indirectly through activities that simultaneously benefit Cascade and the other utilities.

Q. Has the consolidation of operation functions with affiliate companies resulted in a decrease in headcount at Cascade?

A. No. The headcount at Cascade has remained relatively consistent over the last five to ten years even though some roles were transferred from Cascade's headcount to an affiliate's headcount. The reason for this consistency is that a number of roles have been added to Cascade's headcount that did not exist ten years ago. Examples of these new roles include field positions to service areas with customer growth, environmental positions, and positions to ensure regulatory compliance and pipeline safety.

Administratively, as noted above, affiliate companies share a uniform salary policies and benefits structure. The consolidation of functions has been done to streamline operations and increase operational efficiencies.

Q. How are affiliate employee wages and any associated increases allocated to Cascade?

A. Affiliate wages and associated increases are allocated to Cascade following the allocation process discussed in the Direct Testimony of Tammy J. Nygard.[1]

Q. Why is allocation of affiliate wages and any associated increases to Cascade appropriate?

A. Wages and associated increases at Cascade's affiliates follow the same total rewards philosophy as Cascade, and wages for Cascade and its affiliates are determined in the same manner. Wage increases for employees at affiliates of Cascade who have a portion of their time allocated to Cascade increase the total cost of said time that is allocated to Cascade. As such it is appropriate to allocate a percentage of labor costs to Cascade.

Q. Did Cascade's affiliates experience labor market price increases?

A. Yes. MDU Resources and the MDU Utilities Group companies have experienced labor market increases across the service territory since 2021 due to the same competitive market conditions previously discussed.

[1] CNGC/400, Nygard/5-7.

Q. Please describe the Company's short-term incentive pay plan for employees.

A. MDU Resources and the MDU Utilities Group companies utilize the same Short-Term Employee Incentive Compensation Plan ("Plan"). The Plan is available to all employees who are classified as full-time or part-time employees, excluding the bargaining unit at Cascade, and is structured to provide incentive compensation for those employees with satisfactory performance. While the metrics for all MDU Resources companies are combined for purposes of the incentive, Cascade's metrics are integral to the calculations.

The 2025 Plan is based on the CORE strategy discussed earlier in my testimony, with each independent element of the Plan representing a section of the CORE strategy. The "Customers and Community" element is based on the results of the J.D. Power Gas Utility Customer Service Satisfaction Study ("J.D. Power Study") and is ten percent of the total available Plan payout.[2] The "Operational Excellence" element is also ten percent of the total available Plan payout and is measured by the combined incident frequency rate of unplanned service outage events. The "Returns Focused" element is the largest, consisting of seventy percent of the total available payout, and is determined by MDU Resources reaching its target earnings from continuing operations for 2025. Finally, the "Employee Driven" element constitutes ten percent of the total available payout and is measured by the preventable incident frequency rate of motor vehicle and equipment incidents and how timely incidents are reported. If minimum Company performance is achieved in each area, participating employees may earn between 1.5 and 60 percent of their annual salary under the

[2] The J.D. Power Gas Utility Customer Service Satisfaction Study is discussed further in the Direct Testimony of Dan L. Tillis and the results are summarized in an accompanying exhibit. CNGC/300, Tillis/5; CNGC/301, Tillis/1-2.

Plan, depending on their pay grade and the strength of Company performance of the various elements.

Q. How does the incentive pay plan benefit Cascade's customers?

A. The incentive pay plan, particularly as revised for 2025, provides benefits to Cascade customers in multiple ways. Most importantly, as described above, seventy percent of the eligible incentive payout is based on Cascade's progress towards reaching its target earnings from continuing operations. This element includes many sub-items such as reduction of operations and maintenance costs and enhancement of employee engagement and performance which are essential to maintaining a stable business operation that can effectively provide safe, reliable, and affordable service to its customers.

The remaining 30 percent of the eligible incentive payout is also connected to goals that directly benefit customers. Ten percent of the eligible incentive payout is based upon the Company's employees providing superior customer service, measured by the J.D. Power Study. Another ten percent of the eligible incentive payout is based wholly on the incident frequency rate of unplanned service outage events with a goal to directly reduce the amount and duration of service interruptions to customers. The final ten percent of eligible incentive payout is based on employees reducing the number of preventable motor vehicle accidents, which benefits customers by improving the safety of operations for customers and the public, as well as reducing the costs associated with property damage and personal injuries.

Q. How does the Company's total cash compensation package benefit customers?

A. The Company's base compensation benefits customers by effectively meeting the need to compensate employees fairly and competitively to assure the retention of a qualified workforce to provide safe and reliable service to all its customers.

Additionally, the Company's incentive compensation plan benefits customers by creating incentives for employees to focus on key objectives, including high-quality customer service, the reduction of unplanned service outages, operational efficiency, and reduction of preventable safety incidents. Using incentive compensation as a component of total cash compensation also allows the Company to be more competitive in the labor market and lowers fixed costs in the form of base pay. Finally, utilizing both base pay and incentive compensation encourages employees to focus on the key metrics that benefit the Company's customers.

V. BENEFITS

Q. Please describe Cascade's Health and Welfare benefits provided to its employees.

A. All MDU Resources companies utilize the same health and welfare benefits. This includes a health savings account (HSA") coupled with a choice of two high-deductible medical plans, a Company contribution to employees' HSA accounts, dental insurance, vision insurance, life insurance, long-term disability insurance, supplemental life and AD&D insurance, flexible spending plans, and more.

All MDU Resources companies pay the same percentage of the premium for their employees' medical, dental, and vision insurance premiums, and provide their employees with the same contributions to the employees' HSA accounts.

Q. Have the medical plan benefits changed since 2021?

A. The benefits offered and their structure have not changed. However, medical plan premiums have increased for both employees and the Company since 2021. The reasons include increased cost of medical services, the introduction of new specialty prescription drugs, and variations in utilization of the plans.

The Company has successfully implemented various programs to slow these cost increases, including enacting options for video doctor and therapist visits, on-demand on-line therapy options, a program to help employees prevent diabetes and heart disease, and a program for employees with sudden and severe medical conditions to assist them with finding specialists, second opinions, and alternative treatment options. The Company has also slowly begun to shift a larger percentage of the increases in the cost of the medical program to employees; for example, in 2023 employees paid approximately eight percent of the total premium for medical coverage and in 2024, 2025 and 2026 they pay approximately nine percent of the total premium.

Q. Please describe Cascade's retirement plan benefits for its employees.

A. All MDU Resources companies utilize the same retirement plan package for their non-bargained employees. This package includes an annual contribution to their 401(k) account equal to five percent of their salary. Additionally, non-bargained employees that contribute to their 401(k) receive an employer match equal to 100 percent of an employee's salary deferrals with the maximum match being four percent of an employee's salary.

Q. Have the retirement plan benefits changed since 2021?

A. Yes. The current 401(k) matching employer contribution was implemented in 2025. Previously, the employer match equaled 50 percent of an employee's salary deferrals with the maximum match being three percent of an employee's salary.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

DIRECT TESTIMONY OF BRIAN L. ROBERTSON

EXHIBIT 1400

November 2025

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Brian L. Robertson. My business address is 8113 West Grandridge Boulevard, Kennewick, Washington 99336.

Q. By whom are you employed and what are your title and job duties?

A. I am employed by Cascade Natural Gas Corporation ("Cascade" or "Company") as Manager of Supply Resource Planning. My job duties include managing three analysts as well as coordinating and completing the Company's Integrated Resource Plan ("IRP").

Q. Please describe your educational background and professional experience.

A. I graduated from Central Washington University with a bachelor's degree in actuarial science. After graduating, I joined Cascade in February 2014 as a Regulatory Analyst. I joined the Gas Supply department in March 2015 as a Resource Planning Analyst II. In July 2016, I was promoted to Senior Resource Planning Analyst. In June 2019, I was promoted to Supervisor of Resource Planning and in December 2023, I was promoted to Manager of Supply Resource Planning.

Q. Have you previously submitted written testimony to or testified before the Public Utility Commission of Oregon ("Commission") or another regulatory commission?

A. Yes. I previously testified before this Commission in Cascade's rate cases: dockets UG 347 and UG 305. I have also testified before the Washington Utilities and Transportation Commission in dockets UG-152286, UG-170929, UG-190210, UG-200568, and UG-240008.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the scope of your testimony in this proceeding?

A. My testimony in this proceeding focuses on Cascade's long-term demand forecast model, which is used to project monthly demand, monthly usage, and annual customer counts by tariff schedule at the pipeline zone level. The outputs from this model served as the basis for allocating the expected demand, usage, and customer counts outlined in the 2023 IRP.[1]

Q. Please summarize your testimony.

A. My testimony explains that Cascade's demand forecast model provides statistically based projections of customer counts, usage, and demand across pipeline zones, using historical data, economic growth indicators, and heating degree days (HDDs) as key inputs. I highlight that Cascade contracted with ICF International ("ICF") to refine HDD values by incorporating long-term temperature adjustments, which result in fewer projected HDDs compared to traditional 30-year historical averages. This adjustment indicates lower future heating needs, directly reducing expected demand for natural gas. By integrating these refined HDD projections with customer growth and usage models, Cascade ensures that its test year volumes accurately reflect anticipated conditions.

Q. Are you providing any exhibits in support of your testimony?

A. Yes, I am providing Exhibit CNGC/1401, Test Year Forecast Data which contains Cascade's Oregon volumes for the twelve months ended October 31, 2027 ("Test Year"). I am also providing Exhibit CNGC/1402, ICF Temperature Adjustment Methodology which contains ICF's methodology for the provided temperature adjusted HDDs.

[1] *See In re Cascade Nat. Gas Corp., 2023 Integrated Resource Plan*, Cascade's 2023 IRP at Ch. 3 (June 2, 2023).

III. DEMAND FORECAST MODEL

A. Modeling Approach

Q. Generally speaking, why does the Company perform a demand forecast?

A. Cascade employs a demand forecasting model that produces statistically based projections of gas sales and peak demand over a 20-year planning horizon. These forecasts play a critical role in long-term resource and infrastructure planning, enabling Cascade to anticipate future energy needs and implement timely strategies to meet those demands. Furthermore, the demand forecast is performed to determine what the Company's Test Year sales volumes are projected to be under expected customer growth and normal weather. The Company's billing determinants used to set rates in this case are based on normalized weather volumes for the Test Year. Please see the Direct Testimony of Matt Larkin for a discussion of the Company's use of Test Year volumes for this case.[2]

Q. What is demand as used in your testimony?

A. Demand refers to Cascade's historical or future monthly gas usage by pipeline zones and rate schedules. A pipeline zone is a combination of points where natural gas deliveries transfer from the interstate pipeline to Cascade's distribution system. Cascade has three pipeline zones in Oregon: zone 24 in eastern Oregon, zone ME-OR in north-central Oregon, and zone GTN in central Oregon. A rate schedule defines the kind of utility service provided including rates and charges, rules and conditions, and legal and regulatory compliance. Cascade has the following core rate schedules:

- Schedule 101 for residential rates;
- Schedule 104 and Schedule 111-COM for commercial rates,
- Schedule 105 and Schedule 111-IND for industrial rates; and

[2] *See* CNGC/700, Larkin.

- Schedule 170 for interruptible rates.

Cascade also has non-core rate schedules, which are Schedule 163 for Large Volume Industrial, and Schedule 900 for special contracts.

Q. What is the difference between core and non-core demand?

A. Core demand refers to the natural gas usage of residential, commercial, and industrial customers who receive bundled gas services under Cascade's tariff structure. In a bundled service arrangement, Cascade is responsible for purchasing the natural gas supply and securing the necessary upstream pipeline capacity to deliver that gas to the customer. This means the Company manages both the commodity and transportation aspects of the service.

Non-core demand, on the other hand, includes commercial and industrial customers who receive unbundled gas services. These customers procure their own natural gas supply and upstream transportation capacity independently, while Cascade provides only the local distribution service.

Q. What is a forecast model?

A. A forecast model is a statistically driven tool that uses historical information to best predict future natural gas usage and the number of customers at a pipeline zone and rate schedule level.

Q. Would you please describe the Cascade use per customer ("UPC") and customer forecast models?

A. Cascade's UPC forecast model is a statistically based model that uses HDDs, wind, retail rates, and a weekend indicator, calculated from historical weather, rates, and demand data, to develop dynamic regression models for projecting future UPC. Cascade's customer forecast model is a statistically based model that uses household, employment, income, and retail rates data, calculated from historical economic and customer data, to develop dynamic regression models for projecting future customer counts. The customer forecast is then applied to the UPC model to generate forecasted demand values at the pipeline zone level.

Q. How is the UPC and demand forecast broken out by customer class?

A. Historical Customer Care and Billing ("CC&B") system data is used to determine a breakout of customer class for each pipeline zone. The customer class is applied to the total usage for the respective pipeline zone to produce a monthly load by pipeline zones by rate schedule.

B. Customer Counts

Q. What historical customer count data is used in the forecast model?

A. Historical customer count data was compiled by analyzing monthly premise counts. Customer counts, organized by town and tariff, were extracted from the CC&B system and used to calculate annual premise totals by pipeline zones. Monthly premise data by town, tariff, and year was then allocated to the corresponding pipeline zone, resulting in a complete breakdown of premise counts by tariff, year, and month at the pipeline zone level.

Q. What data is used to determine annual growth?

A. Growth is determined based upon Woods & Poole Economics, Inc. ("Woods & Poole") household growth and/or employment projection data. Woods & Poole is an independent firm specializing in long-term economic and demographic projections at the county level throughout the United States. The database includes forecasts through 2060 for more than 900 variables across every U.S. county. Each year, projections are updated using the latest historical data. Since 1983, Woods & Poole has provided growth estimates relied upon by public utilities, government agencies, consultants, retailers, market researchers, and planners for strategic planning and analysis.

Q. What type of regressions does the customer forecast model use to predict future customer counts?

A. Cascade utilizes dynamic regression models for the customer forecast model. Cascade runs this model approximately 57 times to account for each customer class by pipeline zone. The Company begins by evaluating 31 different combinations of the regressors in both dynamic regression models and one Autoregressive Integrated Moving Average ("ARIMA")-only model. The dynamic regression models assess Fourier, households, employment, retail rate and all combinations of those four regressors as an ARIMA model. The last model only uses ARIMA terms and no regressors. The method used to compare and select a model is called the AIC, or the Akaike Information Criterion. This is a measure of the relative quality of statistical models, relative to each of the other models. In each of the models, except for the ARIMA-only model, an ARIMA term is used to capture any structure in the errors (or residuals) of the model. In other words, there could be predictability in the errors, so they could be modeled as well. If the data is non-stationary, the ARIMA function will difference the data. Most times, the data does not require differencing or, if it does, only needs to be differenced once. Once the best model is selected for each customer class by pipeline zone, a forecast is performed using the selected model.

Q. What are the results of the customer forecast model?

A. Table 1 below includes a comparison of the twelve-month average of Test Year customers from Cascade's most recent Oregon general rate case, docket UG 390, and the current application.

Table 1 – Comparison of Test Year Average Customer Counts

Customer Class	Previous Case (UG 390)	Current Application	Difference
Schedule 101	67,704	78,223	10,519
Schedule 104	10,228	10,682	454
Schedule 105	151	160	9
Schedule 111-COM	12	10	(2)
Schedule 111-IND	8	6	(2)
Schedule 163	37	34	(3)
Schedule 170	4	4	-

C. HDD Inputs

Q. What was the source of historical weather data used in the forecast model?

A. Historical weather data used in all weather-related analyses is sourced from the Schneider Electric weather service. This data includes daily minimum and maximum temperatures recorded at each weather station. Schneider Electric derives its weather values from actual observations provided by the National Oceanic and Atmospheric Administration ("NOAA"). In cases where NOAA data is unavailable for a specific station and day, Schneider Electric supplies an estimated value to fill the gap.

Q. How many weather station locations are used in the forecast model?

A. There are three Oregon weather station locations used in the forecast model: Baker City, Pendleton, and Redmond.

Q. How are the HDD values used in the forecast model calculated?

A. HDD values are calculated by first determining the daily average temperature, which is the mean of the day's high and low temperatures. This average is then subtracted from a designated HDD threshold, typically 65°F, to calculate the HDD for that day. If the result is negative, it is set to zero, meaning HDD values are never negative. The threshold is intended to represent the temperature below which heating demand begins to rise noticeably. Historically, 65°F has been the standard threshold for HDD calculations. However, Cascade has found that using a lower threshold of 60°F yields more accurate results when modeling gas demand. The Company's analysis showed that heating demand does not significantly increase until the HDD reaches five (based on the 65°F threshold). By lowering the threshold to 60°F, Cascade achieves a more precise correlation between HDD values and therm usage, improving the reliability of demand forecasts.

Q. How were peak day HDDs determined?

A. Cascade used Monte Carlo simulations to simulate 10,000 weather profiles for each of the weather locations. When performing the Monte Carlo simulations, the Company utilized historical weather data to calculate the average and standard deviation for daily HDDs. Cascade used a Cholesky decomposition matrix in order to correlate the weather locations to one another. Once the simulations were finalized, Cascade found the 99th percentile coldest HDDs.

Q. Were temperature adjustments made to the HDD values used to calculate forecasted demand?

A. Yes, Cascade contracted with ICF, a consulting firm with expertise in energy and environmental analysis, to incorporate temperature change impacts into its forecasting process. ICF's contribution includes evaluating how long-term shifts in temperature patterns may affect heating demand and refinements to the model to account for future climate variability. Cascade describes this temperature adjustment methodology further in ICF Temperature Adjustment Methodology.[3]

Q. What was the impact the temperature adjustments made to HDDs?

A. The table below shows the old methodology of 30-year historical weather data to calculate normals, ICF's normal weather projections, and the difference.

[3] *See* CNGC/1402, Robertson.

Table 2 – Comparison of HDD projections

	Baker City HDDs	Pendleton HDDs	Redmond HDDs
30-year historical method	5,673	3,940	4,906
ICF Projections	5,212	3,619	4,423
Difference	(461)	(320)	(483)

D. UPC Forecast Demand

Q. What was the source of the historical demand data used in the UPC forecast model?

A. Historical monthly demand by pipeline zone was derived from three sources:

- The Company's CC&B system provided billing demand by town, tariff, year, and month;
- The Company's Gas Management System ("GMS") provided non-core demand by pipeline zone, year, and month; and
- Pipeline Electronic Bulletin Board ("EBB") systems provided demand flow data by pipeline zone, year, and month.

Q. How was core and non-core demand calculated from historical data?

A. Cascade determines core demand by analyzing pipeline flow data at each pipeline zone, which reflects the total gas volume delivered to both core and non-core customers. To isolate core demand, Cascade subtracts non-core usage, tracked through its GMS, which monitors individual non-core customer consumption behind each pipeline zone.

Q. What type of regressions do the demand forecast model use to predict future usage?

A. Similar to the customer count regressions, Cascade utilizes dynamic regression models for the UPC forecast model. Cascade begins each model with a simple linear model regressing on HDDs, wind, retail rate, and weekend. If the residuals analyzed show structure, then the models are expanded to include ARIMA and Fourier terms. Cascade runs this model for each of the ten pipeline zones, and breaking each of those out into their respective rate classes results in 57 different regressions.

Q. How is demand calculated?

A. Cascade applies the associated explanatory coefficients to each pipeline zone's UPC regression model to produce a UPC forecast. Similarly, Cascade applies the associated economic and retail data to the customer forecast regression models to produce a customer forecast. The UPC and customer regression models are multiplied to each other to produce a final demand forecast.

E. Model Results

Q. Please describe the results of your UPC forecast.

A. The results of the UPC forecast are provided in the table below, along with a comparison to UPC forecasts for rate classes 101 and 104 from Cascade's most recent general rate case, docket UG 390.

Table 3 – Use per Customer Forecast & Comparison (in therms)

Customer Class	Previous Case (UG 390)	Current Application	Difference
Schedule 101	708	710	2
Schedule 104	3,024	3,188	164

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

TEST YEAR FORECAST DATA

EXHIBIT 1401

November 2025

2026-27 Therm Forecast

	101	104	105	111-COM	111-IND	170
Nov-26	6,914,407	4,065,686	393,990	121,396	156,870	255,302
Dec-26	9,740,390	5,736,704	484,757	138,742	188,844	364,417
Jan-27	8,865,310	5,326,983	451,991	130,126	174,392	416,680
Feb-27	7,468,970	4,502,433	387,625	113,597	144,408	299,014
Mar-27	6,136,883	3,677,989	342,570	101,245	147,704	307,856
Apr-27	4,096,833	2,507,937	239,267	102,045	138,417	236,103
May-27	2,705,419	1,771,294	162,629	93,677	135,684	161,877
Jun-27	1,544,515	1,145,728	112,853	65,567	106,633	115,109
Jul-27	1,389,502	1,109,392	119,605	65,860	107,963	109,531
Aug-27	1,152,991	927,347	104,140	55,025	97,785	94,998
Sep-27	1,679,595	1,090,177	142,415	60,032	92,653	84,265
Oct-27	3,855,469	2,193,251	279,054	90,600	116,151	157,433
Total	55,550,286	34,054,921	3,220,895	1,137,912	1,607,504	2,602,586

2026-27 Customer Forecast

	101	104	105	111-COM	111-IND	170	163
Nov-26	77,647	10,678	160	10	6	4	34
Dec-26	77,777	10,713	160	10	6	4	34
Jan-27	77,899	10,723	161	10	6	4	34
Feb-27	78,099	10,725	161	10	6	4	34
Mar-27	78,184	10,718	161	10	6	4	34
Apr-27	78,243	10,698	160	10	6	4	34
May-27	78,298	10,673	160	10	6	4	34
Jun-27	78,311	10,652	160	10	6	4	34
Jul-27	78,321	10,636	159	10	6	4	34
Aug-27	78,370	10,627	159	10	6	4	34
Sep-27	78,624	10,645	159	10	6	4	34
Oct-27	78,903	10,694	159	10	6	4	34
Total	938,675	128,182	1,919	121	72	48	408

	906	906
	Hermiston Generating	PacifiCorp
Nov-26	5,610,201	11,418,394
Dec-26	8,240,273	12,062,882
Jan-27	10,746,679	12,113,468
Feb-27	11,420,798	11,100,785
Mar-27	11,394,811	9,604,929
Apr-27	9,336,509	9,500,836
May-27	9,560,276	7,965,750
Jun-27	10,097,446	10,638,225
Jul-27	10,563,430	11,598,355
Aug-27	12,243,882	11,548,174
Sep-27	12,132,843	11,147,353
Oct-27	11,076,505	9,606,947
Total	122,423,655	128,306,100

Peak Day	101	104	105	111-COM	111-IND	170							
2026	494,677	289,606	23,680	6,739	8,921	17,561	78,223	10,682	160	10	6	4	34
							89,119	10,692	204				
Total 111 Volumes on Peak Day					15,660		R	C	I				

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

ICF TEMPERATURE ADJUSTMENT METHODOLOGY

EXHIBIT 1402

November 2025

Data description of LOCA2 downscaled CMIP6 projections for Cascade Natural Gas

April 30, 2024

Summary

ICF generated daily average temperature (tas) and Heating Degree Day (HDD) time series for a historical baseline of 1985-2014 and future projection period of 2025-2064. The projections span a set of 7 weather station locations, and HDD calculations assume two base temperatures of 60°F and 65°F and the average of daily maximum and minimum temperatures.

The HDD projections were calculated for an ensemble of 22 Localized Constructed Analogs Version 2 (LOCA2) downscaled Coupled Model Intercomparison Project Phase 6 (CMIP6) Global Climate Models (GCMs) with a 1/16th degree (~6km) grid spacing.[1] Projections were evaluated for two Shared Socioeconomic Pathways (SSPs): SSP2-4.5 and SSP3-7.0, which represent significantly mitigated global greenhouse gas emissions and continued increases in global greenhouse gas concentrations, respectively.

Prior to the HDD calculations, daily temperature data for the LOCA2 GCMs were bias-adjusted using the station-specific historical observations provided by Cascade via a Quantile Delta Mapping (QDM) method. Bias adjustment methods are commonly used to make climate model projections more accurate for specific locations and remove relative biases compared to in-situ observed weather time series. The QDM method helps to resolve important climate characteristics specific to each weather station location related to elevation, topography, proximity to the coastline, and other factors.

QDM is a specific adjustment method well-suited to model extreme events with improved accuracy. QDM achieves this by matching the cumulative distribution functions (i.e., the quantiles) of observational weather data and climate model data over a matching reference time period, and then applies those differences between observed and modeled data (the "deltas") to future projections. As these biases can also vary seasonally, ICF further computed separate quantile deltas for each day of the year using a rolling window of ±2 weeks. Ultimately, ICF bias corrected the climate projections to each weather station location to account for the overall mean model bias, differential biases for more extreme conditions, and variations in model bias based on time-of-year.

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[1] Pierce, D. W., Cayan, D. R., Feldman, D. R., & Risser, M. D. (2023). *Future Increases in North American Extreme Precipitation in CMIP6 Downscaled with LOCA.* Journal of Hydrometeorology, 24(5), 951-975. https://doi.org/10.1175/JHM-D-22-0194.1