Bob Ferguson
ATTORNEY GENERAL OF WASHINGTON
Environmental Protection Division
800 Fifth Avenue STE 2000 • Seattle WA 98104 • (206) 464-7744

November 22, 2023

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: **Gas Transmission Northwest LLC, Docket No. CP22-2-000**

Dear Ms. Bose:

On October 23, 2023, the Commission issued an Order approving the GTN Xpress project in Docket Number CP22-2-000. The States of Washington, California, and Oregon now submit a Request for Rehearing of that Order. Portions of their Request for Rehearing discuss provisions of the precedent agreements that GTN marked as privileged and confidential pursuant to 18 C.F.R. § 388.112. *See* Application, Dkt. CP22-2-000, 3 (Oct. 4, 2021). GTN asserts that these materials contain "sensitive data, proprietary information or information that otherwise is not appropriate for disclosure to the public." *Id*. The States accordingly file this Request for Rehearing with a request to accord it **privileged and confidential treatment pursuant to 18 C.F.R. § 388.112.** In a separate, public version of their Request for Rehearing, the States have redacted the portions discussing material that GTN marked as confidential. *See* 18 C.F.R. § 388.112(b)(2).

Respectfully submitted,

*_/s/ Megan Sallomi*___________

Megan Sallomi
Assistant Attorney General
Washington State Office of the Attorney General
Environmental Protection Division
800 Fifth Avenue, Suite 2000
Seattle, WA 98104-3188
Tel: (206) 389-2437
Megan.Sallomi@atg.wa.gov

Enclosure

cc: All parties of record (cover letter and redacted copy of the Request for Rehearing)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

GAS TRANSMISSION NORTHWEST, LLC

Docket No. CP22-2-000

REQUEST FOR REHEARING OF THE ORDER ISSUING CERTIFICATE, DATED OCTOBER 23, 2023

BY THE STATES OF WASHINGTON, CALIFORNIA, AND OREGON

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I. INTRODUCTION

The State of Washington, at the direction of the Governor, and the States of Oregon and California[1] (collectively, the "States") respectfully urge the Commission to grant rehearing, withdraw its Order Issuing Certificate and its Final Environmental Impact Statement ("EIS"), and deny the GTN Xpress Expansion (the "Expansion"). The Expansion does not serve a public need or interest. To the contrary, it will advance private interests at the expense of our States' consumers, adversely impact the States' efforts to reduce reliance on fossil fuels, and contribute to climate change.

The Commission regulates expansion projects to protect consumers, ensure reasonable prices, prevent overbuilding, and protect the environment. Contracts between private parties do not adequately consider these interests. Yet, in this case, the Commission uncritically deferred to those private contracts and failed to consider other evidence and arguments indicating that the Expansion does not serve a public need or interest. This includes evidence and arguments that: existing consumers will subsidize the Expansion; GTN failed to show a public need for the Expansion based on GTN's precedent agreements and particularly in light of state and local laws that will reduce future demand; reasonable alternatives are available; the Expansion will cause significant harms to the environment; and the Expansion makes it more difficult for the nation, States, and local governments to achieve their climate and clean energy goals. The Commission's decision is arbitrary and capricious, unsupported by substantial evidence and violated the Natural Gas Act (NGA),

[1] The State of California appears by and through the California Attorney General.

the Administrative Procedure Act (APA), the National Environmental Policy Act (NEPA), and their implementing regulations.

II. FACTS

In 2019, GTN announced its 335 million dollar Expansion to investors and sold the Expansion capacity to Cascade Natural Gas Corporation, Intermountain Gas Company, and Tourmaline Oil Company. *See* States' Mot. Intervene and Protest, Dkt. CP22-2-000 (Aug. 22, 2022) ("States' Protest") at Ex. D, TC Energy Press Release. GTN then pursued a build first, ask later strategy for regulatory approval via piecemeal and incomplete applications to the Commission.

In March 2020, GTN filed three notices with the Commission stating it intended to replace aging compressor units at the Athol, Starbuck, and Kent stations under section 2.55(b) of the Commission's regulations implementing the NGA. *See* Notification, Athol Compressor Station, Dkt. CP20-82-000 (Mar. 10, 2020); Notification, Kent Compressor Station, Dkt. CP20-85-000 (Mar. 10, 2020); Notification, Starbuck Compressor Station, Dkt. CP20-86-000 (Mar. 10, 2020). Section 2.55(b) does not authorize replacements that create incremental capacity. 18 C.F.R. § 157.202(b)(2)(i) ("[C]ompressor replacements that . . . will result in an incidental increase in the capacity of the main line facilities" do not qualify under § 2.55(b)). GTN's notices did not disclose how much larger the new compressors would be or that the compressor upgrades would create incremental capacity for the Expansion. GTN finished installing the upgraded compressors in October and November

2021. *See* GTN Response to Apr. 4, 2023 Data Request, Dkt. CP22-2-000 (April 18, 2023), at 11.

Also in October 2021, GTN applied to the Commission to increase the capacity of its pipeline by removing artificial limits on the upgraded compressors at the Athol, Starbuck, and Kent stations. *See* GTN Mot. Leave to Answer Protests, and Answer to Protests and Opp. to Late Interventions (Dec. 16, 2021), at 7; GTN Transmission Northwest LLC, Abbreviated Application for a Certificate of Public Convenience and Necessity, Dkt. CP22-2-000 (Oct. 4, 2021) ("Application"), at 6-7. GTN's Application showed that the upgrades created 40 percent more horsepower than the prior compressors and were necessary to operate the Expansion. GTN's Application excluded 100 percent of the costs of those new compressors.

During the Draft EIS review period, the States intervened and became parties to this proceeding pursuant to 18 C.F.R. §§ 157.10(a)(2), 380.10(a)(1)(i). *See* States' Protest 8-10; Order Issuing Certificate, Dkt. CP22-2-000, 185 FERC ¶ 61,035 (Oct. 23, 2023) ("Order"), ¶ 7 n.15. The States also filed a protest and comments on the Draft EIS, arguing that GTN failed to show a public need for, or public interest in, the Expansion, particularly in light of the Expansion's inconsistency with state and local laws, its harmful environmental impacts, and its unjustified risks to consumers. *See id.* 11-29; States' Comments on Draft EIS, Dkt. CP22-2-000 (Aug. 22, 2022) ("States' DEIS Comments"). The Columbia River Inter-Tribal Fish Commission also filed comments, arguing the Expansion was "in direct conflict" with tribes' goals to reduce fossil fuels and will have "significant and irreversible effects on the region." *See* Columbia River Inter-Tribal Fish Commission, Comments on Draft EIS, Dkt. CP22-2-000 (Aug. 22, 2022) ("CRITFC Comments"). The Final EIS did not discuss whether the Expansion was inconsistent with federal, state, tribal, and local laws and policies to reduce the use of fossil fuels and transition to clean energy. *See* GTN Xpress Project, Final EIS, Dkt. CP22-2-000 (Nov. 18, 2022) ("Final EIS"), at 4-48 – 4-49.

On January 9, 2023, the Council on Environmental Quality ("CEQ") issued updated guidance to agencies on how to analyze greenhouse gas emissions and climate change under NEPA and the CEQ regulations implementing NEPA. *See* CEQ, NEPA Guidance on Consideration of Greenhouse Gas Emissions and Climate Change, 88 Fed. Reg. 1196 (Jan. 9, 2023) ("CEQ Guidance"). The States filed a comment urging the Commission to apply CEQ's Guidance to the Expansion to ensure the Final EIS presented the full scope of environmental harms and available clean energy alternatives as NEPA requires. *See* Letter from the States Regarding the CEQ's Greenhouse Gas Guidance, Dkt. CP22-2-000 (Feb. 10, 2023) ("States' CEQ Guidance Comments"). The Commission did not respond to the States' comment or discuss CEQ's Guidance.

In April 2023, the Commission asked GTN to provide more information including: evidence that methane gas consumption in the region is expected to increase in light of recent legislation; a more detailed response to the States' arguments regarding the Expansion's precedent agreements; a full copy of the confidential "IHS Markit Report" that GTN cited to in its Application; and a discussion of GTN's decision process in sizing each compressor unit when they were upgraded in 2020. *See* Data Request, Dkt. CP22-2-000

(Apr. 4, 2023). GTN chose not to provide evidence showing the Expansion would be needed in light of the impact of state and local laws. *See* GTN Response to Apr. 4 Data Request, 3-6 (Apr. 18, 2023). GTN instead argued that, as a matter of law, the precedent agreements were sufficient and that the impact of the States' laws was "mere speculation." *See id*. GTN also provided letters from Cascade, Intermountain, and Tourmaline to rebut the States' arguments that these particular precedent agreements were not significant evidence of need, but these letters generally did not address the States' arguments. *See id*. 6-8, 14-22. GTN also provided information showing that a smaller compressor would have met the certificated horsepower of the existing units that GTN upgraded in 2021. *See id*. 11-13. GTN filed a full copy of the IHS Markit Report, which is consistent with the States' projections of falling regional gas demand. *See* GTN Suppl. Resp. to Apr. 4 Data Request (May 15, 2023) ("IHS Markit Report"). IHS Markit also forecasted rising production in the Western U.S., which would more than offset any decline in production from the Rocky Mountain region. *See id.*

Many people commented on the Expansion. Most commenters opposed the Expansion, questioned its need, and expressed concern about its inconsistency with state and local laws to transition to clean energy. These commenters included Washington Governor Inslee, Oregon Governor Kotek, Senators Murray, Cantwell, Merkeley, Wyden, Feinstein, and Padilla, over two dozen community groups, and six thousand members of the public. *See generally* Dkt. CP22-2-000. The Oregon Legislature's Environmental Caucus also commented that the Commission's Order "directly undermines all the work being done in the legislature, our state agencies, and in the executive branch to reach our state's climate goals." *See* Or. Leg. Env't Caucus Comments, Dkt. CP22-2-000 (Nov. 9, 2023).

Staff at Washington's Utility and Transportation Commission commented in a separate state oversight proceeding that Cascade has not shown a need for its Expansion contract and the contract could harm Washington consumers. *See* Wash. Utils. and Transp. Comm. Staff Comments Re Cascade 2023 Integrated Resource Plan (Apr. 28, 2023), attached as Ex. C to Rogue Climate and Columbia Riverkeeper, Joint Comment Re GTN's Apr. 28 and May 15 Data Request Responses, Dkt. CP22-2-000 (June 8, 2023) ("WUTC Staff Comments"). Oregon's Citizen Utility Board, the statewide consumer advocate before the Oregon Utility Commission, raised similar concerns. *See* Or. Citizens' Utility Bd., Comments, Dkt. CP22-2-000 (Jan. 27, 2023) ("Or. Citizens' Utility Bd. Comments"). Idaho's Governor and Congressional delegation, individuals associated with the methane gas industry, the Project Shippers, and methane gas trade associations were among those who supported the Expansion.

The Commission unanimously approved the Expansion. *See* Order. The States now timely request rehearing. *See* 15 U.S.C. § 717r(a); 18 C.F.R. § 385.713.

III. STATEMENT OF ISSUES AND ERRORS

Pursuant to 18 C.F.R. § 385.713(c), the States present the following identification of errors and statement of issues:

Errors and Issues Pertaining to the NGA

1. The Order is arbitrary, capricious, contrary to law and regulation, and unsupported by substantial evidence in violation of the APA and NGA because the Commission failed to provide a reasoned decision or analyze all of the evidence regarding whether existing customers will subsidize the Expansion. The Commission failed to provide a reasoned explanation for justifying GTN's compressor upgrades based on their net output power in cold-weather conditions, rather than their certificated horsepower. The Commission also failed to analyze evidence showing that GTN always intended its replacement compressors to create incremental capacity or evidence showing that the Expansion's revenues do not pay for its costs when the costs of upgraded compressors necessary to expand were included. Nor did the Commission provide a reasoned explanation why existing customers should absorb the full cost of GTN's new compressors in light of this evidence. The APA demands more. *See Columbia Gas Transmission Corp. v. FERC*, 448 F.3d 382, 387 (D.C. Cir. 2006) ("It will not do for a court to be compelled to guess at the theory underlying the agency's action; nor can a court be expected to chisel that which must be precise from what the agency has left vague and indecisive.") (quoting *SEC v. Chenery Corp*., 332 U.S. 194, 196–97 (1947)).

2. The Order is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the APA and the NGA because the Commission approved the Expansion without first deciding how to allocate costs between existing and expansion customers, a central issue to determine whether the Expansion is subsidized or

whether need exists. The NGA and Commission policy obligate the Commission to decide that issue before approving the Expansion. *See* Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC ¶ 61,227 (1999), clarified, 90 FERC ¶ 61,128, further clarified, 92 FERC ¶ 61,094 (2000) at 20-21 ("1999 Policy Statement"); *see also Tennessee Gas Pipeline Co., L.L.C.*, 140 FERC ¶ 61,120, 61,595 (2012) (describing Commission practice of making "an upfront determination on the rate treatment for expansion projects").

3. The Order is arbitrary, capricious, contrary to law and regulation, and unsupported by substantial evidence in violation of the APA and the NGA because the Commission unreasonably and unlawfully concluded that GTN's upgrades of existing compressors with substantially larger compressors did not create an incidental increase in capacity. The Commission should have found that section 2.55(b) did not authorize the compressor upgrades because the upgrades created an incidental increase in capacity. The NGA requires advance approval before constructing new facilities. *See* 15 U.S.C. § 717f. Commission regulations have a narrow exception to that rule for basic maintenance and routine repairs, *see* 18 C.F.R. § 2.55(b), but that exception does not apply to replacements that "result in an incidental increase in the capacity," § 157.202(b)(2)(i); *see also Revision of Existing Regulations Under the Natural Gas Act,* 64 Fed. Reg. 54522, 54524 (Sept. 29, 1999) (codified at 18 C.F.R. § 157) (stating replacements under § 2.55(b) "should only involve basic maintenance or repair to relatively minor facilities"). The Commission's determination conflicts with section 2.55(b)'s plain and unambiguous language as well as its

regulatory history and intent and is an unreasonable interpretation. *See Kisor v. Wilkie,* 139 S. Ct. 2400, 2414-16 (2019); 18 C.F.R. § 2.55(b).

4. The Order is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the APA and the NGA because the Commission failed to provide a reasoned explanation for allowing GTN to use a weighted-average depreciation rate principally derived from its last-approved depreciation rate for mainline transmission facilities. *See* Order ¶ 40, nn.84, 85 (describing GTN's last-approved depreciation rates and rejecting the States' request for a modified depreciation rate); *Gas Transmission Nw. LLC*, 177 FERC ¶ 61,110 (2021) (approving GTN's last rate settlement and depreciation rates); *Wyo. Interstate Co*., 119 FERC ¶ 61,251 (2007). Since the Expansion only involves upgrades to GTN's compressor stations, not its mainline transmission facilities, GTN should have used its substantially higher last-approved depreciation rate for compression facilities. By allowing GTN to use a lower, weighted-average depreciation rate, the Commission failed to follow its own policy of using the last-approved depreciation rate and inappropriately relied on an inaccurate assessment of the Expansion's costs and annual cost of service. *See Wyo. Interstate Co*., 119 FERC ¶ 61,251 (2007) (discussing Commission policy to use the last-approved depreciation rate for expansions).

5. The Order is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the APA and the NGA because the Commission did not provide a reasoned explanation for its decision to allow GTN to charge consumers for the Expansion through 2070, despite having no evidence the Expansion will be needed after the

precedent agreements expire (if at all). *See Gulf S. Pipeline Co., LP v. FERC*, 955 F.3d 1001, 1012 (D.C. Cir. 2020) ("We have no basis to review FERC's policy because the Commission has said nothing about what the policy means or why it is justified.").

6. The Order is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the APA and the NGA because the Commission ignored the impact of federal, state, tribal, and local laws and policies on the public's alleged need for more interstate pipeline capacity. The effect of these laws and policies on future need for gas is a critical factor to assessing whether the Expansion serves a public need. *See Motor Vehicle Mfr's Ass'n v. State Farm*, 463 U.S. 29, 43 (1983) (arbitrary action includes when an agency "entirely failed to consider an important aspect of the problem"); *Env't Def. Fund v. FERC*, 2 F.4th 953, 959 (D.C. Cir. 2021) (stating the 1999 Policy Statement requires it to consider "*all* relevant factors" for public need) (emphasis in original). Particularly in light of the NGA's directive for the Commission to protect consumers through complementary regulation to that of the States, the Commission's failure to analyze this factor in its need determination is arbitrary and capricious. *See, e.g.*, *Distrigas Corp. v. Fed. Power Comm'n*, 495 F.2d 1057, 1064 (D.C. Cir. 1974).

7. The Order is arbitrary, capricious, contrary to law, and unsupported by substantial evidence because the Commission failed to consider all relevant evidence of public need. *See Env't Def. Fund*, 2 F.4th at 975 (the Commission must sufficiently evaluate the evidence to reach "a reasoned and principled decision"); *Butte Cnty., Cal. v. Hogen*, 613 F.3d 190, 194 (D.C. Cir. 2010) ("an agency cannot ignore evidence contradicting its

position"). A certificate of public convenience and necessity requires the Commission to consider evidence indicating the needs of the future, not the past. *See City of Pittsburgh v. Fed. Power Comm'n*, 237 F.2d 741, 750-54 (D.C. Cir. 1956) (holding Commission erred when it failed to consider circumstances affecting the public's future needs). The record does not support the Commission's conclusion that state laws will not reduce demand for methane gas in the region, particularly given the States' uncontroverted expert testimony, GTN's IHS Markit Report projecting steep declines in gas demand, and evidence of declining demand in California. The precedent agreements with Cascade, Intermountain, and Tourmaline do not rebut that evidence because: (1) Cascade admittedly fails to consider the likely impact of state law in its need assessment; (2) the Commission did not ask whether any need that Cascade's or Intermountain's precedent agreements demonstrated could be met by other means, without incurring substantial, long-term costs from this expansion; (3) the Commission cannot find that the agreement with Tourmaline will serve a public need when it does not know where the gas would go or for what purpose; and (4) the Commission failed to explain why a precedent agreement with a gas producer is evidence of need in this instance. The Commission's uncritical and exclusive reliance on these precedent agreements also fails to account for the fact that, during this energy transition, some private actors may resist recent legislation or market trends that threaten their business model. In a changing regulatory environment, private actors may also have a greater tolerance for risk than is appropriate for an independent regulator acting in the public interest.

8. The Order is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the APA and the NGA because the Commission did not consider whether alternative clean energy projects could meet the public's alleged need for more energy, particularly in light of the evidence that methane gas competes with clean energy, the region is developing numerous clean energy projects, market trends favoring heat pumps over gas furnaces for buildings, and state and local plans prioritizing clean electricity and building electrification. *See Fed. Power Comm'n v. Transcontinental Gas Pipeline Co*., 365 U.S. 1, 7 (1961) (upholding Commission's consideration of whether alternative energy sources could better serve the demand for a particular project); *Pittsburgh*, 237 F.2d at 751 n.28 ("The existence of a more desirable alternative is one of the factors which enters into a determination of whether a particular proposal would serve the public convenience and necessity. That the Commission has no authority to command the alternative does not mean that it cannot reject the proposal.").

9. The Order is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the APA and the NGA because the Commission did not evaluate how the Expansion could harm future gas consumers in the States. The NGA requires the Commission to protect consumers and ensure reasonable prices, currently and in the future. *See NAACP v. Fed. Power Comm'n*, 425 U.S. 662, 666-68 (1976) (describing the Commission's duty to protect consumers and ensure reasonable rates). The Commission must therefore consider the risk of stranded or underutilized assets on future consumers and

whether requiring consumers to pay for the Expansion through 2070 poses an unreasonable burden on future gas consumers in light of the nation's energy transition.

10. The Order is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the APA and the NGA because the Commission did not hold GTN to its burden to show that the public convenience and necessity required the Expansion and instead unlawfully shifted that burden to the States. As the applicant, GTN had the burden to show the future public convenience and necessity requires its Expansion, which includes showing the Expansion is needed in light of state and local laws. *See Atl. Ref. Co. v. Fed. Power Comm'n*, 316 F.2d 677, 678 (D.C. Cir. 1963); *Williams Gas Processing-Gulf Coast Co., L.P. v. FERC*, 331 F.3d 1011, 1021 (D.C. Cir. 2003); *see also* 18 C.F.R. §§ 157.5(c), 157.6(b)(2). GTN failed to meet this burden. But instead of denying the Application, the Commission faulted the States for allegedly failing to prove their laws would reduce demand or create energy alternatives. *See* Order ¶¶ 24 (rejecting States' arguments that the Commission must consider clean alternatives because the "record did not establish" that non-gas alternatives existed), 27 (faulting the States for not submitting evidence their legislation has actually resulted in reduced demand).

11. The Order is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the APA and the NGA because the Commission did not balance all relevant factors in determining the public interest. The NGA "requires the Commission to evaluate all factors bearing on the public interest." *Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 391 (1959); *see also Vecinos para el Bienestar de la*

Comunidad Costera v. FERC, 6 F.4th 1321, 1331 (D.C. Cir. 2021) (holding the Commission's public interest finding was deficient because it did not fully consider impacts on climate change and environmental justice). Here, the Commission's public interest analysis did not include factors such as: the adverse impacts on current and future consumers; the inconsistencies with international, national, state, tribal, and local laws and policies to reduce emissions and transition to clean energy; the significance of the Expansion's greenhouse gas emissions and their contribution to the extreme heat, flooding, drought, wildfire, and other harms the States already are experiencing; the availability of clean energy alternatives; or the adverse impacts on environmental justice communities from increased air pollution and worsened climate change.

12. The Order is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the APA and the NGA because the Commission arbitrarily ignored record evidence about declining future needs, relying instead on assertions of public benefits that were vague and lacked evidence. The Commission provided no evidence for its assumption that the Expansion would result in lower gas prices, did not engage with evidence regarding future market trends, and did not analyze how those trends will likely impact gas prices. Further, the Commission's findings of reliability and supply diversity are so general that they could apply in virtually any application for a certificate of public convenience and necessity. *See Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305, 1313 (D.C. Cir. 1991) (finding the Commission's general and cursory discussion of benefits was an "unsupported assertion [that] does not amount to

substantial evidence"); *Nat'l Gypsum Co. v. U.S. E.P.A.*, 968 F.2d 40, 43 (D.C. Cir. 1992) (an agency is not permitted to "infer" facts not in the record).

13. The Order is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the APA and the NGA because the Commission failed to follow its 1999 Policy Statement or provide a sufficient explanation for not doing so. The 1999 Policy Statement describes how the Commission will determine whether applications to expand gas infrastructure serve any public need for gas and the public interest. *See generally* 1999 Policy Statement. The Order deviated from the 1999 Policy Statement by refusing to consider and weigh all relevant evidence and factors. Instead, the Order adopted precedent agreements as conclusive evidence of need, unless they are with an affiliate of the pipeline company. *See, e.g.*, Order ¶¶ 25 n.50; 27-36. The Commission also did not explain its departure from the 1999 Policy Statement. *See FCC v. Fox Television Stations, Inc.*, 556 US 502, 513-14 (2009); *Encino Motorcars, LLC v. Navarro*, 579 US 211, 221-22 (2016).

14. The Order is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the APA and the NGA because [redacted]

[redacted]

Errors and Issues Pertaining to NEPA and the NGA

15. The Order is arbitrary, capricious, contrary to law, unsupported by substantial evidence, and without observance of procedure required by law in violation of the APA, NEPA, and the NGA because the Order and the Final EIS did not fully analyze and consider evidence regarding the Expansion's upstream and downstream greenhouse gas emissions or give a reasoned explanation for why it excluded these foreseeable emissions from its analysis. *See* 5 U.S.C. § 706(2)(A); 42 U.S.C. § 4332(2)(C); 40 C.F.R. § 1508.1; *Sierra Club v. FERC*, 867 F.3d 1357, 1374 (D.C. Cir. 2017); *Delaware Riverkeeper Network v. FERC*, 45 F.4th 104, 109-10 (D.C. Cir. 2022) (emphasizing the fact-based nature of the downstream emissions analysis).

16. The Order is arbitrary, capricious, contrary to law, unsupported by substantial evidence, and without observance of procedure required by law in violation of the APA, NEPA, and the NGA because neither the Commission nor the Final EIS determined the significance of the Expansion's greenhouse gas emissions, inconsistencies with national, state, tribal, and local laws and policies, and climate impacts or otherwise factored such impacts into its decision. The Commission abdicated its responsibility to make an informed and rational decision that considers the Expansion's adverse greenhouse gas emissions and climate impacts, including any adverse effects on environmental justice communities. The NGA requires the Commission to "evaluate all factors bearing on the public interest" and to

balance the public benefits of a proposed gas project against its adverse effects—including its adverse greenhouse gas emissions and climate impacts—to determine whether the project meets the public convenience and necessity test. *Vecinos*, 6 F.4th at 1331; *Env't Def. Fund*, 2 F.4th at 961-63; *Sierra Club*, 867 F.3d at 1373; *N. Nat. Gas Co.*, 174 FERC ¶ 61,189, 61,730 (2021) (stating "should we determine that a project's reasonably foreseeable GHG emissions are significant, those GHG related impacts would be considered along with many other factors when determining whether a project is required by the public convenience and necessity"); *see also State Farm*, 463 U.S. at 43; 1999 Policy Statement at 13, 19. Yet the Commission did not factor the Expansion's adverse greenhouse gas emissions and climate impacts into its public interest analysis, or otherwise balance the adverse climate effects of the Expansion against its benefits, in violation of the NGA and the APA. The Commission also violated NEPA's core purpose of informed, transparent decision making by arbitrarily refusing to categorize the Expansion's greenhouse gas emissions and climate impacts as significant or to otherwise factor such impacts into its decision in any way. *See* 42 U.S.C. § 4332(2)(C), (I); 40 C.F.R. § 1502.16(a)(1); *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 352, 356 (1989) (explaining that a "hard look analysis" requires consideration of "the severity" of a project's adverse effects); *Vecinos*, 6 F.4th at 1331. The Commission's analysis also represents an unexplained reversal from Commission precedent in violation of the APA. *See* Order, Clements, Comm'r, concurring at ¶ 7; *Fox Television Stations, Inc.*, 556 U.S. at 515.

17. The Order is arbitrary, capricious, contrary to law, and without observance of procedure required by law in violation of the APA, NEPA, and the NGA because the Final EIS did not address inconsistencies with state laws, national policy, and international commitments as required by 42 U.S.C. § 4332(C); 40 C.F.R. §§ 1502.2(d), 1506.2(d).

18. The Order is arbitrary, capricious, contrary to law, and without observance of procedure required by law in violation of the APA, NEPA, and the NGA because the Final EIS did not include a reasonably complete discussion of mitigation measures. Because the Commission refused to determine the significance of the Expansion's greenhouse gas emissions and climate impacts, or otherwise consider them in reaching its decision, it also did not consider meaningful mitigation measures for those impacts. The Commission violated NEPA and the APA by failing to consider mitigation measures and failing to reasonably respond to the States' and EPA's comments in its Order or the Final EIS. *See* 40 C.F.R. § 1502.9 (requiring agencies to respond to issues raised on the Draft EIS). *See also* 18 C.F.R. § 380.7; *Robertson*, 490 U.S. at 352 ("Omission of a reasonably complete discussion of possible mitigation measures undermines the action-forcing function of NEPA. Without such a discussion, neither the agency nor other interested groups and individuals can properly evaluate the severity of the adverse effects.") (cleaned up).

19. The Order is arbitrary, capricious, contrary to law, unsupported by substantial evidence, and without observance of procedure required by law in violation of the APA, NEPA, and the NGA because the Final EIS adopted GTN's purpose and need without also incorporating: the Commission's mission; statutory and regulatory directives; national,

agency, or other policy objectives applicable to the proposed action; and the public interest. The purpose and need statement also unreasonably restricted the range of alternatives. *See* 40 C.F.R. § 1502.13; NEPA Implementing Regulations Revisions, 87 Fed. Reg. 23453 at 23457-59; *Nat'l Parks & Conservation Ass'n v. Bureau of Land Mgmt.*, 606 F.3d 1058, 1070 (9th Cir. 2010) (stating that, while an applicant's goals for a project are relevant, "those private interests [need not] define the scope of the proposed project.").

20. The Order is arbitrary, capricious, contrary to law, and without observance of procedure required by law in violation of the APA, NEPA, and the NGA because the Final EIS failed to consider reasonable alternatives or the predictable effects of selecting the no-action alternative, which is that consumers will turn to other energy sources to meet their needs. *See* 42 U.S.C. § 4332(2)(C),(E); 40 C.F.R. § 1502.14; 18 C.F.R. § 380.7(b).

21. The Order is arbitrary, capricious, contrary to law, and without observance of procedure required by law in violation of the APA, NEPA, and the NGA because the Final EIS did not give a hard look at other environmental impacts, including environmental justice, climate resiliency, and wildfire risks. *See Vecinos*, 6 F.4th at 1326 (agencies must take a "hard look" at the environmental consequences of their actions and ensure they are disclosed to the public); *id*. at 1330-32 (holding the Commission's environmental justice analysis violated NEPA, the APA, and the NGA); Exec. Order No. 12,898, 59 Fed. Reg. 7629 (1994). The Commission did not adequately or rationally assess the Expansion's adverse climate impacts on environmental justice communities, including the cumulative impacts on public health in these communities. *350 Montana v. Haaland*, 50 F.4th 1254,

1272 (9th Cir. 2022); 40 C.F.R. §§ 1502.15, 1502.16, 1508.1. The Commission also failed to rationally analyze wildfire risks and climate resiliency. The Commissions' cursory analysis of wildfire risk and climate resiliency is arbitrary and capricious and does not satisfy NEPA's mandate that agencies must make a reasoned choice between the alternatives. *See* 42 U.S.C. § 4332(2)(C)(iii); 40 C.F.R. § 1502.14.

IV. ARGUMENT

A. The Commission Failed to Consider Relevant Evidence and Factors or Provide a Reasoned Explanation for Its Finding of Need and Public Interest, in Violation of the NGA

Under Section 7 of the NGA, the Commission is only authorized to permit projects that are required by the public convenience and necessity. 15 U.S.C. § 717f(e). To make such a determination, the Commission must consider all relevant factors bearing on the public interest and all viable alternatives. 15 U.S.C. § 717f(e); *Atl. Ref. Co.*, 360 U.S. at 391; *Citizens Against Burlington, Inc., v. Busey*, 938 F.2d 190, 194-97 (D.C. Cir. 1991). The Commission cannot ignore important aspects bearing upon its decision to permit a project. *See State Farm*, 463 U.S. at 43. Here, those important aspects include the possibility of a subsidy, evidence of need for the full life of a project, the effect of state law on public need, state regulator concerns regarding a regulated utility's contract for capacity, or reasonable alternatives. The Commission's need and public interest analysis must also weigh the Expansion's impacts to consumers in the short- and long-term, risks of stranded assets, the Expansion's greenhouse gas emissions and climate impacts, and whether the Expansion is consistent with state, tribal, and local laws and policies.

The Commission did not consider and weigh those factors in approving the Expansion. The Commission instead relied exclusively on private contracts and vague and unsupported assertions of public benefits. The Commission did not assess how state, tribal, and local laws will impact need for the Expansion, "the risk of over-building and the concomitant risk of saddling ratepayers with the costs of underused facilities," Order, Clements, Comm'r, concurring ¶ 4, the significance of the Expansion's contribution to climate change, or its impact on state, tribal, or local environmental policies. *See id.* ¶¶ 1-8

1. The Commission's conclusion that the Expansion is unsubsidized is arbitrary and unsupported

FERC exercises its authority under Section 7 of the NGA pursuant to its own regulations, 18 C.F.R. Part 157, and its 1999 Policy Statement. Under the Commission's 1999 Policy Statement, "[t]he threshold requirement . . . for existing pipelines proposing an expansion project is that the pipeline must be prepared to financially support the project without relying on subsidization from existing customers." 1999 Policy Statement 19. In other words, "the pipeline [must] price the project using incremental rates in which the full costs of the project are recovered solely from the shippers subscribing to the new capacity." Order Clarifying Statement of Policy, 90 FERC ¶ 61,128, 61,390 (2000). If the full costs of the project are not included, it

> send[s] the wrong price signals to the market [and can] lead to inefficient investment and contracting decisions which can cause pipelines to build capacity for which there is not a demonstrated market need. Such overbuilding, in turn, can exacerbate adverse environmental impacts, distort competition between pipelines for new customers, and financially penalize existing customers of expanding pipelines and customers of the pipelines affected by the expansion.

1999 Policy Statement at 4; *see also Algonquin Gas Transmission, LLC*, 130 FERC ¶ 61,011, 61,033 (2010) (stating subsidization can lead to "overbuilding and inefficient investment").

The Commission analyzes the existence of a subsidy as a threshold issue because it indicates a lack of market-based need for a project. 1999 Policy Statement 22. The existence of a subsidy means that contracts to purchase capacity are not responding to accurate market signals, *see* 1999 Policy Statement 20, and thus are not significant evidence of need.

In this case, the Commission arbitrarily and unlawfully determined that no subsidy exists. *See* Order ¶¶ 15-17, 42. First, the Commission failed to provide a reasoned explanation for its determination that GTN used the closest available size for its new compressors when there are smaller compressors that matched the existing units' certificated horsepower. Second, even if the Commission were correct that GTN used the closest available size, the larger compressors were not eligible for section 2.55(b) replacement because they created an incidental increase in capacity. Third, the Commission failed to consider evidence showing that, even excluding the costs for upgrading the compressors, substantial costs will remain after the precedent agreements expire. Further, there is no evidence to support a finding of long-term demand for the Expansion sufficient to pay for those costs. Finally, the Commission must decide these questions now, not in a later rate case, because if these costs are included or if GTN recovers costs over a shorter time frame, the Expansion's revenues likely do not exceed costs and GTN has thus failed to show a public necessity.

a. The Commission incorrectly determined that section 2.55(b) permitted GTN's compressor upgrades when alternative compressors were available that matched the existing units' certificated horsepower

The Commission failed to provide a reasoned explanation for its determination that GTN selected the closest available size for its new, upgraded compressors. The Commission accepted GTN's explanation that the smaller-sized Solar Mars units "could not meet the same power output as the Avon units in colder temperatures." Order ¶ 16. GTN's existing certificate did not allow it to exceed 14,300 certificated horsepower ("HP") for these compressor units. GTN's prior notice for the compressor upgrades stated:

> GTN proposes to replace one (1) existing RR Avon 14,300 ISO horsepower compressor unit with one (1) Solar Titan 130 gas turbine compressor unit that would be site rated at the existing certificated ISO horsepower of 14,300 at the Station. There will be controls put in place to govern horsepower such that the station operation can be controlled and will not exceed certificated horsepower.[2]

The Solar Titan 130 has a site rating of 23,470 HP, which exceeded its current horsepower certification by more than 9,000 HP. Accordingly, GTN could have satisfied its needs with the smaller Solar Mars, which has a site rating of 15,900 HP and is closer in size to the existing Avon unit. *See* States' Protest, Declaration of Gregory Lander ("Lander Decl."), at 15. In fact, GTN's data response showed that the Solar Mars unit was capable of meeting the certificated 14,300 HP with the altitude and temperature conditions at each station except Kent. *See* GTN Response to Apr. 4, 2023 Data Request at 13. GTN provided this information to the Commission in its April 18, 2023 filing:

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[2] *See* Notification, Athol Compressor Station, Dkt. CP20-82-000, (Mar. 10, 2020); Notification, Kent Compressor Station, Dkt. CP20-85-000, (Mar. 10, 2020); Notification, Starbuck Compressor Station, Dkt. CP20-86-000, (Mar. 10, 2020).

Table 8-1: Compressor Unit Comparison

CS5 - Athol		Elevation (ft)	Ambient Temperature (F)		
		2,440	34	71	75
Current RR Avon 76G	HP - net output power		14,510	12,390	12,161
Selected Option - Solar Titan T130	**HP - net output power**		**20,533**	**18,823**	**18,638**
Option - Solar Mars 100	HP - net output power		14,319	12,874	12,717

CS7 - Starbuck		Elevation (ft)	Ambient Temperature (F)		
		1,070	36	73	85
Current RR Avon 76G	HP - net output power		15,180	12,910	12,174
Selected Option - Solar Titan T130	**HP - net output power**		**21,512**	**19,721**	**19,135**
Option - Solar Mars 100	HP - net output power		14,995	13,466	12,978

CS10 - Kent		Elevation (ft)	Ambient Temperature (F)		
		2,698	37	67	82
Current RR Avon 76G	HP - net output power		14,240	12,500	11,630
Selected Option - Solar Titan T130	**HP - net output power**		**20,194**	**18,821**	**18,134**
Option - Solar Mars 100	HP - net output power		14,062	12,902	12,322

This chart shows that the larger compressor was *not* the "nearest reliable size available" for at least two of the three stations. *Id*. at 12. Further, while the Solar Mars 100 could not reach 14,300 HP at Kent, neither could the prior unit, which GTN used without incident for roughly 50 years. *See id*.

While GTN's chart also shows the original Avon units had a "net output power" exceeding 14,300 HP in cold weather conditions, GTN's certificated HP was 14,300 HP, not the higher "net output power" amount. The Commission's conclusion that GTN needed to replace its original compressors with new compressors that have a delivery capability that exceeded its original certificated horsepower was unsupported and arbitrary. The

Commission did not explain why section 2.55(b) permits GTN to select new compressors for performance that exceeds its certificated horsepower nor did the Commission evaluate whether horsepower in excess of the 14,300 certificated horsepower is necessary to serve existing customers. Finally, the Commission did not inquire whether other smaller compressors were available, including electric compressors.

b. Section 2.55(b) does not apply because GTN's upgrades resulted in an incidental increase in capacity

The Commission incorrectly concluded that section 2.55(b) permitted GTN to upgrade three compressors at Athol, Kent, and Starbuck with larger compressors. The NGA requires the Commission to issue a certificate of public convenience and necessity before a pipeline company may construct any new "facilities." 15 U.S.C. § 717f. However, the Commission's implementing regulations provide a narrow exception to this rule for replacement of deteriorated or obsolete equipment. 18 C.F.R. § 2.55(b). Section 2.55(b) only permits replacement of deteriorated or obsolete facilities that "will have a substantially equivalent designed delivery capacity." Replacements that result in an "incidental increase in the capacity" do not qualify under section 2.55(b). 18 C.F.R. § 157.202(b)(2)(i). Replacements "should only involve basic maintenance or repair to relatively minor facilities." 64 Fed. Reg. at 54524. More extensive work, or work that results in an incidental increase in capacity, must be done under the pipeline's blanket certificate authority. *See id.*; 18 C.F.R. § 157.202(b)(2)(i). Here, however, GTN's compressor upgrades would not have qualified under its blanket certificate authority because replacements "for the primary purpose of creating additional main line capacity" are not eligible. 18 C.F.R.

§ 157.202(b)(2)(i). Additionally, GTN did not follow the blanket certificate authority procedure, which would have, among other procedural protections, allowed parties to file protests and required GTN to describe the relationship between the compressor upgrades "and other existing or planned facilities." 18 C.F.R. § 157.208(c)(1).

The Commission has explained the purpose of these requirements: "replacement facilities must not create new, usable capacity that a pipeline would otherwise need to certificate in a separate section 7(c) proceeding." 64 Fed. Reg. at 54527. The Commission also explained its intent that pipelines use their blanket certificate authority, not section 2.55(b), where replacement facilities "do not exactly match the original" and create an incidental increase in capacity. *Id*. Nonetheless, even under the broader blanket certificate authority, replacements "must be the closest available size and horsepower rating to the facilities being replaced." *Id*.

The Commission acknowledged that GTN's replacement compressors created new, usable capacity that was not necessary to replicate the existing service and instead will be used to expand capacity. Order ¶ 53. The Commission's conclusion that section 2.55(b) justified the replacements because the upgraded compressors had artificial software controls defied the intent and text of its own regulations. As described above, section 2.55(b) applies only to basic maintenance and repair of facilities that have equivalent designed delivery capacity as the original facilities. Yet, the Commission uncritically allowed GTN to rely on this narrow exception to the section 7 process to significantly change the horsepower at three compressor stations and allow it to operate the Expansion.

Further, the Commission failed to consider the undisputed evidence showing GTN's intent to use these replacements to expand:

- In 2019, GTN announced to investors that it intended to replace these compressors to create expanded capacity. *See* States' Protest, Exhibits at 79-80 (TC Pipelines Press Release); 85-86 (TC Pipelines Investor Call Transcript).

- In 2019, GTN sold the capacity the compressor upgrades would create before it sought to install those compressors as routine "replacements" under section 2.55(b) *See* Application 4.

- In March 2020, GTN notified the Commission of its intent to replace the compressors with new compressors under section 2.55(b). Though relevant to GTN's compliance with section 2.55(b), GTN did not disclose the actual horsepower rating of the new compressors, such that neither customers nor the Commission would have been aware that the replacement compressors were 64 percent larger than needed. GTN also did not disclose the replacement's relationship to GTN's planned expansion.[3] *See* 18 C.F.R. § 385.203(a)(6) (stating pleadings must include all "relevant facts").

- In October and November 2021, GTN placed the compressor upgrades in service. *See* GTN Response to Apr. 4, 2023 Data Request at 11 (Apr. 18, 2023). At the same time, GTN applied to use the incidental capacity the upgraded compressors created for the Expansion. *See* Application.

This evidence shows that GTN's replacements and Expansion are not independent projects. Under these circumstances, GTN's use of section 2.55(b) was inappropriate and the Commission should not allow GTN to rely on artificial software controls and piecemeal regulatory processes to circumvent the NGA's mandate that companies obtain a certificate of public convenience and necessity before expanding facilities.

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[3] *See* Notification, Athol Compressor Station, Dkt. CP20-82-000, (Mar. 10, 2020); Notification, Kent Compressor Station, Dkt. CP20-85-000, (Mar. 10, 2020); Notification, Starbuck Compressor Station, Dkt. CP20-86-000, (Mar. 10, 2020).

c. GTN's plan to spread costs for the Expansion over 50 years means that customers who do not benefit from the Expansion will have to pay for its costs

The Commission erred by allowing GTN to recover 75.1 million dollars in Expansion costs over 50 years despite record evidence showing that the Expansion's useful life will, at most, be the 30 to 33 years reflected in the precedent agreements. *See* States' Protest, Ex. C, Energy Futures Group Report 63 ("Hill Report"); Order ¶ 20 n.85; Application, Ex. N. This means that, after the precedent agreements expire in the early 2050s, there will be roughly <u>twenty million dollars</u> in unrecovered costs for the Expansion. *See* Application, Ex. N; Hill Report 63. If GTN is unable to sell the Expansion's capacity to new customers after 2050, then all of GTN's customers at the time will have to pay for those remaining costs. In addition, because the Expansion shifts some risk and costs to GTN's other customers, the precedent agreements underlying it are not responding to the proper price signals and are not significant evidence of need. *See infra* § IV(A)(3)(a).

The Commission did not find that there will be sufficient need for the Expansion after the precedent agreements expire in the 2050s that will pay for these remaining costs. Nor is there substantial evidence to support such a finding. As discussed below, the uncontroverted evidence before the Commission—from both the States' expert and GTN's own market analysis—shows that gas demand will decline in the long term. *See infra* § IV(A)(3)(b)(2).

Thus, the 47-year depreciation rate (i.e., the 2.11 percent rate proffered in GTN's Application, Exhibit N) places responsibility for roughly twenty million dollars in costs for the Expansion on customers who will not benefit from it. GTN, Cascade, Intermountain, and

Tourmaline will not therefore bear all of the risk, or pay for all of the costs, for the Expansion. This conflicts with the 1999 Policy Statement's prohibition on subsidization, which requires the pipeline and its new customers to be "responsible for the costs of new capacity that is not fully utilized." 1999 Policy Statement 21. The "pipeline must be prepared to financially support the project without relying on subsidization from its existing customers . . . [T]he financial risk . . . cannot be shifted to existing customers." *Id*. 19-20.

If GTN were required to recover its costs over a shorter period, the annual cost-of-service will more than double, which "calls into question [GTN's] assertion that project revenues will exceed costs." Hill Report 63. Expert David Hill illustrated the difference in cost recovery over a 20[4] and 50-year period:

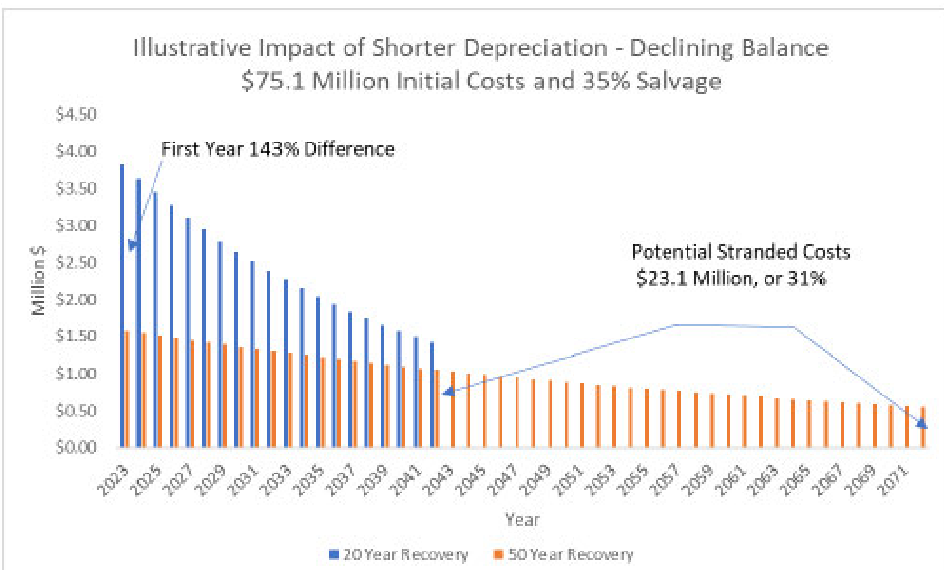

Figure 8: Comparison of 20- and 50-Year Recovery Period on Cost of Service

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[4] Hill's illustration compared a twenty-year period based on the anticipated decline in total regional gas consumption as the States transition to clean electricity. *Id*.

The Commission did not address this evidence other than in a brief footnote, rejecting the States' request for a modified depreciation rate based on the risk of stranded assets. *See* Order ¶ 20 n.85; States' Protest at 17; Hill Report 27-28; States' Comments on GTN's May 5 Response, Dkt. CP22-22-000 (May 31, 2023), at 3 n.3. The Commission did not explain why it believed the Expansion would serve need beyond 2050. Rather, the "Commission's general policy with respect to pipeline expansions is to use the depreciation rate approved in the pipeline's last NGA section 4 general rate proceeding." *See* Order ¶ 20 n.85. Reference to a general policy does not support a reasonable expectation that the Expansion will have a useful economic life through 2070. Nor has the Commission explained why that policy is appropriate here, where there is no basis to conclude the Expansion will be needed after 2050 (much less currently). Additionally, given that GTN's last rate case was a "black box" settlement, there is no indication the last approved depreciation rate reflects any of the States' concerns about GTN's proposed cost recovery here or adequately protects consumers from stranded assets. *See generally Gas Transmission Northwest, LLC*, Petition for Approval of Settlement, Dkt. RP15-904-003 (Sept. 29, 2021) ("2021 Rate Settlement").

Significantly, the Commission has "deviated from this general policy" in appropriate cases. *Wyo. Interstate Co., Ltd.*, 119 FERC ¶ 61,251, 62,416 (2007) (directing pipeline to use a depreciation rate which reflects "the economic life of the lateral facilities" based on either its currently-approved rate "or some other rate supported by a fully developed depreciation study"); *Equitrans, L.P.,* 153 FERC ¶ 61,381 (2015), *aff'd on reh'g* 155 FERC

¶ 61,194 (2016) (approving depreciation rate based on the shipper's contract term, rather than the previously approved depreciation rate); *Gulf S. Pipeline Co., LP*, 955 F.3d at 1015 (stating that "FERC has approved depreciation rates based on the length of the contract at issue"). The Commission's failure to justify its decision to use a 50-year term is arbitrary, capricious, and not based on substantial evidence in violation of the NGA and the APA.

d. The Commission failed to correctly apply its depreciation-rate policy

The Commission also did not correctly applying its own policy to use the depreciation rate from GTN's last section 4 general rate proceeding. *See* Order ¶ 40. The last approved depreciation rate for gas turbine compressor units was 3.50 percent and 1.80 percent for mainline transmission facilities. *See* Order ¶ 40; *see also* 2021 Rate Settlement 12. The Expansion will upgrade compressor units at three compressor stations, add one additional compressor unit, and install related appurtenant, non-mainline transmission, facilities. *See* Application at 6-7; Ex. K (listing Expansion costs). It does not increase or modify GTN's mainline transmission pipeline. *See id*.

Though the Expansion aims solely to increase horsepower at three compressor stations, GTN applied the lower 1.80 percent rate for mainline transmission to nearly all the Expansion's costs. *See* Application, Ex. N at 4. GTN treated labor and other costs to install compressor facilities as "pipeline facilities" (which they are not) and applies the lower depreciation rate for "pipeline facilities." As a result, GTN calculated a weighted average 2.11 percent depreciation rate for the Expansion. *See id*.

The Commission failed to explain why it is not using the last-approved depreciation rate of 3.50 percent to this compressor-only project. *See* Order ¶ 40 n.85. The Commission's error is significant because it means that shippers will pay less of the Expansion's costs, leaving future customers who will not benefit from the Expansion on the hook for recovery of millions of dollars of the Expansion's costs.

e. The Commission cannot defer a decision on how to allocate costs of the compressor upgrades or the appropriate depreciation rate to a future Section 4 rate case

The States presented evidence showing that (1) if even a portion of the compressor upgrade costs are included, *or* (2) if GTN recovers costs over the contract terms for the Expansion, then the Expansion's revenues likely do not exceed costs and a subsidy exists. *See* Lander Decl. 16-18; Hill Report 63. The Commission arbitrarily did not engage with this evidence and relied exclusively on precedent agreements to determine need, deferring these issues for potential litigation in a future rate case.

Although the Commission may engage in a fuller analysis of just and reasonable rates in a later rate case, it must still determine whether the Expansion inappropriately places costs on existing customers who do not benefit from it. The Commission must also critically analyze in this proceeding whether the precedent agreements are, in fact, responding to the "proper price signals." 1999 Policy Statement 20. As the Commission has acknowledged, contracts for a subsidized project do not respond to correct market signals and thus are not indicators of market need. *See id*. In this scenario, "the true costs of the project are not seen by the market or the new customers, leading to inefficient investment and contracting decisions." *Id*. 17. "This can result in overbuilding." *Id*.

Unanswered questions about who is paying for the Expansion's full costs therefore undermine the rest of the Commission's need analysis, which relies exclusively on private contracts to buy the capacity. *See* Order, Clements, Comm'r, concurring ¶ 3. Those contracts are based on unreasonably low rates, since they do not reflect any of the previously incurred costs to replace/upgrade compressors that are necessary to operate the Expansion, and since they will leave millions of dollars in costs for existing customers to pay potentially after the next rate case and certainly after the Expansion contracts expire. Contracts based on unreasonably low rates do not reflect the proper price signals and thus are not significant evidence of market need. When the Commission ultimately balances public benefits against adverse effects, these contracts are not due the same evidentiary weight as precedent agreements for an unsubsidized project or one with proper rates. *See* 1999 Policy Statement 26 (describing balancing test). The Commission failed to justify its decision to rely on contracts that existing ratepayers subsidize or, even if GTN ultimately bears those costs itself, rely on unreasonably low rates.

Deferring central issues related to the rate treatment for the Expansion and connected facilities allegedly replaced under section 2.55(b) is also inconsistent with the Commission's 1999 Policy Statement, which emphasizes that the Commission should decide rate treatment before construction begins. *See* 1999 Policy Statement 21; *see also Tennessee Gas Pipeline Co., L.L.C.*, 140 FERC ¶ 61,120, ¶ 61,595 (2012) (describing Commission practice of making "an upfront determination on the rate treatment for expansion projects"). Nor is it appropriate for the Commission to reason that the costs of the replacement compressors already "appear to be in existing rates." Order ¶ 53. GTN's current rates are the product of a "black box settlement" that, by its own terms, has "no precedential value" and "does not constitute approval of, or precedent regarding, any principle or issue." 2021 Rate Settlement at 15.[5]

2. The Commission's determination of public need was arbitrary and not based on substantial evidence

The Commission may only approve projects that serve a public necessity. *See* 15 U.S.C. § 717f(c). "In analyzing the need for a particular project, the [1999] Policy Statement makes it clear that the Commission will consider *all* relevant factors." *Env't Def. Fund*, 2 F.4th at 959; *see also* 1999 Policy Statement 23. The 1999 Policy Statement recognized that exclusive reliance on precedent agreements did not provide a full picture of a project's benefits or adverse effects. *See* 1999 Policy Statement 16 ("[t]he amount of capacity under contract [] is not a sufficient indicator by itself of the need for a project" in many circumstances); *see also id*. 25-26. Relying almost exclusively on precedent agreements raises "difficult questions of establishing the public need for the project." *Id*. 17. While precedent agreements remain "important evidence" of public need, they are not conclusive. *Id*. at 25; *see also Env't Def. Fund*, 2 F.4th at 972 (noting the difference between "saying that precedent agreements are always *important* versus saying that they are always *sufficient*"). Instead, necessary evidence will depend on balancing the project's adverse effects against its benefits and "will usually include a market study" to aid this analysis. 1999 Policy Statement 25-26. Moreover, as the Commission acknowledged, its role

[5] In any event, the settlement maintained existing rates that were established in 2018, which indicates that the compressor upgrade costs are not included in the current rates. 2021 Rate Settlement at 11.

under the NGA includes exercising its expertise and discretion to determine "to what degree," if any, it should approve an applicant's proposal. Order ¶ 24 (quoting *Transcontinental Gas Pipe Line Co., LLC*, 182 FERC ¶ 61,148, at ¶ 82 (2023)).

There are multiple, fundamental flaws in the Commission's need assessment. The Commission's decision (1) failed to consider evidence indicating these precedent agreements were not reliable evidence of need; (2) arbitrarily concluded that state and local laws will not lead to declining gas demand; (3) erroneously claimed the Commission could not consider clean energy alternatives to meet future need; and (4) relied on vague and unsupported assertions of public benefits. Each of these errors violated the APA and NGA.

a. The Commission erred by uncritically deferring to precedent agreements despite evidence that these agreements do not show need

The Commission wrongly concluded that the Expansion precedent agreements show significant evidence of need because it did not analyze contrary evidence or adequately justify its decision to rely on them. First, the Commission arbitrarily failed to weigh concerns from State regulators and public advocates and other undisputed evidence about deficiencies in Cascade's projection of need. Second, the Commission irrationally determined that Intermountain's contract is "significant evidence of need" when it is not serving new demand and alternatives are likely available. [redacted] Third, the Commission arbitrarily relied on Tourmaline's contract as evidence of market need when it does not know whether Tourmaline will use the capacity, where the gas would go, or for what purpose.

The Commission cannot refuse to engage with arguments why certain precedent agreements are insufficiently probative evidence of need and similtaneously treat the precedent agreements as conclusive evidence of need. *See Env't Def. Fund*, 2 F.4th at 973. "Nothing in the Certificate Policy Statement endorses this approach." *Id*. As former Chairman Glick stated:

> In recent years, [] the Commission has adopted an increasingly doctrinaire position that the mere existence of agreements between a pipeline developer and one or more shippers to contract for capacity on the proposed pipeline is *sufficient*, by itself, to demonstrate the need for the proposed pipeline. The Commission describes this policy as an unwillingness to "look behind" a precedent agreement. But, in practice, it amounts to a "policy" of ignoring any record evidence that might undermine its decision to issue an NGA section 7 certificate.

Spire STL Pipeline LLC, 169 FERC ¶ 61,134, ¶ 62,003 (2019) (Comm'r Glick dissenting). Treating all precedent agreements as equally persuasive, and conclusive, evidence of need, and failing to consider contrary evidence violates the 1999 Policy Statement and is arbitrary and capricious.

(1) The Commission arbitrarily gave full weight to Cascade's projection of need, but no weight to the concerns from State regulators or undisputed record evidence that Cascade's projections are likely inaccurate

The Commission uncritically deferred to Cascade's precedent agreement, stating it "will not second-guess Cascade's decision to contract for the full amount of capacity that it anticipates it will need . . ." Order ¶ 28. The Commission arbitrarily gives full weight to the future projections of a regulated utility, but no weight to the concerns of regulatory staff for the Washington Utilities and Transportation Commission who concluded that Cascade's projections are "likely inaccurate." *See* WUTC Staff Comments at Exhibits-132. Staff at the Washington Utilities and Transportation Commission also expressed concerns that Cascade's Expansion contract will likely become a "stranded asset," and risks "lock[ing] in an unnecessary expense for the next 30 years." *See* WUTC Staff Comments at Exhibits-134. Public advocates for consumers in Oregon raised similar concerns. *See* Or. Citizens Utility Bd. Comments (raising similar concerns).

The States also presented undisputed evidence that Cascade's projections ignore evidence of market dynamics, customer choice, and state and local laws favoring electrification. *See* Hill Report 45-46. When the Commission asked GTN to respond, GTN and Cascade did not refute the States' characterization of Cascade's demand forecasts. *See* GTN Response to Apr. 4 Data Request (Apr. 18, 2023); States' Comment on GTN's Response, Dkt. CP-22-2-000, (May 5, 2023). Cascade's 2020 Integrated Resource Plan admittedly does not account for "carbon legislation [and] building code changes" that took effect after the 2020 Integrated Resource Plan was published (and after this precedent agreement was executed). 2020 Cascade Integrated Resource Plan at 3-21; *see also* Hill Report 46. Significantly, Oregon law directs that Cascade must reduce its Oregon-wide greenhouse gas emissions by approximately 30 percent between 2022 and 2030, an obligation inconsistent with Cascade's assumption of increased demand for methane gas in

Oregon. *See* OR. ADMIN. R. 340-271-9000, Table 4[6]. The Commission arbitrarily relied on Cascade's contract and demand projections without addressing uncontroverted evidence indicating that Cascade's demand projections are likely inaccurate.

The Commission nonetheless gave full weight to Cascade's contract, reasoning that "the States' own analysis shows that a theoretical peak day in Cascade's GTN service area will likely need some of the project's additional capacity much sooner than 2040." Order ¶ 28. The Commission's analysis ignored that Cascade's theoretical peak day needs are minimal, could be served by an alternative, or mitigated through Cascade's required demand reduction efforts. States' expert Lander's analysis concluded that Cascade has well over 100,000 Dekatherms per day (Dth/day) in excess capacity across its system. *See* Lander Decl. at 20. Although Cascade does project some shortfalls in its GTN service area, these are minimal: by 2030, Cascade will need less than 5,000 Dth/d for its theoretical peak day (assuming its 2.12 percent growth rate is correct, which is questionable). *Id*. at 20, 34. Given these minimal needs, Lander reasonably concluded "there could well be alternative means of meeting [this] need" by contracting for existing pipeline capacity. *Id*. at 20. Notably, Oregon law requires Cascade to reduce demand, including by pursing non-gas alternatives. *See* Or. Citizens' Utility Bd. Comments (describing Cascade's existing obligations to reduce demand through energy efficiency and other measures under Oregon law). At best, Cascade's precedent agreement demonstrates only a minimal need for a small portion of the

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[6] Although Cascade serves Washington and Oregon, Cascade claims it needs the capacity to serve "future load growth" in central Oregon. Order ¶ 20.

Expansion's capacity and only in the coming decade. Cascade could satisfy this minimal need by alternatives or through its demand reduction plans. Moreover, Cascade's need itself is questionable when state regulatory staff and public advocates indicate that Cascade's demand projections are "likely inaccurate." *See* WUTC Staff Comments Exhibits-132.

Cascade's precedent agreement thus presents a situation vastly different from the current shortages requiring moratoria and trucked in gas that the Commission considered in *Transcontinental Gas Pipeline*, 182 FERC at ¶ 61,148. *See* Order ¶¶ 27-28. If anything, comparing this case to *Transcontinental Gas Pipeline* shows that the Commission should not give equal weight to all precedent agreements when they demonstrate vastly different needs.

Given the limited need, if any, demonstrated by the Cascade precedent agreement, the Commission erred when it gave Cascade's contract equal weight to all other precedent agreements. Because Cascade's precedent agreement demonstrates a need for only a small portion of the capacity covered by its contract over a limited time, the Commission should give it less weight when it balances the Expansion's public benefits and adverse impacts.

(2) The Commission wrongly relied on Intermountain's contract to show need when [redacted]

The Commission also failed to rationally justify its conclusion that Intermountain's contract is "significant evidence of need" [redacted]

Moreover, the Commission failed to assess what alternatives exist. Per the 1999 Policy

Statement, projects that do not serve new demand may require a greater showing of need and public benefits. *See* 1999 Policy Statement 25. Moreover, without knowing whether alternatives exists, the Commission cannot assess to what extent Intermountain's contract signals a need for this Expansion. *See, e.g.*, *Sierra Club*, 867 F.3d at 1379 (upholding Commission's reliance on precedent agreements in part because the Commission also explicitly found that alternative pipelines "will not satisfy the identified need"); *City of Oberlin v. FERC*, 937 F.3d 599, 605 (D.C. Cir. 2019) (upholding certificate with only 59 percent of capacity under contract because the Commission explicitly found other pipelines could not absorb that need).

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[redacted]

[redacted]

The record evidence also indicates alternatives exist to serve Intermountain's need. Intermountain states that it is already relying on "secondary firm capacity on GTN or direct purchase of gas supplies delivered from other suppliers at Stanfield." GTN Response to Apr. 4 Data Request at 18 (Apr. 18, 2023). Intermountain's 2021 Integrated Resource Plan also states the purpose of the GTN contract is to swap capacity with another pipeline, not to serve new demand. *See* Lander Decl. 21–22; Hill Report 47–48. As an alternative to contracting for the Expansion, Intermountain explained that it could renew existing contracts on other pipelines. *See* Intermountain Gas Company, *Integrated Resource Plan 2021-2026*, 165-66 (Dec. 17, 2021) (attached as Ex. B to States' Comments on GTN's Apr. 18 Response).

Intermountain stated that its current contracts were "under release of long-term temporary segmented capacity from other third parties which was set to expire in the coming years." GTN Response to Apr. 4 Data Request at 17 (Apr. 18, 2023). However, despite this evidence, the Commission did not inquire whether Intermountain could have obtained that capacity during the required open season after those third-party contracts expired, or whether Intermountain could request a permanent release of the capacity from the existing third-party shipper(s), thus vesting Intermountain with a right to renew the contracts. The Commission also did not inquire whether Intermountain could continue to use the secondary firm capacity on GTN that it uses now. As the regulator, the Commission must investigate these alternatives, and its failure to do so was arbitrary and capricious. *See Pittsburgh*, 237 F.2d at 756 n.28.

Finally, Intermountain's plan for "cost mitigation efforts through marketing of such unutilized capacity to secondary third-party markets" raises additional concerns about Intermountain's need for this contract to serve Idaho customers, [redacted] *See* GTN Response to Apr. 4 Data Request at 18 (Apr. 18, 2023). In some instances, when a gas company has capacity that consumers paid for and did not need, it may sell the excess capacity to generate shareholder profit. *See* States' Answer and Mot. Leave to File Answer, Dkt. CP22-2-000 (Sept. 21, 2022), at 9. That profit comes at a low risk, since their ratepayers will pay for any capacity the utility is unable to sell as well as absorb costs not recovered by prices received for the sale of excess capacity. Here, Intermountain indicated it is signing up for excess capacity with plans to sell it, likely for shareholder gain. *See* GTN

Response to Apr. 4 Data Request at 18; *see also* Rogue Climate's Comments on the Draft EIS, Dkt. CP22-2-000 (Aug. 22, 2022), at 9–10 (noting Intermountain has frequently sold unutilized pipeline capacity for profit); *see also id*., Ex. 2 (Intermountain Integrated Resource Plan) at 68 ("Intermountain has and continues to be active in the capacity release market."). In other words, Intermountain has an apparent profit incentive to select the Expansion over other alternatives. This should, at minimum, have led the Commission to analyze whether existing capacity can satisfy Intermountain's alleged need or whether Intermountain would still prefer this contract if the full costs of the Expansion were included. *See supra* § IV(A)(1).

(3) The Commission arbitrarily concluded Tourmaline's contract is evidence of market need when it does not know whether Tourmaline will use the capacity, where the gas would go, or for what purpose

The Commission found Tourmaline's precedent agreement shows a public need for this Expansion simply because "[p]recedent agreements, including agreements with natural gas producers, are significant evidence of need." Order ¶ 35. This is not a reasoned explanation and does not meaningfully address the States' arguments.

First, the Commission failed to explain why a precedent agreement with a Canadian gas producer is evidence of a public need in U.S. markets. Producers secure pipeline capacity to push their gas out of the production area. *See* Lander Decl. at 22. This does not necessarily show that consumers need this pipeline capacity. The 1999 Policy Statement recognized this, stating "[t]he amount of capacity under contract [] is not a sufficient indicator by itself of need for a project, because . . . pipeline capacity is often managed by an entity that is not the actual purchaser of gas." 1999 Policy Statement 16. Instead, the

Commission must consider all relevant factors, and this will usually include a market study. *Id*. at 23. Yet here, the Commission relied uncritically on the Tourmaline contract to evidence need.

Second, the Commission's decision is internally inconsistent. If Tourmaline's contract is evidence of need for additional gas in U.S. markets, then it must also be reasonably foreseeable that the gas Tourmaline ships will be used for energy and increase greenhouse gas emissions. Yet the Commission also claimed these downstream emissions are not reasonably foreseeable, and the location and end-use of the gas Tourmaline intends to ship are "unclear." Final EIS 4-44. The Commission did not explain how a contract to ship gas can be evidence of need in U.S. markets when it is also not reasonably foreseeable that the gas will ultimately be used and failed to inquire where the gas is needed or for what purpose.

Third, the Commission did not analyze the record evidence indicating that West Coast markets do not need Tourmaline's contract. GTN's Application stated that Tourmaline would serve West Coast markets, particularly markets for electricity generation in northern California. *See* Application at 4, 13. Yet, according to GTN's IHS Markit Report, the Western U.S. is experiencing "a steep drop in power sector demand," as renewable energy replaces gas-fired electric generation. *See* IHS Markit Report at 7. Nor does GTN's IHS Markit Report support its claim that Tourmaline's contract is needed to offset the decline in Rocky Mountain production. *See* Order ¶ 34. GTN's market analysis illustrates how rising gas production in the Western U.S. more than offsets any decline in production from the Rockies, and may even oversupply the market. *See* IHS Markit Report at 9. In the Western U.S., the combination of falling regional demand and rising regional production will lead the region to become a net *exporter* of gas as early as 2032. *See id*. at 54, 55.

California's gas utilities also do not project any shortfall in gas supply, as the State has access to multiple gas-producing regions. *See* CAL. GAS AND ELEC. UTIL., *2022 California Gas Report* (2022), at 76[8] ("Most industry forecasts continue to predict that gas production will meet most demand outlooks in the future."). California's gas utilities also did not state a need for increased pipeline capacity. *See id*. at 77 (stating the El Paso, Mojave, Transwestern, GTN, Paiute Pipeline Company, Ruby, and Kern River pipelines serve northern and central California, which provide access to gas-producing regions in the U.S. Southwest and Rocky Mountain areas, and in Western Canada).

The Commission's conclusion that "any risk of declining market demand is borne by Tourmaline itself as a producer and marketer, and not by any captive ratepayer" also lacks rational support. Order ¶ 35. The Commission has not evaluated whether Tourmaline will be able to absorb the risk of declining market demand or, if it cannot, who will pay for those costs. Regardless, GTN intends to spread the costs of the Expansion over 47 years, through roughly 2070. Tourmaline's contract is for 33 years, and Tourmaline will not bear the risk

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[8] https://www.socalgas.com/sites/default/files/Joint_Utility_Biennial_Comprehensive_California_Gas_Report_2022.pdf (attached as Ex. B).

for unused capacity after its contract expires. *See supra* § IV(A)(1). The Commission's claim this will not pose a risk to other customers is thus unfounded.

In sum, the Commission appears willing to credit <u>any</u> precedent agreement as "significant evidence of need" no matter the context or contradictory evidence. According to the Commission's decision, contracts are significant evidence of need even if it is with a regulated utility whose demand projections are likely inaccurate or fail to account for the effect of state law (Cascade). Contracts are significant evidence of need even if they simply replace capacity on another pipeline and alternatives may be available (Intermountain). And contracts are significant evidence of need even when the Commission does not know what they are needed for (Tourmaline). This pattern of review is not rational and is arbitrary and capricious.

b. The Commission arbitrarily failed to consider the effect of state and local laws on future gas demand

The Commission arbitrarily dismissed the effect of state and local laws because, according to the Commission, the States have not shown "their climate legislation has actually resulted in reduced demand for gas." Order ¶ 27. The Commission's analysis unlawfully shifted the burden to the States and accepted GTN's unsupported views of increasing regional methane gas consumption. Here, the effect of state and local laws are highly relevant, and GTN was obligated to support its view that methane gas consumption in the region will increase, accounting for recent legislation.

(1) The Commission must hold GTN to its burden to support its claims of need

As Commissioner Clements notes in her concurrence, the Commission's process "would have greatly benefited from market studies focused on present and future demand for natural gas in the specific markets that the project would serve." Order, Clements, Comm'r, concurring ¶ 2. The Commission "could have asked for those studies," *id*., and in fact, it did ask for them, *see* Data Request (Apr. 4, 2023). GTN simply chose not to provide any studies, claiming instead the effect of state laws was "mere speculation." *See* GTN Response to Apr. 4 Data Request (Apr. 18, 2023).

As the applicant, GTN had the burden to show the future public convenience and necessity requires its Expansion. *See Atl. Ref. Co.*, 316 F.2d at 678 ("The burden of proving the public convenience and necessity is, of course, on the natural gas company."); *Williams Gas Processing-Gulf Coast Co.*, 331 F.3d at 1021("In a public interest analysis, the burden of proof is on the applicant for abandonment to show . . . the public convenience and necessity."); *see also* 18 C.F.R. § 157.5(c) ("the burden of adequate presentation . . . rests with the applicant"); § 157.6(b)(2) (applicants must include in their application "facts relied upon by applicant to show that the [proposal] is or will be required by the present or future public convenience and necessity."). Here, however, the Commission unlawfully shifted that burden to the States and accepted GTN's unsupported claims of speculation. *See* Order ¶ 24 (rejecting States' arguments that the Commission must consider clean alternatives because the "record did not establish" that non-gas alternatives existed), 27 (faulting the States for not submitting evidence their legislation has actually resulted in reduced demand).

If the Commission cannot find, based on the record, that the public convenience and necessity requires the Expansion, "such application shall be denied." 15 U.S.C. § 717f(e). Thus, when a party fails to provide evidence to meet their burden, the Commission must deny the Application. It cannot do what it did here and approve a project based on a "skeletal record" with many "unanswered questions." Order, Clements, Comm'r, concurring at ¶¶ 1-6. Nor is GTN's failure to meet its burden a reason to flip the burden onto the States. *See* Order ¶¶ 24, 27. The Commission's failure to require GTN to meet its burden of proof renders the Commission's approval unlawful.

(2) The record evidence shows declining demand

In contrast to GTN's failure to provide evidence to support it claims, the States' uncontroverted expert testimony and GTN's cited market analysis forecasted steep declines in gas demand based on market trends and the effect of state and local laws. *See* Hill Report 45-57; IHS Markit Report at 7-9, 50-56. This evidence is the only expert analysis in the record of future market demand accounting for the impact of state and local laws. The Commission should not dismiss it in favor of GTN's unsupported claim of speculation.

David Hill, an expert with more than 30 years' experience in the energy industry and specialized in scenario planning and economy-wide decarbonization initiatives, analyzed multiple studies forecasting future energy demand in the region for the Commission. *See* Hill Report 42, 45-57. As Dr. Hill explained in his report, the Commission cannot assess future need for the Expansion without considering the States' laws and policies reducing reliance on gas-powered electricity generation. *See id*. 45, 49-56. Currently, gas-powered generation accounts for 32 percent of total methane use in the region. *See id*. at 54. As the States transition to clean electricity, the amount of methane needed for electricity generation will decline, freeing up capacity for other uses or reducing overall need. *See id*. The below graph demonstrates the potential for reductions to methane gas consumption for electric power generation by 2045:

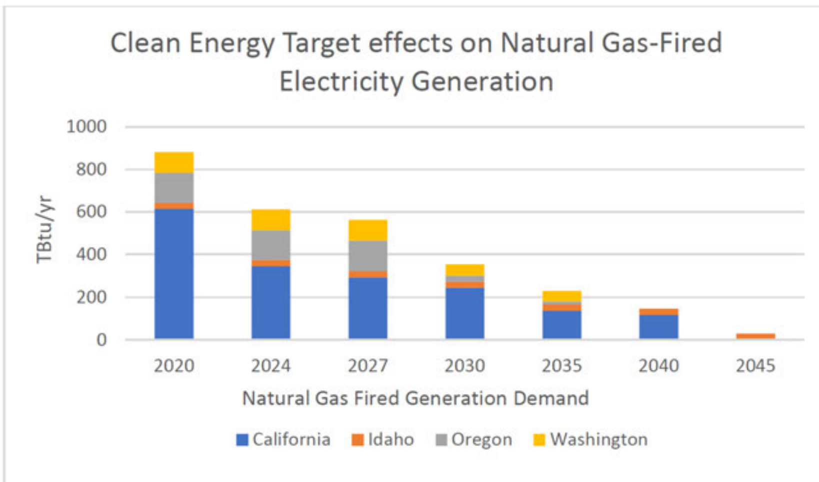

Figure 7: Clean Energy Targets by State, 2020 - 2045, Source: EIA

See id. at 56. The States also presented evidence of numerous renewable energy projects in development to replace fossil fuel generation. *See* States' Protest, Ex. A.

Even if GTN were correct that demand for gas in buildings will continue to grow, Dr. Hill concludes that any "potential growth [in demand from buildings] is de minimis as compared to the expected decline in demand for natural gas as fewer power plants in the region are fueled by natural gas." Hill Report at 56-57. Notably, GTN's cited market analysis confirms this result, stating the Western U.S. is experiencing falling regional demand and “a steep drop in power sector demand,” as renewable energy replaces gas-fired electric generation. *See* IHS Markit Report at 7.

There are substantial reasons to question GTN’s projections of growing demand for gas in buildings. Although the Commission acknowledged Washington’s code requirements limiting gas hookups in new construction, it nonetheless reasoned this does not “materially change the finding of need” because it “has exceptions, exists in only one of several states being served by the project, and … there is no showing of the extent to which the measure will reduce demand.” Order ¶ 28 n.62. Even if the Commission is correct on all these points, they do not support the Commission’s decision to rely completely on GTN’s projections of growing demand. To the extent the Commission had questions about the extent to which the measures will reduce demand or other effects of Washington’s laws, it should have required more information from the parties or otherwise analyzed the issue before determining that the Expansion is needed. *See Env’t Def. Fund*, 2 F.4th at 975 (stating “FERC’s ostrich-like approach flies in the face of the guidelines set forth in the Certificate Policy Statement” and is not reasoned decision-making).

The Commission’s myopic discussion also arbitrarily overlooks the numerous other laws and regulations in the region that aim to reduce reliance on methane in buildings. In California, all newly built homes must install solar systems, and 59 cities and counties have adopted building codes to reduce reliance on methane. *See* States’ Protest, Ex. A at 9; CAL. CODE REGS. tit. 24, Pt 6 (CA Building Standards Energy Code). As noted above, Oregon regulations require reductions in greenhouse gas emissions from fossil fuels used throughout

Oregon in transportation, residential, commercial and industrial settings (for purposes other than electricity generation), and specifically require Cascade to reduce significantly its greenhouse gas emissions. OR. ADMIN. R. 340-271; OR. ADMIN. R. 341-270-9000, Table 4 (showing Cascade must reduce its emissions approximately 30 percent by 2030, 50 percent by 2035, and 90 percent by 2050). The Commission also fails to discuss the comments from staff at the Washington Utilities and Transportation Commission on Cascade's Integrated Resource plan, finding that Washington's statutes and code changes "should result in zero customer growth by 2031. After which time, the natural rate of building stock attrition should consistently decrease customer counts." WUTC Staff Comments at Exhibits-111.

The Commission also provided no rationale for its determination of need despite the market analysis showing declining demand. The only expert analysis before the Commission, from Dr. Hill and GTN's cited market analysis, agree that the States' transition to clean electricity will cause regional gas demand to decline. *See* Hill Report 45, 49-57; IHS Markit Report at 7, 9, 43, 53. GTN's market analysis states "any further potential electrification of residential and commercial space and water heating, especially in California," will reduce regional gas demand even more. IHS Markit Report at 9.

The Commission further shirked its duty to look at all relevant factors by ignoring other evidence in the record and new federal laws that encourage building electrification. Since the IHS Markit Report was published in 2021, the States have further advanced policies to electrify residential and commercial heating and pursue energy efficiency. *See* States' Protest, Ex. A at 4-12 (listing numerous state and local policies to electrify residential and commercial buildings and pending renewable energy projects since 2021). The federal government has also incentivized the electrification of buildings with substantial tax credits for electric heat pumps and stoves through the Inflation Reduction Act.[9]

(3) The Commission's analysis conflicts with the NGA's directive to protect consumers and makes it an outlier in the regulatory community

The Commission arbitrarily concluded that it need not consider these laws unless there is evidence that the legislation "has actually resulted in reduced demand for natural gas." Order ¶ 27; *see also* ¶¶ 24-26. The Commission's role, however, is to determine whether the Expansion serves a current or future public need, not a past one. *See* 15 U.S.C. § 717f(e). The Commission cannot therefore base its decision solely on past data, in spite of evidence of a changing legal landscape and new market trends that will affect the public's future needs. *See Pittsburgh*, 237 F.2d at 752 (stating "[t]he public convenience and necessity for which regulatory agencies issue certificates are the convenience and necessity of the future. The needs of yesterday require no fulfillment if they be not the needs of tomorrow"). Congress directed the Commission "to examine the relevant past and present and then to exercise a rational judgment upon that data to ascertain the public convenience and necessity in the reasonably foreseeable future." *Id*. The Commission did not do that here.

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[9] The White House, *Fact Sheet: New Innovation Agenda Will Electrify Homes, Businesses, and Transportation to Lower Energy Bills and Achieve Climate Goals*, OSTP, News & Updates, Press Releases (Dec. 14, 2022), https://www.whitehouse.gov/ostp/news-updates/2022/12/14.

The Commission's refusal to carefully consider the impact of state and local laws in determining need and public interest makes it an outlier in the regulatory community. State regulators already are acting on the likely declining demand for methane gas from these laws in order to protect consumers. For example, the California Energy Commission recommends "halt[ing] expansion of the gas system . . . Insofar as throughput declines and customer exits can be expected, additional obligations (from new investments in expanded gas infrastructure) will increase the cost of gas service for remaining customers." Hill Report at 52. Similarly, the Washington Utility and Transportation Commission substantially decreased allowances to extend pipelines to serve new customers. The agency based its decision in part on "the likelihood that natural gas lines will not be serving customers in Washington in perpetuity, [state climate policies, and] ensuring that utility tariffs do not increase the likelihood of stranded assets in the future." *See* Order 01 Authorizing and Requiring Tariff Revisions, Wash. Util. and Transp. Comm'n, Dkt. UG-210729, 6-7 (Oct. 29, 2021) (attached as Exhibit C).

Like state regulators, the Commission must consider state climate laws to prevent unreasonably high costs for future customers. *See NAACP*, 425 U.S. at 666-68 (describing Commission's duty to protect consumers "as the task of seeing that no unnecessary or illegitimate costs are passed along to that consumer.") (quoting *NAACP v. Fed. Power Comm'n*, 520 F.2d 432, 444 (D.C. Cir. 1975), *aff'd*, 425 U.S. 662); *see also Atl. Ref. Co.*, 360 U.S. at 388 (describing the Commission's authority to approve new pipelines as the "heart" of the NGA's overall aim to protect consumers from excessive rates); *see also*

Environmental Protection Agency ("EPA"), Comments on the Draft EIS, Dkt. CP22-2-000, 9 (Aug. 18, 2022) ("EPA Draft EIS Comments") (stating the 30-year time horizon presents a "financial risk to energy producers in the Northwest and their ratepayers).

(4) The Commission's analysis ignored the important role of States under the NGA

Finally, the Commission mischaracterized the States' argument as seeking to "limit the Commission's authority to find that a project is required by the public convenience and necessity." Order ¶ 26. The States seek a rational decision supported by the evidence, not to limit the Commission's authority. To rationally determine need, the Commission must "adequately asses how state policies will impact need for the Expansion in the specific markets it is designed to serve." Order, Clements, Comm'r, concurring at ¶ 3. This critical analysis is entirely consistent with the NGA's system of dual federal-state authority over methane gas distribution systems. Congress intended the NGA "to create a comprehensive and effective regulatory scheme … of dual state and federal authority. Although federal jurisdiction was not to be exclusive, [the Commission's] regulation was to be broadly complementary to that reserved to the States, so that there would be no 'gaps' for private interests to subvert the public welfare." *Fed. Power Comm'n v. Louisiana Power & Light*, 406 U.S. 621, 631 (1972) (cleaned up).

The Commission cannot ensure its regulation of pipelines is complementary to the States' own regulation where it does not adequately analyze the impact of state requirements on the need for a project or whether its action is consistent with the aims of state regulation. Nor can the Commission coordinate with State efforts to protect consumers when it has not meaningfully assessed “the risk of over-building and the concomitant risk of saddling ratepayers with the costs of underused facilities.” Order, Clements, Comm’r, concurring at ¶ 4. The Commission’s failure to meaningfully assess the impact of state and local laws on need for this expansion “entirely failed to consider an important aspect of the problem” before it in violation of the APA. *See State Farm*, 463 U.S. at 43.

c. The Commission arbitrarily and unlawfully based its decision on vague and unsupported assertions of public benefits

The Commission also based its determination of need on vague and unsupported assertions of public benefits. The Commission concluded that the Expansion will benefit the public because it “will provide access to lower-cost gas, and will enhance supply diversification and reliability.” Order ¶¶ 36, 39. The Commission did not cite any evidence to support or quantify these public benefits. *See id*. In particular, if a benefit is lower gas or electric rates for consumers, “then the applicant’s market study would need to explain the basis for that projection. Vague assertions of public benefits will not be sufficient.” 1999 Policy Statement 25. The courts agree: findings of public convenience and necessity “must be supported by evidence.” *Atl. Ref. Co.*, 360 U.S. at 391; *see also Env’t Def. Fund*, 2 F.4th at 973 (reasoning that the Commission’s articulation of public benefits like supply diversification and fostering competing alternatives, without citation to concrete evidence in support, was inadequate to justify a finding of need and public interest). Here, the Commission has not cited to a single piece of record evidence to support these assertions. Vague findings of supply diversification or reliability could apply in virtually any case, and are inadequate to justify imposing the Expansion's serious environmental harms and millions of dollars in consumer costs on the public. *See infra* §§ IV(A)(3)(a)(4); (B).

3. The Commission cannot determine that public necessity and interest require the Expansion because it has not considered reasonable alternatives

The Commission's determination that the public necessity and interest require this Expansion is also deficient because it did not consider whether reasonable alternatives that could meet the public's need for energy exist, and likely at a lower cost to consumers and the environment. The Commission arbitrarily refused to consider such alternatives, incorrectly claiming it can only "decide whether to adopt an applicant's proposal" and narrowly defining its purpose as serving "the firm natural gas transportation requirements of its shippers." Order ¶ 24. The Commission erroneously limited its authority under the NGA to consider energy alternatives and thus fails to consider a key factor as to whether the public necessity and convenience require the Expansion. The Commission's narrow definition of its purpose and exclusion of reasonable alternatives also violated NEPA, as discussed further below. *See infra* § IV(C)(4),(5).

a. The Commission arbitrarily refused to consider clean energy alternatives to the Expansion despite record evidence showing clean energy competes with methane gas

If an alternative energy source would better serve the proposed end use of the transported gas, then the Expansion may not serve the public interest, even if the Commission cannot command the alternative. *See Pittsburgh*, 237 F.2d at 751 n.28. For example, in *Transcontinental Gas Pipeline*, the Commission considered whether using methane gas for industrial uses was "wasteful," given that other energy sources that could meet the need. 365 U.S. at 7. The Supreme Court held this was a proper component of the public interest inquiry. *Id*.

Just as the Commission considered alternative energy sources for the designated end-use of gas in *Transcontinental*, 365 U.S. at 7, it must consider here whether alternative technologies exist that can better serve consumers need for energy. As discussed in Part IV(A)(3)(b) above, state laws support transitioning from methane-generated electricity to renewable resources and/or more efficient energy. Generating electricity from lower-emission, renewable sources is preferable to burning methane, which contributes to climate change and air pollution. Another significant use of methane gas in the region is for residential space and water heating, but electric heat pumps can heat more efficiently and cheaper than methane equipment. *See* Hill Report at 54, 58. Other alternatives that State regulators have considered to reduce peak day demand include selective electrification or limiting new gas connections. *See id.* at 58. Cascade, an Expansion Shipper, also has stated it will employ energy alternatives, including "robust energy efficiency," strategically targeted electrification, and biogas, to meet future demand in compliance with Oregon law.[10]

Nor did the Commission explain why the existence or development of renewable energy sources was irrelevant to its analysis of need for more gas. *See* Alexandra B. Klass, *Evaluating Project Need for Natural Gas Pipelines in an Age of Climate Change: A*

[10] Pub. Utility Comm'n, Docket No. UM 2178, Cascade Comments (October 26, 2021), https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAC&FileName=um2178hac145937.pdf&DocketID=22869&numSequence=59 (attached as Exhibit D). *See also* Or. Citizens Utility Bd. Comments.

Spotlight on FERC and the Courts, 39 Yale J. on Reg. 658, 690 (2022) (discussing how "new natural gas infrastructure . . . is often competing with or displacing new wind, solar, and battery storage. . . [M]arket trends show that these renewable energy resources either are currently or will soon be cheaper than natural gas."). Almost a century ago, the Supreme Court found the likelihood of competition from other energy sources to be so obvious that it took "judicial notice of the fact that gas is in competition with other forms of fuel." *W. Ohio Gas Co. v. Pub. Utilities Comm'n of Ohio*, 294 U.S. 63, 72 (1935).

Further, undisputed record evidence, including GTN's own market analysis, shows renewable energy competes with methane gas. *See* IHS Markit Report at 46 ("Our most recent power outlook for the Rockies shows significantly lower growth in gas-fired power generation from 2021 to 2030 from the prior outlook, owing largely to the penetration of solar power generation. We expect solar generation to rise by more than 6,000 GWh from 2021 to 2030"); 53 ("Over the long term, we expect demand to be weaker than previously expected owing to the continued gains of renewable energy fuels in the power market"); *see also id*. at 8, 10, 16, 39 (noting competition between renewables and methane gas in other regions); *see also* Hill Report 57-64.

b. The Commission arbitrarily failed to analyze whether existing pipelines could meet any incremental demand

In addition to failing to consider clean energy alternatives that could meet some or all of the Shippers' needs, the Commission failed to consider whether existing pipelines have capacity that could meet any incremental demand. As discussed above, *infra* § IV(A)(3)(a)(1), Cascade's short-term needs for more pipeline capacity are limited and their long-term needs for an Expansion project are speculative accounting for state laws. Yet the Commission has not evaluated whether any short-term needs could be met via available capacity on GTN or other pipelines. Similarly, Intermountain's contract replaces capacity on another pipeline [redacted] but the Commission has not evaluated whether alternatives on GTN or other pipelines exist. These factors are relevant and within the Commission's jurisdiction to consider. In fact, the Commission's updated draft Certificate Policy explicitly states it will evaluate whether "other suppliers would be able to meet some or all of the needs to be served by the proposed project on a timely, competitive basis or whether other factors may eliminate or curtail such needs." Updated Policy Statement on Certification of New Interstate Natural Gas Facilities, Dkt. PL18-1-000 (Feb. 18, 2022), https://www.ferc.gov/media/pl18-1-000 ("2022 Draft Policy Statement"), at 43.

Thus, even if GTN had presented evidence of growing demand for methane gas, that should give only minimal weight in favor of a certificate because there are renewable alternatives that can meet public demand for energy with fewer risks to the climate or consumers, as well as likely alternatives to meet incremental demand on existing pipelines. *See* Hill Report 57-64; States' Draft EIS Comments at 19-23; Or. Citizens' Utility Bd. Comments.

4. **The Commission failed to consider and balance all relevant factors in determining the public interest**

Where an "application on its face or on presentation of evidence signals the existence of a situation that probably would not be in the public interest," the Commission should not issue a certificate. *Atl. Ref. Co.*, 360 U.S. at 391. To make that determination, the Commission must "evaluate *all* factors bearing on the public interest" and balance the public benefits of a proposed gas project against its adverse effects to determine whether the project meets the public convenience and necessity test. *Env't Def. Fund*, 2 F.4th at 961. As the Commission explained in its 1999 Policy Statement, "[t]he amount of evidence necessary to establish the need for a proposed project will depend on the potential adverse effects of the proposed project on the relevant interests." 1999 Policy Statement 25. The APA in turn requires federal agencies to consider all important aspects of the problem. *See State Farm*, 463 U.S. at 30, 43.

A project's "adverse environmental effects" are relevant factors that the Commission can and must consider when balancing a proposed project's benefits against its adverse impacts. *Sierra Club*, 867 F.3d at 1373; *see also* 1999 Policy Statement 3, 26; Order Clarifying Statement of Policy (February 9, 2000), 90 FERC ¶ 61,128, Dkt. No. PL99-3-001, at 18-19 (potential adverse environmental impacts are important to the Commission's balancing). This consideration of environmental impacts includes greenhouse gas emissions and climate impacts. *Vecinos*, 6 F.4th at 1331 (holding the Commission's public interest and convenience determinations were deficient because they relied on a flawed analysis of environmental impacts); *N. Nat. Gas Co.*, 174 FERC at ¶ 61,728 ("a proposed interstate natural gas pipeline's reasonably foreseeably GHG emissions are relevant to whether the pipeline is required by the public convenience and necessity.").

The Commission must also consider how the gas will be used and whether alternative energy sources are more suitable for that use. The Commission has a long history of considering whether supplying methane gas for a particular use serves the public's interest in conservation and environmental protection. As the Supreme Court stated, the Commission cannot "blind itself to the effects of the purchase and use of the gas when its authority to certificate the transportation of the gas was invoked." *Transcontinental Gas Pipeline Co*., 365 U.S. at 36; *see also Fed. Power Comm'n v. Hope Nat. Gas Co*., 4 FPC 59, 66-67 (1944) (stating "considerations of conservation are material to the issuance of certificates of public convenience and necessity under section 7" and authorizing a project in large part because of the particular end use of the gas); *Transwestern Pipeline Co.*, 36 FPC 176, 185 (1966) (affirming the "end use of gas was properly of concern to [the Commission], and . . . air pollution was a relevant consideration"); *cf. Am. La. Pipe Line Co.*, 16 FPC 897, 900 (1956) (approving certificate of public convenience and necessity because "natural gas is a clean, convenient and efficient fuel[,] . . . can be sold at reasonable rates and generally will be attractive as compared with other fuels").

The Commission's brief analysis of the public interest failed to consider and balance multiple factors relevant to the public interest. These factors include:

- A determination of what weight to give the precedent agreements and general, unsupported statements of public benefits in light of the contrary evidence of need and the fact that the Expansion's revenues do not exceed the full project costs. *See supra* § IV(A)(3)(a).

- The economic risk to future consumers when the Expansion costs are not fully recovered after the precedent agreements expire. *See supra* § IV(A)(3)(b)(3).

- The existence of alternatives, including renewable electricity and transportation on existing pipelines, that could meet consumers need for energy at a lower cost and with fewer environmental harms. *See supra* § IV(A)(4-5).

- The Expansion's inconsistency with federal, state, tribal, and local laws and policies aiming to reduce greenhouse gas emissions and reliance on methane gas. *See supra* §§ IV(A)(3)(b)(4); *infra* IV(C)(2)(a).

- The significance of the Expansion's greenhouse gas emissions or the billions of dollars in environmental harms those emissions will cause. *See infra* § IV(B); IV(C).

Commissioner Clements acknowledged that this case raises serious and complex questions. Order, Clements, Comm'r, concurring ¶ 1. The Commission's "superficial approach," which relies "solely on precedent agreements," cannot determine what is in the public interest in a case like this one. *Id*. Because the Commission cannot wait for a change in policy to comply with its duties under the NGA and APA, however, it must grant rehearing now and revisit its decision.

B. The Commission's Refusal to Assess the Significance of the Expansion's Climate Harms Violated the NGA, NEPA, and the APA

The Commission unlawfully abdicated its responsibility under the NGA, NEPA, and the APA to make an informed decision based on relevant factors when it refused to determine the significance of the Expansion's adverse climate impacts or otherwise disclose how those adverse impacts affect its decision. *See* Order ¶¶ 71-72. The Commission's NEPA and APA violations also render unlawful the Commission's finding of public convenience and necessity. *Vecinos*, 6 F.4th at 1331 (ordering the Commission to reconsider its public convenience and necessity findings that relied on an improper NEPA analysis).

The Commission declined to determine significance of the Expansion's climate and greenhouse gas emissions based on its conclusion that "there are no criteria to identify what monetized values are significant for NEPA purposes and its inability "to identify any such appropriate criteria." Order ¶ 71. Because the Commission concluded that "there currently are no accept[able] tools or methods for the Commission to use to determine significance," it did not decide the significance of the Expansion's greenhouse gas emissions or its climate impacts on environmental justice communities. Order ¶¶ 72, 90.

Yet the record is clear that heat waves, wildfire, sea level rise, and flooding due to climate change are already causing severe harm in the Northwest. In 2021, Washington and Oregon suffered a historic heat wave that would have been virtually impossible without climate change, killing hundreds of State residents. States' DEIS Comments at 21. In 2020, extreme heat and drought conditions sparked wildfires that killed dozens of State residents, destroyed entire towns, and burned more than four million acres. Smoke from the fires made air quality in Seattle, Portland, San Francisco, and Los Angeles among the worst in the world that summer. *Id*.

Despite refusing to determine its significance or otherwise factor the Expansion's climate harms into its decision, the Commission acknowledged that the Expansion will "contribute incrementally to future climate change impacts" and will cause society at least 2.8 to 8.8 billion dollars in environmental and public health harms. Order ¶ 64. Notably, the social cost is likely much higher because the Commission omitted upstream emissions and certain downstream emissions from this calculation. *See infra* § IV(C)(1); EPA Comments on Final EIS, Dkt. CP22-2-000,2-3 (Dec. 15, 2022)("EPA Final EIS Comments") (expressing concern that the Commission's failure to quantify the cost of upstream emissions underestimates project impacts "by several hundred million to over a billion dollars"). The Commission further found that just a portion of the emissions from this single energy project will consume more than one-tenth of Washington's entire greenhouse gas emission budget by 2050 and just shy of one twentieth of Oregon's entire greenhouse gas emission budget by 2050. Order ¶ 69, *but see infra* § IV(C)(1)-(2)(a). Expert David Hill calculated that the downstream emissions from gas on GTN's entire system would consume 48% of the region's target greenhouse gas emissions from all sources by 2050, illustrated in the below graph:

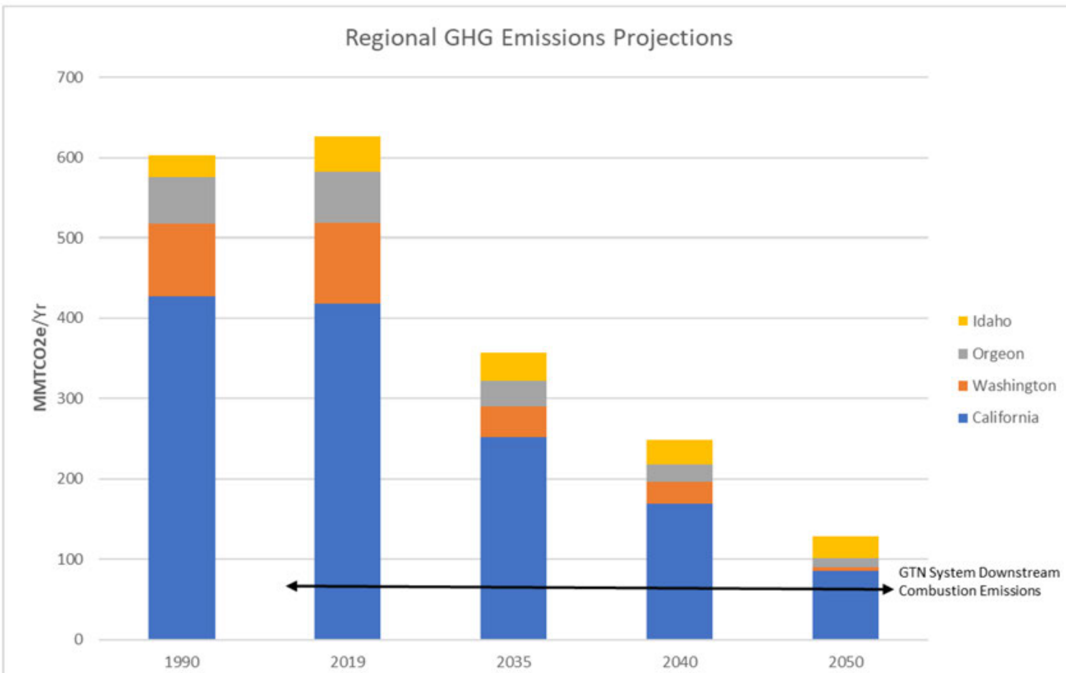

Figure 8: GHG Emission Reduction Profiles by State[40]

Hill Report 25-27.

However, the Commission did not rely on its analysis using the social cost of carbon or the impact of the Expansion's emissions on federal, state, and local emissions targets to decide that the Expansion is in the public interest and is environmentally acceptable, Order ¶¶ 98-101. *See also* Order, Danly, Comm'r, concurring at ¶ 3 ("the social costs of greenhouse gases (GHG) is neither useful nor a part of the Commission's decision making and the Commission offers no means by which to assess the significance of GHG emissions.”). The Commission’s failure to consider these factors in its decision or to determine significance is unlawful, unjustified, and arbitrary and capricious.

1. The Commission’s refusal to evaluate the Expansion’s adverse climate impacts or their significance in its public interest determination violated the NGA and the APA

The Commission’s refusal to consider the Expansion’s adverse climate impacts or their significance in approving the Expansion violated the NGA, the APA, and its own policy. To properly balance the benefits and adverse impacts of a project, the Commission must determine the degree of those impacts. *See supra* § IV(A)(7); 1999 Policy Statement 26. As the Commission explained in its 1999 Policy Statement, “[t]he more interests adversely affected or the more adverse impact a project would have on a particular interest, the greater the showing of public benefits from the project required to balance the adverse impact.” 1999 Policy Statement 26. Stated another way, the more significant an adverse impact is, the more beneficial the Expansion must be to satisfy the public convenience and necessity test.

Contrary to these requirements, the Commission did not factor the Expansion’s adverse greenhouse gas emissions and climate impacts into its public interest analysis or otherwise balance the adverse climate effects of the Expansion against its benefits. Instead, the Commission did the opposite and refused to determine the significance of the Expansion’s greenhouse gas emissions and climate impacts, including how the Expansion’s climate impacts will affect environmental justice communities, or otherwise weigh them in its decision at all. Order ¶¶ 71-72, 90. Had the Commission engaged in this analysis, it may have determined that the Expansion was not in the public interest, chosen or evaluated a different alternative with lesser climate impacts, or required mitigation for the Expansion's adverse climate impacts. *See* Order ¶ 100 (noting the Commission's broad authority to impose mitigation measures for adverse environmental impacts); 15 U.S.C.§ 717f(e) (granting Commission authority to attach reasonable terms and conditions to a project); *Pittsburgh*, 237 F.2d at 751 n.28 ("The existence of a more desirable alternative is one of the factors which enters into a determination of whether a particular proposal would serve the public convenience and necessity."). *N. Nat. Gas Co*., 174 FERC at ¶ 61,728 (stating that "[d]etermining the significance of the impacts from a proposed project's GHG emissions informs the Commission's review in a number of important respects…"); *see also* Consideration of Greenhouse Gas Emissions in Nat. Gas Infrastructure Project Revs., 178 FERC ¶ 61,108, 61,724 (2022) (stating that the Commission routinely requires mitigation as a condition of approval). The Commission's failure to weigh the Expansion's adverse climate impacts against its benefits violates the NGA, the APA, and the Commission's own policy. In the alternative, to the extent the Commission contends that it did consider the Expansion's greenhouse gas emissions and climate impacts in its analysis of public convenience and necessity, the Commission failed to explain how it did so, in violation of the APA. 5 U.S.C. § 706; *State Farm*, 463 U.S. at 43.

2. The Commission's failure to meaningfully analyze the Expansion's climate impacts, or determine their significance, or to otherwise consider them in its decision also violated NEPA and the APA.

For similar reasons, the Commission violated NEPA's core purpose of informed, transparent decision making by arbitrarily refusing to determine the significance of the

Expansion's emissions and climate impacts or otherwise consider these impacts in approving the Expansion. NEPA "places upon an agency the obligation to consider every significant aspect of the environmental impact of a proposed action." *WildEarth Guardians v. Jewell*, 738 F.3d 298, 302 (D.C. Cir. 2013). Agencies must take a "'hard look' at the consequences of the proposed action" and "provid[e] important information" to the public, including about "the severity" of a project's adverse effects. *Robertson* 490 U.S. at 352, 356; 40 C.F.R. §§ 1502.16(a)(1),1502.2(b).

NEPA specifically requires agencies to grapple with "any adverse environmental effects which cannot be avoided should the proposal be implemented," 42 U.S.C. § 4332(2)(C), and to "recognize the worldwide and long-range character of environmental problems" and lend support to "preventing a decline in the quality of mankind's world environment," 42 U.S.C. § 4332(2)(I). Critical evaluation of a gas project's consideration of adverse climate impacts fall squarely within NEPA's hard look mandate. *Vecinos*, 6 F.4th at 1331 (holding the Commission violated NEPA by failing to assess the impact of the project's greenhouse gas emissions or explain why it could not); *Sierra Club*, 867 F.3d at 1373; *N. Nat. Gas Co*., 174 FERC at ¶ 61,728 ("A rigorous review of a project's reasonably foreseeable GHG emissions is also an essential part of the Commission's responsibility under NEPA to take a 'hard look' at a project's environmental impacts.").

Here, however, the Commission abdicated its job to take a hard look at the Expansion's climate consequences by refusing to categorize them as significant or to otherwise factor these adverse climate impacts into its decision. Order ¶ 72; *see also* Final EIS at 4-62 ("This EIS is not characterizing the Project's [greenhouse gas] emissions as significant or insignificant…"). Instead, the Commission disclosed the social cost of the proposed Expansion's emissions solely for "informational purposes," Order ¶ 71, effectively turning its analysis of the Expansion's greenhouse gas emissions into a "paper tiger," *Calvert Cliffs' Coordinating Comm., Inc. v. U. S. Atomic Energy Comm'n*, 449 F.2d 1109, 1114 (D.C. Cir. 1971); Order, Danly, Comm'r, dissenting ¶ 21 (stating the Commission's social cost of carbon calculations "are meaningless"). The Commission's refusal to carefully consider the Expansion's adverse climate impacts and their significance in its decision conflicts with NEPA's core requirement that an "agency, in reaching its decision, will have available, *and will carefully consider*, detailed information concerning significant environmental impacts." *Robertson*, 490 U.S. at 349 (emphasis added); 40 C.F.R. §§ 1502.16(a)(1), 1502.2(b). It also violated NEPA's directive that the Commission use information about environmental impacts to inform its reasoned choice among alternatives and its analysis of mitigation measures. *See* 42 U.S.C. § 4332(2)(C); 40 C.F.R. § 1502.14; 18 C.F.R. § 380.7.

If the Commission did not know the significance of the Expansion's climate impacts, then it could not rationally conclude that the Expansion is environmentally acceptable. Order ¶ 98. Such a conclusion suggests that the Commission unlawfully zeroed out the Expansion's climate impacts in approving the Expansion. *Cf. High Country Conservation Advocs. v. U.S. Forest Serv.*, 52 F. Supp. 3d 1174, 1192 (D. Colo. 2014) (it was arbitrary for agencies to decide not to quantify the costs because the "agencies effectively zeroed out the cost"). As Commissioner Clements explains, the Commission's refusal to determine significance also represents an unexplained reversal from Commission precedent in violation of the APA. Order, Clements, Comm'r, dissenting ¶ 7 (stating that the Commission's assertion that it cannot determine significance "departs from previous Commission precedent without reasoned explanation" in violation of the APA); *see also Fox Television Stations, Inc.*, 556 U.S. at 515 ("a reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by the prior policy."); *Am. Rivers v. FERC*, 895 F.3d 32, 51 (D.C. Cir. 2018) ("Courts, after all, cannot evaluate the reasonableness of the unexplained.").

The Commission's explanations for refusing to determine the significance of the Expansion's climate impacts lack support. The Commission first explained that it lacks "criteria to identify what monetized values" of carbon emissions are significant under NEPA. Order ¶ 71. Notably, the Commission did not dispute that the social cost of carbon, which is the tool the Commission selected to quantify emissions in the Final EIS, is the best available tool to monetize climate costs. *See id*. Indeed, the CEQ, the expert agency on NEPA implementation, states that the social cost of carbon should be used "whenever possible" because it is an "appropriate and valuable metric" to help decision-makers and the public understand a proposed action's potential impacts. CEQ Guidance, 88 Fed. Reg. at 1200-1203; *see also* States' CEQ Guidance Comments at 2-3.

Instead, the Commission's reticence to determine significance flows from its concern that it lacks the ability to assess what amount of climate costs are significant. But the Commission did not explain why converting climate harms flowing from temperature increases, infrastructure damages, and human health effects to the "the familiar unit of dollars" confounds its ability to determine the significance of those harms or to otherwise factor those harms into its decision. CEQ Guidance, 88 Fed. Reg. at 1202 and n.61. As CEQ explains, part of the benefit of the social cost of carbon is that it is particularly helpful for agencies to evaluate "the significance of [a project's] climate impacts." *Id*. at 1200-1203; *see also* States' CEQ Guidance Comments at 2-3. In other words, the expert agency on NEPA views the social cost as a straightforward method to evaluate significance.

Although it may be difficult for the Commission to determine the precise point that a monetary impact becomes significant, it is common sense that a project that will cost society between 2.8 to 8.8 billion dollars in environmental harms meets the threshold of significance. Order ¶ 64; *see also Ctr. for Bio. Div. v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1200 (9th Cir. 2014) (rejecting uncertainty argument as arbitrary and capricious because "while the record shows that there is a range of values, the value of carbon emissions reduction is certainly not zero"). To the extent the Commission disputes this point, it should explain why billions of dollars are not significant and should not rest on its general claim that it does not know at what value a project becomes significant. The Commission should also respond to the States' comments raising these issues. *See Vecinos*, 6 F.4th at 1329 (holding the Commission's greenhouse gas emission analysis was deficient where the Commission failed to respond to petitioner's arguments under 40 C.F.R. § 1502.21).

The Commission further failed to explain why, even if it does not have an outside tool to use, it cannot exercise its own judgment to evaluate the significance of climate costs or the qualitative information in the record about climate harms. A hallmark of NEPA is that it "involves an almost endless series of judgment calls." *Duncan's Puint Lot Owners Ass'n* *v. FERC*, 522 F.3d 371, 376 (D.C. Cir. 2008). The Commission has previously observed that it "routinely makes significance determinations for impacts to various resources from natural gas projects" using qualitative and quantitative data. *Consideration of Greenhouse Gas Emissions in Nat. Gas Infrastructure Project Revs.*, 178 FERC ¶ 61,108, ¶ 61,724 (2022), converted to draft by *Order on Draft Policy Statements*, 178 FERC ¶ 61,197, ¶ 2 (Mar. 24, 2022). And here, the record contains a qualitative analysis of climate harms that the Commission could have used to inform its climate significance determination, including its admission that the Expansion will increase greenhouse gas emissions and contribute to future climate change impacts. *See* Final EIS at 4-45–4-48. The Commission also has before it numerous comments, including those from the EPA, providing additional information about the urgency to curb greenhouse gas emissions to avoid the worst harms of climate change. *See generally* States' DEIS Comments; EPA Draft EIS Comments, EPA Final EIS Comments.

Indeed, the record shows that the Commission made such judgment calls to determine the significance of several impacts, including concluding that the Expansion's impacts on local economies, housing, or demand for municipal services would be minor given the scope of the Expansion and that the disproportionately high and adverse impacts on environmental justice communities near the Athol and Starbuck Compressor Stations "would be less than significant." Order ¶¶ 79 (citing Final EIS 4-31); 89 (citing Final EIS 4-34-51). The Commission provided no rational explanation for why it cannot similarly use its judgment to evaluate the significance of the Expansion's social costs or other climate harms.

The Commission relied on the D.C. Circuit's dicta that the Commission had a reasonable basis for not applying the social cost of carbon. *Center for Biological Diversity v. FERC*, 67 F.4th 1176, 1184 (D.C. Cir. 2023) (determining issue was not exhausted). As an initial matter, that case is not on point because here the Commission chose on its own accord to apply the social cost of carbon to quantify the Expansion's greenhouse gas emissions. Even if it were on point, *Center for Biological Diversity* has little persuasive value when in that case, the Commission provided three bases for its decision not to calculate the social cost of carbon. *Id*. (discussing the Commission's claims that there was a lack of consensus about how to apply the social cost of carbon on a long time horizon, the social cost monetizes emissions but not environmental impacts, and that the Commission had no established criteria to translate the dollar values into an assessment of environmental impacts). Nothing in *Center for Biological Diversity* supports the Commission's reliance on the sole justification in this docket that it cannot evaluate significance even after calculating the social cost of carbon.

To the extent the Commission's position is that the social cost of carbon is not a method generally accepted in the scientific community, its Final EIS supporting its decision is fundamentally flawed. *See* 40 C.F.R. § 1502.21(c)(4). The Commission cannot have it both ways. It cannot choose to apply the social cost of carbon to avoid running afoul of D.C. Circuit precedent in *Vecinos*, 6 F.4th at 1328-30, and then turn around and suggest that the methodology that it chose is not an appropriate methodology. This is particularly true when the Commission previously acknowledged the utility of the social cost of carbon. *See Atlantic Coast Pipeline,* LLC, 164 FERC ¶ 61,100, ¶ 277 (Aug. 10, 2018) (acknowledging that the Social Cost of Carbon "estimate[s] the monetized climate change damage associated with an incremental increase in [carbon dioxide] emissions"); *Mountain Valley Pipeline, LLC*, 163 FERC ¶ 61,197 (June 15, 2018). The States and other comments also provided evidence in the record demonstrating that the social cost of carbon is the best science available to calculate a project's environmental harms and the Commission has not rationally disputed or responded to those comments. *See* States' DEIS Comments at 15-16; Comments of Columbia Riverkeeper on Draft EIS, Dkt. CP22-2-000 (Aug. 22, 2022), at 28, 32-33.

The Commission also stated, without support, that it otherwise lacks acceptable tools or methods to determine significance. Order ¶ 72. The Commission did not explain why it could not apply its proposed threshold of 100,000 tons per year of carbon dioxide equivalent. Order ¶ 72, n.143. Had it done so, it would have concluded that the Expansion's annual emissions of 1.9 million are at least 19 times higher than its proposed significance threshold. *See* Order ¶ 64; Final EIS at 4-48. Indeed, the annual operation emissions for each facility exceed the Commission's 100,000 tons per year threshold. *See* Final EIS Table 4.9-2. To the extent the Commission's Order relied on its position that it need not determine significance now because it will decide the issue sometime in the future, that future action does not absolve the Commission of its obligation to comply with the NGA, NEPA, and the APA in this case. Although the Commission has decided not to apply its 100,000 tons per year threshold until it finalizes its policy,[11] it has not disagreed with its findings or

[11] *See Certification of New Interstate Nat. Gas Facilities Consideration of Greenhouse Gas Emissions in Nat. Gas Infrastructure Project Revs*., 178 FERC ¶ 61,197, 62,315 (2022)

statements in that draft policy or otherwise justified its decision not to apply that threshold here. And even if the Commission plans to adjust this threshold upward or downward to some extent, that adjustment should not matter when the Expansion is 19 times higher than the currently proposed threshold.

Moreover, the record before the Commission in its greenhouse gas emission policy proceeding provides a variety of other methods the Commission could apply to determine significance. *See, e.g.*, *Consideration of Greenhouse Gas Emissions in Nat. Gas Infrastructure Project Revs*., 178 FERC ¶ 61,108, 61,732-35 (2022) (discussing proposals to the Commission for how to determine significance). For example, several States recommended that the Commission evaluate significance based on state, national, and global greenhouse gas emission reduction goals, which the Commission could readily do based on the record here. *See id.* at ¶ 61,732; *see infra* § IV(C)(2). Although the Commission's Order discusses Washington, California, and Oregon's greenhouse gas reduction goals, it does not utilize those goals to determine significance. *See* Order ¶¶ 69, 71-72.

The Commission also did not explain why the Expansion's emissions are not significant when they are inconsistent with Washington, Oregon, and California laws and federal and international efforts to curb climate change. *See* Order ¶¶ 71-72. As the States explained in their comments on the Draft EIS, the Expansion's greenhouse gas emissions are inconsistent with national policy, international commitments, and state laws. *See* States' DEIS Comments at 4-5; *infra* § IV(C)(2). EPA also recommended that the Final EIS provide "context regarding the urgency of the attainment of national and international GHG goals." EPA Draft EIS Comments at 4. Yet the Commission did not consider this urgency or these inconsistencies as an alternative basis to determine significance or explain why they were not an appropriate basis for its decision. *See Vecinos*, 6 F.4th at 1329; *see also Diné Citizens Against Ruining Our Env't v. Haaland*, 59 F.4th 1016, 1042 (10th Cir. 2023) (explaining that NEPA requires agencies to determine whether actions will have significant environmental effects and to apply accurate science to do so or explain why it cannot).

Although the Final EIS and the Commission's Order compared the Expansion's emissions against Washington and Oregon's emission reduction standards, *see* Order ¶ 69; Final EIS 4-49, that analysis alone is not enough because the Commission did not weigh those impacts in reaching its decision. Indeed, the Commission did not even acknowledge that its approval of the Expansion is fundamentally inconsistent with state and local emission reduction goals or urgent federal and international efforts to curb the worst impacts of climate change. *See infra* § IV(C)(2). Nor did the Commission discuss Oregon's specific greenhouse gas emission reduction standards for Cascade. *See* OR. ADMIN. R. 340-271-9000, Table 4. As Commissioner Clements observed, the Commission's "insistence that there are no acceptable tools for determining the significance of GHG emissions remains unsupported and gains nothing through near-constant repetition…." Order, Clements, Comm'r, dissenting ¶ 7. At a minimum, the Commission should include a summary of the alternative methods for evaluating significance and explain why it is not applying them. *See* 40 C.F.R. § 1502.21; *Vecinos*, 6 F.4th at 1329.

The Commission also cannot legitimize its decision not to determine significance by pointing to other parts of its greenhouse gas emission analysis or noting its conclusion that the Expansion is environmentally acceptable. First, the Commission's acknowledgment of incremental climate impacts does little more than acknowledge the existence of climate change itself. It is not a "hard look." *See Diné Citizens*, 59 F.4th at 1044 (holding agency's failure to accurately estimate a project's greenhouse gas emissions and superficial discussion of their impacts on the climate was arbitrary and capricious).

Second, the Commission's simple comparison of the Expansion's greenhouse gas emissions to national and state emissions falls short of NEPA's requirements. Order ¶¶ 67-69.[12] Both the Ninth and Tenth Circuits have indicated that simply comparing emissions to other emissions provides little evidence of the significance of the Expansion's emissions. *See 350 Montana*, 50 F.4th at 1259; *Diné Citizens*, 59 F.4th at 1042. Standing alone, these calculations do little to place the project in context or show the significance of its emissions and climate impacts as NEPA requires. *See* CEQ Guidance, 88 Fed. Reg. at 1203 ("NEPA requires more than a statement that emissions from a proposed Federal action or its alternative represents only a small fraction of global or domestic emissions"). Indeed, EPA expressly counseled against expressing the overall project-level emissions as a percentage of the state or national emissions because it "diminishes the significance of the Project-scale [greenhouse gas] emissions." EPA Draft EIS Comments at 5. Moreover, the Commission did not consider or explain whether these metrics would be an adequate basis for assessing significance.

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[12] As an initial matter, these comparisons lack credibility because they exclude reasonably foreseeable upstream and downstream emissions and do not explore the potential impact on state and regional goals for climate change. *See infra* § IV(C)(1); *see also* EPA Final EIS Comments at 3.

Third, the Commission's general analysis in the Final EIS of greenhouse gas emissions and climate harms cannot be a fall back for NEPA compliance when the Commission expressly disclaimed any analysis in the Final EIS that is inconsistent with or modified by the Commission's analysis and findings in the order. Order ¶ 98; *see also* Order, Danly, Comm'r, concurring ¶ 4 ("[A]ny language in the [Final EIS] that is in tension with the Commission's order is not relied upon or adopted by the Commission."). Because the Commission effectively treated the Expansion's climate emissions as insignificant by failing to factor them into its decision, the underlying Final EIS analysis of greenhouse gas emissions cannot support the Commission's NEPA compliance.

The Commission's conclusion that the Expansion "is an environmentally acceptable action," is also not sufficient. The Commission provided no explanation for how it reached this conclusion or how the Expansion's greenhouse gas emissions factored into this analysis. Order ¶ 98. Such unexplained, unsupported conclusions violate the APA. *State Farm*, 463 U.S. at 43 (agency must make "a rational connection between the facts found and choices made") (cleaned up). Ample evidence in the record also contradicts this conclusion when the States and various other parties have presented significant evidence showing the environmental, public health, and safety harms that will flow from this Expansion. *See generally, e.g.,* States' DEIS Comments, CRITFC Comments; Pipeline Safety Trust, Letter in Opp. (Mar. 29, 2023); Sen. Denbrow, et al. Letter, Dkt. CP22-2-000 (Nov. 9, 2023).

The Commission's statement that the Expansion will contribute to future climate change impacts also did not absolve its failure to comply with NEPA or make a rational, supported decision. The CEQ has explained that "NEPA requires more than a statement that emissions from a proposed Federal action or its alternatives represent only a small fraction of global or domestic emissions." 88 Fed. Reg. at 1203; *see also* States' CEQ Guidance Comments at 3. And as Commissioner Danly notes in dissent, it is "obviously problematic" for the Commission on the one hand to say that it is not considering the significance of the Expansion's emissions and to on the other hand conclude that the Expansion will contribute to climate change impacts. Order, Danly, Comm'r, dissenting ¶ 23.

C. The Commission's Order Violated NEPA, the APA, and the NGA Because it Rests on a Deficient EIS

The Commission committed several violations of NEPA by failing to take a hard look at greenhouse gas impacts, failing to consider a reasonable range of mitigation measures, relying on an inadequate purpose and need statement and failing to consider a reasonable range of alternatives, and failing to take a hard look at other impacts, including impacts to environmental justice communities.

1. The Commission failed to give a hard look at the Expansion's greenhouse gas emissions

The Commission's incomplete analysis of the Expansion's upstream and downstream emissions violated NEPA and the APA. First, the Commission did not rationally explain why it cannot quantify upstream emissions when the supply source is known and record evidence indicates the Expansion will induce additional production. The Commission failed to explain why it cannot use the tools and methods that expert Peter Erickson and the EPA recommend to quantify upstream emissions in this context. Second, the Commission did not rationally explain its conclusion that emissions from gas that Tourmaline intends to produce, ship, and sell from GTN's pipeline are not reasonably foreseeable, and ignores relevant evidence regarding the likely destination of Tourmaline's gas. Third, to the extent the Commission needed more information to quantify the Expansion's upstream or downstream emissions, it should have "at least *attempt[ed]* to obtain" that information. *Birckhead v. FERC*, 925 F.3d 510, 520 (D.C. Cir. 2019).

a. The Commission did not rationally explain why it cannot calculate upstream emissions based on the available information in the record

NEPA requires a "reasonably thorough" discussion of environmental impacts. *See 350 Montana*, 50 F.4th at 1265 (citation omitted); *see also* 40 C.F.R. § 1502.1. This includes indirect effects, which are "caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable." 40 C.F.R. § 1508.1(g)(2). Effects are "reasonably foreseeable" if they are "sufficiently likely to occur that a person of ordinary prudence would take [them] into account in reaching a decision." *EarthReports, Inc. v. FERC*, 828 F.3d 949, 955 (D.C. Cir. 2016) (citation omitted).

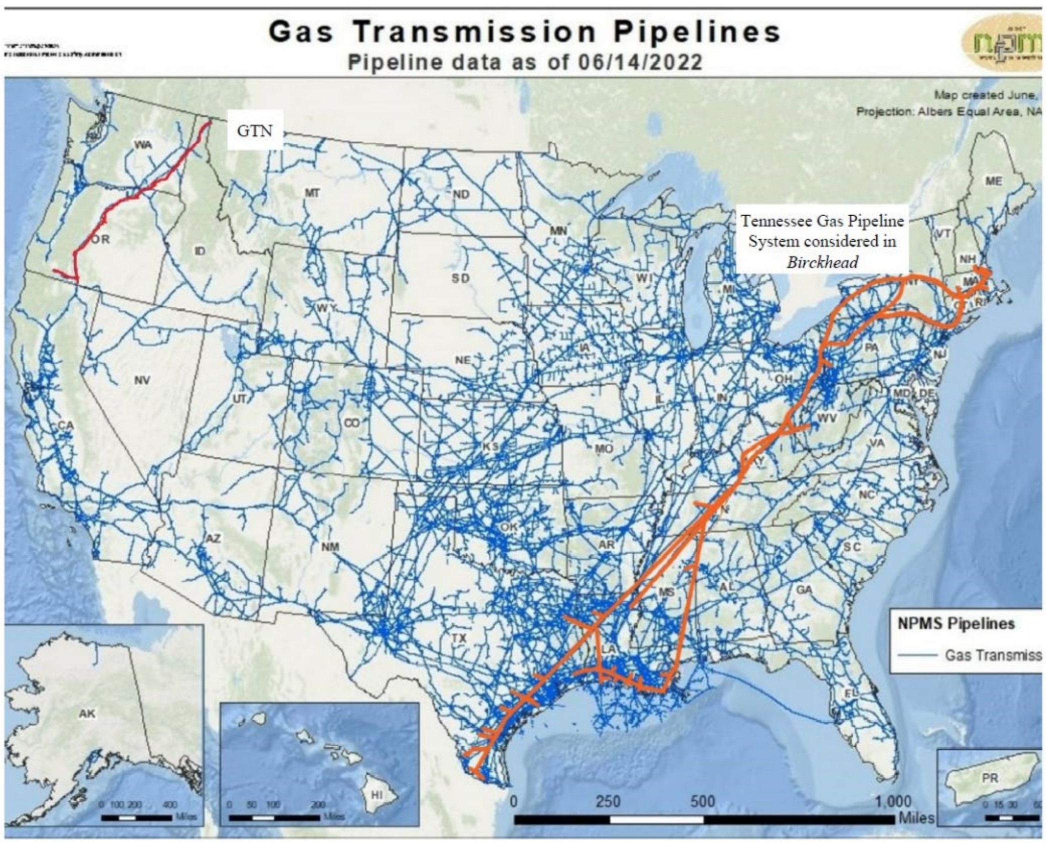
A reasonably prudent person would understand that, to send additional volumes of gas to market for sale, that gas must come from somewhere, and producing it results in greenhouse gas emissions. As the EPA stated in its comments:

> The purpose of the proposed Project is to transport additional natural gas for consumption; that additional natural gas must be produced and transported to supplement the existing throughput volume. If the proposed Project would not occur, the existing throughput would continue at its current rates and additional upstream production would not occur. Upstream emissions from that production and transportation are demonstrably reasonably foreseeable indirect effects of the proposed action and therefore should be considered under the NEPA analysis for this project. Omitting consideration of upstream emissions results in an underestimation of the proposal's impacts.

EPA Draft EIS Comments at 6.

For this reason, the D.C. Circuit has recognized that upstream emissions can be a reasonably foreseeable indirect effect of fossil fuel transportation projects where the source is known and there is evidence showing the Expansion will induce additional production. *See Eagle Cty. v. Surface Transp. Bd.*, 82 F.4th 1152, 1178-79 (D.C. Cir. 2023). CEQ's Guidance confirms that NEPA requires the Commission to quantify upstream and downstream emissions from the Expansion. As CEQ explains, such emissions are "often reasonably foreseeable since quantifiable connections frequently exist between a proposed activity that involves use or conveyance of a commodity or resource, and changes relating to the production or consumption of that resource." 88 Fed. Reg. at 1204. Incomplete information regarding the end-use or source of emissions does not allow the Commission to ignore these emissions. *Id*. at 1205 (stating "agencies should make best efforts to develop a range of potential emissions.").

This case is fundamentally different than *Birckhead*, where the D.C. Circuit concluded that the Commission reasonably declined to consider upstream emissions where the supply source was unknown and there was no evidence showing the Expansion would induce production. 925 F.3d at 517-18. The Tennessee Gas Pipeline system considered in *Birckhead* was far more expansive and interconnected than GTN's, however[13]:



[13] *See* American Petroleum Institute & Liquid Energy Pipeline Association, *Where are the Gas Pipelines Located?*, https://pipeline101.org/topic/where-are-gas-pipelines-located/ (last visted Nov. 22, 2023) (original graphic); TC Energy, TC Gas Transmission Northwest Map, tc-gas-transmission-northwest-map.pdf (tcenergy.com) (map of GTN's pipeline system, superimposed on the graphic); Kinder Morgan, Tennessee Gas Pipeline Company, L.L.C., https://pipeportal.kindermorgan.com/PortalUI/DefaultKM.aspx?TSP=TGPD (last visited Nov. 22, 2023) (map of Tennessee Pipeline System, superimposed on the graphic).

Additionally, unlike in *Birckhead*, there is record evidence showing that the supply source is known and the Expansion will induce additional production, so the Commission should have quantified the upstream emissions.

b. Record evidence indicates the Expansion will induce additional production in Canada, and the Commission has no basis to conclude that other, unidentified pipelines can transport that gas

Whether upstream emissions are reasonably foreseeable is a fact-specific inquiry. *See Delaware Riverkeeper Network*, 45 F.4th at 109-10 (emphasizing the fact-based nature of the downstream emissions analysis). The Commission claimed it cannot calculate upstream emissions because it does not know whether the Expansion will induce additional production. Order ¶ 66. However, the Commission failed to analyze the relevant facts. GTN describes its expansion as partially a "supply push" project, needed by producers in the Western Canada Sedimentary Basin to get their gas to market. *See* States' Protest, Ex. E, *TC Energy Corporation Q3 2019 Earnings Call Transcript* at 89.

This "supply push" explains why a Canadian gas producer, Tourmaline, contracted for a substantial portion of the Expansion's capacity. As industry expert Gregory Lander describes, gas producers commonly purchase capacity to sell more gas at a particular location, and then will "drill to fill" the purchased capacity. *See id.*, Lander Decl. at 22. Tourmaline, Canada's "largest natural gas producer," describes the "project capacity [as] a critical element of Tourmaline's long-term business planning." Mot. To Intervene and Comments in Support of Tourmaline Oil Marketing Corp., at 4 (filed Nov. 9, 2021). Tourmaline's own statements indicate the pipeline capacity is "critical" to future decisions about gas production, and thus emissions from that production are foreseeable and should be considered. *See also* Lander Decl. at 22.

The EPA also provided additional evidence showing the Expansion will result in increased production from Western Canada. *See* EPA Draft EIS Comments at 7; EPA Final EIS Comments at 2 (reiterating this evidence and recommending that the Commission's order include the available information, including "publicly available information provided by the project proponent"). GTN's market analysis also states "Western Canadian production remains demand constrained," meaning that companies will produce more gas if they have a market for it and means to ship it. *See* IHS Markit Report 57; *see also id*. at 10 ("Our forecast production increase [in Western Canada] . . . is predicated on the timely completion of pipeline expansions on the [NOVA Gas Transmission Limited] system in the short term"), 57 ("Western Canadian production remains demand constrained").

The Commission did not explain why, in light of this information, it remains uncertain whether the Expansion will induce production since the gas GTN ships must come from somewhere. The only plausible reason for the Commission's conclusion is an unfounded assumption that, if GTN does not expand its pipeline, another pipeline exists to transport the same gas to another market. Courts repeatedly have rejected such unfounded "perfect substitution" arguments. *See WildEarth Guardians v. U.S. Bureau of Land Mgmt.*, 870 F.3d 1222, 1234-39 (10th Cir. 2017) (holding agency cannot dismiss the effects of downstream emissions from coal mining by claiming perfect substitution); *Mid States Coalition for Progress v. Surface Transp. Bd.*, 345 F.3d 520, 549 (8th Cir. 2003) (holding agency's conclusion that there was perfect substitute for railroad to transport coal was "illogical at best"). There is no evidence here that another pipeline could perfectly substitute for GTN's. Instead, all the available evidence suggests the Expansion will spur gas production.

c. The Commission has sufficient information about the supply source to reasonably estimate upstream emissions

The Commission arbitrarily claimed it cannot calculate upstream emissions because it does not know the supply source for Cascade and Intermountain's gas. *See* Order ¶ 66. This is incorrect. The Order repeatedly states that the supply source is in Western Canada. *See* Order ¶ 21 (noting Intermountain's supply source is in Alberta, Canada); ¶ 23 (stating that GTN "transports natural gas from Western Canada to Washington, Oregon, and California") ¶ 36 (stating the Expansion will "transport natural gas produced in Western Canada to meet demand in markets in the Northwest and West Coast regions").[14] The Commission failed to explain why it needs more detailed information to calculate upstream emissions. *See Eagle Cnty., Colorado*, 82 F.4th at 1179 (holding agency violated APA and NEPA when it failed to explain why it could not estimate the upstream emissions "since it has identified *where* the Railway-induced oil and gas production is expected to occur.") (cleaned up).

The Commission can reasonably forecast the upstream emissions based on the information currently available to the Commission. The EPA explained the Commission "is able to generate an estimate of upstream emissions for this project's scope using information

[14] *See also* States' Protest, Ex. D, TC Pipelines Press Release (Nov. 1, 2019) (GTN's press release stating the Expansion will provide additional access to gas from the Western Canadian Sedimentary Basin).

that it will have available in the project proposal documents, along with general industry assumptions." EPA Detailed Comments on the GTN Xpress Project, Dkt. CP22-2-000 (Feb. 17, 2022) ("EPA Scoping Comments"), at 7. EPA also provided examples where EPA has generated estimates for upstream emissions for other Commission projects and offered technical support on request. *Id*. The Commission has also used Department of Energy studies to make generic estimates of upstream emissions from natural-gas production where detailed information about the number, location, or timing of wells was unavailable. *See Dominion Transmission, Inc.*, 163 FERC ¶ 61,128, *24-*25 & nn.207-208 (May 18, 2018) (LaFleur, Comm'r, dissenting in part). The Commission has not explained why it cannot use similar tools here.

Peter Erickson, a climate scientist, also provided a report to the Commission, explaining that "well-established methods and studies are available to estimate the potential [greenhouse gas] emissions associated with extracting and processing natural gas in Western Canada, and can be readily applied to the [Expansion]." Comment of Columbia Riverkeeper on Draft EIS, Dkt. CP22-2-000 (Aug. 22, 2022), Exhibit A, Erickson Report, at 5. Erickson then provided an estimate of emissions from producing gas in Western Canada, using the best available peer-reviewed science. *Id*. 6-8. The Commission has not considered Erickson's report or explained why his or the EPA's methods are unreliable. NEPA requires agencies to use "reliable existing data and resources" where available. 40 C.F.R. § 1502.23. Further, where the agency lacks complete information to quantify the reasonably foreseeable indirect effects, it must make reasonable efforts to obtain that information. *See* 40 C.F.R. § 1502.21(b), *infra* § IV(C)(1)(e) (explaining the Commission has not made reasonable efforts to obtain the additional information here). If unable to obtain that information, the Commission still must explain what information is unavailable, explain why such information is relevant to evaluating the impact, summarize the "existing credible scientific evidence that is relevant," and evaluate the impacts "based upon theoretical approaches or research methods generally accepted in the scientific community." 40 C.F.R. § 1502.21(c); *see also Vecinos*, 6 F.4th at 1329 (stating that 40 C.F.R. § 1502.21(c) "appears applicable on its face" to whether the Commission adequately analyzed the effect of greenhouse gas emissions).

Because the Commission's failed to analyze relevant evidence indicating the Expansion will result in upstream emissions and does not address relevant and scientifically-accepted methodologies to calculate those emissions, the Final EIS violates NEPA and the APA.

d. The Commission arbitrarily excluded Tourmaline's downstream emissions

The Commission claimed that no emissions from Tourmaline's contract are reasonably foreseeable because the "end use for the natural gas which will be transported using its subscribed capacity is not known." Order ¶ 64, n.120. The Order and the Final EIS failed to explain why the Commission cannot calculate downstream emissions from Tourmaline's gas when it did so in the Draft EIS. The Draft EIS concluded that Tourmaline's gas would serve residential, commercial, and industrial users based on GTN's Application. *See* Draft EIS, Dkt. CP22-2-000 (June 30, 2022)("Draft EIS"), at 1-4 (stating "GTN has indicated that Project shippers . . . intend to serve residential, commercial, and industrial users"). The Draft EIS then calculated the reasonably foreseeable emissions from

Tourmaline's gas and the social cost of carbon for those emissions. *See* Draft EIS 4-40 – 4-41, 4-45 – 4-47. In an unexplained and abrupt departure, the Final EIS reached the opposite conclusion. It removed the reference to GTN's Application regarding end-use and concluded that "information related to how the gas that will be transported by the proposed project will ultimately be used . . . [is] outside the scope of this EIS and [is] not considered further in this analysis." Final EIS at 1-5. The Final EIS then determined that, because the location and end-use of Tourmaline's gas are "unclear," it cannot reasonably forecast what emissions may result. Final EIS at 4-44. The Commission's "unexplained about-face" from the Draft EIS to the Final EIS is arbitrary and unlawful. *See Gulf Restoration Network v. Haaland*, 47 F.4th 795, 804 (D.C. Cir. 2022) (holding that agency acted arbitrarily and capriciously when it initially promised to consider a report but later brushed aside the report as outside the scope of the EIS).

The Commission also did not provide a reasoned explanation for its conclusion that it is not reasonably foreseeable whether Tourmaline's gas will emit greenhouse gases. The APA requires agencies to "examine the relevant data and articulate a satisfactory explanation for its action, including 'a rational connection between the facts found and the choice made.'" *State Farm*, 463 U.S. at 43. Agencies also must disclose the assumptions underlying their conclusions and "address evidence undercutting the assumption." *Gulf Restoration Network*, 47 F.4th at 804. Moreover, agencies cannot "shirk their responsibilities under NEPA" by labeling future environmental effects uncertain or unclear. *Scientists' Inst. for Pub. Info., Inc. v. Atomic Energy Comm'n*, 481 F.2d 1079, 1092 (D.C. Cir. 1973). "NEPA analysis necessarily involves some reasonable forecasting" and "agencies may sometimes need to make educated assumptions about an uncertain future." *Sierra Club*, 867 F.3d at 1374.

The Final EIS's only stated reason that the Commission cannot predict emissions from Tourmaline's gas is that it claims not to know the "location and end-use" of the gas. From that assumption, the Commission effectively drew the conclusion that greenhouse gas emissions are, as a categorical matter, *never* reasonably foreseeable impacts when it claims it does not to know the location and end-use of the gas. Not only has the D.C. Circuit rejected such categorical conclusions, *see Delaware Riverkeeper Network*, 45 F.4th at 109-10, but the Commission offered no basis to support its conclusion that it lacks sufficient information about the location and end-use of the gas based on the record here, particularly when the Commission concluded the opposite and calculated Tourmaline's downstream emissions in the Draft EIS.

The Final EIS also did not explain why the particular location and end-use matters to its analysis when the location of emissions is irrelevant to their climate impact. As the Final EIS acknowledged, when methane gas is burned, it releases greenhouse gasses in the atmosphere. Final EIS at 4-45. And it is no secret that virtually all methane gas consumed in the United States is burned. According to the U.S. Energy Information Administration, 97 percent of methane gas is burned and the remaining three percent is used to make various products, such as lubricants, fertilizer, or plastics, which may also emit greenhouse gasses. States' Comments on the Final EIS, Dkt. CP22-2-000 (Dec. 20, 2022) ("States' FEIS Comments"), Ex. A. Thus, irrespective of the precise location or end-use, the evidence supports the conclusion that emissions from Tourmaline's gas are a reasonably foreseeable effect of the Expansion.

Because the Order and the Final EIS did not disclose any reasoning for why the location and end-use matter to the Commission's analysis of the Expansion's greenhouse gas emissions in this context, one cannot test the Commission's assumptions or the validity of its rationale. The Commission cited no evidence to support its apparent assumption that purchasers of Tourmaline's gas will fall within the three percent of users who do not burn methane gas for energy. Further, it would be "wrong to suggest that downstream emissions are not reasonably foreseeable simply because the gas transported by the [Expansion] may displace" other higher emitting fuels. *Birckhead*, 925 F.3d at 518. If anything, an increased supply of methane gas is more likely to displace renewable energy in the States, further contributing to the Expansion's net emissions. *See* Alexandra B. Klass, *Natural Gas Pipelines in an Age of Climate Change*, 39 YALE J. ON REG. 658, 690 (Jul. 2022) (explaining how "new natural gas infrastructure paid for by captive ratepayers is often competing with or displacing new wind, solar, and battery storage investments either supported by the markets and, in some cases, mandated by a growing number of states.").

Without evidence to support it, the Commission lacked a rational basis to conclude that providing Tourmaline's gas would result in a perfect replacement or net reduction of emissions. For these reasons, the Commission's failure to support its changed position with rational and transparent analysis and record evidence rendered the Final EIS inadequate and unlawful.

Finally, the Final EIS arbitrarily ignored record evidence indicating the location and end-use of Tourmaline's gas. GTN asserted in its Application that the gas that Expansion shippers transport, including Tourmaline, "will meet increased market demand driven by residential, commercial, and industrial customers in the Pacific Northwest region of the United States." Application at 1. Further, GTN's Application states that Tourmaline "will provide low cost natural gas supply and reliability primarily to West Coast markets serving residential, commercial, industrial, and electric generation needs" and "Northern California markets needing natural gas for electric generation." *Id*. 4, 13. The Commission must examine GTN's statements in its Application regarding the reasonably foreseeable location and end-use of Tourmaline's gas and "offer[] an explanation for [its] decision that runs counter to the evidence before [it]." *State Farm*, 463 U.S. at 43. This is particularly true here where the Commission relies on the Tourmaline contract, in part, to define the purpose of the Expansion. *See* Final EIS 3-2 (defining the purpose of the Expansion "to increase capacity of GTN's existing natural gas system by about 150 million standard cubic feet per day," with Tourmaline's contract forming the basis for 51 million cubic feet).

e. To the extent the Commission needed more information, it failed to ask for it

"NEPA [] requires the Commission to at least attempt to obtain the information necessary to fulfill its statutory responsibilities." *Birckhead*, 925 F.3d at 520 (citing *Del. Riverkeeper Network v. FERC*, 753 F.3d 1304, 1310 (D.C. Cir. 2014)); *see also* 40 C.F.R. § 1502.21(b) (directing agencies to obtain available information relevant to a reasonably foreseeable significant adverse impact where the overall costs of obtaining it are not unreasonable). The Commission sent GTN eight data requests asking for additional information. None of them asked GTN to provide information on the supply source for the gas the Expansion would transport, the location and end-use of Tourmaline's gas, or whether alternative pipelines were available to ship the gas to market. The Commission also did not request information from Tourmaline (a party to this proceeding), though the States provided a detailed list of questions that would have allowed the Commission to determine whether Tourmaline's gas is likely to be combusted and release greenhouse gas emissions. *See also* States' FEIS Comments at 4-5 (listing questions for Tourmaline).

If information relevant to upstream production cannot be obtained, the Commission still must include "a summary of existing credible scientific evidence that is relevant to evaluating the reasonably foreseeable significant adverse impacts on the human environment; and [t]he agency's evaluation of such impacts based upon theoretical approaches or research methods generally accepted in the scientific community." 40 C.F.R. § 1502.21(c); *see also Vecinos*, 6 F.4th at 1329. What the Commission cannot do, however, is what it did here: treat upstream and certain downstream emissions as if they did not exist, claiming they are generally not reasonably foreseeable. *See* Final EIS 4-44; Order ¶¶ 64 n.120, 66.

The Commission also failed to explain why, when there was some incomplete information about the likelihood of emissions or their quantity, it could not provide a "reasonable estimated range of quantitative emissions." CEQ Guidance, 88 Fed. Reg. at 1202.*See High Country Conservation Advocs. v. U.S. Forest Serv.*, 52 F. Supp. 3d 1174, 1192 (D. Colo. 2014) (noting that although there is a wide range of estimates about the social cost of greenhouse gas emissions, it was arbitrary for the agencies to decide not to quantify the costs at all because the "agencies effectively zeroed out the cost"); *Ctr. for Bio. Div. v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1200 (9th Cir. 2014) (rejecting uncertainty argument as arbitrary and capricious because "while the record shows that there is a range of values, the value of carbon emissions reduction is certainly not zero").

2. The Commission violated NEPA and implementing regulations by failing to address conflicts with state laws, tribal policies, national policy, and international commitments

The Final EIS's cursory mention of state laws and complete failure to discuss relevant international, national, and tribal policies violated NEPA. Numerous NEPA provisions make clear that agencies cannot ignore international, state, tribal, and local policies to address environmental problems. Agencies must "recognize the worldwide and long-range character of environmental problems" and, where "consistent with the foreign policy of the United States[,] . . . lend appropriate support to initiatives, resolutions and programs designed to maximize international cooperation in anticipating and preventing a decline in the quality of mankind's world environment." 42 U.S.C. § 4332(2)(I). NEPA also requires federal agencies to work in concert with state, tribal, and local governments by making available "advice and information useful in restoring, maintaining, and enhancing the quality of the environment." *Id*. § 4332(J).

Consistent with these directives, NEPA regulations require an EIS to "discuss any inconsistency of a proposed action with any approved State, Tribal, or local plan or law (whether or not federally sanctioned). Where an inconsistency exists, the statement should describe the extent to which the agency would reconcile its proposed action with the plan or law." *See* 40 C.F.R. § 1506.2(d). NEPA regulations further direct agencies to explain "how the agency's ultimate decision will comply with environmental laws and policies" and NEPA's overarching goals of environmental protection. *Am. Rivers*, 895 F.3d at 38; *see also* 40 C.F.R. § 1502.2(d). Taken together, these provisions obligate the Commission to consider the Expansion in the context of international commitments, national policy and state, tribal, and local laws to combat climate change. The Commission's comparison of the Expansion's downstream emissions to state emissions targets is insufficient because it did not discuss whether or how the Expansion is inconsistent with federal, state, tribal, and local laws to reduce use of methane and did not describe the extent to which the Commission will reconcile its approval with these laws and policies.

a. The Expansion is inconsistent with state laws

Washington, Oregon, and California each have laws to cap and reduce emissions and transition to renewable electricity. *See* States' DEIS Comments, Ex. A. The Columbia River Inter-Tribal Fish Commission also has an "Energy Vision" that has a principle goal of mitigating climate impacts to "protect Northwest ecosystems by replacing fossil-fuel electric generation and reducing the reliance on fossil-fuels for power, transportation, and other uses." CRITFC Comments at 7. In addition, dozens of local governments have laws and policies to reduce consumption of fossil fuels, including banning methane gas hookups to new buildings, energy efficiency mandates, and clean energy incentives. *See* States' DEIS Comments, Ex. A. Expanding methane infrastructure in the Pacific Northwest is inconsistent with these laws and policies.

The Final EIS washed its hands of this problem, concluding "impacts on the transition to renewable energy is outside the scope of the EIS." *See* Final EIS at 1-4 – 1-5. It devotes just one paragraph to these laws, inaccurately revising the States' transformational actions to mere "goals" and failing entirely to consider tribal goals to reduce fossil fuel emissions in the Northwest. Final EIS at 4-49; *see also* EPA Final EIS Comments at 3 (criticizing the Commission's failure to "explore the potential impact on state and regional goals for climate change"). NEPA requires more.

(1) The Expansion is inconsistent with Washington's emission limits and the Climate Commitment Act

Washington law requires progressive reductions in greenhouse gas emissions in the state to 1990 levels, or 50 million metric tons by 2030. By 2040, the law limits overall emissions in the state to 27 million metric tons, and, by 2050, to 5 million metric tons. *See* WASH. REV. CODE § 70A.45.020. These limits are not merely a "goal," Final EIS at 4-49, but a statutory limit on emissions that Washington must take steps to achieve.

A major part of this effort is a cap-and-invest program for greenhouse gas emissions. *See* WASH. REV. CODE 70A.65 (Climate Commitment Act)). The program covers facilities that generate 25,000 metric tons or more of carbon dioxide equivalent ("CO_2e") per year. *See* WASH. REV. CODE § 70A.65.080(1). The statute prevents covered facilities from collectively increasing annual emissions, and requires them to reduce their emissions over time, consistent with the States' greenhouse gas emission limits. *See id.* § 70A.65.060. The emissions reductions cannot be met solely through offsets—offsets can satisfy a maximum of five to eight percent of the facility's reduction requirements. *See id.* § 70A.65.170.

The Starbuck Compressor Station is a covered facility under the Climate Commitment Act because its annual emissions already are well above the 25,000 metric-tons-per-year threshold. *See* § 70A.65.080(1); Final EIS at 4-40 – 4-41. The cap-and-invest program will require GTN to either reduce emissions or obtain increasingly scarce allowances or other compliance instruments for the Starbuck Station. The Expansion, however, will more than double Starbuck's operational emissions, rising to 381,391 metric tons of CO_2e per year. *See* Final EIS at 4-40 – 4-41. This is moving in the wrong direction, against the progressive reductions in the overall allowance budgets for emissions in Washington. Allowing GTN to double its emissions not only undermines Washington law that aims to cap and reduce those emissions, but will be increasingly costly to GTN (and ultimately, consumers) due to compliance costs under the Climate Commitment Act.

(2) The Expansion's downstream emissions in Oregon is inconsistent with Oregon's Climate Protection Program

Oregon's Climate Protection Program, adopted by administrative rule in 2021, adopts a declining cap on greenhouse emissions from covered fuel suppliers (including Cascade, the Oregon "project shipper" referenced in the Expansion Application). The overall cap declines from 28,081,335 metric tons of CO_2e per year in 2022 to 15,021,080 in 2035 and to 3,004,216 in 2050. OR. ADMIN. R. 340-271-9000 (2021), Table 2.

Covered fuel suppliers receive a declining number of "compliance instruments" from the Oregon Department of Environmental Quality. Each instrument authorizes the emission of one metric ton of CO_2e per year by a covered fuel supplier. OR. ADMIN. R. 340-271-0020(10). Table 4 of Oregon Administrative Rule 340-271-9000 shows "[c]ompliance instrument distribution to covered fuel suppliers that are local distribution companies."

According to Table 4, Cascade received 743,707 compliance instruments in 2022, declining to 371,854 in 2035 and to 74,371 in 2050.[15]

Approval of the Expansion will result in Cascade receiving an additional 20,000 Dth/d of methane to potentially sell in Oregon for the next 30 years. *See* Application at 9; Order ¶ 20 (noting Cascade's statement that it needs the gas to serve "future load growth" in central Oregon). It appears that as of 2050, this Expansion alone would result in Cascade emitting substantially more that the Climate Protection Program permits. The Final EIS calculates that, for the 99,000 Dth/day of capacity for the Intermountain and Cascade contracts will result in 1.9 million metric tons of reasonably foreseeable downstream emissions each year. Final EIS at 4-48. Cascade contracted for 20 percent of that capacity (20,000 out of 99,000 dekatherms) for 31 years. *See* Application at 9. Assuming that 20 percent of Expansion capacity translates to 20 percent of emissions, Cascade would emit 380,000 metric tons of CO_2e. If even half that amount is emitted in Oregon, it would still greatly exceed the 74,371 metric tons the Oregon's Climate Protection Plan permits Cascade to emit *statewide*.

[15] Covered fuel suppliers may receive "community climate investment credit" through payment of community climate investment funds, which may be used in lieu of a compliance instrument. OR. ADMIN. R. 340-271-0020(7). However, use of such credits is limited. The allowable usage of community climate investment credits to demonstrate compliance is 10 percent for 2022 through 2024, 15 percent for 2025 through 2027, and 20 percent thereafter. OR. ADMIN. R. 340-271-9000, Table 6.

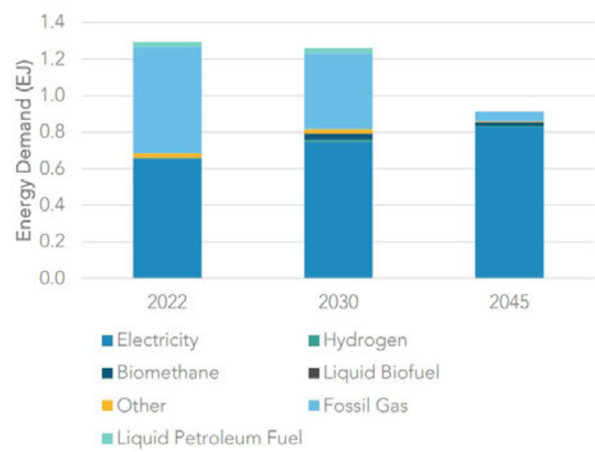
(3) **Increasing methane infrastructure is inconsistent with California laws to curb methane** use **and transition to renewable energy**

California has enacted several climate policies and programs since 2006, starting with Assembly Bill 32 requiring California to reduce its overall greenhouse gas emissions to 1990 levels by 2020 and 40 percent below 1990 levels by 2030. *See* California Global Warming Solutions Act of 2006, AB-32, § 1 (2006). California's Cap and Trade Program followed, with emissions limits set by the California Air Resources Board ("CARB"). CAL. CODE REGS., tit. 7, § 95800, *et. seq*. More recently, the Climate Change Scoping Plan, developed by CARB, outlines the state's approach to achieving greenhouse gas reduction targets, including the goal of reducing emissions 40 percent below 1990 levels by 2030.[16] The Scoping Plan details state goals such as supporting a clean energy economy.[17] The 2022 Scoping Plan Update includes the goal of carbon neutrality by 2045 and describes plans to replace methane gas with clean electricity economy-wide. For example, the Plan graphs the following decline in gas demand in buildings:

[16] CA. AIR RES. BD., *AB 32 Climate Change Scoping Plan* (2022), https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan.

[17] CA. AIR RES. BD., *2022 Scoping Plan Update* (2022), https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

Figure 4-8: Final energy demand in buildings in 2022, 2030, and 2045 in the Scoping Plan Scenario[400]



Id. at 213-215.

California has also passed several other climate-related laws. In 2015, California passed Senate Bill 350 that requires the state to procure 60 percent of all electricity from renewable sources by 2030 and 100 percent from carbon-free sources by 2045. Clean Energy and Pollution Reduction Act of 2015, SB-350 (2015). In 2018, California passed Senate Bill 100, establishing California's Renewables Portfolio Standard that requires electricity providers procure 60 percent of energy from renewable sources by 2030. California Renewables Portfolio Standard Program: Emissions of Greenhouse Gasses, SB-100 (2018).[18] The 2019 Green Building Standard, in turn, sets energy efficiency standards for new construction and retrofitting existing buildings. CAL. GREEN BUILDING STANDARDS CODE, tit. 24, part 11 (2019). This integrated climate change program, as well as state

[18] *See also* CA. ENERGY COMM'N, *Renewables Portfolio Standard – RPS* https://www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard.

programs to reduce greenhouse gas emissions implemented over the past several decades, illustrate California's longstanding commitment to reduce emissions and reliance on fossil fuels while building a cleaner, resilient economy that uses less energy and generates less pollution.

While the Expansion facilities will not be located within California, they connect directly to pipelines that deliver methane gas to California, and it reasonably may be assumed that additional capacity will result in transportation of increased amounts of methane through existing pipelines in California. This is inconsistent with the numerous state laws and policies enacted to reduce emissions and transition to clean energy. Approval of the Expansion would contradict California law and policy.

NEPA requires the Commission to discuss the inconsistencies between the Expansion and each of these state laws and how the alternatives considered will or will not comply with NEPA and other environmental laws and policies. 40 C.F.R. §§ 1506.2(d), 1502.2(d). The Commission must discuss both how increasing emissions is inconsistent with state laws aiming to reduce emissions, but also how expanding methane gas infrastructure adversely affects the transition to renewable energy. The Commission must also describe how it would reconcile the conflict between its proposed action and the state law. For example, the Commission could avoid these conflicts by selecting the no action alternative, require mitigation measures that reduce or offset emissions, or consider protective economic measures to ensure the Expansion will not burden consumers as the States transition to clean energy (such as requiring a shorter depreciation rate, *see infra* § IV(A)(1)(c)-(d). The Order and Final EIS lack this analysis in violation of NEPA.

b. The Expansion is inconsistent with international commitments and national policy

The Commission should have also considered whether the Expansion is consistent with international commitments and national policy, both of which commit to rapid reduction of greenhouse gas emissions by 2030 and net zero emissions by 2050 to avoid the worst impacts of climate change. In Executive Order 14008, President Biden affirmed that "[r]esponding to the climate crisis will require both significant short-term global reductions in greenhouse gas emissions and net-zero global emissions by mid-century or before." Exec. Order 14008, 86 Fed. Reg. 7619 (Feb. 1, 2021). The Order set a national policy to "put the United States on a path to achieve net-zero emissions, economy-wide, by no later than 2050." [19] Subsequently, to meet its obligations under the Paris Agreement, the United States committed to reduce greenhouse gas emissions by 50 percent to 52 percent below 2005 levels by 2030. *See* UNITED NATIONS, NDC Registry: The United States of America: Nationally Determined Contribution.[20] Executive Order 14057 further establishes a policy for the federal government to lead the way to achieve a carbon-pollution free electricity sector by 2035 and net-zero emissions economy-wide no later than 2050. *See* EPA Draft EIS Comments at 3. The recently released Fifth National Climate assessment confirms that United States greenhouse gas emissions must decline by more than 6 percent per year on

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[19] *Id.*

[20] The pledge to reduce "net greenhouse gas emissions by 50-52 percent below 2005 levels in 2030" formed the core of the United States "Nationally Determined Contribution" submitted to the United Nations Framework Convention on Climate Change in line with Article 4 of the Paris Agreement. https://unfccc.int/sites/default/files/NDC/2022-06/United%20States%20NDC%20April%2021%202021%20Final.pdf.

average to reach net-zero emissions around 2050 and achieve current national mitigation targets and international temperature goals. U.S. Global Change, Research Program, Fifth National Climate Assessment, Ch. 1. Overview: Understanding Risks, Impacts, and Responses, at 15.[21]

Despite these national and international commitments, the Expansion will *increase* greenhouse gas emissions for at least the next 30 years, well beyond the United States' net zero target in 2050. It also would complicate the States' companion efforts to reduce emissions on this timeline. GTN presumed its GTN pipeline will continue operating at near-full capacity until well past 2050, but the downstream emissions from this pipeline alone would account for 48 percent of the region's target emissions in 2050. *See* Hill Report 61.

If the United States is to achieve its policy goals, it must stop expanding fossil fuel infrastructure and emissions must rapidly decline. According to the International Energy Agency, "[i]f today's energy infrastructure was to be operated until the end of the typical lifetime in a manner similar to the past," existing infrastructure alone would consume 30 percent more than the remaining total CO_2 budget necessary to keep global warming below 1.5° Celsius. INT'L ENERGY AGENCY, *Net Zero by 2050: A Roadmap for the Global Energy Sector*, 181 (2021).[22] Thus, if the world is to achieve the Paris Agreement's goal of limiting warming to 1.5° Celsius, "significant investment in new gas pipelines is not needed."[23] Inconsistency with important national policy and international commitments is a significant

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[21] https://nca2023.globalchange.gov/downloads/NCA5_Ch1_Overview.pdf.

[22] https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf.

[23] *Id*.

adverse effect that the Final EIS must discuss, so that the Commission can properly consider it in its public interest analysis. It did not do so here.

3. The Commission violated NEPA because it failed to include a reasonably complete discussion of mitigation measures

The Commission also violated NEPA's requirement to include a reasonably complete discussion of mitigation measures in its environmental review. Although the Final EIS purports to improve its discussion of mitigation measures, it continues to fall short of NEPA requirement that an EIS contain a "reasonably complete" discussion of possible mitigation measures. *Robertson*, 490 U.S. at 352; *see also* 18 C.F.R. § 380.7(c) (requiring summaries of mitigation measures). Omitting this discussion "undermine[s] the 'action-forcing' function of NEPA." *Robertson*, 490 U.S. at 352.

Most notably because the Commission refused to determine the significance of the Expansion's climate impacts or otherwise consider them in reaching its decision it did not consider meaningful mitigation measures for those impacts. None of the environmental conditions on the authorization pertain to greenhouse gas emissions or climate impacts. *See generally* Order Appendix: Environmental Conditions. Similarly, the Staff recommended mitigation in the Final EIS does not address greenhouse gas emissions or climate impacts. Final EIS 5-1–5-6. The only mitigation of greenhouse gas emissions considered is a vague and brief discussion of GTN's general focus on "modernizing its existing natural gas assets to facilitate a reduction in GHG emissions" and minimizing greenhouse gas emissions during construction and operation of new gas infrastructure as well as TC Energy, GTN's parent company, annual reporting of GTN's methane emissions. Final EIS at 4-43–4-44; D. Final EIS at 4-43. These mitigation measures relate only to one type of greenhouse gas emissions and do not address mitigation of any of the climate harms associated with the Expansion.

Notably, these mitigation measures do not respond to the recommendation from EPA, a cooperating agency on the EIS, that the Commission "consider and incorporate practical mitigation measures to reduce the proposed action's GHG emissions into the proposed terms and conditions as part of certificate issuance." Final EIS, Appendix E-13; *see* 42 U.S.C. § 4336a(a)(3) (noting that cooperating agencies typically have jurisdiction or special expertise). The Final EIS did not embrace EPA's recommendation that it "analyze and disclose mitigation measures that will reduce net GHG emissions" or "illustrate how the Project has and will mitigate GHG emissions to the greatest extent possible …." Final EIS Appendix E-13. That is no surprise when the Commission has taken the position that significance is a threshold determination for it to mitigate greenhouse gas emissions and climate impacts. *See Jordan Cove Energy Project*, 171 FERC ¶ 61,136, ¶ 61,964 (May 22, 2020) (stating that the Commission sees "no way" to mitigate for greenhouse gas emissions when it "is unable to reach a significance determination").

Moreover, the Final EIS and the Order relied on general references to GTN's applications and lengthy responses to data requests. Order Appendix; Final EIS section 5.1. As the States pointed out in their comments on the Draft EIS, States' DEIS Comments at 29-30, these general references do not identify for the public which mitigation measures apply to which environmental impacts—a key purpose of the environmental review process. *See Robertson*, 490 U.S. at 352 (emphasizing that NEPA requires disclosure of potential mitigation measures so that the agency and the public "can properly evaluate the severity of the adverse effects"). But here, outside of broad requirements, the mitigation measures are buried in GTN's Application and data request responses. To comply with NEPA, the Commission should have identified the specific mitigation measures GTN will follow and explain how those measures will mitigate the specific impacts discussed in the EIS. *Robertson*, 490 U.S. at 352. The Commission should have also explained whether it recommends any mitigation measures that may be more effective than those the applicant proposes. 18 C.F.R. § 380.7(c).

In particular, the Commission should have clarified which mitigation measures to support its conclusion that the Expansion is environmentally acceptable. Order ¶ 98. The Commission stated that all mitigation measures in its appendix are "integral to ensuring that the environmental impact of approved projects are consistent with those anticipated by our environmental analysis." Order ¶ 100. However, as the States noted in their comments on the Draft EIS, States' DEIS Comments at 29-30, many of the mitigation measures are hidden within GTN's Application and supplements, making it challenging for the public to vet those mitigation measures and understand their role in the Commission's conclusions.

The Final EIS also unlawfully failed to analyze other mitigation. Although the Final EIS makes note that the Washington State Department of Fish and Wildlife requested that native grasses and shrubs be used for restoration "and GTN would adhere to this request," Final EIS 4-15, it does not appear to include that requirement in its Order Appendix setting forth the Environmental Conditions of the Permit. Order Appendix. As such, the general statement in the Final EIS is relatively meaningless for the protection of the State Endangered Ferruginous Hawk. It is also remains unclear whether and to what extent the

Commission assessed or recommends any mitigation measures to reduce adverse impacts to the surrounding community, other than noise monitoring. *See* Final EIS Appendix E-43; Order Appendix. For all these reasons, the Commission's analysis of mitigation measures fell short of NEPA and the APA.

4. The purpose and need statement conflicts with NEPA regulations, unreasonably restricts the range of alternatives, and ignores the Commission's statutory obligations

The Commission's Order is fundamentally flawed and uniformed because it relied on a Final EIS that impermissibly limits the scope of its analysis through a constrained purpose and need statement. The Final EIS's purpose and need statement contravenes NEPA, unlawfully elevates private goals above the Commission's statutory obligations under the NGA, and unreasonably constrains the range of alternatives considered.

The Commission's Order and the Final EIS violated NEPA because they focus exclusively on the goals of the applicant and not the Commission's purpose for the proposed action. *See* Order ¶ 24; Final EIS at 1-1 (stating that the Expansion purpose is "increas[ing] the capacity of GTN's existing natural gas transmission system by about 150 million standard cubic feet per day between its Kingsgate Meter Station in Idaho and its Malin Meter Station in Oregon."), *compare with* Application at 1. Although the Final EIS briefly acknowledges the Commission's obligation to consider whether the expansion "is in the public convenience and necessity" under Section 7(c) of the NGA, Final EIS at 1-1, it nonetheless limits the scope of its review to consider only factors relevant to GTN's objective in the Expansion. *See. e.g.,* Final EIS at 1-4 – 1-5. Similarly, although the Order acknowledged the Commission's obligation to consider the goals of the NGA, the

Commission nonetheless relied on the deficient environmental review to support its decision. *See* Order ¶¶ 94-95, 97.

The Commission's narrow focus on GTN's purpose violated NEPA's directive that agencies adopt a purpose and need statement that reflects their proposed action, goals, and decision. *See* 42 U.S.C. §§ 4332(2)(C)(iii) (requiring agencies to consider a reasonable range of alternatives that meet the purpose and need of the proposal); 4336e(12) (defining proposal in terms of agency goals and decisions); 40 C.F.R. § 1502.13; NEPA Regulation Revisions, 87 Fed. Reg. at 23457-59 (explaining that the purpose and need should reflect "the *agency's* purpose for the proposed action and the need it serves."). Although agencies may consider an applicant's goals in developing the purpose and need, they cannot exclude other relevant factors such as the agency's mission, statutory and regulatory requirements, "national, agency, or other policy objectives applicable to a proposed action," and the public interest. *Id*. at 23458; *see also* 42 U.S.C. §§ 4332(2)(C)(iii); 4336e(12); *Nat'l Parks & Conservation Ass'n*, 606 F.3d at 1070 (While an applicant's goals for a project are relevant, "those private interests [need not] define the scope of the proposed project."). That is precisely what the Commission did here.

Despite admitting the Commission's purpose is to decide the public necessity for the Expansion, the Final EIS excludes factors relevant to the public need as "outside the scope of this EIS" and defers analysis of need to the Commission's decision on the Expansion. Final EIS at 1-4 – 1-5. Contrary to this position, the Commission need not first determine the public need under Section 7 in order to include factors relevant to public need in a NEPA purpose and need statement. The purpose of the EIS is to inform the Commission's Section

7 decision. *See* 42 U.S.C. § 4332(2)(B); *see also supra* IV(A)(5) (explaining how energy alternatives are important to the Commission's assessment of need and public interest). The Commission repeated this error in its Order. The Order acknowledged that "the goals set in enacting the NGA" inform alternatives, but nevertheless affirmed a purpose that reflects only GTN's goals and excludes clean energy alternatives from consideration in both the NEPA and NGA analysis. *See supra* § IV(A)(5), Order ¶¶ 24, 92-97.

Defining the purpose and need for the Expansion to exclude information relevant to public interest and need for increased gas in the region prevented the Commission's environmental review from achieving its fundamental purpose of informing the Commission's Order. *See League of Wilderness Defs.-Blue Mountains Biodiversity Project v. U.S. Forest Serv.*, 689 F.3d 1060, 1071 (9th Cir. 2012) (stating the "touchstone for our inquiry is whether [the EIS] fosters informed decision-making"); *Simmons v. U.S. Army Corps of Engineers*, 120 F.3d 664, 666 (7th Cir. 1997) (a purpose and need statement many not be defined so narrowly as to frustrate "Congressional will"). The Order did not satisfy the NGA or NEPA because it relies on an unreasonably constrained environmental analysis. *See* Order ¶ 98; *Backcountry Against Dumps v. Chu*, 215 F. Supp. 3d 966, 979 (S.D. Cal. 2017) (holding purpose and need statement unreasonably excluded alternative energy generation that did not meet the applicant's private interests because if alternative energy sources "are much better alternatives than the one presented by the applicant then that obviously has a profound effect on whether or not the proposed action is actually in the public interest.").

The purpose and need statement also unreasonably limited the Commission's analysis of alternatives. Agencies violate NEPA when the purpose and need statement is so narrowly drawn that it "necessarily and unreasonably constrains the possible range of alternatives." *Nat'l Parks & Conservation Ass'n.*, 606 F.3d at 1070; *see also* 42 U.S.C. §§ 4332(2)(C)(iii); 4336e(12). To ensure a fully informed decision, agencies should consider alternatives that meet the agencies' statutory objectives at a lower environmental cost, even if they do not meet the applicant's private goals. *See* NEPA Regulation Revisions, 87 Fed. Reg. at 23457. Commission regulations further direct that the EIS should consider "[a]ny alternative to the proposed action that would have a less severe environmental impact …." 18 C.F.R. § 380.7(b). Accordingly, the Commission should not limit the scope of the alternatives considered to only those that expand GTN's pipeline. *See Nat'l Parks & Conservation Ass'n*, 606 F.3d at 1070; *see also* EPA Draft EIS Comments at 3-4 (recommending the Commission "evaluate in detail all reasonable alternatives that could provide energy services to support public convenience and necessity," including by exploring non-gas alternatives).

Instead, the EIS should include information relevant to the Commission's statutory objectives to serve as "guardian of the public interest" and "protect consumers against exploitation at the hands of natural gas companies." *Transcontinental Gas Pipeline*, 365 U.S. at 7, 19. Alternative energy sources, produced at a lower environmental and economic cost, are highly relevant to whether additional gas infrastructure is needed or in the public interest. The Commission cannot fulfill its statutory objective without considering such alternative energy sources, and an EIS that fails to consider such alternatives defies NEPA's objective to ensure informed decision-making. *See, e.g., W. Org. of Res. Councils*, 2018 WL 1475470, at *9 (holding agency could not make a reasoned decision as to whether coal leasing would serve its statutory mandates without considering climate change impacts).

Accordingly, the Final EIS should have analyzed in detail these reasonable alternatives. Instead, and as described in more detail below, the Final EIS impermissibly refused to consider lower-emission alternatives because they did not fit the constrained purpose and need statement. *See e.g.*, Final EIS 3-1 – 3-3 (refusing to consider other alternatives that did not increase the capacity of GTN's methane gas transmission system or otherwise meet GTN's definition of the Expansion's purpose and need). By narrowing the purpose to consider only alternatives that will meet GTN's purpose of transporting gas along its pipeline, the Final EIS and the Commission's analysis of alternatives in its Order, Order ¶¶ 92-97, made approving the Expansion as defined by GTN a "foreordained formality." *Citizens Against Burlington*, 938 F.2d at 196 ("an agency may not define the objectives of its action in terms so unreasonably narrow that only one alternative from among the environmentally benign ones in the agency's power would accomplish the goals of the agency's action").

5. The Final EIS failed to consider reasonable alternatives

The Commission's Order and the Final EIS did not fully analyze reasonable alternatives to the Expansion. Instead, the Commission ignored the predictable effects of selecting the no-action alternative, rejected viable alternatives in favor of essentially identical alternatives, and failed to analyze rigorously electric compressor option.

NEPA requires more. Agencies must "study, develop, and describe technically and economically feasible alternatives." 42 U.S.C. § 4332(2)(E); *see also id*. § (2)(C)(iii). In an EIS, this analysis must compare the impacts of different action alternatives, including their direct and cumulative impacts, and the no action alternative. 40 C.F.R. § 1502.14. For proposed fossil fuel-related projects, "agencies should evaluate reasonable alternatives that may have lower [greenhouse gas] emissions, which could include technically and economically feasible clean energy alternatives." 88 Fed. Reg. at 1204. Indeed, in this case, EPA urged the Commission to consider in detail "all reasonable alternatives that could provide energy services to support public convenience and necessity," including renewable energy alternatives. EPA Draft EIS Comments 3-4. Consideration of such alternatives is consistent with FERC's NEPA regulations that direct consideration of any alternatives with less severe environmental impacts. *See* 18 C.F.R. § 380.7(b).

a. The no-action alternative will meet energy demand needs with current or future renewable energy developments

Even assuming *arguendo* the Commission correctly defined the purpose and need, *see supra* IV(C)(4), it still must thoroughly analyze a no-action alternative to comply with NEPA's informed decision-making mandate. *Bob Marshall All. v. Hodel*, 852 F.2d 1223, 1228 (9th Cir. 1988); *see also* 40 C.F.R. § 1502.14(c). The Commission wrongly dismissed the no-action alternative because "it would not meet the project's objectives." Order ¶ 97; *see also* Final EIS at 3-1, 3-7. Under the Commission's arbitrary reasoning, agencies would never need to robustly review a no-action alternative. Although the Commission acknowledged that the no action alternative "would result in fewer environmental impacts" than the Expansion, Order ¶ 97, it dismissed the no-action alternative without analyzing the public benefits of not expanding gas infrastructure in the Pacific Northwest in violation of NEPA, the APA, and the NGA. *See id*.; Final EIS at 3-2.

No action is a reasonable alternative to the Expansion that would avoid the public harms of continued gas reliance and still satisfy regional energy demands at a much lower cost to the public. As noted above, the Final EIS projected the social cost of greenhouse gas emissions from the Expansion potentially exceed 8 billion dollars. *See supra* § IV(B). As an agency obliged to consider ways to avoid environmental impacts, reduce costs from overbuilding, and protect consumers, the Commission should have seriously considered the no-action alternative, which best accomplishes all these goals.

Switching from methane gas to renewable energy sources carries many benefits that align with the Commission's public interest goals to protect the environment and consumers. *See supra* IV(A)(5). Developing renewable energy now is sustainable in the long-term; expanding consumption of methane gas is not. As the country transitions to net-zero emissions economy-wide by 2050, *See* Exec. Order 14008, the need for methane gas will decrease. Further capital investment in gas infrastructure thus carries a high risk of becoming stranded assets, significantly increasing consumer costs. *See* Hill Report 62-64. Renewable energy infrastructure does not carry this risk.

Moreover, the Commission should have acknowledged that the no-action alternative would help facilitate a clean energy future consistent with international, national, and regional climate action goals. *See* 40 C.F.R. § 1502.2(d). A predictable effect of denying the Expansion is that region energy users would turn to other energy sources to meet their energy needs. *See Mid States Coal. for Progress v. Surface Transp. Bd.*, 345 F.3d 520, 549

(8th Cir. 2003) (holding that building railroad to transport coal would increase demand for coal compared to "other potential fuel sources, such as nuclear power, solar power, or natural gas" and "will most assuredly affect the nation's long-term demand for coal"); *WildEarth Guardians*, 870 F.3d at 1235 (acknowledging "basic economic principle" that reduced supply of coal could lead to higher prices and "thus drive down coal consumption"); *High Country Conservation Advocates*, 52 F. Supp. 3d at 1198. Renewable energy is increasingly "competitive or even cheaper than conventional energy sources." WASH. REV. CODE § 19.405.010 (2019). Indeed, as energy planning expert David Hill noted, new research shows "a dramatic shift" towards electrification for space and water heating, and state laws also will lead to the reduction of methane used to generate electricity. *See* Hill Report 46, 53-57. Further, companies and governments are developing numerous renewable energy projects to replace fossil fuels in the region. *See* States' Protest, Ex. A at 9-12.

In dismissing the no-action alternative, the Commission unlawfully failed to consider the benefits to consumers and environmental advantages of using renewable energy in lieu of methane gas. The Commission's failure to consider these benefits is not surprising when the Commissions' decision fails to weigh significant climate impacts of the Expansion. *See supra* IV(B). Because the Commission did not fully analyze the Expansion's harmful climate impacts and also did not fully analyze the benefits of the no-action alternative, its dismissal of the no-action alternative is arbitrary and capricious.

b. The Commission unreasonably ignored reasonable alternatives

The Order relied on a deficient Final EIS that unreasonably limited the range of alternatives considered. *See* Order ¶¶ 92-97. The Final EIS considered just two design alternatives for GTN's pipeline: (a) using an electric compressor or (b) looping the pipeline. Substituting an electric compressor or looping the pipeline are not meaningful alternatives to the Expansion because like GTN's proposal both alternatives will result in expanded methane gas capacity and increased emissions. *See* Hill Report 54. As discussed above, the Commission's narrow focus on GTN's goals blinded it to alternatives that would better suit the public interest and the agency's statutory objectives.

The Commission overlooked other reasonable technically and economically feasible alternatives that would better achieve the Commission's policy objectives in ensuring the public convenience and necessity of a project. *See* 42 U.S.C. § 4332(2)(C)(iii); *Muckleshoot Indian Tribe v. U.S. Forest Serv.,* 177 F.3d 800, 813-14 (9th Cir. 1999) (holding the agency failed to consider an adequate range of alternatives when it did not consider any alternatives that were "more consistent with its basic policy objectives"); *Cf. Pittsburgh*, 237 F.2d at 745 n.28 ("The existence of a more desirable alternative is one of the factors which enters into a determination of whether a particular proposal would serve the public convenience and necessity"). Even where an alternative might not "offer a complete solution to the problem," the Commission still should have evaluated any reasonable alternative that "might possibly reduce the scope" of the Expansion and "thus alleviate a significant portion of the environmental harm." *Nat. Res. Def. Council, Inc. v. Morton*, 458 F.2d 827, 835 (D.C. Cir. 1972). To satisfy its NEPA obligation to consider reasonable alternatives, the Commission should have analyzed in detail alternatives that avoid the need for costly new gas infrastructure and that have fewer emissions than GTN's proposal.

(1) The Commission failed to adequately consider efficiency and electrification options to meet public need

Given the public's strong interest in reducing emissions and transitioning to renewable energy, the Commission should have considered in detail efficiency and electrification options to meet any growth in energy demand. A large portion of methane gas consumed in the region is for residential use. Hill Report 54. Demand-side management and selective electrification can reduce, or possibly eliminate shortfalls in peak day demand. *See* Lander Decl. 20; Hill Report 57-58. Efficiency and electrification options have fewer emissions and are consistent with State and Federal climate policies. *See id.*; States' Protest at 27-29.

(2) Existing capacity on other pipelines could potentially meet some or all of GTN's projected demand

The Commission also failed to consider whether existing pipeline systems could meet some or all of the demand this Expansion claims to serve at a lower environmental cost. The Final EIS unreasonably limits this analysis by insisting the Expansion must transport "150 million standard cubic feet per day between [GTN's] Kingsgate Meter Station to [GTN's] Malin Meter Station." Final EIS at 3-2. For example, there is no explanation for why pipeline capacity continuing all the way to the Malin meter station at the Oregon-California border is needed to serve demand in Idaho. *Compare id.*, *with* Application at 9. As discussed above, Intermountain has acknowledged having multiple alternative means to meet its demand. *See supra* § IV(A)(3)(a)(2). Yet the EIS ignores whether existing capacity on the Northwest Pipeline or another pipeline could serve increased need in Idaho. The EIS assumes, without evidence, that no other system could serve demand without adding infrastructure, but does not address whether capacity is available on existing pipeline systems. *See* Final EIS at 3-3 – 3-4.

(3) The EIS should have analyzed the electric compressor alternative using appropriate tools and considering replacement of both Starbuck compressor units

The Commission also failed to analyze in detail the electric compressor alternative because it relied on a flawed analysis. *See* Order ¶¶ 72 (refusing to determine significance of emissions and climate impacts); 92-97 (adopting the Final EIS emissions analysis); Final EIS at 3-4 – 3-6. The Final EIS claims that an electric compressor will result in substantially more emissions than a gas compressor based on the EPA's Avoided Emissions and Generation Tool ("AVERT"). *See id*. AVERT is intended to estimate the emissions impacts of energy efficiency and renewable energy programs. *See* ENV. PROT. AGENCY, *Avoided Emissions and Generation Tool Overview*.[24] It is based on historical data and, unless the future year scenario is used, it cannot predict emissions more than five years from the baseline year. *See id*.; ENV. PROT. AGENCY, AVERT User Manual, 91 (Oct. 2023) (describing future year scenario template for AVERT).[25] As a result, the AVERT emissions do not include the impact of any forward-looking policies, such as national or regional plans to transition to renewable electricity. *See supra* IV(C)(2). The Commission did not explain its failure to project future emissions based on national or regional clean electricity plans nor does the Final EIS or the Commission's Order weigh the emissions benefits of different alternatives. *See* Order ¶¶ 72; 92-97; Final EIS at 3-4 – 3-6.

[24] https://www.epa.gov/avert/avert-overview-0
[25] https://www.epa.gov/system/files/documents/2023-10/avert-user-manual-v4.2.pdf

The National Renewable Energy Laboratory's Cambium tool is a more appropriate tool that reflects the rapid transition in the electricity sector. Pieter Gagnon, Elaine Hale, Wesley Cole, *Long-run Marginal Emission Rates for Electricity – Workbooks for 2021 Cambrium Data*, NREL (Jan. 5, 2022).[26] Cambium is a power sector emissions tool that is explicitly forward-looking. At the very least, the Commission should have explained its decision to rely on AVERT's backward-looking model over the forward-looking Cambium tool when the States encouraged the Commission to utilize Cambium. 40 C.F.R. § 1502.23 (stating agencies shall ensure the "professional integrity, including scientific integrity," of their analyses and "shall make use of existing reliable data and resources"); States' DEIS Comments at 23-24. The Commission also ignored a key benefit of the electric compressor option, which would be to reduce the air pollution impacts of the Expansion and reduce inconsistencies with state laws. *See supra* § IV(C)(2); *infra* § IV(D).

The Commission also claimed electric compressors are cost-prohibitive. Final EIS at 3-6. But, as explained above, the Commission's failure to analyze the significance of the Expansion's climate harms and social costs renders any economic balancing arbitrary and capricious. The Commission must consider costs to GTN as well as to the public.

The Commission's analysis is further flawed because it adopted GTN's improperly segmented expansion plan, resulting in an impermissibly segmented environmental review. *See* States' Protest at 11-14; Lander Decl. at 15. The scope of environmental review must cover connected, similar, and cumulative actions, particularly where separate reviews

[26] https://data.nrel.gov/submissions/183.

"foreclose the opportunity to consider alternatives." *Delaware Riverkeeper Network v. FERC*, 753 F.3d 1304, 1315 (D.C. Cir. 2014). If GTN made its expansion intentions clear when it replaced an existing compressor at Starbuck, the Commission's NEPA review would have considered both the replacement and expansion modifications as part of Expansion costs and the viability of electric compressors for all new units. *See* 40 C.F.R. § 1501.9 (explaining that actions that are "closely related … should be discussed in the same impact statement). GTN should not be able to evade full consideration of an environmentally beneficial alternative by improperly constructing part of its Expansion before seeking Commission approval.

D. The Commission Failed to Give a Hard Look at the Expansion's Other Environmental Impacts

1. The Commission's environmental justice analysis overlooked climate harms and did not adequately assess other harms

The Commission's analysis of environmental justice violated NEPA and Executive Order 12,898's direction that federal agencies address disproportionately high and adverse human health or environmental effects of their actions on environmental justice communities. *See Vecinos*, 6 F.4th at 1326 (quoting Executive Order 12,898 § 1-101, 59 Fed. Reg. 7629 (Feb. 11, 1994)); *see also id*. at 1330-32 (holding the Commission's environmental justice analysis violated NEPA, the APA, and the NGA); Order ¶ 73 (stating the Commission follows Executive Order 12,898). The Commission's flawed analysis also undermined its public interest determination under the NGA. *See* FERC, Equity Action Plan, 8–9 (April 15, 2022) ("Natural gas infrastructure policy and processes that are consistent with environmental justice will foster greater public trust in FERC's actions and help the Commission carry out its duty to serve the public interest.").[27]

Critically, the Commission failed to assess the adverse climate impacts from the Expansion on environmental justice communities because it did not determine the significance of such harms. *See* Order ¶ 90. For the reasons stated above, *see supra* § IV(B), that determination violated the NGA, NEPA, and the APA. It also ran afoul of the Commissions' obligation to consider cumulative impacts. *350 Montana*, 50 F.4th at 1272; 40 C.F.R. §§ 1502.15, 1502.16, 1508.1(g); *see also* NEPA Regulation Revisions, 87 Fed. Reg. at 23464 (describing obligation to consider cumulative impacts under NEPA).

The Commission's environmental justice analysis also failed to include sufficient information about existing public health disparities near Starbuck Station. *See* States' DEIS Comments at 24-26. In response to the State's comments on this discussion, the Final EIS stated without support that "[i]ssues related to community health data, occupation, and diet are outside the scope of the EIS. Final EIS, Appendix E-38. But this response did not meaningfully address the States' criticism that the EIS does not contain sufficient information about existing public health disparities near the Starbuck Station or analyze the cumulative air quality and climate impacts of the Expansion in combination with the background exposure levels already affecting the surrounding community. *See* States' DEIS Comments at 24-26. As the States explained in their DEIS Comments, EPA's scoping comments highlighted that the Starbuck Station is near communities with disproportionately

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[27] https://www.ferc.gov/news-events/news/ferc-issues-equity-action-plan

high levels of particulate matter (PM 2.5) and ozone exposure and national air toxics assessment respiratory hazards. EPA Scoping Comments at 11-12. EJ Screen 2.0 confirms this. The area within five miles of the Starbuck Station rates at the 90th percentile for PM 2.5, the 91st percentile for Ozone, the 81st percentile for diesel particulate matter, and the 89th percentile for Air Toxics Cancer Risks when compared to regional percentiles. States' DEIS comments, Ex. J, EJ SCREEN REPORT. Similarly, Washington's Environmental Health Disparities Map indicates the census tract ranks high for low birth weight, "a globally recognized marker for population health." States' DEIS Comments, Ex. H, Washington Health Disparities Maps at 137-139. Scientists have linked low birth weight to air pollution. States' DEIS Comments at 25. Yet, the Final EIS does not meaningfully consider this information or consider the cumulative impact of the Expansion's increased pollution with the impacts of summer fire seasons, which can significantly increase PM 2.5 exposure near the Starbuck Station. *See* States' DEIS Comments Ex. I, Austin, Elena, ScD, ET AL., Combined burden of heath and particulate matter air quality in WA agriculture, J AGROMEDICINE (Jan. 1, 2021).

The Final EIS also arbitrarily reversed course from its conclusion in the Draft EIS that "[o]peration of the project would result in long-term impacts on air quality." Draft EIS at 4-31. In their comments on the Draft EIS, the States emphasized the tension between this conclusion and the conclusion that the Expansion would not cause disproportionately high and adverse impacts on environmental justice communities. States' DEIS Comments at 25-26. The Final EIS unlawfully reversed course without explanation to conclude that the "Project would not have a significant long-term adverse impact on air quality and would not result in a significant cumulative impact on air quality." Final EIS at 4-31, 4-60– (discussing cumulative impacts to air quality) Appendix E-38–39 (pointing to cumulative impacts analysis in response to state comments). The Commission's order adopted this conclusion. *See* Order ¶¶ 85-87. Yet the Final EIS's conclusion rests only on its analysis of cumulative impacts for the Kent Compressor Station. Final EIS at 4-60-61. The air quality discussion of cumulative impacts did not mention Starbuck Station or Athol Station, Final EIS at 4-60-61, and is thus not a rational basis for the Commission to dismiss cumulative air pollution harms to environmental justice communities around these two project sites. *See Fox Television Stations, Inc.*, 556 U.S. at 516 ("a reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by the prior policy").

The Final EIS concluded elsewhere that the incremental and cumulative emission from the Athol and Starbuck Compressor Stations will not exceed National Ambient Air Quality Standards (NAAQS). Final EIS 4-32. However, as the States noted in their Draft EIS comments, the Commission cannot rationally rely exclusively on purported compliance with the National Ambient Air Quality Standards (NAAQS) to dismiss air quality impacts while at the same time acknowledging that "NAAQS attainment alone may not assure there is no localized harm" to environmental justice populations from volatile organic compounds, hazardous air pollutants "such as the presence of non-Project related pollution sources, local health risk factors, disease prevalence, and access (or lack thereof) to adequate care." Final EIS 4-32–4-33. It also remains unclear how the Commission factored gas releases and leaks into its air quality and environmental justice analyses. *See* States' DEIS Comments 25-26.

For all these reasons, the Commission's analysis of environmental justice impacts violated NEPA and the APA.

2. The Commission failed to adequately analyze wildfire risk and climate resiliency

The Commission's analysis of wildfire risks and climate resiliency lacked rational support. Despite the States' comments about the need for a more robust discussion of climate resilience, States' DEIS Comments at 27-28, the Final EIS did not analyze the wildfire risk or climate resiliency of other alternatives, including the no-action alternative, and it does not consider the impact of the Expansion's increased methane gas emissions on the climate resiliency of the Expansion. Final EIS 4-49. This cursory analysis of wildfire risk and climate resiliency did not satisfy NEPA's mandate that agencies compare alternative impacts and make a reasoned choice between the alternatives. *See* 42 U.S.C. § 4332(2)(C)(iii); 40 C.F.R. § 1502.14.

The Commission's analysis of wildfire risks is also flawed because it relied on an irrational analysis of wildfire danger. Although the Final EIS states that the Expansion facilities would not likely be subject to significant wildfires, it then acknowledged that all three facilities have "moderate wildfire hazard potential." Final EIS 4-49. The U.S. Forest Service defines moderate fire danger as a level at which "[f]ires can start from most accidental causes" with the number of starts being "generally low." U.S. Forest Serv., *Definitions of Different Levels of Fire Danger* (attached as Exhibit A). Notably for the Expansion facilities, "[f]ires in open-cured grassland will burn briskly and spread rapidly on windy days," and are more likely to spread quickly than wood fires. *Id*. This description accords with the evidence the States provided in their Draft EIS comments showing the fire danger in the area around the Starbuck and Kent Compressor Stations. *See* States' DEIS Comments at 27-29. That evidence included a Washington State Department of Fish and Wildlife Report discussing fire danger in shrub-steppe ecosystems where the Starbuck Station is located and a report detailing hire wildfire risk around Kent Station. *Id*. The States also provided detailed evidence about the Walla Walla County Community Wildfire Protection Plan, which covers the Starbuck Compressor Station, and notes the fire danger in grassland, rangeland and sagebrush steppe habitats and explains that the area around the Starbuck Station would have slower response times when compared to other areas in the County and the response may be further limited by inadequate access roads and water supply. *Id*. The States similarly provided evidence about the wildfire risks around the Kent Compressor Station. State Comments at 28.

The Final EIS did not discuss the data provided by the States or reconcile it with its conclusion that the facilities are not likely to be subject to significant wildfires because they are in unforested areas. Final EIS 4-49. As the States explained in their Draft EIS comments, the assertion that remote, unforested areas do not burn is irrational and ignores the realities of the arid West, where wildland fire threatens the rangelands and sagebrush steppe ecosystem that surround the Starbuck and Kent Compressor Stations. *See* Application, Vol. II, Environmental Report, Appx. B at 334-45 (representative photographs of typical vegetation and habitat). Instead the Final EIS and the Commission's Order ignored the wildfire risks near the Expansion compressor stations, including risks during construction when cleared brush may be piled at the edge of the construction work area and burned. Application, Vol. II, Environmental Report, Appx. 2A, GTN's Environmental Construction

Standards (ECS) with the Spill Prevention, Control, and Countermeasure (SPCC) Plan, at 12 (p. 125 of the pdf). The Commission's analysis of wildfire risks is arbitrary and capricious and violated NEPA.

V. CONCLUSION AND RELIEF SOUGHT

For these reasons, the States respectfully request that the Commission grant this request for rehearing, withdraw the Order and the Final EIS, prepare a new Environmental Impact Statement that remedies the issues identified above, and issue an Order denying GTN's Application.

Respectfully submitted this 22nd day of November, 2023,

FOR THE STATE OF WASHINGTON:

ROBERT W. FERGUSON
Attorney General of Washington

By: */s/ Megan Sallomi*
MEGAN SALLOMI
AURORA JANKE
Assistant Attorneys General
Environmental Protection Division
800 Fifth Avenue, Suite 2000
Seattle, WA 98104-3188
Tel: (206) 389-2437
Megan.Sallomi@atg.wa.gov
Aurora.Janke@atg.wa.gov

FOR THE STATE OF OREGON:

ELLEN F. ROSENBLUM
Attorney General of Oregon

By: */s/ Paul Garrahan*
PAUL GARRAHAN
Attorney-in-Charge
STEVE NOVICK
Special Assistant Attorney General
Natural Resources Section
Oregon Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
Tel: (503) 947-4540
Paul.Garrahan@doj.state.or.us
Steve.Novick@doj.state.or.us

FOR THE STATE OF CALIFORNIA:

ROB BONTA
Attorney General of California
ABIGAIL BLODGETT
Supervising Deputy Attorney General

By: */s/ Adrianna Lobato*
ADRIANNA LOBATO
Deputy Attorney General
Environmental Section
California Department of Justice
1300 I Street
Sacramento, CA 95814
Tel: (916) 210-6384
Adrianna.Lobato@doj.ca.gov

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by electronic mail.

Dated this 22nd day of November, 2023, in Seattle, Washington,

/s/Megan Sallomi
MEGAN SALLOMI
Assistant Attorney General
Environmental Protection Division
Office of the Attorney General
800 Fifth Avenue, Suite 2000, TB-14
Seattle, WA 98104
(206) 389-2437
megan.sallomi@atg.wa.gov

EXHIBIT A

Definitions of different levels of fire dangers

Low Fire Danger – color code is green

- Fuels do not ignite readily from small firebrands, although a more intense heat source such as lightning may start many fires in duff or punky wood.
- Fires in open cured grassland may burn freely a few hours after rain, but woods fire spread slowly by creeping or smoldering, and burn in irregular fingers.
- There is little danger of spotting.

Moderate Fire Danger – color code is blue

- Fires can start from most accidental causes, but with the exception of lightning fires in some areas, the number of starts is generally low.
- Fires in open-cured grassland will burn briskly and spread rapidly on windy days. Wood fires spread slowly to moderately fast.
- The average fire is of moderate intensity, although heavy concentrations of fuel, especially draped fuel, may burn hot. Short-distance spotting may occur, but is not persistent.
- Fires are not likely to become serious, and control is relatively easy.

High Fire Danger – color code is yellow

- All fine dead fuels ignite readily and fires start easily from any cause.
- Unattended brush and campfires are likely to escape.
- Fires spread rapidly and short-distance spotting is common.
- High intensity burning may develop on slopes, or in concentrations of fine fuel.
- Fire may become serious and their control difficult unless they are hit hard and fast while small.

Very High Fire Danger – color code is orange

- Fires start easily from all causes, and immediately after ignition, spread rapidly and increase quickly in intensity.
- Spot fires are a constant danger.
- Fires burning in light fuels may quickly develop high-intensity characteristics; such as, long-distance spotting and fire whirlwinds, when they burn into heavier fuels.
- Direct attack at the head of such fires is rarely possible after they have been burning more than a few minutes.

Extreme Fire Danger – color code is red

- Fires under extreme conditions start quickly, spread furiously, and burn intensely.
- All fires are potentially serious.
- Development into high-intensity burning will usually be faster & occur from smaller fires than in the very high danger class (item 4).
- Direct attack is rarely possible, and may be dangerous, except immediately after ignition.
- Fires that develop headway in heavy slash or in conifer stands may be unmanageable while the extreme burning condition lasts.
- Under these conditions, the only effective and safe control action is on the flanks until the weather changes or the fuel supply lessens.

For more information

- **Fire Restriction Definitions**
- **Videos about fire safety and fire restrictions**
- **Eastern Area Coordination Center**
- **National Interagency Coordination Center**

EXHIBIT B

2022 California Gas Report

Prepared in Compliance with California Public Utilities Commission Decision

D.95-01-039

2022 CALIFORNIA GAS REPORT

PREPARED BY THE CALIFORNIA GAS AND ELECTRIC UTILITIES

Southern California Gas Company
Pacific Gas and Electric Company
San Diego Gas & Electric Company
Southwest Gas Corporation
City of Long Beach Energy Resources Department
Southern California Edison Company

2022 CALIFORNIA GAS REPORT

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2022 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The *2022 California Gas Report* (CGR) presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2035. This report is prepared in even-numbered years, followed by a supplemental report in odd-numbered years, in compliance with California Public Utilities Commission (CPUC or Commission) Decision (D.) 95-01-039. The projections in the CGR are for long-term planning and do not necessarily reflect the day-to-day operational plans of the utilities.

The report is organized into three sections: Executive Summary, Northern California, and Southern California. The Executive Summary provides statewide highlights and consolidated tables on supply and demand. The Northern California section provides details on the requirements and supplies of natural gas for Pacific Gas and Electric Company (PG&E), the Sacramento Municipal Utility District (SMUD), Southwest Gas Corporation (SWG), Wild Goose Storage, LLC., Central Valley Gas Storage, LLC., Gill Ranch Storage, LLC., and Lodi Gas Storage LLC. The Southern California section shows similar detail for Southern California Gas Company (SoCalGas), the City of Long Beach Municipal Oil and Gas Department, Southwest Gas Corporation, and San Diego Gas & Electric Company (SDG&E).

Each participating utility has provided a narrative explaining its assumptions and outlook for natural gas requirements and supplies, including tables showing data on natural gas availability by source, with corresponding tables showing data on natural gas requirements by customer class. Separate sets of tables are presented for average and cold year temperature conditions. Any forecast, however, is subject to considerable uncertainty. Changes in the economy, energy and environmental policies, natural resource availability, and the continually evolving restructuring of the gas and electric industries can significantly affect the reliability of these forecasts. This report should not be used by readers as a substitute for a full, detailed analysis of their own specific energy requirements.

A working committee comprised of representatives from each utility was responsible for compiling the report. The membership of this committee is listed in the Respondents Section at the end of this report.

2022 CALIFORNIA GAS REPORT

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

CALIFORNIA ENERGY MARKETS ARE EVOLVING

Serving the needs of customers and providing safe, reliable, and affordable services are top priorities among the participating investor owned utilities (IOUs). As we meet these needs, there is a growing realization that California energy markets are evolving. Though still undergoing transformation, the economic drivers, customer preferences, climate change, technological innovation, and policy will point out the road forward for our energy system.

The joint IOUs are committed to achieving our state's carbon goals and are taking steps to reduce the energy system carbon footprint, while continuing to serve the energy needs of our customers. More traditional solutions to reduce these emissions include, but are not limited to, conservation measures such as adjusting thermostats to lower baselines, where possible, and energy efficiency measures such as building and appliance improvements. Additional efforts are becoming increasingly important as well, such as efforts to diversify and decarbonize energy portfolios and sources by incorporating low-carbon and renewable fuels. Accelerating the adoption of these low-carbon and renewable energy sources will be critical to meeting carbon neutrality goals and will also be transformational for California's energy system.

Reducing reliance on traditional fuels (fossil fuels) comes with significant tradeoffs. From an economic standpoint it may be costly and is certainly not expected to be rapid or easy. Nonetheless, the push to find ways forward and to provide energy solutions to customers in a clean and affordable way is an imperative.

What is required is a concerted and sustained effort in addition to active participation across multiple sectors, alongside dialogue with all stakeholders with an interest in energy security. Clear communication between governments, industry, consumers and utility service providers is an essential focal point for successful implementation. Through open-minded dialogue, we can ensure a secure and sustainable energy future.

EXECUTIVE SUMMARY

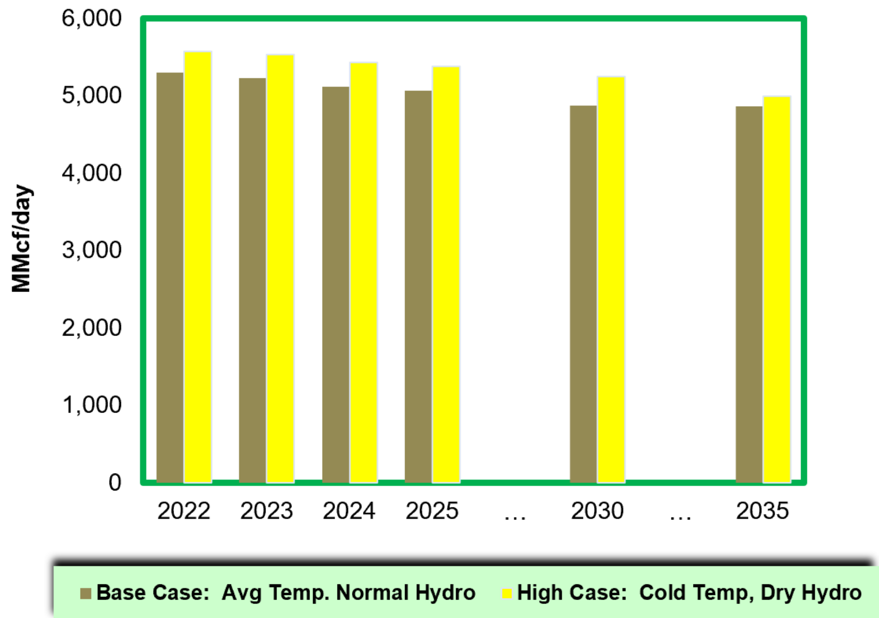
DEMAND OUTLOOK

Utility-served, statewide natural gas demand is projected to decrease at an annual average rate of 1.1 percent per year through 2035. The decline is 0.1 percent faster than what had been projected in the 2020 California Gas Report (CGR). More aggressive energy efficiency and fuel substitution have accelerated the decline in forecasted throughput for the 2022 CGR relative to the 2020 findings. In this Report, fuel substitution refers to the conversion of all or a portion of existing energy uses from one fuel type to another with the goal of reducing greenhouse gas emissions such as replacing a gas water heater with an electric water heater.

The projected decline comes from less gas demand in the major market segment areas of residential, electric generation (EG), commercial and wholesale markets. Total Statewide residential gas demand is projected to decrease at an annual average rate of 2.4 percent per year, a faster decline than the 1.7 percent annual rate of decline that had been forecasted in the 2020 Report. EG demand is projected to decrease at an annual rate of 1.1 percent per year, which is a slightly less rapid rate than the 1.5 percent annual decline that had been forecasted in 2020. The statewide commercial demand is projected to decrease at an annual average rate of 1.8 percent per year, which is slightly more accelerated than the 1.5 percent annual decline from the 2020 CGR. The aggregate statewide wholesale market segment is expected to decline at an annual average rate of 0.25 percent per year. The segments where growth in demand is expected are the natural gas vehicle (NGV) sector and the industrial market segments. The industrial market segment and the NGV sectors are expected to grow at an annual average rate of 0.16 percent and 2.3 percent per year over the forecast period.

There are several drivers of these declines across many of the key energy sectors. Aggressive energy efficiency programs and fuel substitution are expected to dampen gas demand in these sectors. Statewide efforts to minimize greenhouse gas (GHG) emissions are depressing EG demand through aggressive programs that pursue demand side reductions and the acquisition of preferred power generation resources that produce few or no carbon emissions. Nevertheless, for the foreseeable future, gas-fired generation and gas storage will continue to be important technologies that support long-term electric demand growth and growing integration of intermittent renewable resource generation.

FIGURE 1 – CALIFORNIA GAS DEMAND OUTLOOK: 2022-2035



The graph above summarizes statewide gas demand under the Average Demand case (base case) and the Cold Weather, Dry Hydroelectric Generation[1] case (high case). The base case refers to the expected gas demand for an average temperature year and normal hydroelectric generation (hydro) year, and the high case refers to expected gas demand for a cold temperature year and dry hydro conditions. Under the base case, gas demand for the entire state is projected to average 5,298 million cubic feet of gas per day (MMcf/d) in 2022 decreasing to 4,857 MMcf/d by 2035, a decline of 0.67 percent per year.

Compared to the Average Year forecast, the Northern California high demand scenario is 3.3 percent higher in year 2022 while the Southern California demand is 3.0 percent higher for the same year.

[1] Hydroelectric generation refers to generation within the Western Electricity Coordinating Council (WECC).

FOCUS ON ENERGY EFFICIENCY AND ENVIRONMENTAL QUALITY

California utilities continue to focus on conservation and energy efficiency. The IOUs are committed to helping their customers make the best possible energy decisions and helping customers identify and implement ways to benefit environmentally and financially from energy efficiency investments. An important role of the energy efficiency programs includes services, administered by the respective utilities, to help customers evaluate their energy efficiency options and adopt recommended solutions, as well as equipment-retrofit improvements, such as rebates for new hot water heaters and space heaters.

Gas demand for electric power generation is expected to be dampened by statewide GHG reduction goals and electric energy efficiency programs and additional renewable power generation. Both demand forecasts assume that renewable power will meet the CPUC 2021 Integrated Resource Plan Preferred System Plan (IRP PSP).

Renewable power capacity additions are driven, in part, by Senate Bill (SB) 100. Passed in 2018, SB 100 increased and accelerated the Renewables Portfolio Standard (RPS) targets and established the policy goal that zero carbon energy resources supply 100 percent of electric retail sales to end-use customers by the year 2045. One major milestone will occur by 2030, when renewable power generation will generate at least 60 percent of retail electric sales. The currently approved IRP PSP helps the state move towards attainment of this goal.

Additional California legislation and policy direction[2] provides directives and incentives to increase energy efficiency. Some of these efforts require access to building performance data, encouraging pay-for-performance incentive-based programs, and the use of energy management technology for use in homes and businesses. Moreover, legislation requires energy utilities to develop a plan to educate residential customers and small and medium business customers about the incentive programs. The programs and targets must meet three requirements: (1) they must be cost-effective; (2) they must be feasible; and (3) they should not adversely impact the environment. In recent years, California has increasingly focused on the potential for fuel substitution to address GHG emission reduction goals. The Commission has developed a

[2] For more information, see https://www.cpuc.ca.gov/energyefficiency/.

baseline for analyzing and evaluating energy efficiency and fuel substitution using a code baseline, industry standard practice and existing conditions. So far, the Commission standard requires that the fuel substitution measure must both save energy and not harm the environment as measured by GHG emissions.

EXECUTIVE SUMMARY

CALIFORNIA'S LONG-TERM CLIMATE GOALS AND THE ENERGY TRANSITION: FUTURE GAS SYSTEM IMPACTS

California is facing the ambitious goal of economy-wide carbon neutrality by 2045 or sooner and has adopted a suite of policies that begin to move the State towards this goal. Many of these policies are discussed more specifically elsewhere in this Report, but there are still many unknowns about the exact timing and path of the energy transition. The current policy landscape does suggest that there will be significant changes to the way Californians use energy. California natural gas utilities are actively participating in, studying and monitoring this evolution.

While much uncertainty remains about the exact path California will take, the gas utilities recognize it is probable that two segments of natural gas customers in particular may potentially face substantial change – natural gas-fired electric generation (EG) and core (mainly residential and commercial buildings), as discussed above. Today, California relies on gas-fired EG, hydroelectric generation, and growing battery resources to balance its electric grid – a role that will likely persist through the energy transition. This role will evolve, however, as fuel-based electric generation is displaced by increasing amounts of solar and wind to meet energy decarbonization goals. While this is likely to result in less natural gas being used by the EG segment, gas fired EG is forecasted to be an important resource for providing electricity when intermittent renewables or variable hydroelectric generation are not available. This means that peak EG load could persist or grow while usage pattern will become more volatile and less predictable. This could have a greater influence over peak natural gas system design conditions and, accordingly, costs.

At the same time, decarbonization goals will accelerate energy efficiency and support fuel substitution for natural gas end-uses in the core building segment. This is likely to result in declining core gas use over time. The core segment currently contributes the majority of the gas utilities' revenue requirements. These issues combined, among other trends and factors, create the impetus for an evolved approach to natural gas and clean fuels in California – from perspectives of system design, financial, and rate reform. These issues are highlighted in this Report and the subject of the Long-term Gas Reliability and Planning Proceeding (R.20-01-007) currently in Track 2 at the CPUC.

One element of the energy transition and attaining the State's decarbonization goals is building electrification also known as fuel substitution. The gas utilities' forecasts have incorporated these evolving forecasts, including collaborating with the CEC developed fuel substitution scenarios. The state is in the early stages of the energy transition. Forecasts around the timing and degree of these changes are highly uncertain. These forecasts will improve over time as trends are observed in the real world and as policy and market drivers mature. The gas utilities will be actively monitoring these trends and expect that each update of the biannual California Gas Report will further refine these factors and their impacts on resultant gas demand forecasts.

It is important to note that the California Gas Report is relied upon for system planning purposes to help benchmark investment and operating policies that impact natural gas system capacity and reliability. The gas utilities recognize the need to evolve with the government-mandated energy transition. The utilities also recognize the necessity of maintaining flexibility during the energy transition to ensure California gas customers have safe, clean, reliable, and affordable sources of energy.

Since electric utility system operators must balance electrical demand with generation sources on a real-time basis, most system operators rely on "dispatchable" resources that can respond quickly to changes in demand. One challenge with renewable resources is that while they provide energy, the amounts are not always predictable and are not always immediately dispatchable.

The increase in future renewable generation in the state will reduce the total amount of natural gas usage. It is also expected that the increasing and intermittency of renewable generation will add to the daily and hourly load forecast variance on the gas-fired EG fleet. In the long-term, balancing electric supply and demand may come through the higher expected integration of energy storage devices (e.g., batteries, fuel cells, and hydroelectric pumped storage).

Due to the expansion of intermittent renewable resources, there may be an increased need for rapid response, gas-fired generators to follow electric net load fluctuations. Since gas-fired generation is the marginal resource in most hours, the amount of gas consumed for integrating more renewables will fluctuate hourly. The gas system will therefore need to be both robust and flexible to handle such fluctuations and continue to support electric reliability.

The expected growth in electrification poses considerable uncertainty on when, where, and how large the impacts will be on gas demand. In the building sector, electrification could decrease gas use. Recently, some California local jurisdictions have forbidden the use of gas in new building construction. Moreover, there are some indications that jurisdictions may actively pursue appliance substitution away from natural gas and to the electric alternative(s). The expected growth in electrification of vehicles and buildings would result in increasing electric load that could create a need for additional use of gas-fired generators.

Further adding to gas demand variance is the impact of natural gas burner-tip prices. Burner-tip gas prices represent what gas utility customers pay at their premises. For EG, relative geographic burner-tip prices impact generation dispatch economics. If prices in one portion of the state are higher or lower than another portion, gas demand can vary accordingly.

GAS PRICE FORECAST

MARKET CONDITIONS

The natural gas industry has experienced multiple changes over the past two decades. Gas supply rapidly grew on the back of the shale gas revolution. More recently, gas supply growth has come from the rise of associated gas production from tight oil supply growth. Additionally, Liquefied Natural Gas (LNG) export demand has grown rapidly. Since the end of 2021, the European Union (EU) and United Kingdom (UK) imported record-high LNG volumes because of low natural gas inventories and interrupted gas pipeline supplies. As a result, the North American gas market has seen gas prices fluctuate. To exemplify this price variation, the U.S. EIA[3] reported the national benchmark price at Henry Hub was about $3/Million British thermal units (MMBtu) in early June 2021. One year later, the gas price was about $8.50/MMBtu.

Natural gas prices have risen, relative to the 2020 outlook, mainly because of five factors. First, the North American natural gas inventories have fallen below the five-year average. Second, there has been steady demand in U.S. LNG exports due to European natural gas shortages, which have been exacerbated by the war in Ukraine. Europe has become the main destination for U.S. LNG exports and accounted for 74 percent of total U.S. LNG exports during the first 4 months of 2022. Third, the current U.S. Administration is restricting licensing and drilling for traditional fuels including natural gas. Fourth, high demand for natural gas being driven by the growing needs of the electric power sector in the U.S. as a whole. Lastly, natural gas production investment has lagged behind the rapid growth of gas demand over the past year.

For the 2022 CGR, the gas price outlook[4] reflects market conditions in early 2022. The 2022 near term gas price average at the California city-gates[5] is a little above $5.00/MMBtu. During the mid-2020s, gas prices are projected to decline to approximately $4.00/MMBtu.

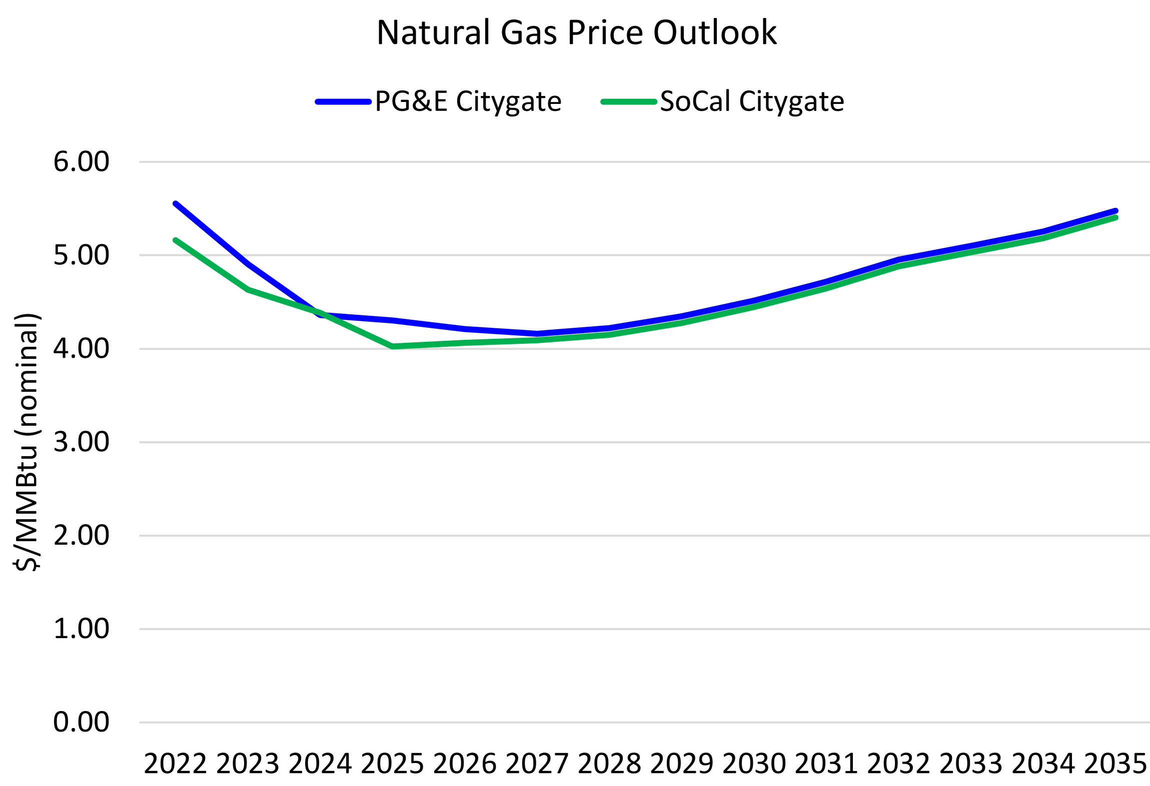
[3] U.S. Energy Information Administration https://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm.
[4] Nominal dollars.
[5] The two Citygate price hubs are the Southern California Gas Company Citygate (SoCal Citygate) and the Pacific Gas and Electric Citygate (PG&E Citygate).

Industry experts forecast that gas prices will increase about $1.50/MMBtu thereafter to average approximately $5.50/MMBtu by year 2035.

DEVELOPMENT OF THE GAS PRICE FORECAST

The 2022 CGR gas price forecast was developed using a combination of market prices and fundamental long -term forecasts. For the 2022 through 2027 period, the gas prices represent a blend of contract futures prices from the Chicago Mercantile Exchange and S&P Global[6] basis differentials to Henry Hub. For 2030 and beyond, S&P Global fundamental price forecasts were used. The forecasts for 2028 and 2029 reflect a blending of futures prices and fundamental prices.

FIGURE 2 – FORECASTED NATURAL GAS PRICES



[6] S&P Global Commodity Insights North American Gas Regional Short-Term Forecast, March 22, 2022.

It is important to recognize that natural gas price forecasts are inherently uncertain. The price forecast used in the Report were developed in early 2022. The prices seen in much of the first half of 2022 have been materially higher than the prices in the forecast. Additionally, gas prices have seen significant volatility.

PG&E, SoCalGas, and the respondents of the 2022 CGR, separately and collectively, do not warrant the accuracy of the gas price projections. PG&E, SoCalGas, or the respondents of the 2022 CGR shall not be liable or responsible for the use of or reliance on this natural gas price forecast.

GAS SUPPLY

California's existing gas supply portfolio is regionally diverse and provides long -term supply availability. Gas production that California has access to includes California (onshore and offshore), Southwestern U.S. (the Permian, Anadarko, and San Juan basins), the Rocky Mountains, and Canada.

California natural gas utilities and customers gain access to this diverse supply portfolio using an extensive pipeline system. Interstate pipelines serving California include Ruby Pipeline LLC, El Paso Natural Gas Company, Kern River Transmission Company, Mojave Pipeline Company, Gas Transmission Northwest LLC (GTN), Transwestern Pipeline Company, Tuscarora Pipeline, and the Baja Norte/North Baja Pipeline. The map on the following page shows the locations of these supply sources and the natural gas pipelines serving California.

FIGURE 3 – WESTERN NORTH AMERICAN NATURAL GAS PIPELINES

1. West Coast Pipeline
2. Woodfibre LNG Terminal
3. Terasen Sumas Gas Pipeline
4. TransCanada Pipeline
5. Alliance Pipeline
6. Northern Border Pipeline
7. Gas Transmission Northwest (GTN Pipeline
8. Northwest Pipeline
9. Jordan Cove LNG (Proposed)
10. Pacific Connector (Proposed)
11. Tuscarora Gas Transmission
12. Paiute Pipeline
13. Ruby Pipeline
14. Questar Pipeline
15. Rockies Express Pipeline
16. Southern Star Pipeline
17. TransColorado Pipeline
18. Kern River Pipeline
19. Pacific Gas and Electric Company
20. Southern California Gas Company
21. San Diego Gas and Electric Company
22. North Baja Pipeline
23. El Paso Natural Gas
24. TransWestern Pipeline
25. Rosarito Pipeline
26. Trasnportadora de Gas Natural (TGN)
27. Costa Azul LNG

California benefits from substantial gas storage capacity in dedicated gas storage facilities across the state. These gas storage facilities supplement pipeline gas supply during high demand periods and also provide supply reliability. Additionally, storage allows gas customers to take advantage of low prices and store gas for use in periods with higher prices. Various regulations and standards[7] have been implemented to ensure safe and reliable operations of California gas storage facilities. The table below gives the current status of gas storage capacity in California.

Table 1: California Natural Gas Storage Capacities Recorded Year 2021				
	Inventory (Bcf)	Injection (MMcf/d)	Withdrawal (MMcf/d)	Cite
Northern California				
Independent Storage Providers				1
Lodi Gas Storage	31	552	750	
Wild Goose Storage	75	525	950	
Gill Ranch	15	165	162	
Central Valley	11	300	300	
Pacific Gas & Electric Company-Utility Storage***	35	315	1,144	2
Northern California Total	167	1,857	3,306	
Southern California				
Southern California Gas Company-Utility Storage	137	790	2,660	3
California Total	375	3,432	7,995	

Citations
1) Capacities derived from information provided by Independent Storage Providers
2) ***Firm maximum inventory level
3) Per the current active Triennial Cost Allocation Proceeding, D 20-02-045

[7] See Geologic Energy Management Division's Underground Natural Gas Storage for more details on regulations and standards at: https://www.conservation.ca.gov/calgem/Pages/UndergroundGasStorage.aspx.

In addition to traditional sources of gas supply, multiple Renewable Natural Gas (RNG) interconnection projects in California have come online in recent years. As further detailed in this CGR, gas utilities see broad potential for RNG in California and are taking significant steps to make RNG interconnection easier and more transparent. As policies evolve and new programs are created, such as California's recently approved Renewable Gas Standard, we expect RNG to play a growing role in serving customers' energy needs beyond the transportation sector. Currently, incentive programs such as California's Low Carbon Fuel Standards (LCFS) and the federal Renewable Fuel Standard (RFS) are successfully supporting the use of RNG in the transportation sector.

As California continues towards achieving a decarbonized energy system, hydrogen (H_2) will become an important fuel source in achieving the State's emissions goals. There is growing potential for generating renewable H_2[8] and storing and delivering it using existing gas utility infrastructure to help meet California's dynamic energy needs. Hydrogen pathways can provide exceptional and important value, such as long-duration, high capacity and high energy storage capabilities relative to other clean energy storage technologies.

LIQUEFIED NATURAL GAS

In years past, the U.S. imported LNG to supplement North American supplies. Since the mid-2010s, LNG imports have primary been used to serve peak winter load. However, U.S. imports of LNG have been declining since 2008. Since this time, the development of low-cost domestic shale gas supplies largely eliminated the need for LNG imports. Since 2016, the U.S. has been exporting LNG.

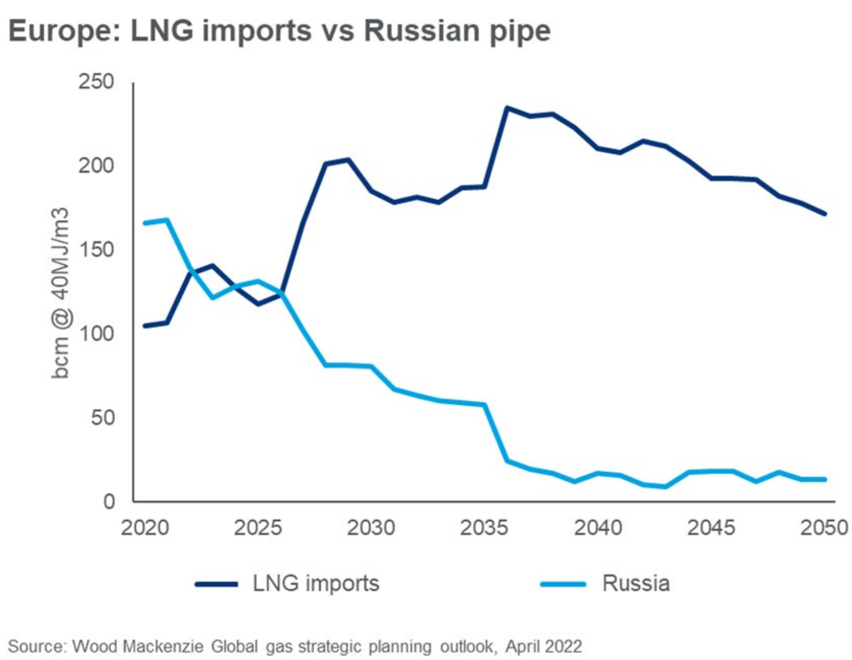
LNG exports are expected to continue growing. Current economic conditions and the sanctions imposed on Russia in response to its invasion of Ukraine have exacerbated natural gas shortages, primarily in Europe. The outlook suggests that LNG will continue to expand and grow because world needs are expanding.

[8] Renewable hydrogen is hydrogen produced by renewable electricity, hydrogen derived from biomethane, or hydrogen derived from biomass using a thermal conversion process.

LNG is expected to help meet European heating load needs as well as its gas fired EG demand. Published studies have found that although the average CO_2 emissions have declined over the last decade, marginal emissions have not decreased, but rather increased slightly due primarily to countries' reliance on coal to satisfy marginal electricity use.[9] Flowing LNG supplies to Europe may mitigate the environmental impact of the forecasted energy shortage in Europe. The chart below illustrates the outlook that industry experts are projecting to sustain LNG demand growth in the European countries including the UK and Turkey for the next twelve years, with demand subsiding somewhat after 2034.

Worldwide LNG demand is expected to almost double from current levels by the year 2040. According to industry experts, the U.S. is expected to become the largest LNG exporter in 2022, leap-frogging Australia and Qatar. Industry surveys of global LNG developers have indicated plans to accelerate the expansion of operations to meet the growth in overseas demand over the long-term**.**

Figure 4 - LNG Outlook



[9] "Why are Marginal CO_2 Emissions Not Decreasing for Electricity? Estimates and Implications for Climate Policy," by Stephen Hallard, Matthew Kotchen, Erin Mansur and Andrew Yates. Presented at the 2022 American Economic Association annual meetings.

EXECUTIVE SUMMARY

In the next few years, LNG export facilities will begin operations in Western Canada and Western Mexico. In the US, exports are expected to increase as global demand for LNG grows. The following maps illustrate (1) Existing U.S. LNG export terminals; (2) U.S. export terminals approved but not yet built; and (3) U.S. LNG export terminals proposed and being evaluated whose application status is in the process of being reviewed.

Figure 5

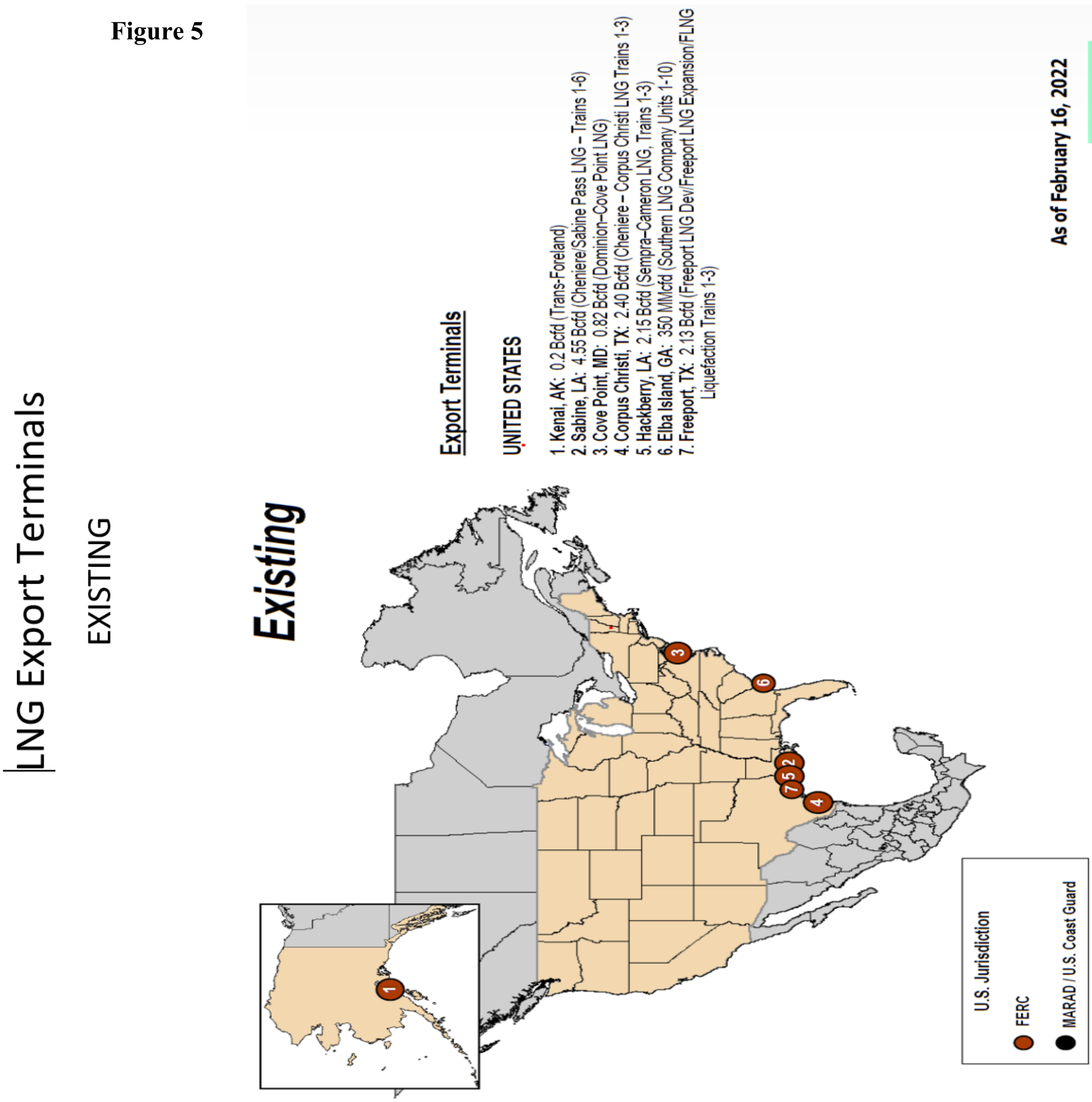
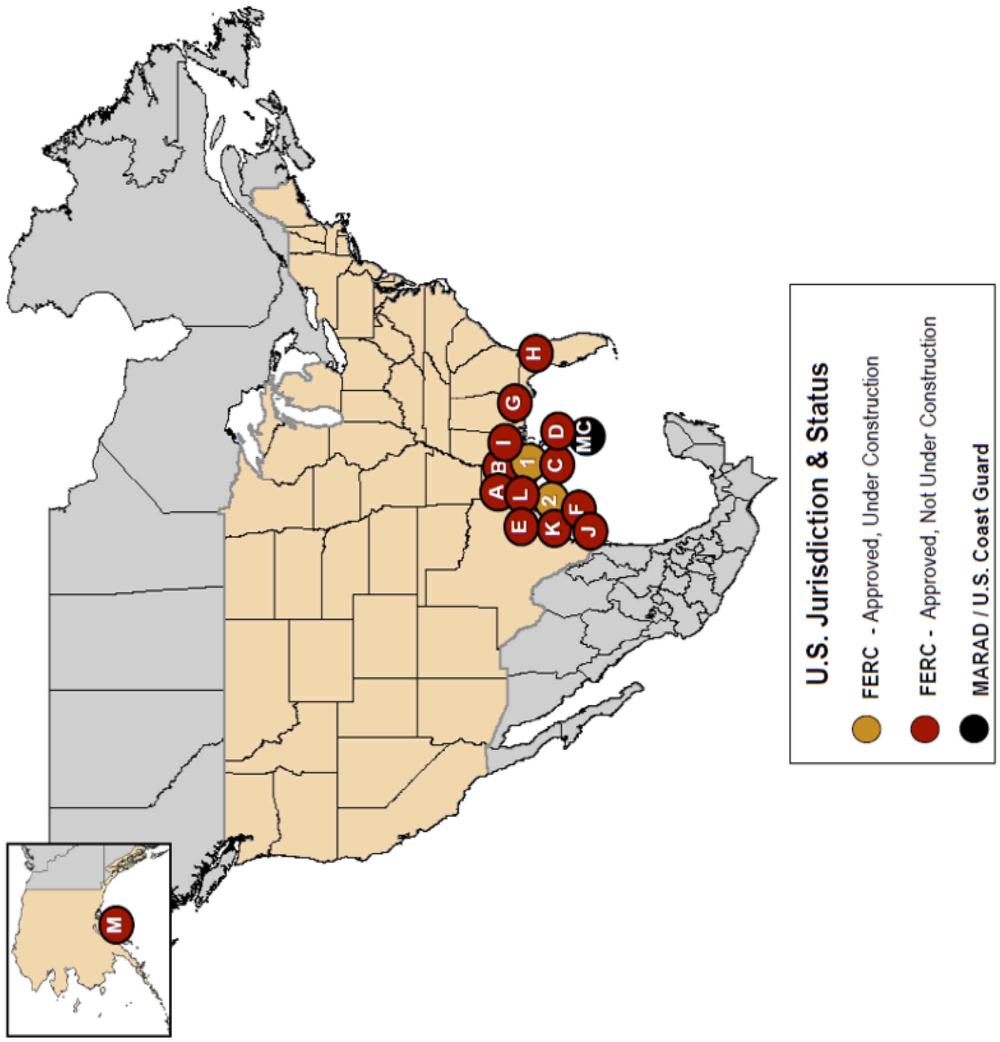

LNG Export Terminals
EXISTING
Existing
Export Terminals
UNITED STATES
1. Kenai, AK: 0.2 Bcfd (Trans-Foreland)
2. Sabine, LA: 4.55 Bcfd (Cheniere/Sabine Pass LNG – Trains 1-6)
3. Cove Point, MD: 0.82 Bcfd (Dominion–Cove Point LNG)
4. Corpus Christi, TX: 2.40 Bcfd (Cheniere – Corpus Christi LNG Trains 1-3)
5. Hackberry, LA: 2.15 Bcfd (Sempra–Cameron LNG, Trains 1-3)
6. Elba Island, GA: 350 MMcfd (Southern LNG Company Units 1-10)
7. Freeport, TX: 2.13 Bcfd (Freeport LNG Dev/Freeport LNG Expansion/FLNG Liquefaction Trains 1-3)
As of February 16, 2022
U.S. Jurisdiction
FERC
MARAD / U.S. Coast Guard

Figure 6

LNG Export Terminals Approved

(In Process: Not Yet Completed)



Export Terminals

UNITED STATES

FERC – APPROVED, UNDER CONSTRUCTION
1. Cameron Parish, LA: 1.41 Bcfd (Venture Global Calcasieu Pass) (CP15-550)
2. Sabine Pass, TX: 2.26 Bcfd (ExxonMobil – Golden Pass) (CP14-517, CP20-459)

FERC – APPROVED, NOT UNDER CONSTRUCTION
A. Lake Charles, LA: 2.2 Bcfd (Lake Charles LNG) (CP14-120)
B. Lake Charles, LA: 1.186 Bcfd (Magnolia LNG) (CP14-347)
C. Hackberry, LA: 1.41 Bcfd (Sempra - Cameron LNG Trains 4 & 5) (CP15-560)
D. Calcasieu Parish, LA: 4.0 Bcfd (Driftwood LNG) (CP17-117)
E. Port Arthur, TX: 1.86 Bcfd (Port Arthur LNG Trains 1 & 2) (CP17-20)
F. Freeport, TX: 0.72 Bcfd (Freeport LNG Dev Train 4) (CP17-470)
G. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Liquefaction) (CP15-521)
H. Jacksonville, FL: 0.132 Bcf/d (Eagle LNG Partners) (CP17-41)
I. Plaquemines Parish, LA: 3.40 Bcfd (Venture Global Plaquemines) (CP17-66)
J. Brownsville, TX: 0.55 Bcfd (Texas LNG Brownsville) (CP16-116)
K. Brownsville, TX: 3.6 Bcfd (Rio Grande LNG – NextDecade) (CP16-454)
L. Corpus Christi, TX: 1.86 Bcfd (Cheniere Corpus Christi Stage III) (CP18-512)
M. Nikiski, AK: 2.63 Bcfd (Alaska Gasline) (CP17-178)

MARAD/USCG – APPROVED, NOT UNDER CONSTRUCTION
MC. Gulf of Mexico: 1.8 Bcfd (Delfin LNG)

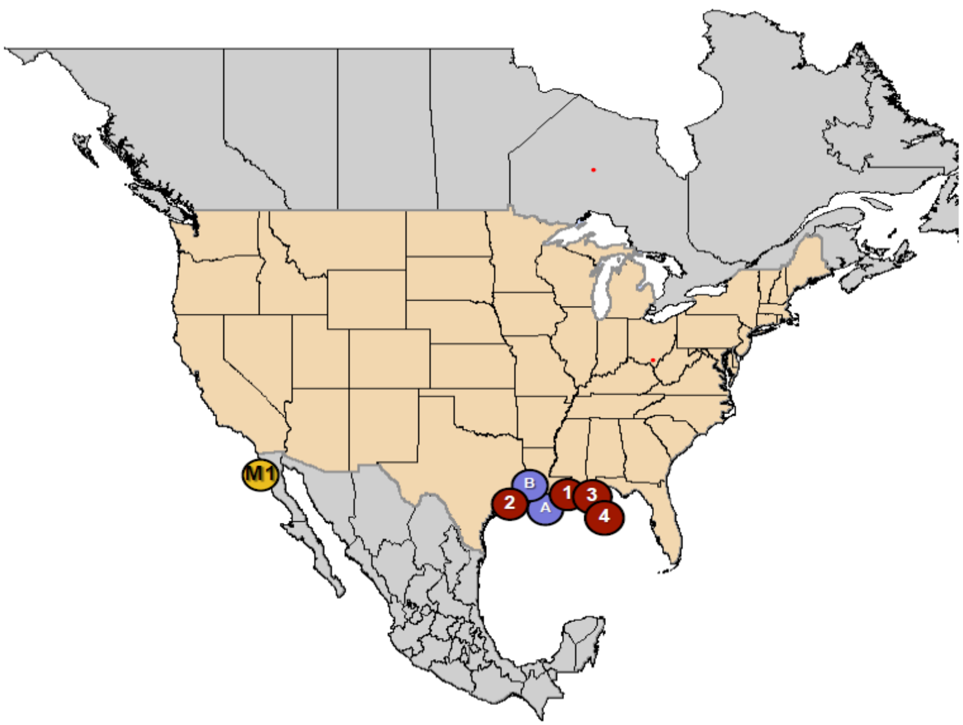
CANADA - LNG IMPORT AND PROPOSED EXPORT FACILITIES
https://www.nrcan.gc.ca/energy/natural-gas/5683

As of February 16, 2022

Figure 7

LNG Export Terminals

PROPOSED & Under Evaluation



UNITED STATES

PROPOSED TO FERC
Pending Applications:
1. Cameron Parish, LA: 1.18 Bcfd (Commonwealth, LNG) (CP19-502)
2. Port Arthur, TX: 1.86 Bcfd (Sempra - Port Arthur LNG Trains 3 & 4) (CP20-55)
3. Cameron Parish, LA: 1.45 Bcfd (Venture Global CP2 Blocks 1-9) (CP22-21)
4. Cameron Parish, LA: .057 Bcfd (Venture Global Calcasieu Pass) (CP22-25)

Projects in Pre-filing:
A. LaFourche Parish, LA: 0.65 Bcfd (Port Fourchon LNG) (PF17-9)
B. Plaquemines Parish, LA: 2.76 Bcfd (Delta LNG - Venture Global) (PF19-4)

CANADA
For Canadian LNG Import and Proposed Export Facilities:

https://www.nrcan.gc.ca/energy/natural-gas/5683

MEXICO (Projects in advanced planning/development stages)
M1. Baja California, MX: 0.4 Bcfd (Sempra – Energía Costa Azul Phase 1)

As of February 16, 2022

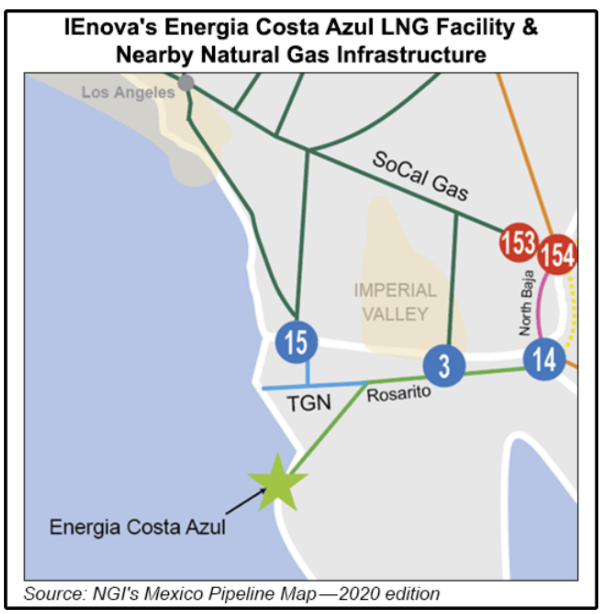
EXECUTIVE SUMMARY

Along the western North American coast, there are two LNG facilities. These include the LNG export terminal in Kenai Alaska owned and operated by Foreland and the LNG facility in Baja California/Mexico owned by Energia Costa Azul, a Sempra-owned subsidiary.

The Kenai plant in Nikiski, Alaska was once the only LNG export terminal in the U. S. but has not exported LNG since Fall 2015. In winter 2020, the FERC voted to approve Trans-Foreland's project to make modifications and reactivate portions of the plant. The project will bring the plant out of "warm idle status" and would enable the transfer of gas to an adjacent refinery.

Energia Costa Azul is a liquified natural gas joint venture between Sempra LNG and IEnova. It is the first and only LNG export project in Mexico. The project connects gas supplies from Texas and the northern U.S. directly to markets in Mexico and countries across the Pacific Basin.

Figure 8 LNG Infrastructure Map in Baja California and Mexico



More locally, in January 2022, under a grant agreement, Sysco Riverside developed a publicly accessible liquefied natural gas station to fuel their expanding fleet of natural gas-powered goods movement vehicles in Riverside, California. The new station established natural gas fueling infrastructure to support its fleet and others operating along one of the busiest stretches of highway in the nation. At the time of application, Sysco operated 35 trucks. This initial fleet is expected to grow to 125 liquefied natural gas trucks during the project life, thus creating a strong need for infrastructure to fuel its vehicles.

Sysco' s contractor, Fullmer Construction, was responsible for the construction of the liquefied natural gas fueling station. Sysco' s objective in constructing this station is to provide the additional necessary infrastructure needed to make alternative fuels like natural gas a commercially available and preferable fueling option. Natural gas contains less carbon than any other traditional fuel, and thus produces lower carbon dioxide and greenhouse gas emissions per year. In fact, natural gas vehicles produce up to 20-30 percent fewer greenhouse gas emissions than comparable diesel vehicles. Natural gas is also typically less expensive than diesel, costing less per unit of energy.

STATEWIDE CONSOLIDATED SUMMARY TABLES

The consolidated summary tables on the following pages show the statewide aggregations of projected gas supplies and gas requirements (demand) from 2022-2035 for Average Temperature and Normal Hydro years (base case) in addition to the Cold Temperature and Dry Hydro (high case).

Gas sales and transportation volumes are consolidated under the general category of system requirements. Details of gas transportation for individual utilities are given in the tabular data for Northern California and Southern California. The wholesale category includes the City of Long Beach Energy Resources Department, SDG&E, Southwest Gas (SWG), City of Vernon, Alpine Natural Gas, Island Energy, West Coast Gas, Inc., and the municipalities of Coalinga and Palo Alto.

Some columns may not sum precisely because of modeling accuracy and rounding differences and do not imply curtailments.

TABLE 2 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2022-2026

	2022	2023	2024	2025	2026
California's Supply Sources					
Utility					
California Sources	117	117	117	117	117
Out-of-State	4,428	4,408	4,310	4,257	4,252
Utility Total	4,545	4,525	4,427	4,374	4,369
Non-Utility Served Load (1)	1,024	1,010	990	995	999
Statewide Supply Sources Total	**5,570**	**5,535**	**5,416**	**5,368**	**5,369**
California's Requirements					
Utility					
Residential	1,101	1,077	1,054	1,031	1,008
Commercial	463	462	455	449	442
Natural Gas Vehicles	52	53	54	56	57
Industrial	906	920	933	938	937
Electric Generation (2)	1,377	1,327	1,252	1,219	1,245
Enhanced Oil Recovery Steaming	27	27	27	27	27
Wholesale/International+Exchange	283	283	282	282	281
Company Use and Unaccounted-for	65	65	64	63	62
Utility Total	4,273	4,215	4,122	4,064	4,059
Non-Utility					
Enhanced Oil Recovery Steaming	640	637	638	634	631
EOR Cogeneration/Industrial	54	52	49	52	45
Electric Generation	330	321	303	309	323
Non-Utility Served Load (1)	1,024	1,010	990	995	999
Statewide Requirements Total (3)	**5,298**	**5,225**	**5,111**	**5,058**	**5,059**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(2) Includes utility generation, wholesale generation, and cogeneration.
(3) The difference between California supply sources and California requirements is PG&E's forecast of off system deliveries.

TABLE 3 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2027-2035

	2027	2028	2029	2030	2035
California's Supply Sources					
Utility					
California Sources	117	117	117	117	117
Out-of-State	3,909	3,844	3,802	3,731	3,594
Utility Total	4,026	3,961	3,919	3,848	3,711
Non-Utility Served Load (1)	995	979	1,006	1,025	1,147
Statewide Supply Sources Total	**5,021**	**4,940**	**4,926**	**4,874**	**4,857**
California's Requirements					
Utility					
Residential	988	964	944	921	804
Commercial	435	425	417	408	366
Natural Gas Vehicles	59	60	62	63	70
Industrial	937	936	935	933	925
Electric Generation (2)	1,240	1,210	1,198	1,162	1,193
Enhanced Oil Recovery Steaming	26	25	24	24	20
Wholesale/International+Exchange	281	280	279	278	274
Company Use and Unaccounted-for	61	61	60	59	58
Utility Total	4,026	3,961	3,919	3,848	3,711
Non-Utility					
Enhanced Oil Recovery Steaming	628	627	672	712	878
EOR Cogeneration/Industrial	40	39	19	14	0
Electric Generation	327	313	316	299	269
Non-Utility Served Load (1)	995	979	1,006	1,025	1,147
Statewide Requirements Total (3)	**5,021**	**4,940**	**4,926**	**4,874**	**4,857**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant
Source: CEC staff-provided forecast results from their own model simulations.
(2) Includes utility generation, wholesale generation, and cogeneration.
(3) The difference between California supply sources and California requirements is PG&E's forecast of off system deliveries.

TABLE 4 – STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2022-2035

Utility	2022	2023	2024	2025	2026
Northern California					
California Sources (1)	56	56	56	56	56
Out-of-State	2,049	2,054	2,043	2,038	2,063
Northern California Total	2,105	2,110	2,099	2,094	2,119
Southern California					
California Sources (2)	61	61	61	61	61
Out-of-State	2,379	2,354	2,266	2,219	2,190
Southern California Total	2,440	2,415	2,327	2,280	2,251
Utility Total	4,545	4,525	4,427	4,374	4,369
Non-Utility Served Load (3)	1,024	1,010	990	995	999
Statewide Supply Sources Total	**5,570**	**5,535**	**5,416**	**5,368**	**5,369**

Utility	2027	2028	2029	2030	2035
Northern California					
California Sources (1)	56	56	56	56	56
Out-of-State	1,749	1,738	1,722	1,698	1,681
Northern California Total	1,805	1,794	1,778	1,754	1,737
Southern California					
California Sources (2)	61	61	61	61	61
Out-of-State	2,160	2,106	2,080	2,034	1,912
Southern California Total	2,221	2,167	2,141	2,095	1,973
Utility Total	4,026	3,961	3,919	3,848	3,711
Non-Utility Served Load (3)	995	979	1,006	1,025	1,147
Statewide Supply Sources Total	**5,021**	**4,940**	**4,926**	**4,874**	**4,857**

Notes:
(1) Includes utility purchases and exchange/transport gas.
(2) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.
(3) Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

TABLE 5 – STATEWIDE ANNUAL GAS REQUIREMENTS (1)
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2022-2026

	2022	2023	2024	2025	2026
Utility					
Northern California					
Residential	491	473	460	445	432
Commercial - Core	208	214	213	210	208
Natural Gas Vehicles - Core	7	7	8	8	8
Natural Gas Vehicles - Noncore	4	4	4	4	4
Industrial - Noncore	462	477	492	497	498
Wholesale	9	9	9	9	9
SMUD Electric Generation	96	96	96	96	96
Electric Generation (2)	484	448	441	442	481
Exchange (California)	38	38	38	38	38
Company Use and Unaccounted-for	34	34	34	34	34
Northern California Total (3)	1,833	1,800	1,794	1,784	1,809
Southern California					
Residential	610	604	594	585	575
Commercial - Core	206	200	194	190	185
Commercial - Noncore	48	49	49	49	49
Natural Gas Vehicles - Core	41	42	43	44	45
Industrial - Core	54	54	53	52	51
Industrial - Noncore	389	390	389	389	388
Wholesale (excluding EG)	236	236	235	235	234
SDG&E, Vernon & Ecogas EG	127	117	104	97	97
Electric Generation (EG) (4)	670	667	612	584	571
Enhanced Oil Recovery Steaming	27	27	27	27	27
Company Use and Unaccounted-for	31	30	29	29	28
Southern California Total	2,440	2,415	2,327	2,280	2,251
Utility Total	4,273	4,215	4,122	4,064	4,059
Non-Utility Served Load (5)	1,024	1,010	990	995	999
Statewide Gas Requirements Total (6)	**5,298**	**5,225**	**5,111**	**5,058**	**5,059**

Notes:
(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern California Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.

TABLE 6 – STATEWIDE ANNUAL GAS REQUIREMENTS [1]
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2027-2035

	2027	2028	2029	2030	2035
Utility					
Northern California					
Residential	423	412	402	391	338
Commercial - Core	205	200	195	189	163
Natural Gas Vehicles - Core	8	8	9	9	10
Natural Gas Vehicles - Noncore	4	5	5	5	5
Industrial - Noncore	499	499	499	498	496
Wholesale	9	9	9	9	9
SMUD Electric Generation	96	96	96	96	96
Electric Generation [2]	489	493	493	486	549
Exchange (California)	38	38	38	38	38
Company Use and Unaccounted-for	33	33	33	33	33
Northern California Total [3]	1,805	1,794	1,778	1,754	1,737
Southern California					
Residential	565	552	542	530	466
Commercial - Core	181	177	174	170	155
Commercial - Noncore	49	49	49	49	48
Natural Gas Vehicles - Core	46	47	48	50	54
Industrial - Core	50	49	48	47	44
Industrial - Noncore	388	388	388	387	385
Wholesale (excluding EG)	234	233	232	231	228
SDG&E, Vernon & Ecogas EG	96	92	92	88	87
Electric Generation (EG) [4]	558	529	516	493	461
Enhanced Oil Recovery Steaming	26	25	24	24	20
Company Use and Unaccounted-for	28	27	27	26	25
Southern California Total	2,221	2,167	2,141	2,095	1,973
Utility Total	4,026	3,961	3,919	3,848	3,711
Non-Utility Served Load [5]	995	979	1,006	1,025	1,147
Statewide Gas Requirements Total [6]	**5,021**	**4,940**	**4,926**	**4,874**	**4,857**

Notes:
(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern California Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.

TABLE 7 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
COLD TEMPERATURE [4] AND DRY HYDRO YEAR
(MMcf/d)
2022-2026

	2022	2023	2024	2025	2026
California's Supply Sources					
Utility					
California Sources	117	117	117	117	117
Out-of-State	4,561	4,581	4,487	4,438	4,443
Utility Total	4,678	4,698	4,604	4,555	4,560
Non-Utility Served Load [1]	1,159	1,144	1,130	1,129	1,152
Statewide Supply Sources Total	**5,837**	**5,842**	**5,734**	**5,684**	**5,713**
California's Requirements					
Utility					
Residential	1,186	1,165	1,142	1,118	1,094
Commercial	488	481	473	467	460
Natural Gas Vehicles	52	53	54	55	57
Industrial	911	924	935	940	939
Electric Generation [2]	1,378	1,374	1,307	1,278	1,315
Enhanced Oil Recovery Steaming	27	27	27	27	27
Wholesale/International+Exchange	297	297	295	295	295
Company Use and Unaccounted-for	67	67	66	65	64
Utility Total	4,406	4,388	4,299	4,245	4,250
Non-Utility					
Enhanced Oil Recovery Steaming	639	635	638	629	628
EOR Cogeneration/Industrial	48	50	50	50	41
Electric Generation	472	460	442	450	484
Non-Utility Served Load [1]	1,159	1,144	1,130	1,129	1,152
Statewide Requirements Total [3]	**5,565**	**5,532**	**5,429**	**5,374**	**5,403**

Notes:

(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.

(2) Includes utility generation, wholesale generation, and cogeneration.

(3) The difference between California supply sources and California requirements is PG&E's forecast of off-system deliveries.

(4) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

TABLE 8 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
COLD TEMPERATURE (4) AND DRY HYDRO YEAR
(MMcf/d)
2027-2035

	2027	2028	2029	2030	2035
California's Supply Sources					
Utility					
California Sources	117	117	117	117	117
Out-of-State	4,116	4,043	4,000	3,925	3,792
Utility Total	4,233	4,160	4,117	4,042	3,909
Non-Utility Served Load (1)	1,143	1,147	1,209	1,204	1,077
Statewide Supply Sources Total	**5,376**	**5,307**	**5,326**	**5,246**	**4,987**
California's Requirements					
Utility					
Residential	1,073	1,049	1,028	1,004	884
Commercial	453	443	434	425	382
Natural Gas Vehicles	58	60	61	63	70
Industrial	939	938	937	935	927
Electric Generation (2)	1,326	1,290	1,277	1,239	1,279
Enhanced Oil Recovery Steaming	26	25	24	24	20
Wholesale/International+Exchange	294	293	293	292	288
Company Use and Unaccounted-for	64	63	62	62	60
Utility Total	4,233	4,160	4,117	4,042	3,909
Non-Utility					
Enhanced Oil Recovery Steaming	625	627	719	756	906
EOR Cogeneration/Industrial	37	37	21	17	6
Electric Generation	481	483	470	431	165
Non-Utility Served Load (1)	1,143	1,147	1,209	1,204	1,077
Statewide Requirements Total (3)	**5,376**	**5,307**	**5,326**	**5,246**	**4,987**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR
Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(2) Includes utility generation, wholesale generation, and cogeneration.
(3) The difference between California supply sources and California requirements is PG&E's forecast of
off-system deliveries.
(4) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

TABLE 9 – STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
COLD TEMPERATURE [4] and DRY HYDRO YEAR
(MMcf/d)
2022-2026

Utility	**2022**	**2023**	**2024**	**2025**	**2026**
Northern California					
California Sources [1]	56	56	56	56	56
Out-of-State	2,109	2,149	2,144	2,141	2,177
Northern California Total	2,165	2,205	2,200	2,197	2,233
Southern California					
California Sources [2]	61	61	61	61	61
Out-of-State	2,452	2,432	2,343	2,298	2,267
Southern California Total	2,513	2,493	2,404	2,359	2,328
Utility Total	4,678	4,698	4,604	4,555	4,560
Non-Utility Served Load [3]	1,159	1,144	1,130	1,129	1,152
Statewide Supply Sources Total	**5,837**	**5,842**	**5,734**	**5,684**	**5,713**

Utility	**2027**	**2028**	**2029**	**2030**	**2035**
Northern California					
California Sources [1]	56	56	56	56	56
Out-of-State	1,876	1,863	1,844	1,821	1,800
Northern California Total	1,932	1,919	1,900	1,877	1,856
Southern California					
California Sources [2]	61	61	61	61	61
Out-of-State	2,239	2,180	2,156	2,104	1,992
Southern California Total	2,300	2,241	2,217	2,165	2,053
Utility Total	4,233	4,160	4,117	4,042	3,909
Non-Utility Served Load [3]	1,143	1,147	1,209	1,204	1,077
Statewide Supply Sources Total	**5,376**	**5,307**	**5,326**	**5,246**	**4,987**

Notes:
(1) Includes utility purchases and exchange/transport gas.
(2) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.
(3) Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant. Source: CEC staff-provided forecast results from their own model simulations.
(4) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

TABLE 10 – STATEWIDE ANNUAL GAS REQUIREMENTS (1)
COLD TEMPERATURE (7) and DRY HYDRO YEAR
(MMcf/d)
2022-2026

	2022	2023	2024	2025	2026
Utility					
Northern California					
Residential	527	512	500	485	472
Commercial - Core	224	224	222	220	217
Natural Gas Vehicles - Core	7	7	8	8	8
Natural Gas Vehicles - Noncore	3	4	4	4	4
Industrial - Noncore	467	480	493	499	499
Wholesale	10	10	10	10	10
SMUD Electric Generation	96	96	96	96	96
Electric Generation (2)	485	490	490	493	543
Exchange (California)	38	38	38	38	38
Company Use and Unaccounted-for	36	35	35	35	35
Northern California Total (3)	1,893	1,895	1,895	1,887	1,923
Southern California					
Residential	660	653	642	632	622
Commercial - Core	214	208	202	197	193
Commercial - Noncore	49	49	49	50	50
Natural Gas Vehicles - Core	41	42	43	44	45
Industrial - Core	55	55	53	52	51
Industrial - Noncore	389	390	389	389	388
Wholesale (excluding EG)	249	249	248	248	247
SDG&E, Vernon & Ecogas EG	127	118	105	98	98
Electric Generation (EG) (4)	670	671	616	591	578
Enhanced Oil Recovery Steaming	27	27	27	27	27
Company Use and Unaccounted-for	32	31	30	30	29
Southern California Total	2,513	2,493	2,404	2,359	2,328
Utility Total	4,406	4,388	4,299	4,245	4,250
Non-Utility Served Load (5)	1,159	1,144	1,130	1,129	1,152
Statewide Gas Requirements Total (6)	**5,565**	**5,532**	**5,429**	**5,374**	**5,403**

(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern California Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.
(7) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

TABLE 11 – STATEWIDE ANNUAL GAS REQUIREMENTS (1)
COLD TEMPERATURE (7) AND DRY HYDRO YEAR
(MMcf/d)
2025-2035

	2027	2028	2029	2030	2035
Utility					
Northern California					
Residential	463	452	441	431	378
Commercial - Core	214	209	204	199	172
Natural Gas Vehicles - Core	8	8	9	9	10
Natural Gas Vehicles - Noncore	4	4	4	4	5
Industrial - Noncore	500	500	500	500	497
Wholesale	10	9	9	9	9
SMUD Electric Generation	96	96	96	96	96
Electric Generation (2)	565	567	564	557	616
Exchange (California)	38	38	38	38	38
Company Use and Unaccounted-for	35	35	34	34	35
Northern California Total (3)	1,932	1,919	1,900	1,877	1,856
Southern California					
Residential	610	597	586	573	506
Commercial - Core	189	184	181	177	161
Commercial - Noncore	50	49	49	49	49
Natural Gas Vehicles - Core	46	47	48	50	54
Industrial - Core	51	50	49	48	45
Industrial - Noncore	388	388	388	387	385
Wholesale (excluding EG)	247	246	245	244	241
SDG&E, Vernon & Ecogas EG	98	93	94	89	92
Electric Generation (EG) (4)	567	534	524	496	474
Enhanced Oil Recovery Steaming	26	25	24	24	20
Company Use and Unaccounted-for	29	28	28	27	26
Southern California Total	2,300	2,241	2,217	2,165	2,053
Utility Total	4,233	4,160	4,117	4,042	3,909
Non-Utility Served Load (5)	1,143	1,147	1,209	1,204	1,077
Statewide Gas Requirements Total (6)	**5,376**	**5,307**	**5,326**	**5,246**	**4,987**

(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern California Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.
(7) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

EXECUTIVE SUMMARY

STATEWIDE RECORDED SOURCES AND DISPOSITION

The Statewide Sources and Disposition Summary complements the existing 5-year recorded data tables included in the tabular data sections for each utility.

The information displayed in the following tables shows the composition of supplies from both out-of-state sources, as well as California sources. The data are based on the utilities' accounting records and available gas nomination and preliminary gas transaction information obtained daily from customers or their appointed agents and representatives. It should be noted that data on daily gas nominations are frequently subject to reconciliation adjustments. In addition, some of the data are based on allocations and assignments that, by necessity, rely on estimated information. These tables have been updated to reflect the most current information.

Some columns may not sum exactly because of factored allocation and rounding differences and do not imply curtailments.

TABLE 12– RECORDED 2017 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	100	443	127	54	208	0	(27)	0	905
Noncore Commercial/Industrial	(4)	97	80	39	158	52	24	0	446
EG (3)	(4)	156	128	63	252	82	39	0	715
EOR	(0)	9	7	3	14	5	2	0	39
Wholesale/Resale/International (4)	(7)	88	72	35	142	46	22	0	398
Total	84	792	414	195	773	185	60	0	2,503
Pacific Gas and Electric Company (5)									
Core	0	18	65	319	(1)	0	0	179	580
Noncore Industrial/Wholesale/EG (6)	29	208	99	840	34	0	12	420	1,642
Total	29	226	164	1,159	33	0	12	599	2,222
Other Northern California									
Core (7)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	698	28	0	0	698	44	0	0	1,468
TOTAL SUPPLIER	833	1,046	578	1,354	1,504	229	84	599	6,227
San Diego Gas & Electric Company									
Core	14	61	17	7	28	0	(4)	0	124
Noncore Commercial/Industrial	(2)	38	31	15	62	20	10	0	175
Total	12	99	49	23	90	20	6	0	299
Southwest Gas Corporation									
Core	22	0	0	0	0	0	12	0	34
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	12	0	36

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, and SDG&E, as shown.
(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(9) California production is preliminary.

TABLE 13 – RECORDED 2018 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	158	439	103	37	173	0	(2)	0	908
Noncore Commercial/Industrial	(17)	99	35	57	207	61	7	0	448
EG (3)	(23)	136	48	78	283	83	10	0	615
EOR	(1)	8	3	5	18	5	1	0	38
Wholesale/Resale/International (4)	(13)	74	26	42	153	45	6	0	333
Total	104	756	214	218	834	194	22	0	2,342
Pacific Gas and Electric Company (5)									
Core	0	3	55	303	(4)	0	0	165	522
Noncore Industrial/Wholesale/EG (6)	28	212	221	966	16	0	0	355	1,798
Total	28	215	276	1,269	12	0	0	520	2,320
Other Northern California									
Core (7)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	401	49	0	0	686	42	0	0	1,178
TOTAL SUPPLIER	555	1,020	490	1,487	1,532	236	34	520	5,874
San Diego Gas & Electric Company									
Core	22	61	14	5	24	0	(0)	0	127
Noncore Commercial/Industrial	(4)	25	9	14	52	15	2	0	112
Total	18	86	23	19	76	15	2	0	239
Southwest Gas Corporation									
Core	22	0	0	0	0	0	12	0	34
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	12	0	36

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, and SDG&E, as shown.
(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(9) California production is preliminary.

TABLE 14 – RECORDED 2019 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company (2)									
Core + UAF (3)	162	476	111	30	223	0	10	0	1,012
Wholesale/Resale/International (5)	(65)	368	47	118	674	213	19	0	1,374
Total	97	844	158	148	897	213	29	0	2,386
Pacific Gas and Electric Company (4)									
Core	0	0	58	286	(2)	0	0	172	514
Noncore Industrial/Wholesale/EG (5)	24	380	223	896	9	0	0	481	2,014
Total	24	380	281	1,182	7	0	0	653	2,528
Other Northern California									
Core (6)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (7, 8)									
Direct Sales/Bypass	388	29	0	0	664	71	0	0	1,152
TOTAL SUPPLIER	531	1,253	439	1,330	1,568	284	41	653	6,100
San Diego Gas & Electric Company									
Core	21	61	14	4	28	0	1	0	129
Noncore Commercial/Industrial	(4)	22	3	7	40	12	1	0	81
Total	17	83	17	11	68	12	2	0	210
Southwest Gas Corporation									
Core	25	0	0	0	0	0	0	0	25
Noncore Commercial/Industrial	3	0	0	0	0	0	0	0	3
Total	28	0	0	0	0	0	0	0	28

Notes:
(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) SoCalGas core volumes are accrued volumes.
(3) Includes NGV volumes
(4) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(5) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(6) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(8) California production is preliminary.

TABLE 15 – RECORDED 2020 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company (2)									
Core + UAF (3)	132	406	151	9	245	0	0	0	943
Noncore	(45)	532	64	169	613	139	38	0	1,510
Total	87	938	215	178	858	139	38	0	2,453
Pacific Gas and Electric Company (4)									
Core	0	8	33	379	(7)	0	0	165	578
Noncore Industrial/Wholesale/EG (5)	26	294	214	936	9	0	0	411	1,890
Total	26	302	247	1,315	2	0	0	576	2,468
Other Northern California									
Core (6)	14	0	0	0	0	0	0	0	14
Non-Utilities Served Load (7,8)									
Direct Sales/Bypass	334	37	0	0	621	60	0	0	1,052
TOTAL SUPPLIER	461	1,277	462	1,493	1,481	199	38	576	5,987
San Diego Gas & Electric Company									
Core	18	56	21	1	34	0	0	0	131
Noncore Commercial/Industrial	(4)	49	6	15	56	13	3	0	138
Total	14	105	27	16	90	13	3	0	269
Southwest Gas Corporation - Southern California Division									
Core	25.4	0	0	0	0	0	0	0	25
Noncore Commercial/Industrial	2.0	0	0	0	0	0	0	0	2
Total	27.4	0	0	0	0	0	0	0	27

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) SoCalGas core volumes are accrued volumes.
(3) Includes NGV volumes
(4) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(5) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(6) Includes Southwest Gas Coproration and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(8) California production is preliminary.

TABLE 16 – RECORDED 2021 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	PG&E/GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	132	406	151	9	245	0	0	0	943
Noncore Commercial/Industrial/EG/EOR/Wholesale/Resale/International	-46	432	206	217	583	85	3	0	1,480
Total	86	838	357	226	828	85	3	0	2,423
Pacific Gas and Electric Company (5)									
Core	0	29	0	410	-2	0	0	159	597
Noncore Industrial/Wholesale/EG (6)	23	356	186	942	6	0	0	32	1,840
Total	23	386	186	1,352	4	0	0	485	2,437
Other Northern California									
Core (7)	13	0	0	0	0	0	0	0	13
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	295	49	0	0	631	42	0	0	1,017
TOTAL SUPPLIER	417	1,273	543	1,578	1,463	127	3	485	5,890

Notes:
(1) Includes storage activities, volumes delivered on North Baja and Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, & SDG&E, as shown.

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
San Diego Gas & Electric Company									
Core	19	59	22	1	36	0	0	0	137
Noncore Commercial/Industrial	-4	37	18	19	50	7	0	0	128
Total	15	91	40	20	86	7	0	0	265
SouthWest Gas									
Core	24	0	0	0	0	0	13.00	0.000	37.00
Noncore Commercial/Industrial	2	0	0	0	0	0	0.17	0.000	2.17
Total	26	0	0	0	0	0	13.17	0.000	39.17

Notes

(1) **Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.**
(2) **SoCalGas core volumes are accrued volumes.**
(3) **Includes NGV volumes.**
(4) **Kern River supplies include net volume flowing over Kern River High Desert interconnect.**
(5) Includes UEG, Cogen, industrial load and deliveries to PG&E's wholesale customers.
(6) Includes Great Basin Gas Transmission Company and Tuscarora Deliveries in the Lake Tahoe and Susanville areas.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(8) California production is preliminary.

STATEWIDE RECORDED HIGHEST SENDOUT

The tables below summarize the highest sendout days by the state in the summer and winter periods from the last 5 years. Daily sendout from SoCalGas, PG&E, and from customers not served by these utilities were used to construct the following tables.

Table 17: Estimated California Highest *SUMMER* Sendout (MMcf/d)

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2017	08/28/2017	2,602	3,484	6,086	1,416	7,502
2018	07/24/2018	2,925	2,926	5,851	1,410	7,261
2019	09/04/2019	2,606	2,907	5,7513	1,310	6,823
2020	08/18/2020	2,792	3,143	5,935	1,270	7,205
2021	09/09/2021	2,909	2,827	5,736	1,080	6,816

Table 18: Estimated California Highest *WINTER* Sendout (MMcf/d)

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2017	12/21/2017	3,665	3,456	7,121	1,259	8,380
2018	02/20/2018	3,527	3,621	7,148	1,378	8,526
2019	02/05/2019	3,751	3,913	7,664	1,097	8,761
2020	02/04/2020	3,230	3,881	7,111	1,261	8,372
2021	12/14/2021	3,470	3,837	7,307	935	8,242

Notes:
(1) PG&E Pipe Ranger.
(2) SoCalGas Envoy.
(3) Source: Provided by the CEC. Data are from DOGGR, Monthly Oil and Gas Production and Injection Report. Nonutility Demand equals Kern-Mojave and California monthly average total flows less PG&E and SoCal Gas peak day supply from Kern-Mojave and California in-state production.

(4) PG&E and SoCalGas sendout(s) are reported for the day on which the *combined* two utilities' total sendout is maximum for the respective seasons each year. For each calendar year, Winter months are Jan, Feb, Mar, Nov and Dec; while Summer months are Apr, May, Jun, Jul, Aug, Sep and Oct.

2022 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA

INTRODUCTION

PG&E owns and operates an integrated natural gas transmission, underground storage, and distribution system across most of Northern and Central California. As of December 31, 2021, PG&E's natural gas system consists of approximately 42,000 miles of distribution pipelines, over 6,400 miles of backbone and local transmission pipelines, and three fully owned underground storage facilities and a 25 percent interest in Gill Ranch Storage. PG&E uses its backbone transmission system, composed primarily of Lines 300A, 300B, 400, and 401, to transport gas from its interconnection with interstate pipelines, other local distribution companies, and California gas fields to PG&E's local transmission and distribution systems.

PG&E provides natural gas procurement, transportation, and storage services to approximately 4.3 million residential customers and over 200,000 commercial and industrial customers. PG&E also provides gas transportation and storage services to a variety of gas-fired Electric Generation (EG) plants in its service area and serves multiple Natural Gas Vehicle (NGV) fleets, including utility owned facilities, with its publicly-accessible fueling stations throughout California. Other wholesale distribution systems, which receive gas transportation service from PG&E, serve a small portion of the gas customers in the region. PG&E's customers are located in 37 counties from southeast of Bakersfield to north of Redding, with high concentrations in the San Francisco Bay Area and the Sacramento and San Joaquin valleys. In addition, some customers, including other regulated utilities, also utilize the PG&E system to meet their gas needs in Southern California.

The Northern California section of this report includes PG&E's gas demand forecast and discussions on gas supply, pipeline capacity, storage, and related policies, as well as the natural gas regulatory environment, including legislative developments and regulatory proceedings. Finally, the report includes PG&E's forecast of supply and demand for an Abnormal Peak Day (APD) and demand for a 1-in-10 Peak Day during the winter and summer. What follows is a summary of key takeaways from the Northern California sections of this report.

PG&E Forecasts a Gradual Decline in Future Gas Demand: PG&E's average year demand is forecasted to decline at an annual average rate of 0.5 percent between 2022 and 2035. The decline in forecasted gas demand is in response to the state's decarbonization policies and reflects reduced demand due to energy efficiency, building electrification resulting from fuel switching from natural gas appliances to electric, and climate change.

The Forecasted Demand is Subject to Significant Uncertainties: Forecast uncertainties are significant including the impacts from Northern and Southern California gas price differentials, impact of climate change on forecasted gas and electric load and hydroelectric generation, planned electric generation buildout, and the level of building electrification.

PG&E is Taking Actions to Evolve the Natural Gas System to be an Affordable Energy Delivery Platform Consistent with Decarbonization Goals. PG&E's work is guided by the following four pillars:

1. Reduce the carbon footprint of the gas system by greening the gas supply, leveraging electrification, facility conversion from dirtier fuel sources, efficiency, and methane abatement.

2. Decrease costs by limiting system expansion, strategically reducing capital and operational expenses, strategically pruning the gas system, and focusing on targeted and zonal electrification.

3. Identify alternative revenue sources through opportunities to 1) convert dirtier fuel sources to cleaner natural gas through investment in compressed natural gas, 2) switch facilities (including backup generation) from dirtier fuel sources, and 3) invest in the rail and marine sectors.

4. Leverage innovative financial mechanisms such as changes to depreciation, rate design, and external funding to help close the gap between costs and revenues.

Policy and Regulatory Solutions and a Managed Transition Plan Are Needed to Keep Customers' Bills Affordable. PG&E is committed to working with regulators and other stakeholders to support statewide GHG reduction policies and develop options to minimize customer bill impacts. PG&E is doing this by safely reducing costs and maximizing utilization of existing infrastructure. In order to successfully implement the State's environmental goals, issues such as obligation to serve, treatment of capital versus expense dollars, and non-traditional funding need to be addressed and resolved.

Regulatory bodies and investor-owned utilities (IOU) should work together to ensure that Californians continue to have access to clean, reliable, and affordable energy. In support of these important goals, PG&E is actively participating in the Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning (Gas System Planning OIR) (R.20-01-007), which addresses crucial topics that will impact the future of the California gas system.

PG&E is accelerating its work on the use of Renewable Natural Gas (RNG) to contribute towards access to clean, reliable, and affordable energy. The current investment and incentives for Renewable Natural Gas (RNG) principally favor the transportation sector resulting in little RNG available to comply with the recently enacted Renewable Gas Standard (RGS). If this is to change, California will have to balance the funding mechanisms between the transportation sector and the RGS so that RNG project developers have opportunities to supply RNG towards the RGS or the transportation sector.

GAS DEMAND

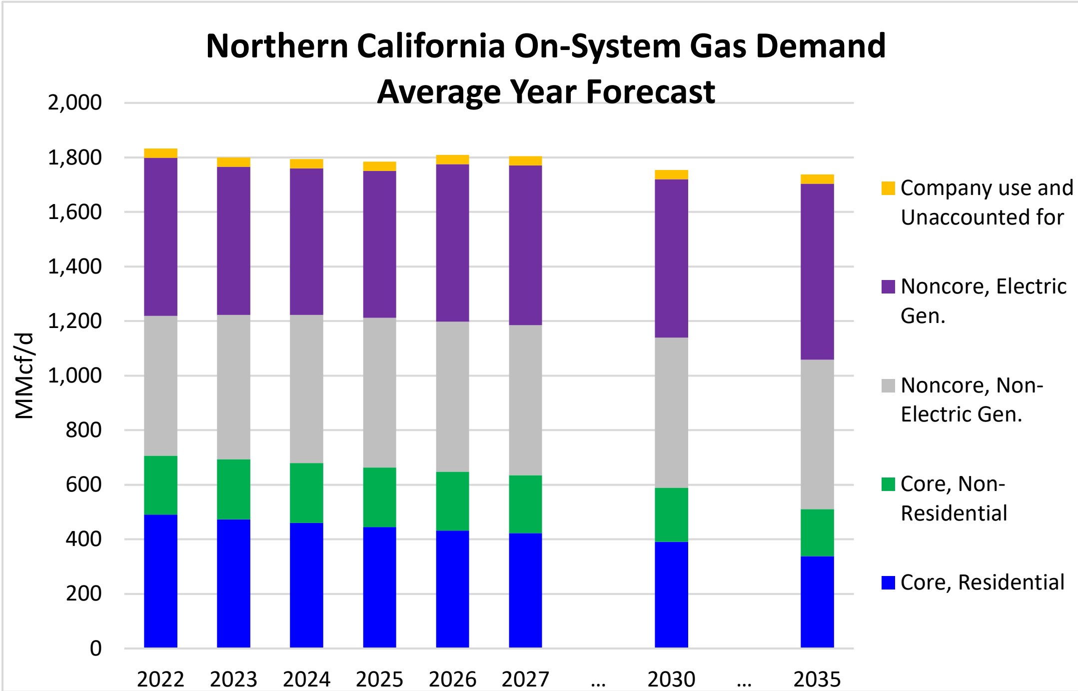
OVERVIEW

PG&E's 2022 CGR Average Year (also known as Average Temperature and Normal Hydro Year) demand forecast projects total on-system demand to decline at an annual average rate of 0.5 percent between 2022 and 2035. The core sectors are forecasted to decline at an average annual rate of 2.5 percent. The noncore sectors increase at a rate of 0.6 percent annually, driven in part by an increase in throughput for electric generation.

This projected decline in total demand could result in gas system operating and maintenance costs allocated over lower usage, causing customer gas rates to increase. Consequently, PG&E and statewide utility stakeholders will need to continue their work to mitigate customer rate increases. In future, additional gas throughput could come from the substitution of higher carbon intensive fuels, such as high sulfur marine shipping fuels, to help allocate transmission costs over a larger customer base.

This chapter includes PG&E's gas demand forecast and begins with a description of the forecast method, including a discussion of important assumptions. After the methodology discussion, the report presents information on the average demand forecast by customer sector. To provide more information about gas throughput under stressed conditions, the Cold Temperature and Dry Hydro Year forecast presents demand under cold temperature and dry hydroelectric conditions. This is followed by a discussion of gas demand policies, trends, and impacts. The chapter concludes with a presentation of abnormal peak day demand.

FIGURE 9



Changes in the major components of on-system gas demand are illustrated in Figure 9 above. Core demand declines, driven by increasing energy efficiency, increasing building electrification, and a warming climate. Noncore, non-EG demand is forecasted to remain largely flat over the forecast horizon, as potential demand growth is partly limited by energy efficiency and increasing gas prices. The Noncore EG demand forecast increases from 2022 to 2035.

The EG demand forecast is largely a function of electric energy demand, the future CAISO generation portfolio, transmission constraints, and gas prices. PG&E's forecast incorporates the higher levels of renewable generation and electric storage from the 2021 California Public Utilities Commission Integrated Resource Plan[10] and reflects higher burner-tip gas prices for Northern California electric generators relative to Southern California. The forecast for gas demand by electric generators[11] and co-generators in Northern California[12] increases at 0.9

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[10] https://www.cpuc.ca.gov/irp/.

[11] This gas demand forecast excludes gas delivered by non-utility pipelines to electric generators and cogenerators in PG&E's service area, such as deliveries by the Kern/Mojave pipelines to the La Paloma and Sunrise plants in Central California.

[12] Northern California electric generation gas demand consists of the generation fleet north of Path 26.

percent per year from 2022 through 2035[13]. The increase is driven in part by Northern California electric reliability needs due to transmission constraints in some hours.

FORECAST METHOD AND ASSUMPTIONS

PG&E's gas demand forecasts for the residential, commercial, and industrial sectors are developed using econometric models as the foundation. These models are then modified to incorporate assumptions around future policy formation and technology adoption. Forecasts for NGVs and wholesale customers are developed based on market information and historical trends over the past five years. To address the impact of COVID, PG&E developed a simplified approach. The first order COVID impacts are assumed to occur between March 2020 and ramping down after the introduction of vaccines to mid-2023, after which COVID effects are considered to be subsumed into economic and population variables. This general profile is consistent with estimates and discussion from our economic forecasting data source, Moody's. This dummy variable[14] approach models the increases in residential load and the decreases in commercial load which are then ramped down to zero in mid-2023. Effects beyond that time period are limited to those explicitly produced by economic and population variables or reflected in the historical time series apart from a simple dummy variable. Such a simplified approach is necessitated by the very limited amount of historical data from the COVID time period as well as the idiosyncratic nature of the COVID response over location and time. The simplified approach could introduce uncertainty on the duration and scale of impacts from COVID.

Forecasts of gas demand by power plants are developed by modeling the electricity market in the Western Electricity Coordinating Council (WECC) using PLEXOS software. PLEXOS is a production cost modeling tool that estimates the consumption of all fuels used for power generation on an economic basis. The tool determines the least cost dispatch of generating resources to meet a given power demand.

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[13] EG demand forecast uses common modeling assumptions developed jointly by the IOUs. Since the forecast is dependent on several factors including gas price differential between northern and southern California, future resource additions and retirements, and hydro-electric generation, actual EG demand in future may vary from the forecast.

[14] A dummy variable is a variable that takes on the values 1 and 0; 1 means something is true. https://www.stata.com/support/faqs/data-management/creating-dummy-variables/.

While variation in short-term gas use depends mainly on prevailing weather conditions and gas prices, longer term projections in gas demand are driven primarily by changes in:

- Customer usage patterns influenced by underlying economic, demographic, and technological changes, such as growth in population and employment;
- Forecasted prices;
- Growth in electricity demand;
- Growth of renewable generation;
- Efficiency profiles of residential and commercial buildings and the appliances within them; and
- Impacts from climate change.

TEMPERATURE ASSUMPTIONS

Space heating accounts for a high percentage of use. Therefore, gas requirements for PG&E's residential and commercial customers are sensitive to prevailing temperature conditions. PG&E's Average Year demand forecast assumes that temperatures in the forecast period will be equivalent to the average of observed temperatures during the past 19 years, with the addition of a temperature adjustment for climate change. Adding the climate change adjustment has little impact to the temperature assumptions in the early years of the forecast; however, the later years begin to show the effects of a warming climate. For example, by 2035 the total December/January heating degree days (HDD) are projected to be 16 percent lower than the 19-year average, reducing core throughput by approximately 6 percent.

Actual temperatures in the forecast period will be higher or lower than the assumption including climate change. Temperature variation impacts gas use. PG&E's Cold, Dry Hydro demand forecast assumes that winter temperatures in the forecast horizon will have a 1-in-10 likelihood of occurrence.

PG&E's EG gas throughput forecast uses an average temperature approach. The forecast does not capture peak day temperatures. Each summer typically contains a few heat waves with temperatures 10 to 15 degrees F above normal. This leads to peak electricity demands and drives up power plant gas demand. This forecast captures the seasonal variations on a monthly basis.

HYDROELECTRIC CONDITIONS ASSUMPTIONS

In contrast to temperature deviations, annual water runoff for hydroelectric plants has varied by 50 percent above and below the long-term annual average. PG&E uses a vintage approach to WECC hydroelectric generation by assuming average generation for the most recent 15 historical years, 2005-2019, in the Average Year demand forecast. PG&E uses the Cold, Dry Hydro forecast to illustrate the impacts from extreme conditions impacting both core space heating demand and EG. PG&E uses the hydroelectric generation conditions for the calendar years 2014 and 2015 to represent the dry hydroelectric condition.

GAS PRICE AND RATE ASSUMPTIONS

Inputs for gas prices and transportation rate assumptions are important for forecasting gas demand. This is especially true for market sectors that are particularly price sensitive, such as the industrial or EG sectors. PG&E used the gas commodity price forecast described in detail in the Executive Summary. It combines transportation rates with the gas commodity price forecast. PG&E's forecast assumes that changes to throughput do not directly impact rates. As a reminder, natural gas price forecasts are inherently uncertain and impact market sectors sensitive to price.

GAS LOAD ASSUMPTIONS

As described above, PG&E's base forecast is developed from econometric regression models. This forecast is modified by forecasts of policy and technology adoption. The major modifiers are building electrification (BE) and energy efficiency (EE). The EG forecast is based on the mid case electricity demand forecast from the CEC 2021 Integrated Energy Policy Report (IEPR). This demand forecast includes the Additional Achievable Fuel Substitution (AAFS 2) scenario building electrification information as described under "Electric Load Assumptions" and the forecast building electrification quantities have accompanying consistent gas reduction quantities. These gas reductions are included in the forecast as a modifier to the base models.

PG&E also includes the impact of EE in its gas forecast. PG&E's model requires the inputs of two categories of energy efficiency, "Additional Achievable Energy Efficiency" (AAEE) savings and "Committed" savings. AAEE represents savings from programs that had not yet been funded and new codes and standards (C&S). Committed represents savings from measures resulting from codes & standards already on the books but implemented during the forecast period. The AAEE forecast used by PG&E is the CEC's 2019 IEPR Mid AAEE case[15]. PG&E also utilizes the Committed savings forecast from the CEC 2019 IEPR to avoid double-counting. Committed savings are provided separately by the CEC since they are embedded in the IEPR baseline. Since committed savings for the 2021 IEPR were not available in time for use in this forecast, PG&E opted to use the previous vintage (2019 IEPR) to avoid introducing overlap between the two categories.

Finally, there is a smaller adjustment that tends to increase gas sales. There is a group of customers who intend to use natural gas as a cleaner alternative to current fuels. A few of these customers have already signed agreements and the remainder are assumed to sign at a 30% conversion rate. These customers are classified as industrial because they are predominately industrial gas users.

Electric Load Assumptions

PG&E's forecast relies on the mid case electricity demand forecast from the CEC 2021 Integrated Energy Policy Report (IEPR). The IEPR captures the increasing electric load as electric vehicles become more commonplace as projected. The electric demand forecast also includes building electrification from the CEC IEPR AAFS 2 forecast[16 & 17]. The AAFS 2 scenario is the CEC's mid-low scenario for electrification.

Finally, the electric load forecast incorporates the CEC IEPR Additional Achievable Energy Efficiency (AAEE) 3 forecast, the mid case[18]. IOU savings are informed by the CPUC's recent 2021 Potential & Goals Study (P&G). Savings for publicly owned utility (POU) utilize the

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15 California Energy Commission, Adopted 2019 Integrated Energy Policy Report https://efiling.energy.ca.gov/getdocument.aspx?tn=232922.

16 The "AAFS" here stands for Additional Achievable Fuel Substitution, so the scenarios include reductions for gas consumption that are "substituted out" through electrification.

17 California Energy Commission https://www.energy.ca.gov/media/6102.

18 California Energy Commission, ADOPTED Final 2021 Integrated Energy Policy Report Volume IV California Energy Demand Forecast https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581.

California Municipal Utilities Association's (CMUA) 2020 Energy Efficiency Potential Forecast for POU program savings. Additionally, the CEC conducts additional studies to assess the impact of codes & standards as well as savings "Beyond Utility" contributions not accounted for in other categories.

Electric Generation and Electric Transmission Assumptions

With increasing electric load and more stringent environmental requirements, California's portfolio of EG resources is expected to change significantly over the forecast horizon to 2035. Generation resource addition and retirement assumptions are from the 2021 CPUC Integrated Resource Plan (IRP) Preferred System Plan (PSP). The PSP proposes a target resource mix that includes new renewable and energy storage resources. Gas-fired plants that employ once-through cooling are assumed to retire by the compliance dates set by the California State Water Resources Control Board (SWRCB) in conjunction with the CPUC direction[19] with some re-powered by new gas-fired units. Lastly, modeled CAISO import capability also aligns with the PSP.

For cogeneration gas demand, the forecast for all years reflects recent past cogeneration usage. Most cogeneration plants are not strongly affected by prices in the wholesale electricity market. The electricity generated comes from some other industrial process, usually steam, and generation does not follow wholesale electric prices. Consequently, the cogeneration gas demand projection exhibits no variation throughout the forecast horizon.

All of these assumptions are subject to uncertainty and puts the forecasted demand at significant uncertainty. The forecasted gradual decline in future gas demand is in response to the state's decarbonization policies and reflects reduced demand due to energy efficiency, building electrification resulting from fuel switching from natural gas appliances to electric, and climate change. Furthermore, the trajectory of gas prices may change dramatically as well. The following four factors have the most impact to the forecasted demand.

[19] California State Water Resources Control Board policy effective December 23, 2021 https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/policy.html.

- **Gas Prices**: Gas prices impact retail customer usage and the extent to which thermal resources are used to meet electric demand. Over the past year, California and the world have been experiencing high and volatile gas prices. Moreover, the relative north-to-south gas burner-tip price differential has a significant impact on which thermal generation resources will dispatch. This forecast assumes a nominal Southern California price advantage.

- **Climate Change:** Changes in climate impacts both core and electric generation gas demand. It also significantly impacts hydroelectric generation which affects the need for gas generation. Although this forecast attempts to use methodologies that best reflects climate change (e.g., use of a 15-year hydroelectric generation average), the impacts and pace of change are not fully understood and will be different than the assumptions used in this forecast.

- **Generation Resource Policy and Buildout:** PG&E's forecasts assume California will invest in generation resources in accordance with the California Public Utilities Commission's 2021 Integrated Resource Plan Preferred System Plan. The Plan is ambitious with over 26,000 megawatts of added resources[20]. Deviation from the plan in either resource mix or timing will impact the gas demand forecast.

- **Building Electrification Policy:** PG&E's Average Year and Cold, Dry Hydro Year demand forecasts reflect the impact of existing building decarbonization policies as reflected in the California Energy Commission's 2021 Integrated Energy Policy Report. The CEC has developed multiple forecasts for building electrification growth, reflecting the uncertainty.

[20] Nameplate capacity.

NORTHERN CALIFORNIA

MARKET SECTOR FORECASTS

RESIDENTIAL

Northern California residential demand is forecasted to decrease from 491 MMcf/d in 2022 to 338 MMcf/d in 2035. Residential households in the PG&E service area are forecasted to be flat to slightly declining from 2022 to 2035. This is the result of continued mild growth until about 2029, after which households with gas service use begins to decline. More importantly, gas use per household has been dropping in recent years due to improvements in appliance and building shell efficiencies. PG&E expects continued efficiency improvements, coupled with the following emerging trends, to decrease long-term residential gas demand.

1. As of June 16, 2022, 57[21] jurisdictions in the state of California have adopted ordinances that require or give preference to all-electric new construction. Around 40 of these jurisdictions used Reach Codes (beyond Title 24, Part 6, of the Energy Code) as a policy tool; these are local ordinances which must be approved by the California Energy Commission (CEC). The remaining jurisdictions adopted local ordinances which do not require further approvals[22]. Not all construction types are covered by these ordinances and there is regional variation (residential versus non-residential). While the number of households are forecasted to grow at 0.9 percent annually, the CEC building electrification outlook indicates that many of these households will install electric-only appliances as new planning cycles comply with these new ordinances.

2. In addition to new construction building electrification, this forecast anticipates that existing households will begin to convert appliances from gas to electric driven by the formation of state or local policies, customer cost savings, or other mechanisms.

3. The warming climate will reduce winter heating needs gradually decreasing residential gas sales.

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[21] Sierra Club https://www.sierraclub.org/articles/2021/07/californias-cities-lead-way-pollution-free-homes-and-buildings.

[22] Some jurisdictions adopt both an energy Reach Code and an ordinance.

Total annual residential demand is projected to continue declining, driven by efficiency gains, building and appliance electrification, and warming temperatures. By 2035, annual residential gas throughput is projected to be 33 percent lower than forecasted 2022 throughput, with most of this decrease occurring in the later years of the forecast.

COMMERCIAL

Northern California commercial demand, not including natural gas vehicles, is forecasted to decrease from 208 MMcf/d in 2022 to 163 MMcf/d in 2035. The number of commercial customers in the PG&E service area is projected to grow on average by 0.23 percent per year from 2022-2035. Similar to the residential customer class, PG&E expects new construction and retrofit building electrification, coupled with continuing existing trends of energy efficiency and climate change, to lead to a long-term decline in commercial throughput. As a result, total commercial gas demand is projected to decline at 1.9 percent per year over the next 13 years, with the decline increasing in later years because total commercial accounts flatten out in those years. Core natural gas vehicles (NGV) remain a minor component but continue to grow at about 3 percent per year.

INDUSTRIAL

Northern California industrial demand is forecasted to increase nominally from 462 MMcf/d in 2022 to 496 MMcf/d in 2035. Gas requirements for PG&E's industrial sector are affected by the level and type of industrial activity in the service area and changes in industrial processes. Gas demand from this sector can fluctuate due to a combination of gas prices, noncore to core migration, capacity at local refineries, and manufacturing demand tied to market dynamics. While the industrial sector has the potential for high year-to-year variability, over the long-term, industrial gas consumption is expected to increase slowly, with energy efficiency and higher gas prices offsetting some growth.[23] As with the commercial category of NGV, industrial category NGV sees moderate growth from a small base, with some as yet unquantified possibilities for additional growth as described in "Future Opportunities" below.

[23] PG&E's industrial forecast includes impacts from California's Cap-and-Trade policies. Future GHG policies may impact industrial demand, adding uncertainty to the forecast.

NORTHERN CALIFORNIA

Given the state's GHG reduction targets, PG&E has been working with many of our industrial customers to begin converting them to natural gas from more polluting fuels, with an eye towards RNG and potentially renewable hydrogen in the future. With these conversions in the planning stage, natural gas demand from the industrial sector is expected to grow by 0.5 annually over the next 13 years.

ELECTRIC GENERATION

Gas demand from EG includes gas-fired cogeneration and power plants connected to PG&E's gas system. PG&E forecasts a relatively steady gas demand for electric generation through the 2020s, ranging between 441 and 493 MMcf/d. This reflects a continuing need in the mid-term for thermal plants to provide electric system reliability. In 2035, EG gas demand is forecasted at 549 MMcf/d.

Through the 2020s to 2035, the CPUC Integrated Resource Plan (IRP) Preferred System Plan (PSP) plans for additional renewables and storage[24] [25]. The IRP PSP forecasts most new renewable resource installation in Southern California, particularly solar. Additionally, transmission capacity constraints sometimes limit the ability to transport Southern California solar generation from south-to-north during daytime hours when solar is generating[26]. Additionally, increases in electric load, driven by electric vehicles and building electrification, need additional generation to meet load. The combination of the increasing level of planned Southern California renewable resources and south-to-north electric transmission congestion drives the EG gas demand higher.

As discussed above, the forecast has significant uncertainty due to factors, including:

- Future burner-tip gas prices;[27]
- Impact of electrification of vehicles and building appliances on electric load;

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[24] Total CAISO renewable and storage capacity planned from 2021 to 2026 is about 26,000 megawatts.

[25] By 2035, capacity increases 50,000 MW compared to 2021.

[26] Estimated at about 80 percent.

[27] Burnertip gas prices are the combination of the commodity price and transportation rate.

- Timing, location, and type of new generation, particularly renewable energy facilities;
- Variable precipitation affecting hydroelectric generation; and
- Impacts of GHG policies and regulations on generation.

The burner-tip gas price forecast and the relative difference between Northern and Southern California prices impacts the EG demand forecast. The price forecast used in this Report has the price of gas ranging from $4 to $6 per MMBtu, with a small price advantage for Southern California for most of the forecast period. This places the Northern California gas-fired EG plants at a competitive disadvantage compared to plants farther south.

Gas prices have recently shown significant volatility. For example, the forecasted PG&E Citygate price for June 2022 is about $5.30/MMBtu. Actual June 2022 daily gas prices show a range of about $7.50/MMBtu to $10.30/MMBtu. This type of volatility and the relative price volatility between prices in Northern and Southern California can drive significant uncertainty in the forecast.

As stated above, the IRP PSP indicates renewable generation and storage capacity buildout mostly built-in Southern California. Additionally, electric transmission capacity from south-to-north is assumed at about 3,000 MW. Differences in the amount or location of the actual California renewable buildout or transmission constraints will impact EG gas throughput.

Finally, variability in hydroelectric generation can significantly impact EG gas demand. In 2017 the average gas demand was 698 MMcf/d in 2017 and in 2021 it was 964 MMcf/d. One of the major drivers of this difference is hydroelectric generation. 2017 was a wet year with ample hydroelectric generation and 2021 was a dry year with lower hydroelectric generation. The wide year-to-year hydroelectric generation fluctuations further illustrate the inherent uncertainty in EG gas demand.

NORTHERN CALIFORNIA

SACRAMENTO MUNICIPAL UTILITY DISTRICT ELECTRIC GENERATION

Sacramental Municipal Utility District (SMUD) is the sixth largest community owned municipal utility in the U.S. and provides electric service to over 575,000 customers within the greater Sacramento area. SMUD operates three cogeneration plants, a gas-fired combined-cycle plant, and a peaking turbine with a total capacity of approximately 1,000 MW. The peak gas load of these units is approximately 171 MMcf/d, and the average load is about 96 MMcf/d. This forecast assumes the average load of 96 MMcf/d, which is embedded in this forecast.

SMUD owns and operates a pipeline connecting the Cosumnes combined-cycle plant and the three cogeneration plants to PG&E's backbone system near Winters, California. SMUD owns an equity interest of approximately 3.8 percent in PG&E's Line 300 and approximately 4.2 percent in Line 401 for about 86 MMcf/d of capacity.

FORECAST SCENARIOS

The Average Year gas demand forecast presented above is a reasonable projection for an uncertain future. However, a point forecast presented in the Average Year forecast cannot capture the uncertainty in the major determinants of gas demand (e.g., weather, economic activity, decarbonization policies, appliance saturation, and efficiencies). Therefore, to capture some of the uncertainties in gas demand, PG&E developed a high gas demand situation for cold temperature conditions and dry hydroelectric (hydro) conditions.

HIGH DEMAND SCENARIO: COLD/DRY HYDRO

For the High Demand scenario, PG&E forecasts gas demand under cold temperature and dry hydro conditions. This forecast assumes that winter temperatures over the time horizon will have a 1-in-10 likelihood of occurrence. The cold weather assumption increases electric load for space heating needs and EG gas demand. To represent dry hydroelectric conditions throughout the WECC, this forecast assumes the same dry hydroelectric generation conditions as those that prevailed during 2014 and 2015. The dry hydroelectric conditions increase EG gas demand.

Total gas demand for this forecast averages 6 percent higher than the Average Year demand forecast. The cold weather impact drives gas throughput higher due to higher space heating.

Winter monthly core throughput is projected to increase on average by 8 percent, ranging from 7 to 10 percent. The noncore industrial segment demonstrates little correlation to temperature leading to an insignificant demand increase over the Average Year demand forecast.

This forecast projects that EG gas demand increases by 10 percent on average over the Average Year demand outlook. In this forecast, the generation from Northern California hydroelectric resources is about half of the 15-year average assumed in the Average Year demand outlook. This lower generation increases EG gas demand. Hydroelectric conditions can vary widely throughout the WECC and illustrates another degree of uncertainty in EG gas demand forecasting.

POLICIES IMPACTING GAS DEMAND

During the forecast horizon covered by this CGR, there are many policies that may significantly impact the future trajectory of natural gas demand. Executive Order (EO) S-3-05 set a goal to reduce annual GHG emissions to 1990 levels by 2020 and to 80 percent below 1990 levels by 2050. EO B-55-18 set a goal to achieve carbon neutrality by 2045. The Global Warming Solutions Act of 2006 (Assembly Bill (AB) 32) established the 2020 GHG emission reduction goal into law. Senate Bill (SB) 32 went further, calling for a 40 percent reduction in GHG emissions below 1990 levels by 2030. Additionally, the California Air Resources Board (CARB) Cap-and-Trade Program complements these policies.

GHG POLICIES

The gas demand forecast includes a Cap-and-Trade GHG allowance price projection.[28] The forecast also incorporates complementary policies that aim to achieve California GHG emissions reductions goals. See below for further discussion of these policies. Finally, any trends embedded in historical demand patterns due to GHG goals and/or the compliance entities' participation in the Cap-and-Trade market translates to the forecast.

Given that the utilization of fossil natural gas emits GHGs, PG&E believes that renewable gases (renewable natural gas or hydrogen) must be part of the solution to reach California's

[28] CEC Integrated Energy Policy Report mid-case forecast to 2030. Extrapolated to 2035 using the real adder to the floor price (5 percent rate).

GHG reduction goals. PG&E will continue to minimize GHG emissions by pursuing both demand-side reductions and acquisition of preferred resources, which produce little or no carbon emissions.

Renewable Electric Generation

PG&E expects renewable EG to grow due to procurement orders by the CPUC in the IRP Proceeding[29]. While this increase in renewable generation will put downward pressure on the demand for generation from natural gas-fueled resources, the intermittent nature of the largest renewable generation supplies (i.e., wind and solar) should cause the electric system to continue to utilize natural gas-fired EG for reliability through the forecast horizon. Offsetting the impact on the EG demand forecast will be both short-term and long-term electric storage.

Energy Efficiency Programs

PG&E engages in many Energy Efficiency and Conservation (EE) programs designed to help customers identify and implement ways to benefit environmentally and financially from EE investments. Programs administered by PG&E include services that help customers evaluate their EE options and adopt recommended solutions, as well as simple equipment retrofit improvements, such as rebates for new hot water heaters.

PG&E's forecast of cumulative natural gas savings is dominated by the residential sector. Additionally, most of the forecasted savings are due to codes and standards, such as federal and state appliance standards and state building codes. State building codes (Title 24) make up most of these savings.

[29] https://www.cpuc.ca.gov/irp/.

IMPACT OF SB 350 ON ENERGY EFFICIENCY

SB 350, which was enacted in fall 2015, requires the CEC, in coordination with the CPUC and the local public utilities, to set EE targets that double the CEC's AAEE mid-case forecast, subject to what is cost-effective and feasible.[30] The CEC issued its final report doubling targets in October 2017,[31] and the CPUC incorporated higher levels of EE savings in their EE goals for 2018 and beyond,[32] which was partially due to the adoption of an interim GHG adder in the Integrated Distributed Energy Resources proceeding.[33] The CEC's final report suggests the State is on a path to meet or exceed the natural gas SB 350 doubling goal after accounting for IOU programs, POU programs, and codes and standards.[34]

IMPACT OF REACH CODES, APPLIANCE ORDINANCES, AND ELECTRIFICATION

In California, cities and counties have enacted ordinances or "reach" building codes that require or give preference to electric new construction. As of June 16, 2022, 57 local jurisdictions have adopted reach codes[35]. Electrification policies continue to evolve at both the local and state level. The California Air Resources Board (CARB) and Bay Area Air Quality Management District (BAAQMD) have introduced proposals aimed at the electrification of

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[30] The bill text states:

"On or before November 1, 2017, the commission, in collaboration with the Public Utilities Commission and local publicly owned electric utilities, in a public process that allows input from other stakeholders, shall establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. The commission shall base the targets on a doubling of the mid case estimate of additional achievable energy efficiency savings, as contained in the California Energy Demand Updated Forecast, 2015-2025, adopted by the commission, extended to 2030 using an average annual growth rate, and the targets adopted by local publicly owned electric utilities pursuant to Section 9505 of the Public Utilities Code, extended to 2030 using an average annual growth rate, to the extent doing so is cost effective, feasible, and will not adversely impact public health and safety."

[31] Jones, Melissa, Michael Jaske, Michael Kenney, Brian Samuelson, Cynthia Rogers, Elena Giyenko, and Manjit Ahuja. 2017. SB 350: Doubling Energy Efficiency Savings by 2030. CEC. Publication Number: CEC-400-2017-010-CMF.

[32] D.17-09-025: Decision Adopting Energy Efficiency Goals for 2018-2030, CPUC, September 28, 2017.

[33] D.17-08-022: Decision Adopting Interim GHG Adder, CPUC, August 24, 2017.

[34] See Figure 2 from the CEC report cited above.

[35] Sierra Club, https://www.sierraclub.org/articles/2021/07/californias-cities-lead-way-pollution-free-homes-and-buildings.

existing buildings—namely space and water heating. BAAQMD's proposal to amend Rules 9-4 and 9-6 would put in place a point-of-sale ban on gas water heaters beginning in 2027 and gas furnaces in 2029.[36] Similarly, CARB's 2022 State Implementation Plan (SIP) calls for all furnaces and water heaters sold within California to comply with a 0 ng/joule NOx limit beginning in 2030. If implemented, this would effectively eliminate the sale of gas water heaters and furnaces in California. Electrification, consequently, appears to be adding electric load in the long-term while removing sources of growth in gas demand. How these policies become implemented, at an unknown scale and timeframe all introduce uncertainty to the gas demand forecasts.

As the Average Year forecast projects an increase in industrial and EG sectors, the effort to achieve the GHG emissions goal could come by differing gas supply options. The natural gas supply sources could be a cleaner version in the form of renewable natural gas (RNG) or renewable hydrogen (RH_2). The next chapter on natural gas supply will elaborate on these potential gas supplies.

FUTURE GAS DEMAND TRENDS AND POLICY

PG&E's gas demand forecast projects lower throughput over the long-term (due to GHG policies, such as electrification and procurement of renewable generation resources) which would show a decline in revenues at current rates. At the same time, policies on safe utility operations have put upward pressure on costs. Investments into long lived assets, such as gas pipelines, are typically recovered over the assets' useful lives, which extend beyond this forecast. The combination of lower throughput and remaining investment in need of being recovered will put upward pressure on gas transportation rates.

In addition, the transition from fossil fuel (traditional fuels) to other forms of energy usage needs to be carefully planned and managed. PG&E is committed to working with regulators and other stakeholders to support the statewide GHG reduction policies and develop options to minimize rate increase for the remaining gas customers.

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[36] Building Appliances (baaqmd.gov.)

To minimize the rate impacts on gas customers, PG&E is following a three-pronged approach while keeping safety as its top priority: (1) reduce cost, (2) identify alternative revenue sources and (3) leverage innovative financial mechanisms. To reduce cost, PG&E is pursuing opportunities to systematically retire infrastructure and reduce capital and operating expenses through PG&E's Integrated Investment Planning. Since 2018 this program has reached agreements with 84 customers which avoided 80 high pressure regulator rebuilds, retired 4.2 miles of distribution main, and retired 22 miles of transmission line. To increase utilization of existing infrastructure where electrification is not feasible or cost effective, PG&E is actively planning for and implementing programs to decarbonize existing gas throughput, exploring new opportunities to support RNG adoption across new industries, increase load on the natural gas system in areas that would replace less favorable hydrocarbon (e.g., marine, rail and transportation sectors) and seek opportunities to utilize the gas system as a long-term and large scale storage mechanism. Innovative financial mechanisms - such as accelerated depreciation, rate reform, and the capital treatment for cost-effective zonal electrification projects will help - but non-traditional funding sources may also be critical as we evolve to an affordable, decarbonized gas system.

FUTURE OPPORTUNITIES

One recent development that could increase throughput comes from the June 2020 California Air Resources Board (CARB) approval of the Advance Clean Truck (ACT) Regulation. This regulation requires increasing percentages of all new medium- and heavy-duty trucks sales in California to be zero-emission vehicles (ZEV)[37]. The regulation begins in 2024 with sales percentages ranging between 5 percent and 9 percent depending on truck or chassis type. By 2035, the percentages increase to a range of 40 percent to 75 percent.

Truck manufactures may choose hydrogen fuel cells as they decide how to meet this requirement. The fuel required for this could be transported via utility gas pipelines (under appropriate safety protocols) which could mitigate the potential for increasing customer costs.

In addition, companies such as Amazon have internal goals for decarbonizing fleets. Chevron has announced that they are building natural gas fueling stations, including about 15 in Northern California, and truck engine producer Cummins has announced a new 15-liter NGV truck engine. While adoption of such NGV technology is determined by market response, and the carbon status of this fuel choice depends on uncertain RNG implementation and markets, this is a potential path to higher NGV adoption than is reflected in the forecast numbers.

RAIL

Another high horsepower sector to consider for increasing gas throughput is rail transportation. Based on a study by the California Air Resource Board (CARB) from 2016, annual statewide locomotive diesel fuel consumption totals about 260 million gallons. Union Pacific Railroad (UP) and BNSF Railway Company (BNSF) combined interstate and intrastate locomotives account for 93 percent of this fuel usage, California's passenger locomotives are 6%, and the remaining 1percent is from military industrial locomotives[38].

[37] ZEVs are defined as either battery electric or hydrogen fuel cell vehicles.
[38] CARB. (2016). *Technology Assessment: Freight Locomotives.* Sacramento: California Air Resource Board.

CNG and LNG as a fuel source has been considered by the rail industry, but thus far has been mostly limited to pilot studies. Based on conversations with representatives from UP, BNSF, and CARB, some of the key obstacles to CNG and LNG locomotive adoption include: few, if any, new locomotives are planned to be purchased in the near future; the high cost of converting the fueling infrastructure from diesel to CNG or LNG; and current emission standards don't adequately promote fuels cleaner than low sulfur diesel. Additionally, because LNG has an energy density of approximately 60 percent that of diesel, its use for long interstate routes would require increased fuel storage volume. This comes in the form of an LNG tender, which is an additional railcar that includes an insulated cryogenic tank and other equipment to convert LNG back to CNG. The added tender increases cost and complexity to the fuel transition[39].

One possible path to greater CNG or LNG locomotive adoption is more stringent emissions standards. Locomotive emissions are governed by the U.S. EPA. Currently, their strictest emission level is Tier 4 and applies to locomotives manufactured in 2015 or later. In g/bhp-hr it limits nitrogen oxide (NO_x), particulate matter (PM), and hydrocarbon (HC) emissions to 1.3, 0.03, and 0.14 respectively[40]. In 2017, CARB petitioned to the U.S. EPA to consider adopting a new, stricter, Tier 5 standard with a proposed effective date of 2025. The Tier 5 standard would limit NO_{x-}, PM, and HC emissions to 0.2, <0.01, and 0.02.[41]

MARINE

Another potential growth area for gas throughput is the marine transportation sector which is increasingly looking at reducing its SOx and GHG emissions. This is orchestrated by the International Maritime Organization (IMO) which regulates global shipping emissions under Annex VI.[42] The IMO updated Annex VI on January 1, 2020 to target reductions in nitrogen

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[39] *Ibid.*

[40] CFR 1033.101 (https://www.ecfr.gov/cgi-bin/text-idx?SID=159ba6f126272ea1995c71a43b7af309&mc=true&node=pt40.36.1033&rgn=div5#se40.36.1033_1101).

[41] https://www2.arb.ca.gov/sites/default/files/2020-07/final_locomotive_petition_and_cover_letter_4_3_17.pdf.

[42] http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Air-Pollution.aspx.

oxides (NOx) and sulfur oxides (SOx). To reduce SOx, the sulphur limit for all marine fuels were reduced from 3.50 percent m/m (mass by mass) to 0.50 percent m/m.

The consensus in the marine fuel industry is that the 0.50 percent sulphur limit is only a stop on the way to a global 0.10 percent sulphur limit, which currently exists in several Emissions Control Areas (ECA)[43] around the globe. Moving to 0.10% would necessitate using road grade diesel fuel as bunker fuel, therefore increasing fuel cost. Refining companies would need to further invest in hydrodesulfurization, which is costly to build and operate.

The push towards lowering SOx is driven by environmental groups, government regulations, and the shipping industry itself. Large European container companies are driving it as part of their corporate carbon strategies.[44]

LNG is widely recognized as the best path forward to reduce SOx and GHG for marine purposes but has not seen much growth in the previous decade. The updated IMO Annex VI are changing that, spurring investments in bunkering equipment[45] and vessels[46]. LNG also allows for decarbonizing of the shipping industry as the fuel can be made from RNG and, eventually, renewable hydrogen.

California marine fuel markets can be divided into ocean and coastal. The ocean market is the largest due to the fuel volumes vessels consume. California, with its large container ports in Oakland, Los Angeles, and Long Beach, may see demand for LNG in the future and would require large investments. Some of the investments needed to meet this demand include storage terminals, bunker loading vessels, or liquefaction terminals.

This demand may come sooner rather than later as modern ship engines are flex-fuel capable in that they can run on either fuel oil or natural gas, thus optimizing fuel costs and environmental

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[43] http://www.imo.org/en/OurWork/Environment/SpecialAreasUnderMARPOL/Pages/Default.aspx.

[44] https://www.maersk.com/news/articles/2019/06/26/towards-a-zero-carbon-future .

[45] https://sea-lng.org/why-lng/bunkering/; https://www.ship-technology.com/news/west-coasts-lng-bunker-abs/.

[46] https://www.cma-cgm.com/news/2749/world-premiere-launching-of-the-world-s-largest-lng-powered-containership-and-future-cma-cgm-group-flagship .

compliance.[47] To give an idea of the potential size of this market, in 2020 vessel bunkering residual fuel oil use in California totaled about 12 million barrels or 62 Bcf.[48]

Coastal market consists mostly of smaller vessels such as passenger ferries, tugs, fishing vessels, etc. These smaller vessels already use an Ultra Low Sulphur Diesel under CARB regulations and these vessels, could see a cost reduction by switching to LNG powered fleets.[49] Small on-demand liquefaction terminals can bunker vessels at berth and have already been installed in Europe[50] successfully. They can be connected directly to the natural gas grid producing fuel on-demand.

NORTH AMERICAN GAS DEMAND

LIQUEFIED NATURAL GAS IMPORTS/EXPORTS

In years past, the U.S. imported LNG to supplement North American supplies to meet demand. Since the mid-2010s, LNG imports have primarily been used to serve peak winter load[51]. The development of low-cost domestic shale gas supplies since the mid-2000s has largely eliminated the need for LNG imports and positioned the U.S. as a net exporter of LNG.

Recent global events have increased the expectations for more LNG exports from North America. As Europe embarks on measures to increase its energy security and diversify its energy sources, LNG export developers in North America are seeking development opportunities. The gas industry anticipates further growth in LNG exports from North America.

47 https://www.wartsila.com/twentyfour7/energy/taking-dual-fuel-marine-engines-to-the-next-level.
48 U.S. Energy Information AdministrationSales of Residual Fuel Oil by End Use https://www.eia.gov/dnav/pet/pet_cons_821rsd_a_EPPR_VVB_Mgal_a.htm
49 https://www.mckinsey.com/industries/oil-and-gas/our-insights/imo-2020-and-the-outlook-for-marine-fuels# .
50 https://ec.europa.eu/energy/intelligent/projects/sites/iee-projects/files/projects/documents/magalog_lng_supply_chain.pdf .
51 U.S. Energy Information Administration (US EIA) U.S. Liquefied Natural Gas Imports https://www.eia.gov/dnav/ng/hist/n9103us2m.htm .

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The U.S. began exporting LNG in 2016. For projects proposing to export LNG, the U.S. Department of Energy (DOE) evaluates the impact of exports to countries without a Free Trade Agreement (FTA) with the U.S. The DOE grants approval if the project is deemed in the public interest. The U.S. Federal Energy Regulatory Commission (FERC) evaluates the environmental impacts of proposed LNG projects and authorizes the siting and construction of LNG facilities.

Currently, there are more than a dozen proposed projects to export LNG to world markets.[52] Many of the projects are "brownfield," using existing U.S. import terminals to export LNG. Some are "greenfield" projects where LNG infrastructure has not been developed in the past. Two greenfield projects on North America's West Coast are in British Columbia. The larger project is LNG Canada located in Kitimat.[53]

A brownfield project on North America's West Coast is the Energia Costal Azul (ECA) LNG export facility in Baja California, Mexico. ECA has received authorization from the DOE to liquify and re-export up to 1.7 billion cubic feet per day (Bcf/d) of U.S. produced natural gas.[54] This facility will have a nameplate capacity of 3.25 million metric tons (mmt) per annum of liquification capacity. Construction of the project is underway with an online date of 2024.[55]

The ECA LNG export project, which would be the second on the North America's West Coast, is positioned to source gas off the El Paso Mainline System. Thus, it could divert gas supplies currently available to Northern California. ECA diversion of gas supplies from California is currently under consideration at the CPUC in the R.20-01-007 Proceeding.[56] This proceeding will investigate whether the demand from ECA could impact supply reliability to California, especially the southern portion, and put upward pressure on gas prices.

[52] U.S. EIA https://www.eia.gov/naturalgas/U.S.liquefactioncapacity.xlsx .

[53] LNG Canada https://www.lngcanada.ca/media-kit/ .

[54] https://ecalng.com/ .

[55] Mexico ECA LNG Development Advancing to 2024 Start Date, Natural Gas Intelligence, https://www.naturalgasintel.com/mexico-eca-lng-development-advancing-to-2024-start-date/#:~:text=The%20facility%20is%20adjacent%20to,the%20facility%20online%20in%202024.

[56] OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning.

U.S. Natural Gas Pipeline Exports to Mexico

With low domestic natural gas prices compared to world markets, the U.S. remained a net exporter of natural gas in 2021.[57] The U.S. natural gas exports to Mexico have grown in recent years from 0.9 Bcf/d in 2010 to 5.9 Bcf/d in 2021,[58] and pipeline exports are projected to reach 7.4 Bcf/d by 2035.[59]

Most of the exports to Mexico are supplied through Texas from the Permian and Western Gulf of Mexico basins. Production growth in the Permian Basin, combined with new pipeline capacity, will enable growing exports to Mexico.

[57] Energy Information Administration (EIA), The U.S. exported more natural gas than it imported in 2017: https://www.eia.gove/todayinenergy/detail.php?id=35392.

[58] EIA, U.S. Natural Gas Pipeline Exports to Mexico: https://www.eia.gov/dnav/ng/ng_move_poe2_dcu_NUS-NMX_a.htm.

[59] EIA, Annual Energy Outlook 2022 – Table 60. Natural Gas Imports and Exports Case: AEO2022 Reference case: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=76-AEO2022&cases=ref2022&sourcekey=0 .

GAS SUPPLY, CAPACITY, AND STORAGE

OVERVIEW

The Gas Supply, Capacity, and Storage section provides information about PG&E's current gas supply, natural gas pipelines, gas storage, and policies affecting these topics. The Gas Supply section includes information about current and anticipated developments regarding Renewable Natural Gas (RNG), as well as gas supply from sources throughout North America. The Pipeline section includes information about "upstream" interstate pipelines, as well as intrastate pipelines. The Storage section gives an overview of PG&E's gas storage capacity and its gas storage facilities. The Policies section looks at a range of current policy developments and their impacts on PG&E's gas supply, including integration challenges for alternative fuel types, such as hydrogen (H_2).

Competition for gas supply, market share, and transportation access has increased significantly since the late 1990s. Implementation of PG&E's Gas Accord in March 1998 and the addition of interstate pipeline capacity and storage capacity have provided all customers with direct access to gas supplies, intra- and inter-state transportation, and related services.

Since gas demand in California is greater than the limited amount of native California production available, most of the gas supplies that serve PG&E customers are sourced from out of state.

PG&E anticipates that sufficient supplies will be available from a variety of sources at market competitive prices to meet existing and projected market demands in its service area. Supply can be delivered through a variety of sources, including any new and expanded interstate pipeline facilities and of PG&E's existing transmission facilities, or other storage facilities.

GAS SUPPLY

Renewable Natural Gas

PG&E has several RNG projects in various phases. Four projects are already connected and flowing clean, renewable gas onto our system. Two projects are in development and should be online by the end of 2022. These six projects are expected to inject roughly 11,500 Mcf/d (thousand cubic feet per day) into PG&E's pipeline system by year end. In addition, there are over a dozen other projects that are in early-stage development that PG&E anticipates will be online over the next two to three years.

Two of the projects are a result of the SB 1383 Dairy Pilot Program, highlighted below, and the other five are identified in the Biomethane Project Incentive Reservation Queue located on the CPUC website.[60]

SB 1383 Dairy Pilot Projects

On December 3, 2018, the CPUC, CARB, and the California Department of Food and Agriculture (CDFA) issued a joint press release announcing the selection of six dairy pilot projects in compliance with CPUC D.17-02-004 and SB 1383. Two of the pilot projects were awarded in PG&E's service territory (see the Figure below): (1) the Merced Pipeline project sited at the Vander Woude Dairy in Merced (6 miles south of Merced); and (2) the J.G. Weststeyn Dairy project in Willows (5 miles west of Logandale).

On January 7, 2022, the Vander Woude Dairy project became operational, and the maximum RNG volumetric flow rate was met in February 2022, qualifying the project's entire authorized costs under the SB 1383 Dairy Pilot Program to be reimbursed.

As of May 2022, the J.G. Weststeyn Dairy project is completing its project design with an anticipated construction start date beginning in 2023.

[60] https://www.cpuc.ca.gov/renewable_natural_gas/.

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FIGURE 10 – PG&E SERVICE AREA: RNG PILOT PROJECTS LOCATION

FUTURE CALIFORNIA RNG SUPPLY

A 2016 CARB-sponsored study by University of California (UC), Davis, "The Feasibility of Renewable Natural Gas as a Large Scale, Low Carbon Substitute" (the "STEPS study"), anticipated that as much as 82 Bcf per year of RNG supply could become available in California with appropriate policy development and investment.[61] The STEPS study identified that the largest opportunity for increasing the supply of RNG would come from landfill sites, followed by dairy, municipal solid waste, and waste-water facilities.

A more recent assessment of in-state RNG supply for transportation, conducted by GNA[62], projects that there will be roughly 16 Bcf annually of RNG interconnected into gas pipelines in California by January 2024. Additionally, the CPUC has required the utilities to file an application in the Summer of 2023 to advance pilot projects that would convert woody biomass into RNG, further expanding the potential long-term supply of RNG in the state.

Given the STEPS study results, the gas flowing from RNG sources by January 2024 is just the first wave of RNG expected to be eventually injected into the gas system. Therefore, going forward, PG&E expects to see more RNG projects as developers realize the near- and mid-term potential of this supply source.

GAS ABSORPTION CAPACITY

To encourage effective development of RNG, PG&E created the Gas Supply Absorption Capacity Map.[63] This map is a high-level snapshot of PG&E's gas system that is designed to help contractors and developers find potential project sites by showing the relative ability (high to low) to accept new gas supply on PG&E transmission pipelines. Suppliers are encouraged to contact PG&E to discuss opportunities to bring on RNG supplies. Currently this map is being revised to provide better information to potential developers.

[61] STEPS Program Study, The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, prepared by Amy Myers Jaffe, available at: https://steps.ucdavis.edu/the-feasibility-of-renewable-natural-gas-as-a-large-scale-low-carbon-substitute/.

[62] https://www.gladstein.org/gna_whitepapers/an-assessment-californias-in-state-rng-supply-for-transportation-2020-2024/ .

[63] Available at: https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/interconnections-renewables/biomethane-map-overview.page .

NORTH AMERICAN SUPPLY DEVELOPMENT

North America has an abundance of natural gas resources. In the United States, the Potential Gas Committee estimates resources of 3,368 trillion cubic feet (Tcf).[64] Natural gas resource development has improved over the past two decades as horizontal drilling and hydraulic fracturing has matured. Furthermore, advancements in drilling know-how and improved efficiencies have improved resource development, typically at lower costs. The U.S. produced almost 94 Bcf/d on average in 2021.[65] Three producing regions contributed about 60 percent of this production: the Haynesville region mainly in Louisiana and Texas, the Permian region in Texas and New Mexico, and the Appalachia region mostly located in Pennsylvania, Ohio, and West Virginia.[66] The resources that contribute to these production regions include both shale gas resources and associated gas from oil production.[67] Most industry forecasts continue to predict that gas production will meet most demand outlooks in the future.

The growth of associated gas production in the Permian Basin and eastern shale plays - the Haynesville and Appalachia) continue to push gas volumes from Canada, the Rocky Mountain area, and the Southwest towards California. These production regions interconnect with California via pipelines as highlighted below.

CALIFORNIA SOURCED GAS

Northern California sourced gas supplies come primarily from gas fields in the Sacramento Valley. In 2021, PG&E's customers obtained on average 23 MMcf/d of California sourced gas. PG&E anticipates that California sourced gas may increase from this level. The primary driver to this growth is RNG production.

[64] http://potentialgas.org/press-release. This estimate represents the total mean technically recoverable resource base as of year-end 2020. Technically recoverable resources means gas can be produced using currently available technology and industry practices.
[65] U.S. Energy Information Administration Natural Gas Dry Production (eia.gov) .
[66] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis .
[67] Production - Amid uncertainty, the United States continues to be an important global supplier of crude oil and natural gas - U.S. Energy Information Administration (EIA) .

U.S. Southwest Gas

PG&E's customers have access to three major U.S. Southwest gas producing basins—Permian, San Juan, and Anadarko—via the El Paso and Transwestern pipeline systems.

PG&E's customers can purchase gas in the producing basins and transport it to California via interstate pipelines. They can also purchase gas at the California Arizona border or at the PG&E Citygate from marketers who hold inter or intrastate pipeline capacity.

Canadian Gas

PG&E's customers can purchase gas from various suppliers in Western Canada (British Columbia and Alberta) and transport it to California, primarily through the Gas Transmission Northwest (GTN) pipeline. Likewise, they can also purchase these supplies at the California-Oregon border or at the PG&E Citygate from marketers who hold interstate or intrastate pipeline capacity.

Rocky Mountain Gas

PG&E's customers have access to gas supplies from the Rocky Mountain area via the Kern River Gas Transmission Pipeline, the Ruby Pipeline and via the GTN Pipeline interconnect at Stanfield, Oregon.

GAS PIPELINE CAPACITY

Interstate Pipeline Capacity

California utilities and end-use customers benefit from access to multiple supply basins, enhanced by produced gas-on-gas and pipeline-on-pipeline competition. Interstate pipelines serving northern and central California include El Paso Natural Gas, Mojave, Transwestern, GTN, Paiute Pipeline Company, Ruby, and Kern River Gas Transmission pipelines. These pipelines provide northern and central California with access to gas producing regions in the U.S. Southwest, Rocky Mountains, and in Western Canada.

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U.S. SOUTHWEST AND ROCKY MOUNTAINS

PG&E's Baja Path (Line 300) is connected to U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, and Kern River) at and west of Topock, Arizona. The Baja Path has a firm capacity of 935 MMcf/d.

CANADA AND ROCKY MOUNTAINS

PG&E's Redwood Path (Lines 400/401) is connected to GTN and Ruby at Malin, Oregon. The Redwood Path has a firm capacity of 2,060 MMcf/d.

IN-STATE PIPELINES

PG&E continues to accelerate the analysis of the existing pipeline system for opportunities to minimize rate increases for our customers by reducing our expenses, look for new opportunities for load growth and to decarbonize by increasing throughput of RNG. PG&E is actively pursuing a variety of initiatives including electrification opportunities on radial feeds where several miles of pipe are in place to serve a small handful of customers, pruning the system of pipe that is underutilized or no longer serving customers, downrating lines, and elimination or streamlining projects. Electrifying these customers and decommissioning the pipeline will achieve greater cost savings in the long term. These opportunities will also help inform PG&E's longer-term efforts, in partnership with cities, to strategize where to reduce our spending and predict long-term gas needs more accurately.

GAS STORAGE

Northern California is served by several gas storage facilities in addition to the longstanding PG&E fields at McDonald Island, Los Medanos, and a 25 percent ownership in Gill Ranch Storage.[68] These facilities combine for a total inventory of 167 Bcf, with 35 Bcf under PG&E management.

[68] PG&E also has operated the Pleasant Creek storage field. The Decision (D.) 19-09-025 for the 2019 Gas Transmission and Storage rate case, Ordering Paragraph 42, adopted PG&E's proposal to sell or decommission the Pleasant Creek storage field.

Other Northern California storage providers consist of Gill Ranch Storage, LLC (a 20 Bcf facility that was co-developed with PG&E), Wild Goose Storage, LLC, Lodi Gas Storage, LLC, and Central Valley Storage, LLC. The abundant storage capacity in Northern California has the effect of creating ample liquidity in the market both in Northern California and in other parts of the West.

Within the past ten years, Northern California natural gas storage facilities have experienced regulatory changes. In response to the Southern California Gas Company's Aliso Canyon Storage natural gas leak in October 2015, the California Department of Conservation, Geologic Energy Management Division (CalGEM), previously known as the Division of Oil Gas and Geothermal Resources (DOGGR), adopted new natural gas storage well safety regulations across California. Key elements of these new rules included requiring all operators to submit risk and integrity management plans, well casing inspection and pressure testing plans, and a schedule to convert or retrofit wells to tubing and packer.[69] Packers seal off the annulus space in the casing and limit the gas flow to the smaller diameter inner tubing only, which is forecasted to reduce traditional storage well performance on average by 40 percent.[70] Partly in response to the new regulations, PG&E proposed a Natural Gas Storage Strategy (NGSS) in its 2019 Gas Transmission and Storage (GT&S) Rate Case. Specifically, PG&E proposed to exit the commercial storage market and focus on reliability services. As a part of the NGSS, PG&E proposed to sell or decommission its Los Medanos and Pleasant Creek storage facilities. The CPUC approved the NGSS in Decision (D.) 19-09-025.

On December 1, 2020, PG&E announced the sale of the Pleasant Creek natural gas storage field, located in Yolo County, California. The Pleasant Creek field is the smallest of four underground natural gas storage fields owned wholly or partly by PG&E.

In PG&E's 2023 General Rate Case application, filed at the CPUC on June 30, 2021, PG&E proposed updates to the NGSS in response to evolving CalGEM regulations. These updates include a proposal to retain the Los Medanos storage facility while still decommissioning or

[69] Geologic Energy Management Division Statutes & Regulations January 2022 (ca.gov) https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

[70] Workpaper Table 7-37. Pacific Gas and Electric Company 2023 General Rate Case Workpapers.

selling the Pleasant Creek storage facility. The proposal to retain Los Medanos is in lieu of drilling additional new wells at the McDonald Island facility to meet the utility's firm withdrawal obligations. PG&E's proposed NGSS updates are pending before the CPUC as of mid-2022.

Last, in March 2019, PG&E submitted an underground storage risk and integrity management plan and accompanying field specific well risk evaluation and construction standard implementation plan (2019 Implementation Plan) to CalGEM consistent with CalGEM's regulations. After input and feedback from CalGEM, PG&E submitted a revised implementation plan in January 2021 (2021 Revised Implementation Plan), which details our well testing, conversion, and risk management plans. In June 2021, CalGEM approved the 2021 Revised Implementation Plan with some additional requirements. Consistent with the 2021 Revised Implementation Plan, PG&E expects all new wells to be drilled and existing wells converted to tubing and packers by 2026.

OTHER CALIFORNIA STORAGE FACILITIES

In addition to storage services offered by PG&E, there are four other storage providers in Northern California: Wild Goose Storage, LLC; Gill Ranch Storage, LLC; Central Valley Gas Storage, LLC; and Lodi Gas Storage, LLC. These facilities have an estimated total working gas capacity of roughly 132 Bcf[71].

POLICIES IMPACTING FUTURE GAS SUPPLY AND ASSETS OVERVIEW

California's policies to reduce GHGs are expected to impact gas supply and assets. PG&E is responding to these policies and actively planning for and implementing programs to decarbonize existing gas throughput, supporting RNG adoption, supplying hard to electrify industries, and planning to utilize the gas system as a long-term energy storage mechanism.

[71] Capacities derived from information provided by Independent Storage Providers.

RENEWABLE NATURAL GAS

As a result of various policy and regulatory changes to decarbonize gas throughput, PG&E is seeing an influx of requests to interconnect RNG to utility pipelines in Northern California. RNG producers are leveraging available grants and incentives to encourage the production of RNG to reduce GHG emissions from these biogas-sources and for use as an alternative fuel source for transportation and other end use customers. PG&E is engaged in the following efforts regarding RNG:

- Procuring RNG for all PG&E-owned Compressed Natural Gas (CNG) fueling stations;
- Actively working with RNG developers to interconnect their projects through the biomethane program;
- Working to file an application to advance woody biomass pilot projects under CPUC D. 22-02-025;
- Planning for implementation of biomethane (RNG) procurement for core customers under CPUC Decision 22-02-025; and
- Participation in various Research and Development (R&D) efforts to further understand and develop new methods and technologies to produce RNG that reduce the carbon intensity of the gas in the pipeline.

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MONETARY INCENTIVE PROGRAM

D.15-06-029 established a biomethane monetary incentive program that included $40 million to encourage biomethane producers to design, construct, and safely operate projects that interconnect and inject biomethane into California's natural gas utilities' pipeline systems.

D.19-12-009 implements an Incentive Reservation System for the biomethane monetary incentive program established in D.15-06-029. The Incentive Reservation System opened to applications on February 3, 2020, and the queue is published on the CPUC's RNG website.[72]

D.20-12-031 authorized an additional $40 million of RNG project incentive funding sourced from Cap-and-Trade allowance auction proceeds subject to projects meeting applicable CARB program regulations.

Based on information provided on the CPUC's RNG website, seven projects have received a total of approximately $29.5 million of funding under the incentive program, leaving $50.5 million remaining in the program.

RESEARCH AND DEVELOPMENT

PG&E's R&D RNG roadmap[73] further outlines PG&E's goals for incorporating RNG into the supply portfolio.

HYDROGEN

Hydrogen, H_2, is seen as a game changer in decarbonizing the gas supply and sectors that will be difficult to electrify. To achieve the goals set forth in SB 100, discussed below, California will likely need to incorporate H_2 into the portfolio of green fuels for various sectors. Many other countries have already embraced H_2 and fuel cell technology to reduce their carbon footprint.

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[72] https://www.cpuc.ca.gov/renewable_natural_gas/ .

[73] https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/RNG_Roadmap_2020.pdf.

Given the momentum, California, through the Governor's Office of Business and Economic Development, is in the process of unifying Northern and Southern California efforts into a single application for the upcoming DOE (U.S. Department of Energy) RFP (Request For Proposals) for hydrogen infrastructure investment. This will be an important step in taking advantage of the geographic diversity in the northern and southern portions of the state.

Additionally, the California IOUs are working together on an action plan for incorporating H_2 into the pipelines through pilot and demonstration projects to help inform an eventual hydrogen injection standard.

HYDROGEN STORAGE (CONVENTIONAL AND NEW TECHNOLOGY)

H_2 has many potential applications. One such application is to produce H_2 through electrolysis from excess renewable energy and store it in the pipeline system (or dedicated underground storage facilities) for later use. Such uses may include H_2 as fuel for electric generation to backup intermittent renewable generation. H_2 storage has great potential for longer-term storage that current electric battery storage technology is unable to serve. Moreover, H_2 storage can provide clean fuel for electric generation at larger volumes as renewable generation experiences seasonal intermittency. Battery storage technology currently cannot provide the scale needed to backup seasonal intermittency.

NORTHERN CALIFORNIA

CNG AS RAIL AND LNG AS MARINE FUEL

As mentioned above in the Gas Demand section, there is tremendous opportunity for growth in the rail and marine markets. The gas supply needed for this demand will need to come from cleaner sources of fuel such as RNG and H_2. Additionally, LNG infrastructure would need to be developed at the appropriate scale to meet marine demand for LNG.

REGULATORY ENVIRONMENT

OVERVIEW

This section provides an overview of the existing and near-term regulatory policies and their effect on the Northern California gas system and its users.

Given the anticipated state and federal regulatory policies surrounding storage, transportation, inspection, and capacity requirements, the cost to safely and reliably operate PG&E's gas system will continue to rise. At the same time, a decline in throughput—which PG&E anticipates is a result of California's GHG reduction goals and cities taking action to establish new electric codes and ordinances—will mean those costs will be spread over fewer therms and possibly fewer customers. Unless the evolution of the gas system is well managed, rising costs combined with reduced throughput would impact the affordability of gas for customers.

Furthermore, despite readily available domestic gas supply and operational innovation, the complex regulatory environment and evolving policies are likely to create price uncertainty in the medium to long term.

FEDERAL AND CANADIAN REGULATORY MATTERS

PG&E actively participates in FERC ratemaking proceedings for interstate pipelines connected to PG&E's system since these proceedings can impact the cost of gas delivered, the reliability of gas supply, and the services provided to the PG&E's gas customers. PG&E also participates in FERC proceedings of general interest to the extent they affect PG&E's operations and policies or natural gas market policies generally.

GTN AND RUBY PIPELINES

Gas Transmission Northwest (GTN) and their shippers settled during pre-rate case negotiations with no rate increase for two years beginning on January 1, 2022. GTN has also filed a certification application in October 2021 for its Xpress Project that PG&E has intervened in and are monitoring for impacts on PG&E's customers. The proposed project will create 150

MDth/d of incremental mainline capacity on GTN's system. The in-service date is November 1, 2023.

On March 31, 2022, Ruby Pipeline, LLC (Ruby) filed to reorganize under Chapter 11 of the United States Bankruptcy Code in response to an upcoming debt repayment obligation.[74] PG&E will follow this event to limit the impacts to PG&E's operations and policies or natural gas market policies.

EL PASO NATURAL GAS COMPANY

On April 21, 2022, FERC issued an order initiating an investigation to determine whether the rates currently charged by El Paso Natural Gas Company, L.L.C. ("El Paso") are just and reasonable and setting the matter for hearing. PG&E is monitoring the proceeding.

OTHER PIPELINES

There are currently no significant regulatory issues regarding Kern River Gas Transmission (Kern River); or Transwestern Pipeline Company, LLC (Transwestern) pipelines.

CANADIAN REGULATORY MATTERS

PG&E continually monitors Canadian regulatory matters that can impact PG&E's customers. Currently, no regulatory issues are currently present.

FERC AND CAISO GAS--ELECTRIC COORDINATION ACTIONS

While there are no general inquiries or proceedings at FERC addressing gas-electric coordination, the California Independent System Operator (CAISO), which is FERC-jurisdictional, has ongoing policy initiatives that may impact gas demand, supply, and prices. These initiatives include:

- Day-Ahead Market Enhancements; and
- Extended Day-Ahead Market

[74] https://cases.ra.kroll.com/rubypipeline/Administration.

These policy initiatives will need FERC approval before the proposed changes can be implemented.

STATE REGULATORY MATTERS

CALIFORNIA STATE SB 100 AND CARBON NEUTRALITY EXECUTIVE ORDER

On September 10, 2018, Governor Brown signed into law SB 100, which further increases the Renewable Portfolio Standard (RPS) targets and includes the following key requirements:

- Accelerates the RPS to 50 percent by 2026 and increases the RPS to 60 percent by 2030;
- Creates a separate state policy that requires 100 percent of all retail sales of electricity to serve end-use customers and 100 percent of electricity procured to serve state agencies to come from RPS-eligible or zero -carbon resources by 2045; and
- Requires the CPUC, in consultation with the CAISO and other balancing authorities, to issue a joint report to the Legislature by January 1, 2021, and every four years thereafter, that evaluates the anticipated costs and benefits of the 100 percent clean policy to electric, gas, and water utilities, including customer rate impacts and benefits.

Additionally, Governor Brown signed an EO on September 10, 2018, establishing a new statewide goal to achieve carbon neutrality by 2045 across all sectors of the California economy and to achieve and maintain net negative GHG emissions thereafter. Implementation of the order will require California to undertake additional decarbonization and carbon removal efforts. CARB is developing California's plan for achieving carbon neutrality in its Climate Change Scoping Plan Update, due to be completed by the end of 2022.[75]

[75] CARB Scoping Plan, available at: https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan.

NORTHERN CALIFORNIA

PIPELINE SAFETY

Since 2011, the CPUC and the California State Legislature have adopted a series of regulations and bills that reinforce the setting of public and employee safety as the top priority for the state's gas utilities. In particular, Senate Bill (SB) 705 mandated that gas operators develop and implement safety plans that are consistent with the best practices in the gas industry.

On March 15, 2022, PG&E filed its 2022 Gas Safety Plan with the CPUC, which explains how PG&E puts the safety of the public, customers, employees, and contractors first, and details gas safety work performed in 2021. The Gas Safety Plan is reviewed and updated annually in accordance with General Order 112-F Section 123.2(k), and Public Utilities Code Sections 961 and 963.1.

Additionally, PG&E submits the following reports to the CPUC: (1) semi-annual Gas Transmission & Storage Compliance Report; (2) annual Gas Distribution Pipeline Safety Report; (3) annual Risk Spending Accountability Report; and (4) annual Safety Performance Metrics Report. These reports are designed to provide the CPUC and other interested stakeholders with insight into the amount of safety, reliability, and maintenance -related work PG&E has completed over the course of the reporting period and/or performance in key safety areas.

Below are selected highlights from PG&E's 2021 reports and the Gas Safety Plan which further demonstrate PG&E's commitment to pipeline safety:

- **Asset Management System:** PG&E maintains an asset management system to help drive the business toward achieving its commitment to the safe, reliable, and affordable management and operation of PG&E's gas assets. Using the Publicly Available Specification (PAS) 55: 2008 and International Organization for Standardization (ISO) 55001: PG&E's asset management system focuses on: (1) knowing the condition of the assets; (2) understanding the risks to those assets; (3) implementing asset risk reduction strategies; (4) maintaining asset condition and performance; and (5) balancing asset cost, risk, and performance in pursuit of the asset management strategic objectives.

- **Process Safety:** Guided by the elements set by the Center for Chemical Process Safety, PG&E's commitment to implement process safety aligns with American Petroleum

Institute (API) Recommended Practice (RP) 754 Process Safety Performance Indicators for the Refining and Petrochemical Industries. A risk-sorting criterion to track and trend process safety leading and lagging indicators is used to identify emerging issues before incidents occur. The Process Safety team continued to review changes to existing procedures and standards and new procedures and standards in order to help Gas Operations operate and maintain safe facilities and consistently implement process safety practices.

- **In-Line Inspection (ILI):** PG&E's current goal is to upgrade the gas transmission pipeline system to be capable of ILI for over 4,500 transmission pipeline miles by the end of 2036, which is approximately 69 percent of PG&E's GT pipeline miles. As of December 31, 2021, PG&E has successfully upgraded 46 percent of the GT pipeline system, resulting in approximately 2,956 miles of piggable transmission lines.

- **Third-Party Dig-Ins:** In 2021, PG&E experienced 0.91 third-party dig-ins per 1,000 Underground Service Alert (USA) tickets, outperforming its 2021 target of 1.07 third-party dig-ins per 1,000 tickets.

- **Community Pipeline Safety Initiative (CPSI)**: A multi-year program designed to enhance safety by improving access to pipeline rights-of-way. To date, the program has cleared more than 99 percent of the work scope, including approximately 1,544 vegetation miles and 359.9 structure miles. Pending outstanding municipality and customer agreements, and receipt of long-lead time permits, the remaining 8.38 miles of vegetation and 0.02 miles of structure clearing has been extended to at least December 2022. For areas with completed CPSI work, PG&E remains committed to keeping the area above and around the pipeline clear through our ongoing Gas Transmission Vegetation Management Program.

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STORAGE SAFETY

In response to the Southern California Aliso Canyon Storage natural gas leak in October 2015, the California Department of Conservation, Geologic Energy Management Division (CalGEM) adopted new safety regulations concerning natural gas storage wells across California. Key elements of these new rules included requiring all operators to submit risk and integrity management plans, well casing inspection and pressure testing plans, and a schedule to convert or retrofit wells to tubing and packer. The elimination of the annulus flow could reduce traditional well performance on average by 40 percent.

Partly in response to the new regulations, PG&E proposed a Natural Gas Storage Strategy (NGSS) in its 2019 Gas Transmission and Storage (GT&S) Rate Case. Specifically, PG&E proposed to exit the commercial storage market and focus on reliability services. As a part of the NGSS, PG&E proposed to sell or decommission its Los Medanos and Pleasant Creek storage facilities. The CPUC approved the NGSS in Decision (D.) 19-09-025.

In its 2023 General Rate Case application, filed at the CPUC on June 30, 2021, PG&E proposed updates to the NGSS in response to evolving CalGEM regulations. These updates include a proposal to retain the Los Medanos storage facility while still decommissioning or selling the Pleasant Creek storage facility. The proposal to retain Los Medanos is in lieu of drilling additional new wells at the McDonald Island facility to meet our firm withdrawal obligations. PG&E's proposed NGSS updates are still pending before the CPUC.

In March 2019, PG&E submitted an underground storage risk and integrity management plan (R&IMP) and accompanying field specific well risk evaluation and construction standard implementation plan (2019 Implementation Plan) to CalGEM consistent with CalGEM's regulations. After input and feedback from CalGEM, PG&E submitted a revised implementation plan in January 2021 (2021 Revised Implementation Plan), which details our well testing, conversion, and risk management plans. In June 2021, CalGEM approved the 2021 Revised Implementation Plan with some additional requirements. Consistent with the 2021 Revised Implementation Plan, PG&E expects all new wells to be drilled and existing wells converted to tubing and packers by of 2026.

CITIES, REGULATORS, AND AIR DISTRICTS PURSUE ELECTRIFICATION

Local governments continue to take steps towards electrification at the city and county level with new electric "reach" building codes that require or give preference to electric new construction.[76] The California Public Utilities Commission has also proposed a removal of gas line extension allowances, discounts, and refunds within the Building Decarbonization OIR (R.19-01-011). PG&E's position was to not oppose a removal of residential gas line extension allowances, but to request that allowances remain for non-residential customers that provide a financial or environmental benefit to ratepayers.

The spread of all-electric new construction and the consideration of point-of-sale bans on gas furnaces and water heaters suggests a future flattening of demand for gas in buildings.

KNOWN REGULATORY HURDLES

Federal regulation along with state and local climate action goals are set to create an evolving and time challenging environment for gas utilities and customers. To succeed in achieving operational safety and climate action goals, the following hurdles need to be addressed:

- As regulations continue to be revised and updated, the cost of providing a safe and reliable gas system will continue to rise. This increase in cost, paired with state and local GHG goals, are expected to drive down gas throughput. Lower gas throughput will likely result in a higher cost per-therm for customers if the evolution is not well-managed.

- While there is significant potential for renewable gas (RG) to replace some portion of natural gas supply, the current investments and incentives for RG end-use principally favor the transportation sector. With the clear financial advantage towards transportation, there is comparatively little RG available to establish a consistent RG supply to meet PG&E's customer or third-party needs now that an RG standard has been established. If this is to change, California will have to balance the funding mechanisms between the

[76] "California's Cities Lead the Way on Pollution-Free Homes and Buildings." Sierra Club, June 16, 2022: https://www.sierraclub.org/articles/2021/07/californias-cities-lead-way-pollution-free-homes-and-buildings.

transportation sector and other sectors so that RG project developers have opportunities to supply RG towards an RG standard or the transportation sector.

California's gas system is going through unprecedented changes. As it evolves, it is important that regulatory bodies and the utilities work together to ensure that Californians continue to have access to clean, reliable, and affordable energy.

OTHER REGULATORY MATTERS

OVERVIEW

This section includes PG&E's GHG and Cap-and-Trade reporting and discusses other regulatory matters that may impact Northern California's gas system.

PG&E is participating in several OIRs, which address crucial topics that will impact the California gas system. For example, the:

- Biomethane OIR (R.13-02-008) helped the utilities make RNG interconnections more efficient and affordable across California as well as established an RNG procurement program for core customers.

Gas System Planning OIR (R.20-01-007) which will allow the utilities to: (1) develop updated reliability standards that are in line with current and future operational challenges of gas system operators, (2) improve coordination between gas utilities and gas -fired generators, and (3) develop and implement a long -term strategy to work towards California's decarbonization goals.

GHG REPORTING AND CAP-AND-TRADE OBLIGATIONS

In March 2022, PG&E Gas Operations reported to the U.S. Environmental Protection Agency (EPA) GHG emissions in accordance with 40 Code of Federal Regulations Part 98 in four primary categories: GHG emissions in reporting year 2021 resulting from combustion at seven compressor stations, where the annual emissions exceed 25,000 metric tons of CO2 equivalent (mtCO2e); the GHG emissions resulting from combustion of all customers except customers consuming more than 460 MMscf; certain vented and fugitive emissions from the seven compressor stations and natural gas distribution system; and GHG emissions from transmission pipeline blowdowns.

In April 2022, PG&E reported to CARB GHG emissions approximately 42.5 million mtCO2e (metric tons carbon dioxide equivalent) in these primary categories for reporting year 2021: GHG emissions resulting from combustion at seven compressor stations and one underground gas storage facility, where the annual emissions exceed 10,000 mtCO2e; the GHG emissions resulting from combustion of delivered gas to all customers; and vented and fugitive emissions from seven compressor stations and one underground gas storage facility.

Both the seven compressor stations obligation and PG&E's natural gas supplier obligation subject to the CARB mandatory reporting are subject to the CARB Cap-and-Trade Program. In 2021, CARB estimated that PG&E's responsibility for compliance obligations of GHG emissions as a natural gas supplier was approximately 17.9 million mtCO2e for reporting year 2020. CARB will issue the final 2020 PG&E's compliance obligations of GHG emissions as a natural gas supplier in October 2022.

In June 2021, PG&E filed the 2020 Annual Natural Gas Leakage Abatement Report and reported 3 billion standard cubic feet (Bscf) of methane emissions from intentional and unintentional releases. The annual report is a partial fulfillment of Rulemaking (R.) 15-01-008 to adopt rules and best practices aiming to reduce methane emissions from the Natural Gas System in application of SB 1371.

In addition, PG&E filed its two-year Leak Abatement Compliance Plan in March 2022. This plan addresses the 26 best practices outlined in the Leak Abatement OIR D.17-06-015. It emphasizes minimizing methane emissions through changes to policies and procedures, personnel training, leak detection, leak repair and leak prevention. PG&E's plan includes transitioning from the three-year gas distribution leak survey cycle to optimized leak surveys, potential reduction of the Super Emitter threshold, extending blowdown reduction strategies to compressor station and storage facilities, lowering the pipeline pressure to near zero for scheduled transmission projects and applying degassing technologies for In-Line Inspection (ILI) and lower volume transmission projects.

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Finally, PG&E is an active member and founding partner in the voluntary EPA Natural Gas STAR and Methane Challenge Programs, respectively, where annual reports are submitted to the EPA showcasing PG&E's efforts and best practices to reduce methane emissions. Each year, on a mandatory basis, PG&E reports its methane emissions to the California Public Utilities Commission and, on a voluntary basis, also reports—and obtains third-party verification for—a more comprehensive corporate greenhouse gas emissions inventory, including PG&E's methane emissions. Each year, PG&E also completes and publishes the Edison Electric Institute (EEI) and American Gas Association (AGA) voluntary Environmental, Social, Governance (ESG) and Sustainability reporting templates for investors, which includes methane emissions. PG&E believes it's essential that investors, customers, policymakers, and other stakeholders have access to information on PG&E's emissions profile. In addition, PG&E is committed through its 1-million-ton challenge to reduce GHG emissions from company operations through 2022. PG&E's strategy to meet this goal includes increased leak survey and repair, removing high-bleed pneumatic devices, replacing vintage distribution main, and reducing transmission pipeline blowdowns.

BIOMETHANE OIR R.13-02-008 PHASE 3

On July 5, 2018, the CPUC reopened R.13-02-008 Phase 3 and ordered the joint California utilities to propose a joint RNG interconnection tariff and interconnection agreements.

On October 28, 2020, the CPUC approved the joint utilities' Standard Renewable Gas Interconnection Tariff pursuant to D. 20-08-035 which established standards and requirements to permit the safe injection of RNG into a jurisdictional common carrier pipeline.

The CPUC also instituted a Reservation System in D.19-12-009 that became effective as of February 3, 2020, for the biomethane incentive program implemented by D.15-06-029.

BIOMETHANE OIR R.13-02-008 PHASE 4

On November 21, 2019, the CPUC issued a Ruling to establish Phase 4 of the proceeding that will address injection of renewable H2 into gas pipelines and implementation of SB 1440 (RNG procurement).

On February 24, 2022, the CPUC approved D.22-02-025 implementing Senate Bill 1440 establishing a framework of a mandatory Biomethane Procurement Program. This Biomethane Procurement Program will assist the state in meeting short-lived climate pollutant emissions reduction goals by requiring the Joint Utilities to procure biomethane (RNG) produced from organic waste for their core customers.

On April 5, and 6, 2022, the Joint Utilities hosted public workshops to discuss the Standard Biomethane Procurement Methodology (SBPM) that included panelists from each stakeholder group. The Joint Utilities are directed to file a joint Tier 2 Advice Letter with a report of the workshop and feedback received. On April 22, 2022, the Joint Utilities hosted a separate public workshop to discuss the Renewable Gas Procurement Plan (RGPP) that also included panelists from each stakeholder group. The Joint Utilities are directed to file a Tier 1 Advice Letter to establish a template RGPP. The joint utilities plan to file a new application outlining three distinct H_2 projects to further understand capabilities of H_2 and inform a statewide injection standard.

GAS SYSTEM PLANNING OIR R.20-01-007

The CPUC has an in-progress Rulemaking - Order Instituting Rulemaking to “Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning.” This proceeding will be conducted in two tracks and will: (1) develop and adopt as necessary updated reliability standards that reflect current and future operational challenges to gas system operators, (2) determine the regulatory changes to improve coordination between gas utilities and gas-fired generators, and (3) implement a long-term planning strategy to manage the transition away from natural gas-fueled technologies to meet California’s decarbonization goals. This proceeding is currently in track two.

ABNORMAL PEAK DAY DEMAND AND SUPPLY

APD DEMAND FORECAST

The Abnormal Peak Day (APD) forecast is a projection of demand under extreme weather conditions. PG&E defines an APD as a 1-in-90 year cold temperature event. The 1-in-90 temperature corresponds to a 28.3 degree Fahrenheit system weighted mean temperature across the PG&E system. The PG&E core demand forecast corresponding to a 28.3 degree Fahrenheit temperature is estimated to be approximately 3.0 Bcf/d. The PG&E load forecast shown here excludes all noncore demand and excludes all electric generation (EG) demand. Under an APD design scenario PG&E is only required to ensure that it can supply enough gas to core customers on the system.

The APD core forecast in the table below is developed using the observed relationship between historical daily weather and core usage data. This relationship is then used to forecast the core load under APD conditions.

APD SUPPLY REQUIREMENT FORECAST

For APD planning purposes, supplies will flow under core Procurement's firm capacity, any as-available capacity, and capacity made available pursuant to supply diversion arrangements. Supplies could also be purchased from noncore suppliers. Flowing supplies may come from Canada, the U.S. Southwest, the Rocky Mountain region, SoCalGas, and California production. Also, a significant part of the APD demand will be met by storage withdrawals from PG&E's and independent storage providers' underground storage facilities located within Northern and Central California.

PG&E's Core Gas Supply Department is responsible for procuring adequate flowing supplies to serve approximately 80 percent of PG&E's core gas usage. Core aggregators provide procurement services for the remaining balance of PG&E's core customers and have the same obligation as PG&E Core Gas Supply to make and pay for all necessary arrangements to deliver gas to PG&E to match the use of their customers.

In previous extreme cold weather events, PG&E has observed a drop in flowing pipeline supplies. Supply from Canada is affected as cold weather drops south from Canada with a two- to three-day lag before hitting PG&E's service territory. There is also impact on supply from the Southwest. While prices can influence the availability of supply to PG&E's system, cold weather can affect producing wells in the basins, which in turn can affect the total supply to the PG&E system and others.

If core supplies are insufficient to meet core demand, PG&E can divert gas from noncore customers, including EG customers, to meet demand. PG&E's tariffs contain diversion and Emergency Flow Order non-compliance charges that are designed to cause the noncore market to either reduce or cease its use of gas, if required. Since little, if any, alternate fuel-burn capability exists today, supply diversions from the noncore would necessitate those noncore customers to curtail operations. Under supply-shortfall conditions—such as an APD—a significant portion of EG customers could be shut down potentially impacting electric system reliability.

TABLE 19 – FORECAST OF CORE GAS DEMAND AND SUPPLY ON AN ABNORMAL PEAK DAY (APD)
(MMcf/d)

Line No.		2022-23	2023-24	2024-25
1	APD Core Demand (1)	3,057	3,062	3,070
2	Independent Storage Provider Withdrawal (2)	2,162	2,162	2,162
3	Firm Flowing Supply (3)	3,051	3,051	3,051
4	Projected Resources to Meet Demands (4)	4,232	4,193	4,108

Notes:
(1) Includes PG&E's Gas Procurement Department's and other Core Aggregator's core customer demands. APD core demand forecast is calculated for 28.3 degrees F system composite temperature, corresponding to 1-in-90-year cold temperature event. PG&E uses a system composite temperature based on six weather sites.
(2) The Independent Storage Provider Withdrawal is based on information provided by the Independent Storage Providers to PG&E and internal analysis by PG&E.
(3) The Firm Flowing Supply includes firm Redwood and Baja capacities and nominal amounts of California gas production. These values are those currently approved for use within PG&E.
(4) Projected Resources to Meet Demands (Line No. 4) are less than the sum of Independent Storage Provider Withdrawal (Line No. 2) and Firm Flowing Supply (Line No. 3) because PG&E's system cannot simultaneously accommodate all flowing supplies and all storage withdrawals. This number is designed for a 1-in-10 design scenario while an APD is a 1-in-90 design scenario, meaning this number may not be representative of what the actual supply on a 1-in-90 day will be, but is sufficient to meet all APD Core demand.

The tables below provide peak day demand projections on PG&E's system for both winter month (December) and summer month (August) periods under PG&E's high Peak Day Demand Cases.

TABLE 20– WINTER PEAK DAY DEMAND
(MMcf/d)

Year	Core Unadjusted for Building Electrification	Building Electrification Modifier	Core With Building Electrification	Noncore Non-EG	EG, Including SMUD	Total Demand
2022-2023	2,574	-2	2,572	458	897	3,927
2023-2024	2,579	-4	2,575	460	908	3,942
2024-2025	2,585	-6	2,579	475	929	3,984
2025-2026	2,591	-8	2,582	488	983	4,054
2026-2027	2,600	-11	2,589	489	1,006	4,085
2027-2028	2,609	-17	2,592	490	1,021	4,104

The core demand in the Winter Peak Day Demand table is developed using the observed relationship between historical daily weather and core gas usage. This relationship is then used to forecast the core load under a 1-in-10 temperature scenario. The building electrification modifier represents the California Energy Commission's 2021 Integrated Energy Policy Report Additional Achievable Fuel Substitution (Low Case, AAFS 2)[77]. The projection in the AAFS 2 represents the building electrification, moving from natural gas use to electric use. The noncore Non-EG forecast is the average daily December demand under 1-in-10 Cold and Dry conditions. Last, the EG, including SMUD projection is the 90th percentile for the months of December through February under 1-in-10 Cold, Dry Hydro Demand conditions.

[77] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report .

TABLE 21 – SUMMER PEAK DAY DEMAND
(MMcf/d)

Year	Core Unadjusted for Building Electrification	Building Electrification Modifier	Core With Building Electrification	Noncore Non-EG	EG, Including SMUD	Total Demand
2022	353	-3	351	585	979	1,914
2023	340	-5	335	598	929	1,892
2024	330	-7	323	610	927	1,860
2025	319	-10	309	615	853	1,777
2026	309	-13	296	616	978	1,890
2027	304	-17	287	616	1,025	1,929

The core and noncore Non-EG demands in the Summer Peak Day Demand table represent the average August daily summer demand under 1-in-10 cold and dry conditions. The building electrification modifier represents the California Energy Commission's 2021 Integrated Energy Policy Report Additional Achievable Fuel Substitution (Low Case, AAFS 2). Last, the EG including SMUD demand forecast is the 90th percentile for the months of July through September under 1-in-10 cold and dry conditions.

2022 CALIFORNIA GAS REPORT

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TABLE 22

ANNUAL GAS SUPPLY AND REQUIREMENTS
RECORDED YEARS 2017-2021
MMCF/DAY

LINE		2017	2018	2019	2020	2021
GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS					
1	Core Purchases	0	0	0	0	0
2	Customer Gas Transport & Exchange	42	49	62	63	60
3	Total California Source Gas	42	49	62	63	60
	OUT-OF-STATE GAS					
	Core Net Purchases					
6	Rocky Mountain Gas	178	161	170	158	158
7	U.S. Southwest Gas	84	58	58	41	29
8	Canadian Gas	319	303	286	379	410
	Customer Gas Transport					
10	Rocky Mountain Gas	461	367	486	416	329
11	U.S. Southwest Gas	304	430	599	505	539
12	Canadian Gas	832	957	888	927	933
13	Total Out-of-State Gas	2,178	2,276	2,487	2,425	2,397
14	STORAGE WITHDRAWAL(2)	328	397	350	252	344
15	Total Gas Supply Taken	2,548	2,722	2,898	2,740	2,801
GAS SENDOUT						
	CORE					
19	Residential	483	489	503	495	488
20	Commercial	220	225	226	196	209
21	NGV	7	7	7	7	7
22	Total Throughput-Core	710	721	736	698	704
	NONCORE					
24	Industrial	543	562	534	467	453
25	Electric Generation (1)	698	855	865	895	964
26	NGV	2	3	4	3	4
27	Total Throughput-Noncore	1,244	1,421	1,403	1,365	1,421
28	WHOLESALE	9	9	9	8	8
29	Total Throughput	1,963	2,151	2,148	2,072	2,133
30	OFF-SYSTEM DELIVERIES	233	264	224	241	284
31	CALIFORNIA EXCHANGE GAS	14	22	38	37	38
32	STORAGE INJECTION (2)	294	244	441	343	292
33	SHRINKAGE Company Use / Unaccounted for	44	41	47	47	55
34	Total Gas Send Out	2,548	2,722	2,898	2,740	2,801
	TRANSPORTATION & EXCHANGE					
38	CORE ALL END USES	139	139	138	115	111
39	NONCORE INDUSTRIAL	543	562	534	467	453
40	ELECTRIC GENERATION	698	855	865	895	964
41	SUBTOTAL/RETAIL	1,380	1,557	1,538	1,477	1,529
43	WHOLESALE/INTERNATIONAL	9	9	9	8	8
45	TOTAL TRANSPORTATION AND EXCHANGE	1,389	1,566	1,547	1,485	1,537
	CURTAILMENT/ALTERNATIVE FUEL BURNS					
48	Residential, Commercial, Industrial	0	0	0	0	0
49	Utility Electric Generation	0	0	0	0	0
50	TOTAL CURTAILMENT (3)	0	0	0	0	0

NOTES:

(1) Electric generation includes SMUD, cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by other pipelines.

(2) Includes both PG&E and third party storage

(3) UEG curtailments include voluntary oil burns due to economic, operational, and inventory reduction reasons as well as involuntary curtailments due to supply shortages and capacity constraints.

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TABLE 23

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2022	2023	2024	2025	2026	LINE
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**	56	56	56	56	56	1
	Out of State Gas						
2	Baja Path [(1)]	960	960	960	960	960	2
3	Redwood Path [(2)]	2,060	2,060	2,060	1,915	1,915	3
3.a	SW Gas Corp. from Great Basin Gas Transmission Company	39	39	39	39	39	3.a
4	**Supplemental** [(3)]	0	0	0	0	0	4
5	**Total Supplies Available**	3,115	3,115	3,115	2,970	2,970	5
GAS SUPPLY TAKEN							
6	**California Source Gas**	56	56	56	56	56	6
7	**Out of State Gas (via existing facilities)**	2,049	2,054	2,043	2,038	2,063	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,105	2,110	2,099	2,094	2,119	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,105	2,110	2,099	2,094	2,119	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential [(4)]	491	473	460	445	432	12
13	Commercial	208	214	213	210	208	13
14	NGV	7	7	8	8	8	14
15	**Total Core**	706	694	680	664	648	15
	Noncore						
16	Industrial	462	477	492	497	498	16
17	SMUD Electric Generation [(5)]	96	96	96	96	96	17
18	PG&E Electric Generation [(6)]	484	448	441	442	481	18
19	NGV	4	4	4	4	4	19
20	Wholesale	9	9	9	9	9	20
21	California Exchange Gas	38	38	38	38	38	21
22	**Total Noncore**	1,093	1,072	1,080	1,087	1,127	22
23	**Off-System Deliveries** [(7)]	272	310	305	310	310	23
	Shrinkage						
24	Company use and Unaccounted for	34	34	34	34	34	24
25	**TOTAL END USE**	2,105	2,110	2,099	2,094	2,119	25
	TRANSPORTATION & EXCHANGE						
26	CORE — ALL END USES	117	117	116	113	111	26
27	NONCORE — COMMERCIAL/INDUSTRIAL	504	519	534	539	540	27
28	ELECTRIC GENERATION	580	544	537	538	577	28
29	SUBTOTAL/RETAIL	1,201	1,180	1,186	1,191	1,229	29
30	WHOLESALE/INTERNATIONAL	9	9	9	9	9	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,210	1,189	1,195	1,200	1,238	31
32	System Curtailment	0	0	0	0	0	32

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, and El Paso pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via TransCanada Gas Transmission Northwest pipeline and Ruby pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Includes Southwest Gas direct service to its northern California service area.
(5) Forecast by SMUD.
(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(7) Deliveries to southern California.

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY
AVERAGE DEMAND YEAR

TABLE 24

LINE			2027	2028	2029	2030	2035	LINE
FIRM CAPACITY AVAILABLE								
1	**California Source Gas**		56	56	56	56	56	1
	Out of State Gas							
2	Baja Path [1]		960	960	960	960	960	2
3	Redwood Path [2]		1,915	1,915	1,915	1,915	1,915	3
3.a	SW Gas Corp. from Great Basin Gas Transmission Company		39	39	39	39	39	3.a
4	**Supplemental [3]**		0	0	0	0	0	4
5	**Total Supplies Available**		2,970	2,970	2,970	2,970	2,970	5
GAS SUPPLY TAKEN								
6	**California Source Gas**		56	56	56	56	56	6
7	**Out of State Gas (via existing facilities)**		1,749	1,738	1,722	1,698	1,681	7
8	**Supplemental**		0	0	0	0	0	8
9	**Total Supply Taken**		1,805	1,794	1,778	1,754	1,737	9
10	**Net Underground Storage Withdrawal**		0	0	0	0	0	10
11	**Total Throughput**		1,805	1,794	1,778	1,754	1,737	11
REQUIREMENTS FORECAST BY END USE								
	Core							
12	Residential [4]		423	412	402	391	338	12
13	Commercial		205	200	195	189	163	13
14	NGV		8	8	9	9	10	14
15	**Total Core**		636	620	605	589	511	15
	Noncore							
16	Industrial		499	499	499	498	496	16
17	SMUD Electric Generation [5]		96	96	96	96	96	17
18	PG&E Electric Generation [6]		489	493	493	486	549	18
19	NGV		4	5	5	5	5	19
20	Wholesale		9	9	9	9	9	20
21	California Exchange Gas		38	38	38	38	38	21
22	**Total Noncore**		1,135	1,140	1,139	1,132	1,193	22
23	**Off-System Deliveries [7]**		0	0	0	0	0	23
	Shrinkage							
24	Company use and Unaccounted for		33	33	33	33	33	24
25	**TOTAL END USE**		1,805	1,794	1,778	1,754	1,737	25
	TRANSPORTATION & EXCHANGE							
26	CORE	ALL END USES	109	106	104	101	86	26
27	NONCORE	COMMERCIAL/INDUSTRIAL	541	542	541	541	539	27
28		ELECTRIC GENERATION	585	589	589	582	645	28
29		SUBTOTAL/RETAIL	1,236	1,238	1,234	1,223	1,270	29
30		WHOLESALE/INTERNATIONAL	9	9	9	9	9	30
31		TOTAL TRANSPORTATION AND EXCHANGE	1,245	1,246	1,243	1,232	1,279	31
32	System Curtailment		0	0	0	0	0	32

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, and El Paso pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via TransCanada Gas Transmission Northwest pipeline and Ruby pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Includes Southwest Gas direct service to its northern California service area.
(5) Forecast by SMUD.
(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(7) Deliveries to southern California.

NORTHERN CALIFORNIA

TABLE 25

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY
HIGH DEMAND YEAR

LINE		2022	2023	2024	2025	2026	LINE
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**	56	56	56	56	56	1
	Out of State Gas						
2	Baja Path [(1)]	960	960	960	960	960	2
3	Redwood Path [(2)]	2,060	2,060	2,060	1,915	1,915	3
3.a	SW Gas Corp. from Great Basin Gas Transmission Company	39	39	39	39	39	3.a
4	**Supplemental** [(3)]	0	0	0	0	0	4
5	**Total Supplies Available**	3,115	3,115	3,115	2,970	2,970	5
GAS SUPPLY TAKEN							
6	**California Source Gas**	56	56	56	56	56	6
7	**Out of State Gas (via existing facilities)**	2,109	2,149	2,144	2,141	2,177	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,165	2,205	2,200	2,197	2,233	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,165	2,205	2,200	2,197	2,233	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential [(4)]	527	512	500	485	472	12
13	Commercial	224	224	222	220	217	13
14	NGV	7	7	8	8	8	14
15	**Total Core**	758	744	729	713	698	15
	Noncore						
16	Industrial	467	480	493	499	499	16
17	SMUD Electric Generation [(5)]	96	96	96	96	96	17
18	PG&E Electric Generation [(6)]	485	490	490	493	543	18
19	NGV	3	4	4	4	4	19
20	Wholesale	10	10	10	10	10	20
21	California Exchange Gas	38	38	38	38	38	21
22	**Total Noncore**	1,099	1,116	1,131	1,139	1,190	22
23	**Off-System Deliveries** [(7)]	272	310	305	310	310	23
	Shrinkage						
24	Company use and Unaccounted for	36	35	35	35	35	24
25	**TOTAL END USE**	2,165	2,205	2,200	2,197	2,233	25
	TRANSPORTATION & EXCHANGE						
26	CORE — ALL END USES	126	124	122	120	118	26
27	NONCORE — COMMERCIAL/INDUSTRIAL	508	521	535	540	541	27
28	ELECTRIC GENERATION	581	586	586	589	639	28
29	SUBTOTAL/RETAIL	1,215	1,231	1,244	1,249	1,299	29
30	WHOLESALE/INTERNATIONAL	10	10	10	10	10	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,225	1,241	1,253	1,259	1,308	31
32	System Curtailment	0	0	0	0	0	32

NOTES:

(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, and El Paso pipelines.

(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via TransCanada Gas Transmission Northwest pipeline and Ruby pipeline.

(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.

(4) Includes Southwest Gas direct service to its northern California service area.

(5) Forecast by SMUD.

(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.

(7) Deliveries to southern California.

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY
HIGH DEMAND YEAR

TABLE 26

LINE		2027	2028	2029	2030	2035	LINE
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**	56	56	56	56	56	1
	Out of State Gas						
2	Baja Path [(1)]	960	960	960	960	960	2
3	Redwood Path [(2)]	1,915	1,915	1,915	1,915	1,915	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.	39	39	39	39	39	3.a
4	**Supplemental** [(3)]	0	0	0	0	0	4
5	**Total Supplies Available**	2,970	2,970	2,970	2,970	2,970	5
GAS SUPPLY TAKEN							
6	**California Source Gas**	56	56	56	56	56	6
7	**Out of State Gas (via existing facilities)**	1,876	1,863	1,844	1,821	1,800	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	1,932	1,919	1,900	1,877	1,856	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	1,932	1,919	1,900	1,877	1,856	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential [(4)]	463	452	441	431	378	12
13	Commercial	214	209	204	199	172	13
14	NGV	8	8	9	9	10	14
15	**Total Core**	685	670	654	638	560	15
	Noncore						
16	Industrial	500	500	500	500	497	16
17	SMUD Electric Generation [(5)]	96	96	96	96	96	17
18	PG&E Electric Generation [(6)]	565	567	564	557	616	18
19	NGV	4	4	4	4	5	19
20	Wholesale	10	9	9	9	9	20
21	California Exchange Gas	38	38	38	38	38	21
22	**Total Noncore**	1,213	1,215	1,212	1,205	1,261	22
23	**Off-System Deliveries** [(7)]	0	0	0	0	0	23
	Shrinkage						
24	Company use and Unaccounted for	35	35	34	34	35	24
25	**TOTAL END USE**	1,932	1,919	1,900	1,877	1,856	25
	TRANSPORTATION & EXCHANGE						
26	CORE ALL END USES	116	113	110	108	93	26
27	NONCORE COMMERCIAL/INDUSTRIAL	542	543	542	542	540	27
28	ELECTRIC GENERATION	661	663	660	653	712	28
29	SUBTOTAL/RETAIL	1,319	1,319	1,313	1,303	1,345	29
30	WHOLESALE/INTERNATIONAL	10	9	9	9	9	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,329	1,328	1,322	1,312	1,355	31
32	System Curtailment	0	0	0	0	0	32

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, and El Paso pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via TransCanada Gas Transmission Northwest pipeline and Ruby pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Includes Southwest Gas direct service to its northern California service area.
(5) Forecast by SMUD.
(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(7) Deliveries to southern California.

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2022 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY

INTRODUCTION

SoCalGas is the principal distributor of natural gas in Southern California and provides retail and wholesale customers with transportation, exchange, storage services and also procurement services to most retail core customers. SoCalGas' distribution network is composed of approximately 51,070 miles of gas mains across an approximate 20,000 square mile service territory. Together with its intricate distribution network and transmission pipelines and four interconnected storage fields, SoCalGas delivered natural gas to over 5.874 million customers in 2021.

SoCalGas' vast system extends from the Colorado River on the eastern end to the Pacific Ocean on the western end and extending as far north as Tulare County and reaches the U.S./Mexico Border in the south (excluding San Diego County).

Figure 11: SoCalGas' Service Territory Map

Southern California

SoCalGas is a gas-only utility and, in addition to serving the residential, commercial, and industrial markets, provides gas for enhanced oil recovery (EOR) and electric generation (EG) customers in Southern California. SDG&E, SWG, the City of Long Beach Energy Resources Department, and the City of Vernon are SoCalGas' four wholesale utility customers. SoCalGas provides gas transportation services across its service territory to a border crossing point at the California-Mexico border at Mexicali to ECOGAS Mexico S. de R.L. de C.V which is a wholesale international customer located in Mexico.

This report covers a 14-year demand and forecast period, from 2022 through 2035; only the consecutive years 2022 through 2030 and the point year 2035 are shown in the tabular data in the next sections. All forecasts are subject to uncertainty, but represent best estimates for the future, based upon the most current information available.

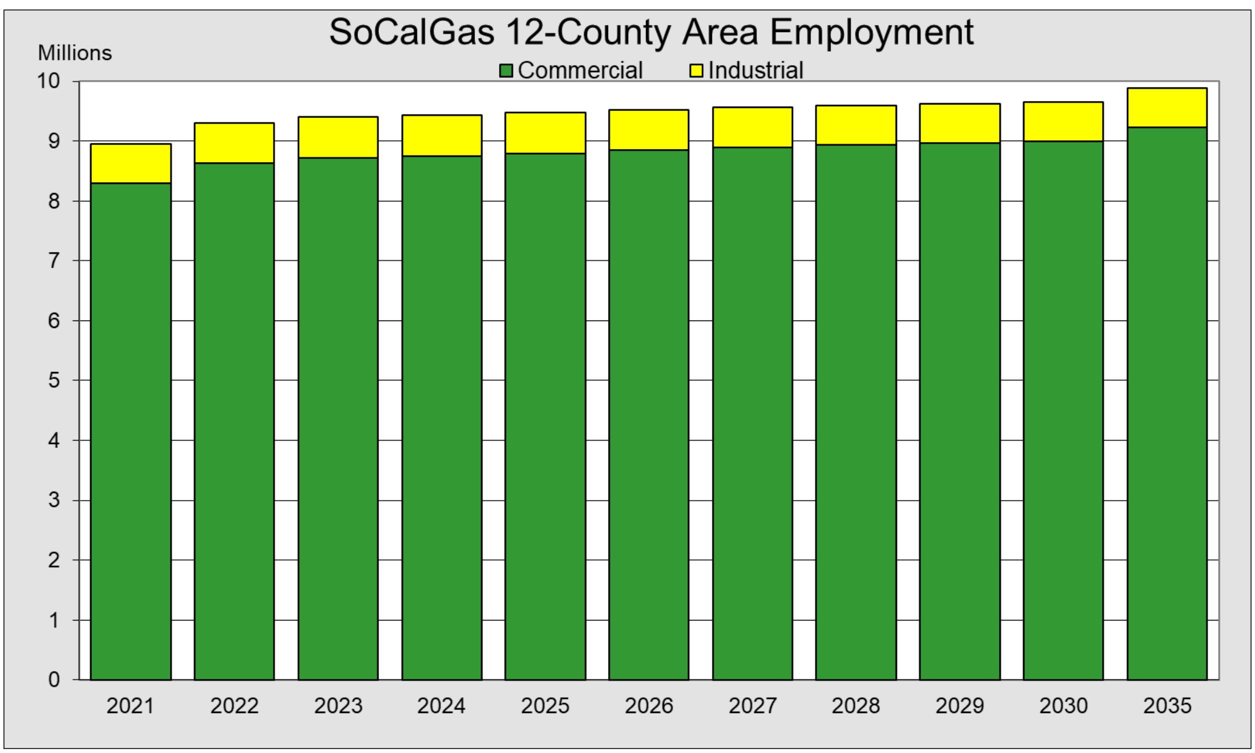
The Southern California section of the 2022 CGR begins with a discussion of the economic conditions and regulatory issues facing the utilities, followed by a discussion of the factors affecting natural gas demand in various market sectors. The outlook on natural gas supply availability, which continues to be favorable, is also presented. The regulatory environment and GHG issues are also discussed, followed by a review of the peak day demand forecast. Summary tables and figures underlying the forecast are also provided.

THE SOUTHERN CALIFORNIA ENVIRONMENT

ECONOMICS AND DEMOGRAPHICS

The gas demand projections are in large part determined by the long-term economic outlook for the SoCalGas service territory. After 2020's severe slowdown from the Covid-19 pandemic and related government restrictions, southern California's economy has nearly fully recovered. Total SoCalGas area jobs are expected to grow an average of 1.4% per year from 2021 through 2025. Local manufacturing and mining industrial employment is projected to average just 0.5% annual growth in the same period, with commercial jobs increasing about 1.5% annually. Jobs in accommodation, personal, and professional and business services should grow faster in the near term, as they recover from their pandemic plunge.

FIGURE 12 – SoCalGas 12-COUNTY AREA EMPLOYMENT



Southern California

Longer term, SoCalGas service-area employment is expected to increase slowly as population growth slows due to population aging and to more residents leaving for lower-cost locations primarily within the United States. From 2021 through 2035, total area job growth should average 0.7 percent per year. Area industrial jobs are forecasted to shrink an average of 0.1 percent per year through 2035; we expect the industrial share of total employment to fall from 7.4 percent in 2021 to 6.6 percent by 2035. Commercial jobs are expected to grow an average of 0.8 percent annually from 2021 through 2035.

Home building and meter hookups are expected to increase significantly in the next few years after the recent pandemic slowdown. Longer term growth should be sustained by pent-up demand and efforts to lessen southern California's longtime housing shortage. Net active meter growth --driven mainly by new home construction-- is projected to recover from a low pandemic-pressured 27,400 (+0.47 percent) in 2021, to 42,700 (+0.73 percent) in 2022 and 42,300 (+0.72 percent) in 2023--about the same percentage growth as last seen in 2017. Longer term, SoCalGas expects active meters to average about 0.6 percent annual growth from 2021 through 2035.

GAS DEMAND (REQUIREMENTS)

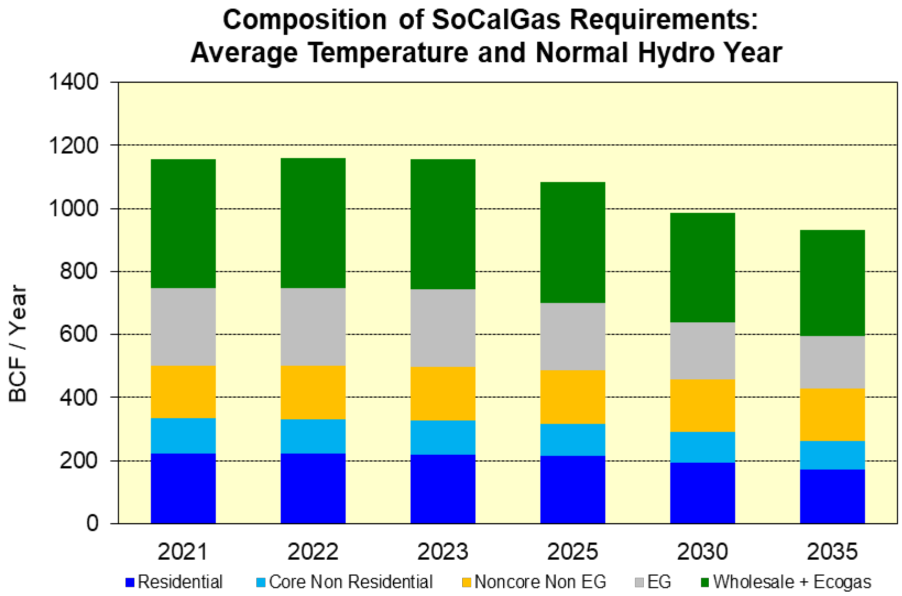
OVERVIEW

SoCalGas projects total gas demand to decline at an annual rate of 1.5 percent from 2022 to 2035. By comparison, the total gas demand had been projected to decline at an annual rate of 1.1 percent in the 2020 CGR. The forecasted, accelerated decline in throughput demand is being driven by modest economic growth and the forecasted energy efficiency and fuel substitution. Other factors that contribute to the downward trend are tighter standards created by revised Title 24 Codes and Standards, and renewable energy goals that impact gas-fired electricity.

The core, non-residential markets (comprised of core commercial, core industrial and natural gas vehicles (NGV)) are expected to decline at an average annual rate of 1.4 percent or from 224 Bcf in 2021 to 170 Bcf by 2035. However, the NGV market is expected to grow 2.1 percent over the forecast horizon. The NGV market is expected to grow due to government (federal, state and local) incentives and regulations encouraging the purchase and operation of alternate fuel vehicles as well as the increased use of RNG that provides significant GHG emission reduction benefits. The noncore, non EG- markets are expected to decline 0.1 percent from 167 Bcf in 2021 to 165 Bcf by 2035. That decline is being driven by very aggressive energy efficiency goals and associated programs. Total EG load, including large cogeneration and non-cogeneration- EG for a normal hydro year, is expected to decline from 243 Bcf in 2021 to 168 Bcf in 2035, a decrease of 2.6 percent per year.

The chart shows the composition of SoCalGas' throughput for the recorded year 2021 (with weather-sensitive market segments adjusted to average year HDD assumptions) and forecasts for the 2022 to 2035 forecast period.

FIGURE 13 – COMPOSITION OF SOCALGAS REQUIREMENTS AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR (2021-2035)



Notes:
(1) Core non-residential includes core commercial, core industrial, gas air-conditioning, gas engine, NGVs
(2) Non-core non-EG includes non-core commercial, non-core industrial, industrial refinery, and EOR-steaming
(3) Retail EG includes industrial and commercial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration EG.
(4) Wholesale includes sales to the City of Long Beach, City of Vernon, SDG&E, SWG, and Ecogas in Mexico.

MARKET SENSITIVITY

Temperature

Core demand forecasts are prepared for two design temperature conditions—average year and cold year—to quantify changes in space heating demand due to weather. Temperature variations can cause significant changes in winter gas demand due to space heating in the residential, core commercial and core industrial markets. The largest core demand variations due to temperature are likely to occur in the month of December. Heating degree day (HDD) differences between the two temperature conditions are developed from a six-zone temperature monitoring procedure within SoCalGas' service territory. One HDD is defined as when the average temperature for the day drops 1 degree below 65 degrees F. The cold design temperature conditions are based on a statistical likelihood of occurrence of 1-in-35 on an annual basis.

In our 2022 CGR, SoCalGas and SDG&E have included a climate-change warming trend that gradually reduces HDD's over the forecast period. First, average temperature year values were computed as the simple average of annual HDD's for the calendar years 2002 through 2021: 1,248 HDD's for SoCalGas and 1,158 HDD's for SDG&E. Corresponding 1-in-35 cold year HDD's were 1,476 for SoCalGas and 1,368 for SDG&E. For the forecast period, projected annual HDD's were reduced each year by 6 HDD's for both SoCalGas and SDG&E. For SoCalGas, projected average year and cold year HDD's both drop by 6 HDD annually: from 1,242 and 1,470 in year 2022, to 1,164 and 1,392 in year 2035. For SDG&E, projected average year and cold year HDD's drop by 6 HDD annually: from 1,152 and 1,362 in year 2022, to 1,074 and 1,284 in year 2035. The annual reductions are based on the latest 20-year trend in 20-year-averaged HDDs. That is, they are based on the observed trend in changes starting with average HDD's for years 1983-2002, then 1984-2003, 1985-2004...and ending with the average HDD's for years 2002-2021.

Southern California

Hydro Conditions

The EG forecasts are prepared for two hydro conditions—average year and dry hydro. The dry hydro case refers to gas demand in a 1-in-10 dry hydro year.

MARKET SECTORS

Residential

SoCalGas served approximately 5.67 million residential customers consisting of 3.79 million single-family households, 1.84 million multi-family households and 38,610 master meters in 2021. Residential usage varies for each of the market segments. Conditional demand estimates based on the 2019 Residential Appliance Saturation Survey (R.A.S.S.) indicate customer needs. This updated information formed part of the basis for the 2022 CGR residential market forecast.

The table below shows the weather-normalized home usage by customer type and the saturations by end use for SoCalGas based upon the conditional demand study update.

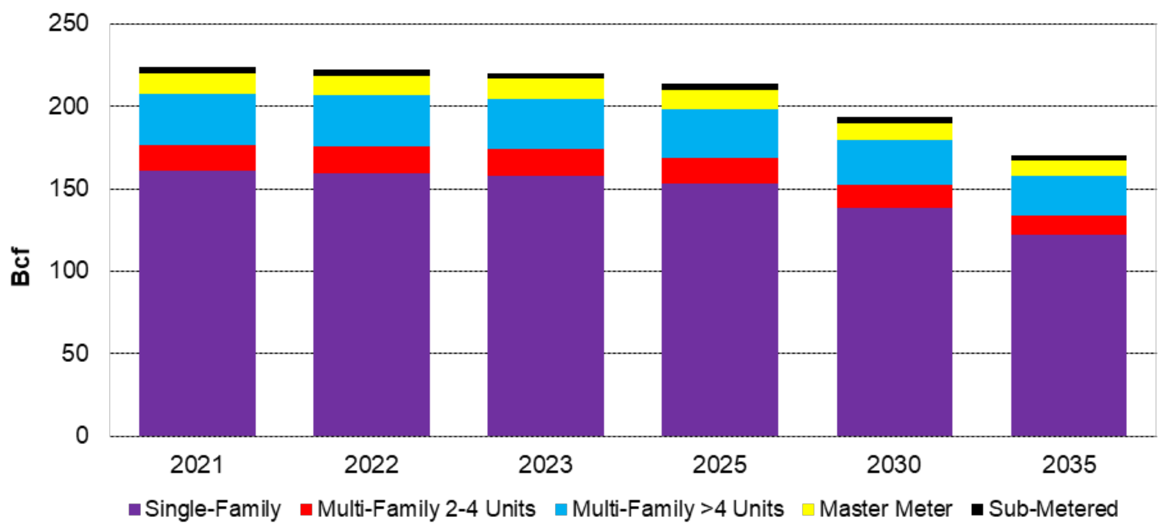
Table 27: SoCalGas Residential Appliance Saturation Survey Results, 2019 Update

		2019 Residential Appliance Saturation Survey								
		Conditional Demand Study								
SoCalGas		Single Family Unit Energy Consumption (UEC)	Single Family Saturation (%)	Single Family Intensity	Single Family Use Proportion		Multi Family Unit Energy Consumption	Multi Family Saturation	Multi Family Intensity	Multi Family Use Proportion
	Space Heat	227	98.62%	224	51.75%		107	89.98%	96	46.67%
	Water Heat	141	95.98%	135	31.28%		94	81.33%	76	37.05%
	Cooking	30	82.37%	25	5.71%		28	77.80%	22	10.56%
	Clothes Drying	33	69.36%	23	5.29%		29	35.19%	10	4.95%
	Pool Heat	151	8.37%	13	2.92%		N/A			
	Spa Heat	102	9.68%	10	2.28%		47	1.19%	1	0.27%
	Gas Fireplace	11	7.33%	1	0.19%		7	4.58%	0	0.16%
	Gas Barbecue	16	15.56%	2	0.58%		14	5.17%	1	0.35%
	Total Household SF			433 Therms/Year	100%				206 Therms/Year	100%

The conditional demand estimates based on the 2019 R.A.S.S. show that the average use per meter is 433 therms for single-family households and 206 therms for multi-family households. The use-per-customer data is constructive in forming the forecast. For the residential market, the change in the baseline forecast from one year to the next is based on the confluence of two immediate economic drivers. In any given year, the residential load will grow due to the new customer hookups that occur. New customers generate a growth in demand. Second, the residential load will change due to existing customers' (vintage customers') changing needs. When gas appliances reach the end of their useful life, customers make a choice about equipment replacement. The choice consists of either replacing the older appliance with a more energy efficient gas appliance or substituting their gas appliance with one using another fuel, namely electricity. Customer choices can be influenced by economic factors, such as capital and operating costs, among other things, and are a key component of the baseline forecast. The usage calculator that generates the forecast is called the end use model.

Southern California

Figure 14: Composition of SoCalGas' Residential Demand Forecast, 2021-2035



Residential gas demand is forecasted to decline from 224 Bcf in 2021 to 170 Bcf by 2035, or at an average annual rate of 1.9 percent. The decline is due to declining use per meter—primarily driven by very aggressive energy efficiency goals, anticipated fuel substitution, tightening Title 24 Codes and Standards, all of which affect the forecast by offsetting the new meter growth forecasted over the planning period.

As described above, SoCalGas' residential base forecast is developed from an end use model. The model results are modified by anticipated impacts of climate change as well as forecasts of policy adoptions that impact gas use. After the base forecast is developed, the forecast is modified by three out-of-model adjustments. The energy savings adjustments made to the forecast include (1) allowing for less heating degree days in the average weather design each year of the forecast period to account for climate change; (2) gas demand destruction due to greater energy efficiency savings forecast over the planning period; and (3) incremental energy savings created from assumed fuel substitution. All of the energy savings incorporated into the forecast reflect market potential and became load modifiers to create a final forecast of demand.

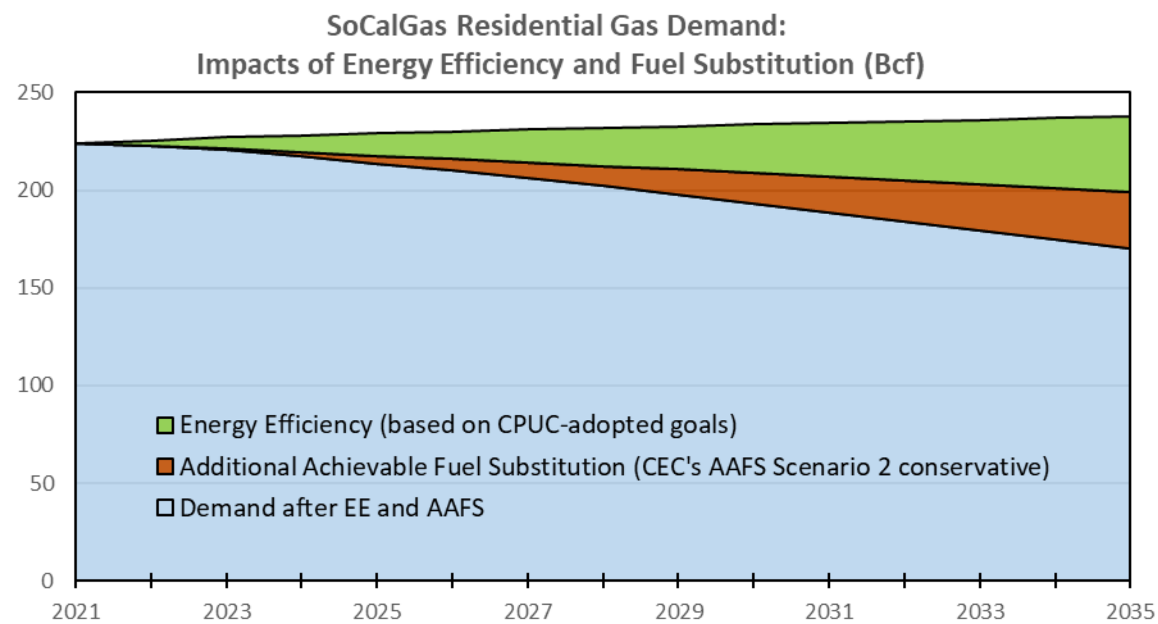
The major modifiers to the forecast are energy efficiency and building electrification. The energy efficiency forecast includes the confluence of two types of gas energy savings. Codes and Standards savings, which include current and expected modifications to Title 24, and the energy savings stemming from customer programs authorized by the CPUC's D.21-09-037. The baseline forecast was adjusted downward to account for these incremental energy saving influences that are expected to occur over the forecast period.

The final forecast also includes a load modifier for fuel substitution. For purposes of constructing a long-term reasonable forecast for the 2022 CGR, SoCalGas participated in an electrification working group committee together with PG&E, SDG&E and Southern California Edison (SCE) to evaluate different approaches and assumptions to modeling the effects of fuel substitution. After several meetings and discussions, SoCalGas aligned around the relatively conservative fuel substitution scenario forecast developed by the California Energy Commission. Fuel substitution was estimated and introduced separately from energy efficiency savings by the CEC in its 2021 IEPR as additional achievable fuel substitution (AAFS). Of the five possible fuel substitution scenarios developed by the CEC, the AAFS-2 Scenario, which is the CEC's mid-low scenario for electrification, was chosen by SoCalGas to prepare the final residential forecast. Scenario 2 quantifies the assumed fuel substitution that would take place with potential future updates in the Title 24 building standards and the presumed additional building electrification encouraged by future ratcheting driven by tighter goals, rate enhancements and higher uptake rates at future points in time. All of the above-mentioned gas reductions were included in the residential forecast as a modifier to the base forecast.

As can be seen from the following graph, the effects of both energy efficiency and fuel substitution have an impact on the residential market. By year 2035, the <u>*assumed*</u> additional energy efficiency removes 16 percent of residential gas demand. Evaluated separately, <u>*assumed*</u> additional fuel substitution removes another 12 percent of residential gas demand by 2035.

Southern California

Figure 15: SoCalGas: Residential Impacts of EE and AAFS



The final published forecast in this report is a product of the economic drivers in addition to policy drivers articulated and accounted for at the particular time the forecast was developed. As discussed elsewhere in this Report, much uncertainty remains in the timing, pace, extent, and overall evolution of residential natural gas demand in California.

Commercial

The core commercial market demand is expected to decline over the forecast period. On a temperature-adjusted basis, the 2021 core commercial market demand totaled 77 Bcf. By the year 2035, the load is anticipated to drop to approximately 56.5 Bcf. The average annual rate of decline from 2021-2035 is forecasted at 2.2 percent. The decline in gas usage is mainly the result of the impact of CPUC-authorized portfolio of energy efficiency programs and Title 24 codes building standards as well as some forecasted fuel substitution in this market.

In 2021, the noncore commercial temperature-adjusted usage was 17.4 Bcf. From 2021 through 2035, demand in this market is expected to be largely stable, reaching to about 17.7 Bcf in 2035. The noncore commercial market will be expected to grow at an average annual rate of 0.1 percent per year. Key factors of the trend are increasing commercial employment, commercial customers that move from core to noncore, and the CPUC-authorized energy efficiency programs.

FIGURE 16 – ANNUAL COMMERCIAL DEMAND FORECAST 2021-2035
BILLION CUBIC FEET PER YEAR (Bcf/y), AVERAGE YEAR WEATHER DESIGN

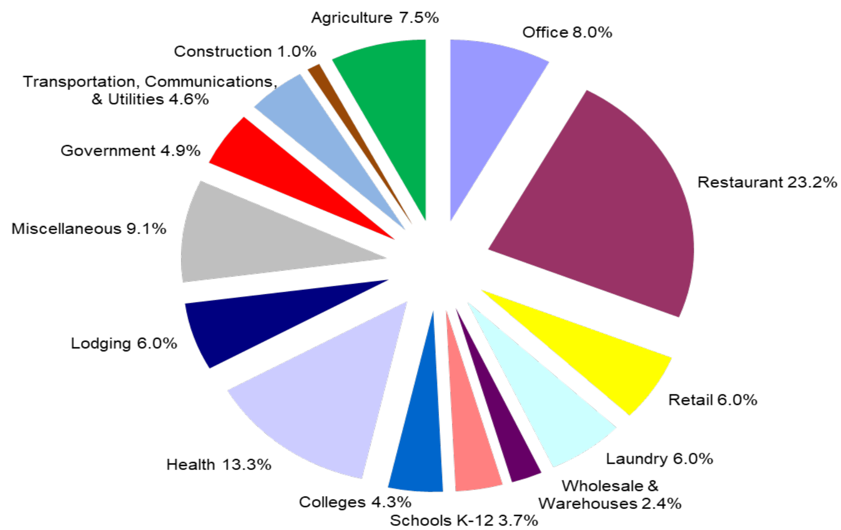
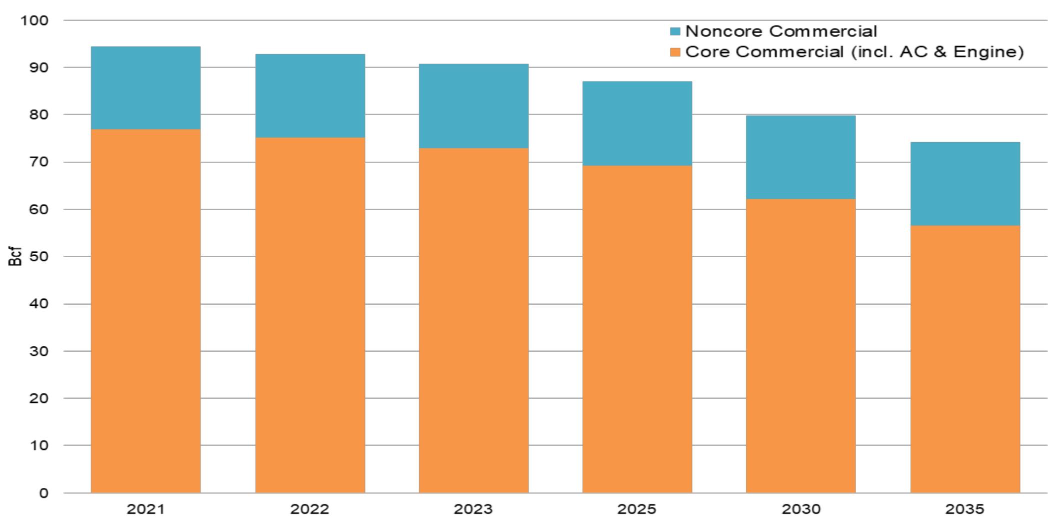


FIGURE 17 – COMMERCIAL GAS DEMAND BY BUSINESS TYPE
COMPOSITION OF INDUSTRY
(2021)



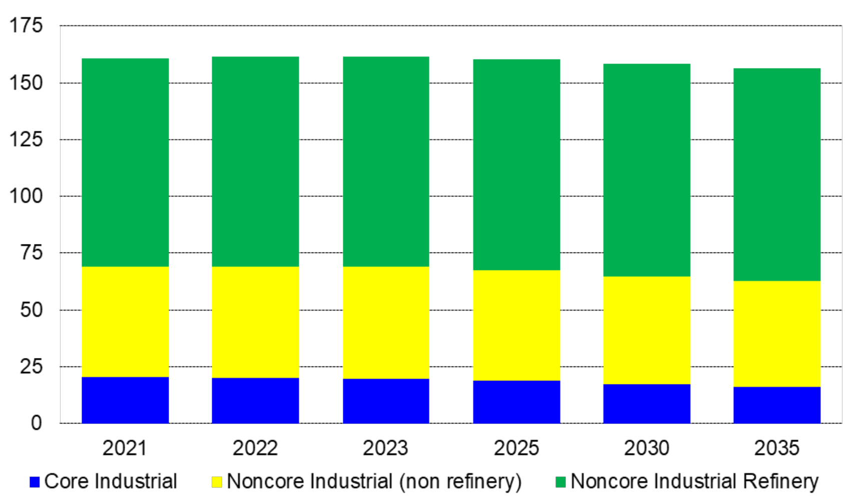
The commercial market consists of 14 business types identified by the customers' North American Industry Classification System codes. It represents includes both core and noncore usage. The restaurant business dominates this market with 23 percent of commercial usage in 2021, followed by the health services industry with a 13 percent share.

Industrial

Non-Refinery Industrial Demand

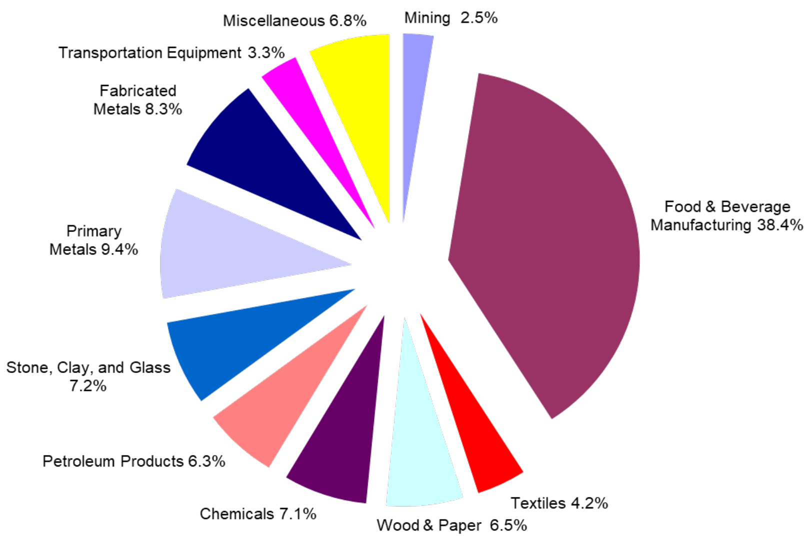
In 2021, temperature-adjusted core industrial demand was 20.4 Bcf. Core industrial market demand is projected to drop by 1.7 percent per year from 20.4 Bcf in 2021 to 16.1 Bcf in 2035. This decrease results from a combination of factors: a minor decrease in employment growth, an increase in marginal gas rates and CPUC-authorized energy efficiency programs.

FIGURE 18– ANNUAL INDUSTRIAL DEMAND FORECAST (Bcf)
(2021-2035)



The 2021 non-refinery industrial gas demand served by SoCalGas is shown below. Food and beverage manufacturing, with 38.4 percent of the total share, dominates this market. The graph below summarizes the composition of the core and noncore industrial market by business type.

FIGURE 19 INDUSTRIAL GAS DEMAND BY BUSINESS TYPE COMPOSITION OF INDUSTRY (2021)–



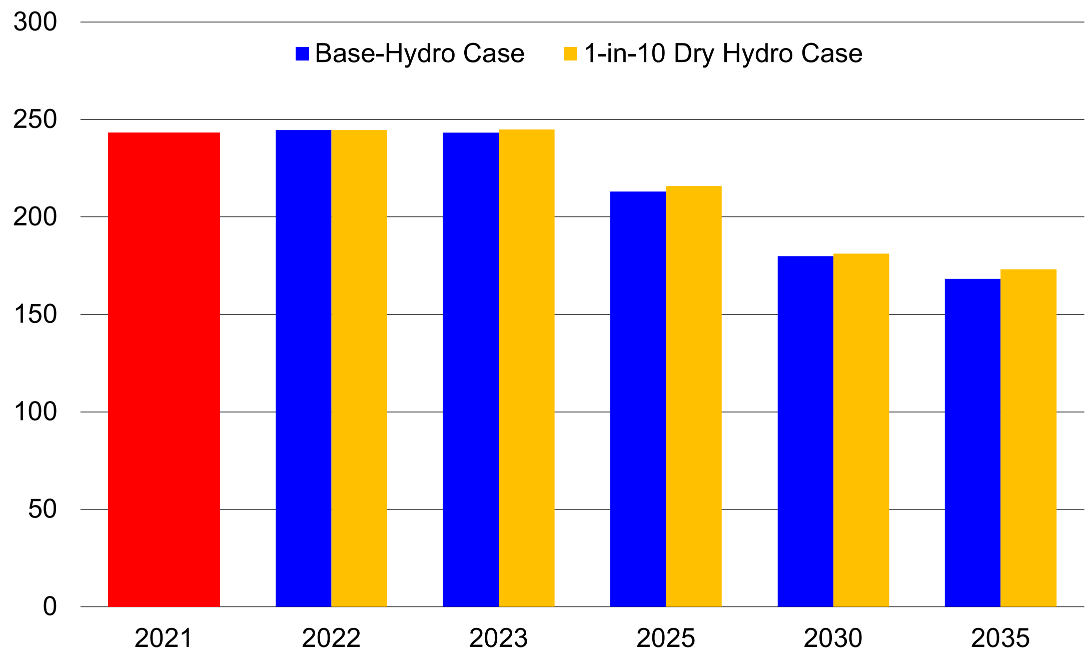
Gas demand for the retail noncore industrial (non-refinery) market is expected to decline at an annual rate of 0.3 percent from 48.6 Bcf in 2021 to 46.8 Bcf by 2035. The reduced demand is primarily due to the CPUC-authorized energy efficiency programs, decreasing industrial employment, and the departure of customers within the City of Vernon to wholesale service by the City of Vernon.

Refinery Industrial Demand

Refinery industrial demand is comprised of gas consumption by petroleum refining customers, H2 producers and refined petroleum product transporters. Gas demand in the refinery industrial market sector is forecasted to be largely stable over the 2022 - 2035 forecast period, from 91.7 Bcf in 2021 to 93.3 Bcf in 2035.

Electric Generation

FIGURE 20 – SoCalGas SERVICE AREA TOTAL EG
(Bcf)



The EG sector includes all commercial/industrial cogeneration, EOR-related cogeneration, and non-cogeneration electric generation. The EG load forecast is subject to a high degree of uncertainty. The forecast uncertainty is, in large part, due to load sensitivity to weather conditions, regional fuel price differences, the construction and retirement of power generating facilities (including thermal, renewable, and energy storage resources), the amount of California's import/export energy, and the state's overall long-term electricity demand growth. The EG gas throughput forecast can be higher or lower than the base case forecast, depending on the factors mentioned above. California's forecasted electricity demand is a major influence of southern California gas-demand EG. If the electricity demand forecast is higher, the EG gas throughput forecast would also tend to be higher. Please refer to the California Energy Commission's (CEC) 2021 Integrated Energy Policy Report for high, mid, and low electricity demand scenarios. On the supply side, lower SoCalGas Citygate gas prices relative to other regions, less energy imported into California, and dry hydro conditions are also factors that would increase the EG gas throughput forecast.

Additionally, many once through cooling (OTC) plants in California are scheduled to either retire or repower during the forecasted period. These are thermal plants, located near the coast, that use ocean water for cooling. A total of 5,370 MW of local gas-fired power plants and a 2,240 MW nuclear plant in northern California will retire by the end of 2029.

The gas-driven EG forecast uses a power market simulation for the period of 2022-2035. The simulation reflects the anticipated dispatch of all EG resources in the SoCalGas service territory using a base electricity demand scenario under both average and low hydroelectric availability market conditions. The base case assumes the CPUC adopted 2021 Preferred System Plan, which also assumes compliance with the Mid-Term Reliability (MTR).[78] Also assumed in the forecast is compliance with the GHG planning target of 38 million by year 2030. This plan includes an aggressive amount of energy storage resources along with significant renewables resources throughout the study period. While California load-serving entities (LSEs) are working to meet their GHG goals, there are uncertainties as to how much renewable power and energy storage resources will be added specifically during the study period.

The EG demand forecast for the State of California, used in the simulation, is sourced from the CEC's California Energy Demand Forecast, 2021 – 2035, adopted January 2022. This energy demand forecast was developed as part of the CEC's Integrated Energy Policy Report process. The mid energy demand forecast with Additional Achievable Energy Efficiency (AAEE) Scenario 3 and Additional Achievable Fuel Substitution (AAFS) Scenario 2 was selected as the energy demand forecast.

Industrial/Commercial/Cogeneration <20 MW

A segment of EG demand is the commercial/industrial cogeneration (including self-generation) market. This segment is comprised by customers with generating capacity of less

[78] Decision D.21-06-035.

than 20 megawatts (MW) of electric power. Most of the cogeneration units in this segment are installed primarily to generate electricity for internal customer consumption rather than for the sale of power to electric utilities. Customers in this market segment install their own electric generation equipment for both economic reasons (gas powered systems produce electricity cheaper than purchasing it from a local electric utility) and reliability reasons (lower purchased power prices are realized only for interruptible service). The gas demand in the small cogeneration market was 25.4 Bcf in 2021 and is expected to modestly increase to 27.6 Bcf by the year 2035, or at an average growth rate of 0.6 percent per year. The increase in demand is primarily due to the increasing electric price compared with natural gas.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. This market is forecasted to be stable over the 2022 - 2035 forecast period, changing from 23 Bcf in 2021 to 23.6 Bcf in 2035.

Enhanced Oil Recovery--Related Cogeneration

In 2021, recorded gas deliveries to the EOR -related cogeneration were 4.1 Bcf. EOR demand is forecasted to increase slightly and stabilize in the immediate future before gradually decreasing to 3.9 Bcf by 2035. Crude oil futures prices appear to be elevated and volatile for the immediate future which is expected to result in California EOR operations increasing slightly in the earlier part of the forecast before the gradual decrease, as volatility subsides.

Southern California

Electric Generation, Including Large Cogen

EG customers are comprised of utility electric generation (UEG) customers, various Exempt Wholesale Generator (EWG) customers and large cogeneration customers where usage exceeds 20 MW. For the base case (average hydro condition), gas demand is forecasted to decrease from 191 Bcf in 2021 to 113 Bcf in 2035. The main factors for the decline are aggressive energy storage resource additions, paired with significant renewable resource additions and the retirement of older gas-fired plants.

Wholesale

SoCalGas provides wholesale transportation service to SDG&E, the City of Long Beach Energy Resources Department (Long Beach), SWG, and the City of Vernon (Vernon), and Ecogas Mexico, L. de R.L. de C.V. The wholesale load excluding SDG&E is expected to increase from 38.6 Bcf in 2021 to 43.0 Bcf in 2035. The change reflects a 0.77 percent average annual increase.

SDG&E

Under average year temperature and normal hydro conditions, SDG&E gas demand is expected to decrease at an average rate of 1.9 percent per year from 94 Bcf in 2021 to 72 Bcf in 2035. Additional information regarding the composition of SDG&E's gas demand is provided in the SDG&E section of this report.

City of Long Beach

The wholesale load forecast is based on forecast information provided by the City of Long Beach Energy Resources Department. Long Beach's gas use is expected to increase slightly, from 8.8 Bcf in 2021 to 9.3 Bcf by 2035. Additional information regarding the City of Long Beach Energy Resources Department's gas demand is provided in the City of Long Beach Energy Resources Department section of this report.

Southwest Gas Corporation

SoCalGas used the forecast prepared by Southwest Gas for this report. In 2021, SoCalGas delivered 9.2 Bcf to Southwest Gas and the total load is expected to rise slightly to 10.3 Bcf by 2035. Refer to Southwest Gas for additional information regarding their gas demand.

City of Vernon

The City of Vernon initiated municipal gas service to its electric power plant within the city's jurisdiction in June 2005. Since 2005, there has also been a gradual increase of commercial/industrial gas demand as customers within the city boundaries have left the SoCalGas retail system and interconnected with Vernon's municipal gas system. The forecasted throughput starts at 8.5 Bcf in 2021 and increases to 9.3 Bcf by 2035. The forecasted throughput includes core and noncore customers and includes Malburg Power Plant throughput. Vernon's commercial and industrial load is based on recorded historical usage for commercial and industrial customers already served by Vernon plus the customers that are expected to request retail service from Vernon.

Ecogas Mexico, S. de R.L. de C.V. (Ecogas)

SoCalGas used the forecast prepared by Ecogas for this report. Ecogas' use is expected to increase, from 12 Bcf in 2021 to 14 Bcf by 2035. Refer to Ecogas or IENova, Ecogas' parent company, for more information.

Enhanced Oil Recovery Steam

In 2021, recorded gas deliveries to the EOR market were 8.5 Bcf. EOR demand is forecasted to increase slightly and stabilize in the immediate future before gradually decreasing to 7.4 Bcf by 2035. Crude oil futures prices appear to be elevated and volatile for the immediate future which is expected to result in California EOR operations slightly increasing in the earlier part of the forecast before the gradual decrease, as volatility subsides.

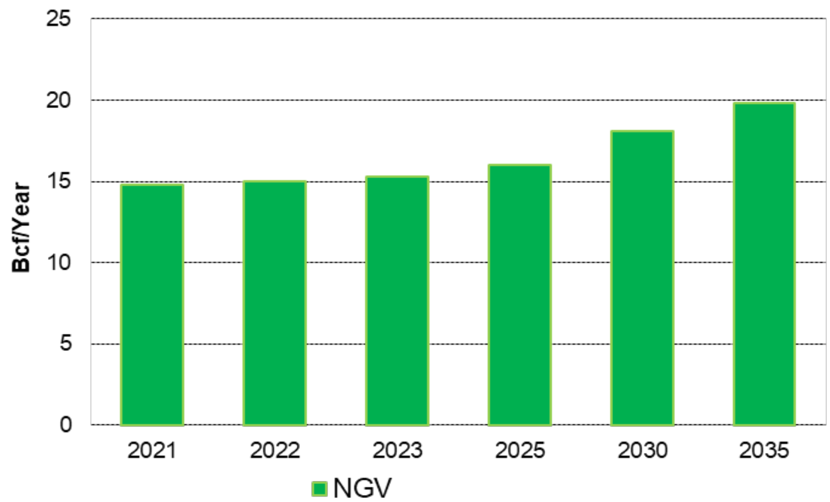
Southern California

Natural Gas Vehicles

The NGV market is expected to continue to grow, albeit at a slower rate than in the past. State regulations encourage the adoption of zero emission alternative fuels. Growth will continue for the next several years until zero emission alternative fuels become cost competitive with gasoline and diesel. NGV growth is also supported by the increased use and availability of RNG that provides significant GHG emission reduction and cost reduction benefits.

At the end of 2021, there were 352 CNG fueling stations delivering approximately15.4 Bcf of natural gas during the year. The NGV market is expected to grow 1.8 percent per year, on average. At the end of 2035, it is expected there will be 414 CNG fueling stations delivering approximately 20.8 Bcf of natural gas during the year.

FIGURE 21 – NGV DEMAND FORECAST
(2021-2035)



ENERGY EFFICIENCY PROGRAMS

SoCalGas engages in several energy efficiency (EE) and conservation programs designed to help customers identify and implement ways to benefit environmentally and financially from energy efficiency investments. Programs administered by SoCalGas include services that help customers evaluate their energy efficiency options and adopt recommended solutions, as well as simple equipment retrofit improvements, such as rebates for new hot water heaters.

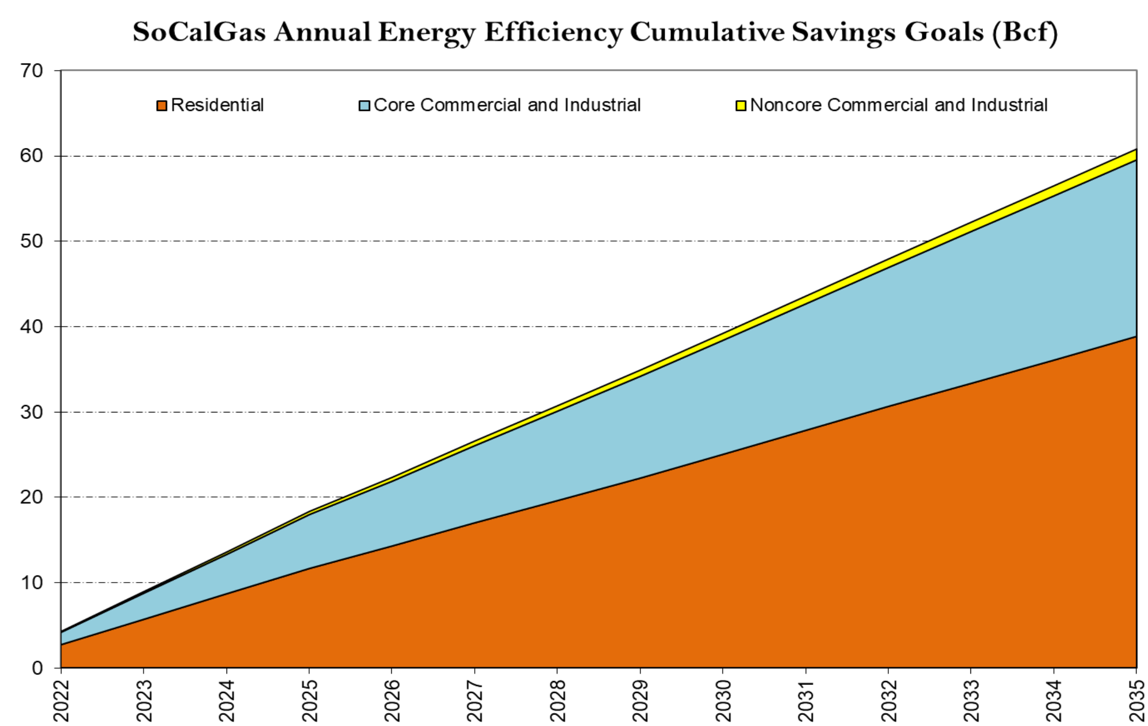
The forecast of cumulative natural gas savings due to SoCalGas' energy efficiency programs is provided in the figure below. The forecasts capture savings from programs developed in support of several goals and standards. Efforts were made to exclude the forecasted fuel substitution from the EE forecast. The forecast for fuel substitution is accounted in the separately in the AAFS Scenario 2, published in the CEC's 2021 Integrated Energy Policy Report. The savings shown below represent the net load impact for the energy efficiency portfolio that includes program savings and the codes and standards savings that SoCalGas anticipates will occur through year 2035.

SoCalGas' EE forecast is based upon inputs from the 2022-23 energy efficiency bi-annual budget advice letter (AL5898-A), utilizing program level energy savings values forecasted for the 2022 program year. Savings estimates from SoCalGas' 2022 EE programs are grouped by the classifications identified in the 2022 CGR (Residential, Commercial, Industrial, Industrial Refinery). These savings estimates are further split between the core and noncore classifications based on the estimated historical core and non-core savings achievements in 2017-2021. The EE program savings for 2017-2021 have been updated for this report.

Forecasted savings for the 2023-2035 period are based on the 2020 EE forecast scaled to the goals approved in the recent EE proceeding goals decision, D.21-09-037, which set EE goals through 2032. Forecasted savings beyond 2032 are held constant based on 2032 forecasted values. Cumulative savings reflect the lifecycle EE program achievements from forecasted program savings starting in 2022 and does not include lifecycle savings from prior program years. SoCalGas currently uses a 15-year lifecycle for cumulative savings calculations.

Combined EE Portfolio of EE Programs and Codes and Standards

FIGURE 22



GAS SUPPLY, CAPACITY, AND STORAGE

GAS SUPPLY SOURCES

SoCalGas and SDG&E receive gas supplies from several sedimentary basins in the Western U.S. and Canada including supply basins located in New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountains, Western Canada, and local California supplies. Recorded 2017 through 2021 receipts from gas supply sources can be found in the Sources and Disposition tables in the Executive Summary.

CALIFORNIA GAS

Gas supply available to SoCalGas and SDG&E from California sources averaged 69 MMcf/d in 2021.

SOUTH-WESTERN U.S. GAS

Traditional southwestern U.S. sources of natural gas will continue to supply most of Southern California's natural gas demand. This gas is primarily delivered via the El Paso Natural Gas pipeline with some volumes also on Transwestern pipeline. The San Juan Basin's gas supplies peaked in 1999 and have been declining at an annual rate of roughly 2 percent. The Permian Basin has experienced a major increase in gas production as a byproduct of the tremendous amount of oil development in the area. Permian gas production increased by over 130 percent during the period 2017-2021. This increase positioned the Permian Basin as a preferred gas supply source of economical gas.

Mexican demand for southwestern U.S. gas along with east of California demand continue to steadily increase and compete for southwestern supplies. This increasing demand will likely continue to compete with southern California for southwest supplies.

Southern California

ROCKY MOUNTAIN GAS

Rocky Mountain supply supplements traditional southwestern U.S. gas sources for southern California. This gas is delivered to southern California primarily on the Kern River Gas Transmission Company's pipeline, although there is also access to Rockies gas through pipelines interconnected to the San Juan Basin. Many pipelines that supply other markets connect to Rocky Mountain region, which allows Rockies gas to be redirected from lower to higher value markets as conditions change.

CANADIAN GAS

Canadian gas only provides a small share of southern California gas supplies due to the relatively high cost of transport.

LIQUEFIED NATURAL GAS

US liquified natural gas (LNG) exports grew in 2021 as additional capacity came online in 2020, however, global LNG demand increased sharply in 2021. Russia supplies to Europe decreased during 2021 which increased the demand for replacement gas in the form of LNG and caused international prices to spike while domestic prices saw less volatility. The global demand increase in 2021 created a supply/demand imbalance in Europe causing prices to spike to record highs. Current LNG supply is insufficient to replace Russian gas previously delivered into Europe which indicates international prices may remain high for several years.

RENEWABLE NATURAL GAS (RNG)

In February 2022, the CPUC adopted Decision (D.) 22-02-025 that implemented SB 1440 (Hueso) and established RNG procurement targets for years 2025 and 2030 to be met by the California natural gas utilities, "Joint Utilities", specifically Pacific Gas & Electric, San Diego Gas & Electric, Southern California Gas Company and Southwest Gas. This CPUC Decision established the nation's first Renewable Gas Standard (RGS) and provided additional support to meet the bill's short-lived pollution reduction goals. In particular, SB 1383 requires California to reduce emissions of methane by 40 percent below 2013 levels by 2030 and also develop landfill-diverted organic waste-to-RNG projects.

The RGS includes short and medium term biomethane procurement targets. The 2025 short-term target for biomethane procurement is 17.6 billion cubic feet (Bcf) annually, produced from eight million tons of organic waste, including wood waste, diverted annually from landfills. Joint Utilities, each, are responsible for procuring a percentage of the 17.6 Bcf according to each of their respective Cap-and-Trade allowance shares: Southern California Gas Company 49.26 percent, Pacific Gas and Electric Company 42.34 percent, San Diego Gas & Electric Company 6.77 percent, and Southwest Gas Corporation 1.63 percent.[79] The medium-term target is by year 2030, where the Joint Utilities, shall procure, on an annual basis, an amount of biomethane equivalent to 12.2 percent of its own share of 2020 annual bundled core customer natural gas demand, excluding Compressed Natural Gas Vehicle demand as noted in the California Gas Report (or approximately 72.8 Bcf).[80]

There is a growing recognition that clean fuels like hydrogen and renewable natural gas (RNG) will play an essential role in diversifying energy supplies while also helping California decarbonize and transform into a carbon neutral economy over the next twenty years.[81] RNG is methane produced from anaerobic digestion (AD) or by a non-combustion gasification process of organic feedstock material that can replace traditional natural gas. RNG produced from AD is typically derived from organic waste streams such as dairy manure, landfilled gas, and municipal organic waste (i.e., food scraps, lawn clippings, and animal or plant-based material). Non-combustion gasification pathways typically process agricultural waste, forest debris, and wastewater treatment by-products, among other feedstocks. Under baseline conditions, these organic waste streams typically release methane into the atmosphere as they decompose. Directing these feedstocks toward RNG production can help to capture and prevent the release of methane into the atmosphere.[82]

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[79] D. 22-02-025, op. 14-16.
[80] D. 22-02-025, op. 18.
[81] Final 2021 Integrated Energy Policy Report, Volume III.
[82] U.S. EPA's Landfill Methane Outreach Program (LMOP) at https://www.epa.gov/lmop/renewable-natural-gas .

RNG interconnected to a gas utility's pipeline[83] replaces traditional natural gas and can similarly be nominated to a variety of end users, providing decarbonized energy for hard-to-electrify sectors of the economy like heavy-duty transportation, industrial activities and dispatchable electric generation. RNG is a drop-in fuel replacing traditional natural gas and does not typically require equipment adjustments, upgrades, replacements or other modifications.

Unlike traditional natural gas, RNG feedstocks are composed of material containing biogenic carbon that has been absorbed from the atmosphere. Carbon emissions from fossil fuels such as traditional natural gas are drawn from geological sources such as deep wells or rocks and contain carbon that has accumulated over a geological timescale. In contrast, biogenic carbon, such as that in RNG, was sourced from the atmosphere on a much shorter biological timescale. This biogenic carbon is cycled from the atmosphere to plants over the course of only a few years or decades.[84] This means that carbon emissions released from the use of RNG are already part of a sustainable natural cycle, which is why GHG reporting protocols treat CO_2 emissions from RNG as carbon neutral.[85] RNG can even be a carbon negative fuel, reducing additional GHG emissions beyond the carbon emissions associated with its combustion, depending on the feedstock and production system used.

[83] SoCalGas Tariff Rule 30 (https://www2.socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf) must be met in order to qualify for pipeline injection into SoCalGas' gas pipeline system.

[84] https://clear.ucdavis.edu/explainers/biogenic-carbon-cycle-and-cattle.

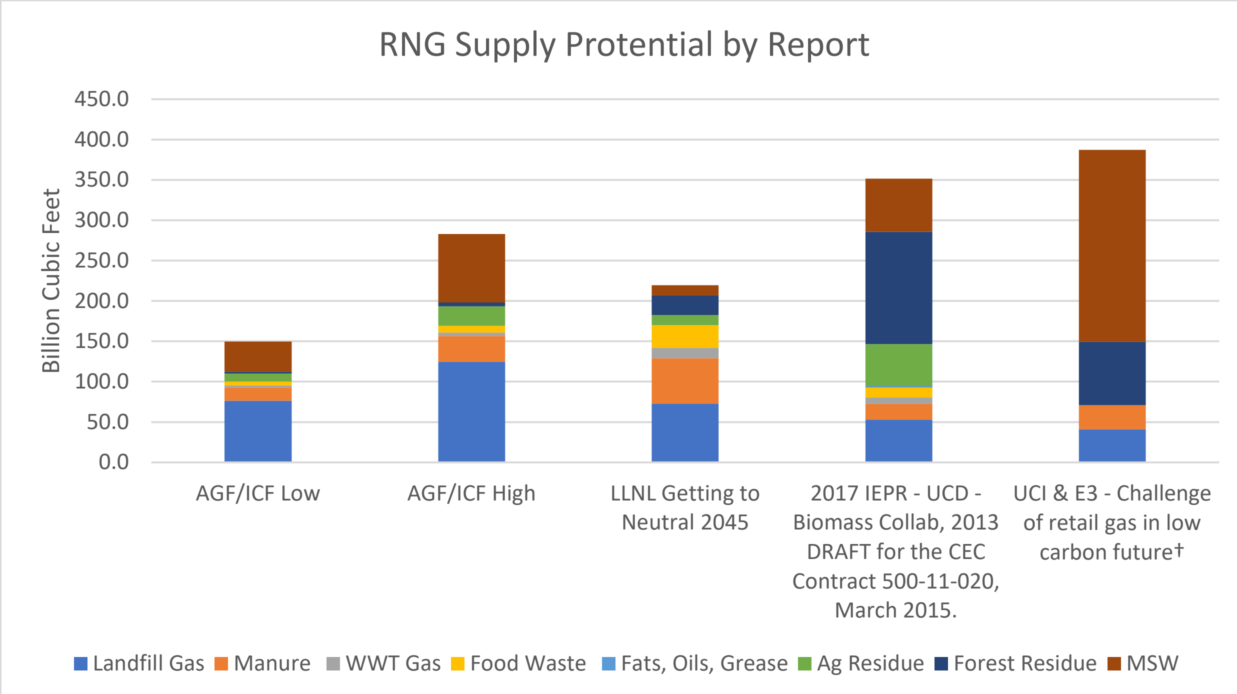
[85] https://www.ipccnggip.iges.or.jp/public/2019rf/pdf/2_volume2/19R_V2_2_Ch02_Stationary_Compbustion.pdf; 2.3-2.4 Treatment of Biomass .

Recent reports estimating RNG supply potential published by Livermore Laboratory Foundation, [86] the CEC, [87] E3 and the University of California Irvine,[88] and ICF,[89] illustrate there is a significant amount of feedstock available within California for the production of biogas and RNG to help replace traditional natural gas and help decarbonize the gas grid. These studies estimate between 70 and 170 Bcf of annual RNG production potential available solely from AD with potential for an additional 50 to 257 Bcf of annual RNG available from non-combustion gasification. Studies that sum both AD and gasification estimates provide an estimate between 148 and 387 Bcf of annual RNG potential within California.[90] RNG potential at the higher end of these summed estimates would be sufficient to meet either approximately 75 percent of the 2020 residential natural gas demand in California or approximately 150 percent of the commercial demand, or approximately 45 percent of industrial demand.[91]

[86] "Getting to Neutral: Options for Negative Carbon Emissions in California," Livermore Laboratory Foundation & Climateworks Foundation, August 2020. Available at https://wwwhttps://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdfgs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf.
[87] "Final 2017 Integrated Energy Policy Report," CEC, February 2018. Available at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2017-integrated-energy-policyhttps://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2017-integrated-energy-policy-reportreport.
[88] "The Challenge of Retail Gas in California's Low Carbon Future, Appendix A," E3 and University of California, Irvine, 2020. Available at https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-APhttps://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-AP-G.pdfG.pdf.
[89] "ICF 2019 Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," American Gas Foundation, 2019. Available at https://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNGhttps://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdfStudy-Full-Report-FINAL-12-18-19.pdf.
[90] Using the top or 'high' estimate when a range is documented, but not the 'technical resource potential,' which does not consider accessibility or economic constraints.
[91] https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SCA_A.htm

Southern California

Figure 23 – RNG In-State Supply Potential



INTERSTATE PIPELINE CAPACITY

California utilities and end users benefit from access to supply basins and enhanced gas and pipeline competition. Interstate, international, and intrastate pipelines serving Southern and central California include the El Paso Natural Gas, Mojave, Transwestern, Kern River, TGN, North Baja, and PG&E pipelines. These pipelines provide southern and central California with access to gas producing regions in the southwest U.S. and Rocky Mountain areas, western Canada, California production and Mexico LNG. Indicated firm capacities for each SoCalGas receipt zone for receiving these supplies are specified in the SoCalGas GBTS Rate Schedule.

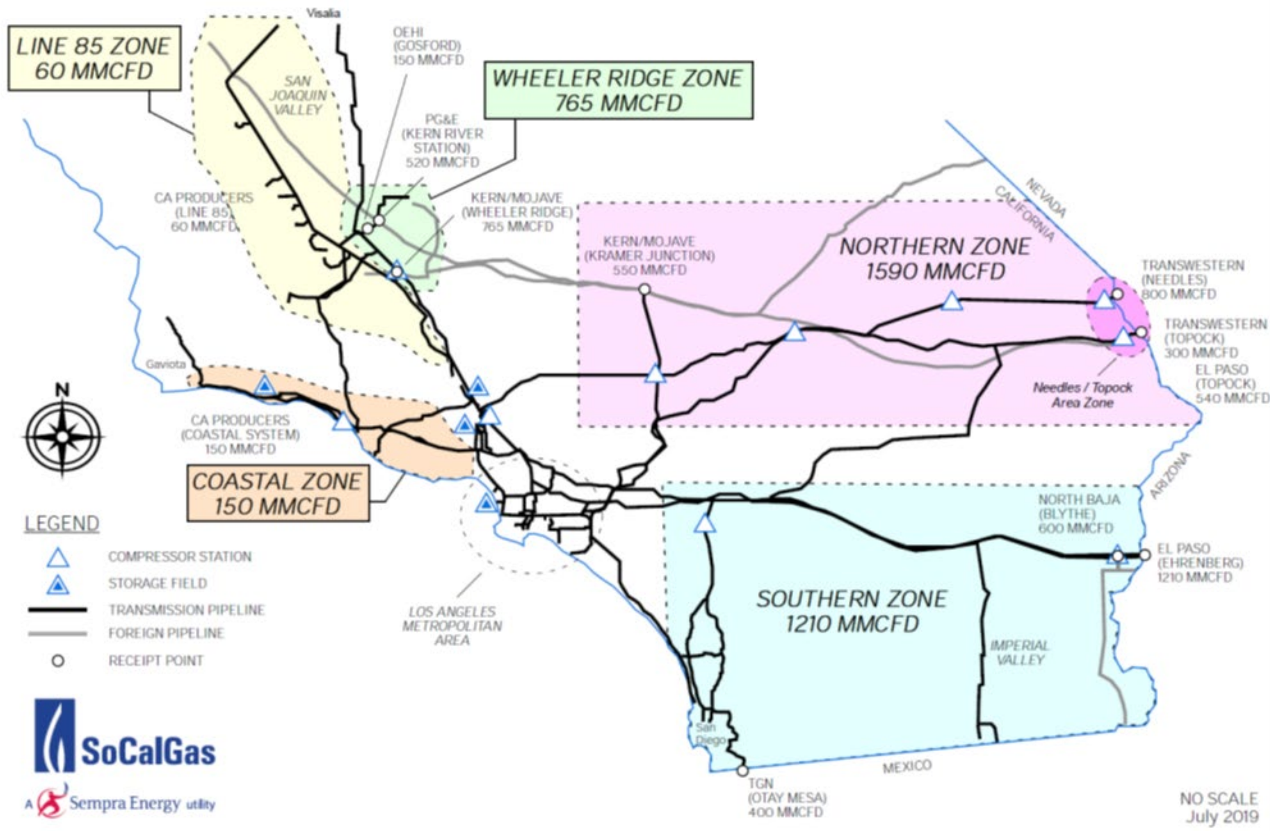
SoCalGas' Southern Zone is connected to U.S. Southwest and Mexico pipeline systems at Ehrenberg, Blythe, and Otay Mesa (to El Paso, North Baja, and TGN) respectively. The Southern Zone has a firm receipt capability of 1,210 MMcf/d.

SoCalGas' Northern Zone is connected to southwestern U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, Kern River, and Mojave) at Needles, west of

Topock AZ, and Kramer Junction. The Northern Zone has a nominal firm receipt capacity of 1,590 MMcf/d. Effective October 1, 2021, Line 4000 returned to service at a higher operating pressure. As a result, the amount of firm BTS capacity available in the Northern Zone and the Needles/Topock Area Zone increased to 1,250 MMcf/d and 800 MMcf/d respectively.

SoCalGas' Wheeler Ridge Zone is connected to Kern River/Mojave, OEHI Gosford, and PG&E and receives supplies from the U.S. Southwest, Rocky Mountain, and Western Canada production areas and California production from Elk Hills. The Wheeler Ridge Zone's firm receipt capacity is 765 MMcf/d.

FIGURE 24– RECEIPT POINT AND TRANSMISSION ZONE FIRM CAPACITIES



STORAGE

Underground storage of natural gas plays a vital role in balancing the region's energy supply and demand, and for systemwide reliability.[92] Natural gas storage is also used to meet peak daily and seasonal gas demand and to hedge against price volatility in natural gas commodity markets. In addition, natural gas storage has played a role in addressing emergency situations, including extreme weather and wildfires.[93] SoCalGas owns and operates four natural gas

[92] California Council on Science and Technology (CCST), January 2018, Long-Term Viability of Underground Natural Gas Storage in California, An Independent Review of Scientific and Technical Information, Conclusion, 2.4 at pp 504 at: Full-Technical-Report-v2_max.pdf (ccst.us) .
[93] *Id.,* Conclusion 2.5 at pp 506.

storage facilities within southern California: Aliso Canyon, Honor Rancho, La Goleta, and Playa Del Rey.

Southern California

In Southern California, natural gas storage fields are in areas with specific underground geologic characteristics, and in proximity to local gas consumers and transmission and distribution pipelines. Storage natural gas is withdrawn and delivered to customers through SoCalGas' transmission and distribution systems when customer demand exceeds flowing natural gas supplies and for system balancing.

SoCalGas' natural gas storage fields have a combined theoretical storage working inventory capacity of more than 130 Bcf.[94] However, the combined working inventory for SoCalGas is reduced due to current working inventory regulatory restrictions imposed at Aliso Canyon.

Prior to 2016 the Aliso Canyon working inventory was 86 Bcf.[95] Since October 2015,[96] the CPUC and CalGEM[97] have maintained restrictions on SoCalGas' use of Aliso Canyon. In November 2020, the CPUC set the Aliso Canyon storage inventory level at 34 BCF based on the prior Energy Division reports assessing whether monthly 1-in-10 peak day demand could be met with forecasted storage inventory levels.[98] In November 2021, the CPUC issued an order increasing the inventory limit for the Aliso Canyon Storage Field from 34 to 41.16 Bcf.[99] The CPUC and CalGEM may authorize a different maximum inventory in the future.

In July 2019, to improve short-term reliability and price stability in the southern California region, the CPUC deemed that Aliso Canyon be made available for withdrawals if certain conditions are met.[100] Aliso Canyon may be used for withdrawals only if any of the following four conditions are met: 1) Preliminary low Operational Flow Order (OFO) calculations for any

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[94] SoCalGas 2019 General Rate Case (GRC) Filing, Exhibit SCG-10-R, p. NPN-3 and NPN-4.
[95] As of July 19, 2017, CalGEM authorized Aliso Canyon to operate with a working inventory of equivalently 68.6 Bcf.
[96] Aliso Canyon experienced a natural gas leak in Well SS25 on October 23, 2015. The leak was stopped on February 11, 2016, and SS25 was permanently sealed on February 18, 2016.
[97] Formerly DOGGR.
[98] CPUC Decision (D.)20-11-044.
[99] CPUC Decision (D.)21-11-008 issued on November 4, 2021.
[100] https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/WithdrawalProtocol-revised-April112020clean.pdf

cycle result in a Stage 2 low OFO or higher for the applicable gas day. 2) Aliso Canyon is above 70% of its maximum allowable inventory between February 1 and March 31. 3) Honor Rancho and/or Goleta fields decline to 110% of their month-end minimum inventory requirements during the winter season and 4) There is an imminent and identifiable risk of gas curtailments created by an emergency condition that would impact public health and safety or result in curtailments of electric load that could be mitigated by withdrawals from Aliso Canyon.

STORAGE REGULATIONS

Since 2015, the CPUC, CalGEM, and Pipeline and Hazardous Materials Safety Administration (PHMSA) have proposed and adopted various regulations addressing natural gas storage requirements and standards including safety and reliability. SoCalGas is committed to working with various regulating bodies and policy makers to promote safe and reliable energy and natural gas storage services.

Most recently, PHMSA issued their Final Rule for Underground Storage regulations, CFR Part 192.12, amending its minimum safety standards for underground natural gas storage facilities, effective March 13, 2020. The PHMSA Final Rule adopts API RP 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, as published, modifies compliance timelines, formalizes integrity management practices, and clarifies the state's regulatory role.

CalGEM established fourteen California Code of Regulations §1726 California Underground Gas Storage regulations effective October 1, 2018, which includes mechanical testing mandates that require each well to be taken out of service for inspection every 24 months, unless an alternative frequency is approved by CalGEM, and semiannual field shut in tests for inventory certification.

REGULATORY ENVIRONMENT

STATE REGULATORY MATTERS

GENERAL RATE CASE

On September 26, 2019, the CPUC unanimously approved a final 2019 GRC decision that adopted a TY 2019 revenue requirement of $2.770 billion for SoCalGas which is $166 million lower than the $2.937 billion that SoCalGas had requested in its updated testimony. The adopted revenue requirement represents an increase of $314 million or a 12.8 percent increase over 2018. The final decision adopted post-test year (PTY) revenue requirement adjustments for SoCalGas are $220 million for 2020 (7.9 percent increase) and $150 million for 2021 (5.0 percent increase).

In January 2020, the CPUC revised the rate case plans and implemented a 4-year GRC cycle for California IOUs. SoCalGas was directed to file a Petition for Modification (PFM) to revise its 2019 GRC decision to add two additional attrition years including adjustment amounts, resulting in a transitional 5-year GRC period (2019-2023).

In April 2020, SoCalGas filed a PFM of its 2019 GRC decision requesting attrition year increases of $155 million (+4.95 percent) for 2022 and $137 million (+4.15 percent) for 2023. In May 2021, the CPUC issued a decision authorizing SoCalGas to apply its PTY mechanism adopted in the 2019 GRC decision to 2022 and 2023 but updated the calculations based on the 2020 4th Quarter Global Insight forecast to more fully capture the impact of Covid-19 to the economy. This decision resulted in revenue requirements of $3.3 and $3.4 billion for SoCalGas for 2022 and 2023 respectively, which were slightly less than the original requests made in SoCalGas' PFM.

In May 2022, SoCalGas filed its 2024 General Rate Case seeking to revise its authorized revenue requirements, effective on January 1, 2024, to recover the reasonable costs of gas operations, facilities, infrastructure, and other functions necessary to provide utility services to customers. SoCalGas requests a $4.426 billion revenue requirement for 2024, which, if approved, would be an increase of $767 million over the expected 2023 revenue requirement, or a 20.9% increase. SoCalGas' 2024-2027 rate request includes investments in four key areas: maintaining and enhancing reliability and safety, supporting sustainability, and promoting innovation and technology to meet operational and customer needs and workforce development. SoCalGas also includes a post-test year revenue requirement and a regulatory account-related proposal. The general rate request process is scheduled to take between 18 months and two years and is expected to conclude in late 2023.

GAS RELIABILITY AND PLANNING OIR

The CPUC initiated a rulemaking (R.20-01-007) to update gas reliability standards, determine the regulatory changes necessary to improve coordination between gas utilities and gas-fired electric generators, and implement a long-term planning strategy to manage the state's transition away from natural gas-fueled technologies to meet California's decarbonization goals.

The rulemaking has two tracks. Track 1 is intended to establish baseline standards and address issues of more immediate concern. These Track 1 issues include: determining whether changes to the reliability standards are needed and, if so, how any additional costs will be recovered and allocated; considering a change to the Operational Flow Order (OFO) penalty structure, which provides a financial incentive for gas customers, including electric generators, to deliver sufficient gas supply; and evaluating whether gas and electric interdependency requires the establishment of new reliability and cost containment protocols. A Proposed Decision (PD) on the OFO penalty structure was issued on March 18, 2022, and voted out at the April 21, 2022, CPUC Business Meeting. A final decision on the remaining Track 1 issues was adopted in July 2022, and includes no changes to design standards, a citation program for failure to meet minimum design standards and new reporting requirements for the California Gas Report starting in 2024.

Track 2 of the Gas Reliability OIR focuses on long-term system planning. Track 2A focuses on gas infrastructure. Its goal is to create new criteria for the CPUC to use when evaluating utility requests for spending on infrastructure as well as for proactively identifying distribution pipelines that can be decommissioned. In this track, the CPUC seeks to find a balance in which California has sufficient transmission and storage infrastructure to avoid creating reliability issues and scarcity that drive up gas commodity prices while at the same time avoiding unneeded investments that could lead to stranded assets and reducing distribution pipeline miles to decrease revenue requirement over time. The CPUC held two workshops in January and issued a workshop report in March 2022. A PD is expected in November 2022.

Track 2B focuses on equity, rates, safety, and workforce issues. The equity portion focuses on barriers that low-income customers would face in advancing state electrification goals and what the CPUC can do to mitigate those barriers. The rates portion will look at ratemaking strategies and develop ways to mitigate the impact of the gas transition on customer rates both now and in the future. The safety portion will look at ways to streamline safety spending where possible, given that most safety spending is required by state or federal agencies.

Track 2C will focus on data and process, considering a long-term strategy for managing gas planning going forward. It is expected to begin in 2023.

Southern California

ALISO CANYON ORDER INSTITUTING INVESTIGATION

On February 9, 2017, the CPUC opened the Aliso Canyon proceeding, Investigation I.17-02-002, as directed by SB 380 (Pavley, 2016). SB 380 required the CPUC to "determine the feasibility of minimizing or eliminating the use of the SoCalGas Aliso Canyon Natural Gas Storage Facility (Aliso Canyon) while still maintaining energy and electric reliability for the region." This facility is the largest of four gas storage facilities serving southern California. The CPUC has modeled the current gas system, finding that the Aliso Canyon facility is currently necessary for winter reliability and cost containment.

A third-party consultant modeled the costs and benefits of adding new infrastructure that would allow Aliso Canyon to be closed by 2027 or 2035. The consultant modeled several different infrastructure portfolios, including gas infrastructure upgrades, new electricity transmission, increased energy efficiency and building electrification, and additional electric generation and storage. This analysis concluded that any of these portfolios could successfully replace the services provided by Aliso Canyon. The consultant found that any of the portfolios modeled, except for new gas infrastructure, would result in a net decrease in energy system costs, when factoring in the costs of compliance with the Cap-and-Trade Program and Renewable Portfolio Standard, because the benefits of using the new resources would outweigh the investment costs. However, on balance the savings would accrue to gas ratepayers, while electricity ratepayer costs would increase. This analysis did not address costs or usage of the Aliso Canyon site itself. The proceeding remains open, with the CPUC yet to determine whether to order that Aliso Canyon be closed and, if so, what infrastructure will be procured to allow that closure and what the timeline and other parameters will be. The CPUC anticipates a ruling in this proceeding before 2023.

The CPUC is also using this proceeding to determine the Aliso Canyon facility's maximum allowable gas storage inventory. The allowed inventory level impacts customers rates because higher storage inventory allows for lower gas costs to ratepayers by enabling the utility to buy and store gas when prices are low and use its stored gas when prices are high. The CPUC increased the maximum inventory level for the facility in November 2021 which will remain in place until the Commission issues a new decision in the proceeding.

BUILDING DECARBONIZATION POLICY

In September 2018, former Governor Brown signed two bills into law related to reducing GHG emissions from buildings, SB 1477 and AB 3232. SB 1477 calls on the CPUC to develop, in consultation with the CEC, two programs (BUILD and TECH) aimed at reducing GHG emissions associated with buildings. AB 3232 calls on the CEC, by 2021, to develop plans and projections to reduce GHG emissions of California's residential and commercial buildings to 40 percent below 1990 levels by 2030, working in consultation with the CPUC and other state agencies.

In January 2019, the CPUC issued an OIR on building decarbonization (R.19-01-011). The proposed scope of the rulemaking includes: (1) implementing SB 1477; (2) potential pilot programs to address new construction in areas damaged by wildfires; (3) coordinating CPUC policies with Title 24 Building Energy Efficiency Standards and Title 20 Appliance Efficiency Standards developed at the CEC; and (4) establishing a building decarbonization policy framework. A final decision D.20-03-027 was issued on April 6, 2020, which establishes a framework for CPUC oversight of two building decarbonization pilot programs—the Building Initiative for Low-Emissions Development (BUILD Program) program and the Technology and Equipment for Clean Heating (TECH Initiative) initiative. These two pilot programs are designed to develop valuable market experience for the purpose of decarbonizing California's residential buildings in order to achieve California's zero-emissions goals. SB 1477 makes available $50 million annually for four years, for a total of $200 million, derived from the revenue generated from GHG emission allowances directly allocated to gas corporations and consigned to auction as part of the Air Resources Board's (ARB) Cap-and-Trade Program. Incentive eligibility for the BUILD Program shall be limited strictly to newly constructed all-electric building projects, without any hookup to the gas distribution grid.

Phase II issued a Final Decision on November 4, 2021, which adopted the Wildfire and Natural Disaster Resilience Rebuild (WNDRR) Program to support all-electric rebuilding of residential properties that were destroyed or red-tagged due to a natural or man-made disaster on or after January 1, 2017. WNDRR will be offered for a ten-year period (2022-2032) across the service territories of the electric IOUs. Further, the decision directs the electric IOUs to study the total electric and gas bill impacts resulting from a customer switching from a natural gas water heater to an electric heat pump water heater (HPWH). Based on this analysis, each electric IOU must propose a HPWH rate adjustment in its next General Rate Case (Phase II) or Rate Design Window applications. In an effort to allow the CPUC and stakeholders to better understand propane use, the decision directs the electric IOUs to ask all new customers whether or not they use: (i) electric space heating equipment; (ii) electric water heating equipment; and (iii) propane to power any appliance other than an outdoor grill. The electric IOUs must report these responses to ED annually beginning on February 1, 2023, along with the number of total customers receiving the all-electric baseline allowance, as well as total customers receiving the new HPWH baseline allowance. Lastly, the decision adopts detailed non-binding guiding principles for how to determine program costs and benefits when programs overlap. These principles apply to the programs adopted under this proceeding (BUILD, TECH, and WNDRR), as well as programs authorized to incentivize clean heating technologies, specifically under Energy Efficiency (EE) (incl. the new statewide Heating, Ventilation, and Air Conditioning and Plug Load Appliance Programs administered by SDG&E), and the Self-Generation Incentive Program (SGIP) (HPWH sub-program).

In Phase III of R.19-01-011, the CPUC is considering changing the rules regarding allowances, refunds, and discounts paid to builders to help facilitate the connection of buildings to the gas distribution system. In November 2021, CPUC's Energy Division staff released a report recommending the complete elimination of these payments for all customer classes effective July 1, 2023. According to the staff report, gas ratepayers subsidize gas line extensions at a cost exceeding $100 million annually. According to the staff report, "By eliminating all gas line extension allowances, builders would be forced to shoulder greater expense if they choose to construct a building that uses gas...the added up-front gas burden would send a signal to builders that building new gas infrastructure is more expensive, and thus make dual-fuel construction less desirable and financially riskier. As such, the builder community would be more likely to gravitate towards all-electric new construction." The CPUC is expected to issue a Proposed Decision in the third quarter of 2022.

AFFORDABILITY OIR

On July 12, 2018, the Commission instituted the OIR (R.18-07-006) to develop a common understanding, methods and processes to assess, the impacts on affordability of individual Commission proceedings and utility rate requests. This OIR includes gas, electric, water and communications utilities. On July 16, 2020, the Commission issued its Phase 1 decision (D.20-07-032), which defines affordability as the degree to which a representative household is able to pay for an essential utility service, given its socioeconomic status. This decision also adopts three metrics and supporting methodologies to be used by the Commission for assessing the affordability of essential utility services, including: hours at minimum wage required to pay for essential utility services; Socioeconomic vulnerability index (SEVI) of various communities; and ratio of essential utility service charges to non-disposable household income—known as the affordability ratio. The decision does not adopt an absolute definition of what constitutes affordable essential utility services; rather, the decision adopts metrics and methodologies for assessing affordability across utilities over time.

In Phase II of the Affordability Proceeding, a Proposed Decision was issued on June 10, 2021, providing further direction on implementation of the three metrics adopted in Phase I the CPUC will use to assess the affordability of utility service. The PD establishes how the affordability framework will be applied in CPUC proceedings and further develops the tools and methodologies used to calculate the three metrics. Gas and electric utilities must include certain Affordability Ratio and Hours-at-Minimum Wage data in any filing that would result in a revenue increase estimated to exceed one percent of currently authorized systemwide revenues. They must also include various estimated bill impacts by climate zone. The affordability metrics must also be updated at the time of a PD in General Rate Case (GRC) proceedings. SDG&E is directed to introduce the required affordability analysis in its next GRC Phase 2 application. Electric, gas and water utilities will also now all be required to submit quarterly rate trackers to the CPUC, aggregating the rate impacts of their various revenue requirements, pending rate requests, and authorizations.

The CPUC held an Affordability Proceeding 2022 En Banc on February 28 and March 1 of 2022 as part of Phase 3 of Affordability Rulemaking A.18-07-006, which examined proposals to contain costs and mitigate rate increases. Stakeholder proposals focusing on gas ratepayers included the following:

- Authorize utilities to deploy capital and recover cost for building decarbonization upgrades via tariffed on-bill structures that enable participation regardless of income, credit score, or renter status.

- Implement rate or infrastructure planning mechanisms to avoid excessive gas infrastructure costs falling disproportionately on residential customers who cannot electrify.

- Determine if electrification warrants securitization and/or accelerated depreciation of natural gas assets.

- Implement a Renewable Balancing Services tariff that would charge different rates to different customer classes, especially during peak hours, based on amount of natural gas use.

- Evaluate natural gas rates and affordability in coordination with the Long-Term Gas Planning Rulemaking.

- Determine how to efficiently prune the natural gas system while providing safety.

- Legislative action to ensure long-term budget availability and use state revenue to recover costs for programs, such as CARE.

The next step in Phase 3 of the proceeding is to build on the En Banc discussions. There will be Statewide listening sessions and a workshop held by the CPUC to solicit recommendations and strategies from parties to mitigate rate increases. A proposed decision is scheduled for Q2-Q3 2023.

PIPELINE SAFETY

In 2011, the CPUC issued an OIR, R.11-02-019, to develop and adopt new regulations on pipeline safety, requiring that the utilities file implementation plans to test or replace natural gas transmission pipelines that do not have sufficient record of a pressure test.

SoCalGas and SDG&E jointly filed their comprehensive Pipeline Safety Enhancement Plan (PSEP) on August 26, 2011, pursuant to D.11-06-017. The comprehensive plan covered all of the utilities' approximately 4,000 miles of transmission lines and would be implemented in two phases. Phase 1 focuses on populated areas and Phase 2 covers less populated areas of SoCalGas' and SDG&E's service territories.

In June 2014, the CPUC issued D.14-06-007 approving the utilities' plan for implementing PSEP, subject to after-the-fact reasonableness review, established criteria to determine the costs that may be recovered from ratepayers, and authorized the establishment of balancing accounts to facilitate the recovery of costs for implementing Phase 1.

Subsequently, in D.16-12-063 the Commission approved SoCalGas' and SDG&E's joint application, (Application (A.) 14-12-016, requesting review and recovery of $33.2 million, which is a portion of the tracked PSEP costs incurred prior to June 12, 2014. Additionally, D.16-08-003, approved SoCalGas' and SDG&E's application (A.15-06-013) to establish Phase 2 memorandum accounts. The decision also authorized 50 percent interim cost recovery for Phase 1 actual revenue requirements booked to the regulatory accounts subject to refund, and a long-term procedural schedule for PSEP going forward. D.16-08-003 ordered SoCalGas and SDG&E to transition PSEP to the GRC starting with Test Year 2019 and that future GRC applications could include PSEP costs until implementation of the Plan is complete.

From 2011 through March 2022, SoCalGas and SDG&E have invested approximately $2.4 billion and $790 million, respectively, in PSEP, with additional expenditures planned, involving the remediation of more than 450 pipeline miles for SoCalGas and 60 miles for SDG&E.

In D,19-02-004, the Commission approved SoCalGas' and SDG&E's second PSEP Reasonableness Review application (A.16-09-005), which presented costs totaling $195 million (including certain costs for which the utilities are not seeking recovery) of pipeline safety projects completed by June 30, 2015. The Commission approved cost recovery of approximately $187 million ($172 million for SoCalGas and $15 million for SDG&E).

In D.19-03-025, the Commission also approved SoCalGas' and SDG&E's PSEP forecast application (A.17-03-021), finding $254.5 million associated with twelve SoCalGas Phase 1B and 2A pipeline projects reasonable and eligible for cost recovery. The decision directs SoCalGas and SDG&E to record costs to a one-way balancing account on an aggregate basis and balance to the authorized revenue requirements.

In December 2018, SoCalGas and SDG&E filed a third joint PSEP reasonableness review application (A.18-11-010) requesting cost review and rate recovery for 83 completed Phase 1 projects. The total costs submitted for review are approximately $941 million ($811 million for SoCalGas and $130 million for SDG&E). In D.20-08-034, the Commission approved a settlement agreement which addressed the reasonableness review of approximately $940 million in costs incurred executing 44 pipeline projects and 39 valve pipeline safety enhancement plan projects by granting cost recovery in total of $934,607,000.

SoCalGas most recently requested additional PSEP funding in its 2024 GRC application (A.22-05-015) that will enable SoCalGas to continue the implementation and prudent execution of PSEP as mandated in Decision (D.) 14-06-007 and in furtherance of the CPUC's order to complete the Plan "as soon as practicable," while balancing other pipeline safety compliance regulations and the obligation to provide customers with safe and reliable service. Since its inception, the four objectives of PSEP have been and continue to be: (1) enhance public safety; (2) comply with Commission directives; (3) minimize customer impacts; and (4) maximize the cost effectiveness of safety investments.

ANGELES LINK APPLICATION

On February 17, 2022, SoCalGas filed A.22-02-007 requesting authorization to establish the Angeles Link Memorandum Account, which would track the incremental costs associated with stakeholder engagement, engineering, design, and environmental work for a proposed pipeline delivering "renewable green hydrogen" into the Los Angeles Basin. The application does not specify a cost recovery mechanism for expenses recorded in the memorandum account, but the company could request cost recovery from ratepayers in a future proceeding if the memorandum account is approved. It states that the project must be approved prior to SoCalGas's next GRC due to the urgent climate benefits that the project would bring. The anticipated costs for the proposed memorandum account do not include construction or capital costs. The application references the use of underground hydrogen transportation infrastructure and "new in-state dedicated hydrogen pipelines," suggesting much of the pipeline will be new infrastructure built underground.

The application says that the project is designed to facilitate the closure of the Aliso Canyon methane storage facility and preserve energy reliability, as well as address overall climate change concerns. The application does not name specific end users of the renewable hydrogen, but it describes an intent to serve future hydrogen end users, including "hard-to-electrify" industries, electric generators, and the heavy-duty transportation sector. The application says that the foundation of the system would be one or more transmission pipelines that would run from generation sources in areas such as the Central Valley, Mojave Desert/Needles, or the Blythe area. The application does not specify how the hydrogen would be produced other than that it would come from electrolysis powered by renewable electricity.

The application describes three phases for the project. Phase 1 would last from 12 to 18 months and cost an estimated $26 million. It would support a pre-Front End Engineering and Design analysis assessing hydrogen demand, identifying end users, and conducting energy studies, in addition to engaging stakeholders. Phase 2 would last from 18 to 24 months and cost $92 million. It would identify a preferred option through design, engineering, and environmental studies and complete refined engineering and implementation plans. Phase 3 would last from 18 to 30 months and cost "several hundreds of millions of dollars." This phase would prepare permit applications, including an application to the CPUC for a Certificate of Public Convenience and Necessity and other long-lead permit applications.

FEDERAL REGULATORY MATTERS

SoCalGas and SDG&E participate in Federal Energy Regulatory Commission (FERC) proceedings involving interstate natural gas pipelines serving California that can affect the deliveries of gas to their customers. SoCalGas holds contracts for interstate transportation capacity on the El Paso, Kern River, Transwestern, and GTN and Canadian pipelines. SoCalGas and SDG&E also participate in FERC and Canadian regulatory proceedings involving the natural gas industry generally as those proceedings may impact their operations and policies.

EL PASO

On August 15, 2021, El Paso Natural Gas's (EPNG) Line 2000 ruptured near Coolidge, Arizona. The National Transportation Safety Board (NTSB) opened Investigation PLD21FR003 into the incident. On April 19, 2022, EPNG reported that "the pipeline failure remains under a PHMSA order, and the entire Line 2000 system is under a reduced operating pressure. The reduced operating pressure in effect removes the Line 2000 system from service from Black River compressor station to the California border."

On April 21, 2022, FERC issued against EPNG an Order on Cost and Revenue Study, Instituting Investigation and Setting Matter for Hearing Procedures Pursuant to Section 5 of the Natural Gas Act. In that section 5 proceeding, FERC alleged that EPNG may be substantially over-recovering its cost of service, causing El Paso's existing rates to be unjust and unreasonable. The section 5 proceeding is anticipated to be resolved by mid-2023.

GTN AND CANADIAN PIPELINES

SoCalGas acquires its Canadian natural gas supplies from the NGTL pipeline located in Alberta, Canada and transports these supplies through the NGTL pipeline in Alberta, to the Foothills Pipelines Limited Company pipeline (Foothills) in British Columbia, and finally to GTN at the Canadian/U.S. international border.

On November 18, 2021, FERC issued a letter order approving GTN's settlement agreement in lieu of GTN filing a NGA section 4 general rate case filing. That settlement agreement, among other things, maintained existing tariff recourse rates, established a moratorium on rate changes through December 31, 2023, and obligated GTN to file a NGA section 4 rate case in early 2024.

NORTH BAJA XPRESS PROJECT

On April 21, 2022, FERC issued a certificate of public convenience and necessity (CPCN) to North Baja Pipeline Company to construct and operate the North Baja Xpress project. The project will enable North Baja to provide 495,000 Dth/day of firm transportation service to Sempra LNG from the EPNG system at Ehrenberg for export to Mexico. The CPCN is conditioned on (1) making the facilities available within 3 years of the order date; (2) compliance with environmental conditions stated in the order; and (3) the execution of a firm service agreement before commencing construction.

GREENHOUSE GAS ISSUES

NATIONAL POLICY

Fundamental elements of the nation's greenhouse gas(es) (GHG) program were established by the Clean Power Plan, which was adopted by the U.S. EPA in August 2015 pursuant to their authority under the federal Clean Air Act. The intent of the Clean Power Plan was to reduce carbon emissions from power plants while maintaining energy reliability and affordability. The Clean Power Plan established customized goals for each state. It was projected to reduce carbon emissions from the power sector 32 percent from 2005 levels by 2030. Individual state targets were based on national uniform "emission performance rate" standards (pounds of carbon dioxide (CO_2) per MWh) and each state's unique generation mix.

On February 9, 2016, the U.S. Supreme Court issued a stay of the EPA's Clean Power Plan, freezing carbon pollution standards for existing power plants while the rule was under review at the U.S. Court of Appeals for the District of Columbia Circuit. In March 2017, President Trump signed an Executive Order directing the EPA Administrator to review the Clean Power Plan and if appropriate, suspend, revise, or rescind the rule. On October 10, 2017, the EPA released a proposed rule to repeal the Clean Power Plan. On June 30, 2022, the U.S. Supreme Court determined that the EPA lacks authority under the Clean Air Act to set GHG standards that require power producers to significantly change the generation mix. The Court held that such consequential rules must be based on explicit congressional authorization.

Former President Trump announced the United States' withdrawal from the Paris Agreement[101] (the international treaty on climate change) in 2017, but a number of U.S. states including California formed the United States Climate Alliance to maintain the objectives of the Clean Power Plan within their state borders separately from the federal government. President

[101] The Paris Agreement | UNFCCC

Biden signed an executive order on January 20, 2021, to re-admit the United States into the Paris Agreement. Readmission became effective 30 days later.

MOTOR VEHICLE EMISSIONS REDUCTIONS

National GHG policymakers realize that motor vehicles are one of the largest sources of GHG emissions, and one of the potential solutions is the substitution of natural gas and electricity for the current diesel and gasoline energy sources. This transition to cleaner fuels will also increase the demand for both natural gas and natural gas-generated electricity. Under the EPA's Mandatory Reporting of GHGs rule, all vehicle and engine manufacturers outside of the light-duty sector must report emission rates of CO_2, nitrous oxide, and methane from their products.

ASSEMBLY BILL 32

The Global Warming Solutions Act of 2006 (AB 32) requires California to reduce GHG emissions to the adopted statewide 1990 level by 2020. AB 32 directs the Air Resources Board (ARB) to adopt rules and regulations in an open public process to achieve the "maximum technologically feasible and cost-effective GHG emission reductions".[102] AB 32 also required the ARB to prepare and approve a scoping plan that provides a roadmap to reach the 2020 emissions reduction target. The first scoping plan was approved by the ARB in 2008 and the ARB is required to update the plan at least once every 5 years. The most recent update, as of this writing, was adopted in December 2017. For each scoping plan, the ARB is required to use a collaborative consultation process through engagement with State agencies including the CPUC and CEC, and a diverse set of stakeholders with public input facilitated through workshops and other meetings. The result is a policy framework that comprises a broad portfolio of recommended GHG reduction strategies and regulations, including a market-based compliance mechanism that are cost effective and minimizes administrative burden and GHG emission leakage.

[102] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32.

SENATE BILL 32

SB 32 (Pavley) was enacted on September 8, 2016 and went into effect on January 1, 2017. The law extended the goals of AB 32 by requiring the ARB to ensure statewide GHG emissions are 40 percent below the 1990 levels by 2030. The continuation of the Global Warming Solutions Act keeps California on track with the emission reduction goals of the Paris Agreement. The 2017 Scoping Plan Update incorporated the 2030 target and constructed California's climate policy portfolio that includes doubling building efficiency, increasing renewable power by 50 percent cleaner zero and near-zero emission vehicles, reducing short-lived climate pollutants such as black carbon and limiting industry emissions through a Cap-and-Trade program. The companion bill to SB 32, AB 197, provides increased legislative oversight of the ARB through a Joint Legislative Committee on Climate Change Policies and directed it to take certain actions to improve local air quality. These actions include internet posting of emissions of GHG, criteria pollutants, and toxic air contaminants from stationary and mobile sources, prioritization of specified emission reduction rules and regulations to protect disadvantaged communities, and consideration of the social cost of carbon when preparing plans to meet GHG reduction targets and goals.

On May 10, 2022, the ARB released the Draft 2022 Scoping Plan Update. The draft of the 2022 Update reflects direction from major climate legislation and four Governor's Executive Orders issued since the adoption of the 2017 Scoping Plan Update. One of the executive orders, B-55-18 (signed September 2018) establishes a statewide goal to achieve carbon neutrality (i.e., the point at which removal of carbon pollution from the atmosphere meets or exceeds emissions) as soon as possible, and no later than 2045, and to achieve and maintain net negative GHG emissions thereafter. It also calls for the ARB to ensure future scoping plans identify and recommend measures to achieve this carbon neutrality goal and to develop a framework for implementation and accounting that tracks progress toward the goal. Further, in July 2021, Governor Newsom wrote to the ARB Chair requesting that the ARB evaluate how to achieve carbon neutrality no later than 2035 including analysis of how to reduce or eliminate demand for fossil fuel and end oil extraction in California. Additionally, the Governor asked for the pathway to carbon neutrality to prioritize strategies that reduce emissions of GHG as well as provide public health co-benefits, include an evaluation of cost effectiveness, and protect against leakage of GHG emissions to other states as mandated by law (AB 32). The Draft 2022 Scoping Plan Update recommends an alternative that achieves carbon neutrality in 2045 and found that the two 2035 alternatives evaluated have much higher direct costs, job losses, rate of slowing economic growth and degree of uncertainty.

SENATE BILL 350

The Clean Energy and Pollution Reduction Act, or SB 350, was signed into law on October 7, 2015, and sets ambitious goals that will help the State achieve the emissions reduction targets of SB 32. SB 350 increased and extended the RPS target to 50 percent by 2030, which later was amended by SB 100. Additionally, the law requires the state to double statewide energy efficiency savings in both the electric and natural gas sectors by 2030. The GHG reduction targets associated with these requirements are to be incorporated into IRPs, which detail how each required utility will reduce GHGs, deploy clean energy resources and otherwise meet the resources needs of their customers. The Energy Commission is coordinating with other state agencies—including the: CPUC, ARB, and CAISO—to implement the bill. SoCalGas has been engaged with these agencies throughout the process and has provided input.

SENATE BILL 1383

SB 1383 was signed into law on September 19, 2016, establishing methane emissions reduction targets in a statewide effort to reduce emissions of Short-Lived Climate Pollutants (SLCP) in various sectors of California's economy.[103] SB 1383 requires a 40 percent reduction in methane, a 40 percent reduction on hydrofluorocarbon gases and a 50 percent reduction in anthropogenic black carbon by 2030, relative to 2013 baseline levels and requires the ARB, the CPUC, and the CEC to undertake various actions related to reducing SLCPs in the state.
SB 1383 also establishes targets to achieve a 50 percent reduction in the level of the statewide disposal of organic waste from the 2014 level by 2020 and a 75 percent reduction by 2025. The law grants CalRecycle the regulatory authority required to achieve the organic waste disposal reduction targets and establishes an additional target that not less than 20 percent of currently disposed edible food is recovered for human consumption by 2025. The bill mandates the ARB,

[103] http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383.

in consultation with the Department of Food and Agriculture, to adopt regulations to reduce methane emissions from livestock and dairy manure operations. SB 1383 also requires state agencies to consider and, as appropriate, adopt policies and incentives to significantly increase the sustainable production and use of RNG.

Pursuant to SB 1383, the ARB formed a Dairy and Livestock GHG Reduction working group in 2017 to help understand ways to reduce dairy and livestock methane emissions by 40 percent from 2013 levels by 2030. The working group's assignment was to identify and address technical, market, regulatory, and other barriers to development of methane reduction projects. SoCalGas actively participated in the working group and its three sub-groups including SoCalGas staff serving as co-chair of the Fostering Markets for Digester Projects sub-group whose task was to establish a roadmap, attentive to the SB 1383 statute dates of July 1, 2020 and January 1, 2024, to significantly expand the number of livestock digester projects in California that support the state's climate and air quality goals.

SoCalGas has participated in the CDFA Dairy Digester Research and Development Program (DDRDP), which provides financial assistance for the installation of dairy digesters in California, which will result in reduced GHG emissions. SoCalGas staff attended and presented at CDFA DDRDP workshops, webinars and listening sessions held in environmental justice (also known as disadvantaged communities) areas near dairies. SoCalGas also provided education and assisted customers who showed interest in the CDFA Program, as well as on other topics related to RNG, such as alternative fuel vehicles. A specific example is our promotion of RNG in our marketing materials especially those developed and displayed at the International Ag Expo held every year in Tulare, California. CDFA also includes a link on their DDRDP website to SoCalGas' RNG website.

SENATE BILL 100 AND EXECUTIVE ORDER B-55-18

The 100 Percent Clean Energy Act of 2019, or SB 100, was signed into law on September 10, 2018. SB 100 sets a state policy that eligible renewable energy and zero-carbon resources supply 100 percent of all retail sales of electricity in California by 2045. The bill also accelerates California's RPS, which, pursuant to a 2016 bill by the same author (SB 350), already mandates that load-serving entities procure at least 50 percent of retail sales from eligible renewable energy resources by 2030; under SB 100, the 2030 target will be increased to 60 percent, and the 50 percent target will be advanced to 2026, in recognition that California retail sellers are well on their way to achieving the target in advance of the existing deadlines. EO B-55-18 establishes a new statewide goal to achieve economy-wide carbon neutrality no later than 2045. In March 2021, the Joint Agencies (California Energy Commission, California Public Utilities Commission, and California Air Resources Board), published the 2021 *SB 100 Joint Agency Report: Achieving 100 Percent Clean Electricity in California: An Initial Assessment*. The report includes a review of the policy to provide 100 percent of electricity retail sales and state loads from renewable and zero-carbon resources in California by 2045. The report assesses various pathways to achieve the target and an initial assessment of costs and benefits. It also includes results from capacity expansion modeling and makes recommendations for further analysis and actions by the joint agencies. The Joint Agencies followed up with a workshop in October 2021 to analyze the non-energy benefits, social costs and reliability. Then the CEC conducted a workshop in collaboration with the CPUC and CAISO in February 2022, to discuss approaches for examining the environmental and land use implications of potential resource portfolios to meet SB 100 targets.

ASSEMBLY BILL 3232

The zero emissions buildings and sources of heat energy bill requires the CEC to assess the potential for the state to reduce the emissions of GHGs from the state's residential and commercial building stock by at least 40 percent below 1990 levels by January 1, 2030. AB 3232 also requires consideration of the impact of emission reduction strategies on grid reliability and as directed by AB 3232, the CEC will conduct additional analyses on strategies and update progress on reducing GHG emissions from residential and commercial buildings in the 2021 and future IEPRs. On August 11, 2021, the California Energy Commission (CEC) voted to adopt the AB 3232 California Building Decarbonization Assessment Final Staff Report (AB 3232 Final Report) during their regular Business Meeting. The Final Commissioner Report was published on August 13, 2021. In addition, a workbook containing updated assumptions being used in the Fuel Substitution Scenario Analysis Tool (FSSAT) was published to the 19-DECARB-01 Docket on February 28, 2022.

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AB 3232 suggests two baseline approaches from which California can track building decarbonization: systemwide and direct emissions. According to the Final Commissioner Report, the bulk of building GHG emissions in 2030 are from today's existing buildings and California has approximately 14 million existing single-family homes and multifamily units. The report defined and analyzed seven GHG emission strategies within seven high-level categories and the analysis concluded that as of 2018, systemwide GHG emissions in residential and commercial buildings are 26 percent below 1990 levels and current policies and activities are on a trajectory to reach 36 percent below 1990 levels by 2030. SoCalGas engaged with the CEC Commissioners and Staff on the Draft Version of the Building Decarbonization Assessment mandated by AB 3232 through attending six public workshops from December 2019 to May 2021 to discuss and share feedback on the findings presented in the AB 3232 Final Report; the CEC received many comments submitted to the public docket 19-DECARB-01.

GHG RULEMAKING

Beginning on January 1, 2015, the ARB's Cap-and-Trade Program expanded to include emissions from all SoCalGas customers. SoCalGas is required to purchase carbon allowances or offsets on behalf of our end-use customers for the emissions generated from the full combustion of the natural gas we deliver. Large end-use customers who emit at least 25,000 $mtCO_2e$ equivalent per year have a direct obligation to the ARB for their own emissions; therefore, SoCalGas' obligation does not include these customers and they will not be responsible for compliance costs related to end-users from SoCalGas.

The CPUC completed a rulemaking proceeding in late 2015 to determine how the costs related to compliance with the Cap-and-Trade program will be included in end-use customers' rates.[104] The rulemaking had also addressed how revenues generated from the sale of directly allocated allowances will be returned to ratepayers. The rulemaking had initially determined that all Cap-and-Trade compliance costs will be included on a forecasted basis in customers' transportation rates beginning April 1, 2016. Customers with a direct obligation to the ARB for their emissions are exempt from SoCalGas' end-users' compliance obligation and will receive a volumetric credit called the "Cap-and-Trade Cost Exemption" for the amount of their

[104] CPUC D.15-10-032.

transportation rates that contribute to these costs. All customers' rates will also include compliance costs related to SoCalGas' covered facilities, as well as for Lost and Unaccounted For (LUAF) gas.

In the same CPUC decision, it was determined that revenues generated from the sale of directly allocated allowances would be returned as a fixed, once-annual, California Climate Credit to all residential households on their April bills. Nonresidential customers were not to receive a California Climate Credit. An Application for Rehearing on the use of the revenues generated from the sale of directly allocated allowances was granted in April 2016. As such, the introduction of Cap-and-Trade costs into rates and the distribution of the gas California Climate Credit was delayed. In March 2018, the CPUC issued its Final Decision (D.18-02-017), which directed IOUs to recover Cap-and-Trade costs and distribute the California Climate Credit. It found that: (1) only residential customers are eligible for the California Climate Credit, with the initial Climate Credit to be distributed in October 2018 and in April ever year thereafter; (2) GHG compliance costs can be incorporated in transportation rates beginning July 1, 2018, with 2018 costs amortized over 18 months; and (3) the accumulated 2015-2017 GHG costs and revenues are to be netted, with the remaining balance either distributed in the 2018 Climate Credit or amortized in transportation rates.

REPORTING AND CAP-AND-TRADE OBLIGATIONS

The ARB publishes total, covered and non-covered emissions because total emissions are used to calculate California's GHG emissions inventory and covered emissions are used to determine a facility's Cap-and-Trade obligation. At the time of the writing of the 2020 CGR, the 2019 GHG numbers have not been verified by the independent third party. The 2018 numbers were the most recent verified numbers for the reporting category. As of 2018, SoCalGas reported to the ARB *verified* GHG emissions of approximately 41.4 mmtCO_2E in three primary categories: (1) combustion emissions at five compressor stations and two storage fields, where annual emissions exceed 10,000 mtCO_2E; (2) vented and fugitive emissions from three compressor stations, two storage fields and the natural gas distribution system; and (3) the GHG emissions resulting from combustion of natural gas delivered to all customers.

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In 2018, GHG emissions for gas delivered to all customers was 39.9 mmtCO_2e, but 20.7 mmtCO_2e for gas delivered to non-covered customers. Non-covered customers consist of smaller customers with emissions of less than 25,000 mtCO_2E. For Cap-and-Trade obligation, 20.7 mmtCO_2e is the appropriate Cap-and-Trade value. Large, covered customers pay their own Cap-and-Trade bill.

Four of the five facilities subject to the EPA's mandatory reporting regulation are also subject to ARB's Cap-and-Trade Program. On January 1, 2015, natural gas suppliers became subject to the Cap-and-Trade Program and now have a compliance obligation for GHG emissions from the natural gas use of their small customers (i.e., those customers who are not covered directly under ARB's Cap-and-Trade Program). More recently, SoCalGas estimated that its GHG emissions compliance obligation as a natural gas supplier to be approximately 22.0 mtCO_2E for 2019. ARB will issue final 2019 GHG emissions compliance obligations for natural gas suppliers in November 2020.

The adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipelines consistent with Pub. Util. Code Section 961 (d), § 192.703 (c) of Subpart M of Title 49 of the CFR, and the Commission's General Order 112-F are covered under R.15-01-008. As part of this rulemaking, natural gas utilities are required to annually report their methane emissions from intentional and unintentional releases as well as their leak management practices. In 2020, SoCalGas reported 2.2 Bcf of methane emissions from intentional and unintentional releases for the year 2019. These emissions were reported in the SB 1371 report. Only some intentional emissions are subject to the ARB Cap-and-Trade Program.

PROGRAMMATIC EMISSIONS REDUCTION: CALIFORNIA GHG REDUCTION STRATEGIES

The ARB has the responsibility to develop the broad strategies to achieve California's GHG emissions reduction targets. The 2017 Scoping Plan Update identified several strategies to achieve the 2030 target to reduce emissions by 40 percent from 1990 levels: double building efficiency; 50 percent renewable power; cleaner transportation; and reduce SLCPs and Cap emissions from various sectors. The SLCP includes targets to reduce methane emissions from organic sources of methane and methane leakage from the oil and gas industry.

The CPUC has an on-going Rulemaking, R.15-01-008, to implement SB 1371, which requires the adoption of rules and procedures to minimize natural gas leakage from Commission -regulated natural gas pipeline facilities. In D.17-06-015, utilities were ordered to implement a Natural Gas Leak Abatement Program consistent with 26 Best Practices for emission mitigation. This proceeding is led by the CPUC in consultation with the ARB. The first phase will develop the overall policies and guidelines for a natural gas leak abatement program consistent with SB 1371. The second phase will develop ratemaking and performance-based financial incentives associated with the natural gas leak abatement program determined through Phase 1 of the proceeding. Energy efficiency and renewables are considered fundamental to GHG emission reduction in the electric sector. As a result, integration of additional renewables will require quick-start peaking capacity for firming and shaping of intermittent power, which in the foreseeable future will be gas-fired combustion turbines.

RENEWABLE NATURAL GAS

STATE AND FEDERAL POLICIES FOR RNG

STATE POLICIES ON RNG

AB 1900 (2012, Gatto) required that the Commission open a rulemaking to ensure that each gas corporation provide non-discriminatory open access to its gas pipeline system to any party for the purposes of physically interconnecting with the gas pipeline system and effectuating the safe delivery of gas. On February 13, 2013, the Commission opened the order instituting rulemaking (OIR) R.13-02-008, (or 'Biomethane OIR') to adopt a biomethane standard and requirement, pipeline open access rules, and related enforcement provisions. In collaboration with and the Office of Environmental Health Hazard Assessment, the Commission determined that biomethane could be safely injected into the natural gas pipeline system and Decision D.14-01-034 (January 16, 2014) adopted pipeline injection standards for 17 constituents of concern potentially found in biomethane. The establishment of these biomethane injection standards was Phase 1 of the Biomethane OIR.

Phase 2 of the Biomethane OIR resulted in Decision D.15-06-029, which adopted a biomethane interconnector monetary incentive program to encourage the development of biomethane projects interconnecting to the utilities gas pipeline systems. The incentive program authorized a total of $40 million for incentives, providing up to $1.5 million per project that successfully interconnect and operate by June 11, 2020. Pub. Util. Code § 399.19 later increased the incentive amounts to $3 million for non-dairy clusters and $5 million for dairy clusters and extended the incentive program to December 31, 2021.

On October 2, 2019, Governor Newsom signed into law SB 457, which extended the biomethane incentive program again until December 31, 2026, or until all available program funds were expended. Decision D.19-12-009 implemented the SB 457 extension which also implemented a reservation system for the biomethane monetary incentive program that allowed project developers to reserve incentive funds during the development of a project and receive the incentive funds once the project is operating. The Incentive Reservation System is publicly available online to promote the transparency of the use of funds and all $40 million earmarked for incentives was reserved by 11 biomethane projects, with an additional 8 projects placed on a waiting list for possible incentive funding later.

Phase 3 of the Biomethane OIR addressed the need for a statewide standard renewable gas interconnection tariff (SRGIT) and interconnection agreement (SRGIA) between the California natural gas utilities and RNG developers. On August 27, 2020, the Commission issued decision D.20-08-035, which adopted the SRGIT filed by SoCalGas, SDG&E, Southwest Gas, and PG&E (IUOs). Decision D.20-08-035 also allocated an additional $40 million for biomethane interconnection incentives to assist those RNG interconnection projects on the incentive waiting list.

Phase 4 of the Biomethane OIR was opened November 21, 2019, to address two issues: (1) standards for injection of renewable H2 into gas pipelines; and (2) implementation of SB 1440 that was signed into law on September 23, 2018 and required the Commission to consider adopting biomethane procurement targets (or goals) for each natural gas corporation in the state.

SB 1440 AND RNG

On February 24, 2022, the Commission issued Decision D.22-02-025 to implement SB 1440 and defined two biomethane procurement targets for the IOUs. A short-term 2025 biomethane procurement target was set at 17.6 billion cubic feet (BCF) of biomethane, which corresponds to 8 million tons of organic waste diverted statewide annually from landfills. This target was set to support the organic waste diversion targets established previously in SB 1383. With this target, each utility will be responsible for procuring only RNG produced from organic waste, including wood waste, at a level in accordance with its proportionate share of statewide Cap-and-Trade allowances.

The medium-term 2030 target for annual biomethane procurement was established at 72.8 BCF to assist the state achieve its goal to reduce methane emissions 40 percent by 2030[105] and is referred to as a "Renewable Gas Standard" (RGS) for California.[106] With this target, each utility will be responsible for procuring a percentage of the total in accordance with its proportionate share of 2020 annual bundled core customer natural gas demand, excluding NGV demand, as noted in the 2020 California Gas Report. Each utility may procure RNG produced from other feedstocks besides organic waste, including landfill, WWTP, Syngas or dairy.[107]

SB 1383 AND RNG

Another significant driver for RNG development in California is SB 1383. Signed into law on September 19, 2016, SB 1383 required the state board to implement a comprehensive strategy to reduce emissions of SLCPs so as to achieve a reduction in methane by 40%, hydrofluorocarbon gases by 40%, and anthropogenic black carbon by 50% below 2013 levels by 2030. The bill established specified targets for reducing organic waste in landfill and required state agencies to consider and, as appropriate, adopt policies and incentives to significantly increase the sustainable production and use of renewable gas.

[105] SB-32 California Global Warming Solutions Act of 2006.
[106] D.22-02-025, p. 32.
[107] Dairy purchases are limited to 4% of the total utility proportionate share of the target volume.

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SB 1383 requires that beginning in 2022, all cities and counties provide organic waste collection services to all residents and businesses and also recycle these organic materials at recycling facilities such as anaerobic digestion facilities that create biofuel and electricity or composting facilities that make soil amendments. City and county governments are also required to procure prescribed amounts of products from in-state recycled organic material depending on their population. Allowed recycled products are, compost, mulch that meets SB 1383 regulations, renewable gas used as fuel for transportation, electricity, or heating applications and electricity generated from biomass conversion of municipal-solid-waste.

SB 1383 also required that the CPUC implement at least 5 dairy biomethane pilot projects to demonstrate interconnection to the common carrier pipeline system. For these pilot projects the gas corporations were allowed to fund and recover in rates the cost of pipeline infrastructure, including biogas collection lines and costs to interconnect with existing pipelines, removing many upfront costs developers would otherwise have to incur. On December 3, 2018, a selection committee consisting of staff members and attorneys from the CPUC, the ARB, and the CDFA, selected six dairy biomethane pilot projects. Four pilot projects are in SoCalGas service territory: CalBioGas Buttonwillow LLC; CalBioGas North Visalia LLC; CalBioGas South Tulare LLC; and Lakeside Pipeline LLC. (The other two projects are in PG&E service territory: Maas Energy Works in Merced; and Weststeyn Dairy in Willows.)

A.19-02-005[108] AND RNG

On February 28, 2019, SoCalGas and SDG&E filed a joint application A.19-02-005 for a voluntary RNG Tariff offering that would give the option to residential and small industrial and commercial customers to identify an amount of their monthly natural gas bill for the purchase of RNG in lieu of traditional natural gas. On December 17, 2020, Decision D.20-12-022, approved the voluntary renewable natural gas tariff authorizing a three-year voluntary Renewable Natural Gas (RNG) Tariff pilot program with two additional years for program wind-down. On March 14, 2022 SoCalGas filed an Advice Letter affirming their intention to implement the program

[108] On June 21, 2021, the Commission granted the Utilities' request for an extension of time to comply with D.20-12-022 as the Commission had provided guidance in OP 1(a) of D.20-12-022 that the Utilities should wait to consider sourcing long-term contracts for the voluntary RNG pilot program in conjunction with any RNG procurement authorized in the implementation of SB 1440.

within one year and review contract opportunities now that D.22-02-025 has implemented SB 1440.

FUEL STANDARDS AND RNG

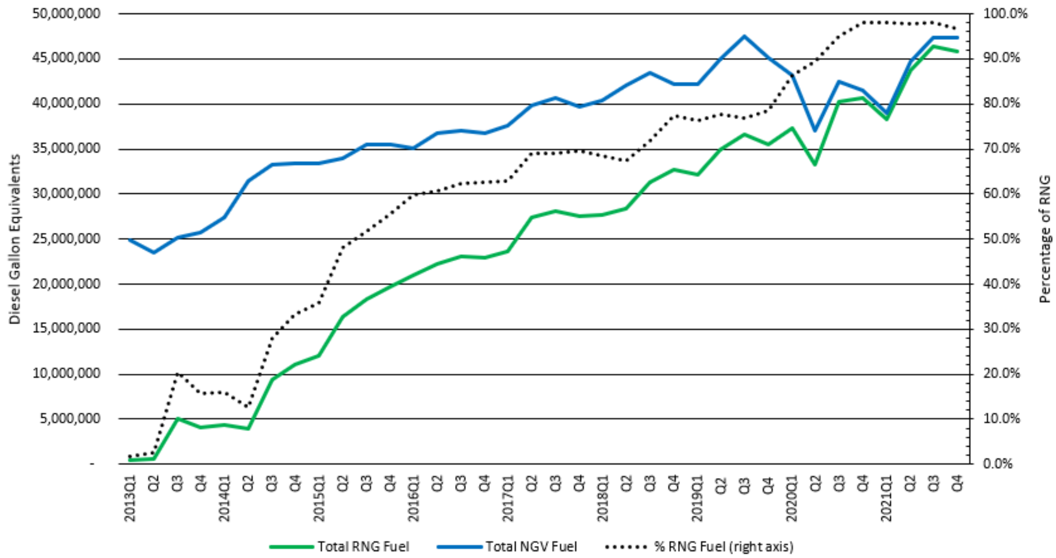
Fuel standards are evolving and becoming more stringent in California. Established by Executive Order and signed into law by then Governor Schwarzenegger in 2007, the fuel standard required a 10 percent carbon intensity reduction in the transportation sector by 2020. Those regulations were amended in 2018 to require a 20 percent reduction by 2030. The fuel standard(s) require fuel providers to ensure that the mix of fuel they sell into the California market meets, on average, provides a declining standard for GHG emissions measured in CO_2 equivalent grams per unit of fuel energy sold.

There is a significant amount of RNG used in California NGVs. The most recent data from the Low Carbon Fuel Standard (LCFS) Program[109] shows that approximately 98 percent of fuel delivered to NGVs in 2021 was RNG. The chart below shows how RNG usage in this important program has grown over time. Since 2013, RNG use by NGV's has displaced more than 886 million gallons of diesel fuel and has been responsible for reducing more than 8.4 MMT of carbon emissions.[110]

[109] https://ww2.arb.ca.gov/sites/default/files/2022-05/quarterlysummary_043022.xlsx.
[110] *Id.*

Southern California

Figure 25 - LCFS Program NGV Statistics for Years 2013 - 2021



The California NGV market continues to represent an important growth opportunity for RNG due to the economic incentives available from the LCFS Program and the Federal Renewable Fuel Standard, which help to offset the price premium between RNG and traditional fuels such as natural gas or diesel.

SoCalGas opted into the LCFS program in 2013 and began generating credits from fossil natural gas dispensed at utility owned CNG refueling stations that serve both company vehicles and the general public. In 2018, the CPUC approved a SoCalGas Advice Letter to initiate a Voluntary RNG Procurement Pilot program to procure and dispense RNG at its utility owned CNG stations. As RNG is an eligible alternative fuel under LCFS program and EPA's Renewable Fuel Standard (RFS), it generates Renewable Identification Number credits from the RFS Program in addition to the LCFS credits. The value from the credits generated is returned to CNG customers by reducing the price at the pump. Also, RNG has as lower carbon intensity than traditional CNG and will generate more credits per unit of energy under the LCFS program. On April 1, 2019, SoCalGas began procuring 100 percent RNG at all utility owned CNG stations. SoCalGas anticipates the Pilot will result in more value returned to its CNG customers while supporting the development of the RNG market.

CAP-AND-TRADE

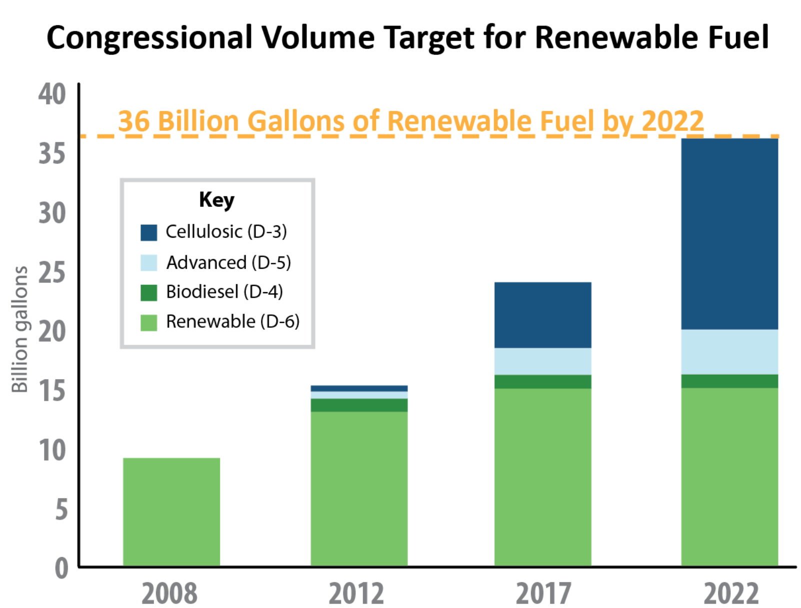
The Cap-and-Trade Regulation establishes a declining limit on major sources of GHG emissions throughout California. The Program applies to certain GHG emission sources and certain fuel suppliers, including natural gas utilities. CARB creates allowances equal to the total amount of permissible emissions and each year reduces the number of allowances created as the annual cap declines. An increasing auction reserve price for allowances and the reduction in annual allowances provides a carbon price signal intended to promote GHG emissions reductions. Many entities covered under the regulation must purchase allowances at quarterly auctions, however, qualifying RNG is exempt from compliance obligations under the program.

FEDERAL POLICIES ON RNG

RENEWABLE FUEL STANDARD (RFS)

The Renewable Fuel Standard (RFS) is a federal program that requires transportation fuel sold in the United States to contain a minimum volume of renewable fuels to expand the use of renewable fuels and reduce reliance on imported oil. RFS originated with the Energy Policy Act of 2005 and was expanded and extended by Congress in the Energy Independence and Security Act of 2007 (EISA). The RFS program provides a market-based monetary value for renewable fuels, including RNG that can be combined with LCFS incentives to increase the incentive amounts available to RNG developers, suppliers, or marketers. The RFS requires renewable fuel to be blended into transportation fuel in increasing amounts each year, escalating to 36 billion gallons by 2022.[111] For a fuel to qualify as a renewable fuel under the RFS program, EPA must determine that the fuel qualifies under the statute and regulations and the fuel must achieve a reduction in greenhouse gas (GHG) emissions as compared to a 2005 petroleum baseline.[112]

Figure 26 – Federal Renewable Fuel Targets



[111] https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard
[112] *Id.*

HYDROGEN

Hydrogen is the simplest and most abundant element, making up approximately 75 percent of the observable universe. Hydrogen can be utilized as a fuel to generate energy. With its abundance and simple chemical structure, hydrogen can be manufactured from feedstock such as methane, or water and electricity, using scalable, sustainable, and renewable methods. Hydrogen has favorable emissions characteristics because it does not contain carbon or produce GHG when it is consumed. For this reason, hydrogen can play an important role in the transition to a clean, low-carbon energy system in California.[113]

As part of the State of California's climate strategy, hydrogen can provide important GHG emissions reductions, and can also play a key role in enabling the use of zero-emissions fuel cell electric vehicles, which can reduce criteria emissions from on-road diesel, the largest and hardest to electrify contributors to the State's black carbon and nitrogen oxides (NOx) inventories.[114] California has also been at the forefront of developing hydrogen fueling stations to demonstrate the feasibility of hydrogen-fueled transportation and the potential that such a network creates for deployment of light duty fuel-cell electric vehicles (FCEVs).

Hydrogen fuel for transportation was adopted in California through the policy framework by Assembly Bill (AB) 8, which provided certainty for hydrogen fueling station deployment.[115] In addition, new programs and policies have been developed and initiated to ensure that some of the most ambitious public-private goals are met as projected. The Low Carbon Fuel Standard's (LCFS) Hydrogen Refueling Infrastructure (HRI) credit provisions took effect, predicated on the goal of reaching 200 hydrogen stations by 2025 as described by Governor Brown's Executive Order B-48-18 (EO B-48-18).[116]

Globally, hydrogen is widely seen as a pivotal component of the future clean energy economy. The two primary technological processes used today to produce hydrogen are electrolysis and

[113] http://hydrogencouncil.com .
[114] https://www.arb.ca.gov/cc/inventory/slcp/slcp.htm .
[115] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB8 .
[116] https://www.ca.gov/archive/gov39/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/index.html.

reformation, including steam methane reformation (SMR) and autothermal reformation (ATR). Hydrogen is also produced when organic mass is gasified, but this "syngas," consisting of mainly carbon monoxide (CO) and hydrogen, is typically an intermediate product often used to generate methane or electricity. Reforming is a mature technology and is the most economical way to produce hydrogen, supplying 95% or more of the hydrogen used in the United States today.[117] The electrolysis process uses renewable electricity to split water (H_2O) into hydrogen (H_2) and oxygen (O_2).

As a gaseous fuel, hydrogen can help decarbonize the gas grid and be used in a variety of end use applications, beyond transportation. The hydrogen can either be stored directly, or methanated and injected into the natural gas grid to be stored and delivered to a variety of end uses, supplementing or displacing traditional natural gas. Storing hydrogen from electrolysis is a scalable and versatile energy storage pathway.

In 2022, SoCalGas proposed the development of what would be the nation's largest green hydrogen energy infrastructure system, the Angeles Link, to deliver clean, reliable energy to the Los Angeles region. As proposed, the Angeles Link would support the integration of more renewable electricity resources like solar and wind and would 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 would 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.

Electrolytic green hydrogen is produced entirely from renewable electricity, and it expands our renewable energy storage capabilities, allowing us to utilize more renewable electricity and avoid curtailment while reducing emissions in hard-to-electrify sectors. As contemplated, the Angeles Link would deliver green hydrogen in an amount equivalent to almost 25 percent of the natural gas SoCalGas delivers today. Building the system to provide a clean alternative fuel could, over time and combined with other future clean energy projects, reduce

[117] The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology, Institute of Transportation Studies, UC Davis (March 2017), available at https://steps.ucdavis.edu/wp-content/uploads/2017/05/2017-UCD-ITS- RR-17-04-1.pdf

natural gas demand served by the Aliso Canyon natural gas storage facility, facilitating its ultimate retirement while continuing to provide reliable and affordable energy to the region.

PEAK DAY DEMAND

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's bundled core gas demand are procured as a combined portfolio. SoCalGas and SDG&E plan and design their systems to provide continuous service to their core customers under an extreme peak day event. On the extreme peak day event, service to all noncore customers is assumed to be fully interrupted. The criteria for extreme peak day design is defined as a 1-in-35 likelihood event foreach utility's service area. This criteria correlates to a system average temperature of 40.5 degrees Fahrenheit for SoCalGas' service area and 43.3 degrees Fahrenheit for SDG&E's service area.

TABLE 28 – CORE 1-IN-35 YEAR EXTREME PEAK DAY DEMAND (MMcf/d)

Year	SoCalGas Core Demand 1/	SDG&E Core Demand 2/	Other Core Demand 3/	Total Demand	*Estimated AAFS Impact on Core Peak Day Demand* 5/
2022	2,869	404	170	**3,443**	-2
2023	2,827	403	170	**3,401**	-9
2024	2,782	402	171	**3,355**	-25
2025	2,735	400	173	**3,308**	-44
2026	2,691	398	174	**3,263**	-65
2027	2,647	397	175	**3,218**	-88
2028	2,601	395	176	**3,173**	-113

Notes:

(1) 1-in-35 peak temperature cold day SoCalGas core sales and transportation. Forecast embodies the baseline forecast with load modifiers that include changing weather design to account for climate change, assumed EE savings and assumed fuel substitution under AAFS 2.

(2) 1-in-35 peak temperature cold day SDG&E core sales and transportation.

(3) 1-in-35 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas.

(4) The criteria for extreme peak day design are defined as a 1-in-35 likelihood event for each utility's service area. These criteria correlate to a system average temperature of 40.5 degrees Fahrenheit for SoCalGas' service area and 43.3 degrees Fahrenheit for SDG&E's service area.

(5) Estimated impact shown represents SoCalGas and SDG&E's combined AAFS impacts. SoCalGas and SDG&E's AAFS Impacts are included in the forecast of Peak day demand of "SoCalGas Core Demand", "SDG&E Core Demand", and "Total Demand".

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Demand on an extreme peak day is met through a combination of withdrawals from underground storage facilities and flowing pipeline supplies. The following table provides forecasted core extreme peak day demand.

SoCalGas aligned around the fuel substitution scenario developed by the California Energy Commission (CEC). SoCalGas emphasizes that we are still in the early stages of this energy transition and forecasts around the timing and degree of these changes are highly uncertain. These forecasts will improve over time as trends are observed in the real world and policy and market drivers mature. SoCalGas will be actively monitoring these trends and expects that each update of the CGR will incorporate greater definition of these factors and their impact(s) on the resultant gas demand segment forecasts.

It is also important to note that the CGR is relied upon for system planning purposes to inform important infrastructure investment and operating decisions that impact the natural gas system capacity and reliability. For these reasons, it is important to recognize that while we need to evolve with the energy transition, we also consider a measured view around prospective load reductions to avoid premature design standard reductions that may not serve California well if less load reductions materialize than are anticipated. We have an obligation to our customers to make sure they have safe, clean, reliable and affordable sources of energy and compromising these outcomes based on prospective and uncertain projections will not serve the public interest so ambition must be appropriately balanced with reality.

The CPUC has also mandated that SoCalGas and SDG&E design its system to provide service to both core and noncore customers under a winter temperature condition with an expected recurrence interval of 10 years. The demand forecast for this 1-in-10-year cold day condition is shown in the table below.

TABLE 29 – WINTER 1-IN-10 YEAR COLD DAY DEMAND CONDITION (MMcf/d)

Year	SoCalGas Core (1)	SDG&E Core (2)	Other Core (3)	Noncore NonEG (4)	Electric Generation (5)	Total Demand	*Estimated AAFS Impact on Core Peak Day Demand* (7)
2022	2,709	380	150	621	812	4,672	*-2*
2023	2,670	380	150	621	792	4,612	*-9*
2024	2,628	378	151	622	749	4,528	*-23*
2025	2,584	376	152	622	725	4,459	*-41*
2026	2,542	375	153	621	710	4,402	*-61*
2027	2,500	373	154	621	735	4,383	*-83*
2028	2,458	372	155	620	669	4,274	*-107*

Notes:
(1) 1-in-10 peak temperature cold day SoCalGas core sales and transportation.
(2) 1-in-10 peak temperature cold day SDG&E core sales and transportation.
(3) 1-in-10 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas.
(4) Noncore-Non-EG includes noncore non-EG end-use customers of SoCalGas, SDG&E, Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas. Average daily December Noncore-Non-EG demand for all market segments except Refinery and SoCalGas noncore Commercial; SoCalGas noncore Commercial is at 1-in-10 peak temperature cold day demand and Refinery is at connected load.
(5) Electric Generation includes UEG/EWG Base Hydro, large cogeneration, industrial and commercial cogeneration (<20MW), refinery-related cogeneration, and EOR-related cogeneration.
(6) The criteria for 1-in-10 peak day design are defined as a 1-in-10 likelihood event for each utility's service area. These criteria correlate to a system average temperature of 42.2 degrees Fahrenheit for SoCalGas' service area and 44.8 degrees Fahrenheit for SDG&E's service area.
(7) Estimated impact shown represents SoCalGas and SDG&E's combined AAFS impacts. SoCalGas and SDG&E's AAFS Impacts are included in the forecast of Peak day demand of "SoCalGas Core Demand", "SDG&E Core Demand", and "Total Demand".

The SoCalGas and SDG&E system is a winter peaking system; peak demand is expected to occur during the winter operating season of November through March. For this reason, the CPUC has not mandated a summer design standard. For informational purposes only, the table below presents a forecast of summer demand on the SoCalGas and SDG&E system.

TABLE 30 – SUMMER HIGH SENDOUT DAY DEMAND
(MMcf/d)

Year	High Demand Month (1)	SoCalGas Core (2)	SDG&E Core (3)	Other Core (4)	Noncore NonEG (5)	Electric Generation (6)	Total Demand
2022	Sep	607	87	57	587	1,241	2,579
2023	Sep	599	87	57	589	1,180	2,513
2024	Sep	591	87	57	590	981	2,306
2025	Sep	582	86	58	590	1,031	2,347
2026	Sep	575	86	58	589	1,080	2,387
2027	Sep	567	85	58	589	1,104	2,403
2028	Sep	558	84	59	588	1,022	2,312

Notes:
(1) Month of High Sendout gas demand during summer (July, August or September).
(2) Average daily summer SoCalGas core sales and transportation.
(3) Average daily summer SDG&E core sales and transportation.
(4) Average daily summer core demand of Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas.
(5) Noncore-Non-EG includes noncore non-EG end-use customers of SoCalGas, SDG&E, Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas. Average daily September Noncore-Non-EG demand for all noncore market segments except Refinery; Refinery is at connected load.
(6) Highest demand during the high demand month under 1-in-10 dry hydro conditions except year 2022, when the Electric Generation highest demand is based on 2022 hydro condition.

2022 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY – TABULAR DATA

Table 31

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2017 TO 2021

Line	CAPACITY AVAILABLE		2017	2018	2019	2020	2021
1	California Source Gas						
	Out-of-State Gas						
2	California Offshore -POPCO / PIOC						
3	El Paso Natural Gas Co.						
4	Transwestern Pipeline Co.						
5	Kern / Mojave						
6	PGT / PG&E						
7	Other						
8	Total Out-of-State Gas						
9	TOTAL CAPACITY AVAILABLE						
	GAS SUPPLY TAKEN						
10	California Source Gas		84	104	97	87	86
	Out-of-State Gas						
11	Other Out-of-State		2,434	2,246	2,305	2,366	2,377
12	Total Out-of-State Gas		2,434	2,246	2,305	2,366	2,377
13	TOTAL SUPPLY TAKEN		2,518	2,350	2,402	2,453	2,463
14	Net Underground Storage Withdrawal		(14)	(8)	7	(19)	(20)
15	TOTAL THROUGHPUT (1)(2)		2,504	2,342	2,409	2,435	2,443
	DELIVERIES BY END-USE						
16	Core	Residential	565	569	645	635	621
17		Commercial	214	217	226	196	211
18		Industrial	55	57	61	53	55
19		NGV	38	40	41	37	40
20		Subtotal	872	883	973	920	927
21	Noncore	Commercial	56	59	58	57	57
22		Industrial	389	389	**357**	369	376
23		EOR Steaming	39	38	51	51	34
24		Electric Generation	713	615	589	641	654
25		Subtotal	1,198	1,101	1,055	1,118	1,121
26	Wholesale/International		401	333	342	374	372
27	Co. Use & LUAF		33	25	39	23	23
28	SYSTEM TOTAL-THROUGHPUT (1)(2)		2,504	2,342	2,409	2,435	2,443
	TRANSPORTATION AND EXCHANGE						
29	Core	All End Uses	62	71	74	63	64
30	Noncore	Commercial/Industrial	446	448	415	426	433
31		EOR Steaming	39	38	51	51	34
32		Electric Generation	713	623	589	641	654
33		Subtotal-Retail	1,260	1,181	1,129	1,181	1,185
34	Wholesale/International		401	333	342	374	372
35	TOTAL TRANSPORTATION & EXCHANGE		1,660	1,514	1,471	1,554	1,557
36	CURTAILMENT (3)						
37	REFUSAL						
38		Total BTU Factor (Dth/Mcf)	1.0343	1.0319	1.0336	1.0293	1.0322

NOTES:

(1) The wholesale volumes only reflect natural gas supplied by SoCalGas; and, do not include supplies from other sources.
Refer to the supply source data provided in each utility's report for a complete accounting of their supply sources.

(2) Deliveries by end-use includes sales, transportation, and exchange volumes and data includes effect of prior period adjustments.

(3) The table does not explicitly show any curtailment numbers for the recorded years because, during some curtailment events.
the estimate of the curtailed volume is not available. This table does not explicitly show any curtailment data for the recorded years, the noncore customer usage data implicitly captures the effects of any curtailment events.

TABLE 1-SCG

Table 32

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2022 THRU 2026

AVERAGE TEMPERATURE YEAR

LINE			2022	2023	2024	2025	2026	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) [1/]		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) [2/]		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) [3/]		1,250	1,250	1,250	1,250	1,250	5
6	Total Out-of-State Gas		3,225	3,225	3,225	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE [4/]		3,435	3,435	3,435	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas [5/]		61	61	61	61	61	8
9	Out-of-State		2,379	2,354	2,266	2,219	2,190	9
10	TOTAL SUPPLY TAKEN		2,440	2,415	2,327	2,280	2,251	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT [6/]		2,440	2,415	2,327	2,280	2,251	12
	REQUIREMENTS FORECAST BY END-USE [7/]							
13	CORE [8/]	Residential	610	604	594	585	575	13
14		Commercial	206	200	194	190	185	14
15		Industrial	54	54	53	52	51	15
16		NGV	41	42	43	44	45	16
17		Subtotal-CORE	912	900	883	870	856	17
18	NONCORE	Commercial	48	49	49	49	49	18
19		Industrial	389	390	389	389	388	19
20		EOR Steaming	27	27	27	27	27	20
21		Electric Generation (EG)	670	667	612	584	571	21
22		Subtotal-NONCORE	1,135	1,132	1,076	1,049	1,035	22
23	WHOLESALE &	Core	208	208	207	207	206	23
24	INTERNATIONAL	Noncore Excl. EG	28	27	27	28	28	24
25		Electric Generation (EG)	127	117	104	97	97	25
26		Subtotal-WHOLESALE & INTL.	363	352	339	332	331	26
27		Co. Use & LUAF	31	30	29	29	28	27
28	SYSTEM TOTAL THROUGHPUT [6/]		2,440	2,415	2,327	2,280	2,251	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	64	64	63	63	62	29
30	NONCORE	Commercial/Industrial	437	438	437	438	437	30
31		EOR Steaming	27	27	27	27	27	31
32		Electric Generation (EG)	670	667	612	584	571	32
33		Subtotal-RETAIL	1,199	1,196	1,139	1,112	1,097	33
34	WHOLESALE & INTERNATIONAL	All End Uses	363	352	339	332	331	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,562	1,548	1,478	1,443	1,428	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)

2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand

3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision

4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.

5/ Average 2021 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2022	2023	2024	2025	2026
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1.3	1.3	1.3	1.2	1.2

7/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

	2022	2023	2024	2025	2026
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	875	863	847	834	820

Table 33

TABLE 2-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2027 THRU 2035

AVERAGE TEMPERATURE YEAR

LINE			2027	2028	2029	2030	2035	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) 3/		1,250	1,250	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,225	3,225	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE 4/		3,435	3,435	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		61	61	61	61	61	8
9	Out-of-State		2,160	2,106	2,080	2,034	1,912	9
10	TOTAL SUPPLY TAKEN		2,221	2,167	2,141	2,095	1,973	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,221	2,167	2,141	2,095	1,973	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	565	552	542	530	466	13
14		Commercial	181	177	174	170	155	14
15		Industrial	50	49	48	47	44	15
16		NGV	46	47	48	50	54	16
17		Subtotal-CORE	842	825	813	797	719	17
18	NONCORE	Commercial	49	49	49	49	48	18
19		Industrial	388	388	388	387	385	19
20		EOR Steaming	26	25	24	24	20	20
21		Electric Generation (EG)	558	529	516	493	461	21
22		Subtotal-NONCORE	1,021	991	977	952	914	22
23	WHOLESALE &	Core	206	205	204	203	199	23
24	INTERNATIONAL	Noncore Excl. EG	28	28	28	28	29	24
25		Electric Generation (EG)	96	92	92	88	87	25
26		Subtotal-WHOLESALE & INTL.	330	324	325	319	315	26
27		Co. Use & LUAF	28	27	27	26	25	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,221	2,167	2,141	2,095	1,973	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	62	62	62	61	61	29
30	NONCORE	Commercial/Industrial	437	437	436	436	433	30
31		EOR Steaming	26	25	24	24	20	31
32		Electric Generation (EG)	558	529	516	493	461	32
33		Subtotal-RETAIL	1,083	1,052	1,039	1,013	975	33
34	WHOLESALE & INTERNATIONAL	All End Uses	330	324	325	319	315	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,413	1,376	1,363	1,333	1,290	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	

NOTES:
1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision
4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.
5/ Average 2021 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2027	2028	2029	2030	2035
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1.2	1.2	1.2	1.2	1.1

7/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

	2027	2028	2029	2030	2035
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	805	788	775	759	680

TABLE 3-SCG

Table 34

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2022 THRU 2026

COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2022	2023	2024	2025	2026	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) 3/		1,250	1,250	1,250	1,250	1,250	5
6	Total Out-of-State Gas		3,225	3,225	3,225	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE 4/		3,435	3,435	3,435	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		61	61	61	61	61	8
9	Out-of-State		2,452	2,432	2,343	2,298	2,267	9
10	TOTAL SUPPLY TAKEN		2,513	2,493	2,404	2,359	2,328	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,513	2,493	2,404	2,359	2,328	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	660	653	642	632	622	13
14		Commercial	214	208	202	197	193	14
15		Industrial	55	55	53	52	51	15
16		NGV	41	42	43	44	45	16
17		Subtotal-CORE	970	957	940	926	911	17
18	NONCORE	Commercial	49	49	49	50	50	18
19		Industrial	389	390	389	389	388	19
20		EOR Steaming	27	27	27	27	27	20
21		Electric Generation (EG)	670	671	616	591	578	21
22		Subtotal-NONCORE	1,136	1,138	1,081	1,057	1,042	22
23	WHOLESALE &	Core	221	221	220	220	219	23
24	INTERNATIONAL	Noncore Excl. EG	28	28	28	28	28	24
25		Electric Generation (EG)	127	118	105	98	98	25
26		Subtotal-WHOLESALE & INTL.	376	366	353	346	345	26
27		Co. Use & LUAF	32	31	30	30	29	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,513	2,493	2,404	2,359	2,328	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	66	65	64	64	64	29
30	NONCORE	Commercial/Industrial	438	439	438	439	438	30
31		EOR Steaming	27	27	27	27	27	31
32		Electric Generation (EG)	670	671	616	591	578	32
33		Subtotal-RETAIL	1,201	1,203	1,146	1,121	1,106	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	376	366	353	346	345	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,577	1,569	1,498	1,467	1,451	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	

NOTES:
1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision
4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.
5/ Average 2021 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2022	2023	2024	2025	2026
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1.3	1.3	1.3	1.3	1.3

7/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

	2022	2023	2024	2025	2026
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	934	921	903	889	874

Table 35

TABLE 4-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2027 THRU 2035

COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2027	2028	2029	2030	2035	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) [1/]		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) [2/]		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) [3/]		1,250	1,250	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,225	3,225	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE [4/]		3,435	3,435	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas [5/]		61	61	61	61	61	8
9	Out-of-State		2,239	2,180	2,156	2,104	1,992	9
10	TOTAL SUPPLY TAKEN		2,300	2,241	2,217	2,165	2,053	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT [6/]		2,300	2,241	2,217	2,165	2,053	12
	REQUIREMENTS FORECAST BY END-USE [7/]							
13	CORE [8/]	Residential	610	597	586	573	506	13
14		Commercial	189	184	181	177	161	14
15		Industrial	51	50	49	48	45	15
16		NGV	46	47	48	50	54	16
17		Subtotal-CORE	896	878	864	848	766	17
18	NONCORE	Commercial	50	49	49	49	49	18
19		Industrial	388	388	388	387	385	19
20		EOR Steaming	26	25	24	24	20	20
21		Electric Generation (EG)	567	534	524	496	474	21
22		Subtotal-NONCORE	1,031	996	985	956	928	22
23	WHOLESALE &	Core	219	217	217	216	212	23
24	INTERNATIONAL	Noncore Excl. EG	28	28	28	28	29	24
25		Electric Generation (EG)	98	93	94	89	92	25
26		Subtotal-WHOLESALE & INTL.	344	339	339	334	333	26
27		Co. Use & LUAF	29	28	28	27	26	27
28	SYSTEM TOTAL THROUGHPUT [6/]		2,300	2,241	2,217	2,165	2,053	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	64	63	63	63	62	29
30	NONCORE	Commercial/Industrial	438	437	437	436	434	30
31		EOR Steaming	26	25	24	24	20	31
32		Electric Generation (EG)	567	534	524	496	474	32
33		Subtotal-RETAIL	1,095	1,059	1,048	1,019	990	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	344	339	339	334	333	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,439	1,398	1,387	1,353	1,324	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)

2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand

3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision

4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.

5/ Average 2021 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2027	2028	2029	2030	2035
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1.3	1.3	1.3	1.3	1.3

7/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

	2027	2028	2029	2030	2035
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	859	841	827	811	727

TABLE 36

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS REQUIREMENTS - MMCF/DAY

1-IN-10 COLD TEMPERATURE YEAR & DRY HYDRO YEAR (1)

Year	CORE	NONCORE	WHOLESALE & INTERNATIONAL	Company Use & LUAF	SYSTEM TOTAL THROUGHPUT
2022	950	1,135	373	31	2,490
2023	938	1,137	363	31	2,469
2024	920	1,081	350	30	2,381
2025	907	1,057	343	29	2,336
2026	892	1,042	342	29	2,305
2027	878	1,031	341	29	2,278
2028	860	996	336	28	2,219
2029	847	985	336	28	2,195
2030	831	956	331	27	2,144
2035	750	928	330	26	2,034

NOTES:

(1) SoCalGas' Demand forecast of 1-in-10 cold temperature year and dry hydro year is used to evaluate the backbone transmission capacity and slack capacity in compliance with CPUC Decision (D.) 06-09-039 and the daily receipt capacity in compliance with D.22-07-002.

2022 CALIFORNIA GAS REPORT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT

The annual gas supply and forecast requirements prepared by the Long Beach Energy Resources Department (Long Beach) are shown on the following tables for the years 2022 through 2035.

Long Beach operates the fifth largest municipally owned natural gas utility in the country and is one of only three in the State. The gas utility provides safe and reliable natural gas services to about 500,000 residents and businesses via approximately 150,000 connected gas meters, delivered through more than 1,800 miles of gas pipelines. Long Beach's service territory includes the cities of Long Beach and Signal Hill, and sections of surrounding communities including Lakewood, Bellflower, Compton, Seal Beach, Paramount, and Los Alamitos. Long Beach's gas use is split at 53 percent residential and 47 percent commercial/industrial.

Long Beach serves core and noncore customers from three incremental supply sources: (1) interstate supplies delivered into the SoCalGas' intrastate pipeline system; (2) gas storage withdrawals; and (3) local gas delivered directly to Long Beach Energy Resources Department's pipeline system from gas fields within the city. Currently, local production supplies about 5 percent of Long Beach's gas use. Long Beach purchases most of its gas supplies from producers in the South-Western U.S. As a Wholesale customer, Long Beach contracts with SoCalGas for intrastate transmission service to deliver that gas from the California border to its service area.

The City of Long Beach is the only municipal government in the State of California that manages oil operations. Through its Energy Resources Department, the City operates the Wilmington Oil Field and has various financial interests in smaller oil fields throughout the City, such as the Signal Hill East and West Units, Recreation Park, and City Wasem.

As a municipal utility, Long Beach's gas rates and policies are established by the City Council, which acts as the regulatory authority. The City Charter requires the gas utility to establish its rates comparable to the rates charged by surrounding gas utilities for similar types of service.

2022 CALIFORNIA GAS REPORT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT – TABULAR DATA

TABLE 37 – CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
RECORDED YEARS 2017-2021

LINE	GAS SUPPLY AVAILABLE	2017	2018	2019	2020	2021	LINE
	California Source Gas						
1	Regular Purchases	0.0	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	4
	Out-of-State Gas						
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN						
	California Source Gas						
13	Regular Purchases	0.6	0.6	1.1	0.7	1.3	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	0.6	0.6	1.1	0.7	1.3	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	16
	Out-of-State Gas						
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	24.6	23.9	25.2	24.8	24.2	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	24.6	23.9	25.2	24.8	24.2	21
22	Subtotal	25.2	24.5	26.3	25.5	25.5	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	25.2	24.5	26.3	25.5	25.5	24

TABLE 38 – CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
RECORDED YEARS 2017-2021 (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2017	2018	2019	2020	2021	LINE
1	CORE	Residential	11.8	12.1	12.9	12.9	12.6	1
2	CORE/NONCORE	Commercial	6.0	5.9	6.1	5.3	5.7	2
3	CORE/NONCORE	Industrial	4.7	4.3	4.7	4.1	4.3	3
4		Subtotal	22.5	22.3	23.8	22.2	22.6	4
5	NON CORE	Non-EOR Cogeneration	2.2	1.9	1.7	2.5	2.3	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	2.2	1.9	1.7	2.5	2.3	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.5	0.2	0.8	0.7	0.6	13
14		Subtotal-END USE	25.1	24.5	26.3	25.5	25.4	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		25.1	24.5	26.3	25.5	25.4	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	2.9	3.0	3.1	2.8	3.1	18
19		Non-EOR Cogeneration	2.0	1.9	1.5	2.5	2.3	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.0	4.9	4.7	5.3	5.4	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.0	4.9	4.7	5.3	5.4	24
	ACTUAL CURTAILMENT							
25		Residential	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	32

NOTE: Actual deliveries by end-use includes sales, transportation, and exchange volumes, but excludes actual curtailments.

TABLE 39– CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 1A-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
AVERAGE YEAR FORECAST FOR THE 2022 CGR REPORT

LINE	ACTUAL DELIVERIES BY END-USE		2022	2023	2024	2025	2030	2035	LINE
1	CORE	Residential	12.3	12.3	12.3	12.4	12.5	12.5	1
2	CORE/NONCORE	Commercial	5.5	5.5	5.5	5.6	5.6	5.7	2
3	CORE/NONCORE	Industrial	3.9	3.9	3.9	3.9	4.0	4.1	3
4		Subtotal	21.7	21.7	21.7	21.9	22.1	22.3	4
5	NON CORE	Non-EOR Cogeneration	2.3	2.3	2.4	2.4	2.6	2.7	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	2.3	2.3	2.4	2.4	2.6	2.7	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	24.9	24.9	25.0	25.2	25.6	25.9	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		24.9	24.9	25.0	25.2	25.6	25.9	16
	ACTUAL TRANSPORTATION AND EXCHANGE								
17		Residential	N/A	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.3	3.4	3.4	3.4	3.5	3.7	18
19		Non-EOR Cogeneration	1.7	1.8	1.8	1.8	1.8	1.9	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.0	5.1	5.1	5.1	5.3	5.6	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.0	5.1	5.1	5.1	5.3	5.6	24
	ACTUAL CURTAILMENT								
25		Residential	0.0	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	0.0	32

NOTE: Actual deliveries by end-use includes sales, transportation, and exchange volumes, but excludes actual curtailments.

TABLE 40 – CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 2A-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
AVERAGE YEAR FORECAST (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2022	2023	2024	2025	2030	2035	LINE
1	CORE	Residential	12.3	12.3	12.3	12.4	12.5	12.5	1
2	CORE/NONCORE	Commercial	5.5	5.5	5.5	5.6	5.6	5.7	2
3	CORE/NONCORE	Industrial	3.9	3.9	3.9	3.9	4.0	4.1	3
4		Subtotal	21.7	21.7	21.7	21.9	22.1	22.3	4
5	NON CORE	Non-EOR Cogeneration	2.3	2.3	2.4	2.4	2.6	2.7	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	2.3	2.3	2.4	2.4	2.6	2.7	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	24.9	24.9	25.0	25.2	25.6	25.9	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		24.9	24.9	25.0	25.2	25.6	25.9	16
	ACTUAL TRANSPORTATION AND EXCHANGE								
17		Residential	N/A	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.3	3.4	3.4	3.4	3.5	3.7	18
19		Non-EOR Cogeneration	1.7	1.8	1.8	1.8	1.8	1.9	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.0	5.1	5.1	5.1	5.3	5.6	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.0	5.1	5.1	5.1	5.3	5.6	24
	ACTUAL CURTAILMENT								
25		Residential	0.0	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	0.0	32

NOTE: Actual deliveries by end-use includes sales, transportation, and exchange volumes, but excludes actual curtailments.

TABLE 41– CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 3C-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d COLD YEAR FORECAST FOR THE 2022 CGR REPORT (CONTINUED)

LINE	GAS SUPPLY AVAILABLE	2022	2023	2024	2025	2030	2035	LINE
	California Source Gas							
1	Regular Purchases	0.0	0.0	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	0.0	4
	Out-of-State Gas							
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN							
	California Source Gas							
13	Regular Purchases	1.3	1.3	1.3	1.3	1.3	1.3	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.3	1.3	1.3	1.3	1.3	1.3	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	0.0	16
	Out-of-State Gas							
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	29.4	29.4	29.4	29.4	29.4	29.4	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	29.4	29.4	29.4	29.4	29.4	29.4	21
22	Subtotal	30.7	30.7	30.7	30.7	30.7	30.7	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	30.7	30.7	30.7	30.7	30.7	30.7	24

TABLE 42– CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 4C-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d COLD YEAR FORECAST FOR THE 2022 CGR REPORT (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2022	2023	2024	2025	2030	2035	LINE
1	CORE	Residential	15.1	15.1	15.1	15.1	15.1	15.1	1
2	CORE/NONCORE	Commercial	7.2	7.2	7.2	7.2	7.2	7.2	2
3	CORE/NONCORE	Industrial	5.6	5.6	5.6	5.6	5.6	5.6	3
4		Subtotal	27.8	27.8	27.8	27.8	27.8	27.8	4
5	NON CORE	Non-EOR Cogeneration	2.0	2.0	2.0	2.0	2.0	2.0	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	2.0	2.0	2.0	2.0	2.0	2.0	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	30.7	30.7	30.7	30.7	30.7	30.7	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		30.7	30.7	30.7	30.7	30.7	30.7	16
	ACTUAL TRANSPORTATION AND EXCHANGE								
17		Residential	N/A	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.6	3.6	3.6	3.6	3.6	3.6	18
19		Non-EOR Cogeneration	1.8	1.8	1.8	1.8	1.8	1.8	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.4	5.4	5.4	5.4	5.4	5.4	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.4	5.4	5.4	5.4	5.4	5.4	24
	ACTUAL CURTAILMENT								
25		Residential	0.0	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	0.0	32

NOTE: Actual deliveries by end-use includes sales, transportation, and exchange volumes, but excludes actual curtailments.

2022 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY

INTRODUCTION

SDG&E is a combined gas and electric distribution utility serving more than three million people in San Diego and the southern portions of Orange counties. SDG&E delivered natural gas to 903,649 customers in San Diego County in 2021, including power plants and turbines. Total gas sales and transportation through SDG&E's system for 2021 were approximately 94 billion cubic feet (Bcf), which is an average of 258.5 MMcf/d.

GAS DEMAND

OVERVIEW

SDG&E's gas demand forecast is largely determined by the long-term economic outlook for its San Diego County service area. The county's economic trends are expected to generally parallel those of the larger SoCalGas area as discussed above.

This projection of natural gas requirements, excluding EG demand and noncore demand, begins with a usage calculator derived from end use models that integrates demographic assumptions, economic growth, energy prices, energy efficiency programs, detailed customer information, building and appliance standards, weather and other factors. After the forecast is developed, the forecast is treated for three out-of-model adjustments. The adjustments made to the forecasts include (1) allowing for less heating degree days in the average weather design each year of the forecast period to account for climate change; (2) gas demand destruction due to greater energy efficiency savings forecast over the planning period; and (3) incremental energy savings created from assumed fuel substitution. All of the energy savings incorporated into the forecast reflect market potential and were used as load modifiers to create a final forecast of demand. The baseline forecast was adjusted downward to account for the incremental energy savings influences that are expected to occur.

The introduction of potential fuel substitution into the long-term demand forecast is new for SDG&E in the CGR long term forecast development. SDG&E's own internal estimates of fuel substitution are preliminary. SDG&E is working on finding methods, using historical usage data, to identify customers who may be converting gas space and water heating to electric substitutes.

Fuel substitution was introduced into the 2021 IEPR as additional achievable fuel substitution (AAFS).[118] The AAFS2 was utilized. It includes the effects of potential updates in

[118] SEE IEPR, Chapter 2, pp. 33-49. See also Appendix A.

the Title 24 building standards and the presumed building electrification encouraged by future ratcheting driven by tighter goals, rate enhancements and higher uptake rates at future points in time.

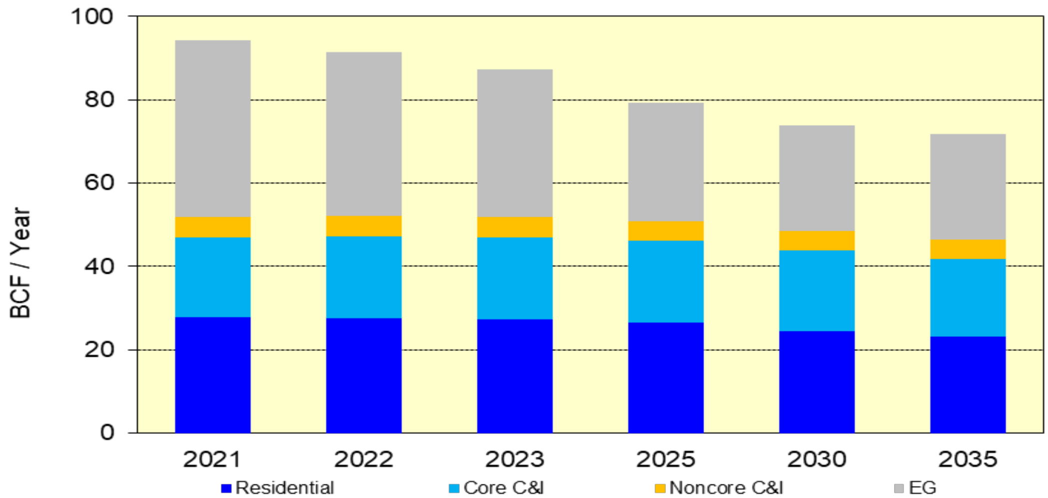
Altogether, SDG&E's gas demand, not inclusive of gas driven EG, is projected to drop slightly from 52 Bcf in 2021 to 46 Bcf in 2035, which is an average annual rate of decline of 0.8 percent. Including EG, overall demand adjusted for average temperature conditions totaled 94 Bcf in 2021 and is expected to drop about 1.9 percent per year to 72 Bcf by 2035.

Assumptions for SDG&E's gas transportation requirements for EG are included as part of the wholesale market sector description for SoCalGas.

ECONOMICS AND DEMOGRAPHICS

SDG&E's gas demand forecast is largely determined by the long-term economic outlook for its San Diego County service area. San Diego County's total employment is forecasted to grow on average just over 1% annually from 2021 to 2035; the subset of industrial (mining and manufacturing) jobs is projected to grow an average of 0.1% per year during the same period. The number of SDG&E gas meters is expected to increase an average of about 0.8% annually from 2021 through 2035.

FIGURE 27 – SDG&E'S COMPOSITION OF NATURAL GAS THROUGHPUT AVERAGE TEMPERATURE, NORMAL YEAR (2021-2035) (Bcf/year)



From 2021 through 2035, SDG&E's forecasted gas demand is expected to decline at an average annual rate of 1.9 percent. The decline is being driven by future projected reductions in the EG load. Additional factors reducing the load forecast are energy efficiency programs and new requirements on Title 24 building codes and standards and assumed fuel substitution over the forecast period.

MARKET SECTORS

Residential

SDG&E served approximately 873,304 residential customers in 2021. The residential usage varies for each of the various residential market segments that SDG&E serves. Conditional demand estimates based on the 2019 Residential Appliance Saturation Survey (R.A.S.S.) have allowed SDG&E to better understand customer usage and needs. The updated survey information included below was part of the estimation and resulting baseline residential market forecast.

The table below shows the weather-normalized home usage by customer type and the saturations by end use for SDG&E based upon the conditional demand study.

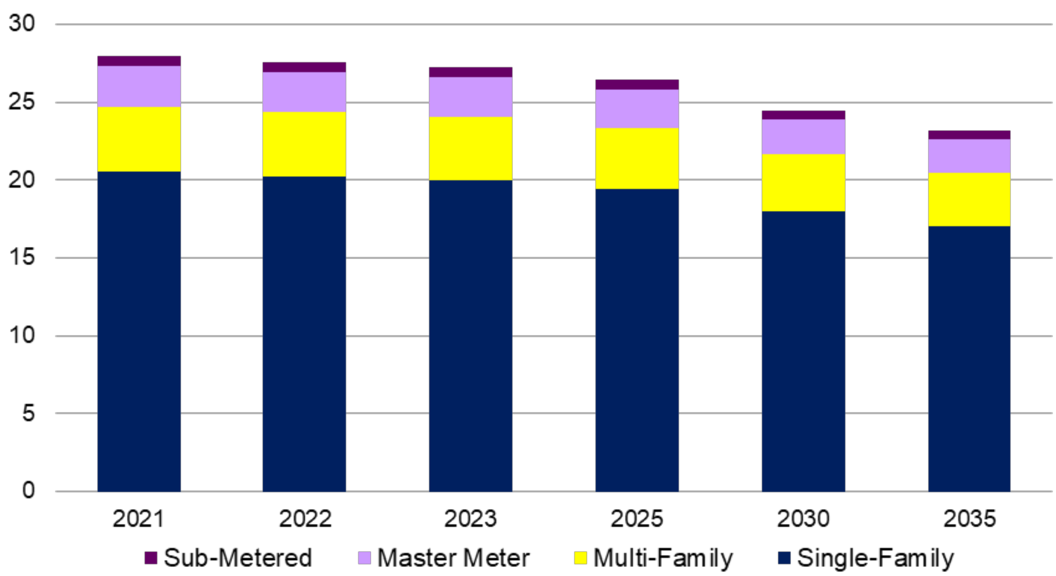
Table 43: SDG&E Residential Appliance Saturation Survey, 2019 Update

		2019 Residential Appliance Saturation Survey								
		Conditional Demand Study								
SDG&E		Single Family Unit Energy Consumption (UEC)	Single Family Saturation (%)	Single Family Intensity	Single Family Use Proportion		Multi Family Unit Energy Consumption	Multi Family Saturation	Multi Family Intensity	Multi Family Use Proportion
	Space Heat	211	98.00%	207	52.91%		107	92.62%	99	46.45%
	Water Heat	128	99.80%	128	32.69%		92	91.54%	84	39.48%
	Cooking	30	75.20%	23	5.78%		27	64.99%	18	8.23%
	Clothes Drying	31	63.71%	20	5.05%		27	40.91%	11	5.18%
	Pool Heat	144	3.40%	5	1.25%		N/A		N/A	
	Spa Heat	101	5.95%	6	1.54%		41	0.97%	0	0.19%
	Gas Fireplace	11	8.33%	1	0.23%		6	7.50%	0	0.21%
	Gas Barbecue	15	14.09%	2	0.54%		10	5.73%	1	0.27%
	Total Household SF			391 Therms/Year	100%				213 Therms/Year	100%

The conditional demand estimates based on the 2019 R.A.S.S. show that the average use per meter is 391 therms for single-family households and 213 therms for multi-family households. The use-per-customer data is constructive in forming the forecast. For the residential market, the change in the forecast from one year to the next is based on the confluence of two immediate economic drivers. In any given year, the residential load will grow due to the new customer hookups that occur. New customers generate a growth in demand. Second, the residential load will change due to existing customers' (vintage customers') changing needs. When gas appliances reach the end of their useful life, customers make a choice. The choice consists of either replacing the older appliance with a more energy efficient gas-using appliance, or changing out the replacement appliance from gas to its electric substitute, a behavior characterized as fuel substitution. The usage calculator that compiles the forecast is referred to as an end use model.

The total residential customer count for SDG&E consists of four residential segment types and each of the segment types exhibits variation in usage behavior that can be identified. The customer types are single-family and multi-family customers, as well as master-meter and sub-metered customers. Residential demand, adjusted for average temperature conditions, totaled 27.9 Bcf in 2021. By the year 2035, the residential demand is expected to drop to 23.2 Bcf. The change reflects a 1.3 percent average annual rate of decline. There are several reasons that justify the decline.

Figure 28 – Composition of SDG&E's Residential Demand Forecast
Average Year Weather Design, 2021-2035
(Bcf/year)



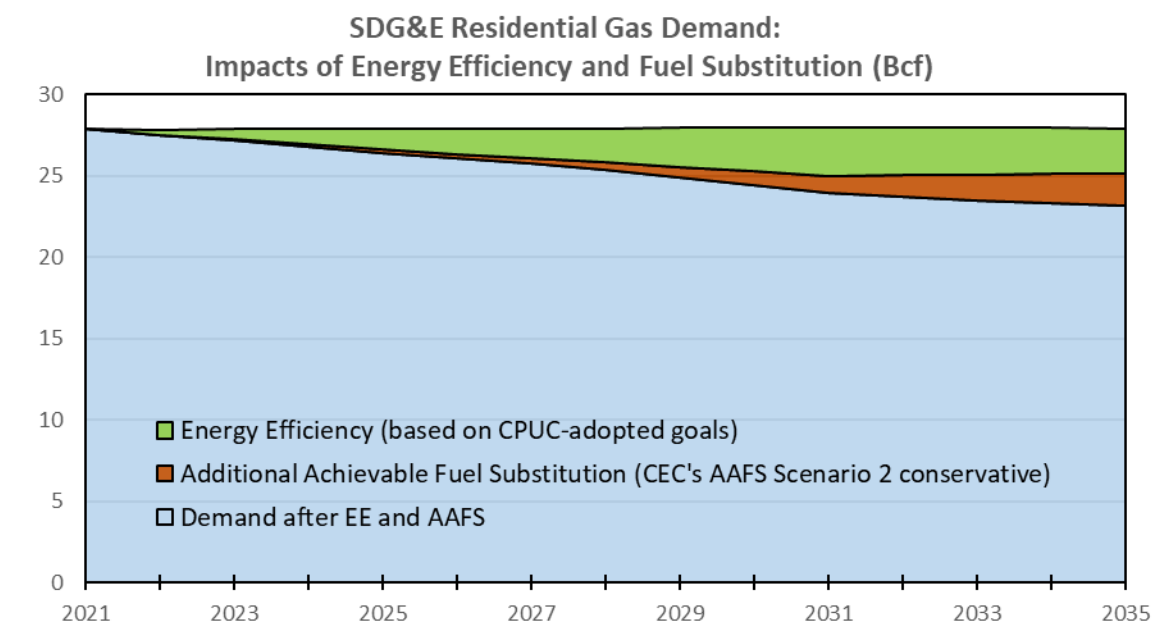
As described above, SDG&E's residential base forecast is developed from an end use model. The model results are modified by anticipated impacts of climate change as well as forecasts of policy adoptions that impact gas use. After the base forecast is developed, the forecast is modified with three out-of-model adjustments. The energy savings adjustments made to the forecast include: (1) allowing for fewer heating degree days in the average weather design for each consecutive year of the forecast to account for climate change; (2) gas demand destruction due to greater energy efficiency savings forecasted over the planning period; and (3) incremental energy savings created from assumed fuel substitution. All of these energy savings incorporated into the forecast reflect market potential and became load modifiers to create a final forecast of demand.

The major modifiers to the forecast are energy efficiency and building electrification. The energy efficiency forecast includes the confluence of two types of gas energy savings: Codes and Standards savings, which include current and expected modifications to Title 24 and the energy savings stemming from the customer programs authorized by the CPUC under D.19-08-034 and D.21-09-037. The baseline forecast was adjusted downward to account for the incremental energy saving influences that are expected to occur over the forecast period.

The final forecast also includes a load modifier for fuel substitution. For purposes of constructing a long-term reasonable forecast for the 2022 CGR, SDG&E participated in an electrification working group committee along with PG&E, SoCalGas and Southern California Edison (SCE) to evaluate different approaches and assumptions to modeling the effects of fuel substitution. After several meetings and discussions, SDG&E aligned around the relatively conservative fuel substitution forecast scenario developed by the California Energy Commission. Fuel substitution was estimated and introduced separately from energy efficiency savings by the CEC in its 2021 IEPR as additional achievable fuel substitution (AAFS). Of the five possible fuel substitution scenarios developed by the CEC, the AAFS-2 Scenario, which is the CEC's mid-low scenario for electrification, was chosen by SDG&E to prepare the final residential forecast. Scenario 2 quantifies the assumed fuel substitution that would take place with potential future updates in the Title 24 building standards and the presumed additional building electrification encouraged by future ratcheting driven by tighter goals, rate enhancements and higher uptake rates at future points in time. All of the above-mentioned gas reductions were included in the residential forecast as modifiers to the base forecast.

As can be seen from the following graph, the effects of both energy efficiency and fuel substitution have an impact on the residential market, with increasing impact out to the end of the forecast period in 2035.

Figure 29: SDG&E Residential EE and Fuel Substitution



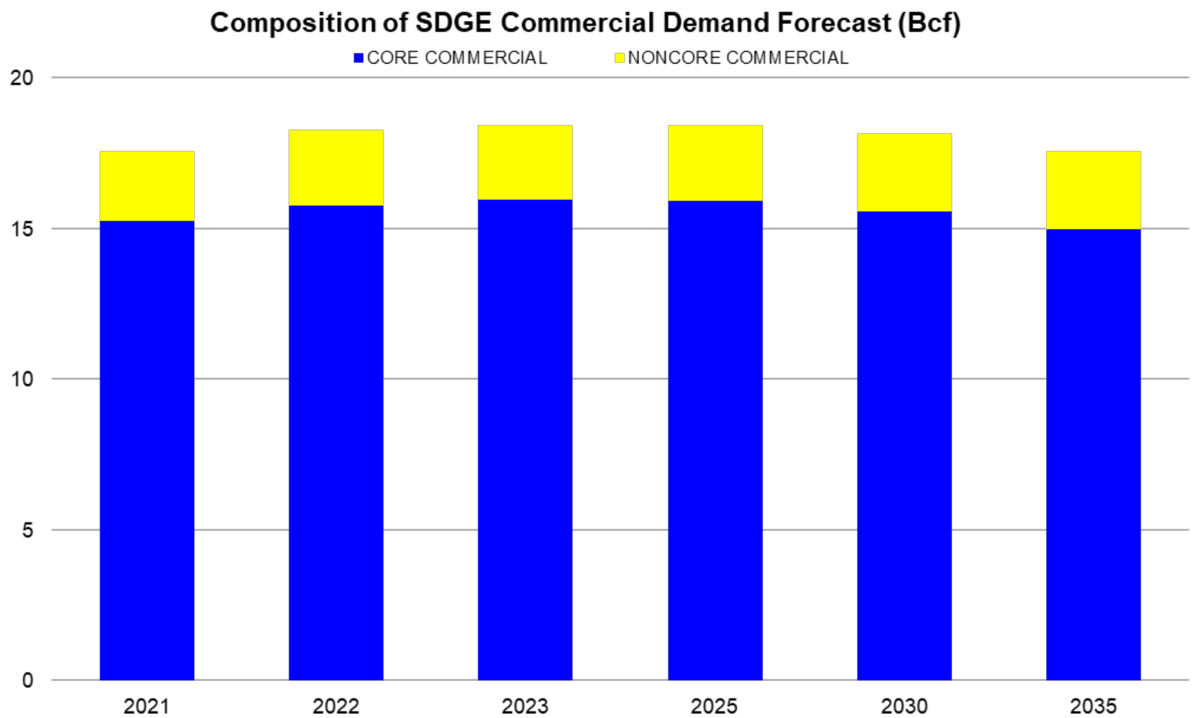
By year 2035, the *assumed* additional energy efficiency removes 10 percent of residential gas demand. Evaluated separately, the *assumed* additional fuel substitution removes another 7 percent of residential gas demand by 2035.

Commercial

On a temperature-adjusted basis, SDG&E's core commercial demand in 2021 totaled 15.23 Bcf. By the year 2035, the core commercial load is expected to decline slightly to 14.98 Bcf. The forecasted annual average rate of decline is 0.1 percent.

SDG&E's non-core commercial load in 2021 was 2.35 Bcf. Over the forecast period, gas demand in this market is projected to grow an average of 0.7 percent per year to 2.58 BCF by 2035, driven by increased economic activity.

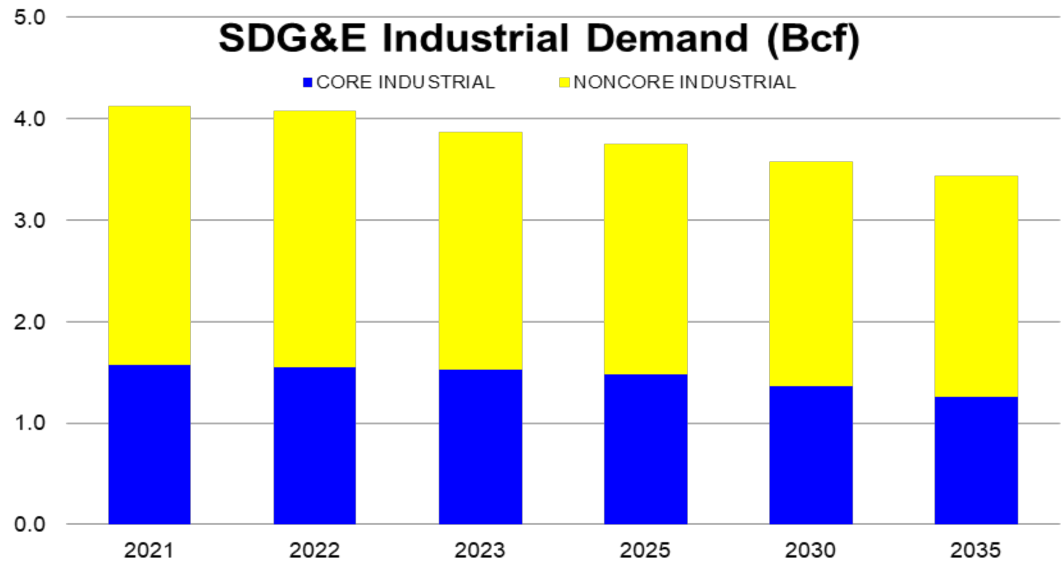
FIGURE 30 –SDG&E COMMERCIAL NATURAL GAS DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN
(2021-2035)



Industrial

Temperature-adjusted core industrial demand was 1.57 Bcf in 2021 and is expected to decline to 1.26 Bcf by 2035, an average decrease of 1.6 percent per year. This result is due to a yearly average increase in marginal gas rates and the impact of savings from CPUC-authorized energy efficiency programs in the core industrial sector.

FIGURE 31 –SDG&E INDUSTRIAL NATURAL GAS DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN
(2021-2035)

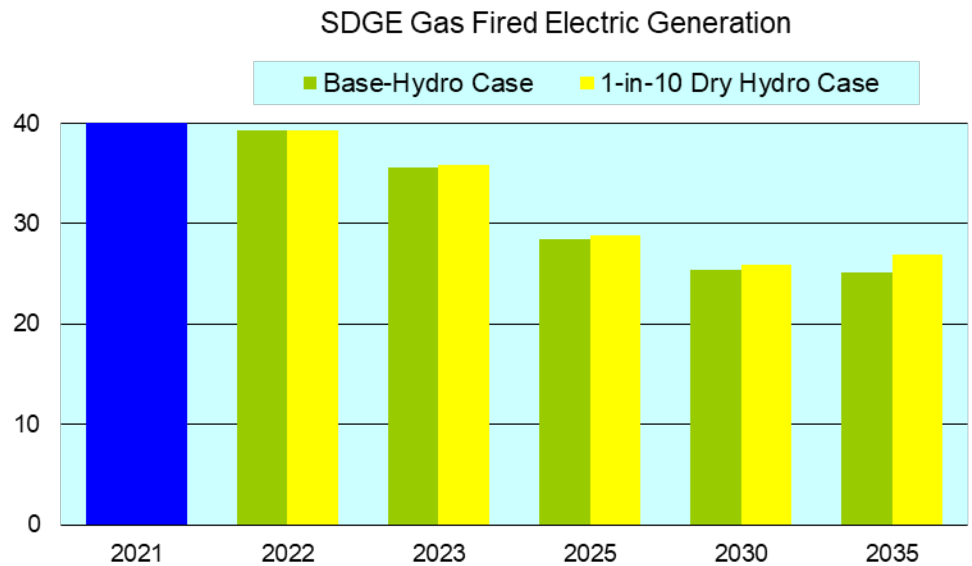


Non-core industrial load in 2019 was 2.4 Bcf and is expected to shrink about 0.6 percent per year to 2.2 Bcf by 2035. Demand-dampening effects of higher energy efficiency and higher carbon-allowance fees will more than offset slight increases from economic growth.

Electric Generation

Total EG, including cogeneration and non-cogeneration EG, was 29 Bcf in 2019. From 2019, EG load is expected to decline an average of 1.35 percent per year to 23 Bcf by 2035. The following graph shows total EG forecasts for a normal hydro year and a 1-in-10 dry hydro year.

FIGURE 32 – SDG&E'S TOTAL EG GAS DEMAND: BASE HYDRO AND 1-IN-10 DRY HYDRO DESIGN, 2021-2035
(Bcf/year)



Small Cogeneration (<20 MW)

Small Electric Generation load from self-generation totaled 7.1 Bcf in 2021 and is projected to increase an average of 0.3 percent per year to 7.3 Bcf by 2035. Economic growth is expected to slightly outpace demand-dampening effects of higher carbon-allowance fees.

Electric Generation Including Large Cogeneration (>20 MW)

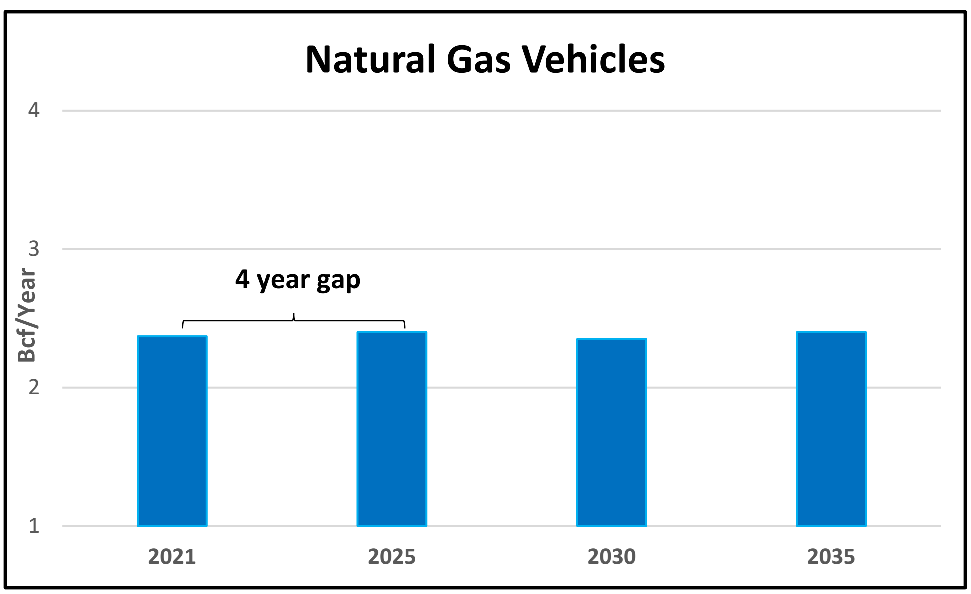
The forecast of large EG loads in SDG&E's service area is based on the power market simulation noted in SoCalGas' EG chapter for "Electric Generation Including All Cogeneration EG demand is forecasted to decrease from 32 Bcf in 2022 to 18 Bcf in 2035. This forecast includes no additional thermal generating resources in its service area, and it assumes no retirement during the same time period. It assumes the same 2021 Preferred System Plan as discussed in the Southern California Gas Company's EG section.

Natural Gas Vehicles

The clean vehicle market is expected to grow due to strong economic fundamentals, increased vehicle options, the continuation of government (federal, state, and local) incentives, additional regulations encouraging alternative fuel vehicle adoption, and regional collaboration for the deployment of necessary infrastructure. Additionally, since April 2019 SDG&E has been procuring 100 percent renewable natural gas (RNG) at all utility owned CNG stations, which provides significant GHG emission reduction benefits.

However, NGV growth may be offset by competing technologies such as vehicle electrification and hydrogen fuel-cell technologies. In addition, the COVID-19 pandemic which began in 2020, disrupted usage and consumption levels compared to a regular year. In 2021, SDG&E served 38 compressed natural gas (CNG) fueling stations located throughout the service territory and delivered approximately 2 Bcf of natural gas. The SDG&E NGV market is expected to remain stable with an average annual rate of 0.11 percent over the forecast horizon.

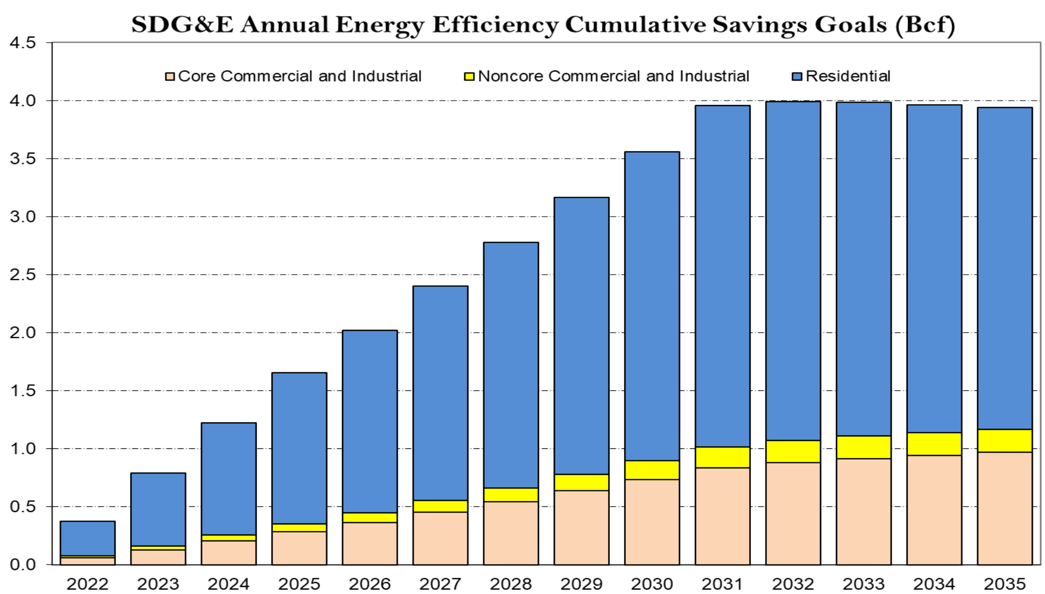
FIGURE 33 – ANNUAL NGV DEMAND FORECAST



ENERGY EFFICIENCY PROGRAMS

Conservation and energy efficiency activities encourage customers to install energy efficient equipment and weatherization measures and adopt energy saving practices that result in reduced gas usage, while still maintaining a comparable level of service. Conservation and energy efficiency load impacts are shown as positive numbers. The "total net load impact" is the natural gas throughput reduction resulting from the energy efficiency programs.

FIGURE 34 – SDG&E ANNUAL ENERGY EFFICIENCY CUMULATIVE SAVING GOALS (Bcf)



The cumulative net load impact forecast from SDG&E's integrated gas and electric energy efficiency programs for selected years is shown in the graph above. The net load impact includes all energy efficiency programs, both gas and electric, that SDG&E has forecasted to be implemented beginning in year 2022 and occurring through the year 2035 in addition to the Title 24 Codes and Standards expected over the 2022-2035 horizon. Savings and goals for these programs are based on the program goals authorized by the Commission in D.19-08-034 and D.21-09-037.

Savings reported are for measures installed under SDG&E's gas and electric Energy Efficiency programs. Credit is only taken for measures that are installed as a result of SDG&E's Energy Efficiency programs, and only for the measure lives of the measures installed.[119] Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. Naturally occurring conservation that is not attributable to SDG&E's Energy Efficiency activities is not included.

Gas Supply

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined SoCalGas/SDG&E portfolio per D.07-12-019 of December 6, 2007. For more information, refer above to the "Gas Supply, Capacity, and Storage" section in the Southern California part of this report.

[119] 1"Hard" impacts include measures requiring a physical equipment modification or replacement. SDG&E does not include "soft" impacts, e.g., energy management services type measures.110 This EE forecast does not include the impacts of fuel substitution measures (natural gas to electric measures). Fuel substitution is addressed in the overview section of the writeup.

REGULATORY ENVIRONMENT

GENERAL RATE CASE

On September 26, 2019, CPUC unanimously approved a final 2019 GRC decision that adopted a TY 2019 revenue requirement of $1.990 billion for SDG&E's combined operations ($1.590 billion for electric, $0.400 billion for gas) which is $213 million lower than the $2.203 billion that SDG&E had requested in its Update testimony. The adopted revenue requirement represents an increase of $107 million or a 5.7 percent increase over 2018. The final decision adopted PTY revenue requirement adjustments for SDG&E of $134 million for 2020 (6.7 percent increase) and $102 million for 2021 (4.8 percent increase).

In January 2020, the CPUC revised the rate case plans and implemented a 4-year GRC cycle for California IOUs. SDG&E was directed to file a PFM to revise its 2019 GRC decision to add two additional attrition years including adjustment amounts, resulting in a transitional five-year GRC period (2019-2023).

In April 2020 (then slightly revised in May), SDG&E filed a PFM of its 2019 GRC decision requesting attrition year increases of $94 million (+4.24 percent) for 2022 and $96 million (+4.13 percent) for 2023. In May 2021, the CPUC issued a decision authorizing SDG&E to apply its PTY mechanism adopted in the 2019 GRC decision to 2022 and 2023 but updated the calculations based on the 2020 4th Quarter Global Insight forecast to more fully capture the impact of Covid-19 to the economy. This decision resulted in revenue requirements of $2.3 and $2.4 billion for SDG&E for 2022 and 2023 respectively, which were slightly less than the original requests made in SDG&E's PFM.

In May 2022 SDG&E filed its 2024 General Rate Case seeking to revise its authorized revenue requirements, effective on January 1, 2024, to recover the reasonable costs of electric and gas operations, facilities, infrastructure, and other functions necessary to provide utility services to customers. SDG&E requests a combined $3.022 billion revenue requirement ($674 million gas and $2.348 billion electric), which, if approved, would be an increase of $475 million over the expected 2023 revenue requirement. SDG&E also includes post-test year revenue requirement and regulatory account-related proposals. The general rate request process is scheduled to take between 18 months and two years and is expected to conclude in late 2023.

Other Regulatory Matters

For more information on non-GRC regulatory matters, refer above to the “Regulatory Environment” section in the Southern California part of this report, which generally applies to SDG&E’s gas business as well.

PEAK DAY DEMAND

Gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined portfolio that contains a total firm storage withdrawal capacity designed to serve the utilities' combined retail core peak day gas demand. Please see the corresponding discussion of "Peak Day Demand and Deliverability" under the SoCalGas portion of this report for an illustration of how storage and flowing supplies can meet the growth in forecasted load for the combined (SoCalGas and SDG&E) retail core peak day demand.

The table below shows SDG&E's Core 1-in-35 Year Extreme Peak Day Demand and Winter 1-in-10 Year Cold Day System Demand.

TABLE 44– SDG&E WINTER PEAK DAY DEMAND (MMcf/d)

Year	Core 1-in-35 Extreme Peak Day Demand [1/]		1-in-10 Cold Day Demand			
			Core [2/]	Noncore C&I [3/]	EG [4/]	Total
2022	**404**		380	13	116	**510**
2023	**403**		380	13	104	**496**
2024	**402**		378	13	94	**484**
2025	**400**		376	13	98	**487**
2026	**398**		375	13	102	**490**
2027	**397**		373	13	102	**488**
2028	**395**		372	13	78	**462**

Notes:

(1) The criterion for core 1-in-35 extreme peak day design is defined as a 1-in-35 likelihood for SDG&E's service area. This criteria correlates to 43.3 degrees Fahrenheit for SDG&E's service area. 1-in-35 and 1-in-10 Core peak day demand forecasts embody the baseline forecast with load modifiers that include changing weather design to account for climate change, assumed EE savings and assumed fuel substitution under AAFS 2.

(2) The criterion for 1-in-10 peak day design is defined as a 1-in-10 likelihood for SDG&E's service area. This criterion correlates to 44.8 degrees Fahrenheit for SDG&E's service area.

(3) Average daily December demand for noncore commercial and noncore industrial.

(4) Electric Generation includes UEG/EWG Base Hydro, large cogeneration, industrial and commercial cogeneration (<20MW).

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SAN DIEGO GAS & ELECTRIC COMPANY – TABULAR DATA

TABLE 45 – SDG&E
ANNUAL GAS SUPPLY TAKEN– MMcf/d
RECORDED YEARS 2017-2021

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY TAKEN (MMCF/DAY)
RECORDED YEARS 2017 -2021

LINE		2017	2018	2019	2020	2021
	CAPACITY AVAILABLE					
1	**California Sources**					
	Out of State gas					
2	California Offshore (POPCO/PIOC)					
3	El Paso Natural Gas Company					
4	Transwestern Pipeline company					
5	Kern River/Mojave Pipeline Company					
6	TransCanada GTN/PG&E					
7	Other					
8	**TOTAL Output of State**					
9	Underground storage withdrawal					
10	**TOTAL Gas Supply available**					

LINE	Gas Supply Taken	2017	2018	2019	2020	2021
	California Source Gas					
11	Regular Purchases	0	0	0	0	0
12	Received for Exchange/Transport	0	0	0	0	0
13	**Total California Source Gas**	0	0	0	0	0
14	**Purchases from Other Utilities**	0	0	0	0	0
	Out-of-State Gas					
15	Pacific Interstate Companies	0	0	0	0	0
16	Additional Core Supplies	0	0	0	0	0
17	Supplemental Supplies-Utility	111	112	128	126	126
18	Out-of-State Transport-Others	188	127	103	151	139
19	**Total Out-of-State Gas**	299	239	230	277	265
20	**TOTAL Gas Supply Taken & Transported**	299	239	230	277	265

(MMCFD)

Table 46

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND SENDOUT (MMCF/DAY)
RECORDED YEARS 2017-2021

Actual Deliveries by End-Use		2017	2018	2019	2020	2021
CORE	Residential	72	70	81	81	78
	Commercial	52	54	57	50	52
	Industrial	-	-	-	-	-
Subtotal -	*CORE*	124	124	138	131	130
NONCORE	Commercial	-	-	-	-	-
	Industrial	11	12	13	13	15
	Non-EOR Cogen/EG	71	51	43	84	77
	Electric Utilities	92	49	33	41	36
Subtotal -	*NONCORE*	174	112	89	138	128
WHOLESALE	All End Uses	-	-	-	-	-
Subtotal -	*Co Use & LUAF*	1	3	4	8	7
SYSTEM TOTAL THROUGHPUT		299	239	230	277	265
Actual Transport & Exchange						
CORE	Residential	1	1	1	1	-
	Commercial	13	14	14	12	11
NONCORE	Industrial	11	12	13	13	15
	Non-EOR Cogen/EG	71	51	43	84	77
	Electric Utilities	92	49	33	41	36
Subtotal -	*RETAIL*	188	127	103	151	139
WHOLESALE	All End Uses	-	-	-	-	-
TOTAL TRANSPORT & EXCHANGE		188	127	103	151	139
Storage						
	Storage Injection	-	-	-	-	-
	Storage Withdrawal	-	-	-	-	-
Actual Curtailment						
	Residential	-	-	-	-	-
	Com/Indl & Cogen	-	-	-	-	-
	Electric Generation	-	-	-	-	-
TOTAL CURTAILMENT		-	-	-	-	-
REFUSAL		-	-	-	-	-

ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes

	2017	2018	2019	2020	2021
MMbtu/Mcf:	1.040	1.038	1.032	1.025	1.030

le and MMCFD Supplies are used in the odd year reports (see P 17-18 of CGR)

TABLE 47 – SDG&E: SDG&E
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2022-2026
AVERAGE TEMPERATURE YEARS

AVERAGE TEMPERATURE YEAR

LINE			2022	2023	2024	2025	2026	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		253	241	227	219	218	5
6	TOTAL SUPPLY TAKEN		253	241	227	219	218	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		253	241	227	219	218	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	75	75	73	72	71	9
10		Commercial	43	44	44	44	44	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	129	129	127	126	125	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	7	6	6	6	6	15
16		Electric Generation (EG)	108	97	85	78	77	16
17		Subtotal-NONCORE	121	111	98	91	91	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		253	241	227	219	218	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	12	12	12	12	12	20
21	NONCORE	Commercial/Industrial	14	13	13	13	13	21
22		Electric Generation (EG)	108	97	85	78	77	22
23	TOTAL TRANSPORTATION & EXCHANGE		134	123	110	103	103	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

1/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual v based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:

	2022	2023	2024	2025	2026
transportation (CAT) in MDth/d:	120	120	118	117	116

TABLE 48 – SDG&E: -SDG&E
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2027-2035
AVERAGE TEMPERATURE YEARS

AVERAGE TEMPERATURE YEAR

LINE			2027	2028	2029	2030	2035	LINE
	CAPACITY AVAILABLE 1/ & 2/							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas 1/		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		215	210	209	204	198	5
6	TOTAL SUPPLY TAKEN		215	210	209	204	198	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		215	210	209	204	198	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	71	69	68	67	63	9
10		Commercial	43	43	43	43	41	10
11		Industrial	4	4	4	4	3	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	124	122	121	120	114	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	76	73	73	70	69	16
17		Subtotal-NONCORE	90	86	86	83	82	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		215	210	209	204	198	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	12	12	12	12	12	20
21	NONCORE	Commercial/Industrial	13	13	13	13	13	21
22		Electric Generation (EG)	76	73	73	70	69	22
23	TOTAL TRANSPORTATION & EXCHANGE		102	98	99	95	94	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:
1/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual v
based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).
2/ For 2020 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.
3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:

	2027	2028	2029	2030	2035
transportation (CAT) in MDth/d:	115	113	112	111	105

TABLE 49 – SDG&E: ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d ESTIMATED YEARS 2022-2026 COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2022	2023	2024	2025	2026	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		262	251	237	229	228	5
6	TOTAL SUPPLY TAKEN		262	251	237	229	228	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		262	251	237	229	228	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	83	82	81	80	79	9
10		Commercial	45	45	45	45	45	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	138	138	136	135	134	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	7	6	6	6	6	15
16		Electric Generation (EG)	108	98	86	79	79	16
17		Subtotal-NONCORE	121	111	99	92	92	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		262	251	237	229	228	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	13	13	13	13	13	20
21	NONCORE	Commercial/Industrial	14	13	13	13	13	21
22		Electric Generation (EG)	108	98	86	79	79	22
23	TOTAL TRANSPORTATION & EXCHANGE		134	124	112	105	104	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

1/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual v based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:

	2022	2023	2024	2025	2026
transportation (CAT) in MDth/d:	129	129	127	126	125

TABLE 50 – SDG&E: ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d ESTIMATED YEARS 2027-2035 COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2027	2028	2029	2030	2035	LINE
	CAPACITY AVAILABLE 1/ & 2/							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas 1/		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		226	220	220	215	212	5
6	TOTAL SUPPLY TAKEN		226	220	220	215	212	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		226	220	220	215	212	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	78	77	76	74	71	9
10		Commercial	45	45	45	44	42	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	133	131	130	129	123	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	78	74	74	71	74	16
17		Subtotal-NONCORE	91	87	87	84	87	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		226	220	220	215	212	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	13	13	13	13	12	20
21	NONCORE	Commercial/Industrial	13	13	13	13	13	21
22		Electric Generation (EG)	78	74	74	71	74	22
23	TOTAL TRANSPORTATION & EXCHANGE		104	100	100	97	99	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

1/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual valu based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:

	2027	2028	2029	2030	2035
transportation (CAT) in MDth/d:	124	122	121	120	114

2022 CALIFORNIA GAS REPORT

GLOSSARY

GLOSSARY

A.
Application.

AAEE
Additional Achievable Energy Efficiency.

AAFS
Additional Achievable Fuel Substitution. The scenarios forecast reductions for gas consumption which are "substituted out" through electrification.

AB
Assembly Bill.

AMI
Advanced Metering Infrastructure.

APD
Abnormal Peak Day.

API
American Petroleum Institute.

A/S
ancillary services.

Average Day (Operational Definition)
Annual gas sales or requirements assuming average temperature year conditions divided by 365 days.

Average Temperature Year
Long-term average recorded temperature.

Bcf
billion cubic feet.

Bcf/d
billion cubic feet per day.

Bcf/y
billion cubic feet per year.

BTU (British Thermal Unit)
Unit of measurement equal to the amount of heat energy required to raise the temperature of one pound of water 1 degree F. This unit is commonly used to measure the quantity of heat available from complete combustion of natural gas.

CAISO
California Independent System Operator.

CalGEM
California Geologic Energy Management Division (formerly, DOGGR).

California-Source Gas
1. Regular Purchases – All gas received or forecasted from California producers, excluding exchange volumes. Also referred to as Local Deliveries.
2. Received for Exchange/Transport – All gas received or forecasted from California producers for exchange, payback, or transport.

CARB
California Air Resources Board.

CCST
California Council on Science and Technology.

CDFA
California Department of Food and Agriculture.

CEC
California Energy Commission.

CFR
Code of Federal Regulations.

CGR
California Gas Report.

CNG (Compressed Natural Gas)
Fuel for NGVs, typically natural gas compressed to 3000 pounds per square inch.

CO_2
carbon dioxide.

Cogeneration
Simultaneous production of electricity and thermal energy from the same fuel source. Also used to designate a separate class of gas customers.

Cold Temperature Year
Cold design-temperature conditions based on long-term recorded weather data.

Combined Heat and Power (CHP)
Combined Heat and Power (CHP) is the sequential production of electricity and thermal energy from the same fuel source. Historically, CHP has been perceived as an efficient technology and is promoted in California as a preferred EG resource.

Commercial (SoCalGas and SDG&E)
Category of gas customers whose establishments consist of services, manufacturing nondurable goods, dwellings not classified as residential, and farming (agricultural).

Commercial (PG&E)
Non-residential gas customers not engaged in EG, EOR, or gas resale activities with usage less than 20,800 therms per month.

Commission
California Public Utilities Commission (see also CPUC).

Company Use
Gas used by utilities for operational purposes, such as fuel for line compression and injection into storage.

Conversion Factor (LNG)
Approximate LNG liquid conversion factor for one therm (High-Heat Value).

- Pounds 4.2020
- Gallons 1.1660
- Cubic Feet 0.1570
- Barrels 0.0280
- Cubic Meters 0.0044
- Metric Tonnes 0.0019

Conversion Factor (Natural Gas)

• 1 cf (Cubic Feet)	= Approximately 1,000 Btus
• 1 Ccf = 100 cf	= Approximately 1 Therm
• 1 Therm = 100,000 BTUs	= Approximately 100 cf = 0.1 Mcf
• 10 Therms = 1 Dth (dekatherm)	= Approximately 1 Mcf
• 1 Mcf = 1,000 cf	= Approximately 10 Therms = 1 MMBtu
• 1 MMcf = 1 million cubic feet	= Approximately 1 MDth (1 thousand dekatherm)
• 1 Bcf = 1 billion cf	= Approximately 1 million MMBtu

Conversion Factor (Petroleum Products)

Approximate heat content of petroleum products (MMBtu per Barrel).

• Crude Oil	5.800
• Residual Fuel Oil	6.287
• Distillate Fuel Oil	5.825
• Petroleum Coke	6.024
• Butane	4.360
• Propane	3.836
• Pentane Plus	4.620
• Motor Gasoline	5.253

Core Aggregator

Individuals or entities arranging natural gas commodity procurement activities on behalf of core customers. Also, sometimes known as an Energy Service Provider (ESP), a Core Transport Agent (CTA), or a Retail Service Provider.

Core Customer (PG&E)

All customers with average usage less than 20,800 therms per month.

Core Customers (SoCalGas and SDG&E)

All residential customers; all commercial and industrial customers with average usage less than 20,800 therms per month who typically cannot fuel switch. Also, those commercial and industrial customers (whose average usage is more than 20,800 therms per year) who elect to remain a core customer receiving bundled gas service from the LDC.

Core Subscription

Noncore customers who elect to use the LDC as a procurement agent to meet their commodity gas requirements.

COVID-19

Coronavirus Disease 2019.

CPUC

California Public Utilities Commission (see also Commission).

Cubic Foot of Gas
Volume of natural gas, which, at a temperature of 60 degrees F and an absolute pressure of 14.73 pounds per square inch, occupies one cubic foot.

Curtailment
Temporary suspension, partial or complete, of gas deliveries to a customer or customers.

D.
Decision.

DDRDP
Dairy Digester Research and Development Program.

DOE
Department of Energy.

DOGGR
California Division of Oil, Gas, and Geothermal Resources (now CalGEM).

ECA
Energia Costal Azul.

EG
Electric Generation (including cogeneration) by a utility, customer, or independent power producer.

Electrification (Building Electrification)
Fuel Substitution

Energy Service Provider (ESP)
Individuals or entities engaged in providing retail energy services on behalf of customers. ESP's may provide commodity procurement, but could also provide other services, e.g., metering and billing.

EO
Executive Order.

EOR (Enhanced Oil Recovery)
Injection of steam into oil-holding geologic zones to increase ability to extract oil by lowering its viscosity. Also used to designate a special category of gas customers.

Exchange
Delivery of gas by one party to another and the delivery of an equivalent quantity by the second party to the first. Such transactions usually involve different points of delivery and may or may not be concurrent.

EWG (Exempt Wholesale Generator)
A category of customers consuming gas for the purpose of generating electric power.

F
Fahrenheit.

FERC
Federal Energy Regulatory Commission.

FTA
Free Trade Agreement.

Futures (Gas)
Unit of natural gas futures contract trades in units of 10,000 MMBtu at the New York Mercantile Exchange (NYMEX). The price is based on delivery at Henry Hub in Louisiana.

Gas Accord
The Gas Accord is a multi-party settlement agreement, which restructured PG&E's gas transportation and storage services. The settlement was filed with the CPUC in August 1996, approved by the CPUC in August 1997 (D.97-08-055) and implemented by PG&E in March 1998. In D.03-12-061, the CPUC ordered the Gas Accord structure to continue for 2004 and 2005. Key features of the Gas Accord structure include the following: unbundling of PG&E's gas transmission service and a portion of its storage service; placing PG&E at risk for transmission service and a portion of its storage service; placing PG&E at risk for transmission and storage costs and revenues; establishing firm, tradable transmission and storage rights; and establishing transmission and storage rates.

Gas Sendout
That portion of the available gas supply that is delivered to gas customers for consumption, plus shrinkage.

GHG (Green House Gas)
GHGs are the gases present in the atmosphere which reduce the loss of heat into space and therefore contribute to global temperatures through the greenhouse effect. The most the most abundant GHGs are, in order of relative abundance are water vapor, CO_2, methane, nitrous oxide, ozone and CFCs.

GRC
General Rate Case.

GT&S
Gas Transmission and Storage.

GTN
Gas Transmission Northwest LLC.

H2
Hydrogen.

HDD (Heating Degree Day)
A HDD is accumulated for every degree F the daily average temperature is below a standard reference temperature (SoCalGas and SDG&E: 65 degrees F; PG&E 60 degrees F). A basis for computing how much electricity and gas are needed for space heating purposes. For example, for a 50 degrees F average temperature day, SoCalGas and SDG&E would accumulate 15 HDD, and PG&E would accumulate 10 HDD.

Heating Value
Number of BTU's liberated by the complete combustion at constant pressure of one cubic foot of natural gas at a base temperature of 60 degrees F and a pressure base of 14.73 psia, with air at the same temperature and pressure as the natural gas, after the products of combustion are cooled to the initial temperature of natural gas, and after the water vapor of the combustion is condensed to the liquid state. The heating value of the natural gas shall be corrected for the water vapor content of the natural gas being delivered except that, if such content is 7 pounds or less per one million cubic feet, the natural gas shall be considered dry.

IEPR
Integrated Energy Policy Report.

ILI
In-Line Inspection.

Industrial (PG&E)
Non-residential customers not engaged in EG, EOR, or gas resale activities using more than 20,800 therms per month.

Industrial (SoCalGas and SDG&E)
Category of gas customers who are engaged in mining and in manufacturing.

IOU
investor-owned utility.

IRP
Integrated Resource Plan.

LCFS
Low Carbon Fuel Standard.

LDC
Local electric and/or natural gas distribution company.

LNG (Liquefied Natural Gas)
Natural gas that has been super cooled to -260 degrees F (-162 degrees C) and condensed into a liquid that takes up 600 times less space than in its gaseous state.

Load Following
A utility's practice of adding additional generation to available energy supplies to meet moment-to-moment demand in the distribution system served by the utility, and for keeping generating facilities informed of load requirements to insure that generators are producing neither too little nor too much energy to supply the utilities' customers.

MCF
The volume of natural gas which occupies 1,000 cubic feet when such gas is at a temperature of 60 degrees F and at a standard pressure of approximately 15 pounds per square inch.

MHP
Mobile Home Park.

MMBtu
Million British Thermal Units. One MMbtu is equals to 10 therms or one dekatherm.

MMcf/d
Million cubic feet per day.

mmt
million metric tons.

mmtCO_2e
million metric tons of carbon dioxide equivalent.

$mtCO_2e$
metric tons of carbon dioxide equivalent.

MW
megawatt.

MWh
megawatt-hour.

NGSS
Natural Gas Storage Strategy.

NGTL
NOVA Gas Transmission Ltd.

NGV (Natural Gas Vehicle)
Vehicle that uses CNG or LNG as its source of fuel for its internal combustion engine.

Noncore Customers
Commercial and industrial customers whose average usage exceeds 20,800 therms per month, including qualifying cogeneration and solar electric projects. Noncore customers assume gas procurement responsibilities and receive gas transportation service from the utility under firm or interruptible intrastate transmission arrangements.

Non-Utility Served Load
The volume of gas delivered directly to customers by an interstate or intrastate pipeline or other independent source instead of the local distribution company.

Off-System Sales
Gas sales to customers outside the utility's service area.

OIR
Order Instituting Rulemaking.

OTC
once-through-cooling.

Out-of-State Gas
Gas from sources outside the state of California.

PFM
Petition for Modification.

PG&E
Pacific Gas and Electric Company.

PHMSA
Pipeline and Hazardous Materials Safety Administration.

Piggable
Refers to the process of using devices known as "pigs" to perform various maintenance operations such as pipeline cleaning and inspection.

Priority of Service (PG&E)
In the event of a curtailment situation, PG&E curtails gas usage to customers based on the following end-use priorities:
1. Core Residential;
2. Non-residential Core;
3. Noncore using firm backbone service (including UEG);
4. Noncore using as-available backbone service (including UEG); and
5. Market Center Services.

Priority of Service (SoCalGas + SDG&E)
In the event of a curtailment situation, SoCalGas and SDG&E curtail gas usage to customers in the following order:
- Up to 60 percent (November thru March) or 40 percent (April thru October) of dispatched EG load;
- Up to 100 percent of nonEG noncore except for refineries;
- Up to 100 percent of refineries and up to 100 percent of the remaining dispatched EG load;
- Non-Residential Core customers; and
- Residential Core customers.

PSEP
Pipeline Safety Enhancement Plan.

PSIA
Pounds per square inch absolute. Equal to gauge pressure plus local atmospheric pressure.

Pub. Util. Code
Public Utilities Code.

Purchase from Other Utilities
Gas purchased from other utilities in California.

R.
Rulemaking.

R.
Rulemaking.

R&D
Research and Development.

Requirements
Total potential demand for gas, including that served by transportation, assuming the availability of unlimited supplies at reasonable cost.

Res.
Resolution.

Resale
Gas customers who are either another utility or a municipal entity that, in turn, resells gas to end-use customers.

Residential
A category of gas customers whose dwellings are single-family units, multi-family units, mobile homes, or other similar living facilities.

RNG
Renewable Natural Gas.

RNGS
Renewable Gas Standard.

RP
Recommended Practice.

RPS
Renewables Portfolio Standard.

RSP
Reference System Plan.

SB
Senate Bill.

SDG&E
San Diego Gas & Electric Company.

Short-Term Supplies
Gas purchased usually involving 30-day, short-term contract or spot gas supplies.

SLCP
Short-Lived Climate Pollutants.

SMUD
Sacramento Municipal Utility District.

SoCalGas
Southern California Gas Company.

Spot Purchases
Short-term purchases of gas typically not under contract and generally categorized as surplus or best efforts.

Storage Banking
The direct use of local distribution company gas storage facilities by customers or other entities to store self-procured commodity gas supplies.

Storage Injection
Volume of natural gas injected into underground storage facilities.

Storage Withdrawal
Volume of natural gas taken from underground storage facilities.

Supplemental Supplies
A utility's best estimate for additional gas supplies that may be realized, from unspecified sources, during the forecast period.

SWG
Southwest Gas Corporation.

SWRCB
State Water Resources Control Board.

System Capacity or Normal System Capacity (Operational Definition)
The physical limitation of the system (pipelines and storage) to deliver or flow gas to end-users.

System Utilization or Nominal System Capacity (Operational Definition)
The use of system capacity or nominal system capacity at less than 100 percent utilization.

Take-or-Pay
A term used to describe a contract agreement to pay for a product (natural gas) whether or not the product is delivered.

Tariff
All rate schedules, sample forms, rentals, charges, and rules approved by regulatory agencies for used by the utility.

TCF
Trillion cubic feet of gas.

Therm
A unit of energy measurement, nominally 100,000 BTUs.

Total Gas Supply Available
Total quantity of gas estimated to be available to meet gas requirements.

Total Gas Supply Taken
Total quantity of gas taken from all sources to meet gas requirements.

Total Throughput
Total gas volumes passing through the system including sales, company use, storage, transportation, and exchange.

Traditional Gas
A term designated to refer to fossil fuels, including but not limited to, natural gas.

Transportation Gas
Non-utility-owned gas transported for another party under contractual agreement.

UC
University of California.

UEG
utility electric generation.

Unaccounted-For
Gas received into the system but unaccounted for due to measurement, temperature, pressure, or accounting discrepancies.

Unbundling
The separation of natural gas utility services into its separate service components, such as gas procurement, transportation, and storage with distinct rates for each service.

U.S.
United States.

USA
Underground Service Alert.

WACOG
Weighted average cost of gas.

WECC
Western Electricity Coordinating Council.

Wholesale
A category of customer, either a utility or municipal entity, that resells gas.

Wobbe
The Wobbe number of a fuel gas is found by dividing the high heating value of the gas in BTU per standard cubic feet (scf) by the square root of a specific gravity with respect to air. The higher a gases' Wobbe number, the greater the heating value of the quality of gas that will flow through a hole of a given size in a given amount of time.

2022 CALIFORNIA GAS REPORT

RESPONDENTS

RESPONDENTS

The following utilities have been designated by the California Public Utilities Commission as respondents in the preparation of the California Gas Report.

- Pacific Gas and Electric Company
- San Diego Gas and Electric Company
- Southern California Gas Company

The following utilities also cooperated in the preparation of the report.

- City of Long Beach Energy Resources Department
- Sacramento Municipal Utilities District
- Southern California Edison Company
- Southwest Gas Corporation
- ECOGAS Mexico, S. de R.L. de C.V.

A statewide committee has been formed by the respondents and cooperating utilities to prepare this report. The following individuals served on this committee.

Working Committee

- Rose-Marie Payan- SoCalGas/SDG&E- *Statewide Chair, 2022 CGR*
- Todd Peterson-PG&E

- Scott Wilder- SoCalGas/SDG&E
- Sharim Chaudhury- SoCalGas/SDG&E
- William Guo – SoCalGas/SDG&E
- Jeff Huang– SoCalGas/SDG&E
- Michelle Clay-Ijomah-SDG&E
- Nasim Ahmed- SoCalGas
- Julia Cortez- SoCalGas
- Brandon Duran-SoCalGas
- Dave Bisi- SoCalGas
- Stan Sinclair- SoCalGas
- Heng Yang- SoCalGas/SDG&E
- Athena Besa-SDG&E
- Lonnie Mansi-SDG&E
- Perla Anaya-SDG&E
- Michelle Clay-Ijomah-SDG&E
- William Flemetakis- Kern River
- Tony Chun-SoCalGas
- Anupama Pandey - PG&E
- Kurtis Kolnowski-PG&E
- Andrew Klingler-PG&E

Observers

- Jean Spencer – CPUC Energy Division
- Eileen Hlavka-CPUC Energy Division
- Melissa Jones-CEC
- Ingrid Neumann-CEC
- Robert Gulliksen-CEC

2023 CALIFORNIA GAS REPORT

RESERVATIONS

RESERVE YOUR SUBSCRIPTION

2023 CALIFORNIA GAS REPORT SUPPLEMENT

Southern California Gas Company
2023 CGR Reservation Form
C/O Rosemarie Payan
Box 3249, Mail Location GT14D6
Los Angeles, CA 90051-1249
or
Fax: (213) 244-4957
Email: Rose-Marie Payan
RPayan@semprautilities.com

- ❑ ▪Send me a 2023 CGR Supplement
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- ❑ ▪Change of address

Company Name: ____
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Please visit our website for digital copies of this Report and the accompanying workpapers. They are located in the regulatory section of the following websites:

www.socalgas.com
www.SDG&E.com

RESERVE YOUR SUBSCRIPTION

2023 CALIFORNIA GAS REPORT – SUPPLEMENT

Pacific Gas and Electric Company
2023 CGR Reservation Form
C/O Todd Peterson
Mail Code B10B
P. O. Box 770000
San Francisco, CA 94177
or
Email: Todd.Peterson@pge.com

❑ ▪Send me a 2023 CGR
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Company Name: ______________________________________
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City: _______________ State: ___________ Zip: ________
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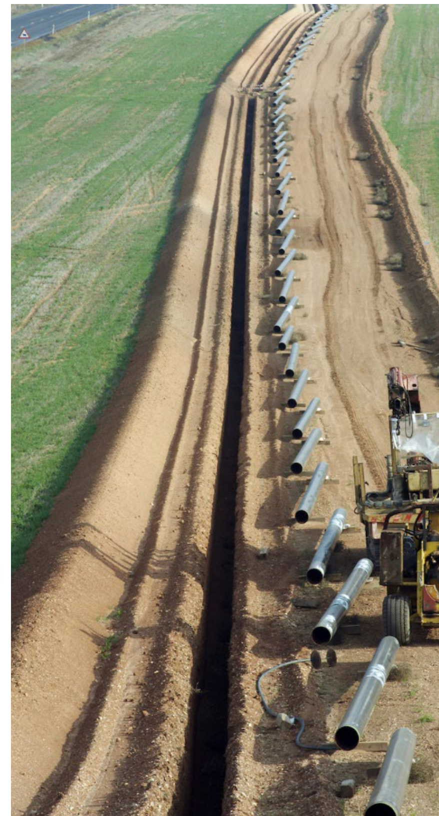
2022 CGR

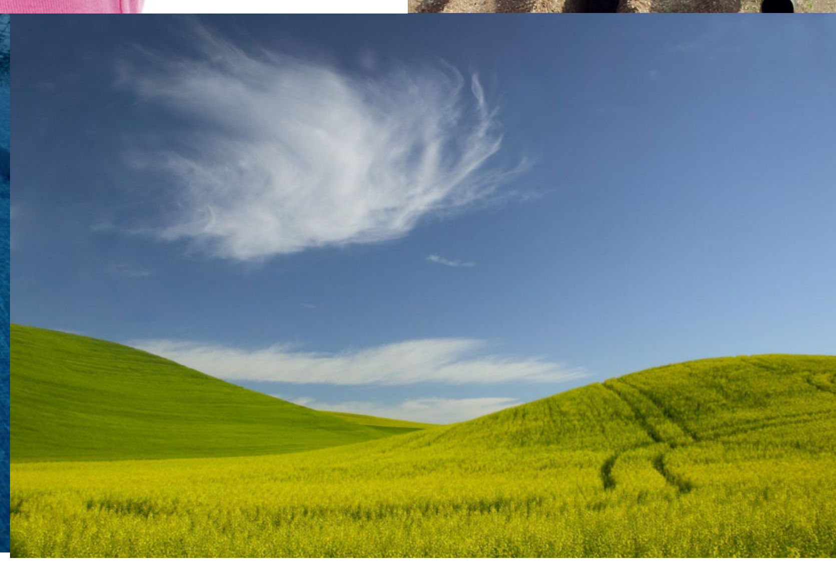



EXHIBIT C

Service Date: October 29, 2021

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of Chair Danner's Motion to Consider Whether Natural Gas Utilities Should Continue to Use the Perpetual Net Present Value Methodology to Calculate Natural Gas Line Extension Allowances	DOCKET UG-210729 ORDER 01 AUTHORIZING AND REQUIRING TARIFF REVISIONS

INTRODUCTION

1 **PROCEDURAL HISTORY.** On September 21, 2021, the Washington Utilities and Transportation Commission (Commission) issued a Notice of Item to be Considered at the Commission's Regularly Scheduled Open Meeting and Notice of Opportunity to File Written Comments (Notice). The Notice explained that Commission Chair David Danner, on his own motion, seeks input from regulated natural gas companies and stakeholders addressing whether natural gas utilities should continue to use the current Perpetual Net Present Value (PNPV) methodology for calculating natural gas line extension allowances.

2 The Notice explained that the Commission would address this issue at its October 28, 2021, regularly scheduled open meeting and requested that interested persons file written comments by October 25, 2021.

3 **BACKGROUND.** Natural gas utilities provide line extension allowances to partially offset the cost of expanding the natural gas distribution system to new customers. In 2014, the Commission opened Docket UG-143616 to discuss the need for natural gas distribution infrastructure expansion as well as the options available to implement such an expansion. Part of that discussion included adopting the PNPV methodology,[1] which significantly increased the credit provided to customers through natural gas line extension allowances.

4 On February 25, 2016, Avista Corporation d/b/a Avista Utilities (Avista) proposed tariffs adopting the PNPV method for calculating line extension allowances. The Commission

[1] Under the PNPV method, a line extension allowance is calculated using the anticipated revenue from the customer divided by the authorized rate of return, which results in the net present value of the customer's presence on the system. The current calculation assumes that a customer will remain on the natural gas system in perpetuity. See Commission Staff's Comments, page 1-2.

authorized the change and increased Avista's natural gas line extension allowance from $1,920 to $4,482 for residential customers. The PNPV method for calculating Avista's natural gas line extensions was made permanent on February 19, 2019.[2]

5 On July 29, 2016, Cascade Natural Gas Corporation (Cascade) filed proposed revisions to its Tariff WN U-3 that adopted the PNPV method to calculate line extension allowances. This change increased the company's line extension allowance from $572 to $3,255 for residential customers. The tariff revisions became effective by operation of law on September 1, 2016.[3]

6 On December 6, 2016, Puget Sound Energy (PSE) filed a tariff revision proposing to implement Rule No. 6 – Extension of Distribution Facilities, which adopted the PNPV methodology consistent with Avista's and Cascade's line extension tariffs. This change increased PSE's natural gas line extension allowance from $1,932 to $4,179 for residential customers. The Commission authorized the tariff change at its January 12, 2017, open meeting.[4]

7 In PSE's 2019 General Rate Case, the Commission received testimony from the Northwest Energy Coalition (NWEC) noting that the current PNPV calculation can result in subsidies from current natural gas customers to new customers and recommending that the Commission require PSE to revert to its previous line extension allowance calculation methodology or to revisit the issue in a broader forum. The Commission declined to adopt NWEC's recommendation as part of that rate case but signaled its intention to revisit the issue in a future proceeding.[5] Chair Danner dissented from this decision. In a concurring statement, Commissioner Rendahl supported revisiting the issue because the record evidence in the rate case was insufficient to support making a change.

8 **STAKEHOLDER COMMENTS.** The Commission received written comments from numerous stakeholders, including Commission staff (Staff). Most comments recommend discontinuing natural gas line extension allowances entirely or at least discontinuing the use of the PNPV methodology. The Alliance of Western Energy Consumers (AWEC) filed comments recommending the Commission retain the PNPV methodology, but later revised its comments at the open meeting to support Staff's or Northwest Natural Gas Company's proposals.

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[2] Docket UG-152394, Staff Memo (Feb. 25, 2016).

[3] Docket UG-160967, Staff Memo (Aug. 29, 2016).

[4] Docket UG-161268, Staff Memo (July 10, 2017).

[5] Docket UE-190529 *et. al.*, Final Order 08 ¶ 614 (July 8, 2020).

9 The City of Seattle urged the Commission to consider the costs of expanding fossil fuels, including the social cost of greenhouse gas, and whether benefits would still accrue for ratepayers, including low-income and vulnerable customers.

10 The Public Counsel Unit of the Attorney General's Office (Public Counsel) recommends the Commission discontinue the use of PNPV and provide line extension allowances that minimize the socialized costs of line extensions while still providing adequate access to natural gas for new customers. At the open meeting, Public Counsel noted that reducing the use of natural gas is consistent with legislative clean energy goals and recommended the Commission adopt an alternative to PNPV that is consistent with Washington state clean energy policy.

11 Avista supports discontinuing the use of the current PNPV methodology and reverting to its prior methodology, or, in the alternative, adopting Staff's recommendation. Avista proposes to use values from its Natural Gas Decoupling Mechanism baseline to determine the natural gas line extension allowance, resulting in an allowance for residential customers of $2,100 (compared to the present allowance of $4,678) and a Non-Residential per therm allowance of $1.36/therm (compared to the present allowance of $3.44/therm). At the Commission's open meeting, Avista stated that it has 272 customers currently under construction and receiving line extension allowances and more than 1,000 customers in the design phase. Avista thus requests a transition date of April 1, 2022, to allow customers who have already begun the line extension process to move forward under the current PNPV calculation.

12 Northwest Natural Gas Company (NW Natural) does not currently use PNPV. Rather, NW Natural calculates its line extension construction allowance as five times the delivery margin for the applicable rate schedule multiplied by the annual estimated therm usage attributable to the customer's installation. NW Natural believes that its existing Schedule E tariff is designed to determine the fair cost of providing fuel choice while economically eliminating cross-subsidization between existing ratepayers and new customers.

13 PSE supports discontinuing the PNPV methodology because it is increasingly out of step with the evolution of the State's energy policy. PSE supports a methodology that reasonably ensures existing natural gas customers are not subsidizing the connection of new natural gas customers and better aligns with both Washington's and PSE's decarbonization goals. To that end, PSE believes that promptly reverting to something like its previous methodology for determining natural gas line extension allowances may be appropriate. PSE's previous line extension allowance used a discounted cash flow

Facilities Investment Analysis (FIA) methodology.[6] PSE supports immediately changing back to the FIA methodology in the interim and addressing this issue more fully in Docket U-210553, the Commission's examination of energy decarbonization impacts and pathways for electric and gas utilities to meet state emissions targets. At the Commission's open meeting, PSE reiterated its recommendation to conduct a broader investigation into this issue and stated that it supports Staff's recommendation.

14 The Department of Commerce (Commerce) asserts that PNPV is contrary to state policy and urges the Commission to consider discontinuing line extension allowances altogether. In the alternative, Commerce supports Staff's recommendation to modify the PNPV calculation.

15 RMI and the Natural Resources Defense Council observe that the line extension allowances generated by the PNPV method are 1.5 to 3 times higher than allowances in Colorado and California, both of which use revenue-based formulas to calculate allowances.

16 Cascade proposes reverting to its previous calculation method of 3.3 times margin allowance for service connections and an additional 3.3 times margin allowance if main extensions are also required. Cascade proposes a transition period to allow the company to complete line extensions already in progress using the current PNPV method.

17 350Seattle recommends ending all natural gas line extension allowances and instead providing allowances for beneficial electrification.

18 The Sierra Club urges the Commission to implement a complete moratorium on new natural gas collections or, in the alternative, to end natural gas line extension allowances.

19 NWEC recommends the Commission evaluate and potentially discontinue line extension allowances completely. NWEC further recommends the Commission evaluate the need for regulatory tools for natural gas utilities to meet state greenhouse gas emission reduction targets.

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[6] The FIA methodology provides a line extension allowance based on a calculation that includes, for example, consideration of the natural gas powered appliances being installed, annual therm assumptions estimated using square footage, whether a main extension is required, and whether other new customers would be included along the same extension the FIA methodology does allow more precise assumptions that can be tailored to reflect current state policy including building codes and to align with PSE's decarbonization goals.

20 The 37th Legislative District Democratic Environmental Caucus recommends discontinuing the use of PNPV or any rate-based fees for extending natural gas distribution infrastructure.

21 Staff recommends retaining the PNPV method but updating the discount timeframe as a matter of policy. Overall, Staff believes this revised PNPV method results in a simpler tariff structure and makes the relevant calculations easier to understand, perform, and apply. Staff also believes that this PNPV method ensures that line extension allowances are economically justified. Staff recommends adopting a Net Present Value (NPV) method that updates the discount timeframe based on consideration of the following policy factors:

- Cost of greenhouse gas emissions
- Environmental impact from oil furnaces and wood-burning stove emissions
- Economic development from expanding service to areas not currently served by natural gas
- Increasing energy efficiency
- Historical equity in access to natural gas for marginalized communities and vulnerable populations
- The treatment of natural gas versus electric infrastructure by the State of Washington

22 Staff recommends using an eight-year timeframe because it aligns the margin allowance discount timeframe with the implementation of the Clean Energy Transformation Act (CETA).[7] Additionally, Staff believes that a calculation using the 8-year timeframe will be closer to or lower than an updated margin allowance calculation using PSE's FIA model.

23 Chair Danner proposes to adopt Staff's recommendation, in part, and modify the PNPV method to include a timeline of seven years, which will result in a limited line extension allowance more consistent with state policy and closer to the amount allowed in 2014 prior to the adoption of PNPV.

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[7] Chapter 19.405 RCW.

DISCUSSION AND DECISION

24 We agree with Staff's recommendation, in part, and require PSE, Avista, and Cascade to file tariff revisions by November 17, 2021, adopting a Net Present Value (NPV) methodology using a seven-year timeline for calculating natural gas line extension allowances for the reasons discussed below.

25 In recent years, the legislature has enacted several laws aimed at reducing greenhouse gas emissions, including emissions from natural gas. In 2019, the legislature passed CETA, which requires electric utilities to eliminate coal by 2025 and all carbon-emitting resources by 2045. In 2021, the legislature amended RCW 80.28.074 to clarify that advancing the availability of natural gas services to Washington residents is no longer state policy. Additionally, as several commenters noted, the legislature directed that Washington's energy code be revised to make new construction more efficient, which will result in new homes and buildings using less natural gas than existing structures currently use.

26 Further, this year, the legislature also passed the Climate Commitment Act,[8] under which gas companies must meet specific emissions reductions requirements and must surrender allowances to cover the greenhouse gas emissions from the use of their product. While gas companies will receive free emissions allowances to address cost impacts to current customers, almost all new customers are excluded from this part of the program.

27 We appreciate the thoughtful perspectives offered by the companies, consumers, and stakeholders, most of whom agree that the current PNPV methodology is contrary to the legislature's clear direction to reduce greenhouse gas emissions and the use of fossil fuels. As many commenters aptly observed, it is imperative that we address climate change, including the health impacts of greenhouse gases and methane emissions on Washington's communities and citizens. Recognizing the urgency of this issue, we view our decision today as an interim measure that will substantially reduce line extension allowances while we continue to engage in dialogue with regulated utilities and other stakeholders in Docket U-210553, the Commission's broader examination of energy decarbonization impacts and pathways for electric and gas utilities to meet state emissions targets.

28 The comments we received in this docket offer several important factors to consider as we move forward, including the likelihood that natural gas lines will not be serving customers in Washington in perpetuity, the laws and rules in Washington related to greenhouse gas emissions, new requirements in the State Energy and Building Codes,

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[8] RCW 70A.65.900.

ensuring that utility tariffs do not increase the likelihood of stranded assets in the future, and ensuring that line extension policies do not shift the cost burden from new to current customers. Although the proceeding in Docket U-210553, which is already underway, provides a more appropriate forum to ensure that these factors are thoroughly considered, we conclude that discontinuing use of the current PNPV calculation immediately is in the public interest because it can result in existing customers subsidizing new customers while significantly increasing reliance on fossil fuels. Given the recent changes to laws and policies discussed above, we conclude that the current PNPV calculation is no longer a valid line extension allocation method for Washington utilities or their customers.

29 Accordingly, we agree Staff's recommendation and require PSE, Avista, and Cascade to adopt an NPV calculation for natural gas line extension allowances. This methodology is simple to calculate because it requires a single assumption — the length of time the service will be installed — and relies on information from recent rate cases. Imposing a seven-year calculation timeline will reduce the line extension allowance for the residential customers of each company to approximately $2,000, which is a substantial, but gradual, decrease from current values.

30 Finally, Avista, Cascade, and PSE request that we provide a transition period for customers who have received approval for a line extension allowance under the current tariff. We agree that the companies should be authorized to exempt from the new tariff provisions those customers who have submitted applications that are approved or pending as of the date the revised tariffs become effective, as well as those customers who can demonstrate or attest that their applications have been submitted to local permitting offices. This exemption will expire on April 1, 2022.

FINDINGS AND CONCLUSIONS

31 (1) The Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including natural gas companies, and has jurisdiction over the parties and subject matter of this proceeding.

32 (2) PSE, Avista, and Cascade are natural gas companies subject to Commission regulation.

33 (3) This matter came before the Commission at its regularly scheduled open meeting on October 28, 2021.

34 (4) The PNPV methodology currently in effect for calculating natural gas line extension allowances significantly increases the margin allowances for each utility and thus increases reliance on fossil fuels contrary to state policy and laws.

38 (5) The NPV methodology proposed by Staff and calculated using a seven-year timeline provides a substantial but gradual decrease in natural gas line extension allowances that is better aligned with the legislature's direction and policy goals and is therefore in the public interest.

39 (6) The Commission should require PSE, Avista, and Cascade to file by November 17, 2021, tariff revisions that reflect the use of the NPV methodology using a seven-year timeframe for calculating natural gas line extension allowances.

ORDER

THE COMMISSION ORDERS THAT:

35 (1) Puget Sound Energy, Avista Corporation d/b/a Avista Utilities, and Cascade Natural Gas Corporation are required and authorized to file by November 17, 2021, tariff revisions necessary and sufficient to effectuate the terms of this Order.

36 (2) The Commission retains jurisdiction to effectuate the terms of this Order.

DATED at Lacey, Washington, and effective October 29, 2021.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chair

ANN E. RENDAHL, Commissioner