BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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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.	Rulemaking 24-09-012 (Filed September 26, 2024)

SOUTHERN CALIFORNIA GAS COMPANY'S (U 904 G) REPORT ON THE FORECASTING ANALYTICS AND FACILITATING NON-PIPELINE ALTERNATIVES WORKSHOP

EDWARD L. HSU

Attorney for:
SOUTHERN CALIFORNIA GAS COMPANY
555 West 5th Street, Suite 1400
Los Angeles, California 90013
Telephone: (213) 244-8197
Facsimile: (213) 629-9620
Email: EHsu2@socalgas.com

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Pursuant to the July 25, 2025, Administrative Law Judges' Ruling Noticing Interim Actions Workshop and Directing SoCalGas to File a Workshop Report, Southern California Gas Company (SoCalGas) hereby submits this workshop report as directed.

Respectfully submitted on behalf of
Southern California Gas Company,

By: /s/ *Edward L. Hsu*
EDWARD L. HSU

Attorney for:
SOUTHERN CALIFORNIA GAS COMPANY
555 West Fifth Street, Suite 1400
Los Angeles, California 90013
Telephone: (213) 244-8197
Facsimile: (213) 629-9620
Email: EHsu2@socalgas.com

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Introduction & Background

On September 22, 2025, the California Public Utilities Commission (Commission or CPUC) hosted a hybrid in-person and virtual workshop in the Order Instituting Rulemaking (OIR) to Establish Policies, Processes and Rules to Ensure a Safe and Reliable Gas Systems in California and Perform Long Term Gas System Planning (Gas Transition OIR or Rulemaking), Rulemaking (R.) 24-09-012. The CPUC's Energy Division Staff facilitated the workshop. The workshop was held from 9:30 a.m. to approximately 4:30 p.m. and included opening and closing remarks from Assigned Commissioner Karen Douglas.

On July 23, 2025, Administrative Law Judges (ALJ) Van Dyken and ALJ Purchia issued a *Ruling Noticing Interim Actions Workshop and directing SoCalGas to file a Workshop Report* (ALJ Ruling). The ALJ Ruling indicated that the Energy Division would circulate a final workshop agenda to the service list of this ALJ Ruling. SoCalGas was directed to file and serve a Workshop Report by October 24, 2025. The agenda titled, R.24-09-012 Workshop: Forecasting Analytics and Facilitating Non-Pipeline Alternatives, was issued on September 12, 2025.

The Workshop Agenda is attached hereto as Appendix A and panel presentations are attached hereto in Appendix B of this report. A link to the workshop recording is available here: Long-Term Gas Planning Rulemaking Workshop Recording [youtube.com]. Note: For the public record and use in this proceeding, the workshop recording should be relied upon rather than this workshop report for a summary of the workshop to the extent in conflict with or inconsistent with this workshop report.

Opening Remarks: Commissioner Karen Douglas, CPUC (Time stamp 0:09)

Commissioner Karen Douglas provided opening remarks for the workshop. The Commissioner outlined the key topics and foundational work covered by the OIR, focusing on efforts to transition California's gas infrastructure while highlighting the following as topics of interest for the parties involved in the proceeding: Non-Pipeline Alternatives (NPAs). A key focus of the foundational work is on interim actions to facilitate non-pipeline alternatives, which has garnered "a lot of interest" and numerous ideas from parties; and Senate Bill (SB) 1221, which imposes specific, aggressive requirements and timelines on the CPUC to designate priority neighborhood decarbonization zones by January 1, 2026, and annually thereafter. The Commissioner emphasized that these are aggressive timelines that require efficient movement and a "lot of help and a lot of engagement from diverse perspectives" to achieve a successful program. The Commissioner also expressed appreciation for the tremendous amount of work done by various entities that will present important perspectives including the Energy Division Staff, California Energy Commission (CEC), and California Air Resources Board (CARB).

Workshop Segment 1: Gas Demand and Rates: Foundational Forecasting Analytics

1. **Background on Gas Rate Components: Jean Spencer, CPUC Energy Division** (Time stamp 5:04)

Jean Spencer, from the CPUC-Energy Division provided an overview of natural gas rates and bills in California including basic principles, rate components and bill structure. The overview included explaining that the General Rate Case (GRC) determines the total revenue requirement for the utility and the Cost Allocation Proceeding (CAP) determines how those costs are allocated among different customer classes. The overview described the characteristics between core vs. noncore customers, where the utility procures gas for core customers

represented as residential and small commercial customers who pay a premium for more reliable service and are users of distribution lines compared to noncore customers, consisting of large commercial and industrial sectors that may procure their own gas and are exposed to more reliability risk. ED Staff further described three gas rate components of core procurement rate, transportation rate, and Public Purpose Program Surcharge. Additionally, the California Climate Credit, and bill components, such as fixed charge vs. per-therm rates for core residential and noncore customers, were discussed, along with an overview of the four gas utilities' current residential and non-residential rates.

Q&A/Discussion (Time stamp 18:15)

- The Utility Reform Network (TURN) asked about recent legislation impacting climate credit. ED Staff responded that they could not speak to it at this time and that CARB may have changes. ALJ Wong directed TURN and parties to the Climate Credit OIR. ED Staff stated that for residential customers, the more gas is used, the higher the rate than for commercial/industrial users and to consider how to incentivize people to use less gas. ED Staff responded it tends to be cheaper for the gas utility to serve larger customers because they do not need as much customer service for the demand.

- TURN asked whether forecasts for noncore or core consumption affected the difference between demand forecasts and actual historical demand. ED Staff responded that they did not recall. EDF then stated that core customers paid most of the distribution costs, but thought that noncore customers paid only transmission costs. ED Staff responded that it depends on where they are located. Core customers get most of the distribution costs because they are heavy users of the distribution system and noncore customers try to site themselves on the backbone system or the local transmission system so they don't have to pay distribution costs.

- PG&E asked ED's position on the discrepancy between the forecast and the California Gas Report versus historical. ED Staff responded that is a part of this workshop discussion.

2. Panel: Current Forecasts and Infrastructure Applications, Gas Utilities

Panel 1: Nate Taylor, SoCalGas/SDG&E (Time Stamp 25:38)

Nate Taylor representing SoCalGas/SDG&E discussed: development of demand forecasts, use of forecasts to develop energy infrastructure needs, and how forecasts impact rates. Representative Taylor provided a comparison of the Integrated Energy Policy Report (IEPR) to the California Gas Report (CGR). Representative Taylor then discussed how SoCalGas/SDGE designs its gas system to meet demand under two different design conditions: 1-in-10-year cold day for all customers (core and non-core) and 1-in-35-year extreme peak day for core customers only using fluid dynamics network software and field data, and how demand forecasts are used to ensure changes in total demand does not introduce risks like reliability and resiliency to the gas system; customer requests for service are considered; if gas demand declines in certain areas then consider opportunities to revisit system design for cost savings (e.g., resizing or derating). Lastly, Representative Taylor explained that demand forecasts are utilized in SoCalGas/SDG&E's cost allocation proceeding (CAP). Revenue requirements, typically litigated in the general rate case (GRC), are not necessarily dependent on demand; therefore, demand forecast is often not included.

Panel 2a: Kurtis Kolnowski, PG&E (Time Stamp 38:33)

Kurtis Kolnowski from PG&E discussed different forecast types that PG&E develops. System-level gas demand forecasts utilize multiple methodologies best tailored to each customer class but are not granular enough for localized analysis (e.g., distribution). Forecasting tools at the system level are: Econometric Regression, Production Cost, and Technology-Driven (not exhaustive). The tools are used for core, noncore, non-EG, and EG. In addition to the different

types of forecasting tools, PG&E develops different forecasts at different granularities (e.g., annual/monthly, average/expected case, four different peak forecasts). Representative Kolnowski then explained that selecting the right type of forecast for a specific purpose helps make that forecast useful and that forecasts are driven by assumptions used. It's about trying to balance the line between meeting policy-driven goals and the best estimate of what will actually happen (expected case). Also, utilizing Sensitivities & Scenarios are useful for identifying "least regret" actions and difference between expected and policy cases; where sensitivity applies to varying one assumption and scenario is when multiple assumptions are varied.

Representative Kolnowski presented on the types of forecasts used by PG&E, including the CGR and IEPR, by stating that PG&E utilizes a Gas Transmission & Storage (GT&S) forecast which is developed in-house. Forecast type is: expected case + Scenario (1-in-35 Cold) applying PG&E's internal assumptions. Representative Kolnowski also talked about point forecasts which are needed for rate setting purposes and how PG&E develops forecasts for local gas demand based on various sources. Uncertainties: there are many variations in gas demand.

Panel 2b: Daven Phelan, PG&E (Time stamp 53:02)

Daven Phelan from PG&E discussed that similar to SoCalGas/SDG&E, the local gas planning team at PG&E does the granular and localized analysis forecast that may happen on the distribution side and this part of the discussion informs how those forecasts impact projecting PG&E's infrastructure needs. Gas distribution projects are mainly driven by operational and maintenance and asset management requirements for safe reliable service vs. being part of forecasting system-wide demand forecast to project large scale infrastructure needs. Representative Phelan added that the priorities for the interim actions is to determine a

streamlined criteria in identifying a cost effective decarbonization project including an NPA analysis to have a win-win for both ratepayers and utilities – to be able to decarbonize the system while looking at risk management activities and to be able to retire pipelines as demand declines and perhaps retire old assets that could be cost efficient for the customer.

Q&A (Time Stamp 56:05)

- Sierra Club asked PG&E to provide insight into the discrepancy in the earlier slide between actual gas demand and the forecasting, whether that might be due to electric generation or core customers. PG&E responded that since this is the first time seeing the slide; therefore, cannot provide details.

- Sierra Club asked SoCalGas what the timeframe is on an increased projections of new demand potentially triggering pressure betterment and system expansion and what the trigger is –1-in-10-day or 1-in-35-year demand? SoCalGas provided an example of a very localized situation when doing a pressure betterment – neighborhood with mix-use of residential and non-residential, but mostly residential; whereby, the large noncore customers are not attached to the medium pressure distribution network where often pressure measurement is discussed.

- The Natural resources Defense Council (NRDC) also asked SoCalGas for the type of pressure betterment project explained, what potential NPAs can be utilized to avoid pressure betterment work? SoCalGas stated that it depends on the situation - how much of a deficit in pressure the project is trying to close. PG&E agreed with SoCalGas that it is very case dependent.

- TURN asked PG&E about how critical such forecasts are for electrification and non-pipeline alternative projects given PG&E statements that infrastructure spending and replacement is O&M rather than driven by forecasts especially on the distribution system. PG&E replied that it's important when talking about this sort of asset maintenance infrastructure aspect to look at NPA as opportunities, but the system level forecasts provide very little information to at least the distribution capital expenditures that we have. However, it's important to point out where that demand is headed and what that will do to rates – revenue requirements divided by rate setting is relevant piece from the presenter's perspective. Also added that there are many ways that building electrification can occur – NPA would electrify to decommission an entire zone, but that there are piecemeal/scattered approach via policy-making as well.

- EDF commented that IEPR and CGR use different units so it's hard to have an equal comparison to understand how the scenarios are different so might be useful to have better understanding using same units in IEPR, in the CGR. EDF commented on the discrepancy between a 20-year planning horizon for the distribution main which is

depreciated over 70 years so there is a timing gap and if there has been consideration for pushing out the 20-year timeline. EDF asked what the difference was in the cost premium between a 1-in-10 reliability and 1-in-35 or 1-in-90 and the cost delta if everybody were subject to 1-in-10 condition including core customers. SoCalGas and PG&E replied that they were not sure if there is an analysis that's been done. EDF asked PG&E how they track localized costs such as if there are a few therms over a long distance with a high cost per therm. PG&E was uncertain if that information were tracked.

- The California Energy Commission (CEC) asked how do the interactions between the utility forecasts and the localized forecast work in regard to planning? PG&E explained that forecasts are separate and distinct though they are based on much the same information. SoCalGas stated that it was largely the same for SoCalGas and added that IEPR and CGR do not address local demand where there may be new business attachment; therefore, utilities do need to look at new customers and new load specifically for distribution.

3. Forecasting Tool Development and Applications

IEPR Gas Demand Scenarios: Nicholas Janusch, Energy Assessments Division - CEC (Time stamp: 1:26:03)

Nicholas Janusch from the CEC began the presentation by providing an overview of the gas assessment and the gas planning process. CARB scoping plan proposes air quality and GHG emission reduction strategies where energy programs standards and regulations are developed in support of carbon neutrality. This work from CARB feeds into the CEC's IEPR demand forecast for both gas and electricity and those forecasts are interdependent. The IEPR forecasts are the foundation for its long-term demand scenarios to assess the impacts of relevant scoping plan components on fuel demand and those scenarios feed into the SB 100 assessments. Separate from the IEPR forecast, the CEC produces a peak of day gas demand forecast, which is an input to CEC's gas system reliability assessment for SoCalGas and PG&E. CalGEM safety regulations are an input to both CEC and CPUC assessments. The CGR, CPUC assessments, and the CalGEM safety regulations inform the CPUC gas proceedings related to rates and system planning.

Representative Janusch gave a general overview of the CEC's three gas demand forecast products: the IEPR Gas Demand Forecast, the Long-Term Demand Scenario and the Peak Day Gas Forecast and gave presented on the IEPR Gas Demand Forecast's Additional Achievable Framework & Scenario (AAFS), Load Modifier Framework, and the additional load modifiers PiCS (Program and incremental Codes & Standards) and FSSAT (Fuel Substitution Scenario Analysis Tool). He explained the characterization and results for 2023 and 2024 AAFS scenarios reports: 2023 IEPR, CARB Scoping Plan, and 2024 IEPR.

Representative Janusch presented graphs to illustrate various scenarios including comparison of 2023 & 2024 AAFS gas demand scenarios; forecasted energy conception for each of the three 2023 scenarios to 2050; both 2023 and 2024 AAFS scenarios; and 2030 gas demand reduction milestones based on 2024 AAFS gas demand scenarios. In regard to the 2024 AAFS scenarios, Representative Janusch suggested some milestones to look for in 2030 when assessing the pace of electrification and the potential impacts on the gas system. Representative Janusch also shared that the CEC is unofficially tracking heat pump estimates for California and has plans to release the tracking dashboard by end of 2025. Relatedly, possible major drivers of gas reductions based on 2024 AAFS 2 scenario are from the zero-emission appliance adoption and new construction projects and existing buildings.

Representative Janusch then moved on to discussing the 2025 IEPR, with its proposed AAFS scenario of replace-on-burnout adoption curves applied to statewide existing buildings, where he emphasized that just to replace-on-burnout option will have the most significant impact on gas forecasts if they are to be replaced with zero emission appliances. Representative Janusch stated all scenarios are more for electric planning and informed the participants of an IEPR workshop on November 13, 2025, to discuss draft scenario results.

Fossil Gas Total Customer Rates: Anthony Dixon, Energy Assessments Division - CEC
(Time stamp 1:52:13)

Anthony Dixon from the CEC explained that the agency is required to do a 30-year forecast of gas rates and for this forecast, CEC developed a single commodity price and electric generation total customer rate as well as an analysis using the four demand cases and one revenue requirement. Representative Dixon stated that the forecast does an average rate for a system by customers – total average rate for residential, industrial, and commercial by using an in-house model, fossil gas commodity price model. The fossil gas commodity price model accounts for about 25% of the total customer rate and 75% of transportation rates; however, these rate forecasts are not adopted, but meant just as a tool, where the three inputs: revenue requirement, class allocation, and demand can be adjusted to forecast transportation rate.

Representative Dixon further explained that the modeling can be difficult due to volatility with weather and pipeline events that cannot be predicted into the model. Representative Dixon presented a graph depicting total customer rate in 2025 cost per therm for SoCalGas residential customer with rates that start under $2/therm, then range in the base case to about $3 therm and up to $45/therm in the CEC's AAFS 2 or gradual transition scenario. Representative Dixon reiterated that these models are not adopted but are bookends to look at and give stakeholders a tool to understand how these different demands can impact rates.

Q&A (Time stamp: 2:03:46)

- TURN asked if climate-related warming in reduced core demand was incorporated into the CEC model. Representative Janusch replied that if it were to have been included it would be in the CEC baseline demand forecast and the sector-based models.
- NRDC asked in terms of rate calculations when dividing revenue by the customer allocation of how many different customer classes pay for investments, does the CEC break it down by transmission versus distribution investment? Representative Janusch replied, no, not at this time. It is just the total required. The total revenue requirement

for the whole gas system then multiplied by whatever might be with 40% of the cost goes to residential, a certain percent to commercial, industrial, and a certain portion goes to power generation.

- Earth Justice: CEC's presentation does adopt certain fuel substitution scenarios for purposes of electric system planning for local reliability and for the system and asked if in this round of IEPR if the CEC was planning to do the same of gas system planning. Representative Janusch stated that is an open question and the CEC didn't make a recommendation about what to use for gas system planning.

- Construction Trades Workforce Initiative then asked if the CEC is looking for opportunities for coordinated investment between thermal energy networks and the gas system? Representative Janusch replied, no. The CEC forecast models take whatever the baseline gas demand is then distributes it out what are the expected technologies are out there based on residential appliance survey and other data sources. There is nothing else in terms of other ways of reducing gas demand.

- EDF asked where in the CEC models do adjustments for code non-compliance happen? Representative Janusch explained that the load modifier PiCS takes this into consideration. There is not a lever of compliance, a set of scenarios, scenario 1 perhaps, has firm commitments in terms of what happened to those standards and as the scenario numbers move up, possible improvements. CEC does not specifically model compliance in particular.

- EDF then asked if price sensitivity impacts are reflected in CEC models? Representative Janusch replied, no. CEC Model does not have any price sensitivity. It's just top-down. CEC determines what percentage of adoption will occur at least with replacement burnout. Nothing in the model that does calculation on a per household basis on the willingness to adopt based on pricing and other demographic information.

- The Utility Consumers' Action Network (UCAN) asked if the CEC's peak day gas demand forecast, specifically the 1-in-10, was available. CEC Staff replied that the CEC is planning to start on the winter gas demand work in November. ED Staff stated that the CEC has started doing the 1-in-10 forecast for the upcoming year, but not the 15-years out as it is in the CGR. CEC responded that is correct. CEC is exploring going further out in the years, but that is something CEC still has to do develop.

- UCAN further asked if the 15-year window time horizon would be available in January. CEC Staff explained that the CEC does only one-year outlook, but is considering doing a longer term.

Workshop Segment 2: Interim Actions: Procedures Facilitating Non-Pipeline Alternatives

Existing Gas Infrastructure Replacement Procedures and Potential Change Points: Eileen Hlavka, CPUC Energy Division (Time Stamp: 2:18:55 to 2:33:32)

Energy Division Staff, Eileen Hlaka, began the presentation by stating that there could be cost savings if the State were to replace existing major gas distribution infrastructure replacement activities currently in practice (e.g., distribution mains and services replacement, services-only replacement, and gas distribution regulator station replacement) with NPAs via targeted electrifications efforts.

ED Staff then gave an overview of the types of distribution system replacement activities, offering considerations such as timelines for each step may vary from project to project and utility to utility; Customer (Landowner, Tenant, OTS) and jurisdictional (Permitting) consent. ED Staff also explained that services-only replacement project could be one customer at a time with shorter timelines compared to main and service replacement projects and distribution regulator station replacement projects are major expense projects; therefore, is another cost savings opportunity if it can be avoided via NPAs. (Slide 95)

Policy Options to Facilitate Non-Pipeline Alternatives

Panel 1. Sarah Steinburg, Advanced Energy United (AEU) (Time Stamp: 2:34:30 – 2:46:41)

AEU representative, Sarah Steinburg provided a snapshot of where NPAs are for New York, Colorado, and Massachusetts and lessons learned from these efforts. New York has relied on competitive solicitations for its NPA activities where scope includes heat pumps, community geothermal network energy efficiency, hydrogen, and specific commercial and industrial projects with various alternative fuels. NY is considering NPAs to advance its Climate Leadership and Community Protection Act goals. Colorado/Excel Energy adopts NPAs via gas system planning

and a desire to contain infrastructure costs while meeting state decarbonization goals. Requires NPA analyses for projects over $3M threshold categorized as new business or capacity expansion. Commission strongly encouraged NPA analyses for system safety and integrity projects. Excel Energy NPA development process is as follows: 1) identify projects by category and timeline; 2) screen eligible projects; and 3) evaluate NPA. Lesson learned from this process is early project identification is key. Lastly, Massachusetts is in early stages of NPA deployment where regulatory process includes 1) local distribution companies needing to prove that NPAs were non-viable before receiving cost recovery and 2) in the reduce gas leak program, the State lowered the revenue cap for to 2.5%, but allows a revenue cap up to 3.0% for NPAs. Concluded the presentation by noting that NPAs are impossible to standardize.

Panel 2. Jalal Anwan, TURN (Time Stamp: 2:47:17)

TURN representative, Jalal Anwan, presented on the TURN's benefit cost assessment framework which includes key questions and definitions that ought to be transparent and consistent for implementing SB 1221 projects. Questions like, What is NPA? How to define gas projects for evaluation? Which risk metrics for 10-year foreseeable replacements? Representative Anwan gave an overview of the four steps within the framework: Step 0 is preliminary screening - identifying short-term low cost and high risk projects authorized in GRCs; Step 1 is preliminary identification of high risk gas asset, large electric headroom, ESJ community; Step 2 is portfolio development – competitive demand-side NPA portfolio, and Step 3 is portfolio evaluation against traditional pipeline. Representative Anwan explained that by working through the four steps is to transition from gas-related infrastructure to fully electric. Representative Anwan recommended to address open questions; direct utilities to provide data to enable risk-based priority

neighborhood decarbonization zones (PNDZ) as part of Track 2 of this proceeding, adopt a uniform benefit cost assessment framework for SB 1221 and non-SB 1221 NPA evaluations and issue a Staff Proposal to address these recommendations.

Panel 3. Kiki Velez, NRDC (Time Stamp: 3:00:24)

NRDC representative, Kiki Velez, discussed potential cost savings of more than $20B from NPAs for California based on forecast of gas utility investments through 2045 from a report by E3 for NRDC. In the presentation, Representative Velez discusses the following topics: An NPA definition: any project(s) that avoids a planned gas investments; a benefit cost analysis framework that compares net-present value of a planned gas project with an NPA, including all associated utility earnings; and streamlined cost recovery framework for NPAs where behind-the-meter costs should be recovered as a gas regulatory asset as practiced in other states. Representative Velez also discussed NRDC models for assessing costs looking at bill and rate, and revenue requirement impacts of paying for NPAs in different ways. For example, paying for NPAs in entirety in year – one or paying for it as a regulatory asset over a X-time period. Overall, on the gas side, if paid for over a longer time period, this would cut into savings because utilities are being allowed to earn returns over a longer time period; however, the bill impact to the customer on year-one is lower. There are tradeoffs to consider from the NRDC model. Representative Velez also mentioned that the model can also be used to see potential electric system impacts and recommended that the Commission should develop a transparent, streamlined process to identify and prioritize NPAs including: additional mapping needs, role of 3rd party review, and low-hanging fruit opportunities.

Panel 4. Matt Vespa, Sierra Club (Time Stamp: 3:10:30 to 3:19:38)

Sierra Club representative, Matt Vespa, opened by expressing thoughts that in the past approximate five years, there has been progress with inter-agency coordination particularly in the area of limiting gas system expansion with CEC's building code increasing electrification and the CPUC ending gas line extension allowances. In regards to interim action, Representative Vespa then stated that the CPUC needs to address questions (e.g., Should NPAs be funded by gas or electric ratepayers? How should utilities recover costs from behind-the-meter investments for SB 1221 and non-SB1221 projects? How should NPA cost-effectiveness be evaluated?) and needs further record development either through Staff Proposal or other. Lastly, Representative Vespa stated that when it comes to NPA for service line replacement it can be standardized since vast majority are connected to a single meter.

Q&A (Time stamp: 3:19:45)

- Center for Accessible Technologies asked how the benefit cost analysis is considering the non-energy benefits? NRDC and TURN both replied that it does not take it into account, but does think the societal benefits should be included if/when allowed and applicable.
- TURN: Agreed w/NRDC and notes that SB 1221 language excludes non-energy benefits
- TURN inquired if the thought is to pursue a set subsidy for participants such as what New York is doing. Sierra Club replied, yes similar. Someone then asked who is New York recovering costs from. NRDC and AEP stated that they thought it were the gas ratepayers.
- Unknown: Regulatory asset is that something that earns a rate of return or return on equity because it would be considered a capital investment? And, is it depreciated over time?
- NRDC: Yes, that's how it works in New York, and that is how it is envisioned. Rate of return would be the same as standard gas infrastructure projects; but with a shorter depreciation life.
- **Unknown:** Sierra Club if the costs presented is based on capping the service line, and not cutting into the distribution main. Sierra Club replied that the figures were just an average to replace the line.

- CCA questioned if there were examples of the voltage stability/sensitivity assessment to evaluate NPAs or NWAs, and whether that data is available? NRDC stated that Excel Energy does include electric headroom analysis. TURN added that in the benefit cost framework, the ICA maps provide some information. Norm Pederson followed by asking TURN what the electric headroom is. TURN replied, the available capacity at final the substation level to where the electrification is occurring.

- When asked by an audience member, is there a way to incentivize participation by returning the avoided future costs to participants or to subsidize electrification? Sierra Club replied that there are states doing this currently; therefore California should be able to as well. NRDC added that it could be a potential bill discount to mitigate customer bills from increasing.

Utility Perspectives on Non-Pipeline Alternatives

Panel 1. Nate Taylor, SoCalGas/SDG&E (Time stamp 3:32:30)

Nate Taylor from SoCalGas/SDG&E started the final panel discussion by presenting on guiding principles about what will be important as we think about constructing a pilot program for NPAs. And, also over the long run, how to think about integrating NPAs into our investment portfolio. Guiding principles include: safety and the importance of streamlining an NPA approach to existing safety investments; reliability in terms of not impacting customers who could be subject to NPAs; and affordability from what the financial impacts are from NPAs within the portfolio and customers' energy bills. SoCalGas/SDG&E also noted that for SoCalGas being a single-fuel utility must have coordination with IOUs and POUs, and stressed the importance of documenting and reporting all findings from the pilot projects.

Panel 2. Christopher Koontz and Tony Foster, Long Beach (Time stamp 3:38:55)

Christopher Koontz and Tony Foster from the City of Long Beach, discussed the city's Climate Action Plan (CAP) that includes obligations to reduce GHG, state goal, and moral obligation as a city. Presented goals for 2030: 40% below 1990 level (AB 32) and aspirational goal of being carbon neutral by 2045. CAP focus is on building energy emissions and with which

includes electrification as one type of control measure, but ability to implement has been affected by legislation with regard to budget. In Long Beach, 80% of the existing housing stock being more than 50 years old; the city has big challenges to both residents and the public utility in terms of electrification where many homeowners are asset rich or cash poor and are on fixed income. When looking to electrify these homes, it's not simple; it's very complex, expensive, but doesn't mean it isn't worthwhile. Currently, these homes remain on the same natural gas fuel source moving to greater energy efficiency and safety.

Presenter 2: Residential natural gas consumption has declined steadily by about 1% per year over the last five years. Goal is to target decarbonization where it matters most (e.g., end of life mains and services and high maintenance pipelines). Long Beach is also in early stages with SCE exploring zonal electrification opportunities on at least two pilot micro zones. Reimagining how to meet demand through NPAs vs. defaulting to traditional pipe replacement. Aim is not just to avoid stranded assets but to ensure that cleaner options are viable.

Panel 3. Mike Kerans and Rachel Wittman, PG&E (Time stamp 3:52:19)

PG&E representatives, Mike Kerans and Rachel Wittman, presented on PG&E's perspective around NPAs, discussed lessons learned from their utility's programs then offered recommendations. PG&E agree with other presenters for a shared definition of what NPAs are. PG&E mentioned demand side management project in Colorado as innovative, but does not believe demand side management is not how to do down rates. PG&E recommends giving focus to the following: cost-effectiveness framework and adequate non-ratepayer funding mechanism; streamlined decision-making process and procedures to ensure customer consent; and quick

decision-making to not delay critical safety work and maintaining safety standards during broader transition to NPAs.

PG&E presented on their two zonal electrification programs: Alternative Energy Program (AEP) and Zonal Equity Electrification Program (ZEEP). For both programs about 25% of customers contacted have ultimately enrolled, on average less than SB 1221 which requires at least 2/3 consent. Some individual zones have successfully reached 2/3 or 100% consent and the programs are still nascent with developing and refining outreach strategy. PG&E's lessons learned include: need for program design flexibility, and understanding that reluctance to electrify may not just be financial but apathy, personal circumstance, and/or grid reliability and while there is success in changing apathy or a "maybe" or a "yes", PG&E finds it hard to convince customers who are firmly opposed. Lastly noted that customer engagement/trusted messenger via local government and partner support is key to successful customer participation.

Panelist 4. Kate Ziemba, Joint CCAs (Time stamp 4:12:22)

Representing San Jose Clean Energy, San Diego Community Power, Silicon Valley Clean Energy, and Sonoma Clean Power. Presentation included background on the CCA and values. CCAs developed a suite of programs to meet customers on their electrification journey (e.g., educational guides, renter protection, workforce development initiatives, and focus on affordability). CCAs view NPAs as an opportunity to align incentives, investing in electrification where it is most cost effective. With regard to SB 1221, CCAs are skilled in outreach and consensus building. Also, partnering with gas corporations to understand and utilize confidential data will help ensure data-driven decisions via NDAs.

Q&A (Time stamp 4:20:31)

- EDF said PG&E's definition of NPAs was helpful and stated that SoCalGas did not identify decarbonization in their presentation. Asked Sierra Club if there is data on leakage of service lines vs. transmission or distribution pipes. PG&E responded that operators are required to report where leaks are in the Pipeline and Hazardous Materials Safety Administration (PHMSA) report and PG&E does it from an asset management perspective. EDF further inquired if there was more leakage per X of pipe that is in a service line or distribution? PG&E answered it depends on the utility. Also, services are not solely replaced because of leakage. Sometimes it's due to reliability issues.

- CCA asked Long Beach on the scale of the zonal projects and if the public utility had a community partner? Long Beach stated that the projects are in very nascent stages and currently, building trades are not involved. CCA then asked PG&E their thoughts on what is the optimal scale for zonal decarbonization projects. PG&E replied that it depended on what is considered in terms of cost effectiveness and added it depends on many specifics to the scope of the project.

- TURN asked PG&E to say more on community engagement and how the utility garnered customers to participate in the AEP program. PG&E explained that community engagement requires a multi-pronged approach – electrification education, specific program details, cost, bill impact, explanation of heat pump, benefits. Local trusted voice looks different depending on who's hearing it. The utility has learned that the message can sometimes be better heard when it comes from someone other than the utilities. Contra Costa County echoed PG&E with the comment that it makes a difference to some when they receive a letter from local government suggesting a program.

- UWUA Local 132 inquired with Long Beach which customers were converting from gas to electric. The presenter stated the customers tend to be those in the higher income bracket. EDF asked Long Beach how the project determines terminus of different gas lines and the public utility replied that it is not a conclusive analysis.

- CforAT referred to PG&E's program by asking what percentage of customers gave a hard-no. PG&E replied that it is difficult to distinguish a hard-no from that of a no-response. Long Beach: Customers switching tend to be higher income doing it because of their commitment to reducing their environmental footprint.

- CCA asked the CPUC and CEC what the status is on having a discussion on coordinating funding.

- UCAN commented that the need to catch up with the other states then referred to their 12 proposals for interim actions from March comments.

- A question was asked on what are the first steps for service pruning? How can we as local governments work most quickly to pair service line pruning with CCA electrification programs in parallel to the longer term zonal approach?

- PG&E replied understanding where the work is in the next near-term horizon then having early engagement is critical. PG&E also stated it is important to understand how to fund behind-the-meter upgrades because without it, probably has low likelihood start. SoCalGas/SDG&E commented that they are looking forward to the development of a pilot program, understanding the cost effectiveness framework to be able to review costs of service replacement project. In addition, stated that SoCalGas absolutely does support decarbonization. However, in today's workshop it wasn't called out since in the context of NPA integration, we're looking at it through affordability lens where decarbonization can be a co-benefit vs. material test for getting a pilot underway.

Open Question & Comments (Time stamp 4:57:39)

- Energy Coalition: Based on the aggressive timeline requirements of SB 1221, how can we design the program to clearly define the program and articulate benefits to potential participants and asked the CPUC to consider steps to identify and design the program.

- UWUA Local 132: After consumers switch over to NPAs, what will offset the rising rate cost of maintenance and improving the infrastructure for electrical? PG&E: For all of our programs, there are a variety of lenses to evaluate cost. We need to have a definition for cost effectiveness as well. The gas transition is also an electric transition where all electric partners from early on and ongoingly jointly address challenges as the transition expands.

- UWUA Local 132: How the pilot projects impact rate payers who remain as gas customers? Also, is there electricity sufficient from renewable sources rather than having to use natural gas or other fossil fuels? How are we ensuring lower bills when gas is currently much cheaper than electricity? PG&E: It's still an issue to consider in terms of which rate payer would be impacted. If they were like-for-like in terms of their total energy usage, and replace them with electric and all of that electricity was sourced from a gas power plant, it would still be more efficient in terms of emissions.

- EDF: Commented that there are different ways of measuring cost effectiveness.

- Tim Frank/CCA: Also on cost effectiveness, discussed importance of proper installation, maintenance, decommissioning at end of life cycle. CCA members include skilled labor that can get program performance as designed for zonal decarbonization projects.

- Unknown: Can someone speak to the feedback loops to achieve the state goals in the natural gas planning process? Will revenue and investment planning for system operations continue based on usage regardless of the goals is there a point when alternatives to gas will be required in those gas funds reallocated?

- SCE: Asked if ED and CPUC open to publishing a staff report to revisit the topics formally in comments and could ED speak to next steps for how we get to the 7/1

deadline for pilots programs to be launched? ED Staff: Utilities will be writing workshop summary. More to come soon on next steps.

- NRDC: follow up to their presentation: regarding upfront costs, comparing cost of NPAs to gas pipeline replacement and returns that customers would pay on those investments would be in the benefit cost assessment and ongoing O&M cost including utilities' income taxes.

- CiCi Vu: What are the implications of SB 1221's provision related to the 67% customer opt-in while lifting the OTS the remaining customers. TURN: No official position. Will do best to ensure 100% buy-in. Tim Frank: to succeed will need generally buy-in higher than 67%. Not fair for the majority to not get the significant benefit because of OTS. PG&E: NPA does not have to be synonymous with decarbonization alternative. For example, the 1/3 who say no, what are the alternatives that can be offered such as propane? NRDC: Getting to 67% seems like a big jump. Start doing one offs such as the service line projects where it is just one household to start ASAP before SB 1221 is fully implemented. There are milestones between now and the large-scale neighborhood projects. PG&E: In PG&E's territory, at least two different community led projects have reached 2/3 consent.

- UWUA Local 132: If decommissioning of pipelines is to happen, highly recommend unionized workers to perform this work.

- Jonathan Bromson, CPUC Attorney: Regarding the 67% opt-in and OTS, that determination will be very fact dependent and depend on the election details we have not yet developed, and other future statutory determinations about equivalent service. That determination will be made after a pilot project is completed, and we will likely be asking for more guidance after the pilots are chosen.

- Jody London: Commented that a zone should be defined small enough to not have to have large amount of yes.

Closing Remarks: Commissioner Karen Douglas, California Public Utilities Commission

Commissioner Douglas expressed appreciation to all for joining and participating in the workshop. She thought it was valuable discussion and would take time to think through all that was heard including the next steps.

End of Report.

APPENDIX A

WORKSHOP AGENDA

R.24-09-012 Workshop:

Forecasting Analytics and Facilitating Non-Pipeline Alternatives

September 22, 2025 | 9:30 a.m. – 4:30 p.m. | In-person and remote

Parties and interested members of the public may attend and participate in person at:
Auditorium
California Public Utilities Commission
505 Van Ness Avenue San Francisco, CA

Parties and interested members of the public may attend and participate remotely at:
Webinar Link: https://cpuc.webex.com/cpuc/j.php?MTID=m810faef821f270a0d6379b899fcc6bf4
Access Code: 2488 672 3907
Passcode: 092025

Join by Phone:
- 1-855-282-6330 United States Toll Free
- +1-415-655-0002 United States Toll

WORKSHOP AGENDA

9:30 – 9:45 **Welcome and Housekeeping**

Commissioner Karen Douglas, California Public Utilities Commission
Energy Division Staff

Workshop Segment 1: Gas Demand and Rates: Foundational Forecasting Analytics
Objective: Provide background and updates on gas demand and rate forecasts as preparation for potential interim actions on rates and for long-term gas planning considerations in this proceeding.

9:45 – 10:05 **Background on Gas Rate Components, CPUC Energy Division staff**

Jean Spencer, California Public Utilities Commission

CPUC staff will review how rates and bills are currently set, including transportation and commodity components as well as fixed and per-therm bill aspects.

10:05 – 10:35 **Panel: Current Forecasts and Infrastructure Applications, Gas Utilities**
Gas IOUs will provide an overview of (a) how they develop and/or use gas demand forecasts, including but not limited to the California Gas Report, the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR), and other forecasts; (b) how they use these forecasts to develop the infrastructure needs and revenue requirements they propose in General Rate Cases and Cost Allocation proceedings; and (c) how these forecasts impact rates. This presentation should include forecasts by sector and how those are used for cost allocation among sectors.

Nate Taylor, **SoCalGas/SDG&E**
Kurtis Kolnowski and Daven Phelan, **PG&E**

10:35 – 10:50 **Q&A with Panel Speakers**

10:50 – 11:00 **Stretch Break**

11:00 – 11:45 **Forecasting Tool Developments and Applications, CEC**

Nicholas Janusch and Anthony Dixon, CEC

The CEC will summarize the Additional Achievable Fuel Substitution (AAFS) scenarios prepared as part of CEC's Integrated Energy Policy Report (IEPR) gas demand forecasts. Depending on which assumptions are used for building electrification adoption, these scenarios result in a wide range of possible gas demand futures. CEC staff will discuss the assumptions behind the AAFS scenarios along with the most critical drivers of the differences in forecasted demand among the scenarios. Additionally, CEC staff will present the estimated 2030 impacts for the scenarios, compared to recent history, to understand the pace of building decarbonization needed to meet the 2030 milestones.

CEC staff will then present forecasts showing how different AAFS demand scenarios may impact rates. The presentation includes a summary of potential rate impacts under the assumption that total expenditures remain unchanged by demand. To provide context, staff will outline key assumptions, note areas of ongoing development, and compare results with other CEC forecasts for gas transportation rates.

11:45 – 12:00 **Q&A with CEC**

12:00 – 1:15 **Lunch Break**

Workshop Segment 2: Interim Actions: Procedures Facilitating Non-Pipeline Alternatives
Objective: Discuss options for creating greater access to cost-saving non-pipeline alternatives. These discussions may apply to SB 1221 and non-SB 1221 decisionmaking, including Scoping Memo Phase 1, Question 3.[1]

1:15 – 1:30 **Existing Gas Infrastructure Replacement Procedures and Potential Change Points, Energy Division Staff**

Eileen Hlavka, California Public Utilities Commission

Staff will discuss key elements of planning and funding gas distribution infrastructure replacement projects, including identification of locations, communication with landowners, cost estimation, and implementation.

1:30 – 2:10 **Panel: Policy Options to Facilitate Non-Pipeline Alternatives**
Panelists will provide their recommendations regarding procedures for defining and accessing cost-saving non-pipeline alternatives, including processes to initiate gas service-level and gas main-level projects, defining cost savings, and concepts and lessons learned from other states.

Jalal Awan , **TURN**
Matt Vespa, **Sierra Club**
Kiki Velez , **NRDC**
Sarah Steinburg, **Advanced Energy United**

2:10 – 2:25 **Q&A with Panel**

2:25 – 2:35 **Stretch Break**

2:35 – 3:15 **Panel: Utility Perspectives on Non-Pipeline Alternatives**
Panelists will provide their perspectives and experience with pursuing non-pipeline alternatives. SoCalGas has a unique perspective as a large gas-only utility; City of Long Beach has begun pursuing electrification pilot coordination with Southern California Edison as a means to achieve cost savings; and PG&E has lessons learned from its CSU Monterey Bay Zonal Decarbonization application as well as its ongoing Alternative Energy Program and Zonal Equity Electrification Program (ZEEP).

Nate Taylor, **SoCalGas/SDG&E**
Christopher Koontz and Tony Foster, **Long Beach / SCE**
Mike Kerans and Rachel Wittman , **PG&E**
Kate Ziemba, **Joint CCAs**

[1] Non-SB 1221 aspects may relate to Scoping Memo Phase 1, question 3: "Should the Commission adopt a new process to facilitate non-pipeline alternatives for some or all distribution pipeline or regulator station repair or replacement projects? If so, what should that process entail and what direction should the Commission give to utilities to enact that process, including how should costs be addressed?"

3:15 – 3:30 **Q&A with Panel**

3:30 – 4:15 **Comments (Open to All)**

4:15 – 4:30 **Closing Remarks**

Commissioner Karen Douglas, California Public Utilities Commission
Energy Division Staff

Note: It is expected that one or more CPUC Commissioners may attend and participate in the workshop but no formal Commission action will be taken. One or more advisors to the CPUC Commissioners, as well as other decision-makers, may also be in attendance. The agenda will be publicly noticed on the CPUC's Daily Calendar 10 days in advance, so statements made at the workshop will not constitute a reportable *ex parte* contact. This agenda is subject to change. The workshop will be recorded.

APPENDIX B

PANEL PRESENTATIONS

R.24-09-012 Workshop: Forecasting Analytics and Facilitating Non-Pipeline Alternatives

September 21, 2025

California Public Utilities Commission

Workshop Logistics

- Today's presentation will be sent to the service list
- There will be opportunity for Q&A after each panel and time for general comments at the end of the workshop.
- To ask a question of the presenters
  - In-Person:
    - Raise hand and speak into the mic
  - Webex:
    - Type question into the chat
- This workshop is being recorded

505 Van Ness

In case of Evacuation

1. Take internal stairs to ground floor
2. Exit to Van Ness Ave
3. Go right on Van Ness Ave
4. Meet at outside courtyard (across from City Hall)

Natural Gas Rates and Bills

CPUC Energy Division Staff Presentation
Jean Spencer

September 22, 2025

California Public Utilities Commission

Agenda

- Basic Principles
- Rate Components
- Bill Structure

Basic Principles

- General Rates Cases vs. Cost Allocation Proceedings
- Core vs. Noncore Customers

General Rate Cases and Cost Allocation Proceedings

- General rate cases
  - Determine the revenue requirement the utility can collect to recover costs to:
    - Operate, maintain, and construct its pipeline and storage systems
    - Run the company, such as administrative costs and customer services costs
  - Allocate capital asset costs across time through depreciation
- Cost allocation proceedings
  - Allocate the revenue requirement to different utility functions and customer classes
    - Generally based on cost causation principles
  - Divide costs into fixed and variable rates with tiers

Core vs. Noncore Customers

- Core customers:
  - Residential and small commercial customers
  - The utility procures and transports their gas
    - Can choose a Core Transport Agent to procure gas
  - Pay a premium for more reliable service
  - Primary users of distribution lines
- Noncore Customers
  - Large commercial and industrial customers
    - Examples: Electric generators, refineries, factories, hospitals
  - Procure their own gas supply and inter- and intrastate transportation services or use a marketer
  - Exposed to more reliability risk

Rate Components

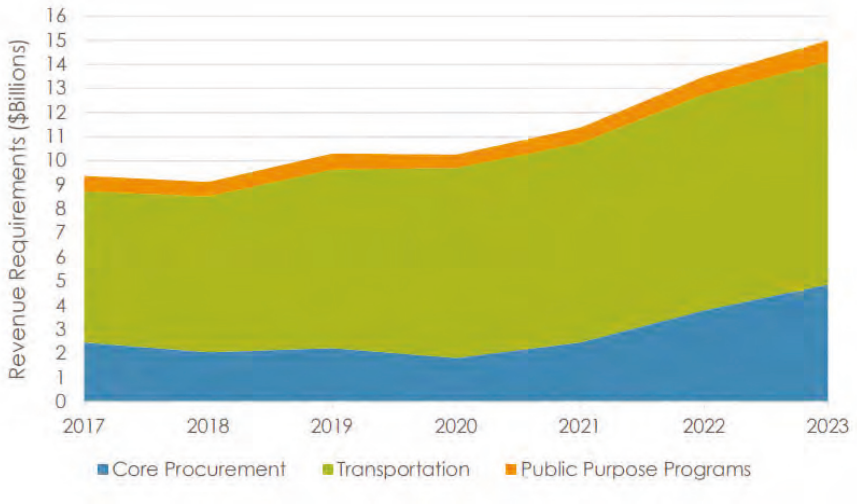
- Core Procurement Rate
- Transportation Rate
- Public Purpose Program Surcharge
- Climate Credit

Three Main Components of Gas Rates

- **Core Procurement Rate**
  - Applies only to bundled core customers
  - Recovers the cost of the gas commodity and the pipeline capacity to transport it to the local transmission system
    - Gas commodity cost is a pass-through cost; utilities don't earn a profit on it
- **Transportation Rate**
  - Recovers revenue requirement, i.e., costs of utility's transmission and distribution pipeline system, storage, and customer-related services plus a rate of return
- **Public Purpose Program (PPP) Surcharge**
  - Recovers costs of mandated public purpose programs

Rate Components Breakdown

Historical Trends in Gas Utility Revenue Requirement Components ($ billions)



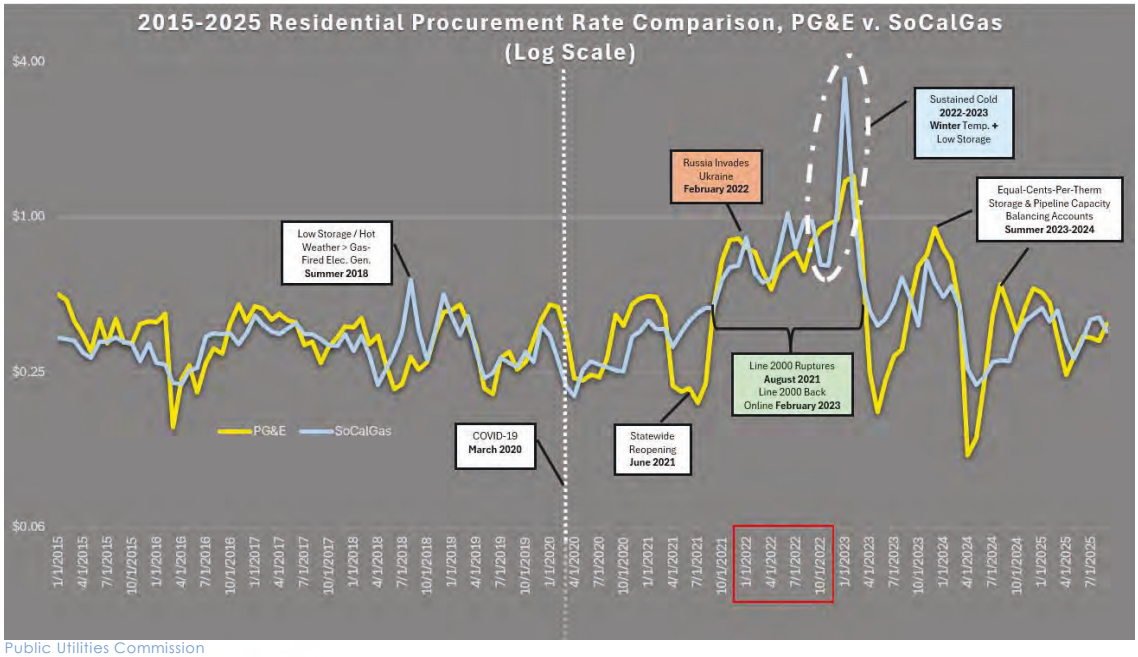
- Transportation rates are the largest component of rates
- However, gas price spikes can increase core procurement costs

Source: CPUC 2024 AB 67 Report

Core Procurement Rates

- Updated every month
- Changes are mostly due to fluctuations in gas commodity prices
- The CPUC reviews the reasonableness of gas purchases through gas cost incentive mechanisms

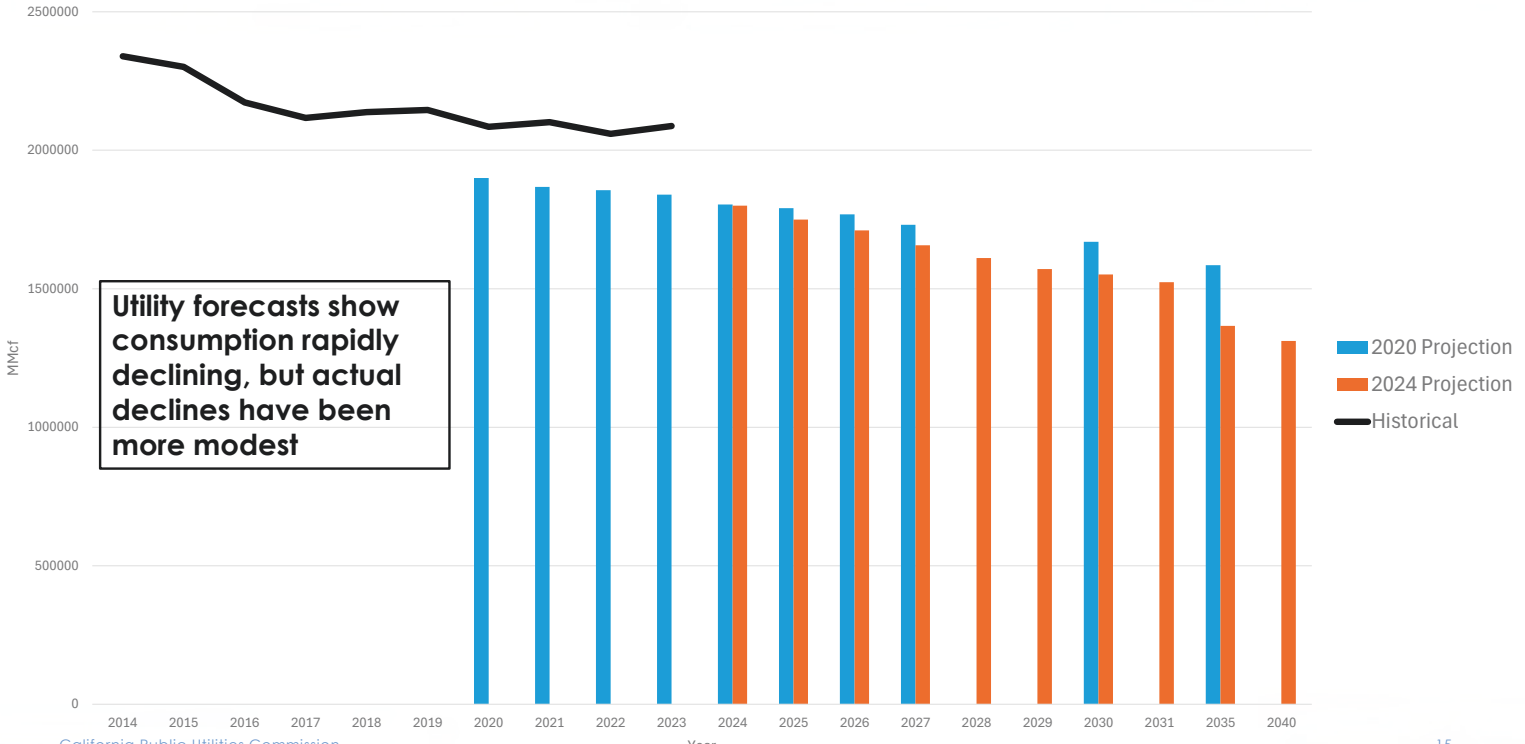
Core Procurement Rates: Impacts of Volatile Gas Market



Transportation Rates

- Usually updated annually but can be updated more often
- Allow for the recovery of the revenue requirement based on a forecast of throughput
- A simplified way of thinking about this is:
  - Rates = Revenue Requirement/Demand
  - An increase in Revenue Requirement and a decrease in Demand = Higher Rates

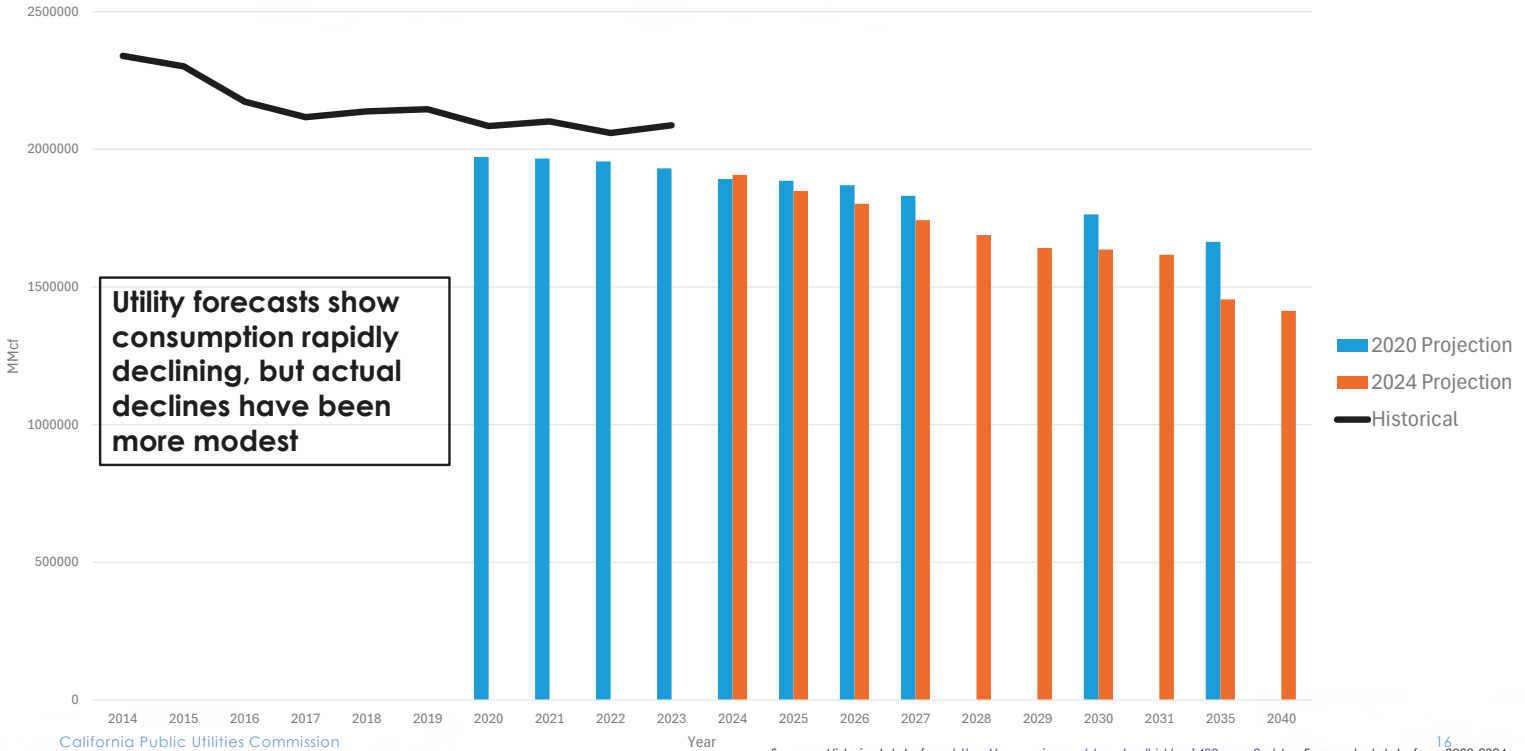
California Historical Natural Gas Consumption vs Normal Demand Year Projected Consumption



Utility forecasts show consumption rapidly declining, but actual declines have been more modest

Sources: Historical data from https://www.eia.gov/dnav/ng/hist/na1490_sca_2a.htm; Forecasted data from 2008-2024 California Gas Report | SoCalGas

California Historical Natural Gas Consumption vs High Demand Year Projected Consumption



Utility forecasts show consumption rapidly declining, but actual declines have been more modest

Sources: Historical data from https://www.eia.gov/dnav/ng/hist/na1490_sca_2a.htm; Forecasted data from 2008-2024 California Gas Report | SoCalGas

Gas PPP Surcharge

- Typically updated annually on January 1
- PPP costs include:
  - Energy efficiency program,
  - A subsidy for CARE customers, and
  - Gas research and development program
- Required by legislation
- Electric generators don't pay the gas PPP

California Climate Credit

- Natural gas utilities have been given some free allowances annually to be sold at auction
- Proceeds from sale of those free allowances have been mostly returned to residential gas customers on their April bill
- Residential gas customers receive a per-customer bill credit (not based on usage)
- Recently passed legislation (AB 1207, Irwin, 2025) may change this process

Bill Components

- Fixed Charges vs. Per-Therm Rates
- Rate Structure

Fixed Charges vs. Per-Therm Rates

- **Core Residential**
  - Procurement rate (unless CTA procurement is chosen) — per therm
  - Fixed charge or minimum bill — per day
  - Transportation rate: seasonal baseline and above baseline — per therm
  - Gas PPP surcharge rate — per therm
  - California Climate Credit — April bill credit

- **Noncore**
  - Customer or access charge — per day or month
  - Transportation rate (tiered decreasing rates for higher usage) — per therm
  - Gas PPP surcharge (but not for EG customers) — per therm

Note: Additional rates apply for noncore customers if they opt to purchase utility storage

Current Residential Rate Structure (Non-CARE as of September 2025)

	Fixed (Per Day)		Volumetric (Per Therm)				Fixed (Per Year)
	Fixed Charge	Minimum Bill	Transportation Rate		Procure-ment Rate	Public Purpose Charge	Climate Credit
			Baseline	Above Baseline			
PG&E	NA	$ 0.13	$ 2.11	$ 2.62	$ 0.39	$ 0.11	$ 67.03
SoCalGas	$ 0.16	NA	$ 1.19	$ 1.68	$ 0.36	$ 0.12	$ 86.60
SDG&E	$ 0.13	NA	$ 2.04	$ 2.39	$ 0.36	$ 0.12	$ 54.21
Southwest Gas	$ 0.19	NA	$ 1.55	$ 1.76	$ 0.25	$ 0.21	$ 73.68

- CARE rates are generally 20% less.
- Baseline usage is roughly half a therm per day in summer and 1-2 therms per day in winter and varies by climate zone.

Non-Residential Rates Are Structured Differently

- **Example: SoCalGas May 2024 Noncore Commercial/Industrial Customer**
- **Schedule GT-NC and G-PPPS**

- Customer charge $350 per month
- Transportation rate
  - Tier 1 0 to 20,833 therms 52.605 cents per therm
  - Tier 2 20,834 to 83,333 therms 41.227 cents per therm
  - Tier 3 83,334 to 166,667 therms 33.948 cents per therm
  - Tier 4 Over 166,667 therms 28.747 cents per therm
- Gas PPP surcharge 7.221 cents per therm

For more information:
jean.spencer@cpuc.ca.gov

GAS DEMAND AND RATES:
FOUNDATIONAL FORECASTING ANALYTICS

Interim Actions Workshop
Gas Planning OIR (R.24-09-021)

September 22, 2025

SDGE SoCalGas

Table of Contents

» Development of Demand Forecasts (e.g., IEPR, CA Gas Report)

» Use of Forecasts to Develop Energy Infrastructure Needs

» How Forecasts Impact Rates

Development of Demand Forecasts

Integrated Energy Policy Report (IEPR)

- California Energy Demand Forecast is developed every two (odd) years
- Collaborative, public process with data sharing and stakeholder input
- ***Includes:***
  - Annualized forecasts for residential, commercial, industrial, and NGV gas demand
  - Based on several factors, including economic and demographic trends, energy efficiency, and fuel substitution
- ***Does not include:***
  - NG-fired EG forecasts
  - Peak forecasts or load shape
  - Location/Customer-specific data
  - Wholesale customer demand
  - Customer count forecast

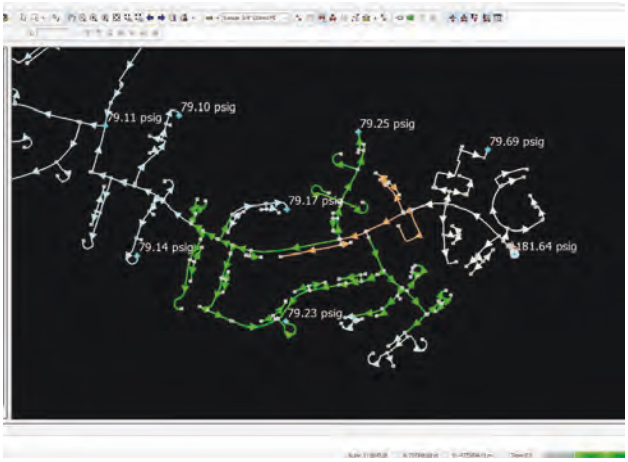
California Gas Report (CGR)

- Developed by statewide gas utilities every two (even) years.
  - Interim reports in odd years provide actuals, but no forecast updates
- Collaborative process that considers IEPR data
- ***Select additions beyond IEPR:***
  - NG-fired EG forecasts
  - Peak day forecasts
  - Selection of scenarios
  - Add wholesale customer demand forecast
  - Develop customer count forecast

How Demand Informs System Design

System Design Approach

- SoCalGas and SDG&E design their natural gas systems to meet demand under two design conditions:
  - 1-in-10-year cold day for all customers
  - 1-in-35-year extreme peak day for core customers only
- Gas system reliability is managed by our planning teams who employ fluid dynamics network software to model the expected performance of our system under design conditions
- The expected design day demand used in these models is derived from actual customer usage data, which is scaled as needed to replicate weather-dependent usage
- Engineers regularly update and run these models to verify that the system maintains safe and reliable service operating between minimum and maximum operating pressures
- These models are validated by comparing modeled results to pressure and other data from sensors on the system



Illustrative network model screenshot

How Demand Informs System Design

How Demand Forecasts are Used

- Demand forecasts are reviewed to make sure that changes in total demand and demand patterns are not expected to introduce reliability, resiliency or other risks for the gas system
- Customer requests for service are also considered, and appropriate investments are developed as and when needed to serve these new demands
- If gas demands decline in a certain area of our system, there may be opportunities to revisit system design when it could generate cost savings. Typically, this occurs when we are facing an investment decision, and alternatives are evaluated:
  - Consider re-sizing or re-routing infrastructure
  - Consider reducing MAOP (derating)
  - Consider infrastructure abandonment
- D.23-12-003 (Gas OIR 1 Phase 2) provides some guidance

How Forecasts Impact Rates

- Demand forecasts are utilized in SoCalGas and SDG&E's Cost Allocation Proceeding (CAP)
- If a California Gas Report forecast was completed in the year a CAP is filed, it is used for the CAP. If not, a current forecast is developed, using the same methodology
- The adopted forecasts in CAP are an artifact of litigation, and may not align exactly with initial proposals
- Revenue Requirements are not necessarily dependent on demand
- Demand forecasts impact rates in two major ways:
- **Cost Allocation**
  - Forecasts are used to update Marginal Demand Measures, which inform cost allocation of functional gas system cost areas to customer classes
- **Rate Design**
  - Forecasts are used to set rates that target recovery of approved revenues over the course of the year

PG&E Gas System-Level Demand Forecasting and Infrastructure Overview

September 22, 2025

Kurtis Kolnowski, Manager, Business Strategy, System Planning Analytics
Daven Phelan, Sr. Director Gas Engineering and Distribution Asset Manager Owner

PG&E

System-Level Gas Demand Forecasting 101

System-level gas demand forecasts utilize multiple methodologies best tailored to each customer class. System-level forecasts are not granular enough for localized analysis (e.g., distribution).

Forecasting Tools

- **Econometric Regression**: Calculates relationship between historical forecast drivers (regression) and demand then applies the relationship to assumed future values of each driver to forecast future gas demand.
- **Production Cost**: Hourly electricity market simulation that optimizes resource dispatch to serve electric demand at least cost. Gas-fired electric generation (EG) is a key resource class in this optimization.
- **Technology-Driven**: Specialized models designed to capture forecast drivers that are not well represented by historical trends. Used for building electrification and other "load modifiers".

Tools Used by Class

- **Core** (e.g., Residential, Commercial) and **Noncore, Non-EG** (e.g., Industrial): Econometric regression + technology-driven
- **Electric Generation**: Production cost (electric load input uses regression and technology-driven)

Granularity of Forecasts Developed – PG&E Gas System

Annual/Monthly:

- Average Demand Year (1-in-2) aka "Expected" case
- Cold/Dry (1-in-10 Cold, 1-in-10 Dry Hydro)
- Cold (1-in-35 Cold)

Peak Day:

- 1-in-2 Cold Winter Day
- 1-in-10 Winter Peak Day
- Summer High Demand
- 1-in-90 Abnormal Peak Day *(Core Only)*

Types of System-Level Gas Demand Forecasts

Demand forecasts have many use cases. Selecting the right type of forecast for a specific purpose helps make that forecast useful.

Expected Case: Best estimate of what will actually happen.

- Useful for certain planning purposes where credible and well-vetted forecasts are needed.
- Assumptions reviewed for "reasonableness" – e.g., compare with history, benchmark multiple sources.
- Accounts for future policies "on-the-books" but incorporates expected uncertainty.

Policy-Driven: Assumes that a policy will be met and then develops assumptions to align.

- Useful for policymakers to understand gaps and identify actions to fully realize policy goals.
- Does not account for uncertainty in policy implementation.
- May not require policy to be enacted.

Sensitivities and Scenarios: Representation of uncertainty to help understand range of impacts and outcomes.

- Useful for identifying "least regrets" actions and difference between expected and policy cases.
- **Sensitivity**: Vary one assumption and quantify impact. (e.g., higher electrification or lower gas prices)
- **Scenario**: Vary multiple assumptions to reflect a coherent potential future (e.g., changes in federal policy could impact cost and trajectory for solar, batteries, transportation electrification, and building electrification.

System-Level Forecasts Utilized by PG&E

PG&E utilizes GT&S and CGR forecasts for internal use cases and accounts for known uncertainty. CEC's IEPR forecast used as a benchmark in system-level gas demand forecasting

Forecast ID: Use Case / Purpose	Forecaster	Forecast Type	Forecast Assumptions	Horizon
Gas Transmission & Storage (GT&S) Forecast: Gas rate setting every 4 years; allocate costs and gas rate design. (GT&S CARD, GCAP)	PG&E	Expected Case + Scenario (1-in-35 Cold)	PG&E-only **internal** assumptions. Accounts for known uncertainty in policy assumptions.	4 Yrs
California Gas Report (CGR): Compliance filing. Combines projections from gas utilities & non-utility stakeholders. Also used for Backbone Capacity Adequacy and informs range for Core Firm Interstate Pipeline Capacity supply and reliability standards.	PG&E	Expected Case + Scenarios and Sensitivities (many)	**External** forecast sub-committees (e.g., Joint IOUs, municipalities, CPUC, CEC) determine CGR forecast assumptions. Accounts for known uncertainty in policy assumptions.	Up to 20 Yrs
Integrated Energy Policy Report (IEPR): External forecast used in electric system planning and local reliability. PG&E's EG forecast utilizes SCE and SDG&E Planning Area inputs. Benchmark for PG&E forecasts.	CEC	Hybrid: Expected Case & Policy-Driven + Scenarios	**External** CEC-driven process that involves many stakeholders, including PG&E. Some assumptions reflect whether a policy is met or not but uncertainty in its implementation.	Up to 20 Yrs

Gas Demand Forecast Uncertainty

Point forecasts needed for rate-setting purposes. Point forecasts should use defensible assumptions but will not capture the impacts of all uncertainty.

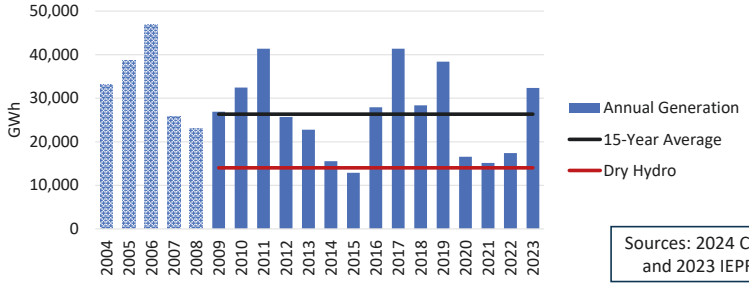
Uncertainty That Does not Affect Expected Case

- Reflects periodic variation or events that do not represent an "average"
- This uncertainty does not affect a point forecast and is best captured by scenarios and sensitivities.
- Examples include temperature and rainfall.

Uncertainty That Changes Expected Case

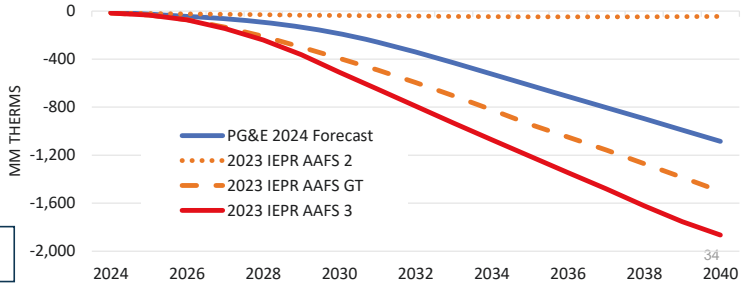
- Reflects changes in assumptions that impact even an "average" year.
- This uncertainty shifts a point forecast up or down and could be the result of policy or market conditions.
- Examples include building electrification policy and rate of electric resource build.

CA Hydro Historical Annual Generation



Sources: 2024 CGR and 2023 IEPR

Building Electrification Impact on Gas Throughput, PG&E System



How Localized Demand Forecasts are Developed by PG&E

PG&E develops forecasts for local gas demand based on various sources

System-level forecasts are not granular enough for localized analysis (e.g., distribution), so external sources are used to develop localized demand forecasts.

For example, a new gas customer on Distribution System A may result in a localized constraint on 123 Main Street and is independent of declining gas demand in Distribution System B.

Description	Source(s)	Horizon
Customer Requests: Existing customers increasing gas demand or new customers connecting gas demand.	Customers	1 to 5 Yrs
Local Development: Master plans by cities and developers.	Cities and developers	5 to 10 Yrs

Forecasting Infrastructure Needs in GRCs

Demand Forecasts vs. Infrastructure Needs

- PG&E utilizes system wide demand forecasts to project large scale infrastructure needs (e.g. backbone transmission & storage) over time.
- Generally, Gas Distribution capital needs are not driven by system wide demand forecasts, and a very small portion is related to customer or demand growth.

Gas Distribution Capital and Expense Forecasts

- Gas Distribution CapEx is driven primarily by Operational and Maintenance requirements and Asset Management activities for the gas distribution system.
- PG&E's obligations under PUC 959 require us to fund "…those projects and activities necessary to maintain safe and reliable service and to meet federal and state safety requirements applicable to its gas plant, in a cost-effective manner."

Highest Priority Interim Actions

- Standardized, streamlined criteria to evaluate the cost-effectiveness of decarbonization projects and Non-Pipeline Alternatives (NPAs), and
- Creation of a "level playing field" for recovery of utility investments and long-term costs for decarbonization projects, including capitalization and a return on those investments comparable to the treatment of the gas system capital costs and assets they replace

Questions?

CEC IEPR Gas Demand Scenarios

Nicholas Janusch, Ph.D., Program and Project Supervisor
Energy Assessments Division
R. 24-09-012 Workshop: Forecasting Analytics and Facilitating Non-Pipeline Alternatives
September 22, 2025

Acronyms, Initialisms, and Abbreviations

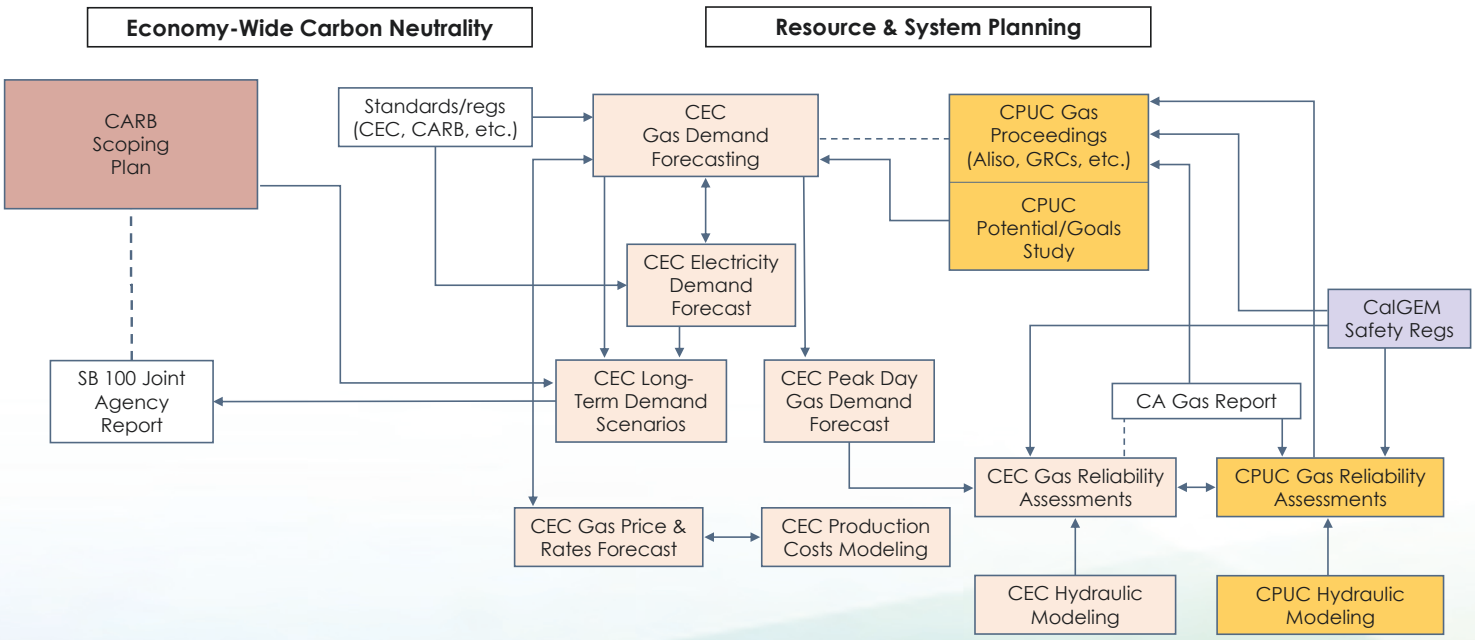
A&A – Additions and Alterations
AAEE – Additional Achievable Energy Efficiency
AAFS – Additional Achievable Fuel Substitution
Aliso – Aliso Canyon
AQMD – Air Quality Management District
BAU – Business as Usual
BUILD – Building Initiative for Low-Emissions Development
CalGem - Geologic Energy Management Division of the California Department of Conservation
CARB – California Air Resources Board
CCA – Community Choice Aggregators
CEC – California Energy Commission
CERIP – Clean Energy Reliability Investment Plan (CERIP)
CGR – California Gas Report
Com – Commercial Sector
EAD – Energy Assessments Division
EBD – Equitable Building Decarbonization
ECAA – Energy Conservation Assistance Act
FSSAT – Fuel Substitution Scenarios Analysis Tool
GRCs – General Rate Cases
GT AAFS – 2023 Gradual Transformation Additional Achievable Fuel Substitution Scenario
HOMES – Home Efficiency Rebates IRA Incentive Program
HPWH – Heat Pump Water Heater
IEPR – Integrated Energy Policy Report
IOU – Investor-Owned Utility
IRA – Inflation Reduction Act
NC – New Construction
QFER – Quarterly Fuel and Energy Report
PACE – Property Assessed Clean Energy (PACE) Financing
PiCS – Programs and incremental Codes and Standards

Acronyms, Initialisms, and Abbreviations (continued)

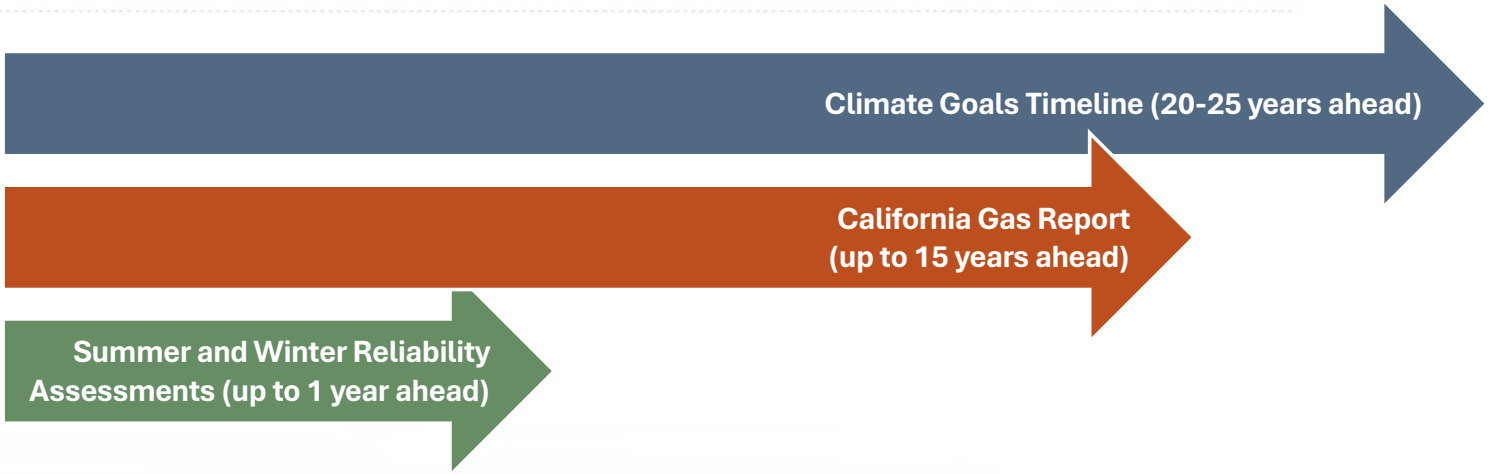
POU – Publicly Owned Utility
RENs – Regional Energy Networks
Res – Residential Sector
ROB – Replace on Burnout
Sc. - Scenario
SH – Space Heaters
TECH – Technology and Equipment for Clean Heating initiative
WH – Water Heaters
ZE - Zero-Emission

Overview of CEC's Gas Assessments

Natural Gas Planning Process



Gas System Planning – Layered Planning Horizons



CEC Gas Demand Assessments

	IEPR Gas Demand Forecast	Long-Term Demand Scenarios	Peak Day Gas Forecast
Uses	Some components used by gas utilities in the CGR	SB 100 planning	CEC Gas System Reliability Assessments
Forecast period	15+ years	2050	Next winter or summer
Update cycle	Every two years	Every two years	Twice per year
Products	Annual sales and consumption	Annual sales and consumption	Monthly peak day demand; Same 1-in-X metrics reported in CGR
Scenarios	Energy efficiency, fuel substitution, transportation electrification	Energy efficiency, fuel substitution, transportation electrification, hydrogen	None
Gas for Electricity Generation	Not included	Not included	Included

IEPR Gas Demand Forecast

AAEE/AAFS Load Modifiers Framework

CEC Load Modifiers: Additional Achievable Framework & Scenarios

- **Additional Achievable framework:** is applied to energy efficiency, fuel substitution, and transportation electrification for the IEPR demand forecast.
- The **additional achievable** scenarios capture a range of incremental market potential impacts, beyond what is included in the baseline demand forecast, but they are within the range of what is reasonably expected to occur.

Additional Achievable Scenarios

AAEE 1, AAEE 2, AAEE 3, AAEE 4, AAEE 5, AAEE 6

AAFS 1, AAFS 2, AAFS 3, AAFS 4, AAFS 5, AAFS 6

← Conservative Optimistic →

AAFS Modeling Framework

Baseline gas demand forecast generated using CEC's sector-based models using economic and demographic input data

Load Modifier Label	Modeling Component(s)	Description	Set of Scenarios Modeled
PiCS AAEE	Programs and incremental Codes & Standards (PiCS)	AAEE gas and electricity savings from PiCS	**PiCS AAEE** Scenarios 1-6
PiCS AAFS	PiCS	AAFS gas and electricity impacts from PiCS	**PiCS AAFS** Scenarios 1-6
FSSAT AAFS	PiCS and Zero-emission (ZE) appliance adoption modeling	Gas and electricity impacts from ZE appliance adoption above and beyond those realized in the PiCS scenarios	**IEPR AAFS** Scenarios 1-6

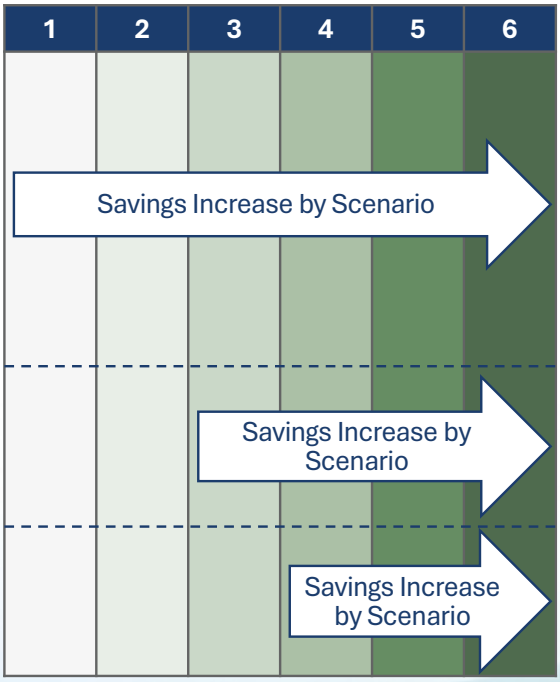
IEPR AAFS Gas Scenario = Baseline + f(PiCS AAFS + FSSAT AAFS + PiCS AAEE)

IEPR Gas Demand Scenarios

Characterization and Results of 2023 and 2024 AAFS Scenarios

2023 IEPR	CARB Scoping Plan	2024 IEPR
• 2023 Baseline • GT AAFS ("AAFS 2.5") • AAFS 3 ("Planning") • AAFS 4 ("Local Reliability")	Proposed Scenario • Gas only • Gas, Hydrogen, and Biogas	• **2023 Baseline** • **AAFS 2** • **AAFS 3 ("Planning")** • **AAFS 4 ("Local Reliability")**
Market impacts presented at the June 6 IEPR Gas Price Outlook Workshop	Market impacts presented at the June 6 IEPR Gas Price Outlook Workshop	**Market impacts will be presented today by Anthony Dixon**

AAEE Modeled in 2023



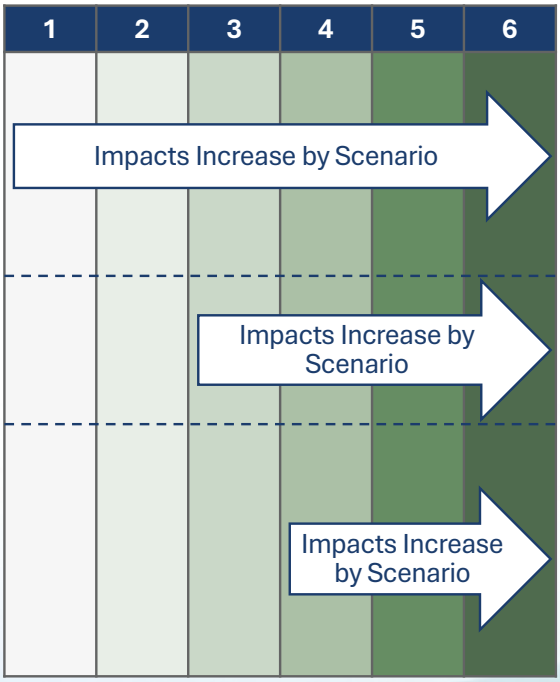
← **AAEE Scenarios**

- **IOU energy efficiency programs**
- **POU energy efficiency programs**
- CCA/RENs
- **Title 24 Res and Non-Res NC and A&A**
- **Building Initiative for Low-Emissions Development (BUILD)**
- **Local Government Ordinances**
- Greenhouse Gas Reduction Fund LI Weatherization
- Energy Conservation Assistance Act (ECAA) Financing
- Property Assessed Clean Energy (PACE) Financing

- **Federal Appliance Standards**
- **Home Efficiency Rebates (HOMES) IRA Incentive Program**
- Energy Asset Rating
- Smart Meter Data Analytics

- **Title 20 State Appliance Standards**
- Industrial and Agricultural Potential
- Clean Energy Reliability Investment Plan (CERIP)
- Conservation Voltage Reduction

PiCS AAFS Modeled in 2023



← **AAFS Scenarios**

- **IOU fuel substitution programs**
- **POU fuel substitution programs**
- CCA/RENs
- **Title 24 Res and Non-Res NC and A&A**
- Targeted Electrification
- Affordable Housing and Sustainable Communities

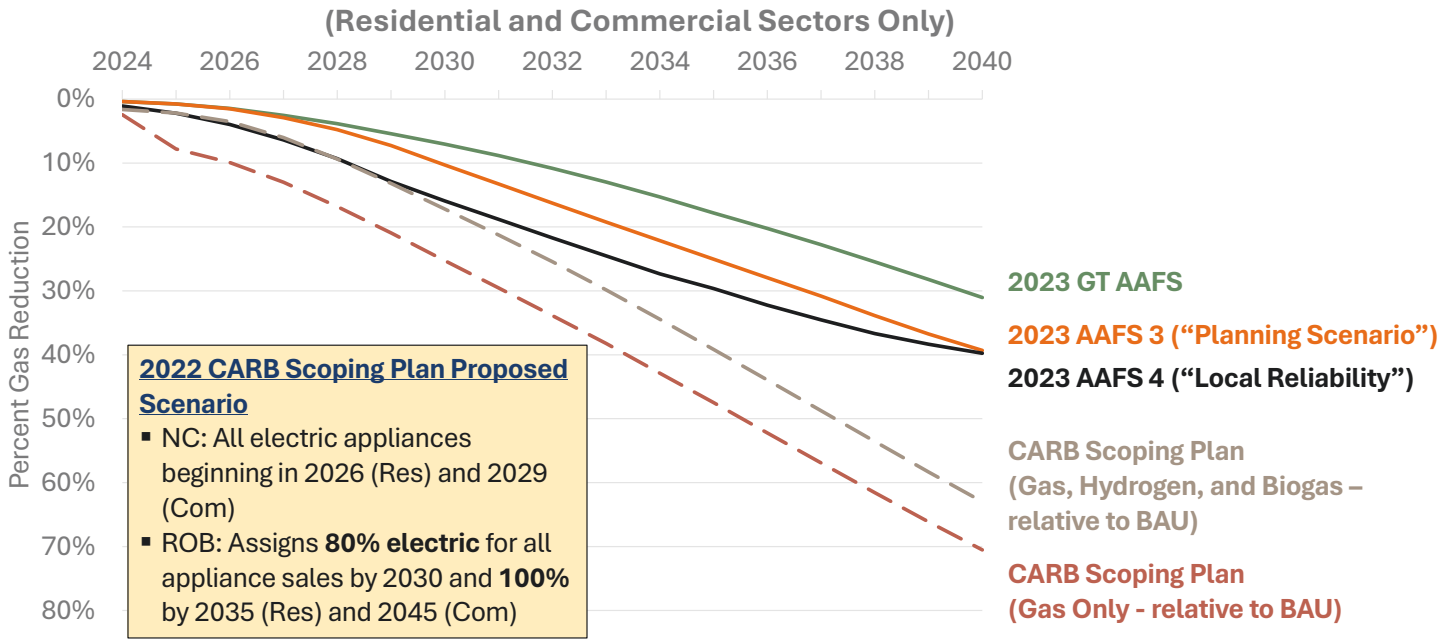
- **TECH Clean California**
- California Electric Homes Program
- Wildfire and Natural Disaster Resiliency Rebuild

- **Equitable Building Decarbonization (EBD)**
  - **IRA Incentive Program**
  - **CEC's EBD Program Direct Install & Tribal Direct Install**
  - **EBD Non-IOU TECH**
- Food Production Investment Program
- Self-Generation Incentive Program HPWH
- Local Governments Challenge

Summary of FSSAT AAFS characterizations

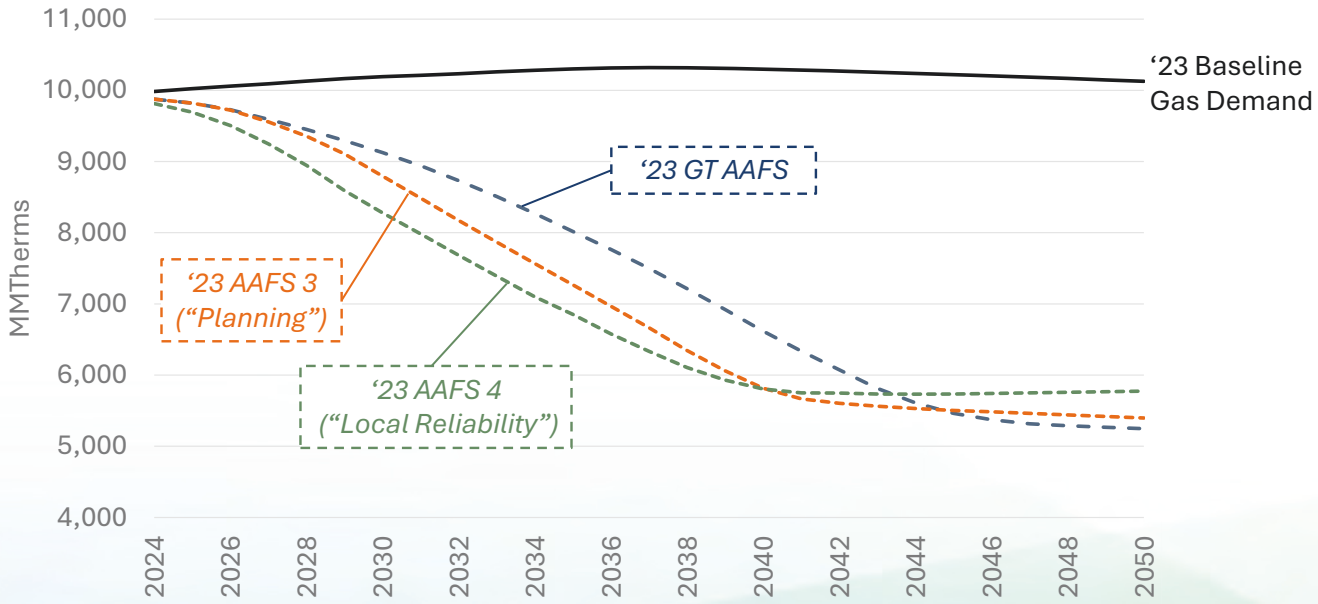
IEPR	IEPR AAFS Scenario	PiCS Scenarios	ZE Appliance Statewide Adoption Description (All include NC adoption and various AQMD zero-NOx regulations)
2023	GT AAFS ("AAFS 2.5")	AAEE 3 PiCS AAFS 3	100% by 2040 ROB adoption rate
2023	AAFS 3 ("Planning")	AAEE 3 PiCS AAFS 3	CARB's concept of 2030 ZE SH and WH appliance standards (with a slower ramp-up rate to 2030)
2023	AAFS 4 ("Local Reliability")	AAEE 2 PiCS AAFS 4	CARB's concept of 2030 ZE SH and WH appliance standards
2024	**AAFS 2**	**AAEE 2 PiCS AAFS 2**	**100% by 2040 ROB adoption rate**
2024	**AAFS 3 ("Planning")**	**AAEE 3 PiCS AAFS 3**	**Earlier and staggered compliance date schedule for CARB's concept of ZE SH and WH appliance standards**
2024	**AAFS 4 ("Local Reliability")**	**AAEE 2 PiCS AAFS 4**	**Earlier and staggered compliance date schedule for CARB's concept of statewide ZE SH and WH appliance standards**

Comparing 2023 IEPR and CARB Scoping Plan



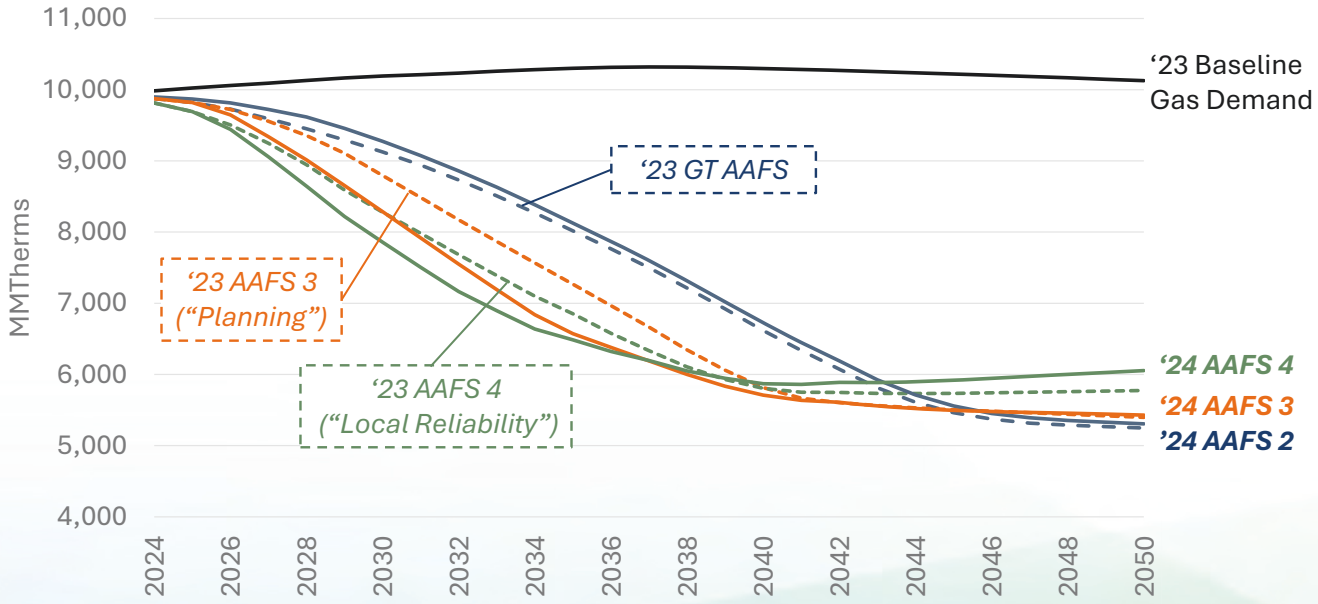
Source: CEC Staff

2023 AAFS Gas Demand Scenarios



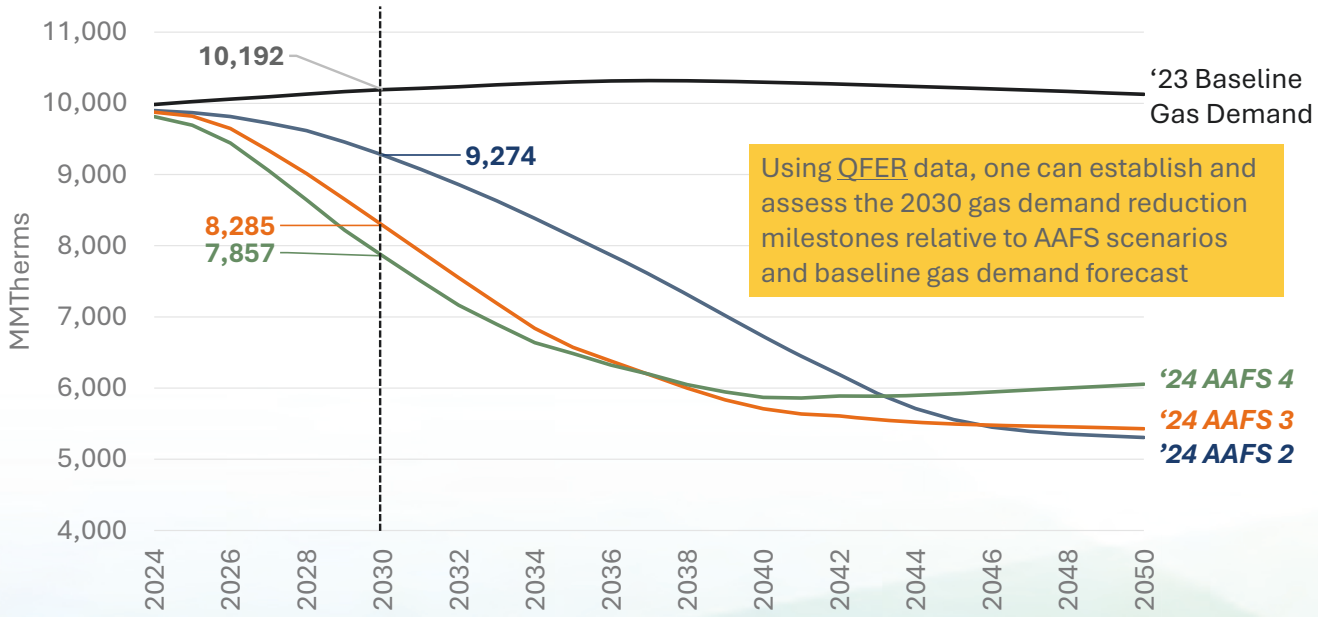
Source: CEC Staff

2023 & 2024 AAFS Gas Demand Scenarios



Source: CEC Staff

2030 Gas Demand Reduction Milestones Based on 2024 AAFS Gas Demand Scenarios



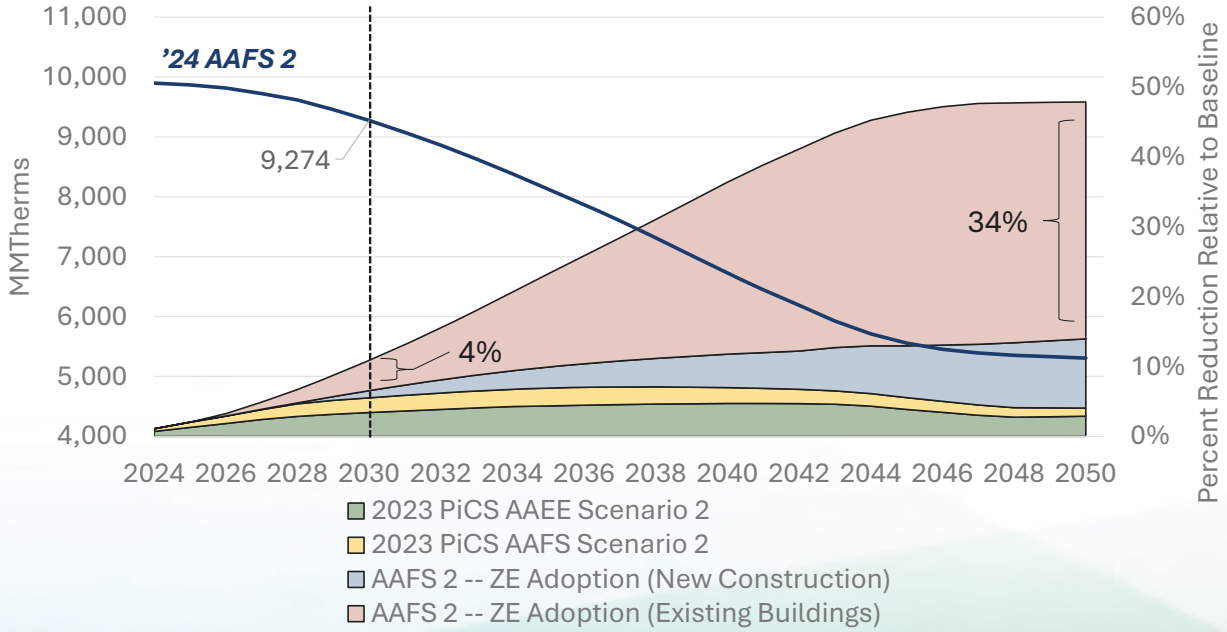
Using QFER data, one can establish and assess the 2030 gas demand reduction milestones relative to AAFS scenarios and baseline gas demand forecast

Source: CEC Staff

2030 Gas Reduction Milestones: Pair with CEC's Heat Pump Tracking Efforts

- CEC staff currently has an unofficial estimate as of Q2 2025
- Increasing agency-wide efforts in tracking equipment, particularly heat pumps
  - Existing available data sources
  - Energy Data Collection Phase 3 – Space Conditioning And Water Heating Equipment Data Tracking
  - AMI data
- Dashboard in development with planned quarterly updates
- Latest estimate in 2025 IEPR analysis

The Major Gas Reduction Components: 2024 AAFS Sc. 2 (100% ROB adoption by '40)

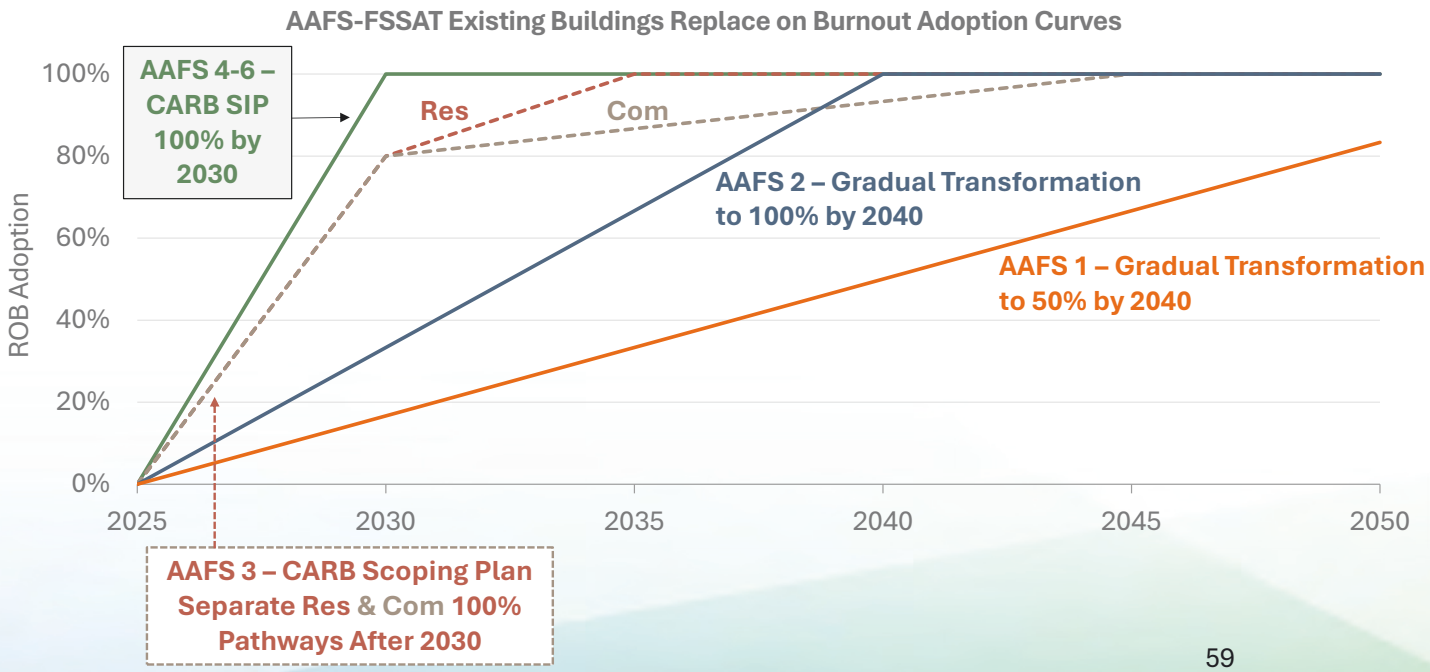


Source: CEC Staff

2025 IEPR Gas Demand Forecast

Draft Characterization of 2025 AAFS Scenarios

Proposed 2025 AAFS Scenario Replace-on-Burnout Adoption Curves



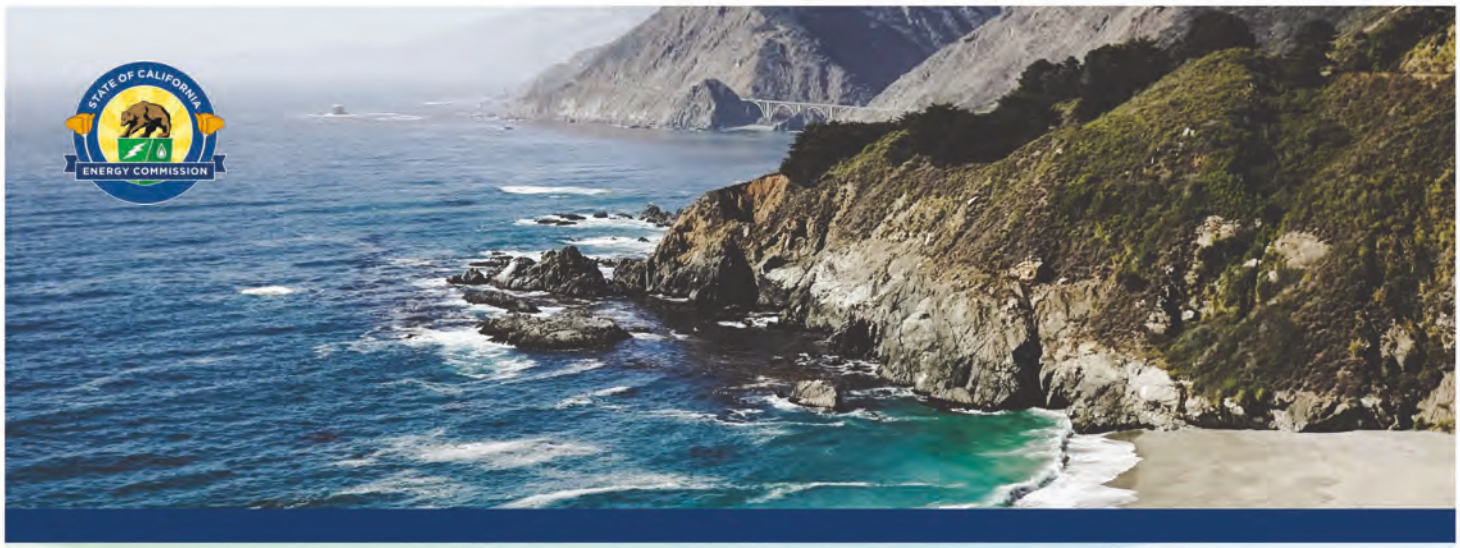
Thank You!

Nicholas Janusch, Ph.D.
Program and Project Supervisor
Advanced Electrification Analysis Branch
nicholas.janusch@energy.ca.gov

Appendix

Helpful AAEE/AAFS Resources

Reference	Description
2023 AAEE and PiCS AAFS Workbooks	A detailed workbook of AAEE and AAFS PiCS characterizations is available here: 2023 AAEE & PiCS AAFS Scenario Characterization Workbook. TN# 262297. Docket Number 24-IEPR-03. March 21, 2025.
2024 FSSAT AAFS Assumptions	A detailed workbook of FSSAT AAFS Assumptions used for 2024 IEPR Update is available here: FSSAT AAFS Assumptions used for 2024 IEPR Update. TN# 260687. Docket Number 24-IEPR-03. December 12, 2024.
2025 IEPR Demand Forecast	For the 2025 IEPR California Energy Demand Forecast Proceeding, please go here.



California Energy Commission

Fossil Gas Total Customer Rates

Presenter: Anthony Dixon, Energy Assessments Division

Date: September 22, 2025

Fossil Gas Resource Planning and Reliability Analysis

Gas Market Assessments

- Tracking national and international market developments
- Forecasting total customer rates
- Tracking revenue requirements

Gas System Assessments

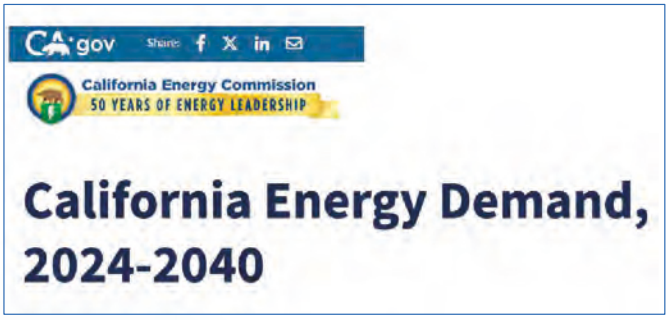
- Tracking gas system operations
- Assessing system reliability
- Assess long-term gas planning scenarios

Further Analysis, Information, and Support

- Daily tracking and reporting of gas system operations
- Assessing future pathways for low-carbon fuels
- Technical support during emergencies

Purpose

- Total Customer Rates modeling process
- California total customer rates with CED Fossil Gas Demand Forecast



Total Customer Rates

Transportation Rate
- Cost to deliver gas from pricing hub to end users

+

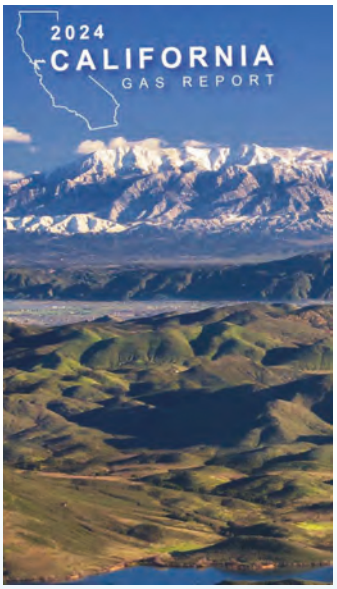
Commodity Price
- Wholesale, pass-through cost
- North America-wide market

=

Total Customer Rate

Final price customer pays for gas
- Electric Generators
- Residential
- Commercial
- Industrial

Total Customer Rates Users



State Energy Entities

- CEC
- CPUC
- California ISO

Outside Stakeholders

- Gas Utilities
- Western Electricity Coordinating Council
- Northwest Public Power Association
- Environmental Groups
- Universities and Consultants

California Utilities Transportation Rate Model

Revenue Requirement × Class Allocation ÷ Demand = Transportation Rate

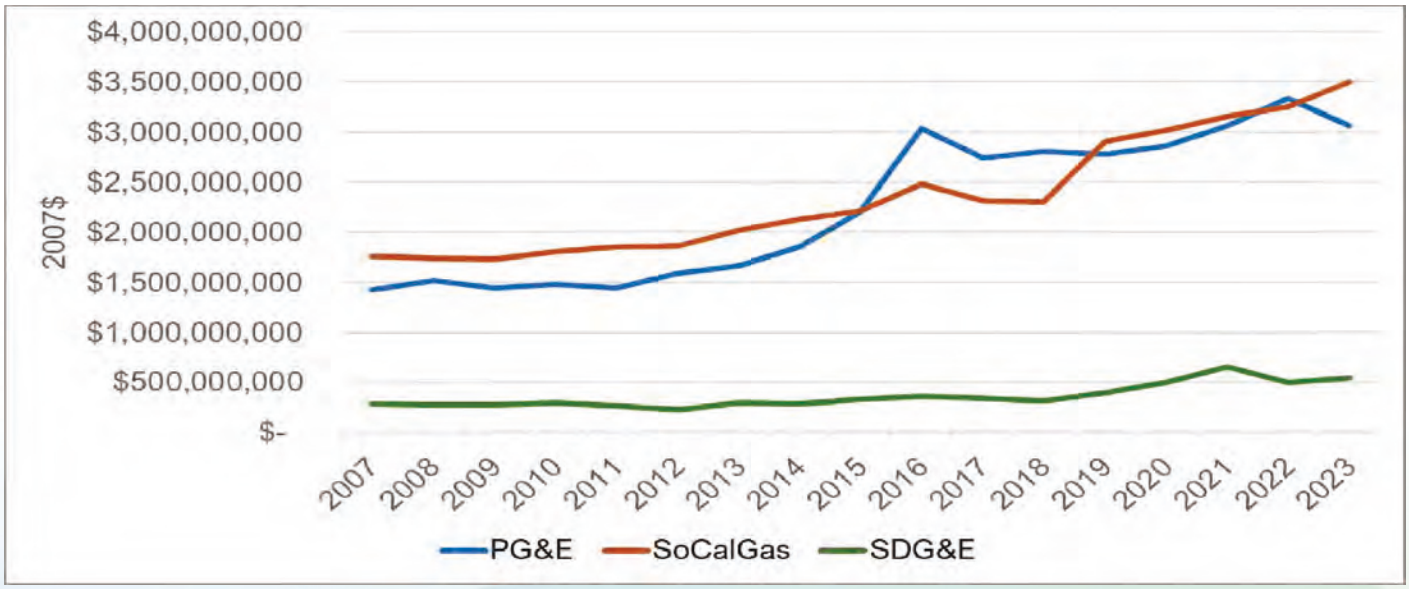
Transportation Rates Approach

Revenue Requirement (RR) x Class Allocations / Demand = Transportation Rate

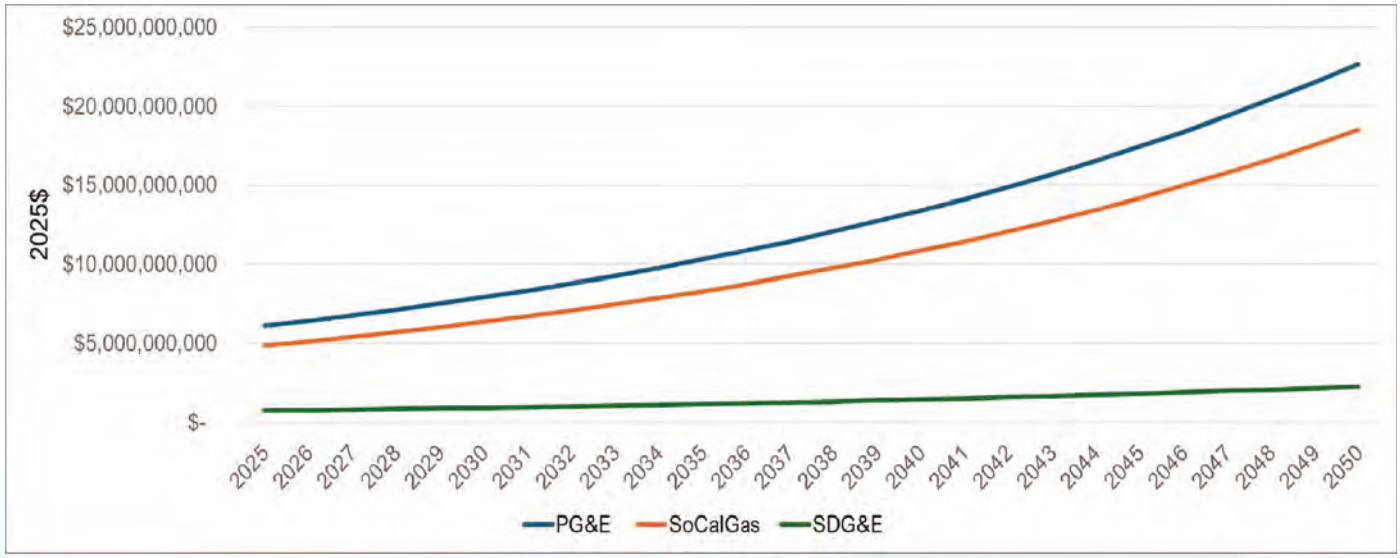
- Revenue Requirement – amount of money a utility needs to operate their fossil gas system.
  - Includes operation and maintenance (O&M), capital investments, administration costs, taxes, interest, profits.
  - Comes from utilities' January of modeling year, 2025 in this case, advice letters
  - Modeled using base year amount (see above) and constant growth rate
- Class Allocations - portion of the total RR that each class pays.
  - Comes from utilities' January of modeling year, 2025 in this case, advice letters
  - Held constant
- Demand is the 2023 CED Base Demand Case, and the three 2024 CED forecasts (AAFS, Planning Are, Local Reliability)

Historical Revenue Requirements

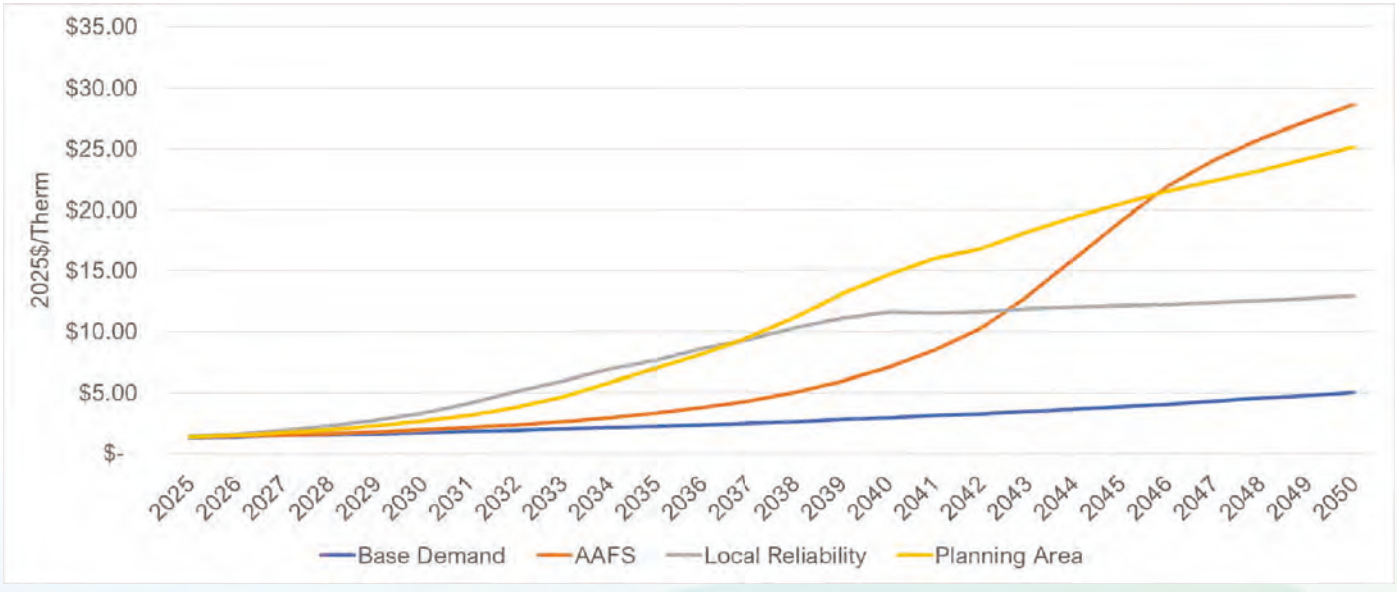
Historical Revenue requirement for the three major CA gas utilities (2007-2023):



Revenue Requirements: Constant Growth



CUTR: Residential Transportation Rates Results for SoCalGas



FGCP Modeled Pricing Hubs

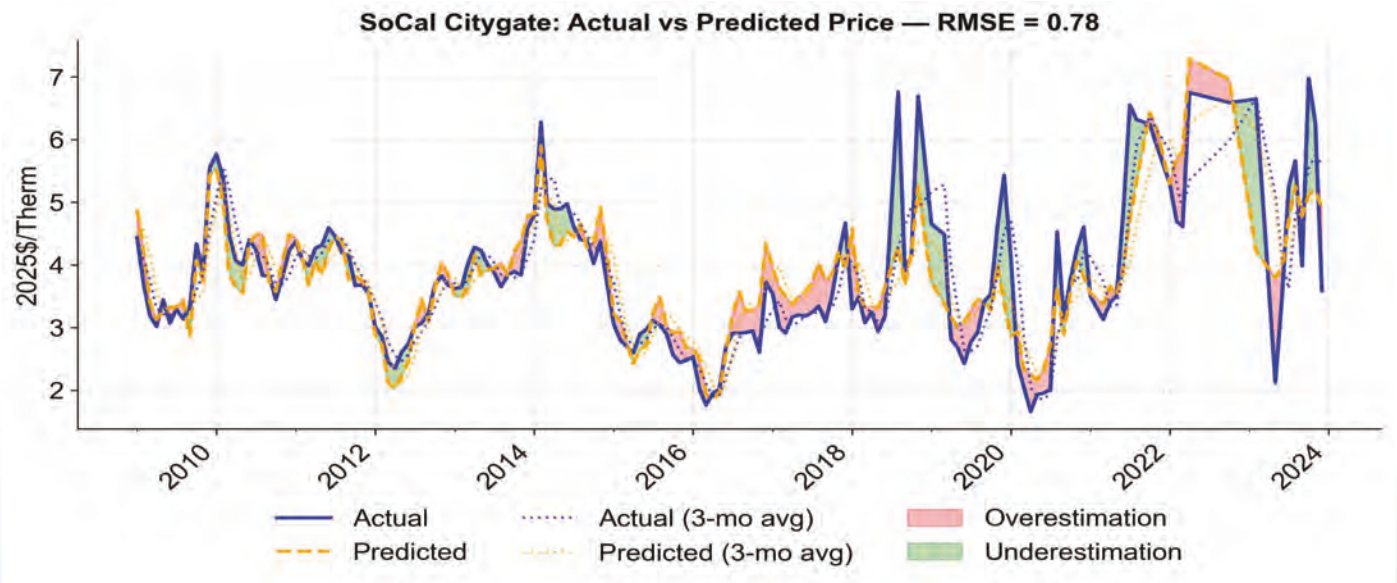
FGCP: Data Used

Data	Data Source	Description	Function in model
Henry Hub spot price	Energy Information Administration (EIA)	• National benchmark for fossil gas prices • Historical monthly data on prices, volumes, and deals • Yearly forecasted price data	The Henry Hub price serves as the benchmark for U.S. natural gas and is linked to multiple interstate and intrastate pipelines. The model uses it to constrain hub price predictions within a reasonable range.
Natural Gas Trading Volume	Natural Gas Intelligence (NGI)	• Historical Daily Hub Data	Volume reflects the 'hub' attribute, enabling the model to capture hub-specific traits, enhance prediction accuracy, and produce more representative forecasts.
Nationwide electricity retail price	EIA	• Historical state-level monthly data • National yearly forecasted price data	The model uses it to represent the 'state' attribute of various hubs, enabling differentiation of commodity price trends across states during prediction.

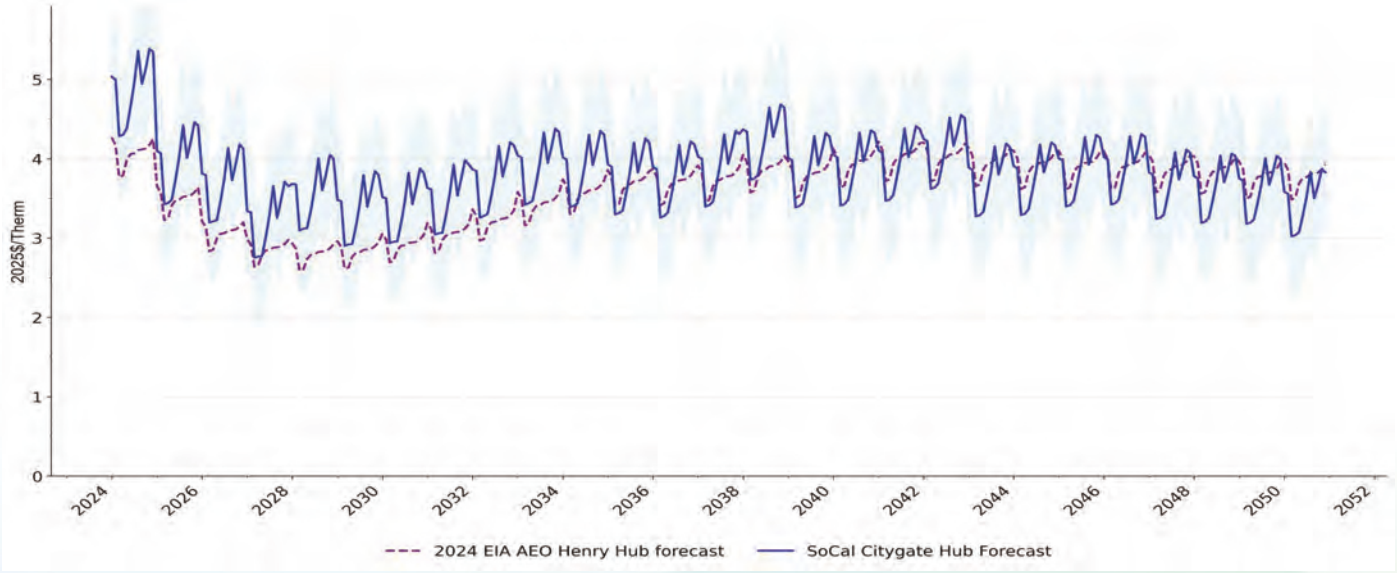
FGCP: Data Used Continued

Data	Data Source	Description	Function in model
Electricity generation from NG	EIA	• Historical state-level yearly data	Serves the same function as the 'Nationwide Electricity Retail Price'.
Renewable energy consumption	EIA	• Historical national monthly data • National yearly forecasted price data	Renewable energy consumption influences natural gas prices by affecting demand, helping the model generate more realistic price predictions.
Heating and cooling degree days	National Ocean and Atmospheric Administration (NOAA)	• Historical state-level yearly data	Functions similarly to the 'Nationwide Electricity Retail Price' and 'Renewable Energy Consumption' regressors.

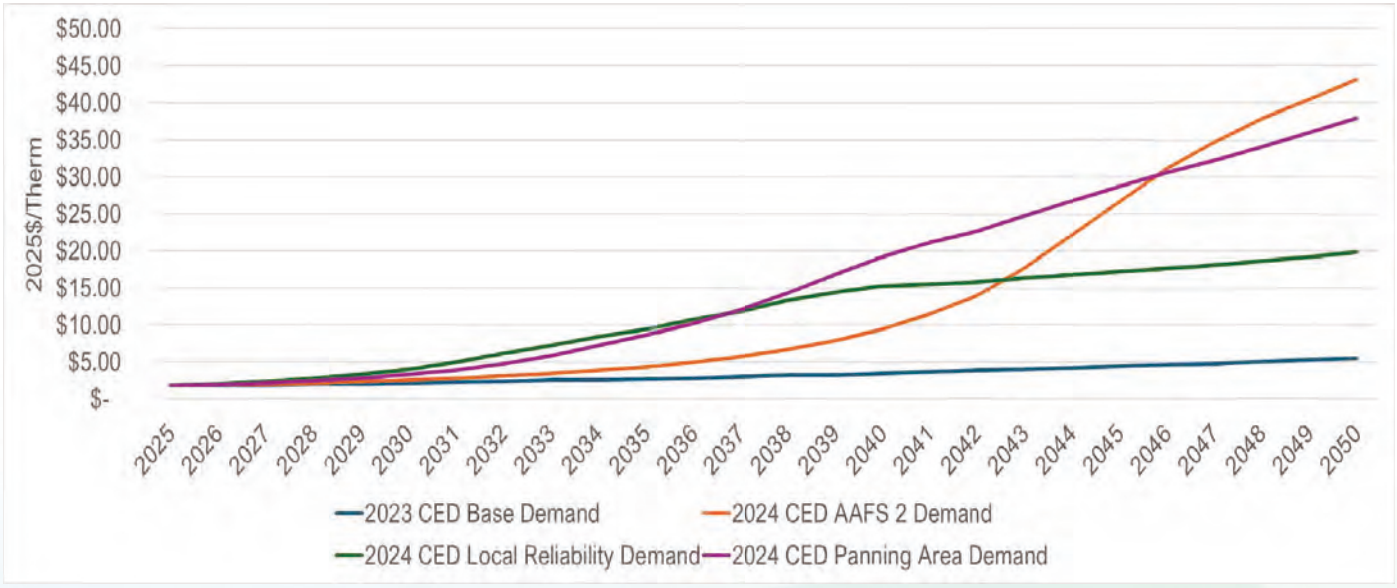
FGCP: Verifying Model's Accuracy



FGCP: Results for SoCal Citygate



Total Customer Rates: SoCalGas Residential



Fossil Gas Total Customer Rates

Thank You!

Questions?

Gas Distribution Infrastructure Replacement

Identifying Cost-Effective Decarbonization Opportunities

CPUC Energy Division Staff Presentation
Eileen Hlavka

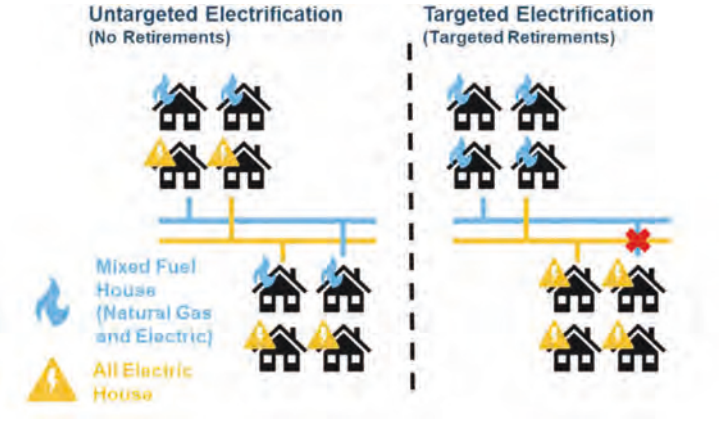
September 22, 2025

California Public Utilities Commission

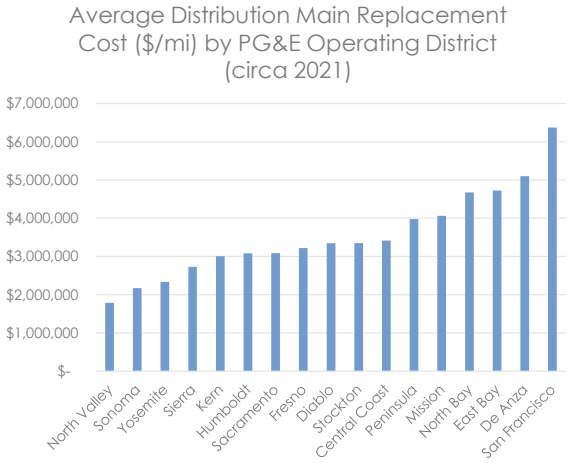
Agenda

- Context
- Major Gas Distribution Infrastructure Replacement Activities
- Distribution Mains and Services Replacement
  - Overview
  - Site Selection
  - Customer and Jurisdiction Consent
  - Cost Estimation
- Services-Only Replacement
- Regulator Station Replacement

Prior Discussions Identify Neighborhood Decarbonization as Cost-Savings Opportunity



Source: E3



Source: PG&E census tract data submitted in proceeding

Major Gas Distribution Replacement Programs

Infrastructure Replaced	GRC Rate Codes			Units of Work
	PG&E	SoCalGas/SDG&E	Southwest Gas	
Mains and Services	14A (Aldyl-A), 14D (aging steel), 50A (other)	VIPP (Aldyl-A) and BSRP (aging steel) in 277, other (252, 253, 255, 267, 278)	TPRP (plastic) and VSP (aging steel) in 9636 and 9605	Work order, aka site
Services Only	50B	256, 257, 258, 260	COYL (customer-owned) Program	Work order, aka site
Regulator Station Replacement	50C	Rebuilds within 265	NA	Regulator station

Mains and Services Replacement Process

What is gas distribution mains and services pipeline replacement?

- **Routine replacement of gas distribution main pipelines, and usually, the services connected to them**
- New pipe laid alongside existing pipe, connected at project endpoints, old pipe disconnected. Also includes site access and restoration (repaving etc.)
- Occupational hazards mitigated: noise, gas exposure, explosion risk

Mains and Services Replacement Aspects

- Each utility conducts an iterative review of its distribution pipelines to identify and replace the highest-risk segments
  - Process initiated **annually** by some utilities or at their discretion up to every four years;
  - Site completion is **staggered**: each work order may occur one to four years later, depending on site-specific factors
- A single "work order" or site may be hundreds of feet to thousands of feet long

Caveat to upcoming timing slides: Timelines for each step may vary from project to project as well as utility to utility, and steps may overlap.

Key Mains and Services Replacement Steps

Utility Action	Approx Time Before Breaking Ground
Site Selection: Prioritization by Calculated Risk	**1-2 years, up to 4 years**
Site Selection: Prioritization by Observation	**1-2 years, up to 4 years**
Initiation: Site Selection: Site Boundary Adjustment and Mapping	12-18 months (6-9 months for SWG)
Initiation: Consider Contacting Agencies and Landowners	12-18 months
Initiation: Scheduling	12-18 months
Execution: Apply for Permits	3-6 months
Execution: Landowner Contact for Consent	0-6 months
Execution: Customer Informational Alert	1-2 weeks
Execution: Online Public Alert (Southwest Gas only)	1-2 weeks
Execution: Construction and Restoration	0
Completion	2-12 weeks after beginning construction
Reconciliation	4-28 weeks after construction

Key Steps: Site Selection

- Sites typically selected at least 1-2 years in advance of target completion date, for risk-based programs
  - Some projects are delayed by months or years based on consent and feasibility
- Can be selected farther in advance using same software
  - SB 1221 maps show just that
- Project boundaries are routinely adjusted
  - Thus implying some adjustment is also acceptable for decarbonization

Key Steps: Customer and Jurisdiction Consent

- Consent processes already exist but do not apply to most customers or incorporate discussion of non-gas options
- Landowner consent, if needed, occurs on multiple timelines and pathways
- Local jurisdictions have permitting authority over projects
- While landowner consent may be required, in many cases it is not, so most customers are not notified well in advance
- Online mapping of upcoming sites is conducted by Southwest Gas only

Key Steps: Cost Estimation

- Cost estimates available early based on project definition
  - Utilities typically have equations for conducting these estimates at two different levels of granularity
- Precise costs not known until after project is completed

Services-Only Replacement

- Funded by dedicated General Rate Case codes
- Replaces only gas services, one at a time
- Follows similar procedures and costs to mains and services replacement
- May have shorter timelines due to fewer customers per site
- PG&E 2023 General Rate Case decision redirected funds disallowed for service replacement ($10.3 million in 2023) to be used for its Alternative Energy Program (AEP)

Note: PG&E's Alternative Energy Program, which fully funds electrification in selected sites of up to 5 customers where large gas investments can be avoided, requires customers to identify their own electrification vendors and typically takes 4-6 months from customer contact to completion.

Gas Distribution Regulator Station Replacement

- One or more gas distribution regulator stations serve a group of customers on interconnected mains and services called a "pressure district" by reducing pressure from upstream lines to mains and services that reach customer meters
- Not to be confused with larger upstream regulator stations
- **Replaces most major equipment** at station: piping and valves for flow control, measurement, and release, and may relocate station nearby
- **Constitutes an additional cost-saving opportunity** if can be avoided

Gas Distribution Regulator Station Replacement Process

- Stations are typically inspected annually and scheduled for replacement based on assessed risk ranking
- PG&E and SoCalGas/SDG&E together replaced about 25 stations per year in 2021-2024 (excluding High-Pressure Regulator or HPR-type stations)
- On average, it takes more than two years from identification for replacement to breaking ground

For more information:
eileen.hlavka@cpuc.ca.gov

Reference Slide: Site Selection

Utility Action	Details
Site Selection: **Prioritization by Calculated Risk**	Use utility-specific DIMP software to identify sites for **aldyl-A and aging steel replacement programs**.
Site Selection: Prioritization by Observation	Use leak surveys, observation to ID sites for other main and service replacement programs.
Initiation: Site Selection: Site Boundary Adjustment and Mapping	Propose site boundary/scope of work order by potentially **adjusting initial boundaries**, including changes based on cost, grouping nearby sites, and reduction of environmental impacts.

- Sites typically selected at least 1-2 years in advance of target completion date, for risk-based programs
  - Some projects are delayed by months or years based on consent and feasibility
- Can be selected farther in advance using same software
  - SB 1221 maps show just that
- Project boundaries are routinely adjusted
  - Thus implying some adjustment is also acceptable for decarbonization

Reference Slide: Customer and Jurisdiction Consent

Utility Action	Approx Time	Communication Details
Initiation: Consider Contact	**12-18 months**	Contact landowners or permitting agencies **in complex cases**, e.g., mobile home park or creek crossing.
Execution: Apply for Permits	3-6 months	Apply to site city and county for construction permits. Seek any environmental permits.
Execution: Landowner Consent	3-6 months	Landowners only contacted for consent (easement, ROW) if they are not the customers, e.g., a service passes through neighboring land.
Execution: Customer Info Alert	1-2 weeks	Customers alerted of work at their location via **door hangers, mailers or forums**
Execution: Online Public Alert (**SWG only**)	1-2 weeks	Post to online map, https://www.swgas.com/en/construction-projects.

- Consent processes already exist but do not apply to most customers or incorporate discussion of non-gas options
- Landowner consent, if needed, occurs on multiple timelines and pathways
- Local jurisdictions have permitting authority over projects
- While landowner consent may be required, in many cases it is not, so most customers are not notified well in advance
- Online mapping of upcoming sites is conducted by Southwest Gas only

Reference Slide: Cost Estimation

Utility Action	Approx Time	Site Costs
Site Selection: Prioritization	1-2 years, up to 4 years	**Estimate costs** defined by main pipeline length, # services, and service density, by operating district. Estimate using last 3 years of historical data. Serves as a target to keep costs, on average, at GRC allocation level.
Site Boundary Adjustment and Mapping	12-18 months (6-9 months for SWG)	**Estimate precise costs** based on scope of work, incl pipeline length, diameter, material, depth, valve count, paving and prelim envl requirements, site operating district, and other work characteristics, aka unit costs. Costs also depend on whether done by utility or contracted out. Sites will cost this amount unless something changes.
Execution: Construction and Restoration	0	Actual costs incurred. **Costs may change** from estimates if unexpected site conditions discovered (e.g. groundwater).
Completion	2-12 weeks later	Contractors paid most costs.
Reconciliation	4-28 weeks later	**Final costs recorded** and contractors paid.

- Cost estimates available early based on project definition
  - Utilities typically have equations for conducting these estimates at two different levels of granularity
- Precise costs not known until after project is completed

Reference Slide: Key Main and Service Replacement Steps

Utility Action	Approx Time Before	Details	Site Costs
Site Selection: Prioritization by Calculated Risk	1-2 years, up to 4 years	Use utility-specific Distribution Intregity Management Program software to rank potential sites based on main risk. Identifies sites for aldyl-A and aging steel replacement programs.	Estimate costs defined by main pipeline length, number of services, and density of services, by operating district. Estimate using last 3 years of historical data. This estimate serves as a target to keep costs, on average, at the level allocated for in GRCs.
Site Selection: Prioritization by Observation	1-2 years, up to 4 years	Identify additional potential sites based on leak surveys and other in-person observation. Applies to other main and service replacement programs.	Estimate costs defined by main pipeline length, number of services, and density of services, by operating district. Estimate using last 3 years of historical data. This estimate serves as a target to keep costs, on average, at the level allocated for in GRCs.
Initiation: Site Selection: Site Boundary Adjustment and Mapping	12-18 months (6-9 months for SWG)	Propose final mix of sites balancing risk, cost and labor resources. Propose final site boundary/scope of work order by potentially adjusting initial boundaries, including changes based on cost, grouping nearby sites, and reduction of environmental impacts. Identify affected services.	Estimate precise costs based on scope of work, including pipeline length, diameter, material, depth, valve count, , paving and prelim environmental requirements, site operating district, and other work characteristics, aka unit costs. These costs also depend on whether done by utility or contracted out. Sites will cost this amount unless something changes.
Initiation: Consider Contacting Agencies and Landowners	12-18 months	Contact landowners or permitting agencies in complex cases, e.g., mobile home park or creek crossing.	
Initiation: Scheduling	12-18 months	Identify target construction month (subject to change).	
Execution: Apply for Permits	3-6 months	Apply to site city and county for construction permits. Apply for any applicable environmental permits.	
Execution: Landowner Contact for Consent	0-6 months	Landowners only contacted for consent (easement, right of way) if they are not the customers, e.g., a service passes through neighboring land.	
Execution: Customer Informational Alert	1-2 weeks	Customers alerted of work expected at their location via door hangers, mailers or forums, depending on site or program. On-site gas tanks mean work usually does not interrupt their gas flow. No broader public notification.	
Execution: Online Public Alert (Southwest Gas only)	1-2 weeks	Post to online map, https://www.swgas.com/en/construction-projects.	
Execution: Construction and Restoration	0	New pipe laid alongside existing pipe, connected at project endpoints, old pipe disconnected. Also includes site access.	Actual costs incurred. Costs may change from estimates if unexpected site conditions discovered (e.g. groundwater).
Completion	2-12 weeks after beginning construction	New gas service in operation	
Reconciliation	4-28 weeks after construction	GIS mapping of completed project, quality control review, cost reconciliation, payment of remaining costs and closeout of work order.	Final costs recorded and contractors paid.

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Non-Pipeline Alternatives:

What we can learn from other jurisdictions

Sarah Steinberg, Managing Director

September 22, 2025

New York

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New York's NPA journey began as a tool to address supply and delivery constraints

They have been more recently recognized as a tool for cost-containment and clean energy policy compliance

The New York Times

Con Ed Cuts Off New Gas Hookups in New York Suburb

By Debra West
March 21, 2019

https://www.nytimes.com/2019/03/21/nyregion/con-ed-natural-gas.html

Commission Directs Central Hudson to Take Additional Action to Reduce Natural Gas Demand, Advancing Goals to Maintain Gas System Reliability and Reduce Greenhouse Gas Emissions

July 17, 2025

…Specifically, the Commission directed the company to develop and propose pilot demand response programs and pursue non-pipes alternatives for at least two locations in its service territory.

"The Commission's natural gas planning procedures bring greater transparency to how our gas utilities provide safe, adequate, and reliable service while striving to meet the State's greenhouse gas emissions reduction targets," said Commission Chair Rory M. Christian. **"This process is critical to ensuring reliability and affordability, while advancing State clean-energy policies to combat climate change."**

https://dps.ny.gov/news/groundbreaking-process-continues-advance-gas-system-reliability-and-planning-transparency

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Early NPAs used competitive solicitations to build portfolios of projects to serve specific gas system needs

conEdison

Projects

SOUNDVIEW DISTRIBUTION SYSTEM REINFORCEMENT

PORTCHESTER DISTRIBUTION SYSTEM REINFORCEMENT

WHOLE BUILDING ELECTRIFICATION SERVICES

NYSEG NPA process (2019-2021)

2019: NYSEG found that growth on gas distribution system led to too-low delivery pressures during peak conditions in Lansing, NY

December 2019: NPA RFP for innovative solutions to defer or avoid the need for construction of a Reinforcement Gas Pipeline Project via demand reduction or equivalent supply

March 2020: 16 proposals received, including: heat pumps (air, ground, water, community loop); efficiency measures; hydrogen injection; thermostat DR; industrial heat recovery; CNG and RNG

August 2020: NYSEG petition at the NY PSC proposing 7 projects from the RFP responses: **1) residential heat pumps; 2-3) commercial GSHP; 4) community GSHP; 5) efficiency at two schools; 6) industrial heat recovery; 7) education and outreach**

June 2021: NY PSC approved the petition (with modifications), allowing NYSEG to proceed with contract negotiations

https://www.nyseg.com/ourcompany/reliableservice/reliability-projects/non-pipe-alternatives

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Later programs offer electrification solutions to customers to replace pre-1972 service lines and avoid leak prone pipe replacement

Consolidated Edison's Energy Exchange Program: eliminates replacement of gas services installed pre-1972 by providing customers with electric alternatives for existing gas end-uses (not including space heating) to facilitate their disconnection from the gas system

- ~38,500 buildings identified
- Limited to the first 100 service lines and associated customers that elect to participate in the program

As of November 2024, **three customers are onboarded; one customer has completed gas disconnection.**

Consolidated Edison's Electric Advantage Program: eliminates replacement of leak prone gas mains by providing customers with electric alternatives for all existing gas end-uses to facilitate their disconnection from the gas system

- 2022-2024: 108 projects were feasible and cost effective; 2024 filing: 24 new projects identified

As of November 2024, 30% of projects are in progress (70% have had customer participation challenges)

14 buildings had been electrified on 9 mains.

- **3 mains have been abandoned**
- **2 main abandonments in progress**
- **Partial electrification is complete on 5 additional mains**

Company recruiting at 92 more locations.

ConEdison: Electric Advantage and Energy Exchange BCA framework

Energy Exchange BCA

Table 1: Service Replacement Portfolio and BCA summary

Portfolio Size (# of service replacements avoided)	Total Energy Savings (MMBtu/year)	Total Benefits (NPV to 2024)	Total Costs (NPV to 2024)	BCA SCT Score	Con Edison Investment (NPV 2024)[4]	Customer Portion of Net Benefit (70% of Net Benefits)	Performance Incentive[5] (30% of Net Benefits)
100	2,309	$2,761,110	$1,982,648	1.39	$2,272,912	$544,923	$233,539

Electric Advantage BCA	
Costs	**Benefits**
Additional program participant incentives	Avoided gas consumption in dekatherms and customer savings
Incentive costs from other efficiency and electrification programs	Avoided peak day gas capacity and customer savings
Administration and implementation planning, marketing, reporting, payments to independent contractors for quality control, evaluation, and M&V	An increase in MWh of electric consumption and a decrease in MW in peak electric system load (can be + or -)
	Avoided oil consumption and customer savings
	Net avoidance of CO_2 emissions reductions and benefits in dollars
	Avoidance of the traditional solution in dollars

https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=67367&MNO=22-G-0065 (7/23/2024 BCA filings and 11/18/2024 NPA Annual Report)

Colorado

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Colorado comes to NPAs via gas system planning and a desire to contain infrastructures costs while meeting state decarbonization goals

Rules include requirement for NPA analyses for all "new business" and "capacity expansion" projects included in the plan (minimum cost threshold of $3 million for projects *and* sets of interrelated projects).

Commission decision on April 3, 2024 "strongly encourage[s]" the Company to include NPA analyses for system safety and integrity projects

Creation of a CBA Handbook with stakeholder input; decision acknowledging factors beyond the CBA: stranded asset risk, commodity cost uncertainty (particularly in extreme weather), locational characteristics, unquantified health impacts

2021: The Commission hosted a "miscellaneous" docket to review gas utility regulation (21M-0395M)

↓

2021: The Colorado legislature passes SB 264 establishing Clean Heat Plans for gas utilities and HB 1238 modifying gas demand side management programs and the Commission opens 21R-0449G to implement rules

↓

2022: Commission finalizes rules after receiving 300+ comments, hosting various public comment sessions, and redlining versions of draft rules

↓

2023: Public Service Company of Colorado files its first (non-adjudicated) Gas Infrastructure plan (23M-0234G)

↓

2024: Commission opens an M-docket to focus on utility forecasting, mapping, and **NPA CBA** to improve 2025 filing (24M-0261G)

↓

2025: Public Service Company files its second (adjudicated) Gas Infrastructure Plan (25A-0220G) and **Mountain Energy NPA CPCN** (25A-044EG)

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Public Service Company's NPA Development Process starts with GIP project identification.

STEP ONE: Identify projects by category and timeline

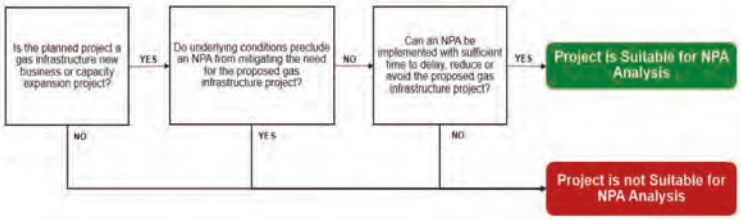
Table 4:
2025 GIP Planned Projects ($/Millions)

	Action Period				Informational Period						
Planned Project Category	2025	2026	2027	No. of Planned Projects	2028	2029	2030	No. of Planned Projects	Total No. Planned Projects	Est. Total Planned Project GIP Period CapEx	Est. Total Planned Project CapEx*
System Safety & Integrity	$67.0	$88.4	$77.5	30	$76.3	$65.4	$32.9	21	51	$407.5	$425.8
Capacity Expansion	$13.1	$75.6	$33.7	2	$0.6	$2.0	$2.6	3	5	$127.5	$135.0
New Business	$25.7	$6.3	$5.4	6	$0.0	$0.0	$0.0	0	6	$37.4	$30.7
Mandatory Relocation	$0.0	$0.0	$0.0	0	$0.0	$0.0	$0.0	0	0	$0.0	$0.0
Planned Projects Total:	**$105.8**	**$170.3**	**$116.6**	**38**	**$76.9**	**$67.4**	**$35.5**	**24**	**62**	**$572.5**	**$591.6**

* Includes capital expenditures for included Planned Projects before GIP Total Period.

STEP TWO: Screen eligible projects

Figure 9: NPA Initial Suitability Criteria Framework



STEP THREE: Evaluate alternatives

Criteria Used to Rank or Eliminate Alternatives	•Technical Potential •Achievable Potential •Cost Benefit Analysis •Best Value Employment Metrics

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The under-review Mountain Energy NPA is the largest NPA to date, impacting over 33,000 customers

PSCo was planning an LNG Hub and Spoke project to serve increasing gas demand in their mountain system.

This traditional project costs up to $328 million.

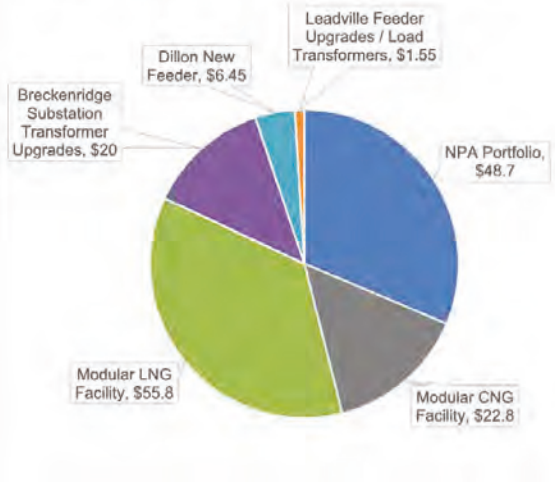
They are seeking approval of an NPA portfolio that include building electrification, demand response, energy efficiency, and smaller CNG and LNG facilities.

The NPA is projected to cost $155 million.

Table 3-1: ME NPA Residential Participation by Type of Measure and Year

ME NPA Residential Measure Type	2025 (Premises)	2026 (Premises)	2027 (Premises)	Totals (Premises)
Energy Efficiency - Non-Equipment	821	1,022	1,271	3,114
Energy Efficiency - Home Energy Reports[2]	~6,000	~6,000	~6,000	~6,000
Energy Efficiency - Equipment	325	413	514	1,252
Building Electrification	54	70	92	216
Demand Response[3]	-	~16,000	~21,000	~21,000

Figure GKJ-D-3:
Hybrid Portfolio Cost Estimates, By Component ($ in millions)



Public Service Company's CBA Framework

PSCo primarily uses the "Expanded, Modified Total Resource Cost" test (EMTRC)

Societal Impact	EMTRC
Incremental Generation Emissions Cost	Included and Quantified
Avoided Methane Leakage Benefit	Included and Quantified
Avoided CO2 Emissions Benefit	Included and Quantified
Incremental Generation Methane Leakage Cost	Included, Not Quantified
Air Pollutants	Included, Not Quantified
Land and Water Impacts	Not Applicable
Workforce Impacts	Not Applicable

Utility Impact	EMTRC
Program Incentive Cost	Not Applicable
Participant Cost	Included and Quantified
Administrative Cost	Included and Quantified
Generation Capacity Cost	Included and Quantified
Transmission Capacity Cost	Included and Quantified
Distribution Capacity Cost	Included and Quantified
Electric Commodity Cost	Included and Quantified
Incremental Line Losses	Included and Quantified
Ancillary Services Cost	Included and Quantified
Winter Mitigation Cost	Included and Quantified
Incremental Gas Infrastructure Cost	Included and Quantified
Avoided Gas System O&M Cost	Included and Quantified
Non-Energy Benefits	Included and Quantified
Net Revenue Impact	Not Applicable
Electric Reliability Cost	Included, Not Quantified
Reliability Benefit	Included, Not Quantified
Higher Utilization of Underutilized Assets	Not Applicable
Avoided Line Extension Subsidies	Not Applicable

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Massachusetts

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The DPU flipped the paradigm, requiring NPAs to be non-viable in order to get cost recovery on traditional gas system investments

- Order 20-80-B in Future of Gas Docket (No. 20-80) (December 6, 2023)

  "Going forward, the Department states that as part of future cost recovery proposals, **LDCs will bear the burden of demonstrating that NPAs were adequately considered and found to be non-viable or cost prohibitive to receive full cost recovery**"

- Order modifying Gas System Enhancement Program (24-GSEP-03) (April 20, 2025)

  "[The DPU will allow] spending in excess of the newly established 2.5 percent revenue cap **up to 3.0 percent for non-pipeline alternatives**, i.e., NPAs, which will encourage gas companies to consider solutions that avoid additional investment in fossil fuel infrastructure"

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Lessons learned

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Key learnings from other states

- NPAs can be a valuable cost-containment mechanism!
- Be expansive in what *types* and *sizes* of projects can become NPAs. Think both ***big*** (Mountain Energy NPA) and ***small*** (Electric Advantage and Energy Exchange)
- ***Early systematic project identification*** is key, whether in the context of an infrastructure plan or by finding projects with similar sets of characteristics
- Competitive solicitations can help utilities identify the lowest-cost solutions, but often require pre-application engagement and then hands-on post-application joint utility-vendor work
- Look for creative ***portfolios of solutions***; don't get too boxed into pre-defined solutions
- Where possible, get stakeholders and the utility on the same page early (outside of litigated dockets)
- Construct CBAs thoughtfully. There is a high risk of double counting electric distribution system costs.
- ***Get started!*** Anything we create now will need iteration, but we'll learn by doing. The CPUC can jumpstart the process by addressing key regulatory hurdles *for now*.

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ssteinberg@advancedenergyunited.org

Thank you.

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Policy Options to Facilitate Non-Pipeline Alternatives

Jalal Awan, Ph.D.

TURN
THE UTILITY REFORM NETWORK

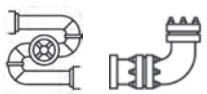
Preliminary Questions & Definitions

❑ <u>What</u> is a Non-Pipeline Alternative (NPA)?

- **Demand-side measures only** (partial/full electrification, EE, DR)*

❑ <u>How</u> to define (gas) "projects" for evaluation?

- **Contiguous pipeline segments** (mains/services)
  - Normalized by a common unit of analysis (e.g. per mile cost and/or risk)

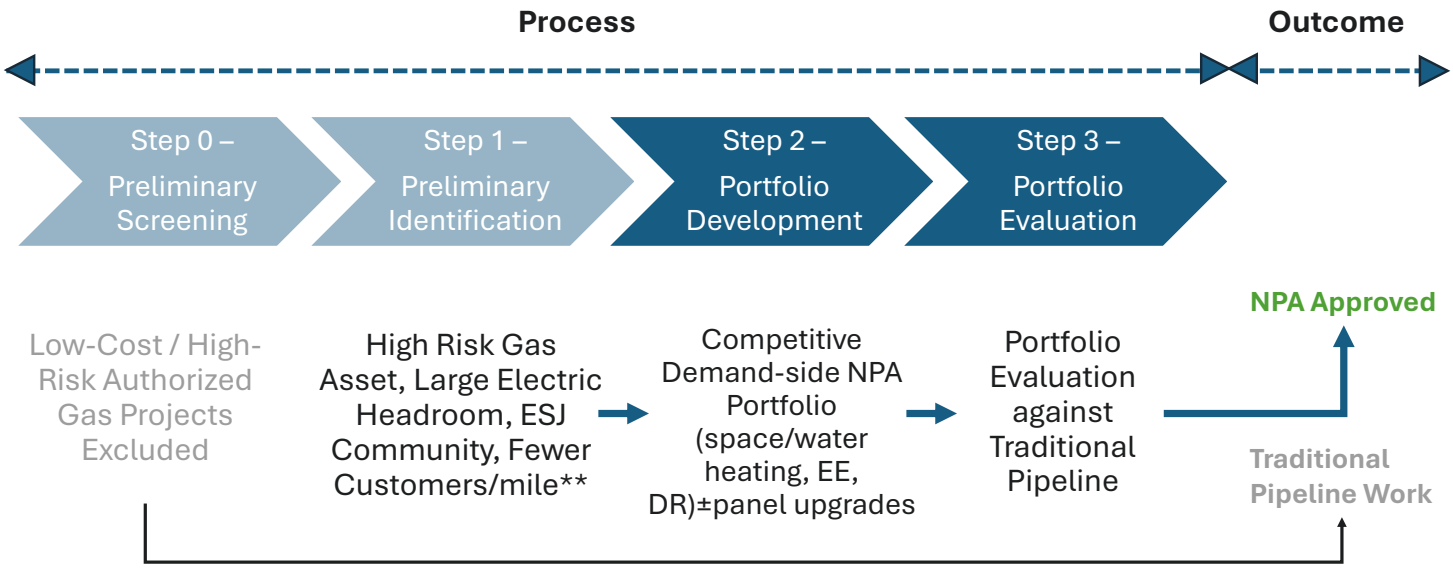


❑ <u>Which</u> risk metrics for 10-year foreseeable replacements?

- **DIMP Risk Ranking** (likelihood * consequence)
- Top X% of mains by DIMP score
- RSE scores
- Others?

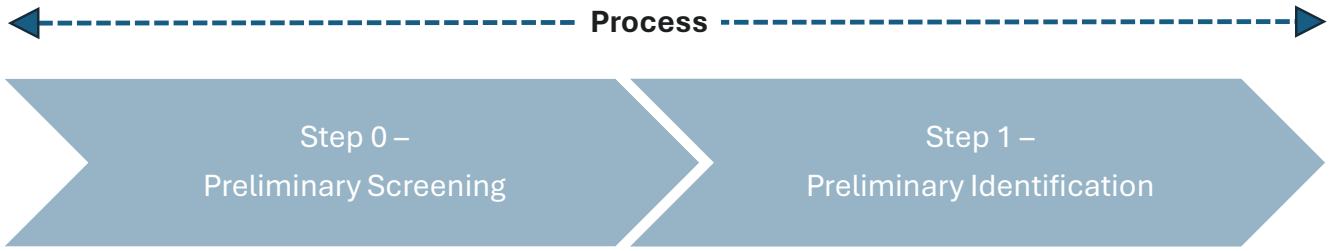
**Supply-side NPAs such as hydrogen blending or biomethane are the subject of separate Commission proceedings (A.22-09-006 and R.13-02-008, respectively)*

Framework for Benefit-Cost Analysis (BCA)*



**This is an illustrative work-flow for a transparent BCA framework. Actual data from IOUs would determine various threshold values.*
*** Lower density sites i.e. fewer customers/mile of gas main exhibit better cost-effectiveness for electrification (E3 / Gridworks)*

Framework for Benefit-Cost Analysis (BCA)



Low-Cost / High-Risk Project Screening

- GRC-approved and/or required by Compliance
- Safety vs. Non-Safety indicator
- *Cost* < *$X* threshold & *Timeline* < *Y* months

Data Source(s): DIMP, GRC/CPCN Applications

High Risk Gas Asset, Large Electric Headroom, ESJ Community

- Top X percentile by DIMP Risk Score (10-year foreseeable)
- Available Load Capacity (ALC) avoids dist. upgrades

Data Source(s): DIMP, ICA Maps, "Project-level" IOU data, CalEnviroScreen 4.0

Framework for Benefit-Cost Analysis (BCA)

Process (contd.)

Step 2 – Portfolio Development

Competitive Demand-side NPA Portfolio (space/water heating, EE, DR)

IOU-proposal | Competitive RFP

Data Source(s): CPUC DEER, TECH, BUILD databases

Step 3 – Portfolio Evaluation

Portfolio Evaluation against Traditional Pipeline

- Use NPV of RRQ w/ avoided gas costs (benefits) vs. total electrification costs*

$$Benefit/Cost_{Net\ Present\ Value} = \frac{\sum_{t=0}^{40}\left[\frac{(Avoided\ Pipeline\ CapEx_t + Pipeline\ O\&M_t)}{(1+0.078)^t}\right]}{2 * \sum_{t=0}^{20}\left[\frac{(Utility\ Investment_t + Participant\ Costs_t + Admin\ Costs_t)}{(1+0.078)^t}\right] - \sum_{t=0}^{40}\left[\frac{(Social\ and\ Environemntal\ Benefits_t)}{(1+0.03)^t}\right]}$$

Data Source(s): TURN recommends using Appendix IV in E3 report on BCA of 11 sites in the Bay Area (2023)

**TURN notes that threshold issues, including but not limited to, cost recovery, BTM treatment may be addressed on an ongoing basis and should not delay the BCA framework.*

Recommendation

TURN recommends that the Commission:

1) Address open definitional questions from this workshop as a priority.
2) Direct Utilities to provide all underlying data to enable risk-based Priority Neighborhood Decarbonization Zones (PNZs) as part of Track 2.
3) Adopt of a uniform BCA framework for both SB-1221 and non-SB-1221 NPA evaluations.

A Staff Proposal addressing these recommendations, followed by intervenor comments, may provide the most efficient path forward.

Policy Options to Facilitate Non-Pipeline Alternatives

Kiki Velez, Equitable Gas Transition Lead

September 22, 2025

NRDC

Quick Background

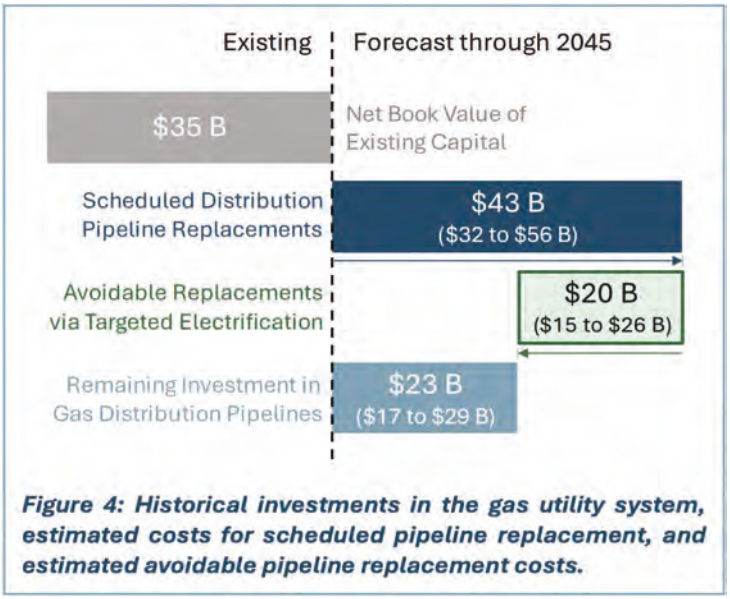


Figure 4: Historical investments in the gas utility system, estimated costs for scheduled pipeline replacement, and estimated avoidable pipeline replacement costs.

- Analysis shows targeted electrification could save Californians **more than $20 billion** in gas pipeline costs by 2045.

Source: *Energy + Environmental Economics for NRDC*

Recommended Next Step:

Issue a **Commission Decision** addressing threshold issues for NPA implementation.

Commission Should Resolve:

1. **NPA Definition**

Commission Should Resolve:

1. **NPA Definition**

Recommendation: NPA = Any project or portfolio of projects that avoids a planned gas investment, including:

- *Zero-Gas NPAs*
- *Demand Reduction NPAs*
- *Pipeline Re-lining*

Commission Should Resolve:

1. NPA Definition
2. **Benefit-Cost Analysis**

Commission Should Resolve:

1. NPA Definition
2. **Benefit-Cost Analysis**

Recommendation: Compare net-present value of a planned gas project with an NPA, including all associated utility earnings.

- *Consider the CEC's proposed BCA as a starting point.*

Commission Should Resolve:

1. NPA Definition
2. Benefit-Cost Analysis
3. **Cost Recovery**

Commission Should Resolve:

1. NPA Definition
2. Benefit-Cost Analysis
3. **Cost Recovery**

Recommendation: NPA behind-the-meter costs should be recovered as a gas regulatory asset.

- *Adopt preliminary framework for next 5-10 years; can revise after that point.*
- ***Other states do this:*** *In NY, utilities recover NPA costs over 20 years + receive 30% of the NPA savings*

Commission Should Resolve:

1. NPA Definition
2. Benefit-Cost Analysis
3. **Cost Recovery**

Recommendation: NPA behind-the-meter costs should be recovered as a gas regulatory asset.

- *Adopt preliminary framework for next 5-10 years; can revise after that point.*
- ***Other states do this:*** *In NY, utilities recover NPA costs over 20 years + receive 30% of the NPA savings*

Next slide shows NRDC analysis →

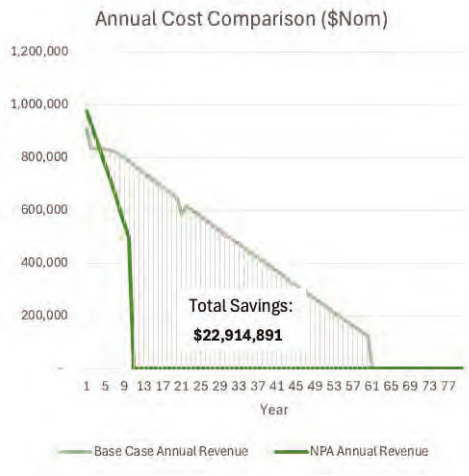
Tradeoffs of Different NPA Cost Recovery Options

1. Regulatory Asset, 15 Years

Year 1 NPA Bill Impact: - 0.15 cents

NPV Savings: ~$5.2 M

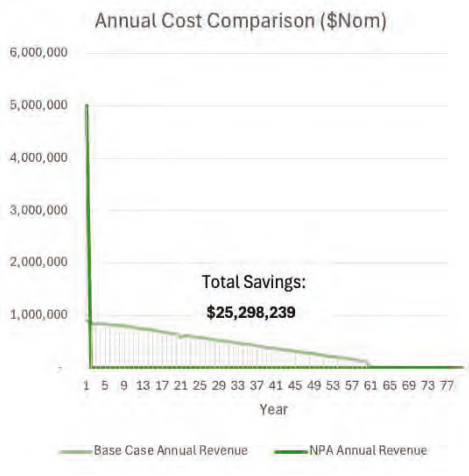
2. Regulatory Asset, 10 Years



Year 1 NPA Bill Impact: 0.14 cents

NPV Savings: ~$5.5 M

3. No Regulatory Asset

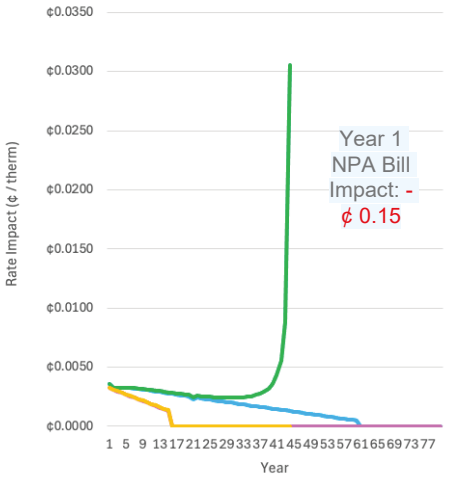


Year 1 NPA Bill Impact: 8 cents

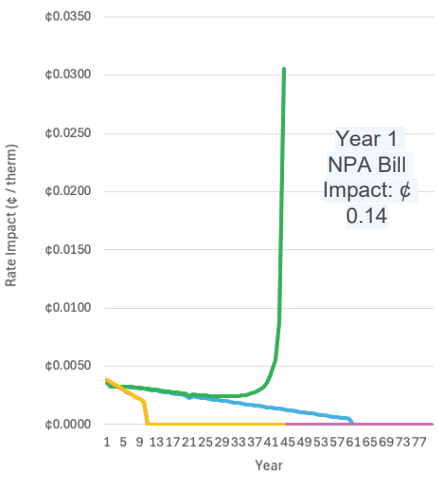
NPV Savings: ~$6.4 M

Comparing NPA Cost Recovery Options: **Rate Impacts**

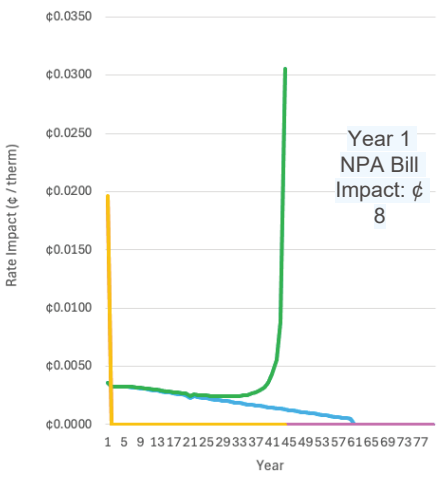
1. Regulatory Asset, 15 Years



2. Regulatory Asset, 10 Years



3. No Regulatory Asset



Base Case (BAU Scenario)
Base Case (Gas Transition Scenario)
NPA (BAU Scenario)
NPA (Gas Transition Scenario)

Recap - Commission Should Resolve

1. NPA Definition
2. Benefit-Cost Analysis
3. Cost Recovery

And after that…

- **NPA Identification Framework**

And after that…

- **NPA Identification Framework**

Recommendation: Develop a transparent, streamlined process to identify and prioritize NPAs, including:

- *Additional **mapping** needs*
- *Role of 3rd-party review (e.g., for hydraulic assessment)*
- *Low-hanging fruit opportunities (e.g., gas service line NPAs)*

Thank you!

Contact information: Kiki Velez, kvelez@nrdc.org

Happy to take any additional questions via email.

Appendix Slides

Expanded Recommendations for Commission NPA Decision

and Discussion of NRDC Analysis

Presentation Roadmap

Quick Background → Recommended Objective → Concrete Next Steps

Quick Background

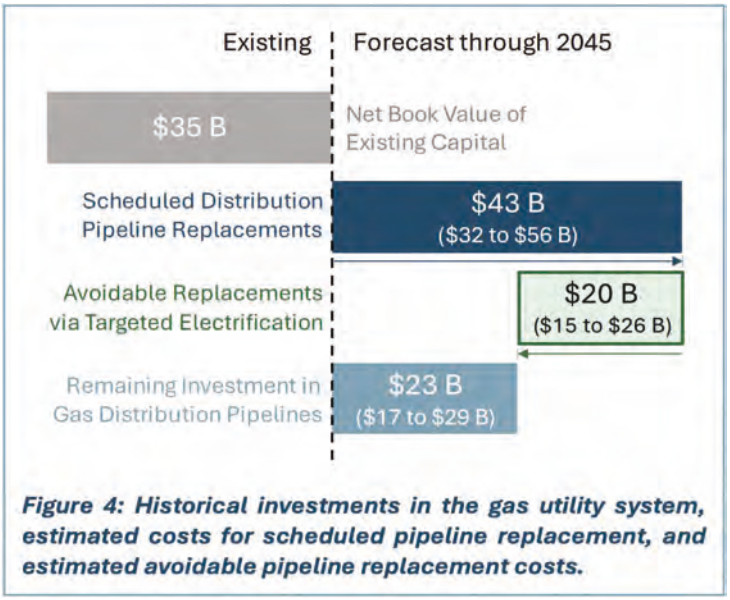


Figure 4: Historical investments in the gas utility system, estimated costs for scheduled pipeline replacement, and estimated avoidable pipeline replacement costs.

- Analysis shows targeted electrification could save Californians **more than $20 billion** in gas pipeline costs by 2045.

Source: Energy + Environmental Economics for NRDC

Proposed Objective

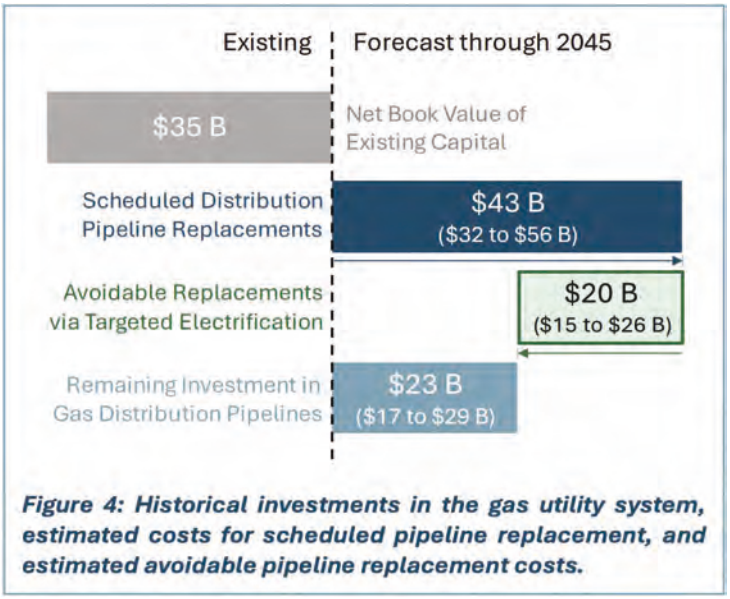


Figure 4: Historical investments in the gas utility system, estimated costs for scheduled pipeline replacement, and estimated avoidable pipeline replacement costs.

1. Require **NPA review** for all planned gas projects.
2. If a cost-effective, feasible NPA exists, do not guarantee gas investment cost recovery.

Commission Should Resolve:

- Key NPA questions, including:
  1. NPA Definition
  2. Benefit-Cost Analysis
  3. Cost Recovery

  Do these first...

And then:

4. Process for Identifying and Prioritizing NPAs

1. NPA Definition

Need: Stakeholders need clarity around what qualifies as an NPA.

Recommendation: NPA = Any project or portfolio of projects that avoids a planned gas investment.

- *Definition must include neighborhood electrification that enables pipeline retirement, but should also include novel solutions like pipeline relining & NPAs that **deploy sufficient demand-side resources*** to avoid capacity expansion or pressure betterment projects.*

** E3 has published a helpful article describing this concept in more detail.*

2. Benefit-Cost Analysis (BCA)

Need: To streamline NPA implementation, it is necessary to adopt a consistent BCA framework.

Recommendation: BCA framework should define cost-effectiveness from the utility customer perspective and should compare the NPVs of a planned gas project with an NPA project, including all associated utility earnings.

- *The Commission can put forth an existing framework for comment, such as the California Energy Commission's proposed BCA.*
- *Societal costs & benefits could be used to prioritize NPAs*

3. Cost Recovery

Need: Disagreement and uncertainty around cost recovery was a key barrier to implementation of the CSU Monterey Bay project. Resolution is needed to streamline NPA cost-effectiveness calculations and implementation.

Recommendation: NPA behind-the-meter costs should be recovered as a gas regulatory asset.

- *Any associated electric system costs should be recovered from electric ratepayers in the usual manner.*
- *Adopt preliminary framework for next 5-10 years; can revise after that point in response to shifting gas system considerations.*
- ***Other states do this:** In NY, utilities recover NPA costs over 20 years + earn a 30% shared-savings mechanism.*

3. Cost Recovery – Analysis Tools

NRDC is developing **two analysis tools** to weigh the benefits and drawbacks of different NPA cost recovery methods:

1. An internal spreadsheet tool to compare the gas system cost and rate impacts of gas projects vs. NPAs on a project- or portfolio-level.
2. A web-hosted model developed by Switchbox to compare the systemwide gas and electric system impacts of paying for NPAs under different scenarios at a large scale.

3. Cost Recovery – Analysis Tools

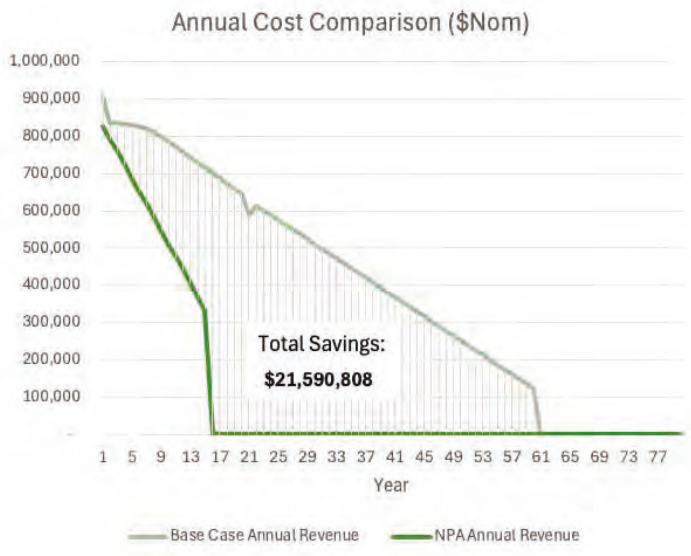
Assumptions for this Run:

- $36,650 / gas project,* 60-year depreciation
- $25,000 / NPA project, 15-year depreciation
- 200 projects completed

Results

- 530,000 kg CO2 avoided/year
- **NPV Savings: ~$5,150,000**

**This is PG&E's rounded average cost to replace a gas service line, per Sierra Club discovery requests.*



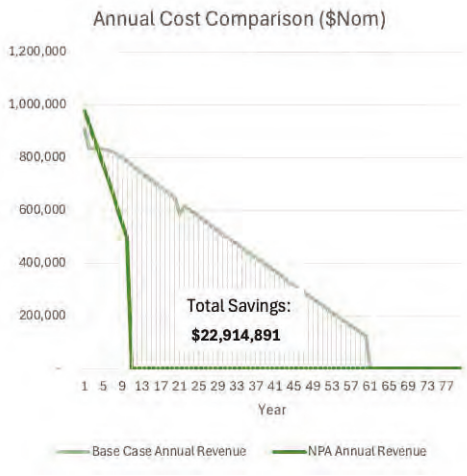
Comparing Different NPA Cost Recovery Options

1. Regulatory Asset, 15 Years

Year 1 NPA Bill Impact: - 0.15 cents

NPV Savings: ~$5.2 M

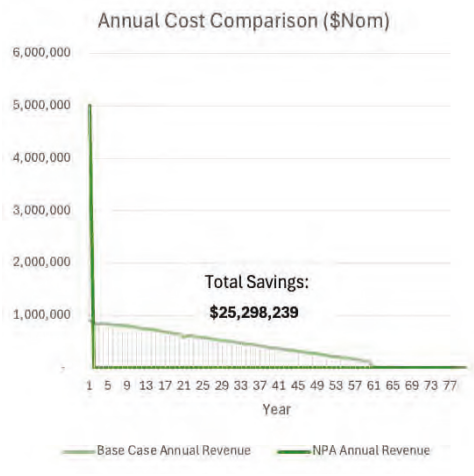
2. Regulatory Asset, 10 Years



Year 1 NPA Bill Impact: 0.14 cents

NPV Savings: ~$5.5 M

3. No Regulatory Asset

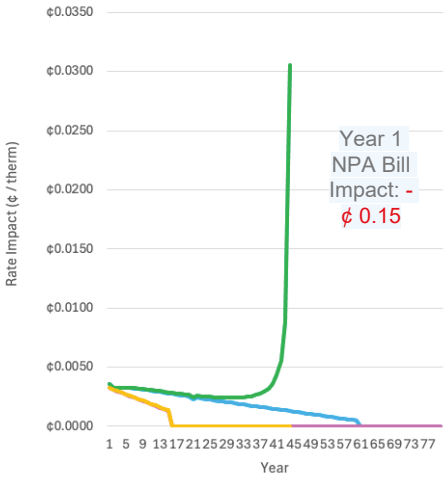


Year 1 NPA Bill Impact: 8 cents

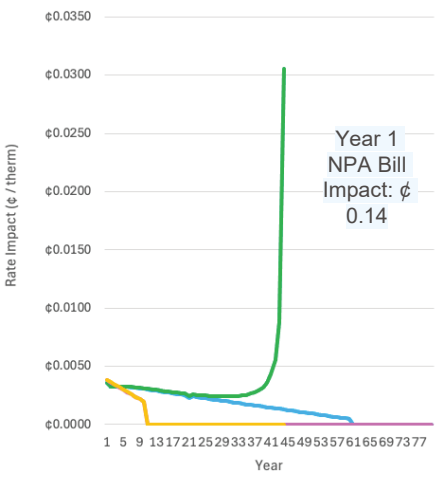
NPV Savings: ~$6.4 M

Comparing NPA Cost Recovery Options: **Rate Impacts**

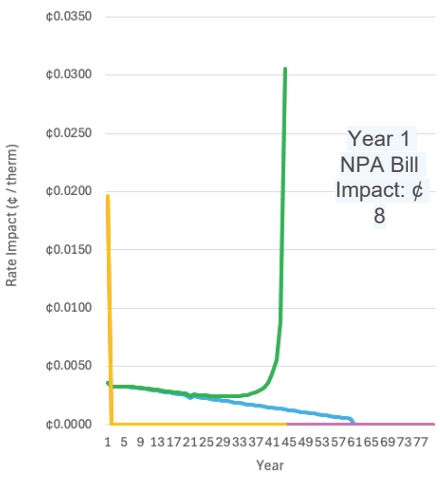
1. Regulatory Asset, 15 Years



2. Regulatory Asset, 10 Years



3. No Regulatory Asset

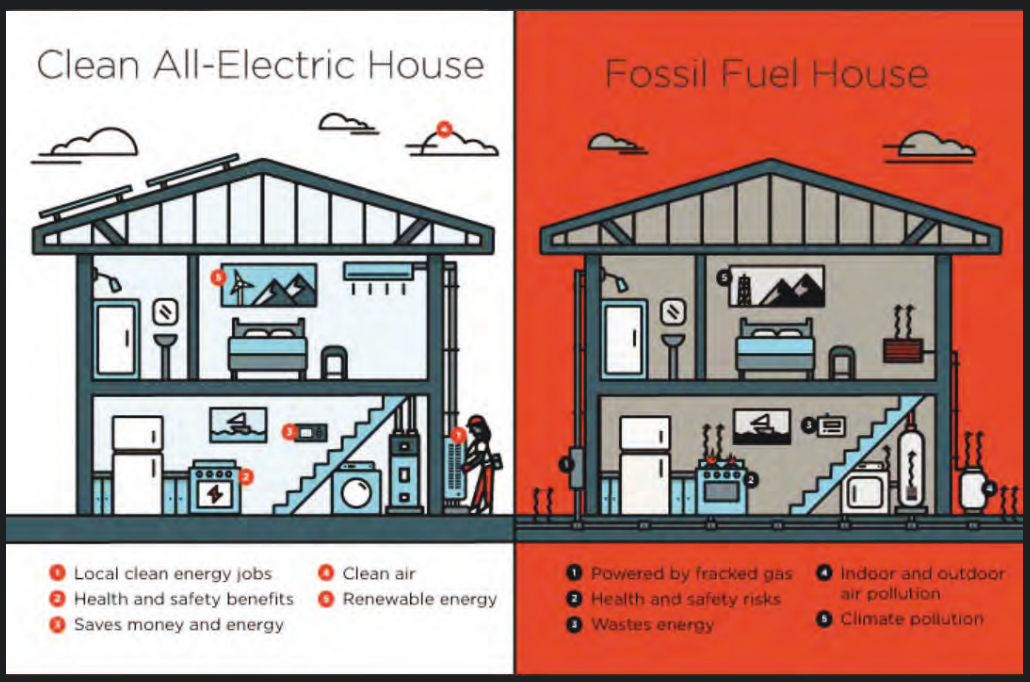


4. NPA Identification Process

Need: There is no transparent, streamlined process to identify and prioritize NPAs.

Recommendation: Staff Proposal should outline:

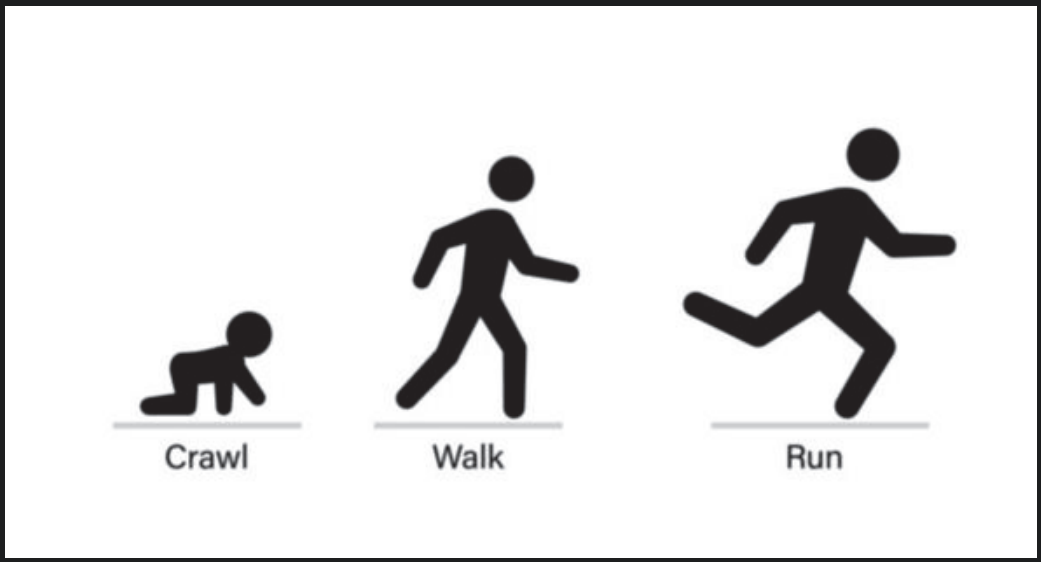
- Additional **mapping** needs
  - Where are individual projects planned to take place?
  - How many customers do they serve?
  - What type of customers do they serve?
  - Preliminary hydraulic feasibility: Is it a terminal branch? Connecting segment? Other?
- Role of 3rd-party review (e.g., for hydraulic assessment)
- Low-hanging fruit opportunities (e.g., NPA to gas service line replacements)



Policy Options to Facilitate Non-Pipeline Alternatives

Matt Vespa, Senior Attorney, Earthjustice, on behalf of Sierra Club
mvespa@earthjustice.org

1. Interim Actions
2. Service Line Replacement NPA program



Questions in Need of CPUC Resolution

- **Should NPAs be funded by gas or electric ratepayers?**
  Gas ratepayers are customers that would otherwise pay for gas investment. Should pay for NPA. (Though any IFOM electric upgrades responsibility of electric ratepayers)
- **How Should Utilities Recovery Costs from BTM investments?**
  - **SB 1221 Projects – Pub. Util. Code Sec. 663**
    - (8) A requirement that gas corporations recover costs related to the pilot projects that are deemed just and reasonable and ***a requirement that prohibits*** a gas corporation from recovering behind-the-meter costs associated with the pilot projects ***as capital costs that are afforded a rate of return.***
    - (9) ***The appropriate rate of return and recovery period that a gas corporation is eligible to receive for its costs to implement a zero-emission alternative…***
  - **Non-SB 1221 Projects**
    Regulatory asset treatment with 10-year cost recovery. Utilities should have *at least* as much incentive to implement climate friendly alternatives to fossil fuel infrastructure.
- **How should NPA cost-effectiveness be evaluated?**

ACR teeing up questions in need of further record development, followed by Commission decision.

NPA for Service Line Replacement:
Low-Hanging Fruit in Gas System Transition

- Vast majority connect to single meter
- Avoids complications of projects involving multiple customers
- Hydraulic feasibility not issue
- NPAs can be standardized
- Begin to prune system
- Participation can be voluntary

Service Line NPAs

ConEdison

Energy Exchange Program

Provides up to $20,000 in incentives to remove and replace gas appliances with new electric equipment

Building Type	SINGLE-FAMILY	2+ UNITS	SMALL BUSINESS + NONPROFIT	COMMERCIAL + INDUSTRIAL
BASE INCENTIVE	up to $10,000	up to $15,000	up to $10,000	up to $10,000
ENHANCED INCENTIVES FOR DISADVANTAGED COMMUNITIES*	up to $15,000	up to $20,000	up to $15,000	up to $15,000

https://www.coned.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-residential-customers/energy-exchange

Service Line NPAs

conEdison

Energy Exchange Program

- Targets customers connected to pre-1972 services
- Customer can choose among pre-approved contractors
- Contractor does site visit, works with customer to select appliances, submits application, which Con Ed uses to determine if need electric service line upgrade
- After installation customer, customer must close out gas account and requires gas service disconnection
- Follow-up survey for feedback to improve program

Con Edison, Non-Pipes Alternative Implementation Plan (2024)

Implementing a Service Line NPA Program in California

PG&E has both stand-alone service line replacement programs and replacements included in larger projects.

Service Line Only:

- *Reliability Service Replacement Program (MAT 50 B)*
  - 87+ percent connect to single customer
  - Average cost
    - $32,651 for residential
    - $53,222 for commercial

- *Single Distribution Service Replacements (MAT 50G/M)*
  - MAT 50G is for single service replacements
  - Average cost (MAT 50G)
    - $21,512 for residential
    - $24,900 for commercial
  - This is leak replacement program
    - Less complicated that MAT 50B
    - Average time from detection to replacement for residential service line is 270 days

	Core Residential[a]	Core Commercial[b]	Single Customer	2 - 5 meters	>5 meters
2022	536	33	499	67	4
2023	540	23	489	77	2
2024	487	23	452	62	1
TOTAL	*1,563*	*79*	*1,440*	*206*	*7*

Customer Type by MAT	2022	2023	2024
Residential	992	890	723
50G	970	866	708
50M	22	24	15
Commercial	103	67	61
50G	97	63	55
50M	6	4	6
Industrial	12	9	8
50G	11	9	8
50M	1		
Grand Total	1107	966	792

Implementing a Service Line NPA Program in California

Bulk of service line replacements part of larger replacement projects that include gas main

- Costs to replace service line as part of larger project currently not tracked, would likely be lower than individual replacements due to implementation efficiencies
- Could offer a certain amount (e.g., up to $15,000) with larger amount if entire project avoided

Program	Year	Total Services Replaced[a]	Core Residential Meters	Core Commercial Meters	Industrial Meters	Noncore Meters	Single meter Services[b]	2-5 meter Services[b]	>5 meter Services[b]
GPRP (MAT 14A)	2022 - 2024	6,106	8,299	679	2	1	5,170	1,013	118
Plastic Pipe Replacement (MAT 14D)	2022 - 2024	35,827	44,383	1,392	2	1	32,282	3,802	422
Reliability Pipe Replacement (MAT 50A)	2022 - 2024	2,563	3,931	159	0	0	1,951	477	78

(a) Excludes counts where a service was unable to be correlated with the meter class data.
(b) Total services replaced varies slightly as data availability for count of meters per service varies from meter class data.

Implementing a Service Line NPA Program in California

Additional Implementation Questions

- Outreach
  - How offer communicated to potential customers
  - How involve interested local governments, CCAs, CBO
- Contractors – use of defined list (e.g. TECH)?
- Gas/Electric utility coordination where panel/service line upgrade needed
- Equity
  - Con Ed program provides additional outreach/higher incentives for projects in DACs
  - How can other programs/non-ratepayer programs be leveraged to do same here
- Reporting/Feedback
- Proceeding coordination – Long-Term Gas Planning/General Rate Case

Questions?

UTILITY PERSPECTIVES ON PROCEDURES FOR FACILITATING NON-PIPELINE ALTERNATIVES

Interim Actions Workshop

Gas Planning OIR (R.24-09-021)

September 22, 2025

SoCalGas

Key Considerations Around NPA Integration

» **Safety**
- Safety is a leading driver for gas infrastructure investments, and is the primary driver for potential projects on July 1 SB 1221 maps
- NPA integration must not delay or otherwise negatively impact these safety investments. Streamlining qualified NPA project approval will be crucial to successful integration

» **Reliability**
- NPA deployment must not impact gas system reliability
- Customer energy reliability must be considered

» **Affordability**
- Appropriate cost-effectiveness testing, cost recovery mechanisms, customer education and engagement, and other program execution controls must be established to ensure NPAs don't negatively impact affordability for any ratepayers – thoughtful program design will be critical to protecting ratepayers and informing future policies
- Energy affordability for impacted customers must also be considered

» **Enhanced Need for Coordination**
- SoCalGas does not have access to data or expertise to assess electric grid capacity
- ICA data in July maps may help, but likely is not conclusive without further review
- Shared service territory with all major IOUs and ~20 POUs
  - POU levels of interest and resources for NPA support are likely varied
  - POU participation not directed by CPUC

» **Reporting**
- Documentation and reporting of successes, failures, costs, challenges, and other key performance criteria will be crucial to support the development of a sustainable program

Long Beach Perspective on Non-Pipeline Alternatives

September 22, 2025

LONG BEACH Utilities
Water · Gas · Sewer

About Long Beach

- 7th largest city in California
- Charter City formed in 1897
- 500,000 in population
- Municipal Planning and Permitting
- Publicly Owned Utilities
  - Water, Gas, Sewer
- Committed to Climate Adaptation

Long Beach's Climate Commitment

Long Beach's **Climate Action and Adaptation Plan** (LB CAP) was adopted in August of 2022 as a Qualified Climate Action Plan per CEQA Guidelines.

The LB CAP demonstrates the City's commitment to reducing emissions, preparing for climate change and mitigating its current and future impacts.

Climate Action Baseline and Goals

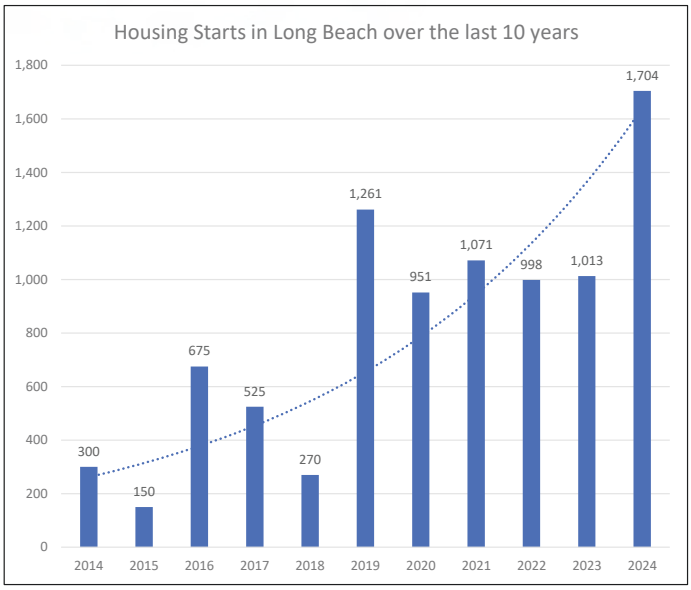
Sector	MT CO2e	% of Total
Stationary Energy	1,377,291	49.20%

Target Year	State Target	Corresponding Legislation	Status
2020	1990 GHG levels by 2020	AB 32, Global Warming Solutions Act (2006)	California met this target Statewide
2030	40% below 1990 levels by 2030	AB 32, Global Warming Solutions Act (2006)	LB CAP is a plan for Long Beach to meet this target by 2030
2045	Carbon neutrality by 2045	Executive Order B-55-18 of 2018	Aspirational for Long Beach
2050	80% below 1990 levels by 2050	Executive Order S-3-05 of 2005	LB CAP's plan horizon is to 2030

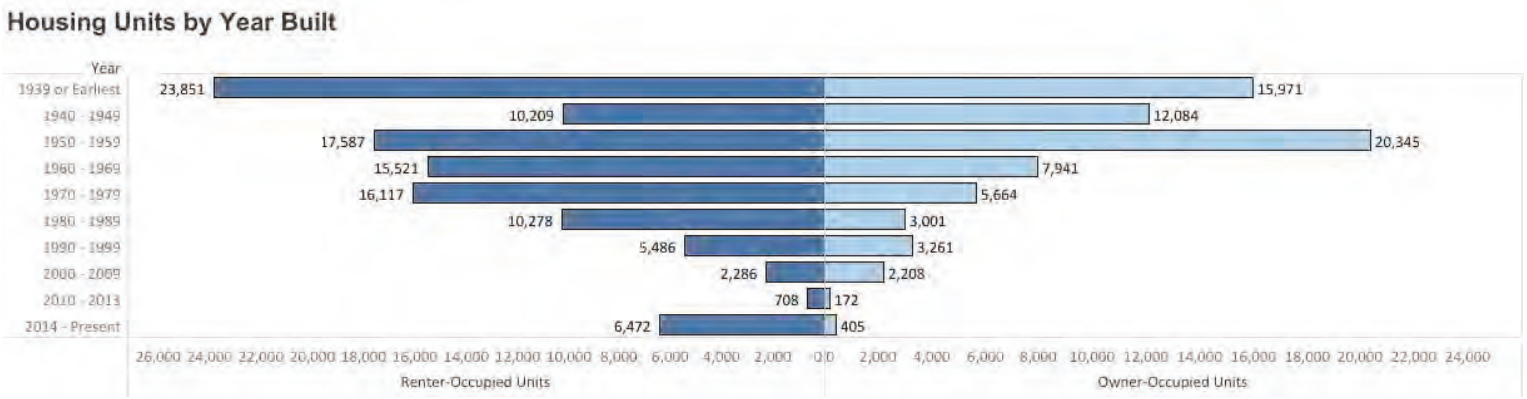
Stationary Energy Sector

Buildings and Energy

- LB CAP provides for a flexible approach with individual control mechanisms that change over time.
- Electrification was included in the LB CAP, and is still being pursued for new development within existing constraints:
  - CRA v Berkeley
  - AB 170
  - Availability of green power
- Electrification currently applies to residential units in buildings with 50 or more units, 100% affordable projects and other discretionary approvals.
- Electrification on smaller projects (such as ADUs) is encouraged but not required.

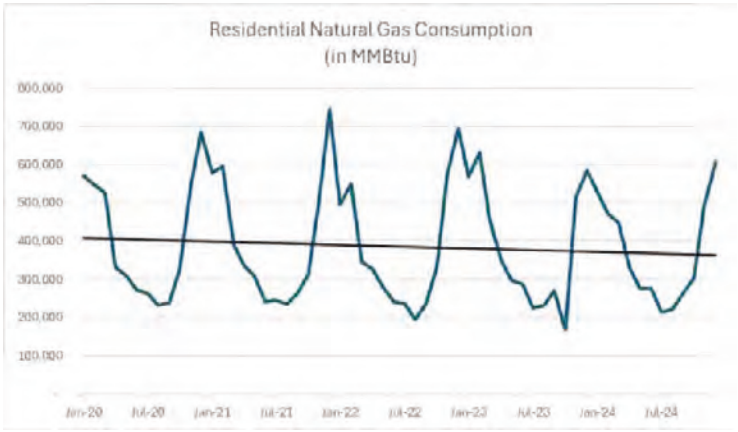


Long Beach Housing Stock



Long Beach Natural Gas Utility

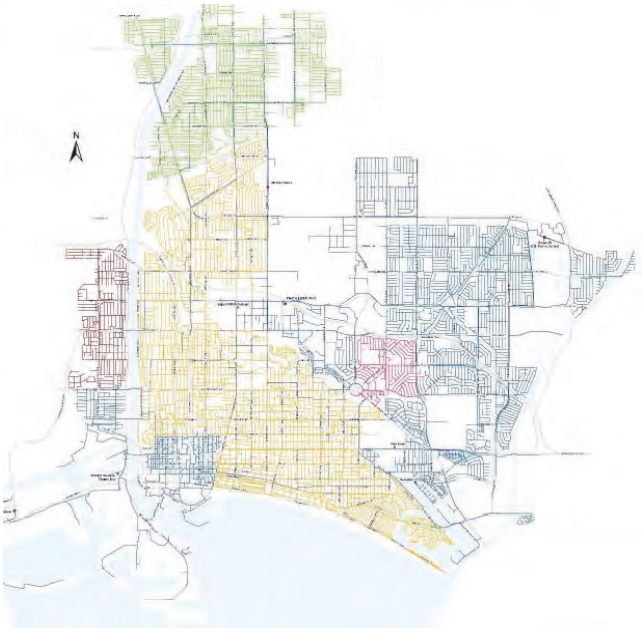
- **Long Beach's publicly owned natural gas distribution system supports 150,000 customer accounts**
  - **90% of accounts are residential** – making up 50% of gas consumption
  - 10% of accounts are commercial, industrial – making up the remaining 50% of consumption
- **1,900 miles of pipeline**



In the last 5 years, there has been a consistent decline of approximately 1% per year

Utilities Participation in Statewide Solutions

- Alignment with State and City Climate Action Plan goals, to:
  - Avoid 'replace-in-place' when cleaner, lower-cost options exist
  - Target decarbonization where it counts, i.e.: end-of-life mains, pipeline corridors with high operations and maintenance costs
- Actively engaging in energy climate adaption projects
  - Interested in exploring NPAs with SCE for Zonal Electrification



Non-Pipeline Alternatives

- Preliminarily gathering data to assess **place-based electrification** for end uses
  - Space heating, water heating, cooking
- **Goal: Understand emerging energy opportunities to protect safety, reliability, affordability for our customer base.**

Non-Pipeline Alternative Study

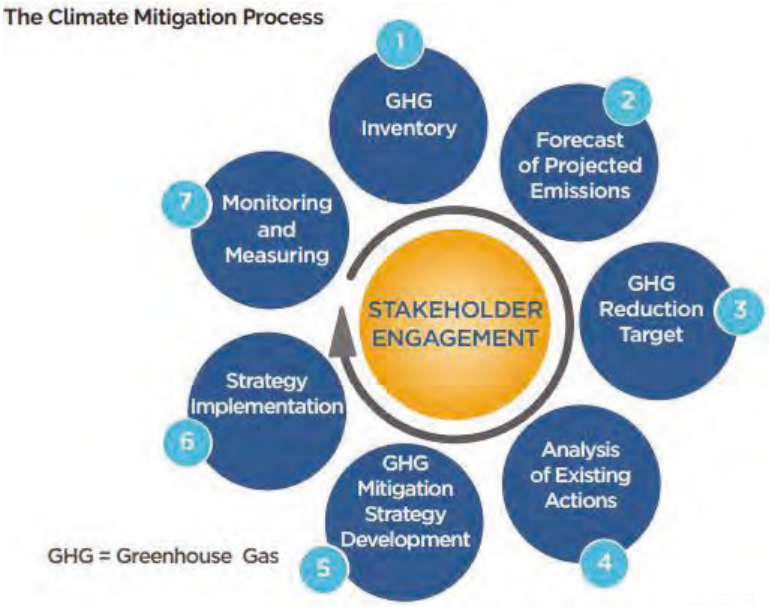
- Joint planning with Southern California Edison
  - Energy currently provided by natural gas, electric capacity
- Project purpose
  - Assess up to two pilot micro-zones (locations still to be identified)
  - Assess energy resources impacting emission reductions
  - Understand the customer journey
    - Incentive programs
    - Customer infrastructure and appliances
      - Initial electrification costs
      - Ongoing monthly bills

LONG BEACH Utilities
Water · Gas · Sewer

SOUTHERN CALIFORNIA EDISON
Energy for What's Ahead

Understanding Non-Pipeline Alternatives

- Risk-benefit
  - Electric readiness
  - Customer readiness
  - Cost / affordability
  - Emissions reduction
  - Stranded energy assets (gas and electric)
  - Reliability
  - Safety



Clean Energy Considerations

Mitigation

- Implementation occurs at both city and state level (siting EV charging stations and updating building codes and zoning to incentivize electrified buildings, for example, require local leadership)
- LB CAP identifies local GHG reduction measures for implementation

Adaptation

- State emissions reduction target does not prepare Long Beach for the impacts of climate change that are happening today
- LB CAP helps increase resilience for current and future threats (extreme heat, poor air quality, sea level rise, etc.)

Equity

- State emissions reduction targets do not ensure that climate issues are equitably addressed
- LB CAP helps address environmental justice and can help steer climate finance opportunities to communities most impacted by climate change

Conclusion

The City of Long Beach and Long Beach Utilities are ready to partner with CPUC, SCE, communities, and other stakeholders to turn good theory into good practice—carefully, transparently, and affordably.

Christopher Koontz
Director, Community Development Department
Christopher.Koontz@longbeach.gov

Tony Foster
Senior Director for Utility Business Services, Long Beach Utilities
Tony.Foster@longbeach.gov

LONG BEACH Utilities
Water · Gas · Sewer

Utility Perspectives on Procedures for Facilitating Non-Pipeline Alternatives

Exploring strategies for energy infrastructure innovation

September 22, 2025

Mike Kerans, Sr. Director, Gas Regulatory and Risk
Rachel Wittman, Building Electrification and EE Strategic Analyst, Principal

PG&E

Purpose of Presentation

- Establish a **shared definition** of an NPA and identify the **necessary actions** the CPUC must take to support the successful large-scale implementation of NPAs.
- Summarize **key insights** gained from current programs and emphasize the significance of **engaging** customers and communities.
- Offer a **set of recommendations** for the CPUC to incorporate into the Interim Actions Proposed Decision for scaling up NPA implementation.

Definition and Scope of NPAs

Definition of NPAs

A Non-Pipeline Alternative (NPA) is a strategy used to address infrastructure needs—such as new pipeline construction, capacity expansion, or pipeline replacement—through alternative solutions that **avoid or defer traditional gas investments**. These alternatives typically include electrification, fuel switching to non-regulated fuels (e.g., propane), and infrastructure retirement or decommissioning.

Scope Limitations

NPAs exclude minor pipeline repairs (such as sleeve installation or valve replacement), near-term high-risk pipe replacement, and O&M.

Importance of Clear Boundaries

Defining NPA boundaries helps utilities focus on projects with cost savings and environmental benefits.

Actions Needed from CPUC

Cost-Effectiveness	Streamlined Process	Safety
Cost-Effectiveness Framework A clear cost-effectiveness framework at the program level ensures consistency and eliminates ambiguity. **Funding Mechanisms** Adequate non-ratepayer funding is crucial for supporting before-the-meter and behind-the-meter expenses including home upgrades and appliance replacements.	**Streamlined Processes Needed** Streamlined decision-making and processes are necessary to avoid delays that could compromise safety timelines and project success. Authorizing portfolio budgets allows projects to be implemented without individual approvals, speeding up program deployment. **Customer Consent** We need procedures to ensure customer consent and support for NPA projects.	**Quick Decision-Making** Timely decisions are critical to maintaining safety when managing assets with known risks. Delays can slow down critical safety work and put projects at risk. Fast decisions mean we can act quickly, fix issues, and stay ahead of potential hazards. **Importance of System, Customer and Worker Safety** Maintaining safety standards during the broader transition to NPAs is essential to ensure reliable and secure utility service for customers and the public.

Existing PG&E Programs & Lessons Learned

Zonal Program Highlights

- The **Alternative Energy Program (AEP)** and **Zonal Equity Electrification Program (ZEEP)** aim to retire gas infrastructure by promoting electrification to support cleaner energy transitions.
- On average, ~25% of customers engaged by AEP and ZEEP have agreed to retire their gas service.

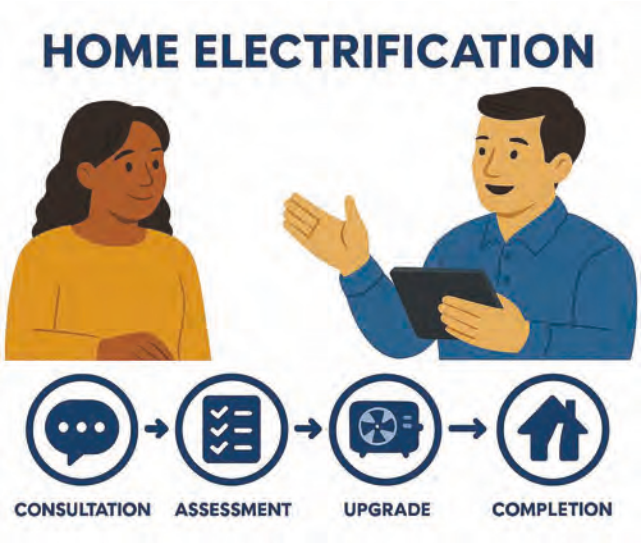
Non-Zonal Program Highlights

- PG&E administers several building electrification programs in its Energy Efficiency and Income Qualified Programs Portfolios that are not NPAs.
- These programs experience similar lessons learned as NPA programs.

Lessons Learned

- **Flexible program design** and **proactive customer & community engagement from trusted messengers are critical** to driving adoption and overcoming barriers.
- **Engagement must be customized to local neighborhood needs** for effectiveness, including method, frequency, and timeline.
- **Customer reluctance to electrify** often stems from **personal circumstances** in addition to cost or preference.
- AEP and ZEEP have not yet had success convincing customers to electrify who firmly oppose.

Importance of Early Customer Engagement



Customer Engagement Importance

Engaged customers inspire greater adoption of non-pipeline alternatives, boosting their success and community acceptance. Especially when there is local government and partner support.

Utility Support Role

Utilities provide essential infrastructure and guidance to support and facilitate customer-driven energy initiatives.

Empowerment and Ownership

Customer-driven programs foster empowerment and ownership, leading to more effective and sustainable energy solutions.

Recommendations to Accelerate Long Term Gas Transition

Cost Recovery

Utilities must be allowed to capitalize and recover decarbonization costs, including financing costs, over a sufficiently long period to mitigate rate and bill impacts on customers.

Cost-Effectiveness

The framework should focus on removing risks and emissions associated with the gas system in a cost-efficient manner.

Funding Mechanisms

Whenever possible, funding sources outside of ratepayer contributions should be utilized to maintain affordable utility rates for these initiatives.

Streamlined Process

A rapid decision-making structure within the CPUC and the IOUs with clear program-level approvals is critical to achieving state climate objectives on schedule.

JOINT CCA PERSPECTIVES ON NON-PIPELINE ALTERNATIVES

September 22, 2025

Kate Ziemba, Senior Environmental Program Manager, San José Clean Energy/City of San José

Sonoma Clean Power

SAN JOSE CLEAN ENERGY
A Program of the City of San José

CCA MOVEMENT

- 25 Community Choice Aggregators in CA serving 14 million customers in 200+ cities and counties
- Urban and rural
- Local control over electricity options and programs
  - Values: affordability, GHG reductions, equity

SAN JOSE CLEAN ENERGY (SJCE)

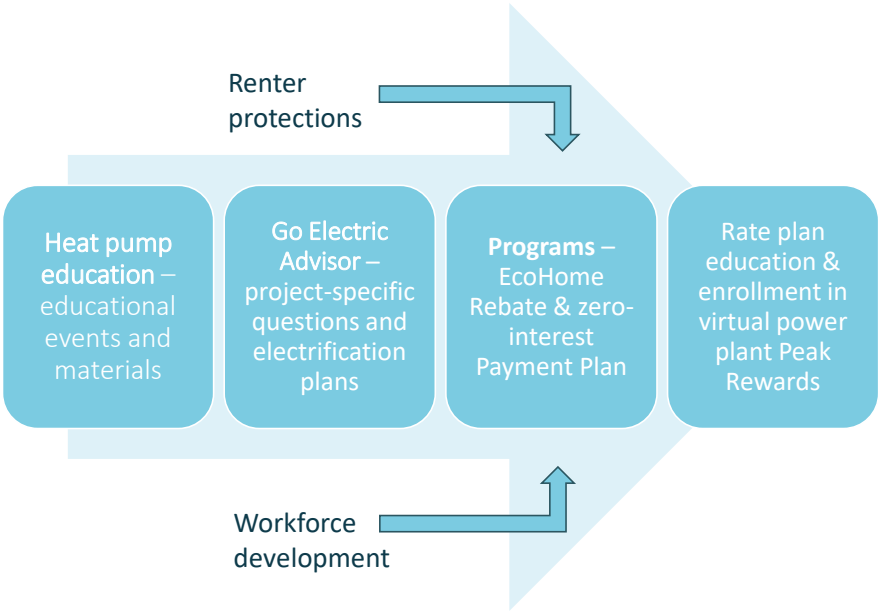
- Largest single-jurisdiction CCA
- Governed by City Council
- Operated by City of San José Energy Department
  - Partner departments: Housing; Office of Racial and Social Equity; Planning, Building, & Code Enforcement

SAN JOSE CLEAN ENERGY

CCA BUILDING ELECTRIFICATION PROGRAMS

- Many supportive programs: direct install, rebates, financing, work force development, education
- Focused on an equitable transition
  - Higher incentives, renter protection policies
- Each CCA approaches BE based on community and governance needs

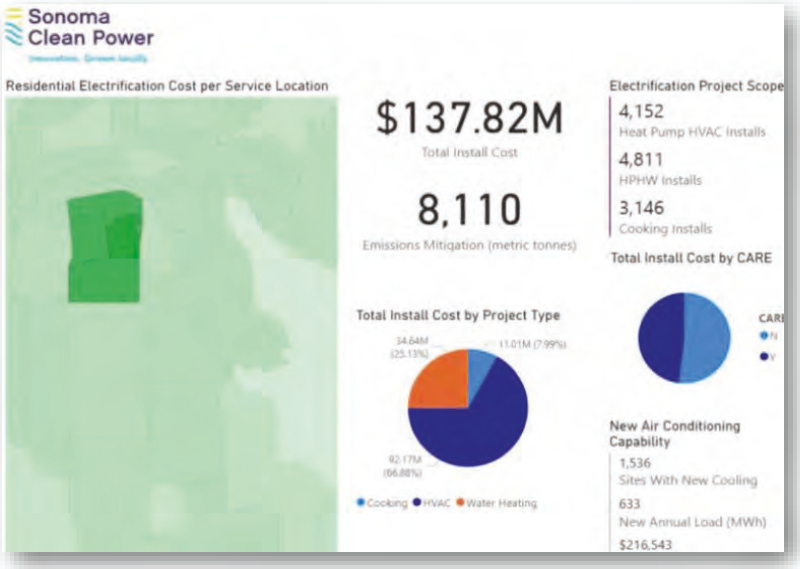
SJCE'S BUILDING ELECTRIFICATION APPROACH



SAN JOSE CLEAN ENERGY

CCA INTEREST IN NON-PIPELINE ALTERNATIVES

- Opportunity to align incentives
- Sonoma Clean Power and UCSB researching zonal decarbonization feasibility, impacts, and scale



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CCAS ARE IDEAL PARTNERS

- Connected to communities
  - Relationships with community-based organizations, neighborhood groups, elected officials
- Already work collaboratively with communities to design programs
- Can navigate social, economic, and political feasibility

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PROCESS INSIGHTS AND RECOMMENDATIONS

- Consensus building and community willingness is going to be large effort
  - It takes time, but CCAs can serve as accelerators
- Choosing communities requires trusted conversations and leaders who are willing to champion – this can't be rushed
- Using confidential gas system information for PNZ identification is helpful for LSEs – nomination based on this data should also be protected by a discrete process respecting the NDA

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Questions?

California Public Utilities Commission