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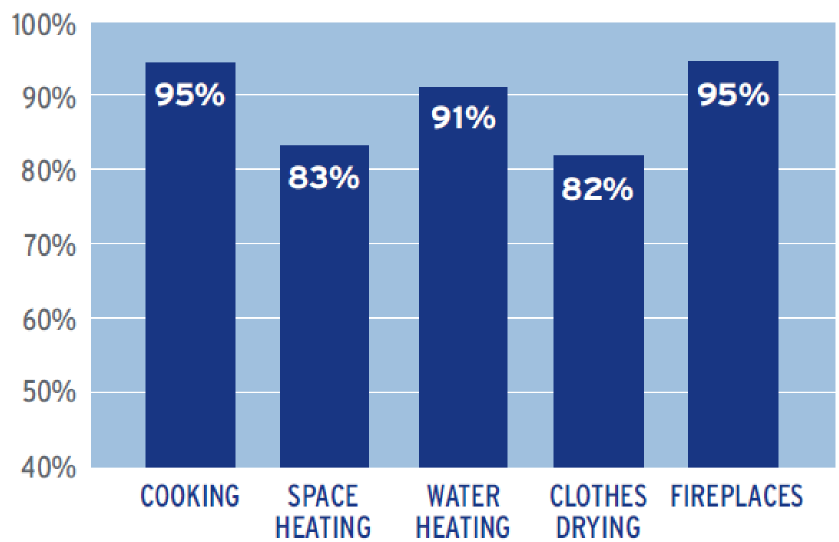
Appendix B

Appendix B1

Appendix B-1
Customer Preference

Southern California residents continue to overwhelmingly prefer natural gas appliances over electric ones. This is demonstrated in the *2014 Visions Home Preference Survey* which found that 91% of respondents preferred natural gas water heating over electric, and on average, 89% chose natural gas appliances over electric, shown in Graph 2 below. Customers also responded that when looking for a new home they noticed whether or not appliances were natural gas,[1] preferred a home with an outdoor natural gas outlet,[2] would spend more for a home with efficient natural gas appliances,[3] and preferred natural gas amenities in community areas.[4] These energy preferences indicate that natural gas continues to be the appliance energy of choice for Southern California homebuyers and renters. Considering this reality, SoCalGas believes that California can still meet air quality and climate change goals with a mixed energy use approach.



Graph 2. Percent of homebuyers and renters that prefer natural gas appliances[5]

Survey Purpose, Methodology and Respondent Profile

The purpose of the 2014 Vision Survey was to assist the Building Industry of Southern California in determining the current home buyer and renter mainstream preferences of their potential customers. The Vision 2014 Home Preference Survey was administered by Meyers Research, LLC and was co-sponsored by the Building Industry of Southern California and SoCalGas: the energy preference questions were a subset of this comprehensive survey. Results are based upon responses received in July 2014 from 1,926 home-buyers and renters, within SoCalGas service area, who had initiated gas service in the previous 30 months. Approximately 94% of all southern California residents have natural gas service to their homes. The survey was completed by respondents through "Survey Monkey's" online process and

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[1] 88% stated that when searching for a home (to purchase or rent) they noticed whether the appliances were NG or electric. SoCalGas Survey, 2.
[2] 92% stated that they preferred their new home provided a NG outlet in the patio area that could be used for outdoor gas appliances like a barbeque or outdoor patio hearer. SoCalGas Survey, 2.
[3] 84% stated that they would spend more for a home or rental that included efficient NG appliances that would both decrease their utility bill and increase their comfort. SoCalGas Survey, 2.
[4] 88% stated that they would prefer that their residence included NG amenities in the community areas like barbeques, fireplaces, or outdoor patio heaters. SoCalGas Survey, 2.
[5] SoCalGas Survey, 2.

consisted of 62 primary questions, five of which were energy related. Survey results were confirmed by Meyers Research, LLC with a 95% confidence level and 2.2% margin of error.

Respondent Profile

- Men: 53%
- Women: 43%
- Mortgage: 53%
- Rent: 47%
- Single: 20%
- Married w/kids: 57%
- Married no/kids: 4%
- Divorced: 16%

- Education:
  - Bachelor Degree: 54%
  - Associate Degree: 46%

- Income Range

Income Range	% Respondents
< $60,000	30%
$60,000 - $90,000	20%
$90,000 - $120,000	14%
$120,000 - $180,000	12%
> $180,000	11%

SoCalGas

A Sempra Energy utility

THE VISION 2014
Home Preference Survey

ENERGY PERSPECTIVE

Southern California Gas Company (SoCalGas®) has been delivering clean, safe and reliable natural gas to its customers for more than 140 years. Our motto, Glad to be of service®, reflects our commitment to provide customers with world-class service.

In order to better understand our customers' preferences and needs when choosing a home, we conducted The Vision 2014 Home Preference Survey*. Homeowners and renters living throughout Southern California were invited to participate in the survey in July 2014 regarding their preferences for a wide variety of home features. The survey was co-sponsored by the Building Industry of Southern California and SoCalGas to provide builders with valuable insight on their customer's housing needs and desires. The following is an excerpt of the survey results reflecting the respondents' preference for the energy used by home appliances.

Whether you serve the residential or commercial markets, we can show you how natural gas continues to be the energy of choice for more than 5.6 million SoCalGas residential customers.

Southern California home buyers and renters:

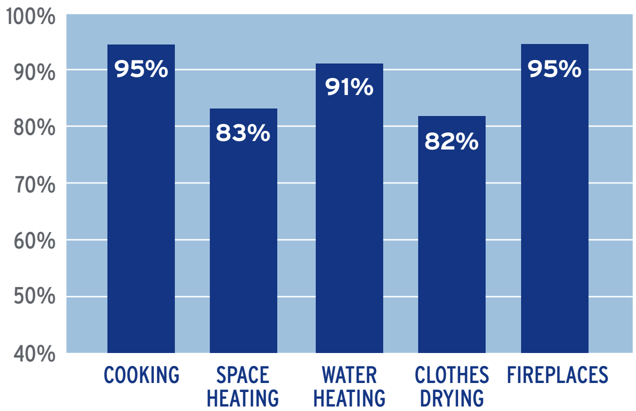
- **Eighty-nine percent**, on average, prefer gas over electric appliances.
- **Eighty-eight percent** notice whether the appliances are natural gas or electric, when searching for a home.
- **Eighty-four percent** would pay more for a home that included efficient natural gas appliances that would both decrease utility bills and increase comfort.

Energy preferences indicate that **NATURAL GAS** continues to be the **ENERGY OF CHOICE** for Southern California home buyers and renters.

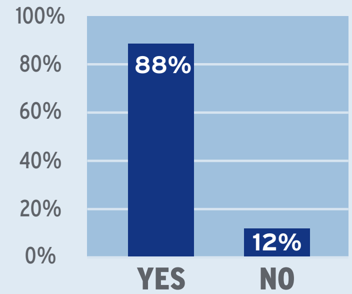
* The 2014 Visions Home Preference Survey was administered by Meyers Research LLC and is based on responses from 1,926 customers in July 2014.

(continued on back)

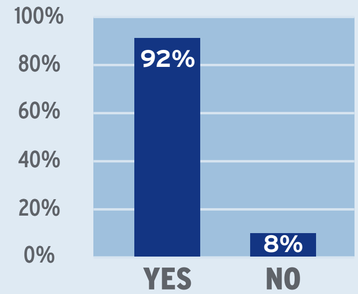
89% AVERAGE PREFERENCE
for natural gas over electric appliances



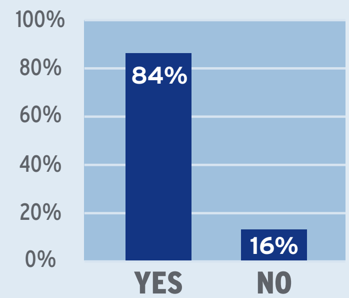
Percent of home buyers and renters answering that "natural gas" was the preferred source of energy for the appliances shown above.



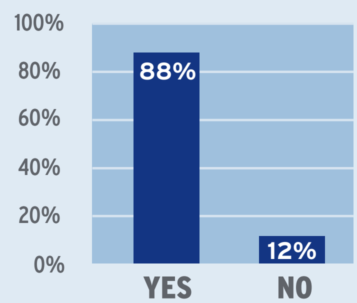
When searching for a home (to purchase or rent), do you notice whether the **APPLIANCES ARE NATURAL GAS OR ELECTRIC?**



Would you prefer that your new home provided a **NATURAL GAS OUTLET IN THE PATIO AREA** that could be used for outdoor gas appliances like a barbecue or outdoor patio heater?



Would you spend more for a home or rental that included **EFFICIENT NATURAL GAS APPLIANCES** that would both decrease your utility bill and increase your comfort?



Would you prefer that your residence included **NATURAL GAS AMENITIES IN THE COMMUNITY AREAS** like barbecues, fireplaces or outdoor patio heaters?

For information please visit **socalgas.com** (search "*BUILDER SERVICES*")

socalgas.com | 1-800-427-2000 | Visit us on:

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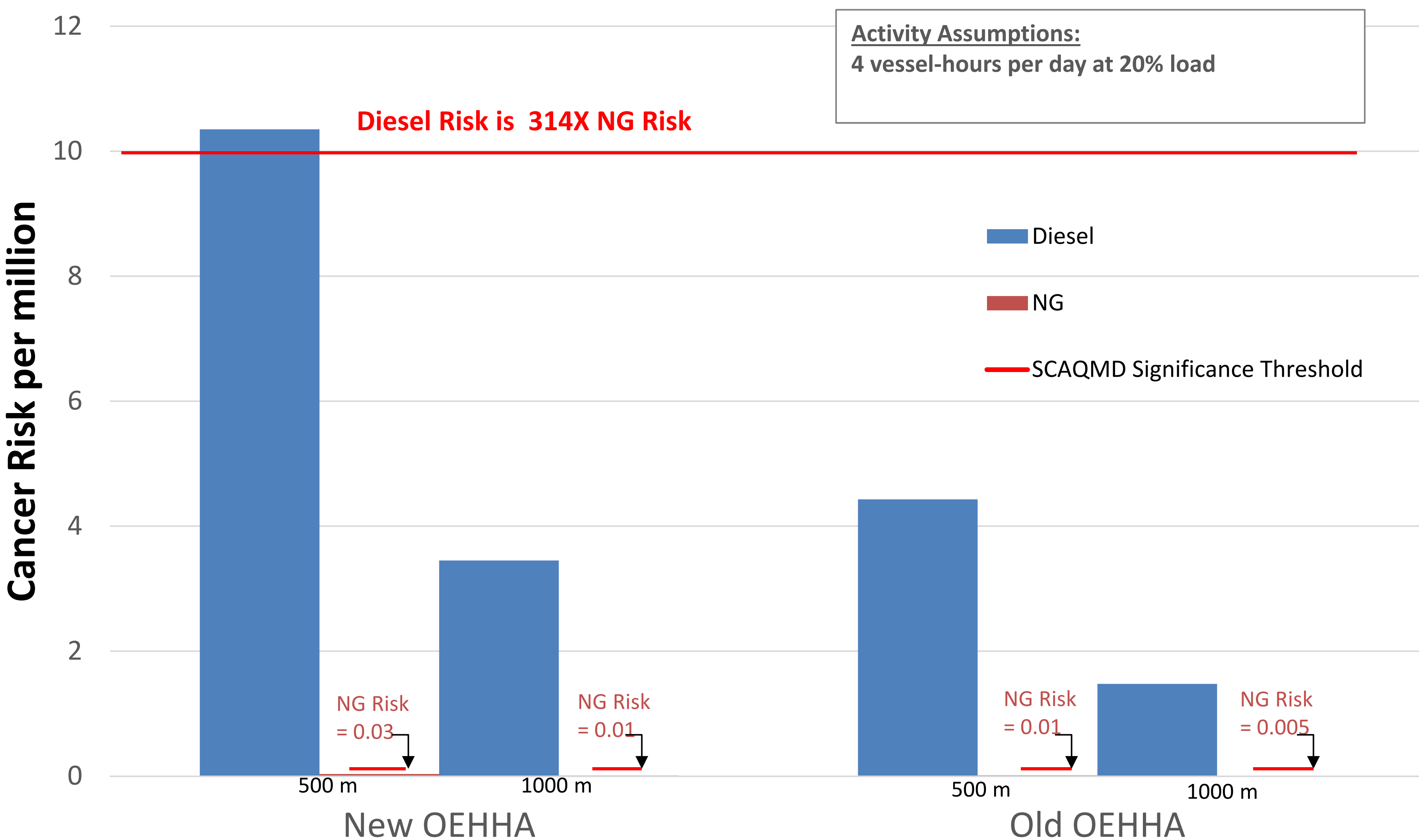
Appendix B2

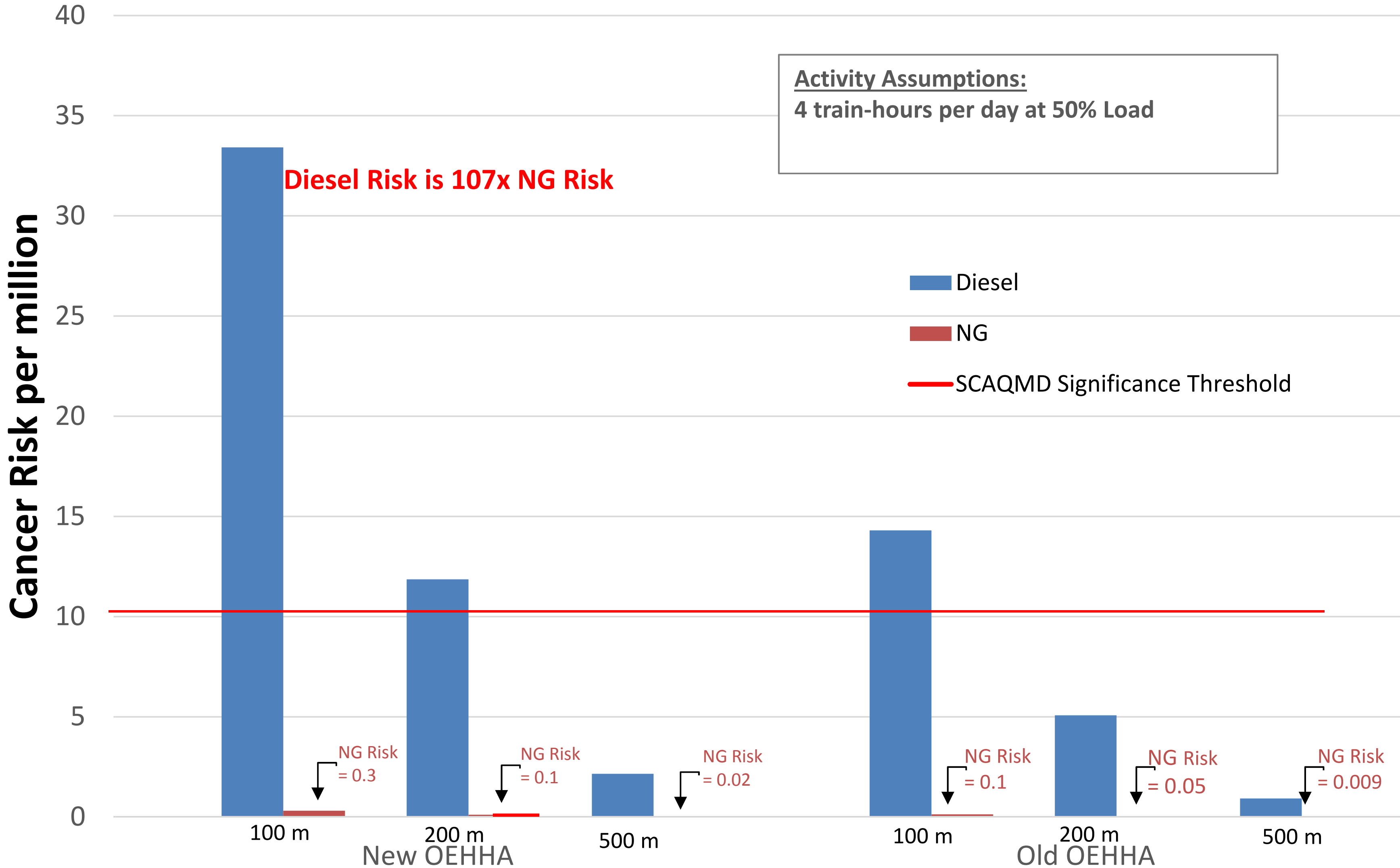
Natural Gas Can Be a Cost Effective Strategy to Reduce Cancer Risk

- OEHHA Guidance for calculating cancer risk revised March 2015
  - Cancer risk estimates for residential exposures increase up to 3 times or more
- Higher cancer risk estimates affect public noticing, CEQA significance determinations, permitting, etc.
- Natural gas: lower cancer risk opportunities
  - <u>CAVEAT:</u> Next 2 slides are generic examples only to illustrate fuel switching calculated risk benefit
  - No specific facility was examined and no inference about actual risk at a specific facility can be derived from just this Tier 2 screening level analysis information

Marine Engine Absolute Residential Cancer Risk- Diesel vs. NG Hypothetical Example: Transiting Near Port Terminal



Locomotive Absolute Residential Cancer Risk- Diesel vs. NG Hypothetical Example: Arrival and Departure Trains



Appendix B3

CODES AND STANDARDS ENHANCEMENT INITIATIVE (CASE)

Residential Instantaneous Water Heaters

Measure Number: 2016-RES-DHW1-F

Residential Water Heating

2016 CALIFORNIA BUILDING ENERGY EFFICIENCY STANDARDS

California Utilities Statewide Codes and Standards Team Updated February 2015

Prepared by: Sarah Schneider, Bijit Kundu, Heidi Hauenstein (Energy Solutions)

This report was prepared by the California Statewide Utility Codes and Standards Program and funded by the California utility customers under the auspices of the California Public Utilities Commission.

Note to Readers

The Title 24 Residential Instantaneous Water Heaters (IWH) CASE Report was originally submitted to the California Energy Commission (CEC) by the Statewide Utilities Codes and Standards Enhancement (CASE) Team on September 19, 2014. The February 2015 version of the CASE Report contains additional information on the proposed standards for residential water heating in new construction and additions as requested by CEC staff. The February 2015 version also includes revisions to the proposed code language originally submitted to CEC in September 2014 and a description of the revised additional prescriptive option and associated energy savings and cost-effectiveness results.

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Document Information

Category: Codes and Standards

Keywords: Statewide CASE, Statewide Codes and Standards Team, Statewide C&S Team, Codes and Standards Enhancements, Title 24, 2016, efficiency, instantaneous water heater, storage water heater, quality insulation inspection, pipe insulation, compact hot water distribution system, domestic hot water system.

EXECUTIVE SUMMARY

Introduction

The Codes and Standards Enhancement (CASE) initiative presents recommendations to support California Energy Commission's (CEC) efforts to update California's Building Energy Efficiency Standards (Title 24) to include new requirements or to upgrade existing requirements for various technologies. The four California Investor Owned Utilities (IOUs) – Pacific Gas and Electric Company, San Diego Gas and Electric, Southern California Edison and Southern California Gas Company – and the Los Angeles Department of Water and Power (LADWP) sponsored this effort. The program goal is to prepare and submit proposals that will result in cost-effective enhancements to energy efficiency in buildings. The report and the code change proposal presented herein is part of the effort to develop technical and cost-effectiveness information for proposed regulations on building energy efficient design practices and technologies.

The goal of this CASE Report is to propose revisions to the prescriptive requirements for water heating in new single family buildings, residential additions, and new multi-family buildings with dedicated water heaters for each dwelling unit. The proposed code changes would modify the code requirements by specifying that the applicant can comply with the prescriptive standards by installing a gas instantaneous water heater (IWH) that meets minimum federal efficiency levels. As an alternative, the Applicant can also comply by installing a gas storage water heater that meets federal minimum efficiency levels. If the Applicant chooses to install a gas storage water heater, they will also be required to have a Home Energy Rating System (HERS) verified Quality Insulation Installation (QII), plus one of the following: installation of a compact hot water distribution design, or a HERS verified domestic hot water pipe insulation.

Additionally, the Statewide CASE Team recommends adding a mandatory measure that requires the installation of a drain kit (i.e. isolation valves) as part of the water heating system if a gas IWH is installed. Isolation valves assist in the flushing of the heat exchanger and help prolong the life of gas IWHs.

The report considers market availability and cost effectiveness[1] of gas IWHs and demonstrates that complying with Title 24 by installing a gas IWH is cost effective and feasible in all California climate zones. While the scope of the CASE proposal is limited to evaluating the impacts of compliance using a gas IWH, the Statewide CASE Team notes that the other proposed pathways to compliance are also cost effective. Applicants that comply using the performance approach can comply by deploying a wide variety of measures. The Statewide CASE Team did not evaluate all compliance pathways.

This report contains pertinent information that justifies the proposed code change including:

[1] CEC is only legally required to demonstrate that the primary prescriptive path is cost effective and viable given the current availability of products.

- Description of the code change proposal, the measure history, and existing standards (Section 2);
- Market analysis, including a description of the market structure for specific technologies, market availability, and how the proposed standard will impact building owners and occupants, builders, and equipment manufacturers, distributers, and sellers (Section 3);
- Methodology and assumption used in the analyses for energy and electricity demand impacts, cost-effectiveness, and environmental impacts (Section 4);
- Results of energy and electricity demand impacts analysis, Cost-effectiveness Analysis, and environmental impacts analysis (Section 5); and
- Proposed code change language (Section 6).

Scope of Code Change Proposal

The proposed code change will affect the following code documents listed in Table 1.

Table 1: Scope of Code Change Proposal

Standards Requirements (see note below)	Compliance Option	Appendix	Modeling Algorithms	Simulation Engine	Forms
M and Ps	No	No	No	No	No

Note: An (M) indicates mandatory requirements, (Ps) Prescriptive, (Pm) Performance.

Measure Description

To comply with Title 24 Standards, an applicant must implement all mandatory requirements in the Standards. In addition to implementing the mandatory measures, the applicant must choose to either (1) implement a discrete set of additional measures, as defined in the prescriptive requirements (i.e. prescriptive approach), or (2) confirm that the building's energy performance meets the required energy budget, as modeled using CEC-approved modeling software (i.e. performance approach). Over 90 percent of applicants comply with the Standards using the performance approach, which provides more flexibility. The energy budget that must be achieved if an applicant complies using the performance approach is developed by modeling the building assuming all the prescriptive measures are deployed. A building will be in compliance with Title 24 if the energy budget of the proposed building achieves the same energy budget that it would have achieved if deploying all of the prescriptive measures.

The 2013 Title 24 prescriptive requirements indicate that if natural gas is available,[2] either a gas-fired storage water heater or gas IWH must be used. If gas is not available, the applicant can comply with the standards prescriptively by installing an electric-resistant water heater

[2] The 2013 Title 24 Standards and accompanying manuals (e.g., Residential Compliance Manual and Alternative Compliance Method Reference Manual) are ambiguous in defining "natural gas availability." As such, this measure is also proposing revisions to the definition of gas availability and recommends an improved method of determining gas availability for compliance enforcement.

(either storage or IWH) combined with a solar water heating system that provides a solar fraction of 0.50.

The Residential IWH measure proposes modifications to the prescriptive requirements for domestic water heating systems in single family homes and multi-family buildings with dedicated water heaters for each individual dwelling unit. The goal of the measure is to update the water heating energy budget to help ensure that builders are encouraged to improve the efficiency of hot water systems in residential buildings.

The proposed code changes would modify the code requirements by specifying that the applicant can comply with the prescriptive standards by installing a gas instantaneous water heater (IWH) that meets minimum federal efficiency levels. As an alternative, the applicant can also comply by installing a gas storage water heater that meets federal minimum efficiency levels. If the applicant chooses to install a gas storage water heater, they will also be required to have a Home Energy Rating System (HERS) verified Quality Insulation Installation (QII), plus one of the following: installation of a compact hot water distribution design or a HERS verified domestic hot water pipe insulation. Each of these options will result in approximately equivalent energy performance on a statewide basis. They were modeled using CEC's approved public domain modeling software program, CBECC-Residential, Version 3 (see Section 5.1for projected savings of proposed prescriptive options).

The proposed prescriptive options are as follows (See Section 6 for proposed code language):

1. Install a single natural gas or propane IWH meeting minimum federal efficiency levels *(used to calculate baseline energy budget for performance approach*); or
2. Install a single gas or propane storage water heater meeting minimum federal efficiency with an input of 105,000 Btu per hour or less in combination with QII requirements (HERS verified) and either:
    a. Compact hot water distribution design that is field verified; or
    b. Hot water pipe insulation requirements (HERS verified).

Since most applicants use the performance approach to comply with the Title 24 Standards, applicants that use the performance approach would still have the option of complying with the Standards by deploying any number of strategies that would allow them to meet the overall energy budget. For example, an applicant could choose to install a storage water heater in conjunction with other efficiency measures, like a higher performing building envelope. An applicant could also choose to install a heat pump water heater (HPWH) in conjunction with another efficiency measure.

The Statewide CASE Team will be recommending revisions to the ACM Reference Manual and Compliance Manual to improve how "gas availability" is defined, and how one determines gas availability.

Finally, the Statewide CASE Team recommends adding a mandatory measure that if a gas IWH is installed, a drain kit (i.e. isolation valves) must be installed as part of the water heating system. Isolation valves assist in the flushing of the heat exchanger and help prolong the life of gas IWHs. Installation of a drain kit has become common practice among installers and plumbers and is recommended by water heater manufacturers. These valves are typically sold separately and not included with the water heater unit.

Reason for Proposed Code Change

Water heating accounts for the largest share of natural gas usage in California homes and 90% of California homes use natural gas to heat water (Hoeschele et al. 2012). Although 49% of natural gas usage in homes is for used for heating water (KEMA 2010)) and that technology advancements have substantially increased the efficiency of water heating equipment, the Title 24 Standards for residential water heating have experienced only gradual increases in energy efficiency over the last couple decades. Given the advancements in the energy efficiency of water heaters, it is an opportune time to update the baseline energy performance of residential water heating to allow for greater energy savings for California. If California is going to achieve zero net energy (ZNE) goals in a cost-effective manner, it is imperative that the water heating energy budget be revised.

This measure builds upon a measure that was added to the Title 24 Standards during the 2013 code change cycle which requires domestic water heating systems in new residential construction (single family and multi-family buildings with dedicated water heaters in individual dwelling units) to be designed to accommodate high-efficiency gas water heaters (e.g., condensing storage and IWHs). By the time the 2016 Title 24 Standards take effect in 2017, builders will be accustomed to designing buildings so they can accommodate gas IWHs.

Section 2 of this report provides detailed information about the code change proposal. Section 2.2 of this report provides a section-by-section description of the proposed changes to the Standards, Alternate Calculation Method (ACM) Reference Manual, and Compliance Manual that will be modified by the proposed code change. See the following tables for an inventory of sections of each document that will be modified:

- Table 6: Scope of Code Change Proposal
- Table 7: Sections of Standards Impacted by Proposed Code Change
- Table 8: Appendices Impacted by Proposed Code Change

Detailed proposed changes to the text of the Building Efficiency Standards, Residential ACM Reference Manual, and the Residential Compliance Manual are given in Section 6 of this report. This section proposes modifications to language with additions identified with <u>underlined</u> text and deletions identified with ~~strikeout~~ text.

The following documents will be modified by the proposed change:

- 2013 Title 24 Standards, Part 6, Subchapter 2 (Section 110.3(c), Subchapter 7 (Section 150.0(n)), Subchapter 8(Section 150.1(c)8), and Subchapter 8 (Section150.2(b)1G
- 2013 Residential ACM Reference Manual, Sections 2.2.10 and 2.10
- 2013 Residential Compliance Manual, Section 5.4.1

Market Analysis and Regulatory Impact Assessment

The proposed code change is justified given the current and future residential water heating market, as high-efficiency water heaters (including gas IWHs) have widespread availability in California. The incremental cost of high-efficiency water heaters relative to their less efficient counterparts are recovered over time by way of lower utility bills (i.e. higher energy efficiency reduces energy use and thus lowers utility costs to homeowners) and because IWH have longer lifespans than storage water heaters and will need to be replaced less frequently. As a result, the proposed code change is cost effective over the 30-year period of analysis[3] in all California Climate Zones.

The expected impacts of the proposed code change on various stakeholders are summarized below:

- **Impact on builders:** The potential effect of all proposed changes to Title 24 on builders will be small. Assuming that builders pass compliance costs on to consumers, demand for construction could decrease slightly if all other factors remain the same.
- **Impact on building designers:** The proposed code change will have little to no impact on building designers, as the existing Title 24 Standards already require domestic water heating systems in new residential construction to be designed for the installation of gas IWHs.
- **Impact on occupational safety and health:** The proposed code change is not expected to have an impact on occupational safety and health. It does not alter any existing federal, state, or local regulations pertaining to safety and health, including rules enforced by California Division of Occupational Safety and Health. All existing health and safety rules will remain in place. Complying with the proposed code changes is not anticipated to have any impact on the safety or health occupants or those involved with the construction, commissioning, and ongoing maintenance of the building.
- **Impact on building owners and occupants:** The proposed code change will have a positive overall impact on building owners and occupants. For building owners, the longer lifespan of IWHs results in fewer water heater replacements over time, particularly if routine maintenance is undertaken to prolong the useful life of the water heater. Homeowner-occupants will benefit from a continual supply of hot water and lower utility bills, though the wait time for hot water may increase slightly due to the additional time it takes for hot water to arrive, particularly if the water heating system is designed so that the water heater is located far from the use points. Research and outreach to stakeholders reveals that homeowners are overwhelmingly satisfied with the performance of their IWH.
- **Impact on equipment retailers (including manufacturers and distributors**): The proposed code change will have some impacts on manufacturers, distributors, and retailers. Sales will increase for manufacturers of qualifying water heaters and for retailers and distributors that stock qualifying products.
- **Impact on energy consultants:** There are no anticipated impacts to energy consultants from the proposed code change.
- **Impact on building inspectors:** As compared to the overall code enforcement effort, this measure has negligible impacts on the effort required to enforce the building codes.

[3] A 30-year period of analysis for residential buildings, as required by the CEC Lifecycle Cost Methodology.

- **Statewide employment impacts:** The proposed changes to Title 24 are expected to impact employment. An increase in employment in the water heating sector (e.g., in-state manufacturing, retailers) is expected while a slight employment decrease for installers may result, as IWHs have higher product life expectancies than storage water heaters; the rate of replacement is lower for the former.
- **Impacts on the creation or elimination of businesses in California:** Based on the California Air Resources Board's economic analyses, the proposed Title 24 code changes will encourage the creation of businesses in California.[4]
- **Impacts on the potential advantages or disadvantages to California businesses:** California businesses would benefit from an overall reduction in energy costs due to the decrease in energy demand from the residential sector. This could help California businesses gain competitive advantage over businesses operating in other states or countries and an increase in investment in California, as noted below.
- **Impacts on the potential increase or decrease of investments in California:** Based on the California Air Resources Board's economic analyses, the proposed Title 24 code changes will encourage more investments in California.
- **Impacts on incentives for innovations in products, materials or processes:** Updating Title 24 standards will encourage innovation through the adoption of new technologies to better manage energy usage and achieve energy savings.
- **Impacts on the State General Fund, Special Funds and local government:** The Statewide CASE Team expects positive overall impacts on state and local government revenues due to higher Gross State Production and personal income resulting in higher tax revenues. Higher property valuations due to energy efficiency enhancements may also result in positive local property tax revenues.
- **Cost of enforcement to State Government and local governments:** All revisions to Title 24 will result in changes to Title 24 compliance determinations. Local governments will need to train permitting staff on the revised Title 24 standards. While this re-training is an expense to local governments, it is not a new/additional cost associated with the 2016 code change cycle.
- **Impacts on migrant workers; persons by age group, race, or religion:** This proposal and all measures adopted by CEC into Title 24 Part 6 do not advantage or discriminate in regards to race, religion or age group.
- **Impact on homeowners (including potential first time home owners):** The proposed code change will have a positive overall impact on homeowners. The longer lifespan of IWHs results in fewer water heater replacements over time, particularly if routine maintenance is undertaken to prolong the useful life of the water heater. Homeowner-occupants will benefit from a continual supply of hot water and lower utility bills, though the wait time for hot water may increase slightly due to the additional time it takes for hot

[4] The California Air Resources Board's economic analyses are discussed in detail in Section 3.5 *Economic Impacts* of this CASE Report.

water to arrive, particularly if the water heating system is designed so that the water heater is located far from the use points. Research and outreach to stakeholders reveals that homeowners are overwhelmingly satisfied with the performance of their IWH.

- **Impact on Renters:** This proposal is advantageous to renters as it reduces the cost of utilities which are typically paid by renters. Since the measure saves more energy costs on a monthly basis than the measure costs on the mortgage as experienced by the landlord, the pass-through of added mortgage costs into rental costs is less than the energy cost savings experienced by renters.
- **Impact on Commuters:** This proposal and all measures adopted by CEC into Title 24 Part 6 are not expected to have an impact on commuters.

Statewide Energy Impacts

Table 2 shows the estimated energy impacts over the first twelve months of implementation of the IWH measure.

Table 2: Estimated First Year Energy Savings for the IWH Prescriptive Option

	Electricity Savings (GWh)	Power Demand Reduction (MW)	Natural Gas Savings (MMtherms)	First Year TDV Energy Savings (Million kBTU) [1]
Proposed Measure	-6.16	-1.34	3.17	828
TOTAL	-6.16	-1.34	3.17	828

1. TDV energy savings calculations include electricity and natural gas use.

Section 4.6.1 discusses the methodology and Section 5.1.1 shows the results for the per unit energy impact analysis.

Cost-effectiveness

Results of the building unit Cost-effectiveness Analyses are presented in Table 3. The Time Dependent Valuation (TDV) Energy Costs Savings are the present valued energy cost savings over the 30-year period of analysis using CEC's TDV methodology. The Total Incremental Cost represents the incremental equipment and maintenance costs of the proposed measure relative to existing conditions (i.e. current minimally compliant construction practices). Costs incurred in the future, such as periodic maintenance costs or replacement costs, are discounted by a 3% real discount rate per CEC's Lifecycle Cost (LCC) Methodology. The Planning Benefit to Cost (B/C) Ratio is the incremental TDV Energy Costs Savings divided by the Total Incremental Costs. When the B/C ratio is greater than 1.0, the added cost of the measure is more than offset by the discounted energy cost savings and the measure is deemed to be cost effective. For a detailed description of the Cost-effectiveness Methodology see Section 4.7 of this report.

Based on the results of the Cost-effectiveness Analysis for the proposed IWH prescriptive option, the Planning B/C Ratio is greater than 1.0 in every California climate zone. This means that the installation of gas IWHs, per the proposed primary prescriptive requirement, will result in cost savings relative to the existing conditions. While the measure is cost effective in every climate zone, the magnitude of cost-effectiveness varies from a high Planning B/C ratio of 3.40 in climate zone 15 to a low Planning B/C ratio of 3.22 in climate zone 1.

Table 3: Cost-effectiveness Summary[1] per Building for All Prescriptive Options

Climate Zone	Benefit: Total TDV Energy Cost Savings + Other Cost Savings[2] (2017 PV $)	Cost: Total Incremental Cost[3] (2017 PV $)	Change in Lifecycle Cost[4] (2017 PV $)	Benefit to Cost Ratio[5]
Prescriptive Option: Instantaneous Water Heater				
Climate Zone 1	$2,334	$725	($1,609)	3.22
Climate Zone 2	$2,372	$725	($1,647)	3.27
Climate Zone 3	$2,370	$725	($1,645)	3.27
Climate Zone 4	$2,387	$725	($1,662)	3.29
Climate Zone 5	$2,359	$725	($1,634)	3.25
Climate Zone 6	$2,398	$725	($1,673)	3.31
Climate Zone 7	$2,378	$725	($1,653)	3.28
Climate Zone 8	$2,409	$725	($1,684)	3.32
Climate Zone 9	$2,414	$725	($1,689)	3.33
Climate Zone 10	$2,415	$725	($1,690)	3.33
Climate Zone 11	$2,414	$725	($1,689)	3.33
Climate Zone 12	$2,395	$725	($1,670)	3.30
Climate Zone 13	$2,415	$725	($1,690)	3.33
Climate Zone 14	$2,420	$725	($1,695)	3.34
Climate Zone 15	$2,467	$725	($1,742)	3.40
Climate Zone 16	$2,354	$725	($1,629)	3.25
Additional Prescriptive Option: Storage Water Heater and QII & Compact Design				
Climate Zone 1	$2,296	$1,182	($1,114)	1.94
Climate Zone 2	$1,635	$1,182	($453)	1.38
Climate Zone 3	$1,333	$1,182	($151)	1.13
Climate Zone 4	$1,508	$1,182	($326)	1.28
Climate Zone 5	$1,291	$1,182	($109)	1.09
Climate Zone 6	$945	$1,182	$237	0.80
Climate Zone 7	$611	$1,182	$571	0.52
Climate Zone 8	$1,069	$1,182	$113	0.90

Climate Zone 9	$1,454	$1,182	($272)	1.23
Climate Zone 10	$1,545	$1,182	($363)	1.31
Climate Zone 11	$2,584	$1,182	($1,402)	2.19
Climate Zone 12	$2,268	$1,182	($1,086)	1.92
Climate Zone 13	$2,489	$1,182	($1,307)	2.11
Climate Zone 14	$2,539	$1,182	($1,357)	2.15
Climate Zone 15	$2,012	$1,182	($830)	1.70
Climate Zone 16	$2,934	$1,182	($1,752)	2.48
Statewide Average	$1,782	$1,182	($600)	1.51
Additional Prescriptive Option: Storage Water Heater and QII & Pipe Insulation				
Climate Zone 1	$2,192	$1,131	($1,061)	1.94
Climate Zone 2	$1,539	$1,131	($408)	1.36
Climate Zone 3	$1,237	$1,131	($106)	1.09
Climate Zone 4	$1,416	$1,131	($285)	1.25
Climate Zone 5	$1,194	$1,131	($63)	1.06
Climate Zone 6	$853	$1,131	$278	0.75
Climate Zone 7	$521	$1,131	$610	0.46
Climate Zone 8	$979	$1,131	$152	0.87
Climate Zone 9	$1,365	$1,131	($234)	1.21
Climate Zone 10	$1,455	$1,131	($324)	1.29
Climate Zone 11	$2,492	$1,131	($1,361)	2.20
Climate Zone 12	$2,176	$1,131	($1,045)	1.92
Climate Zone 13	$2,399	$1,131	($1,268)	2.12
Climate Zone 14	$2,447	$1,131	($1,316)	2.16
Climate Zone 15	$1,935	$1,131	($804)	1.71
Climate Zone 16	$2,829	$1,131	($1,698)	2.50
Statewide Average	$1,689	$1,131	($558)	1.49

1. Relative to existing conditions. All cost values presented in 2017 dollars. Cost savings are calculated using 2016 TDV values.
2. Total benefit includes TDV energy cost savings, cost savings from equipment replacements, and incremental maintenance cost savings.
3. Total cost equals incremental first cost (equipment and installation).
4. Negative values indicate the measure is cost effective. Change in lifecycle cost equals cost minus benefit.
5. The Benefit to Cost ratio is the total benefit divided by the total incremental costs. The measure is cost effective if the B/C ratio is greater than 1.0.

Section 4.7 discusses the methodology and Section 5.2 shows the results of the Cost-Effectiveness Analysis.

Greenhouse Gas and Water Related Impacts

For a more detailed analysis of the possible environmental impacts from the implementation of the proposed measure, please refer to Section 5.3 of this report.

Greenhouse Gas Impacts

Table 4 presents the estimated avoided greenhouse gas (GHG) emissions of the proposed code change for the first year the Standards are in effect. Assumptions used in developing the GHG savings are provided in Section 4.8.1 of this report.

The monetary value of avoided GHG emissions is included in TDV cost factors and is thus included in the Cost-effectiveness Analysis prepared for this report.

Table 4: Estimated First Year Statewide Greenhouse Gas Emissions Impacts

	Avoided GHG Emissions[1] ($MTCO_2e$/yr)
Proposed Measure	14,647
TOTAL	14,647

1. First year savings from buildings built in 2017; assumes 353 $MTCO_2e$/GWh and 5,303 $MTCO_2e$/MMTherms.

Section 4.8.1 discusses the methodology and Section 5.3.1 shows the results of the greenhouse gas emission impacts analysis.

Water Use Impacts

Potential water use impacts were considered but not factored into the savings calculations for the proposed measure. Section 4.8.2 and Section 5.3.2 discusses the Statewide CASE Team's rationale.

Field Verification and Diagnostic Testing

There are no field verification and diagnostic testing requirements associated with the proposed code change.

1. INTRODUCTION

The Codes and Standards Enhancement (CASE) initiative presents recommendations to support California Energy Commission's (CEC) efforts to update California's Building Energy Efficiency Standards (Title 24) to include new requirements or to upgrade existing requirements for various technologies. The four California Investor Owned Utilities (IOUs) – Pacific Gas and Electric Company, San Diego Gas and Electric, Southern California Edison and Southern California Gas Company – and the Los Angeles Department of Water and Power (LADWP) sponsored this effort. The program goal is to prepare and submit proposals that will result in cost-effective enhancements to energy efficiency in buildings. The report and the code change proposal presented herein is part of the effort to develop technical and cost-effectiveness information for proposed regulations on building energy efficient design practices and technologies.

The goal of this CASE Report is to propose revisions to the prescriptive requirements for water heating in new single family buildings, residential additions, and new multi-family buildings with dedicated water heaters for each dwelling unit. The code change proposal would recommend that an applicant can comply with the prescriptive standards by installing a gas instantaneous water heater (IWH) that meets minimum federal efficiency levels. As an alternative, the applicant can also comply by installing a gas storage water heater that meets federal minimum efficiency levels. If the applicant chooses to install a gas storage water heater, they will also be required to have a Home Energy Rating System (HERS) verified Quality Insulation Installation (QII), plus one of the following: installation of a compact hot water distribution design or a HERS verified domestic hot water pipe insulation.

Additionally, the Statewide CASE Team recommends adding a mandatory measure that if a gas IWH is installed, a drain kit (i.e. isolation valves) must be installed as part of the water heating system. Isolation valves assist in the flushing of the heat exchanger and help prolong the life of gas IWHs.

The report considers market availability and cost effectiveness[5] of gas IWHs and demonstrates that complying with Title 24 by installing a gas IWH is cost effective and feasible in all California climate zones. While the scope of the CASE proposal is limited to evaluating the impacts of compliance using a gas IWH, the Statewide CASE Team notes that other pathways to compliance are also cost effective. Applicants that comply using the performance approach can comply by deploying a wide variety of measures. The Statewide CASE Team did not evaluate all compliance pathways.

Section 2 of this CASE Report provides a description of the measure, how the measure came about, and how the measure helps achieve the state's zero net energy (ZNE) goals. This section presents how the Statewide CASE Team envisions the proposed code change would be enforced and the expected compliance rates. This section also summarized key issues that the Statewide CASE Team addressed during the CASE development process, including issues

[5] CEC is legally required to only demonstrate that the primary prescriptive path is cost effective and viable given the current availability of products.

discussed during a public stakeholder meeting that the Statewide CASE Team hosted in May 2014 and a CEC pre-rulemaking meeting in July 2014.

Section 3 presents the market analysis, including a review of the current market structure, a discussion of product availability, and the useful life and persistence of the savings from the proposed measure. This section offers an overview of how the proposed standard will impact various stakeholders including builders, building designers, building occupants, equipment retailers (including manufacturers and distributors), energy consultants, and building inspectors. Finally, this section presents estimates of how the proposed change will impact statewide employment.

Section 4 describes the methodology and approach the Statewide CASE Team used to estimate energy, demand, costs, and environmental impacts. Key assumptions used in the analyses can be also found in Section 4.

Results from the energy, demand, costs, and environmental impacts analysis are presented in Section 5. The Statewide CASE Team calculated energy, demand, and environmental impacts using two metrics: (1) per unit and (2) statewide impacts during the first year buildings complying with the 2016 Title 24 Standards are in operation. Time Dependent Valuation (TDV) energy impacts, which accounts for the higher value of peak savings, are presented for the first year both per unit and statewide. The incremental costs relative to existing conditions are presented as the present value of year TDV energy cost savings and the overall cost impacts over the 30-year period of analysis, as required by CEC.

This report concludes with specific recommendations for language for the Title 24 Standards, Residential ACM Reference Manual, and Residential Compliance Manual.

2. MEASURE DESCRIPTION

2.1 Measure Overview

2.1.1 Measure Description

To comply with Title 24 Standards, an applicant must implement all mandatory requirements in the Standards. In addition to implementing the mandatory measures, the applicant must choose to either (1) implement a discrete set of additional measures, as defined in the prescriptive requirements (i.e. prescriptive approach), or (2) confirm that the building's energy performance meets the required energy budget, as modeled using CEC-approved modeling software (i.e. performance approach). Over 90 percent of applicants comply with the Standards using the performance approach, which provides more flexibility. The energy budget that must be achieved if an applicant complies using the performance approach is developed by modeling the building assuming all the prescriptive measures are deployed. A building will be in compliance with Title 24 if the energy budget of the proposed building achieves the same energy budget that it would have achieved if deploying all of the prescriptive measures.

The 2013 Title 24 prescriptive requirements indicate that if natural gas is available,[6] either a gas-fired storage water heater or IWH must be used. If gas is not available, the applicant can comply with the standards prescriptively by installing an electric-resistant water heater (either storage or IWH) combined with a solar water heating system that provides a solar fraction of at least 0.50.

The Residential IWH measure proposes modifications to the prescriptive requirements for domestic water heating systems in single family homes and multi-family buildings with dedicated water heaters for each individual dwelling unit. The goal of the measure is to update the water heating energy budget to help ensure that builders are encouraged to improve the efficiency of hot water systems in residential buildings.

The Residential IWH measure proposes modifications to the prescriptive requirements for domestic water heating systems in single family homes and multi-family buildings with dedicated water heaters for each individual dwelling unit. The goal of the measure is to update the water heating energy budget to help ensure that builders are encouraged to improve the efficiency of hot water systems in residential buildings.

The proposed code changes would modify the code requirements by specifying that the applicant can comply with the prescriptive standards by installing a gas instantaneous water heater (IWH) that meets minimum federal efficiency levels. As an alternative, the applicant can also comply by installing a gas storage water heater that meets federal minimum efficiency levels. If the applicant chooses to install a gas storage water heater, they will also be required to have a Home Energy Rating System (HERS) verified Quality Insulation Installation (QII), plus one of the following: installation of a compact hot water distribution design or a HERS verified domestic hot water pipe insulation. Each of these options will result in approximately equivalent energy performance on a statewide basis; they were modeled using CEC's approved public domain modeling software program, CBECC-Residential, Version 3 (see Section 5.1for projected savings of proposed prescriptive options).

The proposed prescriptive options are as follows (See Section 6 for proposed code language):

1. Install a single natural gas or propane IWH meeting minimum federal efficiency levels *(used to calculate baseline energy budget for performance approach*); or
2. Install a single gas or propane storage water heater meeting minimum federal efficiency level plus with an input of 105,000 Btu per hour or less in combination with QII requirements (HERS verified) and either:
    a. Compact hot water distribution design that is field verified; or
    b. Pipe insulation requirements (HERS verified).

[6] The 2013 Title 24 Standards and accompanying manuals (e.g., Residential Compliance Manual and Alternative Compliance Method Reference Manual) are ambiguous in defining "natural gas availability." As such, this measure is also proposing revisions to the definition of gas availability and recommends an improved method of determining gas availability for compliance enforcement.

As mentioned, most applicants use the performance approach to comply with the Title 24 Standards. Applicants that use the performance approach would still have the option of complying with the Standards by deploying any number of strategies that would allow them to meet the overall energy budget. For example, an applicant could choose to install a storage water heater in conjunction with other efficiency measures, like a higher performing building envelope. An applicant could also choose to install a heat pump water heater (HPWH) in conjunction with another efficiency measure.

The Statewide CASE Team will be recommending revisions to the ACM Reference Manual and Compliance Manual to improve how "gas availability" is defined, and how one determines "gas availability."

Finally, the Statewide CASE Team recommends adding a mandatory measure that if a gas IWH is installed, a drain kit (i.e. isolation valves) must be installed as part of the water heating system. Isolation valves assist in the flushing of the heat exchanger and help prolong the life of gas IWHs. Installation of a drain kit has become the standard among installers and plumbers and is recommended by water heater manufacturers. These valves are typically not included with the water heater unit.

Additional Prescriptive Options

Prior to CEC's November 3, 2014 pre-rulemaking workshop, CEC released draft language that recommended a prescriptive option that would allow an applicant to install a minimally compliant gas storage water heater in combination with HERS verified QII and either 1) HERS pipe insulation requirements, or 2) compact hot water distribution design. The Statewide CASE Team supports this prescriptive option, as QII as a method for improving envelope efficiency is more practical and cost-effective than the option that called for the use of a solar thermal system to provide a fraction of the water heating demand that was proposed in the CASE Report submitted to CEC in September 2014.

This section of the CASE Report provides information about the additional prescriptive option, including the calculated energy impacts and cost-effectiveness. While the additional prescriptive option is cost effective in most climate zones, it is still the CASE Team's understanding that the prescriptive option does not need to be cost effective in every climate zone as long as the measure is cost effective statewide.

Quality Insulation Inspection (QII)

Interviews with homebuilders, contractors, and energy program implementers have found that the most commonly used wall insulation in California is fiberglass batt, while loose-fill fiberglass insulation is commonly used in attic insulation. Raised-floors are also commonly filled with fiberglass batts. Requiring QII for batt, blanket or loose-fill insulation would ensure that the majority of insulation installations are properly implemented, increasing the effective U-factor of these envelope assemblies. QII requires verification by a HERS rater to ensure proper installation within the entire thermal envelope.

Compact Hot Water Distribution System (HWDS) Design

The goal of a compact HWDS is to reduce the distance between plumbing fixtures and the water heater. There are two elements to a compact HWDS: 1) the intelligent design of a building in terms of appropriately locating bathrooms, kitchen, and laundry nearer each other, and 2) locating the water heater closer to these use points. The latter element will typically result in moving the water heater from the exterior garage wall to a preferred garage location on an interior wall, but could also result in optimally locating the water heater indoors or in an exterior closet. A more compact configuration will result in less hot water distribution piping, which in turn reduces the amount of heat loss (energy loss) and hot water delivery times.

To meet the compact HWD requirement, the longest measured pipe run length between a hot water use point and the water heater serving that use shall be no more than a distance calculated, whereby the maximum radial distance between water heater(s) and all hot water use points are defined. The goal is to move plumbing design towards more efficient layouts that reduce energy and water use.

Table 4.4.5 in Section RA4.4.16 of the Residential Appendix, outlined in Figure 1 below, specifies the maximum pipe length as a function of floor area served, where floor area served is defined as the conditioned floor area divided by the number of installed water heaters. The RA states that a HERS inspection is required in order to obtain the credit.

Floor Area Served (sq-ft)	Maximum Measured Water Heater to Use Point Distance (ft)
< 1000	28’
1001 – 1600	43’
1601 – 2200	53’
2201 – 2800	62’
> 2800	68’

Figure 1. HERS-Verified Compact Hot Water Distribution System Requirements

Pipe Insulation

The 2013 Title 24 Standards include mandatory pipe insulation requirements for domestic hot water system in residential buildings (Section 150.0 (j)2). The following piping must be insulated:

- The first 5 feet (1.5 meters) of hot and cold water pipes from the storage tank.
- All piping with a nominal diameter of 3/4 inch (19 millimeter) or larger.
- All piping associated with a domestic hot water recirculation system regardless of the pipe diameter.
- Piping from the heating source to storage tank or between tanks.
- Piping buried below grade.
- All hot water pipes from the heating source to the kitchen fixtures.

In addition to the pipe insulation requirements in the Standards, the Residential Appendix (RA) includes specifications for the Proper Installation of Pipe Insulation (RA4.4.1) and requirements if an applicant wishes to claim the Pipe Insulation Credit (RA4.4.3) or the HERS-Verified Pipe Insulation Credit (RA4.4.14). The Proper Installation of Pipe Insulation does not include requirements beyond those specified in the Standards. The Pipe Insulation Credit requires that, "[a]ll piping in the hot water distribution system must be insulated from the water heater to each fixture or appliance." The current standards do not require insulation on pipe less than ¾ inch in diameter. The Pipe Insulation Credit would require insulation on all pipe including ½ pipe. The HERS-Verified Pipe Insulation Credit states that a HERS inspection is required to verify pipes are insulated correctly.

As currently written, if the applicant wishes to use pipe insulation as a component of the prescriptive option, they must comply with all relevant sections of the Residential Appendix. In effect, this means that the applicant would need to insulate all pipes in the distribution system, including ½ inch pipes, and a HERS inspection would be required.

Pipe Insulation Requirements in the Uniform Plumbing Code

The Uniform Plumbing Code (UPC) is a model building code developed by the International Association of Plumbing and Mechanical Officials (IAPMO) using the American National Standard Institute (ANSI) consensus development procedures. The purpose of the UPC is to provide consumers with safe and sanitary plumbing systems. The UPC serves as a model code that states can adopt as their own plumbing standards. California has historically used the UPC as a basis for California Plumbing Code (Title 24 Part 5). The Building Standards Commission (BSC) and the Department of Housing and Community Development (HCD) are the regulatory agencies responsible for updating the California Plumbing Code. They have the authority to adopt the full UPC or make California amendments to the UPC.

The pipe insulation requirements in the UPC will be changing in 2015 so that insulation will now be required on all domestic hot water piping regardless of pipe diameter. The full IAPMO technical assembly voted to approve the draft language (see Figure 2) during their September 2014 meeting. The language presented below is almost certainly going to appear in the 2015 UPC, which will be published in early 2015. If adopted by HCD and BSC, the UPC pipe insulation requirements in Part 6 will supersede the mandatory pipe insulation requirements. CEC will maintain the proposed pipe insulation prescriptive option since the pipe insulation installation will be verified by a HERS rater.

610.14 Pipe Insulation. Insulation of domestic hot water piping shall be in accordance with Section 610.14.1 and Section 610.14.2.

610.14.1 Insulation Requirements. Domestic hot water piping shall be insulated.

610.14.2. Pipe Insulation Wall Thickness. Hot water pipe insulation shall have a minimum wall thickness of not less than the diameter of the pipe for a pipe up to 2 inches (50 mm) in diameter. Insulation wall thickness shall be not less than 2 inches (51 mm) for a pipe of 2 inches (50 mm) or more in diameter.

Exceptions:

(1) Piping that penetrates framing members shall not be required to have pipe insulation for the distance of the framing penetration.

(2) Hot water piping between the fixture control valve or supply stop and the fixture or appliance shall not be required to be insulated.

Figure 2: 2015 UPC Pipe Insulation Requirement (to be published by IAPMO in 2015)

2.1.2 Measure History

For the 2013 Title 24 code change cycle, the Statewide CASE Team submitted a CASE Report to CEC that proposed standards to support building component compatibility with high-efficiency water heaters (HEWHs), such as gas IWHs (CA IOUs 2011a). The purpose of the HEWH measure was to remove infrastructure barriers for adopting forced draft, condensing, and/or gas IWHs, for both new construction and future replacements. The Statewide CASE

Team held several discussions on the new proposal ideas with CEC in order to conduct market research and technical analyses to directly address CEC's concerns. The proposed measure was based on application considerations collected from water heater installation guidelines, contractors, and industry experts. Therefore, when the proposal was presented at stakeholder meetings and CEC rulemaking meetings, there were no strong objections or major concerns from either stakeholders or CEC staff and the measure was adopted into the 2013 Standards.

The HEWH requirements, which went into effect July 1, 2014, apply to single family homes and multi-family buildings with a dedicated water heater for each individual dwelling unit. The new mandatory measure requires new construction to include:

1. Accessibility of electrical power supply near the water heater to support draft fans and controls.
2. Vent to accommodate acidic exhaust from high efficiency water heaters, including but not limited to condensing water heaters.
3. Condensate drains must meet local jurisdiction requirements.
4. Gas pipe sizing to support IWHs without any exemptions so that homeowners have the option to install IWHs in the future.

As previously stated, the HEWH requirements were adopted as mandatory requirements for new residential construction and have paved the way for the code change proposal presented in this report.

Reason for Proposed Code Change

Water heating accounts for the largest share of natural gas usage in California homes and 90% of California homes use natural gas to heat water (Hoeschele et al. 2012). Although 49% of natural gas usage in homes is for used for heating water (KEMA 2010)) and that technology advancements have substantially increased the efficiency of water heating equipment, the Title 24 Standards for residential water heating have experienced only gradual increases in energy efficiency over the last couple decades. Given the advancements in the energy efficiency of water heaters, it is an opportune time to update the baseline energy performance of residential water heating to allow for greater energy savings for California. If California is going to achieve zero net energy (ZNE) goals in a cost-effective manner, it is imperative that the water heating energy budget be revised.

This measure builds upon a measure that was added to the Title 24 Standards during the 2013 code change cycle which requires domestic water heating systems in new residential construction (single family and multi-family buildings with dedicated water heaters in individual dwelling units) to be designed to accommodate high-efficiency gas water heaters (e.g., condensing storage and IWHs). By the time the 2016 Title 24 Standards take effect in 2017, builders will be accustomed to designing buildings so they can accommodate gas IWHs.

2.1.3 Existing Standards

The 2013 Title 24 prescriptive requirements state that if natural gas is available, a natural gas water heater (either storage or IWH) must be used. If natural gas is not available, the applicant can comply with the standards prescriptively by installing an electric water heater (either storage or IWH) combined with a solar water heating system that provides a solar fraction of 0.50.

In addition to the Title 24 Standards, there are federal energy performance standards for residential water heating equipment for products sold in California. Table 5 displays the federal residential water heater standards that will take effect in April 2015. In addition to energy performance requirements, the federal standards will require gas storage water heaters larger than 55 gallons to be condensing type (ASAP 2014).

The United States Department of Energy (DOE) recently updated the test procedure for residential water heaters (DOE 2014). The new test procedure includes modifications to the test conditions and the hot water draw patterns of the current test procedure. The new test procedure calls for the use of a Uniform Energy Factor (UEF) rating which will replace the current Energy Factor (EF) rating. The UEF rating nomenclature characterizes the efficiency of water heating equipment in the same way as the EF rating. Because the existing and new ratings are determined under different test conditions, DOE adopted a new name to distinguish between the efficiency result under the existing test procedure and the result under the amended test procedure. The change to the test procedure and the rating factor cannot change the stringency of the federal standards. DOE will be developing a mathematical factor for converting EF ratings to UEF ratings. To avoid confusion, the Statewide CASE Team recommends avoiding specifying a required EF or UEF rating in Title 24. Rather, the proposed standards will specify that the water heating products must meet minimum federal efficiency requirements.

As discussed in Section 2.4 of this report, changes to DOE's test procedure may impact how the energy performance of gas IWH systems are evaluated in the Alternative Calculation Method for applicants that comply with the Standards using the performance approach. The previous test procedure resulted in EF ratings for IWH systems that lab and field testing found to be too high (Burch et al. 2008; Hoeschele et al. 2011). As a result, CEC's compliance simulation software discounted the EF ratings for gas IWH by 8% prior to calculating the energy performance of water heating systems that used gas IWHs. CEC may want to evaluate whether discounting the efficiency ratings that are determined using the new test procedure is still necessary.

Table 5: Federal Water Heater Standards (Effective 2015)

Product Class	Rated Storage Volume	Energy Factor (EF)
Gas Storage Water Heater	≥ 20 gallons and ≤ 55 gallons	0.675 – (0.0015*Vs)
Gas Storage Water Heater	< 55 gallons and ≤100 gallons	0.8012 – (0.00078* V_s)
Gas Instantaneous Water Heater	< 2 gallons	0.82 – (0.0019*V_s)
Electric Water Heater	≥20 gallons and ≤ 55 gallons	0.960 – (0.0003*V_s)
Electric Water Heater	< 55 gallons and ≤120 gallons	2.057 – (0.00113*V_s)
Oil Water Heater	≤ 50 gallons	0.68 – (0.0019*V_s)
Instantaneous Electric Water Heater	< 2 gallons	0.93 – (0.00132*V_s)

V_s: Rated Storage Volume – the water storage capacity of a water heater (in gallons).

2.1.4 Alignment with Zero Net Energy (ZNE) Goals

The Statewide CASE Team and the CEC are committed to achieving the State of California's ZNE goals. Although water heating accounts for nearly 50% of natural gas use in homes, the Standards for residential water heating have experienced only gradual increases in energy efficiency over last couple decades. Given the advancements in water heater technology in recent years that substantially increased the energy efficiency of water heaters, it is an opportune time to update the baseline energy performance of residential water heating to allow for greater energy savings for California. If California is going to achieve ZNE goals in a cost-effective way, it is imperative that the water heating energy budget be revised.

2.1.5 Relationship to Other Title 24 Measures

The proposed measure does not overlap with any other Title 24 code change proposals for the 2016 code update. The September 2014 version of the code change proposal for Residential High Performance Walls and QII included recommendations for QII, however the current version of this code change proposal from February 2015 does not include recommendations for QII.

2.2 Summary of Changes to Code Documents

The sections below provide a summary of how each Title 24 document will be modified by the proposed change. See Section 6 of this report for detailed proposed revisions to code language.

2.2.1 Catalogue of Proposed Changes

Scope

Table 6 identifies the scope of the code change proposal. This measure will impact the following areas (marked by a "Yes").

Table 6: Scope of Code Change Proposal

Mandatory	Prescriptive	Performance	Compliance Option	Trade-Off	Modeling Algorithms	Forms
Yes	Yes	N/A	N/A	N/A	N/A	N/A

Standards

The proposed code change will modify the sections of the California Building Energy Efficiency Standards (Title 24, Part 6) identified in Table 7.

Table 7: Sections of Standards Impacted by Proposed Code Change

Title 24, Part 6 Section Number	Section Title	Mandatory (M) Prescriptive (Ps) Performance (Pm)	Modify Existing (E) New Section (N)
110.3(c)	Mandatory Requirements For Service Water Heating Systems And Equipment	M	E
150.1(c)8	Prescriptive Standards/Component Package for Domestic Water Heating Systems	Ps	E
150.2(b)1(G)	Low-rise Residential Buildings, Alterations, Prescriptive approach for Water-Heating Systems	Ps	E

Appendices

The proposed code change will not modify any sections of the reference appendices (see Table 8).

Table 8: Appendices Impacted by Proposed Code Change

APPENDIX NAME		
Section Number	**Section Title**	**Modify Existing (E) New Section (N)**
N/A	N/A	N/A

Residential Alternative Calculation Method (ACM) Reference Manual

The Statewide CASE Team will be proposing changes to the Residential ACM Reference Manual language in a separate deliverable to CEC. The changes will aim to improve the definition of natural gas availability and provide clarification on how one determines gas availability.

Simulation Engine Adaptations

The proposed code change can be modeled using the current simulation engine. Changes to the simulation engine are not necessary. As mentioned in Section 2.1.3, CEC's compliance simulation software discounted the EF ratings for gas IWH by 8% prior to calculating the energy performance of water heating systems that used gas IWHs. CEC may want to evaluate whether discounting the efficiency ratings that are determined using the new test procedure is still necessary.

2.2.2 Standards Change Summary

The proposed code change will modify Section 110.3(c), Section 150.0(n), and Section 150.1(c)8 of the Standards, as described below. The proposal will impact mandatory and prescriptive requirements for gas domestic water heating systems in single family homes and multi-family buildings with a dedicated water heater for each individual dwelling unit. See Section 6.1 of this report for the detailed proposed revisions to the Standards language.

Note that the proposed code change will not change the scope of the existing Title 24 Standards for residential water heating.

SECTION 110.3 – MANDATORY REQUIREMENTS FOR SERVICE WATERHEATING SYSTEMS AND EQUIPMENT

Subsection 110.3(c): The proposed measure would modify the mandatory requirements for residential water heating by requiring the installation of drain kits on all gas IWHs to assist with the flushing of the heat exchanger. This measure only applies if the applicant chooses to install a gas IWH.

SECTION 150.1 – PERFORMANCE AND PRESCRIPTIVE COMPLIANCE APPROACHES FOR NEWLY CONSTRUCTED RESIDENTIAL BUILDINGS

Subsection 150.1(c)8: The proposed measure would modify the prescriptive requirements in Subsection 150.1(c)8 by specifying that the applicant can comply with the prescriptive standards by installing a gas instantaneous water heater (IWH) that meets minimum federal efficiency levels. As an alternative, the applicant can also comply by installing a gas storage water heater that meets federal minimum efficiency levels. If the applicant chooses to install a gas storage water heater, they will also be required to have a Home Energy Rating System (HERS) verified Quality Insulation Installation (QII), plus one of the following: installation of a compact hot water distribution design or a HERS verified domestic hot water pipe insulation

SECTION 150.2 – ENERGY EFFICIENCY STANDARDS FOR ADDITIONS AND ALTERATIONS IN EXISTING BUILDINGS THAT WILL BE LOW-RISE RESIDENTIAL OCCUPANCIES

Subsection 150.2(a)1D (Additions): There are no proposed changes to this section. The existing language states that if a water heater is installed as part of an addition, the water heater system must meet the prescriptive requirements presented in Section 150.1(c)8. The QII, compact design, and pipe insulation requirements are only intended to apply to the addition, not the entire building. If natural gas is not connected to the building, the water heater can be an electric water heater that meets the minimum efficiency requirements as defined by California's Appliance Efficiency Standards.

Subsection 150.2(b)1G (Alterations): The code language will be updated to clarify that the applicant does not need to retrofit the building to comply with QII, compact design, or pipe insulation requirements if a water heater is replaced as part of an alteration.

2.2.3 Standards Reference Appendices Change Summary

There are no modifications to the Standards Appendices as a result of the proposed code change.

2.2.4 Residential Alternative Calculation Method (ACM) Reference Manual Change Summary

The Statewide CASE Team will be proposing changes to the Residential ACM Reference Manual language in a separate deliverable to CEC.

2.2.5 Residential Compliance Manual

This proposal would modify Section 5.2.2 and Section 5.4 of the Residential Compliance Manual to reflect the changes made to the Standards. See Section 6.4 of this report for the detailed proposed revisions to the text of the Residential Compliance Manual.

2.2.6 Compliance Forms Change Summary

The proposed code change will not modify the compliance forms.

2.2.7 Simulation Engine Adaptations

The proposed code change will not modify the simulation engine that is currently modeled for the proposed measure. Again, as a result of DOE's revised test method, the CEC might consider revising the current methodology that derates the EF or gas IWH by 8% prior to calculating the energy use of water heating systems that use gas IWHs.

2.2.8 Other Areas Affected

There are no other areas of the existing standards affected as a result of the proposed code change.

2.3 Code Implementation

2.3.1 Verifying Code Compliance

There will be no additional requirements for code enforcement entities for determining if a building complies with the proposed code change based on existing Title 24 Standards.

2.3.2 Code Implementation

Since domestic water heating systems are already regulated by Title 24, builders are required to install the necessary components (e.g., vent, electrical connection, ¾ inch gas pipe) for the installation of a gas IWH (effective July 1, 2014). With the new high-efficiency water heating ready measure, builders will be accustomed to designing for high-efficiency water heaters by the time the proposed measure takes effect in 2017. Conversations with various stakeholders indicate that builders have already been specifying IWHs in new residential designs on a regular basis. Builders that comply with the Standards using the performance approach will still have the option of installing any water heater that complies with federal appliance standards, as long as the total energy budget requirements are achieved. This flexibility could make it easier for builders to comply with the requirements. As such, the Statewide CASE Team does not anticipate challenges with code implementation.

2.3.3 Field Verification and Diagnostic Testing

Though field verification and diagnostic testing are required for many residential measures, they are not needed in order to assure optimum performance of the propose IWH prescriptive requirement. The proposed additional prescriptive option does require HERS verification (i.e. field verification) for QII and insulation on domestic hot water piping.

2.4 Issues Addressed During CASE Development Process

The Statewide CASE Team solicited feedback from a variety of stakeholders when developing the code change proposal presented in this report. In addition to personal outreach to key stakeholders, the Statewide CASE Team conducted a public stakeholder meeting to discuss the proposal on May 20, 2014 and presented the proposed measure at a CEC pre-rulemaking Workshop on July 21, 2014. The main issues that were addressed during development of the code change proposal are summarized below.

Relationship between Proposed Code Change and Federal Preemption

Stakeholders expressed concern that the code change proposal was a potential violation of federal preemption under the Energy Policy and Conservation Act of 1975 (EPCA). In response, it is important to note that this measure is not proposing a standard level that exceeds the federal minimum energy efficiency level nor is this measure prohibiting the installation of any type of water heater. Instead, the measure would be resetting the total baseline energy budget based on the efficiency level of a gas IWH that meets but does not exceed the efficiency level required by federal regulations. The proposed prescriptive requirements would allow an applicant that has access to natural gas to comply with the Standards in one of three ways: 1) installing a gas IWH that meets minimum federal efficiency standard level, 2) installing a gas storage water heater that is minimally compliant with federal efficiency standards in conjunction with a solar thermal water heating system that achieves a solar fraction of 0.55, or 3) installing a gas storage water heater that meets or exceeds the energy performance of a minimally compliant gas IWH.

CEC staff has indicated that CEC legal staff has evaluated the relationship between this proposed measure and federal preemption and is comfortable that this measure will not violate preemption. CEC staff has indicated they will continue to evaluate preemption concerns.

DOE Test Procedure Impact on Proposed Code Change

On July 11, 2014, DOE published a Final Rule for the test procedure for residential and certain commercial water heaters (DOE 2014). The new test procedure is scheduled to take effect on July 13, 2015. Stakeholders had questions about the impact of the new test procedure on this measure and Title 24 water heating standards in general. As required by federal law, changes to test procedures cannot increase the stringency of the efficiency standards. In a separate rulemaking, DOE will develop a mathematical conversion to translate existing EF ratings to the new UEF ratings and to ensure that the revised test procedure does not increase the stringency of the efficiency standards. Once DOE has determined the conversion factors, CEC might determine if it is appropriate to revise the CEC's compliance simulation software which discounts the EF rating of gas IWHs by 8%. The proposed Title 24 code change does not dictate a specific EF or UEF rating for water heaters. Rather, the code change would state that gas IWH be compliant with minimum federal efficiency standards. If the federal standard level changes to the new metric based on the new test procedure, the Title 24 Standards will not need to change.

Incremental Cost of Gas IWH

Another concern shared by stakeholders was the incremental cost of a gas storage water heater to a gas IWH, including the installation and maintenance costs. A publicly-available draft version of this CASE Report reported that there are no maintenance costs for a gas storage water heater versus gas IWHs, as research and outreach revealed that routine maintenance was not being undertaken for either type of water heater. Several stakeholders commented that gas IWHs do have higher maintenance costs than gas storage water heaters. As a result of this feedback, the Statewide CASE Team conducted further research and added information about incremental maintenance costs in this version of the CASE Report (See Section 5.2.1).

Definition of Natural Gas Availability

Though the course of developing this CASE Report, it has become apparent that the definition of "natural gas availability" is not clear and that a clearer definition is needed. The definitions of gas availability in the Standards, the ACM Reference Manual, and the Compliance Manuals are contradictory. For example, Section 150.1(c)8D of the Standards, which contain the prescriptive requirements for new residential construction, states that, "(f)or systems serving individual dwelling units, an electric-resistance storage or instantaneous water heater may be installed as the main water heating source only if natural gas is unavailable." The ambiguity in this language has led to questions on whether "availability" means a gas line connection to the proposed building or whether the area is serviced by a natural gas utility, and who has the authority to determine whether natural gas is available. As a result, the Statewide CASE Team will be recommending a clear method for determining if natural gas is available by way of revisions to the ACM Reference Manual and Compliance Manual.

Some stakeholders have requested that CEC reconsider the prescriptive requirement that requires applicants to use gas water heating if gas is available. The Statewide CASE Team does not support a change to the prescriptive requirements that would allow the installation of electric water heaters if natural gas is available. Natural gas water heaters are more TDV efficient than electric water heaters, although heat pump water heaters (HPWH) are closing the efficiency gap. If an applicant wants to install an electric water heater, they still have the option of doing so if they comply with the standards through the performance approach.

Heat Pump Water Heaters as a Prescriptive Option

On a related note, some stakeholders requested the addition of heat pump water heaters (HPWH) as a prescriptive option for situations when natural gas is not available. The Statewide CASE Team determined that exploring electric water heating options is outside the scope of this particular code change proposal.

Venting

Gas-fired water heaters must be properly vented so the products of combustion that are created when fuel is combusted are directed outdoors and away from people. The Statewide CASE Team has received several questions about the assumptions for venting IWHs. During the 2013 Title 24 rulemaking, the Statewide CASE Team recommended that the water heater venting requirements be updated to ensure that high-efficiency water heaters can be installed in new buildings. The High-Efficiency Water Heater Ready CASE Report submitted to CEC by the

Statewide CASE Team in 2011 includes detailed information about venting requirements and the cost associated with vents for high-efficiency water heaters, including gas IWH and condensing gas storage water heaters. The Statewide CASE Team's recommendations on venting have not changed since developing the CASE Report for the 2013 rulemaking.

The High-efficiency Water Heater Ready CASE Report (2011) resulted in a new mandatory requirement in Title 24 that requires systems using gas or propane water heaters to have a Category III or IV vent or a Type B vent with straight pipe between the outside termination and the space where the water heater is installed. This means that buildings already have to install vent systems that are suitable for gas IWHs. The CASE Report submitted in September 2014 does not focus on venting requirements because no changes to Title 24 are needed as a result of the current proposed code change. Similarly, the cost of the appropriate vent is not included in the LCC analysis because new residential buildings already have to be designed to accommodate a gas IWH.

The cost effectiveness analysis presented in the High-Efficiency Water Heater Ready CASE Report (2011) assumes plastic vent piping will be installed. This assumption was made because there are models of high-efficiency water heaters that can use plastic vents, and generally the cost-effectiveness analysis is completed on the basic system design as opposed to an upgraded system design that uses more expensive componentry. The 2011 CASE Report identified the initial cost of plastic vents in a prototype building to be $158 and stainless steel vents to be $482.

The type of vent (e.g., plastic, steel, concentric) is typically specified by the manufacturer of the water heater. While many manufacturers allow plastic vents, several manufacturers of gas IWHs require a stainless steel vent because it can withstand the condensation that is created by the water heater.[7] The installer of the water heater should follow manufacturer specifications to determine the type of vent required for each IWH model.

The following is an excerpt from the 2011 CASE Report regarding appropriate venting for high-efficiency water heaters (CA IOUs 2011a):

> The National Fuel Gas Code (NFGC), ANSI Z223.1[8], divides gas appliances into four categories based on vent operating pressure and the likelihood of condensation occurring in the vent. The four categories, which are used to determine which type of vent is appropriate for a given appliance, are shown in [Figure 3]. Negative pressure systems, also known as non-positive pressure systems, operate at static pressures that are less than the surrounding room pressure. The joints of negative pressure systems do not need to be gas tight. If vent leakage occurs, room air will be sucked into the lower pressure flue stream. On the other hand, positive pressure systems require gas tight seals. If a leak occurs in a positive pressure system, flue gases will escape into the equipment room or, even worse, into the living space causing a potentially fatal buildup of carbon monoxide.
>
> The appliance category does not directly indicate the type of venting material needed. Nearly all residential natural draft water heaters are Category I appliances and use a 3 or 4 inch diameter

[7] Rheem, Bosch, Takagi, and Noritz require Category III stainless steel vents for their gas-fired, non-condensing IWHs.

[8] National Fire Protection Association, National Fuel Gas Code—2009 Edition. http:// www.nfpa.org

double wall metal type-B vent. There are no Category II gas-fired water heaters. Most residential water heaters with power vent fall into Category III or IV, and they require different venting materials than a standard natural draft water heater. Manufacturers usually provide certified vent materials and installation specifications for their products. Plastic vent pipes, such as PVC, CPVC or ABS pipes, are typically used, although aluminum and stainless steel vents are also used for some models. Size of the vent pipe depends on heat input rating, length of the entire horizontal and vertical pipe sections, and the number of installed elbows. For residential applications, 2-inch diameter pipes are usually used. Some manufacturers require the use of proprietary concentric vent pipes, instead of generic plastic pipes.

There is not a vent product that can be used for all types of water heaters. Some stainless steel vent products, e.g. Z-Flex vents, are certified for Category I through IV applications. When they are used for a Category I natural draft water heater, 3-inch or 4-inch pipes are used. If the water heater is to be upgraded to a power vent water heater, the venting system still might have to be replaced even though it is certified for Category III and IV appliances because the new power vent water heater may only certify the use of a 2-inch diameter pipe vent.

Appliance Category	Vent Pressure	Condensing
I	Non-Positive	Non-Condensing
II	Non-Positive	Condensing
III	Positive	Non-Condensing
'IV	Positive	Condensing

Figure 3. National Fuel Gas Code Gas Appliance Category

3. MARKET ANALYSIS

The Statewide CASE Team performed a market analysis with the goals of identifying current technology availability, current product availability, and market trends. The Statewide CASE Team considered how the proposed standard may impact the market in general and individual market players. The Statewide CASE Team gathered information about the incremental cost of complying with the proposed measure. Estimates of market size and measure applicability were identified through research and outreach to key stakeholders including statewide CASE program staff, CEC, and a wide range of industry actors who were invited to participate in Statewide CASE Team's public stakeholder meetings held in May 2014 and the pre-rulemaking meeting hosted by CEC in July 2014.

3.1 Market Structure

The residential water heater market is comprised of manufacturers, distributors/suppliers, retailers, builders, plumbers/installers, and consumers. The majority of water heaters are sold as replacements to existing water heaters. Approximately 7% of water heaters are sold for new construction (NEEA 2012). In the replacement market, water heaters are typically purchased by homeowners or plumber/installers through brick and mortar and online retailers. Market research reveals that the top water heater retailers are The Home Depot, Lowe's Home

Improvement, and Sears (PG&E 2012). In new construction, water heaters can be purchased directly from the manufacturers by suppliers or distributors who in turn sell them to builders and/or contracted plumber/installers (see Figure 4). Builders and plumbers can also purchase water heaters from retailers, such as the three mentioned above.

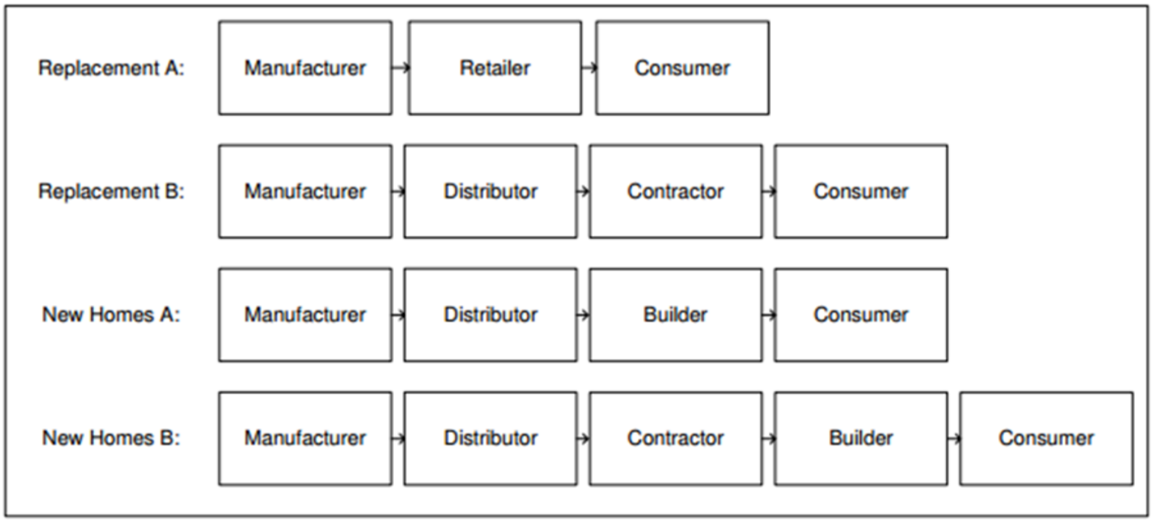


Figure 4: Residential Water Heater Distribution Channels

Source: DOE 2010

There are three manufacturers that comprise more than 95% of the residential water heating market in the United States (PG&E 2012). These manufacturers are A.O. Smith, Bradford White Corporation and Rheem and they manufacturer several unique brands of water heaters (see Figure 5 and Table 9). A.O. Smith and Rheem distribute their products through retailer and contractor channels. Bradford White water heaters are available only through contractors. Over 25 manufacturers make up the remaining 5% of the water heater market. Approximately one-third of water heater manufacturers sell gas IWHs in California (CEC Appliance Efficiency Database 2014).

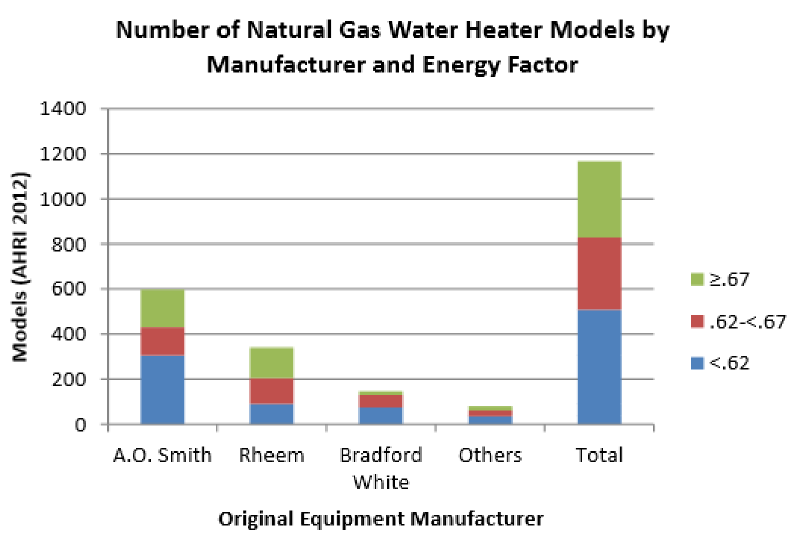


Figure 5: Natural Gas Water Heater Models by Manufacturer and Energy Factors

Source: PG&E 2012

Table 9: Water Heater Manufacturers and Brands

Sources: CEC 2014; Consortium for Energy Efficiency 2014; ENERGY STAR 2014

Manufacturer	Brand
A.O. Smith*	A O Smith Water Products (IWH and Storage) Amercican (IWH) American Water Heater Co. (IWH and Storage) Apollo (Storage) Garrison (Storage) GSW (Storage) Lochinvar Corp. (Storage) Maytag (Storage) Kenmore (IWH) Powerflex (Storage) Reliance (IWH and Storage) Sears Brand (IWH and Storage) State Industries (IWH and Storage) Takagi (IWH) U.S. Craftsmaster (IWH and Storage) Whirlpool (Storage)
Rheem*	EcoSense (IWH) General Electric (Storage) Paloma/Waiwela (IWH) Raypack (IWH) Rheem (IWH and Storage) Richmond (IWH and Storage) Ruud (IWH and Storage) Sure Comfort (IWH) Vanguard (Storage)
Bradford White Corporation*	Bradford White (IWH and Storage) Lochinvar Corp. (Storage)
Rinnai	Giant (IWH) Jaccuzi Luxury Bath - Signature (IWH) Rinnai (IWH)
American Standard	Dura-Glass (Storage)
Navien	Navien (IWH)
Quietside	Quietside (IWH)
Bosch Thermotechology Group	Bosch (IWH) Aquastar (IWH)

	Pro Tankless (IWH) Therm (IWH)
Giant Factories	Giant Factories (IWH and Storage)
Grand Hall	Eternal (IWH)
Contractors Supply Club, LLC/DBA Greenworks Unlimited	EcoHot (IWH)
Heat Cell Technologies, Inc. / ECO Heating Systems	Hamilton Engineering (IWH) Propak TM (IWH)
Noritz America Corp.	Electrolux Home Products (IWH) Noritz America Corp. (IWH)
Water Heater Innovations	Marathon (Storage) Sears (Storage)
Demand Energy LLC	Insta Heat (IWH)

* One of the three largest U.S. manufacturers that comprise approximately 95% of the water heating market.

3.2 Market Availability and Current Practices

3.2.1 Market Availability

There is widespread availability of high efficiency water heaters in California. This CASE Report focuses on the market availability and cost effectiveness of gas IWHs because CEC must show the prescriptive path that is used to establish the building's water heating budget is cost effective and viable given the currently available products. This report demonstrates that complying with Title 24 by installing a gas IWH is cost effective and feasible in all California climate zones. While the scope of the CASE analysis is limited to evaluating the impact of complying using a gas IWH, other compliance paths are likely cost-effective. Applicants that comply using the performance approach can comply by deploying a wide variety of measures. The Statewide CASE Team did not evaluate all compliance pathways.

CEC maintains a database of appliances that can be sold in California (federal and Title 20 compliant). As of September 17, 2014, there are 18 different manufacturers of gas IWHs that comply with the minimum federal efficiency standard of an EF of 0.82 or higher listed in the database (0.82 EF will become the minimum energy efficiency level when the federal standards go into effect in April 2015). Among these manufacturers, there are 41 unique brands. In total, there are 1,475 unique gas IWH models (EF range of 0.82 to 0.99) in the database. Products that meet the federal minimum efficiency of 0.82 EF comprises approximately 47% of the total products listed (CEC 2014). In sum, the market for gas IWHs appears to be more than sufficient to provide builders with many options to comply with the proposed standard using gas IWHs.

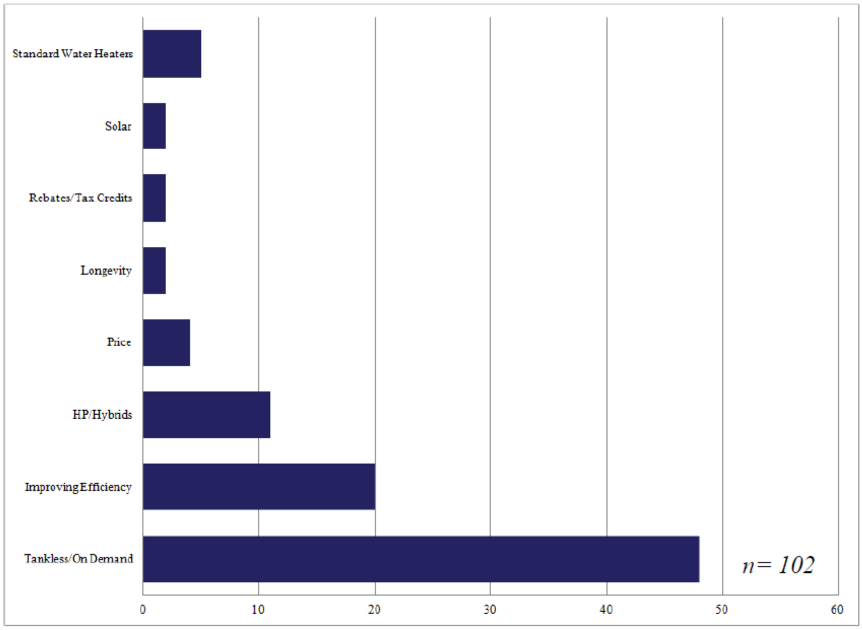
On a national level, sales and shipment data provide evidence that IWHs are growing in market share. For example, ENERGY STAR® certified gas IWHs[9] have seen a 15% increase in the number of units shipped in recent years: there were 337,186 shipments in 2011 (ENERGY STAR 2012) and 397,000 shipments in 2013 (ENERGY STAR 2014).

In the new construction market, IWHs sales have been as high as 18 to 21% (NEEA 2011; PG&E 2012). In other words, the current U.S. market for IWHs is three times as large as the forecast for low rise new construction in California in 2017 (108,032 single family and 27,784 multifamily dwelling units). Thus, manufacturing capacity or equipment availability is not considered to be a constraint.

According to PG&E's Emerging Technology Program, the market potential for gas IWHs is significant, with an estimated potential market of about 250,000 (~25% of the market) units per year in California (137,000 new construction, 113,000 retrofit) (PG&E 2007).

The widespread availability of IWHs can be attributed to numerous factors, including growing consumer interest. According to Kema's (2010) IOU energy efficiency program evaluation study that evaluated programs that were in effect in 2006-08, as well as industry predictions, the water heater and residential retrofit markets are embracing IWHs. A survey of retailers and manufacturers that the Northwest Energy Efficiency Alliance (NEEA) conducted indicated that 1) energy efficiency and 2) IWHs are perceived to be the two most significant market trends in the water heating industry. Results of the survey are presented in Figure 6. NEEA also reported a 61% increase in Internet search traffic for "tankless water heater" between January 2004 and January 2011 (NEEA 2012). Furthermore, a large water heater and plumbing company that installs IWHs in existing buildings across California reports that 25-30% (roughly 600 per year) of their water heater installations are gas IWHs, and that the regions where more IWHs are installed are Los Angeles, Orange, Ventura, and San Diego Counties (personal communication on August 7, 2014). This certainly reflects growing consumer interest in IWHs.

[9] The minimum EF rating for ENERGY STAR Qualified IWHs is 0.82.



SR16. What do you perceive are the latest trends in water heating products?

Figure 6: Key Market Trends in Water Heating Industry

Source: NEEA 2012

The interest in IWHs can be attributed to their benefits, such as compact size, longer product lifespan, and higher energy efficiency, as well as the frequently marketed benefits such as an endless supply of hot water and lower utility bills. Rodgers and O'Donnell (2008) assert that bringing consumer attention to these other benefits may be changing the dynamic of the water heater market as a whole.

State and federal water heating standards will influence the market trend toward higher-efficiency water heating, including IWHs. The 2013 Title 24 Standards, effective July 2014, require new residential construction to be designed so they can accommodate high efficiency water heaters. While the 2013 Title 24 Standards do not require that the high-efficiency water heater be installed, it is anticipated that since buildings have to be designed to accommodate higher efficiency water heaters, some builders will opt to install more efficient water heaters voluntarily. The higher efficiency water heaters could be gas IWH or condensing storage.

Finally, the market penetration of gas IWHs has grown due to the success of reach codes and incentive programs, such as ENERGY STAR and utility rebate programs, such as the one offered by Southern California Gas. Industry projections indicate a future annual growth rate of more than 10% per year (CA IOUs 2011a). The growth in market share of IWHs will result in decreasing installed product costs, which is another factor driving the trend toward instantaneous water heating.

3.2.2 Current Practice

Historically, storage water heaters have dominated the water heater market both in California and nationally. In recent years, however, builders have frequently been offering gas IWHs in addition to gas storage water heaters in the designs on new single family construction, (personal communication with plan checker on May 8, 2014; personal communication with national home builder on July 30, 2014). In fact, IWHs are now more commonly included in the design plans for new homes in Southern California, based on our discussions with various stakeholders. Other high-efficiency water heater technologies are also gaining popularity, such as heat pump water heaters and condensing gas storage water heaters.

3.3 Useful Life and Maintenance

3.3.1 Useful Life

The estimated useful life (EUL) of water heaters is variable and depends largely on usage patterns, water quality, and maintenance. Table 10 lists the EUL of water heaters as reported by numerous reputable sources. As can be seen in Table 10, IWHs are commonly cited as having a useful life of 20 years with storage water heaters ranging between 5 and 13 years.

Manufacturer warranties can also be used as a data point for estimating the EUL of a product. Table 11 lists the warranties of various water heater heaters. Generally, a manufacturer will warranty its products for a portion of their useful life and not for the full life since that would not be cost-effective for the manufacturer. As such, it can be assumed that if a company warranties a product for 15 years, as do a number of IWH manufacturers, then the product will last longer than 15 years if properly installed and maintained.

Based on the range of EULs for IWHs and storage water heaters, it is evident that IWHs are expected to have a longer useful life than their storage counterparts. The useful life depends on how the water heater is maintained. See Section 3.3.2 below for more information about proper water heater maintenance.

The Statewide CASE Team used DOE's estimates of useful life in the Life-cycle Cost (LCC) analysis (13 years for storage water heaters and 20 years for IWHs). DOE's estimates of useful life were developed through a rigorous public process with participation and input from the major players within the water heating industry. As such, the Statewide CASE Team used DOE's estimates because they were vetted through a diligent public process that involved industry experts.

Table 10: Product Life Ranges

Source	Lifespan (years)		Reference
	Storage	IWH	
U.S. Department of Energy (2010)	13	20	http://www.regulations.gov/#!documentDetail;D=EERE-2006-STD-0129-0005
American Council for an Energy-Efficient Economy (2012)	13	13	http://www.aceee.org/consumer/water-heating
Northwest Energy Efficiency Alliance (2006)	12.9	--	http://neea.org/docs/reports/2011waterheatermarketupdatea273dbb87ca3.pdf
Southern California Gas Company Application Tables (2013-2014)	11	20	http://www.socalgas.com/regulatory/documents/A-12-07-003/SCG%20Appendix%20E%20Application%20Tables.pdf
Database for Energy Efficiency Resources (2014)	11	20	http://www.deeresources.com/
Super Efficient Gas Water Heating Appliance Initiative (2008)	13	--	http://www.energy.ca.gov/2007publications/CEC-500-2007-105/C EC-500-2007-105.PDF
National Association of Home Builders/Bank of America Home Equity (2007)	10	20+	https://www.nahb.org/fileUpload_details.aspx?contentID=99359
Center for Energy and Environment (2012)	10-12	15-20	Schoenbauer, B., D. Bohac and M. Hewett. "Tankless Water Heaters - Do They Really Work?" In ACEEE Summer Study Proceedings, 2012. Paper 193. Pacific Grove, CA, 2012.
Builders Websource (2012)	--	15-20	http://www.builderswebsource.com/techbriefs/tankless.htm
A National Home Builder	5-10	--	Personal Communication on July 30, 2014
A statewide professional plumbing company	10	20	Personal Communication on August 7, 2014

Table 11: Water Heater Warranties

Source	Warranty (years)		Reference
	Storage	IWH	
A.O. Smith	6 (tank) 6 (parts)	15 (heat exchanger) 5 (parts)	http://www.americanwaterheater.com/products/resGas.aspx http://www.americanwaterheater.com/products/onDemand.aspx
Bradford White	10 (tank) 6 (parts)	12 (heat exchanger) 5 (parts)	http://www.bradfordwhite.com/sites/default/files/product_literature/39699ZAD.pdf https://www.plumbersstock.com/product/67453/bradford-white-tg-150e-n-nat-gas-tankless-water-heater/?gclid=CIKx6cD6wMACFSsSMwod8hEAIg
Noritz	--	12 (heat exchanger) 5 (parts)	http://www.noritz.com/residential-products/nr71-sv/ http://www.noritz.com/residential-products/nr66/ http://www.noritz.com/residential-products/nr50/
Rheem	9 - 12 (tank and parts)	12 (heat exchanger) 5 (parts)	http://cdn.globalimageserver.com/fetchdocument-rh.aspx?name=performance-platinum-atmospheric-performance-platinum-atmospheric
Lochinvar	6 - 10 (tank) 2 - 6 (parts)	--	http://www.lochinvar.com/products/default.aspx?type=productline&lineid=45
State	6 (tank) 6 (parts)	15 (heat exchanger) 5 (parts)	http://www.statewaterheaters.com/lit/warranty/res-gas.html http://www.statewaterheaters.com/lit/warranty/tankless.html
Rinnai	--	12 (heat exchanger) 5 (parts)	http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CCAQFjAA&url=http%3A%2F%2Fwww.rinnai.us%2Fdocumentation%2Fdownloads%2FRinnai_Value_Series_Tankless_Water_Heater_Warranty.pdf&ei=i_2BVJ6SM4XToATi-YLQAQ&usg=AFQjCNFdXU7FHePug2JqI7-_0-a1n2Y1Rg&bvm=bv.81177339,d.cGU
American Water Heaters	6 – 12 (tank) 6 - 12 (parts)	5 – 15 (heat exchanger) 5 (parts)	http://www.americanwaterheater.com/products/resGas.aspx http://www.americanwaterheater.com/products/onDemand.aspx
Bosch	--	15 (heat exchanger) 5 (parts)	http://www.bosch-climate.us/support-center/product-warranty.html

3.3.2 Maintenance

Water heaters should be maintained according to manufacturer recommendations to ensure proper water heater performance, prolonged useful life, and warranty coverage. If water heaters are not maintained, the useful life can be shortened and failures may not be covered under the warranty. Table 12 lists the primary maintenance activities for storage water heaters and IWH based on manufacturer and plumber recommendations. Some manufacturers recommend additional maintenance activities than those listed in Table 12. For example, a leading water heater manufacturer recommends draining one gallon of water from the bottom of storage water heaters on a monthly basis to remove sediment in the tank. As noted in Table 12, both storage water heaters and IWHs have recommended regular maintenance procedures.

Table 12: Key Maintenance Activities for Water Heaters

Type	Activity	Frequency	Source
IWH	Draining and flushing heat exchanger	Every 2-4 years[1]	Statewide plumbing company
	Inspection of burner, temperature & pressure relief valve, air intake filter, water filter, and venting system	Annually	Rheem Bradford White A.O. Smith American Standard Takagi
Storage	Draining and flushing storage tank	Every 6 months to annually	Bradford White Statewide plumbing company Lochinvar US Craftsmaster GSW
	Inspection of burner, thermostat (operation of), venting system, temperature & pressure relief valve	Every 3 months to annually	Bradford White American Standard Lochinvar State GSW American Standard
	Inspection of the anode rod	Every 1- 2 years, or more frequently in areas with soft water	Bradford White Lochinvar GSW Pacific Northwest National Laboratory

[1] In areas with hard water, flushing is typically recommended every 2 years. In areas with soft water (naturally occurring or conditioned), flushing is recommended every 3-4 years.

With proper maintenance of any water heater, the useful life of the product will be extended. However, the need to replace an IWH will not be as frequent as a storage water heater if maintenance is routinely carried out. According to one national home builder that installs IWHs and storage water heaters in single family homes, storage water heaters typically fail between 5 and 10 years without routine maintenance (the lifetime used in the LCC analysis is 13 years). Failure of a storage water heater (e.g., leaking a large volume of water) requires a full replacement of the unit. Failure of an IWH, on the other hand, oftentimes does not necessitate a replacement of the water heater itself but a repair to or replacement of the damaged part (typically the heat exchanger) (personal communication with home builder on July 30, 2014 and professional plumbing company on August 14, 2014). According to a statewide professional plumbing company, the cost to replace a storage tank is substantially higher than repairing an IWH (personal communication August 14, 2014).

Though water heaters require regular maintenance to prolong their useful life, it is uncertain whether people are maintaining their water heaters as recommended by manufacturers. Anecdotal evidence from conversations with homeowners in areas with varying levels of water quality, various household sizes, and who have had a gas IWH installed in their homes between 2 and 10 years reveals that maintenance is not being performed. None of the homeowners with IWHs claimed they have needed to repair or replace their water heaters in spite of not ever maintaining them. Homeowners with storage water heaters also claimed that were not maintaining their water heaters as recommended.

Section 4.7.1 of this report discusses the maintenance cost assumptions used in the LCC analysis.

Maintenance of Gas IWHs

The primary maintenance activities for an IWH are flushing the heat exchanger to remove scale buildup and inspecting and cleaning the inlet water filter screen which helps minimize the amount of debris or sediment that enters the water heater.

Some manufacturers recommend a maintenance schedule, but the maintenance schedule homeowners deploy will vary based largely on water quality. For example, in areas with hard water, professional plumbers the Statewide CASE Team spoke with recommended more frequent maintenance (every 2 years). In areas where the water quality is relatively good, plumbers recommend servicing the water heater every 3 - 4 years (personal communication with professional plumbers on August 8, 2014 and on August 21, 2014). Frequent inspection of the inlet water filter screen will enable a homeowner to monitor the amount of sediment entering the water heater. If the filter tends to fill with sediment regularly, then more frequent flushing may be required. Homeowners can also reference local water quality data to determine the level of water quality in their area to help guide maintenance schedules.

To assist in flushing the heat exchanger, manufacturers and plumbers recommend the installation of a drain kit (i.e. isolation valves). As shown in Figure 7, the drain kit consists of a cold-in and hot-out multiple function valves. The drain kit allows the IWH to be isolated from both the inlet cold water and the outlet hot water lines. Integral to the kit are hose bibs that allow the flushing hoses to be attached.

Though recommended, the drain kit is not required by manufacturers.[10] However, the installation of a drain kit has become standard practice among plumbers and homebuilders, as it simplifies the activity of flushing the heat exchanger. Therefore, the Statewide CASE Team proposes to add a mandatory measure to Title 24 that would require the installation of drain kits when installing gas IWHs. See Section 4.7.1 for cost information on drain kits.

Manufacturers recommend that a licensed professional flush the heat exchanger to avoid potentially damaging the water heater, though some manufacturers sell flush kits so that homeowners can conduct their own maintenance activities on the water heater. Flush kits are comprised of a submersible pump, two short hoses, hose connections, and a 5-gallon bucket. These components can be purchased separately or as a pre-assembled kit. A solution of white vinegar is widely recommended for flushing the heat exchanger as it is food grade and very effective at removing scale.

In addition to flushing the heat exchanger, manufacturers recommend periodically inspecting and cleaning the inlet water filter screen, which helps minimize the amount of debris or

[10] Rheem's installation guide for 17 unique IWH models state that valve kits may be purchased and installed as optional items (Rheem 2009). Noritz also states that the drain kit/isolation valves are optional (Noritz 2009).

sediment that enters the water heater. This can be done by running the filter screen under hot water and using a brush to remove debris (Noritz 2005; Rheem 2009; Bradford White 2011). Replacement of the inlet water filter screen is not necessary unless it is damaged (personal communication with water heater manufacturer on August 27, 2014).

Figure 7: Drain Kit Components

Source: http://www.brasscraft.com/products.aspx?id=266

Maintenance of Gas Storage Water Heaters

For a storage water heater, maintenance largely consists of draining the tank, inspecting the anode rod, and replacing the anode rod if necessary. The recommended frequency of regular maintenance varies by manufacturer. Like IWHs, the frequency of maintenance depends on water quality. Most manufacturers recommend draining the tank every six months to once per year in order to remove sediment that has accumulated in the bottom of the tank. As previously noted, one manufacturer recommends draining a gallon of water from the tank every month to remove the sediment that builds up during operation. Some manufacturers also recommend that yearly inspections of the burners, venting system, and temperature and pressure relief valves be conducted by a qualified service technician (see Figure 8). [11] Others recommend visual inspections as frequently as every three to six months.

[11] Bradford White storage water heater operation manuals were reviewed for the following models: M-2-XR75S6BN, M-I-30T6FBN, M-I-0S6FBN, M-I-303T6FBN, M-I-40T6FBN, M-I-403S6FBN, M-I-404T6FBN, M-I-5036FBN, M-I-50L6FBN, M-I-504S6FBN, M-I-60T6FBN.

IMPORTANT

The water heater should be inspected at a minimum annually by a qualified service technician for damaged components and/or joints not sealed. DO NOT operate this water heater if any part is found damaged or if any joint is found not sealed.

Figure 8: Storage Water Heater Maintenance Recommendation

Source: Bradford White 2012

Manufacturers typically recommend inspecting the anode rod every two years and to replace it when necessary to prolong tank life, but the frequency of inspection is dependent on local water conditions. With the use of a water softener, more frequent inspection of the anode is needed (Bradford White 2007). According to a statewide professional plumbing company, homeowners do not typically request replacement of the anode rod, as the cost can be high for this service if the setup of the water heater obstructs access to the anode. If the setup of the water heater prevents an easy removal of the 3-foot anode rod, then it might be necessary to completely remove the tank from its location to replace the anode rod. Moving the tank can triple the cost of replacing the anode rod (personal communication with a professional plumber on August 14, 2014). (See Section 4.7.1 for cost information). However, if the anode rod is not periodically replaced it can lead to corrosion of the water heater storage tank, which in turn could lead to the tank leaking water and the need to replace the entire unit.

3.3.3 Water Heater Efficiency Degradation

The Statewide CASE Team was asked by CEC to investigate how efficiency degrades over time for both storage water heaters and IWHs. A 2010 study conducted by the Battelle Memorial Institute, the administrator of several national laboratories, evaluated the impact of scale formation on equipment efficiency for electric storage, gas storage, and gas IWHs using an accelerating testing approach. During the test period, the water heaters were not maintained according to manufacturer recommendations.[12] The researchers evaluated 10 of each type of water heater: five water heaters were connected to water that had been treated with a water softener and contained 0.55 grains per gallon (gpg) of water hardness and five were connected to un-softened well water that contained 26.2 gpg. It should be noted that water hardness of 26 gpg is very hard. For reference, San Diego has a water hardness of about 15 gpg and Anaheim has a water hardness of about 18 gpg. Both cities have some of the hardest water in the state. As described in Section 3.3.2 of the CASE Report, hard water can cause scale buildup which can reduce the efficiency and useful life of IWHs. The Batelle study reported that hard water also reduces the efficiency of storage water heaters. Soft water (e.g., 0.55 gpg) may also have detrimental effects, such as increasing risk of corrosion to the storage tank.

[12] The Battelle study assumed a daily hot water use of 50 gallons per household per day; the study did not replicate draw patterns but simulated total hot water use without evaluating when water was used. Though the study did not use the same temperatures setpoints for all types of water heaters, it did account for the difference in temperature setpoints when conducting the analysis of test results.

The efficiency degradation of gas IWHs can be managed by flushing the heat exchanger. To maintain efficiency, gas IWHs should be flushed more frequently in areas with harder water and as hot water use increases. The Battelle study's analysis assumed that IWHs will be flushed after efficiency degrades by about 8 percent, but water heaters can be flushed more frequently if higher efficiency is desired. Similarly, the efficiency of gas storage water heaters will also degrade overtime, with the rate of degradation increasing as water hardness and water use increases. The study did not identify any maintenance practices that would allow efficiency of storage water heaters to be maintained.

The Battelle study concluded that, "none of the electric or gas storage water heaters or the instantaneous gas water heaters on the un-softened water made it through the entire testing period because the outlet piping system consisting of one-half inch copper pipe, a needle valve, and a solenoid valve became clogged with scale buildup." They found that for storage water heaters, hard water decreased the thermal efficiency of the equipment from 70 percent to 67 percent over the equivalent of two years of field service; a three percent degradation in efficiency. For the gas IWH used in the study, hard water decreased the efficiency from 80 percent to 72 percent over 1.6 years, after which the IWH ceased proper operation because of sediment buildup prevented the controls from functioning properly. However, after the IWH heat exchanger was flushed, the efficiency of the gas IWH returned to 77 percent. This study indicates that the efficiency of both gas storage water heaters and gas IWHs degrades over time and that regular maintenance is important to maintain efficiency, especially when water is hard.

In addition, the Battelle study extrapolated the test data out over a period of years in order to model efficiency degradation over time as a function of water hardness and hot water usage. Table 13 and Table 14 present the results of the extrapolation for gas IWHs and gas storage water heaters, respectively. As can be seen, the efficiencies of gas IWHs and storage water heaters degrade with time due to scale buildup and increased hot water usage. As can be seen in Table 13, at a daily hot water use of 50 gallons, IWHs are projected to require a flushing (i.e. deliming) at roughly two years in areas with *very* hard water (>20 gpg) and at four years in areas with hard water (>10 gpg). These results are similar to the recommended maintenance schedules provided by the professional plumbers that were interviewed as part of the CASE analysis with one exception: the study projects that IWHs will need to be flushed at approximately eight years in areas with soft water, rather than at four years as estimated by plumbing professionals.

A 2013 Pacific Northwest National Laboratory (PNNL) study also confirmed the results of the Battelle study that scale buildup will impact the efficiencies of both storage water heaters and IWHs and can lead to decreased equipment life.

Table 13: Predicted Efficiencies of Instantaneous Water Heaters as a Function of Water Hardness and Hot Water Usage

Source: Battelle Memorial Institute 2010

Time	50 Gallons Per Day of Hot Water Usage							100 Gallons Per Day of Hot Water Usage						
	Water Hardness in Grains Per Gallon							Water Hardness in Grains Per Gallon						
(Years)	0	5	10	15	20	25	30	0	5	10	15	20	25	30
0.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
0.2	80.0	79.8	79.6	79.4	79.2	79.0	78.8	80.0	79.6	79.2	78.8	78.4	78.0	77.6
0.4	80.0	79.6	79.2	78.8	78.4	78.0	77.6	80.0	79.2	78.4	77.6	76.9	76.1	75.3
0.6	80.0	79.4	78.8	78.2	77.6	77.1	76.5	80.0	78.8	77.6	76.5	75.3	74.1	72.9
0.8	80.0	79.2	78.4	77.6	76.9	76.1	75.3	80.0	78.4	76.9	75.3	73.7	72.2	Delime
1.0	80.0	79.0	78.0	77.1	76.1	75.1	74.1	80.0	78.0	76.1	74.1	72.2	Delime	
1.2	80.0	78.8	77.6	76.5	75.3	74.1	72.9	80.0	77.6	75.3	72.9	Delime		
1.4	80.0	78.6	77.3	75.9	74.5	73.1	Delime	80.0	77.3	74.5	Delime			
1.6	80.0	78.4	76.9	75.3	73.7	72.2		80.0	76.9	73.7				
1.8	80.0	78.2	76.5	74.7	72.9	Delime		80.0	76.5	72.9				
2.0	80.0	78.0	76.1	74.1	72.2			80.0	76.1	72.2				
2.2	80.0	77.8	75.7	73.5	Delime			80.0	75.7	Delime				
2.4	80.0	77.6	75.3	72.9				80.0	75.3					
2.6	80.0	77.4	74.9	72.3				80.0	74.9					
2.8	80.0	77.3	74.5	Delime				80.0	74.5					
3.0	80.0	77.1	74.1					80.0	74.1					
3.2	80.0	76.9	73.7					80.0	73.7					
3.4	80.0	76.7	73.3					80.0	73.3					
3.6	80.0	76.5	72.9					80.0	72.9					
3.8	80.0	76.3	72.5					80.0	72.5					
4.0	80.0	76.1	72.2					80.0	72.2					
4.2	80.0	75.9	71.8					80.0	Delime					
4.4	80.0	75.7	Delime					80.0						
4.6	80.0	75.5						80.0						
4.8	80.0	75.3						80.0						
5.0	80.0	75.1						80.0						
5.2	80.0	74.9						80.0						
5.4	80.0	74.7						80.0						
5.6	80.0	74.5						80.0						
5.8	80.0	74.3						80.0						
6.0	80.0	74.1						80.0						
6.2	80.0	73.9						80.0						
6.4	80.0	73.7						80.0						
6.6	80.0	73.5						80.0						
6.8	80.0	73.3						80.0						
7.0	80.0	73.1						80.0						
7.2	80.0	72.9						80.0						
7.4	80.0	72.7						80.0						
7.6	80.0	72.5						80.0						
7.8	80.0	72.3						80.0						
8.0	80.0	72.2						80.0						
8.2	80.0	72.0						80.0						
8.4	80.0	Delime						80.0						

Table 14: Predicted Efficiencies of Gas Storage Water Heaters as a Function of Water Hardness and Hot Water Usage

Source: Battelle Memorial Institute 2010

Time	50 Gallons Per Day of Hot Water Usage							100 Gallons Per Day of Hot Water Usage						
	Water Hardness in Grains Per Gallon							Water Hardness in Grains Per Gallon						
(Years)	0	5	10	15	20	25	30	0	5	10	15	20	25	30
0.00	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4
0.25	70.4	70.3	70.3	70.2	70.1	70.0	70.0	70.4	70.3	70.1	70.0	69.8	69.7	69.5
0.50	70.4	70.3	70.1	70.0	69.8	69.7	69.5	70.4	70.1	69.8	69.5	69.3	69.0	68.7
0.75	70.4	70.2	70.0	69.8	69.5	69.3	69.1	70.4	70.0	69.5	69.1	68.7	68.3	67.8
1.00	70.4	70.1	69.8	69.5	69.3	69.0	68.7	70.4	69.8	69.3	68.7	68.1	67.6	67.0
1.25	70.4	70.0	69.7	69.3	69.0	68.6	68.3	70.4	69.7	69.0	68.3	67.6	66.9	66.1
1.50	70.4	70.0	69.5	69.1	68.7	68.3	67.8	70.4	69.5	68.7	67.8	67.0	66.1	65.3
1.75	70.4	69.9	69.4	68.9	68.4	67.9	67.4	70.4	69.4	68.4	67.4	66.4	65.4	64.4
2.00	70.4	69.8	69.3	68.7	68.1	67.6	67.0	70.4	69.3	68.1	67.0	65.9	64.7	63.6
2.25	70.4	69.8	69.1	68.5	67.8	67.2	66.6	70.4	69.1	67.8	66.6	65.3	64.0	62.7
2.50	70.4	69.7	69.0	68.3	67.6	66.9	66.1	70.4	69.0	67.6	66.1	64.7	63.3	61.9
2.75	70.4	69.6	68.8	68.1	67.3	66.5	65.7	70.4	68.8	67.3	65.7	64.2	62.6	61.0
3.00	70.4	69.5	68.7	67.8	67.0	66.1	65.3	70.4	68.7	67.0	65.3	63.6	61.9	60.2
3.25	70.4	69.5	68.6	67.6	66.7	65.8	64.9	70.4	68.6	66.7	64.9	63.0	61.2	59.3
3.50	70.4	69.4	68.4	67.4	66.4	65.4	64.4	70.4	68.4	66.4	64.4	62.5	60.5	58.5
3.75	70.4	69.3	68.3	67.2	66.1	65.1	64.0	70.4	68.3	66.1	64.0	61.9	59.8	57.6
4.00	70.4	69.3	68.1	67.0	65.9	64.7	63.6	70.4	68.1	65.9	63.6	61.3	59.1	56.8
4.25	70.4	69.2	68.0	66.8	65.6	64.4	63.2	70.4	68.0	65.6	63.2	60.8	58.4	55.9
4.50	70.4	69.1	67.8	66.6	65.3	64.0	62.7	70.4	67.8	65.3	62.7	60.2	57.6	55.1
4.75	70.4	69.1	67.7	66.4	65.0	63.7	62.3	70.4	67.7	65.0	62.3	59.6	56.9	54.2
5.00	70.4	69.0	67.6	66.1	64.7	63.3	61.9	70.4	67.6	64.7	61.9	59.1	56.2	53.4
5.25	70.4	68.9	67.4	65.9	64.4	63.0	61.5	70.4	67.4	64.4	61.5	58.5	55.5	52.5
5.50	70.4	68.8	67.3	65.7	64.2	62.6	61.0	70.4	67.3	64.2	61.0	57.9	54.8	51.7
5.75	70.4	68.8	67.1	65.5	63.9	62.3	60.6	70.4	67.1	63.9	60.6	57.4	54.1	50.8
6.00	70.4	68.7	67.0	65.3	63.6	61.9	60.2	70.4	67.0	63.6	60.2	56.8	53.4	50.0
6.25	70.4	68.6	66.9	65.1	63.3	61.5	59.8	70.4	66.9	63.3	59.8	56.2	52.7	49.1
6.50	70.4	68.6	66.7	64.9	63.0	61.2	59.3	70.4	66.7	63.0	59.3	55.7	52.0	48.3
6.75	70.4	68.5	66.6	64.7	62.7	60.8	58.9	70.4	66.6	62.7	58.9	55.1	51.3	47.4
7.00	70.4	68.4	66.4	64.4	62.5	60.5	58.5	70.4	66.4	62.5	58.5	54.5	50.6	46.6
7.25	70.4	68.3	66.3	64.2	62.2	60.1	58.1	70.4	66.3	62.2	58.1	54.0	49.9	45.7
7.50	70.4	68.3	66.1	64.0	61.9	59.8	57.6	70.4	66.1	61.9	57.6	53.4	49.1	44.9
7.75	70.4	68.2	66.0	63.8	61.6	59.4	57.2	70.4	66.0	61.6	57.2	52.8	48.4	44.0
8.00	70.4	68.1	65.9	63.6	61.3	59.1	56.8	70.4	65.9	61.3	56.8	52.3	47.7	43.2
8.25	70.4	68.1	65.7	63.4	61.0	58.7	56.4	70.4	65.7	61.0	56.4	51.7	47.0	42.3
8.50	70.4	68.0	65.6	63.2	60.8	58.4	55.9	70.4	65.6	60.8	55.9	51.1	46.3	41.5
8.75	70.4	67.9	65.4	63.0	60.5	58.0	55.5	70.4	65.4	60.5	55.5	50.6	45.6	40.6
9.00	70.4	67.8	65.3	62.7	60.2	57.6	55.1	70.4	65.3	60.2	55.1	50.0	44.9	39.8
9.25	70.4	67.8	65.2	62.5	59.9	57.3	54.7	70.4	65.2	59.9	54.7	49.4	44.2	38.9
9.50	70.4	67.7	65.0	62.3	59.6	56.9	54.2	70.4	65.0	59.6	54.2	48.9	43.5	38.1
9.75	70.4	67.6	64.9	62.1	59.3	56.6	53.8	70.4	64.9	59.3	53.8	48.3	42.8	37.2
10.00	70.4	67.6	64.7	61.9	59.1	56.2	53.4	70.4	64.7	59.1	53.4	47.7	42.1	36.4

3.4 Market Impacts and Economic Assessments

3.4.1 Impact on Builders

This particular proposed code change will have a minor impact on builders. Since the 2013 Title 24 Standards already require the installation of system components that are compatible with gas IWHs, there are no additional installation costs to builders. In addition, the large volume of instantaneous units installed in new construction may result in decreasing costs, as contractors may be able to reduce costs over a large number of installations (Schoenbauer, Bohac & Hewett 2012). Furthermore, builders will still have the option of taking the performance approach and can install other types of water heaters as long as the energy budget for the building not exceeded, as well as the other prescriptive options.

3.4.2 Impact on Building Designers

Title 24 is updated on a three-year revision cycle, so acclimating to changes in Title 24 Standards is routine practice for building designers; adjusting design practices to comply with changing code practices is within the normal practices of building designers. This particular revision to the Title 24 water heating standards will not require a departure from standard or common design practices for building designers.

Though water heating design changes are not required, designing for a gas IWH may encourage building designers to explore compact hot water distribution, which is an efficient and effective strategy for increasing energy and water savings as well as user utility. The energy and water savings associated with compact distribution are not accounted for in this report.

As a whole, the measures being considered for the 2016 code change cycle aim to provide designers with options on how to comply with the building efficiency standards. The proposed standards do not aim to limit building aesthetics or any particular type of building equipment.

3.4.3 Impact on Occupational Safety and Health

The proposed code change does not alter any existing federal, state, or local regulations pertaining to safety and health, including rules enforced by the California Department of Occupational Safety and Health (Cal/OSHA). All existing health and safety rules will remain in place. Complying with the proposed code change is not anticipated to have any impact on the safety or health of occupants or those involved with the construction, commissioning, and ongoing maintenance of the building.

3.4.4 Impact on Building Owners and Occupants

The proposed code change will have an impact on building owners and occupants. For building owners, the longer lifespan of IWHs results in fewer water heater replacements over time, particularly if routine maintenance is undertaken to prolong the useful life of the water heater. Homeowner-occupants will benefit from a continual supply of hot water and lower utility bills, though the wait time for hot water may increase slightly due to the additional time it takes for hot water to arrive, particularly if the water heating system is designed so that the water heater is located far from the use points. Research and outreach to stakeholders reveals that homeowners are overwhelmingly satisfied with the performance of their IWH.

3.4.5 Impact on Retailers (including manufacturers and distributors)

The proposed code change will have some impacts on manufacturers, distributors, and retailers. Sales will increase for manufacturers of qualifying IWHs and for retailers and distributors that stock qualifying products. DOE projections indicate roughly a 43% market penetration of IWHs in 2015 in the absence of the recently adopted federal standards (DOE 2010). This implies that product availability and adoption will grow at a steady rate each year, thus reducing the likelihood for a lack of available products.

3.4.6 Impact on Energy Consultants

As discussed in Section. 3.5.2 of this report, the changes made to Title 24 may have a positive impact on job growth in the state. Energy consultants may benefit from being able to offer their builder clients compliance alternatives.

3.4.7 Impact on Building Inspectors

There are no anticipated impacts to building inspectors from the proposed code change. Inspectors will not be required to complete any tasks that they are not already conducting to verify compliance with the 2013 Title 24 Standards.

3.4.8 Impact on Statewide Employment

The proposed changes to Title 24 may impact employment. An increase in employment in the water heating sector is expected while a slight employment decrease for installers may result, as IWHs have higher product life expectancies than storage water heaters; the rate of replacement is lower for the former. More impacts to employment are noted below in Section 3.5.

3.4.9 Impact on Homeowners (including potential first time home owners)

The proposed code change will have an impact on homeowners. The longer lifespan of IWHs results in fewer water heater replacements over time, particularly if routine maintenance is undertaken to prolong the useful life of the water heater. Homeowner-occupants will benefit from a continual supply of hot water and lower utility bills, though the wait time for hot water may increase slightly due to the additional time it takes for hot water to arrive, particularly if the water heating system is designed so that the water heater is located far from the use points. Research and outreach to stakeholders reveals that homeowners are overwhelmingly satisfied with the performance of their IWH.

3.4.10 Impact on Renters

This proposal is advantageous to renters as it reduces the cost of utilities which are typically paid by renters. Since the measure saves more energy costs on a monthly basis than the measure costs on the mortgage as experienced by the landlord, the pass-through of added mortgage costs into rental costs is less than the energy cost savings experienced by renters.

3.5 Economic Impacts

The proposed Title 24 code changes, including this measure, are expected to increase job creation, income, and investment in California. As a result of the proposed code changes, it is anticipated that less money will be sent out of state to fund energy imports, and local spending is expected to increase due to higher disposable incomes due to reduced energy costs.[13] For instance, the statewide life cycle net present value of this measure is $204 million over the 30 year period of analysis. In other words, utility customers will have $204 million to spend elsewhere in the economy. In addition, more dollars will be spent in state on improving the energy efficient of new buildings.

These economic impacts of energy efficiency are documented in several resources including the California Air Resources Board's (CARB) Updated Economic Analysis of California's Climate Change Scoping Plan, which compares the economic impacts of several scenario cases (CARB, 2010b). CARB include one case (Case 1) with a 33% renewable portfolio standard (RPS) and higher levels of energy efficiency compared to an alternative case (Case 4) with a 20 % RPS and lower levels of energy efficiency. Gross state production (GSP),14 personal income, and labor demand were between 0.6% and 1.1% higher in the case with the higher RPS and more energy efficiency (CARB 2010b, Table 26). While CARB's analysis does not report the benefits of energy efficiency and the RPS separately, we expect that the benefits of the package of measures are primarily due to energy efficiency. Energy efficiency measures are expected to reduce costs by $2,133 million annually (CARB 2008, pC-117) whereas the RPS implementation is expected to cost $1,782 million annually, not including the benefits of GHG and air pollution reduction (CARB 2008, pC-130).

Macro-economic analysis of past energy efficiency programs and forward-looking analysis of energy efficiency policies and investments similarly show the benefits to California's economy of investments in energy efficiency (Roland-Holst 2008; UC Berkeley 2011).

3.5.1 Creation or Elimination of Jobs

CARB's economic analysis of higher levels of energy efficiency and 33% RPS implementation estimates that this scenario would result in a 1.1% increase in statewide labor demand in 2020 compared to 20% RPS and lower levels of energy efficiency (CARB 2010b, Tables 26 and 27). CARB's economic analysis also estimates a 1.3% increase in small business employment levels in 2020 (CARB 2010b, Table 32).

3.5.2 Creation or Elimination of Businesses within California

CARB's economic analysis of higher levels of energy efficiency and 33% RPS implementation (as described above) estimates that this scenario would result in 0.6% additional GSP in 2020 compared to 20% RPS and lower levels of energy efficiency (CARB 2010b, Table ES-2). We

[13] Energy efficiency measures may result in reduced power plant construction, both in-state and out-of-state. These plants tend to be highly capital-intensive and often rely on equipment produced out of state, thus we expect that displaced power plant spending will be more than off-set from job growth in other sectors in California.

[14] GSP is the sum of all value added by industries within the state plus taxes on production and imports.

expect that higher GSP will drive additional business creation in California. In particular, local small businesses that spend a much larger proportion of revenue on energy than other businesses (CARB 2010b, Figures 13 and 14) should disproportionately benefit from lower energy costs due to energy efficiency standards. Increased labor demand, as noted earlier, is another indication of business creation.

Table 15 shows California industries that are expected to receive the economic benefit of the proposed Title 24 code changes. It is anticipated that these industries will expand due to an increase in funding as a result of energy efficiency improvements. The list of industries is based on the industries that the University of California, Berkeley identified as being impacted by energy efficiency programs (UC Berkeley 2011 Table 3.8).[15] The list provided below is not specific to one individual code change proposal, but is an approximation of the industries that may receive benefit from the 2016 Title 24 code changes. A table listing total expected job creation by industry that is expected in 2015 and 2020 from all investments in California energy efficiency and renewable energy is presented in the Appendix B of this CASE Report.

[15] Table 3.8 of the UC Berkeley report includes industries that will receive benefits of a wide variety of efficiency interventions, including Title 24 standards and efficiency programs. The authors of the UC Berkeley report did not know in 2011 which Title 24 measures would be considered for the 2016 adoption cycle, so the UC Berkeley report was likely conservative in their approximations of industries impacted by Title 24. The Statewide CASE Team believes that industries impacted by utilities efficiency programs is a more realistic and reasonable proxy for industries potentially affected by upcoming Title 24 standards. Therefore, the table provided in this CASE Report includes the industries that are listed as benefiting from Title 24 and utility energy efficiency programs.

Table 15: Industries Receiving Energy Efficiency Related Investment, by North American Industry Classification System (NAICS) Code

Industry	NAICS Code
Residential Building Construction	2361
Nonresidential Building Construction	2362
Roofing Contractors	238160
Electrical Contractors	23821
Plumbing, Heating, and Air-Conditioning Contractors	23822
Boiler and Pipe Insulation Installation	23829
Insulation Contractors	23831
Window and Door Installation	23835
Asphalt Paving, Roofing, and Saturated Materials	32412
Manufacturing	32412
Other Nonmetallic Mineral Product Manufacturing	3279
Industrial Machinery Manufacturing	3332
Ventilation, Heating, Air-Conditioning, & Commercial Refrigeration Equipment Manufacturing	3334
Computer and Peripheral Equipment Manufacturing	3341
Communications Equipment Manufacturing	3342
Electric Lighting Equipment Manufacturing	3351
Household Appliance Manufacturing	3352
Other Major Household Appliance Manufacturing	335228
Used Household and Office Goods Moving	484210
Engineering Services	541330
Building Inspection Services	541350
Environmental Consulting Services	541620
Other Scientific and Technical Consulting Services	541690
Advertising and Related Services	5418
Corporate, Subsidiary, and Regional Managing Offices	551114
Office Administrative Services	5611
Commercial & Industrial Machinery & Equip. (exc. Auto. & Electronic) Repair & Maintenance	811310

3.5.3 Competitive Advantages or Disadvantages for Businesses within California

California businesses would benefit from an overall reduction in energy costs. This could help California businesses gain competitive advantage over businesses operating in other states or countries and an increase in investment in California, as noted below.

3.5.4 Increase or Decrease of Investments in the State of California

CARB's economic analysis indicate that higher levels of energy efficiency and 33% RPS will increase investment in California by about 3% in 2020 compared to 20% RPS and lower levels of energy efficiency (CARB 2010b Figures 7a and 10a).

3.5.5 Incentives for Innovation in Products, Materials, or Processes

Updating Title 24 standards will encourage innovation through the adoption of new technologies to better manage energy usage and achieve energy savings.

3.5.6 Effects on the State General Fund, State Special Funds and Local Governments

The Statewide CASE Team expects positive overall impacts on state and local government revenues due to higher GSP and personal income resulting in higher tax revenues, as noted earlier. Higher property valuations due to energy efficiency enhancements may also result in positive local property tax revenues. The Statewide CASE Team has not obtained specific data to quantify potential revenue benefits for this measure.

3.5.6.1 Cost of Enforcement

Cost to the State

State government already has the budget for code development, education, and compliance enforcement. While state government will be allocating resources to update the Title 24 standards, including updating education and compliance materials and responding to questions about the revised standards, these activities are already covered by existing state budgets. The costs to state government are small when compared to the overall costs savings and policy benefits associated with the code change proposals.

Cost to Local Governments

All revisions to Title 24 will result in changes to Title 24 compliance determinations. Local governments will need to train permitting staff on the revised Title 24 standards. While this re-training is an expense to local governments, it is not a new cost associated with the 2016 code change cycle. The building code is updated on a triennial basis, and local governments plan and budget for retraining every time the code is updated. There are numerous resources available to local governments to support compliance training that can help mitigate the cost of retraining. For example, the California utilities offer compliance training such as "Decoding" talks to provide training and materials to local permitting departments. As noted earlier, though retraining is a cost of the revised standards, Title 24 energy efficiency standards are expected to increase economic growth and income with positive impacts on local revenue.

The proposed prescriptive standard would revise an existing measure without significantly affecting the complexity of this measure. Therefore, on-going costs are not expected to change significantly.

3.5.6.2 Impacts on Specific Persons

The proposed changes to Title 24 are not expected to have a differential impact on any of the following groups relative to the state population as a whole:

- Migrant Workers
- Persons by age
- Persons by race
- Persons by religion
- Commuters

We expect that the proposed code changes for the 2016 Title 24 code change cycle will reduce energy costs and could put potential first-time homeowners in a better position to afford mortgage payments. On the other hand, homeowners may experience higher first costs to the extent that builders pass through the increased costs of Title 24 compliance to home buyers. Some financial institutions have progressive policies that recognize that home buyers can better afford energy efficiency homes (even with a higher first cost) due to lower energy costs.[16]

Renters will typically benefit from lower energy bills if they pay energy bills directly. These savings should more than offset any capital costs passed-through from landlords. Renters who do not pay directly for energy costs may see more of less of the net savings based on how much landlords pass the energy cost savings on to renters.

On average, low-income families spend less on energy than higher income families, however lower income families spend a much larger portion of their incomes on energy (Roland-Holst 2008). Thus it seems reasonable that low-income families would disproportionately benefit from Title 24 standards that reduce residential energy costs.

4. METHODOLOGY

This section describes the methodology and approach the Statewide CASE Team used to estimate energy, demand, costs, and environmental impacts. The Statewide CASE Team calculated the impacts of the proposed code change by comparing existing conditions to the proposed if the code change is adopted. This section of the CASE Report goes into more detail on the assumptions about the existing and proposed conditions, prototype buildings, and the methodology used to estimate energy, demand, cost, and environmental impacts.

To assess the energy, demand, costs, and environmental impacts of the proposed measure, the Statewide CASE Team compared current design practices to design practices that would comply with the proposed requirements. Since the existing Title 24 Standards cover domestic water heating systems, including water heaters, the existing conditions assume the base case is a building that complies with the 2013 Title 24 Standards.

4.1 Existing Conditions

To assess the energy, demand, costs, and environmental impacts, the Statewide CASE Team compared current design practices to design practices that would comply with the proposed requirements. Since the existing Title 24 Standards cover the domestic hot water system in residential buildings, the existing conditions assume a building complies with the 2013 Title 24 Standards.

As described in Section 2, the existing Title 24 Standards include requirements for domestic gas water heating systems for newly constructed and existing single-family and multi-family buildings. The current prescriptive Standards for residential new construction allow for the

[16] Refer to the ENERGY STAR website for examples.

installation of a gas storage water heater (75,000 BTU or less), a gas IWH (200,000 BTU or less), or an electric storage or electric IWH as part of a solar hot water system in new residential construction (including multi-family buildings with dedicated water heaters for each individual dwelling unit). The IWH prescriptive path (prescriptive baseline), which is used to calculate the energy budget, assumes a 40-gallon gas storage water heater that meets federal minimum efficiency requirements. Though the 2013 ACM Reference Manual uses a 50-gallon storage water heater as the baseline equipment, the Statewide CASE Team assumed a 40-gallon volume because it is more commonly installed in new construction according to builders, plumbers, and manufacturers. The 2015 federal residential water heater minimum efficiency level (EF of 0.62) was used as the baseline for energy savings estimates since it will be in effect starting April 2015, well in advance of the 2016 Title 24 effective date (January 1, 2017).

4.2 Proposed Conditions

The proposed conditions are defined as the design conditions that will comply with the proposed code change. Specifically, the proposed code change will change the prescriptive baseline from a 50-gallon gas storage water heater to a gas IWH (meeting federal minimum standards). The proposed conditions assume a gas IWH with an EF of 0.82 will be installed. In other words, compliance via the performance path will be based on meeting the building's total energy budget that is set using the energy performance of a gas IWH that meets the federal minimum standard. See Section 2 and Section 6 of this report regarding the proposed code language. The Statewide CASE Team used IWHs for savings estimates in our analyses.

4.3 Prototype Building

CEC provided guidance on the type of prototype building that should be modeled in the 2013 Residential ACM Reference Manual. As such, the prototypical single family residential building used in this analysis is a 2,100 square-foot single-story building and a 2,700 square-foot two-story building. Table 16 summarizes the prototype buildings used in the analysis that were used to reflect the most recent updates to the Residential ACM. Based on direction from the CEC, the energy impacts, savings, and cost effectiveness results are reported as a weighted average of the two prototype building sizes in this CASE Report. The weighting between the two prototype buildings is shown in Table 16. Appendix C contains the results for each prototype building.

Since hot water usage patterns in multi-family and single-family buildings is similar, the energy savings for single-family residential prototype buildings can be used as a reasonable estimate for the savings that are likely in multi-family buildings. Multi-family buildings with central water heating systems are outside the scope of this proposal, and therefore, were not modeled.

Table 16: Prototype Single Family Residential Buildings used for Energy, Demand, Cost, and Environmental Impacts Analysis

	Occupancy Type (Residential, Retail, Office, etc.)	Area (Square Feet)	Number of Stories	Relative Weight to Statewide Estimates
Prototype 1	Residential	2,100	1	45%
Prototype 2	Residential	2,700	2	55%

4.4 Climate Dependent

The Statewide CASE Team modeled energy and cost savings in each California climate zone using statewide Time Dependent Valuation factors. Additionally, for each climate zone the cold water inlet temperatures were calculated from ground temperatures based on an hourly basis and air temperatures were based on the average of the last 31 days. This assumption is to reflect the calculations outlined in the Residential ACM Reference Manual, Appendix E.

4.5 Time Dependent Valuation (TDV)

The TDV (Time Dependent Valuation) of savings is a normalized format for comparing electricity and natural gas savings that takes into account the cost of electricity and natural gas consumed during different times of the day and year. The TDV values are based on long term discounted costs (30 years for all residential measures and nonresidential envelope measures and 15 years for all other nonresidential measures). In this case, the period of analysis used is 15 years. The TDV energy estimates are based on present-valued cost savings but are normalized in terms of "TDV kBTUs" so that the savings are evaluated in terms of energy units and measures with different periods of analysis can be combined into a single value.

CEC derived the 2016 TDV values that were used in the analyses for this report (CEC 2014). The TDV energy impacts are presented in Section 5.1 of this report, and the statewide TDV cost impacts are presented in Section 5.2.

4.6 Energy Impacts Methodology

The Statewide CASE Team calculated per unit impacts and statewide impacts associated with all new construction, alterations, and additions during the first year buildings complying with the 2016 Title 24 Standards are in operation.

The Statewide CASE Team calculated the TDV savings for the proposed measure using the outputs from CEC's public domain simulation program known as CBECC-Residential, Version 3.[17] This software is used for Title 24 compliance and is required for permit applications. (See Section 4.6.1 for a discussion on the inputs and assumptions used for the energy analyses.)

[17] CEC 2014

4.6.1 Per Unit Energy Impacts Methodology

The Statewide CASE Team estimated the natural gas savings and electricity use associated with the proposed code change. Gas IWHs consume electrical energy both in standby mode and in firing mode. Electricity use was included in the energy impacts calculations.

The energy impacts were calculated on a per single family dwelling basis. Annual energy use (natural gas and electricity use) was calculated according to the guidelines presented in Section E6 (*Energy Use of Individual Water Heaters*) in Appendix E of the 2013 Residential ACM Reference Manual.

Analysis Tools

To calculate TDV energy impacts, the Statewide CASE Team simulated the existing conditions and proposed conditions using version 3 of the Residential California Building Energy Code Compliance modeling software (CBECC-Res). Version 3 was approved by CEC on August 27, 2014.

Key Assumptions

The Statewide CASE Team used the following assumptions in the energy analysis. Based on CEC guidance, the prototype buildings for a single family home are 2,100 square foot (SF) of conditioned floor area for a single-story and 2,700 SF of conditioned floor area for a two-story home. The daily hot water demand was based on hourly water heating schedules on weekdays and weekends as displayed in Table RE-1 of the 2013 Residential ACM Reference Manual Appendix E. The daily hot water usage is 35.7 gallons for a 2,100 SF building and 39.7 gallons for a 2,700 SF building. Standard distribution loss multipliers, based on conditioned floor areas, were also used to calculate the hourly hot water consumption as outlined in the 2013 Residential ACM Reference Manual, Appendix E. The calculated values are 1.33 for a 2,100 SF building and 1.38 for a 2,700 SF building. Using the approach to calculate useful hot water consumption as outlined in 2013 Residential ACM Reference Manual, Appendix E is comparable to field studies on hot water use in California households (Hoeschele et al. 2011).

To estimate the electricity use associated with the proposed code change, the Statewide CASE Team used electricity consumption estimates from a 2007 PG&E study conducted by the Davis Energy Group (PG&E 2007). The 2007 study noted a gas IWH installed in an average California household consumes approximately 57 kWh per year. For comparison, the 2010 DOE Final Rule modeled the annual electricity consumption of a gas IWH to be 29 kWh per year (DOE 2010). For this CASE proposal we used the value that would result in more conservative energy savings and assumed an electricity consumption of 57 kWh per year per the 2007 PG&E report.

According to the 2013 Residential ACM Reference Manual, Appendix E, the cold water inlet temperatures is assumed to vary on a daily basis with ground temperature and air temperature for each climate zone, and the hot water supply temperature is assumed to be 124^{o} F. Hourly hot water draw is determined using the hot water draw schedule defined by CEC in Table RE-1 in Appendix E.

The present values of hot water heating energy use were calculated using the residential 30-year natural gas 2016 TDV values and corresponding conversion factors.

To determine energy savings between the baseline and measure cases, the Statewide CASE Team used the 2015 federal minimum standard EF ratings for a gas storage water heater (40-gallon) and gas IWH. As discussed in Section 2.1.3 results of a PIER study indicate that the current DOE test procedure underestimates the impact of small volume hot water draws and heat exchanger cycling on annual system performance. Based on these findings, the Title 24 Standards applied a 0.92 derating factor on the nominal EF of all gas IWHs. This derating approach was validated by further PIER field research completed in 2011(Hoeschele et al. 2011). The analysis presented in this CASE Report multiplied the EF rating for gas IWHs by 92% to reflect the impacts of performance under the current DOE test procedure as outlined by the Residential ACM Reference Manual, Appendix E.

Table 17 lists the key inputs used in calculating the per unit energy impact of the proposed measure.

Table 17: Key Assumptions for Per Unit Energy Impacts Analysis

Parameter	Assumption	Source
Conditioned Floor Area of Prototype Building (percent weighted)	▪ 2,100 square feet (45%) ▪ 2,700 square feet (55%)	CEC
Daily hot water use	▪ 35.7 gallons (2,100 SF) ▪ 39.7 gallons (2,700 SF)	2013 Residential ACM Reference Manual, Appendix E
Hot water supply temperature	124° F	2013 Residential ACM Reference Manual, Appendix E
Cold water inlet temperature	Ground and Air Temperature (by climate zone)	2013 Residential ACM Reference Manual, Appendix E
Gas storage water heater (base case)	▪ 40-gallon volume ▪ Federal minimum efficiency level in 2015 (0.62 EF) ▪ Input Rating 40,000 Btu/hr ▪ Recovery Efficiency 70%	AHRI 2014 2013 Residential ACM Reference Manual, Appendix E
Gas IWH (measure case)	▪ 0-gallon volume ▪ Federal minimum efficiency level in 2015 (0.82 EF) ▪ Input Rating: 190,000 Btu/hr ▪ Annual electricity use: 57 kWh/yr	2013 Residential ACM Reference Manual, Appendix E PG&E 2007
IWH efficiency adjustment factor	92%	2013 Residential ACM Reference Manual, Appendix E

4.6.2 Statewide Energy Impacts Methodology

First Year Statewide Impacts

The Statewide CASE Team estimated statewide impacts for the first year that new dwellings comply with the 2016 Title 24 Standards by multiplying per unit savings estimates by statewide construction forecasts.

The CEC Demand Analysis office provided the projected annual residential dwelling starts for the single family and multi-family sectors. CEC provided three projections: low, mid and high estimates with each case broken out by Forecast Climate Zones (FCZ). The Statewide CASE Team translated this data to Building Climate Zones (BCZ) using the same weighting of FCZ to BCZ as the previous code update cycle (2013), as presented in in Table 18.

The Statewide CASE Team used the mid scenario of forecasted residential new construction for statewide savings estimates. The estimates are for dwellings that are not apartments. The projected new residential construction forecast, presented by BCZ is listed in Table 19.The proposed code change applies to newly-constructed single-family buildings, newly constructed multi-family buildings with dedicated water heaters for every dwelling unit, and additions to these types of buildings if the addition includes the installation of a new water heater. The statewide energy savings conservatively include only the savings from new single-family construction. Data on the percentage of low-rise multi-family dwellings with dedicated water heaters is not readily available, so the energy savings from multi-family buildings with dedicated water heaters were not included in the statewide savings estimates. While the measure does applies to additions if a new water heater is installed as part of the addition. In practice, installing a water heater to serve the addition is not common. Because energy savings from additions will be limited, the statewide savings analysis does not include savings from additions.

Table 18: Translation from Forecast Climate Zones to Building Climate Zones

Source: CEC Demand Analysis Office

		Building Standards Climate Zones (BCZ)																
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	Grand Total
Forecast Climate Zones (FCZ)	1	22.51%	20.62%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	9.80%	33.14%	0.16%	0.00%	0.00%	13.77%	100.00%
	2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	22.00%	75.70%	0.00%	0.00%	0.00%	2.30%	100.00%
	3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	20.95%	22.76%	54.50%	0.00%	0.00%	1.79%	100.00%
	4	0.15%	13.73%	8.36%	46.03%	8.94%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	22.81%	0.00%	0.00%	0.00%	0.00%	100.02%
	5	0.00%	4.23%	89.13%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.64%	0.00%	0.00%	0.00%	0.00%	100.00%
	6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
	7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	75.80%	7.08%	0.00%	17.12%	100.00%
	8	0.00%	0.00%	0.00%	0.00%	0.00%	40.37%	0.00%	51.08%	8.09%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.46%	100.00%
	9	0.00%	0.00%	0.00%	0.00%	0.00%	6.97%	0.00%	24.54%	57.85%	0.00%	0.00%	0.00%	0.00%	6.68%	0.00%	3.95%	99.99%
	10	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	74.90%	0.00%	0.00%	0.00%	12.27%	7.90%	4.93%	100.00%
	11	0.00%	0.00%	0.00%	0.00%	0.00%	33.04%	0.00%	24.75%	42.21%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
	12	0.00%	0.00%	0.00%	0.00%	0.00%	0.92%	0.00%	20.20%	75.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.69%	100.00%
	13	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	69.55%	0.00%	0.00%	28.77%	0.00%	0.00%	0.00%	1.56%	0.09%	0.00%	99.97%
	14	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
	15	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.12%	99.88%	0.00%	100.00%
	16	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
	17	2.95%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	97.05%	100.00%

Table 19: Projected New Residential Construction in 2017 by Climate Zone[1]

Building Climate Zone	Single Family Starts	Multifamily Starts[2]
Climate Zone 1	695	47
Climate Zone 2	2,602	507
Climate Zone 3	5,217	3,420
Climate Zone 4	5,992	1,053
Climate Zone 5	1,164	205
Climate Zone 6	4,142	2,151
Climate Zone 7	6,527	2,687
Climate Zone 8	7,110	3,903
Climate Zone 9	8,259	8,023
Climate Zone 10	16,620	1,868
Climate Zone 11	5,970	217
Climate Zone 12	19,465	1,498
Climate Zone 13	13,912	770
Climate Zone 14	3,338	492
Climate Zone 15	3,885	433
Climate Zone 16	3,135	508
Total	**108,032**	**27,784**

1. CEC provided a low, middle, and high forecast. The Statewide CASE Team used the middle forecast for the statewide savings estimates. Statewide savings estimates do not include savings from mobile homes for multi-family buildings.
2. Includes high-rise and low-rise multi-family construction. The statewide savings analysis does not include savings from multi-family buildings.

4.7 Cost-effectiveness Methodology

This measure proposes a modification to the prescriptive requirement for domestic water heating in residential new construction. As such, a lifecycle cost (LCC) analysis is required to demonstrate that the measure is cost effective over the 30-year period of analysis.

CEC's procedures for calculating lifecycle cost-effectiveness are documented in the LCC Methodology (CEC 2011). The Statewide CASE Team followed these guidelines when developing the Cost-effectiveness Analysis for this measure. CEC's guidance dictated which costs were included in the analysis: incremental equipment and maintenance costs over the 30-year period of analysis. TDV energy cost savings from natural gas savings were also considered. Each of these components is discussed in more detail below.

Design costs and the incremental cost of verification were not included in the Cost-effectiveness Analysis as there are none associated with the proposed code change.

4.7.1 Incremental Cost Methodology – Gas IWH

Incremental Construction/Installation Cost Methodology

The 2013 Title 24 Standards for residential water heating require new homes to be equipped with components for the installation of high-efficiency water heaters, such as gas IWHs.

Section 150.0(n) of 2013 the Title 24 Standards already requires the following components for water heaters using gas or propane in newly-constructed low-rise residential buildings (see Section 2.4 for discussion on venting requirements):

- A 120V electrical receptacle that is within 3 feet from the water heater and accessible to the water heater with no obstructions; and
- A Category III or IV vent, or a Type B vent with straight pipe between the outside termination and the space where the water heater is installed; and
- A condensate drain that is no more than 2 inches higher than the base of the installed water heater, and allows natural draining without pump assistance, and
- A gas supply line with a capacity of at least 200,000 Btu/hr.

The installation costs for implementing measures that are already required in the Title 24 Standards were not included in the incremental installation/construction cost for the proposed measure. The installation costs considered in this analysis were the labor costs involved in (1) purchasing and installing a gas water heater in a new dwelling and (2) replacement of the equipment after its useful life. Research the Statewide CASE Team conducted indicates that when excluding the components that are already required in the Standards, there is no difference in the cost of installing a gas storage water heater and a gas IWH. The labor costs for a single installation or replacement were assumed to be the same for the base and measure cases.

Based on the assumptions for the useful life of storage and IWHs described in Section 3.3.1, over the 30-year period of analysis, it was assumed that a storage water heater will be replaced twice, and an IWH will be replaced once.

Incremental Equipment Cost Methodology

To determine the incremental equipment Statewide CASE Team compared price points of gas storage water heaters (EF 0.62) to a gas IWH (EF 0.82) from a number of reputable sources. The incremental equipment costs were adjusted for inflation to 2014 dollars and summarized in Table 20 below.

Table 20: Incremental Equipment Costs of Gas IWH versus Gas Storage Water Heater

Source	Incremental Equipment Cost (2014$)
DOE Technical Support Document, Chapter 8 (2010)	$655*
Presentation from William Hoover (2011)	$635
CBIA/ConSol (2011)	$610
2013 Title 24 High-Efficiency Water Heater Ready CASE Report (2011)	$520

* Cost estimate used by the Statewide CASE Team for the analysis.

The incremental equipment cost between a gas storage water heater and a gas IWH ranges between $520 and $655. For the analysis, the Statewide CASE Team used the incremental equipment cost used by DOE in the establishment of the federal residential water heating standards (DOE Technical Support Document, Chapter 8 2010). This estimate represents the worst-case scenario regarding incremental cost since it is the highest cost value among the four data points provided by stakeholders. DOE conducted extensive studies of costs for water heaters and its methodologies and findings were published as supporting rulemaking documents that were thoroughly vetted by national stakeholders, including water heater manufacturers and homebuilder associations. These documents represent the most comprehensive data source for residential water heater costs (DOE Technical Support Document, Chapter 8 2010).

The analysis presented in this CASE Report assumed the average lifespan of a gas storage water heater as 13 years and gas IWH as 20 years, based on manufacturer claims (including warranties), DOE's assumptions used to develop the federal water heater standards, and the estimates provided by the National Home Builders Association and Database for Energy Efficient Resources (DEER). Based on these values, the Statewide CASE Team factored in 2.3 times the storage water heater equipment costs and 1.5 times the IWH equipment costs for the 30-year LCC analysis.

Key assumptions used to derive costs (both first cost and maintenance costs) are presented in Table 21.

Table 21: Key Assumptions for Per Unit Incremental Cost

Parameter	Assumption	Source	Notes
STORAGE WATER HEATER			
First Cost			
Equipment Cost	$518	DOE 2010	Inflation adjusted to 2014 dollars.
Installation Cost (new construction)	$428	DOE 2010	
Subtotal	***$946***		
Equipment Replacement Cost			
Replacement Water Heater	$518		Cost of water heater in year 1. Assumes a 3% annual discount rate for replacements.
Replacement Labor Cost	$487	DOE 2010	Cost of water heater in year 1. Analysis assumes a 3% annual discount rate.
Equipment Life	13 years	United States Department of Energy 2010 Final Rule: Chapter 8; National Home Builders Association; Database for Energy Efficient Resources	See Table 10 in this report.
Number of Replacements Installations Over 30 Years	2		Based on Equipment Useful Life. Replacements occur in years 13 and 26.
Subtotal	***$1,150***		Replacements costs over 30-year period of analysis.
Maintenance Cost			
Per Event	$144	Interviews with California	Average cost to drain water heater provided by three California

Maintenance Cost		Plumbers	plumbing companies (See Table 22)
Maintenance Frequency (years)	1	Manufacturer and professional plumber recommendations	
Subtotal	***$2,822***		Maintenance Cost over 30-year Period of Analysis.
INSTANTANEOUS WATER HEATER			
First Cost			
Equipment Cost	$1,173	DOE 2010	Inflation adjusted to 2014 dollars.
Water Heater Installation Cost (new construction)	$428	DOE 2010	
Drain Kit (Isolation Valves)	$70	Internet	
Subtotal	***$1,671***		
Equipment Replacement Cost			
Equipment Cost	$1,173		Cost of water heater in year 1. Assumes a 3% annual discount rate for replacements.
Replacement Labor Cost	$487	DOE 2010	
Equipment Life	20 years	United States Department of Energy 2010 Final Rule: Chapter 8; National Home Builders Association; Database for Energy Efficient Resources	See Table 10 in this report.
Number of Replacement Installations Over 30 Years	1		Based on Equipment Useful Life. Replacements occur in years 20.
Subtotal	***$919***		Replacements costs over 30-year period of analysis.
Maintenance Cost			
Per Event Maintenance Cost	$205	Interviews with Plumbing Companies	Average cost to flush heat exchanger provided by three California plumbing companies
Maintenance Frequency (years)	2	Manufacturer and professional plumber recommendations	
Subtotal	***$1,979***		Maintenance Cost over 30-year Period of Analysis.
INCREMENTAL COSTS			
Incremental First	$655	United States Department of	Inflation adjusted to 2014 dollars.

Equipment Cost [1]		Energy 2010 Final Rule: Chapter 8	
Total Incremental First Cost	$725		Includes cost of water heater and IWH drain kit (i.e. isolation valves)
Incremental Equipment Replacement Cost	($231)		Negative value indicates that over the 30-year period of analysis, replacing a storage water heater is more expensive than replacing an IWH.
Incremental Maintenance Cost	($843)		Negative value indicates that over the 30-year period of analysis, the incremental cost of maintaining a storage water heater is higher than it is for an IWH.

1 Incremental equipment cost is calculated by subtracting the equipment cost for a storage water heater ($518) from the equipment cost for an IWH ($1,173). The value was also adjusted for inflation from 2008 cost data provided by DOE (2010) to 2014 dollars.

Incremental Maintenance Cost Methodology

The Statewide CASE Team gathered estimates of maintenance costs for both storage water heaters and IWHs based on conversations with professional plumbing companies across California. Table 22 lists the maintenance prices that were gathered. The price points are provided to show the range of expected maintenance costs for both storage water heaters and IWHs. As shown, there are costs associated with maintaining both storage water heaters and IWHs.

Table 22: Maintenance and Repair Costs

	Activity	Cost Range[1]	Recommended Frequency
Storage	Draining tank by professional plumber	$189 $127 $120	Yearly Yearly Yearly
	Draining tank by homeowner	$0	Manufacturer recommendations range between monthly and yearly.
	Replacing anode rod by professional plumber	$200 - $600	As needed --
IWH	Flushing heat exchanger and cleaning filter by professional plumber	$185 $200 $225	Yearly 1.5 – 2 years 3-4 years (good water quality)
	Flush kit for flushing of heat exchanger by home owner	$85*	
	White vinegar (solution used for flushing)	$10	Every 2 years

1. Cost data were provided by professional plumbing services. Sources are not included to for confidentiality purposes.

* One time upfront cost for the flush kit.

The cost analysis presented in this CASE Report assumes that homeowners will follow the recommendations of manufacturers and hire a professional plumber to conduct routine maintenance of their IWH (e.g., flushing the heat exchanger) or storage water heater (e.g., draining the tank). Based on the cost data provided by professional plumbers around California, the Statewide CASE Team assumed the average cost a plumber charges for draining a storage water heater is $144 and the average cost for a plumber to flush the heat exchanger of an IWH is average $205. Taking net present value into account, the total maintenance costs for an IWH and a storage water heater over the 30-year period is $1,979 and $2,822, respectively. This is based on the manufacturer and professional plumber recommended maintenance schedules of every 2 years for IWHs and every year for storage water heaters. See Section 3.3.2 of this report for a discussion on the frequency of maintenance.

Impact of Isolation Valves on Maintenance Costs of IWHs

After submitting the CASE Report to CEC in September 2014, the Statewide CASE Team was asked by CEC staff whether the presence of isolation valves impacts the maintenance cost for IWHs. Isolation valves (i.e. drain kits) assist in the flushing of the heat exchanger. To help ensure IWHs can be maintained with minimal nuisance, this code change proposal recommends a requirement that IWHs must be installed with isolation valves. The LCC analysis presented in this report assumes that a plumber will flush the IWH heat exchanger on a regular basis. The maintenance cost presented in the report also assumes that the isolation valves are already installed on the IWH. Plumbers have indicated that if there are no isolation valves on an existing IWH, they will charge an additional fee to install the isolation valves. The cost to install a set of valves on an existing IWH can range from $225 to $290 (labor and equipment) with the bulk of the price being labor. The plumbers we spoke with also install new IWHs and they include the installation of isolation valves at no additional labor cost when installing new IWHs (personal communication on August 28, 2014). The cost of the isolation valves is included in the initial incremental cost of the IWH measure (see Section 4.7). In sum, the proposed mandatory standard requiring the installation of isolation valves on IWHS in new construction does not impose additional maintenance costs.

4.7.2 Incremental Cost Methodology – Additional Prescriptive Compliance Option

Table 23 presents the cost assumptions used for evaluating the cost-effectiveness of the proposed additional prescriptive option. All three components of the additional option (QII, compact hot water distribution systems, and pipe insulation) have been evaluated in other CASE Reports that the Statewide CASE Team has developed for the 2016 (Residential High Performance Walls and QII CASE Report, September 2014 version) and 2013 (High Efficiency Water Heater Ready CASE Report) Title 24 code change cycles. See the relevant CASE Reports for more information about cost assumptions for each component of the additional prescriptive option.

Table 23: Key Assumptions for per unit Incremental Construction Cost for Additional Prescriptive Option

Parameter	Assumption	Source	Notes
QII	$890	California Building Industry Association, Statewide CASE Team 2014	CBIA estimate of $843 for the incremental cost of QII was provided during the 2013 Title 24 Standards rulemaking. CBIA cost data from 2011, so cost estimate was adjusted to reflect $2014.
Compact Hot Water Distribution Systems (HWDS)	$292	CA IOUs 2011b, Figure 12	CASE Report for 2013 code Cycle cost estimate of $277 was weighted average for 1-story 2010 sq-ft (45%) and 2-story 2811 sq-ft (55%) prototypes. Cost assumption was adjusted to reflect $2014.
Pipe Insulation on ¾ inch or larger pipe	$241	CA IOUs 2011b, Figure 8	CASE Report cost estimate of $228 was weighted average for 1-story 2010 sq-ft (45%) and 2-story 2811 sq-ft (55%) prototypes. Cost assumption was adjusted to reflect $2014.

4.7.3 Cost Savings Methodology

Energy Cost Savings Methodology

The present value of the energy savings associated with the proposed IWH prescriptive requirement was calculated using the method described in the LCC Methodology (CEC 2011). In summary, the hourly energy savings estimates for the first year of building operation were multiplied by TDV cost values to arrive at the present value of the cost savings over the period of analysis. This measure is climate sensitive, so the energy cost savings were calculated in each climate zone using TDV values for each unique climate zone.

4.7.4 Cost-effectiveness Methodology

The Statewide CASE Team calculated cost-effectiveness using the LCC Methodology. According to CEC's definition, a measure is cost effective if it reduces overall lifecycle cost from the current base case (existing conditions). The LCC Methodology clarifies that absolute lifecycle cost of the proposed measure does not need to be calculated. Rather, it is necessary to calculate the change in lifecycle cost from the existing conditions to the proposed conditions.

If the change in lifecycle cost is negative then the measure is cost effective, meaning that the present value of TDV energy savings is greater than the cost premium. In other words, the proposed measure would reduce the total lifecycle cost as compared to the existing conditions. Propane TDV costs were not used in the evaluation of this measure.

The Planning Benefit to Cost (B/C) Ratio is another metric that can be used to evaluate cost-effectiveness. The B/C Ratio is calculated by dividing the total present value TDV energy cost savings (the benefit) by the present value of the total incremental cost (the cost). If the B/C

Ratio is greater than 1.0 (i.e. the present valued benefits are greater than the present valued costs over the period of analysis), then the measure is cost effective.

4.8 Environmental Impacts Methodology

4.8.1 Greenhouse Gas Emissions Impacts Methodology

Greenhouse Gas Emissions Impacts Methodology

The Statewide CASE Team calculated avoided greenhouse gas (GHG) emissions assuming an emission factor of 353 metric tons of carbon dioxide equivalent ($MTCO_2e$) per Gigawatt-hours (GWh) of electricity savings. As described in more detail in Appendix A: Environmental Impacts Methodology, the electricity emission factor represents savings from avoided electricity generation and accounts for the GHG impacts if the state meets the Renewable Portfolio Standard (RPS) goal of 33% renewable electricity generation by 2020. Avoided GHG emissions from natural gas savings were calculated using an emission factor of 5,303 $MTCO_2e$/million therms (U.S. EPA 2011).

4.8.2 Water Use Impacts Methodology

The Statewide CASE Team reviewed several studies to determine whether IWHs result in increases hot water use due to the continual supply of hot water and the longer hot water delivery times from a cold water start up. Based on the findings of field studies conducted by the Davis Energy Group (Hoeschele et al. 2011) and the Minnesota Center for Energy and Environment (Schoenberger & Bohac 2013), we have determined that the potential water use impacts of the proposed measure are not significant enough to include in the savings analyses. (See Section 5.3.2 for discussion.)

4.8.3 Material Impacts Methodology

The Statewide CASE Team did not develop estimates of material impacts.

4.8.4 Other Impacts Methodology

There are no other impacts from the proposed code change.

5. Analysis and Results

Results from the energy, demand, cost, and environmental impacts analyses are presented in this section.

5.1 Energy Impacts Results

5.1.1 Per Building (Unit) Energy Savings Results

Per building (unit) energy and demand impacts of the proposed measure by climate zone are presented in Table 24. The average natural gas savings for the first year the proposed Standards are in effect are projected to be in the range of 29 to 35 therms per prototype building per year, depending on the climate zone. Since the analysis included the electricity use of gas IWHs to operate combustion fans and controls, whereas the tank type water heater does not use any electricity, the average per unit electricity consumption increase would be 57 kWh/year and a 0.13 kW increase in power demand for each prototype building.

Since the EF rating for IWHs includes site energy consumption from both gas and electricity use and the TDV calculations factor in the EF rating, the TDV savings calculations presented accounts for both the electricity and natural gas consumption of IWHs.

It is estimated that the average per unit net TDV savings (natural gas and electricity) over the 30-year period of analysis will be in the range of 7,300 to 8,000 kBTU depending on the climate zone.

Table 24: First Year[1] Energy Impacts per Building for the IWH Prescriptive Option (Option 1)

Climate Zone	Electricity Savings[2] (kWh/yr)	Demand Savings (kW)	Natural Gas Savings (Therms/yr)	Total TDV Savings (kBTU)[3]
Climate Zone 1	-57	-0.13	35	7,271
Climate Zone 2	-57	-0.13	31	7,490
Climate Zone 3	-57	-0.13	32	7,480
Climate Zone 4	-57	-0.13	30	7,578
Climate Zone 5	-57	-0.13	32	7,417
Climate Zone 6	-57	-0.13	29	7,645
Climate Zone 7	-57	-0.13	29	7,529
Climate Zone 8	-57	-0.13	29	7,709
Climate Zone 9	-57	-0.13	29	7,733
Climate Zone 10	-57	-0.13	29	7,742
Climate Zone 11	-57	-0.13	29	7,733
Climate Zone 12	-57	-0.13	30	7,626
Climate Zone 13	-57	-0.13	29	7,742
Climate Zone 14	-57	-0.13	29	7,767
Climate Zone 15	-57	-0.13	23	8,039
Climate Zone 16	-57	-0.13	34	7,387

1. Savings from one prototype building for the first year the building is in operation.
2. Site electricity savings.
3. TDV energy savings for one prototype building for the first year the building is in operation. Calculated using CEC's 2016 TDV factors and methodology. TDV energy savings calculations include electricity and natural gas use.

Table 25 presents the first year per prototype building energy savings for the prescriptive options. The methodology for the energy savings impacts analysis is described in Section 4 of the CASE Report. The assumptions for existing conditions (baseline building) are the same for all three scenarios. For the additional prescriptive option, it is assumed that the QII, compact distribution, and pipe insulation requirements specified in the Residential Appendix will be implemented. The analysis was completed using version 3 of CBECC-Res.

Table 25: First Year[1] Energy Impacts per Building for All Prescriptive Options

Climate Zone	Total TDV Energy Savings (kBTU)[1]		
	Option 1: Instantaneous Water Heater (kBTU	Option 2a: Storage Water Heater with QII & Compact Design (kBTU)	Option 2b: Storage Water Heater with QII & Pipe Insulation (kBTU)
Climate Zone 1	7,271	13,258	12,656
Climate Zone 2	7,490	9,441	8,887
Climate Zone 3	7,480	7,696	7,143
Climate Zone 4	7,578	8,708	8,178
Climate Zone 5	7,417	7,455	6,892
Climate Zone 6	7,645	5,455	4,926
Climate Zone 7	7,529	3,526	3,006
Climate Zone 8	7,709	6,174	5,654
Climate Zone 9	7,733	8,393	7,879
Climate Zone 10	7,742	8,918	8,398
Climate Zone 11	7,733	14,918	14,388
Climate Zone 12	7,626	13,095	12,566
Climate Zone 13	7,742	14,373	13,854
Climate Zone 14	7,767	14,657	14,128
Climate Zone 15	8,039	11,619	11,173
Climate Zone 16	7,387	16,938	16,336

1. TDV energy savings for one prototype building for the first year the building is in operation. Calculated using CEC's 2016 TDV factors and methodology.

5.1.2 Statewide Energy Impacts Results

First Year Statewide Energy Impacts

The statewide energy impacts of the proposed IWH prescriptive option are presented in Table 26. Though this measure slightly increases statewide electricity consumption and electrical demand, the proposed measure is expected to reduce natural gas use by approximately 3.17 million therms (MMtherms) during the first year the 2016 Title 24 Standards are in effect (2017).

In addition, it is estimated that the statewide net TDV savings (natural gas and electricity) over the 30-year period of analysis will be approximately 828 million kBTU.

All assumptions and calculations used to derive per unit and statewide energy and demand savings are presented in Section 4 of this report.

Table 26: First Year[1] Statewide Energy Impacts for the IWH Prescriptive Option (Option 1)

	Electricity Savings[2] (GWh)	Power Demand Reduction (MW)	Natural Gas Savings (MMtherms)	TDV Energy Savings[2] (Million kBTU)
Proposed Measure	-6.16	-1.34	3.17	828
TOTAL	-6.16	-1.34	3.17	828

1. First year savings from all buildings built statewide during the first year the 2016 Standards are in effect.
2. Site electricity savings.
3. First year TDV savings from all buildings built statewide during the first year the 2016 Standards are in effect. Calculated using CEC's 2016 TDV factors and methodology. TDV energy savings calculations include electricity and natural gas use.

The first year statewide energy impacts of the prescriptive options are presented in Table 27. The methodology used to calculate statewide savings estimates are presented in Section 4 of the CASE Report. The results in Table 27 assume that all buildings will comply using the identified approach. For example, the statewide savings estimate of 838 million TDV kBTU for the IWH prescriptive option assumes that all buildings built in 2017 will comply by installing a gas IWH. If all buildings complied using the QII + Compact Design option, the statewide savings would be 1,133 million TDV kBTU. Though users can comply with Title 24 by implementing any of the prescriptive options, based on historical trends, the majority of users will likely comply using the performance approach. The IWH prescriptive option (option 1) establishes the baseline energy budget for the performance approach.

Table 27: First Year[1] Statewide Energy Impacts of All Prescriptive Options (2017)

Prescriptive Approach	TDV Energy Savings[2] (Million kBTU)
Option 1: Instantaneous Water Heater	828
Option 2a: Baseline Storage Water Heater with QII & Compact Design	1,133
Option 2b: Baseline Storage Water Heater with QII & Pipe Insulation	1,076

1. First year savings from all residential buildings built statewide during the first year the 2016 Standards are in effect (2017). 2017 construction forecast published by CEC's Demand Analysis Office.
2. First year TDV savings from all buildings built statewide during the first year the 2016 Standards are in effect (2017). Calculated using CEC's 2016 TDV factors and methodology. TDV energy savings calculations include electricity and natural gas use.

5.2 Cost-effectiveness Results

5.2.1 Incremental Cost Results

The incremental cost of the proposed measure, relative to existing conditions, is presented in Table 28. The total incremental cost includes the incremental cost during initial installation, the replacement costs of the equipment, and the present value of the incremental maintenance cost over the 30-year period of analysis. Based on assumed lifespans of each water heater type, storage equipment is expected to be replaced twice and IWHs are expected to be replaced once in 30 years. Each of the incremental cost components (installation, equipment, and maintenance) is discussed below.

Table 28: Incremental Cost for the IWH Prescriptive Option[1]

Condition	Equipment Cost[2]		Present Value of Maintenance Cost[5]	Total Cost[6]
	Current[3]	Post Adoption[4]		
Existing Conditions	$2,096	$2,096	$2,822	$4,918
Proposed Conditions	$2,590	$2,590	$1,979	$4,569
Incremental[1]	($494)	($494)	$843	$349

1. Incremental costs equal the difference between existing conditions and proposed conditions.
2. Equipment cost includes cost of the water heater and IWH drain kit plus the installation cost for original equipment and all replacements that are installed within 30-year period of analysis. Initial construction cost using current prices; ΔCI_C.
3. Initial construction cost using estimated prices after adoption; ΔCI_{PA}.
4. Present value of maintenance costs over 30 year period of analysis; ΔCM.
5. Total costs equals incremental cost (post adoption) plus present value of maintenance costs; $\Delta CI_{PA} + \Delta CM$.

Incremental Construction Cost Results

The 2013 Title 24 Standards for domestic water heating requires new single family homes and multi-family buildings with dedicated water heaters for each individual dwelling unit to be equipped with the components to accommodate the installation of IWHs. Research the Statewide CASE Team conducted indicates that when excluding the components that are already required in the Standards, there is no difference in the cost of installing a gas storage water heater and a gas IWH. The labor costs for a single installation or replacement were assumed to be the same for the baseline and measure cases.

The differences in initial cost are attributed to the difference in equipment costs and the inclusion of drain kits for IWHs.

Incremental Maintenance Cost Results

As stated in Section 4.7.1, the Statewide CASE Team assumed that the incremental maintenance cost between the base and measure case for the IWH prescriptive option is -$843. That is, the cost of maintaining an IWH over the 30-year period of analysis is $843 less than the maintenance cost for a storage water heater. See Section 4.7.1 for methodology.

The incremental costs of all the prescriptive option are presented in Table 29.

Table 29: Incremental Cost of All Prescriptive Options[1]

Prescriptive Option	Equipment Cost[2]		Present Value of Maintenance Cost[4]	Total Cost[5]
	Current Post Adoption[3]	Post Adoption[3]		
Option1: IWH	$494	$494	($843)	$349
Option 2a. Baseline Storage Water Heater with QII & Compact HWDS	$1,182	$1,182	$ -	$1,182
Option 2b. Baseline Storage Water Heater with QII & Pipe Insulation	$1,131	$1,131	$ -	$1,131

1. Incremental costs are the difference between existing conditions and proposed conditions when compared to a federal minimally compliant gas-fired storage water heater (i.e. existing condition).
2. Equipment cost includes the materials and installation cost. Initial construction cost using current prices.
3. Initial construction cost uses estimated prices after adoption.
4. Present value of maintenance costs over 30 year period of analysis. There are no maintenance costs assumed for QII + compact design and QII + pipe insulation over the 30-year period of analysis.
5. Total costs equals incremental cost (post adoption) plus present value of maintenance costs.

5.2.2 Cost Savings Results

Energy Cost Savings Results

The per unit TDV energy cost savings over the 30-year period of analysis are presented in Table 30. The analysis shows the per household gas savings for each climate zone. The proposed measure results in positive cost savings in every climate zone.

Table 30: TDV Energy Cost Savings Over 30-Year Period of Analysis - Per Building for All Prescriptive Options[1]

Climate Zone	Total TDV Energy Cost Savings + Other Cost Savings[2] (2017 PV $)		
	Option 1: Instantaneous Water Heater	Option 2a: Storage Water Heater with QII & Compact Design	Option 2b: Storage Water Heater with QII & Pipe Insulation
Climate Zone 1	$2,334	$2,296	$2,192
Climate Zone 2	$2,372	$1,635	$1,539
Climate Zone 3	$2,370	$1,333	$1,237
Climate Zone 4	$2,387	$1,508	$1,416
Climate Zone 5	$2,359	$1,291	$1,194
Climate Zone 6	$2,398	$945	$853
Climate Zone 7	$2,378	$611	$521
Climate Zone 8	$2,409	$ 1,069	$979
Climate Zone 9	$2,414	$1,454	$1,365
Climate Zone 10	$2,415	$ 1,545	$1,455
Climate Zone 11	$2,414	$2,584	$2,492
Climate Zone 12	$2,395	$2,268	$2,176
Climate Zone 13	$2,415	$2,489	$2,399
Climate Zone 14	$2,420	$2,539	$2,447
Climate Zone 15	$2,467	$2,012	$1,935
Climate Zone 16	$2,354	$ 2,934	$2,829
Statewide Average	$2,394	$1,782	$1,689

1. All cost values presented in 2017 dollars. Cost savings are calculated using 2016 TDV values. TDV energy savings calculations include electricity and natural gas use.
2. Total benefit includes TDV energy cost savings, cost savings from equipment replacements, and incremental maintenance cost savings.

5.2.3 Cost-effectiveness Results

The proposed measure results in cost savings over the 30-year period of analysis relative to the existing conditions due to the longer life of IWHs and their lower gas usage (i.e. lower utility bills). In sum, the proposed code change is cost effective in every California climate zone. Prescriptive options 2a and 2b are cost effective in all climate zones except climate zones 6, 7, and 8. As previously stated, the additional prescriptive option does not need to be cost-effective in every climate zone as long as it is cost-effective on a statewide level.

The results of the per-building Cost-effectiveness Analysis are presented in Table 31 - Table 33. The negative values in the “Change in Lifecycle Cost” column indicate that the proposed measure is cost effective in every climate zone, as do the B/C ratio values in the last column. Given the 2017 construction forecast published by CEC’s Demand Analysis Office, the

Statewide CASE Team estimates that the average LCC savings (30-year) of all buildings built during the first year that the 2016 Title 24 Standards are effective will be approximately $143 million for the IWH prescriptive option.

Table 31: Cost-effectiveness Summary per Building, Option 1 (IWH)[1]

Climate Zone	Benefit: Total TDV Energy Cost Savings + Other Cost Savings[2] (2017 PV $)	Cost: Total Incremental Cost[3] (2017 PV $)	Change in Lifecycle Cost[4] (2017 PV $)	Benefit to Cost Ratio[5]
Option 1: Instantaneous Water Heater				
Climate Zone 1	$2,334	$725	($1,609)	3.22
Climate Zone 2	$2,372	$725	($1,647)	3.27
Climate Zone 3	$2,370	$725	($1,645)	3.27
Climate Zone 4	$2,387	$725	($1,662)	3.29
Climate Zone 5	$2,359	$725	($1,634)	3.25
Climate Zone 6	$2,398	$725	($1,673)	3.31
Climate Zone 7	$2,378	$725	($1,653)	3.28
Climate Zone 8	$2,409	$725	($1,684)	3.32
Climate Zone 9	$2,414	$725	($1,689)	3.33
Climate Zone 10	$2,415	$725	($1,690)	3.33
Climate Zone 11	$2,414	$725	($1,689)	3.33
Climate Zone 12	$2,395	$725	($1,670)	3.30
Climate Zone 13	$2,415	$725	($1,690)	3.33
Climate Zone 14	$2,420	$725	($1,695)	3.34
Climate Zone 15	$2,467	$725	($1,742)	3.40
Climate Zone 16	$2,354	$725	($1,629)	3.25

1. Relative to existing conditions. All cost values presented in 2017 dollars. Cost savings are calculated using 2016 TDV values.
2. Total benefit includes TDV energy cost savings, cost savings from equipment replacements, and incremental maintenance cost savings.
3. Total cost equals incremental first cost (equipment and installation).
4. Negative values indicate the measure is cost effective. Change in lifecycle cost equals cost minus benefit.
5. The Benefit to Cost ratio is the total benefit divided by the total incremental costs. The measure is cost effective if the B/C ratio is greater than 1.0.

Table 32: Cost-effectiveness Summary per Building, Option 2a (Storage Water Heater with QII & Compact Design)[1]

Climate Zone	Benefit: Total TDV Energy Cost Savings + Other Cost Savings[2] (2017 PV $)	Cost: Total Incremental Cost[3] (2017 PV $)	Change in Lifecycle Cost[4] (2017 PV $)	Benefit to Cost Ratio[5]
Option 2a: Storage Water Heater with QII & Compact Design				
Climate Zone 1	$2,296	$1,182	($1,114)	1.94
Climate Zone 2	$1,635	$1,182	($453)	1.38
Climate Zone 3	$1,333	$1,182	($151)	1.13
Climate Zone 4	$1,508	$1,182	($326)	1.28
Climate Zone 5	$1,291	$1,182	($109)	1.09
Climate Zone 6	$945	$1,182	$237	0.80
Climate Zone 7	$611	$1,182	$571	0.52
Climate Zone 8	$1,069	$1,182	$113	0.90
Climate Zone 9	$1,454	$1,182	($272)	1.23
Climate Zone 10	$1,545	$1,182	($363)	1.31
Climate Zone 11	$2,584	$1,182	($1,402)	2.19
Climate Zone 12	$2,268	$1,182	($1,086)	1.92
Climate Zone 13	$2,489	$1,182	($1,307)	2.11
Climate Zone 14	$2,539	$1,182	($1,357)	2.15
Climate Zone 15	$2,012	$1,182	($830)	1.70
Climate Zone 16	$2,934	$1,182	($1,752)	2.48
Statewide Average	$1,782	$1,182	($600)	1.51

1. Relative to existing conditions. All cost values presented in 2017 dollars. Cost savings are calculated using 2016 TDV values.
2. Total benefit includes TDV energy cost savings, cost savings from equipment replacements, and incremental maintenance cost savings.
3. Total cost equals incremental first cost (equipment and installation).
4. Negative values indicate the measure is cost effective. Change in lifecycle cost equals cost minus benefit.
5. The Benefit to Cost ratio is the total benefit divided by the total incremental cost. The measure is cost effective if the B/C ratio is greater than 1.0.

Table 33: Cost-effectiveness Summary per Building, Option 2b (Storage Water Heater with QII & Pipe Insulation)[1]

Climate Zone	Benefit: Total TDV Energy Cost Savings + Other Cost Savings[2] (2017 PV $)	Cost: Total Incremental Cost[3] (2017 PV $)	Change in Lifecycle Cost[4] (2017 PV $)	Benefit to Cost Ratio[5]
Option 2b: QII & Pipe Insulation				
Climate Zone 1	$2,192	$1,131	($1,061)	1.94
Climate Zone 2	$1,539	$1,131	($408)	1.36
Climate Zone 3	$1,237	$1,131	($106)	1.09
Climate Zone 4	$1,416	$1,131	($285)	1.25
Climate Zone 5	$1,194	$1,131	($63)	1.06
Climate Zone 6	$853	$1,131	$278	0.75
Climate Zone 7	$521	$1,131	$610	0.46
Climate Zone 8	$979	$1,131	$152	0.87
Climate Zone 9	$1,365	$1,131	($234)	1.21
Climate Zone 10	$1,455	$1,131	($324)	1.29
Climate Zone 11	$2,492	$1,131	($1,361)	2.20
Climate Zone 12	$2,176	$1,131	($1,045)	1.92
Climate Zone 13	$2,399	$1,131	($1,268)	2.12
Climate Zone 14	$2,447	$1,131	($1,316)	2.16
Climate Zone 15	$1,935	$1,131	($804)	1.71
Climate Zone 16	$2,829	$1,131	($1,698)	2.50
Statewide Average	$1,689	$1,131	($558)	1.49

1. Relative to existing conditions. All cost values presented in 2017 dollars. Cost savings are calculated using 2016 TDV values.
2. Total benefit includes TDV energy cost savings, cost savings from equipment replacements, and incremental maintenance cost savings.
3. Total cost equals incremental first cost (equipment and installation).
4. Negative values indicate the measure is cost effective. Change in lifecycle cost equals cost minus benefit.
5. The Benefit to Cost ratio is the total benefit divided by the total incremental costs. The measure is cost effective if the B/C ratio is greater than 1.0.

5.3 Environmental Impacts Results

The greatest environmental impact of the proposed measure is the expected emissions reduction due to reduced natural gas use for water heating.

5.3.1 Greenhouse Gas Emissions Results

Table 34 presents the estimated first year avoided GHG emissions of the proposed code change. During the first year the 2016 Title 24 Standards are in effect the proposed measure will result in avoided GHG emissions of 28,476 $MTCO_2e$.

Table 34: First Year Statewide Greenhouse Gas Emissions Impacts

	Avoided GHG Emissions[1] ($MTCO_2e/yr$)
Proposed Measure	14,647
TOTAL	14,647

1. First year savings from buildings built in 2017; assumes 353 $MTCO_2e/GWh$ and 5,303 $MTCO_2e/MMTherms$.

5.3.2 Water Use Impacts

The Statewide CASE Team considered the potential water use impacts associated with the proposed measure, such as the potential increase in hot water usage from the continual and endless supply of hot water and longer hot water delivery times from a cold start up.

Since hot water usage is largely a function of behavior and is unique to each household, it is challenging to determine if hot water use will increase in a household will use more hot water if there is an IWH as opposed to a storage water heater. Several studies have evaluated this question and have found that despite the “endless supply of water” that IWHs provide hot water usage did not significantly increase after an IWH was installed at the study sites. For example, a study conducted by the Davis Energy Group (2011) that looked at the associated water use of high-efficiency water heaters installed in 18 California single family homes found that IWHs increased hot water consumption by about 15%. The sites retrofitted with IWHs showed an increase in average hot water draw volume from 1.40 to 2.09 gallons per draw, which was counteracted by an average 23% reduction in the daily number of draws (Hoeschele et al. 2011; Hoeschele et al. 2012).[18] In other words, people were using the hot water tap less frequently which cancelled out the longer draws. As such, there was a slight increase in the hot water load after installing an IWH but the results were within the statistical error of the study.

Further, a study by the Minnesota Center for Energy and Environment provided an in-depth look at storage and IWHs in Minnesota homes. The report addressed the impact of the water heater on the amount of hot water used and any behavioral impacts from switching from a storage water heater to IWH. Based on the data collected from each monitoring site, the study determined that there was no statistical difference in hot water usage with the storage water

[18] 2.09/1.40 x (1-0.23) = 1.15

heater and the IWH. The study also found that replacing a storage water heater with an IWH resulted in a 37% savings in water heating energy per household, as well as acceptable service at a reduced monthly cost without increasing total hot water consumption (Schoenbauer & Bohac 2013).

In terms of the time it takes for hot water to arrive at the tap, respondents in both studies reported an increase in wait time ranging from 5 to 60 seconds for hot water. These studies evaluated retrofitting existing buildings with IWS. While hot water wait time in retrofits is an important factor to consider, the proposed measure will only impact new construction (and additions if the addition includes adding a new water heater). Methods to address hot water delivery time in new construction are addressed in the following paragraphs. As noted earlier, there was no statistical difference in the amount of hot water used with a storage water heater over IWH. Moreover, 80% of study respondents were satisfied overall with their IWH, particularly with the consistent hot water temperatures during each draw, and many of the respondents adjusted their behavior to account for the wait time, including not using hot water for shorter tasks (Hoeschele 2011; Schoenbauer & Bohac 2013). Conversations with water heater installers, plumbers, and home builders also reveal consumer satisfaction with IWHs. This is particularly true when the homeowner is informed of the possible delay in hot water and the "cold water sandwich" effect that is common with IWHs (personal communication on July 30, 2014 and August 7, 2014). [19]

Hot water delivery time is a function of several variables, including length and pipe, pipe diameter, fixture flow rate, inlet and outlet water temperatures, and type of water heater.

An effective way to reduce hot water delivery time is to design the hot water distribution system in a manner that minimizes pipe length. Placing the water heater closer to the points of use will help reduce heat loss and decrease the amount of time it takes hot water to reach the tap. Several studies investigating hot water distribution systems have revealed that new homes have increased in size over the past few decades and that the common architecture of homes has resulted in distribution systems that locate the water heater quite a distance from use points. Designing homes with a more compact hot water system would minimize wait times and energy losses in the pipes. Though outside the scope of this proposal, the Statewide CASE Team encourages CEC to consider future measures aimed at more compact hot water distribution systems.

Pipe insulation is another factor to consider in hot water distribution systems. Insulating hot water pipes can reduce wait times for hot water. The 2013 Title 24 water heating standards now require pipe insulation in new residential construction. This mandatory requirement will help reduce the amount of heat loss as the hot water travels from the water heater to the tap.

The Statewide CASE Team concluded that the measure will have a not significant impact on water use or water quality (see Table 35).

[19] A "cold water sandwich" occurs when cold water is introduced into the hot water supply line during frequent on/off operation of an IWH. The effect appears as a momentary drop in temperature as the cold water is discharged from a hot water supply outlet (e.g., shower, tub, or faucet) (Rinnai 2014).

Table 35: Impacts of Water Use and Water Quality

	On-Site Water Savings[1] (gallons/yr)	Embedded Energy Savings[2] (kWh/yr)	Impact on Water Quality Material Increase (I), Decrease (D), or No Change (NC) compared to existing conditions			
			Mineralization (calcium, boron, and salts)	Algae or Bacterial Buildup	Corrosives as a Result of PH Change	Others
Impact (I, D, or NC)	NC	NC	NC	NC	NC	NC
Per Unit Impacts[3]	n/a	n/a	n/a	n/a	n/a	n/a
Statewide Impacts (first year)	n/a	n/a	n/a	n/a	n/a	n/a
Comment on reasons for your impact assessment	n/a	n/a	n/a	n/a	n/a	n/a

1. Does not include water savings at power plant
2. Assumes embedded energy factor of 10,045 kWh per million gallons of water.

5.3.3 Material Impacts Results (Optional)

The material impacts of the proposed code change on material use were not evaluated.

5.3.4 Other Impacts Results

There are no other impacts of the proposed code change.

6. PROPOSED LANGUAGE

The proposed changes to the 2013 Title 24 Standards, Residential ACM Reference Manual, and Compliance Manual are provided below. Changes to the 2013 documents are marked with underlining new language) and ~~strikethroughs~~ deletions).

6.1 Standards

SECTION 110.3 – MANDATORY REQUIREMENTS FOR SERVICE WATERHEATING SYSTEMS AND EQUIPMENT

(c) Installation.

7. **Isolation valves.** Instantaneous water heaters with an input rating greater than 6.8 kBTU/hr (2 kW) shall have isolation valves on both the cold water supply and the hot water pipe leaving the water heater and hose bibs or other fittings on both the cold water supply and leaving hot water piping for flushing the water heater when isolation valves are closed.

SUBCHAPTER 7
LOW-RISE RESIDENTIAL BUILDINGS – MANDATORY FEATURES AND DEVICES

SECTION 150.0 – MANDATORY FEATURES AND DEVICES

Any newly constructed low-rise residential building shall meet the requirements of this Section

(n) **Water Heating System**.

1. Systems using gas or propane water heaters to serve individual dwelling units shall include the following components:

   A. A 120V electrical receptacle that is within 3 feet from the water heater and accessible to the water heater with no obstructions; and

   B. A Category III or IV vent, or a Type B vent with straight pipe between the outside termination and the space where the water heater is installed; and

   C. A condensate drain that is no more than 2 inches higher than the base of the installed water heater, and allows natural draining without pump assistance, and

   D. A gas supply line with a capacity of at least 200,000 Btu/hr.

2. Water heating recirculation loops serving multiple dwelling units shall meet the requirements of Section 110.3(c)5.

3. Solar water-heating systems and collectors shall be certified and rated by the Solar Rating and Certification Corporation (SRCC) or by a testing agency approved by the Executive Director.

4. Instantaneous water heaters with an input rating greater than 6.8 kBTU/hr (2 kW) shall comply with Section 110.3(c) 7.

SECTION 150.1 – PERFORMANCE AND PRESCRIPTIVE COMPLIANCE APPROACHES FOR NEWLY CONSTRUCTED RESIDENTIAL BUILDINGS

{Content that does not pertain to proposed standard omitted}

c) **Prescriptive Standards/Component Package.** Buildings that comply with the prescriptive standards shall be designed, constructed, and equipped to meet all of the requirements for the appropriate Climate Zone shown in TABLE 150.1-A. In TABLE 150.1-A, a NA not allowed) means that feature is not permitted in a particular Climate Zone and a NR no requirement) means that there is no prescriptive requirement for that feature in a particular Climate Zone. Installed components shall meet the following requirements:

{Content that does not pertain to proposed standard omitted}

8. **Domestic Water-Heating Systems.** Water-heating systems shall meet the requirements of either A~~,~~ or B~~, C, or D~~.

~~A. For systems serving individual dwelling units, a single gas or propane storage type water heater with an input of 75,000 Btu per hour or less, and that meets the tank insulation requirements of Section 150.0j) and the requirements of Sections 110.1 and 110.3 shall be installed. For recirculation distribution systems, only Demand Recirculation Systems with manual control pumps shall be used.~~

~~B.~~ A. For systems serving individual dwelling units, the water heating system shall meet the requirements of either i or ii:

i. ~~a~~ A single gas or propane instantaneous water heater with an input of 200,000 Btu per hour or less and no storage tank, and that meets the requirements of Sections 110.1 and 110.3 shall be installed. For recirculation distribution systems, only Demand Recirculation Systems with manual control pumps shall be used.

ii. A single gas or propane storage type water heater with an input of 105,000 Btu per hour or less, and that meets the requirements of Sections 110.1 and 110.3. For recirculation distribution systems, only Demand Recirculation Systems with manual control pumps shall be used. The dwelling unit shall meet all of the requirements for Quality Insulation Installation (QII) as specified in the Reference Appendix RA3.5, and in addition do either a or b:

a. A compact hot water distribution system that is field verified as specified in the Reference Appendix RA4.4.16; or

b. All domestic hot water piping shall be insulated and field verified as specified in the Reference Appendix RA4.4.1, RA4.4.3 and RA4.4.14.

~~C~~ B. For systems serving multiple dwelling units, a central water-heating system that includes the following components shall be installed:

i. Gas or propane water heaters, boilers or other water heating equipment that meet the minimum efficiency requirements of Sections 110.1 and 110.3; and

ii. A water heating recirculation loop that meets the requirements of Sections 110.3c)2 and 110.3c)5 and is equipped with an automatic control system that controls the recirculation pump operation based on measurement of hot water demand and hot water return temperature and has two recirculation loops each serving half of the building; and

EXCEPTION to Section 150.1c)8Cii: Buildings with eight or fewer dwelling units are exempt from the requirement for two recirculation loops.

iii. A solar water-heating system meeting the installation criteria specified in Reference Residential Appendix RA4 and with a minimum solar savings fraction of 0.20 in Climate Zones 1 through 9 or a minimum solar savings fraction of 0.35 in Climate Zones 10 through 16. The solar savings fraction shall be determined using a calculation method approved by the Commission.

~~D. For systems serving individual dwelling units, an electric-resistance storage or instantaneous water heater may be installed as the main water heating source only if natural gas is unavailable, the water heater is located within the building envelope, and a solar water-heating system meeting the installation criteria specified in the Reference Residential Appendix RA4 and with a minimum solar savings fraction of 0.50 is installed. The solar savings fraction shall be determined using a calculation method~~

SUBCHAPTER 9

LOW-RISE RESIDENTIAL BUILDINGS - ADDITIONS AND ALTERATIONS IN EXISTING LOW-RISE RESIDENTIAL BUILDINGS

SECTION 150.2 – ENERGY EFFICIENCY STANDARDS FOR ADDITIONS AND ALTERATIONS IN EXISTING BUILDINGS THAT WILL BE LOW-RISE RESIDENTIAL OCCUPANCIES

{Content that does not pertain to proposed standard omitted}

(b) Alterations. Alterations to existing residential buildings or alterations in conjunction with a change in building occupancy to a low-rise residential occupancy shall meet either Item 1 or 2 below

1. **Prescriptive approach**. The altered component and any newly installed equipment serving the alteration shall meet the applicable requirements of Sections 110.0 through 110.9 and all applicable requirements of Section 150.0(a) through (q); and

{Content that does not pertain to proposed standard omitted}

G. Water-Heating System. Replacement service water-heating systems or components shall:

Meet the requirements of Section 150.0(j)2 and either be:

i. If natural gas is connected to the building, a natural gas water heater that meets the requirements of the Appliance Efficiency Regulations. For storage type water heaters the capacity shall not exceed 60 gallons. ~~A natural gas or propane water-heating system that meets the requirements of 150.1(c)8.~~ No recirculation system shall be installed; or

ii. If no natural gas is connected to the building, an electric water heater that ~~has an energy factor equal to or greater than required under~~ meets the requirements of the Appliance Efficiency Regulations. For storage type water heaters the capacity shall not exceed 60 gallons. No recirculation system shall be installed; or

iii. A water-heating system determined by the Executive Director to use no more energy than the one specified in Item 1 above; or if no natural gas is connected to the building, a water-heating system determined by the Executive Director to use no more energy than the one specified in Item 2 above; or

iv. Using the existing building plus addition compliance approach as defined in Section 150.2(b)2 demonstrate that the proposed water heating system uses no more energy than the system defined in item 1 above regardless of the type or number of water heaters installed

EXCEPTION to Section 150.2(b)1G: Existing inaccessible piping shall not require insulation as defined under 150.0(j)2A iii.

6.2 Reference Appendices

There are no proposed changes to the Reference Appendices.

6.3 ACM Reference Manual

The Statewide CASE Team will be providing recommended changes to the ACM Reference Manual at a future date.

6.4 Compliance Manuals

The following sections of the Residential Compliance Manual will need to be revised:

- Section 5.2.2 – Mandatory Requirements for Water Heaters
- Section 5.4 – Prescriptive Water Hating and Distribution System Requirements

The Statewide CASE Team will recommend changes to the Residential Compliance Manual Specific in a separate deliverable to CEC.

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APPENDIX A: ENVIRONMENTAL IMPACTS METHODOLOGY

Greenhouse Gas Emissions Impacts Methodology

The avoided GHG emissions were calculated assuming an emission factor of 353 metric tons of carbon dioxide equivalents $MTCO_2e$) per GWh of electricity savings. The Statewide CASE Team calculated air quality impacts associated with the electricity savings from the proposed measure using emission factors that indicate emissions per GWh of electricity generated.[20] When evaluating the impact of increasing the Renewable Portfolio Standard RPS) from 20% renewables by 2020 to 33% renewables by 2020, California Air Resources Board CARB) published data on expected air pollution emissions for various future electricity generation scenarios CARB 2010). The Statewide CASE Team used data from CARB's analysis to inform the air quality analysis presented in this report.

The GHG emissions factor is a projection for 2020 assuming the state will meet the 33% RPS goal. CARB calculated the emissions for two scenarios: 1) a high load scenario in which load continues at the same rate; and 2) a low load rate that assumes the state will successfully implement energy efficiency strategies outlined in the AB32 scoping plan thereby reducing overall electricity load in the state.

To be conservative, the Statewide CASE Team calculated the emissions factors of the incremental electricity between the low and high load scenarios. These emission factors are intended to provide a benchmark of emission reductions attributable to energy efficiency measures that could help achieve the low load scenario. The incremental emissions were calculated by dividing the difference between California emissions in the high and low generation forecasts by the difference between total electricity generated in those two scenarios. While emission rates may change over time, 2020 was considered a representative year for this measure.

Avoided GHG emissions from natural gas savings were calculated using an emission factor of 5,303 $MTCO_2e$/million therms (U.S. EPA 2011).

[20] California power plants are subject to a GHG cap and trade program and linked offset programs until 2020 and potentially beyond.

APPENDIX B: JOB CREATION BY INDUSTRY

Table 36 shows total job creation by industry that is expected from all investments in California energy efficiency and renewable energy (UC Berkeley 2011, Appendix D). While it is not specific to codes and standards, this data indicates the industries that generally will receive the greatest job growth from energy efficiency programs.

Table 36: Job Creation by Industry

NAICS	Industry Description	Direct Jobs	
		2015	2020
23822	Plumbing, Heating, and Air-Conditioning Contractors	8,695	13,243
2361	Residential Building Construction	5,072	7,104
2362	Nonresidential Building Construction	5,345	6,922
5611	Office Administrative Services	2,848	4,785
23821	Electrical Contractors	3,375	4,705
551114	Corporate, Subsidiary, and Regional Managing Offices	1,794	3,014
54133	Engineering Services	1,644	2,825
5418	Advertising and Related Services	1,232	2,070
334413	Semiconductor and Related Device Manufacturing	1,598	1,598
541690	Other Scientific and Technical Consulting Services	796	1,382
23831	Drywall and Insulation Contractors	943	1,331
3334	Ventilation, Heating, Air-Conditioning, & Commercial Refrigeration Equipment Manufacturing	453	792
3351	Electric Lighting Equipment Manufacturing	351	613
926130	Regulation and Administration of Communications, Electric, Gas, Other Utilities	322	319
23816	Roofing Contractors	275	277
54162	Environmental Consulting Services	151	261
484210	Used Household and Office Goods Moving	137	239
23835	Finish Carpentry Contractors	120	120
23829	Other Building Equipment Contractors	119	113
3352	Household Appliance Manufacturing	63	110
Other	Other	454	547
	Total	**35,788**	**52,369**

APPENDIX C: ENERGY IMPACTS, ESTIMATED FIRST YEAR ENERGY SAVINGS, AND COST EFFECTIVENESS RESULTS FOR EACH PROTOTYPE BUILDING

The tables below present the per unit energy and cost impacts for each of the two prototype buildings used in the energy savings analysis for the IWH prescriptive option (Option 1). As discussed in Section 4.3 of the report, the results presented in the body of the report represent the weighted average savings of the two prototype buildings. Key assumptions about the prototype buildings and the relative weight assigned to each prototype in the savings analysis are presented in Table 17.

Table 37: First Year[1] Energy Impacts for Prototype Building 1 (conditioned floor area (CFA)= 2,100 SF)

Climate Zone	Electricity Savings[2] (kWh/yr)	Demand Savings (kW)	Natural Gas Savings (Therms/yr)	Total TDV Savings (kBTU)[3]
Climate Zone 1	-57	-0.13	32	7,413
Climate Zone 2	-57	-0.13	29	7,602
Climate Zone 3	-57	-0.13	29	7,581
Climate Zone 4	-57	-0.13	28	7,665
Climate Zone 5	-57	-0.13	30	7,539
Climate Zone 6	-57	-0.13	27	7,749
Climate Zone 7	-57	-0.13	27	7,623
Climate Zone 8	-57	-0.13	26	7,791
Climate Zone 9	-57	-0.13	26	7,812
Climate Zone 10	-57	-0.13	26	7,833
Climate Zone 11	-57	-0.13	26	7,812
Climate Zone 12	-57	-0.13	28	7,707
Climate Zone 13	-57	-0.13	26	7,833
Climate Zone 14	-57	-0.13	26	7,854
Climate Zone 15	-57	-0.13	21	8,064
Climate Zone 16	-57	-0.13	31	7,539

1. Savings from one prototype building for the first year the building is in operation.
2. Site electricity savings.
3. TDV energy savings for one prototype building for the first year the building is in operation. Calculated using CEC's 2016 TDV factors and methodology. Includes savings from electricity and natural gas.

Table 38: First Year[1] Energy Impacts for Prototype Building 2 (CFA = 2,700 SF)

Climate Zone	Electricity Savings[2] (kWh/yr)	Demand Savings (kW)	Natural Gas Savings (Therms/yr)	Total TDV Savings[3] (kBTU)
Climate Zone 1	-57	-0.13	37	7,155
Climate Zone 2	-57	-0.13	33	7,398
Climate Zone 3	-57	-0.13	34	7,398
Climate Zone 4	-57	-0.13	32	7,506
Climate Zone 5	-57	-0.13	34	7,317
Climate Zone 6	-57	-0.13	31	7,560
Climate Zone 7	-57	-0.13	31	7,452
Climate Zone 8	-57	-0.13	31	7,641
Climate Zone 9	-57	-0.13	31	7,668
Climate Zone 10	-57	-0.13	31	7,668
Climate Zone 11	-57	-0.13	31	7,668
Climate Zone 12	-57	-0.13	32	7,560
Climate Zone 13	-57	-0.13	31	7,668
Climate Zone 14	-57	-0.13	31	7,695
Climate Zone 15	-57	-0.13	25	8,019
Climate Zone 16	-57	-0.13	36	7,263

1. Savings from one prototype building for the first year the building is in operation.
2. Site electricity savings.
3. TDV energy savings for one prototype building for the first year the building is in operation. Calculated using CEC’s 2016 TDV factors and methodology. Includes savings from electricity and natural gas.

Table 39: Statewide Energy Impacts (CFA=2,100 SF)

	First Year Statewide Savings[1]			TDV Savings[2]
	Electricity Savings[3] (GWh)	Power Demand Reduction (MW)	Natural Gas Savings (MMtherms)	TDV Energy Savings (Million kBTU)
Proposed Measure	-6.16	-1.34	2.90	838
TOTAL	-6.16	-1.34	2.90	838

1. First year savings from all buildings built statewide during the first year the 2016 Standards are in effect.
2. TDV savings from all buildings built statewide during the first year the 2016 Standards are in effect. Calculated using CEC’s 2016TDV factors and methodology.
3. Site electricity savings.

Table 40: Statewide Energy Impacts (CFA=2,700 SF)

	First Year Statewide Savings[1]			TDV Savings[2]
	Electricity Savings[3] (GWh)	Power Demand Reduction (MW)	Natural Gas Savings (MMtherms)	TDV Energy Savings (Million kBTU)
Proposed Measure	-6.16	-1.34	3.40	821
TOTAL	-6.16	-1.34	3.40	821

1. First year savings from all buildings built statewide during the first year the 2016 Standards are in effect.
2. First year TDV savings from all buildings built statewide during the first year the 2016 Standards are in effect. Calculated using CEC's 2016TDV factors and methodology.
3. Site electricity savings.

Table 41: Estimated First Year Energy Savings

	Electricity Savings (GWh)		Power Demand Reduction (MW)	Natural Gas Savings (MMtherms)		First Year TDV Energy Savings (Million kBTU)	
	CFA = 2,100 SF	CFA = 2,700 SF		CFA = 2,100 SF	CFA = 2,700 SF	CFA = 2,100 SF	CFA = 2,700 SF
Proposed Measure	-6.16	-6.16	-1.34	2.90	3.40	838	821
TOTAL	-6.16	-6.16	-1.34	2.90	3.40	838	821

Table 42: TDV Energy Cost Savings Over 30-Year Period of Analysis - Per Prototype Building 1 (CFA=2,100 SF)

Climate Zone	Total TDV Energy Cost Savings (2017 PV $)
Climate Zone 1	$1,284
Climate Zone 2	$1,317
Climate Zone 3	$1,313
Climate Zone 4	$1,328
Climate Zone 5	$1,306
Climate Zone 6	$1,342
Climate Zone 7	$1,320
Climate Zone 8	$1,349
Climate Zone 9	$1,353
Climate Zone 10	$1,357
Climate Zone 11	$1,353
Climate Zone 12	$1,335
Climate Zone 13	$1,357
Climate Zone 14	$1,360
Climate Zone 15	$1,397
Climate Zone 16	$1,306

All cost values presented in 2017 dollars. Cost savings are calculated using 2016 TDV values.

Table 43: TDV Energy Cost Savings Over 30-Year Period of Analysis - Per Prototype Building 2 (CFA=2,700 SF)

Climate Zone	Total TDV Energy Cost Savings (2017 PV $)
Climate Zone 1	$1,239
Climate Zone 2	$1,281
Climate Zone 3	$1,281
Climate Zone 4	$1,300
Climate Zone 5	$1,267
Climate Zone 6	$1,309
Climate Zone 7	$1,291
Climate Zone 8	$1,323
Climate Zone 9	$1,328
Climate Zone 10	$1,328
Climate Zone 11	$1,328
Climate Zone 12	$1,309
Climate Zone 13	$1,328
Climate Zone 14	$1,333
Climate Zone 15	$1,389
Climate Zone 16	$1,258

All cost values presented in 2017 dollars. Cost savings are calculated

Table 44: Cost-effectiveness Summary[1] for Prototype Building 1 (CFA=2,100 SF)

Climate Zone	Benefit: TDV Energy Cost Savings + Other Cost Savings[2] (2017 PV $)	Cost: Total Incremental Cost[3] (2017 PV $)	Change in Lifecycle Cost[4] (2017 PV $)	Benefit to Cost Ratio[5]
Climate Zone 1	$2,358	$725	($1,609)	3.22
Climate Zone 2	$2,391	$725	($1,647)	3.27
Climate Zone 3	$2,387	$725	($1,645)	3.27
Climate Zone 4	$2,402	$725	($1,662)	3.29
Climate Zone 5	$2,380	$725	($1,634)	3.25
Climate Zone 6	$2,417	$725	($1,673)	3.31
Climate Zone 7	$2,395	$725	($1,653)	3.28
Climate Zone 8	$2,424	$725	($1,684)	3.32
Climate Zone 9	$2,427	$725	($1,689)	3.33
Climate Zone 10	$2,431	$725	($1,690)	3.33
Climate Zone 11	$2,427	$725	($1,689)	3.33
Climate Zone 12	$2,409	$725	($1,670)	3.30
Climate Zone 13	$2,431	$725	($1,690)	3.33
Climate Zone 14	$2,435	$725	($1,695)	3.34
Climate Zone 15	$2,471	$725	($1,742)	3.40
Climate Zone 16	$2,380	$725	($1,629)	3.25

1. Relative to existing conditions. All cost values presented in 2017 dollars. Cost savings are calculated using 2016 TDV values.
2. Total benefit includes TDV energy cost savings, cost savings from equipment replacements, and incremental maintenance cost savings.
3. Total cost equals incremental first cost (equipment and installation).
4. Negative values indicate the measure is cost effective. Change in lifecycle cost equals cost minus benefit.
5. The Benefit to Cost ratio is the total benefit divided by the total incremental costs. The measure is cost effective if the B/C ratio is greater than 1.0.

Table 45: Cost-effectiveness Summary[1] for Prototype Building 2 (CFA=2,700 SF)

Climate Zone	Benefit: TDV Energy Cost Savings + Other Cost Savings[2] (2017 PV $)	Cost: Total Incremental Cost[3] (2017 PV $)	Change in Lifecycle Cost[4] (2017 PV $)	Benefit to Cost Ratio[5]
Climate Zone 1	$2,314	$725	($1,589)	3.19
Climate Zone 2	$2,356	$725	($1,631)	3.25
Climate Zone 3	$2,356	$725	($1,631)	3.25
Climate Zone 4	$2,374	$725	($1,649)	3.28
Climate Zone 5	$2,342	$725	($1,617)	3.23
Climate Zone 6	$2,384	$725	($1,659)	3.29
Climate Zone 7	$2,365	$725	($1,640)	3.26
Climate Zone 8	$2,398	$725	($1,673)	3.31
Climate Zone 9	$2,402	$725	($1,677)	3.31
Climate Zone 10	$2,402	$725	($1,677)	3.31
Climate Zone 11	$2,402	$725	($1,677)	3.31
Climate Zone 12	$2,384	$725	($1,659)	3.29
Climate Zone 13	$2,402	$725	($1,677)	3.31
Climate Zone 14	$2,407	$725	($1,682)	3.32
Climate Zone 15	$2,463	$725	($1,738)	3.40
Climate Zone 16	$2,332	$725	($1,607)	3.22

1. Relative to existing conditions. All cost values presented in 2017 dollars. Cost savings are calculated using 2016 TDV values.
2. Total benefit includes TDV energy cost savings, cost savings from equipment replacements, and incremental maintenance cost savings.
3. Total cost equals incremental first cost (equipment and installation).
4. Negative values indicate the measure is cost effective. Change in lifecycle cost equals cost minus benefit.
5. The Benefit to Cost ratio is the total benefit divided by the total incremental costs. The measure is cost effective if the B/C ratio is greater than 1.0.

APPENDIX D: *INTENTIONALLY OMITTED*

Appendix E: Instructions for Using the Lifecycle cost analysis spreadsheet

The Microsoft Excel file used to perform the lifecycle cost (LCC) analysis that was based on model runs using CBECC-res version 3 software was submitted to CEC along with this CASE Report and entitled, “Residential IWH-LCC Spreadsheet-Appendix E or CASE Report.xlsx.” The original CBECC data and assumptions for the LCC analysis are contained in this Excel file. On the “Inputs” worksheet users may modify certain assumptions on the equipment useful life, maintenance frequencies, and maintenance costs that were used in the CASE analysis to understand the impact of these factors on the LCC analysis. Any assumptions that users choose when modifying the LCC analysis should be reasonable and supported by data.

Appendix B5

Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal

November 2014

(Revised from June 2014 draft)

Energy+Environmental Economics

Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal

November 2014

(Revised from June 2014 draft)

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Executive Summary

This study examines the potential role of decarbonized pipeline gas fuels, and the existing gas pipeline infrastructure, to help meet California's long-term climate goals. The term "decarbonized gas" is used to refer to gaseous fuels with a net-zero, or very low, greenhouse gas impact on the climate. These include fuels such as biogas, hydrogen and renewable synthetic gases produced with low lifecycle GHG emission approaches. The term "pipeline gas" means any gaseous fuel that is transported and delivered through the natural gas distribution pipelines. Using a bottom-up model of California's infrastructure and energy systems between today and 2050 known as PATHWAYS (v.2.1), we examine two "technology pathway" scenarios for meeting the state's goal of reducing greenhouse gas (GHG) emissions to 80 percent below 1990 levels by 2050:

+ **Electrification scenario**, where all energy end uses, to the extent feasible, are electrified and powered by renewable electricity by 2050;
+ **Mixed scenario**, where both electricity and decarbonized gas play significant roles in California's energy supply by 2050.

Both scenarios meet California's 2020 and 2050 GHG goals, to the extent feasible, accounting for constraints on energy resources, conversion efficiency, delivery systems, and end-use technology adoption. Across scenarios, we compare total GHG emissions, costs, and gas pipeline utilization over time relative to a Reference scenario, which does not meet the 2050 GHG target.

The study concludes that a technology pathway for decarbonized gas could feasibly meet the state's GHG reduction goals and may be easier to implement in some sectors than a high electrification strategy. We find that the total costs of the decarbonized gas and electrification pathways to be comparable and within the range of uncertainty. A significant program of research and development, covering a range of areas from basic materials science to regulatory standards, would be needed to make decarbonized gas a reality.

The results also suggest that decarbonized gases distributed through the state's existing pipeline network are complementary with a low-carbon electrification strategy by addressing four critical challenges to California's transition to a decarbonized energy supply.

+ First, decarbonized pipeline gas can help to reduce emissions in sectors that are otherwise difficult to electrify, either for technical or customer-acceptance reasons. These sectors include: (1) certain industrial end uses, such as process heating, (2) heavy duty vehicles (HDVs), and (3) certain residential and commercial end uses, such as cooking, and existing space and water heating.
+ Second, the production of decarbonized gas from electricity could play an important role in integrating variable renewable generation by producing gas when renewables are generating power, and then storing the gas in the pipeline distribution network for when it is needed.
+ Third, a transition to decarbonized pipeline gas would enable continued use of the state's existing gas pipeline distribution network, eliminating

the need for new energy delivery infrastructure to meet 2050 GHG targets, such as dedicated hydrogen pipelines or additional electric transmission and distribution capacity.

+ Fourth, pursuit of decarbonized gas technologies would help diversify the technology risk associated with heavy reliance on a limited number of decarbonized energy carriers, and would allow consumers, businesses and policymakers greater flexibility and choice in the transition to a low-carbon energy system.

1 Introduction

California has embarked on a path to dramatically reduce its GHG emissions over the next four decades. In the nearer term, Assembly Bill 32 (AB 32) requires the state to reduce GHG emissions to 1990 levels by 2020. The state appears to be on track to meet this goal. In the longer term, Executive Order S-3-05 sets a target for California to reduce GHG emissions by 80% relative to 1990 levels by 2050. Achieving this target will require significant changes in the state's energy systems over the coming decades; the state's energy supply will need to be almost entirely carbon free by mid-century.

Natural gas and other gaseous fuels face an uncertain future in California's energy supply mix. The need to reduce the carbon intensity of the state's transportation fuels and industrial output to meet near- to medium-term GHG goals opens up opportunities for natural gas as a substitute for more carbon-intensive oil and coal. However, natural gas from traditional fossil fuel sources cannot represent a significant share of energy use by 2050 if the state is to meet its long-term GHG goal. By 2050, traditional uses of oil and natural gas, including transportation fuels, water and space heating, and industrial boilers and process heating, will need to be mostly, if not fully, decarbonized.

Solutions for achieving a deep decarbonization of California's energy supply have focused on extensive electrification using renewable energy sources, with some liquid biofuel and hydrogen fuel use in the transportation sector. However, there are three principal challenges associated with this decarbonization "pathway." First, there are practical limits to electrifying some energy end uses, such as HDVs and industrial process heating. Second, there are physical limits on sustainable biomass resources, which limit the amount of biomass that can be used as a primary energy source. Third, very high levels of renewable penetration require large-scale energy storage solutions, to integrate wind and solar generation on daily and seasonal timescales. Decarbonized[1] gas fuels distributed through the state's extensive existing gas pipeline network offer a little-explored strategy for overcoming some of these challenges and meeting the state's GHG goals.

To examine the roles of gas fuels in California and utilization of the state's existing gas pipeline infrastructure from now until 2050, Southern California Gas Company (SCG) retained Energy and Environmental Economics (E3) to address four main questions:

1. Are there feasible technology pathways for achieving California's nearer- and longer-term GHG targets where gaseous fuels continue to play a significant role?
2. If yes, how do these pathways compare against a reference case and a "high electrification" strategy in terms of GHG emissions and costs?How does the use of the state's gas pipeline infrastructure differ under scenarios where more and less of the state's energy supply is electrified?
3. In what key areas would research, development, and demonstration (RD&D) be needed to produce decarbonized gas on a commercial scale?

[1] Throughout this report, the term "decarbonized gas" refers to gases that have a net-zero, or very low, impact on the climate, accounting for both fuel production and combustion.

To provide an analytical framework for addressing these questions, we develop two "technology pathway" scenarios that represent different points along a spectrum between higher and lower levels of electrification of energy end uses by 2050:

(1) "Electrification" scenario, where most of the state's energy consumption is powered with renewable electricity by 2050;

(2) "Mixed" scenario where decarbonized gas replaces existing natural gas demand and fuels HDVs, but renewable energy is used to produce electricity and to power most light-duty vehicles (LDVs).

The decarbonized gas technologies examined in this study were selected to represent a range of different options, but are not intended to be exhaustive. The focus in this study is on more generally examining the role of gas fuels over the longer term in a low-carbon energy system, not on comparing different emerging decarbonized gas options.[2] These scenarios are compared to a Reference scenario where current policies are unchanged through 2050 and the state's GHG target is unmet. Table 1 shows a high-level summary of key differences among these three scenarios.

[2] A number of emerging technology options for low-carbon gas, such as artificial photosynthesis, are thus not included in the list of technology options examined in this study. Including these technologies would likely reinforce many of the main conclusions in this study.

Table 1. High-level summary of key differences among the three scenarios examined in this analysis

Scenario	Source of residential, commercial, industrial energy end uses	Source of transportation fuels	Source of electricity supply	Source and amount of decarbonized pipeline gas[3]
Electrification	Mostly electric	Mostly electric LDVs, mostly hydrogen fuel cell HDVs	Renewable energy, some natural gas with CCS	Small amount of biogas
Mixed	Decarbonized gas for existing gas market share of end uses	Electric LDVs, Decarbonized gas in HDVs	Renewable energy, some natural gas with CCS	Large amount of biogas, smaller amounts of SNG, hydrogen, natural gas
Reference	Natural gas	Gasoline, diesel	Mostly natural gas	None

Both the Electrification and Mixed scenarios were designed to meet California's 2020 and 2050 GHG targets. For each scenario we analyzed its technical feasibility and technology costs using a bottom-up model of the California economy. This model (California PATHWAYS v2.1), which includes a detailed "stock-rollover" representation of the state's building, transportation, and energy infrastructure, allows for realistic depiction of infrastructure turnover and technology adoption; sector- and technology-based matching of energy demand and supply; and detailed energy system representation and technology coordination. The model includes hourly power system dispatch and realistic

[3] Throughout this report, the term "pipeline gas" is used to encompass different mixes of gas in the pipeline, including conventional natural gas, gasified biomass, hydrogen (initially limited to 4% of pipeline gas volume, with up to 20% allowed by 2050), and gas produced from P2G methanation.

operating constraints. An earlier version of the model was peer reviewed as part of an article published in the journal *Science*.[4]

The identification of realistic sources of decarbonized gas is a critical piece of this analysis. We considered three energy carriers for decarbonized gas, each with different potential primary energy sources:

+ **Biogas**, which includes gas produced through biomass gasification (biomass synthetic gas) and anaerobic digestion of biomass;
+ **Hydrogen**, produced through electrolysis; and
+ **Synthetic natural gas (SNG)**, produced through electrolysis with renewables (mostly wind and solar "over-generation") and further methanated into SNG in a process referred to as power-to-gas (P2G) throughout this report.[5]

By 2050, there are a limited number of primary energy sources available to supply decarbonized energy: renewable electricity, biomass, nuclear, or fossil fuels with carbon capture and sequestration (CCS). Each has different scaling constraints. For instance, wind and solar energy are intermittent and require energy storage at high penetration levels. Hydropower and geothermal energy are constrained by land and water use impacts and the availability of suitable

[4] James H. Williams, Andrew DeBenedictis, Rebecca Ghanadan, Amber Mahone, Jack Moore, William R. Morrow III, Snuller Price, Margaret S. Torn, "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science* 335: 53-59.

[5] P2G, though often used generically to refer to any process that converts electricity to gas, refers specifically to electrolysis and hydrogen methanation in this report. The methanation reaction requires a source of CO_2, which we assume to be air capture in this study, although carbon capture from seawater is another promising, emerging technology. This extra methanation step, and the costs of seawater carbon capture, or air capture, makes P2G relatively expensive. We examined this technology in this study primarily for its electricity storage benefits. Other potential low-carbon gas production technologies, such as synthetic photosynthesis, are not examined within the scope of this study.

sites for development. Bioenergy is limited by the amount of feedstock that can be sustainably harvested. Nuclear is limited by public acceptance and the lack of long-term storage and disposal of spent fuel. Carbon capture and sequestration is also limited by public acceptance and generates higher emissions than the other options due to partial capture rates of CO_2. Choices of primary energy sources for a decarbonized energy supply require tradeoffs in costs, reliability, externalities, and public acceptance.

Similar limits and tradeoffs exist with conversion pathways from primary energy to secondary energy carriers, often with multiple interrelated options. Biomass, for instance, can be converted into a number of different energy carriers (e.g., liquid biofuels, biogas, hydrogen, electricity) through multiple energy conversion processes. P2G is only cost-effective from an energy system perspective when there is significant renewable over-generation. Fossil fuels can be converted into partially decarbonized energy with carbon capture and sequestration (CCS). Evaluating different decarbonized gas technology options — primary energy sources, energy conversion pathways, and energy carriers — thus requires realistic scaling constraints, an integrated energy system perspective, and strategies for managing uncertainty and complexity.

Our modeling framework addresses these requirements by: consistently constraining physical resources (e.g., biomass availability), conversion efficiencies (e.g., gasification efficiency), and gas distribution (e.g., limits on hydrogen gas volumes in pipelines); allowing for interrelationships among energy sources (e.g., electricity and gas); accounting for system costs and GHG emissions across a range of technologies; and exploring different potential options under a range of inputs and avoiding over-reliance on point estimate assumptions as the driver of technology adoption. The results of this study confirm that the electricity sector will be pivotal to achieving a low-carbon future in California — in both the Electrification and Mixed scenarios the need for low-carbon electricity increases substantially. The results also suggest that decarbonized gases distributed through the state's existing pipeline network are complementary with a low-carbon electrification strategy by addressing four critical challenges to California's transition to a decarbonized energy supply.

+ First, decarbonized pipeline gas can help to reduce emissions in sectors that are otherwise difficult to electrify, either for technical or customer-acceptance reasons. These sectors include: (1) certain industrial end uses, such as process heating, (2) HDVs, and (3) certain residential and commercial end uses, such as cooking, existing space heating, and existing water heating.
+ Second, the production of decarbonized gas from electricity could play an important role in integrating variable renewable generation by producing gas when renewables are generating power, and then storing the gas in the pipeline distribution network for when it is needed. At high penetrations of variable renewable generation, long-term, seasonal electricity storage may be needed to balance demand and supply, in addition to daily storage. On these longer timescales, gas "storage" may be a more realistic and cost-effective load-resource balancing strategy than flexible loads and long-duration batteries.[6]
+ Third, a transition to decarbonized pipeline gas would enable continued use of the state's existing gas pipeline distribution network, reducing or

[6] In this scenario, we assume that electrolysis for hydrogen production, powered by renewable electricity, can be ramped up and down on a daily basis as a dispatchable load in the medium-term. In the long-term, P2G methanation with air capture, or carbon capture from seawater to produce SNG could provide both a source of low-carbon gas and a grid balancing service.

eliminating the need for new energy delivery infrastructure to meet 2050 GHG targets, such as dedicated hydrogen delivery pipelines or additional electric transmission and distribution lines. Increased use of decarbonized gas in the coming decades would preserve the option of continued use of existing gas pipelines as a low-carbon energy delivery system over the longer term.

+ Fourth, pursuit of decarbonized gas technologies would help diversify the technology risk associated with heavy reliance on a limited number of decarbonized energy carriers, and would allow consumers, businesses and policymakers greater flexibility and choice in the transition to a decarbonized energy system.

All of the decarbonized gas energy carriers in this study make use of proven energy conversion processes — none require fundamental breakthroughs in science. Nonetheless, these processes remain relatively inefficient and expensive, and would need significant improvements in conversion efficiency and reductions in costs to be competitive in the medium- to long-term. Additionally, existing gas pipelines and end use equipment were not designed to transport and utilize hydrogen gas, and would require operational changes as the blend of decarbonized gas shifts over time.

Developing a supply of sustainably sourced biomass presents an additional challenge. Biomass resources have competing uses — food, fodder, and fiber — which may limit the amount of sustainably-sourced biomass available for energy production. The Electrification and Mixed scenarios both assume that a limited quantity of sustainably sourced biomass would be available to California in the 2030 and 2050 timeframe. The same quantity of biomass is assumed to produce electricity in the Electrification scenario, and biogas in the Mixed scenario.

However, it remains uncertain whether it will be possible to increase the production of biomass fuels to this scale, as would be needed to significantly reduce fossil fuel use, without negatively impacting food supply or increasing GHG emissions from changes in land use.

Furthermore, current RD&D efforts and policy initiatives have prioritized the production of liquid biofuels, particularly ethanol, over the production of biogas. More generally, the state does not appear to have a comprehensive decarbonized gas strategy, in contrast to low-carbon electricity which is promoted through the state's Renewables Portfolio Standard (RPS) and the decarbonized transportation fuels are encouraged through the state's Low Carbon Fuel Standard (LCFS). Overcoming these challenges would require prompt shifts in policy priorities and significant amounts of RD&D if biofuels, and particularly biogas, are to become an important part of the state's future energy mix.

The results suggest priority areas and time frames, outlined in Table 2, for a RD&D agenda that would be needed if California is to pursue decarbonized pipeline gas as a strategy to help meet the state's GHG reduction goals.

Table 2. RD&D timescales, priorities, and challenges for decarbonized gas fuels

Timeframe of RD&D payoff	RD&D Area	Challenge
Near-term	Energy efficiency	Achieving greater customer adoption and acceptance
	Reduction in methane leakage	Cost-effectively identifying and repairing methane leaks in natural gas mining, processing, and distribution
	Use of anaerobic digestion gas in the pipeline and pilot biomass gasification	Quality control on gas produced via anaerobic digestion for pipeline delivery
Medium-term	Agronomic and supply chain innovation for biomass feedstocks	Competition with liquid fuels, food, fodder, fiber may limit amount of biomass available as a source of decarbonized gas
	Pilot decarbonized SNG technology to improve conversion efficiency and cost	Gasification, electrolysis, and methanation need efficiency improvements, reductions in cost to be competitive; safety, scale, and location challenges must be addressed
	Limits on hydrogen volumes in existing pipelines	Need pipeline and operational changes to accommodate higher volumes
Long-term	Emerging technologies (e.g., P2G, artificial photosynthesis, CO_2 capture from seawater for fuel production)	P2G must be scalable and available as a renewable resource balancing technology; in general, emerging technologies still require innovations in material science

The organization of the report is as follows: Section 2 develops the Reference case and two afore-mentioned scenarios. Section 3 describes the modeling approach and elaborates on the technology pathways for decarbonized gases. Section 4 presents the results. The final section, Section 5, distills key conclusions and discusses their policy and regulatory implications. Further details on methods and assumptions are provided in an appendix.

1.1 About this study

This study was commissioned by SCG to help the company consider their long-term business outlook under a low-carbon future, and to fill a gap in the existing literature regarding long-term GHG reduction strategies that include the use of decarbonized gas in the pipeline distribution network.

A number of studies have evaluated the options for states, countries and the world to achieve deep reductions in GHG emissions by 2050.[7] These studies each make different assumptions about plausible technology pathways to achieve GHG reductions, with varying amounts of conservation and efficiency, CCS, hydrogen fuel cells, nuclear energy, and biofuel availability, to name a few key variables. However, few studies have undertaken an in-depth investigation of the role that decarbonized pipeline gas could play in achieving a decarbonized future.[8]

In our prior work, we highlighted the pivotal role of the electricity sector in achieving a low-carbon future for California.[9] This study for SCG uses an

[7] See for example: "Reducing Greenhouse Gas Emissions by 2050: California's Energy Future," California Council on Science and Technology, September 2012; "Roadmap 2050: A practical guide to a prosperous, low-carbon Europe," European Climate Foundation, April 2010; "EU Transport GHG: Road to 2050?," funded by the European Commission, June 2010; "EPA Preliminary Analysis of the Waxman-Markey Discussion Draft," U.S. EPA, April 2009; "Energy Technology Perspectives, 2008: Scenarios & Strategies to 2050," International Energy Agency, 2008; "The Power to Reduce CO_2 Emissions: The Full Portfolio: 2008 Economic Sensitivity Studies," EPRI, Palo Alto, CA: 2008. 1018431; "Building a Low Carbon Economy: The U.K.'s Contribution to Tackling Climate Change," The First Report of the Committee on Climate Change, December 2008; "Making the Transition to a Secure and Low-Carbon Energy System: Synthesis Report," UK Energy Research Center, 2009.

[8] For an example of a deep decarbonization study from Germany that employs both electrolysis and P2G (Sabatier), see Palzer, A. and Hans-Martin Henning, "A Future Germany Energy System with a Dominating Contribution from Renewable Energies: A Holistic Model Based on Hourly Simulation," Energy Technol. 2014, 2, 13 – 28.

[9] James H. Williams, Andrew DeBenedictis, Rebecca Ghanadan, Amber Mahone, Jack Moore, William R. Morrow III, Snuller Price, Margaret S. Torn, "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science* 335: 53-59.

updated version of the model (California PATHWAYS 2.1) employed in that prior work, relying on the same fundamental infrastructure-based stock roll-over modeling approach, and many of the same underlying input assumptions, such as energy efficiency potential. However, important updates to the analysis include:

+ Updated forecasts of macroeconomic drivers including population and economic growth;
+ Updated technology cost assumptions where new information has become available, including for solar photovoltaic (PV) and energy storage costs;
+ A more sophisticated treatment of electricity resource balancing, moving from a four time period model (summer/winter & high-load/low-load), to an hourly resource balancing exercise; and
+ Slightly higher biomass resource potential estimates, based on new data from the U.S. Department of Energy (DOE).[10]

The model results are driven by exogenous, scenario-defined technology adoption assumptions. Costs of technologies and fuels are exogenous, independent inputs which are tabulated to track total costs. The model does not use costs as an internal decision variable to drive the model results, rather the model is designed to evaluate technology-driven, user-defined scenarios.

[10] U.S. Department of Energy, "U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry," August 2011.

2 Scenarios

2.1 Low-carbon scenarios

Two distinct low-carbon scenarios are developed and compared within this study. Both of these scenarios result in lower GHG emissions than required by California's mandate of reducing emissions to 1990 levels by 2020, and are designed to meet the 2050 goal of reducing GHG emissions 80% below 1990 levels. Each scenario is further constrained to achieve an approximately linear path in GHG reductions between today's emissions and the 2050 goal. The differences between the two scenarios are not in GHG reduction achievements, but between technology pathways, implied RD&D priorities, technology risks, and costs.

The two low-carbon scenarios evaluated include:

+ **Electrification Scenario: This scenario meets the 2050 GHG reduction goal by electrifying most end-uses,** including industrial end uses, space heating, hot water heating, cooking and a high proportion of light-duty vehicles. Low-carbon electricity is produced mostly from renewable generation, primarily solar PV and wind, combined with a limited amount of natural gas with carbon capture and storage (CCS) and 20 GW of electricity storage used for renewable integration. Low-carbon electricity is also used to produce hydrogen fuel for heavy-duty vehicles. California's limited supply of biomass is used largely to generate renewable electricity in the form of biomass generation. In this scenario, the gas distribution pipeline network is effectively un-used by 2050. With very few remaining sales by 2050 and significant remaining fixed distribution costs, it seems unlikely that gas distribution companies would continue to operate under this scenario.

- **Mixed Scenario: This scenario meets the 2050 GHG reduction goal with a blend of low-carbon electricity and decarbonized pipeline gas.** Existing uses for natural gas in California, such as industrial end uses (i.e. boilers and process heat), space heating, hot water heating and cooking are assumed to be supplied with decarbonized pipeline gas, such that the current market share for pipeline gas is maintained over time. California's limited supply of biomass is used to produce biogas which is injected into the pipeline. Over time, this scenario assumes that an increasing share of hydrogen is blended into the pipeline gas, which is assumed to be produced from renewable power (mostly solar and wind) using electrolysis. This scenario includes a significant increase in electric light-duty vehicles, while most heavy-duty vehicles are assumed to be powered with compressed or liquefied decarbonized gas and liquid hydrogen fuel. Electricity is produced mostly from renewable generation, primarily solar PV and wind, with a limited amount of natural gas with CCS and 5 GW of electricity storage used for renewable integration. Load balancing services are primarily provided by cycling the production of decarbonized gas to match the renewable generation profiles. In this way, the decarbonized pipeline gas provides both daily and seasonal energy storage. The Mixed scenario represents neither a significant expansion nor contraction of the gas pipeline distribution system. In this scenario, both the gas pipeline network and the electricity transmission and distribution system operate as conveyors of decarbonized energy.

The key parameters of these scenarios are summarized in Table 3 below.

Table 3. Summary of Low-Carbon Scenarios Based on Key Parameters in 2050

Scenario	Source of residential, commercial, industrial energy end uses	Source of transportation fuels	Source of electricity supply & resource balancing	Uses of biomass
Electrification	Mostly electric	Mostly electric light-duty vehicles, mostly hydrogen HDVs	Renewable energy, limited natural gas with CCS, 5 GW of pumped hydro energy storage and 15 GW of battery energy storage, some hydrogen production	Electricity generation, small amount of biogas
Mixed	Decarbonized gas (biogas, SNG & hydrogen) for existing gas market share of end uses	Decarbonized gas in HDVs; electric light duty vehicles (LDVs)	Renewable energy, limited natural gas with CCS, 5 GW of pumped hydro energy storage, plus P2G and hydrogen production assumed to provide resource balancing services	Biogas

Both of the low-carbon scenarios evaluated here entail different assumptions about the future feasibility and commercialization of key technologies to achieve an 80 percent reduction in GHGs relative to 1990. For the Electrification scenario to be viable, significant amounts of long-term electricity storage must be available on a daily and seasonal basis to balance intermittent renewable generation. The Electrification scenario also relies significantly on the production of low carbon liquid biofuels and hydrogen fuel cell vehicles in the transportation sector, for vehicles that are otherwise difficult to electrify. For the Mixed scenario to succeed, it must be possible to produce large quantities of biogas using sustainably-sourced biomass. Furthermore, the Mixed scenario depends on eventual adoption of P2G methanation with carbon capture from sea water or air capture to produce SNG. All of the technologies that are applied in these scenarios are technically feasible; the science exists today. The challenge is commercializing and scaling these technologies to provide a significant energy service to California before 2050. In Table 4 below, the emerging technologies applied in the low-carbon scenarios are ranked based on their "risk" to the scenario's success. Risk is determined by ranking the amount of energy that passes through each technology in 2050 for a given scenario (higher energy use implies higher reliance on the technology), combined with a measure of the technology's current commercialization stage (lower availability implies higher risk).

Table 4. Ranking of emerging technology's criticality to the Electrification and Mixed scenarios

Emerging Technologies	Overall Ranking of Technology Criticality by 2050 (maximum = 9 for most critical, minimum = 0 for least critical)	
	Electrification	Mixed
Availability of sustainably-sourced biomass	6	9
Power-to-gas methanation using carbon capture from seawater or air	0	6
Battery storage for load balancing	9	0
Carbon capture and storage	3	3
Cellulosic ethanol	6	0
Hydrogen production	4	4
Use of hydrogen in the distribution pipeline	0	4
Gasification to produce biogas	1	3
Fuel cells in transportation (HDVs)	6	3
Electrification of industrial end uses	2	0

2.2 Common strategies and assumptions across all low-carbon scenarios

Both of the low-carbon scenarios described above include a number of other carbon reduction efforts that must be implemented to achieve the state's long-term GHG reduction goal. These other assumptions do not vary between scenarios, and include low-carbon measures such as:

+ Significant levels of energy efficiency in all sectors, including transportation efficiency, industrial and building efficiency;
+ Significant reductions in non-CO_2 and non-energy GHG emissions, such as methane emissions and other high-global warming potential gases such as refrigerant gases;
+ Improvements in “smart growth” planning as per Senate Bill 375,[11] leading to reductions in vehicle miles traveled (VMT) and increased urban density leading to lower building square footage needs per person;
+ All scenarios include the use of sustainably-sourced biomass to produce decarbonized energy. The scenarios differ in how the biomass is used, to produce electricity, liquid or gas fuels.
+ All scenarios include an increase in electrification relative to today; the scenarios differ in how much additional electrification is assumed relative to other sources of low-carbon energy;
+ Flexible loads for renewable resource balancing, including limited use of controlled charging of electric vehicles and a limited share of certain residential and commercial electric thermal end uses.[12] Hydrogen and P2G production are assumed to provide fully dispatchable, perfectly flexible load-following services, helping to integrate variable renewable generation in the low-carbon scenarios.

[11] The Sustainable Communities and Climate Protection Act of 2008

[12] Up to 40 percent of electric vehicle charging load is assumed to be flexible within a 24-hour period to provide load-resource balancing services. Electric vehicles are not assumed to provide energy back to the electric grid, in a “vehicle-to-grid” configuration.

+ Imports of power over existing transmission lines are limited to a historical average and are assumed to maintain the same emissions intensity throughout the study period. New, dedicated transmission lines for out-of-state renewable resources are also tracked. Exports of electricity from California of up to 1500 MW are allowed.

2.3 Reference case

In addition to the low-carbon scenarios evaluated here, a Reference case is developed as a comparison point. The Reference case assumes a continuation of current policies and trends through the 2050 timeframe with no incremental effort beyond 2014 policies to reduce GHG emissions. This scenario is not constrained to achieve specific GHG reduction goals. As a result, this scenario misses the state's GHG reduction targets in 2050 by a wide margin, with 2050 emissions 9% above 1990 levels. In the Reference case current natural gas end uses, such as space heating and hot water heating, continue to be supplied with natural gas through 2050. With no future efforts, California achieves a 33% RPS by 2020 and maintains this share of renewable energy going forward. The transportation sector continues to be dominated by the use of fossil-fueled vehicles in the Reference case.

3 Analysis Approach

3.1 PATHWAYS model overview

This analysis employs a physical infrastructure model of California's energy economy through 2050. The model, known as PATHWAYS (v2.1), was developed by E3 to assess the GHG impacts of California's energy demand and supply choices over time. The model tracks energy service demand (i.e. VMT) to develop a projection of energy demand and the physical infrastructure stock utilized to provide that service (i.e. types and efficiency of different vehicles). End uses in the building sector, vehicles in the transportation sector, and power plants in the electricity sector are tracked by age and vintage, such that new technologies are adopted as older technologies and are replaced in a stock roll-over representation of market adoption rates.

Technology lifetimes, efficiency assumptions and cost data are generally drawn from the U.S. DOE National Energy Modeling System (NEMS), used to support development of the Annual Energy Outlook 2013. Assumptions about new technology adoption are highly uncertain, and are defined by E3 for each scenario. New technology adoption rate assumptions are selected to ensure that the low-carbon scenarios meet the state's 2050 GHG reduction goal.

The model can contextualize the impacts of different individual energy technology choices on energy supply systems (electricity grid, gas pipeline) and energy demand sectors (residential, commercial, industrial) as well as more broadly examine disparate strategies designed to achieve deep de-carbonization targets. Below, Figure 1 details the basic modeling framework utilized in PATHWAYS to project results for energy demand, statewide GHG emissions, and costs for each scenario.

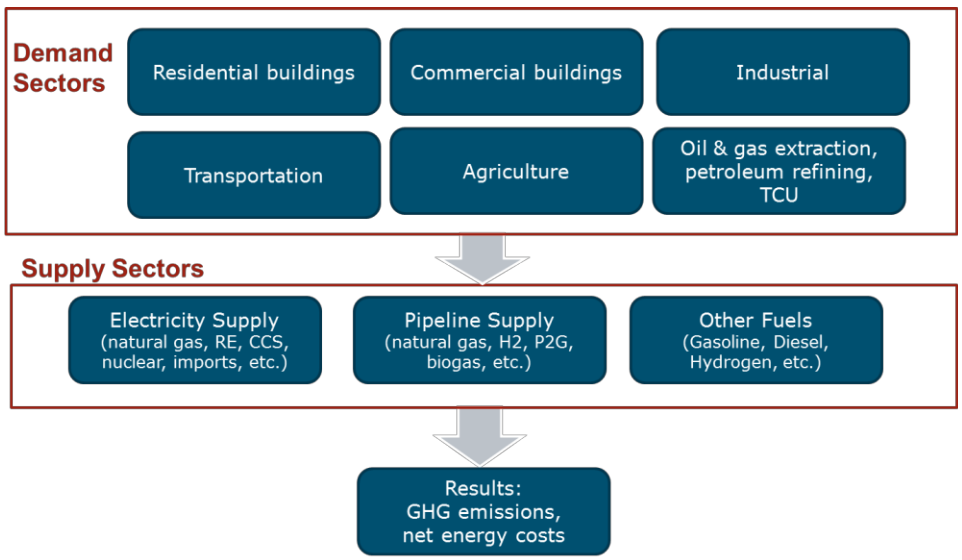


Figure 1. Basic PATHWAYS modeling framework

+ **Energy Demand:** projection of energy demand for ten final energy types. Projected either through stock roll-over or regression approach.
+ **Energy Supply:** informed by energy demand projections. Final energy supply can be provided by either conventional primary energy types (oil; natural gas; coal) or by decarbonized sources and processes (renewable electricity generation; biomass conversion processes; CCS). The energy supply module includes projections of costs and GHG emissions of all energy types.

- **Summary Outputs:** calculation of total GHG emissions and costs (end-use stocks as well as energy costs). These summary outputs are used to compare economic and environmental impacts of scenarios.

PATHWAYS V2.1 projects energy demand in eight sectors, and eighty sub-sectors, as shown below in Table 5.

Table 5. PATHWAYS Energy Demand Sectors and Subsectors

Sector	Subsector
Residential	Water Heating, Space Heating, Central AC, Room AC, Lighting, Clothes Washing, Dish Washing, Freezers, Refrigeration, Misc: Electricity Only, Clothes Drying, Cooking, Pool Heating, Misc: Gas Only
Commercial	Water Heating, Space Heating, Space Cooling, Lighting, Cooking, Refrigeration, Office Equipment, Ventilation
Transportation	Light Duty Vehicles (LDVs), Medium Duty Trucking, Heavy Duty Trucking, Buses, Passenger Rail, Freight Rail, Commercial Passenger Aviation, Commercial Freight Aviation, General Aviation, Ocean Going Vessels, Harborcraft
Industrial	Mining, Construction, Food & Beverage, Food Processing, Textile Mills, Textile Product Mills, Apparel & Leather, Logging & Wood, Paper, Pulp & Paperboard Mills, Printing, Petroleum and Coal, Chemical Manufacturing, Plastics and Rubber, Nonmetallic Mineral, Glass, Cement, Primary Metal, Fabricated Metal, Machinery, Computer and Electronic, Semiconductor, Electrical Equipment & Appliance, Transportation Equipment, Furniture, Miscellaneous, Publishing
Agricultural	Sector-Level Only
Utilities (TCU)	Domestic Water Pumping, Streetlight, Electric and Gas Services Steam Supply, Local Transportation, National Security and International Affairs, Pipeline, Post Office, Radio and Television, Sanitary Service, Telephone, Water Transportation, Trucking and Warehousing, Transportation Service, Air Transportation
Petroleum Refining	Sector-Level Only
Oil & Gas Extraction	Sector-Level Only

For those sectors that can be represented at the stock level – residential, commercial, and transportation – we compute stock roll-over by individual subsector (i.e. air conditioners, LDVs, etc.). For all other sectors, a forecast of energy demand out to 2050 is developed based on historical trends using regression analysis. These two approaches are utilized to project eleven distinct final energy types (Table 6).

Table 6. PATHWAYS Final Energy Types and Sources of Energy

Final Energy Type	
Electricity • many types of renewables, CCS, nuclear, fossil, large hydro.	Gasoline • ethanol & fossil gasoline
Pipeline Gas • natural gas, hydrogen, biogas, SNG	Liquefied petroleum gas (LPG)
Compressed Pipeline Gas • natural gas, hydrogen, biogas, SNG	Refinery and Process Gas
Liquefied Pipeline Gas • natural gas, hydrogen, biogas, SNG	Petroleum coke
Diesel • biodiesel & fossil diesel	Waste Heat
Kerosene-Jet Fuel	

These final energy types can be supplied by a variety of different resources. For example, pipeline gas can be supplied with combinations of natural gas, biogas, hydrogen, and SNG (produced through P2G processes). Electricity can be supplied by hydroelectric, nuclear, coal, natural gas combined cycles and combustion turbines, and a variety of renewable resources including utility-scale & distributed solar PV, wind, geothermal, biomass, etc. These supply composition choices affect the cost and emissions profile of each final energy type. Further methodology description can be found in the Technical Appendix.

3.2 Modeled energy delivery pathways

A decarbonized technology pathway can be thought of as consisting of three stages: (1) the provision of the primary energy itself, (2) the conversion of primary energy into the energy carrier, and (3) the delivery of an energy carrier for final end use. In practice, there can be many variations on this theme, including multiple conversion process steps and the use of CCS. The primary decarbonized energy sources are biomass, renewable and nuclear generated electricity, and natural gas with CCS. The main options for energy carriers in a decarbonized system are electricity, liquid biofuels such as ethanol and biodiesel, and decarbonized gases including biogas, SNG, and hydrogen and decarbonized electricity.

Figure 2 illustrates the main decarbonized technology pathways for delivering energy to end uses represented in the model. In the remainder of this section, we sketch briefly the main low-carbon pathways considered in this study and how they are modeled.

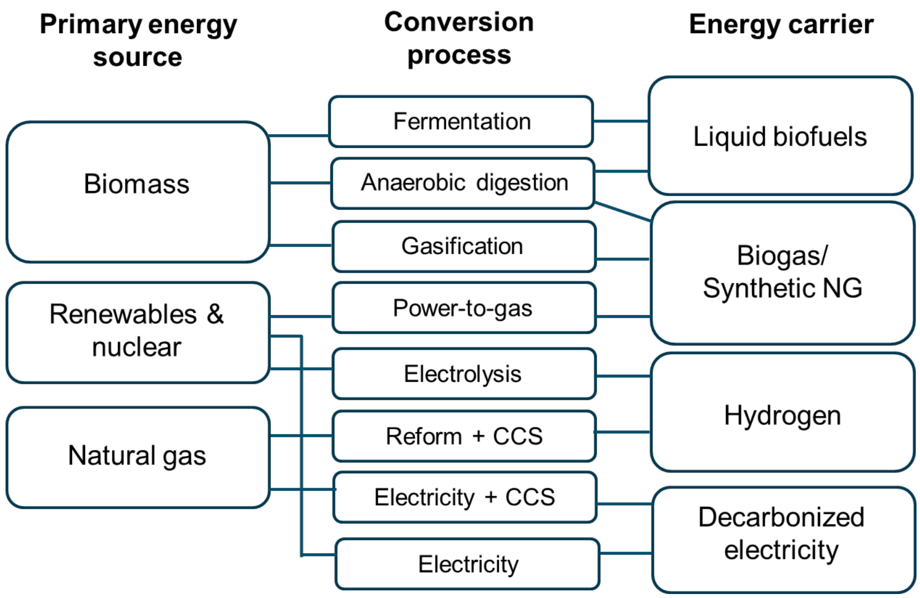


Figure 2. Major low-carbon pathways for delivered energy, from primary energy to conversion process to energy carriers

The technical opportunity for the gas distribution industry lies in providing an alternative to widespread electrification of end uses as an approach to deep decarbonization. The decarbonized gas technologies included in the Mixed scenario have been well-understood and some have been used in commercial applications for decades. For example, synthesized town gas, not natural gas, was the prevalent energy carrier for the first gas distribution companies over a century ago.

However, improvements in cost and efficiency will be required for decarbonized pipeline gas supplies to outcompete other forms of low-carbon delivered energy, such as electricity and liquid biofuels, and other issues require careful consideration and research, such as long-term biomass resource potential and carbon benefits. It is difficult at present to predict which pathways are the most likely to take root and become the dominant forms of energy delivery in a deeply decarbonized world.

3.2.1 BIOMASS RESOURCE ASSUMPTIONS

The principal data source for biofuel feedstocks in our model is the DOE's *Billion Ton Study Update: Biomass Supply for a Bioenergy and Bioproducts Industry* led by Oak Ridge National Laboratory, the most comprehensive available study of long-term biomass potential in the U.S.[13] This study, sometimes referred to as the BT2, updates the cost and potential estimates in the landmark 2005 *Billion Ton Study*, assessing dozens of potential biomass feedstocks in the U.S. out to the year 2030 at the county level (Figure 3).[14]

The estimated future supply of California produced biomass stocks is relatively small compared to the resource potential in the Eastern portion of the U.S., as shown in Figure 3. In this study, we have assumed that California can import up to its population-weighted proportional share of the U.S.-wide biomass feedstock resource potential, or 142 million tons per year by 2030. In the case of the Mixed scenario, where nearly all biomass is assumed to be gasified into biogas, this could be accomplished through production of biogas near the source of of the feedstock, which would then be distributed through the national gas pipeline network. California would not necessarily need to physically import the biomass feedstock into the state in order to utilize, or purchase credits for, the biogas fuel. Under the emissions accounting

[13] U.S. Department of Energy, "U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry," August 2011.
[14] U.S. Department of Energy, "Biomass as a Feedstock for a Bioenergy and Bioproducts Industry: The Technical Feasibility of a Billion-Ton Annual Supply," April 2005.

framework employed in this study, California would take credit for assumed emissions reductions associated with these biofuels, regardless of where the fuel is actually produced. This assumption may not reflect California's long-term emissions accounting strategy. Furthermore, there remains significant uncertainty around the long-term GHG emissions impacts of land-use change associated with biofuels production.

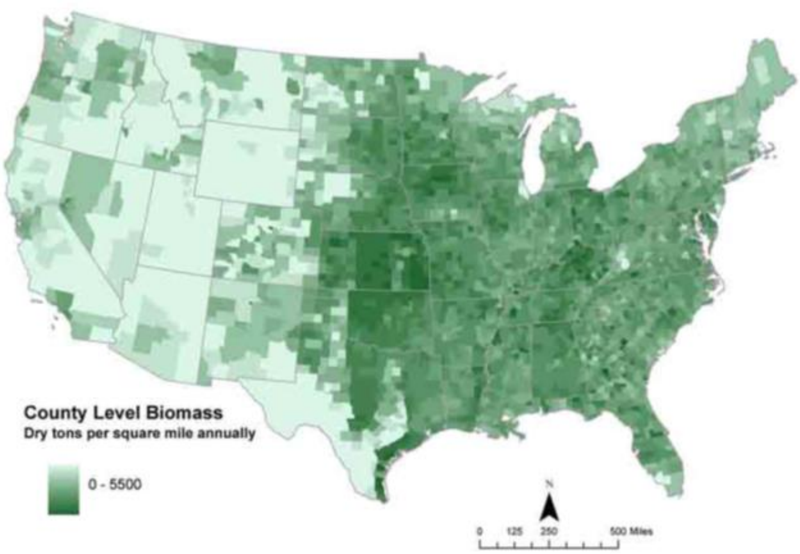


Figure 3. DOE Billions Tons Study Update Biomass Resource Potential (Source: DOE, 2011)

3.2.2 PIPELINE GAS AND LIQUID FUELS FROM BIOMASS

Biomass feedstocks ranging from purpose-grown fuel crops to a variety of agricultural, forestry, and municipal waste products can be converted into decarbonized gas. The main conversion method that is assumed in the Mixed scenario is gasification, including thermal and biochemical variants, which break down complex biomass molecules through a series of steps into a stream of SNG, consisting primarily of hydrogen and carbon monoxide. In the modeled pathway, the SNG is cleaned, shifted, and methanated to produce a pipeline-ready biogas with a high methane content. The other main method for biomass conversion represented in the model is anaerobic digestion. In anaerobic digestion bacterial digestion of biomass in a low-oxygen environment produces a methane-rich biogas which, after the removal of impurities, can be injected into the pipeline. In addition to gas fuels, biomass can be turned into liquid fuels directly through fermentation and distillation, as in the case of ethanol, or through the transesterification of fats such as waste cooking oil to produce biodiesel. Biogas from gasification can also be turned into liquid fuels, for example through the Fischer-Tropsch process.

3.2.3 PIPELINE GAS AND LIQUID FUELS FROM ELECTRICITY AND NATURAL GAS

Renewable energy, fossil generation with CCS and nuclear energy produce low-carbon electricity that can either directly power end uses or be used to produce pipeline gas or liquefied gases for transportation fuels. There are two P2G pathways in the model. One pathway uses electricity for electrolysis to split water and produce hydrogen, which can be injected into the pipeline for distribution up to a certain mixing ratio, or can be compressed or liquefied for use in hydrogen fuel cell vehicles. The other pathway modeled also begins with electrolysis, followed by methanation to produce SNG, which is injected into the pipeline. The SNG pathway requires a source of CO_2, which can come from carbon capture from sea water, air capture or biomass, or under some circumstances from CCS (e.g. situations in which the use of CCS implies no additional net carbon emissions, such as biomass power generation with CCS). The CO_2 and hydrogen are combined into methane through the Sabatier or related process.

Continued use of natural gas under a stringent carbon constraint requires that carbon be captured and stored. The low-carbon scenarios evaluated in this study assume a limited amount of natural gas with CCS is used for electricity generation in both of the low-carbon scenarios. There are two main types of CCS: (1) post-combustion capture of CO_2, and (2) pre-combustion capture of CO_2. In one pathway, CCS occurs after the natural gas has been combusted for electricity generation in a combined cycle gas turbine (CCGT), and the delivered energy remains in the form of decarbonized electricity. In the other pathway, natural gas is subjected to a reformation process to produce hydrogen and CO_2 streams. The CO_2 is captured and sequestered, and the hydrogen can be injected into the pipeline, liquefied for use in fuel cells, or combusted in a combustion turbine.

3.3 Modeling Technology and Energy Costs

3.3.1 GENERAL DESCRIPTION OF APPROACH

For long-term energy pathways scenarios, future costs are particularly uncertain. As a result, the PATHWAYS model does not use technology or energy cost estimates to drive energy demand or resource selection choices. Rather, total capital costs and variable costs of technologies are treated as input variables, which are summed up for each scenario as an indicator of the scenario's total cost. The model does not include a least-cost optimization, nor does the model include price elasticity effects or feedback to macroeconomic outcomes. As such, the model should be understood as primarily a technology and infrastructure-driven model of energy use in California.

The model includes more resolution on cost for two key types of energy delivery: pipeline gas and electricity. These approaches are described in more detail below.

3.3.2 PIPELINE GAS DELIVERY COSTS

We model the California system of delivering pipeline gas as well as compressed pipeline gas, and liquefied pipeline gas for transportation uses. We model these together in order to assess the capital cost implications of changing pipeline throughput volumes. Delivery costs of pipeline gas are a function of capital investments at the transmission and distribution-levels and delivery rates, which can be broadly separated into core (usually residential and small commercial) and non-core (large commercial, industrial, and electricity generation) categories.

Core service traditionally provides reliable bundled services of transportation and natural gas compared to non-core customers with sufficient volumes to justify transportation-only service. The difference in delivery charges can be significant. In September 2013 the average U.S. delivered price of gas to an industrial customer was $4.39/thousand cubic feet compared to

$15.65/thousand cubic feet for residential customers.[15] This difference is driven primarily by the difference in delivery costs and delivery charges for different customer classes at different pipeline pressures.

To model the potential implications of large changes in gas throughput on delivery costs, we use a simple revenue requirement model for each California investor owned utility (IOU). This model includes total revenue requirements by core and non-core customer designations, an estimate of the real escalation of costs of delivery services (to account for increasing prices of materials, labor, engineering, etc.), an estimate of the remaining capital asset life of utility assets, and the percent of the delivery rate related to capital investments.[16]

3.3.3 ELECTRICITY SECTOR AVERAGE RATES AND REVENUE REQUIREMENT

Electricity sector costs are built-up from estimates of the annual fixed costs associated with generation, transmission, and distribution infrastructure as well as the annual variable costs that are calculated in the System Operations Module. These costs are used to calculate an annual revenue requirement of total annualized electric utility investment in each year. These costs are then divided by total retail sales in order to estimate a statewide average electricity retail rates. These average electricity rates are applied to the annual electricity demand by subsector to allocate electricity costs between subsectors.

[15] United States Energy Information Administration, 2013.

[16] We assume that 50% of the revenue requirement of a gas utility is related to throughput growth and that capital assets have an average 30-year remaining financial life. This means that the revenue requirement at most could decline approximately 1.7% per year without resulting in escalating delivery charges for remaining customers.

Transmission and distribution costs are also estimated in the model. Transmission costs are broken into three components: renewable procurement-driven transmission costs, sustaining transmission costs, and reliability upgrade costs. Distribution costs are broken into distributed renewable-driven costs and non-renewable costs. The revenue requirement also includes other electric utility costs which are escalated over time using simple growth assumptions, ("other" costs include nuclear decommissioning costs, energy efficiency program costs and customer incentives, and overhead and administration costs). These costs are approximated by calibrating to historical data. The methodology for calculating fixed generation costs in each year is described below, more details are provided in the Technical Appendix.

3.3.3.1 Generation

Fixed costs for each generator are calculated in each year depending on the vintage of the generator and assumed capital cost and fixed operations and maintenance (O&M) cost inputs by vintage for the generator technology. Throughout the financial lifetime of each generator, the annual fixed costs are equal to the capital cost (which can vary by vintage year) times a levelization factor plus the vintage fixed O&M costs, plus taxes and insurance. This methodology is also used to cost energy storage infrastructure and combined heat and power (CHP) infrastructure. Input cost assumptions for generation technologies are summarized below.[17]

[17] Cost assumptions were informed by E3, "Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process," Prepared for the Western Electric Coordinating Council, Oct. 9, 2012.
<**http://www.wecc.biz/committees/BOD/TEPPC/External/E3_WECC_GenerationCostReport_Final.pdf**>

In general, cost assumptions for generation technologies, as for all technology assumptions in the model, are designed to be conservative, and avoid making uncertain predictions about how the relative costs of different technologies may change over the analysis period. Generation capital cost changes are driven by assumptions about technology learning. As a result, the cost of newer, less commercialized technologies are assumed to fall in real terms, while the costs of technologies that are widely commercialized are assumed to remain constant or to increase.

Table 7. Generation capital cost assumptions

Technology	Capital Cost from present - 2026	Assumed change in real capital cost by 2050	Capital Cost from 2027 - 2050
	(2012$/kW)	% change	(2012$/kW)
Nuclear	9,406	0%	9,406
CHP	1,809	0%	1,809
Coal	4,209	0%	4,209
Combined Cycle Gas (CCGT)	1,243	16%	1,441
CCGT with CCS	3,860	-3%	3,750
Steam Turbine	1,245	0%	1,245
Combustion Turbine	996	44%	1,431
Conventional Hydro	3,709	0%	3,709
Geothermal	6,726	0%	6,726
Biomass	5,219	0%	5,219
Biogas	3,189	0%	3,189
Small Hydro	4,448	0%	4,448
Wind	2,236	-9%	2,045
Centralized PV	3,210	-31%	2,230
Distributed PV	5,912	-30%	4,110
CSP	5,811	-25%	4,358
CSP with Storage	7,100	-30%	5,000

3.3.4 COST ASSUMPTIONS FOR ENERGY STORAGE, DECARBONIZED GAS AND BIOMASS DERIVED FUELS

Cost and financing assumptions for energy storage technologies are summarized below. For this analysis, these costs are assumed to remain fixed in real terms over the analysis period.

Table 8. Capital cost inputs for energy storage technologies

Technology	Capital Cost (2012$/kW)	Financing Lifetime (yrs)	Useful Life (yrs)
Pumped Hydro	2,230	30	30
Batteries	4,300	15	15
Flow Batteries	4,300	15	15

The modeling assumptions for hydrogen production and SNG production are described in detail in Technical Appendix Sections 2.2.3 and 2.2.4, respectively. Below, Table 9 shows final product cost ranges, levelized capital costs, and conversion efficiencies for hydrogen and SNG pathways in the model.

Table 9. Renewable electricity-based pipeline gas final product cost, levelized capital cost, and conversion efficiencies in model

Product	Process	Levelized Capital Cost ($/kg-year for hydrogen; $/mmBTU-year for SNG)	Conversion Efficiency	Product Cost Range ($/GJ)
SNG	Electrolysis plus methanation	$7.60-$18.50	52%-63%	$30-$138
Hydrogen	Electrolysis	$0.65-$1.53	65%-77%	$24-$112

The modeling assumptions for biofuels are described in detail in Technical Appendix Section 3. Below, Table 10 shows final product cost ranges, feedstock and conversion cost ranges, and conversion efficiencies for all biomass conversion pathways in the model.

Table 10. Biomass final product cost, feedstock and conversion costs, and conversion efficiencies in model

Product	Process	Feedstock Cost Range ($/ton)	Conversion Cost ($/ton)	Conversion Efficiency (GJ/ton)	Product Cost Range ($/GJ)
Biogas Electricity	Anaerobic digestion	$40-$80	$96	6.5	$21-$27
Pipeline Biogas	Gasification	$40-$80	$155	9.5	$20-$25
Ethanol	Fermentation	$40-$80	$111	6.7	$23-$29
Diesel	Trans-Esterification	$1000	$160	36.4	$32

4 Results

4.1 Summary of results

The two low-carbon scenarios evaluated in this study present unique technology pathways to achieve California's 2050 GHG reduction goals. Each scenario represents a different technically feasible, plausible strategy to decarbonize the state's energy system, resulting in different levels of energy consumption and different mixes of fuels providing energy services. This section presents energy demand by scenario and fuel type in 2050 for the Reference case and the two low-carbon scenarios. Energy system cost projections for each scenario are provided. The cost trajectories are highly uncertain and cannot be interpreted as definitive at this point in time. Each of the low-carbon scenarios shows a similar statewide GHG reduction trajectory.

4.2 Final energy demand

Figure 4 shows final energy demand by fuel type for each scenario in the year 2050. Of note, both the low-carbon scenarios have significantly lower total energy demand than the Reference case due to the impact of energy efficiency and conservation in the low-carbon scenarios.

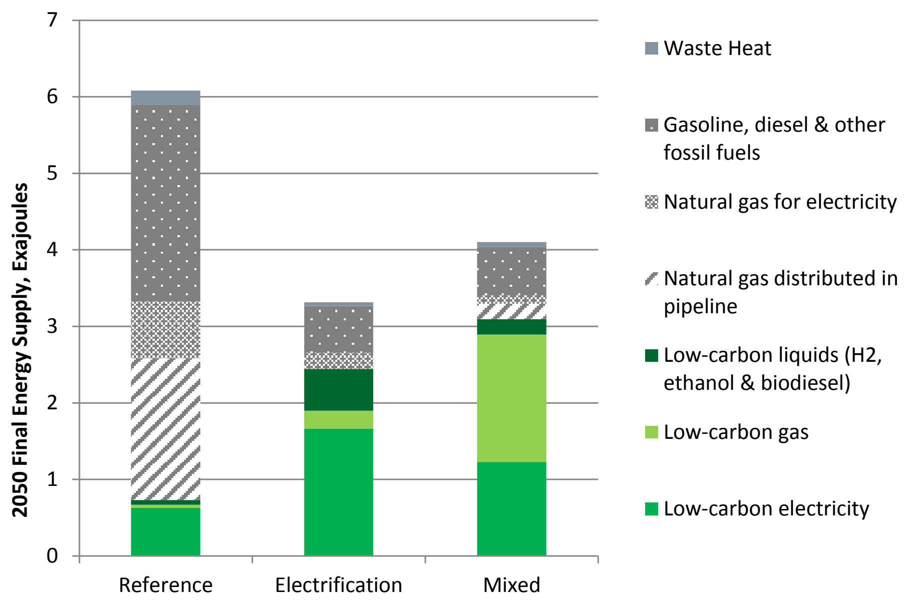


Figure 4. 2050 California economy-wide final energy demand by scenario and fuel type

Final energy consumption in 2050 is lower in the Electrification scenario than the Mixed Scenario due to the higher conversion efficiencies of electric batteries and motors compared to combustion engines and fuel cell vehicles.[18]

Low-carbon electricity is also used as an upstream energy source to produce decarbonized gas and liquid hydrogen, so it plays a larger role in meeting the state's GHG reduction goals in the Mixed scenario than indicated by final energy demand alone. To gain a more complete picture of energy supply by fuel type, the next sections discuss the composition of the pipeline gas by scenario, the sources of electricity in each scenario, and the composition of the

[18] Note that upstream efficiency losses associated with energy production: i.e. P2G methanation, hydrogen production and CCS, do not appear in the final energy supply numbers.

transportation vehicle fleet energy consumption. These results are not meant to be an exhaustive description of each assumption in each sector of the economy, but rather are selected to provide some insights into the biggest differences in energy use between the two low-carbon scenarios and the Reference case.

4.2.1 PIPELINE GAS FINAL ENERGY DEMAND

There are important differences between the two low-carbon scenarios. Pipeline infrastructure continues to be used extensively in the Mixed scenario, with decarbonized gas substituting for the natural gas that would otherwise be used in the pipeline. In the Electrification scenario, pipeline infrastructure is nearly unutilized by 2050. This corresponds to much more widespread electrification of industrial processes, vehicles, space heating, water heating, and cooking. The limited demand for pipeline gas in this scenario is assumed to be met with biogas (Figure 5).

The Mixed scenario includes a higher quantity of biogas, based on the assumption that all of the available sustainably sourced biomass are used to produce biogas. The remaining demand for decarbonized pipeline gas in this scenario is met with a mix of two technologies: 1) SNG produced using P2G methanation with air capture of CO_2[19] and 2) hydrogen produced using electrolysis with renewable electricity.

[19] Methanation using CO_2 capture from seawater is an alternative, potentially more efficient method to creating produced gases that have a net-carbon neutral climate impact.

In the Mixed Scenario, hydrogen use in the gas pipeline is limited by estimates of technical constraints. By 2050, the share of hydrogen gas in the pipeline is assumed to be limited to 20 percent of pipeline volume for reasons of safety as well as compatibility with end-use equipment.[20]

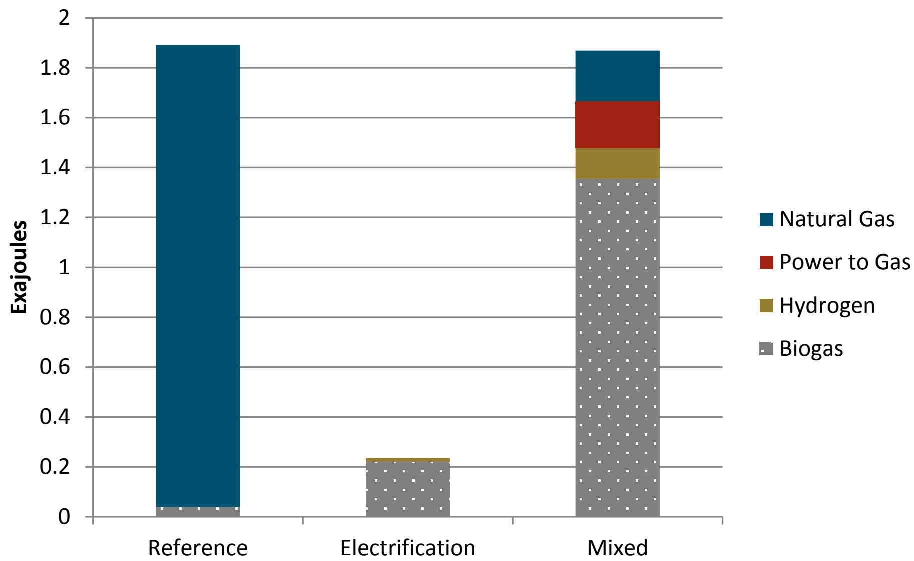


Figure 5. California pipeline gas final energy demand by fuel type by scenario, 2050

4.2.2 ELECTRICITY DEMAND

The 2050 electricity demand in each scenario tells a different part of the energy supply story. In the low-carbon scenarios, 2050 electricity demand is significantly higher in the Reference case due to the impact of electrification, particularly electric LDVs, and the electricity needs associated with P2G and

[20] Note that this limit is only a rough estimate of technical feasibility limits and the actual limit may be lower; additional research is needed to determine an appropriate limit for hydrogen gas in the pipeline.

hydrogen production. The expanding role of the electricity sector in achieving a low-carbon future is evident in each of these scenarios. Figure 6 shows the generation mix by fuel type utilized in each of the scenarios in 2050.

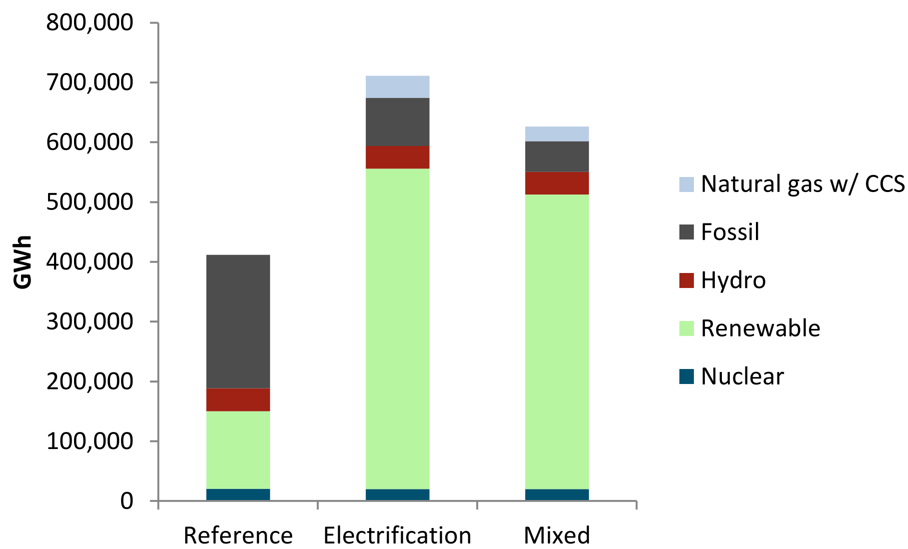


Figure 6. 2050 electricity sector energy demand by scenario and fuel type, GWh

4.2.2.1 Load resource balancing

Both of the low-carbon scenarios reflect a significant increase in intermittent wind and solar PV renewable generation by 2050 (Table 11). This results in new challenges that the grid faces to achieve load-resource balance.

Table 11. Share of 2050 California electricity generation provided by wind and solar PV

	Reference	Low-Carbon Scenarios
Intermittent renewables share of total electricity generation in 2050 (wind and solar PV)	30%	60 -70%

In the model, electricity supply and demand must be equal in each hour of each year. This load-resource balance is achieved using different strategies in each scenario, which contributes to the differences in technology costs and risks. As Table 12 indicates, the Electrification scenario relies heavily on the use of electric energy storage, in the form of flow batteries and pumped hydroelectric storage resources, while the Mixed scenario relies more heavily on P2G production as a load-following resource. Natural gas with CCS is assumed to be a load-following resource in both scenarios. Furthermore, both scenarios assume electric vehicles can provide limited load-resource balancing services through flexible charging of EVs over a 24-hour period, and that hydrogen production for fuel cell vehicles can be operated as a fully-dispatchable, flexible load.

Table 12. 2050 Load Resource Balancing Assumptions by Scenario

Load-resource balancing tool	Electrification	Mixed
Electric energy storage capacity	**20 GW** 75% 6-hour flow batteries, 25% 12-hour pumped hydro energy storage	**5 GW** 100% 12-hour pumped hydro energy storage
P2G capacity	**None**	**40 GW** P2G production cycles on during the daylight hours to utilize solar generation and cycles off at night, significant variation in production by season for load balancing
Electric vehicles & other flexible loads	**40%** of electric vehicle loads are considered "flexible" in both scenarios and can be shifted within a 24-hour period. Vehicle batteries are not assumed to provide power back onto the grid. Certain thermal electric commercial and residential end uses are also assumed to provide limited amounts of flexible loads to the grid. In both scenarios, hydrogen production is assumed to be a fully dispatchable, flexible load.	

4.2.3 ON-ROAD VEHICLE ENERGY CONSUMPTION BY FUEL TYPE

The decarbonization strategy pursed in the transportation sector differs by scenario, as illustrated in Figure 7 (LDV vehicle energy use) and Figure 8 (HDV energy use). Both of the low-carbon scenarios assume a significant reduction in VMT and vehicle efficiency improvements in the LDV fleet compared to the Reference scenario. This leads to a significant reduction in total energy demand by LDVs by 2050 in these scenarios. Among the HDV vehicle fleet, VMT reductions and vehicle efficiency improvements are assumed to be more difficult to achieve than in the LDV fleet. Furthermore, the Mixed scenario relies on a high proportion of fuel cell vehicles using hydrogen or liquefied pipeline gas, which have less efficient energy conversion processes than conventional diesel engines, leading to higher energy demand. As a result, the HDV sector does not show a significant reduction in energy consumption by 2050 relative to the Reference case, although total carbon emissions are significantly lower.

Electricity is the largest source of fuel for the transportation sector among LDVs in both the Electrification and the Mixed scenarios. The HDV fleet is harder to electrify, so the Electrification scenario assumes HDV energy demand is largely met with hydrogen fuel and fuel cells. In the Mixed scenario, the majority of HDV energy demand is assumed to be met with liquefied pipeline gas (an equivalent to decarbonized LPG), with some compressed pipeline gas (the equivalent to decarbonized compressed natural gas), electrification and hydrogen fuel cell vehicles.

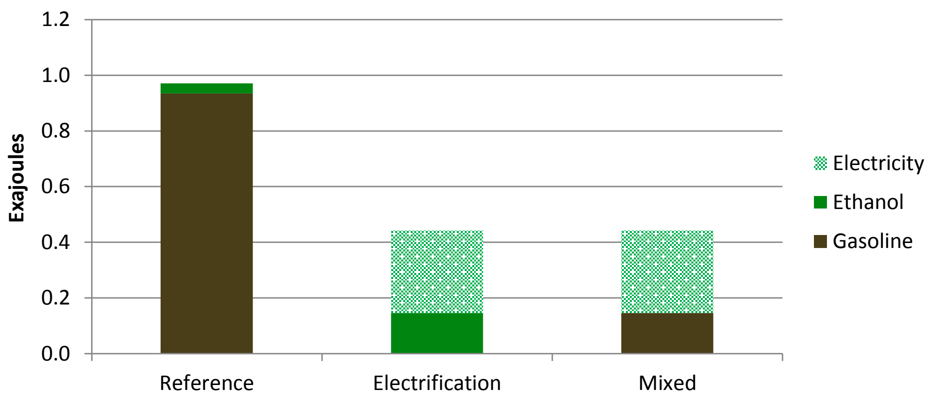


Figure 7. 2050 LDV energy share by fuel type by scenario

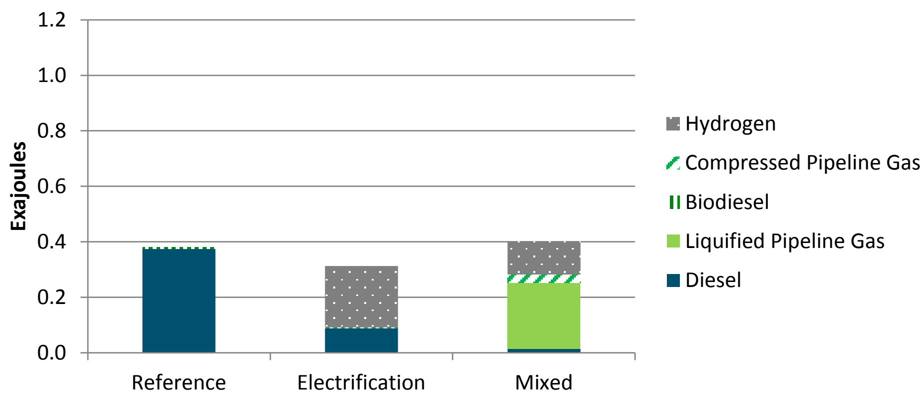


Figure 8. 2050 HDV energy share by fuel type by scenario

4.3 Greenhouse gas emissions

The Reference case shows GHG emissions that are relatively flat through 2030 before slightly increasing in the outer years through 2050. This increase occurs because population growth and increasing energy demand overwhelm the emissions savings generated by current policies. The result is a 9 percent increase in Reference case emissions relative to 1990 levels by 2050.

The GHG emissions trajectories for the two low-carbon scenarios evaluated in this report are essentially the same. Both scenarios achieve the target of 80% reduction in GHG emissions by 2050 relative to 1990 levels, and both scenarios reflect a similar, approximately straight-line trajectory of emissions reductions between current emissions levels and 2050.

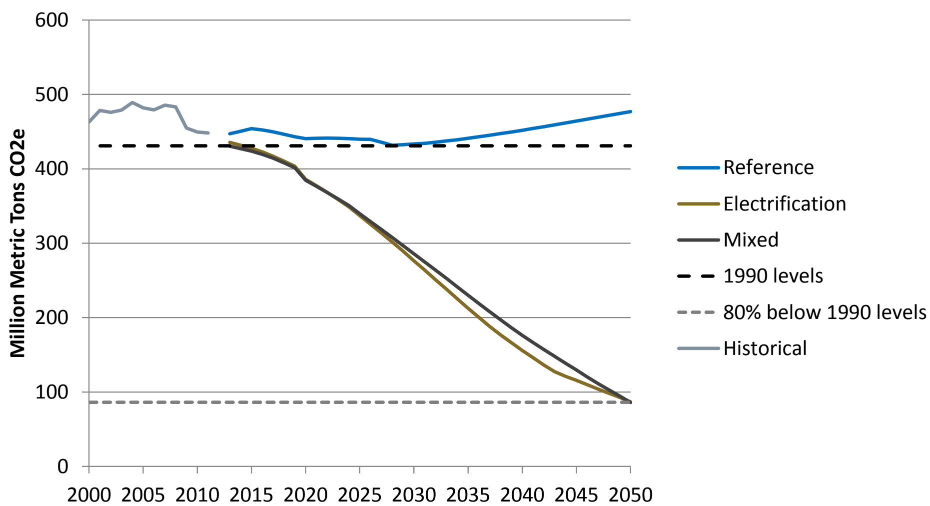


Figure 9. California GHG emissions by scenario, including historical emissions and policy targets (2000 – 2050)

4.4 Energy system cost comparison

The total energy system cost of each of the scenarios analyzed is one metric by which to evaluate different GHG scenarios. Total energy system cost is defined here as the annual statewide cost of fossil fuels and biofuels, plus the levelized cost of electricity and natural gas infrastructure, plus the cost of most energy-consuming customer products (e.g., clean vehicles in the transportation sector and energy efficiency and fuel-switching equipment in the buildings sector). The total energy system cost is calculated on a levelized basis in each analysis year, from 2015 – 2050. Further detail on cost assumptions and how costs are treated in the model is provided in the Technical Appendix.

While the Reference case is the lowest total cost scenario from an energy system perspective, it also does not succeed in meeting the state's GHG reduction goals. Of the two low-carbon scenarios, the Mixed scenario has approximately 10 percent lower cost than the Electrification scenario in 2050 using our base case assumptions. This difference is well within the range of uncertainty of projecting technology costs to 2050, and either scenario could be lower cost.

It is, however, useful to examine the differences in base case scenario costs that result from the modeling assumptions made in this analysis to identify the key drivers. Using the base case assumptions, the Mixed case results in lower total energy system costs in 2050 than the Electrification scenario for two main reasons (Figure 10). First, using the assumptions in this study, adding decarbonized gas in the Mixed case has a lower cost than adding the low-carbon electricity and end-use equipment necessary to electrify certain end-uses in the Electrification case. Therefore, the reduction of electricity-related capital costs between the Electrification and the Mixed scenario shown in Figure 10 is greater than the increase in pipeline gas capital costs and biogas fuel costs between these scenarios. Second, seasonal electricity storage needs are lower in the Mixed scenario than in the Electrification scenario. As a result, the electricity storage that is built in the Mixed scenario is utilized at a higher capacity factor than the electricity storage in the Electrification scenario. This means that the unit cost of electricity storage ($/MWh) is higher in the Electrification scenario than in the Mixed scenario.

In order to evaluate the range of uncertainty, we define high and low cost Scenarios for the key input assumptions. These do not reflect the range of all of the uncertainties in energy demands, population, or other key drivers embedded in the analysis, but serve to provide a boundary of possible high and low total costs given the same assumptions across the three cases. We then evaluate the total costs of each of the cases; Reference, Electrification Case, and Mixed Case with each cost scenario. Table 13, below, shows the range of the cost uncertainties in the analysis. Scenario 1 is purposefully designed to advantage the Mixed Case, and Scenario 2 is designed to advantage the Electrification Case.

Table 13 Cost sensitivity parameters

Cost Assumption	Scenario 1	Scenario 2
Renewable generation capital	+25%	-25%
Electrolysis capital equipment	-50%	+50%
SNG capital equipment	-50%	+50%
Fuel cell HDVs	+50%	-50%
Building electrification cost[21]	+50%	-50%
Natural Gas Costs	-50%	+50%
Other Fossil Fuel Costs	+50%	-50%
Electricity storage costs	+50%	-50%
Biomass Availability[22]	+0%	-50%

The 2050 cost results shown below indicate that there are conditions under which either case is preferable from a cost standpoint. Given that, and given the

[21] Costs of electrified water and space heating equipment
[22] Biomass is replaced with addition P2G to maintain emissions levels +- 5MMT from base case.

additional uncertainties not analyzed in terms of other technology costs, energy demand drivers, etc., the preference for pursuing one mitigation case over the other should come down to other factors than narrow cost advantages displayed over these long term forecasts.

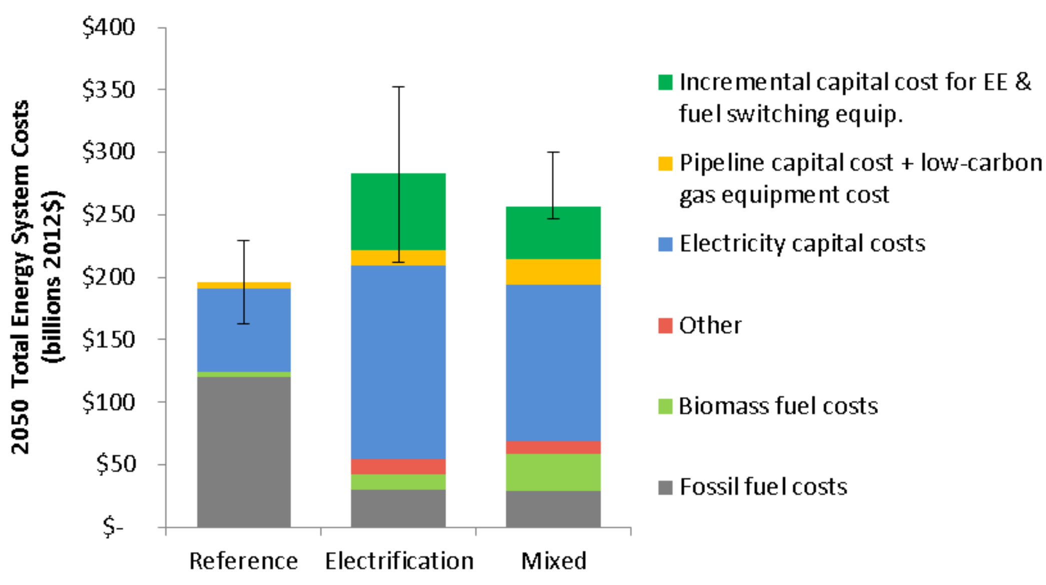


Figure 10. 2050 total energy system cost by scenario (levelized cost of fuel and levelized capital cost of energy infrastructure)

Figure 11, below, shows the base case total levelized energy system capital investment and fuel costs for each scenario along with the uncertainty range. Given the uncertainties associated with forecasting technology and commodity costs out to 2050, a difference in costs of approximately 10% ($27 billion) between the two scenarios is not definitive.

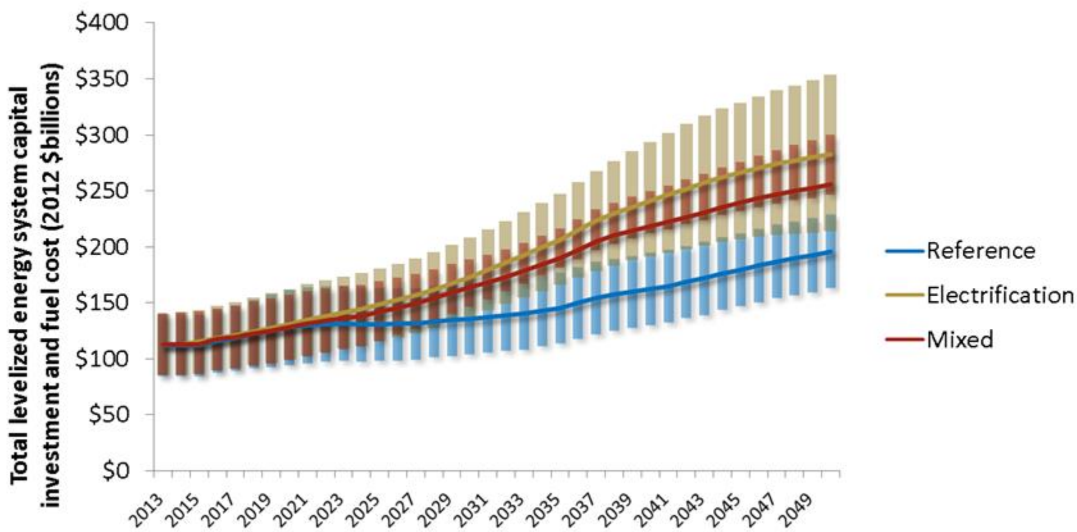


Figure 11. Total energy system cost by scenario, 2013 – 2050 (levelized cost of fuel and levelized capital cost of energy infrastructure, billions, 2012$)

Figure 12, below, shows total electricity sector costs on an annualized basis, or equivalently, the statewide electricity sector revenue requirement, in 2050. Electricity costs are higher in the Electrification scenario both because total electricity demand is higher, and because the unit cost of electricity is higher. The cost of energy storage is highest in the Electrification scenario because more storage is needed to balance intermittent renewables, and because batteries are the primary means of storage. In the Mixed scenario, less energy storage is needed because the production of decarbonized gases (hydrogen and SNG) is dispatched to balance the grid, and because gas is a more cost-effective form of seasonal energy storage, given the assumptions here, than batteries. Again, however, cost forecasts for 2050 are highly uncertain and should be interpreted with caution.

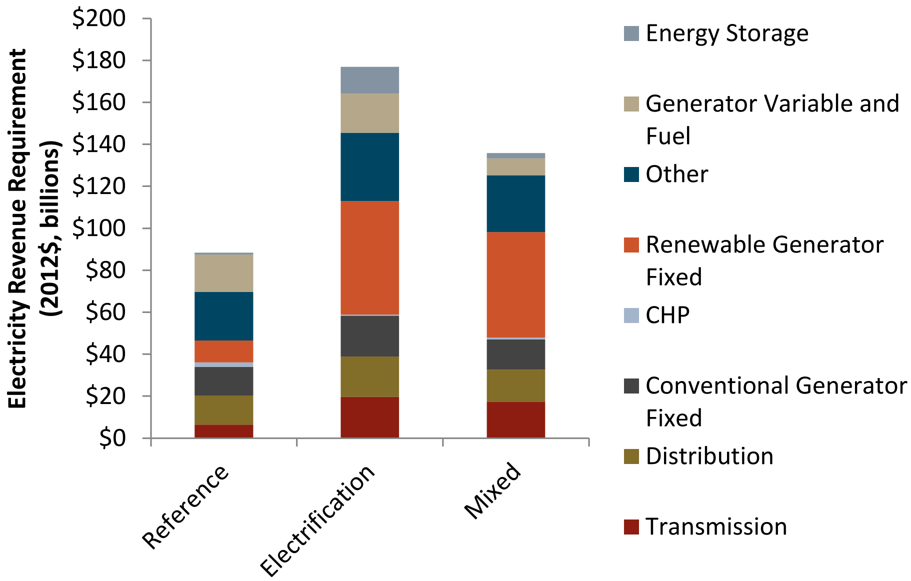


Figure 12. 2050 California total electricity sector revenue requirement by component and scenario (billions, 2012$)

5 Discussion & Conclusions

California is committed to deeply reducing CO_2 and other GHG emissions across all sectors over the next several decades, as well as to sharply reducing ground-level ozone and particulate matter to protect public health. Both of these policies imply a dramatic transition of California's economy away from fossil fuel combustion as we know it, and indeed this transition is already underway. In some places where coal is the dominant form of energy supply, natural gas is often seen as a key transition fuel to a lower carbon system. In California, however, natural gas is the main incumbent fossil fuel in electricity generation, the building sector, and many industries, and is therefore the target of transition to a lower carbon economy rather than its vehicle; the problem of methane leakage in the natural gas production and supply chain, though not modeled in this analysis, only increases the policy pressure to hasten this transition.

It is possible for SCG and other gas distribution companies to be a contributor rather than an impediment to California's transition to a low carbon economy. This path of decarbonizing pipeline gas will require a major technological transformation in the coming years. On the demand side, the transition requires reducing demand in many existing applications and improving combustion processes to increase efficiency. On the supply side, it requires developing decarbonized alternatives to conventional natural gas for delivering energy to end uses.

This study examined the role of gas fuels in California's energy supply from 2013 to 2050, using a bottom-up model of the California economy and its energy systems. We examined the feasibility andcost associated with two distinct technology pathways for achieving the state's 2050 GHG targets: (1) Electrification, and (2) Mixed (electricity and decarbonized gas).

To date, much of the literature on low-carbon strategies and policy strategies for achieving deep reductions in GHG emissions in California by 2050 has focused on extensive electrification. This study's results support our prior conclusions that the electricity sector must play an expanded and important role in achieving a low-carbon future in California. In both of the low-carbon scenarios, the need for low-carbon electricity increases significantly beyond the Reference case level: to power electric vehicles, electrification in buildings and as a fuel to produce decarbonized gases. We also demonstrate that, under reasonable assumptions, there are feasible technology pathways where gas continues to play an important role in California's energy supply.

The costs of technologies in the 2050 timeframe are highly uncertain, making it impossible to reach a definitive conclusion as to which of the low-carbon pathways evaluated here would be the lowest cost. However, we show that the Mixed scenario, where decarbonized gas meets existing natural gas market share in residential, commercial, and industrial end uses, and is used to power the heavy-duty vehicle fleet, could potentially be higher or lower cost depending on the technology and market transformation. A key driver of this result is the ability to use the existing gas pipeline distribution network to store and distribute decarbonized gas, and to use the production of decarbonized gas as a means to integrate intermittent renewable energy production. Excess renewable energy in the middle of the day is absorbed by P2G production of SNG and hydrogen production in the Mixed scenario. The Electrification scenario, which does not utilize the P2G technology to produce decarbonized gas, decreases gas pipeline use out to 2050 (shown for SCG, Figure 13) and requires more relatively high-cost, long-duration batteries for energy storage.[23]

[23] In Figure 13 the slight increase in natural gas used for electricity generation observed in 2020 is due to an existing coal generation contract being partially replaced with natural gas generation.

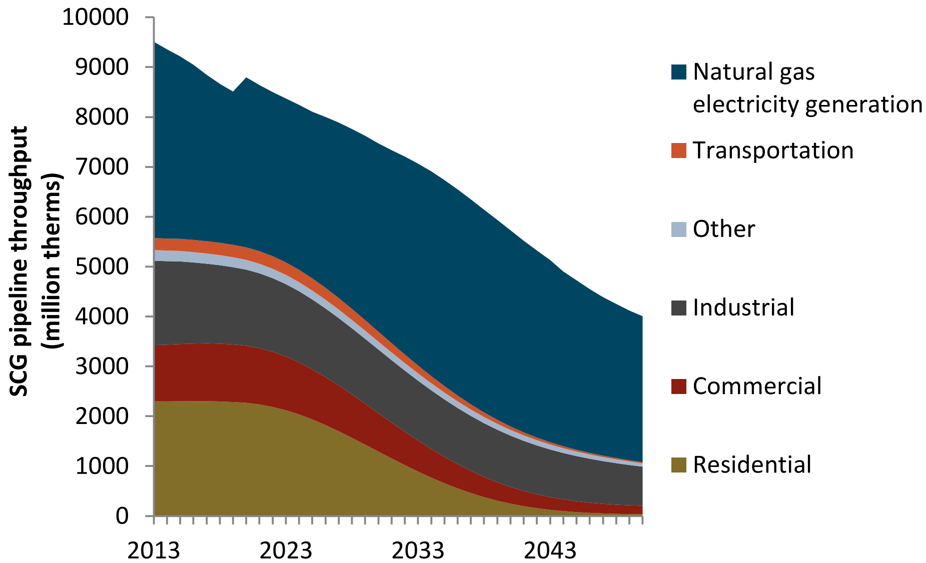


Figure 13. Electrification Scenario, SCG pipeline gas throughput (2013 – 2050)

Strategic use of decarbonized gas would additionally help to overcome four potential obstacles in California's transition to a decarbonized energy system.

First, a number of current uses of natural gas and oil are difficult to electrify. These include certain industrial processes such as process heat, HDVs and certain end uses in the residential and commercial sectors such as cooking, where customers have historically preferred gas fuels. Using decarbonized gas for these end uses could avoid the need for economically and politically costly electrification strategies.

Second, under a high renewable generation future, long-term, seasonal load balancing may be needed in addition to daily load balancing. However, meeting these seasonal balancing needs under the Electrification scenario requires uncertain technical progress in energy storage. Using the production of decarbonized gas to provide daily and seasonal load balancing services may be a more realistic and cost-effective strategy than flexible loads and long-duration batteries for electricity storage.

Third, using decarbonized gas takes advantage of the state's existing gas pipeline distribution system, and reduces the need for other low-carbon energy infrastructure such as transmission lines or a dedicated hydrogen pipeline network.

Fourth, and finally, the Mixed scenario, by employing a range of energy technologies, including electricity and decarbonized gas technologies, diversifies the risk that any one particular technology may not achieve commercial successes.

All of the decarbonized gas energy carriers examined in this analysis rely on century-old conversion processes; none require fusion-like innovations in science. However, these conversion processes — anaerobic digestion, gasification, electrolysis, and methanation — require improvements in efficiency and reductions in cost to be more competitive. Furthermore, existing pipelines were not designed to transport hydrogen, and innovations in pipeline materials and operations would be needed to accommodate a changing gas blend.

Sustainably-sourced biomass feedstock availability is another large source of uncertainty in both of the low-carbon strategies evaluated here. In the Mixed scenario, biogas plays a particularly important role in achieving the GHG emission target. In the Electrification scenario, biomass is used to produce low-carbon electricity. However, biomass feedstocks are constrained by competing uses with energy supply, including food, fodder and fiber. The amount of biomass resources available as a feedstock for fuels, or for biogas production specifically, will depend on innovations in biosciences, biomass resource management, and supply chains. None of the above three challenges — conversion technology efficiency and cost, pipeline transport limits, and biomass feedstock availability — is inherently insurmountable. For decarbonized gas to begin to play an expanded role in California's energy supply in the coming decades, however, a program of RD&D to overcome these challenges would need to begin very soon. This report identifies research priorities with near-term, medium-term and long-term payoff.

As a whole, California policy currently explicitly encourages the production of low-carbon electricity, through initiatives such as the RPS, and the production of decarbonized transportation fuels, through initiatives such as the LCFS. Biogas from landfill capture and dairy farms are encouraged, however, the state does not currently have a comprehensive policy around decarbonized gas production and distribution. This analysis has demonstrated that a technologically diverse, "mixed" strategy of electrification and decarbonized gas may be a promising route to explore on the pathway to a long-term, low-carbon future in California.

Appendix B6

CALIFORNIA BIOFUELS
CAP & TRADE INITIATVE

Biofuels reduce greenhouse gases, provide jobs and lead to economic development throughout California.

- ✓ Transportation is the single largest source of greenhouse gas emissions.
- ✓ Since fuels became subject to AB 32 in 2015, now is the time to allocate cap & trade revenues for in-state biofuels, low carbon fuels that are immediately scalable.
- ✓ Biofuels are low carbon fuels available right now for all classes of vehicles, including heavy duty.
- ✓ To meet Governor Brown's goal of reducing petroleum use in CA by 50% by 2030, an aggressive biofuels program is a necessary component.
- ✓ To meet the climate change objectives of AB 32, production and use of low carbon intensity biofuels in California should be encouraged.
- ✓ To meet the objectives of SB 535 (to stimulate employment and economic improvement in disadvantaged communities as defined by CalEnviroScreen) biofuel production and infrastructure should be encouraged in disadvantaged communities.

PROPOSAL

Allocate $210 million of Cap and Trade funds to be dedicated to support a Biofuel Initiative based upon stimulating (1) California based biofuel production; (2) the low carbon intensity of biofuels, and (3) the benefits to disadvantaged California communities.

Because each of the biofuel types have different characteristics and needs, silos for each biofuel type (diesel alternatives, gasoline alternative and biogas/syngas) will be established with an allocation of $70 million and a program specifically tailored for that biofuel type.

BENEFITS

The Cap & Trade Biofuel Initiative will provide the following benefits:

- In-state production of biofuels will provide meaningful employment to thousands of Californians in disadvantaged communities; biofuels provide 2 to 6 times as many jobs as their fossil fuel equivalents.
- Petroleum fuel replacement and extender fuels such as biodiesel, biomethane, biogas and ethanol have the lowest Carbon Intensities (CI) under the Low Carbon Fuel Standard and there is already fully developed technology for expanding production in CA. The vehicles exist now for using these biofuels, and biofuels are the most cost-effective means of meeting petroleum and greenhouse gas reduction goals immediately.
- To meet Governor Brown's objectives, over 7 billion gallons of low CI biofuel will be needed annually by 2030. Many of these biofuels are already coming from out-of-state to meet the LCFS targets. The LCFS should not be limited to in-state producers, but CA produced biofuels are at a competitive disadvantage when other states and countries provide production incentives for which CA companies do not qualify. Increasing the production of biofuels in CA would

stimulate economic development for the long-term benefit of all Californians.

- Substantial feedstocks exist in California for in-state biofuel production. These include agricultural, forest, livestock, wastewater and municipal waste, as well as purpose grown crops such as algae, energy beets, camelina, canola, energy cane, mustard, sorghum and others that can be grown on fallow land, intercropped in orchards and vineyards, or cultivated as part of a sustainable crop rotation program.
- Increasing in-state production of biofuels will also help California to meet its waste diversion goals, including AB 1826 (Chesbro, 2014) which requires 75% diversion of commercial organic waste as of January 1, 2015.
- Increasing in-state biofuels will help to reduce wildfire impacts by converting forest biomass from high wildfire hazard zones to transportation fuels, as Southwest Airlines has contracted to do.
- In-state production of biofuels provides a diversified and secure source of biofuels to mitigate against market manipulation and shortages of all fuels.

BIOFUEL INITIATIVE COMPONENTS

The Biofuel Initiative will have two components, (1) Production Incentives and (2) Infrastructure/Capital Development.

1. Production Incentives: Production Incentives should be paid quarterly to biofuel producers based upon the volume of fuel production while factoring in the CalEnviroScreen score (disadvantaged communities) and the Carbon Intensity reductions for that biofuel as reported to the California Air Resources Board by biofuel producers under the Low Carbon Fuel Standard. All California producers will receive a pro rata payment so long as their CI is less than their fossil fuel equivalent within their biofuel silo.

Volume of Biofuel x Carbon Intensity Reduction x CalEnviroScreen Score = Production Incentive

2. Infrastructure Development and Production Facilities: Each biofuel type has different infrastructure and capital needs. The chains of distribution from feedstocks to biofuel production to the end user need improvements particular to each biofuel. Because of the silo structure, each biofuel can determine what percentage of funds should go towards infrastructure improvements, and provide advice as to what those improvements should be. Again, the priorities within each silo's infrastructure program should be determined by the volume of biofuel, Carbon Intensity and CalEnviroScreen ranking.

Administration: This program shall be administered jointly by CARB and CEC.

Biofuels: Biofuels shall include renewable and waste based substitutes for diesel, gasoline, and natural gas, including, but not limited to biodiesel, ethanol, biomethane (funding shall be used for projects that produce/generate transportation or pipeline quality "High Btu" biofuel), biogas, syngas and renewable diesel (excluding co-processing of biomass at petroleum refineries), used preferably for transportation, but also for generating heat and power.

Differences from AB118, LCFS and RFS: AB 118 funds are geared towards specific program grants and only a relatively small amount goes towards funding biofuels (typically 20% or less). CA's LCFS Program has faced legal challenges that delayed the realization of intended benefits. The program is scheduled for re-adoption in February 2015 with actual implementation at least one year later. The federal RFS program has been delayed for over one year and continues to be unpredictable. All of these programs are uncertain and the amount of funding inadequate. The biofuels industry in California needs support and a consistent market signal now.

SUPPORTERS

Aemetis (Keyes)
Altitude Fuel (Santa Monica)
Baker Commodities (Hanford, Kerman and Vernon)
Biodico Sustainable Biorefineries (Five Points, Port Hueneme, Santa Barbara and Ventura)
Bioenergy Association of California (Statewide Association of more than 50 local governments, private companies and public agencies converting organic waste to energy)
California Biodiesel Alliance (Statewide Association)
Calgren (Pixley)
Clean Energy Renewable Fuels
(Acton, Anaheim, Anaheim Hills, Antioch, Apple Valley, Arcadia, Arcata, Artesia, Azusa, Bakersfield, Baldwin Park, Banning, Barstow, Beaumont, Bermuda Dunes, Beverly Hills, Bloomington, Blythe, Boron, Borrego Springs, Brawley, Brentwood, Buena Park, Burbank, Buttonwillow, Calipatria, Camarillo, Camp Pendleton, Canoga Park, Canyon Country, Carlsbad, Carpentaria, Carson, Castroville, Cathedral City, Cerritos, Chatsworth, Chino, Chino Hills, Chowchilla, Chula Vista, City of Industry, Claremont, Coachella, Coalinga, Commerce, Compton, Concord, Corona, Corona del Mar, Costa Mesa, Cypress, Daly City, Dana Point, Davis, Desert Hot Springs, Diamond Bar, Duarte, El Cajon, El Centro, El Monte, Elk Grove, Encinitas, Fairfield, Felton, Fontana, Fountain Valley, Fremont, Fresno, Fullerton, Garden Grove, Gardena, Gilroy, Glendale, Goleta, Grass Valley, Gridley, Hanford, Hawthorne, Hayward, Hesperia, Hollister, Hollywood, Huntington Beach, Inglewood, Irvine, Irwindale, Joshua Tree, Jurupa Valley, Kettleman City, La Canada, La Habra Heights, La Jolla, La Puente, La Verne, Ladera Ranch, Laguna Beach, Laguna Niguel, Lake Elsinore, Lake Forest, Lakewood, Lancaster, Lathrop, Lawndale, Lebec, Livermore, Lodi, Long Beach, Los Angeles, Los Gatos, Lost Hills, Madera, Malibu, Manhattan Beach, Marina, McClellan, Milpitas, Mira Loma, Mission Viejo, Modesto, Mojave, Monrovia, Montclair, Montebello, Monterey Park, Moreno Valley, Mountain Pass, Napa, Newhall, Newport Beach, North Highlands, North Hollywood, Northridge, Norwalk, Oakland, Ojai, Ontario, Orange, Oxnard, Pacheco, Pacific Palisades, Pacifica, Palm Desert, Palm Springs, Palmdale, Palo Alto, Palos Verdes, Palos Verdes Estates, Paramount, Pasadena, Perris, Petaluma, Pleasanton, Pomona, Port Hueneme, Rancho Cordova, Rancho Cucamonga, Redlands, Redondo Beach, Ridgecrest, Riverbank, Riverside, Robbins, Rowland Heights, Sacramento, Salinas, San Anselmo, San Bernardino, San Clemente, San Diego, San Francisco, San Jose, San Juan Capistrano, San Leandro, San Luis Obispo, San Marcos, San Pedro, Santa Ana, Santa Barbara, Santa Clara, Santa Clarita, Santa Cruz, Santa Maria, Santa Monica, Santa Rosa, Seal Beach, Selma, Signal

Hill, Simi Valley, South El Monte, South Pasadena, South San Francisco, Sun Valley, Sunnyvale, Sylmar, Temecula, Thousand Palms, Torrance, Tracy, Tujunga, Tulare, Tustin, Twenty-nine Palms, Ukiah, Union City, Upland, Vacaville, Vallejo, Van Nuys, Venice, Ventura, Vernon, Victorville, Visalia, Vista, Walnut, Waterford, West Covina, West Hollywood, West Sacramento, Westlake Village, Wildomar, Wilmington, Woodside, Yermo, Yorba Linda, Yuba City and Yucca Valley)

Coalition For Renewable Natural Gas (Int'l Industry Association based in Palo Alto, representing 90% of the RNG-to-transportation fuel production in the US, and more than 50 private companies interested in the development of biofuel projects in California)

Community Fuels (Stockton and Encinitas)

Crimson Renewable Energy (Bakersfield)

Dave Williamson Biofuel Consulting (Berkeley)

Dogpatch Biofuels (San Francisco)

Elite Energy (Bakersfield and Dos Palos)

Imperial Western Products (Coachella, Corona and Selma)

Mendota Bioenergy (Five Points)

Morrison & Company (Chico)

New Leaf Biofuel (San Diego)

Pacific Ethanol (Stockton and Madera)

Pearson Fuels (Long Beach & San Diego)

Propel

(Anaheim, Arcadia, Berkeley, Chula Vista, Citrus Heights, Claremont, Elk Grove, Fremont, Fresno, Fullerton, Harbor City, Hayward, Hemet, Huntington Beach, La Mirada, Lakewood, Long Beach, Murrieta, Norwalk, Oakland, Oceanside, Ontario, Placerville, Redwood City, Rocklin, Roseville, Sacramento, San Jose, San Marcos, Sylmar, Torrance, West Sacramento, Wildomar and Wilmington)

Red Rock Ranch (Five Points)

San Diego Airport Parking Company (San Diego)

SeaHold (Perris)

Sylvatex (San Francisco)

Team Biogas (Perris)

The Jacobsen Report (Chicago, IL)

TSS Consultants (Rancho Cordova)

West Biofuels (Woodland)

Western States Oil (San Jose and San Leandro)

Biofuel Impacts in California

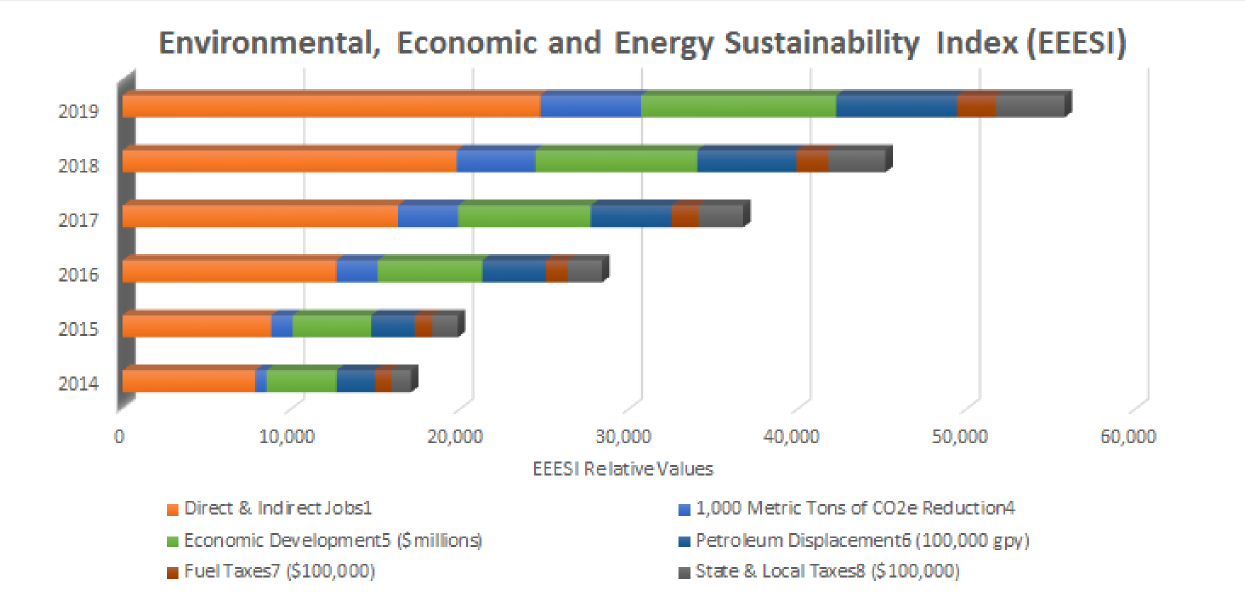
Substantial positive impacts will be realized in California as the result of the Biofuels Initiative as shown in this summary page and followed by individual pages showing the impacts of (1) biodiesel, (2) biogas and (3) ethanol. The table below shows increased California biofuel production as the result of the Biofuel Initiative from 250 mgy in 2014 to 906 mgy in 2019, with direct and indirect jobs of 24,750, a GHG reduction of nearly 6,000,000 metric tons, economic development of $11.5 billion, petroleum displacement of 714 mgy, fuel tax revenues of $230 million and other state and local tax revenues of $408 million.

The $210 million for the Biofuels Initiative will be used to incentivize more in-state production of low Carbon Intensity biofuel and support infrastructure development (from in-state feedstocks to retail distribution) which will provide economic and environmental benefits to some of California's most disadvantaged communities. The ultimate goal is to develop in-state production to meet at least 50% of the biofuel needed under the LCFS to meet GHG mitigation targets by 2020. The Biofuel Initiative would provide proven producers of biofuels in California the financial support to expand their facilities, open new facilities, and develop capacity for new feedstocks and lower carbon intensity.

Summary of Biofuel Initiative Impacts

Fiscal Year	Production Capacity (million gpy)	Direct & Indirect Jobs[1]	Carbon Intensity[3] (gCO2e/MJ)	1,000 Metric Tons of CO2e Reduction[4]	Economic Development[5] ($millions)	Petroleum Displacement[6] (100,000 gpy)	Fuel Taxes[7] ($100,000)	State & Local Taxes[8] ($100,000)
2014	250	7,875	53	663	$4,139	2,296	$950	$1,166
2015	280	8,820	44	1,276	$4,636	2,572	$1,064	$1,496
2016	442	12,660	35	2,470	$6,187	3,774	$1,300	$2,012
2017	585	16,323	32	3,571	$7,846	4,789	$1,589	$2,657
2018	736	19,800	31	4,654	$9,578	5,896	$1,916	$3,340
2019	906	24,750	29	5,978	$11,559	7,140	$2,300	$4,080

A graphic representation of these numbers is shown below.



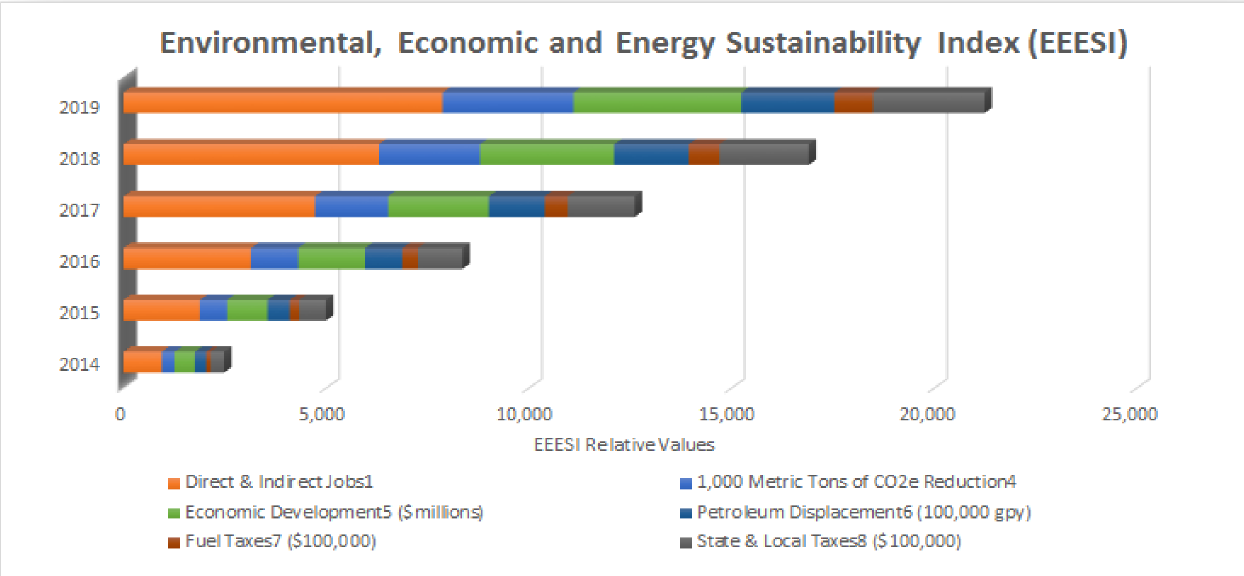
(1) Biodiesel Impacts

Last year nearly 170,000,000 gallons of low carbon diesel alternatives were used in California for Low Carbon Fuel Standard (LCFS) compliance, but only 30 million gallons were produced in-state. The $70 million for biodiesel in the Biofuels Initiative will be used to incentivize more in-state production of low carbon intensity (CI) biodiesel and support necessary infrastructure development (from in-state feedstocks to retail distribution) which will provide economic and environmental benefits to some of California's most disadvantaged communities as highlighted below in the table.

The industry's ultimate goal is to develop in-state production to meet at least 50% of the 500 mgy (million gallons per year) needed under the LCFS to meet petroleum diesel GHG mitigation targets by 2020. The $70 million for biodiesel would allow the industry to double capacity in year 1. Subsequent amounts of GGRF monies to incentivize production would allow the industry to meet the 50% goal by 2020. This would provide proven producers of biodiesel in California the financial support to expand their facilities, open new facilities, and develop capacity for new feedstocks and lower carbon intensity.

Annual Biofuel Initiative Biodiesel Impacts

Fiscal Year	Production Capacity (million gpy)	Direct & Indirect Jobs[1]	Carbon Intensity[3] (gCO2e/MJ)	1,000 Metric Tons of CO2e Reduction[4]	Economic Development[5] ($millions)	Petroleum Displacement[6] (100,000 gpy)	Fuel Taxes[7] ($100,000)	State & Local Taxes[8] ($100,000)
2014	30	945	25	321	$497	276	$114	$330
2015	60	1,890	22	669	$993	551	$228	$660
2016	100	3,150	19	1,160	$1,656	918	$380	$1,100
2017	150	4,725	16	1,805	$2,483	1,378	$570	$1,650
2018	200	6,300	13	2,495	$3,311	1,837	$760	$2,200
2019	250	7,875	10	3,229	$4,139	2,296	$950	$2,750



(2) **Biomethane Impacts**

Biomethane is produced from biogas that has been purified for industrial, commercial and residential end-use, including for pipeline injection, as a transportation fuel and for other purposes. It is generated from the decomposition or conversion of organic waste such as food and yard waste, food processing, wood waste, agricultural and livestock waste, forestry waste, landfills and wastewater treatment facilities. California generates enough organic waste and biogas each year to produce 2.4 billion gallons of transportation fuels, enough to replace ¾ of all diesel used by California vehicles.

Rather than flaring (burning) and wasting biogas, or allowing naturally occurring methane from waste streams to vent into the atmosphere, the *Biofuels Initiative Biomethane Silo* will incentivize the capture, treatment and increased utilization of this renewable resource for use as a transportation fuel. Technologies and treatment processes employed over the last 30 years at nearly 50 projects in 16 states currently remove C02 and other trace constituents from biogas to produce transportation fuel grade or pipeline quality biomethane.

Biomethane is the lowest carbon-intensity transportation fuel available. Biomethane can reduce greenhouse gas emissions by 85 to 115 percent compared to gasoline and diesel. This is significant because transportation accounts for 40% of all greenhouse gas (GHG) emissions in California, which are among the most difficult to cost-effectively reduce.

Biomethane can be used onsite or distributed via the existing natural gas pipeline to fuel motor vehicles, especially the most polluting heavy duty and off-road vehicles and fleets. Thus, we expect dedicated Cap and Trade funds will have a direct, positive impact in the near-term incentivizing the development and interconnection of new biomethane production facilities to meet increased demand for biomethane vehicle fuel.

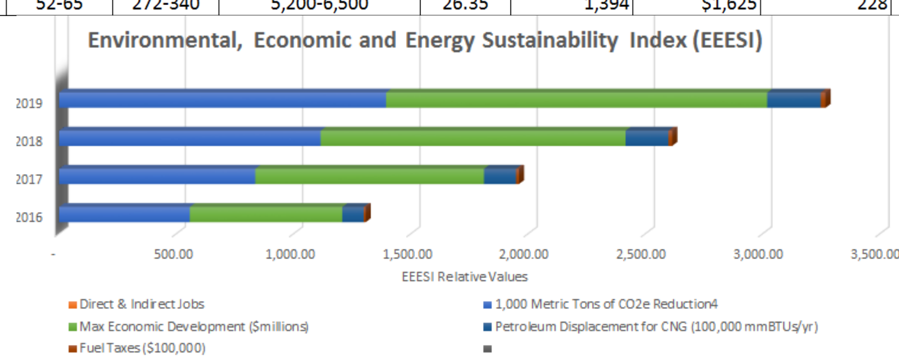
We propose the following allocation of Cap and Trade funds to support increased use of biomethane as a vehicle fuel:

- 3/4 of $70 million ($52.5 million) would help fund new biomethane generation projects at waste diversion facilities, livestock operations and dairies, landfills, wastewater treatment facilities, and other large producers of organic waste. Funds would be awarded in the amount of $2 - $4 million per eligible project to cover the regulatory costs associated with developing and interconnecting such projects to the natural gas grid in California. Available funding should enable the development of 13 - 26 new biomethane production facilities in California within 18 - 36 months of the award;

- 1/4 of $70 million ($17.5 million) would subsidize natural gas vehicles fueled primarily by biomethane, with the fleet operator or vehicle owner agreeing to a long-term contract to purchase the biomethane as a condition for receipt of funds. Available funding is estimated to result in the addition of approximately 700 vehicles fueled by biomethane.

Annual Biofuel Initiative Biomethane Impacts

Fiscal Year	Operating Projects	Production Capacity (million gpy)	Direct & Indirect Jobs	Max Carbon Intensity (gCO2e/MJ)	1,000 Metric Tons of CO2e Reduction[4]	Max Economic Development ($millions)	Petroleum Displacement for CNG (100,000 mmBTUs/yr)	Fuel Taxes ($100,000)
2016	13-26	68-136	1,300-2,600	26.35	558	$650	91	$8.0939
2017	26-39	136-204	2,600-3,900	26.35	837	$975	137	$12.1408
2018	39-52	204-272	3,900-5,200	26.35	1,116	$1,300	183	$16.1878
2019	52-65	272-340	5,200-6,500	26.35	1,394	$1,625	228	$20.2347



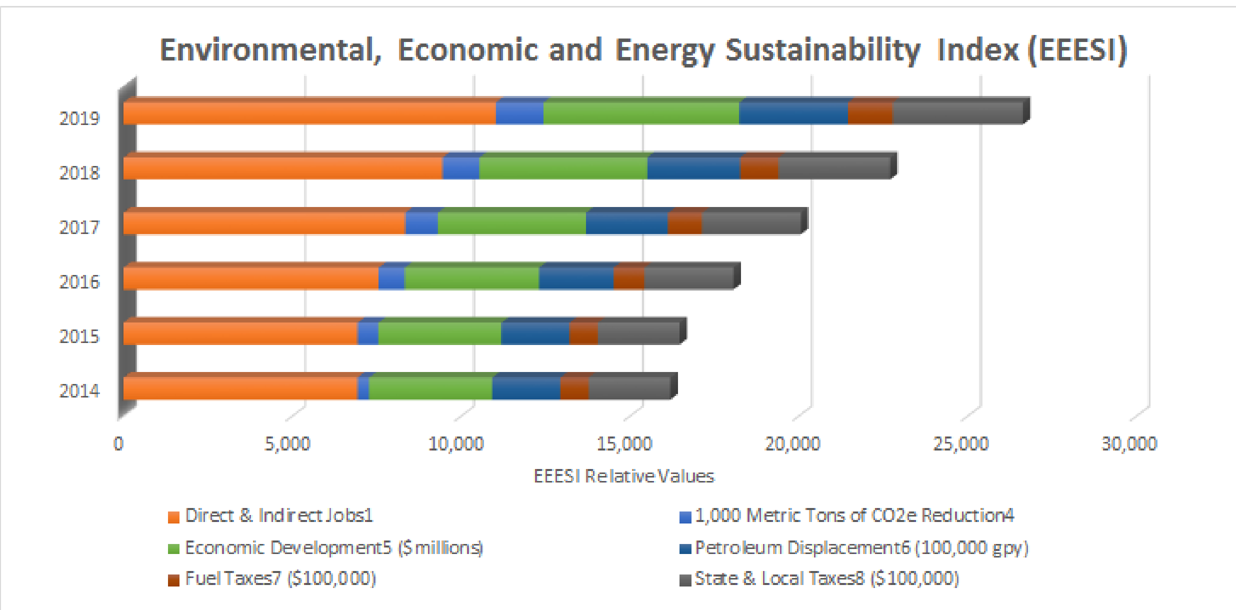
(3) Ethanol Impacts

California is home to the lowest commercially available ethanol in the country making the industry the single largest in-state contributor to carbon reductions. Five facilities produce 222 million gallons of low carbon ethanol and currently reduce over 358,000 metric tons of CO_2 annually. There is currently 1.4 billion gallons of ethanol consumed in California.

The Cap and Trade incentive program will allow these facilities and new facilities to both expand and innovate towards lower carbon scores and multiple of feedstocks. In 5 years the industry goal is to be 350 million gallons of California ethanol with an average CI of 50 reducing over 1, 568,875 metric tons of CO_2 per year.

Annual Biofuel Initiative Ethanol Impacts

Fiscal Year	Production Capacity (million gpy)	Direct & Indirect Jobs[1]	Carbon Intensity[3] (gCO2e/MJ)	1,000 Metric Tons of CO2e Reduction[4]	Economic Development[5] ($millions)	Petroleum Displacement[6] (100,000 gpy)	Fuel Taxes[7] ($100,000)	State & Local Taxes[8] ($100,000)
2014	220	6,930	80	348	$3,642	2,021	$836	$2,420
2015	220	6,930	65	620	$3,642	2,021	$836	$2,420
2016	240	7,560	60	776	$3,974	2,204	$912	$2,640
2017	265	8,348	55	966	$4,387	2,434	$1,007	$2,915
2018	300	9,450	55	1,093	$4,967	2,755	$1,140	$3,300
2019	350	11,025	50	1,420	$5,795	3,215	$1,330	$3,850



Appendix B7

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PRINT THIS

SoCalGas Launches First Power-to-Gas Project in U.S.

Converts Electricity from Renewable Sources to Hydrogen and Methane; and Tests Use of Existing Natural Gas Pipelines to Store Surplus Power

Apr 13, 2015, 03:01 ET from Southern California Gas Company (http://www.prnewswire.com/news/southern+california+gas+company)

LOS ANGELES, April 13, 2015 /PRNewswire/ -- Southern California Gas Company (SoCalGas) is bringing sci-fi innovation to life and has joined with the Energy Department's National Renewable Energy Laboratory (NREL) and the National Fuel Cell Research Center (NFCRC) to launch demonstration projects to create and test a carbon-free, power-to-gas system for the first time ever in the U.S. The technology converts electricity into gaseous energy and could provide North America with a large-scale, cost-effective solution for storing excess energy produced from renewable sources.

Using electrolyzer-based methods, the power-to-gas concept uses electricity from renewable sources, such as solar and wind power, to make carbon-free hydrogen gas by breaking down water into hydrogen and oxygen. The hydrogen can then be converted to synthetic, renewable methane — traditional natural gas — and stored to meet future energy needs. It can also be used as a multi-purpose energy source for vehicles, micro-turbines, fuel cells or other equipment.

"A power-to-gas system can help California meet environmentally-focused energy goals and solve a major energy challenge facing our nation: how to cost-effectively store excess power from renewables to meet energy demands when the wind does not blow or the sun does not shine," said Patrick Lee, senior vice president, customer service, innovation and business strategy for SoCalGas.

California is expected to produce 33 percent of its electricity from renewable sources within five years and Gov. Jerry Brown's new energy goals call for significantly increasing that level to 50 percent by 2030. As the amount of power produced from renewable resources increases, storing it for later use is a worldwide challenge. Batteries, a standard form of storage, require significant capital investment, but have limited capacity and relatively short duration.

Commercial-scale power-to-gas systems are already used in Germany and are being explored globally as a means to convert and store increasing levels of wind and solar power during times of excess supply. Such a commercial system could enable natural gas utilities across North America to use their existing pipeline infrastructure as essentially a large, cost-effective "battery" to store and deliver clean, renewable energy on demand.

Located at the NFCRC at the University of California, Irvine and NREL's laboratories in Golden, Colorado, the power-to-gas demonstrations will also assess the feasibility and potential benefits of using the natural gas pipeline system to store photovoltaic and wind-produced energy.

"As we reach high levels of renewable energy on the grid, storing the electricity generated by solar power and other variable energy sources will help unlock greater use of these renewable resources in the U.S. and throughout the world," said Dr. Martha Symko-Davies, the Director of Partnerships for Energy Systems Integration for NREL. "This project will examine a unique way to reduce the capital cost of energy storage."

While much attention has been focused on developing batteries to store excess energy, battery capabilities are still limited to short-term storage and batteries remain expensive. Power-to-gas offers longer term storage capacity and cost-effectively using existing natural gas infrastructure to potentially create the world's largest storage technology. In addition, power-to-gas storage can conserve the significant amount of energy currently wasted when renewable production exceeds consumption.

"With the extensive storage capacity of natural gas infrastructure, this project will provide important validation of the technical and economic feasibility of carbon-free energy transformation and storage," said Professor Scott Samuelsen, director of the NFCRC.

"SoCalGas continually seeks innovation to benefit our customers and is excited to work with NREL and NFCRC to help make this technology a reality in the U.S.," added Lee.

SoCalGas' power-to-gas project is expected to provide valuable data on the dynamics of hydrogen production in a system flush with renewable electricity. Initial project results are expected by year end.

About SoCalGas: Southern California Gas Co. (http://www.socalgas.com/) has been delivering clean, safe and reliable natural gas to its customers for more than 140 years. It is the nation's largest natural gas distribution utility, providing service to 21.4 million consumers connected through 5.9 million meters in more than 500 communities. The company's service territory encompasses approximately 20,000 square miles throughout central and Southern California, from

Visalia to the Mexican border. Southern California Gas Co. is a regulated subsidiary of Sempra Energy (http://sempra.com/) (NYSE: SRE (http://studio-5.financialcontent.com/prnews?Page=Quote&Ticker=SRE)), a Fortune 500 energy services holding company based in San Diego.

About the National Fuel Cell Research Center:
The National Fuel Cell Research Center (NFCRC) was dedicated in 1998 by the U.S. Department of Energy and the California Energy Commission with the goal to accelerate the development and deployment of advanced fuel cell technology and systems. Examples include the tri-generation of bio-hydrogen, the hybridization of fuel cells with gas turbines, and the deployment of hydrogen fueling infrastructure. The NFCRC is located at the University of California, Irvine. For more information visit www.nfcrc.uci.edu (http://www.nfcrc.uci.edu/).

About the University of California, Irvine: Currently celebrating its 50th anniversary, UCI is the youngest member of the prestigious Association of American Universities. Founded in 1965, UC Irvine is ranked first among U.S. universities under 50 years old by the London-based Times Higher Education. The campus has produced three Nobel laureates and is known for its academic achievement, premier research, innovation and anteater mascot. Led by Chancellor Howard Gillman, UCI has more than 30,000 students and offers 192 degree programs. It's located in one of the world's safest and most economically vibrant communities and is Orange County's second-largest employer, contributing $4.8 billion annually to the local economy. For more on UCI, visit www.uci.edu (http://www.uci.edu/).

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Appendix B8

Environmental Science & Technology

Article

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Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States

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Supporting Information

ABSTRACT: Fugitive losses from natural gas distribution systems are a significant source of anthropogenic methane. Here, we report on a national sampling program to measure methane emissions from 13 urban distribution systems across the U.S. Emission factors were derived from direct measurements at 230 underground pipeline leaks and 229 metering and regulating facilities using stratified random sampling. When these new emission factors are combined with estimates for customer meters, maintenance, and upsets, and current pipeline miles and numbers of facilities, the total estimate is 393 Gg/yr with a 95% upper confidence limit of 854 Gg/yr (0.10% to 0.22% of the methane delivered nationwide). This fraction includes emissions from city gates to the customer meter, but does not include other urban sources or those downstream of customer meters. The upper confidence limit accounts for the skewed distribution of measurements, where a few large emitters accounted for most of the emissions. This emission estimate is 36% to 70% less than the 2011 EPA inventory, (based largely on 1990s emission data), and reflects significant upgrades at metering and regulating stations, improvements in leak detection and maintenance activities, as well as potential effects from differences in methodologies between the two studies.

INTRODUCTION

Methane (CH_4) emissions from the natural gas supply chain account for approximately 30% of the total United States CH_4 emissions.[1] Recent developments in shale gas extraction have resulted in an increased use of natural gas and decreased use of coal and other fossil fuels.[2] Natural gas combustion results in lower carbon dioxide (CO_2) emissions compared to the combustion of coal or oil. However, an increase in throughput of natural gas may increase CH_4 emissions due to greater atmospheric losses. Because the global warming potential of CH_4 is 28 to 34 times greater than CO_2 on a 100 year time frame and up to 84 times greater over a 20-year time frame,[3] an increase in CH_4 emissions may diminish the CO_2 reduction benefit associated with using natural gas as an energy source.[4,5] Near-term reductions in CH_4 emissions are a vital tool for slowing the rate of climate change,[5] and as a complement to long-term reductions in CO_2. Therefore, an accurate estimate of the leak rate of CH_4 from natural gas infrastructure is needed to understand the climate impacts of natural gas use and to identify opportunities for overall reductions in CH_4 emissions.

Much of the data used by the US Environmental Protection Agency (EPA) to estimate CH_4 emissions from the natural gas industry were collected in the 1990s as part of a study by the Gas Research Institute (GRI) and EPA[6] (hereafter, GRI/EPA or GRI/EPA 1992 study, since the base year for the inventory was 1992). The GRI/EPA study compiled CH_4 emission factors (EFs) for components within the industry and developed estimates of the population of each component type (activity factors, AF) across the U.S. The products of EF × AF for each source category were used to compile a national estimate for CH_4 emissions from the natural gas industry. In the EPA emission inventory[1] for the year 2011 (hereafter, 2011 EPA inventory), current AFs are used with the original GRI/EPA EFs (with minor revisions) to calculate the annual CH_4 emission rate from natural gas infrastructure of 6890 Gg/yr,

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with local distribution systems accounting for 1329 Gg/yr, or 19% of the total from the natural gas supply chain and 0.33% of gas delivered to customers.

Considerable changes have occurred in local natural gas distribution systems since the 1990s. There have been substantial replacement and upgrades of equipment within metering and regulating (M&R) facilities along with reductions in miles of older cast iron (−38% to ∼33 000 total miles) and unprotected steel pipeline (−22% to ∼66 000 total miles), and increases in protected steel (+8% to ∼480 000 total miles) and plastic (+150% to ∼620 000 total miles) pipeline miles.[1,7] Leak survey methods have improved since the 1990s, with an increased emphasis on reporting of CH_4 emissions.[8] However, a new assessment of CH_4 emissions from U.S. natural gas distribution systems in response to these changes has not occurred.

Here we present results of direct measurements of CH_4 emissions from underground pipelines and M&R facilities across the U.S. These data were used to develop new EFs as the basis for a revised estimate of CH_4 emissions from natural gas distribution systems. We also compiled information from company surveys to update estimates for emissions from maintenance blow-downs and pipeline dig-ins. We use these results to provide a new estimate of the total amount of CH_4 emitted from the US natural gas distribution system.

EXPERIMENTAL SECTION

Scope of Study. At the beginning of the study, we used the available 2010 EPA emission inventory coupled with uncertainty estimates from the 1992 GRI/EPA study to develop a stratified random sampling plan targeting the largest CH_4 source categories (see Supporting Information SI Section S2.1). On the basis of this analysis, eight categories were targeted for sampling (in order of estimated emissions): M&R with inlet pressures between 100 and 300 psi, plastic mains, unprotected steel services, unprotected steel mains, cast iron mains, regulators >300 psi, M&R > 300 psi, and regulators 100−300 psi. This list includes Transmission−Distribution Transfer Stations (TDTS), also called city gates, where gas custody is transferred from the transmission pipeline to the distribution system. Sampling within these target categories occurred from May through November 2013 at 13 local distribution companies (LDCs) across the U.S. Wintertime conditions were not sampled, and there is little information available to suggest how this might bias the results. While these LDCs represent less than one percent of the 1400 distribution companies in the U.S.,[7] they have 19% of the distribution pipeline mileage (∼226 000 miles), 26% of the services (∼15 million services), and deliver 16% of the total gas delivered to customers in 2011. These companies, thus, account for a significant percentage of natural gas distributed nationally, although we recognize the potential bias in our results because companies volunteered to participate in this study, which was essential for access to facilities for measurements. Pipeline replacement rates for cast iron and unprotected steel mains in our partner companies are similar to other LDCs nationwide. Data from the DOT pipeline program[7] show that the miles of cast iron and unprotected steel mains have decreased due to replacement by 20% from 2005 through 2013 and that for our partner companies, the miles of cast iron and unprotected steel have remained a constant fraction (16% ± 1%) of the decreasing national total miles during this period.

To develop a representative database, a random selection process was developed so that measurements were obtained within targeted, representative areas that we selected within each company's distribution system. Specific pipeline leaks and facilities were selected randomly from LDC leak survey data and facility lists for the targeted areas. Class 1 pipeline leaks were not measured since these leaks are repaired immediately for safety reasons. Because leaks are classified on the basis of safety (i.e., proximity to buildings) and not magnitude, class 1 leaks are not necessarily larger than class 2 or 3 leaks. Further information on the stratified random sampling plan and the partner LDCs is provided in SI Section S2.0. Our study does not address emissions downstream of customer meters or other portions of the natural gas supply chain in urban areas, including natural gas transmission lines and compressor stations, natural gas vehicles and fueling stations, and liquefied natural gas terminals and storage facilities.

Sampling Methods. The high-flow sampling method[9−11] was the primary measurement technique used to quantify leak rates on individual components at M&R stations (SI Section 3.1). The high flow sampler uses a high flow rate (6−8 standard cubic feet per minute) of air and a modified enclosure to completely capture the gas leaking from a component. Catalytic oxidation and thermal conductivity hydrocarbon sensors measure the CH_4 concentration in the air stream, and a thermal gas flow sensor measures sample flow rate. A version of the high-flow technique, modified to include a 1.2×1.2 m^2 surface enclosure and a CH_4 detector with a detection limit <100 ppmv was used to measure surface CH_4 emissions from underground pipeline leaks (SI Section 3.2). High-flow measurements were supplemented, for quality assurance purposes, by downwind tracer-ratio measurements with instruments mounted in a van[12] (SI Section S3.3). We found moderate (±50%) to excellent (±5%) agreement between the downwind tracer-ratio method and high-flow sampling methods (SI Sections S4.11 and S5.2). For six different pipeline leaks where we had tracer and direct measurements, total summed emissions measured were 4.85 and 5.83 g/min for the high flow and tracer methods, respectively, which yields an overall difference (19%) within the experimental uncertainties. Similarly, for eight M&R facilities, the total summed emissions were 66.0 and 51.6 g/min for the high-flow and tracer-ratio methods, respectively, a difference of 24%, within the range of the experimental uncertainty (see SI Sections 3.0 on methods, Sections S4.1.1 and S5.2 on tracer results and SI Appendix B on uncertainty analyses).

Statistical Methods. The population of measured leak rates generally shows marked asymmetry, with a few high emitters accounting for a large fraction of the total measured emissions, requiring highly skewed probability distributions as models. We considered eight different probabilistic models for each data category—Gaussian, log-normal, gamma, Weibull, hyperbolic, inverse Gaussian, Johnson, and generalized Tukey's lambda distributions—and compared them using the Bayesian Information Criterion (BIC), supplemented by inspection of QQ-plots (see SI Section 3.6 and references therein). Once a model was selected for a category, and its parameters estimated, 105 sample data sets were drawn from the fitted model in a manner that recognizes the uncertainty of the fitted parameters, where each of these samples was the same size as the original data set, and their averages were computed. The overall average from these bootstrap data sets was the estimate of the mean leak rate for the corresponding source category, and the 95th

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Table 1. Comparison of National Methane Emission Factor Estimates from Underground Pipeline Leaks Based on the Current Study and the 1992 EPA/GRI Study

	this study			1992 GRI/EPA		
pipeline material	*n*	emission factor (g/min)	95% UCL (g/min)	*n*	emission factor (g/min)	95% UCL (g/min)
			main pipelines			
cast iron	14	0.90	3.35	21	3.57[a]	5.60[a]
unprotected steel	74	0.77	2.07	20	1.91	3.70
protected steel	31	1.21	4.59	17	0.76	1.40
plastic	23	0.33	0.67	6	1.88	8.20
			services			
unprotected steel	19	0.13	0.19	13	0.34	0.54
protected steel	12	0.33	0.93	24	0.74	1.53
plastic	38	0.13	0.19	4	0.11	0.27

[a]GRI/EPA EF converted from SCF/mile to g/min/leak using cast iron pipeline miles and equivalent leaks from this study.

Table 2. Comparison of National Methane Emission Factors for Metering and Regulating Facilities Based on the Current Study and the 1992 EPA/GRI Study

	this study			1992 GRI/EPA		
facilities	*n*	emission factor (g/min)	95% UCL (g/min)	*n*	emission factor (g/min)	95% UCL(g/min)
			M&R stations			
>300 psi	59	4.06	7.67	31	57.4	79.6
100−300 psi	10	1.88	1.88	6	30.5	64.6
<100 psi	0	–	–	3	1.4	4.5
			regulating stations			
>300 psi	41	1.64	4.85	13	51.6	81.4
100−300 psi	41	0.27	0.73	7	12.9	21.4
40−100 psi	13	0.31	0.73	7	0.32	0.60
<40 psi	1	0.0	0.0	0	–	–
vaults[a]	23	0.10	0.13	28	0.03- 0.41	0.06−1.18

[a]All pressure categories are combined for underground vaults.

percentile of the same set of samples, defined as the 95% upper confidence limit (UCL), expresses the uncertainty associated with this overall mean. Further details are provided in SI Section 3.6.

■ RESULTS AND DISCUSSION

Emissions from Underground Pipelines. Methane emissions from 230 individual underground pipeline leaks were measured to form the basis for new pipeline EFs. This sample of leak measurements is twice as large as that used in the 1992 GRI/EPA database, although it is still a small fraction of total leaks in the U.S. On the basis of our stratified sampling plan, the emission rate measurements were from cast-iron, unprotected steel, cathodically protected steel, and plastic main and service pipelines. Typically, cast-iron and unprotected steel pipe have more leaks per mile than protected steel and plastic pipe.[6] Emission factors from pipeline mains ranged from 0.3 to 1.2 g/min/leak, while EFs from pipeline services ranged from 0.1 to 0.3 g/min/leak (Table 1). The estimated 95% UCLs on these EFs were factors of 2 to 4 times larger than the mean EFs.

We found that three large leaks (34.9, 22.2, and 4.9 g/min, from unprotected steel main, protected steel main, and cast iron main leaks, respectively, accounted for 50% of the total measured emissions from pipeline leaks. This type of distribution, where a few leaks account for a large fraction of the total CH_4 emitted, is not unexpected, and it has been observed in other emission studies.[6,13,14] For these skewed distributions, as described previously, the estimated mean for a sampled population and the corresponding UCL are best estimated from explicit probabilistic modeling of the skewed distribution of the measurements to find the distribution type which best matches the observations in each category (see SI, section S3.6, Figures S3.12, S4.1, S4.5).

Our EFs for underground pipeline leaks were about two times lower than reported in the 1992 GRI/EPA study[6] (see Table 1). The maximum emission rates measured in our study were similar to those in the GRI/EPA study, on the order of 30 g/min/leak. For smaller leaks, the GRI/EPA results were larger than the emission rates measured in the current study (median emission rate of 0.6 g/min/leak, versus 0.06 g/min/leak, respectively). Therefore, it is clear that our leak distribution has much lower leak rates than the GRI/EPA study (see SI Figure S4.5).

There are important categorical differences between our measurements and the 1992 GRI/EPA study. The EF for plastic mains in the GRI/EPA work was almost seven times larger than our estimate (0.33 g/min/leak). In this case the GRI/EPA plastic main EF was based on a relatively small sample size of six including one very large leak. Furthermore, recent measurements by the Gas Technology Institute[14] (GTI) also suggest lower EFs (1.0 ± 1.2 g/min/leak) than the rate used by EPA for plastic mains (1.88 g/min/leak) and the GTI rate is similar to our EF for plastic mains when corrections are made for the GTI detection limit (see SI Section S4.2). For leaks from cast iron mains, the GRI/EPA EF was reported on a per foot basis, which makes it difficult to compare to our measurements of emissions per leak. For protected steel mains and plastic services, our EFs were slightly higher than GRI/EPA. The reasons for these differences include better leak

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Table 3. Comparison of Results for High Emitting City Gates in the GRI/EPA Study with Results from Re-Visiting These Same Sites in This Study[a]

facility	GRI/EPA methane ER (g/min)	this study methane ER (g/min)	ratio (1992/2013)	facility modifications
A	162	30.3	5.30	
B	118	6.14	19.3	rebuilt
C	62	8.49	7.2	
D	40	56.2	0.70	no changes
E	29	0.543	53	
F	27	14.6	1.9	
G	24	5.19	4.6	
H	23	1.30	18	rebuilt
I	18	6.14	2.9	
			13	**average ratio**
totals for revisited sites	**504**	**129**	**3.9**	**ratio of totals**

[a]Blank cells indicate no information available from facility operators.

detection technology now compared to the 1990s, replacement of older pipelines, better maintenance activities, and, possibly, methodological differences between this study and the GRI/EPA work.

In the GRI/EPA study, leak rates were measured by digging and isolating pipe sections to measure leak flow rates, which were then adjusted empirically to account for oxidation of CH_4 in the soil.[6] The soil oxidation correction varied from a few percent for large leaks to as much as 40% for leaks from cast iron mains.[15] In this work, a surface enclosure was used to measure the emissions at the ground surface with no disturbance of the pipe and no corrections needed to account for soil oxidation. Considerable care was taken to completely map and then measure the surface expression of each leak using a series of gridded enclosure placements (SI Figure S3.3), and we also found good agreement between the surface enclosure method and an independent tracer-ratio approach (see SI Section S5.2). In the GRI work, LDCs conducted the pipe isolation leak measurements on sections of pipe scheduled for replacement, and audits were conducted to ensure that each company used consistent methods. In our work, leaks were selected randomly from the company leak survey database within the general area we had selected from each LDC service region (SI Section 2.0). It is not possible to determine how these differences might have affected the results in terms of the overall sample population or individual measured leak rates, although GTI showed good agreement between their surface enclosure measurements and a pipe isolation method[14] similar to that used in the GRI/EPA study.

Emissions from Metering and Regulating Stations. We completed measurements at 229 different M&R facilities including 48 TDTS stations (city gates). In the GRI/EPA 1992 study, 55 such facilities were measured. Emission factors for M&R stations are summarized in Table 2 for the different facility categories used in the emission inventory. We found higher emissions for facilities with higher inlet pressures, and lower emissions for vaulted (i.e., below grade) facilities. For facilities with inlet pressures >100 psi, the EFs range from 0.3 to more than 4 g/min/station. For vaulted facilities, the emissions are less than 0.1 g/min/station. In each case, the distribution of measured emission rates is skewed with median emission rates much less than the mean.

M&R stations sometimes have vented devices, such as odorizers and pneumatic controllers, designed to emit natural gas as part of their normal operation. We measured emissions from these devices at M&R facilities and found that they have highly variable emission rates over short periods of time (SI Section S5.1). Therefore, measurements were collected using a high-flow sampling system coupled to a data system to record emissions over 15 to 30 min periods. The emissions from vented devices typically represent a significant fraction of the total emissions for facilities so equipped (SI Section S5.1). The EFs for odorizers and pneumatic controllers measured during our study were 2.2 and 4.9 g/min as compared to whole facility EFs that ranged from less than 1 g/min to more than 4 g/min.

There are significant differences between the emission factors from the GRI/EPA 1992 study and our measurements (Table 2) for M&R facilities. For the larger emitting categories, the GRI/EPA EFs are more than 14 times larger than our EFs. These differences are apparent in the frequency distribution of emissions from all M&R stations, where the maximum emission rate measured in the GRI/EPA work was 157 g/min/station while the maximum emission rate measured in our study was 56 g/min/station (SI Section S5.3; Figure S5.6). The large differences in the EFs are due to the upper 20% of the sites measured in the GRI/EPA work, since the median value in both studies is essentially identical at 0.3 g/min/station.

To understand the large reductions found in this work relative to the GRI/EPA results, we identified nine facilities from among the larger emitting sites measured during the GRI/EPA 1992 program to resample with our high-flow and tracer-ratio techniques (Table 3). These results show substantial reductions in emissions from each individual station (factors of 2 to 50) from 1992 to the present, with one exception. In two cases, the local operator indicated that significant equipment changes had occurred at the site; while at a third site, the local operator indicated that there had been no equipment upgrades at the site in the past 20 years. This particular site was the only site without a significant reduction in emissions. No information was available for equipment changes at the remaining sites. The data collected by resampling these facilities support our findings of substantial reductions in emissions from M&R facilities.

Because of the importance of facility equipment upgrades, we next surveyed the study partner LDCs and other LDC members of the American Gas Association (AGA) to determine how M&R sites have been upgraded since 1992 (SI Appendix G). Results obtained from five partner LDCs for 90 M&R sites of the 229 sites sampled in this study showed that approximately 60% of the 90 facilities had undergone some equipment change since 1992. Information on upgrades was not available for the remainder of the sampled sites. Our

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Table 4. Summary of the Overall Emission Inventory for U.S. Natural Gas Distributions Systems for This Study and the 2011 EPA GHG Inventory (1)

category	this study: methane emissions (Gg)	this study: 95% upper confidence limit (Gg)	EPA 2011: methane emissions (Gg)
pipelines			
mains	132	431	429
services	63.6	124	194
pipeline subtotal	197	554	623
equipment			
M&R facilities	42.3	82.9	552
customer meters[a]	112	150	112
maintenance	1.6	2.5	3.7
upsets	41.6	64.1	38.9
equipment subtotal	197	300	706
total	393	854	1329

[a]EPA emission factor used for this category.

random sampling approach did not consider facility upgrades in sampling location selection. In addition, 14 LDC members from the AGA reported equipment upgrade activities with a total of 5267 out of 12 788, or 41% of facilities having upgrades. Furthermore, 43% of the responding companies reported rebuilding whole stations since the 1990s. It was clear from our interactions with M&R personnel that maintenance activities and attention to leaks have increased, in part, due to the GHG reporting requirements implemented in the past several years.[8] These results highlight the importance of making periodic emission measurements to account for upgrades and changes in the natural gas system, and point to the power of reporting requirements in helping to reduce emissions.

The GTI measured emissions from M&R stations using similar methods during 2008.[16] Our current EF for TDTS stations is lower than the GTI results, but within the large uncertainties associated with these measurements (SI Table S5.13). When the measurements are integrated over all M&R stations on a weighted basis to match the GTI results, the current EFs are approximately half of the GTI results, but still within the uncertainty estimates of the EF. For pressure regulating stations, a significant decrease occurs from the GRI/EPA data to the GTI data and from GTI to our study (see SI Table S5.13). Overall, the GTI results are consistent with our results and with significant upgrades in equipment and procedures for M&R stations from 1992 to the present, although there may be differences in how the GTI study selected stations and integrated the results.

National Emission Inventory. The U.S. natural gas distribution system has undergone modernization and growth since 1992.[1,7] Pipelines mains and services have increased by 44% to 1.2 million miles and 63 million services, respectively. Modernization of the system has led to substantial reductions in the miles of cast iron (−38% to ∼33 000 miles) and unprotected steel pipelines (−22% to ∼66 000 miles). At the same time, there has been an increase in miles of plastic mains (150% to ∼620 000 miles), protected steel mains (8% to ∼480 000 miles), and plastic and copper services (150% to 43 million services and 352% to 1 million services, respectively). For M&R stations, there has been an increase in the number of stations by about 8% to approximately 150 000 stations. For customer meters, there has been an increase of 6% in the number of residential meters to 42 million meters, but a 5% decrease in commercial meters to 4 million meters.

To quantify the total CH_4 emitted from underground pipelines in the U.S., we developed an AF for underground pipelines (units of leaks per mile of pipe or number of services). Because such information is not available on the national scale, we use the concept of an "equivalent leak" where an equivalent leak represents a leak that exists for one year.[6] For each LDC, equivalent leaks account for the number of annual leak indications (including customer call-ins), an estimate of the number of actual leaks based on leak indications (assuming the company does not know about all of their outstanding leaks), the number of annual leak repairs, and the average time between leak indication and leak repair. In the GRI/EPA study, survey results from four LDCs were used as the basis for equivalent leak calculations. We followed the same approach and obtained data from six of the study partner LDCs (see SI Section 4.3 and SI Appendix D). Class 1 leaks were not measured, but were included in the equivalent leak calculations. Since Class 1 leaks are repaired as soon as possible, including them in the equivalent leak calculations is conservative in that it will result in greater national emissions.

The annual CH_4 emissions in each category for the U.S. are calculated by multiplying the AF (number of equivalent leaks) in each pipeline category by the appropriate EF (Table 1). On the basis of our estimates, the national total is 197 Gg/yr with a 95% UCL of 554 Gg/yr, where the UCL only accounts for the uncertainty in the EF values. The uncertainty in AFs in this study and the 1992 GRI/EPA study are similar, on the order of ±30%. These uncertainties are due to variability among the companies surveyed regarding the number of leak repairs, the time between leak detection and repair, and the number of pipe miles. Annual emissions due to leaks in pipeline mains account for 67% of the total underground pipeline emissions. Even though cast iron and unprotected steel mains represent less than 10% of national distribution system pipeline miles, the emissions from these two categories account for 46% of the total emissions from pipeline mains.

The annual emissions from pipeline leaks estimated in our study are approximately 32% of the 2011 EPA estimates of 623 Gg/yr (Table 4) and approximately 26% of the 1992 GRI/EPA estimates of 751 Gg/yr (SI Table S4.8). This is due to a combination of lower EFs (CH_4 emitted per leak) and lower AFs (equivalent leaks in the U.S.). The GRI/EPA 1992 total estimate of 751 Gg/yr decreases to 483 Gg/yr when the GRI/EPA EFs are used with EPA 2011 AFs (SI Table 4.8). Therefore, roughly half of the decrease from the 1992 estimate

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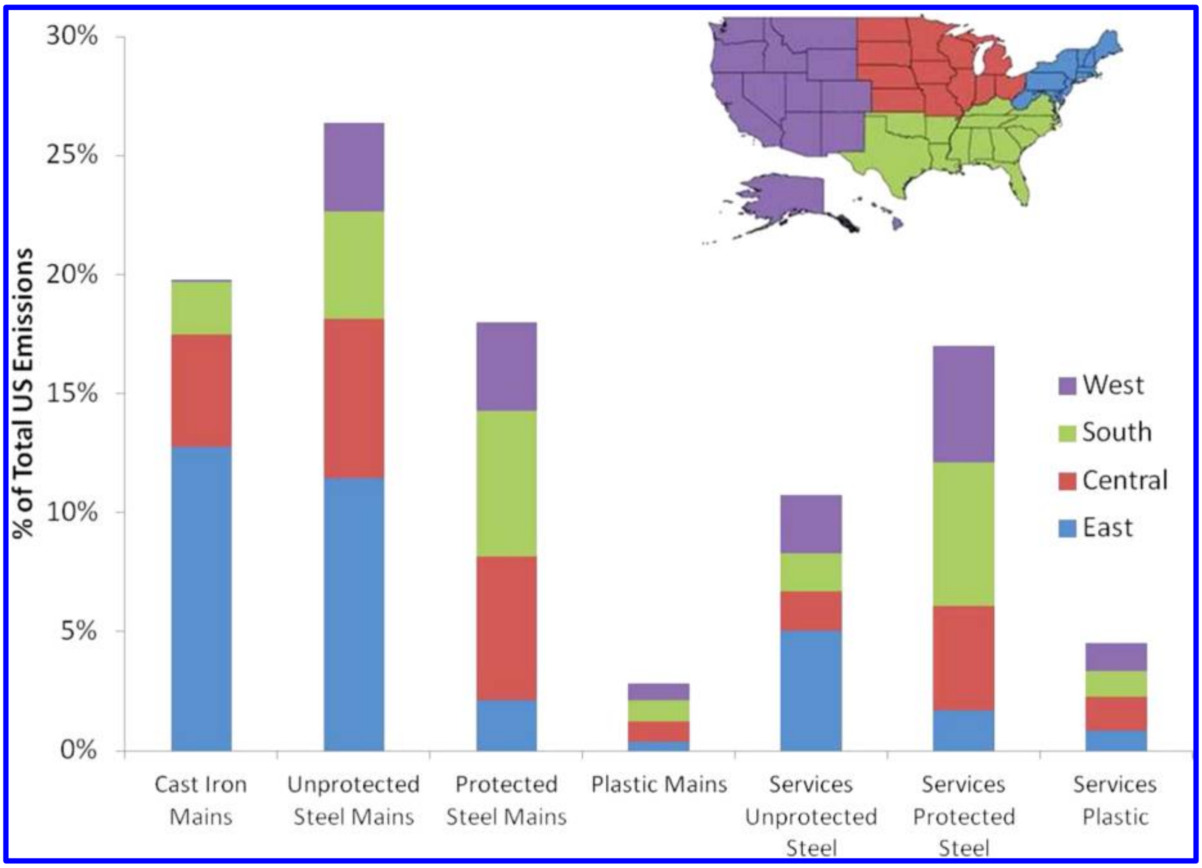

Figure 1. Percentage of total U.S. methane emissions from underground pipeline leaks by region and by pipeline type and category. The total U.S. emission estimate for pipeline leaks is 197 Gg/yr with a 95% upper confidence limit of 554 Gg/yr.

is due to reductions in AF and the other half is due to the aforementioned reductions in EFs.

The primary reason for reductions in AFs is the replacement of older cast-iron and unprotected steel pipe with plastic (see SI Section 4.3 and Tables S4.5−8). Specifically, the number of pipeline leaks has decreased between 25% and 16% for pipeline mains and services, respectively, due to the use of better pipe materials, efforts to seal cast iron joints, and enhanced leak detection and repair procedures. A survey of AGA LDCs made during this study indicates that substantial cast-iron pipe replacement and joint-sealing activities are being conducted in the U.S. In fact, over half of the 20 gas companies who provided information during the survey reported sealing roughly one cast-iron joint per mile of cast-iron pipe in 2011 (SI Appendix G).

As previously mentioned, our emission rate measurements in each category exhibited a skewed distribution, and while this is typical of CH_4 emission studies, these distributions result in large upper confidence limits. In our case, our national emission estimate of 197 Gg/yr has a 95% upper confidence limit of 554 Gg/yr that is within ∼10% of the 2011 EPA emission estimate of 623 Gg/yr. Given the effect that just a few large leaks have on the mean EF, it is important to recognize the upper bound as an integral part of any comparison with other emission estimate methods.

We also examined how emissions from pipeline leaks varied on a regional basis in the U.S. due to differences in pipeline type and miles by region (see SI Section S4.3; there was no statistical difference in EFs by region). The eastern region accounts for 34% of the total U.S. CH_4 from pipeline leaks, while the western region contributes less than 20% (Figure 1). In the eastern region, emissions are dominated by leaks from cast iron and unprotected steel characteristic of older systems. As such, leaks from cast iron and unprotected steel pipe account for 70% of the eastern emissions and almost half of total U.S. emissions. In the western region, systems are newer with more miles of plastic and protected steel pipe, and leaks from these systems contribute less than 5% of the total U.S. emissions. These regional variations and the low emissions associated with plastic pipes are significant as the U.S. moves toward replacement of older pipelines with plastic and uses plastic for new distribution expansion.

To extrapolate to a national level for the M&R emissions, we use the same categories as used in the 2011 EPA GHG emission inventory along with current AF for each category. For the present study, the results indicate a total CH_4 emission rate from M&R stations of 42 Gg/yr with a 95% UCL of 83 Gg/yr (Table 4). The top two contributing categories are M&R (>300 psi) stations, which includes TDTS stations, and M&R (100−300 psi) (see SI Table 5.14), and these account for more than half of the estimated emissions.

Our annual CH_4 emission total for M&R stations in the U.S. is significantly lower than the 2011 EPA estimate (552 Gg/yr) by factors of 7 to 13 (Table 4). These differences are large, but are supported by significant differences in emissions at the revisited large emitting sites from the GRI/EPA study and from industry information, which indicates significant improvements in equipment and maintenance. These differences are also supported by the results from the GTI study,[16] which also

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showed significant decreases in emissions for M&R facilities compared to the GRI/EPA 1992 work.

For comparison to the EPA inventory for distribution systems, we used results from surveys of AGA companies to update estimates for maintenance and mishaps (see SI Appendix G). Together, our estimates for CH_4 losses from pipeline leaks, M&R facilities, maintenance activities, and mishaps, along with the EPA estimate for customer meters, address emissions from U.S. local distribution systems up to and including the customer meter. Our estimate for these categories for the total U.S. emission rate is 393 Gg/yr with a 95% UCL of 854 Gg/yr. The UCL on this new inventory is approximately 36% less than the EPA 2011 emission inventory, while the mean emission total is 70% less than the EPA estimate. The reduction in the national total is due to a combination of lower EFs and AFs. Changes in EF are clearly linked to equipment upgrades at M&R stations and to changes in pipeline leak survey methods, replacement of older pipe, and better maintenance efforts. There may also be a difference in EFs due to the differences in sampling methodologies used here vs the original GRI/EPA work, but the effects of these differences in methods are difficult to determine. The 2012 EPA inventory, currently in draft form, shows a decrease of 100 Gg/yr compared to the 2011 EPA inventory, which does not substantially change the comparison. Our new estimate represents 0.10% to 0.22% of the CH_4 delivered via the distribution system. Our results also show considerable differences on a regional basis throughout the U.S. because of differences in pipeline types and miles by region.

The magnitude of the UCL is due to the skewed distribution of measurements collected in this study and is typical of emission rate measurements from the natural gas distribution system. The upper limit also includes uncertainties for customer meters, maintenance, and mishaps (e.g., accidental dig-ins) that were estimated from company surveys in a manner similar to that used in the GRI/EPA study. For customer meters, GTI conducted high-flow measurements on 2800 customer meters in 2008.[16] If the GTI EFs are used in place of the EPA 2011 emission estimate for customer and commercial meters, then the U.S. total emissions for these meters decreases from 112 Gg/yr to 81 Gg/yr.

While our study provides a significant increase in the number of measurements for pipeline leaks and M&R facility emissions, additional sampling would improve our understanding of the frequency distribution of leaks, particularly for the few large leaks that seem characteristic of the distribution. As noted previously, we were limited to LDCs which volunteered to participate in this work; uncertainties remain regarding leak rates in other locations. However, we might expect leak frequency to differ among LDCs due to maintenance and pipeline material differences, but the actual leak rates (EFs) might be expected to be similar. We were also limited to nonwinter sampling conditions; the effects of frozen soils upon pipeline leak rates and greater natural gas throughput in winter months have not been addressed in this work. Looking forward, technology that would allow rapid leak detection and direct measurement of emission rates would expand the database of leaks and reduce the uncertainty in EFs. Additional efforts to develop AFs by surveying more companies would also help to reduce uncertainties in these bottom-up estimates.

Top-down emission estimates, which infer emission rates from ambient CH_4 observations, are vital in constraining emission estimates. These approaches typically provide larger emissions estimates than bottom-up approaches,[17] which indicates that further work is required to address sources not explicitly included in our direct source measurements. For example, McKain et al.[18] have reported top-down CH_4 and ethane measurements in Boston, MA with inverse modeling analyses that suggest natural gas sources account for 60% to 100% of the enhanced CH_4 levels depending on the season of the year. Similar results have been reported elsewhere from top-down studies,[19,20] and this seems to be supported by nonquantitative city street surveys of CH_4 concentrations.[21,22] Further work on reconciling bottom-up emission inventories with top-down emission estimates is needed to address all of the sources contributing to CH_4 emissions from the natural gas supply chain in urban areas since top-down methods cannot yet provide specific source attributions. These include emissions downstream of customer meters from industrial facilities, commercial structures, and residential housing, emissions from pipeline leaks that migrate into sewer lines and vents, emissions from transmission lines and compressor stations within urban areas, from natural gas vehicles and refueling stations, from liquefied natural gas terminals and storage facilities, or other unidentified sources. Such efforts are underway in Indianapolis, IN,[23] among other urban areas, and EDF is sponsoring emission studies of several of these source sectors. Additional work is needed to treat seasonal differences such as reported in Boston.[18]

In summary, this survey of methane emissions from a sample of the natural gas distribution systems of the U.S. is based on direct measurements and is the most comprehensive since that of the 1990s. Instances of significant emissions reductions have been quantified, in particular, reductions ranging from approximately a factor of 2 to 50 for some M&R stations, and illustrate the impact of two decades of advances in technologies and changes to operational procedures that reduce emissions.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

Project overview; study scope; local natural gas distribution systems; sampling approach; sampling strategy; stratified random sampling; representativeness of the LDC sampling regions; sample selection; emission rate measurement methods; high flow component leak measurements at TDTS and M&R facilities; surface enclosure underground pipeline leak measurements; tracer ratio leak methods for facility and pipeline leaks; isotopic methane sampling; mobile methane mapping; probabilistically modeling of mean and upper bound emission factors; probabilistic modeling—methods; probabilistic modeling—results; underground pipeline emissions; pipeline leak measurement results; tracer ratio results; isotopic analyses; pipeline emission factor analysis; national extrapolation of emissions from pipeline leaks; M&R facility emissions; vented emission measurements; odorizers; pneumatic controllers; tracer ratio results; M&R facility emission factor analysis; national extrapolation of emissions from M&R facilities; national emission inventory; references; glossary; and additional figures and tables. This material is available free of charge via the Internet at http://pubs.acs.org.

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Notes

The authors declare the following competing financial interest(s): Brian Lamb served on the Science Advisory Panel for the University of Texas study for natural gas emissions from production facilities and is a co-author on the Allen et al. (2013) paper describing that work. B.K.L., T.H., C.E.K., M.R.H. were participants in the 1992 GRI/EPA national sampling program (Harrison et al., 1996). Conestoga-Rovers & Associates (T.W.F., T.H., and W.D.) have a number of natural gas production and distribution companies as clients. C.E.K. and M.R.H. were members of the measurement team for the University of Texas led study and were co-authors of the Allen et al. (2013) PNAS article. C.E.K. is also a member of the Science Advisory Board for the ongoing Environmental Defense Fund organized Methane Monitoring Technology Initiative..

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