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California Energy Commission

STAFF PAPER

Fuel Substitution: An Exploratory Assessment of Electric Load Impacts

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Gavin Newsom, Governor
November 2019 | CEC-200-2019-020

DISCLAIMER

ABSTRACT

This study is designed to develop a better understanding of the incremental electric load impacts resulting from displacement of natural gas as a result of hypothetical fuel substitution policies. Five scenarios address varying levels of impact as a result of moderate levels of electrification of new construction, residential sector retrofit, and a major level of residential and commercial sector retrofit comparable to proposed recommendations staff outlined in Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018). This study is limited to fuel substitution in residential and commercial buildings. This study quantifies both annual energy and electric hourly load impacts of five future scenarios for the major utility service areas in California. Testing alternative assumptions can help to reveal the relative importance of uncertain values and motivate deeper investigation of variables. This study is not a forecast of fuel substitution that is sufficiently accurate that it should be included as a load modifier in creating managed demand forecasts that are used for procurement purposes. There are too many uncertainties for these results to be treated in that manner at this time, although inclusion of some level of fuel substitution in officially adopted managed demand forecasts will undoubtedly happen in future CEC forecasts.

Keywords: fuel substitution, building electrification, hourly electric load, demand forecast

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EXECUTIVE SUMMARY

California policymakers have enacted laws that effectively mandate the replacement of fossil fueled electric generation facilities with renewables and other non-carbon emitting sources.[1] Decarbonizing the end-user consumption of energy is now receiving increased attention. Replacing the combustion of natural gas and other fuels with electricity is one means of achieving this decarbonization. California energy agencies refer to displacement of natural gas by electricity as fuel substitution. This paper documents an exploratory study of the incremental electric load resulting from several hypothetical fuel substitution scenarios.

Although the technologies that use electricity to power various residential and commercial building end-uses exist and are deployed in large amounts in some regions of the United States, California has pursued a different path for decades. Electric appliances for space and water heating have been actively discouraged, resulting in California's use of natural gas as the highest in the nation. Eliminating barriers to the use of electricity and programs to incent retrofit are now under discussion and are being implemented at a small scale. Unfortunately, predicting the pace, scale, and energy system impacts of these activities is too uncertain to include in California Energy Commission demand forecasts used by the California Independent System Operator, the California Public Utilities Commission and others for energy planning and procurement.

This study designed and assessed the impacts of five hypothetical fuel substitution scenarios to identify the quantifiable range of natural gas displaced and incremental electric load added for both annual energy and hourly electric load. An Excel-based tool originally used to project hourly energy efficiency savings impacts was adapted to conduct this assessment. These five scenarios and some limited variation of technical assumptions provide a spread of possible consequences out to year 2030. Key results include:

- The average efficiency of the natural gas end-use equipment displaced and the electric equipment installed is a key assumption that drives the results.
- End-use load shapes of heat pumps and electric cooking require much more intensive development.
- A wider range of weather conditions must be assessed to understand the impacts for specific utilities and the coincident impacts on system operators.

Apart from these important technical assumptions, there is little understanding of how end-users will adopt electric technologies on their own in response to climate change exhortations or in response to incentive programs to encourage fuel substitution. These consumer behavior elements have not been directly assessed in the "what if" scenarios assessed in this study, but they loom as a major uncertainties that need to be better understood.

1 Senate Bill (SB) 100, the "100 Percent Clean Energy Act of 2018" (de León, Chapter 312, Statutes of 2018).

CHAPTER 1: Introduction

This report summarizes an exploratory study of the annual electric energy and hourly electric load shape impacts of several alternative future scenarios of fuel substitution from natural gas to electricity. Since there is great uncertainty about the pace and ultimate scope of fuel substitution activities, a scenario approach is used to project annual energy and electric load shape impacts out to year 2030. There are also uncertainties about the specific sectoral and end-use efficiencies of the natural gas equipment being replaced and the efficiency of the electric equipment substituting for natural gas technologies. Finally, since space heating is expected to be a substantial portion of likely substitution activities, the electric load shape of space heat will be strongly weather related, introducing yet further uncertainty about the incremental impacts on needed generating capacity expansion and system operation to assure grid reliability.

In light of these uncertainties, California Energy Commission's Energy Assessments Division (CEC/EAD) has proposed to exclude most fuel substitution load from baseline and managed demand forecasts for the *2019 Integrated Energy Policy Report* (*2019 IEPR*).[2] Nonetheless, understanding the electrical load consequences of alternative scales of fuel substitution activities is critical. CEC/EAD staff have conducted this study and documented the approach and results to provide a view of load impacts and possible consequences.[3]

Background

In the past four years, fuel substitution has entered the climate change policy discussion and building decarbonization has rapidly become a major topic. The following legislation either funds fuel substitution programs directly or mandates energy and/or environmental agencies study the issue and report back to the legislature.

Senate Bill 350

Senate Bill (SB) 350 (de León, Chapter 547, Statutes of 2015) initiated a discussion of fuel substitution through a provision of the energy efficiency doubling mandate. Fuel substitution measures meeting two specific criteria would be allowed to "count" toward the broad array of energy efficiency measures authorized to satisfy the 2029 doubling goal.[4] Since there was minimal experience with fuel substitution at that point in time, only a very limited assessment was included on the impacts from a future, greater share of new construction designed to

2 CEC/EAD staff presentation, *2019 IEPR* Workshop on Emerging Issues, September 26, 2019.
3 CEC/EAD staff presentation on electric generating implications of a pseudo-Assembly Bill 3232 scenario, scheduled for December 4, 2019.
4 SB 350 creates a goal of achieving by 2029 a double of projected electric and natural gas energy efficiency savings as reported in two specific studies. Numerous types of programs and energy efficiency activities can be used in estimating whether the doubling goal will be reached.

have electric space and water heating. A number of specific follow up study recommendations were included in the 2017 SB 350 report.[5]

Senate Bill 1477

SB 1477 (Stern, Chapter 378, Statutes of 2018) authorized the California Public Utilities Commission (CPUC) to expend $200 million over a four-year period to explore programmatic approaches to encourage fuel substitution. The CPUC and CEC are in the final stages of developing the BUILD and TECH programs that were directed by this legislation. This was the first explicit policy decision to promote fuel substitution with funding.

Assembly Bill 3232

Assembly Bill (AB) 3232 (Friedman, Chapter 373, Statutes of 2018) directed the CEC, in consultation with the CPUC and the California Independent System Operator (California ISO), to assess the cost effectiveness of alternative measures that would achieve a 40 percent reduction in 1990 greenhouse gas (GHG) emissions from residential and commercial buildings by 2030. Although this is a study bill, it clearly reflects legislative interest in an aggressive fuel substitution effort. However, the framework of GHG emission reductions, rather than fuel substitution, introduces the complex issues of GHG emissions from activities other than combustion of natural gas in appliances and commercial building processes.[6] The details of the AB 3232 study being designed by the CEC go beyond the scope of this exploratory study, but at a minimum suggest that an aggressive scenario comparable to AB 3232 should be evaluated.

Purpose

The purpose of this study is to develop a better understanding of the incremental electric load impacts resulting from fuel substitution in both annual energy and hourly loads dimensions for the major utility service areas in California. Testing alternative assumptions in a “what if” sense can help to reveal the relative importance of uncertain values, motivating deeper investigation of that variable. This is not a forecast of fuel substitution that is sufficiently accurate such that it should be included as a load modifier in creating managed demand forecasts used for procurement purposes. There are too many uncertainties for that application, although inclusion of some level of fuel substitution in officially adopted managed demand forecasts will undoubtedly happen in a future IEPR cycle.

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5 CEC, Final Commission Report: Senate Bill 350: Doubling Energy Efficiency Savings by 2030, November 2017, CEC-400-2017-010-CMF, October 2017, Chapter 7.

6 These include HFC refrigerants, uncombusted methane within the building, and possibly some portion of the leakage of natural gas in the entire chain of production, transmission and distribution to the end-use customer.

CHAPTER 2:
Framework for Assessment

CEC/EAD demand forecasts of natural gas in the residential and commercial building sectors are the starting point for examining incremental electric load impacts. This is conceptually different from focusing on reduction of GHG emissions or the related term of building decarbonization. The differences in electric load impacts between a fuel substitution perspective and a decarbonization perspective may be small because the means of mitigating the non-combustion sources of GHG emissions may cause little increased electric energy consumption.

Sources of Greenhouse Gas Emission in Buildings

At the time this study was designed, the 1990 California Air Resources Board (CARB) emission inventory was reviewed, and fuel combustion emissions were a significatly large share of total residential and commercial building GHG emissions. The level of GHG emissions from hydrofluorocarbons (HFC) refrigerants, uncombusted methane within the building, and some portion of the leakage of natural gas in the supply chain were small, missing or highly uncertain. As a product of the AB 3232 effort, and more careful review of CARB emission inventories, a different picture has emerged. GHG emissions from the three sources other than direct fuel combustion are much larger in recent years than in 1990. **Table 1** compares official CARB emission inventories for the residential and commercial sectors for years 1990, 2000 and 2017. A dramatic increase in HFC emissions can be observed. Leakage from appliances and equipment using compressor technologies is now 15 percent of the total inventory rather than the negligible percentage in 1990.

Table 1: Total Statewide GHG Emissions from the Residential and Commercial Sectors by Pollutant

Component	GHG Emissions (MM tonnes CO2e) 1990	GHG Emissions (MM tonnes CO2e) 2000	GHG Emissions (MM tonnes CO2e) 2017
NG Fuel Combustion	38.8	39.1	35.4
Other Fuel Combustion	5.3	2.8	3.4
HFCs	0	5.7	12.5
Fugitive	1	1.3	2.1
Beyond Meter Leaks	1.7	1.8	1.9
Total Res/Comm Bldgs	46.8	50.7	55.3

Source: California Energy Commission staff

Implications on Electricity Load of Non-Fuel Combustion Mitigation Measures

CEC/EAD staff conclude that non-fuel combustion GHG emission mitigation measures may have only limited impacts on electric load as summarized below.

- HFC emissions – Emissions come from leaking equipment using refrigerants with high global warming potential (GWP). Devising alternative refrigerants that have low or no GWP is underway and CARB may already be developing initial regulatory mechanisms to require use of these alternative refrigerants. There is no *a priori* belief that the electrical efficiency of compressor-driven equipment using such alternatives will perform differently from use of HFC refrigerants; thus electrical load impacts may be small.[7]
- Within Building Uncombusted Methane – These emissions are small and may largely be mitigated in parallel to fuel substitution measures.
- Natural Gas Supply Leakage – Although there is research underway about the size of these emissions, it is unclear how measures within a single building or even large groups of buildings affect these emissions. Leakage may be largely related to the physical properties of the production, transmission and distribution systems rather than the throughput through the system. Resolving distribution segment leakage may be impossible without rebuilding a distribution system or deactivating an entire portion by electrifying all gas uses in a neighborhood with a common distribution subsystem.

Thus, a simplified analytic framework that is limited to fuel combustion may not fully address the GHG emission reduction requirements of AB 3232 or the overall building decarbonization sentiments of some policy makers. There may be no material consequences of this simplified approach for understanding electrical load impacts.

Baseline Natural Gas Demand Forecast

The baseline natural gas forecast for the residential and commercial sectors is the starting point for estimating incremental electric load from displaced natural gas. The CEC staff *2017 IEPR* baseline gas demand forecast was used for this purpose.

Table 2 provides an overview of the 2017 natural gas demand forecast at the statewide level for residential and commercial building sector end-uses. The right column of Table 1 indicates that residential space and water heating are by far the largest components of this forecast at the statewide level. **Table 3** provides sector/end-use share information for year 2030 for each of the five major electric utility service areas. Although there is variation among the sector/end-use shares by utility, **Table 3** shows that space and water heating dominate in all areas of the state. Although these variations are not necessarily important from a GHG emission reduction or building decarbonization perspective, they may prove to be meaningful

7 University of California, Davis, Western Cooling Efficiency Center, *Performance Testing of R466A: A Low Global Warming Potential Alternative Refrigerant*, October 2019.

for estimating incremental electric load impacts on the utilities that will provide the electric energy to end-use customers.

Table 2: Statewide Baseline Natural Gas Demand Forecast for Residential and Commercial Sectors (MM Therms)

Area	Sector	End-Use	1990	2017	2020	2025	2030	2030%
State	Res	central AC	59.54	0.03	0.04	0.06	0.08	0.0%
State	Res	central space heating	2947.03	2993.32	3020.19	3093.71	3176.10	33.0%
State	Res	clothes drying	150.58	241.53	248.69	262.86	279.43	2.9%
State	Res	cooking	351.07	444.24	445.85	460.87	476.11	4.9%
State	Res	hot tub fuel	92.83	115.45	117.59	121.65	125.20	1.3%
State	Res	hot water clothes washing	540.51	746.06	757.96	793.84	827.51	8.6%
State	Res	hot water dishwashing	325.25	484.43	503.67	545.39	582.28	6.0%
State	Res	pool heating	123.21	129.47	129.26	130.51	131.72	1.4%
State	Res	water heating	1289.50	1585.33	1609.92	1680.83	1748.01	18.1%
State	Comm	Heating	726.91	827.17	826.34	811.26	784.83	8.1%
State	Comm	Cooling	84.83	104.64	107.62	111.76	114.99	1.2%
State	Comm	Water Heating	152.27	227.84	240.48	261.94	282.62	2.9%
State	Comm	Cooking	127.86	176.78	184.22	194.62	203.08	2.1%
State	Comm	Refrigeration	4.82	7.82	8.22	8.80	9.29	0.1%
State	Comm	Miscellaneous	506.64	755.01	790.23	843.90	892.95	9.3%
State	R/C	Total	7482.85	8839.11	8990.28	9321.99	9634.20	100.0%

Source: California Energy Commission staff.

Table 3: Sector/End-use Share of 2030 Natural Gas Consumption by Major Utility

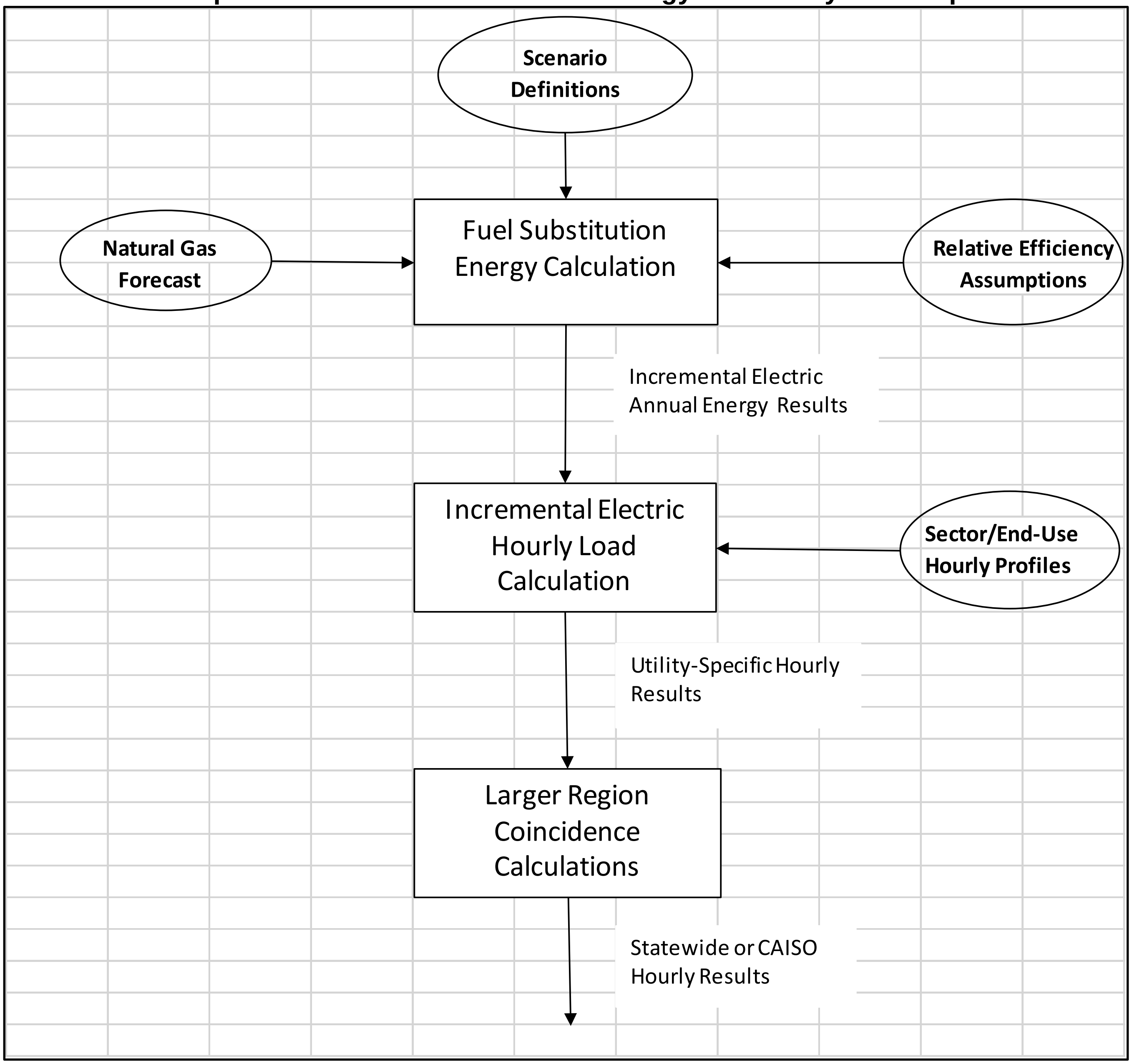
Sector	End-Use	PG&E	SMUD	SCE	LADWP	SDG&E
Res	central AC	0.0%	0.0%	0.0%	0.0%	0.0%
Res	central space heating	39.8%	36.2%	27.6%	35.4%	22.2%
Res	clothes drying	2.0%	1.8%	3.8%	3.3%	3.1%
Res	cooking	4.2%	3.3%	5.7%	5.9%	4.5%
Res	hot tub fuel	1.0%	1.0%	1.7%	0.6%	1.9%
Res	hot water clothes washing	8.6%	7.9%	8.5%	8.4%	9.7%
Res	hot water dishwashing	6.4%	5.7%	5.9%	5.2%	6.7%
Res	pool heating	1.3%	1.6%	1.6%	1.2%	0.6%
Res	water heating	17.5%	16.1%	18.1%	19.4%	20.7%
Comm	Heating	9.3%	13.3%	6.4%	5.3%	11.6%
Comm	Cooling	0.4%	0.2%	1.7%	1.4%	2.6%
Comm	Water Heating	2.5%	3.9%	3.0%	2.7%	3.8%
Comm	Cooking	1.4%	1.9%	2.7%	2.0%	2.6%
Comm	Refrigeration	0.0%	0.2%	0.1%	0.1%	0.0%
Comm	Miscellaneous	5.6%	6.7%	12.9%	9.0%	9.9%
R/C	Total	100.0%	100.0%	100.0%	100.0%	100.0%

Source: California Energy Commission staff.

Flow Chart of Overall Analytic Process

The methodology used to compute displaced natural gas consumption and incremental electric energy and hourly load impacts proceeds in a logical sequence of steps as depicted in **Figure 1**.

Figure 1: Flowchart of Analytic Process to Determine Displaced Natural Gas Consumption and Incremental Electric Energy and Hourly Load Impacts



Source: California Energy Commission staff.

CHAPTER 3:
Fuel Substitution Mechanisms and Barriers

Different mechanisms may be needed to influence fuel choice at the three points when such decisions are typically made - new construction, replacement on appliance failure (or "burnout"), and replacement of existing equipment prior to burnout.

New Construction

Influencing fuel choice at the time of new construction is a mechanism that removes many of the complications of end-user decision-making from the fuel choice process. Builders of residential dwellings and commercial spaces have their own processes for making fuel choices. The 2019 Title 24 Building Standards adopted by the CEC are widely known for the mandate on new solar rooftop equipment, but they also removed barriers that had existed for many years for the construction of all-electric housing. In addition, a growing number of municipalities are outlawing new natural gas hookups through local ordinances as a means to contribute to overall GHG emission reduction in combatting global climate change concerns.[8]

Replacing Equipment at Burnout

Since most residential natural gas use and much commercial building sector gas use is affected by mandatory energy efficiency standards, either by the federal government or state Title 20 regulations, revising standards is one mechanism that can influence choice of natural gas or electricity. However, replacement at burnout can be a fraught time to make fuel substitution decisions since the end-user is generally most interested in getting an appliance that restores heat to the home or hot water for household needs. The heating, ventilating and air conditioning (HVAC) and plumbing trades may need programmatic support to enable a quick and easy process that minimizes end-user discomfort.

Replacing Equipment Prior to Burnout

Replacing equipment prior to burnout is a means to reconcile end-user needs for continuity of service, since embarking on a major, planned change alters end-user service expectations. Whole house retrofit programs are an example of a homeowner making a deliberate choice from among a range of options knowing that some service discontinuity will occur and presumably scheduling occupancy around interruptions. Fuel substitution programs could be designed to reflect these practices.

8 Mears, Michelle. "More Cities in California Are Banning The Use Of Natural Gas." *California Globe*, November 18, 2019.

Fuel substitution efforts may eventually have to confront two electric capacity issues – the amperage and available circuit breaker slots needed for added electric load, and the capacity of the electric utility distribution circuit neded to handle additional electric load.

Inadequate Panel Box Capabilities

It is clear that in the residential sector, some proportion of residential end-use customers in dwellings with panel box amperage and/or unused circuit breaker slots simply cannot handle the added electric load from water heating and space heating, even if the added equipment are efficient heat pumps. Discussions with electric utility personnel confirm this suspicion, but data to quantify this barrier does not appear to exist.[10] Indeed it may well be a barrier to installation of electric appliances since costs of replacing panel boxes can easily reach $2,500 per dwelling, which is a cost on top of the new electric equipment itself. Similar issues are likely to exist for older commercial buildings constructed in a “strip mall” configuration in which each separate space has its own electric service. These small retail and office spaces frequently have rooftop packaged air conditioner and space heating units and are a likely candidate for conversion to heat pumps.

Distribution Equipment Limitations

Similarly, electric utilities have a wide range of distribution equipment deployed over decades and sized to the loads expected at the time of construction. Accommodating the increased electrical load from a single customer on a final distribution circuit may not be an issue, but if multiple customers electrify, then circuit inadequacies may become either an outright barrier or a societal cost issue that should be recognized. These issues are directly comparable to those encountered for battery electric vehicle (EV) home recharging. The combination of appliance fuel substitution and battery EV charging increases the proportion of distribution circuits that may need to be upgraded.

Timeframe for Deployment

All barriers are presumably overcome with sufficient funding, but experience now shows that massive electrical equipment upgrades can take a long time to implement. Creating premature deadlines can increase costs compared to a deployment schedule that recognizes both end-user and utility deployment issues.

10 Personal discussion with staff of Sacramento Municipal Utility District.

CHAPTER 4:
Fuel Substitution Scenarios

Keeping the possible deployment mechanisms and barriers in mind, CEC/EAD staff developed five scenarios that cover a range of alternative fuel substitution implementation mechanisms and end-user target populations. All scenarios begin having impacts in year 2020 and increase the size of the target population through time out to 2030. The scenarios are:

- 10 percent share for all-electric new construction by 2030
- 25 percent share for all-electric new construction by 2030
- 10 percent of Baseline Residential Natural Gas consumption is converted to electricity by 2030
- 25 percent of Baseline Residential Natural Gas consumption is converted to electricity by 2030
- A pseudo-AB 3232 scenario with baseline natural gas forecast reduced to 60 percent of 1990 levels in both the residential and commercial sectors by 2030

This section will describe each scenario and provide a brief description of its key features.

Scenario 1: 10 Percent Share of All Electric New Construction by 2030

Scenario 1 adopts the definition and generally matches the aggregate savings developed in the initial SB 350 analysis from the *2017 IEPR* cycle. A growing share of both residential and commercial new construction is assumed to be all electric. This scenario begins in 2020 and linearly ramps up to a 10 percent share of new construction by 2030. This affects four end-uses in the commercial building sector and five end-uses in the residential sector.

The aggregate savings comparable to the 2017 SB 350 analysis at the statewide level are simply allocated to end-uses as estimated in the Title 24 New Construction workbook developed by NORESCO.[11] These were then proportionally allocated to utility service area using historic shares of electric sales reported by utilities to the CEC.

Local governments adopting bans on new natural gas hookups is one mechanism by which new construction share may ramp up through time.

Scenario 2: 25 Percent Share of All-Electric New Construction by 2030

Scenario 2 is identical to Scenario 1 except the all-electric share reaches 25 percent of annual new construction by 2030. Essentially, the displaced natural gas and the incremental electric load are 2.5 times those from Scenario 1 impacts in every forecast year for each utility.

11 CEC, *Senate Bill 350: Doubling Energy Efficiency Savings by 2030*, CEC-400-2017-010-CMF, October 2017, Appendix B, pp. B-24 to B-27.

Scenario 3: 10 Percent Displacement of Baseline Residential Natural Gas Forecast by 2030

Scenario 3 draws upon the CEC/EAD Staff baseline natural gas demand forecast and assumes that a share of residential sector space and water heating natural gas consumption is displaced by electric appliances to obtain an incremental electric load impact. This displacement begins in 2030 and increases linearly to 10 percent by 2030.

Unlike Scenarios 1 and 2 that can be motivated by city local ordinances that ban new natural gas hookups, effectively requiring 100 percent electric appliances, this retrofit scenario is limited to space and water heating and the minor natural gas appliances are left unchanged. In a holistic assessment of building decarbonization, this scenario design could imply that some portion of upstream and downstream methane leakage would remain unchanged if the distribution line to the building remains pressurized.

Scenario 4: 25 Percent Displacement of Baseline Residential Natural Gas Forecast by 2030

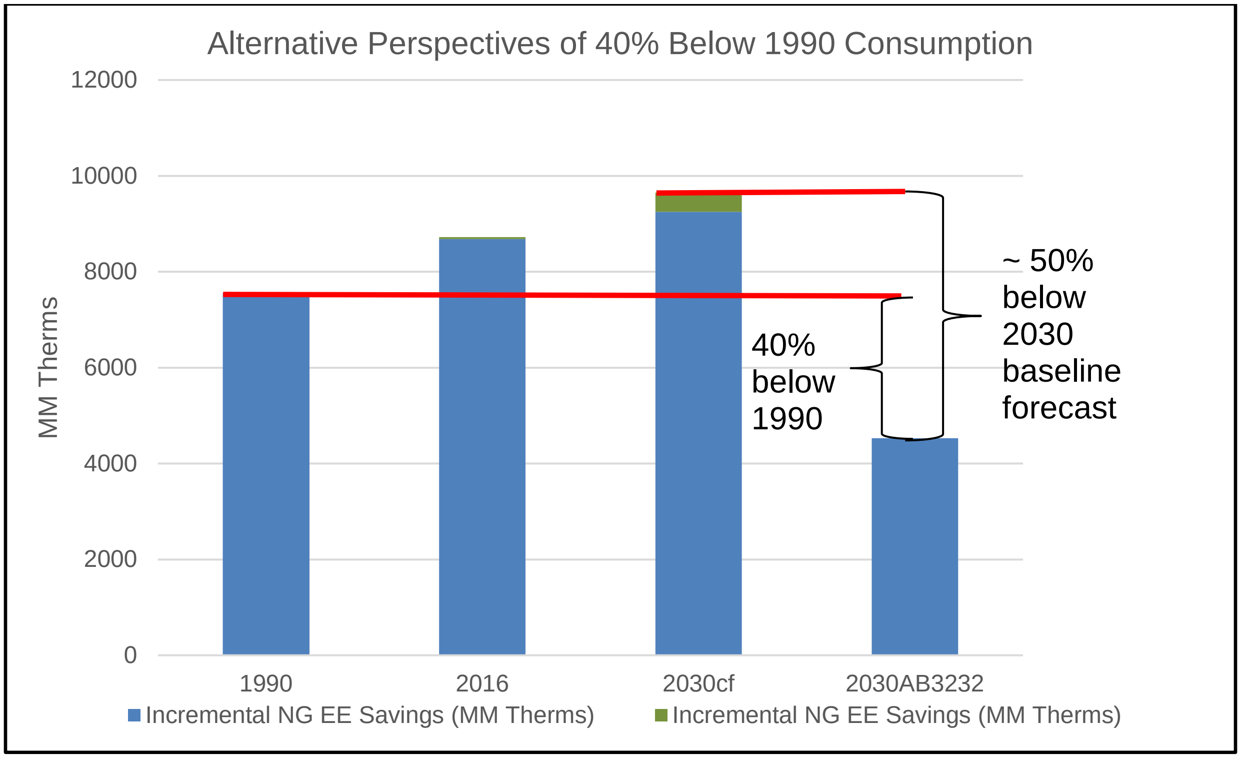
Scenario 4 is identical to Scenario 3 except it increases the 2030 displacement target from 10 percent to 25 percent. As was the relationship between Scenario 1 and Scenario 2, this scenario design implies that the impacts of displaced natural gas and incremental electric load are 2.5 times those from Scenario 3 in every forecast year for each utility.

Scenario 5: Pseudo Assembly Bill 3232 – Reduction of Natural Gas Forecast to 60 Percent of 1990 Levels by 2030

This scenario assumes that natural gas combustion in both the residential and commercial sectors is reduced to 60 percent of 1990 values by 2030. As in other scenarios, there is a linear ramp up toward this 60 percent goal starting in 2020. As **Table 1** showed, the CEC/EAD Staff baseline natural gas demand forecast shows aggregate natural gas consumption growth from 1990 to 2030, so the reduction from the 2030 baseline to satisfy the AB 3232 goal would be much larger than just a 40 percent reduction. The forecast of 2030 is uncertain for many reasons, including policy decisions not yet made about natural gas energy efficiency programs. **Figure 2** illustrates just one of many possible graphic displays of these two perspectives for the Pseudo AB 3232 scenario.

As discussed earlier, while natural gas combustion emissions are by far the largest component of contemporaneous GHG emissions in the residential and commercial sectors, the other GHG emission sources are a growing share. HFC emissions from compressor refrigerants are the principal example. However, to the extent that HFC emissions can be controlled by mitigation measures that do not create incremental electric load, a simple fuel substitution analysis may give as good an estimate of impacts on electric demand as a more complex decarbonization analysis. There are reasons to believe that some HFC emissions reduction can occur through use of new refrigerants, either in new appliance purchases or replacement of refrigerants in existing appliances, or both.

Figure 2: Illustration of Two Perspectives for Depicting the Implications of AB 3232



Source: California Energy Commission staff.

Estimating Incremental Electric Energy Demand from Displaced Natural Gas

Translating displaced natural gas energy to incremental electric energy requires an understanding of the efficiency of the appliances and equipment that are removed and added, respectively. Since this study uses aggregate natural gas energy at the sector/end-use level, rather than examining the distribution of natural gas equipment removed and the distribution of electric equipment installed, and average efficiency at the sector/end-use level is sufficient. Efficiency of both displaced and added equipment is important to developing a correct understanding of incremental electric energy, since the level of useful service to the end-use customer should be assumed to remain equal even though fuel substitution has occurred.

Incremental EE = Displaced NGE * (Average NG Eff/Average EE Eff)

Where:

Incremental EE = incremental electric energy added

Displaced NGE = displaced natural gas energy

Average NG Eff = average efficiency of displaced natural gas appliances/equipment

Average EE Eff = average efficiency of added electric appliances/equipment

The displaced natural gas energy at the sector/end-use level can be defined by the assumptions of a specific “what if” scenario, but the average efficiencies that should be assumed are less clear cut. As an example, there is a wide range of natural gas water heat efficiencies in the field as a result of successive rounds of appliance standards and utility incentive programs. In estimating fuel substitution impacts, it is necessary to be specific about the average efficiency of the appliances to be displaced, and this value is likely to be dependent upon a specific target population that is the focus of a scenario under investigation. One could hypothesize a strategy that selectively targeted low efficiency water heaters for replacement by electric heat pump water heaters of the same size and just satisfied current heat pump appliance efficiency standards. Alternatively, one could hypothesize a strategy of inducing all-electric new construction, which for water heaters would contrast minimum current efficiency of natural gas water heaters against minimum efficiency heat pump water heaters. A therm of displaced natural gas used for water heating might result in a much different number of kilowatt hour (kWh) of electric energy between these two cases. Specific assumptions across sectors/end-uses can vary widely and must be linked to scenarios that imagine some kind of market and/or programmatic delivery mechanism to achieve fuel substitution.

Table 4 provides an illustration of the implications of two alternative sets of average end-use efficiency assumptions. The original average end-use efficiencies were used in most of the analyses of this exploratory study. A more in-depth analysis of individual technologies within end-use categories provided an alternative set.[12] The purpose of using this alternative set of assumed end-use efficiencies is to understand the variation in incremental annual electric load that results from displaced natural gas assuming that the level of energy service is common before and after.

Table 4: Alternative Residential Sector Average End-use Efficiency Assumptions

Sector	End-use	Original Assumptions NG Eff	Original Assumptions Elec Eff	Revised Assumptions NG Eff	Revised Assumptions Elec Eff
Res	Space Heat	0.8	3	0.74	3.631
Res	Water Heat	0.8	3	0.6875	3.119
Res	Clothes Dryer	0.8	3	0.8	2.5
Res	Cooking	0.8	3	0.375	0.82
Res	Pool/Spa	0.8	3	0.8	3

Source: California Energy Commission staff.

Table 5 summarizes the impact of **Table 4**'s alternative assumptions for Scenario 5: Pseudo AB 3232 in year 2030 for the Southern California Edison (SCE) service area. For both original and revised average end-use efficiency assumptions, the amount of natural gas displaced is the same. Multiplying this displaced volume of natural gas converts consumption in the

12 The original assumptions were created by NORESCO, SB 350 Energy Savings Potential Non-Utility Program Technical Assessment Program Data Workbook, as part of the initial analysis of all electric new construction as part of the *2017 IEPR* version of SB 350. Revised assumptions are drawn from preliminary results of the CEC-funded project of Navigant Consulting concerning fuel substitution analyses.

amount of useful service. Dividing this level of service by average electric end-use efficiency determines the incremental electric energy added. Using the revised efficiency assumptions results in incremental electric load increases for some end-uses, but for most end-uses energy impacts decrease, as does the sum across all end-uses.

Table 5: Impact of Alternative Residential Energy Efficiency Assumptions Using Scenario 5: Pseudo AB 3232 for the SCE Service Area in Year 2030

Sector	End-use	Natural Gas Displaced (MM Therms)	Original Electric Energy Added (GWh)	Revised Electric Energy Added (GWh)
Res	Space Heat	413.0	3227.0	2466.3
Res	Water Heat	375.8	2936.4	2427.2
Res	Clothes Dryer	88.4	690.9	829.1
Res	Cooking	107.0	836.4	1434.5
Res	Pool/Spa	50.0	390.5	390.5
Res	Total	1034.2	8081.3	7547.5

Source: California Energy Commission staff.

CHAPTER 5: Fuel Substitution Scenario Energy Results

The five scenarios defined in the previous section were assessed using a Microsoft Excel workbook that implements the displacement of natural gas by electric service area to compute incremental electric energy. Since the goal of this study was to understand electric load impacts, it is critical that the geographic unit of analysis be the electric utility service area.[13] CEC demand forecasting models have been designed around electric utility service areas and forecast zones within these service areas since the inception of Staff demand forecasting analyses. The baseline natural gas demand forecasts by electric service area are provided in Appendix A. Note that these are not adjusted for natural gas additional achievable energy efficiency savings.

Tables 6a through Table 6e summarizes the results for each electric utility service area for the 2030 end-date and also for 2025 – an intermediate date that shows progress toward the end-date. **Table 6f** reports statewide set of results, but this is the sum of the five major utilities, and omits a number of smaller utilities that are outside of the five largest. Appendix B provides the annual results from 2020 through 2030 by utility.

The aggregate results of natural gas displaced and incremental electric energy added increase from Scenario 1 through Scenario 5. These results should not be surprising. Scenarios limited to new construction should not be expected to have as great an impact as those retrofitting substantial portions of the entire building stock. Scenario 5 is displacing residential sector natural gas more deeply than does scenario 4, and to that adds a major displacement in the commercial building sector. The result is that the impacts of Scenario 5 are roughly three times greater than in those for Scenario 4.

The majority of the statewide impacts occur in the Pacific Gas and Electric (PG&E) and SCE service areas since the geographic and demographic scopes of these two utilities are much larger than the other three smaller utilities omitted from this study. SCE's natural gas demand is slightly larger than PG&E's, which translates into a slightly larger incremental electric load.

Finally, it is important to recall that the scenarios are simply "what if" assumptions quantified in a rigorous manner. These are not predictions that any one scenario will occur.[14]

13 Impacts for a natural gas utility service area can be approximated by adding electric service areas. PG&E electric and SMUD form PG&E natural gas service area, and correspondingly the sum of the SCE and Los Angeles Department Water and Power electric service areas approximate the Southern California Gas service area.
14 For this reason, the impacts of these specific fuel substitution scenarios are not included in any baseline or managed demand forecast scenarios proposed for adoption by the CEC. These results are intended to inform a discussion about key elements of fuel substitution assessments so that when policy makers determine a firm course of action for fuel substitution activities, CEC and other stakeholder will be capable of addressing load impacts.

Table 6a: Scenario Results for Selected Years for PG&E by Scenario

#	Scenario Name	Utility	2025 Load Increase (GWh)	2030 Load Increase (GWh)	2025 Load Reduction (MM therms)	2030 Load Reduction (MM therms)
1	SB350REF	PG&E	99.90	329.03	12.79	42.11
2	SB350AGG	PG&E	249.75	822.57	31.96	105.27
3	Res Retrofit 10% by 2030	PG&E	857.15	1633.34	109.70	209.04
4	Res Retrofit 25% by 2030	PG&E	2141.79	4083.35	274.11	522.59
5	Res/Comm 40% below 1990 levels by 2030	PG&E	6586.86	12462.94	842.99	1595.01

Source: California Energy Commission staff.

Table 6b: Scenario Results for Selected Years for SCE by Scenario

#	Scenario Name	Utility	2025 Load Increase (GWh)	2030 Load Increase (GWh)	2025 Load Reduction (MM therms)	2030 Load Reduction (MM therms)
1	SB350REF	SCE	102.34	337.08	13.10	43.14
2	SB350AGG	SCE	255.86	842.69	32.75	107.85
3	Res Retrofit 10% by 2030	SCE	687.69	1286.56	88.01	164.65
4	Res Retrofit 25% by 2030	SCE	1718.38	3216.39	219.92	411.64
5	Res/Comm 40% below 1990 levels by 2030	SCE	6932.89	13084.86	887.28	1674.61

Source: California Energy Commission staff.

Table 6c: Scenario Results for Selected Years for SDG&E by Scenario

#	Scenario Name	Utility	2025 Load Increase (GWh)	2030 Load Increase (GWh)	2025 Load Reduction (MM therms)	2030 Load Reduction (MM therms)
1	SB350REF	SDG&E	22.96	75.62	2.94	9.68
2	SB350AGG	SDG&E	57.40	189.04	7.35	24.19
3	Res Retrofit 10% by 2030	SDG&E	142.72	271.67	18.26	34.77
4	Res Retrofit 25% by 2030	SDG&E	356.61	679.17	45.64	86.92
5	Res/Comm 40% below 1990 levels by 2030	SDG&E	1622.84	3081.14	207.69	394.33

Source: California Energy Commission staff.

Table 6d: Scenario Results for Selected Years for SMUD by Scenario

#	Scenario Name	Utility	2025 Load Increase (GWh)	2030 Load Increase (GWh)	2025 Load Reduction (MM therms)	2030 Load Reduction (MM therms)
1	SB350REF	SMUD	12.56	41.36	1.61	5.29
2	SB350AGG	SMUD	31.40	103.41	4.02	13.23
3	Res Retrofit 10% by 2030	SMUD	91.41	176.00	11.70	22.52
4	Res Retrofit 25% by 2030	SMUD	228.41	440.00	29.23	56.31
5	Res/Comm 40% below 1990 levels by 2030	SMUD	793.56	1505.93	102.90	195.69

Source: California Energy Commission staff.

Table 6e: Scenario Results for Selected Years for LADWP by Scenario

#	Scenario Name	Utility	2025 Load Increase (GWh)	2030 Load Increase (GWh)	2025 Load Reduction (MM therms)	2030 Load Reduction (MM therms)
1	SB350REF	LADWP	28.14	92.68	3.60	11.86
2	SB350AGG	LADWP	70.35	231.71	9.00	29.65
3	Res Retrofit 10% by 2030	LADWP	233.02	434.79	29.82	55.64
4	Res Retrofit 25% by 2030	LADWP	582.26	1086.96	74.52	139.11
5	Res/Comm 40% below 1990 levels by 2030	LADWP	1596.20	2996.20	204.08	383.46

Source: California Energy Commission staff.

Table 6f: Scenario Results for Selected Years "Statewide" by Scenario

#	Scenario Name	Utility	2025 Load Increase (GWh)	2030 Load Increase (GWh)	2025 Load Reduction (MM therms)	2030 Load Reduction (MM therms)
1	SB350REF	"State"	265.90	875.77	34.03	112.08
2	SB350AGG	"State"	664.76	2189.42	85.08	280.20
3	Res Retrofit 10% by 2030	"State"	2011.98	3802.35	257.50	486.63
4	Res Retrofit 25% by 2030	"State"	5027.45	9505.87	643.42	1216.57
5	Res/Comm 40% below 1990 levels by 2030	"State"	17532.34	33131.08	2244.94	4243.09

Source: California Energy Commission staff.

CHAPTER 6: Hourly Electric Load Impacts

To develop hourly load impacts from the annual incremental electric energy requires load profiles corresponding to the nature of the load increases. Staff researched various sources of load profiles from several sources and tested their impacts in a series of steps. Ultimately, a composite of load profiles developed by ADM Associates and Navigant Consulting was used to generate the final hourly results for the five scenarios.

Load Profile Development

Assembling hourly load profiles was a challenge from the outset since the need is for good load profiles of electric space and water heating, but since there is relatively little use of electricity for these end-uses in California load profiles are scarce. In addition, many buildings with electric space heat installed actually use wood as the primary fuel. Load profiles developed with such buildings in the sample would not accurately reflect future electric space hear installations. Other residential sector and many commercial building end-uses could be used directly from conventional hourly load impact studies. As this study progressed, several sources of energy load data were discovered, tested, and replaced by potentially more accurate sources. Although initial sources were unsatisfactory, they did result in the overall conclusion that residential space and water heating were the most important in making overall hourly projections.

Sources

Navigant Consulting conducted a fuel substitution project for Southern California Gas Company (SoCalGas) that clearly utilized load profiles.[15] In its initial version of this hourly model tool, CEC/EAD staff acquired these load profiles from Navigant Consulting and used them along with other end-use profiles already in use in the CEC's hourly Additional Achievable Energy Efficiency tool.[16]

Since the Navigant Consulting study for SoCalGas addressed only a single service area, the load profiles available from Navigant Consulting only included a single Southern California space heating load profile. Seeking a more geographically distributed source of residential space heating load profiles, CEC/EAD staff acquired residential space heating load profiles from OpenEI that were developed using a building simulation tool for a single residential structure employing historic weather records for numerous weather stations around the country.[17] This source had sufficient geographic variation, but no single residential structure

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15 Navigant Consulting, Inc., *Analysis of the Role of Gas for a Low-Carbon California Future*, prepared for SoCalGas, July 2018.
16 Navigant Consulting, Inc., *Investor Owned Utilities 2017 Additional Achievable Energy Efficiency Savings Methodology Documentation*, prepared for California Public Utilities Commission, January 2018.
17 OpenEI.

could reflect the large diversity in residential building sizes, vintages, thermal integrity, and occupancy patterns.

Fortuitously, the CEC/EAD was developing an 8760 hourly version of the HELM peak day hourly model through a contract with ADM Associates. As part of this large project, ADM was developing a wide range of residential and commercial building end-use load profiles that would enable the CEC/EAD to develop an 8760 hourly demand forecast. Although the model development portion of the project was not complete at the time of this study, the load profiles work was nearly finalized. These hourly profiles were acquired and processed.[18]

An important insight gained from serially using these three sources is the link between weather and hourly profiles. Each of the three sources of residential space heating hourly profiles gives different hourly results for the same incremental space heating annual energy. CEC/EAD staff believe this stems from the geographic granularity of the study design and the specific weather data that was used to create the hourly profile. Many building simulation projects are interested in assessing the energy savings of a specific efficiency measure or building practice, and some kind of typical or average weather is assumed to be the best choice. For these studies if the annual heating degree days or cooling degree days match annual averages then the day to day details of how the weather data set was constructed are of little or no interest.

As an illustration of the variability of results from the three load profile sources, **Table 7** summarizes the date that the space heating hourly profile from each source produced a space heating maximum. Naturally, versions of the tool with no geographic variation all result in common peak load dates, while even studies with geographic weather variation have different dates depending upon numerous details of the building simulation tool, the building structure model, and the weather data used. Such variations may have little or no energy consequences, but may have crucial consequences for coincidence of load for the California ISO or even at the statewide level.

Table 7: Variation in Incremental Maximum Load Date by Load Profile Source for Scenario 5: Pseudo AB 3232 in Year 2030

Tool Version/Profile Source	**PG&E**	**SCE**	**SDG&E**	**California ISO**
Ver9C – SoCalGas Study (E3 profiles)	11/23	11/23	11/23	11/23
Ver9D – Ver9C with residential space heat replaced by openEI profiles by zone weighted to utility service area	12/21	12/20	3/15	12/20
Ver10 – ADM profiles with zonal profiles weighted to utility service area	12/1	1/28	11/26	1/23

Source: California Energy Commission staff.

18 CEC, *California Investor Owned Utility Electricity Load Shapes*, ADM Associates, 2019.

Although the HELM 2.0 project undertaken by ADM Associates was the final source of hourly profiles, the ADM profiles were more disaggregated than the granularity of this exploratory study. Several methods were used to either select from among more disaggregate profiles or to process multiple profiles into a weighted average. Principal examples include:

- ADM provided residential profiles disaggregated by single family and multi-family. Single family values were used for all residential profiles since aggregate single family consumption is much larger than aggregate multi-family consumption.
- ADM provided profiles by commercial building type and end-use. For this study, a composite commercial sector profile was constructed for each end-use by weighting together all building type-specific hourly profiles using electric energy projections by building type for that end-use by electric utility service area.
- Since no utility service area was a direct product of the ADM project, larger utility service area load profiles were constructed by weighting together zonal values prepared by ADM.

Table 8 summarizes the selection and/or preprocessing that was used to match the ADM profiles with the level of utility, sector and end-use used in this exploratory study.

Table 8: Source of Final Load Profiles by Sector and End-use

Sector	End-Use	Utility	ADM Hourly Profile	Pre-Processing
Res	Space Heat	PG&E	PG&E SF Heating	zonal profiles weighted to utility
Res	Space Heat	SCE	SCE SF Heating	zonal profiles weighted to utility
Res	Space Heat	SDG&E	SDG&E SF Heating	None
Res	Space Heat	LADWP	LADWP SF Heating	zonal profiles weighted to utility
Res	Space Heat	SMUD	SMUD SF Heating	None
Res	Water Heat	All	Zone 1 SF Water Heating	None
Res	Clothes Dryer	All	Zone 1 SF Clothes Dryer	None
Res	Cooking	All	Zone 1 SF Cooking	None
Res	Pool/Spa	All	Zone 1 SF Spa Heater	None
Com	CoolVent	PG&E, SMUD	PG&E.Cooling	See Note 1
Com	CoolVent	SCE, LADWP	SCE.Cooling	See Note 1
Com	CoolVent	SDG&E	SDG&E.Cooling	See Note 2
Com	Space Heat	PG&E, SMUD	PG&E.Heating	See Note 1
Com	Space Heat	SCE, LADWP	SCE.Heating	See Note 1
Com	Space Heat	SDG&E	SDG&E.Heating	See Note 2
Com	Cooking	PG&E, SMUD	PG&E.Cooking	See Note 1

Sector	End-Use	Utility	ADM Hourly Profile	Pre-Processing
Com	Cooking	SCE, LADWP	SCE.Cooking	See Note 1
Com	Cooking	SDG&E	SDG&E.Cooking	See Note 2
Com	Miscellaneous	PG&E, SMUD	PG&E.Miscellaneous	See Note 1
Com	Miscellaneous	SCE, LADWP	SCE.Miscellaneous	See Note 1
Com	Miscellaneous	SDG&E	SDG&E.Miscellaneous	See Note 2
Com	ComRefrig	PG&E, SMUD	PG&E.Refrigeration	See Note 1
Com	ComRefrig	SCE, LADWP	SCE.Refrigeration	See Note 1
Com	ComRefrig	SDG&E	SDG&E.Refrigeration	See Note 2
Com	WaterHeat	PG&E, SMUD	PG&E.Water.Heating	See Note 1
Com	WaterHeat	SCE, LADWP	SCE.Water.Heating	See Note 1
Com	WaterHeat	SDG&E	SDG&E.Water.Heating	See Note 2

Source: California Energy Commission staff.

Note 1: Composite sector constructed by weighting building type profiles by electric energy; PG&E profiles used for SMUD, and SCE profiles used for LADWP.

Note 2: Composite sector constructed by weighting building type profiles by electric energy.

Hourly Load Results

As in any analysis generating hourly results, the amount of data to be considered is voluminous. Various selected results are all that can be presented in a report itself. Nonetheless, this section will provide an overall assessment using Scenario 5 – the Pseudo AB 3232 scenario. This scenario has the largest energy impact and thus is expected to have the largest hourly impacts. The full results can only be assessed by using the hourly results.[19]

Maximum and Minimum Load Increases

Table 9a provides 2030 maximum and minimum load increases for Scenario 5: Pseudo AB 3232 by each of the five electric utility service areas. By 2030 the full scale of the natural gas displacement and incremental electric energy has been achieved, so the corresponding electric load impacts are also at their maximum. The maximum load impacts are roughly consistent with the annual electric load increases reported in Appendix B, but there are differences because the mix of end-uses differs across the utilities.

Since the space heating load profiles are a composite of distinct climate zones weighted together, the space heating profiles are unique to each utility service area and the results show maximum load increases at different dates across the winter season. There is less

19 See several Excel workbooks posted along with this report.

variation in the time interval of the minimum load increases, which are all clustered from mid-May to mid-June.

Table 9a: Maximum and Minimum Electric Load Increases in 2030 for Scenario 5: Pseudo AB 3232

Values	PGE	SCE	SDG&E	SMUD	LADWP
maximum hourly value (MW)	6723	5526	1783	847	1799
minimum hourly value (MW)	294	448	99	38	82
maximum date	12/1/2030	1/28/2030	11/26/2030	12/24/2030	12/9/2030
minimum date	6/21/2030	5/15/2030	6/1/2030	5/31/2030	5/15/2030

Source: California Energy Commission staff.

Table 9b reports similar information for the three utilities within the California ISO service area, but adds additional information about the coincident California ISO maximum and minimum values and the coincidence factor of the California ISO maximum/minimum compared to the sum of the individual utility values. As might be guessed from the disparity of maximum load dates, the maximum California ISO coincident load is about 12 percent lower than the sum of the individual utility maximums. The coincidence of the minimum load is nearly one, and this can be traced to the dependence of these results on water heating and commercial sector loads, which in the summer period will have little, if any, weather-induced space heating impacts.

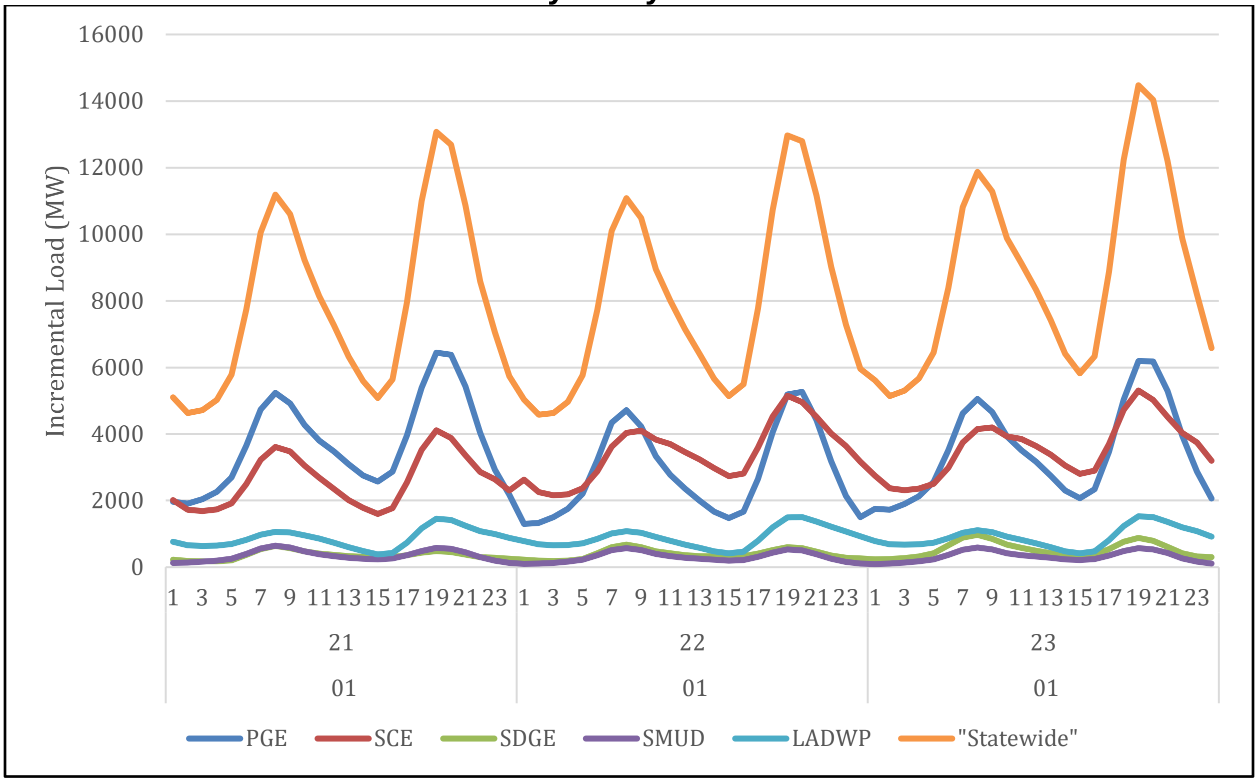
Figure 3 provides a graphical representation of the hourly loads for each utility and the statewide coincident sum of the five major utilities for the three-day period leading up to the maximum load hour. There is an apparent bimodal shape with the maximum load occurring about hour 20 with a strong secondary maximum about hour 9. The 1/23/2030 statewide maximum load day clearly reflects the shapes of the PG&E and SCE, whose size and impacts are much larger than any of the three other utility service areas.

Table 9b: Coincidence of Maximum and Minimum Impacts for the California ISO

Values Utility	Utility Service Area PG&E	Utility Service Area SCE	Utility Service Area SDG&E	Coincident CAISO	Non-Coincident CAISO	Coincidence Factor CAISO
maximum hourly value (MW)	6723	5526	1783	12374	14033	0.882
minimum hourly value (MW)	294	448	99	849	841	1.010
maximum date	12/1/2030	1/28/2030	11/26/2030	1/23/2030	NA	NA
minimum date	6/21/2030	5/15/2030	6/1/2030	6/22/2030	NA	NA

Source: California Energy Commission staff.

Figure 3: Hourly Shape of the Maximum Load Period in 2030 for Scenario 5: Pseudo AB 3232 by Utility Service Area



Source: California Energy Commission staff.

Although winter season space heating loads clearly cause the annual maximum, there are non-trivial impacts in the summer period because of sizeable water heating loads and loads across the commercial building sector. **Table 10** reports summer period (June 1 through September 30) results for each of the three utilities in the California ISO balancing authority area, the California ISO coincident peak, and the coincidence factor for this variable. Interestingly, all three utilities peak on the same day and same hour, leading to a coincidence factor of 1.00.[20]

20 Although this is an accurate reporting of the results of the study, the design of the study does not address incremental air conditioning loads created by the installation of heat pumps that might create or increase levels of air conditioning service that would have been forecast in the absence of a major fuel substitution effort. If this study limitation was removed, then higher summer peak loads and greater diversity among utilities could be expected as is characteristic of the CEC/EAD peak demand forecast.

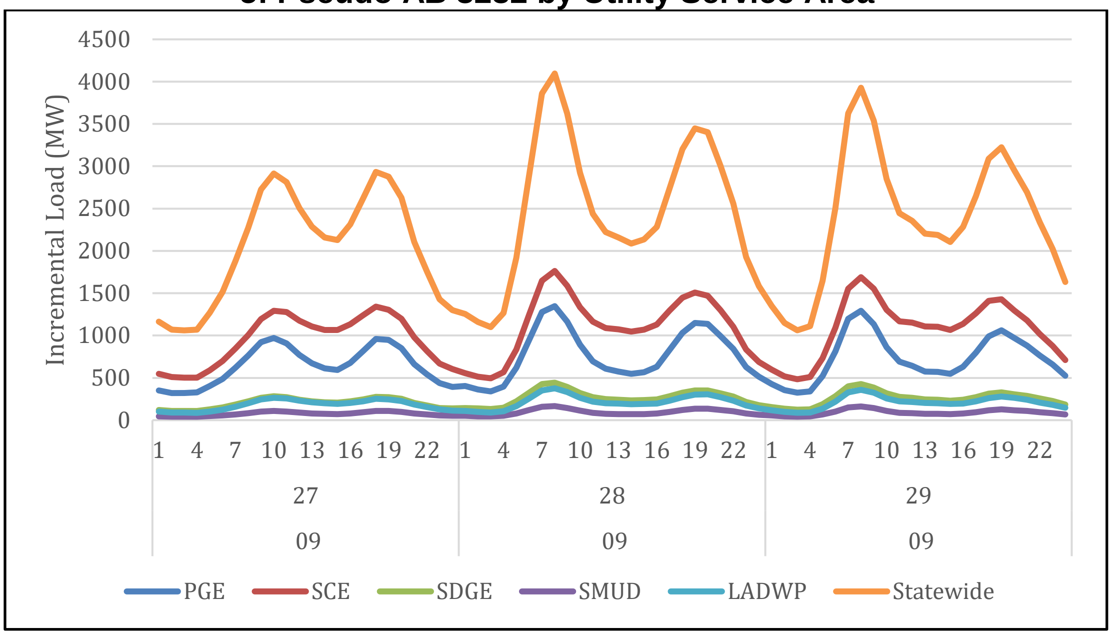
Table 10: Maximum Load Increases in the Summer Period in 2030 for Scenario 5: Pseudo AB 3232 by Utility

Values Utility	Utility Service Area PG&E	Utility Service Area SCE	Utility Service Area SDG&E	Coincident CAISO	Non-Coincident CAISO	Coincidence Factor CAISO
maximum summer value (MW)	1347	1763	443	3554	3554	1.000
maximum summer date (6/1 to 9/30)	9/28/2030	9/28/2030	9/28/2030	9/28/2030	NA	NA

Source: California Energy Commission staff.

Figure 4 depicts the summers for the maximum load increase day during the summer period.

Figure 4: Hourly Shape of the Maximum Summer Peak Load Period in 2030 for Scenario 5: Pseudo AB 3232 by Utility Service Area



Source: California Energy Commission staff.

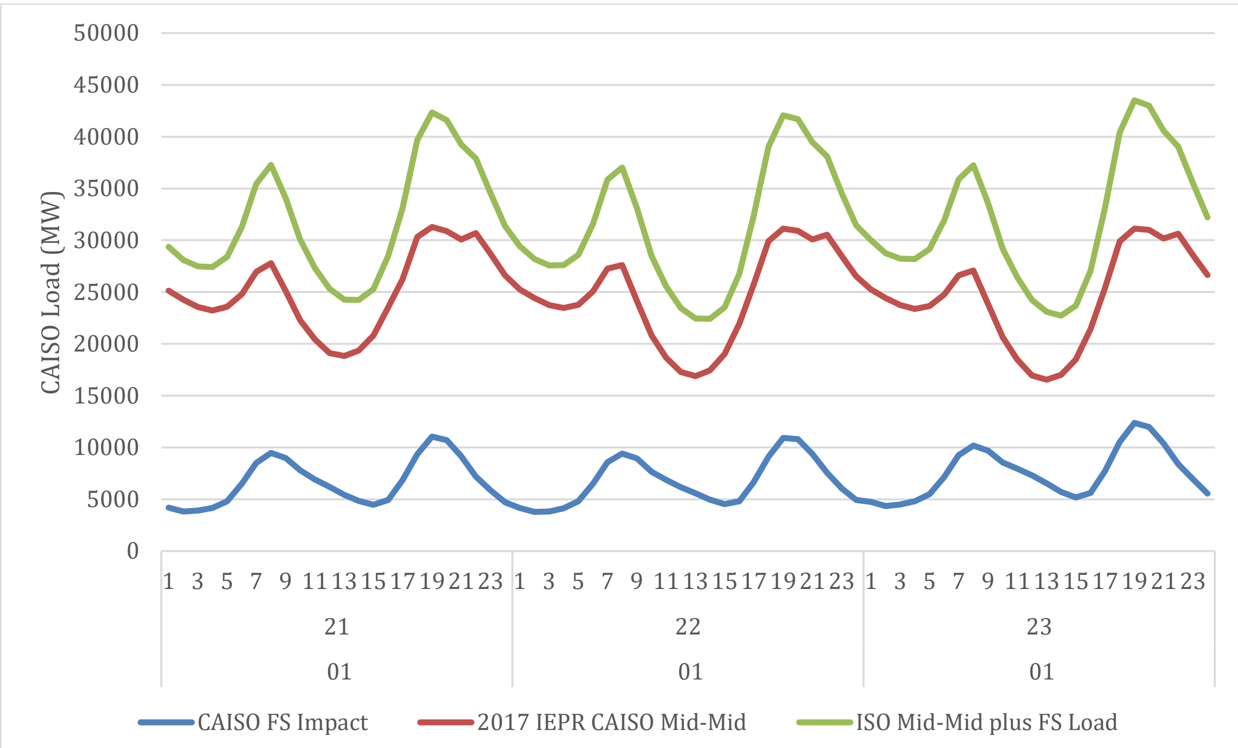
Significance of Fuel Substitution Load Impacts

Although these results seem large, they need to be placed in the context of the managed peak demand forecasts developed by CEC/EAD staff, adopted by the CEC, and used in various planning and procurement-related activities of the CPUC and California ISO. **Figure 5** depicts the three-day period in January that is the California ISO coincident maximum fuel substitution impact from Scenario 5: Pseudo AB 3232 on the *2017 IEPR* Mid-Mid managed hourly load for 2030. Several observations contextualize these loads:

- The underlying bimodal pattern for the base managed hourly forecast is exacerbated by the incremental fuel substitution impacts, which largely reinforce the prior pattern.
- The peak load of 43,510MW within this 72-hour period is nearing the prior Mid-Mid annual peak load of 45,910MW, suggesting that only a moderate amount more incremental load from fuel substitution activities would result in the California ISO being winter peaking.
- The ramping requirements from trough to peak shown in **Figure 5**, if unaltered by any demand response efforts, would exacerbate operating issues for the California ISO, especially since the capacity of the flexible natural gas-fired fleet is expected to decline through time as SB 100 requirements increase renewables and shift the mix of the generating fleet.

These observations indicate that the scale of incremental load increase is significant and requires an in depth assessment of the generating system implications.

Figure 5: Impact on California ISO *2017 IEPR* Mid-Mid Managed Load Forecast of Scenario 5: Pseudo AB3232 Incremental Loads in Year 2030



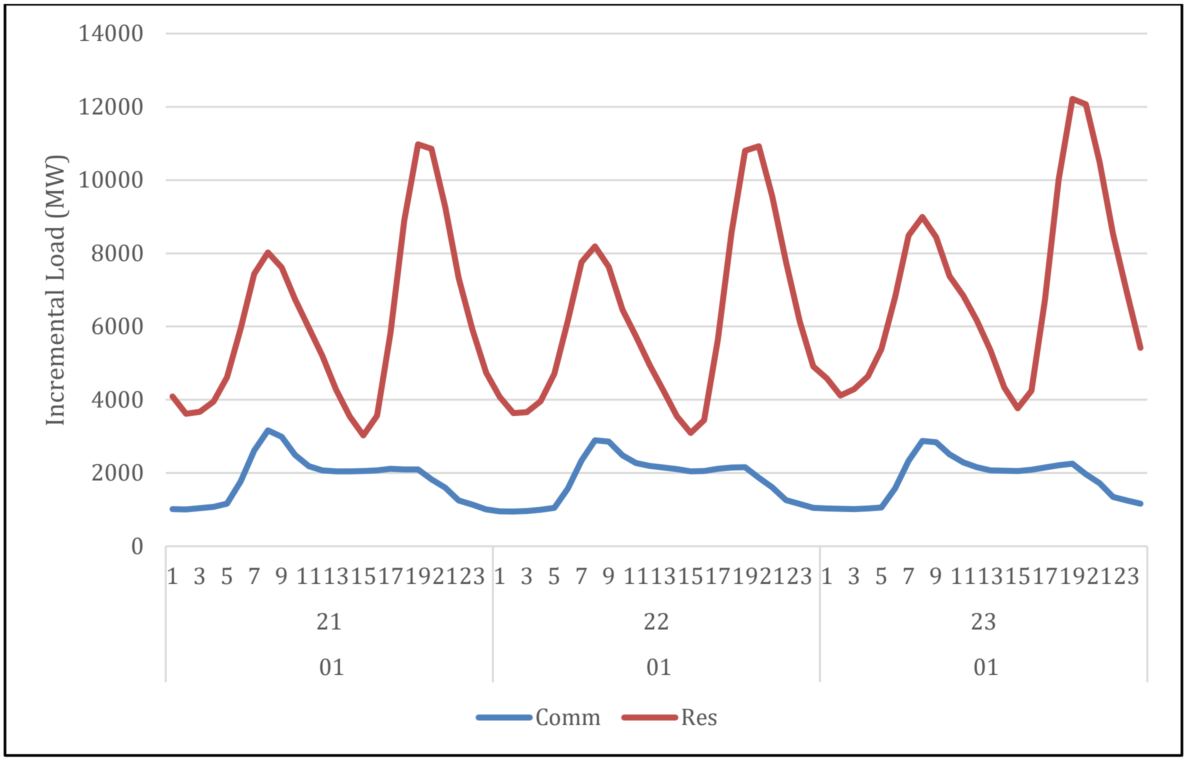
Source: California Energy Commission staff.

Mix of Sectoral Loads Creating Incremental Load Impacts

The relative importance of customer sectors and end-uses within sectors is an important element of this analysis. **Table 3** showed that natural gas consumption is not uniformly distributed across sectors and end-uses, and **Table 4** and **Table 5** showed that average efficiencies can differ substantially among end-uses within a sector with highly specific incremental annual electric energy consequences. **Figure 6** and **Figure 7** report the sectoral contributions to aggregate electric load hourly results for the winter maximum and summer maximum events, respectively.

Figure 6 shows how total load breaks down by customer sector for the sum of coincident hourly loads for the annual maximum incremental electric load time period. Residential load is shown to be much larger and more bimodal than commercial sector load during the winter season. The commercial sector load spikes about 0900, which is about the same hour as the secondary residential peak; when these loads are summed together, the overall secondary peak is closer in size than the primary peak each day.

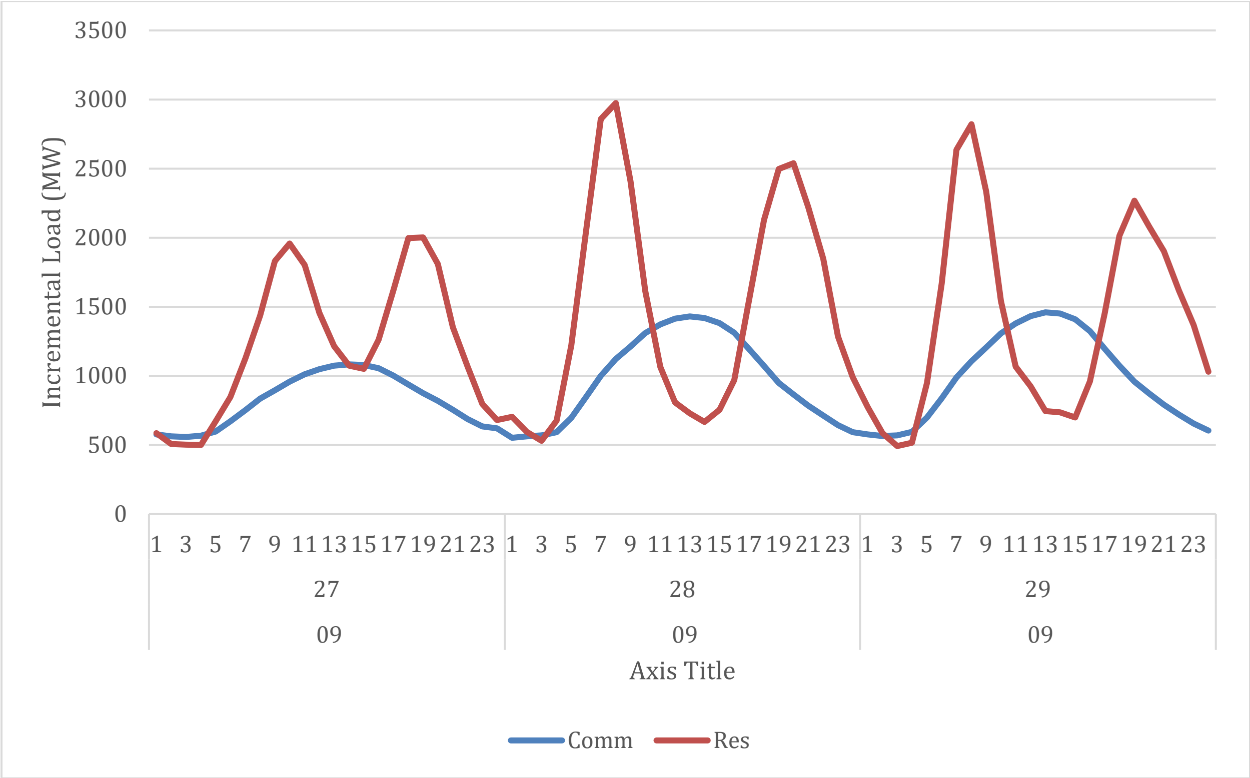
Figure 6: Winter Maximum Load Increase for Scenario 5: Pseudo AB 3232 by Customer Sector for the "State"



Source: California Energy Commission staff.

Figure 7 reports the customer sector contribution to the summer maximum incremental load event. Unlike the winter maximum, this summer maximum shows that the residential and commercial sectors are very non-coincident. The commercial sector peaks at the mid-day trough of the residential sector. This pattern results in a smoothing of the combined effect.

Figure 7: Summer Maximum Load Increase for Scenario 5: Pseudo AB 3232 by Customer Sector for the "State"

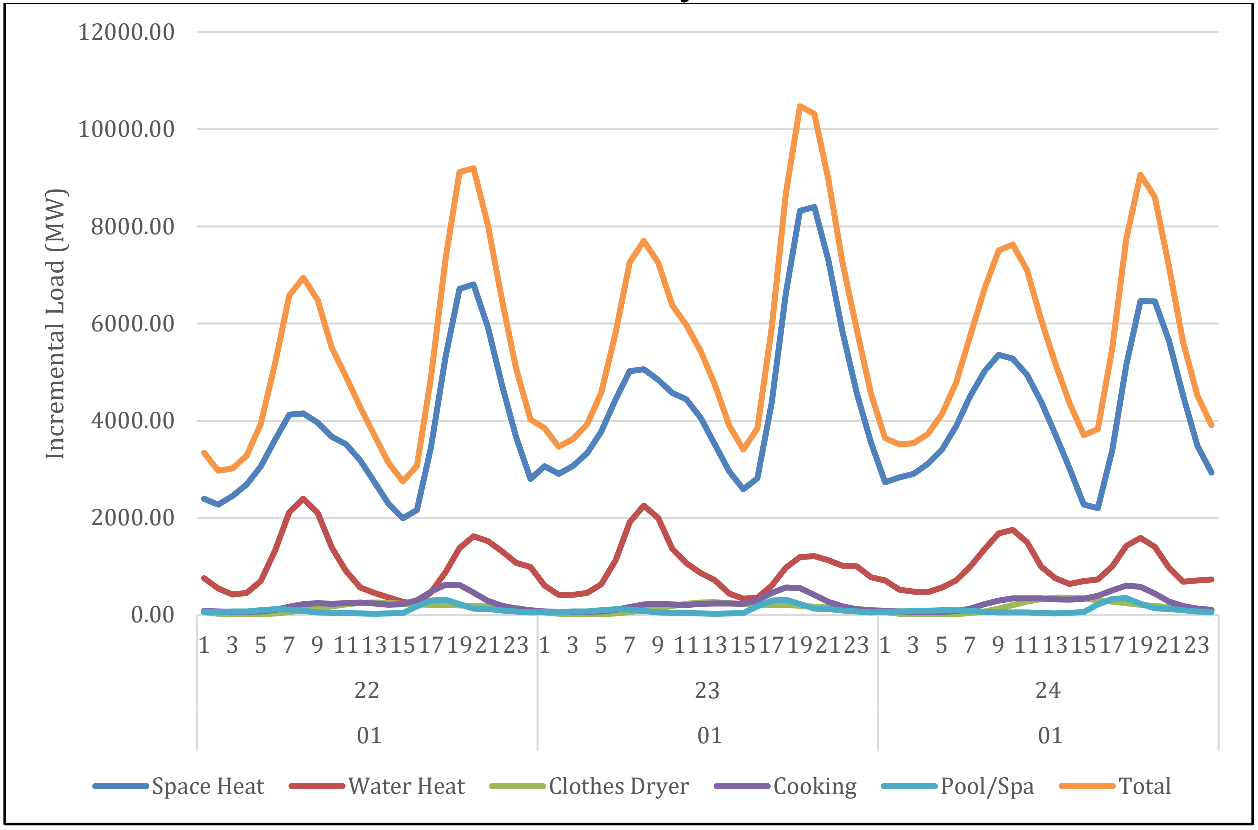


Source: California Energy Commission staff.

Residential Sector End-Use Incremental Load

Finally, the end-use composition of residential load provides an initial indication of relative importance and thus a focus for improving incremental annual energy estimates and hourly load profiles. **Figure 8** provides a coincident composite of the five residential end-uses for the three investor-owned utilities (IOUs) within the California ISO balancing authority area for a three-day event with the maximum incremental load. Clearly, the space heating and water heating end-uses dominate the three other end-uses. For these three days, the bimodal space heating results has its own peak hour in the evening when residences are using many electrical appliances. The water heating end-use is also bimodal, but peaks in the morning period as water heaters deliver hot water for washing and showers. Since the water heating hourly results are nearly coincident with the space heating results, using the ADM Associates hourly profiles makes the composite residential sector results swing even more widely than from space heating alone.

Figure 8: California ISO Coincidental Composite of Winter Maximum Day by Residential End-Use Hourly Loads



Source: California Energy Commission staff.

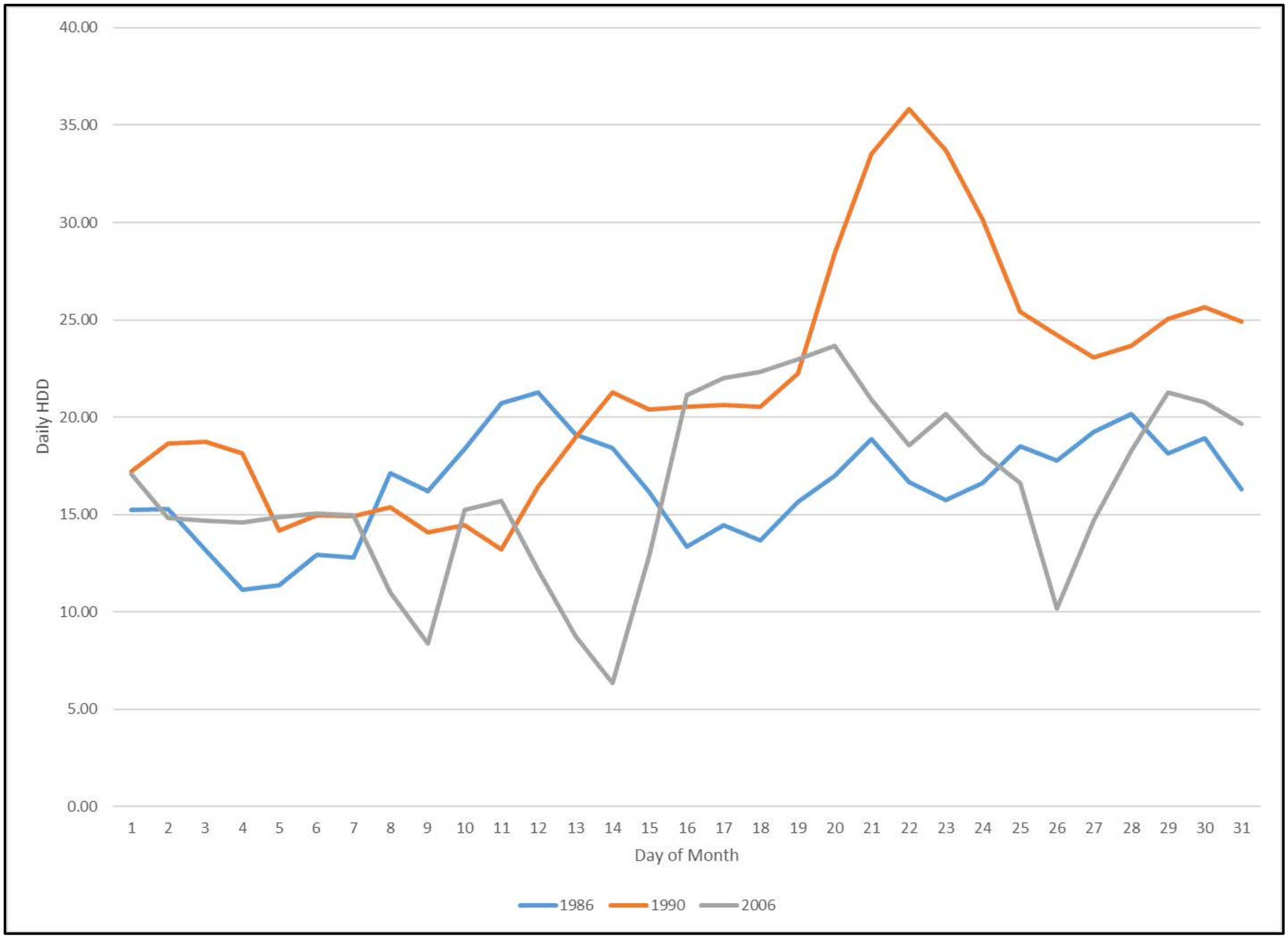
Dependence of Space Heating Load Profiles on Weather Patterns

The space heating load profiles developed by ADM Associates result from building simulation studies using several historic weather years which were then pooled and regressed against heating degree days and cooling degree days. The parameterized equation then used weather data from a single specific year to generate a static load profile. Although this method can be useful if a single load profile is desired, it is limiting when the goal is to understand the uncertainties of hourly loads for a utility and for the coincident impact on multiple utilities.

Appendix C provides charts of monthly heating degree days by IOU service area for years 1985 to 2015. These charts illustrate a gradual warming of heating degree days for November, December and January, but not for February. They also confirm intuitive understanding that December is the coldest of these four months. Comparing across the four charts shows that for PG&E, the coldest month on record is December of 1990.

Figure 9 plots the daily heating degree days for December 1990 versus the two most typical Decembers – 1986 and 2006 - for comparison. Clearly the time period around December 22 stands out for extreme cold even though the first third of the month might be considered typical.

Figure 9: Comparing Selected December Daily Heating Degree Days for the PG&E Service Area



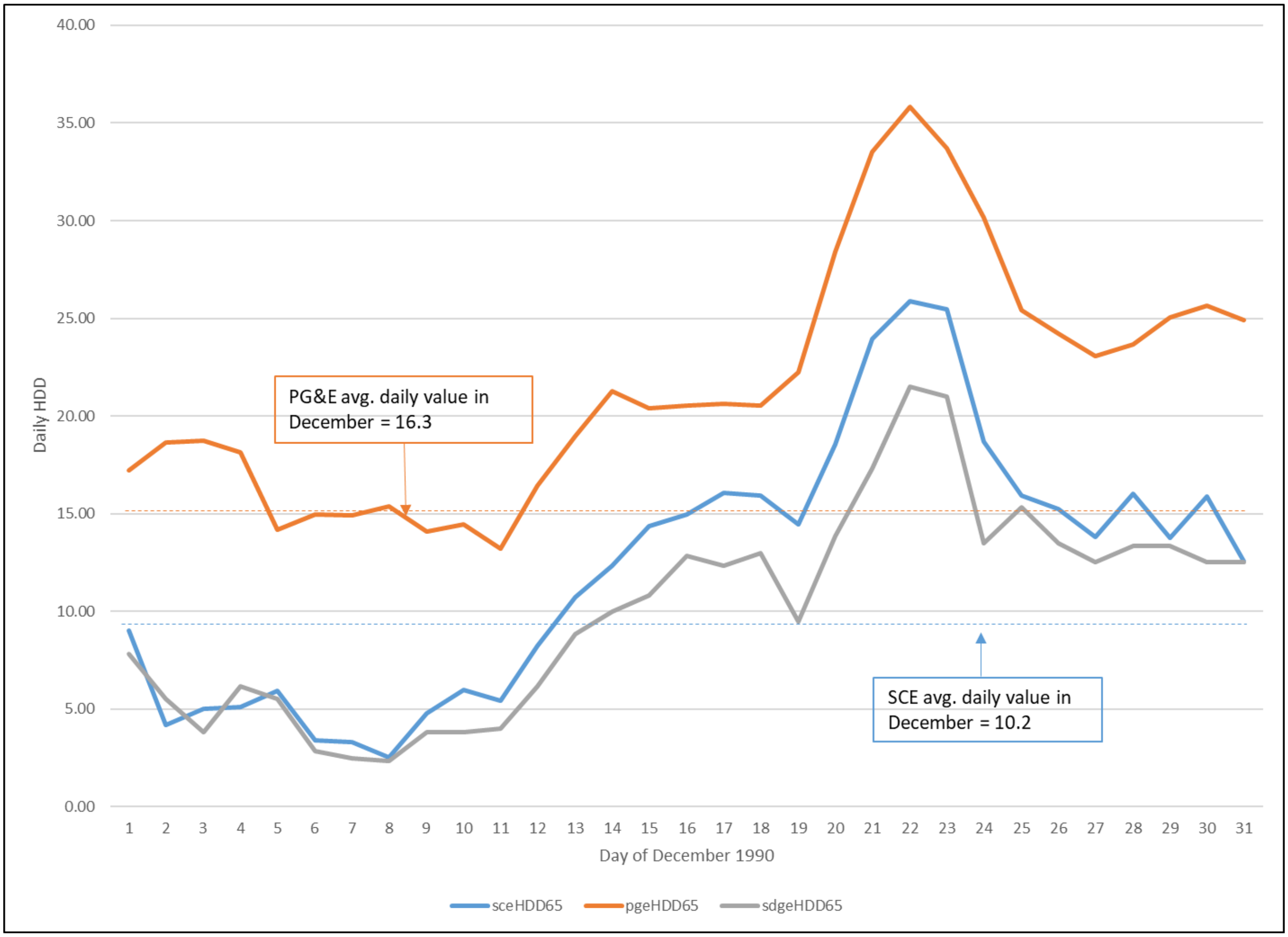
Source: California Energy Commission staff.

Figure 10 shows how the heating degree day patterns for the three IOU service areas compare to one another in the extreme event period of December 1990. As noted in the text boxes, the period around December 22 is more than two and a half times more severe than the average daily December Heating Degree Days (HDD) for SCE and PG&E. Also, all three IOUs have extreme weather at the same time.

The point of this review of historic weather data is to illustrate the variability of cold weather and its implications for choosing what years of weather to assume in developing space heating load profiles. As California embarks on fuel substitution efforts as part of a broad effort to decarbonize buildings, much more intensive study of utility-specific and common weather patterns is needed to understand when incremental electrical load will be placed on the grid. Further, since the performance of heat pumps declines with outdoor temperature, more intensive study of daily patterns of weather and heat pump loads are needed. New load profiles for heat pumps should emerge from such studies.

The California ISO and other system operators have long had experience in addressing the traditional summer peak events induced by air conditioning load, but will now have a whole new set of capacity requirements and operating procedures to develop in addressing growing winter loads.

Figure 10: Comparing December 1990 Heating Degree Day Patterns for the Three IOU Service Areas



Source: California Energy Commission staff.

Sensitivity of Average End-Use Efficiency Assumptions

Table 4 and **Table 5** provided some insights into the impact of alternative average end-use efficiency assumptions on annual electric energy. The impact of this same sensitivity case on maximum incremental load is shown in **Tables 11a** and **Table 11b**. **Table 11a** repeats **Table 4** for the convenience of the reader, and **Table 11b** provides the maximum incremental end-use electric load impacts.

In **Table 11a** the right column shows an annual electric energy reduction of 6.7 percent in the alternative case compared to the original energy impact, whereas in **Table 11b** the right column shows a 15.3 percent reduction in maximum electric load compared to the original maximum load impact. Although the reduction in residential space heat electric load provided most of the decline, the load from this end-use is still so large compared to the other residential end-uses that the SCE service area continues to have its maximum load day on January 28 in both cases.

Table 11a: Impact of Alternative Residential Sector Average End-use Efficiency Assumption Using Scenario 5 for the SCE Service Area in Year 2030 (Annual Incremental Electric Energy Impacts in GWh)[21]

Sector	End-use	Natural Gas Displaced (MM Therms)	Original Assumptions NG Eff	Original Assumptions Elec Eff	Original Assumptions Electric Energy (GWh)	Revised Assumptions NG Eff	Revised Assumptions Elec Eff	Revised Assumptions Electric Energy (GWh)
Res	Space Heat	413.0	0.8	3	3227.0	0.74	3.631	2466.3
Res	Water Heat	375.8	0.8	3	2936.4	0.6875	3.119	2427.2
Res	Clothes Dryer	88.4	0.8	3	690.9	0.8	2.5	829.1
Res	Cooking	107.0	0.8	3	836.4	0.375	0.82	1434.5
Res	Pool/Spa	50.0	0.8	3	390.5	0.8	3	390.5
Res	Total	1034.2	0	0	8081.3	0	0	7547.5

Source: California Energy Commission staff.

21 Table 11a is comparable to the combination of Table 4 and Table 5.

Table 11b: Impact of Alternative Residential Sector Average End-Use Efficiency Assumptions using Scenario 5 for the SCE Service Area in Year 2030 (Maximum Incremental Electric Load Impacts in MW)

Sector	End-use	Natural Gas Displaced (MM Therms)	Original Assumptions NG Eff	Original Assumptions Elec Eff	Original Assumptions Maximum Load (MW)	Revised Assumptions NG Eff	Revised Assumptions Elec Eff	Revised Assumptions Maximum Load (MW)
Res	Space Heat	413.0	0.8	3	3473.311	0.74	3.631	2654.5
Res	Water Heat	375.8	0.8	3	684.918	0.6875	3.119	566.1
Res	Clothes Dryer	88.4	0.8	3	105.278	0.8	2.5	126.3
Res	Cooking	107.0	0.8	3	292.678	0.375	0.82	501.9
Res	Pool/Spa	50.0	0.8	3	86.692	0.8	3	86.7
Res	Total	1034.2	0	0	4642.9	0	0	3935.6

Source: California Energy Commission staff.

CHAPTER 7: Lessons Learned

Although prior studies and simple intuition might have sufficed to know that the residential space heating load would be the dominant result from any broad fuel substitution program, this study has helped to identify the relative importance of residential and commercial building end-uses for each of the five major utilities in California.

- **Table 6** identifies the relative importance of all-electric new construction versus residential retrofit, and the even more comprehensive, necessary fuel substitution effort implied by AB 3232.
- **Table 4** and **Table 5** indicate that average end-use efficiency assumptions are worth further investigation. This would include identifying specific technologies being displaced for the natural gas and for the electric appliances that result from fuel substitution activities. **Table 11** illustrates the possible size of this component of overall uncertainty by comparing the maximum incremental hourly load impacts of the two sets of assumptions.
- **Figure 2** shows that there are complexities in interpreting the requirements of AB 3232 that may markedly affect the results of the ultimate study required by the legislature.
- **Figures 3** through **Figure 8** display the importance of load profiles in translating annual incremental electric energy into hourly impacts. The extremely large daily load swings due to residential space and water heating will create issues for procuring the appropriate mix of flexible resources. New programs must be designed to reduce such swings through load management techniques.
- **Figure 9** and **Figure 10** and Appendix C suggest much more study is needed to investigate how alternative weather assumptions affect heat pump performance and the extent to which weather patterns are, or are not, coincident across the California ISO balancing authority area and the state as a whole.

Caveats

Almost any exploratory study takes short cuts that cause one to be cautious about using the results too readily. That is the case for this study. The brief description above of lessons learned should provide the necessary caution that more analysis and better data are needed.

Large scale replacement of natural gas space heating appliances with heat pumps will introduce new air conditioning loads for those end-users who did not previously have air conditioning or might have only had a room air conditioner. The incremental electrical load of this increased air conditioning service has not been quantified and will increase the summer incremental loads compared to this study.

This study has not examined the implications on summer air conditioning load of those end-users who now have gas space heat/central air conditioning systems and for whom there could be either increased or decreased air conditioning loads depending upon the performance features of the existing air conditioner versus the new heat pump.

As noted earlier, this exploratory study has assessed a number of alternative future scenarios in a “what if” manner. At this time, there is uncertainty about the scope, pace, and programmatic/ratemaking activities that would induce electrification, and it is unwise to include these impacts in the managed forecasts used by the CPUC and California ISO.

Next Steps

This study has developed some initial understanding of the natural gas displacement and incremental electric loads added of several “what if” scenarios. Any exploratory study takes short cuts and leaves out important detail, which limits its utility. Fortunately, an improved capability to assess fuel substitution is already underway that will improve upon the tool used in this effort. It is being developed with the intent of being a primary assessment tool for the legislative study required by AB 3232. However, this tool requires more detailed, geographically granular data, so an extensive building simulation modeling effort is being planned that is intended to improve heat pump space heating and air conditioning load profiles that can be used with the new assessment tool.

APPENDIX A:
Baseline Natural Gas Demand Forecast by Major Electric Utility Service Area

Table A.1: PG&E 2017 IEPR Gas Forecast (MM Therms)

Utility	Sector	End-Use	1990	2017	2020	2025	2030	2030%
PG&E	Res	central AC	20.94	0.00	0.00	0.00	0.00	0.0%
PG&E	Res	central space heating	1288.14	1330.16	1351.26	1399.25	1452.55	39.8%
PG&E	Res	clothes drying	28.90	60.71	62.57	67.43	74.03	2.0%
PG&E	Res	cooking	78.23	136.31	138.20	145.02	153.09	4.2%
PG&E	Res	hot tub fuel	16.22	31.70	32.67	34.36	35.91	1.0%
PG&E	Res	hot water clothes washing	206.49	278.54	285.48	299.07	312.56	8.6%
PG&E	Res	hot water dishwashing	123.14	193.22	201.19	217.46	232.71	6.4%
PG&E	Res	pool heating	14.06	42.74	43.66	45.42	47.15	1.3%
PG&E	Res	water heating	478.48	565.78	579.74	610.20	637.81	17.5%
PG&E	Comm	Heating	373.39	381.18	375.57	359.20	337.83	9.3%
PG&E	Comm	Cooling	17.50	17.28	17.05	16.34	15.30	0.4%
PG&E	Comm	Water Heating	52.02	75.06	78.90	85.38	91.48	2.5%
PG&E	Comm	Cooking	40.36	48.45	49.65	50.92	51.49	1.4%
PG&E	Comm	Refrigeration	0.89	1.42	1.49	1.59	1.67	0.0%
PG&E	Comm	Miscellaneous	126.93	178.79	186.36	196.84	205.77	5.6%
PG&E	R/C	Total	2865.69	3341.34	3403.80	3528.48	3649.35	100.0%

Source: CEC/EAD staff.

Table A.2: SMUD 2017 IEPR Gas Forecast (MM Therms)

Utility	Sector	End-Use	1990	2017	2020	2025	2030	2030%
SMUD	Res	central AC	3.15	0.03	0.04	0.06	0.08	0.0%
SMUD	Res	central space heating	137.94	137.65	141.00	148.15	155.92	36.2%
SMUD	Res	clothes drying	1.18	6.57	6.79	7.33	7.85	1.8%
SMUD	Res	cooking	7.53	13.60	13.74	13.99	14.38	3.3%
SMUD	Res	hot tub fuel	3.20	3.49	3.63	3.99	4.31	1.0%
SMUD	Res	hot water clothes washing	20.49	29.87	30.70	32.43	34.02	7.9%
SMUD	Res	hot water dishwashing	13.50	20.25	21.13	22.94	24.66	5.7%
SMUD	Res	pool heating	6.80	6.38	6.50	6.77	7.04	1.6%
SMUD	Res	water heating	44.29	61.02	62.66	66.14	69.33	16.1%
SMUD	Comm	Heating	53.22	57.86	58.00	57.59	57.04	13.3%
SMUD	Comm	Cooling	1.23	1.09	1.07	1.04	0.99	0.2%
SMUD	Comm	Water Heating	10.42	13.97	14.62	15.68	16.67	3.9%
SMUD	Comm	Cooking	6.82	7.14	7.37	7.75	8.08	1.9%
SMUD	Comm	Refrigeration	0.54	0.71	0.75	0.80	0.85	0.2%
SMUD	Comm	Miscellaneous	19.63	26.01	26.81	27.95	28.93	6.7%
SMUD	R/C	Total	329.97	385.65	394.81	412.61	430.13	100.0%

Source: CEC/EAD staff.

Table A.3: SCE 2017 IEPR Gas Forecast (MM Therms)

Utility	Sector	End-Use	1990	2017	2020	2025	2030	2030%
SCE	Res	central AC	21.76	0.00	0.00	0.00	0.00	0.0%
SCE	Res	central space heating	967.72	959.68	964.74	979.34	993.63	27.6%
SCE	Res	clothes drying	78.78	121.58	125.41	130.88	135.69	3.8%
SCE	Res	cooking	164.43	194.28	194.41	200.46	205.71	5.7%
SCE	Res	hot tub fuel	51.45	58.33	59.23	60.94	62.39	1.7%
SCE	Res	hot water clothes washing	190.32	281.18	282.98	297.19	307.07	8.5%
SCE	Res	hot water dishwashing	120.70	175.80	182.32	198.46	211.27	5.9%
SCE	Res	pool heating	66.95	60.42	59.87	59.34	58.63	1.6%
SCE	Res	water heating	461.87	601.97	607.32	632.86	652.92	18.1%
SCE	Comm	Heating	171.10	229.79	232.64	234.14	231.96	6.4%
SCE	Comm	Cooling	41.09	55.17	57.13	60.18	62.93	1.7%
SCE	Comm	Water Heating	53.16	87.13	92.26	101.10	109.80	3.0%
SCE	Comm	Cooking	49.15	82.36	86.62	92.99	98.61	2.7%
SCE	Comm	Refrigeration	2.32	4.32	4.54	4.89	5.19	0.1%
SCE	Comm	Miscellaneous	238.77	388.20	407.06	437.00	465.23	12.9%
SCE	R/C	Total	2679.57	3300.20	3356.53	3489.78	3601.02	100.0%

Source: CEC/EAD staff.

Table A.4: LADWP 2017 IEPR Gas Forecast (MM Therms)

Utility	Sector	End-Use	1990	2017	2020	2025	2030	2030%
LADWP	Res	central AC	9.60	0.00	0.00	0.00	0.00	0.0%
LADWP	Res	central space heating	358.18	359.83	356.89	357.53	359.25	35.4%
LADWP	Res	clothes drying	24.46	27.54	28.25	30.13	33.51	3.3%
LADWP	Res	cooking	65.19	57.25	57.26	58.50	59.54	5.9%
LADWP	Res	hot tub fuel	9.92	6.49	6.43	6.38	6.31	0.6%
LADWP	Res	hot water clothes washing	63.07	77.04	77.94	81.57	84.91	8.4%
LADWP	Res	hot water dishwashing	31.84	43.65	45.49	49.39	53.12	5.2%
LADWP	Res	pool heating	26.86	12.88	12.39	12.28	12.15	1.2%
LADWP	Res	water heating	169.74	181.44	182.69	188.75	197.19	19.4%
LADWP	Comm	Heating	60.44	56.77	57.02	56.11	54.04	5.3%
LADWP	Comm	Cooling	11.40	12.54	13.12	13.88	14.45	1.4%
LADWP	Comm	Water Heating	17.28	21.48	22.86	25.08	27.16	2.7%
LADWP	Comm	Cooking	14.78	16.85	17.86	19.22	20.30	2.0%
LADWP	Comm	Refrigeration	0.70	0.76	0.80	0.86	0.90	0.1%
LADWP	Comm	Miscellaneous	68.45	77.17	81.03	86.52	91.12	9.0%
LADWP	R/C	Total	931.89	951.68	960.01	986.20	1013.95	100.0%

Source: CEC/EAD staff.

Table A.5: SDG&E 2017 IEPR Gas Forecast (MM Therms)

Utility	Sector	End-Use	1990	2017	2020	2025	2030	2030%
SDG&E	Res	central AC	3.24	0.00	0.00	0.00	0.00	0.0%
SDG&E	Res	central space heating	159.78	169.44	170.48	174.15	179.89	22.2%
SDG&E	Res	clothes drying	13.93	21.98	22.45	23.70	24.82	3.1%
SDG&E	Res	cooking	27.34	36.02	35.59	36.16	36.59	4.5%
SDG&E	Res	hot tub fuel	10.53	14.52	14.73	15.12	15.44	1.9%
SDG&E	Res	hot water clothes washing	51.37	70.10	71.50	73.87	78.92	9.7%
SDG&E	Res	hot water dishwashing	31.22	46.15	48.02	51.21	54.18	6.7%
SDG&E	Res	pool heating	4.62	5.30	5.17	5.08	5.19	0.6%
SDG&E	Res	water heating	113.60	153.24	155.68	160.42	167.80	20.7%
SDG&E	Comm	Heating	58.80	90.75	92.42	93.87	93.96	11.6%
SDG&E	Comm	Cooling	12.56	17.75	18.47	19.63	20.72	2.6%
SDG&E	Comm	Water Heating	15.49	24.76	26.13	28.53	30.93	3.8%
SDG&E	Comm	Cooking	14.03	18.50	19.10	19.94	20.67	2.6%
SDG&E	Comm	Refrigeration	0.13	0.21	0.22	0.23	0.24	0.0%
SDG&E	Comm	Miscellaneous	39.76	66.23	69.57	75.06	80.41	9.9%
SDG&E	R/C	Total	556.38	734.94	749.53	776.98	809.77	100.0%

Source: CEC/EAD staff.

APPENDIX B:
Annual Incremental Electric Energy Added

Table B.1a: Electric Energy Added by Utility and Scenario (GWh)

#	Scenario Name	Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	SD350REF	PG&E	4.54	13.82	27.95	47.03	71.02	99.90	133.65	172.70	217.21	267.34	329.03
2	SB350AGG	PG&E	11.36	34.54	69.88	117.56	177.56	249.75	334.12	431.74	543.03	668.34	822.57
3	Res Retrofit 10% by 2030	PG&E	138.54	277.43	418.73	562.51	708.54	857.15	1007.62	1160.40	1315.58	1473.21	1633.34
4	Res Retrofit 25% by 2030	PG&E	344.29	691.70	1045.14	1404.80	1770.09	2141.79	2518.20	2900.35	3288.51	3682.81	4083.35
5	Res/Comm 40% below 1990 by 2030	PG&E	1105.24	2169.10	3251.25	4349.48	5462.72	6586.86	7729.59	8887.58	10061.78	11251.19	12462.94

Source: CEC/EAD staff.

Table B.1b: Electric Energy Added by Utility and Scenario (GWh)

#	Scenario Name	Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	SD350REF	SCE	4.66	14.16	28.64	48.18	72.76	102.34	136.92	176.92	222.53	273.88	337.08
2	SB350AGG	SCE	11.64	35.39	71.59	120.44	181.90	255.86	342.29	442.30	556.32	684.69	842.69
3	Res Retrofit 10% by 2030	SCE	112.79	225.18	338.49	453.37	569.75	687.69	805.39	924.11	1043.85	1164.66	1286.56
4	Res Retrofit 25% by 2030	SCE	280.29	561.44	844.87	1132.24	1423.34	1718.38	2012.79	2309.74	2609.28	2911.48	3216.39
5	Res/Comm 40% below 1990 by 2030	SCE	1157.94	2274.03	3413.00	4566.73	5738.10	6932.89	8131.71	9344.10	10571.29	11817.96	13084.86

Source: CEC/EAD staff

Table B.1c: Electric Energy Added by Utility and Scenario (GWh)

#	Scenario Name	Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	SD350REF	SDG&E	1.04	3.18	6.42	10.81	16.32	22.96	30.71	39.69	49.92	61.44	75.62
2	SB350AGG	SDG&E	2.61	7.94	16.06	27.02	40.81	57.40	76.79	99.22	124.80	153.60	189.04
3	Res Retrofit 10% by 2030	SDG&E	23.40	46.59	70.18	94.02	118.46	142.72	167.74	193.13	218.92	245.09	271.67
4	Res Retrofit 25% by 2030	SDG&E	58.15	116.17	175.16	234.79	295.93	356.61	419.19	482.73	547.22	612.70	679.17
5	Res/Comm 40% below 1990 by 2030	SDG&E	271.07	532.77	799.64	1069.70	1345.53	1622.84	1906.68	2193.55	2484.38	2780.44	3081.14

Source: CEC/EAD staff.

Table B.1d: Electric Energy Added by Utility and Scenario (GWh)

#	Scenario Name	Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	SD350REF	SMUD	0.57	1.74	3.51	5.91	8.93	12.56	16.80	21.71	27.31	33.61	41.36
2	SB350AGG	SMUD	1.43	4.34	8.79	14.78	22.32	31.40	42.00	54.28	68.27	84.02	103.41
3	Res Retrofit 10% by 2030	SMUD	14.61	29.32	44.33	59.72	75.45	91.41	107.68	124.27	141.18	158.42	176.00
4	Res Retrofit 25% by 2030	SMUD	36.31	73.11	110.64	149.15	188.49	228.41	269.10	310.59	352.90	396.03	440.00
5	Res/Comm 40% below 1990 by 2030	SMUD	135.31	262.33	391.73	523.56	657.62	793.56	931.48	1071.53	1213.84	1358.22	1505.93

Source: CEC/EAD staff.

Table B.1e: Electric Energy Added by Utility and Scenario (GWh)

#	Scenario Name	Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	SD350REF	LADWP	1.28	3.89	7.87	13.25	20.01	28.14	37.65	48.65	61.19	75.31	92.68
2	SB350AGG	LADWP	3.20	9.73	19.69	33.12	50.02	70.35	94.12	121.62	152.96	188.26	231.71
3	Res Retrofit 10% by 2030	LADWP	38.71	77.11	115.69	154.59	193.80	233.02	272.75	312.78	353.12	393.78	434.79
4	Res Retrofit 25% by 2030	LADWP	96.20	192.25	288.76	386.08	484.16	582.26	681.64	781.77	882.68	984.40	1086.96
5	Res/Comm 40% below 1990 by 2030	LADWP	275.44	534.17	795.99	1060.06	1327.05	1596.20	1869.59	2145.93	2425.42	2708.88	2996.20

Source: CEC/EAD staff.

Table B.1f: Electric Energy Added by Utility and Scenario (GWh)

#	Scenario Name	Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	SD350REF	"State"	12.09	36.78	74.40	125.17	189.04	265.90	355.73	459.66	578.15	711.56	875.77
2	SB350AGG	"State"	30.24	91.95	186.01	312.91	472.61	664.76	889.32	1149.16	1445.37	1778.91	2189.42
3	Res Retrofit 10% by 2030	"State"	328.05	655.63	987.40	1324.22	1666.00	2011.98	2361.18	2714.68	3072.65	3435.17	3802.35
4	Res Retrofit 25% by 2030	"State"	815.24	1634.68	2464.57	3307.07	4162.01	5027.45	5900.92	6785.18	7680.59	8587.41	9505.87
5	Res/Comm 40% below 1990 by 2030	"State"	2945.00	5772.41	8651.62	11569.53	14531.02	17532.34	20569.04	23642.69	26756.72	29916.69	33131.08

Source: CEC/EAD staff.

Table B.2a: Natural Gas Consumption Displaced by Utility and Scenario (MM Therms)

#	Scenario Name	Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	SD350REF	PG&E	0.58	1.77	3.58	6.02	9.09	12.79	17.10	22.10	27.80	34.21	42.11
2	SB350AGG	PG&E	1.45	4.42	8.94	15.05	22.72	31.96	42.76	55.25	69.50	85.53	105.27
3	Res Retrofit 10% by 2030	PG&E	17.73	35.51	53.59	71.99	90.68	109.70	128.96	148.51	168.37	188.54	209.04
4	Res Retrofit 25% by 2030	PG&E	44.06	88.52	133.76	179.79	226.54	274.11	322.28	371.19	420.87	471.33	522.59
5	Res/Comm 40% below 1990 by 2030	PG&E	141.45	277.60	416.10	556.65	699.12	842.99	989.24	1137.44	1287.71	1439.93	1595.01

Source: CEC/EAD staff.

Table B.2b: Natural Gas Consumption Displaced by Utility and Scenario (MM Therms)

#	Scenario Name	Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	SD350REF	SCE2	0.60	1.81	3.66	6.17	9.31	13.10	17.52	22.64	28.48	35.05	43.14
2	SB350AGG	SCE2	1.49	4.53	9.16	15.41	23.28	32.75	43.81	56.61	71.20	87.63	107.85
3	Res Retrofit 10% by 2030	SCE2	14.43	28.82	43.32	58.02	72.92	88.01	103.07	118.27	133.59	149.05	164.65
4	Res Retrofit 25% by 2030	SCE2	35.87	71.85	108.13	144.91	182.16	219.92	257.60	295.60	333.94	372.61	411.64
5	Res/Comm 40% below 1990 by 2030	SCE2	148.19	291.03	436.80	584.45	734.37	887.28	1040.70	1195.86	1352.92	1512.47	1674.61

Source: CEC/EAD staff.

Table B.2c: Natural Gas Consumption Displaced by Utility and Scenario (MM Therms)

#	Scenario Name	Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	SD350REF	SDG&E	0.13	0.41	0.82	1.38	2.09	2.94	3.93	5.08	6.39	7.86	9.68
2	SB350AGG	SDG&E	0.33	1.02	2.06	3.46	5.22	7.35	9.83	12.70	15.97	19.66	24.19
3	Res Retrofit 10% by 2030	SDG&E	2.99	5.96	8.98	12.03	15.16	18.26	21.47	24.72	28.02	31.37	34.77
4	Res Retrofit 25% by 2030	SDG&E	7.44	14.87	22.42	30.05	37.87	45.64	53.65	61.78	70.03	78.41	86.92
5	Res/Comm 40% below 1990 by 2030	SDG&E	34.69	68.18	102.34	136.90	172.20	207.69	244.02	280.73	317.95	355.84	394.33

Source: CEC/EAD staff.

Table B.2d: Natural Gas Consumption Displaced by Utility and Scenario (MM Therms)

#	Scenario Name	Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	SD350REF	SMUD	0.07	0.22	0.45	0.76	1.14	1.61	2.15	2.78	3.49	4.30	5.29
2	SB350AGG	SMUD	0.18	0.56	1.12	1.89	2.86	4.02	5.38	6.95	8.74	10.75	13.23
3	Res Retrofit 10% by 2030	SMUD	1.87	3.75	5.67	7.64	9.66	11.70	13.78	15.90	18.07	20.27	22.52
4	Res Retrofit 25% by 2030	SMUD	4.65	9.36	14.16	19.09	24.12	29.23	34.44	39.75	45.16	50.68	56.31
5	Res/Comm 40% below 1990 by 2030	SMUD	17.15	33.70	50.56	67.73	85.20	102.90	120.87	139.11	157.65	176.45	195.69

Source: CEC/EAD staff.

Table B.2e: Natural Gas Consumption Displaced by Utility and Scenario (MM Therms)

#	Scenario Name	Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	SD350REF	LADWP	0.16	0.50	1.01	1.70	2.56	3.60	4.82	6.23	7.83	9.64	11.86
2	SB350AGG	LADWP	0.41	1.25	2.52	4.24	6.40	9.00	12.05	15.56	19.58	24.09	29.65
3	Res Retrofit 10% by 2030	LADWP	4.95	9.87	14.81	19.79	24.80	29.82	34.91	40.03	45.19	50.40	55.64
4	Res Retrofit 25% by 2030	LADWP	12.31	24.60	36.96	49.41	61.96	74.52	87.24	100.05	112.97	125.98	139.11
5	Res/Comm 40% below 1990 by 2030	LADWP	34.85	68.00	101.55	135.38	169.59	204.08	239.11	274.52	310.33	346.64	383.46

Source: CEC/EAD staff.

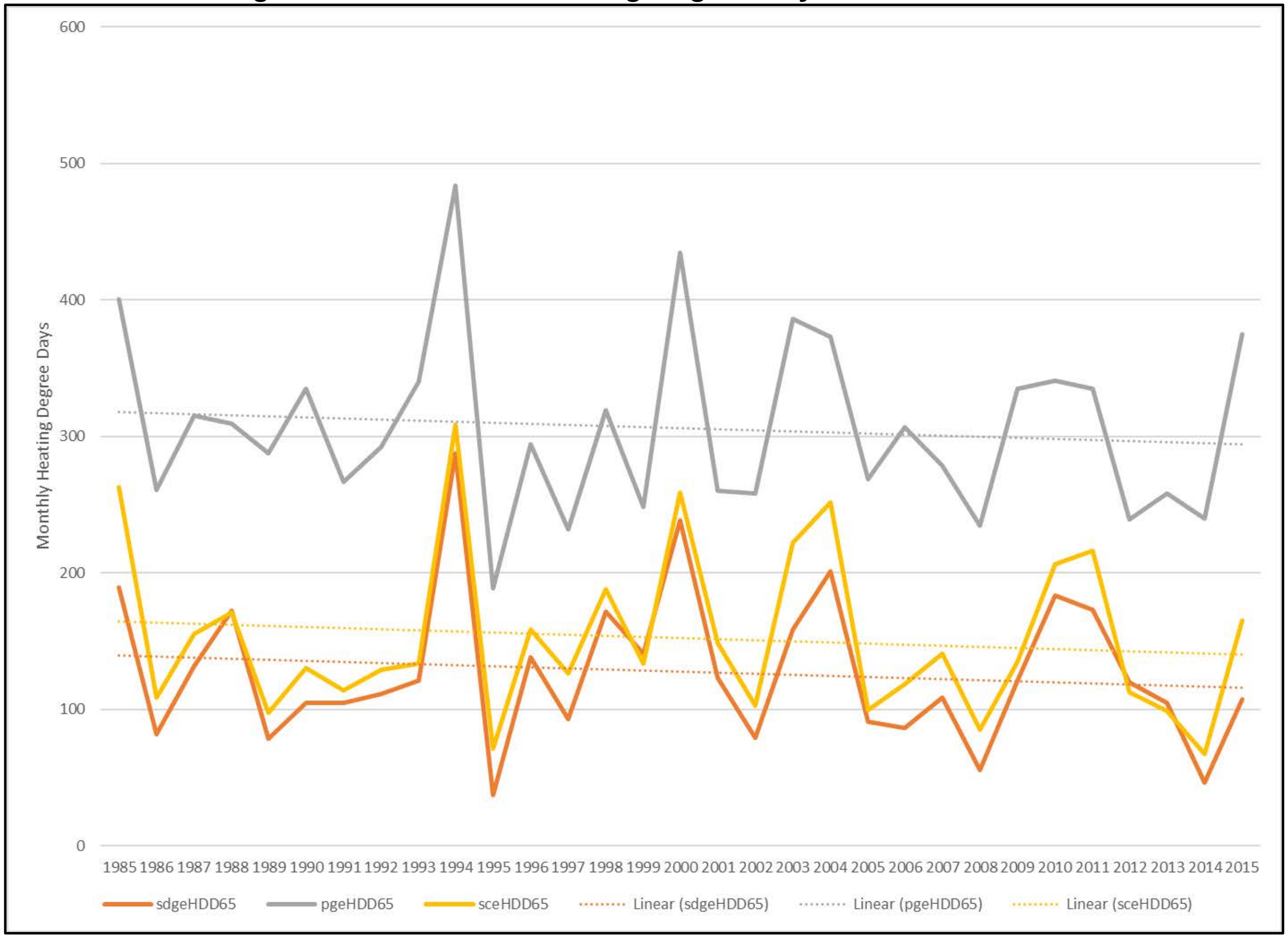
Table B.2f: Natural Gas Consumption Displaced by Utility and Scenario (MM Therms)

#	Scenario Name	Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	SD350REF	"State"	1.55	4.71	9.52	16.02	24.19	34.03	45.53	58.83	73.99	91.07	112.08
2	SB350AGG	"State"	3.87	11.77	23.81	40.05	60.48	85.08	113.82	147.07	184.98	227.67	280.20
3	Res Retrofit 10% by 2030	"State"	41.98	83.91	126.37	169.47	213.22	257.50	302.18	347.43	393.24	439.63	486.63
4	Res Retrofit 25% by 2030	"State"	104.34	209.21	315.42	423.24	532.66	643.42	755.20	868.37	982.97	1099.02	1216.57
5	Res/Comm 40% below 1990 by 2030	"State"	376.33	738.52	1107.34	1481.12	1860.48	2244.94	2633.94	3027.66	3426.56	3831.34	4243.09

Source: CEC/EAD staff.

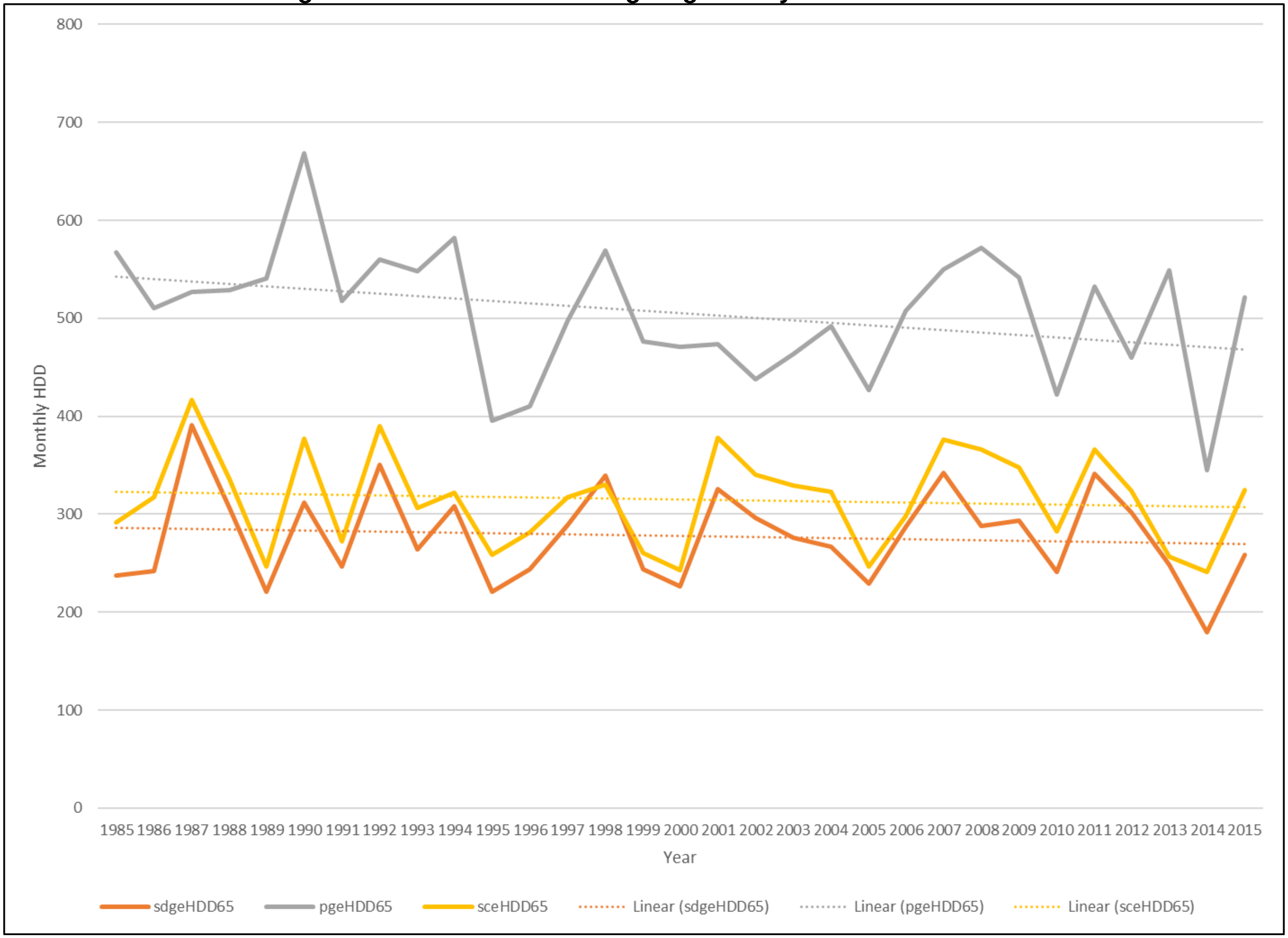
APPENDIX C:
Weather Data from 1985 to 2015 by Utility Service Area

Figure C.1 November Heating Degree Days for 1985 to 2015



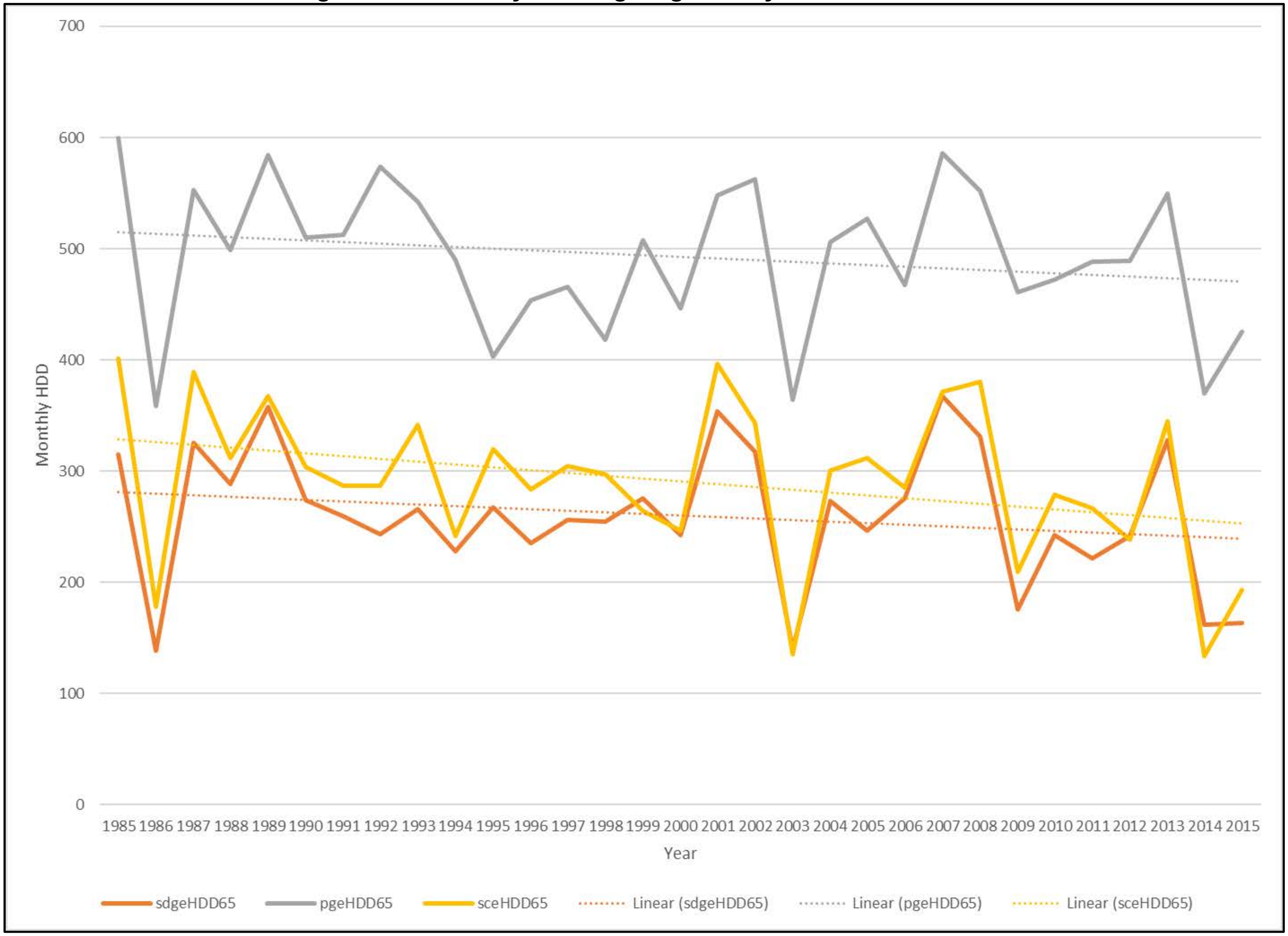
Source: California Energy Commission staff.

Figure C.2 December Heating Degree Days for 1985 to 2015



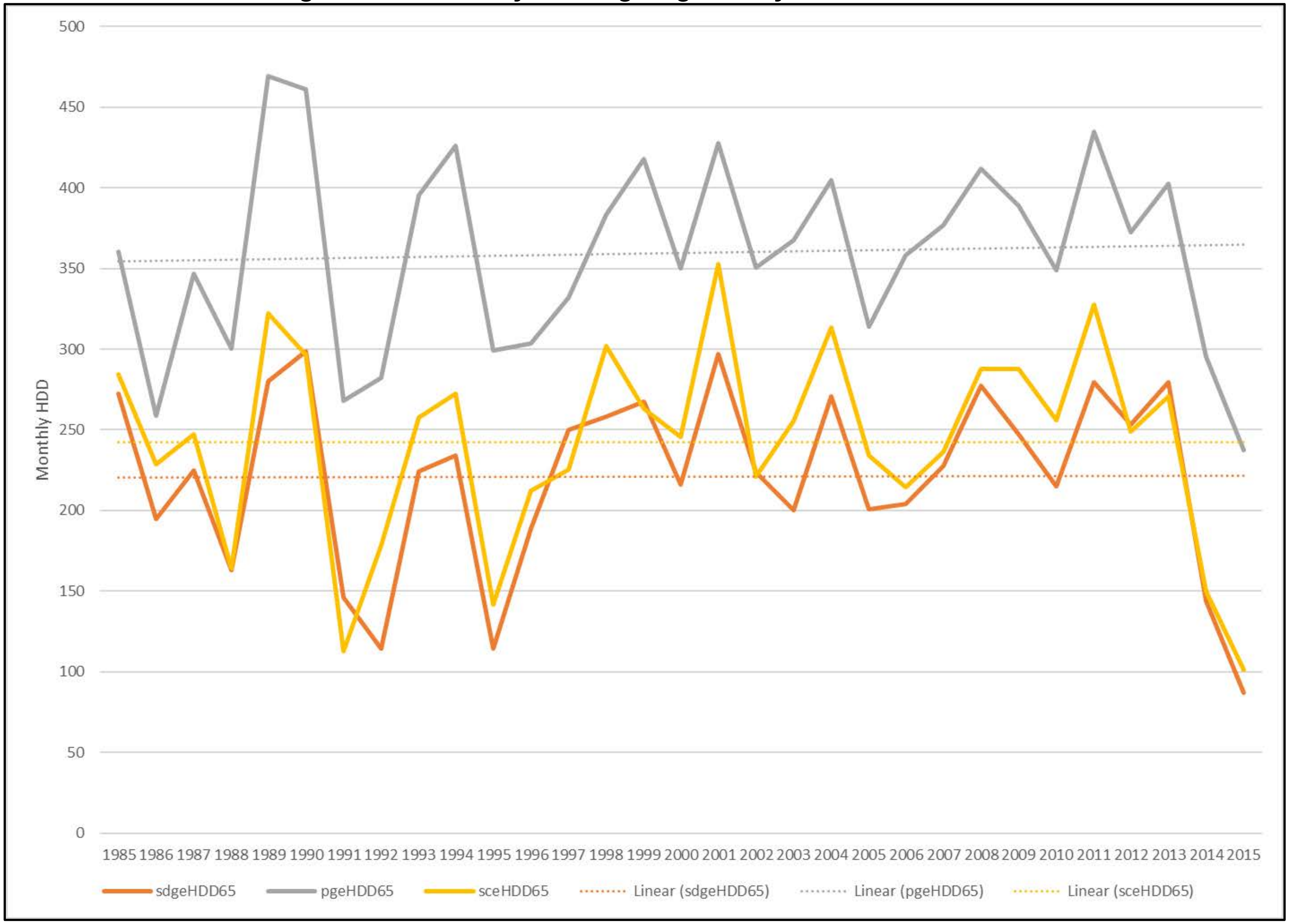
Source: California Energy Commission staff.

Figure C.3 January Heating Degree Days for 1985 to 2015



Source: California Energy Commission staff.

Figure C.4 February Heating Degree Days for 1985 to 2015



Source: California Energy Commission staff.