DOCKETED

Docket Number:	17-IEPR-04
Project Title:	Natural Gas Outlook
TN #:	222400
Document Title:	STAFF FINAL REPORT 2017 Natural Gas Market Trends and Outlook
Description:	STAFF FINAL REPORT: 2017 Natural Gas Market Trends and Outlook Toward a Cleaner Energy Future
Filer:	Raquel Kravitz
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	1/31/2018 7:45:43 AM
Docketed Date:	1/31/2018

California Energy Commission

STAFF FINAL REPORT

2017 Natural Gas Market Trends and Outlook

Toward a Cleaner Energy Future

California Energy Commission

Edmund G. Brown Jr., Governor

January 2018| CEC-200-2017-009-SF

California Energy Commission

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ACKNOWLEDGEMENTS

The authors would like to acknowledge the following individuals for their valuable contributions to this report:

Garry O'Neill, Angela Tanghetti, and Richard Jensen, Energy Commission staff, for developing projections of natural gas demand from electricity generation.

Rachel MacDonald and Marc Pryor, Energy Commission staff, for report development, review, and editing.

Harinder Kaur, Energy Commission staff, for report formatting and processing.

Chris Kavalec, Energy Commission staff, for providing inputs on end use demand.

Catherine Elder, Aspen Environmental Group, for report review and editing.

ABSTRACT

California Energy Commission staff produced the *2017 Natural Gas Market Trends and Outlook* report to support the California Energy Commission's *2017 Integrated Energy Policy Report.* Every two years, California Energy Commission staff, in consultation with industry experts, examines emerging trends in the natural gas market. This report provides analysis and findings on key natural gas topics, including a forecast of the expected prices for natural gas, resource potential and sources of natural gas, and infrastructure used to deliver natural gas from production basins to California consumers, including pipelines and storage. To prepare the forecast, Energy Commission staff modeled the North American natural gas market and developed cases depicting future natural gas demand and supply trends under a variety of assumptions. The results of this modeling effort serve, in part, as inputs to other modeling at the Energy Commission.

Other issues examined include natural gas shipments to Mexico and the potential for increasing liquefied natural gas exports. Even as California transitions away from fossil fuels, the role of natural gas in preserving electricity reliability requires greater coordination between the natural gas and electricity markets. Staff also reports on efforts to quantify and reduce methane leakage in the natural gas system.

Keywords: Natural gas supply, demand, infrastructure, storage, prices, exports, imports, shale, hydraulic fracturing, biomethane, liquefied natural gas, coordination, market uncertainty, leakage

Please use the following citation for this report:

Brathwaite, Leon D, Jason Orta, Peter Puglia, Anthony Dixon, and Robert Gulliksen. 2017. *2017 Natural Gas Market Trends and Outlook*. California Energy Commission. Publication Number: **CEC-200-2017-009-SF**

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EXECUTIVE SUMMARY

Natural Gas Demand

For the United States, residential and commercial natural gas demand is projected to remain relatively flat through 2030 and beyond. Industrial demand is expected to grow moderately, as forecasted low natural gas prices lead to some growth in the petrochemical industry where natural gas is used as a feedstock. Nationwide, significant increases in gas demand for electric generation are anticipated. With historically low gas prices over the last several years, there is a growing preference outside California for using natural gas instead of coal for electric generation.

California end-use natural gas demand is expected to grow slowly, at roughly 0.55 percent, under the mid demand case assumptions from the California Energy Commission's *California Energy Demand 2018-2028 Preliminary Forecast*. The mid demand case represents a "business-as-usual" environment. The high demand and low demand cases use modified assumptions to the mid demand case that either push natural demand higher or lower. The high demand case assumes lower costs for developing proved and potential resources than in the mid demand case, while the low demand case assumes higher costs than in the mid demand case. California mid case natural gas demand for commercial and industrial sectors is projected to be relatively flat, with a slight uptick late in the forecast period, while residential gas demand remains flat with a slight decrease late in the forecast period.

Natural gas demand for electric generation plays an important role in developing future natural gas price projections, discussed in a later section. While the modeling structure of the natural gas market covers all of North America, the comparable structure of the electricity market comprises of only regional markets. As a result, the Energy Commission estimates natural gas demand in the power generation sector for the region known as the Western Interconnection, which includes California. The Western Electricity Coordinating Council oversees this region. Results for mid case natural gas demand for electric generation in California declined by 2.64 percent, while gas demand in the Western Interconnection grew at roughly 0.57 percent between 2016 and 2028.

California's electricity supply and demand assumptions reflect current policy mandates, such as the state's Renewables Portfolio Standard goals, retirement of once-through-cooling plants, and Senate Bill 350 (De León, Chapter 547, Statutes of 2015) energy efficiency doubling targets. For the western region outside California, staff relies on the Western Electricity Coordinating Council's Transmission Electric Planning and Policy Committee's 2026 common case.

Natural Gas Production and Infrastructure

The natural gas system includes several components or phases that move natural gas from underground reservoirs to end-use consumers located hundreds or thousands of miles away in demand centers. The primary sources of natural gas for California are the Western Canadian Sedimentary basin, the Permian and San Juan basins in the Southwest, and the Rocky Mountain region. The use of fracking and horizontal drilling techniques to unlock shale gas resources has dramatically increased U.S. proved natural gas reserves (those that can be economically developed with current technology) from 200 trillion cubic feet in 2005 to 300 trillion cubic feet in 2015. Canada has another 77 trillion cubic feet of proved reserves of natural gas. With increased domestic production of shale gas, liquefied natural gas imports into the United States have declined from a high of 771 billion cubic feet in 2007 to 88 billion cubic feet in 2016.

A system of interstate natural gas pipelines deliver natural gas to the California border, where most of the gas enters the gas systems of the California gas utilities. Some large customers, mostly power plants, take deliveries directly from the interstate pipelines. These pipelines include Gas Transmission Northwest, Ruby, Kern River, El Paso (North and South), Transwestern, Mojave, Southern Trails, TGN, Tuscarora, and North Baja. The total delivery capacity of the interstate pipelines serving California is 12.89 billion cubic feet per day. However, California is unable to take advantage of the full delivery capacity of the *interstate* pipelines, since the receiving capacity of the *intrastate* pipelines reaches only about 9 billion cubic feet per day. This is sufficient to meet the state's average demand, but not California's peak demand of 11.157 billion cubic feet per day, which occurred on December 9, 2013. This is part of the reason why natural gas storage in California is important in balancing supply and demand.

California has a total of 371.3 billion cubic feet of maximum storage capacity, owned by both gas utilities and independent storage operators. Gas storage can provide seasonal, daily, and intraday balancing of supply and demand, allowing utilities to meet higher peak demand than pipeline infrastructure alone can meet. In general, over the year storage levels fluctuate, with gas being withdrawn in the winter months to meet heating needs, and gas being injected in the spring and summer months when demand is lower and gas prices are typically lower. The leak at Aliso Canyon in late 2015 to early 2016 has raised questions about the long-term role of storage, especially in light of the desire to reduce the use of natural gas in the state as a result of climate goals. The California Public Utilities Commission (CPUC) is examining the feasibility of minimizing or eliminating use of Aliso Canyon, while the California Council on Science and Technology is looking at the longer-term role of storage in general.

Natural Gas Prices

As part of an integrated North American natural gas market, national and international prices, supply, and infrastructure issues can have downstream effects on California's prices and supply. The Energy Commission projects future natural gas prices using a model that simulates the behavior of natural gas producers in supply basins and natural gas consumers in demand centers. It also includes representations of intrastate and interstate pipelines, liquefied natural gas import and export facilities, and other infrastructure. Henry Hub in Louisiana is the primary pricing point for natural gas spot and futures transactions in the North American market.

The Energy Commission's natural gas price projections indicate that prices at Henry Hub, after a forecasted price increase of 22 percent between 2016 and 2017, will rise at about 3 percent per year between 2018 and 2030 to about $4.54 per thousand cubic feet. As prices at Henry Hub increase over time, prices at Malin (Oregon) and Topock (Arizona) hubs, the primary western distribution centers on the natural gas system, will grow at 2 percent per year (2018-2030). During the same period, domestic natural gas production will continue to grow, reaching about 38 trillion cubic feet by 2030.

Natural Gas Issues

Several key issues may affect natural gas market conditions and prices in California, including the use of natural gas to integrate renewables and the related need for gas-electric coordination, the emerging market for gas in Mexico, and the potential for liquefied natural gas exports from the United States. California is positioned at the end of the natural gas delivery system with several high-population load centers – including Albuquerque, Phoenix, and Tucson – between it and the natural gas basins that supply the state. California usually experiences peak conditions at the same time as these load centers. Natural gas supplies scheduled for California could be drawn off the system at these load centers and reduce the amount of gas available to California. This requires California to be diligent in monitoring upstream supply and demand conditions that may reduce available supplies and raise prices in the state.

Renewable Integration and Gas-Electric Coordination

Natural gas generation is being used to integrate increasing levels of renewable energy resources by quickly ramping up and down as renewable generation varies throughout the day. In the long run, as prices for energy storage and demand response come down, and the energy imbalance market in the West expands, the role of natural gas for renewables integration will decrease. The changing role of natural gas-fired generators presents some challenges. There is a growing need to better coordinate the natural gas and electricity sectors as they become more interlinked. The electricity market is scheduled on an hourly basis, with some hours having large swings in natural gas generation. The natural gas market's nomination cycles do not allow for the variation and flexibility observed in the electric market. However, PG&E noted in comments to this report that utilities can vary hourly volumes of gas from utility-owned storage fields, including capacity allocated for load balancing and hourly load fluctuations.

In recent years, the Federal Energy Regulatory Commission has made several changes in gas operating practices, such as adding a third intraday scheduling opportunity, giving generators another opportunity to modify nominations to match operations. In addition, the agency has approved changes requested by the California Independent System Operator to address reliability concerns in Southern California resulting from the loss of Aliso Canyon. These actions have been helpful, but it is unclear whether the Federal

Energy Regulatory Commission will take additional actions to better coordinate the two markets. One idea being considered in California is the creation of a natural gas imbalance market, which would allow market participants with excess gas in a given hour to trade with others needing more gas during that hour.

Growing Natural Gas Exports to Mexico

While California is reducing its use of natural gas, Mexico is looking to natural gas to run its factories and generate electricity. In the near term, exports to Mexico are likely to increase as natural gas generators are being installed to replace dirtier oil-fired power plants. Mexico is in the process of expanding its natural gas infrastructure to receive imports from the United States.

With much of its natural gas resources undeveloped, Mexico reports proved reserves of 15.3 trillion cubic feet. However, Mexico has only recently taken steps to accelerate the development of its natural gas resources. In 2013, legislative reform in Mexico permitted investments and development by foreign investors. As a result, Mexico is moving to a more competitive energy industry. Increasing production from the region would help meet growing natural gas demand, particularly from new natural gas-fired generation in Mexico's northeastern region, and make that country less reliant on natural gas imports in the long term.

Liquefied Natural Gas Exports

The United States considered liquefied natural gas importation as a way to diversify existing natural gas supply sources in the early 2000s. While the United States both imports and exports liquefied natural gas, the lower cost of domestic supplies has reduced the demand for imports. In 2016, 64 percent of all pipeline exports from the United States went to Mexico. Market changes since the late-2000s, including increased domestic production and an expanded Panama Canal that allows larger ships to transit, are positioning the United States to become a net exporter of liquefied natural gas.

According to the United States Energy Information Administration, by 2020, the United States could become world's third-largest liquefied natural gas producer for export, after Australia and Qatar. However, Australia recently instituted regulations to give Australian customers priority over other suppliers. The magnitude of liquefied natural gas exports to other countries is uncertain, but some argue that United States exports to other countries, particularly to Asia and Europe, could expose domestic natural gas markets to price increases or price volatility.

Methane Leakage from the Natural Gas System

The structure of the natural gas system, with its varied interconnections, allows numerous opportunities for methane leakage. Methane is a short-lived climate pollutant that is the second most emitted greenhouse gas in California, after carbon dioxide. Methane is more effective at trapping heat than carbon dioxide, but the lifetime of carbon dioxide in the atmosphere exceeds that of methane. In 2015, the California Air

Resources Board reported that methane made up 10 percent of the total amount of greenhouse gas emissions in California. As of 2015, state estimates of emissions from the oil and gas systems and pipelines account for about 16 percent of total methane emissions. However, landfills, dairy animals and other ruminant livestock, waste handling, and agricultural production and other sources – as a result of biological conversion – are the primary producers of methane.

Researchers have suggested that there are certain thresholds for gas emissions, which if exceeded, eliminate the climate benefits of switching to cleaner fuels from heavy-duty diesel vehicles, gasoline powered cars, and coal-fired power plants. Estimating methane emissions from natural gas requires additional research. Until there is a more accurate and comprehensive accounting of emissions from the natural gas system, the benefit of using natural gas as a transition fuel to address climate issues is unclear, highlighting the importance of on-going research in this area. Despite uncertainties, the state is taking actions to reduce methane emissions, including requiring utilities to reduce leaks on their gas systems (which at the same time addresses safety concerns). The California Air Resources Board, the California Public Utilities Commission, and the Energy Commission are undertaking additional actions to reduce short-lived climate pollutants in response to Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016), as well as developing new methodologies and data sources to analyze and quantify emissions from natural gas resources as required by Assembly Bill 1496 (Thurmond, Chapter 604, Statutes of 2015).

CHAPTER 1
Introduction

In support of the *2017 Integrated Energy Policy Report (IEPR)*, the *Natural Gas Market Trends and Outlook* examines emerging trends and uncertainties in the natural gas market. Natural gas is an important component of California's energy system, supplying about one-third of the state's primary energy demand. In 2016, natural gas deliveries to California end users averaged about 5.8 billion cubic feet per day, of which 32 percent flowed to power plants for electricity generation. Even as California moves away from fossil fuels to meet its climate goals, natural gas-fired electricity is playing an important role in integrating increasing amounts of renewables into the electricity grid.

California receives about 90 percent of its natural gas from supply basins outside the state, through the integrated North American natural gas market. The natural gas pipeline network in the United States consists of an interconnected transmission and distribution system that transports natural gas from production basins to end users throughout the country. The pipeline systems of Canada and Mexico also connect to this system so that natural gas can flow between the three countries. As such, trends in natural gas demand, supply, and price in the rest of North America can influence the natural gas market in California. In addition, as the United States becomes an exporter of liquefied natural gas to countries outside North America, the influence of international markets on United States and California natural gas supply and prices may become more prominent.

However, natural gas consists of roughly 90 percent methane, a potent greenhouse gas. In addition, when combusted for energy use, methane produces carbon dioxide, which is a predominant greenhouse gas. As the state works to reduce greenhouse gas emissions to 40 percent below 1990 levels by 2030, it will need to transition away from fossil fuels including natural gas.

This report covers key topics related to natural gas demand, supply and price trends in California, the United States, Mexico, and Canada. Staff structured the report as follows:

- Chapter 2 discusses natural gas demand trends for residential, commercial, industrial and electric generation in the California. It also discusses demand trends in the United States that can influence natural gas supplies and prices in California.
- Chapter 3 addresses natural gas resources, including shale gas, in the Unites States and the sources of natural gas supplies that are consumed in California. It discusses environmental implications of shale gas production, as well as liquefied natural gas (LNG) imports as a natural gas supply source.

- Chapter 4 discusses the interstate natural gas pipelines that deliver gas into California. It describes the intrastate pipeline system in California that receives natural gas from the interstate pipelines, along with related pipeline safety issues and in-state natural gas storage facilities.
- Chapter 5 discusses natural gas price projections developed by the Energy Commission for the North American gas market - referred to as Henry Hub prices - as well as natural gas price projections for delivery points into California, including the Malin and Topock hubs.
- Chapter 6 examines natural gas issues that can have an impact on California supply and prices including renewable resources and the need for improved gas-electric market coordination, the changing market for natural gas in Mexico, and the potential for LNG exports from the United States.
- Chapter 7 discusses methane emissions from the natural gas system, including estimates of the amount of methane emitted, the need for additional research to better estimate methane emissions, and state policies and actions being taken to reduce methane emissions.

Key Findings

- Greenhouse gas (GHG) emission reduction policies, such as higher energy efficiency requirements, the Energy Commission Building and Appliance Standards, the Renewables Portfolio Standard (RPS), and the Emission Portfolio Standards (EPS), have dampened natural gas demand in California and forecasts suggest this trend will continue. The forecast of natural gas demand for power generation in California indicates that gas-fired generation will decrease at an annualized rate of about 1.5 percent between 2017 and 2028. The Energy Commission's demand forecast, between 2016 and 2028, for the residential, commercial, and industrial sectors shows annual average growth rates that vary between 0.37 percent and 0.98 percent.
- The abundance of natural gas originating from shale formations in the United States has driven natural gas production costs down. As a result, natural gas developed out of state and shipped by pipelines to California costs less than developing in-state resources. As of 2016, in-state natural gas production provided less than 10 percent of California's demand requirements.
- The methane leakage at Aliso Canyon that occurred in late 2015 and early 2016 has raised concerns about the operation and maintenance of storage facilities in California. As a result, the long-term role of this facility in meeting California's energy needs has gained the attention of decision-makers. On July 19, 2017, Energy Commission Chair Robert B. Weisenmiller released a letter to CPUC President Michael Picker urging the CPUC to plan for the future closure of the Aliso Canyon natural gas storage facility. In that letter, Chair Weisenmiller wrote that Energy Commission staff is prepared to work with the CPUC and other

agencies on a plan to phase out the use of the Aliso Canyon natural gas storage facility within 10 years.

- The Energy Commission's price forecasts indicate that the abundance of natural gas resources, particularly from shale formations, will keep prices lower than historical averages for the foreseeable future. From 2006 to 2016, estimates of potential natural gas reserves have more than doubled and, in the same period, the cost of finding and developing has declined. These reduced costs faced by natural gas producers are passed on in the form of lower natural gas hub prices.
- In 2016, natural gas exports to Mexico accounted for 64 percent of all pipeline exports from the United States. According to Mexico's Ministry of Energy, Mexico's natural gas demand grew from 5.09 Bcfd in 2005 to 7.50 Bcfd in 2015 as the country's power plant fleet switched from fuel oil and diesel to natural gas for power generation. As California will likely compete with Mexico for natural gas, these developments will need to be monitored to ensure that sufficient supplies are available for California. However, increased natural gas production from the Permian Basin may mitigate this concern.
- Emissions of methane, a short-lived climate pollutant, can occur throughout the natural gas system. As a result, California has taken steps to reduce methane emissions through aggressive GHG reduction goals. Further, state policy requires the reporting of emissions from gas companies, the tracking of methane emissions, the instituting of best practices for minimizing methane emissions, and the funding of emission research and development.

CHAPTER 2
Natural Gas Demand

Natural gas remains a key fuel source in California. It satisfied about 31 percent of total energy use in California in 2015, and more than the 29 percent for the United States as a whole.[1] Unlike electricity, 90 percent of the natural gas consumed in California is imported from out of state.[2] Also unlike electricity, natural gas trades in an integrated market that spans the North American continent, and gas flows to California from production basins located hundreds or thousands of miles from end users through a complex system of pipelines. To understand the trends and market factors that that will affect natural gas prices in California, one must therefore look at demand across the United States.

The following describes trends in natural gas demand in California and for the entire United States. In particular, state policies such as aggressive energy efficiency in relation to policy goals and the shift to increased renewable energy generation affect California's natural gas demand.

United States Natural Gas Demand

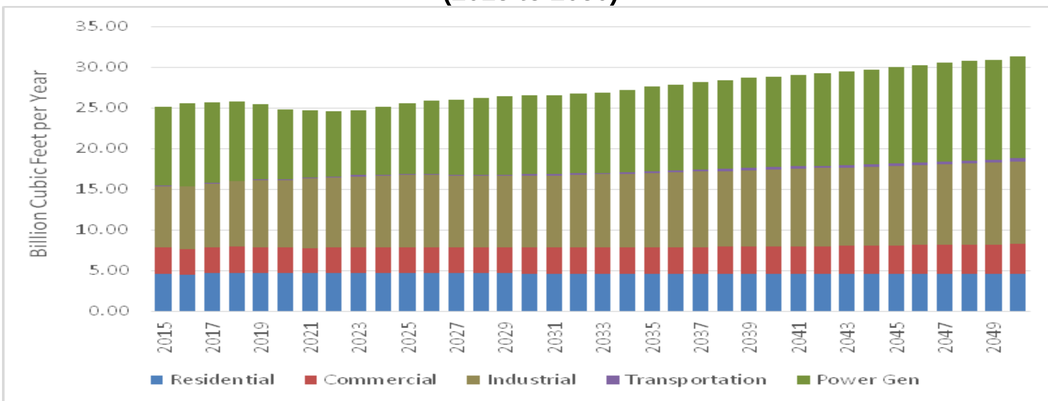
Total nationwide demand for natural gas in 2016 was 27.5 trillion cubic feet (which equates to 75.3 billion cubic feet per day).[3] The U.S. Energy Information Agency (EIA) projects that demand to grow by 0.15 percent per year over the *2018 to 2028* period. (Beyond this period, U.S. EIA's reference case projects annual compound growth of only 0.48 percent out to 2050). **Figure 1** shows the projections for natural gas demand by sector in the United States to 2050.

1 California Energy Commission, using data provided by U.S. EIA: https://www.eia.gov/state/seds/seds-data-fuel.php?sid=US.

2 California Energy Commission, Energy Almanac (natural gas data), http://www.energy.ca.gov/almanac/naturalgas_data/overview.html.

3 U.S. EIA, Natural Gas Monthly, found at https://www.eia.gov/naturalgas/monthly/.

Figure 1: Annual Energy Outlook Reference Case Natural Gas Demand by Sector (2015 to 2050)



Source: U.S. EIA, *2017 Annual Energy Outlook*, https://www.eia.gov/outlooks/aeo/pdf/0383%282017%29.pdf.

Natural gas prices for the last several years have remained relatively low. One consequence of these historically low natural gas prices is the growing preference outside California to use natural gas instead of coal to generate electricity. In fact, gas-fired generation in the United States exceeded coal-fired electric generation for the first time in April 2015.[4]

California Natural Gas Demand

Deliveries of natural gas in 2016 to California totaled 2.1 trillion cubic feet (Tcf).[5] This averages to about 5.8 billion cubic feet of natural gas per day. As shown in **Figure 2**, residential and commercial customers used a total 29 percent of that gas in 2016. Power plants generating electricity used 32 percent and the industrial sector used 37 percent. Transportation accounted for 1 percent of natural gas use in California. Most of this use was in fleet vehicles, such as buses.

Figure 3 shows California's annual natural gas demand by sector back to 1990. California's total natural gas demand has changed only modestly, while California's population grew 31 percent during this same period.[6] The Energy Commission generally attributes this result to the success of the energy efficiency building codes and appliance standards, along with utility efficiency programs.

The variability displayed in **Figure 3** is attributable largely to weather and hydroelectric conditions. Weather is a major driver of residential natural gas demand, the largest portion of which is space heating for homes. Weather is also a large driver of gas use by

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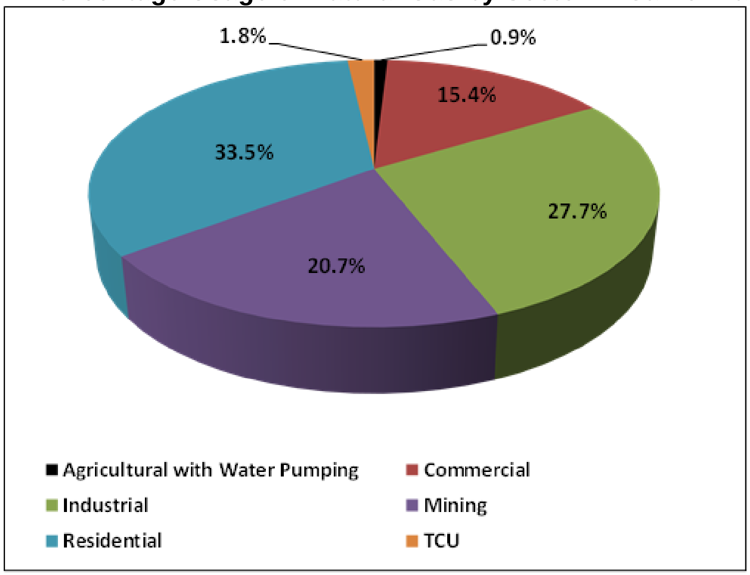
4 U.S. EIA, Today in Energy, March 16, 2016, https://www.eia.gov/todayinenergy/detail.php?id=25392.

5 U.S. EIA, Natural Gas Consumption by End Use, found at https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SCA_m.htm.

6 State of California, Department of Finance, California *Population Estimates, with Components of Change and Crude Rates*, July 1, 1900-2016. December 2016, http://www.dof.ca.gov/Forecasting/Demographics/Estimates/E-7/.

electric generators: warmer summers mean higher air conditioning demand and consequently, more output from gas-fired generation. Wet years versus dry years also play a part, as gas use in the electric generation sector dips in wet years and increases in dry years. The decline in gas demand in 2015 after the most recent drought reflects increased renewable generation and reduced reliance on gas-fired generation.

Figure 2: Percentage Usage of Natural Gas by Sector in California (2016)

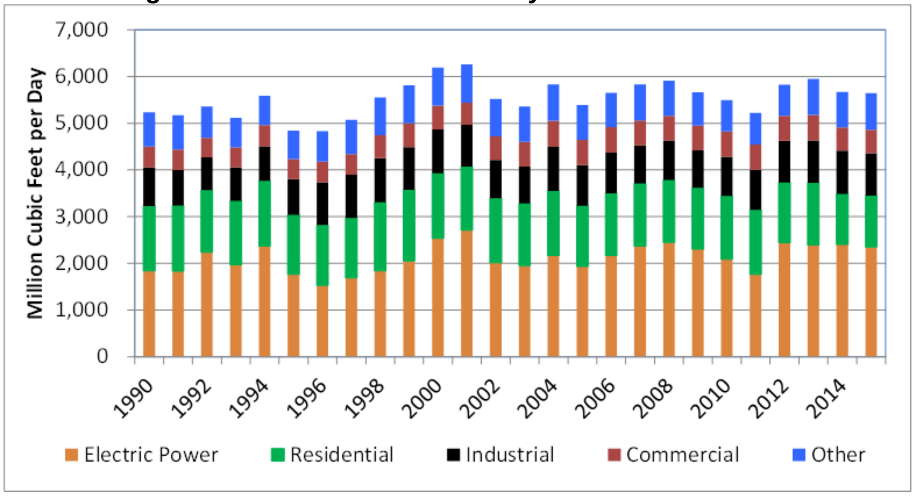


Source: California Energy Commission staff, Quarterly Fuel and Energy Reports (Note: TCU stands for transportation, communications, and utilities).

Demand from the industrial sector has grown since 2010 by 1,173 billion cubic feet (Bcf), or 15 percent. Some of that demand growth has been due to the growth in combined heat and power installations, particularly in the 1990s.[7] The slight uptick, recently, is explained by lower natural gas prices.

7 U.S. EIA (U.S. Department of Energy), *April 2017 Monthly Energy Review*, "Table 4.3 Natural Gas Consumption by Sector," at https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T04.03#/?f=A.

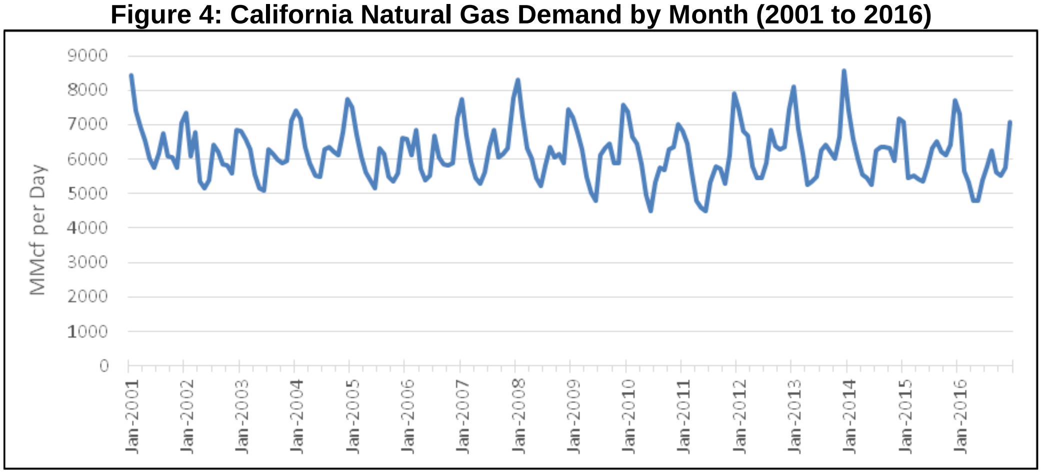
Figure 3: Natural Gas Demand by Sector in California



Source: California Energy Commission.

As depicted in **Figure 4**, California's demand for natural gas is typically highest in January, due to winter space heating. A secondary peak often occurs in September as a result of an increase in power generation because of reduced hydroelectric generation supplies and because the marine layer that keeps the coast cooler begins to dissipate. Those higher coastal temperatures in late summer drive up demand for air conditioning.

Figure 4: California Natural Gas Demand by Month (2001 to 2016)



Source: U.S. EIA, www.eia.gov.

Estimates of future natural gas demand for California comes from the Energy Commission's demand forecast, except for demand by the power generator sector. The future demand for natural gas in the power generation sector is described later in this chapter.[8] The preliminary natural gas forecast is published by planning area and shows

8 California Energy Commission, *Draft Staff Report: California Energy Demand 2018-2028 Preliminary Forecast*, August 2017. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-03/TN220615_20170809T083759_California_Energy_Demand_20182028_Preliminary_Forecast.pdf.

annual average growth rates for the 2016 to 2028 period ranging from 0.37 percent to 0.98 percent in the mid demand case.

However, Additional Achievable Energy Efficiency (AAEE) plays a role in the forecast of natural gas demand. This resource represents potential incremental energy "…savings from initiatives that are neither finalized nor funded but are reasonably expected to occur, including impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented (during the forecast period)."[9] As a result, natural gas demand is expected to fall once AAEE is incorporated into the revised forecast slated to be complete later this year.[10] The utilities, in the *2016 California Gas Report*,[11] forecast growth rates that are negative. This should more closely match growth rates in the Energy Commission's demand forecast once the AAEE is incorporated.[12]

California's Natural Gas Demand from Power Generation in the West

Electricity market generation and competition across the West affect electricity imports and use of natural gas for power generation inside California. The Energy Commission considers this by simulating electricity production westwide, including California. This simulation, conducted using the PLEXOS production cost model,[13] generates estimates of all fuels used for power generation sector for the Western Electricity Coordinating Council (WECC) region, including natural gas, on an economic basis.[14] Staff's WECC-wide production simulation model dataset covers the years 2017 through 2030 for the three common cases for the *2017 IEPR* and one other case with a higher level of AAEE.[15] **Table C-1** in **APPENDIX C** summarizes these cases.

The natural gas demand projections from the PLEXOS modeling for WECC-wide electricity generation (including California), along with the Energy Commission's forecasted demand for the other end uses inside California, become inputs to staff's

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9 http://www.energy.ca.gov/2013publications/CEC-200-2013-005/CEC-200-2013-005-SD.pdf.

12 *2016 California Gas Report*, p.5, https://www.pge.com/pipeline_resources/pdf/library/regulatory/downloads/cgr16.pdf.

13 PLEXOS is a modeling platform owned by Energy Exemplar Ltd. Various models of this type are routinely used to estimate electricity production costs and calculate fuel use, as well as hours of operation by the various generators used to produce electricity.

14 The WECC region, also known as the Western Interconnection, extends from Canada to Mexico and includes the provinces of Alberta and British Columbia in Canada; the northern portion of Baja California, Mexico; and all, or portions of, 14 western states in the United States.

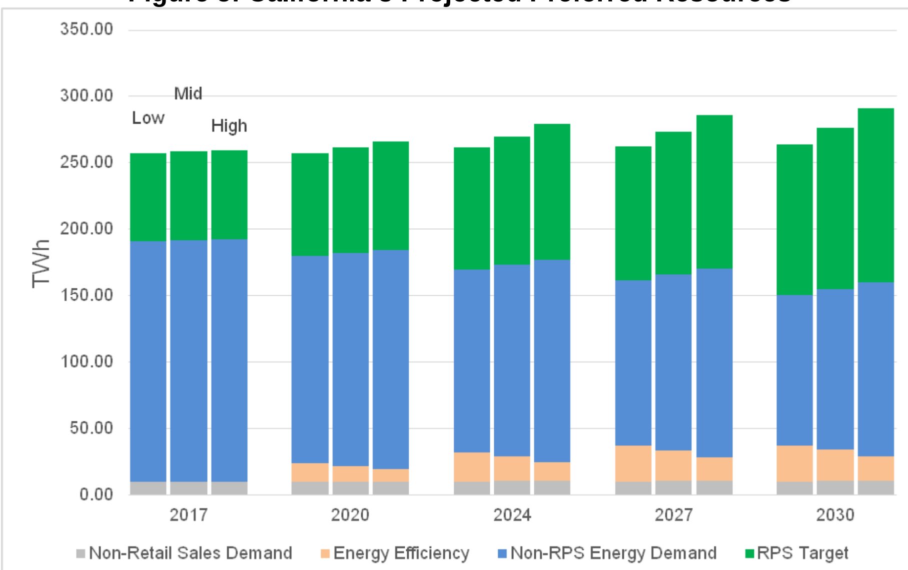
15 Additional achievable energy efficiency is savings from initiatives that are planned but not yet approved by the utilities or any other entity.

North American Market Gas-trade (NAMGas) model.[16] The natural gas demand forecast assumptions for the rest of the United States come from applying an econometric analysis state by state to U.S. EIA recorded data by sector. These combined forecasts provide the natural gas demand inputs for the NAMGas model.[17]

The PLEXOS electricity supply and demand assumptions for California reflect current policy mandates, such as the state's renewables portfolio standard (RPS), retirement of once-through-cooling plants, and Senate Bill 350 energy efficiency targets. Details regarding modeling assumptions are discussed in **APPENDIX C** of this report.

Figure 5 highlights the growing dependence on renewables and energy efficiency resources to meet the forecast of California's electricity retail sales, while reducing the need for natural gas, large hydro, and nuclear resources.

Figure 5: California's Projected Preferred Resources



Source: California Energy Commission, 2017 PLEXOS results.

Future Electric Generation Natural Gas Demand

Figure 6 shows natural gas demand for the residential, commercial, and industrial sectors. California mid case natural gas demand for all three sectors is relatively flat through the forecast period.

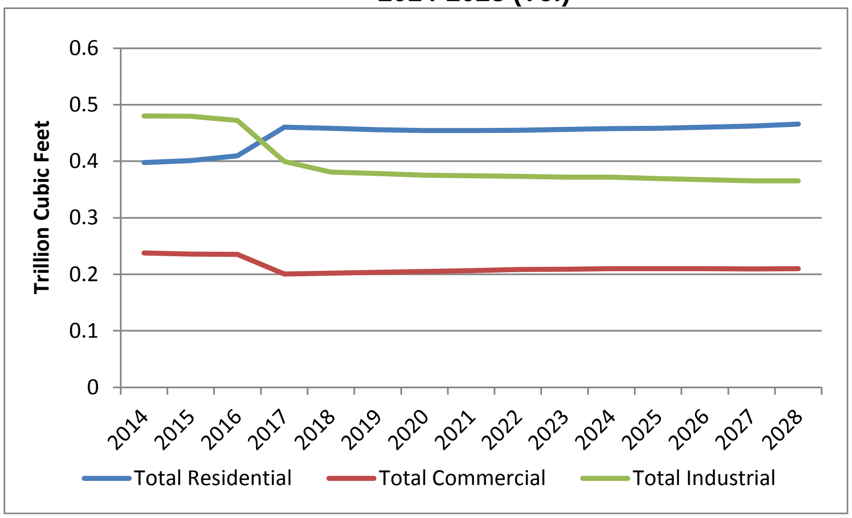
Figure 7 shows the PLEXOS simulation results for annual California natural gas use for power generation for all three common cases. A slight expansion in gas used for power

16 The NAMGas model simulates the economic behavior of natural gas producers in supply basins and natural gas consumers in demand centers. The model will be described in detail in Chapter 5.

17 NAMGAS solves for demand, supply, and price simultaneously and, as it does so, applies elasticities to come up with final equilibrium demand for all sectors that is different from the demand inputs described in this chapter.

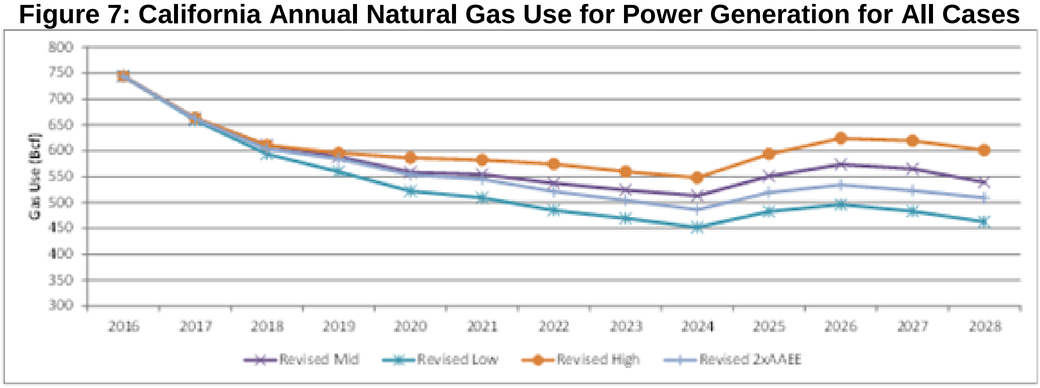
generation in the mid part of the forecast can be attributed partially to the retirement of the 1,775 megawatts (MW) coal-fired Intermountain Power Plant in Utah and its replacement with a 1,200 MW gas-fired unit. However, the end of the forecast period projects a contraction due to the increased contribution of renewable resources and AAEE targets.

Figure 6: California Residential, Commercial, and Industrial Mid Demand Case 2014-2028 (Tcf)



Source: California Energy Commission. *California Energy Demand 2018-2028 Preliminary Forecast*, August 2017.

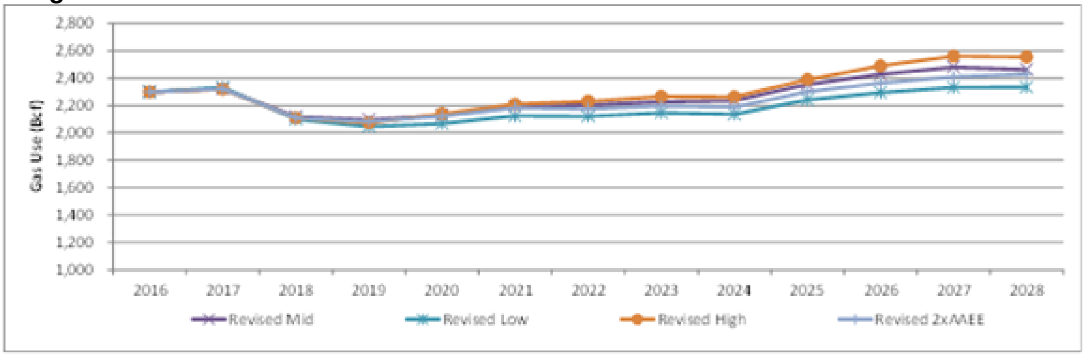
Figure 7: California Annual Natural Gas Use for Power Generation for All Cases



Source: California Energy Commission, PLEXOS results.

Figure 8 shows annual natural gas consumption for electric generation for the WECC region. WECC-wide, there is an expansion of close to 300 Bcf per year (820 million cubic feet per day) over the forecast period, or an increase of 13 percent by 2030. This is driven largely by the retirement of almost 16,000 MW of coal in the West by 2030 and the expected replacement with gas-fired generation.

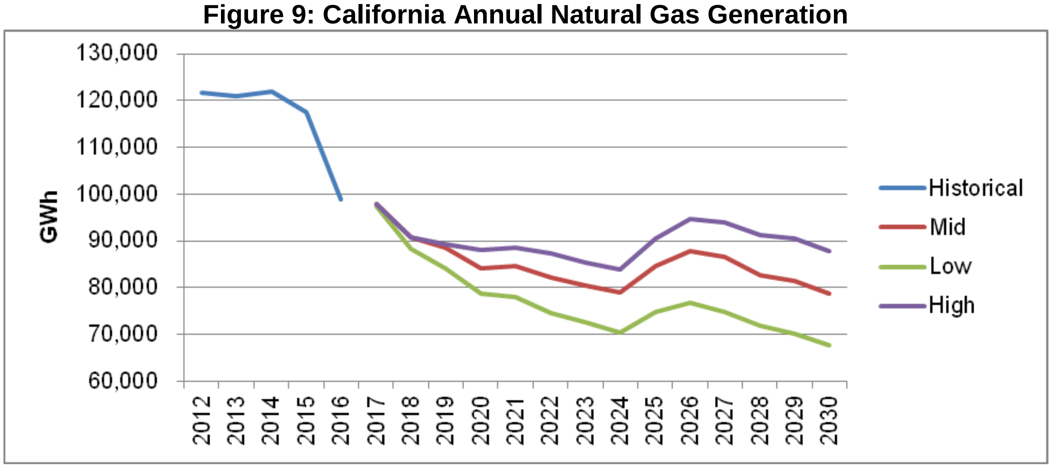
Figure 8: WECC-Wide Annual Natural Gas Use for Power Generation for All Cases



Source: California Energy Commission, PLEXOS results.

Figure 9 also shows that the natural gas demand for electricity generation in California decreases, as existing gas-fired generation operates less frequently and at lower load factors.

Figure 9: California Annual Natural Gas Generation



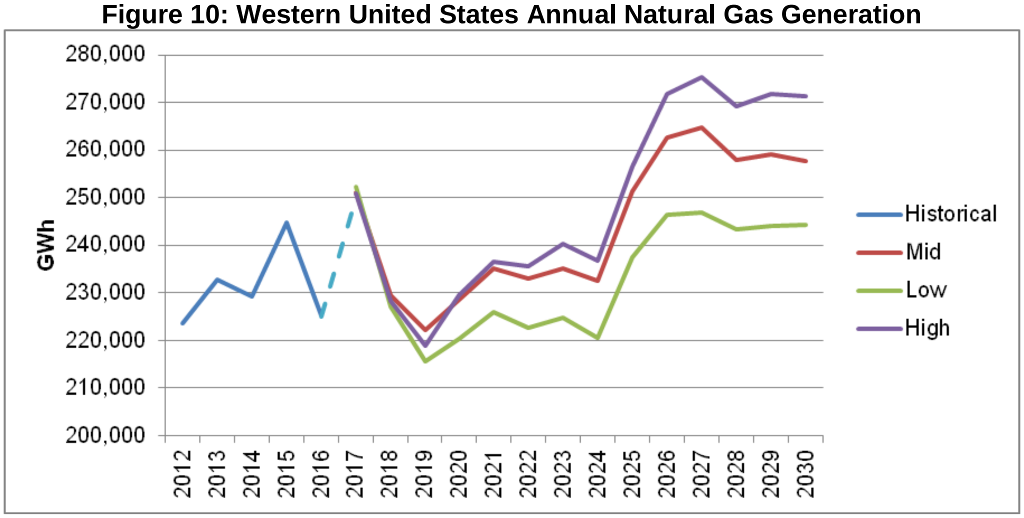
Source: California Energy Commission, PLEXOS results.

The results for the western United States project that natural gas power generation will increase by roughly 20 percent, increasing from about 225,000 gigawatt-hours (GWh) in 2016 to about 260,000 GWh in 2028 for the *2017 IEPR* mid demand case (**Figure 10**). Some of this growth is economic, with natural gas prices projected to remain low so that gas-fired generation continues to compare favorably to the cost of coal-fired generation in the near term. Over the long term, the generation growth is driven by retirements of coal generation facilities as power plants end their useful life and power purchase agreements expire.

Many western utilities have indicated plans to replace these aging coal plants with natural gas-fired power plants. The largest increase in natural gas generation is between 2024 and 2026, when nearly one-third of the expected coal retirements are assumed to retire, while 1,200 MW of new natural gas-fired plants and 4,500 MW of new renewable capacity become operational.[18] During this period, more than 3,000 MW of coal powered plants are also assumed to retire.

The WECC-wide dispatch simulation includes the Canadian provinces of British Columbia and Alberta. The Alberta Electric System Operator (AESO) has announced plans to achieve a complete coal phase-out in Alberta by 2030. The AESO provides its reference case scenario for replacing retired capacity with renewables and natural gas plants in the *AESO 2017 Long-term Outlook*, which was used as the basis for the model generation buildout.[19]

Figure 10: Western United States Annual Natural Gas Generation



Source: California Energy Commission, PLEXOS results.

Each of the common cases developed in PLEXOS displays an increase in total hours of gas-fired generation. In the mid demand case, comparing the California results (**Figure 9**) to the WECC results (**Figure 10**) reveals that California's share of gas-fired generation decreases from 44 percent of the total WECC-wide in 2016 to 33 percent by 2028. These results show California reducing its reliance on natural gas while the rest of the WECC's natural gas generation increases. Similar findings apply to the high and low cases.

18 The Diablo Canyon Power Plant (2,400 MW) is also assumed to retire and, per the proposed settlement, to be replaced with preferred resources.

19 The *AESO 2017 Long-term Outlook* describes Alberta's expected electricity demand over the next 20 years, as well as the expected generation capacity needed to meet that demand, https://www.aeso.ca/grid/forecasting/.

CHAPTER 3:
Natural Gas Sources and Production

Natural gas produced from underground reservoirs can be either dry or wet gas. Wet gas contains methane and natural gas liquids such as propane, ethane, and butane, while dry gas is associated with fewer liquids.[20] In the last 20 years, technological innovations in hydraulic fracturing, often referred to as *fracking,*[21] and in horizontal drilling have allowed for the widespread production of shale-deposited natural gas and other deposit types. In addition, imports of LNG are used to supplement natural gas supplies mainly on the East Coast. This chapter discusses natural gas production and LNG imports.

Natural Gas Sources and Production

The abundance of shale gas resources increased proved reserves, making the United States the largest among gas-producing countries in 2011.[22] Natural gas production, climbing since 2005, reached more than 77,000 million cubic feet (MMcf) per day in 2016. Natural gas produced from shale formations drove total production in the United States to a record high in 2015, and, by 2016, 60 percent of dry natural gas production originated from this formation type. As of 2015, the latest full year for which data are available, the United States is still the leading producer of natural gas among gas-producing countries. The Marcellus (Pennsylvania, New York, and West Virginia) and the Utica (Ohio and West Virginia) shale formations are producing large quantities of natural gas. The U.S. EIA estimated that, in 2016, "about 60 percent of total U.S. dry natural gas production" originated from shale formations.[23]

Today, most of the natural gas consumed in California originates from the following out-of-state sources:

- Western Canadian Sedimentary Basin (Alberta and British Columbia, Canada)
- Permian basin (Texas and New Mexico)
- San Juan basin (New Mexico and Colorado)
- Rocky Mountain region (Wyoming and surrounding states)

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20 *Dry gas deposits* are natural gas accumulations with less than 0.1 gallons of liquid per thousand cubic feet; wet gas deposits have more than 0.1 gallons of liquid per thousand cubic feet.

21 *Hydraulic fracturing* involves the pumping of a sand-laden viscous fluid, into a well/wellbore, to create fractures in a rock formation that stimulate the flow of natural gas or oil, increasing the volumes that can be recovered. Wells may be drilled vertically hundreds to thousands of feet below the land surface and may include horizontal or directional sections extending thousands of feet.

22 U.S. EIA, International rankings, https://www.eia.gov/beta/international/.

23 U.S. EIA, Frequently Asked Questions, https://www.eia.gov/tools/faqs/faq.php?id=907&t=8.

Reserves Estimates

In general, the oil and gas industry recognizes two categories of reserves: proved and potential. Two factors distinguish proved reserves from potential reserves: capital needed for production and level of certainty of production. Proved reserves comprise all resources with sufficient geological and engineering information, indicating with reasonable certainty, that oil and gas operators can recover such reserves using existing technology under existing economic and operating conditions. Production of proved resources requires the expenditure of operating and maintenance funds and minimal capital dollars.

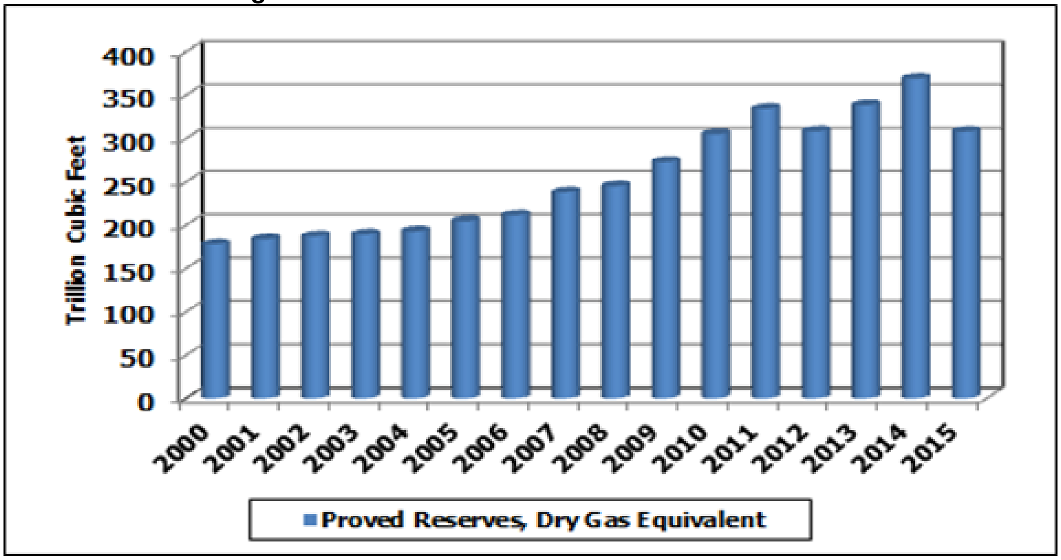
Potential reserves, all undeveloped natural gas resources are geologically known but with decreasing levels of certainty, require operating and maintenance costs and the full expenditures of capital dollars for the production of these resources.

Figure 11 shows the proved natural gas reserves in the United States. In 2005, proved reserves stood at 200 trillion cubic feet. In 2014, proved reserves peaked at more than 350 trillion cubic feet and fell to 300 trillion cubic feet in 2015. The Potential Gas Committee, a group comprising of industry experts, estimated the size of the natural gas resource base, which consists of both proved and potential reserves. As of January 2015, total (proved plus potential) recoverable reserves in the United States climbed to 2,884 trillion cubic feet, up from 2,073 trillion cubic feet in 2008.[24]

The United States consumes about 70,000 MMcf of natural gas per day. Production plus imports from Canada satisfies this demand and provides exports to Mexico, though the abundance of shale gas production has pushed the United States to net exporter status. At the current rate of nationwide consumption, including adjustments for projected exports, the total reserves suggest more than 100 years of available natural gas.

24 Potential Gas Committee, http://potentialgas.org/.

Figure 11: Proved Reserves in the United States



Source: U.S. EIA.

The use of fracking and the resulting abundance of natural gas supplies have driven natural gas production costs down. As a result, natural gas developed out of state and shipped by pipelines to California is less expensive than the cost of developing in-state resources. In 2000, in-state sources provided about 15 percent of California's consumption. That share peaked at more than 16 percent in 2002; by 2016, in-state sources provided less than 10 percent. California's natural gas proved reserves (dry gas equivalent) lingered above 2,500 MMcf between 2000 and 2011 but have dipped below 2,000 MMcf since 2012. California's two identified shales, the Monterey and the Monterey-temblor, have experienced limited testing because of unfavorable economic conditions compared to other locations.

In Canada, the resource base consists of 77 Tcf of proved reserves and 1,087 Tcf of potential.[25] The Canadian oil and gas industry has begun to use fracking techniques and horizontal drilling that have resulted in expanding production. The increased production supports the country's exports to the United States, including California.

Shale-Deposited Natural Gas

Technological innovations in exploration, drilling, and hydraulic fracturing have transformed shale formations from marginal producers of natural gas to substantial contributors to the natural gas supply portfolio. In 2007, shale formations produced about 5,000 MMcf per day, a volume more than eight times the 1998 average of 656 MMcf per day. By 2016, dry gas production averaged more than 43,000 MMcf per day. **Figure 12** displays the average daily dry gas production from shale formations in the United States.

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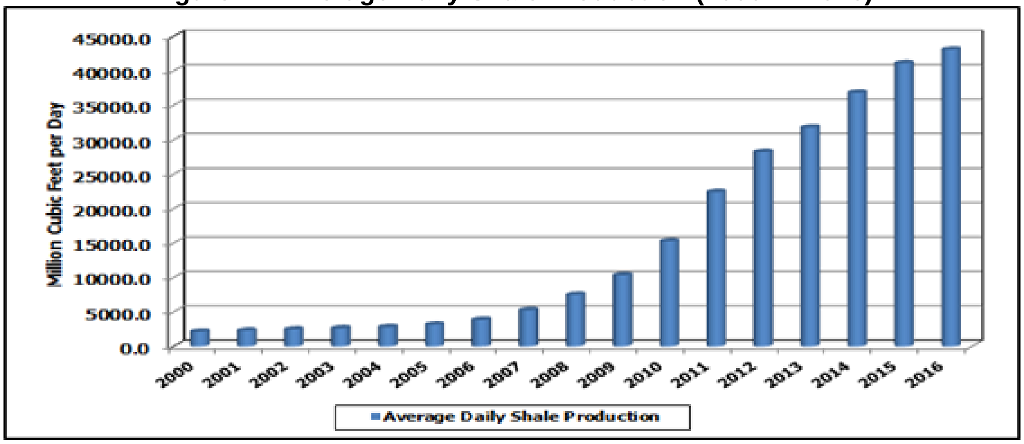
25 Canadian Association of Petroleum Producers, www.capp.ca.

Natural gas from shale formations is increasing the associated share of the Lower 48 supply portfolio, growing from about 1 percent in 1998 to more than 50 percent in 2015. As of January 1, 2015, the Potential Gas Committee estimates that shale formations contain about 1,253 Tcf of recoverable natural gas reserves. **Figure 12** demonstrates the expansion of shale gas production over the last 16 years.

Figure 12: Average Daily Shale Production (2000 — 2016)



Source: U.S. EIA.

Hydraulic fracturing and horizontal drilling have decreased the cost per thousand cubic feet to find and develop natural gas reserves. As result, the development of shale-deposited natural gas surged. The oil and gas industry relies on horizontal wells to access shale formations, and **Figure 13** demonstrates this fact. Since around 2009, the number of vertical wells drilling (rig count, shown on left axis) has collapsed, while the number of horizontal wells drilled has expanded and exceeds the number of vertical wells.[26]

The industry's heavy reliance on horizontal wells to access shale formations establishes a linkage between prices and wells drilling weekly (rig count). **Figure 13** shows the relationship between level of investment (as represented by the horizontal rig count, left axis) and prices (as represented by Henry Hub spot prices, right axis). The vertical well rig count can also represent the level of investment. However, this analysis focuses only on the horizontal well rig count.

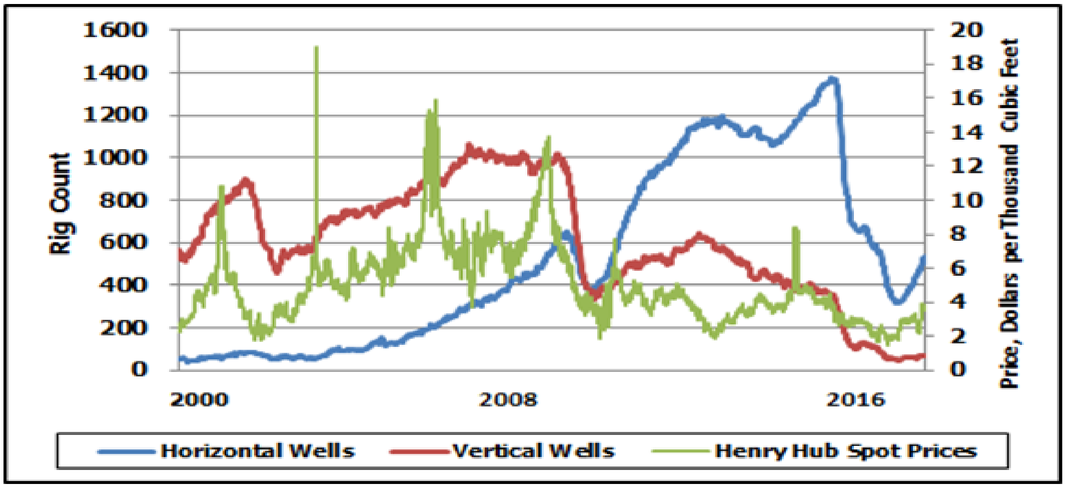
In general, the graph shows that investments rise and fall with prices. Declining prices usually force cutbacks and postponements in scheduled drilling programs. In August 2008, with prices hovering around $11.00/Mcf, the weekly horizontal rig count climbed to more than 600. As prices plunged in late 2008 and early 2009, the horizontal rig count dropped to fewer than 450. The industry experienced a similar phenomenon

26 Rig count refers to the number of wells drilling in a fixed period, such as a week.

between 2014 and 2016. As such, current and expected market prices determine the level of investments in shale formation drilling and development.

Starting around 2012, the industry was drilling fewer wells. Despite fewer wells being drilled, both proved and potential natural gas reserves have continued their upward trajectory due to increased recovery per well.

Figure 13: Horizontal and Vertical Wells Drilled in the United States Versus Natural Gas Prices



Source: Baker Hughes, U.S. EIA.

Environmental Implications of Shale Gas Development

While technological innovations have increased the development of natural gas from shale formations, widespread use of these techniques has raised environmental and other concerns. First, shale formation development may pose an environmental risk to the groundwater supply of surrounding communities. Second, the carbon footprint of a single horizontal well far exceeds that of a typical single vertical well since the drilling process, completion, and hydraulic fracturing require more carbon-based fuels, drilling mud, and water. Lastly, running the required equipment and pumps creates greenhouse gas (GHG) emissions.

In 2013, the California Legislature passed, and the Governor signed, Senate Bill 4 (Pavley, Chapter 313, Statutes of 2013). In November 2013, the California Department of Conservation began the formal rulemaking for well stimulation treatment regulations. As part of SB 4, on July 1, 2015, the Division of Gas and Geothermal Resources (DOGGR) certified the final environmental impact report, *Analysis of Oil and Gas Well Stimulation Treatments in California.*[27] Also under SB 4, on July 9, 2015, the California Council on

27 DOGGR, SB 4 Environmental Impact Report, http://www.conservation.ca.gov/dog/Pages/SB4_Final_EIR_TOC.aspx.

Science and Technology released its final report on well stimulation, *An Independent Scientific Assessment of Well Stimulation in California*.[28]

As a result, a set of rules and regulations, taking effect in 2014, requires oil and gas well operators "to submit notification of well stimulation treatments and various types of data associated with well stimulation operations, including chemical disclosure of well stimulation fluids, to the Division."[29] In addition, the California Department of Conservation now compiles submitted information regarding these activities and makes such information available to the public in a searchable database.

The process of hydraulic fracturing produces large quantities of wastewater. Field operators inject the resulting wastewater into deep wells for disposal. Several jurisdictions, including Ohio, Oklahoma, and Arkansas, have experienced increased frequency of seismic events (earthquakes > 3.0 on the Richter scale). The United States Geological Survey examined the linkage between seismicity and wastewater disposal and concluded that "[f]racking is not causing most of the induced earthquakes. Wastewater disposal is the primary cause of the recent increase in earthquakes in the central United States." Further, the agency added that "[w]astewater disposal wells typically operate for longer durations and inject much more fluid than hydraulic fracturing, making them more likely to induce earthquakes."[30]

Given the geological structure in California, this could be an issue if in-state production with fracking techniques were developed. The United States Geological Survey and other institutes and agencies are continuing work to better understand the linkage between wastewater disposal and earthquakes. The results of these studies can inform decision-makers about how much of an impact this issue could have on California's oil and gas operations.

Liquefied Natural Gas Imports

In the late 2000s, facing declining production from traditional natural gas supply basins, the United States considered LNG importation as a way to diversify existing natural gas supply sources. While the United States still imports and exports LNG, the lower cost of domestic supplies has reduced the demand for imports. As of May 2017, operators in the continental United States manage more than 18 Bcf/day of LNG import capacity, which is underutilized due to the abundance of shale natural gas and the resulting low prices. LNG imports enter the United States mainly through the country's pipeline system on the Eastern Seaboard. States in the Northeast, mid-Atlantic, and

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28 California Council on Science and Technology, http://ccst.us/projects/hydraulic_fracturing_public/SB4.php.

29 California Department of Conservation, Interim Well Stimulation, http://www.conservation.ca.gov/dog/Pages/WellStimulation-OLD.aspx .

30 U.S. Geological Survey, Earthquake Hazards Program, https://earthquake.usgs.gov/research/induced/myths.php.

Southeast are highly populated, and those in the northern portion of the Eastern Seaboard have cold winters. Moreover, pipeline capacity is constrained in the Northeast and the Southeast.

While LNG imports have declined from 349 Bcf in 2011 to 88 Bcf in 2016,[31] the following three LNG import facilities account for more than 95 percent of total importations: Everett LNG in Massachusetts, Cove Point LNG in Maryland, and Elba Island LNG in Georgia. In 2016, 95 percent of the LNG imported into the United States originated from Trinidad, located just off the northeast coast of Venezuela. Much of the remaining LNG is imported from Norway.

Liquefied Natural Gas on the Pacific Coast

While most of the activity related to LNG in the United States is occurring on the Atlantic and Gulf Coasts, this section discusses LNG activity in Canada's Pacific Coast, Oregon, and Baja California, and the relation to the California natural gas market. Liquefied natural gas activity on the Pacific Coast is relevant to California's natural gas market, as proposed LNG export facilities may draw natural gas supply from resource areas that California already uses, including those in western Canada along with the Rockies and the Southwest in the United States.

Across the border from California, in Baja California, Mexico, there is the 1 Bcf/day Costa Azul LNG import terminal in Ensenada, which opened in May 2008 at a cost of $1 billion. Sempra, the parent company of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E), owns and constructed Costa Azul LNG. Costa Azul LNG has a berth that could accommodate one LNG tanker ship. Natural gas received at Costa Azul LNG could be exported to California via pipeline at Otay Mesa in San Diego or at Ogilby in Imperial County. At Costa Azul, the natural gas is regasified and distributed to a secondary pipeline that connects with the 186-mile-long Gasoducto Rosarito pipeline in northern Mexico.

In a 2009 presentation for the IEPR,[32] Sempra claimed that California consumers having access to regasified LNG from Costa Azul would be a secure supply source similar to existing gas production basins in North America (San Juan, Rockies, and western Canada), with the level of supply being determined by market forces. Regarding a Sempra LNG contract with the Mexican national electric company, Comisión Federal de Electricidad (CFE), Sempra also stated that LNG delivered from Costa Azul to Mexico will increase natural gas supply available for delivery to California consumers. Sempra LNG has contractual commitments to CFE that are being supplied by natural gas delivered from the United States.

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31 U.S. EIA, U.S. *Natural Gas Imports by Point of Entry*, https://www.eia.gov/dnav/ng/ng_move_poe1_a_EPG0_IML_Mmcf_a.htm.

32 Sempra LNG Update to the California Energy Commission, August 2009, http://www.energy.ca.gov/lng/documents/costa_azul/2009-08-04_Sempra_LNG_Update_Presentation.pdf.

The U.S. EIA's *International Energy Outlook 2016* report explains the market conditions at Costa Azul. The report states that imports at the Energía Costa Azul terminal have averaged only
4 percent of the nameplate capacity of the terminal since 2011. Sempra originally constructed the terminal to supply the Southern California market and new power plants in Baja California. However, those plants also could be supplied via pipelines from the United States. In addition, the terminal depended mostly on natural gas demand in California, which was limited by the availability of less costly U.S. supplies. The Costa Azul contract allowed for most of the contracted supply from Indonesia to go instead to higher-priced Asian markets over the past several years."

Sempra also has an agreement to sell gas from Costa Azul to California utilities. A 2006 comprehensive legal settlement with the State of California to resolve the Continental Forge litigation included an agreement that, for a period of 18 years beginning in 2011, Sempra Natural Gas would sell to the California utilities, subject to annual CPUC approval, up to 500 MMcf/per day of regasified LNG from Sempra Mexico's Energía Costa Azul facility, that is not delivered or sold in Mexico at the California border index minus $0.02 per MMBtu.[33] There are no specified minimums required, and to date, according to Sempra Energy's *2016 Annual Report*,[34] Sempra Natural Gas has not been required to deliver any natural gas under this agreement.

Current economics are pushing Sempra to consider improvements at Costa Azul that would allow for LNG exports. Specifically, in February 2015, Sempra Natural Gas, IEnova, and a subsidiary of PEMEX (the state-owned oil company in Mexico) entered into a memorandum of understanding to develop a natural gas liquefaction project at this LNG terminal. According to Sempra Energy's *2016 Annual Report*, Sempra Mexico is applying for the primary governmental authorizations for the project. This project could impact California, as Costa Azul is connected to pipelines that receive natural gas from the American Southwest. California also receives gas from this region and could be competing with a Costa Azul LNG export facility for supplies.

33 http://www.wikinvest.com/stock/SEMPRA_ENERGY_(SRE)/Continental_Forge_Settlement.

34 Sempra Energy, *Balance Growth: 2016 Annual Report*, http://www.sempra.com/2016_annualreport/.

CHAPTER 4: Natural Gas Infrastructure

Adequate infrastructure including transmission pipelines, storage, distribution mains, and related equipment is necessary to safely meet the needs of state's natural gas consumers. About
90 percent of California's natural gas supply is delivered to its borders through several interstate pipelines that originate in production basins located several hundred and, in some cases, thousands of miles away. The state's natural gas utilities then deliver natural gas to consumers through their distribution systems. In-state underground storage plays an important role in balancing gas supply and demand on the system, especially during periods of high demand. The state's gas utilities are addressing safety and environmental concerns on their gas systems by replacing and upgrading aging infrastructure. Issues related to interstate and in-state natural gas infrastructure are discussed in this chapter.

Interstate Natural Gas Pipelines

The natural gas pipeline network in the United States consists of an integrated transmission and distribution system that transports natural gas from numerous producing basins to users all over the country via 318,000 miles of interstate and intrastate transmission lines.[35] The pipeline systems of Canada and Mexico connect to this system so that natural gas can flow between the three countries. These interstate pipelines deliver natural gas to the California border, where it enters the in-state gas system operated primarily by California's gas utilities. Some large natural gas users, mostly power plants, receive their gas directly from interstate pipelines.

Figure 14 shows the pipelines and production basins that supply gas to California. These interstate pipelines provide California with supplies from the U.S. Southwest, Rocky Mountains, and western Canada, and regasified LNG, as discussed in Chapter 3.[36] The maximum delivery capacities of these pipelines that serve California, as shown in **Table 1**, provide a total maximum delivery capacity of up to 12.89 Bcf/day. However, California's in-state capacity to receive gas from those interstate pipelines is only about 9 Bcf/day.[37] This exceeds the state's average consumption of about 6 Bcf/day but is less

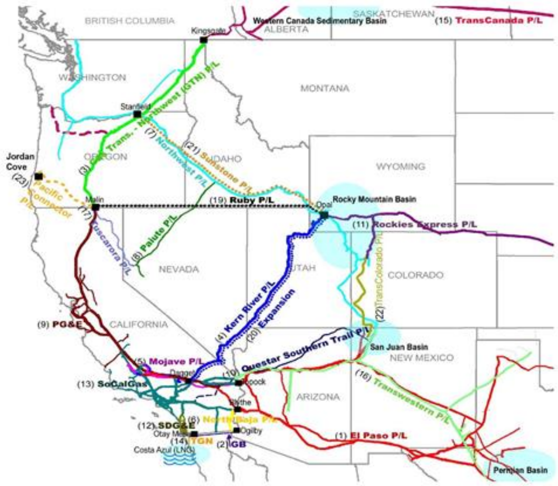
35 U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA), https://www.phmsa.dot.gov/pipeline/library/data-stats.

36 SoCalGas, *2016 California Gas Report*, prepared by California's gas and electric utilities, p.4 https://www.socalgas.com/regulatory/documents/cgr/2016-cgr.pdf.

37 Staff estimated this using data from the *2016 California Gas Report*.

than California's recorded peak-day consumption of 11.157 Bcf, which occurred on December 9, 2013.[38]

Figure 14: Western North American Natural Gas Pipelines



Western North American Natural Gas Pipelines Legend	
1. El Paso Natural Gas	13. Southern California Gas Company
2. Gasoducto Bajanorte (GB)	14. Transportadora de Gas Natural (TGN)
3 Gas Transmission Northwest (GTN)	15. TransCanada Pipeline
4. Kern River Pipeline	16. Transwestern Pipeline
5. Mojave Pipeline	17. Tuscarora Pipeline
6. North Baja Pipeline	18. Unused
7. Northwest Pipeline	19. Ruby Pipeline
8. Piute Pipeline	20. Kern River Expansion
9. Pacific Gas & Electric Company	21. Sunstone Pipeline
10. Questar Southern Trail Pipeline	22. Transcolorado Pipeline
11. Rockies Express	23. Pacific Connector Pipeline
12. San Diego Gas & Electric Company	

Source: *2016 California Gas Report*, https://www.socalgas.com/regulatory/cgr.shtml.

Table 2 provides information on the quantities of natural gas shipped to California along main interstate pipeline systems. The maximum capacities reported in **Table 1** do not equate to actual deliverability. According to the 2016 *California Gas Report*, interstate pipelines connected to Southern California could deliver as much as 6,765 MMcf/day.[39] However, the SoCalGas's infrastructure limits deliveries into its system to 3,875 MMcf/day in firm capacity. For example, while the physical interconnection that PG&E has with SoCalGas at Kern River has a physical capacity of 650 MMcf/day, PG&E

38 SoCalGas, *2016 California Gas Report*, p. 29.

39 Pg. 81-82, 2016 *California Gas Report*.

could deliver only up to 520 MMcf/day from that interconnection point to SoCalGas. North Baja, for example, is not designed to "serve" California but rather transports gas through California from Ehrenberg, Arizona, into Mexico's Baja Norte system.[40] The combined physical capacity of both Gas Transmission Northwest and the Ruby pipelines, which deliver natural gas to Malin, Oregon, totals 3,956 MMcf/day. PG&E's Redwood Path (Lines 400/401) is connected to Gas Transmission N0rthwest and Ruby, and has a firm capacity of 2,023 MMcf/day.[41] In-state firm capacity to receive gas is not large enough, which explains why California does not fully use the capacity of interstate pipeline systems delivering gas to the state.

Table 1: Main Interstate Pipeline Systems Serving California (Bcf/day)

Pipeline System	Maximum Capacity	Average Capacity Utilization Rates (2012-2016)
Gas Transmission Northwest	2.272	51%
Ruby	1.684	46%
Kern River	1.942	77%
El Paso North	2.033	35%*
El Paso South	1.459	35%*
Transwestern	1.150	65%
Mojave	0.976	19%
Southern Trails	0.120	Incorporated into Other in the *2017 California Gas Report Supplement*
TGN	0.415	Utilization not reported in the *2017 California Gas Report Supplement*
Tuscarora Gas Transmission Company	0.236	Utilization not reported in the *2017 California Gas Report Supplement*
North Baja Pipeline System	0.600	Not designed to serve California but transports gas from Arizona

40 Pg. A-1, California Energy Commission, *AB 1257 Natural Gas Act Report: Strategies to Maximize the Benefits Obtained from Natural Gas as an Energy Source.*

41 Pg. 41, *2016 California Gas Report.*

		through California to serve Mexico.
Total	12.89	

Sources: PointLogic, 2017 Supplemental California Gas Report, https://www.socalgas.com/regulatory/cgr.shtml.

*Average capacity utilization rate for both El Paso North and South combined.

Table 2: Utilization of Main Interstate Pipeline Systems (Bcf/day)

Year	El Paso*	Transwestern	GTN	Kern River	Mojave	Other**	Ruby	Total
2012	1.081	0.865	1.064	1.814	0.396	0.046	0.872	6.138
2013	1.181	0.945	0.948	1.429	0.161	0.109	0.779	5.552
2014	1.155	0.832	1.173	1.414	0.23	0.084	0.826	5.714
2015	1.544	0.491	1.26	1.251	0.111	0.413	0.758	5.828
2016	1.104	0.611	1.331	1.543	0.014	0.128	0.631	5.362

Source: 2017 Supplemental California Gas Report, https://www.socalgas.com/regulatory/cgr.shtml.

*The 2017 Supplemental California Gas Report reports El Paso North and El Paso South as one.

**Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.

Natural Gas Storage Facilities in California

Underground natural gas storage plays an important role in balancing California's demand requirements with supply availability. California has 14 natural gas storage facilities: four owned by SoCalGas, three by PG&E, and seven by independent operators. **Table 3** shows the natural gas storage working capacity in California.[42] The table also breaks down natural gas storage in California by utility-owned and independently owned working capacity. Natural gas storage facilities (including independently owned) that are interconnected to PG&E's natural gas system have a working gas capacity of 236.0 Bcf. SoCalGas operates four storage fields that interconnect with its transmission system and have a working gas capacity totaling 135.3 Bcf. Combined, the systems of both gas utilities have a capacity of 237.4 Bcf. California's total capacity is 371.3 Bcf.

As the previous discussion of interstate pipeline capacity indicates, pipeline flows into the state at the receipt points at the border, which are less than the interstate pipelines can deliver, are not sufficient to meet peak demand. In general, natural gas storage can provide seasonal, daily, and intraday balancing of supply and demand, allowing utilities to meet higher peak demand than pipeline infrastructure might otherwise allow.

42 Storage working capacity is the portion of total capacity that operators use to satisfy demand requirements.

Table 3: California Natural Gas Storage Working Capacity

	Working Capacity(Bcf)	Maximum Withdrawal Capacity(Bcfd)
PG&E[43]	102.1	2.7
Independently-owned/PG&E controlled	133.9	
SoCalGas	135.3	3.7
Utility Total	237.4	
California Total	371.3	

Sources: U.S. EIA Natural Gas Annual Respondent Query System (EIA-191 Data through 2015),https://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP7&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compid=&f_fullscreen.

Table 4 includes aggregated, or combined, data of injections and withdrawals of California natural gas storage facilities.[44]

Table 4: Injections and Withdrawals at California Natural Gas Storage Facilities MMcf

	2011	2012	2013	2014	2015	2016
Injections	263,067	218,663	182,046	280,516	206,774	124,474
Withdrawals	242,477	170,586	268,548	235,181	204,077	164,077
Net Withdrawals	-20,590	-48,077	86,502	-45,335	-2,697	39,603

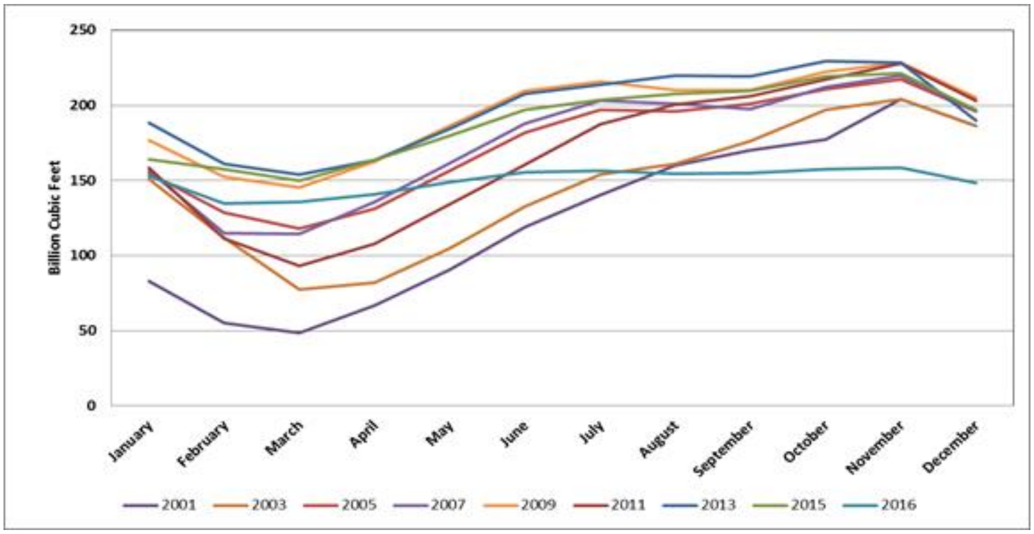
Source: U.S. EIA.

Within the calendar year, storage levels fluctuate as natural gas withdrawal figures are higher during the winter months to meet heating demand, while injections are higher in the spring and summer as space heating demand declines in those months, as shown in **Figure 15.**

43 California Energy Commission, *Natural Gas Market Assessment, Staff Report* , 2003, p. 51, http://www.energy.ca.gov/reports/2003-08-08_100-03-006.PDF. Accessed July 2017.

44 The reduced availability of Aliso Canyon is reflected in the decline in natural gas injections and withdrawals between 2015 and 2016.

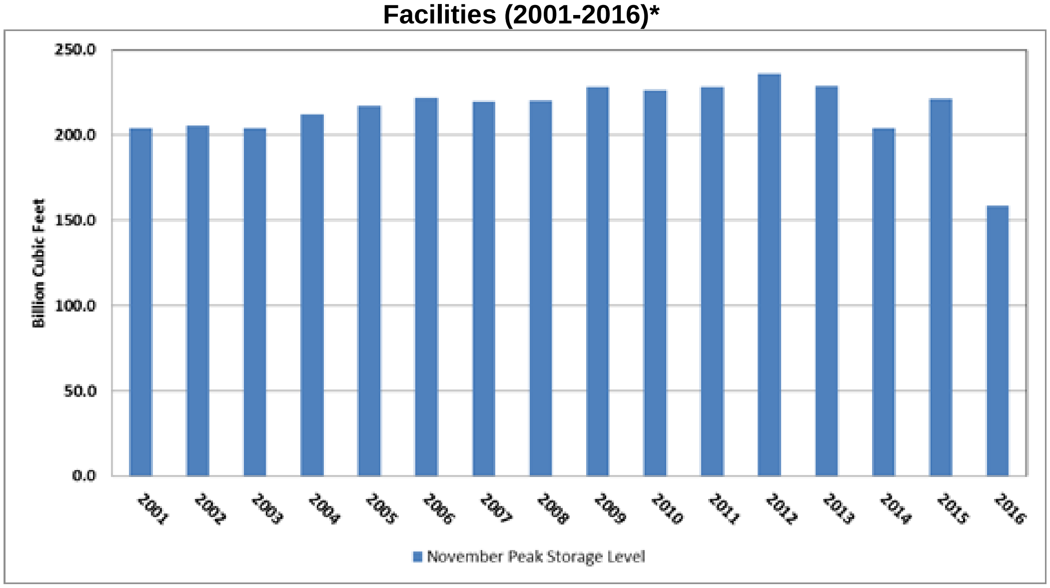
Figure 15: Natural Gas Storage Levels by Month for California Natural Gas Storage Facilities



Source: U.S. EIA.

November is when California's natural gas storage levels are at their annual peak, before the start of winter withdrawals. **Figure 16** shows November storage levels for California natural gas storage facilities for the years 2001 through 2016. As with injections and withdrawals, the low November storage level in 2016 is low due to the loss of Aliso Canyon.

Figure 16: November Storage Levels for California Natural Gas Storage Facilities (2001-2016)*



Source: California Energy Commission, using PG&E and SoCal gas data.

* Aliso Canyon excluded.

Long-Term Role of Storage

The long-term role of storage in California's gas system has been brought into question as a result of the leak at Aliso Canyon that occurred in late 2015 and early 2016. On July 19, 2017, following months of testing, inspection, and implementing new safety protocols, DOGGR and the CPUC concurred that the facility is safe to operate at a greatly reduced capacity, but with restrictions on withdrawing gas only if there is a reliability issue. The Energy Commission's *2017 IEPR* includes a chapter on energy reliability issues in Southern California. That chapter details the energy reliability impacts of the Aliso Canyon leak, along with information on mitigation measures.

Also on July 19, 2017, Energy Commission Chair Robert B. Weisenmiller released a letter to CPUC President Michael Picker urging the CPUC to plan for the future closure of the Aliso Canyon natural gas storage facility. In that letter, Chair Weisenmiller wrote that Energy Commission staff is prepared to work with the CPUC and other agencies on a plan to phase out the use of the Aliso Canyon natural gas storage facility within 10 years.[45]

Senate Bill 380 (Pavley, Chapter 14, Statutes of 2016), also required the CPUC to open a proceeding to determine the feasibility of minimizing or eliminating the use of SoCalGas' Aliso Canyon storage facility while maintaining energy and electric reliability for the Los Angeles region. In response, the CPUC opened an order instituting investigation (I.17-02-002) proceeding and expects to make a final decision in mid-2018.

Finally, the California Council on Science and Technology is developing a report that will include a review of potential health risks and community impacts associated with the operation of Aliso Canyon; fugitive gas emissions; and the linkages between gas storage, California's current and future energy needs, and its GHG reduction goals.[46] Staff expects this report to be completed by late December 2017.

Natural Gas Pipeline Safety

Natural gas infrastructure safety has become more prominent since the *September 9, 2010* explosion of a PG&E high-pressure pipeline, along with the major gas leak at Aliso Canyon. In the wake of these events, the CPUC has authorized increased revenue requirements for Pacific Gas and Electric (PG&E), Southern California Gas (SoCalGas), and San Diego Gas & Electric (SDG&E) related to natural gas transmission and distribution infrastructure safety. As gas utilities place greater emphasis on safety and replacing aging infrastructure, natural gas utility revenue requirements for transmission, distribution and storage services increased by 11.9 percent in 2016, 12.6

45 California Energy Commission, News Release: "Energy Commission Chair Releases Letter Urging the Future Closure of Aliso Canyon," July 2017.

46 California Council on Science and Technology, Current Projects: Natural Gas Storage, http://ccst.us/projects/natural_gas_storage/index.php.

percent in 2015, and by 45 percent from 2010 until 2017.[47] **Table 5** shows that the increases in total authorized revenue requirements for transmission, distribution, storage, and customer services, combined under the "transportation" category, have increased by 73 percent from 2011 to 2016.[48] These costs increased by 115, 45, and 48 percent for PG&E, SoCalGas, and SDG&E, respectively, from 2011 to 2016.

Table 5: Historical Revenue Requirements for Transportation Summary (Thousand dollars)

Utility	2011	2012	2013	2014	2015	2016
PG&E	$1,533,332	$1,731,021	$1,828,380	$2,076,507	$2,500,926	$3,292,033
SoCalGas	$1,971,438	$2,018,108	$2,218,229	$2,392,986	$2,511,953	$2,850,150
SDG&E	$276,573	$244,973	$324,022	$318,647	$378,037	$408,148
Total	$3,781,343	$3,994,102	$4,370,631	$4,788,140	$5,390,916	$6,550,331

Source: CPUC Energy Division, *California Electric and Gas Utility Cost Report*, April 2017.

In its most recent rate case, SoCalGas/SDGE received CPUC approval for funding for 2016 through 2018 for safety enhancements. PG&E's approval extended from 2017 to 2019.[49] With this funding, PG&E and SoCalGas/SDG&E will enhance the safety of their respective pipeline systems by replacing infrastructure, installing cathodic protection[50] to protect pipelines from corrosion, and performing assessments of their pipeline systems.

SoCalGas' five-year capital plan includes $6 billion in infrastructure investments, including about $1.2 billion in 2017 for improvements to distribution, transmission, and storage systems and for pipeline safety.[51] In 2017, the CPUC authorized a $58 million

47 CPUC, Energy Division, *California Electric and Gas Utility Cost Report*, April 2017, http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2017/AB67_Leg_Report_PDF_Final_5-5-17.pdf.

48 CPUC, *California Electric and Gas Utility Cost Report*, April 2017, p. 41, http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2017/AB67_Leg_Report_PDF_Final_5-5-17.pdf.

49 *General rate cases* are proceedings used to address the costs of operating and maintaining the utility system and the allocation of those costs among customer classes. For more information: http://www.cpuc.ca.gov/General.aspx?id=10431.

50 *Cathodic protection systems* help prevent corrosion from occurring on pipeline exteriors by imparting a direct current onto the buried pipeline using a device called a *rectifier*. As long as the current is sufficient, corrosion is prevented or at least mitigated and held in check. For more information, please view the PHMSA website at https://primis.phmsa.dot.gov/comm/FactSheets/FSCathodicProtection.htm.

51 SoCalGas, News Release: "SoCalGas Begins a More than $14 Million Pipeline Safety Project in the Counties of San Luis Obispo and Santa Barbara," https://www.socalgas.com/1443740785750/5-25-17-SoCalGas-to-Begin-Infrastructure-Testing-Upgrades-in-SLO-County.pdf.

increase from $375 million to $433 million in revenue requirements for the operation and maintenance of PG&E's gas distribution system.[52]

In spring 2018, the Energy Commission intends to submit a formal application to the CPUC to expand the Natural Gas Research and Development program. This application will include the proposed funding amount for the expanded program, the schedule, and a summary of planned research initiatives. Prior to this application, the Energy Commission will host public workshops to solicit input from the natural gas utilities and other interested stakeholders. This application will propose roughly double the current funding amount and will primarily focus research on infrastructure safety, along with climate change adaptation issues.

Recent Developments

On October 1, 2017, a portion of SoCalGas Line 235-2, a 30-inch pipeline which delivers natural gas from Needles, California, exploded and caught fire five miles west of Newberry Springs in San Bernardino County.[53] In response to the incident, SoCalGas isolated the exploded section of Line 235-2. While the incident resulted in some damage to construction equipment, there were no reported injuries. The cause of the explosion on Line 235-2 remains under investigation,[54] and SoCalGas has not provided an estimate of when repairs will be completed. In addition, since July 2016, SoCalGas has performed unplanned maintenance on Line 3000, which delivers natural gas from Topock, Arizona to Southern California. The utility expects maintenance on Line 3000 to continue until May 1, 2018. SoCalGas's Line 4000, which delivers natural gas from SoCalGas Northern Zone towards the Los Angeles Metropolitan area, was undergoing maintenance since September 2017. The pipeline is back in service as of December 22, 2017.

Although Line 4000 is operational again, changes in pipeline capacity from the other two lines undergoing maintenance limit the quantities of natural gas that could be injected into storage facilities for use in the 2017-2018 winter months. While SoCalGas/SDG&E's current firm receipt capacity totals 3,875 million cubic feet per day (MMcf/day), receipt capacity on the Northern Zone totals 1,590 MMcf/day.[55] Natural gas delivered to SoCalGas Northern Zone comes through Topock, Arizona; Needles, California; and from the Kern River Pipeline at Kramer Junction, California.

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52 CPUC, Decision 16-06-056: *Decision Authorizing Pacific Gas And Electric Company's Revenue Requirement For Gas Transmission and Storage Services and Adopting Interim Rates*, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K610/164610296.pdf.

53 October 3, 2017. The Times of India. "Natgas pipe catches fire in Southern California, no injuries – SoCalGas." https://timesofindia.indiatimes.com/business/international-business/natgas-pipe-catches-fire-in-southern-california-no-injuries-socalgas/articleshow/60917851.cms

54 October 1, 2017. San Bernardino Sun. "Newberry Springs Gas Line Catches Fire, Destroys Heavy Equipment" http://www.sbsun.com/2017/10/01/newberry-springs-gas-line-catches-fire-destroys-heavy-equipment/

55 Pg. 82, *2016 California Gas Report.*

CHAPTER 5: Natural Gas Prices

As mentioned in the Chapter 4, California's natural gas system interconnects with the larger North American natural gas pipeline network. Because California connects to a natural gas pipeline network that encompasses North America, staff modeled supply, demand, and the transportation of natural gas for the three countries in the continent: Canada, United States, and Mexico. Energy Commission staff uses the NAMGas model to simulate the economic behavior of natural gas producers in supply basins and natural gas consumers in demand centers. The model also includes representations of intrastate and interstate pipelines, LNG import and export facilities, and other infrastructure.

The model encompasses the regions of the continental United States, Alaska, Canada, and Mexico. Staff developed three "common" cases for the *2017 IEPR*: the high demand, mid demand, and low demand cases, using inputs and assumptions such as increased energy efficiency, renewable generation and varying amounts of coal-fired electrical generation retirements. The inputs and assumptions are expected to have an impact on the natural gas market. In addition, values for proved and potential reserves in North America appear on the supply side of the NAMGas model.

In the NAMGas model, producers, consumers, and natural gas transporters try to maximize economic utility; suppliers aim to maximize profits while consumers try to get the lowest price. The interaction of suppliers and consumers produce estimates of the competitive price of natural gas. The model reconstructs the North American natural gas market by modeling the connections of the North American supply basins to intrastate and interstate pipelines, which deliver natural gas to demand centers. The model used by staff was constructed and used over several years.[56]

For the *2017 Natural Gas Outlook Report*, staff updated the model to include North American natural gas infrastructure, including new pipelines and new LNG export capacity, while resetting assumptions in the California portion of the model to account for *2017 IEPR* cases. To calibrate the model, actual production and demand data were used for the years 2014 to 2016, provided by the U.S. EIA, Mexico's Ministry of Energy, and Canada's National Energy Board. The model iterates back and forth among the aforementioned components to find economic equilibrium at all modeled pricing hubs (nodes) and in all time periods. As a consequence, the model produces forecasts of natural gas supply, demand, and prices.

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56 Brathwaite, Leon, Anthony Dixon, Jorge Gonzales, Chris Marxen, Peter Puglia, and Angela Tanghetti. 2015 Natural Gas Outlook Draft Staff Report, California Energy Commission. CEC-200-2015-007-SD, p. 12. Kennedy, Robert, Silas Bauer, Leon Brathwaite, Peter Puglia, Jorge Gonzales, and Katherine Anderson, 2013 Natural Gas Issues, Trends, and Outlook Final Staff Report, California Energy Commission. CEC-200-2014-001-SF, p. 19.

Three "Common" Cases: High Demand, Mid Demand, and Low Demand

The variables and assumptions for each of the three common cases are explained in **APPENDIX A.** The model incorporates information from the Energy Commission's preliminary 2017 *California Energy Demand* forecast of natural gas for residential, commercial, industrial, and transportation sectors. The 2015 estimates of California's AAEE came from the *2015 California Energy Demand Forecast*.

NAMGas incorporates a forecast of natural gas demand for power plants in the WECC region. This forecast comes from an electricity dispatch model that uses the PLEXOS software. The Energy Commission's electricity demand forecast serves as an input to the PLEXOS model and includes estimates of coal retirements in the WECC. Staff incorporated August 2017 PLEXOS model run outputs into the NAMGas model.

Staff also constructed three common residential, commercial, industrial and transportation natural gas demand cases for North American regions outside of California and for natural gas power generation demand outside of the WECC region. To build reference demand for the three common cases, staff used an econometric model that forecasts reference demand in the residential, commercial, industrial, and transportation sectors outside California along with natural gas demand for the power generation sector outside the WECC region.[57] This econometric model, known as "small-m," includes factors such as economic growth, an estimate of coal retirements, heating and cooling degree-days, and historical demand for natural gas by sector.[58]

Modeling Natural Gas Supply

The NAMGas model was populated with assumptions of natural gas supply and incorporated estimates of both proved and potential reserves. Potential reserves include all undeveloped natural gas resources. In the United States, estimates of potential reserves, published by the PGC's *Potential Supply of Natural Gas in the United States: Report of the Potential Gas Committee* (December 31, 2014), provide the basis of available natural gas supply and the EIA provides estimates of proved reserves.[59] The National Energy Board provided estimates of proved and potential resources for Canada, while Ministry of Energy in Mexico furnished estimates of proved and potential resources in that country.

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57 An econometric model specifies the hypothesized statistical relationship between the various economic quantities pertaining to a particular economic phenomenon under study. Staff's small "m" model uses variables including economic growth, an estimate of coal retirements, heating and cooling degree days, and historical natural gas demand to build high demand, mid demand, and low demand reference cases for use in the NAMGas model.

58 Heating degree days are a measure of how cold the temperature was on a given day or over a period of days. Cooling degree days (CDD) measure how hot the temperature was on a given day or over a period of days. See U.S. EIA website: https://www.eia.gov/Energyexplained/index.cfm?page=about_degree_days.

59 Potential Gas Committee, http://potentialgas.org/biennial-report.

As total demand for natural gas grows, producers will bring more of these resources online, beginning with the lowest-cost resources. Since California imports about 90 percent of its natural gas supply, estimates of potential and proved reserves of natural gas basins in North America are very important components of the NAMGas model, because California depends on imported natural gas.

The Natural Gas Market in the United States (2014 — 2016)

To calibrate the model, staff incorporated historical data from 2014 to 2016. At Henry Hub, Malin, and Topock, natural gas prices decreased each year from 2014 to 2016. Better resource recovery technology, which resulted in over a decade of increased supply, accounts for this observation. Each year, from 2005 through 2015, dry natural gas production in the United States increased.

However, dry gas production in the United States decreased to an estimated 26.46 Tcf in 2016. As prices drop, there will be less economic incentive for producers to invest capital to develop additional gas wells and to increase production. Available data reflects this trend. The U.S. EIA indicates that the number of producing gas wells in the United States decreased from nearly 578,000 in 2012 to about 555,000 in 2015.[60] However, production efficiency, such as increased recovery or output per well, may account for some of the decline.

Nationwide demand for natural gas also increased from 22.91 Tcf in 2009 to 27.49 Tcf in 2016. This increase is in response to the lower prices. Demand for natural gas in the electric generation sector displayed strong growth as the lower price of natural gas made it more economical to use than coal. In the United States, natural gas demand in the electric generation system increased from 7.57 Tcf in 2011 to an estimated 9.98 Tcf in 2016.

As natural gas prices have declined due to increased production in the United States, California natural gas utility ratepayers have experienced lower procurement costs. For example, natural gas procurement costs for core customers for PG&E, SoCalGas, and SDG&E decreased from $3.55 billion in 2014, to $2.05 billion in 2016 (a 42 percent decline).[61] This trend started in 2010, as natural gas procurement costs fell 51 percent between 2010 and 2016.[62] Major pricing points provide relevant information. Henry Hub serves as the benchmark for natural gas prices in North America while also serves as the trading location used to price the New York Mercantile Exchange natural gas futures

60 Producing gas wells are wells currently producing natural gas. However, the rig count indicates the number of wells the industry is currently drilling.

61 CPUC Energy Division, *2017 California Electric and Gas Utility Cost Report*, p. 38, April 2016.

62 CPUC Energy Division, *2017 California Electric and Gas Utility Cost Report*, p. 39, April 2016.

contracts. Malin, Oregon is the point at which gas enters Northern California from Canada and the Rocky Mountains.

Natural Gas Price Projections

While the NAMGas model produced hub price backcasts[63] and forecasts for natural gas hubs throughout North America, this paper presents forecasts for the following three hubs: Henry Hub (near Erath, Louisiana), Malin (Oregon), and Topock (Arizona). In addition, the Kern River Gas Transmission pipeline can transport natural gas from the Rocky Mountains to Southern California to Bakersfield via Daggett, California. Natural gas from both the San Juan Basin in the Four Corners area and the Permian Basin in western Texas and eastern New Mexico may be transported to Topock, Arizona.

The model provides projections of prices and supply of natural gas for California and the continental United States for 2017 through 2030.[64] Between 2016 and 2017, natural gas prices at Henry Hub increased. The daily average Henry Hub price from January 4, 2016, through August 18, 2016, was $2.29/Mcf, while the daily average Henry Hub price from January 3, 2017, through August 18, 2017, was $3.10/Mcf, an increase of 36 percent.[65]

In the mid demand forecast, the model estimates that the Henry Hub price for 2017 will be $3.11/Mcf. After a forecasted average price increase of 6.2 percent a year from 2017 through 2020, prices will rise at about 2.1 percent per year between 2020 and 2030. Staff calculated that after accounting for inflation, prices dropped an average of 6.7 percent per year between 2010 through 2016. The development of shale-deposited natural gas accounts for the lowering of real prices.[66]

The faster growth rate in Henry Hub prices occurring between 2017 and 2020 arises from growing natural gas demand, particularly in the electricity sector in parts of the South and in Indiana, Ohio, West Virginia, and Pennsylvania. By 2020, the model forecasts that Henry Hub prices will climb to $3.71 per thousand cubic feet. As prices at Henry Hub increase over time, prices at Malin and Topock will rise as well. Prices at Malin and Topock will grow at a slower pace than Henry Hub because much of the natural gas demand growth will occur in the eastern half of the United States, where natural gas is replacing coal in the power generation fleet.

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63 A backcast calibrates a model used for forecasting and assesses the model's ability to produce known results, such as prices in prior years (2014-2016 in the current modeling work). This process should provide results that are close or at the actual prices for 2014, 2015, and 2016.

64 The model provides estimates through 2050. However, staff only publishes projections through 2030. This affords consistency with the Demand Analysis Office and all PLEXOS simulations.

65 Hub prices in this chapter are presented in 2016 U.S. dollars.

66 Inflation adjusted.

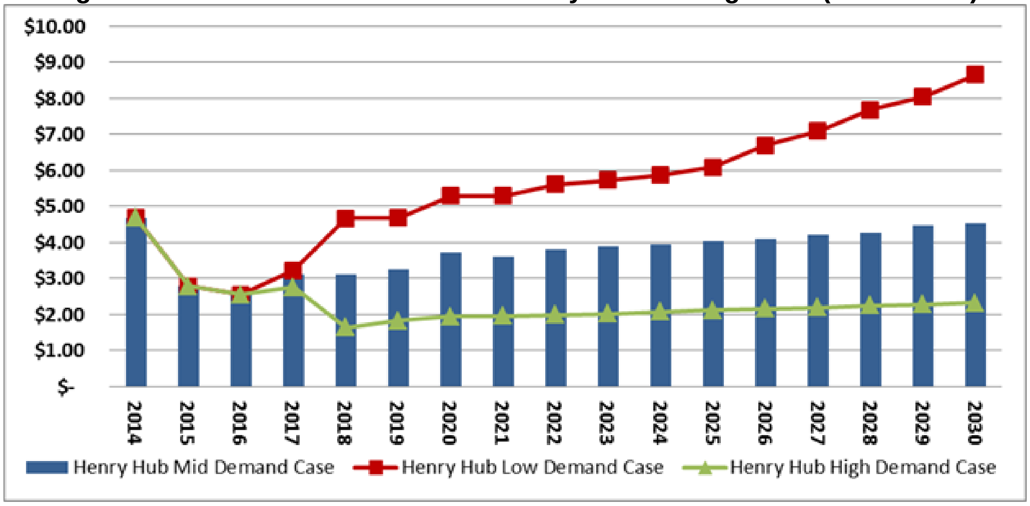
Figure 17[67] shows the forecasted Henry Hub prices for the low demand, mid demand, and high demand cases. The mid demand case represents a "business-as-usual" environment. However, the high demand and low demand cases use modified assumptions to the mid demand case that either push natural demand higher or lower. The high demand case assumes lower costs for developing proved and potential resources than in the mid demand case, while the low demand case assumes higher costs than in the mid demand case.

Furthermore, the high demand case assumes larger estimates of available potential resources when compared to the mid demand case. Similarly, the low demand case assumes smaller estimates of potential resources. The additional production in the higher demand case will result in lower prices during the forecast period while the high production costs in the low demand case will keep prices high.

As the high demand case is also a low-cost case with higher estimates of potential reserves, production is forecasted to be higher than the mid demand and low demand cases. **Figure 18** shows natural gas production in the three common cases. The U.S. natural gas production in the mid demand case is forecasted to reach 38 Tcf in 2030, while climbing to 41 Tcf in the high demand case and falling to 28 Tcf in the low demand case. According to the U.S. EIA, dry natural gas production was 26.46 Tcf in 2016.

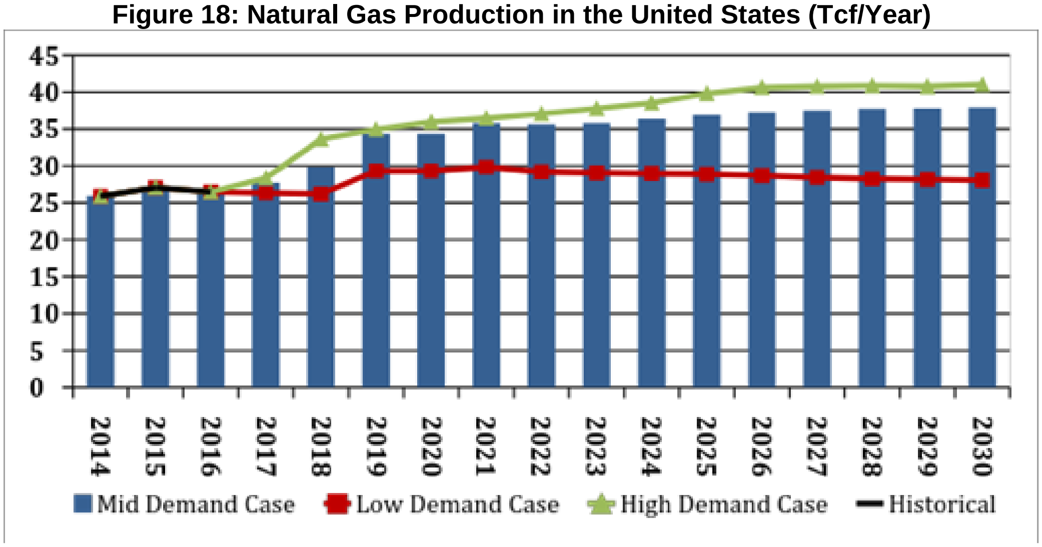
67 Staff updated this figure with the revised model runs.

Figure 17: IEPR Common Cases for Henry Hub Pricing Point (2016$/MCF)



Source: California Energy Commission.

Figure 18: Natural Gas Production in the United States (Tcf/Year)

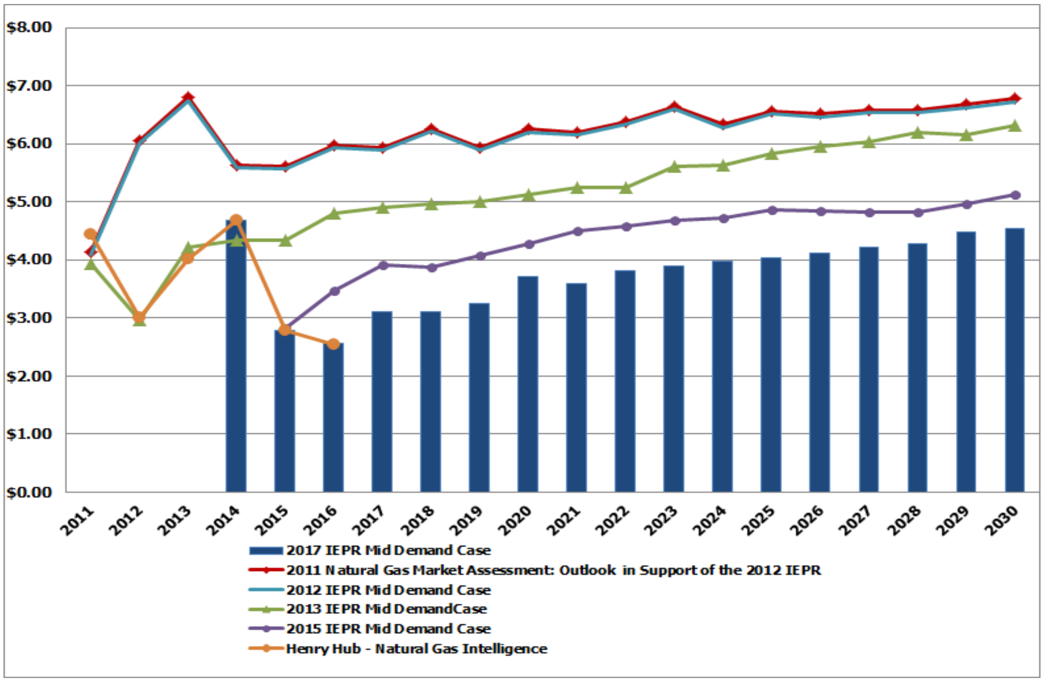


Source: California Energy Commission.

Prices from the Energy Commission's mid demand forecast for the years 2017 through 2030 have declined substantially since the *2011 Natural Gas Market Assessment*. **Figure 19** displays actual and forecasted prices for Henry Hub. In 2011, the Energy Commission's modeling forecasted that the mid demand Henry Hub price in 2020 would be $6.25/Mcf. In 2015, this estimate fell to $4.27 for 2020. However, in 2017, the mid demand Henry Hub 2020 price reached only $3.71/Mcf. Increasing estimates of potential natural gas resources account for much of the changes seen in the forecast. Resource estimates are one of the main drivers in the model.

Under each biennial assessment of natural gas resources since 2006, the PGC has increased its estimates of potential resources.[68] The PGC estimated that in 2006, there were 1,321 Tcf of potential natural gas resources.[69] In 2016, the PGC's estimate has more than doubled to 2,817 Tcf.[70] Much of the additional potential natural gas resources come from upward revisions of estimates of available natural gas in the Appalachian Mountains.

Figure 19: Energy Commission Forecasted, Actual, and Futures Prices for Henry Hub 2016$/Mcf



Source: California Energy Commission.

Figure 20 shows the backcasted (2014 — 2016) and forecasted mid demand prices (2017 — 2030) for the Henry Hub, Malin, and Topock hubs compared to actual prices for 2014 to 2016. For 2014 to 2016, the backcasted hub prices produced by staff's modeling track closely with historical prices.

For California, the model shows how the state's natural gas supply will evolve from 2017 to 2030. Staff assumed that pipeline capacities for interstate lines (that deliver natural gas to California) and intrastate lines (that deliver gas within the state) will not increase over time. Much of California's in-state natural gas production comes from existing resources in the Central Valley, and it is expected that production from those

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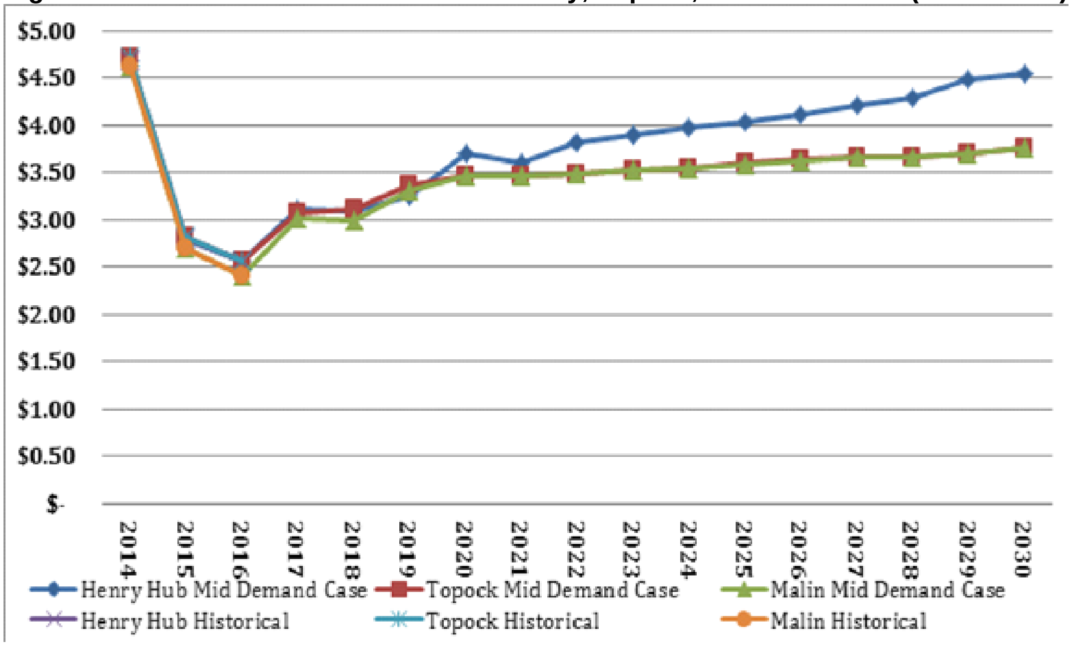
68 Housed at the Colorado School of Mines (Boulder, Colorado), the Potential Gas Committee assesses the future supply of natural gas in the U.S and publishes its assessment every two years.

69 Potential Gas Committee, *Potential Supply of Natural gas In the United States*, p. 3, April 2015.

70 Potential Gas Committee, Press Release: "U.S. Potential Gas Committee Reports Record Future Supply of Natural Gas in the U.S.," July 19, 2017.

resources will decline over time. As Mexico draws more gas from the Permian Basin in Texas and New Mexico, California's reliance on gas delivered to Ehrenberg, Arizona, could encompass a smaller percentage of the state's supply. However, rising natural gas production in the Permian Basin could dampen the effects of increased shipments to Mexico and declining production from the San Juan Basin.

Figure 20: Mid Demand Case Prices for Henry, Topock, and Malin Hubs (2016$/MCF)



Source: California Energy Commission.

According to the U.S. EIA, pipeline exports to Mexico from the United States increased from 0.499 Tcf in 2011 to 1.38 Tcf in 2016 and the forecast of shipments is showing minimal changes.[71] In the mid demand case, model projections indicate that pipeline exports from the United States to Mexico will hover between 1.3 Tcf to 1.5 Tcf per year through 2030.

However, the forecast shows the percentage of gas received at Malin, Oregon, to remain roughly the same at 39 percent of California's out-of-state supply in 2030, compared to 38 percent in 2016. PG&E's Redwood Path (Lines 400/401), which is connected to the Gas Transmission Northwest pipeline and the Ruby pipeline at Malin, Oregon, tends to operate close to maximum capacity. Modeling results indicate that this will continue. Furthermore, natural gas received at Malin originates in either Canada or the Rocky Mountains and, as a result of the long transport distance, none of this gas will serve Mexican market demand.

71 United States Energy Information Administration and Energy Commission Staff NAMGas modeling.

CHAPTER 6: Natural Gas Issues

This chapter highlights key issues and trends affecting the outlook for natural gas market conditions and prices in California. These key issues and trends include the impact of more renewable generation on natural gas demand, California's locational challenge being at the western and southern end of the natural gas pipeline system, the evolving natural gas market in Mexico, and the prospect of LNG exports.

Renewables and Gas Electric Coordination

California's RPS goal now requires 50 percent of the state's power to be generated by renewable energy sources by 2030. The California Independent System Operator's (California ISO) often shows renewable generation in excess of 30 percent of net demand.[72] It is commonly asserted that natural gas is needed to back up intermittent renewables, although as prices of demand response and energy storage technologies continue to fall, and with the expansion of the regional Energy Imbalance Market,[73] those resources may be better suited to fill this role. The key impact of renewable energy intermittency is that natural gas-fired generators will need to ramp up and down (sometimes quickly and unexpectedly) to fill in behind those renewable resources.

The need to coordinate more between the gas and electricity sectors arises due to changes in natural gas end use, in particular the need to integrate increasing levels of renewable resources. The electricity market is scheduled on an hourly basis with some hours having increasingly large swings in gas-fired generation. The tariffs and operating characteristics of the gas system, however, are predicated on flat hourly nominations. Until enough energy storage is installed so that renewable generation can continue to serve load even when it cannot produce electricity, electricity dispatchers will continue to rely on the natural gas generation fleet to serve electricity demand when renewable resources are not available.

Nationwide, the percentage of natural gas supply devoted to generating electricity has doubled over the last 20 years.[74] In 2015, natural gas was used to generate almost as many gigawatts of electricity as coal, and in summer 2016 EIA also reported the first ever net withdrawal from underground gas storage during a summer month.[75, 76] As

72 See http://www.caiso.com/Pages/TodaysOutlook.aspx#Power%20Mix%20by%20Fuel%20Type.

73 Energy Imbalance Market is a mechanism whereby natural gas shippers can balance their overage and/or underage with the pipelines.

74 EIA, Natural Gas Consumption by Year at https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

75 EIA, Total Electric Power Industry Summary Statistics, 2015 and 2014. Found at https://www.eia.gov/electricity/annual/html/epa_01_01.html.

76 U.S. EIA, Today in Energy, August 8, 2016, https://www.eia.gov/todayinenergy/detail.php?id=27412.

discussed in Chapter 2, California's use of gas for electricity generation varies seasonally and monthly largely in response to wet versus dry years affecting hydroelectric generation. However, the RPS and the push for energy efficiency should cause a decrease in the gigawatt hours of electricity generated with natural gas by 2028. Incidents such as the 2011 cold weather event that caused gas curtailments to electric generators in San Diego, the recent operational constraints at the Aliso Canyon gas storage field, and changes in the gas load profile as more renewables come on-line, have highlighted the role of gas-fired generation in preserving electricity reliability.

FERC launched a proceeding in 2013, to encourage the gas and electric industries to modify their operating practices to make them more consistent and ease the challenges associated with gas-electric coordination. This resulted in changes such as moving the timely nomination deadline[77] to later in the day, reducing the lag between when gas nominations are submitted and when organized markets announce dispatch bid results to generators, adopted in FERC Order No. 809.[78] It also added a third intraday scheduling opportunity, giving generators another opportunity to modify nominations to match operations. The effort did not, however, result in changes to move to a single U.S.-wide scheduling time for the two industries or otherwise fully eliminate the mismatches in scheduling windows between gas and electricity. It is unclear if FERC will take any additional action in this area; California parties largely opposed any changes, stating they are unnecessary.[79]

The leak at the Aliso Canyon storage facility renewed the emphasis on gas-electric coordination as the Energy Commission worked with the two electric balancing authorities, the California ISO, Los Angeles Department of Water and Power (LADWP), the CPUC, and SoCalGas to develop an action plan to reduce the risk of electricity blackouts should insufficient gas supply be available. Among the key findings of the team was that variation in gas demand, caused especially by generators as they ramp to follow load or to replace renewables in the afternoon, unavoidably causes imbalances on the gas system. When gas demand from the generators increases, the only way to meet it is through:

- Intraday load diversity, when available
- Linepack[80] that might be available
- Injecting or withdrawing gas from underground gas storage.[81]

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77 For more information on the Timely Nomination deadlines, please see the following description on the FERC website: https://www.ferc.gov/whats-new/comm-meet/2015/041615/M-1.pdf.

78 A copy of Oder No. 809 is available at https://www.ferc.gov/whats-new/comm-meet/2015/041615/M-1.pdf.

79 See, for example, comments in California ISO stakeholder comments from San Diego Gas & Electric, available at http://www.caiso.com/Documents/SDGEComments_FERCOrderNo809.pdf.

80 *Linepack* means the increased volume of a fluid within a given pipe due to increased pressure, http://www.iadclexicon.org/line-pack-or-linepack/.

The action plan included changes to tighten the gas balancing rules and disallowed natural gas withdrawals from Aliso Canyon, except when needed to preserve electric reliability or service to core gas customers. The plan also included estimates of how much generation could be moved out of the Greater Los Angeles Area (when necessary) to power projects outside the area. For winter 2017, it included the first known efforts asking natural gas consumers for conservation when called upon. It also sped up the installation of several battery storage projects.[82]

LADWP sought and obtained permission to burn diesel fuel in its generators if needed, and the California ISO received approval from FERC to make several changes to its tariff. Among these changes were permissions to give generators advance warning of expected gas dispatch quantities to help generators align their gas burn quantities more closely with their nomination quantities.[83] A detailed discussion of Southern California reliability issues was included in the *2017 Draft IEPR,* released on October 16, 2017.

The Environmental Defense Fund has proposed the creation of a "natural gas imbalance market" (GIM) in California to better address gas-electric coordination issues.[84] A GIM could enable market participants with excess supply in a given hour to sell gas to others needing more that day. This proposal, if implemented, will allow the development of an hourly trading market of unneeded natural gas. Consequently, the EDF suggests that a gas imbalance market would increase market efficiency and transparency. California's gas utilities already allow trading of daily and monthly gas imbalances. PG&E and SMUD filed comments expressing concerns with the EDF proposal. PG&E stated that existing rules and market mechanisms make a GIM unnecessary and that their current gas tariff adequately keeps the utility's system in balance. SMUD stated several concerns, including that the required daily 5 percent tolerance band on imbalances would be difficult to achieve, that a GIM would limit system flexibility and result in the need for more storage, and that staffing a third party structure would result in higher electric

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81 Whether an imbalance is met with an injection or a withdrawal depends on whether the supply-demand imbalance is positive or negative.

82 CPUC, Aliso Canyon Well Failure Web page: http://www.cpuc.ca.gov/aliso/. Three action plans were prepared, one for summer 2016, winter 2016-2017 and one for summer 2017. They can be found at http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Action_Plan_to_Preserve_Gas_and_Electric_Reliability_for_the_Los_Angeles_Basin.pdf; http://www.energy.ca.gov/2016_energypolicy/documents/index.html#08262016 and http://www.energy.ca.gov/2017_energypolicy/documents/#05222017.

83 See ER 17-110-000, "Order Accepting Tariff Revisions, Subject to Condition," November 28, 2016. Found at http://www.caiso.com/Documents/Nov28_2016_OrderAcceptingTariffAmendment_AlisoCanyonElectricGasCoordinationPhase2_ER17-110.pdf. The tariff change request can be found at http://www.caiso.com/Documents/Oct14_2016_TariffAmendment_AlisoCanyonGasElectricCoordination_Phase2_ER17-110.pdf.

84 Comment letter from Environmental Defense Fund and Skipping Stone, June 5, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217837_20170605T093823_Tim_O'Connor_Comments_Comment_letter_from_EDF_and_Skipping_Stone.pdf, pp. 6–10.

service cost. The Energy Commission believes that the proposal warrants further consideration and recommends that this be raised in the Aliso Canyon Well Failure proceeding (I.17-02-002) underway at the CPUC.

The WECC and the North American Electricity Reliability Council are conducting detailed efforts on natural gas and electricity coordination. The WECC’s study will assess the adequacy, security, and risks associated with the natural gas infrastructure and its ability to serve the evolving bulk electric system.

California's Location at the End of the Pipeline System

California is located at the end of the natural gas delivery system. The state's supplies of natural gas start in Western Canada, the Northern Rockies, the San Juan Basin in New Mexico, and the Permian Basin in west Texas. Many demand centers, including the cities of Albuquerque, Phoenix, and Tucson, draw natural gas from the delivery lines before the natural gas reaches California. This means that higher demand to the east, which can be caused by cold weather such as in February 2011, can draw off gas supplies, sending them eastward. This leaves less available for California.[85]

Extreme weather events, such as a cold snap or a hurricane, can trigger emergency actions by pipeline companies. Hurricane Harvey provides an example. On August 31, 2017, El Paso Natural Gas, one of the key pipelines that connect California to San Juan and Permian basin supplies, warned shippers it faced a strained operating condition.[86] Gas supply that normally would have been nominated into El Paso Natural Gas to meet demand in New Mexico, Arizona, and California was instead delivered to pipelines flowing east when the multiday rainfall and flooding of the hurricane reduced gas production on the Texas Gulf Coast. As a result, California must monitor what is going on with gas supply and pipeline flows upstream, and considers those conditions in reliability planning and coordination.

California's underground gas storage provides the state with make-up supply. Changes in Mexico, discussed in the section immediately below, may cause California to experience more impacts from its location at the end of the pipeline.

The Changing Market in Mexico

Exports from the United States to Mexico are rising, made feasible by new infrastructure under construction and excess supply in the United States. This may be a short-term phenomenon. If Mexico further develops its natural gas resources without accompanying demand growth, exports would decline. Staff's modeling shows that exports to Mexico will rise until about 2030 and decline thereafter due to Mexico's expanded development of its domestic resources, which will result in increased production.

Demand for Natural Gas in Mexico

In recent years, as the Mexican economy has grown, so have natural gas exports from the United States to meet its rapidly growing demand for natural gas. Mexico's economy

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85 See FERC/NERC *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011*, pp.169 – 187 for a list of years with cold weather events and discussion of electric-gas reliability issues. https://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf.

86 http://passportebb.elpaso.com/ebbmasterpage/Notices/NoticesAutoTable.aspx?code=EPNG&status=Notice&name=Critical%20Notices&sParam3=17557&sParam14=D&details=Y.

and energy demand both increased by 25 percent between 2000 and 2015.[87] According to Mexico's Ministry of Energy, from 2005 through 2015, Mexico's natural gas demand grew from 5.09 Bcf per day in 2005 to 7.50 Bcf per day in 2015. In 2015, the electricity sector accounted for almost 51 percent of Mexico's natural gas demand, followed by the oil, industrial, and residential sectors.[88] Much of the increase in demand is the result of demand growth for electricity generation. Oil-fired power plants, at their peak in 2000, supplied nearly half of Mexico's total electric generation, a scenario that remained largely unchanged as of 2014. However, by 2014 oil-fired generation fell to less than half of the peak-year generation, as Mexico's regulators call for the replacement of high-cost and highly polluting oil power plants with natural gas-fired power plants and other cleaner sources of energy.[89]

Recent natural gas demand growth can also be attributed to Mexico's energy reforms – approved by the federal government in December 2013 –which permit foreign investment to create a more competitive industry.[90] In addition to increased natural gas shipments to Mexico, these energy reforms may lead to increased renewable energy capacity. Mexico's Ministry of Energy projects that, between 2016 and 2029, natural gas fired capacity will account for 24.9 gigawatts (GW) of total capacity additions, and renewables will account for 20.4 GW.[91]

Mexico, with much of its natural gas resources undeveloped, reports proved reserves of 15.3 Tcf and potential reserves (mostly from shale formations) of about 545 Tcf.[92] Despite the potential, only in the last five years has Mexico taken steps to accelerate development of its natural gas resources. The U.S. EIA states, "The [Burgos] basin [in northern Mexico] holds the largest undeveloped shale resources in the country. Increasing production from the region would help meet growing natural gas demand, particularly from new natural gas-fired generation in Mexico's Northeastern region, and make Mexico less reliant on natural gas imports in the long term."

While these natural gas resources may be developed in the longer term, U.S. natural gas exports to Mexico are expected to continue for the foreseeable future. Mexico's energy market reforms and economic growth are expected to promote increasing exports of natural gas from the United States, increasing from 3,719 MMcf per day in 2016 to nearly 5,600 MMcf per day in 2023.

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87 © OECD/IEA Mexico Energy Outlook, p. 17. IEA Publishing, License: http://www.iea.org/t&c/.

88 Secretary of Energy, Mexico, *Prospectiva de Gas Natural 2016-2030*, p. 27.

89 © OECD/IEA *Mexico Energy Outlook*, pp. 20-21. IEA Publishing, License: http://www.iea.org/t&c/.

90 Wilson Center, "Mexico's Energy Reform: The Timeline," at https://www.wilsoncenter.org/article/mexicos-energy-reform-the-timeline.

91 U.S. EIA, Natural gas-fired power plants lead electric capacity additions in Mexico, https://www.eia.gov/todayinenergy/detail.php?id=29592.

92 U.S. EIA, Mexico energy data, https://www.eia.gov/beta/international/country.cfm?iso=MEX.

United States Exports to Mexico

In 2006, more than half of natural gas pipeline exports from the United States went to Canada.[93] However, this trend has changed in the last 10 years. In 2016, natural gas exports to Mexico accounted for 64 percent of all pipeline exports from the United States, with new pipelines crossing the border at Sasabe, Arizona, and Rio Grande, Texas, accounting for 45 percent of these exports. **Figure 21** shows natural gas pipelines from the United States into Mexico. Since 2006, exports to Mexico have increased 322 percent, from 882 MMcf per day in 2006 to 3,718 MMcf per day in 2016.[94] These increased exports to Mexico can decrease available supply to California.

To accommodate additional imports of natural gas from the United States, Mexico is expanding its natural gas pipeline capacity. These expansions include the 520-mile Los Ramones pipeline project, which was completed in 2015. The Los Ramones natural gas pipeline can import up to 2.1 Bcf per day of natural gas from shale gas locations in the United States. The 15-mile, 1.14 Bcf/day San Isidro-Samalayuca pipeline was completed in May 2017 and transports gas from the Permian Basin in Texas to a 906 MW power plant across the border in Chihuahua, Mexico.[95]

Completed in June 2017, the 127-mile, 1.35 Bcf/day Ojinaga–El Encino Gas Pipeline will supply power plants operating with fuel oil, but will soon be converted to natural gas.[96] The San Isidro-Samalayuca and Ojinaga-El Encino pipelines draw natural gas produced in the Permian Basin, which is a source of supply for California.

Using the NAMGas model, staff estimates in the future as Mexico draws more natural gas from the Permian Basin, California will shift its demand toward gas produced in other resource basins including the San Juan Basin, located in the four corners area of the southwest United States. However, recent production history and staff's modeling show greater volume of natural gas originating from the Permian Basin. This phenomenon may ease concerns about rising natural gas shipments to Mexico.

Also under construction is the El Encino-Topolobampo pipeline, a $1.1 billion project that will bring natural gas from Chihuahua, Mexico (which will likely import more Permian Basin Gas) southwest to Topolobampo, Sinaloa. The 30-inch diameter pipeline will be about 329 miles long and have contracted capacity of 670 Mcf/day.

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93 U.S. EIA (U.S. Department of Energy), "U.S. Natural Gas Pipeline Exports by Point of Exit," http://www.eia.gov/dnav/ng/ng_move_poe2_a_epg0_enp_mmcf_a.htm.

94 U.S. EIA, U.S. Natural Gas Pipeline Exports, https://www.eia.gov/dnav/ng/hist/n9132mx2A.htm.

95 U.S. EIA, In the News: *IEnova completes construction on two pipelines bringing Permian gas into Mexico.* https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2017/06_29/.

96 U.S. EIA, In the News: *IEnova completes construction on two pipelines bringing Permian gas into Mexico.* https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2017/06_29/.

Figure 21: Natural Gas Pipelines in Mexico

Source: U.S. EIA.

There are additional pipeline projects announced and under construction in Mexico that will enable more imported natural gas from the United States to be distributed throughout the country. An example is the announced $2.1 billion Sur de Texas to Tuxpan (Marino) gas pipeline, which will transport natural gas from south Texas underwater through the Gulf of Mexico to Tuxpan, Veracruz, in Mexico.

Pipeline developers are looking to develop projects that will ship Permian natural gas to the Gulf of Mexico, where it could be exported to Mexico or overseas. Kinder Morgan Texas Pipeline LLC held an open season bid period in 2017 for firm service on its proposed Gulf Coast Express Pipeline, which would transport up to 1.7 million decatherms (1.7 Bcf) per day through 430 miles of 42-inch diameter pipeline from the area near Waha, Texas, to Agua Dulce, Texas. Another company, NAmerico Energy Holdings LLC's, is planning a 468-mile intrastate natural gas system originating in west Texas and terminating at various points around Corpus Christi, Texas.

While Mexico has been importing increasing quantities of pipeline gas from the United States, it is also importing significant quantities of LNG. As of the end of March 2017, Mexico accounted for 18 of the 90 cargoes shipped from Sabine Pass since operations commenced.[97] As Mexico is working to expand and upgrade its natural gas pipeline system, the 0.5 Bcf/day LNG import facility in Manzanillo, Mexico, on the Pacific Coast is receiving shipments from Sabine Pass LNG. The expansion of the Panama Canal, which opened in June 2016, reduced the one-way voyage from Sabine Pass to the Manzanillo

97 *Forbes Magazine*, "Mexico Is Also Importing U.S. Liquefied Natural Gas", April 5, 2017. https://www.forbes.com/sites/judeclemente/2017/04/05/mexico-is-also-importing-u-s-liquefied-natural-gas/#2c3fa864e292.

terminal to just 10 days, down from the 27 days it took to travel around Cape Horn in South America.

As California will likely compete with Mexico for natural gas produced in west Texas, these pipeline developments will need to be monitored to ensure that sufficient supplies are available for California. California could also see an increase in natural gas prices as the state competes for Permian natural gas with Mexico and other LNG importing countries due to additional pipeline infrastructure shipping Permian natural gas east to the Gulf of Mexico. Liquefied natural gas exports from Corpus Christi, Texas could occur at the 2.14 Bcf/day Corpus Christi LNG facility, which is under construction.

LNG Exports from the United States

It is expected that the United States will export increasing amounts of LNG. In 2016, the United States exported nearly 187 Bcf of LNG, an all-time high. According to the U.S. EIA, that amount could increase to 2.4 Tcf to 8.5 Tcf by 2030. Due to the increase in LNG exports and pipeline exports to Mexico, modeling shows that the United States will be a net natural gas exporter in 2018. While exports will increase, natural gas production will be sufficient to meet domestic and international demand.

Moreover, the basins that provide natural gas for LNG export in the United States are not ones that serve California. However, there are proposed pipeline projects that aim to ship gas from the Permian Basin to LNG export facilities on the Gulf Coast.[98] While a future pipeline from the Permian Basin to the Gulf of Mexico would require California to compete for supplies with countries that receive U.S. LNG, California is already forecasted to receive smaller quantities of natural gas from the Permian Basin. Rising production in this basin may satisfy both its traditional and new demand requirements, as noted by PG&E in comments to this report.

Since the late 2000s, increased domestic production from shale formations and an expanded Panama Canal are positioning the United States to become a net exporter of LNG. By 2020, market observers expect the United States to become the world's third-largest LNG producer, after Australia and Qatar.[99] However, a growing LNG export market could affect natural gas prices in the United States.

Increased natural gas production in the Marcellus and Utica basins, along with pipeline capacity that could ship more gas to the Atlantic and Gulf of Mexico, is enabling natural gas exports as LNG. The United States is developing liquefaction facilities on the Atlantic and Gulf of Mexico coasts. Developers are also converting import terminals to LNG liquefaction export facilities. These conversions are occurring at the Cove Point and Elba Island terminals that have received LNG imports for almost 40 years. The oldest U.S.

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[98] Natural Gas Intelligence, *Kinder Proposing Permian-to-Gulf Coast NatGas Pipeline*, March 22, 2017, http://www.naturalgasintel.com/articles/109850-kinder-proposing-permian-to-gulf-coast-natgas-pipeline.

99 U.S. EIA, Today in Energy, https://www.eia.gov/todayinenergy/detail.php?id=32412.

LNG export facility, the 0.2 Bcf/day Kenai LNG facility in Alaska, came on-line in 1969 to serve the Asia Pacific market, and nearly all the LNG produced at Kenai is sold via contract to two Japanese utilities.[100]

Sabine Pass LNG is the first LNG export facility built in the continental United States. In 2016, when it commenced operation, Sabine Pass LNG exported 186 Bcf of natural gas, twice the amount of LNG imported by the United States that year.[101] Liquefied natural gas produced at Sabine Pass was shipped to Asia (primarily China and India), South America (Chile, which received the highest volumes of LNG from Sabine Pass along with Argentina and Brazil), Europe (Italy, Portugal, and Spain), and Mexico. After Chile, Mexico received the second highest volume.

In September 2017, Veresen Inc. filed applications with FERC for the construction of the 0.8 Bcf/day Jordan Cove LNG export project on the Oregon coast, along with the associated 232-mile Pacific Connector pipeline that would run northwest from Malin, Oregon, to the Jordan Cove LNG facility in Coos Bay, Oregon. Jordan Cove and Pacific Connector are requesting that FERC issue a draft environmental impact statement in 2018, which could lead to FERC decisions by the end of 2018. If Jordan Cove LNG is constructed, this project would access natural gas supplies shipped to Malin, Oregon, the hub through which natural gas is delivered to Northern California.

There is 2.1 Bcf/day of existing LNG export capacity in the continental United States, 9.65 Bcf/day of LNG export capacity under construction, and an additional 6.79 Bcf/day of capacity that has received FERC approval.[102] According to the U.S. EIA, more than 4.0 Bcf/day of LNG export capacity has long-term (20 years) contracts with markets in Asia, including Japan and South Korea.[103] As part of its July 2017 *Short-Term Energy Outlook*, the U.S. EIA forecasts that LNG exports will increase from 0.5 Bcf/day in 2016 to 1.9 Bcf/day in 2017, as all four trains of Sabine Pass LNG and Cove Point LNG will be on-line by the end of 2017.

The impact of increasing LNG exports is uncertain as this is a new industry for the continental United States. Some analysts have examined how prices and production will be affected, and on how the United States LNG export industry will fare in the marketplace. A 2015 U.S. Department of Energy (DOE)-funded study *The Macroeconomic Impact of Increasing U.S. LNG Exports* found that most of the increase in LNG exports will be accommodated by expanded domestic production rather than reduced demand. The U.S. DOE study also argues the price impacts would be small. However, this study

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100 Kenai LNG Exports, ConocoPhillips Alaska, http://alaska.conocophillips.com/what-we-do/natural-gas/lng/Pages/kenai-lng-exports.aspx.

101 U.S. EIA, Natural Gas, https://www.eia.gov/dnav/ng/ng_move_poe2_a_EPG0_ENG_Mmcf_a.htm.

102 Federal Energy Regulatory Commission, LNG, https://www.ferc.gov/industries/gas/indus-act/lng.asp.

103 U.S. EIA, Today In Energy web page, "Expanded Panama Canal Reduces Travel Time For Shipments Of U.S. LNG to Asian Markets," June 30, 2016, https://www.eia.gov/todayinenergy/detail.php?id=26892.

finds that LNG exports will raise domestic prices while lowering international prices. The majority of the price movement, however, would be in Asia markets.

In 2016, Columbia University's Center on Global Energy Policy and Columbia's School of International and Public Affairs published a paper *If You Build It, Will They Come? The Competitiveness of US LNG In Overseas Markets*. This paper argues that full utilization of the United States' export capacity seems unlikely if overseas natural gas spot market prices remain low over a long period. In addition, a spike in Henry Hub prices or shipping costs can render LNG exports uneconomic. While U.S. LNG currently remains competitive in overseas markets, this opportunity can easily vanish, even from small changes in Henry Hub prices, vessel charter rates, shipping fuel costs, canal fees, overseas spot prices, and a host of other factors.

On the other hand, the U.S. EIA sees opportunity for LNG exports from the United States. In its July 2017 study *Gas 2017*, the U.S. EIA states that the shale revolution in the United States will keep production high, which will in turn attract new customers as the number of LNG consuming countries continues to rise (from 15 in 2005 to 39 in 2017), particularly in the developing world.[104]

Australia, the second largest exporter of LNG after Qatar, has instituted new regulations to contain rising energy prices, giving Australian customers first priority to natural gas supplies before they are exported. This restricts available supply from Australia while giving other suppliers, including those from the United States, a greater opportunity to serve Asian markets.

There are three proposed LNG export facilities in British Columbia, Canada, with capacity totaling 6.6 Bcf/day – LNG Canada, Woodfibre LNG Ltd., and Pacific NorthWest LNG. These facilities have received regulatory approval, but while these and other proposed LNG facilities in Canada have benefits, they face substantial economic barriers. According to an energy market assessment published by Canada's National Energy Board in July 2017:

> "Canadian projects have certain advantages, including abundant and relatively low cost natural gas supplies. In addition, west coast Canadian LNG projects have a shorter shipping distance to Asian markets compared to U.S. Gulf Coast facilities. Disadvantages facing Canadian projects include high costs to develop projects in remote locations with limited infrastructure, and, where the construction of new pipelines is required to supply the necessary gas. With LNG prices falling in recent years, the margins needed to justify this type of capital-

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104 Natural Gas Intelligence, "U.S. Natural Gas Fueling 'Second Revolution' in Rising LNG Supply, Says IEA," July 13, 2017.

> intensive development have eroded. Increased competition has also made it difficult for Canadian projects to sign long-term supply contracts."[105]

Greenfield and Brownfield Facility Development

A greenfield is defined as a plot of land that has not been previously developed, such as forests, wetlands, or open fields, and generally features no significant amount of toxic materials. A brownfield is land that has been formerly developed but is no longer in use. This land may contain some level of contamination.

The United States' expanding supply can present challenges for LNG export facilities from Canada as increasing supply can push prices downward. The three proposed LNG facilities in British Columbia are greenfield facilities, while American facilities that are approved or under construction are located at existing brownfields that include the infrastructure to handle gas and dock LNG tanker ships.

Greenfield LNG export facilities are more expensive to construct than their brownfield counterparts. Greenfields face greater land acquisition costs and additional permitting expenditures.

105 National Energy Board, *Canada's Role In The Global LNG Market: Energy Market Assessment*, p. 1, July 2017.

CHAPTER 7: Methane Emissions From the Natural Gas System

Natural gas contains about 90 percent methane and about 10 percent various other alkalines and impurities. Methane is a short-lived climate pollutant and is the second most emitted GHG in California, accounting for about 9 percent of the state's total GHG emissions. The lifetime of carbon dioxide (CO_2) in the atmosphere exceeds that of methane. However, methane possesses more effective heat-trapping characteristics than CO_2. The result is that methane affects the atmosphere most when it is first released.[106] Emissions of methane, or methane leakage, can occur throughout the natural gas system and currently constitute about 10 percent of total methane emissions in the state.[107]

The Natural Gas System

The natural gas system includes several components or phases that move natural gas from reservoirs located thousands of feet below the earth's surface to end-use consumers located thousands of miles away in demand centers or consumption regions. The structure of the natural gas system allows for numerous occasions for methane leakage. The flow of natural gas through the system underscores the potential problem.

Exploration and drilling/extraction initiate the process. The other main components of the system are:

- Production – Moving natural gas from the underground reservoir to the wellhead.
- Transportation – Flowing natural gas through high-pressure pipelines.
- Storage – Placing natural gas in underground reservoirs for later use.
- Distribution – Moving natural gas in lower pressure pipelines to satisfy the demand of end users.

Figure 22 displays a schematic of the flow of natural gas, from producing basins to the demand centers or consumption regions.[108] In addition to these traditional components,

106 LaCont, R, *Methane Emissions in the Natural Gas Life Cycle*, April 2015, p. 3, http://mjbradley.com/sites/default/files/MJBradleyWIEBNGMethaneEmissionsImplicationsforPolicymakersFinal.pdf.

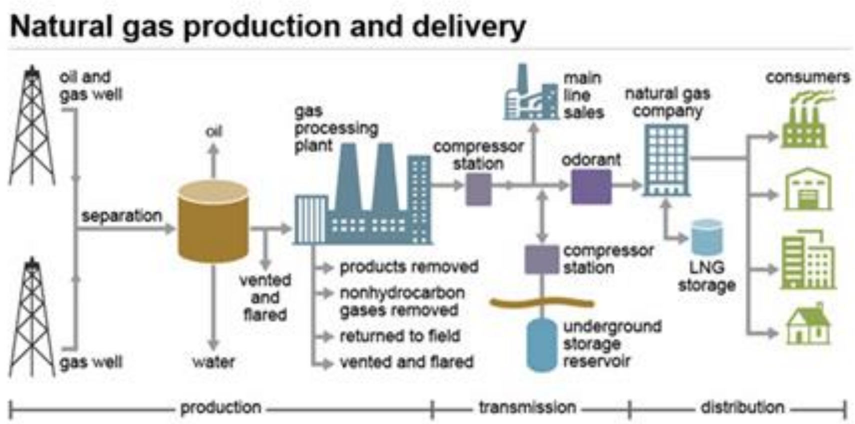
107 https://www.arb.ca.gov/cc/inventory/pubs/reports/ghg_inventory_00-12_report.pdf.

108 When produced, natural gas consists of methane, ethane, propane, butane, and pentane. However, the substance consumers refer to as natural gas consists of 100 percent methane, an energy source that travels through pipelines to reach consumption regions.

a more complete understanding of methane emissions from the natural gas system includes emissions from abandoned and idle wells, natural gas seepage, and emissions from consumption downstream of customers' gas meters.

While not captured in state estimates of methane emissions from the natural gas system, methane emissions from natural gas production upstream of California are important in quantifying the climate implications of natural gas since California imports about 90 percent of its gas from Canada, the Southwest United States, and the Rocky Mountains.

Figure 22: Typical Natural Gas System



Source: U.S. Energy Information Administration

Methane Leakage

In 2015, the CARB reported that methane made up 10 percent of the total amount of GHG emissions in California.[109] However, the major sources of methane originate from landfills, dairy animals and other ruminant livestock, livestock waste handling, and agricultural production as a result of biological conversion.[110] As of 2015, CARB estimates that emissions from oil and gas production, processing, transmission, and distribution systems account for about 16 percent of total methane emissions in California.[111]

Methane emissions from the natural gas system can be unintentional or intentional. Unintentional releases, also known as fugitive emissions, can occur anywhere in the system. Examples of sources include compressor stations, abandoned wells, leaking

109 CARB, *California Greenhouse Gas Inventory – 2017 Edition*, 2017, https://www.arb.ca.gov/cc/inventory/data/data.htm.

110 CARB, *California Greenhouse Gas Inventory – 2017 Edition*, 2017, https://www.arb.ca.gov/cc/inventory/data/data.htm.

111 CARB, *California Greenhouse Gas Inventory – 2017 Edition*, 2017, https://www.arb.ca.gov/cc/inventory/data/data.htm.

infrastructure, or inefficient operation of valves and meters. Intentional releases have a purpose and occur during both normal operations and maintenance of the natural gas system. One example, known as a blowdown, is a venting of natural gas from pipelines or other infrastructure for routine maintenance. For accuracy, an estimate of methane emissions should include both intentional and fugitive emissions.

Estimating Methane Emissions

Bottom-up and top-down are two methods for estimating methane emissions. Both have advantages and disadvantages, which can cause uncertainties and variability in estimates. The bottom-up method applies emission factors, which are averages based on measured emissions from specific devices or whole facilities. These emission factors are multiplied with activity factors for different parts of the system—the number of compressors or miles of pipeline. The results are totaled from all the components of the system. The CARB and EPA use this method in their emissions estimations.

The disadvantages of the bottom-up method are associated with the emission factors, which may not represent the whole population being measured. In some cases, the technology and age of individual components and whole facilities can be different, so that taking measurements at relatively few facilities will not represent the whole natural gas system.[112]

Top-down studies take atmospheric measurements at the facility or regional level. Aircraft fitted with specialized detection equipment usually perform measurements in top-down studies. The plane does a complete circle of the study area at various altitudes. Measurements are taken both upwind and downwind of the source or region. While taking into account wind velocity, downwind readings subtracted by the upwind readings determine actual emissions coming from the source area.

The biggest challenge for top-down studies is parsing sources of methane from anthropogenic sources such as the natural gas industry, and biological sources such as dairy farms.[113] To separate natural gas industry sources from biological sources, tracers such as methane content ratios or stable isotopes must be identified. However, there are still sources that can frustrate this way of parsing the data due to natural geologic seepage of methane and emissions from abandoned wells.

Whether top-down or bottom-up, these studies estimate methane emissions by relying on assumptions with relatively small test data pools.[114] One study found that the top 5 percent of leaks (by volume) from natural gas production accounted for over 50 percent

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112 Brandt, A. R., "Methane Leaks From North American Natural Gas Systems," *Science Magazine*, 2014, 343 (6172), pp. 733-735, http://www.novim.org/wp-content/uploads/2011/02/ScienceMethane.02.14.14-1.pdf.

113 Ibid, pp. 733-735.

114 LaCont, R., *Methane Emissions in the Natural Gas Life Cycle.* April 2015, p. 6. http://westernenergyboard.org/2015/05/final-report-released-by-mj-bradley/.

of total emissions measured.[115] That study, along with others, uses the top 5 percent of leaks as the working definition of super-emitters.[116, 117].The relatively low number of super-emitters in the system means that the chances of missing one are high when selecting a sample for study. Findings from a recent review of multiple studies in the United States indicate that bottom-up and top-down methods can produce similar results.[118] Both have shortcomings, but using a combination of the two techniques can help validate emissions results.

Research suggests that to realize immediate net climate benefits from using natural gas instead of dirtier fuel sources, methane emissions from the natural gas system should not exceed 0.8 percent of production to justify a transition from diesel used in heavy-duty vehicles. Further, the same research shows that methane emissions cannot exceed 1.4 percent of production to justify a switch from the gasoline used in automobiles, whereas the cap on emissions stands at 2.7 percent of production to justify transition for coal used power plants.[119] Until there is a more accurate and comprehensive accounting of methane emissions from the natural gas system, the climate benefits of natural gas as a transition fuel remain unclear, highlighting the importance of ongoing research in this area.

Recent Studies

In recent years, major research efforts have been undertaken to quantify methane emissions from all portions of the natural gas system. The Environmental Defense Fund (EDF), along with the natural gas industry, is funding and fostering a large-scale cooperative research effort that examines methane emissions from the natural gas system. A collection of 16 studies is attempting to improve the understanding and characterization of methane. Most participants in the project have completed their studies on the natural gas system, showing estimated leakage rates of about 1.5 percent of the total gas produced. However, the EDF is still working on an overarching project

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115 Brandt, A. R., "Methane Leaks from Natural Gas Systems Follow Extreme Distributions," *Environmental Science & Technology*, 50 (22), pp. 12,512-12,520, http://pubs.acs.org/doi/abs/10.1021%2Facs.est.6b04303.

116 Ibid, pp. 12,512-12,520.

117 Zimmerle, Daniel J., "Methane Emissions from the Natural Gas Transmission and Storage System in the United States," *Environmental Science & Technology*, 2015, 49 (15), pp. 9374-9383, http://pubs.acs.org/doi/abs/10.1021%2Facs.est.5b01669.

118 Alvarez, M, Joint Agency Methane Symposium, June 6, 2016, p. 92. http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN211181_20160422T102708_Transcript_of_the_04082016_Joint_Agency_Workshop_on_Aliso_Canyo.pdf.

119These numbers were modified from original source of Alvarez et al. 2012 by the Environmental Defense Fund to account for new data. http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN211773_20160609T130055_Methane_Using_New_and_More_Data_to_Manage_Rising_Risk_in_a_Carb.pdf.

synthesis, to develop an overall methane emissions rate across the natural gas supply chain. This is expected to be complete in fall 2017.[120]

Another paper has synthesized data from EDF's various published sources and found that between extraction and delivery, 1.7 percent of the total natural gas produced is released to the atmosphere (with 95 percent confidence interval from 1.3 and 2.2 percent).[121] This compares to the U.S. EPA's national GHG inventory implied methane emission rate of 1.4 percent.

Emissions vary among different parts of the natural gas system. Multiple studies have examined specific parts of the system. The largest emissions during production are from pneumatic devices, which are used as liquid levelers, valve controllers, and pressure regulators. These, as well as other uncharacterized emissions, warrant further study. A 2015 study found that the gathering of gas from wells and the processing of the gas to produce pipeline quality gas emits 0.47 percent of total emissions within the natural gas supply chain.[122] Modeling determined that transmission and storage made up about 0.35 percent of total emissions in 2012. Distribution system emissions were found to be improving compared to assumptions in previous U.S. EPA greenhouse gas (GHG) inventories. This is because distribution system pipelines are being improved with replacement of older pipeline material (for example, cast iron) with new steel or plastic pipe.[123]

State and Federal Greenhouse Gas Inventories

The EPA's latest GHG inventory report is for 1990 to 2015. The years 2011 through 2015 show a general 5 percent increase in methane emissions from the natural gas system. CARB's emissions inventory for California separates oil and gas production and processing from transmission and distribution. In 2015, oil and gas production and processing made up 6 percent of methane emissions, while transmission and distribution emissions made up 10 percent of methane emissions. This excludes Aliso Canyon emissions. **Figure 24** shows the totals from both sectors between 2010 and 2014.

Figure 23 shows the trend of a slight year-over-year increase from 2011 to 2014 and leveling off in 2015. CARB's emissions inventory for California separates oil and gas

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120 EDF, Methane Research: The 16 Study Series. http://www.edf.org/sites/default/files/methane_studies_fact_sheet.pdf.

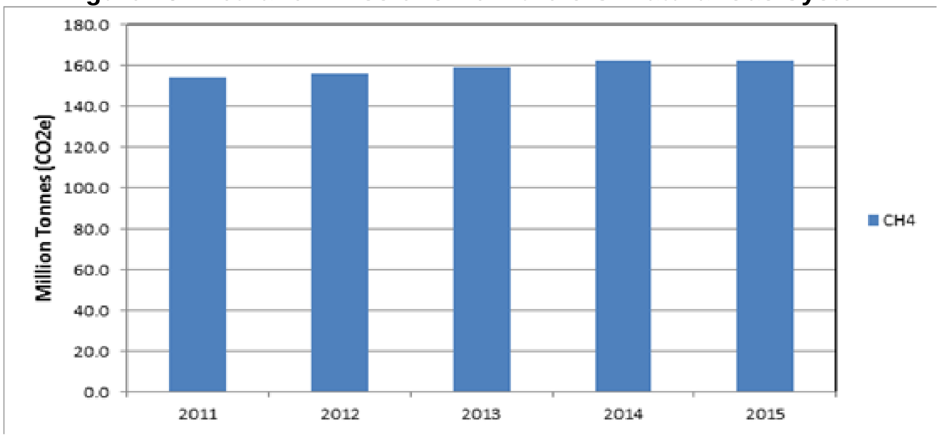
121 Littlefield, J. A., "Synthesis of Recent Ground-Level Methane Emission Measurements From the U.S. Natural Gas Supply Chain," *Journal of Cleaner Production*, 2017, 148 (17), pp. 9,374-9,383. http://pubs.acs.org/doi/abs/10.1021%2Facs.est.5b01669.

122 Marchese, A. J., "Methane Emissions From United States Natural Gas Gathering and Processing," *Environmental Science and Technology, 2015*, pp. 10,718-10,727, http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02275.

123 Lamb, B. K., "Direct Measurements Show Decreasing Methane Emissions From Natural Gas Local Distribution Systems in the United States," *Environmental Science and Technology*, 2015, pp. 5161-5169, http://pubs.acs.org/doi/abs/10.1021%2Fes505116p.

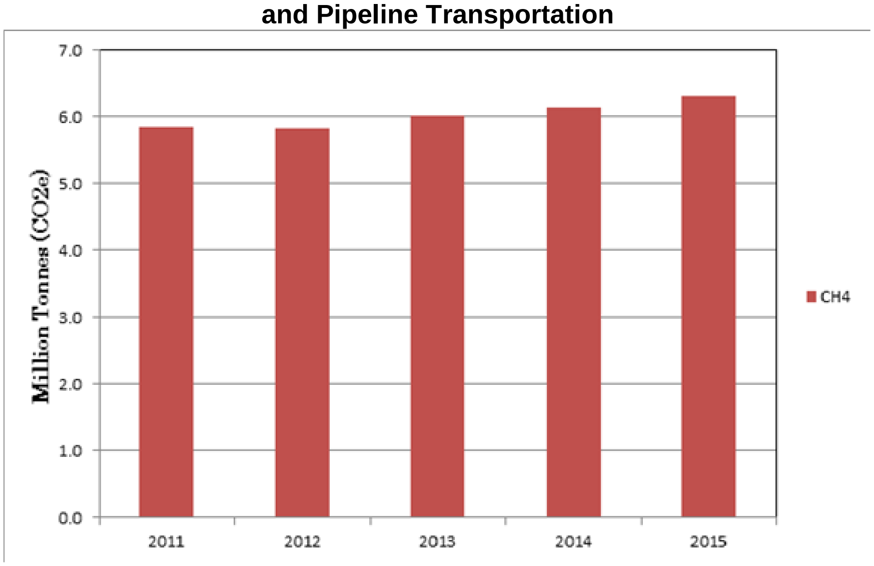
production and processing from transmission and distribution. In 2015, oil and gas production and processing made up 6 percent of methane emissions, while transmission and distribution emissions made up 10 percent of methane emissions. This excludes Aliso Canyon emissions.[124, 125] **Figure 24** shows the totals from both sectors between 2010 and 2014.

Figure 23: Methane Emissions from the U.S. Natural Gas System



Source: U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2015*, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2015.

Figure 24: Methane Emissions from California Oil and Natural Gas Production, Processing, and Pipeline Transportation



Source: California Air Resources Board, California Greenhouse Gas Emission Inventory – 2017 Edition, https://www.arb.ca.gov/cc/inventory/data/data.htm.

124 CARB, in making emission estimates from oil and gas extraction, does not separate the emissions attributed to oil production from those produced by natural gas extraction, so methane emissions from natural gas could be understated or overstated.

125 CARB, *Short-lived Climate Pollutant Reduction Strategy, Appendix C: California SLCP Emissions*, 2017, https://www.arb.ca.gov/cc/shortlived/meetings/11282016/appendixc.pdf.

As required by Senate Bill 1371 (Leno, Chapter 525, Statutes of 2014),[126] CARB and the CPUC prepare joint annual reports to track and analyze natural gas emissions from the transmission, distribution, and storage activities throughout the state. In January 2017, the two agencies issued a joint report estimating gas emissions from the natural gas system in California at 6,601.2 million standard cubic feet or 2.955 million metric tons of carbon dioxide equivalents (100-yr global warming potential).[127] This report excluded extraordinary events like Aliso Canyon.

Current State Efforts to Reduce Methane Emissions

In California, Governor Edmund G. Brown Jr. signed Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016) into law in September 2016, [128] which built upon AB 32 and set a 40 percent GHG reduction from 1990 levels for 2030.[129] As already noted, Senate Bill 1371 requires gas companies to report natural gas emissions from their facilities and to summarize utility leak management practices, among other things.

CARB and CPUC staff indicated that gas system operators should use the information from these reports to help determine where they can achieve emission reductions to meet the state's methane emission reduction goal, while maintaining the safe and reliable operation of the regulated gas storage and delivery systems.[130]

At its June 15, 2017, meeting, the CPUC took the following actions as part of its SB 1371 proceeding:

- Instituted annual reporting for tracking methane emissions.
- Approved 26 mandatory best practices for minimizing methane emissions.
- Required a biennial compliance plan incorporated into the utilities' annual gas safety plans, beginning in March 2018.
- Instituted a cost recovery process to simplify CPUC review and approval of incremental expenditures to implement best practices,[131] which included expenditures for pilot programs and research and development.

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126 California State Legislature, Senate Bill 1371. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB1371.

127 CPUC, Rulemaking 15-01-008, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M172/K518/172518969.PDF.

128 California State Legislature, Senate Bill 32, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32.

129 California State Legislature, Assembly Bill 32. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32; passed in 2006; set GHG reductions goals.

130 CARB and CPUC, *Joint Staff Report: Analysis of the Utilities' June 17, 2016, Methane Leak and Emissions Reports*, required by SB 1371, p. 3.

131 At this time, only the proposed decision is available on the CPUC's website: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M186/K437/186437714.PDF.

Senate Bill 1383 requires CARB, CPUC, and the Energy Commission to "undertake various actions related to reducing short-lived climate pollutants in the state." The bill focuses attention on reducing methane emissions from dairy and organic wastes by containing methane and using it as a renewable gas.[132] The legislation also directs CARB to begin implementing a short-lived climate pollutant strategy with the goal of reducing methane emissions by 40 percent below 2013 levels by 2030.[133, 134]

As part of the work to reduce short-lived climate pollution, the Energy Commission funds methane emission research through its natural gas research and development program. This research found evidence that fugitive emissions occur in every subsector throughout the natural gas system, including homes, natural gas vehicle refilling stations, and plugged and abandoned natural gas wells.

Other projects related to methane emissions include research to:

- Characterize fugitive emissions from commercial buildings in California.
- Study the potential impacts of subsidence (vertical and horizontal changes in elevation due to groundwater extraction during the drought) to the natural gas system and methane emissions from abandoned wells.

Senate Bill 605 (Lara, Chapter 523, Statutes of 2014) requires CARB to develop strategies that further reduce short-lived climate pollutants, such as methane.[135] The latest proposed regulations associated with the natural gas system suggest greater mandatory monitoring on a wider assortment of components than was previously considered. New laws and regulations are also pushing for better mitigation strategies for emissions from pipelines.[136]

The data and associated studies from SB 605 will be used in the CARB/CPUC annual joint staff report that analyzes the utilities' emission reports. This work will improve understanding of the amount of emissions from utilities' facilities and pipelines.

State agency efforts to reduce methane emissions from natural gas system infrastructure are ongoing. CARB staff are working with local air quality districts to

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132 The *Draft 2017 Integrated Energy Policy Report* to be released later this fall is expected to include a discussion of cost-effective strategies and priority end uses of renewable gas in relation to existing state policies and climate goals. Emerging opportunities for renewable gas resource and technology solutions to reach longer-term SLCP goals will also be addressed.

133 California State Legislature, Senate Bill 1383, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383.

134 California State Legislature, Assembly Bill 1257, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB1257.

135 California State Legislature, Senate Bill 605, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB605.

136 CARB, *Short-Lived Climate Pollutant Reduction Strategy*, March 2017, pp. 79-80. https://www.arb.ca.gov/cc/shortlived/meetings/03142017/final_slcp_report.pdf.

develop new regulations, which will include vapor collection from high-emitting storage tanks and other equipment, leak detection and repair on more components then covered by local air districts, and ambient methane monitoring and more frequent wellhead monitoring at underground gas storage facilities.

CARB is also cooperating with DOGGR on above- and below-ground monitoring of storage facilities. CARB proposed improved above-ground methane monitoring of underground storage facilities in the agency's Oil and Gas Production, Processing and Storage Regulation program to implement some requirements of SB 887. DOGGR is formalizing and adding to the emergency regulations implemented in February 2016. This new legislation would require that "…the operator of a gas storage well, before January 1, 2018, to have commenced a mechanical integrity testing regime specified by the [DOGGR] and would require the division to promulgate regulations that establish standards for all gas storage wells, as specified."

Assembly Bill 1496 (Thurmond, Chapter 604, Statutes of 2015) calls on CARB to monitor and measure high-methane emission hot spots in the state, and to conduct a life-cycle GHG emission study for natural gas produced in or imported into California. As of December 2017, work on these requirements is ongoing.

In early 2017, the Energy Commission approved more than $5 million in grants for research examining the natural gas system. The approved projects include:

- $1.1 million to Energy and Environmental Economics, Inc. to assess long-term technology pathways for natural gas systems to meet energy and GHG emission goals.
- $1.6 million to Lawrence Berkeley National Laboratory to research new technology to identify areas with high risk of natural gas infrastructure damage due to land subsidence and to recommend remedial actions.
- $597,433 grant to University of California, Davis, to survey methane leakage from abandoned and plugged natural gas wells in California.
- $1.4 million to the Electric Power Research Institute to address fugitive GHG emissions, including methane and nitrous oxide, at industrial plants.

Tracking Natural Gas Emissions

In the past few years, California has developed new regulations and policies to improve the monitoring, reporting, and repairing of its natural gas infrastructure and exceed federal requirements. These new regulations and reporting requirements will provide information and data on the state's natural gas infrastructure. About 90 percent of the gas used in California is imported from outside the state, and the emissions associated with these imports are not well understood. Senate Bill 839 (Committee on Budget and Fiscal Review, Chapter 340, Statutes of 2016) requires the Energy Commission to report on the resources needed to develop a system that would allow California to track emissions from both in-state and out-of-state emissions. The tracking system is intended to provide CARB with the data it needs to model emissions. The Energy Commission is working with CARB to determine the most appropriate data to collect. Staff recently completed a progress report, which should be available in early 2018.

ACRONYMS

Acronym	Proper Name
AAEE	additional achievable energy efficiency
AB	Assembly Bill
AESO	Alberta Electric System Operator
BAA	balancing area authorities
Bcf	billion cubic feet
BLM	Bureau of Land Management
California ISO	California Independent System Operator
CARB	California Air Resources Board
CED	*California Energy Demand*
CHP	combined heat and power
CO2	carbon dioxide
CPUC	California Public Utilities Commission
DOGGR	Division of Oil, Gas, & Geothermal Resources
EDF	Environmental Defense Fund
Energy Commission	California Energy Commission
FERC	Federal Energy Regulatory Commission
Fracking	hydraulic fracturing
GDP	gross domestic product
GHG	greenhouse gas
GIM	gas imbalance market
GTN	Gas Transmission Northwest Company
GW	gigawatt
GWh	gigawatt-hours
IEPR	*Integrated Energy Policy Report*
IOU	investor-owned utility

LADWP	Los Angeles Department of Water and Power
LNG	liquefied natural gas
MAPE	mean absolute percentage error
MMBtu	million British thermal unit
MMcf	million cubic feet
MW	megawatt
NAMGas	North American Market Gas-Trade Model
NGCC	Natural gas combined-cycle
NWPCC	Northwest Power and Conservation Council
NYMEX	New York Mercantile Exchange
OTC	once-through cooling
PEMEX	Petróleos Mexicanos
PG&E	Pacific Gas and Electric Company
POU	publicly owned utilities
PSEP	Pipeline Safety Enhancement Plan
PV	photovoltaic
QFER	*Quarterly Fuels and Energy Report*
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SMUD	Sacramento Municipal Utility District
SoCalGas	Southern California Gas Company
SWRCB	State Water Resources Control Board
Tcf	trillion cubic feet
TEPPC	Transmission Electric Planning and Policy Committee
U.S.	United States
U.S. EIA	United States Energy Information Administration

U.S. EPA	United States Environmental Protection Agency
WECC	Western Electricity Coordinating Council

APPENDIX A: NAMGas Model Assumptions

Three "Common" Cases - High, Mid, and Low Demand

Staff developed three "common" cases for the 2017 IEPR - high, mid, and low demand. **Table A-1** outlines the assumptions used in the model.

Table A-1: Common Case Assumptions

Input Category	High Demand	Mid Demand	Low Demand
GDP/GSP	High Case in EIA's 2016 Energy Outlook: 2.8% Annual GDP Growth	Reference Case in EIA's 2016 Energy Outlook: 2.2% GDP Growth	Low Case in EIA's 2016 Energy Outlook: 1.6% Annual GDP Growth
Additional Achievable Energy Efficiency	2015 IEPR Low for Residential, Commercial, and Industrial Gas Demand	2015 IEPR Mid for Residential, Commercial, and Industrial Gas Demand	2015 IEPR High for Residential, Commercial, and Industrial Gas Demand
California Reference Demand	Preliminary High Natural Gas Demand Forecast For The Residential, Commercial, Industrial, And Transportation Sector Prepared For The CEC's *2017 California Energy Demand* Report	Preliminary Mid Natural Gas Demand Forecast For The Residential, Commercial, Industrial, And Transportation Sector Prepared For The CEC's *2017 California Energy Demand* Report	Preliminary Low Natural Gas Demand Forecast For The Residential, Commercial, Industrial, And Transportation Sector Prepared For The CEC's *2017 California Energy Demand* Report
Reference Demand For The Power Generation Sector In The	PLEXOS Electricity Dispatch Model Run Forecasting Natural Gas Demand In The	PLEXOS Electricity Dispatch Model Run Forecasting Natural Gas Demand In The	PLEXOS Electricity Dispatch Model Run Forecasting Natural Gas Demand In The

Input Category	High Demand	Mid Demand	Low Demand
WECC Region	Power Generation Sector (High Demand Case) For The WECC Region	Power Generation Sector (Mid Demand Case) For The WECC Region	Power Generation Sector (Low Demand Case) For The WECC Region
Reference Demand for the Residential, Commercial, Industrial, and Transportation Sector Outside of California. Reference Demand for the Power Generation Sector Outside of The WECC Region	Small “m” Econometric Model (High Demand Case)	Small “m” Econometric Model (Mid Demand Case)	Small “m” Econometric Model (Low Demand Case)
Renewables	50% by 2030	50% by 2030	50% by 2030
Coal Retirement Through 2050	73 GW	53 GW	33 GW
Resource Capital Costs	50% Lower Than 2015 Inputs	2016 Inputs	50% Higher Than 2015 Inputs
Resource Operation & Maintenance Costs	50% Lower Than 2015 Inputs	2016 Inputs	50% Higher Than 2015 Inputs
Proved Supply Forward Costs	50% Lower Than Reference Case (2017 And After)	Estimate Based on Hub Prices	50% Higher Than Reference Case (2017 And After)

Source: California Energy Commission staff.

APPENDIX B: Burner Tip Method

Actual burner tip prices include a commodity price and a transportation rate, both of which are assessed per unit of natural gas. The commodity price is the price of natural gas after production from the well and processing for injection into a nearby utility pipeline. The transportation rate is the cost of transporting the gas from its injection point near the production basin to the electric generator for consumption. Actual commodity prices and transportation rates are publicly available, with the former as an average of actual transactions. Commodity prices are provided by industry journals, such as *Natural Gas Intelligence*, which publish average wholesale volume-weighted prices from surveys of monthly "bidweek" transactions at more than a hundred pricing points across North America.[137]

Transportation rates are published in the tariffs posted by the natural gas pipeline operators on their websites and are also filed with regulators. Energy Commission staff learned from discussions with industry personnel that generators procure most natural gas on contract and are indexed to a bidweek price at one of these pricing points. Actual power plant burner tip prices usually include additional contract costs such as procurement, price risk, transactions, and others. The terms of these contracts are proprietary and not publicly available. Consequently, no model, including the Burner Tip Model, can account for these costs. The model is the best estimate developed by staff, using publicly available information.

137 Market participants in the natural gas industry buy much of their physical natural gas, or gas they will consume, for the upcoming month as part of a process called bidweek.

APPENDIX C: PLEXOS Modeling Assumptions

There are several assumptions made to align with other planning exercises. The following sections discuss assumptions in which analyses show that the results are sensitive to changes. Energy Commission staff's WECC-wide production simulation model dataset covers 2017 through 2030 for the three common cases for the *2017 IEPR* and one other case with a higher level of AAEE.[138] **Table C-1** summarizes these cases.

Table C-1: IEPR Common Cases

Common Case	2017 IEPR Preliminary Load Forecast	Energy Efficiency*	RPS Target
High Energy Consumption	High	Low 2016 IEPR Update AAEE	50% by 2030
Mid Energy Consumption	Mid	Mid AAEE	50% by 2030
Low Energy Consumption	Low	High AAEE	50% by 2030

Source: California Energy Commission staff.

*Uses *2016 IEPR Update* because 2017 AAEE data are not yet available.

Diablo Canyon Retirement

The Diablo Canyon power plant is retired in all IEPR common cases. The model assumes Diablo Canyon Unit 1 is retired December 31, 2024, and Unit 2 by August 26, 2025. Consistent with the Diablo Canyon Retirement Proposal, all common cases include 2,000 GWh of gross energy efficiency in addition to the AAEE already embedded in the IEPR common cases and an additional 2,000 GWh/yr of new renewables developed between 2020 and 2024.

Hourly Net Export Constraint

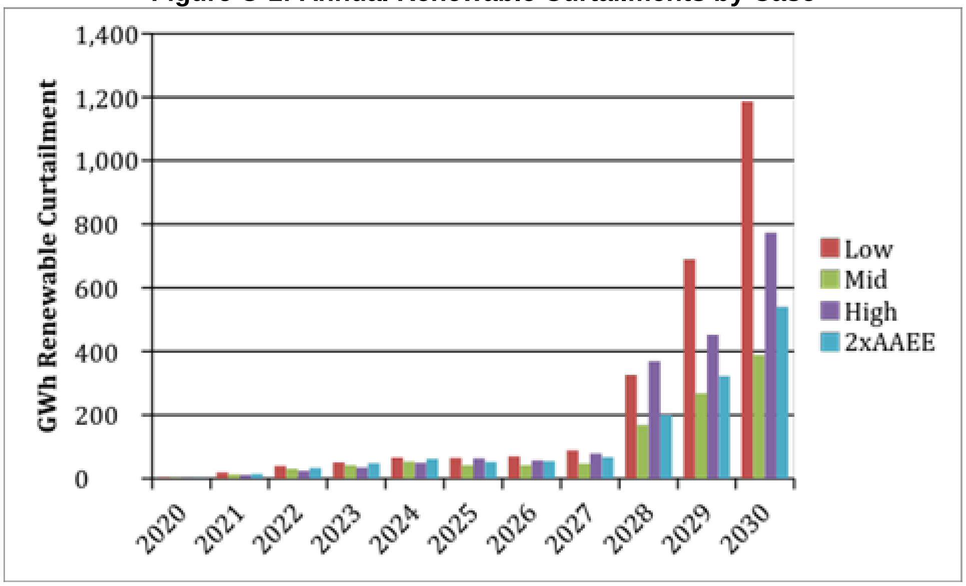
Staff imposed an hourly net export constraint of 4,000 MW in all IEPR common cases. The CPUC's Draft *2017 Assumptions and Scenarios for Long-Term Planning*[139] recommend 2,000 MW for all cases except the interregional coordination scenario, which assumes 5,000 MW. Staff used 4,000 MW because the IEPR simulations are statewide, while the CPUC assumptions are for California ISO's area only. This constraint allows the production cost model to curtail zero-cost renewable power. This emerges from the

138 Additional achievable energy efficiency is savings from initiatives that are planned but not yet approved by the utilities or any other entity.

139 CPUC, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M172/K519/172519400.PDF.

fact that renewable energy resources in certain hours experience excess loads, and are considered transmission constrained. The renewable curtailments are below 100 GWh per year in all cases until 2028. The mid demand case consistently has the lowest amount of renewable curtailment, while the low and high demand cases consistently incur the highest amount of renewable curtailments. **Figure C-1** shows the amount of annual renewable curtailments by case.

Figure C-1: Annual Renewable Curtailments by Case



Source: California Energy Commission, PLEXOS results.

Load Forecast for Non-California WECC (2017 to 2030)

Staff used data submitted to the WECC by balancing area authorities (BAAs) for 2015 and the WECC TEPPC 2026 common case[140] load forecast as "bookends" to estimate the non-California BAA load. Staff used a compound annual growth rate formula to calculate the peak and energy demand for the intervening years (2017 to 2025). The period for *2017 IEPR* PLEXOS simulations extended beyond the TEPPC common case year of 2026, so staff used the compound annual growth rate to extrapolate the forecast by four years to 2030. Staff used the annual peak and energy forecasts as inputs to PLEXOS, and developed hourly energy profiles (GWh) and regional peak demand (MW) for each year using the "build"[141] function embedded in the PLEXOS software.

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140 WECC, Datasets, https://www.wecc.biz/SystemAdequacyPlanning/Pages/Datasets.aspx#f727be3b-b212-4e51-8f5d-538497ae357d=%7B%22k%22%3A%22%22%7D#c6981a26-5370-44c9-b968-8836159a8cae=%7B%22k%22%3A%22%22%7D#0cf7cc46-0612-4858-a694-967947be8e76=%7B%22k%22%3A%22%22%2C%22s%22%3A21%7D#db6a7e9a-a52d-42ad-88b9-e742744164ad=%7B%22k%22%3A%22%22%7D.

141 The linear programming model uses the peak and energy forecast and an average hourly load profile for load-serving entities in the WECC to develop hourly profiles for 2017 – 2030.

Staff developed energy (GWh) and peak (MW) forecasts for the high demand/low price and low demand/high price cases using different multipliers for each BAA by using data from the U.S. EIA. The U.S. EIA provided data for high and low electricity demand cases by region (Northwest, Southwest, and Rocky Mountains).[142] To calculate the high and low demand cases, staff again used compound growth formulas for each region for each year of the forecast period. **Figure C-2** displays the annual WECC (Non-California) load forecast in GWh for the period of 2017 to 2030 for all three common cases. Staff calculated annual peak demand for each BAA using the same method. Because different regions experience system peak at different times of the year (summer or winter) and different times of the day, aggregated, or combined, peak demand data are not presented here.

Figure C-2: WECC (Non-CA) Electricity Load Forecast—All Cases (GWh)

Source: California Energy Commission.

Hydro Generation Forecast

Continuing the *2015 IEPR* hydro generation input assumption technique, staff developed WECC-wide hydroelectric generation input data using a shorter and more recent set of historical hydro generation data from the U.S. EIA.[143] This method is used to reflect the overall trend of reduced hydroelectric generation due to persistent or semi-persistent drought conditions in the western United States and to reflect changes in hydroelectric operations due to federal and state regulations concerning water flows for fish protection.

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142 U.S. EIA, *Annual Energy Outlook*, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2016&region=0-0&cases=ref2016~highmacro~lowmacro&start=2017&end=2030&f=A&linechart=~~~ref2016-d032416a.56-8-AEO2016~highmacro-d032516a.56-8-AEO2016~lowmacro-d032516a.56-8-AEO2016&ctype=linechart&sourcekey=0.

143 See U.S. EIA's website at: http://www.eia.gov/electricity/monthly/.

Historically, staff has used the hydroelectric generation data from 1991 to the most recent year for which a complete set of plant data is available (2015). For this *IEPR* cycle, staff used hydroelectric generation data from 2001 to 2015 to calculate the average monthly generation by hydroelectric plant. Data for calendar year 2016 were not complete at the time of simulation runs, and staff does not anticipate them being ready for publication by U.S. EIA until October 2017. Due to a lack of available data, staff did not update the Canadian hydroelectric generation forecast for Alberta and British Columbia, but recent information posted on the BC Hydro, Columbia Power, and Fortis B.C. websites are consistent with PLEXOS inputs for British Columbia's hydro generation.

The monthly projections for California hydroelectric generation are an average based on plant level 2001 to 2015 monthly historical generations. However, since 2016, California has seen an increase in precipitation activity and associated hydroelectric output. As such, staff inflated the 2017 average monthly hydro generation input for California plants using recent data submittals to reflect the projected increase in hydro generation. This adjustment will better reflect hydro performance and result in a reduction in the amount of California gas-fired generation in PLEXOS simulations for 2017. Staff did not make similar adjustments to hydro conditions for the rest of the Western Interconnect.

Unit Commits

For this modeling cycle, staff analyzed roughly 80 out-of-state coal and combined-cycle generators throughout the Western Interconnect. Staff sought to update a modeling characteristic of these plants to forecast and provide more accurate data.

Each generator has unique properties. It is important to assign qualities and data to a simulated generator that reflects the real world. One such characteristic is a *unit commit*. Setting a unit commit tells the modeling software how the generator should operate. There are three basic settings the generator can have: always on (constantly running), off (not running), or optimized (running according to when it is most economically efficient and profitable). Setting the commit status to "always on" is often best for baseload generators such as coal facilities. Occasionally, staff needs to update the plants in the simulation so that the model can predict more accurate outcomes. This is due to factors such as changes in market fuel prices or announced plant retirements.

Staff analyzed and compared the historical trend to the results of the sample plants in two scenarios. The first scenario tested the plant units running always on with a few running in the optimized setting. The second scenario tested the opposite with the majority of the plant units running an optimized (economic) case with a minority in a must-run (non-economic) case. Staff gathered five-year historical data from sources including U.S. EIA and the U.S. EPA's Continuous Emission Monitoring reporting. Staff sought to compare the best fit for each generator based on either simulated scenario to the actual historical data.

After reviewing the results, staff agreed on an appropriate commit status for the analyzed generators to reflect more accurate results. Staff decided that almost a third of the generators would be set as must-runs while the remaining would be run economically. A few plant units in Nucla, Colorado, and Mesquite, Arizona, fit neither scenario. Staff decided to split the commit status by months. In general, they would be operating as must-runs for the summer months while running economically the rest of the year.

Renewable Energy Build–Out Targets

In all three cases, demand for conventional generation decreases over the forecast period, as states are assumed to achieve more aggressive renewable energy targets. **Table** C-2 lays out the energy build-out targets assumed in this modeling cycle.

Table C-2: Energy Build-Out Targets by State

	2017	2020	2024	2027	2030
Arizona	4.20	6.10	8.70	9.40	9.60
Colorado	5.80	10.70	11.00	11.40	11.60
Montana	1.50	1.60	1.60	1.60	1.60
New Mexico	2.70	3.80	3.90	3.90	4.00
Nevada	4.70	6.10	6.20	8.10	8.30
Oregon	4.90	6.90	7.00	9.90	12.80
Utah	3.13	4.43	6.16	7.46	8.76
Washington	6.60	11.30	11.40	11.40	11.50
Alberta	4.76	7.52	11.20	13.96	15.80

Sources: Barbose, Galen L., U.S. Renewables Portfolio Standards: *2017 Annual Status Report*, 2017, WECC Transmission Expansion Planning Policy Committee 2026 Common Case, and *AESO 2017 Long-term Outlook,* https://www.aeso.ca/grid/forecasting/.

APPENDIX D:
Detailed Method for Historical and Forecasted Rates

The following sections describe the method for the historical and forecasted data set for the three utilities: PG&E, SoCalGas and SDG&E.

Pacific Gas and Electric End-Use Rates

Residential

For the 1967 to 1990 historical rates, staff used PG&E's annual statistical reports[144]. Staff divided the reported total revenues by total volumes to devise the rates. For 1990 to 1996 historical rates, staff used the Energy Commission's Quarterly Fuels and Energy Report (QFER) form 7 and 1308 schedule 3. For the 1997 to 2015 rates, staff used the U.S. EIA's Natural Gas Annual Respondent Query System (EIA-176) to populate the data.[145]

For forecasted rates, staff added transportation and public purpose program surcharges (PPPS) to NAMGas modeled PG&E hub rates. PG&E posts the current transportation and PPPS on the California Gas Transmission, Pipe Ranger website.[146] Staff used weighted averages for both the transportation and PPPS. Staff escalated the transportation charge from 2017 to 2026 by the Bureau of Labor Statistics' (BLS) utility-piped gas consumer price index (CPI) 12-month average – 0.82 percent as of December 2016.[147]

Commercial and Industrial

For the 1967 to 1990 rates, staff interpolated the data. Staff used average percentage differences between residential and commercial/industrial for the known data years (1990 to 2015), and then multiplying the residential rate by the average percentage to interpolate historical rates for commercial and industrial. For 1990 to 1996, staff used the Energy Commission's QFER form 7 and 1308, schedule 3. For the 1997 to 2015 rates,

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144 PG&E, Financials, http://investor.pgecorp.com/financials/annual-reports-and-proxy-statements/.

145 U.S. EIA, http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RPC&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compid=&f_fullscreen=.

146 PG&E, http://www.pge.com/tariffs/tm2/pdf/GAS_SCHEDS_G-PPPS.pdf, http://www.pge.com/tariffs/tm2/pdf/GAS_SCHEDS_G-1.pdf.

147 BLS, News Release, August 2017, https://www.bls.gov/news.release/pdf/cpi.pdf.

staff used U.S. EIA's Natural Gas Annual Respondent Query System (EIA-176)[148] to populate the data.

For forecasted rates, staff added transportation and public purpose program surcharges (PPPS) to NAMGas-modeled PG&E hub rates. PG&E posts the current transportation and PPPS on the California Gas Transmission, Pipe Ranger website.[149] Staff used weighted averages for both the transportation and PPPS. Staff escalated the transportation charge from 2017 to 2026 by the BLS CPI 12-month average – 0.82 percent as of December 2016.[150]

Southern California Edison/Southern California Gas Company

Since SCE does not service natural gas, staff used SoCalGas as a proxy for the SCE electricity planning area.

Residential

For the 1967 to 1996 historical rates, staff used SoCalGas' annual statistical reports.[151] Staff divided the reported total revenues by total volumes. For 1990 to 1996 historical rates, staff used the Energy Commission's QFER form 7 and 1308 schedule 3. For the 1997 to 2015 rates, staff used EIA's Natural Gas Annual Respondent Query System (EIA-176)[152] to populate the data.

For forecasted rates, staff added transportation charges and PPPS to NAMGas-modeled SoCalGas hub rates. SoCalGas posts the charges on the SoCalGas ENVOY website.[153] Staff used weighted averages for both the transportation charges and PPPS. Staff escalated the transportation charge from 2017 to 2026 by the BLS' utility-piped gas CPI 12-month average, 0.82 percent as of December 2016.[154]

Commercial and Industrial

For the 1967 to 1990 historical rates, staff interpolated the data. Staff used average percentage differences between residential and commercial/industrial for the known

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148 U.S. EIA, http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RPC&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compid=&f_fullscreen=.

149 PG&E, http://www.pge.com/tariffs/tm2/pdf/GAS_SCHEDS_G-1.pdf .

150 U.S. EIA, http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RPC&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compid=&f_fullscreen=.

151 Sempra Energy, Financial Reports, http://investor.shareholder.com/sre/annuals.cfm.

152 U.S. EIA, http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RPC&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compid=&f_fullscreen=.

153 SoCalGas, https://scgenvoy.sempra.com/.

154 BLS, News Release, https://www.bls.gov/news.release/pdf/cpi.pdf.

data years (1990 to 2015), then multiplying the residential rate by the average percentage to interpolate historical rates for commercial and industrial. For 1990 to 1996, staff used the Energy Commission's QFER form 7 and 1308 schedule 3. For the 1997 to 2015 rates, staff used EIA's Natural Gas Annual Respondent Query System (EIA-176)[155] to populate the data.

For forecasted rates, staff used the same methodology as residential with adjustments to the transportation and public purpose program charges.

155 U.S. EIA, http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RPC&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compid=&f_fullscreen=.

San Diego Gas & Electric End-Use Rates

Residential

For the 1997 to 2015 rates, staff used U.S. EIA's Natural Gas Annual Respondent Query System (EIA-176).[156] For the 1967 to 1996 rates, staff used Sempra's *Annual Statistical Report*,[157] taking total revenues divided by total volume.

For forecasted rates, staff added weighted average transportation and PPPS charges to NAMGas-modeled SDG&E hub rates. The transportation and PPPS charges come from SDG&E's tariff rates posted online at the SoCalGas ENVOY website.[158] Staff escalated the transportation charge from 2017 to 2026 by the BLS' utility-piped gas CPI 12-month average – 0.82 percent as of December 2016.[159]

Commercial

For the 1997 to 2015 rates, staff used the same method as residential rates. For 1990 to 1996, staff used the Energy Commission's QFER form 7 and 1308 schedule 3. For the 1967 to 1990 rates, staff interpolated data. Staff used average percentage differences between residential and commercial for the known data years (1990 to 2015), and then multiplied the residential rate by the average percentage to interpolate historical rates for commercial.

Industrial

For the 1967 to 1990 rates, staff interpolated data. Staff used average percentage differences between residential and commercial for the known data years (1997 to 2015), and then multiplied the residential rate by the average percentage to interpolated historical rates for commercial and industrial. For the 1997 to 2015 rates staff obtain total commercial and industrial volumes and revenues from SDG&E's annual Statistical Reports, then obtain commercial volumes and revenues from U.S. EIA's Natural Gas Annual Respondent Query System, EIA-176. Staff found the difference between commercial volumes and revenues from totals in the annual statistical report and U.S. EIA's data to find industrial volumes and revenues, then divided revenues by volumes to get an implied rate. **Table D-1** through **Table D-3** display PG&E, SoCalGas, and SDG&E modeling results.

156 U.S. EIA, cbid.

157 SDG&E, http://investor.shareholder.com/sre/annuals.cfm.

158 SoCalGas, https://scgenvoy.sempra.com.

159 BLS, News Release, https://www.bls.gov/news.release/pdf/cpi.pdf.

Table D-1: Modeling Results for PG&E, Reference Case

2016$/Mcf	Residential	Commercial	Industrial
2017	$14.79	$11.53	$6.65
2018	$14.94	$11.65	$6.72
2019	$15.31	$11.99	$7.00
2020	$15.52	$12.18	$7.14
2021	$15.65	$12.26	$7.18
2022	$15.78	$12.36	$7.23
2023	$15.92	$12.47	$7.29
2024	$16.07	$12.57	$7.34
2025	$16.23	$12.71	$7.42
2026	$16.39	$12.84	$7.50
2027	$16.56	$12.96	$7.57
2028	$16.67	$13.05	$7.59
2029	$16.84	$13.18	$7.67
2030	$17.01	$13.31	$7.75

Source: California Energy Commission.

Table D-2: Modeling Results for SoCalGas, Reference Case

2016$/Mcf	Residential	Commercial	Industrial
2017	$9.58	$7.57	$7.57
2018	$9.68	$7.65	$7.65
2019	$9.99	$7.95	$7.95
2020	$10.15	$8.09	$8.09
2021	$10.22	$8.14	$8.14
2022	$10.30	$8.21	$8.21
2023	$10.40	$8.28	$8.28
2024	$10.48	$8.34	$8.34
2025	$10.59	$8.44	$8.44
2026	$10.70	$8.52	$8.52
2027	$10.80	$8.61	$8.61
2028	$10.87	$8.65	$8.65
2029	$10.98	$8.74	$8.74
2030	$11.09	$8.84	$8.84

Source: California Energy Commission.

Table D-3: Modeling Results for SDG&E, Reference Case

2016$/Mcf	Residential	Commercial	Industrial
2017	$13.87	$7.56	$7.56
2018	$14.02	$7.66	$7.66
2019	$14.38	$7.95	$7.95
2020	$14.60	$8.10	$8.10
2021	$14.71	$8.14	$8.14
2022	$14.84	$8.21	$8.21
2023	$14.98	$8.28	$8.28
2024	$15.12	$8.35	$8.35
2025	$15.28	$8.45	$8.45
2026	$15.43	$8.53	$8.53
2027	$15.59	$8.61	$8.61
2028	$15.69	$8.65	$8.65
2029	$15.86	$8.74	$8.74
2030	$16.03	$8.84	$8.84

Source: California Energy Commission, Supply Analysis Office.

APPENDIX E: Comparison of Gas Price Forecasts

This appendix compares the Energy Commission's NAMGas model results of natural gas prices at Henry Hub to other forecasts of Henry Hub prices. The comparison includes the following forecasts, along with the date of release:

- U.S. EIA Annual Energy Outlook (January 2017).
- Northwest Power and Conservation Council (NWPCC), The Seventh Power Plan Proposed Fuel Price Forecasts (February 2016).

U.S. EIA, Annual Energy Outlook, January 2017

The U.S. EIA ran several natural gas price cases.[160] Staff examined cases that are most comparable to the Energy Commission's staff assessment of natural gas price forecast. Three cases were used: 1) U.S. EIA's reference case, 2) low oil and gas resources and technology, and 3) high oil and gas resources and technology.

In the reference case, U.S. EIA assumes population growth of 0.7 percent per year and GDP increases of 2.2 percent per year, with 2.6 percent GDP growth in the high resource case and 1.6 percent growth in the low resource case, the same as the Energy Commission's assumptions.

In the low oil and gas resource and technology case, the estimated ultimate recovery per tight oil, tight gas, or shale gas in the United States and undiscovered resources in Alaska and the offshore Lower 48 states is assumed to be 50 percent lower than in the reference case. Rates of technology improvement that reduce costs and increase productivity in the United States are also 50 percent lower than in the reference case.

These assumptions increase the per-unit cost of crude oil and natural gas development in the United States. The total unproved technically recoverable resource of crude oil is decreased to 150 billion barrels, and the natural gas resource is decreased to 1,303 trillion cubic feet (Tcf), as compared with unproved resource estimates of 238 billion barrels of crude oil and 2,136 Tcf of natural gas as of January 1, 2014, in the reference case.

In the high oil and gas resource and technology case, the resource assumptions are adjusted to allow a continued increase in domestic crude oil production through 2040, to 18 million barrels per day (bpd) compared with 11 million bpd in the reference case. This case includes:

160 For more on U.S. EIA's AEO 2017, see https://www.eia.gov/outlooks/aeo/.

- Fifty percent higher estimated ultimate recovery per tight oil, tight gas, or shale gas well, as well as additional unidentified tight oil and shale gas resources to reflect the possibility that additional layers or new areas of low-permeability zones will be identified and developed.
- Diminishing returns on the estimated ultimate recovery once drilling levels in a county exceed the number of potential wells assumed in the reference case, to reflect well interference at greater drilling density.
- Fifty percent higher assumed rates of technological improvement that reduce costs and increase productivity in the United States relative to the reference case.
- Fifty percent higher technically recoverable undiscovered resources in Alaska and the offshore Lower 48 states than in the reference case. The total unproved technically recoverable resource of crude oil increases to 385 billion barrels, and the natural gas resource increases to 3,109 Tcf as compared with unproved resource estimates of 238 billion barrels of crude oil and 2,136 Tcf of natural gas in the reference case as of the start of 2014.[161]

Comparing U.S EIA to Energy Commission Forecast

The U.S. EIA uses the National Energy Modeling System, while Energy Commission staff uses the Market Builder platform. Due to the different algorithms used, it may not be possible to have the same assumptions in both models. Even with the same assumptions, it may not be possible to see the same results. Comparisons based on estimates, however, are feasible.

Both reference cases follow the same basic trajectory through 2030. The U.S. EIA's reference case starts at $3.11 Mcf (in 2016$) in 2017 and climbs to $5.19 Mcf in 2030; whereas the Energy Commission's prices start at $3.11 Mcf in 2017 and rise to $4.54 Mcf in 2030, a 14 percent difference in price in 2030.

The U.S. EIA's high oil and gas resource and technology case prices are higher than the Energy Commission's through 2030. The Energy Commission's prices are 66 percent lower ($3.88 vs $2.33 Mcf) in 2030. For the U.S. EIA's low oil and gas resource and technology case, prices start higher in 2017 compared to the Energy Commission's ($3.29 vs $3.15). The U.S. EIA's forecasted prices climb higher until 2030, when the Energy Commission's prices exceed those of the U.S. EIA's. The U.S. EIA's 2030 price of $8.26 Mcf is 5 percent lower than the Energy Commission's price of $8.66 per Mcf.

Both modeling efforts have similar economic growth, demands, cost variations and supplies. The price differences in the first few years can be attributed to how the

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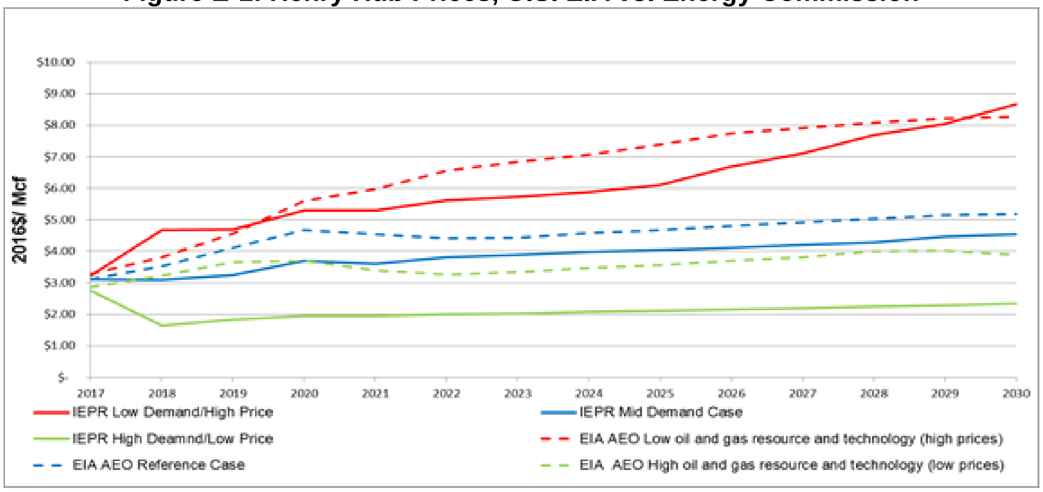
161 For more on U.S. EIA's assumptions, see https://www.eia.gov/outlooks/aeo/assumptions/pdf/introduction.pdf.

differing models work. The U.S. EIA's model has a more gradual inclusion of the change in resources and costs, while NAMGas' inclusion of these takes effect immediately. The Energy Commission's projection trends lower than U.S. EIA's partially because NAMGas' total recoverable resources are higher than U.S. EIA's 188 Tcf in the mid demand or reference cases. **Figure E-1** compares U.S. EIA's price projections with that of the Energy Commission and Henry Hub.

Figure E-1: Henry Hub Prices, U.S. EIA vs. Energy Commission



Source: U.S. EIA *AEO 2017* and California Energy Commission, Supply Analysis Office.

Northwest Power and Conservation Council, Fuel Price Forecast, February 2016

The NWPCC developed three natural gas price cases: low, high, and medium price.

The low price case ranges from $2.72 Mcf in 2016 to $3.39 Mcf by 2030 under ample supplies and slow recovery in demand. The high price case ranges from $3.60 Mcf in 2016 to $8.42 Mcf by 2030 (in constant 2014$). These prices represent the range of current expectations by NWPCC's Natural Gas Advisory Committee. The high and low forecasts are intended to capture extreme future price variations from today's relatively consistent market.

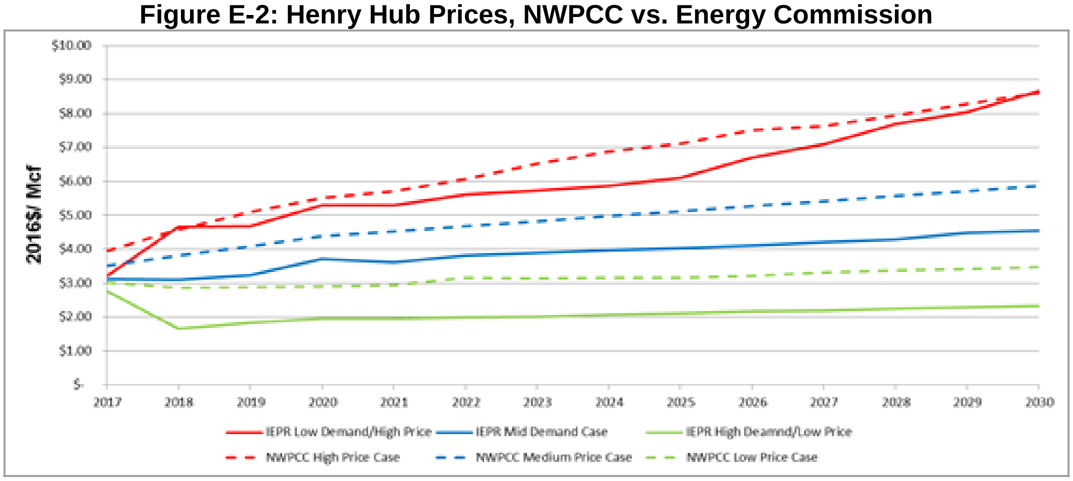
For long-term trend analysis, the stress on prices from an increased need to expand energy supplies is considered the dominant relationship. The high natural gas price scenario assumes rapid world economic growth. This scenario might be consistent with high oil prices, high environmental concerns that limit use of coal, limited development of world LNG capacity, slower improvements in drilling and exploration technology, and the high cost of other commodities and labor necessary for natural gas development. It is a world in which there are limited alternative sources of energy and opportunities for demand reductions.

The low price case assumes slow world economic growth that reduces the pressure on energy supplies. It is a future in which world supplies of natural gas are made available through aggressive development of LNG capacity, favorable nonconventional supplies and the technologies to develop them, and low world oil prices providing an alternative to natural gas use. The low case would also be consistent with a scenario of more rapid development of renewable electric generating technologies, thus reducing demand for natural gas. In this case, the normal increases in natural gas use in response to lower prices would be limited by aggressive carbon control policies. It is a world with substantial progress in efficiency and renewable technologies, combined with more stable conditions in the Middle East and other oil and natural gas-producing areas.

Comparing NWPCC to Energy Commission Forecast

Both mid and high price cases follow the same trajectory as the Energy Commission's. The IEPR mid demand case is at $2.86 Mcf in 2017, and the NWPCC is at $3.44. In 2030, the IEPR mid demand case is $5.64 Mcf in 2030, and the NWPCC is at $5.73 Mcf. For the high price cases, the IEPR starts at $3.58 Mcf in 2017 and the NWPCC is at $3.85 Mcf. For 2030, the IEPR high price case is at $7.02 Mcf and the NWPCC is at $8.42 Mcf. The low price cases vary from each other. The IEPR low price starts at $2.61 Mcf and grows to $5.19 in 2030. The NWPCC starts at $2.95 Mcf in 2017 and grows to $3.40 Mcf in 2030. **Figure E-2** shows the comparison of NWPCC and Energy Commission forecasting.

Figure E-2: Henry Hub Prices, NWPCC vs. Energy Commission



Source: Northwest Power and Conservation Council Fuel Price Forecast, February 2017 and California Energy Commission, Supply Analysis Office.

The Energy Commission's forecasts run lower than those for the U.S. EIA and NWPCC. The total recoverable natural gas resources and recovery costs parameters are partially accountable for the differences. The modeling methods and models used (NAMGas vs. NIMS vs. NWPCC) are also partially accountable for the differences.

Natural Gas Price Forecast Retrospective

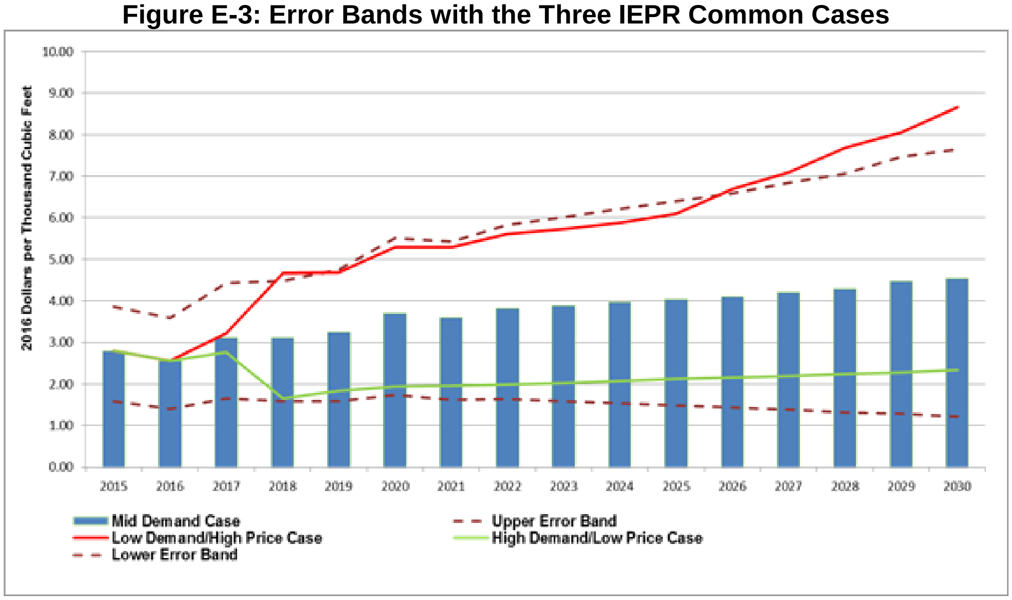
The forecasting of natural gas prices depends on many factors, including economic growth rates, expected rates of resource recovery, integration of renewable resources, retirement of coal fired power generation, and other factors. For example, higher rates of economic growth tend to lead to increased consumption of natural gas, which leads to higher natural gas prices. NAMGas uses annual inputs to produce annual average prices. It does not account for fluctuations that occur in the natural gas market seasonally, monthly, or daily.

To account for inherent uncertainty in natural gas markets, staff used past natural gas forecast results generated by the Energy Commission to produce error bands around price results of the IEPR mid demand case. Staff generated the error bands by using the statistical method of mean absolute percentage error (MAPE), which determines how well past forecasts fit against actual Henry Hub prices.

Using forecasts that began in 1999, staff calculated a linear regression equation using the MAPE results, then applied the equation to the IEPR mid demand case to generate the upper and lower error bands. These error bands capture a much wider range of price uncertainty than seen in the price differential between the IEPR common cases. The error bands allow for comparison of the IEPR common cases to historical estimates and ensure that the IEPR common cases are reasonable assumptions. For policy use, the error bands are a better fit as they encompass more uncertainty than the IEPR common cases. **Figure E-3** shows the resulting error bands and the IEPR common cases.

The current range of the IEPR common cases captures about 87 percent of the total uncertainty implied by the historical forecast error and captures roughly 65 percent of the total uncertainty in U.S. EIA's forecasts.

Figure E-3: Error Bands with the Three IEPR Common Cases



Source: California Energy Commission, Supply Analysis Office, 2017.

Natural Gas Markets: Financial and Physical

The natural gas market has changed dramatically since the mid-1980s move to deregulate commodity prices and require open access, nondiscriminatory transportation services.[162] Financial markets have evolved, beginning with the creation of the natural gas futures contract, which require delivery at Henry Hub in Louisiana. Now, daily volume of natural gas trading exceeds 100,000 contracts. As a result, the natural gas market evolved into a duality where both financial and physical transactions play important roles.

The physical natural gas market emerged decades ago and is simply a marketplace for the purchase and sale of natural gas. Physical market participants include producers, third-party marketers, and local distribution companies.

The physical market comprises of thousands of market participants buying and selling natural gas at trading points all over the United States and the world. In these transactions, participants arrange to move natural gas from Point A to Point B for various purposes, but ultimately for consumption. Actors buy and sell physical natural gas on long-term and day-ahead markets.

The financial market consists of financial investors and speculators, such as Goldman Sachs, Macquarie, and JP Morgan Chase who profit from trading but also provide risk mitigation services to the physical market. For example, a producer may wish to protect future sales from lower prices or a local distribution company may wish to protect its customers from price spikes. Financial transactions involve the use of various instruments, including:

- Futures contracts - agreements in a current period to buy and sell natural gas for delivery at a future date.
- Options contracts - a right, but not an obligation, to buy or sell natural gas.
- Swaps contracts - exchanging a variable-priced contract for a fixed price contracts.

Financial and Physical Markets Interaction

Originally, producers and buyers of natural gas made up the vast majority of financial market transactions. These purchases were to hedge the physical price of natural gas to protect against price fluctuations. As financial institutions looked to increase profitability, commodity markets became more lucrative.

This has changed the dynamic of the markets, and financial markets are now a profit mechanism. Just as the underlying physical commodity influences the financial price, the financial markets influence the physical markets.

162 For example, see Tussing and Tipee, *The Natural Gas Industry: Evolution, Structure and Economics,* PennWell Books, 1995.

Platt's Henry Hub index price generally relies on physical basis transactions. Consequently, the Henry Hub monthly spot market, the one the futures market was based on, now prices off the futures market itself. Monthly price discovery do not only come from the underlying physical market anymore; price discovery comes from both the physical and futures markets.

On the marketing side, California's large purchasers of natural gas use both the physical and financial markets to deliver natural gas to end users. In the past, producers and buyers of natural gas (physical market participants) made up the vast majority of financial market transactions. They made purchases to protect against price fluctuations ("hedging").

Now, financial institutions have entered the natural gas market, where they provide risk mitigation services and seek increased profitability. These entities also promote liquidity – that is, the ability to trade with little or no hindrances. As a result, the link between financial and physical transactions has strengthened, changing the dynamics of the market. Now, both the financial and physical markets influence the price of natural gas, and price discovery has become more transparent.

APPENDIX F: Glossary of Terms

Absorbed gas: Methane molecules attached to organic material contained within solid matter.

Baseload generation: A power plant that produced electricity to meet minimum demand requirements.

Biogas: Typically refers to gas that is a mixture of methane and carbon dioxide that results from the decomposition of organic matter, often from landfills.

Burner tip prices: Refers to the price paid for the end use of natural gas at its point of consumption, which includes items such as stoves and heaters. This price reflects all the costs throughout the process, such as exploration, development, and transportation, along with the price of the natural gas.

Carbon footprint: The total set of GHG emissions caused by the direct and/or indirect action of an individual, organization, event, or product.

Casing pipe: Set with cement in a hole drilled in the earth.

Clean energy: An energy source that results in little to no environmental impacts. An example would be renewable energy.

Coal-bed methane (CBM): Natural gas from coal deposits.

Combined heat and power generation: A form of generation that creates electricity and uses the heat that is produced during electric generation.

Curtailment: The restriction of natural gas usage.

Demand response: The responsiveness of consumer demand to changes in the market price.

Digester gas: Methane that is derived from the decomposition of organic matter, usually agricultural waste.

Drilling: The process of boring a hole in the earth to find and remove subsurface fluids, such as oil and natural gas.

Electric generation: Creating electricity for use.

Energy imbalance market: An energy market formed by California ISO and PacifiCorp that determines and reconciles system energy imbalances. An energy imbalance is the difference between load and generation.

Environmental impact: Adverse effect upon natural ambient conditions.

Equilibrium: A balancing point where demand equals supply.

Error bounds: A statistical measure that establishes a range that an estimate can reasonably lie within.

Finding and development: The cost associated with exploring for and developing a resource.

Firm gas delivery: A contract agreement that reserves pipeline capacity for delivery of natural gas, causing it to be available during a period.

Formation: A bed or rock deposit composed, in whole, of substantially the same kind of rock; also called reservoir or pool.

Fuel-switching capabilities: The ability to switch from one type of fuel to another in an efficient manner.

Gas shippers: Anyone who owns rights on a natural gas distribution system

Greenhouse effect: Greenhouse gases, such as carbon dioxide, methane, and nitrous oxide, trap radiant energy from the Earth's surface.

Greenhouse gas emissions: Gases, primarily carbon dioxide, methane, and nitrous oxide, that are released and contribute to the greenhouse effect.

Groundwater: Water in the Earth's subsurface used for human activities, including drinking.

Henry Hub: Located in Southern Louisiana, it is a major pricing point in the Lower 48.

Horizontal well: A hole at first drilled vertically and then horizontally for a significant distance (500 feet or more).

Hub price: A pricing point.

Hydraulic fracturing: The forcing into a formation of a proppant-laden liquid under high pressure to crack open the formation, thus creating passages for oil and natural gas to flow through and into the wellbore.

Hydroelectric generation: Creating electricity using hydrologic resources.

Infrastructure: The structures needed to support civilization, specifically pipelines, LNG compressor stations.

Interruptible supply: A contract agreement that allows service to be unavailable for a period.

Interstate pipeline system: Pipeline systems that run from state to state.

Intrastate pipelines: Pipeline systems that run within a state.

Iterative process: A function that is performed repeatedly.

Liquefied natural gas: Natural gas that has been cooled to a certain temperature or subjected to pressure to change it from a gas to a liquid. This reduces the volume of the gas and makes it easier to transport.

Local distribution companies: Utility companies that distribute gas to consumers, after receiving it from transmission lines.

Locally distributed generation: The production of electricity from local sources.

Mitigation costs: Costs that offset existing or potential environmental impact.

Moratorium: The restriction or banning of a proposed activity.

Natural gas-fired generation: Creating electricity from natural gas.

Nuclear generation: Creating electricity using radioactive elements.

Once-through cooling: The process of using water from a nearby water source to cool the pipes in a power plant. The water is then returned to the source from which it came.

Operating and maintenance cost: The variable cost of producing natural gas.

Permeability: The ability of a fluid (such as oil or natural gas) to flow within the interconnected pore network of a porous medium (such as a rock formation).

Petroleum coke: A by-product of oil refinery or cracking that comes in different grades, some of which can be used for fuel.

Pipeline: Transports gas to another region or local delivery system.

Pipeline capacity: The amount of gas that can be safely transported through a pipeline.

Pipeline-quality methane: Gas that meets certain quality specifications that make it suitable for transportation in a pipeline.

Price elasticities: A measure of how responsive a commodity is to changes in price.

Procurement: The acquisition of a resource, for example, would be obtaining fuels for electricity generation.

Proppant: A granular substance (sand grains, walnut shells, or other material) carried in suspension by a fracturing fluid that keep the cracks in the shale formation open after the well operator retrieves the fracturing fluid.

Ramping: The ability to increase or decrease electricity generation in order to meet load requirements.

Recoverable reserves: The unproduced but recoverable oil and/or natural gas in-place in a formation.

Regression analysis: The statistical method of finding a trend line from data, then using this information to determine a relationship between the variables.

Renewable generation: Creating electricity from hydro, solar, or wind energy sources. These sources are renewable, meaning they are easily and naturally replenished.

Renewables Portfolio Standard: A regulation that determines how much energy should be produced from renewable resources.

Rig count: The number of drilling rigs actively punching holes in the earth.

Shale: A fine-grained sedimentary rock whose original constituents were clay minerals or mud.

Shale gas: Natural gas produced from shale formations.

Spot market: A market in which natural gas is bought and sold for immediate or very near term delivery, usually for a period of 30 days or less. The transaction does not imply a continuing agreement between the buyers and sellers. A spot market is more likely to develop at a location with numerous pipeline interconnects, thus allowing for a large number of buyers and sellers. The Henry Hub in Southern Louisiana is the best-known spot market for natural gas.

Well stimulation: The process of using methods and practices to make a well more productive.

Technological innovation: The improvement of existing technology.

Tight gas: Natural gas from very low permeability rock formations.

Unconventional production: Natural gas from tight formations or from coal deposits or from shale formations.

Well: A hole in the earth caused by the process of drilling.

Well completion: The activities and methods necessary to prepare a well for the production of oil and natural gas.

Wellbore: The hole made by drilling. It may be cased, i.e., pipe set by cement within the hole.

Wellhead: The mouth of the gas well.

Wind turbines: The rotating blades that are used to generate electricity.