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AIR QUALITY IMPACTS OF LIQUEFIED NATURAL GAS IN THE SOUTH COAST AIR BASIN OF CALIFORNIA

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Notice about Report and Appendix Availability

This report has been submitted to the California Energy Commission (CEC). It is anticipated that a version of the report – containing the same technical information but potentially differing in presentation based on changes made by CEC technical editors – will be published by the Energy Commission. If published by CEC, the report should be available at the following site: http://www.energy.ca.gov/reports/.

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ABSTRACT

The effects of liquefied natural gas (LNG) on pollutant emission inventories and air quality in the South Coast Air Basin of California were evaluated using recent LNG emission measurements by Lawrence Berkeley National Laboratory and the Southern California Gas Company (SoCalGas), and with a state-of-the-art air quality model. Pollutant emissions can be affected by LNG owing to differences in composition and physical properties, including the Wobbe index, a measure of energy delivery rate. This analysis uses LNG distribution scenarios developed by modeling Southern California gas flows, including supplies from the LNG receiving terminal in Baja California, Mexico. Based on these scenarios, the projected penetration of LNG in the South Coast Air Basin is expected to be limited. In addition, the increased Wobbe index of delivered gas (resulting from mixtures of LNG and conventional gas supplies) is expected to cause increases smaller than 0.05 percent in overall (area-wide) emissions of nitrogen oxides (NO_X). Based on the photochemical state of the South Coast Air Basin, any increase in NO_X is expected to cause an increase in the highest local ozone concentrations, and this is reflected in model results. However, the magnitude of the increase is well below the generally accepted accuracy of the model and would not be discernible with the existing monitoring network. Modeling of hypothetical scenarios indicates that discernible changes to ambient ozone and particulate matter concentrations would occur only at LNG distribution rates that are not achievable with current or planned infrastructure and with Wobbe index values that exceed current gas quality tariffs. Results of these hypothetical scenarios are presented for consideration of any proposed substantial expansion of LNG supply infrastructure in Southern California.

Keywords: pollutant emissions, emissions inventory, ozone, particulate matter, nitrogen oxides, air quality modeling

TABLE OF CONTENTS

List of Figures

All figures were created by the authors for this report unless otherwise noted.

List of Tables

All tables were created by the authors for this report unless otherwise noted.

EXECUTIVE SUMMARY

Introduction

Anticipating increasing use of liquefied natural gas (LNG) in California, the California Energy Commission (Energy Commission) requested research to assess the potential device performance and air quality impacts of this change. Lawrence Berkeley National Laboratory and the Gas Technology Institute have been working in collaboration to assess these impacts, with Lawrence Berkeley National Laboratory focusing on residential appliances and air quality, and the Gas Technology Institute focusing on industrial burners. For the work described in this report, the University of California at Irvine joined the collaboration.

Liquefied natural gas imported from overseas generally differs in composition from most conventional natural gas supplied to California. Liquefied natural gas typically has more non-methane hydrocarbons, higher heating value (energy density), and higher Wobbe index (WI, a measure of energy delivery that is particularly relevant to devices that control gas flow with a fixed orifice) compared to other natural gas distributed in California. Controlled experiments have shown that use of higher Wobbe fuel leads to emission increases in some burners. The research described in this report focuses on the impact of LNG on overall pollutant emission inventories and the effect of this change on air quality in the South Coast Air Basin of California.

Purpose and Objectives

This purpose of this project was to investigate the possible effects of projected LNG use on overall pollutant emissions and ambient air quality in the South Coast Air Basin of California. This investigation combined results from controlled emissions experiments conducted by Lawrence Berkeley National Laboratory as part of this project, and separately by the Southern California Gas Company (SoCalGas), with a baseline planning emission inventory developed by the South Coast Air Quality Management District for the year 2023.

The spatial extent of LNG receipt into the South Coast Air Basin modeling domain was estimated for a range of expected LNG delivery scenarios. The baseline inventory was updated to account for spatial and temporal differences between scenarios without and with LNG at the varied levels of distribution and use. These emission inventories were used as inputs to a state-of-the-art air quality model to investigate the potential impacts of LNG on ozone and secondary particulate matter formation.

The project had the following specific objectives:

1. Apply technology-specific results of recent emissions experiments and quantify the impact of these changes to the South Coast Air Quality Management District baseline planning emission inventory for 2023, which does not include LNG
2. Apply results of controlled emission experiments with simulated LNG (higher Wobbe index) fuels, to assess the impact of LNG use on the overall emission inventory

3. Use state-of-the-art air quality modeling to investigate the impact of LNG use on ambient ozone and particulate matter concentrations in the South Coast Air Basin

Outcomes

Update of emission inventories

As a starting point for this work, the South Coast Air Quality Management District provided a compliance emission inventory for the year 2023. This inventory was developed as part of a plan to meet U.S. federal ambient air quality standards and did not include any LNG impacts. The emissions in this compliance inventory were calculated using both emission factors from the U.S. Environmental Protection Agency AP-42 compilation and annual emissions reported to the district for specific facilities. This inventory projected that in 2023, 58 percent of NG-related NO_X emissions will be from area sources and 42 percent will be from point sources. The point sources are primarily in the electrical utility, manufacturing and industrial, and service and commercial sectors, while the area sources are primarily in the residential sector and service and commercial sector. Residential fuel combustion is estimated to be the largest sub-category, accounting for 33 percent of all nitrogen oxides (NO_X) from natural gas burners in the South Coast Air Basin.

While compiling emission information on natural gas sources for the current work, it became clear that, in general, the natural gas sector is one that lacks the type of emissions testing data to support emission factors for the range of combustion technologies in use. This is perhaps unsurprising, since natural gas-fueled area and point sources are projected to account for only about 13 percent of the total NO_X in the basin, with mobile sources accounting for the vast majority of the remainder. Of particular importance is the use of a single AP-42 emission factor for all residential appliances based on measurements of residential furnaces in the 1970s. The residential appliance experiments performed by Lawrence Berkeley National Laboratory provided technology-specific emission factors that were used to update the baseline South Coast Air Quality Management District emission inventory.

For most technologies, the more relevant NO_X emission factors were lower than the AP-42 values. Updating the emission factors for residential natural gas appliances used in the original inventory with emission factors obtained in experimental measurements decreased projected NO_X emissions by a total of 2.4 tons/day in the Southern California Air Basin. This reduction translates to a reduction of 1.2 percent in projected NO_X emissions from all sources in the basin.

Figure ES1 shows the spatial distribution of the daily decreases in NO_X emissions due to updating emission factors in the inventory. The updated emission inventory for 2023, termed *the LBNL Baseline inventory,* was used as a reference to evaluate the impacts of using liquefied natural gas on emissions from natural gas combustion.

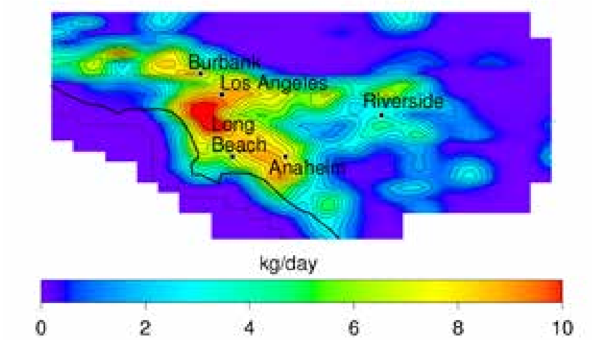


Figure ES1: Decrease in Daily NO_X Emissions in the LBNL Baseline Emissions Inventory with Respect to the South Coast Air Quality Management District Baseline Inventory

Changes in emissions due to projected use of fuels with higher Wobbe index (associated with LNG) were assessed using available experimental data. Experimental data from LBNL provided emissions changes as a function of Wobbe index for residential NG appliances. These values were also used for commercial space and water heating, which were assumed to respond in a manner similar to the residential technologies. Emissions testing of the effect of Wobbe index on selected low and ultra-low NO_X commercial and industrial burners and boilers by SoCalGas were used to provide an upper bound of the impact of LNG in the commercial and industrial sectors for boilers and process heaters, as well as for unspecified industrial area sources.

The use of LNG not only affects emissions from natural gas combustion, it can also impact fugitive sources emissions from the transmission and distribution of natural gas. The emissions inventory received from the South Coast Air Quality Management District does include estimates of fugitive emissions. However, in California, the generally available natural gas has a lower fraction of non-methane hydrocarbons than most of the potential supply of LNG available from the Energía Costa Azul terminal in Mexico. Emissions of non-methane hydrocarbons are potentially relevant because these compounds can act as precursors to ozone formation; large increases in non-methane hydrocarbons can lead to increases in ozone concentrations. These delivered fuels will have to meet specific upper limits for the fraction of non-methane hydrocarbons and inert components allowed in compressed natural gas by the California Air Resources Board (ARB).

Increases in emissions from fugitive sources of non-methane hydrocarbons due to LNG were modeled, assuming that the LNG will have the maximum composition specified by the ARB. (The ARB was allowing exceptions to this maximum composition as of 2009, but these exceptions were not considered in the modeling work.) For air quality modeling purposes, these emissions are lumped into a group that represents short-chain alkanes. These additional fugitive emissions were restricted to the areas of the basin expected to receive LNG, as calculated for each scenario.

Realistic LNG delivery scenarios

All of the LNG that enters the Southern California Air Basin is assumed to originate from the Energía Costa Azul terminal. Eight realistic scenarios were selected to represent the expected distribution of LNG into the basin; these scenarios span the parameters that influence natural gas flow through the distribution system. These three parameters are the LNG output of Energía Costa Azul terminal, the amount of natural gas entering the southern California system from El Paso through Blythe, and total in-basin demand during the summer modeling period. The total capacity of the Energía Costa Azul terminal was assumed to vary from 800 to 950 million cubic feet per day (MMcf/day), of which between 400 and 500 MMcf/day are expected to be available for import into the United States. The typical demand in a summer month was projected to be 2700 MMcf/day, with a maximum demand of 3200 MMcf/day during periods of increased natural gas consumption due to electricity generation. (It should be noted that based on these estimates, the maximum capacity of the Energía Costa Azul terminal is well below the demand for all of Southern California.) The details of these eight realistic delivery scenarios are listed in Table ES1.

The parameters for these eight realistic scenarios were used as inputs into a SoCalGas transmission system model, resulting in the predicted penetration of LNG into the modeling domain of the South Coast Air Basin. Figure ES2 shows the results for Scenario 7, which represents the largest penetration of LNG into the domain based on maximum supply of LNG from the Energía Costa Azul terminal, minimum receipts of natural gas at Blythe, and typical summer demand in Southern California. The results show limited spatial extent of LNG distribution into the basin, primarily restricted to southeast Riverside County, even at this maximum expected penetration. It should be noted that San Diego County receives close to 100 percent LNG in all eight realistic scenarios. These eight realistic scenarios are used as the basis for assessing expected impacts of LNG use on ambient air quality in the SoCAB.

Table ES1: Parameters for the Eight Realistic LNG Scenarios Projected for the Year 2023 in the Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E) System (Gas Volumes in MMcf/day)

	Scenarios							
	Base		Min Domestic		Max ECA Deliveries		Max ECA Deliveries & Min Domestic	
	1	2	3	4	5	6	7	8
SoCalGas/SDG&E	Typical	Maximum	Typical	Maximum	Typical	Maximum	Typical	Maximum
Summer Demand	2679	3212	2679	3212	2679	3212	2679	3212
ECA Supply	Typical	Typical	Typical	Typical	Maximum	Maximum	Maximum	Maximum
Otay Mesa	312	312	312	312	400	400	400	400
Blythe	112	112	112	112	84	84	84	84
Receipts from El	Typical	Typical	Minimized	Minimized	Typical	Typical	Minimized	Minimized
Paso (EP) at Blythe	508	508	140	220	478	478	140	220
Other Supplies	1747	2280	2115	2568	1717	2250	2055	2508

ECA = Energía Costa Azul terminal

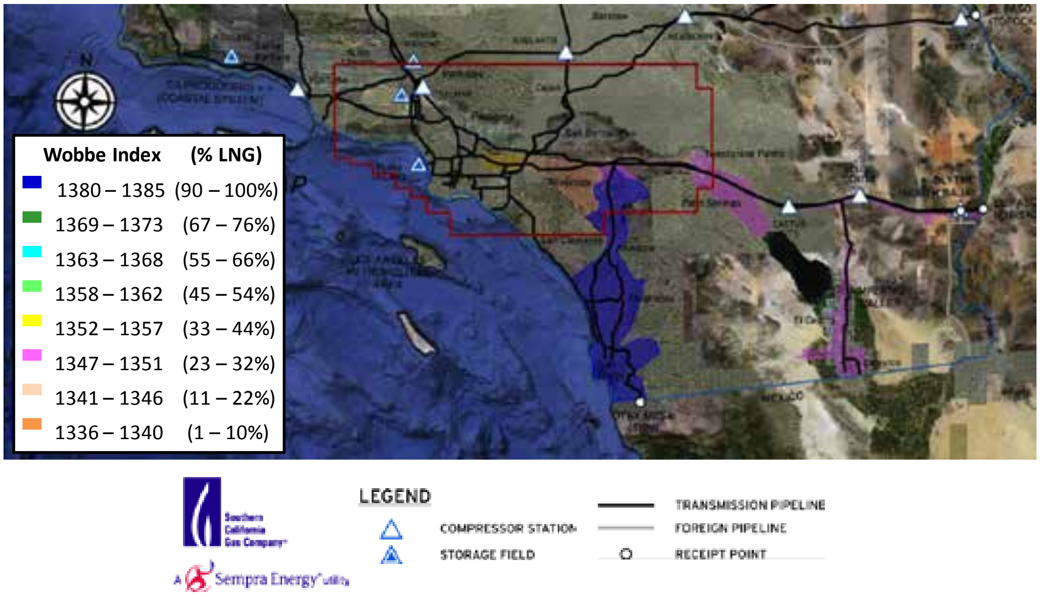


Figure ES2: Zones of Influence in the Southern California Gas Company/San Diego Gas and Electric System for Scenario 7: Scenario with the Maximum Penetration of Liquefied Natural Gas

Hypothetical LNG delivery scenarios

For the purpose of exploratory and bounding analysis, additional modeling was conducted on several hypothetical scenarios. These scenarios included: (a) 100 percent penetration (use) of LNG throughout the South Coast Air Basin, (b) an increase in the Wobbe index of distributed LNG from 1385 to 1400, and (c) the above combined with the mitigation measure of adjusting all burners in the area to optimize operation with LNG. Scenario (a) is not feasible with current or planned LNG receiving infrastructure, and scenario (b) is not allowable under current gas quality tariff limits. Scenario (c) is an idealized, theoretical control option.

Impacts of liquefied natural gas on emissions

Under all eight realistic scenarios, the impact of LNG on overall basin-wide emissions is assessed to be marginal. To illustrate, the changes in NO_x emissions for all LNG delivery scenarios are listed in Table ES2. Nitrogen oxide emissions are projected to increase by less than 0.1 percent. Recall that the current planning inventory is estimated to overstate projected emissions by 2.1 percent as a result of using generic emission factors for residential and commercial burners instead of the newer technology specific emission factors. Note that the increase in nitrogen oxide emissions due to LNG use is significantly less that these possible discrepancies in the emission inventories. The primary reason for this small increase is the low penetration of liquefied natural gas expected in the modeling domain. The maximum increase in basin-wide NO_x emissions projected for the hypothetical scenario of 100 percent penetration of LNG is estimated to be 2.8 tons per day (2.5 percent), giving an indication of the magnitude and type of LNG use that would be required to cause discernible changes in the basin-wide emission inventory. The hypothetical mitigation measure of readjusting all commercial and industrial burners to operate on LNG has the potential to counter almost all of the emission increase at 100 percent distribution of 1385 Wobbe LNG.

Table ES2: Impacts on Emissions of NO_X Estimated for All LNG Delivery Scenarios. Increases in Emissions Are Expressed with Respect to (w.r.t.) the LBNL Baseline Case.

Case	NO_x Increase (tons/day) w.r.t. LBNL Baseline	NO_x Increase (%) w.r.t. LBNL Baseline
LBNL Baseline Total NOx = 112 tons/day	--	--
Realistic LNG Distribution Scenarios		
Scenario 1	0.037	0.03
Scenario 2	0.027	0.02
Scenario 3	0.044	0.04
Scenario 4	0.039	0.03
Scenario 5	0.084	0.07
Scenario 6	0.046	0.04
Scenario 7	0.092	0.08
Scenario 8	0.034	0.03
Hypothetical Scenarios		
100% LNG	2.76	2.5
Scenario 7 (WI_{max}=1400)	0.12	0.11
100% LNG (WI_{max}=1400)	3.58	3.2
100% LNG with Tuning	0.17	0.15

Impacts of liquefied natural gas on air quality

The changes in emissions based on LNG use in the eight realistic delivery scenarios were very small. As a result, the impacts on ozone and secondary particulate matter concentrations due the use of LNG are not discernable. The average change in ozone concentration for all of the realistic scenarios was less than 0.1 part per billion (ppb), with no predicted change in the domain-wide average of the 24-hour average concentration of particulate matter smaller than 2.5 micrometers ($PM_{2.5}$). The predicted change in ozone concentration varied spatially across the modeling domain, ranging from -0.3 ppb to 0.5 ppb. The spatial variability in the predicted 24-hour $PM_{2.5}$ concentrations varied from -0.6 micrograms per cubic meter ($\mu g/m^3$) to 0.6 $\mu g/m^3$. Figure ES3 shows the spatial results of this scenario on peak ozone concentration.

The hypothetical scenario with 100 percent LNG penetration resulted in an increase in the average ozone concentration of 0.36 ppb and in the 24-hour average $PM_{2.5}$ concentration of 0.07 $\mu g/m^3$, primarily due to the increase in NO_x emissions. The emissions that would result from increasing the Wobbe index limit to 1400 would enhance ozone formation; for this hypothetical scenario the model predicted an increase in the average ozone concentration of 0.46 ppb. Equipment tuning is estimated to counter most of the increase in NO_X emissions, with a resulting impact on ozone and PM formation that is less than the scenario with maximum expected LNG delivery and no mitigation.

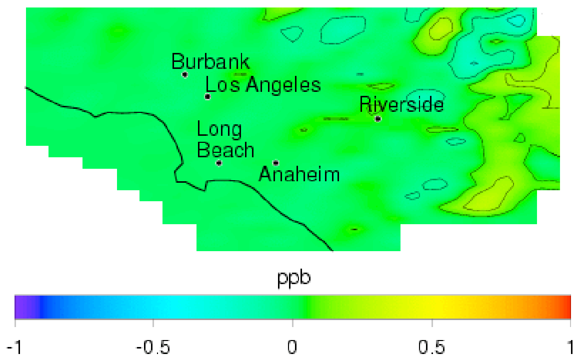


Figure ES3: Changes in Peak Ozone Concentrations (ppb) Based on LNG Distribution Projected by Sempra for the Year 2023. The LNG distribution assumes typical summer demand of natural gas in the South Coast Air Basin and maximum capacity at the Energía Costa Azul LNG terminal of 950 million cubic feet per day.

Conclusions

These results indicate that the impact of LNG on overall basin-wide NO_X emissions should be very small, and may be below the level at which the models can discern. Uncertainty in the emission inventory—owing to a lack of solid technology-specific emissions data—appears to be much larger than any expected change in emissions associated with LNG use. The difference in emissions between the 2023 South Coast Air Quality Management District inventory and the Lawrence Berkeley National Laboratory baseline is larger than the difference in basin-wide emissions estimated for the realistic scenario with the maximum penetration of LNG. The differences in the two emissions inventories approach the same order of magnitude as the difference in basin-wide emissions estimated for the hypothetical 100 percent LNG scenario. Thus, barring a substantial increase in the capacity to deliver LNG into the South Coast Air Basin, there appears to be no discernable outdoor air quality impacts.

Benefits to California

The research summarized in this report finds that current and projected trends of LNG distribution will not lead to discernible ambient air quality impacts in the South Coast Air Basin of California. This finding should help inform the debate on potential impacts and help establish a more predictable planning horizon for natural gas suppliers. Analysis of hypothetical distribution scenarios indicates that use of LNG throughout large parts of the South Coast Air Basin could cause discernible increases in basin-wide NO_X emissions, with corresponding increases in ambient ozone and particulate matter concentrations. These results indicate the need for caution and careful review prior to dramatically expanding LNG distribution in this area. Since San Diego may see these higher levels of LNG penetration, a similar study should be conducted for that area. Overall, this research is intended to help lay the groundwork for maintaining a safe and reliable natural gas supply in California.

Chapter 1: Introduction

Most of California's natural gas (NG) supply is from out of state. In 2008, California customers received 46 percent of their natural gas supply from basins located in the Southwest, 19 percent from Canada, 22 percent from the Rocky Mountains, and 13 percent from basins located within California (CPUC 2010). With a growing demand for natural gas in California, the state has been investigating additional sources of natural gas. An alternative for current natural gas supply by pipeline from other regions in the North American subcontinent is the use of liquefied natural gas (LNG) obtained from areas such as Indonesia, South America, and Australia. Liquefied natural gas is used in other parts of the United States, with terminals in Massachusetts, Maryland, Georgia, Puerto Rico, Louisiana, Texas, and Alaska. While there are currently no LNG terminals located in California, Sempra Energy has commissioned and started operations at the Energía Costa Azul (ECA) LNG terminal, in Ensenada, Baja California, which is expected to supply natural gas to Southern California.

One of the most important issues the State of California faces with the possible increased use of LNG is the potential impact of the changes in natural gas composition on pollutant emissions and associated exposure and health effects. The new LNG supplies will likely differ in composition (e.g., contain a lower fraction of methane, higher fraction of ethane, and other non-methane hydrocarbons) and properties (e.g., higher heating value and Wobbe index, WI). Wobbe index is particularly relevant, as it is a measure of energy delivery to devices that control gas flow with a fixed orifice. With these concerns in mind, the California Energy Commission tasked Lawrence Berkeley National Laboratory (LBNL) and the Gas Technology Institute (GTI) to investigate the potential safety, performance, emissions, and air quality impacts of increased variability in delivered natural gas in California. The component of the effort concerning the assessment of the LNG air quality impacts presented in this report was primarily performed by the University of California at Irvine in collaboration with LBNL.

This report evaluates possible changes in air pollutant emissions in the South Coast Air Basin of California (SoCAB) due to the use of LNG, and investigates the possible impacts on air quality. One concern is that future increases in nitrogen oxide (NO_x) emissions associated with LNG use may affect attainment of the ozone standard. Approximately 9 percent of NO_x emissions in the SoCAB are produced by NG combustion in the residential, commercial, industrial, and utilities sectors. As controls on NO_x emissions from other sources are tightened, the relative contribution of NG sources is projected to increase. The work presented here integrates experimentally determined emission factors from LBNL and the Southern California Gas Company (SoCalGas) with current emissions inventories generated by the South Coast Air Quality Management District (SCAQMD) to determine spatially and temporally resolved emission changes due to the use of LNG in natural gas combustion processes. The spatial extent of LNG receipt in the SoCAB modeling domain due to LNG delivery from the ECA terminal is estimated for a set of realistic LNG distribution scenarios. In addition, a few hypothetical LNG distribution scenarios are devised for the purpose of bounding the analyses.

The resulting emissions and spatial use scenarios are used as inputs to a state-of-the-art air quality model to determine the potential impacts of LNG on ozone and secondary particulate matter concentrations.

Chapter 2: Modeling LNG Distribution

The Southern California Gas Company supplies natural gas throughout the South Coast Air Basin and other parts of Southern California, including San Diego. Figure 1 shows a system map of the transmission system, with the arrows indicating the direction of flow along the pipelines. The total amount of NG used in the SoCAB is greater than the current capacity of the ECA terminal; therefore, even if all of the LNG from ECA were shipped to the SoCAB, only a fraction of total NG use in the basin would be LNG. In reality, only a small fraction of the LNG sent out from ECA makes it to the SoCAB. To quantify this amount, it is necessary to model the flow of gas supply and demand at key points in the Southern California gas distribution system. Only those locations within the SoCAB that receive some fraction of LNG should have modified emissions in the air-quality model; the other locations will receive the same baseline NG as has been historically delivered. This spatial distribution of LNG in the SoCalGas system is termed the "LNG Zone-of-Influence."

For future deliveries of LNG from the ECA terminal to the SoCalGas system (Figure 1), gasified LNG is expected to enter the system through Otay Mesa receipt point, in the border between Tijuana and San Diego, and through Blythe receipt point, near the California-Arizona border. In general, the potential volume of LNG delivered at Otay Mesa is expected to be larger than at Blythe, because the former is located significantly closer to the ECA terminal than the latter.

An important factor to understand about the transmission of LNG throughout the system is the direction of the natural gas flow. From Otay Mesa, natural gas flows northward toward the RAINBOW-MORENO pipeline, merging with the CACTUS CITY-MORENO segment, whose supply originates in the Blythe receipt point. Therefore, the natural gas provided from Otay Mesa is first consumed in the San Diego area, and the remnant is transmitted to Riverside, and then toward Los Angeles. From Los Angeles, the natural gas flows southward toward Orange County, along the coastal pipeline through San Clemente. Based on this configuration, San Diego County will receive the highest concentration of gasified LNG, followed by Riverside County. Due to the limited capacity of the ECA terminal, the supply of LNG to San Bernardino, Los Angeles, and Orange County should be marginal.

Natural gas flow through the SoCalGas system is modeled based on changes in hydrostatic pressure that depend on pipeline diameters, location of compression stations, and spatially resolved gas delivery, among other factors. The distribution of potential LNG receipts is assessed by including in the model a simulated inert tracer that is mixed and transmitted along with the existing natural gas. The tracer concentration is then assumed as the fraction of LNG present in the natural gas stream. This modeling was performed by Sempra based on different delivery scenarios discussed and agreed upon by a subgroup of members from the project advisory council and other stakeholders.

The distribution of LNG in the SoCalGas system map was parameterized based upon three main factors:

1. Total LNG output from the ECA terminal
2. Natural gas receipts at Blythe from the El Paso delivery point
3. In-basin forecasted summer demand

The analysis focuses on summer demand because this is when ozone concentration is typically the highest, and thus will be the most sensitive to changes in emissions. The variation of these three parameters affects the fraction of Southern California natural gas that is LNG; this in turn, determines the Wobbe index of the NG in different geographic regions through the SoCalGas system.

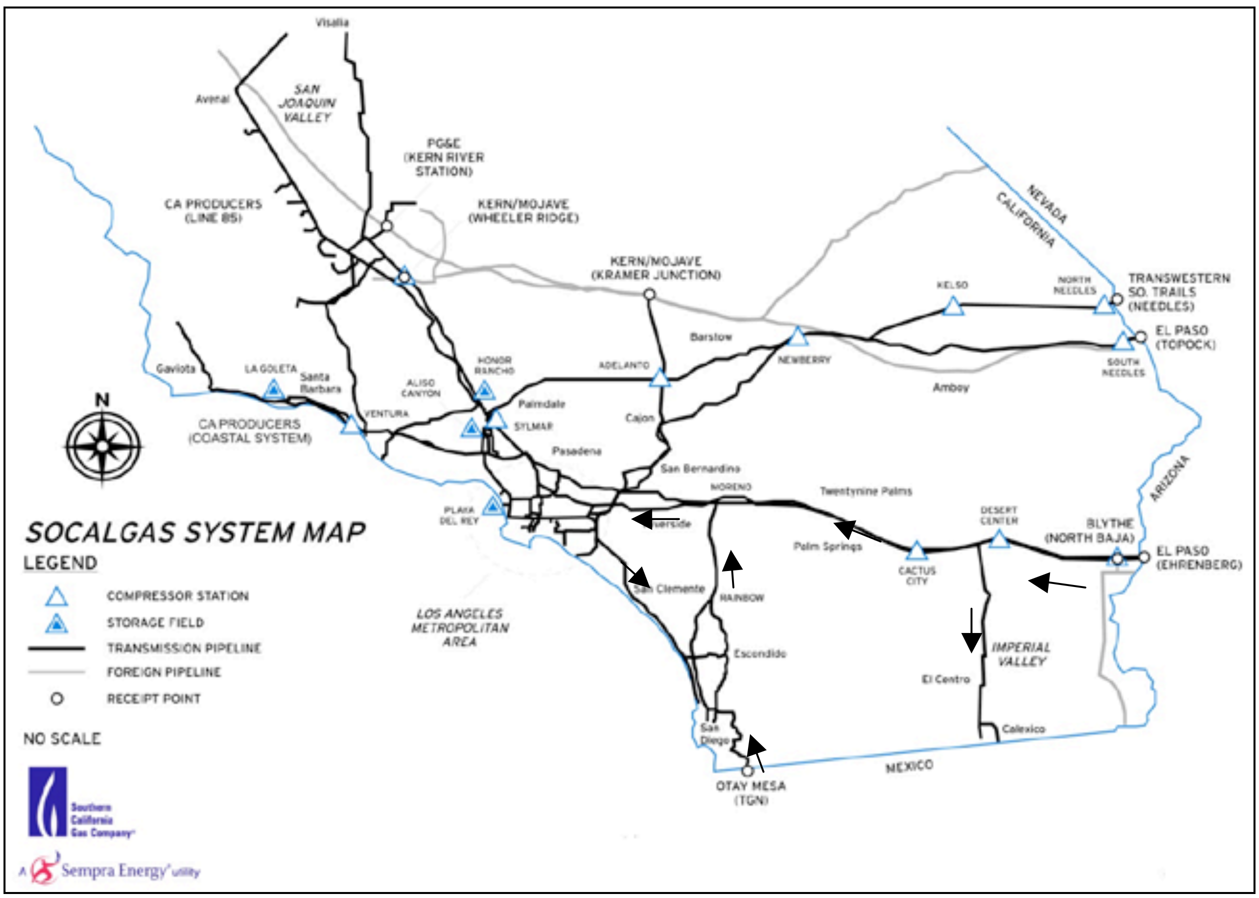


Figure 1: Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E) Natural Gas Distribution System Map

1. **Total LNG Output from Energía Costa Azul (ECA) Terminal**
   The overall fraction of gasified LNG in the SoCalGas/SDG&E system is a function of the total capacity of the ECA terminal. The higher the capacity of the ECA, the higher the concentration of gasified LNG in the system will be. Typical output from the ECA terminal is expected to be 800 million cubic feet per day (MMcf/day), with a projected maximum capacity of 950 MMcf/day. Part of the LNG from the ECA terminal is supplied to the gas system in Baja California (Mexico), and the remaining LNG enters the SoCalGas system through the Otay Mesa and Blythe receipt points. Under typical ECA output conditions, the estimated volume of gasified LNG through Otay Mesa and Blythe is 312 MMcf/day and 112 MMcf/day, respectively. Under maximum ECA output conditions, the estimated gasified LNG flow is 400 MMcf/day and 84 MMcf/day, respectively. These volumes contribute to the total natural gas supply to the SoCalGas/SDG&E system of 2679 MMcf/day for a typical summer demand, and 3212 MMcf/day for the estimated maximum demand.

2. **Natural Gas (NG) Receipts at Blythe from the El Paso Delivery Point**
   The domestic natural gas receipts at Blythe coming from El Paso determine the fraction of gasified LNG in the natural gas stream entering the SoCalGas system through Blythe. The higher the domestic natural gas receipts at El Paso, the lower the LNG fraction fed at Blythe. Hence, the fraction of LNG in the SoCalGas system increases as the domestic natural gas coming from El Paso decreases. Typical volumes of domestic natural gas at Blythe coming from El Paso are 508 MMcf/day, but they can be as low as 140 MMcf/day and still provide enough natural gas needed to meet the system's demand.

3. **In-Basin Forecasted Summer Demand**
   In the modeling described later in this report, future impacts of LNG use in the South Coast Air Basin were investigated for the year 2023. An inventory of basin-wide pollutant emissions for that year was provided by the South Coast Air Quality Management District (SCAQMD). Consequently, the projected demand of natural gas should be relevant to that year. SoCalGas projections for the year 2023 estimate that a typical demand in a summer month will be 2,679 MMcf/day for the entire system. Maximum demand is projected at 3,212 MMcf/day due to an expected increase in natural gas consumption for electricity generation. In general, an increase in natural gas demand implies a reduction in the total fraction of LNG in the gas stream that will reach Los Angeles due to increased consumption upstream.

2.1 LNG Zones-of-Influence Projected Scenarios

Sempra developed a set of eight realistic LNG delivery scenarios that span the three parameters described in Section 2. The scenarios are designed to evaluate how the fraction of gasified LNG changes due to changes in ECA output, domestic gas supply, and natural gas demand in the SoCalGas and San Diego Gas and Electric (SDG&E) systems. The highest expected LNG fraction results from maximizing the output from ECA, minimizing the receipts of natural gas from El Paso, and minimizing the in-basin natural gas demand. Although all scenarios presented here are technically possible, some of them might not be as economically sound. Nevertheless, the scenarios were designed to analyze the range of changes in the Wobbe index of the natural gas in the system without any economic constraints. The list of scenarios is presented in Table 1.

The parameters described above are a set of inputs for the natural gas system model described above. The model simulations produce a spatial distribution of the Wobbe index based on the fraction of gasified LNG in that area of the SoCalGas distribution network. In this model, the lower limit for Wobbe index is 1335 Btu/standard cubic foot (scf); this occurs when there is no LNG introduced into the system. The upper limit for an area receiving only LNG is 1385 Btu/scf, which is the maximum allowable Wobbe index according to current gas tariffs. The resulting spatially resolved Zones-of-Influence for all scenarios are presented in Figure 2 through Figure 9.

As expected, maximal ECA output (scenarios 5 through 8) leads to higher penetration of gasified LNG in the system, and in particular, in the air quality modeling domain (shown as a red line in the figures). Maximizing the natural gas demand reduces the penetration of LNG into the modeling domain with respect to a case with typical demand (e.g., comparing Scenario 5 with Scenario 6). Minimizing domestic deliveries at Blythe increases the penetration of LNG around Riverside, but decreases the LNG penetration in Los Angeles County, because additional natural gas supply coming from the north is required to balance the lower supply of natural gas at Blythe.

Table 1: Parameters for the Eight Realistic LNG Scenarios Projected for the Year 2023 in the Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E) system (gas volumes in MMcf/day)

	Scenarios							
	Base		Min Domestic Deliveries		Max ECA Deliveries		Max ECA and Min Domestic Deliveries	
	1	2	3	4	5	6	7	8
SoCalGas/SDG&E	Typical	Maximum	Typical	Maximum	Typical	Maximum	Typical	Maximum
Summer Demand	2679	3212	2679	3212	2679	3212	2679	3212
ECA Supply	Typical	Typical	Typical	Typical	Maximum	Maximum	Maximum	Maximum
Otay Mesa	312	312	312	312	400	400	400	400
Blythe	112	112	112	112	84	84	84	84
Receipts from El	Typical	Typical	Minimized	Minimized	Typical	Typical	Minimized	Minimized
Paso (EP) at Blythe	508	508	140	220	478	478	140	220
Other Supplies	1747	2280	2115	2568	1717	2250	2055	2508

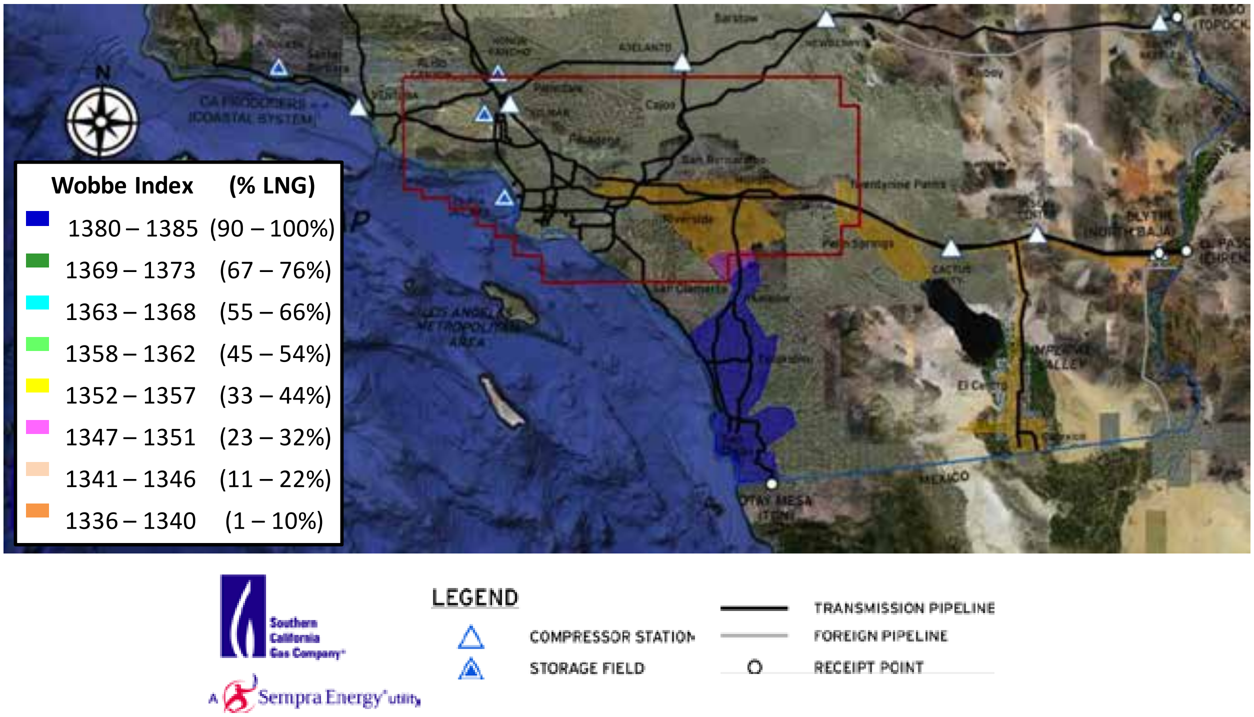


Figure 2: Zones of Influence in the SoCalGas/SDG&E System for Scenario 1: Typical Summer Demand, Typical Supply of LNG from ECA, and Typical NG Receipts of NG from El Paso at Blythe.

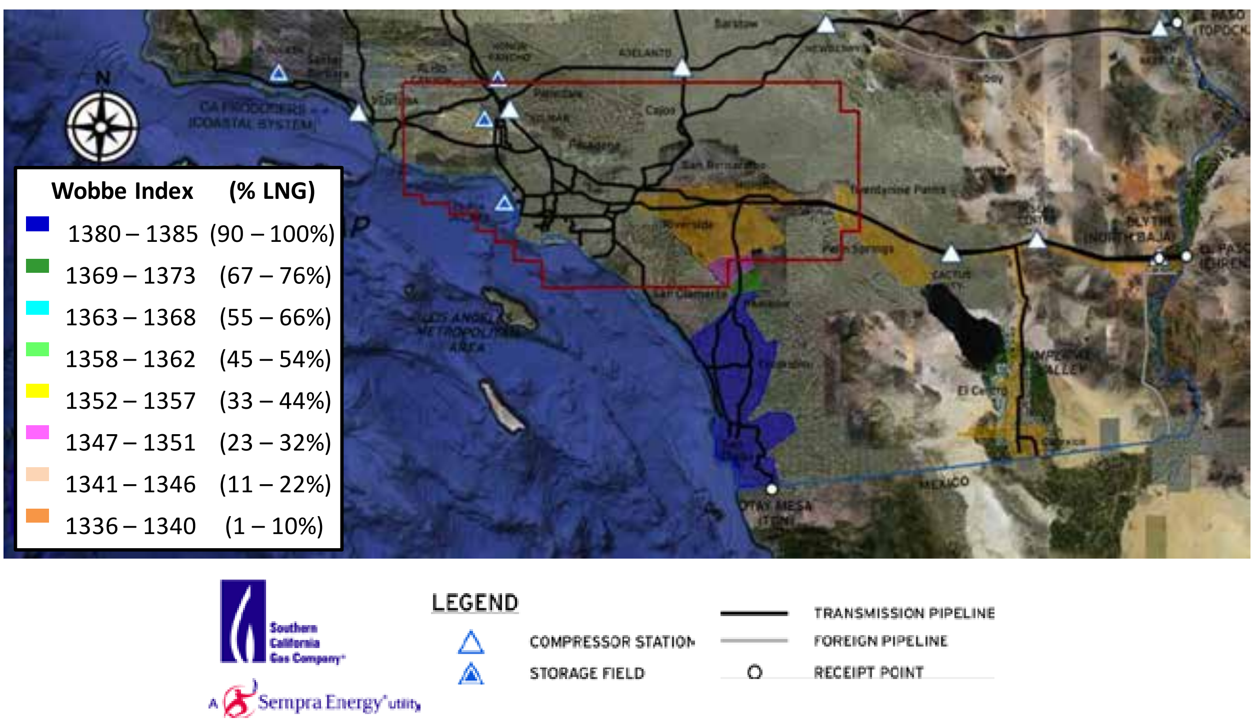


Figure 3: Zones of Influence in the SoCalGas/SDG&E System for Scenario 2: Maximum Summer Demand, Typical Supply of LNG from ECA, and Typical NG Receipts of NG from El Paso at Blythe.

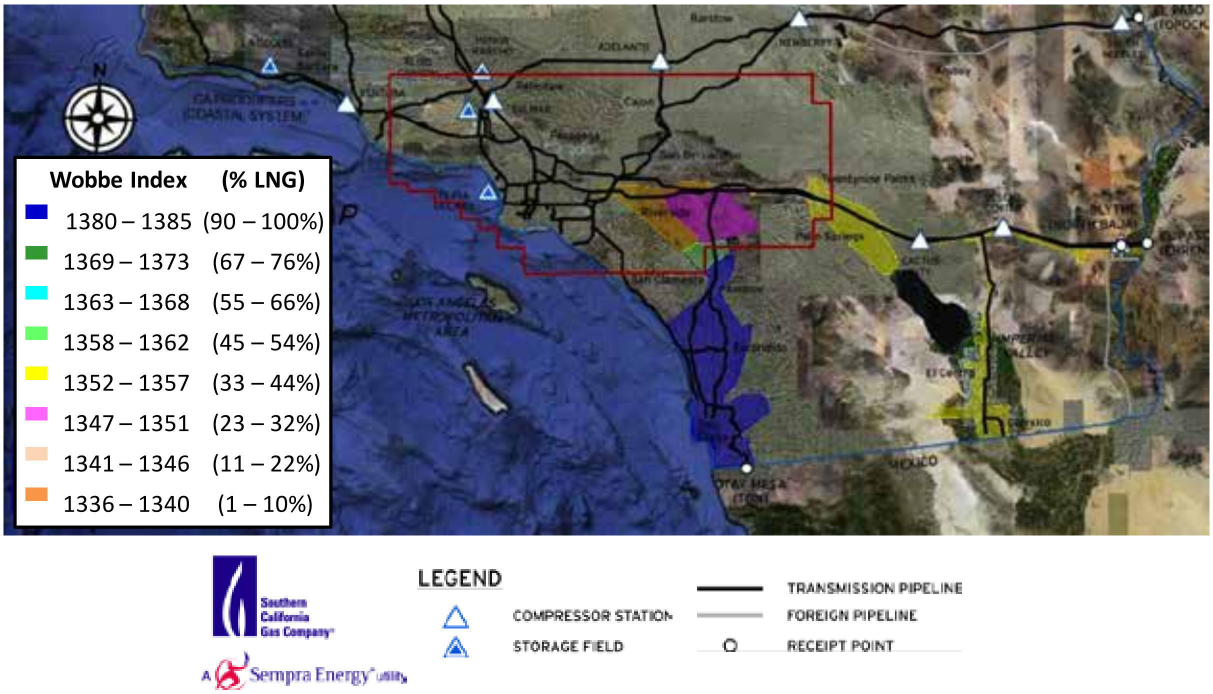


Figure 4: Zones of Influence in the SoCalGas/SDG&E System for Scenario 3: Typical Summer Demand, Typical Supply of LNG from ECA, and Minimized NG Receipts of NG from El Paso at Blythe.

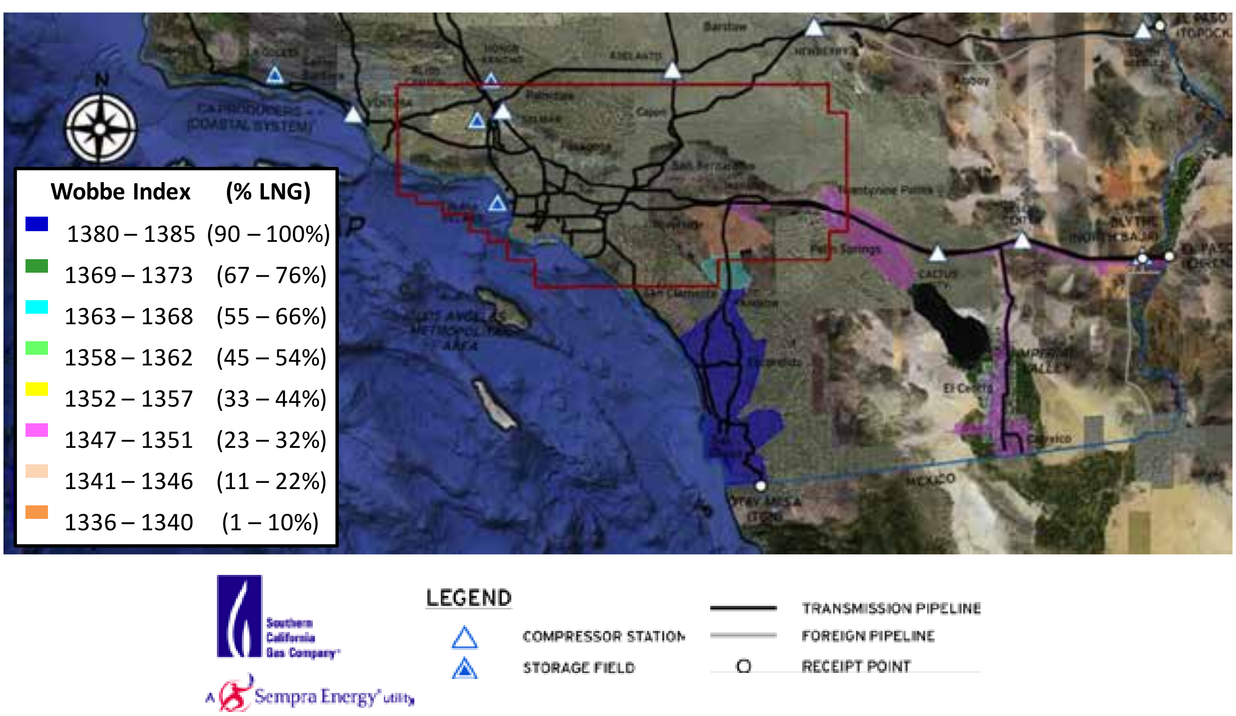


Figure 5: Zones of Influence in the SoCalGas/SDG&E System for Scenario 4: Maximum Summer Demand, Typical Supply of LNG from ECA, and Minimized NG Receipts of NG from El Paso at Blythe.

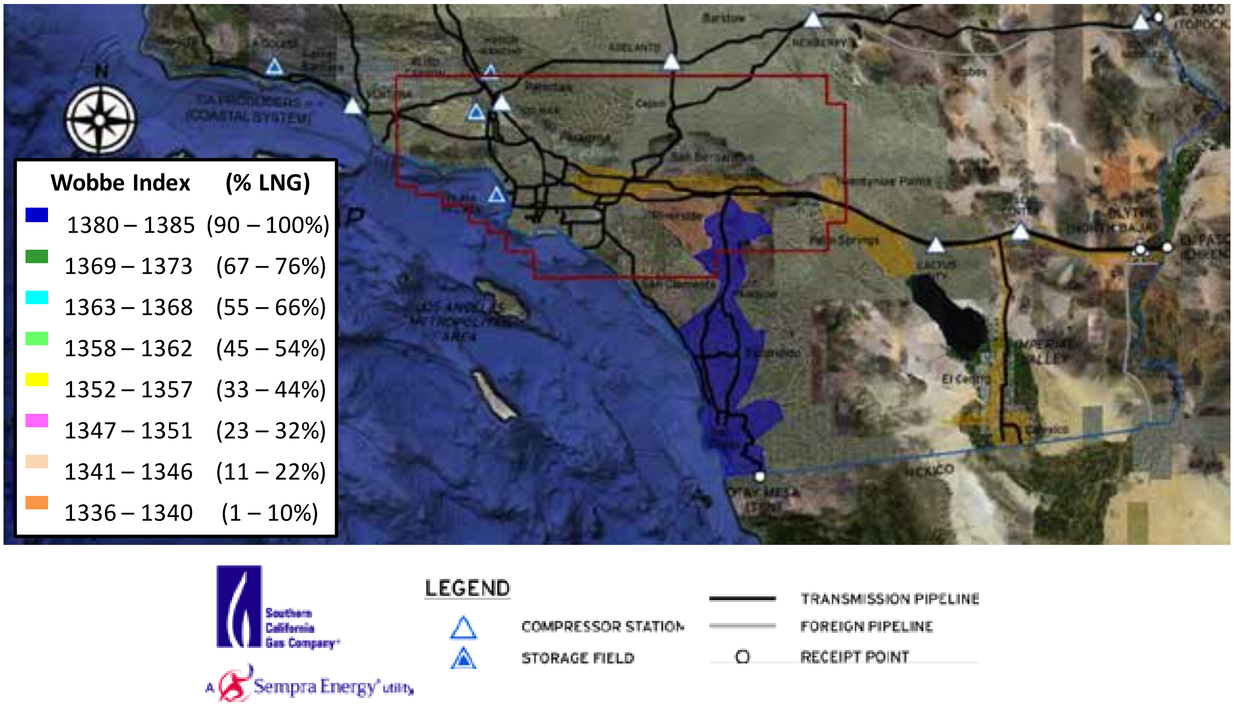


Figure 6: Zones of Influence in the SoCalGas/SDG&E System for Scenario 5: Typical Summer Demand, Maximum Supply of LNG from ECA, and Typical NG Receipts of NG from El Paso at Blythe.

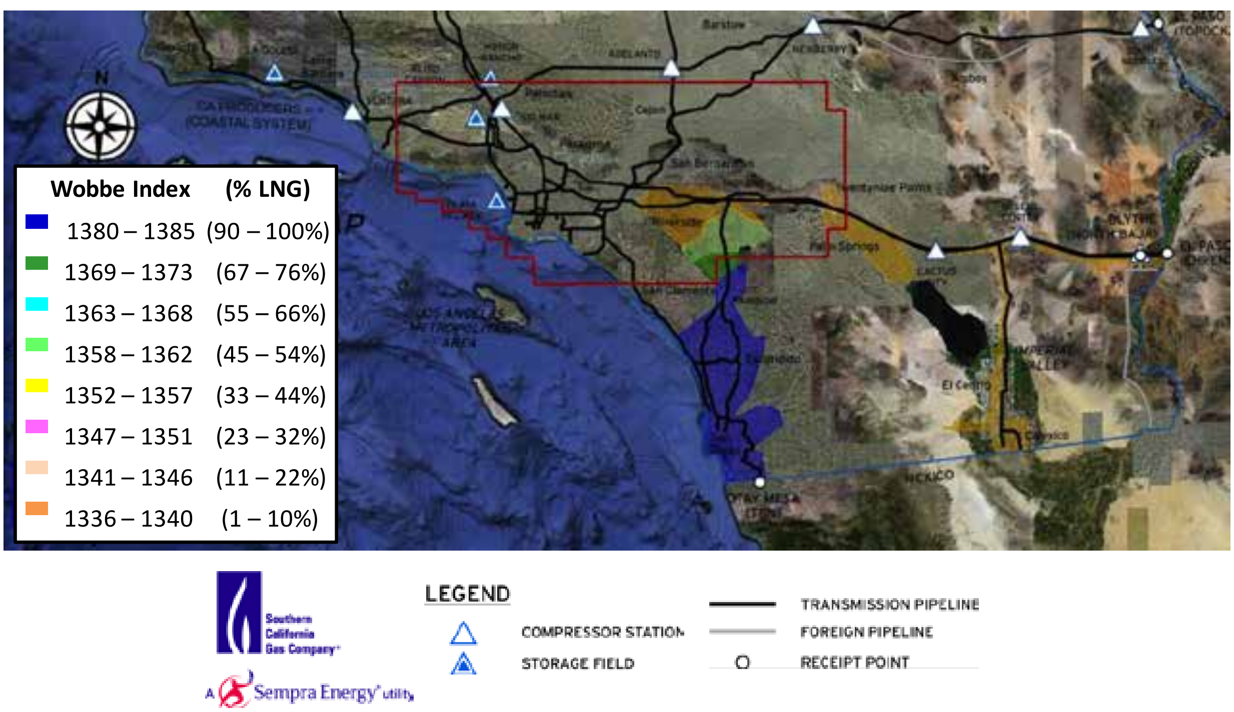


Figure 7: Zones of Influence in the SoCalGas/SDG&E system for Scenario 6: Maximum Summer Demand, Maximum Supply of LNG from ECA, and Typical NG Receipts of NG from El Paso at Blythe.

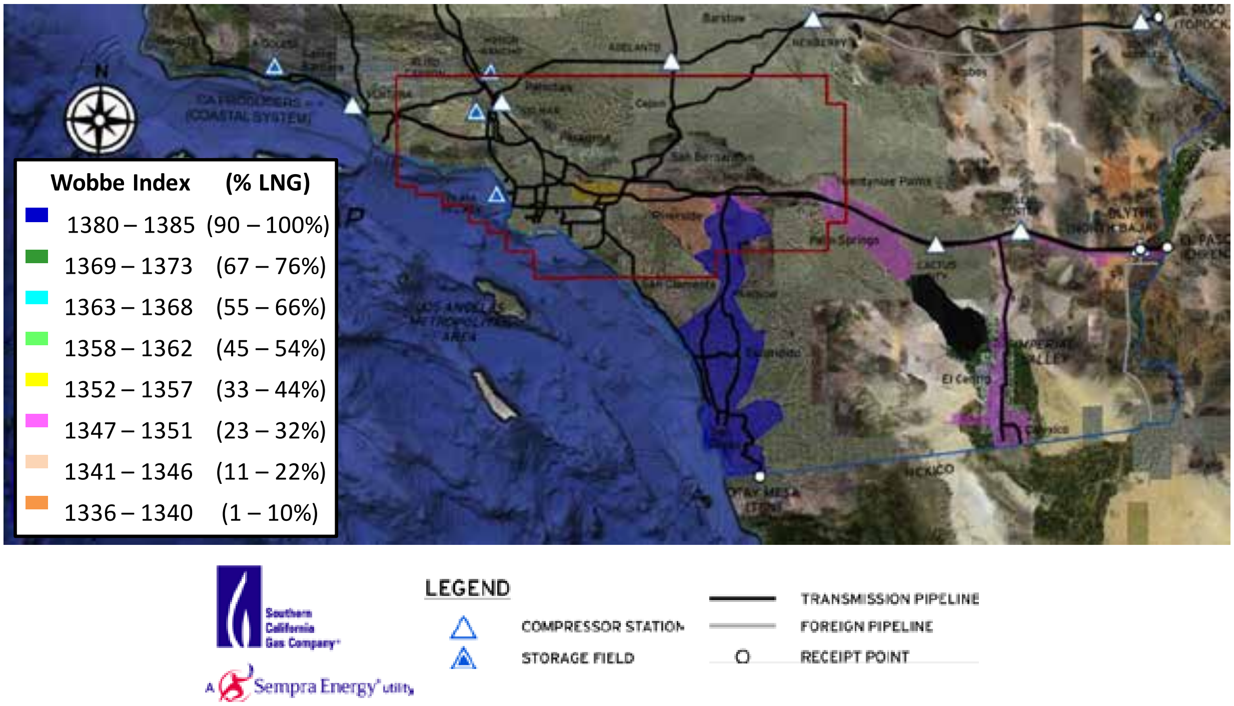


Figure 8: Zones of Influence in the SoCalGas/SDG&E System for Scenario 7: Typical Summer Demand, Maximum Supply of LNG from ECA, and Minimum NG Receipts of NG from El Paso at Blythe.

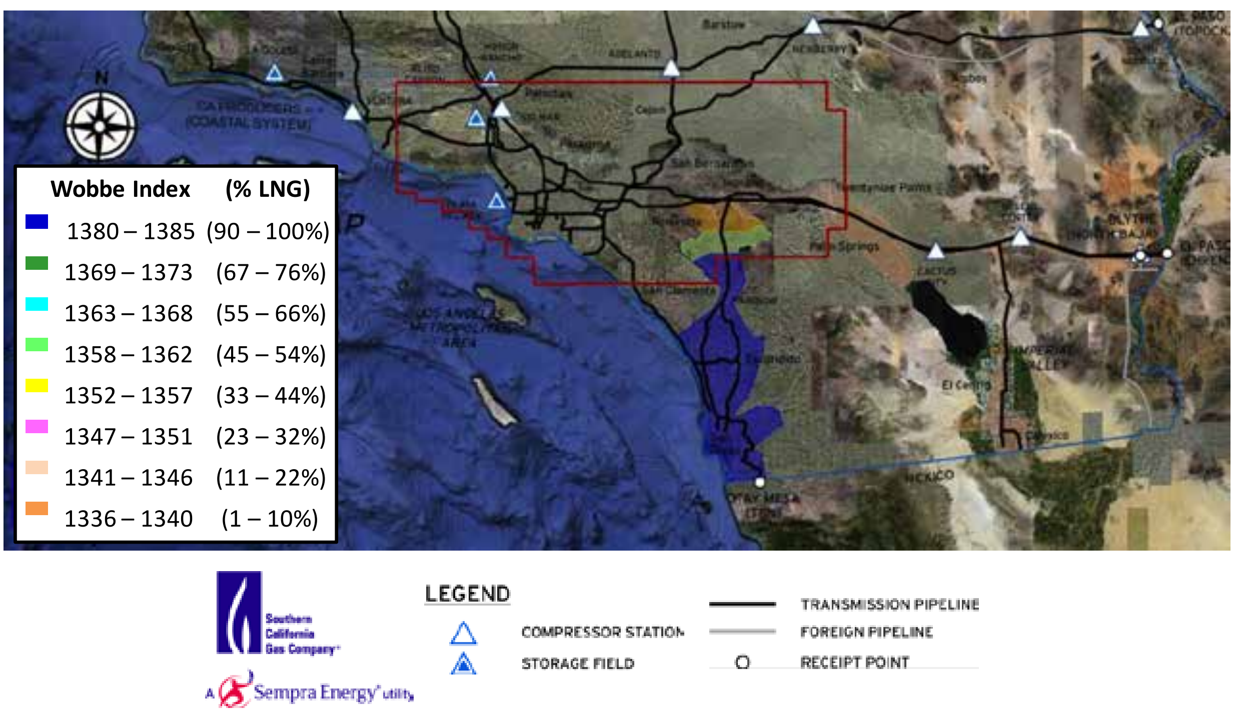


Figure 9: Zones of Influence in the SoCalGas/SDG&E System for Scenario 8: Maximum Summer Demand, Maximum Supply of LNG from ECA, and Minimum NG Receipts of NG from El Paso at Blythe.

Chapter 3:
Air Quality Impact Assessment Modeling Scenarios

The suite of LNG Zone-of-influence scenarios presented above should capture the range of likely LNG penetration into the South Coast Air Basin of California. These eight realistic scenarios are used as the basis to investigate the potential impacts of expected LNG use on ambient air quality in the SoCAB.

In addition, several hypothetical bounding scenarios were used to investigate whether LNG use at any plausible scale would have substantial impacts on overall emissions and ambient air quality. Both the realistic and hypothetical scenarios are compared to a baseline case scenario, which is adapted from a projected emission inventory developed by SCAQMD. To be very clear, the following hypothetical scenarios are NOT realistic or expected scenarios.

The following sections briefly describe the assumptions applied to each scenario and start to provide detail regarding how the emissions inventory was constructed. The key differences between the scenarios are the geographic regions of the basin that will receive LNG and the expected Wobbe index of the LNG/NG mixture in each region. Details on the construction of the emission inventories are provided in Section 4.

3.1 Baseline Scenarios

2023 SCAQMD Baseline: This emissions inventory was included in the 2007 Air Quality Management Plan to show attainment of the ozone standard by the year 2023. The 2023 SCAQMD Baseline corresponds to a future emissions inventory that includes long-term emissions controls that limit total NO_X emissions in the South Coast Air Basin of California to 114 short tons per day (shown in Table V-4-4, Appendix V, in the Final 2007 Air Quality Management Plan). Natural gas-related emissions from area sources are based upon emission factors from the U.S. Environmental Protection Agency's (U.S. EPA's) AP-42, a compendium of emission factors for a variety of sources. Natural gas-related emissions from point sources are directly obtained by SCAQMD through its emission reporting system for permitted sources.

2023 LBNL Baseline: This emissions inventory is based on the 2023 SCAQMD Baseline but includes updated emission factors obtained by LBNL for residential NG applications. This emissions inventory is used as a reference for the impacts of LNG, because increments in emissions due to LNG are expressed relative to the values measured by LBNL. In addition, the baseline NG emissions for residential appliances measured by LBNL provide more device-specific emission factors than those reported in AP-42.

3.2 Realistic Delivery Scenarios

Sempra Scenarios: As described above, scenarios 1 through 8 are considered as realistic based on modeling of expected LNG receipts, gas demand, and other supplies. The baseline Wobbe index for natural gas with no LNG is 1335 Btu/scf (the typical Wobbe index for NG delivered to Southern California), and the maximum Wobbe number assumed for a 100 percent LNG is 1385 Btu/scf (which is the maximum Wobbe index currently allowed in Southern California).

Changes to emissions from residential appliances as a function of Wobbe index are based on experimental measurements obtained by LBNL. Changes to emissions from area sources from LNG use in the commercial and industrial sectors are estimated by using measurements conducted by SoCalGas on low-NO_X burners.

3.3 Hypothetical Bounding Scenarios

100 percent LNG penetration: Although the scenario of 100 percent LNG penetration into the SoCAB is not possible with current infrastructure, this case is considered as a bounding case that could inform consideration of any future proposals to dramatically expand distribution of higher Wobbe index natural gas in the SoCAB. This scenario may also be relevant—with many caveats—to estimating the magnitude of emissions and air quality impacts from LNG use in San Diego, where LNG accounts for a large fraction of delivered NG. This bounding scenario assumes that 100 percent of distributed NG in the SoCAB has a Wobbe index of 1385 (50 Btu/scf higher than the baseline fuel and the maximum allowed by current tariff limits).

Scenario 7 with increased Wobbe index limit: Even though current tariffs limit the maximum Wobbe index to 1385 Btu/scf, re-gasified LNG can reach Wobbe numbers of up to 1440 Btu/scf. This scenario assumes the same spatial distribution of LNG as in the realistic Scenario 7, the largest amount of LNG expected to be delivered into the SoCAB, and a Wobbe index of 1400 Btu/scf for the re-gasified LNG. This hypothetical scenario was included to provide information about the potential impacts of raising Wobbe index limits should this policy pathway be considered at some future time.

100 percent LNG penetration with increased Wobbe index limit: Combining the hypothetical factors introduced in the previous two cases, this scenario assumes that 100 percent of all natural gas used in the basin comes from LNG, and that Wobbe index of the re-gasified LNG is 1400 Btu/scf. This scenario represents a hypothetical worst-case for LNG impact in the SoCAB.

100 percent LNG penetration with commercial and industrial equipment tuning: This scenario assumes that due to the high penetration of LNG, the basin experiences a prolonged supply of LNG. With a steady inflow of LNG as the primary source for natural gas, businesses would be able to plan adjustments of commercial and industrial equipment, retuning them for a high Wobbe index gas, and hence, minimizing the impacts of LNG on emissions from these installations.

Chapter 4: Modeling Emissions from Natural Gas-Related Sources

To evaluate the potential impacts of the emissions from LNG use on air quality in the South Coast Air Basin, it is necessary to first establish the baseline inventory of emissions from all sources in the basin. From this inventory, the emissions specifically due to natural gas sources need to be identified, and a method developed to modify the emissions for changes in gas quality due to LNG use. Modifications of the emission inventory requires an understanding of the factors used to produce the inventory, including items like the emission factors for specific technologies and any information regarding the distribution of these technologies within the different sectors of the inventory.

4.1 Baseline Emissions Inventories

The baseline emission inventories for the South Coast Air Basin were obtained from the South Coast Air Quality Management District (SCAQMD). The inventories were gridded, with emissions assigned to specific 5 by 5 kilometer (km) locations within the SoCAB modeling domain. Three different inventories were received, representing:

1. Baseline emissions for the year 2005
2. Baseline 2023, which assumes growth of emissions accounting only for the air emission control measures currently approved
3. Attainment 2023, which includes future emission control measures needed to attain ozone air quality standards

These three inventories were presented in the 2007 Air Quality Management Plan (AQMP) developed by the SCAQMD, and contain emissions from 6,410 different sources, including on-road and off-road mobile sources, stationary and area sources, and biogenic sources. Each emission inventory contains nearly 3 million entries, which include the information in Table 2.

Table 2: Description of Entries in the Emission Inventories

1. Standard Industrial Classification (SIC)
2. Standard Classification Code (SCC)
3. Emission Inventory Code (EIC)
4. X – model coordinate (origin at 150 UTME, 3580 UTMN)
5. Y – model coordinate
6. Facility ID (if applicable)
7. Stack ID (if applicable)
8. Average daily emission (kg/day) for CO, NO_X, SO_X, TOG, and PM
9. Speciation factors for NO_X (NO, NO_2, HONO), SO_X (SO_2, SO_3), TOG and PM
10. Monthly cycle: January through December weighting factors
11. Weekly: Monday through Sunday weighting factors
12. Daily cycle: hour 0 through hour 23 weighting factors

UTME = universal transverse mercator easting ; UTMN = universal transverse mercator northing ; CO = carbon monoxide; NO_X = nitrogen oxides; SO_X = sulfur oxides; TOG = total organic gases; PM = particulate matter; NO = nitric oxide; NO_2 = nitrogen dioxide; HONO = nitrous acid; SO_2 = sulfur dioxide; SO_3 = sulfur trioxide.

In addition, the emissions are explicitly disaggregated for each of the sub-categories defined by the Emission Inventory Code (EIC), which contain the following descriptors:

General:	**Example:**
EIC = EIC1 – EIC2 – EIC3 – EIC4	EIC = 610 – 608 – 0110 – 0000
EIC1: General activity sector	EIC1: 610 – Residential
EIC2: Technology	EIC2: 608 – Water heating
EIC3: Fuel	EIC3: 0110 – Natural gas
EIC4: Sub-category	EIC4: 0000 – Sub-Category Unspecified

Figure 10 presents the spatial distribution of NO_X emissions from the major emitters: light- and heavy-duty vehicles, area, and off-road sources for the Baseline 2023 scenario. This detailed information allows specific sources to be identified and modified by EIC code. For example, emissions from natural gas use from different parts of the residential sector can be perturbed independently using emission impacts obtained by LBNL.

The spatial distribution of NO_X emissions from the residential sources from cooking, water heating, and "other" sources for the month of July are presented in Figure 11. Note that for the summer modeling period, emissions from space heating are assumed to be negligible (not shown).

The emission inventory also provides detailed information on the location of large emission point sources. As an illustration, Figure 12 presents the spatial location of the point sources of NG boilers and process heaters included in the inventory.

The overall contribution to total NG-related NO_X emissions in the year 2023 by all of the different area and point sources categorized by "General Activity Sector" (EIC1) and "Technology" (EIC2) is presented in Figure 13. The NG-related emissions of NO_X add up to 26 tons/day out of basin-wide total NO_X emissions of 198 tons/day. One thing to note in Figure 13 is the significant fraction of emissions by Technology (EIC2) that are assigned to the "other" category, particularly for area emissions. These emissions are not assigned to a specific technology either due to a large mix of miscellaneous sources or sources that are hard to characterize.

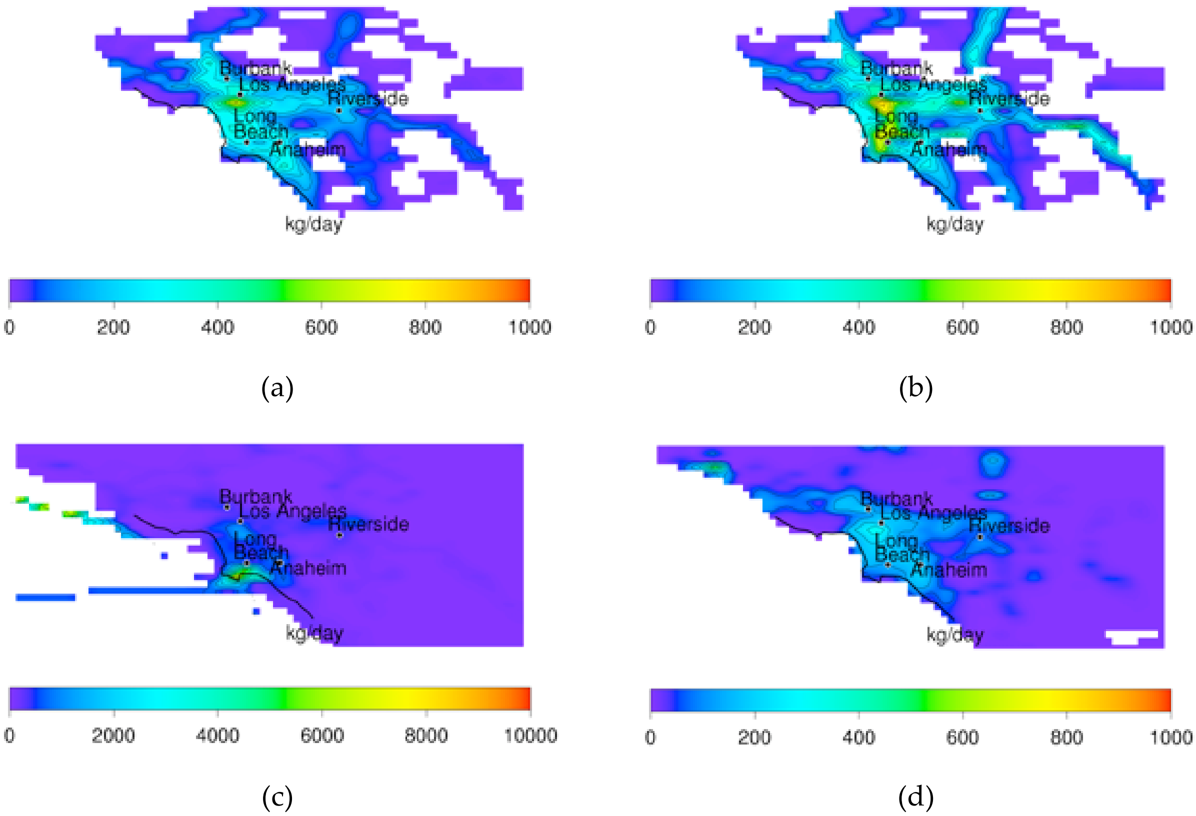


Figure 10: 2023 Baseline Emissions of Nitrogen Oxides (NO_X), in kilograms (kg)/day, Developed for the 2007 Air Quality Management Plan, by the South Coast Air Quality Management District (SCAQMD). These emissions assume growth of emissions accounting only for the air emission control measures currently approved. (a) light- and medium-duty vehicles, (b) heavy-duty vehicles, (c) off-road, (d) area sources.

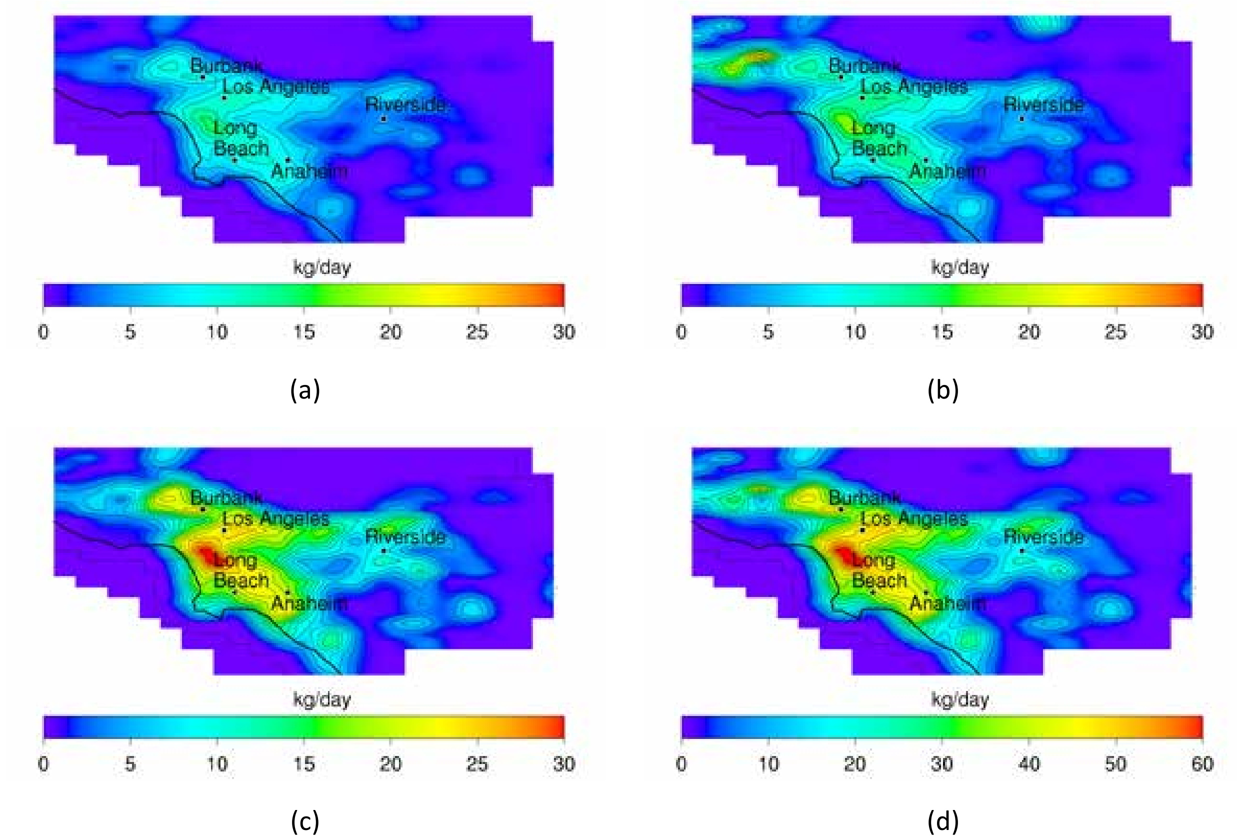


Figure 11: Spatial Distribution of NO_X Emissions from Natural Gas Use in Residential Applications for the Month of July: (a) cooking, (b) water heating, (c) other, which includes pool heating and gas barbeque, and (d) total emissions. Note that the scales in this figure (30 or 60 kg/day) are much smaller than in the preceding figure (1000–10000 kg/day), reflecting the much lower emissions of NO_X from residential sources compared with mobile sources.

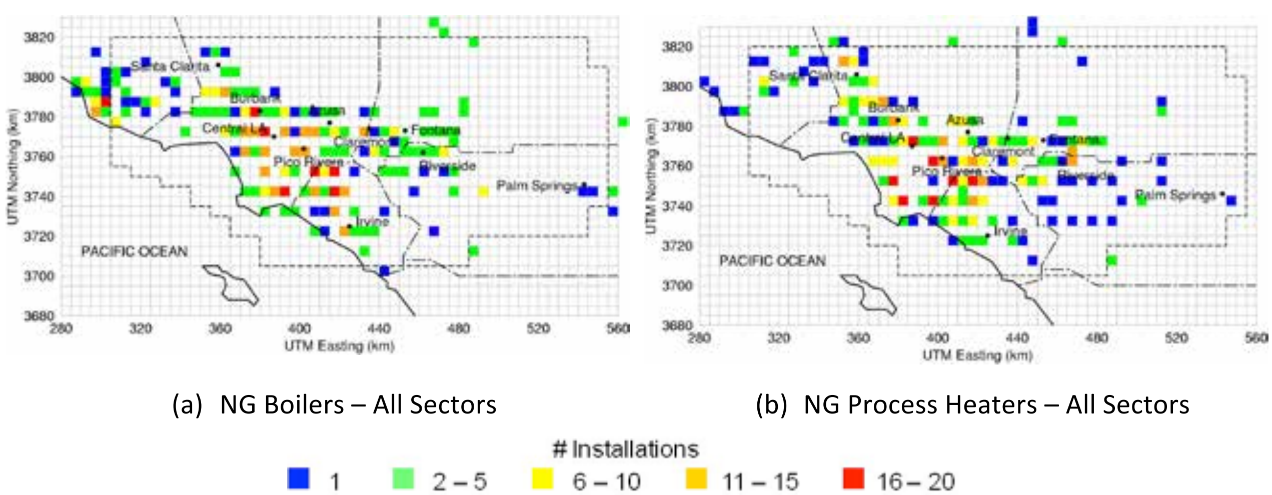


Figure 12: Spatial Distribution of Sources from Natural Gas Use in All Industrial Applications: (a) NG Boilers, and (b) NG Process Heaters. Note that different sources may represent installations of different sizes and different emission levels. The emissions from each source are included in the inventory as stated in Table 2.

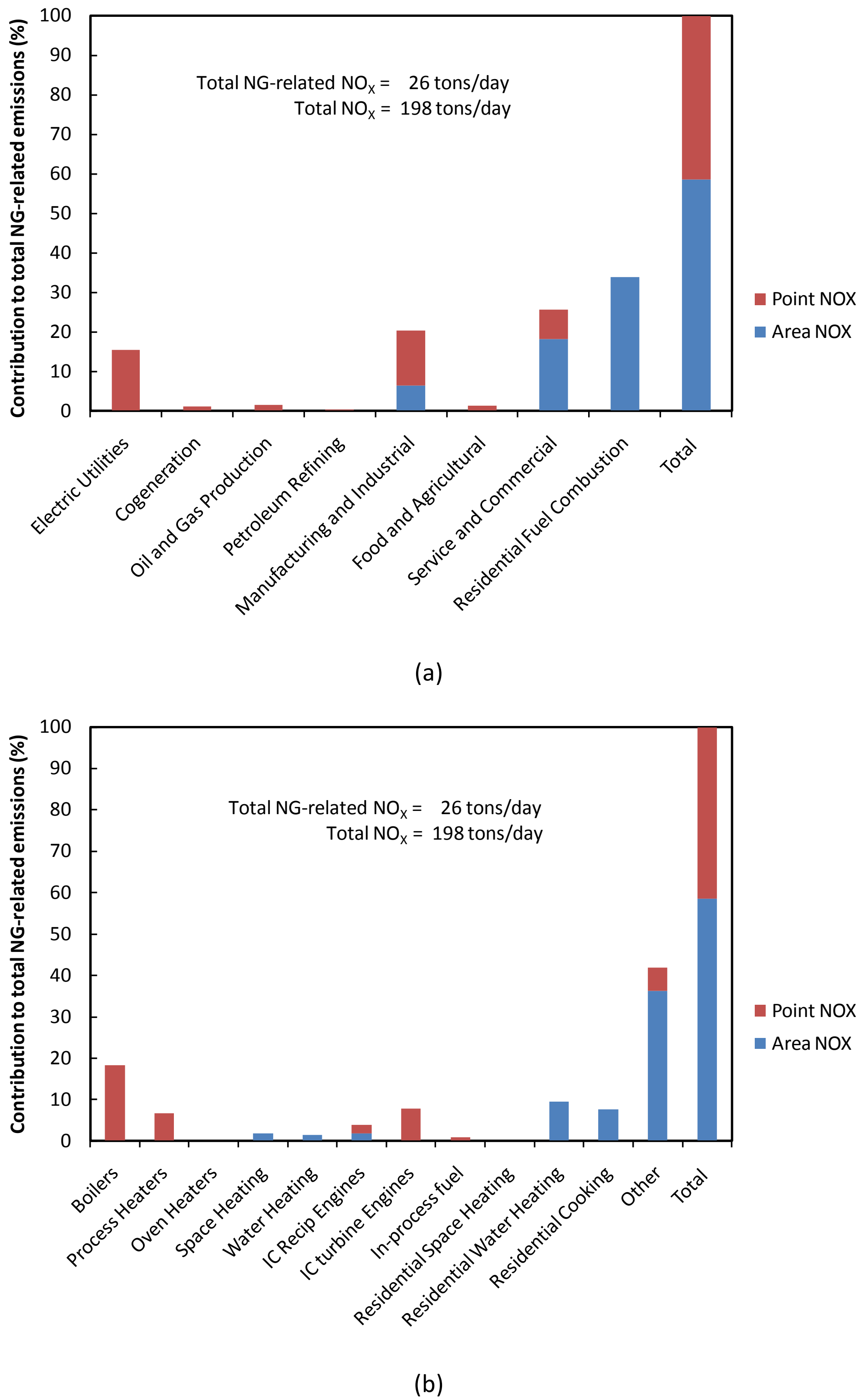


Figure 13: Contribution to Total NG-Related Sources—Both Area and Point Sources—to NO_x Emissions Estimated for the Year 2023 by: (a) General Activity Sector (EIC1) and (b) Technology (EIC2).

4.2 Adjustments to the Baseline Inventory

As described above, emissions in the 2023 SCAQMD inventory are calculated using either emission factors from the USEPA's AP-42 compilation of emission factors, or emissions directly reported to the district from point sources either using the district's continuous monitoring system or reported emissions for the specific permitted source. The fraction of NG-related NO_x emissions that are due to either area or point sources is shown in Figure 13. Fifty-eight percent of NG-related NO_x emissions are from area sources, and forty-two percent are from point sources. The AP-42 emission factors used in compiling the SCAQMD emission inventory are primarily for area sources, and are reported as emission of the pollutant of interest per unit of natural gas consumed. The area source emission factors of NO_x and carbon monoxide (CO) for the sectors and technologies that comprise the majority of emissions are listed in Table 3. Of the point sources, 17 percent are from the electrical utility industry, 16 percent are from the manufacturing and industrial sector, and 10 percent are from the service and commercial sector. Modest emissions of NO_x are due to point source emissions from other sectors.

Table 3: Emission Factors Used in the SCAQMD Inventory for Natural Gas Area Sources ($EF_{i,j,m}$)

CES	Description	2002 NO_X (lb/MMcf)	2002 CO (lb/MMcf)	2023 NO_X (lb/MMcf)	2023 CO (lb/MMcf)
66787	Industrial Stationary - I.C. Engines - Natural Gas	214	323	144	323
47142	Industrial Natural Gas Combustion (Unspecified)	130	35	62(1)	35
58743	Commercial Natural Gas Combustion - Water Heating	66	35	32(1)	35
58735	Commercial Natural Gas Combustion - Space Heating	94	35	94	35
47167	Commercial Natural Gas Combustion - Other	94	35	45(1)	35
54585	Residential Fuel Combustion - Natural Gas - Cooking	94	40	94	40
54577	Residential Fuel Combustion - Natural Gas - Water Heating	94	40	24(2)	40
54569	Residential Fuel Combustion - Natural Gas - Space Heating	94	40	94	40
47191	Residential Fuel Combustion - Natural Gas - Other	94	40	94	40

(1) Rule 1146.2: NO_X control factor (CF) for large water heaters and small boilers, CF = 0.48
(2) Rule 1121: NO_X control factor (CF) for residential NG-fired water heaters, CF = 0.25
Note: EFi,j,m = emission factors for sector i, technology/appliance j, and pollutant m.

The area emission factors reported in Table 3 are Industrial, Commercial, and Residential Fuel consumption. To establish the emission factors reported in AP-42, the U.S. EPA compiled data from either source-specific emission testing or from continuous emission monitors. However, not all sources have the type, quality, or number of test data available to provide robust emission factor calculations. While compiling emission information on natural gas sources for the current work, it became clear that, in general, the natural gas sector is one that lacks the type of emissions testing data to support emission factors for the range of combustion technologies in use. In the residential sector, the emission factors for all technologies are based on test data from 41 residential furnaces primarily measured during the late 1970s. As a result, the emission factors from all residential sources, cooking, water heating, space heating, and other sources, are based on these test data from residential furnaces. In the industrial sector, SCAQMD selected emission factors adapted from AP-42 for four-stroke lean-burn engines to represent the I.C. (internal combustion) engine technology, and for industrial boilers to represent unspecified NG combustion. Note that the NO_x emission factor for industrial boilers in 2023 is adjusted to meet the emissions specified in SCAQMD Rule 1146.2. In the commercial sector, emissions for space heating are based on uncontrolled boilers, and emissions for water heating are based on boilers that meet SCAQMD Rule 1146.2.

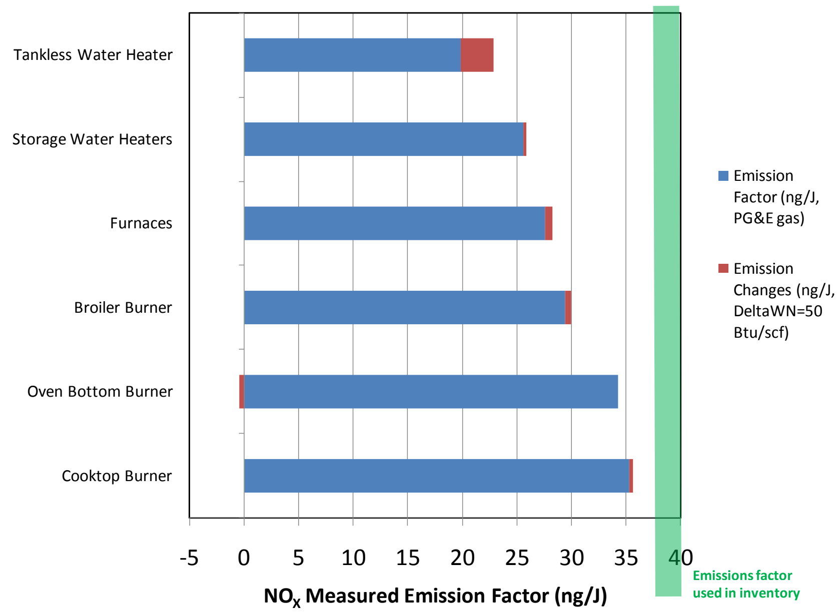
4.2.1. Update of Baseline Emissions Based on Experimental Measurements

As part of the overall California Energy Commission project to assess the emission impacts of higher Wobbe index, LBNL performed experiments to measure emissions with NG and LNG on a number of residential appliances (Singer et al. 2009). These measurements provide an opportunity to compare the emission factors resulting from the recent field and lab measurements of devices covering a suite of technologies with the emission factor provided for all residential sources in AP-42. The experimental emission factors for NO_x and CO are shown in Figure 14. For NO_x, the emission factors for all technologies fall below the AP-42 value of 40 pounds per million cubic feet (lb/MMcf). The measured technology-specific CO emission factors are much higher than the AP-42 values for cooking burners and tankless water heaters, and much lower for storage water heaters and residential furnaces.

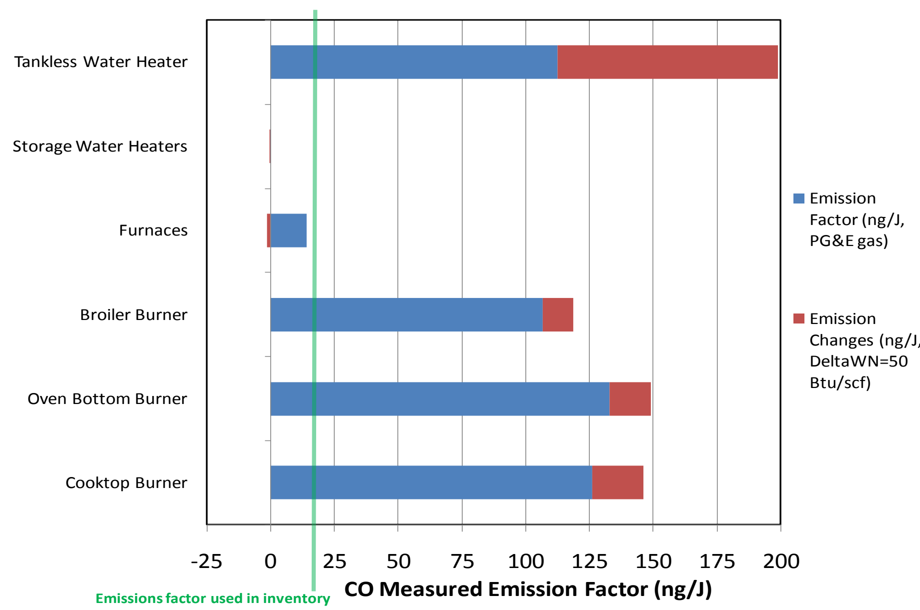
The results presented in Figure 14 suggest that the emission factors in AP-42 do not represent emissions from the residential technologies currently in place in California. Even the newly measured furnace emission factor for NO_x is lower than the AP-42 value, which was based on measurements performed several decades ago on the residential furnaces available at that time. The current population of California furnaces includes many designed for lower NO_X emissions. In addition, the changes in residential emissions as a function of Wobbe index were computed in relation to these experimental emission factors. Therefore, the SCAQMD 2023 Baseline inventory for residential appliances was modified to use these newer emission factors. This updated inventory is called the 2023 LBNL Baseline inventory.

SoCalGas conducted a series of experiments to analyze the effect of changing gas quality on emissions for several low and ultra-low NO_X technologies. The experiments examined a limited number of installations that were expected to be sensitive to changes in natural gas composition. Consequently, SoCalGas test results provide something of an upper bound for equipment sensitivity, although there is not enough information to attest that the technologies studied by SoCalGas are representative of the overall technology mix in commercial and industrial applications. As a result, the emission testing results by SoCalGas are not used to update the baseline emissions, but they are used in Section 4.2.2. to incorporate the effects of LNG on commercial and industrial emissions. In summary, only the LBNL measurements on residential appliances are used to update the baseline emissions inventory. In addition, the baseline assumed that emissions from commercial space and water heating, which had been based on uncontrolled boilers, would be better represented by the emission factors measured for the same technologies in the residential sector.

The 2023 LBNL Baseline inventory, which includes updated emission factors obtained from the measurements by LBNL for the area sources, was created using the following methodology. The emission factors $EF_{i,j,m}$ for sector i (denoted by EIC1), technology/appliance j (denoted by EIC2) and pollutant m (either NOx or CO) in Table 3 are updated with new emission factors $uEF_{i,j,m}$, calculated using the information from emissions testing ($et_{l,m}$) shown in Figure 14. The emission factors obtained by the experimental measurements are technology specific, which are not directly comparable with the generic technology/appliance described by EIC2. Consequently, technology mix factors ($f_{i,j,l}$) are required to link a specific technology l, with sector i and technology/appliance j. The $f_{i,j,l}$ factors, presented in Table 4, were established after discussions with stakeholders, including SCAQMD, ARB, SoCalGas, and the San Diego Air Pollution Control District, and the insights from an LBNL technology survey.



(a)



(b)

Figure 14: Emission Testing Results for Residential Appliances Obtained by Lawrence Berkeley National Lab. In blue, emission factors in nanograms per Joule (ng/J) obtained with delivered natural gas (Wobbe index mostly in range of 1330–1340 Btu/scf). In red, increments in emission factors (ng/J) due to an increase in Wobbe index of 50 Btu/scf. The green line denotes the emission factor assumed in the 2005 SCAQMD emissions inventory. The storage water heaters evaluated in this study were found to have negligible levels of CO in exhaust.

Source: Singer et al. 2009

The methodology to update the emissions inventory consists of three steps:

STEP 1: Calculate natural gas consumption $NGc_{i,j,k}$ in cell k from area sources using the emission factors $EF_{i,j,m}$ for activity sector i, technology j and pollutant m.

The emissions inventory includes total emissions of pollutant m, at a grid cell k, for an activity sector i and technology j. The $E_{i,j,k,m}$ values are divided by the generic emission factors $EF_{i,j,m}$ to obtain the natural gas consumption $NGc_{i,}$j in each grid cell k:

$$NGc_{i,j,k} = \frac{E_{i,j,k,m}}{EF_{i,j,m}} \qquad (1)$$

STEP 2: Calculate the updated emission factors $uEF_{i,j,m}$ using emission factors from experimental measurements $et_{l,m}$.

$$uEF_{i,j,m} = \sum_{l} f_{i,j,l} \cdot et_{l,m} \qquad (2)$$

Updated emission factors $uEF_{i,j,m}$ are presented in Table 5.

STEP 3: Update total emissions $uE_{i,j,k,m}$ using calculated natural gas consumption $NGc_{i,j,k}$ and updated emission factors $uEF_{i,j,m}$.

$$uE_{i,j,k,m} = NGc_{i,j,k} \cdot uEF_{i,j,m} \qquad (3)$$

Table 4: Technology Distribution Factors ($f_{i,j,l}$) Among Area Sources to Relate Emission Testing with Emissions Source Categories in the Inventory

CES	Description	Furnace	Storage Water Heater	Tankless Water Heater	Cook-top	Oven Burner	Broiler Burner	Low-NO_X Burner	Ultralow-NO_X Burner
47142	Industrial Natural Gas Combustion (Unspecified)							1.00	
58743	Commercial Natural Gas Combustion - Water Heating		0.70	0.30					
58735	Commercial Natural Gas Combustion - Space Heating	1.00							
47167	Commercial Natural Gas Combustion – Other							1.00	
54585	Residential Fuel Combustion - Natural Gas – Cooking				0.80	0.15	0.05		
54577	Residential Fuel Combustion - Natural Gas - Water Heating		0.70	0.30					
54569	Residential Fuel Combustion - Natural Gas - Space Heating	1.00							
47191	Residential Fuel Combustion - Natural Gas - Other	0.34	0.23	0.10	0.26	0.05	0.02		

Table 5: Updated Emission Factors for Area Sources Based on Emission Testing by LBNL, and Increments in Emissions Due to an Increase of 50 Btu/scf in the Wobbe Number Tested by LBNL and SoCalGas.

		Updated Emission Factor ($uEF_{i,j,m}$)		Increase in Emission Factor $\Delta EF_{i,j,m}$ (ΔWN = 50)	
		NO_X	CO	NO_X	CO
CES	**Description**	**lb/MMcf**		**lb/MMcf**	
66787	Industrial Stationary - I.C. Engines - Natural Gas	214[(1)]	323[(1)]	-	-
47142	Industrial Natural Gas Combustion (Unspecified)	62[(1)]	35[(1)]	25[(2)]	-
58743	Commercial Natural Gas Combustion - Water Heating[(3)]	59	83	3	64
58735	Commercial Natural Gas Combustion - Space Heating[(3)]	68	35	2	-4
47167	Commercial Natural Gas Combustion – Other	45[(1)]	35[(1)]	18[(2)]	-
54585	Residential Fuel Combustion - Natural Gas – Cooking[(4)]	79	302	0	37
54577	Residential Fuel Combustion - Natural Gas - Water Heating[(4)]	59	83	3	64
54569	Residential Fuel Combustion - Natural Gas - Space Heating[(4)]	68	35	2	-4
47191	Residential Fuel Combustion - Natural Gas – Other[(4)]	69	142	1	32

(1) No new data. Emission factor is the same as in SCAQMD inventory.
(2) Emission increase of 40% in the WI range of 1335–1385 Btu/scf based on low-NO_X technologies tested by SoCalGas (Figure 15)
(3) Assume same emission factor as in "Residential"
(4) Measurements by LBNL

4.2.2. Estimating Change in Emission from LNG Use

The updated emissions from the 2023 LBNL Baseline emissions inventory are considered as the baseline reference to evaluate the impacts of LNG use. Changes in emissions related to LNG use, described by change in Wobbe index, need to be assessed by the available experimental data. The available emissions data can be divided into two groups:

Group 1: Residential appliances and commercial space and water heating.

Group 2: "Other" commercial and industrial natural gas combustion area sources and industrial and commercial boilers and process heaters, included in point sources.

The methodology to assess changes in emissions due to changes in NG composition from Group 1 uses experimental results obtained by LBNL, and uses the same approach as that used to update the baseline inventory described in Section 4.2.1. The methodology for Group 2 uses available emission testing data measured by SoCalGas.

The methodology to determine the impacts in emissions due to LNG in Group 1 is as follows:

STEP 1: Calculate the incremental emission factors for a maximum increment of Wobbe number.

Similarly to baseline emission, incremental emission factors $\Delta EF_{i,j,m}$ for an increase in Wobbe number of 50 Btu/scf are calculated using the factors in Table 4 and the incremental emission factors obtained from experimental measurements, $\Delta et_{l,m}$, calculated by LBNL. The resulting values are presented in Table 5.

$$\Delta EF_{i,j,m} = \sum_{l} f_{i,j,l} \cdot \Delta et_{l,m} \qquad (4)$$

STEP 2: Calculate increments in overall pollutant emissions as a function of the fraction of re-gasified LNG in the natural gas stream.

The zone-of-influence model results shown in Figure 2 through Figure 9 provide information on the fraction of re-gasified LNG that flows in the SoCalGas system. A maximum fraction of 100 percent signifies that the Wobbe index in the natural gas is 1385 Btu/scf, which is 50 Btu/scf higher than the baseline natural gas without any LNG. The impacts on emissions due to LNG are assumed linear within the range of 1335–1385 Btu/scf. For instance, if a region receives 50 percent re-gasified LNG, the increase in emissions due to LNG would be half of that experienced in an area with 100 percent re-gasified LNG. Hence, the increase in emissions is proportional to the fraction of natural gas in grid cell *k* that originates from the ECA terminal, denoted by A_k.

$$\Delta E_{i,j,k,m} = A_k \cdot NGc_{i,j,k} \cdot \Delta EF_{i,j,m} \qquad (5)$$

STEP 3: Add incremental emissions to baseline updated emissions to determine new emissions for LNG scenarios.

$$uE^{LNG}_{i,j,k,m} = uE_{i,j,k,m} + \Delta E_{i,j,k,m} \qquad (6)$$

The impact in assessment of LNG in Group 2 is more simplified than the methodology for Group 1. In contrast with the specific emission factors expressed as mass per unit of energy obtained by LBNL, the emission testing conducted by SoCalGas provided a broad upper bound for the impact of LNG used in commercial and industrial applications. As a result, the methodology for Group 2 is more simplified than the methodology for Group 1 in the sense that the emissions from natural gas applications are not strictly related to natural gas consumption. Instead, emissions from Group 2 are scaled by an overall factor that was obtained by emissions testing conducted by SoCalGas. Within Group 2, commercial and industrial area sources are expected to be smaller units that employ low-NO_X burner technology, and commercial and industrial point sources are expected to be large installations that employ ultra-low-NO_X

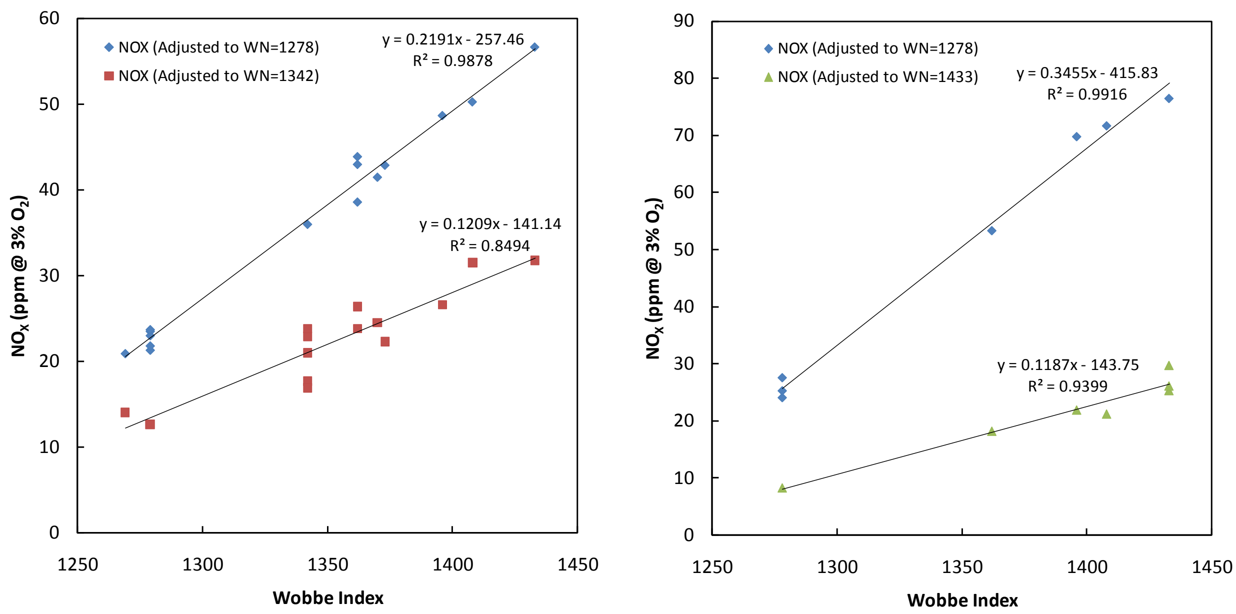
technologies. These assumptions are based on an internal equipment survey conducted by SCAQMD (Baez 2010).

SoCalGas conducted several emission tests on low-NOx (Figure 15) and ultra-low-NOx burners (Figure 16). Interpolation of SoCalGas testing data for low-NOx burners shows that NOx emissions increase by up to 40 percent for an increase in Wobbe index from 1335 to 1385 Btu/scf. Ultra-low-NOx burners showed increase in NOx emissions of 15 percent over the same Wobbe index range.

To calculate the resulting emissions in the LNG scenarios for these Group 2 technologies, the following expression is used:

$$uE_{i,j,k,m}^{LNG} = uE_{i,j,k,m} \cdot (1 + A_k \cdot F_{i,j,m}) \qquad (7)$$

where $F_{i,j,m}$ is the overall increase factor obtained by SoCalGas, for sector i (industrial and commercial), technology j (low-NOx and ultra-low-NOx), and pollutant m. Note that only changes in NOx emissions are estimated due to a lack of data on other pollutants.



(a) (b)

Figure 15: Emission Testing Results for Commercial and Industrial Burners Obtained by SoCalGas: (a) Steam Boiler with Premixed Gun-Type Power Burner, (b) Low-NO$_X$ Steam Boiler

Source: SoCalGas 2006

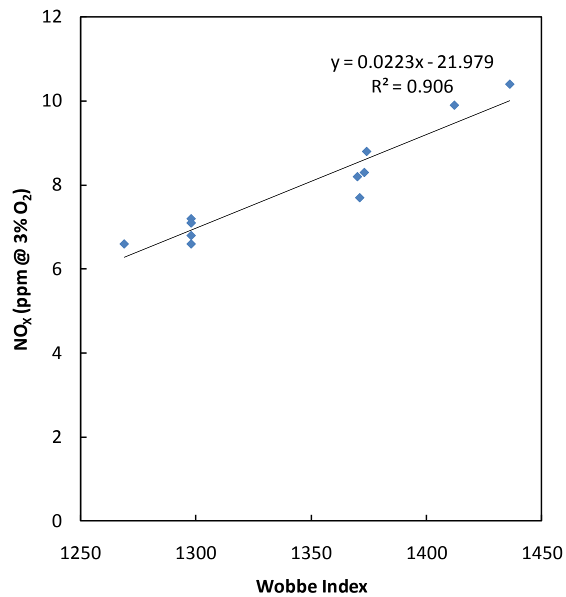


Figure 16: Emission Testing Results for Industrial Ultra-low NO_X Steam Boiler Obtained by SoCalGas

Source: SoCalGas 2006

4.3 Estimating VOC Fugitive Emissions from LNG

The use of LNG not only affects emissions from natural gas combustion, it can also impact emissions from fugitive sources released from the transmission and distribution of natural gas. In California, natural gas generally has a lower fraction of non-methane hydrocarbons (NMHC) than most of the potential supply of LNG available for the ECA terminal. Emissions of NMHC are important because they are precursors of ozone formation, and significant increases in NMHC can lead to increases in ozone concentrations.

Switching to LNG would increase the emissions of these volatile organic compounds (VOC) from fugitive sources in the NG transmission and distribution lines. Table 6 presents the composition of natural gas from different origins. The ECA terminal has been receiving natural gas from Peru and could potentially receive from the Tangguh project in Indonesia. While gas composition from each source will vary over time, the differences between supply sources are generally much larger. All delivered fuels have to meet specification limits for ethane, higher hydrocarbons, and inert components. The limits for compressed natural gas set by the ARB are used as reference for comparison, and provide the upper limit for the fraction of NMHCs allowed in the natural gas. Compared to the median natural gas distributed throughout Southern California, the ARB specifications increase the fraction of NMHC by 200 percent.

Figure 17 presents emissions of VOCs from fugitive sources in the natural gas distribution and transmission system in the 2023 SCAQMD emissions inventory. For air quality modeling purposes, the emissions of ethane through hexane are lumped in a group that represents short-chain alkanes (ALKL). The basin-wide emissions of ALKL from fugitive NG transmission and distribution are 1.2 tons/day, out of 99.8 tons/day of total emissions of ALKL. It is also important to note that ALK1 is only one class of VOCs. Thus, the change to overall VOC reactivity relevant to ozone formation is much, much smaller than the increment in ALK1 emissions.

Table 6: Mass Composition of Natural Gas from Different Origins

	SoCalGas Median %	ARB[1] %	Peru %	Tangguh %
Methane	89.74	75.32	81.29	92.62
Ethane	4.43	9.82	18.07	4.69
Propane	1.30	7.20	0.05	1.32
Butanes	0.00	0.00	0.00	0.70
Hexane and higher	0.21	0.79	0.00	0.00
Carbon Dioxide	3.25	0.00	0.00	0.00
Nitrogen (N_2)	1.07	6.87	0.59	0.67

[1]ARB corresponds to the specification limits for ethane, higher hydrocarbons and inert compounds allowed by ARB for compressed natural gas (CNG).

Source: Suellentrop 2005

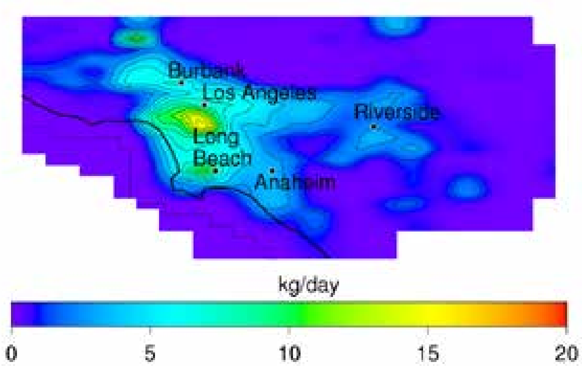


Figure 17: Fugitive Emissions of VOC from Natural Gas Transmission and Distribution Estimated for the Year 2023

The increase in emissions of ALKL due to LNG is based on the assumption that the LNG-free natural gas has the composition of the median southern California gas, and the composition of the LNG is based on the ARB specifications. Based on these assumptions, the emissions of ALKL in LNG scenarios are calculated as follows:

$$uE_{k,ALKL}^{LNG} = E_{k,ALKL} \cdot \left(1 + A_k \cdot \frac{X_{ALKL}^{LNG}}{X_{ALKL}^{SoCal}}\right) \quad (8)$$

Where $uE_{k,ALKL}^{LNG}$ represents the updated emissions of ALKL in an LNG scenario in modeling cell k, $E_{k,ALKL}$ represents the baseline ALKL emissions in cell k, A_k is the fraction of natural gas in cell k that originates from the ECA terminal, X_{ALKL}^{LNG} is the mass fraction of ALKL (all non-methane hydrocarbons) in the LNG, and X_{ALKL}^{SoCal} is the mass fraction of ALKL in the SoCal median natural gas.

4.4 Summary of Estimated Emissions for the LNG Modeling Scenarios

4.4.1 Realistic Scenarios

Table 7 presents total emissions from the eight realistic LNG scenarios. The impact on emissions from these scenarios (shown in Figures 2 through 9) is less than 0.1 percent of total emissions for all pollutants. Even for the highest penetration scenario, Scenario 7, the increase in NO_X emissions is 0.09 tons/day, an increase of 0.08 percent in total basin-wide emissions of NO_X from natural gas combustion. Increases in CO and short-chain alkanes to basin-wide emissions are proportionally much smaller for the highest penetration scenario, 0.1 and 0.008 tons/day respectively; corresponding to increases of 0.005 percent and 0.008 percent. The scenarios that show the smallest increase in emissions are approximately one-third of those seen in the highest penetration scenario.

4.4.2 Hypothetical Scenarios

The impacts on emissions from the four hypothetical scenarios are also listed in Table 7. Recall that these scenarios are for the purpose of exploratory and bounding analysis only, and are not meant to represent expected LNG usage.

Scenario "100% LNG" assumes 100 percent penetration (use) of LNG throughout the South Coast Air Basin. While this is not feasible with current or planned LNG receiving infrastructure, it does provide a bound on the maximum air quality impact that can be expected from LNG use. The NO_X emissions increase by 2.76 tons/day, corresponding to 2.5 percent increase in total basin-wide emissions of NO_X from natural gas combustion. This scenario also adds 2.6 and 1.0 tons/day of CO and short-chain alkanes to basin-wide emissions, respectively, which represent an increase of 0.1 percent and 1 percent.

Two hypothetical scenarios explore the effects of increasing the limit of Wobbe index in the SoCAB to 1400 Btu/scf: Scenario 7 (WI_{max}=1400) and 100% LNG (WI_{max}=1400). Although this is currently not feasible under current gas quality tariff limits, experimental results suggest that increasing the Wobbe index to 1400 Btu/scf will not significantly affect safe operation of most equipment. Assuming linear changes in emissions within the expected range of the Wobbe index, incremental changes in emissions ($\Delta EF_{i,j,m}$) for NO_X and CO due to a Wobbe index of 1400 are 30 percent larger than for 1385. The resulting increases in emissions for Scenario 7 (WI_{max}=1400) due to LNG are 0.1 percent of total basin-wide emissions. In contrast, the increase in NO_X emissions due to Scenario 100% LNG (WI = 1400) add up to 3.6 tons/day (3.2 percent) of total basin-wide NO_X emissions. In addition, emissions of CO and ALKL increase by 3.5 and 1.0 tons/day, respectively.

Finally, the hypothetical scenario "100% LNG with Tuning" investigates the possible mitigating effects of basin-wide adjustments of burners to optimize operation with LNG. This scenario assumes that due to the high penetration of LNG, the basin experiences a prolonged supply of LNG. With a steady inflow of LNG as the primary source of natural gas, businesses would be able to plan adjustments of commercial and industrial equipment, retuning them for a high Wobbe index gas, and hence, minimize the impacts of LNG on emissions from these installations. This tuning reduces the overall impacts of LNG on NO_X emissions to 0.17 tons/day (0.15 percent of total basin-wide emissions of NO_X). The impacts on CO remain the same as in scenario 100% LNG because increases of CO emissions from industrial and commercial installations were not accounted for due to lack of data. The impacts on ALKL emissions also remain the same as in scenario 100% LNG because tuning does not affect fugitive emissions.

Table 7: Impacts on Emissions of CO, NO_X, and Short-Chain Alkanes (ALKL) Estimated for All LNG Scenarios. Increases in Emissions are Expressed with Respect to (w.r.t.) the LBNL Baseline Case

Case	CO Increase (tons/day) w.r.t. LBNL Baseline	CO Increase (%) w.r.t. LBNL Baseline	NO_x Increase (tons/day) w.r.t. LBNL Baseline	NO_x Increase (%) w.r.t. LBNL Baseline	ALKL Increase (tons/day) w.r.t. LBNL Baseline	ALKL Increase (%) w.r.t. LBNL Baseline
LBNL Baseline (tons/day)						
Total CO = 2248.534						
Total NO_X = 112.178						
Total ALKL = 98.450						
Realistic LNG Distribution Scenarios						
Scenario 1	0.043	0.002	0.037	0.033	0.003	0.003
Scenario 2	0.033	0.001	0.027	0.024	0.002	0.002
Scenario 3	0.055	0.002	0.044	0.039	0.004	0.004
Scenario 4	0.039	0.002	0.039	0.035	0.003	0.003
Scenario 5	0.112	0.005	0.084	0.075	0.008	0.008
Scenario 6	0.062	0.003	0.046	0.041	0.005	0.005
Scenario 7	0.111	0.005	0.092	0.082	0.008	0.008
Scenario 8	0.046	0.002	0.034	0.030	0.004	0.004
Hypothetical Bounding Scenarios						
100% LNG	2.651	0.12	2.763	2.463	1.001	1.017
Scenario 7 (WI_{max}=1400)	0.145	0.01	0.118	0.105	0.008	0.008
100% LNG (WI_{max}=1400)	3.493	0.15	3.581	3.192	1.001	1.017
100% LNG with Tuning	2.651	0.12	0.166	0.148	1.001	1.017

Chapter 5:
Overview of the SoCAB Air Quality Modeling

5.1 The South Coast Air Basin

California is divided into regional air basins based on topographical air transport features. The South Coast Air Basin encompasses most of the greater Los Angeles area and stretches nearly 300 km from west to east and 150 km from south to north. The South Coast Air Basin of California includes Orange County, Los Angeles County (except the Antelope Valley), and parts of San Bernardino and Riverside counties (see Figure 18). The basin is delimited by the Pacific Ocean on the south and west, by the San Gabriel and San Bernardino Mountains on the north, and the San Jacinto Mountains on the east. Typical summer meteorological conditions consist of an on-shore sea breeze that pushes pollutants to inland areas. The presence of mountain ranges on the north and east stops the transport farther inland, and accumulates pollutants in regions around Riverside and San Bernardino, where the highest ozone concentrations typically occur. The current population in the SoCAB is over 16.4 million people and is expected to grow to 18.6 million by 2020.

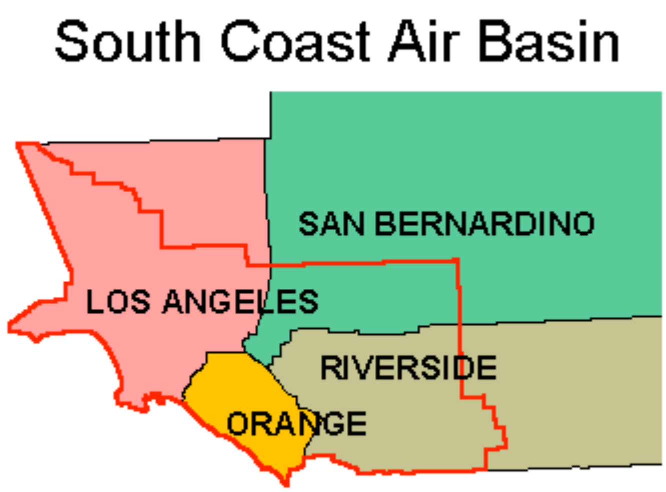


Figure 18: South Coast Air Basin of California

Source: http://www.arb.ca.gov/ei/maps/basins/ abscmap.htm

Criteria pollutants such as ozone and particulate matter are formed from atmospheric transformation of both biogenic and anthropogenic emissions that come from a variety of sources. The National Ambient Air Quality Standards (NAAQS) and the State of California air quality standards regulate ambient levels of pollutants such as ozone (O_3), nitrogen oxides (NO_2), sulfur oxides (SO_X), particulate matter (PM), and carbon monoxide (CO), to protect public health. Ambient concentrations of criteria pollutants are constantly monitored and should be below the maximum concentrations defined by state and federal air quality standards. To support attainment of air quality standards, the state regulates sources that emit criteria pollutants or ozone precursor compounds.

Figure 19 presents the evolution of maximum 1-hour and 8-hour average ozone concentration in the SoCAB for the past three decades, and Figure 20 presents the number of days a year that the California 1-hour and the federal 1-hour and 8-hour ozone standard are exceeded. Although there has been a significant improvement in air quality from the mid 1970s, concentration of ozone still exceeds the federal 1-hour ozone air quality standard over 30 days a year. In addition, the 8-hour average ozone standard is exceeded over 80 days a year. Based on the poor air quality in the SoCAB, the U.S. EPA classified this area as a severe non-attainment region for the purposes of compliance with the federal 8-hour ozone standard, and the state was required to develop a plan that shows attainment of standards by the year 2023.

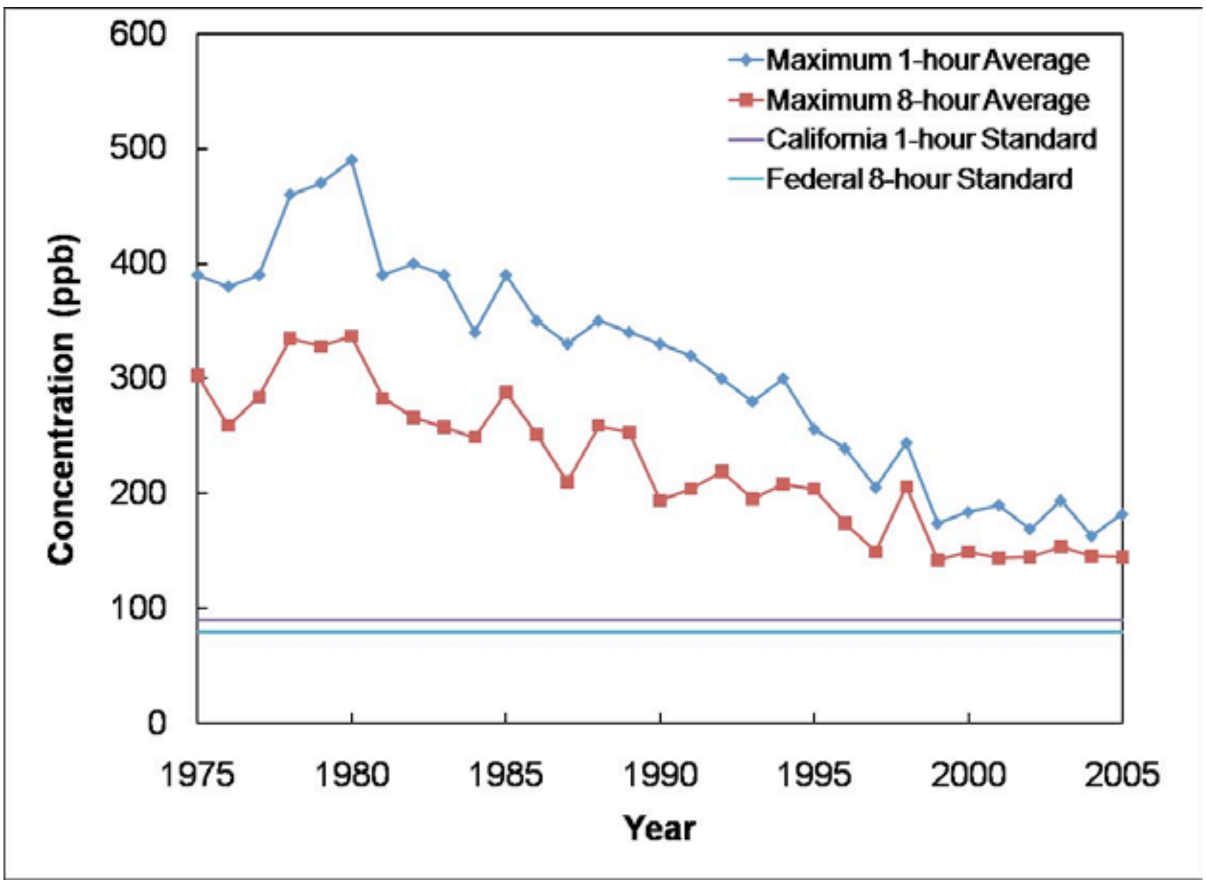


Figure 19: SoCAB Basin-Wide Maximum Ozone Concentrations (Parts Per Billion) with Reference to State and Federal Standards

Source: ARB 2006

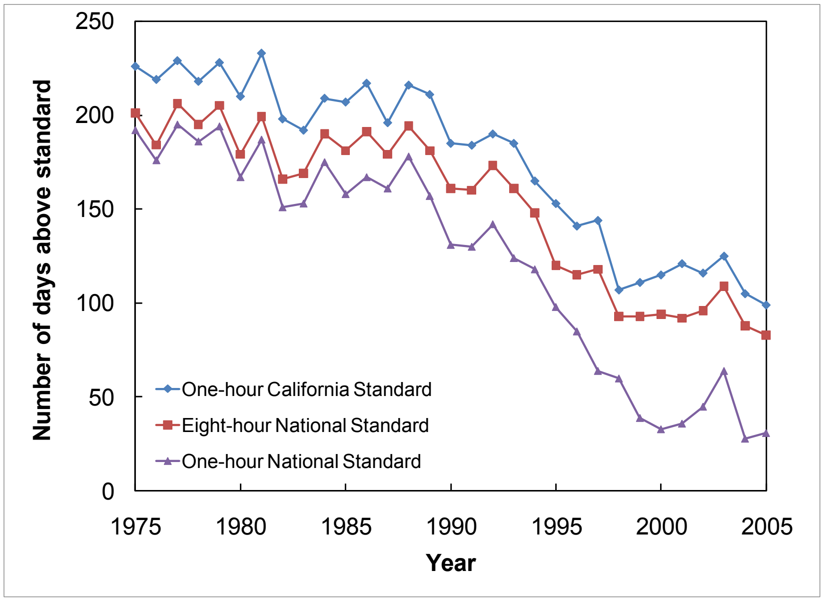


Figure 20: Number of Days the SoCAB Is Out of Compliance with the State and Federal Ozone Standards

Source: ARB 2006

5.2 Air Quality Modeling Formulation

Tropospheric ozone is a product of photochemistry that occurs between NO_x and VOCs in the ambient atmosphere in the presence of sunlight. In the SoCAB, NO_x and VOCs, the precursors of ambient ozone, are mostly emitted from anthropogenic sources such as on-road and off-road vehicles, power plants, and industrial operations, although there are significant biogenic sources of VOCs. The ambient level of ozone, on a regional scale, highly depends upon spatial and temporal profiles of precursor emissions, meteorological conditions, transport of precursors and reaction products through atmospheric transport mechanisms, and removal processes such as dry deposition and wet deposition. Therefore, comprehensive models that incorporate all these physical and chemical processes in detail, commonly known as Air Quality Models (AQMs), are widely used to understand and characterize the formation of ozone on regional scales. These models numerically solve a series of atmospheric chemistry, diffusion, and advection equations in order to determine ambient concentrations of pollutants over a given geographic region.

Most models employ an Eulerian representation (i.e., one that considers changes as they occur at a fixed location in the fluid, usually called a cell or control volume) of physical quantities on a three-dimensional computational grid. The atmospheric diffusion and advection equation for species m is given as:

$$\frac{\partial Q_m^k}{\partial t} = -\nabla \cdot \left(uQ_m^k\right) + \nabla \cdot \left(K\nabla Q_m^k\right) + \left(\frac{Q_m^k}{\partial t}\right)_{sources\ /\ sinks} + \left(\frac{Q_m^k}{\partial t}\right)_{aerosol} + \left(\frac{Q_m^k}{\partial t}\right)_{chemistry} \quad (9)$$

The above equation is numerically integrated in time for each species m, over a series of discrete time steps in each of the spatially distributed discrete cells of the AQM. Air quality models typically employ operator splitting, which is a numerical method that splits each term in Equation 9, so that each process is calculated separately, instead of calculating the entire differential equation at once (Yanenko 1971). Each term in the right-hand side of Equation 9 represents a major process in the atmosphere. From left to right: (1) advective transport due to wind transport, (2) turbulent diffusion due to atmospheric stability/instability, (3) emissions (sources) and deposition (sinks) of pollutants, (4) mass transfer between gas and aerosol phases, and (5) chemical reactions. The operator-splitting method is computationally efficient and has an added advantage of providing modularity to choose between various available parameterizations of atmospheric processes and numerical algorithms.

The outputs from AQMs are spatially and temporally resolved concentration profiles of major and trace species of interest over a geographic region. To minimize the effects of initial conditions and conduct various analyses, air quality modeling involves simulation of episodes involving multiple days. This modeling approach greatly facilitates study of various scenarios involving changes in emissions and associated impacts on the air quality in a particular region.

5.3 Air Quality Modeling of the SoCAB

The gas-phase chemical mechanism used in the present simulations is the Caltech Atmospheric Chemical Mechanism (CACM, see Griffin et al. 2002a). The CACM is based on the work of Stockwell et al. 1997; Jenkin et al. 1997; and Carter 2000a, and includes ozone chemistry and a state-of-the-art mechanism of the gas-phase precursors of secondary organic aerosol (SOA). The full mechanism consists of 361 chemical reactions and 191 gas-phase species, which describe a comprehensive treatment of VOC oxidation.

In the current work, inorganic aerosol formation was calculated using the Simulating Composition of Atmospheric Particles at Equilibrium 2 model (SCAPE2, Meng et al. 1995); organic aerosol formation is calculated using the Model to Predict the Multiphase Partitioning of Organics (MPMPO, Griffin et al. 2002b). The MPMPO allows the simultaneous formation of SOA in a hydrophobic organic phase and a hydrophilic aqueous phase. In addition, MPMPO modifies SCAPE2 to account for the interaction between organic ions present in the aqueous phase and the inorganic aerosol components. The module consists of 37 size-resolved aerosol-phase species, in eight different size bins ranging from 0.04 to 10 micrometers. The integrated module allows particulate matter to undergo advection, turbulent diffusion, condensation/evaporation, nucleation, emissions, and dry deposition processes.

The California Institute of Technology (CIT) Airshed Model has been updated and modified over the course of more than a decade of work at the University of California (UC), Irvine. This model, now dubbed the UCI-CIT Airshed Model, is used as the host model for the chemical and aerosol mechanisms (Harley et al. 1993; Griffin et al. 2002b; and Meng et al. 1998). The grid used by the UCI-CIT model encompasses Orange County and part of Los Angeles, Ventura, San Bernardino, and Riverside counties (Figure 21). The grid consists of cells with an area of 25 square kilometers (km^2). Additionally the vertical resolution is described through five vertical layers with the following dimensions from ground level upward: (1) 0 meters (m)–39 m, (2) 39 m–154 m, (3) 154 m–308 m, (4) 308 m–671 m, and (5) 671 m–1,100 m.

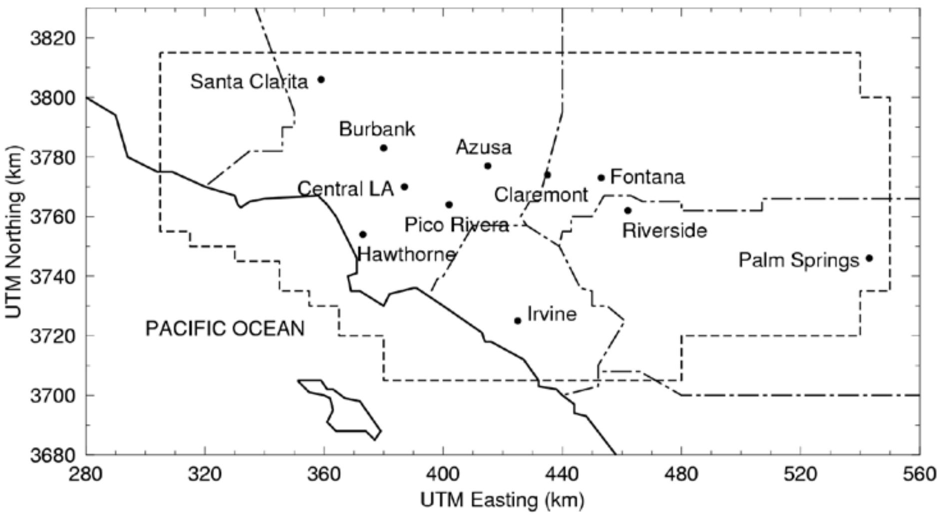


Figure 21: UCI-CIT Airshed Modeling Domain of the South Coast Air Basin of California

The Southern California Air Quality Study (SCAQS) was a comprehensive campaign of atmospheric measurements that took place in the SoCAB during August 27–29, 1987. The study collected an extensive set of meteorological and air quality data that has been used widely to validate air quality models (Meng et al. 1998; Griffin et al. 2002a; Griffin et al. 2002b; Moya et al. 2002). Zeldin et al. (1990) found that August 28, 1987 is representative of the meteorological conditions in the SoCAB, which makes it suitable for modeling. In addition, the August 27–28, 1987 episode is statistically within the top 10 percent of severe ozone-forming meteorological conditions. Hence, the meteorological conditions for August 28 are used here as the basis to evaluate air quality impacts of LNG emissions.

The SCAQS episode in August 27–29, 1987, was characterized by a weak onshore pressure gradient and warming temperatures aloft. The wind flow was characterized by a sea breeze during the day and a weak land-mountain breeze at night. The presence of a well-defined diurnal inversion layer at the top of neutral and unstable layers near the surface, along with a slightly stable nocturnal boundary layer, facilitated the accumulation of pollutants over the SoCAB, which lead to a high ozone concentration occurrence.

Model performance needs to be analyzed and compared with available observations, since simulation of an air quality episode requires various input parameters, each subject to some level of uncertainty. Griffin et al. (2002a) validated results obtained with the UCI-CIT model and the CACM chemical mechanism using the August 27–29, 1987, meteorology and emissions inventory. They also reported comparisons between observed and simulated data at Pasadena and Riverside. In general, ozone concentrations in Pasadena are under-predicted each day; whereas, NO_2 concentrations at this location compare reasonably well with observation, except for the third day. In Riverside, ozone concentrations agree with observed data for the second and third day. However, NO concentrations are under-predicted during the daylight hours and over-predicted at nighttime. A statistical analysis was conducted to determine the overall performance of the model versus observed data (see Table 8). Results show a typical level of agreement for current three-dimensional air quality models.

Table 8: Statistical Analysis of Model Performance Versus Observed Data on August 28, 1987, for Ozone and Nitrogen Oxides

Statistical Measure	O_3	NO_2
Bias, ppb	15.9	-0.4
Normalized bias, %	21.7	12.6
Sum of residuals, ppb	55.3	28.1
Gross error, ppb	39.5	21.4
Normalized gross error, %	41.1	51.6

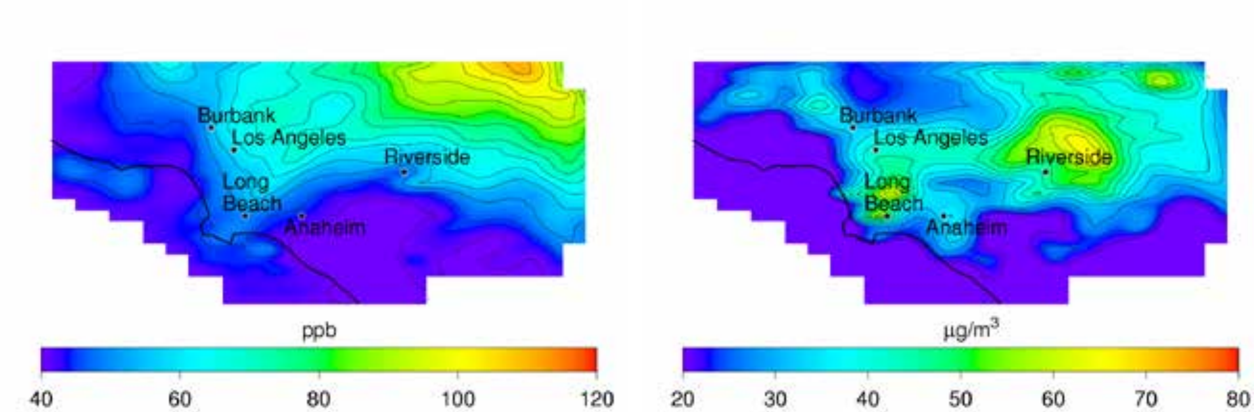
Source: From Griffin et al. 2002a

5.4 Baseline Air Quality in 2023

This section presents simulation results using the baseline emission inventory as received from the SCAQMD for the year 2023 and the meteorological conditions of the August 27–29, 1987, episode. Results show that ozone and $PM_{2.5}$ concentrations peak at locations downwind from Los Angeles. Carbon monoxide concentrations, however, peak in Central Los Angeles. Ozone, NO_2 and $PM_{2.5}$ peaks occur downwind from main emissions because they are secondary pollutants; whereas, CO is a primary pollutant, and its concentrations depend mainly on direct emissions.

Although baseline simulations for the year 2023 use emission inventories that have been developed for the 2007 AQMP to demonstrate attainment of ozone and $PM_{2.5}$ air quality standards, ozone and $PM_{2.5}$ concentrations exceed the established air quality standards (84 ppb ozone; 50 micrograms per cubic meter $PM_{2.5}$), as shown in Figure 22. The CACM chemical mechanism used in the CIT-UCI model predicts higher oxidative capacity that leads to higher concentrations of ozone than those predicted by other chemical mechanisms, such as SAPRC-99, which was used to produce the results in the AQMP (Jimenez et al. 2003).

The synoptic conditions in the SoCAB create a regime of circulation that favors transport of pollutants, emitted mainly in Los Angeles and Long Beach, toward the Northeast. In the northeastern part of the domain there are mountain ranges that trap the pollution arriving from upwind, leading to ozone accumulation. Near Riverside, a high density of dairy farms produces ammonia, which reacts with nitric acid formed via oxidation of nitrogen oxides emitted upwind. Nitric acid and ammonia react to form secondary particulate matter leading to the high $PM_{2.5}$near Riverside. Two other foci of $PM_{2.5}$ concentration develop near Central Los Angeles and the Port of Long Beach. The former is due to direct emissions from vehicles; whereas, the latter comes from the activity at the port, where there are high emissions from trucks and ships.



(a) (b)

Figure 22: Baseline Air Quality for the Year 2023: (a) 8-Hour Ozone Concentration, and (b) 24-Hour $PM_{2.5}$ Concentrations

5.5 Air Quality Resulting from Updating Area Sources Emissions Inventory

This sections presents simulation results from using the LBNL Baseline inventory. The updated inventory, using emission testing by LBNL, reduces the basin-wide emissions of NO_X by 2.1 tons/day. This reduction translates into a reduction of 1.8 percent in NO_X emissions with respect to the SCAQMD Baseline emissions inventory. The spatial distribution of the decrease in NO_X emissions is shown in Figure 23. In general, the decreases in emissions are due to changes in the emission factors for the residential natural gas sector. As a result, the largest decreases occur near Los Angeles, where the highest population density exists.

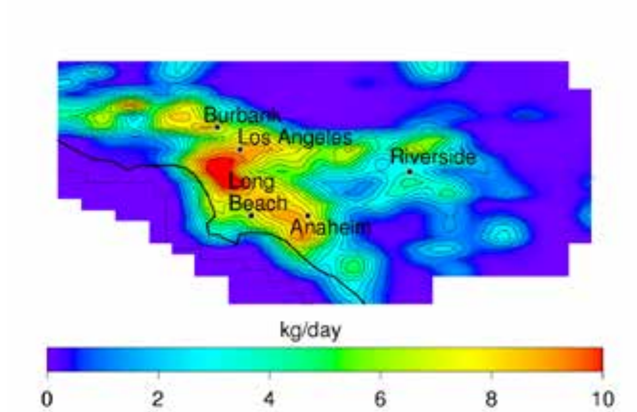
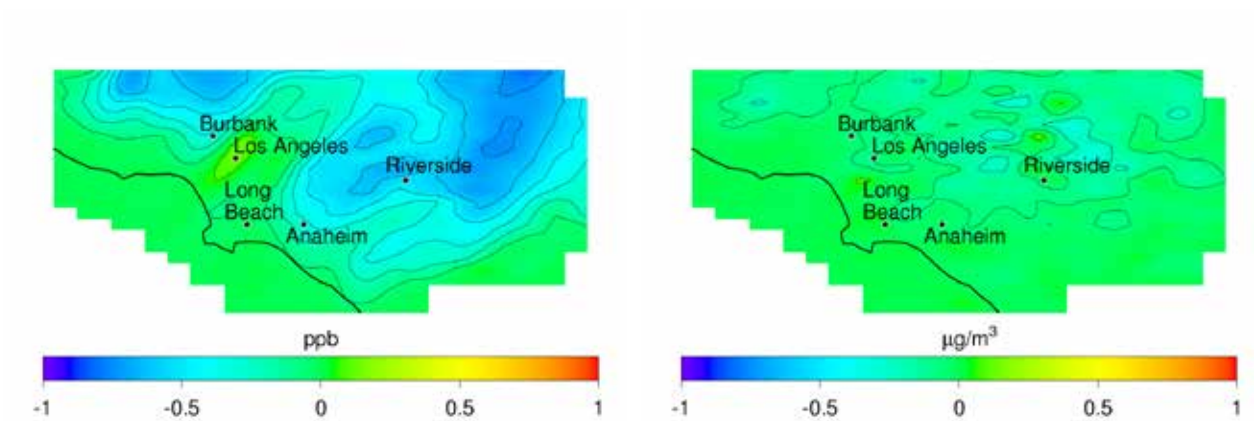


Figure 23: Decrease in Daily NO_X Emissions in the LBNL Baseline Emissions Inventory with Respect to the SCAQMD Baseline Inventory

Figure 24 shows the difference in the concentration of air pollutants calculated using the 2023 SCAQMD baseline inventory and the updated LBNL Baseline inventory. The decrease in NO_X emissions leads to a slight increase in ozone concentration around Los Angeles, due to the high overall amount of NO_X emissions and the VOC-limited regime in that area. In contrast, ozone concentration decreases in the eastern portion of the domain, where the highest ozone concentrations typically occur. Overall, the peak 8-hour ozone concentration in the LBNL Baseline case is 1 ppb lower than in the SCAQMD Baseline case. Due to the reduction of NO_X emissions and ozone concentrations around Riverside, $PM_{2.5}$ concentrations also decrease, by a maximum of 1 microgram per cubic meter.



(a) (b)

Figure 24: Difference in Air Pollutant Concentrations Baseline LBNL Minus Baseline SCAQMD: (a) Peak 8-Hour Average Ozone, (b) 24-Hour Average $PM_{2.5}$

Chapter 6: Air Quality Impacts of LNG

6.1 Air Quality Impacts of Expected LNG Penetration

The changes in emissions based on LNG use in the expected delivery scenarios, presented in Table 7, were very small. The highest increase in emissions due to LNG use occurred in Scenario 7, which estimated an increase of 92 kg of NO_X per day (0.08 percent with respect to total emissions). The lowest increase in emissions due to LNG occurred in Scenario 2, with an increase of 27 kg of NO_X per day (0.02 percent with respect to total emissions). As a result, the impacts on ozone and secondary particulate matter concentrations due to the use of LNG are very small, showing no change in the basin-wide average of peak ozone and $PM_{2.5}$ concentrations. Spatially, the maximum increase in peak ozone concentrations and 24-hour $PM_{2.5}$ concentrations are 0.5 ppb and 0.6 $\mu g/m^3$, respectively. Other areas of the modeling regions show decreases in these two concentrations of similar magnitude. Figure 25 and Figure 26 present the changes in peak ozone and 24-hour average $PM_{2.5}$ concentrations for the eight realistic delivery LNG scenarios. Table 9 summarizes the key values describing these results.

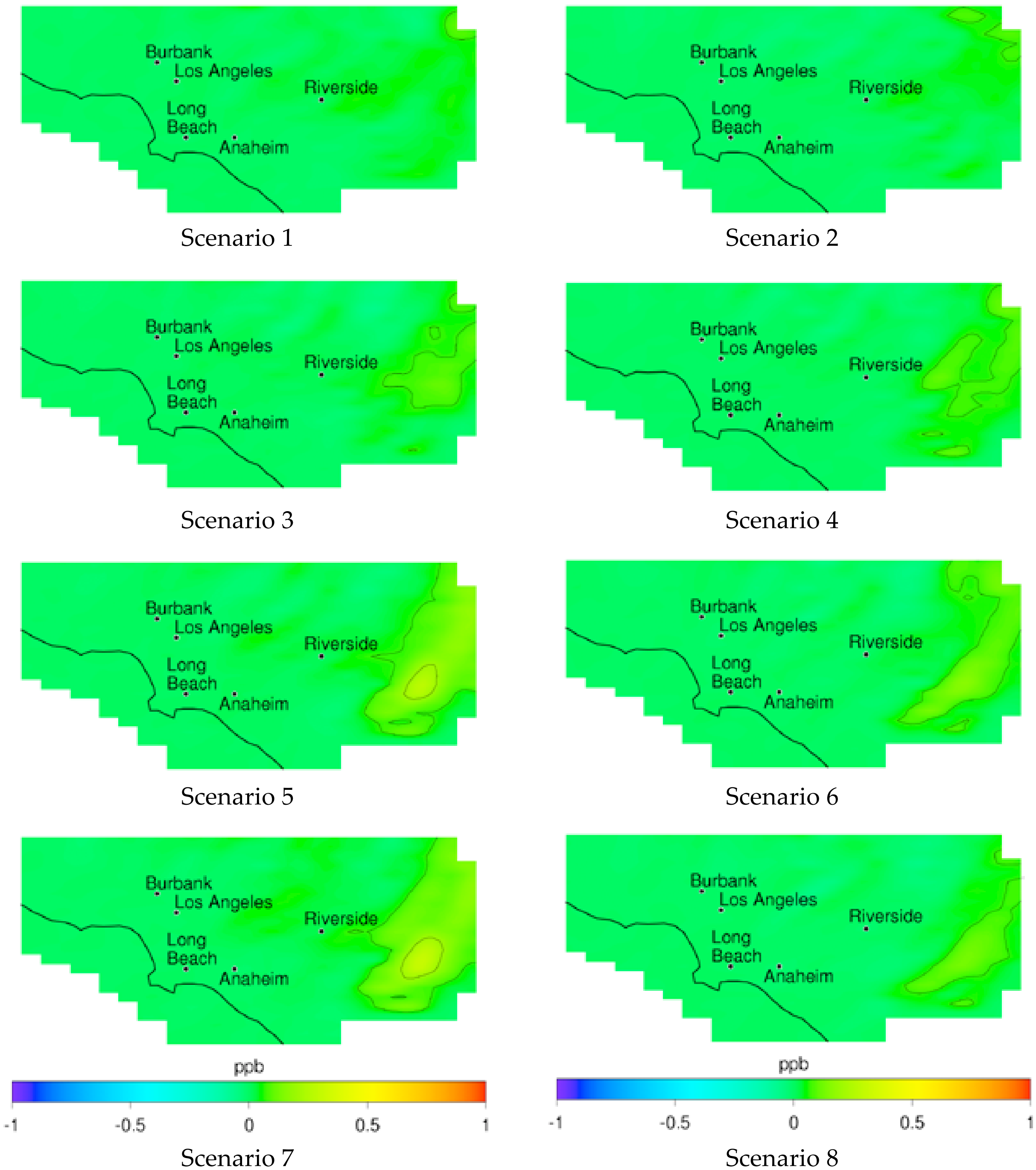


Figure 25: Changes to Peak Ozone Concentrations (ppb) of the Realistic LNG Scenarios Projected for the Year 2023

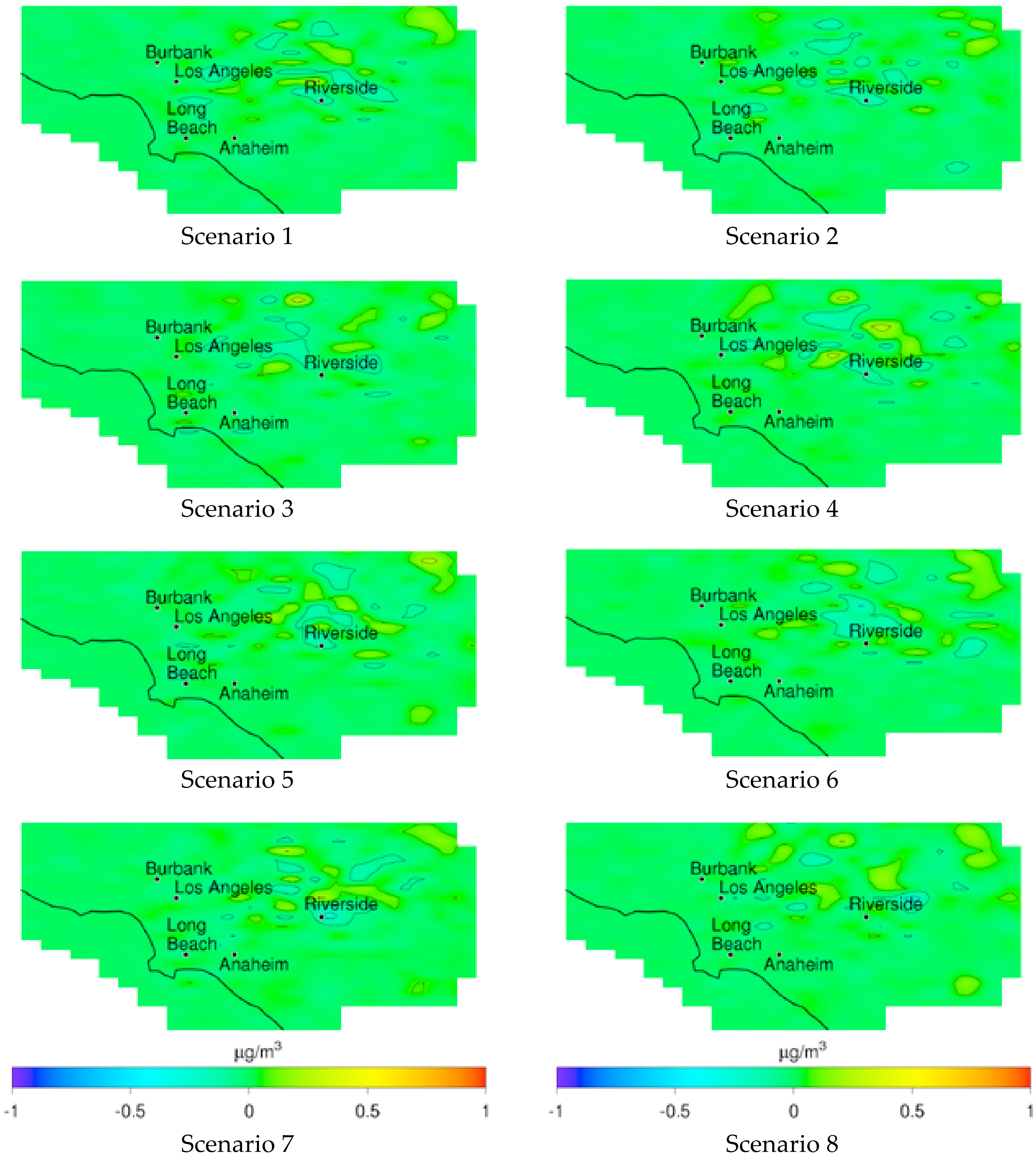


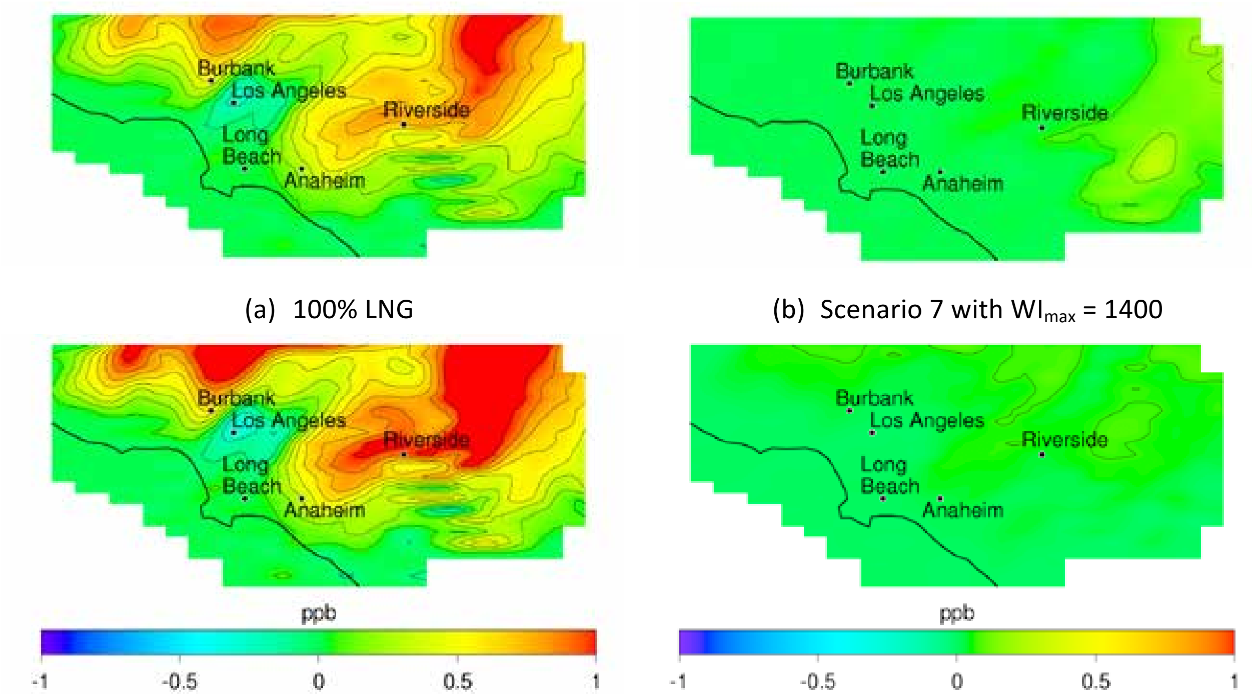
Figure 26: Changes to 24-Hour Average $PM_{2.5}$ (Micrograms Per Cubic Meter) Concentrations of the Realistic LNG Scenarios Projected for the Year 2023

6.2 Air Quality Impacts of Hypothetical Bounding Scenarios

As presented in Table 7, hypothetical bounding scenarios introduce significantly higher emissions due to LNG implementation that is greater than the realistic delivery scenarios. Scenario 100% LNG increased NO_X emissions by 2.5 percent, which led to an increase in the average model-predicted peak ozone concentrations of 0.4 ppb, and maximum increases in some locations in the model domain are 1.9 ppb (shown in Figure 27a). Scenario 100% LNG with WI_{max}=1400 increases emissions of NO_X by 3.2 percent, resulted in an increase in predicted peak ozone concentrations of 2.3 ppb (shown in Figure 27c). The impact on ozone concentration due to these two scenarios is an expected outcome of a moderate increase of NO_X emissions in the SoCAB. Increasing NO_X emissions led to a reduction of ozone concentrations around central Los Angeles and an increase in ozone concentrations farther downwind in the eastern segment of the domain, where typically the highest ozone concentrations occur. In addition, increases in ozone concentrations occurred in the northwestern part of the domain (Ventura County) due to high ozone productivity caused by incoming clean air from the coast and local NO_X emissions. Scenario 7 with WI_{max}=1400 presents impacts on ozone concentration that are comparable to Scenario 7, due to the overall small increase in NO_X emissions (with respect to LBNL Baseline). Finally, Scenario 100% LNG with Tuning presents the potential benefits of tuning NG commercial and industrial installations to minimize NO_X emissions.

As shown in Table 7, increase in NO_X emissions due to LNG use in conjunction with equipment tuning is less than 0.2 percent, even with 100 percent penetration of LNG. The resulting impacts on ozone concentrations are marginal, less than ±0.3 ppb. Even though the increase in volatile organic gases in the tuning case is the same as in the 100% LNG case, the emitted short-chain alkanes have low ozone production potential, as reported by Carter (2000b), based on VOC reactivity scales. As a result, the impact of fugitive emissions of VOC on ozone formation is marginal, even for a high penetration of LNG. It should be noted that it is uncertain how many facilities could implement the maintenance and equipment tuning necessary to use high Wobbe number LNG.

Figure 28 presents the impact of hypothetical bounding scenarios on 24-hour $PM_{2.5}$ concentrations. As in the case of ozone, scenarios 100% LNG and 100% LNG with WI_{max}=1400 lead to the highest model-predicted impacts. Scenario 100% LNG with WI_{max}=1400 increases the average model-predicted $PM_{2.5}$ by 0.1 $\mu g/m^3$, and maximum increase in $PM_{2.5}$ of less than 1 $\mu g/m^3$. As for ozone, tuning of equipment minimizes the impacts on secondary particulate matter, producing impacts that are comparable to the impacts caused by the realistic scenarios.



(a) 100% LNG

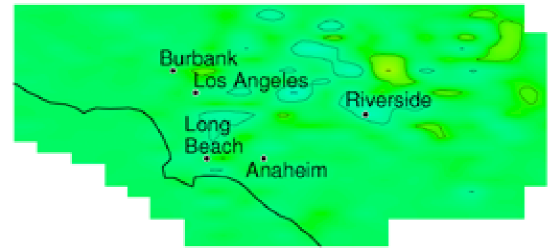
(b) Scenario 7 with WI_{max} = 1400

(c) 100% LNG with WI_{max} = 1400

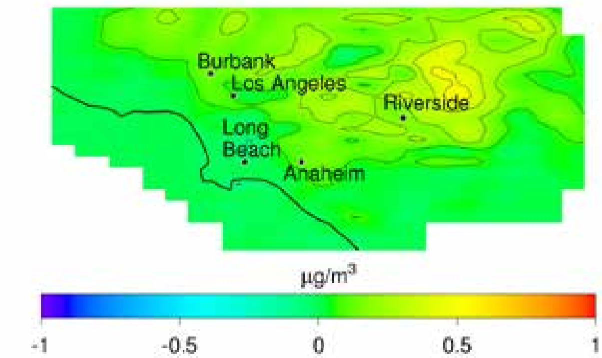
(d) 100% LNG with Tuning

Figure 27: Impacts on Peak Ozone Concentrations of the Hypothetical Bounding Scenarios for LNG Implementation Projected for the Year 2023

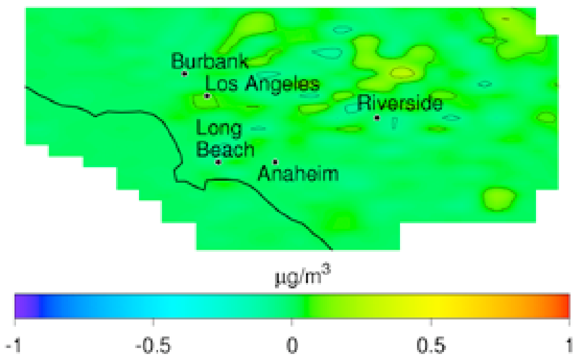
100% LNG



Scenario 7 with WI_{max} = 1400



100% LNG with WI_{max} = 1400



100% LNG with Tuning

Figure 28: Impacts on 24-Hour Average $PM_{2.5}$ Concentrations of the Hypothetical Bounding Scenarios for LNG Implementation Projected for the Year 2023.

Table 9: Summary of impacts on peak ozone and 24-hour $PM_{2.5}$ due to LNG scenarios

Case	$\Delta[O_3]_{max}$ (ppb)			$\Delta[PM_{2.5}]_{24\text{-}hour}$ ($\mu g/m^3$)		
	Average	**Maximum**	**Minimum**	**Average**	**Maximum**	**Minimum**
Future LNG Distribution Scenarios						
Scenario 1	0.01	0.30	-0.20	0.00	0.33	-0.44
Scenario 2	0.00	0.30	-0.20	0.00	0.52	-0.37
Scenario 3	0.00	0.30	-0.30	0.00	0.58	-0.37
Scenario 4	0.01	0.40	-0.20	0.00	0.49	-0.38
Scenario 5	0.03	0.34	-0.13	0.00	0.56	-0.56
Scenario 6	0.01	0.50	-0.20	0.00	0.41	-0.46
Scenario 7	0.03	0.42	-0.22	0.00	0.55	-0.36
Scenario 8	0.01	0.30	-0.20	0.00	0.47	-0.47
Hypothetical Bounding Scenarios						
100% LNG	0.36	1.90	-0.99	0.07	0.66	-0.39
Scenario 7 (WI_{max}=1400)	0.03	0.45	-0.20	0.00	0.46	-0.35
100% LNG (WI_{max}=1400)	0.46	2.27	-1.23	0.09	0.66	-0.21
100% LNG with Tuning	0.03	0.30	-0.13	0.01	0.49	-0.33

Chapter 7: Conclusions

With the growing demand for natural gas in California, the state has been investigating additional sources for natural gas. One alternative is to import liquefied natural gas (LNG) into California from overseas. An important concern arising from the increased use of LNG is the potential impact of the changes of natural gas composition on emissions and exposure to these emissions. The overall aim of the research presented in this report was to evaluate the possible changes in air pollutant emissions in the South Coast Air Basin of California due to the use of LNG and the impact of these emissions on air quality. The work presented here integrates laboratory measurements obtained by LBNL and SoCalGas with current emissions inventories generated by the SCAQMD to determine spatially and temporally resolved emission changes due to the use of LNG in natural gas combustion processes. The spatial extent of LNG receipt in the SoCAB modeling domain due to LNG delivery from the Energía Costa Azul terminal is estimated for a number of realistic NG use scenarios, as well as for four hypothetical bounding scenarios. The resulting emissions and spatial use scenarios are used as inputs to a state-of-the-art air quality model to determine the potential impacts of LNG on ozone and secondary particulate matter formation.

7.1 Update of Emissions Inventory Based on Measurements

A baseline emission inventory for the SoCAB for the year 2023 was obtained from the SCAQMD. This inventory was developed as part of a plan to meet U.S. federal ambient air quality standards and did not include any impacts of LNG. The area and point source components to this inventory were calculated with emission factors from the U.S. Environmental Protection Agency AP-42 compilation and annual emissions reported to the district for specific facilities.

While compiling emission information on natural gas sources for the current work, it became clear that, in general, the natural gas sector is one that lacks the type of emissions testing data to support emission factors for the range of combustion technologies in use. This is perhaps unsurprising since natural gas-fueled area and point sources are projected to account for only about 13 percent of the total NO_x in the basin, with mobile sources accounting for the vast majority of the remainder. Of particular importance is the use of a single emission factor for all residential appliances based on measurements of residential furnaces in the 1970s. The residential appliance experiments performed by LBNL provided technology specific emission factors that were used to update the baseline SCAQMD emission inventory. For most technologies, the more relevant NO_x emission factors were lower than the AP-42 values. Updating the emission factors for residential natural gas appliances used in the original inventory with emission factors obtained in experimental measurements decreased projected nitrogen oxides emissions by a total of 2.4 tons/day in the SoCAB. This reduction translates to a reduction of 1.2 percent in projected NO_x emissions from all sources in the basin.

7.2 Impacts of LNG on Emissions

A set of eight realistic scenarios were selected to represent the expected distribution of LNG into the SoCAB from the Energía Costa Azul terminal. The parameters in these scenarios were used as inputs into a SoCalGas transmission system model that resulted in predicted penetration of LNG into the modeling domain. The results show that the penetration of natural gas to the SoCAB is limited. A large portion of the LNG introduced in the system will be absorbed by the natural gas demand in Mexico and San Diego, with San Diego receiving close to 100 percent re-gasified LNG in all eight scenarios. The spatial extent of LNG into the SoCAB is restricted to southeast Riverside County, with limited amounts reaching San Bernardino and Los Angeles counties. These eight scenarios are used as the basis for assessing expected impacts of LNG use on ambient air quality in the SoCAB. In addition, four hypothetical bounding scenarios were included to investigate whether LNG use at any plausible scale would have substantial impacts on overall emissions and ambient air quality.

The results show that the impacts of LNG on emissions of NO_x and CO in the SoCAB for the realistic LNG distribution scenarios developed by SoCalGas will be marginal. The scenario with the largest amount of LNG penetration (Scenario 7, which reflects the maximum supply of LNG from the ECA terminal, typical summer demand), and minimum receipts of NG from El Paso through Blythe, would result in an increase in NO_x of 0.092 tons/day, corresponding to 0.08 percent of the total NO_x emissions in the basin. Emissions of CO and short-chain alkanes also would increase marginally, by less than 0.01 percent.

The hypothetical scenario with the largest potential impact is 100 percent LNG penetration into the basin, which results in an increase of NO_x emissions of 2.8 tons/day and corresponds to a 2.5 percent increase in total basin-wide NO_x emissions. It is important to note that additional LNG facilities would be required to reach this level and that this increase in emissions is of the same order as the difference between the SCAQMD baseline inventory and the emissions inventory updated with the measurements by LBNL. In addition, 100 percent penetration of LNG increases emissions of CO and short-chain alkanes by 2.6 and 1.0 tons/day, respectively.

The implementation of tuning strategies to adjust equipment to changes in Wobbe number in commercial and industrial installations would reduce the impacts of LNG even in high penetration cases. Even though tuning of equipment would not avoid fugitive emissions from LNG distribution, adjustment of NO_x emissions could practically offset the potential increases in NO_x emissions due to changes in widespread LNG use. It should be noted that it is uncertain how many facilities could implement the maintenance and equipment tuning necessary to use high Wobbe number LNG.

7.3 Impacts of LNG on Air Quality

The air quality impacts were calculated using the UC Irvine/California Institute of Technology Airshed model. The basis for analysis is a summer episode where ozone concentration is typically the highest and will be the most sensitive to changes in emissions. In particular, increases in NO_x emissions due to the use of LNG could lead to increases in ozone and secondary particulate matter concentrations that would affect compliance with air quality standards in the SoCAB.

The changes in emissions based on LNG use in the eight realistic delivery scenarios were very small. As a result, the impacts on ozone and secondary particulate matter concentrations due to the use of LNG are not discernable. The average change in ozone concentration for all of the realistic scenarios was less than 0.03 ppb, with no predicted change in the domain-wide average of the 24-hour average $PM_{2.5}$ concentration. The predicted change in ozone concentration varied spatially across the modeling domain, ranging from -0.3 ppb to 0.5 ppb. The spatial variability in the predicted 24-hour $PM_{2.5}$ concentrations varied from -0.6 $\mu g/m^3$ to 0.6 $\mu g/m^3$. Note that the location of the increase often occurs in areas with the highest pollution levels.

The hypothetical scenario with 100% LNG penetration resulted in an increase in the average ozone concentration of 0.36 ppb and in the 24-hour average $PM_{2.5}$ concentration of 0.07 $\mu g/m^3$. The spatial variability across the modeling domain of ozone concentration ranged from 1.90 to -0.99 ppb and $PM_{2.5}$ ranged from 0.66 to -0.39 $\mu g/m^3$. These increases are primarily due to the increase in NO_X emissions of 2.5 percent. The emissions that would result from increasing the Wobbe index limit to 1400 enhance ozone formation; for this theoretical scenario the model predicted an increase in the average ozone concentration of 0.46 ppb. Tuning of equipment is estimated to counter most of the increase in NO_X emissions, with a resulting impact on ozone and PM formation that is less than the scenario with maximum realistic LNG delivery and no mitigation. Even though fugitive emissions of VOC would not be avoided by tuning strategies, these compounds have low ozone potential, and the impacts on air quality of 100 percent LNG penetration with tuning are comparable to the impacts of low LNG penetration scenarios.

These results indicate that the impact of LNG on overall basin-wide nitrogen oxides emissions should be very small, and may be below the level at which the models can discern. Indeed, even when the SoCAB is assumed to receive a hypothetical 100 percent LNG, the impact on the ozone concentrations are marginal, and may be within the predictive error limits of the model. In fact, the emission factors for the natural gas sector in general lack the test data necessary to provide robust emission factor calculations necessary for robust model predictions at the changes in concentrations predicted for LNG use. The difference in emissions between the 2023 SCAQMD baseline and the LBNL Baseline is of the same order of magnitude as that predicted by the hypothetical 100 percent LNG penetration. Thus, the available emissions data and air quality model results suggest no significant impact of LNG use on air quality in the South Coast Air Basin.

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9. Glossary

ALKL	Alkanes
APCD	Air Pollution Control District
AQM	Air Quality Models
AQMD	Air Quality Management District
AQMP	Air Quality Management Plan
ARB	California Air Resources Board
Btu	British Thermal Unit
CACM	California Institute of Technology Chemistry Mechanism
CF	Control Factor
CIT	California Institute of Technology
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CPUC	California Public Utility Commission
ECA	Energía Costa Azul
EIC	Emission Inventory Code
Energy Commission	California Energy Commission
GTI	Gas Technology Institute

LBNL	Lawrence Berkeley National Laboratory
LNG	Liquefied Natural Gas
MMcf	Million Cubic Feet
MPMPO	Model to Predict the Multiphase Partitioning of Organics
NAAQS	National Ambient Air Quality Standards
NG	Natural Gas
NMHC	Non-Methane Hydrocarbon
NOx	Nitrogen Oxides
PM	Particulate Matter
ppb	Parts per Billion
SCAPE2	Simulating Composition of Atmospheric Particles at Equilibrium 2 model
SCAQMD	Southern California Air Quality Management District
SCAQS	Southern California Air Quality Study
SCC	Standard Classification Code
scf	Standard Cubic Foot
SCG	Southern California Gas Company
SDG&E	San Diego Gas and Electric
SIC	Standard Industrial Classification
SoCAB	South Coast Air Basin
SOx	Sulfur Oxides
UCI	University California at Irvine
U.S. EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds