SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Preliminary Staff Report for

PROPOSED RULE 433 – NATURAL GAS QUALITY

March 2009

Executive Officer
Barry R. Wallerstein, D.Env.

Deputy Executive Officer
Planning, Rule Development, and Area Sources
Elaine Chang, DrPH

Assistant Deputy Executive Officer
Planning, Rule Development, and Area Sources
Laki Tisopulos, Ph.D., P.E.

Author: Martin Kay, P.E., M.S., Program Supervisor

Reviewed by: Kurt Wiese, General Counsel
Kavita Lesser, Deputy District Counsel II

TABLE OF CONTENTS

TABLE OF CONTENTS (CONTINUED)

CHAPTER 1: BACKGROUND

- SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
- 2007 AQMP
- NATURAL GAS UTILITIES
- NATURAL GAS
- NATURAL GAS REGULATIONS
- NATURAL GAS QUALITY ISSUES
- LIQUEFIED NATURAL GAS

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

The South Coast Air Quality Management District (AQMD) is the air pollution control agency for all of Orange County and the urban portions of Los Angeles, Riverside and San Bernardino counties. This area of about 10,000 square miles is home to nearly 16 million people. It is the second most populated urban area in the United States and one of the smoggiest.

AQMD is responsible for controlling emissions primarily from nonvehicular sources of air pollution. These can include anything from large power plants and refineries to the local dry cleaner. Emission standards for mobile sources are established by the state or federal agencies, such as the California Air Resources Board (CARB) and the U.S. Environmental Protection Agency (EPA), rather than by local agencies such as the AQMD.

Under the Federal Clean Air Act, EPA establishes health-based ambient air quality standards that all states must achieve. The California Clean Air Act establishes additional standards to be met. AQMD develops plans to achieve these public health standards and adopts and implements regulations to reduce stationary source emissions in accordance with the plan.

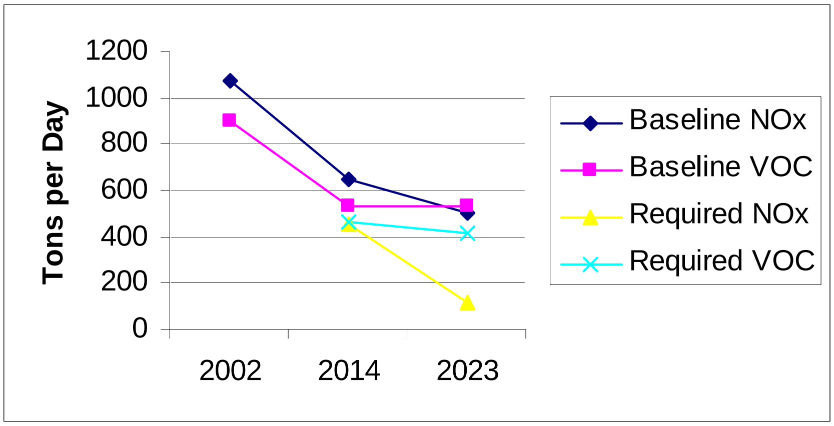
2007 AQMP

The AQMD is required to prepare an Air Quality Management Plan (AQMP) and periodically revise it to achieve the ambient air quality standards. AQMD approved the 2007 AQMP, whose primary purpose is to achieve compliance with the new federal 8-hour ozone and fine particulate (PM2.5) ambient air quality standards. These new ambient air quality standards are more stringent than the previous 1-hour ozone standard and PM10 standards, and they require more emission reductions than the old standards. However, the new standards do allow some additional time to comply: 2015 for the PM2.5 standards, and 2024 for the ozone standard.

Although air quality in the AQMD will continue to improve in future years, the existing local, state and federal regulations will not be adequate to achieve the new ambient air quality standards. Significant additional reductions of volatile organic compounds (VOC), oxides of nitrogen (NOx), oxides of sulfur (SOx) and PM2.5 are needed to attain the federal air quality standards and to protect public health. All four pollutants contribute to PM2.5 levels, directly or indirectly through reactions that form secondary PM2.5 in the atmosphere, while VOC and NOx are precursors to ozone formation.

Figure 1 shows the projected baseline emissions of NOx and VOC, based on current regulations, and the emission levels that need to be reached to achieve the PM2.5 standards in 2015 and the ozone standard in 2024. In order to meet these federally-mandated standards, the emission reductions must be achieved by 2014 and 2023. Although NOx and VOC will be significantly lower in 2014 than current levels, they must be reduced another 78% and 22%, respectively, by 2023. In addition, SOx emissions must be reduced by 56% from baseline levels and direct PM2.5 emissions by 14% by 2014 to achieve the PM2.5 standards.

Figure 1 – NOx and VOC Baseline Emissions and Emission Reductions Needed to Achieve the PM2.5 and Ozone Standards



NATURAL GAS UTILITIES

The natural gas utilities in the AQMD area include the municipal gas utilities in the Cities of Vernon and Long Beach, and the investor-owned utilities of Southwest Gas Corporation and Southern California Gas Company.

Southwest Gas is a small utility serving San Bernardino desert areas outside AQMD as well as the communities around Big Bear Lake in AQMD.

Southern California Gas Company (SoCalGas)

SoCalGas is the largest gas utility in Southern California, serving 20 million people in the counties of Los Angeles, Orange, Riverside, San Bernardino, Imperial, Ventura, Santa Barbara, San Luis Obispo, Fresno, Kern, Kings and Tulare, or portions thereof. Figure 2 shows a map of the SoCalGas service territory, although it does not show the other three gas utilities previously mentioned. SoCalGas, along with Sempra LNG and San Diego Gas & Electric Company, are subsidiaries of Sempra Energy.

Figure 2 – SoCalGas Service Area

NATURAL GAS

What is Natural Gas?

Natural gas is the predominate fuel used by stationary sources in AQMD. Natural gas is considered to be a “clean” fuel, compared to other fossil fuels such as fuel oil and coal. As a result of the 1988 adoption of AQMD’s Clean Fuels Policy, and adoption of stationary source rules based on the use of natural gas, very little oil or coal is burned by stationary sources in AQMD.

Rule 431.1 defines natural gas as “a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the California Public Utilities Commission.”

Where Does Natural Gas Come From?

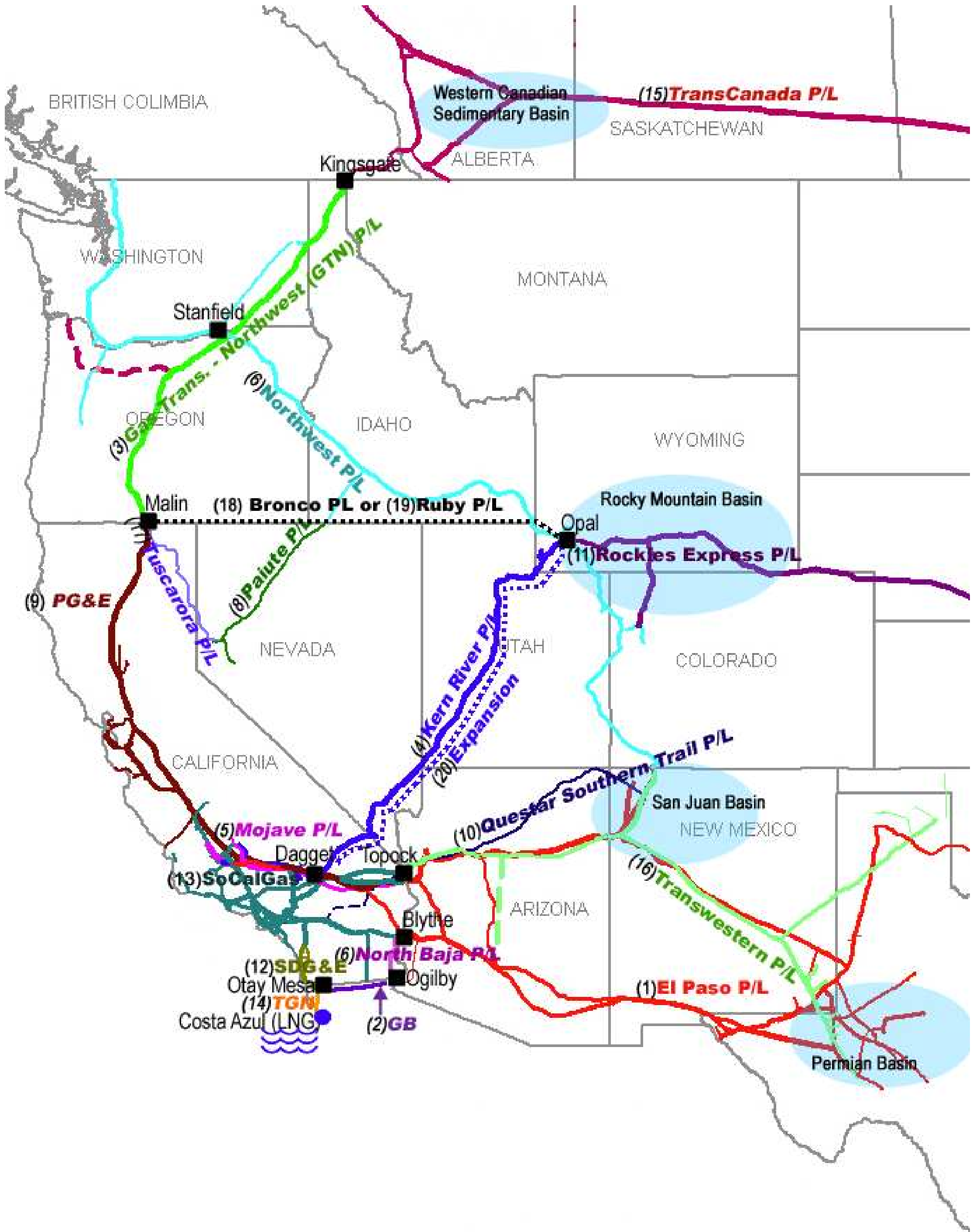
Natural gas is produced in gas wells and by some oil wells. Less than 15% of the natural gas used in California is produced in California. According to the California Energy Commission, the sources of natural gas used in the State are as follows.

Table 1 - Sources of Natural Gas Used in California in 2006

	Million Cubic Feet Per Day
California Production	860
Canada	1,371
Southwest	2,380
Rocky Mountains	1,421
Total	**6,032**

The various pipelines that bring natural gas to California are shown in the figure on the following page.

Figure 3 - Western North American Natural Gas Pipelines



In operation:		Proposed:
1. El Paso Natural Gas	9. Pacific Gas Electric Company	18. Bronco Pipeline
2. Gascoducto Bajanorte (GB)	10. Questar Southern Trail Pipeline	19. Ruby Pipeline
3. Gas Transmission Northwest (GTN)	11. Rockies Express (REX)	
4. Kern River Pipeline	12. San Diego Gas &Electric Company	20. Kern River Expansion
5. Mojave Pipeline	13. Southern California Gas Company	
6. North Baja Pipeline	14. Transportadora de Gas Natural (TGN)	**Source: 2008 California Gas Report**
7. Northwest Pipeline	15. TransCanada Pipeline	
8. Paiute Pipeline	16. Transwestern Pipeline	
	17. Tuscarora Pipeline	

What is the Composition of Natural Gas?

Although natural gas is primarily methane (CH_4), there are other components that affect the combustion characteristics and emissions of natural gas. These other components include:

- Higher hydrocarbons such as ethane (C_2H_6), propane (C_3H_8), and butane (C_4H_{10}), which increase the heating value of natural gas;
- Inert compounds such as carbon dioxide (CO_2) and nitrogen (N_2) which reduce the heating value of natural gas;
- Oxygen (O_2); and
- Trace sulfur compounds, such as mercaptans, which are intentionally added to give an odor to the normally odorless natural gas.

NATURAL GAS REGULATIONS

AQMD Rule 431.1

The AQMD Board adopted Rule 431.1 – Sulfur Content of Gaseous Fuels on November 4, 1977 and has subsequently amended the rule several times with the most recent amendment being June 12, 1998. The purpose of the rule is to reduce sulfur oxides emissions from the burning of gaseous fuels in stationary equipment located in the AQMD. The rule applies to gaseous fuels such as digestor gas, landfill gas, refinery gas and natural gas. Paragraph (c)(1) of the rule includes the following requirement for natural gas:

> "A person shall not transfer, sell or offer for sale for use in the jurisdiction of the District natural gas containing sulfur compounds calculated as H_2S in excess of 16 parts per million by volume (ppmv)."

Any hydrogen sulphide or other sulfur compounds are converted to sulfur dioxide or sulfur trioxide when burned. Based on an average natural gas consumption of 2 billion cubic feet per day (bcfd) in the AQMD, this limits natural gas SOx emissions to 2.7 tons/day. Total SOx emissions are estimated to be 40.9 tons/day in 2008.

California Public Utilities Commission (CPUC) General Order 58-A

CPUC regulations only apply to investor-owned utilities such as SoCalGas and do not apply to municipal gas utilities. CPUC's General Order 58-A: STANDARDS FOR GAS SERVICE IN THE STATE OF CALIFORNIA establishes many ground rules for gas utilities.

Sections 6 and 7 of General Order 58-A regulate the quality of natural gas. These sections are provided in their entirety in Appendix A of this report. Section 6 – Heating Value of Fuel Gas requires gas utilities to develop a plan that:

1. Establishes distinct distribution system areas in which a uniform quality of gas will be supplied.
2. Identifies a heating value range for each such area.

3. Provides for verification of the average heating value of the gas supplied to each area, at intervals frequent enough to assure that the heating value is being maintained within the heating value range established for the area.

3. Requires that records be kept for three years.

These requirements give gas utilities wide latitude in deciding how to maintain a "uniform quality" of natural gas.

Section 7 – Purity of Gas establishes concentration limits for hydrogen sulfide and total sulfur. For natural gas derived from landfill gas, there is also a vinyl chloride concentration limit.

Southern California Gas Company (SoCalGas) Rule 30

Southern California Gas Company's Rule 30 – Transportation of Customer-Owned Gas establishes the general terms and conditions that apply whenever SoCalGas transports customer-procured gas (i.e., large natural gas users who purchase gas directly from an energy supplier rather than from SoCalGas) over its distribution system. Under Section I – Gas Delivery Specifications, Rule 30 further sets some standards for natural gas quality (Section I can be found in its entirety in Appendix B of this report). SoCalGas Rule 30 was approved by the CPUC.

SoCalGas Rule 30 imposes the following natural gas quality requirements on interstate pipelines, and, to a lesser extent, on in-state producers that deliver gas into the SoCalGas distribution system:

a. Heating Value: From 990 to 1150 Btu (gross) per standard cubic foot on a dry basis.

b. Moisture Content or Water Content: Maximum of seven or 20 pounds per million standard cubic feet, depending on delivery pressure.

c. Hydrogen Sulfide: Maximum of 0.25 grains of hydrogen sulfide, measured as hydrogen sulfide, per one hundred (100) standard cubic feet (4 ppm).

d. Mercaptan Sulfur: Maximum of 0.3 grains of mercaptan sulfur, measured as sulfur, per hundred standard cubic feet (5 ppm).

e. Total Sulfur: Maximum of 0.75 grains of total sulfur compounds, measured as sulfur, per one hundred (100) standard cubic feet (12.6 ppm).

f. Carbon Dioxide: Maximum of 3% by volume.

g. Oxygen: Maximum of 0.2% by volume.

h. Inerts: Maximum of 4% total inerts (the total combined carbon dioxide, nitrogen, oxygen and any other inert compound) by volume.

i. Hydrocarbons: Maximum gas hydrocarbon dew point of 45 or 20 degrees F depending on the delivery pressure.

j. Merchantability: No dust, sand, dirt, gums, oils and other substances injurious to SoCalGas facilities or that would cause gas to be unmarketable.

k. Hazardous Substances: No hazardous substances (including but not limited to toxic and/or carcinogenic substances and/or reproductive toxins) concentrations which would prevent or restrict the normal marketing of gas, be injurious to pipeline facilities, or which would present a health and/or safety hazard to SoCalGas employees and/or the general public.

l. Delivery Temperature: The gas delivery temperature is not to be below 50 degrees F or above 105 degrees F.

m. Interchangeability: Wobbe Number from 1279 to 1385. The gas shall meet American Gas Association's Lifting Index, Flashback Index and Yellow Tip Index interchangeability indices for high methane gas relative to a typical composition of gas in the SoCalGas system serving the area.

Acceptable specification ranges are:

Lifting Index (IL): IL <= 1.06

Flashback Index (IF): IF <= 1.2

Yellow Tip Index (IY): IY >= 0.8

n. Liquids: No liquids at or immediately downstream of the receipt point.

o. Landfill Gas: Gas from landfills will not be accepted or transported.

p. Biogas: Biogas refers to a gas made from anaerobic digestion of agriculture and/or animal waste. The gas is primarily a mixture of methane and carbon dioxide. Biogas must be free from bacteria, pathogens and any other substances injurious to utility facilities or that would cause the gas to be unmarketable and it shall conform to all gas quality specifications identified in this Rule.

The key specification is the Wobbe Number range of 1279 to 1385 Btu/scf, which is equivalent to 1332 Btu/scf ± 4.0%. This Wobbe Number range, and the other specifications, resulted from the September 21, 2006 CPUC Decision 06-09-039 in Rulemaking 04-01-025.

Because some natural gas produced and used in California at the time of the CPUC decision exceeded the 1385 Wobbe Number maximum, the decision required and Rule 30 allows for a generic deviation from the Rule 30 minimum gas quality specifications for California natural gas producers. California producers (offshore or onshore) producing as of January 1, 2006 are allowed to comply with the less-stringent requirements of SoCalGas Rule No. 30 in effect on September 21, 2006, or, to the extent that production had a deviation in place at that time, to the agreement governing that deviation.

Although a previous version of SoCalGas Rule 30 allowed a much wider Wobbe Number range of ± 10.0%, the Wobbe Number was not a limiting factor for California producers because the 1150 Btu/scf limit on heating value essentially limited the Wobbe Number to a maximum of approximately 1435.

It is also noteworthy that the Rule 30 maximum total sulfur specification of 12.6 ppm is more stringent than AQMD's 16 ppm limit in Rule 431.1.

NATURAL GAS QUALITY ISSUES

Why Are There Concerns about the Composition of Natural Gas?

In 2005, a group of natural gas industry stakeholders organized by the Natural Gas Council[1] (NGC) and called NGC+, released a "white paper" (Reference 1) (hereinafter referred to as "NGC+ White Paper") on natural gas interchangeability. "Interchangeability" is defined in the report as:

> "The ability to substitute one gaseous fuel for another in a combustion application without materially changing operational safety, efficiency, performance or materially increasing air pollutant emissions." Reference 1, p. 2

The report was initiated because of concerns raised by the natural gas industry regarding current and potential changes to the composition of natural gas due to importation of liquefied natural gas, development of unconventional gas supplies such as shale gas and coal seam gas, and other factors. The objective of the NGC+ White Paper was "to define acceptable ranges of natural gas characteristics that can be consumed by end users while maintaining safety, reliability, and environmental performance." NGC+ White Paper, p. 4. Accordingly, the report examined the impact of changing natural gas quality on end-use equipment including appliances, industrial boilers, reciprocating engines, and non-combustion uses.

Notably, the report identified a number of undesirable effects on combustion equipment that can result from changing natural gas composition, including the following:

- "In appliances, it can result in soot formation, elevated levels of carbon monoxide and pollutant emissions, and yellow tipping. It can also shorten heat exchanger life, and cause nuisance shutdowns from extinguished pilots or tripping of safety switches." *Id*. p. 4
- "In reciprocating engines, it can result in engine knock, negatively affect engine performance and decreased parts life." *Id*. at p. 5
- "In combustion turbines, it can result in an increase in emissions, reduced reliability/availability, and decreased parts life." *Id*. at p. 5
- "In appliances, flame stability issues including lifting are also a concern." *Id*. at p. 5
- "In industrial boilers, furnaces and heaters, it can result in degraded performance, damage to heat transfer equipment and noncompliance with emission requirements." *Id*. at p. 5

What Were the Recommendations of the NGC+ White Paper?

The NGC+ White Paper recommended the following Interim Guidelines for natural gas interchangeability. These guidelines reflect merely recommendations rather than mandatory requirements:

---

[1] Members of the Natural Gas Council include the American Gas Association, Interstate Natural Gas Association of America, Independent Petroleum Association of America, and the Natural Gas Supply Association.

"A. A range of plus and minus 4% Wobbe Number Variation from Local Historical Average Gas or, alternatively, Established Adjustment or Target Gas for the service territory. (Note 1)

Subject to:

Maximum Wobbe Number Limit: 1,400 (Note 2)

Maximum Heating Value Limit: 1,110 Btu/scf (Note 2)

B. Additional Composition maximum limits: (Note 1)

Maximum Butanes+: 1.5 mole percent

Maximum Total Inerts: 4 mole percent

C. EXCEPTION: Service territories with demonstrated experience (Note 3) with supplies exceeding these Wobbe, Heating Value and/or Composition Limits may continue to use supplies conforming to this experience as long as it does not unduly contribute to safety and utilization problems of end use equipment.

Notes:

1 Experience has shown that using this plus/minus four percent formula in combination with the compositional limits will result in a local Wobbe range that is above 1,200.

2 Based on gross or higher heating value (HHV) at standard conditions of 14.73 psia, 60°F, dry, real basis.

3 Demonstrated experience refers to actual end use experience established by end-use testing and monitoring programs." *Id*. at p. 27

The NGC+ White Paper's recommendations were based on data and analysis of traditional gas appliances, but lacked data on gas interchangeability for a broad range of other end-use applications. As such, the report recommended interim guidelines and identified major data gaps to be filled within three (3) years of the report's issue date. After that time period, it was envisioned that development of more complete and longer-term guidelines could be pursued. Notably, the NGC filed its report on February 26, 2005 and to date, no subsequent guidelines have been issued.

What is the Wobbe Number?

The Wobbe Number, also known as the Wobbe Index, is one of the most important characteristics of natural gas in terms of natural gas interchangeability and its effects on air pollutant emissions.

The WOBBE INDEX (WI) of natural gas is the higher heating value (HHV) of the natural gas, expressed as Btu per standard cubic foot, divided by the square root of the natural gas specific gravity (SG), i.e.,

$$WI = HHV / SG^{1/2}$$

$$\text{Where, } SG = \frac{\text{density of gas in pounds per standard cubic foot}}{\text{density of air in pounds per standard cubic foot } (.07650 \text{ lb/ft}^3)}$$

The above definition is based on standard conditions of 14.73 psia and 60 ^{0}F. The units of WI are Btu/scf, the same as HHV.

Significantly, the heat input rate (Btu/hr) through a fixed orifice at constant pressure is proportional to WI. If the WI of the gas increases 10%, the heat input rate through the orifice increases 10%. Unless the combustion device has the capability of adjusting air flow with changes in WI, which few do, the air-to-fuel ratio will be reduced if the WI increases. Changes in the air-to-fuel ratio are the primary cause for changes in emissions from combustion equipment.

The following table shows the HHV and WI of the most commonly found hydrocarbons in natural gas. Both the HHV and WI of natural gas will increase with higher levels of ethane and higher (more carbon atoms) hydrocarbons

Table 2 – Properties of Hydrocarbons in Natural Gas

Hydrocarbon	Higher Heating Value (Btu/scf)	Wobbe Index (Btu/scf)
Methane	1010	1357
Ethane	1769	1736
Propane	2517	2040
Butane	3262	2303

Natural gas also usually contains the inert compounds carbon dioxide (CO_2) and nitrogen (N_2). These compounds significantly reduce the WI because they have no heating value, they displace hydrocarbons with heating value, and they have a density much greater than methane that also reduces the WI. One percent nitrogen by volume reduces the WI about 1.4%.

What is the Composition of Natural Gas in the AQMD?

SoCalGas reported that the system-wide average natural gas composition, based on 1997 data, was as shown in the following Table 3:

Table 3 – Average SoCalGas System Properties

Heating Value (Btu/scf)	1020
Wobbe Index (Btu/scf)	1332
Methane	95.4%
Ethane	2.1%
C3+	0.5%
Carbon Dioxide	1.25%
Nitrogen	0.6%
Oxygen	0.1%

More recently, SoCalGas reported that the average WI has increased to 1342. The composition, HHV, and WI of natural gas varies in the AQMD between suppliers. As shown previously in

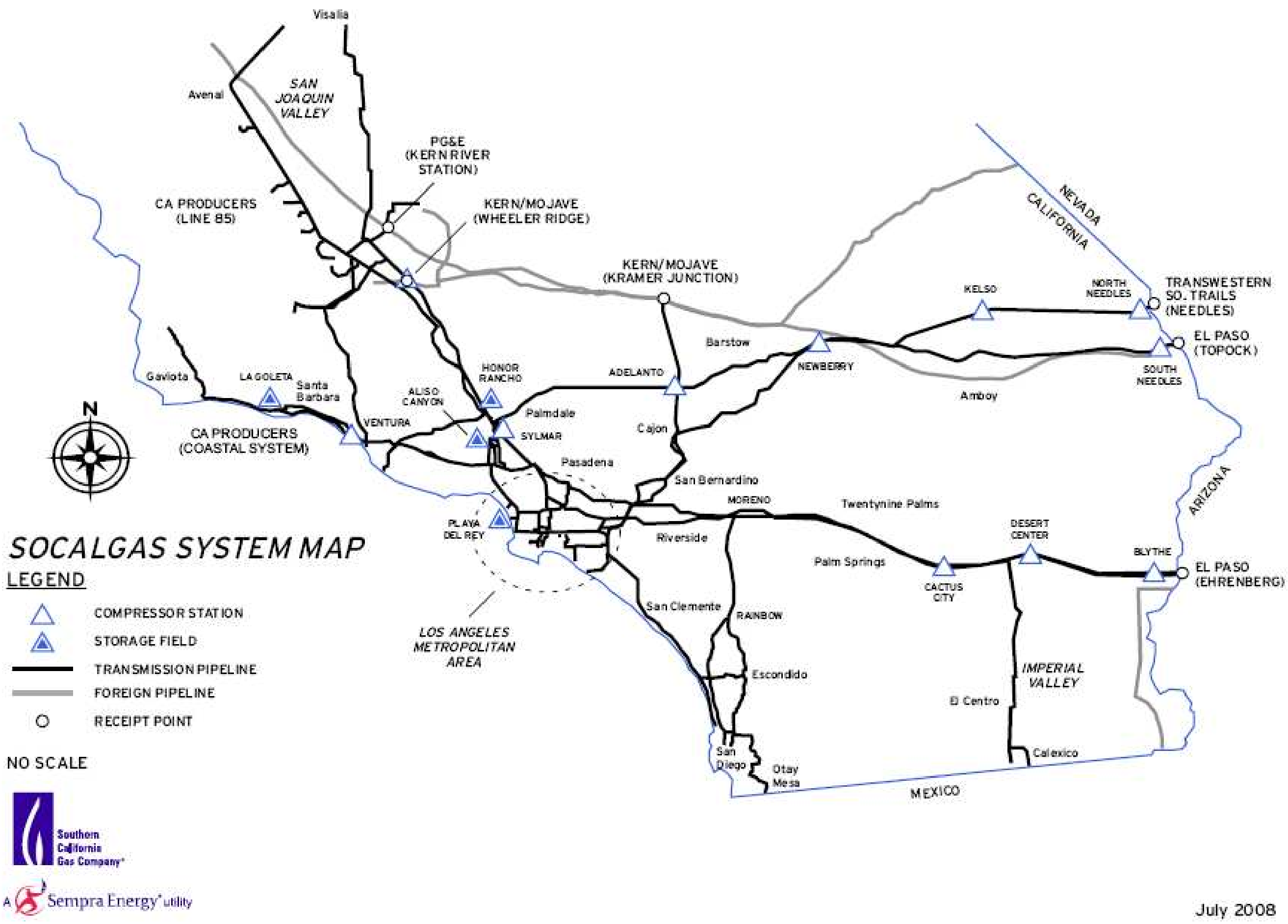
Figure 3, there are four major out-of-state gas producing areas as well as in-state local producers providing natural gas to SoCalGas. In 2007, natural gas supplies came from the following sources listed in Table 4[2]:

Table 4 – 2007 Annual Average SoCalGas Natural Gas Supplies (billion cubic feet per day)

Supplier	Bcf/day	Percentage
El Paso Natural Gas	1.108	40.8%
Transwestern Pipeline	0.615	22.6%
Kern River Pipeline	0.529	19.5%
California Producers	0.232	8.5%
GTN (Canada)	0.176	6.5%
Other	0.057	2.1
Total	2.717	

The following figure shows receipt points where the interstate pipelines connect to the SoCalGas system.

[2] Reference 4



The WI of these supplies varies. According to data reported by SoCalGas[3], El Paso Natural Gas and Transwestern Pipeline tend to have low WI (less than 1340), Kern River Pipeline generally has a moderate WI (about 1355), and California Producers vary significantly (from 1283 to 1431).

Further, the supply percentages listed above in the Table 3 vary significantly in time as illustrated in the following Figure 4A and Figure 4B[4]. Compared to the overall SoCalGas flows in Figure 4A, the gas flows from the El Paso Pipeline at Ehrenberg varied much more in the short term and long term. The El Paso percent of total supplies appears to vary from 13 to 40%[5].

---

[3] Hourly WI data are available at SoCalGas's Envoy website: https://envoyproj.sempra.com/

[4] Reference 5

[5] The capacity reported in Figure 4B does not include the gas that El Paso Pipeline delivers to the Topock receipt point.

Figure 4A – Total SoCalGas Flows

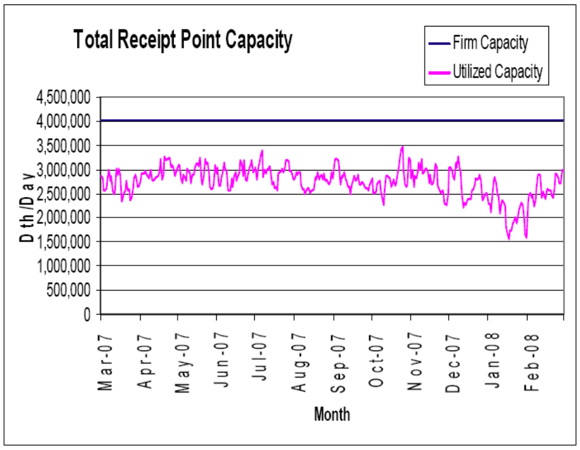
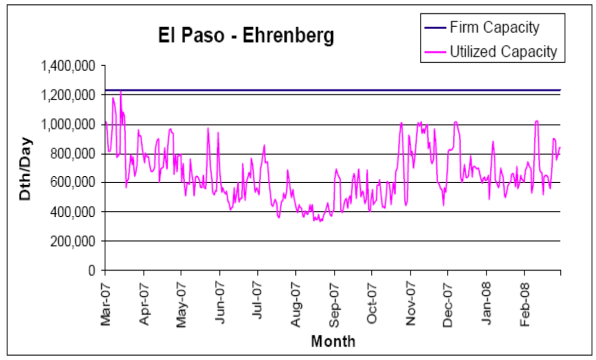


Figure 4B – El Paso Flows at Ehrenberg



At any given location in AQMD, a gas user may be receiving gas that is 100% from one supplier or a mix of supplies from multiple suppliers. Composition will depend on the local fuel demand and how much gas enters the SoCalGas system at each receipt point. This will vary both daily and seasonally.

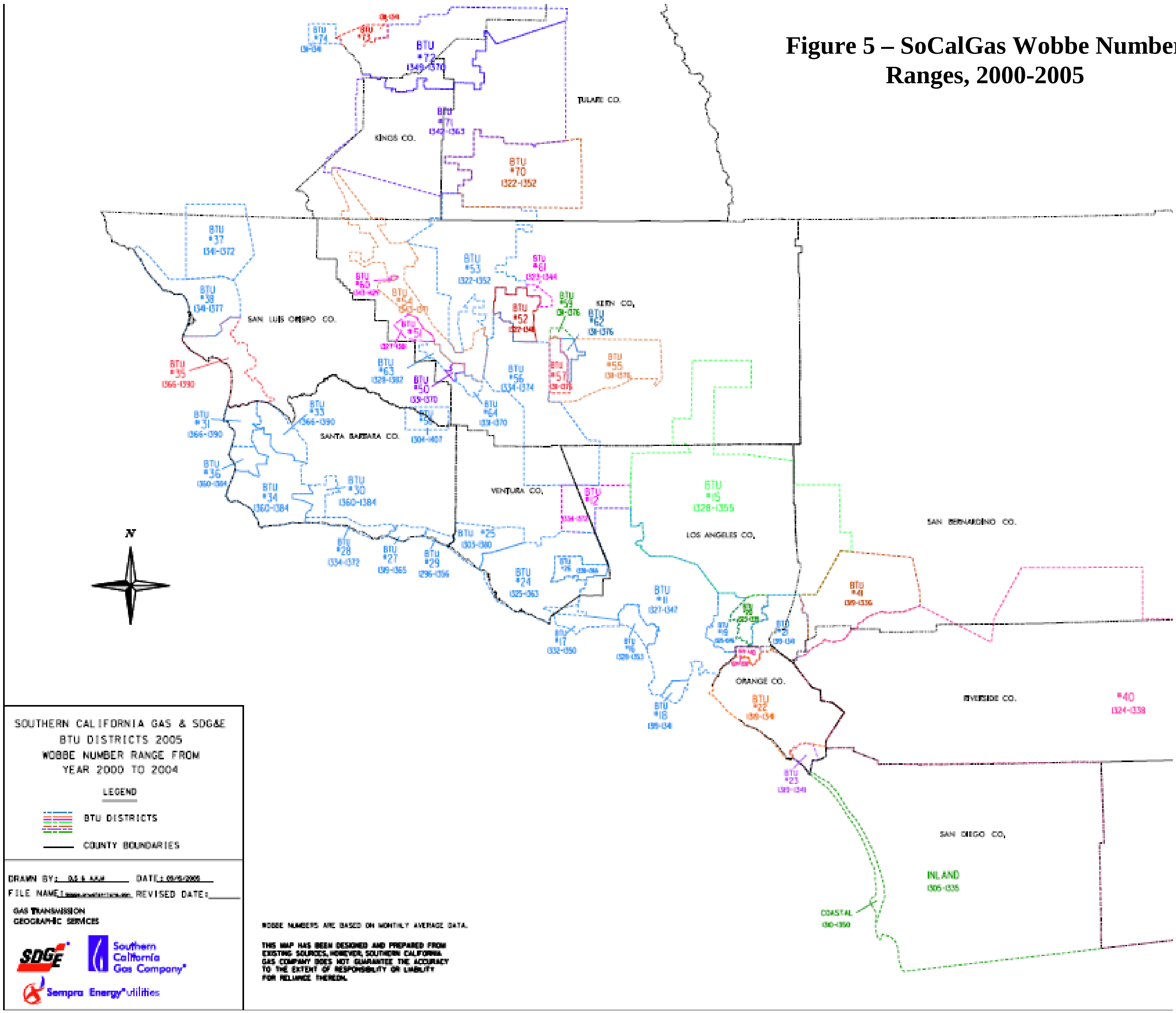
How Much Does the Wobbe Index Vary in AQMD?

Although there are not a great deal of publicly available regarding the WI variability in the AQMD, the following Figure 5 from SoCalGas shows the range of WI over a five-year period of 2000 to 2004 for the 48 "Btu Districts" in the SoCalGas territory. Because the relevant data are not easily legible, staff reproduced the same figure for the 13 Btu Districts in the AQMD in a more legible format (see Figure 6).

Btu Districts are the areas that SoCalGas has set up to track the heating value of the natural gas. The data are compiled monthly and used to calculate the therms of fuel used for each customer in that area. This is necessary because fuel meters only measure the volume of fuel used and not the heating value. The Btu Factor (in therms per 100 cubic feet) is published on the SoCalGas website.[6] For February 2009 the Btu Factors ranged from 1.025 (equivalent to 1,025 Btu per scf) in Riverside County to 1.134, 11% higher, in the small Btu District 58 (Cuyama) straddling the border between San Luis Obispo and Santa Barbara Counties,

[6] See http://www.socalgas.com/residential/prices/btu/

Figure 5 – SoCalGas Wobbe Number Ranges, 2000-2005



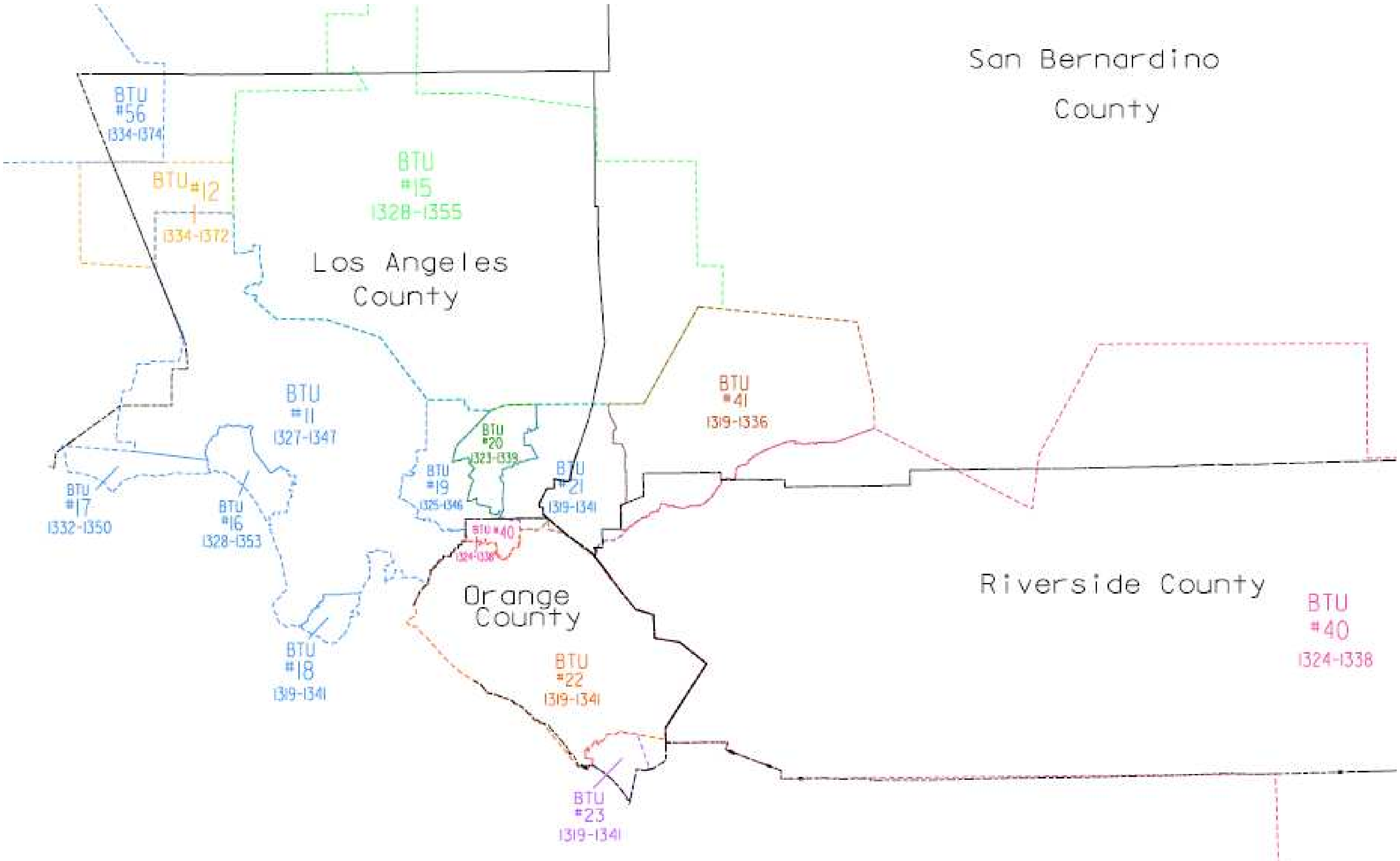


Figure 6 – Detail from Figure 5 - SoCalGas Wobbe Number Ranges, 2000-2005

The size of the Btu Districts varies greatly. Some are quite large occupying most of a county, whereas others are very small. Generally where there are smaller Btu Districts there are local gas producers that may have a significant effect on the gas quality in that district.

The WI ranges for all of the AQMD Btu Districts and some other significant Btu Districts outside AQMD are shown in Table 5 on the next page. In general, the AQMD area is less affected by local gas producers. Excluding the remote Btu Districts 12 and 56 in the Castaic/Gorman area of Los Angeles County, the 5-year WI range was very narrow in each Btu District, from only ±0.5% in most of Riverside County to ±0.9% in Santa Monica. The overall WI range for these areas was only 1319-1353. Compared to the 1279 to 1385 Wobbe Index range (±4.0%) allowed by SoCalGas Rule 30, the gas quality in AQMD has been very stable.

Outside of AQMD the situation is much different. Although some Btu Districts have WI levels comparable to AQMD, other areas affected by local gas production and shown on the right-hand side of Table 5 have very high WI up to 1429, and larger ranges up to ±3.8%.

LIQUEFIED NATURAL GAS

What is Liquefied Natural Gas?

Some large natural gas fields are located in remote areas or areas without sufficient demand for natural gas. By cooling natural gas to -256 ^{0}F and condensing it to liquefied natural gas (LNG), its volume is reduced to 1/600 of its gaseous state, making it possible to ship it in specialized, marine vessels with insulated storage tanks to natural gas markets. The ships deliver the LNG to regasification terminals where the LNG is heated, returned to a gaseous state and put into natural gas pipeline systems.

LNG is produced in countries such as Abu Dhabi, Algeria, Australia, Brunei, Indonesia, Malaysia, Qatar and Trinidad and Tobago. Primary consumers of LNG have been China, France, Japan, Korea, Spain, Taiwan and the United States.

Table 5 – 2000-2004 Wobbe Number Ranges

AQMD Btu Districts			Other California Btu Districts		
Btu District	**Wobbe No. Range**	**% Change**	**Btu District**	**Wobbe No. Range**	**% Change**
#11 – Los Angeles	1327-1347	±0.8%	#25 - Ventura	±1303-1380	±2.8%
#12 – Castaic	1334-1372	±1.4%	#31 – Santa Maria	±1366-1390	±0.8%
#16 – Santa Monica	1328-1353	±0.9%	#58 - Cuyama	±1304-1407	±3.8%
#17 – Malibu	1332-1350	±0.7%	#60 –Kern County	±1343-1429	±3.1%
#18 – San Pedro	1319-1341	±0.8%	#55, 57, 59 62 Kern County	±1311-1376	±2.4%
#19 – El Monte	1325-1346	±0.7%			
#20 – West Covina	1323-1339	±0.6%			
#21 – Pomona	1319-1341	±0.8%			
#22 & 23– Orange County	1319-1341	±0.8%			
#40 – Riverside County	1324-1338	±0.5%			
#41 – San Bernardino	1319-1336	±0.6%			
#56 – Gorman	1334- 1374	±1.5%			
Overall AQMD	1319-1374	±2.0%			
AQMD except #12 and #56	1319-1353	±1.3			

What is the Composition of LNG?

LNG compositions vary depending on where they are produced and how much processing they undergo. In the US, domestic gas is often processed to remove most of the propane, butane, and higher hydrocarbons called natural gas liquids (NGL). Even ethane is separated to and used to make ethylene, a common feedstock for plastics. Most LNG liquefaction plants, on the other hand, are in remote areas where there is little or no NGL market, so ethane and some NGLs are left in the LNG. The following table shows some typical LNG compositions and specifications.

Table 6 – LNG Characteristics

	Alaska	Bontang, Indonesia	Malaysia	Australia
Methane %	99.72	90.60	91.20	87.80
Ethane %	0.06	6.00	4.28	8.30
C3+ %	0.00	3.31	4.24	3.84
Inerts %	0.22	0.09	0.28	0.06
HHV, Btu/scf	1008	1111	1114	1137
Wobbe, Btu/scf	1356	1412	1414	1426

Source: Reference 5

The Alaska LNG, which is exported to Japan, is unusual in that it is almost pure methane. The other three are more typical, having higher levels of ethane, propane and higher hydrocarbons and a WI exceeding 1400. These LNG sources could still comply with the SoCalGas Rule 30 WI limit of 1385 by adding nitrogen to the gas. Some LNG regasification terminals, in the US and elsewhere, have nitrogen production and injection facilities to do this. The Australian LNG, with the highest WI, would require about 2.3% nitrogen by volume.

LNG in the United States

Nine regasification terminals with a combined capacity of about 11 billion cubic feet per day (bcf/d) are currently located on the Eastern and Gulf Coasts of the United States. Several more have been approved, including one in Oregon, and others are proposed, including in Southern California and Oregon. LNG deliveries to the US over the last few years have not been large, only between 1.0 to 2.0 bcf/d on an annual average, because natural gas prices have been higher in Europe and Asia, drawing LNG cargos to those locations.

Several LNG regasification terminals have been proposed in the Southern California area, although all but one have been disapproved or have withdrawn. The remaining active proposed facility is the 1.4 bcf/d Clearwater Port project to be located on a converted oil platform 10.5 miles offshore, near Oxnard, California. It is still in the permitting process with the US Coast Guard and California State Lands Commission.

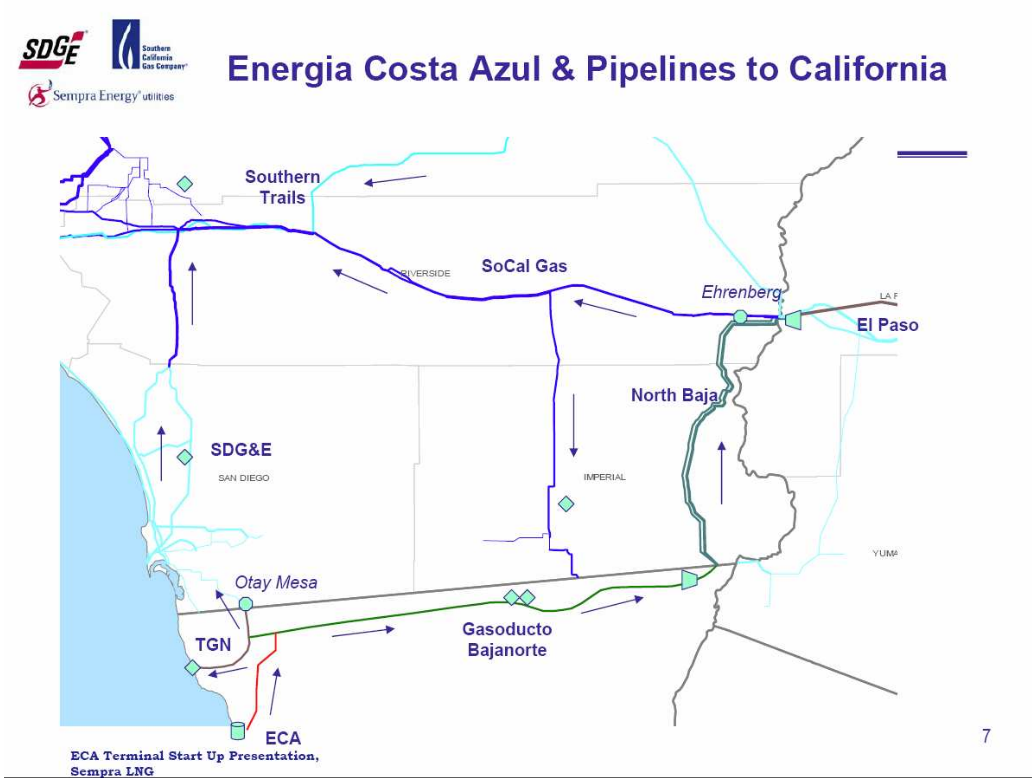
Energia Costa Azul LNG Terminal

Of most immediate concern to Southern California is the Energia Costa Azul (ECA) regasification terminal located 14 miles North of Ensenada, Mexico. The 1.0 bcf/d facility is owned by Sempra LNG, a subsidiary of Sempra Energy. Fifty percent of the capacity of the facility is leased to Royal Dutch Shell ("Shell").

ECA is intended to serve gas users in Baja Mexico, including two large power plants near the US border, and the US market. Figure 7 shows how the gas will flow into the US. Before ECA, gas used in Baja Mexico came from the El Paso pipeline, then South through the North Baja pipeline into Mexico. ECA natural gas will enter the US at two locations. The first is at Otay Mesa near San Diego, where SoCalGas and San Diego Gas & Electric Company have established a receipt point for up to 0.4 bcf/day. This gas will primarily serve San Diego County, although some gas could flow North into Riverside County. By reversing the flow of the North Baja Pipeline, the second location will be at Blythe, California, near where the El Paso pipeline also connects to the

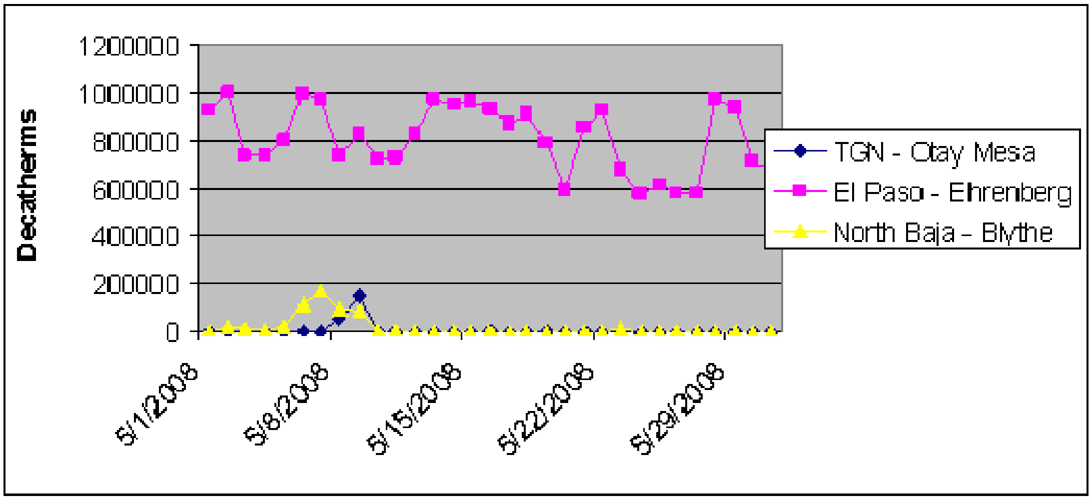
SoCalGas system. From this location, gas up to 1.2 bcf/day could flow to Imperial County, Riverside County and other parts of Southern California.

Figure 7 – Energia Costa Azul LNG Terminal Connections with the SoCalGas/SDG&E System



Sempra LNG has contracted for LNG supplies from Tangguh, Indonesia, and Shell has contracted for LNG supplies from Sakhalin, Russia. Both of these supplies are from new LNG liquefaction facilities that are expected to begin production in March or April 2009. Sempra's supplier can divert some of the LNG to other markets. The same may be true for the Russian supplies. Sempra LNG and Shell may also bring in spot cargos of LNG from other suppliers. Sempra LNG brought in two spot cargoes in early 2008 to commission the facility and to cool down the storage tanks. In May 2008 the first LNG-derived natural gas was delivered to Mexico and the United States, but gas flowed into the US only for a few days. As shown in Figure 8, the flows were relatively low. The flow from Otay Mesa most likely remained in the San Diego area. The flows from the North Baja Pipeline mixed with the much greater flows from the El Paso Pipeline before they were delivered to Riverside County and other AQMD areas.

Figure 8 – Flows into the US during the ECA Commissioning



Sempra LNG has not released the gas specifications for their Tannguh LNG, but they have told AQMD staff that the WI will be less than 1385 without any nitrogen being added.

In March 2008, Sempra LNG was reported to have given a $100 million contract to build a nitrogen injection plant for ECA, to be started up by the end of 2009. Once it is installed it could be used to reduce the WI of cargos from other suppliers that exceed a 1385 WI.

CHAPTER 2: LNG EMISSION STUDIES

INTRODUCTION

In addition to the 2005 NGC+ White Paper that discussed previous studies and described the effects of changing gas quality on various types of combustion equipment, testing of residential, commercial and industrial combustion equipment has been occurring in California, other parts of the US, and internationally such as in the United Kingdom. References 6 and 7 are two literature reviews sponsored by the California Energy Commission on this subject. This chapter will not be an exhaustive report on these studies, but will briefly review some of the important results.

LNG EFFECTS WITH DIFFERENT BURNER TYPES

As previously described in the discussion of the NGC+ White Paper, natural gas with a high WI, compared to historical supplies, can cause emission changes with some equipment. Some burner types are relatively insensitive to moderate WI changes. Other burner types are quite sensitive. Since a change in WI usually results in a change of the air-to-fuel ratio (AFR), burners whose emissions are sensitive to changes in AFR will be sensitive to changes of WI.

In general, most residential equipment with partial premix burners and secondary air, such as storage type water heaters and furnaces, are not sensitive to changes in WI. However, a few appliances have been found to have excessive CO with high-WI gas.

Burners that use a lean premix strategy to reduce NOx emissions have been found to be very sensitive to WI changes. Small commercial boilers often use this strategy. High-WI gas reduces the AFR, increases adiabatic flame temperature, and increases NOx.

Not many industrial nozzle-mix burners have been tested, but high-WI gas should not normally increase NOx significantly. It may even reduce NOx slightly with some burners. However, CO emissions can increase significantly if the burner has been adjusted to operate with low excess air with normal WI gas, and then begins burning high WI gas.

Burners that are not properly adjusted at the outset may also behave differently than properly adjusted burners. Most residential and commercial combustion equipment are rarely checked for proper adjustment after initial setup, and may operate for tens years or more without adjustment.

SOCALGAS GAS QUALITY AND LNG RESEARCH STUDY

SoCalGas tested and reported on the effects of high WI gas on a variety of residential and commercial combustion equipment in 2005. The main final report and individual test reports for each device tested are found on the SoCalGas website at:
http://www.socalgas.com/business/gasQuality/researchStudy.html .

Some units demonstrated increased CO emissions with the highest WI gas. For example, a commercial fryer had excessive CO, over 1,000 ppm air free, with the highest WI gas.

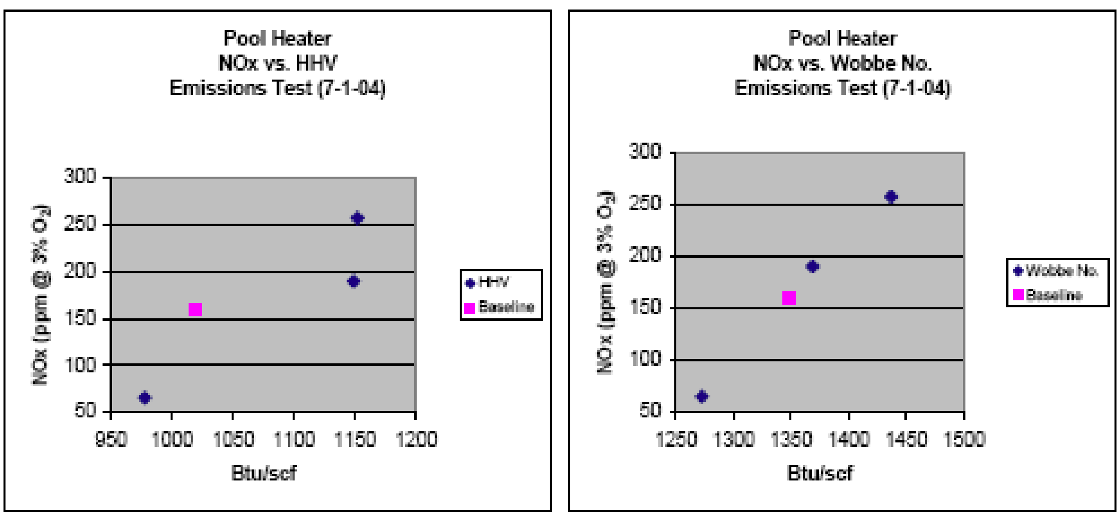
Appendix G of the SoCalGas report illustrates the test results for NOx emissions (Appendix G has been reproduced in Appendix C of this report). Of the various residential and commercial combustion units tested, conventional domestic furnaces and storage-type water heaters were not sensitive to the varying WI. Staff has been informed that SoCalGas has recently tested the newest 10 nanograms NOx per Joule water heaters that comply with AQMD Rule 1121, but these results have not yet been released.

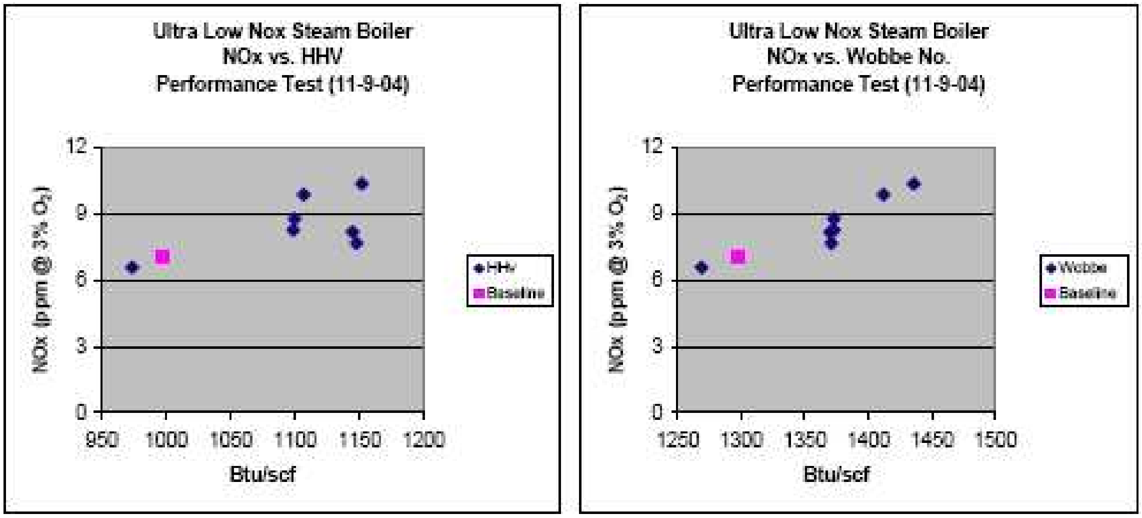
Seven units' NOx emissions, however, demonstrated sensitivity to changes in the WI, albeit to differing degrees. These units include the:

- Instantaneous water heater (residential)
- Pool heater
- Condensing hot water boiler
- Hot water boiler
- Steam boiler
- Ultra Low NOx Boiler
- Deep Fat Fryer

Figure 9 illustrates the NOx emission results for two of the tested units: a pool heater and an ultra low NOx boiler. As shown below, NOx emissions increased linearly with WI but NOx emissions demonstrated a weaker correlation with HHV. Although both units' NOx emissions increased with WI, the degree of sensitivity was markedly different. From the lowest to highest WI, the pool heater NOx increased about 400% and about 200 ppm, whereas the ultra low-NOx boiler only increased about 50% and 3 ppm. Notably, the range of WI of the gases tested was large – indeed, the highest WI was about 1440, which significantly exceeds the SoCalGas Rule 30 WI limit of 1385.

Figure 9 – Sample Results from the SoCalGas Study





SoCalGas also conducted follow-up testing on three boilers, whose NOx emissions increased with WI, and found that by retuning the boilers to operate with a higher WI gas, the NOx emission increases with high-WI gas could be reduced.[7]

SOCALGAS NATURAL GAS VEHICLE STUDIES

SoCalGas has also conducted and published on its website[8] several studies and tests of natural gas vehicles. One of the studies[9] tested two Detroit Diesel Series 50G engines, which combined were used in about 50% of all heavy duty natural gas vehicles, such as transit buses, in the AQMD in 2005. Reference 9 at p. 6 The results of the SoCalGas study are not reported in a manner that illustrates the relationship between NOx emissions and WI. As such, staff has reproduced the data from the SoCalGas report in Figure 10.

Two versions of the engine were tested: an older TK model, and a newer MK model with an oxygen sensor and closed loop AFR control. Even with the AFR control, which maintained a constant AFR with all of the fuels, the NOx emissions of the newer MK model still increased significantly with a higher WI.

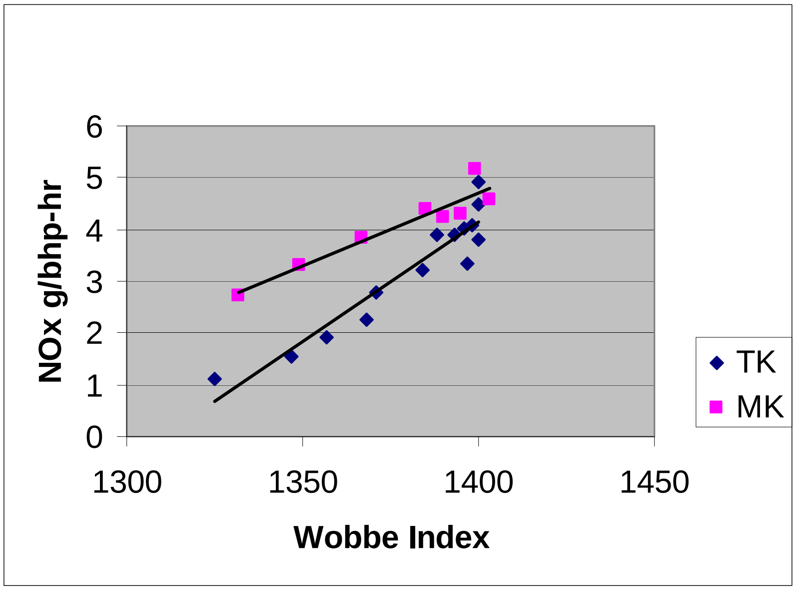
---

[7] See the "Low-NOx Boilers –Expanded Testing" section of the following SoCalGas webpage: http://www.socalgas.com/business/gasQuality/equipmentStudies.html

[8] http://www.socalgas.com/business/gasQuality/legacyFleetStudy.html

[9] Reference 8

Figure 10 – NOx versus Wobbe Index for Detroit Diesel Series 50 G Engines



CALIFORNIA ENERGY COMMISSION NATURAL GAS QUALTITY STUDIES

Residential Appliances

The California Energy Commission has contracted with the Lawrence Berkeley National Laboratory to test the emissions of residential ovens, broilers, furnaces, cooktops, and water heaters with different qualities of natural gas. This study is still in progress, but preliminary results show that most residential appliances are not very sensitive to changes in gas quality. However, a few appliances had small increases in NOx (<10%) and some tankless water heaters had significant NOx increases (up to 82%) with higher WI gas. Some units also had higher CO emissions with high-WI gas. The CO increases were generally negligible, except for one tankless water heater that demonstrated a significant increase in CO emissions with the high-WI gas.

Industrial Burners

The NGC+ White Paper identified a gap in data regarding the effects of changes in gas quality on industrial combustion equipment. The California Energy Commission has contracted with the Gas Technology Institute to test the emissions of burners used in industrial boilers, ovens, and furnaces. This study is still in progress. Tests are completed for an infrared burner, a radiant U-tube burner, a linear ribbon burner, a high velocity burner, an oxy-fuel burner, and a boiler burner. Generally, the burners were not sensitive to gas quality, except for: (1) the radiant U-tube burner, which had several thousand ppm increase in CO emissions with high-WI gas; and (2) the oxy-fuel burner, which had increased CO emissions and decreased NOx emissions with higher WI. The effects of high CO emissions could be mitigated by retuning burners for higher WI gas.

The boiler burner tested was not sensitive to WI, but the burner was not a low-NOx type that would be required to comply with AQMD rules. More boilers burners are expected to be tested.

SAN DIEGO COUNTY AIR POLLUTION CONTROL DISTRICT/SAN DIEGO GAS & ELECTRIC EMISSIONS TESTING

During the commission of the ECA LNG regasification terminal in Baja California in May 2008, the San Diego County Air Pollution Control District (SDCAPCD) and San Diego Gas & Electric Company (SDG&E) collaborated on emission testing of stationary industrial combustion equipment, including one rich-burn engine, three lean-burn engines, five gas turbines, eight boilers, a small kiln and a pool heater. The equipment was tested a day before the arrival the LNG-derived natural gas as well as during the LNG event. Before the LNG arrived, the WI ranged between 1341 and 1346. During the LNG event, the WI ranged between 1372 and1384.

Nearly all of the equipment had emission increases or decreases of less than 10%, which may not be statistically significant due to only single tests on different days. A few had higher percent increases or reductions, but the absolute values of the concentration changes were low.

Contrary to expectations, two 2400-horsepower lean-burn engine tests showed a decrease in NOx emissions by 16 to 19% with LNG. Also unexpected was an increase in the AFR of the engines with LNG, indicated by the % oxygen in the exhaust. Normally, the AFR would be reduced with a higher WI gas, unless the engine is equipped with an oxygen sensor and AFR controller, which would maintain a constant AFR. Another lean-burn engine’s NOx emissions increased 13% with LNG.

SDCAPCD also reviewed NOx continuous emission data before and during the LNG event at eight gas turbines and two steam generators at large electrical power plants. With active add-on controls (selective catalytic reduction), the units did not experience significant changes in NOx emissions.

CHAPTER 4: PROPOSED RULE

INTRODUCTION

APPLICABLILITY – SUBDIVISION (B)

DEFINITIONS – SUBDIVISION (C)

REQUIREMENTS - SUBDIVISION (D)

COMPLIANCE – SUBDIVISION (E)

MONITORING, TESTING AND RECORDKEEPING – SUBDIVISION (F)

TEST METHODS – SUBDIVISION (G)

EXEMPTIONS - SUBDIVISION (H)

INTRODUCTION

The basic purpose of PR 433 is to monitor the quantity of LNG supplied to AQMD, the effects of the LNG on the quality of natural gas in AQMD, and the effects of natural gas changes on combustion equipment emissions in AQMD. A summary of the proposed rule follows.

APPLICABILITY – SUBDIVISION (b)

PR 433 will apply to "…all natural gas distribution system operators that convey natural gas to end users located within the District…" except for operators that qualify for the exemptions described in the next section. Currently, AQMD staff believes that the rule will only apply to SoCalGas.

DEFINITIONS – SUBDIVISION (c)

Definitions in subdivision (c) include:

(1) A BTU DISTRICT is a geographic area defined by the operator of a natural gas distribution system for the purpose of determining the heating value of natural gas and natural gas bills for natural gas customers within that area.

(2) LIQUEFIED NATURAL GAS (LNG) is natural gas that has been converted to a liquid state for shipment by a marine vessel and then converted back to a gaseous state for delivery to a natural gas distribution system.

(3) A STANDARD CUBIC FOOT is one cubic foot of gas at a standard temperature of 60^o Fahrenheit and a standard pressure of 14.73 pounds per square inch absolute.

(4) The WOBBE INDEX (WI) of natural gas is the higher heating value (HHV) of the natural gas, expressed as Btu per standard cubic foot, divided by the square root of the natural gas specific gravity (SG), i.e.,

$$WI = HHV / SG^{1/2}$$

$$\text{Where, } SG = \frac{\text{density of gas in pounds per standard cubic foot}}{\text{density of air in pounds per standard cubic foot } (.07650 \text{ lb/ft}^3)}$$

REQUIREMENTS – SUBDIVISION (d)

Gas Quality Monitoring Plan

Paragraph (d)(1) requires the gas utility to have a Gas Quality Monitoring (GQM) Plan. The objectives of the GQM Plan are to monitor the quantity, composition and WI of LNG delivered to distribution system receipt points and the composition and WI of natural gas in each Btu District. The GQM Plan must include:

A) Locations in the distribution system at which the WI will be monitored,

B) Information showing that the selected locations are sufficient to determine the composition and WI at all locations in the distribution system,

C) Sampling and analytical methods and calculations to be used in determining the composition and WI,

D) Frequency of composition and WI determination at each location,

E) Receipt points at which LNG is being added to the distribution system,

F) Frequency at which LNG quantities added to the distribution system at each LNG addition location will be recorded, and

G) Method, frequency and format of reporting the LNG composition, WI and quantity data to the District.

Much of this monitoring information will already be available to the gas utility given that the CPUC General Order 58-A requires SoCalGas to monitor heating value in each area or district. An example of the monthly billing factors for SoCalGas, which reports the HHV of the gas but not the WI, is found in Appendix D to this report. The GQM will make it publicly available how a gas utility monitors natural gas quality.

Paragraph (d)(2) requires the GQM Plan to be updated whenever there is a change in the locations of receipt points at which LNG is being added to the distribution system or a change in the distribution system that requires a change in the locations at which the composition, WI and/or LNG additions must be monitored to comply with paragraph (d)(1).

Historical Data

Paragraph (d)(3) requires gas utilities to submit to AQMD a summary of the daily average HHV, SG and WI at each Btu District within the District for the three year period from January 1, 2006 until December 31, 2008. This will provide baseline information about current natural gas quality before the introduction of LNG-derived natural gas.

LNG Rollout Plan

Paragraph (d)(4) requires the gas utility to document their LNG Rollout Plan. The plan must include the following:

(A) Past actions and future planned actions to educate natural gas end-users about gas quality changes and recommend revisions to end-user equipment maintenance or tuning practices;

(B) Past actions and future planned actions to determine the effects of gas quality changes from LNG on emissions from end-user combustion equipment;

(C) Results of emission testing conducted prior to June 5, 2009 by the gas utility or a contractor at an end-user, or at a test facility, for the purpose of determining effects of changes to gas quality from LNG, including the AQMD application or permit number of the tested equipment, equipment description (type of equipment, make, model, rated thermal input), the date of the test, sampling and measurement methods, the natural gas WI, and the test conditions and emission results. It must be identified whether a test was conducted to determine baseline emissions prior to changes in WI from LNG, or after changes in WI due to LNG. If emission tests are done before and after any repairs, adjustments or tuning of the equipment, all emission tests and what repairs, adjustments or tuning was conducted must be reported. Results of tests that were posted by June 5, 2009 on a publicly available website identified in the plan do not have to be submitted;

(D) A map of Btu Districts existing as of June 5, 2009;

(E) A map of any planned changes to Btu Districts; and

(F) Past actions and future planned actions to mitigate effects of gas quality changes from LNG such as retuning end-user combustion equipment.

LNG Rollout Plan Amendments

Paragraph (d)(5) requires Plan amendments whenever necessary.

District-Wide Projection of LNG Emission Effects

Paragraph (d)(6) requires the gas utility to develop and maintain a projection of LNG effects on emissions within the District based on population data of end-user equipment and available information on the effects of LNG on emissions from various end-user equipment types. The projection must be updated to incorporate new information on the effects of LNG on emissions as it becomes available. Periodical reports of the data and methodology used for the projection and the results in annual tons of NOx, CO and VOC are required.

COMPLIANCE – SUBDIVISION (e)

Subdivision (e) requires:

(A) Submittal of the historical data by July 10, 2009;

(B) Submittal of the initial GQM Plan and LNG Rollout Plan by July 10, 2009;

(C) Implementation of the approved GQM Plan and LNG Rollout Plan by August 1, 2009 or the plans as submitted if they have not yet been approved;

(D) Development of an initial projection of LNG effects on emissions by December 31, 2009; and

(E) Plan modifications when needed.

MONITORING, TESTING AND RECORDKEEPING – SUBDIVISION (f)

Subdivision (f) requires the following minimum monitoring, recordkeeping and reporting:

(1) At each receipt point where LNG is being added to the distribution system:

  (A) Determination and recordkeeping of the composition, WI, SG and HHV of LNG being added to the distribution system at least once every hour, and

  (B) Recording the volume, expressed as standard cubic feet, of LNG added each hour.

(2) At each Btu District in the natural gas distribution system, determination and recordkeeping of the natural gas composition, WI, SG and HHV at least once every hour.

(3) Reporting the recorded data monthly to AQMD in electronic format.

(4) Reporting monthly all actions required by and information resulting from the LNG Rollout Plan. The first report must include all actions taken since those reported in the LNG Rollout Plan application. Each report shall include the following.

  (A) Results of all emission tests on end-user equipment, including the AQMD application or permit number, equipment description (type of equipment, make, model, rated thermal input), the date of the test, sampling and measurement methods, the natural gas WI, and test conditions. The gas utility must identify whether a test was conducted to determine baseline emissions prior to changes in WI from LNG, or after changes in WI due to LNG. If emission tests are done before and after any repairs, adjustments or tuning of the equipment, all emission tests, and what repairs, adjustments or tuning was conducted must be reported.

(B) Guidance, services or technologies offered to end-users to mitigate emission increases caused by LNG.

(5) Beginning July 1, 2009, a semi-annual report on the District-wide projection of LNG effects on emissions.

TEST METHODS – SUBDIVISION (g)

The gas utility is required to use the following Gas Processors Association (GPA) methods to determine the WI, HHV and SG of natural gas, unless an alternate method is approved by AQMD:

(A) GPA Method 2166, Obtaining Natural Gas Samples for Analysis by Gas Chromatograph,

(B) GPA Method 2261, Analysis of Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, and

(C) GPA Method 2172, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis.

A calibrated gas chromatography system that complies with California Public Utilities Commission General Order 58-B, items 4 and 8 must be used.

EXEMPTIONS – SUBDIVISION (h)

PR 433 includes the following two exemptions:

(1) Any natural gas distribution system operator whose only source of natural gas is by receiving natural gas from another natural gas distribution system operator at supply points located within the District is exempt from this rule.

(2) Any natural gas distribution system operator that does not receive LNG directly from an LNG supplier is exempt from paragraphs (d)(4), (d)(5), (d)(6) and (d)(7) of this rule.

The cities of Vernon and Long Beach, and the Southwest Gas Corporation are expected to qualify for the second partial exemption. Long Beach does receive gas from local gas producers in the Long Beach area and, thus, will not qualify for the first complete exemption.

CHAPTER 4: IMPACT ASSESSMENTS AND LEGAL MANDATES

EMISSION IMPACTS

COST EFFECTIVENESS

COMPARATIVE ANALYSIS

DRAFT FINDINGS

EMISSION IMPACTS

PR 433 will not have any direct emission impacts because it does not specify any emission limits or natural gas quality specifications. It will only require monitoring and reporting of natural gas quality, LNG rollout activities and estimation of emission changes resulting from LNG-derived natural gas delivered to AQMD. However, mitigation measures such as equipment tuning, may occur as part of the LNG Rollout plan which will reduce emissions impacts from LNG. These emission reductions can not be estimated at this time.

COST EFFECTIVENESS

Since this is a monitoring and reporting rule, cost effectiveness cannot be calculated.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

Pursuant to the California Environmental Quality Act (CEQA) and AQMD Rule 110, SCAQMD staff is reviewing the proposed project and, as a Lead Agency, will be preparing the appropriate CEQA document after analyzing any potential adverse environmental impacts associated with the proposed project pursuant to CEQA Guidelines § 15002(k) – Three Step Process.

SOCIO-ECONOMIC ANALYSIS

A socio-economic analysis will be made available at least 30 days prior to a public hearing for the proposed rule.

COMPARATIVE ANALYSIS

Health and Safety Code Section 40727.2 requires that AQMD identify and compare any other AQMD or federal regulations that apply to the same equipment or source type. There are none in this case.

DRAFT FINDINGS

Before adopting, amending or repealing a rule, the AQMD shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference, as defined in Health and Safety Code Section 40727. The findings are as follows:

Necessity - The AQMD Governing Board finds and determines that Proposed Rule 433 – Natural Gas Quality is necessary in order to monitor and mitigate the impacts of LNG-derived natural gas deliveries to AQMD.

Authority - The AQMD Governing Board obtains its authority to adopt, amend or repeal rules and regulations from Health and Safety Code §§40000, 40001, 40440, and 40720-40728.

Clarity - The AQMD Governing Board finds and determines that Proposed Rule 433 is written and displayed so that the meaning can be easily understood by persons directly affected by it.

Consistency – The AQMD Governing Board finds and determines that Proposed Rule 433 is in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or federal or state regulations.

Non-Duplication – The AQMD Governing Board has determined that Proposed Rule 433 does not impose the same requirements as any existing state or federal regulations.

Reference - In adopting Proposed Rule 433, the AQMD Governing Board references the following statutes which AQMD hereby implements, interprets or makes specific: Health and Safety Code Sections 40001, and 40440.

REFERENCES

1. NGC+ Interchangeability Work Group, "White Paper on Natural Gas Interchangeability and Non-Combustion End Use", February 28, 2005 http://www.aga.org/Kc/resourcesbydiscipline/OperationsEngineering/gasquality/0502NGINTERCHANGE.htm

2. California Public Utilities Commission, General Order 58-A: STANDARDS FOR GAS SERVICE IN THE STATE OF CALIFORNIA, December 16, 1992 http://docs.cpuc.ca.gov/published/General_order/54827.PDF

3. Southern California Gas Company, Rule No. 30 - TRANSPORTATION OF CUSTOMER-OWNED GAS http://socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf

4. 2008 California Gas Report, Prepared by California Gas and Electric Utilities http://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf

5. Liquefied Natural Gas, Simmons & Company International, April 7, 2005 http://www.globaloilwatch.com/reports/Simmons%20LNG.pdf

6. NATURAL GAS VARIABILITY IN CALIFORNIA: ENVIRONMENTAL IMPACTS AND DEVICE PERFORMANCE LITERATURE REVIEW AND EVALUATION FOR RESIDENTIAL APPLIANCES, Lawrence Berkeley National Laboratory for California Energy Commission, CEC-500-2006-110, February 2007 http://www.energy.ca.gov/2006publications/CEC-500-2006-110/CEC-500-2006-110.PDF

7. NATURAL GAS IN CALIFORNIA: ENVIRONMENTAL IMPACTS AND DEVICE PERFORMANCE LITERATURE REVIEW AND INDUSTRIAL BURNER EVALUATIONS, Gas Technology Institute for California Energy Commission, CEC-500-2006-096, October 2006 http://www.energy.ca.gov/2006publications/CEC-500-2006-096/CEC-500-2006-096.PDF

8. Fuel Composition Testing Using DDC Series 50G Natural Gas Engines, Southwest Research Institute for SoCalGas, August 2006 http://www.socalgas.com/business/gasQuality/documents/Legacy_DD_report.pdf

9. Southern California Heavy-Duty CNG Vehicle Report, Southern California Gas Company and San Diego Gas & Electric, April 10, 2006 http://www.socalgas.com/business/gasQuality/documents/041306_HD_CNG_VehicleRept.pdf

APPENDIX A

California Public Utilities Commission General Order 58-A: Standards for Gas Service in the State of California

The following excerpts from General Order 58-A: STANDARDS FOR GAS SERVICE IN THE STATE OF CALIFORNIA contain the California Public Utilities Commission (CPUC) Regulations on natural gas quality.

6. Heating Value of Fuel Gas

a. Each gas utility supplying fuel gas for domestic, commercial or industrial purposes shall develop and maintain a plan establishing the heating value of the gas being supplied. This plan shall provide for the following requirements:

   1. Establish distinct distribution system areas in which a uniform quality of gas will be supplied.

   2. Identify a heating value range for each such area. Provide for verification of the average heating value of the gas supplied to each area, at intervals frequent enough to assure that the heating value is being maintained within the heating value range established for the area, and to assure adequate accuracy for customer billing.

   3. Provide for establishing, and maintaining for three years, records of the heating value of the gas provided in each area.

b. Each gas utility shall establish and maintain, as outlined in General Order 58-B, Heating Value Measurement Standard For Gaseous Fuels, heating value measurement stations, and shall develop and implement the procedures necessary to determine the heating value of the fuel gas being supplied in each area, to meet the requirements of Section 6.a. If heating value determination of the same gas is satisfactorily made by another utility, supplier or qualified laboratory, it may be used for the purpose of the above record upon written approval of the Commission.

   Such utility, supplier, or qualified laboratory shall use a heating value measurement device of a type that has been approved by the Commission.

c. Each gas utility supplying a liquefied petroleum gas-air mix, shall establish and maintain, with the approval of the Commission, a standard heating value for its product. The maximum daily variation shall not exceed twenty-five (25) Btu per standard cubic foot above or below the standard heating value.

d. Each gas utility supplying fuel gas, including liquefied petroleum gas and a liquefied petroleum gas—air mix, shall file with the Commission as a part of its schedule of rates, rules and regulations, the average total heating value of such gas together with the maximum fluctuation above and below the average total heating value which may be expected.

e. The monthly average total heating value at any given test station shall be the average of all total heating value tests made during each month.

f. As an alternative to establishing a heating value measurement station, samples may be taken near the center of a distribution system area. Where this is done, at least one determination per week shall be made of the total heating value of gas delivered to customers in distribution system areas identified as in Section 6.a.1. which have annual sales in excess of one hundred million (100,000,000) cubic feet of gas. Where a number of distribution system areas are so interconnected as to be certain of receiving gas from the same source, there may be established a testing or sampling station at a location where the gas tested will be representative of that served in all such distribution system areas.

7. Purity of Gas

a. Hydrogen Sulfide

No gas supplied by any gas utility for domestic, commercial or industrial purposes in this state shall contain more than one-fourth (0.25) grain of hydrogen sulfide per one hundred (100) standard cubic feet.

b. Total Sulfur

No gas supplied by any gas utility for domestic, commercial or industrial purposes shall contain more than five (5) grains of total sulfur per one hundred (100) standard cubic feet.

c. Test procedures used to determine the amounts of hydrogen sulfide and total sulfur shall be in accordance with accepted gas industry standards and practices.

d. When hydrogen sulfide, or total sulfur, exceeds the limits set forth in Section 7.a. and Section 7.b., the gas utility shall notify the Commission and commence remedial action immediately. The Commission shall be notified when the level of hydrogen sulfide, or total sulfur, has been reduced to allowable limits.

e. Vinyl Chloride

No regulated gas utility shall knowingly purchase landfill gas if that landfill gas, when supplied to any existing gas customer, contains vinyl chloride in a concentration greater than 1,170 parts per billion by volume. This value is adopted as instructed by Section 25421(b) of the California Health and Safety Code as the maximum amount of vinyl chloride that may be found in landfill gas supplied to a gas utility customer pursuant to Section 25421(a). Testing for vinyl chloride shall be performed as specified by Section 25421(d) of the Health and Safety Code. When vinyl chloride exceeds the limits set forth herein, the gas utility shall notify the Commission and commence remedial action immediately. The gas utility shall notify the Commission when the level of vinyl chloride is reduced to allowable limits. Direct delivery for industrial use of landfill gas is exempted from these requirements as provided by Section 25421(e). A gas utility desiring to purchase landfill gas with a vinyl chloride content that exceeds the Commission adopted standard shall file an application with the commission. The application shall demonstrate that dilution of landfill gas exceeding the Commission's standard with other natural gas in the utility's system shall not result in any customer receiving gas with a vinyl chloride concentration level exceeding the Commission's standard.

APPENDIX B

Southern California Gas Company Rule No. 30 – Transportation of Customer-Owned Gas

The following is Section I from Southern California Gas Company's Rule No. 30 – Transportation of Customer-Owned Gas, which relates to natural gas quality:

I. Gas Delivery Specifications

1. The natural gas stream delivered into the Utility's system shall conform to the gas quality specifications as provided in any applicable agreements and contracts currently in place between the entity delivering such natural gas and the Utility at the time of the delivery. If no such agreement is in place, the natural gas shall conform to the gas specifications as defined below.
2. Gas delivered into the Utility's system for the account of a customer for which there is no existing contract between the delivering pipeline and the Utility shall be at a pressure such that the gas can be integrated into the Utility's system at the point(s) of receipt.
3. Gas delivered, except as defined in I.1 above, shall conform to the following quality specifications at the time of delivery:
    a. Heating Value: The minimum heating value is nine hundred and ninety (990) Btu (gross) per standard cubic foot on a dry basis. The maximum heating value is one thousand one hundred fifty (1150) Btu (gross) per standard cubic foot on a dry basis.
    b. Moisture Content or Water Content: For gas delivered at or below a pressure of eight hundred (800) psig, the gas shall have a water content not in excess of seven (7) pounds per million standard cubic feet. For gas delivered at a pressure exceeding of eight hundred (800) psig, the gas shall have a water dew point not exceeding 20 degrees F at delivery pressure.
    c. Hydrogen Sulfide: The gas shall not contain more than twenty-five hundredths (0.25) of one (1) grain of hydrogen sulfide, measured as hydrogen sulfide, per one hundred (100) standard cubic feet (4 ppm). The gas shall not contain any entrained hydrogen sulfide treatment chemical (solvent) or its by-products in the gas stream.
    d. Mercaptan Sulfur: The gas shall not contain more than three tenths (0.3) grains of mercaptan sulfur, measured as sulfur, per hundred standard cubic feet (5 ppm).
    e. Total Sulfur: The gas shall not contain more than seventy-five hundredths (0.75) of a grain of total sulfur compounds, measured as sulfur, per one hundred (100) standard cubic feet (12.6 ppm). This includes COS and CS2, hydrogen sulfide, mercaptans and mono, di and poly sulfides.
    f. Carbon Dioxide: The gas shall not have a total carbon dioxide content in excess of three percent (3%) by volume.
    g. Oxygen: The gas shall not have an oxygen content in excess of two-tenths of one percent (0.2%) by volume, and customer will make every reasonable effort to keep the gas free of oxygen.
    h. Inerts: The gas shall not contain in excess of four percent (4%) total inerts (the total combined carbon dioxide, nitrogen, oxygen and any other inert compound) by volume.

i. Hydrocarbons: For gas delivered at a pressure of 800 psig or less, the gas hydrocarbon dew point is not to exceed 45 degrees F at 400 psig or at the delivery pressure if the delivery pressure is below 400 psig. For gas delivered at a pressure higher than 800 psig, the gas hydrocarbon dew point is not to exceed 20 degrees F measured at a pressure of 400 psig.

j. Merchantability: The gas shall not contain dust, sand, dirt, gums, oils and other substances injurious to Utility facilities or that would cause gas to be unmarketable.

k. Hazardous Substances: The gas must not contain hazardous substances (including but not limited to toxic and/or carcinogenic substances and/or reproductive toxins) concentrations which would prevent or restrict the normal marketing of gas, be injurious to pipeline facilities, or which would present a health and/or safety hazard to Utility employees and/or the general public.

l. Delivery Temperature: The gas delivery temperature is not to be below 50 degrees F or above 105 degrees F.

m. Interchangeability: The gas shall have a minimum Wobbe Number of 1279 and shall not have a maximum Wobbe Number greater than 1385. The gas shall meet American Gas Association's Lifting Index, Flashback Index and Yellow Tip Index interchangeability indices for high methane gas relative to a typical composition of gas in the Utility system serving the area.

Acceptable specification ranges are:

* Lifting Index (IL)

  IL <= 1.06

* Flashback Index (IF)

  IF <= 1.2

* Yellow Tip Index (IY)

  IY >= 0.8

n. Liquids: The gas shall contain no liquids at or immediately downstream of the receipt point.

o. Landfill Gas: Gas from landfills will not be accepted or transported.

p. Biogas: Biogas refers to a gas made from anaerobic digestion of agriculture and/or animal waste. The gas is primarily a mixture of methane and carbon dioxide. Biogas must be free from bacteria, pathogens and any other substances injurious to utility facilities or that would cause the gas to be unmarketable and it shall conform to all gas quality specifications identified in this Rule.

4. The Utility, at its option, may refuse to accept any gas tendered for transportation by the customer or on his behalf if such gas does not meet the specifications at the time of delivery as set out in I. 2 and I. 3 above, as applicable.

5. A generic deviation from the minimum gas quality specifications set forth in Paragraph I.3 is granted for "Historical California Production." Quality specifications for Historical

California Production will be governed by SoCalGas Rule No. 30 in effect as of September 21, 2006, or, to the extent that production had a deviation in place at that time, pursuant to the agreement governing that deviation. “Historical California Production” is defined as follows: Onshore or offshore California-produced natural gas delivered at points of interconnection existing as of January 1, 2006, up to the maximum historical deliveries or Maximum Daily Volume effective on that date as specified in any agreement permitting supply delivery at those points. If a producer moves its deliveries of Historical California Production from a point of interconnection existing as of January 1, 2006, to another existing or a new point on the system, or if one or more producers consolidate two or more existing points of interconnection existing as of January 1, 2006, to another existing or a new point on the system, the deviation granted under this provision will follow the Historical California Production provided that (a) the Utility has required or approved the change in receipt point location and (b) the continuing deviation shall not exceed the Maximum Daily Volume stated in the access agreement(s) governing deliveries at the producer’s original point of interconnection and (c) specifically, the quality of the gas should not lessen to the point that it falls outside the grandfathered Rule No. 30 specifications.

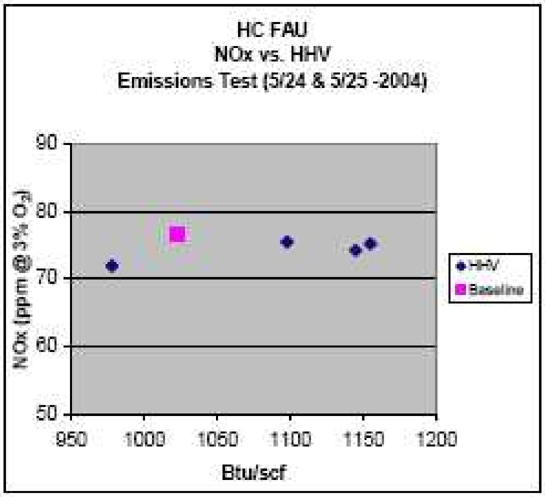
6. In addition to the generic deviation provided in paragraph 5, the Utility will grant other specific deviations to California production from the gas quality specifications defined in Paragraph I.3 above, if such gas will not have a negative impact on system operations. Any such deviation will be required to be filed through Advice Letter for approval prior to gas actually flowing in the Utility system.
7. The Utility will grant a deviation to existing interstate supplies consistent with prior gas quality specifications if requested by the interconnecting interstate pipeline for a period of not more than 12 months from the date of D.06-09-039.
8. The Utility will post on its EBB and/or general website information regarding the available real-time Wobbe Number of gas at identified operational locations on its system.

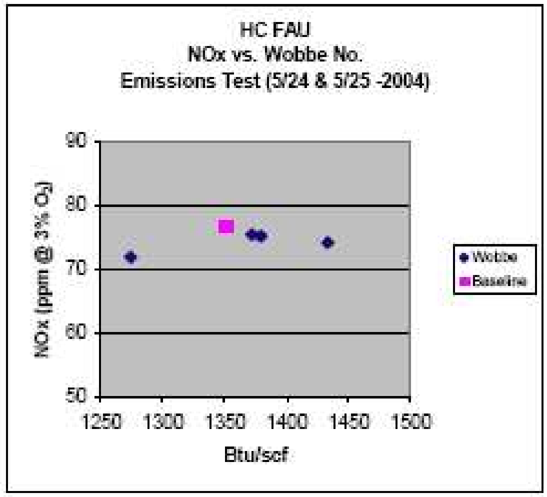
APPENDIX C

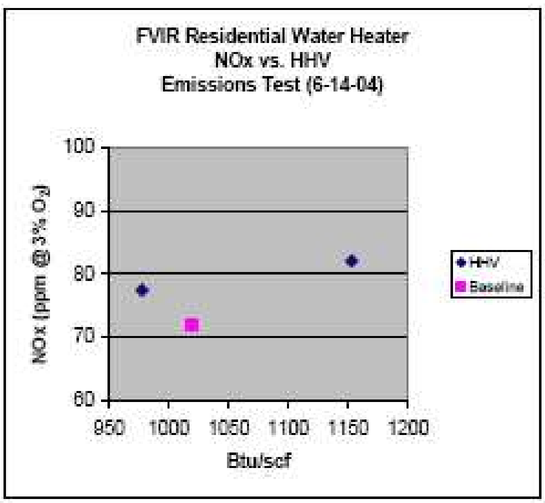
SoCalGas Gas Quality and LNG Research Study, Appendix G

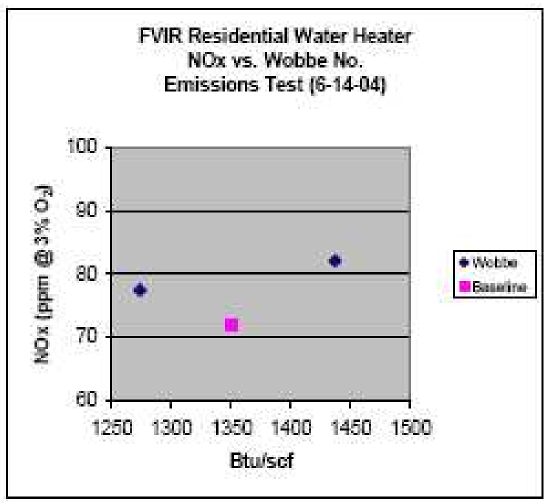
Southern California Gas Company
A Sempra Energy utility

Gas Quality and LNG Research Study
Appendix G





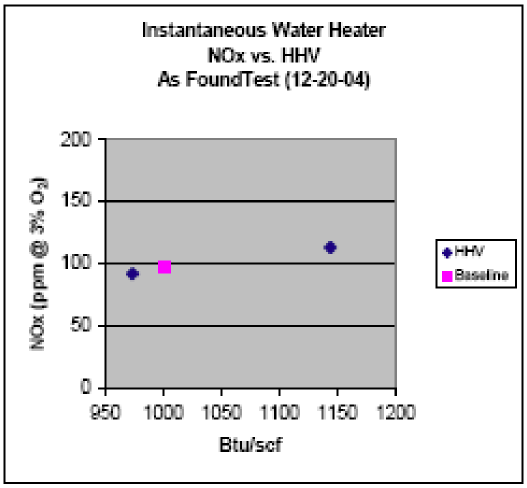


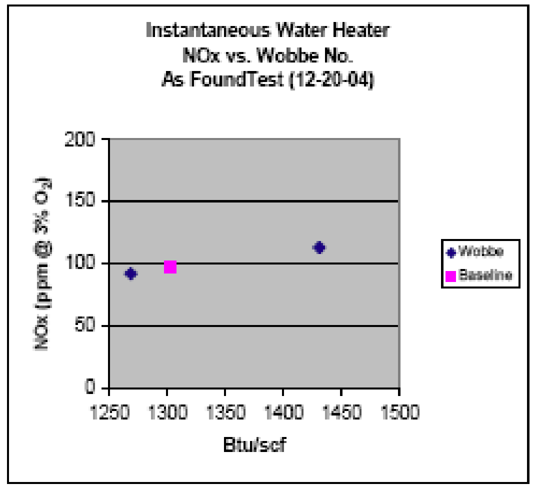


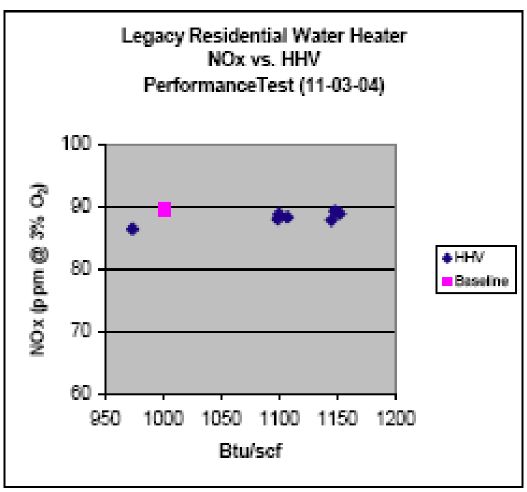
Note: Baseline Emissions are from equipment set up to appropriate test standards or manufacturer's specifications on Base Gas. The other emission points result from the introduction of difference gas compositions to the equipment without re-adjusting the set up. See Gas Quality & LNG Research Study Appendices for detailed equipment reports.

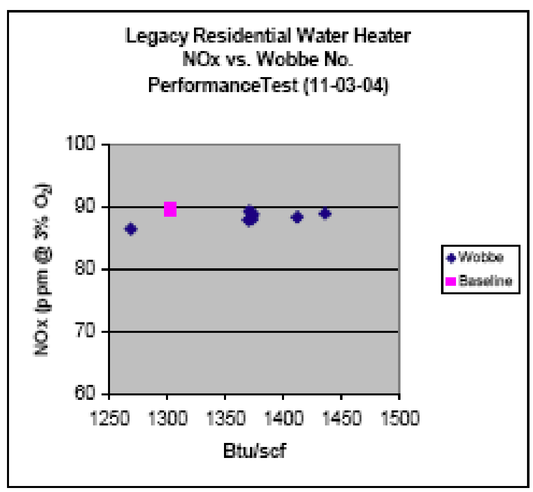
Southern California Gas Company
A Sempra Energy utility

Gas Quality and LNG Research Study
Appendix G







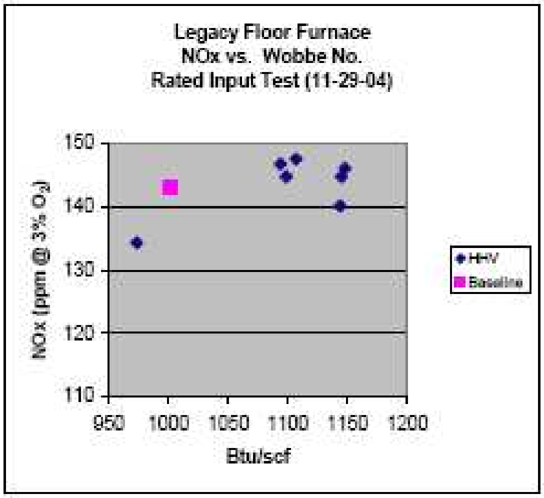


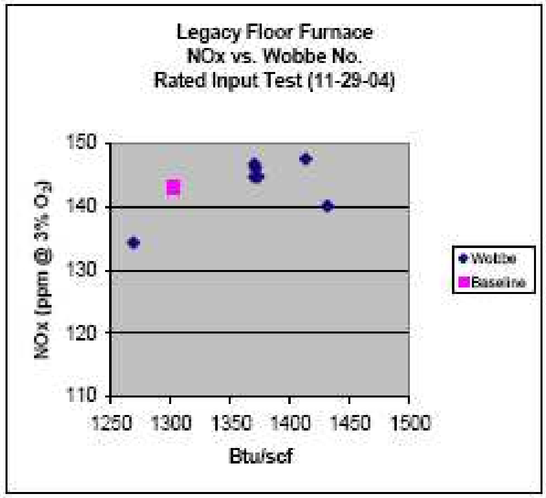
Note: Baseline Emissions are from equipment set up to appropriate test standards or manufacturer's specifications on Base Gas. The other emission points result from the introduction of difference gas compositions to the equipment without re-adjusting the set up. See Gas Quality & LNG Research Study Appendices for detailed equipment reports.

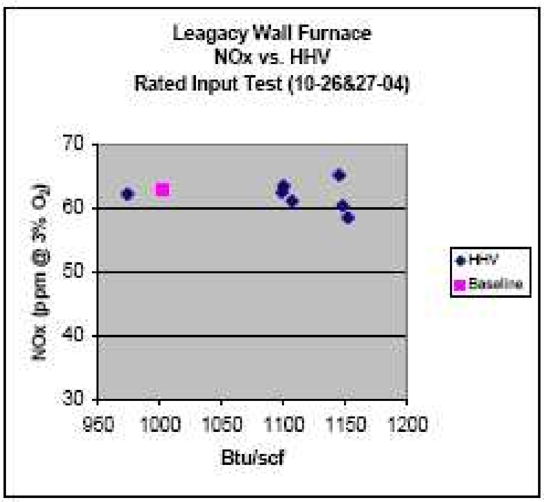
Southern California Gas Company

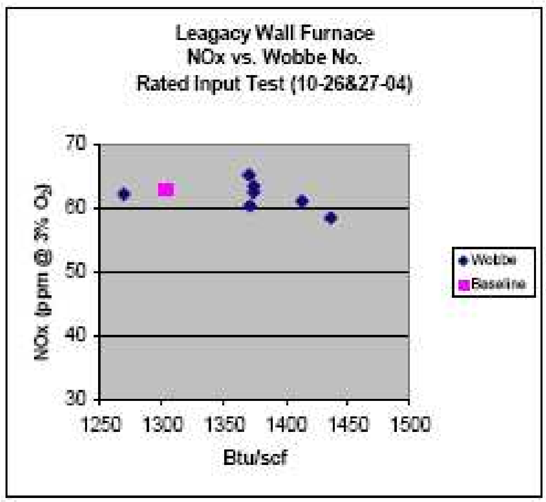
A Sempra Energy utility

Gas Quality and LNG Research Study
Appendix G





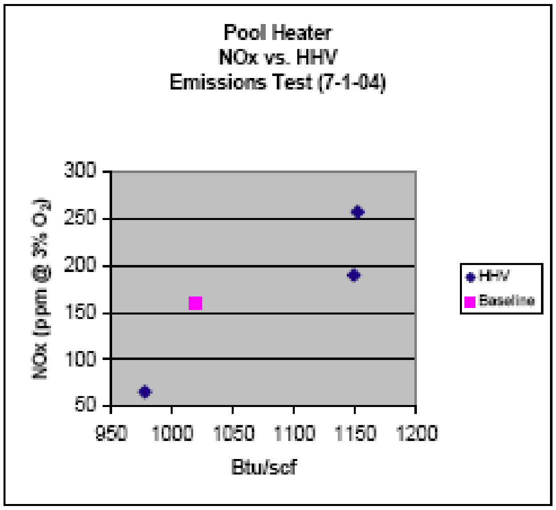


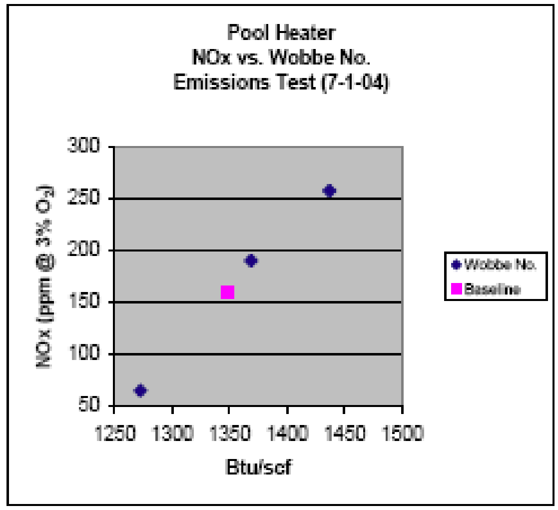


Note: Baseline Emissions are from equipment set up to appropriate test standards or manufacturer's specifications on Base Gas. The other emission points result from the introduction of difference gas compositions to the equipment without re-adjusting the set up. See Gas Quality & LNG Research Study Appendices for detailed equipment reports.

Southern California Gas Company
A Sempra Energy utility

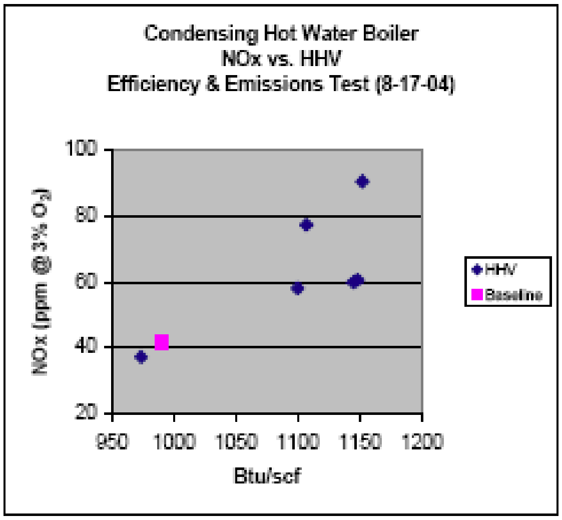
Gas Quality and LNG Research Study
Appendix G

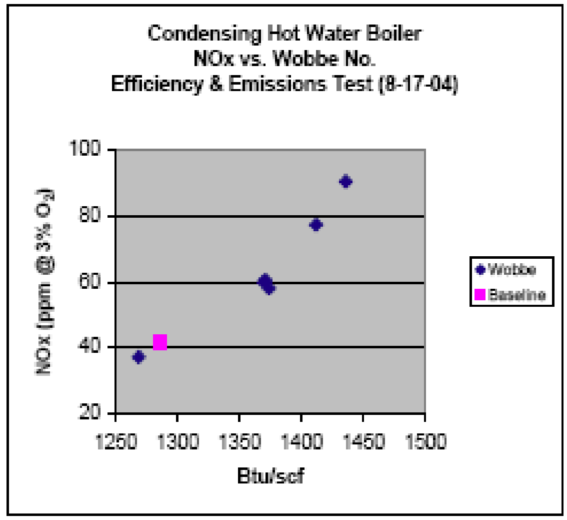


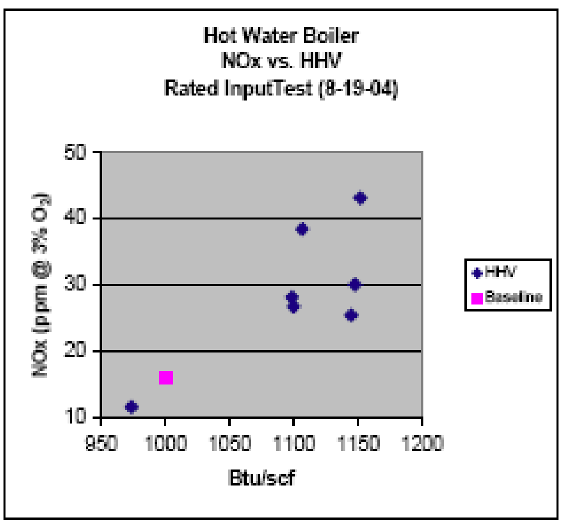


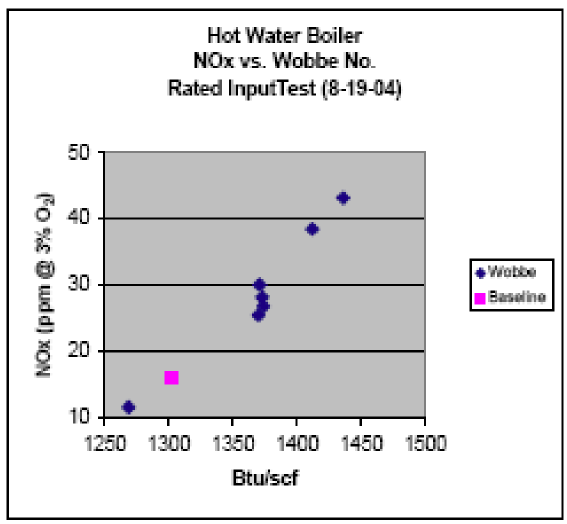
Southern California Gas Company
A Sempra Energy utility

Gas Quality and LNG Research Study
Appendix G



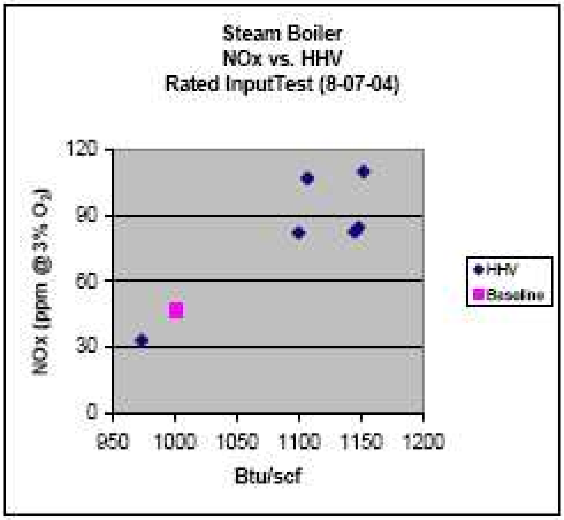


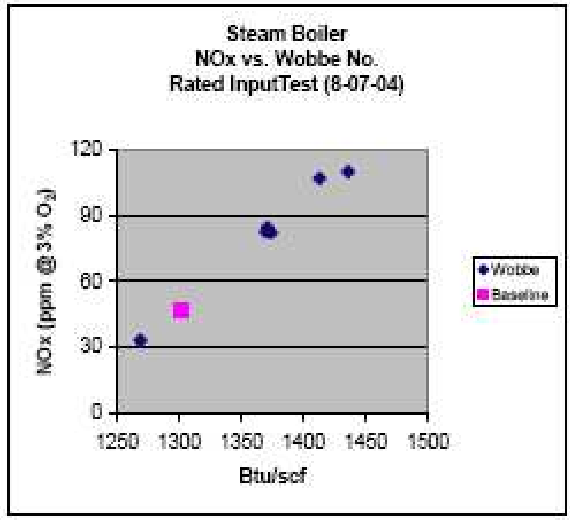


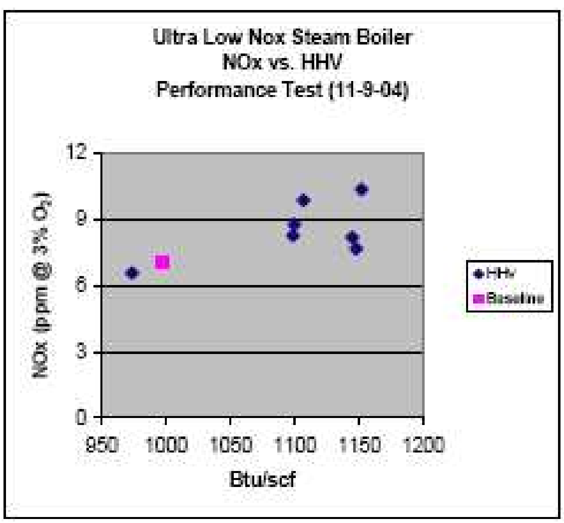


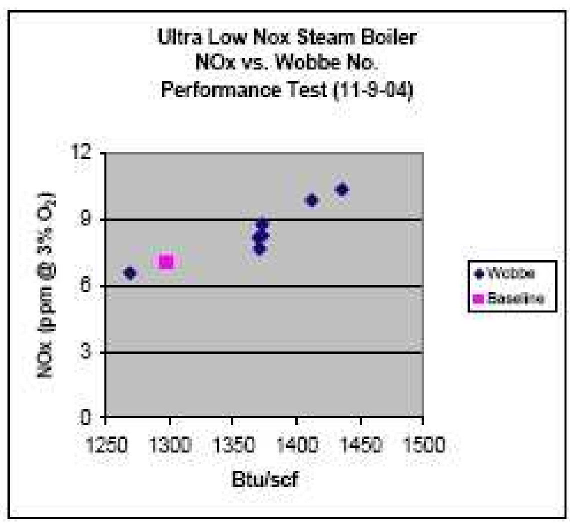
Note: Baseline Emissions are from equipment set up to appropriate test standards or manufacturer's specifications on Base Gas. The other emission points result from the introduction of difference gas compositions to the equipment without re-adjusting the set up. See Gas Quality & LNG Research Study Appendices for detailed equipment reports.

Gas Quality and LNG Research Study
Appendix G



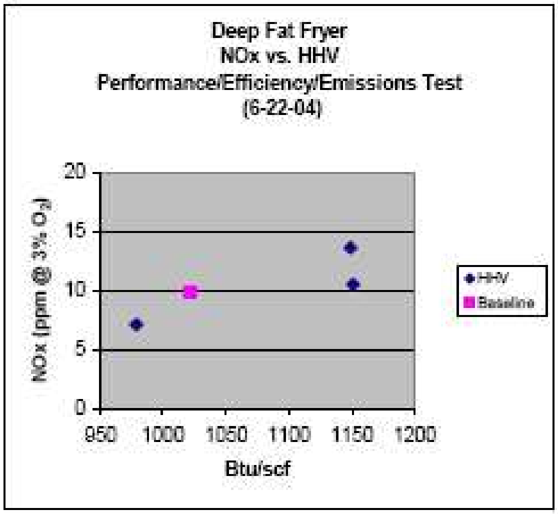


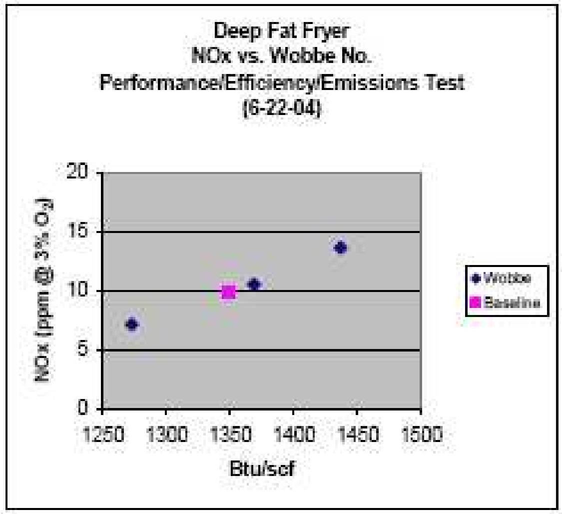


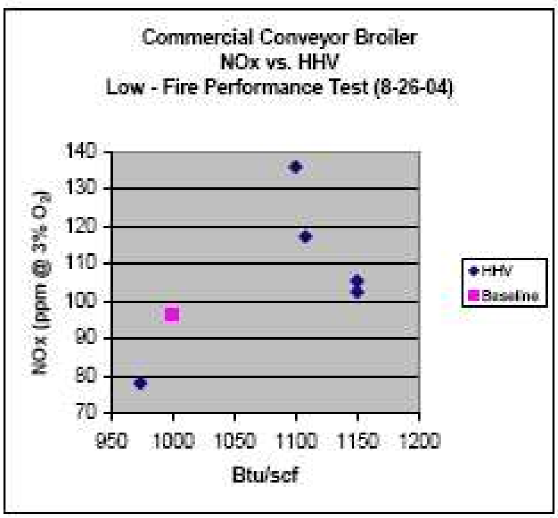


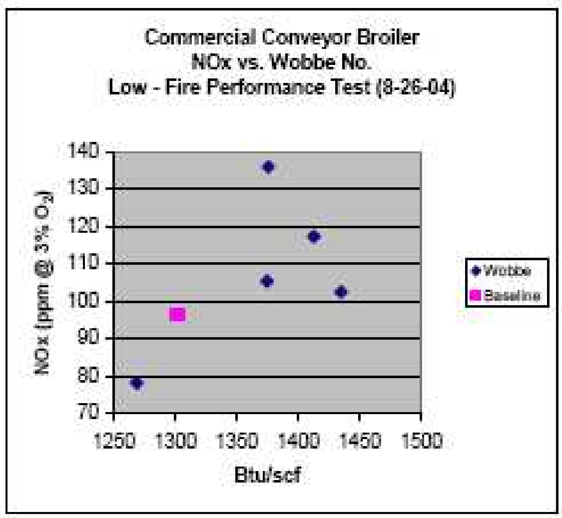
Note: Baseline Emissions are from equipment set up to appropriate test standards or manufacturer's specifications on Base Gas. The other emission points result from the introduction of difference gas compositions to the equipment without re-adjusting the set up. See Gas Quality & LNG Research Study Appendices for detailed equipment reports.

Gas Quality and LNG Research Study
Appendix G









Note: Baseline Emissions are from equipment set up to appropriate test standards or manufacturer's specifications on Base Gas. The other emission points result from the introduction of difference gas compositions to the equipment without re-adjusting the set up. See Gas Quality & LNG Research Study Appendices for detailed equipment reports.

APPENDIX D

Example SoCalGas Monthly Billing Factors

Month- Mar-2009 Altitude Zone Applicable for Standard Pressure Meters Only

BTU DIST	BTU FACTOR	0 1.000	1 0.968	2 0.935	3 0.903	4 0.871	5 0.841	6 0.812	7 0.782	8 0.755
11	1.026	1.026	0.993	0.959	0.926	0.894	0.863	0.833	0.802	0.775
12	1.036	1.036	1.003	0.969	0.936	0.902	0.871	0.841	0.810	0.782
15	1.026	1.026	0.993	0.959	0.926	0.894	0.863	0.833	0.802	0.775
16	1.031	1.031	0.998	0.964	0.931	0.898	0.867	0.837	0.806	0.778
17	1.030	1.030	0.997	0.963	0.930	0.897	0.866	0.836	0.805	0.778
18	1.025	1.025	0.992	0.958	0.926	0.893	0.862	0.832	0.802	0.774
19	1.025	1.025	0.992	0.958	0.926	0.893	0.862	0.832	0.802	0.774
20	1.023	1.023	0.990	0.957	0.924	0.891	0.860	0.831	0.800	0.772
21	1.021	1.021	0.988	0.955	0.922	0.889	0.859	0.829	0.798	0.771
22	1.019	1.019	0.986	0.953	0.920	0.888	0.857	0.827	0.797	0.769
23	1.024	1.024	0.991	0.957	0.925	0.892	0.861	0.831	0.801	0.773
24	1.055	1.055	1.021	0.986	0.953	0.919	0.887	0.857	0.825	0.797
25	1.044	1.044	1.011	0.976	0.943	0.909	0.878	0.848	0.816	0.788
26	1.034	1.034	1.001	0.967	0.934	0.901	0.870	0.840	0.809	0.781
27	1.054	1.054	1.020	0.985	0.952	0.918	0.886	0.856	0.824	0.796
28	1.080	1.080	1.045	1.010	0.975	0.941	0.908	0.877	0.845	0.815
29	1.043	1.043	1.010	0.975	0.942	0.908	0.877	0.847	0.816	0.787
30	1.113	1.113	1.077	1.041	1.005	0.969	0.936	0.904	0.870	0.840
31	1.114	1.114	1.078	1.042	1.006	0.970	0.937	0.905	0.871	0.841
33	1.114	1.114	1.078	1.042	1.006	0.970	0.937	0.905	0.871	0.841
34	1.113	1.113	1.077	1.041	1.005	0.969	0.936	0.904	0.870	0.840
35	1.114	1.114	1.078	1.042	1.006	0.970	0.937	0.905	0.871	0.841
36	1.113	1.113	1.077	1.041	1.005	0.969	0.936	0.904	0.870	0.840
37	1.091	1.091	1.056	1.020	0.985	0.950	0.918	0.886	0.853	0.824
38	1.102	1.102	1.067	1.030	0.995	0.960	0.927	0.895	0.862	0.832
40	1.022	1.022	0.989	0.956	0.923	0.890	0.860	0.830	0.799	0.772
41	1.026	1.026	0.993	0.959	0.926	0.894	0.863	0.833	0.802	0.775
42	1.024	1.024	0.991	0.957	0.925	0.892	0.861	0.831	0.801	0.773
43	1.024	1.024	0.991	0.957	0.925	0.892	0.861	0.831	0.801	0.773
50	1.041	1.041	1.008	0.973	0.940	0.907	0.875	0.845	0.814	0.786
51	1.069	1.069	1.035	1.000	0.965	0.931	0.899	0.868	0.836	0.807
52	1.039	1.039	1.006	0.971	0.938	0.905	0.874	0.844	0.812	0.784
53	1.042	1.042	1.009	0.974	0.941	0.908	0.876	0.846	0.815	0.787
54	1.088	1.088	1.053	1.017	0.982	0.948	0.915	0.883	0.851	0.821
55	1.044	1.044	1.011	0.976	0.943	0.909	0.878	0.848	0.816	0.788
56	1.044	1.044	1.011	0.976	0.943	0.909	0.878	0.848	0.816	0.788
57	1.044	1.044	1.011	0.976	0.943	0.909	0.878	0.848	0.816	0.788
58	1.140	1.140	1.104	1.066	1.029	0.993	0.959	0.926	0.891	0.861
59	1.044	1.044	1.011	0.976	0.943	0.909	0.878	0.848	0.816	0.788
60	1.088	1.088	1.053	1.017	0.982	0.948	0.915	0.883	0.851	0.821
61	1.041	1.041	1.008	0.973	0.940	0.907	0.875	0.845	0.814	0.786
62	1.044	1.044	1.011	0.976	0.943	0.909	0.878	0.848	0.816	0.788
63	1.080	1.080	1.045	1.010	0.975	0.941	0.908	0.877	0.845	0.815
64	1.041	1.041	1.008	0.973	0.940	0.907	0.875	0.845	0.814	0.786
70	1.042	1.042	1.009	0.974	0.941	0.908	0.876	0.846	0.815	0.787
71	1.076	1.076	1.042	1.006	0.972	0.937	0.905	0.874	0.841	0.812
72	1.088	1.088	1.053	1.017	0.982	0.948	0.915	0.883	0.851	0.821
73	1.022	1.022	0.989	0.956	0.923	0.890	0.860	0.830	0.799	0.772
74	1.022	1.022	0.989	0.956	0.923	0.890	0.860	0.830	0.799	0.772

Btu Factor units are therms per 100 scf.

Current billing factors are available at: http://www.socalgas.com/residential/prices/btu/