SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

FINAL STAFF REPORT FOR

Proposed Rule 1148.1 - Oil and Gas Production Wells

Proposed Amended Rule 222 - Filing Requirements for Specific Emission Sources Not Requiring a Written Permit Pursuant to Regulation II

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The purpose of Proposed Rule (PR) 1148.1 – Oil and Gas Production Wells, is to reduce volatile organic compound (VOC) emissions from well cellars as well as from sources of untreated process gas located at oil and gas production facilities. These goals will be achieved through an enhanced visual inspection and maintenance program and by requiring facilities to control untreated produced gas.

PR 1148.1 will implement Control Measure FUG-05 of the 2003 Air Quality Management Plan (AQMP).

Currently there are three rules in the South Coast Air Quality Management District (AQMD) that address fugitive emissions at oil and gas production fields. Rule 1148 – Thermally Enhanced Oil Recovery Wells limits the VOC emissions from steam drive wells. Rule 1173 – Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants, addresses VOC leaks and releases from pumps, valves, and other components. Rule 1176 – VOC Emissions from Wastewater Systems controls emissions from sumps, wastewater separators and associated control equipment.

Currently, the AQMD has no rule in place that addresses the fugitive emissions from the control of well cellars. In addition, the AQMD does not have a rule that requires control of untreated produced gas at oil and gas production operations. PR 1148.1 will control VOC emissions from these sources. Well cellar maintenance and other activities at oil field production facilities are regulated by the State of California, Department of Conservation, Division of Oil, Gas and Geothermal Resources, in accordance with California Code of Regulations, Article 3; Section 1774 - Oilfield Facilities and Equipment Maintenance. The proposed rule will work in concert with State regulations.

The overall VOC emission reductions resulting from the proposed rule will be 1.76 tons per day. Of this amount, 0.97 tons per day of VOC emission reductions will come from the improved maintenance of wellheads and well cellars. Another 0.79 tons per day of VOC emission reductions will be obtained by controlling produced gas that would have otherwise been vented to the atmosphere.

Based on the reduction of emissions from both well cellars and produced gas sources, the overall cost effectiveness of PR 1148.1 is $2,483 per ton of VOC reduced.

Proposed Amended Rule 222 - Filing Requirements for Specific Emission Sources Not Requiring a Written Permit Pursuant to Regulation II

Rule 222 was adopted in September 1998 and subsequently amended in May 2000 to help simplify and streamline the permitting process by reducing the number of permit applications required by the AQMD. The rule identifies specific types of equipment that individually have small emissions and minimal toxic health risks. However, in the aggregate, these equipment categories have significant emissions or health risk.

Operators of such equipment are required to file information with AQMD which includes a description of the equipment, facility information, and other data for estimating emissions and determining compliance. Compliance is achieved for such equipment by meeting existing rule and recordkeeping requirements. The implementation of Rule 222 has resulted in a filing program for low-emitting equipment as an alternative to the conventional permitting process. This amendment will require filing for additional equipment that previously was not subject to Rule 222, which includes well cellars, wellheads and well pumps that will be regulated under PR 1148.1.

PROPOSED RULE 1148.1

BACKGROUND

A. PURPOSE

The purpose of PR 1148.1 – Oil Field Production Wells is to reduce VOC emissions from the wellheads and the well cellars located at oil and gas production facilities through an enhanced self-inspection and maintenance program. The proposed rule will also reduce VOC emissions by controlling or treating process gas that would have otherwise been vented directly into the atmosphere. VOCs are precursors to ozone and the AQMD is designated as an extreme non-attainment area for the federal and state ozone standards.

B. LEGISLATIVE AUTHORITY

The California Legislature created the AQMD in 1977 (the Lewis-Presley Air Quality Management Act, Health and Safety Code Section 40400 et seq.) as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin). By statute, the AQMD is required to adopt an AQMP demonstrating compliance with all state and federal ambient air quality standards for the Basin (Health and Safety Code Section 40460(a)). In addition, the AQMD must adopt rules and regulations that implement the AQMP [Health and Safety Code Section 40440(a)].

The California Clean Air Act (CCAA) requires districts that are unable to achieve five percent annual emission reductions to demonstrate to the California Air Resources Board's (CARB's) satisfaction that it has included every feasible measure in its plan and an expeditious adoption schedule. CARB interprets the adoption of "every feasible measure" to mean that at a minimum, a district consider regulations that have been successfully implemented elsewhere. CARB also allows local air districts to consider not only technological factors, but also social, environmental, economic (e.g., cost-effectiveness), and energy factors which prevail in the district, along with the resources realistically available to the district to adopt, implement, and enforce the measures. (CARB, 1999)

C. AQMP CONTROL MEASURES

PR 1148.1 will implement Control Measure FUG-05 - Emission Reductions from Fugitive Sources (VOC), pursuant to the 2003 AQMP, which has an emissions reduction target of 2.0 tons per day (tpd) by the end of 2008. This control measure proposes further VOC emission reductions from fugitive emission sources, such as refineries, oil and gas production facilities, terminals, chemical plants and manufacturing facilities. These VOC emission reductions are needed to contribute towards achieving attainment of the national ambient air quality standard for ozone Section 182(b) (1) (A) of the Federal CAA.

D. OIL AND GAS PRODUCTION OPERATIONS

Oil field production involves bringing crude oil and produced gas from the subsurface to the surface and preparing it for shipment to the refinery. This process involves drilling, well construction and operations, treatment, separation and storage. This rule will address onshore wells exclusively.

In oil drilling operations, two well types are commonly drilled; exploratory and development. Exploratory wells are drilled into unknown formations in search of oil and gas. Development wells are wells that are drilled within an area that has already proven to be productive. Once oil or gas is discovered in a commercial viable quantity, development wells are drilled to recover as much of the oil or gas as possible. There are also service wells which are drilled for injecting liquids or gases into an underground formation in order to increase the pressure and force the oil toward the producing wells. Service wells also include wells drilled for the underground disposal of salt water produced with the oil and gas.

During the last 40 years, rotary drilling techniques have been improved so that the drill string can follow a curved path as the hole gets deeper. Such controlled directional drilling can tap reserves that are inaccessible by vertical drilling. This technique is very useful and has allowed oil deposits lying beneath the Pacific Ocean off California to be reached by wells drilled directionally from shore.

When discovered, a crude oil reservoir can contain a mixture of water, oil and gas in the small pore spaces in the reservoir rock. Initially, the reservoir holds these fluids under considerable pressure, caused by the hydrostatic pressure of the groundwater. At this pressure a large part of the gas is dissolved in the oil. These two fluids, the initial water and the gas in solution, combine to provide the driving force for moving the oil into the well where it is pushed by the underlying pressure.

A field may yield 20 percent to 30 percent of the oil and gas through the natural pressure of the underground formation. However, when pressures in the oil reservoir fall to levels where a well will not produce by natural energy, some method of artificial lift must be used. Some artificial lift methods include rod-beam pumping, gas lift, hydraulic pumping and subsurface centrifugal pumping. The rod pumping unit is a complete set of surface equipment necessary to impart an up and down motion which allows oil to the pushed to the surface.

After drilling, an oil well is constructed and it may best be described as a pipeline, reaching from the top of the ground to the oil-producing formation. It is through this pipe that oil is brought to the surface. The pipeline is a series of joints of a special kind of pipe (casing) screwed together to form a continuous tube or string for the oil and gas to flow through. Sometimes in drilling a well, more than one commercially productive formation is found. In such cases a separate tubing string is run inside the casing for each productive formation. Production from the separate formations is directed through the proper tubing strings and is isolated from the others by packing that seals the annular space between the tubing strings and casing. These are known as multiple completion wells.

To control the flow of oil and gas from the time the well starts producing, a set of valves and control equipment is put in place at the top of the well. This arrangement is sometimes referred to as a wellhead or "Christmas tree" because of its many branch-like fittings. It is usually made of steel and it forms a seal to prevent well fluids from blowing or leaking at the surface. The wellhead is sometimes made up of many heavy fittings with certain parts of the wellhead designed to hold pressures up to 20,000 psi. In other cases, wellheads may be just a simple assembly to support the weight of the tubing in the well and may not be built to hold pressure. The kind of head and configuration to be used is determined by well conditions, with high pressure formations requiring heavy, high-pressure wellheads.

Because of the valves, flanges and threaded connections on the wellhead, fugitive emissions from the oil, water and gas flow are a possibility. This is why it is important for sources to have a routine program of inspection and repair of equipment to detect and eliminate conditions that may result in a breakdown.

Abandoned Wells

When an oil or gas reservoir is depleted, the well is abandoned and the site is cleaned up. The hole is plugged with cement to protect all underground strata, prevent any flow or leakage at the surface and protect water zones, in accordance with California Code of Regulations, Subchapter 4; section 1920.1. Salvageable equipment is removed; pits used in the operations are filled in and the site is regraded. Where practical the ground is replanted with grass or other kinds of vegetation and sometimes home building sites are constructed.

Well Cellars

In most cases the wellhead resides in or above the well cellar which is a small subsurface containment basin used to capture any leaking liquid from oil and gas extraction or maintenance and workover of the well or wellhead. Based on research of AQMD's Annual Emissions Reporting program, well cellars were determined to be a source of considerable fugitive emissions. Well cellars can be lined or unlined and there can be one or more wellheads allocated to a well cellar. On average, a well cellar has approximate dimensions of 6 feet by 6 feet with a depth of between 5 feet to 8 feet. In the absence of containers used to catch discarded liquid (crude/water) produced during sampling and maintenance at the wellhead, there is an accumulation of crude oil that falls to the bottom of the well cellar. Therefore, it is common to find well cellars with an accumulation of crude oil in the bottom. Also, since there needs to be access to wellheads for maintenance and sampling, well cellars are uncovered and become sources of volatile organic compound emissions when crude oil is collected in this containment.

Separation and Treatment

After the well fluids and gas reach the wellhead they are transferred to a treatment plant. At the treatment plant the crude oil, natural gas, produced water and solid contaminants are separated and treated. A treatment plant may be simple or complex and can take many different forms depending on treatment needs. Typically, the treatment plant includes a well flow-line manifold in addition to separators, free water knockout vessels, heaters (if crude is heavy), heater-treaters, wash tanks, stock tanks, wastewater separators or oil/water separators, sumps, pits, ponds and a vapor recovery unit.

Some of the equipment that require permits by the AQMD include American Petroleum Institute (API) separators, tanks, vessels, heaters, boilers, vapor recovery units, internal combustion engines and clean-out sumps which are in most cases part of the wastewater system permit unit, oil dehydration unit or water injection facilities. Open ditches also require a permit, but there are no active permits currently in the South Coast Basin. Issues related to wastewater associated with the separation and treatment process are addressed in AQMD Rule 1176.

The well fluids (oil/water) and gas mixture flows to a well manifold that connects with each well in the field. From the manifold, the mixture is directed to either a test or a production separator. A test separator separates and measures the three phases separately and is used to determine the production of each well from the field. Under normal conditions, the mixture flows to a production separator or free water knockout where gas is separated from the mixture. From there, the oil/water stream flows to a free water knockout vessel, a heater treater, a wash tank and an oil/water separation vessel where water is removed from the oil. After it is determined that there is a sufficient reduction of water content, the oil flows to an oil storage or stock tank. Upon sale, the oil flows through Lease Automated Custody Transfer (LACT) units for metering.

Gases removed from the oil during treatment may be treated and then 1) sold to a utility; 2) used as fuel by the operator; 3) re-injected into the reservoir for pressure maintenance; or 4) vented to the atmosphere (usually only during emergency upset conditions at larger facilities). Gas collected from separators and oil treaters, along with vapors from storage tanks, may be processed through a dehydration unit (usually containing glycol). This unit removes the water from the gas before it is put into a sales pipeline or used again in the dehydration process. A common practice to control production gas from small to medium operations is to use a gas-fired heater which burns the facility's gas and produces heat to reduce the viscosity of the crude oil product. Reducing the viscosity of crude oil facilitates the handling within the production operation or the transport via pipeline to the refineries.

The oily water collected from the separators and the oil treaters may flow directly to a sump or may flow to a water treatment facility prior to disposal. At the water treatment facility the oil content of the water is reduced by skimming tanks, dissolved air flotation units, pits, filters or a combination of these. The water may be used on-site, discharged to the surface, or injected back into water injection wells or disposal wells. Vapor recovery is usually on all of the separation vessels and is piped back to the gas pipeline for dehydration.

E. AQMD RULES REGULATING OIL AND GAS PRODUCTION

Health and Safety Code Section 40727.2 requires a comparative analysis of the proposed rules and all existing federal air pollution control requirements, as well as existing or proposed AQMD rules and regulations that apply to the same equipment or source type. There are no federal air pollution control requirements that apply to wells or well cellars. There are currently three AQMD rules that regulate the emissions of fugitive VOCs at Oil and Gas Production facilities and one rule that exempts most oil production equipment from permit requirements.

Rule 1148

This rule applies to Thermally Enhanced Oil Recovery Wells. It limits VOC emissions to 4.5 pounds per day or less per well for both wells that are connected to vapor control systems and those that are not.

Rule 1173

Rule 1173 - Fugitive Emissions of Volatile Organic Compounds serves the purpose of reducing VOC leaks from components such as valves, fittings, pumps, compressors, pressure relief devices, diaphragms, hatches, sight glasses and meters at oil and gas production fields, natural gas processing plants and pipeline transfer stations.

Rule 1176

This rule applies to wastewater systems and associated control equipment located at petroleum refineries, onshore oil production fields, off-shore oil production platforms, chemical plants and industrial facilities. Sumps and wastewater separators are required to be covered with either a floating cover equipped with seals or a fixed cover, equipped with a closed vent system vented to an Air Pollution Control system.

Currently, under Rule 1176(i)(5)(H), well cellars used in emergencies at oil production fields are exempt if clean-up procedures are implemented within 24 hours after each emergency occurrence and completed within ten (10) calendar days.

Rule 219 Exemption

All wellheads, except for those with steam injection are exempt from written permit requirement per Rule 219 (n) (1) – Natural Gas and Crude Oil Production Equipment.

F. OTHER CALIFORNIA AIR POLLUTIOIN CONTROL DISTRICT (APCD) RULES REGULATING OIL AND GAS PRODUCTION

Santa Barbara County APCD

Rule 344

This rule was adopted in November 1994. The purpose of the rule is to address VOC emissions associated with sumps, pits and well cellars. As far as well cellars are concerned, the rule seeks to minimize the collection of crude oil, requiring operators to use a portable container with a cover to collect liquid whenever a valve at the wellhead is opened, and also to pump out liquid when the depth exceeds 50 percent of the total well cellar depth.

Rule 325

This rule applies to equipment used in the production, gathering, storage, processing, and separation of crude oil and natural gas prior to custody transfer. The rule requires that emissions of produced gas be controlled at all times using properly maintained and operated systems that direct all produced gas to a gas plant, a flare or any other device that has a VOC vapor removal efficiency of at least 90 percent by weight. There is a provision in the rule that exempts gas used in a tank battery vapor recovery system, which is expected to be well controlled.

Ventura and San Luis Obispo County APCD's

Ventura County Air Pollution Control District (VCAPCD) and San Luis Obispo County Air Pollution Control District have rules controlling emissions similar to SBCAPCD Rule 344. There are slight differences in the time allowed before pump-out and the length of time organic material can be stored in a well cellar. VCAPCD also has a gas production control rule similar to SBCAPCD Rule 325.

G. CALIFORNIA DEPARTMENT OF CONSERVATION DIVISION OF OIL, GAS & GEOTHERMAL RESOURCES

Currently, the maintenance of well cellars at oil and gas production operations in California is overseen by the Department of Conservation's Division of Oil, Gas & Geothermal Resources (Division of Oil and Gas). The Public Resources Code, Division 3, Chapters one through four, governs the regulatory functions of the Division of Oil and Gas. The code charges the Division of Oil and Gas with the responsibility of supervising oil, gas and geothermal well drilling, operation, maintenance, plugging and abandonment operations to prevent damage to life, health, property and natural resources. However, none of the regulations pertain to restricting the emissions of air contaminants from this equipment. More specifically, the Division of Oil and Gas must ensure actions are taken to:

1) Prevent damage to underground oil, gas and geothermal deposits;
2) Prevent damage to underground and surface waters suitable for irrigation or domestic use;
3) Prevent other surface environmental damage, including subsidence;
4) Prevent conditions that may be hazardous to life or health; and
5) Encourage the wise development of oil, gas and geothermal resources through good conservation and engineering practices.

The Division of Oil and Gas programs include well permitting and testing; safety inspections; oversight of production and injection projects; lease inspections; idle-well testing; inspection of oilfield tanks, pipelines, and sumps; hazardous and orphan-well plugging and abandonment contracts; and subsidence monitoring.

The oil fields in California are divided into six Districts. The AQMD is located primarily in District 1 and the southeast section of District 2. District 1 and District 2 are the second and third largest oil and gas producing Districts in California, respectively. District 1 includes most of Los Angeles County and all of Orange, Riverside, San Bernardino, Imperial and San Diego Counties. A small section of northwest Los Angeles County is located in District 2. Most of the producing oil fields in District 1 are located in Los Angeles and Orange Counties with 75 percent of the 2001 production coming from the from the following oil fields: Wilmington, Huntington Beach, Inglewood, Long Beach, and Brea-Olinda. For 2001, these five oilfields had a combined total of 2,688 production wells. Wilmington had 1,228 production wells; Brea-Olinda 527; Inglewood 341; Huntington Beach 324; and Long Beach 268.

In 2001, there were 43 active oil fields with 4,164 oil producing wells in District 1. The AQMD portion of District 2 had 419 oil producing wells. Of the 4,164 producing oil wells, 3,169 wells were onshore, while the remaining 995 were offshore wells. Therefore, the total number of on-shore wells in the AQMD in 2001 was 3,588 (3,169 + 419).

The 2,688 production wells located in the five major producing oil-fields represent almost 85 percent of the onshore wells in District 1. Also, there were 72 new wells drilled and another 52 wells completed in 2001 in District 1 alone. When a well is drilled there is no production of oil and gas. However, a well is determined to be properly completed when the manner of producing oil or gas or injecting fluids into the well is satisfactory and the well has maintained production of oil or gas or injection for a continuous 6-month period. There were also 201 wells that were plugged and abandoned.

H. AFFECTED FACILITIES

Operators of oil wells and well cellars are not required to obtain AQMD permits for that equipment and not all oil wells utilize well cellars. Only those facilities with equipment such as API separators, tanks, vessels, heaters, boilers, internal combustion engines and clean-out sumps (part of the dehydration or wastewater system permit unit), and "control" equipment such as heaters, flares, gas treatment equipment, internal combustion engines and boilers would have AQMD permits.

The Division of Oil and Gas requires permits for oil and gas production facilities. Based on data from their 2001 annual report, the Division of Oil and Gas has identified 220 facilities that operated 3,588 onshore wells located within the AQMD.

Based on the AQMP's 2000-2001 Annual Emissions Reporting (AER) program, 54 facilities or oilfield operators reported VOC emissions of four tons per year or greater from well cellars and other equipment operated at those facilities. The other remaining 166 facilities (220 - 54 = 166) are classified as area sources.

EMISSIONS INVENTORY

Based on information provided by the Division of Oil and Gas, the production of crude oil in District 1 has dropped from 62.5 million barrels per year in 1987 to 32.3 million barrels in 2001 and District 2 has dropped from 18.3 million barrels per year in 1987 to 10.5 million barrels per year in 2001. In Southern California, 1991-92 marked a period of time when several onshore wells were abandoned due to a home construction boom as well as regulations which increased the cost of operations considerably. In addition, the cost of imported crude oil affects the operation (profitability) of local oil wells.

Although California's crude production has decreased over the last 15 years, current demand for petroleum is still substantial and Department of Oil and Gas permits for new wells continue to be issued each year. Therefore, there still exists a need to ensure that oil and gas production facilities are operated so that there are minimal fugitive emissions in the South Coast Basin.

In order to address the 2003 AQMP control measure FUG-05, staff examined the activities of oil and gas production wells. A broad-based approach was taken to establish which sources were viable options for possible emission reductions. A search of AQMD databases based on Standard Industrial Classification (SIC) codes (1311-crude petroleum and natural gas; 2821-chemicals and allied products, 2911-petroleum refining and 5171-petroleum bulk stations and terminals) that were applicable to oil and gas production activities was completed. This search resulted in a total of 95 facilities of which 54 were associated with SIC 1311. It was established that emissions from the remaining 41 sources were already being reported under the AQMD AER program.

A. WELL CELLARS

The emission inventory was established based on reported emissions by oil and gas facilities for the fiscal year 2000-01 and the 2003 AQMP. In 2000-01, 54 oil and gas production facilities reported 0.62 tpd of VOCs from the well cellars in the AQMD AER program. Almost 80 percent of the total VOC emissions came from 13 of the facilities identified in the inventory.

To determine the contribution of area sources (oil and gas operations that did not report emissions under the AER program), staff used the 2010 AQMP Controlled Planning Inventory, which estimates fugitive VOC emissions from well cellars as 0.59 tpd. The 2010 planning inventory was based on current oil production with the assumption that there would be zero growth in the oil and gas production industry. As such, the 2010 planning inventory is equal to the 2000-01 emissions inventory and is used in estimating both VOC emission reductions and cost effectiveness. Therefore, the total fugitive VOC emissions from all well cellars (point and area sources) are estimated to be 1.21 tpd for

2000-01. The number of onshore wells, VOC emissions from well cellars and overall VOC emissions from oil and gas operations are shown in Table 1.

Table 1 – Breakdown of Well Cellar Emissions

	Point Sources	Area Sources (2)	Total
No. of Wells	2,257 (1)	1,331	3,588 (3)
Well Cellar Emissions (tpd)	0.62 (4)	0.59 (5)	1.21
Emissions from all Oil & Gas Production Sources (tpd)	3.11 (5)	2.95 (5)	6.06 (5)

(1) Represents the number of onshore wells listed in the Division of Oil & Gas - 2001 Annual Report, for the facilities reporting well cellar emissions (2000-2001 AER).
(2) Area sources defined by the AQMD as sources for which operators did not report emissions to the AER program.
(3) Represents the total number of onshore wells listed in the Division of Oil & Gas -2001 Annual Report.
(4) VOC emissions reported under the 2000-2001 AER program.
(5) Based on AQMP 2010 Planning Inventory.

B. STEAM INJECTION WELLS

Thermally enhanced oil recovery wells are sources of VOC emissions whereas the steam injection wells have negligible VOC emissions. Two facilities in the South Coast Basin reported VOC emissions of 76 tons of VOCs for 2000-01, from the thermally enhanced oil recovery operations. The wellheads at these facilities are vented to steam generators and/or boilers. In addition, one of the two companies has already started to cut back their operations by reducing their energy production by going from a total of 26 steam generators to five since it plans on abandoning the project in a year or two. These changes have been made in preparation for plans to develop a housing project at the site. Therefore, staff will not pursue further regulation of steam injection wells at this time.

C. PRODUCED GAS

Currently, the AQMD does not have detailed records documenting the amount of produced gas for oil and gas production facilities. The 2001 Annual Report of the Division of Oil and Gas reported produced gas from approximately 2,800 wells located at 100 onshore facilities in the AQMD as 11 billion cubic feet for the year 2001. Based on interviews of facility operators, it was estimated that approximately 99.1 percent of the produced gas is directed to on-site gas treatment equipment, on-site control equipment, such as heaters, flares, internal combustion engines or boilers, or directed to other facilities, such as the Southern California Gas Company or other facilities using pipeline quality “natural gas”. Therefore, the remaining 0.9 percent of the produced gas which is approximately 100 million cubic feet of produced gas which is uncontrolled and is vented directly to the atmosphere.

Produced gas is primarily methane and non-methane hydrocarbon compounds. Only the reduction in non-methane hydrocarbons will be considered as VOC emission reductions. The volume of produced gas was determined from data listed in the Division of Oil & Gas 2001 Annual Report and the AQMD permitting database. The average molecular weight of the produced gas from the oil wells is assumed to be that of a typical natural gas based on five different compositions listed in the Petroleum Engineering Handbook. The gas density was calculated using the average molecular weight of the produced gas divided by the gas constant of 379.4 cubic feet per lb-mole (ideal gas at standard conditions).

Data/Assumptions:

Untreated Volume of Produced Gas	100 million cubic feet per year
Gas Molecular Weight (MW)	23 lb/lb-mole (average)
Gas Density	0.0606 lb/cubic feet
Produced Gas Methane Content	90 percent (average)
Heater Destruction Efficiency	95 percent

Based on this data, the overall mass of non-methane VOC gases produced in the South Coast Basin prior to control or combustion is as follows:

$$100 \times 10^6 \ \frac{\text{cu ft gas}}{\text{year}} \times (1.0-0.9) \times 0.0606 \ \frac{\text{lb}}{\text{cu ft}} \times \frac{1 \ \text{ton}}{2000 \ \text{lb}} \times \frac{1 \ \text{year}}{365 \ \text{day}} = 0.83 \ \text{tpd}$$

CONTROL TECHNOLOGY ASSESSMENT

There are three primary techniques for reducing VOC emissions from well cellars: (a) sample management, (b) equipment installation and repair, and (c) implementing an inspection and maintenance program. In addition, there are a number of techniques for controlling the emissions of produced gas.

A. SAMPLE MANAGEMENT

Sample management focuses on the good work practice standards which include catching and collecting discarded liquid produced at the wellhead during sampling. The use of a portable container prevents the crude oil from falling to the bottom of the well cellar or on the ground, spreading out and emitting from the surface of the accumulation. The container is equipped with a cover, which is required to be closed whenever crude oil is not being collected, to significantly reduce VOC emissions to the atmosphere. The collected crude oil is typically added back to the separation treatment system.

B. EQUIPMENT INSTALLATION, MAINTENANCE AND REPAIR

1. Crude Oil

Three possible equipment installations/modifications and component maintenance and repair are briefly described.

a) Adapter Installation

This technology involves the installation of an adapter to the stuffing box for the pump rod of the oil well. The adapter includes a reservoir to collect leakage from the stuffing box packing. Similar to the use of a container under Sample Management, the use of a portable container prevents the crude oil from falling to the bottom of the well cellar or on the ground, spreading out and emitting from the surface of the accumulation. The reservoir is equipped with a cover, which is required to be closed whenever crude oil is not being collected, to significantly reduce VOC emissions to the atmosphere. The adapter also includes a shut off switch that will automatically shut down the pump operation when the liquid in the reservoir is nearly full.

b) Stuffing Box Maintenance

This option involves the increased maintenance and repair of the stuffing box. The stuffing box is a packing gland, chamber, or "box" used to hold packing material compressed around a moving pumping rod to prevent escape of gas or liquid. Therefore, adjusting or replacing the packing will reduce the fugitive emissions resulting from the accumulation of crude oil in the well cellar or on the ground and thereby eliminate associated clean-up costs.

c) Closed-Purge Systems

A closed-purge system captures leaking liquid and either returns it to a production system or routes it to a closed disposal system. The control efficiency of a closed-purge system depends on the percentage of leakage that is routed to the disposal system. A closed-purge system can be installed on a single component or on a group of components. The control efficiency of closed-purge system can be at least 95 percent.

2. Produced Gas

a) Gas Plant

The overall objective of an oil and gas production facility is to prepare the oil and gas for pipeline transport. The oil is usually transferred to a pipeline terminal and eventually to a refinery, while the gas may be sold to a pipeline company for further sale or transported directly to a gas plant for additional treatment. The types of process equipment required at a production facility depend on the quality of the well-head product and whether or not both oil and gas are produced by the well.

Produced gas exiting the separators is composed primarily of methane, ethane, propane and butane. It may also contain impurities such as nitrogen, helium, carbon dioxide, hydrogen sulfide, mercaptans and water vapor. Condensable hydrocarbons are recovered from the gas using absorption, refrigeration or gas expansion processes. Water is removed by passing the gas through equipment such as glycol dehydrators, where water is absorbed by the glycol. This water is ultimately vented as steam from the glycol reboiler.

Gas sweetening and product separation are often conducted at a gas plant that is not located at the oil and gas production facility. In order to "sweeten" sour produced gas, hydrogen sulfide and carbon dioxide are usually scrubbed from the gas using an amine solution in an absorption tower. The acid gas stream may be flared, incinerated or processed further in a sulfur-recovery facility, and the scrubbed gas stream is further processed to separate products.

Some small oil and gas production operators are part of a cooperative system that purchases gas from other small operators and collectively sends it to a gas plant. However, other smaller oil and gas production operators do not produce large enough quantities of gas that are of suitable quality to be sent directly to a pipeline company. For these operators, a gas plant may be cost-prohibitive and therefore it is not regarded as a cost effective control option. One of the following control options would be selected by these operators

b) <u>Heaters</u>

Produced gas can be used as fuel for heaters that are used to heat crude oil. When the crude is heated, its viscosity is reduced thereby allowing for easier transport of the material. There are two types of heaters that are usually used at oil and gas production operations. They are direct-fired and indirect-fired heaters.

A direct-fired heater is one in which the fluid to be heated comes in direct contact with the immersion-type heating tube or element of the heater. Direct-fired heaters are generally used to heat non-corrosive organic fluids that are under relatively low pressure. These units are normally constructed so that the heating tube can be removed for cleaning, repair or replacement.

An indirect-fired heater is one in which the fluid passes through pipe coils or tubes immersed in a bath of water, oil, salt, or other heat transfer medium that, in turn, is heated by an immersion-type heating tube similar to the one used in the direct fired heater. The immersion-type heating tube heats the bath, which in turn heats the fluid flowing through coils immersed in the bath. When water is used as the bath, water free of impurities will prolong the life of the heater and prevent fouling of the surface of the heating tube and coils. Indirect fired heaters are generally used to heat corrosive or high pressure fluids. Indirect heaters are constructed so that the heating tube and pipe coil are individually removable for cleaning and replacement.

Heaters designed to comply with Rules 1146, 1146.1 and 1146.2 will reduce VOC's by a minimum of 95 percent.

c) Flares

Produced gas is a byproduct of many oil field production facilities. Facilities use flares to burn off produced gas when their compressors break down, are being serviced, or when there is another problem in the produced gas production system. In some cases, flares are used when the heating value of the gas cannot be recovered economically because of intermittent or uncertain flow or when process upsets occur as described above. Some operators may flare all their produced gas if they do not recover it. Flares may also be used on the vapor recovery system at a loading rack or tank battery. If properly operated and maintained flares should not give off any visible emissions and only a flame should be emanating from the stack of a flaring unit. If the flare uses supplemental natural gas, it must be equipped with a device that automatically shuts off the flow of natural gas in the event of a flame-out or a pilot failure. This will minimize the potential of an explosive mixture of gas accumulating in the area surrounding the flare.

Some types of flares include steam-assisted, air-assisted and pressure head flares. Steam- assisted flares are single burner tips, elevated above ground, that burn the vented gases in a diffusion flame. This type of flare system injects steam into the combustion zone to promote turbulence and to induce air into the flame. Steam-assisted flares also account for the majority of flares installed. Flares can typically achieve a VOC destruction efficiency of at least 90 percent.

During discussion with the Santa Barbara County Air Pollution Control District (SBCAPCD) staff revealed that many small oil and gas production facilities in their jurisdiction have installed their own operator-built flares to suit their individual gas treatment needs and meet SBCAPCD rule requirements.

Flares will also need to meet all applicable regulatory requirements in the AQMD.

d) Other Combustion Devices

Gases removed from the oil during treatment may be burned as fuel. The fuel may be used in devices such as internal combustion (IC) engines, heater treaters, boilers, steam generators or turbines. At some facilities these IC engines are used to drive pumps, compressors and other prime movers involved in the oil and gas production operations.

e) Carbon Adsorbers

Activated carbon adsorption systems can also be used to control VOC emissions. In situations where the carbon is virgin material, the VOC reduction efficiency will be high. However, when the carbon becomes saturated, it will have to be replaced and the spent carbon will have to be regenerated.

C. INSPECTION AND MAINTENANCE

A required inspection and maintenance (I & M) program is effective in reducing fugitive VOC emissions. In this approach, the four most important factors in determining the control effectiveness are: (1) to determine that a leak is occurring or has occurred, (2) to correct the cause of the leak, (3) to remove or cleanup the accumulation of VOC emitting material, and (4) to determine the frequency at which the leaks are occurring. An I & M program can be designed to identify oil production well components that are emitting sufficient amounts of material to warrant reduction of the emissions through repair.

To determine the effectiveness or a control factor for well cellars, staff analyzed two rules that require an I & M program: AQMD Rule 1173 – Control of Volatile Organic Compound Leaks And Releases From Components At Petroleum Facilities and Chemical Plants and SBCAPCD Rule 344 - Petroleum Sumps, Pits and Well Cellars.

AQMD Rule 1173 requires the use of a Leak Detection and Repair (LDAR) program. LDAR incorporates the elements of an I & M program. However, LDAR goes one step further in that it quantifies the fugitive gaseous VOC leaks with a portable analyzer, as per United States Environmental Protection Agency (USEPA) Reference Method 21. Inspections with VOC measurements for heavy liquid pumps are required on a quarterly basis. All other components must meet an emission concentration limit. A conservative estimate of a control factor for components (pumps, valves, connectors, ect.) in heavy liquid service (including crude oil) was documented as 84 percent. (Rule 1173 Staff Report – October 10, 2002).

SBCAPCD Rule 344 requires the use of a sample management program and an I & M program that includes the installation of an adapter system and/or maintenance and repair to reduce fugitive VOC emissions. A 70 percent control factor was estimated by SBCAPCD staff. Although not explicitly stated in the rule, SBCAPCD equipment permitting staff requires weekly inspections as a permit condition when issuing well cellar permits, since SBCAPCD requires written permits for production wells and well cellars.

SBCAPCD Rule 344, adopted in February 1996 and subsequently approved by CARB and USEPA for inclusion in the SIP, claimed reduction of well cellar VOC emissions from 406 tpy in inventory year 1995 to 94 tpy in inventory year 1997; an overall 77 percent reduction in VOC fugitive emissions from well cellars. Although some of the emission reductions can be attributed to shutdown and closure of production wells, the majority of the reported VOC reductions were claimed to be as a result of the implementation of sample management and I & M of well cellars required by the rule.

A control factor of 80 percent is used to calculate the VOC emission reductions resulting from an I & M program for well cellars. This determination is based on AQMD's experience with the highly successful implementation of the I & M programs for light and heavy liquids and gases under Rule 1173 that have resulted in significantly fewer leaking components at affected facilities, the reported success of the SBCAPCD's Rule

344 in reducing fugitive VOC emissions, and the fact that PR 1148.1 goes beyond the SBCAPCD rule by requiring quarterly total organic compound (TOC) measurements based on USEPA Method 21.

PROPOSED RULE

A. PURPOSE

PR1148.1 reduces VOC emissions from oil field production well heads and the well cellars that house the wellheads that control the flow of crude oil from onshore oil wells. These reductions will be accomplished through an improved sample management, and an inspection and maintenance program. The proposed rule will also reduce the amount of produced gas released to the atmosphere by requiring it to be collected and controlled.

B. APPLICABILITY

This rule will apply to wellheads and well cellars at onshore facilities where petroleum is produced, gathered, separated, processed and stored.

C. DEFINITIONS

Key definitions are listed in the proposed rule for clarity.

SIC Code 1311 defines an oil and gas production field as a facility where both crude petroleum and natural gas production are conducted. However, the primary purpose of PR 1148.1 is to reduce VOC emissions resulting from the accumulation of crude petroleum in the well cellar and the release of gaseous VOC from the wellhead.

Sensitive receptor is defined as a school, a licensed daycare center, a hospital or a convalescent home since special inspection and repair requirements apply to wells and well cellars located near these receptors.

D. REQUIREMENTS

Well cellars at oil and gas production operations are a source of VOC emissions. Prior to this proposed rule, there were no rules that addressed this source category.

To accomplish the VOC emission reductions, the proposed rule will require the implementation of improved sample management utilizing good work practice standards through the use of a portable container with a cover anytime a valve is opened at the wellhead. This requirement has an effective date of July 1, 2004.

Periodic audio-visual inspection of the stuffing box of the oil well pump and quarterly inspection and TOC measurement of the well cellars is required starting July 1, 2004.

The proposed rule has established that if the AQMD inspection detects that a TOC concentration in the well cellar exceeds 500 ppm as determined by USEPA Method 21, the operator will be in violation of this rule. A TOC concentration of 250 ppm, and also for those well cellars located within 100 meters of a sensitive receptor, 2 inches of accumulated organic liquid, measured by AQMD inspection or operator inspection will trigger maintenance or repair of the wellhead stuffing box or other source of leakage and the removal of accumulated material in the well cellar.

PR 1148.1 will also require the operator to minimize emissions during maintenance and well workover. The proposed rule requires the operator to remove any liquid that accumulates in the well cellar during maintenance or workover, within two (2) days after such activity has been completed. In the event that a portable enclosed storage vessel is used to store the crude oil or petroleum products during a well workover or during significant maintenance, the operator will also be required to equip the enclosed storage vessel with air pollution control (APC) equipment. The APC equipment will reduce the VOC emitted from the collected crude oil/water mixture from being released into the atmosphere. The APC unit will also be required to reduce VOC emissions to less than 250 ppm of TOC and the operator will be required to conduct USEPA Method 21 measurement at the time of filling to verify this concentration limit.

As part of their maintenance activity, operators will occasionally apply steam to production wells to clean them since this will enable the wells to function more efficiently and ultimately decrease the overall cost of production. Before the well is steamed the underground equipment is removed. This equipment may include underground pump lift rods, usually hundreds of feet long, which are pulled through the wellhead. This activity creates gallons of crude oil that accumulates in the well cellar. Steam is then applied to the underground formation through the wellhead and the heat from the wellhead in turn heats the contents of the well cellar. Therefore, in order to minimize the evaporation of VOCs, the proposed rule requires that immediately prior to steaming the well, the operator shall pump out the well cellar in which the well is located. In addition, all liquids should be pumped out after steam cleaning components in a well cellar. Since these are planned activities, it is reasonable to require the operator to remove the source of potential fugitive emissions.

PR 1148.1 will also focus on ensuring that if and when crude oil does accumulate in the well cellars the residence time is minimized. This requirement will be accomplished through quarterly inspections and maintenance of components of the oil well. The operator is required to pump out or remove any organic material that accumulates in the well cellar within five calendar days after the material is discovered or after the operator determines that the total TOC concentration in the well cellar exceeds 250 ppm using USEPA Method 21. In cases where oil wells are located within 100 meters of a sensitive receptor, the operator is required to pump out or remove any organic material within 24 hours.

At many larger oil and gas production facilities, produced gas that is extracted from production wells is treated at a gas plant in preparation for use as fuel in engines, boilers and turbines; for sale to the Southern California Gas Company or other buyers; or for underground injection at the facility. Gas treatment may involve the removal of carbon dioxide and hydrogen sulfide. These operations along with some of the smaller type facilities may also direct their produced gas to other combustion equipment to reduce potential VOC emissions. The proposed rule requires that in the absence of a gas plant, the operator has to control the emissions of all produced gas, except gas that is associated with a tank battery which already has a closed-type vapor recovery system. Control may be achieved by use of any control equipment that: a) is capable of achieving a VOC destruction efficiency of at least 95 percent by weight or b) demonstrates an outlet VOC concentration of 50 ppm or less, no later than January 1, 2006. In order to verify that the equipment efficiency and the VOC concentrations in the exhaust, operators will be required to perform periodic source tests using the relevant EPA Methods (25 and 25 A), the equivalent District Method 25.1 or USEPA Method 21. EPA Test Method 18 or ARB Method 422 discussed in the Test Methods section of the rule will be required to be used to determine emissions of exempt compounds.

The proposed rule will also require that if any control device used to reduce the VOC emissions requires the use of supplemental natural gas, it will be required to be equipped with an automatic shut-off device in the event that there is a flame-out or a pilot failure. This shut-off device will prevent any leaks of natural gas that may occur when the flame of the control equipment is extinguished.

The rule also requires that for produced gas handling activities within 100 meters of a sensitive receptor, operators are required to repair any gaseous leaks of 250 ppm TOC or greater, within 24 hours of discovery or take action to prevent the release of TOCs. This requirement addresses the Governing Board's Environmental Justice directive which places increased emphasis on emission sources within close proximity of sensitive receptors.

E. OPERATOR INSPECTION REQUIREMENTS

For wellhead stuffing boxes located in well cellars, the operator is required to conduct weekly visual inspections, which will take effect on July 1, 2004. Weekly visual inspection of the stuffing boxes will allow the operator to repair any leaks before there is a sizeable accumulation of organic liquid in the well cellar. If a liquid leak is observed, the operator must conduct a USEPA Method 21 measurement within two days of discovery. In addition, the operator will be required to perform quarterly inspections using a portable analyzer if liquid or the presence of organic material is visible in the well cellar. The operator may choose to schedule these inspections to coincide with the quarterly inspections required for Rule 1173.

In the AQMD, we expect to find only a small number of oil and gas production wells that have wellheads, which are not located in a well cellar. Therefore, when leaks occur in these situations, the crude oil-water mixture accumulates on the soil and will evaporate and be released to the atmosphere. For this reason, if a stuffing box is not located in a well cellar, the operator will be required to do daily visual inspections.

In order to address the Governing Board's Environmental Justice directive, the proposed rule also includes a provision that takes into consideration facilities that are located within 100 meters of a sensitive receptor. In these circumstances, operators are required to do daily audio-visual inspections as well.

PR 1148.1 also includes a provision that allows an operator to perform monthly visual inspections for stuffing boxes fitted with a stuffing box adapter with a well shut off switch and a closed crude oil collection container. If the operator decides to add a stuffing box adapter equipped with a well shut off switch, and a closed container that collects any liquid leak, he may seek to change the frequency of visual inspection of the stuffing box. For there to be a change in inspection frequency to monthly, the operator will need to seek the prior approval of the AQMD Executive Officer. This reduction in inspection frequency is due to the fact that the adapter with a shut off switch helps to reduce the chances of liquid leakage onto the ground. In addition, the operator will be expected to maintain the adapter and the shut off switch and ensure that they are both kept in good working condition at all times. However, this inspection frequency option does not apply to wells located within 100 meters of a sensitive receptor.

F. RECORDKEEPING REQUIREMENTS

Facility operators will be required to maintain records of inspections and repair and the conditions that would require them to pump out their well cellars. These records are to be kept in a form acceptable to the AQMD that will include the time and date, in addition to a description of actions taken and the individuals responsible for these actions. Records of data collected must be maintained for a period of three years and a minimum of five years for all Title V facilities. Facility operators must also maintain purchase and installation records for stuffing box adapter systems and all records must be made available to the Executive Officer upon request.

G. TEST METHODS

Proposed rule language requires approved test methods to be used in determining TOC or VOC concentration and control efficiency.

H. EXEMPTIONS

PR 1148.1 has an exemption for any wells that have been idle and out of operation for more than six months, for wells that have been officially abandoned as defined by the Division of Oil and Gas, or for water, gas, or steam injection wells. The operator must have inspection and production records to demonstrate compliance with these exemptions.

Most wells are not free flow wells and would require the application of energy applied by a pump. Therefore, when a well has been idle for as long as six months and there are neither gaseous nor liquid leaks, the chances of future leaks become minimal.

In cases where a well has been certified as abandoned by the Division of Oil and Gas, the hole is plugged with cement to protect the underground strata and to prevent any flow or leakage of crude oil at the surface.

Rule 1148 addresses requirements for steam injection wells and therefore are not included in PR 1148.1. Wells that are exclusively associated with water and gas injection are different from production wells and do not produce crude oil flows. Therefore, the activities of these wells are exempted from this proposed rule.

Rule 1176 allows the use of well cellars for storage of VOC-containing materials during emergencies, provided certain requirements are met. Under the provisions of these requirements, well cellars are exempt from some of the limits and requirements of Rule 1148.1 during emergencies.

EMISSION REDUCTIONS

To achieve the VOC emission reductions, the rule will require periodic visual and USEPA Method 21 inspections and improved maintenance of the well cellar and wellheads. As part of the improved maintenance requirements, AQMD will limit both the length of time that the operator is allowed to have crude oil remain in the well cellar, and the depth of liquid in the well cellar before pump-outs are required. Produced gas from the oil wells will need to be treated and stored/transported offsite, flared, or controlled to reduce VOC emissions.

A. Well Cellars

The fugitive VOC emission inventory for well cellars in the AQMD is 0.62 tpd for the larger oil and gas production facilities and 0.59 tpd for the smaller "area sources". Therefore, the total VOC emission inventory for all well cellars in the AQMD is 1.21 tpd (see Emissions Inventory).

As discussed in the "Inspection and Maintenance" section of the Control Technology Assessment, staff has determined that the control factor for PR 1148.1 is 80 percent. Therefore, based on the 80 percent control factor, the total VOC emission reductions are calculated as follows:

Emission Reductions = (1.21 tpd)(0.80) = 0.97 tpd

B. Produced Gas

Based on the 2001 annual report of the Division of Oil and Gas, staff's calculations have determined that a total of approximately 100 million cubic feet of produced gas is released to the atmosphere without being treated or controlled. The VOC portion of these emissions is 0.83 tpd. It is expected that the selected method of control of produced gas will be flaring. Based on permitting experience, a properly designed flare for an oil and gas production operation should achieve a minimum of 95 percent control. Therefore, VOC emissions associated with the flaring of produced gas was calculated as follows:

VOC (non-methane gas) Emissions Reduced = (0.95) (0.83) = 0.79 tpd

C. Total VOC Emission Reductions

Therefore, the total reductions from this proposed rule are estimated as follows:

Total Reductions = (Reductions from well cellars) + (Reductions from controlling produced gas)

= 0.97 tpd + 0.79 tpd = 1.76 tpd

Due to the fact that there was no emissions inventory associated with produced gas emissions for the sources identified, SIP credit was not claimed for the 0.79 tons per day emissions reduction from produced gas, but these emission reductions will provide an environmental benefit. The VOC emission reductions that will be SIP creditable will be 0.97 tons per day.

COST AND COST EFFECTIVENESS

PR 1148.1 will regulate VOCs from the liquid side of crude oil production (primarily evaporation of crude oil) and VOCs from the untreated/controlled produced gas associated with crude oil production. In order to provide a clear understanding, staff will calculate the cost separately for these categories of VOC emission reductions and then calculate the overall cost effectiveness of the combined categories for the proposed rule.

A. LIQUID CONTROL COSTS

Oil leaks from wellhead components, as well as from sampling activities are considered lost production. Crude oil that spills during the daily sample gathering procedure would enter a container as described previously, and can then be added to the process stream. In addition, leaks large enough to trigger well cellar rule requirements will result in crude oil being pumped out and returned to the process stream as opposed to being accumulated and emitted into the atmosphere. Pumping costs can be eliminated if the problem that causes accumulation in the well cellar or on the ground is corrected.

The costs of the proposed rule associated with control of the liquid organic material are as follows:

a) Purchase of sample containers;
b) Daily or weekly visual inspections; and
c) Periodic pump-out of organic liquid.

The number of oil wells operating in the AQMD is approximately 3,588 as reported in the Division of Oil and Gas 2001 Annual Report. This number will be used to compute annual operating costs and capital costs in this report.

A facility will be required to purchase containers with covers that are used to collect crude oil discharged during sampling and maintenance. It will be assumed that a facility will have one container for every four well cellars.

The inspection program required by PR 1148.1 consists of periodic audio-visual inspections of the stuffing boxes and a quarterly USEPA Method 21 inspections/TOC measurement of the well cellars. Most of these inspections can be conducted concurrently with inspections required by Rule 1173 with a minimal increase in inspection time. Rule 1173 requires audio-visual inspections of the well pumps/stuffing boxes for manned oil and gas production wells once during every eight-hour operating period and TOC measurement once every quarter. The following will discuss in greater detail staff's analysis regarding the additional inspection costs to implement PR 1148.1.

PR 1148.1 requires the operator to perform a weekly audio-visual inspection of the stuffing boxes located in or above the well cellar. PR 1148.1 also requires that a stuffing box installed on a wellhead pump that is not located in a well cellar or oil wells located within 100 meters of a sensitive receptor be audio-visually inspected daily. Staff estimates that the total amount of additional time needed to conduct a PR 1148.1 audio-visual inspection, re-inspection and TOC measurement required by any observed leakage at the well pump stuffing box, and the extra handling associated with catching sampling discharge will take an average of 5 minutes per well. In addition, when the wellhead fittings are inspected quarterly pursuant to Rule 1173, operators can take this opportunity to inspect the well cellar and address any related maintenance activities. However, this concurrent Rule 1173 inspection/TOC measurement event will not be factored into the cost-effectiveness calculations. Based on discussions with industry representatives and consultants that conduct USEPA Method 21 inspections/TOC measurements at oil and gas operation facilities pursuant to Rule 1173, staff agrees that the quarterly TOC measurements for PR 1148.1 will be conducted at the same time as the Rule 1173 measurements with minimal additional time required. Therefore, the oil and gas facilities will not incur any additional cost for this requirement of PR 1148.1. The 5-minute well cellar inspection is regarded as conservative since most wells would be located in the same vicinity and audio-visual inspection of its multiple wells could be completed over a shorter time interval. The cost of the inspection is estimated at $25 per hour. Since the inspection of wells at manned oil and gas operations can be conducted concurrently with Rule 1173 inspection, travel time costs will only be considered for those wells located at unmanned facilities. Staff will include an additional ten minutes per well inspection at unmanned facilities in its cost calculations.

As previously discussed, the total number of onshore oil wells operating in the AQMD is 3,588. The number of oil wells for the 54 oil and gas production facilities reporting under the AQMD's AER program was determined to be 2,257 wells. It is assumed that all 2,257 wells are contained in well cellars and are located at manned facilities. Therefore, , the number of wells operating at the smaller oil and gas production facilities is 1,331 oil wells (3,588 - 2,257).

Staff estimates conservatively, based on discussions with operators, that 25 percent of these 1,311 wells are not located inside well cellars. Based on the proposed rule, the operator of these 333 wells would have to inspect these wells on a daily basis. For purposes of the calculation, staff will assume that all of these wells are located at unmanned facilities.

Compliance records indicate that there are 17 sites within 100 meters of a sensitive receptor. Of these 17 sites, five are manned and are already subject to the once per eight-hour shift inspection requirements of Rule 1173. The remaining 12 sites which are unmanned will incur additional cost associated with an increased inspection frequency and travel costs. Staff estimates that there are on average, 10 wells associated with each of these unmanned facilities. Therefore, there are a total of 120 wells located at unmanned facilities that are within 100 meters of a sensitive receptor that will require daily audio-visual inspections.

The number of oil wells located at unmanned facilities that are subject to weekly audio-visual inspections is 878 wells (1,331 - 333 - 120).

Liquid Control Costs

(1) Capital Cost

It is estimated that the containers will be replaced every 3 years based on field experience with this type of equipment and that the cost of the containers will not change over each 3-year period, but will be adjusted to present value using a real interest rate of 4 percent. The calculations below also takes into consideration that over a 10-year period, there will be 4-batches of containers purchased, starting at the beginning of the compliance period.

Batch #1 (Initial Purchase)		
Container		
Expected Service Life for Metal Container		3 years
Individual Metal Container Cost		$25
Container Capital Cost = (3,588 wells/1 container per 4 wells)		$22,425
Batch #2 (year 3)		
Container Capital Cost =	(0.889) ($22,425) =	$19,936
Batch #3 (year 6)		
Container Capital Cost =	(0.7903) ($22,425) =	$17,722
Batch #4 (year 9)		

Container Capital Cost = (0.7026) ($22,425) = $15,756

Total Liquid Control Capital Cost (Present Value) = $75,839

(2) Annual O & M Cost

(a) Audio-Visual Inspections

(i) Wells with Well Cellars at Manned Facilities - Annual Inspection Cost (Based on weekly inspections for 2,257 well cellars) @ 5 minutes per well cellar; $25/hr (technician labor)

2,257 w/cellars x 1 insp/wk x 52 wk/yr x (5/60) hr/insp x $25/hr = **$244,508/year**

(ii) Wells with Well Cellars at Unmanned Facilities - Annual Inspection Cost (Based on weekly inspections for 878 well cellars) @ 5 minutes per well cellar and 10 minutes travel and $25/hr (inspection labor)

878 w/cellars x 1 insp/wk x 52 wk/yr x (15/60) hr/insp x $25/hr = **$285,350/year**

(iii) Wells without Well Cellars – Annual Inspection Cost (Based on daily inspections for 333 wells) @ 5 minutes per well and 10 minutes travel and $25/hr (inspection labor)

333 w/o well cellars x 365 insp/yr x (15/60) hr/insp x $25/hr = **$759,656/year**

(iv) Wells at Unmanned Facilities within 100 meters of a Sensitive Receptor (Based on daily inspections for 333 wells) @ 5 minutes per well and 10 minutes travel and $25/hr (inspection labor)

120 wells x 365 days/yr x (15/60) hr/insp x $25/hr = **$273,750/year**

Total Annual Audio-Visual Inspection Cost = **$1,563,264/year**

(b) Pump-Outs

<u>Wet Season</u>
Based on comments from facility operators, well cellars are currently pumped out one time during the wet season due to accumulated rain water. Therefore, since Rule 1148.1 requires that the criterion for pump-out is VOC concentration and not non-organic liquid depth for all but perhaps a few well cellars near sensitive receptors, staff does not estimate that there will be a need for any additional

pump-outs during the wet season. As a result, there will be no additional pump-out cost to industry during the wet season due to the adoption of this rule.

Dry Season
Based on information provided by industry, the current pump-out rate during the summer is estimated at approximately 651 pump-outs or 20 percent pump-outs based on a total of 3,255 (3,588 - 333) well cellars. However, since PR 1148.1 requires operators to perform weekly visual inspections and requires pump-outs based on 250 ppm TOC, staff has estimated that there will be an additional 130 (20 percent of 651) new pump-outs associated with this rule.

A combined vacuum truck and operator rate of $75 per hour, including travel and disposal costs, where appropriate, was provided by an operator of an oil and gas production facility. Based on this rate and assuming that each well pump-out takes ½ hour, the overall cost of pump-outs is as follows:

Pump-out cost = (130 pump-outs)(½ hr/pump-out)($75/hr) = **$4,875/year**

	Inspections		Pump-Outs
Total Liquid Control Annual O&M Cost =	**$1,563,264**	**+**	**$4,875**
=	**$1,568,139**		

B. PRODUCED GAS CONTROL COSTS

Based on a review of the Division of Oil and Gas 2001 Annual Report staff has determined that of the 220 facilities operating oil and gas wells in the AQMD, 100 facilities reported 11 billion cubic feet of produced gas. The Division of Oil and Gas does not have a deminimus reporting level. Based on a review of the AQMD permitting database, and interview of facility operators in conjunction with the 2001 Division of Oil and Gas Annual Report, it was determined that 135 out of 220 oil and gas production facilities directed their produced gas to gas treatment for use offsite or to gas control systems (flares, heaters, IC engines, or boilers). Approximately 99 percent of the reported produced gas was sold, used or controlled.

Staff estimated an overall average gas to oil ratio based on the total annual gas and oil production, respectively, for facilities that reported. This gas to oil ratio was used to estimate the annual gas production for facilities that reported only oil production (but no gas production) to the Division of Oil and Gas in 2001. Further, the gas production rate was used to estimate the size (BTU rating) for a heater that would be needed to control a facility's produced gas.

It was determined that the remaining 85 (220 – 135) facilities did not treat nor control their produced gas. Since the cost of treating the produced gas for sale to other facilities or the Southern California Gas Company is not practical for the lower gas producing facilities, staff believes that these facilities will install heaters to combust the 100 million cubic feet per year of produced gas, using the derived energy to heat the crude oil in preparation for sale or use on site. Information provided for gas-fired heaters by manufacturers indicated that the installed unit price of a heater designed to burn (or control) the produced gas from the smaller oil and gas production facilities ranged from $6,000 and $20,000 for heaters with a 400,000 BTU per hour rating and from $31,000 to $60,000 for heaters rated at 2 MMBTU per hour. Although it will overestimate the actual cost, staff assumed that all operators purchasing heaters will do so at the high end of the range, or $20,000 for a 400,000 BTU per hour heater and $60,000 for a 2 MMBTU per hour heater. The manufacturer also estimated annual maintenance cost for small heaters to be about $1,000 per year. Further, based on staff's estimation, it was determined that 83 of the 85 facilities would each be expected to install one heater that was rated at approximately 400,000 BTU per hour. The remaining two (2) facilities would each require a 2 MMBTU per hour heater.

For facilities that are required to install heaters, there is a permit processing fee of $2,232.96 for the first heater (Schedule C). Although staff believes many of these facilities will qualify as a small business with a reduced permit processing fee, staff will base the costs as if all facilities are large businesses and are subject to the full fee. There is also an annual operating fee of $722.68 for each heater.

Produced Gas Control Costs

(1) Capital Cost

Heaters
For each heater there is a permit processing fee of $2,232.96. It should be noted that since the information provided by the heater manufacturers indicated a range of $6,000 to $20,000 for a 400,000 BTU per hour heater (installed) and that 83 out of 85 facilities were identified as requiring this category of heater. Two facilities will need a 2,000,000 BTU per hour heater at an installed cost of $31,000-$60,000.

Expected Service Life			10 years
i) Total Capital Cost (Installed) (400,000 BTU/hr)	$20,000 x 83 heaters	=	$1,660,000
ii) Total Capital Cost (Installed) (2,000,000 BTU/hr)	$60,000 x 2 heaters	=	$ 120,000
iii) Permit Processing Fee =	(85 x $2,232.96)	=	$ 189,802
Total Produced Gas Control Cost (Present Value)		=	**$1,969,802**

(2) Annual O & M Cost

Heater

Annual O&M Costs (including testing & maintenance)	= 85 x $1,000	=	$85,000/year
Annual Operating Fee	= 85 x $722.68	=	$61,428/year

Total Annual Heater O&M Cost = (Annual Testing & Maintenance Cost) + (Annual Operating Fees)

Total Produced Gas Annual O & M Cost = $146,428

Total Costs for Liquid and Produced Gas Control

Total Capital Cost = (Liquid Control Capital Cost) + (Produced Gas Control Capital Cost)

= $75,839 + $1,969,802 = **$2,045,641**

Total Annual O & M Cost = (Annual Liquid O & M Cost) + (Annual Produced Gas O & M Cost)

= $1,568,139 + $146,428 = **$1,714,567**

C. COST EFFECTIVENESS ANALYSIS

The cost-effectiveness analysis uses the Discounted Cash Flow (DCF) method to compute the present value of the costs of the proposed rule over a recurring 3-year period (the assumed lifetime of the sample containers) adjusted for a 10-year period (the assumed lifetime of the heaters).

Consistent with rulemaking for other AQMD control measures, a real interest rate of 4 percent will be used in this report to estimate the present value of the annual cost of operations and maintenance. Since all the costs are expressed in present value, the effects of future inflation are removed from this analysis. The annual recurring costs of inspection are assumed to be the same for each year. In order to calculate the present value of 10 years of annual costs at 4 percent, the annual cost is multiplied by the present value factor (PVF) of 8.11. The DCF cost effectiveness can then be calculated as follows:

Overall Cost Effectiveness (based on 10 years) =

$$\frac{\text{Total Capital Costs + (Total Annual O \& M Cost x 8.11)}}{\text{Total Annual Emission Reductions (tpy) x 10 yrs}}$$

Overall Cost-Effectiveness (CE)

$$CE = \frac{(\$2{,}045{,}641) + [(\$1{,}714{,}567 \times 8.11]}{(1.76 \text{ ton/day} \times 365 \text{ days/yr} \times 10 \text{ yr})}$$

CE = **$2,483 per ton VOC reduced**

Based on these calculations, the cost effectiveness is $2,483 per ton and therefore the cost effectiveness of implementing the rule would be well within the range that is generally considered as cost-effective for VOC control measures.

INCREMENTAL COST-EFFECTIVENESS

Pursuant to Health and Safety Code Section 40920.6, prior to adopting rules or regulations to meet the requirement for best available retrofit control (BARCT) technology pursuant to Sections 40918, 40919, 40920, and 40920.5, or for a feasible measure pursuant to Section 40914, the AQMD is required to adopt written findings that identify one or more potential control options which achieve emission reduction objectives, determine the cost-effectiveness of each potential control option and determine the incremental cost-effectiveness of potential control options.

The incremental cost effectiveness of PR 1148.1 will be determined by comparing the difference in the present values of control costs for a potential control option and the proposed rule divided by the difference in the emission reductions between the potential control option and the proposed rule. Since the economical life of the gas processing plant in the potential control option is 20 years, the present value of all components will be based upon the recurring cost of those potential control components over a 20-year period.

Control Option

Requiring the use of a stuffing box adapter, a closed crude oil collection container and a well shut-off switch that will shut down the well when the container is full, for all wellheads, would result in a reduction of loss of crude oil. Use of this option would also significantly reduce the need for pump-outs. No additional costs for pump-outs will be added to the cost calculations. To evaluate the incremental cost effectiveness for the liquid portion of the rule, it will be assumed that there would be a stuffing box adapter cost incurred at 3-year intervals. Therefore, over this (20-year) period there will be a total of seven (7) stuffing box adapter replacements. It is staff's estimate that the cost of stuffing box adapters will not change over the 20-year period.

To evaluate the incremental cost effectiveness for the produced gas portion of the rule, requiring construction of a gas plant at all facilities with uncontrolled wells will be evaluated as an option. Based on information obtained for this equipment, it was determined that the cost may range from $250,000 to $2.5 million based on the number of units and the complexity of the gas plant. For the purpose of this report an average capital cost of $1 million will be assumed, based on the smaller facilities and the expected number of wells per facility. The information also estimates annual operating cost to be 2 percent of the capital cost of the equipment and the useful life of the equipment was estimated to be 20 years.

Using information reported in the 2001 Division of Oil and Gas Annual Report and a telephone survey conducted by staff, it was estimated that approximately 85 facilities did not treat nor control their produced gas for sale to other facilities or the Southern California Gas Company. Therefore, using a real interest rate of 4 percent, the annual cost will be multiplied by a present value factor (PVF) of 13.59.

Potential Control Option Cost

Liquid Control Cost

(1) Capital Cost

(a) Containers

As previously discussed in the Cost Effectiveness section, the containers will be replaced every 3 years. The cost of the containers will not change over each 3-year period for calculation purposes since the cost will be adjusted to present value using a real interest rate of 4 percent. Since the gas plant equipment life of this control option is 20 years, staff will calculate the container costs over a 20-year period to normalize the costs and associated emission reductions. The calculations below take into consideration that over a 20-year period the operator will purchase 7 batches of containers, starting at the beginning of the compliance period.

Batch 1 (Initial Purchase)

Expected Service Life For the Metal Container	3 years
Individual Metal Container Cost	$25
Container Capital Cost = (3,588 well/1 container per 4 wells)	$22,425

The following table summarizes the cost to purchase the container over the 20-year period.

Container Capital Cost for 20 years

Container Batch Number	Years Used	Present Value Discount Factor	Present Value Capital Cost
1	1 -3	1.0	$ 22,425
2	4-6	0.8890	$ 19,936
3	7-9	0.7903	$ 17,722
4	10-12	0.7026	$ 15,756
5	13-15	0.6246	$ 14,067
6	16-18	0.5553	$ 12,453
7	19-20	0.4936	$ 11,069
Total Cost (over 20 years)			**$113,428**

Capital Cost of Containers = $113,368

(b~~a~~) Adapters

The assumed life of the adapter is set at 3 years at a cost of $600 per unit. The following costs are associated with the installation of an adapter based on 20 years to normalize the cost based on the gas plant equipment life, using the present value factors at 4 percent interest at the recurring periods over the 20 years.

i) Capital Costs = $600 x 3,588 = $2,152,800

ii) Installation Costs, including the use of 2 people for 2 hrs

4 hr/adapter x 3,588 adapters x $25/hr = $358,800

Total Cost for Adapters (1st. Yr.)
Capital + Installation = $2,511,600

Stuffing Box Adapter Capital Cost for 20 years

Adapter Batch Number	Years Used	Present Value Discount Factor	Present Value Capital Cost
1	1 -3	1.0	$ 2,511,600
2	4-6	0.8890	$ 2,232,812
3	7-9	0.7903	$ 1,984,917
4	10-12	0.7026	$ 1,764,650
5	13-15	0.6246	$ 1,568,745
6	16-18	0.5553	$ 1,394,691
7	19-20	0.4936	$ 1,239,726
Total Cost (over 20 years)			**$12,697,141**

Capital Cost of Adaptors = $12,697,141
Total Liquid Capital Costs = $113,386 + $12,697,141 = **$12,810,509**

(2) Annual O&M Costs

(a) Stuffing Box Adaptors

(i) Inspection
An adapter on a worn stuffing box will need resetting once monthly and take one hour each time. Otherwise, it will take 5 minutes per month to check. Operators are already required to do daily inspections on 120 out of 3,588 pumps since they located within 100 meters of a sensitive receptor. The remaining 3,468 wells can be inspected monthly. Therefore, the operator will not incur any additional inspection costs for the stuffing box adaptors.

(ii) Maintenance
Assumption: A conservative approach will be used in assuming that there is one wellhead per well cellar and that 50% of all wellheads have worn stuffing boxes.

(ii) 1,734 adapters (on worn stuffing boxes) @ 1 hr/month @ $25/hr @ 12 mo/yr

= **$520,200**

(iii) 1,734 adapters (on good stuffing boxes) @ 5 mins per mth to check @ $25/hr @ 12 mo/yr

= **$43,3500**

Annual O&M Cost for Adapters = $520,200 + $43,500

= **$563,550**

(b) Audio-Visual Inspections

With the installation of the stuffing box adaptor with a container and an auto well shut off to shut off the well when the container becomes full, oil leakage will be effectively eliminated. Therefore, the operator can change their audio-visual inspection frequency of the stuffing box on well pumps from daily or weekly, as required, to monthly for all wells not located within 100 meters of a sensitive receptor. The wells near sensitive receptors must be inspected daily.

(i) Wells with Well Cellars at Manned Facilities – Annual Inspection Costs
(Based on monthly inspections for 2,257 wells @ 5 minutes per well; $25/hr technician labor)

2,257 wells x 1 insp/mo x 12 mo/yr x 5/60 hr/insp x $25/hr = **$56,425/year**

(ii) Wells with Well Cellars at Unmanned Facilities – Annual Inspection Costs
(Based on monthly inspections for 2,257 wells @ 5 minutes per well and 10 minutes travel; $25/hr technician labor)

878 wells x 1 insp/mo x 12 mo/yr x 15/60 hr/insp x $25/hr = **$65,850/year**

(iii) Wells without Well Cellars – Annual Inspection Costs
(Based on monthly inspections for 2,257 wells @ 5 minutes per well and 10 minutes travel; $25/hr technician labor)

333 wells x 1 insp/mo x 12 mo/yr x 15/60 hr/insp x $25/hr = **$24,975/year**

(iv) Wells at Unmanned Facilities within 100 meters of a Sensitive Receptor
(Based on daily inspections for 120 wells @ 5 minutes per well and 10 minutes travel; $25/hr technician labor)

120 wells x 365 insp/yr x 15/60 hr/insp x $25/hr = **$273,750/year**

Total Annual Audio-Visual Inspection Cost = **$421,000/year**

Total Liquid Annual O & M Costs **=** $563,550 + 421,000 **= $984,550**

Produced Gas Control Cost

(a) Capital Cost

The assumed life of the gas plant is set at 20 years at an average cost (capital and installation) of $1,000,000 per unit. The following represents the overall capital cost for 85 facilities:

Capital Costs = $1,000,000 x 85 = **$85,000,000**

(b) Annual O&M Gas Plant

The annual O & M cost of the gas plant is 2% of the total capital cost of the equipment.

Total annual O & M cost for gas plant = 85 [2% ($1,000,000)] = **$1,700,000**

Total Costs

Total Potential Control Option Cost = (Capital Cost of Container) + (Capital Cost Adaptor) + (Capital Cost Option of Gas Plant) + (Annual Inspection & Maintenance Cost) x 13.59 + (Annual O & M Cost) gas plant x 13.59

= $12,810509 + $85,000,000 + ($984,550)(13.59) + ($1,700,000)(13.59)

= $134,293,544

Potential Control Option Emission Reductions

a) Well Cellars

The emission reduction associated with the use of an adapter is 90 percent compared to 80 percent obtained from the proposed rule's I & M requirement.

Emission reductions associated with the use of adapters:
(1.21) tons/day x (0.9) (365) days/yr = 397.49 tons/year

Emissions reduction over 20-year period:
20 years (397.49~~85~~ tons/year) = **7,950 tons**

b) Produced Gas

The emission reductions associated with the use of a gas plant to control produced gas will be 100 percent.
Emission Reductions = 0.83 tpd (365)days/yr = 302.95 tons/year

Emissions reduction over 20-year period:
20 years (302.95 tons/year) = **6,059 tons**

Total Emission Reductions of Potential Control Option = 14,009 tons/20 years

Rule Proposal Cost (Adjusted for 20 years)

Total Cost
Based on previous calculations in the Cost Effectiveness section of the report, capital cost was based on 10 years. These costs will be adjusted for a 20-year period for both the containers and the heaters. The annual costs will be multiplied by the present value factor of 13.59 based upon 4 percent over 20 years.

Total Proposed Rule Control Cost
= \$113,368 + (2)(1,969,802) + [(1,568,139) + (146,428)] 13.59

= \$27,353,938

Proposed Rule Emission Reductions (adjusted to 20 years)

Emissions reduction calculated in the Cost Effectiveness section of the report are:

Liquid portion of the rule = 353.3 tons/year
Produced gas portion of the rule = 287.8 tons/year

Total 20-yr Emissions Reduction = 12,833 tons

The following table lists the incremental cost-effectiveness along with the present value cost and emission reductions based on the proposed rule and the more stringent control option.

Incremental Cost-Effectiveness

	Present Value (\$)	20-yr Emission Reduction (tons)
PR 1148.1 (20 yr period)	\$27,353,938	12,822
Control Option	\$ **134,293,544**	14,009
Incremental Cost Effectiveness (\$/ton)	**134,293,544 – 27,353,938** **14,009 – 12,822** **\$90,092**	

IMPACT ASSESSMENT

Pursuant to the California Environmental Quality Act (CEQA) and AQMD Rule 110, an Environmental Assessment (EA) is being prepared for Proposed Rule 1148.1 and will be circulated for review. Comments received will be addressed when evaluating the potential for adverse environmental impacts from the proposal and will be incorporated into the EA.

A. SOCIOECONOMIC ASSESSMENT

Staff is preparing a socioeconomic assessment which is included as an attachment to the Staff Report in the hearing package.

B. COMPARATIVE ANALYSIS

Under the Health and Safety Code Section 40727.2, the AQMD is required to compare and analyze PR 1148.1 with existing AQMD or federal regulations. There are no existing federal regulations and the comparison to other AQMD rules is discussed on pages 7 and 8 of this report.

C. FINDINGS REQUIRED BY THE CALIFORNIA HEALTH AND SAFETY CODE

Health and Safety Code Section 40727 requires that prior to adopting, amending or repealing a rule or regulation, the AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the hearing.

Necessity - The AQMD Governing Board has determined that a need exists to adopt Proposed Rule 1148.1 to implement Control Measure FUG-05 of the 2003 Air Quality Management Plan (AQMP), to further reduce VOC emissions and make progress toward meeting the state and federal ambient air quality standards for ozone.

Authority - The AQMD Governing Board obtains its authority to adopt, amend or repeal rules and regulations from California Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702 and 41508.

Clarity - The AQMD Governing Board has determined that Proposed Rule 1148.1, as proposed to be amended, is written or displayed so that its meaning can be easily understood by the persons directly affected by it.

Consistency - The AQMD Governing Board has determined that Proposed Rule 1148.1, as proposed to be amended, is in harmony with and not in conflict with or contradictory to, existing statutes, court decisions or state or federal regulations.

Non Duplication - The AQMD Governing Board has determined that Proposed Rule 1148.1, as proposed to be amended, does not impose the same requirements as any existing state or federal regulations, and the amendments are necessary and proper to execute the powers and duties granted to, and imposed upon, the AQMD.

Reference - The AQMD Governing Board by adopting this regulation is implementing, interpreting or making specific the provisions of: Health and Safety Code Sections 40001 (rules to achieve ambient air quality standards), 40440(a), (rules to carry out the Air Quality Management Plan), (b) (Best Available Retrofit Control Technology), and (c) (rules which are also cost-effective and efficient), 40702 (rules to execute duties necessary to preserve original intent of rule) and 40910 et seq., (California Clean Air Act).

AMENDMENTS SUBSEQUENT TO THE JANUARY HEARING

Proposed Rule 1148.1 was the subject of a public hearing on January 9, 2004. Testimony at the hearing from DOGGR and representatives from industry expressed several concerns about the proposal. Based upon this testimony, the Board continued the hearing to March 5 and directed staff to meet with DOGGR, industry and other interested parties to address the concerns. Two lengthy meetings were held on January 28 and February 5 with DOGGR and industry to discuss their concerns.

Since some concerns were based on speculations about events that might occur if any rule was adopted, staff consulted with staff of SBCAPCD regarding the implementation of their rules that were adopted several years ago. Two of the issues raised by DOGGR were that a rule such as PR 1148.1 would encourage operators to fill in their well cellars to avoid being subject to the rule and that a large number of marginal operators would desert their wells because of the additional operating costs a rule would impose. SBCAPCD staff indicated that there were incidents of well cellars being filled in but these were not widespread. However, there was no indication that mass desertion of wells by marginal operators occurred. On an unrelated issue, they also recommended that in our exemption for maintenance and repair, drilling and abandonment operations, we clarify that these activities are to be conducted in a safe manner that minimizes emissions.

As a result of these additional discussions, staff is proposing amendments to PR 1148.1. The following summarizes the amendments. The amendments are not substantial and do not significantly affect the meaning of the rule. An explanation for each amendment is included in the summary.

A. OPTIONAL TWO-INCH TEST

PR 1148.1 requires that operators visually check for leakage of liquid into the well cellar. If evidence of organic liquid is discovered, the operator must determine the TOC emissions using the equipment and test method specified in the rule. If the emissions are greater than 250 ppm of VOC, the operator is required to remove the organic material. In addition, as currently written, the rule requires pump-out for wells located near sensitive receptors if there is a 2-inch accumulation of organic material in the well cellar, irrespective of the TOC measurement.

Industry has argued that the direct measurement of TOC is a more effective method for determining emissions to the atmosphere than measuring two inches of organic material, and that to require both methods for some well cellars is unnecessary. Although many operators and the contractors that perform the quarterly inspections have the instruments necessary to measure TOC, some of the small operators may not have ready access to a TOC measuring instrument. Since the other districts that have EPA-approved well cellar rules allow measurement of the thickness of organic material accumulated in the well cellar using a “copper coat” gauge as the triggering mechanism for pump-out, PR 1148.1

should allow that method as an option for the small operators that do not readily have access to a TOC measurement instrument.

Staff concurs that measurement of TOC with an approved instrument is a most effective method for determining the magnitude of emissions to the atmosphere and should be used when such an instrument is available. However, when an instrument is not available, use of the standard that is in SBCAPCD and other districts' rules that require pump-out when two inches of organic material is accumulated in the well cellar is adequate to ensure emissions to the atmosphere are minimized. To require both methods to be used concurrently at the same well cellar may not result in any additional air quality benefit.

Therefore, staff proposes to amend PR 1148.1 to require that operators only measure well cellar emissions with an approved TOC instrument with the option of the two-inch measurement as the triggering mechanism for pump-out. The quarterly inspection will continue to require the use of the TOC measuring instrument. The prohibitory standard, which is the primary enforcement standard, will also continue to be based on TOC measurement. Therefore, this amendment is not a substantive change. Since there is no change in the requirement for pump-out, the amendment does not significantly change the meaning of the rule.

B. WELL DRILLING AND WELL ABANDONMENT

DOGGR commented that the proposed rule did not adequately provide for drilling and abandonment operations. Although these operations are done infrequently to a well, are of short duration and in the case of abandonment, will result in no potential to emit when the operation is complete, they nevertheless are operations that may result in some venting of gas or accumulation of organic material in the well cellar during the safe completion of these operations.

Staff interpreted these activities as subcategories of routine maintenance when preparing our proposal. In our subsequent discussions with DOGGR and industry, it was pointed out that technically this may not be correct. Therefore, to clarify and ensure that it is technically correct to those affected by the rule or implementing it, language has been added to the requirements in paragraph (d)(3) and the exemptions in paragraph (h)(2) to make clear that drilling and abandonment operations are to be regulated in the same manner as routine maintenance or well workover and conducted in a safe manner that minimizes emissions. This clarification of intent improves the meaning of the rule without significantly or substantively changing it.

C. REMOVAL OF WELL CELLARS

DOGGR expressed concern that some operators would choose to eliminate their well cellars in lieu of complying with the requirements of PR 1148.1, particularly since there was some evidence of this in Santa Barbara after a well cellar rule was implemented there. Elimination of well cellars could have a detrimental impact on the environment, not just air quality but other media as well. The reason one would choose to eliminate the well cellar is simply the cost savings on the periodic inspections.

Staff concurs that well cellars are to provide an environmental benefit to the air and other media and does not intend to encourage elimination of well cellars and their benefit. To ensure there was not an economic incentive to eliminate well cellars or forego well cellars at new wells, PR 1148.1 requires much more frequent inspection for wells without well cellars. It was believed that the additional inspection cost would far outweigh the perceived economic benefit of eliminating well cellars and, in effect in an indirect way, prohibit the elimination of well cellars.

To clarify the matter, staff proposes to amend PR 1148.1 to address the elimination of the well cellar issue directly by prohibiting the elimination of a well cellar at a producing well and requiring well cellars at all new wells. Since this directly clarifies staff's indirect prohibition of well cellar elimination currently in the proposed rule, it is not a substantive change nor does it significantly change the meaning of the proposed rule noticed for hearing.

D. SMALL PRODUCER EXEMPTION

DOGGR expressed the concern that the very marginal operator with low production wells would simply desert their operation because of the additional costs imposed by PR1148.1 would push them over the edge of economic viability. This was particularly of concern with wells with a low volume of produced gas that would be required to control the gas emissions. Since DOGGR would be responsible for abandonment operations for those wells deserted by the operator, there was concern that if the rule triggered this for a number of operators all at once that there would not be adequate resources to complete abandonment operations in a timely manner.

Staff determined that the overall cost effectiveness of PR1148.1 is $2,483 per ton of VOC reduced which is very cost effective compared to other measures with AQMP. A significant portion of the cost is estimated to be for purchase, installation and operation of the produced gas control equipment. On an individual basis, the cost effectiveness for the low volume gas producer could be greater than the industry-wide average. For example, for a well that produces 200 cubic feet of gas per day that results in a little more than a pound per day of VOC, depending on the control used, the cost effectiveness ranges from $10,568 to $17,230 per ton reduced. Likewise, for a well that produces 400 cubic feet of produced gas per day the individual cost effectiveness ranges from $5,284 to $8,615 per ton of VOC reduced.

In order to estimate the number of wells that produce 200 cubic feet of gas or less and thus the emissions from those wells the DOGGR production data from 2001 was used. However, DOGGR does not collect produced gas data for such a low level of production but they do collect all oil production data. Although the gas to oil ratio varies, an average ratio is 200 cubic feet: l barrel. The DOGGR data indicated 45 wells with production of one barrel or less. Assuming all 45 wells produce one barrel per day, the VOC emissions would be 45 lbs/day which is below the CEQA significance threshold. Since the average production of those 45 wells ranges from zero to one barrel per day, it is expected the actual total emissions would be less.

Staff proposes an exemption from the gas control requirements of PR1148.1 for facilities wells that cumulatively produce no more than 200 cubic feet per day of gas or one barrel of oil per day, provided the wells are not located near a sensitive receptor. Staff believes it would be cost-effective to control individual wells or multiple wells at a facility when production exceeds the exemption level. It is cost-effective for multiple low-production wells at a facility since several wells could be vented to a single control device. Wells located adjacent to sensitive receptors are excluded from this exemption consistent with the Board policy on environmental justice to provide health protective standards near sensitive receptors. The other requirements of the rule will remain in place for these sources. To qualify, the operator must provide records that demonstrate eligibility which would mean that those choosing gas production would need meter readings as records. Some operators already have meters but those that do not would need to install one. However, since operators report the oil production to DOGGR, it is expected this would be the method most operators would choose to demonstrate eligibility and it is not expected that the small operators will choose to install gas metering.

Since even under the worst case scenario the emission impact of the proposed exemption from the gas control requirements for low volume gas production wells is below the CEQA significance threshold of 55 pounds per day of VOC, this amendment is not substantive nor does it significantly change the meaning of the proposed rule.

E. APPLICABILITY OF RULE 1173

Industry expressed a concern that the repair interval in paragraph (d)(7) was different than that of Rule 1173 and since (d)(7) referred to produced gas handling equipment in general, there could be confusion that leaking components subject to Rule 1173 would be subject to the repair interval of PR1148.1. It was not staff's intent to mix the requirements of Rule 1173 with the repair intervals of PR1148.1 for components on produced gas handling equipment. Staff has included language in paragraph (d)(7) to clarify this so that it does not significantly change the meaning of the rule noticed for hearing nor is it a substantive change.

COMMENTS AND RESPONSES

Comment 1
The definition of wellhead indicates that it is connected to an oil production line and a vapor recovery line, but in some cases wells are not connected to a gas gathering line. In addition, the vapor recovery line is in fact the casing gas line.

Response 1
The definition has been revised to incorporate this comment.

Comment 2
Requiring operators to install carbon canisters on vacuum trucks and portable tanks during well pump-outs is inconsistent with other operations where this same equipment is used to handle petroleum.

Response 2
Consistent with other AQMD rules, PR 1148.1 has been revised to no longer require the use of carbon canisters on vacuum trucks that are used to store crude oil, but requires that portable enclosed storage vessels or Baker tanks be equipped with air pollution control. Other AQMD rules require vapor control equipment to be in place for other types of storage vessels. Air pollution control equipment will reduce TOC emissions released to the environment to less than 250 ppm.

Comment 3
What is the basis for the maximum outlet concentration of the Baker tank or other portable enclosed storage vessels being established as 50 ppm?

Response 3
The 50 ppm level is consistent with other AQMD rules and control equipment permit conditions for VOC emissions released to the atmosphere. However, in response to comments received, the allowable maximum concentration has been modified and set at 250 ppm to be measured as Total Organic Compound (TOC) emissions, not just as VOC. This measurement as TOC will simplify the implementation of the rule, improve its enforceability, and will result in better maintenance procedures focusing on all organic emissions.

Comment 4
The rule should be consistent with Rule 1176 by allowing the operator to pump out the well cellar within ten (10) days after discovery of organic liquid accumulation.

Response 4
Rule 1176 allows operators to store crude oil in well cellars for up to ten days for emergency purposes. PR 1148.1 has been revised to include this exemption. PR 1148.1 requires the operator to pump out the well cellar within five (5) days or within 24 hours for wells located within 100 meters of a sensitive receptor after the discovery of the

organic liquid accumulation in the well cellar. Since well cellars are receptacles that are open to the atmosphere, it is expected that any accumulation of organic material will continue to volatilize if kept in the well cellar. Therefore, allowing the material to accumulate for longer periods of time prior to pump-out will undoubtedly result in the majority of VOCs being emitted to the atmosphere. This would be counterproductive to the intent of the rule.

Comment 5
The rule requires that when the depth of the liquid in the well cellar exceeds 50% of the actual well cellar depth, this would trigger operators to pump out. During major storms this would require immediate pump-out of all well cellars within two days even though there may be no oil in the cellars. The logistics of such a requirement would be, at best, cost prohibitive and potentially unsafe and would provide no benefit if the cellar contents are predominantly water.

Response 5
Staff has revised PR 1148.1 to require pump out of organic liquid material when the TOC concentration is 250 ppm or greater, and for those well cellars located within 100 meters of a sensitive receptor when there is an accumulation of 2 or more inches of organic material. The revised rule in effect, excludes the pump out of well cellars that accumulate only water.

Comment 6
Paragraph (d)(4) – Requirements. Immediately before a well is steamed or after a wellhead is steam cleaned, the liquid accumulated in the well shall be pumped out.
This requirement does not make it clear that the District is referring to fluids containing crude oil or other hydrocarbons as opposed to rainwater, groundwater, brines or other fluids not containing VOCs that may be found in the cellars.

Response 6
The wording has been changed to clarify the intent of the requirement, which is to address organic liquids and not non-organic liquids such as rainwater, groundwater and brines.

***Comment** 7*
Industry would like a clarification of the requirement that indicates that no person is allowed to purposely <u>hold</u> crude oil or petroleum product in the well cellar.

Response 7
The wording has been changed to clarify the intent of the requirement and is as follows:
No person shall be allowed to purposely <u>store</u> crude oil or petroleum product in the well cellar.

The proposed rule requires that the operator only be allowed to accumulate organic liquid in the well cellar during maintenance or well workover activities. In addition, the operator is required to pump out the well cellar within 2 days after each maintenance activity has been completed. When there is accumulation as a result of non-maintenance activity or when the total VOC concentration in the well cellar exceeds 250 ppm TOC and 2 inches of organic material for those well cellars within 100 meters of a sensitive receptor according to test methods outlined in the rule, the operator is required to pump out the well cellar within 5 calendar days, or 2 days if the well is located near a sensitive receptor. PR 1148.1 includes an exemption consistent with Rule 1176 to allow storage of organic liquids resulting from emergencies for a period of up to 10 days.

Comment 8

Well cellar emissions used to determine the emission inventory for this rule have been grossly overstated because fees for this source category, emissions were estimated using an emission factor for VOCs that was based on organic material surface area exposed to the atmosphere. It is also believed that once the District started charging fees, operators were more careful in reporting emissions only for well cellars that actually contained organic liquid material and not for others that may have been empty.

Response 8

The emissions information that oil and gas production facilities reported to the AQMD as part of their Annual Emissions Reporting (AER) was used to establish the point source portion of the well cellar emissions inventory. This inventory captured 54 larger oil and gas production facilities located in the South Coast Air Basin, while an estimate for the area source portion of the inventory for the remaining smaller facilities that did not report was based on a 2010 AQMP planning inventory projection. Any future improvements to the emissions inventory and emissions reductions resulting from the implementation of Proposed Rule 1148.1 will be reflected in future revisions to the AQMP. Staff acknowledges the default emission factors are conservative by design to be health protective. The emission factor for well cellars was developed by CARB in conjunction with KVB (a consulting firm) and this factor is the basis of well cellar emission factors used by other air districts in California. It is the best emission factor currently available.

Comment 9

Based on information of operational practices in other states, industry has learned that the stuffing box adapter has proven to be very ineffective.

Response 9

Stuffing box adapter manufacturers have indicated that the adapters are effective and have been used extensively outside of California. However, operators indicated they have determined that such devices require significantly more maintenance and may be more applicable in other areas of the country where wells are more remotely located. Since most wells in the SCAQMD are not remotely located, an inspection and maintenance program could provide an equivalent emission reduction without mandating the use of a specific technology for all wells. As an option, an operator may request the AQMD to change the audio-visual inspection frequency from daily or weekly to a monthly frequency for those wells/stuffing boxes that are equipped with a stuffing box adapter. The change in inspection frequency is not allowed for wells located within 100 meters of a sensitive receptor.

Comment 10
The District's estimation of 550 million cubic feet (or 5% of 11,000 mmcf) of produced gas being vented to the environment is an overestimation and the amount of uncontrolled produced gas is probably closer to 1% or 110 million cubic feet.

Response 10
AQMD records did not provide data on the amounts of produced gas reported by facilities in the South Coast Basin. Initially, staff used the 2001 Division of Oil and Gas Annual Report to estimate the amount of produced gas vented. In that report, less than 50% of oil and gas production facilities in the AQMD actually reported their gas production. In addition, the AQMD permitting database indicated that less than half of these facilities directed their produced gas to treatment systems for use offsite or to gas control systems (flare, IC engine or boiler). Based on this information staff estimated that 5% (or 550 million cubic feet) of the total 11 billion cubic feet of produced gas was untreated or uncontrolled.

Subsequently, the AQMD followed up this estimation with a telephone survey in conjunction with CIPA's survey, which yielded data indicating that more facility operators use heaters and engines than the AQMD permit database indicated. These heaters and engines do not require a written AQMD permit based on their size. This was not accounted for in the original estimation. Based upon the follow-up survey which should yield a more accurate estimation, the revised amount of uncontrolled and untreated produced gas is now expected to be approximately 0.91 % or 100 million cubic feet.

Comment 11
Industry has expressed concern that District Permitting Division would only allow shrouded flares to be permitted and that the cost effectiveness analysis included in the draft staff report did not reflect the cost of the complex controls associated with shrouded flares.

Response 11
Staff has revised the rule to allow the operator the option of choosing, with AQMD approval, any control equipment (not just flares) that is capable of achieving a VOC vapor removal efficiency of at least 95% by weight or an outlet VOC concentration of 50 ppm using test methods outlined in the rule. Information obtained from a telephone survey led staff to believe that heaters were more commonly used at smaller oil and gas production operations due to cost and energy conservation. Both heater and flare manufacturers have stated that their equipment comply with all applicable AQMD regulations.

Comment 12
Paragraph (d)(6) –Produced Gas Requirements. These rule requirements are not directly related to oil and gas productions wells, but are production facility issues.

Response 12
The AQMD, as an extreme non-attainment area, is required to implement all feasible control measures. Both Santa Barbara County APCD's Rule 325 – Crude Oil Production and Separation and Ventura County APCD's Rule 71.1 – Crude Oil Production and Separation include requirements for produced gas. Staff also determined that some oil and gas production operations, including smaller ones were venting produced gas to the atmosphere. Therefore, staff was required to determine if the rules are technologically feasible for oil and gas production facilities in the AQMD. Staff has determined that the control of produced gas is both technologically feasible and cost effective.

Comment 13
Paragraph (d)(6) – Control of Produced Gas. It requires the operator to use a properly maintained system that directs all produced gas, except gas used in a tank battery vapor recovery system to a system handling gas for fuel, sale or underground injection or to a flare or other device that demonstrates vapor removal efficiency of at least 95% by weight.

Industry believes that this requirement is too restrictive because minor amounts of gas are typically released to the atmosphere while servicing a well or performing maintenance of well equipment at oil and gas production operation facilities.

Response 13
Rule language has been revised to include a provision that exempts operators from venting produced gas during maintenance and repair activities.

Comment 14
Paragraph (d)(7) – Totalizing Gas Meters. Industry believes that it is not feasible to install a totalizing meter to measure monthly produced gas from an oil production field since gas produced within a typical production field is measured by several meters and the aggregate of these devices is reported to the California Division of Oil and Gas.

Response 14
Totalizing gas meters were necessary to demonstrate a rule exemption level. Since staff has determined that the use of heaters is technologically feasible and cost effective at all production levels an exemption is no longer appropriate. Therefore, the requirement to install a totalizing gas meter has been removed from PR 1148.1.

Comment 15
Industry questions the validity of the emission inventory used for this rule based on the use of the 7.5 pounds VOC per square foot of accumulated organic material exposed to the atmosphere.

Response 15
The 7.5 pound per square foot emission factor used to estimate the VOC emissions from well cellars was based on a study that was conducted by CARB and KVB many years

ago. This emission factor was found to be in close correlation with emission factors used by other Air Quality Districts. While this currently is the best emission factor available for this source category, any future improvement to the emission factor will be reflected in the future emissions inventory and AER. See also response to Comment #8.

Comment 16
When cost effectiveness is evaluated for individual requirements, the numbers range from $300 per ton to $750,000 per ton which is much higher than the District's estimate of $643 per ton.

Response 16
The cost analysis in the staff report has been revised and the revised current cost effectiveness is $2,483 per ton. However, although it is not common practice to break down cost effectiveness based on different rule requirements, the well cellar and produced gas portions were each determined to be cost effective when evaluated separately. The cost effectiveness value of $750,000 per ton submitted by industry to staff was based on the cost of a large flare that would be used only at the larger oil and gas production facilities. These larger facilities currently meet the requirements for produced gas stated in PR 1148.1. Accordingly, staff's cost and cost effectiveness were much lower because the size and cost to control the produced gas at the smaller facilities venting directly to the atmosphere were significantly lower.

Comment 17
Please modify the Applicability section PR 1148.1 to clarify that the rule is intended to apply only to oil production wells that are located onshore.

Response 17
Staff has revised the Applicability subdivision to emphasize that the proposed rule applies only to oil and gas production wells located on land.

Comment 18
PR 1148.1, as currently written, requires all operators to pump-out the well cellar when a TOC concentration is detected at 250 ppm using EPA Method 21 or when 2 inches of organic material is measured in the well cellar. This requires both standards to be applied when the Method 21 method should be sufficient. This could trigger a pump-out even though the well cellar emissions are significantly below the 250 ppm of TOC threshold.

Response 18
The proposal has been amended to require the additional requirement for pump-out when 2 inches or more of organic material has accumulated in the well cellar for those well cellars located within 100 meters of a sensitive receptor. Although staff believes the 250 ppm of TOC threshold is sufficient to limit emissions from well cellars in most instances, an additional factor of safety is appropriate near sensitive receptors. Organic material accumulation in a well cellar is indicative of a leak that should be repaired if good housekeeping and maintenance procedures are in place.

Comment 19
Industry believes that the PAR 222 fee structure unfairly targets the larger facilities and should be revised to distribute the cost more evenly on a per facility basis as opposed to using the number of wells as a basis for fee determination. It should also be noted that the larger facilities already have a Rule 1173 fugitive emissions program in place. This would mean that the AQMD's incremental cost ($112,000) of implementing the PR 1148.1 sampling of well cellars cannot be justified since the inspector would be able to conduct Rule 1173 testing concurrently and would not be required to make any additional trips to the facility.

Response 19
Staff has explored other options to determine a fee structure that would be equitable to industry, and at the same time address the cost associated with AQMD staff conducting quarterly TOC well cellar measurements. Our analysis has determined that this is the best approach that would be equitable and revenue-neutral. However, staff is open to re-evaluate this issue at a later date.

Comment 20
The word "any" in paragraphs (d)(2), (d)(3) and (d)(5) should be removed from the proposed rule, since it could be interpreted that a well should be cleaned to a point where there is no measurable TOC rather than to the minimum emission standards required by the rule.

Response 20
Staff has removed the language for clarity.

Comment 21
Short term use of a Baker tank during a well workover operation for 2-3 days until fluids are transferred to a handling facility should not be considered "storage" at the well site and, thus, subject to the requirement for carbon canisters and Method 21 measurements.

Response 21
Staff does not require immediate removal of organic material during maintenance and workover since pump-out operations may not be practical and the delay it could cause in the completion of maintenance or workover may result in greater emissions to the atmosphere than if accumulated material was removed soon after the maintenance or workover is complete. However, in those situations where the operator determines it is practical to pump-out to a storage tank during maintenance or workover control of the emissions from the tank should be required since it is technologically feasible and cost effective.

Comment 22
The definition of Oil Production Field does not address operators with multiple well sites at non-contiguous surface locations that are producing from the same oil field that send the crude oil from several facilities to one production field or tank farm for handling.

Response 22
The definition "Oil Production Field" was needed to address the requirement to install totalizing gas meters to measure the produced gas at a facility. Subsequently, staff has deleted the requirement to install totalizing gas meters. Therefore, this definition is no longer needed and has been deleted from PR1148.1.

Comment 23
The District should revise the definition of a Stuffing Box: "Stuffing Box is a packing gland, chamber, or "box" used to hold packing material compressed around a moving pump rod" and delete "to reduce the escape of gas or liquid."

Response 23
Staff disagrees. Staff believes that the packing material of the stuffing box reduces the escape of gas and liquid from the moving pump rod of the oil well. This definition is used by the California Air Resources Board (CARB) in their inspection and training manual for oil well production facilities.

Comment 24
Staff should revise the rule requirements in paragraph (d)(2) to include that the "container shall be kept closed to the atmosphere when it contains crude oil and is not in use".

Response 24
Staff agrees and has revised the rule.

Comment 25
Not all stuffing boxes are not located completely within the well cellars. Staff should revise, where appropriate, the rule requirements to state "in or above a well cellar."

Response 25
Staff agrees and has revised the rule.

Comment 26
PR 1148.1 requires operators to inspect well cellars weekly which can change to a monthly frequency after such time when the operator equips the stuffing box with a stuffing box adaptor. The District should require quarterly inspections of the well cellars to be consistent with Rule 1173 inspection requirements. Therefore, the District should delete the requirement for weekly inspections under paragraph (e)(3). [This comment was received on September 16, 2003, which was based on the proposed rule released for the Public Workshop on August 26, 2003]

Response 26
After hearing industry comments at the Public Consultation Meeting on September 18, 2003, staff has revised PR 1148.1 to incorporate the proposal by industry to include in PR 1148.1 an alternative to the required installation of stuffing box adaptors on well pumps. Staff has determined that this alternative, which includes periodic audio-visual inspection

of the stuffing box (daily for wells without well cellars, weekly for wells with well cellars, and monthly for wells with stuffing box adaptors and closed containers and an oil well auto shut off when the container is full) and a quarterly TOC measurement of the well cellar, and a maximum allowable TOC concentration of 500 ppm results in greater VOC emission reductions compared to just requiring the installation of stuffing box adaptors. The inclusion of Rule 1173 inspection/TOC measurement requirements greatly enhances the effectiveness of PR 1148.1 compared to the visual inspection requirements of earlier draft rule proposals. Paragraph (e)(3) was clarified to require weekly audio-visual inspections of the well cellars.

Comment 27
Under Recordkeeping Requirements, the District should delete references to paragraph (e)(3) and weekly inspection of well cellars, the name of the person and company performing the inspection because this information is collected with Rule 1173 inspections, and records of produced gas (since it may be impractical to measure all gas through a single gas meter).

Response 27
Staff has revised PR 1148.1 to clarify the requirement of weekly <u>audio-visual</u> inspection of well cellars and that AQMD will provide a recordkeeping form to ensure that duplicative reporting of information on the inspections with Rule 1173 does not occur. Staff has informed the industry representatives at the Public Consultation Meeting on September 18, 2003, that the reporting of produced gas can be determined by adding the volumes measured by several gas meters at the facility (and not a single meter for the whole oil field).

Comment 28
Industry does not believe that an exemption for control requirements for facilities with produced gas of 100,000 cubic feet per month is practical since very few facilities operate at or below that level.

Response 28
The exemption for control requirements for facilities with produced gas of 100,000 cubic feet per month was based on a determination by staff that it would not be cost effective to install and operate a small flare at or below that level. However, staff has since determined that small process heaters can be operated at very low level of produced gas. As a result, staff has removed the exemption for operators with low levels of produced gas.

Comment 29
Rule 1173 exempts components exclusively handling fluids with a VOC content of ten percent by weight or less. The industry suggests that the same apply to wells handling similar fluids under PR 1148.1

Response 29
PR 1148.1 has established an action level (inspection, maintenance and repair) of 250 PPM TOC, as determined by EPA Method 21 to account for the non-VOC compounds. This action level is equivalent to 50 PPM VOC because most crude oil emissions and produced gas in the AQMD is anticipated to consist of non-VOC compounds such as methane (approximately 80 percent or more). The 50 PPM level is consistent with current BACT and permit condition levels for the remediation of VOC contaminated soil (primarily petroleum products) under Rule 1166.

Comment 30
The requirement to conduct the measurement of TOC concentrations at a distance of no more than three inches above the organic liquid surface is not practical because it will require our testing contractors to enter the well cellar, which is a confined space.

Response 30
In discussions with a major manufacturer of portable organic vapor analyzers, staff was informed that the analyzers are sold with a three-foot probe extension and that additional probe extensions could be added without compromising the accuracy of the TOC/VOC measurement, provided the operator allowed enough time) for the analyzer to stabilize.

Comment 31
Self monitoring by the operators should not be relied upon for compliance determination. In particular, I am concerned about those facilities located near young children.

Response 31
The AQMD has determined that self monitoring and inspection programs are effective in reducing emissions from industrial sources if they are accompanied by regular AQMD inspections and audits. Similarly, the self monitoring requirements in PR 1148.1 do not replace but augment AQMD's inspection program. Most facilities use third party contractors to implement the self monitoring requirements of AQMD rules. All records of inspection, maintenance, repair and pump-out will be audited by the AQMD.

PR 1148.1 has additional requirements for oil wells located near sensitive receptors, which includes schools (kindergarten to 12^{th} grade). These additional requirements include more frequent inspections and a faster response to correct deficiencies upon discovery by the operator or AQMD staff.

Comment 32
What is the driving force behind the development of this rule?

Response 32
PR 1148.1 has been under active development since early 2003. The rule implements Control Measure FUG-05 in the 2003 AQMP. A similar control measure was included in the previous AQMP. In addition, since the AQMD is an extreme non-attainment area for ozone, the California Clean Air Act requires adoption of all feasible measures, which would include the elements of PR 1148.1. In an effort to further minimize exposure of

sensitive receptors to emissions, the rule also includes additional inspection and maintenance requirements for wells located within 100 meters of sensitive receptors as directed by the AQMD Board Environmental Justice Initiatives.

REFERENCES

1. "Annual Report, California Department of Conservation, Division of Oil, Gas & Geothermal Resources 2001"

2. California Air Resources Board. Identification of Performance Standards for Existing Stationary Sources. A Resource Document. April 26, 1999.

3. "California Laws for Conservation of Petroleum and Gas", January 2001

4. "Oil Field Production Manual, Compliance Assistance Program", California Air Resources Board, Compliance Division

5. "Petroleum Engineering Handbook", edited by Howard B. Bradley, Editor-in-Chief, June 1989

PROPOSED AMENDED RULE 222

BACKGROUND

The Air Pollution Control Permit Streamlining Act of 1992 (Article 1.5 of Chapter 4 of the Health and Safety Code) requires air pollution control districts to "institute new, efficient procedures which will assist businesses in complying with regional, state, and federal air quality laws in an expeditious fashion, without reducing protection of public health and the environment."

In September 1998, the AQMD Governing Board adopted Rule 222 - Filing Requirements for Specific Emission Sources Not Requiring a Written Permit Pursuant to Regulation II, as an alternative to permitting commonly used equipment that emit small amounts of air contaminants. The rule establishes a filing program wherein operators of such equipment are required to submit to AQMD a description of the equipment and data for estimating emissions and determining compliance. The filing program under Rule 222 reduces permit and renewal fees for the operator, is less burdensome than the conventional permit process, and also decreases the permitting workload at AQMD.

Rule 222 currently includes three equipment categories: negative air machines used for asbestos removal, charbroilers, and boilers and process heaters with rated heat inputs from 1,000,000 Btu per hour up to and including 2,000,000 Btu per hour. Staff is proposing to include in Rule 222 equipment associated with moving crude oil from the subsurface to the surface which includes well cellars, wellheads and well pumps. This encompasses approximately 3,588 oil producing wells located at 220 oil production facilities that will require filing to ensure compliance with PR 1148.1, and to assist in the development of emission inventory data. The initial filing fee and subsequent annual fee will be assessed to each group of up to four well cellars. Staff has determined that this approach is equitable to all affected facilities, which can range in size of 1 well to just over 300 wells per facility. This approach is also expected to provide sufficient revenue to fund the administrative and the inspection requirements of PR 1148.1. The majority of the equipment filings will be received in 2004.

LEGISLATIVE AUTHORITY

H&SC section 40522.5 authorizes the AQMD to adopt "a schedule of fees to be assessed on area-wide or indirect sources of emissions which are regulated, but for which permits are not issued by AQMD to recover the costs of AQMD's programs related to these sources."

Chapter 6 of the H&SC section 40701(g) grants districts the power "to require any owner or operator of any air pollution emission source, except a non-commercial, vehicular source, to provide (1) a description of the source, and (2) disclosure of the data necessary to estimate the emissions of pollutants for which ambient air quality standards have been adopted, or their precursor pollutants."

PROPOSED AMENDMENTS

1. Rule applicability is expanded to include oil production well group which is no more than four well cellars located at an oil and gas production facility that would be subject to the requirements of PR 1148.1.

2. The terms "OIL PRODUCTION WELL GROUP", "WELL CELLAR", "WELLHEAD", and "WELL PUMP" are added to paragraph (c) of PR 1148.1 – Definitions.

California Health and Safety Code Section 40727.2 Analysis for Proposed Amended Rule 222 – Filing Requirements For Specific Emission Sources Not Requiring a Written Permit Pursuant to Regulation II.

Proposed Amended Rule (PAR) 222 imposes a filing and annual renewal requirement for well cellars, wellheads and well pumps. This equipment is currently exempt from District permitting requirements. Thus, the filing and annual renewal requirements constitute a "new reporting" requirement and the District is required to perform an analysis pursuant to California Health and Safety Code Section 40727.2 to determine all existing federal air pollution control requirements and any existing or proposed District rules or regulations that apply to the same equipment or source type. Staff has determined that there are no federal air pollution control requirements for well cellars, wellheads and well pumps. PR 1148.1 – Oil Field Production Wells will reduce VOC emissions resulting from the evaporation of uncontained crude oil and the venting of produced gas directly to the atmosphere.

COST AND COST-EFFECTIVENESS

PAR 222 will require that all facilities in the PR 1148.1 program be required to complete a filing process with the AQMD. Oil and gas production facilities range in size from 1 to over 300 oil wells per facility. An initial filing fee of $112.66 and an annual fee of $112.66, respectively will be charged to each group of four wellheads/well cellar. Staff has determined that this proposal provides fee equity for the smaller facilities as well as the larger facilities and will provide revenue sufficient to fund the inspector position equivalent to implement the inspection requirement of PR 1148.1. All of the AQMD fees stated are based on Rule 301 for fiscal year 2003-04.

The specific initial filing fee and the annual renewal fee are not part of the proposed amendment to Rule 222. The specific fee proposal will be part of the staff proposal to amend Regulation III – Fees that will be presented to the Governing Board in May 2004.

The proposed amendments to Rule 222 will not have an effect on the emission levels normally associated with the equipment specified in this amendment. As a result, traditional cost-effectiveness for this amendment cannot be calculated.

The increased cost to industry resulting from the initial filing and the annual fees associated with the implementation of PR 1148.1 and amendment to Rule 222 are as follows:

Facility Filing Fee
Each group of four well pumps/well cellars (approximately 3,588 well cellars) identified in the program will be required to pay an initial filing fee of $112.68)

Filing Fee Cost $= \frac{3,588}{4} \times \$112.68 =$ **$ 101,074**

Annual Facility
Filing Fee $= \frac{3,588}{4} \times \$112.66 =$ **$ 101,074/year**

DRAFT FINDINGS

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

Necessity - The AQMD Governing Board has determined that a need exists to amend Rule 222 - Filing Requirements for Specific Emission Sources Not Requiring a Written Permit Pursuant to Regulation II and to add approximately 3,600 oil producing wells to improve inventory information and facilitate compliance efforts .

Authority - The AQMD Governing Board obtains its authority to adopt, amend, or repeal rules and regulations from Health and Safety Code Sections 40000, 40001, 40440, 40702, 42300 et seq.

Clarity - The AQMD Governing Board has determined that PAR 222 - Filing Requirements for Specific Emission Sources Not Requiring a Written Permit Pursuant to Regulation II, are written and displayed so that the meaning can be easily understood by persons directly affected by them.

Consistency - The AQMD Governing Board has determined that PAR 222 - Filing Requirements for Specific Emission Sources Not Requiring A Written Permit Pursuant to Regulation II, are in harmony with, and not in conflict with, or contradictory to, existing statutes, court decisions, federal or state regulations.

Non-Duplication - The AQMD Governing Board has determined that the proposed amendments to PAR 222 - Filing Requirements for Specific Emission Sources Not Requiring a Written Permit Pursuant to Regulation II, do not impose the same requirement as any existing state or federal regulation, and the proposed amended rules are necessary and proper to execute the powers and duties granted to, and imposed upon the AQMD.

Reference - In adopting these regulations, the AQMD Governing Board references the following statutes which AQMD hereby implements, interprets or makes specific: Health and Safety Code Sections 40001 (rules to achieve ambient air quality standards), 40506 (rules regarding the issuance of permits), 40701 (rules regarding district's authority to collect information), 40725 through 40728, 42300 et seq. (authority for permit system), and 42320 (rules implementing the Air Pollution Permit Streamlining Act of 1992).