FILED
02-18-11
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application by Sacramento Natural Gas Storage, LLC for a Certificate of Public Convenience and Necessity for Construction and Operation of Natural Gas Storage Facilities and Requests for Related Determinations	Application No. 07-04-013 (filed April 9, 2007)

SECOND REQUEST FOR OFFICIAL NOTICE IN SUPPORT OF SUPPLEMENTAL REPLY BRIEF OF SACRAMENTO NATURAL GAS STORAGE, LLC

ALFRED F. JAHNS
Law Office of Alfred F. Jahns
3436 American River Drive, Suite 12
Sacramento, CA 95864
Telephone: (916) 483-5000
Facsimile: (916) 483-5002
E-mail: ajahns@jahnsatlaw.com

JOHN V. DIEPENBROCK
DAVID A. DIEPENBROCK
Diepenbrock Harrison
400 Capitol Mall, Suite 1800
Sacramento, CA 95814
Telephone: (916) 492-5000
Facsimile: (916) 446-4525
E-mail: jdiepenbrock@diepenbrock.com
E-mail: ddiepenbrock@diepenbrock.com

Dated: February 18, 2011

00306952

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application by Sacramento Natural Gas Storage, LLC for a Certificate of Public Convenience and Necessity for Construction and Operation of Natural Gas Storage Facilities and Requests for Related Determinations	Application No. 07-04-013 (filed April 9, 2007)

SECOND REQUEST FOR OFFICIAL NOTICE IN SUPPORT OF SUPPLEMENTAL REPLY BRIEF OF SACRAMENTO NATURAL GAS STORAGE, LLC

Pursuant to Commission Rule of Practice and Procedure 13.9, SACRAMENTO NATURAL GAS STORAGE, LLC ("SNGS") hereby respectfully requests that Administrative Law Judge Richard Smith and Assigned Commissioner Timothy Alan Simon take official notice of the matters set forth below.

1. PG&E operates under strict requirements, which limit the amount of certain hydrocarbons that can be contained in "pipeline quality" gas.

This fact is not reasonably subject to dispute and is capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy, including PG&E Gas Rule 21. A true and correct copy of relevant excerpts from Rule 21 is attached hereto as **Exhibit A.**

2. The natural gas SMUD receives is generally composed of approximately 96% methane, 2% ethane, and only trace amounts of other hydrocarbons.

This fact is not reasonably subject to dispute and is capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy, including "PG&E Gas Quality Information for BTU Area P81," a true and correct exemplar of which is attached hereto as **Exhibit B.**

3. The Florin Gas field is a "dry gas" reservoir.

This fact is not reasonably subject to dispute and is capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy. A true and correct copy of a document with information taken from DOGGR's on-line database for the Florin Gas field (in which a "DG" notation for "dry gas" is listed next to each well that produced gas from the Florin Gas field), is attached hereto as **Exhibit C**.

4. One of the key advantages of a "dry gas" field is that "there are no hydrocarbon liquids (oil or gas condensate) accompanying the gas as it is withdrawn from the field. … Only the produced water, which is high in mineral concentration, must be separated and disposed."

This fact is not reasonably subject to dispute and is capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy. A true and correct copy of relevant excerpts from the 1997 Negative Declaration for the Wild Goose storage facility, in which this advantage was recognized, is attached hereto as **Exhibit D.**

5. The Lodi, Wild Goose, Kirby Hills & McDonald Island gas storage fields are "dry gas" fields. None of those storage fields produced oil or condensate in 2010. These facts are not reasonably subject to dispute and are capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy. A document with information taken from DOGGR's on-line database for these four gas fields, which verify the above fact, is attached hereto as **Exhibit E**.

6. Free liquid water withdrawn with natural gas from "dry gas" wells is removed by simple separation methods that occur at or near the wellhead.

This fact is not reasonably subject to dispute and is capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy, including the source attached hereto as **Exhibit F.**

7. The free liquid water separation system that will be installed at the proposed SNGS Project's wellhead site does *not* qualify as a natural gas processing, fractionating, or cycling plant.

This fact is not reasonably subject to dispute and is capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy, including those attached hereto as **Exhibits F & G.**

8. The only component of the proposed SNGS Project that could conceivably qualify as a downstream "processing plant" capable is the glycol dehydrator that will be located at the compressor station.

This fact is not reasonably subject to dispute and is capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy, including those attached hereto as **Exhibits F, G & H**.

9. California well operators must report the nature of water they re-inject into gas wells on a monthly basis.

This fact is not reasonably subject to dispute and is capable of immediate and accurate determination by reference to section 3227 of the Public Resources Code, a true and correct copy of which is attached hereto as **Exhibit I**.

10. Guidelines of the Division of Oil, Gas, & Geothermal Resources ("DOGGR") require operators to specify that water being injected into a gas well is: (1) "Saline water"; (2) "Fresh water"; (3) "Water combined with chemicals, such as polymers, for injection purposes"; or (4) "Another kind of water".

This fact is not reasonably subject to dispute and is capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy. True and correct

copies of relevant excerpts from these DOGGR reporting guidelines are attached hereto as **Exhibit J & K.**

11. State regulations require "a chemical analysis of the injecting product" that is injected into gas wells.

This fact is not reasonably subject to dispute and is capable of immediate and accurate determination by reference to (a) section 1724.10 of Title 14, Division 2 of the California Code of Regulations, a true and correct copy of which is attached hereto as **Exhibit L**, and (b) the FEIR for the proposed SNGS Project, at p. D.6-11.

12. Sentinel® T-50, manufactured by Chevron Phillips Chemical Company is a mixture of butyl mercaptan and thiophane that is a closely related chemically to methyl mercaptan and is reported to be an even more efficient odorant with at least as good a safety profile.

These facts are not reasonably subject to dispute and are capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy, including the document attached hereto as **Exhibit M**.

13. Odorizing agents manufactured by Chevron Phillips Chemical Company, such as Sentinel® T-50, are distributed to the natural gas industry in containers ranging in size from 5 gallons to 57 gallons.

This fact is not reasonably subject to dispute and is capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy, including the document attached hereto as **Exhibit M**.

14. The City of Sacramento's 2030 General Plan defines "High-Impact Use" as "[a] use that generates disproportionately large environmental impacts such as pollution, noise, or traffic."

This fact is not reasonably subject to dispute and is capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy, including the

glossary for the 2030 General Plan. A true and correct copy of excerpts from that glossary is attached hereto as **Exhibit N**.

Respectfully submitted,

Dated: February 18, 2011 DIEPENBROCK HARRISON

By: _____/s/_____
David A. Diepenbrock
Attorney for Sacramento Natural Gas Storage, LLC

Exhibit A

GAS RULE NO. 21

TRANSPORTATION OF NATURAL GAS

This Rule describes the general terms and conditions that apply whenever PG&E transports Customer-owned gas over its system. Customers who wish to transport gas must sign the applicable Agreement.

A. GENERAL

1. NATURE OF SERVICE

Customers or their designated Agent or Core Transport Agent hereinafter referred to as "Customer" and meaning Customer and/or their Agent will deliver or have delivered to PG&E quantities of gas, and PG&E will deliver equivalent quantities of gas adjusted for In-Kind Shrinkage Allowance, on a Btu-for-Btu basis, to the Customer's Delivery Point. Customers must endeavor to ensure that daily gas deliveries match daily gas usage. The gas that PG&E delivers to the Customer's Delivery Point will not necessarily be the gas that the Customer delivered to PG&E.

2. GAS SPECIFICATIONS

Unless otherwise agreed to by both parties, the gas delivered to PG&E must meet the quality specifications detailed in Section C, below. The minimum and maximum heating value and the pressure of the gas must be such that the gas can be integrated into PG&E's system at the Receipt Point(s).

B. QUANTITIES OF GAS

1. IN-KIND SHRINKAGE ALLOWANCE

The in-kind shrinkage quantities represent the unaccounted-for gas and the utility fuel use attributable to the volume of natural gas received by PG&E for backbone transmission, distribution, and storage service. PG&E may adjust distribution, transmission and storage shrinkage annually, or as necessary. (See Preliminary Statement Part C.12.c. for further details) (T)

(Continued)

GAS RULE NO. 21 Sheet 14
TRANSPORTATION OF NATURAL GAS

C. QUALITY OF GAS

Gas delivered to PG&E for transportation to the Delivery Point(s) shall meet the gas quality specifications stated in the service agreement between the delivering pipeline company and PG&E. If no gas-quality specifications agreement exists between the delivering pipeline company and PG&E for the Receipt Point(s), or if the natural gas is not delivered by a pipeline, the gas received by PG&E shall meet the following specifications:

1. Carbon dioxide: The gas shall contain no more than one percent by volume of carbon dioxide.

2. Oxygen: The gas shall contain no more than 0.1 percent by volume of oxygen.

3. Hydrogen sulfide: The gas shall contain no more than 0.25 grains of hydrogen sulfide, measured as hydrogen sulfide, per one hundred standard cubic feet (4 parts per million (ppm)). (T) | (T)

4. Mercaptan sulfur: The gas shall contain no more than 0.5 grains of mercaptan sulfur, measured as sulfur, per one hundred standard cubic feet (8 ppm). (T) (T)

5. Total sulfur: The gas shall contain no more than one grain of total sulfur, measured as sulfur, per one hundred standard cubic feet (17 ppm). (T) (T)

6. Water vapor: The gas shall contain no more than seven pounds of water vapor per million standard cubic feet at 800 pounds per square inch gauge (psig) or less; dew point of 20° Fahrenheit (F) if gas is supplied at over 800 psig. (T) (T)

7. Hydrocarbon dewpoint: The gas shall have a hydrocarbon dewpoint of 45°F or less for gas delivered at 800 psig or below, but measured at 400 psig; or 20°F for gas delivered at above 800 psig, also measured at 400 psig. (T) | (T)

8. Liquids: The gas shall contain no liquids at, or immediately downstream of, the Receipt Point(s). (T)

9. Merchantibility: The gas shall not contain dust, sand, dirt, gums, oils, or other substances in an amount sufficient to be injurious to PG&E facilities or which shall cause the gas to be unmarketable. (T)

(Continued)

GAS RULE NO. 21 Sheet 15
TRANSPORTATION OF NATURAL GAS

C. QUALITY OF GAS (Cont'd.)

10. Temperature: The gas shall not be delivered at less than 60 degrees Fahrenheit or more than 100 degrees Fahrenheit. (L)

11. Gas interchangeability: The gas shall be interchangeable with the gas in the receiving pipeline. Interchangeability shall be determined in accordance with the methods and limits presented in Bulletin 36 of the American Gas Association. (T)

12. Heating value: The gas shall have a heating value that is consistent with the standards established by PG&E for each Receipt Point. (T) (T)

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

14. Landfill Gas: Gas from landfills will not be accepted or transported under this Rule. (T)(L) (T)

D. ACCOUNTING AND BILLING

1. DESIGNATION OF QUANTITIES DELIVERED FOR TRANSPORTATION

PG&E may be receiving gas from various sources at the Receipt Point(s). Gas entering the PG&E system shall be measured by either PG&E or a third party designated by PG&E as its agent. Where such third party acts as PG&E's measuring agent, the Customer shall accept as correct the agent's determination of the quantity of gas (in Mcf and Decatherms) it has delivered to PG&E for the Customer's account subject to the limitations of Rule 14. Where gas is measured by PG&E, the Customer shall accept as correct PG&E's measurement of the gas received (see Section D.3 below for information about access to meters and charts and other records).

2. BILLING

Each month, PG&E shall send the Customer a bill. The bill will show the quantities of gas adjusted for In-Kind Shrinkage Allowance, delivered to PG&E for the Customer's account at each Delivery Point for the billing month. PG&E may use estimated quantities in the bill, and the Customer shall be obligated to pay the estimated bill as presented; PG&E will then make any necessary adjustments in the subsequent months' billings.

(Continued)

Exhibit B

Gas Quality Information for BTU Area P81

from 02/17/2011 *to* 01/17/2011

Date	Btu Content per std cf	Specific Gravity density, air=1.0	N2 mole %	CO2 mole %	Methane mole %	Ethane mole %	Propane mole %	I-Butane mole %	N-Butane mole %	I-Pentane mole %	N-Pentane mole %	C6+ mole %
02/17/2011	1,016.17	0.576	0.73	0.77	96.48	1.86	0.14	0.01	0.01	0.00	0.00	0.00
02/16/2011	1,016.87	0.577	0.71	0.81	96.35	1.97	0.14	0.01	0.01	0.00	0.00	0.00
02/15/2011	1,017.12	0.578	0.70	0.84	96.24	2.08	0.12	0.01	0.01	0.00	0.00	0.00
02/14/2011	1,015.73	0.576	0.69	0.81	96.50	1.86	0.12	0.01	0.01	0.00	0.00	0.00
02/13/2011	1,016.67	0.577	0.71	0.82	96.34	1.96	0.14	0.01	0.01	0.00	0.00	0.00
02/12/2011	1,018.70	0.579	0.70	0.85	96.04	2.23	0.15	0.01	0.01	0.00	0.00	0.00
02/11/2011	1,019.03	0.579	0.67	0.85	96.11	2.18	0.16	0.01	0.01	0.00	0.00	0.00
02/10/2011	1,017.43	0.577	0.70	0.82	96.30	2.00	0.16	0.01	0.01	0.00	0.00	0.00
02/09/2011	1,016.95	0.576	0.70	0.78	96.46	1.88	0.16	0.01	0.01	0.00	0.00	0.00
02/08/2011	1,017.73	2002018671962095600.000	0.63	0.78	96.49	1.88	0.16	0.01	0.01	0.00	0.00	0.00
02/07/2011	1,019.99	0.578	0.64	0.81	96.22	2.07	0.21	0.02	0.02	0.00	0.00	0.00
02/06/2011	1,026.10	0.583	0.60	0.88	95.55	2.56	0.33	0.03	0.04	0.01	0.01	0.00
02/05/2011	1,021.52	0.580	0.75	0.79	95.91	2.21	0.27	0.03	0.03	0.01	0.00	0.00
02/04/2011	1,020.95	0.579	0.72	0.78	96.05	2.12	0.26	0.02	0.03	0.01	0.00	0.00
02/03/2011	1,021.06	0.579	0.63	0.78	96.22	2.04	0.26	0.02	0.03	0.00	0.00	0.00
02/02/2011	1,020.29	0.579	0.75	0.78	96.09	2.05	0.26	0.03	0.03	0.01	0.00	0.00
02/01/2011	1,015.73	0.576	0.78	0.77	96.47	1.77	0.16	0.02	0.02	0.00	0.00	0.00
01/31/2011	1,014.98	0.575	0.70	0.74	96.78	1.61	0.14	0.01	0.02	0.00	0.00	0.00
01/30/2011	1,015.02	0.574	0.61	0.76	96.88	1.60	0.12	0.01	0.01	0.00	0.00	0.00
01/29/2011	1,016.55	0.575	0.57	0.77	96.78	1.72	0.13	0.01	0.01	0.00	0.00	0.00
01/28/2011	1,015.45	0.574	0.62	0.74	96.90	1.58	0.13	0.01	0.01	0.00	0.00	0.00
01/27/2011	1,015.04	0.574	0.66	0.72	96.89	1.56	0.13	0.01	0.01	0.00	0.00	0.00
01/26/2011	1,016.17	0.575	0.62	0.78	96.70	1.74	0.14	0.01	0.01	0.00	0.00	0.00
01/25/2011	1,016.78	0.575	0.58	0.78	96.72	1.75	0.14	0.01	0.01	0.00	0.00	0.00
01/24/2011	1,017.12	0.576	0.58	0.81	96.61	1.82	0.14	0.01	0.01	0.00	0.00	0.00
01/23/2011	1,016.92	0.575	0.55	0.79	96.77	1.71	0.15	0.01	0.01	0.00	0.00	0.00
01/22/2011	1,018.96	0.577	0.51	0.87	96.42	2.00	0.16	0.02	0.02	0.00	0.00	0.00
01/21/2011	1,018.16	0.576	0.51	0.84	96.58	1.89	0.15	0.01	0.01	0.00	0.00	0.00
01/20/2011	1,018.49	0.577	0.51	0.85	96.51	1.96	0.14	0.01	0.01	0.00	0.00	0.00
01/19/2011	1,019.02	0.577	0.52	0.83	96.48	2.00	0.14	0.01	0.02	0.00	0.00	0.00
01/18/2011	1,017.67	0.575	0.53	0.78	96.75	1.76	0.15	0.01	0.02	0.00	0.00	0.00
01/17/2011	1,018.29	0.576	0.56	0.78	96.61	1.85	0.15	0.02	0.02	0.00	0.00	0.00

Disclaimer: The data on these pages is a representative sample of gas quality information only. It is raw, unreviewed, real-time data provided solely for informational purposes, and not for billing purposes. PG&E makes no claim or representation that the data provided is accurate. No party should rely on such data, including, but not limited to, for billing purposes. Data may be subject to adjustments and corrections prior to being used for billing or record keeping.

Copyright © 2008 Pacific Gas and Electric Company.
All rights reserved.

Exhibit C

Florin Gas Field Well List

Dist	Operator Name	Field Name	Lease	Well#	API	Well Stat	Pool	WellType	PWT Stat	S	T	R	BM	Op Cd	Field	Area	Area Name	Pool Name
6	Union Oil Co. of Calif.	Florin Gas (ABD)	Florin	2	06720206	Plugged	05	DG	Plugged	35	8N	5E	MD	U0200	249	00	Any Area	Winters
6	Union Oil Co. of Calif.	Florin Gas (ABD)	Florin	4	06720227	Plugged	05	DG	Plugged	35	8N	5E	MD	U0200	249	00	Any Area	Winters
6	The Procter and Gamble Co.	Florin Gas (ABD)	Florin	2	06720231	Plugged	05	DG	Plugged	34	8N	5E	MD	P4730	249	00	Any Area	Winters
6	Union Oil Co. of Calif.	Florin Gas (ABD)	Florin	1	06720125	Plugged	05	DG	Plugged	35	8N	5E	MD	U0200	249	00	Any Area	Winters
6	The Procter and Gamble Co.	Florin Gas (ABD)	Florin	1	06720203	Plugged	05	DG	Plugged	34	8N	5E	MD	P4730	249	00	Any Area	Winters

This is the list of wells for Florin Gas from the DOGGR online production data base.

Note that all of the wells are welltype DG (dry gas).

Exhibit D

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

NEGATIVE DECLARATION

WILD GOOSE STORAGE, INC.
WILD GOOSE GAS STORAGE PROJECT
NATURAL GAS STORAGE FACILITIES
(A.96-08-058)

PROJECT DESCRIPTION

The California Public Utilities Commission is considering a Certificate of Public Convenience and Necessity for the construction of natural gas storage facilities by Wild Goose Storage, Inc. (WGSI) in Butte County. See Figure 1 for a project vicinity map. WGSI provided the Commission with a Proponent's Environmental Assessment (PEA) that was available for public review along with this document from March 31 to April 29, 1997. WGSI also prepared a series of environmental surveys and mitigation implementation plans that accompanied the PEA and were also available for public review. Attachment A to this document is a collection of the comments on the draft of this document and responses to those comments.

The Administrative Law Judge's Proposed Decision, which included this document as Appendix C, was mailed to parties in this proceeding for further comments. The comments of the parties (on the CEQA document) and the resulting changes to the Negative Declaration are discussed in Attachment B to this document.

Project Overview

Located in the southwest corner of Butte County, California, the Wild Goose Gas Storage Project involves development of a previously abandoned 137-billion-cubic-foot (Bcf) underground natural gas field for use in natural gas storage. The project Proponent is Wild Goose Storage, Inc. (WGSI), a wholly-owned subsidiary of Alberta Energy Company Ltd. Equipment and surface facilities required for natural gas storage are not extensive, requiring only a small amount of land to accommodate compressors, gas dehydration equipment and liquid handling systems. See Figure 2 for a project components map. As proposed, project development will require construction of:

- an interconnect to the 12-inch-diameter Line 167 of Pacific Gas and Electric Company's (PG&E's) Sacramento Valley Gas Transmission System.
- a 3-acre Remote Facility Site at West Liberty Road for metering, processing and compressing the gas.
- approximately 4 miles of 18-inch-diameter gas pipeline and 2-inch-diameter bi-directional produced water pipeline between the Well Pad Site and the Remote Facility Site.
- a 1.5-acre Well Pad Site at the location of the now-abandoned compression facility and well pad.

The Wild Goose Gas Storage Project is designed to move gas between PG&E's existing gas pipeline system and the storage field. During periods of low natural gas demand, gas will be injected into the storage field and during periods of high demand, the gas will be withdrawn from the storage field and returned to PG&E's pipeline system.

INSERT FIGURE 1

INSERT FIGURE 2

- The Wild Goose Gas Field consists of 12 distinct underground porous rock "reservoirs" located at depths ranging from 2,550 to 3,450 feet below the ground surface. The individual reservoirs are separated from each other by the presence of impervious rock (shale) formations. These reservoirs have three primary characteristics that make the field technically attractive for conversion to gas storage:

  - An impervious dome-shaped "cap rock," which varies in thickness from 10 to 75 feet, serves as the top of the reservoir and traps the natural gas within the top portion of the dome.

  - The reservoir body is composed of highly porous and permeable sandstone rock within which the gas is actually contained.

  - The flanks of the reservoir are saturated with water and are in contact with large, deep aquifers that provide pressure support during gas withdrawal.

In California there are presently 10 active underground natural gas storage facilities in operation near primary market centers: 5 in the Los Angeles area (owned by Southern California Gas), 4 near San Francisco (3 owned by PG&E and 1 by Dow Corporation) and 1 in Santa Barbara (owned by Southern California Gas). Stringent standards set by the California Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR) govern underground construction and operation of natural gas wells and underground storage reservoirs to ensure safety and security of stored gas.

The Applicant for the Wild Goose Storage Project is:

Wild Goose Storage, Inc.
c/o Dean Cockshutt
3900, 421 - 7th Avenue, S.W.
Calgary, Alberta
Canada T2P 4K9

Field Operation

During injection operations, gas will flow from PG&E's Line 167 through the Remote Facility Site compressor and the project's 18-inch-diameter, bi-directional pipeline to the Well Pad Site for injection into the field. Typically, gas will be taken from the PG&E line at pressures ranging from 550 to 800 pounds per square inch gauge (psig) and injected into the reservoir at a maximum design surface pressure of 2,000 psig using an 8,900-horsepower, low-NO_x, turbine-driven compressor. This amount of compression will provide 80 million standard cubic feet per day (MMcfd) of firm injection service.

During withdrawal operations, gas will flow from the Well Pad Site back to the Remote Facility Site and into PG&E's Line 167. Wellhead surface pressures under withdrawal conditions will typically range from 1,500 psig to approximately 500 psig. Wells and facilities have been designed to provide 200 MMcfd of firm withdrawal service. The volume of daily, weekly and monthly injections and withdrawals will vary with customer demand, subject to the volume, deliverability and injection capabilities of the field. All injections and withdrawals will be operationally dispatched and controlled by project personnel working at the Remote Facility Site.

When gas is withdrawn from the reservoir, small amounts of water from aquifers connected to the storage reservoir may also be withdrawn with the gas. This water is termed "produced water" and is removed from the gas by a three-stage process. Stage one is at the Well Pad Site where separators remove most of the water. Produced water will be piped through a 2-inch-diameter pipeline to the Remote Facility Site for disposal. Stages two and three of produced water removal are conducted at the Remote Facility Site. One of the key advantages of the Wild Goose Gas Field is its classification as a "dry" gas field. As such, there are no hydrocarbon liquids (oil or gas condensate) accompanying the gas as it is withdrawn from the field, as may be the case in some oil and gas fields that have been converted to storage. Only the produced water, which is high in mineral concentration, must be separated and disposed.

If produced water quantities are small, the water will be periodically trucked to disposal site approved by the DOGGR. Off-site disposal would be by a hauler licensed by the California Department of Transportation and the California Highway Patrol, who would dispose of the water at a DOGGR-approved disposal/injection well, as is common practice in gas and oil field operations. Disposal vacuum truck service is provided for PG&E locally by Gomes Excavating, Inc. of Rio Vista, and produced water is disposed of in permitted injection wells in Solano County. Otherwise, produced water will be pumped into a deep disposal well, which may be located at the Remote Facility Site. Reinjection of produced water back to a suitable deep aquifer is a common practice subject to permitting by the DOGGR. The disposal well will be drilled and cased to a depth considerably below the base of fresh water in the area, into an aquifer containing greater than 10,000 mg/l total dissolved solids, as required by DOGGR in their disposal well permitting process.

Prior to full project operation, a 2- to 3-month start-up phase is required to inject "cushion gas" into the storage reservoir. Cushion gas is injected to re-establish the gas saturation, slowly depress the gas-water contact zone in the porous sandstone formations, and establish the base field pressure. Cushion gas becomes a permanent component of the reservoir and is not withdrawn. It will be owned by WGSI, unlike the working gas inventory, which will be owned by storage customers.

History of the Field

The Wild Goose Gas Field was discovered in 1951 and produced in excess of 100 Bcf of gas from 12 wells that tapped each of the 12 reservoirs. Gas from the field was routed to a compressor previously located at the proposed Well Pad Site. From here it was transported through a 8-inch-diameter collector pipeline to PG&E's Wild Goose Mixer Station on West Liberty Road. Production ceased at the end of primary depletion in 1988 and all wells were abandoned in accordance with DOGGR standards. Over time, excellent production and pressure records were kept, resulting in a very complete and high-quality database available for analyses. All 12 reservoirs are segregated by impervious shale layers, which allows individual zones to be converted to storage in response to market demand. For the storage demand identified in the near term, the L4 reservoir (second deepest zone) is considered to be the best candidate due to its appropriate size, high-quality rock and strong aquifer support.

Well Pad Site

Primary pressure regulation, water separation, metering and flow-rate control will occur at the Well Pad Site. The Well Pad Site is located in the extreme southwest corner of Butte County in an area that has historically been used for natural gas production facilities and waterfowl hunting clubs. This site is on private property owned by the Wild Goose Club, which also owns the majority of the surface rights above the gas field. The Well Pad Site supports moderately dense freshwater marsh habitat, limited open water habitat, and a small amount of ruderal annual grassland (on the former compressor pad and the levee

berm.) Although the freshwater marsh area is privately managed by the club, it is Army Corps Of Engineers (ACOE) jurisdictional wetland.

Results of extensive engineering and geologic studies indicate that current storage needs can be met with one vertical and five to nine horizontal wells in the L4 reservoir. This will utilize approximately 50 percent of the field's total storage capacity. The first well drilled will be vertical and will provide a rock core for cap rock and reservoir studies. The use of horizontal well technology for the remaining wells minimizes the total number of wells required. All wells will be used for both withdrawal and injection of stored gas.

The Well Pad Site will consist of 1.5 acres within an 8.5-acre lease tract. The remaining 7 acres will be available should project expansion ever occur. The 8.5-acre lease tract and a majority of the underground storage and mineral rights needed for the project have been secured from the Wild Goose Club. The balance of the needed storage rights have been secured from neighboring property owners. Actual acreage required for the stored gas is less than half of the total underground storage rights acquired, providing a large buffer zone around the project.

The Well Pad Site is accessed from the south via a private gravel road through the Wild Goose Club site. The club's existing approaches and bridge crossing the Cherokee Canal are not adequate for the length and weight of the pipeline construction and well drilling equipment. A new access road and bridge will be installed across the Cherokee Canal just south of the Wild Goose Club compound.

During the original gas production, the compressor and well pad occupied a one-quarter-acre area parallel and adjacent to the Cherokee Canal. Construction of the proposed Well Pad Site involves the re-establishment and expansion of a portion of this original well pad and compressor site to minimize surface disturbance. To lessen the effects of periodic flooding, the Well Pad Site will be elevated approximately 5 feet to the level of the existing access road and surrounded by an earthen perimeter berm. The site will then be covered with compacted aggregate and the berm will be landscaped with native vegetation to blend with the surroundings and to visually screen the facility from the nearby wildlife habitat and hunting areas. The design and appearance of the Well Pad Site must conform to the Wild Goose Club's specifications.

Depending on the final compaction ratio, approximately 22,000 cubic yards of fill material will be required to elevate the site and construct the berm. This fill material will be taken from four adjacent locations on Wild Goose Club property—three existing upland sites and one at Goose Island (See Figure 2). The upland areas are intended to be converted to wetlands to offset wetlands loss at the Well Pad Site.

Surface facilities will include the well heads with valves, a pipeline pig receiver (used to clean and inspect the pipeline connecting the Well Pad Site and Remote Facility Site), water separators, pressure control valves, emergency shutdown valves, and methanol and corrosion inhibitor storage tanks. All tanks containing hazardous materials will be constructed with dual containment systems. Approximately 500 gallons of methanol and 25 gallons of corrosion inhibitor will be temporarily stored and used on site. Methanol is used only during very cold weather and may be present at the Well Pad Site for less than two months during the winter. The tanks will be installed in 110 percent external containment cells, with the top vent above the historic flood level. The wellheads and associated piping, valves and tanks will be less than 3 feet high. Site lighting installed for security will operate on photo cells. A short whip-style radio antennae will be installed for the remote operational monitoring and control communications link to the Remote Facility Site.

Remote Site Facility

While the facility site for this type of project would typically be located adjacent to the withdrawal and injection wells, a remote site is proposed to minimize potential environmental effects. The proposed site is presently a rice field located adjacent to PG&E's Line 167, which provides the project connection to the existing gas transmission system. In addition, West Liberty Road provides the all-weather road access required for the Remote Facility Site. A 5-acre tract for the Remote Facility Site will be purchased in fee or obtained under a long-term lease agreement. Initial site development will occupy approximately 3 acres, with the remaining two acres serving initially for temporary construction staging and material storage, and ultimately as a buffer area while it is held in reserve should project expansion ever occur.

All aboveground structures at the Remote Facility Site will be painted a flat, neutral color to minimize any visual impact. Site lighting, installed for security and nighttime operational activities, will operate on photo cells. The design, construction, operation and maintenance of the Remote Facility Site will be in compliance with the applicable specifications, standards and regulations established by the federal government and the industry.

Major components of the Remote Facility Site are (see Figure 3):

- ***Gas Compressor:*** A centrifugal natural gas compressor driven by a turbine engine producing 8,600 to 8,900 horsepower. Turbine exhaust emissions will be minimized by using best available control technology (BACT). The compressor will be housed in a noise attenuated, pre-engineered building. Exterior materials will be chosen to blend with surrounding land uses and building styles. The building will be approximately 75 feet long, 75 feet wide, and 35 feet high, and large enough to provide sufficient space for warehousing equipment and repair parts.

- ***Produced Water Storage and Disposal:*** Wellhead separators will remove the majority of produced water at the Well Pad Site. Produced water will be piped to the Remote Facility Site in a 2-inch-diameter pipeline buried along side the 18-inch-diameter gas pipeline. Any water remaining in the gas stream will be removed at the Remote Facility Site by the second stage inlet separator. Produced water will be stored temporarily at the Remote Facility Site in four aboveground 21,000-gallon tanks with 110 percent external containment. The tanks storage enclosure will be approximately 50 feet long, 50 feet wide, and 25 feet high. If produced water quantities are small, the water will be periodically trucked to an approved disposal site.

- ***Dehydration Units and Reboilers:*** Two dehydration units consisting of triethylene glycol/natural gas contactor towers and two natural-gas-fired glycol reboilers. The gas contactors will be approximately 30 feet high. Vapors from the glycol still will be flared to reduce emissions. The flame will not be visible since it will be contained within an incinerator stack approximately 30 feet high.

Gas Odorant System: Gas in PG&E's transmission system is odorized with methyl mercaptan for safety. The Remote Facility Site will be equipped with a trim odorant system to supplement odorant lost during storage and withdrawal.

INSERT FIGURE 3

- ***Gas Coolers:*** Gas must be cooled before it enters the discharge header to Line 167 or the Well Pad Site to reduce the thermal stress on the pipeline and valves. The coolers are approximately 15 feet high and are driven by electric motors.

- ***Gas Scrubbers:*** One gas scrubber vessel will remove fine particulate matter (salt-coated sand and bits of formation rock) from the gas to protect the internal surfaces of the equipment.

- ***Pressure Control Facilities:*** Pressure control valves at the Remote Facility Site will regulate the total gas flow entering the Remote Facility Site during withdrawal from the storage field. Each individual well at the Well Pad Site will be equipped with a pressure control valve to control gas flow.

- ***Relief Vents:*** Two emergency shutdown relief vents will be used to vent pressurized gas to the atmosphere from pressure relief valves following an emergency blowdown, or a blowdown required for pipeline maintenance activities. The relief vents have not yet been designed, but may consist of horizontal cylinders, approximately 36 inches in diameter and 12 feet long, with a vertical exit pipe. Baffles will reduce blowdown noise to acceptable levels.

- ***Waste Oil Storage Tank:*** Oil wastes include approximately 1,000 gallons annually from maintenance of the compressor and emergency generator. These wastes will be stored temporarily in an aboveground tank pending off-site shipment to permitted treatment, storage or disposal facilities by a licensed hauler. The 1,000-gallon tank, approximately 15 feet in height, will be located within concrete containment walls providing 110 percent of the volume of the tank. The tank and containment walls will be located near the dehydration units and compressor building.

- ***Glycol Supply Tank:*** A 1,000-gallon aboveground tank, approximately 15 feet in height, with 110 percent containment will supply make-up glycol for any minor amounts lost as vapor in the glycol reboilers. The glycol-supply tank will be located near the compressor building.

- ***Generator:*** To ensure Remote Facility Site has continuous power, a natural-gas-fueled, 500-horsepower back-up generator will be activated if the local PG&E power supply is interrupted.

- ***Office Building:*** A single-story office/control building for the operators and maintenance workers will be architecturally similar to the compressor building. The building will be approximately 30 wide, 60 feet long, and 16 feet high.

- ***Radio Antennae:*** A radio antennae will be used for remote safety and operations monitoring at the Well Pad Site and to provide operational data to PG&E's gas control center. The antennae will be mounted on a slender pyramid-shape tower, reaching a total height of approximately 30 feet.

- ***Utilities:*** Natural gas will be used as the fuel for the compressors, standby generator and glycol reboiler. Electricity from the existing 12 kV distribution line along West Liberty Road will be used for gas coolers, pumps, site lighting, office lighting, heating/ventilation/air conditioning system, air compressors and other miscellaneous equipment. Pacific Bell will provide phone service from their existing cable along Pennington Road. Potable water for the Remote Facility Site will be supplied from an on-site water well. Sanitary wastewater will flow to an approved on-site septic system and leach field. The entire site will be enclosed by a 6-foot-high chainlink fence with a one-foot barbed wire extension. The perimeter will be landscaped to screen the facility and minimize its visibility.

Exhibit E

Lodi Gas Storage

	Production				Injection			
DATE	Oil / Condensate	WATER	GAS	DAYS	GAS	DAYS	WATER	DAYS
12/2010	-	2,912	2,497,805	237	1,720,987	113	1,900	4
11/2010	-	8,902	3,335,082	259	1,477,953	98	10,503	14
10/2010	-	1,652	873,335	217	2,011,374	175	-	-
09/2010	-	4,271	1,774,616	274	1,598,529	136	1,501	6
08/2010	-	10,583	2,750,362	258	2,486,584	148	11,683	13
07/2010	-	14,420	3,760,204	264	1,216,465	129	16,597	16
06/2010	-	5,169	1,515,774	210	3,137,596	208	5,508	4
05/2010	-	1,336	531,080	147	5,287,712	269	-	-
04/2010	-	5,521	1,116,175	173	3,191,080	220	5,374	3
03/2010	-	7,491	1,914,040	250	2,505,769	150	6,706	6
02/2010	-	17,805	3,667,237	246	255,410	52	19,663	16
01/2010	-	15,243	3,372,191	270	872,469	83	11,531	21

Wild Goose Gas Storage

	Production				Injection			
DATE	Oil / Condensate	WATER	GAS	DAYS	GAS	DAYS	WATER	DAYS
12/2010	-	1,015	339,314	115	122,781	10		
11/2010	-	-	286,742	68	2,381,917	69		
10/2010	-	-	16,414	34	3,477,575	90		
09/2010	-	-	156	3	5,657,315	174		
08/2010	-	1,037	93,920	35	1,357,163	49		
07/2010	-	-	15,448	12	3,493,228	125		
06/2010	-	886	7,843	6	8,331,845	149		
05/2010	-	-	8,822	5	7,827,146	149		
04/2010	-	-	1,823	7	5,295,937	149		
03/2010	-	850	3,732,510	131	4,544	37		
02/2010	-	178	5,373,728	141	4	3		
01/2010	-	36	8,406,251	200	17	7		

Kirby Hills Gas Storage

	Production				Injection			
DATE	Oil / Condensate	WATER	GAS	DAYS	GAS	DAYS	WATER	DAYS
12/2010	-	518	2,401,718	269	11,756	4		
11/2010	-	188	664,351	121	1,675,953	202		
10/2010	-	-	329	98	2,688,216	286		
09/2010	-	116	659,853	203	439,609	48		
08/2010	-	1,798	2,824,683	287	27,835	8		
07/2010	-	720	1,404,793	204	342,774	76		
06/2010	-	-	-	-	1,531,907	262		
05/2010	-	-	35	42	2,336,535	269		
04/2010	-	18	18,083	7	1,996,219	174		
03/2010	-	982	1,398,513	196	1,094,328	51		
02/2010	-	6,375	2,832,062	234	-	-		
01/2010	-	36	8,406,251	200	37,378	20		

McDonald Island Gas Storage

	Production				Injection			
DATE	Oil / Condensate	WATER	GAS	DAYS	GAS	DAYS	WATER	DAYS
12/2010	-	-	7,326,673	2,240	547,450	176		
11/2010	-	2	7,667,373	1,470	1,558,345	144		
10/2010	-	-	1,691,014	626	1,110,681	615		
09/2010	-	-	409,190	287	2,633,761	756		
08/2010	-	3,688	1,547,934	340	3,695	32		
07/2010	-	7,605	1,275,115	575	1,807,102	390		
06/2010	-	4,255	19,375	30	6,335,914	1,200		
05/2010	-	1,626	21,964	31	9,727,508	1,209		
04/2010	-	125	1,001,333	247	5,671,469	858		
03/2010	-	6	1,326,840	364	4,867,636	967		
02/2010	-	7	3,737,242	1,084	366,738	200		
01/2010	-	5	10,042,132	1,459	58,406	82		

Exhibit F

NaturalGas.org

> Home
> Overview of Natural Gas
> Natural Gas - From Wellhead to Burner Tip
> Exploration
> Extraction
> Production
> Transport
> Storage
> Distribution
> Marketing
> Business Overview
> Natural Gas Regulations
> Environment & Technology
> Focus on LNG
> Natural Gas Quiz

Processing Natural Gas

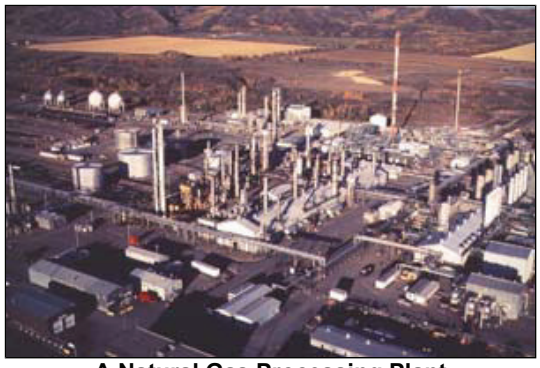
Source: Duke Energy Gas Transmission Canada

Natural gas, as it is used by consumers, is much different from the natural gas that is brought from underground up to the wellhead. Although the processing of natural gas is in many respects less complicated than the processing and refining of crude oil, it is equally as necessary before its use by end users.

The natural gas used by consumers is composed almost entirely of methane. However, natural gas found at the wellhead, although still composed primarily of methane, is by no means as pure. Raw natural gas comes from three types of wells: oil wells, gas wells, and condensate wells. Natural gas that comes from oil wells is typically termed 'associated gas'. This gas can exist separate from oil in the formation (free gas), or dissolved in the crude oil (dissolved gas). Natural gas from gas and condensate wells, in which there is little or no crude oil, is termed 'nonassociated gas'. Gas wells typically produce raw natural gas by itself, while condensate wells produce free natural gas along with a semi-liquid hydrocarbon condensate. Whatever the source of the natural gas, once separated from crude oil (if present) it commonly exists in mixtures with other hydrocarbons; principally ethane, propane, butane, and pentanes. In addition, raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds. To learn about the basics of natural gas, including its composition, click here.

Natural gas processing consists of separating all of the various hydrocarbons and fluids from the pure natural gas, to produce what is known as 'pipeline quality' dry natural gas. Major transportation pipelines usually impose restrictions on the make-up of the natural gas that is allowed into the pipeline. That means that before the natural gas can be transported it must be purified. While the ethane, propane, butane, and pentanes must be removed from natural gas, this does not mean that they are all 'waste products'.

In fact, associated hydrocarbons, known as 'natural gas liquids' (NGLs) can be very valuable by-products of natural gas processing. NGLs include ethane, propane, butane, iso-butane, and natural gasoline. These NGLs are sold separately and have a variety of different uses; including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants, and as sources of energy.


A Natural Gas Processing Plant
Source: Duke Energy Gas Transmission Canada

While some of the needed processing can be accomplished at or near the wellhead (field processing), the complete processing of natural gas takes place at a processing plant, usually located in a natural gas producing region. The extracted natural gas is transported to these processing plants through a network of gathering pipelines, which are small-diameter, low pressure pipes. A complex gathering system can consist of thousands of miles of pipes, interconnecting the processing plant to upwards of 100 wells in the area. According to the American Gas Association's Gas Facts 2000, there was an estimated 36,100 miles of gathering system

pipelines in the U.S. in 1999.

In addition to processing done at the wellhead and at centralized processing plants, some final processing is also sometimes accomplished at 'straddle extraction plants'. These plants are located on major pipeline systems. Although the natural gas that arrives at these straddle extraction plants is already of pipeline quality, in certain instances there still exist small quantities of NGLs, which are extracted at the straddle plants.

The actual practice of processing natural gas to pipeline dry gas quality levels can be quite complex, but usually involves four main processes to remove the various impurities:

- Oil and Condensate Removal
- Water Removal
- Separation of Natural Gas Liquids
- Sulfur and Carbon Dioxide Removal

Scroll down, or click on the links above to be transported to a particular section.

In addition to the four processes above, heaters and scrubbers are installed, usually at or near the wellhead. The scrubbers serve primarily to remove sand and other large-particle impurities. The heaters ensure that the temperature of the gas does not drop too low. With natural gas that contains even low quantities of water, natural gas hydrates have a tendency to form when temperatures drop. These hydrates are solid or semi-solid compounds, resembling ice like crystals. Should these hydrates accumulate, they can impede the passage of natural gas through valves and gathering systems. To reduce the occurrence of hydrates, small natural gas-fired heating units are typically installed along the gathering pipe wherever it is likely that hydrates may form.

Oil and Condensate Removal

In order to process and transport associated dissolved natural gas, it must be separated from the oil in which it is dissolved. This separation of natural gas from oil is most often done using equipment installed at or near the wellhead.

The actual process used to separate oil from natural gas, as well as the equipment that is used, can vary widely. Although dry pipeline quality natural gas is virtually identical across different geographic areas, raw natural gas from different regions may have different compositions and separation requirements. In many instances, natural gas is dissolved in oil underground primarily due to the pressure that the formation is under. When this natural gas and oil is produced, it is possible that it will separate on its own, simply due to decreased pressure; much like opening a can of soda pop allows the release of dissolved carbon dioxide. In these cases, separation of oil and gas is relatively easy, and the two hydrocarbons are sent separate ways for further processing. The most basic type of separator is known as a conventional separator. It consists of a simple closed tank, where the force of gravity serves to separate the heavier liquids like oil, and the lighter gases, like natural gas.

Gas Processing Engineers
Source: ChevronTexaco Corporation

In certain instances, however, specialized equipment is necessary to separate oil and natural gas. An example of this type of equipment is the Low-Temperature Separator (LTX). This is most often used for wells producing high pressure gas along with light crude oil or condensate. These separators use pressure differentials to cool the wet natural gas and separate the oil and condensate. Wet gas enters the separator, being cooled slightly by a heat exchanger. The gas then travels through a high pressure liquid 'knockout', which serves to remove any liquids into a low-temperature separator. The gas then flows into this low-temperature separator through a choke mechanism, which expands the gas as it enters the separator. This rapid expansion of the gas allows for the lowering of the temperature in the separator. After liquid removal, the dry gas then travels back through the heat exchanger and is warmed by the incoming wet gas. By varying the pressure of the gas in various sections of the separator, it is possible to vary the temperature, which causes the oil and some water to be condensed out of the wet gas stream. This basic pressure-temperature relationship can work in

reverse as well, to extract gas from a liquid oil stream.

Water Removal

In addition to separating oil and some condensate from the wet gas stream, it is necessary to remove most of the associated water. Most of the liquid, free water associated with extracted natural gas is removed by simple separation methods at or near the wellhead. However, the removal of the water vapor that exists in solution in natural gas requires a more complex treatment. This treatment consists of 'dehydrating' the natural gas, which usually involves one of two processes: either absorption, or adsorption.

Absorption occurs when the water vapor is taken out by a dehydrating agent. Adsorption occurs when the water vapor is condensed and collected on the surface.

Glycol Dehydration

An example of absorption dehydration is known as Glycol Dehydration. In this process, a liquid desiccant dehydrator serves to absorb water vapor from the gas stream. Glycol, the principal agent in this process, has a chemical affinity for water. This means that, when in contact with a stream of natural gas that contains water, glycol will serve to 'steal' the water out of the gas stream. Essentially, glycol dehydration involves using a glycol solution, usually either diethylene glycol (DEG) or triethylene glycol (TEG), which is brought into contact with the wet gas stream in what is called the 'contactor'. The glycol solution will absorb water from the wet gas. Once absorbed, the glycol particles become heavier and sink to the bottom of the contactor where they are removed. The natural gas, having been stripped of most of its water content, is then transported out of the dehydrator. The glycol solution, bearing all of the water stripped from the natural gas, is put through a specialized boiler designed to vaporize only the water out of the solution. While water has a boiling point of 212 degrees Fahrenheit, glycol does not boil until 400 degrees Fahrenheit. This boiling point differential makes it relatively easy to remove water from the glycol solution, allowing it be reused in the dehydration process.

A new innovation in this process has been the addition of flash tank separator-condensers. As well as absorbing water from the wet gas stream, the glycol solution occasionally carries with it small amounts of methane and other compounds found in the wet gas. In the past, this methane was simply vented out of the boiler. In addition to losing a portion of the natural gas that was extracted, this venting contributes to air pollution and the greenhouse effect. In order to decrease the amount of methane and other compounds that are lost, flash tank separator-condensers work to remove these compounds before the glycol solution reaches the boiler. Essentially, a flash tank separator consists of a device that reduces the pressure of the glycol solution stream, allowing the methane and other hydrocarbons to vaporize ('flash'). The glycol solution then travels to the boiler, which may also be fitted with air or water cooled condensers, which serve to capture any remaining organic compounds that may remain in the glycol solution. In practice, according to the Department of Energy's Office of Fossil Energy, these systems have been shown to recover 90 to 99 percent of methane that would otherwise be flared into the atmosphere.

To learn more about glycol dehydration, visit the Gas Technology Institute's website here.

Solid-Desiccant Dehydration

Solid-desiccant dehydration is the primary form of dehydrating natural gas using adsorption, and usually consists of two or more adsorption towers, which are filled with a solid desiccant. Typical desiccants include activated alumina or a granular silica gel material. Wet natural gas is passed through these towers, from top to bottom. As the wet gas passes around the particles of desiccant material, water is retained on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the bottom of the tower.

Solid-desiccant dehydrators are typically more effective than glycol dehydrators, and are usually installed as a type of straddle system along natural gas pipelines. These types of dehydration systems are best suited for large volumes of gas under very high pressure, and are thus usually located on a pipeline downstream of a compressor station. Two or more towers are required due to the fact that after a certain period of

use, the desiccant in a particular tower becomes saturated with water. To 'regenerate' the desiccant, a high-temperature heater is used to heat gas to a very high temperature. Passing this heated gas through a saturated desiccant bed vaporizes the water in the desiccant tower, leaving it dry and allowing for further natural gas dehydration.

Absorption Towers
Source: Duke Energy Gas Transmission Canada

Gas Processing Plant with Absorption Towers
Source: Duke Energy Gas Transmission Canada

Gas contains many natural gas liquids that are commonly removed. In most instances, natural gas liquids (NGLs) have a higher value as separate products, and it is thus economical to remove them from the gas stream. The removal of natural gas liquids usually takes place in a relatively centralized processing plant, and uses techniques similar to those used to dehydrate natural gas.

There are two basic steps to the treatment of natural gas liquids in the natural gas stream. First, the liquids must be extracted from the natural gas. Second, these natural gas liquids must be separated themselves, down to their base components.

NGL Extraction

There are two principle techniques for removing NGLs from the natural gas stream: the absorption method and the cryogenic expander process. According to the Gas Processors Association, these two processes account for around 90 percent of total natural gas liquids production.

The Absorption Method

The absorption method of NGL extraction is very similar to using absorption for dehydration. The main difference is that, in NGL absorption, an absorbing oil is used as opposed to glycol. This absorbing oil has an 'affinity' for NGLs in much the same manner as glycol has an affinity for water. Before the oil has picked up any NGLs, it is termed 'lean' absorption oil. As the natural gas is passed through an absorption tower, it is brought into contact with the absorption oil which soaks up a high proportion of the NGLs. The 'rich' absorption oil, now containing NGLs, exits the absorption tower through the bottom. It is now a mixture of absorption oil, propane, butanes, pentanes, and other heavier hydrocarbons.

Pipes and Absorption Towers
Source: Duke Energy Gas Transmission Canada

The rich oil is fed into lean oil stills, where the mixture is heated to a temperature above the boiling point of the NGLs, but below that of the oil. This process allows for the recovery of around 75 percent of butanes, and 85 - 90 percent of pentanes and heavier molecules from the natural gas stream.

The basic absorption process above can be modified to improve its effectiveness, or to target the extraction of specific NGLs. In the refrigerated oil absorption method, where the lean oil is cooled through refrigeration, propane recovery can be upwards of 90 percent, and around 40 percent of ethane can be extracted from the natural gas stream. Extraction of the other, heavier NGLs can

be close to 100 percent using this process.

The Cryogenic Expansion Process

Cryogenic processes are also used to extract NGLs from natural gas. While absorption methods can extract almost all of the heavier NGLs, the lighter hydrocarbons, such as ethane, are often more difficult to recover from the natural gas stream. In certain instances, it is economic to simply leave the lighter NGLs in the natural gas stream. However, if it is economic to extract ethane and other lighter hydrocarbons, cryogenic processes are required for high recovery rates. Essentially, cryogenic processes consist of dropping the temperature of the gas stream to around -120 degrees Fahrenheit.

There are a number of different ways of chilling the gas to these temperatures, but one of the most effective is known as the turbo expander process. In this process, external refrigerants are used to cool the natural gas stream. Then, an expansion turbine is used to rapidly expand the chilled gases, which causes the temperature to drop significantly. This rapid temperature drop condenses ethane and other hydrocarbons in the gas stream, while maintaining methane in gaseous form. This process allows for the recovery of about 90 to 95 percent of the ethane originally in the gas stream. In addition, the expansion turbine is able to convert some of the energy released when the natural gas stream is expanded into recompressing the gaseous methane effluent, thus saving energy costs associated with extracting ethane.

The extraction of NGLs from the natural gas stream produces both cleaner, purer natural gas, as well as the valuable hydrocarbons that are the NGLs themselves.

Natural Gas Liquid Fractionation

Once NGLs have been removed from the natural gas stream, they must be broken down into their base components to be useful. That is, the mixed stream of different NGLs must be separated out. The process used to accomplish this task is called fractionation. Fractionation works based on the different boiling points of the different hydrocarbons in the NGL stream. Essentially, fractionation occurs in stages consisting of the boiling off of hydrocarbons one by one. The name of a particular fractionator gives an idea as to its purpose, as it is conventionally named for the hydrocarbon that is boiled off. The entire fractionation process is broken down into steps, starting with the removal of the lighter NGLs from the stream. The particular fractionators are used in the following order:

- **Deethanizer** - this step separates the ethane from the NGL stream.
- **Depropanizer** - the next step separates the propane.
- **Debutanizer** - this step boils off the butanes, leaving the pentanes and heavier hydrocarbons in the NGL stream.
- **Butane Splitter or Deisobutanizer** - this step separates the iso and normal butanes.

By proceeding from the lightest hydrocarbons to the heaviest, it is possible to separate the different NGLs reasonably easily.

To learn more about the fractionation of NGLs, click here.

Sulfur and Carbon Dioxide Removal

In addition to water, oil, and NGL removal, one of the most important parts of gas processing involves the removal of sulfur and carbon dioxide. Natural gas from some wells contains significant amounts of sulfur and carbon dioxide. This natural gas, because of the rotten smell provided by its sulfur content, is commonly called 'sour gas'. Sour gas is undesirable because the sulfur compounds it contains can be extremely harmful, even lethal, to breathe. Sour gas can also be extremely corrosive. In addition, the sulfur that exists in the natural gas stream can be extracted and marketed on its own. In fact, according to the USGS, U.S. sulfur production from gas processing plants accounts for about 15 percent of the total U.S. production of sulfur. For information on the production of sulfur in the United States, visit the USGS here.

Sulfur exists in natural gas as hydrogen sulfide (H_2S), and the gas is usually considered sour if the hydrogen sulfide content exceeds 5.7 milligrams of H_2S per cubic meter of natural gas. The process for removing hydrogen sulfide from sour gas is commonly referred to as 'sweetening' the gas.

Gas Sweetening Plant
Source: Duke Energy Gas Transmission Canada

The primary process for sweetening sour natural gas is quite similar to the processes of glycol dehydration and NGL absorption. In this case, however, amine solutions are used to remove the hydrogen sulfide. This process is known simply as the 'amine process', or alternatively as the Girdler process, and is used in 95 percent of U.S. gas sweetening operations. The sour gas is run through a tower, which contains the amine solution. This solution has an affinity for sulfur, and absorbs it much like glycol absorbing water. There are two principle amine solutions used, monoethanolamine (MEA) and diethanolamine (DEA). Either of these compounds, in liquid form, will absorb sulfur compounds from natural gas as it passes through. The effluent gas is virtually free of sulfur compounds, and thus loses its sour gas status. Like the process for NGL extraction and glycol dehydration, the amine solution used can be regenerated (that is, the absorbed sulfur is removed), allowing it to be reused to treat more sour gas.

Although most sour gas sweetening involves the amine absorption process, it is also possible to use solid desiccants like iron sponges to remove the sulfide and carbon dioxide.

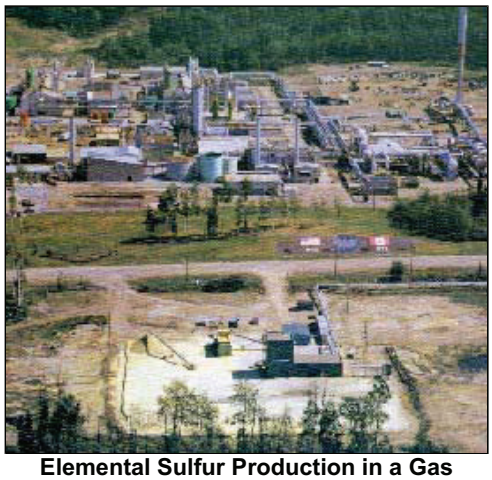
Sulfur can be sold and used if reduced to its elemental form. Elemental sulfur is a bright yellow powder like material, and can often be seen in large piles near gas treatment plants, as is shown. In order to recover elemental sulfur from the gas processing plant, the sulfur containing discharge from a gas sweetening process must be further treated. The process used to recover sulfur is known as the Claus process, and involves using thermal and catalytic reactions to extract the elemental sulfur from the hydrogen sulfide solution.

For more information on sulfur recovery and the Claus process, click here.

In all, the Claus process is usually able to recover 97 percent of the sulfur that has been removed from the natural gas stream. Since it is such a polluting and harmful substance, further filtering, incineration, and 'tail gas' clean up efforts ensure that well over 98 percent of the sulfur is recovered.

To learn more about the environmental effects of sour gas treatment and flaring, click here.

Gas processing is an instrumental piece of the natural gas value chain. It is instrumental in ensuring that the natural gas intended for use is as clean and pure as possible, making it the clean burning and environmentally sound energy choice. Once the natural gas has been fully processed, and is ready to be consumed, it must be transported from those areas that produce natural gas, to those areas that require it.



Elemental Sulfur Production in a Gas Treatment Plant
Source: Duke Energy Gas Transmission Canada

Click here to learn about the transportation of natural gas.

© 2004 - 2010 - All rights reserved - NaturalGas.org

Exhibit G

Natural gas processing

Background

Natural gas processing begins at the head. The composition of the raw natural gas extracted from producing wells depends on the type, depth, and location of the underground deposit and the geology of the area. Oil and natural gas are often found together in the same reservoir. The natural gas produced from oil wells is generally classified as "associated-dissolved," meaning that the natural gas is associated with or dissolved in crude oil. Natural gas production absent any association with crude oil is classified as "non-associated." In 2004, 75 percent of U.S. wellhead production of natural gas was non-associated.

Most natural gas production contains, to varying degrees, small (two to eight carbons) hydrocarbon molecules in addition to methane. Although they exist in a liquid state at underground pressures, these molecules will become gaseous at normal atmospheric pressure. Collectively, they are called condensates or natural gas liquids (NGLs). The natural gas extracted from coal reservoirs and mines (coalbed methane) is the primary exception, being essentially a mix of mostly methane and carbon dioxide (about 10 percent).

A natural gas processing plant

Natural gas processing plants, or Whatever (apparatus capable of separating liquid substance into component parts) are used to purify the raw natural gas produced from underground gas fields or extracted at the surface from the fluids produced from oil wells. A fully operational plant will deliver pipeline-quality natural gas that can be used as fuel by residential, commercial and industrial consumers. Contaminants have been removed and heavier hydrocarbons (any class of compound containing only hydrogen and carbon; examples are methane gas (CH_4), Benzene(C_6H_6)) have been captured for other commercial uses. For economic reasons, however, some plants may be designed to yield an intermediate product typically containing over 90% pure methane and smaller amounts of nitrogen, carbon dioxide and sometimes ethane. This can be further processed in downstream plants or used as feedstock for chemicals manufacturing. Now we will look into the contaminants in raw natural gas and the types of raw natural gas wells.

Types of raw natural gas wells

Raw natural gas comes primarily from any one of three types of wells: crude oil wells, gas wells, and condensate wells.

Natural gas that comes from crude oil wells is typically termed *associated gas*. This gas can have existed as a gas cap above the crude oil in the underground formation, or could have been dissolved in the crude oil.

Natural gas from gas wells and from condensate wells, in which there is little or no crude oil, is termed *non-associated gas*. Gas wells typically produce only raw natural gas, while condensate wells produce raw natural gas along with other low molecular weight hydrocarbons. Those that are liquid at ambient conditions (i.e., pentane and heavier) are called *natural gas condensate* (sometimes also called *natural gasoline* or simply *condensate*).

Natural gas is termed *sweet gas* when relatively free of hydrogen sulfide; however, some produced gas does contain this substance and thus is called *sour gas*.

Raw natural gas can also come from methane deposits in the pores of coal seams, and especially in a more concentrated state of adsorption onto the surface of the coal itself. Such gas is referred to as *coalbed gas* or coalbed methane. Coalbed gas is a from of natural gas that is has being extracted from coalbed. This coalbed gas has become an important source of energy in recent decades.

Contaminants in raw natural gas

Raw natural gas typically consists primarily of methane (CH_4), the shortest and lightest hydrocarbon molecule. It also contains varying amounts of:

- Heavier gaseous hydrocarbons: ethane (C_2H_6), propane (C_3H_8), normal butane (n-C_4H_{10}), isobutane (i-C_4H_{10}), pentanes and even higher molecular weight hydrocarbons. When processed and purified into finished by-products, all of these are collectively referred to as **NGL (Natural Gas Liquids)**.
- Acid gases: carbon dioxide (CO_2), hydrogen sulfide (H_2S) and mercaptans such as methanethiol (CH_3SH) and ethanethiol (C_2H_5SH).
- Other gases: nitrogen (N_2) and helium (He).
- Water: water vapor and liquid water. Also dissolved salts and dissolved gases (acids).
- Liquid hydrocarbons: perhaps some natural gas condensate (also referred to as *casinghead gasoline* or *natural gasoline*) and/or crude oil.
- Mercury: very small amounts of mercury primarily in elemental form, but chlorides and other species are possibly present.[1]
- Radioactive gas: radon. Also, when radon is present, decay products of radon, such as polonium, can accumulate in specific locations within processing equipment.

The raw natural gas must be purified to meet the quality standards specified by the major pipeline transmission and distribution companies. Those quality standards vary from pipeline to pipeline and are usually a function of a pipeline system's design and the markets that it serves. In general, the standards specify that the natural gas:

- Be within a specific range of heating value (caloric value). For example, in the United States, it should be about 1035 ± 5% BTU per cubic foot of gas at 1 atmosphere and 60 degrees Fahrenheit (41 MJ ± 5% per cubic metre of gas at 1 atmosphere and 0 degrees Celsius).
- Be delivered at or above a specified hydrocarbon dew point temperature (below which some of the hydrocarbons in the gas might condense at pipeline pressure forming liquid slugs that could damage the pipeline).
- Dew-point adjustment serves the reduction of the concentration of water and heavy hydrocarbons in natural gas to such an extent that no condensation occurs during the ensuing transport in the pipelines
- Be free of particulate solids and liquid water to prevent erosion, corrosion or other damage to the pipeline.
- Be dehydrated of water vapor sufficiently to prevent the formation of methane hydrates within the gas processing plant or subsequently within the sales gas transmission pipeline. A typical water content specification in the U.S.

is that gas must contain no more than seven pounds of water per million cubic feet (MMCFD) of gas.[2] [3]

- Contain no more than trace amounts of components such as hydrogen sulfide, carbon dioxide, mercaptans, and nitrogen. The most common specification for hydrogen sulfide content is 0.25 grain H_2S per 100 cubic feet of gas, or approximately 4 ppm. Specifications for CO_2 typically limit the content to no more than two or three percent.
- Maintain mercury at less than detectable limits (approximately 0.001 ppb by volume) primarily to avoid damaging equipment in the gas processing plant or the pipeline transmission system from mercury amalgamation and embrittlement of aluminum and other metals.[1] [4] [5]

Description of a natural gas processing plant

There are a great many ways in which to configure the various unit processes used in the processing of raw natural gas. The block flow diagram below is a generalized, typical configuration for the processing of raw natural gas from non-associated gas wells. It shows how raw natural gas is processed into sales gas pipelined to the end user markets.[6] [7] [8] [9] [10] It also shows how processing of the raw natural gas yields these byproducts:

- Natural gas condensate
- Sulfur
- Ethane
- Natural gas liquids (NGL): propane, butanes and C_5+ (which is the commonly used term for pentanes plus higher molecular weight hydrocarbons)

Raw natural gas is commonly collected from a group of adjacent wells and is first processed at that collection point for removal of free liquid water and natural gas condensate. The condensate is usually then transported to an oil refinery and the water is disposed of as wastewater.

The raw gas is then pipelined to a gas processing plant where the initial purification is usually the removal of acid gases (hydrogen sulfide and carbon dioxide). There are many processes that are available for that purpose as shown in the flow diagram, but amine treating is the process that was historically used. However, due to a range of performance and environmental constraints of the amine process, a newer technology based on the use of polymeric membranes to separate the carbon dioxide and hydrogen sulfide from the natural gas stream has gained increasing acceptance.

The acid gases, if present, are removed by membrane or amine treating can then be routed into a sulfur recovery unit which converts the hydrogen sulfide in the acid gas into either elemental sulfur or sulfuric acid. Of the processes available for these conversions, the Claus process is by far the most well-known for recovering elemental sulfur, whereas the conventional Contact Process and the WSA Process are the most used technologies for recovering sulfuric acid.

The residual gas from the Claus process is commonly called *tail gas* and that gas is then processed in a tail gas treating unit (TGTU) to recover and recycle residual sulfur-containing compounds back into the Claus unit. Again, as shown in the flow diagram, there are a number of processes available for treating the Claus unit tail gas and for that purpose a WSA Process is also very suitable since it can work autothermal on tail gasses.

The next step in the gas processing plant is to remove water vapor from the gas using either the regenerable absorption in liquid triethylene glycol (TEG)[3] , commonly referred to as glycol dehydration, deliquescent chloride desiccants, and or a Pressure Swing Adsorption (PSA) unit which is regenerable adsorption using a solid adsorbent.[11] Other newer processes like membranes may also be considered.

Mercury is then removed by using adsorption processes (as shown in the flow diagram) such as activated carbon or regenerable molecular sieves.[1]

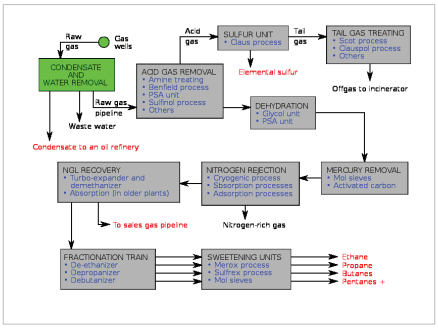
Although not common, nitrogen is sometimes removed and rejected using one of the three processes indicated on the flow diagram:

- Cryogenic process[12] using low temperature distillation. This process can be modified to also recover helium, if desired.
- Absorption process[13] using lean oil or a special solvent[14] as the absorbent.
- Adsorption process using activated carbon or molecular sieves as the adsorbent. This process may have limited applicability because it is said to incur the loss of butanes and heaver hydrocarbons.

The next step is to recover the natural gas liquids (NGL) for which most large, modern gas processing plants use another cryogenic low temperature distillation process involving expansion of the gas through a turbo-expander followed by distillation in a demethanizing fractionating column.[15] [16] Some gas processing plants use lean oil absorption process[13] rather than the cryogenic turbo-expander process.

The residue gas from the NGL recovery section is the final, purified sales gas which is pipelined to the end-user markets.

The recovered NGL stream is sometimes processed through a fractionation train consisting of three distillation towers in series: a deethanizer, a depropanizer and a debutanizer. The overhead product from the deethanizer is ethane and the bottoms are fed to the depropanizer. The overhead product from the depropanizer is propane and the bottoms are fed to the debutanizer. The overhead product from the debutanizer is a mixture of normal and iso-butane, and the bottoms product is a C_5+ mixture. The recovered streams of propane, butanes and C_5+ may be "sweetened" in a Merox process unit to convert undesirable mercaptans into disulfides and, along with the recovered ethane, are the final NGL by-products from the gas processing plant. Currently, most cryogenic plants do not include fractionation for economic reasons, and the NGL stream is instead transported as a mixed product to standalone fractionation complexes located near refineries or chemical plants that use the components for feedstock. In case laying pipeline is not possible for geographical reason,or the distance between source and consumer exceed 3000km, natural gas is then transported by ship as LNG (liquefied natural gas) and again converted into its gaseous state in the vicinity of the consumer.



Legend:

- Located at gas wells
- Located at gas processing plant
- Red indicates final sales products
- Blue indicates optional unit processes available

Notes:

- Condensate is also called natural gasoline or casinghead gasoline.
- "Pentanes +" refers to pentanes and heavier hydrocarbons, and are also called natural gasoline.
- "Acid gases" are hydrogen sulfide and carbon dioxide.
- PSA is Pressure Swing Adsorption.
- NGL is Natural Gas Liquids.
- Sweetening processes remove mercaptans from the NGL products.

Consumption

The consumption of natural gas differs widely from country to country. Countries with large own reserves tend to handle the raw material natural gas more generously, while countries with scarce or lacking resources are of course more economical. Despite the considerable findings, the predicted availability of the natural gas reserves has hardly changed.

Applications of Natural Gas

- a fuel for industrial heating and desiccation process
- a fuel for the operation of public and industrial power stations
- a household fuel for cooking, heating and providing hot water
- a fuel for environmentally friendly liquid natural gas vehicles
- a raw material for chemical synthesis
- a raw material for large-scale fuel production using gas-to-liquid (GTL) process (e.g. to produce sulphur-and aromatic-free diesel with low-emission combustion)

References

[1] *Mercury Removal from Natural Gas and Liquids* (http://www.uop.com/objects/87MercuryRemoval.pdf) UOP website page
[2] Dehydration of Natural Gas (http://www.ipt.ntnu.no/~jsg/undervisning/naturgass/parlaktuna/Chap7.pdf) by Prof. Jon Steiner Gudmundsson, Norwegian University of Science and Technology
[3] Glycol Dehydration (http://www.processgroup.com.au/Technologies/GasProcessing/GlycolDehyrdation/tabid/84/Default.aspx) (includes a flow diagram)
[4] *Desulfurization of and Mercury Removal From Natural Gas* (http://www.tigg.com/ACTIVATED-CARBON/desulfurization.html) by Bourke, M.J. and Mazzoni, A.F., Laurance Reid Gas Conditioning Conference, Norman, Oklahoma, March 1989.
[5] Using Gas Geochemistry to Assess Mercury Risk (http://www.gaschem.com/mercur.html), OilTracers, 2006
[6] *Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market* (http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2006/ngprocess/ngprocess.pdf)
[7] *Example Gas Plant* (http://www.uop.com/gasprocessing/6070.html)
[8] *From Purification to Liquefaction Gas Processing* (http://www.axens.net/upload/presentations/fichier/axens_gpagcc_2004v2.pdf)
[9] *Feed-Gas Treatment Design for the Pearl GTL Project* (http://www.spe.org/specma/binary/files/5804785Syn10682.pdf)
[10] of integrating NGL extraction and LNG liquefaction (http://lnglicensing.conocophillips.com/EN/publications/documents/AICHELNGNGLIntegrationPaper.pdf"Benefits)
[11] Molecular Sieves (http://www.uop.com/objects/96 MolecularSieves.pdf) (includes a flow diagram of a PSA unit)
[12] *Gas Processes 2002*, Hydrocarbon Processing, pages 84-86, May 2002 (schematic flow diagrams and descriptions of the Nitrogen Rejection and Nitrogen Removal processes)
[13] *Market-Driven Evolution of Gas Processing Technologies for NGLs* (http://www.aet.com/gtip1.htm) Advanced Extraction Technology Inc. website page
[14] AET Process Nitrogen Rejection Unit (http://www.aet.com/aetnrubig.pdf) Advanced Extraction Technology Inc. website page
[15] *Cryogenic Turbo-Expander Process* (http://www.aet.com/turbo.htm) Advanced Extraction Technology Inc. website page
[16] *Gas Processes 2002*, Hydrocarbon Processing, pages 83-84, May 2002 (schematic flow diagrams and descriptions of the NGL-Pro and NGL Recovery processes)

External links

- Natural Gas Processing Principles and Technology (http://www.ucalgary.ca/ENCH/class_notes/ench607/mainmenu.pdf) (an extensive and detailed course text by Dr. A.H. Younger, University of Calgary, Alberta, Canada).
- Processing Natural Gas (http://www.naturalgas.org/naturalgas/processing_ng.asp) a website maintained by the Natural Gas Supply Association.
- Natural Gas Processing (http://www.epa.gov/ttn/chief/ap42/ch05/final/c05s03.pdf) (part of the US EPA's AP-42 publication)

- Natural Gas Processing Plants (http://primis.phmsa.dot.gov/comm/FactSheets/FSNaturalGasProcessingPlants.htm) (a US Department of Transportation website)
- (http://gpaglobal.org/) Gas Processors Association, a website for the oldest natural gas processing association in the US

Further Reading

- Haring, H.W. (2008). Industrial Gases Processing. Weinheim, Germany: WILEY-VCH Verlag Gmbh & CO. KGaA
- Kohl, A., & Nielsen, R. (1997). Gas Purification. 5TH Edition. Houston, Texas: Gulf Publishing Company

Article Sources and Contributors

Natural gas processing *Source*: http://en.wikipedia.org/w/index.php?oldid=412470768 *Contributors*: Accurizer, Amse12, Beagel, Behtis, Bill W Ca, Bja12, Casey56, Chemical Engineer, Diannaa, Element16, Engineeringmaster, Gaius Cornelius, Gene Nygaard, Goatchze, Gracenotes, GraemeMcRae, Hmains, Iporter, Jak123, Lhutchinson, Liz-ldavis, Majorclanger, Mbeychok, Micjohn7, Motoroladigital, NebY, Ngener, Nnoell, Pmbcomm, Qurozon, Reyk, Rich njitwill, SKopp, Shubham.cricket10, Silivrenion, State99, SunCreator, Swpb, Teratornis, The Wiki ghost, Tide rolls, Tuttleboy, Twooars, UncleDouggie, Vsmith, Whiner01, X31forest, Zvar, 43 anonymous edits

Image Sources, Licenses and Contributors

Image:NaturalGasProcessingPlant.jpg *Source*: http://en.wikipedia.org/w/index.php?title=File:NaturalGasProcessingPlant.jpg *License*: Public Domain *Contributors*: User:Mbeychok

Image:NatGasProcessing.svg *Source*: http://en.wikipedia.org/w/index.php?title=File:NatGasProcessing.svg *License*: GNU Free Documentation License *Contributors*: User:Hairy Dude, User:Mbeychok

License

Creative Commons Attribution-Share Alike 3.0 Unported
http://creativecommons.org/licenses/by-sa/3.0/

Exhibit H

TEG Dehydrator Description

Equipment Description
Equipment (Regeneration Unit) • Horizontal Mono-Tube Type Reboiler, 3.0 MMBtu/hr x 84" OD x 28'-0" S/S x 5 psig MAWP, +450°F MDMT, with Integral Surge Section, 0.0625" Corrosion Allowance, Non-Code • Still Column, 36" OD x 9'-2" F/F x Atmospheric • (2) Firetubes, 20" OD, SA106 Gr.B. Removable • (2) Stacks, 20" OD x 14'-0" FBE, ERW-53 Gr.B. • Vertical Fuel Gas Scrubber, 10-3/4" OD x 2'-2"S/S x 125 psig MAWP, 0.0625" Corrosion Allowance, ASME Code Constructed and Stamped, NB Registered • Horizontal Three-Phase Flash Separator, 72" OD x 10'-0" S/S x 150 psig MAWP, 0.0625" Corrosion Allowance • Vertical Still Overheads Knockout Drum, 16" OD x 4'-0" S/S x Atmospheric DP, No Corrosion Allowance, Non-Code • Vertical Process Filter, 8-5/8" OD x 4'-3" OAH x 150 psig MAWP • Vertical Charcoal Filter, 60" ID x 5'-0" OAH x 150 psig MAWP • Hot Heat Exchanger, Glycol to Glycol, Shell and Tube • Cold Heat Exchanger, Glycol to Glycol, Shell and Tube
Equipment (Absorber/Scrubber) • (2) Vertical Absorber/Scrubbers, Hanover Modified Standard Part No. 486860032-M, 60" ID x 32'-0" S/S x 1440 psig MAWP x 17-Ft. Structured Packing, +4°F to 120°F MDMT, 0.125" Corrosion Allowance, ASME Code Constructed and Stamped, NB Registered • (2) Heat Exchangers, Gas to Glycol, Shell and Tube
Structural • TEG Regeneration Unit Structural Steel Skid, 13'-0" x 38'-0" x 3-Runners of WF 89# I-Beam with (4) Lift Lugs, Decking and Drain Pan • Caged Ladder and L-Shaped Landing for Regeneration Unit • Absorber/Scrubbers are Free Standing (No Skid)
Instruments, Controls and Valves • Burner Management System Panel (Honeywell)
Weld Spools and Piping Assembly
Pumps • (2) Electric Glycol Pumps, 100% Operating, Rotary Gear Type
Paint • Hanover Standard Onshore System

TEG Dehydration Process Description

The wet gas enters the integral scrubber in the bottom section of the absorber. This is to remove any entrained liquids. The gas then passes upward through a wire mesh mist extractor, where fine liquid particles are coalesced and removed. Next it enters the bottom of the absorber (contactor) and flows countercurrent to the glycol. Glycol-gas contact occurs on the trays or packing. Hanover standard absorbers typically has 6 to 12 bubble cap trays of 24" spacing or 14 to 17 feet of structured packing. The dehydrated gas leaves the top of the absorber.

The lean glycol enters through a flow distributor and onto the top tray or the top of the packing and flows downward, absorbing water as it goes. It leaves rich in water at the bottom of the absorber.

The rich glycol from the bottom of the absorber then flows to a reflux condenser at the top of the still column. The rich glycol then enters the cold glycol/glycol exchanger where the rich glycol is heated by the hot lean glycol to approximately 170°F to 200°F.

After heating, the glycol flows to a glycol/condensate separator operating at 45-75 psig, where the entrained gas and any liquid hydrocarbons present are removed. The glycol/condensate separator is a standard three-phase vessel designed for at least 15-30 minutes retention time and may be either horizontal or vertical. The gas from the glycol/condensate separator can be used for fuel gas, stripping gas or sent to flare.

The wet glycol from the separator flows through a sock filter to remove solids and a charcoal filter to absorb small amounts of hydrocarbons that may build up in the circulating glycol. Sock filters are normally designed for the removal of 10-microns solids. The filters help minimize foaming and sludge build-up in the regenerator.

The glycol then flows through the hot glycol/glycol exchanger to the still column mounted on the regenerator, which operated at approximately atmospheric pressure. As the glycol falls through the 1" ceramic saddle packing in the still column, it is heated by the mostly water vapor with small amount of glycol that is being boiled off from the liquid in the reboiler. The vapors then leave the top of the still where it exchanges heat with the reflux condenser. The cold rich glycol from the contactor cools the vapor, condensing the glycol vapors at 200-215°F. This help to reduce the glycol losses to the atmosphere.

The glycol liquids in the reboiler are normally heated from 350°F to 400°F. Higher temperatures would vaporize more water to achieve higher glycol purity, but may degraded the glycol.

If a very high purity of glycol is required, stripping gas may be used. The lean glycol flows from the reboiler over the Hanover proprietary sparge section into the surge tank, which is the integral part of the reboiler. A small amount of wet natural gas can be taken from the utility stream or from the glycol/condensate separator and injected into the Hanover proprietary sparge section to achieve above 99.3wt% TEG purity. The stripping gas exits in the still column with the water vapor.

The lean glycol from the surge tank is redirected through the glycol/glycol exchanger where it is cooled down to less than 200°F before it is sent to the glycol circulation pumps. The glycol is then pumped back to the contactor through the gas/glycol exchanger where it is cooled down to within 10°F above the inlet gas temperature. This completes the glycol regeneration cycle.

Vendor List

Description	Manufacturer
Charcoal Filter	Nowata
Glycol Exchanger	Kinetic Engineering
Glycol Pump	Glyrotor Rotary Gear type
BMS Panel	Honeywell HC-900
Control Valve	Fisher
Level Controller	Fisher
Relief Valve	Mercer or equal
Press. Gauge, Temp. Gauge	Ashcroft
Level Switch	Magnetrol
Pressure Switch	Neodyne
Temp. Switch	Neodyne
Level Gauge	Penberthy
Solenoid	Asco
Ball Valve	KF or equal

Exhibit I

DEERING'S CALIFORNIA CODE ANNOTATED
Copyright © 2011 by Matthew Bender & Company, Inc.
a member of the LexisNexis Group.
All rights reserved.

*** THIS SECTION IS CURRENT THROUGH THE 2011 SUPPLEMENT ***
(ALL 2010 LEGISLATION)
SPECIAL NOTICE: CHAPTERS ENACTED BETWEEN OCTOBER 20, 2009, AND NOVEMBER 2, 2010, ARE SUBJECT TO REPEAL BY PROPOSITION 22.

PUBLIC RESOURCES CODE
Division 3. Oil and Gas
Chapter 1. Oil and Gas Conservation
Article 4. Regulation of Operations

GO TO CALIFORNIA CODES ARCHIVE DIRECTORY

Cal Pub Resources Code § 3227 (2010)

§ 3227. Drilling and production reports

The owner of any well shall file with the supervisor, on or before the last day of each month, for the last preceding calendar month, a statement, in the form designated by the supervisor, showing all of the following:

(a) The amount of oil and gas produced from each well during the period indicated, together with the gravity of the oil, the amount of water produced from each well, estimated in accordance with methods approved by the supervisor, and the number of days during which fluid was produced from each well.

(b) The number of wells drilling, producing, injecting, or idle, that are owned or operated by the person.

(c) What disposition was made of the gas produced from each field, including the names of persons, if any, to whom the gas was delivered, and any other information regarding the gas and its disposition that the supervisor may require.

(d) What disposition was made of the water produced from each field, and the amount of fluid or gas injected into each well used for enhanced recovery, underground storage of hydrocarbons, or waste water disposal and any other information regarding those wells that the supervisor may require.

Any operator that produces oil by the application of mining or other unconventional techniques shall file a report with the supervisor, on or before March 1 of each year, showing the amount of oil produced by those techniques in the preceding calendar year.

Upon request and making a satisfactory showing therefor, a longer filing period may be established by the supervisor for any particular owner or operator.

HISTORY:

Enacted 1939 ch 93, effective September 19, 1939. Amended Stats 1951 ch 1333 § 2, operative January 1, 1952; Stats 1961 ch 2074 § 2; Stats 1967 ch 457 § 1; Stats 1972 ch 898 § 22; Stats 1976 ch 813 § 3; Stats 1980 ch 1055 § 1, effective September 26, 1980; Stats 1981 ch 741 § 7; Stats 1984 ch 278 § 7.

Exhibit J

Publication No. M04

MANUALLY PREPARED PRODUCTION, INJECTION, AND DISPOSITION REPORTS

Fifth Edition, March 1997

California Department of Conservation
Division of Oil, Gas, & Geothermal Resources

STATE OF CALIFORNIA
PETE WILSON, *Governor*

RESOURCES AGENCY
DOUGLAS P. WHEELER, *Secretary*

DEPARTMENT OF CONSERVATION
LAWRENCE J. GOLDZBAND, *Director*

OIL AND GAS DISTRICT OFFICES

Headquarters	801 K Street, 20th Floor, MS 20-20, Sacramento, CA 95814-3530 Phone: (916) 445-9686, TDD (916) 324-2555 Telefax: (916) 323-0424
District No. 1	245 W. Broadway, Suite 475, Long Beach, CA 90802 Phone: (562) 590-5311 Telefax: (562) 590-5301
District No. 2	1000 S. Hill Rd., Suite 116, Ventura, CA 93003-4458 Phone: (805) 654-4761 Telefax: (805) 654-4765
District No. 3	5075 S. Bradley Rd., Suite 221, Santa Maria, CA 93455 Phone: (805) 937-7246 Telefax: (805) 937-0673
District No. 4	4800 Stockdale Hwy., Suite 417, Bakersfield, CA 93309 Phone: (805) 322-4031 Telefax: (805) 861-0279
District No. 5	466 N. Fifth St., Coalinga, CA 93210 Phone: (209) 935-2941 Telefax: (209) 935-5154
District No. 6	801 K Street, 20th Floor, MS 20-22, Sacramento, CA 95814-3530 Phone: (916) 322-1110 Telefax: (916) 323-0424

DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

William F. Guerard, Jr., *State Oil and Gas Supervisor*

NOTICE TO OPERATORS

Instructions for filing manually prepared production, injection, and disposition reports are in this manual. Every staff member who prepares production, injection, and disposition reports should have immediate access to the manual. If you need additional copies, please notify the EDP Control Unit of the California Division of Oil and Gas. Whenever changes are made to the manual, we will send you the updated pages.

Operators with 5 or less wells may request to file production, injection, and disposition reports quarterly instead of monthly. Contact the EDP Control Unit for additional information.

CONTENTS

	Page
MAP OF DISTRICTS; ADDRESSES	Inside front cover
FILING REQUIREMENTS	1.00
Requirements	1.00
Delinquent reports	1.00
FORMS	
Reports	1.00
Preprinted and supplied	1.00
Available on request	1.00
Package	2.00
Blank forms	2.00
Three sheets	2.00
ASSISTANCE	
Completing and filing reports	2.00
Technical questions	2.00
MAILING REPORTS	
EDP Control Unit address	2.00
Postage; return address	2.00
PREPARING OIL, WATER, AND GAS PRODUCTION REPORTS	3.00
Basic data	3.00
Well production data	5.00
PREPARING OIL, WATER, AND GAS INJECTION REPORTS	12.00
Basic data	12.00
Well injection data	14.00
PREPARING REPORTS OF PRODUCED OIL AND GAS DISPOSITION	19.00
Basic data	19.00
Disposition data	21.00
CORRECTING PRODUCTION, INJECTION, AND DISPOSITION REPORTS	23.00
Rejected reports	23.00
Accepted and processed reports	23.00
Correcting production reports	24.00
Correcting injection reports	26.00
Correcting disposition reports	28.00

REPORT CERTIFICATION 30.00

REPORT OF WELLS TRANSFERRED TO ANOTHER OPERATOR 31.00

Code Used 31.00
Notice of Transfer 31.00

ATTACHMENTS

A. Sample production forms package 32.00
B. Sample injection forms package 33.00
C. Oil, water, and gas production report data filing requirements 34.00
D. Injection report data filing requirements 35.00

MANUALLY PREPARED vs. COMPUTER-PREPARED REPORTS . . . . . Inside back cover

FILING REQUIREMENTS

Requirements

Every month (or quarter if appropriate), an operator must file:

1. A production report for any well producing or capable of producing oil or gas; and an injection report for any well injecting or capable of injecting fluids. (When a well is completed in more than one pool, the production from, or injection into, each pool must be reported.);
2. A report describing the disposition of produced oil and gas by field;
3. Completed certification statements for production and injection reports.

Delinquent Reports

Reports are delinquent if not received by the Division before the 30th day of the month following the period in which production or injection occurred.

FORMS

Reports

Production, injection, and disposition reports MUST be filed on the following forms.

Preprinted Forms supplied monthly or quarterly to operators by the EDP Control Unit in Sacramento

REPORT	FORM NUMBER
Production report (by well)	OG110
Injection report (by well)	OG110B
Oil and gas disposition report (by field)	OG110
Report certification sheet	OG110 and/or OG110B

Forms available upon request from the EDP Control Unit or from district offices

Corrections to production report	OG110X
Corrections to injection report	OG110BX
Corrections to oil and gas disposition report	OB110DX

Forms package	Based on information on file with the Division, a forms package consisting of applicable produc- tion, injection, disposition, and report certification forms is sent to each operator by the Division EDP Control Unit (Attachments A and B).
Blank forms	Blank forms are available from any Division office.
Three sheets	Forms OG110 and OG110B are produced in triplicate. Return only the original copy to the EDP Control Unit. Keep the second copy for your records. The third copy may be used to supply information to the Conservation Committee of California Oil Producers.

● ASSISTANCE

	FOR:	CONTACT:
Completing and filing reports	Information on how to complete and file reports; and help with preprinted and blank forms.....	EDP Control Unit California Divison of Oil and Gas 1416 Ninth Street, Room 1310 Sacramento, CA 95814 (916) 445-4240
Technical questions	Technical assistance on report contents (e.g., proper field designation, operator, or well identi- fication data, etc.).....	The appropriate district office. Addresses are listed on the inside front cover.

● MAILING REPORTS

EDP Control Unit address	For your convenience, an envelope is provided with each forms package for use in returning reports. If you do not use the furnished envelope, send your reports to this address: EDP Control Unit California Division of Oil and Gas 1416 - 9th Street, Room 1310 Sacramento, CA 95814
Postage, return address	Apply sufficient postage and write a return address on the envelope. The post office will not forward mail with insufficient postage and cannot return such mail to you if your return address is not on the envelope. In these cases, the mail is destroyed.

PREPARING OIL, WATER, AND GAS PRODUCTION REPORTS

STEP I Enter or check basic data. Type or print clearly in unshaded areas. Line out errors before entering corrections. Division-assigned field, area, lease, pool names, and operator well numbers must be used.

* 1 OPERATOR.

2 ADDRESS used for <u>all</u> communication regarding reports.

* 3 FIELD where reported well(s) are located.

* 4 COUNTY where reported well(s) are located.

5 MONTH(S) production occurred.

6 CALENDAR YEAR production occurred (last two digits).

7 AREA; SEC. - T. - R.; LEASE; and POOL for the following wells.

* 8 OPERATOR WELL NUMBER.

* 9 WELL TYPE CODE:

DG = Nonassociated (dry) gas.
OG = Oil and associated gas.**
GS = Gas storage withdrawal.
LG = Liquified petroleum gas storage withdrawal (propane, butane, olefin, etc.)
WS = Water source.

* 10 API well number.

---

* Report all corrections to these items to the appropriate district office(s) as well as to the EDP Control Unit in Sacramento. The correction is reported to the EDP Control Unit by lining out the error and entering correct data.

** A report is required for an OG well even if it is used temporarily for such purposes as cyclic steam injection, pressure maintenance, observation, etc.

ITEM	INSTRUCTIONS

6 WATER OR STEAM INJECTED (bbl)

Total number of barrels of water or steam (as water equivalent) injected during the report month.

Report whole barrels only, rounding up for .5 bbl and greater, down for less than .5 bbl.

	ACTUAL (bbl)		REPORT (bbl)
EXAMPLE:	0.49	=	0
	0.50	=	1
	10.49	=	10
	10.50	=	11

7 GAS OR AIR INJECTED (Mcf)

Total amount of gas or air injected during the report month.

Report whole Mcf (thousand cubic feet) only, rounding up for 500 cubic feet (cf) and greater, down for less than 500 cf.

	ACTUAL (cf)		REPORT (Mcf)
EXAMPLE:	499	=	0
	500	=	1
	103,499	=	103
	103,500	=	104

8 NUMBER OF DAYS WELL INJECTED

The number of calendar days during which fluid was injected into the well. If columns 6 & 7 are zero, days will be zero. Use whole numbers only. Count injection for fractional part of a day as one day of injection.

This number cannot exceed the total number of days in the report month.

9 SURFACE INJECTION PRESSURE

Injection pressure at the well head, rounded to the nearest whole psig value.

	ACTUAL (psig)		REPORT (psig)
EXAMPLE:	525.4	=	525
	525.5	=	526
	-10.0	=	0*

* If the pressure is negative (vacuum) or less than 0.5 psig, report 0.

ITEM	INSTRUCTIONS
10 SOURCE OF WATER	Code which indicates the source of injected water, including water injected as steam. If a well did not inject, this item is blank or zero. SOURCE OF WATER CODE 1 = Produced from an oil or gas well. 2 = Produced from a water-source well. 3 = Obtained from any domestic water system (water district, domestic water well, etc.). 4 = Extracted from the ocean. 5 = Obtained as waste from an industrial facility. 6 = Obtained from a domestic waste disposal or treatment facility. 7 = Obtained from any other source or a combination of above-mentioned sources.
11 KIND OF WATER	Code which indicates the kind of water being injected, including water injected as steam. If a well did not inject, this item is blank or zero. KIND OF WATER CODE 1 = Saline water. 2 = Fresh water. 3 = Water combined with chemicals, such as polymers, for injection purposes. 4 = Another kind of water.
12 REASON WELL IS NOT INJECTING	If a well is injecting, this item remains blank. It must contain a code if: A. The well did not inject at all during the report month (see Reason 1, 4, 6, and 8). B. The well was transferred to another operator during the report month (see Reason 9). C. The well was abandoned or converted to another use during the report month (see Reason 5).

(Continued on the next page.)

Exhibit K

Publication No. MO5

PRODUCTION AND INJECTION REPORTING PROCEDURES FOR COMPUTERIZED OPERATORS

Eighth Edition

October 2003

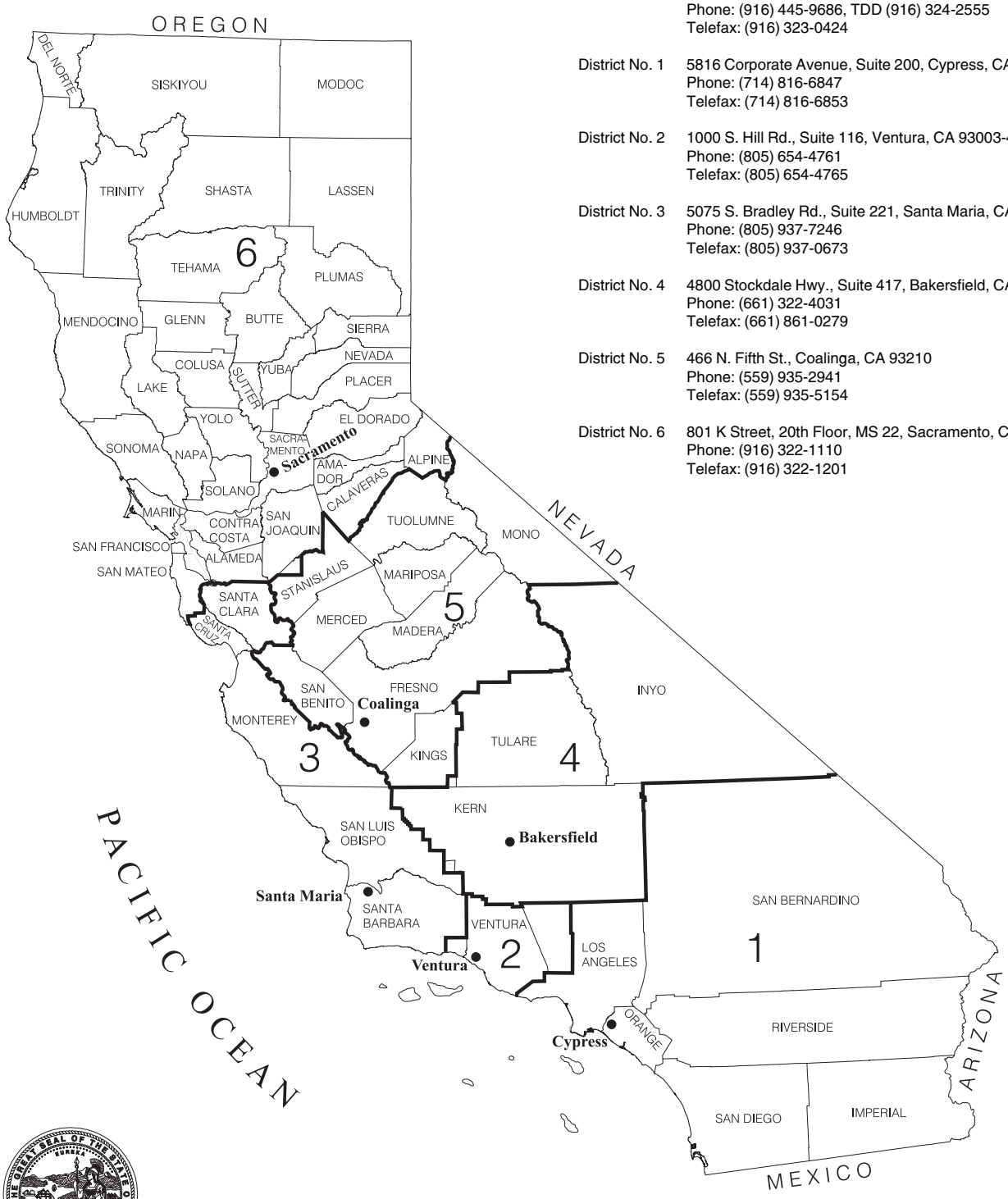
California Department of Conservation
Division of Oil, Gas, and Geothermal Resources

STATE OF CALIFORNIA
GRAY DAVIS, *Governor*

RESOURCES AGENCY
MARY D. NICHOLS, *Secretary*

DEPARTMENT OF CONSERVATION
DARRYL YOUNG, *Director*

OIL AND GAS DISTRICT BOUNDARIES AND OFFICES
of the
Division of Oil, Gas, and Geothermal Resources



Headquarters	801 K Street, 20th Floor, MS 20, Sacramento, CA 95814-3530 Phone: (916) 445-9686, TDD (916) 324-2555 Telefax: (916) 323-0424
District No. 1	5816 Corporate Avenue, Suite 200, Cypress, CA 90630-4731 Phone: (714) 816-6847 Telefax: (714) 816-6853
District No. 2	1000 S. Hill Rd., Suite 116, Ventura, CA 93003-4458 Phone: (805) 654-4761 Telefax: (805) 654-4765
District No. 3	5075 S. Bradley Rd., Suite 221, Santa Maria, CA 93455 Phone: (805) 937-7246 Telefax: (805) 937-0673
District No. 4	4800 Stockdale Hwy., Suite 417, Bakersfield, CA 93309 Phone: (661) 322-4031 Telefax: (661) 861-0279
District No. 5	466 N. Fifth St., Coalinga, CA 93210 Phone: (559) 935-2941 Telefax: (559) 935-5154
District No. 6	801 K Street, 20th Floor, MS 22, Sacramento, CA 95814-3530 Phone: (916) 322-1110 Telefax: (916) 322-1201

DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES
HAL BOPP, *State Oil and Gas Supervisor*

CONTENTS

Page

Map of Districts; Addresses ..... Inside front cover

Filing Requirements 1-2

Compiling Computerized Production Reports 3-9

Compiling Computerized Gas and Water Injection Reports 10-15

Oil and Gas Disposition Report Instructions 16-17

Transmittal Memo Instructions 18

Transferred Well Instructions 18

Correcting Data -- Computer-Produced Reports 18

Correcting Production Data -- Hardcopy 19

Correcting Injection Data -- Hardcopy 20

Correcting Disposition Reports 21

Attachments

A - Sample Transmittal Memorandum
B - Production Report Format
C - Production Report Data Filing Requirements
D - Injection Report Format
E - Injection Report Data Filing Requirements
F - Sample Disposition Report and Signature Sheet

FILING REQUIREMENTS

This booklet contains instructions for completing the required reports listed below.

Reports are delinquent if not received by the Division of Oil, Gas, and Geothermal Resources in Sacramento on or before the 30th day following the month of production or injection.

Manually Produced vs. Computer-Produced Reports

Subject to Division approval, operators have the option of filing reports manually on forms supplied by the Division, or they may produce reports by computer in the manner prescribed in this publication. Operators may exercise this option for any one, or all of the reports shown below, by contacting the data processing unit to make the necessary arrangements.

Should a loss or problem with an electronic file occur, the Division of Oil, Gas, and Geothermal Resources will not take responsibility for replacement of, nor the restoration of the data on the file. For this reason, it is imperative that the operator ***maintain a backup copy*** of any data sent to the Division.

		SUBMITTAL METHODS	
	REPORT	MANUALLY	COMPUTERIZED
1.	Production Report by Well, Type, and Pool	Form OG110*	Text or flat file, attached to an e-mail transmittal memo
2.	Injection Report by Well, Type, and Pool	Form OG110B*	Text or flat file, attached to an e-mail transmittal memo
3.	Oil and Gas Disposition Report by Field	Form OG110*	Hardcopy printout or spreadsheet
4.	Transmittal memo	Form OG110* and/or OG110B*	Transmittal memo inserted (pasted) into an e-mail message
5.	Corrections to Production/ Injection Reports	Form OG110X and/or OG110BX	Text or flat file, attached to an e-mail transmittal memo
6.	Correction to Oil and Gas Disposition Reports	Form OG110DX	Form OG110DX or spread sheet

Changing to Computer-Produced Reports

If an operator wishes to change from manually produced reports to computer-produced reports, contact the Division's data processing unit in Sacramento for information on how to make the change and to obtain the e-mail address where reports are to be sent. Until permission is granted from the Division to file computer-produced reports, manually produced reports must be submitted.

* Supplied each month to operators by the Division with basic well data preprinted on the forms.

Electronic Filing Process

Once a month, an operator e-mails a transmittal memo to the Division with an electronic text file(s) attached. The transmittal memo tells the Division what month is being reported and other basic information about the attached text file(s). The Division saves the text file, validates the information in the file, and uploads the validated reports to the Division WellStat computer. Upon receipt of the electronic file, an acknowledgement is e-mailed to the operator. Errors failing validation are e-mailed back to the operator, as well.

Where to Obtain Assistance

For help completing or filing reports, please contact the data processing unit in Sacramento at (916) 445-9686. For help with technical aspects of the report, such as: field, area, and pool designations; authorized pool breakdowns; approved well uses, conversions, or abandonments; operator or well identification data; application of reporting codes; confidentiality; etc., please contact the appropriate district office. District offices have the regulatory responsibility for wells within their jurisdiction, including all technical aspects of the reports.

Well Metering Methods

If you do not meter your wells individually, you must prorate the production or injection by well according to the best information available. If you ship production quarterly, and do not have monthly figures available, please report estimated figures each month so the actual quarterly figures equal the sum of the figures reported for the three-month period. Adjust all reported volumes to the same base using standard temperature (60^0F) and pressure (14.73 psi).

COMPILING COMPUTERIZED MONTHLY OIL, WATER, AND GAS PRODUCTION REPORTS

The following information must be submitted for each production transaction record.

(Data item number corresponds to data item listed on Attachment B. See Attachment C for data required for production well types.)

Data Item Number	Item Name	Description	Column Location
1	Operator code	Five-character, division-assigned operator code.	1-5
2	Year and month	Year = Last two digits of the calendar year in which production occurred Month = Two-digit code indicating the month production occurred. 01 to 12 for January to December EXAMPLE: January 2004 = 0401	6-7 8-9
3	Transaction type	Code 99 = Either a regular monthly report or a correction for a regular report that was REJECTED by the Division. Code 88 = A corrected report for a regular report that was ACCEPTED by the Division.	10-11
4	Transaction record type	00 = Production record.	12-13
5	Report date	The date these production data were created. CODE: MONTH, DAY, YEAR Month = 01 to 12 for January to December Day = 01 to 31 Year = Last two digits of calendar year EXAMPLE: March 10, 2004 = 031004	14-19
6	API well number	Eight-character, division-assigned API well number. This number is shown on the "Permit to Conduct Well Operations" (Form OG111). If you cannot locate this number, contact the appropriate district office.	20-27

PRODUCTION REPORTS

Data Item Number	Item Name	Description	Column Location
7	Pool code	Two-digit pool code number, assigned by the Division. To add or change any pool code, contact the appropriate district office.	28-29
8	Well-type code	Appropriate well-type code. Indicates the production usage of the pool completion. PRODUCTION WELL-TYPE CODES 1 = Nonassociated gas withdrawal 2 = Oil and associated gas withdrawal 3 = Gas storage withdrawal 5 = Liquefied petroleum gas storage withdrawal (propane, butane, olefin, etc.) 9 = Water source B = Observation NOTE: Production well types 3 (GS) and 5 (LG) require an injection transaction in addition to a production transaction.	30
9	Blank	Make no entry.	31-33
10	Clean oil or condensate produced - bbl	Total number of barrels of oil or condensate produced during the report month. Right justify and zero fill. Report whole barrels only, rounding up for .5 bbl and greater, down for less than .5 bbl. ACTUAL (bbl) REPORT (bbl) EXAMPLE: 0.49 0000000 (7*) 0.50 0000001 10.36 0000010 10.50 0000011	34-40

*Maximum number of characters allowed. Should you have a larger figure, indicate this on the transmittal memorandum (Attachment A).

PRODUCTION REPORTS

Data Item Number	Item Name	Description	Column Location
11	Blank	Make no entry.	41-42
12	Water produced-bbl	Total number of barrels of water produced during the report month. Right justify and zero fill. Report whole barrels only, rounding up for .5 bbl and greater, down for less than .5 bbl. ACTUAL (bbl) REPORT (bbl) EXAMPLE: 0.49 = 00000000 (8*) 0.50 = 00000001 156.49 = 00000156 156.50 = 00000157	43-50
13	Number of days well produced	The number of calendar days during which fluid was produced from the well. If data item numbers 10, 12, and 15 are zero, days will be zero. Use whole numbers only. Count production for a fractional part of a day as one day of production. This number cannot exceed the total number of days in the report month. Right justify and zero fill.	51-52
14	Blank	Make no entry.	53
15	Gross gas produced-Mcf	Total amount of gas produced during the report month. Right justify and zero fill. Report whole Mcf (thousand cubic feet) only, rounding up for 500 cubic feet (cf) and greater, and down for under 500 cf. ACTUAL (cf) REPORT (Mcf) EXAMPLE: 499 = 000000 (6*) 500 = 000001 103,499 = 000103 103,500 = 000104	54-59

*Maximum number of characters allowed. Should you have a larger figure, indicate this on the transmittal memorandum (Attachment A).

PRODUCTION REPORTS

Data Item Number	Item Name	Description	Column Location
16	Gravity of oil	API gravity of oil produced, with an assumed decimal point before position 62. Round to the nearest tenth. Right justify and zero fill. ACTUAL REPORT EXAMPLE: 25.449 = 254 (3*) 25.450 = 255	60-62
17	Blank	Make no entry.	63
18	Casing pressure-psi	Casing pressure at the well head, rounded to the nearest whole psi value. Right justify and zero fill. ACTUAL (psi) REPORT (psi) EXAMPLE: 525.4 = 0525 (4*) 525.5 = 0526 -10.0 = 0000 If the pressure is negative (vacuum) or less than 0.5 psi, report 0000. Leave blank if not applicable.	64-67
19	Blank	Make no entry.	68
20	Tubing pressure-psi	Tubing pressure at the well head (static pressure if the well is not on production; flowing pressure if the well is flowing) rounded to the nearest whole psi value. Right justify and zero fill. ACTUAL (psi) REPORT (psi) EXAMPLE: 630.4 = 0630 (4*) 630.5 = 0631 -10.0 = 0000 If the pressure is negative (vacuum) or less than 0.5 psi, report 0000. Leave blank if not applicable.	69-72

* Maximum number of characters allowed. Should you have a larger figure, indicate this on the transmittal memorandum (Attachment A).

PRODUCTION REPORTS

Data Item Number	Item Name	Description	Column Location
21	Blank	Make no entry.	73
22	Gas produced - Btu	British Thermal Unit (Btu) heating value of produced gas (per cubic foot), rounded to the nearest whole Btu value. Right justify and zero fill. ACTUAL (Btu) REPORT (Btu) EXAMPLE: 980.4 = 0980 (4*) 980.5 = 0981 Leave blank if not applicable.	74-77
23	Method of operation	Code indicating the method of operation used to produce oil, gas, or water. If a well is not producing, this position is zero or blank. METHOD OF OPERATION CODE 1 = Flowing well 2 = Jack line method 3 = Beam rod pump 4 = Hydraulic rod pump 5 = Bottom-hole hydraulic pump 6 = Bottom-hole electric pump 7 = Gas lift method 8 = Other	78

* Maximum number of characters allowed. Should you have a larger figure, indicate this on the transmittal memorandum (Attachment A).

PRODUCTION REPORTS

Data Item Number	Item Name	Description	Column Location
24	Water disposition method	Code that indicates the method used to dispose of produced water from the well. If a well did not produce any water, this position is zero or blank. WATER DISPOSITION CODE 1 = Evaporation - percolation. (Water is allowed to percolate into the ground and evaporate into the atmosphere, such as in an unlined sump.) 2 = Evaporation - lined sump. (Water is placed in a lined sump, open tank, or similar container for evaporation into the atmosphere.) 3 = Surface water body. (Water is dumped into any surface body of water such as a lake, ocean, pond, stream, river, canal, or irrigation ditch.) 4 = Sewer system. (Water is placed in a sewage disposal or treatment system.) 5 = Subsurface injection. (Water is injected into the subsurface.) 6 = Other. (Water is disposed of by another method, such as being turned over to a water disposal contractor.)	79

Data Item Number	Item Name	Description	Column Location
25	Reason well not on production	If a well is producing, this position is zero (0). The position must contain a code 1 through 9 if: A. The well did not produce at all during the entire report month (see reasons 1, 4, 6, and 8 below). B. The well was transferred to another operator during the report month (see reason 9 below). C. The well was abandoned or converted to another use during the report month (see reason 5 below). REASON WELL NOT ON PRODUCTION CODE 1 = Standing (incapable of production in its present condition) during the entire report month, or temporarily abandoned. 4 = Uncompleted or not drilled. 5 = Abandoned. Written approval to plug and abandon was received from the appropriate district office and the work has been completed. Plugged and abandoned wells should be reported once with a code of 5 and then dropped from subsequent reports. OR Converted. Written approval to convert to another well type was received from the appropriate district office and the conversion has been completed. **SEE NOTE BELOW.** 6 = Shut-in (capable of production in its present condition) during the entire report month. 8 = Other. No production during the entire report month for any other reason (e.g., well was used for observation). 9 = Operator change. Sold or transferred at any time during the report month. **SEE NOTE BELOW.** Transferred wells should be reported once with a code of 9 and then dropped from subsequent reports. NOTE: When reporting codes 5 or 9, report any production that may have occurred during the report month prior to abandonment, conversion, or transfer. **Special Instructions for Wells That Both Produce and Inject (Turnaround Wells)** GS well type and LG well type: These well types have the capability to withdraw and inject. Use an appropriate code under "Reason well not on production" if the well did not withdraw during the month. Combined OG and SC well types: If the well did not produce, even though it did inject, use an appropriate code under "Reason well not on production".	80

COMPILING COMPUTERIZED MONTHLY GAS AND WATER INJECTION REPORTS

The following information must be submitted for each injection transaction record.

(Data item number corresponds to the data item listed on Attachment D. See Attachment E for data required for injection well types.)

Data Item Number	Item Name	Description	Column Location
1	Operator code	Five-character, division-assigned operator code.	1-5
2	Year and month	Year = Last two digits of the calendar year in which injection occurred. Month = Two-digit code indicating the month in which injection occurred. 01 to 12 for January to December EXAMPLE: January 2004 = 0401	6-7 8-9
3	Transaction type	Code 99 = Either a regular monthly report or a correction for a regular report that was REJECTED by the Division. Code 88 = A corrected report for a regular report that was ACCEPTED by the Division.	10-11
4	Transaction record type	55 = Injection record.	12-13
5	Report date	The date these injection data were created. CODE: MONTH, DAY, YEAR Month = 01 to 12 for January to December Day = 01 to 31 Year = Last two digits of calendar year EXAMPLE: March 10, 2004 = 031004	14-19
6	API well number	Eight-character, division-assigned API well number. This number is shown on the "Permit to Conduct Well Operations" (Form OG111). If you cannot locate this number, contact the appropriate district office.	20-27

INJECTION REPORTS

Data Item Number	Item Name	Description	Column Location
7	Pool code	Two-digit pool code number, assigned by the Division. To add or change any pool code, contact the appropriate district office.	28-29
8	Well-type code	Appropriate well-type code. Indicates the injection usage of the pool completion. INJECTION WELL-TYPE CODES A = Cyclic steam 3 = Gas storage injection 4 = Pressure maintenance (gas injection) 5 = Liquefied petroleum gas storage injection (propane, butane, olefin, etc.) 6 = Water disposal 7 = Waterflood 8 = Steamflood 0 = Air injection C = Gas disposal NOTE: Injection well types 3 (GS) and 5 (LG) require a production transaction in addition to an injection transaction.	30
9	Blank	Make no entry.	31-33
10	Water or steam injected - bbl	Total number of barrels of water or steam (as water equivalent) injected during the report month. Right justify and zero fill. Report whole barrels only, rounding up for .5 bbl and greater, down for less than .5 bbl. ACTUAL (bbl) REPORT (bbl) EXAMPLE: 0.4 = 00000000 (8*) 0.5 = 00000001 10.4 = 00000010 10.5 = 00000011	34-41

*Maximum number of characters allowed. Should you have a larger figure, indicate this on the transmittal memorandum (Attachment A).

INJECTION REPORTS

Data Item Number	Item Name	Description	Column Location
11	Blank	Make no entry.	42-43
12	Gas or air injected - Mcf	Total amount of gas or air injected during the report month. Right justify and zero fill. Report whole Mcf (thousand cubic feet) only, rounding up for 500 cubic feet (cf) and greater, down for less than 500 cf. ACTUAL (cf) REPORT (Mcf) EXAMPLE: 499 = 00000000 (8*) 500 = 00000001 103,499 = 00000103 103,500 = 00000104	44-51
13	Number of days well injected	The number of calendar days during which fluid was injected into the well. If data item numbers 10 & 12 are zero, days will be zero. Use whole numbers only. Count injection for a fractional part of a day as one day of injection. This number cannot exceed the total number of days in the report month. Right justify and zero fill.	52-53
14	Blank	Make no entry.	54
15	Surface injection pressure - psi	Injection pressure at the well head, rounded to the nearest whole psi value. Right justify and zero fill. ACTUAL (psig) REPORT (psig) EXAMPLE: 525.4 = 0525 (4*) 525.5 = 0526 -10.0 = 0000 If the pressure is negative (vacuum) or less than 0.5 psi, report 0000. Leave blank if not applicable.	55-58

* Maximum number of characters allowed. Should you have a larger figure, indicate this on the transmittal memorandum (Attachment A).

INJECTION REPORTS

Data Item Number	Item Name	Description	Column Location
16	Source of water	Code which indicates the source of injected water, including water injected as steam. If a well was not injecting, this position is zero or blank. SOURCE OF WATER CODE 1 = Produced from an oil or gas well 2 = Produced from a water-source well 3 = Obtained from any domestic water system (water district, domestic water well, etc.) 4 = Extracted from the ocean 5 = Obtained as waste from an industrial facility 6 = Obtained from a domestic waste disposal or treatment facility 7 = Obtained from any other source or a combination of above-mentioned sources	59
17	Kind of water	Code which indicates the kind of water being injected, including water injected as steam. If a well was not injecting, this position is zero or blank. KIND OF WATER CODE 1 = Saline water 2 = Fresh water 3 = Water combined with chemicals, such as polymers, for injection purposes 4 = Another kind of water	60

Exhibit L

powered by Westlaw California Office of Administrative Law Home Most Recent Updates Search Help ©

Welcome to the online source for the California Code of Regulations

14 CA ADC § 1724.10

§ 1724.10. Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects.

Term

14 CCR § 1724.10

Cal. Admin. Code tit. 14, § 1724.10

Barclays Official California Code of Regulations Currentness
Title 14. Natural Resources
Division 2. Department of Conservation
Chapter 4. Development, Regulation, and Conservation of Oil and Gas Resources
Subchapter 1. Onshore Well Regulations
Article 3. Requirements
§ 1724.10. Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects.

(a) The appropriate Division district deputy shall be notified of any anticipated changes in a project resulting in alteration of conditions originally approved, such as: increase in size, change of injection interval, or increase in injection pressure. Such changes shall not be carried out without Division approval.

(b) Notices of intention to drill, redrill, deepen, or rework, on current Division forms, shall be completed and submitted to the Division for approval whenever a new well is to be drilled for use as an injection well and whenever an existing well is converted to an injection well, even if no work is required on the well.

(c) An injection report on a current Division form or in a computerized format acceptable to the Division shall be filed with the Division on or before the 30th day of each month, for the preceding month.

(d) A chemical analysis of the liquid being injected shall be made and filed with the Division whenever the source of injection liquid is changed, or as requested by the Supervisor.

(e) An accurate, operating pressure gauge or pressure recording device shall be available at all times, and all injection wells shall be equipped for installation and operation of such gauge or device. A gauge or device used for injection-pressure testing, which is permanently affixed to the well or any part of the injection system, shall be calibrated at least every six months. Portable gauges shall be calibrated at least every two months. Evidence of such calibration shall be available to the Division upon request.

(f) All injection piping, valves, and facilities shall meet or exceed design standards for the maximum anticipated injection pressure, and shall be maintained in a safe and leak-free condition.

(g) All injection wells, except steam, air, and pipeline-quality gas injection wells, shall be equipped with tubing and packer set immediately above the approved zone of injection within one year after the effective date of this act. New or recompleted injection wells shall be equipped with tubing and packer upon completion or recompletion. Exceptions may be made when there is:

(1) No evidence of freshwater-bearing strata.

(2) More than one string of casing cemented below the base of fresh water.

(3) Other justification, as determined by the district deputy, based on documented evidence that freshwater and oil zones can be protected without the use of tubing and packer.

(h) Data shall be maintained to show performance of the project and to establish that no damage to life, health,

property, or natural resources is occurring by reason of the project. Injection shall be stopped if there is evidence of such damage, or loss of hydrocarbons, or upon written notice from the Division. Project data shall be available for periodic inspection by Division personnel.

(i) To determine the maximum allowable surface injection pressure, a step-rate test shall be conducted prior to sustained liquid injection. Test pressure shall be from hydrostatic to the pressure required to fracture the injection zone or the proposed injection pressure, whichever occurs first. Maximum allowable surface injection pressure shall be less than the fracture pressure. The appropriate district office shall be notified prior to conducting the test so that it may be witnessed by a Division inspector. The district deputy may waive or modify the requirement for a step-rate test if he or she determines that surface injection pressure for a particular well will be maintained considerably below the estimated pressure required to fracture the zone of injection.

(j) A mechanical integrity test (MIT) must be performed on all injection wells to ensure the injected fluid is confined to the approved zone or zones. An MIT shall consist of a two-part demonstration as provided in subsections (j)(1) and (2).

(1) Prior to commencing injection operations, each injection well must pass a pressure test of the casing-tubing annulus to determine the absence of leaks. Thereafter, the annulus of each well must be tested at least once every five years; prior to recommencing injection operations following the repositioning or replacement of downhole equipment; or whenever requested by the appropriate Division district deputy.

(2) When required by subsection (j) above, injection wells shall pass a second demonstration of mechanical integrity. The second test of a two-part MIT shall demonstrate that there is no fluid migration behind the casing, tubing, or packer.

(3) The second part of the MIT must be performed within three (3) months after injection has commenced. Thereafter, water-disposal wells shall be tested at least once each year; waterflood wells shall be tested at least once every two years; and steamflood wells shall be tested at least once every five years. Such testing for mechanical integrity shall also be performed following any significant anomalous rate or pressure change, or whenever requested by the appropriate Division district deputy. The MIT schedule may be modified by the district deputy if supported by evidence documenting good cause.

(4) The appropriate district office shall be notified before such tests/surveys are made, as a Division inspector may witness the operations. Copies of surveys and test results shall be submitted to the Division within 60 days.

(k) Additional requirements or modifications of the above requirements may be necessary to fit specific circumstances and types of projects. Examples of such additional requirements or modifications are:

(1) Injectivity tests.

(2) Graphs of time vs. oil, water, and gas production rates, maintained for each pool in the project and available for periodic inspection by Division personnel.

(3) Graphs of time vs. tubing pressure, casing pressure, and injection rate maintained for each injection well and available for periodic inspection by Division personnel.

(4) List of all observation wells used to monitor the project, indicating what parameter each well is monitoring (i.e., pressure, temperature, etc.), submitted to the Division annually.

(5) List of all injection-withdrawal wells in a gas storage project, showing casing-integrity test methods and dates, the types of safety valves used, submitted to the Division annually.

(6) Isobaric maps of the injection zone, submitted to the Division annually.

(7) Notification of any change in waste disposal methods.

Note: Authority cited: Section 3013, Public Resources Code. Reference: Section 3106, Public Resources Code.

HISTORY

1. New section filed 2-17-78; effective thirtieth day thereafter (Register 78, No. 7).

2. Amendment filed 6-30-80; effective thirtieth day thereafter (Register 80, No. 27).

3. Editorial correction of Note filed 12-28-84; effective thirtieth day thereafter (Register 84, No. 52).

4. Amendment of subsection (j), new subsections (j)(1)-(4) and amendment of Note filed 8-4-95; operative 9-3-95 (Register 95, No. 31).

5. Change without regulatory effect amending subsection (i) filed 9-3-96 pursuant to section 100, title 1, California Code of Regulations (Register 96, No. 36).

6. Change without regulatory effect amending section filed 12-26-2006 pursuant to section 100, title 1, California Code of Regulations (Register 2006, No. 52).

14 CCR § 1724.10, **14 CA ADC § 1724**.**10**

This database is current through 2/4/11 Register 2011, No. 5

END OF DOCUMENT

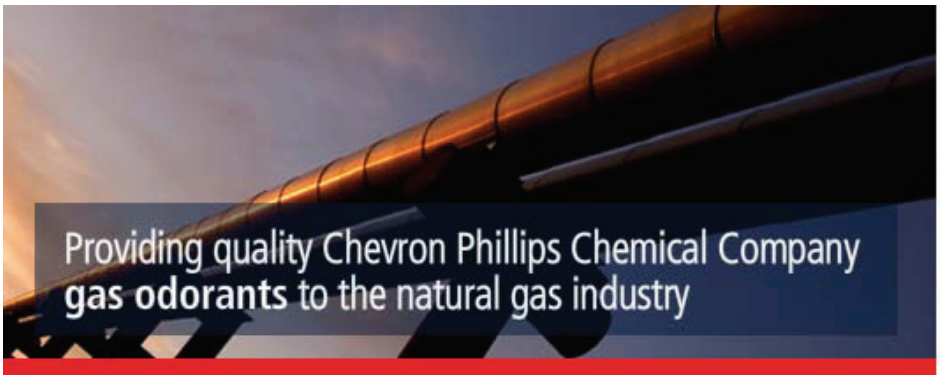
Term

© 2011 Thomson Reuters. No Claim to Orig. U.S. Govt. Works.

Westlaw, part of Thomson Reuters
© 2011 West | Privacy | Accessibility

THOMSON REUTERS

Exhibit M



Welcome to GOSS!

Gas Odorant Service & Supply, a woman owned business, was established in 2007 to distribute quality Scentinel® natural gas and propane package odorants for Chevron Phillips Chemical Company to the United States gas industry. Selected for our dedication to marketing, sales, and customer service, Gas Odorant Service & Supply (GOSS) strives to serve, educate and train the gas odorant industry on the safe handling and application of natural gas and propane odorants.

Ordering Gas Odorant package products should not be complicated. That is why our slogan is "Odorizing Made Easy." At GOSS we pride ourselves on dependable, prompt and efficient customer service. Your orders are handled with the care you deserve from start to finish with most shipments being sent the same day as the order is placed. It is that Easy!

We also handle Micro-bulk for the Western United States. Micro-bulk states include Arizona, California, Colorado, Idaho, Louisiana, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah, Washington and Wyoming.

We know you have a choice and we want your choice to be Gas Odorant Service & Supply!

"Odorizing Made Easy"

Contact Us

Phone: (877) 578-4646
Fax: (281) 371-2858
Email:info@gasodorant.com

© Copyright GOSS. All rights reserved.
Katy, Texas

Powered by Hyperlinks Web Sites
W3C CSS / XHTML Validated

Products

PRODUCT SIZE: 5 gallon can

DIMENSIONS: Height: 14 inches
Diameter: 12 inches

DISCHARGE FITTINGS: 2 inch bung and ¾ inch bung

PSI RATING: 8 pounds or less

BLENDS AVAILABLE:

- Scentinel® E - Tertiary Butyl Mercaptan and Isopropyl Mercaptan
- Scentinel® S-20 - Tertiary Butyl Mercaptan and Methyl Ethyl Sulfide
- Scentinel® H-85 - Hexane and Secondary Butyl Mercaptan
- Scentinel® T - Tetrahydrothiphene (Thiophane/THT)
- Nose Guard ® (MSDS) (TDS)
- GOSS Masking Agent: Cha-Cha Cherry (MSDS) Island Mist (MSDS)

  *Also Available in 1 qt. spray bottles and in cases (12 – 1 qt. spray bottles).

PRODUCT SIZE: 5 gallon cylinder

DIMENSIONS: Height: 23 inches
Diameter: 12 inches

DISCHARGE FITTINGS: ½ in liquid valve and ½ in vapor valve

PSI RATING: 240 psi working pressure

BLENDS AVAILABLE:

- Scentinel® A – Ethyl Mercaptan
- Scentinel® E – Tertiary Butyl Mercaptan and Isopropyl Mercaptan
- Scentinel® S-20 – Tertiary Butyl Mercaptan and Methyl Ethyl Sulfide

Product Conversion

CP Chem Scentinel®			NGO Captan
A	(MSDS)	(TDS)	Ethyl Mercaptan
E	(MSDS)	(TDS)	BP
H-85	(MSDS)	(TDS)	DL
O-10	(MSDS)	(TDS)	Captan
S-20	(MSDS)	(TDS)	RP(V)
T	(MSDS)	(TDS)	CS
T-50	(MSDS)	(TDS)	Captan 50

- Scentinel® O-10 – Isopropyl Mercaptan, Tertiary Butyl Mercaptan, Dimethyl Sulfide and n-propyl Mercaptan
- Scentinel® H-85 – Hexane and Secondary Butyl Mercaptan
- Scentinel® T - Tetrahydrothiphene (Thiophane/THT)
- Scentinel® T-50 – Tertiary Butyl Mercaptan and Tetrahydrothiophene (Thiophane/THT)

Powered by Hyperlinks Web Sites
W3C CSS / XHTML Validated

PRODUCT SIZE: 54 gallon drum

DIMENSIONS: Height: 35 inches
Diameter: 23 inches

DISCHARGE FITTINGS: 2 inch bung and ¾ inch bung

PSI RATING: 8 pounds or less

BLENDS AVAILABLE:

- Scentinel® A – Ethyl Mercaptan
- Scentinel® E – Tertiary Butyl Mercaptan and Isopropyl Mercaptan
- Scentinel® S-20 – Tertiary Butyl Mercaptan and Methyl Ethyl Sulfide
- Scentinel® H-85 – Hexane and Secondary Butyl Mercaptan
- Nose Guard ® (MSDS) (TDS)

PRODUCT SIZE: 57 gallon cylinder
(White – Chevron Phillips cylinder)

DIMENSIONS: Height: 47 inches
Diameter: 22 inches

DISCHARGE FITTINGS: 1 in liquid valve and ¾ in vapor valve
PLEASE SPECIFY IF A RELIEF VALVE IS NEEDED

PSI RATING: 240 psi working pressure

BLENDS AVAILABLE:

- Scentinel® A – Ethyl Mercaptan
- Scentinel® E – Tertiary Butyl Mercaptan and Isopropyl Mercaptan
- Scentinel® S-20 – Tertiary Butyl Mercaptan and Methyl Ethyl Sulfide
- Scentinel® O-10 – Isopropyl Mercaptan, Tertiary Butyl Mercaptan, Dimethyl Sulfide and n-propyl Mercaptan
- Scentinel® H-85 – Hexane and Secondary Butyl Mercaptan

- Scentinel® T - Tetrahydrothiphene (Thiophane/THT)
- Scentinel® T-50 – Tertiary Butyl Mercaptan and Tetrahydrothiophene (Thiophane/THT)

PRODUCT SIZE: 57 gallon cylinder
(Blue – prior NGO cylinder)

DIMENSIONS: Height: 54 inches
Diameter: 22 inches

DISCHARGE FITTINGS: ½ in liquid valve and ½ in vapor valve

PSI RATING: 240 psi working pressure

BLENDS AVAILABLE:

- Scentinel® A – Ethyl Mercaptan
- Scentinel® E – Tertiary Butyl Mercaptan and Isopropyl Mercaptan
- Scentinel® S-20 – Tertiary Butyl Mercaptan and Methyl Ethyl Sulfide
- Scentinel® O-10 – Isopropyl Mercaptan, Tertiary Butyl Mercaptan, Dimethyl Sulfide and n-propyl Mercaptan
- Scentinel® H-85 – Hexane and Secondary Butyl Mercaptan
- Scentinel® T - Tetrahydrothiphene (Thiophane/THT)
- Scentinel® T-50 – Tertiary Butyl Mercaptan and Tetrahydrothiophene (Thiophane/THT)

PRODUCT SIZE: 100 gallon cylinder

DIMENSIONS: Height: 61 inches
Diameter: 30 inches

DISCHARGE FITTINGS: ½ in liquid valve and ½ in vapor valve

PSI RATING: 240 psi working pressure

BLENDS AVAILABLE:

- Scentinel® A – Ethyl Mercaptan
- Scentinel® E – Tertiary Butyl Mercaptan and Isopropyl Mercaptan
- Scentinel® S-20 – Tertiary Butyl Mercaptan and Methyl Ethyl Sulfide

- Scentinel® T-50 – Tertiary Butyl Mercaptan and Tetrahydrothiophene (Thiophane/THT)

PRODUCT SIZE: 250 gallon cylinder

DIMENSIONS: Height: 76 inches
Diameter: 39 inches
Cubic Feet: 76.56

DISCHARGE FITTINGS: 1 ½ in liquid valve and 1 in vapor valve

PSI RATING: 240 psi working pressure

BLENDS AVAILABLE:

- Scentinel® A – Ethyl Mercaptan
- Scentinel® E – Tertiary Butyl Mercaptan and Isopropyl Mercaptan
- Scentinel® S-20 – Tertiary Butyl Mercaptan and Methyl Ethyl Sulfide
- Scentinel® T - Tetrahydrothiphene (Thiophane/THT)

---

*Click for Unloading Procedures
*Click for Terms and Conditions

Return to top of page
© Copyright GOSS. All rights reserved.
Katy, Texas

Exhibit N

Glossary

The definitions in the glossary were compiled from a variety of sources including the 2030 General Plan Background Report, City planning documents, Sacramento City Code (SCC), and outside sources. Sources other than those produced by the City of Sacramento are noted in parenthesis after the definition.

A

Acres, Gross. The total area of a site including portions that cannot be developed (e.g., right-of-way, open space).

Acres, Net Developable. The total area of a site excluding portions that cannot be developed (e.g., right-of-way, open space). Sometimes referred to as the "buildable" area of the project.

Adaptive Reuse. A method by which a building is adapted to a different use from its original use, while its general physical form is retained.

Airport Land Use Commission (ALUC). Responsible for developing and maintaining comprehensive land use plans (CLUPs) to protect public health and safety, ensuring compatible land uses in the areas around each airport, and ensuring consistency between local land use plans and comprehensive land use plans for airport areas. The Sacramento Area Council of Governments serves as the ALUC for Sacramento, Sutter, Yolo, and Yuba Counties.

Alternative Fueling Station. Refueling stations offering alternative fuels such as compressed natural gas, biofuels, hydrogen, or electricity.

Alternative Planning Strategy (APS). Plan that is prepared and adopted by a Metorpolitan Planning Agency (MPO) that cannot meet its GHG reduction targets through a Sustainable Communities Strategy (SCS). An APS is not part of the Regional Transportation Plan, however it must be consistent with the Regional Housing Needs Allocation (RHNA) established by the Council of Governments (COG). An APS must show how regional greenhouse gas emissions targets from automobiles and light trucks would be achieved and regional housing needs met through alternative development patterns, infrastructure, or additional transportation measures or policies. City plans and ordinances are not required to be consistent with an APS, however development projects that are found to be consistent with an SCS are eligible for CEQA streamlining.

Asset Management Program. A program for managing infrastructure assets to minimize the total cost of owning and operating these assets. It combines engineering principles with business practices and economics to provide the tools and facilitate an organized approach to decision-making for both short- and long-range utility plans.

Hazardous Waste. A waste or combination of wastes, which because of its quantity, concentration, or physical, chemical, or infectious characteristics may either (a) cause, or significantly contribute to, an increase in mortality or an increase in serious, irreversible, or incapacitating irreversible, illness or (b) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported or disposed of, or otherwise managed. (California Health and Safety Code 25501)

Heritage Tourism. Tourism oriented toward experiencing places, artifacts, and activities that authentically represent the stories and people of the past and present.

Heritage Trees. Any tree of any species with a trunk circumference of 100 inches or more, which is of good quality in terms of health, vigor of growth, and conformity to generally accepted horticultural standards of shape and location for its species.

High-Impact Use. A use that generates disproportionately large environmental impacts such as pollution, noise, or traffic.

Historic. Known or established in the past.

Historical. Of, relating to, or having the character of history.

Historic Preservation. The field of identifying, protecting, and helping to preserve historic and cultural resources, including the maintenance, restoration, and rehabilitation of historically or culturally significant resources.

Historic Resources. Resources listed or eligible for listing in the National Register of Historic Places, the California Register of Historical Resources, and/or the Sacramento Register of Historic and Cultural Resources.

I

Impact Fees. Fees required by City code, ordinance, resolution or other City law to be paid as a condition of, or prerequisite to, issuance of a building permit for the development of residential uses, as those fees may be amended from time to time. (SCC 17.191.020)

Incidental Take. Take that results from, but is not the purpose of, carrying out an otherwise lawful activity. (U.S. Fish and Wildlife Service)

Incidental Take Permits. A permit issued under Section 10(a)(1)(B) of the Endangered Species Act (ESA) to a non-Federal party undertaking an otherwise lawful project that might result in the take of an endangered or threatened species. Application for an incidental take permit is subject to certain requirements, including preparation by the permit applicant of a conservation plan, generally known as a Habitat Conservation Plan (HCP). (U.S. Fish and Wildlife Service)

CERTIFICATE OF SERVICE

I hereby certify that I have this day served by electronic mail to each person listed on the attached official service list, in accordance with Rules 1.9 and 1.10 of the Commission's Rules of Practice and Procedure, the SECOND REQUEST FOR OFFICIAL NOTICE IN SUPPORT OF SUPPLEMENTAL REPLY BRIEF OF SACRAMENTO NATURAL GAS STORAGE, LLC, as submitted for electronic filing in proceeding A.07-04-13 on February 18, 2011.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Dated February 18, 2011 at Sacramento, California.

_____/s/_____

Alfred F. Jahns

CALIFORNIA PUBLIC UTILITIES COMMISSION
Service List

Proceeding: A0704013 - Sacramento Natural Gas Storage, LLC
Last Changed: January 5, 2011

Parties

PETER G. ESPOSITO
CRESTED BUTTE CATALYSTS, LLC
PO BOX 668
CRESTED BUTTE, CO 81224
FOR: LODI GAS STORAGE

RASHID A. RASHID
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
ROOM 4107
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
FOR: CONSUMER PROTECTION AND SAFETY DIVISION

LAW DEPARTMENT
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120-7442
FOR: PACIFIC GAS AND ELECTRIC COMPANY

DAN L. CARROLL
ATTORNEY AT LAW
DOWNEY BRAND, LLP
621 CAPITOL MALL, 18TH FLOOR
SACRAMENTO, CA 95814
FOR: LODI GAS STORAGE

JOHN V. DIEPENBROCK
ATTORNEY AT LAW
DIEPENBROCK HARRISON
400 CAPITOL MALL, SUITE 1800
SACRAMENTO, CA 95814
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

EILEEN M. TEICHERT
CITY ATTORNEY
CITY OF SACRAMENTO
915 I STREET, ROOM 4010
SACRAMENTO, CA 95814-2604
FOR: CITY OF SACRAMENTO

JONATHAN BROMSON
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
ROOM 4107
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
FOR: DRA

JEANNE B. ARMSTRONG
GOODIN MACBRIDE SQUERI DAY & LAMPREY LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE

COLIN A. BAILEY
LEGAL SERVICES OF NORTHERN CALIFORNIA
515 12TH STREET
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

DAVID A. DIEPENBROCK
ATTORNEY AT LAW
DIEPENBROCK HARRISON, P.C.
400 CAPITOL MALL, SUITE 1800
SACRAMENTO, CA 95814
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

TINA THOMAS
REMY, THOMAS, MOOSE AND MANLEY LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

ALFRED F. JAHNS
LAW OFFICE ALFRED F. JAHNS
3620 AMERICAN RIVER DRIVE, SUITE 105
SACRAMENTO, CA 95864
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

Information Only

ARBARA J. CHISHOLM
ATTORNEY
ALTSHULER BERZON LLP
EMAIL ONLY
EMAIL ONLY, CA 0000

JENNIFER SUNG
ATTORNEY
ATLSHULER BERZON, LLP
EMAIL ONLY
EMAIL ONLY, CA 00000

JOHN W. LESLIE, ESQ.
LUCE, FORWARD, HAMILTON & SCRIPPS, LLP
EMAIL ONLY
EMAIL ONLY, CA 00000

KAREN NORENE MILLS
ATTORNEY AT LAW
CALIFORNIA FARM BUREAU FEDERATION
EMAIL ONLY
EMAIL ONLY, CA 00000

PEDRO VILLEGAS
SEMPRA ENERGY UTILITIES
EMAIL ONLY
EMAIL ONLY, CA 00000

MRW & ASSOCIATES, LLC
EMAIL ONLY
EMAIL ONLY, CA 00000
FOR: MRW AND ASSOCIATES, INC.

JEFFREY L. SALAZAR
SOUTHERN CALIFORNIA GAS COMPANY
555 WEST FIFTH STREET, GT14D6
LOS ANGELES, CA 90013

KARI KLOBERDANZ
SOUTHERN CALIFORNIA GAS COMPANY
555 WEST 5TH STREET, GT14D6
LOS ANGELES, CA 90013-1011
FOR: SOUTHERN CALIFORNIA GAS COMPANY

STEVEN D. PATRICK
SAN DIEGO GAS AND ELECTRIC COMPANY
555 WEST FIFTH STREET, SUITE 1400
LOS ANGELES, CA 90013-1011
FOR: SOUTHERN CALIFORNIA GAS COMPANY

MARCIE MILNER
DIRECTOR - REGULATORY AFFAIRS
SHELL TRADING GAS & POWER COMPANY
4445 EASTGATE MALL, SUITE 100
SAN DIEGO, CA 92121

KATARZYNA M. SMOLEN
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MC B10A
SAN FRANCISCO, CA 94105

SEEMA SRINIVASAN
ALCANTAR & KAHL, LLP
33 NEW MONTGOMERY STREET, SUITE 1850
SAN FRANCISCO, CA 94105

JEANNE B. DAY
GOODIN,MACBRIDE,SQUERI,DAY&LAMPREY,LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE, LLC

MICHAEL B. DAY
GOODIN MACBRIDE SQUERI DAY & LAMPREY LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE

EDWARD O'NEILL
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
FOR: DAVIS WRIGHT TREMAINE LLP

HILARY CORRIGAN
CALIFORNIA ENERGY MARKETS
425 DIVISADERO ST. SUITE 303
SAN FRANCISCO, CA 94117-2242

KERRY C. KLEIN
ATTORNEY AT LAW
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120
FOR: PACIFIC GAS AND ELECTRIC COMPANY

CASE COORDINATION
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000; MC B9A
SAN FRANCISCO, CA 94177

KENNETH BRENNAN
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000, MC N15A
SAN FRANCISCO, CA 94177

KRISTIN FORD
DEVELOPMENT SERVICES DEPARTMENT
CITY OF SACRAMENTO
300 RICHARDS BOULEVARD, 3RD FLOOR
SACRAMENTO, CA 95811

TOM BUDFORD
DEVELOPMENT SERVICES DEPARTMENT
CITY OF SACRAMENTO
300 RICHARDS BOULEVARD, 3RD FLOOR
SACRAMENTO, CA 95811

ASHLE CROCKER
REMY, THOMAS, MOOSE AND MANLEY, LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

CHRIS BUTCHER
REMY, THOMAS, MOOSE AND MANLEY, LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

ELIZABETH HUGHES
1325 J STREET, SUITE 1300
SACRAMENTO, CA 95814

MATTHEW C. TABARANGAO
REMY, THOMAS, MOOSE AND MANLEY, LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814

RACHEL N. JACKSON
REMY, THOMAS, MOOSE AND MANLEY, LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814

SARAH R. ROPELATO
LEGAL SERVICES OF NORTHERN CALIFORNIA
515 12TH STREET
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN.

STEPHEN GOLDBERG
LEGAL SERVICES OF NORTHERN CALIFORNIA
515 12TH STREET
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN.

MICHAEL T. SPARKS
SENIOR DEPUTY CITY ATTORNEY
CITY OF SACRAMENTO
915 I STREET, ROOM 4010
SACRAMENTO, CA 95814-2604
FOR: CITY OF SACRAMENTO

GILLES ATTIA
DLA PIPER US LLP
400 CAPITOL MALL, SUITE 2400
SACRAMENTO, CA 95814-4428

SCOTT W. PINK
DLA PIPER US LLP
400 CAPITOL MALL, SUITE 2400
SACRAMENTO, CA 95814-4428
FOR: AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION

THOMAS ENSLOW
ADAMS BROADWELL JOSEPH & CARDOZO
520 CAPITOL MALL, SUITE 350
SACRAMENTO, CA 95814-4715
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

SLIDER CONSTANCE
CO-CHAIR
AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN.
5740 WILKINSON STREET
SACRAMENTO, CA 95824
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSOCIATION (AGENA)

WILLIAM W. WESTERFIELD III
SR. ATTORNEY - OFF. OF GEN. COUNSEL
SACRAMENTO MUNICIPAL UTILITY DISTRICT
6201 S ST., M.S. B402
SACRAMENTO, CA 958817

ANN L. TROWBRIDGE
DAY CARTER & MURPHY LLP
3620 AMERICAN RIVER DRIVE, SUITE 205
SACRAMENTO, CA 95864

ANNIE STANGE
ALCANTAR & KAHL LLP
1300 SW FIFTH AVENUE, SUITE 1750
PORTLAND, OR 97201

MIKE CADE
ALCANTAR & KAHL, LLP
1300 SE 5TH AVE., 1750
PORTLAND, OR 97201

State Service

CHRISTOPHER CHOW
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5301
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

DARRYL J. GRUEN
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
ROOM 4300
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

ERIC CHIANG
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

EUGENE CADENASSO
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

HARVEY Y. MORRIS
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
ROOM 5036
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

MICHAEL ROSAUER
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

PAUL S. PHILLIPS
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5212
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

RICHARD A. MYERS
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
FOR: ENERGY DIVISION

RICHARD SMITH
CALIF PUBLIC UTILITIES COMMISSION
DIVISION OF ADMINISTRATIVE LAW JUDGES
ROOM 5007
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

JAMES W. REEDE JR., ED.D.
ENVIRONMENTAL SCIENCE PROFESSOR
1516 - 9TH STREET
SACRAMENTO, CA 95814

CALIFORNIA PUBLIC UTILITIES COMMISSION
Electronic Mail Service Lists

Proceeding: A0704013 - Sacramento Natural Gas
Last Changed: January 5, 2011

peteresposito@earthlink.net	PETER G.	ESPOSITO
jab@cpuc.ca.gov	JONATHAN	BROMSON
rhd@cpuc.ca.gov	RASHID A.	RASHID
jarmstrong@goodinmacbride.com	JEANNE B.	ARMSTRONG
cbailey@lsnc.net	COLIN A.	BAILEY
dcarroll@downeybrand.com	DAN L.	CARROLL
dad@diepenbrock.com	DAVID A.	DIEPENBROCK
jvd@diepenbrock.com	JOHN V.	DIEPENBROCK
tthomas@rtmmlaw.com	TINA	THOMAS
ETeichert@cityofsacramento.org	EILEEN M.	TEICHERT
ajahns@jahnsatlaw.com	ALFRED F.	JAHNS
bchisholm@altber.com	BARBARA J.	CHISHOLM
jsung@altber.com	JENNIFER	SUNG
jleslie@luce.com	JOHN W.	LESLIE
kmills@cfbf.com	KAREN NORENE	MILLS
PVillegas@SempraUtilities.com	PEDRO	VILLEGAS
mrw@mrwassoc.com	MRW &	ASSOCIATES, LLC
JLSalazar@SempraUtilities.com	JEFFREY L.	SALAZAR
KKloberdanz@SempraUtilities.com	KARI	KLOBERDANZ
SDPatrick@SempraUtilities.com	STEVEN D.	PATRICK
marcie.milner@shell.com	MARCIE	MILNER
kmsn@pge.com	KATARZYNA M.	SMOLEN
sls@a-klaw.com	SEEMA	SRINIVASAN
jarmstrong@goodinmacbride.com	JEANNE B.	ARMSTRONG
mday@goodinmacbride.com	MICHAEL B.	DAY
edwardoneill@dwt.com	EDWARD	O'NEILL
cem@newsdata.com	HILARY	CORRIGAN
kck5@pge.com	KERRY C.	KLEIN
regrelcpuccases@pge.com	CASE	COORDINATION
KJBh@pge.com	KENNETH	BRENNAN
kford@cityofsacramento.org	KRISTIN	FORD
tbuford@cityofsacramento.org	TOM	BUFORD
acrocker@rtmmlaw.com	ASHLE	CROCKER
cbutcher@rtmmlaw.com	CHRIS	BUTCHER
elizabeth.hughes@hdrinc.com	ELIZABETH	HUGHES
MTabarangao@rtmmlaw.com	MATTHEW C.	TABARANGAO
RJackson@rtmmlaw.com	RACHEL N.	JACKSON
sropelato@lsnc.net	SARAH R.	ROPELATO
sropelato@lsnc.net	STEPHEN	GOLDBERG
msparks@cityofsacramento.org	MICHAEL T.	SPARKS
Gilles.Attia@dlapiper.com	GILLES	ATTIA
scott.pink@dlapiper.com	SCOTT W.	PINK

tenslow@adamsbroadwell.com	THOMAS	ENSLOW
constanceslider@sbcglobal.net	CONSTANCE	SLIDER
wwester@smud.org	WILLIAM W.	WESTERFIELD
atrowbridge@daycartermurphy.com	ANN L.	TROWBRIDGE
sas@a-klaw.com	ANNIE	STANGE
wmc@a-klaw.com	MIKE	CADE
crs@cpuc.ca.gov	CHRISTOPHER	CHOW
djg@cpuc.ca.gov	DARRYL J.	GRUEN
eyc@cpuc.ca.gov	ERIC	CHIANG
cpe@cpuc.ca.gov	EUGENE	CADENASSO
hym@cpuc.ca.gov	HARVEY Y.	MORRIS
fly@cpuc.ca.gov	MICHAEL	ROSAUER
psp@cpuc.ca.gov	PAUL S.	PHILLIPS
ram@cpuc.ca.gov	RICHARD A.	MYERS
rs1@cpuc.ca.gov	RICHARD	SMITH
jwreede@csus.edu	JAMES W.	REEDE JR.