Attachment 1

Wet Gas, Fuel Gas, and Flare Gas Recovery System Descriptions

Public Version

Vent Gas Recovery Systems - Overview

There are three systems to recover vent gas streams. They are the Wet Gas system, the Flare system, and the Vapor Recovery system. The Wet Gas system can handle gas streams that are above a pressure of about 10 psig. Lower pressure gas streams are typically sent to the Flare system since there is inadequate pressure to get into the Wet Gas system. The Vapor Recovery system recovers vapors from cone roof tanks, marine loading, and a few other very low pressure streams. Wet Gas typically is routed to the No. 5 Gas Plant where it is combined with the No. 5 Gas Plant produced gas, treated to remove H2S, and sent to the Fuel Gas system. If the No. 5 Gas Plant is down, the wet gas streams can be sent to the No.4 Gas Plant. However, the capacity of the No. 4 Gas Plant to handle these wet gas streams is lower than that at No. 5 Gas Plant. A block flow diagram of the relationship between the Wet Gas, Flare Gas, Vapor Recovery and Fuel Gas systems is provided in Figure 1.

Wet Gas System

Wet gas is comprised of off-gasses from various units that are usable as fuel gas. The wet gas system provides an alternate destination for gasses, which would otherwise be sent to flare. The refinery wet gas system consists of 4 major pipelines which connect the suppliers of wet gas such as the FCC and the crude units to the #5 Gas Plant. Typically, that is when No. 5 Gas Plant is in operation, the No. 5 Gas Plant collects the wet gas streams in the refinery, compresses those gases, separates out heavier gasses like propane and butane, and treats the remainder to remove H2S. This treated gas is then sent to the Fuel Gas system. When the No. 5 Gas Plant is shut down, the refinery wet gas streams are diverted to the No. 4 Gas Plant, where similar processing takes place. As noted above, the No. 4 Gas Plant has a lower capacity to handle these wet gas streams than the No. 5 Gas Plant.

Flare Gas System

The 24 inch diameter, 42 inch diameter, and 48 diameter flare headers collect low pressure gases and send them to the flare area. At the flare area, a recycle compressor draws flare gas from the flare headers, compresses the flare gas, and sends it to the No. 5 Gas Plant for recovery as wet gas.

The primary reduction in flare gas comes from the flare recovery compressors directing gasses from the flare headers into the wet gas system where they are converted to fuel gas as described above. Additionally, when some equipment/units are taken out of service, they can be depressured to the wet gas system instead the flare system, if the pressure is high enough to get into the wet gas system.

There are several limitations associated with this process. The flare recovery compressors can only compress about 5 MMSCFD. If the flow to the flare headers is more than 5 MMSCFD, the excess gas will be directed to the flares. Also, if the wet gas system is already at maximum capacity, the flare recovery compressors will be limited to avoid over-pressurization problems at the No. 5 Gas Plant (excess gas going to the No. 5 Gas Plant are directed to flare, so it would just result in a recycle loop). Additionally, if the refinery is producing more fuel gas than it is consuming, the flare gas recovery will be ineffective since the flare gas will further increase the amount of fuel gas that will then be sent to the flare as the fuel gas pressure exceeds its set point. In such cases, the refinery will typically cut rate/severity at the FCC or rate at the Coker to restore balance to the fuel or wet gas systems.

Vapor Recovery System

The vapor recovery system is comprised of pipelines which route very low pressure streams to the No. 1 Gas Plant where the gas is compressed and routed to the 40 psig fuel gas system. Tank vents from cone roof tanks and the vapors recovered by the Marine Vapor Recovery system are the primary sources of gas to this system. Various other low pressure streams that are piped to the vapor recovery system can also be routed to this system.

Fuel Gas System

The Fuel Gas system includes gases produced in the No. 5 Gas Plant and No. 4 Gas Plant, as well as recovered vapors from the Wet Gas system and recovered Flare Gas. It also includes gases recovered from the Vapor Recovery system which includes tank vapors and vapors from the Marine Vapor Recovery system. In addition, No. 1 Hydrogen Plant off-gasses are sent to the fuel gas system (see Figure 1). Purchased natural gas is added to the Fuel Gas system to make up for any shortage between the fuel gas produced and consumed, maintaining pressure control in the system. Lastly, propane or butane can be added to the Fuel Gas system, if needed, to increase the BTU content of the fuel gas. Fuel Gas system production and consumption rates are provided in the section below.

The fuel gas is sent to the refinery furnaces and boilers, the Foster Wheeler Cogeneration facility, the No. 2 Hydrogen Plant, the Chemical Plant (i.e. Sulfur Plant, Ammonia Recovery Unit, and Sulfuric Acid Plant), and the Monsanto catalyst facility to provide a source of energy to support the various processes.

There are no specific fuel gas quality specifications, but there are general levels we attempt to meet for various parameters. For example, we attempt to meet a BTU content of about 1000 BTU/scf and maintain an oxygen level below 1%. We do not have any targets for molecular weight or specific gravity. We also do not have any alarms on the molecular weight of the flare gas. In addition, we do not have a specific target for nitrogen levels, but try to minimize the amount of nitrogen introduced into the fuel gas. Lastly, there are no hydrogen content specifications for fuel gas. However, the No. 5 Gas Plant operators monitor the operation of the wet gas compressors (e.g. the flow and RPMs). If the operation of the wet gas compressors begins to become erratic, they limit the flare gas recovery flow to maintain wet gas compressor operational stability.

Wet Gas and Fuel Gas Production and Consumption Rates

Typically, the refinery producers will generate 70-90 MMSCFD of wet gas. After being processed at the No. 5 Gas Plant, where butane and propane is recovered, about 40-60 MMSCFD of fuel gas is produced. This gas is mixed with 5-10 MMSCFD of fuel gas from the No. 4 Gas Plant, 1-5 MMSCFD from the vapor recovery system, and 0-6 MMSCFD of hydrogen bleed from #1 Hydrogen plant. These streams are supplemented with natural gas purchased from PG&E which averages around 5 MMSCFD to balance the supply of fuel gas with the demand.

There is limited flexibility to increase refinery consumption of fuel gas. This can be done via three methods. First, by switching electric drivers of rotating equipment to steam drivers (turbines), extra steam demand can be generated, allowing the boiler firing rates to be increased. However, there isn't normally a lot of room to increase consumption in this manner. Second, the amount of steam imported from Foster Wheeler can be minimized, which will increase the boiler firing rates. Lastly, it is occasionally possible to export more fuel gas to Foster Wheeler if their operating conditions allow them to receive it (e.g. if they can accept more fuel gas and still meet their permit limits). Foster Wheeler often receives between 0-10 MMSCFD of gas.

Attachment 2

Manufacturer's Recommended Compressor Repair & Maintenance

Section 3
TROUBLESHOOTING

3-1 Locating Troubles

Nash vacuum pumps and compressors require little attention other than checking the ability of the unit to obtain full volume or maintain constant vacuum. If a V-belt drive is used, V-belt tension should be checked periodically and the V-belt should be inspected for excessive wear. V-belts are normally rated for service lives of 24,000 hours. If operating difficulties arise, make the following checks:

a. Check for proper seal water flow rate as specified in Paragraph 2-2.

b. Check for the correct direction of the pump shaft rotation as cast on the body of the pump.

c. Check that the unit operates at the correct rpm-not necessarily the test rpm stamped on the pump name plates. (Refer to Paragraph 2-5, step g.)

d. Check for a restriction in the gas inlet line.

e. If the pump is shut down because of a change in temperature, noise/vibration from normal operating conditions, check bearing lubrication, bearing condition, and coupling or V-belt drive alignment. Refer to Bulletin No. 642, Installation Instructions, Nash Vacuum Pumps and Compressors, for alignment procedures and V-belt tensioning.

Note

If the trouble is not located through these checks, **call your Nash Representative** before dismantling or dissembling the pump. He will assist in locating and correcting the trouble.

Section 4
PREVENTIVE MAINTENANCE

4-1 Periodic Maintenance

Note

The following schedules should be modified as necessary for your specific operating conditions.

4-2 Six-Month Intervals

a. If the drive coupling is lubricated, it should be filled with oil or grease in accordance with the coupling manufacturer's guide.

b. Check the pump bearings and lubricate as specified in Paragraph 4-4.

c. Relubricate the drive motor bearings according to the motor manufacturer's instructions.

4-3 Twelve-Month Intervals

a. Inspect the pump bearings and lubricate as specified in Paragraph 4-4.

b. Replace the stuffing box packing as specified in Paragraph 4-5.

4-4 Bearing Lubrication

Bearings are lubricated before shipment and require no lubrication for approximately six months. To check condition and quantity of grease in the bearing bracket proceed as follows:

Note

Lubricate the bearings every year, unless the pump is being operated in a corrosive atmosphere or with a liquid compressant other than water, in which case the interval should be shortened. Lubrication should be done while the pump is running.

a. Check condition of grease in bearing caps for contamination or presence of water.

b. If grease is contaminated, remove fixed or floating bearing bracket (109 or 108), fixed or floating bearing (120 or 119) and associated parts as specified in Paragraph 5-2, steps a thru r for fixed bearing (120), or Paragraph 5-3, steps a thru l for floating bearing (119). Discard bearing.

c. Flush bearing bracket and bearing cap to remove all grease.

d. Install bearing bracket, bearing and associated parts as specified in Paragraph 5-17 and as follows:

   1. For floating bearing (119), perform steps a, c, and d, Paragraph 5-17, and steps b thru m, in Paragraph 5-18. Use associated parts.

Note

Make certain that new lip seal (5-1) is seated in floating bearing outer cap (115) with sealing lip away from bearing.

2. Install new lip seal (5-1) and secure floating bearing outer cap (115) and new gasket (115-3) to floating bearing bracket (108) as specified in Paragraph 5-20, steps m thru p.

3. Rotate shaft (111) by hand and make sure there is no rubbing or metal-to-metal contact.

4. For fixed bearing (120), perform steps a, c, and d, Paragraph 5-17; and steps a thru n, Paragraph 5-18.

CAUTION

THICKNESS OF SHIMS (4) EQUAL TO THICKNESS OF SHIMS REMOVED FROM PUMP MUST BE REINSTALLED TO MAINTAIN REQUIRED END TRAVEL.

5. Install shims (4) and fixed bearing outer cap (117) on fixed bearing bracket (109) as specified in Paragraph 5-20, steps j and k.

6. Rotate shaft by hand and make sure there is no rubbing or metal-to-metal contact.

4-5 Stuffing Box Packing

A preventive maintenance schedule should be established for the tightening and replacement of the packing in the stuffing boxes of the pump. The packing in the stuffing boxes in pumps used in continuous process systems should be replaced at annual shutdown. More frequent replacement may be required on severe process applications in which liquid compressant in the pump is contaminated by foreign material. (The packing material consists of four rings with the dimensions listed in Table 5-1.)

When replacing the packing in a stuffing box, remove the old packing as follows:

Note

Record position and number of packing rings on each side of lantern gland. This information is used to make certain that lantern gland is correctly aligned.

a. Slide slinger (3) against bearing inner cap (116 or 118).

b. Loosen and remove gland nuts (101-1 or 102-1, Figure 4-3) from studs.

Table 4-1. General Grease Specifications

GENERAL REQUIREMENTS:

A. *Premium quality* industrial bearing grease.

B. *Consistency grade:* NLGI #2

C. *Oil viscosity (minimum):*
 @ 100° (38°C) - 500 SSU (100 cSt)
 @ 210° (99°C) - 58 SSU (10 cSt)

D. *Thickener (Base):* Lithium, Lithium Complex or Polyurea for optimum WATER RESISTANCE.

E. *Performance characteristics* at operating temperature:
 1. Operating temperature range; at least 0° to 250°F (18° to 121°C)
 2. "Long-Life" performance
 3. Good mechanical and chemical stability.

F. *Additives — Mandatory:*
 1. Oxidation inhibitors
 2. Rust inhibitors

G. *Additives — Optional:*
 1. Anti-wear agents
 2. Corrosion inhibitors
 3. Metal deactivators

H. *Additives — Objectionable:*
 1. Extreme Pressure (EP)* agents
 2. Molybdenum disulfide (MoS_2)
 3. Tackiness agents

*Some greases exhibit EP characteristics without the use of EP additives. These EP characteristics are not objectionable.

NASH STANDARD GREASE RECOMMENDATIONS (By Manufacturer):

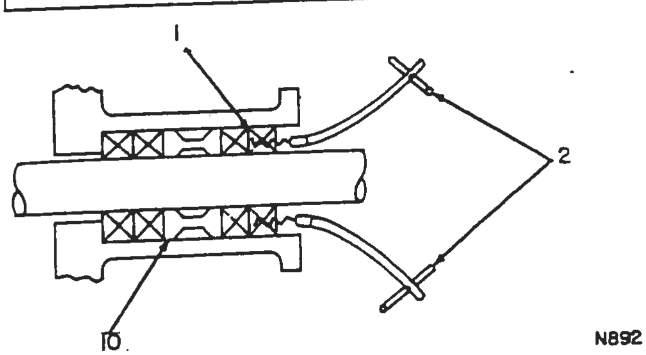
The following is a list of some greases that exhibit the desired characteristics required by Nash.

Grease Manufacturer	*Product*
AMOCO	Rykon Premium 2
Atlantic Richfield (ARCO)	ARCO Multipurpose
Chevron Oil	Chevron SRI-2
Exxon	Unirex N2
Gulf Oil	Gulfcrown No. 2
Mobil	Mobilux 2
Shell Oil	Alvania 2 or Dolium R
Texaco	Premium RB #2

*Nash Standard grease.

NOTE: This list is not an endorsement of these products and is to be used only for reference. A customer can have his local lubricant supplier cross reference these greases for an equivalent or current grease so long as it meets the General Requirements.

Grease Compatibility Note: The above listed greases are compatible with Nash Standard grease, Chevron SRI-2. To maximize a grease lubricant's performance, however, it is recommended that intermixing of different greases be kept to a minimum.



1. Packing Ring
2. Packing Pullers
10. Lantern Gland

Figure 4-1. Removing Stuffing Box Packing

Attachment 3

Main Flare System Process Flow and Vessel Diagrams

Public Version – Confidential Information Redacted

Attachment 3A

50 Unit Flare System
Process Flow and
Vessel Diagrams

Public Version
Confidential Information Redacted

Attachment 4

ARU Flare
Process Flow and
Vessel Diagrams

Public Version
Confidential Information Redacted

Attachment 5

Reductions Previously Realized – Causal Analyses Actions

Public Version
Confidential Information Redacted

Attachment 6

Planned Reductions Table

Public Version
Confidential Information Redacted

Attachment 7

Causal Analyses –
Open Action Items

Public Version
Confidential Information Redacted

Attachment 8

Main Flare Gas
Recovery System Diagram

Public Version
Confidential Information Redacted

Attachment 9

Cost Effectiveness Calculations

Hydrocarbon Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT using the "levelized cash flow method"
Input parameters are in blue text

Cost Effectiveness = (Annualized Cost of Abatement System ($/yr)) /
(Reduction in Annual Pollutant Emissions (ton/yr))

Reduction in Annual Pollutant Emissions =
Baseline Uncontrolled Emissions
- Control Option Emissions

Baseline Uncontrolled Emissions:

0.8	MM scf/d flared gas
292	MM scf/yr flared gas
0.009324	lb non-methane hydrocarbon (POC) to flare / scf flared gas
98	% destruction of hydrocarbon in flare
0.000186	lb non-methane hydrocarbon (POC) emitted / scf flared gas
54,455	lb/yr non-methane hydrocarbon emissions prior to control
27.23	ton/yr

Control Option Emissions:

118	MM scf/yr additional flare gas captured
174	MM scf/yr flared gas after controls
32,449	lb/yr non-methane hydrocarbon emissions following control
16.22	ton/yr

Reduction in Annual Pollutant Emissions =

22,006	lb/yr non-methane hydrocarbon emissions (POC)
11.00	tons/yr

Total Capital Cost $10,600,000

CRF = Capital Recovery Factor (to annualize capital cost)

CRF = $[i(1+i)^n]/[(1+i)^n - 1]$

i = interest rate, at 0.06

n = lifetime of abatement system, at 10 yrs

CRF = 0.1359

Utilities

Power

400	bhp for flare gas compressor
0.85	efficiency at design
351.1	kw
0.10	$/kw
8,760	operating hours per year
$307,528	/yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		$/year
Labor	2 % of capital cost	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System = $2,765,000

Cost Effectiveness =	$251,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton	

Attorney Client Privileged Communication

SO2 Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT using the "levelized cash flow method"
Input parameters are in blue text

Cost Effectiveness = (Annualized Cost of Abatement System (\$/yr)) /
(Reduction in Annual Pollutant Emissions (ton/yr))

Reduction in Annual Pollutant Emissions =
Baseline Uncontrolled Emissions
- Control Option Emissions

Baseline Uncontrolled Emissions:

0.8	MM scf/d flared gas
292	MM scf/yr flared gas
0.000319	lb SO2/ scf flared gas
0	% destruction of SO2 in flare
0.000319	lb SO2 emitted / scf flared gas
93,074	lb/yr non-methane hydrocarbon emissions prior to control
46.54	ton/yr

Control Option Emissions:

118	MM scf/yr additional flare gas captured
174	MM scf/yr flared gas after controls
55,462	lb/yr SO2 emissions following control
27.73	ton/yr

Reduction in Annual Pollutant Emissions =

37,612	lb/yr SO2 emissions
18.81	tons/yr

Total Capital Cost \$10,600,000

CRF = Capital Recovery Factor (to annualize capital cost)

CRF = $[i (1 + i)^n] / [(1 + i)^n - 1]$

i = interest rate, at 0.06

n = lifetime of abatement system, at 10 yrs

CRF = 0.1359

Utilities

Power

400	bhp for flare gas compressor
0.85	efficiency at design
351.1	kw
0.10	\$/kw
8,760	operating hours per year
\$307,528	/yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		$/year
Labor	2 % of capital cost	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System = $2,765,000

Cost Effectiveness = $147,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton

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Nox Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT
using the "levelized cash flow method"
Input parameters are in blue text

Cost Effectiveness = (Annualized Cost of Abatement System ($/yr)) /
(Reduction in Annual Pollutant Emissions (ton/yr))

Reduction in Annual Pollutant Emissions =
Baseline Uncontrolled Emissions
- Control Option Emissions

Flarre gas average BTU
732 BTU/scf
0.068 lb NOx/MMBtu

Baseline Uncontrolled Emissions:

0.8	MM scf/d flared gas
292	MM scf/yr flared gas
0.0000498	lb NOx / scf flare gas
0	% destruction of NOx in flare
0.0000498	lb NOx emitted / scf flared gas
14,535	lb/yr NOx emissions prior to control
7.27	ton/yr

Control Option Emissions:

118	MM scf/yr additional flare gas captured
174	MM scf/yr flared gas after controls
8,661	lb/yr NOx emissions following control
4.33	ton/yr

Reduction in Annual Pollutant Emissions =

5,874	lb/yr NOx emissions
2.94	tons/yr

Total Capital Cost $10,600,000

CRF = Capital Recovery Factor (to annualize capital cost)

CRF = $[i (1 + i)^n] / [(1 + i)^n - 1]$

i = interest rate, at 0.06

n = lifetime of abatement system, at 10 yrs

CRF = 0.1359

Utilities

Power

400	bhp for flare gas compressor
0.85	efficiency at design
351.1	kw
0.10	$/kw
8,760	operating hours per year
$307,528	/yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		$/year
Labor	2 % of capital cost	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System = $2,765,000

Cost Effectiveness =	$942,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton	

Attorney Client Privileged Communication

CO Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT
using the "levelized cash flow method"
Input parameters are in blue text

Cost Effectiveness = (Annualized Cost of Abatement System ($/yr)) /
(Reduction in Annual Pollutant Emissions (ton/yr))

Reduction in Annual Pollutant Emissions =
Baseline Uncontrolled Emissions
- Control Option Emissions

Flarre gas average BTU
732 BTU/scf
0.37 lb CO/MMBtu

Baseline Uncontrolled Emissions:

0.8	MM scf/d flared gas
292	MM scf/yr flared gas
0.0002708	lb CO / scf flare gas
0	% destruction of CO in flare
0.0002708	lb CO emitted / scf flared gas
79,085	lb/yr CO emissions prior to control
39.54	ton/yr

Control Option Emissions:

118	MM scf/yr additional flare gas captured
174	MM scf/yr flared gas after controls
47,126	lb/yr CO emissions following control
23.56	ton/yr

Reduction in Annual Pollutant Emissions =

31,959	lb/yr CO emissions
15.98	tons/yr

Total Capital Cost $10,600,000

CRF = Capital Recovery Factor (to annualize capital cost)

CRF = $[i (1 + i)^n] / [(1 + i)^n - 1]$

i = interest rate, at 0.06

n = lifetime of abatement system, at 10 yrs

CRF = 0.1359

Utilities

Power

400	bhp for flare gas compressor
0.85	efficiency at design
351.1	kw
0.10	$/kw
8,760	operating hours per year
$307,528	/yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		$/year
Labor	2 % of capital cost	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System = $2,765,000

Cost Effectiveness =	$173,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton	

Attorney Client Privileged Communication

PM Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT
using the "levelized cash flow method"
Input parameters are in blue text

Cost Effectiveness = (Annualized Cost of Abatement System ($/yr)) /
(Reduction in Annual Pollutant Emissions (ton/yr))

Reduction in Annual Pollutant Emissions =
Baseline Uncontrolled Emissions
- Control Option Emissions

Flarre gas average BTU
732 BTU/scf
0.1 lb PM/MMBtu

Baseline Uncontrolled Emissions:

0.8	MM scf/d flared gas
292	MM scf/yr flared gas
0.0000732	lb PM / scf flare gas
0	% destruction of PM in flare
0.0000732	lb PM emitted / scf flared gas
21,374	lb/yr PM emissions prior to control
10.69	ton/yr

Control Option Emissions:

118	MM scf/yr additional flare gas captured
174	MM scf/yr flared gas after controls
12,737	lb/yr PM emissions following control
6.37	ton/yr

Reduction in Annual Pollutant Emissions =

8,638	lb/yr PM emissions
4.32	tons/yr

Total Capital Cost $10,600,000

CRF = Capital Recovery Factor (to annualize capital cost)

CRF = $[i (1 + i)^n] / [(1 + i)^n - 1]$

i = interest rate, at 0.06

n = lifetime of abatement system, at 10 yrs

CRF = 0.1359

Utilities

Power

400	bhp for flare gas compressor
0.85	efficiency at design
351.1	kw
0.10	$/kw
8,760	operating hours per year
$307,528	/yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		$/year
Labor	2 % of capital cost	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System = $2,765,000

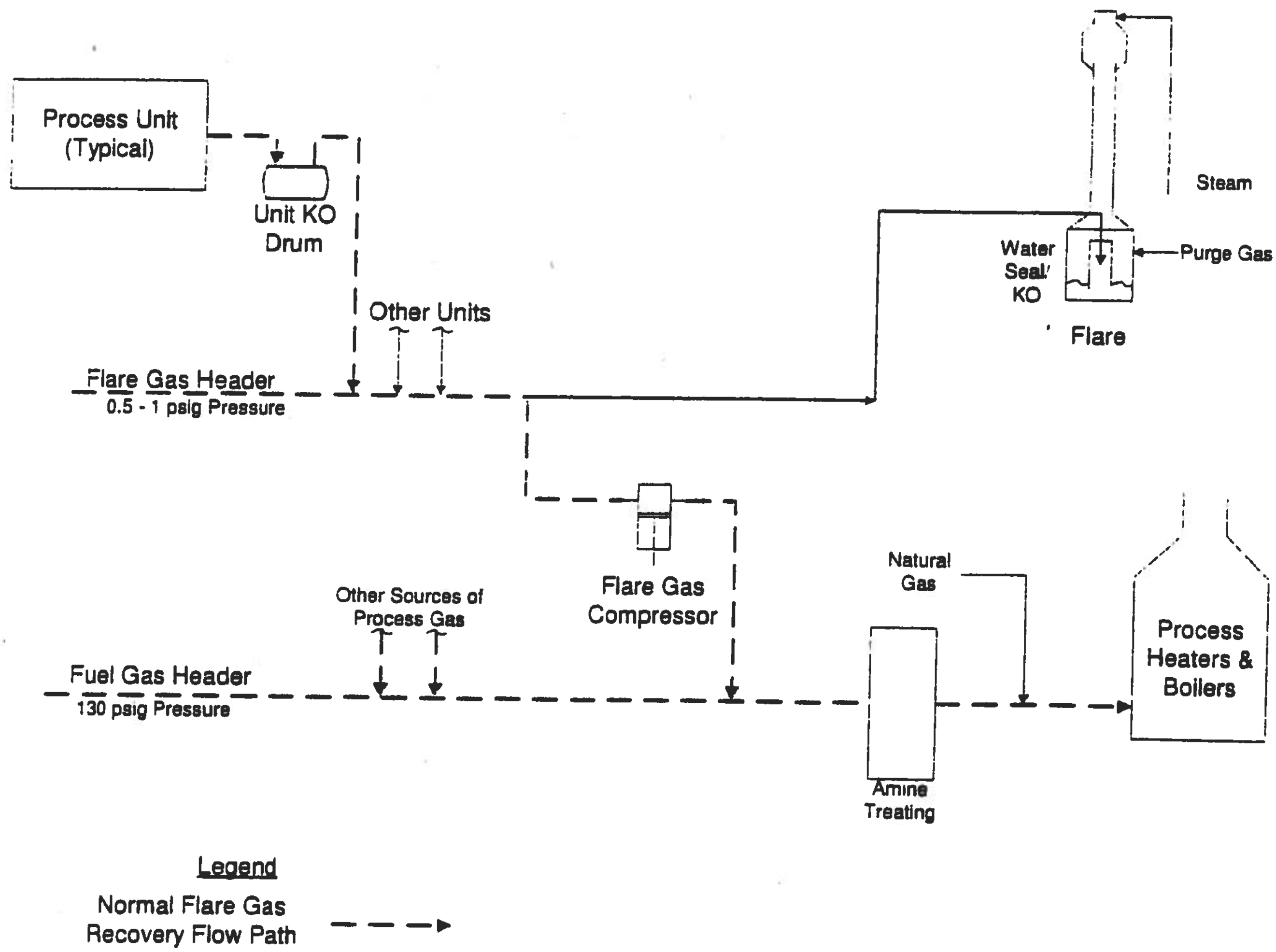
Cost Effectiveness = $640,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton

Attorney Client Privileged Communication

Attachment 10

Typical Flare Gas Recovery System Diagram

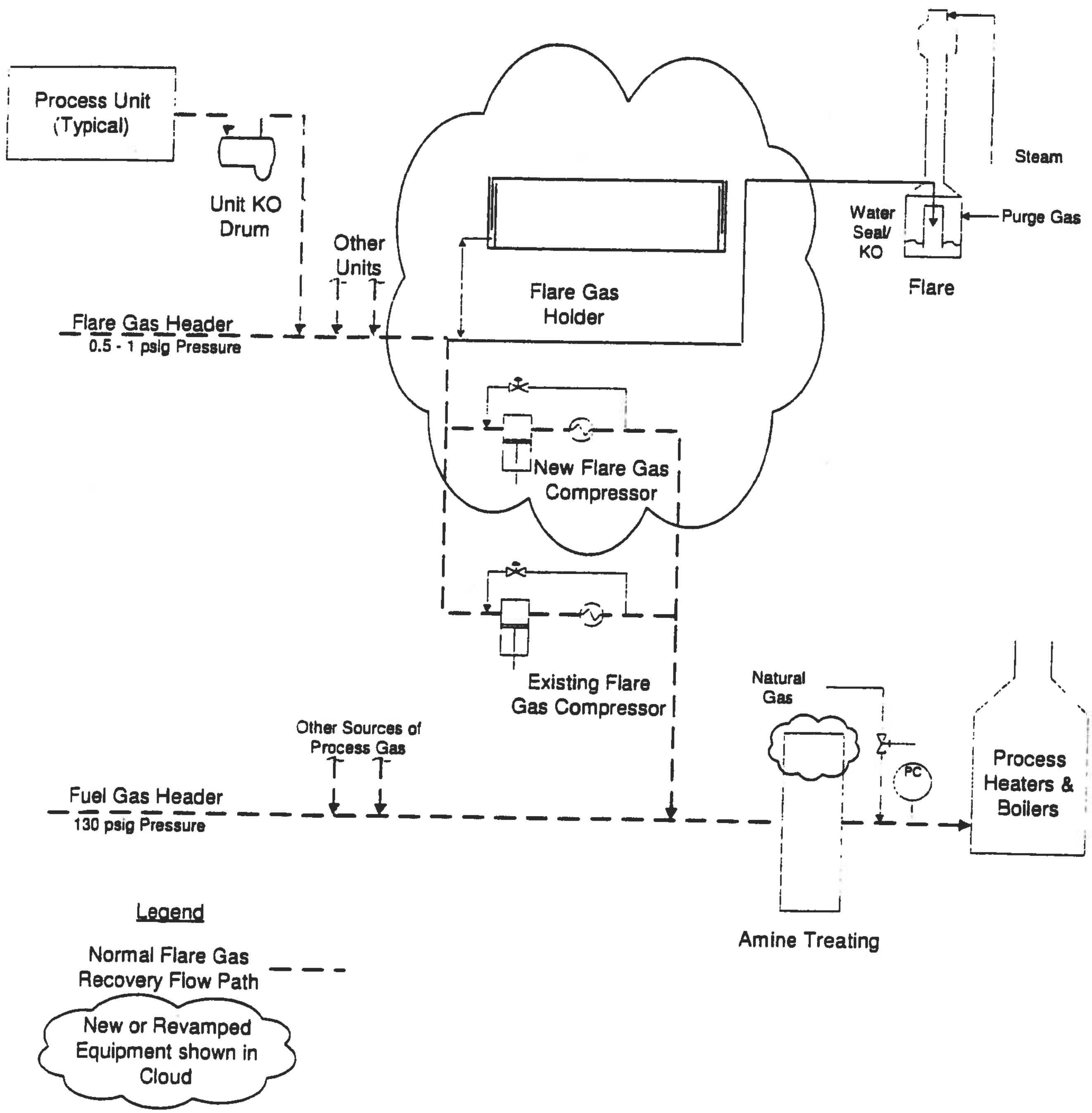
Typical Flare Gas Recovery System



Attachment 11

Flare Gas Recovery with Gas Holder Diagram

Flare Gas Recovery With Gas Holder

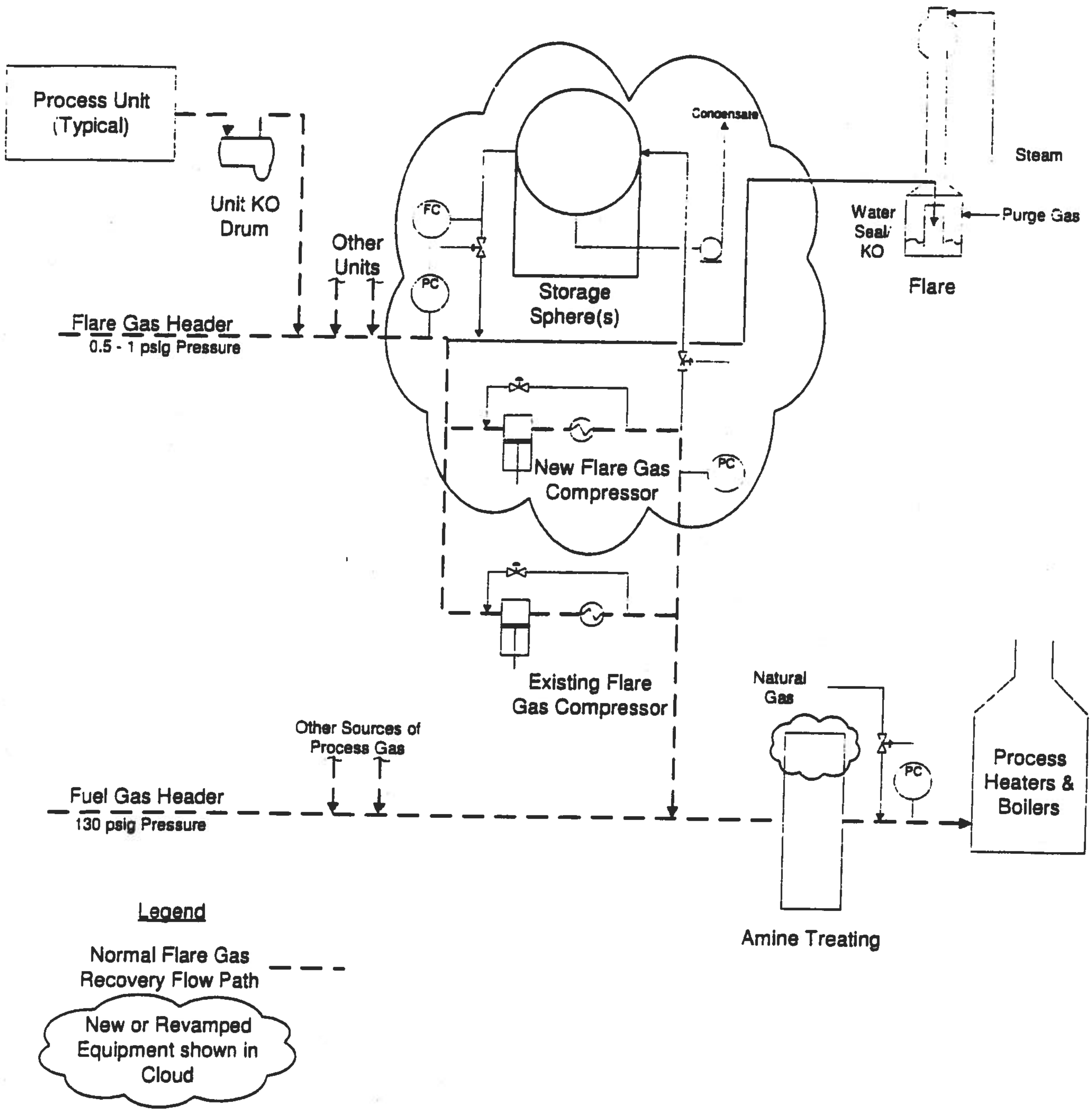


June 6 2006

Attachment 12

Flare Gas Recovery with Gas Storage Diagram

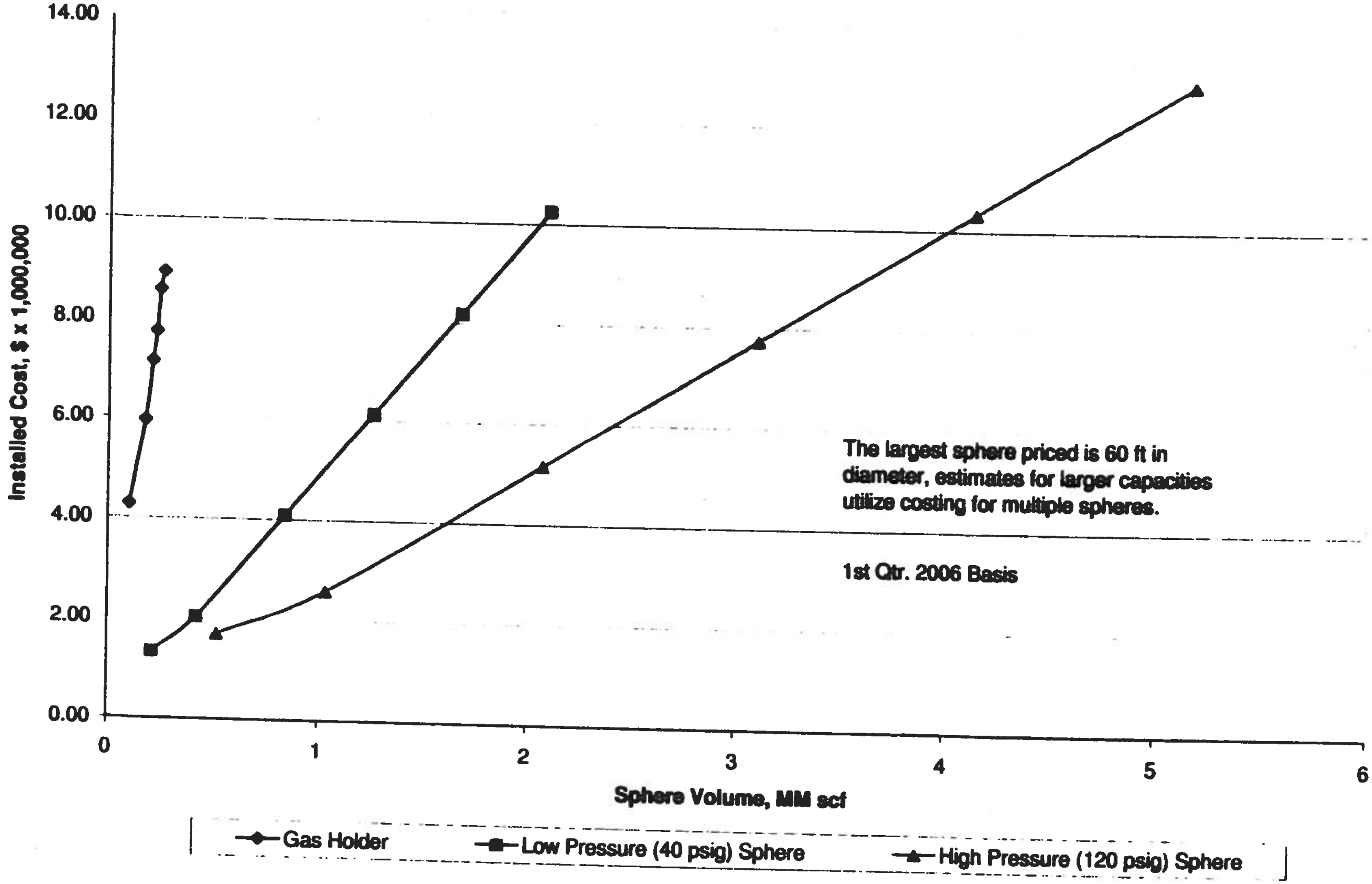
Flare Gas Recovery With Storage Sphere



Attachment 13

Vessel Cost Curve

Flare Gas Storage Options

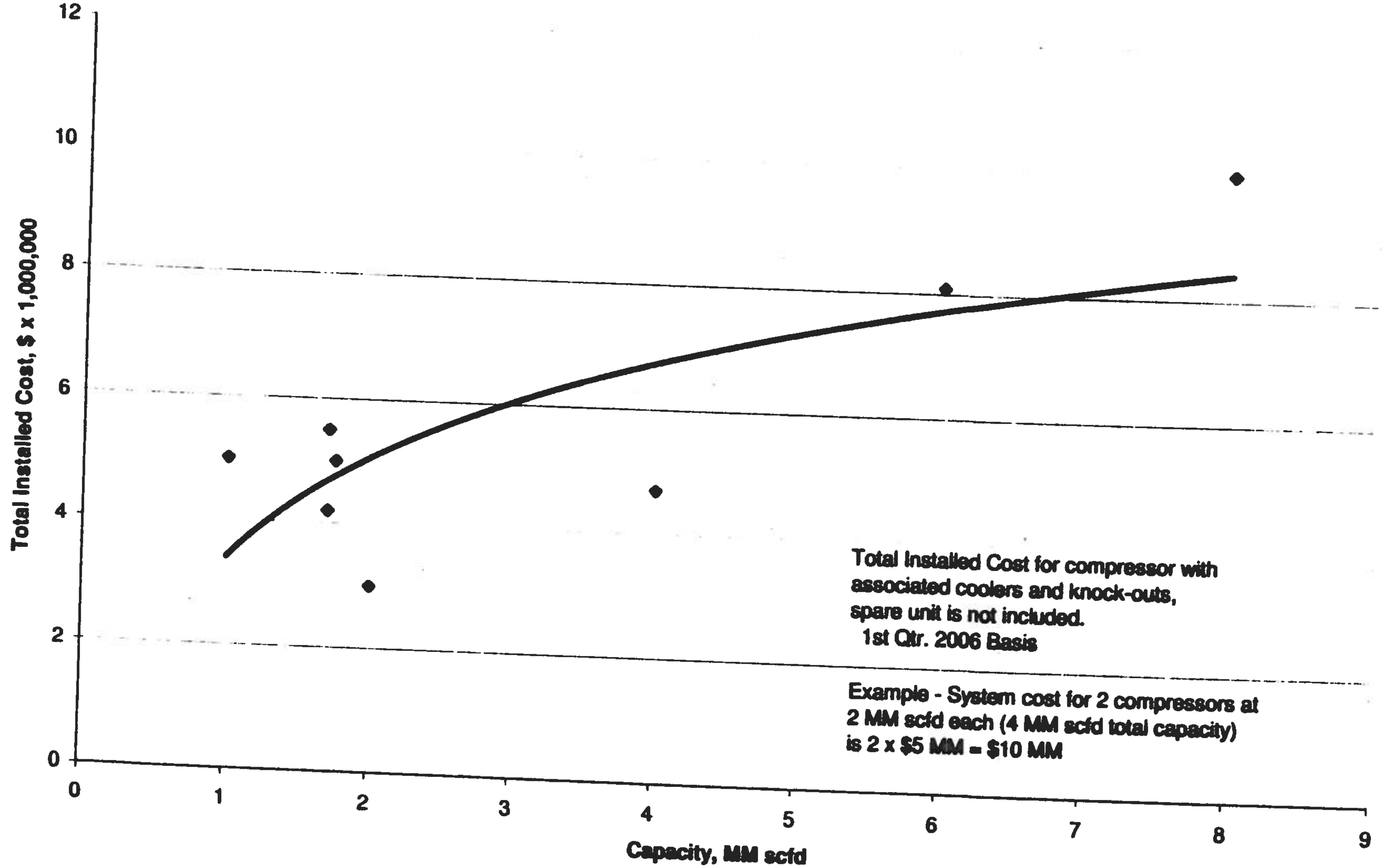


Confidential Attorney-Client Priviliged Work Document

Attachment 14

Compressor Cost Curve

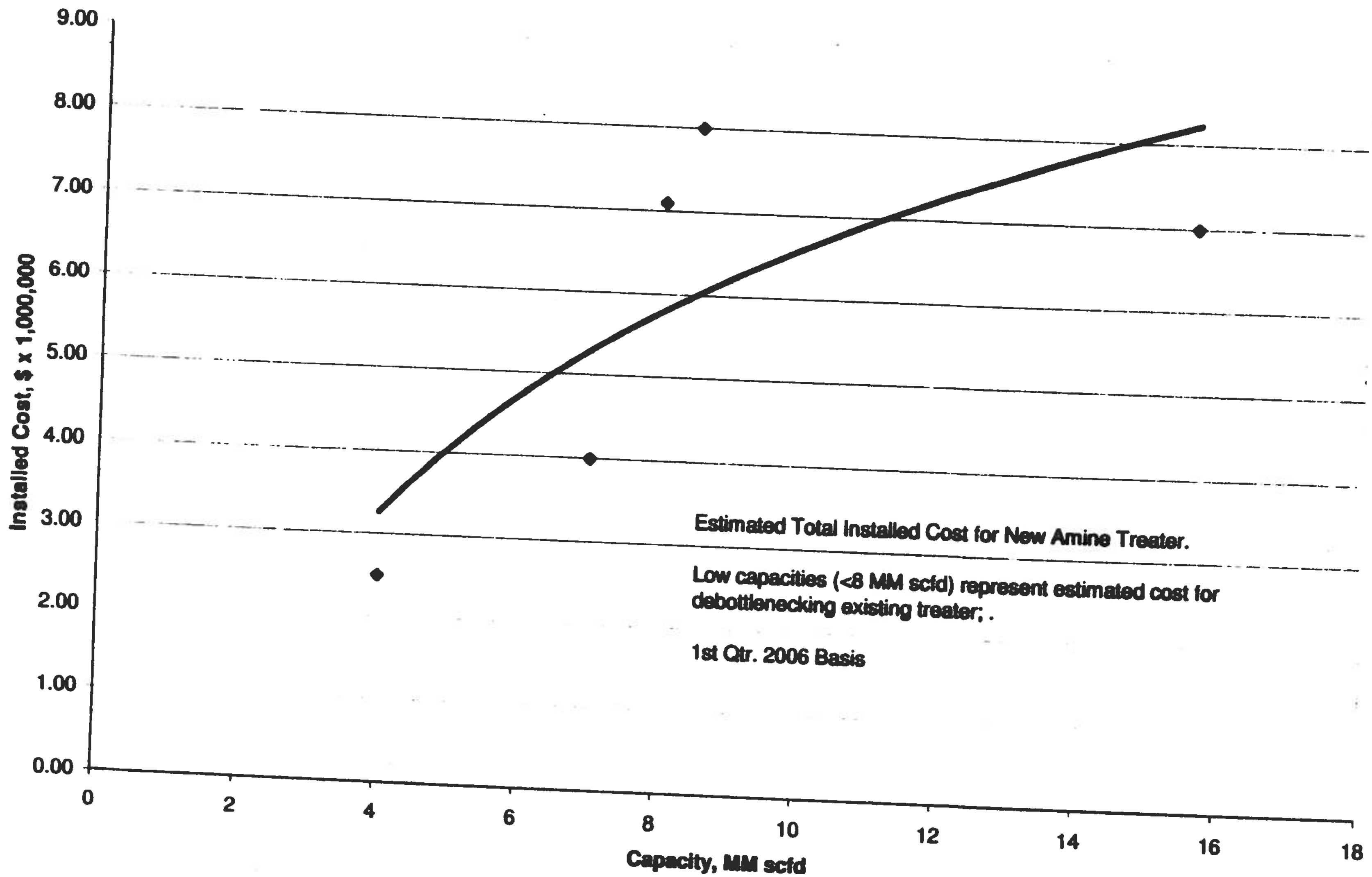
Flare Gas Compressor System Costs



Attachment 15

Gas Treatment Cost Curve

Fuel Gas Amine Treater Costs



Confidential Attorney-Client Privileged Document

Attachment 16

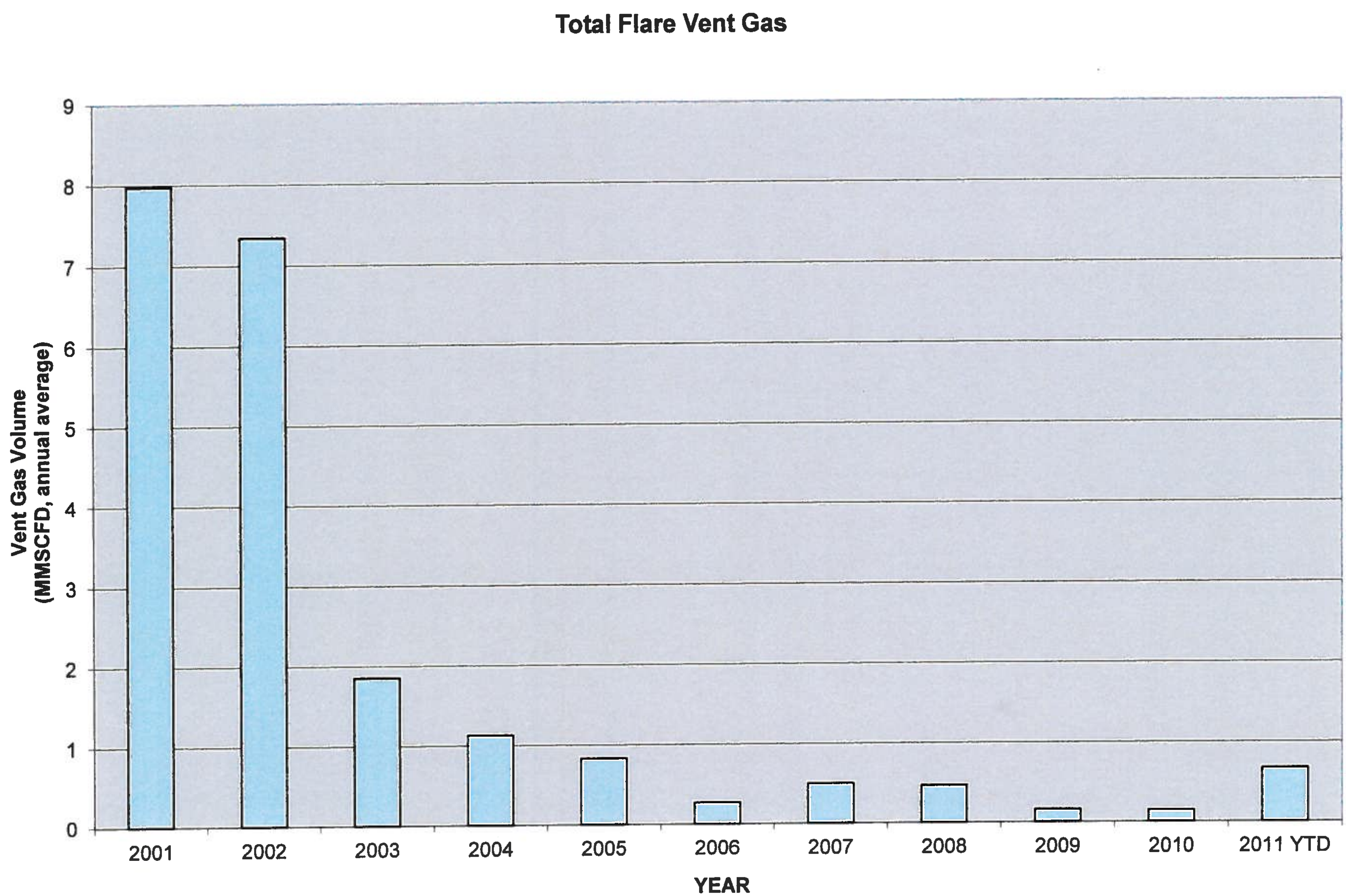
Small Flare Events
Action List

Public Version
Confidential Information Redacted

Attachment 17

Executive Summary Graphs

Tesoro Golden Eagle Refinery
Flare Minimization Plan - 2011 Update



Tesoro Golden Eagle Refinery
Flare Minimization Plan - 2011 Update

TOTAL FLARE EMISSIONS