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

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):

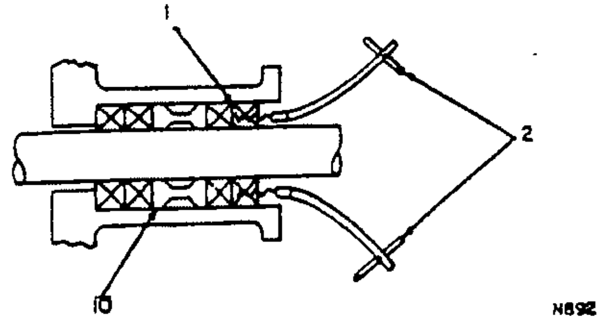
The following is a list of some greases that exhibit the desired characteristics required by Nash.

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

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

SO2 Cost/Benefit Analysis for Flare Mininimization

Year	SO2 (tons/year)
2012	48
2013	62
2014	370
2015	69
2016 YTD	22
Average for 2012 - 2015 (Baseline Emissions)	137
Control Option Emissions	27
Reduction in Emissions	110

This number is still conservatively high since there are instances that no matter how much extra flare gas compressor capacity, we would not recover the gases, such as power outages, higher flow events, and loss of 5 Gas Plant compressors or Flare Gas Recovery Compressors.

Assumes 80% reduction due to above instances

	In $millions	
	2006	2016
Compressor Cost Two 5.5 MMSCFD Comp	15	
Amine Treater Cost	7	
Piping	4.4	
Total Capital Cost	26.4	30.9936
2006 to 2016 Inflation (%)	17.4	

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		10	years
CRF =		0.1359	
Utilities	$/Year	363,940.00	

Annual Costs = Direct Costs + Indirect Costs

Direct Costs	$/Year	
Labor	619872	2% of capital cost
Replacement Parts	619872	2% of capital cost
Utilities	363940	(400 bhp for flare compressor, 0.85 efficiency at design, 8760 operating hours per year)
	$ 1,603,684	

Indirect Costs	
Overhead at 80% of Labor Costs	495898
Property Tax at 1% of Total Capital	309936
Insurance at 1% of Total Capital	309936
General & Admin at 2% of Total Cap	619872
Capital Recovery at CRF x Total Cap	4211037
	$ 5,946,679

Annualized Cost of Abatement System $ 7,550,363

Cost Effectiveness for SO2 = $ 68,715 per ton

based on annualized emissions and annualized cost

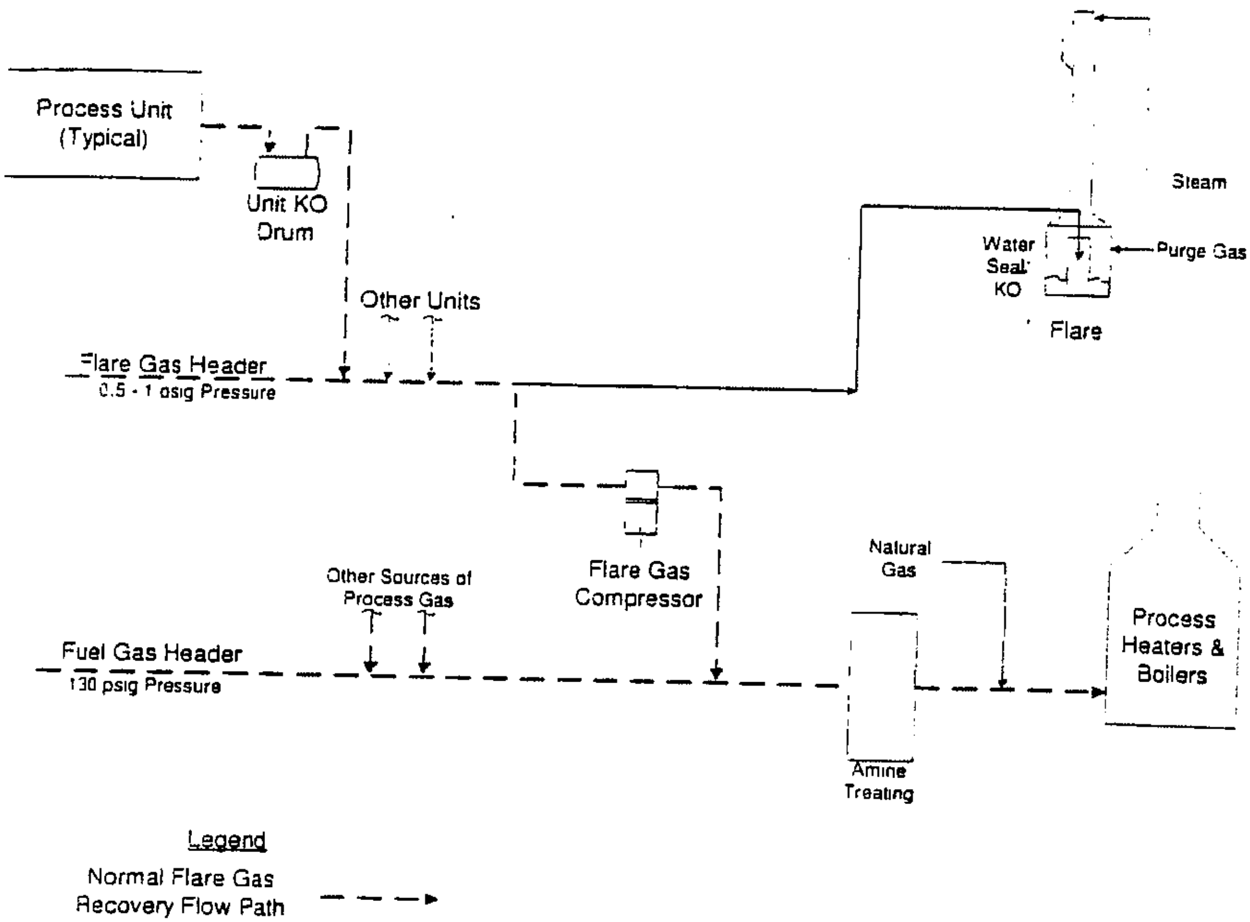
Cost Effectiveness hurdle for BACT analysis is $18,200 / ton SO2

Attorney Client Privileged Communication

Attachment 10

Typical Flare Gas Recovery System Diagram

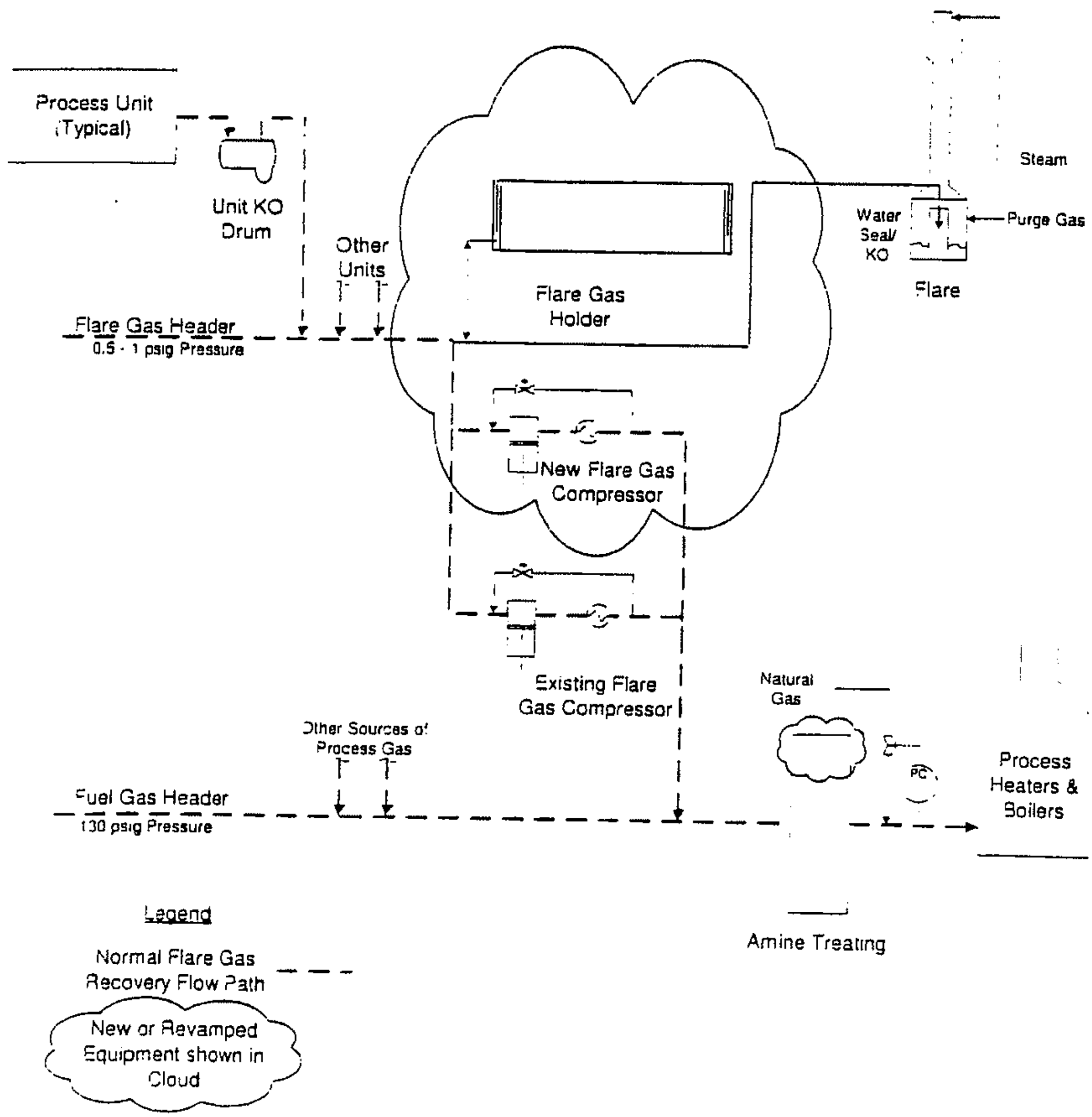
Typical Flare Gas Recovery System



Attachment 11

Flare Gas Recovery with Gas Holder Diagram

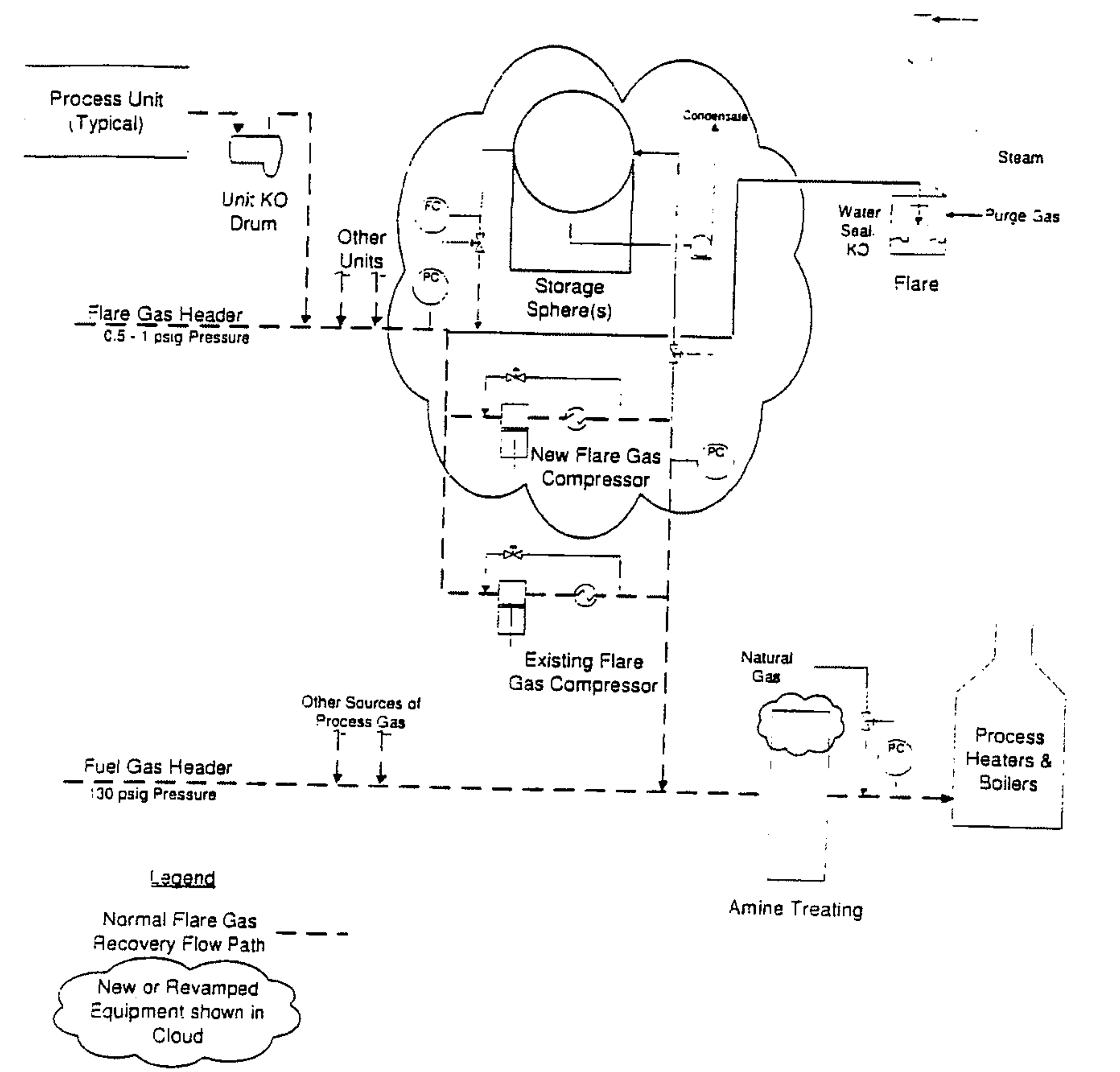
Flare Gas Recovery With Gas Holder



Attachment 12

Flare Gas Recovery with Gas Storage Diagram

Flare Gas Recovery With Storage Sphere



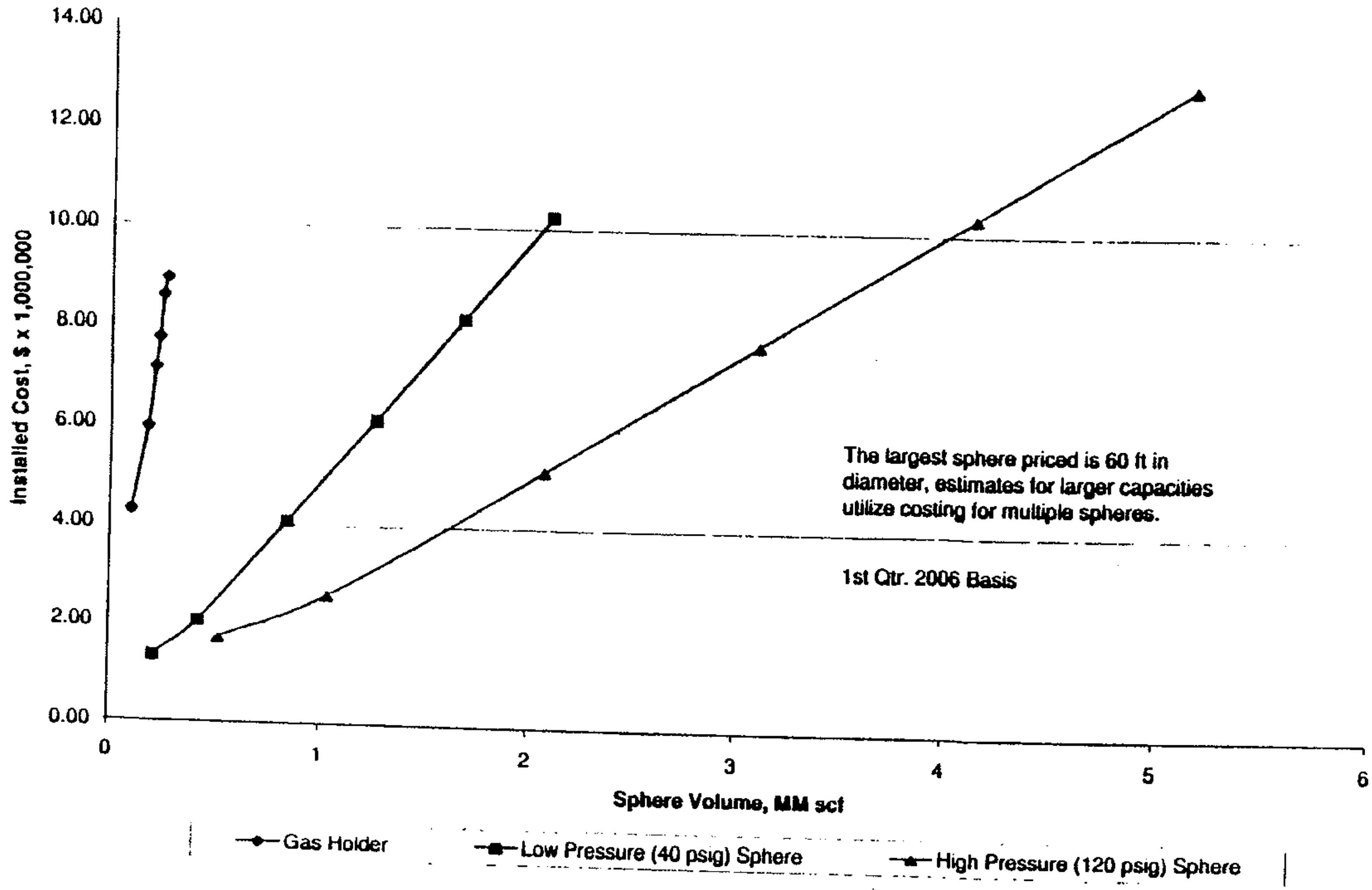
Attorney-Client Privileged Communication - Confidential

May 30 2006

Attachment 13

Vessel Cost Curve

Flare Gas Storage Options

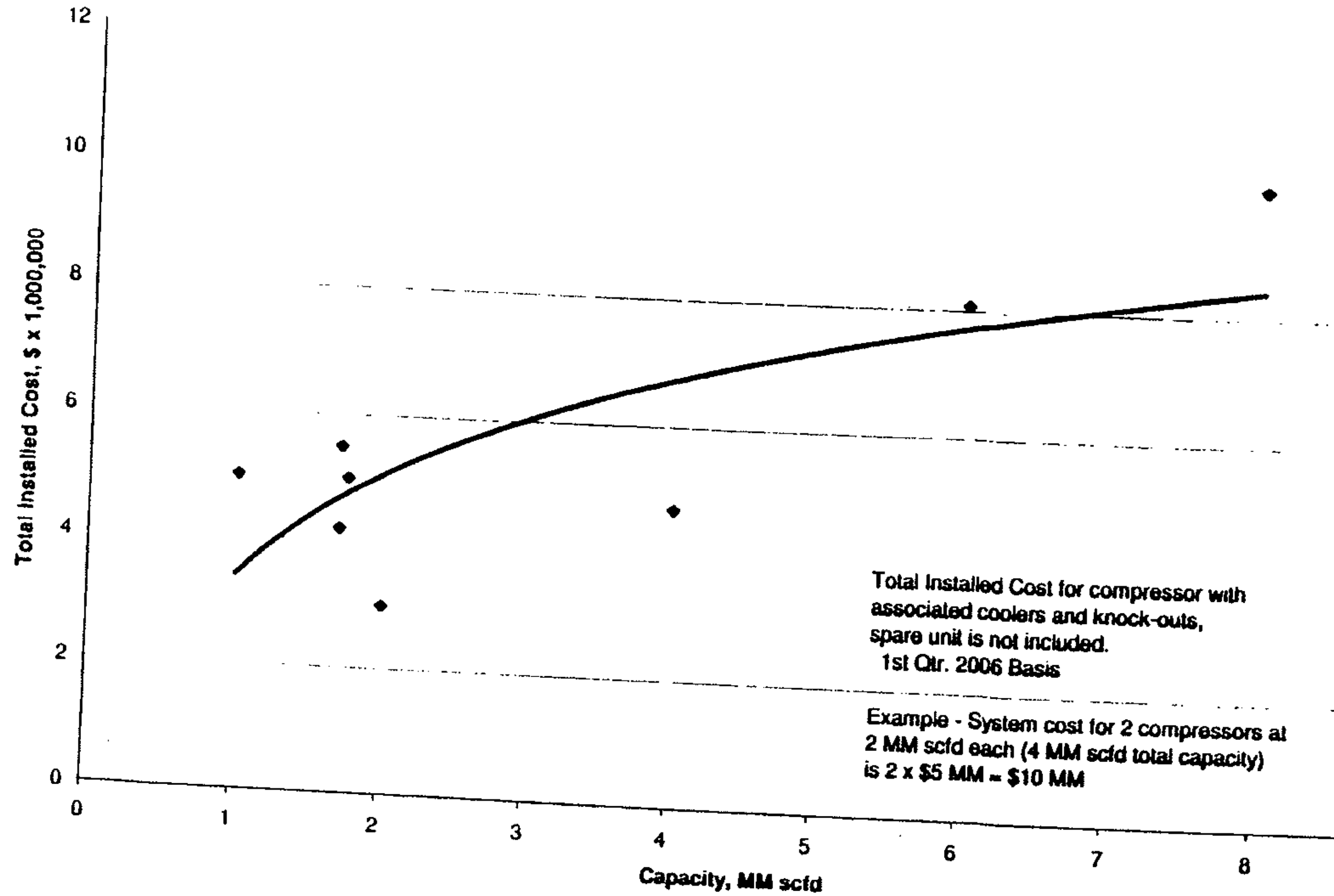


Confidential Attorney-Client Priviliged Work Document

Attachment 14

Compressor Cost Curve

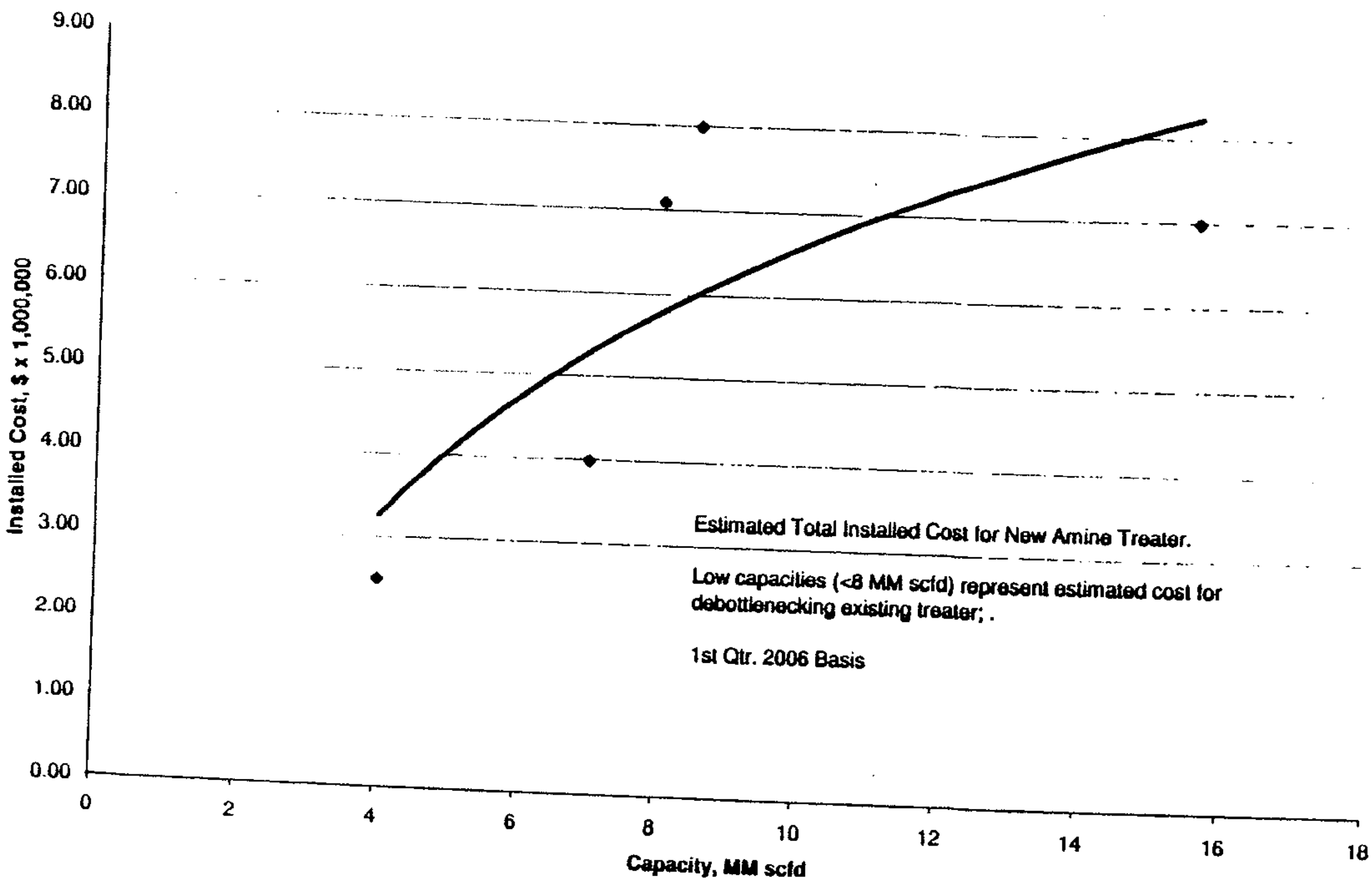
Flare Gas Compressor System Costs



Attachment 15

Gas Treatment Cost Curve

Fuel Gas Amine Treater Costs



Attachment 16

Small Flare Events
Action List

Public Version
Confidential Information Redacted

Attachment 17

Executive Summary Graphs

Tesoro Martinez Refinery
Flare Minimization Plan - 2016 Update

Total Flare Vent Gas