Routing Centrifugal Compressor Seal Oil De-gassing Emissions to Fuel Gas as an Alternative to Installing Dry Seals

Global Methane Initiative All-Partnership Meeting

Oil and Gas Subcommittee – Technical and Policy Sessions

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Agenda

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- Centrifugal Compressor Wet Seals
- Retrofitting/Installing Dry Seals
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Natural Gas STAR Program Background

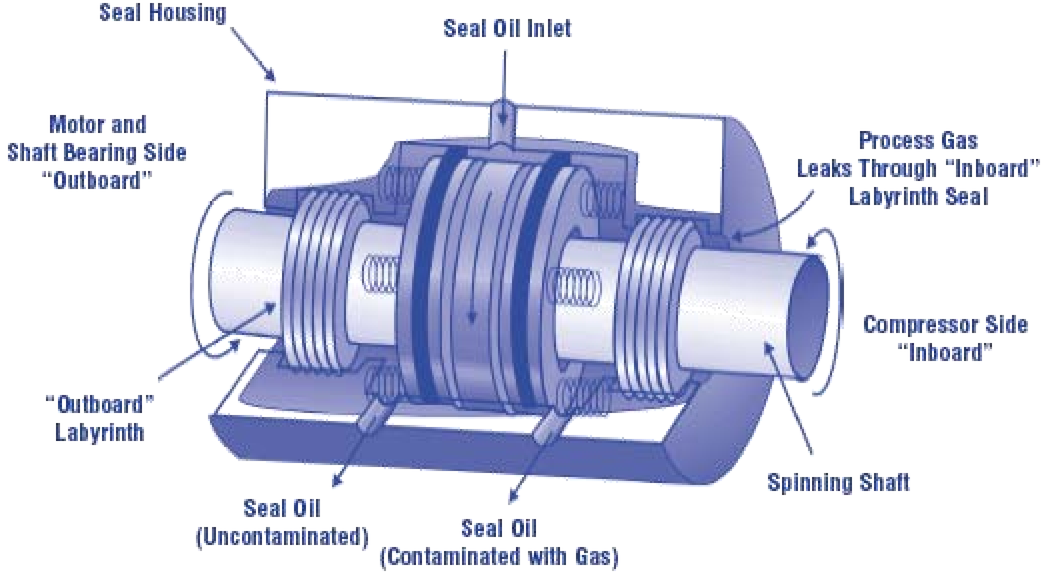
- The Natural Gas STAR Program is a *flexible*, *voluntary* partnership with oil and natural gas companies—both in the United States and internationally to promote *cost-effective* technologies and practices that reduce emissions of methane.
- The main goal of Natural Gas STAR is to work with Partner companies to develop technical information and then facilitate the implementation of mitigation practices across the industry.
- As both a potent greenhouse gas and clean energy source, reducing methane emissions has both environmental and economic benefits.
- BP has been an active Partner since 1995, contributing to the Natural Gas STAR Program's technical information and technology transfer efforts.

Centrifugal Compressor Wet Seals

- High pressure seal oil circulates between rings around the compressor shaft
- Oil absorbs the gas on the inboard side
  - Little gas leaks through the oil seal
  - Seal oil degassing vents methane to the atmosphere

- Wet seals leak little gas at the seal face
- Most emissions are from seal oil degassing
- Seal oil degassing may vent 1.1 to 5.7 m^3/minute
- One Natural Gas STAR Partner reported emissions as high as 2,124 m^3/day

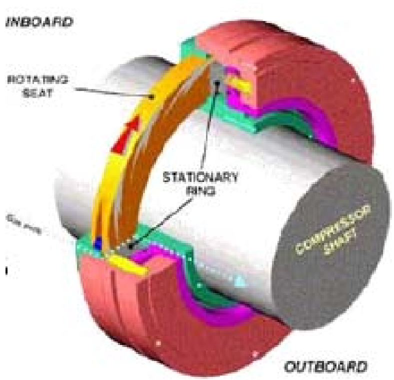
Source: PEMEX



Traditional Solution: Retrofitting/Installing Dry Seals

- Dry seals:
  - 0.8 to 5.1 m^3/hour (0.01 to 0.08 m^3/ minute) leak rate
  - Significantly less than the 1.1 to 5.7 m^3/minute emissions from wet seals
- Very cost-effective option for new compressors
- Significant capital costs and downtime for retrofitting compressors
  - See *Lessons Learned* for more info
- Alternative exists for more cost-effective seal oil degassing and vapor recovery retrofit with less downtime

Dry seals keep gas from escaping while rotating with the shaft



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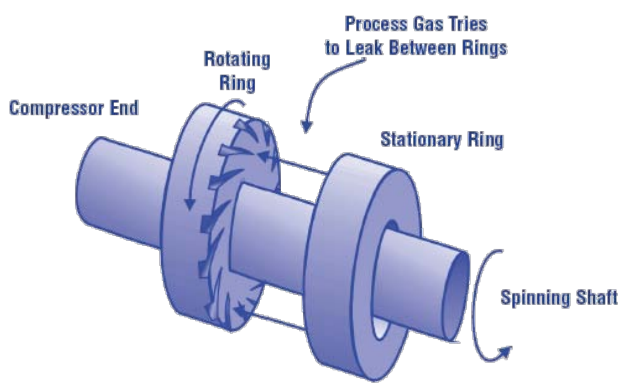
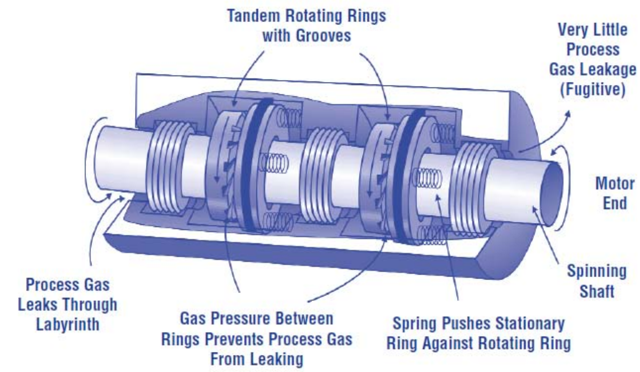


Tandem dry seals



Background of North Slope Study

- Natural Gas STAR learned of anecdotal information on this potential mitigation opportunity a few years back
  - Developed a theoretical example and presented to Natural Gas STAR Partners at workshops and in the Spring 2009 Newsletter
- In taking measurements, BP discovered their wet seal recovery system on centrifugal compressors at its North Slope facilities
  - BP's initial results showed recovery of >99% of seal oil gas that would be otherwise vented to atmosphere from degassing tank
- Led to BP and Natural Gas STAR collaboration on detailed measurement study of alternative wet seal capture mitigation opportunity
  - Recovery system that separates gas from the sour seal oil before being sent to the degassing tank
  - Recovered gas sent to various outlets: flare, low pressure fuel, turbine fuel ~273 psig (18.6 Bar), compressor suction
  - System leads to lower emissions from degassing tank vent (more details on following slide)

Summary of North Slope Study

Purpose:

Evaluate methane emissions capture from sour seal oil vapor recovery systems on centrifugal compressors at the North Slope. Systems show evidence of reducing wet seal degassing emissions.

Goals:

A detailed evaluation and review of all sour seal oil recovery systems on the North Slope with:

- Real-time measurement data from one facility (CCP)
- Engineering calculations from CGF and other facilities as applicable

Comprehensive characterization of wet seal degassing recovery system including process/operating requirements, applicability, limitations, emission reduction potential, costs, and economics.

The Team:

- Natural Gas STAR
- BP local and global staff
- North Slope facility operators
- North Slope emissions measurement specialists

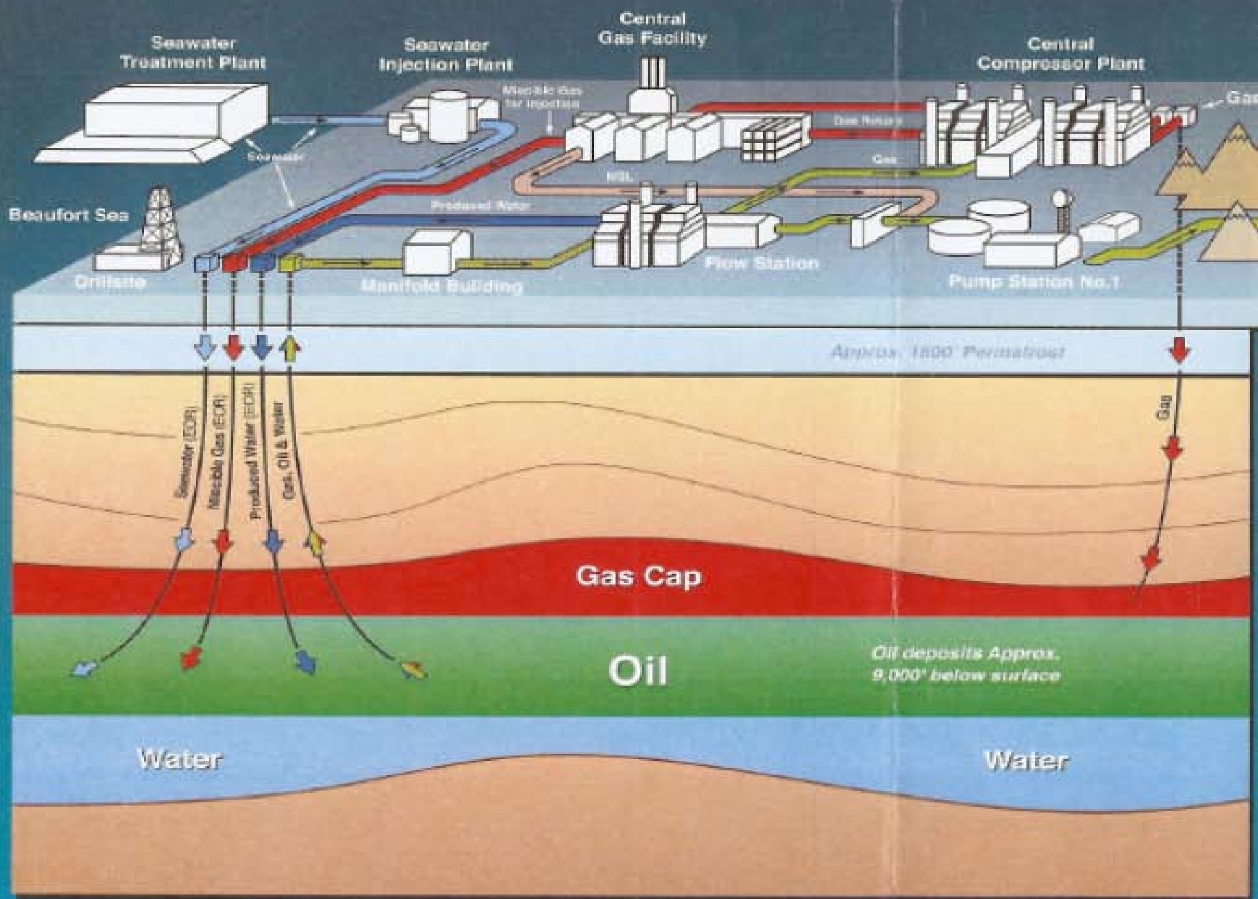
The Tools:

- In-depth understanding of compressor wet seal recovery system design and layout
- FLIR IR camera
- Vent anemometer
- P&IDs and operational data
- Complete readouts of compressor operating conditions and key parameters

This presentation is focusing on preliminary results from Central Compressor Plant (CCP) only; final results will be available at a later date.

Overview of North Slope Operations

Prudhoe Bay

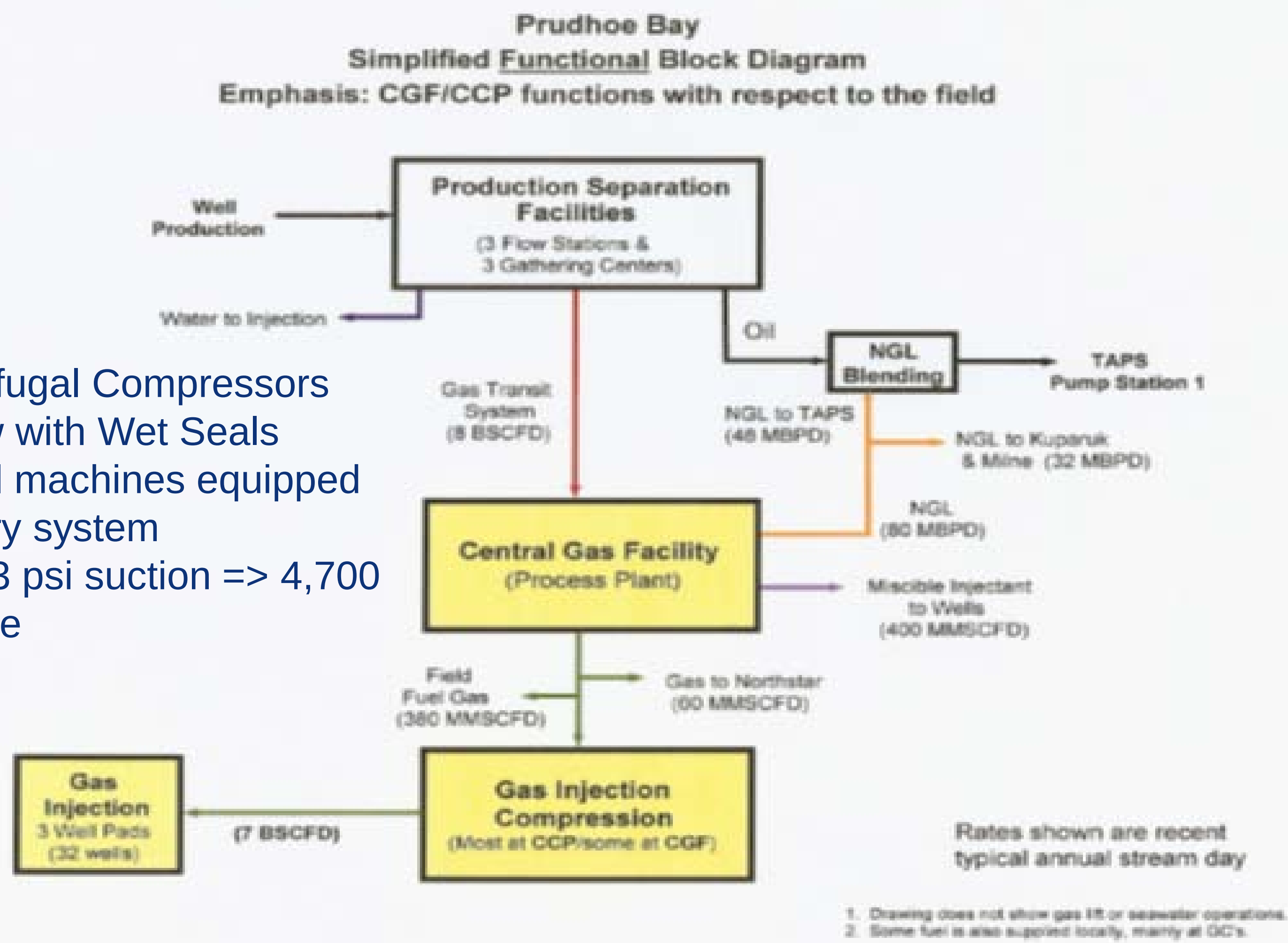


How we get the oil from the ground to the Trans-Alaska pipeline.

Crude oil at Prudhoe Bay is located in the Sadlerochit zone, a sandstone formation at approximately 9,000 feet below the earth's surface. Pressure from the formation, pushes the crude up a well to the surface where a wellhead controls the flow of crude. Wellheads are located on gravel drillsites and are covered by a well house for worker and equipment protection against the harsh arctic environment. From here the crude flows through the manifold building, also located on the drill site, where oil/gas/water ratio is determined. Crude then travels to a processing center and is separated into oil, gas and water. Natural gas is sent to the gas handling facilities for reinjection back into the field. Produced water is sent back to the drillsites and reinjected into the formation to help in the oil recovery. Oil continues its journey to Alyeska's Pump Station 1 to begin its 800 mile trip to Valdez.

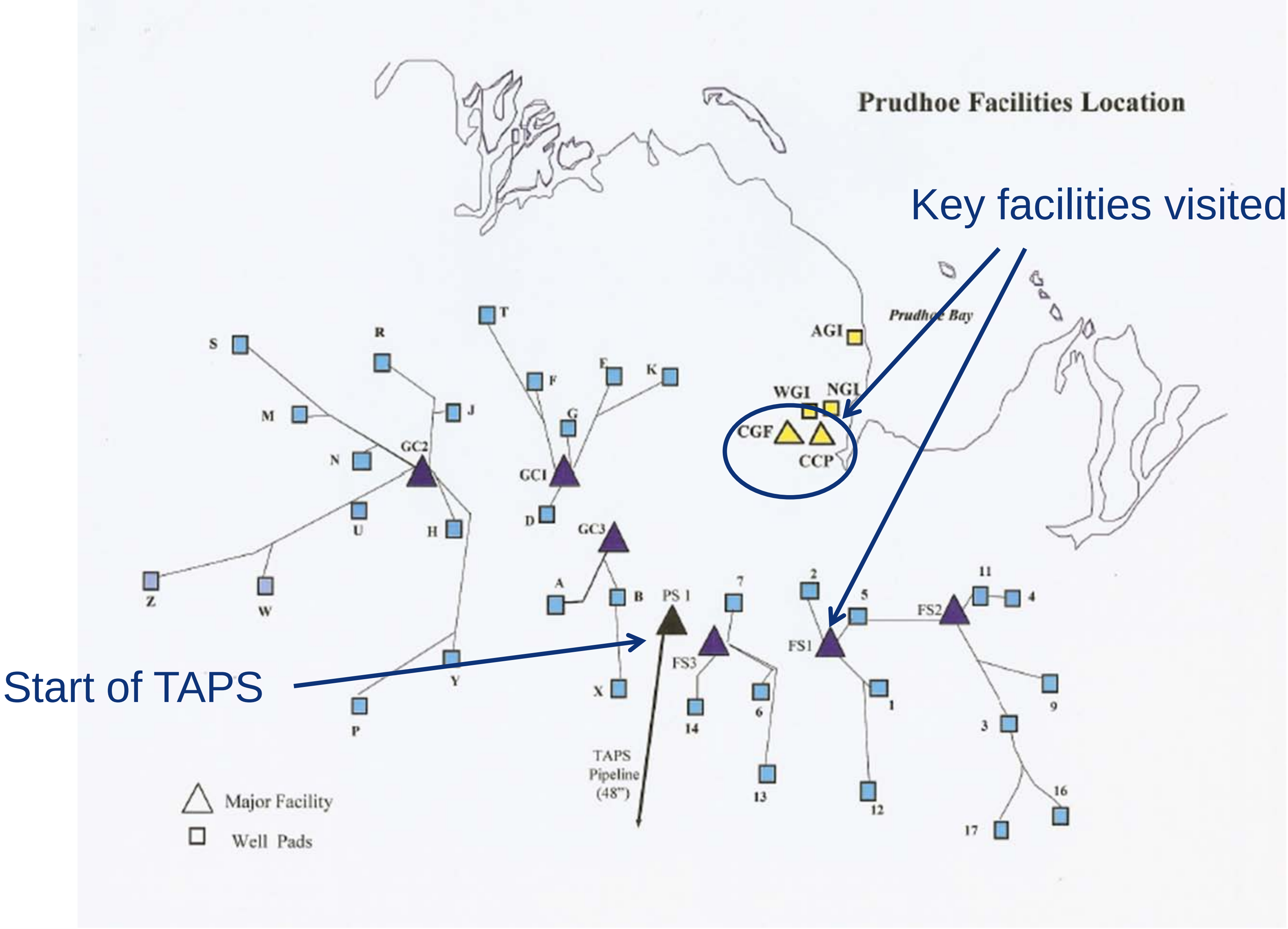
Overview of North Slope Operations

~100 Centrifugal Compressors
All but a few with Wet Seals
All Wet Seal machines equipped with recovery system
Pressures: 3 psi suction => 4,700 psi discharge



Prudhoe Bay process flow and volumes

Overview of North Slope Operations



Central Gas Facility (CGF)

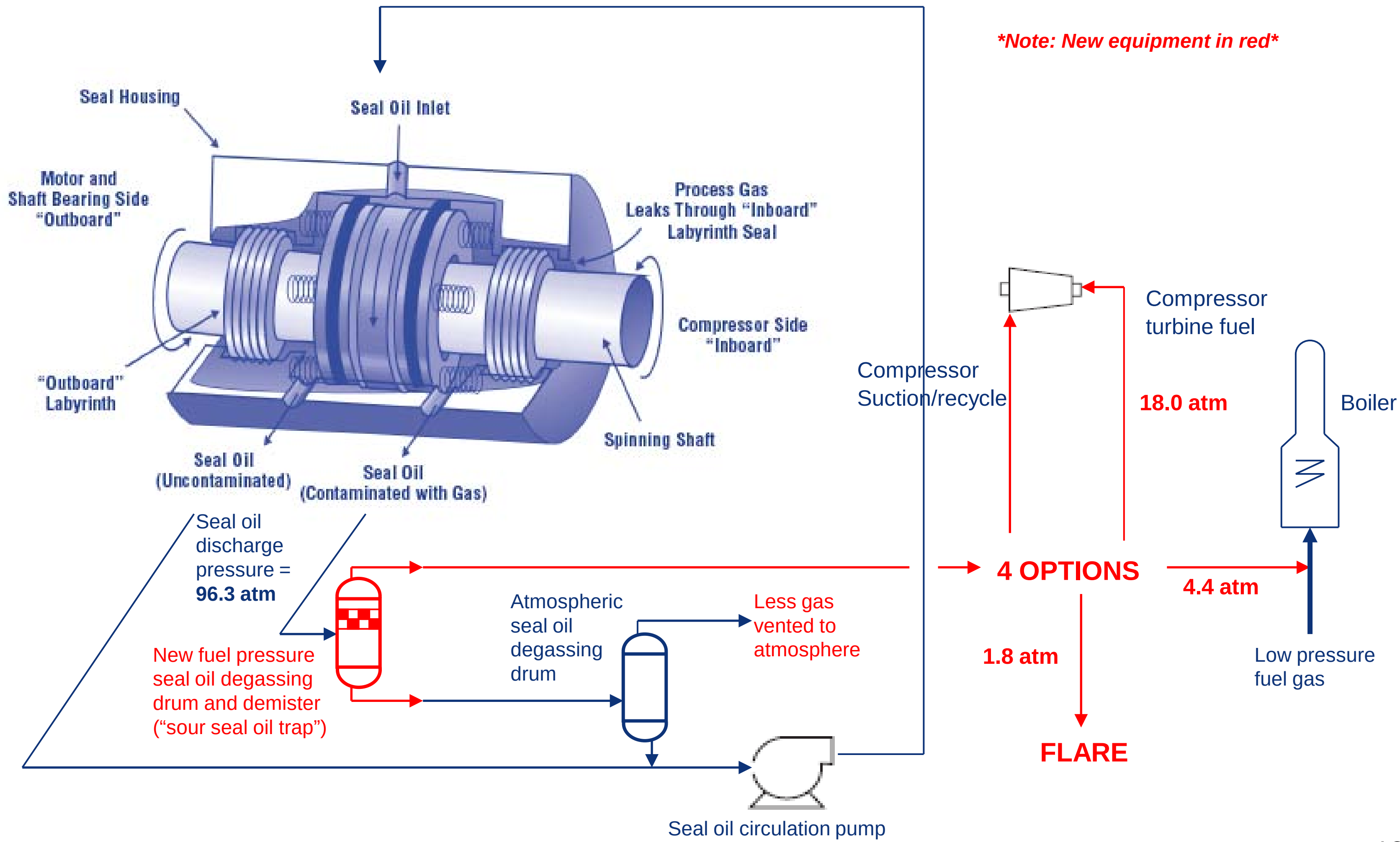
- World's largest gas processing plant (max feed of 246 MMcm/day)
- Processes all gas from Prudhoe Bay gathering & boosting stations (except local fuel)
- Products:
  - Residue gas
  - Natural gas liquids (blended with oil and delivered to TAPS)
  - Miscible injectant (used for EOR purposes)
- 11 compressors (totaling over 500,000 HP)
  - Three boosters
  - Two refrigerant
  - Two MI
  - Four tandems
- Seal oil vapor recovery lines sent to flare

Central Compressor Plant (CCP)

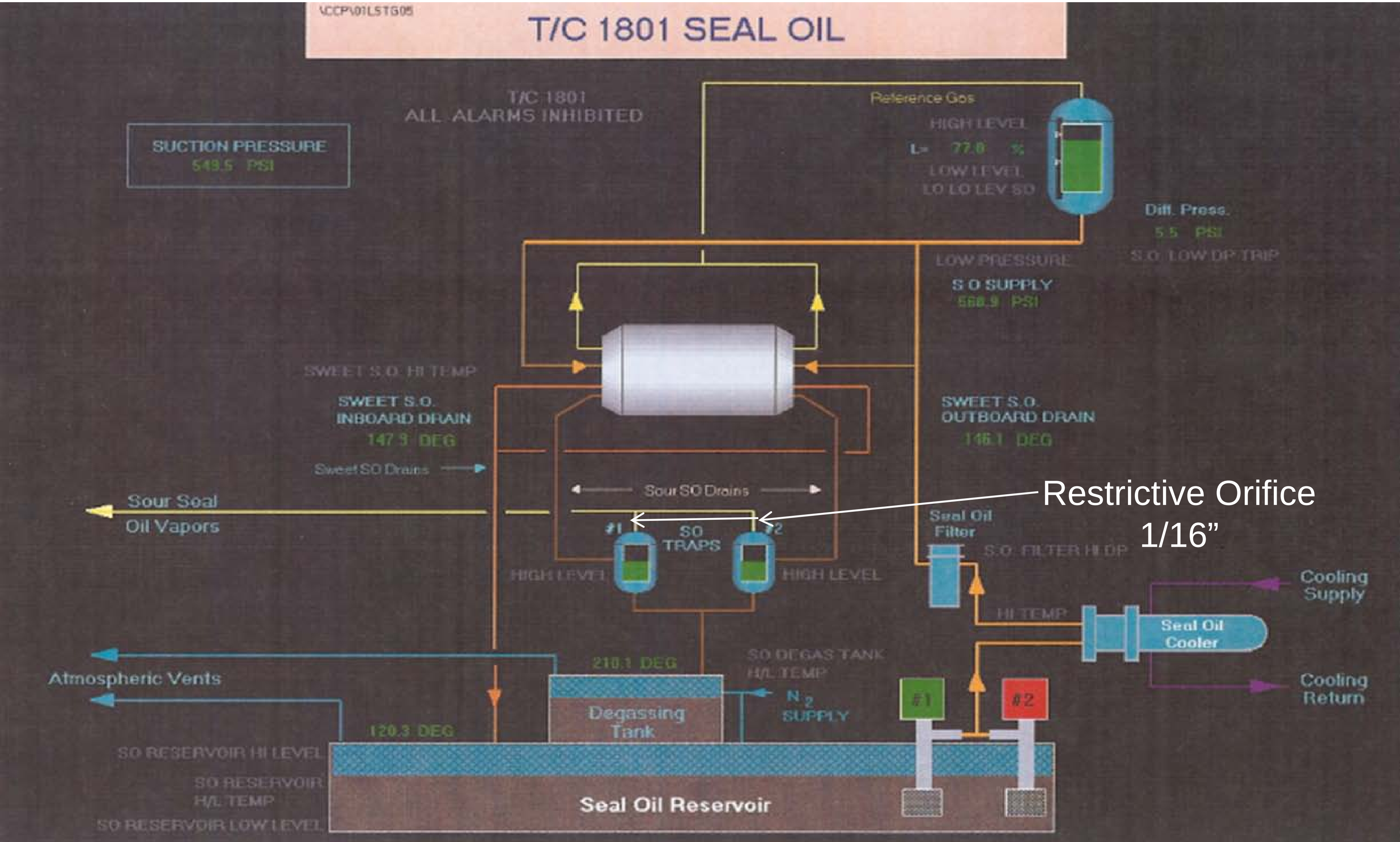
- World's largest compressor station (~238 MMcm/day capacity)
- Receives residue gas from CGF, compresses to higher pressures, and sends to gas injection wellpads (~200 MMcm/day at 3,600 to 4,000 psig)
- 15 compressors (totaling 537,000 HP)
  - Nine low pressure (1st stage) compressors in parallel
  - Four high pressure (2nd stage) compressors in parallel
  - Two tandem compressors (1st and 2nd stages) in parallel
- Seal oil vapor recovery lines sent to flare or fuel gas (for compressor turbines, heaters, and blanket gas)

Sour Seal Oil Vapor Recovery System

Note: New equipment in red



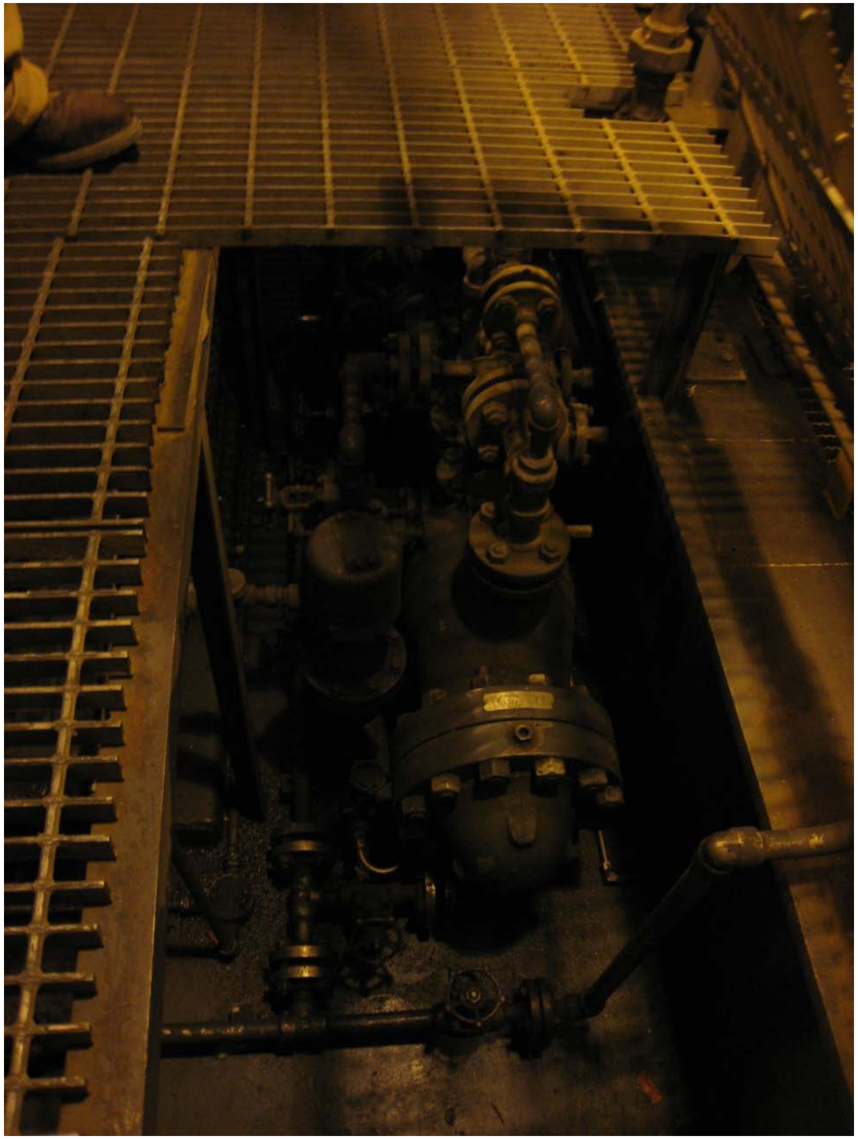
Sour Seal Oil Vapor Recovery System: CCP



Seal Oil Degassing Separators

Seal Oil
Degassing
Pots

Seal Oil Degassing Separators

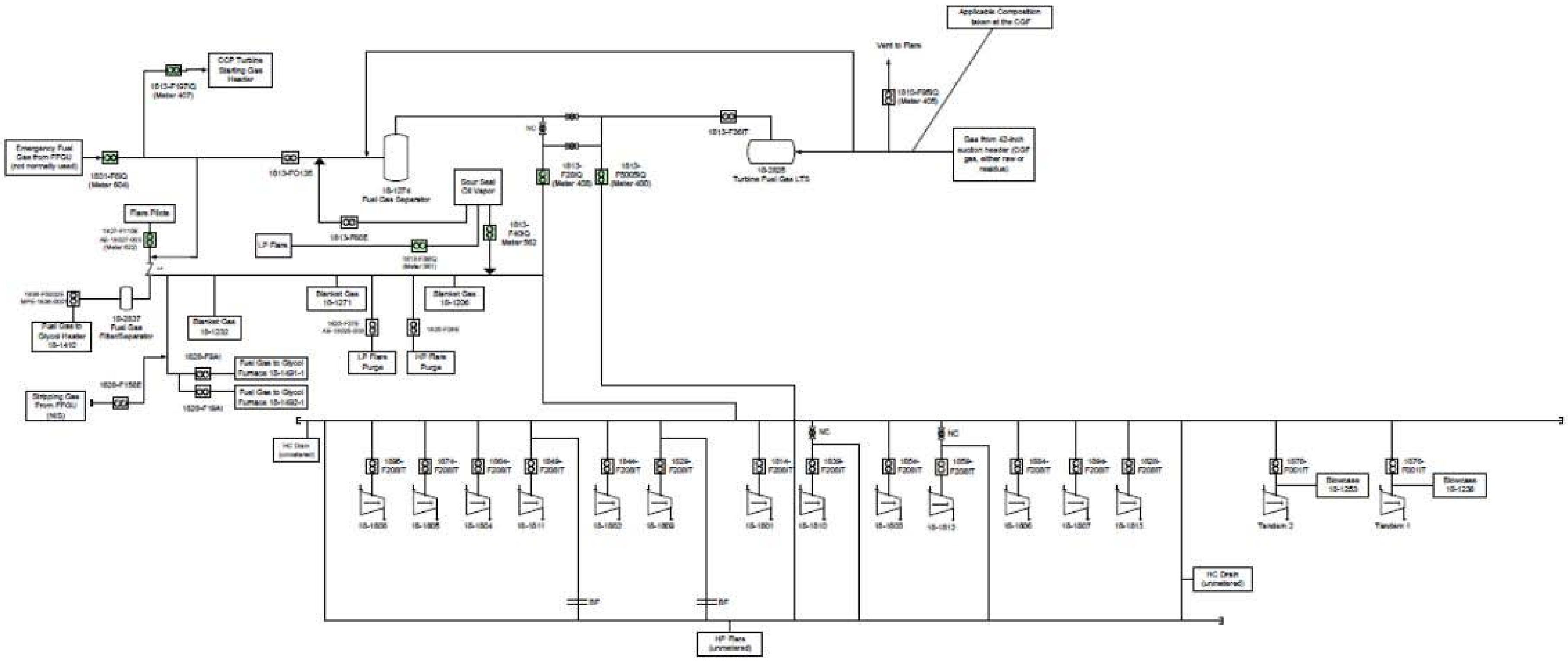


Seal Oil Degassing Separator/System

Seal Oil Degassing Separators

CCP Fuel Gas Layout

CCP Fuel Gas Schematic



Early Results: BP Measurements of CCP

- Table shows initial measurements taken by BP from a low- and high-pressure compressor at CCP before study
- Used nitrogen as "tracer gas" to calculate methane and total hydrocarbon flow-rates
- Recovered Gas: 0.92 MMSCFD LP; 3.7 MMSCFD HP Turbine Fuel

	High-Pressure Compressor	Low-Pressure Compressor
Nitrogen Purge Rate (SCF/Hr)	33	25
Vent Analysis (mole%)		
Nitrogen	43.846	86.734
Methane	37.872	6.93
Total Hydrocarbon + CO2	56.1540	13.2660
Total Methane Flow (SCFM)	0.4751	0.0333
Total Process Gas Flow (SCFM)	0.7044	0.0637
Number of Seals	2	2
Total Methane Flow (SCFM/Seal)	0.2375	0.0166
Total Process Gas Flow (SCFM/Seal)	0.3522	0.0319
"Average" Total Gas/Seal (SCFM)	108	108
Control Percentage	0.997	1.000

Preliminary Results: Velocity Measurements

- Table shows vane anemometer measurements taken prior to and during the study
- Full results of study are not yet final, but initial results from CCP measurements show generally consistent with BP's results from before the study

Facility	Compressor Tag	Compressor description		# of Seals per Tank	Vent size in	1 Min Mean m/s	1 Min Mean m/s	1 Min Mean m/s	Vent Area ft2	fpm	scf/min	N2 Purge scf/min
CCP Velocity Readings - During Study												
CCP	K-18-1801	1st Stage Injection comp	Degassing Tank Vent	2	2	0.36	0.38	0.28	0.022	66.9	1.5	
			Seal Oil Reservoir Vent		4	0.35	0.34	0.37	0.087	69.5	6.1	
CCP	K-18-1809	2nd Stage Injection comp	Degassing Tank Vent	2	2	0.42	0.4	0.2	0.022	66.9	1.5	
			Seal Oil Reservoir Vent		4	0.6	0.57	0.81	0.087	129.9	11.3	
Velocity Readings - Prior to Study												
END	K-E3-1510/20/30A	Main A (1st, 2nd, 3rd stages)	Degassing Tank Vent	6	2	0.86	0.8	0.48	0.022	140.4	3.1	
END	K-E3-1510/20/30A	second vent	Degassing Tank Vent	6	6	0.87	0.52	0.71	0.196	137.8	27.1	
											30.1	
END	K-E3-1510/20/30B	Main B (1st, 2nd, 3rd stages)	Degassing Tank Vent	6	2	3.84	3.5	3.15	0.022	688.1	15.0	
END	K-E3-1510/20/30B	second vent	Degassing Tank Vent	6	6	2.68	2.14	4.67	0.196	622.5	122.3	
											137.3	
END	C-1501/02B	Booster B (1st & 2nd stages)	Degassing Tank Vent	2	2	0.64	0.42	0.67	0.022	113.5	2.5	
END	C-1501/02B	second vent	Degassing Tank Vent	2	2	0.54	0.39	0.46	0.021825	91.2	2.0	
											4.5	
LPC	K-52-1807	Reinjection Compressors	Degassing Tank Vent	2	2	0.82	0.91	0.83	0.022	167.9	3.7	
LPC	K-52-1808	Reinjection Compressors	Degassing Tank Vent		2	1.44	1.73	1.6	0.022	312.9	6.8	
LPC	K-42-1801	STV/IP Compressors	Degassing Tank Vent	2	2	0.82	0.93	1.06	0.022	184.3	4.0	
LPC	K-42-1801	Second vent	Degassing Tank Vent		4	0.96	0.58	0.52	0.087	135.1	11.8	
											15.8	
CCP	K-18-1801	1st Stage Injection comp	Degassing Tank Vent	2	2	0.3	0.33	0.32	0.022	62.3	1.4	
CCP	K-18-1802	1st Stage Injection comp	Degassing Tank Vent	2	2	0.54	0.56	0.45	0.022	101.7	2.2	
CCP	K-18-1803	1st Stage Injection comp	Degassing Tank Vent	2	2	0.45	0.15	0.19	0.022	51.8	1.1	
CCP	K-18-1804	1st Stage Injection comp	Degassing Tank Vent	2	2	0.05	0.17	0.06	0.022	18.4	0.4	
CCP	K-18-1805	1st Stage Injection comp	Degassing Tank Vent	2	2	2.65	2.67	2.52	0.022	514.3	11.2	
CCP	K-18-1806	1st Stage Injection comp	Degassing Tank Vent	2	2	0.38	0.74	0.56	0.022	110.2	2.4	
CCP	K-18-1807	1st Stage Injection comp	Degassing Tank Vent	2	2	0	0.04	0.22	0.022	17.1	0.4	
CCP	K-18-1808	1st Stage Injection comp	Degassing Tank Vent	2	2	0.2	0.09	0.09	0.022	24.9	0.5	
CCP	K-18-1813	1st Stage Injection comp	Degassing Tank Vent	2	2	0.54	0.64	0.65	0.022	120.0	2.6	
CCP	K-18-1809	2nd Stage Injection comp	Degassing Tank Vent	2	2	0.54	0.42	0.29	0.022	82.0	1.8	
CCP	K-18-1810	2nd Stage Injection comp	Degassing Tank Vent	2	2	1.17	0.46	0.34	0.022	129.2	2.8	
CCP	K-18-1811	2nd Stage Injection comp	Degassing Tank Vent	2	2	1.44	1.38	0.59	0.022	223.7	4.9	
CCP	K-18-1812	2nd Stage Injection comp	Degassing Tank Vent	2	2	0.38	0.43	0.4	0.022	79.4	1.7	
CGF	K-19-1802A/B	Booster #2	Degassing Tank Vent	2	3	0.26	0.31	0.93	0.049	98.4	4.8	
CGF	K-19-1802A/B	Second vent	Degassing Tank Vent		3	0.36	0.25	0.82	0.049	93.8	4.6	
											9.4	
CGF	K-19-1805	MI Compressor	Degassing Tank Vent	2	2	0.49	0.4	0.38	0.022	83.3	1.8	
CGF	K-19-1805	Second vent	Degassing Tank Vent		2	9.98	9.55	9.77	0.022	1922.1	42.0	
											43.8	

CCP Compressor Vent Measurement

Close-up

FLIR Camera Verification

Wet Seal.wmv

MOD-4904_GT-1801.avi

MOD-4905_GT-1809.avi

Applicability/Benefits to Oil and Gas Companies

- Based on the results of this study, this sour seal oil vapor recovery system could prove to be an economic alternative to dry seal retrofits on centrifugal compressors
  - Dry seals on new compressors are now more prevalent in industry—typically cheaper than wet seals
  - Dry seal retrofits on older compressors are still very high in cost; ~$250,000 to $1 million per compressor
  - Sour seal oil vapor recovery system on wet seals compressors much lower in capital cost, requires short-duration compressor shutdown or interruption in gas service
- Project characterization could provide companies with a way to both reduce methane emissions and utilize recovered gas <u>cost-effectively</u>

Applicability/Benefits

- Investment includes cost of:
  - Intermediate degassing drum (“sour seal oil trap”)
  - New piping
  - Gas demister/filter
  - Pressure regulator for fuel gas line
- Project summary:
  - Less expensive capital costs compared to dry seals
  - Prevents most seal oil gas emissions from venting to atmosphere while also improving site efficiency
  - Positive cash flow after less than a month

PROJECT SUMMARY: CAPTURE AND USE OF SEAL OIL DEGASSING EMISSIONS			
Operating Requirements	▪Centrifugal compressor with seal oil system ▪Nearby use for low pressure fuel gas ▪New intermediate pressure flash drum, fuel filter, pressure regulator		
Capital & Installation Costs	$22,000[1]		
Annual Labor & Maintenance Costs	Minimal		
Methane saved	1.8 million m^3		
Gas Price per Mcm	$105	**$175**	$250
Value of Gas Saved	$189,000	**$315,000**	$450,000
Payback Period in Months	1.4	**0.8**	0.6

[1]Assuming a typical seal oil flow rate of 14.20 liters/minute (3.75 gallons/minute)

Conclusions and Next Steps

- Preliminary results are promising and indicate that sour seal oil vapor recovery from centrifugal compressors can be a viable project option for companies
- BP and Natural Gas STAR currently analyzing data obtained during study
- BP and Natural Gas STAR will continue to collaborate on this study to fully characterize the seal oil vapor recovery system seen on the North Slope
- Team to publish more detailed results of study in a future article

Contact Information

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