Centrifugal Compressor Wet Seals
Seal Oil De-gassing & Control

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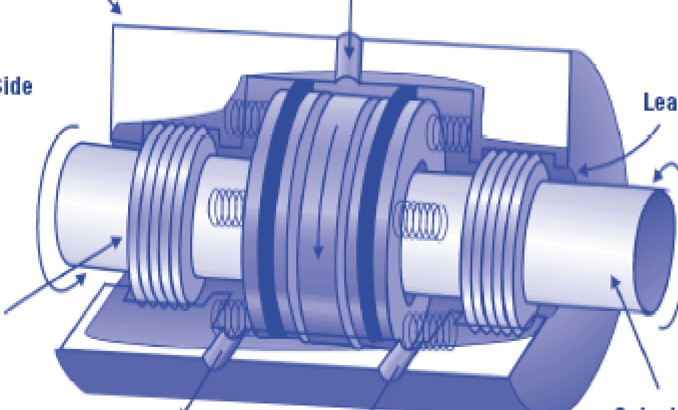
Centrifugal Compressor Wet Seals

- 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

Source: PEMEX

- Wet seals leak little gas at the seal face
- Most emissions are from seal oil degassing
- Seal oil degassing may vent 40 to 200 scf/minute
- One Natural Gas STAR Partner reported emissions as high as 75,000 scf/day



Traditional Solution: Retrofitting/Installing Dry Seals

Dry seals:

- 0.4 to 2.8 scf/min leak rate
- Significantly less than emissions from wet seals

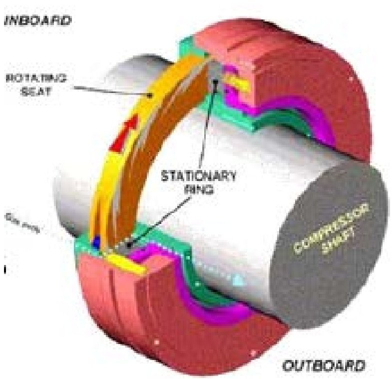
Very cost-effective option for new compressors

Significant capital costs and downtime for retrofitting compressors

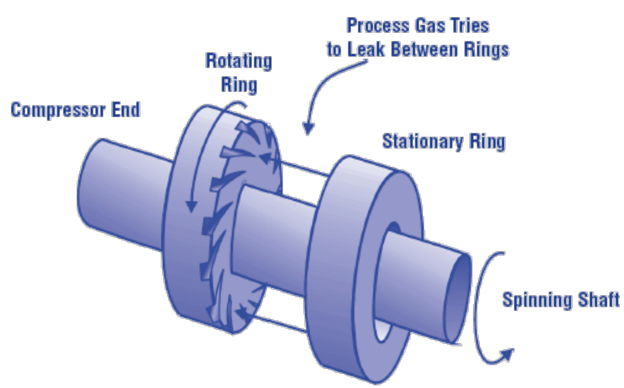
See *Lessons Learned* for more info[1]

Seal-oil degassing and vapor recovery is a more cost effective retrofit with less downtime and roughly equivalent emissions

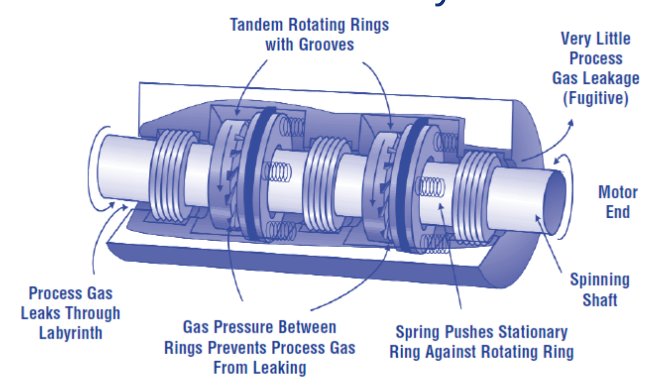
Dry seals keep gas from escaping while rotating with the shaft



Source: PEMEX



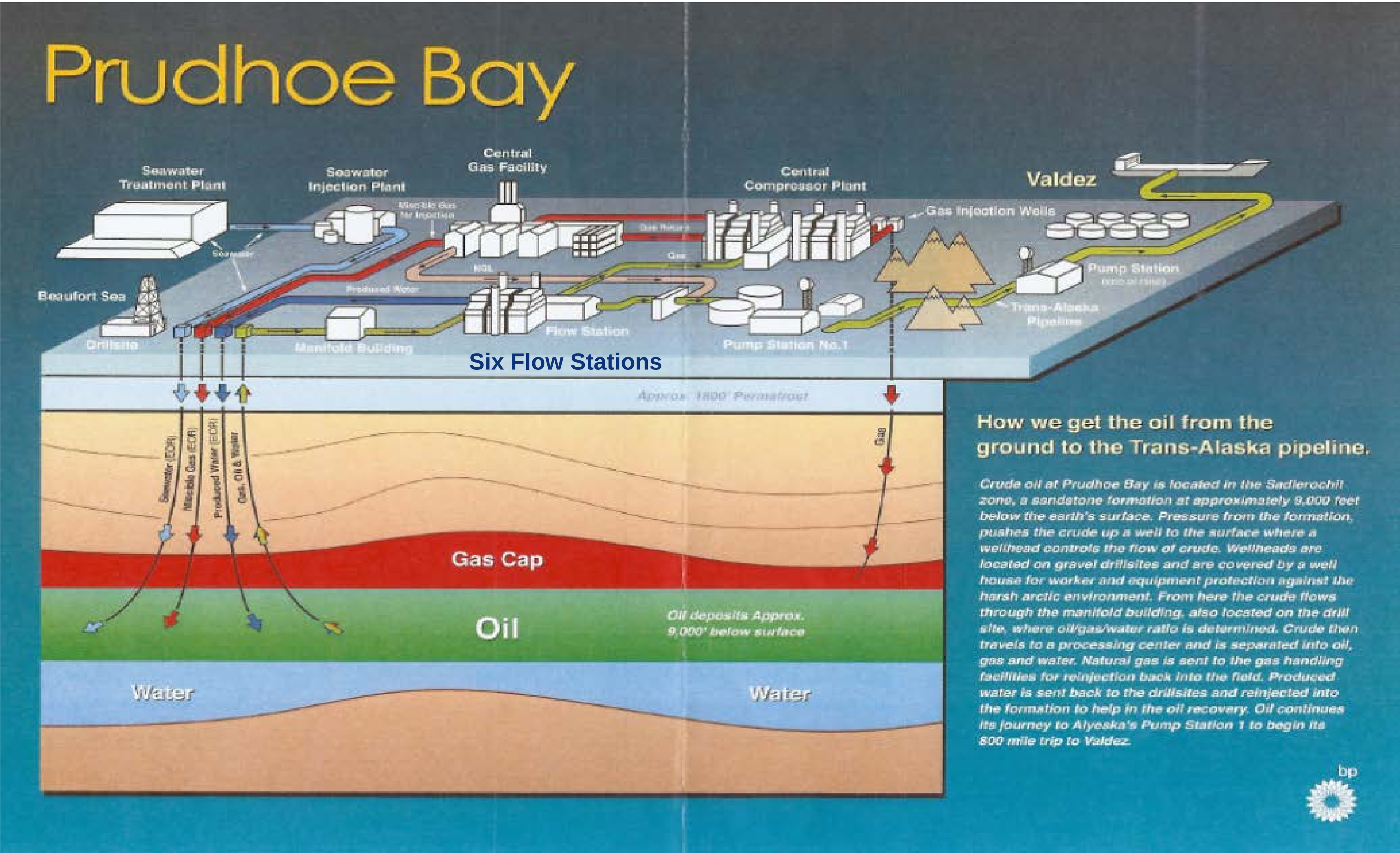
Tandem dry seals



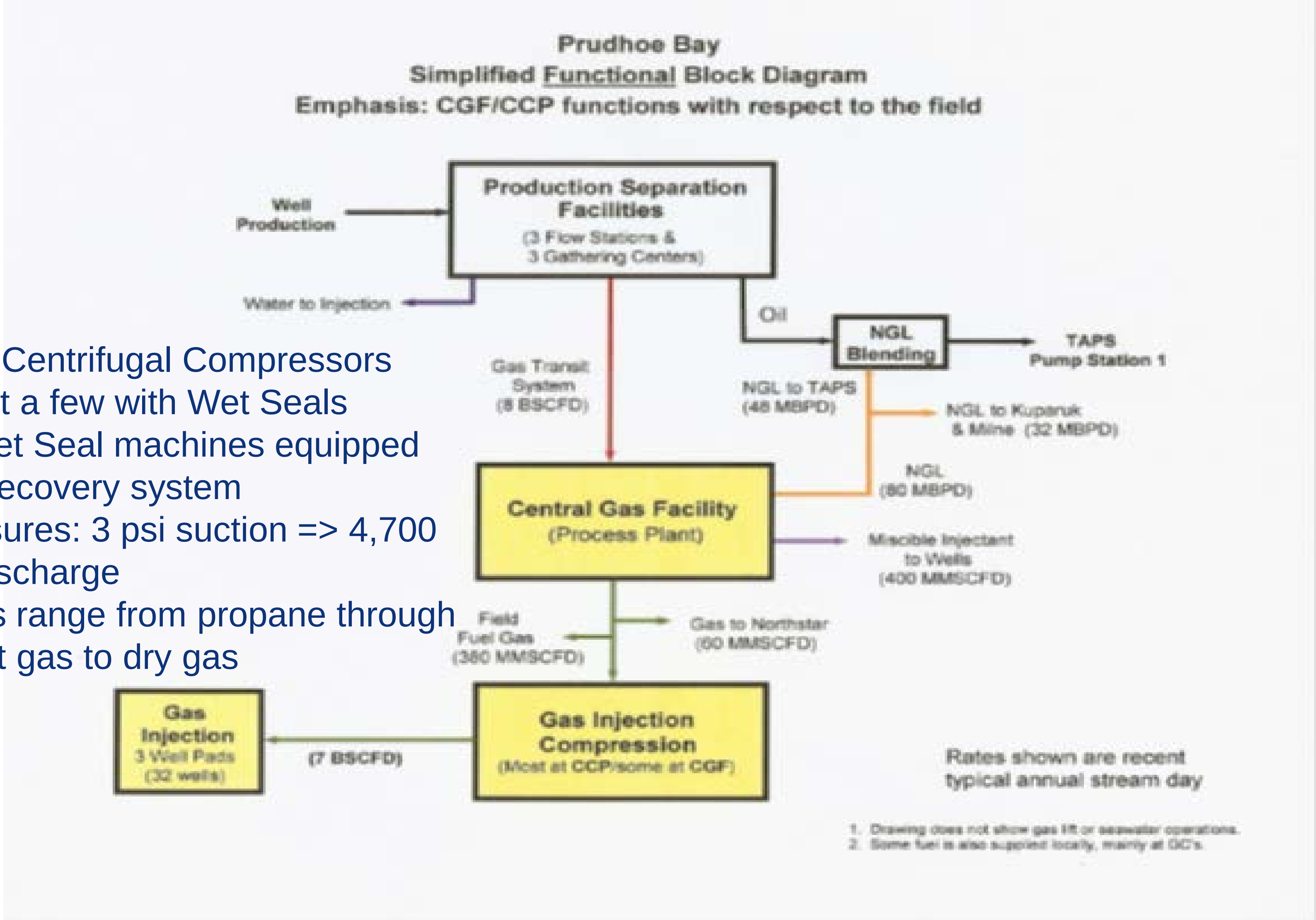
Background of North Slope Study

- 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 identified wet seal gas recovery systems 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 purge, 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 slides)

Overview of North Slope Operations



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
Fluids range from propane through to wet gas to dry gas

Prudhoe Bay process flow and volumes

Central Gas Facility (CGF)

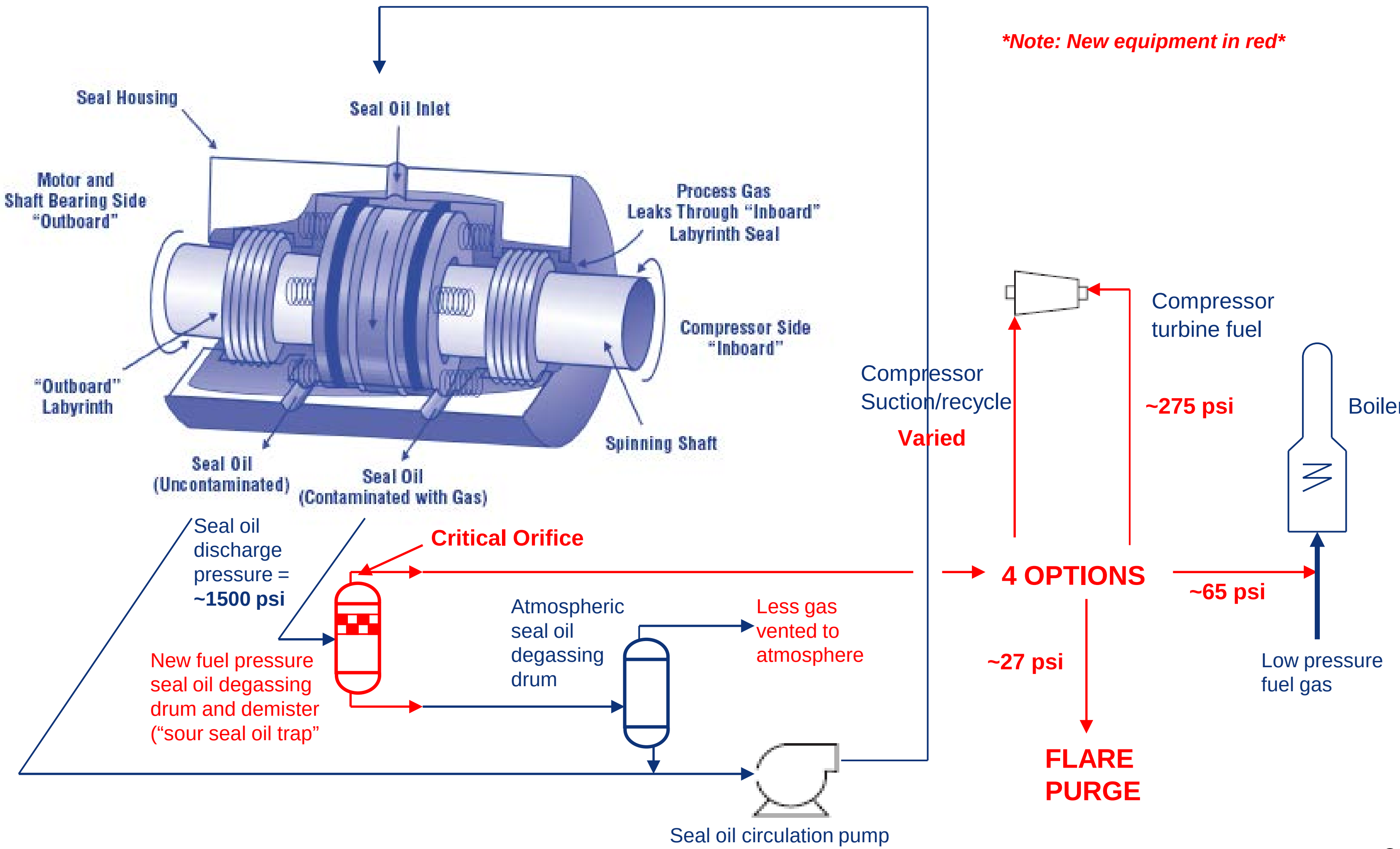
- World's largest gas processing plant (max feed of ~ 8bcf/day)
- Processes all gas from Prudhoe Bay gathering & boosting stations (except local fuel)
- Products:
  - Residue gas
  - Natural gas liquids (blended with oil and delivered to TAPS)
  - Miscible injectant (used for EOR purposes)
- 11 compressors (totaling over 500,000 HP)
  - Three boosters
  - Two refrigerant
  - Two MI
  - Four tandems
- Seal oil vapor recovery lines routed to flare purge

Central Compressor Plant (CCP)

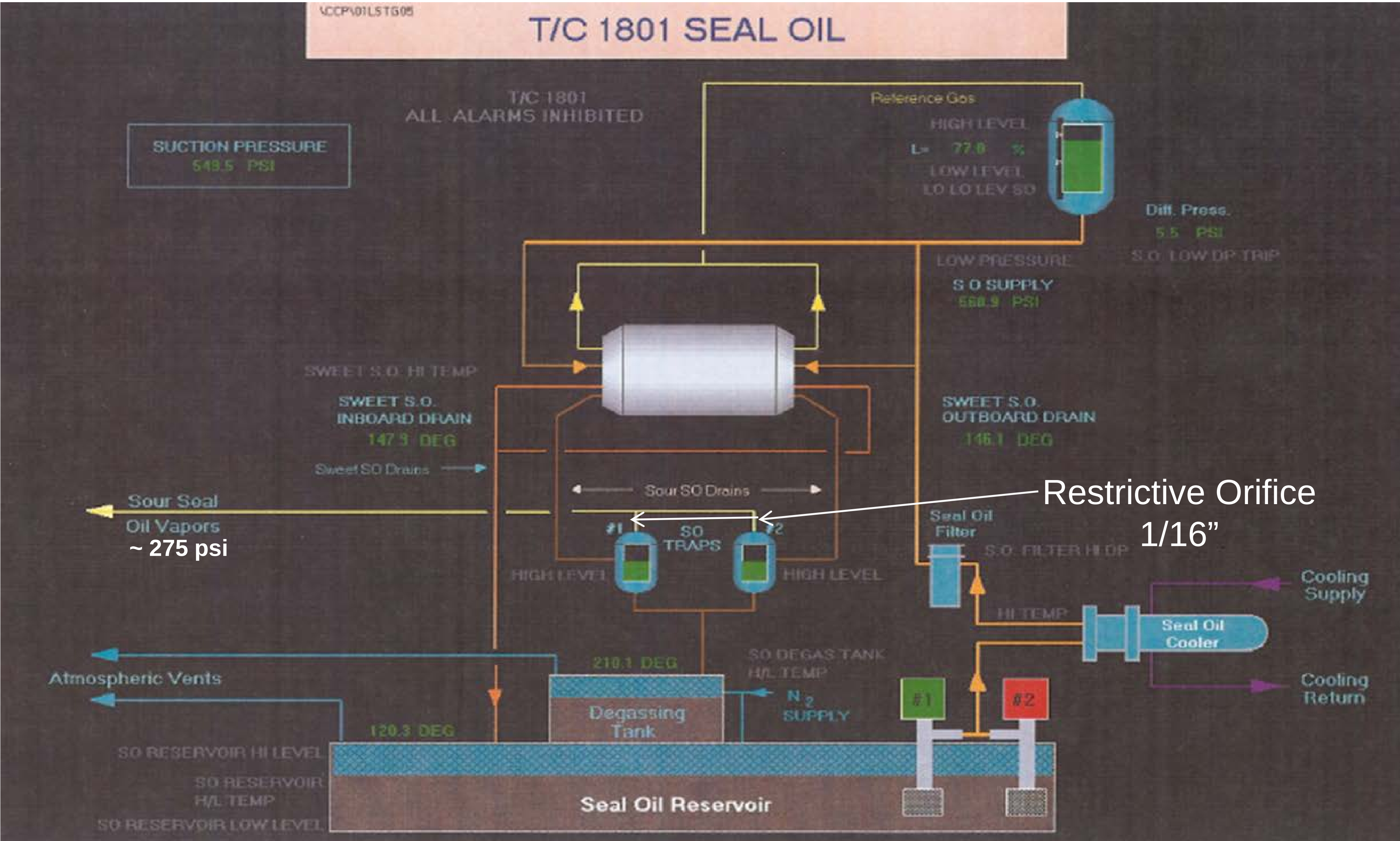
- World's largest compressor station (~8bcf/day capacity)
- Receives residue gas from CGF, compresses to higher pressures, and sends to gas injection well-pads (~7.1 BCF/day at 3,600 to 4,000 psig)
- 15 compressors (totaling 537,000 HP)
  - Nine low pressure (1st stage) compressors in parallel
  - Four high pressure (2nd stage) compressors in parallel
  - Two tandem compressors (1st and 2nd stages) in parallel
- Seal oil vapor recovery lines routed to fuel gas (for compressor turbines, heaters, and blanket gas)

Sour Seal Oil Vapor Recovery System

Note: New equipment in red

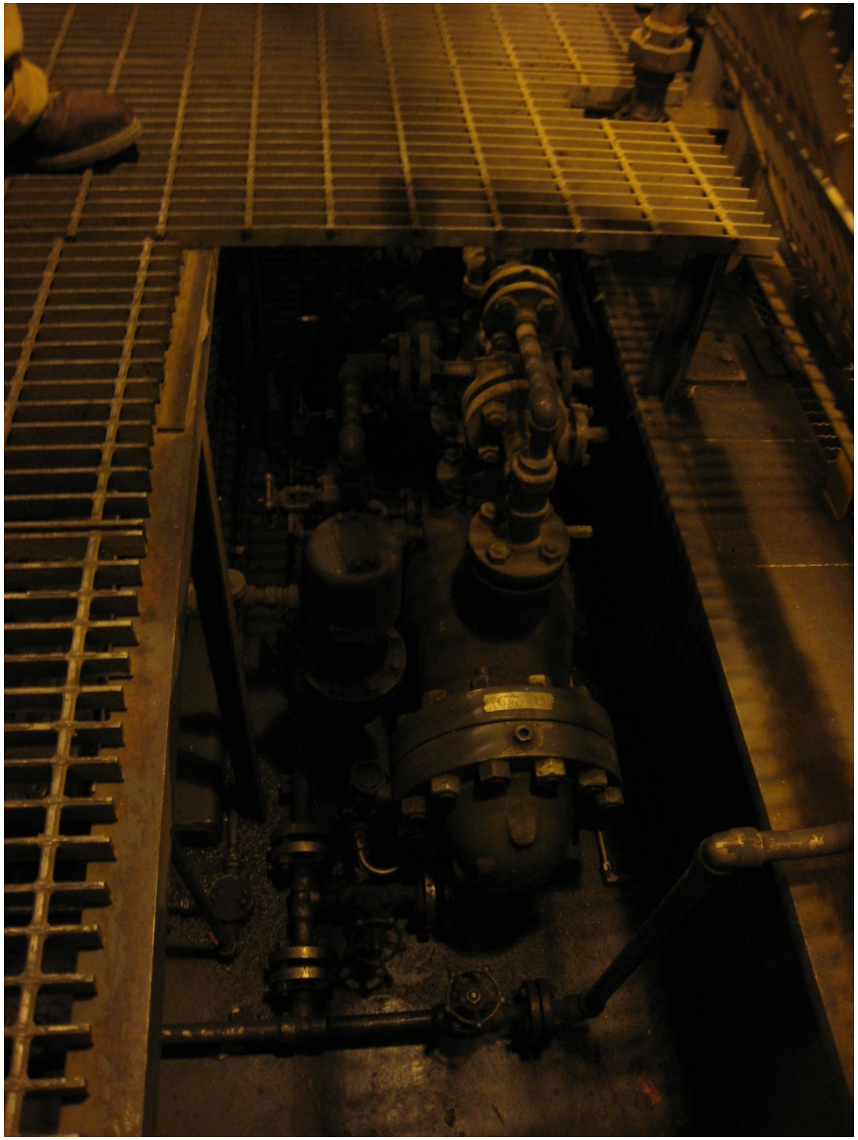


Sour Seal Oil Vapor Recovery System: CCP



Seal Oil Degassing Separators

Seal Oil Degassing Separators



Seal Oil Degassing Separator/System

Seal Oil Degassing Separators

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 from vents
- 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 Vent Flow (SCFM)	0.4751	0.0333
Total Vent Gas Flow (SCFM)	0.7044	0.0637
Number of Seals	2	2
Total Methane Vent Flow (SCFM/Seal)	0.2375	0.0166
Total Vent Gas Flow (SCFM/Seal)	0.3522	0.0319
"Average" Total Gas/Seal (Including Recovered) (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

CCP Velocity Readings - During 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	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

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Applicability & Benefits

- Based on the results, a 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 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
- Recovery projects can 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 seal retrofit
  - 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 fuel gas or recycle ▪New intermediate pressure flash drum, fuel filter, pressure regulator		
Capital & Installation Costs	$22,000[1]		
Annual Labor & Maintenance Costs	Minimal		
Gas saved	~100 MMSCF/Year (2 seals @ 108 scf/min each)		
Gas Price per mscf	$2.5	$3.0	$3.5
Value of Gas Saved	$250,000	$300,000	$350,000
Payback Period in Months	1	<1	<1

[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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