Increasing Profits Using Vapor Recovery and Casinghead Pressure Reduction

Practical Applications

&

Case Studies

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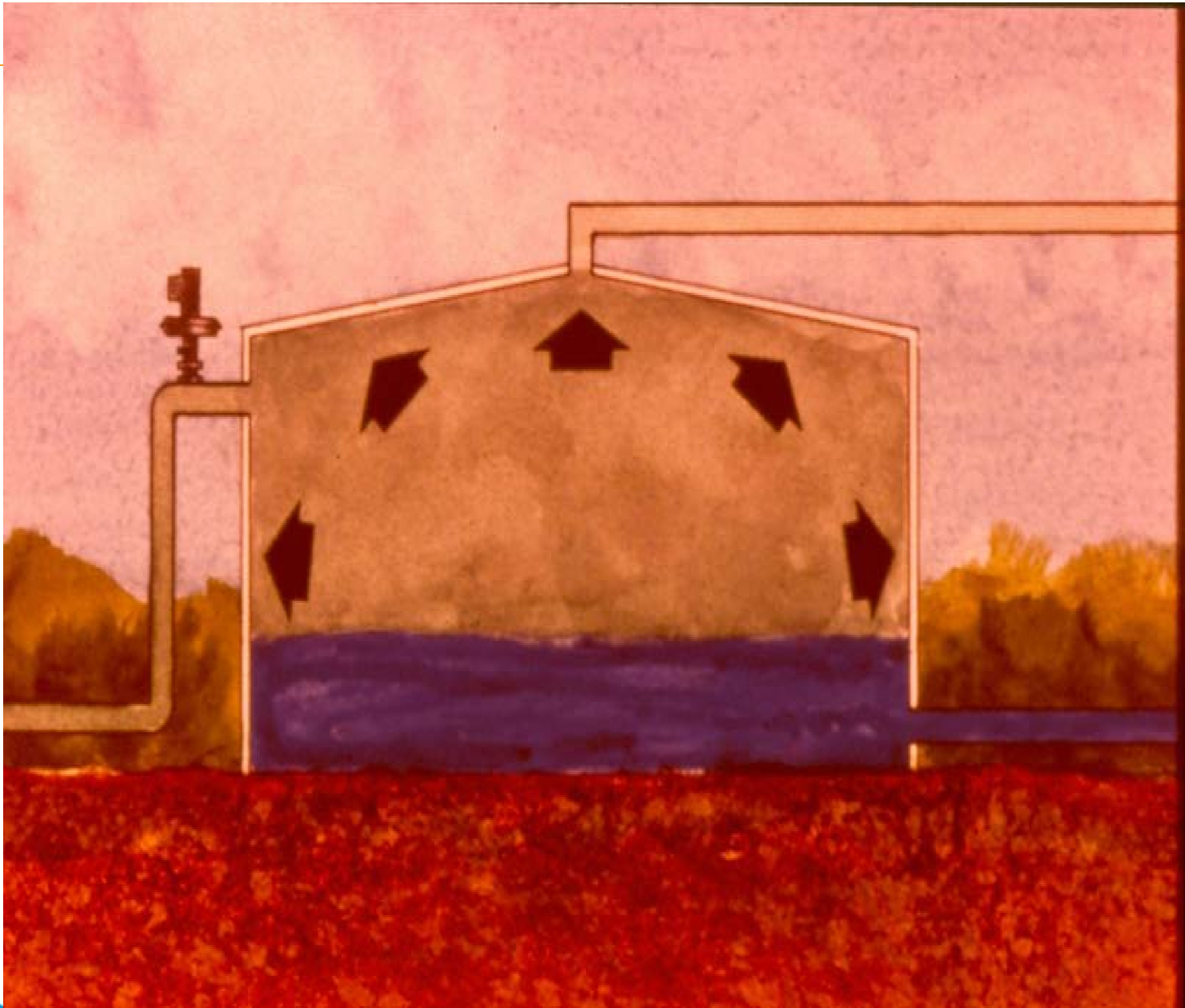
Global Methane Initiative

VAPOR RECOVERY SYSTEMS

What is Vapor Recovery?

TANK OPERATIONS

As the oil resides in the tanks, it gives off vapors, thereby increasing the pressure inside the tank.



Sources of Methane Losses

- Approximately 26.6 BCF/YR of Methane lost from storage tanks
  - Flash losses
    - occur when crude is transferred from containment at a high pressure to containment at a lower pressure
  - Working losses
    - occur when crude levels change and when crude in the tank is agitated
  - Standing losses
    - occur with daily and seasonal temperature and pressure changes

Source: Natural Gas STAR Partners

VAPOR RECOVERY SYSTEMS

PURPOSE

Vapor Recovery units are designed to comply with EPA standards, provide additional profits to the oil producer and eliminate the emission of stock tank vapors to the atmosphere.

Most vapors contain varying amounts of methane, ethane, propane, butanes and pentanes, etc. and contribute to the gravity of lease crude.

Dissipation of these products to the atmosphere on a conventional tank battery means a reduction in gravity of the liquid in the tank, thereby **decreasing its value**.

How The System Works

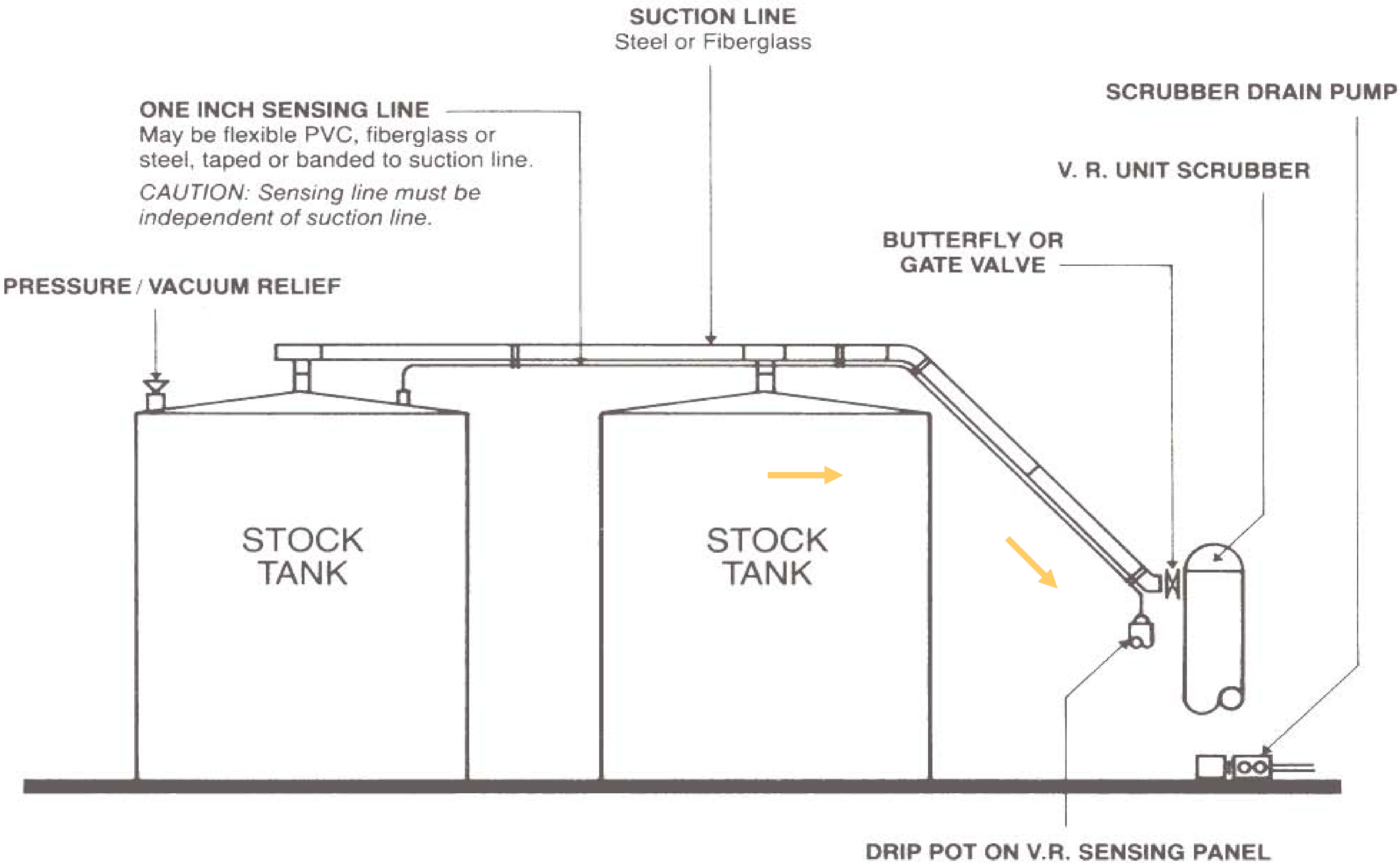
A tank (or tanks manifolded to a common suction line), is piped to the suction scrubber on the vapor recovery unit.

An independent sensing line, generally 2-inch, is run from any one tank to the drip pot on the control panel. This sensing line should be an independent connection to the tanks and as far as practical from the suction line.

The discharge piping from the VRU is connected to the gas gathering line, a meter run, the suction of the field gas compressor, or a combination of all three.

The scrubber drain system is piped either to waste or back to the stock tanks.

The electrical control panel may be mounted remotely, or in an explosion proof (NEMA 7X) enclosure on the skid.



NOTES
All lines must be horizontal, or sloped down to V.R.U. suction as shown.
Scrubber fluid is piped back to tanks or to waste.
The system must be closed — no air entry.

How The System Works

Maintaining a “closed” system is imperative to a successful Vapor Recovery system.

Systems are programmed to start automatically at a predetermined set point. As a general rule a 2” W.C. pressure will start the unit.

As the tank(s) pressure is reduced to approximately 1 - 1½” W.C., a by-pass mode is initiated and a small percentage of the discharge volume is diverted back to the suction scrubber. This allows the tank pressure to increase and, as it reaches the 2” mark, the by-pass closes. If, while in the by-pass mode, that tank pressure continues to diminish, the unit will stop and wait for the start pressure to be attained.

To avoid pulling a vacuum on any tank, shut-down pressure is generally at ½” W.C.

Benefits of Vapor Recovery Units

- Capture up to 95 percent of hydrocarbon vapors that accumulate in tanks
- Recovered vapors have much higher BTU content than pipeline quality natural gas
- Recovered vapors can be more valuable than methane alone
- Reduce regulatory & liability exposure

Criteria for VRU Locations

- Steady source and sufficient quantity of losses
  - Available gathering system
- Outlet for recovered gas
  - Access to pipeline or on-site fuel use
- Tank batteries that are subject to state/federal air regulations

Quantify Volume of Losses

- Measure losses using orifice well tester and recording manometer
- Estimate losses from chart based on oil characteristics, pressure, and temperature at each location
- Estimate emissions using the *E&P Tank* Model

What is the Recovered Gas Worth?

- Value depends on BTU content of gas
- Value depends on how gas is used
  - On-site fuel - measured in terms of fuel that no longer must be purchased
  - Natural gas pipeline - measured by the higher price for rich (higher BTU) gas (=2.5 X)
  - Gas processing plant - measured by sale of NGLs and methane, which can be separated

Value of Recovered Gas

Gross revenue per year =

$$(Q \times P \times 365 \times B) + NGL$$

Q = Rate of vapor recovery (mcfd)

P = Price of natural gas

B = Btu adjustment (typically 2.5)

NGL = Value of natural gas liquids

What Is the Payback?

Financial Analysis for VRU Projects

Peak Capacity (Mcfd)	Installation & Capital Costs[1] ($)	O&M Costs ($/year)	Value of Gas[2] ($/year)	Payback[3]	Return on Investment[4] (%)
25	26,470	5,250	25,869	1 yrs, 4 mos	73
50	34,125	6,000	51,738	9 mos	132
100	41,125	7,200	103,477	7 mos	234
200	55,125	8,400	206,955	3 mos	360
500	77,000	12,000	465,648	2 mos	589

[1] Unit cost plus estimated installation cost of 75% of unit cost.
[2] $5.67 per Mcf x ½ capacity x 365. Assumed price includes value of Btu-enriched gas (1,285 Btu/scf).
[3] Based on 10% discount rate for future savings. Excludes value of recovered gas liquids.
[4] Calculated for 5 years.

Source: Natural Gas Star Partners

VRU Decision Process

Identify possible locations for VRUs

Quantify the volume of losses (IQR?)

Determine the value of recoverable losses

Determine the cost of a VRU project

Evaluate VRU project economics

Industry Experience: ConocoPhillips

- Vapor recovery units installed in Baker, MT
- Anticipated multiple sites, so detailed technical review of options was conducted
- Volumes per site ranged from 30 mcfd to 350 mcfd
- Pipeline pressure ranged from 20 to 40 psig
- Captures vapors from
  - Crude oil storage tanks
  - Produced Water tanks
  - All manifolded together in closed loop system
  - Gas blanket system used to backfill tanks

Industry Experience: ConocoPhillips

- Evaluated rotary screw, rotary vane, vapor jet and EVRU
- Selected rotary vane VRU's due to wide range of volumes of gas and low discharge pressure across the sites
- Pilot project on 3 locations, then added 6 additional sites
- Designed for optimum gas capture
  - Pressure transmitter on the tanks
  - Sloping lines to the VRU
  - Package specifically designed for vapor recovery service
  - Automated liquid handling and bypass systems

Baker, MT ConocoPhillips VRU installation; Picture Courtesy of Hy-bon Engineering

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Industry Experience: ConocoPhillips

- Payback Economics – Project for 9 Tank Batteries
  - Purchase Price for 9 VRU's $475,000
  - Estimate Install Cost $ 237,500
  - Total Capital Costs $ 712,500

- Approximate Gas Revenue
  - 1,050 mcfd x $6/mcf (2005 & 6) X 30 days = $189,000/ month

  - Payback on Capital Investment < 4 months
  - Installed in 2005 & early 2006 – all locations continue to generate incremental revenue and meet environmental compliance goals today

CASINGHEAD GAS CAPTURE

STRATEGIES
AND
CASE STUDIES

Global Methane Initiative

CASINGHEAD GAS

- Approximately 18 Bcf/year of Methane is estimated to be lost from well venting and flaring in the U.S.   In many oil producing countries these numbers could be measured in the Bcf per DAY.

  2 Primary Sources Include:
  - Separator gas vented or flared during oil processing
    - occurs at each stage of separation process (typically 3) as water and gas are separated from the oil for collection
  - Casinghead gas
    - Most mature formations produce more oil if the gas pressure on the casing (or annulus) is reduced.
    - This is often accomplished by venting this casinghead gas at or near the wellhead

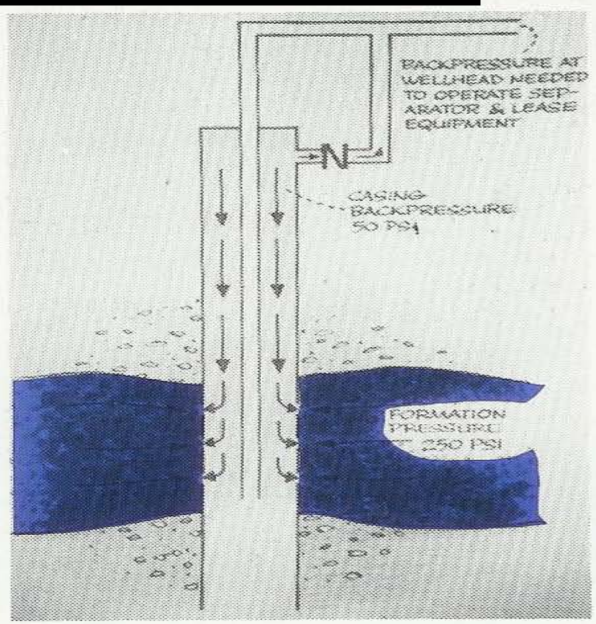
CASINGHEAD GAS REDUCTION
The Concept

- Casinghead gas relatively wet (.85 spec gravity / 16gpm)
- Weight of this column of wet gas sitting on the formation has an incremental effect on bottom hole pressure
  - Dictated by oil specific gravity and the well depth
- When you add wellhead pressure (i.e. flowline or 1st stage separator), this pressure on the formation is significantly impacted
  - Further complicated by fluctuating wellhead pressure from the pipeline
- Concept is simple – relieving this pressure in the casinghead reduces the weight (pressure) on the formation, allowing oil or gas to more easily flow from the formation into the well bore.

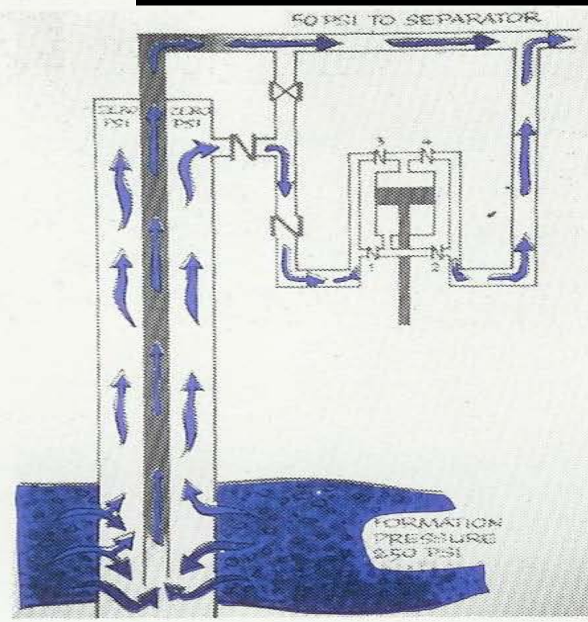
Relieving Back Pressure

BEFORE COMPRESSION

Restricting Back pressure holds back the flow of Hydrocarbons into the well bore.

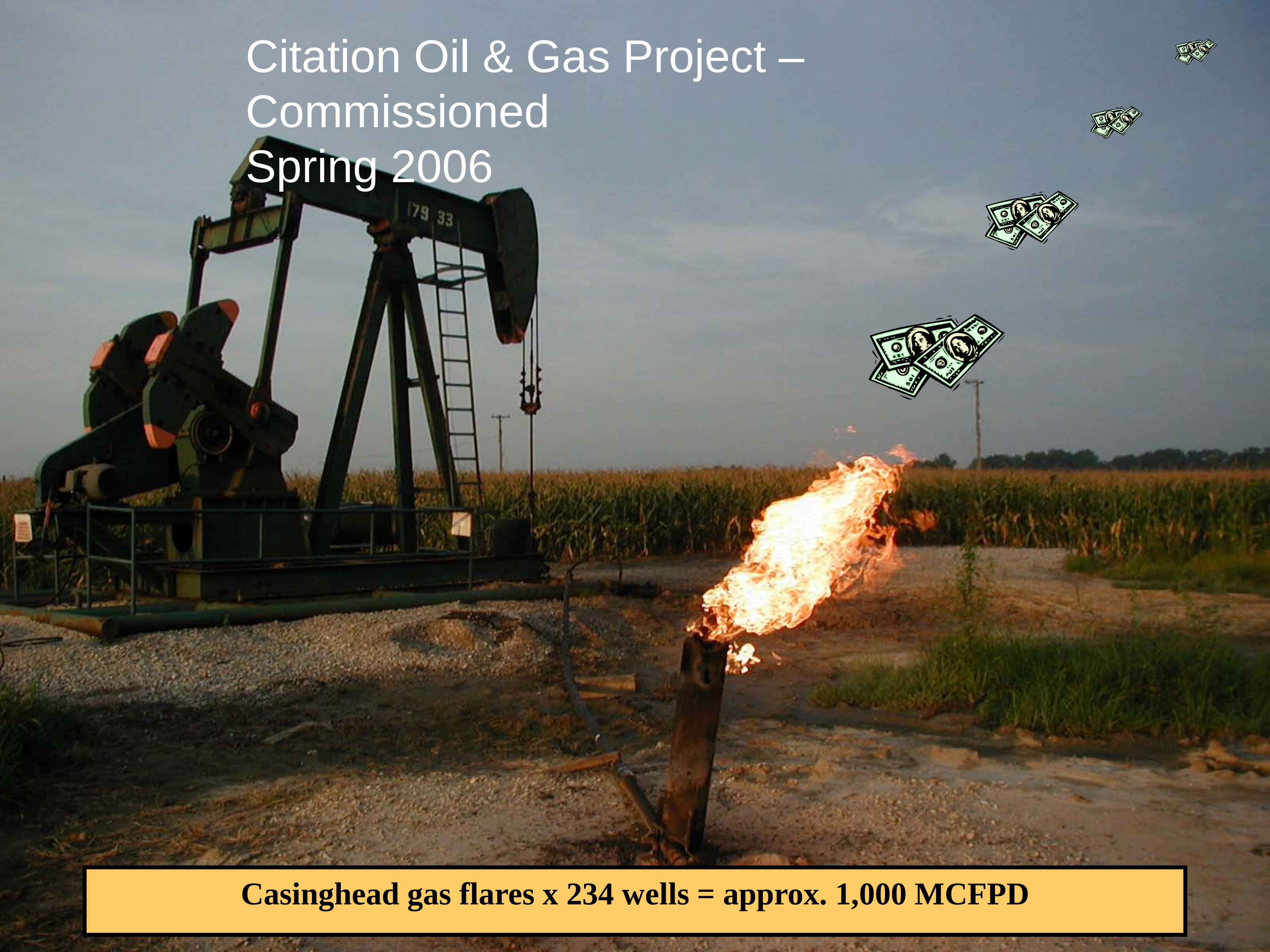


AFTER COMPRESSION



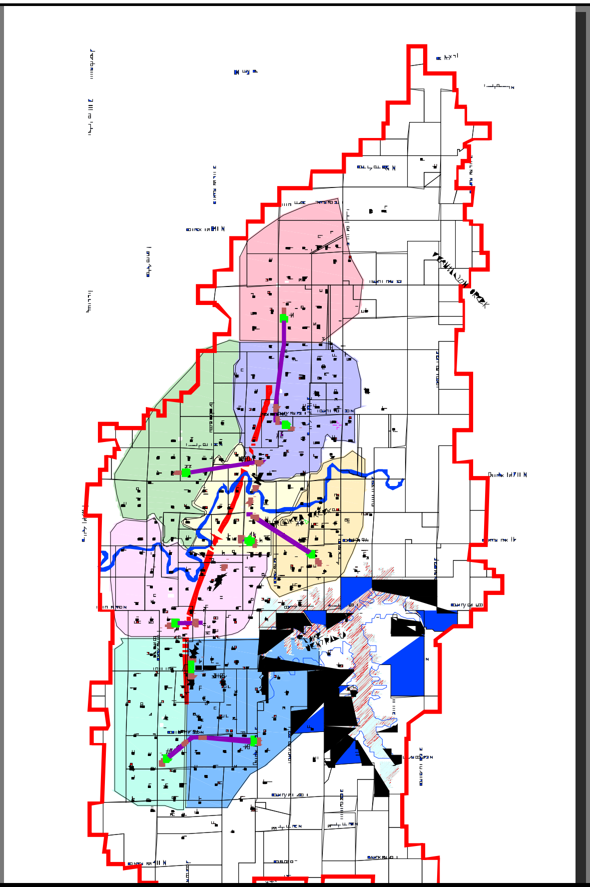
Back pressure is relieved from the face of the formation allowing more hydrocarbons to flow into the well bore.

Citation Oil & Gas Project – Commissioned Spring 2006



Casinghead gas flares x 234 wells = approx. 1,000 MCFPD

Salem Unit



Gas Gathering System

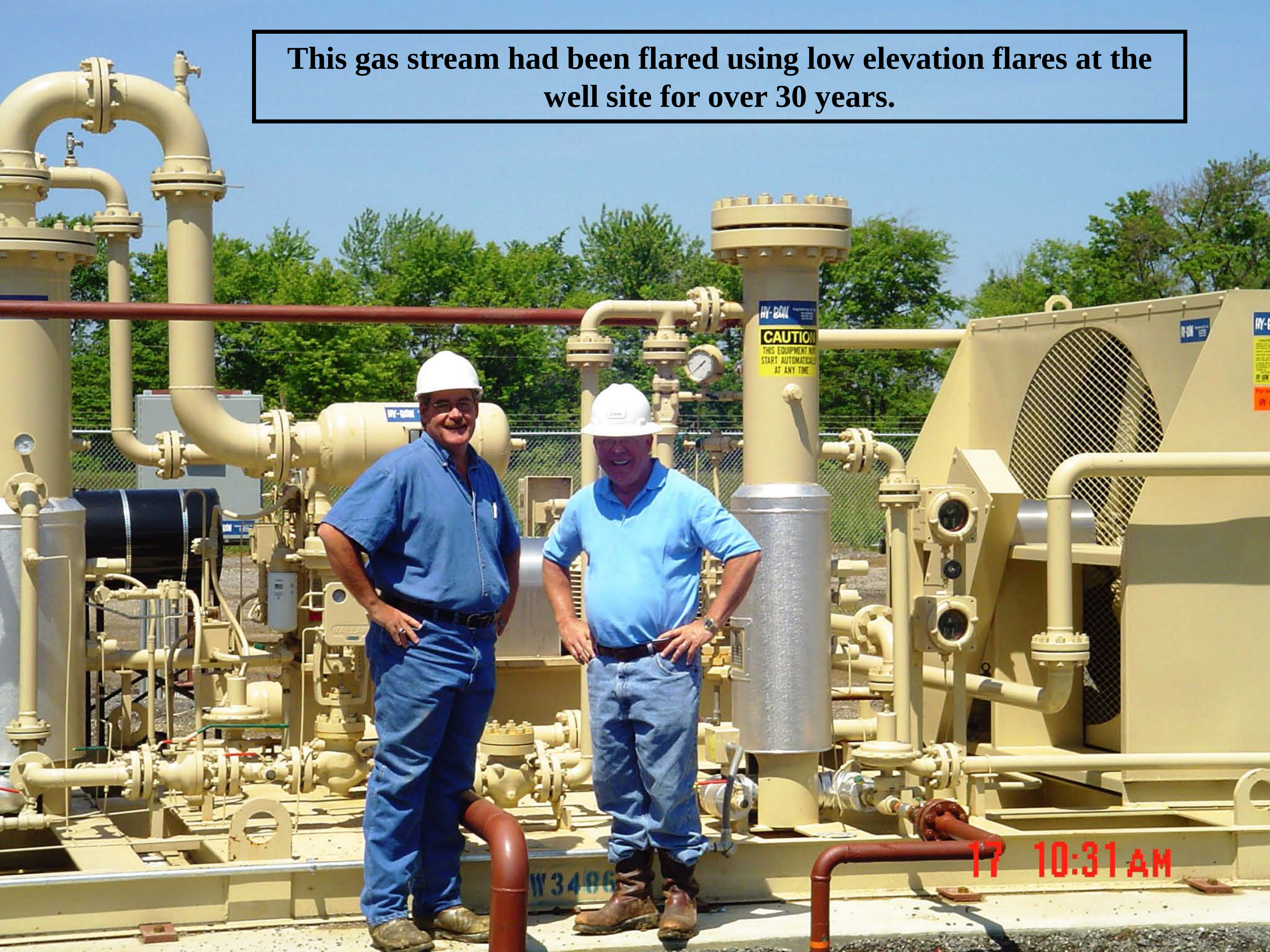
100 HP Casinghead Pressure Reduction Units were installed across the field

Eight (8) Units are staged logistically to pull in the 234 wells (30 wells each)

Rotary Screw Compressor Packages w/ gas after coolers were used in this application

Rotary Screw compressors were used due to the wet nature of this gas stream. Filters are used before the skid to remove iron sulfide, then a scrubber vessel and automated liquid transfer system on skid to handle the liquids which are common in this application.

This gas stream had been flared using low elevation flares at the well site for over 30 years.



Project Results

Over 1 MMCFD of gas flaring eliminated

Oil production

Increase of approximately 8 %

Condensate production (NGL's)

Capture of approximately 122 BPD

Gas production

545 mcfd residual gas being sold

CASINGHEAD GAS REDUCTION
How It Works

Goal is to maintain a casinghead pressure as close to zero as possible without pulling a vacuum

- Low horsepower compressor units utilized
  - Can be rotary vane, rotary screw or small reciprocating based on gas stream
- Pressures as low as ½” water column are maintained using a bypass system with a recycle/ throttling valve
  - Bypass pilot control maintains this pressure / gas recycled below set point
- Steady pressure is maintained on the well bore, and produced gas is sent down the flowline or gas line

CASINGHEAD GAS REDUCTION
Benefits

- The majority of wells tested in older, mature basins tend to respond favorably to a reduction in casinghead pressure
- Many wells respond with dramatic increases in oil and or gas production – particularly in water flood or CO_2 flood projects
- Often allows subsurface pumps to operate more efficiently, and often eliminates “gas locking” problems
- Eliminates the impact of fluctuating or rising pipeline pressures on your production
- On wells that respond favorably, the payback economics are extremely compelling

CASINGHEAD GAS REDUCTION
Weaknesses

- Not all formations respond favorably; even individual, adjacent wells in the same formation often respond differently
- While we know some entire formations that do not respond, within areas that do respond it requires well-by-well testing
- Some formations respond with increased produced water
- In some cases, wells respond incredibly for 7 to 10 days, and then drop to previous levels
- While oil production gains after 30 days generally remain constant, gains in gas production may drop to previous levels.

CASE STUDY - LEA CO., N.M. Hobbs Area

	BEFORE COMPRESSION	AFTER COMPRESSION	GROSS MONTHLY INCOME INCREASE
CASINGHEAD PRESSURE	50 PSIG	2 PSIG	
GAS PRODUCTION	200 MSCFD	250 MSCFD	50 X $3.00 X 30 = $4500.00
OIL PRODUCTION	30 BBLD	35 BBLD	5 X $20.00 X 30 = $3000.00
DISCHARGE PRESSURE	-	50 PSIG	**Total = $7,500 per Month**

Case Study – Ector County
4 Separate Compressors / Multiple Wells
Cowden Area

	BEFORE COMPRESSION	AFTER COMPRESSION	GROSS MONTHLY INCOME INCREASE
CASINGHEAD PRESSURE	45 PSIG	2 PSIG	
GAS PRODUCTION	Incremental Gas Produced	18 MSCFD 12 MSCFD 7 MSCFD 8 MSCFD	45 X $3 X 30 = $4,050
OIL PRODUCTION	160 BBLD 50 BBLD 46 BBLD 17 BBLD	180 BBLD 115 BBLD 58 BBLD 27 BBLD	107 X $20.00 X 30 = $64,200.00
DISCHARGE PRESSURE	-	45 PSIG	**$68,250 per Month**

RECOMMENDED PROCESS

1. Determine which fields may respond most favorably, and then prioritize well locations.

HY-BON brings over 15 years of casinghead gas reduction field experience in the Permian Basin to assist in this process.

RECOMMENDED PROCESS

2. Following well selection, a mobile, trailer mounted unit (natural gas engine driven) is moved to location for a 45 day test.

RECOMMENDED PROCESS

3. Following 30 days of sustained production increase, an electric drive, skid mounted unit is moved to location, and the trailer is released to test the next candidate well.

RECOMMENDED PROCESS

4. Based on the proximity of the wells and line pressure, evaluate linking opportunities for multiple well gathering systems