
## Section Objectives

- To help understand others mistakes and successes
- To help avoid the mistakes and copy the successes

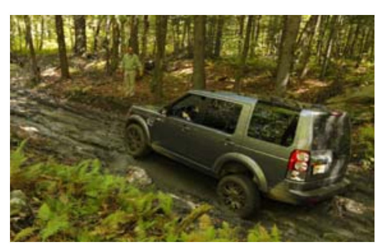
# Ownership

- This class has covered a very wide range of material from how hydrocarbons are created through final processing of sales gas and produced water
  - Few people will have responsibilities that span this range
  - Everyone's responsibilities are touched by each of the things I've talked about
  - The reason for this scope is "ownership"
- This sense of ownership means
  - You question things being done to the things you own
  - You understand "steady state" conditions
  - You learn to recognize "anomalies" before they become "problems"
- "Ownership" is the key element to becoming "Best in Class"



# How to achieve ownership?

- The dealer hands you the keys to a new car, but the seat and mirror are in the wrong position, the knobs and switches have the wrong settings, and there are a couple of sounds that you are not sure are right
  - You spend some time with the owners manual
  - You spend some time adjusting ergonomic things
  - You pay attention to every squeak, rattle, and roar until your subconscious knows what is right
  - You drive it fast and you drive it slow to understand limitations
- A gas well costs a lot more than a car
  - What do you need to do to "adjust the seat" and "select the performance settings"?
  - How do you learn what "normal" looks like?

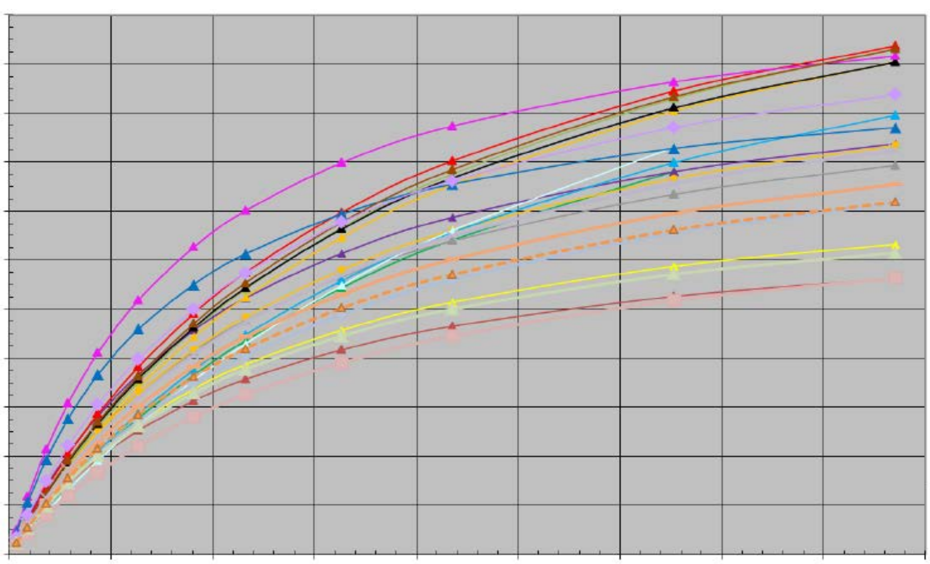


# Owning a well
## Reservoir Pressure

- If you can't reliably say what the reservoir pressure is today, then how do you know what pressures you should be trying to achieve?
- For conventional and Tight formations, this can be really difficult, but the Reservoir Engineers can guess for you
- For CBM:
  - Get your hands on the underlying data that went into the isotherm (if that isn't possible, get a copy of the paper isotherm, it exists somewhere)
  - Compare the last build up to the cum production to see if there is a fit (does the build up pressure match the GIP for the cum taken out?)
  - Calibrate the input parameters and regenerate the isotherm and look at another shut-in to see if the pressures make sense
  - Keep working until it does
- There are more possibilities than you might imagine



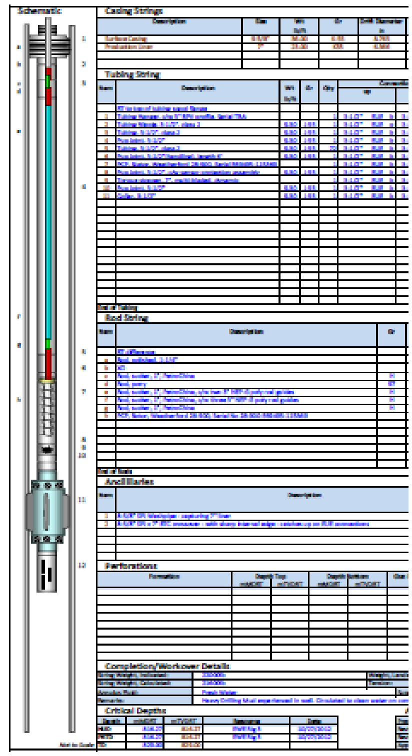
# Isotherms in a Field



22 wells in the field, Highest OGIP twice lowest OGIP

# Owning a Well

- Wellbore sketches
  - Get a copy of the wellbore sketch and make sure that it is current
  - Look at everything on it and ask "why is this here?" and "is this in the right place?" and "is this the right device to do this task?"
  - It is amazing how often stuff is in a well because "that is the way we do it" instead of "that is what the reservoir needs"



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# Owning a well

- Drawings
  - Look for a pipeline map that shows take-away pipe size and length
  - Look for a P&ID and go to the well to make sure that the P&ID is current, they often aren't
  - Note "normal" position on the P&ID vs. actual position in the field—find out why any differences exist
- Automation data
  - Too often the story that the automation data tells is a fairy tale
  - The most neglected instruments on a wellsite are tubing and casing pressure
  - The most relied-upon data by Engineers is tubing and casing pressure
  - You need to make sure that the readings on automation have a relationship to field data (it is common for a transducer to be calibrated to one range in the instrument and a different range in the RTU, so if the transducer actually calibrated to 0-1000 kPa sends a 12 mA signal meaning 500 kPa to an RTU that has 0-10000 kPa then the reading is 5000 kPa and you make the wrong decision

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# Owning a Well
# Gas Flow Meter

- What flow measurement technology is being used?
- Is the meter sized properly?
  - If it is a V-Cone, is the meter size consistent with flow rate? Is the $\beta$-Ratio consistent with flow rate? You should be able to determine a minimum measured rate and see if the well can do that much gas
  - If it is an AGA-3 meter run then you need to ask the same questions, but you also have to ask if $\beta$-ratio is between 0.32 and 0.72, if not then the uncertainty of the instrument is too high.
  - If it is another technology, then what are the limiting parameters and are you within a valid operating range?
- Is the RTU doing the right calculations?
- Are all the meter parameters really associated with the well you are trying to own?
  - It is too common to load a default analysis into a calculation routine
  - The reported Energy/day is kind of low if your RTU thinks you are measuring air



# Owning a well

- Water flow meter
  - It is hard to get much traction with water meters, but you can:
    - Confirm that meters downstream of dump valves have appropriate latency (V-Cone, Vortex, or Mag Flow meters have pretty low latency, Turbine meters have very high latency)
    - Confirm that there is a decent chance that the meter will remain full
    - Confirm any input parameters
  - The measurement will still be at odds with final disposed volume, but it will be better

## What do you do with a well you own?

- In spite of ownership, you probably can't sell it
- You now have data that can be "used" instead of "questioned"
  - Anomalies or day-to-day changes become vivid
  - You can see potentially expensive issues while they are still small enough to fix cheaply
  - You can participate and contribute in discussions with other well owners (the Production Foreman, Lease Tech, Production Engineer, and Facilities Engineer are roughly equal owners)
  - You will make more gas at lower costs than otherwise
- When we implemented this approach in the San Juan Basin:
  - Our LOE dropped from \$0.26/MCF to \$0.04/MCF (while adding \$250k/month in compressor rental and dropping Lease Tech well count from over 60 wells/Tech to 22 wells/Tech)
  - We identified "water in gas system" as our biggest opportunity and increased pigging from 1-2 runs/month to 2-3 runs/day



## Case Studies

- CBM POD
- You Get What You Measure
- Managing the Reservoir from the burner tip
- Major Projects

# Producing Coalbed Methane at High Rates at Low Pressures SPE84509

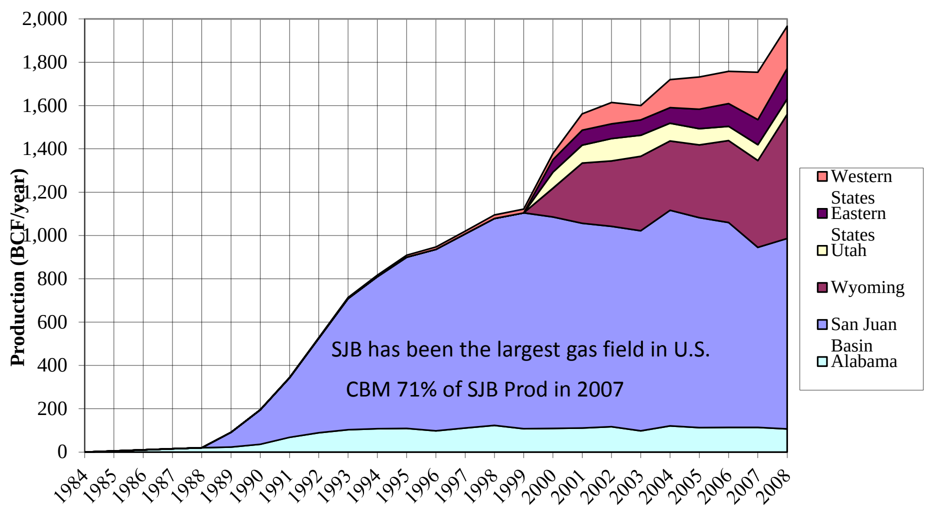
by

David Simpson, MuleShoe Engineering

Mike Kutas, BP America Production Co.



# Annual U.S. CBM Production



## Why the San Juan Basin?

- The Fruitland Coal seam was encountered in 20,000 wellbores between 1927 and 1988
- Drillers knew it was there and hated it (often got a significant kick)
- Section 29 Tax Credits offered a real incentive to try to make the Fruitland productive
  - We expected significant water that there was no infrastructure to handle
  - We expected out of spec $CO_2$
  - “Discovery” well produced 16,000 bbl/day of water, 9% $CO_2$, and little gas
- Factors for success:
  - Fairway Coal rock mechanics suitable for Cavitation (big wells encouraged enthusiasm)
  - Existing take-away pipelines provided exceptional access to markets
  - Gathering companies unwilling to take gas (forced producer-owned gathering)
  - Producers big enough to “encourage” development of necessary

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## Economic Significance

- San Juan Basin CBM growth:
  - 1986—CBM was 2% of basin production(0.024 BCF/d out of 1.3 BCF/d)
  - 1996—CBM was 64% of basin production (2.4 BCF/d out of 3.6 BCF/d)
- By late 1996 it was becoming clear that:
  - Production incline in CBM was mostly over
  - CBM wells on decline could see 60-80% annual decline rate
  - None of the traditional reservoir performance models adequately described either the incline or the decline
  - We needed an unconventional reservoir, wellbore, and pipeline model to determine what was next

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# CBM Plan of Depletion (POD)

- POD 1996 starting point:
  - 1989 predictions from reservoir model did not match the performance of **any** of the 62 Amoco-operated San Juan Basin CBM Fairway Wells
  - Re-Cavitation opportunities were gone
  - Decline rates far higher than expectations
  - Original well bore equipment, surface facilities, and gathering systems were inadequate for the well's needs
- In late 1996 Amoco management commissioned an evaluation of the needs of the field over the next 10 years including:
  - Predicted reservoir performance
  - Wellbore and deliquification interventions
  - Surface facility requirements
  - Staffing levels required
- Evaluation completed and projects funded in early 1997



# Transition from Reservoir to Sales

- Traditionally:
  - Reservoir Engineers were certain that Drilling Engineers ruined the reservoir by poking holes in it
  - Production Engineers were victims of both reservoir uncertainty and unyielding facilities
  - Facilities Engineers wanted the wellhead to be a plant feed
  - The three groups tried very hard not to talk to each other
- POD approach
  - The goal is to maximize reservoir long-term profit
  - Interventions on surface facilities are every bit as valid a reservoir management tool as rig-work
  - Rig work only makes since if there are facilities to handle the results (i.e., must fund necessary facilities upgrades when rig-work funded)
- In short, the combination of the reservoir, wellbore, and surface facilities all had to work together if any of it was to work at all

# POD Well-by-Well Approach

- Reservoir model:
  - Calibrate A, b, $\phi_0$, and kh for each of 62 wells
  - Hold calibrated parameters constant with time and calculate Skin using the empirical rock mechanics model
  - Compute pressure drops from reservoir into near wellbore (typify reservoir performance using an "equivalent pipe length" for each well)
  - Model system from first production to abandonment
- Wellbore model
  - Use standard nodal analysis equations
- Wellsite model
  - Convert current pressure drops to "equivalent pipe length")
- Gathering model
  - Use a commercial model to evaluate gathering system at each time step
- Link the models using custom program and a database



# Interventions Wellbores

- Cleanouts and/or re-cavitations
  - Wells with positive *Skin*
  - Wells with history of bridging/fill
- Wellbore tubulars
  - Run liners where possible
  - Use small tubing for water management
  - Gas flow up tubing/casing annulus
  - Adjust tubing set depth as necessary (some wells had tubing set depth changed 5 times in the first year)

## Interventions Deliquification


- Installed when model predicted fluid velocity < 36 ft/sec up the tubing (not a criteria that I would use today)
- Rod Pumps
  - Beam unit with gas engine – difficult to do pump-off control
  - Pneumatic-ram driven – easy pump-off control, requires high line pressure
- Eductors/Ejectors
  - Very effective for about 100 bbl/day and less

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## Interventions Wellsites

- Converted pressure drop & flow rate to a length of 3-inch pipe:
  - >1,000 ft, 1997 de-bottlenecking
  - <100 ft, no problem
  - Otherwise, fix when other work is done
- Wellsite design included:
  - Three lines from wellhead to separator
  - Separators with two inlet nozzles
  - Many vent/drain valves installed for future (unspecified) maintenance activities
  - Manifolds for compressor installations
  - Blowcases to move water from the separators to the water system

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# Interventions--Compression

- Compared well site compression to lateral compression
- Three well site compression cases:
  - Immediate compression (highest NPV on 23 wells)
  - No compression (highest NPV on 21 wells)
    - First three wells to get compressors were in this group
    - All three provided significant uplift, so other 18 scheduled for 1998
    - Further work showed all the wells in this group had wellbore problems
  - Staged compression (highest NPV on 17 wells)
    - Start with no-compression case
    - Develop empirical equations for q(t), cp(t), and decln(t)
    - Take $d/dt$ and $d^2/d^2t$ of each equation
    - Install compressors at distinct local minimum of either derivative
    - Interesting theoretical exercise that worked, but probably wasn't worth the effort

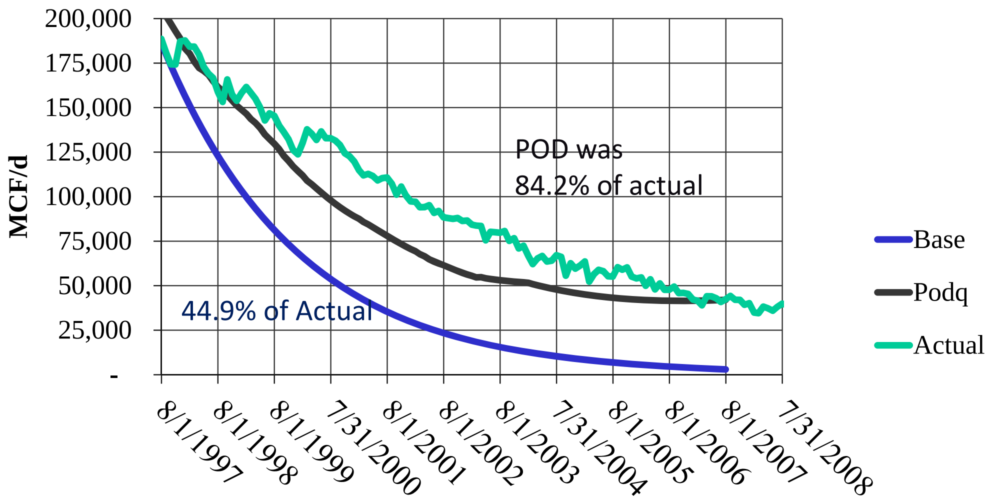


# Results

| Actual Compared to Target | Target 2/1/04 Gas Rate (MMCF/d) | Actual 2/1/04 Gas Rate (MMCF/d) | Well Count |
|---|---|---|---|
| <-50% | 3.3 | 1.3 | 5 |
| -50% < x < -10% | 10.7 | 6.9 | 10 |
| ±10% | 9.4 | 9.4 | 10 |
| +10% >x>50% | 12.5 | 15.8 | 16 |
| Sub-total | 35.8 | 33.6 (94%) | 41 |
| >50% ** | 10.8 | 19.2 | 21 |
| Total | 46.6 | 52.8 (113%) | 62 |

** This group is predominantly those wells that the model said not to compress and that were compressed anyway. The model category was actually a reflection of wellbore damage and all required major well work

# Project Post Appraisal






# Results

- Initial field development was authorized on 176 BCF EUR with production through Jan, 2004
- In January, 2004:
  - Predicted rate (revised in 1997) predicted without the project 13 MMCF/d
  - Model rate 52 MMCF/d
  - Actual rate 67 MMCF/d
- Project verified that very low abandonment pressures were achievable in the coal (80 psia used for reserves)
- May, 2009 Status of 62 POD wells:
  - Gas rate 30 MMCF/d
  - Cum-weighted average reservoir pressure of model wells was 74 psia
  - 36 wells below 80 psia making 18 MMCF/d (0.5 MMCF/d avg)
  - 22 wells below 50 psia making 13 MMCF/d (0.6 MMCF/d avg)
  - Wells have a cumulative production of 820 BCF (13 BCF/well, one well has accumulated 44 BCF)

## CBM POD Conclusions

- Unconventional analysis is required for unconventional reservoirs
- It is profitable to manage a reservoir from the burner tip
- Late-life CBM operations require a different mind-set than early-time operations

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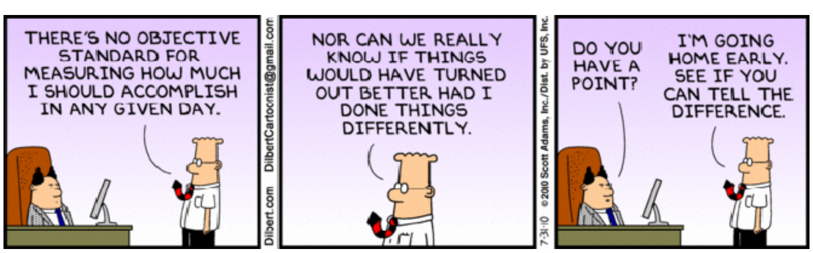
## You Get What You Measure

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[We] are in the business of finding, developing, producing, transporting, processing, and marketing hydrocarbon products. If we do that very well, we will be very successful.

John Sweringin, CEO
Standard Oil (Indiana), 1981



## Farmington Coal Gas Screw Compressor Operation Overview

- Fleet consists of:
  - 68 compressors on 62 wells
  - 22,000 Hp
  - Wells make 85 MMCF/d (1.25 MMCFd/well)
- Fleet is operated by POI (now Exterran) with:
  - 3 Mechanics (2 foreman and a floater mechanic)
  - 9 Operators
  - 1 Superintendent
  - POI provides the compressors and all operations, maintenance, and response to callouts for a fixed monthly fee

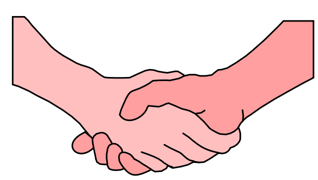
## Wellhead Screw Compressor Group Operation Overview

- These compressors move a lot of gas, and need to be restarted at night
- The learning curve is very steep on screw compressors and long-term employment adds value
  - First year of operation saw entire staff replaced 1.5 times
- Need to align POI incentives with BP productivity and encourage longevity



## Characteristics of a Successful Incentive Program

- Based on objective parameters
- Parameters can be directly influenced by operator
- Quick feedback
- Encourage performance that impacts the company’s goals
- Encourage employment stability
- Operators have to trust that payouts will happen



## Traditional Measures (KPI)

**Run Time**
- Pro—Easy to measure
- Con—No clear tie from run time to gas sales

**Mechanical Availability**
- Pro—Easy to measure
- Con—Creates incentives to leave wells down (as long as the problem is not the compressor)

**Utilized vs. installed hp**
- Pro—Hp weighted
- Cons
  - Hp not proportional to rate
  - Hard to determine actual

**Cost per hp**
- Pro—Effective for controlling variable cost
- Con—We didn't have any variable costs



## Screw Approach

- Calculate a Production Target for each well based on last three months production
  - Decline at 30% annual

$$Target = \frac{q_{-1} * e^{-0.3/12} + q_{-2} * e^{-0.3*2/12} + q_{-3} * e^{-0.3*3/12}}{3}$$

  - Exclude first two months of compressor run
  - Exclude months with wellbore problems
- Sum the actual and Targets for all wells
  - Target > actual, no payout
  - Actual >1.03* Target, max payout
  - else, (actual - target)/(0.03*target)

## Gates

To be eligible for a payout in any given month an individual must have:

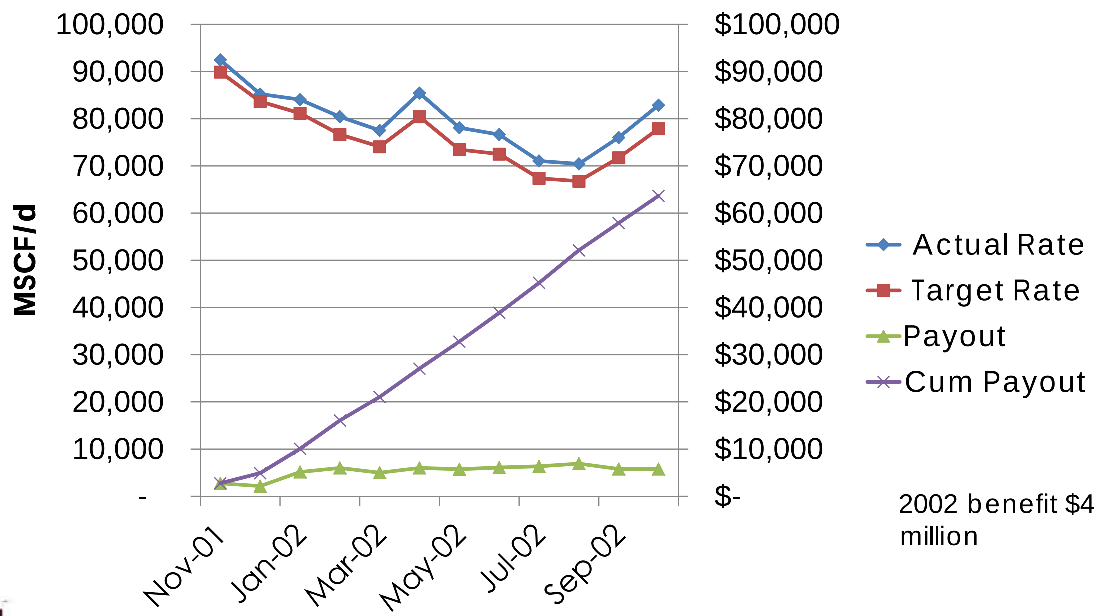
- Zero OSHA reportable accidents
- Zero mystery drums on location. Mystery drums are:
  - Missing hazmat label,
  - Missing product-identification label, or
  - Drums on the ground
- Zero abandoned hazmat items (e.g., 12-volt batteries left in the weeds)
- Acceptable overall housekeeping on all units



## Limitations

- If any individual fails to pass all gates:
  - He gets zero payout for that month
  - His mechanic gets zero payout for that month
  - The floater mechanic gets zero payout for that month
  - The superintendent also gets zero for the month
- Only payout in December, if you leave the team before payout you get nothing

# 2002 Program

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# Behaviors

## Before Incentive

- Each Compressor operated in isolation
  - A machine on a high rate well blows a turbo, the well is down until a replacement can be acquired
  - Measuring run time
- Wells visited on rigid schedule
- Run time maximized

## Year 5

- Consideration given to fleet
  - A machine on a high rate well blows a turbo and the mechanic pulls one off a lower rate well and leaves that one down until replaced
  - Measuring production
- Mechanic starts every day on the biggest well
- Sales maximized

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## Program Results

| Year | Turnover | Sales to target | Benefit to company | Payout to operators |
|---|---|---|---|---|
| One | 250% | -2% | Before Program | Before Program |
| Two | 18% | +1% | $1.9MM | $45k |
| Three | 12% | +3% | $2.6MM | $44k |
| Four | 22% | +4% | $3.1MM | $42k |
| Five | 14% | +5% | $4.0MM | $63k |
| Total | | | $11.6MM | $194k ($8MM NPV(15)) |



# Break

# 10:00

# Managing a Reservoir from the Burner Tip




## Managing the Reservoir from the Burner Tip

- Every decision can either look back toward the reservoir or look forward toward the end use
  - Looking back asks the question "how will this decision affect reservoir performance, ultimate recovery, and profitability"?
  - Looking forward asks the question "how will this decision affect installed facilities?"
- The first decision that installs equipment incompatible with full reservoir pressure has shifted the focus forward



 

## Why do we change focus?

- The primary cause of shifting the industry focus is decreased risk tolerance:
  - Safety risks
  - Environmental risks
  - Performance/profitability risks (distant third)
- The primary tools of risk-elimination are:
  - Supply Chain Management
  - Process Safety Management (PSM)
  - Processes and Procedures



## Supply Chain Management

- In the 1970's auto makers and large retailers began using computers to work towards the goal of "just in time" inventory control
- By the 1980's PhD and MBA candidates were writing thesis on this trend and Oil & Gas jumped onto the band wagon
- Focus and intent of Supply Chain Management is:
  - Manage units of production to provide components as required with minimal warehousing
  - Manage the tools of production to minimize the amount that they constrain the production process
- Units of production are the things that go into the final product
- Tools of production are the things that stay in the factory when the final product leaves (like robots, assembly lines, factory lighting, compressed air systems, etc)

## Supply Chain Management

- In Oil & Gas our units of production are hydrocarbon molecules and there is no really good method to manage the supply of those molecules
- Our tools of production are valves, valve repair kits, pipe, tanks, pumps, compressors, gensets, etc.
- To properly implement Supply Chain Management in Oil & Gas, we would need to take extraordinary efforts to ensure that:
  - Repair/replacement equipment was immediately available
  - Field workers are adequate in number and extensively trained in repairing and diagnosing failures in all of the tools of production
  - Cost control takes a secondary position to production optimization
  - Work management has "flexibility" as a primary goal
- Proper implementation is kind of boring and hard to build an empire upon so our industry has decided to apply techniques appropriate to units of production to tools of production

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## Process Safety Management (PSM)

- PSM is a set of processes and procedures designed to:
  - Ensure that system design contains appropriate risk mitigation
  - Ensure that system modifications meet the standards of the original design as applied to current operating parameters
  - Ensure that procedures used will minimize the risk to the environment, the public, workers, and equipment
- The basic tenet of PSM is to balance risk mitigation with risk density

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## Risk Density

- Risk density is a measure of the likelihood and consequences for an excursion to:
  - Harm employees
  - Damage other equipment
  - Harm the environment
  - Harm the public

- A plant
  - Is manned 100% of the time by a number of people
  - Has numerous components
  - Has fluids that can do real harm to the environment
  - Is often located in population centers
  - Very high risk density



## Risk Density

- A wellsite
  - Is manned 1-2% of the time, usually by a single person
  - Has very little equipment
  - Has little opportunity to harm the environment
  - Is generally remote from population centers
  - Very low risk density

- Successful risk-mitigation strategies will always consider risk density in the establishment of processes and procedures

## PSM

- When you ignore <u>risk density</u>, then it is reasonable to apply processes appropriate for a refinery to wellsites:
  - Require Management of Change (MOC) and Hazardous Operations (HazOp) reviews to change orifice plates in a meter run
  - Require full lock-out/tag-out protocols to spray a wellsite for weeds
  - Develop extensive drawing packages for wellsites (and require the drawings to be updated before work can be started)



## PSM

- When you consider <u>risk density</u>:
  - MOC and HazOp are not required for routine activities (e.g., swapping compressors within a fleet, changing plunger type, changing orifice plates)
  - Lock-out/tag-out is only required when multiple unrelated activities are done concurrently or the well is left unmanned in an unstable condition
  - Operating procedures are flexible to the point where they can be ignored if a particular well requires other procedures

## Processes and Procedures

- Process—a description of something that must be done
- Procedure—a description of how to do something
- Both are intended to:
  - Minimize the risk of an error
  - Ensure that everyone does the same task the same way on every location every time
- Actual outcome is to:
  - Force workers to lie about having followed procedures that are inappropriate for a given location
  - Stifle innovation
  - Provide an easy excuse for failure (instead of providing a reasonable path to success)

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## Completion techniques

- Experience shows that CBM wells completed with Cavition Stress Technique significantly out perform any other completion (often by a factor of 20-40 times)
  - Cavitations only work in a limited number of wells
  - Cavitations are messy and have an unpredictable duration which makes scheduling difficult
  - Looking towards the reservoir, any well that could possibly have a successful cavitiation must be cavitated
  - Looking towards the budget and the schedule it is easier to case and frac the wells even if the result could be less than 1/10th the production rate
- Experience shows that coal is self healing and frac proppant quantity/type is largely irrelevant
  - Looking towards the reservoir would have frac's with large carrier volume and only enough sand to enhance abrasive action
  - Looking towards supply chain management you farm out the decision to Schlumberger and get a huge sand load

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## Flowing bottomhole pressure

- Steady pressure improves the affected reservoir area and results in higher flow rates and more ultimate recovery
  - Looking towards the reservoir you would make an effort to determine the most effective pressure relationship between reservoir pressure and flowing bottomhole pressure and try to stay as close as possible to that value over time—if there is a wellhead choke it is a "backpressure" choke that holds FTP constant
  - Looking towards the lease equipment and gathering system you put a "pressure regulating" choke that ignores upstream pressure and keeps downstream pressure constant

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## Lease equipment

- Typically, each pressure class will result in costs about 10-20% higher than the next lower pressure class
  - Looking towards the reservoir would have you pick an MAWP based on reservoir pressure and will typically be something like ANSI 600 (1440 psig or 10 MPag) and not require wellhead chokes to protect the artifacts
  - Looking towards a low pressure gathering system would select ANSI 150 (280 psig or 1.9 MPA) or less and would require wellhead chokes and wellsite ESD's to protect the artifacts

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## Gathering systems

- Gathering systems can either be a tool of reservoir management or a sales tool
  - Looking towards the reservoir
    - The system MAWP is consistent with reservoir pressures
    - The system anticipates difficult reservoir fluids (large quantities of condensed water, significant potential for corrosive fluids)
  - Looking towards the sales line
    - Pressure rating is largely irrelevant (you can build compressor stations to maintain whatever MAWP you select)
    - Cost is king, and assumptions about installation costs are often naïve
    - Assumptions about the long-term reliability of remote, automated equipment can be very naïve

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## Administrative processes

- We use administrative processes and procedures to relieve individuals of the risk of making the wrong decision
  - Looking towards the reservoir
    - Individuals have the authority to make changes that are required to optimize reservoir performance
    - A meter change, changing pump speed, or running a pig requires budget money, not MOC
    - Local control of maintenance resources and local ability to change priorities
  - Looking towards process-driven activities
    - Every decision refers to a process document
    - Every change requires MOC
    - Maintenance resources are centrally controlled and the work order system has goals like "all work will be scheduled 30 days in advance", "no spare parts will be issued without a work order", and "no squirrel stores"

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## Managing the reservoir from the burner tip conclusions

- The reason for the very existence of our industry is to exploit Oil & Gas ***reservoirs*** for profit
- Any activity that loses that fact will make less profit than it could have
- Any statement that contains the phrase "reservoir _______ is irrelevant" (e.g., "reservoir pressure is irrelevant") leads to a sub-optimal decision
- Any procedure or process that doesn't consider the needs of the reservoir is sub-optimum
- Any facility that puts an artificial constraint on the reservoir is inappropriate



## Major Projects




 

# Major Projects

- Over the last decade upstream field development has moved away from “organic field development” to the “EPC model”
  - Organic field development implies:
    - Project designed by company Engineers with contractors providing components (e.g., drawings, survey’s, etc.) and field personnel providing significant input to design
    - Procurement done by company personnel (not “Supply Chain Management”) with significant ongoing input from design Engineer
    - Company personnel managed construction contractors to build system
    - Design Engineer often retained responsibility for operating project



# EPC Model

- Company personnel develop a “Pre-FEED” project description
- Supply Chain Management sends the Pre-FEED to several Engineering Consultants to bid on developing the “Front End Engineering Design” (FEED), bids are awarded based on various criteria, none of which have any consideration of the needs of the reservoir
- An Engineering consultant develops a FEED that is typically too big, too expensive, and too complex for anyone within the company to have time to fully understand the ramifications of all the decisions
- Supply Chain Management sends the FEED out to “Engineering, Procurement, and Construction (EPC)” contractors for bids on the job, which includes something called “detailed Engineering” that is often more expensive than the FEED

# EPC Model

- Bids are let and the chosen EPC company
  - "Finishes" the Engineering design, generates Engineering drawings, buys/builds stuff for the project, and installs it
  - Assigns senior plant Engineers to direct junior plant Engineers in developing the design(zero field Engineering experience is the norm)
- 6-18 months later the issuing company gets concerned about the amount of money they've committed and how little tangible results are on the ground
- On three occasions I've been called in to evaluate what went wrong and assess the possibility of success on CBM/CSG Major Projects
  - USA
  - India
  - Australia
- Contractual relationships keep me from providing specific details, but I can share common threads

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# Major Projects—Pre-FEED

- The main point of the Pre-FEED is to lay out the "nominal conditions", for example:
  - Reservoir will need very low pressures (< 50 kPag [7.3 psig]) on the surface facilities
  - Produced water will be 2,000 bbl/day/well [318 $m^3$/day/well]
  - Gas production will be 5 MMSCF/day/well [141 kSCM/day/well]
  - Must minimize operating manpower requirements
- Result of these nominal conditions is:
  - FEED defines gathering system MAWP of 350 kPag [50 psig]
  - Pigging facilities omitted because the plastic pipe isn't subject to normal corrosion and pigging takes a lot of manpower
  - Pro-forma separator too big for average conditions (which are much less than the nominal conditions)
  - Automated line drips spotted all over the system

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# Major Projects—FEED

- FEED is required by Supply Chain Management protocols
- Intention is to enter the procurement process with Engineering completed and every component specified to a degree that would allow a procurement specialist to send it out for bid **without further Engineering involvement**
- The goal sounds laudable when you say it fast, but excluding Engineering from procurement decisions hasn't worked out well:
  - Key details don't get written into the FEED
  - Alternatives don't get considered (e.g., when a vendor says "You called for XYZ widget, but DEF widget does the same thing and will allow you to eliminate QRS widget", the Engineer would say "let me look at the specs" and Supply Chain Management says "NO!")
- The basic concept was naïve, and all the work in the FEED is now re-done in EPC, generally with less company input
- FEED should go away, but it is now part of the institution



# A field is NOT a plant—Organic projects

- Drawings were limited to pipeline Alignment Sheets and Fabrication Isometric Drawings
- No P&ID's were developed (in fact, no wellsite drawings at all were developed)
- Vessels were a collaboration between a vessel fabrication shop and the Design Engineer
- Automation was done by analogy (i.e., you put in the same thing as the rest of the field or the last field, the design of that particular wheel was not up for review on every project)
- Pipeline construction done in collaboration, company personnel intimately involved

# A field is not a plant—EPC Model

- P&ID is king, and it is common to have many drawings for each wellsite (one project had 107 drawings/well another 109 drawings/well)
- Adjusting equipment location for terrain required modifying dozens of drawings and could shut the work down for weeks
- Field piping is a shock
  - One project had an inspector show up in a small 2-door coupe because he knew “he could walk to the pipe rack”
  - Another project shut down for over a week while the head office determined how to lay pipe across a dry wash (the head office wanted to build a pipe bridge)
  - A fence crossing in Colorado caused 10 days delay (and there are fences every km or so) while plant guys decided what to do
- Vessel design is done with nominal values in a vacuum and no input is allowed until the vessel hits the ground, and then it is a change order



# Wellsite vessels—EPC Model

MAWP
960 kPa
[139 psig]

Bigger than the plant inlet sep

Fully Enclosed
Class 1 Zone 0

Can’t open meter

No dump valve
Pump maintains
level with VFD

ANSI 900 (10 MPa 1450 psig)

Door in the way

6% CO2 seems
to require SS

No way to
keep line full
Min flow rate 6000 bbl/day

Head basher

# Major Project Conclusion

- Current status
  - Two of the projects were stopped at less than 30% of field work completed (law suits are pending)
  - The third project is still underway, but cost overruns continue to throw up red flags
- One of the cancelled projects has continued the work in the organic model and the results are proving acceptable (they still have far too many drawings and far too much process, but it is a fraction of the EPC model and they are meeting budget and calendar targets)
- The other cancelled project has turned the work over to a different EPC and the preliminary data looks like they are starting over down the same path
- The vessel on the right in the preceding slide cost over $500k, and was recently sold at auction for $7k (purchaser planned to dismantle it and sell the parts)

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# Final Word

- Even with the best planning, coordination, and execution in the world:

- The creeks will still rise and the plan will need to change

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Thank you for your attention.
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