CHALLENGES TO ACCURATE OIL & GAS ASSET VALUATIONS

LOOKING BEYOND THE 1P RESERVES

INCLUDING ASSESSMENT OF FIELD OPERATIONS

SUMMARY OF INEXS EXPERTISE
Asset Valuations
Independent Review of Third Party Engineering Reserve Reports
Review of Technical Expertise and Management of Portfolio Companies
Full Contract Field Operations
Full Field Equipment Audit
Vertical Vs. Horizontal Drilling And Completions

Challenges Between Conventional Vs. Unconventional Reservoirs

Proved Reserves – 1p, 2p, 3p + Probable & Possible

Risking Proved / Force Ranking Well Operations

Undrilled Acreage – Term and HBP

Valuation Challenges using Precedent Transactions

Valuation Challenges using Drill-Out Option

Field Operations Cost Analysis / Optimization

Field Equipment Audit And Inventory
VERTICAL VS. HORIZONTAL DRILLING AND COMPLETIONS

NOTE: Throughout the presentation, blue dialog boxes such as this one are added to provide the detail and context that remains unexplained without the verbal presentation.
The primary objective in horizontal vs. vertical drilling is to expose more volume of rock to the wellbore for higher production rates.
# Reservoir Challenges

<table>
<thead>
<tr>
<th>Unconventional Reservoirs</th>
<th>Conventional Reservoirs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tight, low permeability, low porosity reservoir</td>
<td>Higher permeability, and higher porosity reservoir</td>
</tr>
<tr>
<td>Brittle shale, tight sand, or fractured carbonate</td>
<td>Porous sands, porous carbonates, fractured carbonates</td>
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<tr>
<td>Trapped by lack of horizontal permeability</td>
<td>Requires a stratigraphic or structural trap</td>
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<tr>
<td>High total organic carbons (TOCs) in reservoir</td>
<td>Low total organic carbons (TOCs) within reservoir</td>
</tr>
<tr>
<td></td>
<td>Sourced from high TOC shales above or below</td>
</tr>
<tr>
<td>Mostly drilled with horizontal well through reservoir</td>
<td>Drilled with vertical well through reservoir</td>
</tr>
<tr>
<td>Challenges to geosteer within the formation</td>
<td>Clear definition of field and reservoir limits</td>
</tr>
<tr>
<td>Generally fraced (fracked) to stimulate production</td>
<td>Generally no need to stimulate production</td>
</tr>
<tr>
<td>Rarely any risk of water interrupting production</td>
<td>Often water is the drive mechanism for production</td>
</tr>
<tr>
<td>Exception is fracking to water reservoir above or below</td>
<td></td>
</tr>
<tr>
<td>Pressure depletion and gas expansion are primary drive mechanisms</td>
<td>Pressure depletion is also a common drive mechanism</td>
</tr>
<tr>
<td>Highly repeatable within close proximity</td>
<td>Not easy to repeat within close proximity</td>
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<tr>
<td>Reliance on type curves for Estimated Ultimate Recoverable - EUR</td>
<td>Reliance on pressure or volume for EUR</td>
</tr>
<tr>
<td>Often insufficient wells for accurate analysis</td>
<td>Often insufficient data for accurate analysis</td>
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<tr>
<td>Greater rock heterogeneity than expected</td>
<td>Rock heterogeneity is always expected</td>
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<tr>
<td>Normalization of EUR to constant lateral length</td>
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<tr>
<td>Modeling of EUR range based on multiple variables</td>
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<tr>
<td>Rapid phase changes from oil to volatile oil to gas</td>
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</table>
Resource Classes

1P Reserves
- **PDP** = Proved Developed Producing
- **PNP** = Proved Not Producing (behind pipe)
- **PUD** = Proved Undeveloped (requires drilling new well)

2P Reserves
- **PROB** = Probable

3P Reserves
- **POSS** = Possible

CONTINGENT (requires further proof of commerciality)

PROSPECTIVE (requires drilling new well to prove)
Third Party Reserve Reports

- Rigorous process, standards, and methodology
- Satisfies SPE and SEC reporting standards
- Designed to provide banks, lenders, and investors a high degree of confidence in the accuracy of the numbers
- Options for price deck using flat, projected, or NYMEX strip price
- The PROBABLE and POSSIBLE reserve category are still part of the Commercial Reserves category and acknowledge a certain percentage probability of additional Commercial Reserves beyond the PROVED
- Reserve Categories routinely change with updated results from offset operator drilling
RISKING PROVED / FORCE RANKING WELL OPERATIONS
### APPLYING RISK AND NPV-10/INV RATIO

<table>
<thead>
<tr>
<th>Reserve Category 17-Case Subset</th>
<th>Lease Name</th>
<th>Field</th>
<th>Reservoir</th>
<th>Gross Oil (MMbbls)</th>
<th>Gross Gas (MMcf)</th>
<th>Expense &amp; Tax (M$)</th>
<th>Invest. (M$)</th>
<th>Non-Risked Cash Flow $M</th>
<th>NPV-10 Non-Risked $M</th>
<th>PROB Geol</th>
<th>PROB Oper</th>
<th>NPV-10 Risked $M</th>
<th>RISKED NPV-10 /INV</th>
<th>AVERAGE NPV-10 /INV</th>
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</thead>
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<tr>
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</table>

Conventional Approach
Risk Applied to all cases
Risk Applied & > 1.5

<p>| | | | | | | | | | | | | | | | | | | |</p>
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</table>

Geological risk and operational risk assessed and applied
False High Ratio - Ignores existing risk & includes non-executable cases
The application of realistic risk reduces the NPV-10/INV to an unattractive ratio
Optimized results obtained by only selecting well operations with > 1.5:1
# COMBINING WELL OPERATIONS INTO SINGLE CASE

<table>
<thead>
<tr>
<th>Reserve Category</th>
<th>Lease Name</th>
<th>Field</th>
<th>Reservoir</th>
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<th>NPV-10 Non-Risked $M</th>
<th>PROB Geol</th>
<th>PROB Oper</th>
<th>NPV-10 Risked $M</th>
<th>RISKED NPV-10 /INV</th>
<th>INDIVIDUAL NPV-10 /INV</th>
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</thead>
<tbody>
<tr>
<td>Probable Undeveloped</td>
<td>Lease A-1</td>
<td>GOOD</td>
<td>A Sand</td>
<td>412</td>
<td>0</td>
<td>2459</td>
<td>5500</td>
<td>9617</td>
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<td>5,259</td>
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<td>C Sand</td>
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<td>570</td>
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</tbody>
</table>

All well operations in the same wellbore are grouped together to generate a shared Risked NPV-10/INV Ratio

False high ratio due to not sharing the drill and completion costs
## Conventional vs. Optimized Approach

<table>
<thead>
<tr>
<th>Reserve Category</th>
<th>Lease Name</th>
<th>Field</th>
<th>Reservoir</th>
<th>Gross Oil (MBbls)</th>
<th>Gross Gas (MMcf)</th>
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<th>Invest. (M$)</th>
<th>Non-Risked Cash Flow $M</th>
<th>NPV-10 Risked $M</th>
<th>PROB Geol</th>
<th>PROB Oper</th>
<th>NPV-10 Risked $M</th>
<th>Cases Considered</th>
<th>AVERAGE NPV-10 /INV</th>
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<tbody>
<tr>
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<td>PUD + PRUD</td>
<td>GOOD</td>
<td>PUD + PRUD</td>
<td>5,682</td>
<td>45,527</td>
<td>76,301</td>
<td>92,365</td>
<td>181,841</td>
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<td>None</td>
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<td>Optimized</td>
<td>PUD + PRUD</td>
<td>GOOD</td>
<td>PUD + PRUD</td>
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<td>97,481</td>
<td>57,593</td>
<td>Applied</td>
<td>Applied</td>
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<td>1.5+</td>
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</table>

Executing all of the well operations results in 1/6 of the capital investment to generate more than half the same cash flow.

When applied to all wells and all cases an optimized result is obtained.
UNDRILLED ACREAGE – TERM AND HBP
MINERAL RIGHTS

- US Government Land and Sea
- State Lands and Waterways
- Private Mineral Ownership

**RED** = Gas Fields
**GREEN** = Oil Fields
ALL OTHER COLORS = Acreage Controlled by Various Departments of the Federal Government.
Basic Lease Terms

- Negotiated with private mineral owner or state or US Government
- Royalty – generally 1/8 to 1/4 (12.5% to 25%)
- Lease Bonus – $20/acre to $20,000+/acre
- Rentals – often fully paid up but certain states have annual rental payments
- Term – often 3 to 5 years, but can be 10 years or more
- Renewals – options available

Restrictions and Limitations

- Pugh Clauses – depth limitation
- Continuous Drilling Clauses
- Held by Production – HBP
VALUATION CHALLENGES USING PRECEDENT TRANSACTIONS
Multiple variables simultaneously interact both positively and negatively to impact the valuation of undrilled acreage including:

- Date and oil/gas prices at time of transaction
- Market trend increasing or decreasing at time of transaction
- Costs for pipeline transportation, processing, compression, and basis differential(s)
- Type curve(s) supporting precedent transaction vs type curve(s) for valuation target
- Geological setting in basin relative to TOC (total organic content), depth, reservoir thickness, maturity
- Local basin drilling rig and drilling permitting activity
- Drilling and completion costs for precedent transaction vs. valuation target
- Identification of ‘best practices’ drilling and completion techniques for model
- Normalization of lateral lengths to EUR (estimated ultimate recovery)
- Normalization of frac stages and proppant to valuation target
- Number of acres
- Percentage of acres in contiguous blocks to create production units
- Percentage of “loose” acreage scattered throughout area
<table>
<thead>
<tr>
<th>Announce Date</th>
<th>Buyers</th>
<th>Sellers</th>
<th>Deal Value ($MM)</th>
<th>Acres</th>
<th>$/Acre (Est.)</th>
<th>Spot Price of NG/Mcf</th>
<th>$/Acre (Adjusted)</th>
<th>New Deal Value ($MM)</th>
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<td>East Resources Inc</td>
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<td>6/30/2014</td>
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<td>Undisclosed Seller</td>
<td>$95</td>
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<td>$14,930.00</td>
<td>4.59</td>
<td>$5,198.47</td>
<td>$33</td>
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<td>7/7/2014</td>
<td>Rice Energy Inc</td>
<td>Chesapeake; Statoil</td>
<td>$330</td>
<td>33051</td>
<td>$9,969.55</td>
<td>4.05</td>
<td>$4,085.88</td>
<td>$135</td>
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<tr>
<td>7/29/2014</td>
<td>Mountaineer Keystone Energy LLC</td>
<td>PDC; Lime Rock Partners</td>
<td>$500</td>
<td>131000</td>
<td>$4,750.00</td>
<td>4.05</td>
<td>$1,946.72</td>
<td>$255</td>
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<tr>
<td>8/13/2014</td>
<td>Shell¹</td>
<td>Ultra Petroleum</td>
<td>$925</td>
<td>15493</td>
<td>$5,968.00</td>
<td>3.91</td>
<td>$2,563.57</td>
<td>$397</td>
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<tr>
<td>9/30/2014</td>
<td>Antero Resources Corp¹</td>
<td>Undisclosed Seller</td>
<td>$185</td>
<td>12000</td>
<td>$15,417.00</td>
<td>3.92</td>
<td>$6,599.74</td>
<td>$79</td>
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<tr>
<td>10/16/2014</td>
<td>Southwestern Energy</td>
<td>Chesapeake; Statoil</td>
<td>$4,975</td>
<td>413000</td>
<td>$12,046.00</td>
<td>3.78</td>
<td>$5,416.37</td>
<td>$2,237</td>
</tr>
<tr>
<td>12/2/2014</td>
<td>Southwestern Energy</td>
<td>WPX Energy Inc</td>
<td>$288</td>
<td>46700</td>
<td>$6,167.00</td>
<td>3.48</td>
<td>$3,108.37</td>
<td>$145</td>
</tr>
<tr>
<td>12/22/2014</td>
<td>Southwestern Energy</td>
<td>Statoil</td>
<td>$365</td>
<td>64238</td>
<td>$5,682.00</td>
<td>3.48</td>
<td>$2,863.91</td>
<td>$184</td>
</tr>
<tr>
<td>4/3/2015</td>
<td>TH Exploration LLC</td>
<td>Trans Energy Inc</td>
<td>$71</td>
<td>5159</td>
<td>$10,100.00</td>
<td>2.61</td>
<td>$7,841.61</td>
<td>$40</td>
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<td>5/26/2015</td>
<td>Antero Resources Corp¹</td>
<td>Magnum Hunter Resources Corp</td>
<td>$41</td>
<td>5210</td>
<td>$7,869.00</td>
<td>2.85</td>
<td>$5,316.89</td>
<td>$28</td>
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<tr>
<td>7/1/2015</td>
<td>Alpha Natural Resources¹</td>
<td>EDF</td>
<td>$126</td>
<td>12500</td>
<td>$10,800.00</td>
<td>2.84</td>
<td>$6,847.83</td>
<td>$86</td>
</tr>
</tbody>
</table>

Source: PLS, A&D Center
(1) Transaction only included acreage

The original $/acre payment is adjusted and normalized to current gas prices and takes into account operating and transportation costs to calculate the Adjusted $/acre.
The Adjusted $/acre oscillates around $5000/acre

Source: PLS
It is important to compare all precedent transactions to key developments in the basin and industry including dropping natural gas prices, rig counts, and drilling permits.
VALUATION CHALLENGES USING DRILL-OUT OPTION
The fundamental assumption with this option is that the operator will attempt to drill all of the possible undrilled wells on term and HBP acreage, with the following concerns, necessities, and limitations:

- Identify all potential well locations on undrilled acreage
- Remove all PDP and PUD locations
- How much of the acreage is clustered into sufficient density to create drilling units?
- What percentage of acreage does the operator control within a unit?
- What are the actual or predicted drilling, completion, and lease operating expenses?
- What are the gathering system, processing, compression, and pipeline costs?
- What basis differential at final sales point?
- What is the EUR – Estimated Ultimate Recoverable reserves per well?
- What price deck – NYMEX strip?
- What is the rig availability?
- What permitting time, restrictions (e.g. migratory birds and deer), and limitations exist?
- If the answer to all is positive IRR and NPV then continue, otherwise move to next area
- THE definitive answer to EUR for any resource play is the All Important Type Curve
Definition and Application

- Quantitative and qualitative method of analyzing reservoir and field production
- Performed by using a sample set of wells in a given area or reservoir and evaluating the average historical production to determine the decline curve that best matches that production
- Decline curve then used to project future production on a single well basis through the manipulation of many variables that affect the overall decline of the curve
- Variables include hyperbolic exponent (b-factor), initial production (IP), effective initial decline, and terminal decline
- Estimated ultimate recovery (EUR) can be calculated using these variables
- The wells that factor into a type curve must be cautiously categorized into groups with similar well traits
- Traits include but are not limited to operator, basin, field, reservoir, well status, production date, and drill type
- With a precise EUR calculation, many different economic scenarios can be ran to determine a reasonably accurate value for acreage
**Definition and Application**

- **B factor** is a coefficient used in the Arps decline curve equation to model either exponential or hyperbolic decline, depending on the reservoir and production characteristics.

- Exponential decline, using the b value of zero, is exhibited by a straight line on a semi-log graph, whereas hyperbolic decline with b values ranging from zero to 1 represent a decline that is characterized by an early steep drop followed by flattening, which is typical of tight gas formations including shale.

- When modeling shale gas decline, it is not uncommon for reservoir engineers to use b-factors in excess of 1.

- The problem with values greater than 1, is that they will approach unreasonable amounts over the entire life of the well.

- Therefore, after a substantial b-factor has been applied to the initial decline (1.1-1.4), a terminal exponential decline should be used to realistically project the EUR.

---

**Exponential Decline (b = 0)**
- EUR = 3.1 Bcf

**Hyperbolic Decline (b = .8)**
- EUR = 4.2 Bcf

**Hyperbolic Decline (b = 1)**
- EUR = 5.9 Bcf

**Hyperbolic Decline (b = 1.2)**
- EUR = 7.4 Bcf

**Hyperbolic Decline (b = 1.4)**
- EUR = 11.6 Bcf
The following slides demonstrate an example of analyzing a cluster of wells surrounding an undrilled acreage position in southwestern Pennsylvania. The comparison looks at where the wells sit in the basin, and how selectively choosing different wells to generate the type curves yields significantly different results.
The yellow acreage has numerous producing wells around it. The question to be answered is which wells should be included in a type curve and why. The Marcellus thickness map suggests that the southern wells are more similar in thickness to the yellow acreage than the northern wells.
The Marcellus depth map is further evidence that the southern wells are more similar to the acreage than the shallower northern wells.
41 Wells

Observations

- While the type curve for all these wells is fairly decent, it is important to break out certain areas and completion techniques to understand which wells are contributing the most to the curve.

All 41 wells generate a type curve with an EUR of 9.1 BCF and PV-10 of $4.2 MM

PV 0: $20,458,000
D&C¹: $5,750,000
PV 10²: $4,217,000

Source: DrillingInfo
(1) Source: EQT
(2) PV 10 Net Revenue after 25 years, $35.00 oil, $2.25 gas, 100% WI, $10,000 LOE/mo, 80% NRI, economic limit of 30 boe/d
NOTE: # of wells reported will differ from data shown on bubble map and type curve due to lack of information on publicly available data.
PV 0: $16,557,000  
D&C: $5,750,000  

**PV 10**: $1,739,000

**13 Wells**

**Observations**
- These wells North of the acreage have lower reservoir thickness as well as lower depth compared to the wells South of the acreage.

---

*Source: DrillingInfo*

(1) Source: EOT  
(2) PV 10 Net Revenue after 25 years, $35.00 oil, $2.25 gas, 100% WI, $10,000 LOE/mo, 80% NRI, economic limit of 30 boe/d  

**NOTE:** # of wells reported will differ from data shown on bubble map and type curve due to lack of information on publicly available data.

---

*The northern 13 wells generate a type curve with an EUR of 7.4 BCF and PV-10 of $1.7 MM*
PV 0: $22,663,000
D&C¹: $5,750,000

PV 10²: $5,618,000

28 Wells

Observations
- These wells South of the acreage have slightly greater depths and reservoir thickness than the wells to the North, which could explain the difference in IP and EUR

Source: Drillinginfo
(1) Source: EQT
(2) PV 10 Net Revenue after 25 years, $35.00 oil, $2.25 gas, 100% WI, $10,000 LOE/mo, 80% NRI, economic limit of 30 boe/d
NOTE: # of wells reported will differ from data shown on bubble map and type curve due to lack of information on publicly available data

The southern 28 wells generate a type curve with an EUR of 10.1 BCF and PV-10 of $5.6 MM
2013
- PV10: $16.1MM
- EUR: 17.4 Bcf
- Avg. Lat. Length: 6,800 ft
- b-factor: 1.4

2012
- PV10: $8.8MM
- EUR: 12.3 Bcf
- Avg. Lat. Length: 6,000 ft
- b-factor: 1.3

2011
- PV10: $6.4MM
- EUR: 10.6 Bcf
- Avg. Lat. Length: 3,700 ft
- b-factor: 1.3

2010
- PV10: $1.7MM
- EUR: 7.3 Bcf
- Avg. Lat. Length: 3,500 ft
- b-factor: 1.2

Breaking out the wells to the year they were drilled yields the clear trend of longer laterals, higher EURs, and higher NPV-10 with the most recent drilling, suggesting that new drill wells will achieve the same or better results.
ADJUSTED EUR GAS (MMCF) TO 5000’ LATERAL
2010-2013 HORIZONTAL WELLS (13 WELLS)

Calculating the BCF yield per 1000 ft of lateral length then plotting the distribution of wells allows an estimate of average EUR based on lateral length.
ADJUSTED EUR GAS (MMCF) TO 6000’ LATERAL
2010-2013 HORIZONTAL WELLS (13 WELLS)

- Data Points
  - P99 = 3001.6
  - P90 = 4443.3
  - P50 = 7188.9
  - Mean = 7612.1
  - P10 = 11631.0
  - P1 = 17217.5

- Swansons Mean: 7,697.88
- Statistical Mean - Untruncated: 7,713.84
- Arithmetic Mean: 7,603.17

Cumulative Probability

EUR GAS (MMCF)
FIELD OPERATIONS COST ANALYSIS / OPTIMIZATION
The valuation of producing assets is based upon the current production rates, EUR, LOEs, downtime, 'non-recurring costs', future CAPEX and D&C costs.

The level of production optimization employed by an operator dramatically affects the current valuation, as well as the upside potential to be gained by production optimization.

Production operations require continuous monitoring during the life of a field.

Optimization is dependent upon producing conditions and pricing environment.
Operations need to be optimized to maximize profit and equipment service life

- Facility equipment including pumps, electric motors and gas compressors probably installed early in life of field
- Declining rates and pressures could provide opportunity to reduce costs
  - Pumps could be swapped out or modified to fit current application reducing repair costs and downtime
  - Electric motors could be properly matched to horsepower requirements, reducing power consumption and cost
  - Compressors could be modified or swapped out reducing costs and downtime
- Numerous types of artificial lift equipment may be utilized within a field
  - Surfactant Injection (capillary string)
  - Plunger Lift
  - Progressive cavity pump
  - Gas lift
  - Rod pump
  - Hydraulic pump
  - Electrical submersible pump (ESP)
- The more liquid a lift method can handle, the more expensive it is to maintain and operate
Many variables affect the efficiency of an artificial lift system. A partial list of variables for a rod pumped well are shown below.

- Pumping unit size
- Stroke length and speed
- Sucker rod size and type
- Downhole pump type and size
- Pump intake pressure
- Gas oil ratio, well head pressure
- Type of fluid produced
- Pump spacing, compression ratio
- Plunger/barrel clearance

Changing conditions during well life cycle necessitate revising equipment design to maximize efficiency.
A major operating cost driver is well failures

Controlling equipment failures is critical to optimizing field operations and profitability
- Operating artificial lift equipment outside of design capacities increase equipment failures
- ESP equipment operating below its designed range will prematurely fail
- Over stressed rod pump equipment will lead to premature sucker failures due to buckling and increased tubing wear

Optimization of operating practices for mitigating scale, corrosion, emulsions, paraffin and H2S will reduce costs and failures
- Example: running a plunger in a gas lifted well may remove paraffin build up more effectively than chemical treating

Determine the proper balance between maximum production rate operating cost

Optimization work could have the best rates of return of any project within a company’s portfolio.
<table>
<thead>
<tr>
<th>Unit</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit 11</td>
<td>Injection well shuts in at atmosphere; good pump.</td>
</tr>
<tr>
<td>Unit 17</td>
<td>Injection well shuts in at atmosphere; good pump.</td>
</tr>
<tr>
<td>Unit 21</td>
<td>Injection well shuts in at atmosphere; good pump.</td>
</tr>
<tr>
<td>Unit 72</td>
<td>Injection well shuts in at atmosphere; no pressure; no motor.</td>
</tr>
<tr>
<td>Unit 319</td>
<td>Injection well shuts in at atmosphere; no pressure; no motor.</td>
</tr>
<tr>
<td>Pot'l 2845-2880</td>
<td>Pot'l 2688-2708</td>
</tr>
<tr>
<td>Cum gas - mcf</td>
<td>Pot'l 2845-2880</td>
</tr>
<tr>
<td>FB</td>
<td>Pot'l 2845-2880</td>
</tr>
</tbody>
</table>

Confidential:

- Pumping:
  - up and running as of Jan 1, 2012 with new motor; however, wrist pin bearings may need repair.

Confidential:

- Water to surface in tubing, no pressure on annulus; BJ report inactive.

Confidential:

- 3957 / 3948
- 2,614 / 2,694

Confidential:

- 2564-2608 / 2581-2620
- 118,340 / 74,300
- 72,681 / 64,352
- 223,419 / 270,487
- Oct-67 / Jan-08
- Jun-09 / Jul-11

Confidential:

- Pot'l 2648-2678

Shallower:
It is necessary for operators to keep a detailed and up-to-date inventory of each individual wellbore schematic. This applies to newly drilled wells as well as older wells that may have been acquired.

The more detailed and available these schematics are, the easier it is to address potential operational issues.
- INEXS provides full analysis of field operations including wellbore utilization evaluation
- INEXS provides direct field operations supervision including accounting
- Pricing based on $/wellbore, $/BOEPD, and shared upside success
FIELD EQUIPMENT AUDIT AND INVENTORY

It is equally important to conduct a complete and thorough inventory of physical equipment in the field, and to complete a detailed written field inventory report so that the producing company can optimize the artificial lift operations, to right size the artificial lift systems, and to monitor and track spills, failed equipment, and potential for future problems.
Clean Looking site, note top of foremost tank
note oil spray:
Far right tank appears to have leaked/sprayed oil
Remains of another failed tank. Operations improvements indicated.
Equipment shown here is in service. Maintenance improvements indicated.
Clean looking site, equipment in good working order
Clean looking site, equipment in good working order
Wellhead without pumpjack
Pumpjack without wellhead or rods.
Pipe storage facility?
Potential leaking issue. Note discoloration of ground and leaking of wellhead.
Field road washed out. Note exposed supply piping, risk of leak.
Exposed, uncapped electrical wiring in operational service box.
Note discoloration of ground around push rod. Leak?
Cleanout of 3-stage separator.
<table>
<thead>
<tr>
<th>Base Info / Manufacturer / Type / size/rating / Misc Info</th>
<th>COPAS Cond</th>
<th>General Comments</th>
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</thead>
<tbody>
<tr>
<td><strong>Access Road</strong></td>
<td>Caliche/Native Soil</td>
<td></td>
</tr>
<tr>
<td><strong>Well Site Pad</strong></td>
<td>Caliche/Native Soil</td>
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<tr>
<td><strong>Deadman Anchors</strong></td>
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<tr>
<td><strong>Wellhead - Prod String</strong></td>
<td>Threaded</td>
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<tr>
<td><strong>Wellhead - Conductor String</strong></td>
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<tr>
<td><strong>Water Injection Head:</strong></td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td><strong>Tubing:</strong></td>
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<tr>
<td><strong>Pump System Type</strong></td>
<td>Beam Unit</td>
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<td><strong>Pump-off-controller</strong></td>
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<td></td>
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<tr>
<td><strong>Prime Mover</strong></td>
<td>Electric Motor</td>
<td>Worldwide Elec</td>
</tr>
<tr>
<td><strong>Polish Rod Liner</strong></td>
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<td><strong>Stuffing Box</strong></td>
<td>Yes</td>
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<td><strong>Flowline - Production</strong></td>
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<td><strong>Water Injection Head:</strong></td>
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<td><strong>Chemical System:</strong></td>
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<td></td>
</tr>
<tr>
<td><strong>Misc Equip - 2:</strong></td>
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<td></td>
</tr>
</tbody>
</table>
- INEXS provides full analysis of field equipment and audit of inventory
- INEXS generates full written reports and incorporates the audit into a field optimization program

SUMMARY OF INEXS EXPERTISE
- Asset Valuations
- Independent Review of Third Party Engineering Reserve Reports
- Review of Technical Expertise and Management of Portfolio Companies
- Full Contract Field Operations
- Full Field Equipment Audit

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