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WHITE PAPER

ESal
Engineered Salinity

Wettability Alteration Experts

Breaking Down

$/bbl Economics

of Enhanced Oil Recovery Technologies

Oil and Gas Challenges

Developing New Resources or Boosting Existing Production with Cutting Edge EOR?

The decade of the 2020`s is presenting energy investors and C-Suite managers a landscape of ever-shifting demand and regulatory climates that will challenge balance sheets and capex determinations. Topping those decisions is whether to spend millions of dollars finding and developing new resources or to allocate a fraction of that on enhanced oil recovery (EOR) methods that often can double production from existing wells in a large percentage of fields.

This paper will examine all aspects of costs for both approaches in order to visualize their true dollars-per-barrel costs and determine how to save millions of dollars while still increasing production.

The Biggest Challenge for Producers

Commodity prices in the oil and gas industry are dictated by supply and demand in the larger market, putting individual operators at the mercy of those forces. While producers cannot control price, they have some control over their own production and overhead. Adjusting those factors is, then, their best avenue for preserving profitability when the market price drops.

Most exploration and production (E&P) companies try to overcome declining production in existing reserves by discovering and developing new fields. While increasing or at least preserving production is necessary, an alternative to drilling is often overlooked in the decision-making process. Enhanced oil recovery projects offer an alternative to E&P investments. However, these projects are often considered as an add-on to existing operations rather than separate projects that can not only add immediate production but also increase reserves for a fraction of the cost of E&P. This analysis will detail the advantages to producers of considering EOR projects and offer the more in-depth economic analysis that projects require for serious evaluations.

Evaluating the Cost/Barrel Equation

One of the greatest value differentiators is the per-barrel production cost. The lower the breakeven point, the more resilient the producer can be through the inevitable price volatility and long-term production decline. Lower production costs lead to higher profit margins and higher cash flows, providing more attractive returns on capital investments. It is especially important to track this metric in a market where crude oil is a commodity whose value can widely fluctuate. Over the long term, only low-cost producers can generate consistent and sustainable profits. Therefore, it is vital to understand the structure of expenses and their key drivers.

$/BBL is one of the most important long-term success benchmarks for oil production.

$$\frac{Total\ CAPEX + Total\ Cash\ OPEX}{Cumulative\ Barrels\ Recovered}$$

$$in\ a\ \boldsymbol{specific\ timeframe}$$

The following example involves a simplified oilfield with assumptions derived from actual field data. It assumes $50 WTI, 15% royalty interest, $2.50 WTI differential, 10 producing wells, 20% annual decline in production, $5,500/well monthly operational cost, $3-5/bbl crude oil gathering and transportation expenses, 8% production taxes, 1% annual fixed OPEX reduction synergies, and pre-tax cash flows. The increased production from the EOR project is based on a 5% OOIP increase in estimated ultimate recovery (EUR). EOR tax benefits are not captured in pre-tax forecasts.

$/bbl Dynamic

Figure 1 shows the base case without an EOR project. As expected, the OPEX $/bbl increases through time as the production declines.

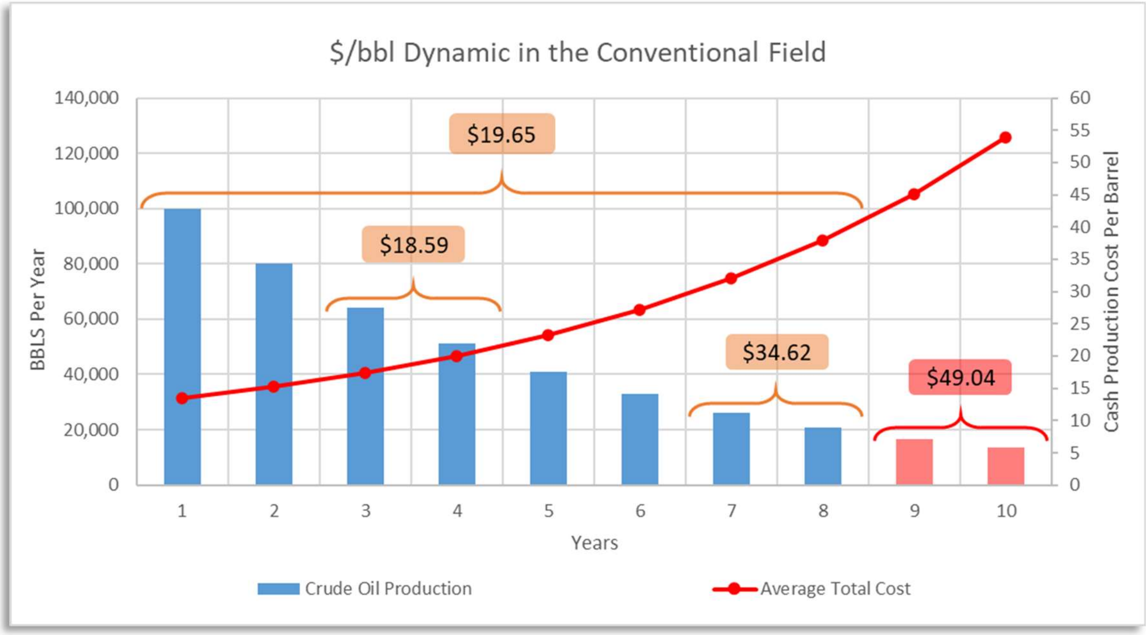


Figure 1. Graph of oil production versus time with calculated cash production cost per barrel based on assumptions discussed above. Brackets show averaged production cost per barrel over specific time periods.

Figure 2 adds the production from the EOR project to the chart and shows the $/bbl is lower since most of the costs are unchanged. Pumping more oil and less water does not significantly alter operational costs, but does improve cash flow from sales of greater amounts of oil.

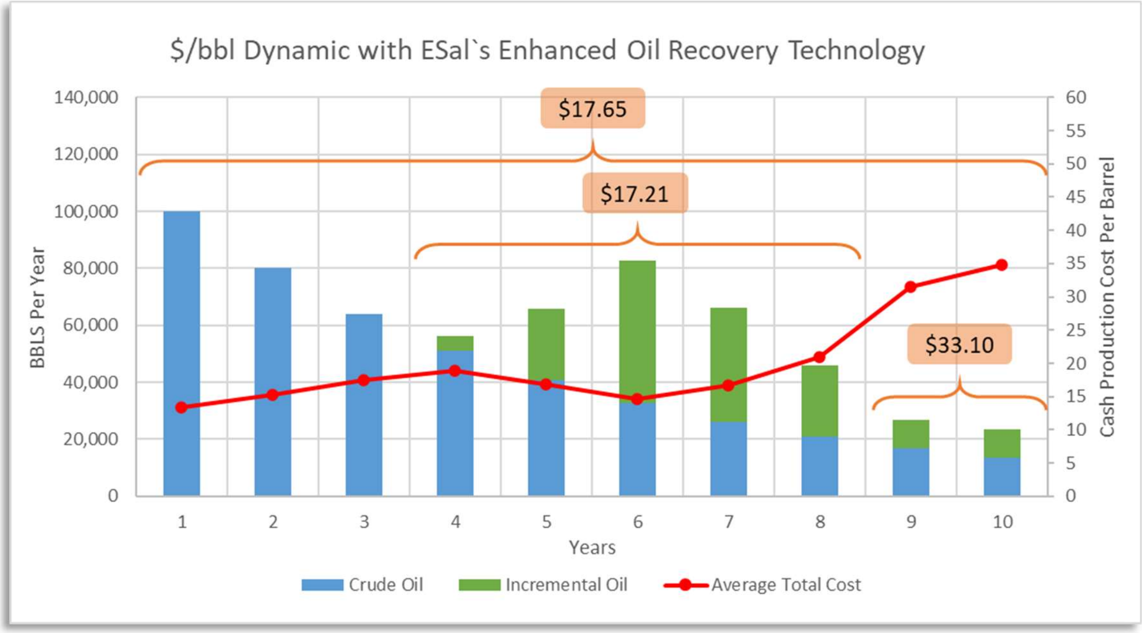


Figure 2. Graph of oil production versus time with calculated cash production cost per barrel based on assumptions discussed above. The EOR recovery is based on typical ESal EOR projects that have little or no CAPEX and 5% OOIP additional recovery. Brackets show averaged cost per barrel over specific time periods.

Types of Expenses

It is important to note that in standard waterflood operations, the per barrel production costs are constantly increasing because, while production declines, most operational costs remain relatively fixed. Tracking these changes throughout the life of the field is important for economic forecasting and evaluation of the overall project performance.

The goal of this paper is to compare the financial viability of EOR technologies to other reserve-boosting investments including exploration, drilling, and acquisitions. This will be accomplished by including baseline expenses for both methods, arriving at a clear number for each option's true $/bbl costs.

Types of Expenses

Per-barrel production expenses consist of two main classes:

- First is CAPEX, represented in accounting as depletion, depreciation, and amortization over time after the expenditure. Often referred to as sunk costs, they mostly provide an insight on the long-term profitability of an asset from its development.

- Second is OPEX, which includes cash expenses such as lease operating expenses, production taxes, and sales, general and administrative. These categories describe the dynamics of past, present, and future cash flows.

While both types are important, most companies have historically concentrated on CAPEX. The industry's method of replenishing reserves focuses on E&P, applying the metric of exploration and development costs per barrel. Secondary, tertiary, and other enhanced oil recovery projects are often downplayed and not directly compared to the per-barrel costs of recovering new oil.

Numerator and Denominator

When prices inevitably slide, operators quickly shift focus to the second class of expenses (OPEX): pumping costs per barrel to try and increase profitability. This is particularly true when oil fields enter the secondary recovery phase - waterflooding. Oil fields have life spans measured in decades during waterflooding and develop predictable decline curves. During this portion of field-life the calculation can be simplified to total cash operating expenses divided by the cumulative barrels of oil recovered during a specific period: a month, year, or life of the field. This paper will focus on the economics of the second phase of production because it is critical in evaluating enhanced oil recovery technologies and production improvements in existing oilfields.

The Numerator in the $/bbl Equation

Waterfloods require significant upfront infrastructure investments for injected, produced, and disposable water handling. Due to high volumes and field longevity, that infrastructure must be maintained for decades in many cases. Over that time, infrastructure depreciates, leaving cash operating expenses mostly fixed. While the assumption of “mostly fixed” is applicable to conventional oilfields, an in-depth investigation of SEC documents and report audits suggests that, on the macro scale, about 2/3 of total production expenses are fixed while 1/3 are variable.

The focus in EOR project evaluation is first on the equation’s denominator (cumulative barrels recovered). Future publications will dig deeper into the difference between numerator and denominator technologies, but in this case, the denominator refers to increasing the amount of oil that can be recovered, the estimated ultimate recovery (EUR). Numerator technologies can include digitalized production monitoring, data management, analysis, pollution monitoring, automation, efficiencies, and billing optimization. Denominator technologies include enhanced oil recovery, production optimization, improved drilling and completion, and waterflood designs.

Numerator and Denominator

The Denominator in the $/bbl Equation

Conventional assets under waterflood or tertiary recovery typically produce 90-95% of barrels of energy (BOE) from crude oil. Gas is often flared or sold at very low prices, leaving oil to account for virtually all production revenues. So EOR goals focus on maximizing crude oil recovery. Throughout the life of the field, the number of barrels recovered during later periods of time typically follow established decline curves.

$$\frac{Total\ CAPEX + Total\ Cash\ OPEX}{Cumulative\ Barrels\ Recovered}$$

$$in\ a\ \boldsymbol{specific\ timeframe}$$

Dynamics of Fixed and Variable Operating Expenses

The denominator is constantly decreasing due to production decline. Establishment of a decline curve in mature fields creates opportunities for good reserves estimates and cash flow planning, but it comes with challenges related to ever-growing pressure to reduce the $/bbl production costs. The numerator decreases as the variable costs decline, but at a much lower rate than production. Since about 2/3 of cash operating expenses are fixed, increasing the denominator (number of barrels recovered) has only minimal effect on total expenses, significantly increasing operational cash flow.

Compelling Financial Case for EOR

As Figure 3 below reveals in more detail, total production expenses generally decrease over the life of the field due to lower total variable production costs (gathering & transportation, and production taxes) associated with lower production. Operational efficiency improvements and other cost-reduction measures also play a part, but this change in total operational expenses is much less than typical production changes because the numerator in the equation is only slightly affected by the volume of crude oil produced. This leads to ever increasing per-barrel production costs up to the breakeven point. This point is often referred to field`s economic limit.

The EOR cost example below uses wettability alteration RightWater® technology. Defining proper salinity and ionic composition for injected water can release a significant portion of a reservoir’s previously unreachable oil. The process includes securing an alternative water source that improves reservoir wettability at a very low CAPEX without changing the OPEX. Figure 4 shows the result of a $500,000 CAPEX investment together with the increase in recovery.

Figure 4 shows production almost doubles in year 6, however, total cash production costs did not rise significantly. This resulted in an extremely low cost of producing incremental barrels of oil. Additionally, the EOR technology prolonged field life and unlocked previously uneconomic barrels of oil from the base decline curve in years 9 and 10. In those years, incremental barrels were added to the total production, pushing it above the economic limit.

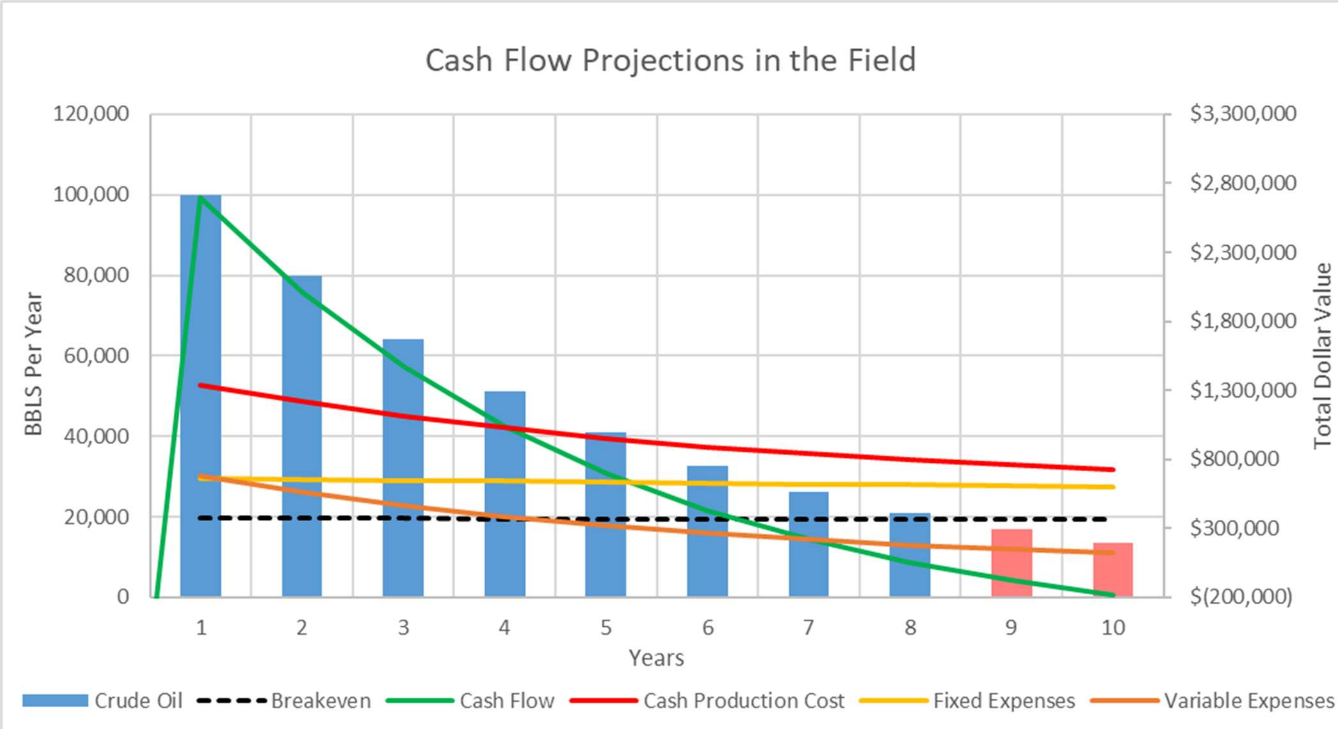


Figure 3. Graph of oil production versus time with calculated cost per barrel based on assumptions discussed above. Red line is total cash production costs (fixed + variable). Costs and production are based on 20% annual decline.

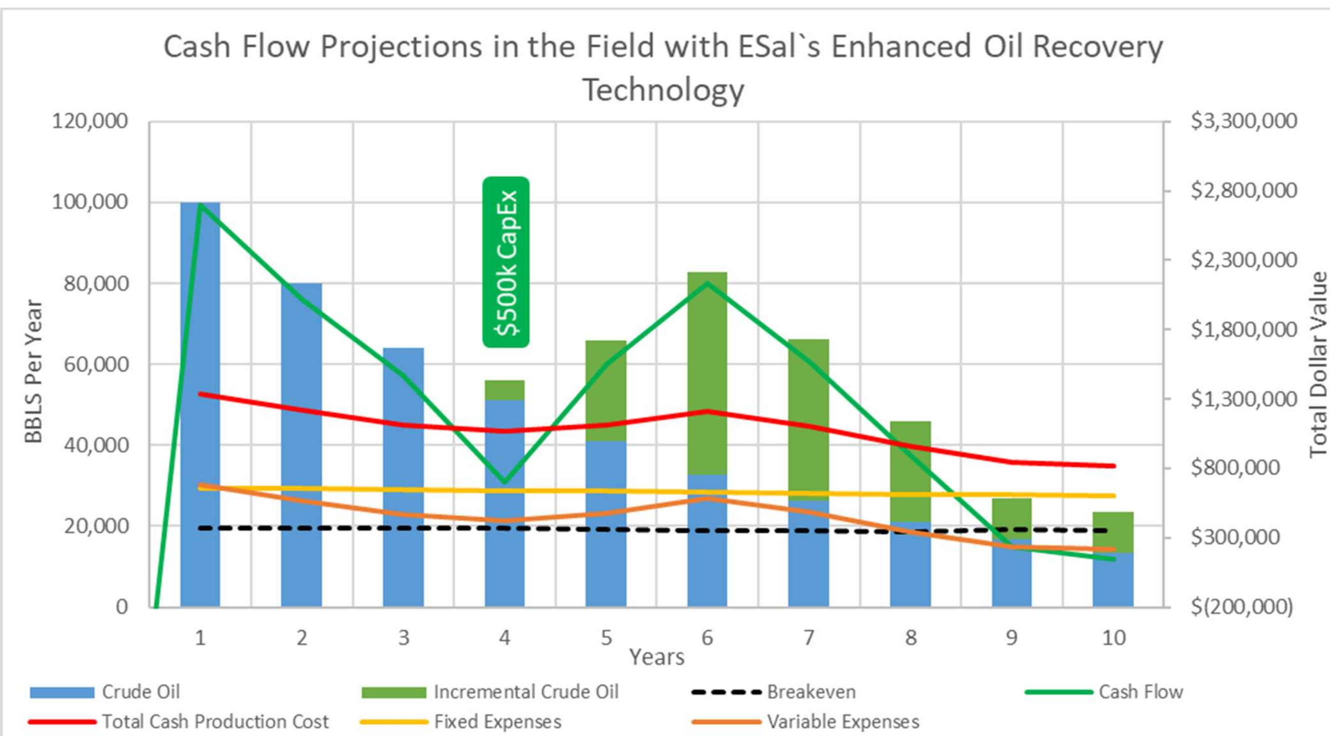


Figure 4. Graph of oil production versus time with total dollar value based on adding a one-time CAPEX expense related to increased production (e.g. drilling source water well). Red line is total cash production costs (fixed + variable). Costs and production are based on 20% annual decline supplemented by EOR starting in year 4. EOR costs and recovery based on ESal EOR projects with $500,000 CAPEX.

Figures 5 and 6 show the same information in $/bbl metrics. The figures show that the cost per barrel steadily increases with time as the production declines, while adding more barrels with enhanced oil recovery technology lowers the ever increasing per barrel production cost.

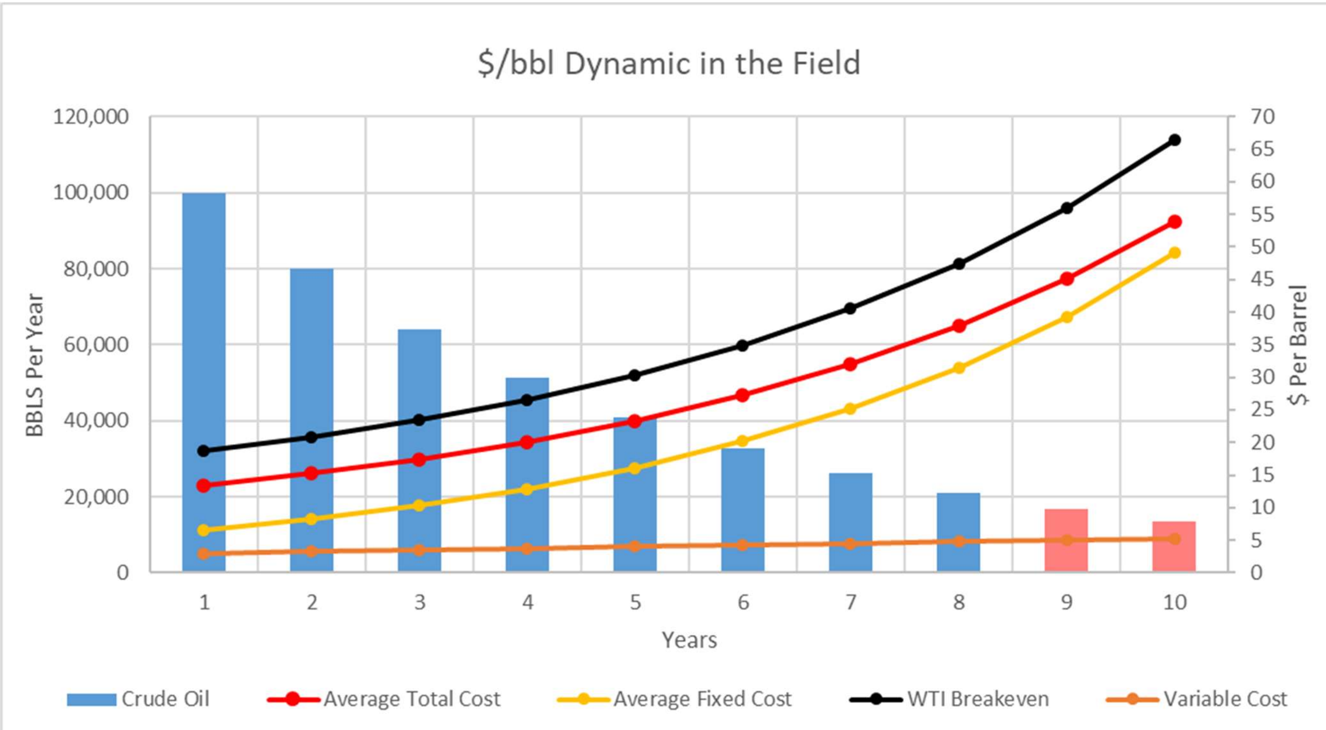


Figure 5. Graph of oil production versus time with calculated cash production cost per barrel based on assumptions discussed above. Red line is total cash production costs (fixed + variable).

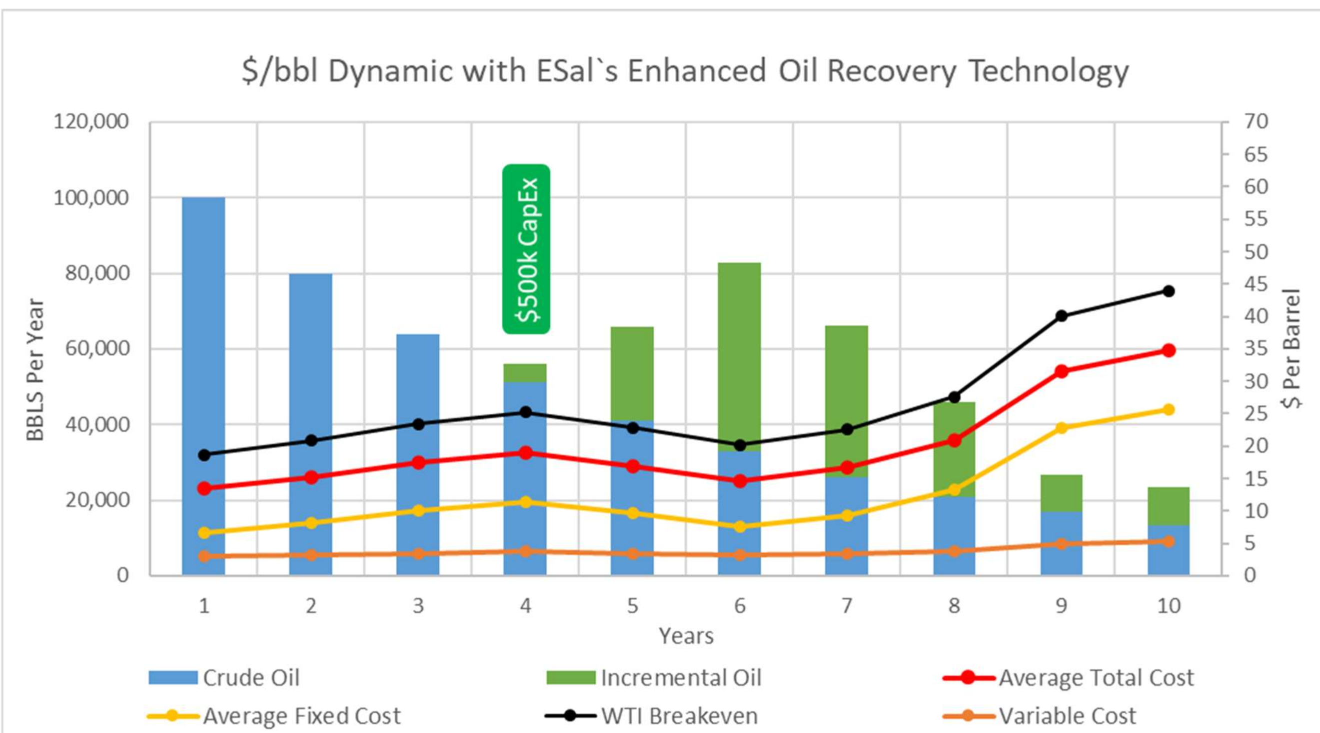
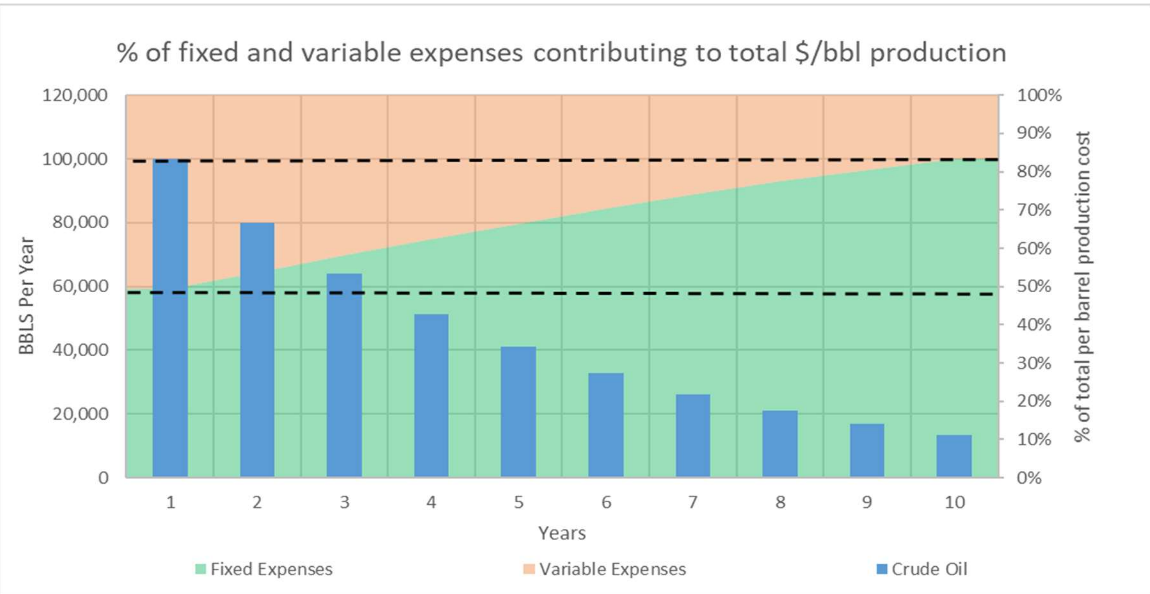


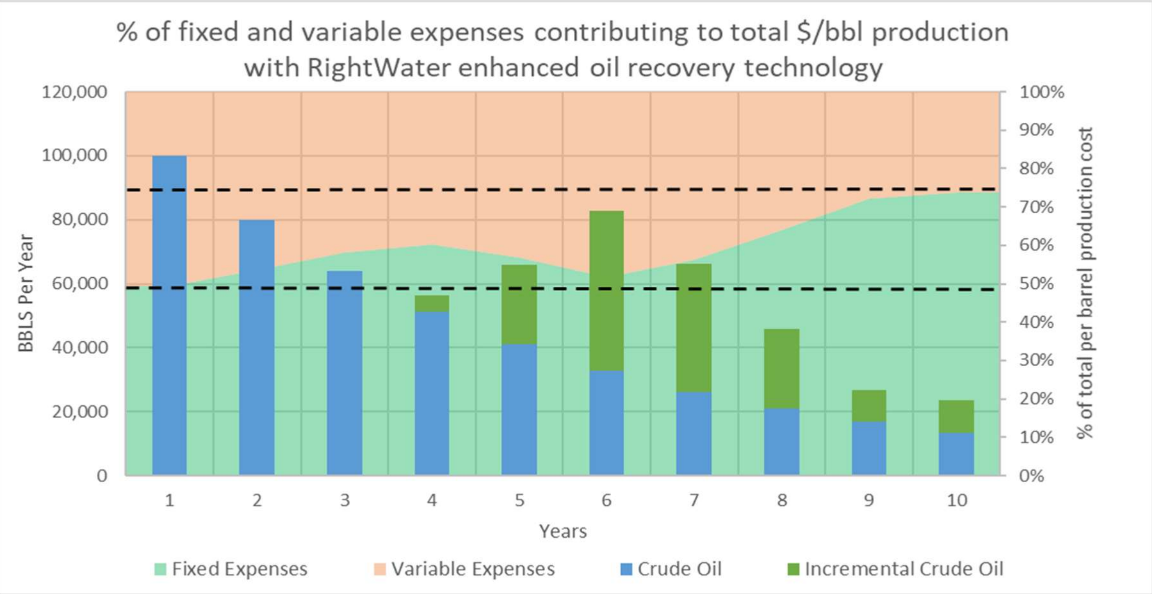
Figure 6. Graph of oil production versus time with calculated cash production cost per barrel based on assumptions discussed above. Red line is total cash production costs (fixed + variable). EOR costs and recovery based on ESal EOR projects with $500,000 CAPEX.

To reduce production costs, operators can either decrease the numerator (operating expenses) or increase the denominator (number of barrels produced) in the $/bbl equation

A significant denominator boost will not correspondingly increase total operating expenses because most of those costs are fixed, assuming there is no significant OPEX associated with the EOR technique. Considering $/bbl CAPEX, low-cost EOR technologies are becoming more attractive to operators because exploration and drilling costs, on the other hand, are rising at a rate of 10% CAGR. Combining both factors, EOR technologies can more cheaply unlock and produce new barrels of oil than any other strategy.

The examples above identified the fixed production cost synergies of enhanced oil recovery technologies. Identifying the highest ROI opportunities depends on a field's maturity and cost structure.





Figures 7 and 8. Show the dynamics of variable and fixed expenses as percentage of total cash operating expenses throughout the life of the field with and without enhanced oil recovery technology in place.

Enhanced oil recovery technologies are more attractive at later stages of the field's life, when mostly fixed production costs contribute to $/bbl metrics that are nearing the breakeven point.

Risk/Reward Comparisons for Increasing Reserves through Acquisitions & Divestitures (A&D), Drilling & Completion (D&C), and Enhanced Oil Recovery (EOR)

A&D: Relatively low risk but low reward. Acquisition cost per new barrels of oil is high and targets relatively modest long-term profit margins. With oil prices hovering around $50/bbl, the costs of acquiring reserves can reach up to $20/bbl without consideration of future CAPEX and retirement obligations. (Based on select data retrieved from boereport.com)

D&C: High risk with high reward. This strategy still requires property acquisition, development, and multi-year capital deployment programs, resulting in relatively high upfront costs of increasing reserves on the company balance sheet. CAPEX of D&C ranges between $16 and $34 per barrel, not including the cost of acquiring the properties. (Based on data from DrillingInfo)

EOR: Low-high risk depending on the technology, with high potential reward. Improvements and technological advancements allow EOR to land within $5-20 per barrel range. Most benefits come from improving production in existent fields and infrastructure, providing low-cost solutions. ESal targets its EOR technology costs at less than $4 per incremental barrel unlocked. Risk is mitigated by executing pilot projects to verify costs and benefits.

Key Takeaways

Increasing the denominator at a low cost has a much higher effect on profitability than cost-reduction efforts.

Enhanced oil recovery projects can deliver new crude oil at a lower cost per barrel than new development and drilling programs.

Taking advantage of synergies in fixed operating expenses in developed conventional assets is a cost-effective strategy for diversifying capital investment and company operating portfolio.

EOR technologies provide high undiscounted ROI on projects for profitable and sustainable long-term investments.

As upheaval continues in the energy sector, conventional methods of coping with cost structure are less and less effective. Producers are turning to proven new technologies to more effectively increase and recover proven, probable, and possible reserves (P1, P2 and P3). ESal's EOR process that changes salinity in order to optimize wettability has proven in the field to be a technology that improves the denominator of the equation without materially affecting the numerator.

Evaluating Enhanced Oil Recovery projects

Focus on cash flows
Consider only cash operating expenses and exclude DD&A expenses - they do not affect the pre-tax cash flow, nor do they contribute to a mature field's present value.

Define fixed and variable field operating expenses
Pumping costs, wages, planned maintenance, and overhead are mostly fixed expenses. Gathering, storage, transportation, and production taxes are typically variable and tied to production volumes. As observed in historic data, big-scale operations typically allocate 2/3 of total expenses towards fixed, and 1/3 towards variable as a conservative measure, all depending on field-specific operations.

Estimate CAPEX and incremental barrels recovered from enhanced oil recovery technologies
The $/bbl metric can be used to compare exploration and drilling costs to EOR costs. Depending on the technology used, there can be a big range, and new techniques should target the lowest $/bbl cost possible. Risk-adjusted metrics should be used to fit company risk-return profile.

Estimate incremental cash operating expenses, fixed and variable
How will the cost of production per barrel pattern look going forward and how will changes in fixed or variable expenses affect it?

Compare cash flows from the field with and without enhanced oil recovery technologies
Side by side comparison should clearly illustrate the cash flow under each scenario.

Analyze incremental cash flow
Apply common financial and economic analysis metrics such as NPV, IRR, MIRR, ROI (disc / undisc), Payback Period (disc / undisc), Sensitivity Analysis, Monte Carlo, and any other risk analysis techniques.

Compare these projects to regular exploration, development, and drilling programs
Prioritize the ones that bring highest ROIs, diversify investment portfolio & capex spending, reduce risks, maximize returns, improve efficiency, and contribute to the responsible use of non-renewable natural resources.

Why ESal is right for you

Is Your Field Experiencing

Low Oil Production

High Water Cut

Poor Waterflood Performance

Poor Chemical Performance

ESal`s RightWater® is for You

Increase Total EUR

Fast and accurate testing to determine the optimal solution

No change in normal operations

Successful pilot test can be used to increase reserves

RightWater® technology typically does not exceed $4 per incremental barrel

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