DISSERTATION

# MODELLING AND ANALYSIS OF SYSTEMS ON OFFSHORE OIL AND GAS PLATFORMS


Submitted by

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In partial fulfilment of the requirements

For the Degree of Doctor of Philosophy

Colorado State University

Fort Collins, Colorado

Fall 2019


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ABSTRACT

MODELLING AND ANALYSIS OF SYSTEMS ON OFFSHORE OIL AND GAS PLATFORMS


This research examines oil and gas systems from the seemingly underutilized perspective of energy; this is counterintuitive since the energy content of hydrocarbon products is its most distinguishing characteristic and the very reason why it is valued by society. It is clear that the amount of energy required to extract crude oil is increasing over time, at the long-term global level, and at the much shorter time span of individual fields. The global trend is a well-documented phenomenon and is related to the depletion of the most energetically favorable reservoirs and a coincidental growing global demand for energy. Concerning existing fields, it is often necessary to implement increasingly higher energy intensity methods to extract the remaining crude oil resources. These trends are the impetus for the industry to gain a better understanding of the relationship between the application of energy and the production of crude oil across a wide spectrum of production methods.

Reservoir management and petroleum engineering are highly evolved and scientifically rigorous disciplines, but their practices and methods tend to circumvent the single most important, value-added, quality of hydrocarbon extraction systems, the actual energy recovered, which is the difference between the energy extracted and the energy applied. Therefore, the motivation for this research is to outline existing energy evaluation methods which can be applied to oil extraction systems, illuminate the elements of these methods which can provide the greatest practical advantage to the oil and gas industry, and last, but certainly not least, to demonstrate the pivotal role of energy in crude oil extraction systems.

As such, case studies are developed for three small offshore oilfields. The techniques applied include the identification of appropriate boundaries for the system, subsystems and equipment items, the calculation of energy related balances at each level, the development of energy related performance indicators, and lastly, analysis of performance. Indicators, such as the Energy Intensity (EI) and the Energy Return on Investment (EROI), are derived for different levels of the crude oil extraction systems.

The dimensionless EROI is the energy returned divided by the energy invested, while the thermodynamic EI is essentially the inverse of the EROI, although alternative dimensional EIs may also be applied on a commodity or process basis.

The case studies begin by developing long term time-series EROIs for three oil fields, with breakdowns that take into account the construction, drilling and operational phases of each field. The results corroborated the work of other researchers that indicated that the energy required to produce crude oil at the individual field level increases over time. The calculated EROIs drop steeply in all three fields as the crude oil production declines and the production of associated formation water increases. The increasing energy intensity of the production operations phase tends to dominate the long-term EROI behaviour since construction energy is recovered quickly and drilling energy tends to decrease after the initial wells are drilled.

A more focused perspective is applied to address the main energy consumers of the three fields. It is learned that the drivers for energy consumption are the downhole Electrical Submersible Pumps (ESPs) and the surface mounted water disposal, or injection pumps, which together constitute more than 95% of the total energy consumed in each of the three offshore fields. There are relatively few water disposal, or injection, pumps and their performance is well understood. On the other hand, the numerous ESPs, which are narrow multi-staged centrifugal pumps installed downhole in the casing of the well, are more notable due to the extreme conditions in which they operate, the diversity of operating conditions, and their essential role in extracting hydrocarbons from the reservoirs. Consequently, a set of 18 ESPs are analyzed in detail by conducting energy balances around each pump's electrical and hydraulic subsystems. It is shown that the greatest energy losses in the ESP system are the hydraulic losses which occur within the pumps themselves. It is also learned that the performance of the ESPs varies considerably among the population in terms of their energy returns (EROIs), EIs and related fuel costs, and that this information can be used to prioritize and rank the wells.

Over the course of this research, it became evident that each energetic indicator serves a very distinct purpose. The EI is a parameter which can be used to better understand the efficiency of processes and products, which is essential information for oil and gas operational managers in terms of pursuing energy optimization, while the EROI parameter is a more holistic indicator which is related to the value of energy derived from a system or subsystem, and how it is affected by different activities and conditions. It is suggested that the EROI indicator can be applied by oil and gas managers to support decision making with respect to fields, platform and to some extent to individual wells. This researcher also believes that the EROI concept can be applied on a strategic level in support of a portfolio level evaluations. Furthermore, this researcher suggests that governmental regulators can potentially use estimated EROIs when developing fiscal terms and conditions for oil and gas concessions.

Finally, it should be noted that while ESP equipment items are modestly priced, the cost of installation, or of replacement of failed ESPs, is quite expensive due to the equipment, labor and time required for well interventions. Additionally, the loss of revenue from failed ESPs can be significant. Therefore, the pursuit of high ESP availability rates is a worthwhile goal, and a system that can predict, and potentially prevent, failures would be highly beneficial to oil and gas operators. As such, a fuzzy logical system which utilizes trend pattern matching for operational parameters is developed and tested. A derived first-pass pattern matching system based on fuzzy logic is applied to nine case studies of ESPs. The system is unable to detect an impending failure mode, but is able to distinguish between ESPs experiencing problems and ESPs running smoothly

# ACKNOWLEDGEMENTS

It would not have been possible to conduct this research without the support of my colleagues at Mubadala Petroleum, particularly our distinguished QHSSE director, Mohamed Hussen Bahatem, and our esteemed CEO, Bakheet Al Katheeri. When I initially broached my desire to pursue this research, without any hesitation they both responded with unequivocal words of support. For this, I am forever grateful.

Over the course of this research, I also had the good fortune of receiving guidance from a number of knowledgeable and experienced oil and gas industry insiders, including the Director of Developments, Khamis Al Abdali, the Manager of Wells Technology, Ikenna Chigbo, and the Manager of Subsurface Studies, Maurice Edwards. The insight and encouragement provided by these gentlemen enabled me to shape the research into a more practical form.

Mubadala Petroleum is serious, goal-oriented, business, but it is also a place of warmth, kindliness, joviality and comradeship. In many ways Mubadala Petroleum is like a close family, which I feel very fortunate to have been a part of.

Finally, I would like to acknowledge my outstanding advisor at Colorado State University, Daniel Olsen. It’s not easy to have a good working relationship when the student and the advisor are more than 6,000 miles apart, but somehow it worked, partly due to internet-based technologies, which we used regularly, but mainly due to Dr, Olsen’s unwavering commitment and support for this research. I am very grateful that Dr. Olsen accepted me as a student and that I have had the opportunity to work closely with him these last few years.

DEDICATION

This is dedicated to my wonderful parents, Marilyn and Solomon Grassian, and my amazing sister, Vick Grassian. My parents have provided unending love and encouragement to me throughout my life. They are my source of strength, my inspiration, and my foremost roles models. I am a very lucky person to have them in my life. My professional role model has always been, and will always be, my incredibly accomplished sister. She has demonstrated to me time and time again the benefits of persistence, dedication and passion. Her example is a constant source of inspiration to me. Vicki is also an incredibly dear sister and my closest friend.

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Chapter 1 Symbols
$BEP_{full\ cycle\ economic}$ = total economic breakeven (USD/barrel)
$BEP_{operational\ economic}$ = operational economic breakeven point (USD/barrel)
$BEP_{lifting\ economic}$ = lifting economic breakeven point (USD/barrel)
$BEP_{lifting\ energy}$ = lifting energy breakeven point (GJ/barrel)
$E_{crude\ oil}$ = thermal energy of crude oil production (GJ/BBL)
$EI_{crude\ oil}$ = operational energy intensity of crude oil production (GJ/BBL)
$E_c$ = consumed construction energy (GJ)
$E_d$ = $c$onsumed decommisioning energy (GJ)
$E_g$ = generated energy (GJ)
$E_o$ = consumed operational energy (GJ)
$E_{net\ total}$ = net energy (GJ)
$E_{net\ op}$ = energy surplus during the operational phase (GJ)
$\dot{E}_g$ = rate of energy generation (GJ/s)
$\dot{E}_g$ = generated energy rate (GJ/s)
$OPEX_{\ total}$ = total operational expenses (USD/BBL)
$P_{crude\ oil}$ = market price of crude oil (USD/BBL)

Chapter 2 Symbols
$EROI\_1d_{lifting}$ = EROI for lifting
$EROI\_1d_{lifting+drilling}$ = EROI for lifting and drilling
$EROI\_1d_{lifting+drilling+contstruction}$ = EROI for lifting, drilling and construction

Chapter 3 Symbols
$C$ = pipe friction factor
$ESP$ = electrical submersible pump
$E_{barrel}$ = chemical energy per barrel crude (GJ/BBL)
$E_{cost}$ = energy cost (USD/GJ)or (USD/kWh)
$\dot{E}^{in}_{lifting}$ = overall lifting power in (kW)
$\dot{E}^{in}_{ESP}$ = ESP electrical power in (kW)
$\dot{E}^{in}_{water\ injection}$ = water injection electrical power in (kW)
$\dot{E}^{in}_{process\ and\ utilities}$ = process and utilities electrical power in (kW)
$\dot{E}^{out}_{lifting}$ = crude chemical energy (kJ/s)
$\dot{E}^{in}_{lifting}$ = lifting energy (kJ/s)
$\dot{E}^{in}_{e}$ = electrical power input (kW)
$\dot{E}^{surface\ loss}_{e}$ = electrical power loss in surface equipment (kW)
$\dot{E}^{cable\ loss}_{e}$ = electrical power loss in cables (kW)
$\dot{E}^{esp\ motor\ loss}_{e}$ = electrical loss by ESP motor (kW)
$\dot{E}^{in}_{e}$ = electrical power input (kW)
$\dot{E}^{esp\ motor\ in}_{e}$ = electrical power into ESP motor (kW)
$\dot{E}^{uplifting}_{h}$ = hydraulic lifting power (kW)
$\dot{E}^{bp}_{h}$ = hydraulic power lost due to surface backpressure (kW)

$\dot{E}_h^{fr} =$ frictional power loss (kW)
$\dot{E}_h^{esp\ pump\ loss}$ = power loss in ESP pump
$EI_{lifting} =$ energy intensity for lifting only (GJ/BBL)
$EROI_{lifting}$ = energy return on enegy invested for lifting only
$f_2, f_1 =$ AC frequencies, Hz
$GJ$ = gigajoule
$g =$ gravitational constant (9.81 m/sec2)
$HP$ = horsepower
$Hz$ = hertz
$h =$ total developed head (meters)
$h_{bp} =$ head from surface backpressure (meters)
$h_{TVD} =$ true vertical depth (meters)
$I$ = current (amps)
$ID$ = pipe inner diameter (inches)
$kJ$ = kilojoule
$kW$ = kilowatt
$kWh$ = kilowatt hour
$LC =$ lifting cost (USD/BBL)
$N_{1,2}$ = pumping speeds (RPM)
$N_{P,S} =$ number of turns in the primary and secondary coils
$q$ = flowrate (barrels per hour)
$\dot{Q}_{crude}$ = crude oil production rate (barrel per hour)
$Q =$ flowrate (cubic meters per hour)
$\mathrm{R_T} =$ resistance of the power cable at well temperature (ohms)
$U$ = voltage (volts)
$U_{P,S} =$ primary and secondary voltage (volts)
$\Delta H_{crude}^{chemcal}$ = crude oil chemical energy (GJ/barrel)
$\Delta \mathrm{H_{fr}}$ = frictional head loss in tubing (ft/100 ft)
$\emptyset =$ phase angle
$\rho$ = fluid density in (kg/meter^3 )
$\eta^{electrical}$ = electrical power efficiency for each well
$\eta^{esp\ motor}$ = ESP motor efficiency (derived from manufacturers motor efficiency curves)
$\eta^{hydraulic}$ = hydraulic efficiency for each well
$\eta^{overall}$ = overall energy efficiency for each well
$\eta^{surface}$ = surface equipment power factor (assumed to be 0.95)
$\gamma_l =$ specific gravity of produced liquid

Chapter 4 Symbols
$Cg_{exhaust}$ = heat capacity of exhaust gas J/(kg · K)
$C_{water}$ = heat capacity of water J/(kg · K)
$EI_{cost}$ = cost energy intensity (USD/barrel)
$EI_{thermodynamic}$ = thermodynamic energy intensity (kJ/kJ)
$\dot{E}_{electrical\ input}$ = electrical energy flow (kJ/s)
$\dot{E}_{elec.}$ = electrical energy flow (kJ/s)
$\dot{E}_{exhaust}$ = exhaust energy flow (kJ/s)
$\dot{E}_{fuel}$ = fuel energy flow (kJ/s)
$\dot{E}_{heat}$ = heat energy flow (kJ/s)
$\dot{E}_{hydraulic\ head}$ hydraulic head energy flow (kJ/s)

$\dot{E}_{inj.\ fluids}$ = injection fluids energy flow (kJ/s)
$\dot{E}_{product}$ = product energy flow (kJ/s)
$\dot{E}_{res.\ fluids}$ = reservoir fluids energy flow (kJ/s)
$\dot{E}_{vent\ and\ flare}$ = vent and flare energy elow (kJ/s)
$F$ = future amount
$g$ = 9.81 m/s$^2$
$h_{exhaust}$ = exhaust specifc enthalpy (kJ/kg)
$h_{inj.\ fluids}$ = injection fluids specifc enthalpy (kJ/kg)
$h_{in}$ = flow in specifc enthalpy (kJ/kg)
$h_{out}$ = flow out specifc enthalpy (kJ/kg)
$h_{product}$ = product specifc enthalpy (kJ/kg)
$h_{res.\ fluids}$ = reservoir fluids specifc enthalpy (kJ/kg)
$h_{vent\ and\ flare}$ = vent and flare specifc enthalpy (kJ/kg)
$i$ = nominal annual interest rate
$kW$ = kilowatt
$kJ$ = kilojoule
$LHV_{Fuel}$ = lower heating value (kJ)
$\dot{m}$ = mass flow rate (kg/s)
$\dot{m}_{cooling\ water}$ = cooling water mass flow rate (kg/s)
$\dot{m}_{exhaust}$ = exhaust mass flow rate (kg/s)
$\dot{m}_{fuel}$ = fuel mass flow rate (kg/s)
$\dot{m}_{product}$ = product mass flow rate (kg/s)
$\dot{m}_{res.\ fluids}$ = reservoir fluids mass flow rate (kg/s)
$\dot{m}_{vent\ and\ flare}$ = vent and flare mass flow rate (kg/s)
$n$ = number of interest rate periods
$P$ = principal amout at a time assumed to be present
$\dot{Q}_{cooling\ water}$ = heat flow of cooling water (kJ/s)
$\dot{Q}_{exhaust}$ = heat flow exhaust (kJ/s)
$\dot{Q}_j$ = heat flow of stream j (kJ/s)
$\dot{Q}_{loss}$ = heat loss (kJ/s)
$\dot{Q}_{out}$ = heat flow out (kJ/s)
$SFC$ = specific fuel consumption (kg/s)
$t$ = time (years)
$T_{ambient}$ = abient temperature (K)
$T_{cooling\ water}$ = cooling water temperature (K)
$T_{exhaust}$ = exhaust temperature (K)
$V_{in}$ = velocity in (m/s)
$V_{out}$ = velocity out (m/s)
$\dot{W}_j$ = work (kJ/s)
$z_{in}$ = elevation in (m)
$z_{inj.\ fluids}$ = elevation of injection fluids out (m)
$z_{out}$ = elevation out (m)
$z_{res.\ fluids}$ = elevation of reservoir fluids in (m)
$\eta_{plant}$ = plant energy efficiency
$\eta_{power\ generation}$ = power generation efficiency
$\eta_{pump\ system}$ = pump system efficiency

Chapter 5 Symbols

$A_{i,k}$ = premise k of rule i
$a_k$ = input variable k
$D_i$ = degree of fulfilment
$n$ = number of days in the period
$p$ = p norm value
$\mu_{A_{i,k}}(a_k)$ = membership function of $A_{i,k}$
$x$ = meausred daily value
$\bar{x}$ = mean of the daily values
$y$ = days
$\bar{y}$ = mean of the days

Chapter 6 Symbols

$\dot{E}_{net\ operational}$ = the net surpluse rate during the operational phase (GJ/s)
$\dot{E}_g$ = rate of energy generation (GJ/s)
$\dot{E}_{op}$ = rate of operational energy consumption (GJ/s)
$E_{net\ operational}$ = the total energy return during the operational phase (GJ)

# CHAPTER 1 – INTRODUCTION AND RESEARCH MOTIVATIONS

## 1.1 Introduction

The purpose of the oil and gas industry is to produce high energy hydrocarbon products to be used by society. These hydrocarbon products are predominantly used as fuel for power generation and transportation. Liquid fuels used in transportation are primarily derived from crude oil. It is clear that the amount of energy invested to produce crude oil products is increasing on both a global and a local scale. In light of this trend, it is critical for the industry to gain a better understanding of the relationship between applied energy and crude oil production across a wide range of production methods and conditions. The task is not straightforward since crude oil extraction is an inherently dynamic process, unlike other types of industrial processes. Nonetheless, the imperative remains, and the starting point is the application of practical energy accounting methods.

There is a wide body of research into methodologies for analyzing and improving energy utilization in the manufacturing and process industries, including in the petrochemical industry [1-3]. Considerably less work has been undertaken to develop practical approaches for analyzing the energy utilization of oil and gas extraction processes, which are commonly referred to as "upstream". This may be due to the challenging nature of upstream processes, which entail a high degree of uncertainty concerning the full lifecycle conditions. The dynamic nature of upstream processes is so pervasive that even during the relatively stable plateau period of hydrocarbon production other aspects of the overall system can still be variable, such as the reservoir pressure and the production of side-products, e.g., water. Furthermore, advancements in recovery methods and technologies can lead to operational conditions which were not originally envisioned by the development team.

It should also be noted that in most upstream oil and gas operations, a portion of the produced gas, or crude oil, is used internally to generate power, but this resource should never be considered as "free". Improved energy efficiency, even while using unmarketable reservoir fluids (e.g. stranded gas in an oil development) can lead to lower operational and capital costs. Lower capital costs are realized from a reduced requirement for power generation and related equipment and complimentarily lower operational costs are achieved due to lower maintenance costs. Another benefit of minimizing energy consumption is a reduction in emissions, regardless of whether the fuel consumed is produced or purchased. Therefore, the "free fuel" mindset can impede the approach necessary to minimize energy consumption, costs, and emissions.

It is also apparent that for upstream processes an improvement in energy efficiency by itself does not necessarily constitute an economic improvement (e.g. if the savings from energy efficiency are offset by a loss of income from lower production rates). Therefore, it is necessary to apply a life-cycle approach, which takes into account present value trade-offs for energy improvement options. The present value method factors in all of the relevant economic considerations, such as the production profile, market prices for hydrocarbons, the operating and maintenance costs, the capital costs, and fiscal outlays such as taxes and royalties.

Despite the unique characteristics and challenges of upstream processes, there are a number of general energy management techniques which can be applied. These techniques include the delineation of appropriate boundaries for the system, subsystems and equipment items, the calculation of energy related balances at each level, the development of different types of energy related performance indicators, the analysis of performance against design expectations and best practices, the application of a structured decision framework for improving energy utilization and the overall integration of energy performance into production management practices [4].

### 1.2 Alignment with Systems Engineering

The practices described in this research above are aligned with the Systems Engineering approach in a number of ways, which are outlined in the following sections.

#### *1.2.1 Oil Extraction as a "System"*

A system can be defined as "a set of interrelated components functioning together towards common objective(s) or purpose(s)" [5]. The purpose of an oil extraction scheme is to safely, environmentally and economically extract hydrocarbon resources from subterranean reservoirs. Clearly, an oil extraction scheme, which is the focus of this research, satisfies this basic definition of a system.

*1.2.2 Systems Perspective*

Like any system, an oil and gas system can be viewed from a number of different perspectives, and it is only by viewing a complex system from diverse viewpoints that the overall nature of the system can be revealed. This is one of the central tenets of systems thinking. There are nearly an unlimited number of frames of reference that can be applied; some of the high level ones are related to economics, environmental, technical, political, sociology, etc. The identifying nature of complex systems, such as with oil and gas extraction systems, is the inherent connectedness of all of these different frames of reference, and as such the development of new perspectives, or the enhancement of exiting perspectives, incrementally increases our understanding of the system as a whole. Therefore, this research examines oil and gas systems from the infrequently used perspective of energy.

*1.2.3 Lifecycle Approach*

The lifecycle of an oil extraction system satisfies the basic requirements of the system's development model, since it entails the needs analysis, concept evaluation and selection, preliminary design, development/realization, operations and the decommissioning phases. It is suggested that energy considerations should be integrated into the full lifecycle of the oil extraction system, as some operators are striving to accomplish [6].

*1.2.4 Definition of System Operational Parameters*

In the early phases of the oil extraction system lifecycle it is necessary to define preliminary system operational parameters. This research suggests the inclusion of energy related parameters such as energy intensity and absolute energy consumption, and to apply them at all levels of the system, including the main subsystems and equipment items. Energy related parameters should be considered technical performance measures (TPMs) of the system, which shall be the basis of design, and continuously verified during the developmental phase and ultimately validated, or not, during the operational phase of the system.

### *1.2.5 Analysis of Design Alternatives*

The concept selection analysis will evaluate alternatives exploitation strategies with differing energetic characteristics such as:

- Reservoir exploitation strategy
- Stimulation and recovery methods
- The number of wells
- The number of drilling locations
- Surface processing and transportation options
- Energy sourcing options

Energy and economics are clearly interrelated. Each consideration has a material impact on the energetic profile of the development and on the overall economics. It is sensible to closely analyze the trade-offs between options to ensure an optimized concept selection, and this research describes appropriate methodologies and tools which can be applied for this purpose.

### *1.2.6 Functional Decomposition and Allocation of Requirements*

An integral component of the Systems Engineering Method is the functional decomposition of the system to the subsystem and component level, along with the allocation of requirements, including energy related. This practice is certainly applicable to oil and gas systems. System building blocks can be generally categorized into four types by operating medium: signals, data, materials and most relevant to this research, energy [7].

### *1.2.7 Performance Evaluation*

The systems engineering method is an iterative approach, which entails continuous verification that the predetermined requirements are met. The evaluation of performance may be with regards to capacity, reliability, availability and of particular interest to this research, energy. The performance of the overall system and all of its constituent parts are continuously evaluated. This approach is aligned with the methodology used in this research to evaluate energy related performance of oil extraction processes by decomposing and analyzing the relevant subsystems, and equipment items.

## 1.3 Research Motivation

### *1.3.1 Apply Systems Engineering Practices to Analyze Oil Extraction Processes*

It would seem that the development of best practices in the oil and gas industry, and other capital-intensive industries, is closely aligned with the emergence of systems engineering as an academic and professional discipline. The rigor by which systems engineering practices, such as those described in the preceding section, are applied in the oil and gas industry depends greatly on the organization's culture and collective experience. Typically, larger upstream oil and gas companies employ a more disciplined and structured system's approach to developments, while the approach by smaller companies tends to be less deliberate, but considerably nimbler. As with anything, a balanced approach is sensible, and this research strives to demonstrate a practical application of system's engineering, which can be adopted by both large and small oil and gas enterprises.

### *1.3.2 Document Applicable Energy Performance Analysis Methods*

Energy is a subject that has garnered considerable attention over the last fifty years or so. A number of methods have been developed, both general and specific to the oil and gas industry. This research strives to highlight the most prominent developments in energy accounting over recent times.

### *1.3.3 Demonstrate the Benefits of Conducting Energy Accounting on Oil Extraction Processes*

One of the main goals of this research is to demonstrate the benefits of applying conventional energy performance evaluation practices to the unique circumstances of oil extraction. There are numerous reasons why the energetic operational performance of an oil extraction process changes over time, some of which are anticipated, but many are unanticipated during the conceptual stage of the development. Effective measures are needed to monitor and predict performance, and very often to make critical decisions, which can have a considerable impact on the energetic, environmental and economic performance of the system. An effective way to demonstrate the importance and practicality of energy accounting in the upstream oil extraction sector is by developing case studies.

### *1.3.4 Illuminate the Energetic Behavior of Small Offshore Oil Extraction Fields*

Small oil fields collectively contribute a sizable proportion of global production, and as such are deserving of an appropriate amount attention. It has been generally observed that small fields have shorter lifecycles and tend to be more dynamic than large fields. Therefore, the time available to make critical decisions is often limited. The accelerated behaviour of small fields, compared to major fields, makes them ideal subjects for case studies, since the full lifecycle can be evaluated based on a relatively small and accessible dataset. Fortunately, the researchers have access to three small oilfields located in South East Asia, including historical data with respect to the construction, production-operations and drilling. Naturally, the energetic details of these three oil fields will not be representative of all oil fields, but it is expected that the broad applicability and benefits of the method can be sufficiently revealed by cases studies of small fields.

*1.3.5 Examine the Performance of Electrical Submersible Pumps*

"Artificial lift" is an oil and gas term, which refers to the extraction of crude oil from low-pressure reservoirs, which would generally not flow at economically sufficient rates without intervention. Artificial lift technologies are generally energy intensive, and in many cases constitute the predominant energy demand of the oil extraction system. Electrical Submersible Pumps (ESPs) are widely applied throughout the world, due to their low cost, relatively small surface footprint, suitability for a wide range of reservoir conditions, flowrates, crude properties, tolerance to deep set wells, tolerance to gas, and to a well's deviations from vertical. Therefore, this research aims to examine the energetic performance of ESPs, as well as a method to understand, and potentially anticipate, common failure modes based on trend analysis.

## 1.4 Analyzing Energy Performance

Energy management is an indispensable consideration in the industrial sector. The discipline has evolved over time and there have been numerous publications on the subject. Murray G. Patterson published a landmark paper in 1996 which described the concepts and indicators used to analyze energy efficiency of industrial processes [4]. This publication described four categories of energy indicators, namely: purely thermodynamic, physical-thermodynamic, economic-thermodynamic and purely economic as described in Table 1.1. The use of energy efficiency indicators to describe the performance of energy intensive processes has become the mainstay of modern energy efficiency analysis. There are numerous subsequent studies which expand on the early work by Patterson, but the basic categories of indicators have withstood the test of time.

*Table 1-1 Energy Efficiency Indicators [4]*

| Indicator | Example |
|---|---|
| 1. Thermodynamic Indicators | Energy input/Energy output |
| 2. Physical-Thermodynamic Indicators | Transportation sector<br>- energy input/ton-kilometer<br>- energy input/ton-kilometer/unit of time<br>Manufacturing<br>- energy input/ton of butter, bricks, wheat<br>Oil and Gas<br>- energy input/barrel of oil or MMSCFD of natural gas |
| 3. Economic-Thermodynamic Indicators | energy input/GDP<br>(usually applied at national and sectorial levels) |
| 4. Economic Indicators | national energy input ($)/national output ($ GDP)<br>(usually applied at national and sectorial levels) |

Methodologies for industrial energy efficiency studies are also well represented in literature and are typically included with the development of meaningful energy efficiency indicators, as described above. All of the methodologies generally include the following steps:

1. Definition of the boundaries for the system
2. Decomposition of the system to be analyzed
3. Derivation of energy balances for the system, subsystem and components
4. Derivation of performance indicators at all levels of the system
5. Analysis of performance
6. Identification of potential improvements
7. Continuous performance monitoring

### *1.4.1 Energy Intensity Applied to Oil and Gas*

In the oil and gas industry the term "upstream" generally refers to the processes that occur prior to refining, such as extraction, initial treatment and transportation. An excellent early reference on the subject of energy intensity in the oil and gas industry is a paper funded by the UK Offshore Operators Association (UKOOA) entitled "Energy Use in Offshore Oil and Gas Production" [8]. As one might expect from an operator's association, this research endeavored to provide practical guidance to oil and gas operators with appropriate methods and tools.

This research explores the Energy Intensity (EI) of offshore oil and gas platforms. The EI is a dimensionless ratio, which is defined as the Energy Input divided by the Energy Output, as depicted by Equation 1.1.

$$EI = \frac{Energy\ input}{Energy\ output} \tag{1.1}$$

This research suggests that the EI of a typical offshore platform is affected by a number of possible events, or trends, over the course of the field's lifecycle. A demonstrative plot of EI vs. life of field is shown in Figure 1.1. It is notable that the events which increase the energy intensity of the field significantly outnumber the events that cause a decrease.

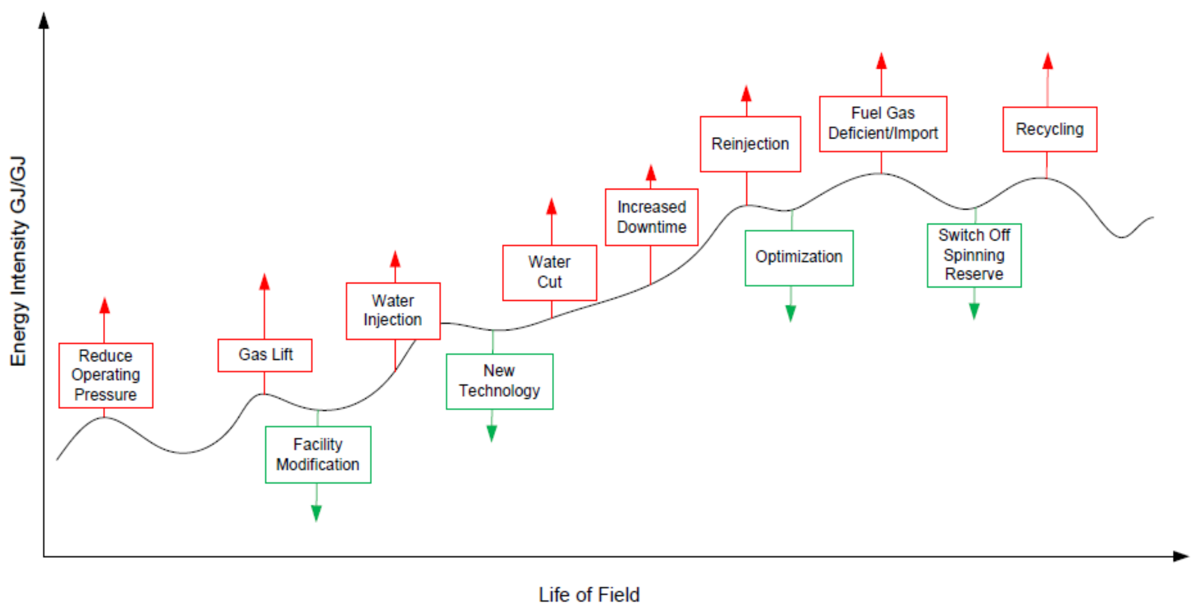


*Figure 1-1 Typical Oil and Gas Energy Intensity Lifecycle Influencing Events [8]*

Furthermore, this paper includes the opinion of experts from Shell Oil and British Petroleum (BP) regarding the key factors that influence the EI of an upstream oil and gas platform, as shown in Table 1.2.

*Table 1-2 Key Operating Practices that Influence Energy Intensity [8]*

| | |
|---|---|
| Key energy factors – oil | - System uptime<br>- System pressure relative to export pressure<br>- The need for energy intensive lift/treatment activities (gas lift, water injection) |
| Key energy factors – gas | - System throughput<br>- System pressure relative to export pressure<br>- System throughput relative to original design capacity(% recycle) |
| Key process issues | - System operating pressure relative to export system pressure<br>- Systems throughput relative to original equipment/system design basis<br>- Topsides process stability (whether prone to unplanned outages)<br>- Changes in time in gas/oil ratio (GOR), and gas /liquid ratio. |
| Key equipment issues | - Compressors, turbines, motors<br>- Electric submersible pumps<br>- Water injection requirements<br>- Gas lift requirements<br>- Requirement for equipment redundancy (e.g. spinning reserve on generators)<br>- Facility modifications (upgrades, new technology)<br>- Availability of sophisticated controls systems for turbines and compressors |

Finally, this paper analyzed fifteen offshore oil and gas platforms in the UK portion of the North Sea and derived EIs for each field [8]. The platforms analyzed were at various stages of field life and were classified as either Gas, Gas and Oil, or Oil platforms. This work generated a combined thermodynamic EI time-series, as shown in Figure 1.2. The input energy used to calculate the EIs does not appear to include the energy required for drilling the wells and for constructing the facilities. This study indicated an increasing EI trend over the time period analyzed.

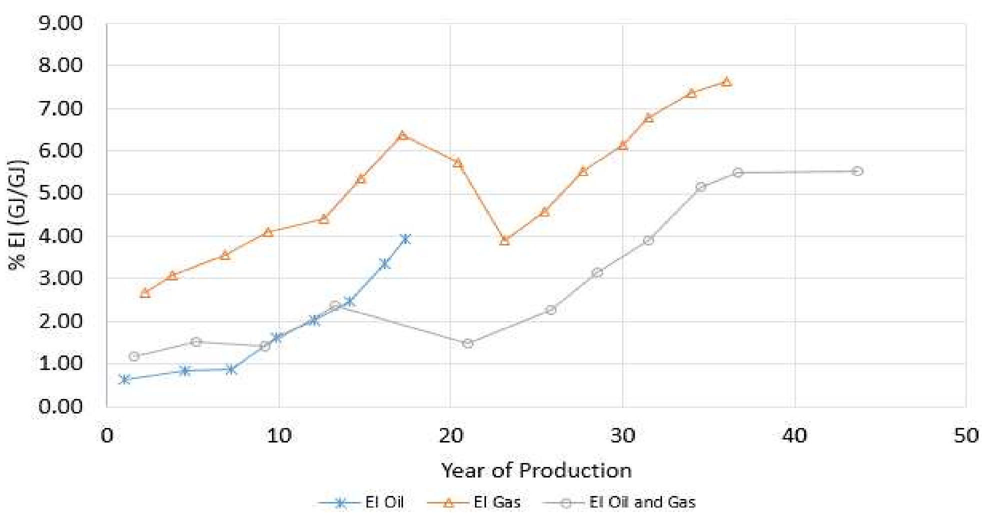


*Figure 1-2 UK Offshore EI Trend [8]*

*1.4.2 Other Common Energy Metrics*

Another body of literature regarding energy performance of upstream oil and gas processes comes from the journal of the Society of Petroleum Engineering (SPE). SPE journal articles also take an industry perspective since they are written by oil and gas professionals. John Edwards of British Petroleum wrote an SPE journal article which described three levels of energy performance indicators as shown below [9]. It is suggested that these indicators can be used for performance monitoring and benchmarking.

- Level 1: High-level energy indicators at the plant level
  - Energy as a percent of exported production
  - Flaring as a % of energy production
  - Venting as a percent of energy production.
- Level 2: Unit Operation type energy indicators
  - Gas Compressions: kW/mmscfd/compression ratio
  - Oil Pumping: kW/bbl/bar
  - Water Injection: kW/bbl/bar
  - Power Generation: %
- Level 3: Individual equipment items

*1.4.3 Energy Return on Investment Applied to Oil and Gas*

While oil and gas insiders focused on the energy intensity, academia took on a more holistic perspective and focused on the concept of energy return. The Energy Return on Investment (EROI) is a dimensionless ratio used to describe the energy obtained from a specific amount of energy invested. It is used to characterize the efficiency of processes delivering high-energy products, such as in the oil and gas industry as well as in alternative energy industries like solar, wind and biofuels.

Some of the early work on the EROI indicator for oil and gas processes was conducted by Cutler Cleveland et.al [10]. In this work the EROI is defined as the Energy Output divided by the Energy Invested, as described by Equation 1.2. The EROI is essentially the inverse of the thermodynamic EI. If the system boundaries take into account the full lifecycle of the development including construction, operation and deconstruction, the total net energy is the sum of the energy outputs minus the energy inputs, which can be calculated as the total energy generated over the life of the system less the energy expended during the construction, operational and decommissioning phases, as described in Equation 1.3. Therefore, the ratio of the cumulative energy generated to the cumulative energy invested is the overall net EROI for the full life-cycle, as shown in Equation 1.4.

$$EROI = \frac{Energy\ output}{Energy\ invested} \tag{1.2}$$

$$E_{net} = E_g - E_{op} - E_c - E_d \tag{1.3}$$

$$EROI_{net} = \frac{E_g}{E_{op} + E_c + E_d} \tag{1.4}$$

where:

$E_g$ = energy generated (GJ)

$E_{op}$ = energy invested during operation of the system (GJ)

$E_c$ = energy invested during construction of the system (GJ)

$E_d$ = energy invested during decommissioning of the facilities (GJ)

$E_{net}$ = balance between energy generated and invested (GJ)

It also common to calculate an instantaneous EROI based on energy rates during the operational phase only, and exclude the construction and decommissioning stages, as indicated in Equation 1.5. The basis for the instantaneous EROI can be an appropriate time increment such as a second, hour, day or year.

$$EROI_{instantaneous} = \frac{\dot{E}_g}{\dot{E}_{op}} \tag{1.5}$$

where:

$\dot{E}_g$ = rate of energy generation (GJ/s)

$\dot{E}_{op}$ = rate of operational energy consumption (GJ/s)

*1.4.4 EROI Boundaries in the Oil and Gas Industry*

Cutler et al. also addressed the problem of ambiguous, inconsistent, or unidentified assumptions in calculating the EROI by developing a framework for delineating the boundaries of an oil and gas system [11]. As such, this framework takes into account a number of boundary defining dimensions of the system such as:

- Lifecycle phase (extraction, processing, end-use)
- Source of input energy (internal or external)
- Type of energy input (direct or indirect)

A notation was developed to indicate the aforementioned boundaries of the EROI calculation, with subscripts of 1, 2 and 3 used to indicate the processing phase, such as extraction, processing and end-use. A number of other subscripts were employed to indicate whether direct, indirect, internal and external inputs were included in the calculation.

Consistent with this work another group of researchers led by Adam Brandt developed an open source spreadsheet tool called the Oil Production Greenhouse Gas Emissions Estimator (OPGEE), which is used to calculate mass and energy balances and emissions [12]. The tool contains spreadsheet templates which utilize embedded factors and formulas to automate the calculations based on a combination of field-specific data and default values.

This research group also divided the EROI into two types: Net Energy Return (NER) and External Energy Return (EER). NER and EER are calculated in different ways: NER includes internal energy investments, while EER excludes internal energy investments. NER and EER can also be used to describe the oil return only or can include all energy returns, such as from associated natural gas, as described by Equations 1.6 and 1.7.

$$NER\ EROI = \frac{Energy\ Return}{External\ Energy\ Invested\ + Internal\ Energy\ Invested} \quad 1.6$$

$$EER\ EROI = \frac{Energy\ Return}{External\ Energy\ Invested} \quad 1.7$$

*1.4.5 Global and Regional EROI Case Studies*

The EROI parameter has been used extensively to compare technologies and to understand the long term direction of energy developments. A number of studies have concluded that the EROIs for oil and gas developments have been steadily decreasing over the last few decades [10,13]**.** This phenomenon in the oil and gas industry has been observed both on a global, long-term, scale as well as on the shorter time frame of a specific field's operational life [14]. Table 1.3 describes the results of EROI analysis conducted on both a global and regional scale.

The global and regional declines in EROIs are most likely attributable to the depletion of easily exploitable hydrocarbons reservoirs with favorable conditions. Reservoirs which are easily reached geographically and have strong pressure support are typical of high EROI developments, and it is clear that they are getting harder and harder to find. The decreasing trends of EROIs in the oil and gas industry are the impetus for stakeholders to gain a better understanding of their energy intensive processes and to seek more energy efficient extraction, processing and transportation methods.

*Table 1-3 Global and Regional EROI Case Studies*

| Year Published | Author/s | Sector | Method | Period | EROI Range | Trend |
|---|---|---|---|---|---|---|
| 1992 [11] | Cutler J. Cleveland | US petroleum | Top Down: Converting published production rates to energy out and published direct costs to energy in. | 1954 to 1984 | 10 to 15 | (unclear) |
| 2004 [15] | Cutler J. Cleveland | US petroleum | Top Down: Converting published production rates to energy out and published direct costs to energy in. | 1954 to 1994 | 16 to 24 | (unclear) |
| 2009 [16] | Gagnon N., et al | Global petroleum | Top down: Converting published production rates to energy out and published direct costs to energy in. | 1992 to 2006 | 25 to 20 | (Decreasing) |
| 2011 [13] | Brandt., Adam R. | California petroleum | Hybrid: Converting published production rates to energy out and engineering estimates for energy in. | 1950 to 2010 | 65 to 10 | (Decreasing) |
| 2011 [17] | Guilford, M., et al | US petroleum | Top down: Converting published production rates to energy out and published direct costs to energy in. . | 1920 to 2010 | 24 to 15 | (Decreasing) |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2013 [18] | Poisson and Hall | Canadian petroleum | Top down: Converting published production rates to energy out and published direct costs to energy in. | 1990 to 2010 | 17 to 14 | (Decreasing) |
| 2014 [19] | Nogovitsyn and Sokolov | Russia petroleum | Top down: Converting published production rates to energy out and published direct costs to energy in. | 2005 to 2012 | 36-30- | (Decreasing) |

*1.4.6 Field Specific EROI Analysis*

A more detailed engineering based EROI methodology was applied to a several prominent fields located throughout the world using the OPGEE tool [20]. It is notable that all fields exhibited a strongly decreasing EROI trend over the operational life, and the primary reason appears to be related to the introduction of energy intensive water, gas and steam injection processes which are typically required to stimulate the reservoir and/or to protect the environment. Case studies on EROI analysis using the OPGEE tool are described in Table 1.4 and Figure 1.3.

*Table 1-4 Field Specific EROI Case Studies [20]*

| Year Published | Author/s | Subject | Method | Field and Period |
|---|---|---|---|---|
| 2017 | Tripathi and Brandt | Boundary model expanded. NER-EROI and EER-EROI time series for six major oil and gas fields. | Hybrid: Converting published production rates to energy out and engineering estimates for energy in. | Field: Cantarell, Mexico<br>Period: 1978 to 2012 |
| | | | | Field: Forties, North Sea<br>Period: 1974 to 1999 |
| | | | | Field: Midway-Sunset, California<br>Period: 1965 to 2007 |
| | | | | Field: Prudhoe Bay, Alaska<br>Period: 1977 to 2004 |

Data for the trends described in Table 1.4 were extracted and plotted and reanalyzed using the linear regression method to better understand the slope of the EROI decline trends and potentially for comparison with field specific EROI decline slopes derived in this research. The results of linear regression for the four major fields are shown in Figure 1.3.

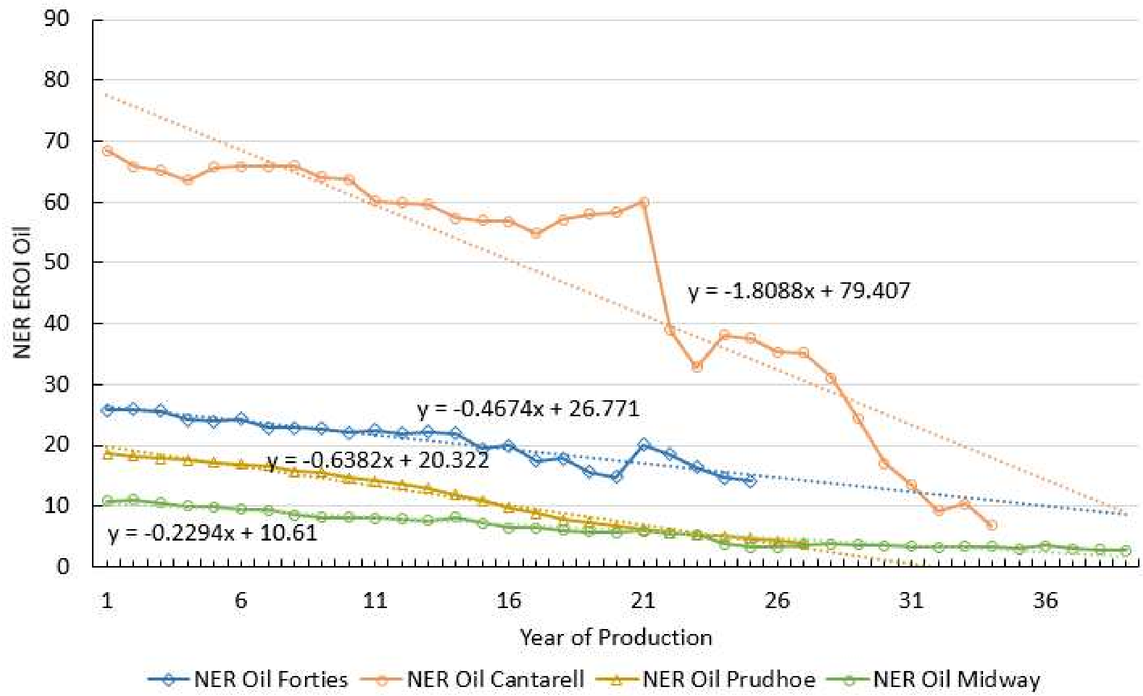


*Figure 1-3 Decades long EROI trend for several major oil fields*

*1.4.7 Breakeven Analysis*

An interesting perspective on economic breakeven analysis in the oil and gas industry is provided by Kleinberg et al. [22]. This research described several different types of economic breakeven points such as Full Cycle, Operational and Lifting. The Full Cycle breakeven analysis includes all capital and operating expenses normalized to a barrel of crude oil. The Full Cycle breakeven analysis is a very important parameter for field development, and is a contributing factor to financial investment decisions (FID).

For fields that are already in production, the capital costs are often considered as "sunk costs" and may or may not have already been fully recovered. Operational teams are often more interested in the Operational breakeven point, which is the point where operating costs per barrel are equal to the income received from the sales of each barrel of crude, excluding outlays due to taxes and royalties.

Operating costs are often divided into variable and fixed costs. In many fields, the fixed operating costs dominate the overall operational costs (e.g. if facilities, or land, are leased on a long-term basis with significant costs). It is proposed that the fixed operating costs can be considered as "committed" costs and that a more restricted version of operating costs be developed which excludes the fixed operation costs. The restricted version of can referred to as “Lifting Costs” and shall only take into account the costs of fuel and power only. The proposed breakeven points are described in Figure 1.4.

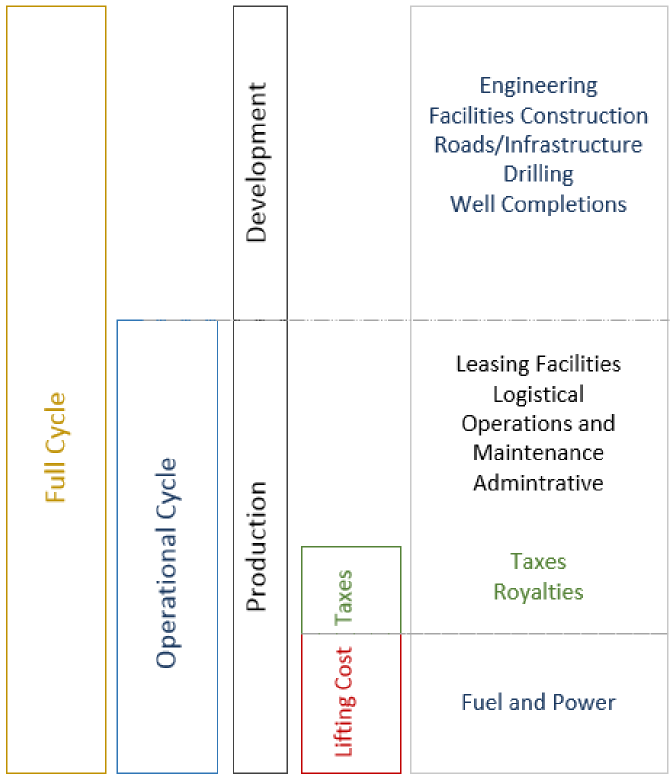


*Figure 1-4 Breakeven Analysis Categories*

Other researcher have described the lifting costs as the incremental costs to produce an additional barrel of crude oil and it has been found to be a function of the following variables [21].

- Gross rate
- Oil rate
- Gas rate
- Injection water rate
- Oil wells count
- Gas wells count
- Injection wells count

This definition of lifting cost seems to be aligned with the restricted definition proposed for lifting breakeven analysis.

In summary, the Full Cycle breakeven point is the production capacity costs plus the total operational costs per barrel, including taxes and royalties, which must be below the sales prices of the crude oil, as indicated in Equation 1.8.

$$BEP_{full\ cycle\ economic} = C_{dev} + OPEX_{total} = P_{crude\ oil} \qquad 1.8$$

where:

$\mathrm{BEP}_{full\ cycle\ economic}$ = total economic breakeven point (USD/barrelof crude oil)

$C_{dev}$ = production capacity costs (USD/BBL crude oil)

$OPEX_{total}$ = total operatiing costs (USD/BBL crude oil)

$P_{crude\ oil}$ = sales price ber barrel(USD/BBL crude oil)

The Operational Cycle breakeven point is the total operational costs per barrel of crude oil, including fixed and variable expenses, as well as taxes and royalties as shown in Equation 1.9.

$$BEP_{operational\ economic} = OPEX_{\ total} = P_{crude\ oil} \qquad 1.9$$

where:

$\mathrm{BEP}_{opertional\ economic}$ = operational economic breakeven point (USD/barrelof crude oil)

Finally, the proposed Lifting Economic breakeven point, as described by Equation 1.10, is simply the cost of fuel and/or imported power per barrel of crude oil. An analogous Lifting Energy breakeven point is proposed by this research, as shown in Equation 1.11, and is thus defined as the maximum energy per barrel that can be expended in the extraction process, which must be less than the heating value of a barrel of crude oil. The Lifting Energy breakeven point is equivalent to an instantaneous operational EROI value of 1.

$$BEP_{lifting\ Economic} = P_{crude\ oil} \qquad 1.10$$

$$BEP_{lifting\ Energy} = E_{crude\ oil} \qquad 1.11$$

where:

$\mathrm{BEP}_{lifting\ economic}$ = lifting economic breakeven point (USD/BBL crude oil)

$P_{crude\ oil}$ = price of crude oil (USD/BBL crude oil)

$BEP_{lifting\ Energy}$ = energetic breakeven point (GJ/BBL crude oil)

$E_{crude\ oil}$ = heating value of crude oil (GJ/BBL crude oil)

For example, the lifting cost (comprised only of fuel costs) may be 5 USD per barrel of crude, but the total OPEX per barrel may be as high as 30 USD per barrel, including fiscal obligations. If the market price is 40 USD per barrel, the operation is below the operational breakeven point. On the other hand, if the market price is 35 USD per barrel, the operation is equal to the operational breakeven point. In this situation, it would make sense for the operational team to consider how the lifting costs can be reduced, which would be achieved by reducing the energy intensity of the operation. The Lifting Energy breakeven, would also be good to reference to know, particularly on a well by well basis, since it can provide oil and operators with an absolute minimum production threshold.

## 1.5 Oil Fields Analyzed in this Study

The materials used in this research were offshore platforms belonging to three small oil producing fields. Data was collected for each field with respect to production rates, fuel consumption rates, drilling programs, drilling energy loads, and construction costs. The data collected extended from the pre-production construction period to the present time for each field. Furthermore, detailed data was collected on the ESPs from the platform power control system, the motor controllers, and the step-up transformers. What follows is a description of each field including field maps, process flow diagrams (PFDs), platform specification tables, field-wide production profiles, and energy snapshots.

### *1.5.1 Field 1 Description*

The field is located in tropical waters with a water depth of 60 meters and produces oil from more than 30 separate reservoirs at depths of 790 - 1,600 meters below sea level. The field employs four Wellhead Processing Platforms (WPP) and one Wellhead Platform (WHP). Each of the five platforms, have between 16 and 24 wells. Platform WHP-A is the only platform which has wells and manifolds only, and as such fluids from WHP-A are transferred to WPP-B for processing via a dedicated subsea pipeline. Platforms WPP-B, C, D and E are equipped with three phase separators, water treatment and water disposal facilities. Produced crude from the five platforms is transported via an eight-inch subsea pipeline network to a Floating, Production, Storage and Offloading (FPSO) vessel, where crude oil is stabilized and stored. Residual produced water is stripped from the FPSO crude oil tanks and pumped back to the

WHP-A via a dedicated 8-inch water return pipeline. The field relies exclusively on the use of ESPs to maintain production. The produced gas is generally high in CO2, which means that the platforms cannot use produced gas as fuel.

Images of Field 1 platforms and the FPSO are shown in Figures 1.5 to 1.7. The layout of Field 1 is shown in Figure 1.8. The platform process flow diagrams are shown in Figures 1.9 and 1.10. Additional Field 1 parameters are shown in Table 1.5

*Figure 1-5 Field 1 WPP-C Platform*

*Figure 1-6 Field 1 WHP-A Platform*

*Figure 1-7 Field 1 FPSO*

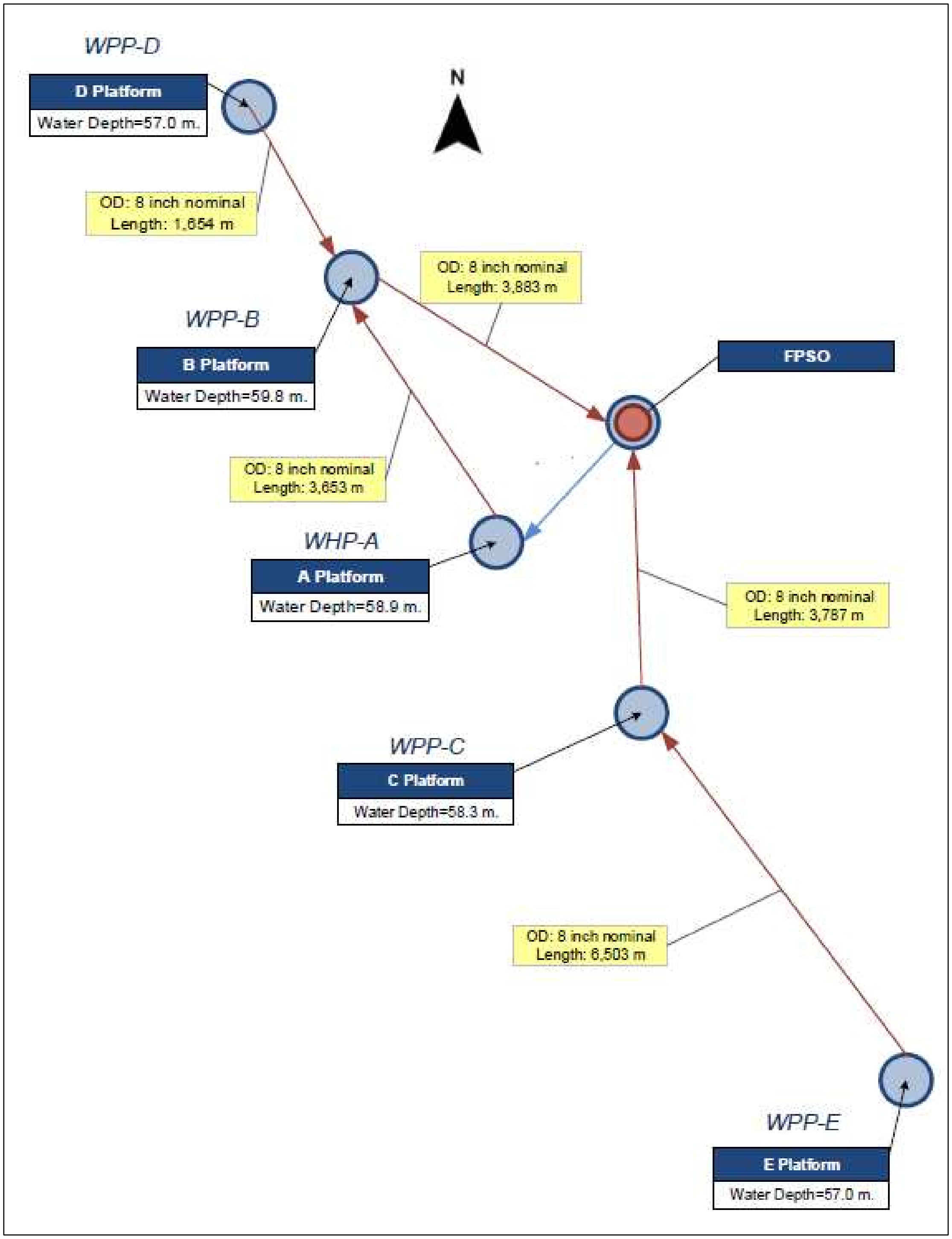


*Figure 1-8 Field 1 Layout*

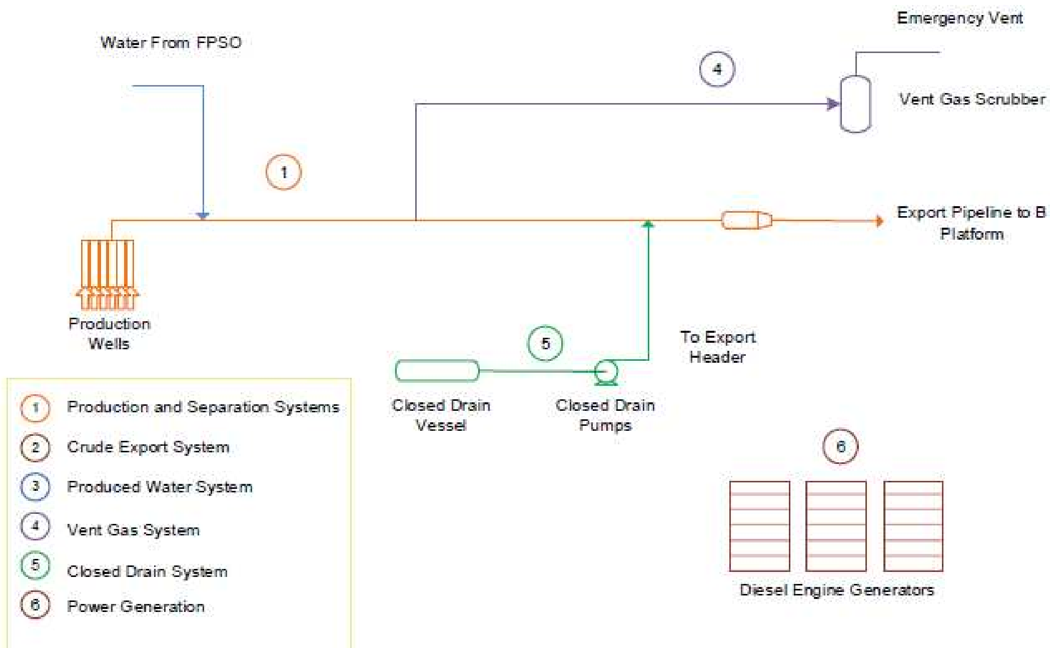


*Figure 1-9 Field 1 WHP-A Process Flow Diagram*

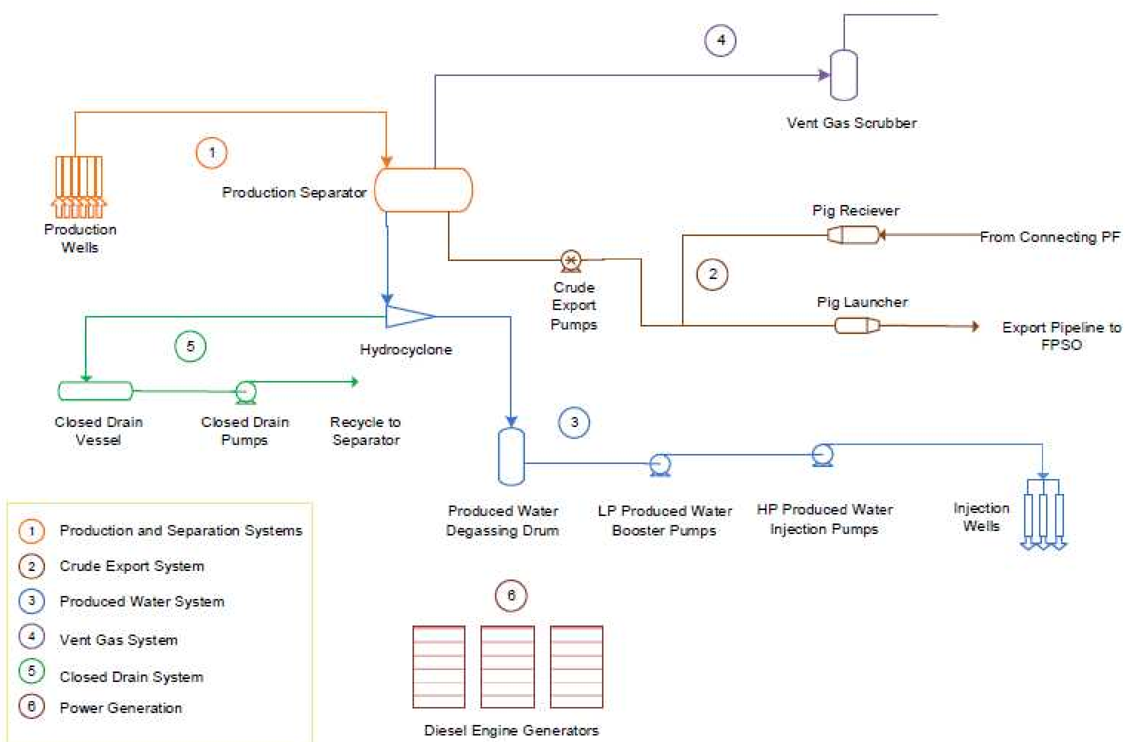


*Figure 1-10 Typical Process Flow Diagrams of Field 1 WPP-B, C, D, and E*

*Table 1-5 Field 1 Parameters*

| Parameter | Units | WHP-A | WPP-B | WPP-C | WPP-D | WPP-E |
|---|---|---|---|---|---|---|
| Well fluid production - design | BLPD | 30,000 | 74,000 | 30,000 | 30,000 | 30,000 |
| Water injection capacity | BWPD | 0 | 74,000 | 30,000 | 30,000 | 30,000 |
| Vent gas rate - design | MMSCFD | 10 | 10 | 10 | 10 | 10 |
| Slots – total | # | 16 | 24 | 22 | 24 | 24 |
| Water depth | Meters | 58.9 | 59.6 | 58.3 | 57 | 57 |

### *1.5.2 Field 2 Description*

Field 2 is exploited from a single Wellhead Processing Platform A (WPP-A), two subsea pipelines and a Floating, Storage and Offloading (FSO) vessel. The WPP-A platform is located in a water depth of approximately 46 m. The oil produced from the WPP-A is exported directly to the FSO, which is two kilometres away.

WPP-A platform is equipped with 30 well slots with corresponding manifolds to allow for simultaneous production of the wells. Production is accomplished with artificial lift using ESPs and pressure in the reservoir is supported with produced water injection wells. While the reservoir pressure is maintained via water injection; production also relies extensively on the use of Electrical Submersible Pumps (ESPs) to maintain flow.

On the Platform crude oil, produced water and associated gas are separated in a two stage separation train. Crude oil is stabilized in the separation train and pumped through the 6-inch export pipeline to the FSO. Produced water is treated by a hydrocyclone and an induced gas flotation cell to reduce the Oil in Water (OIW) to 10 to 50 ppm. Residual produced water is stripped from the FSO crude oil tanks and pumped back to the platform via the 6-inch water return pipeline. Produced gas is treated and used for fuel on the platform in the gas engine generators. Residual gas is flared on the WPP.

Images of Field 2 platform and the FSO are shown in Figures 1.11 and 1.12. The layout of Field 2 is shown in Figure 1.13. The platform process flow diagram is shown in Figures 1.14. Additional Field 2 parameters are shown in Table 1.6.

*Figure 1-11 Field 2 WPP-A Platform*

*Figure 1-12 Field 2 FSO*

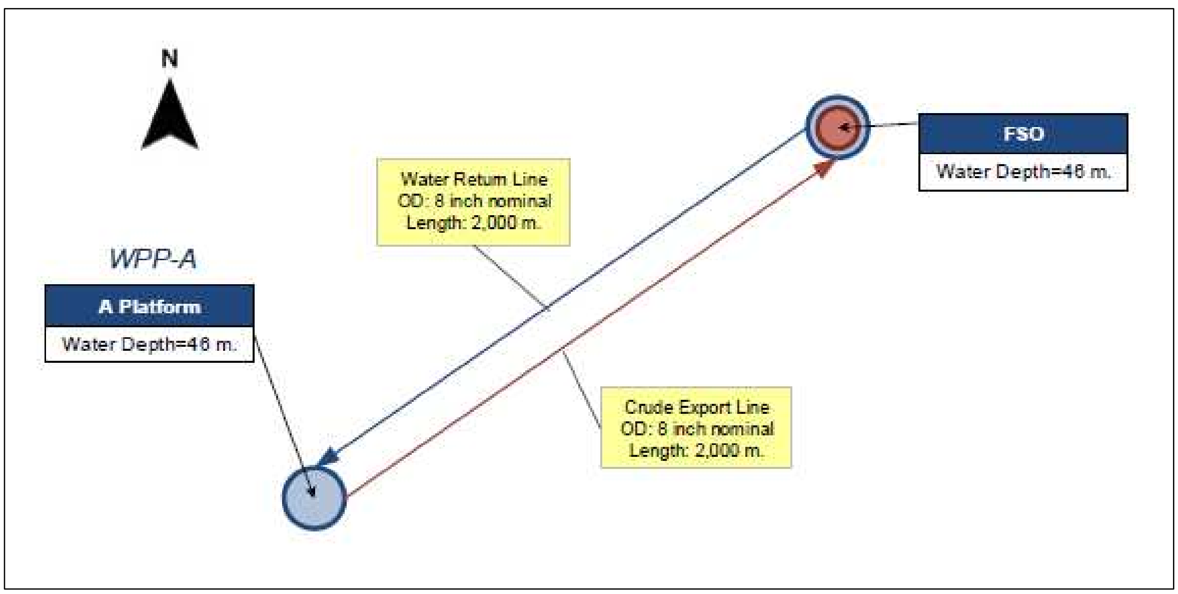


*Figure 1-13 Field 2 Layout*

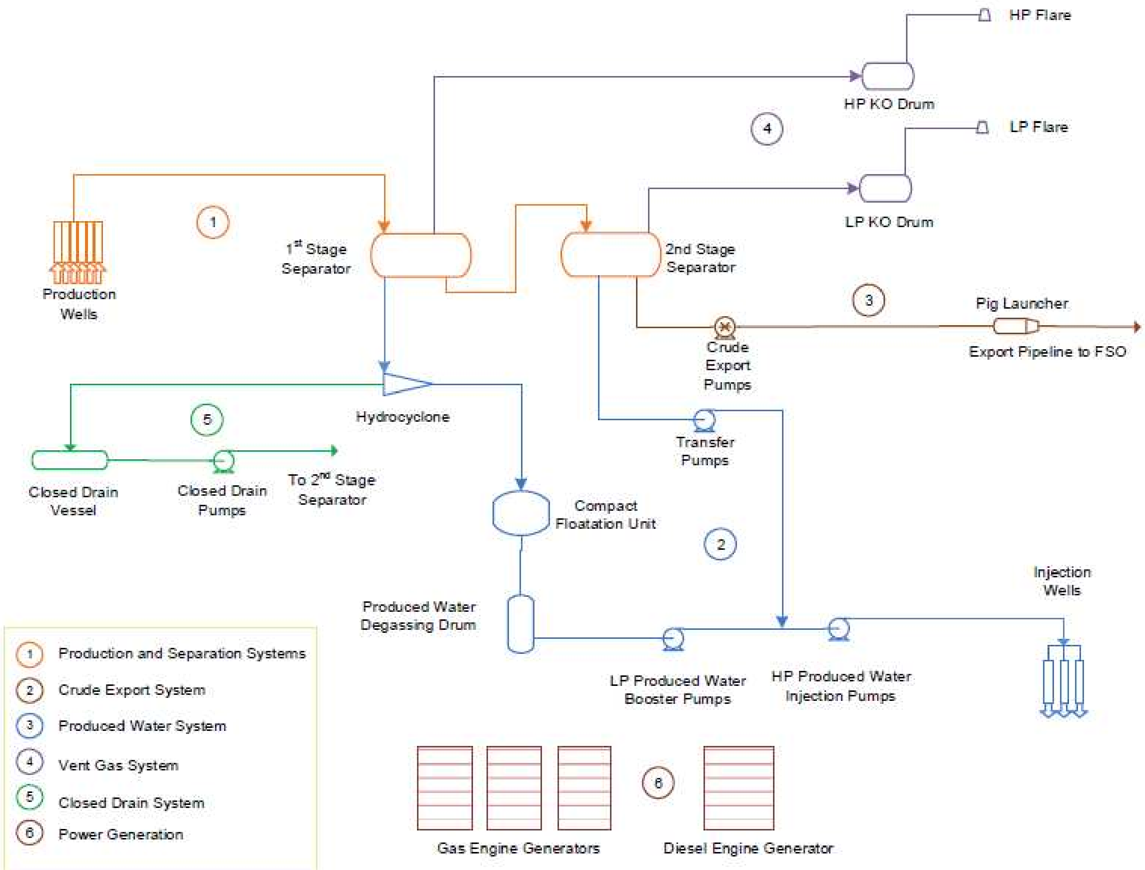


*Figure 1-14 Field 2 WPP-A Process Flow Diagram*

*Table 1-6 Field 2 Parameters*

| Parameter | Units | WPP-A |
|---|---|---|
| Well fluid production - design | BLPD | 30,000 |
| Produced Water Treatment and Disposal capacity | BWPD | 30,000 |
| Total Water Injection Capacity | BWPD | 30,000 |
| Flare gas rate - design | MMSCFD | 4 |
| Slots – total | # | 30 |
| Water depth | Meters | 46 |

### *1.5.3 Field 3 Description*

Field 3 is exploited with a Wellhead Processing Platform (WPP-A), a minimal facilities Wellhead Platform (WHP-B), four subsea pipelines, and a Floating, Storage and Offloading (FSO) vessel. The WPP and WHP are located in a water depth of approximately 75 m. The WHP and WPP platforms are equipped with 16 and 24 well slots respectively with corresponding manifolds. Production is accomplished with artificial lift using ESPs and pressure in the reservoir is supported with produced water injection wells.

Fluids from both WPP-A and WHP-B are treated on the WPP-A platform. An 8 inch three phase pipeline is in place to bring WHP fluids to the WPP. Produced fluids are therefore separated in the WPP separator. Separated crude is stabilized in the separator before being pumped through the 6-inch export pipeline to the FSO.

Produced water is treated and pressurized on the WPP-A platform and injected on both the WPP and WHP. A high pressure water injection pipeline is in place between the WPP and WHP to bring produced water to the WHP injection wells. Residual produced water is stripped from the FSO crude oil tanks and pumped back to the platform via the 6-inch water return pipeline. Produced gas is treated and used for fuel on the WPP platform in the dual-fuel generators. Residual gas is flared on the WPP. Images of Field 3 platform and the FSO are shown in Figures 1.15 and 1.17. The layout of Field 3 is shown in Figure 1.18. The platform process flow diagrams are shown in Figures 1.19 to 1.20. Additional Field 3 parameters are shown in Table 1.7.

*Figure 1-15 Field 3 WPP-A Platform*

*Figure 1-16 Field 3 WHP-B Platform*


*Figure 1-17 Field 3 FSO*

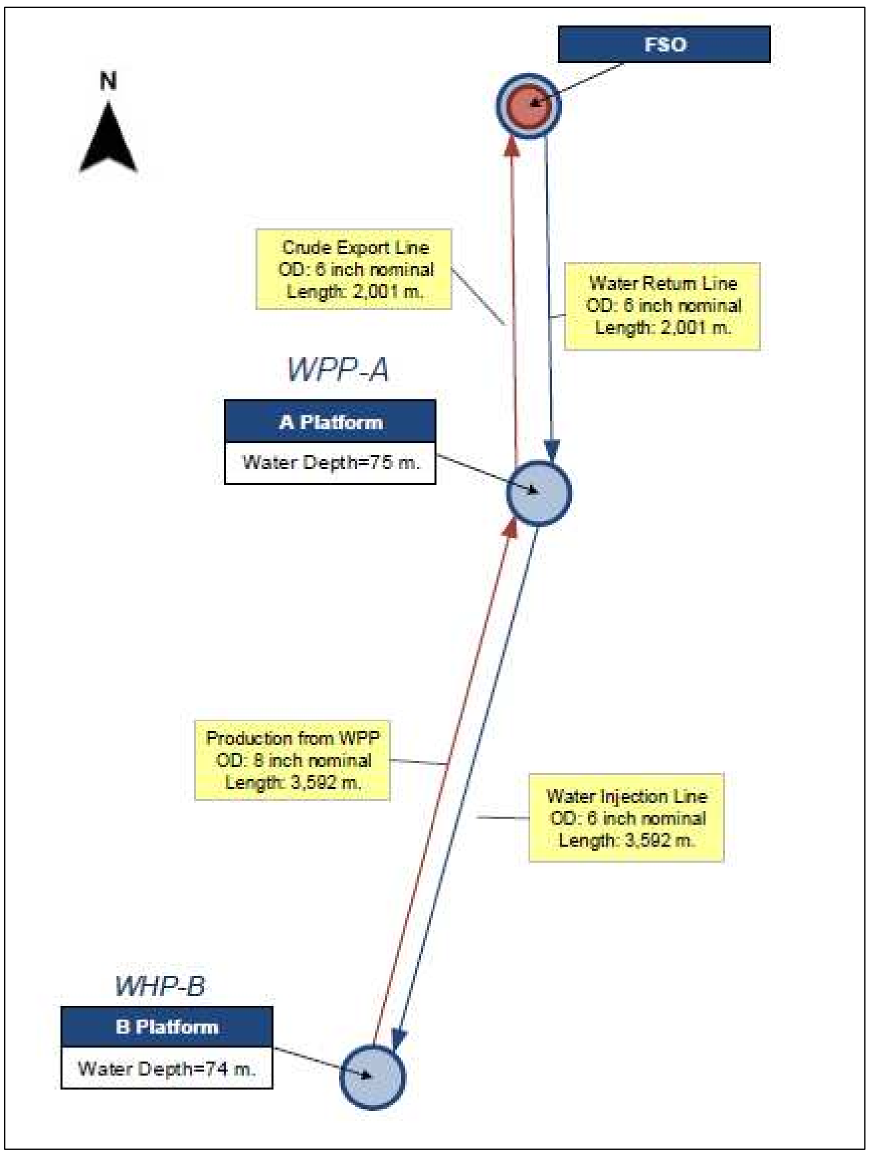


*Figure 1-18 Field 3 Layout*

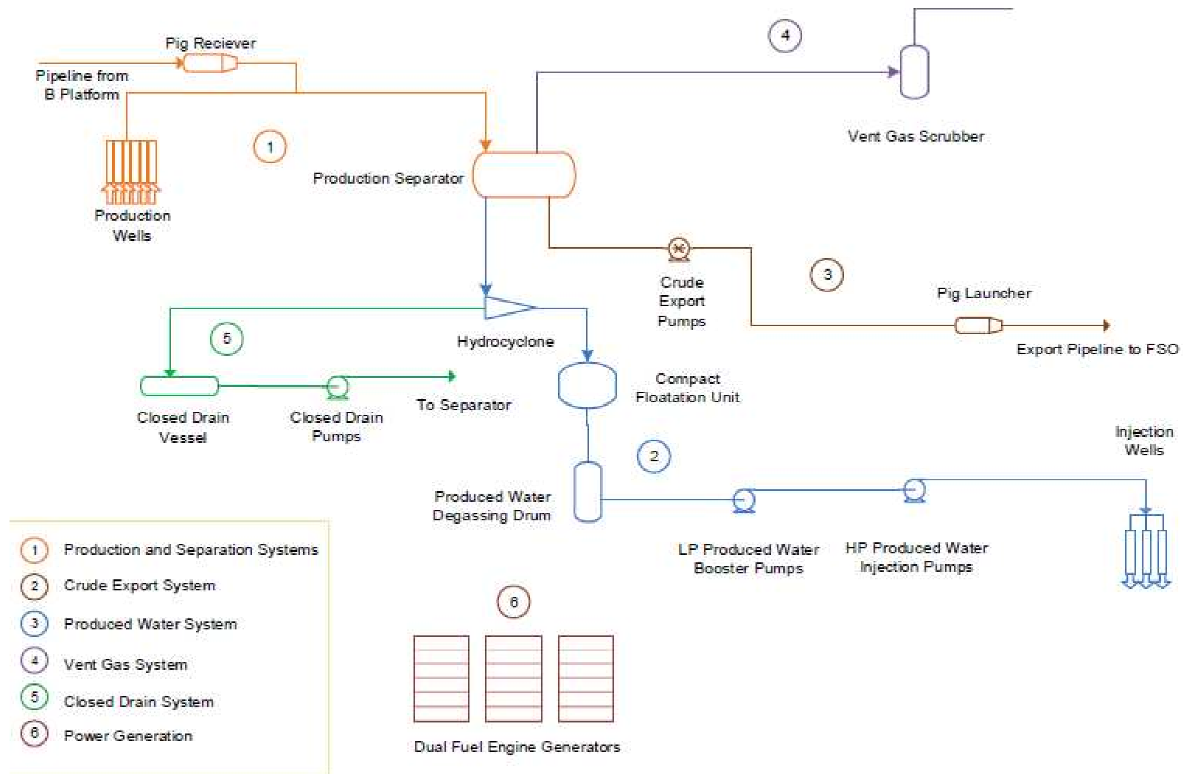


*Figure 1-19 Field 3 WPP-A Process Flow Diagram*

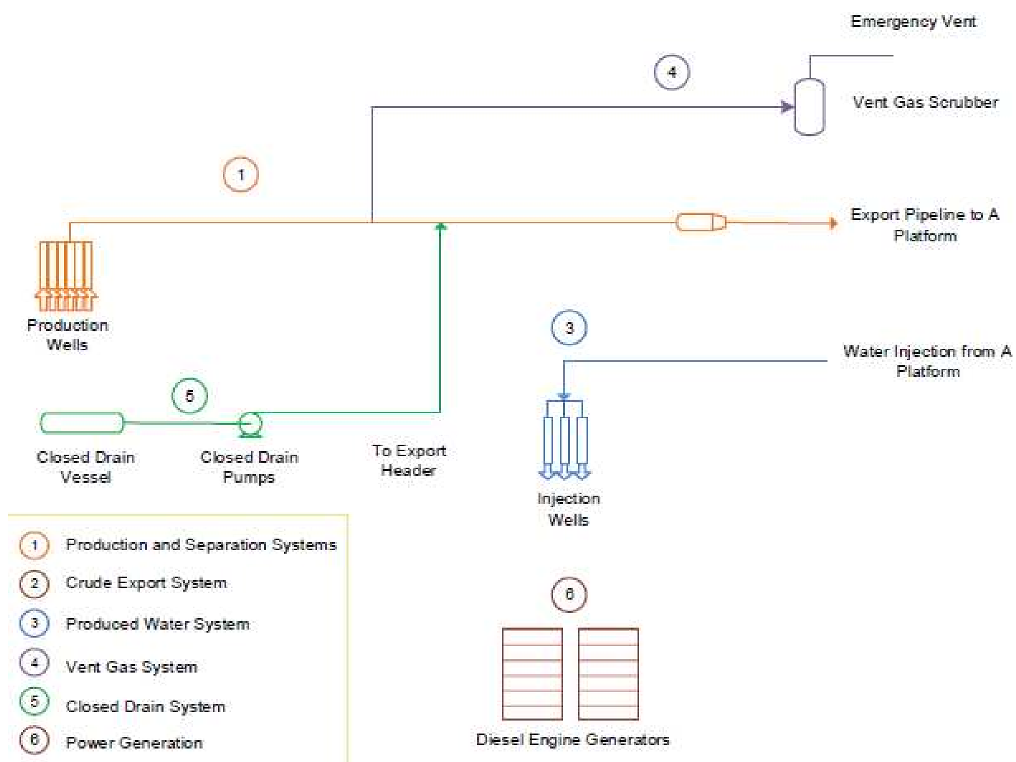


*Figure 1-20 Field 3 WHP-B Process Flow Diagrams*

*Table 1-7 Field 3 parameters*

| Parameter | Units | WPP-A | WHP-B |
|---|---|---|---|
| Well fluid production - design | BLPD | 55,000 | 30,000 |
| Produced Water Treatment and Injection capacity | BWPD | 45,000 | 0 |
| Flare gas rate - design | MMSCFD | 4 | 4 (emergency vent) |
| Slots – total | # | 24 | 16 |
| Water depth | Meters | 75 | 74 |

### *1.5.4 Production Profiles*

Production profiles for fields 1 through 3 are indicated in Figures 1.21 and 1.22. The plots are configured in terms of years of production, rather than actual years, to facilitate comparisons. Field 1 is the largest field, and experienced high initial crude oil production rates of more than 25,000 barrels of oil per day (BOPD) and a modest production decline rate as new platforms were added and additional wells drilled. Fields 2 and 3, are smaller fields and crude oil production and initial production ranged from approximately 10,000 BOPD for Field 3 and 16,000 BOPD for Field 2.

All three fields are experiencing increasing water-oil-ratio ratio over time. Field 1's water production reached more than 150,000 barrels of water per day (BWPD) in the 12$^{th}$ year of production. Field 2 and Field 3 produce approximately 30,000 BWPD each. It should be noted that all fields inject, or dispose, of water by pumping into subterranean reservoirs. Field 1 employs water disposal, while Fields 2 and 3 employ water injection. Water disposal is only intended to depose of the water in an environmentally acceptable manner. Water injection is intended to stimulate the reservoir by maintaining pressure or by sweeping crude into extraction zones. Water injection normally involves much higher pumping pressures than water disposal.

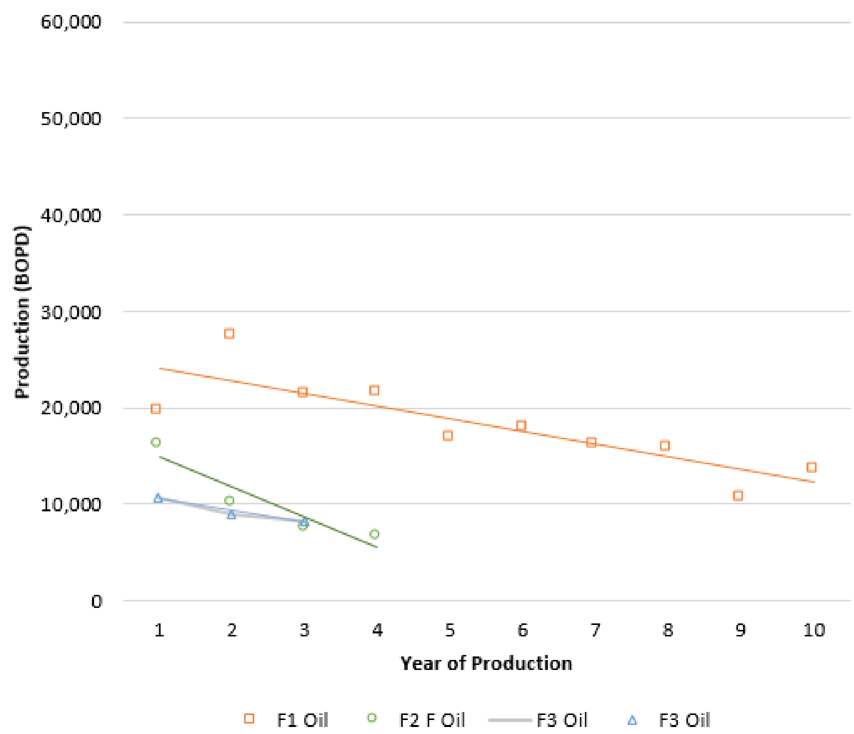


*Figure 1-21 Production Profiles for Fields 1, 2 and 3 (crude oil)*

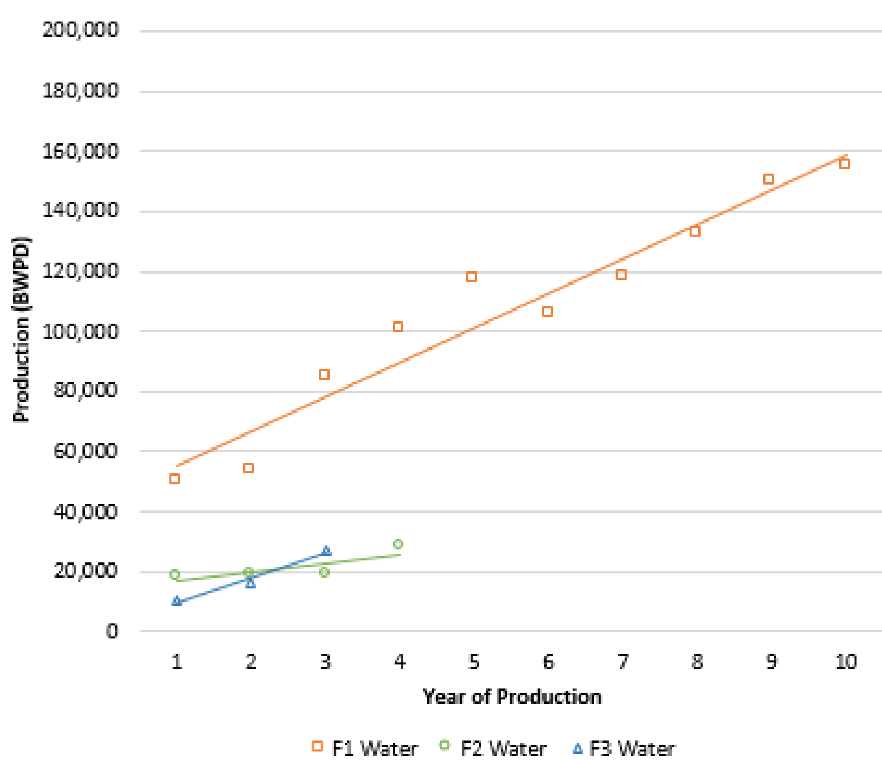


*Figure 1-22 Production Profiles for Fields 1, 2 and 3 (water)*

*1.5.5 Offshore Platform Energy Flows*

Figure 1.23 indicates the flows of energy and fluids on an offshore platform typical of the fields analyzed in this research. The red dashed lines indicate the flow of energy, which is directed to the ESPs, produced water injection or disposal pumps, crude export pumps, and miscellaneous platform utilities. Black solid arrows indicate the flow of fluids. This diagram is intended to illustrate the primary flows of energy and fluids on the platforms.

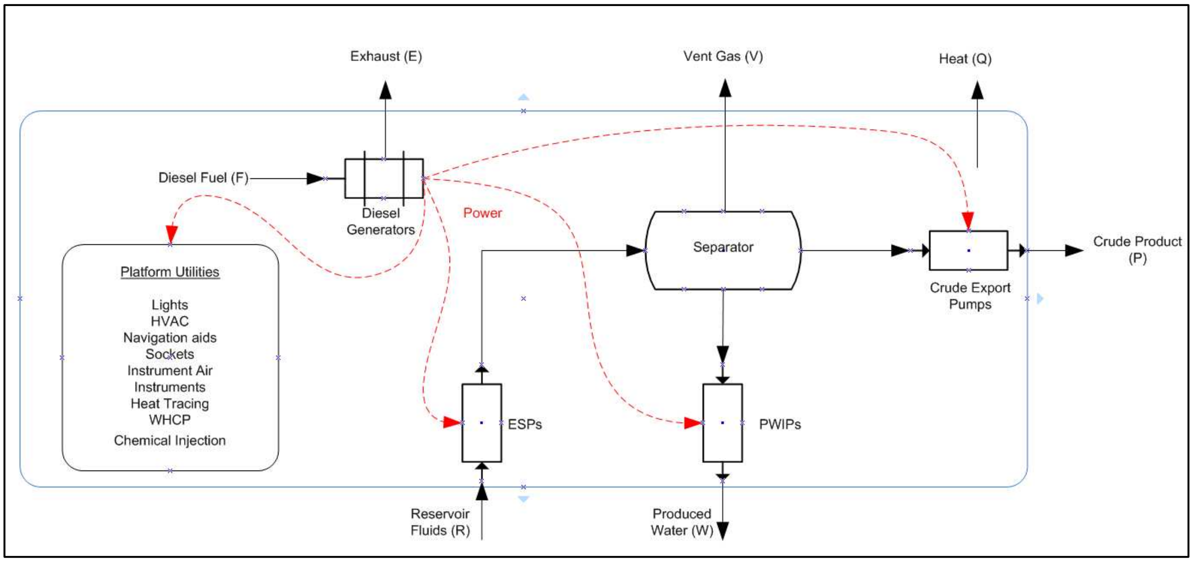


*Figure 1-23 Integration of power and fluids*

*1.5.6 Field Specific Energy Flows*

As per the hypothetical flows described in Figure 1.23, the actual energy flows for each field, and platform, are assessed to determine the performance of power generation and the main flows of power generation in each field. As indicated in Figures 1.24 through 1.26, the power generation systems for Field 1, 2 and 3 operate between 30% to 35% efficiency, with energy losses due to outflows of heat from the exhaust system, heat removal via the engine cooling system, convectional heat losses as well as smaller energy losses from vibration and noise.

In terms of consumption, it can be seen that ESPs and water injection/disposal pumps are by far the largest users of electrical power, with ESPs typically consuming between 40% to 55% of the total power generated. The combination of ESPs and injection/disposal pumps consume approximately 96% of the total power in all three fields. The remaining 4% is consumed by the crude export pumps, small utility pumps and compressors, heat tracing, lights, instrumentation and navigational aids. The crude export pumps operate against a minimal backpressure in all fields due to the short pipeline distances, and in most cases the backpressure is less than 100 psig, so the energy consumed by these pumps is quite small. Therefore, the conclusion from this analysis is that efforts to improve energy utilization should focus on the ESPs and the water injection/disposal pumps.

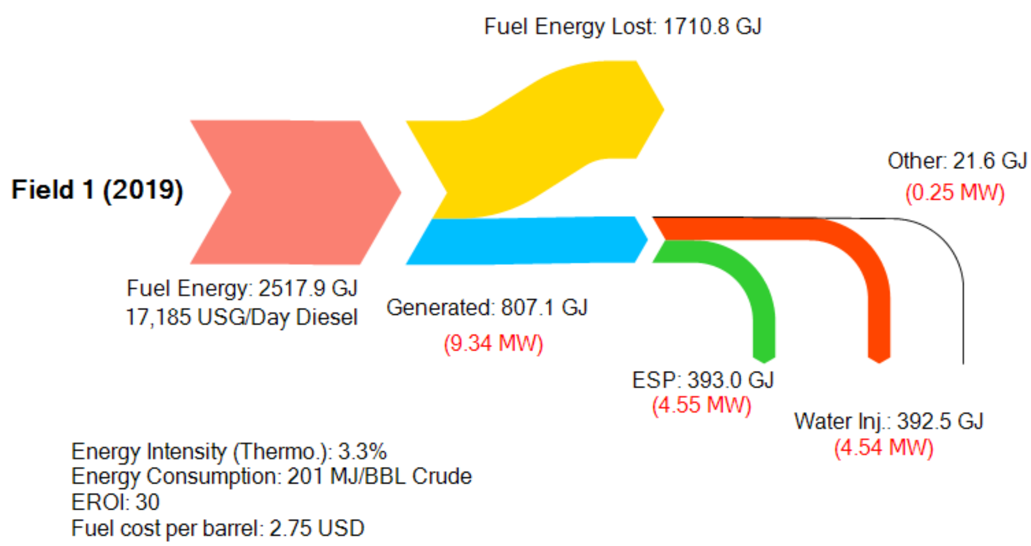


*Figure 1-24 Energy flows – Field 1*

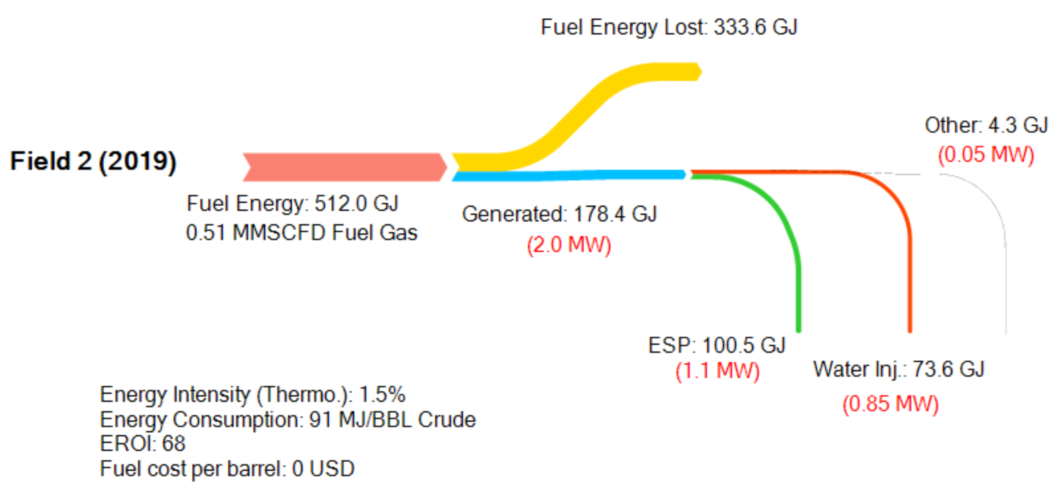


*Figure 1-25 Energy flows – Field 2*

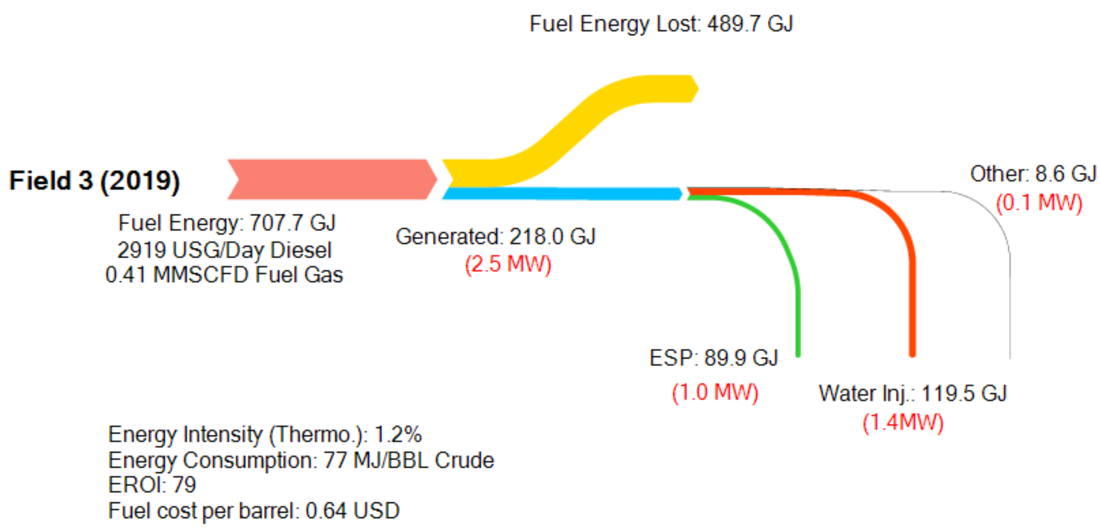


*Figure 1-26 Energy flows - Field 3*

## 1.6 Research Questions

The goal of this research is to conduct energy balances and develop performance measures for three offshore fields. The energy analysis will include a high level, long term, energy analysis of three offshore fields covering a period of 3 to 12 years. A highly focused energy analysis will be carried out for one offshore platform by conducting a detailed energy balance around the main subsystems and equipment items. Research questions to be addressed are:

- Question 1. What energy accounting methods are appropriate for oil and gas extraction schemes?
- Question 2. How do performance parameters, such as EROI, EI and lifting cost, of the fields behave over time?
- Question 3. What are the drivers for EROI, EI and lifting cost among the three fields reviewed?
- Question 4. What are the energetic breakeven points for each field?
- Question 5. How can a detailed energy accounting of the systems and subsystems of a platform be applied to provide practical benefits to the operational team?
- Question 6. What does an energy balance of individual ESPs look like, and how can this information be used by operators?

- Question 7. What are the main failure modes of ESPs, and can failures be anticipated by applying analytical performance techniques?

**1.7 Dissertation Structure**

- Chapter 1:

  Introduction and Research Motivations

- Chapter 2:

  Lifecycle Energy Accounting of Three Small Offshore Oil Fields

  Publication: Energies Journal, Published July 17, 2019

- Chapter 3:

  Detailed Energy Accounting of Electrical Submersible Pumps

  Publication: Energies Journal, Submitted June 7, 2019 (under review)

- Chapter 4:

  Development of an Energy Efficiency Improvement Methodology for Upstream Oil and Gas

  Publication: Abu Dhabi International Petroleum Exhibit and Conference, Nov. 12-17, 2017

- Chapter 5:

  Application of a Fuzzy Expert System to Analyze and Anticipate ESP Failure Modes

  Publication: Abu Dhabi International Petroleum Exhibit and Conference, Nov. 12-17, 2017

- Chapter 6:

  Conclusions and Recommendations

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# CHAPTER 2 – LIFECYCLE ENERGY ACCOUNTING OF THREE SMALL OFFSHORE FIELDS[1]

## 2.0 Introduction

Small oil fields are expected to play an increasingly prominent role in the delivery of global crude oil production. As such, the Energy Return on Investment (EROI) parameter for three small offshore fields are investigated following a well-documented methodology, which is comprised of a "bottoms-up" estimate for lifting and drilling energy and a "top-down" estimate for construction energy. EROI is the useable energy output divided by the applied energy input, and in this research subscripts for "lifting", "drilling" and "construction" are used to differentiate the types of input energies accounted for in the EROI ratio. The $EROI_{Lifting}$ time series data for all three fields exhibits a decreasing trend with values that range from more than 300 during early life to less than 50 during latter years. The $EROI_{Lifting}$ parameter appears to follow an exponentially decreasing trend, rather than a linear trend, which is aligned with an exponential decline of production. $EROI_{Lifting}$ is also found to be inversely proportional to the lifting costs, as calculated in USD/barrel of crude oil. Lifting costs are found to range from 0.5 dollars per barrel to 4.5 dollars per barrel. The impact of utilizing produced gas is clearly beneficial and can lead to a reduction of lifting costs by as much as 50% when dual fuel generators are employed, and more than 90% when gas driven generators are utilized. Drilling energy is found to decrease as the field ages, due to a reduction in drilling intensity after the initial production wells are drilled. The drilling energy as a percentage of the yearly energy applied is found to range from 3% to 8%. As such, the $EROI_{Lifting+Drilling}$ value for all three fields approaches $EROI_{Lifting}$ as the field life progresses and the drilling intensity decreases. The construction energy is found to range from 25% to 63% of the total applied energy over the life of the field.

[1] The chapter was published as a journal article in Energies, 2019, 12(14), 2731

## 2.1 Background

Giant oil fields have been described in a number of ways, but a generally accepted definition is a field which has a daily production rate that exceeds one hundred thousand barrels of oil per day and/or Ultimate Recoverable Reserves (URR) of greater than 500 million barrels of oil [1]. There are believed to be more than 500 giant fields in existence, which only constitute approximately 1% of the total number of oil fields but account for approximately 60% global daily oil production [1]. The remaining 40% of global daily production is produced by smaller fields which tend to receive considerably less attention than the giant fields. It is widely believed that the contribution of smaller fields to global production will gradually increase over time [2]. This due to the fact that many of the existing giant fields are over 50 years old and are experiencing declining production. Another factor is the decline in discoveries of giant fields which are needed to replace the existing depleted giant fields [1]. As such, it is worthwhile to gain a better understanding of small oil fields in terms of their energetic characteristics.

Energy accounting is a valuable method used to understand the energetic characteristics of systems and to distinguish between different types of systems, such as between large scale and small scale oil and gas developments. Energy accounting can be used to gain insight into the value-added nature of an oil and gas development and supplement economic analysis [3-5]. It is readily apparent that nearly all of the economical drivers of oil and gas production operations are related to energy. For example, oil and gas costs are fundamentally underpinned by energy utilization, such as with regards to the energy used to drive drilling equipment, the energy used to power the devices which lift fluids from the reservoir to the surface and the energy used to drive the surface processing equipment. There is also a significant amount of energy expended to construct and assemble surface facilities. Other forms of energy consumption in oil and gas operations are less apparent and more difficult to quantify, such as the energy expended to support logistical activities, or the energy consumed by the labor force both in the field and in the business office. Three very important and quantifiable categories of oil field energy utilization are with respect for construction, drilling and lifting.

The first law of thermodynamics states that energy is conserved, but if the purpose of the analysis is to better understand the energy efficiency of a process, then only the invested energies into the system and only the returned energies out of the system need to be considered. The returned energy out of the system is simply the chemical energy in the crude oil product, which is normally described by the heating value. The ratio of returned energy output to invested energy input, as described by Equation 2.1, is commonly referred to as the Energy Return on Investment (EROI), a parameter that has been applied to a wide number of energy related industries. Concerning the oil and gas industry, there have been numerous EROI studies covering a wide range of boundaries, such as for global production, for country level production, and for specific fields

$$EROI = \frac{Energy\ Return\ (Output)}{Energy\ Invested\ (Input)} \tag{2.1}$$

The EROI parameter can be used to better understand the energetic effectiveness of oil and gas producing schemes and how it changes over time. A well-structured method is required to consistently analyze the EROI of an oil and gas extraction process, and fortunately a lot of progress has been made in this area. Firstly, a standardized method for defining the boundaries for the inputs and outputs was developed by Murphy et al. The boundaries and associated notations are described in Table 2.1 [13].

*Table 2-1 EROI Boundaries*

| | Boundaries | Extraction (1) | Processing (2) | End-Use (3) |
|---|---|---|---|---|
| **1** | Direct energy and materials | EROI 1d | EROI 2d | EROI 3d |
| **2** | Indirect energy and materials input | EROI standard | EROI 2i | EROI 3i |
| **3** | Indirect labor consumption | EROI 1lab | EROI 2lab | EROI 3lab |
| **4** | Auxiliary services consumption | EROI 1aux | EROI 2aux | EROI 3aux |
| **5** | Environmental | EROI 1env | EROI 2env | EROI 3env |

The EROI boundaries include extraction, initial processing and end use. For crude oil, the extraction, initial processing and transportation to the refinery is sometime referred to as the Well to Refinery (WTF) pathway [22].

It was suggested by Murphy et al that EROI-standard could be a benchmarked parameter used to characterize the extraction process. The difficulty with the EROI-standard parameter is that it includes indirect materials and energy. Indirect energy may be the fuel used to run supporting equipment such as ships, helicopters, and road transportation vehicles. Indirect materials are related to the energy used to form and build the secondary equipment. The practicality and usefulness to oilfield analyst of including these types of secondary energy contributions in the accounting exercise is questionable. Therefore, it is suggested that EROI-1d is a more practical benchmark with regards to oil and gas extraction operations. It is also suggested to consider subsets of EROI-1d to better understand the impact of construction, drilling and lifting energies. The proposed approach is to progressively include more information in the EROI-1d parameter as indicated in Table 2.2.

*Table 2-2 Proposed EROI-1D Sub-parameters*

| Sub- parameter of EROI-1d | Purpose |
|---|---|
| EROI-$1d_{Lifting}$ | Used to understand lifting energy breakeven points and lifting costs |
| EROI-$1d_{Lifting+Drilling}$ | Used to understand the main continuous direct energy consumers during the life of the field, post construction phase. |
| EROI-$1d_{Lifting+Drilling+Construction}$ | The original intention of EROI-1d, which includes all direct energy and materials. |

*2.1.1 Lifting Energy*

This research proposes the category "lifting energy", which is the incremental energy used to produce one additional barrel of crude oil. The lifting energy include the energy required to produce reservoir fluids, the energy required to dispose associated water, and the energy required to stimulate the reservoir via secondary or tertiary recovery methods. The proposed EROI-$1d_{Lifting}$ indicator is the ratio of the produced crude oil energy output to the lifting energy input. The minimum operational requirement of sustainable production is that the produced energy is greater than the lifting energy. This implies that the EROI-$1d_{Lifting}$ must be greater than one. When the EROI-$1d_{Lifting}$ value reaches unity, the operation is no longer energetically favorable, as there is no energy surplus being produced. This is the case regardless of any commercial factors such as production commitments, the market price of oil, currency exchange rates, fiscal regimes, and tax rates. It is also equally applicable if the fuel source is derived from "free" produced fluids, like from associated natural gas that has no path to market. In actuality, an EROI-1d$_{Lifting}$ greater than one is required to offset energy intensive refining processes and end-use inefficiencies when liquid fuels are converted to useable forms of energy such as shaft work and electricity. Therefore, a minimum EROI-1d$_{Lifting}$ in the range of 3 to 5 is probably more realistic [23].

The proposed "lifting energy" category is considered to have the same constituents as lifting costs. Therefore, by understanding the lifting energetics, we can gain insight into the main influences to the lifting costs. Lifting energy, and therefore lifting costs, tend to increase as a field matures due to a number of reasons, two of which are increasing production of water and decreasing crude oil production. Empirical formulas have been developed to correlate lifting costs with percent recovery of the reservoir or with production rates [24], but these formulas are field specific due to the unique operational conditions of each field.

*2.1.2 Drilling Energy*

Drilling and completion of oil and gas wells is an energy intensive process and consequently, the associated drilling costs are normally a significant portion of the overall development costs. Depending on the development, the drilling costs can as much as 60% of the total Capital Expenditure [24]. In many fields, drilling is a continuous exercise that continues from year to year as depleted wells are side-tracked, extended or replaced. It is common to have an annual drilling campaigns with multiple rigs servicing a single oil and gas development. The energy expended by a drilling rig can be estimated using a bottoms up approach which takes into account the electrical loads applied in the various stages of drilling such as drilling, tripping (running and pulling completions), standby and transit. A very important parameter related to drilling energy, and costs, is the time it takes to drill and complete a well. This can range from a few days to a few months depending on the well complexity. Therefore, it is necessary to understand the EROI-1d$_{Lifting+Drilling}$ parameter due the fact that it can represent a substantial component of the continuous direct energy applied to an oil field.

*2.1.3 Construction Energy*

Finally, the construction of oil and gas facilities represents another energy intensive activity. Surface facilities for oil and gas operations are designed for the specific circumstances of the field with respect to the operating environment, fluid properties and related processing requirements. Offshore fields typically require large steel structures to support the wellheads and processing equipment. Onshore facilities are normally delivered at a much lower cost than offshore facilities in terms of production capacity costs which are reported in US dollars per barrel per day (USD/BPD), but it depends on the unique qualities of the development. The method used to calculate construction energy can be either “top-down” or “bottoms-up”. The bottoms-up method, which is often used for the lifting and drilling categories, involves collecting detailed energy utilization data at the equipment level. With regards to construction, this type of information would need to cover a wide range of activities and is not readily available to oil and gas companies. Therefore, a top-down approach is more practical to use in most circumstances. The top-down method is to convert monetary expenditures to energy using published energy intensity values. For example, input/output tables have been developed covering a number of industries and commodities. These tables indicate the energy required for specific products, such as steel in MJ/ton, or can developed for more generic industrial processes, such as with respect to heavy industry [3,8]. A figure that has been used in previous energy accounting work for oil and gas facilities is 14.5 MJ per dollar (2005 basis) [13]. Therefore, the $\text{EROI-1d}_{\text{Lifting+Drilling+Construction}}$ is a relevant parameter that includes an aggregation of the most significant forms of direct energy applied to an oil extraction process, and is aligned with the original intention of the EROI-1d category as defined by Murphy et al [13].

*2.1.4 Lifting Costs*

The cost per barrel parameter has long been used as an economic decision tool in the oil and gas industry [25]. The term “lifting cost” is commonly used in the oil and gas industry to describe the incremental costs of producing one additional barrel of crude oil. The lifting cost is an important parameter affecting oil field economics and is normally reported in US dollars per barrel produced (USD/BBL). Lifting cost has been found to be a function of the following variables [26]:

- Gross rate
- Oil rate
- Gas rate
- Injection water rate
- Oil wells count
- Gas wells count
- Injection wells count

It is notable that the lifting cost is more than the cost of raising reservoir fluids to the surface with artificial lift technologies, such as sucker rod pumps and electrical submersible pumps, as it also includes the costs of initial processing and injection, or disposal, of associated water or gas to comply with environmental requirements and/or to stimulate the reservoir. Initial processing includes separation of water and gas from the crude, stabilization of the crude to meet vapor pressure specifications for storage, treatment of water to remove oil and treatment of the gas to be used as fuel. The variables listed above do not differentiate between water injection and disposal, but an important distinction is needed. In many parts of the world associated water produced in the oil extraction process must be safely disposed of in subterranean reservoirs, rather than discharged to the sea or to evaporation pits, for example. The intention is to dispose the water in an environmentally acceptable way only, not to influence or stimulate the hydrocarbon bearing reservoir. For water disposal the preference is to pump the water into low pressure reservoirs, to minimize the energy used by the disposal pumps, and related costs. Primary recovery is defined by the exclusion of reservoir stimulation methods [27].

Conversely, water injection is a form of secondary recovery which is used to stimulate the hydrocarbon reservoir to maintain pressure or to sweep the hydrocarbons into extraction zones, a practice which is known as water-flooding [28,29]. The source of water can be treated associated water or external seawater or fresh water. Pressure maintenance and water-flooding usually entail the injection of water directly into the hydrocarbon reservoir at very specific locations, which is usually much deeper and at a higher pressure than disposal reservoirs. Therefore, water injection requires significantly more energy than water disposal, which implies higher lifting costs. There are many other types of energy intensive secondary recovery methods such as pressure maintenance via gas injection, reservoir sweeping mechanisms such as gas flooding. All of these methods have an impact on the lifting cost.

Tertiary recovery methods are often labelled as "Enhanced Oil Recovery" (EOR), and entail more recent technologies such as alternating water and gas injection, polymer flooding and thermal recovery methods such as steam injection [30-33]. Heavy oils with low viscosities often require reservoir stimulation via thermal methods such as steam flooding, cyclic steam injection, informally known as "huff and puff" in the industry, or by the steam assisted gravity drainage (SAGD) method [34]. There has been extensive research into the economics, and hence lifting costs, of steam injection, which is characterized by an exceptionally high energy demand [35-38].

*2.1.5 Internal vs. External Energy Sources*

An additional dimension related to the source of direct energy used for $EROI_{Lifting}$ was derived to differentiate between external and internal energy sources. Net Energy Return (NER) includes both internal and external energy investments, while External Energy Return (EER) only includes external energy investments such as imported fuel gas, liquid fuels such as diesel, and electricity imported from an external grid [17]. NER and EER ratios are described by Equations 2.2 and 2.3.

$$NER = \frac{Energy\ Return}{External\ Energy\ Invested\ + Internal\ Energy\ Invested} \qquad 2.2$$

$$EER = \frac{Energy\ Return}{External\ Energy\ Invested} \qquad 2.3$$

Therefore, to take into account the internal/external nature of the fuels used in lifting, the notation of NER and EER are be appended to the front of the referenced nomenclature where applicable such as:

- NER-EROI-$1d_{Lifting}$
- EER-EROI-$1d_{Lifting}$
- EER-EROI-$1d_{Lifting+Drilling}$
- EER-EROI-$1d_{Lifting+Drilling+Construction}$

NER (which includes both internal and external energy) is only applied to lifting since internal energy is rarely used for drilling or construction activities.

### *2.1.6 Previous Work on Field-Specific EROI derivations*

There has been a considerable effort to develop field specific EROI calculation models and tools, such as the Oil Producing Greenhouse Emissions Estimator (OPGEE), which is a tool used to estimate field specific EROIs using a combined bottoms-up and top-down approach [39]. The tool also employs smart defaults to assist with the EROI calculation, when information is incomplete.

Consistently, field specific EROIs have been shown to decline over time as production declines and the energy intensity of the operation increases [14,19]. Brandt et. al. used the OPGEE tool to calculate the time series EROIs of several giant oilfields over several decades. In this study, all fields experienced a significant decrease in EROI over time due to a combination of factors, including declining production rate, implementation of more rigorous recovery methods, and the application of more stringent environmental measures to dispose of unwanted by-products [19].

There has been very little work published on developing EROIs for small fields, which as mentioned above are now emerging in terms of their importance. Small fields have a number of challenging characteristics, as opposed to large fields, such as shorter field lives, shorter time frames for decision making, and an inability to capitalize on economies of scale. Therefore, it is imperative for oil and gas operators to understand the energetic behavior and associated cost implications of small fields and be able to make informed, timely decisions.

### *2.1.7 Case Studies*

This research attempts to illuminate the practical aspects of the energy accounting methodology by developing cases studies. A secondary goal is to describe the energetic and economic behavior of three small offshore fields. The selected three fields share some characteristics, such as the water depth, the lifting mechanism, the crude properties, the processing requirements, the processing capacities, and to some extent the requirement to dispose or inject water into subterranean reservoirs. The fields also have some important distinguishing aspects, which makes for interesting comparisons, with respect to recovery method and produced gas quality and quantity. These characteristics are described in Table 2.3.

*Table 2-3 Summary of Case Studies*

| Field | Water Depth | Production Period Evaluated | Processing Requirements | Lifting Mechanism | Recovery Method | Fuel |
|---|---|---|---|---|---|---|
| Field 1 | 60 meters | 2008 to 2018 | Crude/water/gas separation, crude stabilization and associated water treatment and disposal. | Electrical Submersible Pumps (ESPs) | Initially secondary recovery, employing water injection at >1000 psig at the wellhead. In 2012 the field switched to primary recovery, with associated (produced) water disposal at low pressure <300 psig. | Exclusively diesel since the gas produced is of insufficient quality and quantity (High CO2) (100% diesel) |
| Field 2 | 55 meters | 2015 to 2018 | Crude/water/gas separation, crude stabilization, associated water treatment and injection. | Electrical Submersible Pumps (ESPs) | Secondary recovery, employing associated (produced) water injection >1000 psig at the wellhead. | Primarily produced natural gas. (approximately 95% natural gas) |
| Field 3 | 70 meters | 2016 to 2018 | Crude/water/gas separation, crude stabilization, associated water treatment and injection. | Electrical Submersible Pumps (ESPs) | Secondary, employing associated (produced) employing water injection >1000 psig at the wellhead. | Combination of natural gas and diesel. (approximately 30% natural gas, 70 percent diesel) |

What makes this research unique is the authors' access to detailed field specific data. The ensuing analysis contains very few assumptions, as production rates, fuel consumption rates, including diesel fuel and natural gas, are based on actual field data. Furthermore, the researchers have access to original capital cost data for all three field, as well as access to the detailed drilling program stretching back to the initial drilling campaign and includes the actual drilling energies based on drilling equipment loads. Therefore, this research endeavors to illuminate the energetic behavior of three small offshore oil fields by analyzing actual detailed field level data.

## 2.2 Results and Discussion

Figures 2.1-2.3 indicates the time series production rates of oil and water for three small offshore oil fields along with the corresponding NER-EROI-1d$_{\mathrm{Lifting}}$. It is clear that NER-EROI-1d$_{\mathrm{Lifting}}$ declines as crude production declines and/or produced water increases in all three fields. The largest dataset was for Field 1 in terms of the time period covered, so the decreasing trend is more mature. It should be noted that Field 1 switched from high pressure water injection to low pressure disposal in 2011. Therefore, the decreasing NER-EROI-1d$_{\mathrm{Lifting}}$ was attenuated by this change in recovery strategy. The decision was based on the development team's belief that natural aquifer drive was sufficient to maintain reservoir pressure and sweep the hydrocarbons into extraction zones. Regardless of the switch from was disposal to water injection, Field 1 exhibits decreasing crude, increasing water and hence decreasing NER-EROI-1d$_{\mathrm{Lifting}}$ over it's field life.

Field 2 and 3, which employs high pressure water injection only, exhibit similar trends, although since they are both relatively young fields, and the data only covers the early phase of field life.

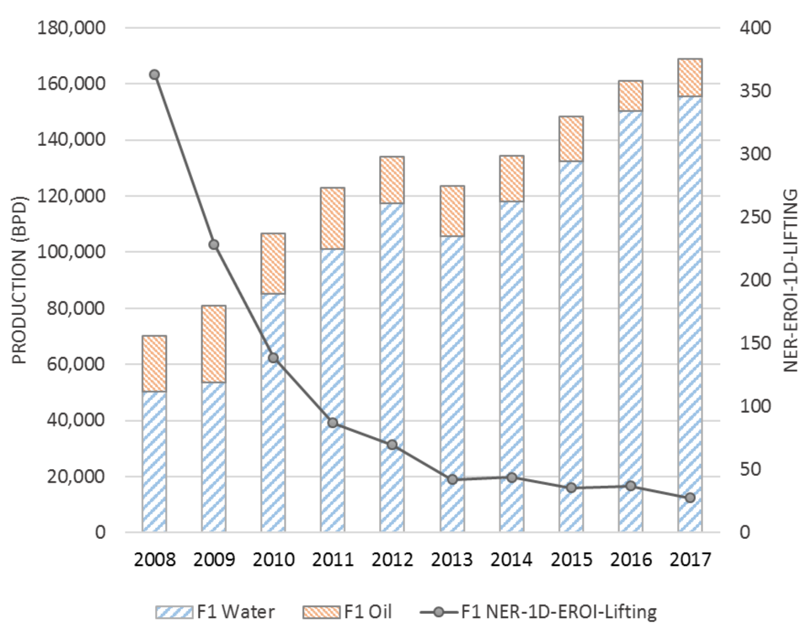

*Figure 2-1 Field 1 Production vs. NER-1d-EROI-Lifting*

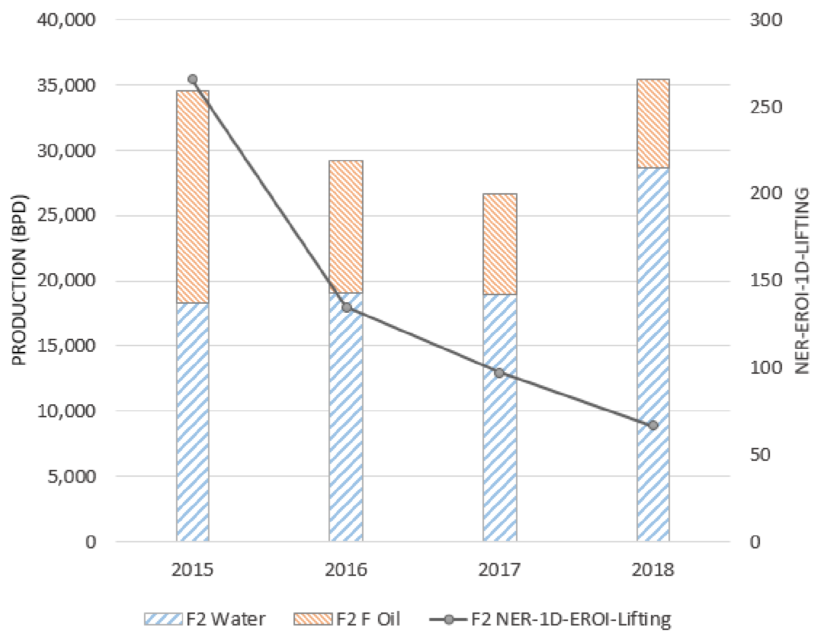


*Figure 2-2 Field 2 Production vs. NER-1d-EROI-Lifting*

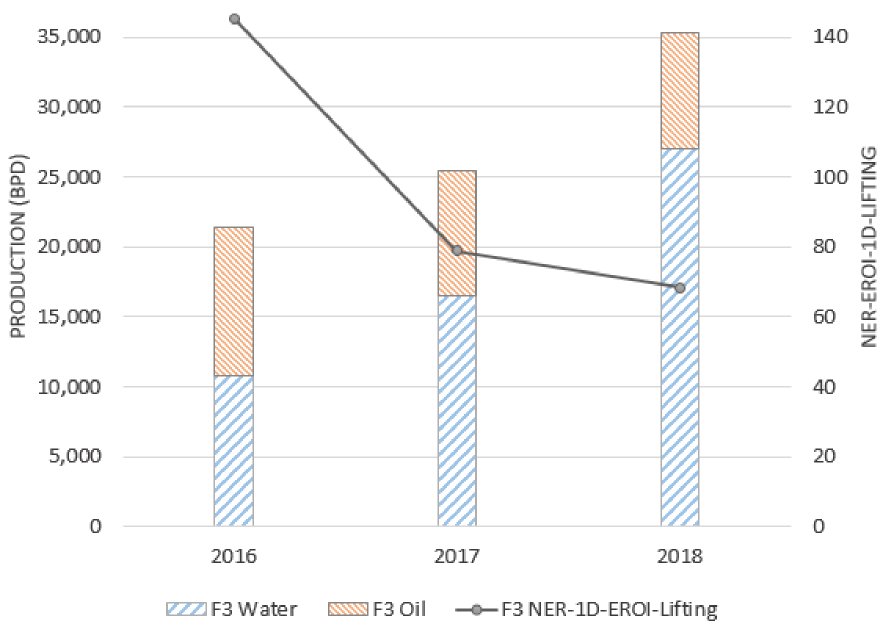


*Figure 2-3 Field 3 Production vs. NER-1d-EROI-Lifting*

General trends for each field are shown in Table 2.4, indicates that all three fields are experiencing decreasing NER-EROI-1d$_{Lifting}$ under similar production trends.

*Table 2-4 Trends for three small fields*

| Field | Crude Oil | Produced Water | NER-EROI-1d-Lifting |
|---|---|---|---|
| Field 1 | Decreasing | Increasing | Decreasing |
| Field 2 | Decreasing | Increasing | Decreasing |
| Field 3 | Decreasing | Increasing | Decreasing |

It should be noted that all three fields have recently reached their current water handling capacity limit, a condition commonly referred to as “bottlenecked”. A debottlenecking campaign is underway to increase each field’s water handling capacity. The debottlenecking is needed to sustain crude oil production, but will result in an increase of energy consumption to handle and inject the additional water. Therefore, the EROI decreasing trends are expected to accelerate in the post-debottlenecking phase of operation for all three fields.

The NER-EROI-1d$_{Lifting}$ time series trends for the three small fields included in this study are shown in Figure 2.4. The NER-EROI-1d$_{Lifting}$ values all decline rapidly in the first years of production followed by a slower decline in later years. The three fields exhibit a similar pattern of decline, which is caused by a combination of declining crude oil production and increasing water production.

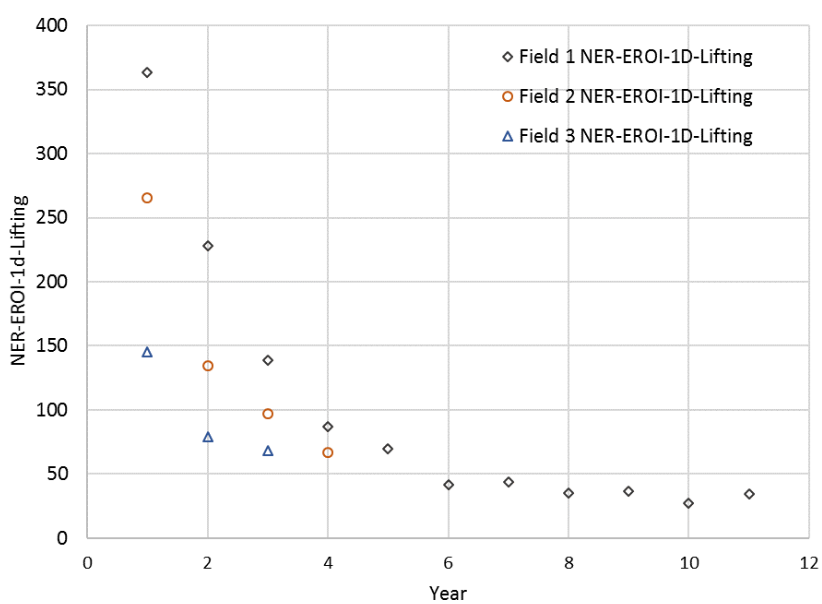


*Figure 2-4 NER-EROI-1d-Lifting Time Series for three small fields*

Linear and exponential regression analysis was applied to model the declining NER-EROI-1d$_{\text{Lifting}}$ of the three fields. As can be seen in Figure 2.5, the fields exhibited differing slopes of decline. Fields 1 and 3 exhibited similar slopes, while Field 2 exhibited a steeper decline slope.

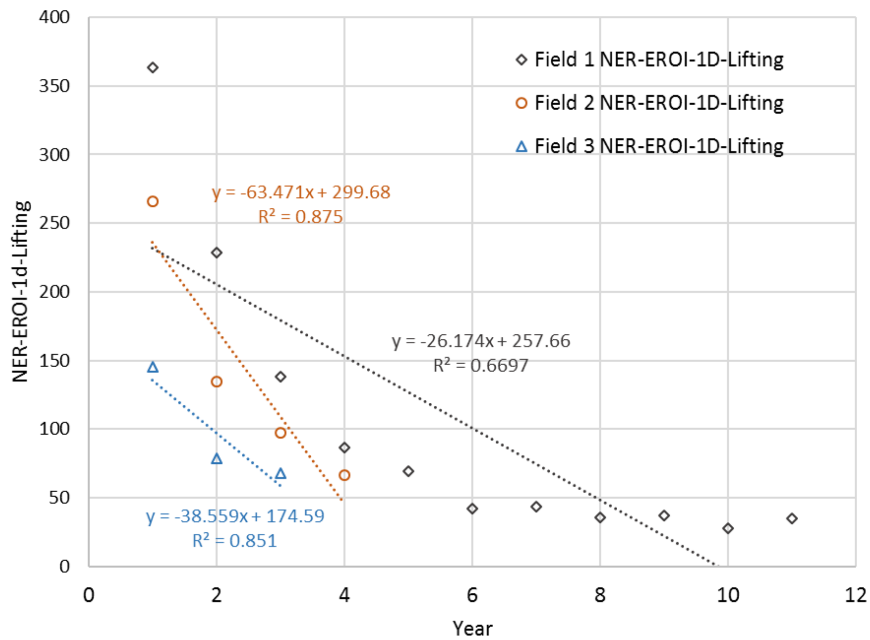


*Figure 2-5 NER-EROI-1d-Lifting Regression Analysis (Linear)*

Exponential regression analysis was applied to the NER-EROI-1d$_{\text{Lifting}}$ data and generally exhibited a better fit with regards to the R2 value as indicated in Figure 2.6. Once again, Fields 1 and 3 exhibited similar exponential declines, as opposed to Field 2, which exhibited a much steeper decline. Crude oil production profiles are often modeled with exponential or hyperbolic decline functions [20]. Therefore, since the crude oil decline curve influences the EROI decline curve, it is hypothesized that an analogous EROI exponential decline approach may represent a reasonable model and future work should revolve around developing mathematical decline models for NER-EROI-1d$_{\text{Lifting}}$.

An interesting aspect of this work was the significance of drilling energy for all three fields. This can be understood by examining the differences between NER-EROI-1d$_{\text{Lifting}}$ and NER-EROI-1d$_{\text{Lifting+Drilling}}$ for each field, as exhibited in Figures 2.4 and 2.7. Drilling energy calculations are shown in Appendix A, Figure 2.13. Generally speaking, the EROIs dropped by as much as 70% in early life to as little as 2% in later life. This indicates that the NER-EROI-1d$_{\text{Lifting+Drilling}}$ approaches NER-EROI-1d$_{\text{Lifting}}$ as drilling activities are reduced from the initial intensive drilling phase of the field.

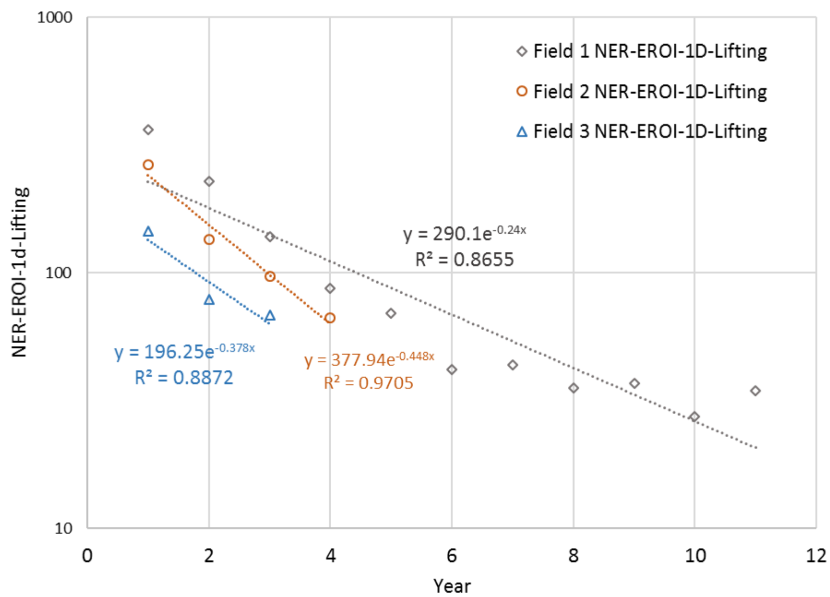


*Figure 2-6 NER-EROI-1d-Lifting Regression Analysis (Exponential)*

As shown in Figure 2.8, when drilling and construction energies are accounted for, the EROIs shift downward by up to 87% in early life from EROI-1d$_{\text{Lifting}}$, which only includes the lifting energy. Drilling and Construction energy calculations are shown in Appendices A and B, Figures 2.13 and 2.14 respecively. The construction energies are amortized over the first three years of production; therefore, the shift downward due to facilities construction is realized only during the early years of production. The construction of offshore platforms that weigh between 1,000 to 2,000 tons is an energy intensive process.

Therefore, it is not surprising that there is a significant impact on EROIs when construction energies are included in the early years of production.

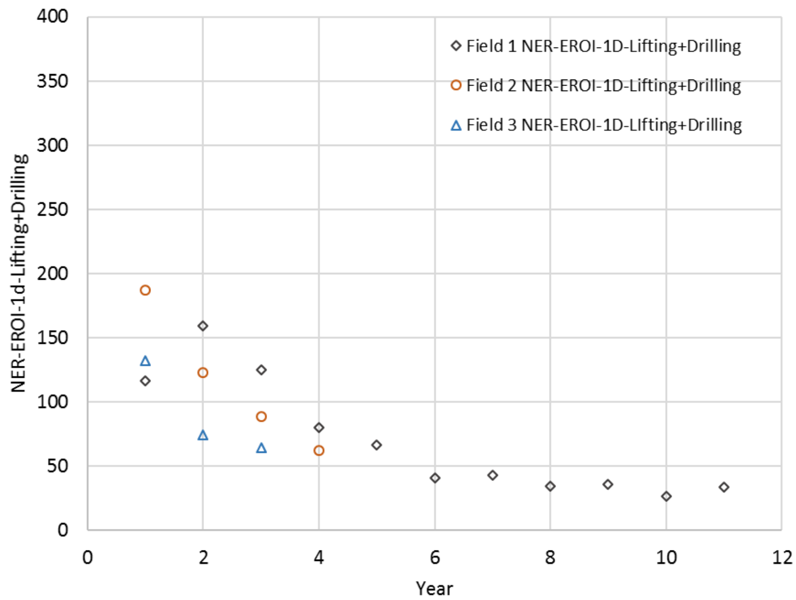


*Figure 2-7 NER-EROI-1d-Lifting+Drilling for three fields*

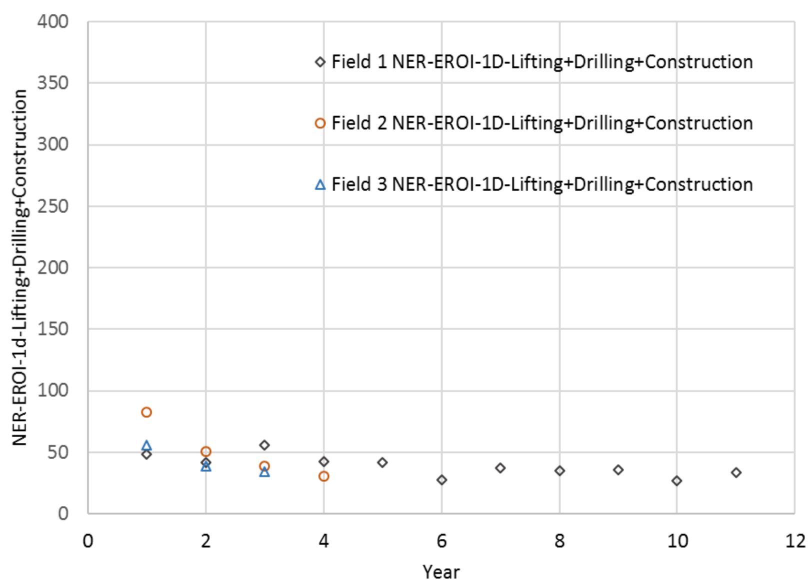


*Figure 2-8 NER-EROI-1d-Lifting+Drilling+Construction for three fields*

An energy balance time series, which does not amortize construction was developed to better understand the following:

- Actual cumulative energy profile
- The energy breakeven point for all the 3 fields

- The actual annual proportion of energy-in from lifting, drilling and construction
- The overall (field-life) proportion of energy-in from lifting, drilling and construction

As can described in Appendix 2C, Figure 2.15, the drilling energies share of the yearly energy-in for Field 1 ranges from 13% in early life to approximately 3% in late life, as the drilling rate decreases. Drilling energy for Field 2 and 3 as a percentage of the yearly energy applied ranges from 11% to 5%. Construction energy as a percentage of the total applied over the entire field life ranged from 25% for Field 1, the oldest field, to 63% for Field 3, the newest field. All fields experience the energy breakeven point within the first year of production. This is due to the large quantity of energy produced during the initial early life high crude oil production rates.

Overall, there is greater confidence in the EROI-1d$_{\text{Lifting}}$ results compared to the EROIs which take into account drilling and construction. This is due to the fact that actual fuel consumption on the platforms is a well-known quantity, while drilling energy and construction energy employed less certain energy consumption assumptions.

It is proposed that there is great insight which can be gained by understanding the relationship between EROI-1d$_{\text{Lifting}}$ and lifting costs. Lifting costs trends are shown in Figure 2.9 for Fields 1, 2 and 3. The lifting cost of Field 1 increases at a higher rate than Field 3 due the fact that Field 1 runs exclusively on imported diesel fuel, while Field 3 runs on a combination of imported diesel fuel and "free" produced natural gas. Field 2, which runs primarily on associated gas, actually shows a decreasing trend as the operational team have focused on minimizing the use of diesel fuel in the field. Field 3 was selected for comparison between NER- EROI-1d$_{\text{Lifting}}$ and EER- EROI-1d$_{\text{Lifting}}$, since Field 3 generators run on a combination of diesel fuel and natural gas, commonly referred to as "dual fuel" engines.

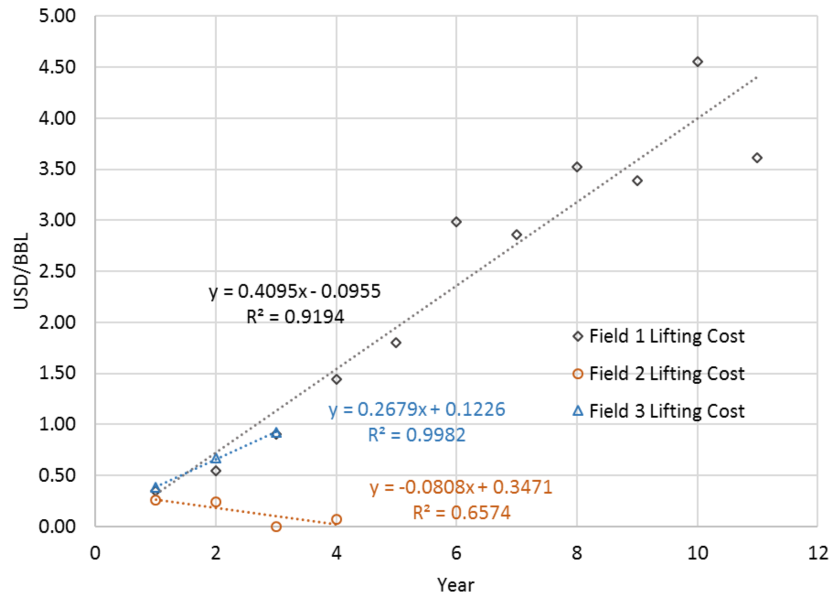


*Figure 2-9 Comparison of Lifting Costs between Field 1, 2 and 3*

As indicated in Figure 2.10, the EROIs for Field 3 are significantly higher when only external fuel is accounted.

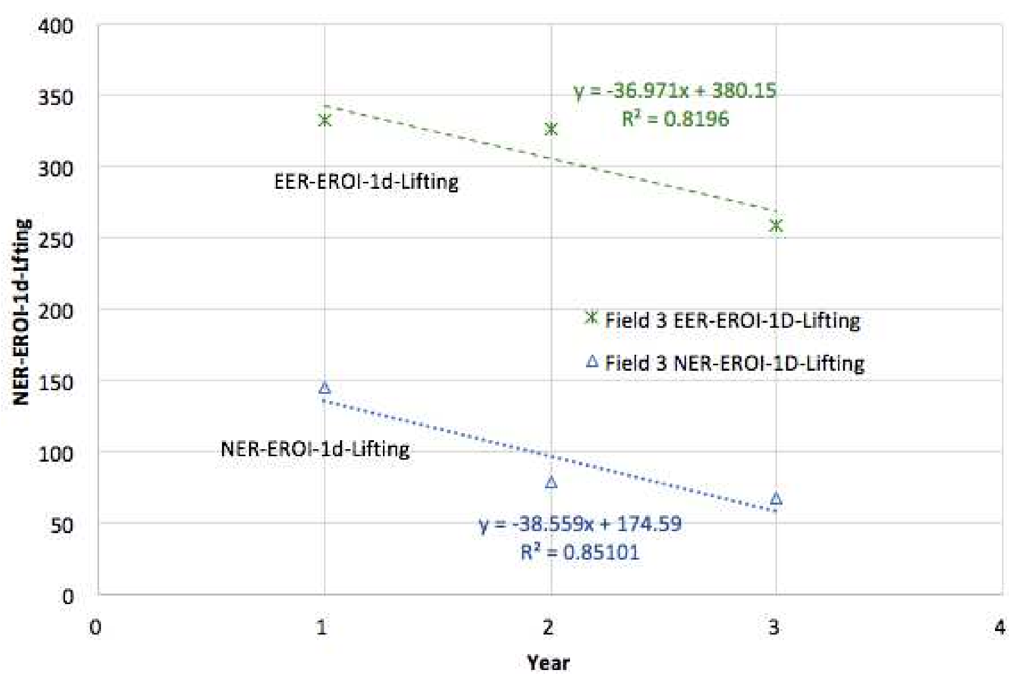


*Figure 2-10 Comparison of NER-EROI-1d-Lifting vs EER-EROI-1d-Lifting for Field 3*

The NER- EROI-1d$_{Lifting}$ value is inversely proportional to lifting costs as can be seen in Figures 2.11 and 2.12, which represent Field 1 and Field 3, respectively. The correlation coefficients are - 0.822 for Field 1 and -0.887 for Field 3.

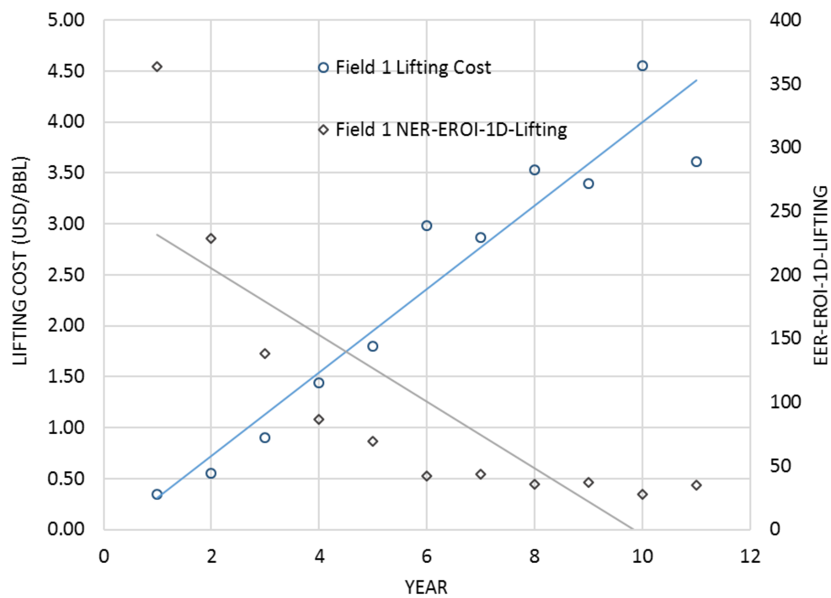


*Figure 2-11 Lifting Costs and NER-EROI-1dLifting vs. Time for Field 1*

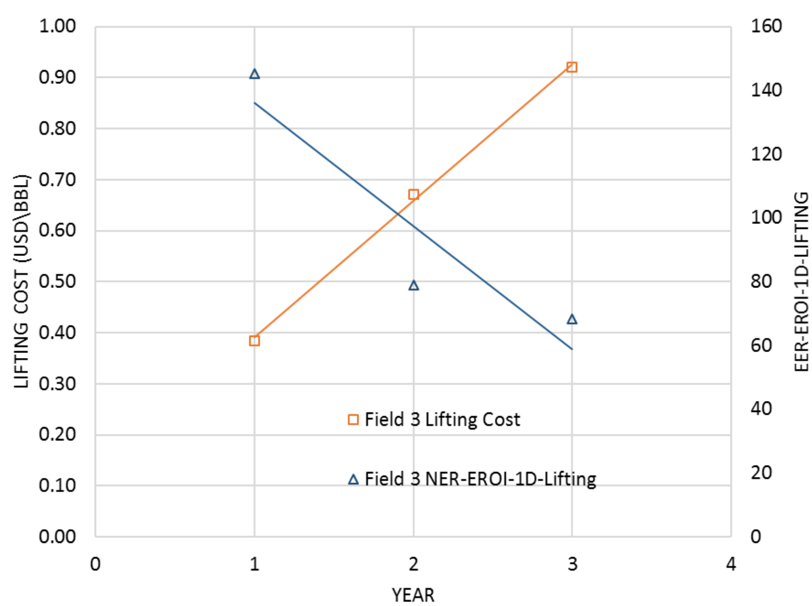


*Figure 2-12 Lifting Costs and NER-EROI-1dLifting vs. Time for Field 3*

## 2.3 Material and Methods

Three small offshore fields were developed as case studies. Each field's peak production was under 25,000 barrels of oil per day, and as such are classified as non-giant fields. Each field has been in operation for between 3 and 12 years. Each field employs artificial lifting of reservoir fluids utilizing downhole electrical submersible pumps (ESPs) and employs conventional surface centrifugal pumps to pressurize and inject, or dispose, the associated produced water. Power required for the ESPs and the surface water injection pumps represent more than 90% of each platform's total platform power demand.

ESP systems are composed of two subsystems, electrical and hydraulic. The electrical system is composed of an electrical power source, surface equipment (motor controllers and transformers), cables and the ESP motor itself, which is located in the well, beneath the pump. The hydraulic subsystem is composed of the pump and the discharge piping, which traverses up the well to the offshore platform.

The processing requirements on the platform are minimal and include only separation of reservoir fluids into oil, water and gas by gravity, crude stabilization by flashing at low pressure, and water treatment with the use of cyclonic devices driven by a small pressure gradient between the production separator and the water degassing vessel.

Reciprocating internal combustion engine generators are installed on each platform and generally consume either diesel fuel or natural gas, although several diesel generators are equipped with dual fuel systems which allows for the produced natural gas to supplement the imported diesel fuel. Additional characteristics of the three fields are described in Table 2.5.

*Table 2-5 Field Parameters*

| Field Name | Start Year | Number of Production Platforms | Number of Wells | Fuel Source | Peak Production Rate (BPD) | Power Generation |
|---|---|---|---|---|---|---|
| Field 1 | 2007 | 6 | 100 | Diesel fuel | 20,000 | 17 Diesel Generators |
| Field 2 | 2014 | 1 | 12 | Natural Gas | 15,000 | 3 Gas Generators<br>1 Diesel Generator |
| Field 3 | 2015 | 2 | 25 | Diesel and Natural Gas | 12,000 | 3 Dual Fuel Generators<br>2 Diesel Generators |

The method employed in this research is comprised of the following main steps:

1. Gather energy inputs and outputs for three small offshore fields
2. Calculate time series EROI-1d values for each field
3. Apply regression analysis to the time series data where appropriate
4. Calculate lifting costs for three small offshore fields
5. Analysis of results

*2.3.1 Energy Outputs*

Energy outputs are derived by converting the average daily crude production rate for each year to an energy rate using typical lower heating value of crude, of 6.1 GJ/barrel.

*2.3.2 Energy Input – Lifting Energy*

Lifting energy is calculated by converting fuel consumption rates to energy equivalents using the lower heating value. For Field 1, 2 and 3 the average daily diesel consumption for each platform which is recorded in US gallons per day is converted to an average daily energy rate by using a lower heating value of 146 MJ per US gallon. For Fields 2 and 3 the average daily natural gas consumption recorded in million standard cubic feet per day (MMSCFD) is converted to an average daily energy rate using a lower heating value of 1.0 MJ per standard cubic foot.

*2.3.3 Energy Input – Drilling Energy*

The reservoirs are highly compartmentalized. The exploitation strategy for this type of reservoir generally requires numerous wells; therefore, there is continuous drilling of new wells in the annual drilling campaign. The high level of drilling activity is required to sustain production on each platform. As such, the energy consumed by the annual drilling program is calculated based on an estimate of the historical number of wells drilled per year and an estimated drilling rig power load for each well.

*2.3.4 Energy Input – Construction Energy*

Finally, construction and installation of offshore platforms is an energy intensive process. For large capital expenditures, it is commonplace to convert capital expenditures to energy consumption values using published energy intensities for heavy industry. For platform construction an energy intensity value of 14 MJ/USD (2005 USD basis) was applied, which is consistent with published data. Construction energy was amortized for three years following initial production. All platform costs are converted to 2005 dollars, which is aligned with the energy intensity value applied.

*2.3.5 Derivation of EROI-1d*

With the energy inputs and energy outputs derived, several time series for EROI-1ds of interest are developed for each field. For all fields NER-EROI-1d is calculated. For Field 3 both NER-EROI-1d-NER and EER-EROI-1d is calculated since the field employs both external and internal fuel sources.

*2.3.6 Lifting Cost*

Lifting costs are calculated by converting the annual daily diesel fuel consumption to an average daily cost using a diesel fuel cost of 3.0 USD per US gallon. A representative cost is selected and no attempt was made to account for market fluctuations in diesel fuel cost.

## 2.4 Conclusions

This study demonstrates the benefits to oil field analyst of applying the EROI methodology. This is established with respect to the examination of the energetic behavior of three small offshore fields. It is clear that the EROI methodology can be used to aggregate energy information in order to provide insight into the energetic valued-added nature of a development, which is not as readily understood when the underlying information is dispersed and generally disconnected, such as with regards to production profiles, utility tables, drilling schedule, construction reports etc. Conversely, this study reveals that the EROI methodology can also be used to dissect energy information to illuminate particular aspects of the development, such as with respect to lifting energy, which is known to be a significant component of the total energy consumed by oil fields and a key influencer of the variable costs. The following conclusions can be drawn from this research:

1. All three fields indicate a steeply declining EROI-1d trend. The EROI-1d$_{Lifting}$ decline can be directly attributed to the lifting process becoming more energy intensive over time. This applies equally to Field 1 despite the fact that the recovery method was changed employing low-pressure water disposal rather than high-pressure water injection. Without the change in recovery strategy, the EROI-1d$_{Lifting}$ trend would have declined more steeply from 2011 onwards.

2. The decreasing EROI-1d trend also holds true for the EROI-1d$_{Lifting+Drilling}$ and for the EROI-1d$_{Lifting+Drilling+Construction}$ parameters, but to a lesser extent since:

   1) drilling energy intensity decreases after the initial production wells are drilled

   2) the methodology used amortized the construction energy evenly over the first three years of production.

3. Production decline modelling in an oilfield is an intensely studied topic. Energy return decline modelling generally receives very little attention and is therefore not as well understood. It is suggested that more vigorous effort should be made to understand the EROI decline behavior of oilfields, since it has a direct impact on the efficiency and economics of the field, even more so than the production decline.

4. Drilling and construction energies constitute a substantial component of the total energy consumption. The drilling contribution to energy consumption is related to the drilling intensity over the life of the field, which usually starts with a large number of initial development wells and then tapers off to a lesser number of wells per year later in the field life. Construction energy on the other hand, is completely expended just prior to first production. The energy breakeven point was found to occur within the first year of production for all three fields, due to the large energy gains obtained by early high production rates.

5. EROI-1d$_{Lifting}$ and lifting costs are found to be inversely related, since the input energy has a cost, such as the cost of diesel fuel. The magnitude of the lifting cost and the degree by which lifting costs increase over time depends on the mix of fuels used, which can range from complete reliance on procured diesel fuel (Field 1) to total fuel self-sufficiency when sufficient quantities and quality of internally derived natural gas are available (Field 2). In between these two extremes, is the case where there is a mixture of internal and external fuels sources applied (Field 3).

6. This method describes a more rigorous approach to understanding and estimating lifting costs and highlights the impact on costs of the source of energy consumptions with respect to internal vs. external.

*2.4.1 Limitations of this work*

The energetic analysis of three offshore small fields as case studies is revealing, but may not be representative of the numerous small fields scattered across the world. The diversity of small fields is enormous. Each small field has identifying qualities, such as the location (e.g. offshore v. onshore), environment (e.g. tropical, desert and artic), number and capacity of wells, the drilling complexity of the wells, the crude oil properties, the crude production rate profile, the associated water profile, and the associated gas qualities and quantities. One of the most important distinguishing elements of a small field is the recovery strategy (e.g. primary, secondary or tertiary), and the lifting mechanism (e.g. natural flow, sucker-rod pumps, electrical submersible pumps, progressive cavity pumps, gas lift etc.). All of these variables will have an impact on the energy profile of a particular small field.

Furthermore, the relationships explored in this research are in some cases limited by the span of field data available. Fields 2 and 3 are relatively young developments with only 4 and 3 years of data available, respectively. The results of the regression analysis therefore must be considered preliminary and the continued monitoring of these fields is required to truly understand the trends and project future EROI and lifting costs.

The conversion of construction costs to energy has an unknown degree of error due to the accuracy of the energy intensity factor employed, which may not be representative of the region or of local construction practices. The intention was to provide an order of magnitude estimate only for construction energy of the three fields studied.

In spite of these limitation, the intention of this research is to illuminate a more detailed EROI methodology, describe the energetic behavior of three somewhat typical fields, and most importantly to highlight the value of employing detailed energy accounting to development teams managing small fields.

*2.4.2 Future Work*

It is suggested that future work should revolve around the development of mathematical models to describe EROI decline trends and associated lifting costs. Another suggested area of future work is related to the development of an EROI-centered methodology for improving lifting cost estimates during concept evaluations. As such, concept evaluations could test EROI and lifting costs sensitivities with respect to recovery methods and fuel sources. Finally, it is suggested that the energetic behavior of small fields can be analyzed with respect to understanding the common energetic patterns linked to the recovery method.

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CHAPTER 3 – DETAILED ENERGY ACCOUNTING OF ELECTRICAL SUBMERSIBLE PUMPS[2]

## 3.0 Introduction

The concept of Energy Return on Investment (EROI) is focused on a set of eighteen Electrical Submersible Pumps (ESPs) by conducting a detailed energy accounting over a one-day period. Each of the ESPs operated under unique conditions with respect to the flowrate, reservoir pressure, water to oil ratio, and depth of the pump. The energy accounting results are used to quantify the energy losses and efficiencies of each ESP system as well as the EROI of the lifting process (EROILifting), which is derived by dividing the energy out of each well, which is the chemical energy of the crude oil produced, by the energy consumed by each ESP system and by the surface equipment used to dispose of the well's produced water. The resulting EROILifting values range from 93 to 565, with a corresponding energy intensity of 18.3 to 3.0 kWh/barrel of crude, respectively. The energy consumed by each well is also is used to calculate the lifting costs, which is the incremental cost of producing an additional barrel of crude oil, which range from 0.64 to 3.90 USD/barrel of crude. The lifting costs are entirely comprised of procured diesel fuel, since there is no natural gas available on the platform to be used as fuel. Electrical efficiencies range from 0.60 to 0.80, while Hydraulic efficiencies range from 0.12 to 0.56. The overall ESP efficiencies range from 0.09 to 0.39, with the largest losses occurring in the hydraulic system, particularly within the ESP pump itself. Improvement of pump efficiencies is the only practical option to improve the overall ESP system efficiencies. Other losses, such as within the electrical and hydraulic systems present few opportunities for improvement.

## 3.1 Background

The search for new oil fields has led oil and gas companies to develop less favorable, geographically challenged, fields, such as offshore. The development and exploitation of offshore oil fields are generally energy intensive, due to the remote marine environment in which they operate. Large

[2] The chapter was submitted as a journal article to Energies, 2019, 7 June.

steel structures are often required to support extraction facilities, such as with respect to drilling rigs and offshore processing platforms. Logistically, energy is required to transport resources to the facilities to support drilling, operations and maintenance activities. Energy is also necessary to store and transport the crude oil to market. Finally, from a life cycle perspective, a significant amount of energy is required to raise reservoir fluids to the surface facilities and to inject separated water back into the formation. The focus of this research is to provide insight into the last category by developing and analyzing appropriate energy performance indicators, such as the Energy Return on Investment (EROI) and the energy intensity, as well as to understand how the derived energy performance indicators relate to the operating costs.

*3.1.1 Energy Performance Indicators*

EROI is the energy return (output) divided by the energy invested (input) of a system [1]. Equation 1 provides the definition of EROI. The first law of thermodynamics states that energy is conserved, but if the purpose of the analysis is to better understand the energy efficiency of a process, then only the invested energy into the system and the useful energy returns out of the system are included. For example, invested energy can take the form of electricity used to run extraction equipment, while the energy returns are typically described by the chemical energy embodied in the crude oil and natural gas products, which is normally described by the heating value.

$$EROI = \frac{Energy\ Return\ (Output)}{Energy\ Invested\ (Input)} \tag{3.1}$$

Researchers have developed EROIs for a number of systems with different degrees of focus. Initially, researchers focused on quite large systems such as the global oil and gas industry, or the oil and gas industry within a country [2-4]. These large scale oil and gas systems were typically modeled using a top down approach which converts monetary investments to energy investments, while energy out was derived by converting published production rates to energy rates, by means of the heating values of the hydrocarbon produced [5]. Subsequently, researchers began using the EROI concept to better understand the energetic behavior of specific oil and gas fields by employing a bottoms up approach, which delved into the details of the extraction and initial processing systems [6,7]. For example, a bottoms up approach would isolate and take into account the energy used by a diverse assortment of equipment used in the extraction process.

The boundaries for oil and gas EROI studies were originally defined by Murphy et. al. using two dimensions, processing and energy types [1]. The processing boundaries extends from extraction to end-use. These types of energies invested, which appears in the denominator of the EROI ratio, includes direct and indirect energy, the energy embodied in materials, and the energy consumed by labor and by auxiliary services.

The predominant energy demand for a typical oil extraction process is often the energy required to raise the reservoir fluids to the surface, a practice which is generally referred to as “artificial lift” in the oil and gas industry [8]. The energy required to inject associated water is also a significant component of the total energy demand. The term “Lifting Cost” is often used in the oil and gas industry to describe the incremental costs of producing an additional barrel of oil [9]. This research introduces a new corresponding term called “Lifting Energy”, which can be thought of as the incremental energy of producing an additional barrel of oil. In this paper, lifting energy is proposed to include the energy required to raise reservoir fluids to the surface, to inject separated water back into the formation, as well as the incremental energy required for initial processing on the platform. The energy inputs and outputs accounted for in the overall lifting balance are described in Figure 3.1.

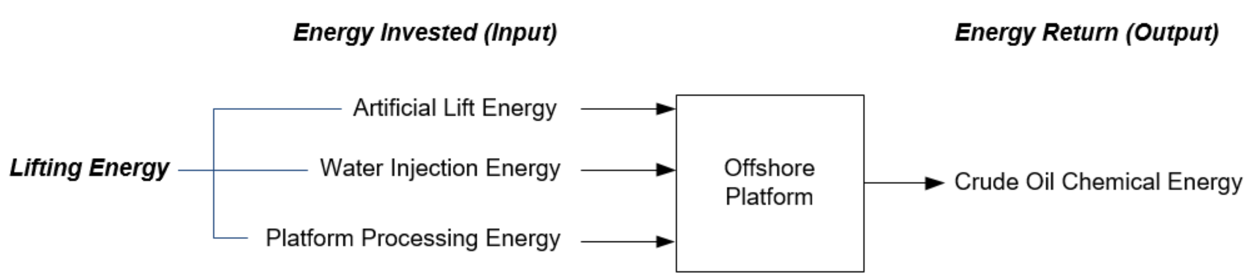



*Figure 3-1 Overall Lifting Energy Balance*

In relation to the “Lifting Energy” concept, this research proposes a new more practical category of EROI, which includes only the direct energy used for lifting, excluding indirect energies and the energies embodied in materials. The proposed category is “$EROI_{Lifting}$”. It should be noted that $EROI_{Lifting}$ is closely related to the "energy intensity" of lifting, which is essentially the inverse of the EROI, except that instead of using an energy output, the energy intensity uses a non-energy unit as the output, which for crude oil is a standard barrel (bbl). Equation 2 describes the energy intensity ratio.

$$Energy\ Intensity\ of\ Lifting\ (EI) = \frac{Energy\ Invested\ (Input)}{Unit\ of\ Production\ (Output)} \qquad 3.2$$

This level of focus into EROILifting, and the related energy intensity of lifting, can provide several benefits:

- Insight into the energy returns and energy intensities of the extraction process on an individual well basis
- A means to better understand the factors impacting the lifting costs of the extraction process
- An additional factor by which to rank wells and support decision making regarding operations

*3.1.2 Lifting Costs*

As described in the preceding section, lifting costs are the variable costs used to produce one additional barrel of oil [9]. The lifting cost of a well is an important parameter affecting oil field economics and is normally reported in US dollars per barrel of crude produced (USD/BBL). In most oil and gas fields the lifting costs are directly related to energy consumption. Therefore, it is proposed that by understanding the detailed lifting energetics, we can gain insight into the main influences on lifting costs. Lifting cost has been interpreted to be a function of the following parameters [9]:

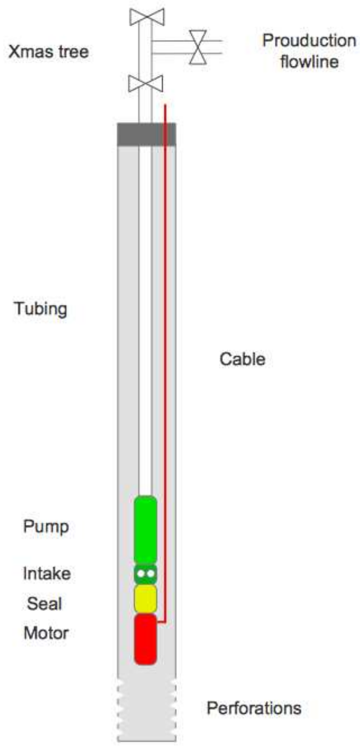
- Gross rate
- Oil rate
- Gas Rate
- Injection Water Rate
- Oil wells count
- Gas wells count
- Injection wells count.

Consistent with the energetic definition of "lifting" used in this research, lifting cost is assumed to include the costs of raising the fluids from the subsurface reservoir to the surface, the costs of injection of associated water or gas to comply with environmental requirements and/or to stimulate the reservoir, and the costs to run processing equipment and miscellaneous support utilities on the offshore platform. In the proposed method, the share of costs for injection of associated water is allocated based on each well's contribution of water, while the share of costs required for processing and miscellaneous utilities is split equality by all wells. For imported energy, lifting costs is simply the energy intensity multiplied by the unit cost of energy as described by Equation 3.3.

$$Lifting\ Costs = EI\ x\ Energy\ Costs = \left(\frac{kWh}{Barrel\ Crude}\right) x \left(\frac{USD}{kWh}\right) = \frac{USD}{Barrel\ Crude} \qquad 3.3$$

*3.1.3 ESP Energy Balances*

The mechanisms employed to raise fluids to the surface typically involves various pumping technologies. A widespread technology involves the installation of centrifugal pumps within the well close to the reservoir. This technology goes by the name Electrical Submersible Pumps (ESPs). ESP systems are composed of two general subsystems, electrical and hydraulic. The electrical system includes an electrical power source, surface equipment (motor controller and transformer), cables and the ESP motor itself, which is located beneath the pump in the well. The hydraulic subsystem includes the pump and the discharge piping which raises the reservoir fluids to the surface facilities (the well tubing). A seal system is in place to prevent reservoir fluids from entering the motor housing. Figures 3.2 and 3.3 describe the ESP systems and it's two primary subsystems, electrical and hydraulic.



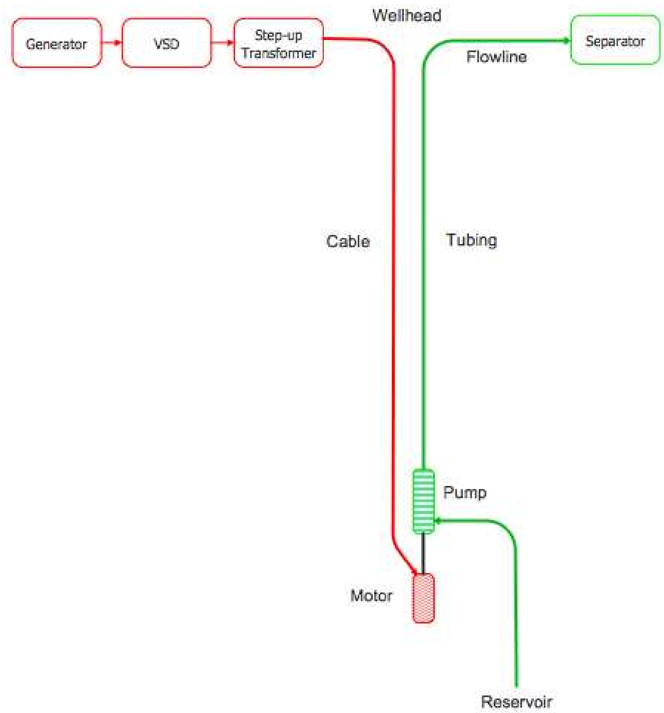




*Figure 3-2 ESP System configuration* *Figure 3-3 ESP System Electrical and Hydraulic components*

The ESP pump itself, is a multistage centrifugal pump with numerous rotating impellers, each of which is an integral component of a single pump stage. The performance of an ESP pump is best described by curves provided by the manufacturer. A set of ESP pumps curves describe the Flow/Head relationship, the brake horsepower (BHP) required by the pump over the full range of its flow, the pump hydraulic efficiency as a function of flow rate, and the motor efficiency as a function of the percentage nameplate power provided to the motor. Typical ESP performance curves are shown in Figures 3.4 and 3.5.

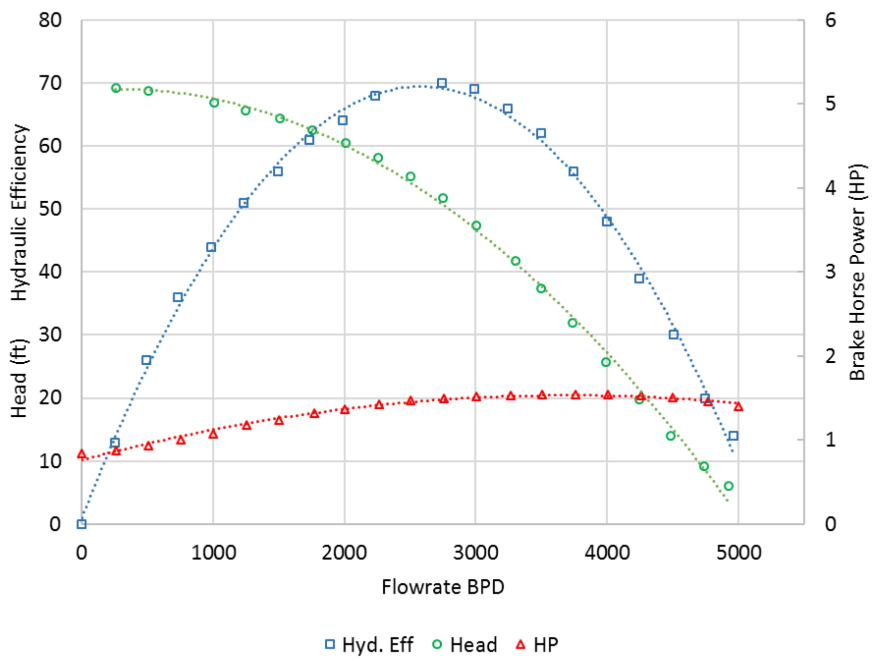



*Figure 3-4 Example Pump Curves – 1 Stage at 60HZ*

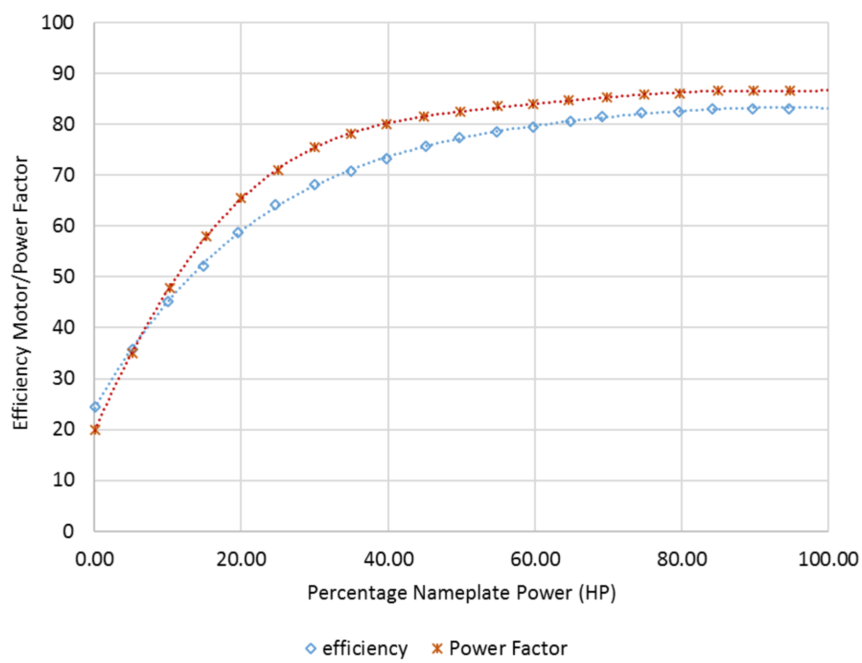



*Figure 3-5 Example ESP Motor Efficiency Curve*

Hydraulic efficiencies generally range between 0.20 and 0.60 for the pump itself depending on the operating conditions. For every centrifugal pump there is an optimal point where the maximum efficiency is achieved. This is commonly called the Best Efficiency Point (BEP) and it usually identified as a point on the Flow/Head curve. It is not always possible to operate at the BEP; therefore, a typical ESP Flow/Head curve also includes the recommended operating range. ESP systems are frequently provided with Variable Speed Drives (VSDs), which can be used to adjust the speed of the pump and cause a shift in both the Flow/Head and the efficiency curves.

Energy balances can be derived by considering the ESP system components shown in Figure 3.6. Electrical losses can occur at the surface equipment (variable speed drive and transformer), downhole cables and within the ESP motor itself. Hydraulic losses are due to pumping inefficiencies, frictional losses in the tubing and losses associated with backpressure at the surface. Figure 3.6 indicates the flow of energy through the ESP system as well as the location of energy consumption and losses.

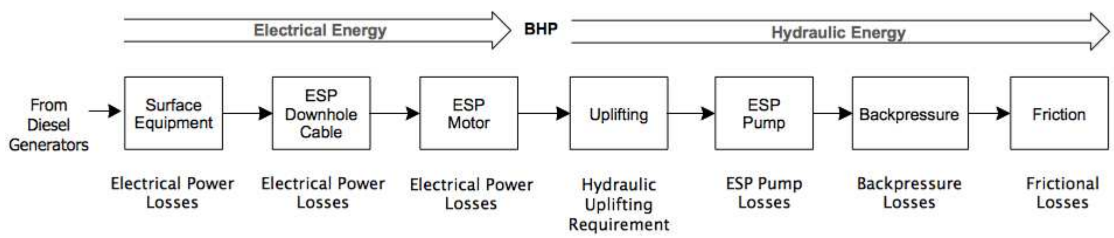



*Figure 3-6 Electrical and Hydraulic Components of an ESP system*

Referring to the left side of Figure 6, the electrical balance is simply the electrical power into the system minus the energy losses in the surface equipment, the cable and the motor. Therefore, the electrical efficiency is the ratio of brake power provided by the ESP motor divided by the electrical energy into the ESP surface equipment.

A hydraulic balance can be conducted by evaluating the elements on the right side of Figure 6. The hydraulic power balance is simply the brake power less the hydraulic power required to raise/uplift the fluids from the subsurface reservoir to the surface, the hydraulic losses in the pumps, the hydraulic power required to overcome backpressure at the surface and the hydraulic power required to overcome friction in the discharge piping. Therefore, the hydraulic efficiency is the hydraulic head provided by the pump (for uplifting, backpressure, and friction) divided by the break horsepower provided by the motor.

### 3.2 Results and Discussion

The total power consumed by the platform is 1,536 kW. The largest consumers of power are the ESPs which consume 1,034 kW, followed by the water injection pumps which consume 451 kW, with miscellaneous utilities consuming the remaining 51 kW. Surface mounted injection pumps inject water into designated low-pressure reservoirs and the performance of the surface pumps is impacted by the injection pressure and the flowrate, which are relatively stable. The ESP conditions vary significantly from well to well and depend on a wide number of parameters such as the inflow conditions, the True Vertical Depth (TVD), the Measure Depth (MD), the liquid, oil, water and gas rates, the differential pressure across the pumps, the number of stages installed, and the design of the stages. Furthermore, ESPs systems are dynamic with inlet conditions continuously changing due to complex transient reservoir behavior.

As such, of the 18 wells examined, it's safe to assume that no two wells experience the exact same operating conditions. This assumption is validated on inspection of the EROI and energy intensities of each of the 18 ESP systems, as indicted in Figure 3.7. As expected the $EROI_{Lifting}$ and energy intensity are inversely related. The $EROI_{Lifting}$ values range from 93 to 565, and the wide range is explained by the highly variable conditions the ESPs are exposed to. The lowest $EROI_{Lifting}$ of 93 indicates that even the worst performing ESP system provides an energy return which is nearly two orders of magnitude above the energy expended. Oil field analyst are more familiar with using energy intensity as a benchmarked parameter, and the lifting energy intensity ranges from 3.0 to 18.3 kWh per barrel of crude produced depending on the ESP. The overall energy intensity on the platform is 10.6 kWh per barrel of crude and the overall $EROI_{Lifting}$ on the platform is 160.

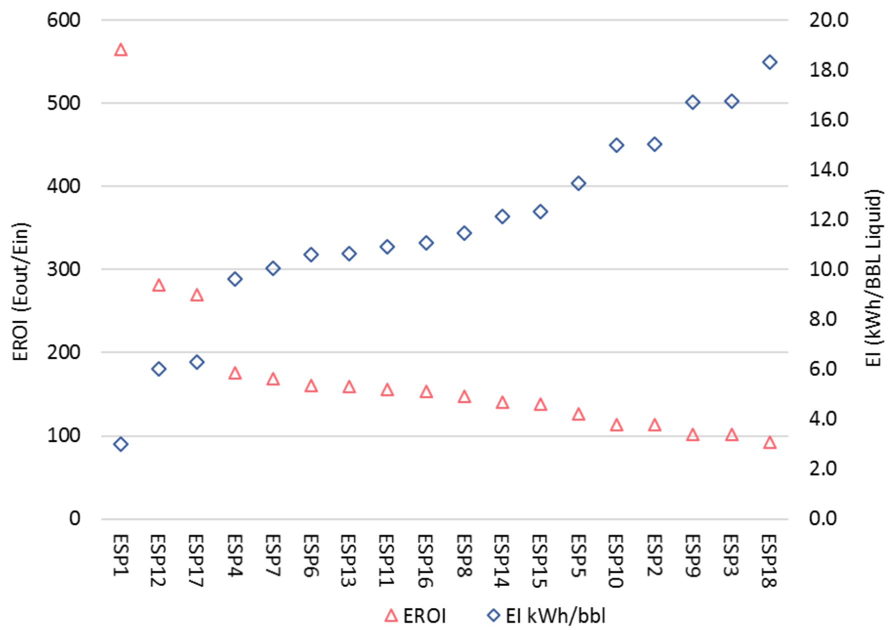



*Figure 3-7 EROI-Lifting and energy intensity for 18 ESP systems*

In order to better understand the variability observed in the calculated EROIs and energy intensities, a detailed energy accounting was conducted for each of the 18 ESP systems. The energy balance for ESP-06 is shown in Figure 3.8 as an example. In this example, the power provided to the ESP system is 72.0 kW, which is equivalent to 96.6 HP. The brakehorse power provided by the motor is 76.8 HP, therefore the electrical efficiency is equivalent to 0.80. The hydraulic head required is 29.0 HP and the hydraulic efficiency is equal to the hydraulic head divided by the brake horsepower provided to the pump, which yields an hydraulic efficiency of 0.38. The overall efficiency for this ESP is 0.30. The efficiencies for all 18 ESP systems are shown in Figure 3.9. Electrical efficiencies ranged from 0.60 to 0.80, while hydraulic efficiencies ranged from 0.12 to 0.56. This results in a range of overall efficiencies from 0.09 to 0.39. Clearly, hydraulic efficiencies are disproportionally contributing to the overall efficiency. The electrical efficiencies are mainly influenced by the ESP motor losses, which are relatively consistent among the 18 ESPs, as indicated by the narrow range exhibited in the box plot shown in Figure 3.10. As can be seen in Figure 3.10, significant hydraulic energy losses occur within the pump itself.

Overall, Figure 3.10 describes a highly variable hydraulic system and a relatively low variability electrical system.

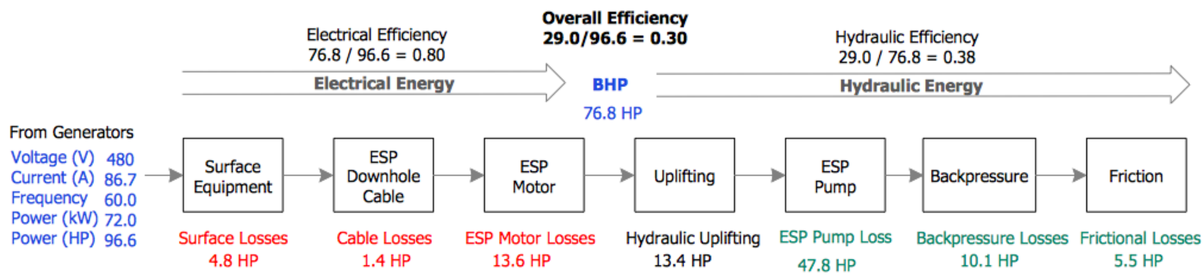



*Figure 3-8 Energy Balance for ESP-06.*

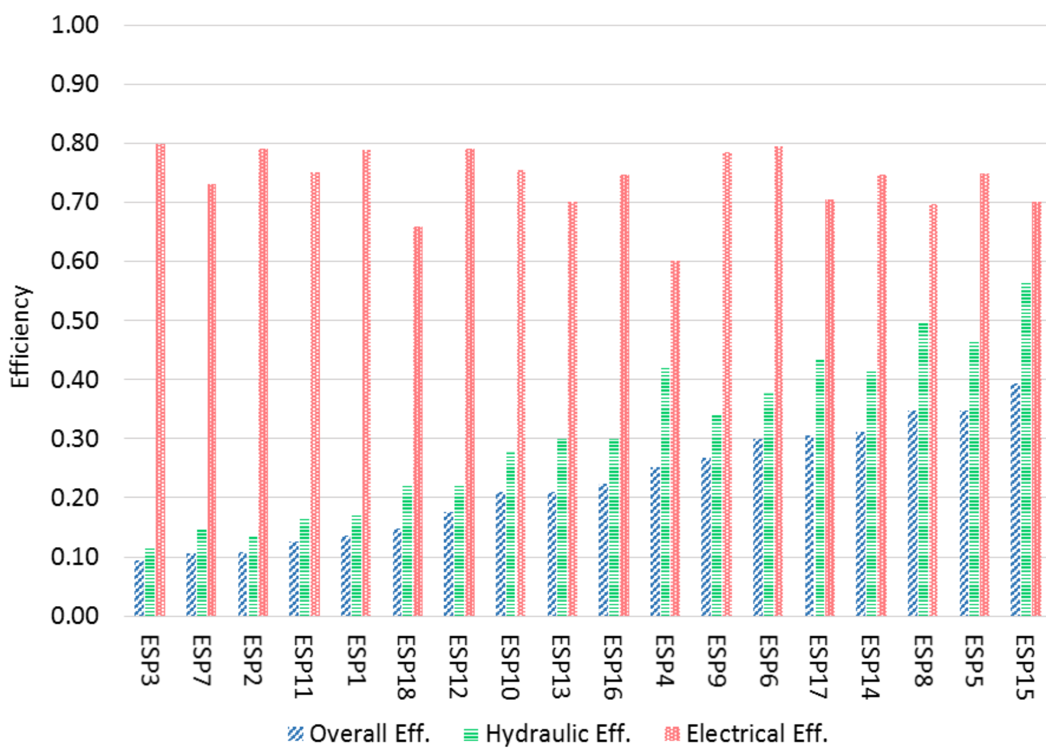



*Figure 3-9 ESP Hydraulic, Electrical and Overall Efficiencies*

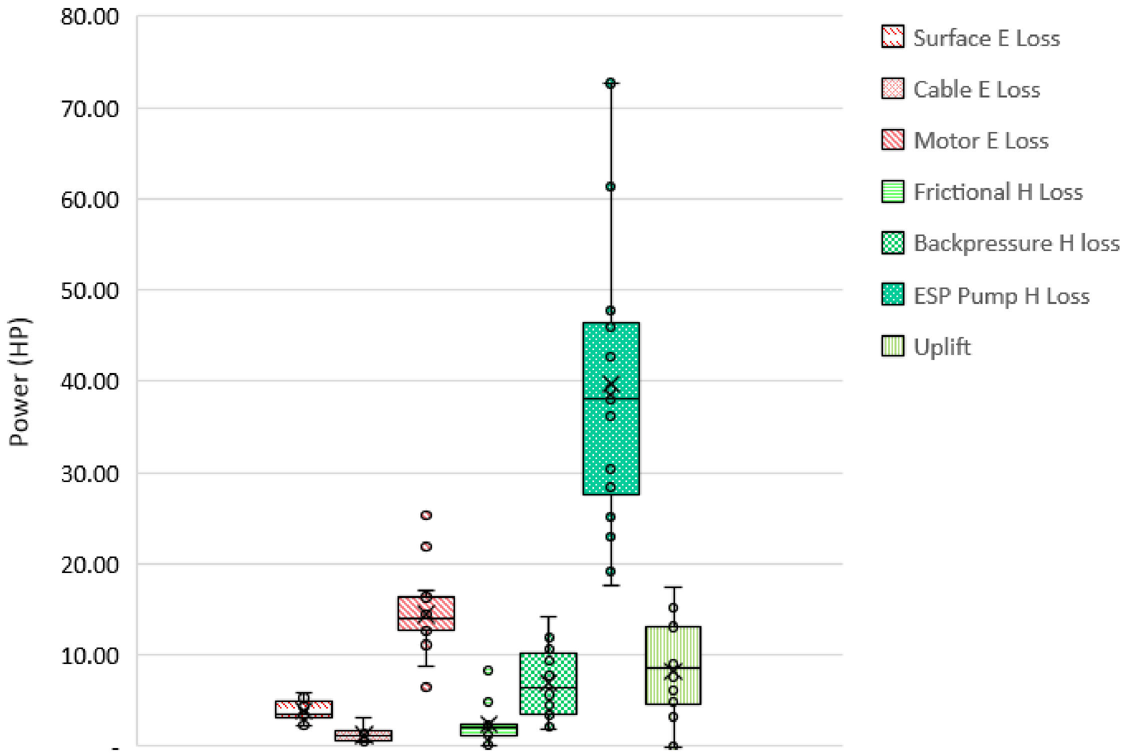



*Figure 3-10 ESP Hydraulic, Electrical and Overall Losses*

A Pearson correlation matrix was developed in order to better understand the factors that affect the EROI, energy intensity and fuel costs. This matrix is described by Figure 3.11. Diesel generators provide the power to the platform exclusively, since there is insufficient quantity of natural gas, therefore imported diesel is the only driver of costs for energy and the energy intensity and fuel costs are directly proportional. Most of the relationships with correlations above 0.7 or below -0.7 are expected, such as the correlation between the water flow rate and the injection energy, or between the produced liquid flow rate and the uplifting energy. An interesting correlation, while, not entirely unexpected, was between the water cut and energy intensity, as well as between water cut and $EROI_{Lifting}$. Water cut is simply an oilfield term used to describe the fraction of water within the total liquids produced. The water cut exhibited a 0.79 correlation factor with energy intensity and fuel cost, and a 0.90 correlation factor with EROI. While most of the correlations can be explained by obvious causal associations, the relationship between water cut and energy intensity, fuel cost and EROI is less obvious, and warrants a closer inspection. In Figure 3.12, the water cut is plotted against the fuel costs. Clearly, the fuel costs increase as the water cut rises. Linear and exponential regression analysis was preformed to better understand this relationship. Exponential regression resulted in a higher R squared value of 0.78. The benefit of mathematically modeling this relationship is that operators can potentially use water cut as a means of estimating the fuel costs per barrel of crude. This has significant ramifications to the modeling of future operating expenses. The difficulty lies with comparing wells with water cuts above 0.90, where the accuracy of water cuts measurements tends to be lower due to limitations of equipment and techniques. It is therefore suggested that if the water cut measurements can be improved, this method can be used to quickly the estimate the fuel costs for each well, and as a means to rank the wells in terms of costs and efficiency.

For instance, as displayed in Figure 3.13, if we are to believe that ESP-06 and ESP-08 have an equivalent water cut of 0.92, with both wells producing the same amount of oil, we might conclude that ESP-06 is superior to ESP-08 due to its lower energy intensity of 10.6 kWh per barrel of crude compared to 11.5 kWh per barrel of crude for ESP-08. Similarly, we might conclude that ESP-02 is superior to ESP-9, due to its lower energy intensity and higher crude production rate.

| | Oil (BPD) | Water (BPD) | Liquids (BPD) | Water Cut | Lifting (KWH) | Injection (KWH) | EI KWh/bbl | Fuel (USD/bbl) | Ein (kWh) | Eout (kWh) | EROI | DP (PSI) | Depth (ft) | ESP System EFF |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil (BPD) | 1.00 | | | | | | | | | | | | | |
| Water (BPD) | -0.10 | 1.00 | | | | | | | | | | | | |
| Liquids (BPD) | -0.01 | 1.00 | 1.00 | | | | | | | | | | | |
| Water Cut | -0.65 | 0.78 | 0.72 | 1.00 | | | | | | | | | | |
| Lifting (KWH) | 0.04 | 0.51 | 0.51 | 0.37 | 1.00 | | | | | | | | | |
| Injection (KWH) | -0.10 | 1.00 | 1.00 | 0.78 | 0.51 | 1.00 | | | | | | | | |
| EI KWh/bbl | -0.79 | 0.45 | 0.38 | 0.79 | 0.43 | 0.45 | 1.00 | | | | | | | |
| Fuel (USD/bbl) | -0.79 | 0.45 | 0.38 | 0.79 | 0.43 | 0.45 | 1.00 | 1.00 | | | | | | |
| Ein (kWh) | -0.01 | 0.77 | 0.78 | 0.59 | 0.94 | 0.77 | 0.50 | 0.50 | 1.00 | | | | | |
| Eout (kWh) | 1.00 | -0.10 | -0.01 | -0.65 | 0.04 | -0.10 | -0.79 | -0.79 | -0.01 | 1.00 | | | | |
| EROI | 0.80 | -0.57 | -0.50 | -0.90 | -0.45 | -0.57 | -0.85 | -0.85 | -0.56 | 0.80 | 1.00 | | | |
| DP (PSI) | -0.12 | 0.22 | 0.20 | 0.25 | 0.24 | 0.22 | 0.25 | 0.25 | 0.26 | -0.12 | -0.23 | 1.00 | | |
| Depth (ft) | -0.16 | -0.34 | -0.36 | -0.15 | -0.03 | -0.34 | 0.04 | 0.04 | -0.16 | -0.16 | 0.05 | 0.44 | 1.00 | |
| ESP System EFF | -0.10 | -0.02 | -0.02 | 0.23 | 0.03 | -0.02 | -0.03 | -0.03 | 0.02 | -0.10 | -0.16 | 0.24 | -0.15 | 1.00 |

*Figure 3-11 Correlation Matrix*

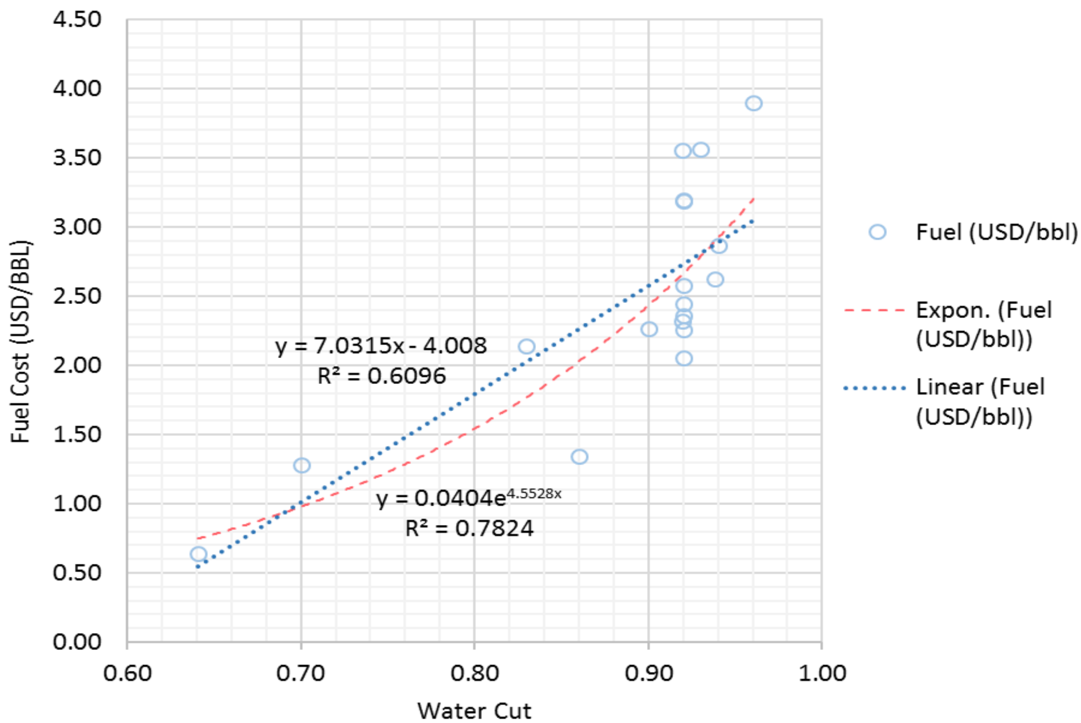



*Figure 3-12 Water cut plotted against fuel costs*

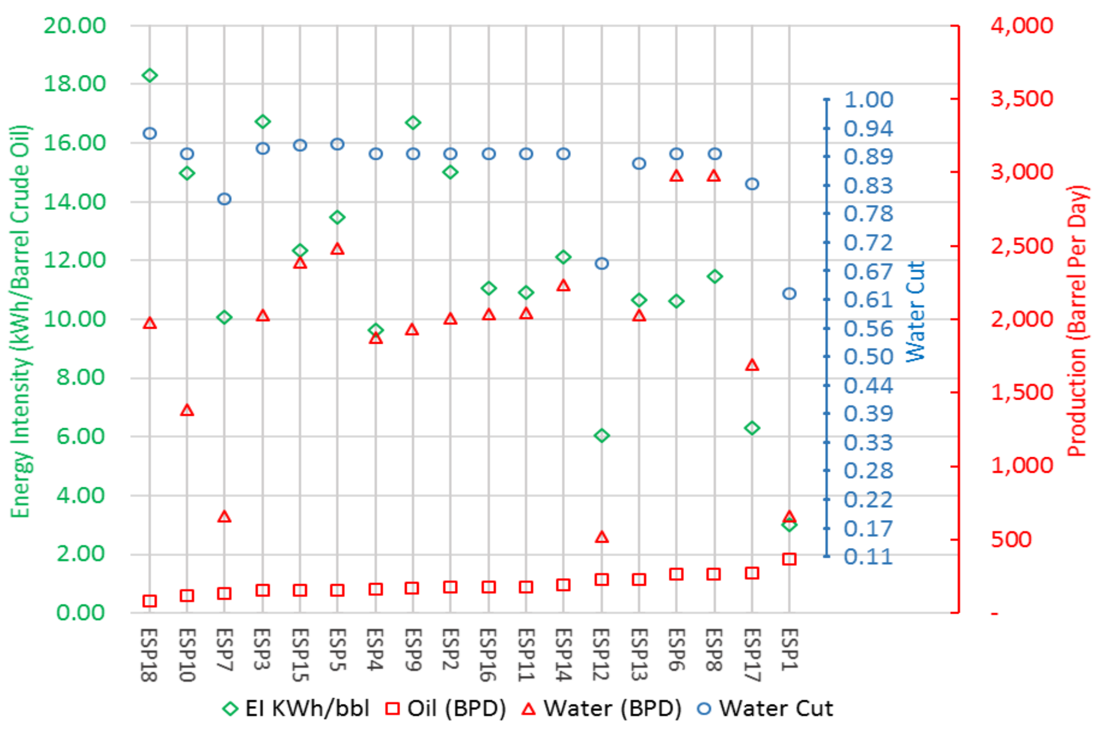



*Figure 3-13 Comparison of ESP systems*

### 3.3 Materials and Methods

The methodology for this research entails the following steps:

- Step 1: Development of $\text{EROI}_{\text{Lifting}}$ and energy intensity
- Step 2: Development of lifting costs
- Step 3: Detailed Accounting of ESP Systems
- Step 4: Analysis

*3.3.1 Step 1: Development of EROI-Lifting and energy intensity*

The equations used to calculate the $\text{EROI}_{\text{Lifting}}$ for each well are indicated in Equations 3.4 through 3.6. Equation 3.4 is the overall energy balance that can be applied to any well. The total lifting energy input for the well is comprised of the energy supplied to the ESP plus the energy supplied to inject any associated water produced from the well into the injection reservoir, plus the marginal energy required for platform processing and utilities.

$$\dot{E}_{lifting}^{in} = \dot{E}_{ESP}^{in} + \dot{E}_{water\ injection}^{in} + \dot{E}_{process\ and\ utilities}^{in} \quad 3.4$$

where:

$\dot{E}_{liting}^{in}$ = overall lifting power in (kW)

$\dot{E}_{ESP}^{in}$ = ESP electrical power (kW)

$\dot{E}_{water\ injection}^{in}$ = water injection electrical power (kW)

$\dot{E}_{process\ and\ utilities}^{in}$ = process and utilities electrical power (kW)

Equation 3.5 is used to calculate the energy output from an ESP equipped well, which is simply the well's volumetric flowrate of crude oil produced multiplied by the chemical energy of the crude product, also known as the heating value. A typical lower heating value of 6.1 GJ per barrel is assumed in all calculations.

$$\dot{E}_{lifting}^{out} = \dot{Q}_{crude}\ \Delta H_{crude}^{chemcal} \quad 3.5$$

where:

$\dot{E}_{lifting}^{out}$ = overall lifting energy out (kW)

$\dot{Q}_{crude}$ = crude oil production rate (barrel/second)

$\Delta H_{crude}^{chemcal}$ = crude oil chemical energy (GJ/barrel)

Therefore, the overall $EROI_{Lifting}$ for each well can be calculated by dividing Equation 3.4 by Equation 3.5, as indicated in Equation 3.6.

$$EROI_{Lifting} = \left(\frac{\dot{E}_{Lifting}^{out}}{\dot{E}_{Lifting}^{in}}\right) \qquad 3.6$$

where:

$EROI_{Lifting} =$ energy return on investment of lifting

$\dot{E}_{Lifting}^{In} =$ lifting energy (kJ/s)

$\dot{E}_{Lifting}^{out} =$ crude chemical energy (kJ/s)

The energy intensity for lifting for each well, as shown in Equation 3.7, can be found by taking the inverse of the $EROI_{Lifting}$ and multiplying it by the chemical energy per barrel of crude.

$$EI_{Lifting} = \frac{1}{EROI_{Lifting}}(E_{barrel}) \qquad 3.7$$

where:

$EI_{Lifting} =$ energy intensity (GJ/BBL)

$EROI_{Lifting} =$ ratio of useful energy output to applied energy input

$E_{barrel}$ = chemical energy per barrel crude (GJ/BBL)

*3.3.2 Step 2: Development of lifting costs*

Lifting costs were developed by converting the daily diesel consumption to a cost based on a diesel cost of 2.7 US dollars per gallon, which was the 2017 average cost of diesel. Therefore, the lifting cost for each well can be derived by multiplying the energy intensity by the energy costs as described in Equation 3.8.

$$LC = EI_{Lifting}\ x\ E_{cost} \qquad 3.8$$

where:

$LC =$ lifting cost (USD/BBL)

$EI_{Lifting} =$ energy intensity (GJ/BBL)or (kWh/BBL)

$E_{cost} =$ energy cost (USD/GJ)or (USD/kWh)

$BBL =$ barrel crude

*3.3.3 Step 3: Detailed Accounting of ESP Systems*

This research involved an analysis of a set of ESPs from an actual offshore platform in order to gain a better understanding of the energetic behavior of ESP systems in an actual operating environment. A typical day was selected and data was retrieved from site via the distributed control system, the variable speed drives and the transformer tapping arraignments. The provided data and calculated parameters are shown in Table 3.1.

*Table 3-1 Provided and derived ESP data*

| **Provided Data** | **Calculated Data** |
|---|---|
| Amps out of Variable Speed Drive (Amps)<br>Data derived from motor efficiency curve<br>ESP Model Number<br>Frequency out of Variable Speed Drive (Hz)<br>True Vertical Depth (meters)<br>Measured Depth (meters)<br>Volts out of Variable Speed Drive (Volts)<br>Volts out of step-up Transformer (Volts)<br>Liquids Flowrate (BPD)<br>Oil Flowrate (BPD)<br>Water Flowrate (BPD) | Amps out of Step-up Transformer (Amps)<br>Brake power supplied to the ESP pump<br>Electrical Power Losses – Surface Equipment<br>Electrical Power Losses – Downhole Cable<br>Electrical Power Losses – ESP Motor<br>Electrical Efficiency - Pump Motor<br>Electrical Efficiency<br>Hydraulic Lifting Energy<br>Hydraulic Power Losses – Backpressure (HP)<br>Hydraulic Power Losses – Frictional (HP)<br>Hydraulic Efficiency<br>Power out of VSD (kW)<br>Power out of Step-up Transformer (kW)<br>Power supplied to the ESP motor |

A number of equations are employed to calculate an energy balance for each of the 18 ESP systems. Input to the calculations are indicated on the left side of Table 3.1, are retrieved from the platform control systems. The parameters on the right side of Table 3.1 are either calculated or obtained from the manufacture's specification.

The overall electrical balance for each well is described by Equation 3.9.

$$\dot{E}_e^{in} - \dot{E}_e^{surface\ loss} - \dot{E}_e^{cable\ loss} - \dot{E}_e^{esp\ motor\ loss} = BHP\ (0.746) \qquad 3.9$$

where:

$\dot{E}_e^{in} =$ electrical power input (kW)

$\dot{E}_e^{surface\ loss} =$ electrical power loss in surface equipment (kW)

$\dot{E}_e^{cable\ loss} =$ electrical power loss in cables (kW)

$\dot{E}_e^{esp\ motor\ loss} =$ electrical loss by ESP motor (kW)

$BHP =$ shaft power provided by motor (HP)

$0.746 =$ conversion factor HP to kW

Surface Power Losses are calculated by taking into account the power factor of the surface equipment as indicated in Equation 3.10.

$$\dot{E}_e^{surface} = \dot{E}_e^{in}\left(1 - \eta^{surface}\right) \qquad 3.10$$

where:

$\dot{E}_e^{surface}$ = electrical power losses in surface equipment (kW)

$\dot{E}_e^{in} =$ electrical power input (kW)

$\eta^{surface} =$ surface equipment power factor (assumed to be 0.95)

Downhole cable losses are a function of the cable resistance, and the current as shown in Equation 3.11.

$$\dot{E}_e^{cables} = \frac{3I^2 R_T}{1{,}000} \qquad 3.11$$

where:

$\dot{E}_e^{cables} =$ electrical power loss in cables (kW)

$I =$ required motor current (amps)

$R_T =$ resistance of the power cable at well temperature (ohms)

Motor losses are calculated by multiplying the electrical power into the motor by the ESP motor efficiency factor, which is extracted from the motor efficiency curve, as indicated in Equation 3.12.

$$\dot{E}_e^{esp\ motor\ loss} = \dot{E}_e^{esp\ motor\ in}(1 - \eta^{esp\ motor}) \qquad 3.12$$

where:

$\dot{E}_e^{esp\ motor\ loss} =$ electrical power loss in ESP motor (kW)

$\dot{E}_e^{esp\ motor\ in}$ = electrical power into ESP motor (kW)

$\eta^{esp\ motor} =$ ESP motor efficiency (derived from manufacturers motor efficiency curves)

The overall electrical power efficiency for each well is simply the brake power output of the motor divided by the power into the ESP electrical system as described in Equation 3.13.

$$\eta^{electrical} = \frac{BHP}{\frac{\dot{E}_e^{in}}{0.746}} \qquad 3.13$$

where:

$\eta^{electrical}$ = electrical power efficiency for each well

$BHP$ = shaft power provided by motor (HP)

$\dot{E}_e^{in}$ = power in ESP system (kW)

0.746 = conversion factor HP to kW

The overall hydraulic energy balance for each well is described in Equation 3.14.

$$BHP = (\dot{E}_h^{uplifting} + \dot{E}_h^{bp} + \dot{E}_h^{fr} + \dot{E}_h^{esp\ pump\ loss})/0.746 \qquad 3.14$$

where:

$BHP$ = shaft power provided by motor (HP)

$\dot{E}_h^{uplifting}$ = hydraulic lifting power (kW)

$\dot{E}_h^{bp}$ = hydraulic power lost due to surface backpressure (kW)

$\dot{E}_h^{fr}$ = hydraulic power lost due to friction in well tubing (kW)

$\dot{E}_h^{esp\ pump\ loss}$ = hydraulic power lost in the ESP pump (kW)

0.746 = conversion factor HP to kW

The hydraulic lifting power of the ESP pump is indicated in Equation 3.15.

$$\dot{E}_h^{uplifting} + \dot{E}_h^{bp} = \frac{(Q\rho g h)}{3.6x10^6} 0.746 \qquad 3.15$$

where:

$\dot{E}_h^{uplifting}$ = hydraulic lifting power (kW)

$\dot{E}_h^{bp}$ = hydraulic power lost due to surface backpressure (kW)

$Q$ = flowrate (cubic meters per hour)

$\rho$ = fluid density in (kg/meter^3 )

$g$ = gravitational constant (9.81 m/sec2)

$h$ = total developed head (meters)

0.746 = conversion factor HP to kW

The total head in meters is calculated by taking into account the true vertical depth of the pump, as well as the surface backpressure converted to head as described in Equation 3.16:

$$h = h_{TVD} + h_{bp} = h_{TVD} + \left(\frac{WHP\ x\ 2.31}{\gamma_l}\right) x\ 0.348 \qquad 3.16$$

where:

$h =$ total developed head (meters)

$h_{TVD} =$ true vertical depth (meters)

$h_{bp} =$ head from surface backpressure (meters)

$WHP =$ wellhead pressure (psi)

$\gamma_l =$ specific gravity of produced liquid

Frictional losses are calculated as per equations 3.17 and 3.18.

$$\Delta H_{fr} = 2.083 \left(\frac{100}{C}\right)^{1.85} \left(\frac{q^{1.85}}{ID^{4.86}}\right) \qquad 3.17$$

where:

$\Delta H_{fr}$ = frictional head loss in tubing (ft/100 ft)

$C =$ pipe quality number

$q =$ flowrate (gallon per minute)

$ID =$ pipe diameter (inches)

$$\dot{E}_h^{fr} = \left(7.368x10^{-6} q_L \Delta H_{fr} \gamma_l\right) 0.746 \qquad 3.18$$

where:

$\dot{E}_h^{fr} =$ frictional power loss (kW)

$q_L$ = liquid production rate (barrel per day)

$\Delta H_{fr\ total} =$ total frictional head loss in tubing (feet)

$\gamma_l$ = specific gravity of produced liquid

0.746 = converstion factor HP to kW

The hydraulic efficiency for each well is simply the hydraulic head required to uplift the fluids to the surface plus the energy required to overcome backpressure and friction divided by the brake power provided to the pump as shown in Equation 3.19:

$$Hydraulic\ Efficiency = \eta^{hydraulic} = \frac{\dot{E}_h^{uplifting} + \dot{E}_h^{bp} + \dot{E}_h^{fr}}{BHP(0.746)} \qquad 3.19$$

where:

$\eta^{hydraulic} =$ hydraulic efficiency for each well

$\dot{E}_h^{uplifting} =$ hydraulic lifting power (kW)

$\dot{E}_h^{bp} =$ hydraulic power lost due to surface backpressure (kW)

$\dot{E}_h^{fr} =$ frictional power loss (kW)

$BHP =$ shaft power provided by motor (HP)

0.746 = converstion factor HP to kW

Finally, the overall ESP system efficiency can be calculated by multiplying the hydraulic efficiency by the electrical efficiency as described in Equation 3.20.

$$Overall\ Efficiency = \eta^{overall} = \left(\eta^{electrical}\right)\left(\eta^{hydraulic}\right) \qquad 3.20$$

where:

$\eta^{overall} =$ overall energy efficiency for each well

$\eta^{electrical} =$ electrical power efficiency for each well

$\eta^{hydraulic} =$ hydraulic efficiency for each well

The relationship of flowrate, electrical frequencies and pumping speeds, head and power is described by the pump Affinity Laws. The Affinity Laws state that the flow rate of the pump changes directly proportional to the speed, the head developed by the pump changes proportionally to the square of the speed and the power required to drive the pump changes proportionally to the cube of the speed. The Affinity laws are described by Equations 3.21, 3.22 and 3.23.

$$Q_2 = Q_1\left(\frac{N_2}{N_1}\right) \qquad 3.21$$

$$H_2 = H_1\left(\frac{N_2}{N_1}\right)^2 \qquad 3.22$$

$$Power_2 = Power_1\left(\frac{N_2}{N_1}\right)^3 \qquad 3.33$$

where:

$N_2, N_1 =$ pumping speeds (RPM)

$Q_2, Q_1 =$ pumping rates at $N_2$ and $N_1$ (barrels per day)

$H_2, H_1 =$ developed heads at $N_2$ and $N_1$ (ft)
$Power_2, Power_1 =$ required brake power at $N_2$ and $N_1$ (kW)

Since the power frequency is directly related to the motor speed, the affinity laws can be calculated with either the pump speed or the power frequency as described in Equations 3.24, 3.25 and 3.26.

$$Q_2 = Q_1 \left(\frac{f_2}{f_1}\right) \qquad 3.24$$

$$H_2 = H_1 \left(\frac{f_2}{f_1}\right)^2 \qquad 3.25$$

$$Power_2 = Power_1 \left(\frac{f_2}{f_1}\right)^3 \qquad 3.26$$

where:
$f_2, f_1 =$ AC frequencies, Hz
$Q_2, Q_1 =$ pumping rates at $f_2$ and $f_1$(barrels per day)
$H_2, H_1 =$ developed heads at $f_2$ and $f_1$( (ft)
$Power_2, Power_1 =$ required brake power at $f_2$ and $f_1$ (kW)

It should also be noted that transformers are used to vary the voltage of an AC electrical source and work on the principle of electromagnetic induction. A transformer typically consists of an iron core and two coils of insulated metal wires. The incoming AC power is directed through the primary coils and the circuit to be powered is connected to the secondary coils. Alternative tapping points on the secondary coils can be used to select from a range of output voltages. The relationship between voltage, current and the number of turns in the primary and secondary coils are show in equations 3.27 and 3.28.

$$U_s = U_p \left(\frac{N_s}{N_p}\right) \qquad 3.27$$

where:
$U_P, U_S =$ primary and secondary voltage (volts)
$N_P, N_S =$ number of turns in the primary and secondary coils

The frequencies of the electric currents in both coils are identical, but the currents will be different. The following formula is found for the relationship of current.

$$I_s = I_p\left(\frac{N_p}{N_s}\right) \quad 3.28$$

where:

$I_P, I_S =$ primary and secondary current(amps)

$N_P, N_S =$ number of turns in the primary and secondary coils

Finally, it should be noted that the real electric power, typically designated in kW units is found by considering the real current such that $I_{real} = I_{line} * \cos(\emptyset)$. For a three phase power supply Equations 3.29 and 3.30 can be used to determine the line power and the real power, respectively.

$$KVA = \sqrt{3}\frac{U_{line}I_{line}}{1{,}000} = 1.732\ x\ 10^{-3}U_{line}I_{line} \quad 3.29$$

$$KW = \sqrt{3}\frac{U_{line}I_{line}}{1{,}000}\cos\emptyset = 1.732\ x\ 10^{-3}U_{line}I_{line}\cos\emptyset \quad 3.30$$

where:

$U$ = voltage (volts)

$I$ = current (amps)

$\emptyset$ = phase angle

$\cos\emptyset$ = power factor

These equations can be used to determine the power anywhere within the system if the current, voltage and power factor are known.

### 3.4 Conclusions

- An energy breakdown of a small offshore extraction scheme reveals that artificial lift and water injection are the prevalent consumers of energy. The energy consumed by the platform is distributed to each well based on the well-specific ESP power demand and the proportion of energy used to dispose of its share of produced water.
- The wells exhibit a wide range of performance in terms of EROI, energy intensity and lifting cost. This information can be used to rank wells and support decision making with regards to prioritization of wells.

- The predominant loss of energy in an ESP system is within the pump itself, with hydraulic efficiencies ranging from 0.12 to 0.56. The pump efficiency can be improved by adjusting the speed of the pump, but this may or may not improve the energy intensity, lifting costs and EROI. Careful analysis of changing pump speeds requires a reassessment of the energy in, energy out and associated energy intensity and lifting cost intensity.
- There is little opportunity to improve other factors influencing ESP system efficiencies.
- The water cut, which is the fraction of water in the produced liquids, is highly correlated to energy intensity and lifting costs. It is suggested that water cut measurements may be used to provide a high-level estimate of lifting costs for each well.
- There are several wells which exhibit similar flowrates and water cuts but with differing energy intensities and lifting costs. This information has the potential to facilitate well ranking, prioritization and decision-making, but necessitates a more accurate measurement of water cuts above 0.9.

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# CHAPTER 4 – DEVELOPMENT OF AN ENERGY EFFICIENCY IMPROVEMENT METHODOLOGY FOR UPSTREAM OIL AND GAS[3]

## 4.0 Introduction

The main objective of this study was to develop a simple and effective methodology for capturing, analyzing and improving energy intensive processes in an upstream oil and gas field. The proposed methodology consists of the following steps: identification and decomposition of system boundaries, selection of suitable energy metrics for the facility, collection of operational data, calculation of energy balances and metrics, assessment of performance against design expectations and best practices for systems, subsystems and equipment, and finally the application of a structured approach to identify and screen potential opportunities for improvement. Each step is described in details from an oil and gas perspective.

## 4.1 Background

The energy required for extracting oil and gas continues to rise as the percentage of wells requiring artificial lift increases [1]. At the same time the oil and gas industry is struggling to remain profitable in a low oil price environment. These conditions have forced companies to examine all aspects of their operations in order to identify cost savings opportunities. Energy related costs are known to be a significant component of the overall operating costs of an upstream facility. As such, an effective energy efficiency improvement method designed specifically for upstream oil and gas operators would be a valuable tool.

There is a wide body of research into methodologies for improving energy efficiency in downstream sectors such as the manufacturing and process industries [2-8], but much less work has been undertaken on developing approaches to improve energy efficiency in upstream oil and gas operations.

[3] This chapter was published as a conference paper for the Abu Dhabi International Petroleum Exhibit and Conference (ADIPEC), Nov. 12-17, 2017.

Such operations are unique in a number of ways. Upstream oil and gas processes are inherently non-steady state, primarily because of the dynamic behavior of the hydrocarbon reservoir. Dynamic reservoir phenomena such as hydrocarbon depletion, pressure decline and water intrusion can have significant impacts on the energy efficiency of upstream facilities [9]. Consequently, surface facilities must be designed to handle a large range of conditions, and achieving optimal energy efficiency is not possible across the wide operational range required. Production profiles typically contain a plateau period in which the production of hydrocarbons is relatively stable, but even during the plateau period other aspects of the overall system may be variable, such as reservoir pressure or the rate of production of side products (e.g. Produced Water and Carbon Dioxide). Furthermore, upstream facilities are designed based on a projected production profile and process conditions, and the actual production profile and process conditions realized after startup may be very different than was originally anticipated, often resulting in suboptimal energy performance.

In most upstream oil and gas operations, a portion of the produced gas or crude oil is used to generate power, but this resource should certainly not be considered as "free" energy [10]. Improved efficiency, even while using produced fluids, can lead to lower operational and capital costs. Lower operational costs related to reduced maintenance costs and lower capital costs because of a reduced requirement for power generation and electrical motors. As mentioned above, there is also a sustainability element to the proposed methodology, which rewards reductions in emissions, regardless of whether the energy source is produced or purchased.

It should also be noted that for upstream processes in particular, an improvement in energy efficiency by itself does not necessarily constitute an economic improvement (e.g. if the savings from energy efficiency are offset by a loss of income from lower production rates). Therefore, the proposed method will incorporate a life cycle approach which takes into account the Net Present Value (NPV) for any energy efficiency improvements that require a large capital investment. The proposed methodology also includes an analysis of sustainability related metrics related to emissions reduction. Reduced emissions cannot usually be directly tied to monetary gains, but they are typically aligned with other nonmonetary sustainability related business objectives of oil and gas companies [11].

Despite differences between upstream and downstream processes, there are a number of general downstream energy efficiency techniques which can be applied to upstream facilities, such as the delineation of appropriate boundaries for the system, subsystems and equipment, the calculation of energy related balances at each level, the development of different types of energy related performance indicators, the analysis of performance against design expectations and best practices, the application of a structured decision framework for improving energy efficiency and the overall integration of energy efficiency performance into production management practices.

Therefore, the objective of this paper is to develop a simple but effective energy efficiency improvement methodology that is specifically designed for upstream oil and gas operations. The methodology will be described as a series of steps which can support structured and informed decision making.

## 4.2 Methodology

The approach involved is straightforward and consists of the following steps:

1. Set appropriate boundaries
2. Develop energy balances and indicators at the system level
3. Develop energy balances and indicators at the subsystem and equipment levels
4. Analyze performance
5. Identify and Screen Opportunities
6. Monitor performance

The overall methodology is an adaptation of conventional energy efficiency practices customized to account for the specific conditions of upstream oil and gas operations. The unique attributes will be described in each step of the methodology.

*Step 1: Set appropriate boundaries*

The oil and gas industry can be loosely defined as a collection of activities related to the extraction, treatment, transportation and transformation of hydrocarbons. An informal delineation classifies these activities into upstream, midstream and downstream categories. While the boundaries are not formally defined, conventionally upstream activities include drilling, extraction, initial surface processing and treatment to meet sales and transportation specifications. Midstream has recently taken on increasing significance particularly with respect to unconventional developments due to the typically large geographical spread of the operation which encompasses gathering systems, pipelines, pumping and compressor stations as well as storage and treatment facilities. Downstream normally refers to treatment, separation and transformation of hydrocarbons within the petrochemical sector. The actual boundaries for systems used in energy efficiency studies must be logically defined on a case by case basis.

There is a body work which describes a boundary setting logic for upstream oil and gas systems [12-14]. The framework is described in Figure 1. In this work, the purpose of setting boundaries is to develop energy indicators such as Energy Return on Investment (EROI), which will be discussed in more detail in Step 2 of this methodology. The boundaries presented in this framework can be aggregated or divided as necessary. The overall flow from left to right in this model is aligned with the flow of produced fluids and energy can be supplied externally, such as from an external fuel source or from a municipal electrical supply, or internally by fuels derived from production fluids.

The overall boundary of inclusion for the system under investigation should coincide with the activities which can be influenced. A typical offshore platform is designed to extract and process hydrocarbons; therefore, the boundaries may include Production and Extraction as well as Surface Processing Upstream, which is enclosed by the dashed line in Figure 4.1.

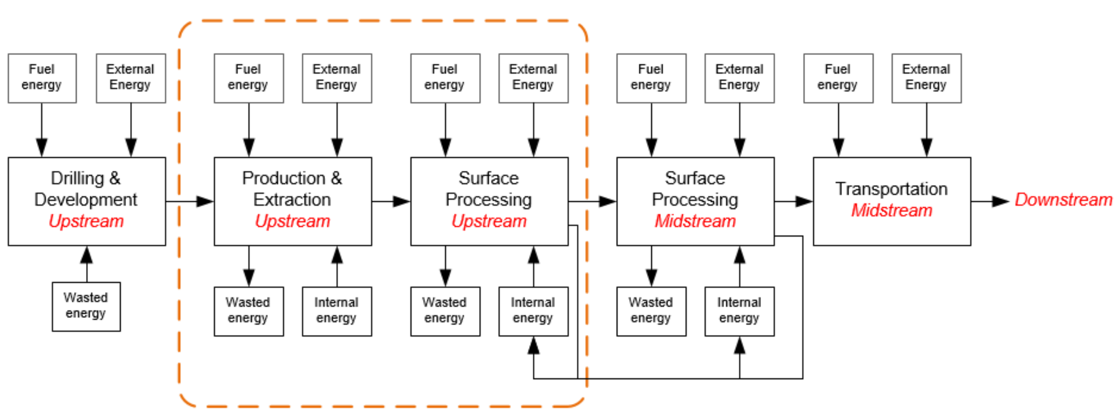

*Figure 4-1 Setting System Boundaries*

Extending the offshore platform example, possible flows of energy are described in Figure 4.2 [9]. Inflows to the facility will be reservoir fluids and energy sources. Outflows are hydrocarbon exports, injection fluids, flares, vents, exhaust and heat. The assumptions for this example are that energy sources are from external sources and that injection fluids are derived from reservoir fluids. Within the boundary, there are subsystems and equipment items.

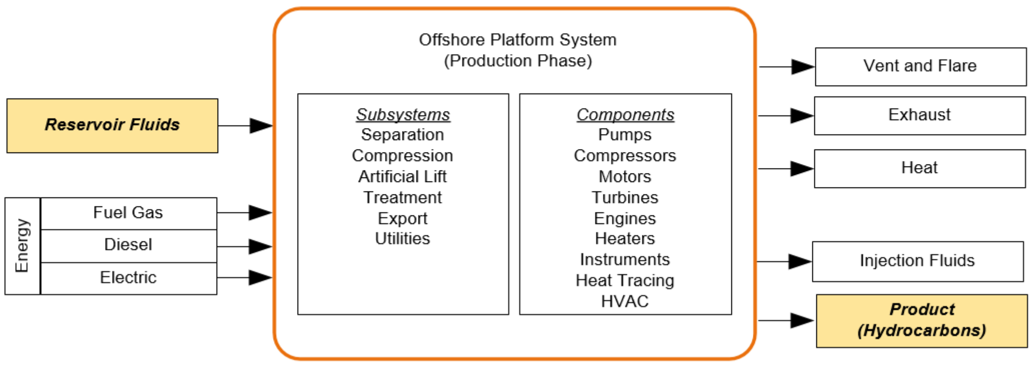


*Figure 4-2 Offshore Platform System Flows*

*Step 2: Develop Energy Balances and Indicators at the System Level*

Energy balances on a system level can be developed once the boundaries have been identified, such as for an offshore platform as described in Figure 4.2. The general energy balance for a control volume is shown in Equation 4.1 [15]:

$$\frac{dE_{cv}}{dt} = \sum_i \dot{Q}_i + \sum_i \dot{W}_i + \sum_i \dot{m}_{in}\left(h_{in} + \frac{V_{in}^2}{2} + gz_{in}\right) - \sum_i \dot{m}_{out}\left(h_{out} + \frac{V_{out}^2}{2} + gz_{out}\right) \qquad 4.1$$

For a steady state process, the accumulation term is equal to zero as indicted in Equation 4.2, where Q is the heat flow into and out of the system and W is the work produced by, or on, the system. The convention used in this analysis is that heat out and work in are positive. The remaining flow terms represent the inflows and outflows of materials which contain internal energy as well as macroscopic kinetic and potential energy.

$$0 = \sum_i \dot{Q}_i + \sum_i \dot{W}_i + \sum_i \dot{m}_{in}\left(h_{in} + \frac{V_{in}^2}{2} + gz_{in}\right) - \sum_i \dot{m}_{out}\left(h_{out} + \frac{V_{out}^2}{2} + gz_{out}\right) \qquad 4.2$$

We can also develop a specific energy balance for the offshore platform flows indicated in Figure 4.2.

$$\sum_i \dot{E}_{res.\ fluids} + \sum_i \dot{E}_{fuel} + \sum_i \dot{E}_{elec.} =$$
$$\sum_i \dot{E}_{product} + \sum_i \dot{E}_{vent\ and\ Flare} + \sum_i \dot{E}_{exhaust} + \sum_i \dot{E}_{inj.\ fluids} + \sum_i \dot{E}_{heat\ out} \qquad 4.3$$

A simplifying assumption is that there is only one flow for each type of stream as indicated in Equation 4.4.

$$\dot{E}_{res.\ fluids} + \dot{E}_{fuel} + \dot{E}_{elec.} =$$
$$\dot{E}_{product} + \dot{E}_{vent\ and\ flare} + \dot{E}_{exhaust} + \dot{E}_{inj.\ fluids} + \dot{E}_{heat\ out} \qquad 4.4$$

The terms in the general energy balance described in Equation 4.2 can be mapped to the terms in the upstream oil and gas energy balance shown in Equation 4.4. These terms are described in Equations 4.5 through 4.11.

$$\dot{E}_{res.\ fluid} = \dot{m}_{res.\ fluids}\left(h_{res.\ fluids} + gz_{res.\ fluids}\right) \qquad 4.5$$

$$\dot{E}_{fuel} = \dot{m}_{fuel}(LHV_{fuel}) \qquad 4.6$$

$$\dot{E}_{product} = \dot{m}_{product}\left(h_{product}\right) \qquad 4.7$$

$$\dot{E}_{vent\ and\ flare} = \dot{m}_{vent\ and\ flare}\left(h_{vent\ and\ flare}\right) \qquad 4.8$$

$$\dot{E}_{exhaust} = \dot{m}_{exhaust}\ (h_{exhaust}) \qquad 4.9$$

$$\dot{E}_{inj.\ fluids} = \dot{m}_{inj.\ fluids}\left(h_{inj.\ fluids} + gz_{inj.\ fluids}\right) \qquad 4.10$$

$$\dot{E}_{heat\ out} = \dot{Q}_{out} \qquad 4.11$$

The Produced fluids enter the facility through the wells at varying depths below the surface. Therefore, if we consider the wells to be within the overall system boundary the inflow of energy associated with produced fluids is shown in Equation 4.5, which takes into account the enthalpic content of the stream as well as the potential energy at the elevation of the entry into the platform system, which is the datum elevation. This also applies to the inflow and outflow of injection fluids as shown in Equation 4.10. The energy flow associated with imported fuels is directly related to the heating value as described in Equation 4.6. The enthalpic energy flow of outflows such as hydrocarbon product, exhaust gas and vent/flare gas are described in Equations 4.6 through 4.9, and finally the heat evolved from the platform process is described in Equation 4.11. In contrast to downhole flows which are thousands of feet below the platform, the potential energy associated with surface flows are assumed to be zero since this they are assumed to be at the same elevation as the datum. Another simplifying assumption is that kinetic flows are negligible for all streams. Therefore, combining terms results in the overall upstream platform energy balance as shown in Equation 4.12. This equation will be the basis for the calculation of energy related indicators at the system level.

$$\dot{m}_{res.\ fluids}\left(h_{res.fluids} + gz_{res.\ Fluids}\right) + \dot{m}_{fuel}LHV + \dot{E}_{elec.} = \dot{m}_{inj.\ fluids}\left(h_{inj.\ fluids} + gz_{inj.\ fluids}\right)$$

$$\dot{m}_{vent\ and\ flare}\left(h_{vent\ and\ flare}\right) + \dot{m}_{exhaust}h_{exhaust} + \dot{m}_{product}\left(h_{product}\right) + \dot{Q}_{out} \qquad 4.12$$

There are a number of different types of energy efficiency indicators available for analysis. Early work on energy efficiency identified four general categories for indicators, which consisted of thermodynamic, physical/thermodynamic, economic/thermodynamic and economic [16]. Thermodynamic indicators are focused on 1st law efficiency (energy) and in some advanced cases can be based on 2nd law analysis (exergy). The thermodynamic indicators are dimensionless since they are a ratio of either the inlet and outlet energy flows, or exergy flows.

Expanding on the overall energy balance, a purely thermodynamic energy efficiency for the platform system can be calculated by dividing the useful energy outputs by the energy inputs as shown in Equation 4.13.

$$\eta_{plant} = \frac{\dot{m}_{product}\left(h_{product}\right)}{\dot{m}_{res.\ fluids}\left(h_{res.\ fluids} + gz_{res.\ fluids}\right) + \dot{m}_{fuel}\left(LHV_{fuel}\right) + \dot{E}_{elec.}} \qquad 4.13$$

The difficulty with using the overall plant efficiency is that the internal chemical energy of the hydrocarbon in both the numerator and the denominator dominates the equation and results in an indicator that is always close to one. A more revealing dimensionless indicator is the Thermodnamic Energy Intensity which is the ratio of the energy consumed (Input) to the energy exported (Output) as described by Equation 4.14 [17].

$$EI_{thermodynamic} = \frac{Energy\ Invested\ (Input)}{Energy\ Return\ (Output)} = \frac{\dot{m}_{fuel}\left(LHV_{fuel}\right) + \dot{E}_{elec.}}{\dot{m}_{product}\left(h_{Product}\right)} \qquad 4.14$$

Finally, the inverse of Equation 4.14 is another indicator known as the Energy Return on Investment (EROI) as shown in Equation 4.15

$$EROI = \frac{Energy\ Invested\ (Input)}{Energy\ Return\ (Output)} = \frac{\dot{m}_{[roduct}\left(h_{Product}\right)}{\dot{m}_{fuel}LHV_{fuel} + \dot{E}_{elec.}} \qquad 4.15$$

The EROI is a parameter that has been used to compare different types of oil and gas operations, such as oil sands and other unconventional technologies to more conventional oil and gas operations [12]. It can also be used to compare oil and gas operations to alternative energy systems, to compare different types of alternative energy systems, as well as to investigate differences in energy efficiency on a regional level [13]. As such, EROI is of primary use to policy makers. Oil and gas development managers are naturally more interested in the relationships between energy use and production. One can derive a practical economic indicator from the Energy Intensity by calculating the cost of energy consumed, i.e. fuel to produce a given product, such as a barrel of oil. The cost based Energy Intensity, as shown in Equation 4.16, is an indicator that directly relates to the operating expenses (OPEX) of an upstream operation.

$$EI_{Cost} = \frac{Cost\ of\ energy\ consumed}{Barrel\ of\ oil\ produced} \qquad 4.16$$

As noted earlier, in an upstream environment achieving increased energy efficiency may or may not improve the economics, but it will definitely reduce emissions. Direct emissions of greenhouse gases (GHGs) from oil and gas activities vary considerably depending on a number of factors, particularly the energy efficiency of the operation. GHG emissions include combustion emissions, flaring and venting of produced gas, fugitive emissions and non-routine releases, including maintenance operations [18]. In this methodology the incremental reduction of GHGs from the implementation of energy efficiency initiatives is due to a reduced requirement for fuel. Focusing on combustion emissions, a calculation on GHG reduction should be included in the analysis, i.e. quantified as reduction in metric tons of CO2 equivalent released to the atmosphere.

*Step 3: Develop Energy Balances and Indicators at the Subsystem and Equipment Levels*

While the overall energy balance equation and derived energy efficiency indicators on a plant basis are useful in terms of benchmarking and performance monitoring of the plant, a more tangible benefit can be realized by conducting energy balances on individual subsystems and equipment items. Prominent examples are with regards to pumping systems, compression systems, heat exchangers networks and power generation utilities.

Pumping and Compression systems include the rotating equipment as well as piping both upstream and downstream of the pumps or compressors. The balance should take into account the performance of the rotating equipment as well as energy losses due to other components such as piping, control valves and recycle loops. Energy metrics for pumping and compression systems used by some operators are as follows [19]:

- Gas compression: kW/MMSCFD/compression ratio
- Oil pumping: kW/BBL/bar
- Water injection: kW/BBL/bar

While a full energy balance around pumping and compressing systems is beyond the scope of this paper, developing energy balances around pumps and turbines is rather straight forward. The work delivered to a pump or a compressor is used to increase the internal energy of the working fluid. As such, the energy balance for a pump or a compressor is indicated in Equation 4.17.

$$\dot{W}_{in} = \dot{m}(h_2 - h_1) + \dot{Q}_{out} \qquad 4.17$$

The thermodynamic efficiency of a pump or a compressor can be calculated by conducting a simple energy balance, but it can only be truly understood by examining the pump or compressor performance characteristics which are typically provided in graphical or tabular format [20,21]. For example, the efficiency of a centrifugal pump depends on the operating point with respect to flowrate and head. The pump motor also exhibits a range of efficiencies that depends on the electrical horse power provided to the motor, or more specifically the percentage of the nameplate power rating of the motor.

The efficiency of a pump is related to the power provided to the pump system and the hydraulic power developed by the pump, shown in Equation 18. There may be small losses in the cables and junction boxes, but usually the power provided to the pump system is very close to the power that actually reaches the motor. Therefore, the pump efficiency can be shown is shown in Equations 4.18.

$$\eta_{pump\ system} = \frac{\dot{E}_{hydraulic\ head}}{\dot{E}_{electrical\ input}} \tag{4.18}$$

The relative isolation of upstream facilities means that it is quite common for power generation to be provided on site. A diesel or gas generator balance can be conducted by examining the fuel energy supplied to the generator, the energy outflows due the cooling system, exhaust and heat loss, and the amount of electrical power generated as described by Equations 4.19-4.22 [22-24] .

$$\dot{m}_{fuel}\left(LHV_{fuel}\right) = \dot{Q}_{cooling\ water} + \dot{Q}_{exhaust} + kW_{system\ output} + \dot{Q}_{oss} \tag{4.19}$$

$$\dot{m}_{fuel}\left(LHV_{fuel}\right) = (SFC)(kW)(LHV) \tag{4.20}$$

$$\dot{Q}_{cooling\ water} = \dot{m}_{cooling\ water} C_{water}\left(T_{cooling\ water\ out} - T_{cooling\ water\ in}\right) \tag{4.21}$$

$$\dot{Q}_{exhaust} = \dot{m}_{exhaust}\left(1 + AF\right)Cg_{exhaut\ gas}\left(T_{exhaust\ gas} - T_{ambient}\right) \tag{4.22}$$

$$\eta_{power\ generation} = \frac{kW_{system\ output}}{\dot{m}_{fuel}\left(LHV_{fuel}\right)} \tag{4.23}$$

The power generation efficiency as calculated in Equation 4.23 is impacted by a number of factors:

- Fuel combustion efficiency, which is dependent on several factors such as air-fuel ratio, combustion chamber temperature, compression ratio and turbocharger design.
- Thermodynamic cycle efficiency which is bounded by the Carnot cycle efficiency.
- Mechanical efficiency, primarily related to frictional losses.
- Alternator efficiency, which is related to electrical phenomena such as power loss through the windings due to heating and magnetic circuit losses.

The operator should also compare actual fuel consumption for a given output to the predicted fuel consumption as indicated in the generator manual. A more detailed analysis of power generation efficiencies is beyond the scope of this paper.

*Step 4: Analyze Performance and Identify Potential Opportunities*

The energy balances are helpful in developing an understanding of the flows of energy around and within a system. An informative visual aid for energy flows is the Grasmann diagram (Figure 4.3). The example shown is of a hypothetical upstream operation equipped with Electrical Submersible Pumps (ESPs) and Produced Water Injection Pumps (PWIPs). This diagram reveals that the best opportunity for improving energy efficiency is by improving the efficiencies of the generators and pumps. The opportunity to improve energy efficiency by studying the "other" consumers appears to be quite limited; nonetheless, they should not be discounted completely.

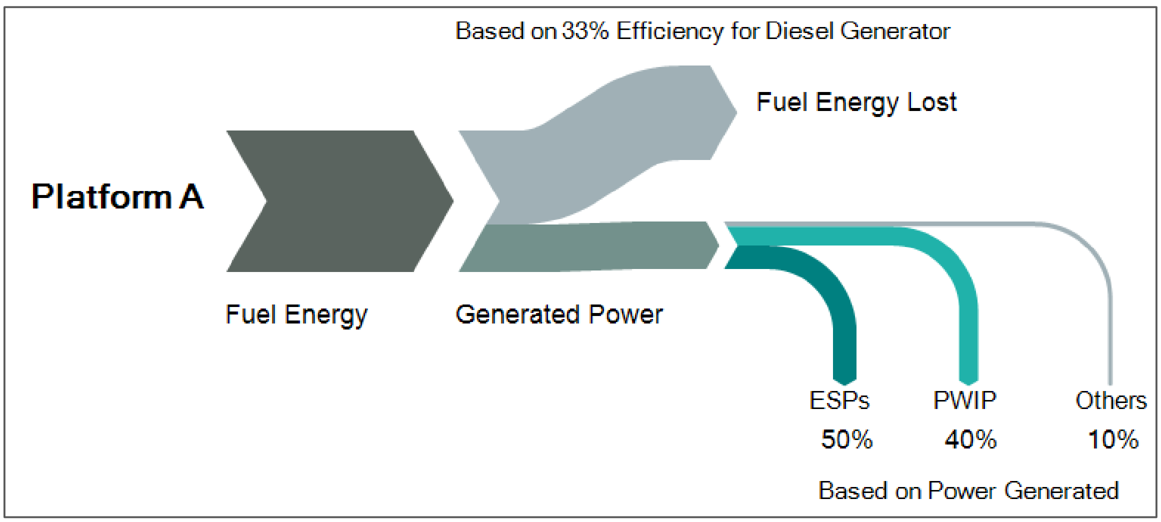


*Figure 4-3 Energy Diagram for an offshore platform*

It is also helpful to understand the energy use patterns. An upstream facility may experience seasonal use variations or changes in use over the full lifecycle. Daily or weekly patterns, while useful for downstream and manufacturing processes, are not that revealing for upstream operations, since production profiles tend to be independent of these constraints. On the other hand upstream lifecycle events, such as those listed below, could have a significant impact energy performance [9].

- Reduced Reservoir Pressure
- Introduction of Artificial Lift
- Introduction of Booster Compressors
- Increasing Water Cut
- High Pressure Water Injection

- Sub-optimal throughput
- Increased Downtime
- Compressor Recycling
- Fuel Gas Deficient
- GOR Changes

During the planning stage of the development a prudent operator should anticipate the dynamic nature of the operation in order to understand the impacts on energy use, efficiency and costs. For unanticipated changes, development managers need to adjust their assumptions, and possibly modify the facilities. One can envision a study of the trade-offs around high pressure water injection vs. low pressure water disposal, making ESP frequency adjustments to increase pump and motor performance or to maximize production. In conclusion, anticipating and managing these types of lifecycle events is at the heart of accurate forecasts, an optimized design and operational decision making.

Energy Efficiency Indicators at the plant level, system and equipment level can also be used for benchmarking internally or externally [10]. The internal benchmarking approach is currently being applied by several of the major operators. For smaller oil and gas companies, external benchmarks would be more appropriate, but unfortunately there do not appear to be any joint industry projects addressing energy efficiency in upstream operations. There are a few publications which do contain relevant benchmarks at the plant level and subsystem level [10,17,19], but unfortunately benchmarking of energy use in upstream oil and gas processes is not well established.

While system and equipment level external benchmarks may not be available, the original equipment manufacturer performance specifications are usually readily available to operators. A good practice is to compare current performance to the design expectations and factory acceptance performance tests. This is one of the best reference points by which to judge the performance of equipment.

*Step 5: Identify and Screen Opportunities*

There are a number of general guidelines available for energy optimization in the process industry. Some generic recommendations are shown in Table 4.1 [3]. Initiatives which require minor adjustments to operating practices, or small modifications without having a significant impact on production are actionable by the operations manager without much deliberation.

Modifications which involve significant capital costs must be evaluated in a structured manner to ascertain the impact of the project on the overall economics of the development, taking into account operational savings, capital investments and alterations to production rates. Analysis of incremental Net Present Value (NPV) is a suitable method to determine the impact of modification projects on the overall economics. The incremental NPV will compare the NPV of the existing operation to that of the proposed operation, where NPV is defined in Equation 4.24.

$$NPV = P + \sum_{t=0}^{n} F_t (1+i)^{-t} \qquad 4.24$$

*Table 4-1 Energy Efficiency Practices [3]*

| | |
|---|---|
| **Heating, Cooling and Process Integration** | **Process Heaters** |
| Reduce fouling in heat transfer equipment | Control air to fuel ratio |
| Heat recovery | Improve heat transfer |
| Process Integration | Improve control |
| Pinch Analysis | Maintenance |
| **Pumps** | **Compressor air systems** |
| Pump system maintenance | System maintenance |
| Pump demand reduction | Monitoring/Lead reduction |
| High efficiency pumps | Reducing the inlet air temperature |
| Properly sized pumps | Maximize allowable pressure dew point |
| Impeller trimming | Improve load management |
| Avoiding throttling valves | Properly sized regulators |
| Proper pipe sizing | Heat recovery |
| Adjustable-speed drives | Adjustable-speed drives/High efficiency motors |
| **Motor Systems** | **HVAC Systems** |
| Properly sized motors | Energy efficiency system design |
| High efficiency motors | Duct leakage repair |
| Improve power factor | Variable-air–volume systems |
| Reduce voltage imbalance | Adjustable-speed drives |
| Adjustable speed drives | Heat recovery systems |
| Variable voltage controls | Fan modification/Efficiency exhaust fans |
| **Lighting** | Use of ventilation fans |
| Lighting controls | Cooling water recovery |
| High-intensity discharge voltage reduction | Solar air heating |
| High-intensity fluorescent lights | Low emittance windows |

A more measured way of eliciting energy efficiency improvement ideas is through a Process Flow Diagram (PFD) review [25]. A PFD review typically involves Plant Operations, Maintenance personnel and Facilities Engineers. This type of workshop is conducted away from site, preferably in a location free of distractions of the day to day operational activities. The purpose is to review and identify inefficiencies in the main streams, equipment items, and systems. Suggestions may be related to control set-points, piping configurations, equipment modifications or possibly new or novel processes and technologies [25]. The cross-function team may also meet onsite for a few days to inspect facilities and interact with the operators. The review may include a condition survey.

*Step 6: Monitor Performance*

Measurement and analysis are the precursors to effective monitoring and enhanced communications. There are various means to monitor and communicate energy related information such as structured workshops and company dashboards, which include energy related Key Performance Indicators (KPIs). Suggested information to be conveyed in an energy dashboard for an upstream offshore platform in the form of four levels is:

- Level 1
    - Energy use of system (Total energy consumed)
    - Energy Intensity (Energy consumed/Oil and gas export energy)
    - Energy Cost Intensity (Cost of Energy consumed/BBL
    - Exhaust/Vent/Flare Emissions (GHG Tons/BBL
- Level 2
    - The total energy attributed to the main areas of consumption such as:
    - Oil Pumping: kW/BBL/bar
    - Water Injection: kW/BBL/bar
    - Gas Compression: kW/MMSCFD/bar
- Level 3
    - Cascade down from Level 2 to individual trains
- Level 4
    - Cascade down from Level 3 to individual equipment items

KPIs should be developed based on a case by case basis, after taking into account the nature of the facility and performance expectations. The purpose of the dashboard and other communications measures is to emphasize the importance of energy management in upstream processes to all levels of the organization. Communications can nurture an environment of proactivity rather than of complacency. Energy efficiency suggestions should be encouraged through appropriate communications channels.

### 4.3 Conclusions

While methodologies for energy management have been developed by a number of major operators, the details of their implementation are not well documented. The novel information obtained from this study is related to the development of an energy efficiency improvement methodology specifically designed for upstream oil and gas operators. The methodology borrows heavily from downstream methodologies but provides guidance on how to develop upstream oil and gas specific boundaries and how to calculate energy balances and indicators for upstream processes. The proposed methodology also provides useful information on how to identify and analyze potential opportunities which can be derived from routine observations or from a structured approach using a diverse collection of specialists that are brought together into energy management teams.

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# CHAPTER 5 – APPLICATION OF FUZZY EXPERT SYSTEMS TO ANALYZE AND ANTICIPATE ESP FAILURE MODES[4]

## 5.0 Introduction

An ESP Fuzzy Expert system is developed to analyze ESP operational data. The analysis is conducted to determine whether the system can predict developing failure modes or to retroactively determine the causes of a prior failures. The ESP fuzzy expert system is developed by employing the following steps: identify input variables, develop membership functions, develop rule sets and develop output functions. Input variables representing slopes were mapped to membership functions denoted by linguistic terms such as "increasing", "constant", and "decreasing". The input variables are also assigned a member value to indicate the Degree of Fulfilment (DOF) of the individual premise. The Degrees of Fulfilment (DOF) of all the premises are then combined to determine the overall DOF of the rules, with each rule representing a distinct failure mode. To test the system, an operational dataset consisting of nine ESP systems are selected from a pool of more than 100 ESPs installed in the field. The nine ESP systems were composed of four ESP pumps which were running smoothly and five ESP systems that eventually failed. For the failed ESPs the operational data leading up to the failure is analyzed. Trends are analyzed for periods of 7 days, 30 days and 60 days for each ESP system. The developed system is not able to identify the root cause failure of the ESP systems which experienced a failure, but can anticipate approaching failures. For the failed ESPs, the overall Degrees of Fulfilment (DOF) for the seven day trends was consistently higher than for DOF of the running pumps. Therefore, the method can provide an indication that the ESP is experiencing difficulty, and alert the operators to troubleshoot and potentially prevent the failure from occurring.

[4] This chapter was published as a conference paper for the Abu Dhabi International Petroleum Exhibit and Conference (ADIPEC), Nov. 12-17, 2017.

### 5.1 Background

It is estimated that twenty five percent of oil and gas wells have ESPs installed [1]. The ESP equipment is subject to extreme environmental conditions and are physically inaccessible to the operations and maintenance teams. Downtime of the ESPs for any reason results in lost production and lost revenues [2].

ESP systems include a number of interacting elements and are inherently complex. The behavior of ESP systems varies significantly due to differing fluid properties, reservoir conditions, well completion methods and the different types of equipment installed. There is also a large amount of operational data collected by the ESP control and monitoring system. The analysis of this data can be time-consuming for the surveillance team [3], who may have varying degrees of experience. Consequently, the overall approach to ESP monitoring can be inconsistent. For this reason it is common for ESP owners to rely on outsourced experts to analyze the data and make appropriate recommendations, but ESP experts are expensive and their knowledge is often not disseminated to less experienced engineers in the organization.

In recent years there has been progress in the development of ESP Decision Support Systems (DSS) [1,3-5]. An ESP DSS can be designed to provide analytics such as:

- Exception Alarm Reports
- Predictive Analytics for Early Detection of Trends that could lead to failures. (Advanced)
- Recommendations for interventions to prevent full failure of the ESP system. (Advanced)

An ESP DSS may be offered by equipment vendors as a complementary service. The more advanced DSS systems utilize fuzzy inference models, but the detailed inner working of these models are not revealed since they are considered proprietary. It should be noted that fuzzy inference models employ fuzzy set theory which is an approach based on developing membership functions for linguistic qualifiers such as “increasing” or “decreasing” and determining the “degrees of truth” for numerical values. Nonetheless, based on discussions with experts, ESP DSS systems with predictive analytics are not known to be entirely effective. Therefore, this research involved the development and application of a simple spreadsheet based ESP Fuzzy Expert System which can be used to analyze ESP operational data.

### 5.2 Objectives

The main objectives of this research was to:

- Develop a rudimentary ESP Fuzzy Expert System from first principles based on the elicitation of attitudes from a group of ESP experts and on methods established in literature.
- Develop an ESP Fuzzy Expert system which can anticipate failure mechanisms as they develop so that timely and appropriate intervention measures can be made to prevent a total system failure.
- In situations where the ESP system experiences a critical failure, the objective is to demonstrate that a Fuzzy Expert System can be used to gain a better understanding of the actual root cause of the failure, which would serve as a lessons learned for the application of improvements.

### 5.3 Method an Procedures

The methodology was to develop a spreadsheet based Fuzzy Expert System and apply it to a number of case studies consisting of actual ESP operations. The high level framework for development of the Fuzzy Expert System involved three main components; Fuzzification, Rule Evaluation and Defuzzification (Figure 5.1).

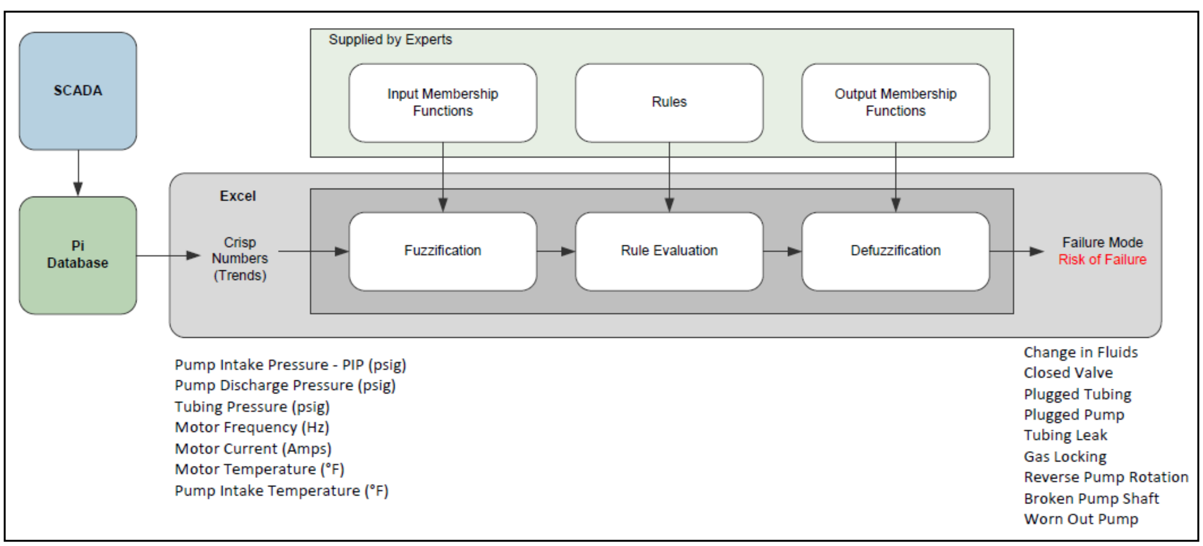


*Figure 5-1 Fuzzy Inference Model*

The more detailed method used in this study involved the following ten steps:

1. Determination of input variables
2. Data retrieval from operational database
3. Determination of slopes
4. Normalization of slopes
5. Development of fuzzy membership functions
6. Determination of fuzzy rules
7. Derivation of degrees of fulfillment of rule premises
8. Application of combination methods to determine degrees of fulfilment of rules
9. Defuzzification to determine failures modes
10. Analysis of results

*Step 1: Determination of input variables*

Downhole sensors are used to measure a number of ESP parameters. Surface equipment can also be used to measure volumetric rates, fluid properties, gas to oil ratio and water cut. A literature review was conducted and it was determined that the main variables used in proprietary ESP Fuzzy Expert Systems are the following [1,5]:

- Pump Intake Pressure - PIP (psig)
- Pump Discharge Pressure - PDP (psig)
- Tubing Pressure (psig)
- Motor Frequency (Hz)
- Motor Current (Amps)
- Motor Temperature (°C)
- Pump Intake Temperature (°C)
- Total Fluids (barrels per day)

*Step 2: Data Retrieval*

Data from the Distributed Control System (DCS) and from the individual Variable Speed Drive (VSD) Controllers is transferred to an Historian Database every 5 seconds. The VSD receives data from the downhole sensor and the ESP itself via the power supply cable. The parameters listed in Step 2 were therefore downloaded from the Historian Database for nine pre-selected wells. For failed ESPs 60 days of data were downloaded just prior to the failure event. For running ESPs 60 days of data were downloaded just prior to the time of this study. The data was collected in Excel spreadsheets for further analysis.

*Step 3: Determination of Slopes*

The slopes of the individual ESP parameters was calculated by using Equation 5.1 [5]:

$$slope = \frac{\sum(x - \bar{x})((y - \bar{y})}{\sum(x - \bar{x})^2} \qquad 5.1$$

where:

$\bar{x} = \frac{\sum x_i}{n}$ $\quad \bar{y} = \frac{\sum y_i}{n}$

$x$ = measure daily value

$y$ = days

The value of $x$ is the median daily value of the variable collected for days 1 to n. The value of $y$ is simply the day associated with the $x$ variable, and $n$ is the number of days in the period.

*Step 4: Normalization of slopes*

ESPs are installed at varying depths, have different capacities, different number of stages and different motor sizes. In a field with more than one hundred ESPs it would be challenging to develop a unique membership function for each well configuration and for each variable. Therefore, for the sake of expediency a normalization method was employed. This also allowed variables with different units of measure to use the same set of input membership functions. This method has been applied in a proprietary ESP Fuzzy Expert System [5].

Therefore, the input slope values for all variables were normalized by using the arc tan function.

$$Unit\ scale = \frac{2\ x\ \tan^{-1}(slope)}{\pi} \qquad 5.2$$

*Step 5: Development of fuzzy membership functions*

A set of input membership functions were developed to allow normalized operational trend data to be assigned to linguistic variables such as “increasing”, “constant”, and “decreasing” as shown in Figure 5.2. The values selected for triangular functions are indicated in Figure 5.3.

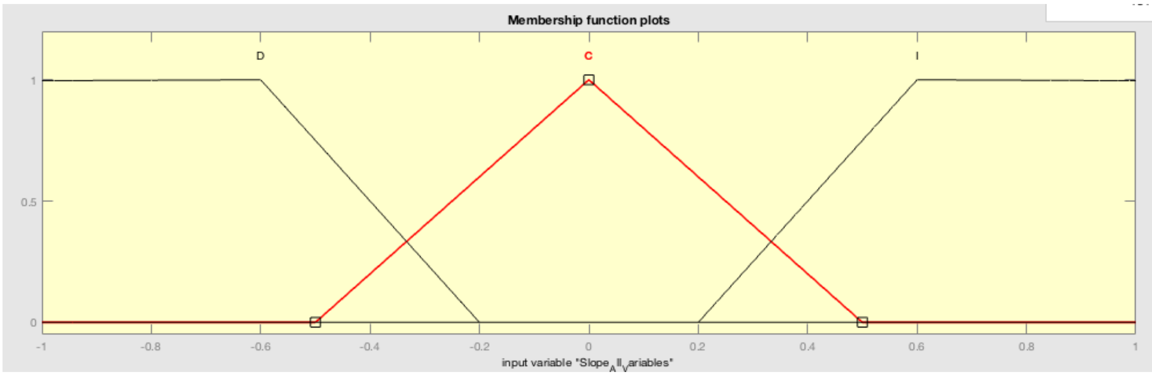


*Figure 5-2 Input Membership Function*

| | | |
|---|---|---|
| D (a1) | D (a2) | D (a3) |
| -100 | -0.6 | -0.2 |
| C(a1) | C(a2) | C(a3) |
| -0.5 | 0 | 0.5 |
| I(a1) | I(a2) | I(a3) |
| 0.2 | 0.6 | 100 |

| Key | |
|---|---|
| D: | Decreasing Slope |
| C: | Constant Slope |
| I: | Increasing Slope |

*Figure 5-3 Input Membership Function Values*

*Step 6: Determination of fuzzy rules*

A literature review was also conducted to determine the “if then” rules for the ESP systems. There were several references which described rule sets for ESP systems [1,5]. The rule sets were compared and in general there was agreement between the rule sets. The most comprehensive rule set was selected [5], as shown in Figure 4. These rules were used to determine the failure mode.

| | RULES | Frequency | Motor Amps | PIP | Motor Temp | Flowrate | Tubing Pressure | PDP | Intake Temp |
|---|---|---|---|---|---|---|---|---|---|
| R1 | Change in Fluids | C | C | I | C or D | I | C or I | C or I | C or D |
| R2 | Closed Valve | C | D | I | I | D | I | I | I |
| R3 | Plugged Tubing | C | D | I | I | D | D | I | I |
| R4 | Plugged Pump | C | D | I | I | D | D | D | I |
| R5 | Tubing Leak | C | C or D | I | I | D | D | C | I |
| R6 | Gas Locking | C | D | C or I | I | D | D | D | I |
| R7 | Reverse Pump Rotati | C or D | D | I | C or I | D | D | C or D | C or I |
| R8 | Broken Pump Shaft | C | D | I | I | D | D | D | I |
| R9 | Worn Out Pump | C | D | I | I | D | D | D | I |

**C: Constant Slope, D: Decreasing Slope, I: Increasing Slope**

*Figure 5-4 Rule Sets*

*Step 7: Derivation of degrees of fulfilment of rule premises*

This step involves converting normalized slopes into linguistic variables along with an associated membership value. The equations used to convert normalized slopes to fuzzy numbers are shown in Equation 3 [6]. This yields the DOF of the individual premises, where x is the normalized slope, $a_1$ and $a_2$ represents the triangular bases and $a_3$ represents the triangular peak:

$$(a_1, a_2, a_3)_T$$

$$\mu_A(x) = \begin{cases} 0 & for\ x \le a_1 \\ \dfrac{x - a_1}{a_2 - a_1} & for\ a_1 < x \le a_2 \\ \dfrac{a_3 - x}{a_3 - a_2} & for\ a_2 < x \le a_3 \\ 0 & for\ a_3 < x \end{cases} \qquad 5.2$$

*Step 8: Application of combination methods to determine degrees of fulfilment of rules*

The DOF of the individual premises are then combined to determine the overall DOF of each of the Rules. Three combination methods were employed as indicated in equations 4 through 6 [6].

Degree of fulfilment for “And” coupling (product inference):

$$D_i = \prod_{k=1}^{K} \mu_{A_{i,k}}(a_k) \tag{5.4}$$

Degree of fulfilment for “Or” coupling, i.e. 2 clauses (product inference):

$$D_{\boldsymbol{i}} = \mu_{A_{i,1}}(a_1) + \mu_{A_{i,2}}(a_2) - \mu_{A_{i,1}}(a_1) * \mu_{A_{i,2}}(a_2) \tag{5.5}$$

Degree of fulfilment for “Most Of” coupling:

$$D_i = 1 - \left( \sum_{k=1}^{K} \frac{1}{K} \left(1 - \mu_{A_{i,k}}(a_k)\right)^p \right)^{1/p} \tag{5.5}$$

where:

$D_i$ = Degree of fulfillment

$A_{i,k}$ = Premise $k$ of rule $i$

$a_k$= Input variable $k$

$\mu_{A_{i,k}}(a_k)$ = Membership Function of $A_{i,k}$

$p$ = p-norm value

*Step 9: Defuzzification to determine failures modes*

Each of the nine rules applied in this study results in a unique output which is the predicted failure mode of the ESP system. Therefore, a defuzification method is not required, and the results of the combination method for each rule can be used to rank the overall DOFs for each rule. A representative diagram describing the “Most of” combination method is shown in Figure 5.5. This diagram was developed using actual data (ESP#9 – 7 Day Trend).

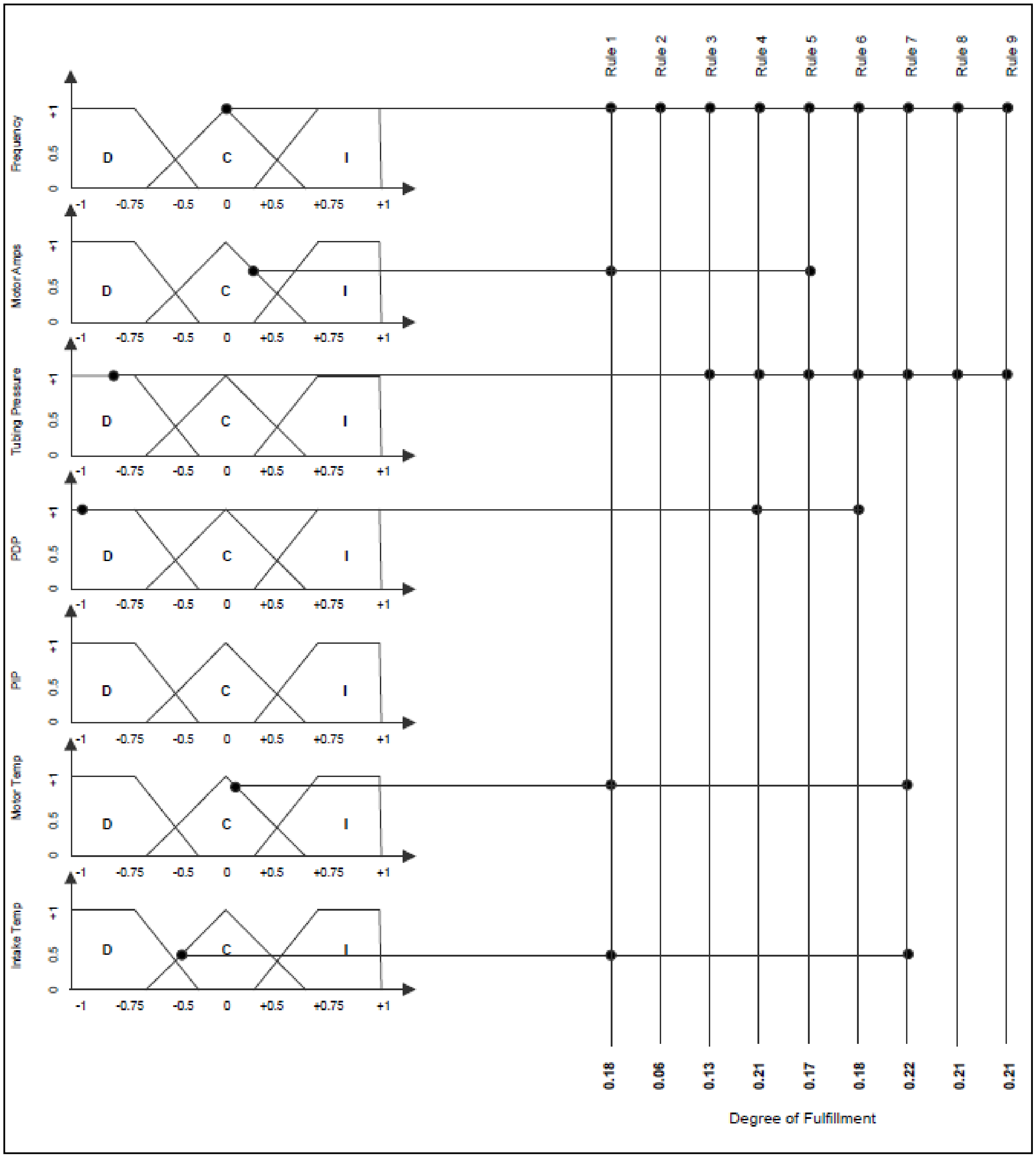


*Figure 5-5 Example of Results from "Most of" Coupling Method (Based on ESP# 9 - 7 Day Trends)*

**Step 10: Analysis of Results**

Nine ESP driven wells were analysis using the developed ESP Fuzzy Logic Expert System. The wells were selected with a wide range of operating conditions. Of the nine wells selected, four ESPs were running smoothly, while five were ESPs that experienced a total failure. For the failed ESPs data analyzed were from 7, 30 and 60 days prior to the full failure. For running ESPs data was collected from 7, 30 and

60 days from the time of the research. Figure 5.6 describes the 9 wells selected for the case study. The DOF of Rules for all Wells in the Case Study for 7, 30 and 60 day trends are indicated in Figure 5.7.

| Type | Possible Cause | From | To | Period (days) | Well | Oil (bpd) | Water (bpd) | Gas (mmscfd) | BS&W |
|---|---|---|---|---|---|---|---|---|---|
| Running | NA | 2/17/2017 | 4/18/2017 | 60 | ESP 1 | 324 | 1,294 | 0.07 | 80 |
| Running | NA | 2/18/2017 | 4/19/2017 | 60 | ESP 2 | 121 | 1,386 | 0.00 | 92 |
| Running | NA | 2/18/2017 | 4/19/2017 | 60 | ESP 3 | 218 | 2,502 | 0.03 | 92 |
| Running | NA | 2/24/2017 | 4/25/2017 | 60 | ESP 4 | 212 | 2,444 | 0.01 | 92 |
| | | | | | | | | | |
| Failed | Pump Stuck (sand) | 3/12/2014 | 5/11/2014 | 60 | ESP 5 | 271 | 1,233 | 0.38 | 82 |
| Failed | Pump Stuck (gas) | 3/2/2015 | 5/1/2015 | 60 | ESP 6 | 594 | 643 | 0.44 | 52 |
| Failed | Pump Stuck (gas) | 5/7/2013 | 7/6/2013 | 60 | ESP 7 | 728 | 109 | 3.91 | 13 |
| Failed | Pump Stuck (gas) | 11/17/2013 | 1/16/2014 | 60 | ESP 8 | 369 | 92 | 0.35 | 20 |
| Failed | Pump Stuck (gas/scale) | 3/4/2015 | 5/3/2015 | 60 | ESP 9 | 210 | 314 | 0.04 | 60 |

*Figure 5-6 Case Study Wells*

| | | | | | | Change in Fluids | Closed Valve | Plugged Tubing | Plugged Pump | Tubing Leak | Gas Locking | Reverse Pump Rotation | Broken Pump Shaft | Worn Out Pump |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 Day Trends | ailure Mode | Coupling | From | To | Well | R1 | R2 | R3 | R4 | R5 | R6 | R7 | R8 | R9 |
| Running | NA | Most of | 4/12/2017 | 4/18/2017 | ESP 1 | 0.28 | 0.06 | 0.06 | 0.06 | 0.18 | 0.07 | 0.18 | 0.06 | 0.06 |
| Running | NA | | 4/13/2017 | 4/19/2017 | ESP 2 | 0.28 | 0.06 | 0.06 | 0.06 | 0.17 | 0.11 | 0.18 | 0.06 | 0.06 |
| Running | NA | | 4/13/2017 | 4/19/2017 | ESP 3 | 0.29 | 0.06 | 0.06 | 0.06 | 0.18 | 0.12 | 0.18 | 0.06 | 0.06 |
| Running | NA | | 4/19/2017 | 4/25/2017 | ESP 4 | 0.29 | 0.06 | 0.06 | 0.06 | 0.18 | 0.11 | 0.18 | 0.06 | 0.06 |
| | | | | | | | | | | | | | | |
| Failed | Pump Stuck (sand) | | 5/5/2014 | 5/11/2014 | ESP 5 | 0.29 | 0.28 | 0.20 | 0.13 | 0.13 | 0.12 | 0.19 | 0.13 | 0.13 |
| Failed | Pump Stuck (gas) | | 4/25/2015 | 5/1/2015 | ESP 6 | 0.18 | 0.06 | 0.13 | 0.21 | 0.17 | 0.18 | 0.22 | 0.21 | 0.21 |
| Failed | Pump Stuck (gas) | | 6/30/2013 | 7/6/2013 | ESP 7 | 0.29 | 0.21 | 0.13 | 0.06 | 0.12 | 0.06 | 0.10 | 0.06 | 0.06 |
| Failed | Pump Stuck (gas) | | 1/10/2014 | 1/16/2014 | ESP 8 | 0.11 | 0.11 | 0.19 | 0.27 | 0.16 | 0.23 | 0.24 | 0.27 | 0.27 |
| Failed | Pump Stuck (gas/scale) | | 4/27/2015 | 5/3/2015 | ESP 9 | 0.19 | 0.21 | 0.29 | 0.38 | 0.25 | 0.33 | 0.31 | 0.38 | 0.38 |

| 60 Day Trends | ailure Mode | Coupling | From | To | Well | R1 | R2 | R3 | R4 | R5 | R6 | R7 | R8 | R9 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Running | NA | Most of | 2/17/2017 | 4/18/2017 | ESP 1 | 0.23 | 0.06 | 0.12 | 0.15 | 0.21 | 0.20 | 0.23 | 0.15 | 0.15 |
| Running | NA | | 2/18/2017 | 4/19/2017 | ESP 2 | 0.29 | 0.13 | 0.13 | 0.13 | 0.25 | 0.18 | 0.23 | 0.13 | 0.13 |
| Running | NA | | 2/18/2017 | 4/19/2017 | ESP 3 | 0.28 | 0.06 | 0.06 | 0.06 | 0.17 | 0.12 | 0.18 | 0.06 | 0.06 |
| Running | NA | | 2/24/2017 | 4/25/2017 | ESP 4 | 0.18 | 0.06 | 0.13 | 0.21 | 0.18 | 0.25 | 0.24 | 0.21 | 0.21 |
| | | | | | | | | | | | | | | |
| Failed | Pump Stuck | | 3/12/2014 | 5/11/2014 | ESP 5 | 0.28 | 0.13 | 0.13 | 0.06 | 0.10 | 0.09 | 0.13 | 0.06 | 0.06 |
| Failed | Pump Stuck | | 3/2/2015 | 5/1/2015 | ESP 6 | 0.35 | 0.13 | 0.13 | 0.13 | 0.25 | 0.12 | 0.23 | 0.13 | 0.13 |
| Failed | Pump Stuck | | 5/7/2013 | 7/6/2013 | ESP 7 | 0.18 | 0.39 | 0.50 | 0.39 | 0.42 | 0.33 | 0.24 | 0.39 | 0.39 |
| Failed | Pump Stuck | | 11/17/2013 | 1/16/2014 | ESP 8 | 0.19 | 0.50 | 0.39 | 0.29 | 0.26 | 0.25 | 0.18 | 0.29 | 0.29 |
| Failed | Pump Stuck | | 3/4/2015 | 5/3/2015 | ESP 9 | 0.23 | 0.20 | 0.13 | 0.06 | 0.06 | 0.06 | 0.13 | 0.06 | 0.06 |

*Figure 5-7 DOF of Rules for all Wells in Case Study for 7 and 60 day trends*

## 5.4 Discussion of Results

A Fuzzy Expert System was developed based on methods published in literature. An attempt was made to validate the system by analyzing actual ESP data from an offshore operation. The following is a discussion of the results:

*5.4.1 Combining Methods:*

Since many of the premises yielded zero fuzzy numbers, the product inference combing rule could not be used. Therefore the “Most of” method were employed.

*5.4.2 Trend Data:*

Automatic analysis of 30 and 60 day trends was problematic due to numerous interruptions in the data sets. Interruptions can be due to ESP system trips, platform trips and planned shutdowns. Furthermore, some pumps were started and failed within 60 days, therefore in some cases, 30 and 60 day trends could not be developed.

*5.4.3 Degrees of Fulfilment of Rules:*

For the running ESP systems, most of the premises did not fire, and as such the rules did not fire. This was expected. For Failed ESP systems there were no cases where the degrees of the fulfilment of any of the overall rules was high. There are several possible reasons for this:

- Different Failure Modes:

  It is possible that the root cause of failure for the failed ESPs is not included in the rule set. Therefore, more rules may be required.

- Incorrect Rule Sets:

  It is also possible that the rule sets do not accurately describe the conditions leading to the root causes. The literature cited did not offer much evidence that the rule sets actually predicted failure modes consistently. Rule systems could not be derived using data analysis techniques, since the actual failure modes were never established.

- Similar Rule Sets:

  The rules employed in this study were derived from literature published by a leading ESP system provider. The nine rules had very similar premises, with small difference between them. Therefore when only some premises are triggers, the overall rule responses to each of the rules were very close.

- Normalization method:

The normalization method used the Arc tan function for all variables, regardless of the units of measure or the overall magnitude of the values. The normalized output is sensitive to unit of measure, such as psig or bar for pressure. A more rigorous approach would be to apply correction factors to the normalization function based on units of measure and the magnitude of the measured variable.

Possible corrections are as follows:

- In the normalization formula apply a factor that takes into account the unit of measure, the magnitude of the measured variable and maximum and minimum slope possible. This will take into account the nonlinear nature of the arc tan function.
- Instead of normalizing all trend data, base the membership functions on a range of actual slopes taking into account the upper and lower limits. This would be challenging due to the large number of ESPs installed and the wide range of operating parameters across the field.
- Develop membership functions specific to each well/pump configuration. This would also be challenging considering the large number of pumps and the wide range of ESP equipment and well configurations across the field.
- Simple triangular membership functions were developed as a first pass to test the system. The membership functions were not defined using sophisticated methods such as Counting Algorithm or Least Squares method. A common membership function was used for all normalized variables. A more accurate method would be to develop membership functions for each variable separately and based on the actual variables rather than the normalized variables.

## 5.5 Conclusions

The developed system did not identify the root cause failure of the ESP systems which experienced a failure. One possibility is that the actual failure mode was not included in the rule set. Another possibility is that the sensitivity of the system was not sufficient to pick up the trends. This could be due to the normalization method or due to the period of data collected. For example, pump wear takes time to develop, perhaps over years. The data also contained disruptions due to platform or generator trips, which affected the slope calculations. For the failed ESPs, the overall ruleset DOF for the seven day trends was consistently higher than for the ruleset DOFs of the running pumps. This does not identify the developing failure mode, but perhaps is an indication that the ESP is in trouble. As such, the simple system developed may be used to alert the surveillance team that the risk of failure of an ESP is high.

The way forward is to develop a more sophisticated system with finer sensitivity to trends, longer periods of data collection and automatic exclusion of start/stop events from the dataset. Furthermore, additional rule sets may need to be developed to cover failure modes not included in the ruleset.

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## CHAPTER 6 – CONCLUSIONS AND RECOMMENDATIONS

### 6.1 Research Questions

Detailed conclusions and recommendations are discussed at the ends of Chapters 2 to 5, which were included in the original publications. This chapter contains high-level findings related to the research questions, as well as broad conclusions and recommendations derived from the entirety of this research.

#### *6.1.1 Research Question 1*

Question: What energy accounting methods are appropriate for oil and gas extraction systems?

Finding: The general energy accounting methods typically applied to industry can also be applied to oil and gas extraction systems. These methods have been extended to the realm of oil and gas systems via the application of suitable indicators such as EI and EROI.

#### *6.1.2 Research Question 2*

Question: How do performance parameters, such as EROI, EI and lifting cost, of the fields behave over time?

Finding: The EROI of the fields is found to decline as the crude oil production declines, and the production of associated water increases. While EIs were not explicitly generated at the field level, it is understood that the EIs is essentially the inverse of the EROI, therefore it is inferred that the EI for the fields increases over time. The lifting costs is found to be inversely proportional to the EROI for the fields that utilized procured fuel.

#### *6.1.3 Research Question 3*

Question: What are the drivers for EROI, EI and lifting cost among the three fields reviewed?

Finding: There are two main drivers for EROI and EI. The first one is the decline of crude, which causes the energy produced to decrease of time. The second driver is the persistent requirement to produce and dispose, or inject, formation water, which is continuously increasing throughout the field life for all three fields. The additional energy required to manage the water has an impact on the fuel costs, when diesel generators are employed.

*6.1.4 Research Question 4*

Question: What are the energetic breakeven points for each fields?

Finding: The overall yearly energetic breakeven point for the fields depends on the construction energy, drilling energy and operational energy applied on a yearly basis for each field. This number ranges from approximately 1 million GJ in early years, for field 1, to as low as 150 thousand GJ for field 3, during later years. When considering the energy applied during the construction and pre-operational drilling phases, it is found that payback period occurs within the first year of production for all three fields. The production energetic breakeven point occurs when the EROI reaches unity, which was not observed in an of the fields, or wells, reviewed in this research.

*6.1.5 Research Question 5*

Question: How can a detailed energy accounting of the systems and subsystems of a platform be applied to provide practical benefits to the operational team?

Finding: The practical benefits of energy accounting is to support decision making with respect to fields, platforms and wells. With respect to fields, all things being equivalent, a field with the higher energy return is favorable to one with a lower energy return. This concept can be applied to individual platforms or wells. The development of indicators, such as EROI, EI and Lifting Costs can increase the operational teams understanding of the drivers of energy consumption, and lifting costs, and as such can allow them to focus their attention on ways to improve energy utilization where it is needed.

*6.1.6 Research Question 6*

Question: What does an energy balance of individual ESPs look like, and how can this information be used by operators?

Finding: The energy balances on individual ESPs revealed the location of energy losses within the system. The electrical losses were relatively small compared to the hydraulic losses. The larges hydraulic losses were within the pump itself. The information points to the need for improvements in ESP pump efficiency.

### *6.1.7 Research Question 7*

Question: What are the main failure modes of ESP, and can failures be anticipated by applying analytical performance techniques?

Finding: The main mechanical failure modes of ESPs are tubing leak, gas locking, and broken pump shaft, worn out pump. Electrical failure modes are with respect to the cables and motor. Cable splicing is a major failure mode of ESPs, due to the conditions by which the cable is exposed to. The developed fuzzy logic system was unable to anticipate failure modes, but was able to identify an impending failure.

## 6.2 Recommendation 1: Application of Energy Accounting and Performance Indicators

This research includes an energy accounting exercise and the derivation of number of different indicators for three small offshore oil fields. The two types of performance indicators explored in this research are Energy Intensity (EI) and Energy Return on Investment (EROI). It would appear that while these two indicators are related, they serve very different purposes.

### *6.2.1 Energy Intensity*

As demonstrated by this research, the EI, which most typically take on the form of Physical-Thermodynamic Indicators, can provide a commodity-focused perspective on performance, such as gigajoules per barrel of crude produced, or a processing-focused perspective such as kilowatt-hour per barrel of crude per bar of pressure raised. While each serves a different purpose, the common thread for Physical-Thermodynamic EIs is that they are related to the energetic effectiveness of a system, process, or equipment item. The experience of this author while conducting this research is that oil and gas operators and managers are quite interested in Energy Intensity type indicators since it represents practical information which can be used to understand and potential improve performance both energetically and economically. These kinds of indicators are ideal for benchmarking and the basis for continuous improvement of production or processes. As demonstrated in this research, they can also be translated to operational costs, since energy always comes with a cost.

Benchmarking of EI related indicators has become standard in many industries, and is often promoted by regulatory authorities, of which an example is the Energy Star program supported by the U.S. Environmental Protection Agency and U.S. Department of Energy [1-3]. There are also sustainability reporting initiatives such as the Global Reporting Initiative (GRI) which provides fairly extensive guidelines on sustainability reporting, including energy related parameters [4]. Unfortunately, sustainability reporting by oil and gas companies tends to be inconsistent in terms of the indicators reported and the boundaries selected [5]. Benchmarking initiatives for upstream oil and gas extraction systems are less prominent, and while there are several industry focused organizations which promote benchmarking such as the International Petroleum Industry Environmental Conservation Association (IPIECA) and the Intrnational Association of Oil and Gas Producers (OGP) [6] , clearly more can be done.

Some of the larger oil and gas companies have developed energy efficiency methods, such as Exxon Mobile's Global Energy Management System (GEMS) [7], but the methods, knowledge and benefits are retained within the company. Many manufactures are now moving toward cloud-based analytical systems for monitoring performance of their equipment, but the tools, methods and data are often proprietary, and the services often comes with a steep cost.

Therefore, it is recommended that oil and gas companies join and support Joint Initiative Projects (JIPs) aimed at benchmarking upstream oil and gas energetic processes and equipment items. The creation of a cloud-based network in which operational data is collected, analysed and benchmarked is suggested. It is anticipated that there will be resistance to sharing operational information in this way, due to competitive predispositions, but it is suggested that the overall benefit to individual companies far outweighs any perceived detrimental impacts.

### *6.2.2 Energy Return on Energy Investment*

It is the observation of this researcher in conducting this study, that oil and gas operational teams are uninterested in EROI type analysis. The practical implications of EROIs are apparently not evident to oil and gas managers. This may be because the EROI is better suited to a more holistic understanding of the value extracted from an oil and gas extraction system, rather than on the performance of individual processes or equipment items. The relationship of EROI to economics, for example, is obscured by a myriad of financial assumptions. This is unfortunate, since it is the belief of this researcher that the EROI can be used to measure the real value of an oil and gas extraction system, and how it changes over time. The time series EROI of a development can be used to better understand the value being provided by the development as conditions change or as more energy intensive recovery methods are introduced. It can also be used to evaluate different exploitation strategies.

#### *6.2.3 Energy Surplus*

This researcher believes that the concept of absolute energy surplus of a development can be used to support comparisons of opportunities and to make portfolio decisions. The concept of absolute energy was briefly mention by Cleveland, C. in an early paper on EROI [8] but the concept has not gained wide acceptance in the oil and gas industry or in academics. The absolute energy surplus is the total energy produced less the energy expended over the full lifecycle. It is suggested that the absolute energy surplus for a development, may be of interest to regulators of oil and gas concessions, and potentially used to derive fiscal terms and conditions which are commiserate with the value at large. A more in-depth discussion on the absolute energy surplus of a development and on possible future research on this subject are discussed in Section 6.4.

### 6.3 Recommendation 2: Integration of Energy Analysis into the Full Lifecycle

The robustness by which oil and gas companies develop energy estimations during initial analysis and concept evaluation vary considerably by company. It is suggested that it is appropriate to perform a rigorous analysis of energy during concept selection and design engineering since the potential economic impact of conceptual and design decisions can be significant. Sensitivities on energy intensity for the system, subsystems and equipment items should be conducted to gain a fuller understanding of the potential economic upsides and downsides of conceptual trade-offs, design decision or from deviations from operational expectations.

During the detailed design stage of a facility, trade-offs need to be understood, in terms of the interplay of capital and operating expenses. For example, there is a considerable energetic impact with regards to the selection of a sparing philosophy for compressors or pumps, which is complicated by different availabilities of the system and potentially further complicated by spatial constraints, particularly for offshore operations. The system must typically be designed for a wide range of flowrates, which makes it very difficult to achieve a high energy efficiency throughout the full range of conditions. For example, a 3x50% sparing philosophy for pumps will provide a very different energetic performance than 4x33% sparing philosophy. The latter being more effective for maintaining the pumps within the higher efficiency region of the pump curve and thus achieving superior overall energy efficiency, but this comes at the expense of increased capital costs. A similar issue is the decision regarding variable speed motor controllers, which can be used to maintain higher efficiencies of the pumps, but which also comes with an increased capital cost. Very often development funds are limited, and companies will choose the option with lower capital costs at the expense of improved lifecycle economics. Even in situation where the present value calculations clearly suggest that an increased upfront capital costs is preferable, budgetary constraints may dictate the selection of less than optimized design strategy. This is understandable, but it is suggested that it is better to make these kinds of decisions with all relevant information at hand and with clear eyes.

Of the fields analysed in this study, it is clear that the future energetic performance was not entirely anticipated during the conceptual stage of the development. This is quite normal in the oil and gas industry, where new fields are often developed incrementally with limited initial information. As the field life progresses, knowledge is gained about the reservoir and operations. Therefore, energetic analysis for these types of development requires a progressive strategy with continuous performance monitoring and the implementation of corrective actions which are economically and environmentally sensible. It is very possible that the corrective actions may be minimal yet result in significant improvements such as by minimizing pressure losses in piping systems by changing out control valves or increased maintenance of filters, heat exchangers etc. Other kinds of corrective actions are more difficult, such as changing out equipment, re-wheeling compressors, trimming pump impellors, etc. The more significant corrective actions require appropriate present value evaluations.

The most significant type of intervention in a field is the implementation or adjustment of the recovery methods, such as with regards to reservoir stimulation via water flooding, gas flooding, alternating water and gas injection, thermal methods such steam injection, chemical methods etc. These kind of technologies, often referred to as secondary or tertiary recovery methods, are employed to extend a field's life, improve recovery factors, and moderate the decline of production, but they are all energy intensive. Consequently, oil and gas companies will typically explore the economic impact of initiating such measures, and the energetic consequences will be concealed within the economic analysis. This researcher suggest that energy accounting should come to the forefront of the analysis, with revised economics as outcome of the more energy intensive exploitation strategy. It is suggested that energetic sensitivities would reveal economic possibilities, as much or more so than sensitivities on the price of oil, or on the ultimate reserves extracted.

## 6.4 Recommendation 3: Understanding Energy Efficiency

As a result of this research, particularly the calculation of generator and ESP efficiencies, it became apparent that the overall efficiencies for the crude oil extraction process was fairly low. For example, the initial conversion of fuels to electrical power using reciprocating generators typically delivers an efficiency of approximately 32 to 35%, based on the lower heating value of the fuel and the electrical power provided. After that, the electrical energy is converted to mechanical and hydraulic energy in the pumps with efficiencies found to range from 10 to 35%. If we multiply these two efficiencies together, we end up with an estimate of the overall fuel efficiency of the extraction process which is in the range of 3 to 12% depending on the platform and the ESP. This example neglects the energy required to dispose or inject the associated water and the utilities required on the platform. The point of this example is that the overall efficiency of the process is rather low, and that seemingly small improvements can have big impact. For example, if the power generation efficiency and the ESP performance are improved by 10%, the overall efficiency will increase to a range of 5 to 20%, which is nearly a 100% increase in efficiency of the process. The conclusion is that small improvements in efficiency are meaningful and should be pursued.

The share of total energy consumed to run the ESPs is approximately 50%, while the energy used to drive the water disposal, or injection, pumps is approximately 45%. Consequently, the drivers for energy efficiency improvement in the facilities researched are related to the generators and pumping systems. As noted above, a small improvement in the power generation system, or in the ESP system, can have a big impact on the overall efficiency. The recommendation is to always search for the drivers of energy efficiency and to pursue incremental improvements wherever possible. For the facilities studied in this research, it is recommended to explore ways to improve the efficiency of the power generation system, the ESP systems and the water disposal/injection pumps. For example, small turbine generators are known to provide improved efficiency over reciprocating engine generators. Also, it is suggested to explore the implementation of waste heat recovery systems, high efficiency motors, improved design of ESP pump stages, and to seek reduction of pressure losses in piping systems in these systems.

**6.5 Recommendation 4: Future Research – Concept of Energy Surplus**

A common observation to make is that two oil extraction systems can produce the same volume at the same rate and yet not be equivalent in terms of the energy value added, as measured by the EROI or by the absolute energy surplus. This is due to the differing energy intensities of the lifecycles of the two systems, particularly during the production phase. A good example is to compare an energy intensive heavy oil development that requires both steam flooding and artificial lift to achieve production, to a more desirable development which contains free-flowing wells with favorable crude properties, and thus a very low energy intensity operation. Is it suggested that the proposed "cumulative energy surplus" can be an indicator of the overall value provided by the oil extraction system, and can support decision making by policy makers, energy analysts and senior oil and gas management teams. The cumulative energy surplus parameter is the raw, unfiltered value provided by the system, irrespective of commercial factors such as the price of oil, the fiscal regime, interest rates etc. The cumulative energy surplus can be found by integration of the instantaneous rate based energy surplus over the production life of the field, as can be seen by Equations 1.12 and 1.13

$$Instantaneous\ Energy\ Surplus = \dot{E}_{net\ operational} = \dot{E}_g - \dot{E}_{op} \tag{6.1}$$

$$Cumulative\ Energy\ Surplus = E_{net\ operational} = \int_0^t (\dot{E}_g - \dot{E}_{op})\, dt \tag{6.2}$$

where:

$\dot{E}_{net\ operational}$ = the net surpluse rate during the operational phase (GJ/s)

$\dot{E}_g$ = rate of energy generation (GJ/s)

$\dot{E}_{op}$ = rate of operational energy consumption (GJ/s)

$E_{net\ operational}$ = the total energy return during the operational phase (GJ)

A hypothetical plot is shown in Figure 6.1 below, which depicts the energy-in, energy-out, and energy-surplus, which is the shaded area.

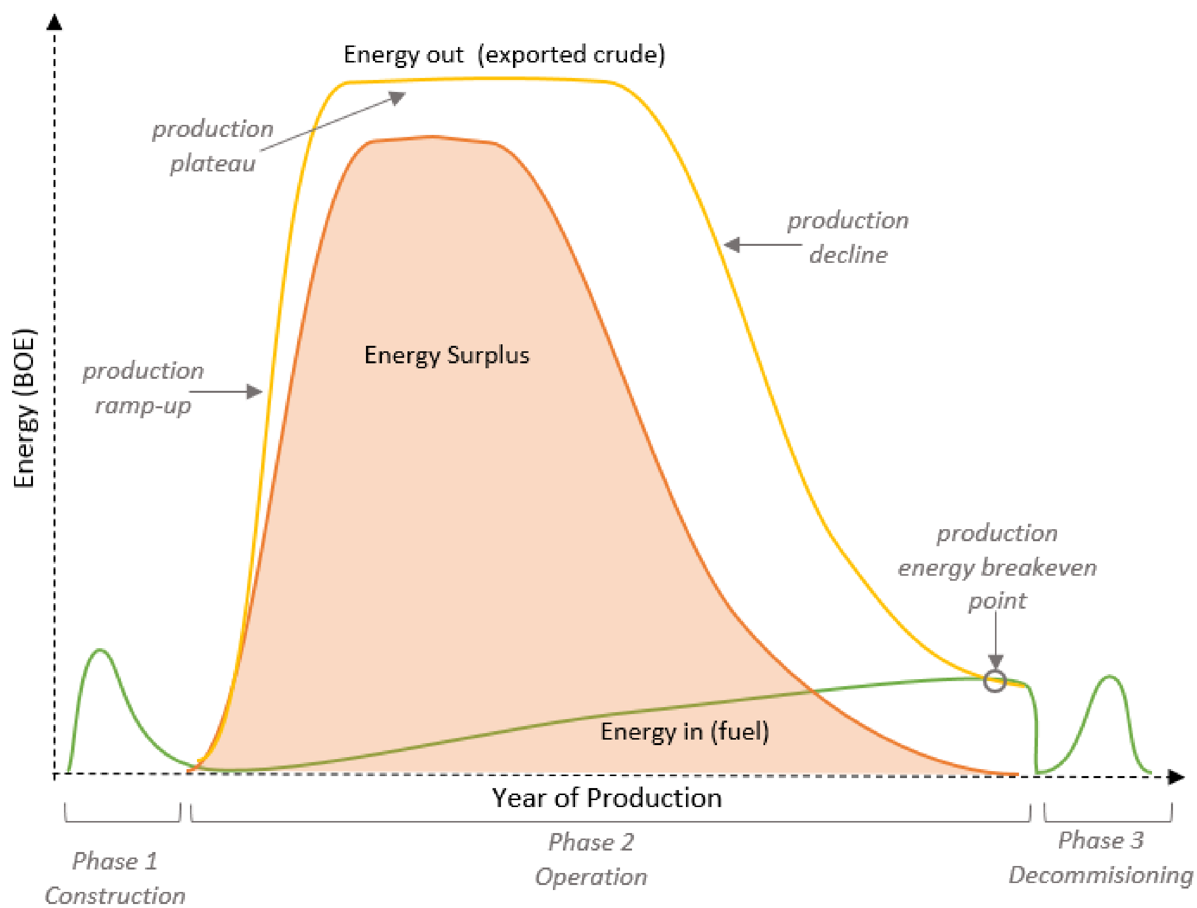


*Figure 6-1 Example Energy Profile*

The plot also indicates the production ramp-up, plateau and decline periods of an oil field, as well as the energy input during the construction, operational and decommissioning phases. Also, as per the previous section, the lifting energy breakeven point (BEP) is depicted at the junction of energy out and energy in, which corresponds to an instantaneous surplus value of zero.

Mathematical modelling of production decline has long been a subject of interest to petroleum engineers [9,10]. A number of relationships have been developed to model the decline phase of a well or an entire field, such as by using exponential and hyperbolic decline functions. Decline functions take into account several factors, such as the initial production rate and a decline rate. It is suggested that this practice can be extended to mathematically model the cumulative energy surplus. Adapting production decline equations to equivalent energy decline equations is quite straightforward, since only a conversion factor is required (e.g. a commonly used value is 6.1 GJ per barrel of crude oil). Mathematical functions for energy input are more challenging, but can be developed by taking into considering the specific energy consumption behavior of the well or fields, e.g., situations where artificial lifting and water management are the drivers for energy consumption. The hypothetical plots shown in Figure 6.2 were modelled using an exponential function for decline of production, and by extension energy-out, and a logistics function for increasing applied energy input. This mathematical model for energy-in was merely intended to demonstrate the proposed method. Future research may entail more rigorous models for energy in, potentially taking into consideration a number of factors.

It is suggested that this kind of analysis can be used to preliminarily estimate energetic conditions of a development, or an individual well, and to support evaluations of the cumulative energy surplus as described by Equation 1.9. It is also interesting to note that the EROI trends can also be modelled by this kind of analysis using Equation 1.3, as shown in Figure 1.6. Finally, another area of future work is to incorporate the total integrated surplus energy into high level economic analysis.

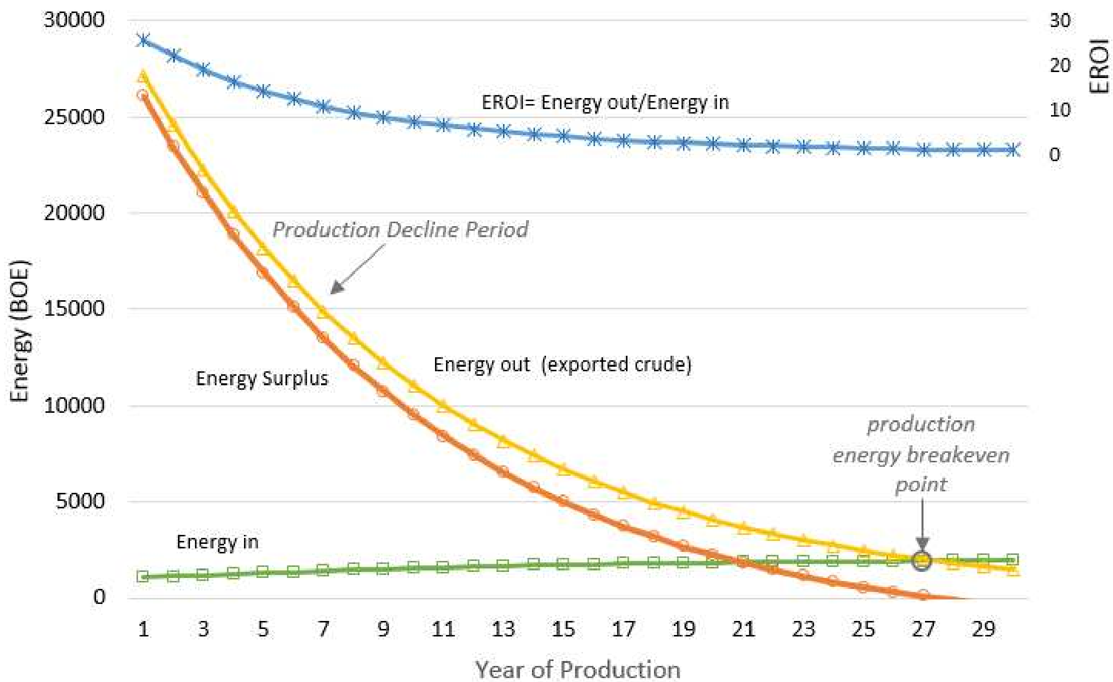


*Figure 6-2 Mathematical Modelling of Energy Profile*

### 6.6 Research Contributions

The body of work contained in this dissertation contained a number of research contributions:

#### *6.6.1 Energy Accounting for Oil Fields*

It is clear that energy accounting is inconsistently applied by oil and gas operators and by governmental regulators. This research demonstrates the insight that can be gained by employing explicit energy accounting practices to the specific circumstances of an oil and gas extraction system. It is demonstrated that the insight gained by an energy-based perspective can be used to better understand operating costs, and support decision making with respect to field development and evolving operational conditions.

#### *6.6.2 Energy Accounting for Wells*

This research describes the benefits that can be gained by developing energy balances, and energy related indicators, around individual wells, which employ artificial lifting in the form of ESPs. A demonstration of how energy balances can be used to better understand operating costs of individual wells, and thus provide oil and gas operational teams with a means to rank and prioritize individual wells.

*6.6.3 Demonstration of a Fuzzy Logical Approach to the Identification of ESP Failure Modes*

The application of fuzzy logic to determine failure modes of mechanical processing equipment items has been established in literature and deployed in industry. This research provides some insight into the challenges of applying fuzzy logic to determine ESP failure modes.

*6.6.4 Energy Centred Perspective of Oil and Gas Fields*

This research suggests an innovative means by which to describe oil and gas fields base on net energy, rather than on economics and recovered hydrocarbons.

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APPENDICES

## Appendix 2.A

| Load Basis | | | | | |
|---|---|---|---|---|---|
| | TRANSIT | JACKING | DRILLING MODE | EMERGENCY MODE | TRIPPING MODE |
| RATED | AVERAGE | AVERAGE | AVERAGE | AVERAGE | AVERAGE |
| POWER | OPERATING LOAD | OPERATING LOAD | OPERATING LOAD | OPERATING LOAD | OPERATING LOAD |
| kW | kW | kW | kW | kW | kW |
| 13,972 | 1,274 | 4,015 | 5,607 | | 3,049 |
| GJ/Day | GJ/Day | GJ/Day | GJ/Day | | GJ/Day |
| 1207 | 110 | 347 | 484 | | 263 |

| Productive Days | | 1 Well Basis | | | | | | | | | | | Totals |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **4** | Drilling (GJ) | | | | | | | 1,938 | | | | | 1,938 |
| **2** | Tripping (GJ) | | | | | | | | | | | 527 | 527 |
| **4** | Completion (GJ) | | | | | | | | | | | 1,054 | 1,054 |
| Non-Productive Days | | | | | | | | | | | | | |
| **1** | Jacking (GJ) | | | | | 347 | | | | | | | 347 |
| **2** | Transit (GJ) | | | 220 | | | | | | | | | 220 |
| | | | | | | | | | | | | | **4,085** |

| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Field 1 | Well per Year | **10** | **14** | **12** | **12** | **12** | **12** | **8** | **6** | **6** | **6** | **6** | **6** | **6** |
| | Drilling Energy (GJ) | 40,854 | 57,195 | 49,025 | 49,025 | 49,025 | 49,025 | 32,683 | 24,512 | 24,512 | 24,512 | 24,512 | 24,512 | 24,512 |
| | Drilling Energy per day (GJ) | 112 | 157 | 134 | 134 | 134 | 134 | 90 | 67 | 67 | 67 | 67 | 67 | 67 |
| Field 2 | Well per Year | | | | | | | | | | **10** | **4** | **4** | **4** |
| | Drilling Energy (GJ) | | | | | | | | | | 40,854 | 16,342 | 16,342 | 16,342 |
| | Drilling Energy per day (GJ) | - | - | - | - | - | - | - | - | - | 111.93 | 45 | 45 | 45 |
| Field 3 | Well per Year | | | | | | | | | | | **8** | **4** | **4** |
| | Drilling Energy (GJ) | | | | | | | | | | | 32,683 | 16,342 | 16,342 |
| | Drilling Energy per day (GJ) | - | - | - | - | - | - | - | - | - | - | 89.54 | 45 | 45 |

*Figure 2-1 Drilling Energy Calculation*

## Appendix 2.B

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Field 1 | Platform | 1&2 | 3*4 | 5 | 6 | 7 | |
| | Total Project Cost | 45,000,000 | 50,000,000 | 30,000,000 | 30,000,000 | 30,000,000 | |
| | Project Period | 2,006 | 2,007 | 2,008 | 2,008 | 2,009 | |
| | | Jun-06 | May-07 | Feb-08 | May 08 | May-08 | |
| | 2005 Value | 45,000,000 | 50,000,000 | 30,000,000 | 30,000,000 | 30,000,000 | |
| | MJ | 652,500,000 | 725,000,000 | 435,000,000 | 435,000,000 | 435,000,000 | |
| | J | 6.5E+14 | 7.3E+14 | 4.4E+14 | 4.4E+14 | 4.4E+14 | |
| | | | | | | | |
| | Amortization years | 3 | 3 | 3 | 3 | 3 | Total |
| | Amortization days | 1095 | 1095 | 1095 | 1095 | 1095 | |
| | J/D Amortized (Daily | 6.0E+11 | 6.6E+11 | 4.0E+11 | 4.0E+11 | 4.0E+11 | 2.4E+12 |
| | | | 662 | 397 | 397 | 397 | 2450 |

| | | | |
|---|---|---|---|
| Field 2 | Platform | 1 | |
| | Total Project Cost | 120,000,000 | |
| | | 2,014 | |
| | | Dec-14 | |
| | 2005 Value | 50,891,714 | |
| | MJ | 737,929,856 | |
| | J | 7.4E+14 | |
| | Amortization years | 3 | Total |
| | Amortization days | 1095 | |
| | J/D Amortized (Daily | 6.7E+11 | 6.7E+11 |
| | | 674 | 674 |

| | | | | |
|---|---|---|---|---|
| Field 3 | Platform | 1 | 2 | |
| | Total Project Cost | 80,000,000 | 40,000,000 | |
| | | 2,015 | 2,015 | |
| | | Oct-15 | Oct-15 | |
| | 2005 Value | 33,927,809 | 16,963,905 | |
| | MJ | 491,953,237 | 245,976,619 | |
| | J | 4.9E+14 | 2.5E+14 | |
| | Amortization years | 3 | 3 | Total |
| | Amortization days | 1095 | 1095 | |
| | J/D Amortized (Daily | 4.5E+11 | 2.2E+11 | 6.7E+11 |
| | | 449 | 225 | 674 |

| | |
|---|---|
| Interest rate | MJ/2005 Dollar |
| 0.1 | 14.5 |

*Figure 2-2 Construction Energy Calculation*

## Appendix 2.C

| Field 1 | | Construction | Drilling | Lifting | Total Ein | | | Construction | Drilling | Lifting |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Year | Energy (GJ) | Energy (GJ) | Energy (GJ) | (GJ) | Crude Energy (GJ) | Cumulative (GJ) | Percent Ein | Percent Ein | Percent Ein |
| 2006 | 0 | (652,500) | (98,049) | | (750,549) | | (1,501,099) | 87% | 13% | 0% |
| 2007 | 1 | (725,000) | (49,025) | (50,111) | (824,135) | 18,201,347 | 15,051,978 | 88% | 6% | 6% |
| 2008 | 2 | (870,000) | (49,025) | (112,468) | (1,031,493) | 25,679,731 | 38,668,723 | 84% | 5% | 11% |
| 2009 | 3 | (435,000) | (49,025) | (443,294) | (927,319) | 61,412,518 | 98,226,604 | 47% | 5% | 48% |
| 2010 | 4 | | (49,025) | (550,468) | (599,492) | 47,829,057 | 144,856,676 | 0% | 8% | 92% |
| 2011 | 5 | | (32,683) | (696,895) | (729,578) | 48,398,477 | 191,795,996 | 0% | 4% | 96% |
| 2012 | 6 | | (24,512) | (894,396) | (918,908) | 37,521,436 | 227,479,615 | 0% | 3% | 97% |
| 2013 | 7 | | (24,512) | (917,072) | (941,584) | 40,134,070 | 265,730,517 | 0% | 3% | 97% |
| 2014 | 8 | | (24,512) | (1,025,956) | (1,050,469) | 36,451,311 | 300,080,890 | 0% | 2% | 98% |
| 2015 | 9 | | (24,512) | (959,962) | (984,475) | 35,439,596 | 333,551,537 | 0% | 2% | 98% |
| 2016 | 10 | | (24,512) | (868,084) | (892,596) | 23,880,337 | 355,646,681 | 0% | 3% | 97% |
| 2017 | 11 | | (24,512) | (872,523) | (897,035) | 30,271,530 | 384,124,140 | 0% | 3% | 97% |
| | Totals | (2,682,500) | (473,905) | (7,391,229) | (10,547,634) | 405,219,408 | 2,353,712,259 | 25% | 4% | 70% |

| Field 2 | | Construction | Drilling | Lifting | Total Ein | | | Construction | Drilling | Lifting |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Year | Energy (GJ) | Energy (GJ) | Energy (GJ) | (GJ) | Crude Energy (GJ) | Cumulative (GJ) | Percent Ein | Percent Ein | Percent Ein |
| 2014 | 0 | (737,930) | (40,854) | | (778,784) | | (1,557,567) | 95% | 5% | 0% |
| 2015 | 1 | | (16,342) | (180,227) | (196,569) | 22,294,472 | 21,901,335 | 0% | 8% | 92% |
| 2016 | 2 | | (16,342) | (182,500) | (198,842) | 19,063,292 | 18,665,609 | 0% | 8% | 92% |
| 2017 | 3 | | (16,342) | (226,300) | (242,642) | 12,422,291 | 11,937,008 | 0% | 7% | 93% |
| | Totals | (737,930) | (89,879) | (589,027) | (1,416,835) | 53,780,055 | 50,946,384 | 52% | 6% | 42% |

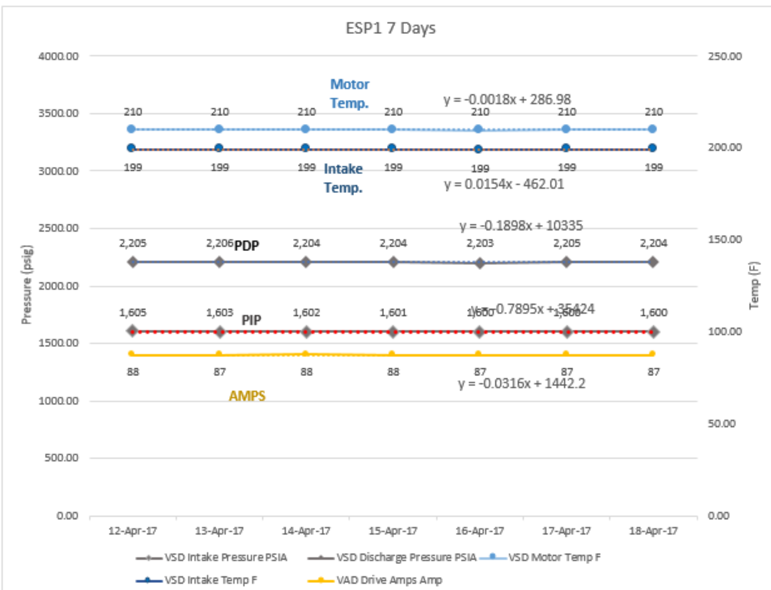
| Field 3 | | Construction | Drilling | Lifting | Total Ein | | | Construction | Drilling | Lifting |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Year | Energy (GJ) | Energy (GJ) | Energy (GJ) | (GJ) | Crude Energy (GJ) | Cumulative (GJ) | Percent Ein | Percent Ein | Percent Ein |
| 2015 | 0 | (737,930) | (32,683) | | (770,613) | | (1,541,226) | 96% | 4% | 0% |
| 2016 | 1 | | (16,342) | (139,168) | (155,509) | 25,693,129 | 25,382,110 | 0% | 11% | 89% |
| 2017 | 2 | | (16,342) | (229,495) | (245,837) | 21,307,477 | 20,815,804 | 0% | 7% | 93% |
| | Totals | (737,930) | (65,366) | (368,663) | (1,171,959) | 47,000,606 | 44,656,688 | 63% | 6% | 31% |

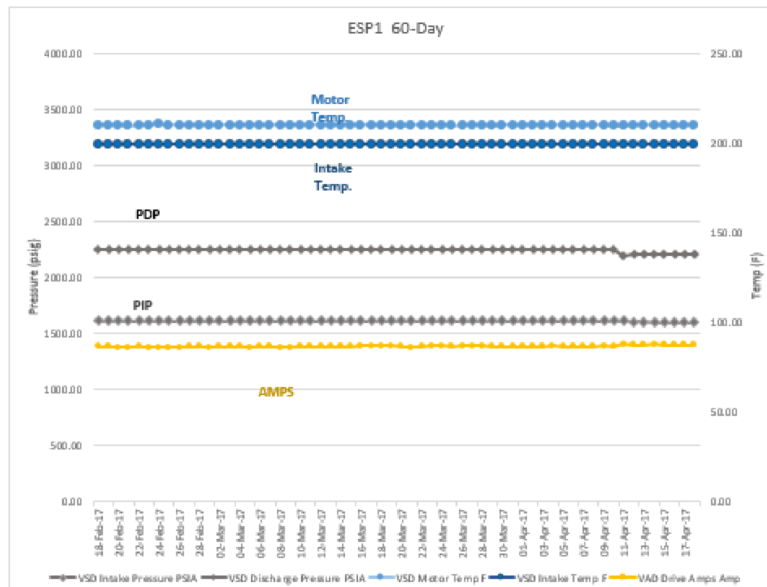
*Figure 2-3 Energy Breakeven Calculation*

**Appendix 5A**

| ESP 1 | R1 | | R2 | | R3 | | R4 | | R5 | | R6 | | R7 | | R8 | | R9 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **RULES** | Change in Fluids | | Closed Valve | | Plugged Tubing | | Plugged Pump | | Tubing Leak | | Gas Locking | | Reverse Pump Rotati | | Broken Pump Shaft | | Worn Out Pump | |
| Frequency | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.00 | C | 1.00 | C | 1.00 |
| | | | | | | | | | | | | | D | 0.00 | | | | |
| Motor Amps | C | 0.960 | D | 0.000 | D | 0.000 | D | 0.000 | C | 0.960 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | | | | | | | | | D | 0.000 | | | | | | | | |
| PIP | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.149 | I | 0.00 | I | 0.00 | I | 0.00 |
| | | | | | | | | | | | I | 0.000 | | | | | | |
| Motor Temp | C | 0.998 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 1.00 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |
| Tubing Pressure | C | 0.724 | I | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | I | 0.000 | | | | | | | | | | | | | | | | |
| PDP | C | 0.761 | I | 0.000 | I | 0.000 | D | 0.000 | C | 0.761 | D | 0.000 | C | 0.76 | D | 0.00 | D | 0.00 |
| | I | 0.000 | | | | | | | | | | | D | 0.00 | | | | |
| Intake Temp | C | 0.980 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.98 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |

*Figure 5.8: DoF for Premises based on Seven Day Trends for ESP #1 (Running ESP)*

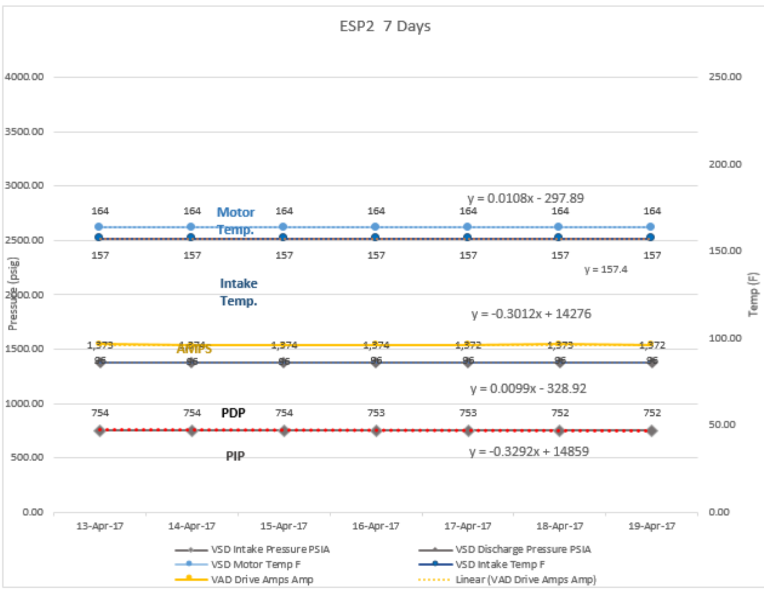


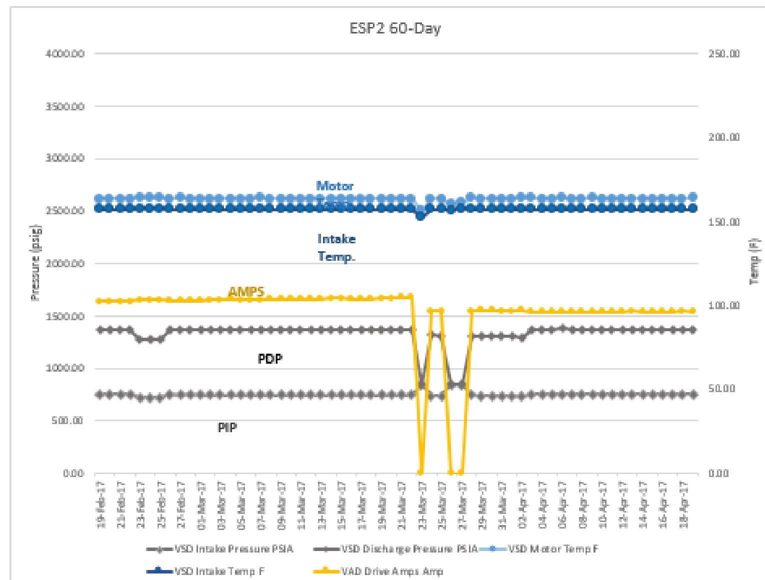




*Figures5.9 and 5.10: Seven and Sixty Day Trends for ESP #1*

| ESP 2 | R1 | | R2 | | R3 | | R4 | | R5 | | R6 | | R7 | | R8 | | R9 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **RULES** | Change in Fluids | | Closed Valve | | Plugged Tubing | | Plugged Pump | | Tubing Leak | | Gas Locking | | Reverse Pump Rotati | | Broken Pump Shaft | | Worn Out Pump | |
| Frequency | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.00 | C | 1.00 | C | 1.00 |
| | | | | | | | | | | | | | D | 0.00 | | | | |
| Motor Amps | C | 0.987 | D | 0.000 | D | 0.000 | D | 0.000 | C | 0.987 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | | | | | | | | | D | 0.000 | | | | | | | | |
| PIP | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.595 | I | 0.00 | I | 0.00 | I | 0.00 |
| | | | | | | | | | | | I | 0.000 | | | | | | |
| Motor Temp | C | 0.986 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.99 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |
| Tubing Pressure | C | 0.809 | I | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | I | 0.000 | | | | | | | | | | | | | | | | |
| PDP | C | 0.628 | I | 0.000 | I | 0.000 | D | 0.000 | C | 0.628 | D | 0.000 | C | 0.63 | D | 0.00 | D | 0.00 |
| | I | 0.000 | | | | | | | | | | | D | 0.00 | | | | |
| Intake Temp | C | 1.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 1.00 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |

*Figure 5.11: DoF for Premises based on Seven Day Trends for ESP# 2 (Running ESP)*

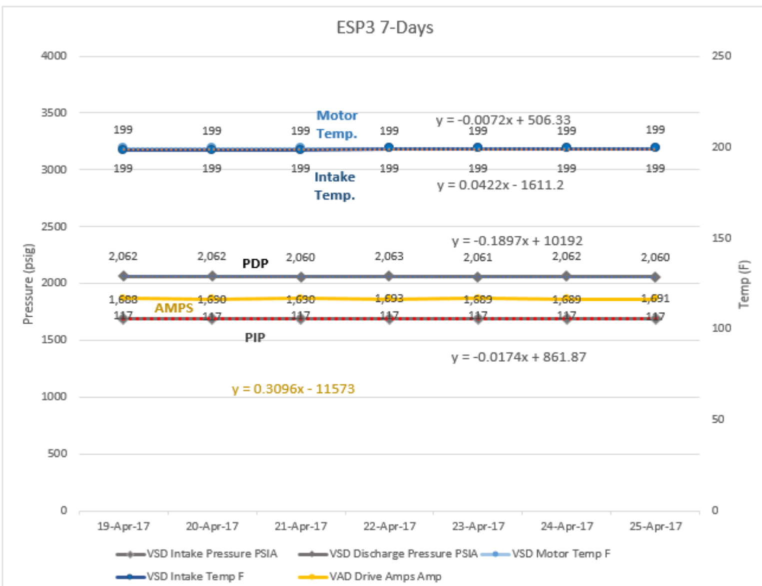


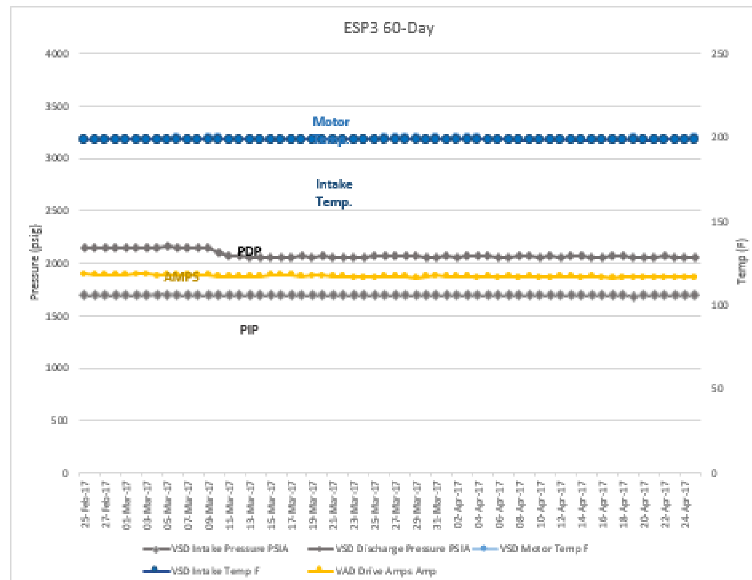




*Figures 5.12 and 5.13: Seven and Sixty Day Trends for ESP #2*

| ESP 3 | R1 | | R2 | | R3 | | R4 | | R5 | | R6 | | R7 | | R8 | | R9 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RULES | Change in Fluids | | Closed Valve | | Plugged Tubing | | Plugged Pump | | Tubing Leak | | Gas Locking | | Reverse Pump Rotation | | Broken Pump Shaft | | Worn Out Pump | |
| Frequency | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.00 | C | 1.00 | C | 1.00 |
| | | | | | | | | | | | | | D | 0.00 | | | | |
| Motor Amps | C | 0.978 | D | 0.000 | D | 0.000 | D | 0.000 | C | 0.978 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | | | | | | | | | D | 0.000 | | | | | | | | |
| PIP | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.618 | I | 0.00 | I | 0.00 | I | 0.00 |
| | | | | | | | | | | | I | 0.000 | | | | | | |
| Motor Temp | C | 0.991 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.99 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |
| Flowrate | I | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | | | | | | | | | | | | | | | | | | |
| Tubing Pressure | C | 0.825 | I | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | I | 0.000 | | | | | | | | | | | | | | | | |
| PDP | C | 0.761 | I | 0.000 | I | 0.000 | D | 0.000 | C | 0.761 | D | 0.000 | C | 0.76 | D | 0.00 | D | 0.00 |
| | I | 0.000 | | | | | | | | | | | D | 0.00 | | | | |
| Intake Temp | C | 0.946 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.95 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |

*Figure 5.14: DoF for Premises based on Seven Day Trends for ESP# 3 (Running ESP)*

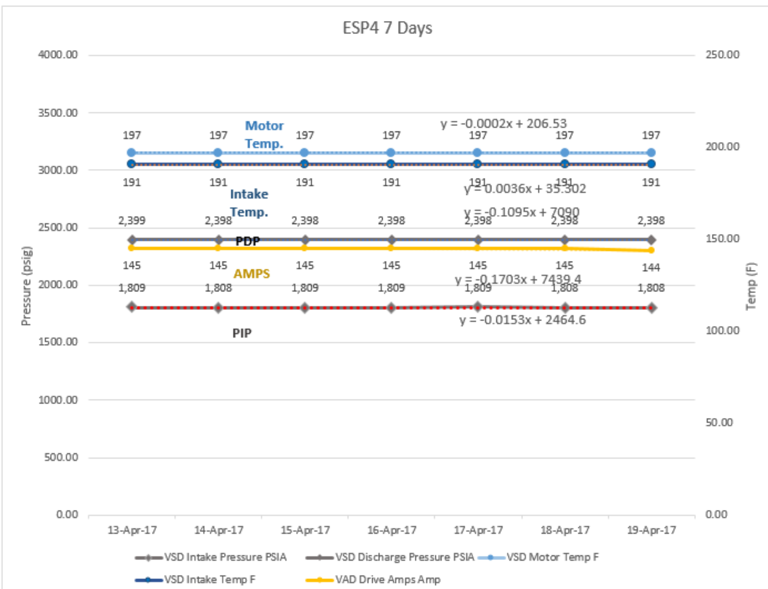


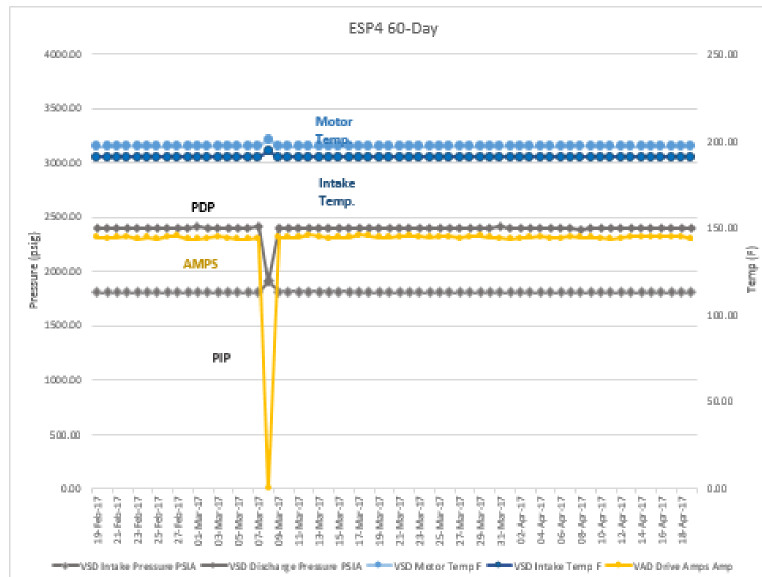




*Figures 5.15 and 5.16: Seven and Sixty Day Trends for ESP# 3*

| ESP 4 | R1 | | R2 | | R3 | | R4 | | R5 | | R6 | | R7 | | R8 | | R9 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RULES | Change in Fluids | | Closed Valve | | Plugged Tubing | | Plugged Pump | | Tubing Leak | | Gas Locking | | Reverse Pump Rotation | | Broken Pump Shaft | | Worn Out Pump | |
| Frequency | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.00 | C | 1.00 | C | 1.00 |
| | | | | | | | | | | | | | D | 0.00 | | | | |
| Motor Amps | C | 0.785 | D | 0.000 | D | 0.000 | D | 0.000 | C | 0.785 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | | | | | | | | | D | 0.000 | | | | | | | | |
| PIP | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.981 | I | 0.00 | I | 0.00 | I | 0.00 |
| | | | | | | | | | | | I | 0.000 | | | | | | |
| Motor Temp | C | 1.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 1.00 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |
| Flowrate | I | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | | | | | | | | | | | | | | | | | | |
| Tubing Pressure | C | 0.857 | I | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | I | 0.000 | | | | | | | | | | | | | | | | |
| PDP | C | 0.861 | I | 0.000 | I | 0.000 | D | 0.000 | C | 0.861 | D | 0.000 | C | 0.86 | D | 0.00 | D | 0.00 |
| | I | 0.000 | | | | | | | | | | | D | 0.00 | | | | |
| Intake Temp | C | 0.995 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 1.00 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |

*Figure 5.17: DoF for Premises based on Seven Day Trends for ESP# 4 (Running ESP)*

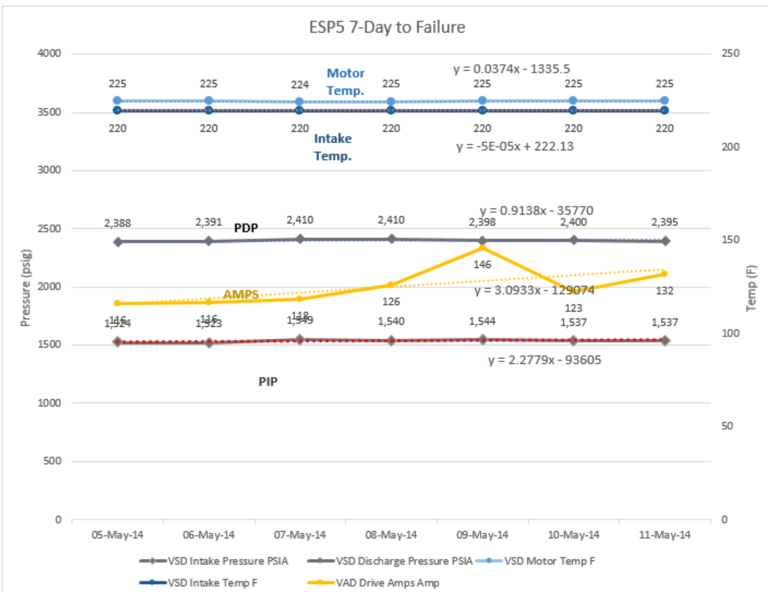


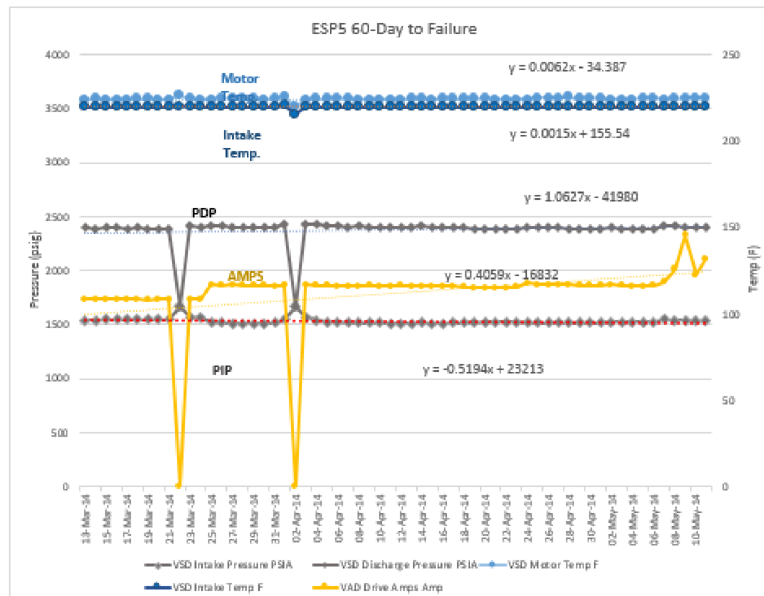




*Figures 5.18 and 5.19: Seven and Sixty Day Trends for ESP#4*

| ESP 5 | R1 | | R2 | | R3 | | R4 | | R5 | | R6 | | R7 | | R8 | | R9 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **RULES** | Change in Fluids | | Closed Valve | | Plugged Tubing | | Plugged Pump | | Tubing Leak | | Gas Locking | | Reverse Pump Rotation | | Broken Pump Shaft | | Worn Out Pump | |
| Frequency | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.00 | C | 1.00 | C | 1.00 |
| | | | | | | | | | | | | | D | 0.00 | | | | |
| Motor Amps | C | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | C | 0.000 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | | | | | | | | | D | 0.000 | | | | | | | | |
| PIP | I | 0.999 | I | 0.999 | I | 0.999 | I | 0.999 | I | 0.999 | C | 0.000 | I | 1.00 | I | 1.00 | I | 1.00 |
| | | | | | | | | | | | I | 0.999 | | | | | | |
| Motor Temp | C | 0.952 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.95 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |
| Tubing Pressure | C | 0.000 | I | 0.999 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | I | 0.999 | | | | | | | | | | | | | | | | |
| PDP | C | 0.057 | I | 0.678 | I | 0.678 | D | 0.000 | C | 0.057 | D | 0.000 | C | 0.06 | D | 0.00 | D | 0.00 |
| | I | 0.678 | | | | | | | | | | | D | 0.00 | | | | |
| Intake Temp | C | 1.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 1.00 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |

*Figure 5.20: DoF for Premises based on Seven Day Trends for ESP# 5 (Failed ESP)*

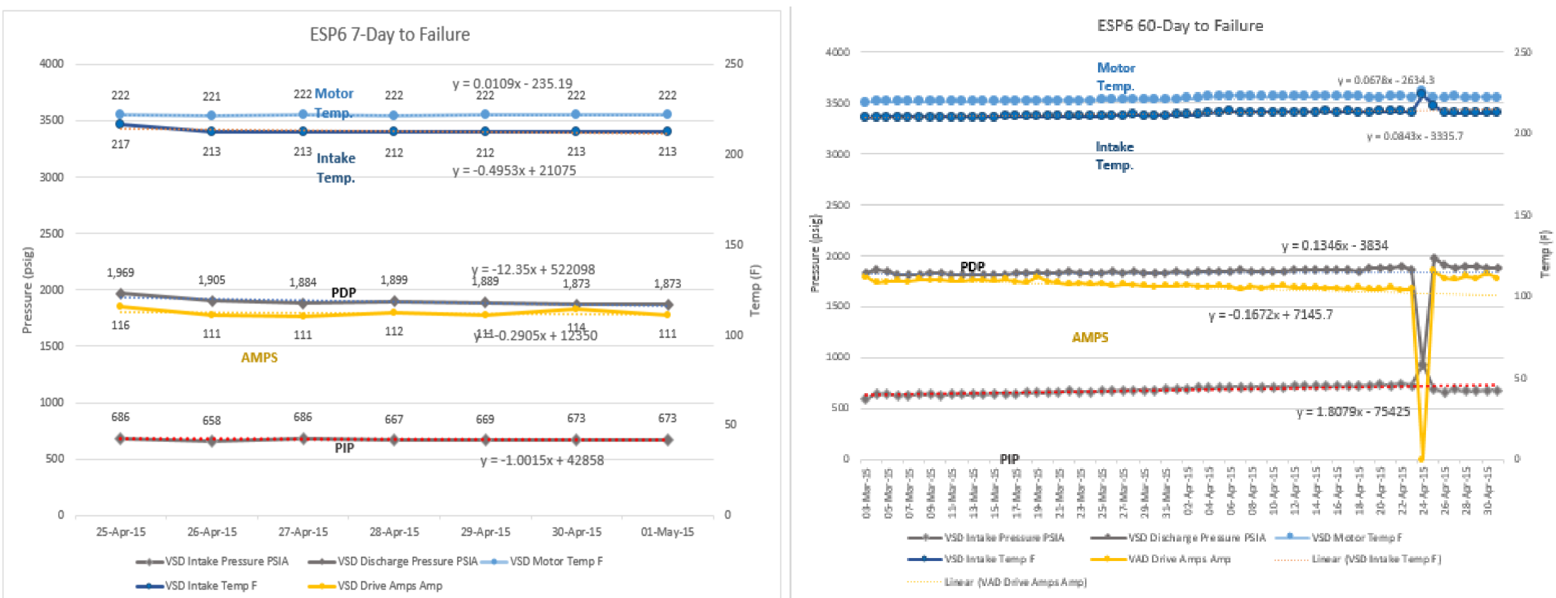



*Figures 5.21 and 5.22: Seven and Sixty Day Trends for ESP# 5 (Up to Full Failure)*

| ESP 6 | R1 | | R2 | | R3 | | R4 | | R5 | | R6 | | R7 | | R8 | | R9 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RULES | Change in Fluids | | Closed Valve | | Plugged Tubing | | Plugged Pump | | Tubing Leak | | Gas Locking | | Reverse Pump Rotation | | Broken Pump Shaft | | Worn Out Pump | |
| Frequency | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.00 | C | 1.00 | C | 1.00 |
| | | | | | | | | | | | | | D | 0.00 | | | | |
| Motor Amps | C | 0.640 | D | 0.000 | D | 0.000 | D | 0.000 | C | 0.640 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | | | | | | | | | D | 0.000 | | | | | | | | |
| PIP | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.000 | I | 0.00 | I | 0.00 | I | 0.00 |
| | | | | | | | | | | | I | 0.000 | | | | | | |
| Motor Temp | C | 0.986 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.99 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |
| Tubing Pressure | C | 0.000 | I | 0.000 | D | 0.997 | D | 0.997 | D | 0.997 | D | 0.997 | D | 1.00 | D | 1.00 | D | 1.00 |
| | I | 0.000 | | | | | | | | | | | | | | | | |
| PDP | C | 0.000 | I | 0.000 | I | 0.000 | D | 0.996 | C | 0.000 | D | 0.996 | C | 0.00 | D | 1.00 | D | 1.00 |
| | I | 0.000 | | | | | | | | | | | D | 1.00 | | | | |
| Intake Temp | C | 0.414 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.41 | I | 0.00 | I | 0.00 |
| | D | 0.232 | | | | | | | | | | | I | 0.00 | | | | |

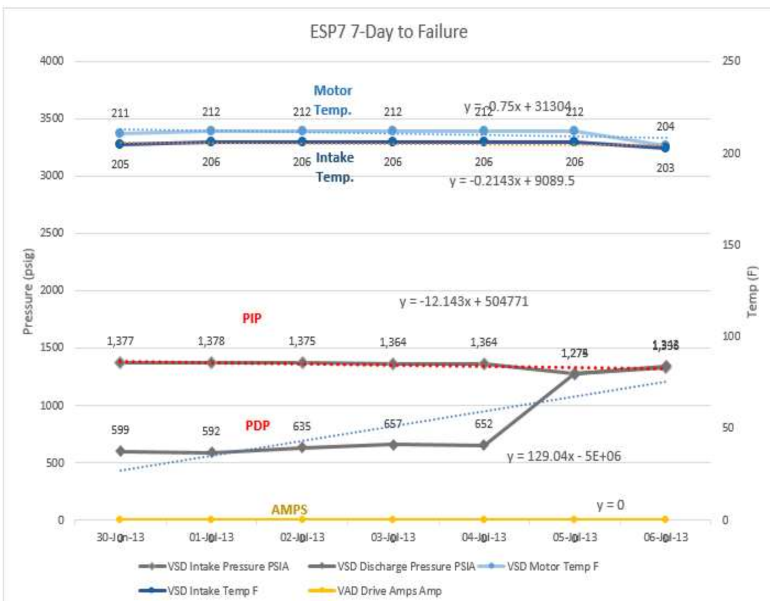
*Figure 5.23: DoF for Premises based on Seven Day Trends for ESP# 6 (Failed ESP)*

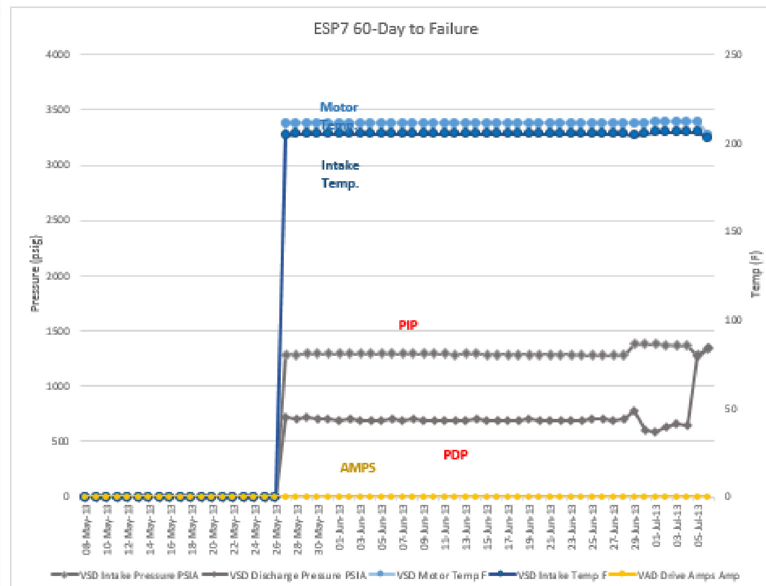



*Figures 5.24 and 5.25: Seven and Sixty Day Trends for ESP# 6 (Up to Full Failure)*

| ESP 7 | R1 | | R2 | | R3 | | R4 | | R5 | | R6 | | R7 | | R8 | | R9 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RULES | Change in Fluids | | Closed Valve | | Plugged Tubing | | Plugged Pump | | Tubing Leak | | Gas Locking | | Reverse Pump Rotation | | Broken Pump Shaft | | Worn Out Pump | |
| Frequency | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.00 | C | 1.00 | C | 1.00 |
| | | | | | | | | | | | | | D | 0.00 | | | | |
| Motor Amps | C | 1.000 | D | 0.000 | D | 0.000 | D | 0.000 | C | 1.000 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | | | | | | | | | D | 0.000 | | | | | | | | |
| PIP | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.000 | I | 0.00 | I | 0.00 | I | 0.00 |
| | | | | | | | | | | | I | 0.000 | | | | | | |
| Motor Temp | C | 0.181 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.18 | I | 0.00 | I | 0.00 |
| | D | 0.524 | | | | | | | | | | | I | 0.00 | | | | |
| Tubing Pressure | C | 0.000 | I | 0.997 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | I | 0.997 | | | | | | | | | | | | | | | | |
| PDP | C | 0.000 | I | 0.996 | I | 0.996 | D | 0.000 | C | 0.000 | D | 0.000 | C | 0.00 | D | 0.00 | D | 0.00 |
| | I | 0.996 | | | | | | | | | | | D | 0.00 | | | | |
| Intake Temp | C | 0.731 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.73 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |

*Figure 5.26: DoF for Premises based on Seven Day Trends for ESP# 7 (Failed ESP)*

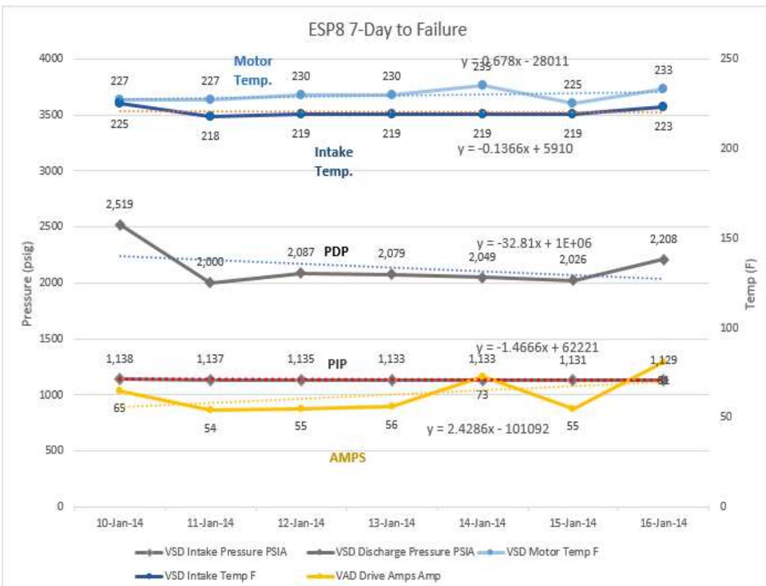


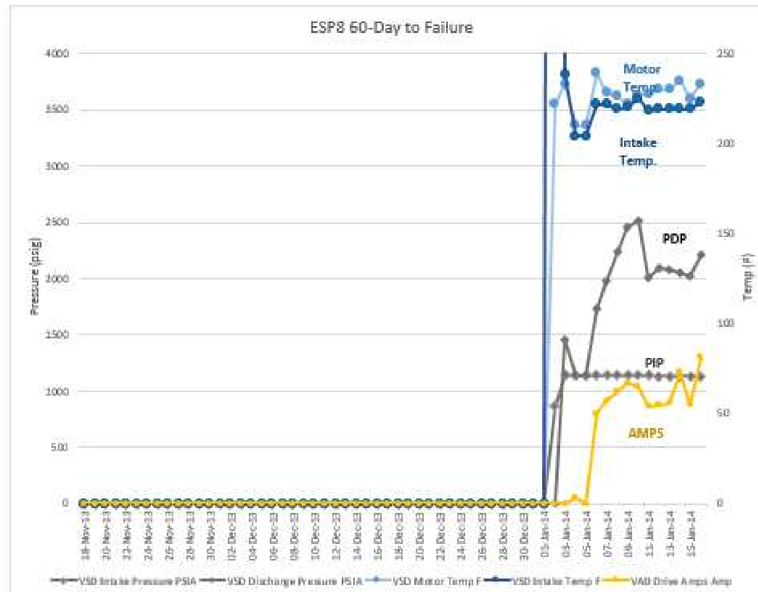




*Figures 5.27 and 5.28: Seven and Sixty Day Trends for ESP# 7 (Up to Full Failure)*

| ESP 8 | R1 | | R2 | | R3 | | R4 | | R5 | | R6 | | R7 | | R8 | | R9 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RULES | Change in Fluids | | Closed Valve | | Plugged Tubing | | Plugged Pump | | Tubing Leak | | Gas Locking | | Reverse Pump Rotation | | Broken Pump Shaft | | Worn Out Pump | |
| Frequency | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.00 | C | 1.00 | C | 1.00 |
| | | | | | | | | | | | | | D | 0.00 | | | | |
| Motor Amps | C | 0.000 | D | 0.000 | D | 0.000 | D | 0.000 | C | 0.000 | D | 0.000 | D | 0.00 | D | 0.00 | D | 0.00 |
| | | | | | | | | | D | 0.000 | | | | | | | | |
| PIP | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.000 | I | 0.00 | I | 0.00 | I | 0.00 |
| | | | | | | | | | | | I | 0.000 | | | | | | |
| Motor Temp | C | 0.241 | I | 0.448 | I | 0.448 | I | 0.448 | I | 0.448 | I | 0.448 | C | 0.24 | I | 0.45 | I | 0.45 |
| | D | 0.000 | | | | | | | | | | | I | 0.45 | | | | |
| Tubing Pressure | C | 0.000 | I | 0.000 | D | 0.997 | D | 0.997 | D | 0.997 | D | 0.997 | D | 1.00 | D | 1.00 | D | 1.00 |
| | I | 0.000 | | | | | | | | | | | | | | | | |
| PDP | C | 0.000 | I | 0.000 | I | 0.000 | D | 0.996 | C | 0.000 | D | 0.996 | C | 0.00 | D | 1.00 | D | 1.00 |
| | I | 0.000 | | | | | | | | | | | D | 1.00 | | | | |
| Intake Temp | C | 0.827 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.83 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |

*Figure 5.29: DoF for Premises based on 7 Day Trends for ESP# 8 (Failed ESP)*

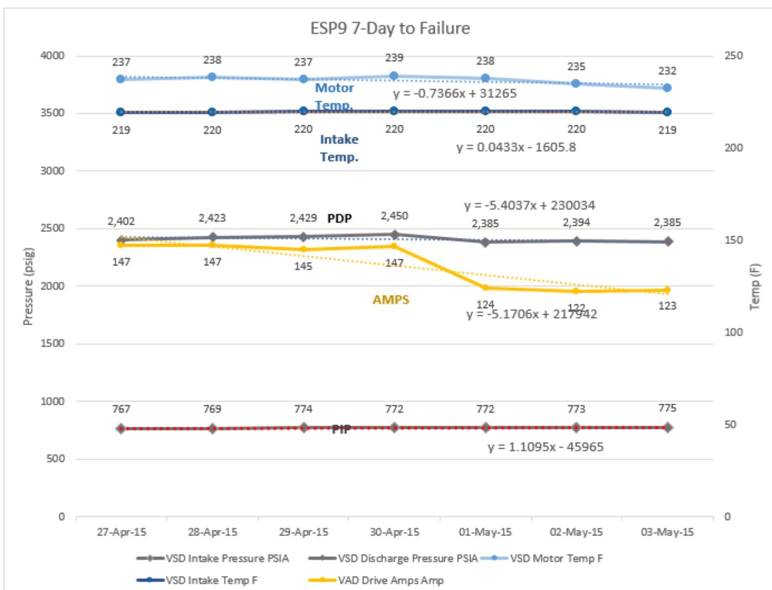


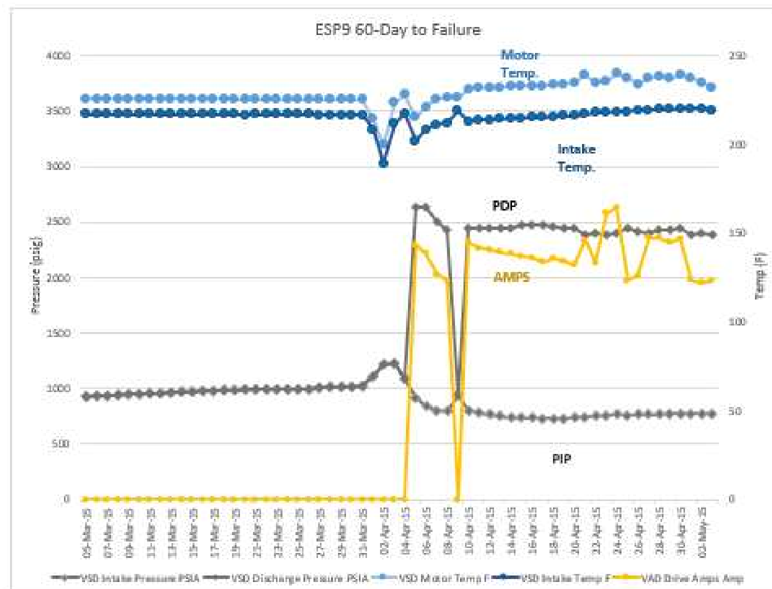




*Figures 5.30 and 5.31: Sixty and Seven Day Trends for ESP# 8 (Up to Full Failure)*

| ESP9 | R1 | | R2 | | R3 | | R4 | | R5 | | R6 | | R7 | | R8 | | R9 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **RULES** | Change in Fluids | | Closed Valve | | Plugged Tubing | | Plugged Pump | | Tubing Leak | | Gas Locking | | Reverse Pump Rotation | | Broken Pump Shaft | | Worn Out Pump | |
| Frequency | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.000 | C | 1.00 | C | 1.00 | C | 1.00 |
| | | | | | | | | | | | | | D | 0.00 | | | | |
| Motor Amps | C | 0.000 | D | 0.997 | D | 0.997 | D | 0.997 | C | 0.000 | D | 0.997 | D | 1.00 | D | 1.00 | D | 1.00 |
| | | | | | | | | | D | 0.997 | | | | | | | | |
| PIP | I | 0.833 | I | 0.833 | I | 0.833 | I | 0.833 | I | 0.833 | C | 0.000 | I | 0.83 | I | 0.83 | I | 0.83 |
| | | | | | | | | | | | I | 0.833 | | | | | | |
| Motor Temp | C | 0.192 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.19 | I | 0.00 | I | 0.00 |
| | D | 0.510 | | | | | | | | | | | I | 0.00 | | | | |
| Tubing Pressure | C | 0.000 | I | 0.000 | D | 0.998 | D | 0.998 | D | 0.998 | D | 0.998 | D | 1.00 | D | 1.00 | D | 1.00 |
| | I | 0.000 | | | | | | | | | | | | | | | | |
| PDP | C | 0.000 | I | 0.000 | I | 0.000 | D | 0.997 | C | 0.000 | D | 0.997 | C | 0.00 | D | 1.00 | D | 1.00 |
| | I | 0.000 | | | | | | | | | | | D | 1.00 | | | | |
| Intake Temp | C | 0.945 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | I | 0.000 | C | 0.94 | I | 0.00 | I | 0.00 |
| | D | 0.000 | | | | | | | | | | | I | 0.00 | | | | |

*Figure 5.32: DoF for Premises based on Seven Day Trends for ESP# 9 (Failed ESP)*




*Figures 5.33 and 5.34: Sixty and Seven Day Trends for ESP# 9 (Up to Full Failure*

LIST OF ABBREVIATIONS

Chapter 1 Abbreviations
$API$ = American Petroleum Institute
$BBL$ = barrel
$BLPD$ = barrel of liquid per day
$BOPD$ = barrel of oil per day
$BPD$ = barrel per day
$BWPD$ = barrel of water per day
$EI$ = energy intensity
$EER$ = external energy return (EROI with only external energy inputs)
$EROI$ = energy return on energy invested
$ESP$ = electrical submersible pump
$F1$ = field one
$F2$ = field two
$F3$ = field three
$FPSO$ = floating production, storage and offloading vessel
$FSO$ = floating, storage and offloading vessel
$HP$ = high pressure
$GDP$ = gross domestic product
$GJ$ = gigajoule
$GOR$ = gas oil ratio
$OD$ = pipe outer diameter
$OIW$ = oil in water expressed in parts per million
$OPEX$ = operating expense
$OPGEE$ = oil producers greenhouse gas emissions estimator
$MJ$ = megajoule
$MMSCFD$ = million standard cubic feet per day
$MW$ = megawatt
$NER$ = net energy return (EROI with net energy inputs)
$PPB$ = parts per billion
$SPE$ = Society of Petroleum Engineers
$TPM$ = technical performance measure
$UKOOA$ = UK Offshore Operators Association
$USD$ = US dollar
$WHP$ = wellhead platform
$WOR$ = water oil ratio
$WPP$ = wellhead processing platform

Chapter 2 Abbreviations
$BPD$ = barrel per day
$EROI$ = energy return on energy invested
$EER$ = external energy return (EROI with only external energy inputs)
$GJ$ = gigajoule
$MJ$ = megajoule
$NER$ = net energy return (EROI with net energy inputs)
$USD$ = US dollar

Chapter 3 Abbreviations
$BBL$ = barrel
$BEP$ = best efficiency point
$BHP$ = brake horse power
$EROI$ = energy return on energy invested
$ESP$ = electrical submersible pump
$MD$ = measured depth
$TVD$ = true vertical depth
$URR$ = ultimate reserves recovery
$VSD$ = variable speed drive
$WHP$ = wellhead pressure (psi)

Chapter 4 Abbreviations
$AF$ = air fuel ratio
$bar$ = unit of pressure
$bbl$ = barrel
$EROI$ = energy return on energy invested
$ESP$ = electrical submersible pump
$GHG$ = greenhouse gas
$HVAC$ = heating, ventillation and air conditioning
$KPI$ = key performance indicator
$MMSCFD$ = million standard cubic feed per day
$NPV$ = net present value
$OPEX$ = operating expense
$PFD$ = process flow diagram
$PWIP$ = produced water injection pumps

Chapter 5 Abbreviations
$DCS$ = distributed control system
$DOF$ = degree of fulfilment
$DSS$ = decision support system
$ESP$ = electrical submersible pump
$Hz$ = hert
$PDP$ = pump discharge pressure (psig)
$PIP$ = pump intake pressure (psig)
$psig$ = pounds per square inch
$VSD$ = variable speed drive

Chapter 6 Abbreviations
$BEP$ = breakeven point
$EI$ = energy intensity
$EROI$ = energy return on energy invested
$ESP$ = electrical submersible pump
$GJ$ = gigajoule
$GEMS$ = Global Energy Management System
$GRI$ = Global Reporting Initiative
$IPIECA$ = International Petroleum Industry Environmental Conservation Association
$JIP$ = joint initiative project
$OGP$ = Association of Oil and Gas Producers