Chapter 1
Introduction

1.1 Background

Oil and gas companies are required to meet market demand and set production targets to shareholders. Many activities take place in the field that interrupt the production chain which impacts the theoretical capacity of the facilities resulting in production plans not matching what is actually produced.

Continuous measurement of produced fluid contents ratios at the well can produce accurate material balance (Deruyck, B., Joseph, J. and Ehlig Economides, C., 1992). This can't be done dynamically and companies rely on the stock tank readings after water and gas is separated from oil. The individual well contribution to production is computed based on the most recent available well test record. The computed well back allocation often has discrepancies with the actual well contribution due to changing oil and gas ratios from the time elapsed when the last well testing was done. Gas and water ratios are estimated based on the latest available well test (the period between well tests can exceed many months). The process of continuously reading accurate volumes of oil, water and gas at the well string is not in place. This is known as phase metering. It is best done if the well is equipped with a permanent test separator. Very few wells are equipped with test separators due to their high cost. The majority of the wells are tested by providing a mobile test separator. This process is also costly and has production impact. However, it is the most accurate and viable method (Gjesdal, A., Abro, E. and Midttveit, O., 1988) but can't be done very frequently. The need for phase metering is important for:

- Defining the well production plan through lift curve computations
- Measuring the produced volume and phase ratios at the well
- Obtaining the efficiency of the injection and water flooding
- Back allocating the actual volumes produced
- Obtaining an accurate balance sheet for oil in place
- Better managing of the reservoir

The fluid ratios measurement is estimated at the stock tank; the readings at the tank do not serve the purpose of accurate production planning by well or zone due to the commingled oil from different sources and zones. Therefore, the readings at the stock tanks are only useful for actual production volumes and to estimate the well contribution.

The practice of using a test separator to obtain water/gas/oil ratios is the prevailing practice in the United Arab Emirates (UAE) and the world. Recent technological advances in the digital oil field have introduced a costly solution for installing online multiphase flow metering (MPFM[i]) gauges. This method is still in debate due to the readings' accuracy, the maintenance issues, requirement for power and fiber networking which is not available in most brown fields (Hess, W. and Immerman, N., 2013). But, according to Statoil study (Gjesdal, A., Abro, E. and Midttveit, O., 1988), the use of multiphase flow meters can't replace the traditional well testing. This is because MPFM does not do physical separation as it relies on the fluid phase properties; it requires regular calibration and it is not economical to install at each well.

Production planning in oil and gas is done by setting the production flow rate at the well based on allowed production targets issued by production and reservoir engineering. For large fields with a production network, the allowable targets are not easy to achieve (Burchel, S., 2014; Kaufman, R., Ahmed, A. and Hempkins, W., 1997) due to the commingled flow constraints, back pressure changes and other contributing factors of regular repair activities and inspections taking place in the production chain. Planners need to provide a strong convincing well setting to field operators to achieve enhancements not far from the situation they are used to. This was also highlighted by (Shamlou, S. and Holm, S., 2013) and (Wang, P., 2003), et al. in their discussions on modeling and implementation work process and in the recommendation to further investigate multi-objective optimization methods for surface facility design problems.

During the course of production, the pipelines network flow assurance is modeled and simulated based on techniques that assess pressure, volume and temperature (PVT) model of the network. Specialized simulators are used for each production stage covering reservoirs, wells, transport network, plants and storage capacities.

Simulations at each stage are often done in silos and in isolation from the interactions of some activities taking place at the surface facilities. One example is flow management when one well declines and gets overtaken by other. Another example is the interaction between producer and injector wells that can result in a change in the gas and water ratios. This can go unnoticed until a well testing is conducted several months later. The unnoticed decline in oil ratios affects the planned computations and volumes at the stock tank. This can also cause inaccurate computations of well contribution (back-allocation) which can impact the well production settings causing undesired results by not achieving optimum production opportunity.

1.2 Need for the study

There is a need for the study to enhance production capabilities to the optimum potential of the production system. This is also required to satisfy the rise in demand, to achieve operational excellence, to produce an accurate well contribution by accurate back allocations and to develop a sound investment strategy. The increase in shale oil production has caused a downward trend in the price of oil. Efficient asset utilization to control production losses will optimize the return on investments.

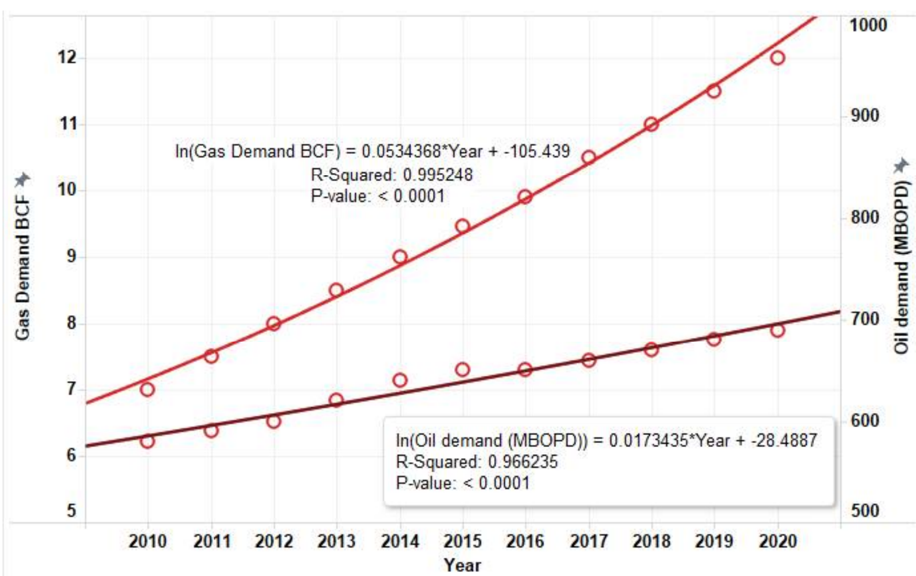
UAE had maintained the status as a major oil supplier due to low production costs and the estimated proven reserve of both oil and natural gas (97.8 billion barrels and 215 trillion cubic feet respectively - Source: UAE government portal and (UAE National Media Council, 2015)). This means that the UAE holds 4 per cent of the world’s oil reserves and 3.5 per cent of gas reserves. Despite continued growth in sectors such as tourism, construction and real estate, the oil and gas industry remains as the biggest contributor to the UAE's gross domestic product. The UAE is the fourth largest oil exporter with a heavy program of investment in Abu Dhabi seeking to achieve a larger production quota by 2018. Therefore, optimization of production is in the country’s economic interest.

1.2.1 Rise in demand for energy

Abu Dhabi's gas production has increased significantly in recent years from large oil fields due to reduced gas flaring. Abu Dhabi has contractual commitments to export gas. At the same time, local demand for gas used for power and desalination plants has increased. Gas is also used for reinjection into oilfields to maintain wellhead pressure and it is used in the petrochemicals and fertilizer sectors.

The market shift and change in demand are key elements that contribute to the price and consequently decisions concerning production management. In addition, the UAE is pursuing plans to diversify its energy supply to include nuclear, solar power, and waste-to-energy. Such initiatives should help to reduce carbon emissions and lessen the pressure on the country's gas supplies. However, oil and gas will remain the main source of energy, at 70 per cent by 2020. Nuclear power and renewable energy contribution will be 30 percent (Abu Dahbi Council of Economic Development, 2016) and (The Energy Industry Weekly - GCC, 2016).

The drive to enhance production of oil and gas will continue to be a focus of the Abu Dhabi National Oil Company (ADNOC) to meet local demand. ADNOC's vision is to target 70% oil recovery after raising it from 60% which was the previous target over the past half century). Since OPEC's production quota over the past 10 years is fixed for the UAE (UAE share is approx. 3.2 MMBOPD), the increase in production is mainly to satisfy the local consumption which has witnessed a growth ratio in the last decade as seen in (Figure 1-1 Oil and gas demand in UAE - Source US Information Admin.). Hence, local demand is a key focus of this research.



Caption

Gas Demandin billions cubic feet (BCF) and oil demand (MBOPD). Lower and upper curves represnt Oil and gas respectively. Source (US Infromation Adminsitration)

Figure 1-1 Oil and gas demand in UAE - Source US Information Admin.

Local gas consumption is at a steady increase of 0.5 BCF annually. Oil consumption is also on the rise at the rate of 2% per year. The following equations represent the demand curves for gas and oil.

$$Ln(Gas\ Demand) = 0.0534368 * (Y) - 105.439$$

Equation 1-1 Gas demand trend formula

$$Ln(Oil\ Demand) = 0.0173435 * (Y) - 28.4887$$

Equation 1-2 Oil demand trend formula

1.2.2 Production losses case studies

Early in 2015 and in previous years, case studies are conducted to evaluate the reasons for lost production opportunities in the company. The exercise was repeated in 2016 and produced the same results. An estimate of 15% of lost production opportunity was the result of the study according to the report produced by the planning unit which analyzed reasons of production losses. (ADMA production annual report, 2014). According to the study, the value constitutes 15% of the total field production (approx. 330MBOPD). The study concluded that the reasons are caused by activities in Figure 1-2.

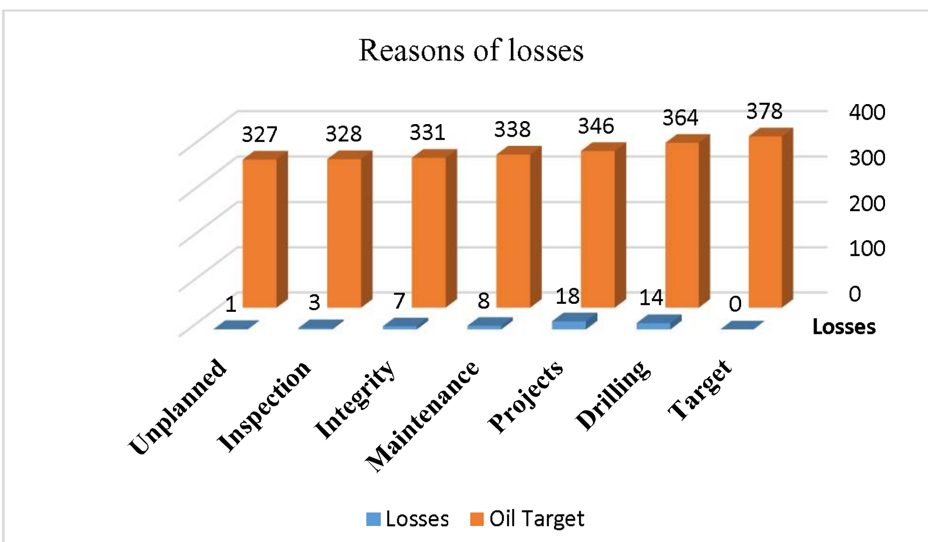


Figure 1-2 Identified losses 51 BOPD by activity

The full field capacity is the sum of the wells' production based on the well lift curves models computed and obtained during well testing. The reviewed Company report does not question a key factor for the losses related to the difference between the target lift curve values and actual production. This research is addressing this question as well as other factors in consultation with subject matter experts.

Other case studies obtained from the reviewed literature are listed in Table 1-1 Lost production case studies) with four business cases for production enhancement in four different studies;

Table 1-1 Lost production case studies

Case	Problem	Method	Reason
(Cuacenetl, R., 2008) On-Shore Mexico – Schlumberger	Improvement to overcome GOR caused by piping condensation.	Sustain maximum 5-6% by using many Schlumberger simulators.	Key variables are related to pipeline topography, temperature changes and velocity.
(Palen, W. and Goodwin, A., 2008) Case study North sea. 1996-2008 BP	Identified 15% lost production opportunity based on the designed process.	Gained 4% after identifying operational choke points and enhanced their interfaces.	Use of discrete simulator showed some results due to maintenance and reliability focus. It did not include lift curve or decline.
(ADMA production annual report, 2014) Case study UAE 2012-2014	Identified 15% difference between reservoir potential and production system potential.	In-house solution for oil accounting with chokes of the process chain run iterations for optimum results.	Use of Integer programming on/off is based on determined program excluding failure rates, GOR/WOR or asset availability.
(Tucker, R., Straub, T. and Feng, S., 2012) Off-shore Golf of Mexico – 2012	Identified 12% lost potential production due to asset failure and other issues (weather, etc.)	Independent consultant (ZIFF Energy Group) study on losses.	Study used data mining between 2008 and 2012 to improve predictive maintenance and reduce losses.

1.2.3 How production opportunity is lost

The production system relies on a reservoir that is pressurized enough to push the oil through the well peripherals. Any imbalance in pressure will impact the flow to the surface. Hence, well-balanced water/gas injection will sustain the lost reservoir pressure as a result of the recovered oil and gas. Likewise, the production system must be performing efficiently to sustain the process and separation to meet the production targets that are based on the designed process capacities. Any imbalance such as asset breakdown, unplanned outage, degradation in performance or unexpected operational issues can affect production targets and causes losses to the planned production. In order to compensate, operators may require changing the wells' priorities by over-producing from some wells or maximizing injection in others which impact the overall injection strategies and long term production. The balance between an efficient production system and a sustainable reservoir system can lead to minimizing lost production opportunities and consequently meeting production guidelines that are set by the shareholders and the market. Figure 1-3 Production optimization process) is used to explain the lost production opportunity.

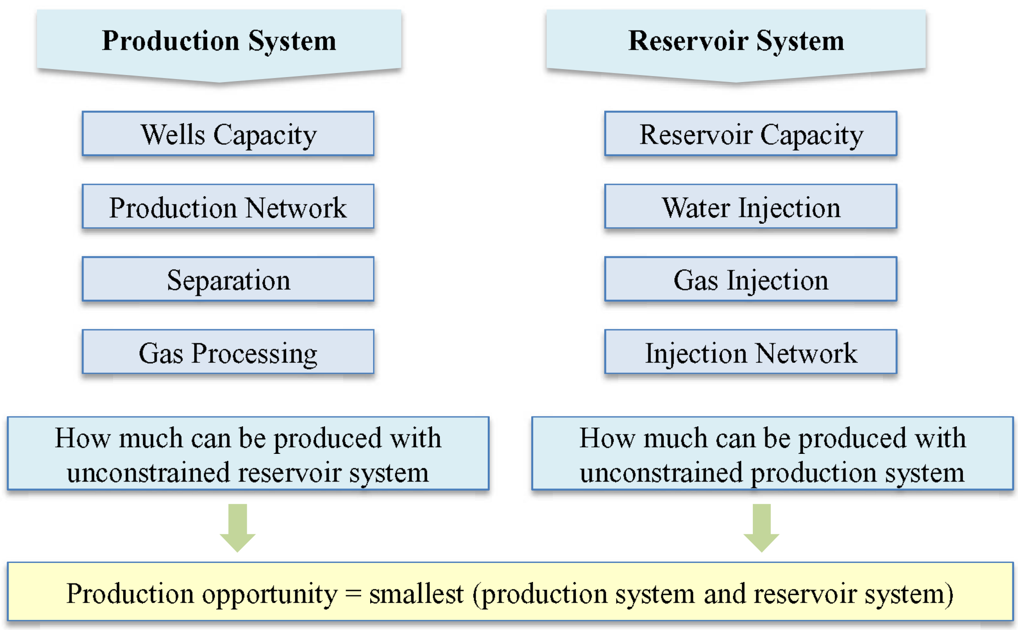


Figure 1-3 Production optimization process

The production opportunity is the smallest value between the capacities of a production system and the reservoir system. Minimizing the difference between the two systems will optimize production and result in business gains (ADMA production annual report, 2014). This difference is defined as the lost production opportunity.

The reviewed literature addresses partially the constraints of Figure 1.3 process. The study by (Alimonti, C., Sapienza, L. and Falcone, G., 2002) recognises that no research achieved the integrated model with all constraints to project the dynamic system behaviour. The answer can only be obtained if the full production stream is simulated by experts from petroleum and computer science disciplines.

1.2.4 The well lift curve and back allocation factor

The well contribution to the overall production is modeled through a lift curve formulation. This is a theoretical curve based on the inflow pressure constrained by the surface facilities. Since fluid is a mix of oil, water and gas which are commingled upstream from many production zones and wells, the computation of actual well contribution to production is a challenging one in spite of the flow measurements available at the well. Well testing is used for back allocation to balance the measured hydrocarbon production at the tank and provides proportional estimates of production from the well strings (Popa, C., Popa, A. and Cover, A. , 2004). Well testing is not done very frequently rendering the well setting value to be out of date over time and far from the recommended lift curve setting. Well testing is conducted in periods above six months while it needs to be done monthly based on (Alberta Energy Regulator, 2016). Well testing is also important for effective reservoir management, accounting for the material balance, flow assurance, and adherence to the initial design conditions. The steps involve:

- Conduct periodic well tests and obtain contents ratios, flow and pressure.
- Compute the total theoretical estimates of the field and stock tank volume for the month
- Record actual daily field volumes at wells, separators and stock tanks.
- Determine the difference between the total field theoretical and actual volumes
- Allocate the actual produced volumes and total it back to the facilities
- Allocate a corrected portion to individual wells considering well uptime and total monthly rates for the wells.
- Sum well allocated volumes to obtain volumes per formation string/zone

The results of well contributions are used to input data into the reservoir simulator for calibrating the model, understanding the flow change, volume accounting, pressure settings, well maintenance, future rework plans, re-testing, shutdowns, flow lines management and decisions on future allowable rates. The value of the research in this area is that allocations will not be based on old well test data. It will also be benefiting from the trend, as well as the computed lift curve allowed production boundaries.

1.2.5 Production dynamics factor

Production optimization involves all the stages in the process as described in (Figure 1-4 Pressure drop in production). However, on the well level, production optimization is to optimize the flow rate with considerations to Inflow Performance Relationship (IPR) and the topside effects. During the course of production, a number of stages show pressure drops in the process chain that impacts production (Mach, J., Proano, E. and Brown, K., 1979). The pressure drop is represented by the formula in (Figure 1-4 Pressure drop in production).

$$\Delta \boldsymbol{P} = \boldsymbol{P1} + \boldsymbol{P2} + \boldsymbol{P3} + \boldsymbol{P4}$$

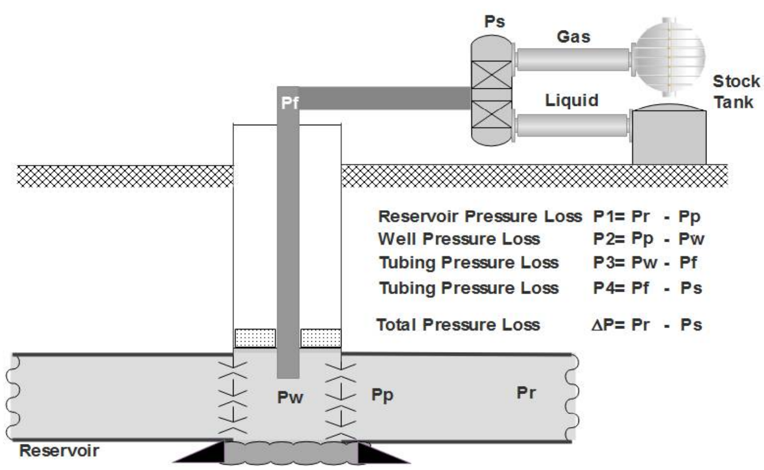


Figure 1-4 Pressure drop in production

The change in pressure impacts flow rate and production. Changes that take place in the field affect the pressure and the overall production. The process of capturing that change and reapplying it in the lift curve formulas may take several months before it is updated to produce new well settings. Hence, the delay results with a production level that is not as planned. (Note that Pp is pressure at peripherals, Pf is pressure at the field flow lines and Ps is pressure at the separator). The optimum flow rate at the well is obtained by the intersection of the inflow performance curve and tubing performance subject to the backpressure and tubing diameter Figure 1-5 Well Inflow performance relationship – (Dawe, R. , 2000)). The various PVT (pressure, volume and temperature) readings from the well, during the well testing, are fitted in a simulation model to produce the best settings for the choke valves of the wells for the whole field.

Well testing is conducted by a test separator that evaluates accurately the decision variables (flow rates, pressure, temperatures, volumes, etc.). The test is planned based on opportunity and barge availability. When the well is maintained or stimulated, the IPR gets improved due to removal of flow obstacles of wax, asphaltene, slugs, scale or uncontrollable zonal communication (Rajeev, P., Surendranathan, A.O. and Murthy, S.N., 2012). The physical separation of gas and water is translated to multiphase flow ratios that are required for the production accounting. At a well test, the theoretical production is computed by the lift curve based on the well test flow rates readings. As time elapses, changes take place to the parameters used to produce the lift curve (pressure and flow rates). Consequently, the choke setting becomes out of range and does not tally with the early production estimates.

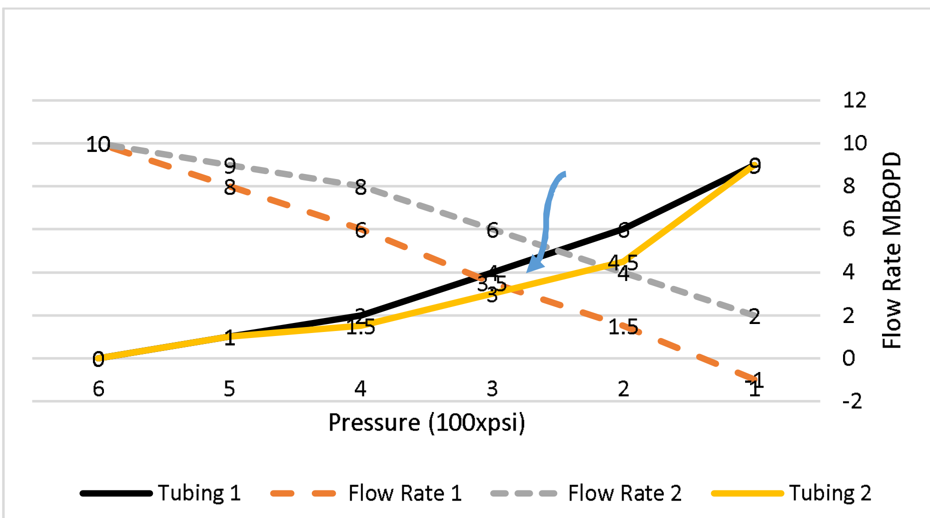


Figure 1-5 Well Inflow performance relationship – (Dawe, R. , 2000)

The intersections between the tubing performance and the well flow rate curves represents the area of an optimum setting for the production parameters used to obtain the lift curve. Although the lift curve is accounting for time changes, this is only applicable in steady state. Operational requirements which result in changes to production priorities impact the pressure. The uncertainty is due to either the well or the tubing pressure changes that can result in changes to the well output.

1.2.6 The mathematical methodology factor

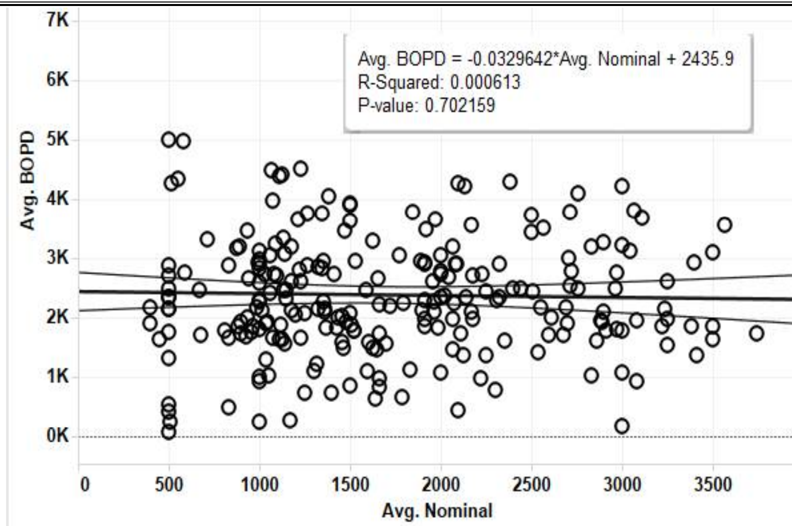
Mathematical programming is a subject of operations research that deals with formulating an industrial optimization through multivariate mathematical modelling of all variables within a set of exiting constraints. An iteration method is used until all variables are solved for and securing the maximum outcome or minimum impact on a model. An atypical linear programming (LP) example is explained in Appendix 18.

Operations research provides a number of optimization techniques for production (Hillier, F. and Lieberman, G., 1975). Linear programming and simulation are the most commonly used techniques in oil fields. The process of modeling the real process through formulation is lengthy and complex. A small number of wells are easier to manage is separable programming. However, when the number of wells is too large to formulate with possible flow interaction between the wells, the model becomes irrelevant by the time production happens (Saputelli, L., Nikolaou, M. and Economides, M., 2006). In this respect, the speedy delivery of a model is a key factor for having it followed. For this reason, an interactive dynamic simulator becomes the most viable option.

This modelling is very effective when the approach is deterministic using a set of equations of equalities or inequalities. Oil field models need to be dynamic and involve probability or unexpected behavior due to random events or a dynamic situation where changes occur subject to field conditions. Hence, simulation becomes a better approach than formulating equations to solve the model or formulate trends of historical records for predictions configuration in the system (Vangheluwe, H., 2001) .

1.2.7 The production performance history factor

The production data was correlated against the planned production targets. The graphs below show very poor correlation between the planned and what is actually produced for the elapsed five year period (ADMA production annual report, 2014).



Caption
Average of planned Nominal vs. actual BOPD. Details are shown for Well/Str.
R-square = 0.000613. R=0.0247.

Figure 1-6 Correlation of planned and actual production

The R-square value of 0.000613 and R-Factor of 0.025 depicts the absence of correlation between allowable and actual production values as obtained on Figure 1-6 Correlation of planned and actual production).

1.3 The business problem

The reviewed literature in chapter two and the analyzed data which demonstrated poor correlation between planned and actual production revealed that:

- There is lost production as a result of not meeting the reservoir potential
- Therefore, a portion of the profit is lost and the production cost per barrel is affected

1.4 The research objective

The objectives in the research are:

Objective number 1: To identify the variables that can be used to enhance offshore oil and gas production in the UAE.

Objective number 2: To develop a simulation model to forecast offshore oil and gas production in the UAE using decision variables behavior.

The above objectives aim to enhance production forecasts quantitatively. It also aims to develop a simulation scenario for field development and testing of production results

A simulation model is capable of conducting many new scenarios. For example, what if a new resource is added, or if a shutdown is planned or a production shipment is delayed. These scenarios can be tested without impacting the real world.

1.5 The research plan and simulation approach

The two objectives are handled in two methods. The first objective method is handled by studying the references and literature related to the key decision variables. This is followed by consultation with subject matter experts and opinion polls (through a questionnaire) of production analysts and operators to identify all variables that contribute to production modeling.

The second objective method is related to the execution of the study by collecting related data so as to produce a correlation analysis and obtain data trends for the decision variables. The identified variables and assets constraints capacities are used to develop a simulation model for a number of scenarios to be compared against the results of the existing model. Further, an investment strategy is formulated to sustain production based on the demand curve. The methodology is briefed in chapter 3.1

Simulation has vast areas of implementations. Continuous and discrete simulators have been used to study the effects of changes on a computer model before applying the changes in the real system. Oil and gas simulation is traditionally based on continuous simulators using differential equations to solve thermodynamics phase behaviour or using the Monte Carlo geophysical modelling to visualise the reservoir model. These are built with a special purpose to do a specific task while discrete event simulators can be tailored to model the production flow of a petroleum process (Woo, J.H., Ho Nam, J. and HeeKo, K., 2014).

The general purpose discrete simulators are designed to be used across many applications and industries such as factory modelling, production modelling and assembly lines modelling. General purpose simulators rely on probabilities and profiles of events that are generated to achieve a certain task in the model. The models are time based and require the setting time needed to complete a task and setting the random creation of events that represent industrial processes. The random events can be based on probability distribution or a polynomial of certain degree. Most recently, discrete simulators are being used for continuous flow of products like petrochemicals and pharmaceuticals (DNVGL RAM Discrete Simulator, 2016).

The general purpose simulators can be tailored to model a real process in the real world to analyse the effect of the objects' changes (linear or nonlinear) on the model only, prior to modifying the physical plant.

This research is using a general purpose simulator because it can be configured with linear and nonlinear trends as well as random and stochastic (Jensen, P.A., 2004). It can accept models of the real process and generate production entries on the basis of probabilities and formulas obtained from the used objects such as reservoir model, well model, asset availability model or probability based breakdown event – Ref. Operations Research (Hillier, F. and Lieberman, G., 1975).

1.6 Structure of thesis

The thesis structure is briefed in (Figure 1-7 The chapters' structure). Chapters 1 and 2 shed light on the background and literature review timeline. The review identified the business problem and the various models used to control the problem. Chapters 3 and 4 define and execute the methodology. Chapter 5 adds model analysis to define a development strategy for production sustainability.

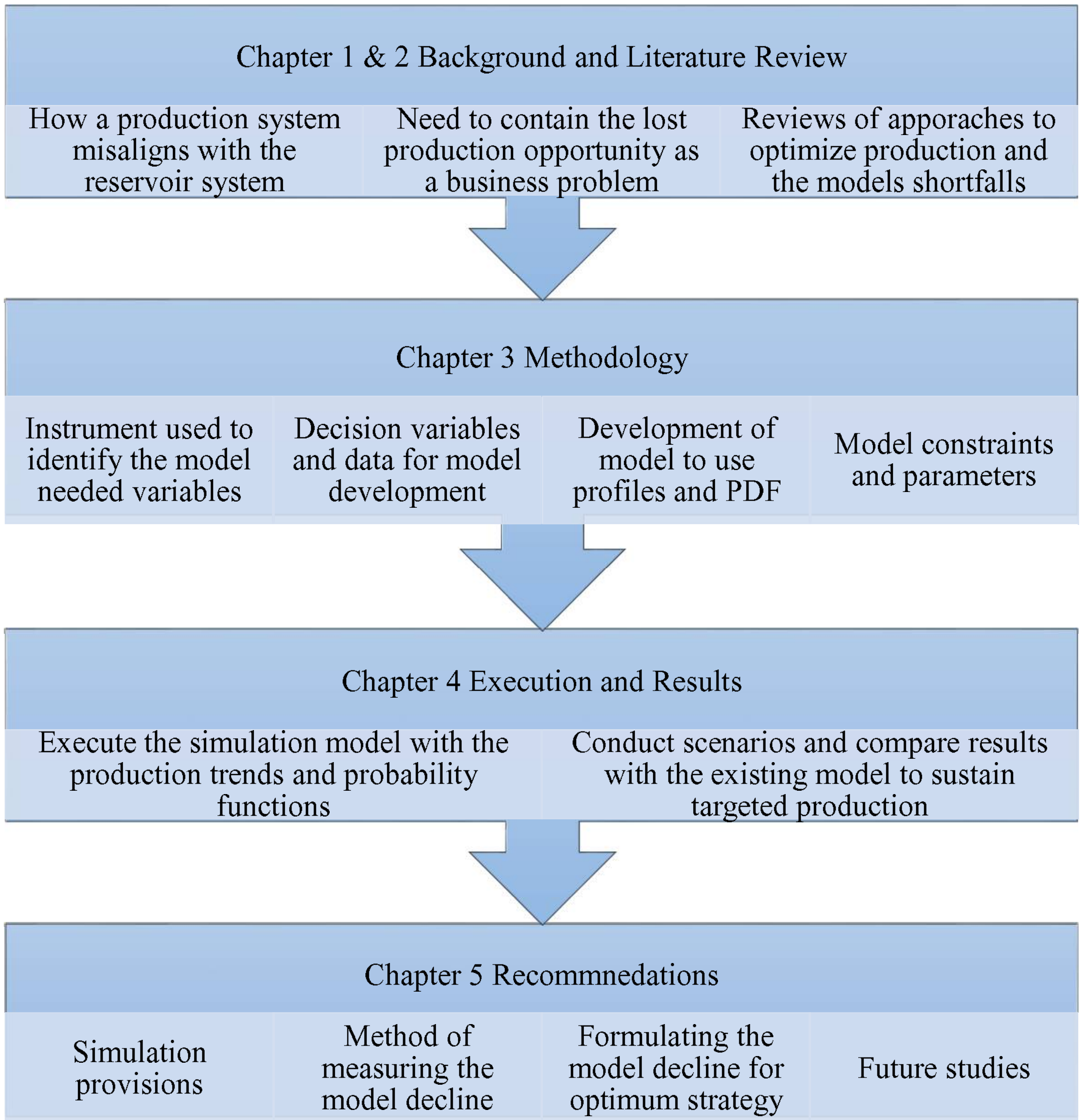


Figure 1-7 The chapters' structure

1.7 Chapter conclusions

This chapter presents the business problem of using outdated well models for production planning which impacts the total planned production by up to 15%. The production systems' dynamics and changes to pressure in the process chain require quicker reactions for measuring key variables and using them in a fast manner for production settings. The referenced literature reaffirms the field dynamics and the gap between the available information and the reality of the field. The subject of production and reservoir constraints is briefly explained along with highlighting the gaps between capacities and what is actually produced. The difference between the production and the reservoir systems' capabilities need to be addressed and minimized. The need for an updated lift curve in reference to pressure changes is one factor that impacts the overall production. The absence of frequent well testing makes the production curve (lift curve) obsolete during the periods away from the test time due to changes in the condition of the well and the production system (Saputelli, L. A., 2003). The chapter discusses the production process, the process of well contribution measurement and how it is used in planning the targeted production.

The case studies' business problem suggests the question of the decision variables related to probabilistic events and questions the existing methodologies that achieved limited improvements.

The chapter identifies the business problem of missed production opportunities within the existing designed plant capacity based on the reviewed case studies. Two main optimization methods are used. These are mathematical programming and simulation. The achievements and limitations of mathematical programming is discussed further in the next chapter along with existing simulation techniques of specialized fit for purpose simulators.