A SYSTEMATIC APPROACH TO OFFSHORE FIELDS DEVELOPMENT

USING AN INTEGRATED WORKFLOW

A Thesis

by

MARI HUSSAIN M. ALQAHTANI

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2010

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Gioia Falcone
Committee Members,	Catalin Teodoriu
	Mahmoud El-Halwagi
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ABSTRACT

A Systematic Approach to Offshore Fields Development Using an Integrated Workflow.

(August 2010)

Mari Hussain M. Alqahtani, B.En., West Virginia University

Chair of Advisory Committee: Dr. Gioia Falcone

I present a systematic method to primary develop existing black oil fields. This method uses integrated reservoir development workflow (IRDW) that relies on integrated asset model (IAM). Developing any existing field means providing a plan that generally serves the development goal(s) specified by management. However, serving the development goal(s) by itself does not guarantee an optimal development plan. Plans that do not rely on an IAM are less accurate. Some plans do not include economics in their evaluation. Such plans are technically accepted but usually impractical or unprofitable. Plans that only evaluate the field based on current, or short-term, conditions are potential candidates for bottlenecks, thus costly reevaluations. In addition, plans that do not consider all suitable options are misleading and have no room for optimization. Finally, some plans are based on “rules of thumb,” ease of operations, or operators’ preference, not on technical evaluation. These plans mostly lower long-term profitability and cause further production problems. To overcome these problems, project management must form a multidisciplinary team that uses the IRDW. The IRDW guides the team through its phases, stages, and steps to selecting the optimal development plan. The IAM consists of geological, reservoir, wellbore, facility, and economic models. The IRDW dictates building an IAM for the base (do nothing) case and for each development plan. The team must evaluate each scenario over the lifetime of the field, or over the timeframe the management specifies. Net present value (NPV) and Present value ratio (PVR) for all options are compared to the base case and against each other. The optimum development plan is the one that have the highest NPV and highest PVR. The results of the research showed that forming a multidisciplinary team and using a LDFC saves time and it guarantees selecting the optimal development plan if all applicable development options are considered.

DEDICATION

I dedicate this work to the love of my life, my soul-mate, and my wife, Rawan Saad Alqahtani. I could not have accomplished such a major goal without your love, support, selflessness, and sacrifice.

I also dedicate this work to my beloved daughter, Fairooz Mari Alqahtani, and my beloved father-in-law, *Shaikh* Saad son of *Shaikh* Hadi Aal Saad Alqahtani.

ACKNOWLEDGEMENTS

All praise due to Allah almighty, the most compassionate and the most merciful. Thank you Allah for giving me the knowledge, the strength, and the patience to do this work.

I would like to thank my committee chair, Dr. Falcone, and my committee members, Dr. Teodoriu, and Dr. El-Halwagi, for their guidance and support throughout the course of this research.

Thanks also go to my friends and colleagues and the department faculty and staff for making my time at Texas A&M University a great experience.

NOMENCLATURE

B/CS	Bryan/College Station
Bg	gas formation volume factor
Bo	oil formation volume factor
Bw	water formation volume factor
FOPR	field oil production rate
FPR	field pressure
FWCT	field water cut
FWIR	field water injection rate
FWPR	field water production rate
IAM	integrated asset model
IPR	inflow performance relationship
IRD	integrated reservoir development
IRDW	integrated reservoir development workflow
J	productivity index
k	absolute permeability
k_{rg}	relative permeability to gas
k_{ro}	relative permeability to oil
k_{rw}	relative permeability to water
NPV	net present value
OP	oil producer

P_c	capillary pressure
PI	productivity index
PVR	present value ratio
scf	standard cubic foot
S_{girr}	irreducible gas saturation
S_{oirr}	irreducible oil saturation
STB	stock tank barrel
S_{wirr}	irreducible water saturation
VLP	vertical lift performance
WD	water disposal well
WI	water injector for pressure support
WS	water supply well
μ	viscosity
φ	porosity

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CHAPTER I

INTRODUCTION

A reservoir's life begins with exploration and discovery and it ends with abandonment. Between the beginning and the end there is reservoir delineation; field development; and production by primary, secondary, and tertiary means (**Fig. 1.1**) (Satter et al., 1994). My study will focus on primary development of an existing offshore oil field using IRDW. IRDW depends on integrated reservoir development (IRD), which is a development oriented version of integrated reservoir management. The Crisman institute at Texas A&M University is a pioneer in integrated reservoir management. It published the first manual of modern reservoir management that proposed an integrated approach (Satter et al., 1994).

Before introducing the IRDW, what it does, and its' benefits, I find it useful to introduce its two pillars: the IRD team and the IAM.

This thesis follows the style of *SPE Journal*.

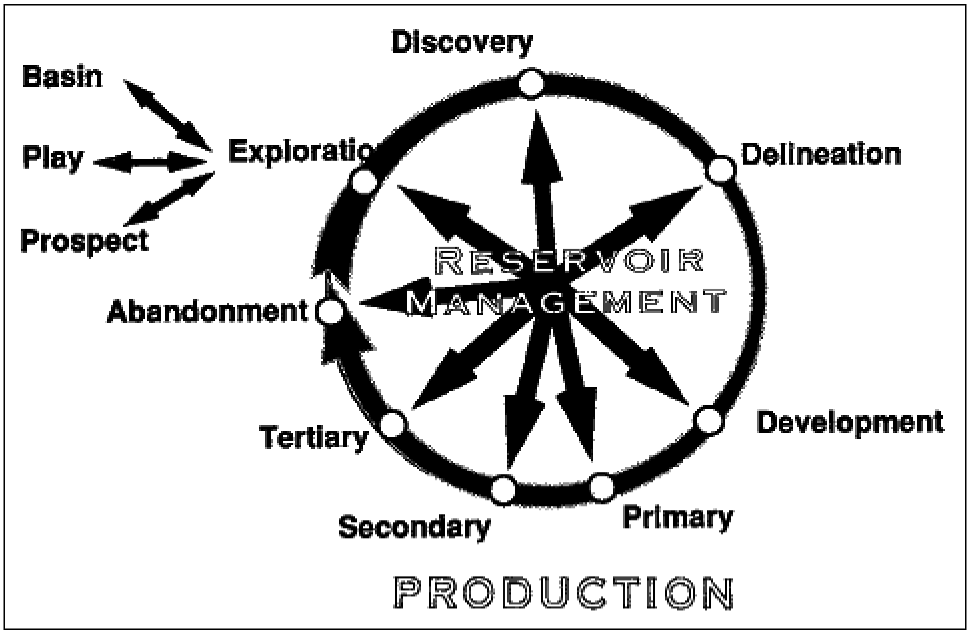

Fig. 1.1–Reservoir life cycle and reservoir management (Satter et al., 1994)

1.1 Forming an IRD team

The IRD team is a multidisciplinary team that consists of all involved personnel, petroleum engineers, geologists, geophysicists, and all other needed engineering or scientific disciplines. This teams' goal is to find the most economical development plan for their field of choice. In other words, the IRD team is the same team of the integrated reservoir management (IRM) team, but with a single task to perform; filed development.

1.2 Using an IAM

The IAM is a project evaluation tool (or a model) that consists of different independent sub-tools (or sub-models). It consists of a reservoir simulator, wellbore simulator, facilities simulator, and an economic evaluator. All those different parts are integrated in the IAM to form a single interaction point between the IRD team and all the sub-tools. The concept of integrating different field models to produce an accurate development plan is not a new concept. Its humble beginnings date back to late 1970's and early 1980's (Sullivan, 1981). However, available software and computer abilities at that time prevented simultaneous integration as known today. In addition, the IAM as defined earlier in this section dates back to mid 1990's (Dingeman et al., 1995; Heinemann et al., 1997).

The IAM is more accurate in simulating the actual field performance, because it deals with all system components simultaneously in real-time. Therefore, it has the ability to identify future bottlenecks in the system. This enables advanced engineering analysis and resourceful decision making (Moitra et al., 2007). Thus, it leads to selecting the optimum development plan that introduces the right development option at the right time (Arias et al., 2007; Moitra et al., 2007; Serbini et al., 2009; Ursini et al., 2010). Investing in the right sized facilities during the development stage is an example of the benefits that result from forecasting bottlenecks (Serbini et al., 2009). Once integrated, the IAM interacts with the user as a single program. Therefore, it really saves time because the user does not have to deal with 2 to 4 programs at the same time, like the traditional method. The IAM abilities are limited only by the capabilities of the subprograms and the computational speed of the computer(s) used (Heinemann et al., 1997).

Ideally, the IAM should have an economic software integrated into it or built in it. However, sometimes this feature is not available. If an economic evaluation software is not available, the integration continues between the available models. The model that results from integrating the reservoir, wellbore, and facilities model without an integrated economical model is still considered an IAM. However, a thorough economical evaluation has to be done afterwards.

Any production system (**Fig. 1.2**) must have the following three elements: the reservoir; the well, which includes the bottomhole and the wellhead; and the surface facilities, which include the gathering network, the separation system, and the storage facilities (Economides et al., 1993). This means that any well cannot produce with a bottleneck in any component of the production system. The series of pressure drops that corresponds to every part of the system (Eq. 1.1) dictates the oil path (Economides et al., 1993). It all starts in the reservoir, where fluids in pores move through the permeable rock toward the lower pressure perforations at the well. The well, then, receives production from the reservoir at the sand face, and lifts and delivers it to the surface facilities at the wellhead. Finally, production goes from the wellhead toward the separator in horizontal lines. In technical terms, the system performance depends on the inflow performance relationship (IPR), the well vertical lift performance (VLP), and the facilities network performance (Economides et al., 1993).

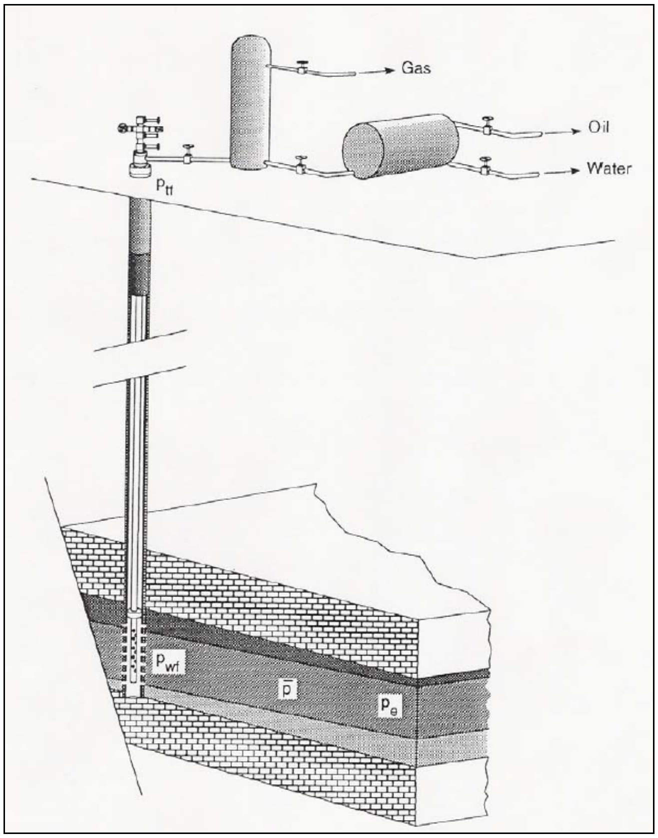

Fig. 1.2–A production system (Economides et al., 1993)

$\Delta p = \Delta p_{res} + \Delta p_s + \Delta p_{comp} + \Delta p_{tub} + \Delta p_{hor}$ ……………………………………(eq.1.1)

where

$\Delta p = \bar{p} - p_{sep}$

$\bar{p}$: average reservoir pressure

p_{sep}: separator pressure

Δp_{res}: pressure drop in the reservoir

Δp_s: pressure drop due to skin

Δp_{comp}: pressure drop due to completion type

Δp_{tub}: pressure drop in the tubing

Δp_{hor}: pressure drop in the horizontal lines

1.2.1 IPR

IPR is a representation of production rate as a function of bottomhole pressure (Economides et al., 1993). For a single phase incompressible oil, the IPR curve forms a straight line with a slope equals to one over the productivity index (J) (**Fig. 1.3**). This straight line represents equation 1.2. Undersaturated oil flow rate (qo) is calculated for transient, steady-state, and pseudo-steady-state flows by equations 1.3, 1.4, and 1.5 respectively, modified from (Economides et al., 1993).

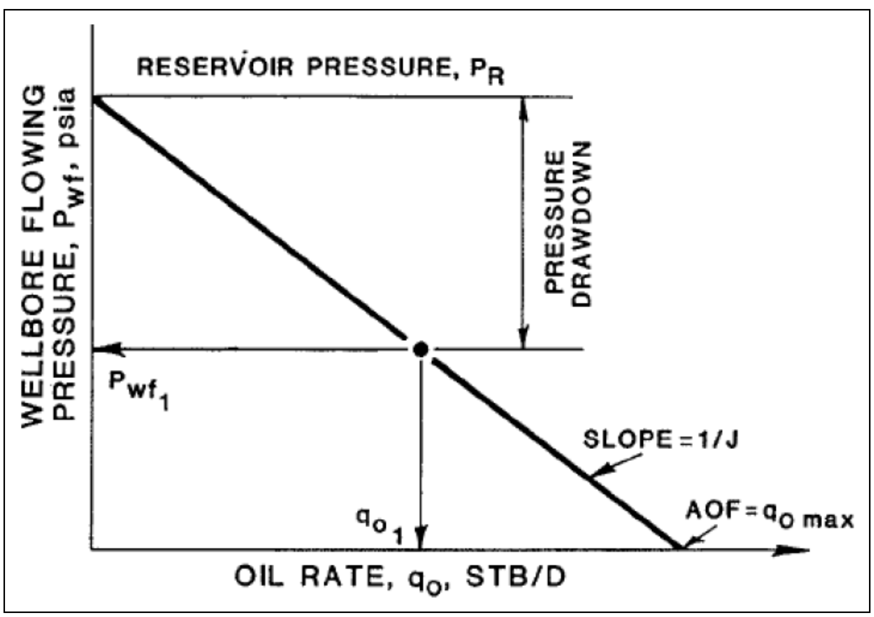

Fig. 1.3–Typical single phase oil IPR curve*

*PETE 618 course notes, Fall 2008

$q_o = J(p_R - p_{wf})$………………………………………………………………..(eq.1.2)

where $p_R \approx p_e$

$$q = \frac{kh(p_i - p_{wf})}{162.6B\mu}\left(\log t + \log\frac{k}{\phi\mu c_t r_w^{\ 2}} - 3.23 + 0.87S\right)^{-1} \text{ ……………………………(eq.1.3)}$$

$$q = \frac{kh(p_e - p_{wf})}{141.2B\mu\left(\ln\frac{r_e}{r_w} + S\right)} \text{ ………………………………………………….............(eq.1.4)}$$

$$q = \frac{kh(\overline{p} - p_{wf})}{141.2B\mu\left(\ln\frac{0.472r_e}{r_w} + S\right)} \text{ ……………………………………………………..(eq.1.5)}$$

When p_{wf} becomes lower that the p_b, gas evolves in the reservoir causing the flow to be a two-phase flow. This causes the nonlinear behavior in the IPR curve as shown in **Fig. 1.4**. Equation 1.6 represents the general two-phase IPR. Furthermore, equations 1.7 and 1.8 represent the two-phase Vogel pseudo-steady state maximum oil flow rate equation and oil flow rate equation respectively.

$$\frac{q_o}{q_{o\,max}} = 1 - (1 - V)\left(\frac{p_{wf}}{p_R}\right) - V\left(\frac{p_{wf}}{p_R}\right)^2 \text{ ………………………………………..(eq.1.6)}$$

If

V = 0 → straight-line IPR,

V = 0.8 → Vogel equation

and

V = 1 → Fetkovich equation

$$q_{o,\max} = \left(\frac{1}{1.8}\right)\frac{k_o h\overline{p}}{141.2B_o\mu_o[\ln(0.472r_e/r_w) + S]} \text{ …………………………….............(eq.1.7)}$$

$$q_o = \frac{k_o h \overline{p}\left[1 - 0.2\left(p_{wf}/\overline{p}\right) - 0.8\left(p_{wf}/\overline{p}\right)^2\right]}{254.2 B_o \mu_o \left[\ln(0.472 r_e/r_w) + S\right]} \quad \text{(eq.1.8)}$$

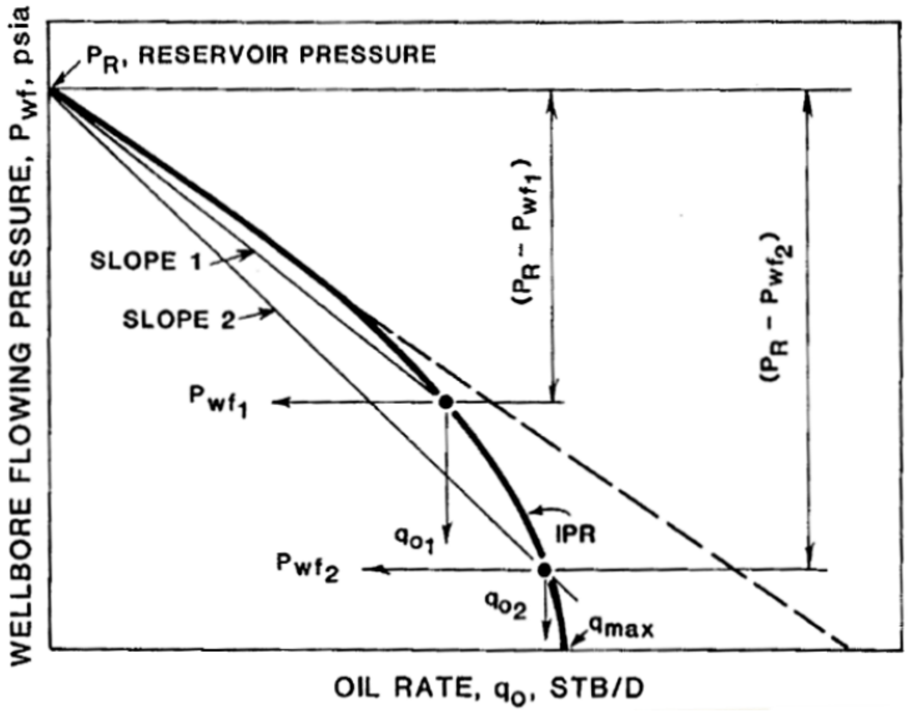

Fig. 1.4–Typical two-phase IPR curve*

1.2.2 VLP

Wellbore flow performance depends on many components such as: the flow geometry (single or two phase flow; pipe or annular flow; or vertical, horizontal, or in between flow), the fluid properties (PVT and rheological behaviors), and the flow rates (laminar or turbulent flow). The mechanical energy balance equation (Economides et al., 1993)

*PETE 618 course notes, Fall 2008

governs fluid flow in the wellbore (Eq.1.9). However, for a single phase liquid flow (constant ρ) and assuming no shaft work applied, the mechanical energy balance equation is integrated to from equation 1.10 below (Economides et al., 1993).

$$\frac{dp}{\rho} + \frac{udu}{g_c} + \frac{g}{g_c}dz + \frac{2f_f u^2\, dL}{g_c D} + dW_s = 0 \quad \text{(eq.1.9)}$$

$$\Delta p = p_1 - p_2 = \frac{g}{g_c}\rho\Delta z + \frac{\rho}{2g_c}\Delta u^2 + \frac{2f_f\rho u^2 L}{g_c D} \quad \text{(eq.1.10)}$$

Equation 1.10 states that the pressure drop associated with the fluid movement from point 1 to point 2 equals the summation of the pressure drop due to potential energy (Eq.1.11), the pressure drop due to kinetic energy (Eq.1.12) (Economides et al., 1993), and the pressure drop due to friction (Eq.1.13) (Economides et al., 1993).

$$\Delta p_{PE} = \frac{g}{g_c}\rho\Delta z \quad \text{(eq.1.11)}$$

$$\Delta p_{KE} = \frac{\rho}{2g_c}\Delta u^2 \quad \text{(eq.1.12)}$$

$$\Delta p_F = \frac{2f_f\rho u^2 L}{g_c D} \quad \text{(eq.1.13)}$$

The pressure drop due to potential energy is further expressed as equation 1.14 (Economides et al., 1993), since equation 1.15 defines Δz for pipe with a length L, and a horizontal deviation angle θ.

$$\Delta p_{PE} = \frac{g}{g_c}\rho L \sin\theta \quad \text{(eq.1.14)}$$

$$\Delta z = z_2 - z_1 = L\sin\theta \quad \text{(eq.1.15)}$$

The pressure drop due to kinetic energy change is further expressed as equation 1.16 (Economides et al., 1993). For an incompressible fluid, the velocity only changes if pipe diameter changes, because volumetric flow rate does not change (Eq.1.17, 1.18, and 1.19) (Economides et al., 1993). Therefore, the kinetic energy pressure drop due to pipe diameter change is expressed in equation 1.20 (Economides et al., 1993).

$$\Delta p_{KE} = \frac{\rho}{2g_c}({u^2}_2 - {u^2}_1) \quad \text{(eq.1.16)}$$

$$u = \frac{q}{A} \quad \text{(eq.1.17)}$$

$$A = \frac{\pi D^2}{4} \quad \text{(eq.1.18)}$$

$$u = \frac{4q}{\pi D^2} \quad \text{(eq.1.19)}$$

$$\Delta p_{KE} = \frac{8\rho q^2}{\pi^2 g_c}\left(\frac{1}{{D^4}_2} - \frac{1}{{D^4}_1}\right) \quad \text{(eq.1.20)}$$

In the pressure drop due to friction, the Fanning friction factor is expressed in terms of Reynolds number in equation 1.21 (Economides et al., 1993). However, in turbulent flow the Fanning friction factor depends on both the Reynolds number and on relative pipe roughness, ε (Eq.1.22) (Economides et al., 1993). Please refer to **Fig. 1.5** for relative roughness of common piping material. The most common way to obtain the Fanning friction factor is from the Moody friction factor chart (**Fig. 1.6**), which is based on equation 1.23 (Economides et al., 1993). However, equation 1.24 represents an explicit equation for the Fanning friction factor (Economides et al., 1993).

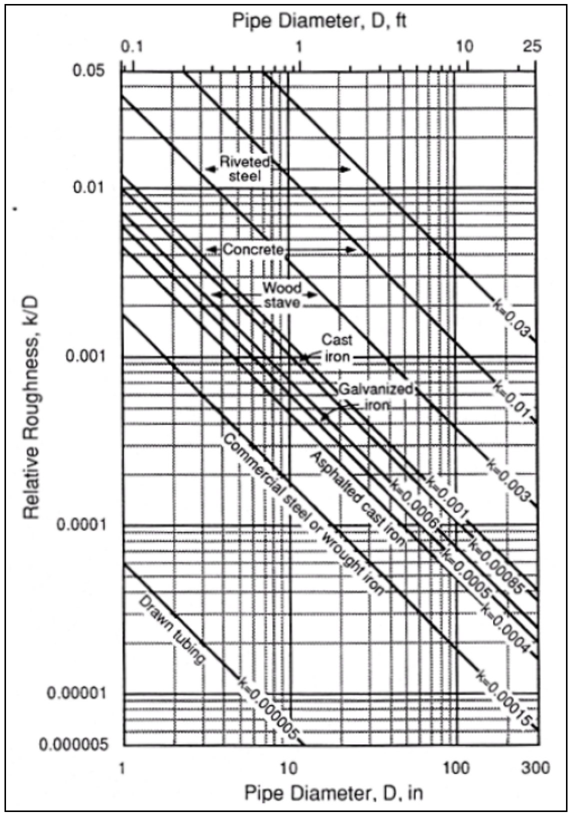

Fig. 1.5–Relative roughness of common piping material (Economides et al., 1993)

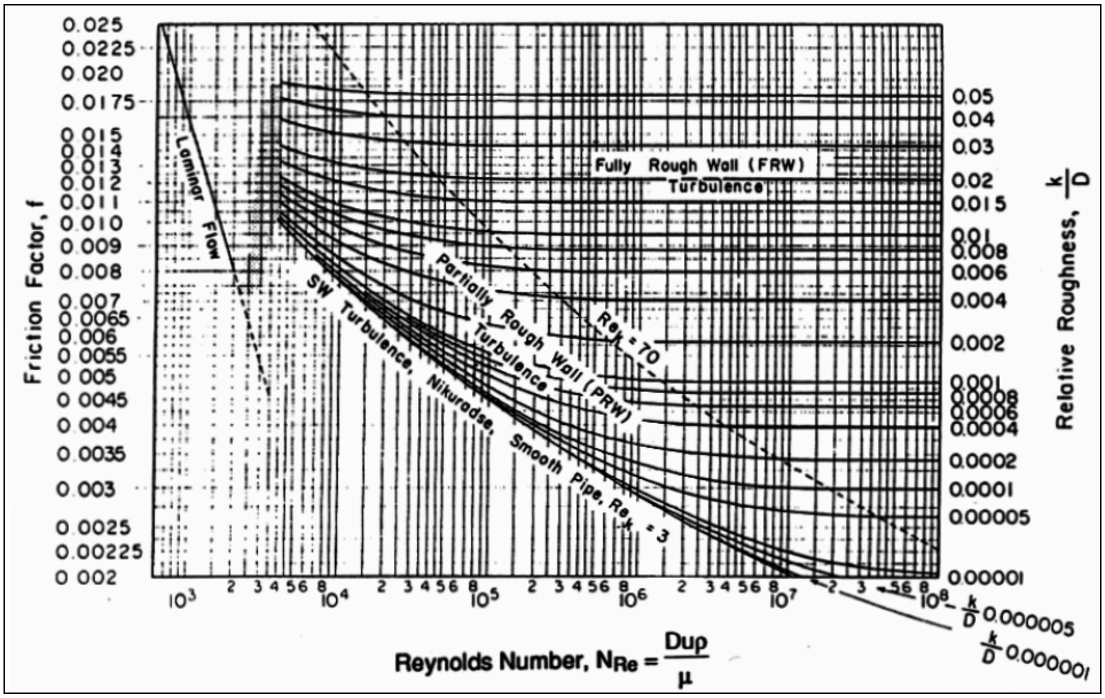

Fig. 1.6–Moody friction factor diagram (Economides et al., 1993)

$$f_f = \frac{16}{N_{Re}} \quad \text{(eq.1.21)}$$

$$\epsilon = \frac{k}{D} \quad \text{(eq.1.22)}$$

where k is the protrusions length on the pipe wall

$$\frac{1}{\sqrt{f_f}} = -4\log\left(\frac{\epsilon}{3.7065} + \frac{1.2613}{N_{Re}\sqrt{f_f}}\right) \quad \text{(eq.1.23)}$$

$$\frac{1}{\sqrt{f_f}} = -4\log\left\{\frac{\epsilon}{3.7065} - \frac{5.0452}{N_{Re}}\log\left[\frac{\epsilon^{1.1098}}{2.8257} + \left(\frac{7.149}{N_{Re}}\right)^{0.8981}\right]\right\} \quad \text{(eq.1.24)}$$

Most fluid flow in wellbores happens in multiphase, especially if wellhead pressure is falls below the bubble point pressure. One of the most important factors affecting two-phase flow in wellbore is the two phases distribution, which is known as holdup. Equations 1.25 and 1.26 define hold up for the denser (β) and the lighter (α) phases respectively, and equation 1.27 relates them together (Economides et al., 1993). The input fraction (λ) of each phase is another parameter that describes two-phase flow (Eq.1.28 and 1.29) (Economides et al., 1993). In addition, slip velocity (u_s) is used as another measure of holdup (Eq.1.30) (Economides et al., 1993), which is the difference between the two phases average velocities. Equations 1.31 and 1.32 define superficial velocity and equations 1.33 and 1.34 show the relation between superficial velocity and average in-situ velocity. Therefore, equation 1.30 becomes equation 1.35 (Economides et al., 1993).

$y_\beta = \frac{V_\beta}{V}$ ……………………………………………………………………..(eq.1.25)

where V is the pipe volume and Vβ is the volume of the denser phase

$y_\alpha = \frac{V_\alpha}{V}$ ……………………………………………………………………..(eq.1.26)

where Vα is the volume of the lighter phase

$y_\alpha = 1 - y_\beta$……………………………………………………………….(eq.1.27)

$\lambda_\beta = \frac{q_\beta}{q_\alpha + q_\beta}$ ...……………………………………………………………..(eq.1.28)

$\lambda_\alpha = 1 - \lambda_\beta$ ………..……………….…………………………………………(eq.1.29)

$u_s = \bar{u}_\alpha - \bar{u}_\beta$ …..…………………………....…………………………..(eq.1.30)

$u_{s\alpha} = \frac{q_\alpha}{A}$………………………………………………………………….(eq.1.31)

$u_{s\beta} = \frac{q_\beta}{A}$ ……...…………………………....……………………………….(eq.1.32)

$\bar{u}_\alpha = \frac{u_{s\alpha}}{y_\alpha}$ ……………..……………………..…………………………………….(eq.1.33)

$\bar{u}_\beta = \frac{u_{s\beta}}{y_\beta}$…………………………..……...……………………………………(eq.1.34)

$$u_s = \frac{1}{A}\left(\frac{q_\alpha}{1-y_\beta} - \frac{q_\beta}{y_\beta}\right) \text{..(eq.1.35)}$$

There are different vertical flow correlations with different definitions of the two-phase viscosity, average velocity, and friction factor. Each correlation relies on its own set of vertical flow regimes to make those calculations in order to obtain the pressure gradient (Economides et al., 1993). Identifying those correlations is beyond the scope of this section. Calculating the pressure drop is repeated for every flow rate anticipated.

To include the pressure drop in the surface facilities, equation 1.9 and 1.10 have to be applied for horizontal flow conditions. For a horizontal flow equation 1.10 becomes 1.36 (Economides et al., 1993), assuming a fixed diameter and no elevation change potential and kinetic energy pressure drops are equal to zero. Similar to vertical two-phase flow, horizontal flow has its own set of correlations to calculate Δp. Each correlations has its own horizontal flow regimes too (Economides et al., 1993).

$$\Delta p = p_1 - p_2 = \frac{2 f_f \rho u^2 L}{g_c D} \text{..(eq.1.36)}$$

The VLP curves in the IAM reflect a Δp that covers the bottomhole pressure all the way to the separator. In other words, both vertical and horizontal system pressure drops are incorporated in a single VLP table. **Fig. 1.7** represents a typical VLP curve.

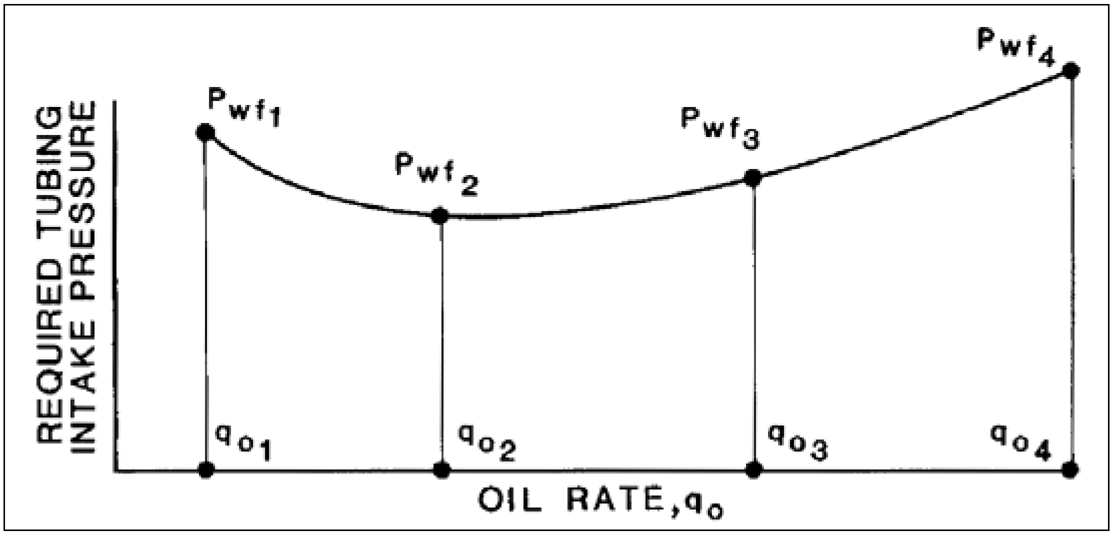

Fig. 1.7–A typical VLP curve*

1.2.3 Integration

In order to have a fluid flow from the reservoir to the final destination in the surface facilities, the reservoir needs to be able to deliver the fluids to the bottomhole and at the same time the well needs to be able to deliver the fluids it gets from the reservoir to the surface facilities. In technical terms, the IPR and the VLP curves have to agree on the point that solves them both, a point of natural flow (**Fig. 1.8**). The same concepts is applied in the IAM, where the reservoir model continuously provides the IPR, the wellbore and facilities models continuously provide the VLP, and the overall controller simultaneously finds the point of natural flow. The IAM does this process for each and every well in its system. Thus, finds the most accurate flow rates and pressure drops.

* PETE-618 Fall 08 course notes

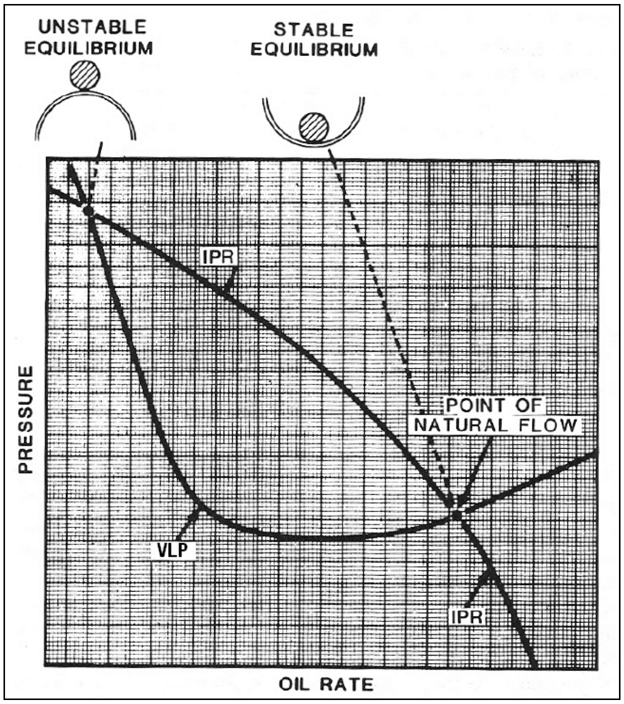

Fig. 1.8–Point of natural flow, modified from source*

A key feature of the IAM is its ability to respond to changes in the IPR (**Fig. 1.9**), VLP (**Fig. 1.10**), or both (**Fig. 1.11**).

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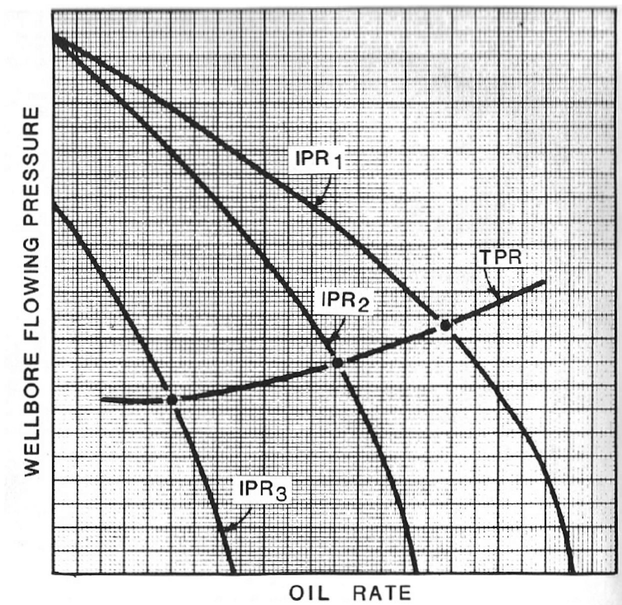

Fig. 1.9–Total system with changing IPR, TPR = VLP*

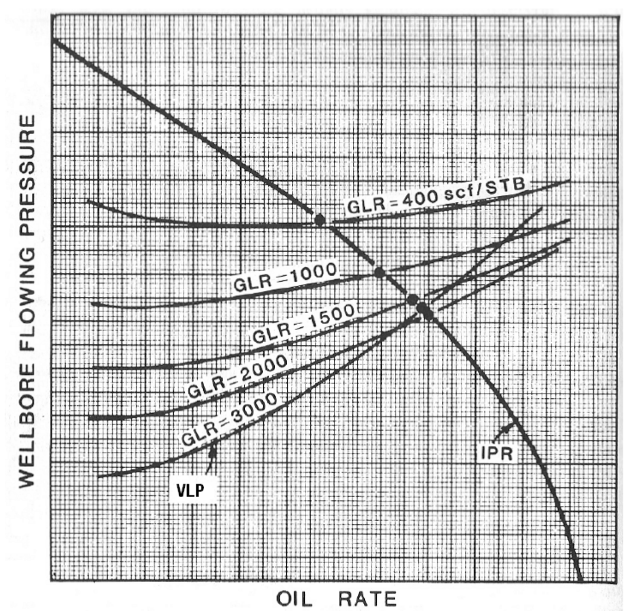

Fig. 1.10–Different VLP curves associated with different GLR, modified from source*

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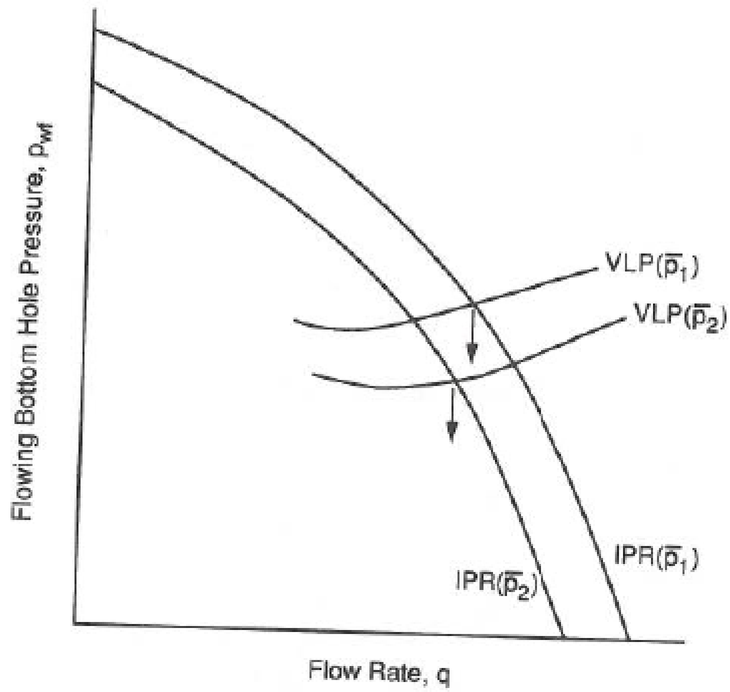

Fig. 1.11–A total system with changing IPR and VLP (Economides et al., 1993)

1.3 The IRDW

The IRDW is a systematic way that leads to selecting the optimal primary development plan (and optimal development goal if applicable). This workflow I am proposing does not represent a new concept to reservoir development and it is not the only workflow that can lead to the optimum development plan. However, this workflow represents a roadmap that leads to optimum field primary development if followed correctly. The need to developing such a workflow comes from noticeable improper development plan selection processes worldwide, both in the past and nowadays (Clegg et al., 1993; Dingeman et al., 1995; Khedr et al., 2009; Takacs, 2009). In addition, the development concept and evaluation tool (the IRD and the IAM) have been available for a while and their importance have been recognized (Sullivan, 1981; Satter et al., 1994; Dingeman et al., 1995; Thakur, 1996), yet they were not implemented. Thus, I realized that the need is for an effective workflow that is based on the IRD and uses IAM to be a systematic way that leads the IRD team to the optimum development plan. The IRDW requires forming an IRD team to follow its steps and perform the development planning. In addition, the IRDW requires the team to use an IAM, or build it by integrating suitable commercial software models.

Starting with a specific development goal in mind, the IRDW leads the IRD team to select all applicable development options. Then it leads the team to propose a development plan for each development option and to refine and optimize each development plan using IAM. Finally, the optimal development plan for each development goal is selected among all others using the IAM. The IRDW consists of 3 main phases and 7 stages in total. Perhaps the most important stage of the IRDW is the data analysis stage, because it the one that specifies applicable options and suitable evaluation tools. In addition, when an IRD team uses the IRDW it would select the optimal development plan in a timely manner. I will describe how this IRDW works and the benefits associated with it in Chapter II.

Ideally integrated reservoir management involves all aspects of evaluation. However, that is not always practical, based on the size of the development, the timeframe, the available personnel, and the available data. Missing an element of the integrated process does not justify dropping the integrated reservoir management concept. Modern reservoir management can still be applied regardless of how comprehensive the evaluation is. (Satter et al., 1994) states that “while a comprehensive program for reservoir management is highly desirable, every reservoir may not warrant such a detailed program because of cost-effectiveness. However, the keys to success are to have a management program (comprehensive or not) and implement it from the start.” My evaluation is an example of performing an integrated reservoir management with a lower than ideal level of available analog field data.

Development planning is an investment in money and time. Planning time and cost is the lowest when compared to the actual project life, but it is far more important and critical. For example, well planning cost could be as low as 0.1% of the well cost (Mitchell, 2006). Proper planning is fundamental to successful project execution. Unfortunately, sometimes proper planning is not executed. Amazingly, the motivation to such an act is to save development planning time, cost, or both. (Mitchell, 2006) states that if hydrocarbon well planning is sacrificed, the consequence “is a final well cost that exceeds the amount required to drill the well if proper planning had been exercised.” Therefore, it is far more important to invest our money and time to increase our chances of getting an optimal development plan from the beginning. In fact, that is the goal the IRDW aspires to achieve.

The traditional approach for field development treats different models as separate entities. Each model provides boundary conditions and/or gives approximate constraints to the other model through manual data entry. This manual data entry is impractical because it requires frequent updates and it is time consuming too. Consequently, the top-hole pressure is held constant for long periods of time. Unfortunately, this traditional approach lacks the ability to model the overall system interaction and response to new conditions, such as introducing new well (Khedr et al., 2009).

Regardless of how accurate the integrated model is, the actual field performance would not match predictions. Therefore, the development team must continuously monitor the performance of the field and the team's adherence to the development plan. This surveillance leads to accurate evaluation of the whole project, assuring that the development plan is followed, working, and is still optimal (Satter et al., 1994).

1.4 Problem statement

Find the optimum development plan for each of the following synthetic field (Fairooz field) development goals:

1. Increasing the overall field production by 10%., and maintaining this rate for the longest period of time.

2. Maintaining the current plateau for the longest period of time.

Your final selection should be based on the following two economical evaluation yardsticks: NPV and PVR. Discount yearly with a hurdle rate of 15% and an inflation rate of 1%/year. The timeframe of this project is 16 years of production. However, stop forecasting and abandon the field when water cut exceeds 80%. You can refer to **Table 1.1** below for CAPEX and OPEX. Please note that the development should not exceed two years of major operations. In addition, development plans must honor existing facility capacities with no upgrades. Fairooz field is synthetic black oil field that is assumed to exist in the North Sea, and you can consider Nelson field an analog to Fairooz.

TABLE 1.1–FAIROOZ FIELD GIVEN CAPEX AND OPEX

Item	Value	Unit	Category
Abandonment	80	%	WC
	30	MM$	CAPEX
Workover	1	MM$	CAPEX
OP	9	MM$	CAPEX
WI	7	MM$	CAPEX
Produced Oil	1	$/STBO	OPEX
Produced Water	0.5	$/STBWP	OPEX
Injected Water	0.4	$/STBWI	OPEX
Produced Gas	0.75	$/Mscf	OPEX
ESP	2	MM$	CAPEX
	0.3	$/STBO	OPEX
Gaslift	0.2	$/STBO	OPEX

I did not choose Nelson field to be an analog to my synthetic Fairooz field due to its particular features. Nelson is just a field that would allow me to build my synthetic field models that are closer to reality. Therefore, Nelson field data is only used to build a base case for Fairooz. In the following chapters I will further discuss my development tools, the development options, and the results and recommendations of this study.

CHAPTER II

THE INTEGRATED RESERVOIR DEVELOPMENT WORKFLOW

2.1 The proposed IRDW (Fig. 2.1)

The IRD team must start with specific development goals, a specific development and planning timeframes, and an accepted level of accuracy. These goals are predetermined by corporation management, at this stage. In general, the management sets its goals for a particular field in a way that fits the bigger corporate production strategy, which changes according to global supply and demand of energy. Development goals could be: reaching maximum oil recovery, producing at a higher production rate (Khedr et al., 2009; Dismuke et al., 2010), sustaining the plateau for a certain (usually the longest) period of time (Khedr et al., 2009), and mitigating overall production decline, just to name a few. Management dictates the development timeframe, which covers planning the development and implementing it. The engineer gets his/her first indication of the level of how detailed his plan should be based on the timeframe given. For example, a one month plan is expected to evaluate the project with less details than a one year one. Every step that comes after specifying the goals have to bring the engineer closer to fulfilling them. With a clear goal(s) in mind, the engineer begins gathering specific information about the field he/she is developing. This stage of information gathering is critical to the development process, because it is the first step in nominating suitable development options. The engineer has a challenging responsibility of finding useful information promptly.

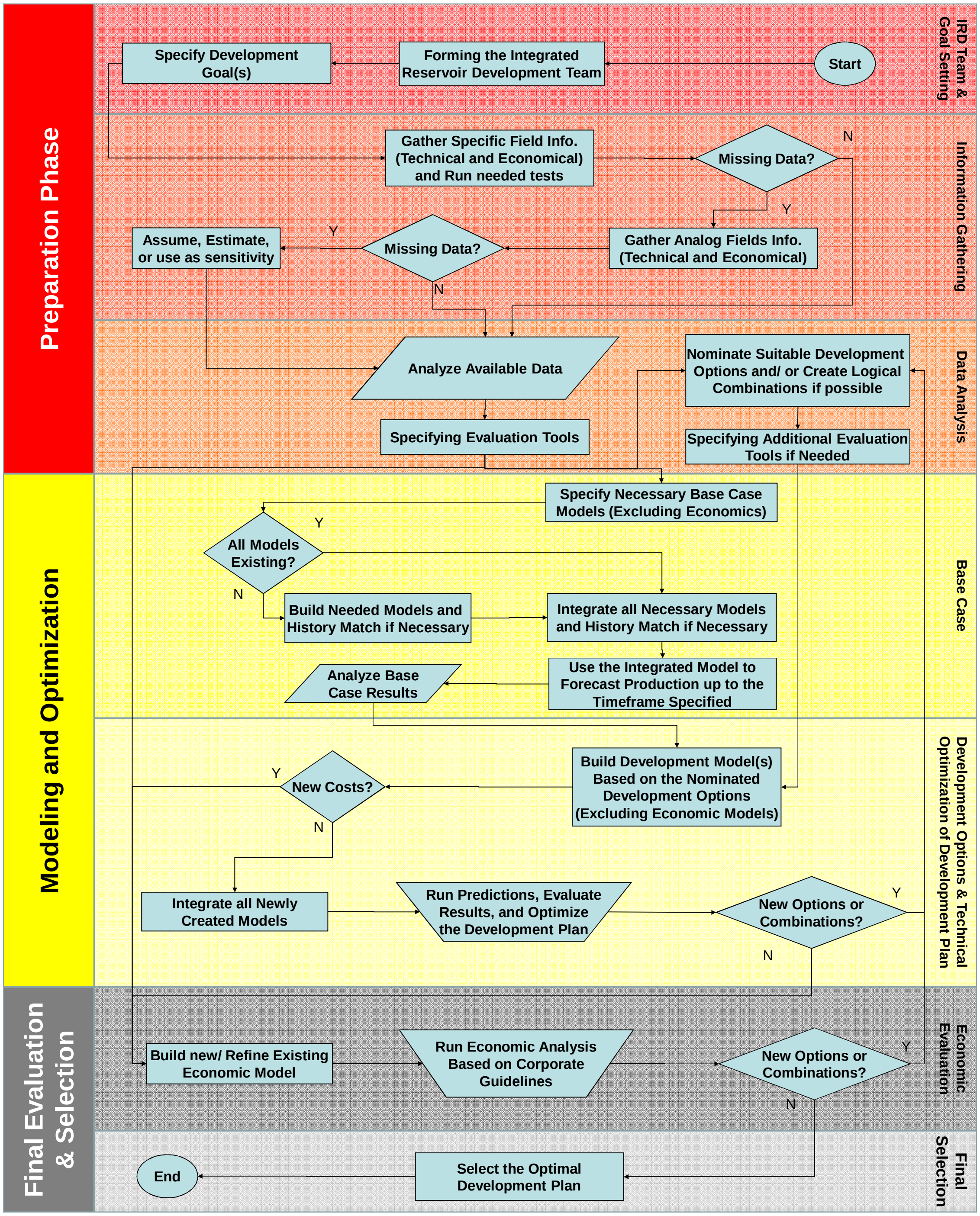

Fig. 2.1–The integrated reservoir development workflow

Selecting development options is a process by itself. It has to go through preparation and selecting and refining phases. In the preparation phase, the team analyzes available data.

The IRDW I developed (**Fig. 2.1**) consists of:

3 phases: preparation, modeling and optimization, and final evaluation and selection.

7 stages: IRD team and goal setting, information gathering, data analysis, base case, development options and technical optimization of development plan, economic evaluation, and final selection.

Every phase in this IRDW depends on the one before it, because every phase sets the stage for the one that follows. The same applies to stages and steps in this IRDW. In addition, the user cannot go from a phase to the one after it without completing all of its steps. Although, completing some steps in a particular phase leads to another step in another phase, the user has to finish all the steps in the phase or stage he/she is in before proceeding to the next phase. In addition, some steps in the first phase leads to another step in the third phase. In this case, the user has to wait until he/she completes all the steps in the second phase. Furthermore, every phase in the IRDW begins with a single step, which marks the beginning of that phase.

2.2 Preparation phase

The IRDW begins with the preparation phase. This phase sets the stage for the whole development.

2.2.1 IRD team and goal setting stage

The goal setting stage begins with an important step to the reservoir development process, which is forming an IRD team. The second step in this stage is setting development goals. The development team, usually, does not set the development goals. Instead, development goals are dictated by their management. The development could consist of one goal, for example increasing overall oil production by 20%, or multiple goals, such as increasing reservoir-a oil production by 15% and extending reservoir-c plateau 3 additional years. In addition, the development goal(s) could be broad, such as reaching the maximum recovery of the field, or detailed, such as increasing the reservoir's oil production by 5% for 8 years, while maintaining its pressure above the bubble point and keeping its water cut as low as possible.

2.2.2 Information gathering stage

The information gathered in this stage is the first indication of the development options, tools, and future problems. For example, the development team can consider gas injection for pressure support as a development option if there is a gas cap. However, a thorough data analysis, in the data analysis stage, will determine the actual selections and anticipated problems.

2.2.3 Data analysis stage

In my opinion, data analysis is the most important stage in the whole IRDW. It defines the development options that would be evaluated and it specifies the tools that form the integrated asset model. The final development plan, the IRDW recommends, is optimum among the selected development options and combinations. Therefore, the integrated reservoir development team must make a thorough analysis of the available data, to make a comprehensive selection of the development options. In addition, good data analysis results in selecting the most suitable tool for the evaluation. For example, if a development team analyzes the type of existing surface facilities network in the field they will select the right evaluation tool to evaluate it. Therefore, if the field has a flowline network, the team has to use a surface facilities software, such as GAP, to model that network. On the other hand, a wellbore evaluation tool that can simulate the total flow from sandface through the wellhead to a single flowline, such as PROSPER, is an applicable (or more convenient) choice if there is no common facilities network that connects all wells to the separator. For example, if each well is directly connected to the platform through a riser. Finally flowline network on the sea bed may find ESPs more attractive than gas-lift because the ESP option has less gas associated with it. More gas in the flowline network results in more backpressure on the whole system (Khedr et al., 2009).

2.3 The modeling and optimization phase

The first stage of this phase is the base case stage. In this stage, the team builds the base case model, matches its history, runs it for predictions, and analyzes its results. Excluding the IAM, the most important model in the base case stage is not the facilities model or the wellbore model, it is the reservoir model. The same history matched reservoir model will serve as a platform for adding in different development options. Therefore, the reservoir model requires more attention usually.

2.4 The final evaluation and selection phase

The economic evaluation stage is the first stage of the final evaluation and selection phase, and it begins with refining existing economical model if necessary or building a new economical model if an existing one does not exist. Each company has its own favorite yardsticks that it prefers to take its decisions based on.

The IRDW does not treat the economical evaluation as just a decision making tool, it also conceders it as an additional layer of optimization. Chapter VI shows an example of economic optimization’s significant of the development plan selection.

CHAPTER III

THE DEVELOPMENT PREPARATION PHASE

This chapter marks the beginning of the actual implementation of the IRDW in developing Fairooz field. In this chapter I will illustrate how to complete the preparation phase of the IRDW. The problem statement of this development asks to find the optimal development scenario for two different development goals, and then nominating the most economical goal for the company to adapt.

I will illustrate how to implement the IRDW for only one development goal, because of the repetitive nature of the IRDW. I have chosen increasing production by 10% for this illustration. However, I will present the final results of both development goals in the results and Chapter VII.

3.1 The IRD team and goal setting stage (Fig. 3.1)

Assuming that the IRD team has been formed, the two goals that the management specified are:

1. Increasing Production by 10% and maintain it for the longest period of time.
2. Maintaining the existing plateau for the longest period of time.

After I have clearly specified the development goals I should begin gathering all necessary information that help me achieve those goals. Therefore, completing this stage leads to the information gathering stage.

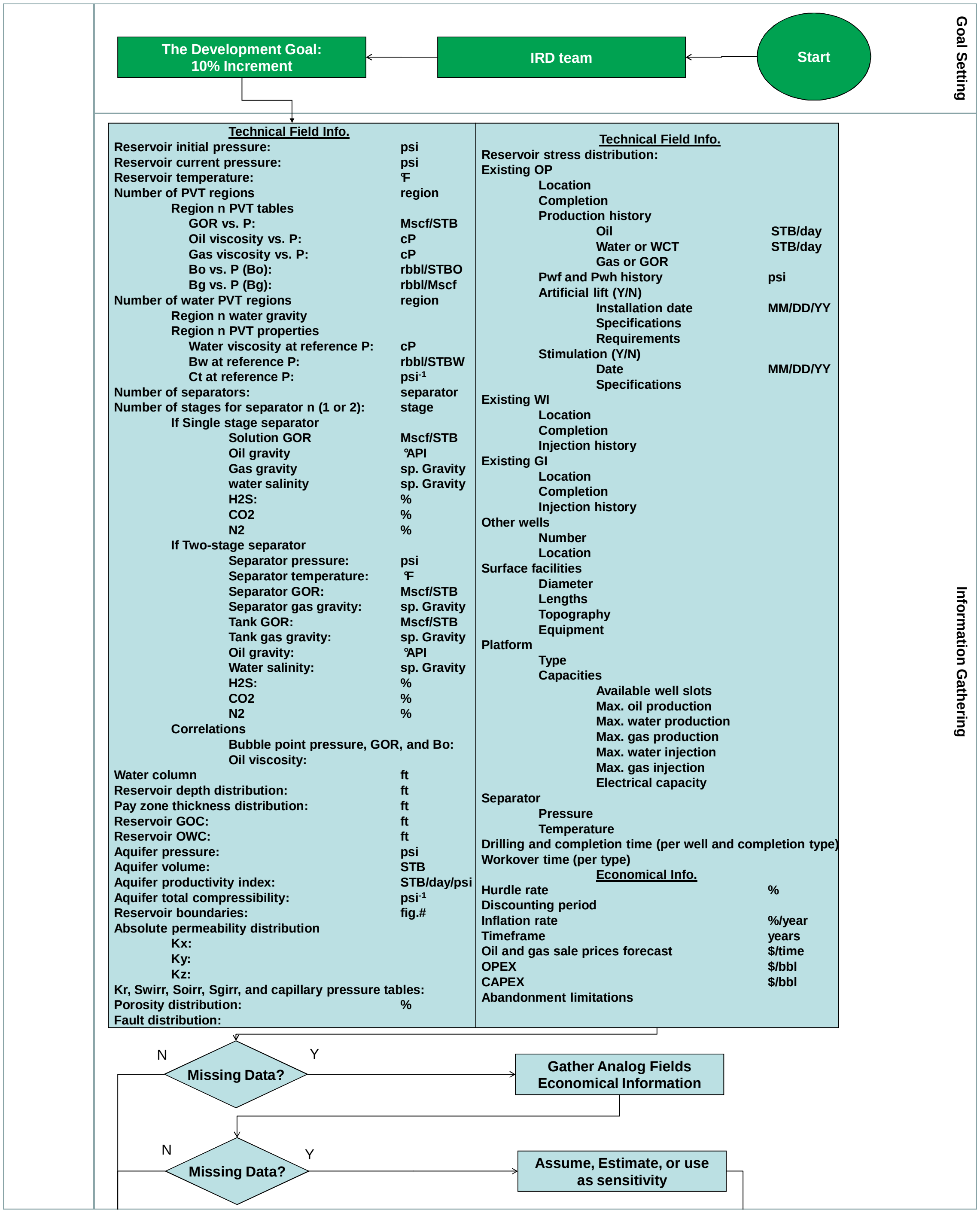

Fig. 3.1–The completed IRD team and goal setting stage

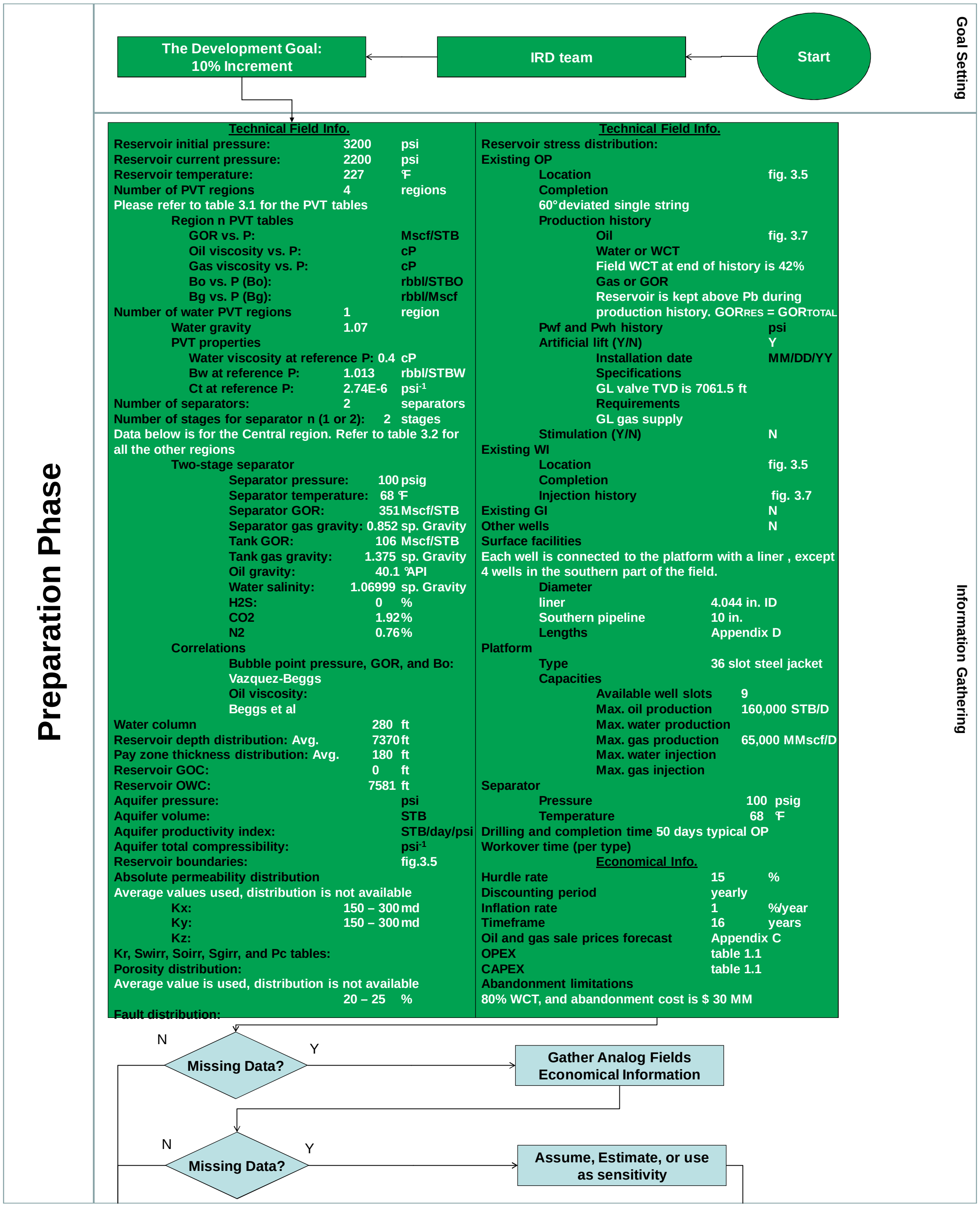

Fig. 3.2–Gathering specific field information step

3.2 Information gathering stage

The first step in this stage is gathering specific field information. However, because Fairooz field is a fictitious North Sea field, all information will be gathered about Nelson field (its analog).

3.2.1 Gathering specific field information (technical and economical) (**Fig. 3.2**)

Nelson field (**Fig. 3.3**) was discovered in 1987 by Enterprise Oil PLC (Griffin, P.G. et al., 1995). It had an estimated proved and probable reserves of 480 million bbl of oil and 85 bcf of sales gas. The major partners, at the time where production started, were Enterprise oil, Elf Enterprise Caledonia and Shell/Esso, with Enterprise as the operator (Ewy et al., 1994). The reservoir structure, which lays at 7,200 ft TVDSS, is a dome-shaped structure draped over fault blocks (Jordan et al., 1998); **Fig. 3.4** shows a generalized stratigraphic sequence in the reservoir. The field is normally pressured at initial conditions. It also has a natural water drive from a strong aquifer underneath it. The stock tank oil gravity is 40 ° API and the GOR is around 470 scf/STB (Griffin, P.G. et al., 1995). Please refer to **Table 3.1** for separation specifications and **Table 3.2** for PVT properties.

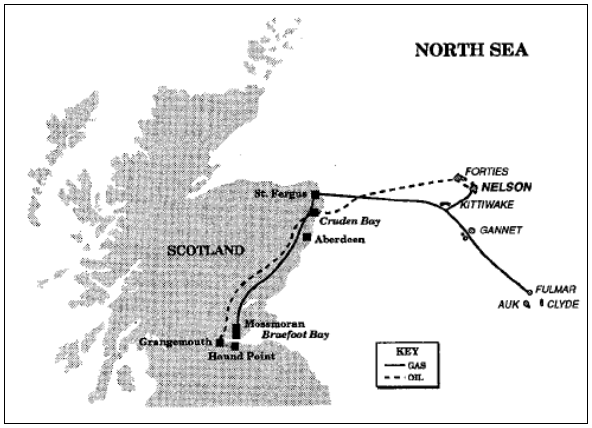

Fig. 3.3–Nelson field location (Griffin, P. G. et al., 1995)

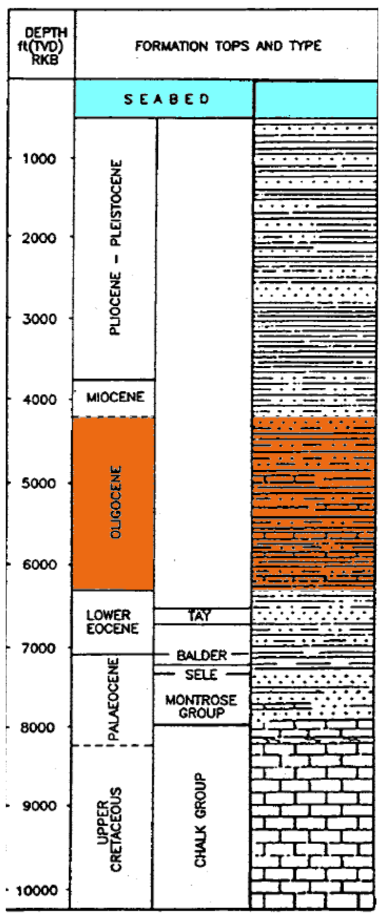

Fig. 3.4–A generalized stratigraphic sequence in the reservoir, modified from (Kwakwa et al., 1991)

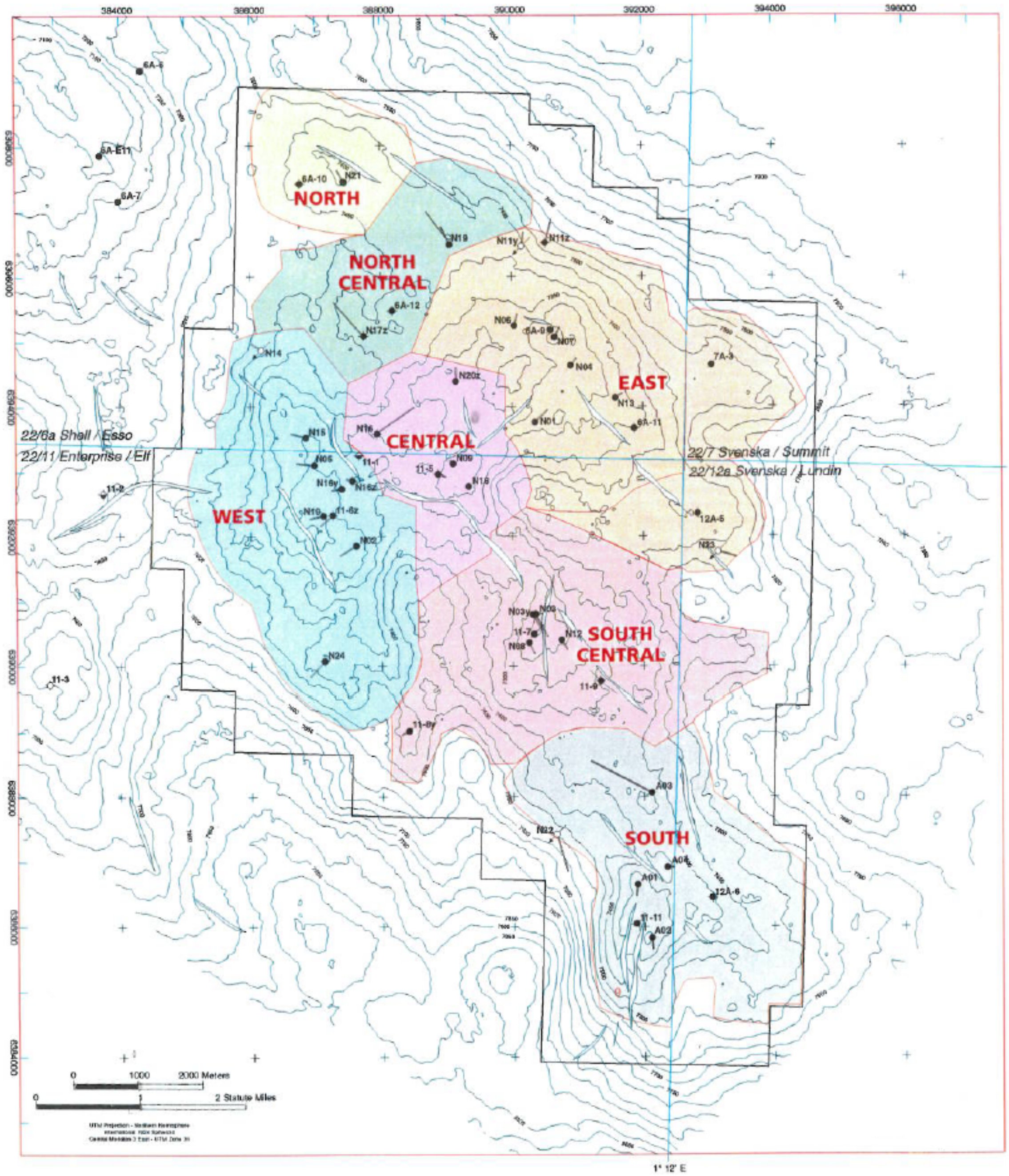

Fig. 3.5–Nelson reservoir boundary map, existing well locations, and its 7 geographical regions

TABLE 3.1–TWO STAGE SEPARATOR SPECIFICATIONS, FOR EACH REGION

	Area	Central	Eastern	Western	Southern
Separator Pressure	psig	100	100	100	100
Separator Temperature	°F	68	150	68	68
Separator GOR	Mscf/STB	351	506	346	361
Separator gas gravity	sp. gravity	0.852	1.012	0.827	0.838
Tank GOR	Mscf/STB	106	50	102	94
Tank gas gravity	sp. gravity	1.375	1.5	1.376	1.352
Oil gravity	°API	40.1	39.2	40.3	40.8
Water salinity	sp. gravity	1.06999	1.06999	1.06999	1.06999
H_2S	%	0	0	0	0
CO_2	%	1.92	1.92	1.92	1.92
N_2	%	0.76	0.76	0.76	0.76

TABLE 3.2–OIL AND GAS PVT TABLES FOR EACH REGION, GAS PVTS ARE GENERATED IN PROSPER

Area	Central					
Wells	N09, N17, N18, N19, N20, N21, F03, F05, and F07					
	p (psia)	Rs (Mscf/stb)	Bo (rb/stb)	Viso (cp)	Bg (rb/Mscf)	Visg (cp)
	14.7	0.027	1.13224	0.82124	234.736	0.01253
	570.252	0.183	1.22024	0.55358	5.532	0.01334
	1125.81	0.38	1.33097	0.43013	2.56463	0.01496
	1666.31	0.457	1.37085	0.4035		
	1681.36				1.60741	0.0175
	2236.92	0.457	1.35812	0.4244	1.1806	0.02083
	2792.48	0.457	1.34986	0.45218	0.96221	0.02451
	3348.03	0.457	1.34437	0.48513	0.83712	0.02818
	3903.59	0.457	1.34046	0.52267	0.7582	0.03166
	4459.14	0.457	1.33753	0.56429	0.70436	0.0349
	5014.7	0.457	1.33526	0.60956	0.66529	0.0379

Area	Western					
Wells	N02, N05, N10, N15, N16, and F01					
	p (psia)	Rs (Mscf/stb)	Bo (rb/stb)	Viso (cp)	Bg (rb/Mscf)	Visg (cp)
	14.7	0.027	1.13509	0.81182	234.761	0.012618
	570.252	0.182	1.22175	0.55087	5.55878	0.013394
	1125.81	0.377	1.33081	0.4292	2.59216	0.014938
	1666.31	0.448	1.36818	0.40413		
	1681.36				1.63212	0.017317
	2236.92	0.448	1.35604	0.4248	1.19944	0.020413
	2792.48	0.448	1.34787	0.45268	0.97526	0.023863
	3348.03	0.448	1.34243	0.48574	0.84575	0.027341
	3903.59	0.448	1.33855	0.52339	0.76366	0.030673
	4459.14	0.448	1.33565	0.56516	0.70758	0.033797
	5014.7	0.448	1.3334	0.61056	0.66689	0.036703

Area	Eastern					
Wells	N01, N04, N06, N07, N13, F02, F04, and F06					
	p (psia)	Rs (Mscf/stb)	Bo (rb/stb)	Viso (cp)	Bg (rb/Mscf)	Visg (cp)
	14.7	0.027	1.12467	0.83825	236.357	0.012296
	570.252	0.191	1.21643	0.55604	5.47452	0.013204
	1125.81	0.399	1.33189	0.4294	2.48143	0.015151
	1681.36				1.52939	0.018388
	1906.43	0.556	1.41585	0.38206		
	2236.92	0.556	1.41001	0.38833	1.12418	0.022646
	2792.48	0.556	1.39909	0.41111	0.92655	0.027189
	3348.03	0.556	1.39184	0.43836	0.8165	0.031533
	3903.59	0.556	1.38668	0.46955	0.74788	0.035514
	4459.14	0.556	1.38281	0.5042	0.70111	0.039129
	5014.7	0.556	1.37981	0.54192	0.66697	0.042428

Area	Southern					
Wells	NA01, NA02, NA03, NA04, N03, N08, and N12					
	p (psia)	Rs (Mscf/stb)	Bo (rb/stb)	Viso (cp)	Bg (rb/Mscf)	Visg (cp)
	14.7	0.027	1.13746	0.78858	234.77	0.012724
	570.252	0.183	1.22481	0.53736	5.56834	0.013608
	1125.81	0.38	1.33473	0.42	2.60195	0.015207
	1672.44	0.455	1.37586	0.39348		
	1681.36				1.64093	0.017584
	2236.92	0.455	1.3625	0.4141	1.20625	0.020598
	2792.48	0.455	1.35412	0.44107	0.98004	0.023914
	3348.03	0.455	1.34855	0.47306	0.84896	0.027249
	3903.59	0.455	1.34458	0.50951	0.76573	0.030452
	4459.14	0.455	1.34161	0.54993	0.70882	0.033464
	5014.7	0.455	1.3393	0.59389	0.66754	0.036276

Five deviated appraisal wells were drilled around the time of discovery (Kwakwa et al., 1991). After that, 8 highly deviated wells were planned (**Fig. 3.6**), along with installing a 36-slot fixed steel jacket at the center of the area, in addition to a subsea satellite development (Griffin, P. G. et al., 1995). This marked the first development of Nelson field. The platform has the capacity of 160,000 BOPD of oil production, 65 MMSCF/D of gas production (Jordan et al., 1998; Gerrard et al., 2007). Gas is supplied through a pipeline to St. Fergus and also to the gas-lift header. Production commenced in 1994 with a peak production of 160,000 BOPD which lasted for 5 months (Griffin, P. G. et al., 1995).

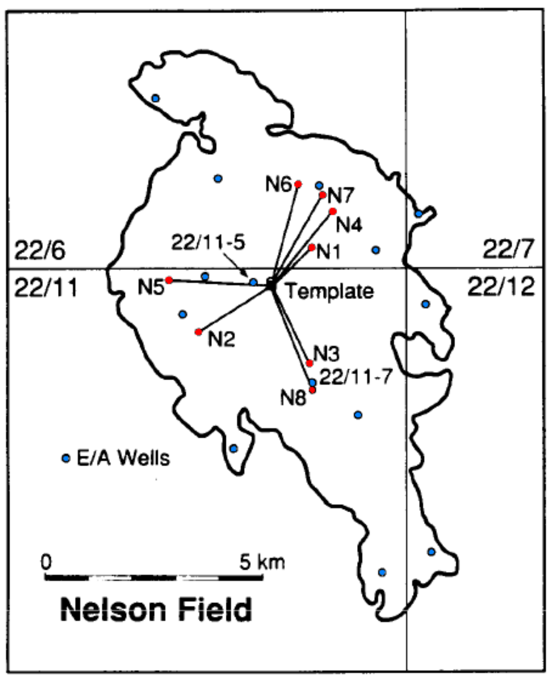

Fig. 3.6–The location of the 8 deviated wells, modified from (Ewy et al., 1994)

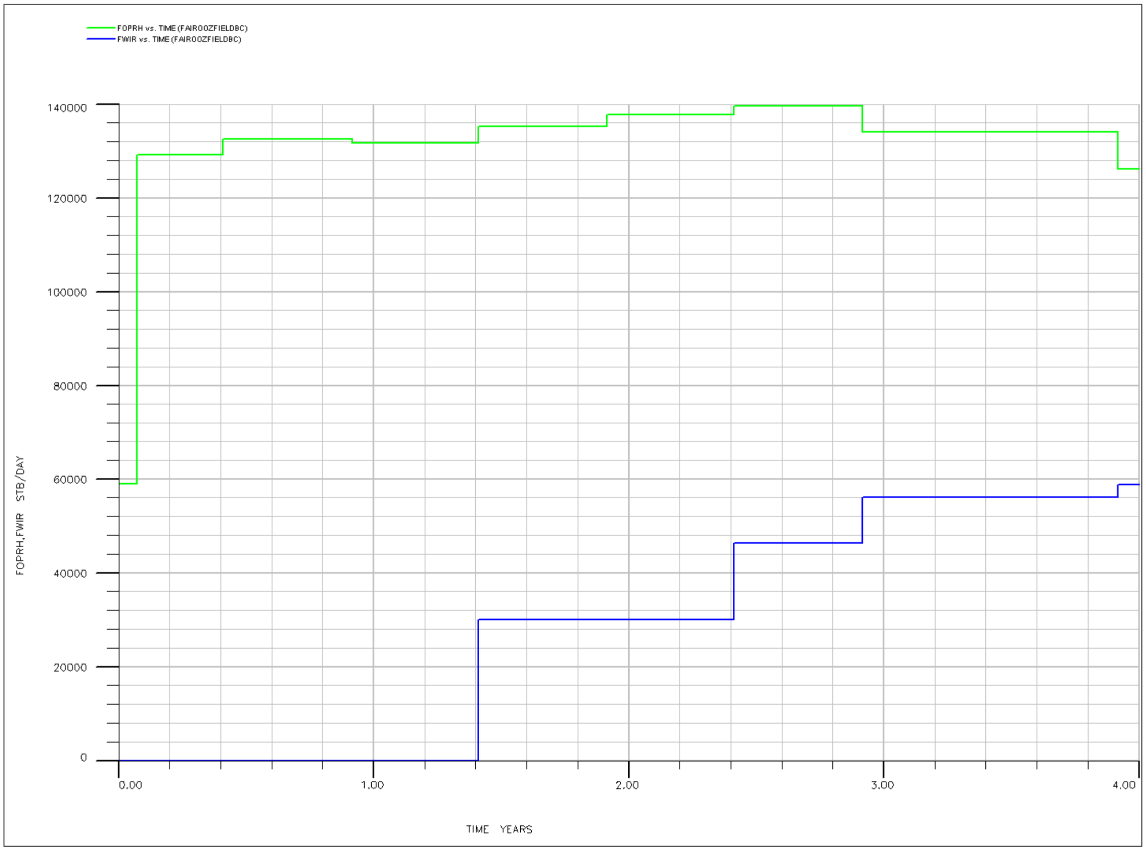

Fig. 3.7–Nelson field modified oil production and water injection histories

3.2.2 Gathering analog field information (**Fig. 3.8**)

Nelson field is found in an area of massive sandstone deposit in a submarine fans environment. Hydrocarbons have migrated to those reservoirs while they were in a relatively shallow depths (Gautier, 2005).

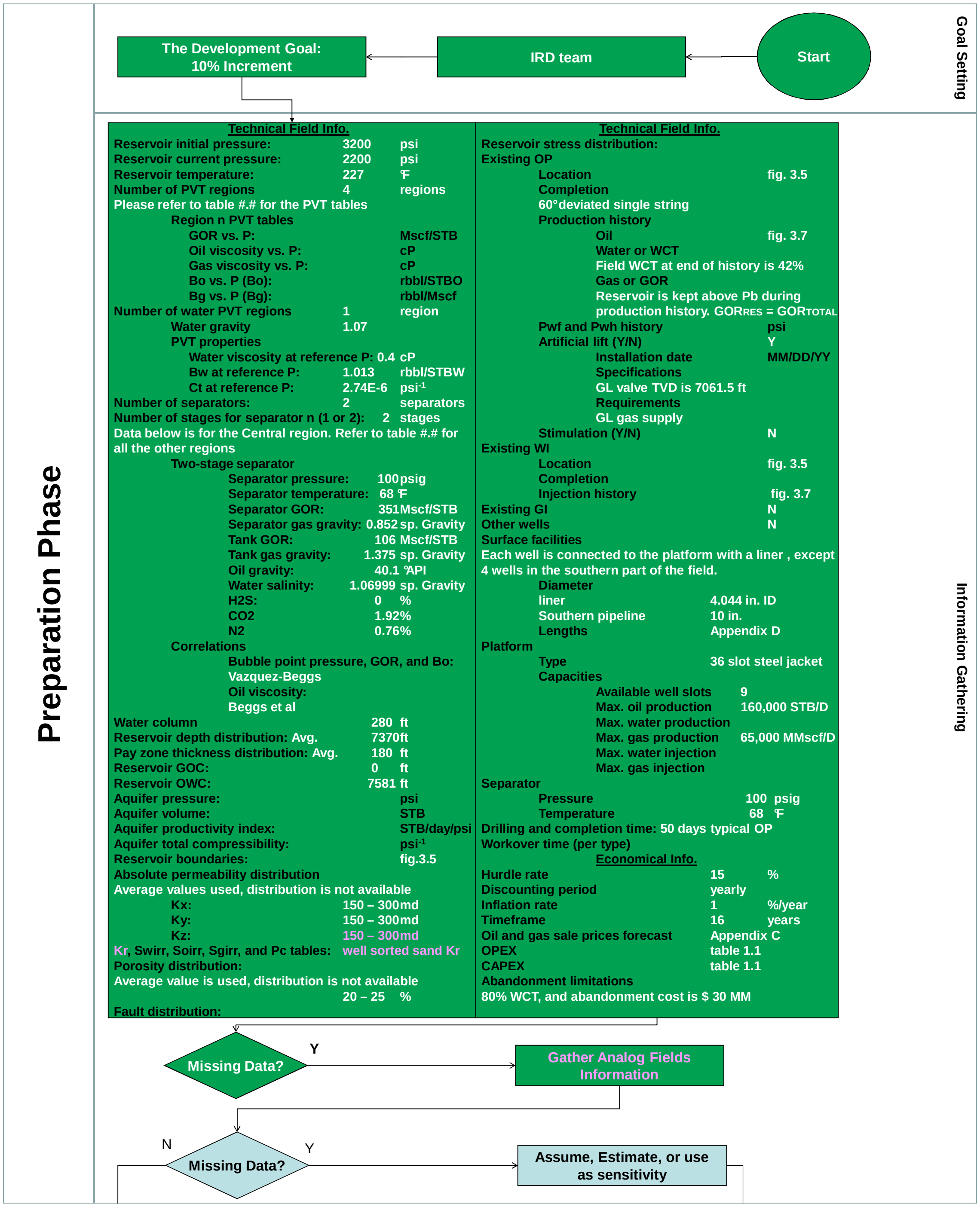

Fig. 3.8–Gathering analog field information step, analog information is purple

3.2.3 Assumption, estimation, or sensitivity step (**Fig. 3.9**)

The following data is still missing, and it is needed to run the reservoir model. Therefore, I had to assume, estimate, or use it as a sensitivity parameter:

1. Assumed values (data accepted to be not available are included in this section):
   - Fault distribution is not available → the reservoir is assumed to have no faults.
   - P_{wf} and P_{wh} are not available → Accepted at this stage because the tophole pressure in the IAM will be the separator pressure (100 psig).
   - Maximum water production and injection rates are not available → accepted to be unavailable at this stage.
2. Estimated:
   - The gaslift installation date is not available → estimated to be the same as the on-stream date.
   - The existing WIs completion is not available → estimated to be 4.044 inch ID.
   - Maximum gas injection capacity is unknown → estimated to be the same capacity of gaslifting all wells with a 5 MMscf/day.
   - Workover time is unknown → estimated for gaslift tie-in to be 7 days and for ESP installation to be 14 days.
3. Used as sensitivity:

- Aquifer pressure is unknown → set as auto sensitivity in ECLIPSE, where it gets calculated for each run to be in equilibrium with the reservoir pressure on top.
- Aquifer volume is unknown → it is used as a history matching sensitivity after integration. Its final value after history matching the IAM is 1×10^{16} STBW.
- Aquifer productivity index is unknown → this parameter is one of the most important history matching sensitivities because it has a direct affect on the reservoir pressure specially with a high vertical permeability, and it also has a direct affect on water cut. Its final value after history matching the IAM is 206 STB/day/psi.
- Aquifer total compressibility (rock + water) is unknown → its value is used as a sensitivity, and its final value after history matching the IAM is 1×10^{-5} psi^{-1}.
- S_{wirr}, S_{oirr}, S_{girr}, and Pc are unknown → all those parameters are used as a sensitivity during the IAM history matching. The final values are in **Table 3.3**.

TABLE 3.3–THE RELATIVE PERMEABILITY CURVES AND CAPILLARY PRESSURE OF FAIROOZ FIELD, IT INCLUDES SWIRR, SOIRR, SGIRR, AND PC VALUES

Sw	Krw	Krow	Pcow
0.2	0	1	45
0.25	0.0002	0.9946	30
0.3	0.002	0.9848	15
0.35	0.0066	0.9226	6.5
0.4	0.0156	0.8441	6
0.45	0.0305	0.767	5.5
0.5	0.0527	0.6931	5
0.55	0.0837	0.6201	4.5
0.6	0.125	0.5305	4
0.65	0.178	0.4506	3.5
0.7	0.2441	0.3863	3
0.8	0.4219	0.2175	2
0.95	1	0	0.5

Sg	Krg	Krog	Pcog
0	0	1	0
0.06	0	0.525	0
0.1	0	0.375	0
0.14	0	0.213	0
0.19	0.002	0.106	0
0.24	0.006	0.042	0
0.29	0.013	0.011	0
0.33	0.035	0.001	0
0.37	0.061	0	0
0.8	0.9	0	0

Swirr 20%
Soirr 5%

Sgirr 14%

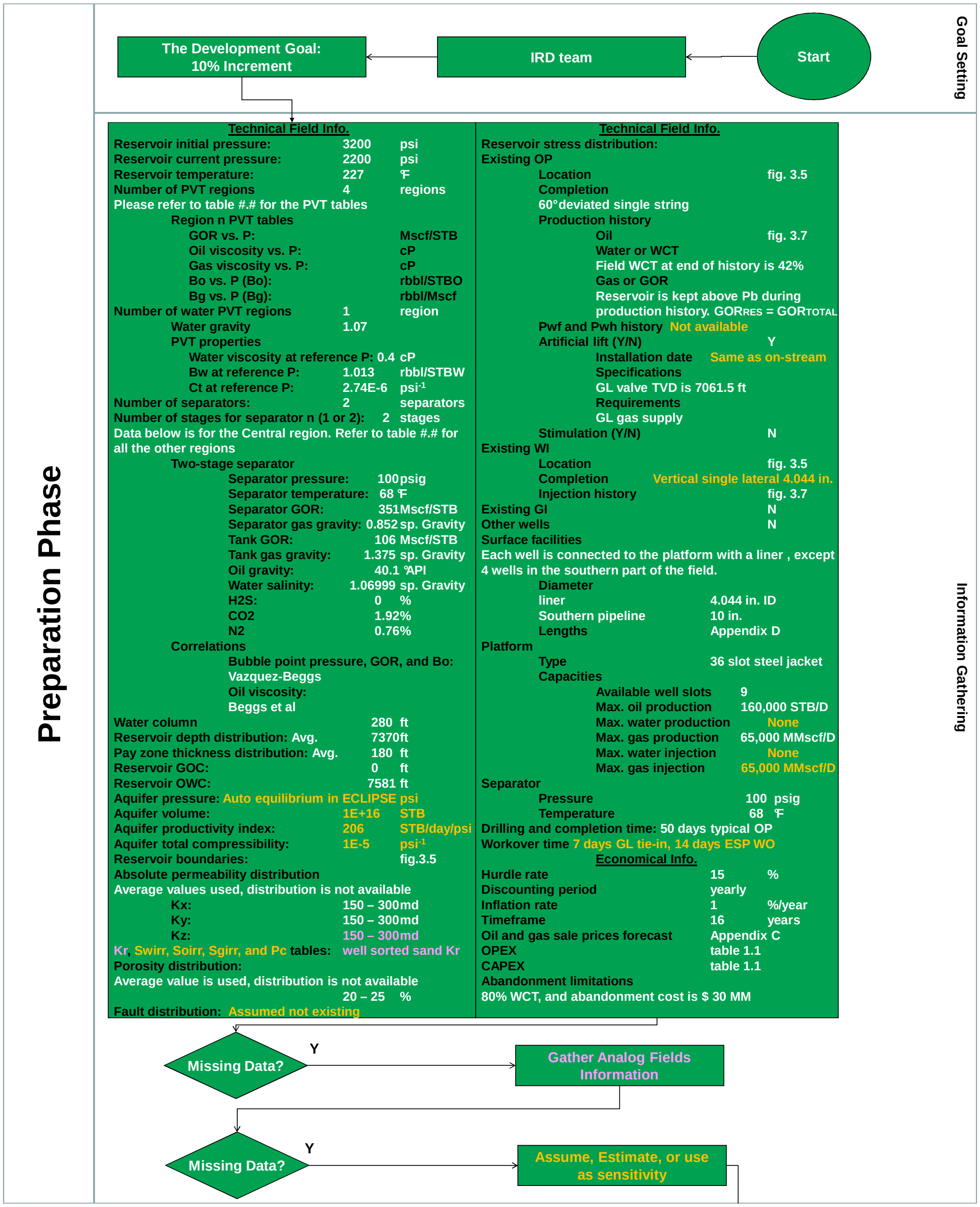

Fig. 3.9–Assumption, estimation, or sensitivity step, new information is yellow

Finishing this step (3.2.3) ends the information gathering stage and leads to the data analysis stage.

3.3 Data analysis stage (Fig. 3.10)

At this stage, the team starts with analyzing available data from information gathering stage. The analysis will help them select development options and tools, and it could help them anticipate future problems and bottlenecks.

3.3.1 Analyze available data

Below is an example of the available data analysis performed. For more information please refer to **Fig. 3.10**.

3.3.1.1 Sand sorting and permeability

Massive sandstone accumulations in a submarine fan environment, indication that the reservoir sand is well sorted and could have high vertical permeabilities. Therefore, I can assume the relative permeability curves of the well-sorted sands as an initial value to begin my history matching. In addition, high water cut is anticipated at a relatively faster time.

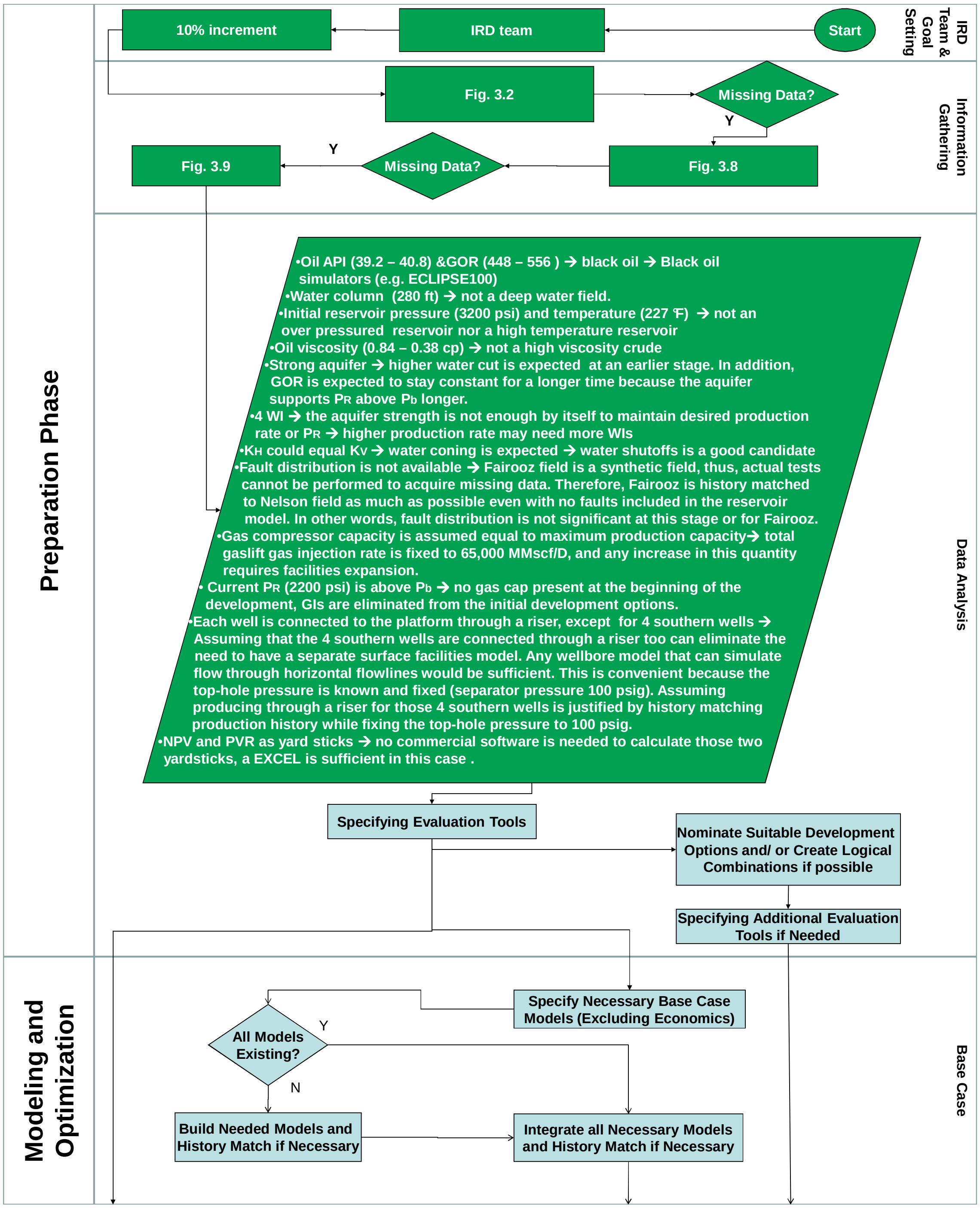

Fig. 3.10–Data analysis stage and data analysis step

3.3.1.2 Higher vertical permeability effect

Higher vertical permeabilities coupled with strong aquifer and a number of WIs could lead to sustaining PR above Pb for a longer time. Therefore, gas cap is not expected to from. Thus, GIs are not likely development options candidates. In addition, higher water cuts and water coning are possible results. Therefore, water cut and water saturation should be monitored carefully during the forecast. Solutions to such a problem could be water shutoffs, or lowering the rate of the oil producer with the highest water production.

3.3.1.3 Oil type

The 40° API and 470 scf/STB indicate that Nelson has a black oil crude. Therefore, a black oil reservoir model is needed.

3.3.1.4 Surface facilities

The typical well completion* states that wellheads are on the platform, therefore, there is no surface facility network on the seabed. This means that PROSPER is a good evaluation tool from the bottomhole to the separator. In addition, the backpressure problems associated with gaslifting remote offshore wells that share a common network facilities (Khedr et al., 2009) are not applicable to this situation.

3.3.2 Specifying evaluation tools (**Fig. 3.11**)

Based on the 3.3.1 above the most suitable tool to build the reservoir model is ECLIPSE-100 (or any similar software). It has the ability to integrate VLP tables, thus if the VLP tables reflect surface facilities there is no need for a separate facilities model.

* Internal field report (unpublished data)

ECLIPSE has the ability to be the overall controller of the field models. It also has the ability to evaluate infill drilling well locations (unlike material balance simulators). In addition, it has the ability to reflect the changes of reservoir geological parameters (reservoir heterogeneity). However, I did not choose ECLIPSE based on unique or specific features it has, I could have used any commercial software with similar capabilities.

The most suitable tool to build a wellbore model and facilities model is PROSPER (or any similar commercial software), because it has the ability to simulate horizontal pipe flow, and most oil producers (OPs) in the field produce through a liner without facilities network.

I will use Microsoft Excel as the tool to build my economic model. Excel has all the features needed to perform the economical analysis. I will develop a table that calculates the NPV and the PVR when production rates are entered.

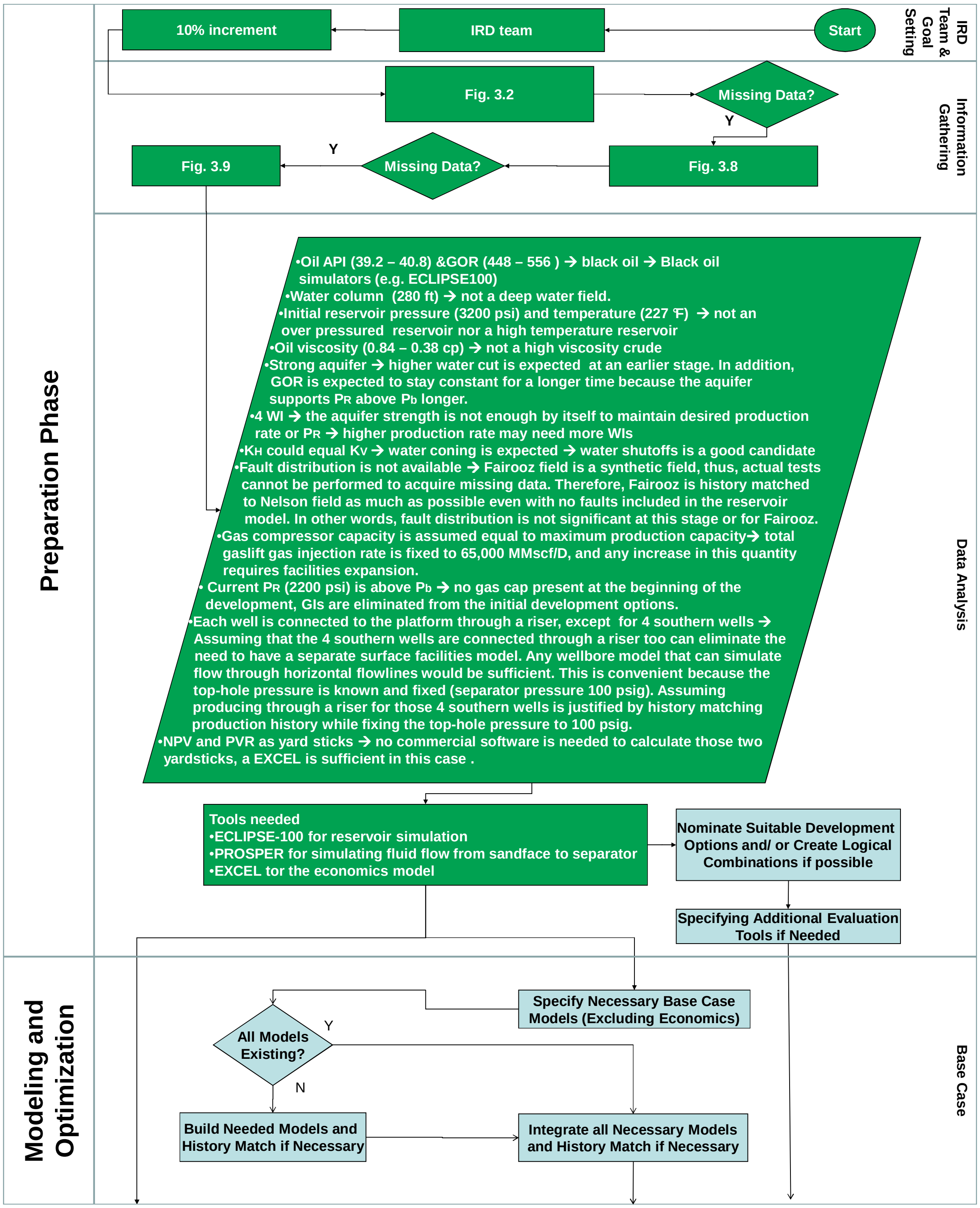

Fig. 3.11–Data analysis stage and specifying evaluation tool step

3.3.3 Nominate suitable development options and/ or create logical combinations if possible (**Fig. 3.12**)

I have chosen the following development options based data availability, and available resources. Those development options are: infill and pressure support drilling, gaslift, electrical submersible pumps, and water shutoffs.

Proving the IRDW ability to produce the optimum development plan in a timely manner does not require a thorough evaluating all possible development options in my field of choice. Only a few number of suitable development options is needed, because of the comparative nature of the IRDW final selection criterion. The freedom to choose the desired number of development options is very convenient, because I cannot consider all applicable options in the data analysis state of the IRDW. Available data and resources are the main hurdles that prevent considering all suitable development options. Evaluating all applicable options beyond the scope of this thesis. Therefore, I decided to evaluate for primary development option: infill and pressure support drilling, gas lift, electrical submersible pumps, and water shutoffs. Those options are the most applicable primary development options for the purposes of this research. Plus they are widely used in Nelson field (except for ESP). However, I will not consider any development option combinations, such as drilling infill OPs initially and then gaslift the needed wells afterwards. This allows for better analysis of the development option itself, so the technical reason behind favoring option-A is easier to identify. Remember that Fairooz is a fictitious field that does not require a full-scale implementation of the IRDW, because there is no actual need for its development. It is all for illustrative purpose.

In reality, operating companies have access to the necessary data (confidential or not) and resources that allow them to evaluate all applicable options. Incase those data or resources are not available, the operating companies could easily acquire them. Furthermore, the IRD team must evaluate all development options that pass through the screening process. In addition, the team has to evaluate all legitimate combinations between development options. After all, finding the absolute optimum development plan is the goal of all real life field developments.

3.3.4 Specify additional evaluation tool if needed (**Fig. 3.13**)

No additional evaluation tool is needed at this stage. Mainly, this step is intended to specify additional evaluation tool necessary to evaluation new options that the optimization stages might nominate.

Completing this step marks the end of the data analysis stage and the preparation phase as a whole. The next phase is modeling and optimization phase.

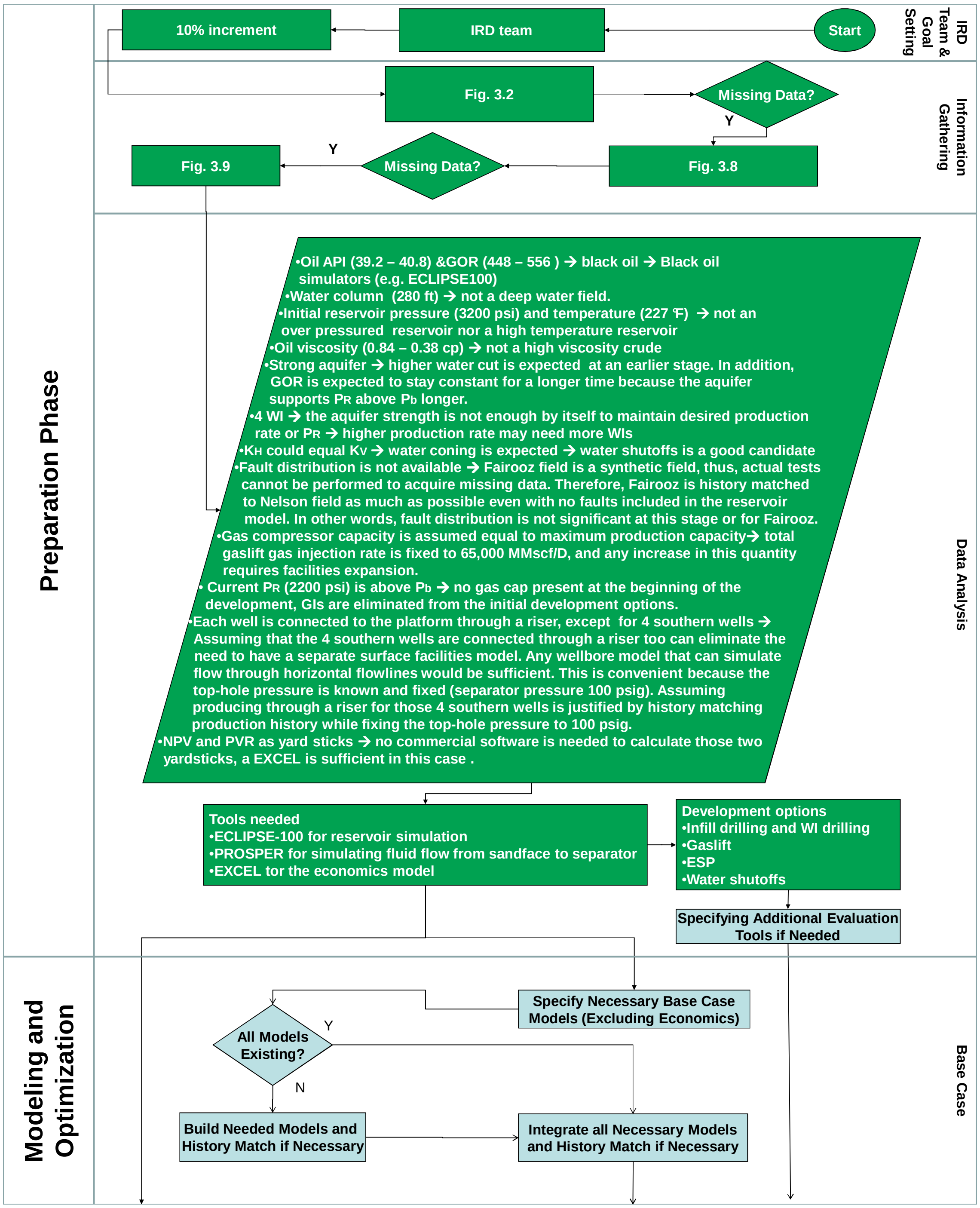

Fig. 3.12–Data analysis stage, and nominate suitable development options and/ or create logical combinations step

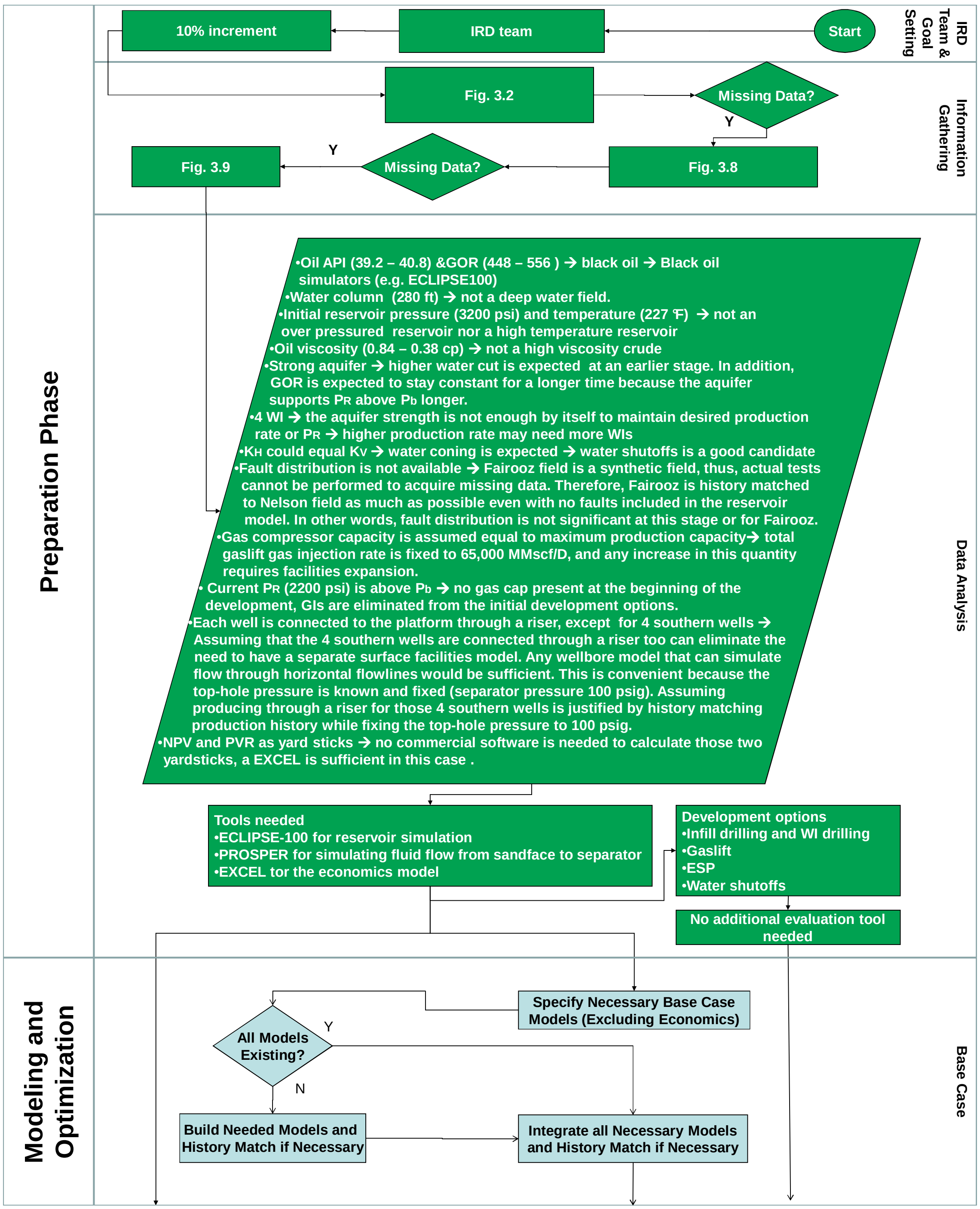

Fig. 3.13–Data analysis stage and specifying additional evaluation tools step

CHAPTER IV

DRILLING AND WATER SHUTOFFS

Drilling new wells, with respect to primary oil field development, could mean drilling an OP, a gas injector (GI) for pressure support, a water injector (WI) for pressure support, or other water wells such as water disposal (WD) or water supply (WS) ones. In fact, drilling is an integral part in many oil field developments, since without it no reservoirs could be reached, no hydrocarbons could be produced, and no reservoir pressure could artificially be supported. It also refines reservoir boundaries; it either confirms them with a dry hole or extends them with new net pays and new well testings. Furthermore, drilling is the only source of cores that give critical reservoir information such as rock wettibility, residual water saturation, original and effective porosity, absolute and relative permeabilities, capillary pressure, rock compressibility, and reservoir heterogeneity, just to name a few [*]. In addition, well testing a new well gives useful information about its new drainage area, which could be an area not reached by well testing before. Furthermore, well testing gives information such as formation permeability, distance to faults, fracture half-length, average reservoir pressure, and drainage area [**], and this information is extremely useful especially for newly drilled OPs. Drilling also opens the door for logging new areas in the reservoir, which gives information such as porosity, permeability, structural stresses, lithology, hydrocarbon

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* PETE-665 Fall 08 and PETE-618 Fall 08 course notes

**PETE 663 Summer 09 notes, Well Testing part types, and oil water contacts*. However, the benefits of drilling do not stop at supplying reservoir information; they also include increasing reservoir overall recovery (Anderson, 1991; Chilingarian et al., 1996), supporting reservoir pressure (Anderson, 1991), increasing reservoir production rate (Anderson, 1991), and extending production plateau.

4.1 Drilling options

In this development, drilling options will be drilling OPs (infill drilling) and drilling pressure support WIs. I have chosen a single string 60° deviated well configuration for the OPs and a vertical well configuration for the WIs. This OP completion configuration is the most suitable one because one reservoir is present in the field and based on its available geological information. These two reasons will be discussed further in this chapter. I will use this OP configuration in building both the base case and infill drilling scenarios. Furthermore, the base case scenario OPs will have a 4.044 inch inner diameter tubing because it is the actual existing inner diameter. The infill OP will have the same completion configuration as the existing OPs. I have chosen the vertical water injection configuration because the WIs are completed in a strong aquifer, below the original OWC. GIs for pressure support are not among the development options because there is no primary gas cap present in the field, and no secondary gas cap had formed until the end of the production history period. Sea water is the water source for water injection in the North Sea, thus there is no need to drill water

* PETE 663 course notes Summer 09, Log part

supply wells in this development (Kumar et al., 2007). In addition, OSPAR regulations states that produced formation water could be disposed in the North Sea after treating it (Kumar et al., 2007). Therefore, water disposal wells are not among the drilling options considered in this development.

4.2 The reason behind choosing the proposed well configuration

I have chosen a single string 60° deviated well configuration for all OPs in the field because there is one reservoir present in the field and based on the limited geological information available. The original OPs were mainly 60° deviated wells, with the exception of two single lateral horizontal wells*. Plus, the original OPs have a 4.044 inch tubing. Therefore, all existing OPs in my model are 60° deviated wells with a 4.044 inch tubing. Furthermore, the infill oil wells are going to have the same degree of deviation and the same tubing diameter for consistency and ease of comparison. In addition, all infill drilling wells will have a single string completion because they only penetrate one reservoir. Producing from a single reservoir eliminates the need to have another producing string. It is worth to mention that the majority of Nelson OPs are gas lifted, and these gas-lifted wells produce from single tubing. However, the gas-lift gas is not injected through the annulus of the well, it is actually injected through an injection string for safety precautions (Griffin, P. G. et al., 1995). This means that those wells have an upper dual string configuration and a lower single string configuration (**Fig. 4.1**). However, the injection pathway is irrelevant to oil production as long as the desired gas-lift gas injection rate is met. Therefore, I will use a single string well configuration

* Internal field report (unpublished)

with annular gas lift injection, for the base case OPs too. I have stated the reasons behind choosing the existing OP completion and the deviation angle and tubing diameter for the infill OPs. However, I still have to justify the suitability of the deviated configuration for infill OPs among all other possible configurations.

It is more convenient to justify choosing the proposed configuration by stating why other configurations are not applicable. There are four known types of well configurations: vertical, deviated, horizontal, dual lateral, and multilateral. While vertical and deviated well configurations share the same vertical well production equation (Eq. 4.1)*, horizontal, dual lateral, and multi lateral configurations share the same horizontal well production equation. It is worth mentioning that the production equation for the dual and multi lateral wells is simply the summation of the horizontal production equations associated with each lateral (Joshi, 2000), since each lateral is a horizontal branch in the well (**Fig. 4.2**). Assuming all parameters are constant and all wells are drilled in their optimal locations, comparing the deviated and horizontal well productivities to the vertical well one gives the following conclusions. Deviated well productivity is greater than vertical well productivity due to the overall deviated well skin factor reduction caused by the negative slant pseudo skin (Economides et al., 1993). In addition, horizontal well productivity is greater than the vertical one because horizontal well experience decreased pressure drawdown (Economides et al., 1993).

* PETE-618 Fall 08 course notes

$$p_e - p_{wf} = \frac{141.2\ B\ \mu\ q}{k\ h}\left(\ln\frac{r_e}{r_w} + s\right) \text{ ....(eq.4.1)}$$

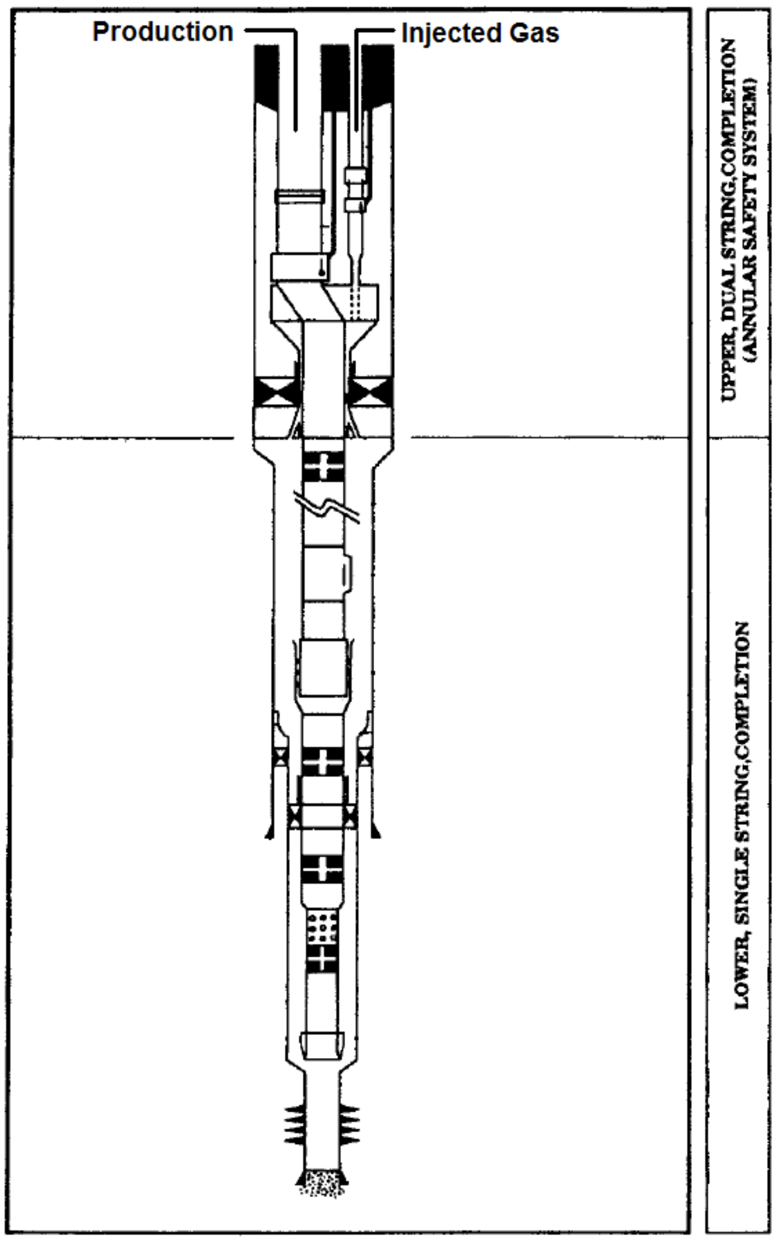

Fig. 4.1–Nelson's typical gas-lift oil producer completion, modified from (Griffin, P. G. et al., 1995)

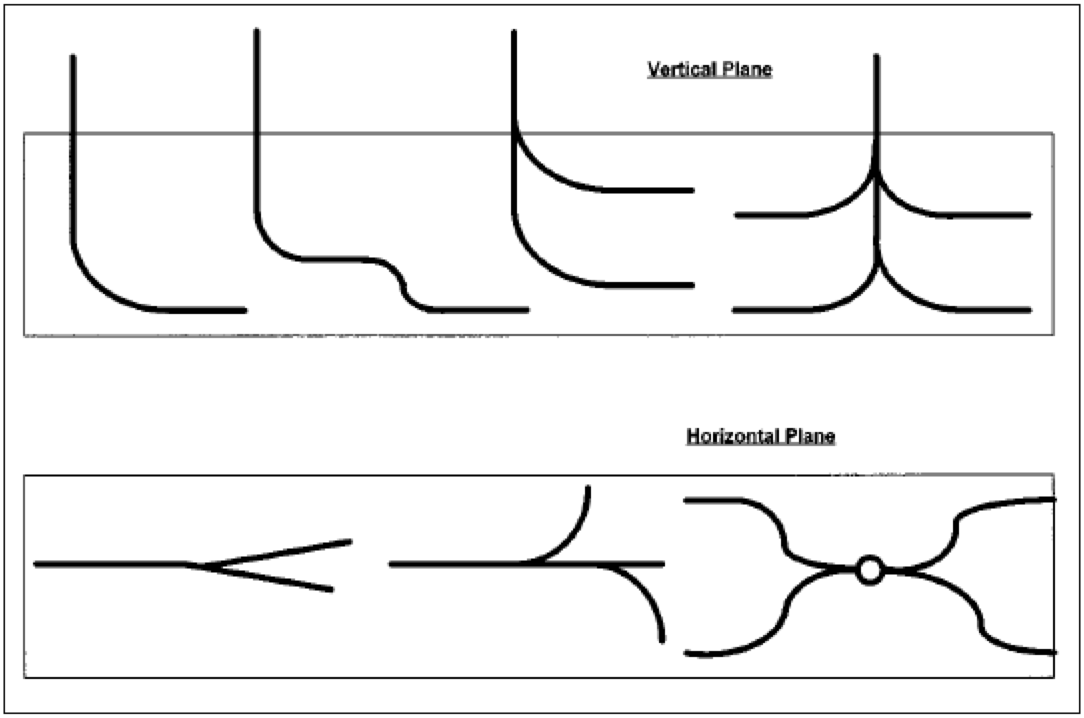

Fig. 4.2–Horizontal, dual and multilateral well configurations (Joshi, 2000)

Horizontal wells require much more details and accuracy in reservoir description, reservoir heterogeneities, reservoir anisotropies (I_{ani}) (Eq. 4.2) (Furui et al., 2003), and well drainage boundaries when compared to vertical wells (Economides et al., 1993). Calculating horizontal well productivity requires knowing the following three parameters: producing length, I_{ani}, and the skin factor (Babu and Odeh, 1989; Joshi, 2000; Furui et al., 2005). Those parameters are hard to find and mostly estimated (Joshi, 2000). To add to the complexity the situation, the skin factor and the I_{ani} are interrelated. The dependency of the skin factor on the I_{ani} contributed to the usual nonuniform damage zone (**Fig. 4.3**).

$$I_{ani} = \sqrt{\frac{K_H}{K_V}} \quad \text{(eq.4.2)}$$

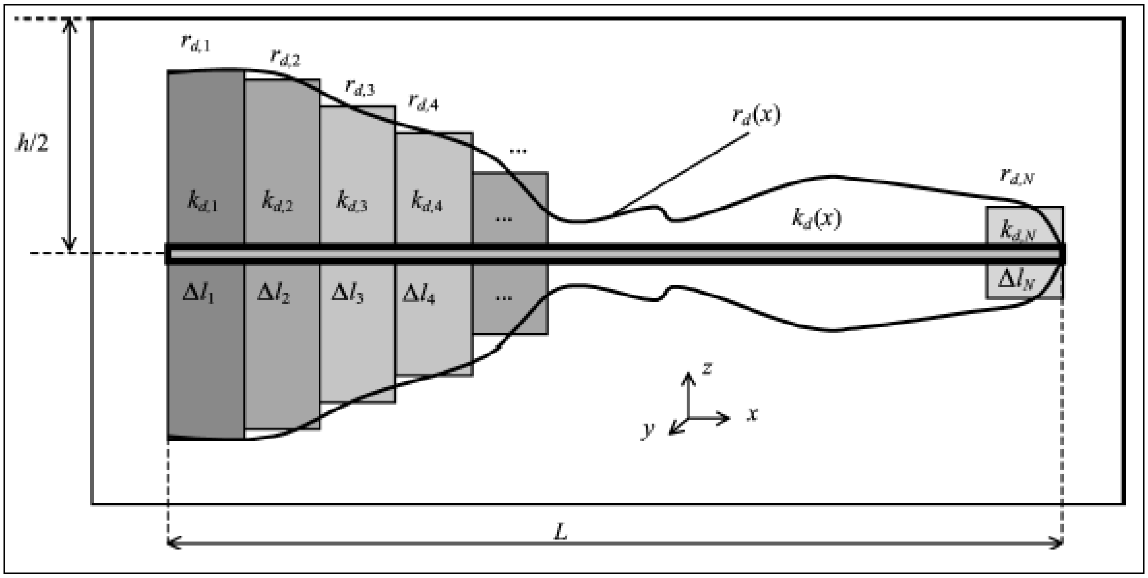

Fig. 4.3–Nonuniform damage zone associated with heterogeneities in Iani (Furui et al., 2003)

The available geological information does not include detailed vertical and horizontal distribution, which makes selecting a horizontal or multilateral well configuration misleading. Therefore, drilling horizontal, dual lateral, and multilateral wells is not among the development options I considered for this field.

4.3 Drilling schedule and new well location

I am going to use the combination of reservoir pressure mapping (Anderson, 1991), oil saturation, and reservoir thickness as a method to locate new wells. This method is affective and suitable to the level of available data. However, in reality, the IRD team must also conceder an approach such as the one proposed by (Mancini et al., 2004):

1. Characterize the geologic, petrophysical, and engineering properties of the formation

2. Construct a three dimensional geologic model and a reservoir simulation model for the reservoir intervals
3. Use the reservoir characterization, engineering reservoir performance analysis, and geologic and reservoir simulation modeling to assess propose the most suitable well location

Reservoir pressure mapping contributes to determining optimal oil well locations (Dehdari et al., 2008). However, the reservoir pressure mapping method, as Anderson originally presented it, is not suitable to my reservoir because he assumed constant reservoir thickness. Therefore, I had to factor in reservoir thickness and oil saturation to my method in order to get accurate results. The reservoir pressure mapping method, including my thickness and oil saturation modification (step # 5), requires performing the following steps:

1. Locating existing wells on reservoir's map
2. Plotting reservoir pressure on a contour map (isobaric map) (**Fig. 4.4**)

   Anderson proposed a set of equations to calculate reservoir pressure based on five general assumptions. However, I am not going to use it in locating infill drilling wells, simply because it is much accurate, more convenient, and a lot faster to use ECLIPSE to calculate the reservoir pressure at any point in the reservoir. Furthermore, the need to use a reservoir simulator, such as ECLIPSE, to calculate reservoir pressure is grater when multiple wells are scheduled at different times during the development. Introducing a new well to the system has its own effect on reservoir pressure, thus the whole process has to be repeated for every well in the drilling schedule.

3. Drawing streamlines (**Fig. 4.5**):
   a. Streamlines intersect pressure contours orthogonally, because fluids flow in the direction of the “maximum pressure gradient” (Anderson, 1991).
   b. Streamlines go from high pressures to lower pressures (Anderson, 1991).
   c. Streamlines pass through counters with minimum curvature (Anderson, 1991).
4. Locating the infill drilling well in the area with the lowest pressure gradient

   Lower pressure gradients (widely spaced pressure contours) indicate a poorly drained region of the reservoir (Anderson, 1991). Therefore, areas with lower pressure gradients are good candidates for new OPs. On the other hand, higher pressure gradients (closely spaced pressure contours) indicate good drainage (Anderson, 1991).
5. Changing the well location if either thickness or oil saturation is not sufficient for significant oil production.

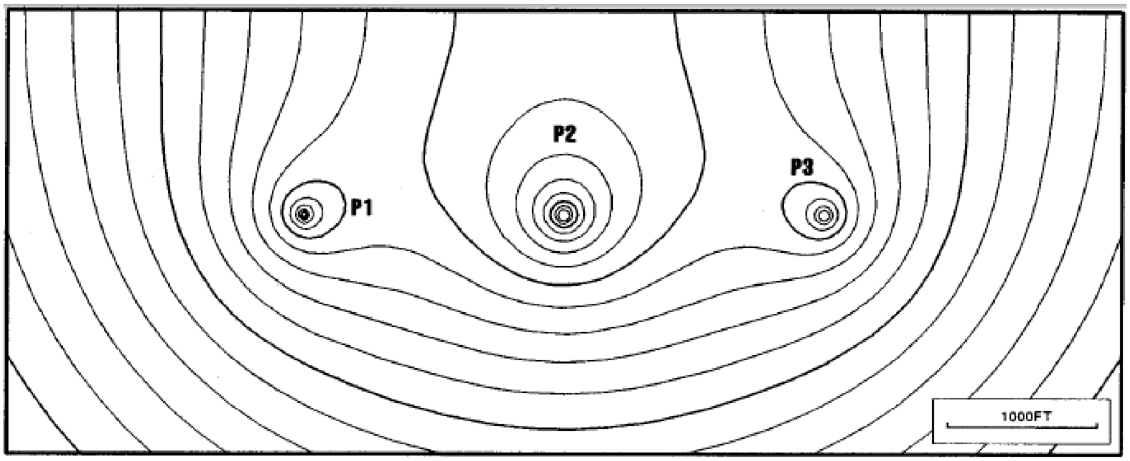

Fig. 4.4–Hypothetical pressure contour map for three oil wells P1, P2, and P3 (Anderson, 1991)

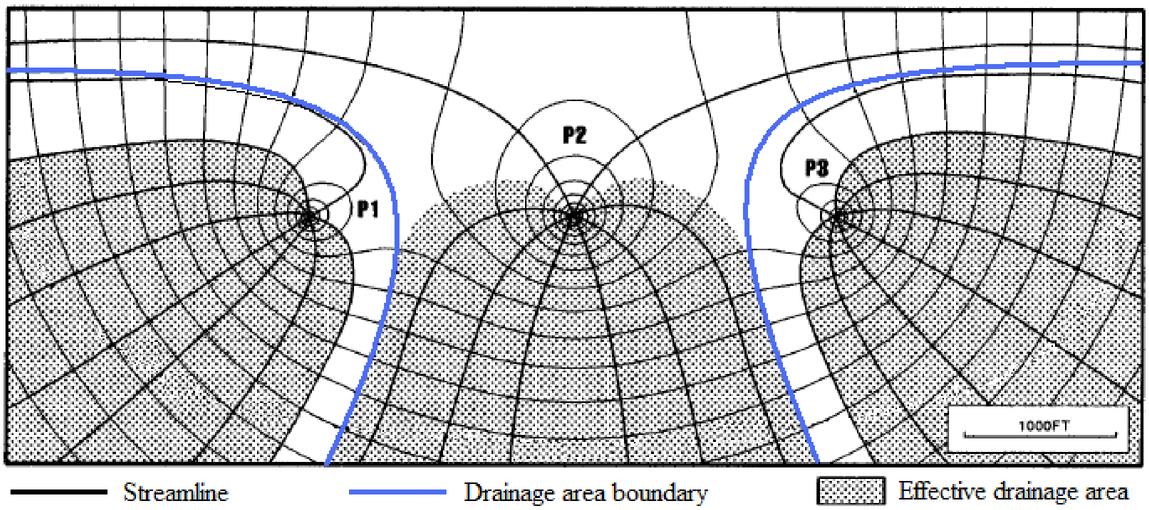

Fig. 4.5–Streamlines crossing pressure contours, modified from (Anderson, 1991)

I will construct the drilling schedule assuming the availability of one rig on the platform. OP drilling time is 50 days (Ewy et al., 1994), and WI drilling time is 45 days. These times include drilling, completing, and tieing-in the well to the platform.

4.4 Water shutoffs

Increasing water cut has its own negative effect of the production system. (Ghedan et al., 2009) states that “increasing water cut will reduce oil recovery, diminish wells’ productivity and increases cost of eventual artificial lift and produced water handling.” He went further to state that 75% of produced fluid is formation water. This problem could be treated by many options such as (Cholet, 2000):

- polymer/gel placement around the wellbore to modify relative permeability
- mechanically installing an inflatable composite sleeve polymerized in-situ

CHAPTER V

ARTIFICIAL LIFT

There are two artificial lift options I am going to consider, continuous Gaslift and ESP.

5.1 Gaslift (Fig. 5.1)

Gaslifting is a process that works by injecting natural gas into a producer tubing to reduce the density of the fluid to increase the production rate, or make the well flow again*. Gaslift can operate from 10 to 80,000 STB/day, and it can handle higher deviation and sand production*. Other than the initiation stage, the continuous gaslift injects gas from the lowest valve available*. Eq. 5.1* is used to calculate the flowing bottomhole pressure in a gaslifted well.

$$P_{wf} = p_{wh} + G_{av}D_{ov} + G_{bv}(D_f - D_{ov}) \qquad \text{(eq.5.1)}$$

where

Pwf is the flowing bottomhole pressure

Pwh is the wellhead pressure

Gav is the tubing flowing gradient above point of injection

Gbv is the flowing gradient below point of injection

Dov is the depth of injection

Df is the depth of the formation

* PETE-618 Fall 08 course notes

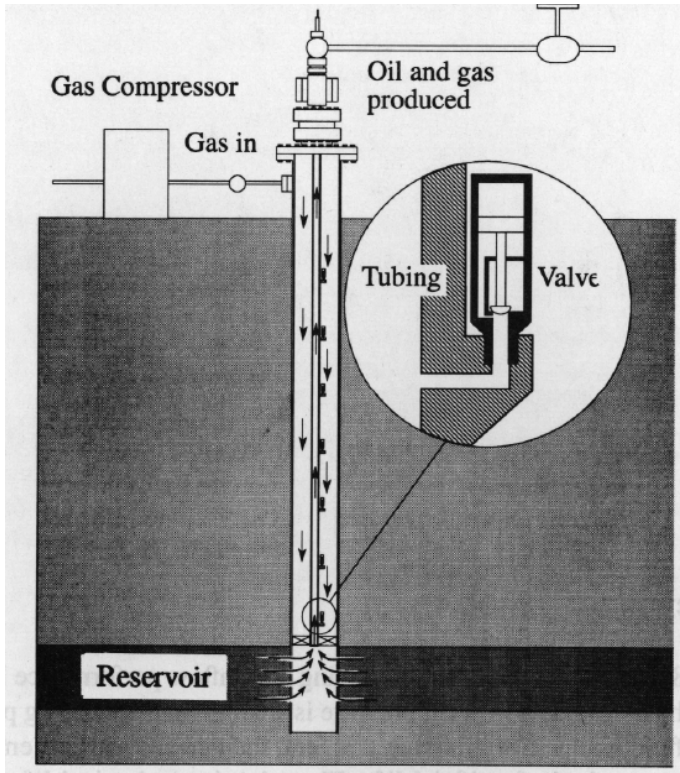

Fig. 5.1–A typical gaslift system*

5.2 ESP

ESP operates mechanical work on the wellbore liquid. This work is transferred to the liquid as pressure. In other words, the liquid that leaves the pump has a higher pressure that when it entered it*. Eq. 5.2, shows how to calculate the work required by the pump for an incompressible fluid*.

$W_s = \frac{p_2 - p_1}{\rho} + F$ ……..………………………………………………………….(eq.5.2)

* PETE-618 Fall 08 course notes

Below is the procedure to design an ESP*:

1. Determine the needed Pwf for the production rate of choice (from the IPR)
2. Calculate the pressure just below the pump, from a 2-phase flow calculation and starting with Pwf
3. To determine P2 at the desired rate, base your calculations on a single-phase liquid flow.
4. You can find the required work once the ΔP is known, based on empirical knowledge of frictional losses in the pump.

* PETE-618 Fall 08 course notes

CHAPTER VI

MODELING AND OPTIMIZING PHASE AND ECONOMIC EVALUATION STAGE

6.1 The modeling and optimizing phase (Fig. 6.1)

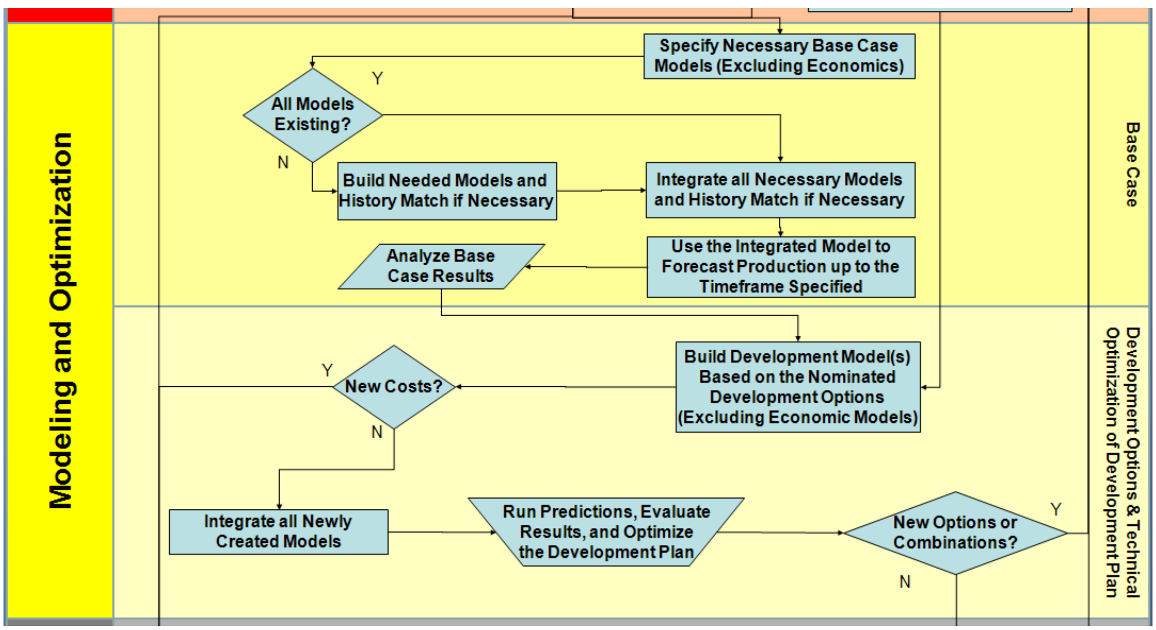

Fig. 6.1–The modeling and optimization phase, the second phase of the IRDW

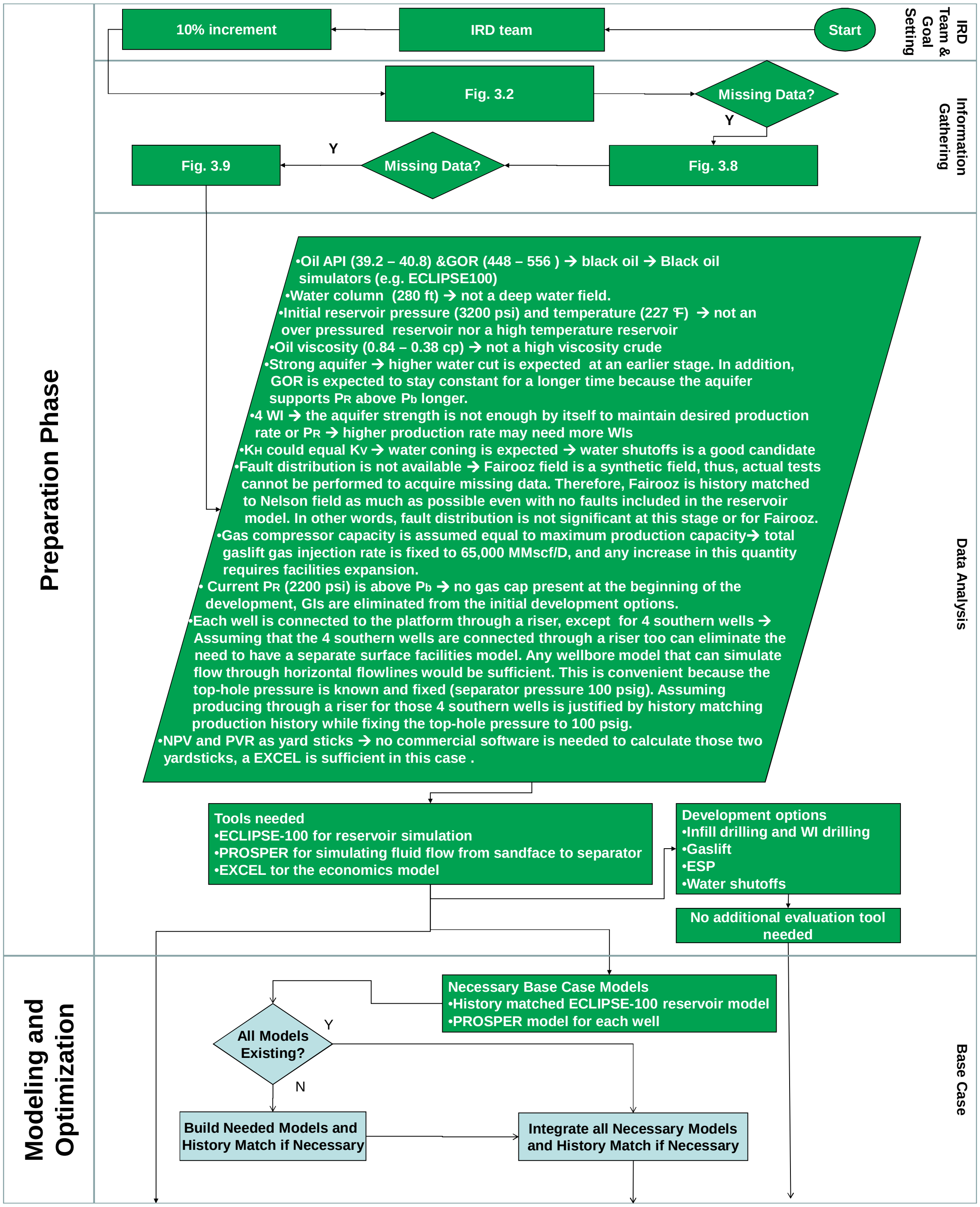

Fig. 6.2–The modeling and optimization phase, specifying necessary base case models

6.1.1 The base case stage

6.1.1.1 Specify necessary base case models (**Fig. 6.2**)

I need a history-matched ECLIPSE-100 model for the analog field (Nelson field), in order to use it as a base to run predictions and develop my synthetic field (Fairooz field). This reservoir model does not have to exactly match Nelson field, because Nelson is just an analog to Fairooz. I also need a PROSPER model for all 23 existing OPs. Those 23 PROSPER models have to model production from the bottomhole all the way to the separator. In other words, surface facilities has to be modeled as discussed in Chapter IV.

6.1.1.2 Are all models existing?

No, none of the models specified in 6.1.1.1 exists.

6.1.1.3 Build needed models and history match if necessary (**Fig. 6.3**)

6.1.1.3.1 Building the reservoir model in ECLIPSE-100

Please refer to Appendix-A for the actual codes used for the base case and the infill drilling option for the 10% increment development goal. No history matching is required at this stage. I will history match the IAM, after I integrate all models.

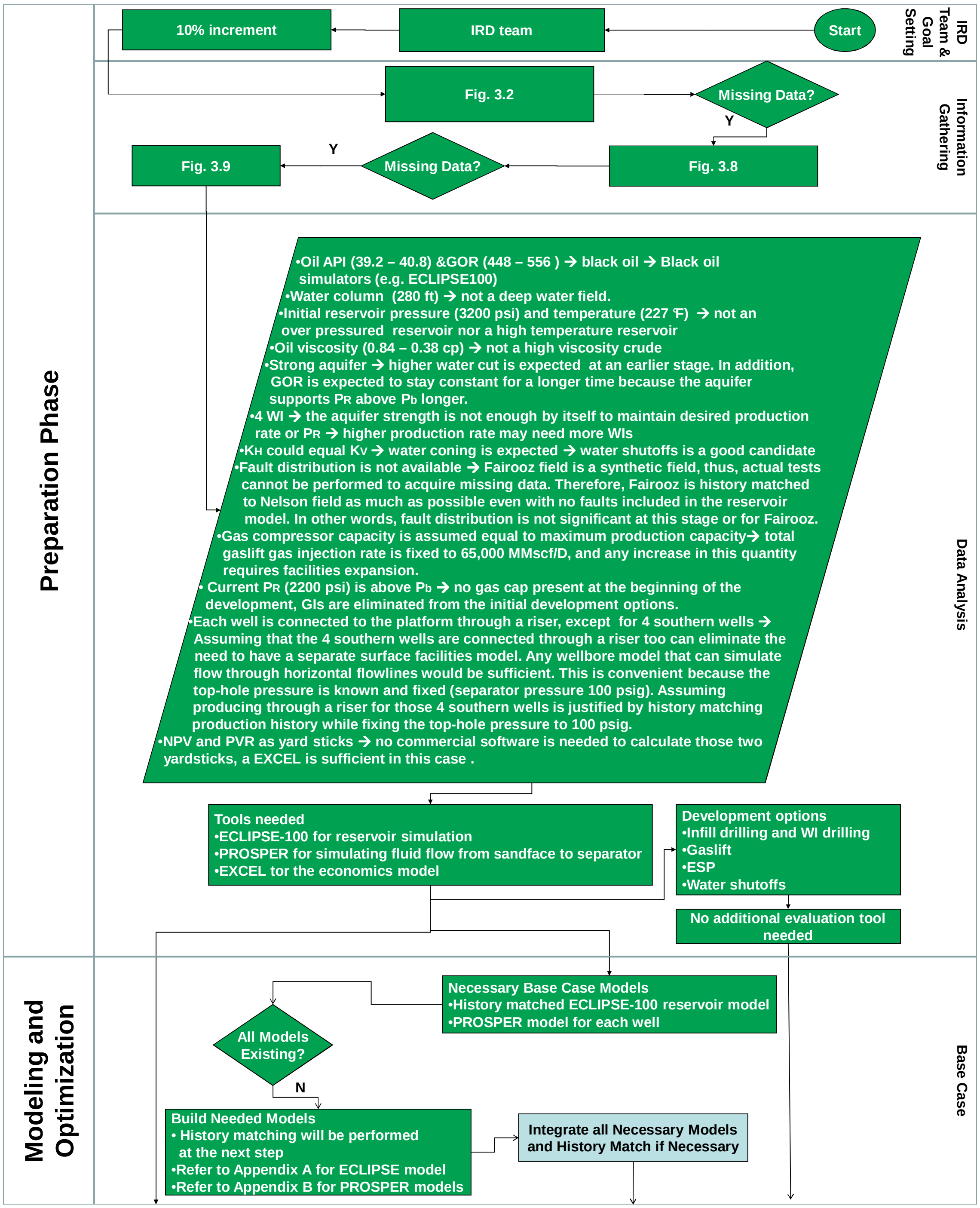

Fig. 6.3–The modeling and optimization phase, building needed models

The strategy I adapted in building the model was to incorporate all certain Nelson parameters with all their details, incorporate uncertain or analog parameters with a lower level of details, and change the uncertain parameters or decrease their details until I achieve an acceptable history match.

Nelson consists of 7 geological regions (**Fig. 3.5**), and 4 PVT regions (**Table 3.2**). I have decided to reduce the initial number of geological regions from 7 to 4, mimicking the PVT regions. Those 4 PVT regions are central, eastern, western, and southern. Initially, I thought that reducing the geological regions to 4 might be an oversimplification. However, the limited reservoir heterogeneity data, that I have, forced me to simplify the parameters even more. After that, I realized that the more I simplify and generalize the uncertain data while maintaining the certain data, the faster I get toward reasonable history match (see section 6.1.1.4). Therefore, I have decided to unify the geological regions into one, while keeping the 4 PVT regions because it certain. I have used the PVT reports in the oil PVT data section in ECLIPSE. However, I had to use PROSPER to generate the gas PVT tables I used in the gas PVT section in ECLIPSE (**Table 3.2**). I have set Water PVT and compressibility as history matching sensitivities, and I have set an estimated initial value to both of them. I have set rock compressibility as a history matching sensitivity, and estimated an initial value to it too. In addition, I have assumed that the reservoir has a flat tops and bottoms for simplicity. However, to reflect the dome shape of the reservoir, I have deactivated necessary grid cells (**Fig. 6.4**). Nelson has a strong water aquifer underneath it, so I assumed it has a large volume and assumed it had a productivity index of 100 STB/day/psi and then used those two parameters as history matching sensitivities. The aquifer productivity index became an integral history matching parameter (see section 6.1.1.4).

Although relative permeabilities are set as history matching parameters, their initial values had to be estimated. The initial relative permeability curve is based on the well sorted sand provided by (Ahmed, 2006) correlation.

At this step I have only matched the original oil in place (OOIP) (**Fig. 6.5**), by lowering porosity, changing the irreducible water saturation (S_{wirr}) value in the relative permeability curves, and deactivating border cells while maintaining the overall dome shape. Porosity was reduced to its lowest reported value of 20% and the suitable S_{wirr} was 20%. The reported OOIP at the end of 1997 was 728 MMstb*, and with an average production of 120 Mstb/d for 3 years, the OOIP at the beginning would be around 859 MMstb. The OOIP the model calculated was around 933 MMstb, which is an acceptable 8.6% increase.

* Internal field report (unpublished)

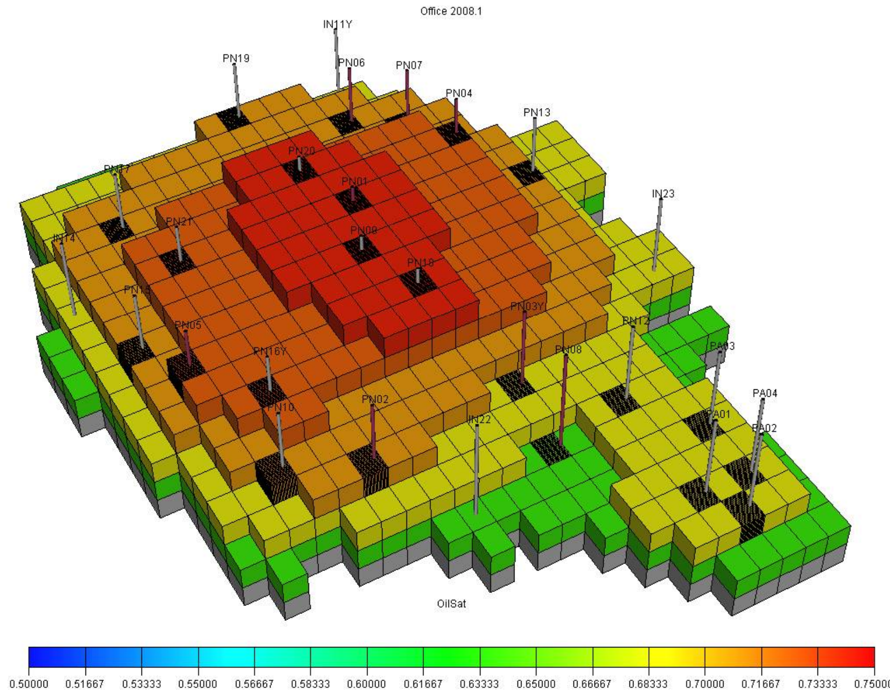

Fig. 6.4–Fairooz field dome shape

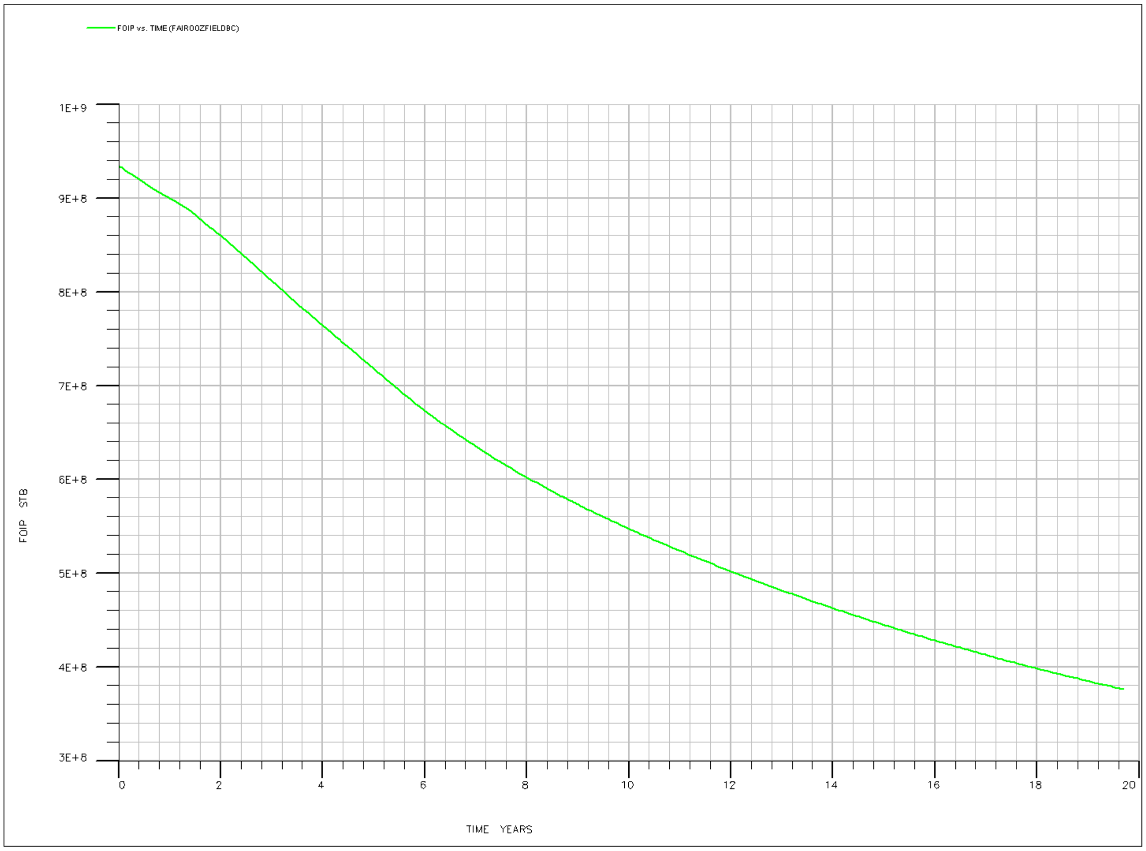

Fig. 6.5–Fairooz STOIP (STB)

I will defer matching the production rate until I integrate the models in section 6.1.1.4, because including the wellbore and facilities models increases the accuracy of history matching. Integrating allows to history match production rates and tophole pressures. In my case the tophole pressure is the separator pressure (100 psig).

6.1.1.3.2 Building the wellbore and facilities models for all existing OPs

Please refer to Appendix-C for a detailed description of how I built PROSPER wellbore models for each well, by showing a step by step demonstration on building N01 model.

I have assumed that the point of communication between PROSPER and ECLIPSE is the top of the formation. In other words, all OP PROSPER models are going to share the same last casing that has a TVD of 7371 ft. I will use PROSPER models to mainly generate the VLP files for the purpose of integration. I will not use PROSPER to generate IPR files because ECLIPSE can do it in real time. When building the wellbore and facilities PROSPER models for the 4 wells that are not gaslifted, I will consider them as gaslifted wells.

6.1.1.4 Integrate all necessary models and history match if necessary (**Fig. 6.6**)

In building an integrated model for the base case WI wells are not going to be modeled all the way to the surface. I will place them in the reservoir model only and assume they are capable of injecting up to the maximum recorded water injection rate over the history of the field. Integration is done in ECLIPSE.

Please refer to Appendix-A for the input data file used for the base case IAM and the 10% increment by infill drilling IAM. Also, refer to **Fig. 6.7** for the results of the base case IAM history matching.

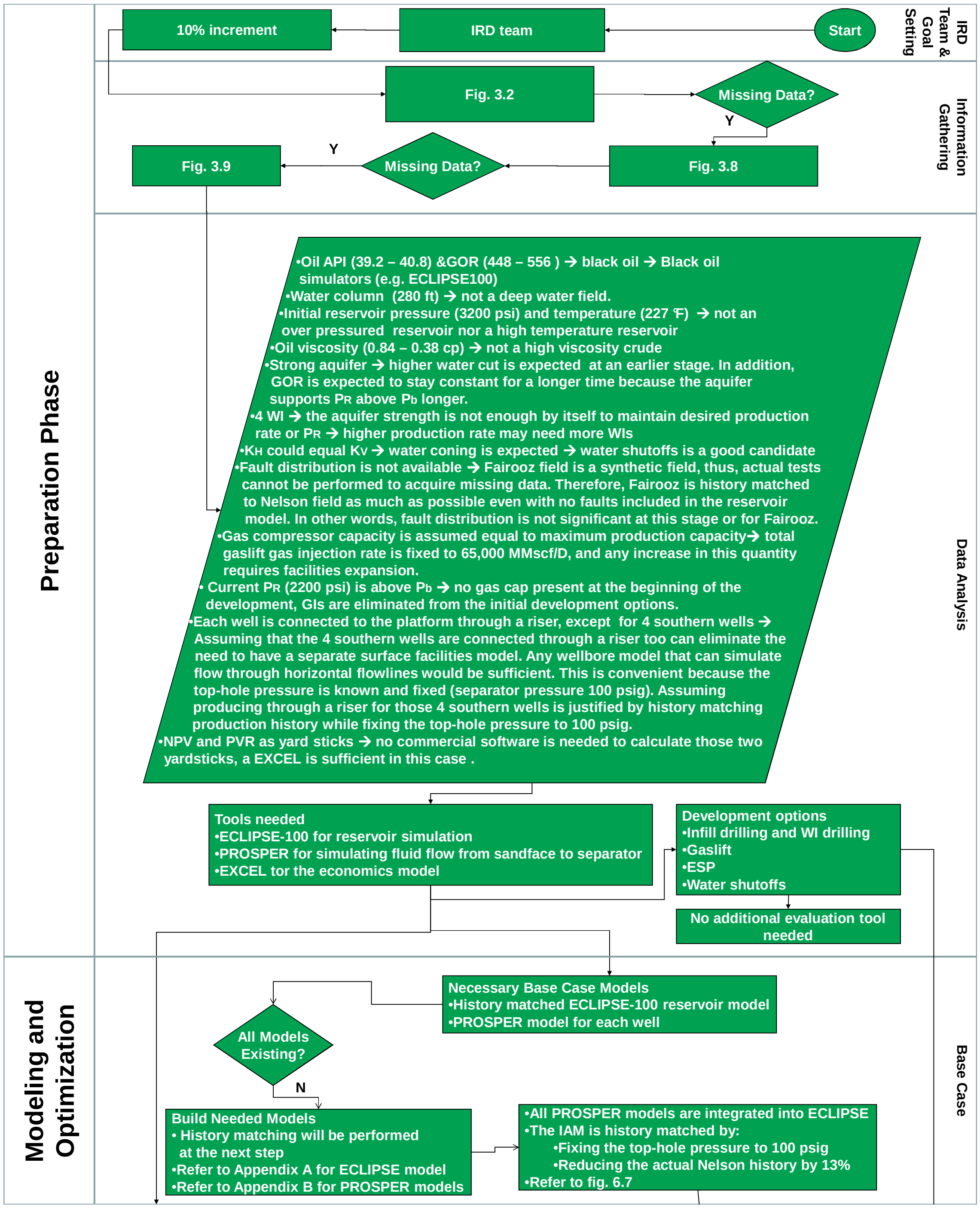

Fig. 6.6–The integration and matching step in the base case stage

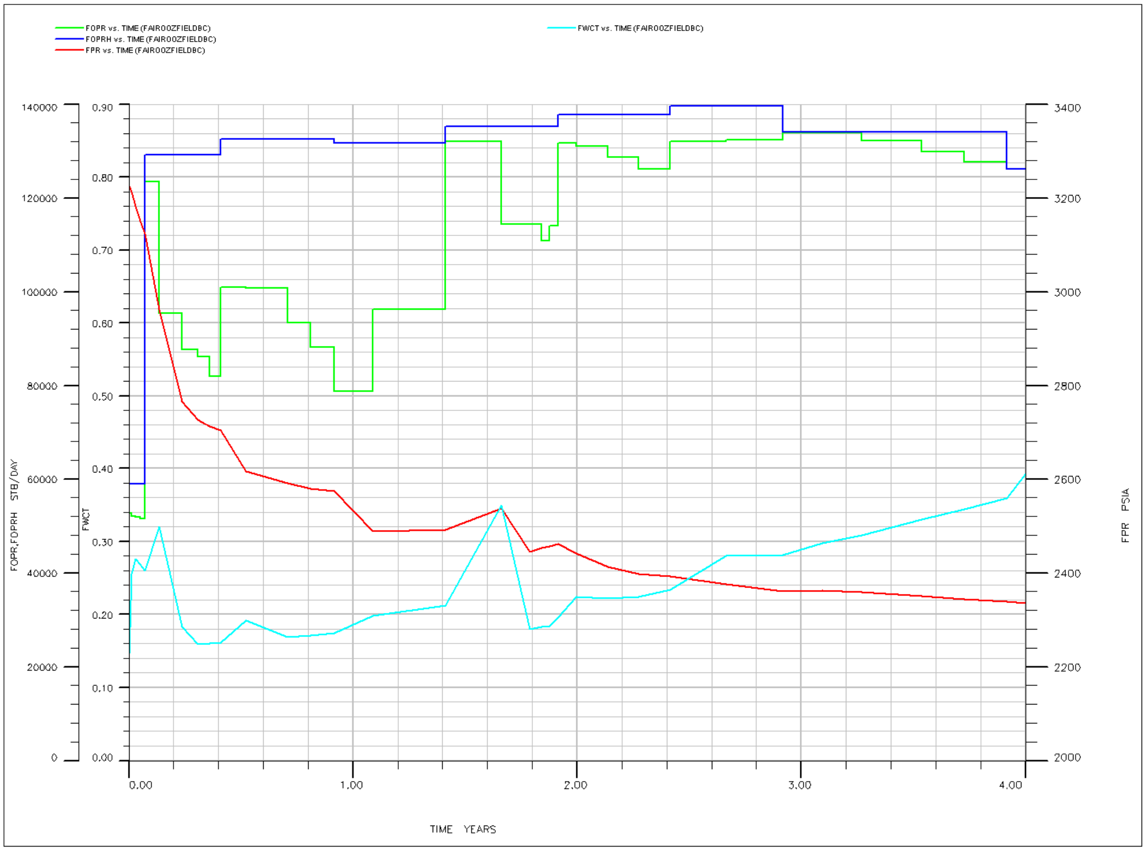

Fig. 6.7–History matching the IAM, oil rate matching and history, reservoir pressure, and water cut

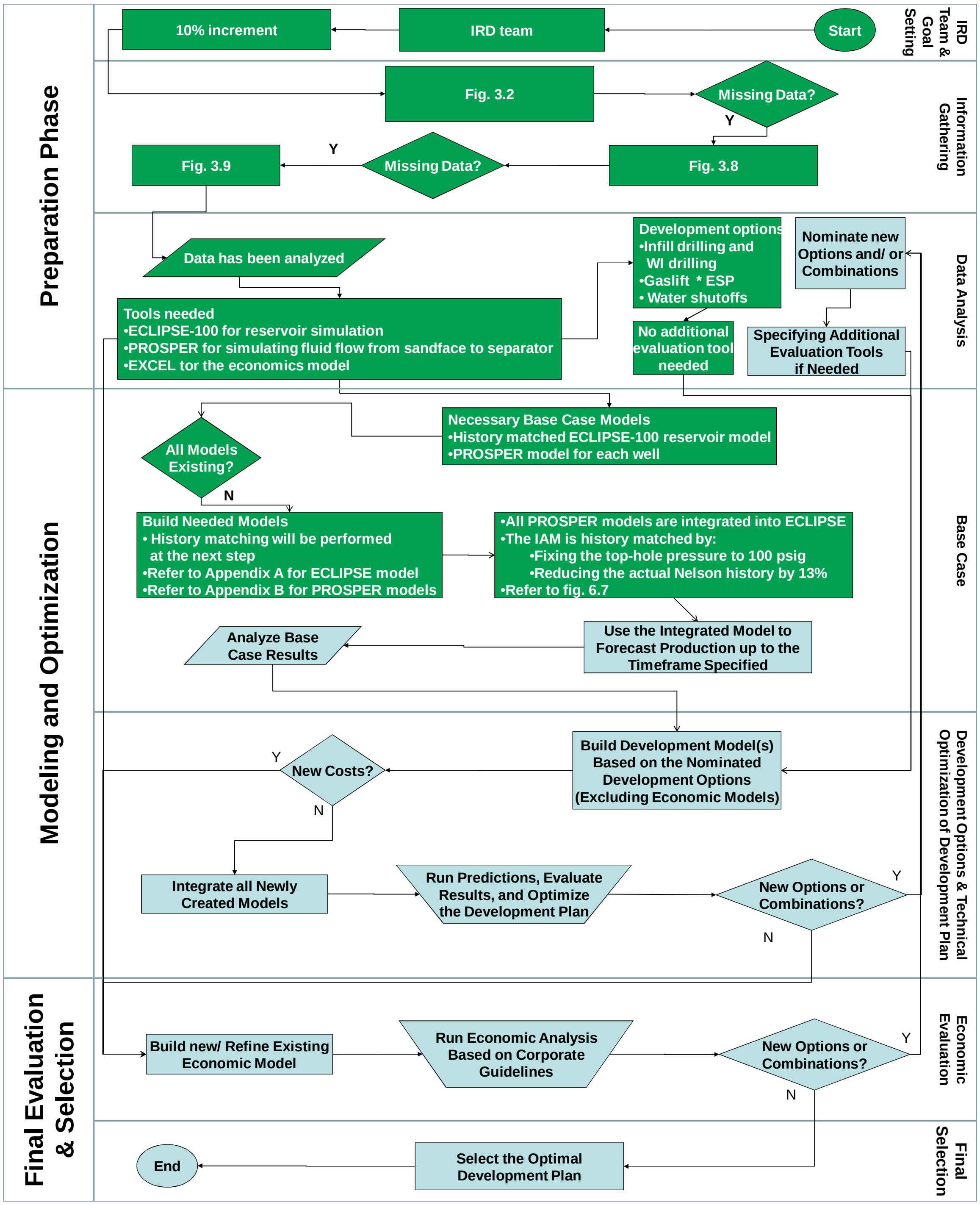

Fig. 6.8–The IAM forecasting step in the base case stage

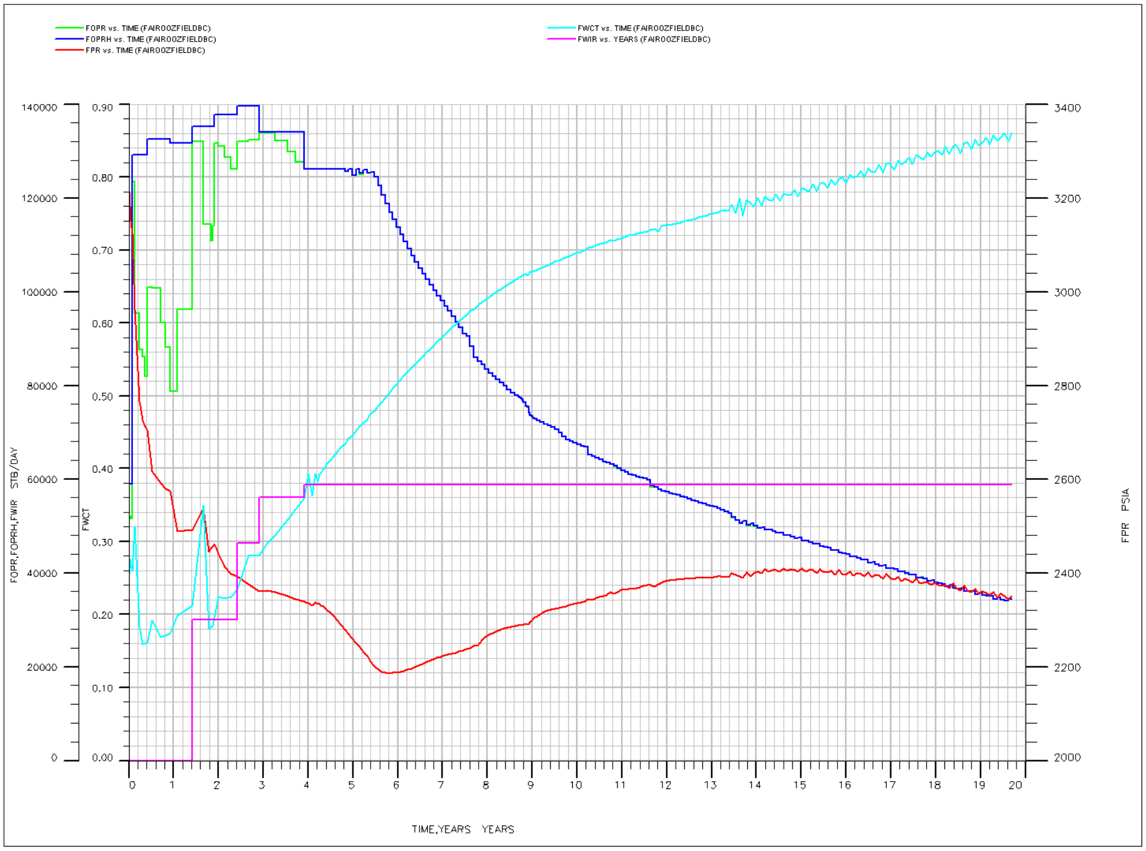

Fig. 6.9–The IAM forecast, oil rate, reservoir pressure, water injection rate, and water cut

6.1.1.5 Use the integrated model to forecast production up to the timeframe specified (**Fig. 6.8**)

The results (**Fig. 6.9**) are ready for analysis. The next step in the base case stage is analyzing the forecast of the IAM. **Fig. 6.10** shows the completed IAM forecasting step.

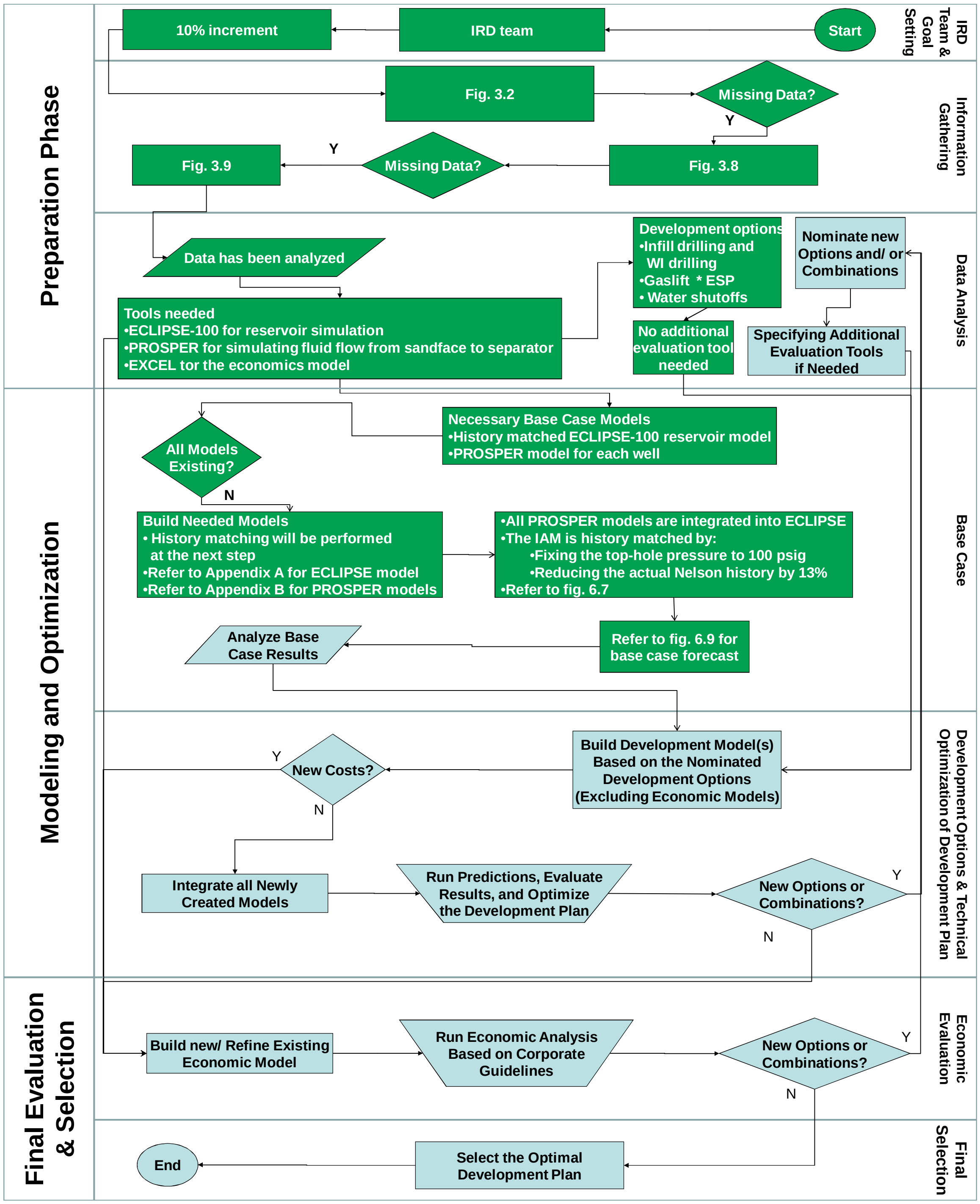

Fig. 6.10–The IAM forecasting step with reference to the results, part of the base case stage

6.1.1.6 Analyze base case results (**Fig. 6.13**)

Fig. 6.9 shows the reservoir pressure, oil production rate, water cut, and water injection rate of Fairooz field base case. I have realized that the field sustained its overall production plateau for a year and a half. After that, oil production starts declining, water injection rate stays the same, water cut continues to increase but in a slower acceleration, and reservoir pressure starts to increase. The increase in reservoir pressure was interesting, especially that the water injection rate is fixed during the forecasting period. **Fig. 6.11** shows the increasing trend of field water production rate and the fixed water injection rate vs. time. It indicates that the reason for this phenomenon is the strong natural aquifer pressure support.

After running the results from the integrated asset model I found that gas production was less than the actual (forecasted or max limit) (**Fig. 6.12**), but I will apply the same percentage 65% (Gerrard et al.) for fuel gas.

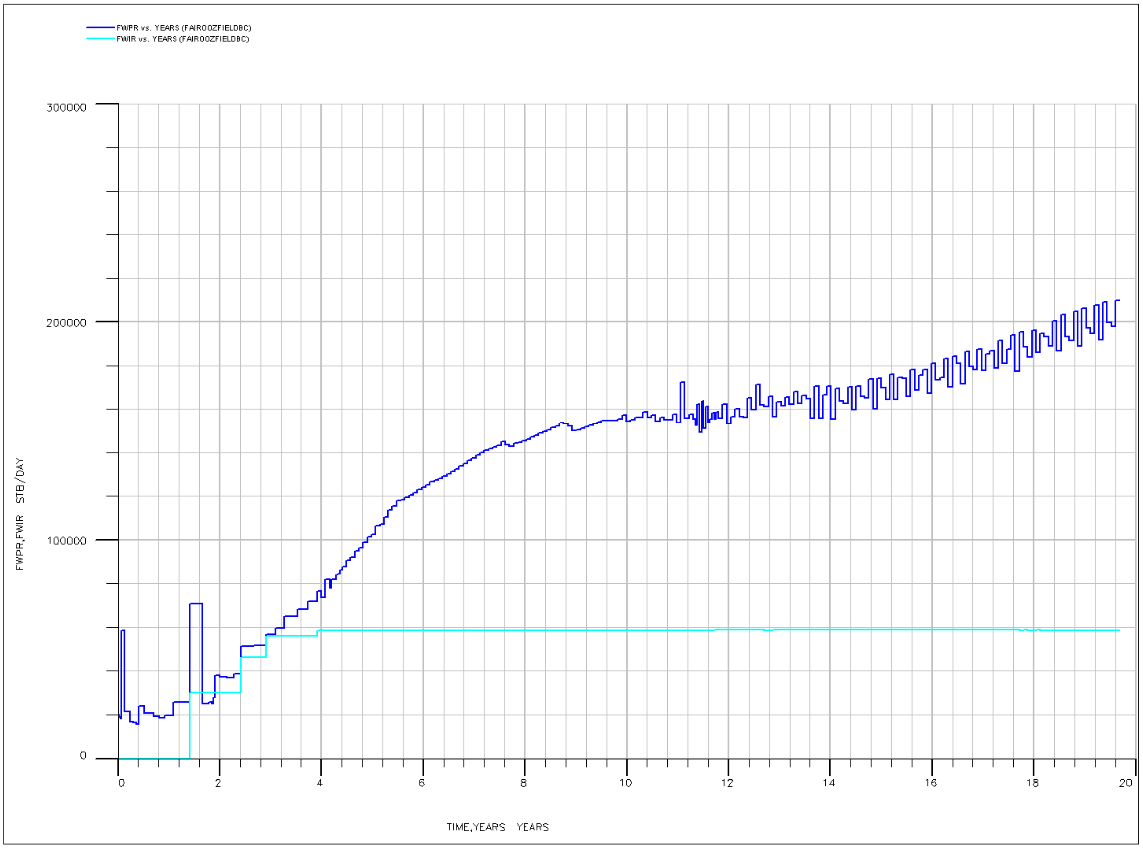

Fig. 6.11–Base case field water injection rate (FWIR) and field water production rate (FWPR)

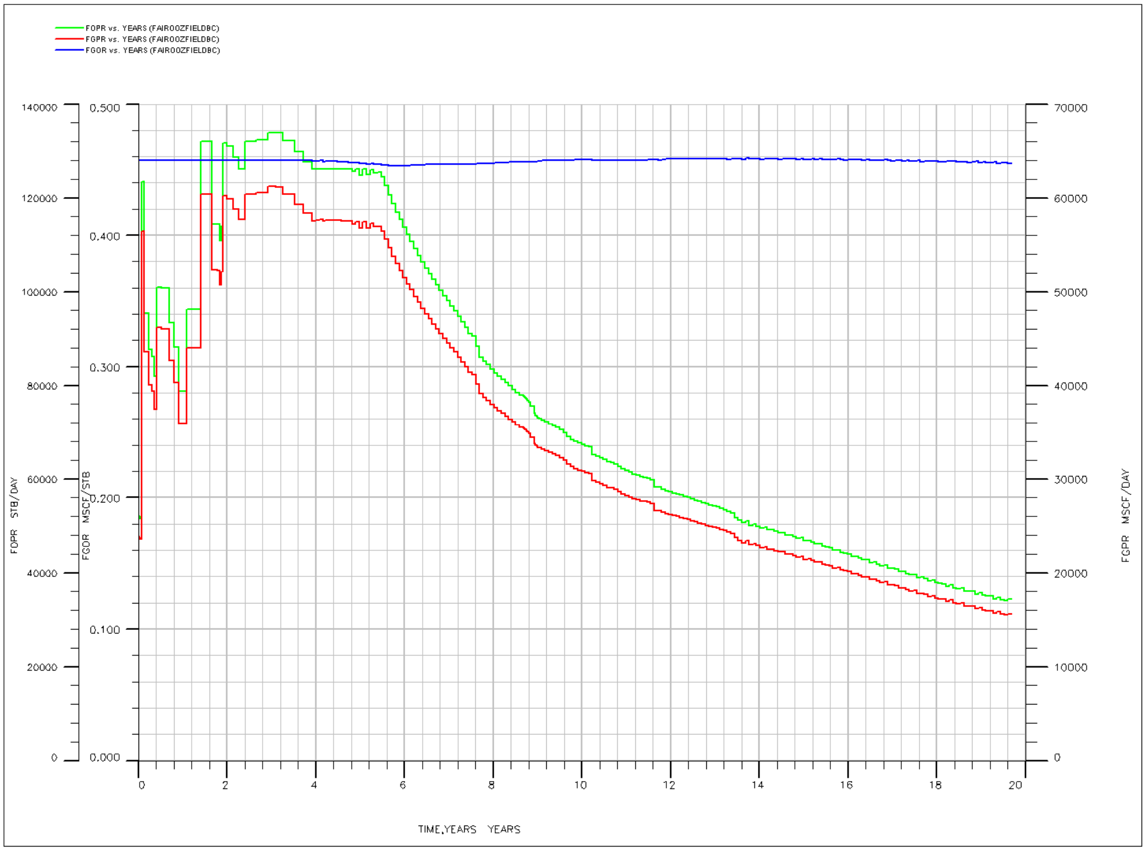

Fig. 6.12–IAM oil production rate, gas production rate, and GOR

(Gerrard et al., 2007) stated, that the available gas compressor capacity is lower than all producers' gas-lift gas needs. However, because Nelson at that time have had more gas lifted wells drilled, I am going to assume that the current gas compressor is capable of supplying the gas-lift gas needs for all 23 existing oil producers. This makes the current gas compressor capacity 69,000 Mscf/day, because all wells needed an average of 3,000 Mscf/day of gas-lift gas to match the field production (23 $\times$ 3000 Mscf/day = 69,000 Mscf/day). However, I am not assuming 100% gas-lift gas recycling efficiency. Instead, I am assuming 90% efficiency, which means that the actual gas rate allocated for gas-lift is 6,900 Mscf/day (10% of 69,000 Mscf/day). This same quantity of

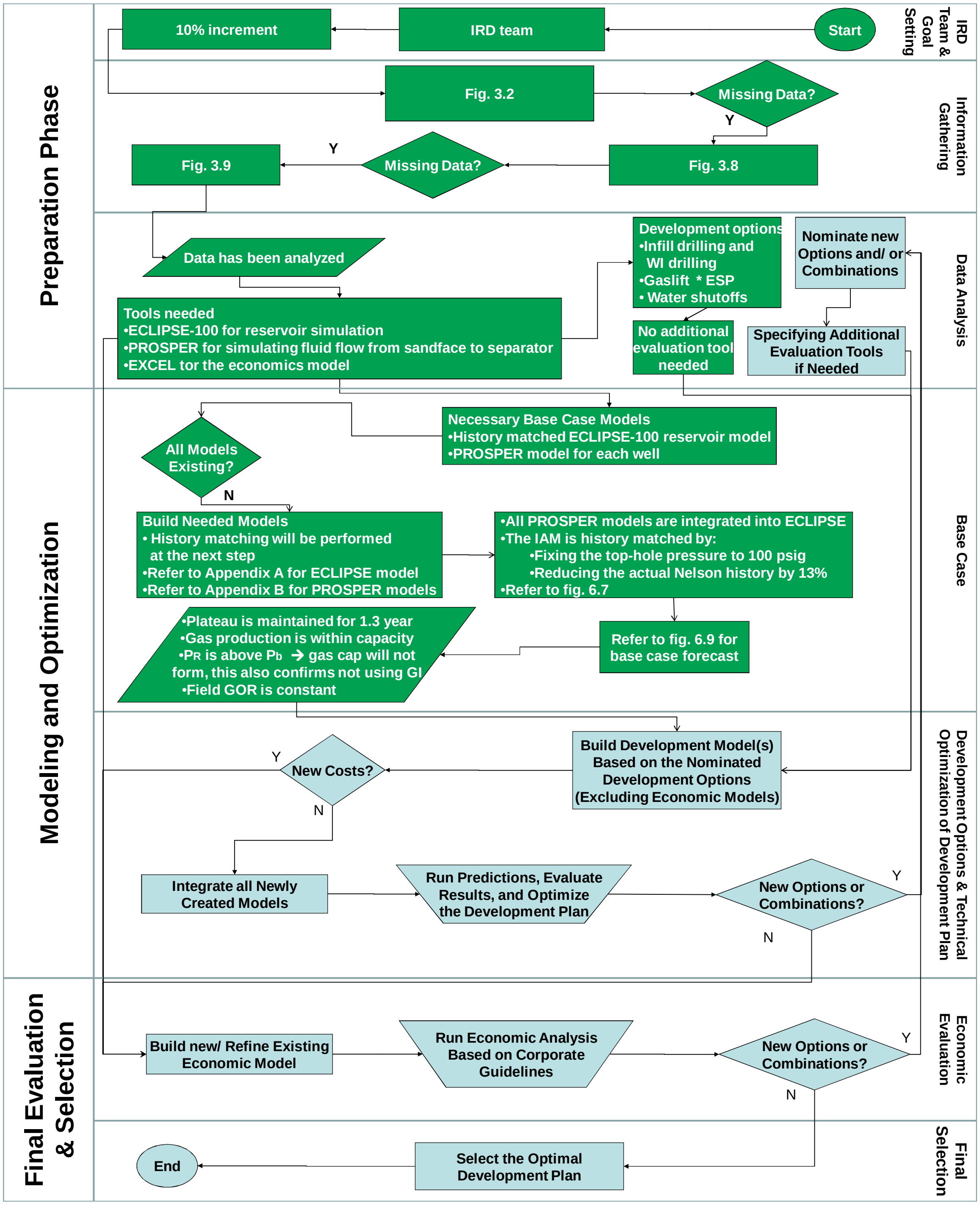

Fig. 6.13–Analyzing base case results

gas-lift gas will apply to the ESP cases, because the initial 19 gas-lifted wells still need the gas-lift gas. This means that the 69,000 Mscf/day is going to be divided between 19 wells instead of 23, thus more gas-lift gas per gas-lifted well.

6.1.2 Development options and technical optimization of development plan (**Fig. 6.14**)

At this stage the evaluation becomes specified for each development option. All steps in this stage will be repeated for all 4 development options. I will illustrate this state for infill drilling only. However, I will present the final development plan for the rest of the development options, in the following chapter.

6.1.2.1 Infill drilling

6.1.2.1.1 Build development models based on the nominated development options

Please refer to Appendix-A for the IAM infill drilling data file.

For infill drilling I need a wellbore and facilities PROSPER model for each new well drilled. All infill wells are not artificially lifted during the lifetime of this development. However, I will use the VLP files from the nearest well that shares the same PVT properties. This approximation is justifiable since all wells are drilled from the same platform, with the same deviation angle, the same completion, and they all stop at the top of the formation (7371 ft TVD). Finally, the PROSPER VLP files I generated cover all possible ranges of water cut and GOR, thus they are applicable for the whole development timeframe. When the new OPs are introduced in ECLIPSE, I will set the gaslift injection rate to zero, and this turns the well to a natural flowing mode (no artificial lift). Please refer to (**Fig. B-14**) and to Appendix-B in general for more information about natural lift VLP and gaslift VLP.

I will use the history matched base case model and modify it to be able to evaluate the infill drilling development option for the selected development goal. The first step is to increase the field oil plateau by 10%, which is the new goal I am trying to meet. This increment takes the field oil production rate from 126200 STB/day to 138820 STB/day. In addition, I will change all parameters needed to allow ECLIPSE to account for adding up to 9 extra wells, such as WELLDIMS or TABDIMS. On the other hand, and based on the strong aquifer support and its effect on reservoir pressure (see base case analysis in 6.1.1.6), I cannot justify drilling new WIs at this initial point in the development. However, I will evaluate drilling new WIs if the field performance analysis indicates a need to do so.

This step does not ask to run predictions, so I will move to the next step in the IRDW.

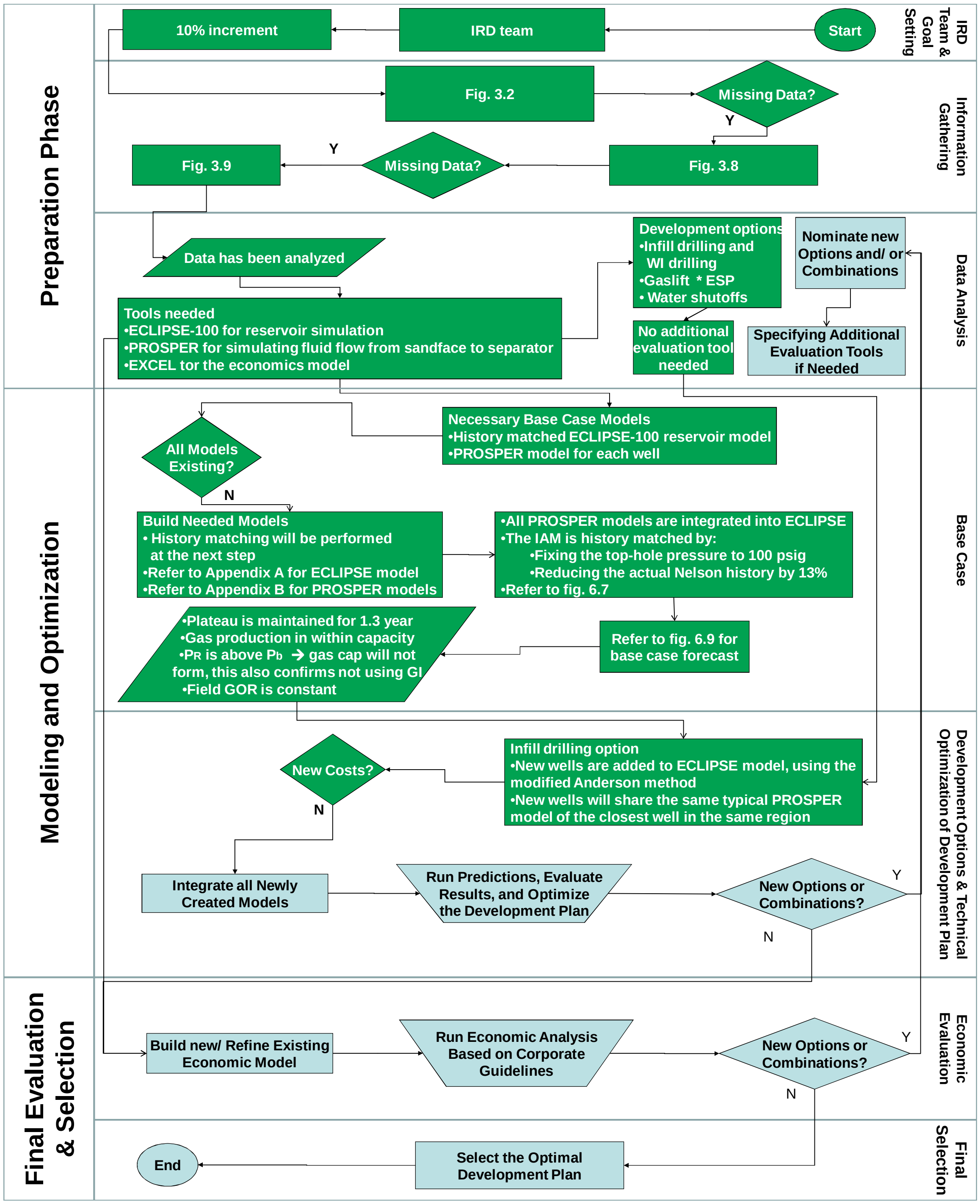

Fig. 6.14–Building development options models

6.1.2.1.2 Are there any new updates to cost?

No, there is no update to cost, because drilling cost is estimated and set to a fixed value. However, in reality, drilling cost is calculated by multiplying target depth with the calculated drilling cost/ft (Eq. 6.1) (Mitchell, 2006). This means that the actual drilling cost could be estimated after the well location is specified. In other words, in reality the IRD team would calculate drilling cost while evaluating the results in section 6.1.2.1.4 below.

$$\$/ft = \frac{C_B + C_R T_T + C_R T_R}{Y} \qquad \text{(eq. 6.1)}$$

where

$\$/ft$ = cost per foot

C_B = bit cost

C_R = rig cost

T_R = rotating time (hours)

T_T = trip time (hours)

and

Y = footage per bit run

6.1.2.1.3 Integrate all newly created models (**Fig. 6.15**)

The base case wells are all integrated, and I will integrate the VLP files for every new OP as soon as I find its location.

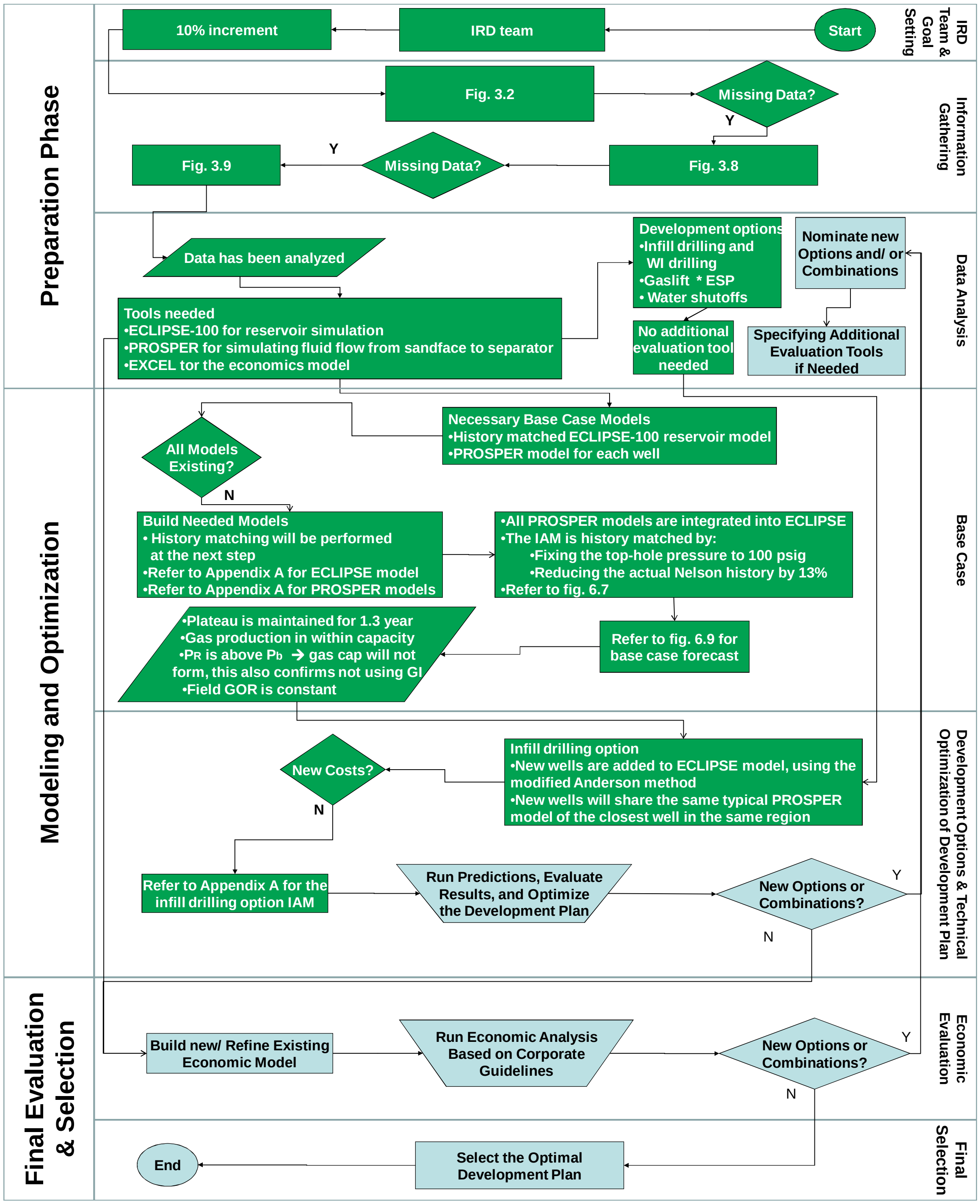

Fig. 6.15–Integrating all newly created models

6.1.2.1.4 Run predictions, evaluate results, and optimize the development plan

The first run is going to be the modified base case (see 6.1.2.1.1). **Fig. 6.16** shows that the plateau is maintained for 9 months.

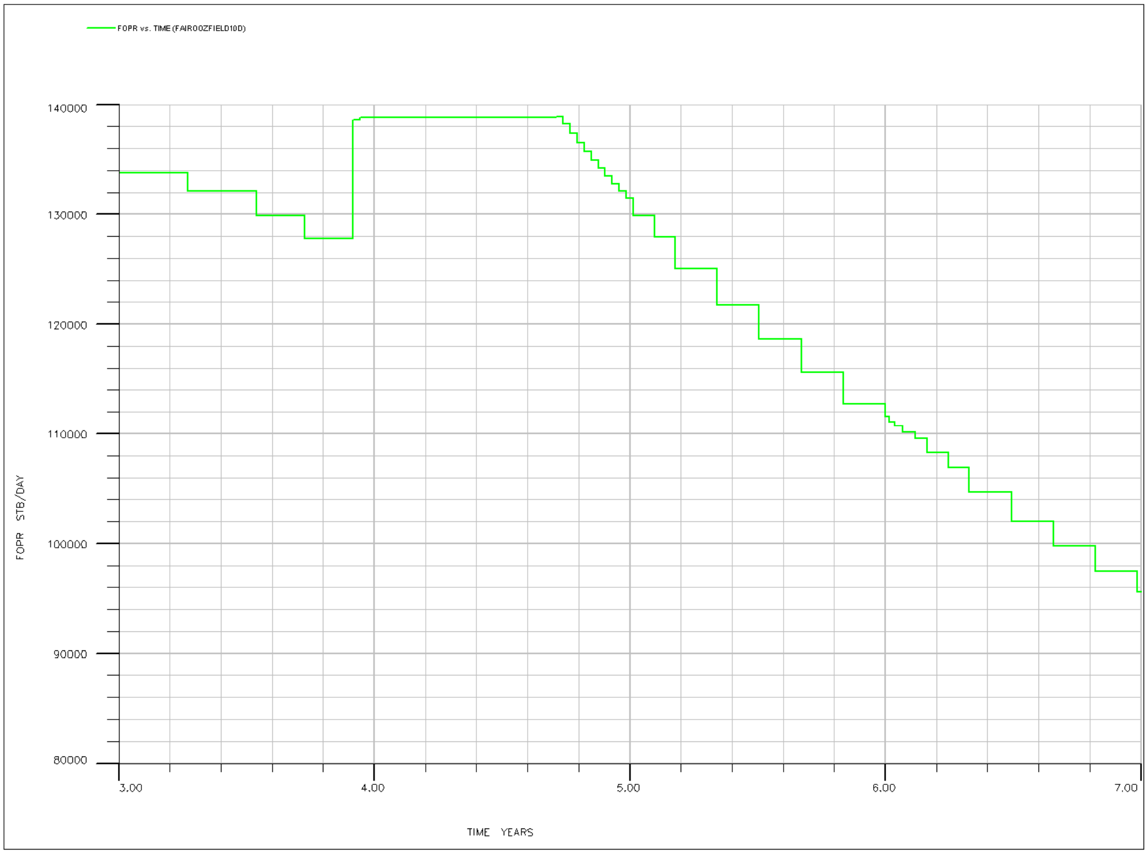

Fig. 6.16–Initial oil rate results of the infill drilling option for the 10% increment goal

This means that the first well has to be on-stream after 8 months. I will use my modification to Anderson method (see Chapter IV) to find the location of the infill wells. Therefore, I plot a pressure contour map of the field after 8 months of production, right before the decline (**Fig. 6.17**).

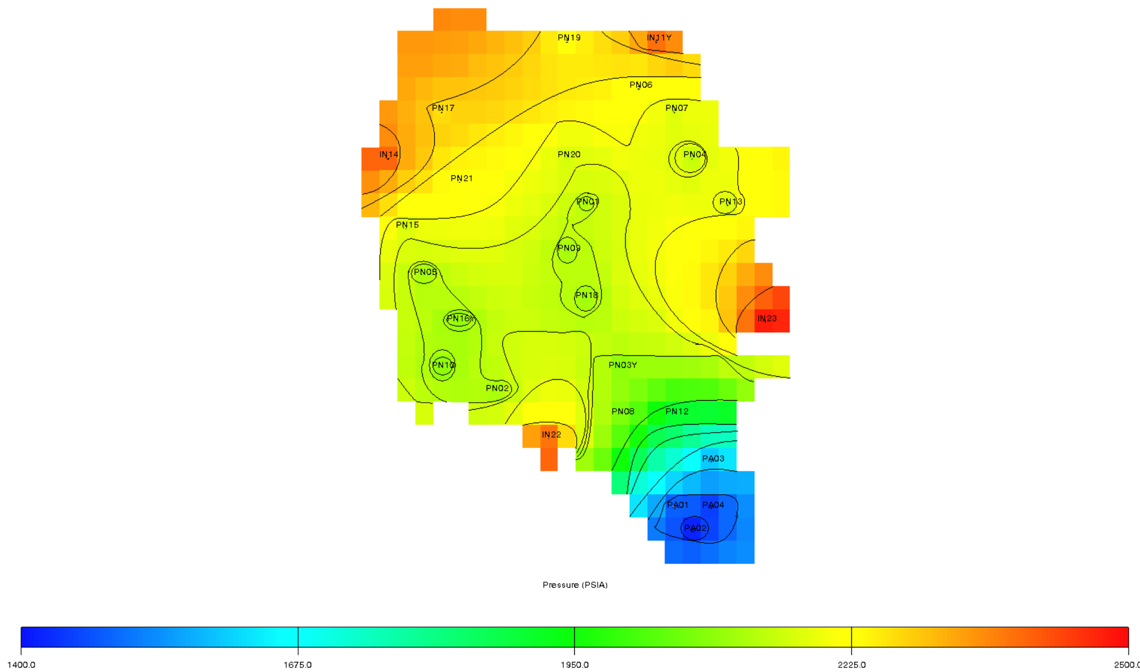

Fig. 6.17–An Isobaric map of Fairooz field

Then, I draw streamlines over the same map (**Fig. 6.18**). The location of the first infill well (F01) is in the area of lowest pressure gradient (**Fig. 6.18**). However, the pressure gradient by itself is not enough for such a decision, thickness and saturation are evaluated also. As a result, I had to change F01 location and move it toward the northeast. This will allow for more recovery because the well will encounter more pay zone and more oil saturation. At this point, I know the new location of F01, thus I have to choose its PROSPER model. The closest well is N09. However, the chosen location for F01 has different PVT properties than N09. Therefore, I have to look for the closest well that has the same PVT properties. N16 shares the save PVT properties as F01, and it is the closest well to F01. Therefore, I will use its VLP files in my model.

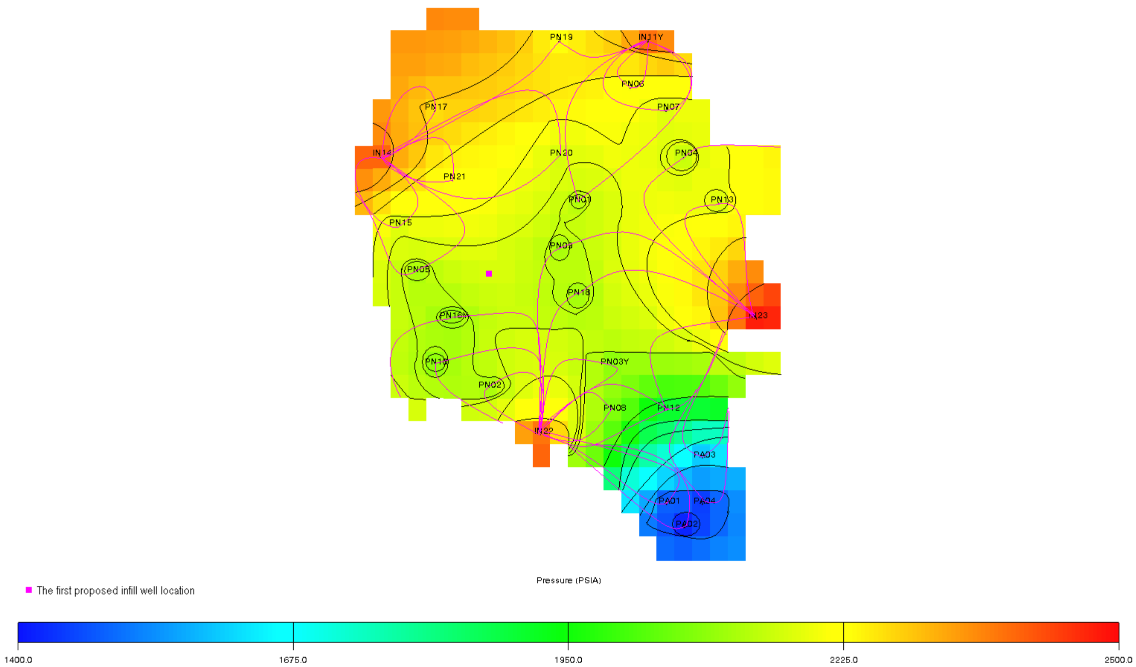

Fig. 6.18–Fairooz isobaric map with streamline and the location of the first proposed well

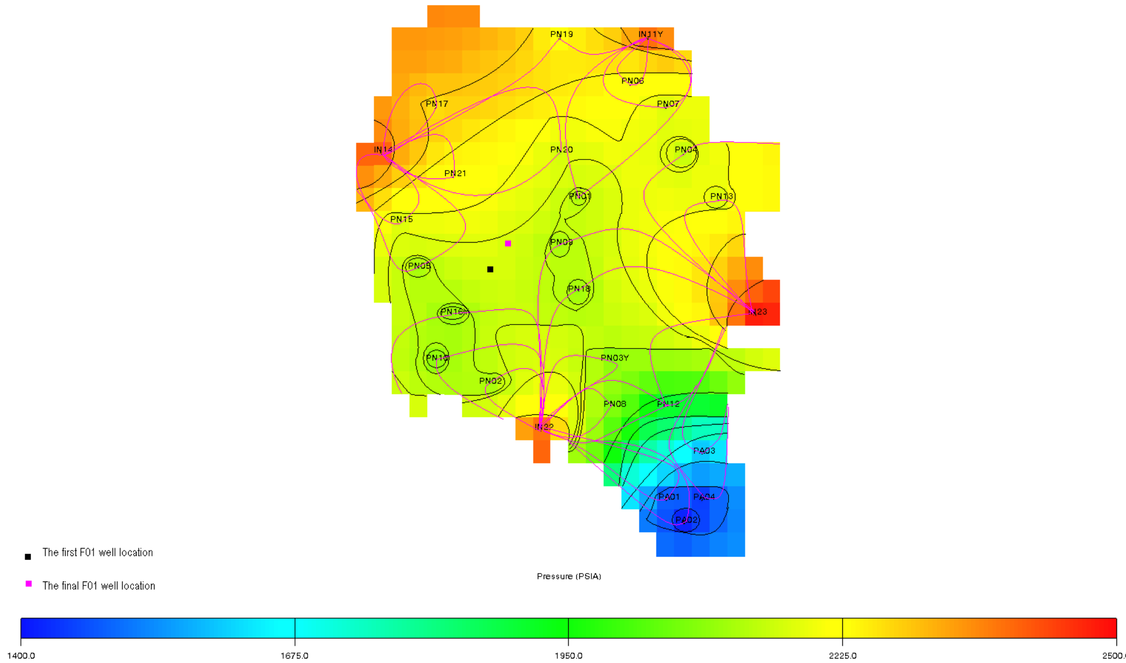

Fig. 6.19–Fairooz isobaric map with streamline and the old and new location of the first proposed well

Running the reservoir model with F01 drilled and on stream resulted in a slight rate reduction and two-month plateau extension (**Fig. 6.21**). Therefore, I will assume that F01 is drilled 50 days prior to its current on-stream date and introduce F02 at the end of the 9 months period. F02 well location is found using the same modified Anderson method (**Fig. 6.19**). The closest well to F02 is N01, and they share the same PVT properties. Therefore, F02 will have the same VLP files as N01.

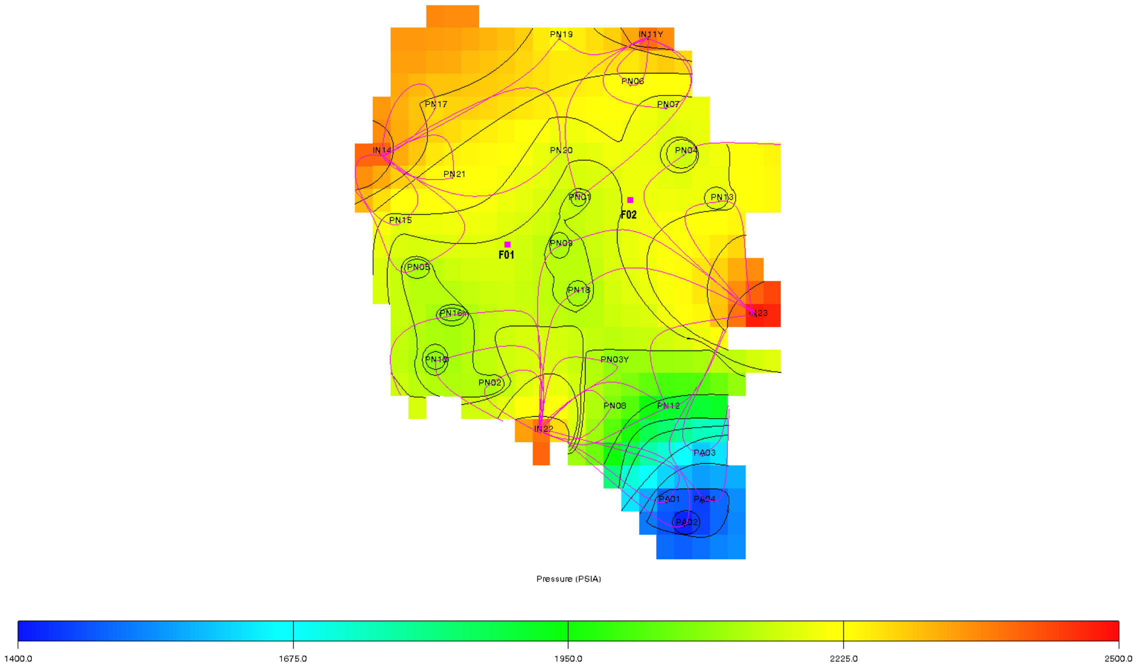

Fig. 6.20–F01 and F02 locations

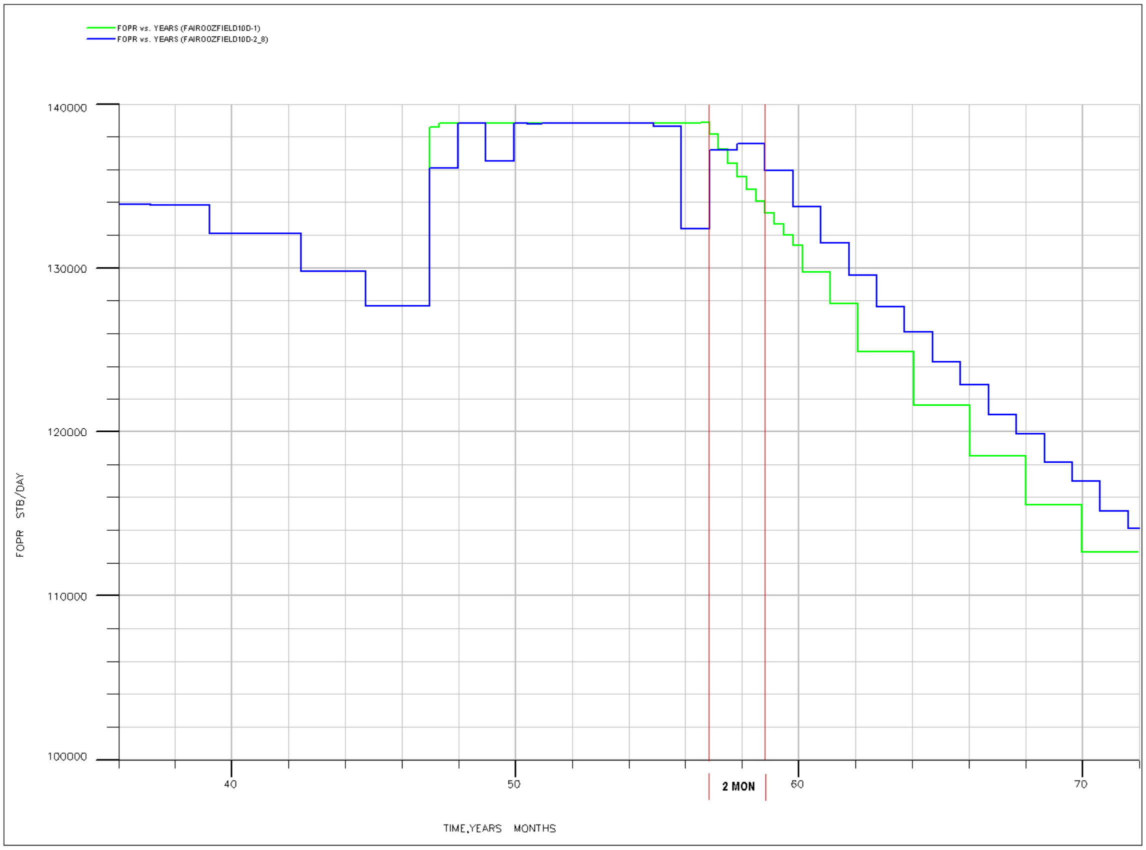

Fig. 6.21–Two-month plateau extension

Running the reservoir model with the F01 and F02 schedule mentioned above resulted in a two-month plateau extension (**Fig. 6.21**). This leads to plotting the pressure contour, the streamline, the thickness, and the oil saturation maps for each plateau decline. Due to the repetitive nature of this process, I will present below the proposed development plan (**Table 6.1**), which is the final version before the economical evaluation. **Fig. 6.20** shows well locations, and **Fig. 6.22** shows final production forecast.

TABLE 6.1–THE PROPOSED DRILLING SCHEDULE

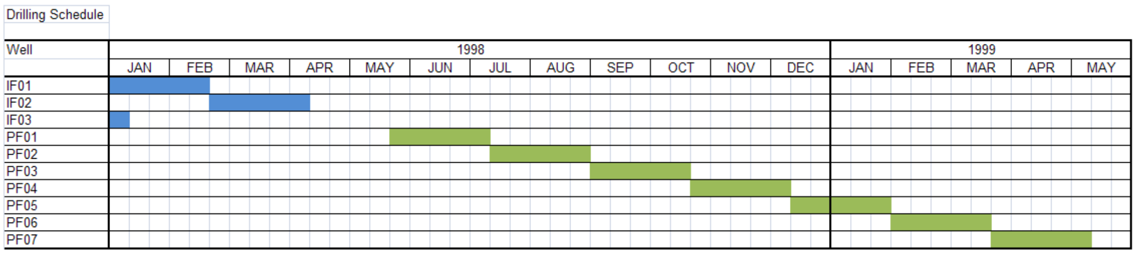

Table 6.1 above illustrates the drilling schedule of the proposed development plan. At the very early stages of the development I workover PN08 (Shut) and convert it into a water injector PF03. Then I drill two water injectors to maintain the declining reservoir pressure. Pressure decline was not expected based on analyzing production and pressure profiles of the base case (see 6.1.1.6). However, running the reservoir model without additional water injection resulted in reservoir pressure decline (**Fig. 6.24**). Consequently, water injection was an additional sensitivity to development planning, in terms of the number of WIs and their locations. The modified Anderson method nominated WI locations except for the worked-over IF03, because its location is already known. WIs and OPs were competing against each other for the available 9 opening slots. Analyzing the simulation runs indicate that the ratio of 7 new OPs to 3 new WI is the optimum, having in mind the 80% water cut limit.

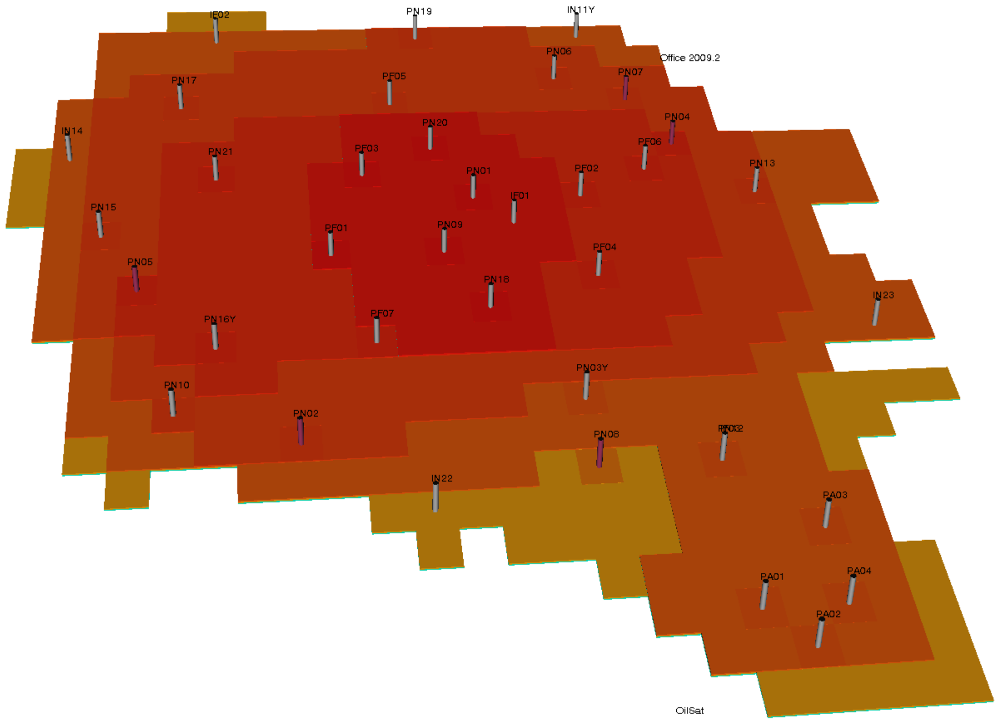

Fig. 6.22–Existing and new well locations, new wells start either with PF or IF

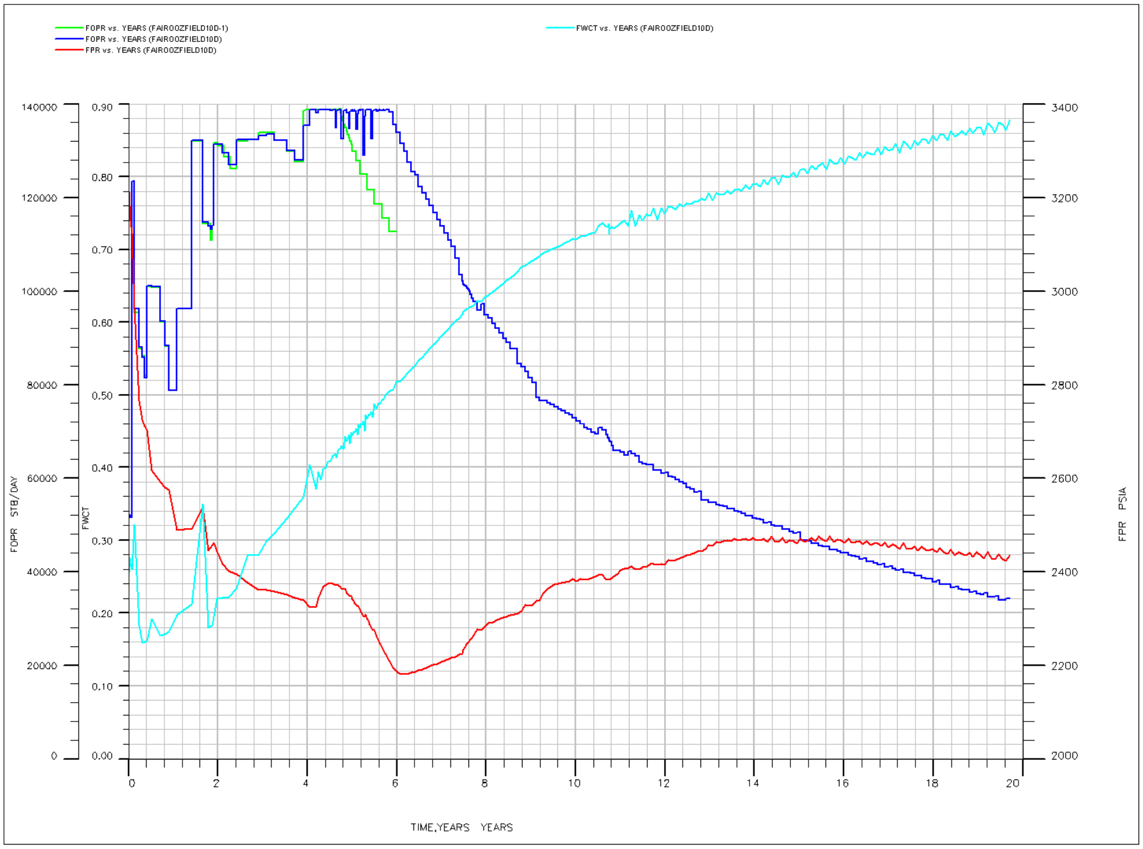

Fig. 6.23–The final production forecast for infill drilling options

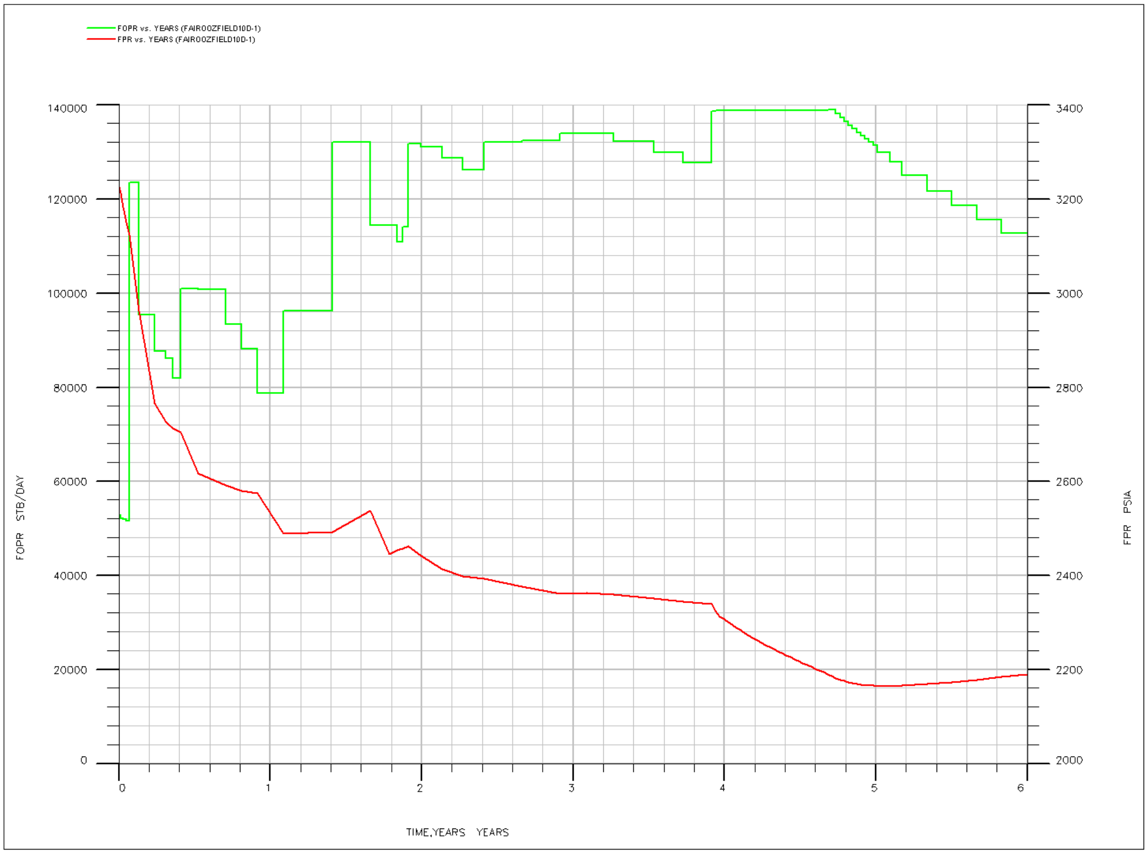

Fig. 6.24–The reservoir pressure decline associated with the infill drilling option without additional water injection

Based on **Fig. 6.23** above, this development plan increases oil production by 10% and maintains it for an additional year with respect to the base case.

Fig. 6.25 summarizes this step (Running predictions, evaluating the results, and optimizing step).

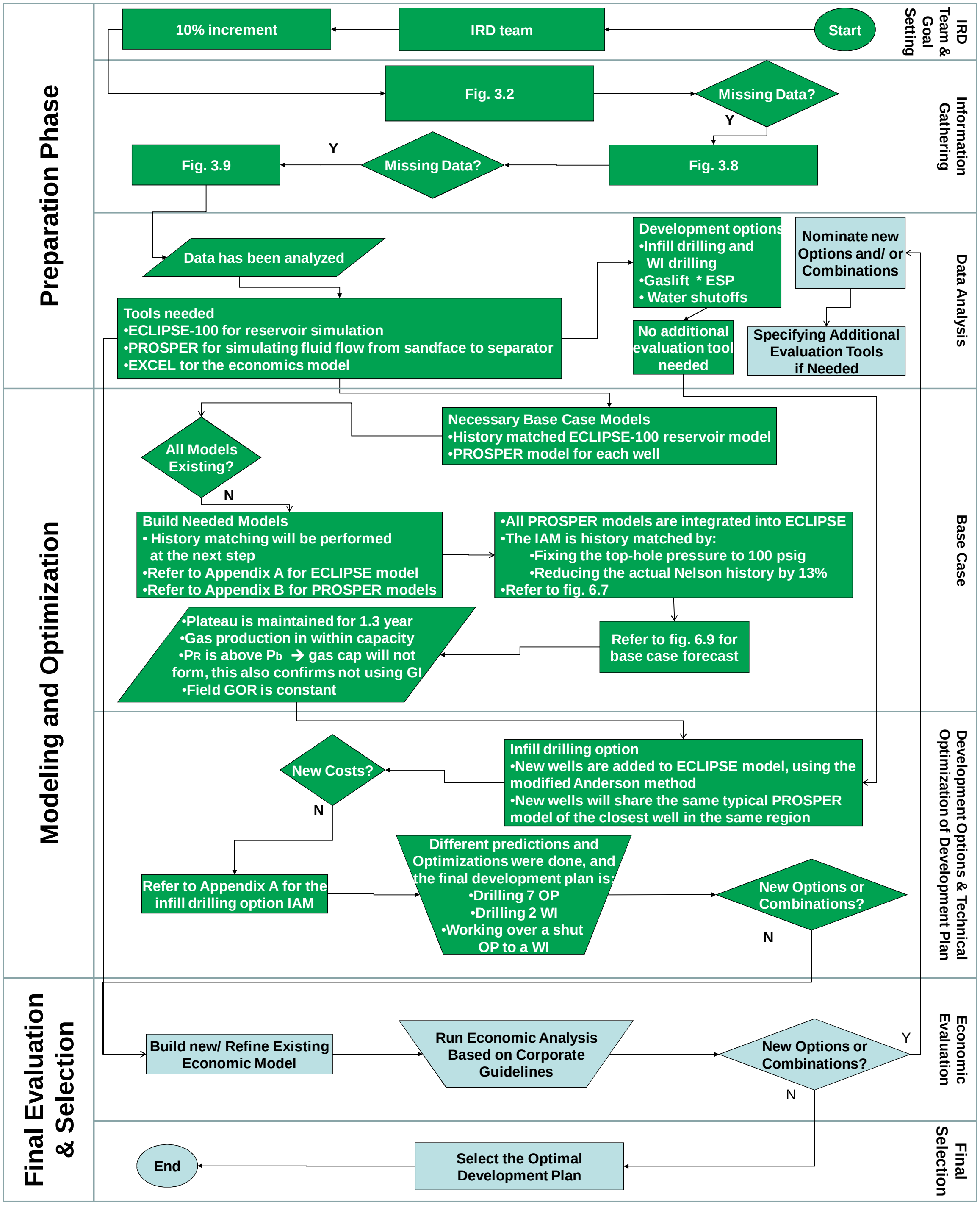

Fig. 6.25–Running predictions, evaluating the results, and optimizing step

6.1.2.1.5 Are there any new options or combinations?

No, there are no further options or combinations. However, in reality adding a new platform and new wells might be evaluated.

6.2 The economic evaluation stage (Fig. 6.26)

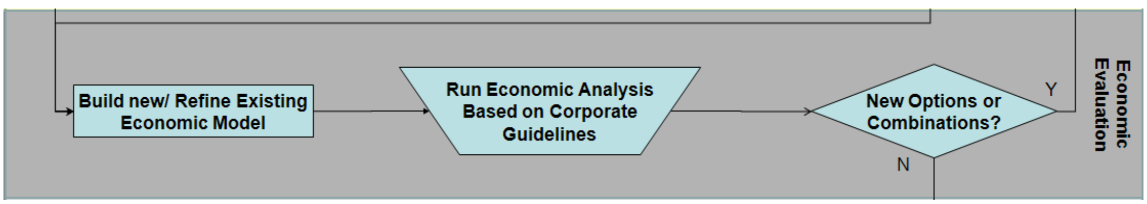

Fig. 6.26–The economic evaluation stage, part of the final evaluation and selection phase

6.2.1 Build new or refine existing economic model

This step asks to use Microsoft Excel (my evaluation tool of choice) to build an economical model that calculates the NPV (Eq.6.2) and PVR (Eq.6.3) for each development plan. **Table 6.2** below has all the parameters I need to build the economic model.

TABLE 6.2–ALL ECONOMIC PARAMETERS USED IN BUILDING THE ECONOMIC MODEL

Timeframe	16	years	
Discount Rate	15	%	ie
Abandonment	80	%	WC
	30	MM$	CAPEX
Workover	1	MM$	CAPEX
OP	9	MM$	CAPEX
	50	days	Drill & Complete
WI	7	MM$	CAPEX
	50	days	Drill & Complete
Produced Oil	1	$/STBO	OPEX
Produced Water	0.5	$/STBWP	OPEX
Injected Water	0.4	$/STBWI	OPEX
Produced Gas	0.75	$/Mscf	OPEX
ESP	2	MM$	CAPEX
	0.3	$/STBO	OPEX
Gaslift	0.2	$/STBO	OPEX
Fule	65	%	of produced gas
Gaslift gas	10	%	of gaslift gas needed

$NPV = \sum_{j=1}^{n} (NCF)_j \left[\frac{1}{(1+i_e)^j}\right]^*$ ……………..……………………..………………..(eq. 6.2)

where

NCF is the net cash flow

NCF = total cash flow – total costs

j is the current year

n is the last year of the timeframe

i is the interest rate

$PVR = \frac{NPV}{\sum present\ CAPEX\ value}^{**}$ ……..………………………………………………...(eq. 6.3)

I have built an economic model that uses the production and injection data to calculate the NPV and the PVR for each development plan. The model calculates the OPEX automatically, because all individual operating costs are in the form of cost per barrel. However, the user has to enter CAPEX by hand at the corresponding time. Please note that CAPEX include the abandonment cost.

*PETE 664 class notes titled Petroleum Economics 1, Summer 2009

**PETE 664 class notes titled Investment Yardsticks, Summer 2009

6.2.2 Run economic analysis based on corporate guidelines

The economic evaluation shows that this development plan passes both corporate yardsticks. It has a NPV of $ 5,210 MM, and a PVR of $ 65 MM (**Table 6.3**). In 2008 water cut exceeds the abandonment limit of 80%. Therefore, the timeframe of this project becomes 11 years instead of 16.

TABLE 6.3–INFILL DRILLING INITIAL ECONOMIC EVALUATION FOR THE 10% INCREMENT GOAL

Time years	Gross Income MM$	CAPEX MM$	OPEX MM$	Total Cost MM$	Cash Flow MM$	Present Value MM$	Present CAPEX Val. MM$
1998	611.11	51.00	108.34	159.34	451.77	421.28	47.56
1999	853.72	27.00	115.84	142.84	710.88	662.90	25.18
2000	1286.25	0.00	114.01	114.01	1172.24	950.54	0.00
2001	918.55	0.00	104.98	104.98	813.57	573.65	0.00
2002	766.08	0.00	97.57	97.57	668.51	409.89	0.00
2003	794.17	0.00	91.19	91.19	702.99	374.81	0.00
2004	977.31	0.00	88.91	88.91	888.41	411.88	0.00
2005	1182.58	0.00	84.86	84.86	1097.72	442.54	0.00
2006	1266.05	0.00	82.70	82.70	1183.35	414.84	0.00
2007	1262.10	0.00	79.71	79.71	1182.39	360.44	0.00
2008	767.55	30.00	32.95	62.95	704.60	186.77	7.95
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00

NPV MM$	5,209.53
PVR	64.56

6.2.3 Are there any new options or combinations?

Yes, there are some options that can change the development plan and hopefully turn better NPV and PVR. This leads us to the data analysis stage in the preparation phase of the IRDW, where the team has to specify the combinations needed. **Fig. 6.27** below, shows the progress of this economic evaluation stage.

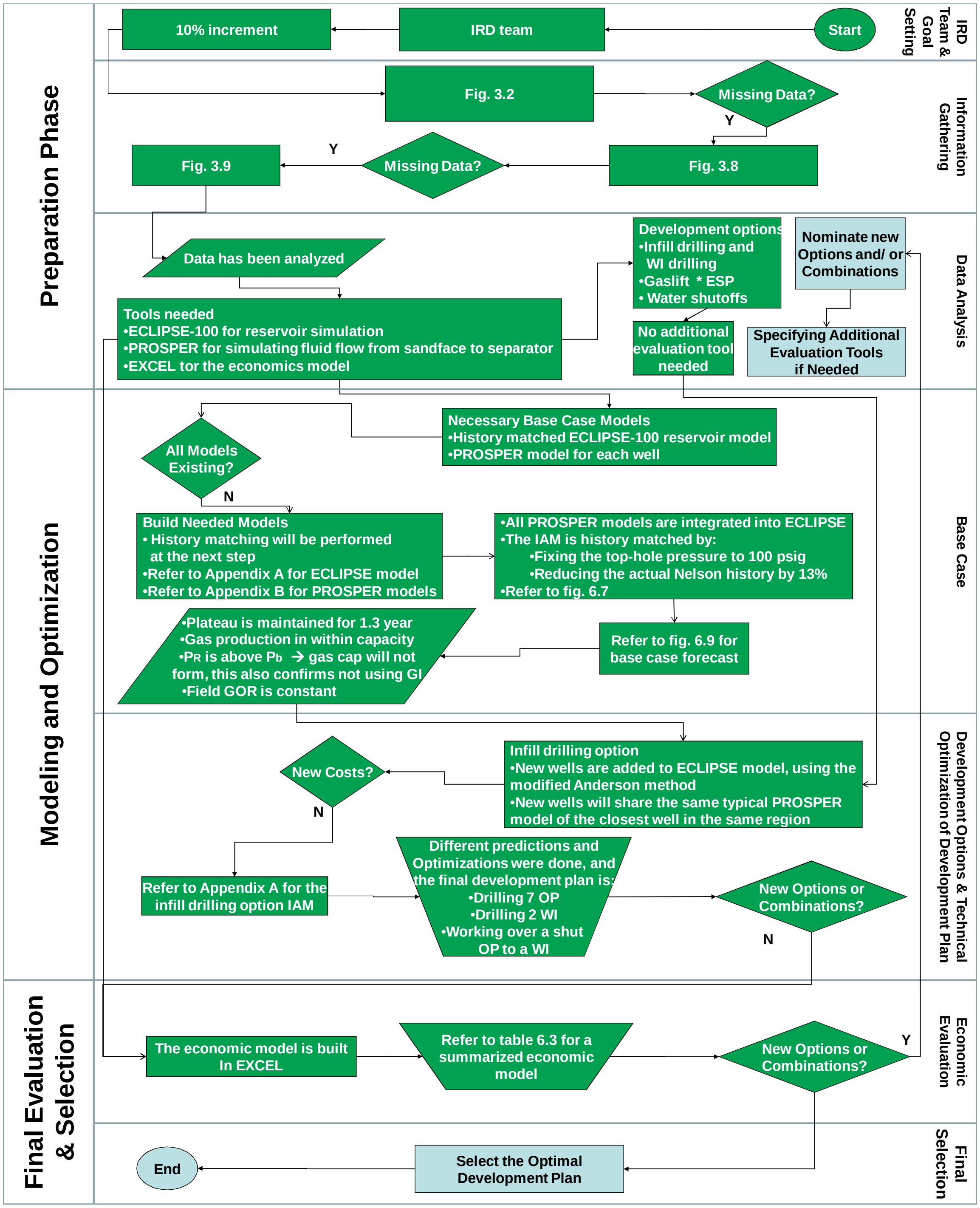

Fig. 6.27–The progress of the economic evaluation stage, completed steps are colored in green

Water shutoffs is ideal at this stage. However, I will not consider it at this evaluation, because I want to exclusively evaluate all 4 development options I have chosen earlier. A second solution to this water cut problem is to reduce production rate of high water cut OPs, especially after production starts declining. Therefore, I have changed the necessary code in ECLIPSE to shut the most violating water cut OPs. The results of this costless optimization are presented in **Table 6.4** below. NPV has increased from $ 5,210 MM to $ 6,376 MM, and the PVR has increased from $ 65 MM to $ 88 MM.

TABLE 6.4–INFILL DRILLING ECONOMIC EVALUATION FOR THE 10% INCREMENT GOAL AFTER ECONOMIC OPTIMIZATION

Time years	Gross Income MM$	CAPEX MM$	OPEX MM$	Total Cost MM$	Cash Flow MM$	Present Value MM$	Present CAPEX Val. MM$
1998	611.11	51.00	108.34	159.34	451.77	421.28	47.56
1999	853.72	27.00	115.84	142.84	710.88	662.90	25.18
2000	1281.86	0.00	113.87	113.87	1167.99	947.09	0.00
2001	905.95	0.00	104.04	104.04	801.91	565.43	0.00
2002	765.61	0.00	97.58	97.58	668.02	409.59	0.00
2003	809.56	0.00	92.50	92.50	717.06	382.31	0.00
2004	985.92	0.00	89.34	89.34	896.58	415.67	0.00
2005	1189.93	0.00	85.34	85.34	1104.59	445.31	0.00
2006	1236.38	0.00	81.83	81.83	1154.55	404.74	0.00
2007	1229.74	0.00	77.71	77.71	1152.03	351.18	0.00
2008	1668.38	0.00	74.89	74.89	1593.49	422.40	0.00
2009	908.30	0.00	72.72	72.72	835.58	192.60	0.00
2010	1462.37	0.00	67.93	67.93	1394.44	279.50	0.00
2011	916.55	0.00	65.76	65.76	850.79	148.29	0.00
2012	991.10	0.00	62.06	62.06	929.04	140.80	0.00
2013	1475.48	0.00	59.88	59.88	1415.61	186.56	0.00

NPV MM$	6,375.66

PVR	87.66

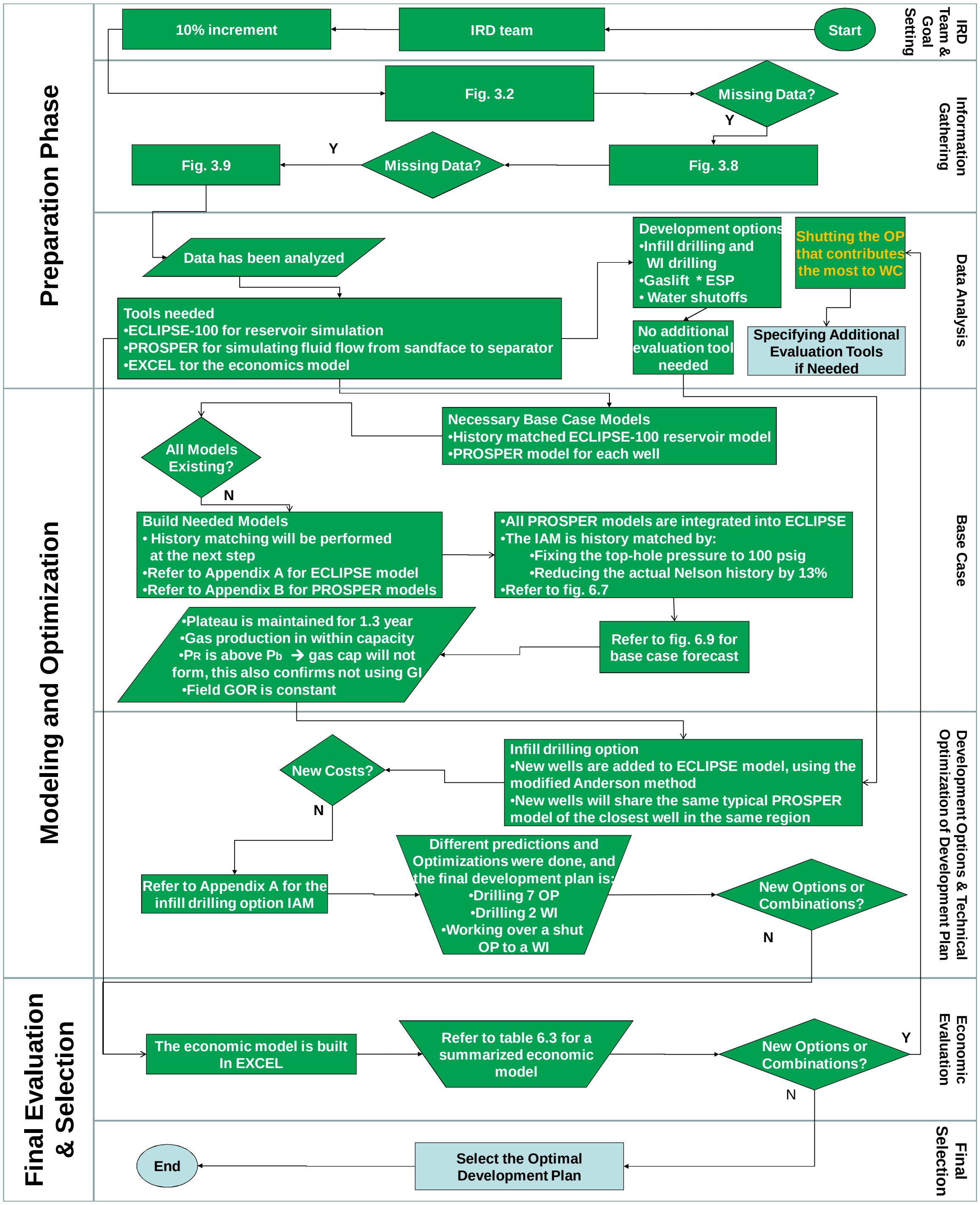

Fig. 6.28–The economic optimization loop, new options

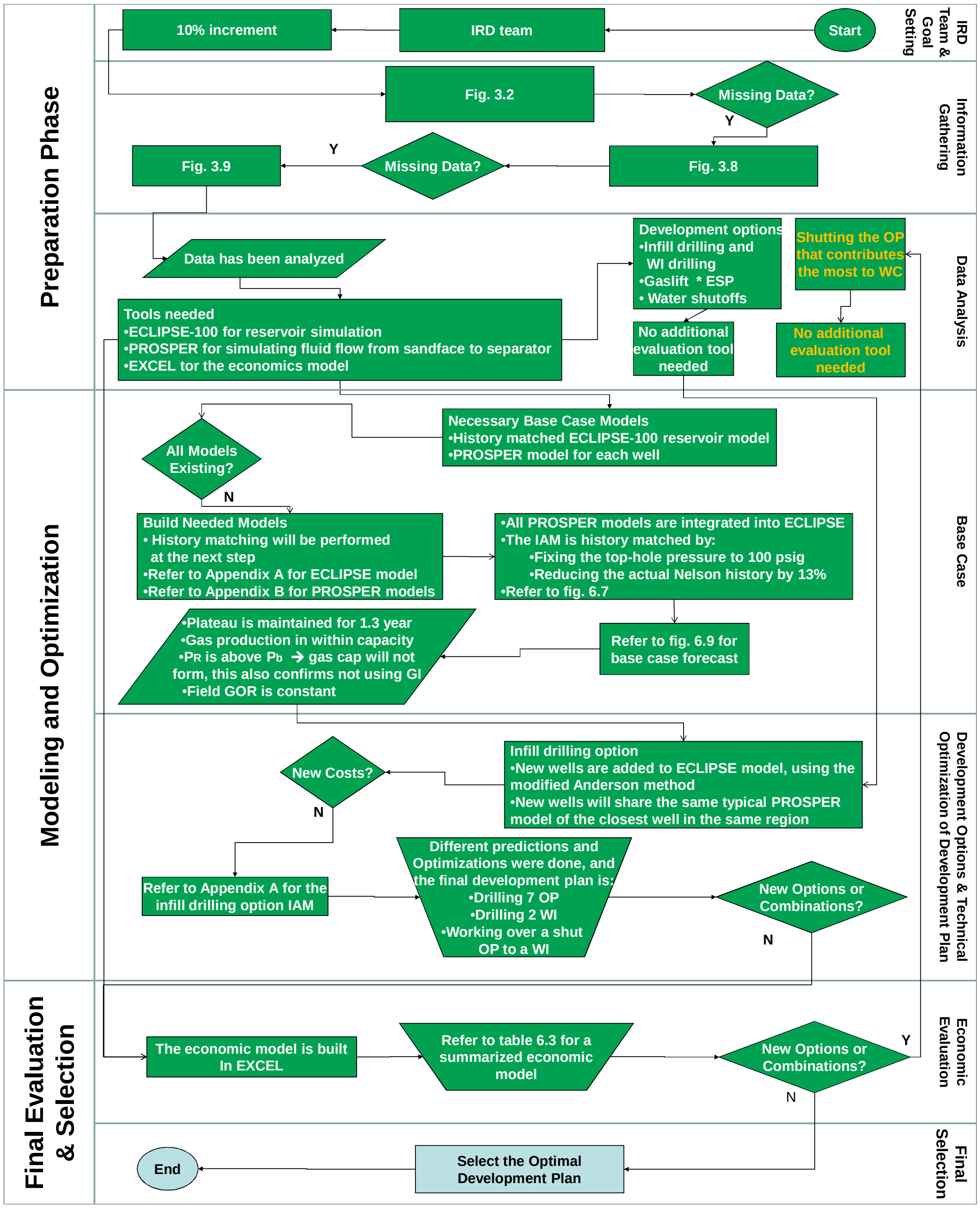

Fig. 6.29–The economic optimization loop, additional evaluation tools

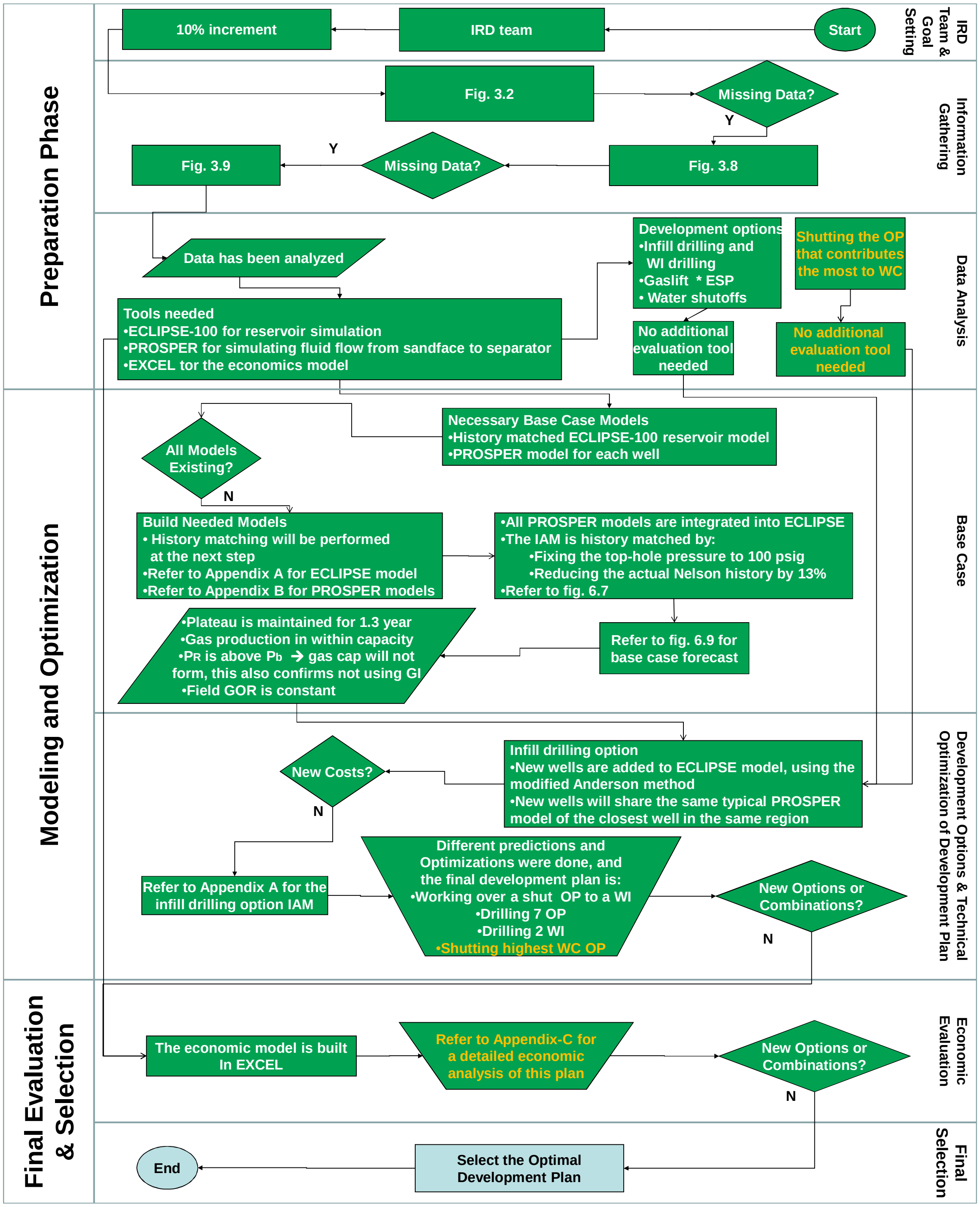

Fig. 6.30–The economic optimization loop, the second economic evaluation

As a conclusion, the final optimal development plan, for infill drilling option, is to increase field oil production 10% and maintain it the longest period of time using infill drilling is:

- Drilling 7 OPs according to the drilling schedule presented in **Table 6.1**, and according to the well locations specified in **Fig. 6.22**.
- Drilling 2 new WIs and converting PN08 to a third water injector according to the drlling schedule presented in **Table 6.1**, and according to the well locations specified in **Fig. 6.22**.
- Shutting the OPs that significantly contribute to the over al water cut increase of the field.

Those results and the economic optimization loop are illustrated in the IRDW (**Fig. 6.28**, **6.29**, and **6.30**).

The IRD team has to repeat the steps of the following two stages; the development options and technical optimization of development plan stage (**Fig. 6.14**) and the economic evaluation stage (**Fig. 6.26**) for all other 3 development options. This will lead to finding the optimum development plan for each development option for one goal. The whole process is then repeated to get the optimum development plan for each development option for the second goal. Upon completing the economical evaluation stage for all development options and goals the team moves to the final selection stage. In the final selection stage the team economically compares all development options and selects the optimum.

CHAPTER VII

RESULTS, FINAL SELECTION, AND DISCUSSION

7.1 Results

Table 7.1 below, summarizes the final results of the Fairooz field development. The development plans are summarized below.

TABLE 7.1–FINAL ECONOMIC EVALUATION OF FAIROOZ FIELD DEVELOPMENT

Development goal	Yardstick	Development option			
		Infill	Shutoffs	Gaslift	ESP
10% Increase	NPV $MM	6,375.66	5,941.16	6,284.39	5,914.74
	PVR	87.66	25,774.98	1,684.82	792.86
Maintain Plateau	NPV $MM	5,149.38	5,914.95	6,311.93	5,938.31
	PVR	155.92	25,661.31	1,692.20	796.02

Infill drilling

1. 10% increment goal
    a. Drilling 7 OPs and 2 WI
    b. Converting a shut-in OP to a WI
    c. Shutting the OP that contributes the most toward WC
2. Maintain plateau goal
    a. Drilling 3 OPs
    b. Converting a shut-in OP to a WI
    c. Shutting the OP that contributes the most toward WC

Gaslift

1. 10% increment goal
    a. After 6 months of production start tieing-in the 4 OPs, which are not gaslifted, to the gaslift line
    b. Shutting the OP that contributes the most toward WC
2. Maintain plateau goal
    a. After 11 months of production start tieing-in the 4 OPs, which are not gaslifted, to the gaslift line
    b. Shutting the OP that contributes the most toward WC

ESP

1. 10% increment goal
    a. After 2 months of production start installing the pumps to the 4 OPs, which are not artificially lifted.
    b. Shutting the OP that contributes the most toward WC
2. Maintain plateau goal
    a. After 2 months of production start installing the pumps to the 4 OPs, which are not artificially lifted
    b. Shutting the OP that contributes the most toward WC

Please note that the ESPs are installed at the same time for both development goals. That is due to the different ESP designs used for each goal.

Water shutoffs

1. 10% increment goal

    Shutting the perforations the contribute the most water cut in the OPs

2. Maintain plateau goal

Shutting the perforations the contribute the most water cut in the OPs

7.2 Final selection

7.2.1 The development option for each development goal

7.2.1.1 10% increment

The development option of choice for the 10% increment goal is gaslift. Although gaslift did not get the highest NPV nor the highest PVR, but its NPV ($ 6,285 MM) is very close to the infill drilling's highest NPV ($ 6,376 MM) with a difference of $ 90 MM. It also has the second highest PVR, unlike infill drilling which has the lowest PVR. Gaslift overall performance on the selected yardsticks makes it the optimal development option for this particular goal.

7.2.1.2 Maintaining the plateau

The development option of choice for the maintain plateau goal is gaslift also. Its NPV ($ 6,312 MM) was the highest among all other options. It, also, has the second highest PVR. Therefore, gaslift's overall performance on the economical evaluation yardsticks makes it the optimal development option once again.

7.2.2 The development goal

Since gaslift was the optimal development option for both goals, selecting the optimal development goal becomes relatively easier. The development goal that has the highest gaslift NPV is the optimal one. Thus, maintaining the plateau is the optimal development goal.

Based on the results presented above, my recommendation is to maintain the current field plateau with gaslift.

7.3 Discussion

The IRDW leads to viewing the economic evaluation as an optimization loop, and a final decision making tool, as it was clearly done in 6.2.2 and 6.2.3. If economic evaluation is considered as an economic evaluation only, not further optimization would have been done to infill drilling. Consequently it would have had a lower NPV.

To further illustrate how IRDW guides to viewing the economic evaluation as an optimization loop, I will compare different evaluation processes and show how misleading their decisions are. I will perform this comparison on the 10% increment goal with infill drilling, gaslift, and ESP the development options. The first process totally ignores economic evaluation, the second one uses economic evaluation as a decision making tool, and the third process is the one the IRDW adapts; using the economic evaluation as an optimization loop and a decision making tool.

TABLE 7.2–HOW EACH DEVELOPMENT OPTION IS RANKED WITH DIFFERENT EVALUATION CRITERIA

10% Goal	No economic evaluation		Economic evaluation as a decision making tool		Economic evaluation as an optimization loop and an economic evaluation tool	
	Cumulative oil production MM STB	Plateau time Days	NPV $MM	PVR	NPV $MM	PVR
Infill	435	1650	5,210	65	6,376	88
Gaslift	425	510	5,367	553	6,284	1,685
ESP	402	330	5,071	353	5,915	793

Best
Second best

Table 7.2 shows that when no economic evaluation is performed, the development option that has the highest production rate becomes the most favorable. Not considering the economic evaluation is misleading and wrong. However, just considering the economic evaluation as a decision making tool is misleading too. The final evaluation in **Table 7.2** considered the economic evaluation as an optimization loop, and I believe it is the most accurate way to do economic evaluation, because it reflects reality the most. For example, let us assume that gaslift was chosen based on the second method (using economic evaluation as just a decision making tool), thus the high water cut was not considered as a problem at the time of the development. Then when water cut increases to a value near 80% a new development team may form and evaluate this “new” problem, while they could have anticipated it and found its solution long time ago.

After completing the study and making the recommendations, there is one question to ask: what could have lead to the good overall performance of gaslift, especially against infill drilling for the 10% increment goal?

The relatively lower CAPEX and OPEX in gaslift development plan played a major role in its overall good economical performance. In fact, there is no doubt that infill drilling supersedes gaslift in terms of production. Infill drilling maintained the plateau 3 times longer than gaslift, and it produced 10 MM STB more oil than gaslift (**Table 7.2**). However, the final decision had to come through the economical evaluation yardsticks specified. Gaslift has a lower CAPEX, due to the total number of gaslift candidates (4 OPs) and their existing completion. All Nelson OPs were gaslifted except

4 OPs, thus gaslift option could not be performed on more than 4 wells. However, infill drilling options had more candidates, because it was limited by the 9 available slots on the platform. In addition, all existing OPs in Fairooz share the same typical Nelson completion that has gaslift valves installed already. This means that the actual cost to gaslift an OP in Fairooz is the cost of tie-in (a very small cost when compared to drilling), and the maximum possible CAPEX equals the tie-in cost of 4 wells. On the other hand, gaslift has a lower OPEX too. The gaslift development plan resulted in relatively lower oil, gas, and water production rates, with respect to the infill drilling development plan (**Fig. 7.1**). Therefore, gaslift OPEX is lower than infill drilling, because OPEX is calculated as a cost per standard volume. Please refer to **Table 7.3** below for a CAPEX and OPEX comparison between both development options.

In this study I have illustrated the importance of performing a comprehensive evaluation to a particular development goal, and I have presented a method that organizes this process and leads to the optimal development plan and development goal if implemented correctly.

TABLE 7.3–CAPEX AND OPEX COMPARISON BETWEEN INFILL DRILLING AND GASLIFT DEVELOPMENT OPTION FOR THE 10% INCREMENT GOAL

10% Goal	CAPEX Present Value $ MM	OPEX Present Value $ MM
Infill	73	691
Gaslift	4	620
Difference*	69	71

* Infill - Gaslift

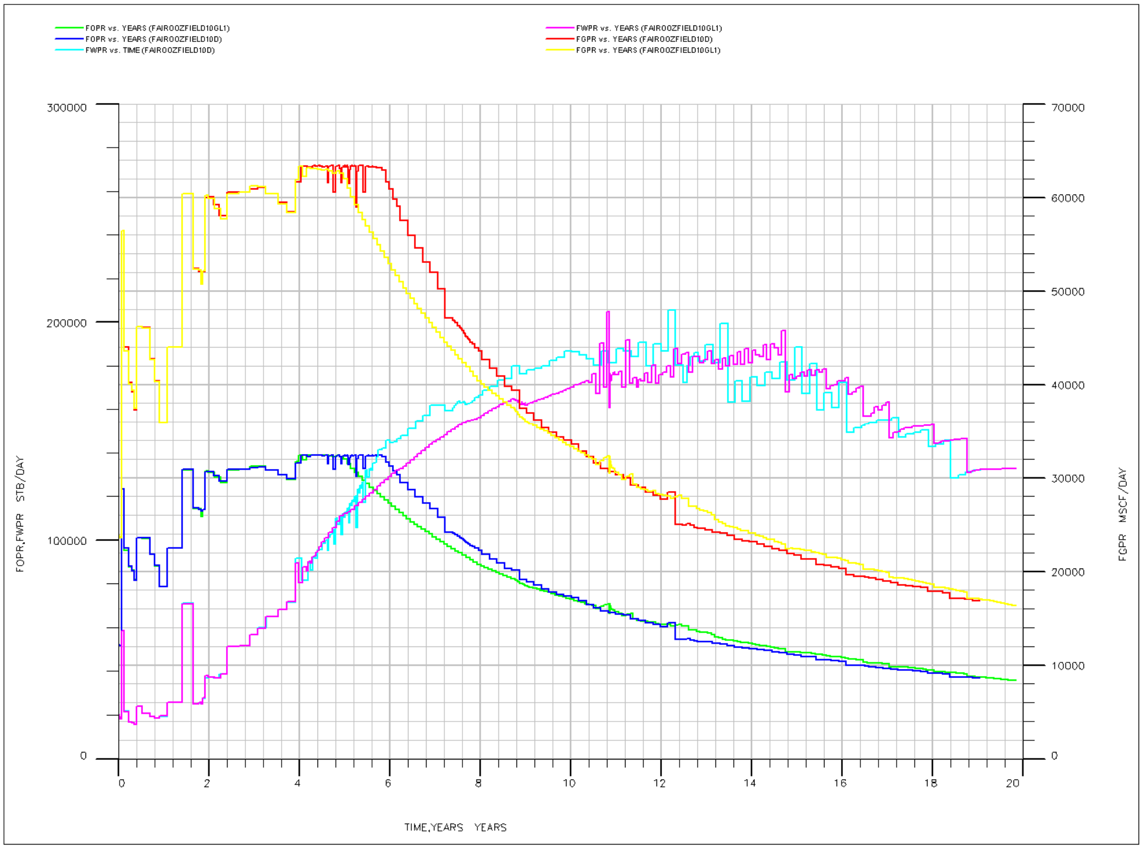

Fig. 7.1–The 10% increment oil, water, and gas production rates for gaslift and infill drilling development options

CHAPTER VIII

CONCLUSIONS

8.1 Conclusions

8.1.1 IRDW leads to optimal development plan and optimal development goal

The IRDW leads the IRD team to selecting the optimal primary development plan between the different development plans it evaluates. Each development plan paces through a loop of thorough technical and economical evaluations and optimizations, and the comparative nature of the IRDW favors the most economical one.

The IRDW also leads to selecting the optimal development goal, if the operating company requires evaluating more than one goal.

8.1.2 Data analysis: the most important stage of the IRDW

Although the IRDW leads to selecting the optimal development plan, the selected plan is not the absolute optimum unless the team evaluates all applicable development options. The need to evaluate all applicable options highlights the importance of the data analysis stage, in the IRDW. If the IRD team performs the data analysis step in the data analysis stage correctly, it will identify all applicable development options. Therefore, the evaluation will be comprehensive. Furthermore, selecting the development tools, which form the IAM, takes place in this stage. The selection process depends on available data analysis. If the IRD team does not perform the data analysis step correctly, it might not be able to select the right evaluation tool. In fact, selecting the wrong evaluation tool leads to less accurate results or inability to evaluate some applicable development options. Therefore, the IRD team must pay extra attention to this stage because of the critical decisions it takes during it.

8.1.3 The IRDW helps reducing development planning time

The IRDW shortens the overall planning time because it leads the IRD team to evaluate only applicable (technical and economical) options. The team does not waste any time evaluating technically or economically impractical options. In addition, the IRDW bases its final development plan selection on economical evaluation. This assures that the development plan would not be uneconomical during implementation. Furthermore, the IRDW relies of an IAM. As a result, the IRDW does not require frequent manual boundary conditions updates to get accurate results because the integration is done in real-time. On the other hand, the time wasting routine of manual data entry is required for nonintegrated models to get accurate predictions.

8.2 Future work

Although this IRDW specifically deals with primary development of black oil fields, similar workflows could be developed for natural gas, gas condensate, volatile oil, heavy oil, and unconventional oil or gas fields. In addition, similar workflows, such as the IRDW, could be modified to target specific categories of black oil fields. For example, a workflow that specializes in mature field development.

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APPENDIX A

THE BASE CASE AND THE INFILL DRILLING OPTION FOR THE 10% INCREMENT DEVELOPMENT GOAL ECLIPSE MODELS

I have used ECLIPSE to build the reservoir model for the whole project. For this project my interaction with ECLIPSE passes through two stages, model building and result viewer. The first screen that appears when ECLIPSE is first launched is shown in (**Fig. A-1**). In that screen the user can run the model he/she built (ECLIPSE button), and the user can view the results of the model he/she created (Office button). In this Appendix, I will illustrate how I built the reservoir model and the IAM for the base case and the infill drilling 10% incremental.

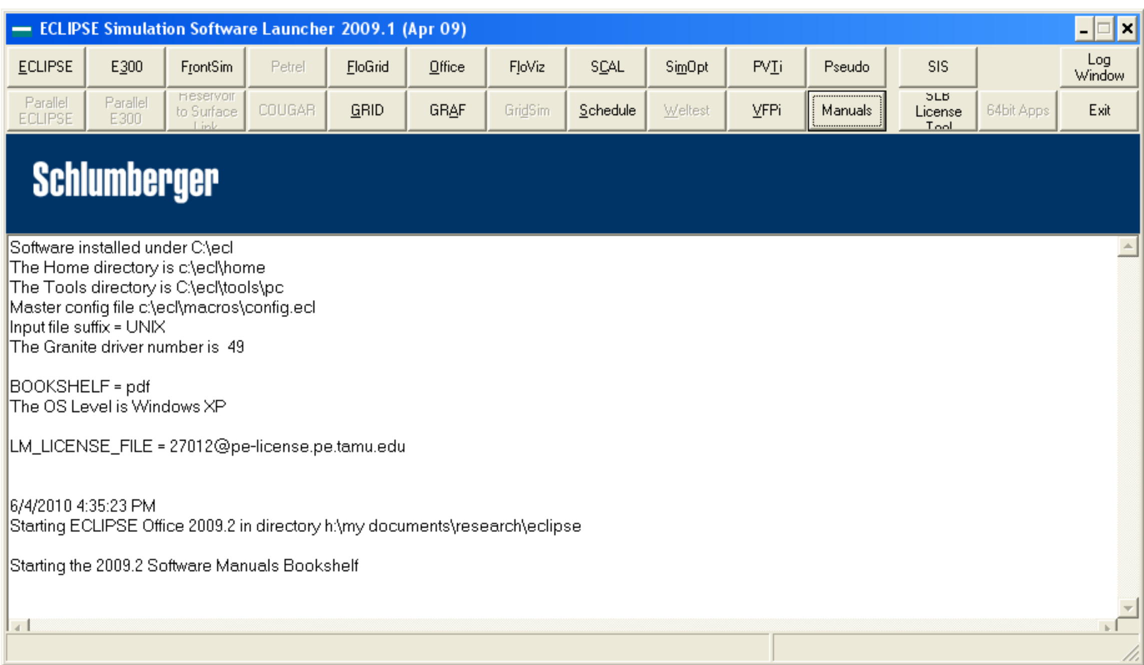


Fig. A-1–ECLIPSE main window

Any model built in ECLIPSE100 is based on the following sections: RUNSPEC, GRID, EDIT, PROPS, REGIONS, SOLUTION, SUMMARY, and SCHEDULE. The RUNSPEC section allocates memory and specifies general model parameters. The GRID section provides necessary information to calculate pore volume and transmissibility. The EDIT section carries adjustments to the GRID section output. The PROPS section provides pressure and saturation-dependent properties of the reservoir fluid and rocks. The REGIONS section assigns variable properties to the reservoir. The SOLUTION section finds the initial conditions of the simulation. The SUMMARY section specifies the variables to be written in the output. Finally the SCHEDULE section is one of the most important sections in ECLIPSE because it is the section that enables integration. It also controls surface faculties and wells*.

Below is the base case of Fairooz field. The infill drilling 10% increment case has two kinds of added data. The first kind omits the base case data, and the second one works with it. The data that omits the base case data is colored in red, and the data that works with the existing data is colored in green. This model is the history matched IAM too, and the integration keywords are underlined. In other words, to read the data file for the base case reservoir model only, omit the underlined and red texts. However, if you would like to read the data file for the base case IAM, omit the red text only. The same applied to infill drilling. If you would like to view the IAM data file for infill drilling, read the data file with the underlined text, omitting the base case data with the red colored text, reading both data with the green colored text.

*Schlumberger course notes: ECLIPSE Blackoil Reservoir Simulation, training and exercise guide, version 2.0.

```
RUNSPEC   ------------------------------------------------------------------------------------------

TITLE
-- Fairooz field base case

-- turn on end point scaling option
ENDSCALE
/

-- make initial solutions stable for fine-grid method
EQLOPTS
 QUIESC /

-- define tracer dimensions (we are trasing aquifer water)
TRACERS
-- oil-tracer  water-tracer  gas tracer
   0          1            0         /

DIMENS
-- NX    NY    NZ
   24    25    6 /

-- Specifies phases present: oil, water, gas and dissolved gas

OIL
GAS
WATER
DISGAS

-- Field units to be used
FIELD

WELLDIMS
---------- UPPER LIMITS ----------------
-- WELLS  CONN/WELL  GROUPS  WELLS/GROUP
    30       20        30       15  /
    38       20        38       30  /

TABDIMS
--- EXACT ---  ---- UPPER LIMIT ---
-- SAT   PVT   SAT-NODE   PVT-NODE
   23    4     23         20  /
```

```
START
-- Represents the starting time of this study
-- DD  MMM  YYYY
  01  FEB  1994 /

UNIFOUT  generate single "unified" output file
UNIFIN   read single "unified" restart file

-- define aquifer dimensions
AQUDIMS
--    analytical-aquifer   max-connection-block
  4*         1                   600/

-- Specifies the size of the stack for Newton iterations
NSTACK
100 /

VFPPDIMS
15 1  10 10 10 23 /


GRID      ------------------------------------------------------------------------------------------

TOPS
600*7370/


-- Specifies the length of the cell in the X direction: 1,000 ft
DX
3600*1000 /

-- Specifies the length of the cell in the Y direction: 1,300 ft
DY
3600*1300/

-- Specifies the length of the cell in the Z direction: 36 ft
DZ
3600*30 /
/

-- import the Active cells from external file
INCLUDE
 'IncludeS\MariACTNUM.GRDECL' /
```

```
BOX
1 24   1 25   1 6 /

-- Specifies absolute permeability in the X direction: 300 mD (Maximum Value)
PERMX
3600*300
/

-- Specifies absolute permeability in the Y direction: 300 mD (Maximum Value)
PERMY
3600*300
/

-- Same as horizontal value
PERMZ
3600*300
/

-- Specifies porosity: 20%
PORO
3600*.20
/

ENDBOX

-- Refining the grid arround each well
CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N02'     8  8    17 17  1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N05'     4  4    12 12  1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N10'     5  5    16 16  1  5     11  11  10  /
/
ENDFIN
```

```
CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N15'     3  3    10 10  1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N16y'    6  6    14 14  1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N03y'    15 15   16 16  1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N08'     15 15   18 18  1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N12'     18 18   18 18  1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'A01'     18 18   22 22  1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'A02'     19 19   23 23  1  5     11  11  10  /
/
ENDFIN

CARFIN
```

```
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'A03'     20 20   20 20  1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'A04'     20 20   22 22  1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N01'     13 13   9  9   1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N04'     19 19   7  7   1  5     11  11  10  /
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N06'     16 16   4  4   1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N07'     18 18   5  5   1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N13'     21 21   9  9   1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N09'     12 12   11 11  1  5     11  11  10  /
/
```

```
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N17'     5  5    5  5   1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N18'     13 13   13 13  1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N19'     12 12   2  2   1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N20'     12 12   7  7   1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'N21'     6  6    8  8   1  5     11  11  10  /
/
ENDFIN


CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'F01'     09 09  11 11   1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'F02'     16 16   9  9   1  5     11  11  10  /
/
ENDFIN
```

```
CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'F03'     10 10   8  8   1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'F04'     16 16  12 12   1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'F05'     11 11   5  5   1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'F06'     18 18   8  8   1  5     11  11  10  /
/
ENDFIN

CARFIN
-- Name      I1 I2  J1 J2   K1 K2    NX  NY  NZ
  'F07'     10 10  14 14   1  5     11  11  10  /
/
ENDFIN

-- Specifies what is to be written in the GRID output file
RPTGRID
1 1 1 1 1 0 0 0 /

--  export initial properties (PERMX, etc.) to *.INIT file
--  for 2D/3D disply
INIT

-- export grid geometry to *.GRID (old) or *.EGRID (new) file
-- for 2D/3D display
GRIDFILE
-- Grid-file (old)   Egrid-file (new)
      0              1  / 0 = no output; 1 = output
```

```
-- export properties to *.PRT (print file)
-- for data check
RPTGRID
 TRANX ALLNNC /

EDIT      ---------------------------------------------------------------------------------------


PROPS     ---------------------------------------------------------------------------------------

-- define tracer properties
-- 1. tracer name is limited to 3 characters
-- 2. each ECLIPSE model can have up to 50 tracers
-- 3. tracer is passive, it doesn't change fluid properties
TRACER
-- tracer-name  phase
   AQW        WAT  / AQW is water tracer in aquifer
/

--Oil PVT Data
PVTO
--    Rs        p         Bo        Viso
--(Mscf/stb)   (psia)    (rb/stb)    (cp)
       0.027      14.700     1.13224     0.82124 /
       0.183     570.252     1.22024     0.55358 /
       0.380     1125.81     1.33097     0.43013 /
       0.457     1666.31     1.37085     0.40350
                 2236.92     1.35812     0.42440
                 2792.48     1.34986     0.45218
                 3348.03     1.34437     0.48513
                 3903.59     1.34046     0.52267
                 4459.14     1.33753     0.56429
                 5014.70     1.33526     0.60956/
 / null record terminates table 1 Central
       0.027      14.700     1.12467     0.83825 /
       0.191     570.252     1.21643     0.55604 /
       0.399     1125.81     1.33189     0.42940 /
       0.556     1906.43     1.41585     0.38206
                 2236.92     1.41001     0.38833
                 2792.48     1.39909     0.41111
                 3348.03     1.39184     0.43836
                 3903.59     1.38668     0.46955
                 4459.14     1.38281     0.50420
```

```
                    5014.70     1.37981     0.54192/
 / null record terminates table 2 Eastern
      0.027      14.700     1.13509     0.81182 /
      0.182      570.252     1.22175     0.55087 /
      0.377      1125.81     1.33081     0.42920 /
      0.448      1666.31     1.36818     0.40413
                 2236.92     1.35604     0.42480
                 2792.48     1.34787     0.45268
                3348.03     1.34243     0.48574
                3903.59     1.33855     0.52339
                 4459.14     1.33565     0.56516
                5014.70     1.33340     0.61056/
 / null record terminates table 3 Western
      0.027      14.700     1.13746     0.78858 /
      0.183      570.252     1.22481     0.53736 /
      0.380      1125.81     1.33473     0.42000 /
      0.455      1672.44     1.37586     0.39348
                 2236.92     1.36250     0.41410
                 2792.48     1.35412     0.44107
                 3348.03     1.34855     0.47306
                3903.59     1.34458     0.50951
                4459.14     1.34161     0.54993
                5014.70     1.33930     0.59389/
 / null record terminates table 4 Southern

--Gas PVT Data
PVDG
--    P         Bg       Visg
--  (psia)  (rb/Mscf)    (cp)
      14.700 234.73600  0.012530
     570.252   5.53200  0.013340
    1125.810   2.56463  0.014960
    1681.360   1.60741  0.017500
    2236.920   1.18060  0.020830
    2792.480   0.96221  0.024510
    3348.030   0.83712  0.028180
    3903.590   0.75820  0.031660
    4459.140   0.70436  0.034900
    5014.700   0.66529  0.037900
/ null record terminates table 1 Central
      14.700 236.35700  0.012296
     570.252   5.47452  0.013204
    1125.810   2.48143  0.015151
    1681.360   1.52939  0.018388
```

```
    2236.920   1.12418  0.022646
    2792.480   0.92655  0.027189
    3348.030   0.81650  0.031533
    3903.590   0.74788  0.035514
    4459.140   0.70111  0.039129
    5014.700   0.66697  0.042428
/ null record terminates table 2 Eastern
      14.700 234.76100  0.012618
     570.252   5.55878  0.013394
    1125.810   2.59216  0.014938
    1681.360   1.63212  0.017317
    2236.920   1.19944  0.020413
    2792.480   0.97526  0.023863
    3348.030   0.84575  0.027341
    3903.590   0.76366  0.030673
    4459.140   0.70758  0.033797
    5014.700   0.66689  0.036703
/ null record terminates table 3 Western
      14.700 234.77000  0.012724
     570.252   5.56834  0.013608
    1125.810   2.60195  0.015207
    1681.360   1.64093  0.017584
    2236.920   1.20625  0.020598
    2792.480   0.98004  0.023914
    3348.030   0.84896  0.027249
    3903.590   0.76573  0.030452
    4459.140   0.70882  0.033464
    5014.700   0.66754  0.036276
/ null record terminates table 4 Southern

-- define water PVT table
PVTW
-- P-ref   Bw     Cw      Vw   Cvw
  3200  1.013   2.74E-6   0.4     / null record terminates table 1 Central
  3400  1.013   2.74E-6   0.4     / null record terminates table 2 Eastern
  3200  1.013   2.74E-6   0.4     / null record terminates table 3 Western
  3200  1.013   2.74E-6   0.4     / null record terminates table 4 Southern


-- define surface density of each phase
GRAVITY
-- OIL    WATER   GAS
  40.1   1.07   0.852 / null record terminates table 1 Central
  39.2   1.07   1.012 / null record terminates table 2 Eastern
```

```
  40.3   1.07   0.827 / null record terminates table 3 Western
  40.8   1.07   0.838 / null record terminates table 4 Southern


-- define rock compressibility
ROCK
-- P-ref    Cr
  3200     2.81E-6  / null record terminates table 1
  3400     2.82E-6  / null record terminates table 2
  3200     2.80E-6  / null record terminates table 3
  3200     2.81E-6  / null record terminates table 4

-- define saturation functions
--Oil-Water Saturation Table Data
-- typical well sorted sand stone
SWOF
--  Sw     Krw     Krow      Pcow
    0.20  0.0000  1.0000    45.0
    0.25  0.0002  0.9946    30.0
    0.30  0.0020  0.9848    15.0
    0.35  0.0066  0.9226    6.5
    0.40  0.0156  0.8441    6.0
    0.45  0.0305  0.7670    5.5
    0.50  0.0527  0.6931    5.0
    0.55  0.0837  0.6201    4.5
    0.60  0.1250  0.5305    4.0
    0.65  0.1780  0.4506    3.5
    0.70  0.2441  0.3863    3.0
    0.80  0.4219  0.2175    2.0
    0.95  1.0000  0.0000    0.5
 / end of table 1
    0.20  0.0000  1.0000    45.0
    0.25  0.0002  0.9946    30.0
    0.30  0.0020  0.9848    15.0
    0.35  0.0066  0.9226    6.5
    0.40  0.0156  0.8441    6.0
    0.45  0.0305  0.7670    5.5
    0.50  0.0527  0.6931    5.0
    0.55  0.0837  0.6201    4.5
    0.60  0.1250  0.5305    4.0
    0.65  0.1780  0.4506    3.5
    0.70  0.2441  0.3863    3.0
    0.80  0.4219  0.2175    2.0
    0.95  1.0000  0.0000    0.5
```

/ end of table 2

0.20	0.0000	1.0000	45.0
0.25	0.0002	0.9946	30.0
0.30	0.0020	0.9848	15.0
0.35	0.0066	0.9226	6.5
0.40	0.0156	0.8441	6.0
0.45	0.0305	0.7670	5.5
0.50	0.0527	0.6931	5.0
0.55	0.0837	0.6201	4.5
0.60	0.1250	0.5305	4.0
0.65	0.1780	0.4506	3.5
0.70	0.2441	0.3863	3.0
0.80	0.4219	0.2175	2.0
0.95	1.0000	0.0000	0.5

/ end of table 3

0.20	0.0000	1.0000	45.0
0.25	0.0002	0.9946	30.0
0.30	0.0020	0.9848	15.0
0.35	0.0066	0.9226	6.5
0.40	0.0156	0.8441	6.0
0.45	0.0305	0.7670	5.5
0.50	0.0527	0.6931	5.0
0.55	0.0837	0.6201	4.5
0.60	0.1250	0.5305	4.0
0.65	0.1780	0.4506	3.5
0.70	0.2441	0.3863	3.0
0.80	0.4219	0.2175	2.0
0.95	1.0000	0.0000	0.5

/ end of table 4

0.20	0.0000	1.0000	45.0
0.25	0.0002	0.9946	30.0
0.30	0.0020	0.9848	15.0
0.35	0.0066	0.9226	6.5
0.40	0.0156	0.8441	6.0
0.45	0.0305	0.7670	5.5
0.50	0.0527	0.6931	5.0
0.55	0.0837	0.6201	4.5
0.60	0.1250	0.5305	4.0
0.65	0.1780	0.4506	3.5
0.70	0.2441	0.3863	3.0
0.80	0.4219	0.2175	2.0
0.95	1.0000	0.0000	0.5

/ end of table 5

0.20	0.0000	1.0000	45.0

```
   0.25  0.0002  0.9946    30.0
   0.30  0.0020  0.9848    15.0
   0.35  0.0066  0.9226    6.5
   0.40  0.0156  0.8441    6.0
   0.45  0.0305  0.7670    5.5
   0.50  0.0527  0.6931    5.0
   0.55  0.0837  0.6201    4.5
   0.60  0.1250  0.5305    4.0
   0.65  0.1780  0.4506    3.5
   0.70  0.2441  0.3863    3.0
   0.80  0.4219  0.2175    2.0
   0.95  1.0000  0.0000    0.5
/ end of table 6
   0.20  0.0000  1.0000    45.0
   0.25  0.0002  0.9946    30.0
   0.30  0.0020  0.9848    15.0
   0.35  0.0066  0.9226    6.5
   0.40  0.0156  0.8441    6.0
   0.45  0.0305  0.7670    5.5
   0.50  0.0527  0.6931    5.0
   0.55  0.0837  0.6201    4.5
   0.60  0.1250  0.5305    4.0
   0.65  0.1780  0.4506    3.5
   0.70  0.2441  0.3863    3.0
   0.80  0.4219  0.2175    2.0
   0.95  1.0000  0.0000    0.5
/ end of table 7
   0.20  0.0000  1.0000    45.0
   0.25  0.0002  0.9946    30.0
   0.30  0.0020  0.9848    15.0
   0.35  0.0066  0.9226    6.5
   0.40  0.0156  0.8441    6.0
   0.45  0.0305  0.7670    5.5
   0.50  0.0527  0.6931    5.0
   0.55  0.0837  0.6201    4.5
   0.60  0.1250  0.5305    4.0
   0.65  0.1780  0.4506    3.5
   0.70  0.2441  0.3863    3.0
   0.80  0.4219  0.2175    2.0
   0.95  1.0000  0.0000    0.5
/ end of table 8
   0.20  0.0000  1.0000    45.0
   0.25  0.0002  0.9946    30.0
   0.30  0.0020  0.9848    15.0
```

0.35 0.0066 0.9226 6.5
0.40 0.0156 0.8441 6.0
0.45 0.0305 0.7670 5.5
0.50 0.0527 0.6931 5.0
0.55 0.0837 0.6201 4.5
0.60 0.1250 0.5305 4.0
0.65 0.1780 0.4506 3.5
0.70 0.2441 0.3863 3.0
0.80 0.4219 0.2175 2.0
0.95 1.0000 0.0000 0.5
/ end of table 9
0.20 0.0000 1.0000 45.0
0.25 0.0002 0.9946 30.0
0.30 0.0020 0.9848 15.0
0.35 0.0066 0.9226 6.5
0.40 0.0156 0.8441 6.0
0.45 0.0305 0.7670 5.5
0.50 0.0527 0.6931 5.0
0.55 0.0837 0.6201 4.5
0.60 0.1250 0.5305 4.0
0.65 0.1780 0.4506 3.5
0.70 0.2441 0.3863 3.0
0.80 0.4219 0.2175 2.0
0.95 1.0000 0.0000 0.5
/ end of table 10
0.20 0.0000 1.0000 45.0
0.25 0.0002 0.9946 30.0
0.30 0.0020 0.9848 15.0
0.35 0.0066 0.9226 6.5
0.40 0.0156 0.8441 6.0
0.45 0.0305 0.7670 5.5
0.50 0.0527 0.6931 5.0
0.55 0.0837 0.6201 4.5
0.60 0.1250 0.5305 4.0
0.65 0.1780 0.4506 3.5
0.70 0.2441 0.3863 3.0
0.80 0.4219 0.2175 2.0
0.95 1.0000 0.0000 0.5
/ end of table 11
0.20 0.0000 1.0000 45.0
0.25 0.0002 0.9946 30.0
0.30 0.0020 0.9848 15.0
0.35 0.0066 0.9226 6.5
0.40 0.0156 0.8441 6.0

0.45 0.0305 0.7670 5.5
0.50 0.0527 0.6931 5.0
0.55 0.0837 0.6201 4.5
0.60 0.1250 0.5305 4.0
0.65 0.1780 0.4506 3.5
0.70 0.2441 0.3863 3.0
0.80 0.4219 0.2175 2.0
0.95 1.0000 0.0000 0.5
/ end of table 12
0.20 0.0000 1.0000 45.0
0.25 0.0002 0.9946 30.0
0.30 0.0020 0.9848 15.0
0.35 0.0066 0.9226 6.5
0.40 0.0156 0.8441 6.0
0.45 0.0305 0.7670 5.5
0.50 0.0527 0.6931 5.0
0.55 0.0837 0.6201 4.5
0.60 0.1250 0.5305 4.0
0.65 0.1780 0.4506 3.5
0.70 0.2441 0.3863 3.0
0.80 0.4219 0.2175 2.0
0.95 1.0000 0.0000 0.5
/ end of table 13
0.20 0.0000 1.0000 45.0
0.25 0.0002 0.9946 30.0
0.30 0.0020 0.9848 15.0
0.35 0.0066 0.9226 6.5
0.40 0.0156 0.8441 6.0
0.45 0.0305 0.7670 5.5
0.50 0.0527 0.6931 5.0
0.55 0.0837 0.6201 4.5
0.60 0.1250 0.5305 4.0
0.65 0.1780 0.4506 3.5
0.70 0.2441 0.3863 3.0
0.80 0.4219 0.2175 2.0
0.95 1.0000 0.0000 0.5
/ end of table 14
0.20 0.0000 1.0000 45.0
0.25 0.0002 0.9946 30.0
0.30 0.0020 0.9848 15.0
0.35 0.0066 0.9226 6.5
0.40 0.0156 0.8441 6.0
0.45 0.0305 0.7670 5.5
0.50 0.0527 0.6931 5.0

```
  0.55  0.0837  0.6201    4.5
  0.60  0.1250  0.5305    4.0
  0.65  0.1780  0.4506    3.5
  0.70  0.2441  0.3863    3.0
  0.80  0.4219  0.2175    2.0
  0.95  1.0000  0.0000    0.5
/ end of table 15
  0.20  0.0000  1.0000    45.0
  0.25  0.0002  0.9946    30.0
  0.30  0.0020  0.9848    15.0
  0.35  0.0066  0.9226    6.5
  0.40  0.0156  0.8441    6.0
  0.45  0.0305  0.7670    5.5
  0.50  0.0527  0.6931    5.0
  0.55  0.0837  0.6201    4.5
  0.60  0.1250  0.5305    4.0
  0.65  0.1780  0.4506    3.5
  0.70  0.2441  0.3863    3.0
  0.80  0.4219  0.2175    2.0
  0.95  1.0000  0.0000    0.5
/ end of table 16
  0.20  0.0000  1.0000    45.0
  0.25  0.0002  0.9946    30.0
  0.30  0.0020  0.9848    15.0
  0.35  0.0066  0.9226    6.5
  0.40  0.0156  0.8441    6.0
  0.45  0.0305  0.7670    5.5
  0.50  0.0527  0.6931    5.0
  0.55  0.0837  0.6201    4.5
  0.60  0.1250  0.5305    4.0
  0.65  0.1780  0.4506    3.5
  0.70  0.2441  0.3863    3.0
  0.80  0.4219  0.2175    2.0
  0.95  1.0000  0.0000    0.5
/ end of table 17
  0.20  0.0000  1.0000    45.0
  0.25  0.0002  0.9946    30.0
  0.30  0.0020  0.9848    15.0
  0.35  0.0066  0.9226    6.5
  0.40  0.0156  0.8441    6.0
  0.45  0.0305  0.7670    5.5
  0.50  0.0527  0.6931    5.0
  0.55  0.0837  0.6201    4.5
  0.60  0.1250  0.5305    4.0
```

```
   0.65  0.1780  0.4506    3.5
   0.70  0.2441  0.3863    3.0
   0.80  0.4219  0.2175    2.0
   0.95  1.0000  0.0000    0.5
/ end of table 18
   0.20  0.0000  1.0000    45.0
   0.25  0.0002  0.9946    30.0
   0.30  0.0020  0.9848    15.0
   0.35  0.0066  0.9226    6.5
   0.40  0.0156  0.8441    6.0
   0.45  0.0305  0.7670    5.5
   0.50  0.0527  0.6931    5.0
   0.55  0.0837  0.6201    4.5
   0.60  0.1250  0.5305    4.0
   0.65  0.1780  0.4506    3.5
   0.70  0.2441  0.3863    3.0
   0.80  0.4219  0.2175    2.0
   0.95  1.0000  0.0000    0.5
/ end of table 19
   0.20  0.0000  1.0000    45.0
   0.25  0.0002  0.9946    30.0
   0.30  0.0020  0.9848    15.0
   0.35  0.0066  0.9226    6.5
   0.40  0.0156  0.8441    6.0
   0.45  0.0305  0.7670    5.5
   0.50  0.0527  0.6931    5.0
   0.55  0.0837  0.6201    4.5
   0.60  0.1250  0.5305    4.0
   0.65  0.1780  0.4506    3.5
   0.70  0.2441  0.3863    3.0
   0.80  0.4219  0.2175    2.0
   0.95  1.0000  0.0000    0.5
/ end of table 20
   0.20  0.0000  1.0000    45.0
   0.25  0.0002  0.9946    30.0
   0.30  0.0020  0.9848    15.0
   0.35  0.0066  0.9226    6.5
   0.40  0.0156  0.8441    6.0
   0.45  0.0305  0.7670    5.5
   0.50  0.0527  0.6931    5.0
   0.55  0.0837  0.6201    4.5
   0.60  0.1250  0.5305    4.0
   0.65  0.1780  0.4506    3.5
   0.70  0.2441  0.3863    3.0
```

```
    0.80  0.4219  0.2175    2.0
    0.95  1.0000  0.0000    0.5
 / end of table 21
    0.20  0.0000  1.0000    45.0
    0.25  0.0002  0.9946    30.0
    0.30  0.0020  0.9848    15.0
    0.35  0.0066  0.9226    6.5
    0.40  0.0156  0.8441    6.0
    0.45  0.0305  0.7670    5.5
    0.50  0.0527  0.6931    5.0
    0.55  0.0837  0.6201    4.5
    0.60  0.1250  0.5305    4.0
    0.65  0.1780  0.4506    3.5
    0.70  0.2441  0.3863    3.0
    0.80  0.4219  0.2175    2.0
    0.95  1.0000  0.0000    0.5
 / end of table 22
    0.20  0.0000  1.0000    45.0
    0.25  0.0002  0.9946    30.0
    0.30  0.0020  0.9848    15.0
    0.35  0.0066  0.9226    6.5
    0.40  0.0156  0.8441    6.0
    0.45  0.0305  0.7670    5.5
    0.50  0.0527  0.6931    5.0
    0.55  0.0837  0.6201    4.5
    0.60  0.1250  0.5305    4.0
    0.65  0.1780  0.4506    3.5
    0.70  0.2441  0.3863    3.0
    0.80  0.4219  0.2175    2.0
    0.95  1.0000  0.0000    0.5
 / end of table 23

--Gas-Oil Saturation Table Data
SGOF
--  Sg     Krg   Krog   Pcog
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
```

```
    0.80  0.900  0.000    0.0
/ -- 1
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 2
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 3
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 4
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
```

```
    0.80  0.900  0.000    0.0
/ -- 5
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 6
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 7
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 8
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
```

```
    0.80  0.900  0.000    0.0
/ -- 9
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 10
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 11
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 12
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
```

```
    0.80  0.900  0.000    0.0
/ -- 13
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 14
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 15
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 16
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
```

```
    0.80  0.900  0.000    0.0
/ -- 17
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 18
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 19
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 20
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
```

```
    0.80  0.900  0.000    0.0
/ -- 21
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 22
    0.00  0.000  1.000    0.0
    0.06  0.000  0.525    0.0
    0.10  0.000  0.375    0.0
    0.14  0.000  0.213    0.0
    0.19  0.002  0.106    0.0
    0.24  0.006  0.042    0.0
    0.29  0.013  0.011    0.0
    0.33  0.035  0.001    0.0
    0.37  0.061  0.000    0.0
    0.80  0.900  0.000    0.0
/ -- 23


-- export end points to *.INIT file
-- for 2D/3D display
FILLEPS

-- export a warning message if PVT table extrapolation happens
EXTRAPMS
 1 /


REGIONS    ------------------------------------------------------------------------------------------
-

-- import the saturation regions from external file
INCLUDE
 'IncludeS\FairoozSATNUM.GRDECL' /

SOLUTION   ------------------------------------------------------------------------------------------
```

```
-- initialize the reservoir by equilibration
-- accuracy=0 for block-center method
-- accuracy is > or <0 for fine-grid method
-- DATUM is calculated backwards from OWC per Region
EQUIL
-- DATUM   P@DATUM   OWC        PC@OWC   GOC   PC@GOC   RSVD   RVVD
Accuracy (N)
  7370  3200    7550     0      1*   1*     1     1*    10     /

-- initial solution GOR (Rs) vs depth
RSVD
-- DEPTH  Rs
-- (ft)   (Mscf/stb)
  7370   0.457
  8615   0.457
/

-- export initial solutions (pressure, So, Sw, Sg, Rs) to restart file
-- for 2D/3D display or restart cases
RPTRST
 BASIC=2 /

-- define Fetkovich aquifer
AQUFETP
-- ID  DEPTH  PRESSURE  VOLUME  Ct(Cw+Cr)  PI       PVTW
  1   7581   1*       1E+16    1E-5     206      1   /

-- connect the aquifer to the bottom of the reservoir
AQUANCON
-- ID  I1-I2  J1-J2  K1-K2  PHACE
  1   1  24  1  25  6  6   K+ /
/

-- initial concentration of AQW tracer in a grid block
-- 1. TBLK = prefix; F=free state (could be dissolved state); AQW=name
-- 2. Concentration is dimensionless, defined as C/Cmax
TBLKFAQW
 3600*1 /

-- initial concentration of AQW tracer in the aquifer
AQANTRC
-- aquifer-ID  tracer-name  tracer-concentration
  1          AQW        1.0              /
/
```

```
SUMMARY    ----------------------------------------------------------------------------------------

-- import pre-defined vectors
INCLUDE
 'Includes\FairoozSUMMARY.INC'/

SCHEDULE    ----------------------------------------------------------------------------------------
-

INCLUDE
 'Includes\PROSPER\GLP01.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP02.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP03.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP04.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP05.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP06.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP07.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP08.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP09.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP10.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP12.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP13.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP15.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP16.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP17.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP18.Ecl'/
INCLUDE
```

```
 'Includes\PROSPER\GLP19.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP20.Ecl'/
INCLUDE
 'Includes\PROSPER\GLP21.Ecl'/
INCLUDE
 'Includes\PROSPER\GLA01.Ecl'/
INCLUDE
 'Includes\PROSPER\GLA02.Ecl'/
INCLUDE
 'Includes\PROSPER\GLA03.Ecl'/
INCLUDE
 'Includes\PROSPER\GLA04.Ecl'/


-- export solutions to restart file at each reporting step
RPTRST
 BASIC=3  FREQ=1 /

RPTSCHED
 WELLS=5  CPU=2 /

-- drill wells
-- 1. well & group name is limited to 8 characters (no space)
-- 2. I J is located at reservoir top
-- 3. BHP-depth is defaulted to mid depth of top most completions
WELSPECL
-- WELL   GROUP   L-GROUP    I  J    BHP-depth  PHASE
   PN02  West     N02        6  6     7370      OIL   /
   PN05  West     N05        6  6     7370      OIL   /
   PN10  West     N10        6  6     7370      OIL   /
   PN15  West     N15        6  6     7370      OIL   /
   PN16y West     N16y       6  6     7370      OIL   /
   PN03y South    N03y       6  6     7370      OIL   /
   PN08  South    N08        6  6     7370      OIL   /
   PN12  South    N12        6  6     7370      OIL   /
   PA01  South    A01        6  6     7370      OIL   /
   PA02  South    A02        6  6     7370      OIL   /
   PA03  South    A03        6  6     7370      OIL   /
   PA04  South    A04        6  6     7370      OIL   /
   PN01  East     N01        6  6     7370      OIL   /
   PN04  East     N04        6  6     7370      OIL   /
   PN06  East     N06        6  6     7370      OIL   /
   PN07  East     N07        6  6     7370      OIL   /
```

```
   PN13  East     N13       6  6     7370      OIL   /
   PN09  Central  N09       6  6     7370      OIL   /
   PN17  Central  N17       6  6     7370      OIL   /
   PN18  Central  N18       6  6     7370      OIL   /
   PN19  Central  N19       6  6     7370      OIL   /
   PN20  Central  N20       6  6     7370      OIL   /
   PN21  Central  N21       6  6     7370      OIL   /
   PF01  West     F01       6  6     7370      OIL   /
   PF02  East     F02       6  6     7370      OIL   /
   PF03  Central  F03       6  6     7370      OIL   /
   PF04  East     F04       6  6     7370      OIL   /
   PF05  Central  F05       6  6     7370      OIL   /
   PF06  East     F06       6  6     7370      OIL   /
   PF07  Central  F07       6  6     7370      OIL   /
/

WELSPECS
-- WELL   GROUP    I  J    BHP-depth  PHASE
   IN11y  East     17 2     1*        WATER /
   IN23   East     23 14    1*        WATER /
   IN14   West     2  7     1*        WATER /
   IN22   South    11 19    1*        WATER /
   IF01   South    14 10    1*        WATER /
   IF02   Centeral 6  2     1*        WATER /
   IF03   South    15 18    1*        WATER /
/

-- complete wells
COMPDATL
-- Well   L-GRID   I  J  K1-K2  Status  Sat  CF  Diam   kh  Skin  D   direc
   PN02   N02      6  6  1  3   OPEN    1*   1*  0.708  1*  -3    1*  z  /
   PN02   N02      6  6  3  5   OPEN    1*   1*  0.708  1*  -3    1*  z  /
   PN02   N02      6  6  5  8   OPEN    1*   1*  0.708  1*  -3    1*  z  /
   PN02   N02      6  6  8  10  OPEN    1*   1*  0.708  1*  -3    1*  z  /

   PN05   N05      6  6  1  3   OPEN    1*   1*  0.708  1*  -3    1*  z  /
   PN05   N05      6  6  3  5   OPEN    1*   1*  0.708  1*  -3    1*  z  /
   PN05   N05      6  6  5  8   OPEN    1*   1*  0.708  1*  -3    1*  z  /
   PN05   N05      6  6  8  10  OPEN    1*   1*  0.708  1*  -3    1*  z  /

   PN10   N10      6  6  1  3   OPEN    1*   1*  0.708  1*  -3    1*  z  /
   PN10   N10      6  6  3  5   OPEN    1*   1*  0.708  1*  -3    1*  z  /
   PN10   N10      6  6  5  8   OPEN    1*   1*  0.708  1*  -3    1*  z  /
   PN10   N10      6  6  8  10  OPEN    1*   1*  0.708  1*  -3    1*  z  /
```

```
PN15   N15     6  6  1  3   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN15   N15     6  6  3  5   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN15   N15     6  6  5  8   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN15   N15     6  6  8  10  OPEN   1*   1*  0.708  1*  -3   1*  z  /

PN16y  N16y    6  6  1  3   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN16y  N16y    6  6  3  5   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN16y  N16y    6  6  5  8   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN16y  N16y    6  6  8  10  OPEN   1*   1*  0.708  1*  -3   1*  z  /

PN03y  N03y    6  6  1  3   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN03y  N03y    6  6  3  5   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN03y  N03y    6  6  5  8   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN03y  N03y    6  6  8  10  OPEN   1*   1*  0.708  1*  -3   1*  z  /

PN08   N08     6  6  1  3   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN08   N08     6  6  3  5   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN08   N08     6  6  5  8   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN08   N08     6  6  8  10  OPEN   1*   1*  0.708  1*  -3   1*  z  /

PN12   N12     6  6  1  3   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN12   N12     6  6  3  5   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN12   N12     6  6  5  8   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PN12   N12     6  6  8  10  OPEN   1*   1*  0.708  1*  -3   1*  z  /

PA01   A01     6  6  1  3   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PA01   A01     6  6  3  5   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PA01   A01     6  6  5  8   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PA01   A01     6  6  8  10  OPEN   1*   1*  0.708  1*  -3   1*  z  /

PA02   A02     6  6  1  3   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PA02   A02     6  6  3  5   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PA02   A02     6  6  5  8   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PA02   A02     6  6  8  10  OPEN   1*   1*  0.708  1*  -3   1*  z  /

PA03   A03     6  6  1  3   OPEN   1*   1*  0.708  1*  -3.5 1*  z  /
PA03   A03     6  6  3  5   OPEN   1*   1*  0.708  1*  -3.5 1*  z  /
PA03   A03     6  6  5  8   OPEN   1*   1*  0.708  1*  -3.5 1*  z  /
PA03   A03     6  6  8  10  OPEN   1*   1*  0.708  1*  -3.5 1*  z  /

PA04   A04     6  6  1  3   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PA04   A04     6  6  3  5   OPEN   1*   1*  0.708  1*  -3   1*  z  /
PA04   A04     6  6  5  8   OPEN   1*   1*  0.708  1*  -3   1*  z  /
```

```
PA04  A04    6  6  8  10  OPEN   1*   1*  0.708  1*  -3    1*  z  /

PN01  N01    6  6  1  3   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN01  N01    6  6  3  5   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN01  N01    6  6  5  8   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN01  N01    6  6  8  10  OPEN   1*   1*  0.708  1*  -3    1*  z  /

PN04  N04    6  6  1  3   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN04  N04    6  6  3  5   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN04  N04    6  6  5  8   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN04  N04    6  6  8  10  OPEN   1*   1*  0.708  1*  -3    1*  z  /

PN06  N06    6  6  1  3   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN06  N06    6  6  3  5   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN06  N06    6  6  5  8   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN06  N06    6  6  8  10  OPEN   1*   1*  0.708  1*  -3    1*  z  /

PN07  N07    6  6  1  3   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN07  N07    6  6  3  5   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN07  N07    6  6  5  8   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN07  N07    6  6  8  10  OPEN   1*   1*  0.708  1*  -3    1*  z  /

PN13  N13    6  6  1  3   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN13  N13    6  6  3  5   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN13  N13    6  6  5  8   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN13  N13    6  6  8  10  OPEN   1*   1*  0.708  1*  -3    1*  z  /

PN09  N09    6  6  1  3   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN09  N09    6  6  3  5   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN09  N09    6  6  5  8   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN09  N09    6  6  8  10  OPEN   1*   1*  0.708  1*  -3    1*  z  /

PN17  N17    6  6  1  3   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN17  N17    6  6  3  5   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN17  N17    6  6  5  8   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN17  N17    6  6  8  10  OPEN   1*   1*  0.708  1*  -3    1*  z  /

PN18  N18    6  6  1  3   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN18  N18    6  6  3  5   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN18  N18    6  6  5  8   OPEN   1*   1*  0.708  1*  -3    1*  z  /
PN18  N18    6  6  8  10  OPEN   1*   1*  0.708  1*  -3    1*  z  /

PN19  N19    6  6  1  3   OPEN   1*   1*  0.708  1*  -3.5  1*  z  /
PN19  N19    6  6  3  5   OPEN   1*   1*  0.708  1*  -3.5  1*  z  /
```

```
PN19  N19    6 6 5 8   OPEN   1*  1* 0.708 1* -3.5 1* z /
PN19  N19    6 6 8 10  OPEN   1*  1* 0.708 1* -3.5 1* z /

PN20  N20    6 6 1 3   OPEN   1*  1* 0.708 1* -3   1* z /
PN20  N20    6 6 3 5   OPEN   1*  1* 0.708 1* -3   1* z /
PN20  N20    6 6 5 8   OPEN   1*  1* 0.708 1* -3   1* z /
PN20  N20    6 6 8 10  OPEN   1*  1* 0.708 1* -3   1* z /

PN21  N21    6 6 1 3   OPEN   1*  1* 0.708 1* -3   1* z /
PN21  N21    6 6 3 5   OPEN   1*  1* 0.708 1* -3   1* z /
PN21  N21    6 6 5 8   OPEN   1*  1* 0.708 1* -3   1* z /
PN21  N21    6 6 8 10  OPEN   1*  1* 0.708 1* -3   1* z /

PF01  F01    6 6 1 3   OPEN   1*  1* 0.708 1* -3   1* z /
PF01  F01    6 6 3 5   OPEN   1*  1* 0.708 1* -3   1* z /
PF01  F01    6 6 5 8   OPEN   1*  1* 0.708 1* -3   1* z /
PF01  F01    6 6 8 10  OPEN   1*  1* 0.708 1* -3   1* z /

PF02  F02    6 6 1 3   OPEN   1*  1* 0.708 1* -3   1* z /
PF02  F02    6 6 3 5   OPEN   1*  1* 0.708 1* -3   1* z /
PF02  F02    6 6 5 8   OPEN   1*  1* 0.708 1* -3   1* z /
PF02  F02    6 6 8 10  OPEN   1*  1* 0.708 1* -3   1* z /


PF03  F03    6 6 1 3   OPEN   1*  1* 0.708 1* -3   1* z /
PF03  F03    6 6 3 5   OPEN   1*  1* 0.708 1* -3   1* z /
PF03  F03    6 6 5 8   OPEN   1*  1* 0.708 1* -3   1* z /
PF03  F03    6 6 8 10  OPEN   1*  1* 0.708 1* -3   1* z /

PF04  F04    6 6 1 3   OPEN   1*  1* 0.708 1* -3   1* z /
PF04  F04    6 6 3 5   OPEN   1*  1* 0.708 1* -3   1* z /
PF04  F04    6 6 5 8   OPEN   1*  1* 0.708 1* -3   1* z /
PF04  F04    6 6 8 10  OPEN   1*  1* 0.708 1* -3   1* z /

PF05  F05    6 6 1 3   OPEN   1*  1* 0.708 1* -3   1* z /
PF05  F05    6 6 3 5   OPEN   1*  1* 0.708 1* -3   1* z /
PF05  F05    6 6 5 8   OPEN   1*  1* 0.708 1* -3   1* z /
PF05  F05    6 6 8 10  OPEN   1*  1* 0.708 1* -3   1* z /

PF06  F06    6 6 1 3   OPEN   1*  1* 0.708 1* -3   1* z /
PF06  F06    6 6 3 5   OPEN   1*  1* 0.708 1* -3   1* z /
PF06  F06    6 6 5 8   OPEN   1*  1* 0.708 1* -3   1* z /
PF06  F06    6 6 8 10  OPEN   1*  1* 0.708 1* -3   1* z /
```

```
   PF07   F07     6  6  1  3   OPEN    1*   1*  0.708  1*  -3    1*  z   /
   PF07   F07     6  6  3  5   OPEN    1*   1*  0.708  1*  -3    1*  z   /
   PF07   F07     6  6  5  8   OPEN    1*   1*  0.708  1*  -3    1*  z   /
   PF07   F07     6  6  8  10  OPEN    1*   1*  0.708  1*  -3    1*  z   /
/

COMPDAT
-- Well   I  J  K1-K2  Status  Sat  CF  Diam   kh  Skin  D   direc
   IN11y  1* 1* 6  6   OPEN    1*   1*  0.708  1*  1*    1*  Z   /
   IN23   1* 1* 6  6   OPEN    1*   1*  0.708  1*  1*    1*  Z   /
   IN14   1* 1* 6  6   OPEN    1*   1*  0.708  1*  1*    1*  Z   /
   IN22   1* 1* 6  6   OPEN    1*   1*  0.708  1*  1*    1*  Z   /
   IF01   1* 1* 6  6   OPEN    1*   1*  0.708  1*  1*    1*  Z   /
   IF02   1* 1* 6  6   OPEN    1*   1*  0.708  1*  1*    1*  Z   /
   IF03   1* 1* 6  6   OPEN    1*   1*  0.708  1*  1*    1*  Z   /
/


-- specifying new wells' control data before the history matching process
-- because they are not included in the history include file

WCONPROD
'PF01'  'SHUT' 'THP' 6*  115  16 0   /
'PF02'  'SHUT' 'THP' 6*  115   1 0   /
'PF03'  'SHUT' 'THP' 6*  115  20 0   /
'PF04'  'SHUT' 'THP' 6*  115   2 0   /
'PF05'  'SHUT' 'THP' 6*  115  20 0   /
'PF06'  'SHUT' 'THP' 6*  115   4 0   /
'PF07'  'SHUT' 'THP' 6*  115   3 0   /
/

WCONINJE
   IF01 WATER SHUT RESV 1* 14900.25 /
   IF02 WATER SHUT RESV 1* 14900.25 /
   IF03 WATER SHUT RESV 1* 14900.25 /
/

-- import production history
-- Also, specifies well controls for the producers after the history
-- Status of the well: open to production
-- Well control mode: Oil rate
-- The value set per region
INCLUDE
 'Includes\FairoozHIST_ORAT.SCH' /
```

```
WCONPROD
'PA01'  'OPEN' 'THP' 6*  115  11 3000/
'PA02'  'OPEN' 'THP' 6*  115  14 3000/
'PA03'  'OPEN' 'THP' 6*  115  22 3000/
'PA04'  'OPEN' 'THP' 6*  115  23 3000/
'PN01'  'OPEN' 'THP' 6*  115  1  3000/
'PN02'  'OPEN' 'THP' 6*  115  2  3000/
'PN03y' 'OPEN' 'THP' 6*  115  3  3000/
'PN04'  'OPEN' 'THP' 6*  115  4  3000/
'PN05'  'OPEN' 'THP' 6*  115  5  3000/
'PN06'  'OPEN' 'THP' 6*  115  6  3000/
'PN07'  'OPEN' 'THP' 6*  115  7  3000/
'PN08'  'SHUT' 'THP' 6*  115  8  0   /
'PN09'  'OPEN' 'THP' 6*  115  9  3000/
'PN10'  'OPEN' 'THP' 6*  115  10 3000/
'PN12'  'OPEN' 'THP' 6*  115  12 3000/
'PN13'  'OPEN' 'THP' 6*  115  13 3000/
'PN15'  'OPEN' 'THP' 6*  115  15 3000/
'PN16y' 'OPEN' 'THP' 6*  115  16 3000/
'PN17'  'OPEN' 'THP' 6*  115  17 0   /
'PN18'  'OPEN' 'THP' 6*  115  18 3000/
'PN19'  'OPEN' 'THP' 6*  115  19 0   /
'PN20'  'OPEN' 'THP' 6*  115  20 0   /
'PN21'  'OPEN' 'THP' 6*  115  21 0   /
'PF01'  'SHUT' 'THP' 6*  115  16 0   /
'PF02'  'SHUT' 'THP' 6*  115   1 0   /
'PF03'  'SHUT' 'THP' 6*  115  20 0   /
'PF04'  'SHUT' 'THP' 6*  115   2 0   /
'PF05'  'SHUT' 'THP' 6*  115  20 0   /
'PF06'  'SHUT' 'THP' 6*  115   4 0   /
'PF07'  'SHUT' 'THP' 6*  115  18 0   /
/
```

```
-- Specifies well controls for the injector
-- Name of the well: I
-- Status of the well: open to injection
-- Well control mode: reservoir injection rate: The total water injection rate / 4 wells
-- The final record specifies target for the control parameter: 19,591.25 reservoir barrels/ day
-- This number came from W.I. Rate of Dec-97 (78,365 rb/d) / 4 W.I. Wells

WCONINJE
```

```
   IN11y WATER OPEN RESV 1* 14900.25 /
   IN23  WATER OPEN RESV 1* 14900.25 /
   IN14  WATER OPEN RESV 1* 14900.25 /
   IN22  WATER OPEN RESV 1* 14900.25 /
   IF01  WATER SHUT RESV 1* 14900.25 /
   IF02  WATER SHUT RESV 1* 14900.25 /
   IF03  WATER OPEN RESV 1* 14900.25 /
/


GCONPROD
 FIELD ORAT  126200 3* RATE /
 FIELD ORAT  138820 3* RATE /
/


-- Specifies the number and length of the timesteps required: 50 timesteps of 30 days each
TSTEP
192*30
/

TSTEP
1*50
/

WCONPROD
'PA01'  'OPEN' 'THP' 6*  115  11 3000/
'PA02'  'OPEN' 'THP' 6*  115  14 3000/
'PA03'  'OPEN' 'THP' 6*  115  22 3000/
'PA04'  'OPEN' 'THP' 6*  115  23 3000/
'PN01'  'OPEN' 'THP' 6*  115  1  3000/
'PN02'  'OPEN' 'THP' 6*  115  2  3000/
'PN03y' 'OPEN' 'THP' 6*  115  3  3000/
'PN04'  'OPEN' 'THP' 6*  115  4  3000/
'PN05'  'OPEN' 'THP' 6*  115  5  3000/
'PN06'  'OPEN' 'THP' 6*  115  6  3000/
'PN07'  'OPEN' 'THP' 6*  115  7  3000/
'PN08'  'SHUT' 'THP' 6*  115  8  0   /
'PN09'  'OPEN' 'THP' 6*  115  9  3000/
'PN10'  'OPEN' 'THP' 6*  115  10 3000/
'PN12'  'OPEN' 'THP' 6*  115  12 3000/
'PN13'  'OPEN' 'THP' 6*  115  13 3000/
'PN15'  'OPEN' 'THP' 6*  115  15 3000/
```

```
'PN16y' 'OPEN' 'THP' 6*  115  16 3000/
'PN17'  'OPEN' 'THP' 6*  115  17 0   /
'PN18'  'OPEN' 'THP' 6*  115  18 3000/
'PN19'  'OPEN' 'THP' 6*  115  19 0   /
'PN20'  'OPEN' 'THP' 6*  115  20 0   /
'PN21'  'OPEN' 'THP' 6*  115  21 0   /
'PF01'  'SHUT' 'THP' 6*  115  16 0   /
'PF02'  'SHUT' 'THP' 6*  115   1 0   /
'PF03'  'SHUT' 'THP' 6*  115  20 0   /
'PF04'  'SHUT' 'THP' 6*  115   2 0   /
'PF05'  'SHUT' 'THP' 6*  115  20 0   /
'PF06'  'SHUT' 'THP' 6*  115   4 0   /
'PF07'  'SHUT' 'THP' 6*  115  18 0   /
/

WCONINJE
   IN11y WATER OPEN RESV 1* 14900.25 /
   IN23  WATER OPEN RESV 1* 14900.25 /
   IN14  WATER OPEN RESV 1* 14900.25 /
   IN22  WATER OPEN RESV 1* 14900.25 /
   IF01  WATER OPEN RESV 1* 14900.25 /
   IF02  WATER SHUT RESV 1* 14900.25 /
   IF03  WATER OPEN RESV 1* 14900.25 /
/

TSTEP
1*50
/

WCONPROD
'PA01'  'OPEN' 'THP' 6*  115  11 3000/
'PA02'  'OPEN' 'THP' 6*  115  14 3000/
'PA03'  'OPEN' 'THP' 6*  115  22 3000/
'PA04'  'OPEN' 'THP' 6*  115  23 3000/
'PN01'  'OPEN' 'THP' 6*  115  1  3000/
'PN02'  'OPEN' 'THP' 6*  115  2  3000/
'PN03y' 'OPEN' 'THP' 6*  115  3  3000/
'PN04'  'OPEN' 'THP' 6*  115  4  3000/
'PN05'  'OPEN' 'THP' 6*  115  5  3000/
'PN06'  'OPEN' 'THP' 6*  115  6  3000/
'PN07'  'OPEN' 'THP' 6*  115  7  3000/
'PN08'  'SHUT' 'THP' 6*  115  8  0   /
'PN09'  'OPEN' 'THP' 6*  115  9  3000/
'PN10'  'OPEN' 'THP' 6*  115  10 3000/
```

```
'PN12'  'OPEN' 'THP' 6*  115  12 3000/
'PN13'  'OPEN' 'THP' 6*  115  13 3000/
'PN15'  'OPEN' 'THP' 6*  115  15 3000/
'PN16y' 'OPEN' 'THP' 6*  115  16 3000/
'PN17'  'OPEN' 'THP' 6*  115  17 0   /
'PN18'  'OPEN' 'THP' 6*  115  18 3000/
'PN19'  'OPEN' 'THP' 6*  115  19 0   /
'PN20'  'OPEN' 'THP' 6*  115  20 0   /
'PN21'  'OPEN' 'THP' 6*  115  21 0   /
'PF01'  'SHUT' 'THP' 6*  115  16 0   /
'PF02'  'SHUT' 'THP' 6*  115   1 0   /
'PF03'  'SHUT' 'THP' 6*  115  20 0   /
'PF04'  'SHUT' 'THP' 6*  115   2 0   /
'PF05'  'SHUT' 'THP' 6*  115  20 0   /
'PF06'  'SHUT' 'THP' 6*  115   4 0   /
'PF07'  'SHUT' 'THP' 6*  115  18 0   /
/

WCONINJE
   IN11y WATER OPEN RESV 1* 14900.25 /
   IN23  WATER OPEN RESV 1* 14900.25 /
   IN14  WATER OPEN RESV 1* 14900.25 /
   IN22  WATER OPEN RESV 1* 14900.25 /
   IF01  WATER OPEN RESV 1* 14900.25 /
   IF02  WATER OPEN RESV 1* 14900.25 /
   IF03  WATER OPEN RESV 1* 14900.25 /
/

TSTEP
4*40
/

WCONPROD
'PA01'  'OPEN' 'GRUP' 6*  115  11 3000/
'PA02'  'OPEN' 'GRUP' 6*  115  14 3000/
'PA03'  'OPEN' 'GRUP' 6*  115  22 3000/
'PA04'  'OPEN' 'GRUP' 6*  115  23 3000/
'PN01'  'OPEN' 'GRUP' 6*  115  1  3000/
'PN02'  'OPEN' 'GRUP' 6*  115  2  3000/
'PN03y' 'OPEN' 'GRUP' 6*  115  3  3000/
'PN04'  'OPEN' 'GRUP' 6*  115  4  3000/
'PN05'  'OPEN' 'GRUP' 6*  115  5  3000/
'PN06'  'OPEN' 'GRUP' 6*  115  6  3000/
'PN07'  'OPEN' 'GRUP' 6*  115  7  3000/
```

```
'PN08'  'SHUT' 'GRUP' 6*  115  8  0   /
'PN09'  'OPEN' 'GRUP' 6*  115  9  3000/
'PN10'  'OPEN' 'GRUP' 6*  115  10 3000/
'PN12'  'OPEN' 'GRUP' 6*  115  12 3000/
'PN13'  'OPEN' 'GRUP' 6*  115  13 3000/
'PN15'  'OPEN' 'GRUP' 6*  115  15 3000/
'PN16y' 'OPEN' 'GRUP' 6*  115  16 3000/
'PN17'  'OPEN' 'GRUP' 6*  115  17 0   /
'PN18'  'OPEN' 'GRUP' 6*  115  18 3000/
'PN19'  'OPEN' 'GRUP' 6*  115  19 0   /
'PN20'  'OPEN' 'GRUP' 6*  115  20 0   /
'PN21'  'OPEN' 'GRUP' 6*  115  21 0   /
'PF01'  'OPEN' 'GRUP' 6*  115  16 0   /
'PF02'  'SHUT' 'GRUP' 6*  115   1 0   /
'PF03'  'SHUT' 'GRUP' 6*  115  20 0   /
'PF04'  'SHUT' 'GRUP' 6*  115   2 0   /
'PF05'  'SHUT' 'GRUP' 6*  115  20 0   /
'PF06'  'SHUT' 'GRUP' 6*  115   4 0   /
'PF07'  'SHUT' 'GRUP' 6*  115  18 0   /
/

GCONPROD
  FIELD ORAT  138820 3* RATE /
/

TSTEP
5*10
/

WCONPROD
'PA01'  'OPEN' 'GRUP' 6*  115  11 3000/
'PA02'  'OPEN' 'GRUP' 6*  115  14 3000/
'PA03'  'OPEN' 'GRUP' 6*  115  22 3000/
'PA04'  'OPEN' 'GRUP' 6*  115  23 3000/
'PN01'  'OPEN' 'GRUP' 6*  115  1  3000/
'PN02'  'OPEN' 'GRUP' 6*  115  2  3000/
'PN03y' 'OPEN' 'GRUP' 6*  115  3  3000/
'PN04'  'OPEN' 'GRUP' 6*  115  4  3000/
'PN05'  'OPEN' 'GRUP' 6*  115  5  3000/
'PN06'  'OPEN' 'GRUP' 6*  115  6  3000/
'PN07'  'OPEN' 'GRUP' 6*  115  7  3000/
'PN08'  'SHUT' 'GRUP' 6*  115  8  0   /
'PN09'  'OPEN' 'GRUP' 6*  115  9  3000/
'PN10'  'OPEN' 'GRUP' 6*  115  10 3000/
```

```
'PN12'  'OPEN' 'GRUP' 6*  115  12 3000/
'PN13'  'OPEN' 'GRUP' 6*  115  13 3000/
'PN15'  'OPEN' 'GRUP' 6*  115  15 3000/
'PN16y' 'OPEN' 'GRUP' 6*  115  16 3000/
'PN17'  'OPEN' 'GRUP' 6*  115  17 0   /
'PN18'  'OPEN' 'GRUP' 6*  115  18 3000/
'PN19'  'OPEN' 'GRUP' 6*  115  19 0   /
'PN20'  'OPEN' 'GRUP' 6*  115  20 0   /
'PN21'  'OPEN' 'GRUP' 6*  115  21 0   /
'PF01'  'OPEN' 'GRUP' 6*  115  16 0   /
'PF02'  'OPEN' 'GRUP' 6*  115   1 0   /
'PF03'  'SHUT' 'GRUP' 6*  115  20 0   /
'PF04'  'SHUT' 'GRUP' 6*  115   2 0   /
'PF05'  'SHUT' 'GRUP' 6*  115  20 0   /
'PF06'  'SHUT' 'GRUP' 6*  115   4 0   /
'PF07'  'SHUT' 'GRUP' 6*  115  18 0   /
/

GCONPROD
  FIELD ORAT  138820 3* RATE /
/

TSTEP
4*15
/

WCONPROD
'PA01'  'OPEN' 'GRUP' 6*  115  11 3000/
'PA02'  'OPEN' 'GRUP' 6*  115  14 3000/
'PA03'  'OPEN' 'GRUP' 6*  115  22 3000/
'PA04'  'OPEN' 'GRUP' 6*  115  23 3000/
'PN01'  'OPEN' 'GRUP' 6*  115  1  3000/
'PN02'  'OPEN' 'GRUP' 6*  115  2  3000/
'PN03y' 'OPEN' 'GRUP' 6*  115  3  3000/
'PN04'  'OPEN' 'GRUP' 6*  115  4  3000/
'PN05'  'OPEN' 'GRUP' 6*  115  5  3000/
'PN06'  'OPEN' 'GRUP' 6*  115  6  3000/
'PN07'  'OPEN' 'GRUP' 6*  115  7  3000/
'PN08'  'SHUT' 'GRUP' 6*  115  8  0   /
'PN09'  'OPEN' 'GRUP' 6*  115  9  3000/
'PN10'  'OPEN' 'GRUP' 6*  115  10 3000/
'PN12'  'OPEN' 'GRUP' 6*  115  12 3000/
'PN13'  'OPEN' 'GRUP' 6*  115  13 3000/
'PN15'  'OPEN' 'GRUP' 6*  115  15 3000/
```

```
'PN16y' 'OPEN' 'GRUP' 6*  115  16 3000/
'PN17'  'OPEN' 'GRUP' 6*  115  17 0   /
'PN18'  'OPEN' 'GRUP' 6*  115  18 3000/
'PN19'  'OPEN' 'GRUP' 6*  115  19 0   /
'PN20'  'OPEN' 'GRUP' 6*  115  20 0   /
'PN21'  'OPEN' 'GRUP' 6*  115  21 0   /
'PF01'  'OPEN' 'GRUP' 6*  115  16 0   /
'PF02'  'OPEN' 'GRUP' 6*  115   1 0   /
'PF03'  'OPEN' 'GRUP' 6*  115  20 0   /
'PF04'  'SHUT' 'GRUP' 6*  115   2 0   /
'PF05'  'SHUT' 'GRUP' 6*  115  20 0   /
'PF06'  'SHUT' 'GRUP' 6*  115   4 0   /
'PF07'  'SHUT' 'GRUP' 6*  115  18 0   /
/
GCONPROD
  FIELD ORAT  138820 3* RATE /
/

TSTEP
6*10
/

WCONPROD
'PA01'  'OPEN' 'GRUP' 6*  115  11 3000/
'PA02'  'OPEN' 'GRUP' 6*  115  14 3000/
'PA03'  'OPEN' 'GRUP' 6*  115  22 3000/
'PA04'  'OPEN' 'GRUP' 6*  115  23 3000/
'PN01'  'OPEN' 'GRUP' 6*  115  1  3000/
'PN02'  'OPEN' 'GRUP' 6*  115  2  3000/
'PN03y' 'OPEN' 'GRUP' 6*  115  3  3000/
'PN04'  'OPEN' 'GRUP' 6*  115  4  3000/
'PN05'  'OPEN' 'GRUP' 6*  115  5  3000/
'PN06'  'OPEN' 'GRUP' 6*  115  6  3000/
'PN07'  'OPEN' 'GRUP' 6*  115  7  3000/
'PN08'  'SHUT' 'GRUP' 6*  115  8  0   /
'PN09'  'OPEN' 'GRUP' 6*  115  9  3000/
'PN10'  'OPEN' 'GRUP' 6*  115  10 3000/
'PN12'  'OPEN' 'GRUP' 6*  115  12 3000/
'PN13'  'OPEN' 'GRUP' 6*  115  13 3000/
'PN15'  'OPEN' 'GRUP' 6*  115  15 3000/
'PN16y' 'OPEN' 'GRUP' 6*  115  16 3000/
'PN17'  'OPEN' 'GRUP' 6*  115  17 0   /
'PN18'  'OPEN' 'GRUP' 6*  115  18 3000/
'PN19'  'OPEN' 'GRUP' 6*  115  19 0   /
```

```
'PN20'  'OPEN' 'GRUP' 6*  115  20 0   /
'PN21'  'OPEN' 'GRUP' 6*  115  21 0   /
'PF01'  'OPEN' 'GRUP' 6*  115  16 0   /
'PF02'  'OPEN' 'GRUP' 6*  115   1 0   /
'PF03'  'OPEN' 'GRUP' 6*  115  20 0   /
'PF04'  'OPEN' 'GRUP' 6*  115   2 0   /
'PF05'  'SHUT' 'GRUP' 6*  115  20 0   /
'PF06'  'SHUT' 'GRUP' 6*  115   4 0   /
'PF07'  'SHUT' 'GRUP' 6*  115  18 0   /
/

GCONPROD
  FIELD ORAT  138820 3* RATE /
/

TSTEP
6*10
/

WCONPROD
'PA01'  'OPEN' 'GRUP' 6*  115  11 3000/
'PA02'  'OPEN' 'GRUP' 6*  115  14 3000/
'PA03'  'OPEN' 'GRUP' 6*  115  22 3000/
'PA04'  'OPEN' 'GRUP' 6*  115  23 3000/
'PN01'  'OPEN' 'GRUP' 6*  115  1  3000/
'PN02'  'OPEN' 'GRUP' 6*  115  2  3000/
'PN03y' 'OPEN' 'GRUP' 6*  115  3  3000/
'PN04'  'OPEN' 'GRUP' 6*  115  4  3000/
'PN05'  'OPEN' 'GRUP' 6*  115  5  3000/
'PN06'  'OPEN' 'GRUP' 6*  115  6  3000/
'PN07'  'OPEN' 'GRUP' 6*  115  7  3000/
'PN08'  'SHUT' 'GRUP' 6*  115  8  0   /
'PN09'  'OPEN' 'GRUP' 6*  115  9  3000/
'PN10'  'OPEN' 'GRUP' 6*  115  10 3000/
'PN12'  'OPEN' 'GRUP' 6*  115  12 3000/
'PN13'  'OPEN' 'GRUP' 6*  115  13 3000/
'PN15'  'OPEN' 'GRUP' 6*  115  15 3000/
'PN16y' 'OPEN' 'GRUP' 6*  115  16 3000/
'PN17'  'OPEN' 'GRUP' 6*  115  17 0   /
'PN18'  'OPEN' 'GRUP' 6*  115  18 3000/
'PN19'  'OPEN' 'GRUP' 6*  115  19 0   /
'PN20'  'OPEN' 'GRUP' 6*  115  20 0   /
'PN21'  'OPEN' 'GRUP' 6*  115  21 0   /
'PF01'  'OPEN' 'GRUP' 6*  115  16 0   /
```

```
'PF02'  'OPEN' 'GRUP' 6*  115   1 0   /
'PF03'  'OPEN' 'GRUP' 6*  115  20 0   /
'PF04'  'OPEN' 'GRUP' 6*  115   2 0   /
'PF05'  'OPEN' 'GRUP' 6*  115  20 0   /
'PF06'  'OPEN' 'GRUP' 6*  115   4 0   /
'PF07'  'SHUT' 'GRUP' 6*  115  18 0   /
/

GCONPROD
  FIELD ORAT  138820 3* RATE /
/

TSTEP
6*10
/

WCONPROD
'PA01'  'OPEN' 'GRUP' 6*  115  11 3000/
'PA02'  'OPEN' 'GRUP' 6*  115  14 3000/
'PA03'  'OPEN' 'GRUP' 6*  115  22 3000/
'PA04'  'OPEN' 'GRUP' 6*  115  23 3000/
'PN01'  'OPEN' 'GRUP' 6*  115  1  3000/
'PN02'  'OPEN' 'GRUP' 6*  115  2  3000/
'PN03y' 'OPEN' 'GRUP' 6*  115  3  3000/
'PN04'  'OPEN' 'GRUP' 6*  115  4  3000/
'PN05'  'OPEN' 'GRUP' 6*  115  5  3000/
'PN06'  'OPEN' 'GRUP' 6*  115  6  3000/
'PN07'  'OPEN' 'GRUP' 6*  115  7  3000/
'PN08'  'SHUT' 'GRUP' 6*  115  8  0   /
'PN09'  'OPEN' 'GRUP' 6*  115  9  3000/
'PN10'  'OPEN' 'GRUP' 6*  115  10 3000/
'PN12'  'OPEN' 'GRUP' 6*  115  12 3000/
'PN13'  'OPEN' 'GRUP' 6*  115  13 3000/
'PN15'  'OPEN' 'GRUP' 6*  115  15 3000/
'PN16y' 'OPEN' 'GRUP' 6*  115  16 3000/
'PN17'  'OPEN' 'GRUP' 6*  115  17 0   /
'PN18'  'OPEN' 'GRUP' 6*  115  18 3000/
'PN19'  'OPEN' 'GRUP' 6*  115  19 0   /
'PN20'  'OPEN' 'GRUP' 6*  115  20 0   /
'PN21'  'OPEN' 'GRUP' 6*  115  21 0   /
'PF01'  'OPEN' 'GRUP' 6*  115  16 0   /
'PF02'  'OPEN' 'GRUP' 6*  115   1 0   /
'PF03'  'OPEN' 'GRUP' 6*  115  20 0   /
'PF04'  'OPEN' 'GRUP' 6*  115   2 0   /
```

```
'PF05'  'OPEN' 'GRUP' 6*  115  20 0   /
'PF06'  'OPEN' 'GRUP' 6*  115   4 0   /
'PF07'  'OPEN' 'GRUP' 6*  115  18 0   /
/

GCONPROD
  FIELD ORAT  138820 3* RATE /
/


TSTEP
50*90
/


END
```

APPENDIX B

BUILDING PROSPER MODEL FOR N01

PROSPER consists of five sections: options summary, PVT data, IPR data, equipment data (which splits to artificial lift and equipment data sections if the well is artificially lifted), and analysis summary.

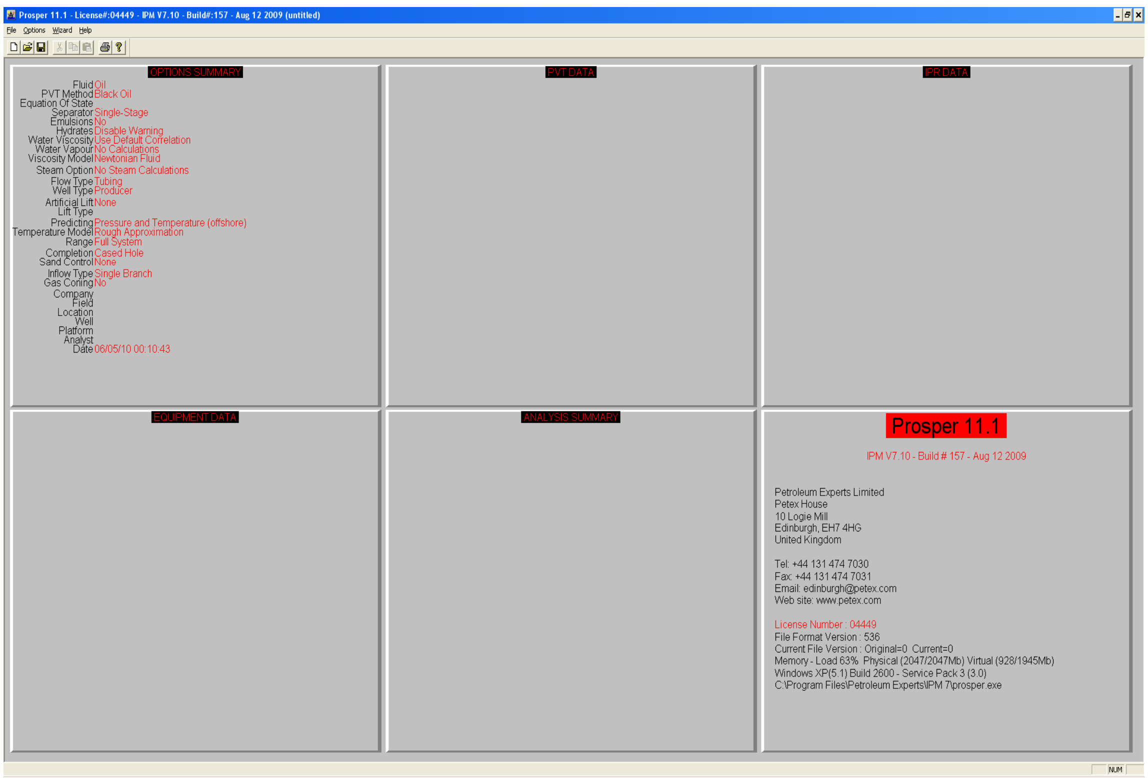


Fig. B-1–PROSPER main window

Below is the input parameters for the options summary section based on the information collected during the information gathering and data analysis stages.

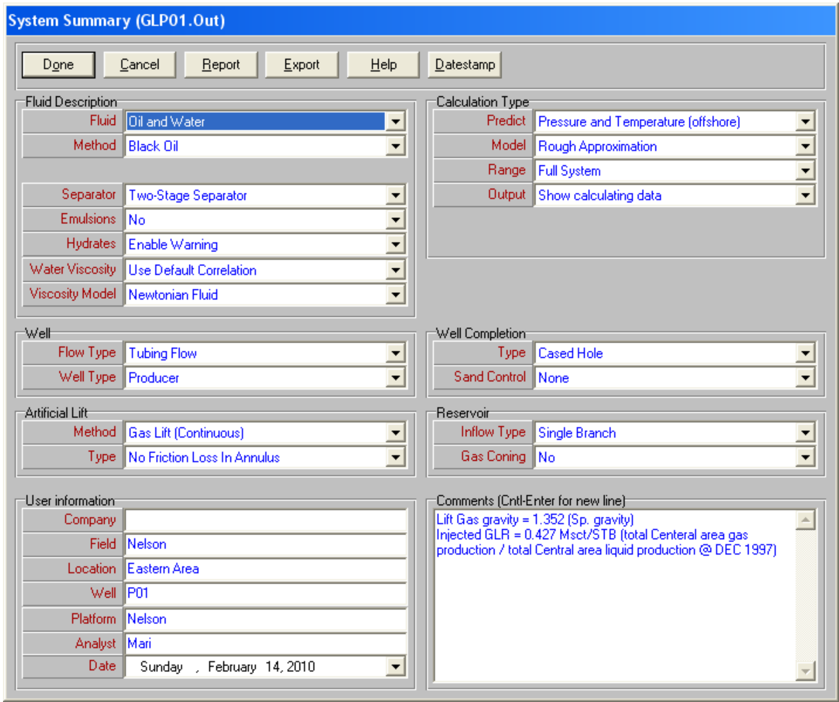


Fig. B-2–The option summary section

I entered the two-stage separator data in the first PVT data window below (**Fig. B-3**). Then I clicked on Match Data button to enter the corresponding PVT table value (**Fig. B-4**). After that, I clicked on done to go back to the PVT input data window and I clicked on calculate (**Fig. B-3**). In the calculation window (**Fig. B-5**), I specified the correlations and the pressure and temperature ranges, then I clicked continue. After that, an empty calculation results window appeared. Then I clicked on calculate, and PROSPER started the calculation process. After a short while PROSPER displays the results in the calculation results window (**Fig. B-6**). At this stage, all needed PVT data are calculated and available. To view the results, please refer to **Table 3.2**.

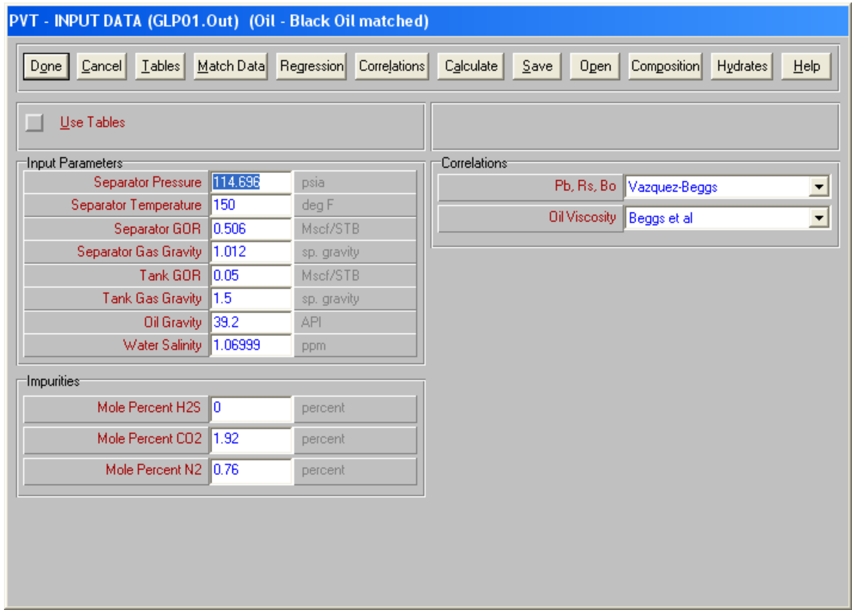


Fig. B-3–PVT input data section

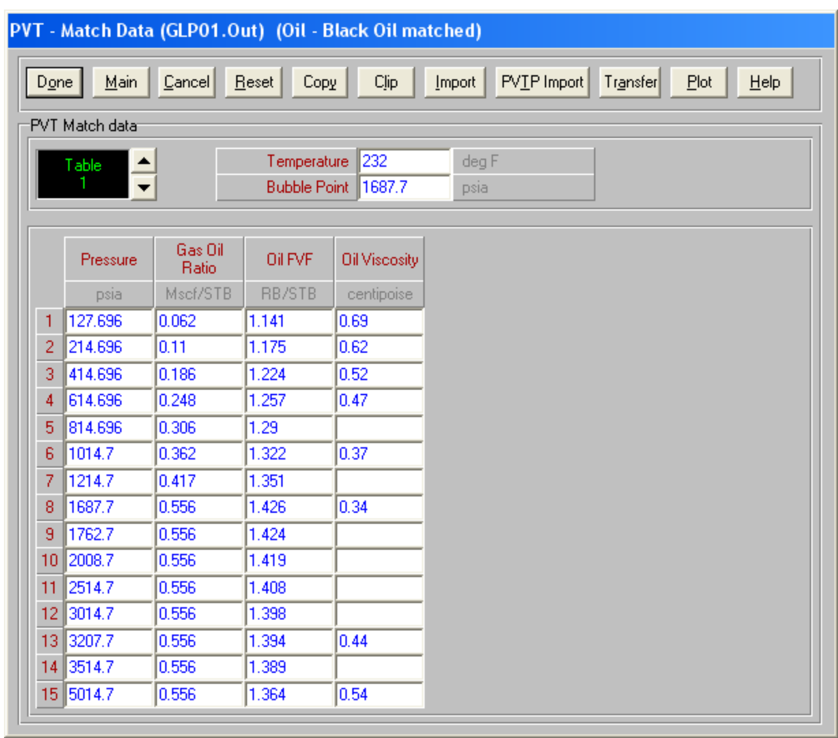


Fig. B-4–Match data window

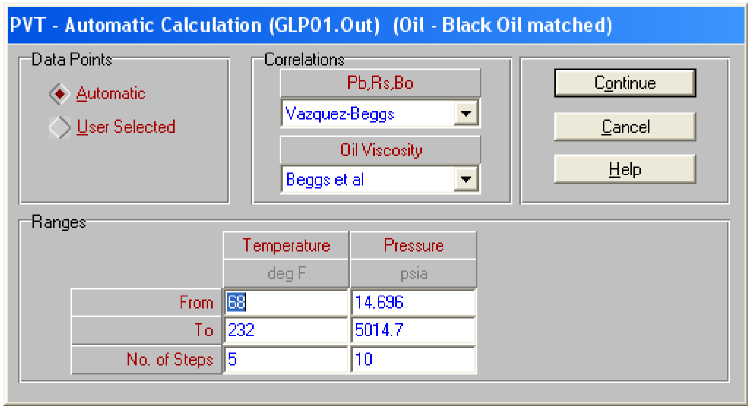
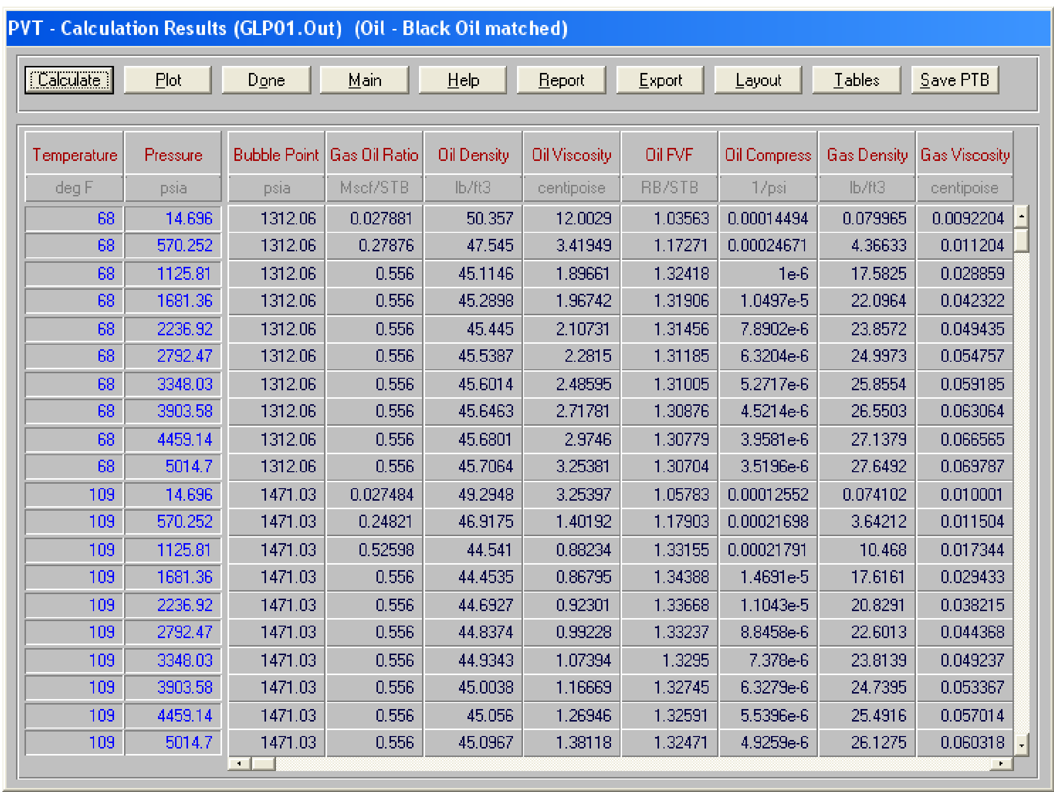


Fig. B-5–Automatic calculation window



Temperature	Pressure	Bubble Point	Gas Oil Ratio	Oil Density	Oil Viscosity	Oil FVF	Oil Compress	Gas Density	Gas Viscosity
deg F	psia	psia	Mscf/STB	lb/ft3	centipoise	RB/STB	1/psi	lb/ft3	centipoise
68	14.696	1312.06	0.027881	50.357	12.0029	1.03563	0.00014494	0.079965	0.0092204
68	570.252	1312.06	0.27876	47.545	3.41949	1.17271	0.00024671	4.36633	0.011204
68	1125.81	1312.06	0.556	45.1146	1.89661	1.32418	1e-6	17.5825	0.028859
68	1681.36	1312.06	0.556	45.2898	1.96742	1.31906	1.0497e-5	22.0964	0.042322
68	2236.92	1312.06	0.556	45.445	2.10731	1.31456	7.8902e-6	23.8572	0.049435
68	2792.47	1312.06	0.556	45.5387	2.2815	1.31185	6.3204e-6	24.9973	0.054757
68	3348.03	1312.06	0.556	45.6014	2.48595	1.31005	5.2717e-6	25.8554	0.059185
68	3903.58	1312.06	0.556	45.6463	2.71781	1.30876	4.5214e-6	26.5503	0.063064
68	4459.14	1312.06	0.556	45.6801	2.9746	1.30779	3.9581e-6	27.1379	0.066565
68	5014.7	1312.06	0.556	45.7064	3.25381	1.30704	3.5196e-6	27.6492	0.069787
109	14.696	1471.03	0.027484	49.2948	3.25397	1.05783	0.00012552	0.074102	0.010001
109	570.252	1471.03	0.24821	46.9175	1.40192	1.17903	0.00021698	3.64212	0.011504
109	1125.81	1471.03	0.52598	44.541	0.88234	1.33155	0.00021791	10.468	0.017344
109	1681.36	1471.03	0.556	44.4535	0.86795	1.34388	1.4691e-5	17.6161	0.029433
109	2236.92	1471.03	0.556	44.6927	0.92301	1.33668	1.1043e-5	20.8291	0.038215
109	2792.47	1471.03	0.556	44.8374	0.99228	1.33237	8.8458e-6	22.6013	0.044368
109	3348.03	1471.03	0.556	44.9343	1.07394	1.3295	7.378e-6	23.8139	0.049237
109	3903.58	1471.03	0.556	45.0038	1.16669	1.32745	6.3279e-6	24.7395	0.053367
109	4459.14	1471.03	0.556	45.056	1.26946	1.32591	5.5396e-6	25.4916	0.057014
109	5014.7	1471.03	0.556	45.0967	1.38118	1.32471	4.9259e-6	26.1275	0.060318

Fig. B-6–Calculation results window

After that, I opened the gaslift input data window (**Fig. B-7**) and entered the gaslift gas gravity (1.012) and the gaslift valve depth calculated in Appendix-C (8646.71 feet MD). GLR is ignored at this stage because the injected gas rate is going to be used as a variable in the VLP calculations, which is considered over the GLR value in this window. I then clicked on done.

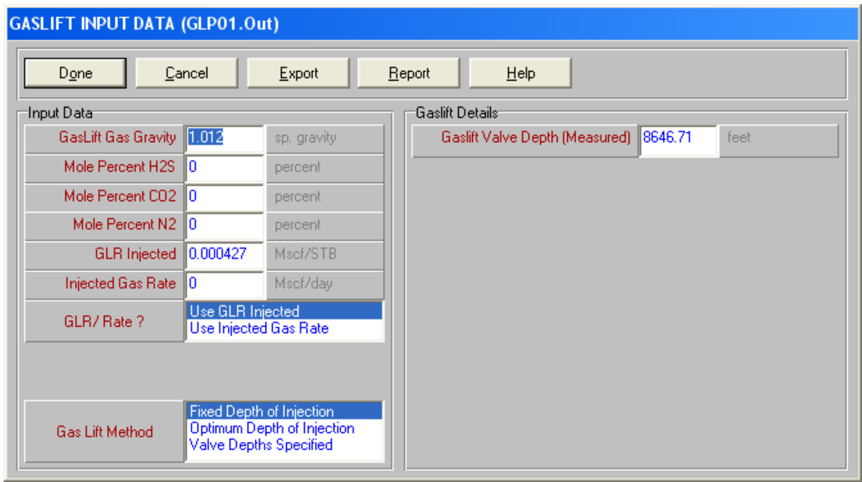


Fig. B-6–Gaslift input data window

After that I opened the equipment data window (**Fig. B-7**) and entered all parameters needed, based on the information gathering and data analysis stages. I have entered the data as illustrated in **Fig. B-8**, **B-9**, and **B-10**. After that I clicked on done in the equipment data window (**Fig. B-7**)

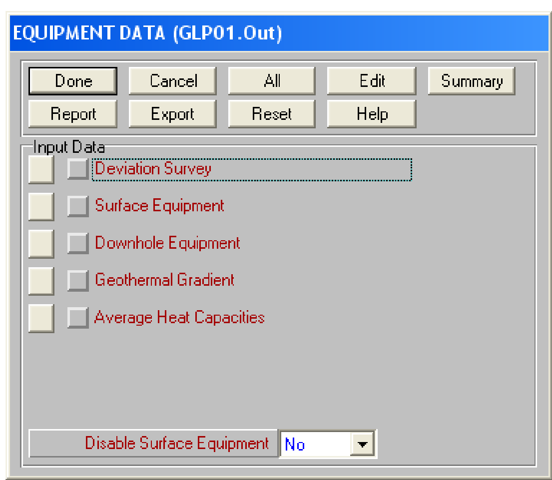


Fig. B-7–Equipment data window

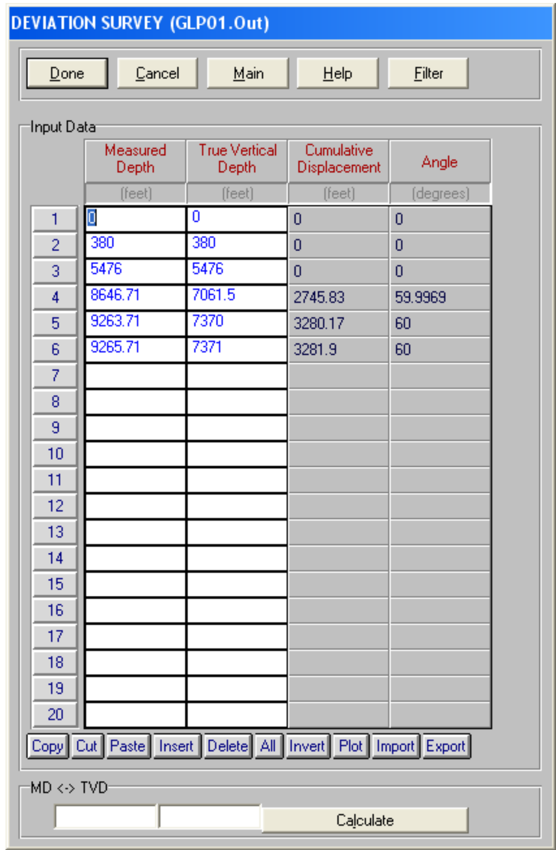


Fig. B-8–Deviation survey window

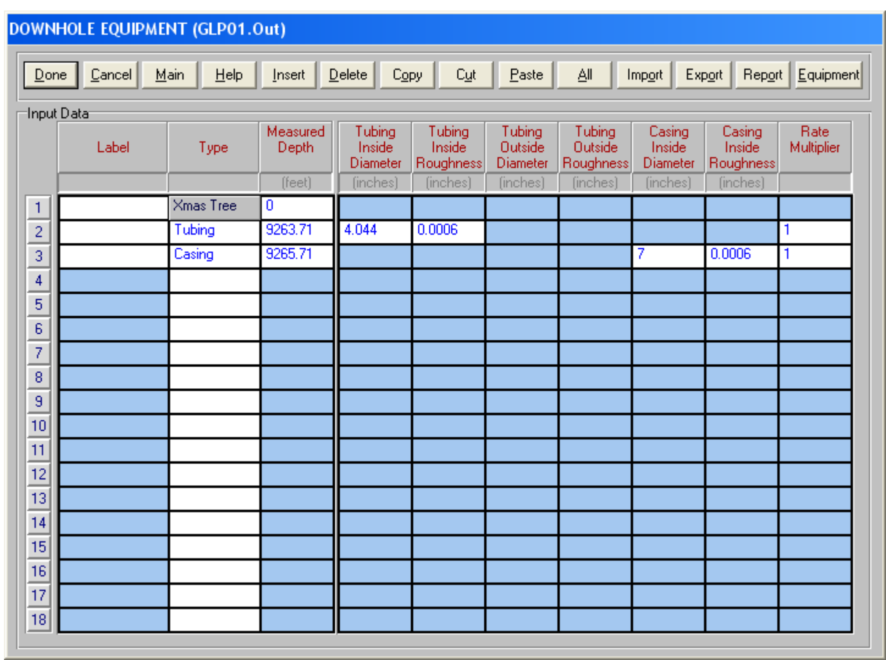


Fig. B-9–Downhole equipment window

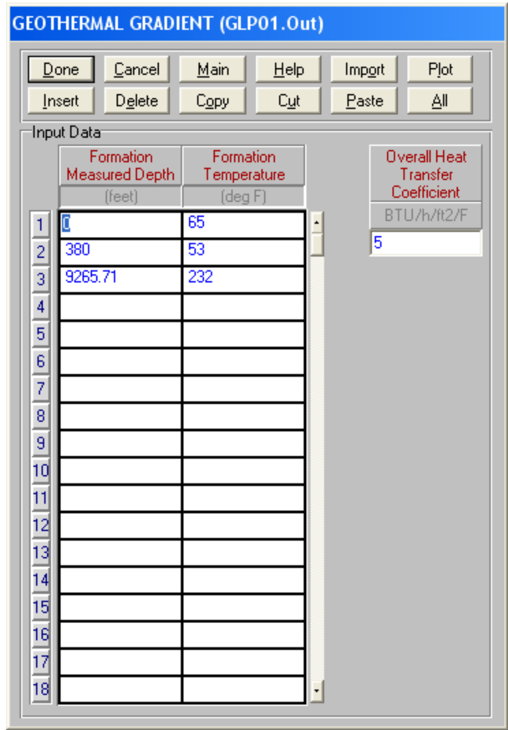


Fig. B-10–Geothermal gradient window

By now, I have moved to the last stage of the PROSPER model, which is the analysis summary stage. In that stage, I have chosen VLP (4 variables) (**Fig. B-11**). In the VLP calculations window I entered current tophole pressure, water cut, and total GOR. I have chosen Petroleum Experts 2 as the vertical lift correlation (for more information about the VLP concept, please refer to section 1.2.2). Finally I entered the desired oil flow rates and clicked continue. After that, the select variables window opened. In that window I entered the variables range, please note that the tophole pressure is fixed to the separator pressure 100 psig (**Fig. B-12**). In addition, the variables range was very broad to cover all possible scenarios, remember that the VLPs that would be generated in this stage would be integrated in ECLIPSE. After that I clicked on continue, and an empty VLP calculation window opened and I clicked calculate. After a short while results appeared in the VLP calculation window (**Fig. B-13**). (**Fig. B-14**) illustrates the resulted VLP curves for N01, both curves share the same GOR and water cut (0.45 Mscf/STB and 45% respectively). However, the lower curve is gaslifted with a 5000 Mscf/day. Then I moved to exporting the generated VLP tables to ECLIPSE by clicking on export lift curve (**Fig. B-13**), and then the lift curve export window appeared (**Fig. B-15**). I, then, selected a unique table number for N01 VLP table, and I selected ECLIPSE as the format of interest, and I clicked continue. Finally, the resulted VLP tables are now generated in a format that can be integrated into ECLIPSE.

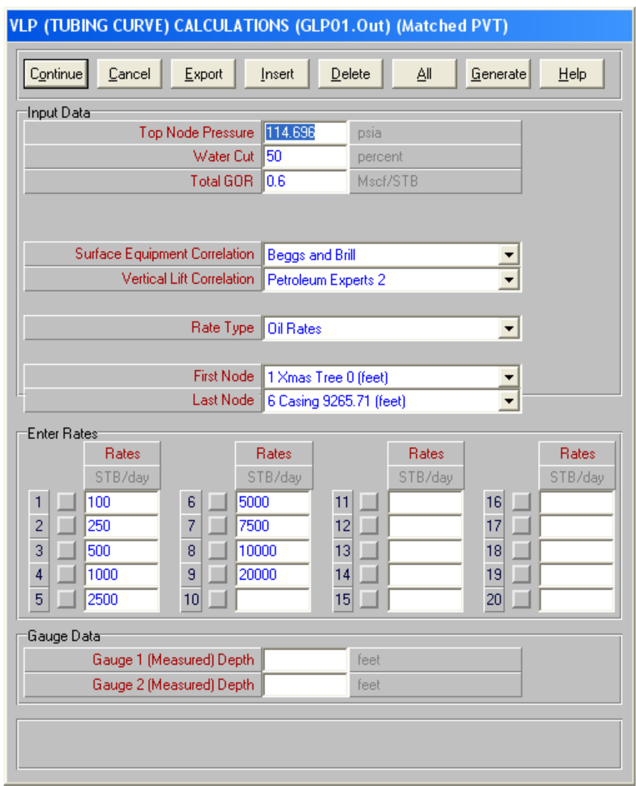


Fig. B-11–VLP calculation window

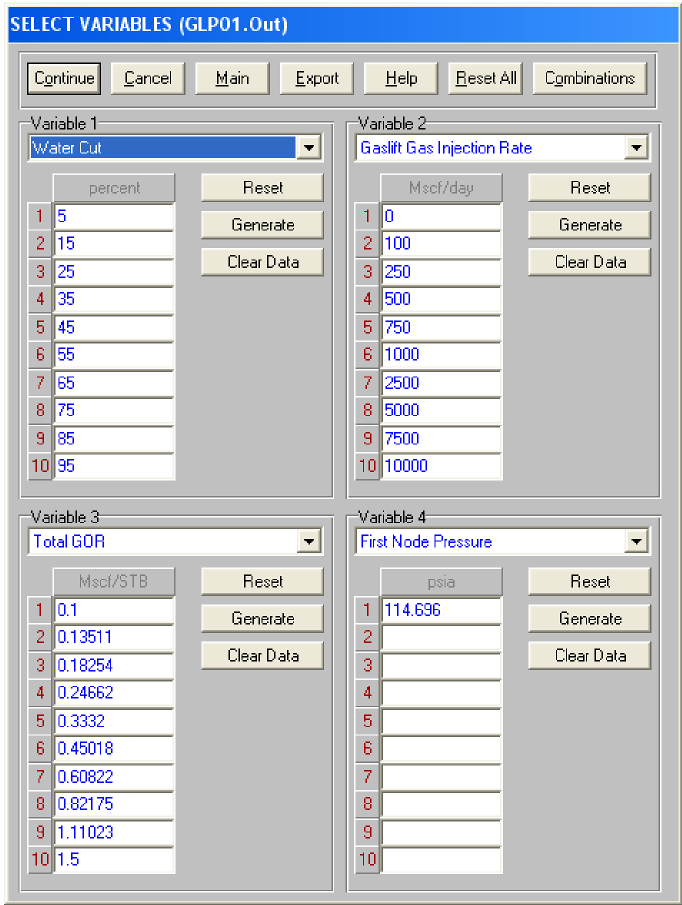


Fig. B-12–Select variables window

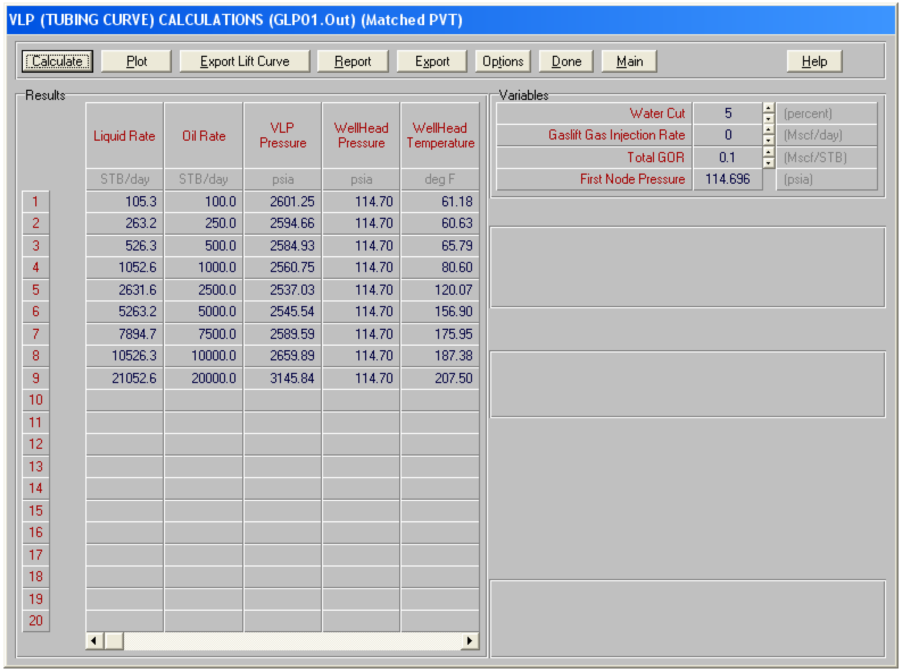


Fig. B-13–VLP calculations window

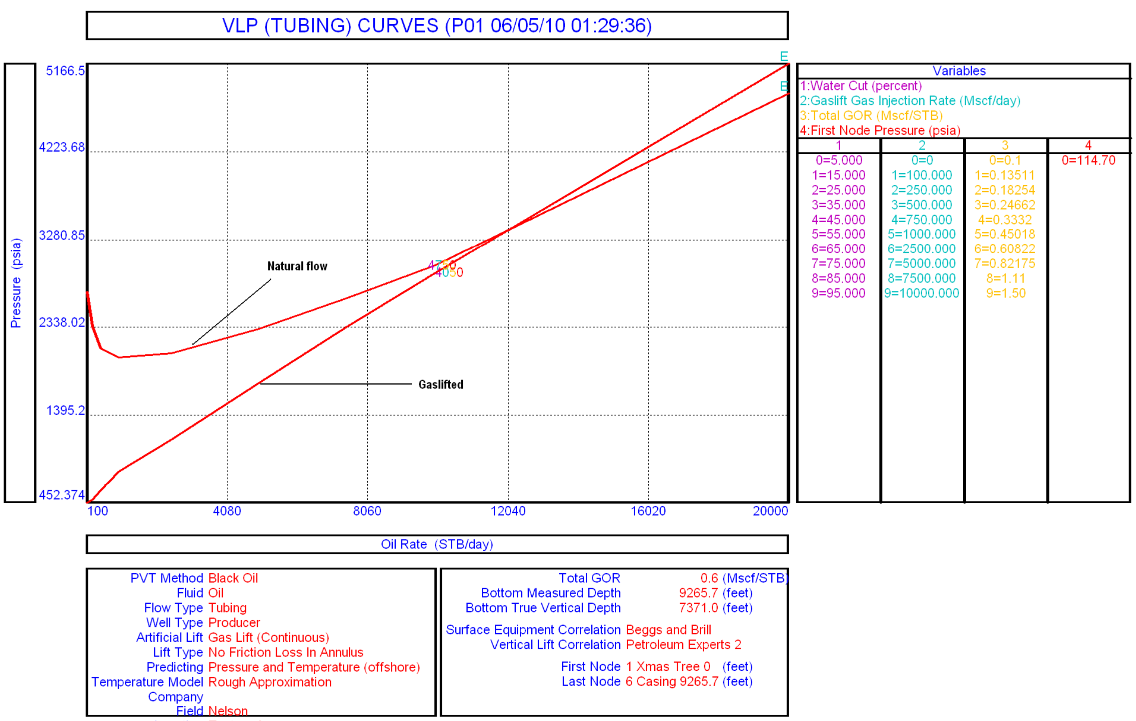


Fig. B-14–Well N01 VLP curves, with and without gaslift

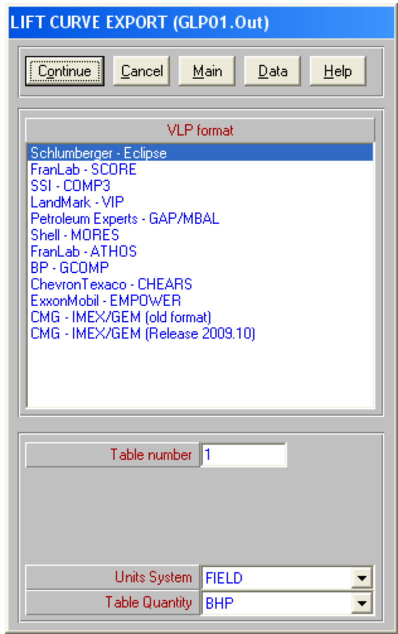


Fig. B-15–Lift curve export window, for the VLP tables generated for N01

APPENDIX C

THE ECONOMIC EVALUATION

The list below represents the equations I used in building this economic analysis spreadsheet.

WC = Water production *100 / (Water production + Oil production)

Fuel and flare rate reduction = 0.65 * Gas production rate

Allocated gaslift gas rate reduction = 0.1 * Gaslift gas injection rate

Gross oil produced, STB = (days/month) * (oil production rate, STBO/day)

Gross water produced, STB = (days/month) * (water production rate, STBW/day)

Gross water injected, STB = (days/month) * (water injection rate, STBW/day)

Gross gas produced, Mscf = (days/month) * (gas production rate, Mscf/day)

Net gas production = Gross gas produced – [(days/month)*(Fuel and flare rate reduction + Allocated gaslift gas rate reduction)]

Gross oil income, MM$ = (oil price, $/STB) * (Gross oil produced, STB) / 1,000,000

Gross gas income, MM$ = (gas price, $/Mscf) * (Gross gas produced, Mscf) / 1,000,000

Gross income, MM$ = Gross oil income, MM$ + Gross gas income, MM$

CAPEX is entered manually into the model

OPEX is calculated based on the flow rates

Total cost, MM$ = CAPEX, MM$ + OPEX, MM$.

Cash flow, MM$ = Gross income, MM$ - Total cost, MM$.

Please refer to Eq.6.2 and Eq.6.3 for NPV and PVR equations.

Time				Production and Injection						WC	Rate Reductions		Gross Production and Injection				Net Production		Oil and Gas Prices		Gross Income				Costs						Cash Flow
Time Year	Time Month	No	Days per Month	Oil Production STB/day	Water Production STB/day	Gas Production Mscf/day	Water Injection STB/day	Gas Injection Mscf/day	Gaslift Gas Injection Mscf/day	Water Cut %	Fule and Flare Mscf/day	Allocated Gas-lift gas Mscf/day	Gross Oil Produced STB	Gross Water Produced STB	Gross Water Injected STB	Gross Gas Produced Mscf	Net Oil Production STB	Net Gas Production Mscf	Oil Price Inflated $/STB	Gas Price Inflated $/Mscf	Gross Oil Income MM$	Gross Gas Income MM$	Gross Income MM$	Gross Income MM$	CAPEX MM$	Total CAPEX MM$	ESP Y = 1 N = 0	OPEX MM$	Total OPEX MM$	Total Cost MM$	Cash Flow MM$
1998	JAN	1	31	127906.20	71664.95	58453.14	56000.00	0.00	58500.00	36%	37994.54	5850.00	3965092.20	2221613.45	1736000.00	1812047.34	3965092.20	452866.57	14.56	2.00	57.73	0.91	58.64		1.00		0	7.92			
1998	FEB	2	28	135294.60	91658.23	61606.16	73371.75	0.00	54000.00	40%	40044.00	5400.00	3788248.80	2566430.44	2054409.00	1724972.48	3788248.80	452540.37	13.71	2.10	51.94	0.95	52.89		7.00		0	7.94			
1998	MAR	3	31	138668.90	81399.02	63337.55	88042.31	0.00	54000.00	37%	41169.41	5400.00	4298735.90	2523369.62	2729311.61	1963464.05	4298735.90	519812.42	12.75	2.20	54.81	1.14	55.95				0	8.98			
1998	APR	4	30	138125.50	89546.54	63235.33	102716.50	0.00	54000.00	39%	41102.96	5400.00	4143765.00	2686396.20	3081495.00	1897059.90	4143765.00	501970.97	13.15	2.30	54.49	1.15	55.65		7.00		0	8.97			
1998	MAY	5	31	138820.00	86100.57	63247.69	102722.10	0.00	54000.00	38%	41111.00	5400.00	4303420.00	2669117.67	3184385.10	1960678.39	4303420.00	518837.44	12.67	2.40	54.52	1.25	55.77				0	9.24			
1998	JUN	6	30	138820.00	91923.55	63385.46	102725.30	0.00	54000.00	40%	41200.55	5400.00	4164600.00	2757706.50	3081759.00	1901563.80	4164600.00	503547.33	11.03	2.50	45.94	1.26	47.19				0	9.04			
1998	JUL	7	31	138820.00	95575.52	63361.79	102729.40	0.00	54000.00	41%	41185.16	5400.00	4303420.00	2962841.12	3184611.40	1964215.49	4303420.00	520075.42	11.52	2.60	49.58	1.35	50.93		9.00		0	9.39			
1998	AUG	8	31	138820.00	95714.79	63341.44	102730.40	0.00	54000.00	41%	41171.94	5400.00	4303420.00	2967158.49	3184642.40	1963584.64	4303420.00	519854.62	10.20	2.70	43.89	1.40	45.30		9.00		0	9.39			
1998	SEP	9	30	138820.00	99826.00	63345.33	102730.40	0.00	54000.00	42%	41174.46	5400.00	4164600.00	2994780.00	3081912.00	1900359.90	4164600.00	503125.97	12.44	2.80	51.81	1.41	53.22				0	9.15			
1998	OCT	10	31	138555.50	101472.50	63286.72	102729.70	0.00	54000.00	42%	41136.37	5400.00	4295220.50	3145647.50	3184620.70	1961888.32	4295220.50	519260.91	11.88	2.90	51.03	1.51	52.53		9.00		0	9.47			
1998	NOV	11	30	138820.00	104572.30	63390.73	102728.40	0.00	54000.00	43%	41203.97	5400.00	4164600.00	3137169.00	3081852.00	1901721.90	4164600.00	503602.67	10.36	2.80	43.15	1.41	44.56				0	9.23			
1998	DEC	12	31	138490.10	109899.30	63278.84	102727.20	0.00	54000.00	44%	41131.25	5400.00	4293193.10	3406878.30	3184543.20	1961644.04	4293193.10	519175.41	8.64	2.70	37.09	1.40	38.49	611.11	9.00	51.00	0	9.60	108.34	159.34	451.77
1999	JAN	1	31	138054.50	110378.00	63052.81	102724.90	0.00	54000.00	44%	40984.33	5400.00	4279689.50	3421718.00	3184471.90	1954637.11	4279689.50	516722.99	9.86	2.60	42.20	1.34	43.54		9.00		0	9.59			
1999	FEB	2	28	138820.00	110420.50	63427.04	102723.00	0.00	54000.00	44%	41227.58	5400.00	3886960.00	3091774.00	2876244.00	1775957.12	3886960.00	470384.99	9.30	2.50	36.15	1.18	37.32				0	8.69			
1999	MAR	3	31	138419.70	114637.60	63230.21	102718.70	0.00	54000.00	45%	41099.64	5400.00	4291010.70	3553765.60	3184279.70	1960136.51	4291010.70	518647.78	12.05	2.40	51.71	1.24	52.95		9.00		0	9.67			
1999	APR	4	30	138820.00	115802.80	63426.05	102716.80	0.00	54000.00	45%	41226.93	5400.00	4164600.00	3474084.00	3081504.00	1902781.50	4164600.00	503973.53	14.60	2.30	60.80	1.16	61.96				0	9.39			
1999	MAY	5	31	138669.00	120161.80	63335.31	102712.20	0.00	54000.00	46%	41167.95	5400.00	4298739.00	3725015.80	3184078.20	1963394.61	4298739.00	519788.11	15.17	2.20	65.21	1.14	66.36		9.00		0	9.77			
1999	JUN	6	30	138820.00	121706.70	63431.68	102711.80	0.00	54000.00	47%	41230.59	5400.00	4164600.00	3651201.00	3081354.00	1902950.40	4164600.00	504032.64	15.24	2.10	63.47	1.06	64.53				0	9.48			
1999	JUL	7	31	138820.00	126765.80	63407.60	102705.70	0.00	54000.00	48%	41214.94	5400.00	4303420.00	3929739.80	3183876.70	1965635.60	4303420.00	520572.46	17.43	2.00	75.01	1.04	76.05				0	9.88			
1999	AUG	8	31	138523.10	131894.80	63286.99	102702.60	0.00	54000.00	49%	41136.54	5400.00	4294216.10	4088738.80	3183780.60	1961896.69	4294216.10	519263.84	18.55	2.10	79.66	1.09	80.75				0	9.94			
1999	SEP	9	30	138453.80	132602.20	63207.00	102698.70	0.00	54000.00	49%	41084.55	5400.00	4153614.00	3978066.00	3080961.00	1896210.00	4153614.00	501673.50	20.94	2.20	86.98	1.10	88.08				0	9.63			
1999	OCT	10	31	138565.10	135118.50	63208.81	102694.30	0.00	54000.00	49%	41085.73	5400.00	4295518.10	4188673.50	3183523.30	1959473.11	4295518.10	518415.59	19.93	2.30	85.61	1.19	86.80				0	9.99			
1999	NOV	11	30	138599.30	138150.40	63173.67	102690.10	0.00	54000.00	50%	41062.89	5400.00	4157979.00	4144512.00	3080703.00	1895210.10	4157979.00	501323.54	22.26	2.40	92.56	1.20	93.76				0	9.72			
1999	DEC	12	31	138717.50	141480.00	63155.62	102688.10	0.00	54000.00	50%	41051.15	5400.00	4300242.50	4385880.00	3183331.10	1957824.22	4300242.50	517838.48	23.33	2.50	100.32	1.29	101.62	853.72		27.00	0	10.09	115.84	142.84	710.88
2000	JAN	1	31	138242.90	142164.00	62896.89	102684.10	0.00	54000.00	51%	40882.98	5400.00	4285529.90	4407084.00	3183207.10	1949803.59	4285529.90	515031.26	24.11	2.60	103.32	1.34	104.66				0	10.08			
2000	FEB	2	29	135520.10	145658.90	61656.13	102679.90	0.00	54000.00	52%	40076.48	5400.00	3930082.90	4224108.10	2977717.10	1788027.77	3930082.90	469209.72	26.54	2.70	104.30	1.27	105.57				0	9.36			
2000	MAR	3	31	133934.00	144421.60	60906.19	102677.90	0.00	54000.00	52%	39589.02	5400.00	4151954.00	4477069.60	3183014.90	1888091.89	4151954.00	493432.16	27.44	2.80	113.93	1.38	115.31				0	9.91			
2000	APR	4	30	129779.20	146350.00	59036.76	102676.10	0.00	54000.00	53%	38373.89	5400.00	3893376.00	4390500.00	3080283.00	1771102.80	3893376.00	457885.98	22.99	2.90	89.51	1.33	90.84				0	9.43			
2000	MAY	5	31	129779.20	146350.00	59036.76	102676.10	0.00	54000.00	53%	38373.89	5400.00	4023155.20	4536850.00	3182959.10	1830139.56	4023155.20	473148.85	26.06	2.80	104.84	1.32	106.17				0	9.74			
2000	JUN	6	30	126355.40	148001.20	57492.74	102676.30	0.00	54000.00	54%	37370.28	5400.00	3790662.00	4440036.00	3080289.00	1724782.20	3790662.00	441673.77	28.57	2.70	108.30	1.19	109.49				0	9.29			
2000	JUL	7	31	126355.40	148001.20	57492.74	102676.30	0.00	54000.00	54%	37370.28	5400.00	3917017.40	4588037.20	3182965.30	1782274.94	3917017.40	456396.23	27.17	2.60	106.43	1.19	107.61				0	9.60			
2000	AUG	8	31	122860.90	151109.60	55909.06	102677.60	0.00	54000.00	55%	36340.89	5400.00	3808687.90	4684397.60	3183005.60	1733180.86	3808687.90	439213.30	28.27	2.50	107.67	1.10	108.77				0	9.49			
2000	SEP	9	30	122860.90	151109.60	55909.06	102677.60	0.00	54000.00	55%	36340.89	5400.00	3685827.00	4533288.00	3080328.00	1677271.80	3685827.00	425045.13	30.88	2.40	113.82	1.02	114.84				0	9.18			
2000	OCT	10	31	119880.00	154570.90	54552.52	102678.60	0.00	54000.00	56%	35459.14	5400.00	3716280.00	4791697.90	3183036.60	1691128.12	3716280.00	424494.84	30.01	2.30	111.53	0.98	112.50				0	9.40			
2000	NOV	11	30	119880.00	154570.90	54552.52	102678.60	0.00	54000.00	56%	35459.14	5400.00	3596400.00	4637127.00	3080358.00	1636575.60	3596400.00	410801.46	31.16	2.20	112.06	0.90	112.97				0	9.09			
2000	DEC	12	31	116719.60	157350.00	53109.15	102680.40	0.00	54000.00	57%	34520.95	5400.00	3618307.60	4877850.00	3183092.40	1646383.65	3618307.60	408834.28	25.50	2.10	92.27	0.86	93.13	1281.86		0.00	0	9.29	113.87	113.87	1167.99
2001	JAN	1	31	116719.60	157350.00	53109.15	102680.40	0.00	54000.00	57%	34520.95	5400.00	3618307.60	4877850.00	3183092.40	1646383.65	3618307.60	408834.28	28.66	2.00	103.70	0.82	104.52				0	9.29			
2001	FEB	2	28	114218.30	161783.60	51961.90	102682.10	0.00	54000.00	59%	33775.24	5400.00	3198112.40	4529940.80	2875098.80	1454933.20	3198112.40	358026.62	26.72	2.10	85.45	0.75	86.21				0	8.34			
2001	MAR	3	31	114218.30	161783.60	51961.90	102682.10	0.00	54000.00	59%	33775.24	5400.00	3540767.30	5015291.60	3183145.10	1610818.90	3540767.30	396386.62	23.96	2.20	84.84	0.87	85.71				0	9.24			
2001	APR	4	30	110294.30	161706.60	50179.08	102683.30	0.00	54000.00	59%	32616.40	5400.00	3308829.00	4851198.00	3080499.00	1505372.40	3308829.00	364880.34	26.77	2.30	88.58	0.84	89.42				0	8.76			
2001	MAY	5	31	110294.30	161706.60	50179.08	102683.30	0.00	54000.00	59%	32616.40	5400.00	3419123.30	5012904.60	3183182.30	1555551.48	3419123.30	377043.02	25.44	2.40	86.98	0.90	87.89				0	9.05			
2001	JUN	6	30	103552.00	159286.70	47096.73	102685.80	0.00	54000.00	61%	30612.87	5400.00	3106560.00	4778601.00	3080574.00	1412901.90	3106560.00	332515.67	24.27	2.50	75.40	0.83	76.23				0	8.41			
2001	JUL	7	31	103038.70	160659.90	46845.20	102692.50	0.00	54000.00	61%	30449.38	5400.00	3194199.70	4980456.90	3183467.50	1452201.20	3194199.70	340870.42	23.58	2.60	75.32	0.89	76.21				0	8.69			
2001	AUG	8	31	101642.70	163563.70	46260.02	102695.30	0.00	54000.00	62%	30069.01	5400.00	3150923.70	5070474.70	3183554.30	1434060.62	3150923.70	334521.22	24.08	2.70	75.87	0.90	76.78				0	8.67			
2001	SEP	9	30	101064.30	163129.70	46004.64	102697.40	0.00	54000.00	62%	29903.02	5400.00	3031929.00	4893891.00	3080922.00	1380139.20	3031929.00	321048.72	20.82	2.80	63.12	0.90	64.02				0	8.35			
2001	OCT	10	31	99607.61	163091.00	45390.14	102699.30	0.00	54000.00	62%	29503.59	5400.00	3087835.91	5055821.00	3183678.30	1407094.34	3087835.91	325083.02	19.04	2.90	58.79	0.94	59.74				0	8.56			
2001	NOV	11	30	98304.66	162741.50	44841.43	102701.40	0.00	54000.00	62%	29146.93	5400.00	2949139.80	4882245.00	3081042.00	1345242.90	2949139.80	308835.02	16.45	2.80	48.51	0.86	49.38				0	8.22			
2001	DEC	12	31	97538.31	163463.30	44515.03	102702.50	0.00	54000.00	63%	28934.77	5400.00	3023687.61	5067362.30	3183777.50	1379965.93	3023687.61	315588.08	16.21	2.70	49.01	0.85	49.87	905.95		0.00	0	8.47	104.04	104.04	801.91
2002	JAN	1	31	96201.62	165403.40	43941.43	102704.50	0.00	54000.00	63%	28561.93	5400.00	2982250.22	5127505.40	3183839.50	1362184.33	2982250.22	309364.52	16.65	2.60	49.65	0.80	50.46				0	8.44			
2002	FEB	2	28	95307.82	166489.70	43540.08	102705.80	0.00	54000.00	64%	28301.05	5400.00	2668618.96	4661711.60	2875762.40	1219122.24	2668618.96	275492.78	18.88	2.50	50.38	0.69	51.07				0	7.60			
2002	MAR	3	31	95307.82	166489.70	43540.08	102705.80	0.00	54000.00	64%	28301.05	5400.00	2954542.42	5161180.70	3183879.80	1349742.48	2954542.42	305009.87	20.97	2.40	61.96	0.73	62.69				0	8.41			
2002	APR	4	30	93397.79	168798.10	42659.05	102706.90	0.00	54000.00	64%	27728.38	5400.00	2801933.70	5063943.00	3081207.00	1279771.50	2801933.70	285920.03	22.83	2.30	63.97	0.66	64.63				0	8.09			
2002	MAY	5	31	93397.79	168798.10	42659.05	102706.90	0.00	54000.00	64%	27728.38	5400.00	2895331.49	5232741.10	3183913.90	1322430.55	2895331.49	295450.69	23.79	2.20	68.88	0.65	69.53				0	8.36			
2002	JUN	6	30	91264.05	170450.80	41691.03	102708.40	0.00	54000.00	65%	27099.17	5400.00	2737921.50	5113524.00	3081252.00	1250730.90	2737921.50	275755.82	22.16	2.10	60.67	0.58	61.25				0	8.01			
2002	JUL	7	31	91264.05	170450.80	41691.03	102708.40	0.00	54000.00	65%	27099.17	5400.00	2829185.55	5283974.80	3183960.40	1292421.93	2829185.55	284947.68	23.69	2.00	67.02	0.57	67.59				0	8.28			
2002	AUG	8	31	89399.16	173260.60	40841.30	102709.90	0.00	54000.00	66%	26546.85	5400.00	2771373.96	5371078.60	3184006.90	1266080.30	2771373.96	275728.11	24.90	2.10	69.01	0.58	69.59				0	8.23			
2002	SEP	9	30	89399.16	173260.60	40841.30	102709.90	0.00	54000.00	66%	26546.85	5400.00	2681974.80	5197818.00	3081297.00	1225239.00	2681974.80	266833.65	26.28	2.20	70.48	0.59	71.07				0	7.97			
2002	OCT	10	31	87046.02	174135.90	39764.99	102711.10	0.00	54000.00	67%	25847.24	5400.00	2698426.62	5398212.90	3184044.10	1232714.69	2698426.62	264050.14	25.38	2.30	68.49	0.61	69.09				0	8.14			
2002	NOV	11	30	87046.02	174135.90	39764.99	102711.10	0.00	54000.00	67%	25847.24	5400.00	2611380.60	5224077.00	3081333.00	1192949.70	2611380.60	255532.40	22.92	2.40	59.85	0.61	60.47				0	7.87			
2002	DEC	12	31	86261.86	180037.00	39410.17	102712.70	0.00	54000.00	68%	25616.61	5400.00	2674117.66	5581147.00	3184093.70	1221715.27	2674117.66	260200.34	25.25	2.50	67.52	0.65	68.17	765.61		0.00	0	8.19	97.58	97.58	668.02
2003	JAN	1	31	86261.86	180037.00	39410.17	102712.70	0.00	54000.00	68%	25616.61	5400.00	2674117.66	5581147.00	3184093.70	1221715.27	2674117.66	260200.34	29.44	2.60	78.73	0.68	79.40				0	8.19			
2003	FEB	2	28	81955.68	176402.50	37444.36	102713.50	0.00	54000.00	68%	24338.83	5400.00	2294759.04	4939270.00	2875978.00	1048442.08	2294759.04	215754.73	32.13	2.70	73.73	0.58	74.31				0	7.16			
2003	MAR	3	31	81955.68	176402.50	37444.36	102713.50	0.00	54000.00	68%	24338.83	5400.00	2540626.08	5468477.50	3184118.50	1160775.16	2540626.08	238871.31	30.26	2.80	76.88	0.67	77.55				0	7.93			
2003	APR	4	30	80931.88	178218.60	36964.56	102716.90	0.00	54000.00	69%	24026.96	5400.00	2427956.40	5346558.00	3081507.00	1108936.80	2427956.40	226127.88	25.22	2.90	61.23	0.66	61.89				0	7.65			
2003	MAY	5	31	80931.88	178218.60	36964.56	102716.90	0.00	54000.00	69%	24026.96	5400.00	2508888.28	5524776.60	3184223.90	1145901.36	2508888.28	233665.48	23.61	2.80	59.23	0.65	59.89				0	7.91			
2003	JUN	6	30	79324.83	178890.70	36218.32	102719.70	0.00	54000.00	69%	23541.91	5400.00	2379744.90	5366721.00	3081591.00	1086549.60	2379744.90	218292.36	27.23	2.70	64.80	0.59	65.39				0	7.59			
2003	JUL	7	31	79324.83	178890.70	36218.32	102719.70	0.00	54000.00	69%	23541.91	5400.00	2459069.73	5545611.70	3184310.70	1122767.92	2459069.73	225568.77	27.39	2.60	67.35	0.59	67.94				0	7.84			
2003	AUG	8	31	77455.17	180023.40	35365.40	102721.70	0.00	54000.00	70%	22987.51	5400.00	2401110.27	5580725.40	3184372.70	1096327.40	2401110.27	216314.59	28.33	2.50	68.02	0.54	68.56				0	7.77			
2003	SEP	9	30	77455.17	180023.40	35365.40	102721.70	0.00	54000.00	70%	22987.51	5400.00	2323655.10	5400702.00	3081651.00	1060962.00	2323655.10	209336.70	25.14	2.40	58.42	0.50	58.92				0	7.52			
2003	OCT	10	31	76202.03	182305.50	34795.94	102723.10	0.00	54000.00	71%	22617.36	5400.00	2362262.93	5651470.50	3184416.10	1078674.14	2362262.93	210135.95	27.07	2.30	63.95	0.48	64.43				0	7.74			
2003	NOV	11	30	76202.03	182305.50	34795.94	102723.10	0.00	54000.00	71%	22617.36	5400.00	2286060.90	5469165.00	3081693.00	1043878.20	2286060.90	203357.37	27.66	2.20	63.23	0.45	63.68				0	7.49			
2003	DEC	12	31	75154.43	183866.10	34312.44	102724.40	0.00	54000.00	71%	22303.09	5400.00	2329787.33	5699849.10	3184456.40	1063685.64	2329787.33	204889.97	28.83	2.10	67.17	0.43	67.60	809.56		0.00	0	7.72	92.50	92.50	717.06

Time				Production and Injection						WC	Rate Reductions		Gross Production and Injection				Net Production		Oil and Gas Prices		Gross Income				Costs						Cash Flow
Time Year	Time Month	No	Days per Month	Oil Production STB/day	Water Production STB/day	Gas Production Mscf/day	Water Injection STB/day	Gas Injection Mscf/day	Gaslift Gas Injection Mscf/day	Water Cut %	Fule and Flare Mscf/day	Allocated Gas-lift gas Mscf/day	Gross Oil Produced STB	Gross Water Produced STB	Gross Water Injected STB	Gross Gas Produced Mscf	Net Oil Production STB	Net Gas Production Mscf	Oil Price Inflated $/STB	Gas Price Inflated $/Mscf	Gross Oil Income MM$	Gross Gas Income MM$	Gross Income MM$	Gross Income MM$	CAPEX MM$	Total CAPEX MM$	ESP Y = 1 N = 0	OPEX MM$	Total OPEX MM$	Total Cost MM$	Cash Flow MM$
2004	JAN	1	31	75154.43	183866.10	34312.44	102724.40	0.00	54000.00	71%	22303.09	5400.00	2329787.33	5699849.10	3184456.40	1063685.64	2329787.33	204889.97	30.87	2.00	71.92	0.41	72.33				0	7.72			
2004	FEB	2	29	74459.88	186824.20	34015.50	102725.30	0.00	54000.00	72%	22110.08	5400.00	2159336.52	5417901.80	2979033.70	986449.50	2159336.52	188657.33	31.03	2.10	67.00	0.40	67.40				0	7.23			
2004	MAR	3	31	74459.88	186824.20	34015.50	102725.30	0.00	54000.00	72%	22110.08	5400.00	2308256.28	5791550.20	3184484.30	1054480.50	2308256.28	201668.18	33.48	2.20	77.28	0.44	77.72				0	7.73			
2004	APR	4	30	73512.57	186305.90	33543.37	102727.80	0.00	54000.00	72%	21803.19	5400.00	2205377.10	5589177.00	3081834.00	1006301.10	2205377.10	190205.39	33.08	2.30	72.95	0.44	73.39				0	7.43			
2004	MAY	5	31	73512.57	186305.90	33543.37	102727.80	0.00	54000.00	72%	21803.19	5400.00	2278889.67	5775482.90	3184561.80	1039844.47	2278889.67	196545.56	36.31	2.40	82.75	0.47	83.22				0	7.68			
2004	JUN	6	30	72037.54	184844.10	32848.94	102727.70	0.00	54000.00	72%	21351.81	5400.00	2161126.20	5545323.00	3081831.00	985468.20	2161126.20	182913.87	33.80	2.50	73.05	0.46	73.50				0	7.34			
2004	JUL	7	31	72037.54	184844.10	32848.94	102727.70	0.00	54000.00	72%	21351.81	5400.00	2233163.74	5730167.10	3184558.70	1018317.14	2233163.74	189011.00	36.25	2.60	80.95	0.49	81.44				0	7.58			
2004	AUG	8	31	70524.79	183175.40	32215.28	102726.60	0.00	54000.00	72%	20939.93	5400.00	2186268.49	5678437.40	3184524.60	998673.68	2186268.49	182135.79	40.67	2.70	88.92	0.49	89.41				0	7.49			
2004	SEP	9	30	70524.79	183175.40	32215.28	102726.60	0.00	54000.00	72%	20939.93	5400.00	2115743.70	5495262.00	3081798.00	966458.40	2115743.70	176260.44	41.25	2.80	87.27	0.49	87.77				0	7.24			
2004	OCT	10	31	69057.31	180148.20	31519.54	102728.70	0.00	54000.00	72%	20487.70	5400.00	2140776.61	5584594.20	3184589.70	977105.74	2140776.61	174587.01	48.71	2.90	104.28	0.51	104.78				0	7.37			
2004	NOV	11	30	69057.31	180148.20	31519.54	102728.70	0.00	54000.00	72%	20487.70	5400.00	2071719.30	5404446.00	3081861.00	945586.20	2071719.30	168955.17	44.30	2.80	91.78	0.47	92.25				0	7.13			
2004	DEC	12	31	67680.42	186612.00	30938.59	102729.40	0.00	54000.00	73%	20110.08	5400.00	2098093.02	5784972.00	3184611.40	959096.29	2098093.02	168283.70	39.20	2.70	82.25	0.45	82.70	985.92		0.00	0	7.40	89.34	89.34	896.58
2005	JAN	1	31	67680.42	186612.00	30938.59	102729.40	0.00	54000.00	73%	20110.08	5400.00	2098093.02	5784972.00	3184611.40	959096.29	2098093.02	168283.70	42.21	2.60	88.56	0.44	89.00				0	7.40			
2005	FEB	2	28	66895.70	181250.70	30592.88	102732.90	0.00	54000.00	73%	19885.37	5400.00	1873079.60	5075019.60	2876521.20	856600.64	1873079.60	148610.22	42.91	2.50	80.37	0.37	80.75				0	6.58			
2005	MAR	3	31	66895.70	181250.70	30592.88	102732.90	0.00	54000.00	73%	19885.37	5400.00	2073766.70	5618771.70	3184719.90	948379.28	2073766.70	164532.75	48.55	2.40	100.68	0.39	101.08				0	7.28			
2005	APR	4	30	66202.73	187850.70	30289.42	102734.80	0.00	54000.00	74%	19688.12	5400.00	1986081.90	5635521.00	3082044.00	908682.60	1986081.90	156038.91	46.63	2.30	92.61	0.36	92.97				0	7.12			
2005	MAY	5	31	66202.73	187850.70	30289.42	102734.80	0.00	54000.00	74%	19688.12	5400.00	2052284.63	5823371.70	3184778.80	938972.02	2052284.63	161240.21	43.27	2.20	88.80	0.35	89.16				0	7.35			
2005	JUN	6	30	65550.62	186795.30	29985.47	102736.00	0.00	54000.00	74%	19490.56	5400.00	1966518.60	5603859.00	3082080.00	899564.10	1966518.60	152847.44	49.56	2.10	97.46	0.32	97.78				0	7.07			
2005	JUL	7	31	65550.62	186795.30	29985.47	102736.00	0.00	54000.00	74%	19490.56	5400.00	2032069.22	5790654.30	3184816.00	929549.57	2032069.22	157942.35	52.13	2.00	105.93	0.32	106.25				0	7.30			
2005	AUG	8	31	63794.41	184039.00	29193.19	102737.80	0.00	54000.00	74%	18975.57	5400.00	1977626.71	5705209.00	3184871.80	904988.89	1977626.71	149346.11	58.07	2.10	114.84	0.31	115.15				0	7.18			
2005	SEP	9	30	63794.41	184039.00	29193.19	102737.80	0.00	54000.00	74%	18975.57	5400.00	1913832.30	5521170.00	3082134.00	875795.70	1913832.30	144528.50	58.56	2.20	112.07	0.32	112.39				0	6.95			
2005	OCT	10	31	63202.56	190843.70	28917.50	102738.50	0.00	54000.00	75%	18796.38	5400.00	1959279.36	5916154.70	3184893.50	896442.50	1959279.36	146354.88	55.12	2.30	108.00	0.34	108.33				0	7.26			
2005	NOV	11	30	62207.93	179933.40	28461.39	102739.70	0.00	54000.00	74%	18499.90	5400.00	1866237.90	5398002.00	3082191.00	853841.70	1866237.90	136844.60	51.18	2.40	95.51	0.33	95.84				0	6.81			
2005	DEC	12	31	62207.93	179933.40	28461.39	102739.70	0.00	54000.00	74%	18499.90	5400.00	1928445.83	5577935.40	3184930.70	882303.09	1928445.83	141406.08	52.31	2.50	100.88	0.35	101.23	1189.93		0.00	0	7.04	85.34	85.34	1104.59
2006	JAN	1	31	61534.43	189910.30	28142.09	102740.80	0.00	54000.00	76%	18292.36	5400.00	1907567.33	5887219.30	3184964.80	872404.79	1907567.33	137941.68	58.30	2.60	111.21	0.36	111.57				0	7.16			
2006	FEB	2	28	61534.43	189910.30	28142.09	102740.80	0.00	54000.00	76%	18292.36	5400.00	1722964.04	5317488.40	2876742.40	787978.52	1722964.04	124592.48	54.65	2.70	94.16	0.34	94.50				0	6.47			
2006	MAR	3	31	60483.73	186810.80	27675.80	102740.20	0.00	54000.00	76%	17989.27	5400.00	1874995.63	5791134.80	3184946.20	857949.80	1874995.63	132882.43	55.42	2.80	103.91	0.37	104.28				0	7.06			
2006	APR	4	30	60483.73	186810.80	27675.80	102740.20	0.00	54000.00	76%	17989.27	5400.00	1814511.90	5604324.00	3082206.00	830274.00	1814511.90	128595.90	62.50	2.90	113.41	0.37	113.78				0	6.84			
2006	MAY	5	31	62078.35	205630.60	28467.99	102743.10	0.00	51000.00	77%	18504.19	5100.00	1924428.85	6374548.60	3185036.10	882507.69	1924428.85	150777.69	62.94	2.80	121.12	0.42	121.55				0	7.43			
2006	JUN	6	30	62078.35	205630.60	28467.99	102743.10	0.00	51000.00	77%	18504.19	5100.00	1862350.50	6168918.00	3082293.00	854039.70	1862350.50	145913.90	62.85	2.70	117.05	0.39	117.44				0	7.19			
2006	JUL	7	31	54520.88	180246.40	24975.27	102756.50	0.00	54000.00	77%	16233.93	5400.00	1690147.28	5587638.40	3185451.50	774233.37	1690147.28	103581.68	66.28	2.60	112.02	0.27	112.29				0	6.68			
2006	AUG	8	31	54403.42	172471.90	24886.26	102743.60	0.00	54000.00	76%	16176.07	5400.00	1686506.02	5346628.90	3185051.60	771474.06	1686506.02	102615.92	64.93	2.50	109.50	0.26	109.76				0	6.55			
2006	SEP	9	30	54867.90	180167.50	25106.66	102744.60	0.00	54000.00	77%	16319.33	5400.00	1646037.00	5405025.00	3082338.00	753199.80	1646037.00	101619.93	55.73	2.40	91.73	0.24	91.98				0	6.48			
2006	OCT	10	31	54328.95	184100.20	24887.31	102750.20	0.00	54000.00	77%	16176.75	5400.00	1684197.45	5707106.20	3185256.20	771506.61	1684197.45	102627.31	50.98	2.30	85.86	0.24	86.10				0	6.73			
2006	NOV	11	30	53883.39	185965.20	24683.36	102753.70	0.00	54000.00	78%	16044.18	5400.00	1616501.70	5578956.00	3082611.00	740500.80	1616501.70	97175.28	50.98	2.20	82.41	0.21	82.62				0	6.52			
2006	DEC	12	31	53883.39	185965.20	24683.36	102753.70	0.00	54000.00	78%	16044.18	5400.00	1670385.09	5764921.20	3185364.70	765184.16	1670385.09	100414.46	54.06	2.10	90.30	0.21	90.51	1236.38		0.00	0	6.73	81.83	81.83	1154.55
2007	JAN	1	31	53575.14	182000.20	24542.51	102756.00	0.00	54000.00	77%	15952.63	5400.00	1660829.34	5642006.20	3185436.00	760817.81	1660829.34	98886.23	46.53	2.00	77.28	0.20	77.48				0	6.66			
2007	FEB	2	28	53575.14	182000.20	24542.51	102756.00	0.00	54000.00	77%	15952.63	5400.00	1500103.92	5096005.60	2877168.00	687190.28	1500103.92	89316.60	51.36	2.10	77.05	0.19	77.23				0	6.01			
2007	MAR	3	31	53344.82	189718.80	24448.43	102758.20	0.00	54000.00	78%	15891.48	5400.00	1653689.42	5881282.80	3185504.20	757901.33	1653689.42	97865.47	52.64	2.20	87.05	0.22	87.27				0	6.77			
2007	APR	4	30	53344.82	189718.80	24448.43	102758.20	0.00	54000.00	78%	15891.48	5400.00	1600344.60	5691564.00	3082746.00	733452.90	1600344.60	94708.52	56.08	2.30	89.75	0.22	89.97				0	6.55			
2007	MAY	5	31	52693.14	181267.40	24135.72	102760.00	0.00	54000.00	77%	15688.22	5400.00	1633487.34	5619289.40	3185560.00	748207.32	1633487.34	94472.56	55.43	2.40	90.54	0.23	90.77				0	6.61			
2007	JUN	6	30	52693.14	181267.40	24135.72	102760.00	0.00	54000.00	77%	15688.22	5400.00	1580794.20	5438022.00	3082800.00	724071.60	1580794.20	91425.06	59.25	2.50	93.66	0.23	93.89				0	6.39			
2007	JUL	7	31	52515.86	199514.10	24066.95	102759.70	0.00	54000.00	79%	15643.52	5400.00	1627991.66	6184937.10	3185550.70	746075.45	1627991.66	93726.41	65.96	2.60	107.38	0.24	107.63				0	6.88			
2007	AUG	8	31	52515.86	199514.10	24066.95	102759.70	0.00	54000.00	79%	15643.52	5400.00	1627991.66	6184937.10	3185550.70	746075.45	1627991.66	93726.41	64.23	2.70	104.57	0.25	104.82				0	6.88			
2007	SEP	9	30	51835.57	163458.50	23803.93	102761.10	0.00	51000.00	76%	15472.55	5100.00	1555067.10	4903755.00	3082833.00	714117.90	1555067.10	96941.27	70.94	2.80	110.32	0.27	110.59				0	6.09			
2007	OCT	10	31	51835.57	163458.50	23803.93	102761.10	0.00	51000.00	76%	15472.55	5100.00	1606902.67	5067213.50	3185594.10	737921.83	1606902.67	100172.64	77.56	2.90	124.63	0.29	124.92				0	6.29			
2007	NOV	11	30	50947.72	173113.00	23408.05	102767.20	0.00	51000.00	77%	15215.23	5100.00	1528431.60	5193390.00	3083016.00	702241.50	1528431.60	92784.53	86.92	2.80	132.85	0.26	133.11				0	6.19			
2007	DEC	12	31	50947.72	173113.00	23408.05	102767.20	0.00	51000.00	77%	15215.23	5100.00	1579379.32	5366503.00	3185783.20	725649.55	1579379.32	95877.34	83.46	2.70	131.81	0.26	132.07	1229.74		0.00	0	6.40	77.71	77.71	1152.03
2008	JAN	1	31	50689.75	163803.50	23263.47	102769.80	0.00	51000.00	76%	15121.26	5100.00	1571382.25	5077908.50	3185863.80	721167.57	1571382.25	94308.65	84.70	2.60	133.10	0.25	133.34				0	6.24			
2008	FEB	2	29	50689.75	163803.50	23263.47	102769.80	0.00	51000.00	76%	15121.26	5100.00	1470002.75	4750301.50	2980324.20	674640.63	1470002.75	88224.22	86.64	2.50	127.36	0.22	127.58				0	5.84			
2008	MAR	3	31	50398.85	174947.40	23113.35	102773.30	0.00	51000.00	78%	15023.68	5100.00	1562364.35	5423369.40	3185972.30	716513.85	1562364.35	92679.85	96.87	2.40	151.35	0.22	151.57				0	6.40			
2008	APR	4	30	50398.85	174947.40	23113.35	102773.30	0.00	51000.00	78%	15023.68	5100.00	1511965.50	5248422.00	3083199.00	693400.50	1511965.50	89690.18	104.31	2.30	157.71	0.21	157.92				0	6.19			
2008	MAY	5	31	49901.47	171046.30	22882.60	102775.80	0.00	51000.00	77%	14873.69	5100.00	1546945.57	5302435.30	3186049.80	709360.60	1546945.57	90176.21	117.40	2.20	181.61	0.20	181.81				0	6.31			
2008	JUN	6	30	49901.47	171046.30	22882.60	102775.80	0.00	51000.00	77%	14873.69	5100.00	1497044.10	5131389.00	3083274.00	686478.00	1497044.10	87267.30	126.33	2.10	189.12	0.18	189.30				0	6.11			
2008	JUL	7	31	49455.08	176852.90	22669.24	102776.40	0.00	51000.00	78%	14735.01	5100.00	1533107.48	5482439.90	3186068.40	702746.44	1533107.48	87861.25	126.16	2.00	193.42	0.18	193.59				0	6.38			
2008	AUG	8	31	49455.08	176852.90	22669.24	102776.40	0.00	51000.00	78%	14735.01	5100.00	1533107.48	5482439.90	3186068.40	702746.44	1533107.48	87861.25	108.46	2.10	166.28	0.18	166.47				0	6.38			
2008	SEP	9	30	48906.70	174021.60	22418.85	102777.40	0.00	51000.00	78%	14572.25	5100.00	1467201.00	5220648.00	3083322.00	672565.50	1467201.00	82397.93	96.13	2.20	141.04	0.18	141.22				0	6.11			
2008	OCT	10	31	48906.70	174021.60	22418.85	102777.40	0.00	51000.00	78%	14572.25	5100.00	1516107.70	5394669.60	3186099.40	694984.35	1516107.70	85144.52	68.50	2.30	103.85	0.20	104.05				0	6.31			
2008	NOV	11	30	48453.34	181667.90	22210.44	102776.80	0.00	51000.00	79%	14436.79	5100.00	1453600.20	5450037.00	3083304.00	666313.20	1453600.20	80209.62	49.29	2.40	71.65	0.19	71.84				0	6.20			
2008	DEC	12	31	48453.34	181667.90	22210.44	102776.80	0.00	51000.00	79%	14436.79	5100.00	1502053.54	5631704.90	3186080.80	688523.64	1502053.54	82883.27	32.94	2.50	49.48	0.21	49.68	1668.38		0.00	0	6.41	74.89	74.89	1593.49
2009	JAN	1	31	47808.93	173353.60	21915.70	102777.10	0.00	51000.00	78%	14245.21	5100.00	1482076.83	5373961.60	3186090.10	679386.70	1482076.83	79685.35	33.07	2.60	49.01	0.21	49.22				0	6.25			
2009	FEB	2	28	47808.93	173353.60	21915.70	102777.10	0.00	51000.00	78%	14245.21	5100.00	1338650.04	4853900.80	2877758.80	613639.60	1338650.04	71973.86	31.04	2.70	41.55	0.19	41.75				0	5.64			
2009	MAR	3	31	47441.08	188505.90	21748.50	102775.40	0.00	51000.00	80%	14136.53	5100.00	1470673.48	5843682.90	3186037.40	674203.50	1470673.48	77871.23	40.13	2.80	59.02	0.22	59.24				0	6.47			
2009	APR	4	30	47441.08	188505.90	21748.50	102775.40	0.00	51000.00	80%	14136.53	5100.00	1423232.40	5655177.00	3083262.00	652455.00	1423232.40	75359.25	42.45	2.90	60.42	0.22	60.63				0	6.26			
2009	MAY	5	31	46548.68	167116.50	21338.04	102776.70	0.00	48000.00	78%	13869.73	4800.00	1443009.08	5180611.50	3186077.70	661479.24	1443009.08	82717.73	51.27	2.80	73.98	0.23	74.21				0	6.09			
2009	JUN	6	30	46548.68	167116.50	21338.04	102776.70	0.00	48000.00	78%	13869.73	4800.00	1396460.40	5013495.00	3083301.00	640141.20	1396460.40	80049.42	61.71	2.70	86.18	0.22	86.39				0	5.90			
2009	JUL	7	31	46524.75	180989.60	21328.02	102779.10	0.00	48000.00	80%	13863.21	4800.00	1442267.25	5610677.60	3186152.10	661168.62	1442267.25	82609.02	56.16	2.60	81.00	0.21	81.21				0	6.31			
2009	AUG	8	31	46524.75	180989.60	21328.02	102779.10	0.00	48000.00	80%	13863.21	4800.00	1442267.25	5610677.60	3186152.10	661168.62	1442267.25	82609.02	62.80	2.50	90.57	0.21	90.78				0	6.31			
2009	SEP	9	30	45270.24	159640.10	20714.71	102783.20	0.00	45000.00	78%	13464.56	4500.00	1358107.20	4789203.00	3083496.00	621441.30	1358107.20	82504.46	60.98	2.40	82.82	0.20	83.02				0	5.72			
2009	OCT	10	31	45270.24	159640.10	20714.71	102783.20	0.00	45000.00	78%	13464.56	4500.00	1403377.44	4948843.10	3186279.20	642156.01	1403377.44	85254.60	67.43	2.30	94.63	0.20	94.83				0	5.91			
2009	NOV	11	30	45097.82	167638.40	20639.37	102788.60	0.00	45000.00	79%	13415.59	4500.00	1352934.60	5029152.00	3083658.00	619181.10	1352934.60	81713.39	69.43	2.20	93.93	0.18	94.11				0	5.84			
2009	DEC	12	31	45097.82	167638.40	20639.37	102788.60	0.00	45000.00	79%	13415.59	4500.00	1398032.42	5196790.40	3186446.60	639820.47	1398032.42	84437.16	66.33	2.10	92.73	0.18	92.91	908.30		0.00	0	6.03	72.72	72.72	835.58

Time				Production and Injection						WC	Rate Reductions		Gross Production and Injection				Net Production	
Time Year	Time Month	No	Days per Month	Oil Production STB/day	Water Production STB/day	Gas Production Mscf/day	Water Injection STB/day	Gas Injection Mscf/day	Gaslift Gas Injection Mscf/day	Water Cut %	Fule and Flare Mscf/day	Allocated Gas-lift gas Mscf/day	Gross Oil Produced STB	Gross Water Produced STB	Gross Water Injected STB	Gross Gas Produced Mscf	Net Oil Production STB	Net Gas Production Mscf
2010	JAN	1	31	44682.04	160648.60	20450.08	102793.20	0.00	45000.00	78%	13292.55	4500.00	1385143.24	4980106.60	3186589.20	633952.48	1385143.24	82383.37
2010	FEB	2	28	44682.04	160648.60	20450.08	102793.20	0.00	45000.00	78%	13292.55	4500.00	1251097.12	4498160.80	2878209.60	572602.24	1251097.12	74410.78
2010	MAR	3	31	44392.71	172474.80	20318.65	102794.00	0.00	45000.00	80%	13207.12	4500.00	1376174.01	5346718.80	3186614.00	629878.15	1376174.01	80957.35
2010	APR	4	30	44392.71	172474.80	20318.65	102794.00	0.00	45000.00	80%	13207.12	4500.00	1331781.30	5174244.00	3083820.00	609559.50	1331781.30	78345.83
2010	MAY	5	31	42783.79	149167.70	19583.45	102796.20	0.00	42000.00	78%	12729.24	4200.00	1326297.49	4624198.70	3186682.20	607086.95	1326297.49	82280.43
2010	JUN	6	30	42783.79	149167.70	19583.45	102796.20	0.00	42000.00	78%	12729.24	4200.00	1283513.70	4475031.00	3083886.00	587503.50	1283513.70	79626.23
2010	JUL	7	31	42582.64	151552.40	19491.42	102801.00	0.00	42000.00	78%	12669.42	4200.00	1320061.84	4698124.40	3186831.00	604234.02	1320061.84	81281.91
2010	AUG	8	31	42503.75	152547.70	19455.05	102806.30	0.00	42000.00	78%	12645.78	4200.00	1317616.25	4728978.70	3186995.30	603106.55	1317616.25	80887.29
2010	SEP	9	30	42374.11	153129.60	19395.77	102807.90	0.00	42000.00	78%	12607.25	4200.00	1271223.30	4593888.00	3084237.00	581873.10	1271223.30	77655.59
2010	OCT	10	31	42374.11	153129.60	19395.77	102807.90	0.00	42000.00	78%	12607.25	4200.00	1313597.41	4747017.60	3187044.90	601268.87	1313597.41	80244.10
2010	NOV	11	30	42068.32	153970.50	19256.15	102809.00	0.00	42000.00	79%	12516.50	4200.00	1262049.60	4619115.00	3084270.00	577684.50	1262049.60	76189.58
2010	DEC	12	31	42068.32	153970.50	19256.15	102809.00	0.00	42000.00	79%	12516.50	4200.00	1304117.92	4773085.50	3187079.00	596940.65	1304117.92	78729.23
2011	JAN	1	31	41740.75	154889.00	19106.67	102810.20	0.00	42000.00	79%	12419.34	4200.00	1293963.25	4801559.00	3187116.20	592306.77	1293963.25	77107.37
2011	FEB	2	28	41740.75	154889.00	19106.67	102810.20	0.00	42000.00	79%	12419.34	4200.00	1168741.00	4336892.00	2878685.60	534986.76	1168741.00	69645.37
2011	MAR	3	31	41395.54	155202.50	18949.21	102810.70	0.00	42000.00	79%	12316.99	4200.00	1283261.74	4811277.50	3187131.70	587425.51	1283261.74	75398.93
2011	APR	4	30	41395.54	155202.50	18949.21	102810.70	0.00	42000.00	79%	12316.99	4200.00	1241866.20	4656075.00	3084321.00	568476.30	1241866.20	72966.71
2011	MAY	5	31	41030.58	156159.30	18782.60	102810.70	0.00	42000.00	79%	12208.69	4200.00	1271947.98	4840938.30	3187131.70	582260.60	1271947.98	73591.21
2011	JUN	6	30	41030.58	156159.30	18782.60	102810.70	0.00	42000.00	79%	12208.69	4200.00	1230917.40	4684779.00	3084321.00	563478.00	1230917.40	71217.30
2011	JUL	7	31	40432.00	147111.60	18509.24	102810.80	0.00	39000.00	78%	12031.01	3900.00	1253392.00	4560459.60	3187134.80	573786.44	1253392.00	79925.25
2011	AUG	8	31	40364.16	148726.20	18478.20	102815.90	0.00	39000.00	79%	12010.83	3900.00	1251288.96	4610512.20	3187292.90	572824.20	1251288.96	79588.47
2011	SEP	9	30	40364.16	148726.20	18478.20	102815.90	0.00	39000.00	79%	12010.83	3900.00	1210924.80	4461786.00	3084477.00	554346.00	1210924.80	77021.10
2011	OCT	10	31	40155.68	149411.80	18382.71	102818.80	0.00	39000.00	79%	11948.76	3900.00	1244826.08	4631765.80	3187382.80	569864.01	1244826.08	78552.40
2011	NOV	11	30	40155.68	149411.80	18382.71	102818.80	0.00	39000.00	79%	11948.76	3900.00	1204670.40	4482354.00	3084564.00	551481.30	1204670.40	76018.45
2011	DEC	12	31	39867.84	150368.80	18250.93	102819.90	0.00	39000.00	79%	11863.10	3900.00	1235903.04	4661432.80	3187416.90	565778.83	1235903.04	77122.59
2012	JAN	1	31	39867.84	150368.80	18250.93	102819.90	0.00	39000.00	79%	11863.10	3900.00	1235903.04	4661432.80	3187416.90	565778.83	1235903.04	77122.59
2012	FEB	2	29	39094.18	142908.30	17897.49	102820.40	0.00	36000.00	79%	11633.37	3600.00	1133731.22	4144340.70	2981791.60	519027.21	1133731.22	77259.52
2012	MAR	3	31	39094.18	142908.30	17897.49	102820.40	0.00	36000.00	79%	11633.37	3600.00	1211919.58	4430157.30	3187432.40	554822.19	1211919.58	82587.77
2012	APR	4	30	38951.23	143834.80	17832.05	102824.40	0.00	36000.00	79%	11590.83	3600.00	1168536.90	4315044.00	3084732.00	534961.50	1168536.90	79236.53
2012	MAY	5	31	38951.23	143834.80	17832.05	102824.40	0.00	36000.00	79%	11590.83	3600.00	1207488.13	4458878.80	3187556.40	552793.55	1207488.13	81877.74
2012	JUN	6	30	38664.99	145678.50	17701.20	102826.50	0.00	36000.00	79%	11505.78	3600.00	1159949.70	4370355.00	3084795.00	531036.00	1159949.70	77862.60
2012	JUL	7	31	38664.99	145678.50	17701.20	102826.50	0.00	36000.00	79%	11505.78	3600.00	1198614.69	4516033.50	3187621.50	548737.20	1198614.69	80458.02
2012	AUG	8	31	37339.14	128557.20	17063.99	102827.50	0.00	33000.00	77%	11091.59	3300.00	1157513.34	3985273.20	3187652.50	528983.69	1157513.34	82844.29
2012	SEP	9	30	37339.14	128557.20	17063.99	102827.50	0.00	33000.00	77%	11091.59	3300.00	1120174.20	3856716.00	3084825.00	511919.70	1120174.20	80171.90
2012	OCT	10	31	37330.84	129935.40	17060.19	102835.10	0.00	33000.00	78%	11089.12	3300.00	1157256.04	4027997.40	3187888.10	528865.89	1157256.04	82803.06
2012	NOV	11	30	37330.84	129935.40	17060.19	102835.10	0.00	33000.00	78%	11089.12	3300.00	1119925.20	3898062.00	3085053.60	511805.70	1119925.20	80131.99
2012	DEC	12	31	37153.27	131178.00	16979.05	102839.40	0.00	33000.00	78%	11036.38	3300.00	1151751.37	4066518.00	3188021.40	526350.55	1151751.37	81922.69
2013	JAN	1	31	37153.27	131178.00	16979.05	102839.40	0.00	33000.00	78%	11036.38	3300.00	1151751.37	4066518.00	3188021.40	526350.55	1151751.37	81922.69
2013	FEB	2	28	36890.80	131990.80	16859.09	102841.60	0.00	33000.00	78%	10958.41	3300.00	1032942.40	3695742.40	2879564.80	472054.52	1032942.40	72819.08
2013	MAR	3	31	36890.80	131990.80	16859.09	102841.60	0.00	33000.00	78%	10958.41	3300.00	1143614.80	4091714.80	3188089.60	522631.79	1143614.80	80621.13
2013	APR	4	30	36890.80	131990.80	16859.09	102841.60	0.00	33000.00	78%	10958.41	3300.00	1106724.00	3959724.00	3085248.00	505772.70	1106724.00	78020.44
2013	MAY	5	31	36890.80	131990.80	16859.09	102841.60	0.00	33000.00	78%	10958.41	3300.00	1143614.80	4091714.80	3188089.60	522631.79	1143614.80	80621.13
2013	JUN	6	30	36890.80	131990.80	16859.09	102841.60	0.00	33000.00	78%	10958.41	3300.00	1106724.00	3959724.00	3085248.00	505772.70	1106724.00	78020.44
2013	JUL	7	31	36890.80	131990.80	16859.09	102841.60	0.00	33000.00	78%	10958.41	3300.00	1143614.80	4091714.80	3188089.60	522631.79	1143614.80	80621.13
2013	AUG	8	31	36890.80	131990.80	16859.09	102841.60	0.00	33000.00	78%	10958.41	3300.00	1143614.80	4091714.80	3188089.60	522631.79	1143614.80	80621.13
2013	SEP	9	30	36890.80	131990.80	16859.09	102841.60	0.00	33000.00	78%	10958.41	3300.00	1106724.00	3959724.00	3085248.00	505772.70	1106724.00	78020.44
2013	OCT	10	31	36890.80	131990.80	16859.09	102841.60	0.00	33000.00	78%	10958.41	3300.00	1143614.80	4091714.80	3188089.60	522631.79	1143614.80	80621.13
2013	NOV	11	30	36890.80	131990.80	16859.09	102841.60	0.00	33000.00	78%	10958.41	3300.00	1106724.00	3959724.00	3085248.00	505772.70	1106724.00	78020.44
2013	DEC	12	31	36890.80	131990.80	16859.09	102841.60	0.00	33000.00	78%	10958.41	3300.00	1143614.80	4091714.80	3188089.60	522631.79	1143614.80	80621.13

Time		Oil and Gas Prices		Gross Income				Costs						Cash Flow
Time Year	Time Month	Oil Price Inflated $/STB	Gas Price Inflated $/Mscf	Gross Oil Income MM$	Gross Gas Income MM$	Gross Income MM$	Gross Income MM$	CAPEX MM$	Total CAPEX MM$	ESP Y = 1 N = 0	OPEX MM$	Total OPEX MM$	Total Cost MM$	Cash Flow MM$
2010	JAN	69.85	2.00	96.75	0.16	96.92				0	5.90			
2010	FEB	78.27	2.10	97.93	0.16	98.08				0	5.33			
2010	MAR	81.62	2.20	112.33	0.18	112.51				0	6.07			
2010	APR	84.97	2.30	113.17	0.18	113.35				0	5.88			
2010	MAY	88.32	2.40	117.14	0.20	117.34				0	5.63			
2010	JUN	91.67	2.50	117.66	0.20	117.86				0	5.45			
2010	JUL	95.02	2.60	125.44	0.21	125.65				0	5.66			
2010	AUG	98.37	2.70	129.62	0.22	129.84				0	5.67			
2010	SEP	101.73	2.80	129.32	0.22	129.53				0	5.49			
2010	OCT	105.08	2.90	138.03	0.23	138.26				0	5.68			
2010	NOV	108.43	2.80	136.84	0.21	137.05				0	5.49			
2010	DEC	111.78	2.70	145.77	0.21	145.98	1462.37		0.00	0	5.67	67.93	67.93	**1394.44**
2011	JAN	115.13	2.60	148.97	0.20	149.17				0	5.67			
2011	FEB	118.48	2.50	138.47	0.17	138.64				0	5.12			
2011	MAR	121.83	2.40	156.34	0.18	156.52				0	5.66			
2011	APR	80.00	2.30	99.35	0.17	99.52				0	5.48			
2011	MAY	40.00	2.20	50.88	0.16	51.04				0	5.66			
2011	JUN	30.00	2.10	36.93	0.15	37.08				0	5.48			
2011	JUL	32.00	2.00	40.11	0.16	40.27				0	5.49			
2011	AUG	33.07	2.10	41.38	0.17	41.55				0	5.51			
2011	SEP	31.04	2.20	37.59	0.17	37.76				0	5.33			
2011	OCT	40.13	2.30	49.95	0.18	50.14				0	5.51			
2011	NOV	42.45	2.40	51.14	0.18	51.32				0	5.33			
2011	DEC	51.27	2.50	63.36	0.19	63.56	916.55		0.00	0	5.51	65.76	65.76	**850.79**
2012	JAN	61.71	2.60	76.27	0.20	76.47				0	5.51			
2012	FEB	56.16	2.70	63.67	0.21	63.88				0	5.01			
2012	MAR	62.80	2.80	76.11	0.23	76.34				0	5.36			
2012	APR	60.98	2.90	71.26	0.23	71.49				0	5.19			
2012	MAY	67.43	2.80	81.42	0.23	81.65				0	5.37			
2012	JUN	69.43	2.70	80.54	0.21	80.75				0	5.21			
2012	JUL	66.33	2.60	79.50	0.21	79.71				0	5.38			
2012	AUG	69.85	2.50	80.85	0.21	81.06				0	5.05			
2012	SEP	78.27	2.40	87.68	0.19	87.87				0	4.89			
2012	OCT	81.62	2.30	94.46	0.19	94.65				0	5.07			
2012	NOV	84.97	2.20	95.16	0.18	95.34				0	4.91			
2012	DEC	88.32	2.10	101.73	0.17	101.90	991.10		0.00	0	5.09	62.06	62.06	**929.04**
2013	JAN	91.67	2.00	105.59	0.16	105.75				0	5.09			
2013	FEB	95.02	2.10	98.15	0.15	98.31				0	4.59			
2013	MAR	98.37	2.20	112.50	0.18	112.68				0	5.09			
2013	APR	101.73	2.30	112.58	0.18	112.76				0	4.92			
2013	MAY	105.08	2.40	120.17	0.19	120.36				0	5.09			
2013	JUN	108.43	2.50	120.00	0.20	120.19				0	4.92			
2013	JUL	111.78	2.60	127.83	0.21	128.04				0	5.09			
2013	AUG	115.13	2.70	131.66	0.22	131.88				0	5.09			
2013	SEP	118.48	2.80	131.12	0.22	131.34				0	4.92			
2013	OCT	121.83	2.90	139.32	0.23	139.56				0	5.09			
2013	NOV	121.83	2.90	134.83	0.23	135.06				0	4.92			
2013	DEC	121.83	2.90	139.32	0.23	139.56	1475.48		0.00	0	5.09	59.88	59.88	**1415.61**

Time years	Gross Income MM$	CAPEX MM$	OPEX MM$	Total Cost MM$	Cash Flow MM$	Present Value MM$
1998	611.11	51.00	108.34	159.34	451.77	421.28
1999	853.72	27.00	115.84	142.84	710.88	662.90
2000	1281.86	0.00	113.87	113.87	1167.99	947.09
2001	905.95	0.00	104.04	104.04	801.91	565.43
2002	765.61	0.00	97.58	97.58	668.02	409.59
2003	809.56	0.00	92.50	92.50	717.06	382.31
2004	985.92	0.00	89.34	89.34	896.58	415.67
2005	1189.93	0.00	85.34	85.34	1104.59	445.31
2006	1236.38	0.00	81.83	81.83	1154.55	404.74
2007	1229.74	0.00	77.71	77.71	1152.03	351.18
2008	1668.38	0.00	74.89	74.89	1593.49	422.40
2009	908.30	0.00	72.72	72.72	835.58	192.60
2010	1462.37	0.00	67.93	67.93	1394.44	279.50
2011	916.55	0.00	65.76	65.76	850.79	148.29
2012	991.10	0.00	62.06	62.06	929.04	140.80
2013	1475.48	0.00	59.88	59.88	1415.61	186.56

Discount Rate %	15
NPV MM$	6,375.66
PVR	87.66

APPENDIX D

WELL COMPLETION

TABLE D-1–DETAILED COMPLETION AND DEVIATION OF EACH EXISTING OP IN NELSON FIELD

Central

P09 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
5969	5969		Tubing	4.044
8154.345	7061.5	Gas lift	Valve	
8771.345	7370	Production	Tubing	4.044
8773.345	7371	Liner	Casing	7

P17

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
3583	3583		Tubing	4.044
10540.42	7061.5	Gas lift	Valve	
11157.42	7370	Production	Tubing	4.044
11159.42	7371	Liner	Casing	7

P18 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
5476	5476		Tubing	4.044
8646.709	7061.5	Gas lift	Valve	
9263.709	7370	Production	Tubing	4.044
9265.709	7371	Liner	Casing	7

P19 H

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
2636	2636		Tubing	4.044
11487.27	7061.5	Gas lift	Valve	
12104.27	7370	Production	Tubing	4.044
12106.27	7371	Liner	Casing	7

P20

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
6158	6158		Tubing	4.044
7964.974	7061.5	Gas lift	Valve	
8581.974	7370	Production	Tubing	4.044
8583.974	7371	Liner	Casing	7

P21

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
401	401		Tubing	4.044
13721.85	7061.5	Gas lift	Valve	
14338.85	7370	Production	Tubing	4.044
14340.85	7371	Liner	Casing	7

East

P01 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
5476	5476		Tubing	4.044
8646.709	7061.5	Gas lift	Valve	
9263.709	7370	Production	Tubing	4.044
9265.709	7371	Liner	Casing	7

P04 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
4264	4264		Tubing	4.044
9858.683	7061.5	Gas lift	Valve	
10475.68	7370	Production	Tubing	4.044
10477.68	7371	Liner	Casing	7

P06 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
4529	4529		Tubing	4.044
9593.563	7061.5	Gas lift	Valve	
10210.56	7370	Production	Tubing	4.044
10212.56	7371	Liner	Casing	7

P07 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
4037	4037		Tubing	4.044
10085.93	7061.5	Gas lift	Valve	
10702.93	7370	Production	Tubing	4.044
10704.93	7371	Liner	Casing	7

P13

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
3583	3583		Tubing	4.044
10540.42	7061.5	Gas lift	Valve	
11157.42	7370	Production	Tubing	4.044
11159.42	7371	Liner	Casing	7

West

P02 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
2636	2636		Tubing	4.044
11487.27	7061.5	Gas lift	Valve	
12104.27	7370	Production	Tubing	4.044
12106.27	7371	Liner	Casing	7

P05 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
2636	2636		Tubing	4.044
11487.27	7061.5	Gas lift	Valve	
12104.27	7370	Production	Tubing	4.044
12106.27	7371	Liner	Casing	7

P10 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
2446	2446		Tubing	4.044
11676.64	7061.5	Gas lift	Valve	
12293.64	7370	Production	Tubing	4.044
12295.64	7371	Liner	Casing	7

P15 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
2636	2636		Tubing	4.044
11487.27	7061.5	Gas lift	Valve	
12104.27	7370	Production	Tubing	4.044
12106.27	7371	Liner	Casing	7

P16 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
3128	3128		Tubing	4.044
10994.91	7061.5	Gas lift	Valve	
11611.91	7370	Production	Tubing	4.044
11613.91	7371	Liner	Casing	7

South

PA01 G

MD	TD (ft)		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
23996	380		Flowline	4.044
29831	6215		Tubing	4.044
31523.7	7061.5	Gas lift	Valve	
32140.7	7370	Production	Tubing	4.044
32142.7	7371	Liner	Casing	7

PA02 G

MD	TD (ft)		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
26620	380		Flowline	4.044
32455	6215		Tubing	4.044
34147.7	7061.5	Gas lift	Valve	
34764.7	7370	Production	Tubing	4.044
34766.7	7371	Liner	Casing	7

PA03 G H

MD	TD (ft)		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
20060	380		Flowline	4.044
25895	6215		Tubing	4.044
27587.7	7061.5	Gas lift	Valve	
28204.7	7370	Production	Tubing	4.044
28206.7	7371	Liner	Casing	7

PA04 G

MD	TD (ft)		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
23799	380		Flowline	4.044
29634	6215		Tubing	4.044
31326.9	7061.5	Gas lift	Valve	
31943.9	7370	Production	Tubing	4.044
31945.9	7371	Liner	Casing	7

P03 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
1689	1689		Tubing	4.044
12434.13	7061.5	Gas lift	Valve	
13051.13	7370	Production	Tubing	4.044
13053.13	7371	Liner	Casing	7

P08 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
931	931		Tubing	4.044
13191.61	7061.5	Gas lift	Valve	
13808.61	7370	Production	Tubing	4.044
13810.61	7371	Liner	Casing	7

P12 G

MD	TD		Type	Diameter in
0	0		Wellhead	
380	380		Riser	4.044
742	742		Tubing	4.044
13380.98	7061.5	Gas lift	Valve	
13997.98	7370	Production	Tubing	4.044
13999.98	7371	Liner	Casing	7

H Horizontal well
G Gaslifted well

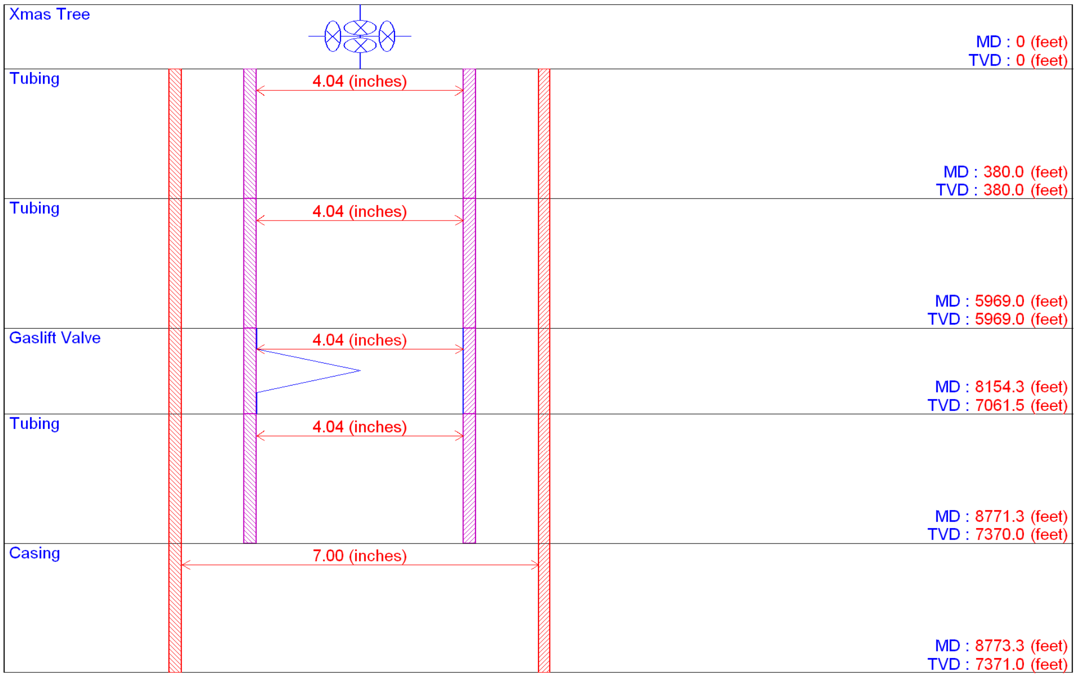


Fig. D-1–N09–completion as found in its PROSPER model

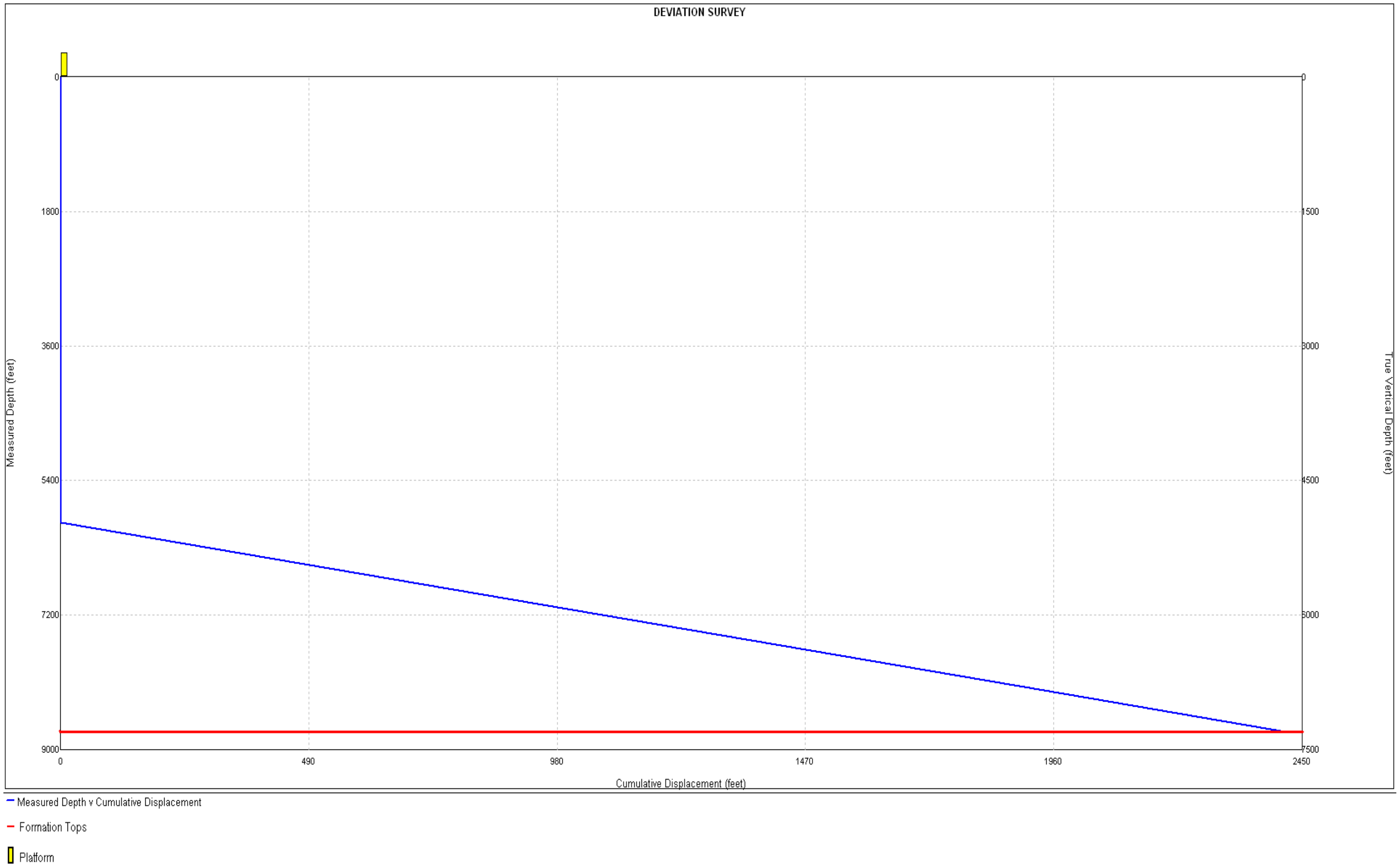


Fig. D-2–N09 deviation survey from its PROSPER model

VITA

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