OPTIMAL ELECTRICAL SUBMERSIBLE PUMP (ESP) DESIGN USING VARIABLE SPEED TECHNIQUE FOR VARING WELL CONDITIONS

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การออกแบบปั๊มไฟฟ้าแบบจุ่มน้ำ(อีเอสพี)น้ำที่เหมาะสมโดยใช้เทคนิคความเร็วแบบแปรผัน สำหรับรองรับการเปลี่ยนแปลงของหลุมผลิต

นายธนัชชา คุณเมฆ

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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Field of Study	Petroleum Engineering
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ธนัชชา คุณเมฆ: การออกแบบปั๊มไฟฟ้าแบบจุ่มน้ำ(อีเอสพี)ที่เหมาะสมโดยใช้เทคนิคความเร็วแบบแปรผันสำหรับรองรับการเปลี่ยนแปลงของหลุมผลิต (OPTIMAL ELECTRICAL SUBMERSIBLE PUMP (ESP) DESIGN USING VARIABLE SPEED TECHNIQUE FOR VARING WELL CONDITIONS) อ. ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 208 หน้า.

ในการศึกษานี้ การจำลองแหล่งกักเก็บได้ถูกนำมาประยุกต์ใช้ในการคาดคะเนอัตราการผลิตและแรงดันที่ก้นหลุม ประสิทธิภาพในการะผลิตจากท่อผลิตถูกนำมาใช้ในการคาดการณ์ ความดันก้นหลุมเพื่อจะผลิตของไหลขึ้นมาที่ผิวดิน ผลจากการจำลองแหล่งกักเก็บกับและประสิทธิภาพในการะผลิตจากท่อผลิตถูกนำมาใช้ในการออกแบบจำนวนชั้นของปั๊ม กลไกลหลักในการผลักดันน้ำมันสองชนิดคือน้ำและก๊าซที่ละลายตัวอยู่ในน้ำมันดิบ ได้ถูกนำขึ้นมาพิจารณาเพื่อค้นหาพฤติกรรมของแรงดันและคำนวนหาจำนวณของชั้นของตัวปั๊มและรุ่นของปั๊ม

ผลจากการศึกษาพบว่าความถ่วงจำเพาะของของไหลมีอิทธิพลอย่างมาก ถึงจำนวนของชั้นของปั๊ม ในกรณีของกลไกลการขับเคลื่อนด้วยน้ำนั้นพบว่าขนาดของแหล่งน้ำที่มีขนาดใหญ่นั้นจะต้องการจำนวนชั้นของปั๊มมากกว่าแหล่งน้ำขนาดเล็ก สำหรับการขับเคลื่อนโดยก๊าซที่ละลายในน้ำมันนั้น เมื่อก๊าซที่ละลายอยู่ระเหยออกไปจะส่งผลให้เกิดการลดลงของความหนาแน่นจึงมีผลทำให้จำนวนชั้นของปั๊มลดลง

ท้ายที่สุดแล้วจำนวนชั้นของปั๊มที่คำนวณได้จากการออกแบบทั่วไป ในอุตสาหกรรมนั้นด้วยการลดทอนแรงดันของหลุมผลิต 10%, 25% และ 50% ถูกนำมาเปรียบเทียบกับวิธีที่เสนอในการศึกษานี้ จำนวนชั้นของปั๊มที่คำนวณได้ด้วยการลดทอนแรงดันของหลุมผลิตในทุกกรณีนั้นน้อยกว่าที่คาดการณ์เมื่อเทียบกับผลที่ได้จากจำลองในกรณีของการประยุกต์ความเร็วแบบคงที่ ในกรณีของการประยุกต์ความเร็วแบบแปรผันนั้น การลดทอนแรงดันที่ 50% ในการออกแบบทั่วไปเท่านั้นที่สามารถให้ผลเป็นที่พอใจตามข้อกำหนด อย่างไรก็ตามจำนวนชั้นที่ได้มีค่ามากเกินความจำเป็นในกรณีที่ลดทอนแรงดันที่ 50%

ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต..
สาขาวิชาวิศวกรรมปิโตรเลียม ลายมือชื่ออ.ที่ปรึกษาวิทยานิพนธ์หลัก..........................
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THANUDCHA KHUNMEK. OPTIMAL ELECTRICAL SUBMERSIBLE PUMP (ESP) DESIGN USING VARIABLE SPEED TECHNIQUE FOR VARING WELL CONDITIONS. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 208 pp.

In this study, reservoir simulation is applied to predict the performance of the fluid rate and bottom-hole pressure. The vertical lift performance is used to estimate the discharge pressure required to lift fluid to the surface. The results from reservoir simulation together with vertical lift performance are used to design the number of pump stages and compare with industrial practice. Water and solution-gas drive reservoir were considered to investigate the pressure behavior and determine the number of pump stages and the pump model.

From the results, it was found that the specific gravity of fluid mixture has a significant influent in number of pump stage. In the case of water drive reservoir has proved that the larger aquifer will require a higher number of pump stages than smaller aquifer. For solution-gas drive reservoir, once the solution gas vaporizes as a free gas, it has a significant effect of reducing fluid density, resulting in number of pump stage reduction.

Finally, the number of pump stages calculated from conventional design with 10%, 25% and 50% reduction factor was compared with the proposed method. The numbers of pump stages calculated from conventional design with all reduction factors are underestimated when compared with the results from the simulation in the fixed speed application. In the variable speed application, only 50% reduction factor in the conventional design can satisfy the requirement when compared to simulation results. However, overestimation of pump stages happens in many cases when 50% reduction factor is used.

Department: Mining and Petroleum Engineering Student's Signature:……...............
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List of Abbreviations

STB/D	barrel (bbl/d : barrel per day)
BHP	bottom hole pressure
SCF/STB	standard cubic feet per stock tank barrel
PVT	pressure-volume-temperature
PSIA or psia	pounds per square inch absolute
PSI or psi	pounds per square inch
SCAL	special core analysis
SWAT	water saturation
SG	specific gravity
MG	specific gravity of mixture
PD	true vertical pump setting depth
Tf	tubing friction losses
TP	surface pressure necessary to move the produced fluid to the production facilities
PIP	pump suction or intake pressure which helps lift the fluid.

Nomenclature

K	permeability
k_r	relative permeability
k_{rg}	gas relative permeability
k_{rw}	water relative permeability
k_{rog}	oil relative permeability for a system
k_{row}	oil relative permeability for a system with oil and water
k_{rowg}	oil relative permeability for a system with oil and water at $S_g = 0$
q_o	oil production rate.
$q_{o,max}$	maximum oil production rate.
P_r	reduced reservoir pressure.
P_{wf}	bottom-hole flowing pressure.
n	exponent of back-pressure curve.
A	laminar-flow coefficient
B	turbulence coefficient

GREEK LETTER

ϕ	porosity
α	oil IPR parameters for the new IPR model

SUBSCRIPTS

g	gas
w	water

CHAPTER I

INTRODUCTION

In general, the natural flowing well uses the differential pressure between reservoir and wellbore as the driving force to displace fluid out of the reservoir. Fluid can flow naturally to the surface. If the pressure between wellbore and the surface facility is sufficient. In the case that differential pressure in the system is not adequate to lift the fluid to the surface, the well must be implemented by some form of artificial lift such as electrical submersible pump.

Electrical Submersible Pump (ESP) is a multistage, centrifugal pump. The pump stage consists of rotating impeller and stationary diffuser which generates the differential pressure that is required by the well. The pump part is driven by downhole motor. The total dynamic head (TDH) is produced by converting shaft horsepower to velocity energy that in turn is converted to fluid horsepower.

To effectively design an ESP, one needs to know the volume of fluid to be pumped and the total dynamic head (pump pressure) which change continuously during the life of the well or the life of the pump. In order to accommodate variations in the volume of pumped fluid and pump pressure, variable-speed-drive ESP has been used. The design of such pump is based on trial and error method with an attempt to accommodate the worst case scenario such as high water cut.

This worst case scenario is generally assumed by the engineer designing the pump without incorporation of production profile forecast. Failure to include dynamic prediction of the well inflow and outflow performances inevitably results in over-sizing or under-sizing the pump. In some cases, this could result in premature equipment failure and costly equipment change.

In order to design variable-speed-drive ESP to handle dynamic changes in reservoir and wellbore conditions effectively, we will consider the dynamic change of inflow performance via reservoir simulation and dynamic change of outflow performance via vertical flow performance. The reservoir simulation will help us to identify pump suction pressure and total liquid rate at different times during the life of the well while vertical flow performance will help us determine the pump discharge pressure at different times as well. With these three parameters, namely, pump suction pressure, pump discharge pressure, and liquid rate, we can predict pump requirements which are pumping rate and pump pressure at different times throughout the life of the well and design variable-speed-drive ESP appropriately to accommodate the requirements.

In this study, reservoir and fluid conditions which are depth, solution gas oil ratio, and size of aquifer support are varied in order to observe dynamic changes in the flow rates of oil, water, gas and bottom-hole pressure (pump suction pressure) as well as dynamic changes in down-hole pressure calculated from vertical flow performance (pump discharge pressure). The purpose of this variation is to investigate the impacts of these parameters on designing variable-speed-drive ESP in terms of the number of pump stages and power requirement in order to make appropriate ESP design to handle different reservoir and fluid conditions.

1.1 Objectives

1. To determine the optimal design of variable-speed-drive electrical submersible pump (ESP) under influence of different reservoir and fluid conditions in terms of number of pump stages.

2. To compare the performance, advantages, and disadvantages of fixed speed ESP design, conventional variable-speed-drive ESP design by trial and error (current industrial practice), and optimal variable-speed-drive ESP design by incorporation of production profile and vertical flow performance forecast under different reservoir and fluid conditions.

1.2 Scopes of Work

1. Set up various cases to study the effect of the following parameters on pump design:

    a. reservoir depth: 5000, 7000, 10000 ft

    b. solution gas-oil ratio: 100, 250, 500 SCF/STB

    c. size of water aquifer: 1 PV, 5 PV, 10 PV

2. Design fixed speed ESP for each case based on available well and reservoir information and pump characteristic curve.

3. Design variable-speed-drive ESP for each case to accommodate worst case scenario by trial and error (current industrial practice) based on variable-speed-drive pump performance curve.

4. Design variable-speed-drive ESP based on production profiles predicted by ECLIPSE and vertical flow performance from PROSPER for each case.

5. Compare and analyze the designs based on the three methods in terms of the number of pump stages and power requirement for different reservoir and fluid characteristics as stated in item 1.

6. Make conclusions and recommendations for fixed speed and variable-speed-drive ESP design compare to the industrial practices.

CHAPTER II

LITURATURE REVIEW

The fast changing of global economy has a great influence on demanding of world's energy. This has pushed up the prices of world energy. In order to minimize the operation cost and maximize the oil production, many studies and research had been conducted.

Petroleum industry plays a major role in supplying world's energy. Petroleum is recovered mostly through oil drilling. It is refined and separated, most easily by boiling point, into a large number of consumer products, from gasoline and kerosene to asphalt and chemical reagents used to make plastics and pharmaceuticals. Predicting present and future of well productivity effectively can help control operating cost, production rates, capital cost, and minimize losses as well.

Kelly[1] showed in his paper that by installing a variable-frequency generator in place of the standard motor controller at the surface, a Variable-Speed Electric Submersible Pumps (VSEP) can utilize this variation in frequency and this result in wider operation range of retrieving fluid productivity. A well test was conducted to compare both single speed and variable speed. The result clearly showed that a variable speed pump can produce more than a resizing ESP of single speed because variable speed pump does not loss time on pulling out the downhole equipment and has no lead time as well. VSESP also helps increase the accuracy of predicting the behavior of well by mean of wider range of operation.

Understanding ESP operation in two-phase conditions is not an easy task. it involves many parameters such as gas degradation and surging prediction correlations. An experiment was conducted to gather data on pressure change at each stage. Surging and gas lock were found during the test, and each stage pressure was recorded. The result showed that the average pump behavior was different in each stage.

Pessoa and Prado[2] concluded that with current knowledge, it is not sufficient to develop an accurate model for predicting head degradation, gas lock, and surging conditions.

Powers[3] discussed in his paper the effect of speed variation on the performance and longevity of electric submersible pumps. This paper demonstrates the downside of speed variation on complexity of ESP equipment selection and difficulties to achieve the maximum pump life. The effect of thrust wear can dramatically shorten pump life, which results from operating in the severe downthrust zone. Vice versa, operating with high speed will result in increasing cavitation which causes a very destructive impact to any type of centrifugal pump. The longer duration of critical speed operation during startup and frequent change of speed greatly affects the problem of vibration. The motor used in ESP system is a two-pole induction motors that have speed equal to the driving frequency. Both the motor and centrifugal pump used in ESP do not form a good partnership if frequency is varied.

Sipra, Muqbali, and Beattie[4] discussed the well design, well inflow and outflow behavior in their paper. The well bore inflow is said to be a well characteristic, and the outflow is characteristic of pump properties. At any point, these curves intersect and define an operating point. Then, Gradient Traverse was plotted to analyze the ESP system by its design parameters, performance monitoring and failure analysis. The design parameters such as well inflow, fluid properties, completion design, require rated, and etc can help one to understand a typical environment of an ESP system. Many downhole equipment such sensor, gauges, and etc are installed to help monitoring and responding to the operating condition. The data from failure are collected and analyzed for overall system improvement. Comprehensive usage of these data sets enables right/ real time decision to sustain ESP at optimum range, leading to enhancing ESP run life.

Powers[5] developed an equation, useful in making economic evaluations for power consumption for ESP. It is categorized into the energy required to perform useful work, the energy absorbed by tubing friction, and power-cable electrical losses. Practical examples using his design techniques are shown in the paper. The value of power consumption on tubing size, power-cable size, and motor voltage are presented and being compared on economical viewpoint.

Knight and Bebak[6] presented an economic viewpoint for ESP offshore operation. Since offshore operation is more costly than onshore operation in term of capital and operating expenditures, ESP reliability and common failure reviewed to seek for an improvement and optimize ESP runtime. Three crucial areas were equipment, installation and operation. This paper also shows the common failure and breakdown frequency from collected data of dismantles. These failures are ESP motor failure, shaft break, corrosion, well problems, and etc. Careful consideration of the application and proper system monitoring can significantly increase the life cycle of downhole equipment as well as minimize the cost of overall system, especially with the offshore operation. These are some of studies for understanding the inflow and outflow production. Being able to predict the well performance accurately can result in maximizing future financial return through question such as tubing and choke size, timing of artificial lift, future revenue streams, and abandonment time with some certainty.

CHAPTER III

Basic ESP Sizing

This chapter will explain the basic of ESP design in term of system components and selection of ESP. The ESP system can be separated into downhole and surface components. The surface components are transformers, motor controllers, and junction box. The wellhead accommodates the passage of the power cable and tubing from the surface to the well bore. The main down-hole components are the motor, seal, pump and cable. Additional items may include the check and drain valves, gas separators, cable bands and protectors, motor lead guards and data acquisition instrumentation. Figure 3.1 shows schematic diagram of a submersible pump installation. In a normal installation, the ESP assembly is connected to the bottom of tubing string via the pump discharge head.

The pump discharge head is usually a separate component that bolts onto the top of the pump section. Occasionally, the pump is built in either an upper tandem or single configuration. In these cases, the discharge head as an integral part of the pump assembly. The pump is a multi-stage centrifugal pump and is generally built as a center tandem configuration. The pump may be a single piece pump as shown in Figure 3.1.

Fluid enters the pump through pump intake. Usually, the intake is a separate component that bolts onto the bottom of the pump section. Occasionally, the pump is built in either a lower tandem or single configuration. In these cases, the intake is an integral part of the pump section. A bolt-on intake is usually a standard screened intake but sometimes a gas separator is used instead.

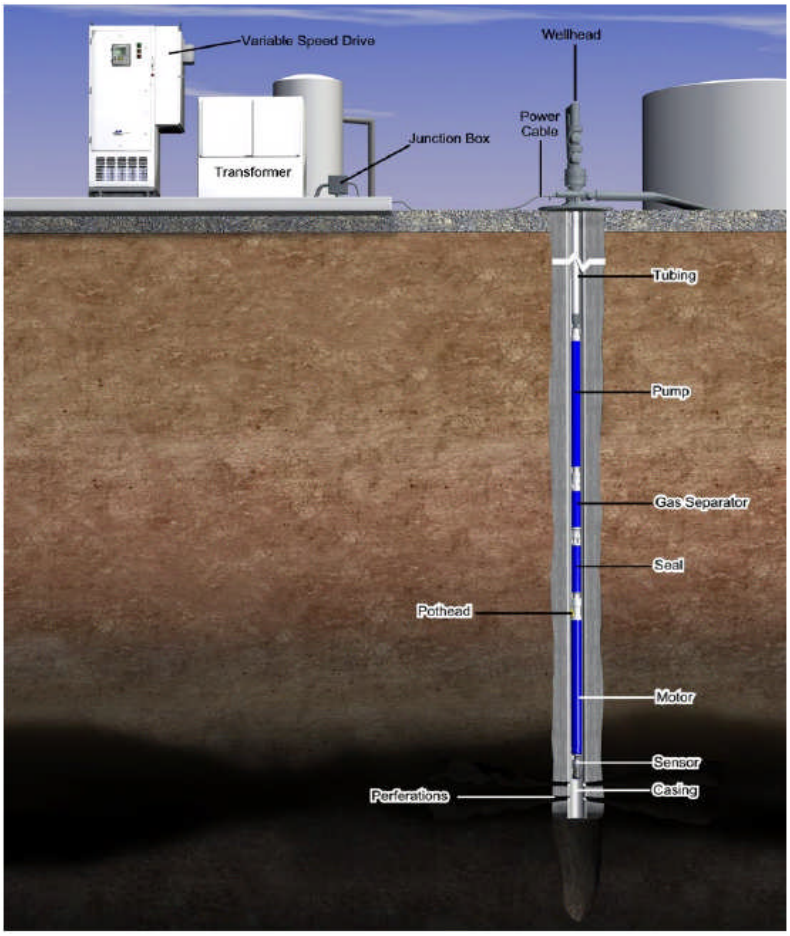

Figure 3.1: Typical ESP system component [7].

The seal section is located between the pump intake and the motor. Other names for the seal section include motor protector and equalizer. The seal section is designed to prevent well fluids from entering the motor while providing a reservoir for motor oil expansion. It also allows for the equalization of the pressure between the motor and well bore. The seal section also includes a thrust bearing to carry pump shaft thrust.

The seal section can be a single unit as shown in Figure 1.1 may be run in tandem where it is desired to have additional seals and oil volume capabilities for high horsepower motors or more protection. The number of shaft seals varies with the type of seal section used. The motor is connected to the bottom of the seal section. An ESP motor is a 60-hertz power, rotates between 3400 to 3500 RPM, depending on the load.

Located between the wellhead and the motor starter (switchboard or VSD) is a junction box. Within the junction box, the cable is separated and stripped to the bare copper conductor. The conductors are then tied back together on insulated terminal blocks. This allows any gas that might have migrated up the cable to escape and vent to the atmosphere. The remaining surface equipment consists of a motor controller and transformer(s).

Typically, the ultimate goal of ESP sizing is to deliver the desirable liquid rate with the highest operational efficiency of selected equipment. Prior to selecting suitable equipment, we need to emphasize on the well data that ESP will be utilized. Therefore, reservoir data which are include bottom-hole pressure, bottom-hole temperature well production date, fluid properties, well geometry, and reservoir producing characteristics come to play a significant role.

ESP Performance curve

The pump curve in Figure 3.2 describes the performance of a particular pump type. All the manufacturers describe their pumps with this type of curve. The left vertical axis is scaled in feet and meters of head. The bottom horizontal axis is scaled in bbl/d. The curve labelled Head-Capacity defines the head that impeller can produce at all of the available flow rates. For example, at 1200 bbl/d the single stage P11 shown in Figure 3.2 will produce 44 ft. of lift.

Note that centrifugal pump performance is defined by the head they produce, not pressure. The 44 ft. of lift in the example above represents 19.05 psi for specific gravity 1.00 fluids. However, the impeller will produce the same 44 ft. of lift with a specific gravity 0.85 fluid with an associated pressure of 16.19 psi. This is because the centrifugal forces acting on the fluid are the same regardless of the fluid's density.

Density does affect the power required to lift the fluid. The curve in Figure 3.2 labeled Horsepower Motor Load indicates the power requirements for this impeller at

various flow rates. The first vertical axis on the right is scaled in horsepower motor load. This horsepower is based on pumping water with a specific gravity of 1.00.
As an example, at 1200 bbl/d the one stage pump in Figure 3.2 will require 0.72 hp if the fluid has a specific gravity of 1. For fluid having a specific gravity of 0.85, the pump will only require 0.61 hp.

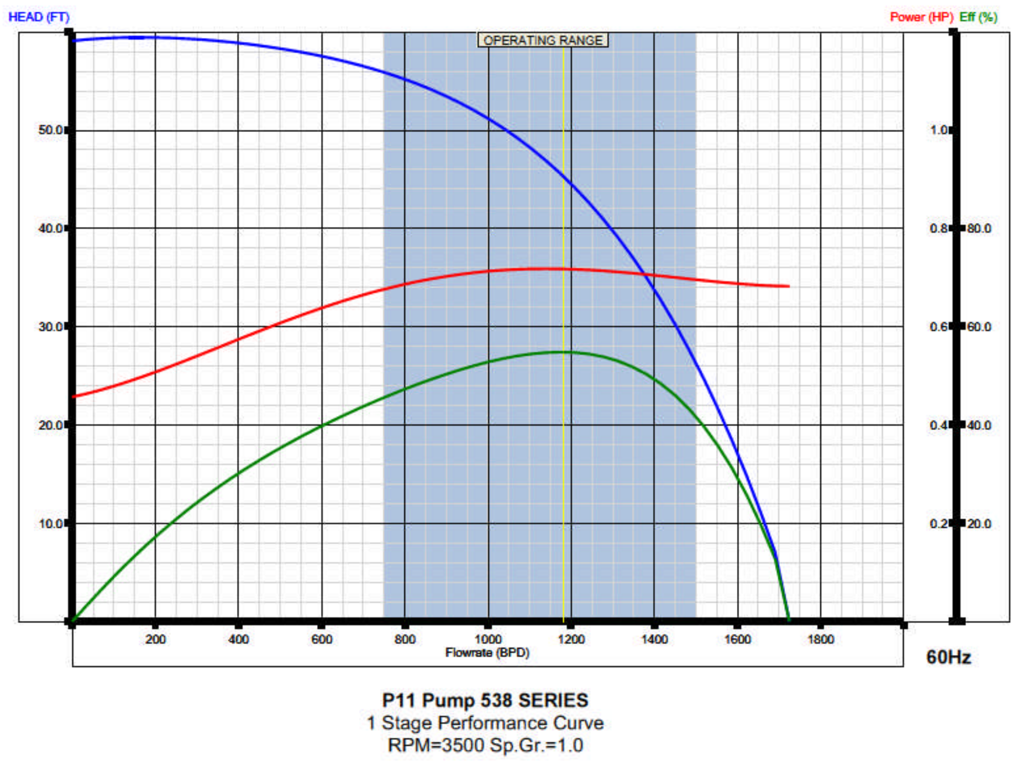

Figure 3.2: Typical pump curve[8].

The rightmost vertical axis of Figure 3.2 is scaled in percent efficiency. Sometimes the curves will not agree with the calculation due to errors in reading and reproducing the curves. Because of this, the API has established that mathematical coefficients should be used to determine an impeller's head, horsepower and efficiency. The published curves will usually be for a single stage pump but sometimes the curve will be on a 100-stage basis. In the example above, if we had read the head at 1200 bbl/d of a 100-stage curve we would read 4,400 ft. The curves are also rotational speed dependent and the speed for the curve will be listed. Changing the speed of the impeller will affect the head and horsepower curves according to the pump and fan affinity laws. This will be covered in the section on variable speed drives.

3.1 Well Data

Any kind of artificial lift design, whether it is gas lift, ESP, or PCP, it is mandatory to start with the well data and it can be classified into six categories.

1. General information: well name, well location, date of collected date and well history.
2. Well geometry: deviation survey, exiting completion details, perforation depth, production casing/liner profile
3. Surface information: flowline pressure, wellhead type, available power and cost.
4. Fluid properties: kill fluid density, oil °API or specific gravity, PVT laboratory reports, water cut, and etc.
5. Well inflow data: well test data, static and flowing bottom-hole pressure, productivity index (PI).
6. Design goal: desirable fluid rate, maximum efficiency, extended run-life and minimum investment, including operating frequency.

3.2 Design and Selection

Produced fluid in a well that has a high water cut and low gas-oil can be considered as a single phase fluid or incompressible fluid. In this case, there is no concern about multiphase fluid flow into the pump intake. This means we can assume that the volume produced at the surface is equivalent to the volume that is pumped from down-hole. However, in reality, we are dealing with compressible fluid in the wellbore such as gas, oil and water flowing from the reservoir into the wellbore and being produced through the production tubing to the surface. This is more complicated and unable to do by hand calculation. There are several software in the market that will assist petroleum engineer to design the ESP. However, we need to follow the three main steps to design and select the pump:

- Determine the flow rate (Q)
- Calculate the total dynamic head (TDH)
- Select the proper pump, number of pump stages and pump housing

Inflow Performance

Flow rate (Q) is the most basic item that is needed in the design of multi-stage ESP pump. There are several cases that pump size is larger than well fluid productivity, resulting in pump off or fluid level below the pump intake. In the case that selected pump size is smaller than the capacity of the well can deliver, the return rate of project will be less worthy. Therefore, design engineer needs to spend more time with well's productivity and finds proper productivity index and flow characteristics from available reservoir data.

Many assumptions for predicting a well inflow and outflow are based on single phase mixture. It is often assumed that production rates are proportional to pressure drawdown. This straight-line relationship can be derived from Darcy's law for steady-state flow of a single, incompressible fluid and is called the productivity index (PI). Since the condition of well is dynamic and none of them having the same conditions, the intake pressure, the volumetric fractions of free gas and liquid phases, the liquid flow rate, and the angular speed are some of the main parameters causing variations in each of the well condition. This led to the development of several empirical inflow performance relationships (IPR) to predict the pressure, production behavior of oil wells producing under two-phase flow condition.

Fetkovich's work[9] proposed the isochronal testing of oil wells to estimate their productivity. He got his n value from his field experiment. By mean of methods not shown in his paper, Fetkovich found an n =1.24 for his q_{o}. Using data from multirate tests on 40 different oil wells in six fields, Fetkovich showed the following approach:

$$\frac{q_o}{q_{o,max}} = \left[1 - \left(\frac{P_{wf}}{P_r}\right)^2\right]^n \quad (3.1)$$

where q_o = oil production rate.

$q_{o,max}$ = maximum oil production rate.

P_r = reduced reservoir pressure.

P_{wf} = bottom-hole flowing pressure.

n = exponent of back-pressure curve.

Jones, Blount, and Glaze[10] method requires that a multi-rate test be conducted to determine the coefficients, *A* and *B*, in which *A* is the laminar-flow coefficient and *B* is the turbulence coefficient. It is evident that a Cartesian plot of the ratio of the pressure difference to the flow rate vs. the flow rate yields a straight line, with the *y*-intercept being *A* and the slope, *B*. Once the coefficients are estimated the flow rate at any flowing pressure can be determined.

$$q_o = \frac{-A + \sqrt{A^2 + 4B(P_r - P_{wf})}}{2B} \quad (3.2)$$

On the basis of Vogel's work[11], Klin and Majcher[13][14] developed an IPR that incorporates the bubble point pressure. Using the nonlinear regression analysis, they presented the following IPR.

$$\frac{q_o}{q_{o,max}} = 1 - 0.295\left(\frac{P_{wf}}{P_r}\right) - 0.705\left(\frac{P_{wf}}{P_r}\right)^n \quad (3.3)$$

Sukarno and Wisnogroho[12] developed an IPR based on simulation results that attempts to account for the flow efficiency variation caused by rate-dependent skin as the flowing bottom-hole pressure changes. The authors developed the following relationship using nonlinear regression analysis.

$$\frac{q_o}{q_{o,max}} = \left[1 - 0.1489\left(\frac{P_{wf}}{P_r}\right) - 0.4416\left(\frac{P_{wf}}{P_r}\right)^2 - 0.4093\left(\frac{P_{wf}}{P_r}\right)^3\right] \quad (3.4)$$

Al-Saadoon's[12] used a similar method with Standing but different in definition of *J*: However, both authors obtained the same curves q_o vs p_{wf}

$$J = \frac{dq_o}{dP_{wf}} \quad (3.5)$$

Klins and Clark III[14][15] had studied from previous research and came up with a more realistic equation used to predict the future IPR curves of their own. They predict future maximum oil deliverability as a function of f J and n from Fetkovich equation. By assuming a flowing BHP of zero, the AOF potential at any reservoir pressure below the bubble point can be estimated. Coupled with Vogel's[11] and Klins and Majcher's[14][15] IPR relationships, we obtain

$$\frac{q_o}{q_{o,max}} = 1 - 0.2\left(\frac{P_{wf}}{P_r}\right) - 0.8\left(\frac{P_{wf}}{P_r}\right)^2 \quad (3.6)$$

Elias et al. [16] derived their equation to predict inflow performance based on oil mobility- pressure profile where α is the oil IPR parameter for the new IPR model.

$$\frac{q_o}{q_{o,max}} = 1 - \frac{\ln(\alpha P_{wf}+1)}{\ln(\alpha P_r+1)} \quad (3.7)$$

The result gives a more precise prediction of IPR behavior curve than the methods used in the industry. It is ranked number one whereas model of Fetkovich, Sukarno, Vogel, and Wiggins is ranked the second, the third, the forth, and the fifth, respectively.

After the target production rate is decided, a production engineer then can select the pump setting depth, pump intake pressure, and pump model that is suitable for the reservoir and operations. The flow may be decided based on other reason such as surface facility limitation, availability of the equipment in inventory or lead time of ESP system. In addition, it will depend on the economic decision as well.

Outflow Performance

Instead of dealing with the fluid flow from the reservoir into the wellbore like the previous section, the outflow performance is involving with fluid flow from the wellbore up to the tubing. The fluid will flow only when the pressure at te tubing intake is greater than the hydrostatic pressure, plus the friction loss in the tubing itself, plus the tubing discharge pressure or wellhead pressure.

The friction loss calculation in single phase fluid is very simply and can be determined by Hazen-William equation [17]. Nevertheless, the fluid that is produced is multi-phase fluid and it is difficult to calculate since the average density and the velocity of the fluid is usually unknown because the gas breakout and fluid slip.

Many researchers have performance the experiment and come up with empirical solution to solve multi-phase fluid problem. Many tubing correlation have been published and applied worldwide. Poetmann and Carpenter[18] established the vertical flow performance that can be used with 2-3/8” to 31/2” OD tubing and flow rate graer than 400 STB/D with minimum slippage.

Dun and Ros[18], Hagedon and Brown[18], Begg and Bill[18], and other have developed additional outflow correlation intended to improve the accuracy of the friction loss calculation. Most are applicable to all conditions including annular flow. In addition, these correlations can be applied in deviated well from 15° to 20° from vertical.

However, no correlation that satisfies for every well conditional. The correlation will need to calibrate with actual filed data and select the most accurate calculation. Figure 3.2 shows the typical pressure travers curves from the Hagedon and Brown[18] correlation. When the surface pressure is known, this curve can be used to obtain frication loss in tubing as the following procedure.

1. Pick proper curve to fit the situation, i.e. flow rate, pipe size, WOR etc.
2. Draw a vertical line from surface pressure intersect with gas-liquid ratio to determine pseudo depth.

3. From the pseudo depth that obtains from above add the well depth to determine pressure depth.
4. Move horizontally from pressure depth to proper gas-liquid ratio and read bottom-hole pressure.
5. Subtract surface pressure from bottom-hole pressure to determine pressure drop in the tubing.

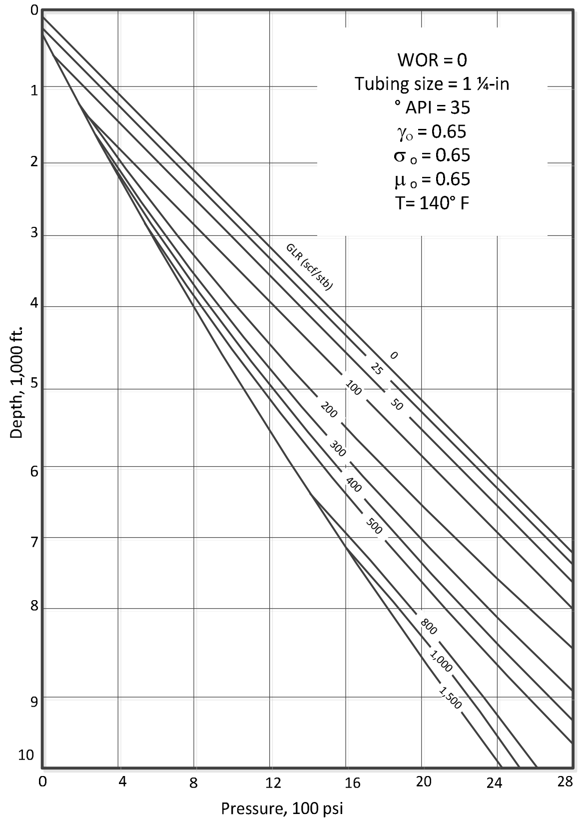

Figure 3.3: Typical vertical pressure transverse curves[19].

Total Dynamic Head

Total Dynamic Head or TDH is the differential pressure that pump need to supply in order to deliver the fluid to the surface at desirable flow rate. Normally, the amount of head is defined in term of height unit such as feet or meter. The total dynamic head can be calculated as following equation:

$$TDH = PD + T_f + TP - PIP \tag{3.8}$$

where:

PD = true vertical pump setting depth

T_f = tubing friction losses

TP = surface pressure necessary to move the produced fluid to the production facilities

PIP = pump suction or intake pressure which helps lift the fluid and therefore need not be supplied by the pump. This includes casing pressure.

Equation 3.8 is combination of head and pressure units and needs to normalize into one common units of head. Pressure can be converted to head by divided by specific gravity as shown in following equation.

$$Head(ft) = \frac{PSI}{(SG\ x\ 0.433)} \tag{3.9}$$

The specific gravity (*SG*) in the equation is specific gravity of mixture (*MG*) or specific gravity of gas, oil and water that is produced by the pump. The Total Dynamic Head equation can now be written with common units:

$$\mathrm{TDH} = \mathrm{PD} + \mathrm{Tf} + \left(\frac{\mathrm{TP}}{MG}\right) - \left(\frac{\mathrm{PIP}}{MG}\right) \tag{3.10}$$

From equation 3.10, most of the terms have already been defined except the tubing friction losses (T_f). The loss of head due to friction of water may be calculated using Hazen-Williams formula [16].

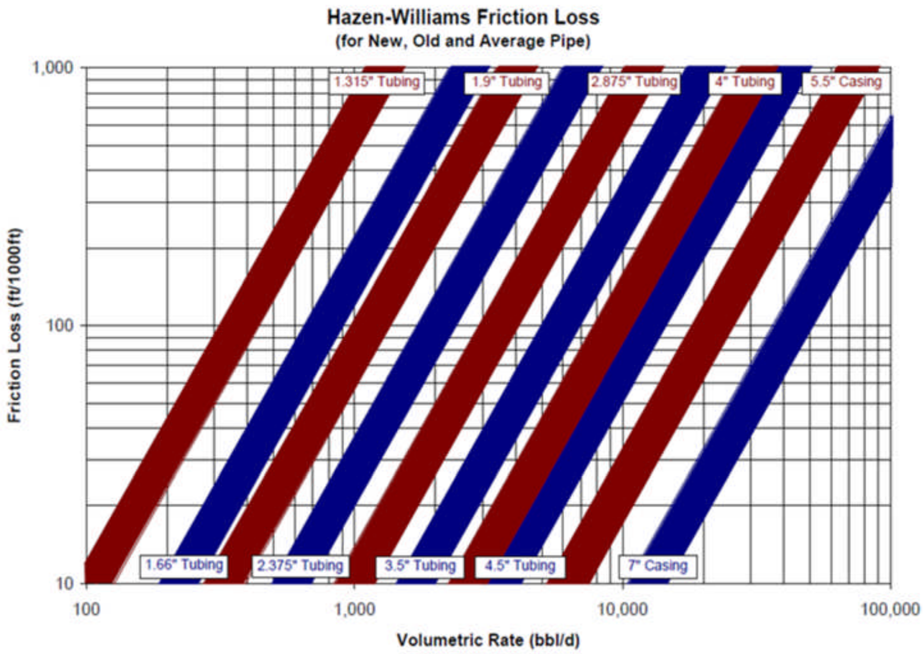

Figure 3.4: Hazen-William friction loss for new, oil and average pipe[17].

The total dynamic head or TDH determined from Equation 3.10 can be used to calculate number of pump stages by dividing the TDH by the ability of lift per stage (head per stage).

Pump Selection

At this point, the number of pump stages can be determined by selecting the pump model based on desirable flow. Bearing in mind that the manufacturing pump catalog curves and select must be meet with two the criteria below:

- A pump outside diameter fits in the casing internal diameter.
- The pump can deliver the highest efficiency among selected model.

Basically, the largest diameter of pumps that fits in the well casing is more efficient than the smaller diameter. In normal practice, there will be two or three pump models that meet the volume and diameter requirements. On another hand, we also need to consider the availability and delivery requirements.

After the number of pump stages has been determined, we need to refer to manufacturing standard catalog available in the market. Pump housing or housings are available to handle the required number of stages. It must be emphasized at this point that all ESP manufacturers have different standard size pump housings. For each standard housing, many different stages can be combined in order to meet multi-stage pump requirement. For example, if the required number of pump stages is 114 stages, and there are two available pumps in the catalog and the standard pump sizes that vendor makes are:

1. Housing #14 which contains 100 stages.
2. Housing #15 which contains 128 stages.

The two choices are :

1. Use the #14 housing and have 114 stages less than required.
2. Use the #15 housing and have 114 stages more than required.

It is vital that we know this so that we can make a decision. However, it is recommended to select the higher number of stages than calculated in case there is no variable speed drive available.

3.3 Variable Speed Design

Nowadays, the variable speed drive (VSD) is more popular in the ESP industry due to the flexibility and adjustability to the ESP pump base on varying of well condition. The affinity laws was applied to calculate the new rate, head and break horse power as follow equations:

$$Q_2 = Q_1 \left(\frac{N_2}{N_1}\right) \tag{3.9}$$

$$H_2 = H_1 \left(\frac{N_2}{N_1}\right)^2 \tag{3.10}$$

$$BHP_2 = BHP_1 \left(\frac{N_2}{N_1}\right)^3 \tag{3.11}$$

where: Q_1, H_1, BHP_1 and N_1 = initial capacity, head, brake horse power and speed.

Q_2, H_2, BHP_2 and N_2 = new capacity, head, brake horse power and speed.

The variable speed pump curve is depicted in Figure 3.3.

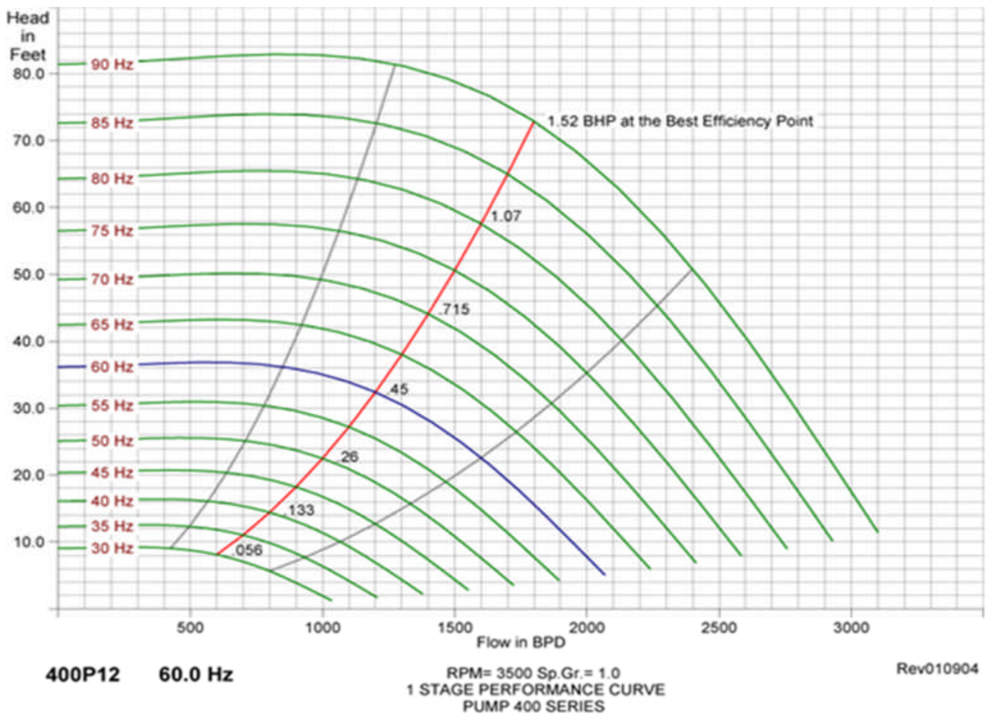

Figure 3.5: Variable-speed-drive pump performance curve[7]

CHAPTER IV

RESERVOIR SIMULATION MODEL

In order to determine optimal pump stages with a various reservoir conditions, reservoir simulator together with vertical lift performance were used to determine total dynamics head (TDH) behaviour under different reservoir conditions. As a result, the optimal pump stages can be obtained in fixed and variable speed application.

The reservoir simulator ECLIPSE 100 specializing in blackoil modeling was used in this study. There are two drive mechanism model in this research, solution gas drive (depletion drive) and water drive. The solution gas drive reservoir was constructed with various Gas Oil Ratio (GOR) – 100, 250 and 500 scf/STB. The water drive reservoir was built with bottom aquifer support – 1PV, 5PV, and 10PV aquifer size. We can divide the reservoir simulation model into three main sections as follows:

1. **Grid section.** In this section the geometry of the reservoir and its permeability and porosity were specified.
2. **Fluid section.** The PVT was assumed with different reservoir conditions. Initial reservoir condition was also included in this section.
3. **SCAL section.** In special core analysis or SCAL section, gas and oil relative permeability in gas-oil system with connate water as a function of gas saturation, oil and water relative permeability in water-oil system as a function of water saturation were specified.
4. **Wellbore Section.** The wellbore model was constructed and used to incorporate the vertical flow performance from other software into the simulation model.

This chapter describes in details on how properties are gathered in each section. The detail of the simulation input is shown in Appendix A.

4.1 Grid Section

In this study, we performed simulation for two different reservoirs which are water drive and solution gas drive (depletion drive). Both reservoirs were constructed using Cartesian coordinate under simple geometry and homogeneous conditions. The dimension of each reservoir is 2500 ft x 2500 ft x 50 ft. The number of grid blocks of each reservoir is 50 x 50 x 5 in the x, y and z direction, respectively. The top of reservoir is located at depth of 10,000 ft in the base case, and the top of the reservoir was varied in order to consider the effect of depth at 5,000 and 7,000 ft.

The porosity of the reservoir was assumed to be 18.0%. The horizontal permeability was set at 100 mD, and the vertical permeability was 10 mD. Figures 4.1, 4.2, 4.3 and 4.4 display the reservoir shape for solution and water drive with a bottom aquifer support of the size 1PV, 5PV and 10PV, respectively.

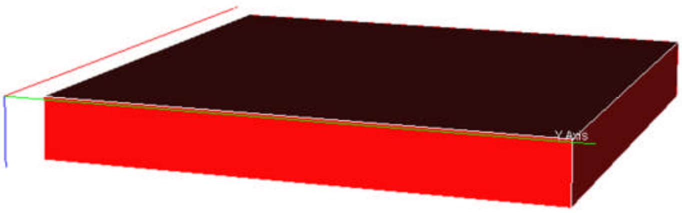

Figure 4.1: 3D view of solution gas drive model.

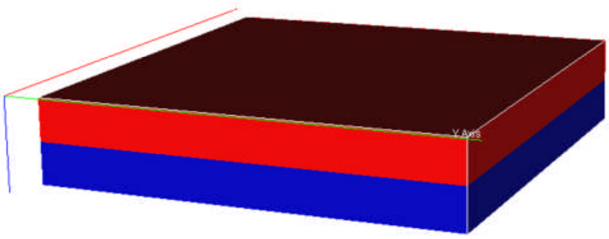

Figure 4.2: 3D view of bottom water-drive reservoir with 1PV with aquifer.

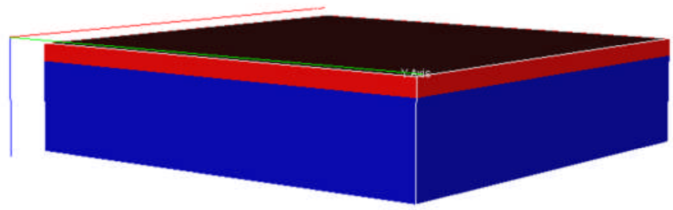

Figure 4.3: 3D view of bottom water-drive reservoir with 5PV aquifer.

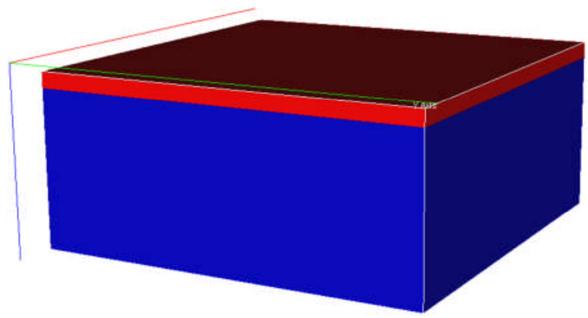

Figure 4.4: 3D view of bottom water-drive reservoir with 10PV aquifer.

4.2 Fluid Section

The PVT data such as initial reservoir pressure, temperature, gas-oil ratio, specific gravity of gas and fluid were input in this section and varied by depth as shown in Tables 4.1, 4.2, 4.3 and 4.4. The data are required to calculate the density of each phase in each grid block for material balance purposes.

Table 4.1: PVT input data.

Depth (ft.)	Pressure (psi)	Temperature (°F)	Gas Oil Ratio (scf/STB)
5,000	2,200	168	100, 250, 500
7,000	3,300	200	100, 250, 500
10,000	4,400	250	100, 250, 500

Table 4.2: Oil property correlation.

Oil property	Correlation
Solution gas ratio (R_s)	Velarde Blasingame
Bubble point pressure (P_b)	Valko McCain
Dead oil viscosity	Beggs Robinson
Viscosity below bubble point pressure	Beggs Robinson
Viscosity above bubble point pressure	Vasquez Beggs
Formation volume factor (B_o)	Casey Cronquist
Compressibility above bubble point pressure	Spivey Valko Mccain
Compressibility below bubble point pressure	Spivey Valko Mccain

Table 4.3: Gas property correlation.

Gas property	Correlation
Z factor	Hall and Yarborough
Viscosity	Lee
Critical properties	Mccain Corredor Grav
Formation volume factor (B_g)	Spivey McCain

Table 4.4: Water and rock property correlation.

Water and rock property	Correlation
Viscosity	Kestin Khalifa
Formation volume factor (B_w)	McCain
Compressibility	Meehan
Reservoir density	Spivey McCain
Compressibility	Newman

4.3 SCAL (Special Core Analysis) Section

Two tables of relative permeabilities (k_r) and capillary pressures (p_c) as functions of saturation in ECLIPSE allow us to enter gas/oil relative permeabilities and oil/water relative permeabilities into the software as depicted in Tables 4.5 and 4.6, respectively. These functions are shown in Figures 4.5 and 4.6.

$k_{rg}$is relative permeability to gas
$k_{ro}$is relative permeability to oil
$k_{rw}$is relative permeability to water
S_w is saturation of water
$S_g$is saturation of gas
$p_c$is capillary pressure

Table 4.5: Gas and oil relative permeability.

S_g	k_{rg}	k_{ro}
0.000	0.000	0.600
0.121	0.000	0.367
0.196	0.001	0.258
0.272	0.007	0.173
0.347	0.022	0.109
0.423	0.053	0.063
0.498	0.101	0.032
0.574	0.178	0.014
0.649	0.282	0.004
0.725	0.421	0.001
0.800	0.600	0.000

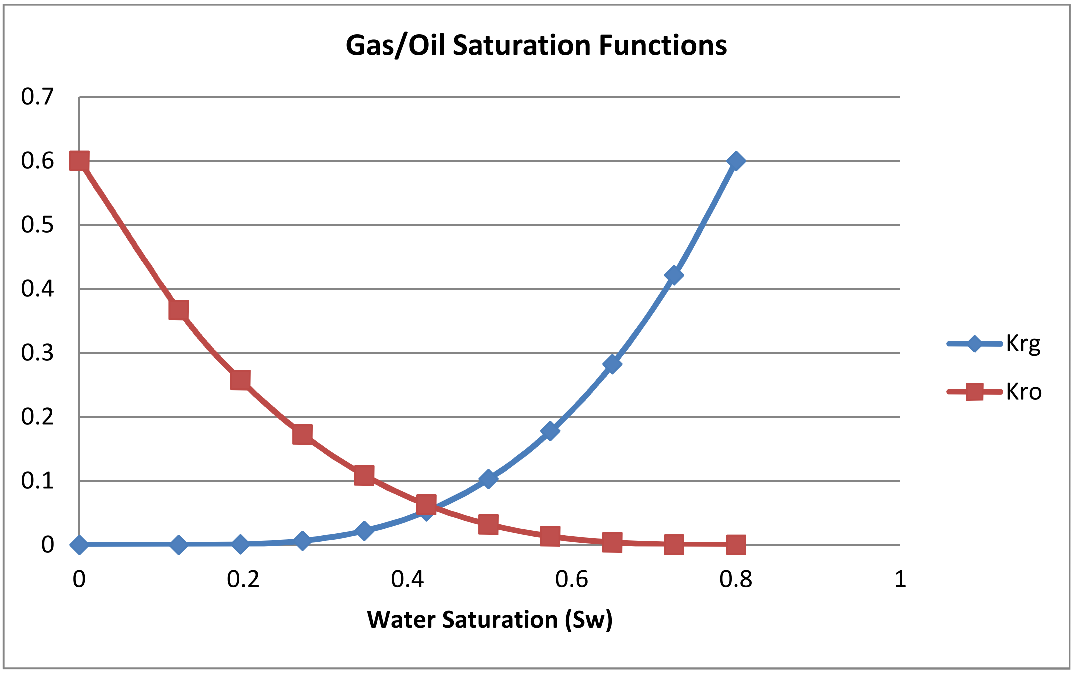

Figure 4.5: Gas and oil relative permeability.

Table 4.6: Oil and water relative permeability.

S_w	k_{rw}	k_{ro}
0.200	0.000	0.600
0.250	0.000	0.476
0.319	0.001	0.334
0.388	0.007	0.224
0.457	0.024	0.141
0.526	0.057	0.082
0.595	0.111	0.042
0.664	0.193	0.018
0.733	0.306	0.005
0.802	0.457	0.001
0.871	0.650	0.000

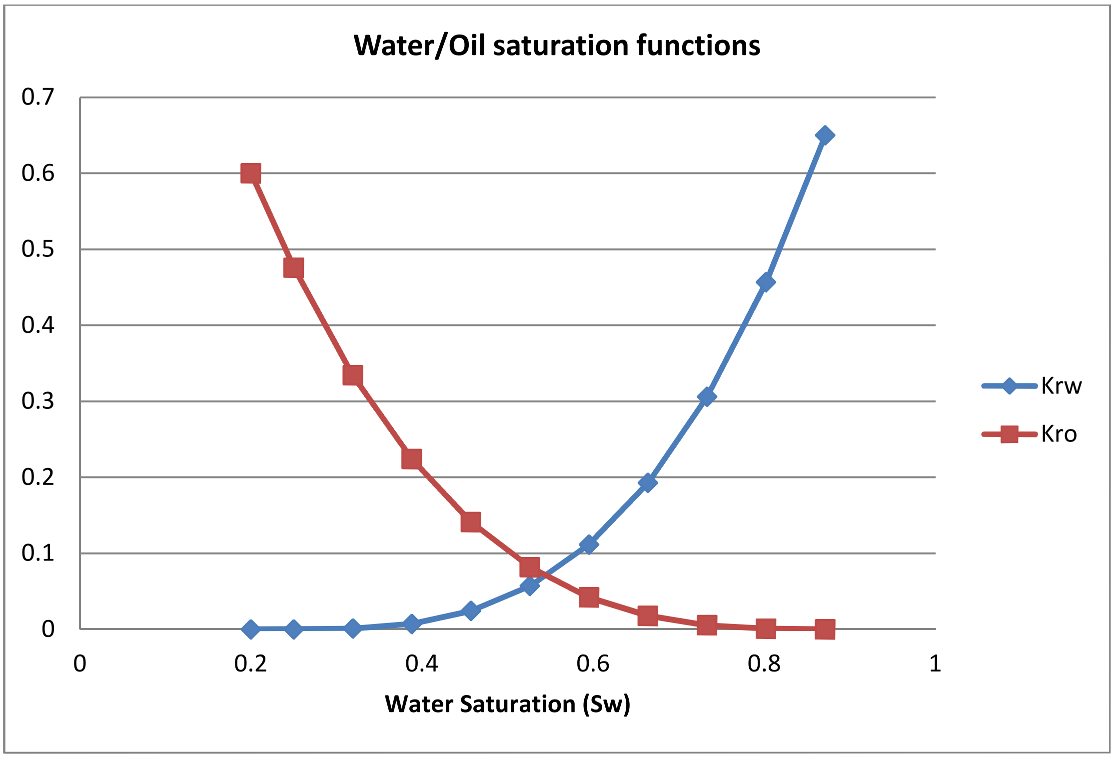

Figure 4.6: Oil and water relative permeability.

4.4 Wellbore Section

The well in this study has the tubing outside diameter of 3-1/2 inches with an inside diameter of 2.992 inches. The well is completed with conventional 500 series ESP Pump, seal and motor and set above perforation 100 ft. There is no packer installed above the pump discharge. The well schematic of production well is shown in Figure 4.7.

In this study, multiple sets of vertical lift performance(VLP) curves were generated by production and system performance analysis software (PROSPER) for the variety of fluid produced from the reservoir. Each set of VLP curves is for specific fluid properties and depth. The chosen vertical flow correlation is Petroleum Expert 2. The bottomhole flowing pressure is calculated based on the tubing head pressure, gas rate, and gas oil ratio of the producing well.

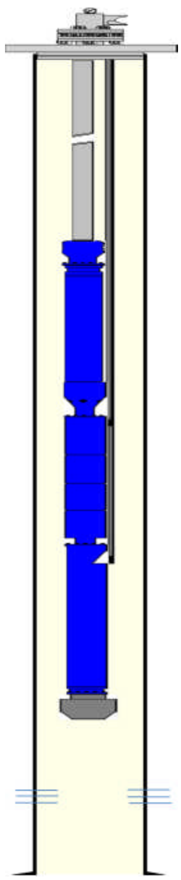

Figure 4.7: Well schematic.

CHAPTER V

RESULTS AND DISCUSSIONS

5.1 Base Case for Solution-Gas-Drive Reservoir

The main source of drive energy for this kind of reservoir is from expansion of liberated gas and the expansion of the oil itself as the reservoir pressure is reduced. In this case, the reservoir pressure declines rapidly with the production of oil from the reservoir and no water is produced during the entire reservoir life. A sample of production profile is illustrated in Figure 5.1.

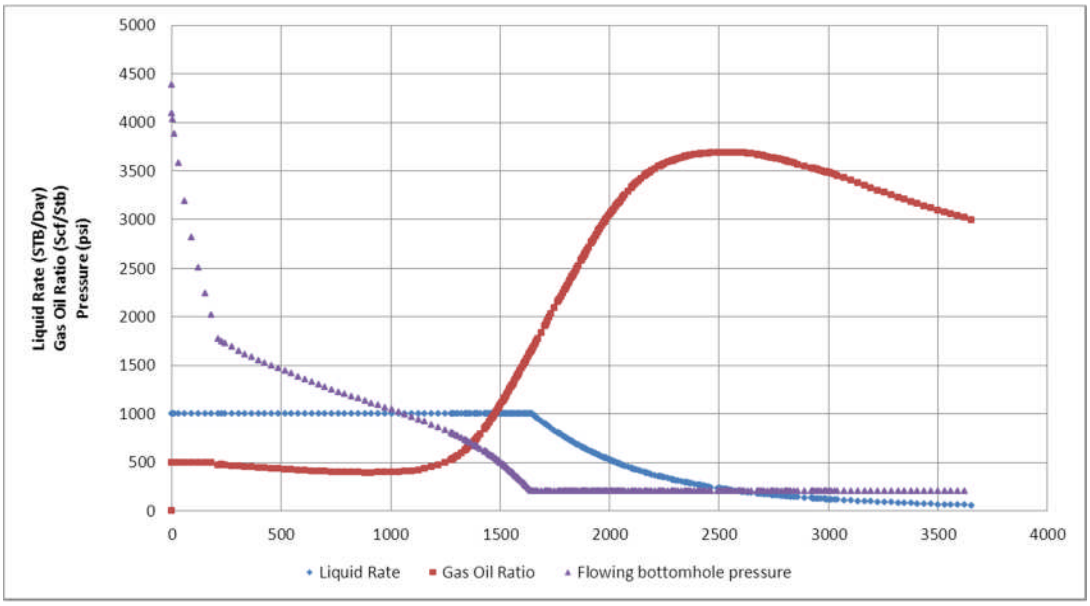

Figure 5.1: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for solution-gas drive reservoir.

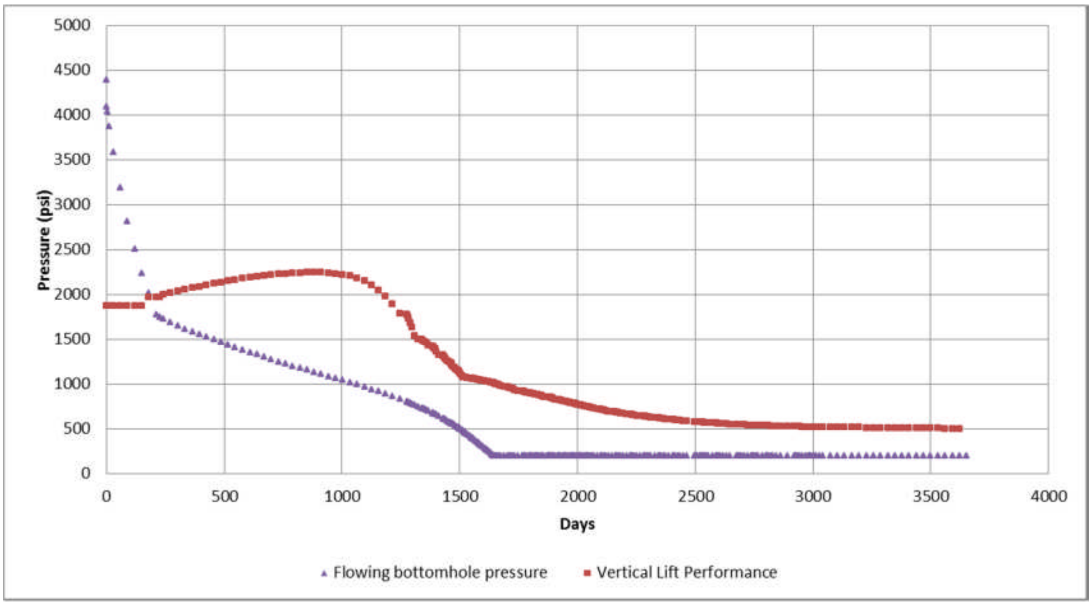

Figure 5.2: Bottom-hole pressures from ECLIPSE and vertical lift performance for solution-gas drive reservoir.

In the simulation, the control parameters are maximum liquid production rate of 1,000 STB/D, minimum bottom-hole pressure of 200 psia and economic oil rate of 50 STB/D. Vertical lift performance tables are not incorporated in reservoir simulation since one of the purposes of running the simulation is to observe the behavior of bottom-hole pressure from inflow performance perspective in order to determine the suction pressure in the design of a pump to boost the pressure of the produced fluids to the surface.

As depicted in Figures 5.1, liquid production rate from the reservoir is maintained at 1,000 STB/D for a period of 1,600 days. Then, it keeps declining until reaching an abandonment rate of 50 STB/D. The bottom-hole pressure declines rapidly at the beginning (while the liquid rate is maintained at 1,000 STB/D) until it reaches the minimum bottom-hole pressure of 200 psia at 1,600 days and stays there until the end of the production period. Once the bottom-hole pressure cannot be reduced any further, the liquid production rate dramatically decreases.

Figure 5.1 also shows gas-oil ratio and water cut profiles. The gas-oil ratio is more or less constant at early time as the reservoir and bottom-hole pressures are still high. In later stage of production, the gas oil ratio increases as more and more gas liberated inside the reservoir starts flowing into the wellbore. At late time, the amount of gas-oil ratio decreases again as the liberated gas that flows into the wellbore and the dissolved gas that is produced with the oil can expand less due to lower reservoir pressure at late time. For the water cut, it is zero for the entire life of the reservoir because there is no aquifer attached to the reservoir model.

The values of liquid rate, gas-oil ratio, and water cut from Figure 5.1 are used to determine the bottom-hole flowing pressure based on Petroleum Expert 2 correlation for multi-phase flow in tubing. This calculated bottom-hole pressure is shown in Figure 5.2 as the vertical lift performance curve and is actually the discharge pressure of a pump. Also shown in Figure 5.2 is the bottom-hole pressure calculated from inflow of fluids from the reservoir into the wellbore which is actually the suction pressure. The difference between the discharge pressure and the suction pressure is the required pump pressure to lift the produced fluids to the surface. Subsequently, the head is determined by dividing the differential pressure by the fluid gravity as plotted in Figure 5.3.

During the early period of plateau production, the head gradually increases because of the reduction in the suction pressure while the required bottom-hole pressure for vertical lift increases. Once, the reservoir pressure is below bubble point and free gas starts to flow into wellbore (free gas liberated from solution), the head starts to decrease due to a sharp decline in the bottom-hole pressure required to lift fluids from bottom-hole to surface while the bottom-hole pressure keeps declining gradually. After the end of the plateau period, the head required to pump the fluid declines as the pressure required by vertical lift performance becomes lower as there is less oil produced inside the tubing.

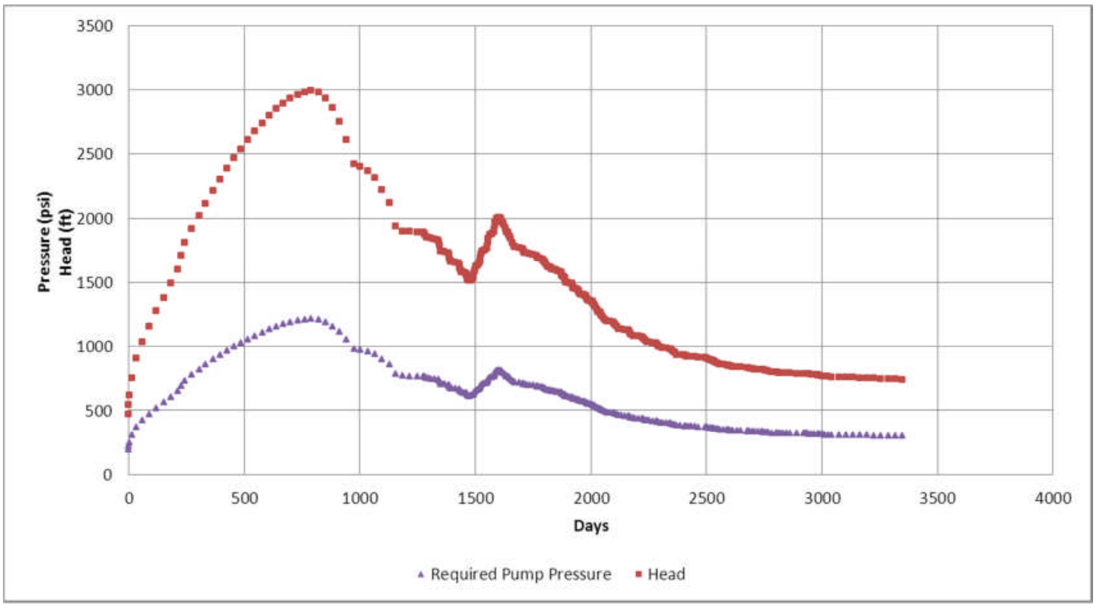

Figure 5.3: Required pump pressure and head for solution-gas drive reservoir.

5.1.1 Fixed Speed Pump

In order to determine the appropriate number of pump stages, the pumping head is plotted as a function of pump intake rate on pump curve at 60 Hz operating frequency in Figures 5.4 and 5.5. Note that the pump intake rate is different from liquid production rate at surface since it has dissolved gas in it. The oil intake rate is simply calculated by multiplying the surface oil rate by the formation volume factor at the pump intake pressure, and the water intake rate can be calculated in the same fashion. However, there is no water production in this case.

Two pump sizes, P11 and P17, were selected to compare the performance in fixed speed application. The shaded area shown in Figures 5.4 and 5.5 is the recommended operating range (ROR). The pump run-life can be extended if the pump is operated in this shaded area. The numbers of stages shown in the figures are the published stages as listed in the pump catalog. In our study, we assume that a high efficiency gas separator is deployed in the well and no free gas enters the first stage of the pump.

For fixed speed, an ESP is operated at either 50 or 60 Hz only, depending on power source. The pump stages are selected based on the maximum head and liquid rate. It is a good practice to add a few extra stages to handle worst-case scenario. Therefore, a safety factor needs to be applied by choosing the number of stages higher than the calculated one.

During the production of liquid from the reservoir, the maximum head required to deliver the liquid to surface is around 3,000 ft as derived from Figure 4.3. If P11 model is used, Figure 5.4 suggests that 130 stages should be chosen in order to provide a safety factor for pump operation. However, if P17 model is to be used, only 58 stages are needed as shown in Figure 5.5. As the liquid intake rate is between 50 to 1450 RB/D as shown by the red line, P11 model should be selected because its recommended operating range is from 750 to 1500 RB/day while the recommended operating range of P17 model is from 1,000 to 2,400 RB/day. The ROR of pump P11 covers a wider range of liquid intake rate than that of P17 pump. At late time, as the reservoir pressure is depleted, the liquid production declines and becomes lower than the recommended operating range. At this point, a smaller ESP is recommended to accommodate the well conditions.

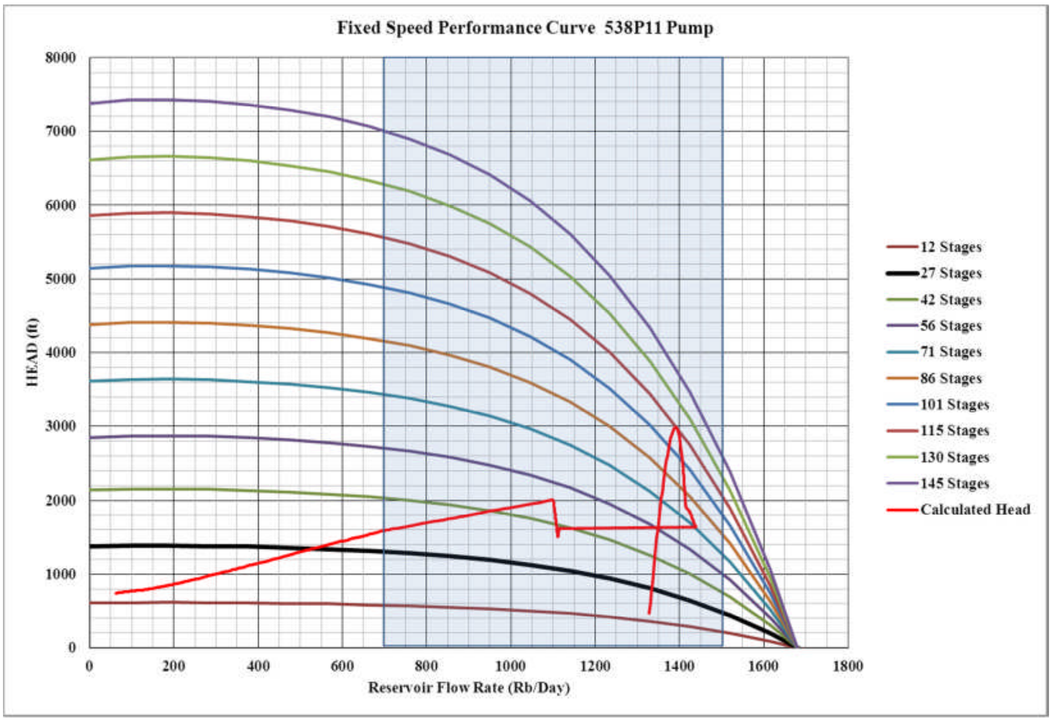

Figure 5.4: Fixed speed pump design for 60-Hz 538P11 pump model

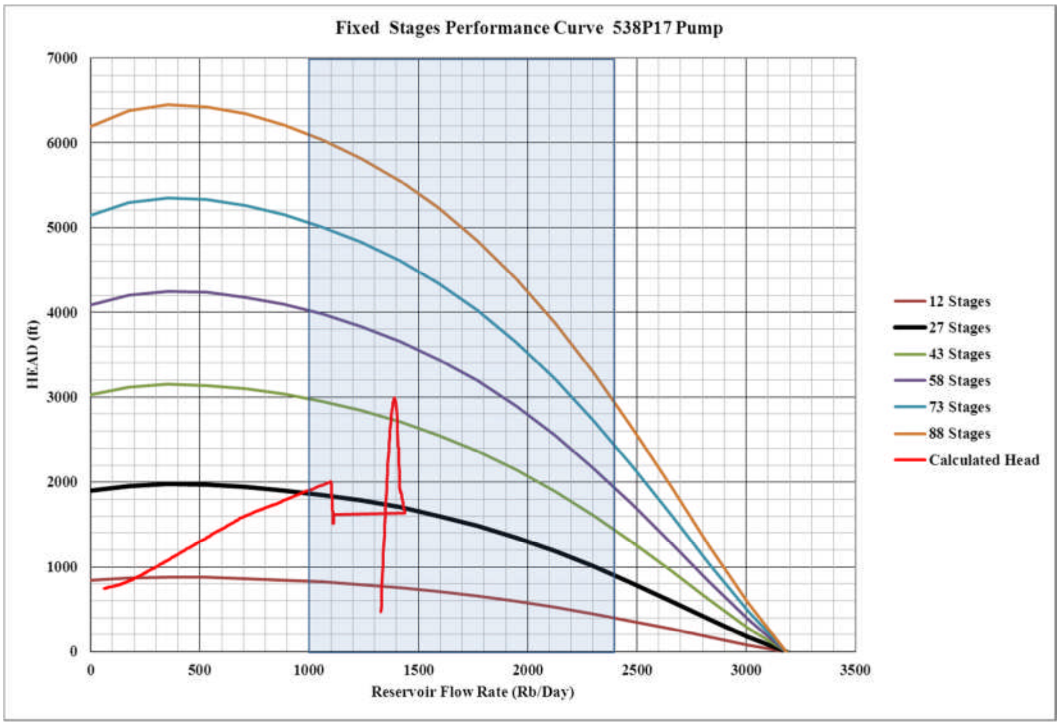

Figure 5.5: Fixed speed pump design for 60-Hz 538P17 pump model.

5.1.2 Variable Speed Drive Pump

As seen in Figure 5.3, the head requirement at early time is small since the bottom-hole pressure from the reservoir inflow is still high. Thus, there is not much need to pump the bottom-hole pressure up. If a fixed speed pump is used, it will generate excessive pressure at the wellhead because there are too many pump stages. Therefore, a variable speed drive pump should be evaluated. With variable speed drive (VSD), the speed can be adjusted to reduce the energy losses in the system. In another word, the system will be operated with more efficiency.

In this section, variable speed application is considered and will be compared with fixed speed design. The variable speed pump performance curves for 58 stages of model P17 and those for 115 stages of pump P11 are plotted in Figures 5.6 and 5.7, respectively. The two pumps are designed to operate at minimum frequency of 40 Hz and maximum frequency of 60 Hz.

From the plot, it is clearly shown that at the early production stage, pump P11 is slightly operating in the up-thrust region, compared to pump P17 which can handle the liquid rate better. As the liquid rate becomes smaller, the frequency of both pumps can be reduced to accommodate lesser volume of pumping liquid. With variable speed drive, pump P11 can handle the liquid rate down to 820 RB/day at 40 Hz. in comparison with minimum liquid rate of 750 RB/day when a fixed speed pump is used. On the other hand, variable speed drive enables pump P17 to handle a minimum liquid rate of 800 RB/day at 40 Hz. in comparison with minimum liquid rate of 1,000 RB/day when a fixed speed pump is used. Therefore, if a variable speed pump is to be used, pump P17 is better suited to the producing conditions. At late times, the calculated head falls outside the ROR because of reservoir depletion. It is advisable to use a smaller ESP at this point to prevent the down-thrust and extend the pump life.

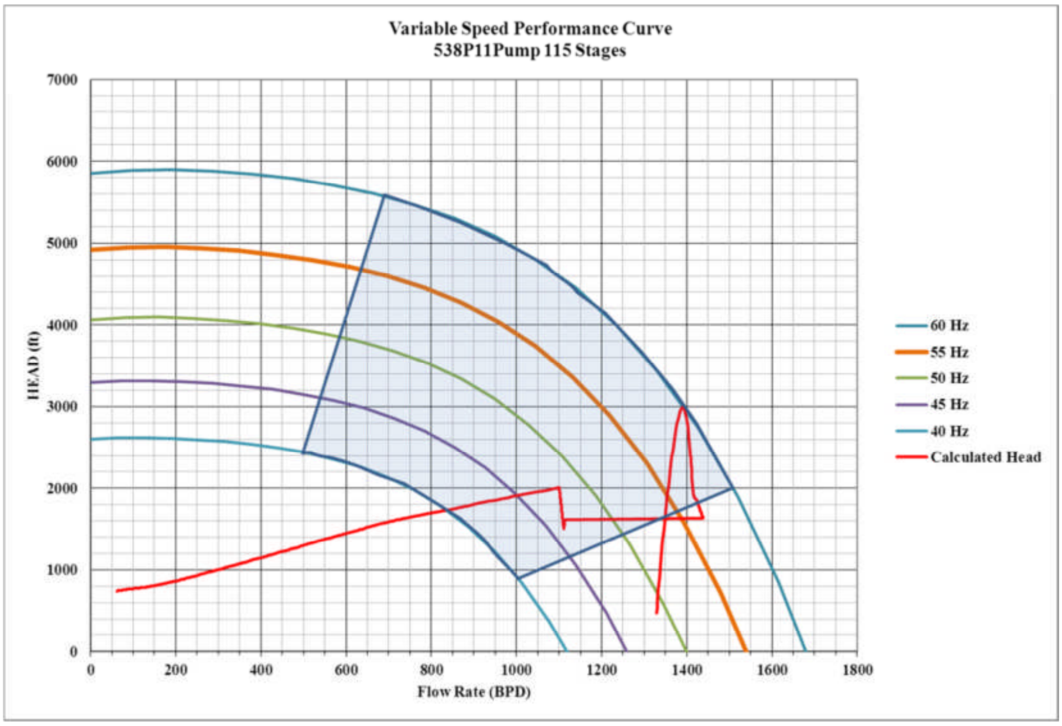

Figure 5.6: Variable speed pump design for pump 538P11 for solution-gas-drive

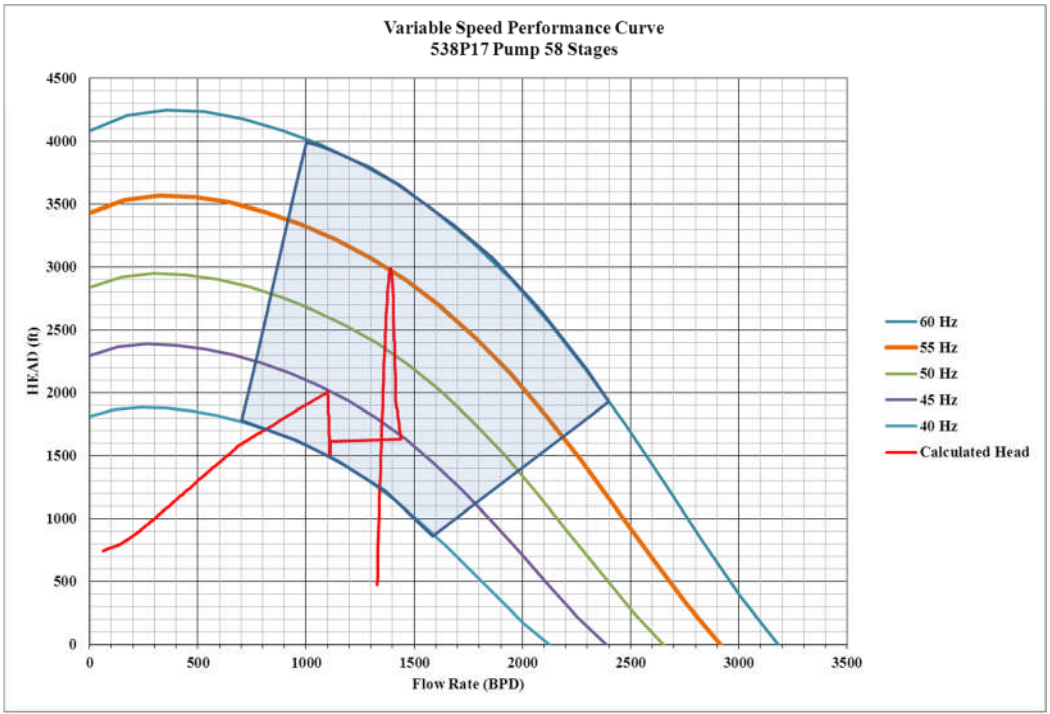

Figure 5.7: Variable speed pump design for pump 538P17 for solution-gas-drive.

5.2 Base Case for Water-Drive Reservoir

In this section, the performance of oil production from a reservoir supported by a bottom aquifer is investigated. The aquifer size is 1, 5, and 10 times the pore volume of the oil reservoir. Similar to the simulation for solution-gas-drive reservoir, the control parameters are maximum liquid production rate of 1,000 STB/D, minimum bottom-hole pressure of 200 psia, economic water cut 95%, and producing time of 10 years. Vertical lift performance tables are not incorporated in reservoir simulation since one of the purposes of running the simulation is to observe the behavior of bottom-hole pressure from inflow performance perspective in order to determine the suction pressure in the design of a pump to boost the pressure of the produced fluids to the surface.

As depicted in Figures 5.8, liquid production rate from the reservoir is maintained at 1,000 STB/D for the entire life of the well. However, the water cut increases from 0 to more than 80%, meaning that the oil production decreases from 1,000 STB/D to less than 200 STB/D. The bottom-hole pressure declines at a moderate rate at the beginning and starts to decline at a slow pace at 1,800 days due to pressure support from the water aquifer. For the gas-oil ratio, it is more or less constant for the entire life of the well due to small changes in reservoir pressure.

The values of liquid rate, gas-oil ratio, and water cut from Figure 5.8 are used to determine the bottom-hole flowing pressure in the same fashion as the one for solution-gas-drive reservoir. This calculated bottom-hole pressure is shown in Figure 5.9 as the vertical lift performance curve and is actually the discharge pressure of a pump. Also shown in Figure 5.9 is the bottom-hole pressure calculated from inflow of fluids from the reservoir into the wellbore which is actually the suction pressure.

The head which is determined by dividing the difference between the discharge pressure and suction pressure by the fluid gravity is plotted in Figure 5.10. At early stage of production, as oil is produced from the reservoir at constant liquid rate, the head increases at a moderate rate due to the moderate reduction in the suction pressure while the required bottom-hole pressure for vertical lift increases. Later on, the required increases at a slow rate because of a slow reduction in the suction pressure while the required bottom-hole pressure for vertical lift still increases due to higher water cut.

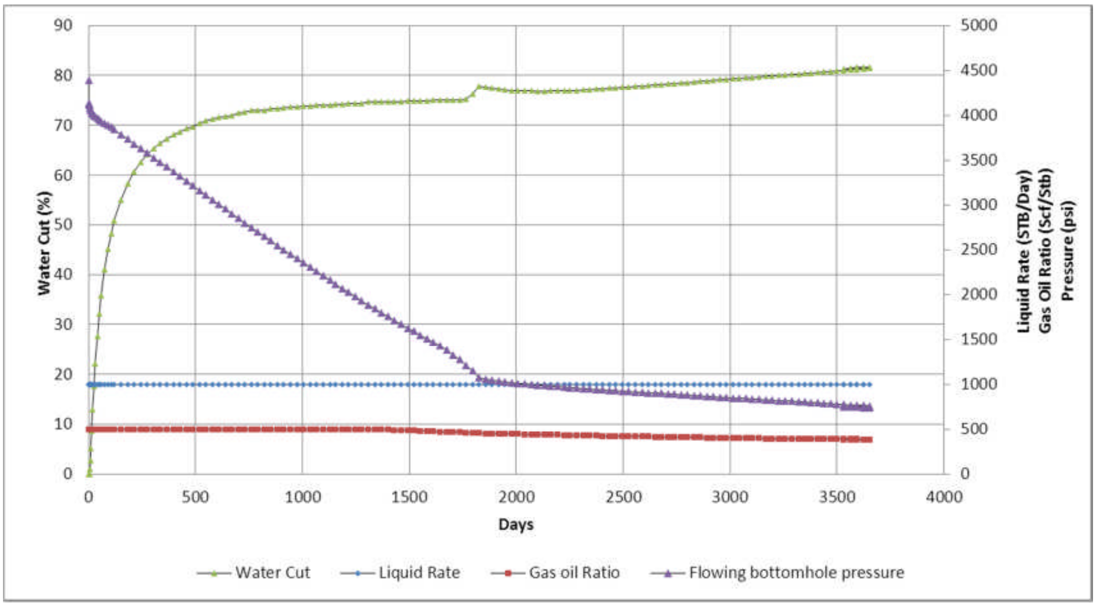

Figure 5.8: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water-drive reservoir.

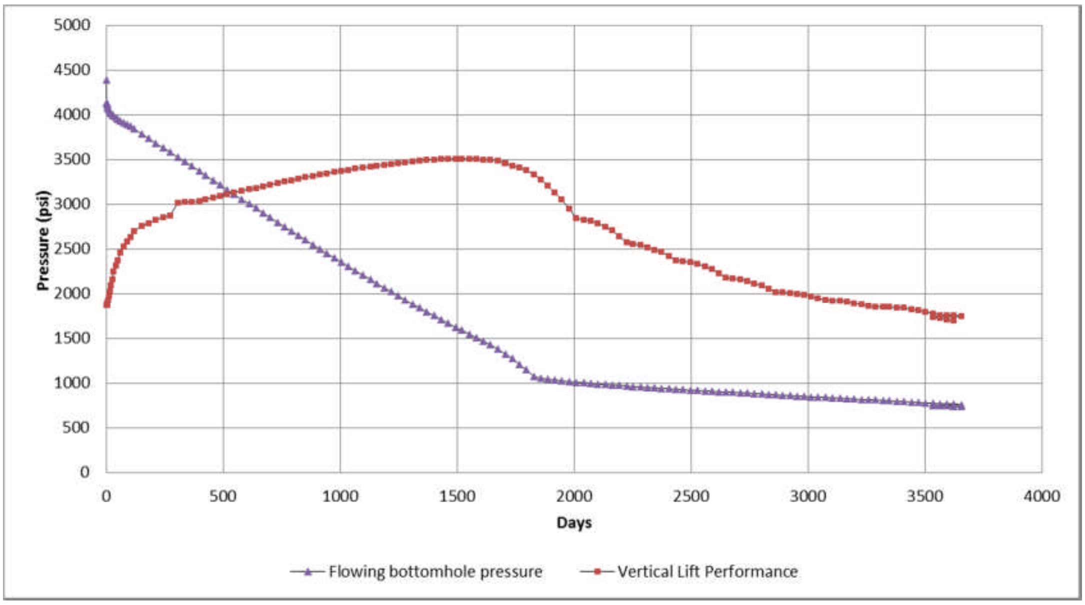

Figure 5.9: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water-drive reservoir.

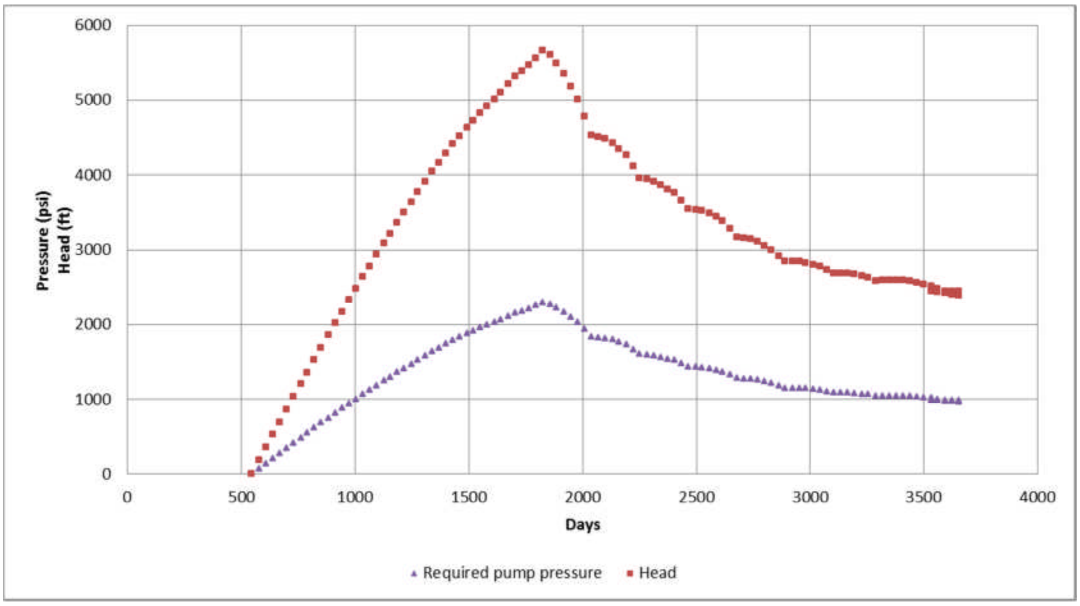

Figure 5.10: Required pump pressure and head for solution-gas drive reservoir.

5.1.2 Fixed Speed Pump

In order to determine the appropriate number of pump stages, the pumping head is plotted as a function of pump intake rate on pump curve at 60 Hz operating frequency in Figures 5.11 and 5.12. Note that the pump intake rate is different from liquid production rate at surface since it has dissolved gas in it. The oil intake rate is simply calculated by multiplying the surface oil rate by the formation volume factor at the pump intake pressure, and the water intake rate can be calculated in the same fashion. Two pump sizes, P11 and P17, were selected to compare the performance in fixed speed application. The shaded area shown in Figures 5.11 and 5.12 is the recommended operating range (ROR). During the production of liquid from the reservoir, the maximum head required to deliver the liquid to surface is around 8,000 ft as derived from Figure 5.10. If P11 model is used, Figure 5.11 suggests that 334 stages should be chosen in order to provide a safety factor for pump operation. However, if P17 model is to be used, only 134 stages are needed as shown in Figure 5.12. As the liquid intake rate is between 1290 to 1420 RB/D as shown by the red line, either pump can be chosen as the liquid rate falls within the recommended operating range. Nonetheless, pump P17 with 134 stages should be selected because it requires a smaller number of stages.

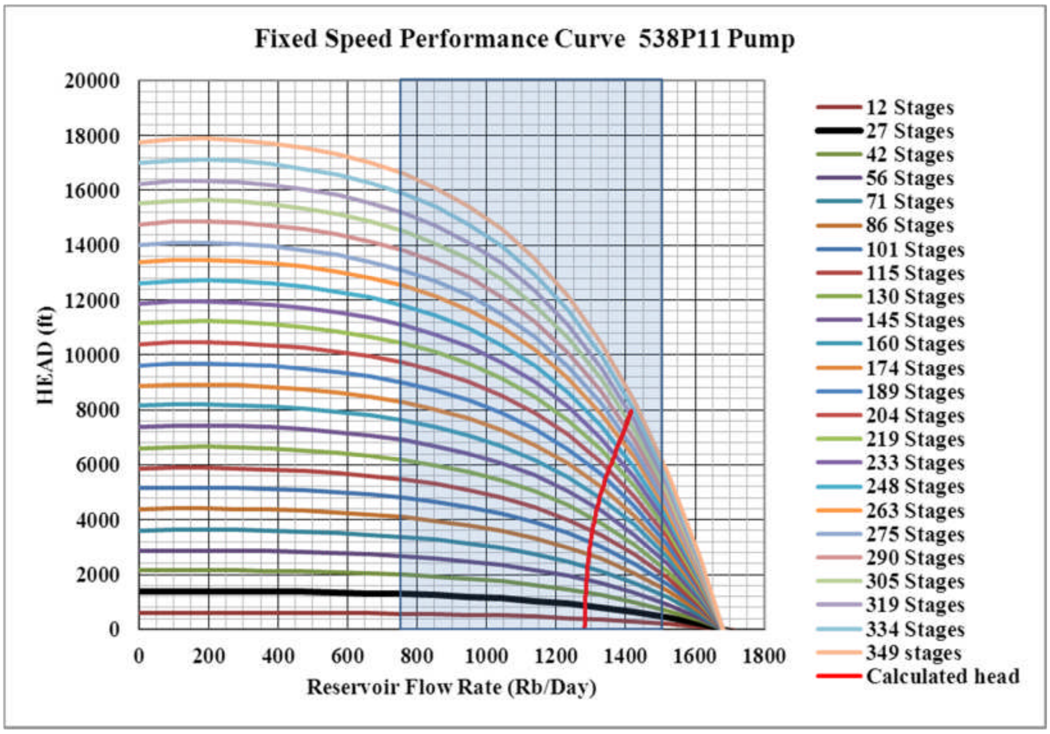

Figure 5.11: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir.

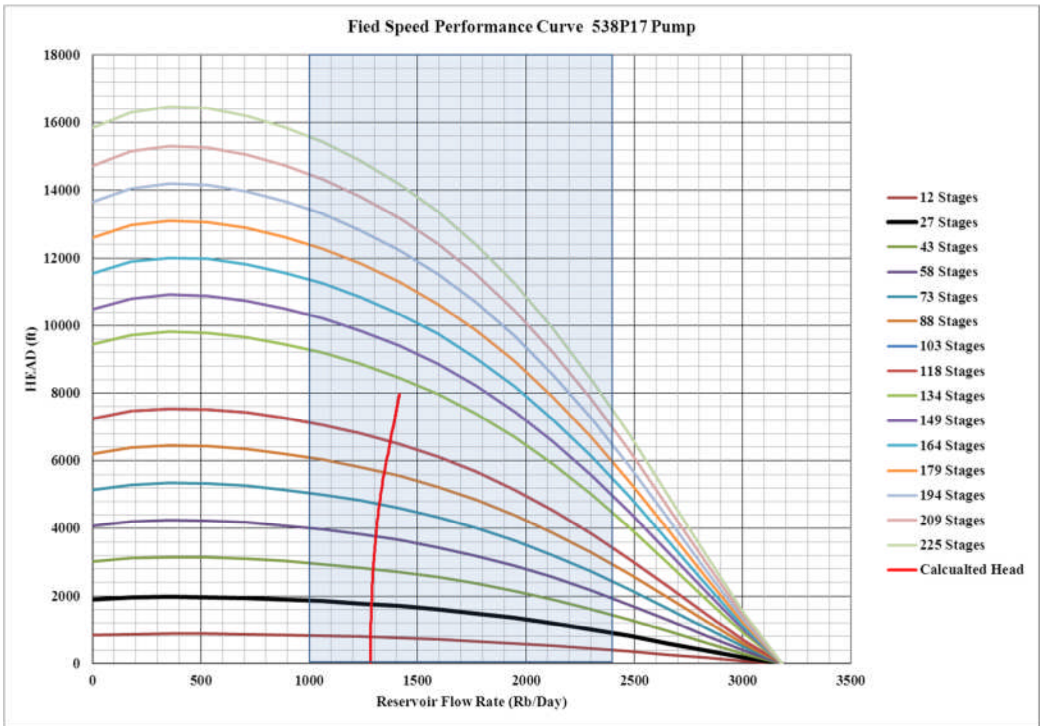

Figure 5.12: Fixed speed pump design for 60-Hz 538P17 pump model for water-drive reservoir.

5.2.2 Variable Speed Drive Pump

In this section, variable speed application is considered and will be compared with fixed speed design. The variable speed pump performance curves for 334 stages of model P17 and those for 134 stages of pump P11 are plotted in Figures 5.13 and 5.14, respectively. The two pumps are designed to operate at minimum frequency of 40 Hz and maximum frequency of 60 Hz. Since pump P17 requires a smaller number of stages, it is selected for the case. From the plot, it is clearly shown that at the early production stage, pump P11 is slightly operating in the up-thrust region, compared to pump P17 which can handle the liquid rate better. With variable speed drive, pump P11 can handle the liquid rate in the range of 1,500 RB/day at 60 Hz down to 500 RB/day at 40 Hz. in comparison with 1,500 down to 750 RB/day at a fixed speed of 60 Hz. On the other hand, variable speed drive enables pump P17 to handle liquid rate of 2,400 RB/day at 60 Hz. down to 650 RB/day at 40 Hz. in comparison with liquid rate of 2,400 RB/day down to 1,000 RB/day when a fixed speed of 60 Hz. is used.

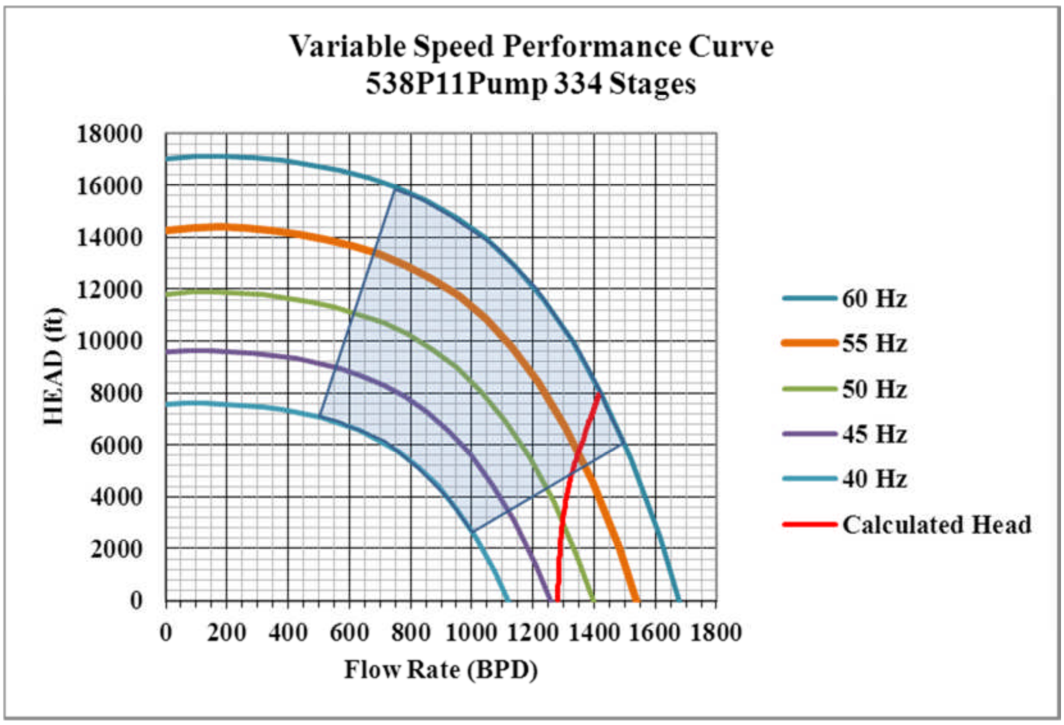

Figure 5.13: Variable speed pump design for pump 538P11 for water-drive reservoir.

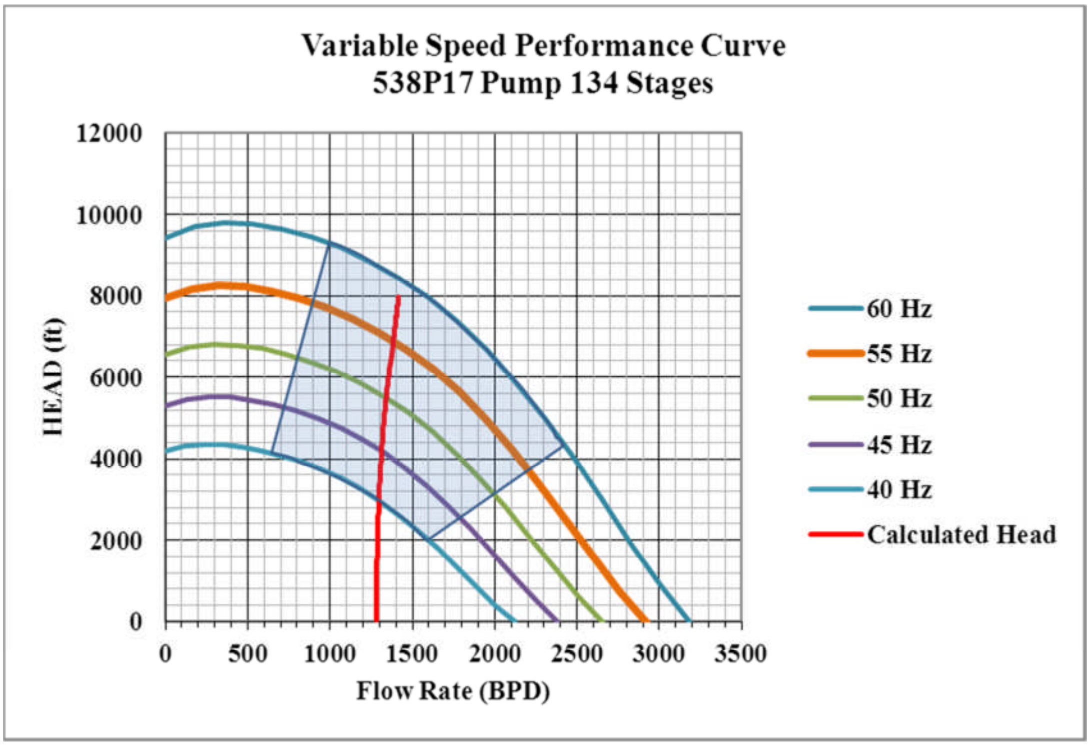

Figure 5.14: Variable speed pump design for pump 538P11 for water-drive reservoir.

5.3 Case Studies for Solution-Gas Drive Reservoir

In this section, the reservoir parameters such as the reservoir pressure, reservoir temperature, reservoir depth, initial solution gas-oil ratio are varied. The reservoir is perforated 25 ft. from the total thickness of 50 ft. The perforation interval is 15 ft. away from the top of reservoir and 10 ft. away from the bottom of the reservoir. The full factorial combination of sensitivity analysis is applied to determine fixed and variable speed of pump stage design for various reservoir and fluid conditions. The designs are then compared with commercial software designs.

In the case of solution-gas drive reservoir, nine combinations of initial solution gas-oil ratio (GOR) 100, 250 and 500 scf/STB and reservoir depth of 5,000, 7,000 and 10,000 ft. are obtained as shown in Table 5.1 to investigate the influence of solution-gas with pump stage calculation. Note that the reservoir pressure and temperature change accordingly with the depth of the reservoir and that the bubble-point pressure of the reservoir fluid varies accordingly to the initial solution gas-oil ratio.

Table 5.1: Varied parameters of solution-gas-drive reservoir

Case no.	Reservoir depth (ft.)	Reservoir pressure (psi)	Reservoir temperature (°F)	Gas-oil ratio (scf/STB)	Bubble point pressure (psia)
1	5,000	2,200	168	100	510
2	5,000	2,200	168	250	1110
3	5,000	2,200	168	500	1934
4	7,000	3,300	200	100	543
5	7,000	3,300	200	250	1182
6	7,000	3,300	200	500	2061
7	10,000	4,400	220	100	588
8	10,000	4,400	220	250	1282
9	10,000	4,400	220	500	2239

5.2.2 Solution-gas Drive Reservoir at Reservoir Depth 5,000 ft.

Case 1: Reservoir pressure 2,200 psi, reservoir temperature 168°F, and initial solution GOR 100 scf/STB.

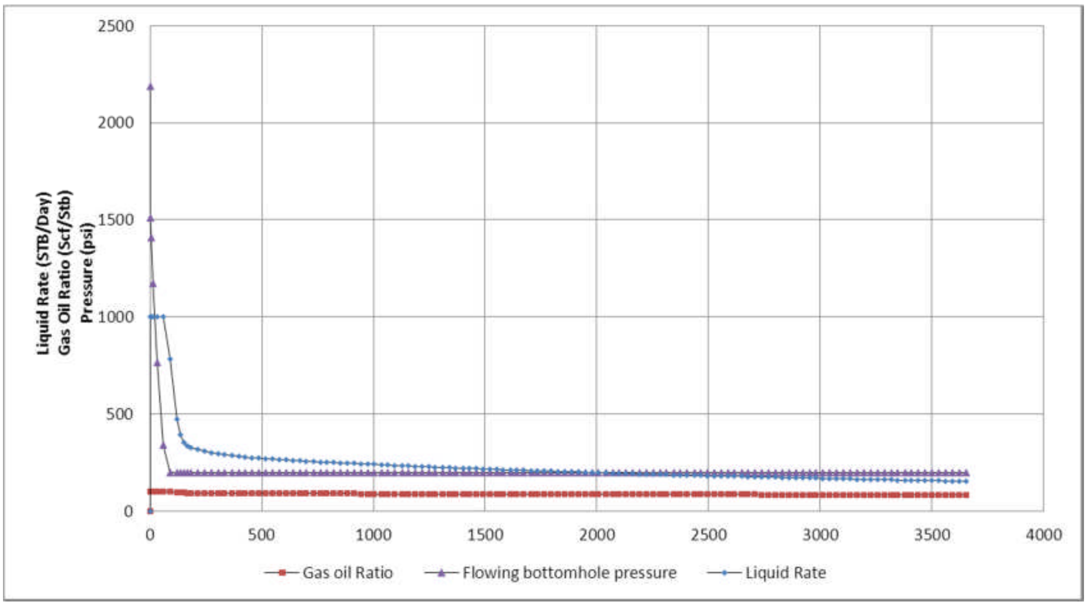

Figure 5.15: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for solution-gas drive reservoir in case 1.

The simulation results of initial solution gas-oil ratio of 100 scf/STB are illustrated in Figure 5.15. Liquid production rate from the reservoir is maintained at 1,000 STB/D for only 60 days and then, it sharply drops to 400 STB/D. Once the bottom-hole pressure cannot be reduced any further, the liquid production rate dramatically decreases to 150 STB/D with the minimum flowing bottom-hole pressure limit of 200 psia.

Figure 5.16 depicts the plot for flowing bottom-hole pressure from reservoir inflow via simulation and bottom-hole pressure from vertical lift performance. The difference between these two curvess is the head requirement to lift the fluid to the surface as plotted in Figure 5.17.

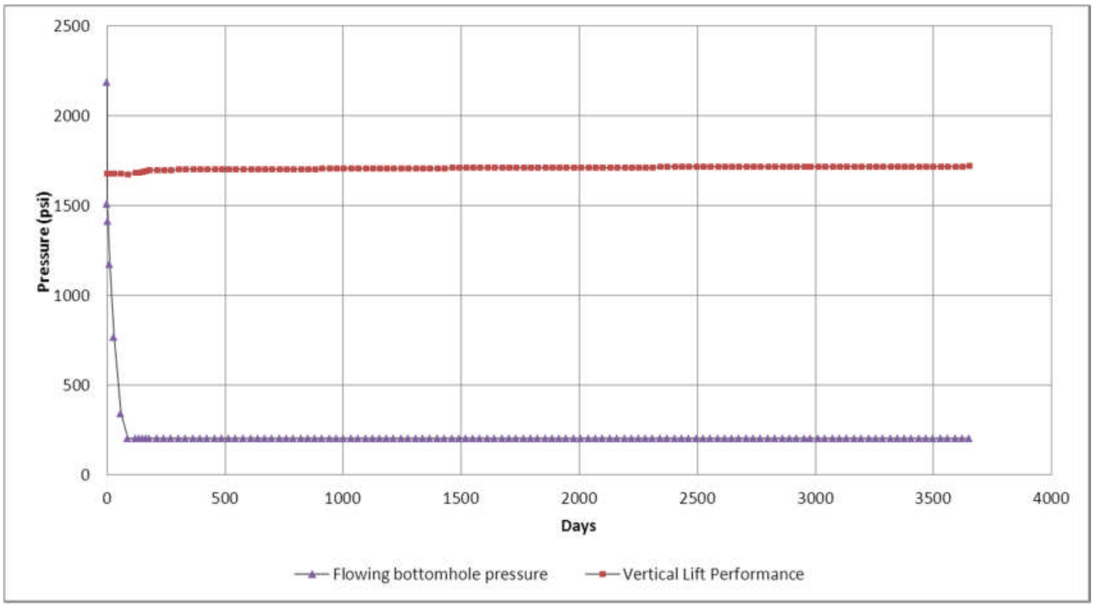

Figure 5.16: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for solution-gas drive in case 1

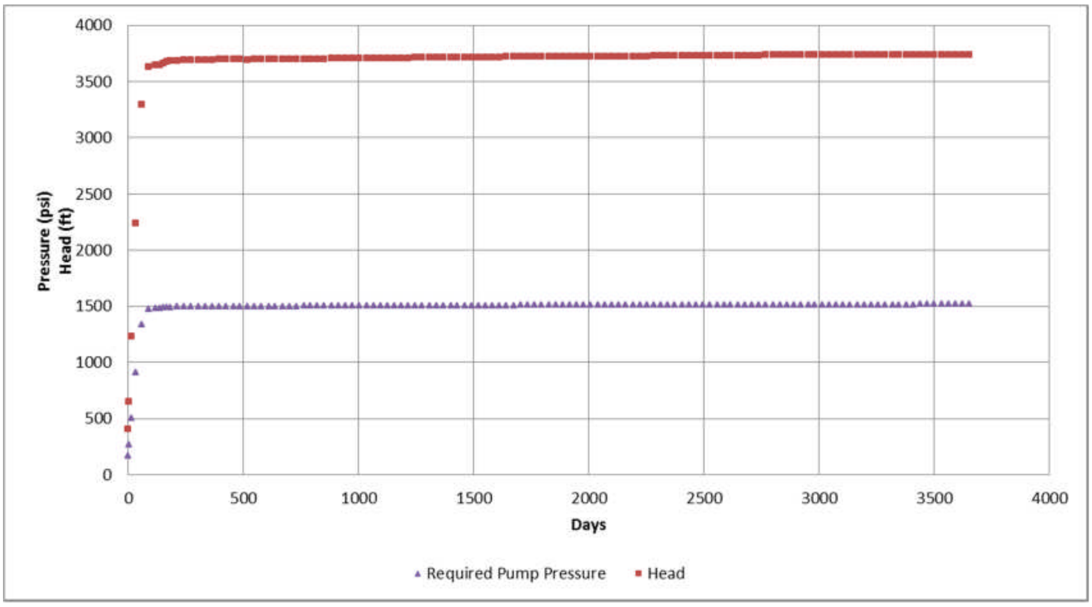

Figure 5.17: Required pump pressure and head for solution-gas drive reservoir in case 1.

At early production stage, the head rapidly increases because of the reduction in the suction pressure while the required bottom-hole pressure for vertical lift is high. As soon as the reservoir pressure drops to the minimum limit of 200 psia, the head starts to remain more or less constant because there is no significant change in oil and gas production rate.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 1 is P11 with 86 stages as shown in the Figure 5.18. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 86 stages as depicted in Figure 5.19.

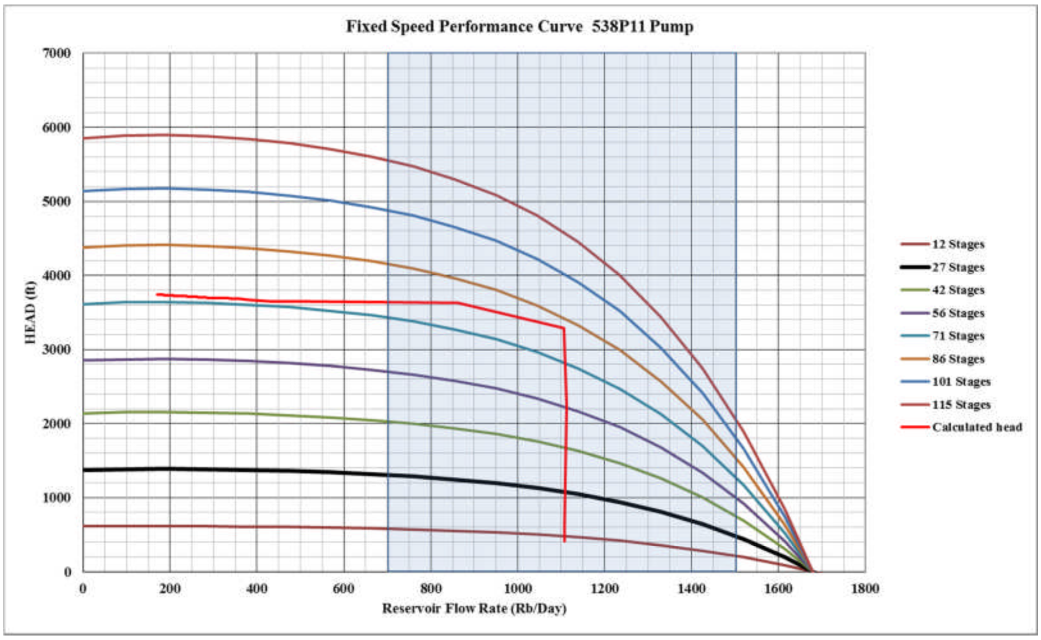

Figure 5.18: Fixed speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 1.

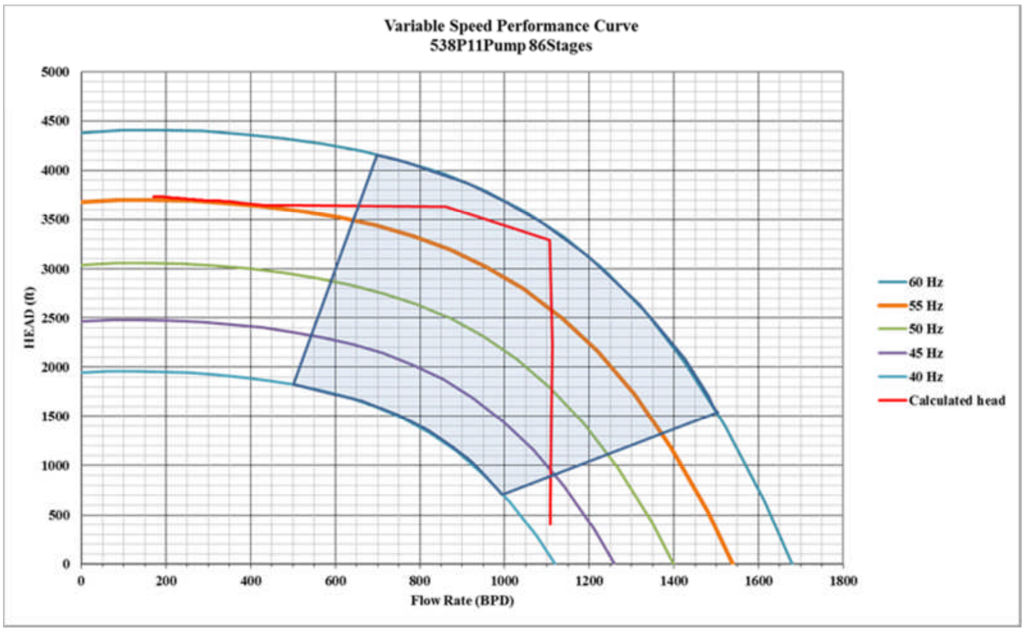

Figure 5.19: Variable speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 1.

Case 2: Reservoir pressure 2,200 psi, reservoir temperature 168°F, and initial solution GOR 250 scf/STB.

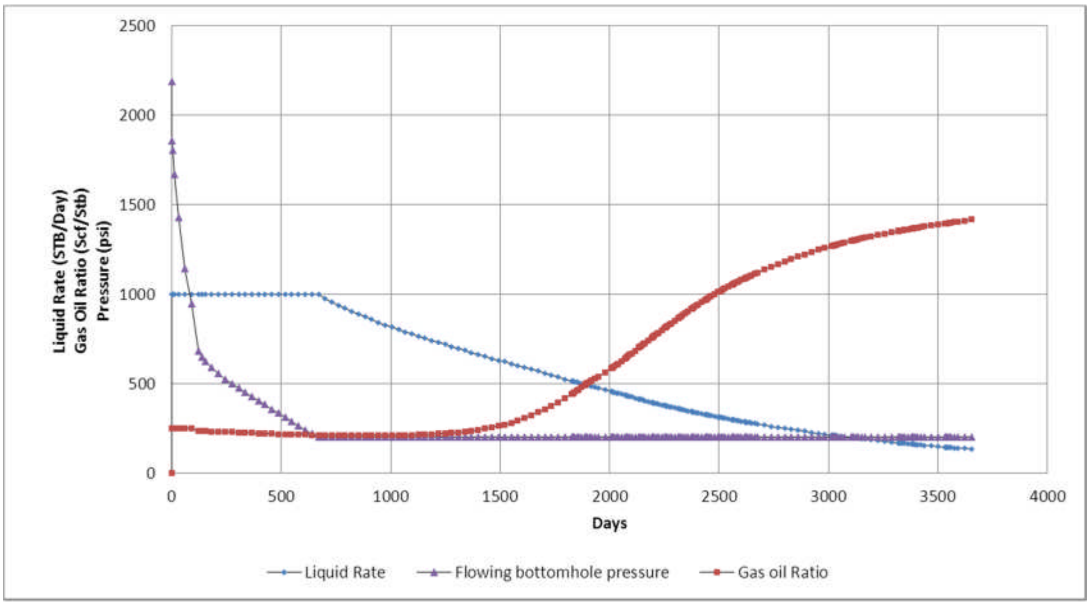

Figure 5.20: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for solution-gas drive reservoir in case 2.

Figure 5.20 depicts the simulation results for initial solution gas-oil ratio of 250 scf/STB. Fluid production can be sustained at 1,000 STB/D for 640 days, and then, it steadily declines until reaching 150 STB/D with minimum flowing bottom-hole pressure at 200 psia. As the reservoir pressure drops below the bubble point of 1,110 psia, producing gas-oil ratio increases gradually.

The plot for flowing bottom-hole pressure from simulation and the bottom-hole pressure determined from vertical lift performance is shown in Figure 5.21. At the primary production stage before 500 days, the differential pressure is high because there is a high amount of liquid production in the tubing, resulting in large head required to lift the fluid as shown in Figure 5.22. Since there is a high gas-oil ratio in the tubing after 500 days, the pressure required for vertical lift and the head requirement reduces accordingly.

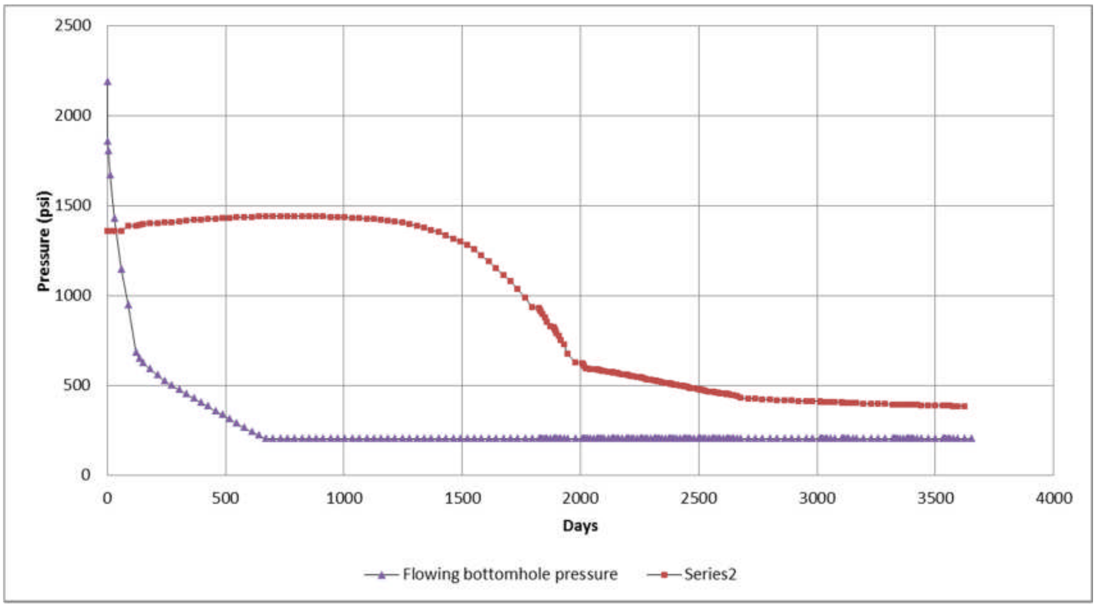

Figure 5.21: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for solution-gas drive in case 2.

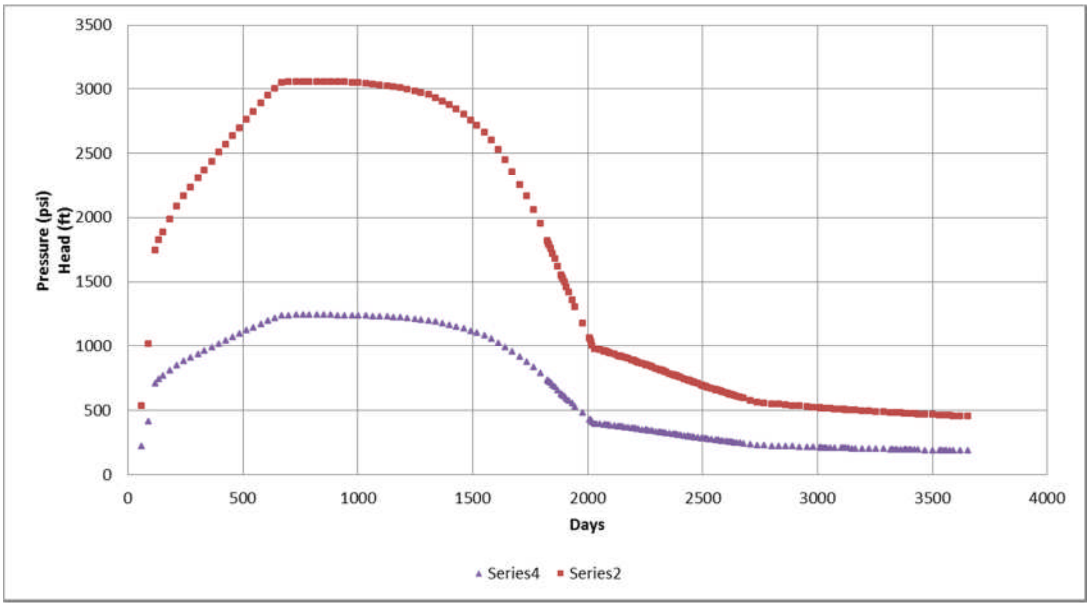

Figure 5.22: Required pump pressure and head for solution-gas drive reservoir in case 2.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 2 is P11 with 86 stages as shown in the Figure 5.23. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P17 with 71 stages as depicted in Figure 5.24

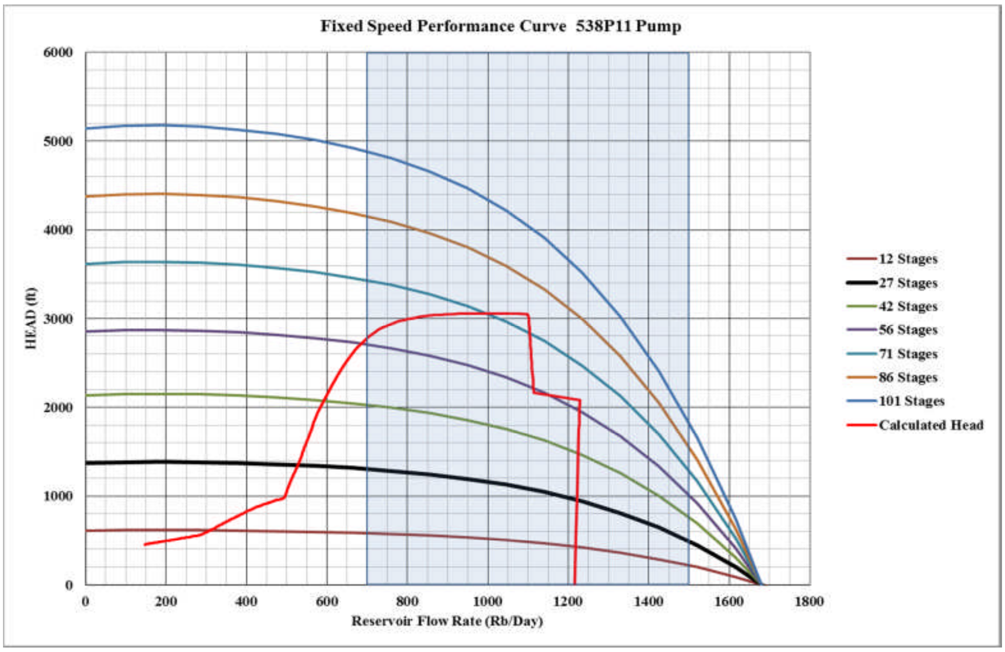

Figure 5.23: Fixed speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 2.

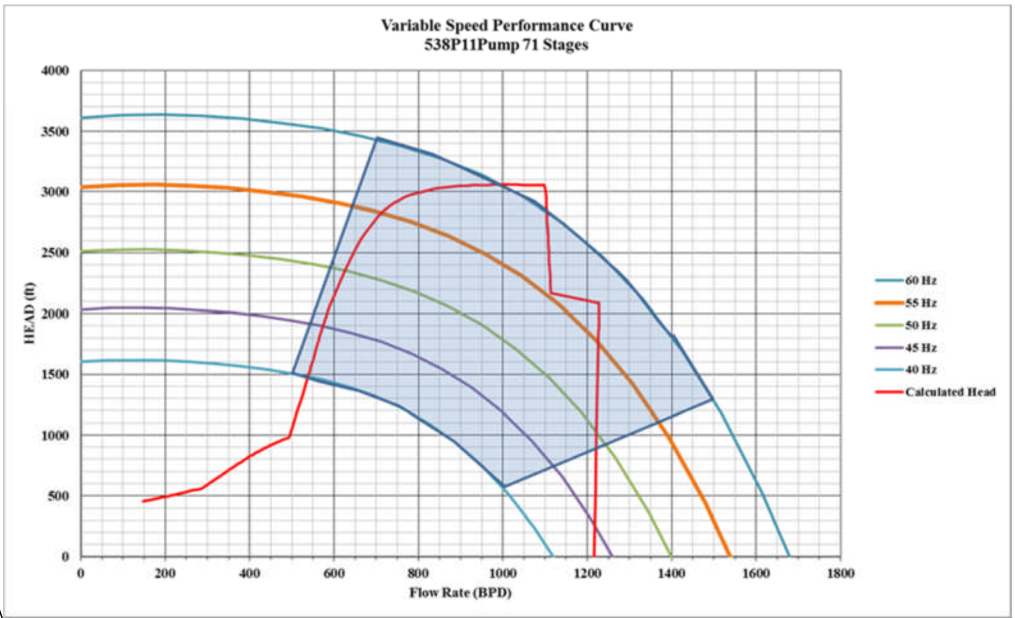

Figure 5.24: Variable speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 2.

Case 3: Reservoir pressure 2,200 psi, reservoir temperature 168°F, and initial solution GOR 500 scf/STB.

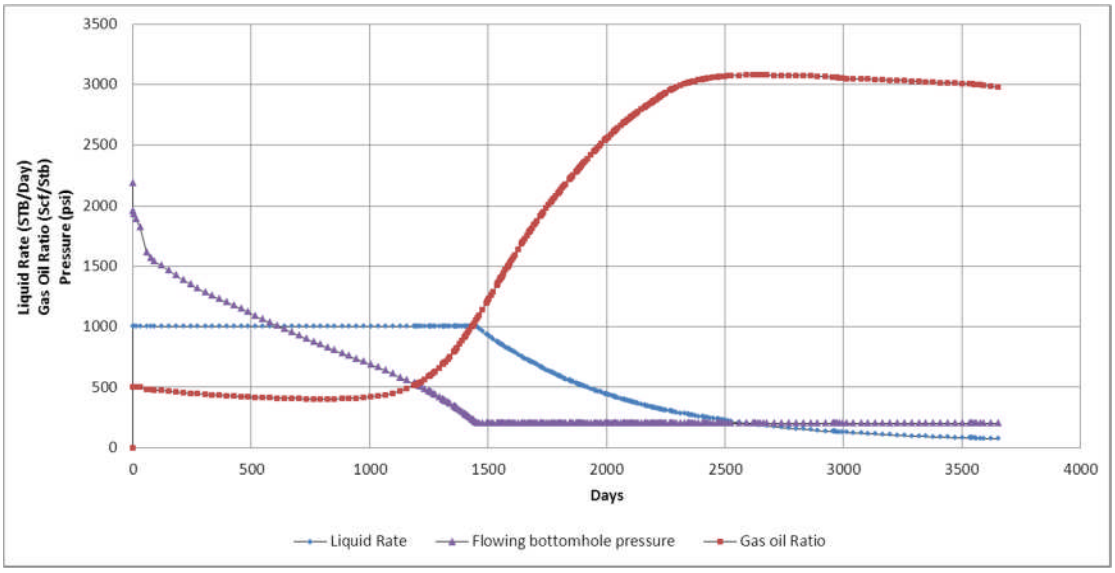

Figure 5.25: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for solution-gas drive reservoir in case 3.

The simulation result of initial solution gas-oil ratio of 500 scf/STB is demonstrated in Figure 5.25. The fluid is produced and maintained at 1,000 STB/D for 1,400 days. Later on, the production rate declines as the bottom-hole pressure drops to the minimum limit of 200 psia.

The gas-oil ratio is more or less constant over the first 1,000 days as the bottom-hole pressures declines. After that, the gas-oil ratio increases as more and more gas is liberated gas inside the reservoir and starts flowing into the wellbore. Finally, the amount of gas-oil ratio slightly decreases as the liberated gas that flows into the wellbore and the dissolved gas that is produced with the oil can expand less due to lower reservoir pressure at late time.

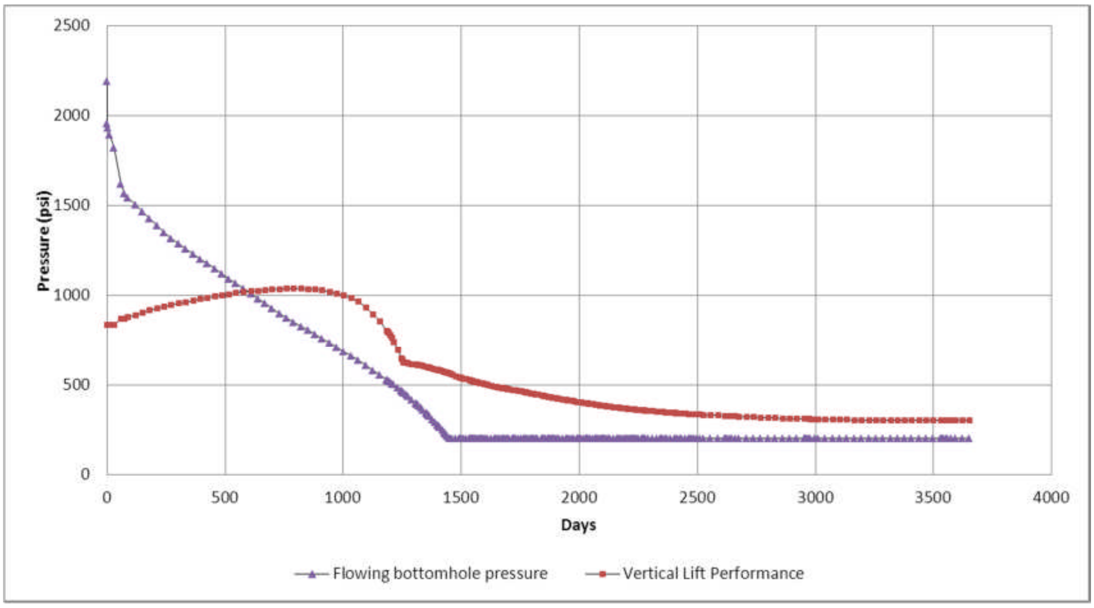

Figure 5.26: Bottom-hole pressure from ECLIPSE and
Vertical Lift Performance for solution-gas drive in case 3.

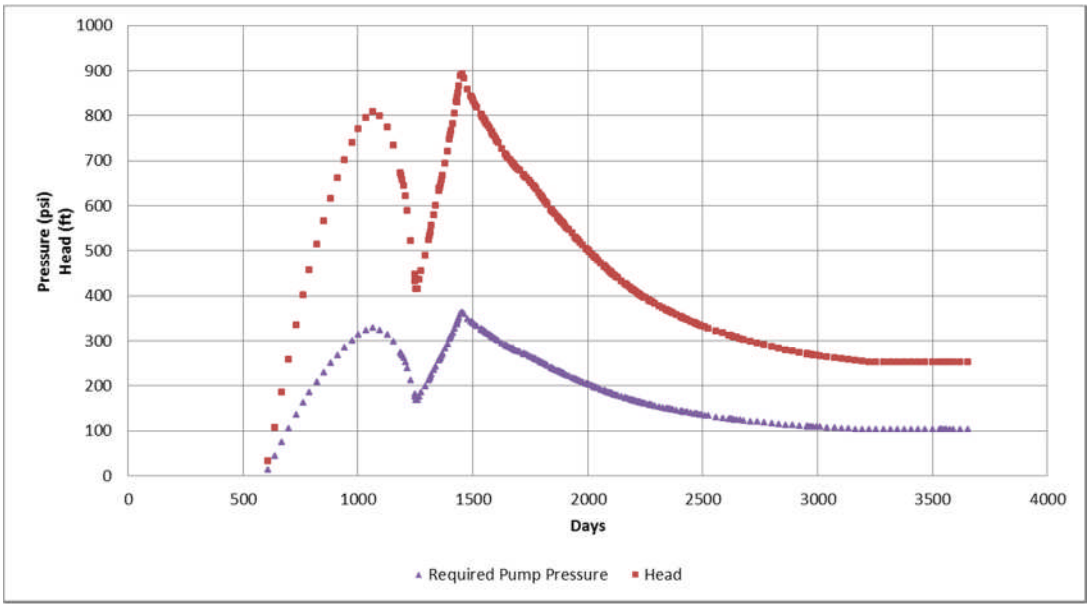

Figure 5.27: Require pump pressure and head
for solution-gas drive reservoir in case 3.

The difference between the flowing bottom-hole pressure and bottom-hole pressure from tubing performance as shown in Figure 5.26 is quite small due to high amount of gas production in the tubing. The less head requirement at late time as shown in Figure 5.27 is due to the fact that there is more free gas liberated from the solution as the reservoir pressure declines.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 3 is P11 with 42 stages as shown in the Figure 5.28. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 27 stages as depicted in Figure 5.29.

In summary, case 1 which has initial solution gas-oil ratio of 100 scf/STB has the smallest effect of solution gas in the entire life of reservoir as shown in Figures 5.16 and 5.17. The head requirement is initially high and stays at the same level until abandonment. In contrast, case 2 with an initial solution gas-oil ratio 250 scf/STB has small head requirement at the beginning, relatively large head in the middle, and small head at late time, resulting from the negative effect of the decrease in reservoir pressure and positive effect of liberated gas. A similar trend can be observed in case 3. However, there is no head requirement at early time in this case since there is enough gas-oil ratio flowing in tubing.

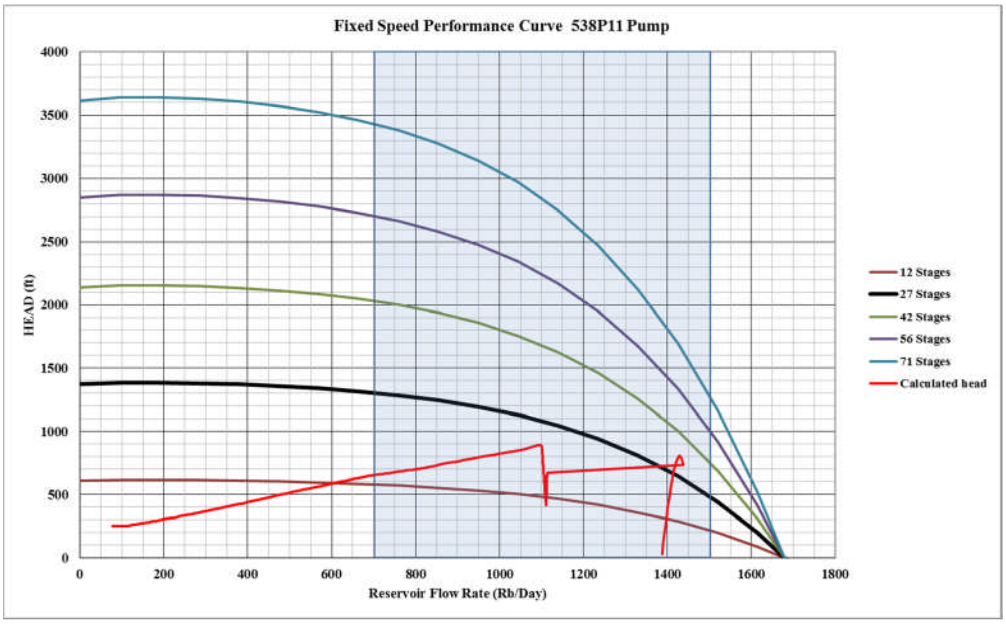

Figure 5.28: Fixed speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 3.

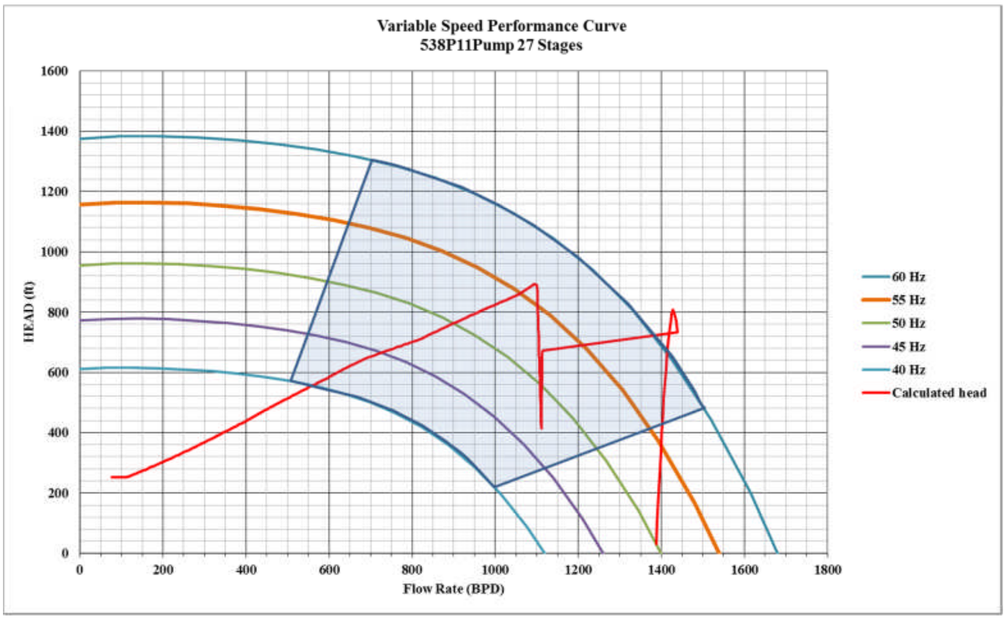

Figure 5.29: Variable speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 3.

5.3.2 Solution-gas Drive Reservoir at Reservoir Depth 7,000 ft.

Case 4: Reservoir pressure 3,300 psi, reservoir temperature 200°F, and initial solution GOR 100 scf/STB.

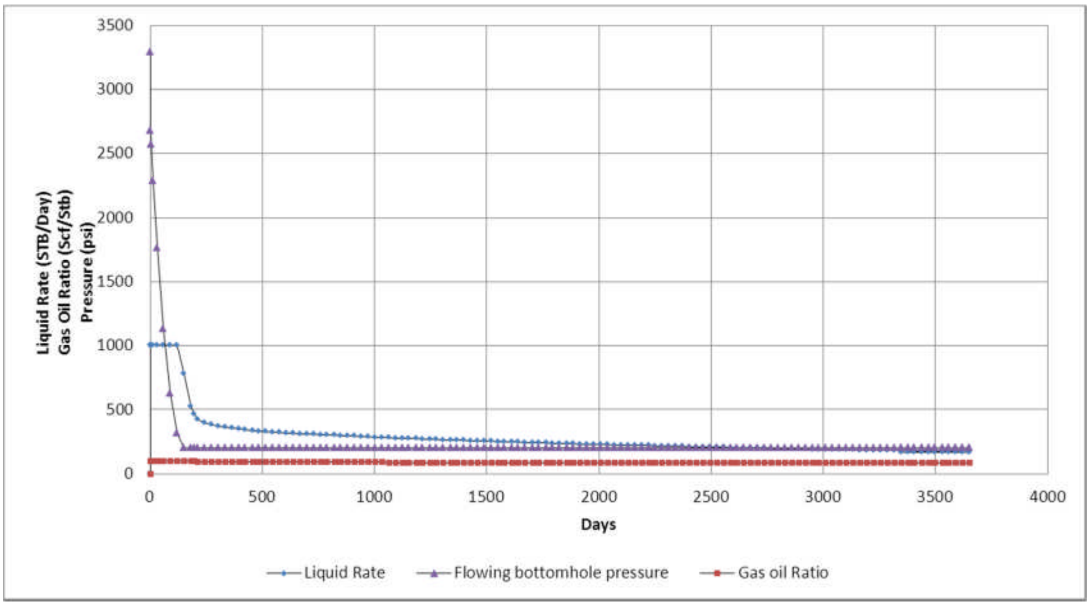

Figure 5.30: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for solution-gas drive reservoir in case 4.

This section is similar to the previous cases except for the reservoir depth, reservoir pressure and temperature. Figure 5.30 represents the simulation result for reservoir pressure 3,300 psi and reservoir temperature 200°F. For the case of the lowest initial solution gas-oil ratio, the production target rate can be sustained for a slightly longer from time 60 days to 90 days when compared to case 1 in which the reservoir pressure is higher.

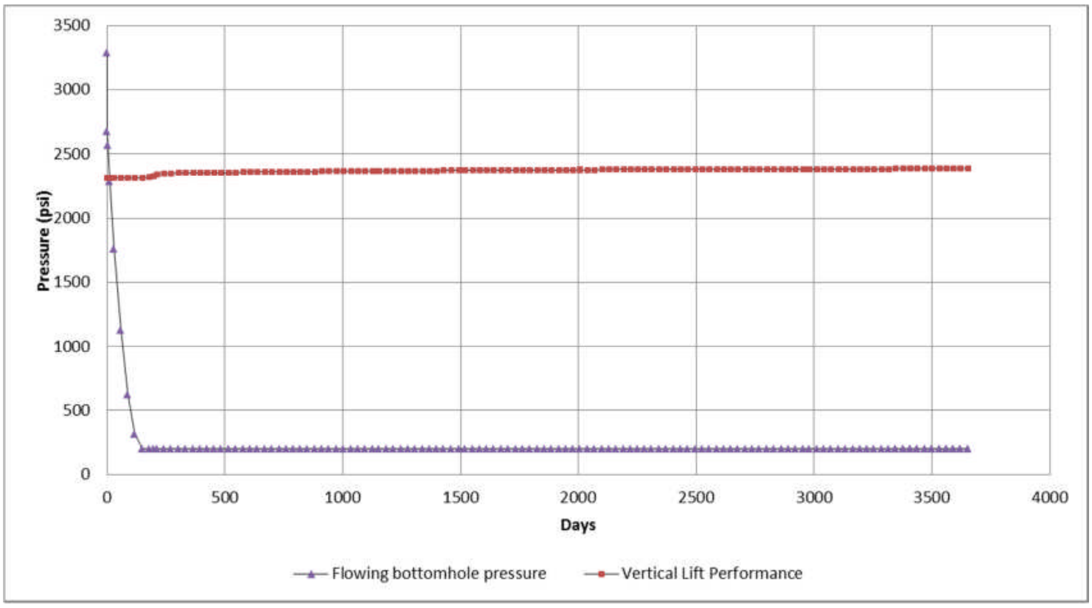

Figure 5.31: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for solution-gas drive reservoir in case 4.

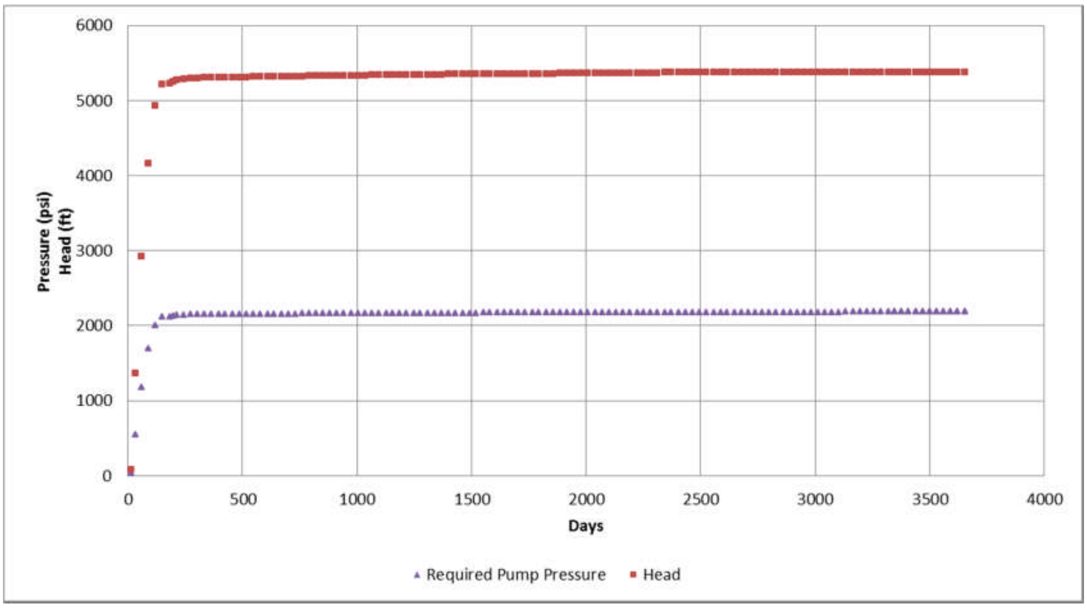

Figure 5.32: Required pump pressure and head for solution-gas drive reservoir in case 4.

The flowing bottom-hole pressure, vertical lift performance, required pump pressure and head are illustrated in Figures 5.21 and 5.32. They have the same trend as those in case 1. The head dramatically at the beginning because of the reduction in suction pressure and later remains constant and high due to a small amount of solution gas-oil ratio.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 4 is P11 with 130 stages as shown in the Figure 5.33. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 115 stages as depicted in Figure 5.34.

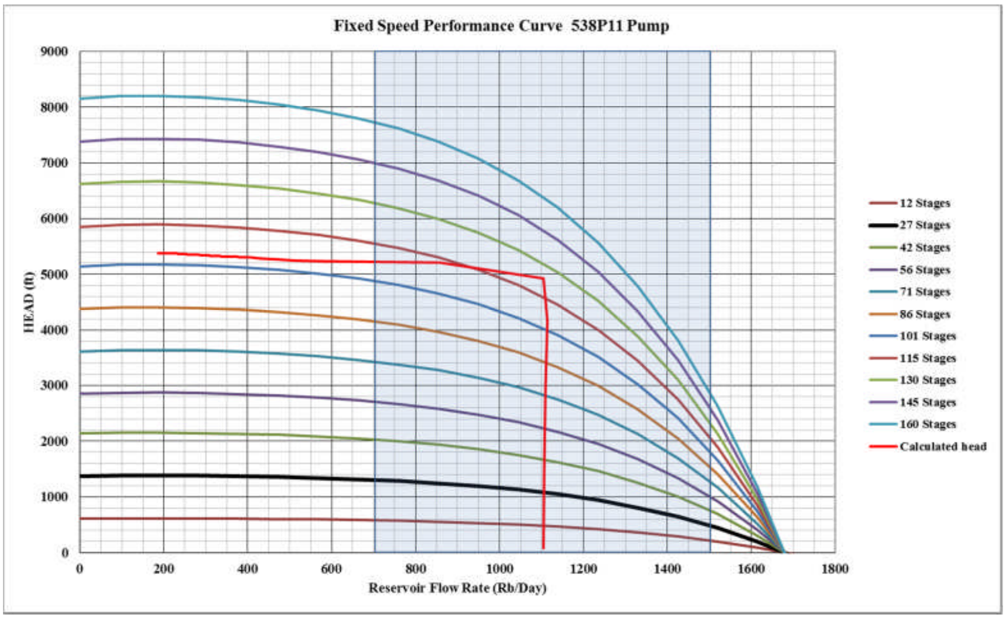

Figure 5.33: Fixed speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 4.

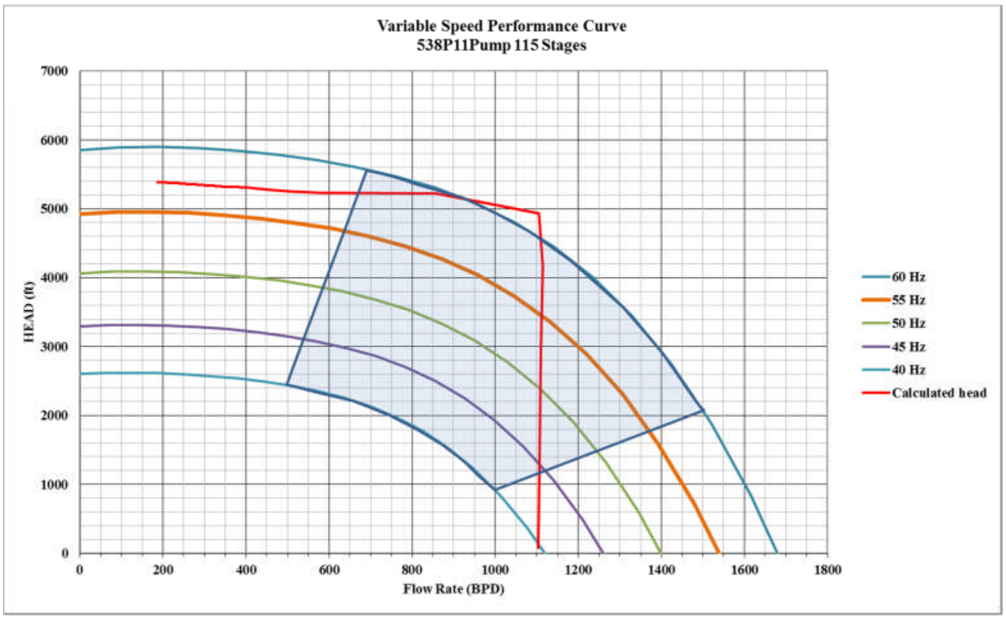

Figure 5.34: Variable speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 4.

Case 5: Reservoir pressure 3,300 psi, reservoir temperature 200°F, and initial solution GOR 250 scf/STB.

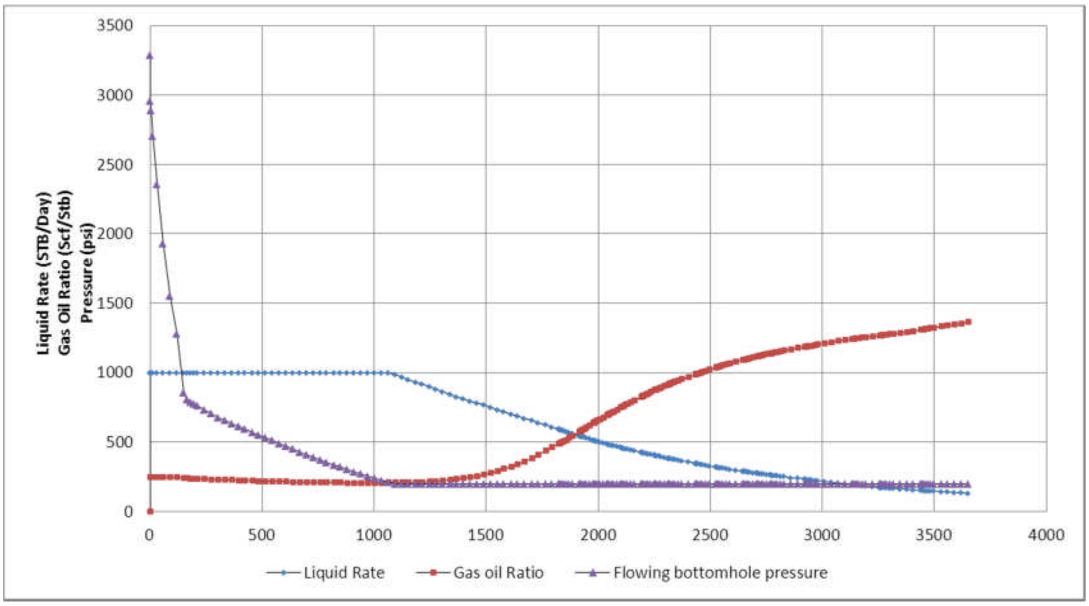

Figure 5.35: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for solution-gas reservoir in case 5.

The simulation results of solution-gas drive with reservoir pressure 3,300 psi and reservoir temperature 200°F depicts in Figure 5.35. The initial solution gas-oil ratio of this case was altered to 250 scf/STB. The results have similar trend as those in case 2. The target rate can be continued to 1,100 days as the reservoir pressure is higher than the one in case 1. The producing gas-oil ratio is constant for almost 1,500 days and rapidly increases afterward.

Figure 5.36 illustrates the plot of flowing bottom-hole pressure from reservoir simulation and bottom-hole pressure from vertical lift performance, required pump pressure and head. Once more, they have the same trend as the ones in case 2. The head in Figure 5.37 gradually increases because of the reduction in the suction pressure from the reservoir inflow and then gradually decreases because the bottom-hole pressure calculated from tubing performance decrease as the gas –oil ratio in the tubing increases.

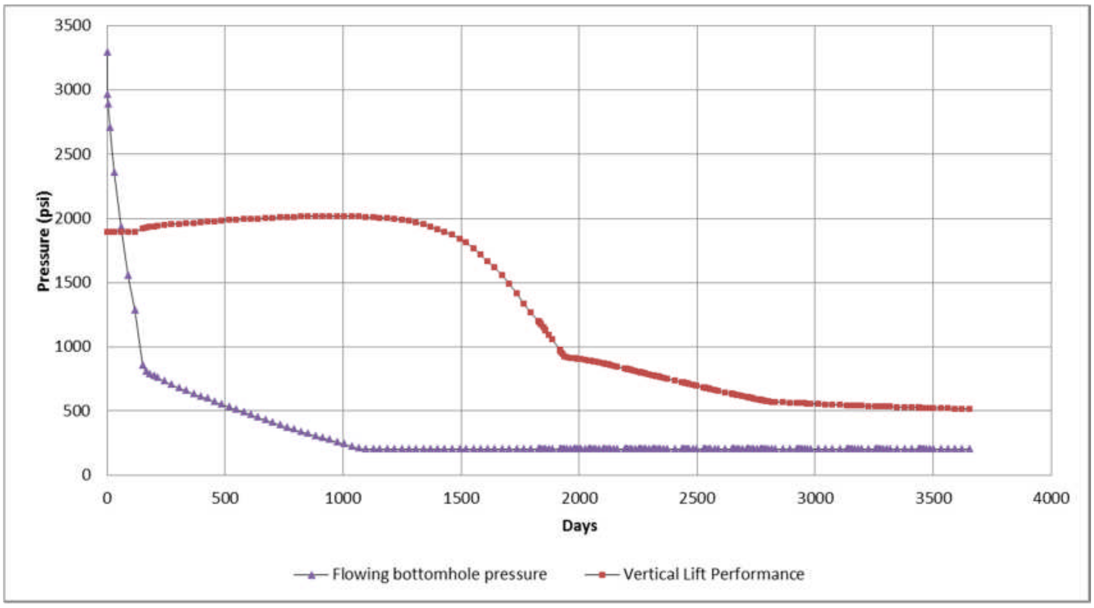

Figure 5.36: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for solution-gas drive reservoir in case 5.

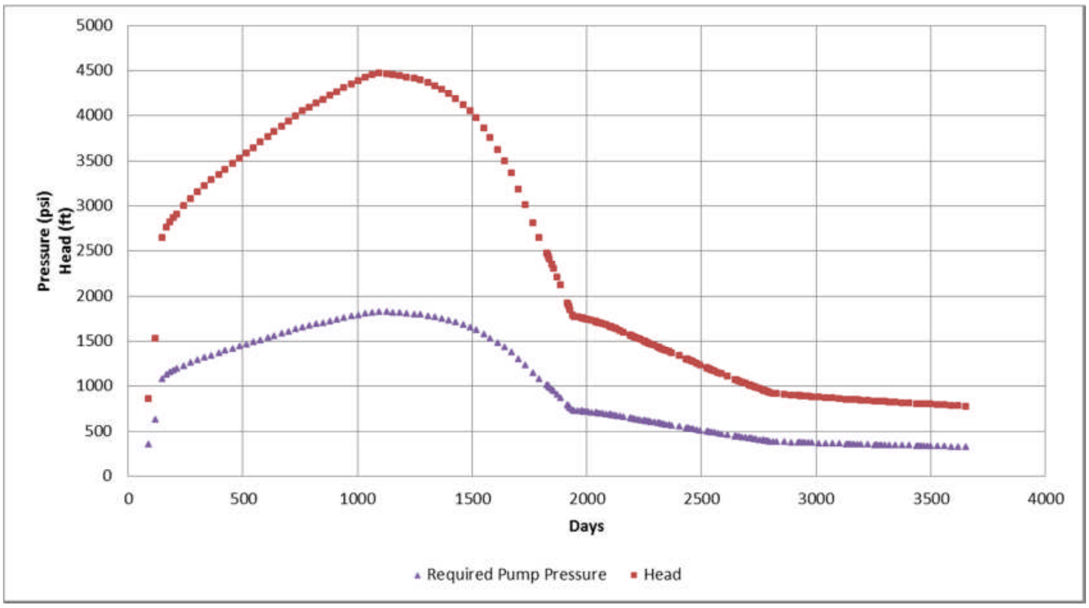

Figure 5.37: Required pump pressure and head for solution-gas drive reservoir in case 5.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 5 is P11 with 115 stages as shown in the Figure 5.38. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 101stages as depicted in Figure 5.39.

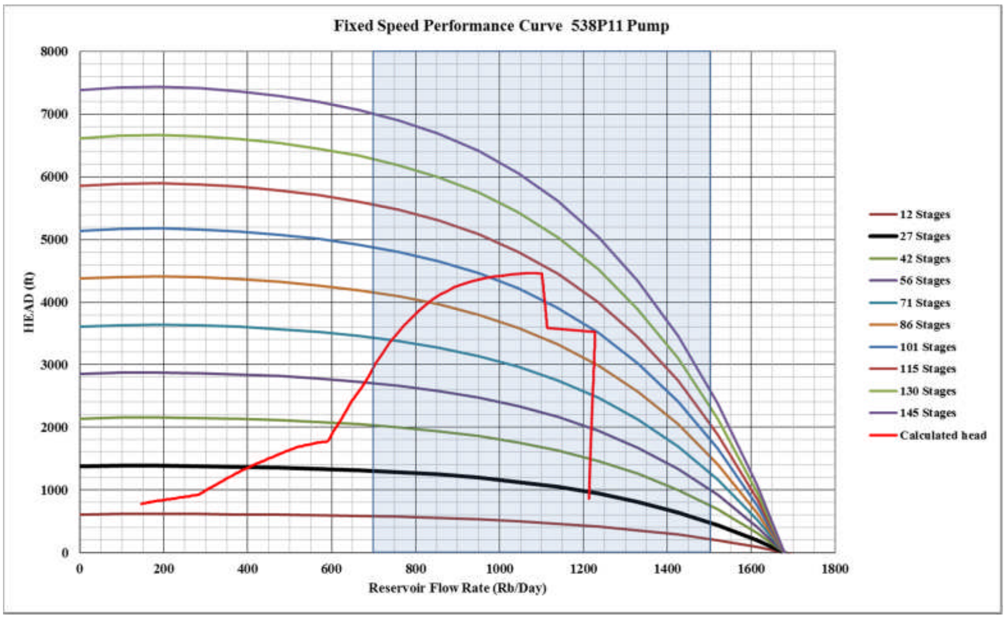

Figure 5.38: Fixed speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 5.

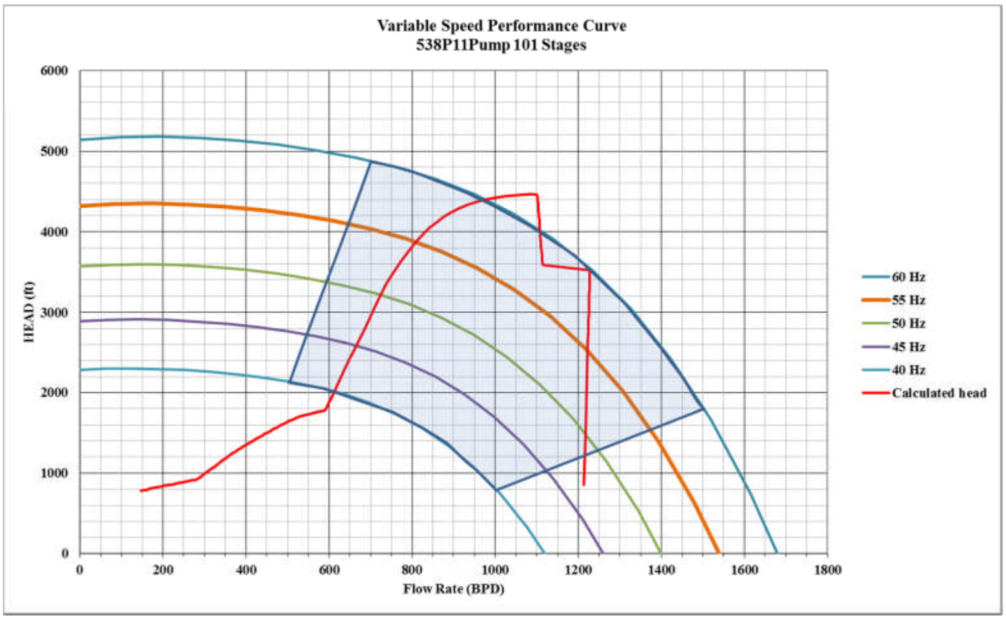

Figure 5.39: Variable speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 5.

Case 6: Reservoir pressure 3,300 psi, reservoir temperature 200°F, and initial solution GOR 500 scf/STB.

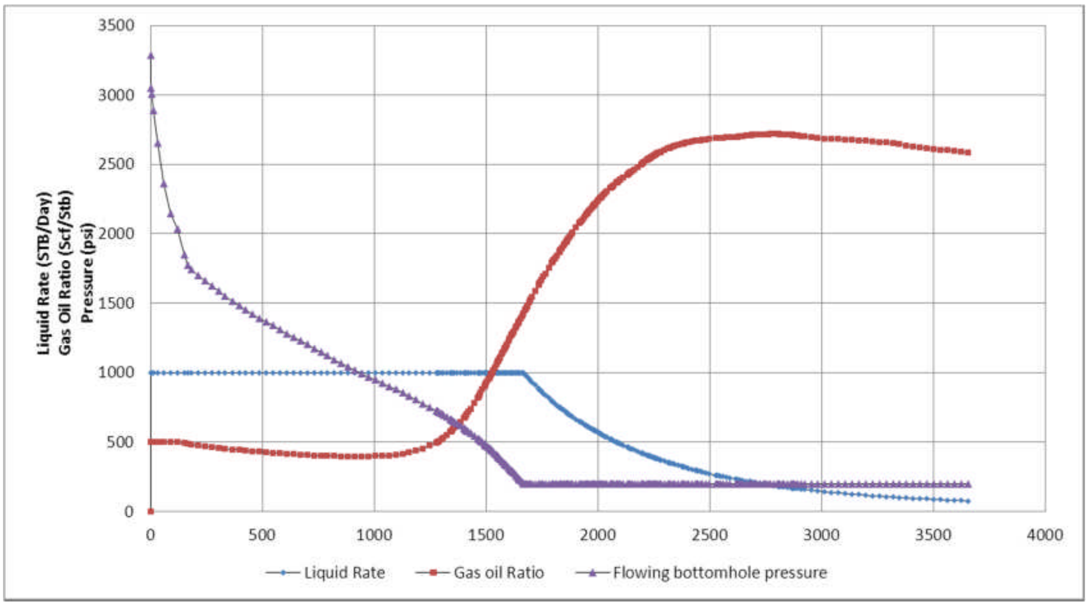

Figure 5.40: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for solution-gas reservoir in case 6.

Case 6 simulation results are depicted in Figure 5.40. The initial solution gas-oil ratio was increased to 500 scf/STB. At initial production, the GOR is more or less constant while production target is maintained at plateau rate of 1,000 STB/D up to 1,700 days. After 1,200 days, the gas-oil ratio dramatically increases as liberated gas inside the reservoir starts flowing into the wellbore. Later on, the amount of producing gas-oil ratio slightly decreases as the liberated gas that flows into the wellbore and the dissolved gas that is produced with the oil can expand less due to lower reservoir pressure.

Figure 5.41 illustrates the plot between flowing bottom-hole pressure and bottom-hole pressure from vertical lift performance. The well can flow naturally for 400 days by the dissolved gas that expands and flows into the tubing. Afterward, the well needs an artificial lift to produce liquid to the surface. However, the differential pressure is slightly small due to high amount of gas production in the tubing.

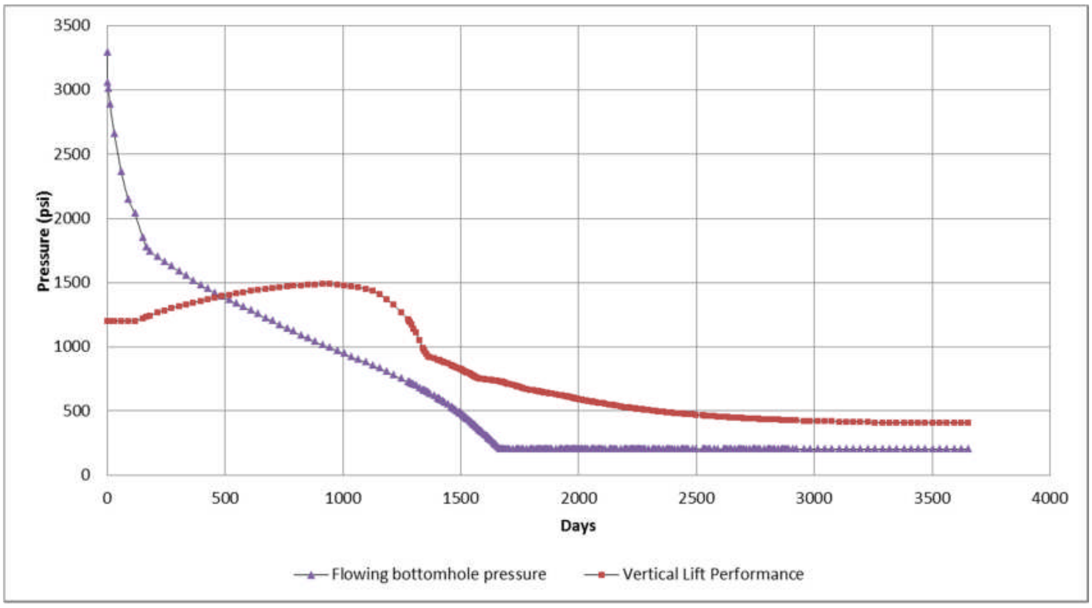

Figure 5.41: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for solution-gas reservoir in case 6.

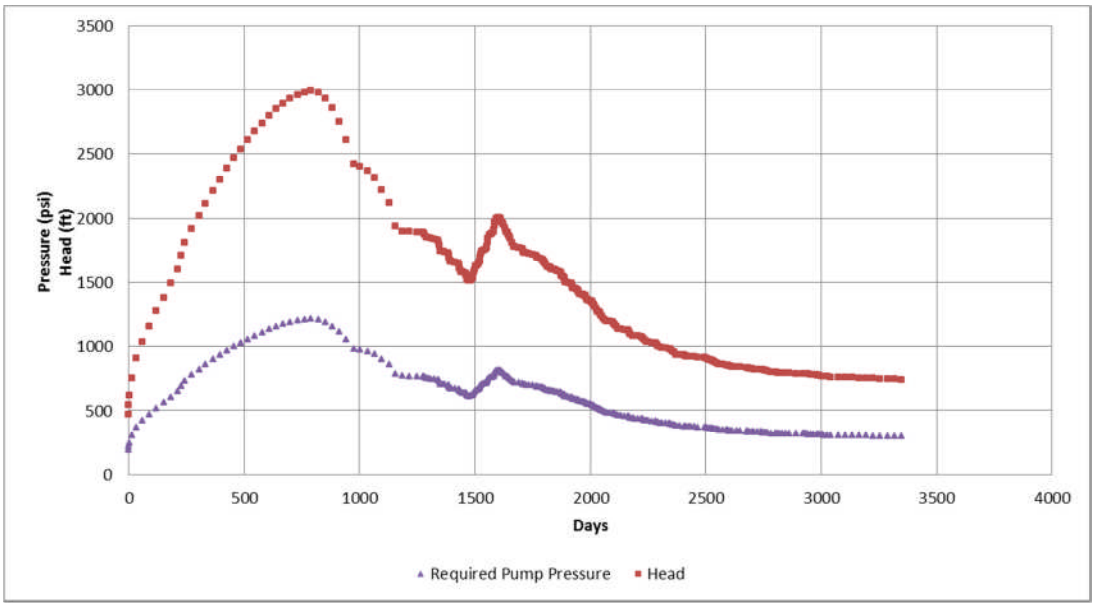

Figure 5.42: Required pump pressure and head for solution-gas drive reservoir in case 6.

Required pump pressure and head is represented in Figure 5.42. Once more, they have the same trend as the ones in case 3 as the two cases have the same initial solution gas-oil ratio. The head in Figure 5.42 is initially zero which means that the well can produce by itself without artificial lift. Later on, the head dramatically increases because of the reduction in the suction pressure and later on drops because of higher amount of gas production in tubing.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 6 is P11 with 56 stages as shown in the Figure 5.43. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 56 stages as depicted in Figure 5.44.

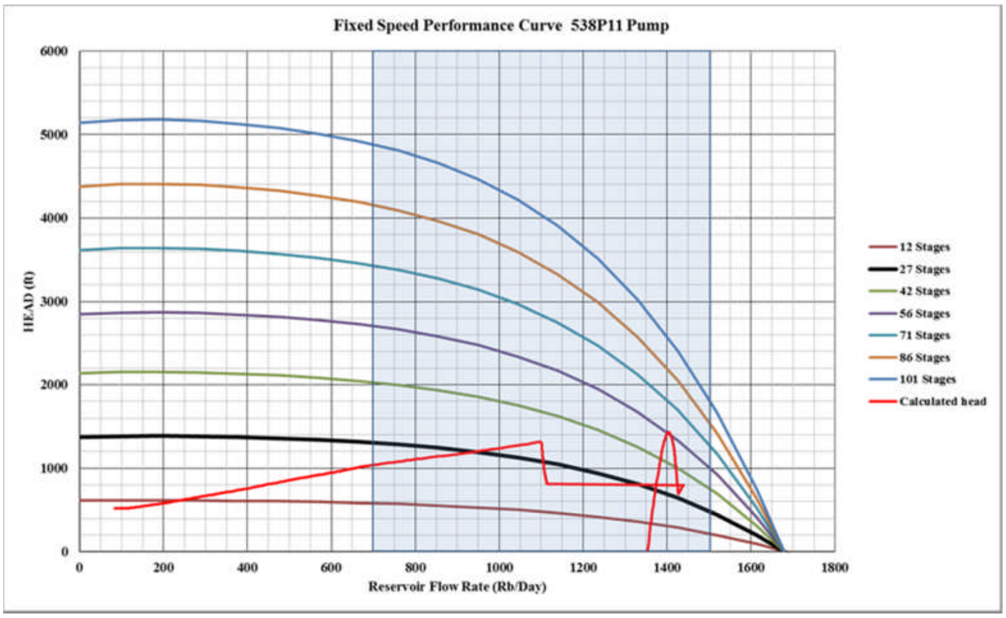

Figure 5.43: Fixed speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 6.

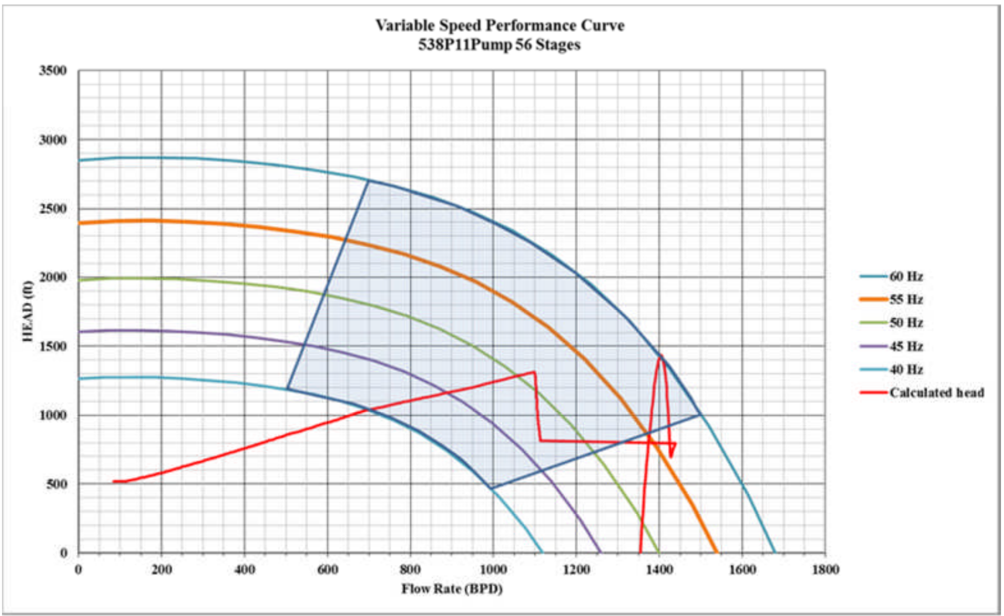

Figure 5.44: Variable speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 6.

5.3.3 Solution-gas Drive Reservoir at Reservoir Depth 10,000 ft.

Case 7: Reservoir pressure 4,400 psi, reservoir temperature 250°F, and initial solution GOR 100 scf/STB.

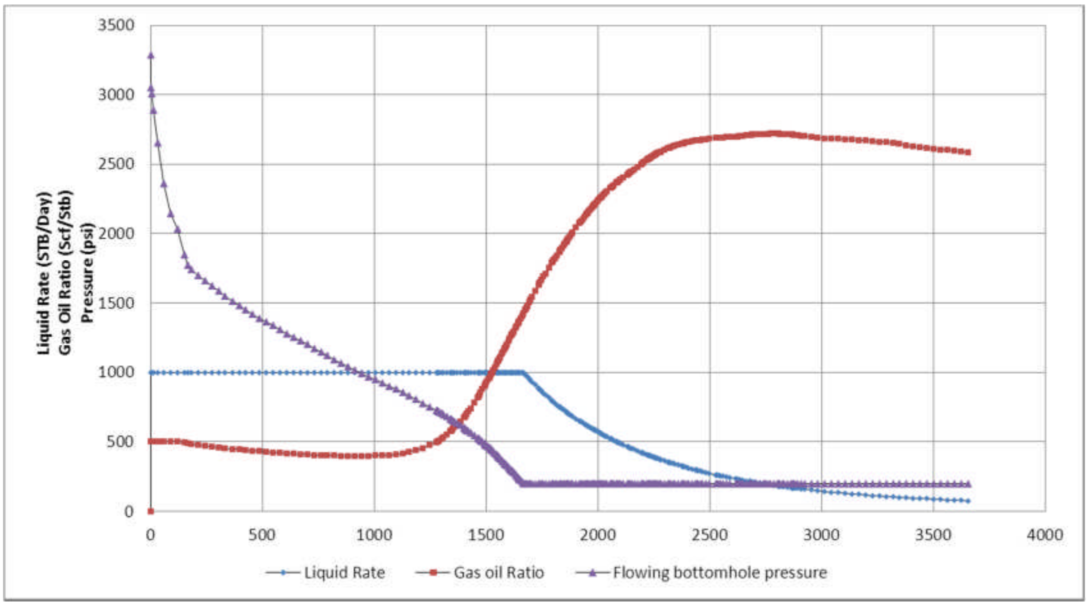

Figure 5.45: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for solution-gas drive reservoir in case 7.

This case is similar to the previous cases except for the reservoir depth, reservoir pressure and temperature. Figure 5.45 represents the simulation results for reservoir pressure 4,400 psi and reservoir temperature 250°F. At the lowest initial solution gas-oil ratio of 100 scf/STB, the production target rate can be sustained for a slightly longer time from 90 days to 150 days when compared to case 4 as the reservoir pressure is highest among all solution-gas drive case studies.

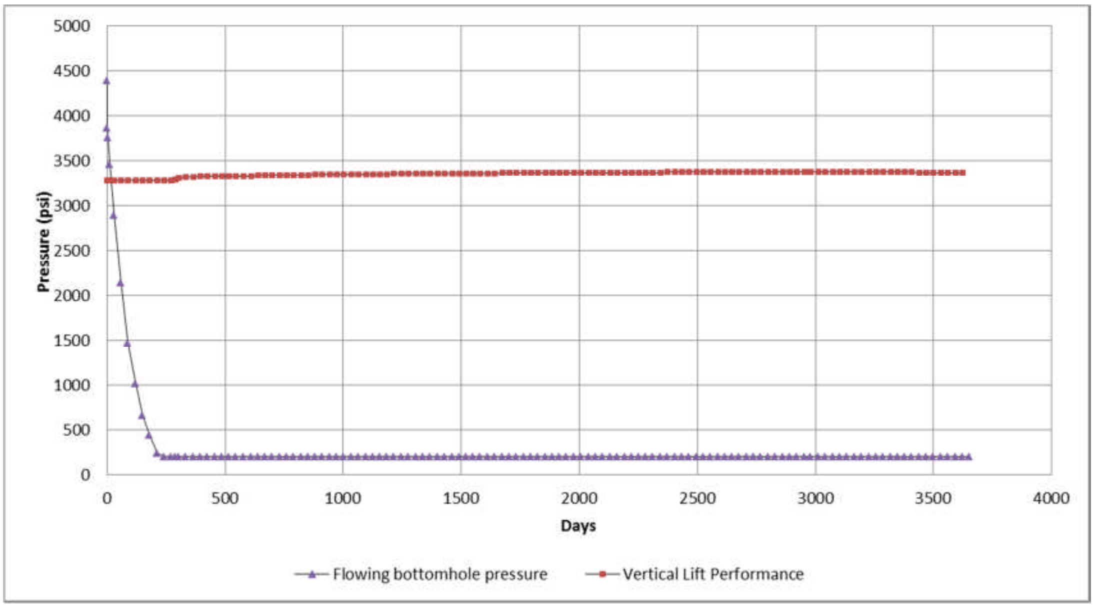

Figure 5.46: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for solution-gas drive reservoir in case 7.

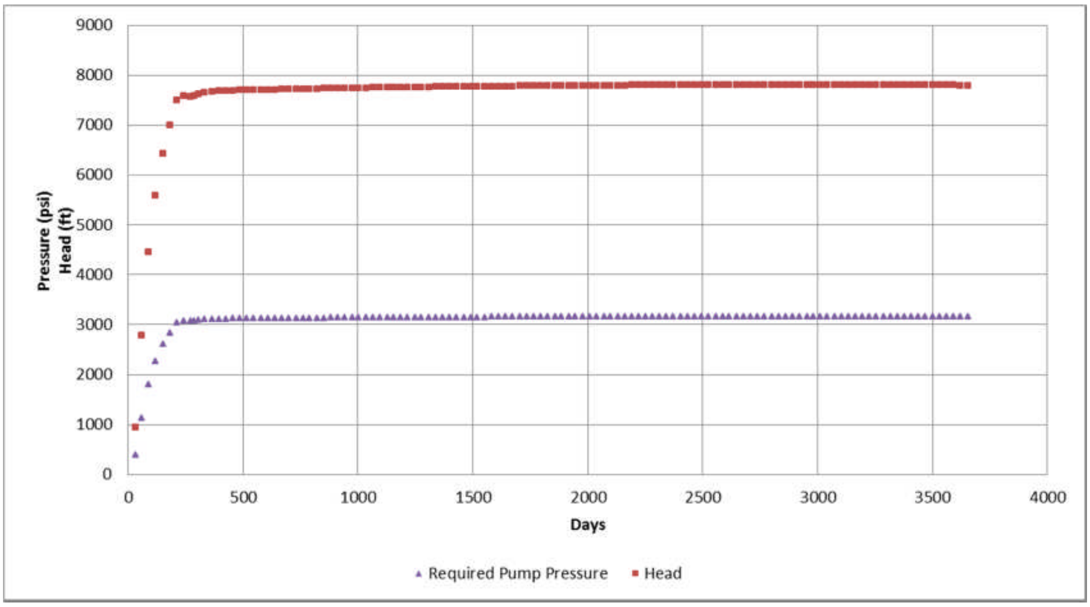

Figure 5.47: Required pump pressure and head for solution-gas drive reservoir case 7.

The flowing bottom-hole pressure, pressure from vertical lift performance, required pump pressure and head are illustrated in Figures 5.46 and 5.47. They have the same trend as those in case 1 and case 4. The head dramatically at the beginning because of the reduction in suction pressure and later remains constant and high due to a small amount of solution gas-oil ratio.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 7 is P11 with 189 stages as shown in the Figure 5.48. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 189 stages as depicted in Figure 5.49.

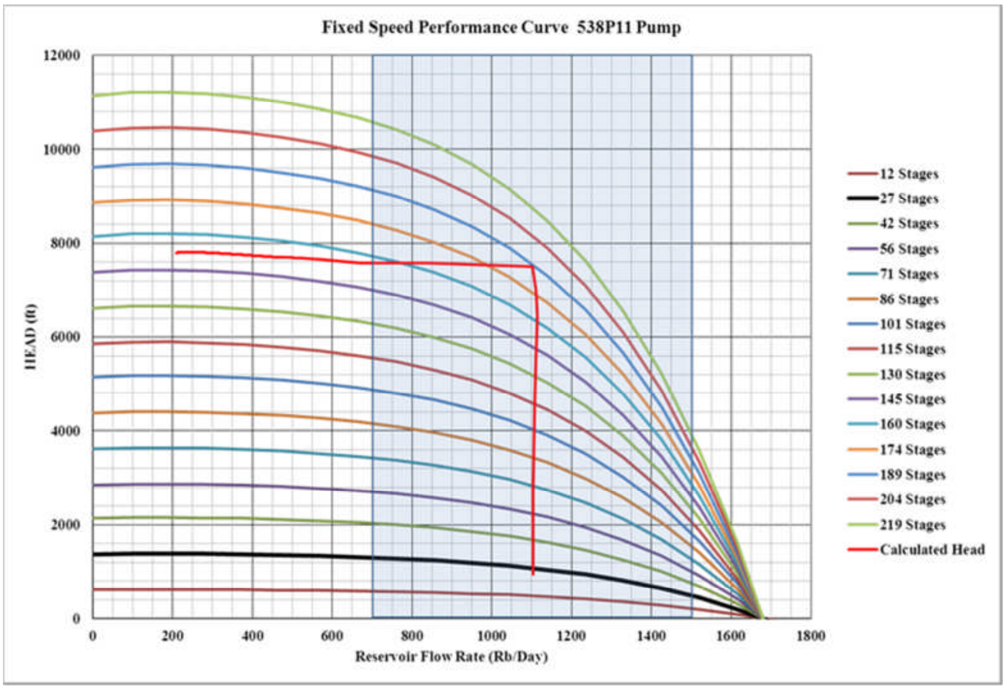

Figure 5.48: Fixed speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 7.

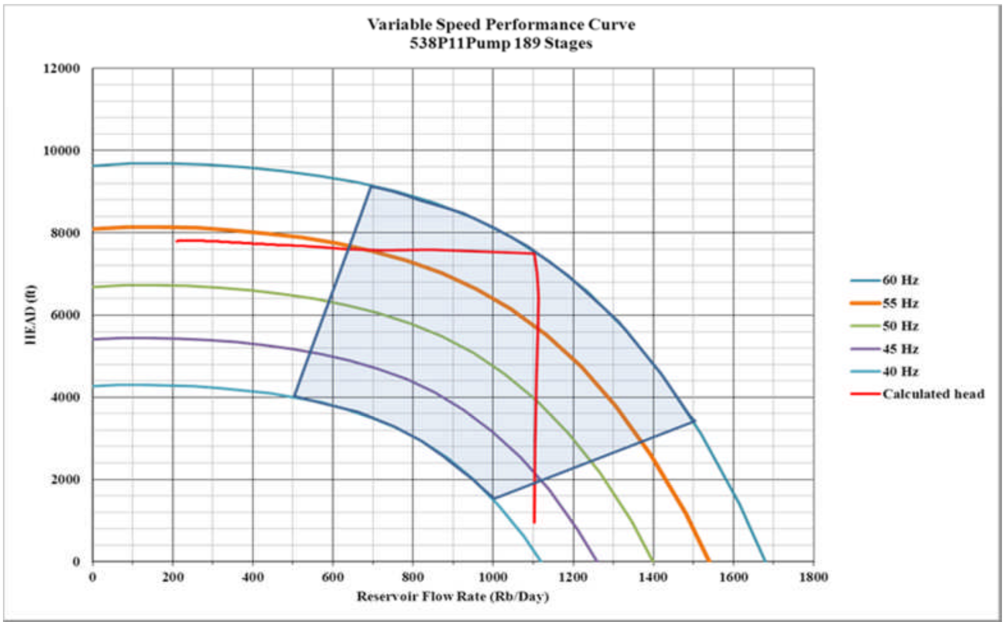

Figure 5.49: Variable speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 7.

Case 8: Reservoir pressure 4,400 psi, reservoir temperature 250°F, and initial solution GOR 250 scf/STB.

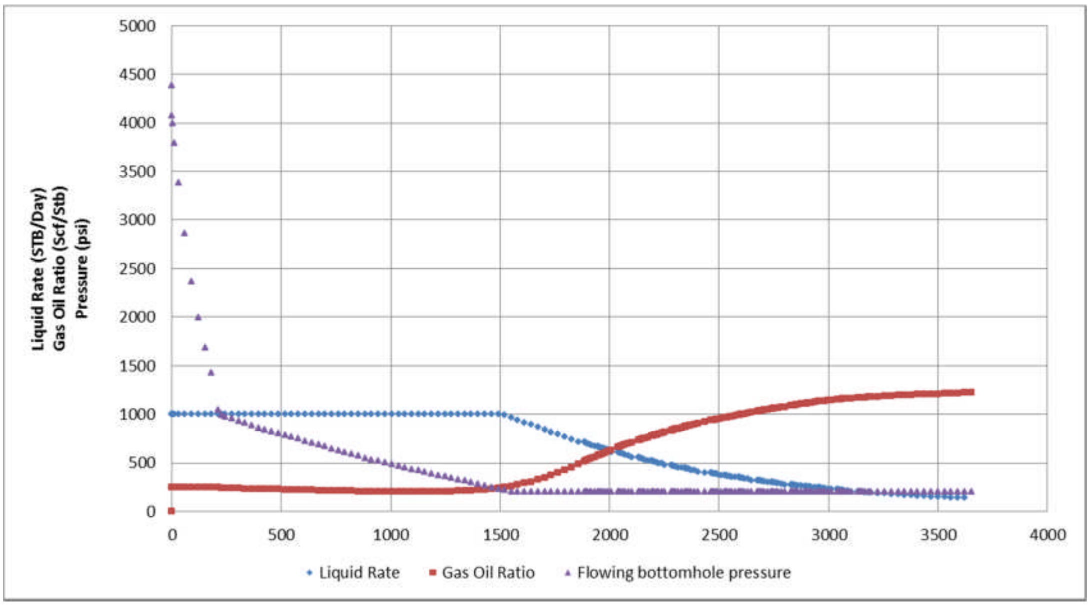

Figure 5.50: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for solution-gas drive reservoir in case 8.

In this case, the initial solution gas-oil ratio is altered to 250 scf/STB, and reservoir pressure and temperature remains the same as those in case 7. Comparing between production target rate in Figure 5.50 with the one in case 7, the rate can be produced continuously up to 1,500 days and after that it declines at a moderate rate. Producing gas-oil ratio is more or less constant initially and considerably increases after 1,500 days due to the reason that gas starts to expand and flows into the wellbore.

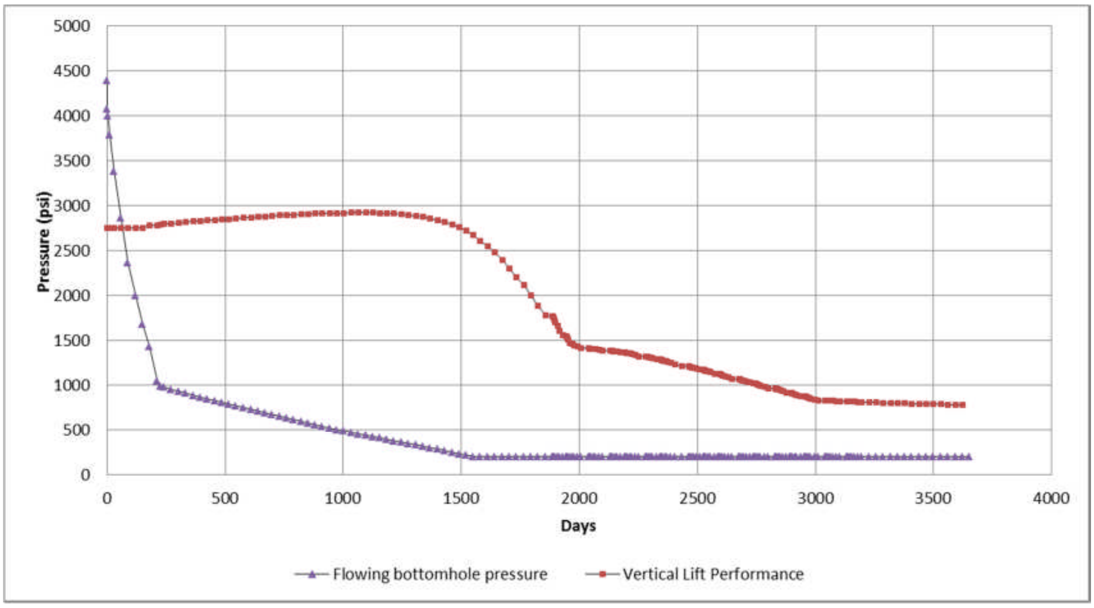

Figure 5.51: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for solution-gas drive reservoir in case 8.

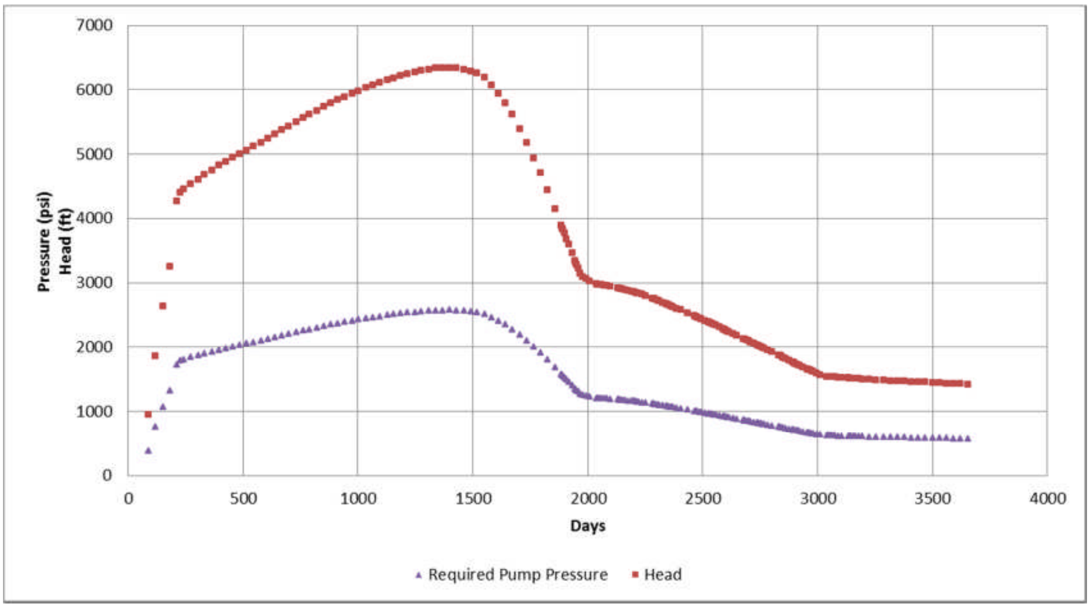

Figure 5.52: Required pump pressure and head for solution-gas drive reservoir in case 8.

The flowing bottom-hole pressure and pressure calculated from vertical lift performance are shown in Figure 5.51. The pressure from vertical lift performance falls after 1,500 days due to higher amount of producing gas in the tubing. Figure 5.52 illustrates the required pump pressure and head which have similar trend. In the first 31 days, the head requirement is zero, meaning that the fluid can flow naturally to the wellhead during that period. As the bottom-hole pressure required by the inflow dramatically drops, the head dramatically increases. As the pressure becomes lower, more liberated gas flows into tubing. The required pump pressure decreases as well as the head.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 8 is P11 with 174 stages as shown in the Figure 5.53. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P17 with 160 stages as depicted in Figure 5.54.

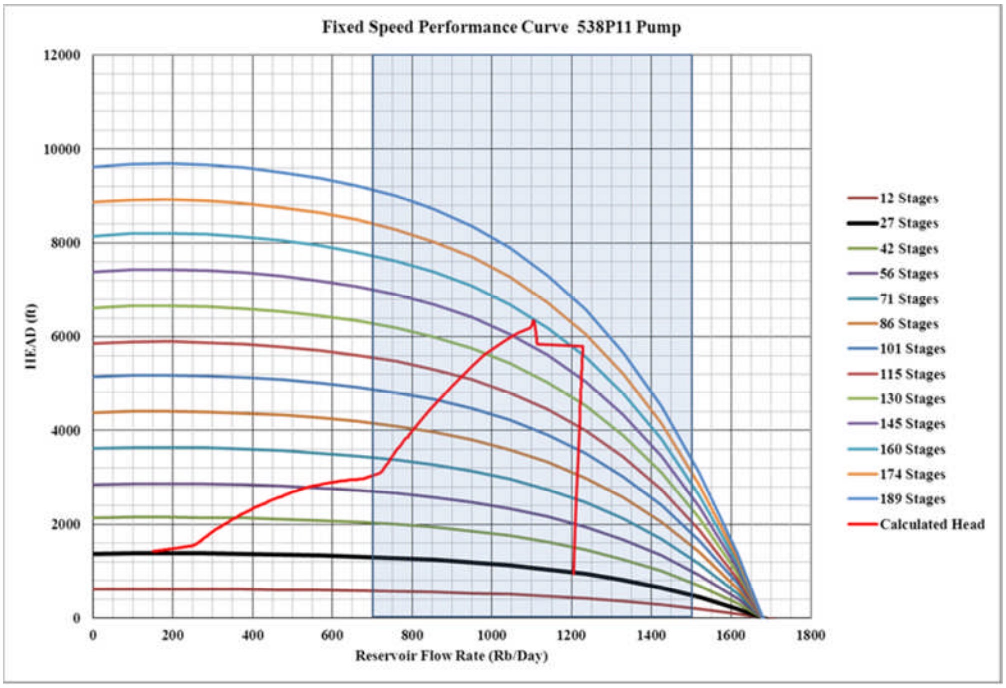

Figure 5.53: Fixed speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 8.

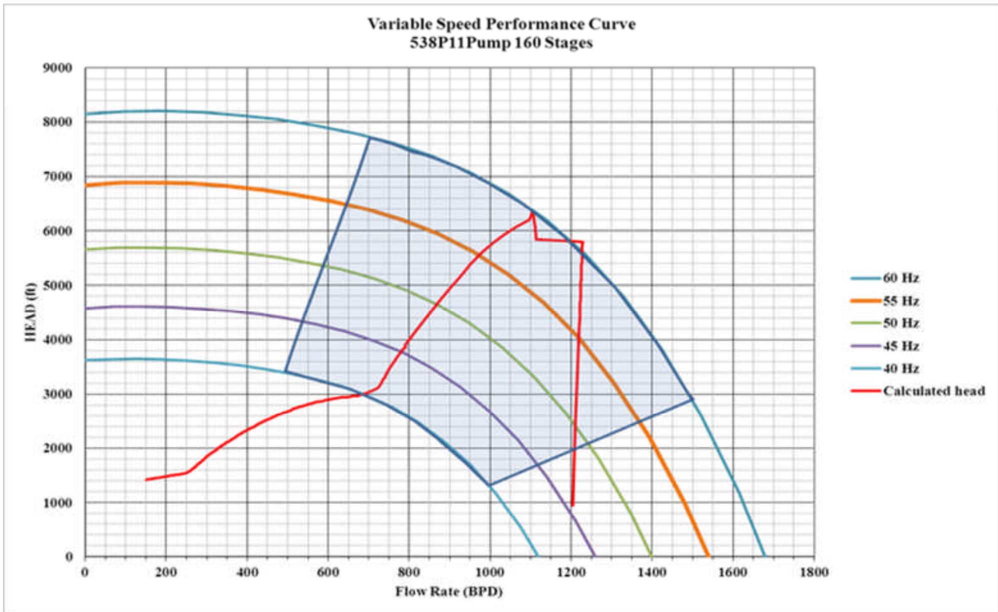

Figure 5.54: Variable speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 8.

Case 9: Reservoir pressure 4,400 psi, reservoir temperature 250°F, and initial solution GOR 500 scf/STB.

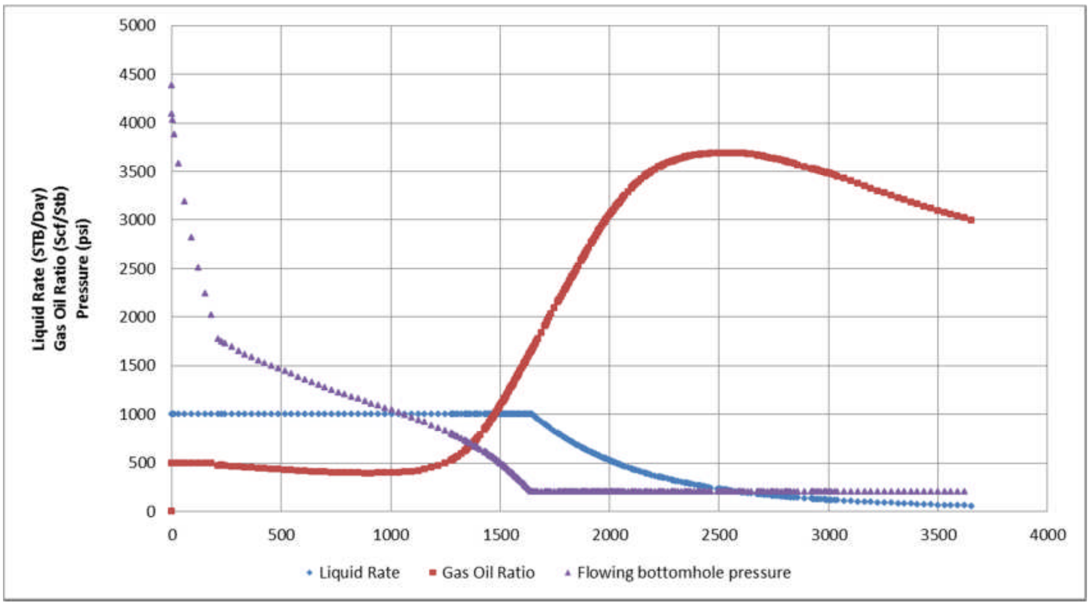

Figure 5.55: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for solution-gas drive reservoir in case 9.

Figure 5.55 represents the simulation results of the last initial solution-gas drive case. The initial solution gas-oil ratio is increased to maximum of 500 scf/STB. At initial production, the producing gas-oil ratio is more or less constant while the liquid is produced at the target rate until 1,600 days. Producing gas-oil ratio significantly increases as liberated gas inside the reservoir starts flowing into the wellbore after 1,200 days. After 2,500 days, the amount of producing gas-oil ratio decreases again as the liberated gas flowing into the wellbore and the dissolved gas being produced with the oil can expand less due to lower reservoir pressure.

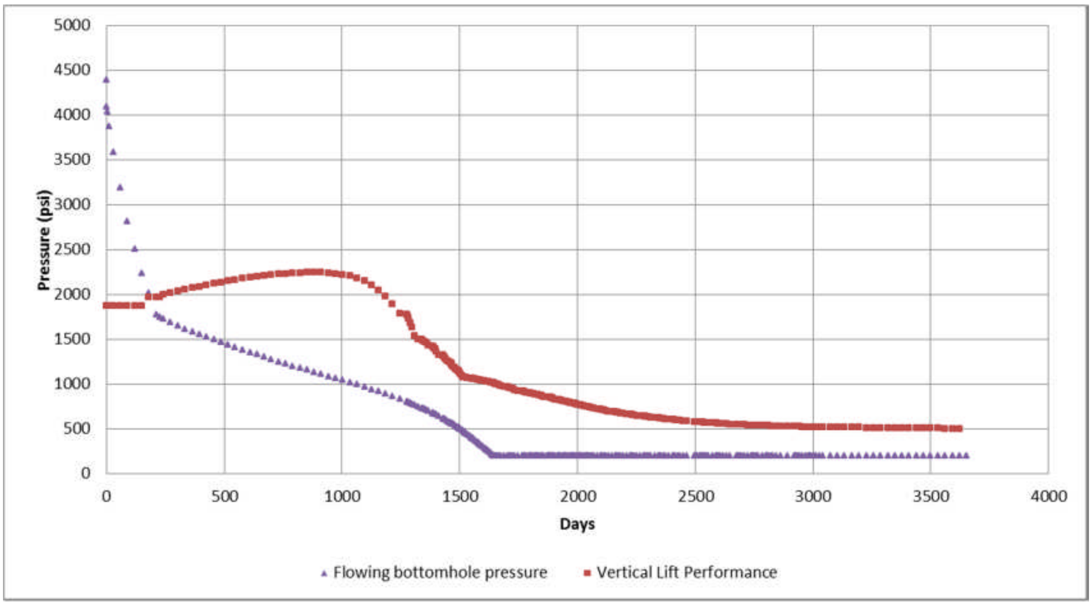

Figure 5.56: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for solution-gas drive reservoir in case 9.

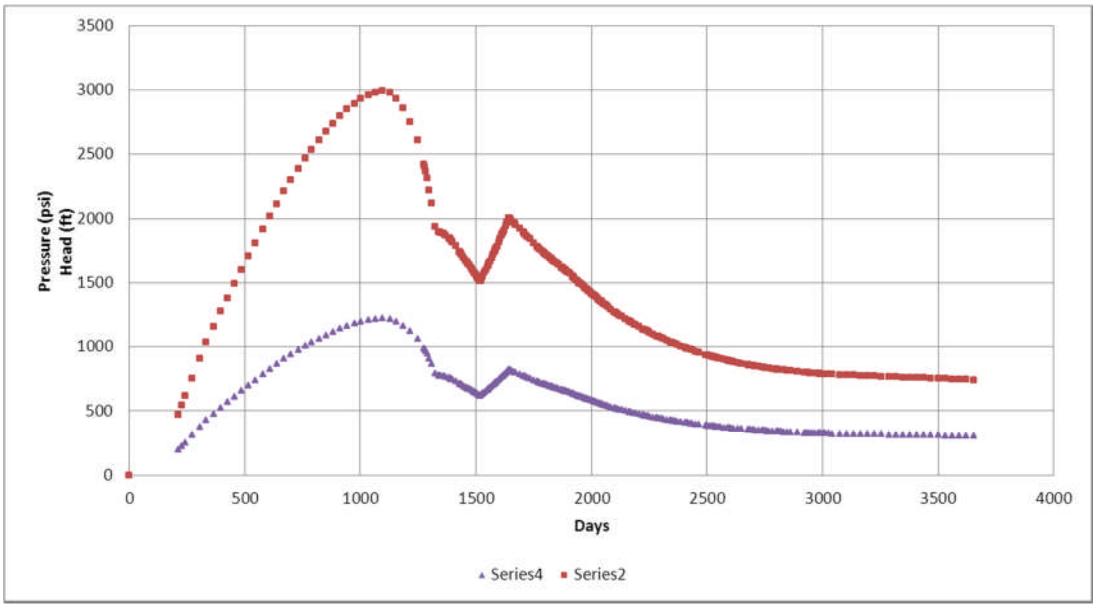

Figure 5.57: Required pump pressure and head for solution-gas drive reservoir in case 9.

Figure 5.56 illustrates the plot of flowing bottom-hole pressure and pressure form vertical lift performance. The well flows naturally for approximately 150 days by the dissolved gas. While the gas expands more and more, pressure from vertical lift performance reduces because there is less hydrostatic loss in the tubing. The difference in the pressure from reservoir inflow and the pressure from tubing performance is plotted in Figure 5.57. The required pump pressure and head have similar trend as those in case 3 and case 6 for the same reason.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 9 is P11 with 115 stages as shown in the Figure 5.58. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P17 with 58 stages as depicted in Figure 5.59.

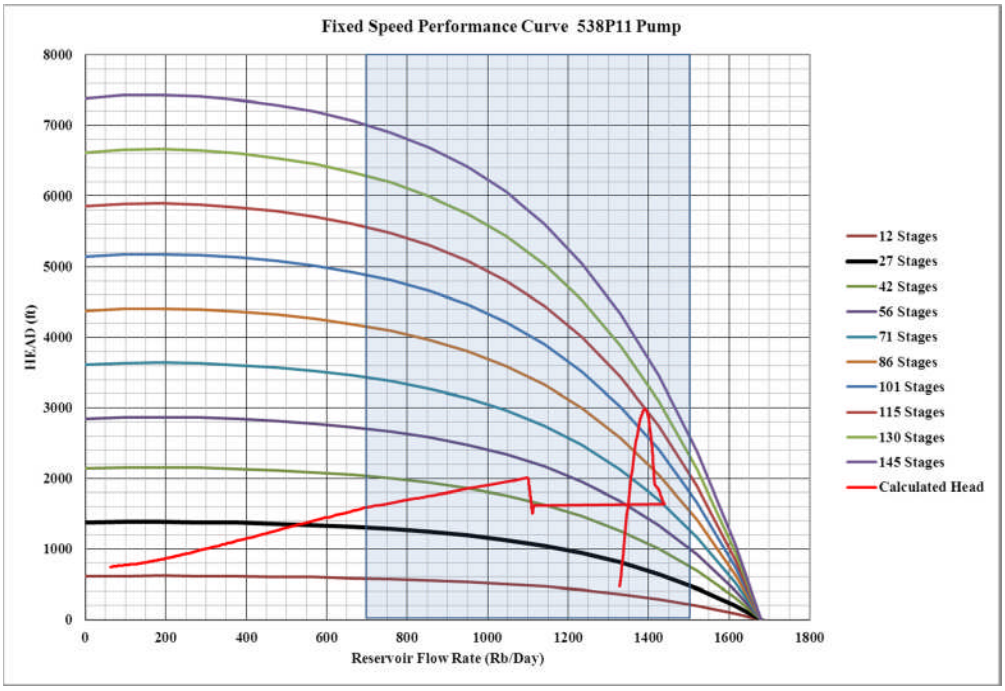

Figure 5.58: Fixed speed pump design for 60-Hz 538P11 pump model for solution-gas drive reservoir in case 9.

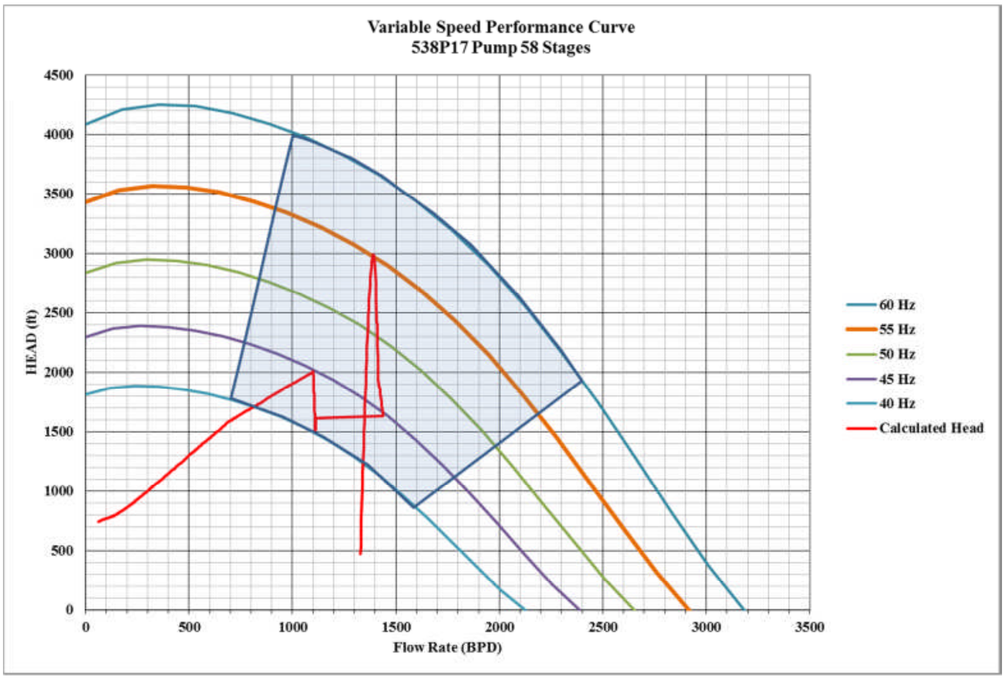

Figure 5.59: Variable speed pump design for 60-Hz 538P17 pump model for solution-gas drive reservoir in case 9.

5.4 Case Studies for Water-Drive Reservoir

For water-drive reservoir, twenty seven cases of various aquifer sizes, namely, 1PV, 5PV, 10PV including reservoir parameters such as pressure and temperature were varied to study the effect of aquifer strength in pump stage design. Not only the aquifer strength but also the initial solution gas-oil ratio is altered from 100, 250, and 500 scf/STB to investigate the influence of solution-gas in water-drive reservoir in pump stage calculation. The formation is perforated for 25 ft. from total of 50 ft., 15 ft. from the top and 10 ft. from the bottom. Cases are categorized by reservoir depth and fluid properties as tabulated in Table 5.2.

The control criteria in the simulation remain the same as the previous section. These constrains are the maximum liquid production rate of 1,000 STB/D, minimum bottom-hole pressure of 200 psia and economic oil rate of 50 STB/D. Vertical lift performance is calculated by Petroleum Expert 2 correlation for the outflow of fluid from bottom-hole to surface.

Pump size is selected based on the head requirement from the simulation results for fixed speed and used as a reference to select the number of pump stages in variable speed application at different frequencies. In some cases, the pump may need to be operated slightly above 60 Hz due to the fact that head requirement is not sufficient to select a lager pump housing.

Table 5.2: Varied parameters of water-drive reservoir.

Case no.	Reservoir depth (ft.)	Reservoir pressure (psi)	Reservoir temperature (F)	Aquifer size	Gas-oil ratio (scf/STB)	Bubble point pressure (psia)
10	5,000	2,200	168	1PV	100	510
11	5,000	2,200	168	1PV	250	1110
12	5,000	2,200	168	1PV	500	1934
13	5,000	2,200	168	5PV	100	510
14	5,000	2,200	168	5PV	250	1110
15	5,000	2,200	168	5PV	500	1934
16	5,000	2,200	168	10PV	100	510
17	5,000	2,200	168	10PV	250	1110
18	5,000	2,200	168	10PV	500	1934
19	7,000	3,300	200	1PV	100	543
20	7,000	3,300	200	1PV	250	1182
21	7,000	3,300	200	1PV	500	2061
22	7,000	3,300	200	5PV	100	543
23	7,000	3,300	200	5PV	250	1182
24	7,000	3,300	200	5PV	500	2061
25	7,000	3,300	200	10PV	100	543
26	7,000	3,300	200	10PV	250	1182
27	7,000	3,300	200	10PV	500	2061
28	10,000	4,400	250	1PV	100	588
29	10,000	4,400	250	1PV	250	1282
30	10,000	4,400	250	1PV	500	2239
31	10,000	4,400	250	5PV	100	588
32	10,000	4,400	250	5PV	250	1282
33	10,000	4,400	250	5PV	500	2239
34	10,000	4,400	250	10PV	100	588
35	10,000	4,400	250	10PV	250	1282
36	10,000	4,400	250	10PV	500	2239

5.4.1 Water-drive Reservoir at Reservoir Depth 5,000 ft.

Case 10: 1PV Aquifer, reservoir pressure 2,200 psi, reservoir temperature 168°F, and initial solution GOR 100 scf/STB.

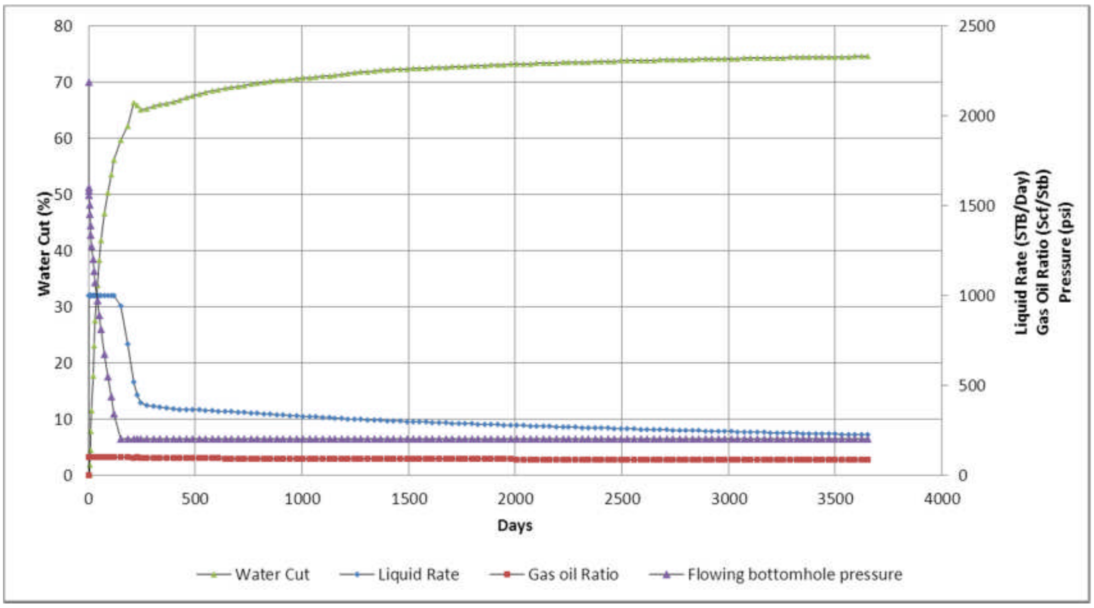

Figure 5.60: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 10.

As depicted in Figure 5.60, liquid production rate from the reservoir is maintained at 1,000 STB/D for 60 days and rapidly decreases to around 200 STB/D. The bottom-hole pressure declines rapidly at the beginning and is maintained at the minimum of 200 psi at the same time as the production rate falls down to 200 STB/D. The water cut increases quickly since the beginning to around 65% within 250 days and reaches 75% at the end of production. For the gas-oil ratio, it is more or less constant for the entire life of the well due to small solution gas-oil ratio.

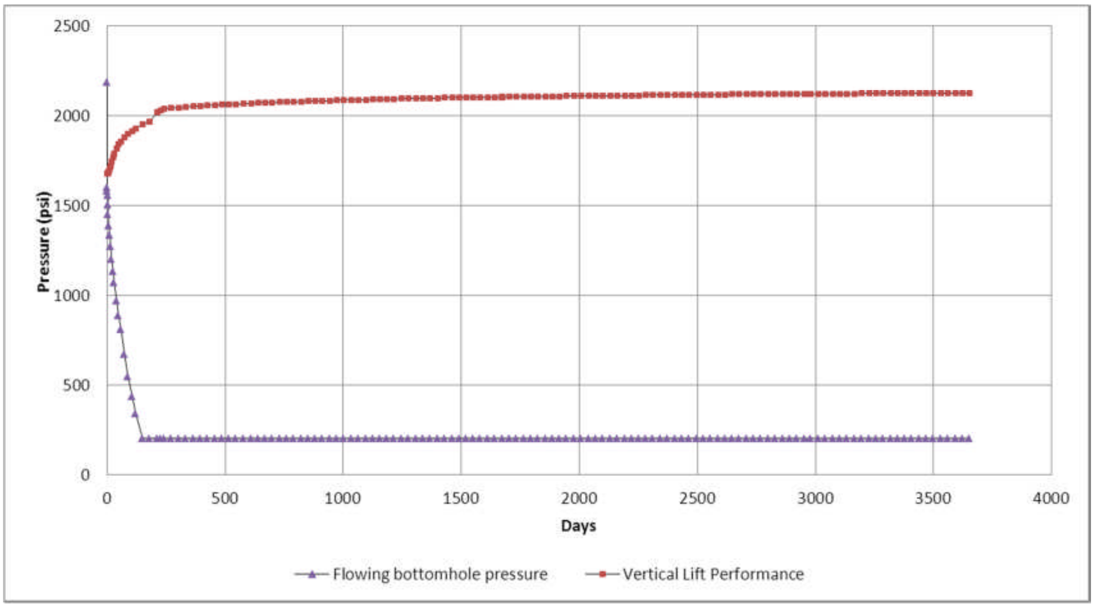

Figure 5.61: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 10.

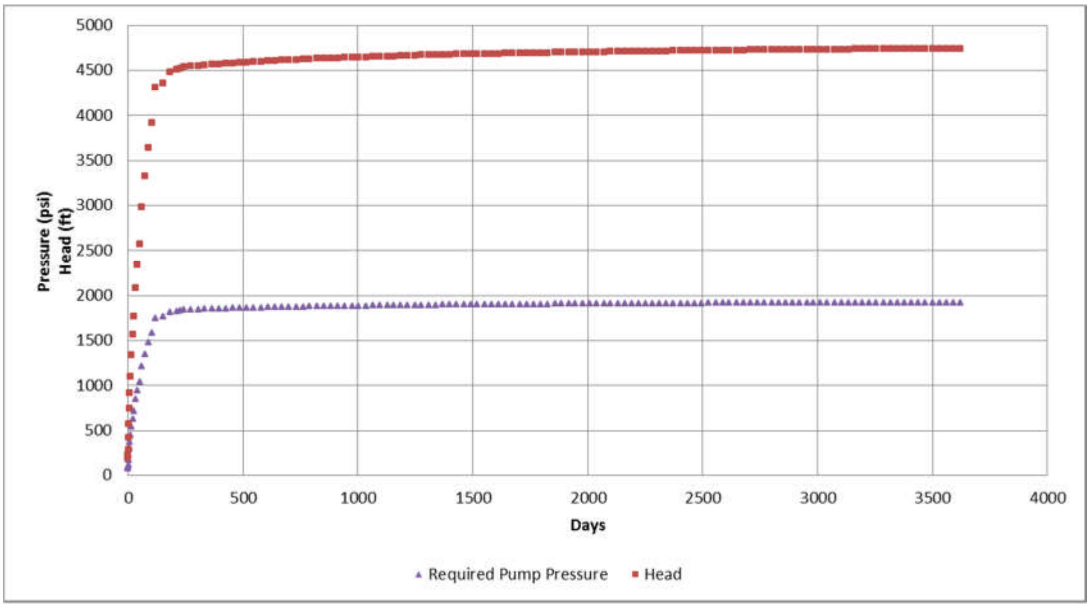

Figure 5.62: Required pump pressure and head for water drive reservoir in case 10.

The well cannot flow naturally at the very first day due to high amount of water flowing into the wellbore. The differential pressure between the bottom-hole pressure and pressure from vertical lift performance increases rapidly and stays stable until ten years as shown in Figure 5.61. The head in Figure 5.62 significantly increases at the beginning as the well flowing pressure sharply declines. Then, the head stays constant and high due to small solution gas-oil ratio. In comparison with case 1, the head in this case is higher due to water production.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 10 is P11 with 101 stages as shown in the Figure 5.63. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 101 stages as depicted in Figure 5.64.

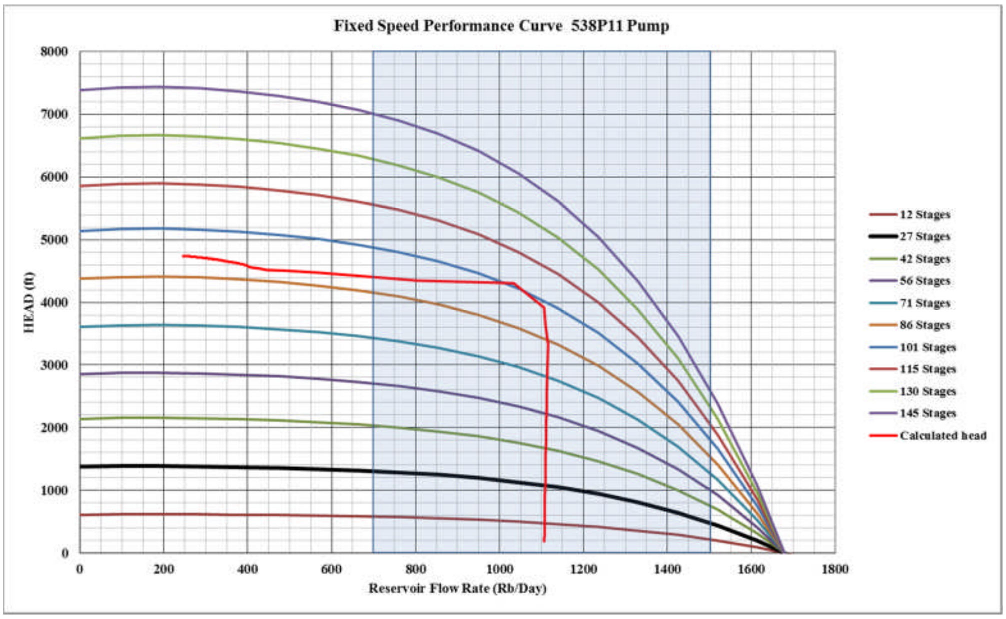

Figure 5. 63: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 10.

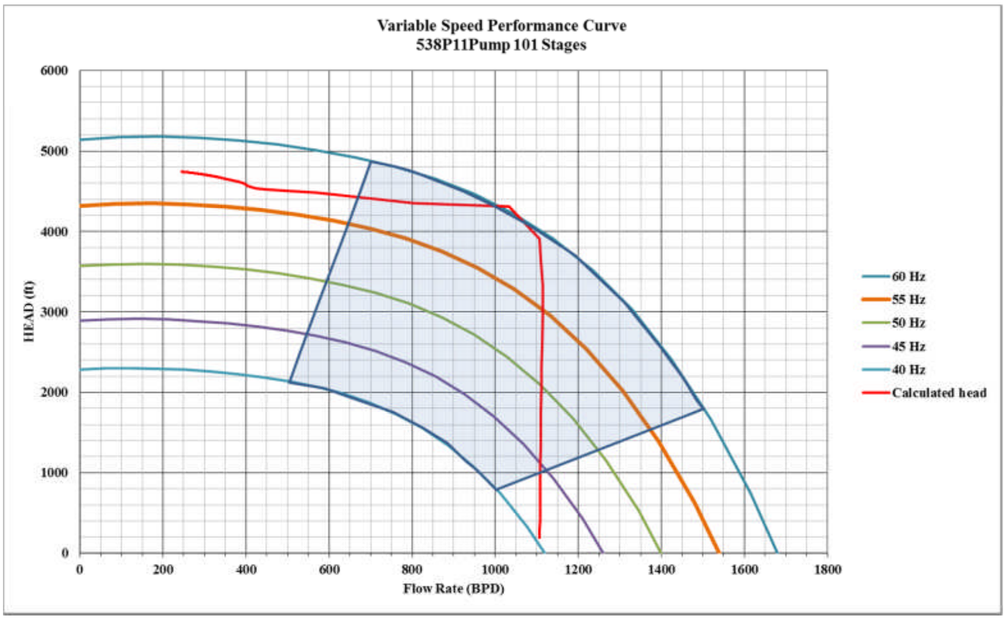

Figure 5.64: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 10.

Case 11: 1PV Aquifer, reservoir pressure 2,200 psi, reservoir temperature 168°F, and initial solution GOR 250 scf/STB.

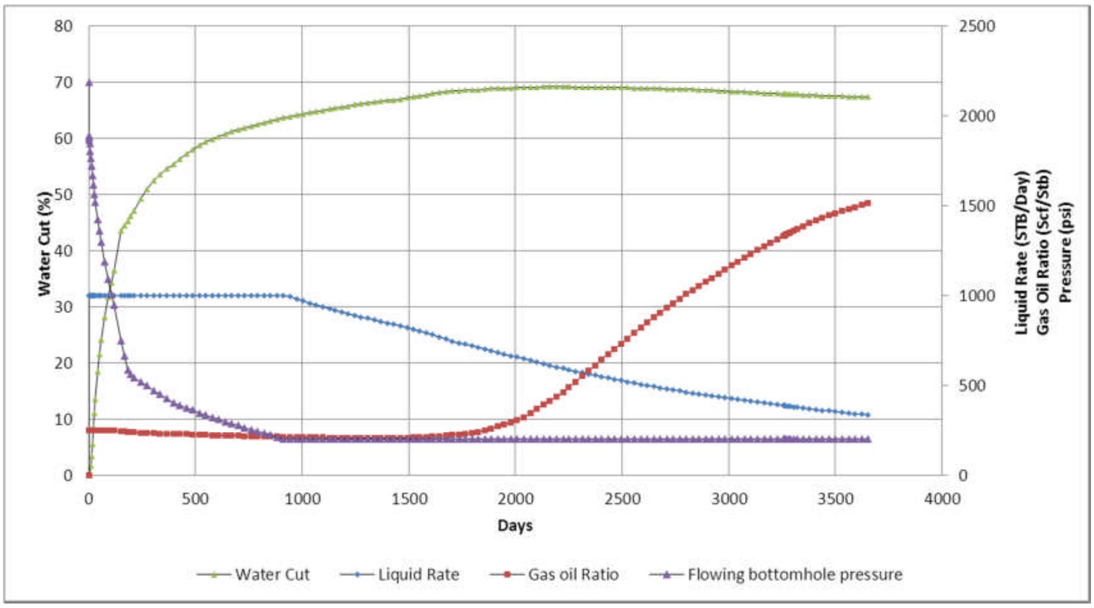

Figure 5.65: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 11.

In this case, the initial solution gas-oil ratio is altered to 250 scf/STB while other reservoir parameters remain the same. From Figure 5.65, liquid production rate is sustained at target rate for about 1,000 days and moderately decreases afterward. The water increases rapidly since the beginning to around 60% within 500 days and reaches almost 70% at the end of production. The bottom-hole pressure sharply drops since the first day due water production. Producing gas-oil ratio is constant until 1,700 days and then starts to increase afterward due to reduction in reservoir pressure.

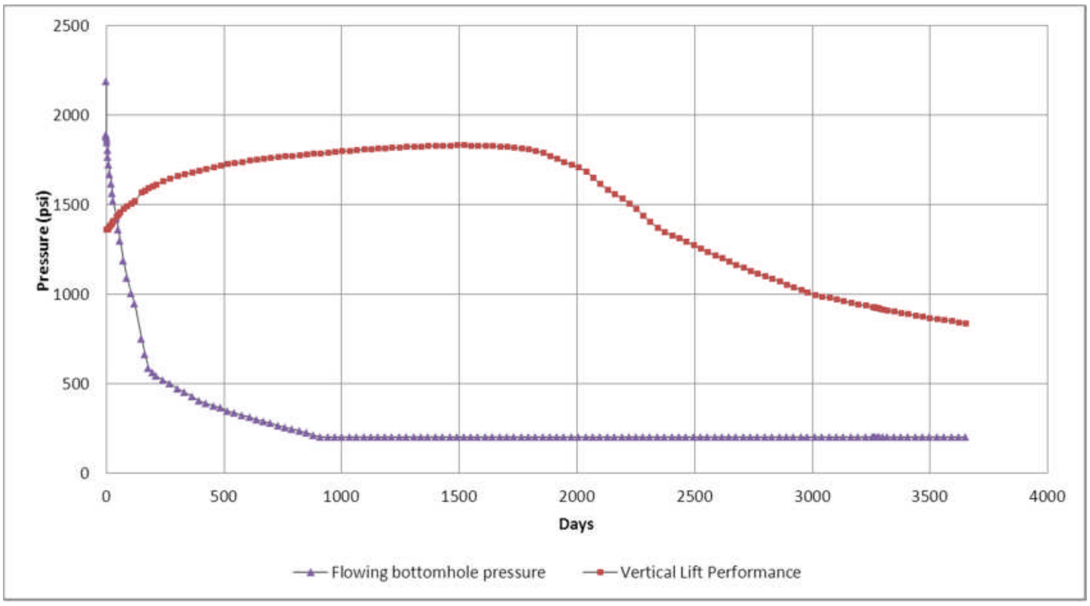

Figure 5.66: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 11.

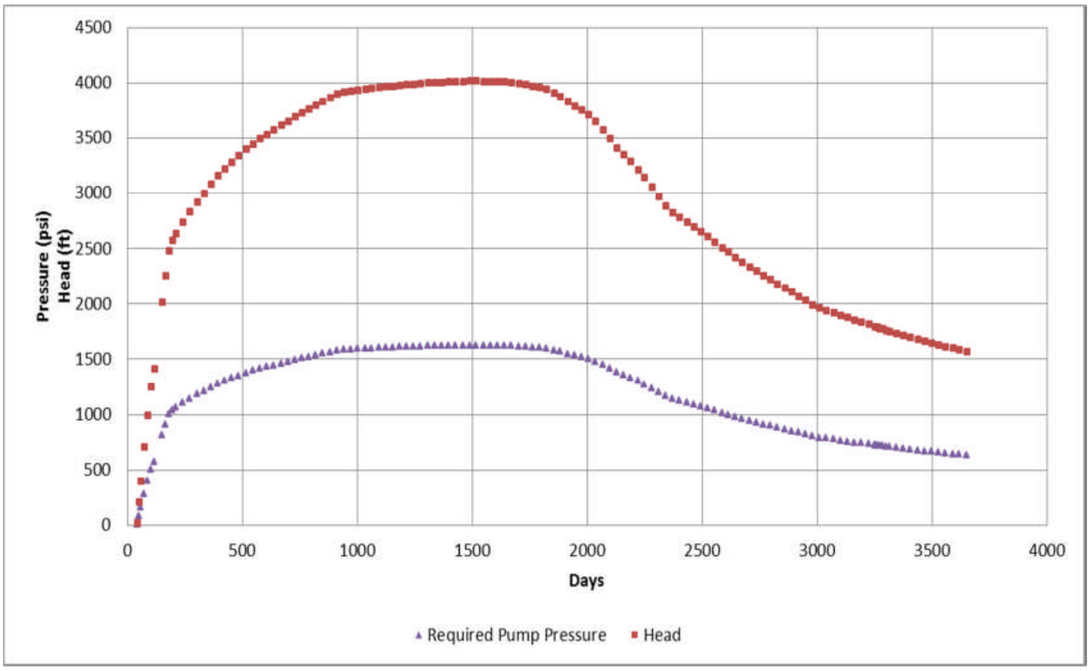

Figure 5.67: Required pump pressure and head for water drive reservoir in case 11.

The well flows naturally for a very short period because rapid of increase in water cut. The bottom-hole pressure and pressure from vertical lift performance are shown in Figure 5.66. The pressure from tubing performance is high in the middle of production period and lower after gas flows into the wellbore due to pressure reduction. The head in Figure 5.67 significantly increases at the beginning due the reduction in the suction pressure and higher water production rate. As more gas flows into the wellbore at later times, the required pump pressure slowly declines. In comparison with case 2, the head requirement in this case is higher due to high water cut.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 11 is P11 with 115 stages as shown in the Figure 5.68. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 101 stages as depicted in Figure 5.69.

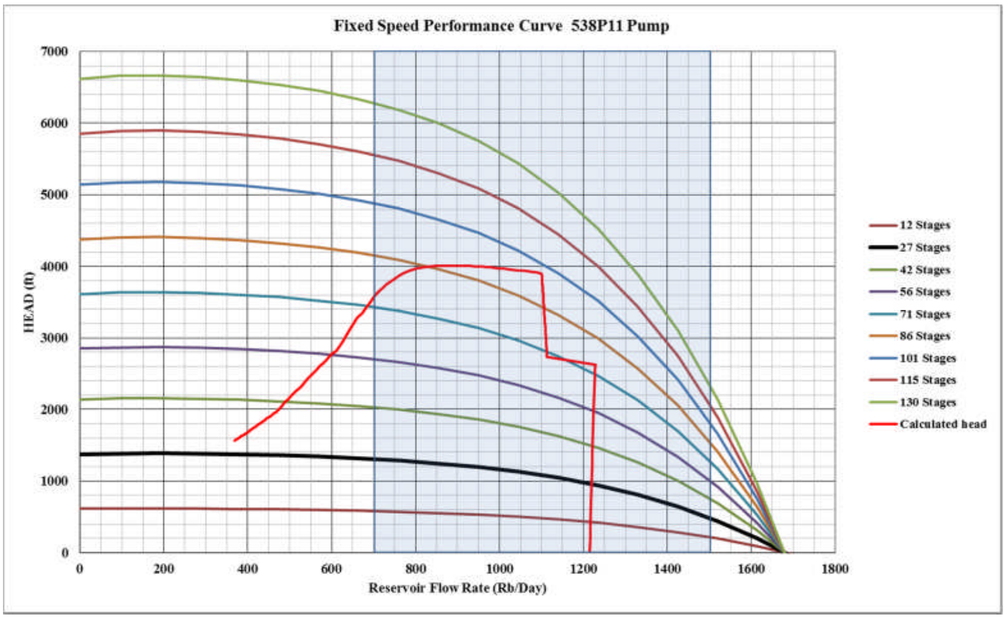

Figure 5.68: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 11.

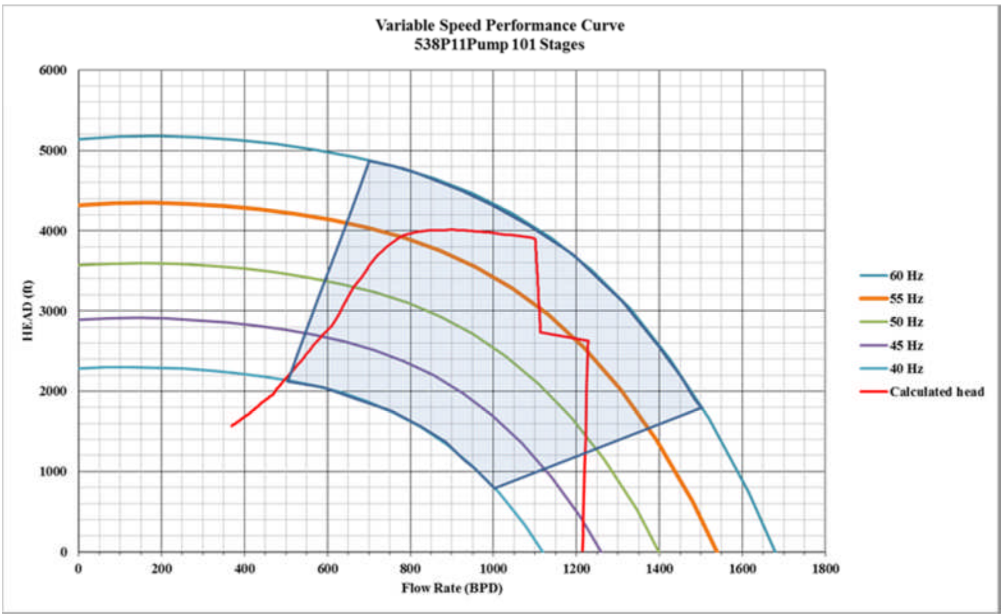

Figure 5.69: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 11.

Case 12: 1PV Aquifer, reservoir pressure 2,200 psi, reservoir temperature 168°F, and initial solution GOR 500 scf/STB.

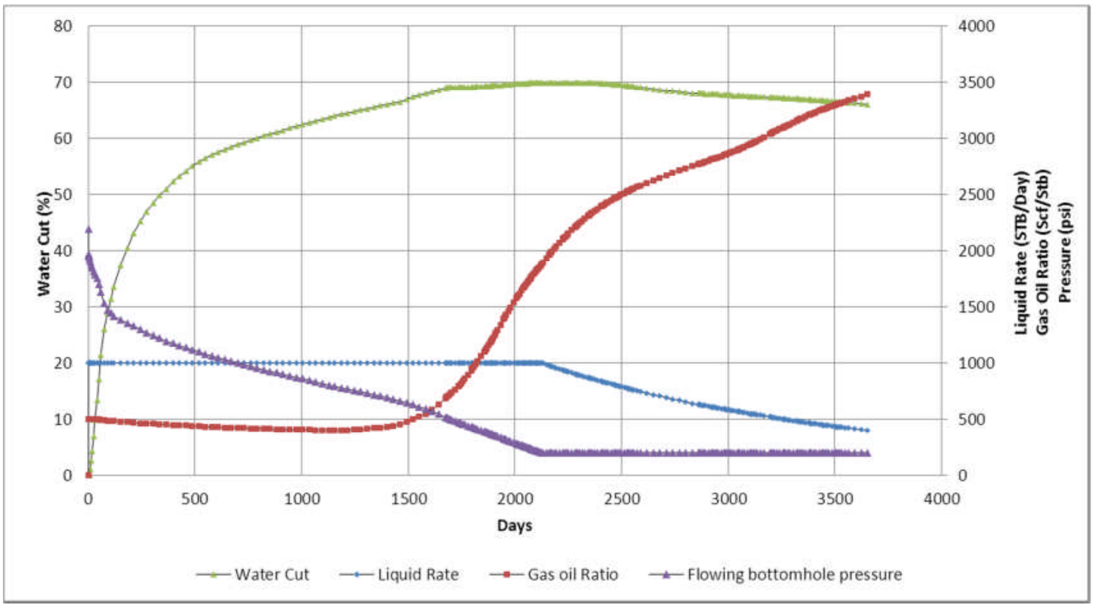

Figure 5.70: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 12.

Figure 5.70 illustrates the simulation results of initial solution gas-oil ratio 500 scf/STB while other reservoir parameters are the same. Liquid production rate is constantly produced at the target rate for 2,200 days and decreases gradually later. The water increases sharply since the beginning to around 55% within 500 days and reaches nearly 70% at the end of production. On the other hand, the bottom-hole pressure suddenly drops from the first day and declines at a slow pace until reaching the minimum requirement at 200 psia around 2,200 days. Producing gas-oil ratio increases after 1,500 days because the reservoir pressure drops below the bubble point pressure and gas starts to flow into the wellbore.

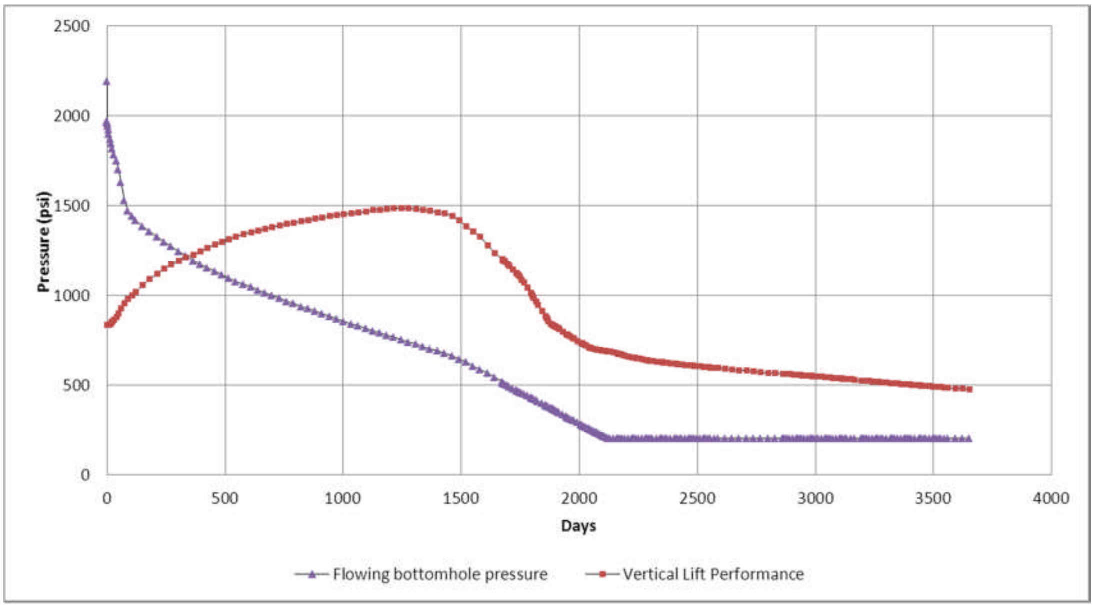

Figure 5.71: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 12.

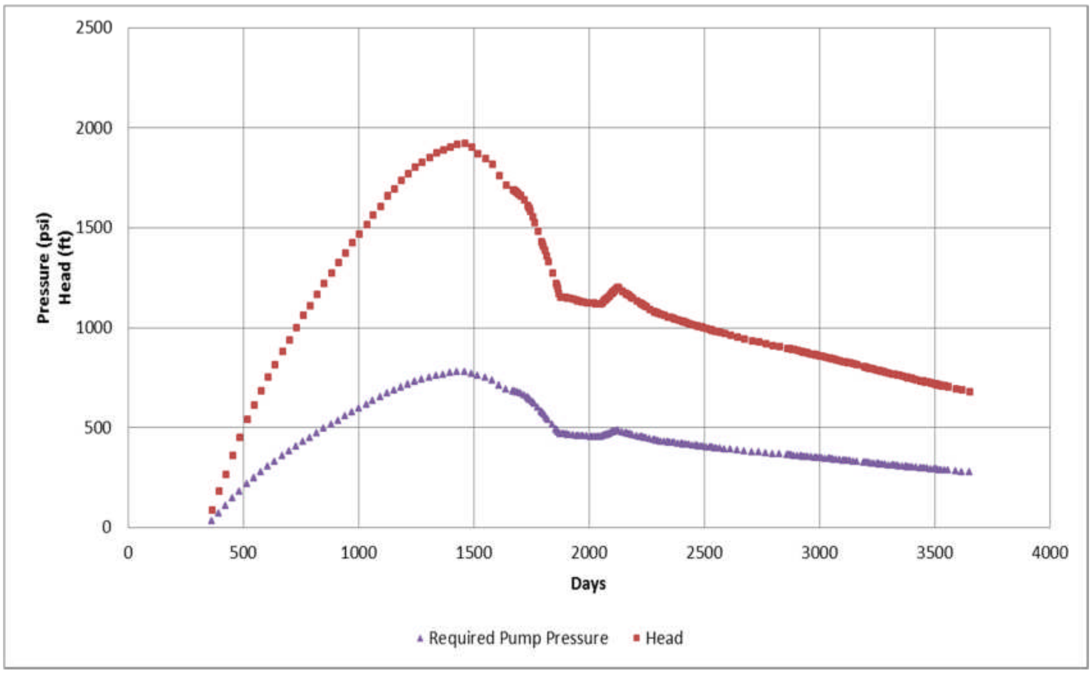

Figure 5.72: Required pump pressure and head for water drive reservoir in case 12.

The well naturally flows for around 300 days due to influence of pressure support from water aquifer and liberated gas in the tubing. The bottom-hole pressure and pressure from vertical lift performance increase gradually until 1,500 days and decline after free gas starts to flow as shown in Figure 5.71. The head in Figure 5.72 remarkably increases during 300 days to 1,500 days of production due to the reduction in the suction pressure to maintain the target rate and the increase in pressure required for vertical lift as water cut increases. When free gas starts to flow, the required pump pressure slowly declines in the same trend as the head. In comparison with case 3, the water production in case 12 causes the head requirement to be higher.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 12 is P11 with 86 stages as shown in the Figure 5.73. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 71 stages as depicted in Figure 5.74.

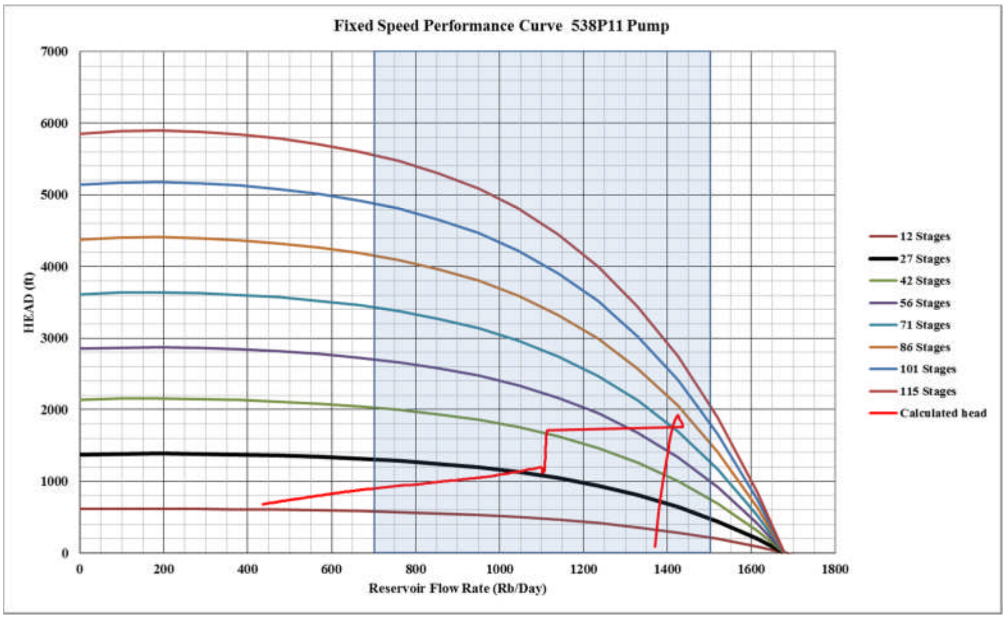

Figure 5.73: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 12.

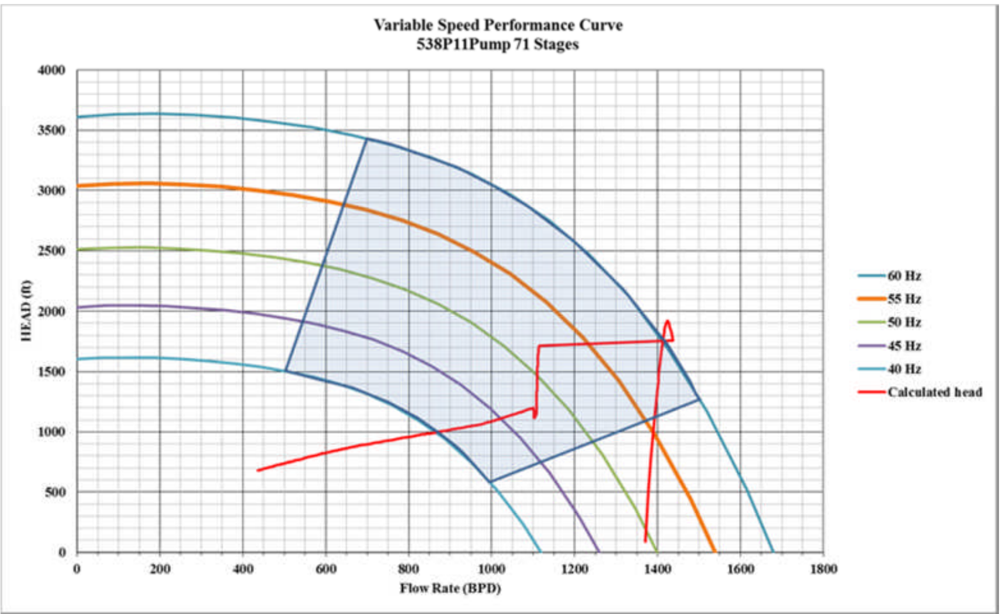

Figure 5.74: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 12.

Case 13: 5PV Aquifer, reservoir pressure 2,200 psi, reservoir temperature 168°F, and initial solution GOR 100 scf/STB.

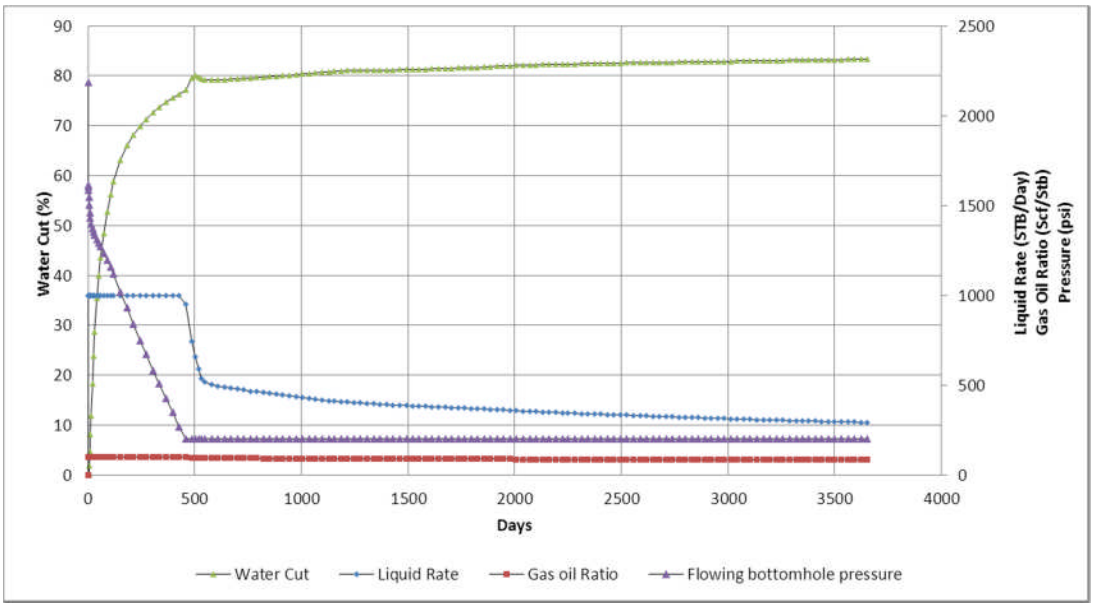

Figure 5.75 Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 13.

In this scenario, water aquifer is upsized to 5 times of reservoir pore volume (PV). The rest of reservoir parameters have not changed. The initial solution gas-oil ratio in this case is 100 scf/STB. From Figure 5.75, the bottom-hole pressure declines sharply due to the reduction of suction pressure and reaches the minimum at 200 psia. The liquid rate is maintained at the target rate for 490 days and then drops in the same fashion as the bottom-hole pressure. The water cut increases quickly since the beginning to around 80% within 500 days and reaches over 80% at the end of production. The water cut in this case is higher than the one in case 10 as a result of stronger water aquifer. Producing gas-oil ratio is more or less stable through the end of reservoir life because of small solution gas-oil ratio.

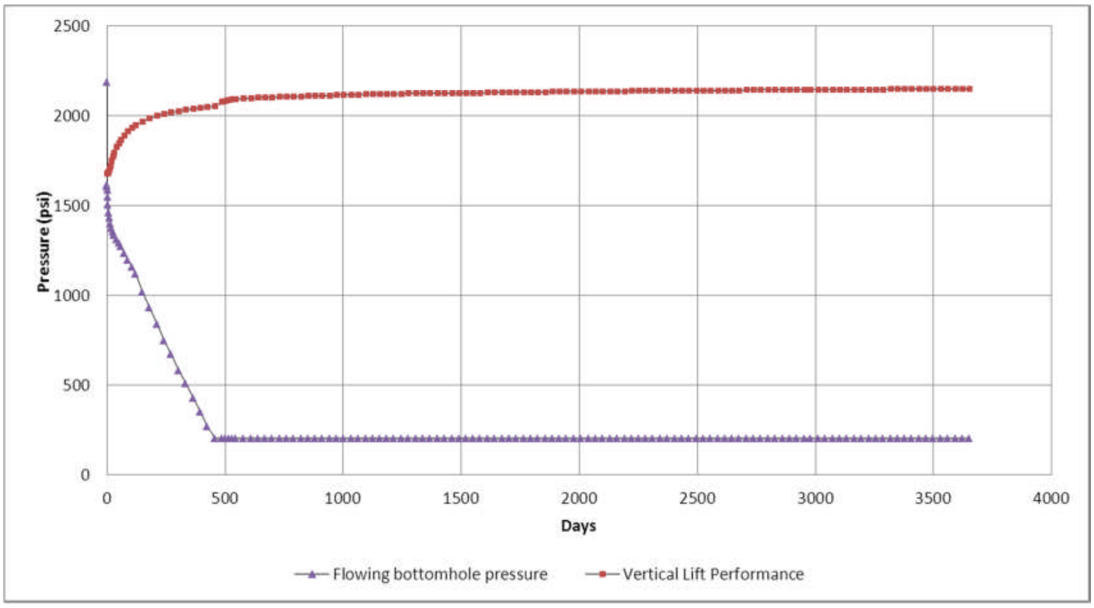

Figure 5.76: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 13.

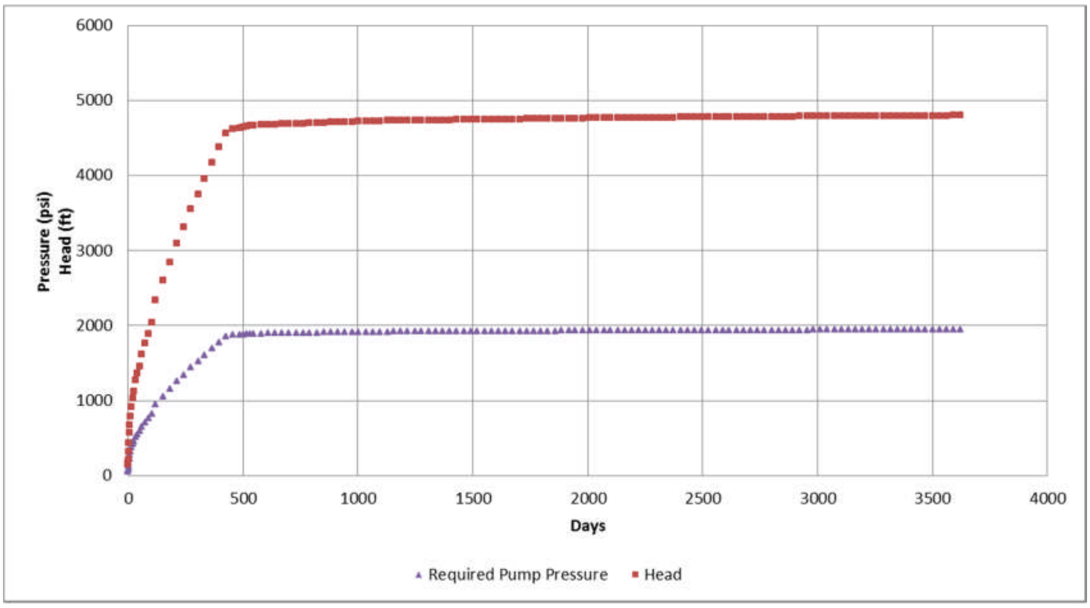

Figure 5.77: Required pump pressure and head for water drive reservoir in case 13.

The well is unable to flow naturally since the first day of production because the rapid production of water. The pressure required by vertical lift performance is high since the beginning and moderately increases and stays the same for the entire production period but flowing bottom-hole pressure drops quickly at the beginning and stays constant as shown in Figure 5.76. The head and the required pump pressure in Figure 5.77 rapidly increases due the reduction in the suction pressure and stays stable as there is no significant change in gas-oil ratio and water cut. In comparison to case 10 the head requirement in this case is higher due to higher amount of water cut.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 13 is P11 with 115 stages as shown in the Figure 5.78. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 101 stages as depicted in Figure 5.79.

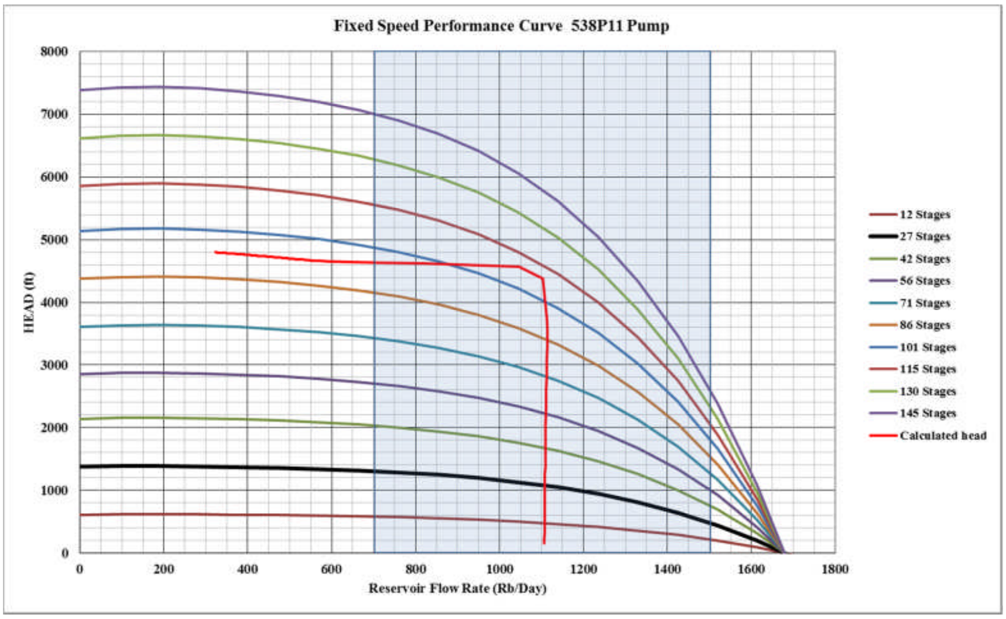

Figure 5.78: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 13.

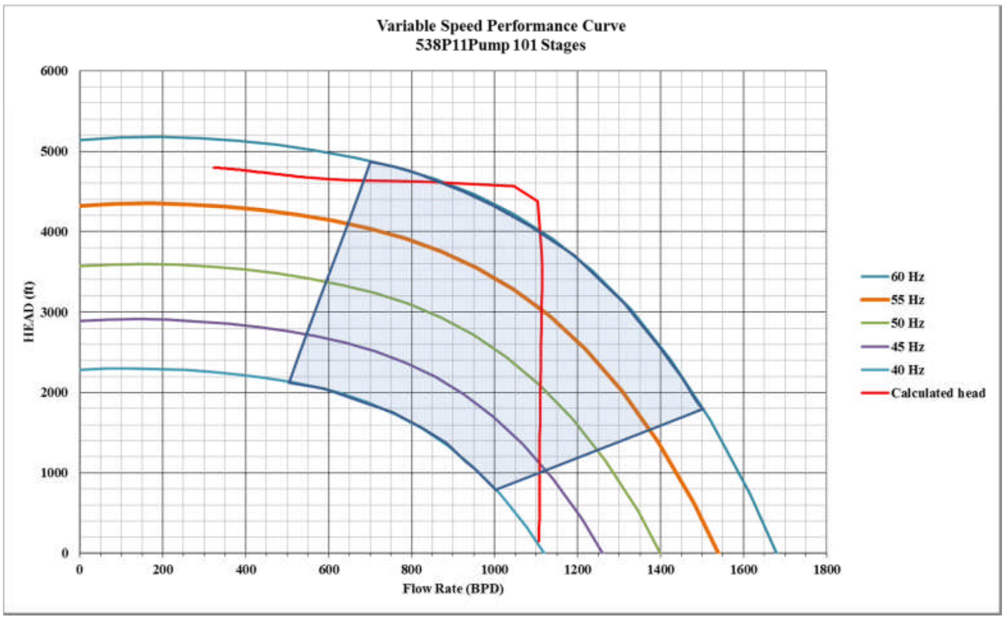

Figure 5.79: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 14.

Case 14: 5PV Aquifer, reservoir pressure 2,200 psi, reservoir temperature 168°F, and initial solution GOR 250 scf/STB.

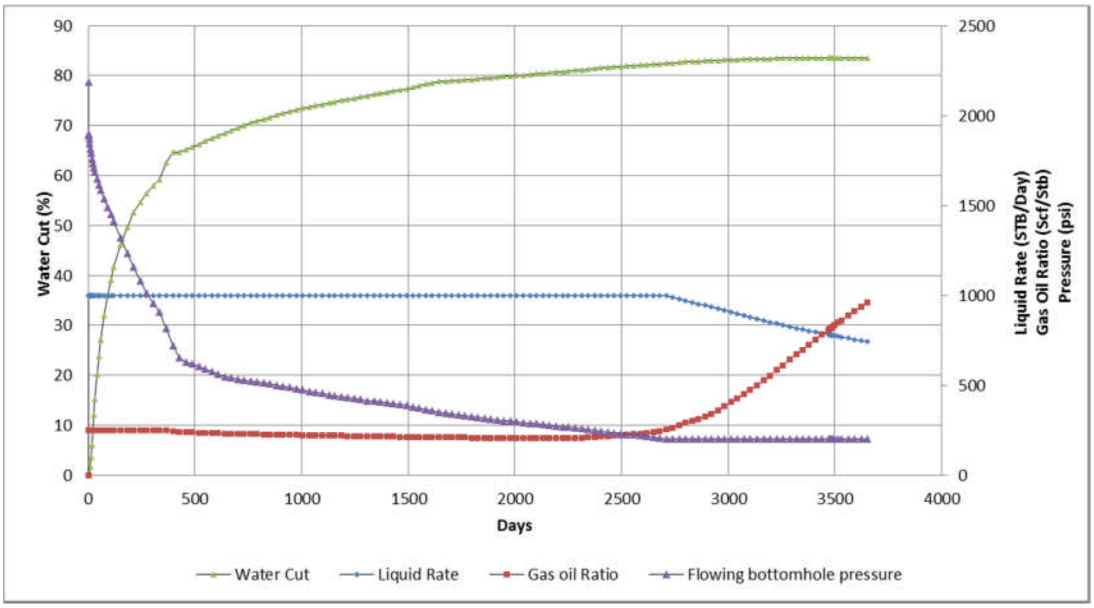

Figure 5.80: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 14.

The initial solution gas-oil ratio is varied to 250 scf/STB. As shown in Figure 5.80, the bottom-hole pressure rapidly changes due to the reduction of suction pressure. The liquid production rate is maintained at the target rate for 2,700 days by the aquifer support and slightly drops at the end of the reservoir life. In comparison to case 11, in which the aquifer is only 1PV, the liquid production rate in this case can be sustained for a longer period of time. The water cut increases quickly since the beginning to around 70% within 250 days and reaches over 80% at the end of production. At early stage, producing gas-oil ratio is stable until 2,500 days and increases moderately after 2,500 days.

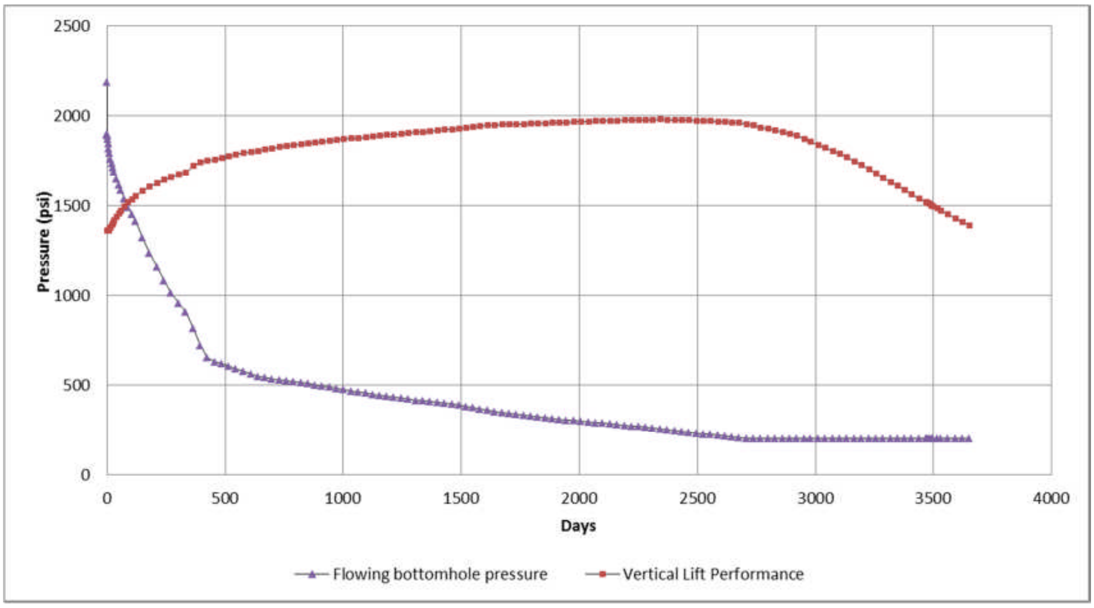

Figure 5.81: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 14.

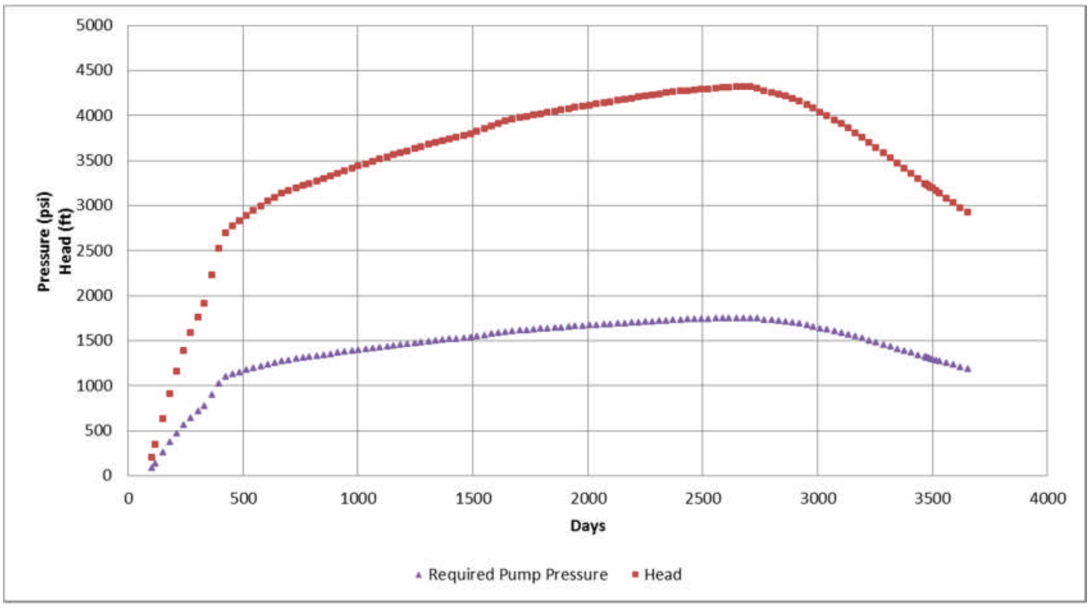

Figure 5.82: Required pump pressure and head for water drive reservoir in case 14.

The well is able to flow freely for a very short period. The pressure required by vertical lift performance in Figure 5.81 is high since the beginning and moderately increases and become more or less constant until it slightly drops at the end due to less hydrostatic loss in the tubing as more gas flows into the tubing. In contrast, the flowing bottom-hole pressure keeps falling down until reaching at the minimum limit of 200 psia. The required pump pressure and head as depicted in Figure 5.82 sharply increases at the beginning and later on gradually increases and finally declines after gas starts flowing into the well. In comparison to case 11, the maximum head in this case is higher due to higher water production.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 14 is P11 with 115 stages as shown in the Figure 5.83. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P17 with 73 stages as depicted in Figure 5.84.

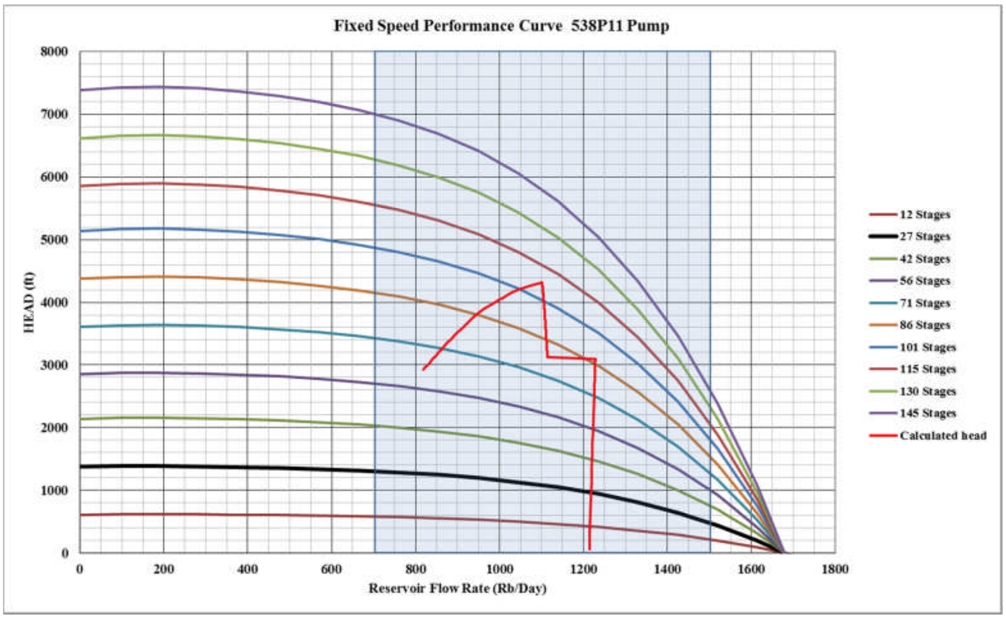

Figure 5.83: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 14.

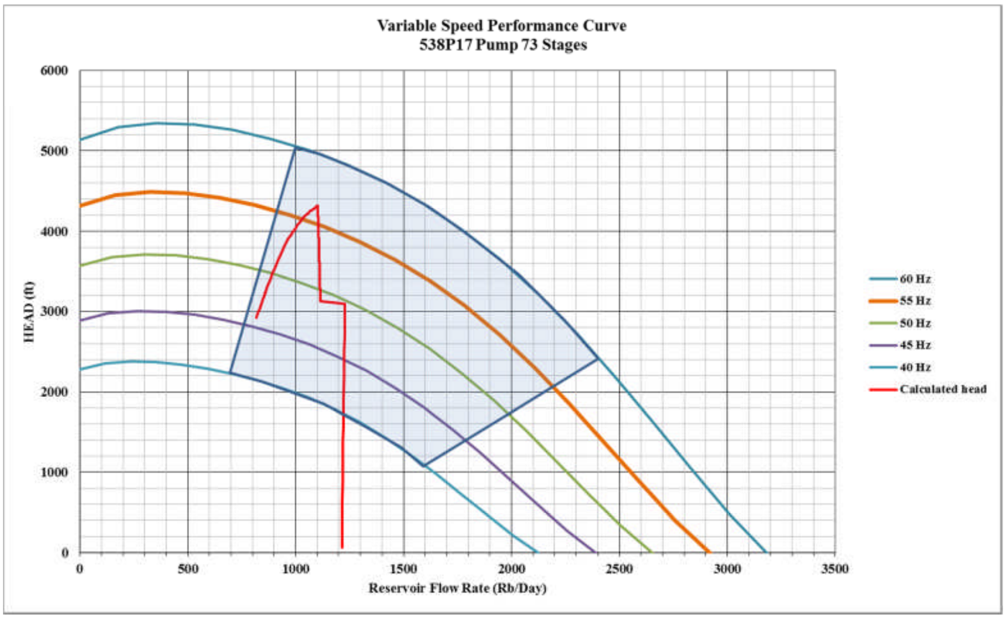

Figure 5.84: Variable speed pump design for 60-Hz 538P17 pump model for water-drive reservoir in case 14.

Case 15: 5PV Aquifer, reservoir pressure 2,200 psi, reservoir temperature 168°F, and initial solution GOR 500 scf/STB.

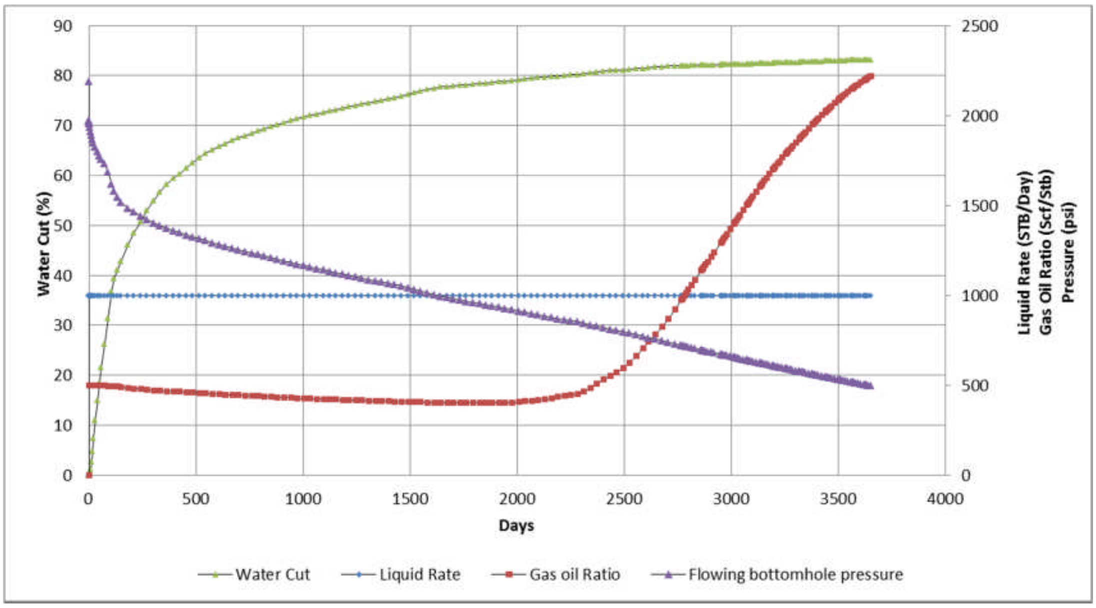

Figure 5.85: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 15.

In Figure 5.85, the bottom-hole pressure steadily drops whereas the production is stabilized at target rate 1,000 STB/D through the end of simulation due to strong aquifer support. The water cut increases quickly since the beginning to around 65% within 250 days and reaches 75% at the end of production. At early stage, gas-oil ratio does not change until 1,300 days. Then, the value steeply goes up because free gas starts to flow.

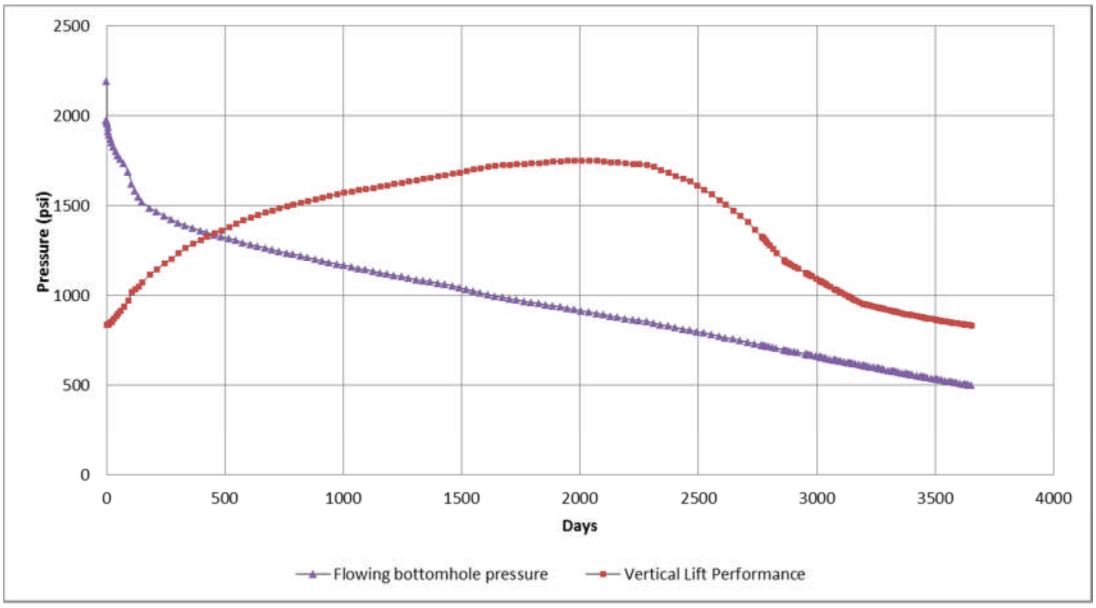

Figure 5.86: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 15.

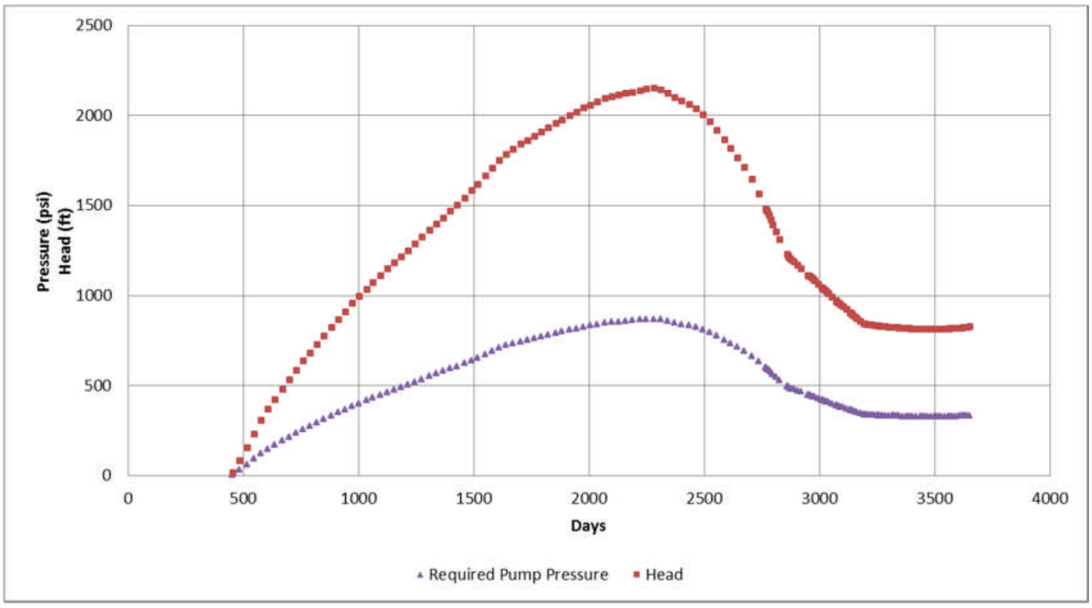

Figure 5.87: Required pump pressure and head for water drive reservoir in case 15.

The well can naturally flow for around 450 days as shown in Figure 5.58. The pressure from vertical lift performance in Figure 5.86 gradually increases and drops at the end of simulation due to less hydrostatic loss in the tubing as the producing gas-oil ratio increases. However, the flowing bottom-hole pressure required by the inflow steadily declines. The required pump pressure and head as depicted in Figure 5.87 sharply increases after the well cannot flow naturally until 2,300 days and afterward declines because free gas starts to flow into the wellbore. In comparison to case 12, the maximum head in this case is higher due to higher water production.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 15 is P11 with 86 stages as shown in the Figure 5.88. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P17 with 43 stages as depicted in Figure 5.89.

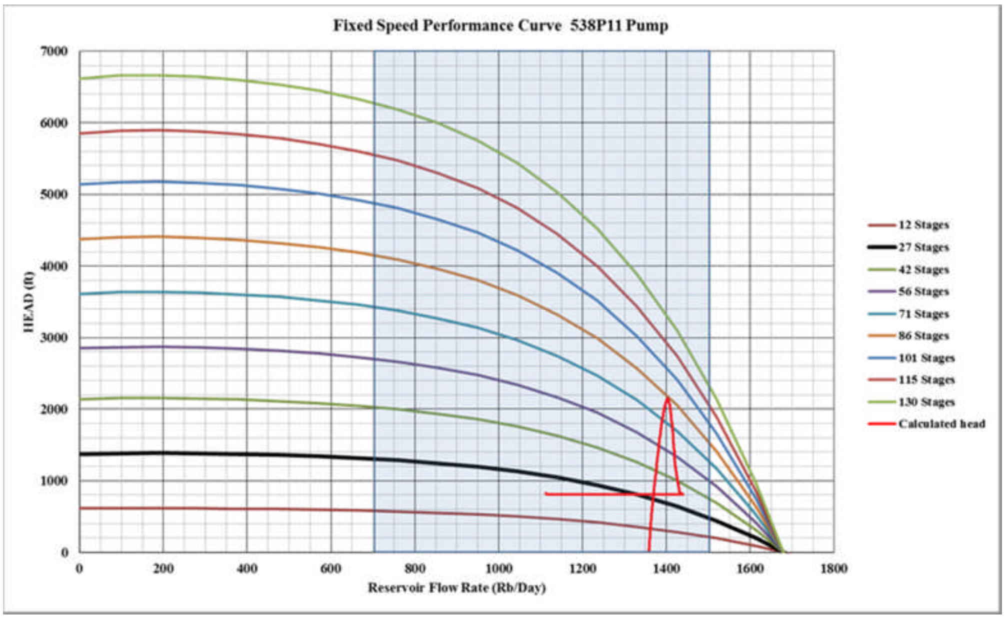

Figure 5.88: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 15.

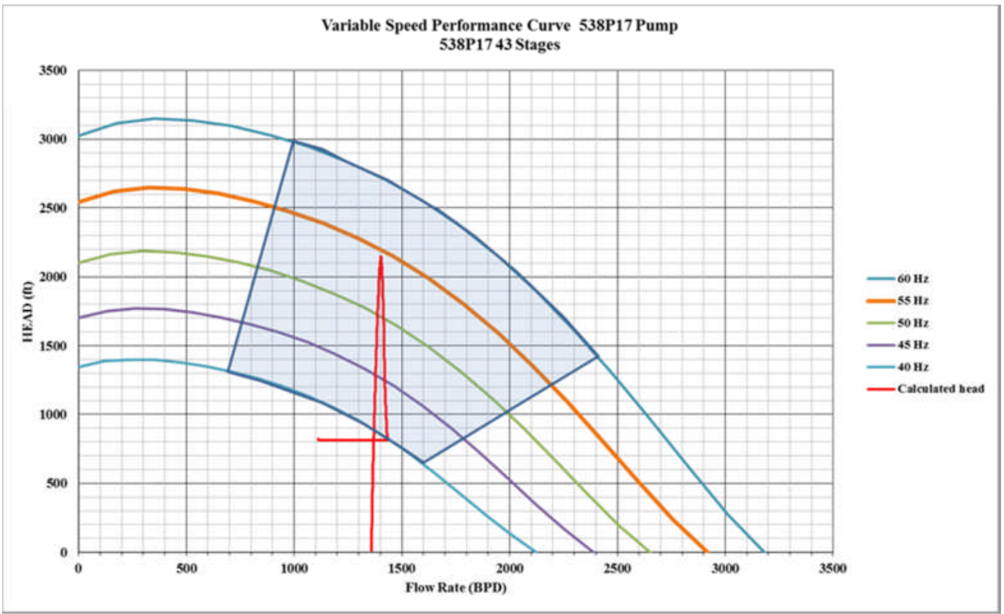

Figure 5.89: Variable speed pump design for 60-Hz 538P17 pump model for water-drive reservoir in case 15.

Case 16: 10PV Aquifer, reservoir pressure 2,200 psi, reservoir temperature 168°F, and initial solution GOR 100 scf/STB.

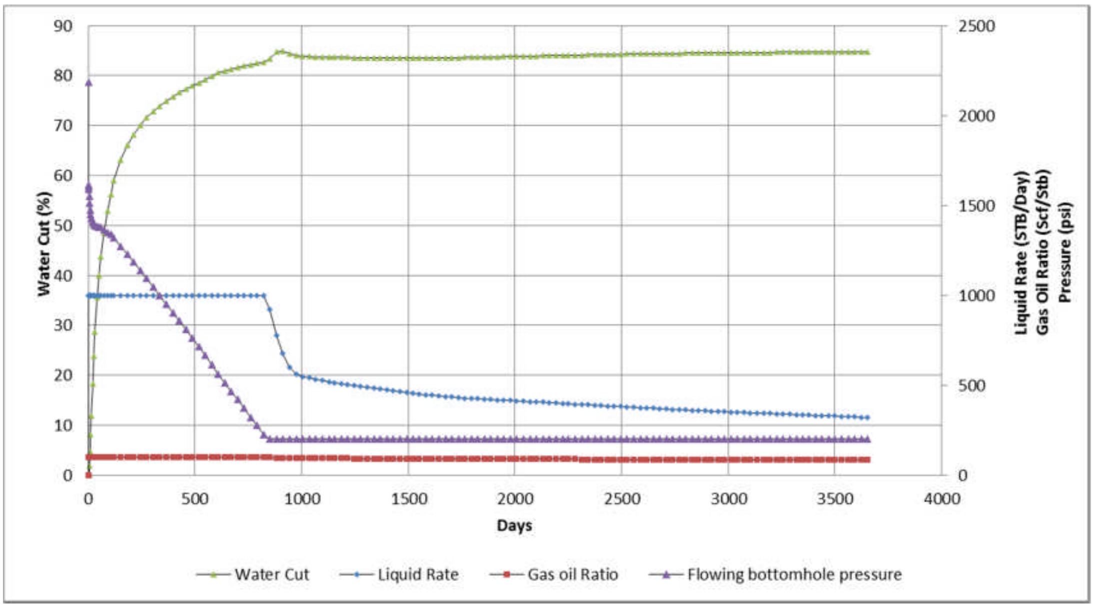

Figure 5.90: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 16.

The aquifer support is changed from 5 times to 10 times of reservoir pore volume in this case to study the influence of aquifer size on pump stage design. As represented in Figure 5.90, the bottom-hole pressure steadily declines while the liquid production target rate can be sustained for 900 days. The water cut increases quickly since the beginning to around 80% within 500 days and reaches 85% at the end of production. In comparison to case 13, in which the aquifer size is 5PV, the water cut in this case is higher due to larger aquifer.

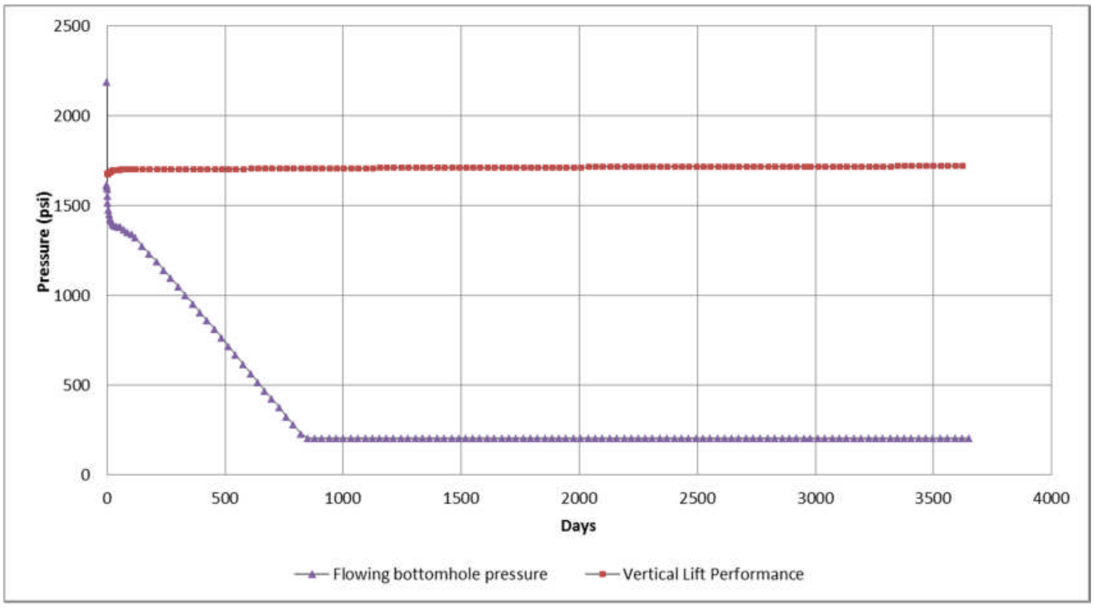

Figure 5.91: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 16.

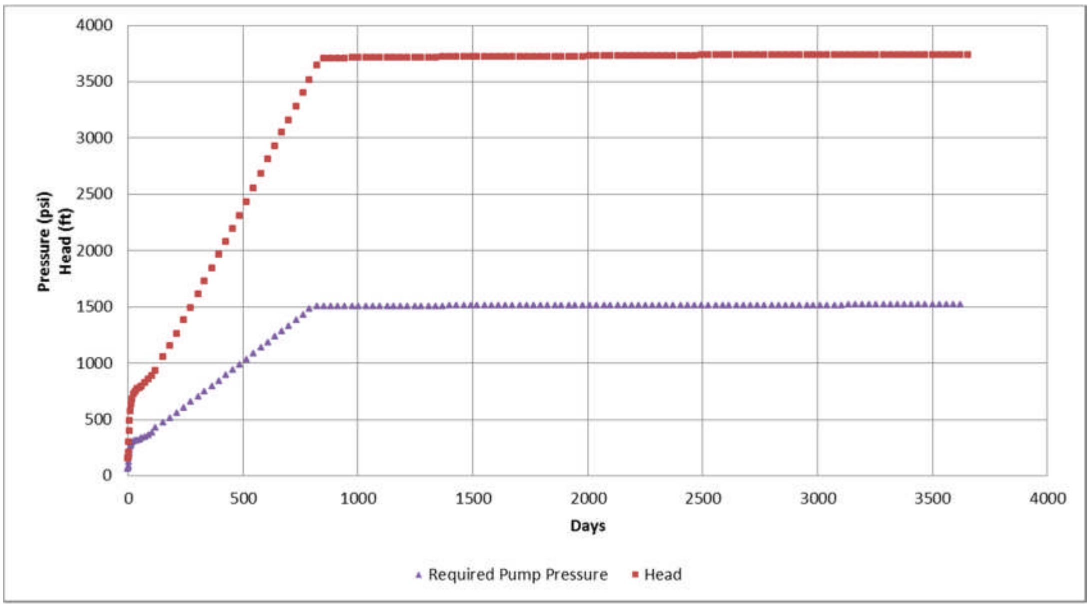

Figure 5.92: Required pump pressure and head for water drive reservoir in case 16.

The well cannot flow naturally since the first day as shown in Figure 5.61. The pressure from vertical lift performance is also high from the beginning and stays flat until the end but flowing bottom-hole pressure moderately declines until reaching the minimum as shown in Figure 5.91. The required pump pressure and head as depicted in Figure 5.92 rapidly increases at the beginning and remains unchanged after 750 days. In comparison to case 10 and 13, which have smaller aquifer size, the head requirement in this case of 10PV aquifer is the highest.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 16 is P11 with 101 stages as shown in the Figure 5.93. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 86 stages as depicted in Figure 5.94.

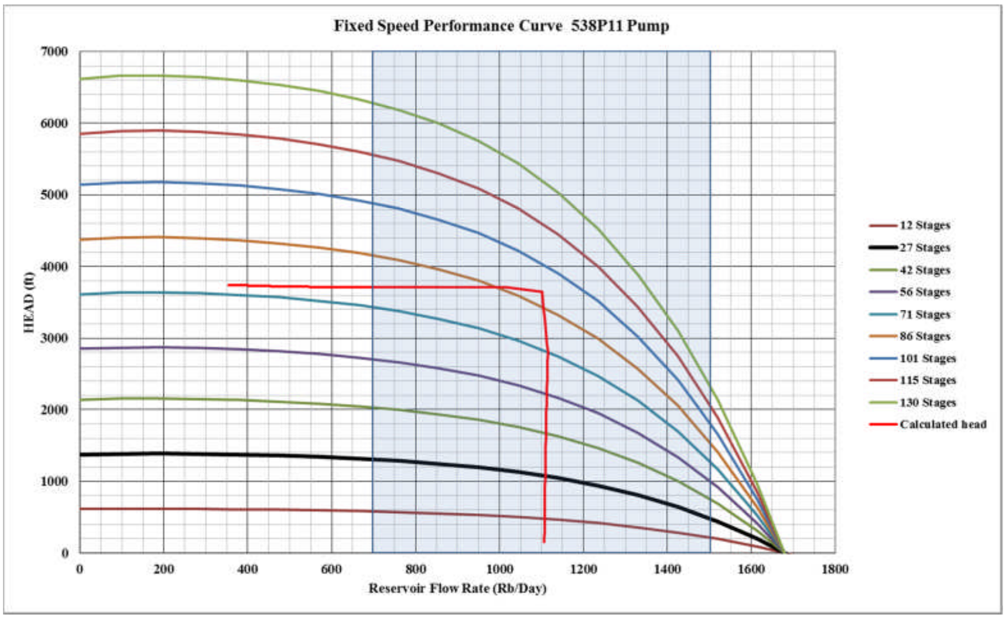

Figure 5.93: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 16.

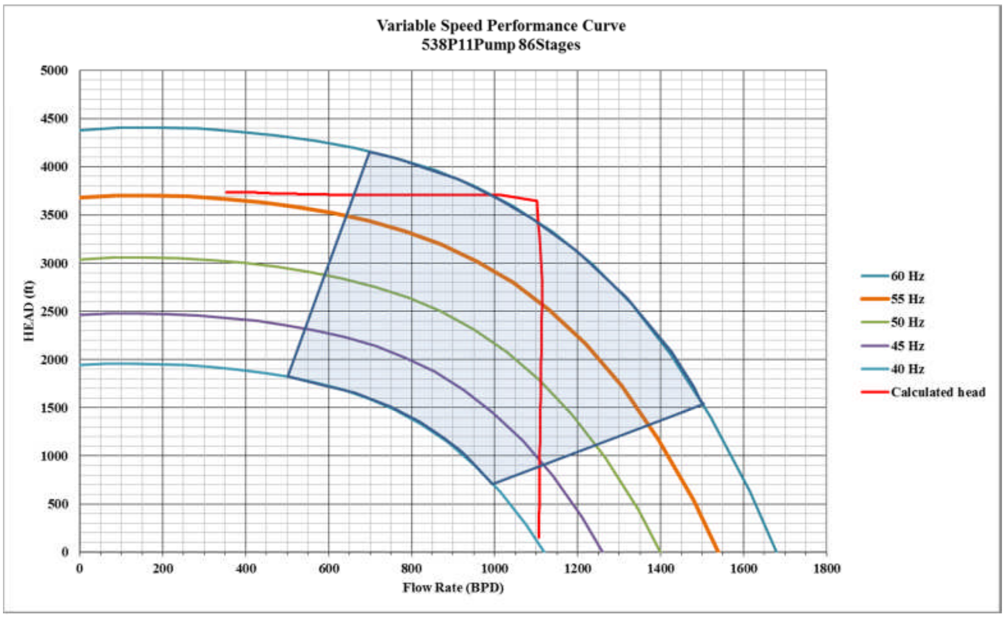

Figure 5.94: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 16.

Case 17: 10PV Aquifer, reservoir pressure 2,200 psi, reservoir temperature 168°F, and initial solution GOR 250 scf/STB.

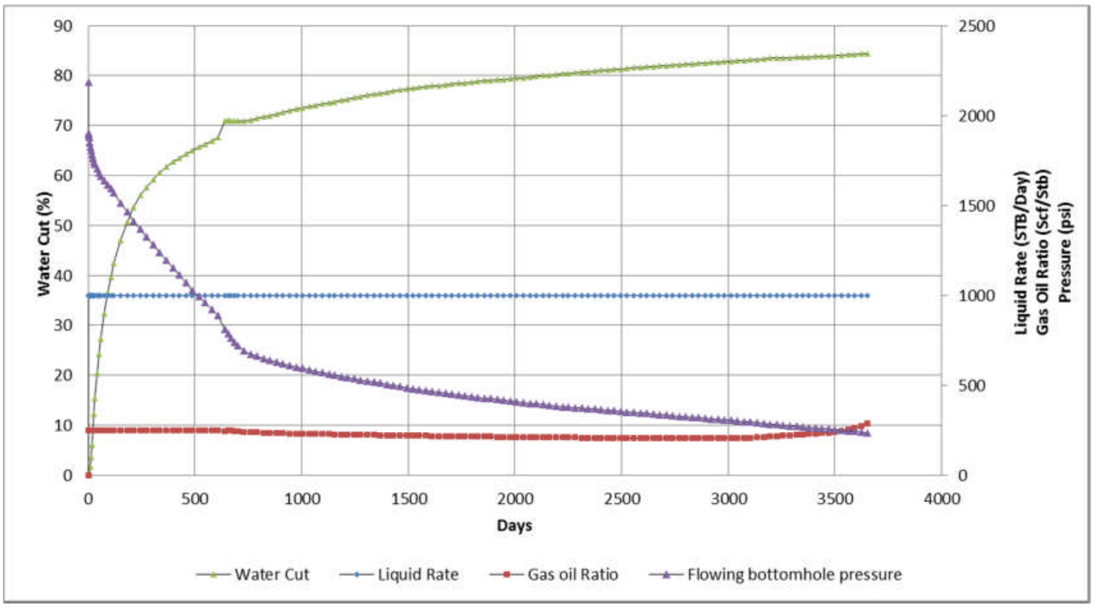

Figure 5.95: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 17.

In this case, the initial solution gas-oil ratio is altered to 250 scf/STB. The simulation results are shown in Figure 5.95. The production target rate remains stable at 1,000 STB/D for the entire life of simulation period because of aquifer support. The bottom-hole pressure declines while the water cut rapidly increases to around 70% within 500 days and reaches over 80% at the end of production.

From Figure 5.96, the well can flow naturally for a very short period and the bottom-hole pressure from vertical lift performance is initially high and gradually increases after the water cut increases gradually. The differential pressure between flowing bottom-hole pressure and pressure from vertical lift performance is plotted in Figure 5.97 as a required pump pressure. In another word, it is the difference between the discharge pressure and suction pressure and after dividing by fluid gravity, it is plotted as head in the same trend. In contrast with cases 11 and 14, the head does not decline at late times due to constant producing gas-oil ratio.

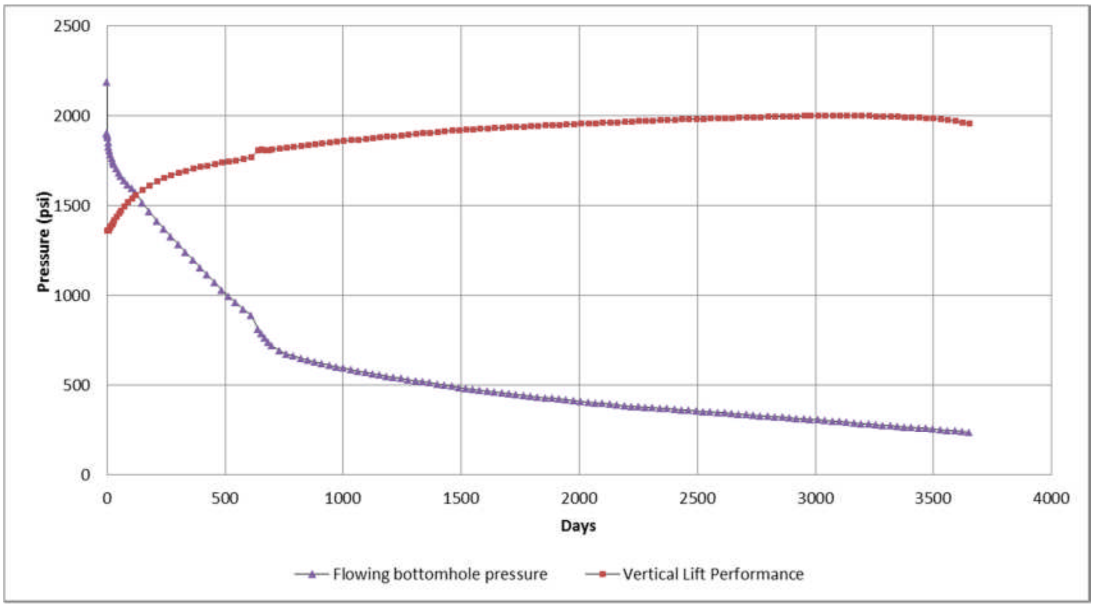

Figure 5.96: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 17.

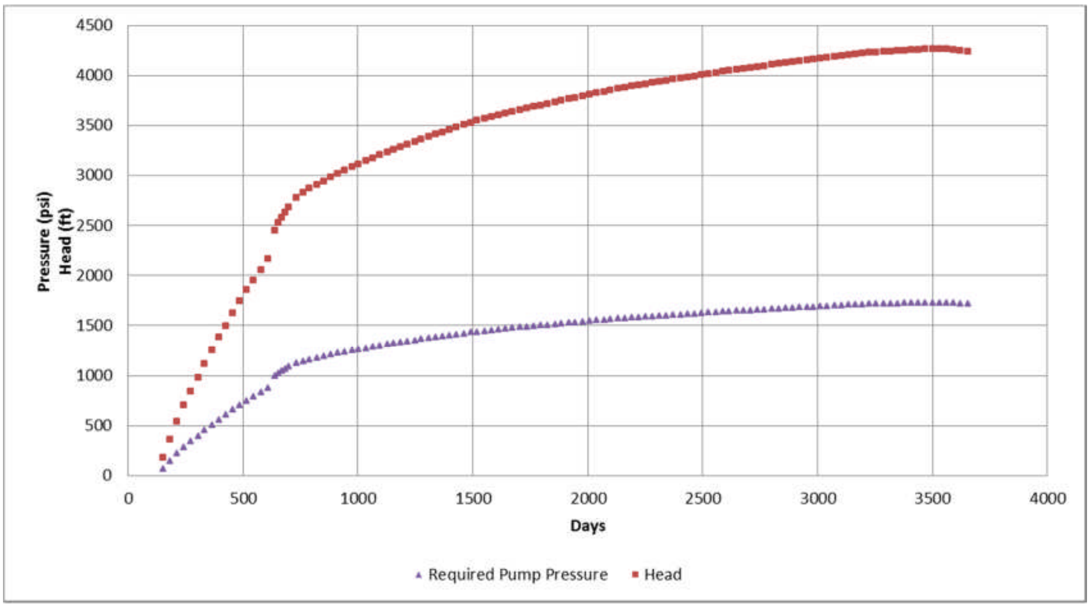

Figure 5.97: Required pump pressure and head for water drive reservoir in case 17.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 17 is P11 with 115 stages as shown in the Figure 5.98. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 101 stages as depicted in Figure 5.99.

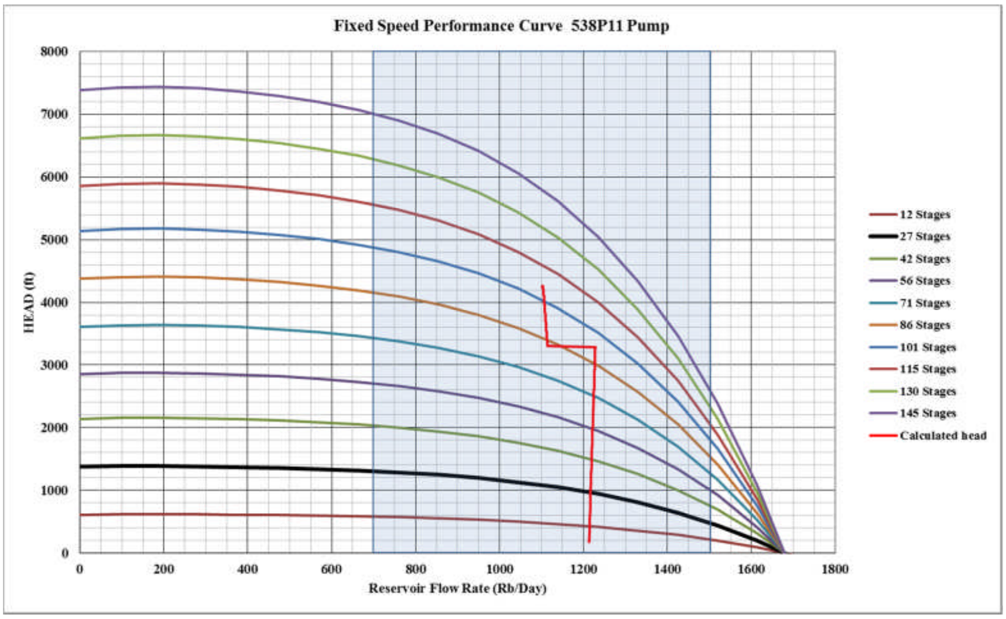

Figure 5.98: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 17.

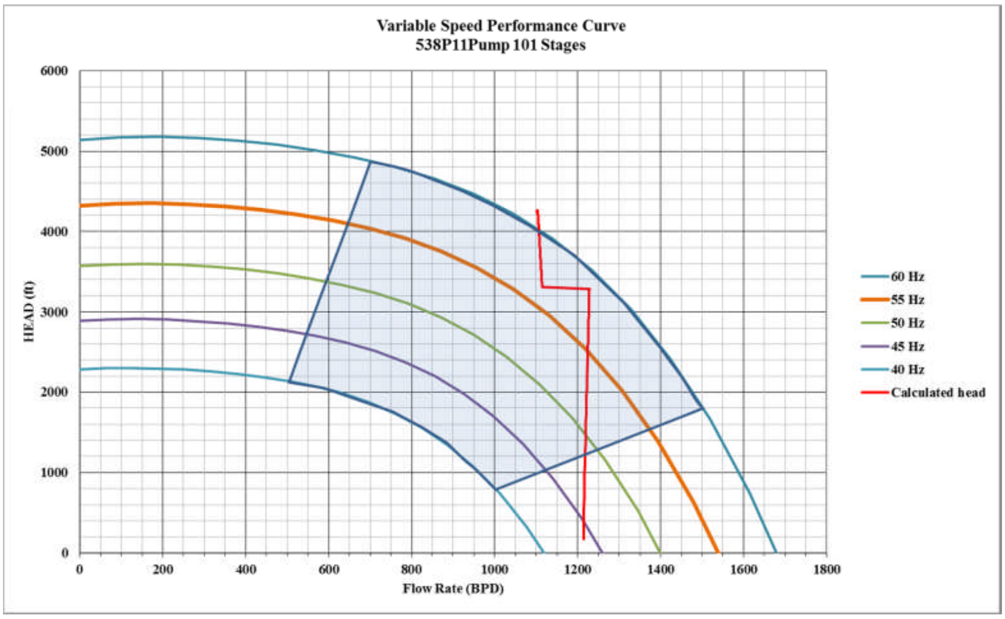

Figure 5.99: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 17.

Case 18: 10PV Aquifer, reservoir pressure 2,200 psi, reservoir temperature 168°F, and initial solution GOR 500 scf/STB.

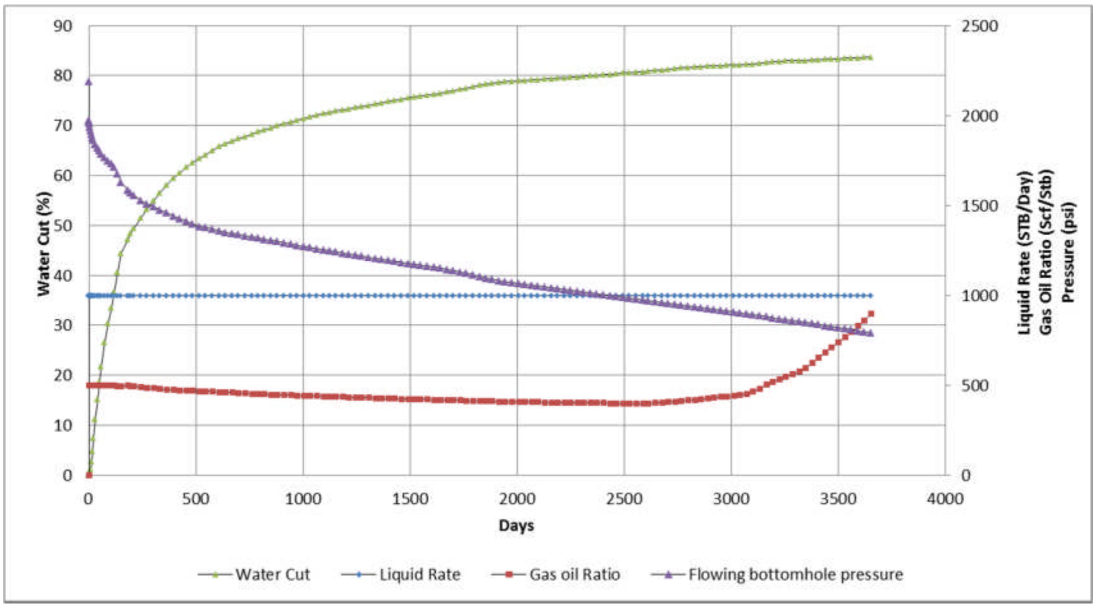

Figure 5.100: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 18.

This is the last case of water drive reservoir at depth 5,000 ft. Initial solution gas-oil ratio is changed to 500 scf/STB. The simulation results are shown in Figure 5.100. Due to pressure support from water aquifer, the production target rate remains stable at 1,000 STB/D for the entire life of reservoir. The producing gas-oil ratio is more or less unchanged for 3,000 days and steadily increases afterward. The bottom-hole pressure declines at a slow pace while the water cut increases quickly since the beginning to around 65% within 500 days and reaches over 80% at the end of production.

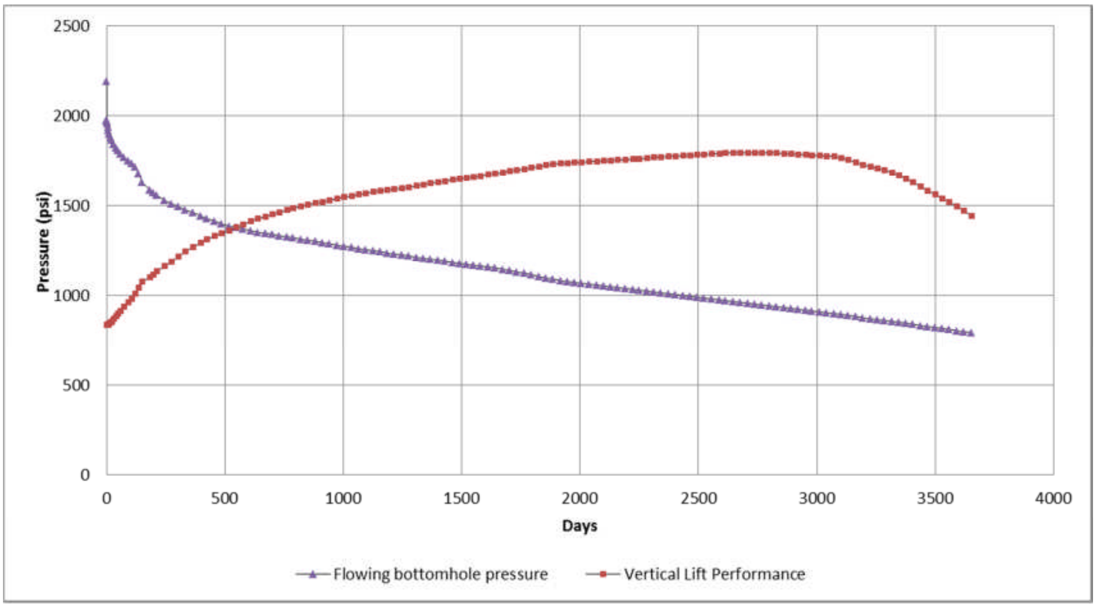

Figure 5.101: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 18.

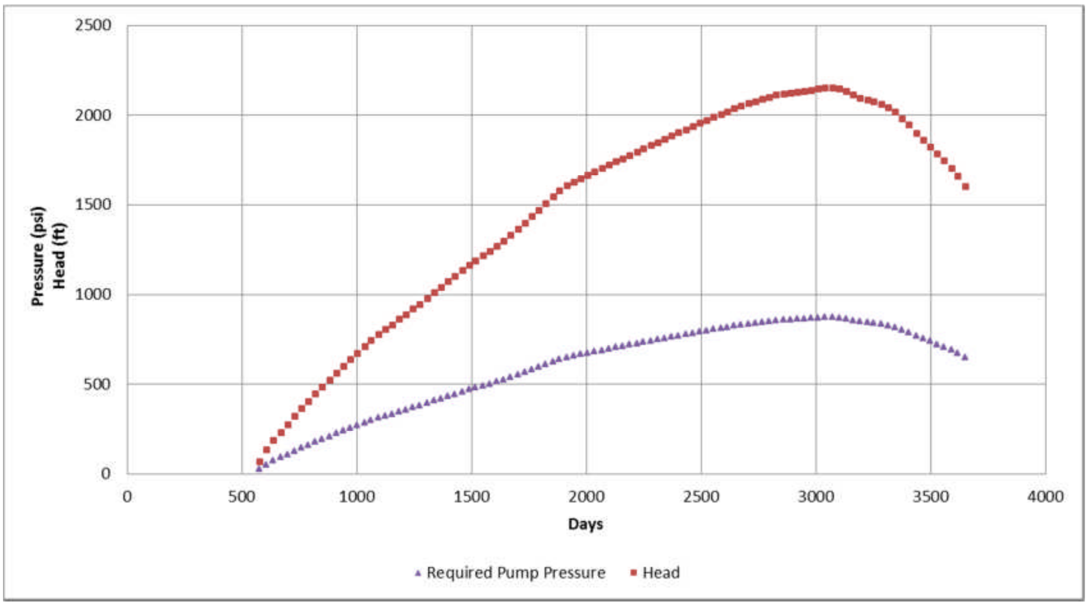

Figure 5.102: Required pump pressure and head for water drive reservoir in case 18.

From Figure 5.101, the well flows naturally for around 500 days. The flowing bottom-hole pressure declines at moderate rate while the pressure required for vertical lift performance increases due to water production in the tubing. Later on, when more gas flows into the wellbore, the pressure for vertical lift performance deceases because a lighter fluid is produced in the tubing. The required pump pressure and head are shown in Figure 5.102. They steadily increase in the same style due to water production and afterward when more gas flows into the wellbore, they gradually decrease. In comparison to cases 12 and 15, the head requirement in this case is the highest due to high water cut.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 18 is P11 with 86 stages as shown in the Figure 5.103. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P17 with 43 stages as depicted in Figure 5.104.

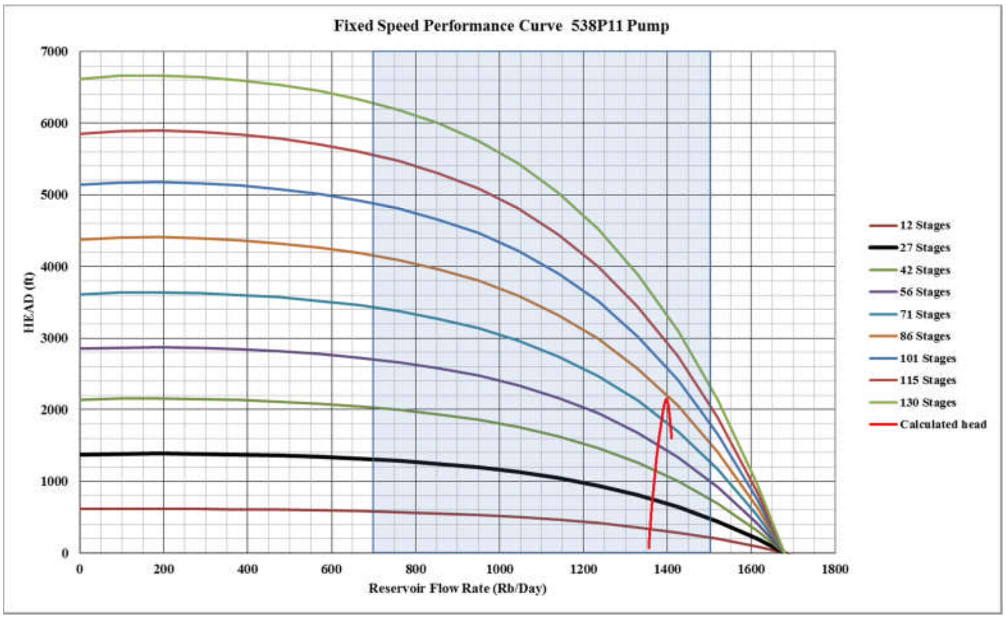

Figure 5.103: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 18.

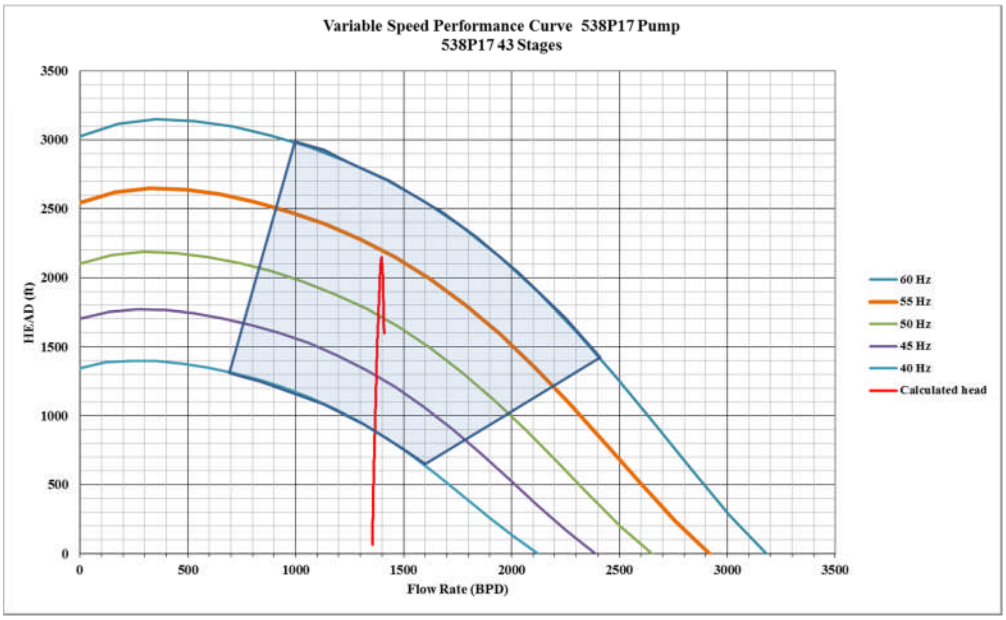

Figure 5. 104: Variable speed pump design for 60-Hz 538P17 pump model for water-drive reservoir in case 18.

5.4.2 Water-drive Reservoir at Reservoir Depth 7,000 ft.

Case 19: 1PV Aquifer, reservoir pressure 3,300 psi, reservoir temperature 200°F, and initial solution GOR 100 scf/STB.

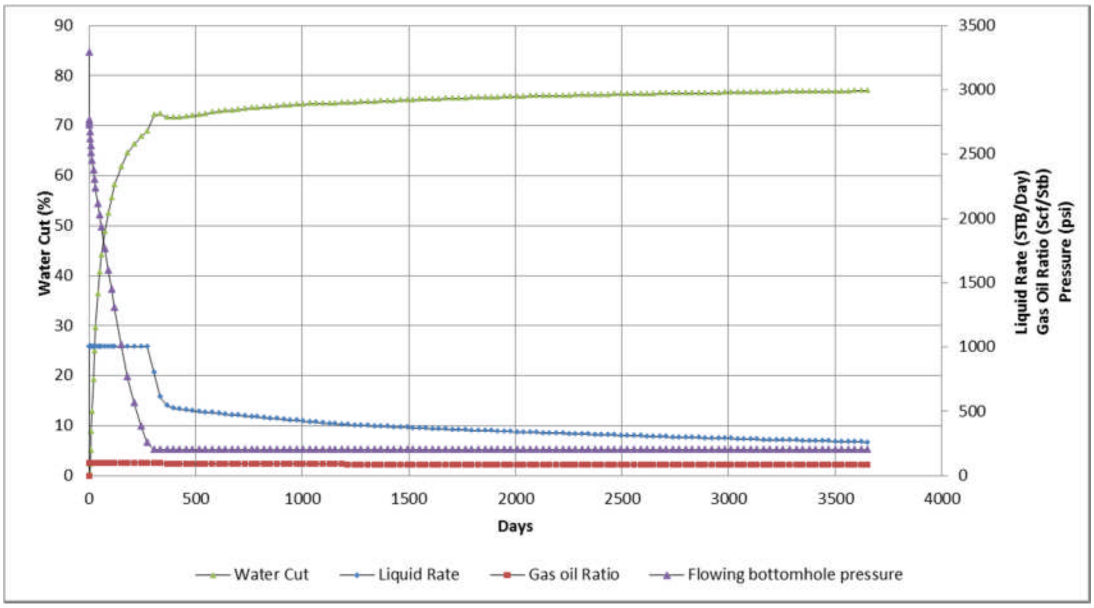

Figure 5.105: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 19.

In this section, the reservoir depth is changed to7,000 ft. with the higher reservoir pressure, and reservoir temperature. The initial solution gas-oil ratio and aquifer size is altered in the same fashion as section 5.4.1. As depicted in Figures 5.105, liquid production rate is sustained at 1,000 STB/D for around 200 days and it steadily decreases to minimum of 200 STB/D. The water cut increases quickly since the beginning to around 70% within 250 days and reaches over 75% at the end of production. The bottom-hole pressure rapidly declines at the beginning until reaches at minimum of 200 psia. The producing gas-oil ratio is more or less constant for the entire life of the well because of small solution gas-oil ratio.

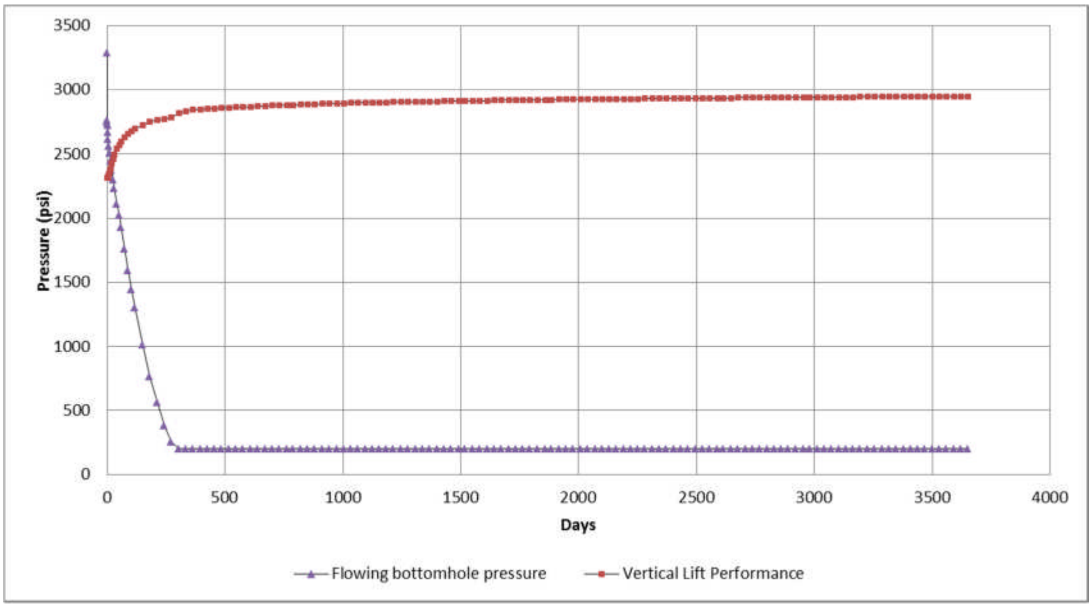

Figure 5.106: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 19.

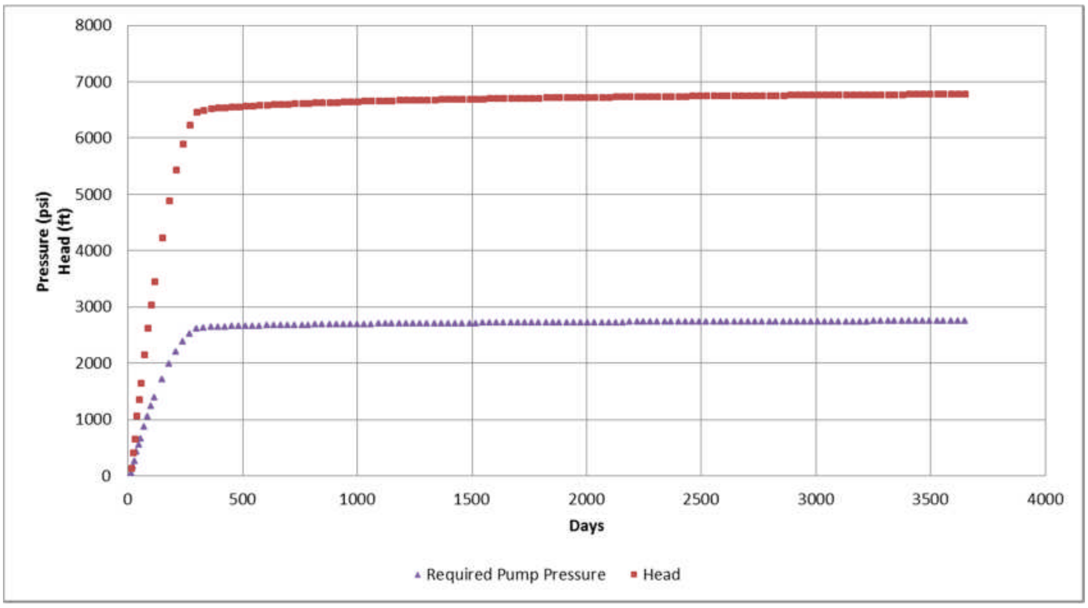

Figure 5.107: Required pump pressure and head for water drive drive reservoir in case 19.

The well cannot flow naturally at the first day of production because of high amount of water production. The differential pressure between the bottom-hole pressure and pressure from vertical lift performance increases rapidly and stays stable until the end of simulation period as shown in Figure 5.106. The head in Figure 5.107 significantly increases at the beginning as the well flowing pressure sharply declines. Then, the head stays constant and high due to small solution gas-oil ratio. In comparison with case 1, the head in this case is higher due to water production.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 19 is P11 with 160 stages as shown in the Figure 5.108. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 145 stages as depicted in Figure 5.109.

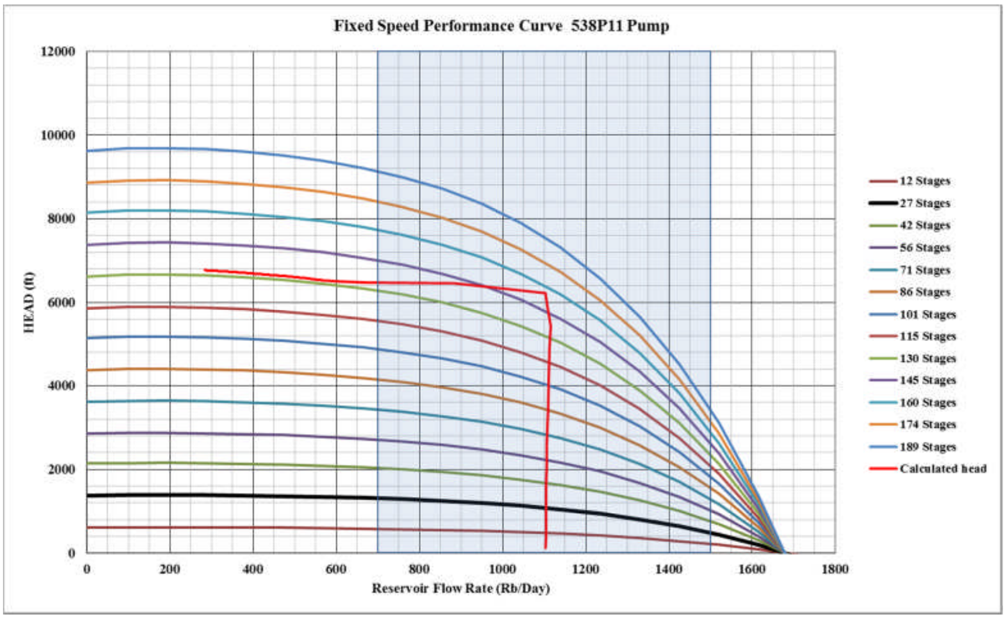

Figure 5.108: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 19.

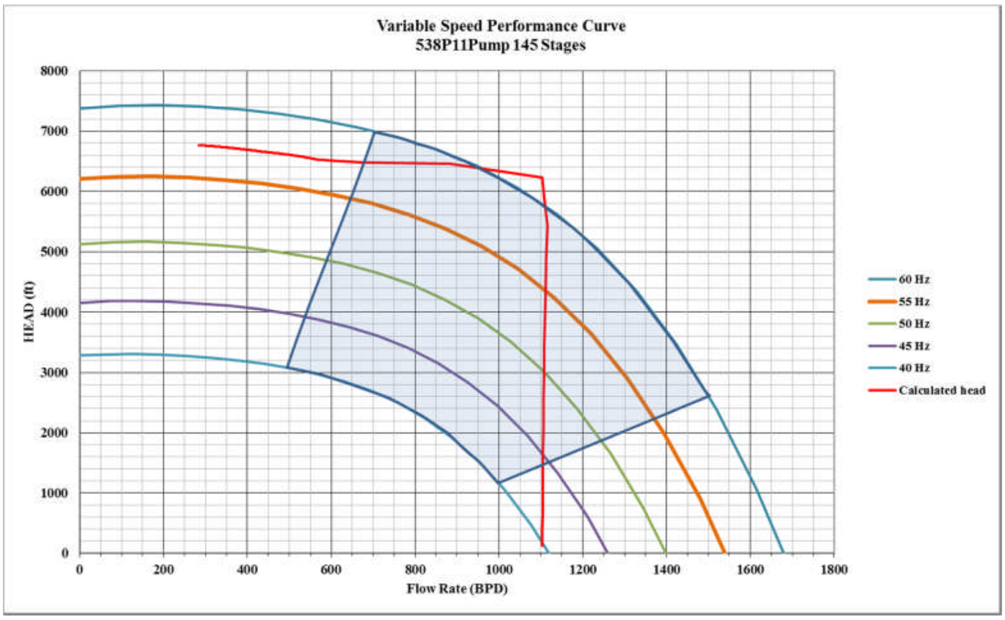

Figure 5.109: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 19.

Case 20: 1PV Aquifer, reservoir pressure 3,300 psi, reservoir temperature 200°F, and initial solution GOR 250 scf/STB.

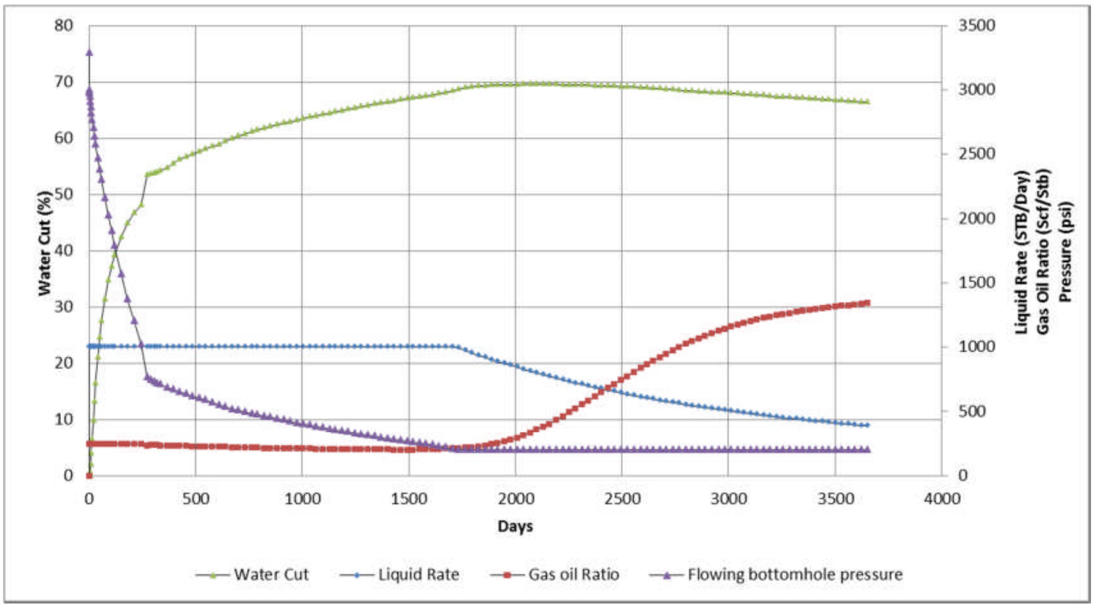

Figure 5.110: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 20.

In this case the initial solution gas-oil ratio is altered to 250 scf/STB . From Figure 5.110, liquid production rate is sustained at target rate for 1,700 days and steadily decreases afterward. The bottom-hole pressure suddenly drops at the beginning because of water production and small size of aquifer support. Producing gas-oil ratio is constant until 1,700 days and then starts to increase afterward due to reduction of reservoir pressure below the bubble point pressure. The water cut increases quickly since the beginning to around 60% within 500 days and reaches over 70% at the end of production.

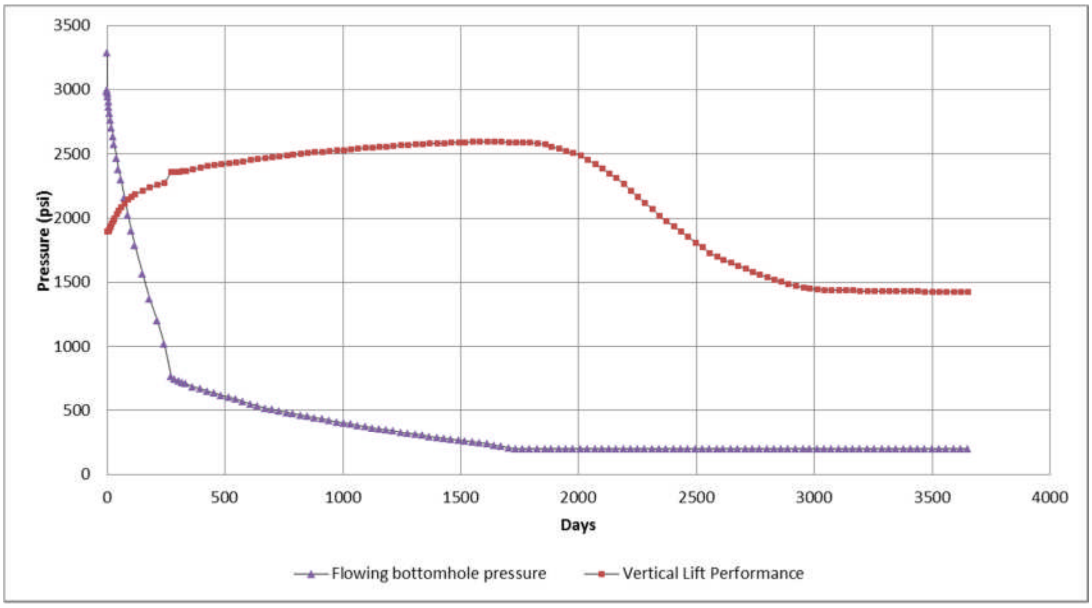

Figure 5.111: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 20.

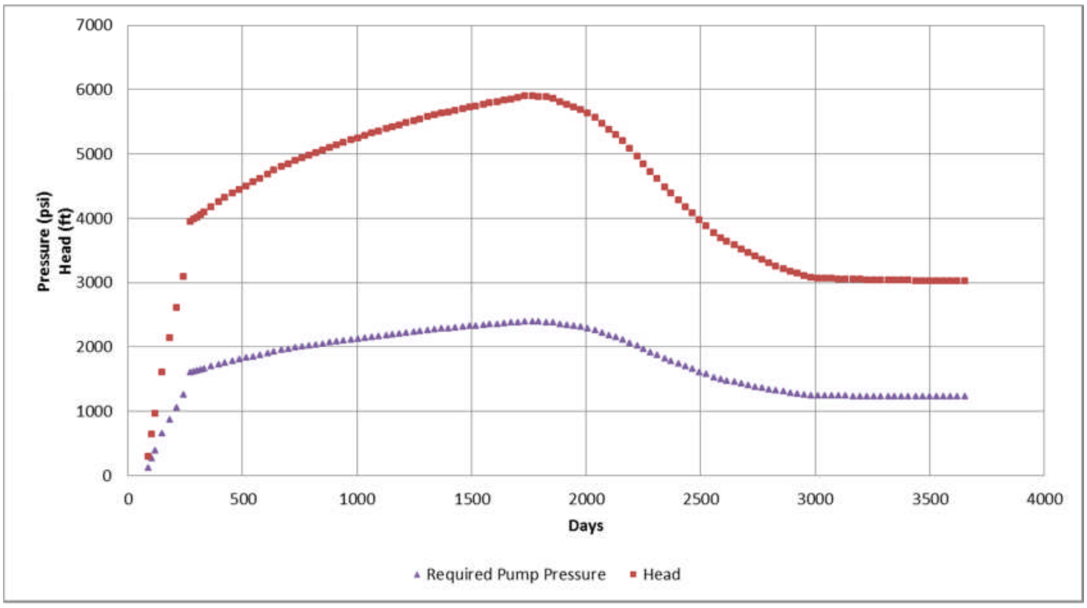

Figure 5.112: Required pump pressure and head for water drive reservoir in case 20.

The well flows naturally for a very short period because rapid increase in water cut. The bottom-hole pressure and pressure from vertical lift performance are shown in Figure 5.111. The pressure from tubing performance is high in the middle of production period and lower after gas flows into the wellbore due to pressure reduction. The head in Figure 5.112 significantly increases at the beginning due the reduction in the suction pressure and higher water production rate. As more gas flows into the wellbore at later times, the required pump pressure slowly declines. In comparison with case 2, the head requirement in this case is higher due to high water cut.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 20 is P11 with 145 stages as shown in the Figure 5.113. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 130 stages as depicted in Figure 5.114.

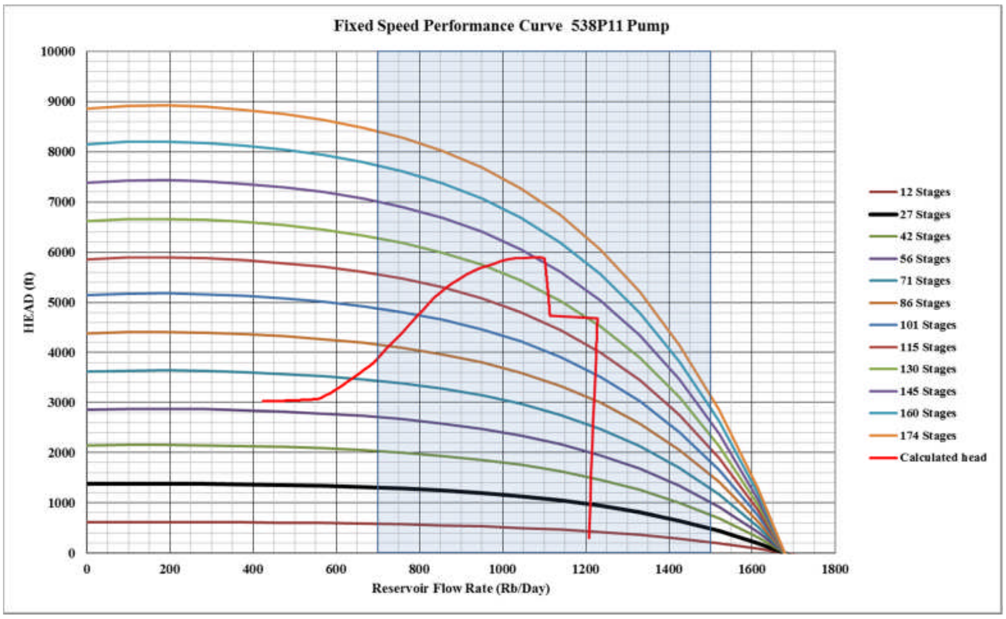

Figure 5.113: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir case 20.

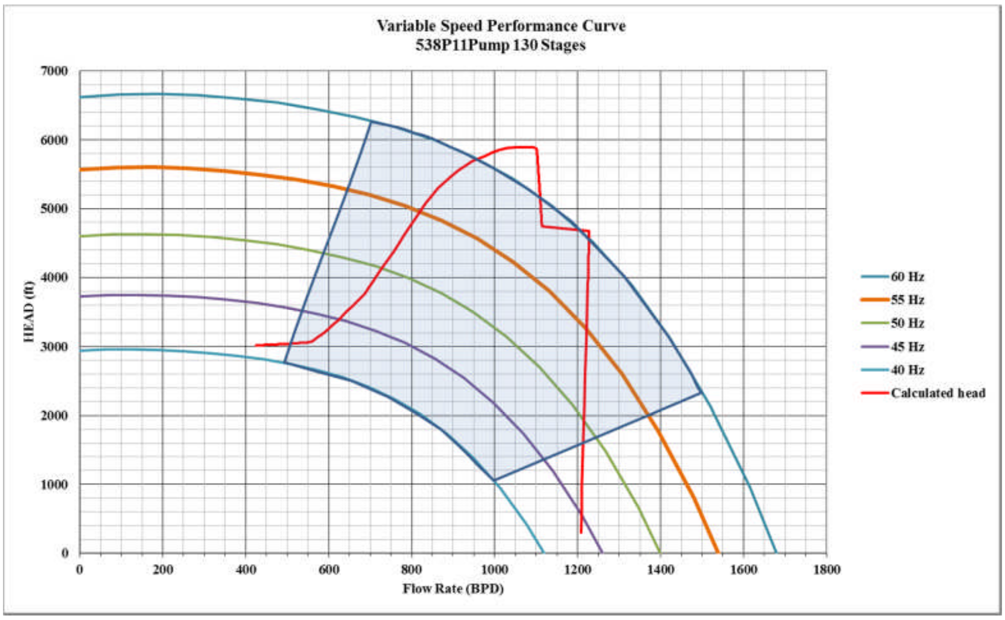

Figure 5.114: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 20.

Case 21: 1PV Aquifer, reservoir pressure 3,300 psi, reservoir temperature 200°F, and initial solution GOR 500 scf/STB.

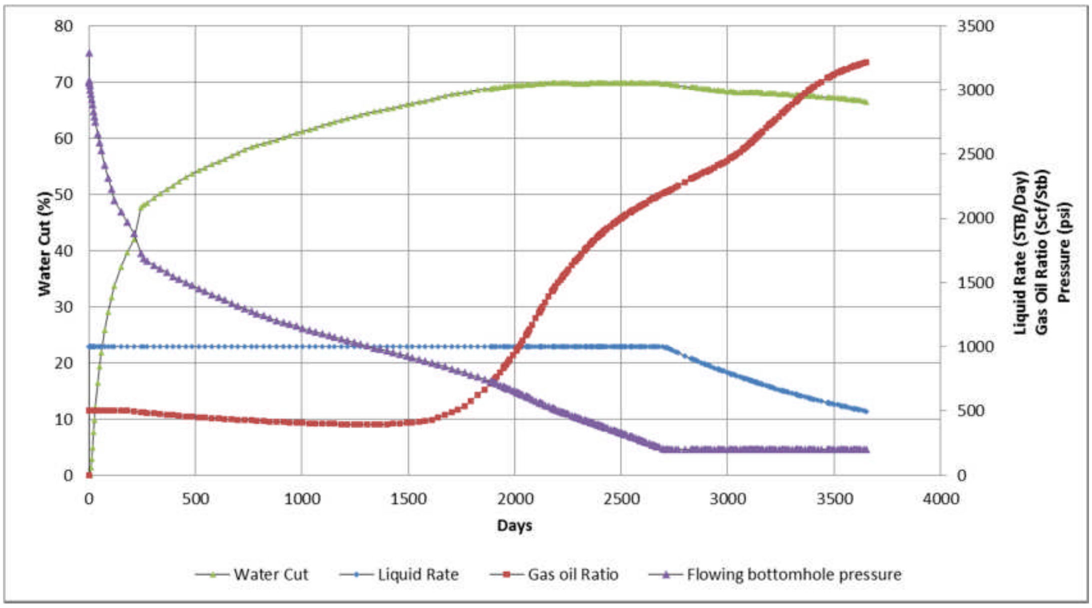

Figure 5.115: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 21.

Figure 5.115 illustrates the simulation results of initial solution gas-oil ratio 500 scf/STB while other reservoir parameters are the same. Liquid production rate is constantly produced at the target rate for around 2,700 days and decreases gradually later. The water increases sharply since the beginning to around 55% within 500 days and reaches nearly 70% at the end of production. On the other hand, the bottom-hole pressure suddenly drops from the first day and declines at a slow pace until reaching at the minimum requirement at 200 psia around 2,200 days. Producing gas-oil ratio increases after 1,500 days because the reservoir pressure drops below the bubble point pressure and gas starts to flow into the wellbore.

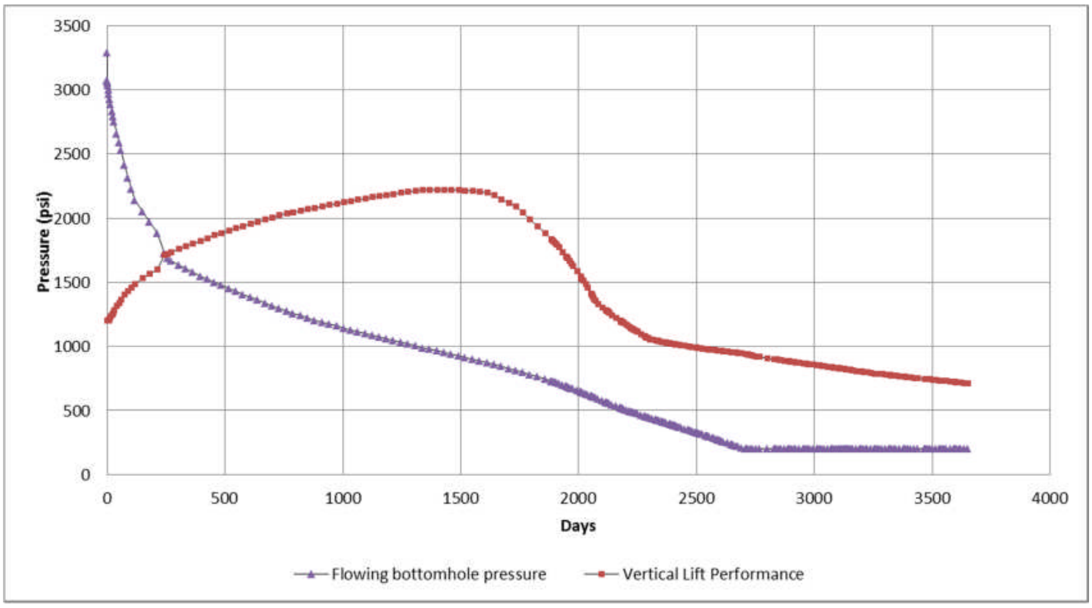

Figure 5.116: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 21.

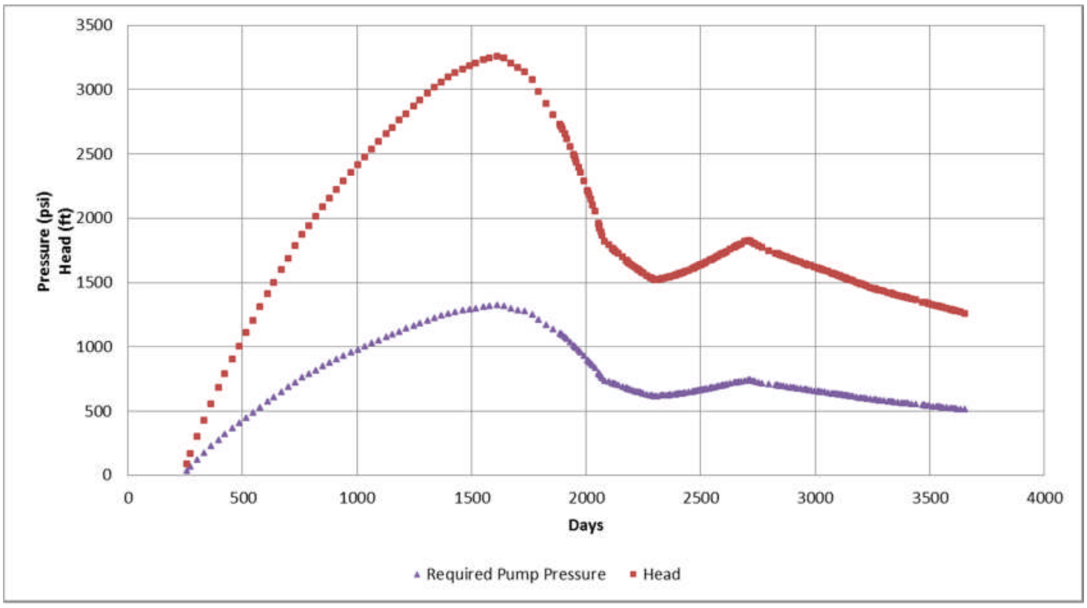

Figure 5.117: Required pump pressure and head for water drive reservoir in case 21.

The well naturally flows for around 250 days due to influence of pressure support from water aquifer and liberated gas in the tubing. The bottom-hole pressure and pressure from vertical lift performance increases gradually until 1,500 days and declines after free gas starts to flow as shown in Figure 5.116. The head in Figure 5.117 remarkably increases during 250 days to around 1,500 days of production due to the reduction in the suction pressure to maintain the target rate and the increases in pressure required for vertical lift as water cut increase. When free gas starts to flow, the required pump pressure slowly declines in the same trend as the head. In comparison with case 3, the water production in case 21 causes the head requirement to be higher.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 21 is P11 with 130 stages as shown in the Figure 5.118. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 115 stages as depicted in Figure 5.119.

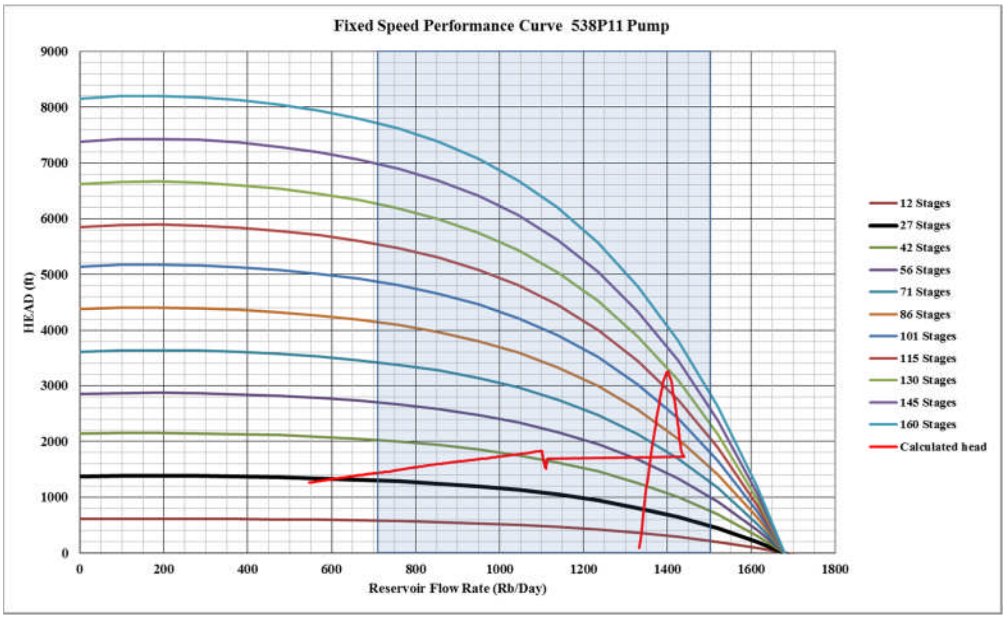

Figure 5.118: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 21.

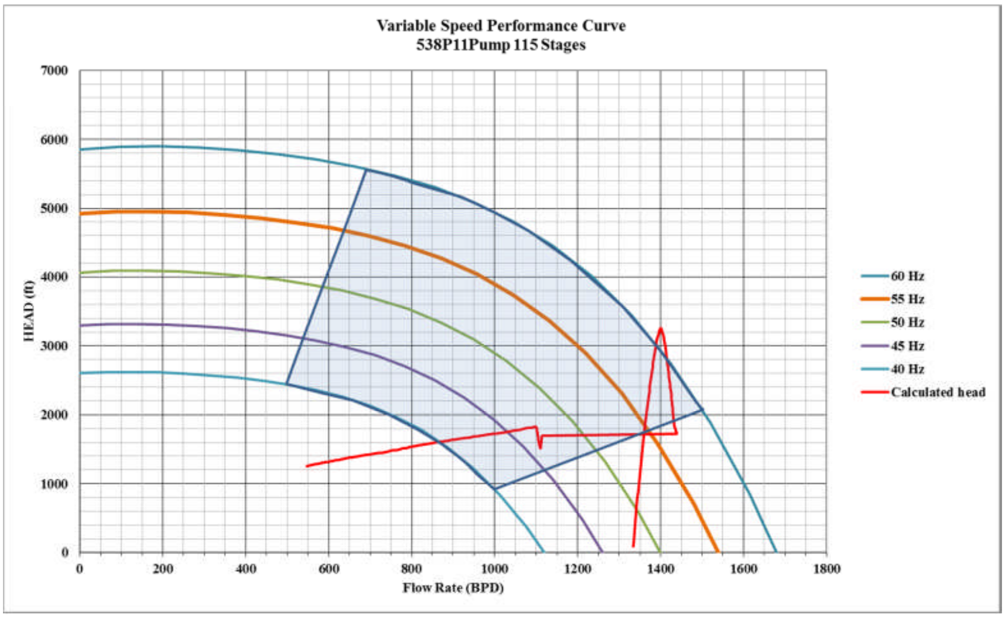

Figure 5.119: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 21.

Case 22: 5PV Aquifer, reservoir pressure 3,300 psi, reservoir temperature 200°F, and initial solution GOR 100 scf/STB.

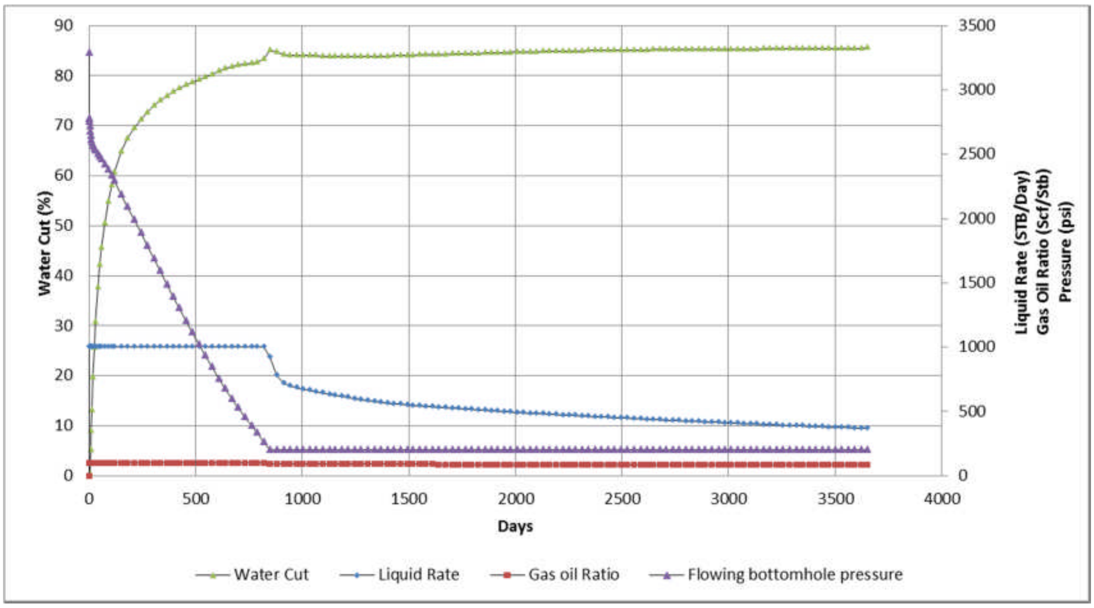

Figure 5.120: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 22.

In this scenario, water aquifer is upsized to 5 times of reservoir pore volume (PV) and the rest of reservoir parameters have not changed. The initial solution gas-oil ratio in this case is altered to 100 scf/STB. From Figure 5.120, the bottom-hole pressure suddenly declines due to the reduction of suction pressure and reaches at minimum requirement of 200 psia. The liquid rate is maintained at the target rate for around 800 days and then drops in the same fashion as the bottom-hole pressure. The water cut rapidly increases since the beginning to around 80% within 500 days and reaches 85% at the end of production. The water cut in this case is higher than the one in case 19 as a result of stronger water aquifer. Producing gas-oil ratio is more or less contestant through the end of reservoir life because of small solution gas-oil ratio.

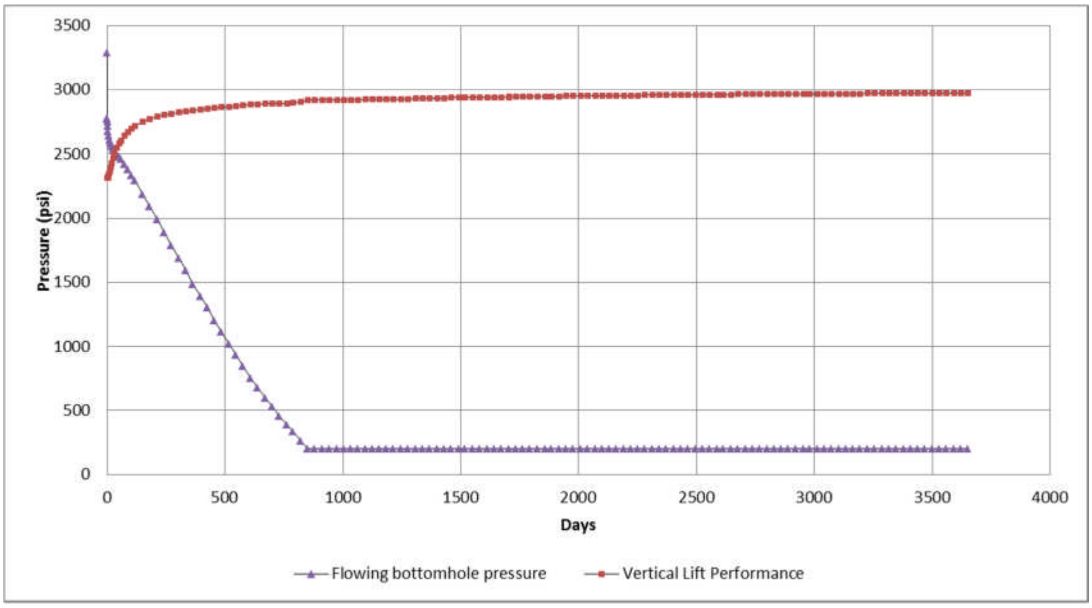

Figure 5.121: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 22.

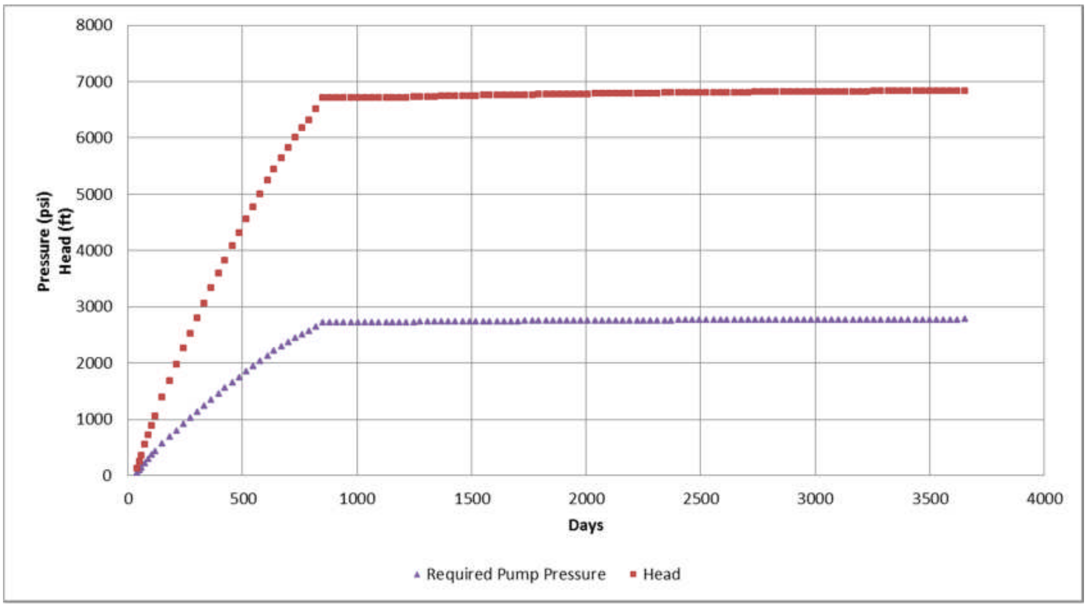

Figure 5.122: Required pump pressure and head for water drive reservoir in case 22.

The well flows naturally at the very short period because of high amount of water production. The pressure from vertical lit performance is high since the beginning and stable for entire production period but flowing bottom-hole pressure drops quickly at the beginning and stays constant as shown in Figure 5.121. The head and required pump pressure in Figure 5.122 rapidly increases due to the reduction in the suction pressure and stay stable in as there is no significant change in gas-oil ratio and water cut. In comparison to case 19, the head requirement in this case is slightly higher due to higher amount of water cut.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 22 is P11 with 160 stages as shown in the Figure 5.123. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 160 stages as depicted in Figure 5.124.

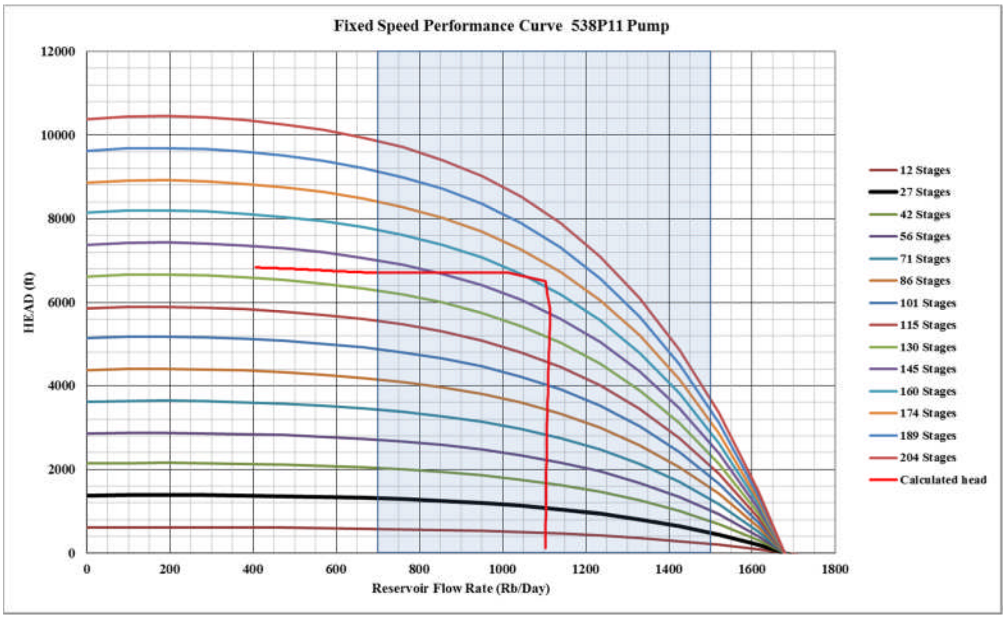

Figure 5.123: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 22.

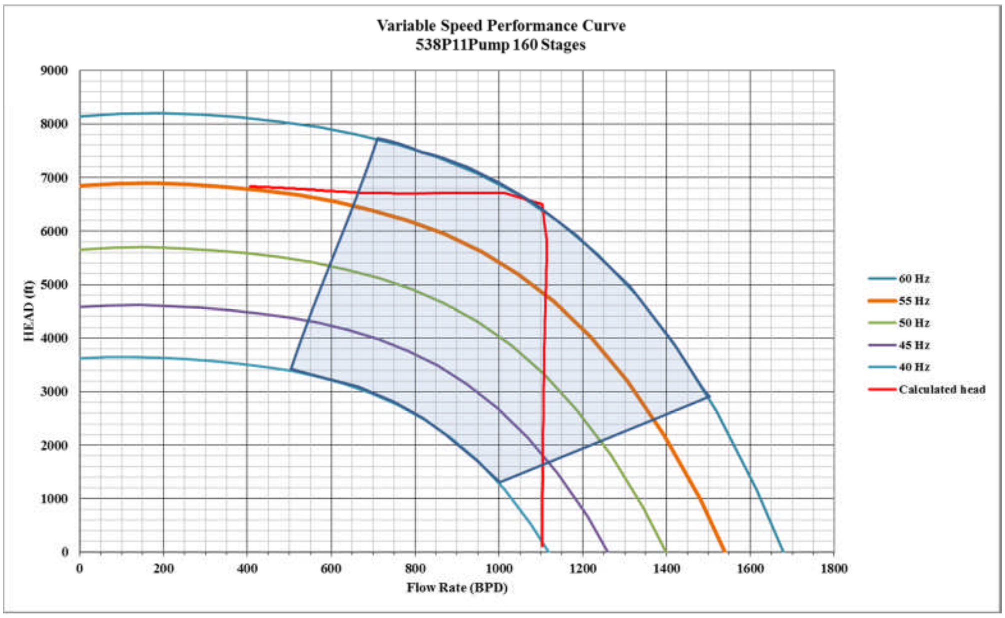

Figure 5.124: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 22.

Case 23: 5PV Aquifer, reservoir pressure 3,300 psi, reservoir temperature 200°F, and initial solution GOR 250 scf/STB.

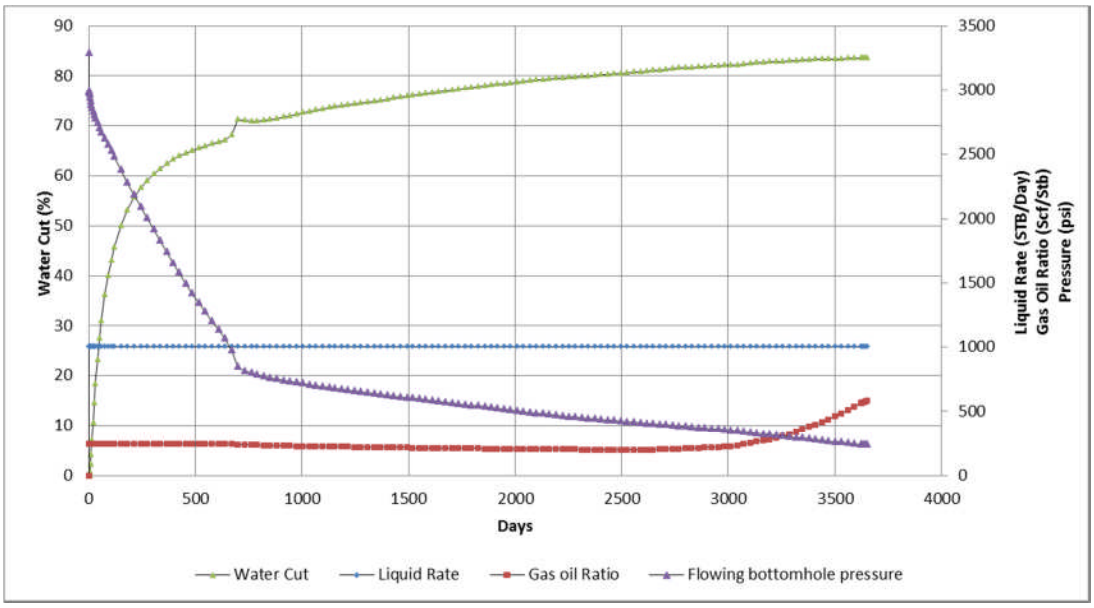

Figure 5.125: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 23.

In this case, the initial solution gas-oil ratio is varied to 250 scf/STB with the same aquifer size. As shown in Figure 5.125, the bottom-hole pressure rapidly decreases due to the reduction of suction pressure. The liquid production rate is maintained at the target rate through the end of the simulation period. In comparison to case 20, in which the aquifer is only 1PV, the liquid production rate in this case can be sustained for a larger period of time. The water cut rapidly increases since the beginning to around 65% within 500 days and reaches over 80% at the end of production. At early stage, producing gas-oil ratio is more or less stable until 3,000 days and slightly increases afterward.

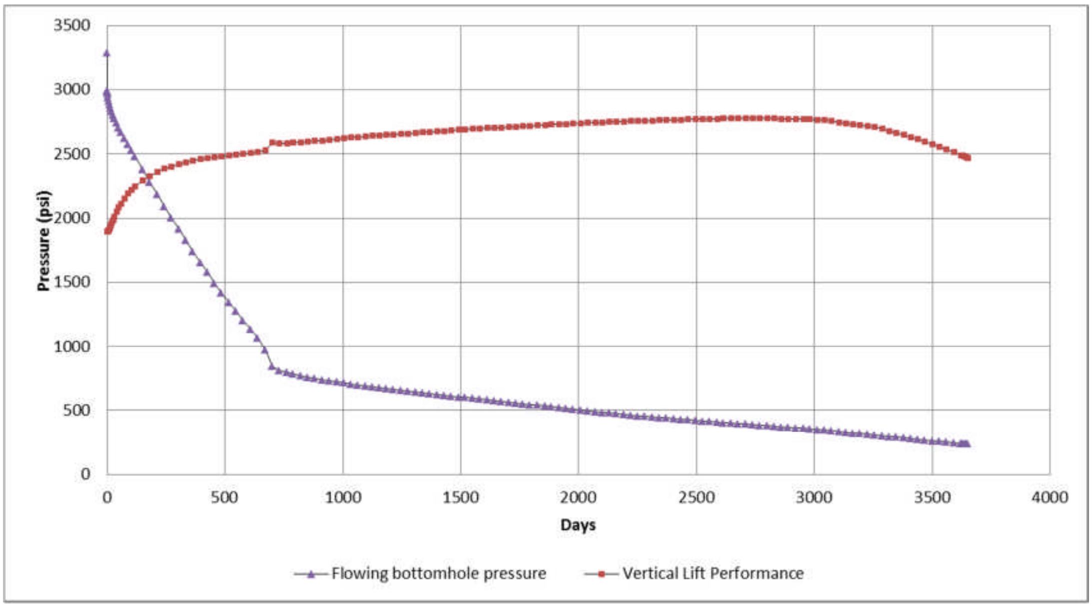

Figure 5.126: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 23.

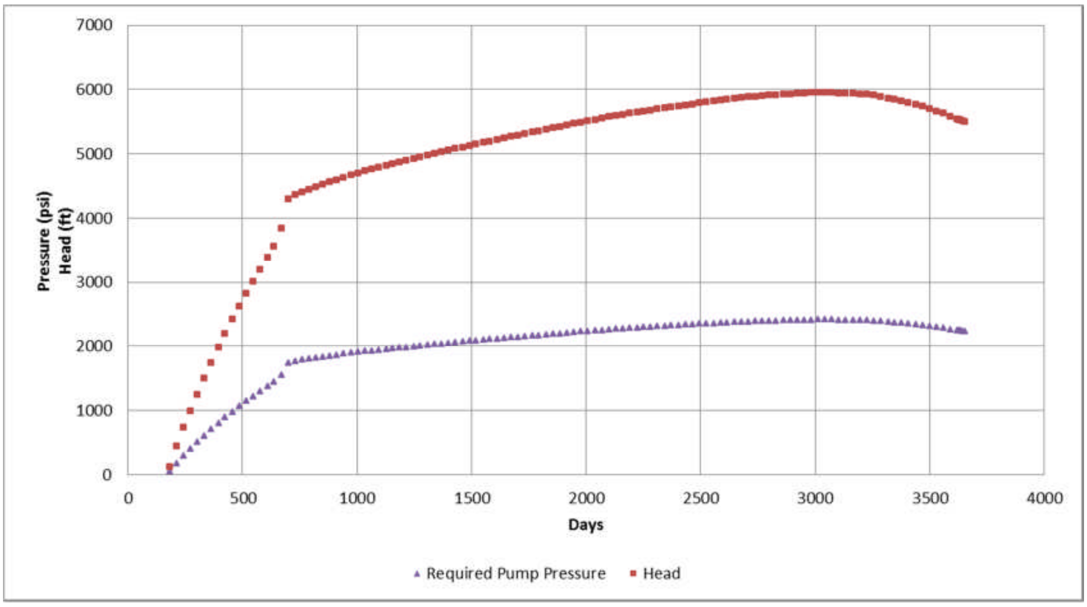

Figure 5.127: Required pump pressure and head for water drive reservoir in case 23.

The well flows freely for around 150 days. The pressure required by vertical lift performance in Figure 5.126 is high since the beginning and moderately increases and become more or less constant until it slightly drops at the end due to less hydrostatic loss in the tubing as more gas flows into the tubing. In contrast, the flowing bottom-hole pressure keeps falling down until reaching at the minimum limit of 200 psia. The required pump pressure and head as depicted in Figure 5.127 sharply increases at the beginning and later on gradually increases and finally declines after gas starts flowing into the well. In comparison to case 20, the maximum head in this case is higher due to higher water production.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 23 is P11 with 160 stages as shown in the Figure 5.128. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 145 stages as depicted in Figure 5.129.

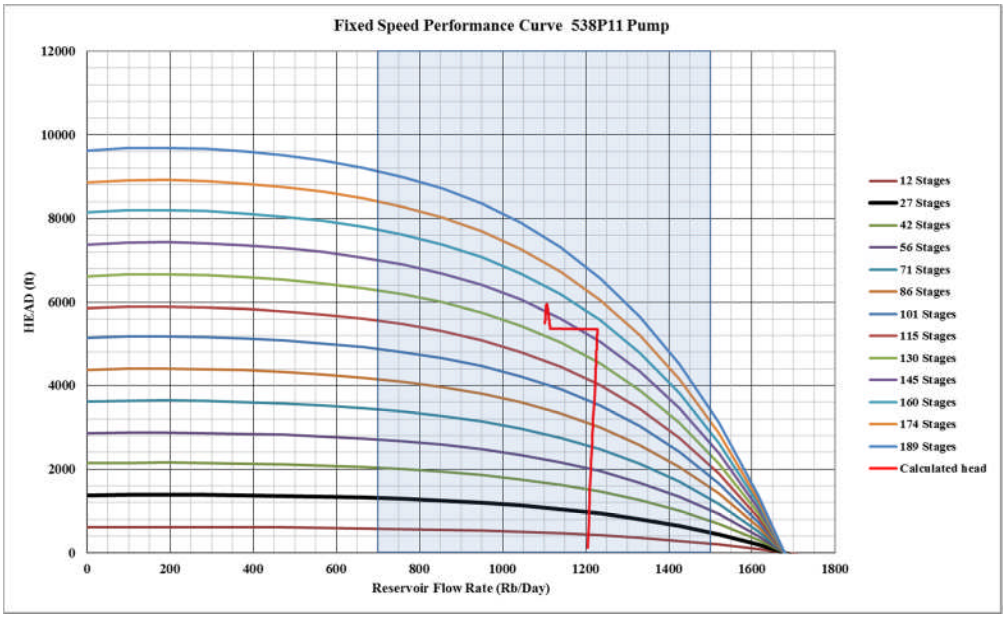

Figure 5.128: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 23.

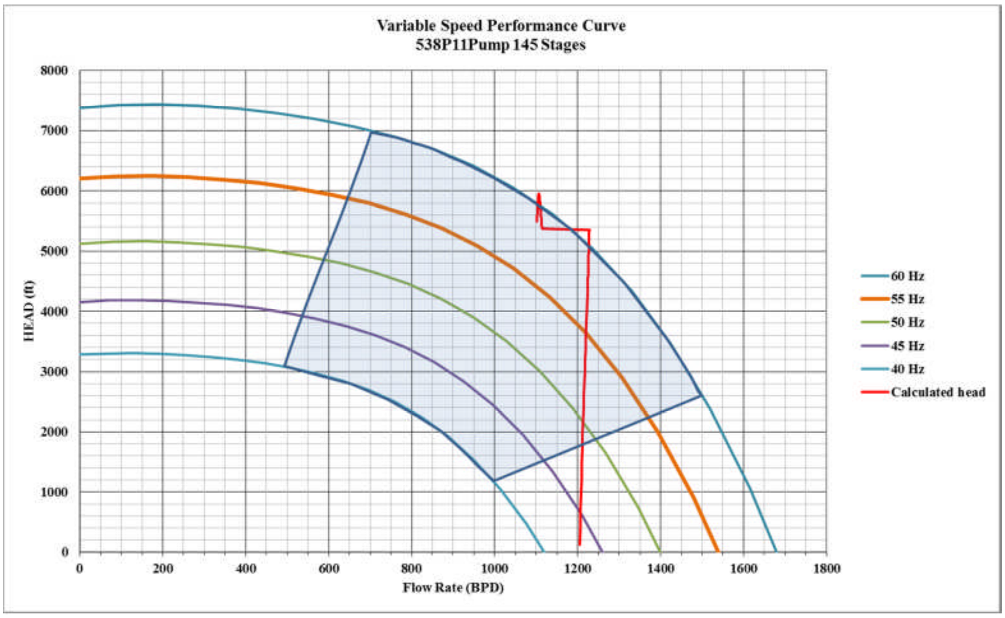

Figure 5.129: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 23.

Case 24: 5PV Aquifer, reservoir pressure 3,300 psi, reservoir temperature 200°F, and initial solution GOR 500 scf/STB.

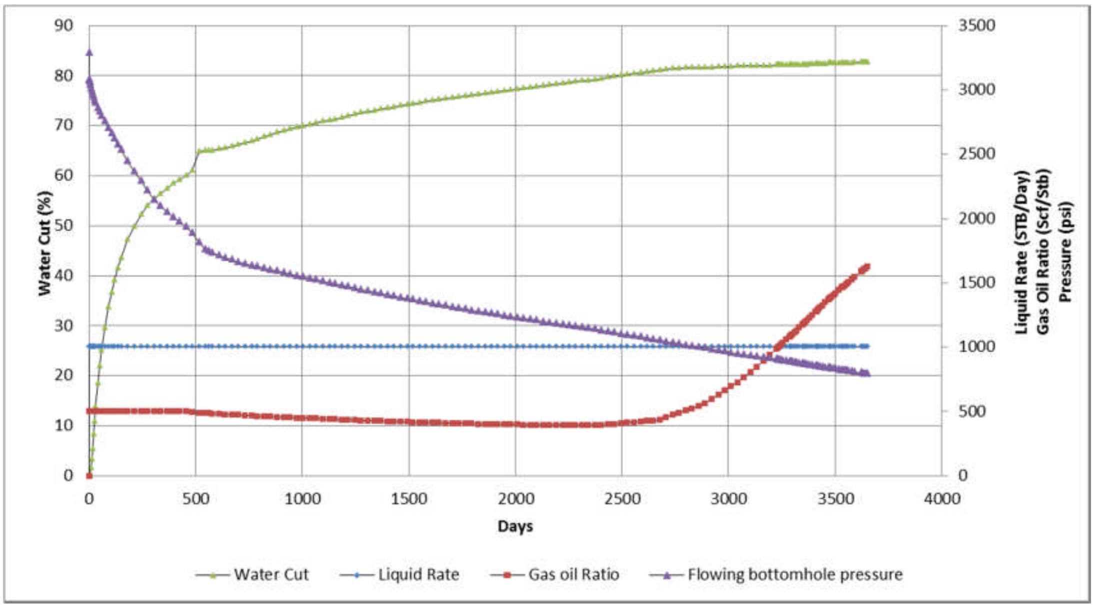

Figure 5.130: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 24.

In the Figure 5.130, the bottom-hole pressure steadily drops whereas the liquid production rate is sustained at the target rate of 1,000 STB/D until the end of simulation because strong aquifer support. The water cut rapidly increases since the beginning to around 60% within 500 days and reaches 80% at the end of production. At early stage, producing gas-oil ratio is more or less stable until 2,500 days. Then the value steeply goes up because free gas flows from the reservoir to the surface.

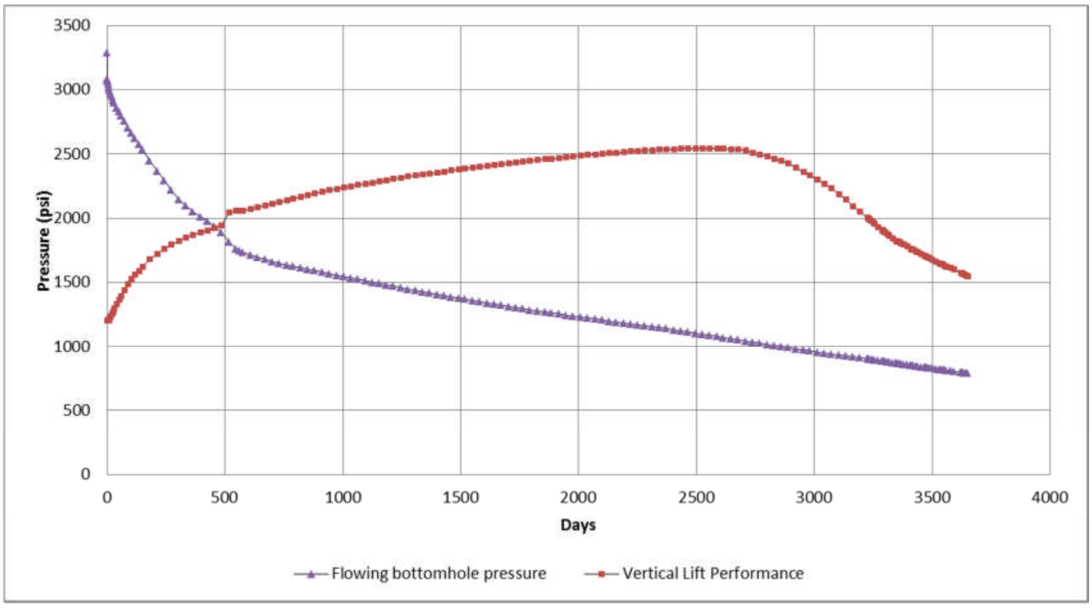

Figure 5.131: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 24.

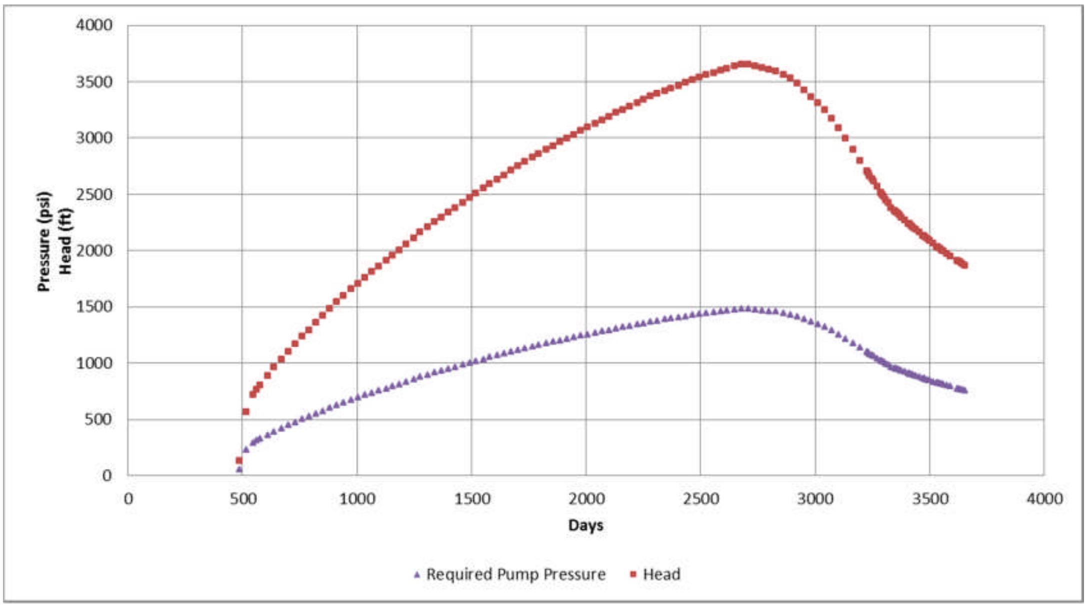

Figure 5.132: Required pump pressure and head for water drive reservoir in case 24.

The well naturally flows around 500 days as show in Figure 5.131. The pressure from vertical lift performance gradually increases and drops at the end of simulation due to less hydrostatic loss in the tubing due to higher amount of gas production increases. In contrast with flowing bottom-hole pressure required by the inflow steadily declines until the end of simulation period as depicted in Figure 5.132. The required pump pressure and the head suddenly increases and rapidly declines as free gas flows into the tubing as depicted in Figure 5.59. In comparison to case 21, the maximum head in this case is higher due to higher water production.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 24 is P11 with 145 stages as shown in the Figure 5.133. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P17 with 58 stages as depicted in Figure 5.134.

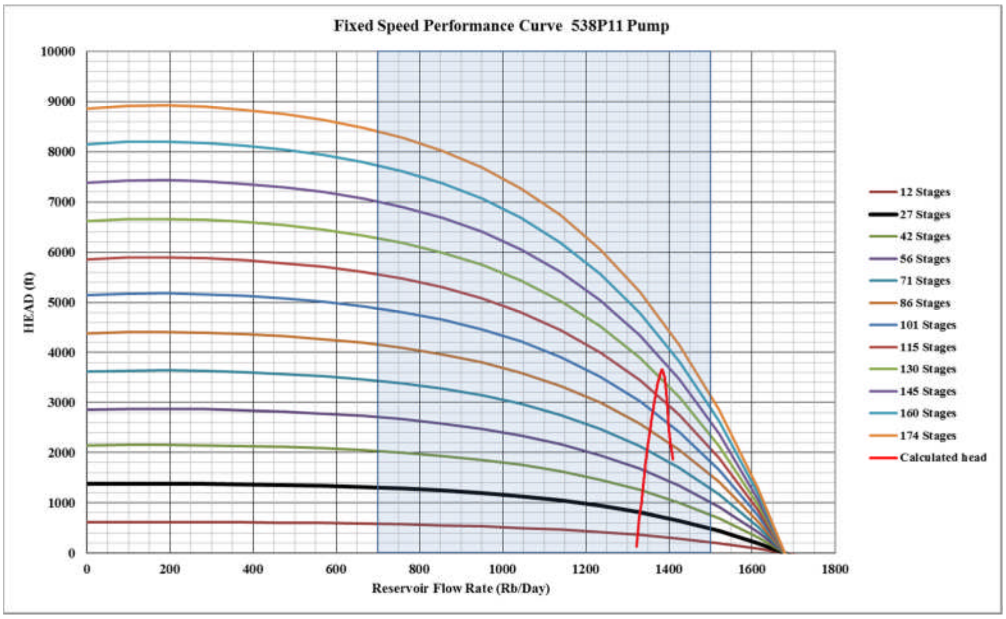

Figure 5.133: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 24.

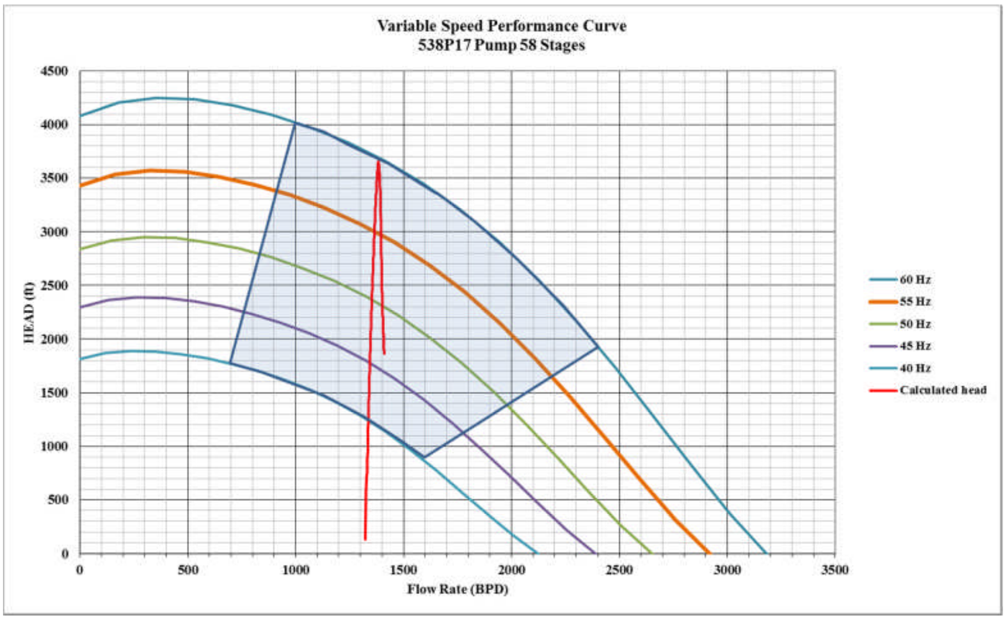

Figure 5.134: Variable speed pump design for 60-Hz 538P17 pump model for water-drive reservoir in case 24.

Case 25: 10PV Aquifer, reservoir pressure 3,300 psi, reservoir temperature 200°F, and initial solution GOR 100 scf/STB.

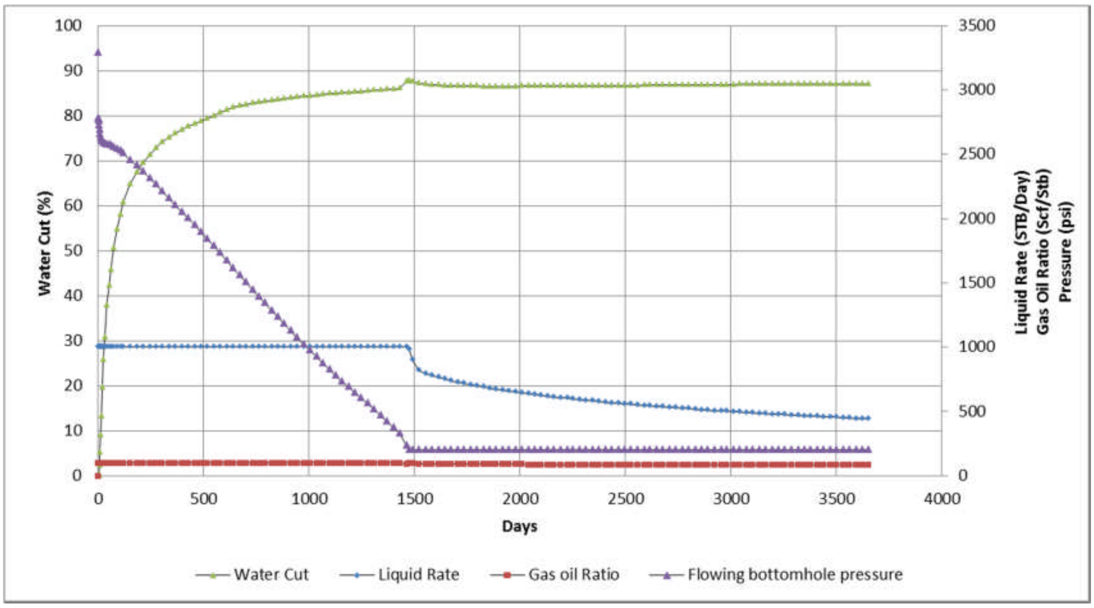

Figure 5.135: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 25.

In this scenario, the aquifer support is changed from 5 times to 10 times of reservoir pore volume.in this case to study the influence of aquifer size on pump stage design. As represented in Figure 5.135, the bottom-hole pressure steadily declines while the liquid production target rate can be sustained for 1,500 days. The water cut increases quickly since the beginning to around 80% within 500 days and reaches 85% at the end of production. In comparison to case 22, in which the aquifer size is 5PV, the water cut in this case is higher due to larger aquifer.

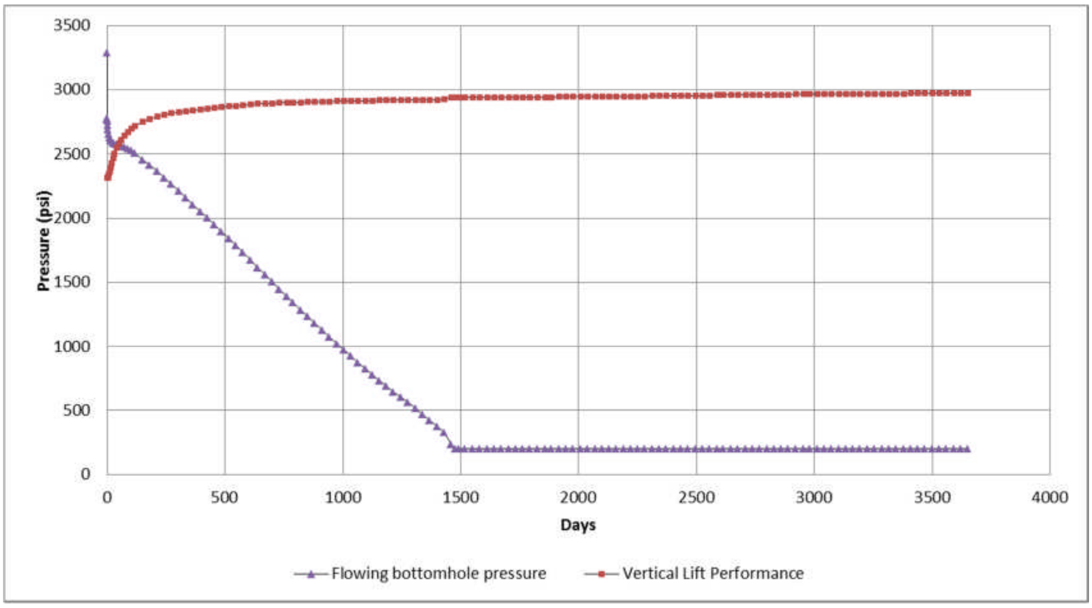

Figure 5.136: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 25.

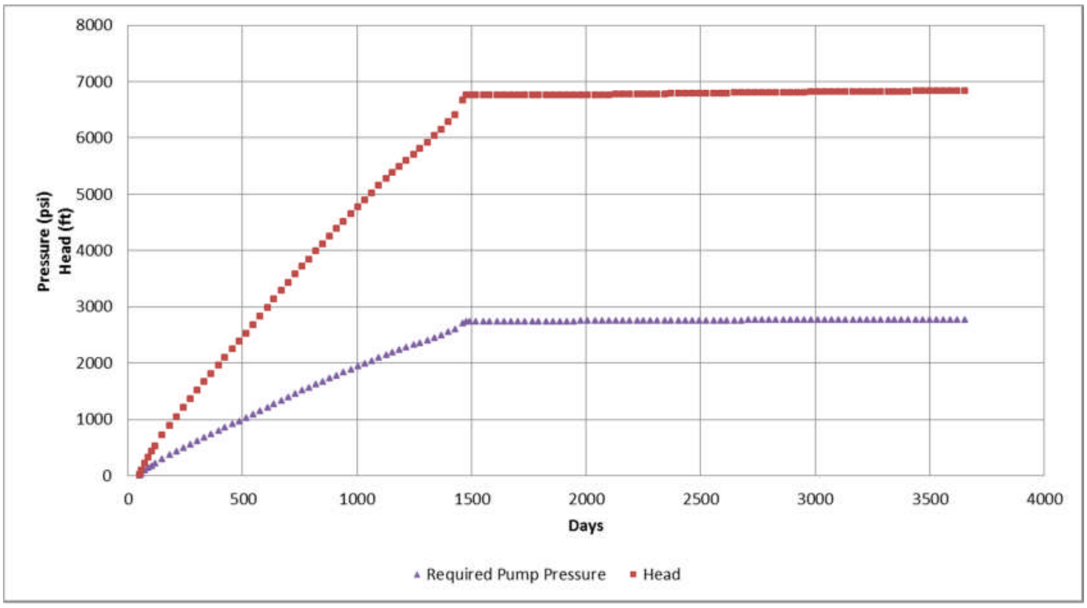

Figure 5.137: Required pump pressure and head for water drive reservoir in case 25.

The well can flow naturally at very short period as shown in Figure 5.61. The pressure from vertical lift performance is also high from the beginning and stays flat until the end but flowing bottom-hole pressure moderately declines until reaching the minimum as shown in Figure 5.136. The required pump pressure and head as depicted in Figure 5.137 rapidly increases at the beginning and remains unchanged after 1,500 days. In comparison to case 19 and 22, which have smaller aquifer sizes the head requirement in this case of 10PV aquifer is the highest.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 25 is P11 with 174 stages as shown in the Figure 5.138. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 160 stages as depicted in Figure 5.139.

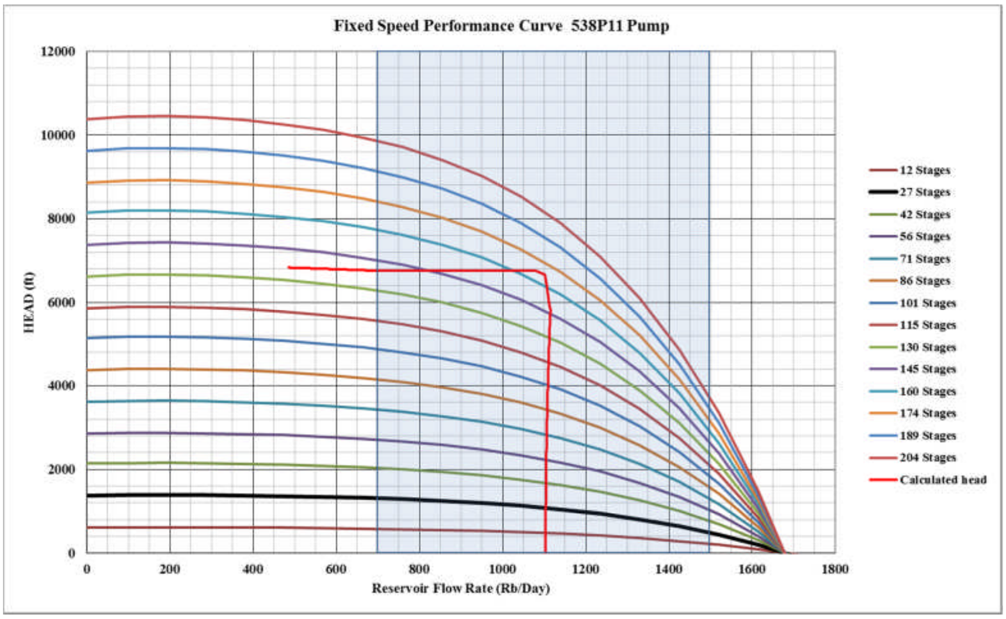

Figure 5.138: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 25.

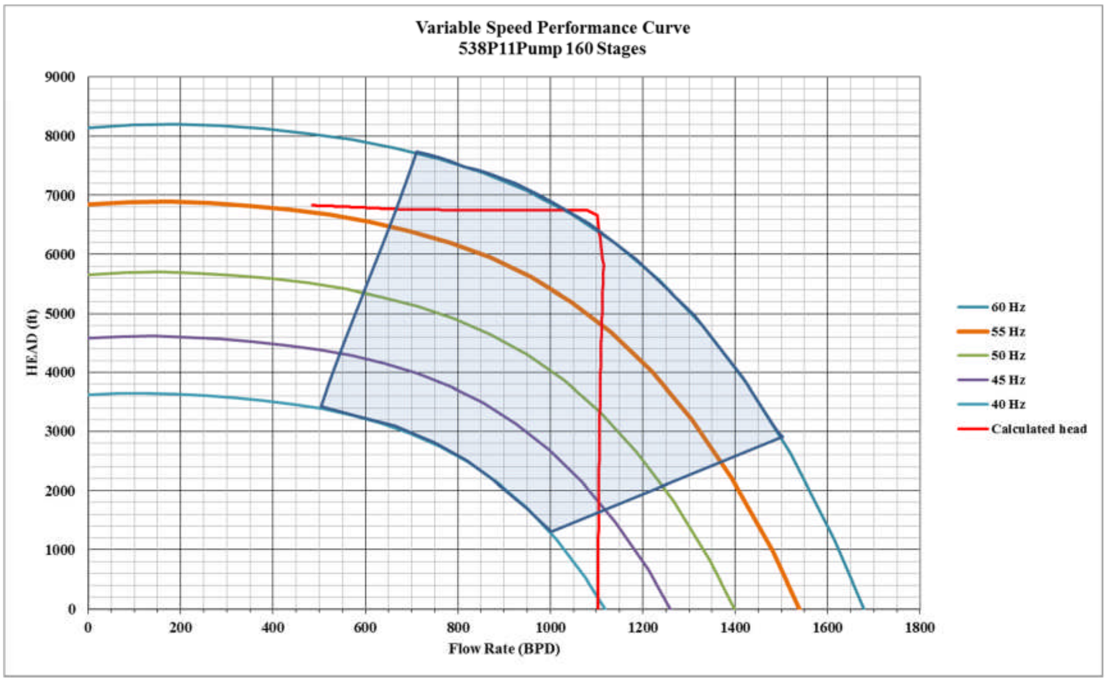

Figure 5.139: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 25.

Case 26: 10PV Aquifer, Reservoir pressure 3,300 psi, reservoir temperature 200°F, and initial solution GOR 250 scf/STB.

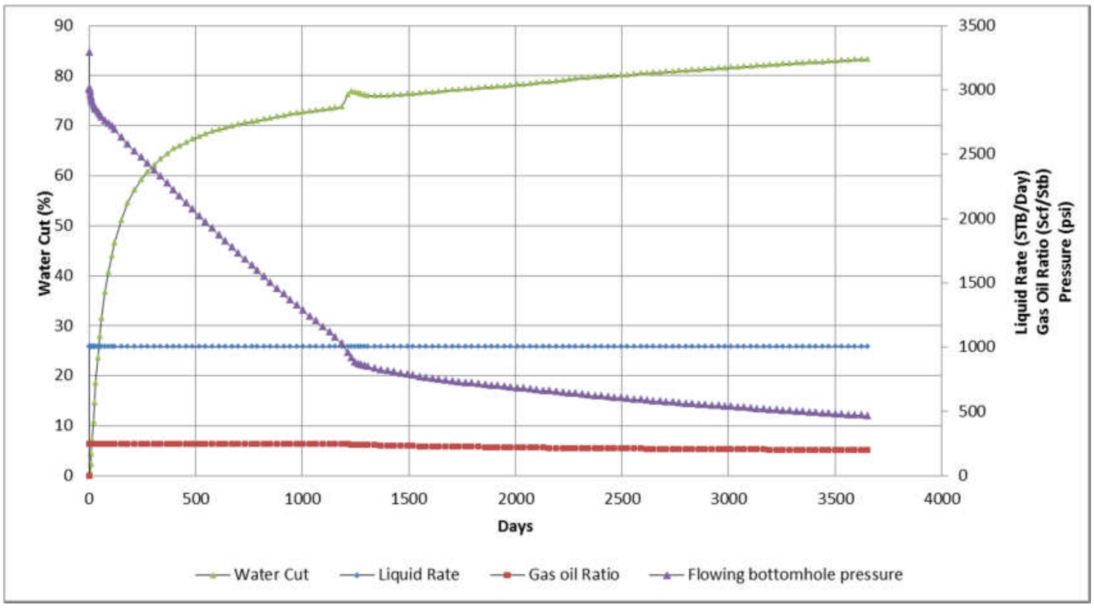

Figure 5.140: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 26.

In this case, the initial solution gas-oil ratio is altered to 250 scf/STB. The simulation results are shown in Figure 5.140. The production target rate remains stable at 1,000 STB/D for the entire life of simulation period because of aquifer support. The bottom-hole pressure declines while the water cut rapidly increases to around 70% within 500 days and reaches over 80% at the end of production.

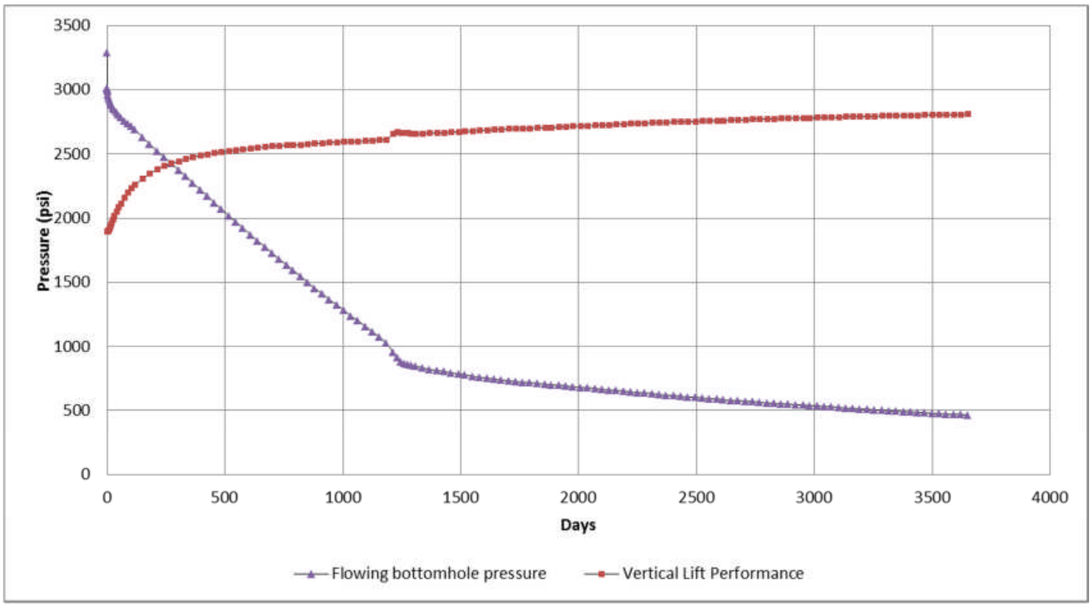

Figure 5.141: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 26.

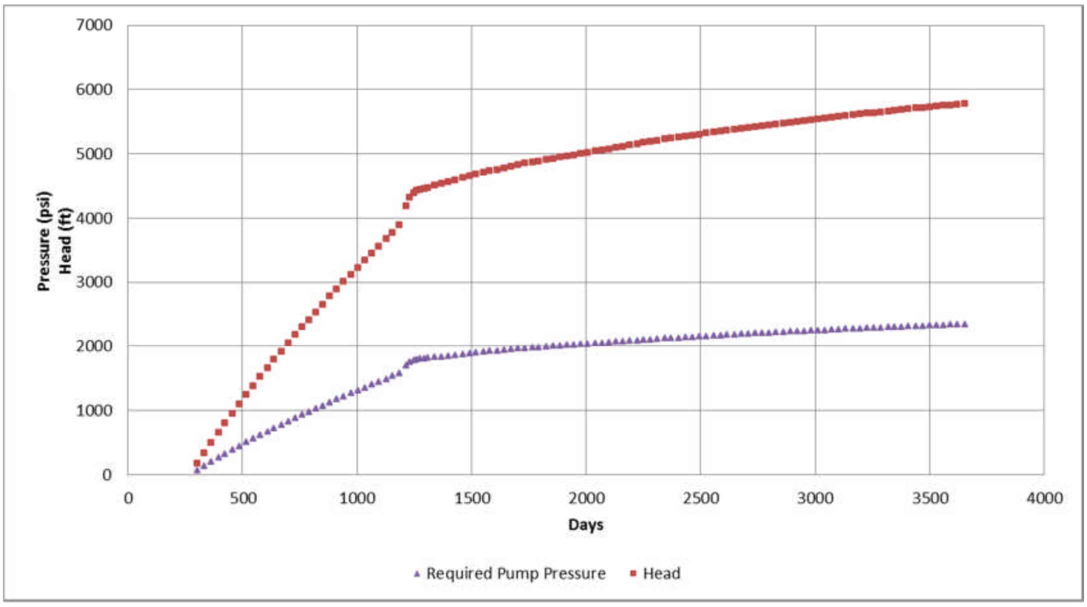

Figure 5.142: Required pump pressure and head for water drive reservoir in case 26.

From Figure 5.141, the well can flow naturally for around 250 days and the bottom-hole pressure from vertical lift performance is initially high and gradually increases after the water cut increases gradually. The differential pressure between flowing bottom-hole pressure and pressure from vertical lift performance is plotted in Figure 5.142 as a required pump pressure. In another word, it is the difference between the discharge pressure and suction pressure and after dividing by fluid gravity, it is plotted as head in the same trend. In contrast with case 20 and 23, the head does not decline at the late times due to constant producing gas-oil ratio.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 26 is P11 with 160 stages as shown in the Figure 5.143. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 145 stages as depicted in Figure 5.144.

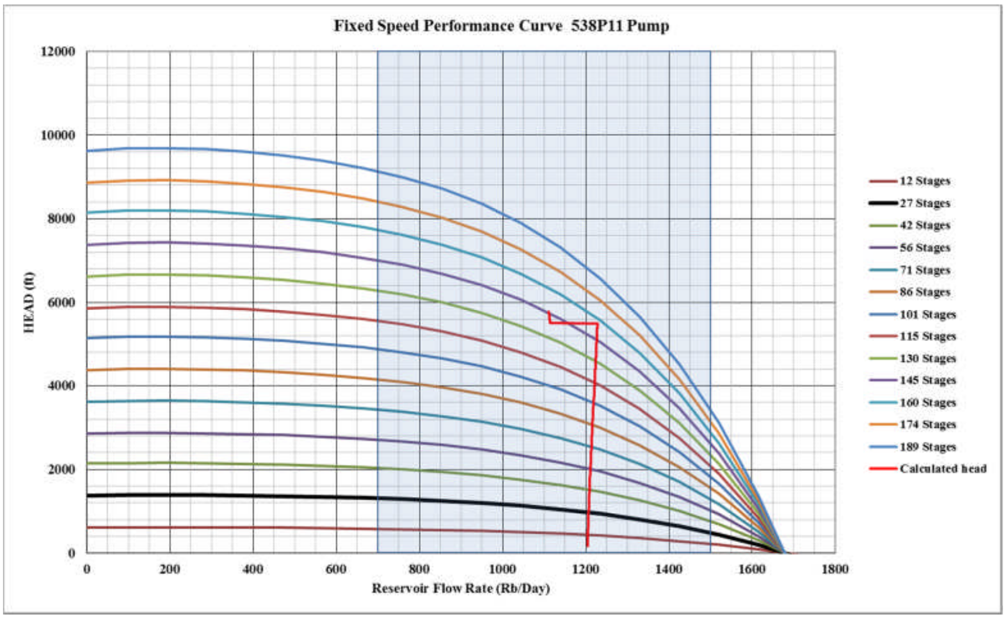

Figure 5.143: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in in case 26.

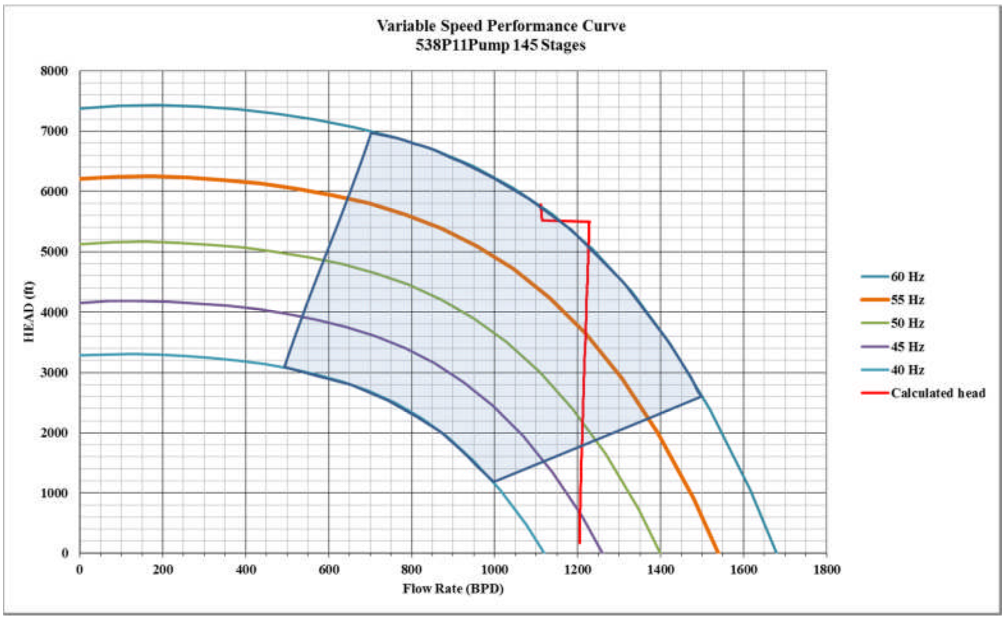

Figure 5.144: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 26.

Case 27: 10PV Aquifer, reservoir pressure 3,300 psi, reservoir temperature 200°F, and initial solution GOR 500 scf/STB.

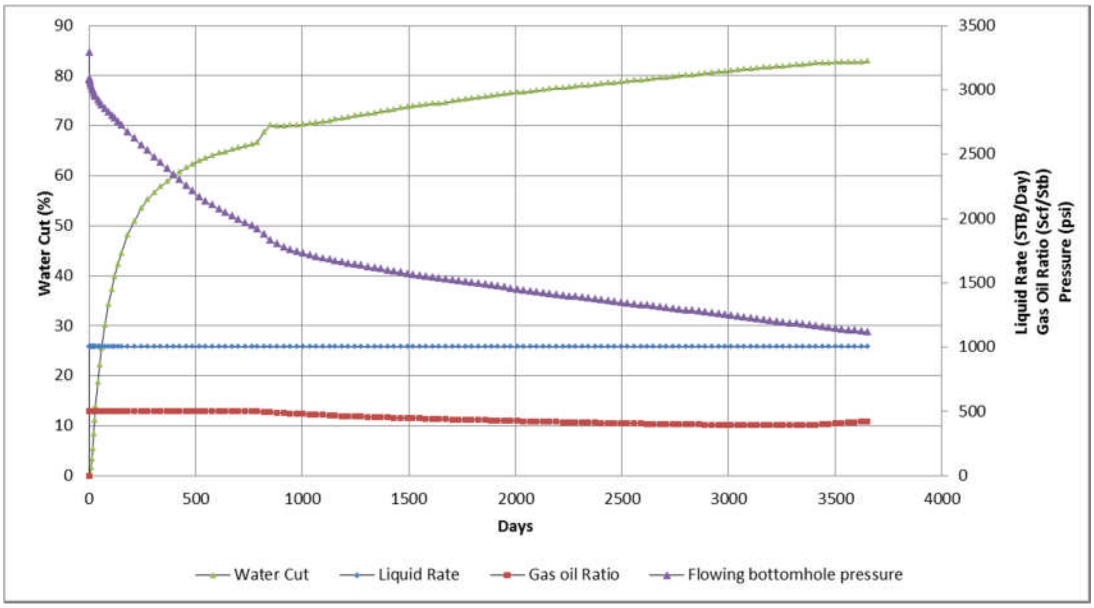

Figure 5.145: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 27.

This case is considered as the last case of ware drive reservoir at depth 7,000 ft. Initial solution gas-oil ratio is changed to 500 scf/STB. The simulation results are shown in Figure 5.145. The production target rate can be sustained at for the entire life of reservoir due to the pressure support from water aquifer. The bottom-hole pressure declines at a slow pace while the water cut rapidly increases since the beginning to around 60% within 500 days and reaches over 80% at the end of production. The producing gas-oil ratio is more or less stable through the end of simulation.

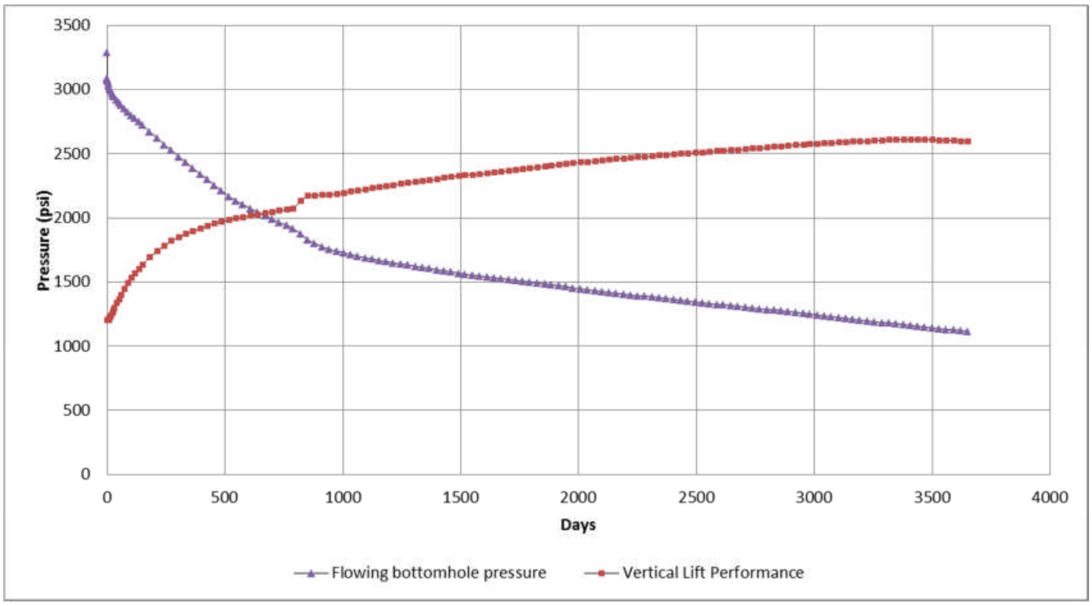

Figure 5.146: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 27.

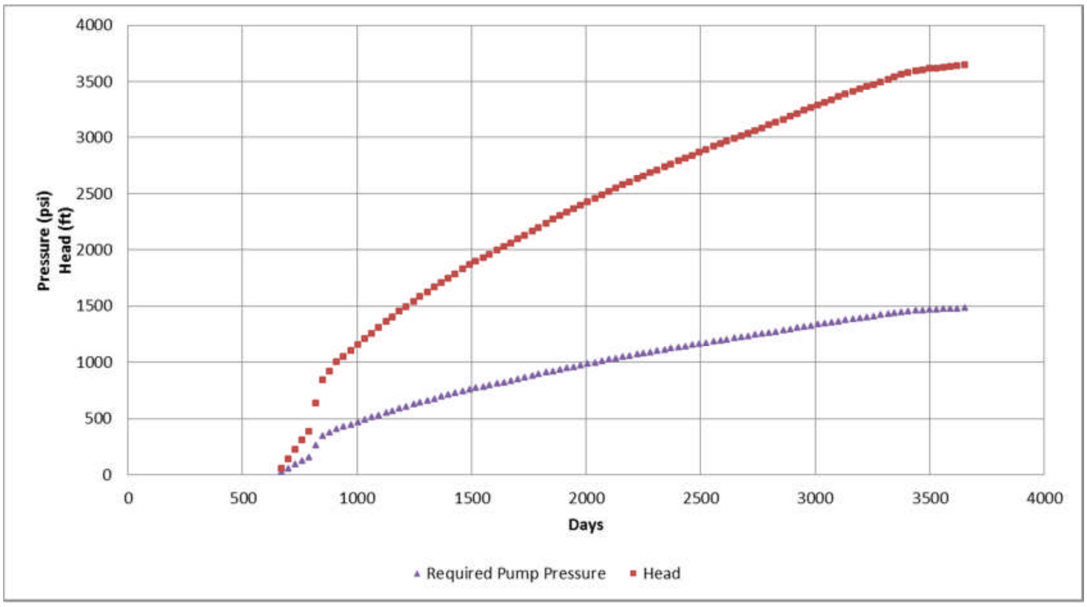

Figure 5.147: Required pump pressure and head for water drive reservoir in case 27.

From Figure 5.146, the well flows naturally for around 600 days. The flowing bottom-hole pressure declines at moderate rate while pressure required for vertical lift performance increases due to water production in the tubing. Later on, when more gas flows into the wellbore, the pressure for vertical lift performance deceases because a lighter fluid is produced in the tubing. The required pump pressure and head are shown in Figure 5.147. They steadily increase in the same style due to water production and afterward when more gas flows into the wellbore, they gradually decrease. In comparison to case 21 and 24, the head requirement in this case is the highest due to high water cut.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 27 is P11 with 130 stages as shown in the Figure 5.148. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P17 with 58 stages as depicted in Figure 5.149.

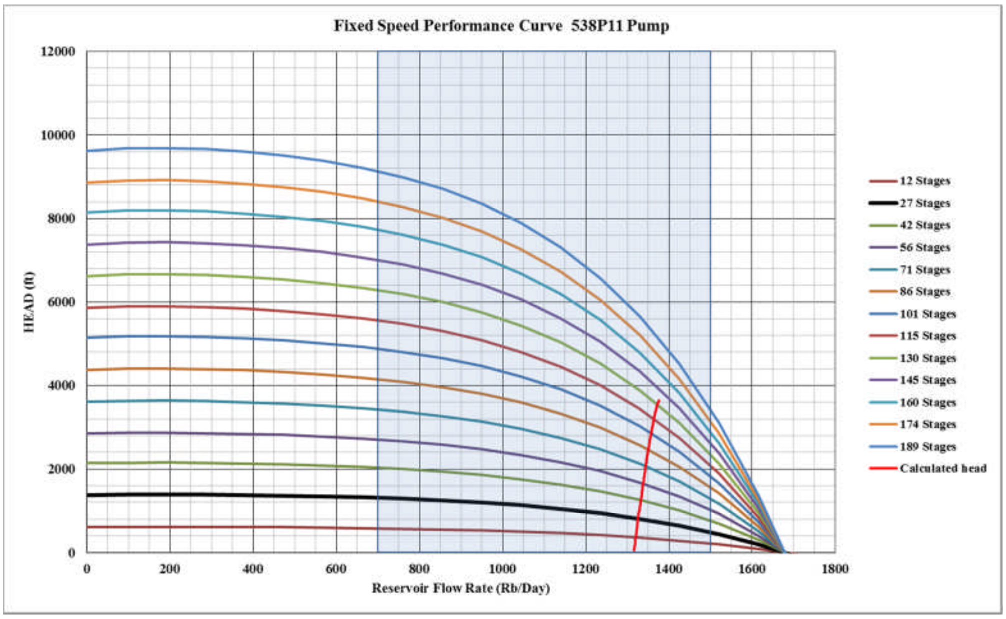

Figure 5.148: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 27.

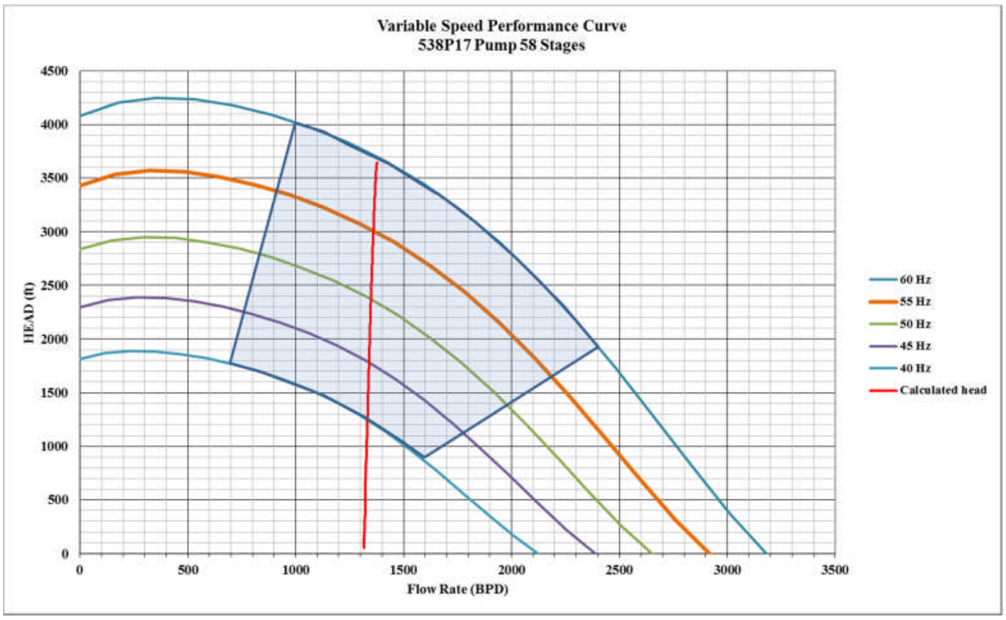

Figure 5.149: Variable speed pump design for 60-Hz 538P17 pump model for water-drive reservoir in case 27.

5.4.2 Water-drive Reservoir at Reservoir Depth 10,000 ft.

Case 28: 1PV Aquifer, reservoir pressure 4,400 psi, reservoir temperature 250°F, and initial solution GOR 100 scf/STB.

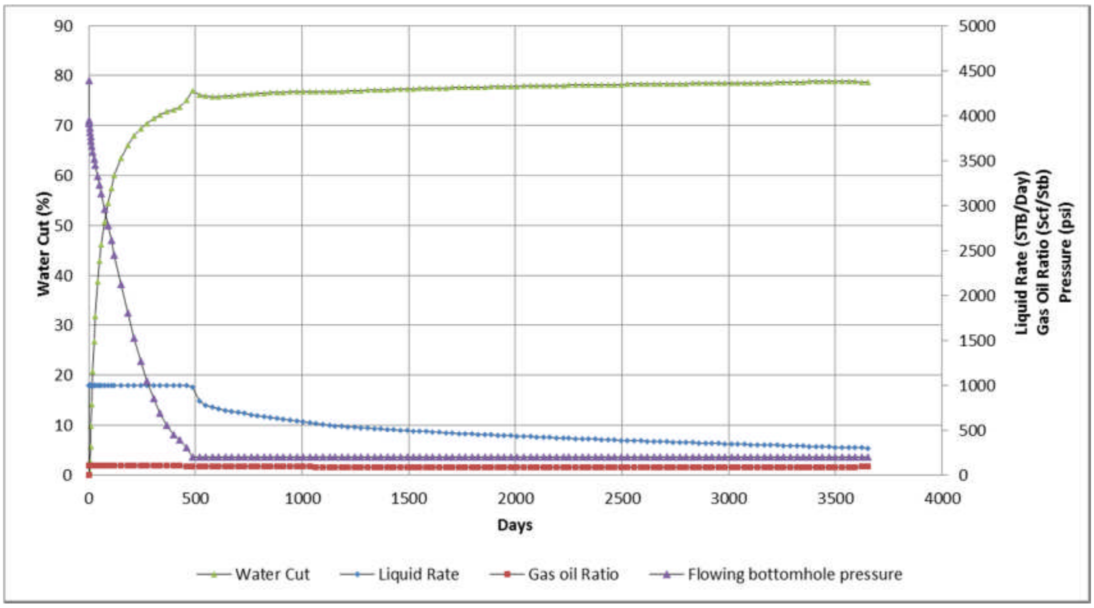

Figure 5.150: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 28.

In this section, reservoir depth is changed to 10,000 ft. with the new reservoir pressure and temperature to investigate pump stage design. From above Figure 5.150, liquid production rate is maintained at 1,000 STB/D for around 500 days and rapidly drops to around t 200 STB/D. The bottom-hole pressure sharply declines and drops to minimum of 200 psia after 500 days. The water cut rapidly increases at the beginning to around 60% within 500 days and reaches over 80% at the end of production. Producing gas-oil ratio is more or less constant for the entire life of the well due to small amount of initial solution gas-oil ratio.

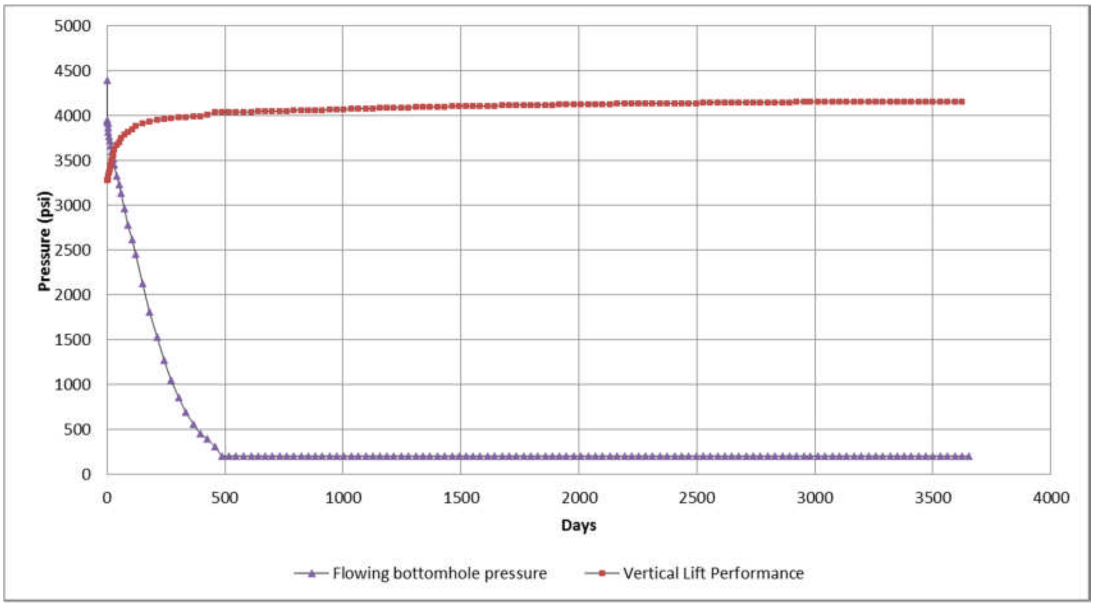

Figure 5.151: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 28.

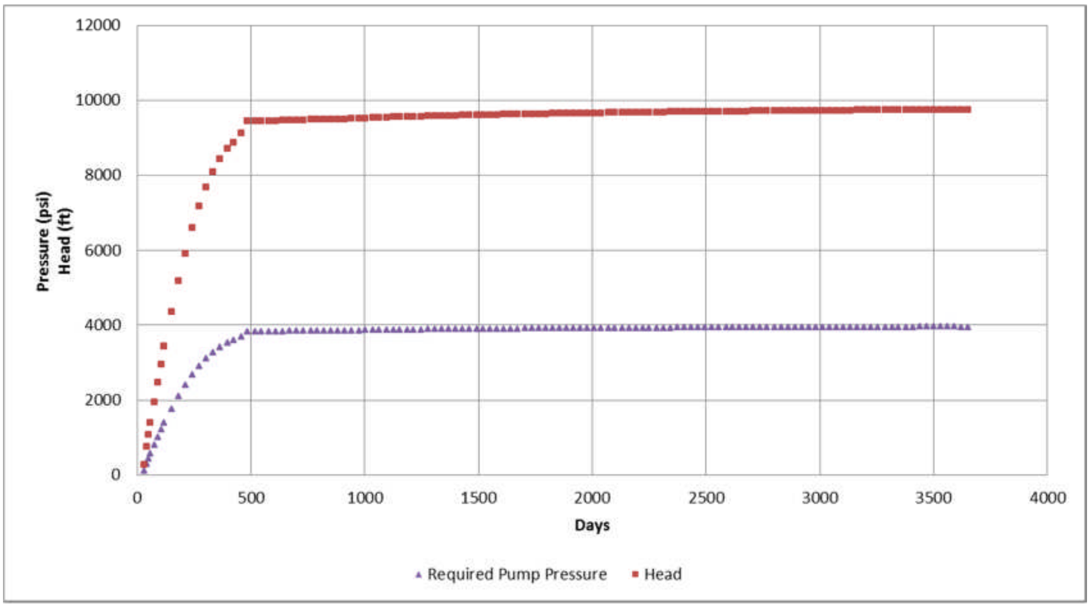

Figure 5.152: Required pump pressure and head for water drive reservoir in case 28.

The well cannot flow naturally at the very first day due to high amount of water flowing into the wellbore. The differential pressure between the bottom-hole pressure and pressure from vertical lift performance increases rapidly and stays stable until ten years as shown in Figure 5.151. The head in Figure 5.152 significantly increases at the beginning as the well flowing pressure sharply declines. Then, the head stays constant and high due to small solution gas-oil ratio. In comparison with case 1, the head in this case is higher due to water production.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 28 is P11 with 233 stages as shown in the Figure 5.153. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 233 stages as depicted in Figure 5.154.

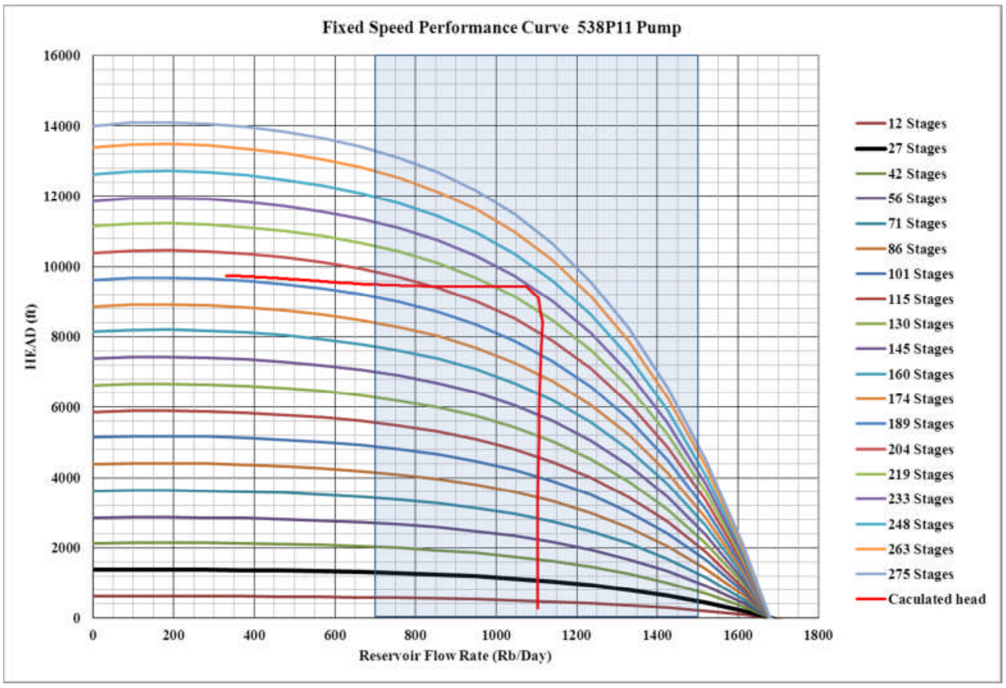

Figure 5.153: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive drive reservoir in case 28.

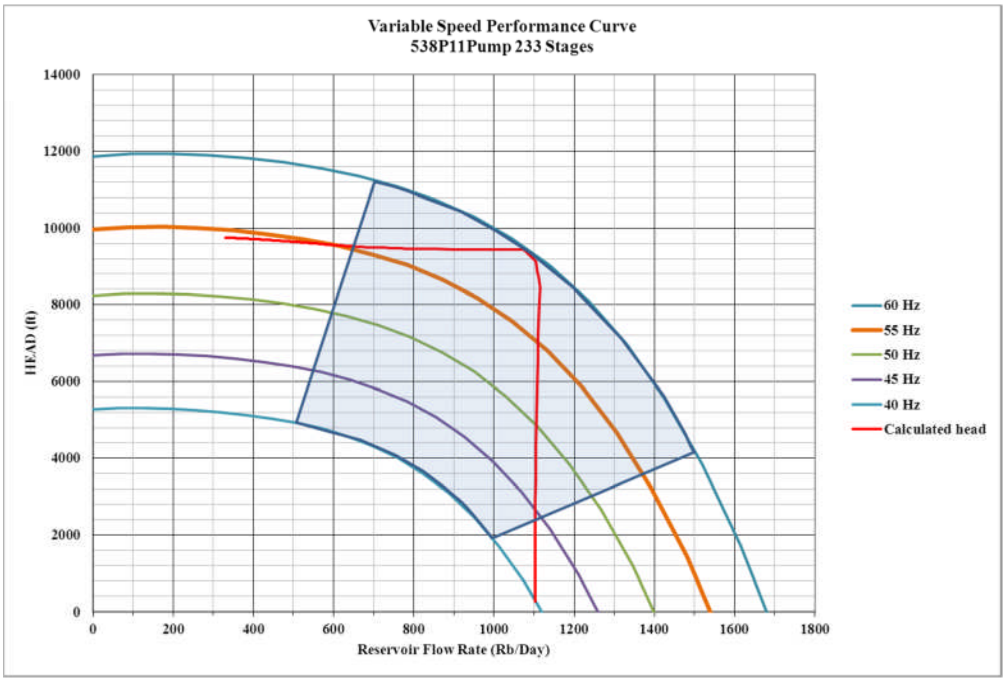

Figure 5.154: Variable speed pump design for 60-Hz 538P11 pump model for water-drive drive reservoir in case 28.

Case 29: 1PV Aquifer, reservoir pressure 4,400 psi, reservoir temperature 250°F, and initial solution GOR 250 scf/STB.

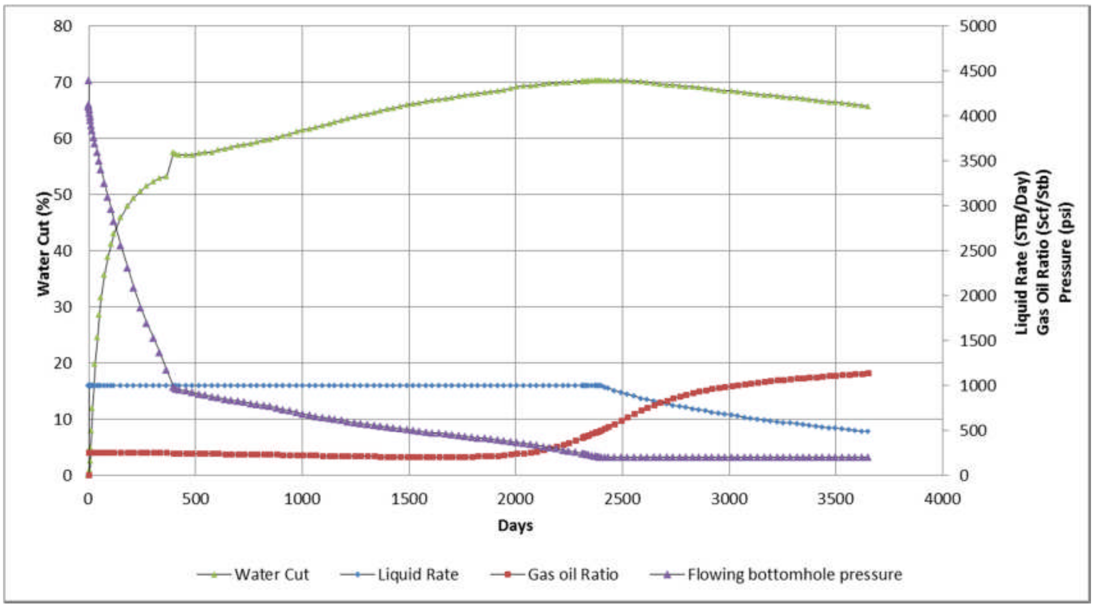

Figure 5.155: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 29.

In this case, the initial solution gas-oil ratio is varied to 250 scf/STB. As shown in Figure 5.155, the bottom-hole pressure steadily decreases while liquid production rate is maintained at target rate for around 2,400 days. The water cut rapidly increases since the beginning to around 58% within 500 days and reaches over 70% at the end of production. At early stage, producing gas-oil ratio is more or less stable for around 2,000 days and slightly increases afterward due to reduction of reservoir pressure below the bubble point pressure.

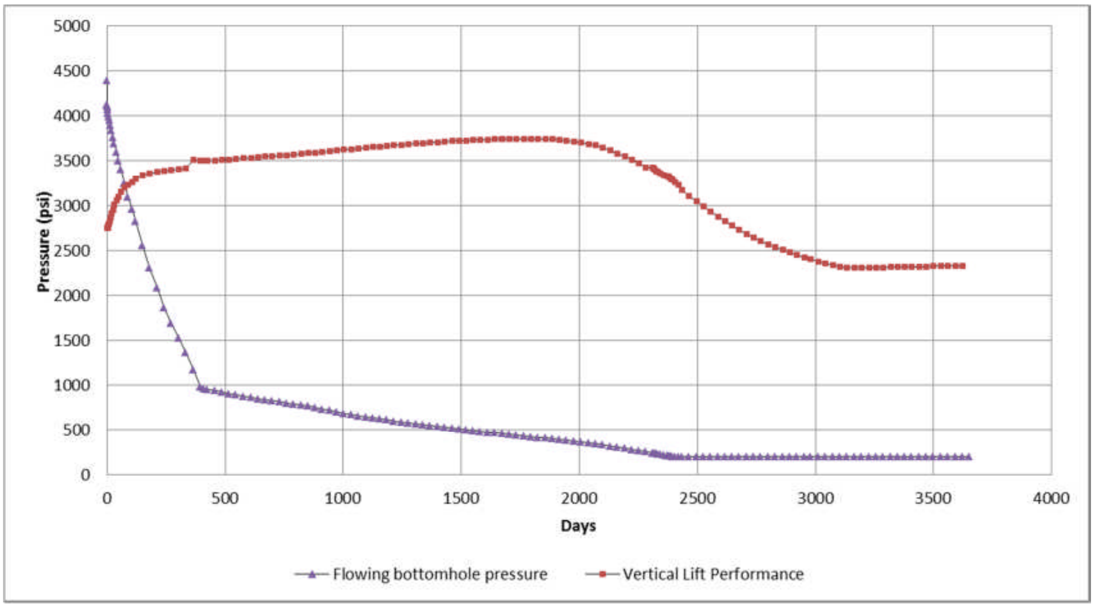

Figure 5.156: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 29.

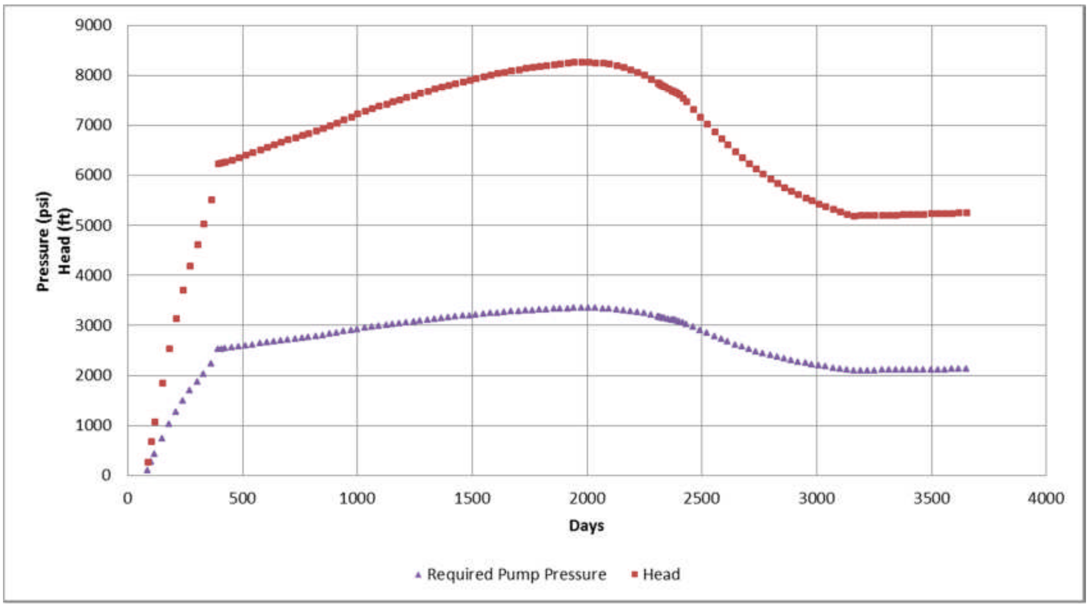

Figure 5.157: Required pump pressure and head for water drive reservoir in case 29.

The well flows naturally for a very short period around 60 days because rapid increases in water cut. The bottom-hole pressure and pressure from vertical lift performance are shown in Figure 5.156. The pressure from tubing performance is high in the middle of production period and lower after gas flows into the wellbore due to pressure reduction. The head in Figure 5.157 significantly increases at the beginning due the reduction in the suction pressure and higher water production rate. As more gas flows into the wellbore at later times, the required pump pressure slowly declines. In comparison with case 2, the head requirement in this case is higher due to high water cut.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 29 is P11 with 219 stages as shown in the Figure 5.158. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 219 stages as depicted in Figure 5.159.

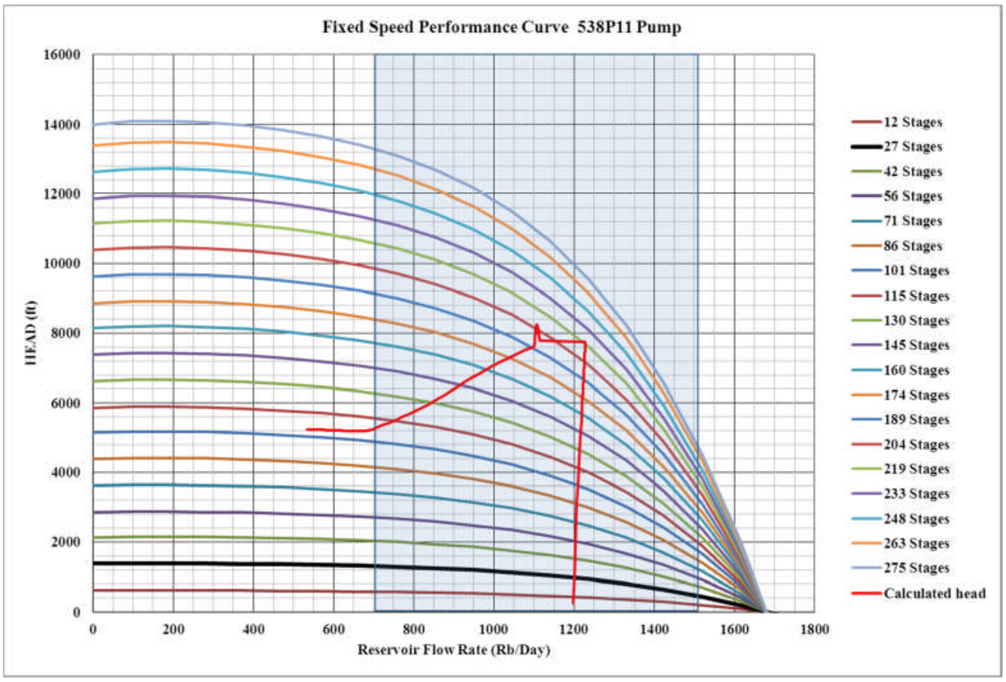

Figure 5.158 : Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 29.

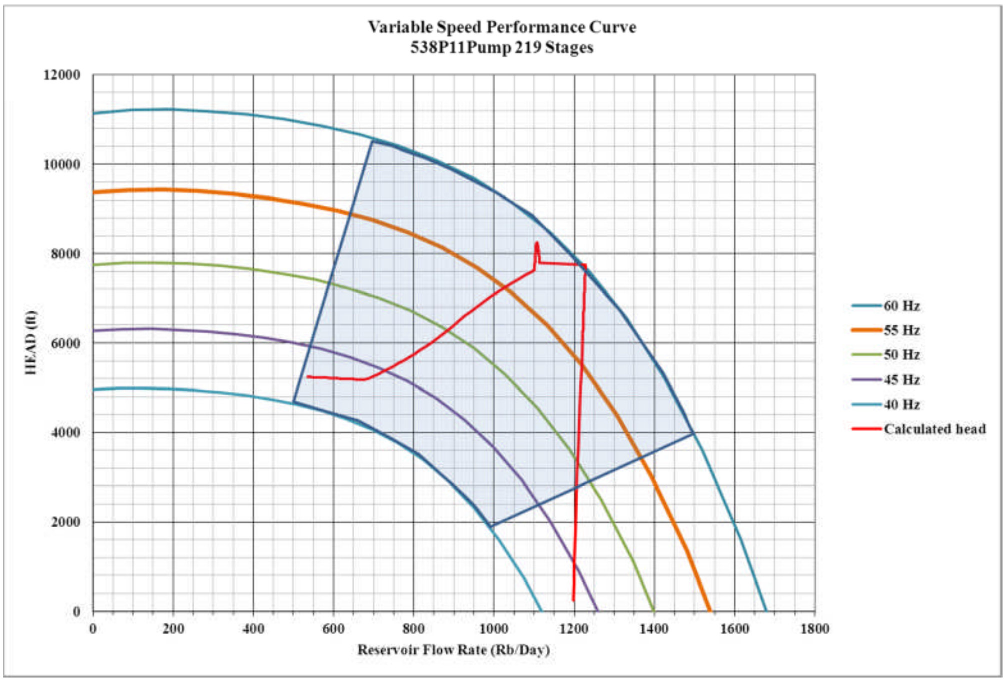

Figure 5.159: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 29.

Case 30: 1PV Aquifer, reservoir pressure 4,400 psi, reservoir temperature 250°F, and initial solution GOR 500 scf/STB.

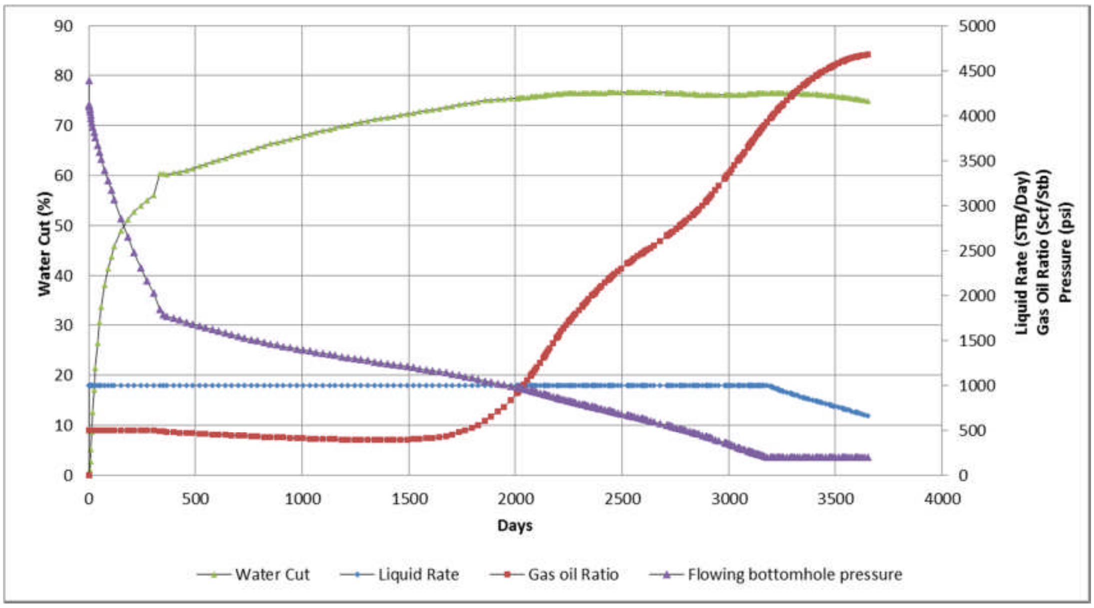

Figure 5.160: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 30.

Figure 5.160 illustrates the simulation results of water aquifer size 1PV and initial solution gas-oil ratio of 500 scf/STB. Liquid production rate is constantly produced at the target rate for around 3,100 days and decrease simultaneously later. On another hand, bottom-hole pressure suddenly drops since the first day and declines at a slow pace until it keeps stable at minimum requirement of 200 psia. The water cut rapidly increases since the beginning to around 60% within 500 days and reaches over 75% at the end of production. Producing gas-oil ratio is more or less stable and increases after 1,500 days due to reservoir pressure drops below bubble point pressure.

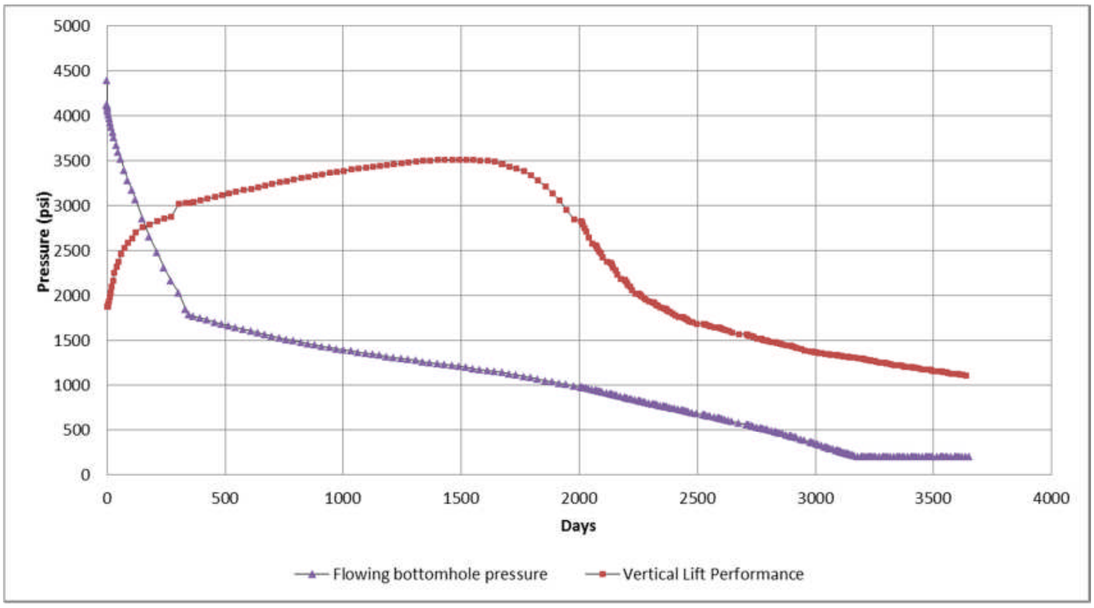

Figure 5.161: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 30.

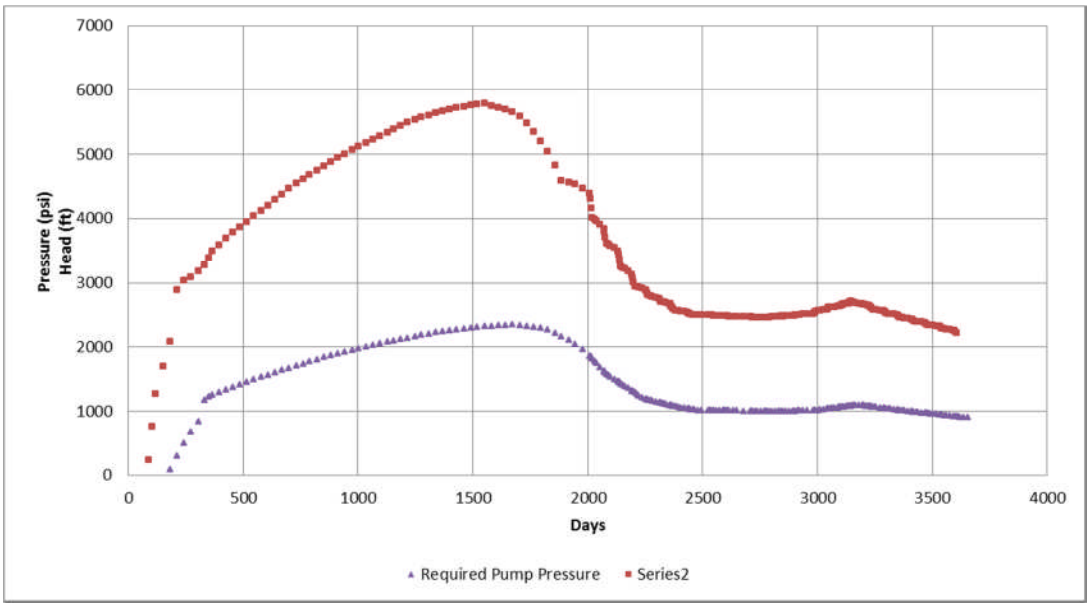

Figure 5.162: Required pump pressure and head for water drive reservoir in case 30.

The well naturally flows for around 300 days due to influence of pressure support from water aquifer and liberated gas in the tubing. The bottom-hole pressure and pressure from vertical lift performance increases gradually until 1,500 days and declines after free gas starts to flow as shown in Figure 5.161. The head in Figure 5.162 remarkably increases during 300 days to 1,500 days of production due to the reduction in the suction pressure to maintain the target rate and the increases in pressure required for vertical lift as water cut increase. When free gas starts to flow, the required pump pressure slowly declines in the same trend as the head. In comparison with case 3, the water production in case 30 causes the head requirement to be higher.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 30 is P11 with 219 stages as shown in the Figure 5.163. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P17 with 88 stages as depicted in Figure 5.164.

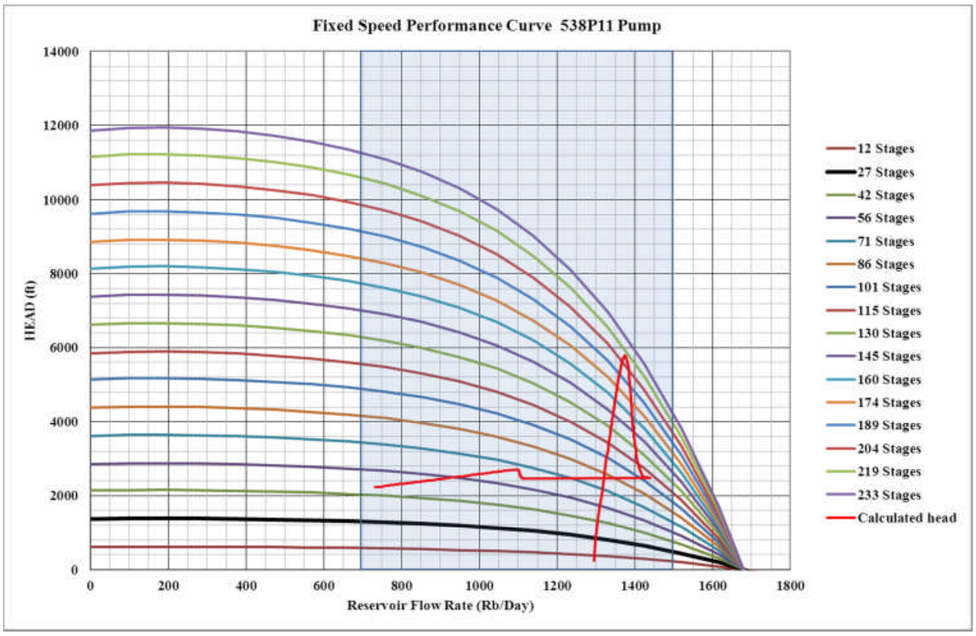

Figure 5.163: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 30.

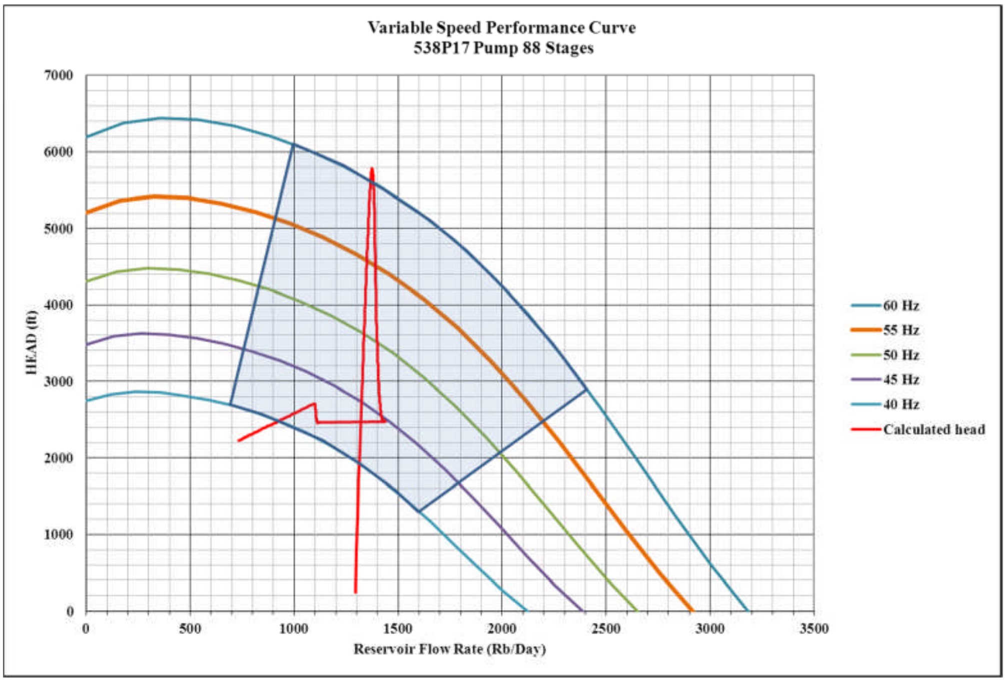

Figure 5.164: Variable speed pump design for 60-Hz 538P17 pump model for water-drive reservoir in case 30.

Case 31: 5PV Aquifer, reservoir pressure 4,400 psi, reservoir temperature 250°F, and initial solution GOR 100 scf/STB.

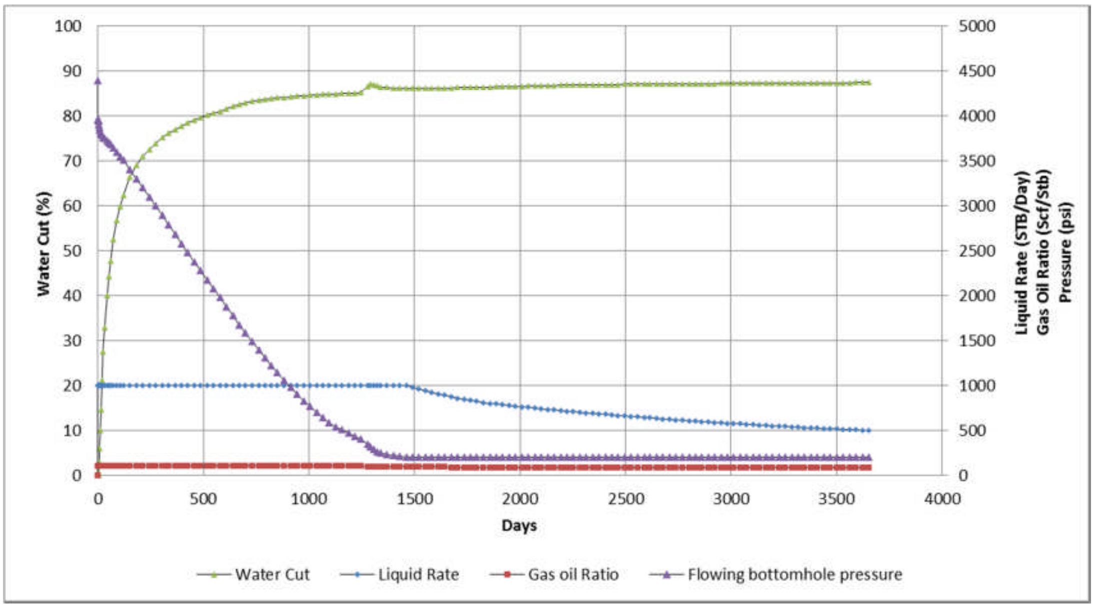

Figure 5.165: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 31.

In this scenario, aquifer size is increased to 5 times of reservoir pore volume and initial solution gas-oil ratio is altered to 100 scf/STB. From Figure 5.165, the bottom-hole pressure declines sharply due to the reduction of suction pressure and reached at minimum 200 psia after 1,500 days. The liquid rate is maintained at the target rate for 1,500 days and then drops in the same fashion as the bottom-hole pressure. The water cut increases quickly since the beginning to around 80% within 500 days and reaches over 80% at the end of production. The water cut in this case is higher than the one in case 28 as a result of stronger water aquifer. Producing gas-oil ratio is more or less stable through the end of reservoir life because of small solution gas-oil ratio.

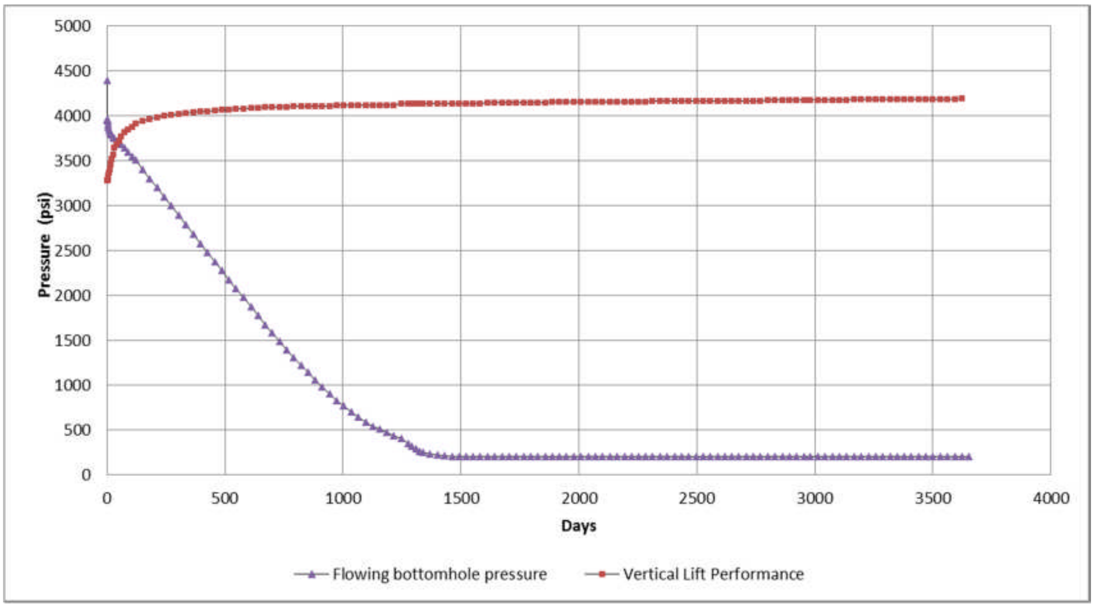

Figure 5.166: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 31.

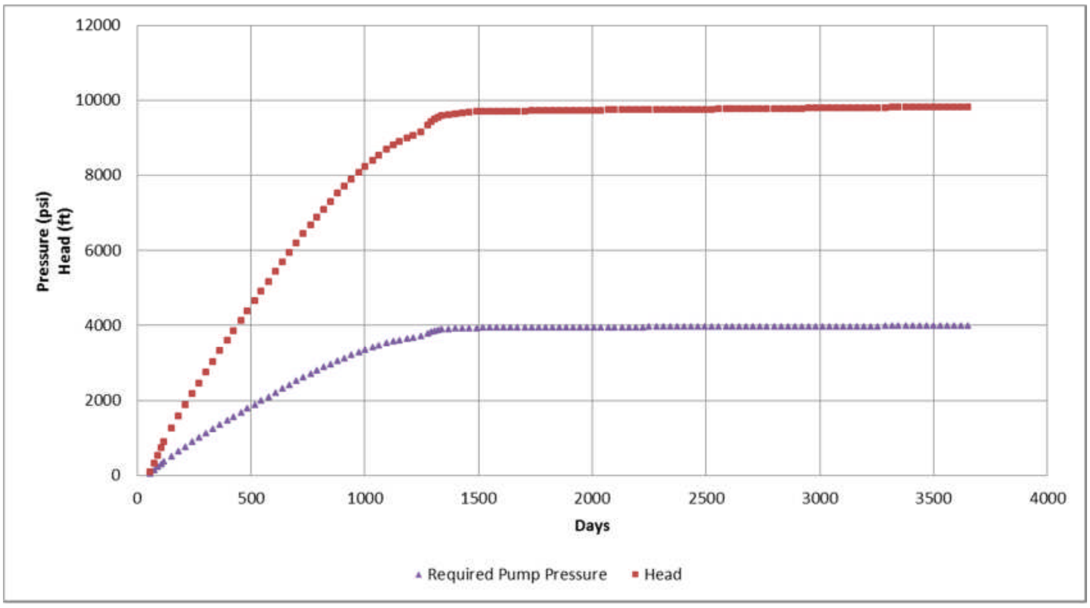

Figure 5.167: Required pump pressure and head for water drive reservoir in case 31.

The well can flow naturally at the very short period. The pressure required by vertical lift performance is high since the beginning and moderately increases and stays the same for the entire production period but flowing bottom-hole pressure drops quickly at the beginning and stays constant as shown in Figure 5.166. The head and the required pump pressure in Figure 5.167 rapidly increases due the reduction in the suction pressure and stays stable as there is no significant change in gas-oil ratio and water cut. In comparison to case 28 the head requirement in this case is slightly higher due to higher amount of water cut.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 31 is P11 with 248 stages as shown in the Figure 5.168. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 233 stages as depicted in Figure 5.169.

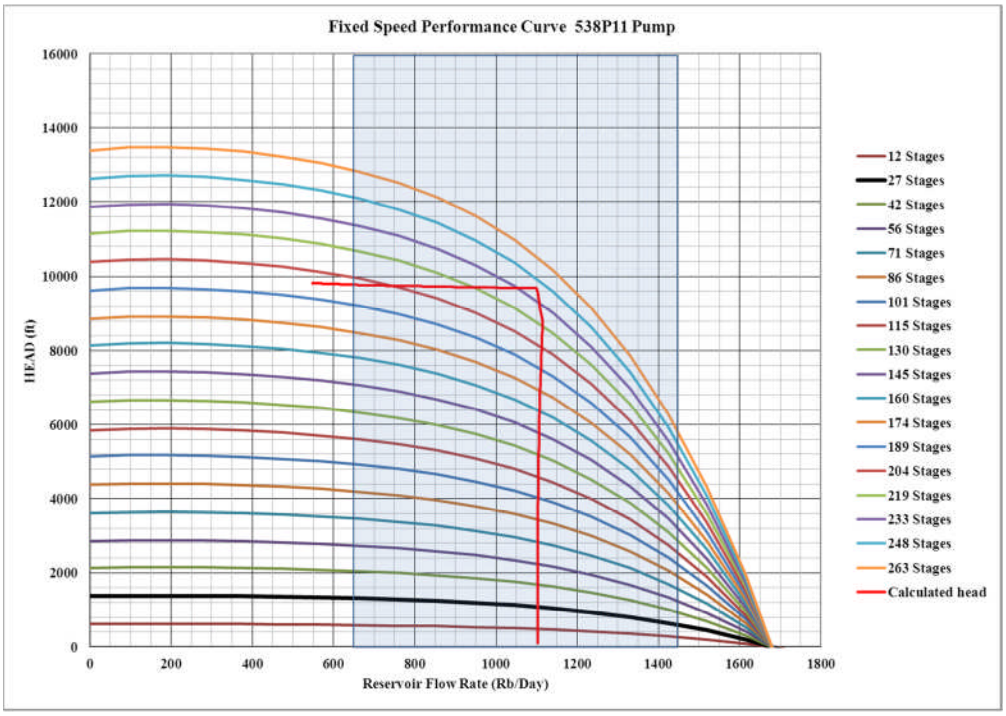

Figure 5.168: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 31.

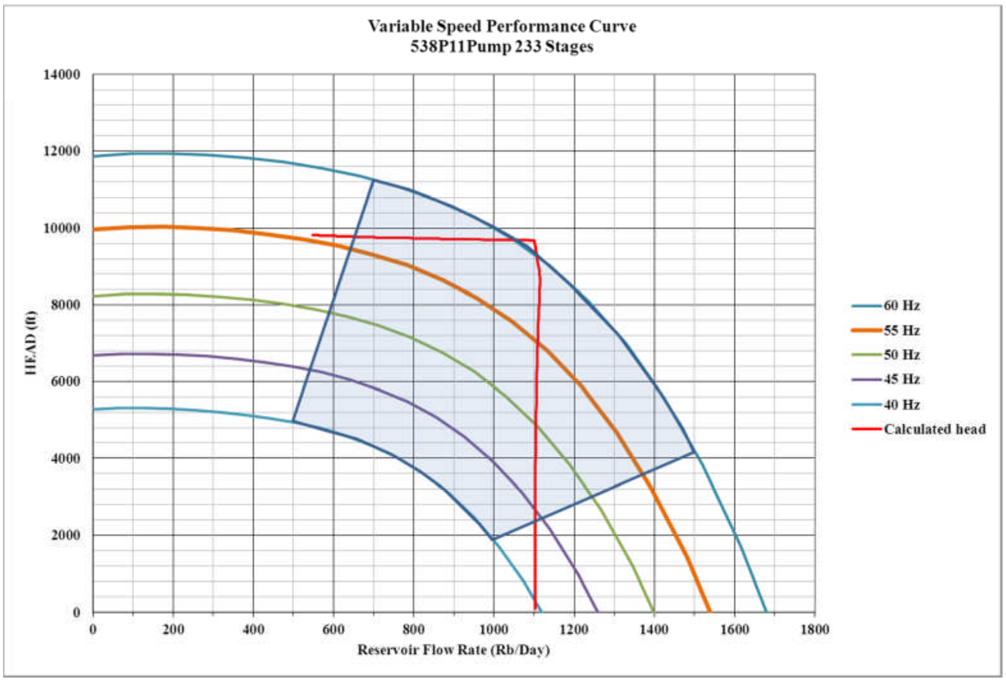

Figure 5.169: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 31.

Case 32: 5PV Aquifer, reservoir pressure 4,400 psi, reservoir temperature 250°F, and initial solution GOR 250 scf/STB.

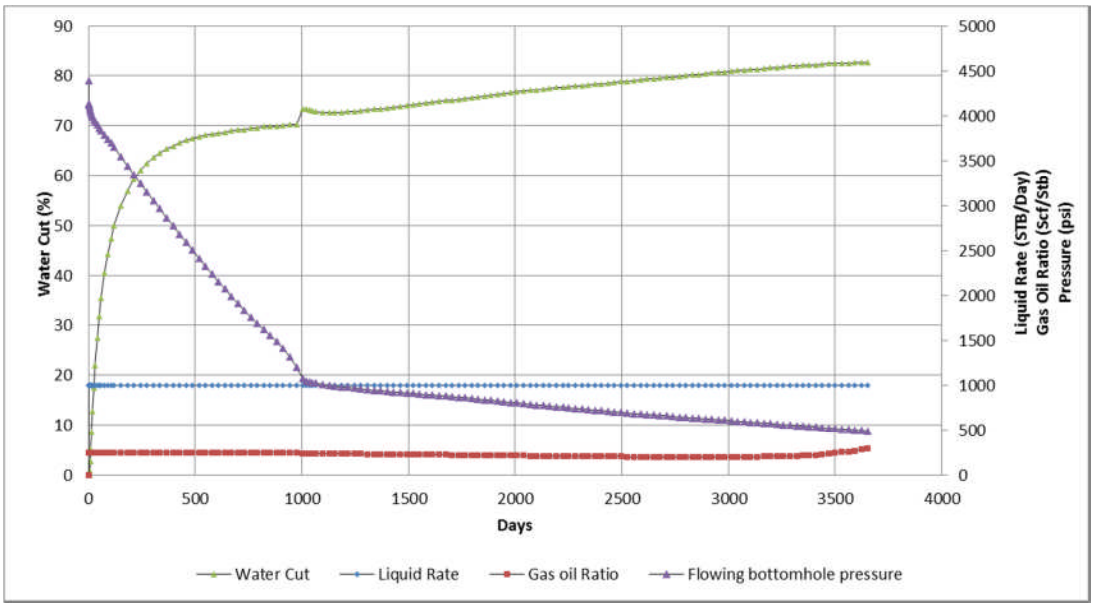

Figure 5.170: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 32.

In this case, the initial solution gas-oil ratio is changed to 250 scf/STB and the aquifer size is remained the same. As shown in Figure 5.170, the bottom-hole pressure rapidly changes due to the reduction of suction pressure. The liquid produces rate is maintained at the target rate for entire production period by the aquifer support. In comparison to case 28, in which the aquifer is only 1PV, the liquid production rate in this case can be sustained for a larger period of time. The water cut increases quickly since the beginning to around 70% within 500 days and reaches over 80% at the end of production. The producing gas-oil ratio is stabled until 3,500 days and slightly increases afterward.

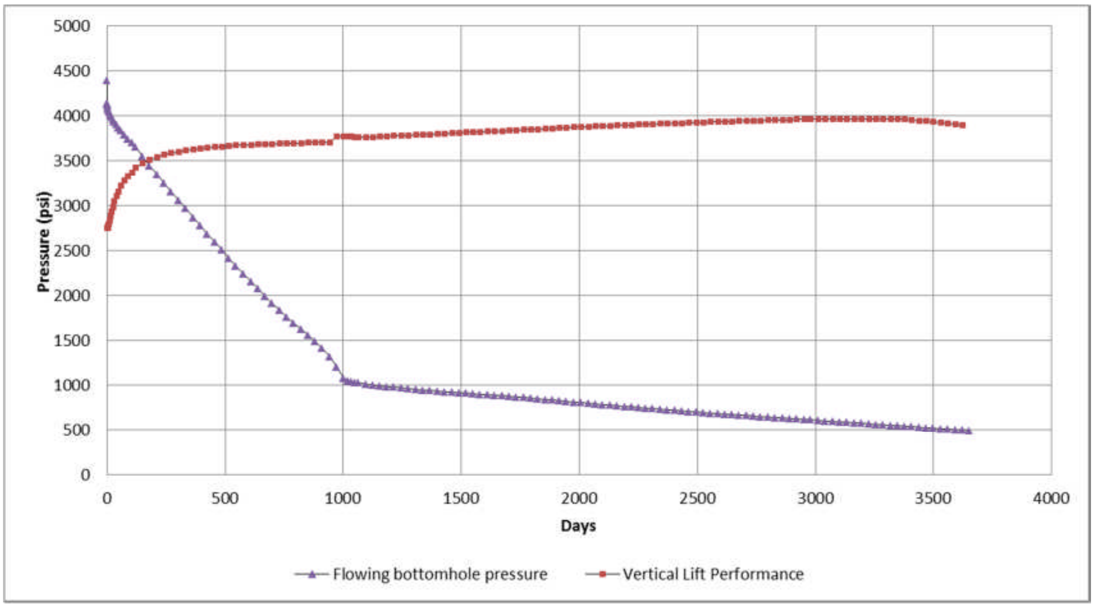

Figure 5.171: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 32.

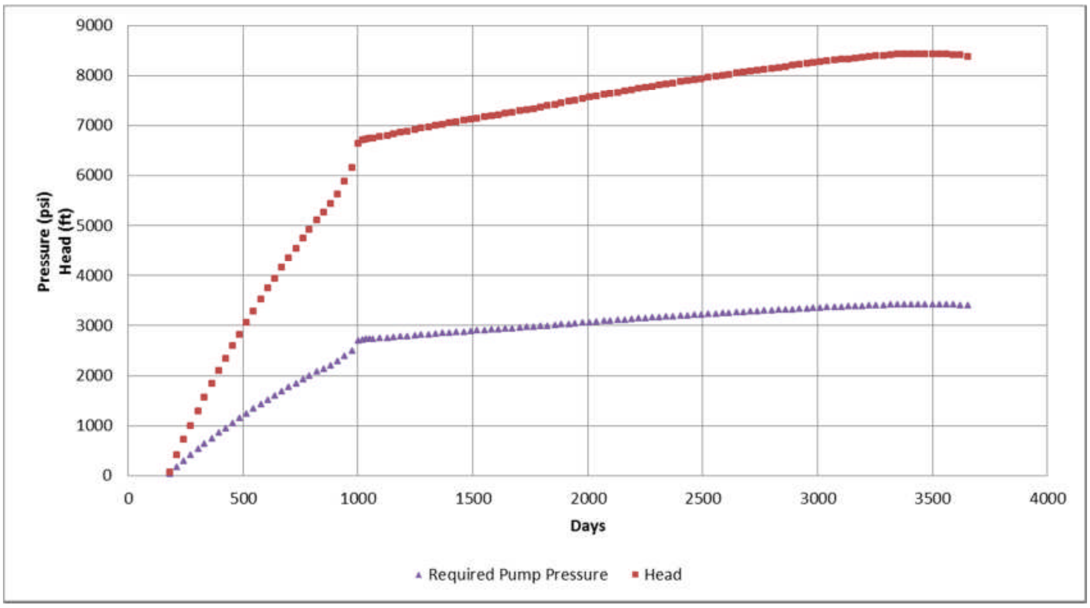

Figure 5.172: Required pump pressure and head for water drive reservoir in case 32.

The well is able to flow freely for around 250 days. The pressure required by vertical lift performance in Figure 5.171 is high since the beginning and moderately increases and become more or less constant until it slightly drops at the end due to less hydrostatic loss in the tubing as more gas flows into the tubing. In contrast, the flowing bottom-hole pressure keeps falling down until reaching at 500 psia at the end of simulation. The required pump pressure and head as depicted in Figure 5.172 sharply increases at the beginning and later on gradually increases and finally declines after gas starts flowing into the well. In comparison to case 29, the maximum head in this case is higher due to higher water production.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 32 is P11 with 248 stages as shown in the Figure 5.173. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 233 stages as depicted in Figure 5.174.

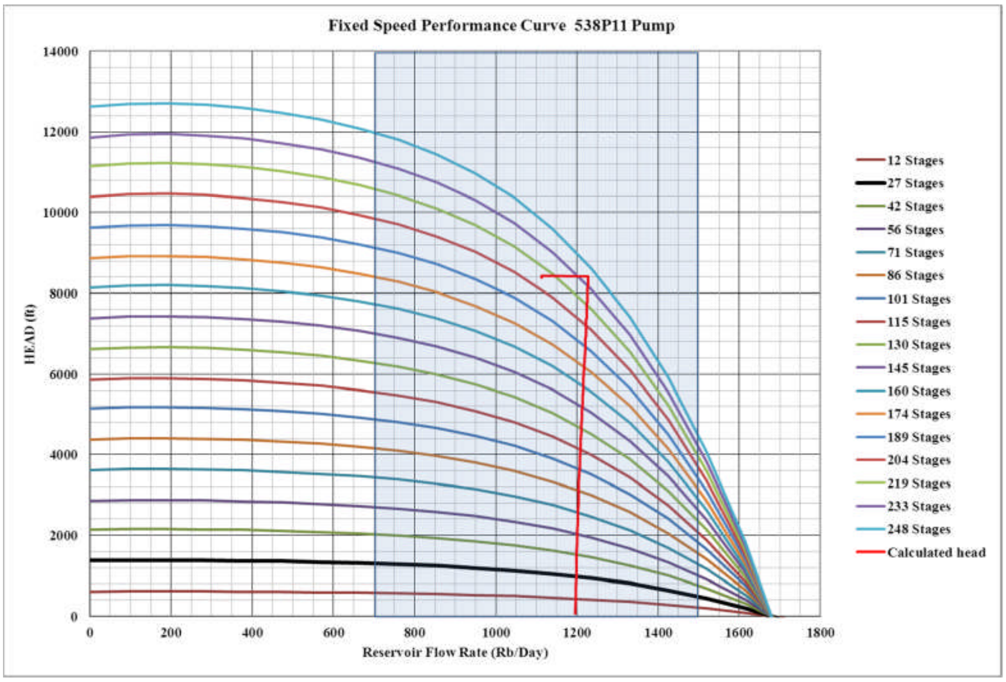

Figure 5.173: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 32.

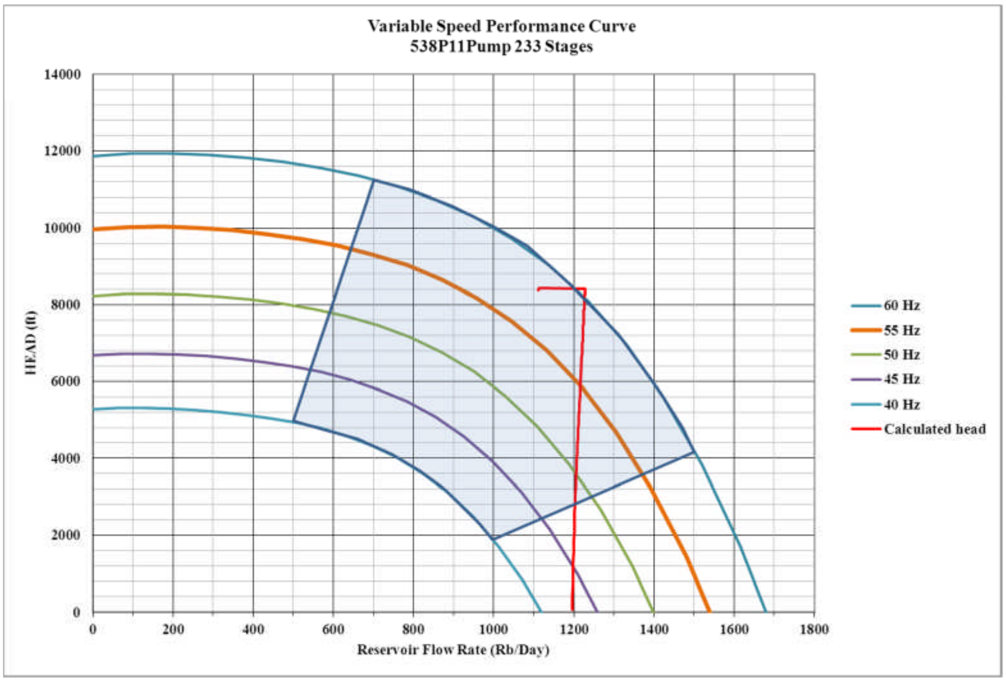

Figure 5.174:Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 32.

Case 33: 5PV Aquifer, reservoir pressure 4,400 psi, reservoir temperature 250°F, and initial solution GOR 500 scf/STB.

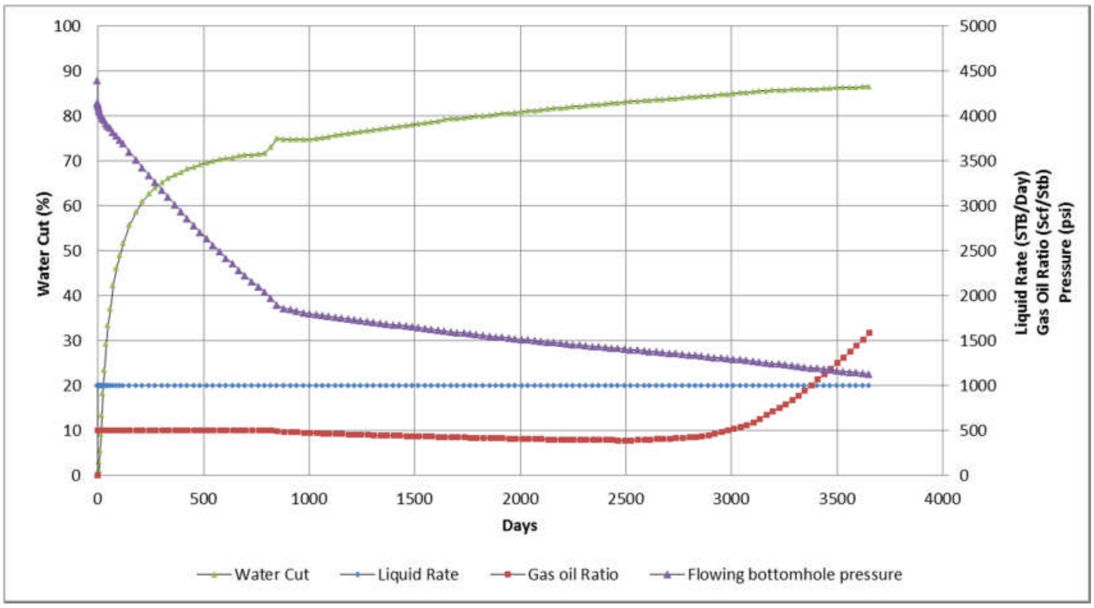

Figure 5.175: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 33.

In Figure 5.175, the bottom-hole pressure steadily drops whereas the production is stabilized at the target rate 1,000 STB/D through the end of simulation due to strong aquifer support. The water cut increases quickly since the beginning to around 70% within 500 days and reaches 85% at the end of production. At early stage, gas-oil ratio does not change until 3,000 days. Then the value steeply goes up because free gas starts to flow.

The well can naturally flowing around 300 days as show in Figure 5.112. The pressure from vertical lift performance in Figure 5.176 gradually increases and drops at the end of simulation due to less hydrostatic loss in the tubing as the producing gas-oil ratio increases. However, the flowing bottom-hole pressure required by the inflow steadily declines. The required pump pressure and head as depicted in Figure 5.177 sharply increases after the well cannot flow naturally until 3,000 days and afterward declines because free gas starts to flow into the wellbore. In comparison to case 30, the maximum head in this case is higher due to higher water production.

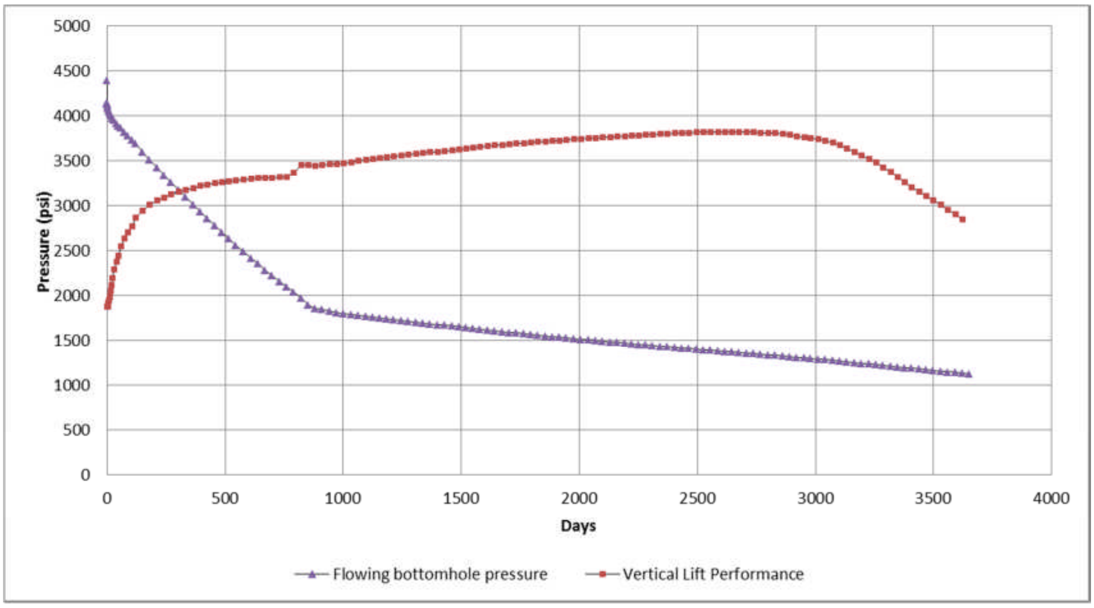

Figure 5.176: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 33.

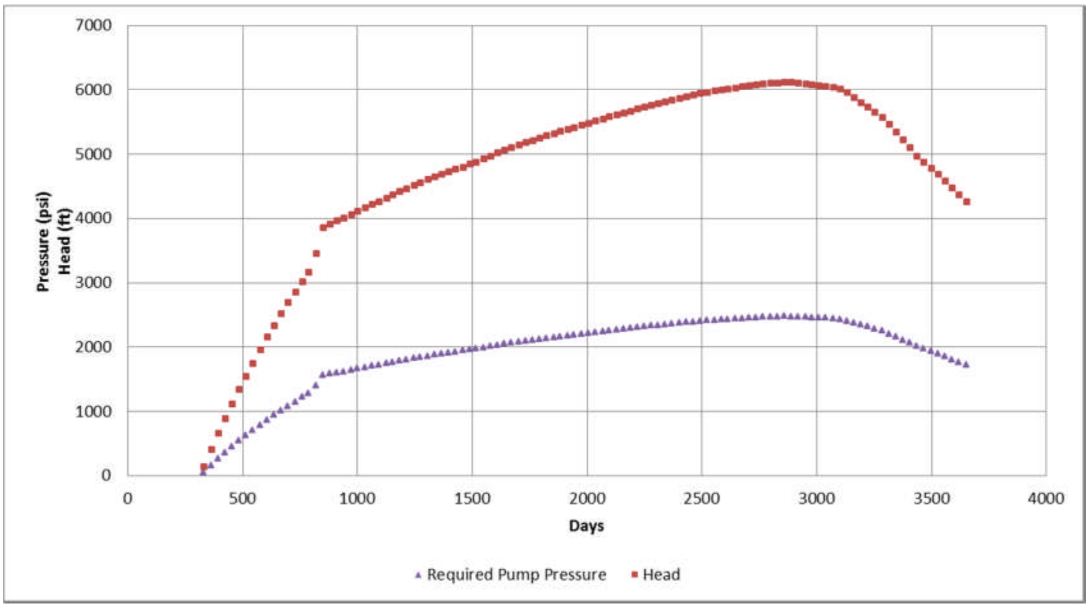

Figure 5.177: Required pump pressure and head for water drive reservoir in case 33.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 33 is P11 with 219 stages as shown in the Figure 5.178. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P17 with 88 stages as depicted in Figure 5.179.

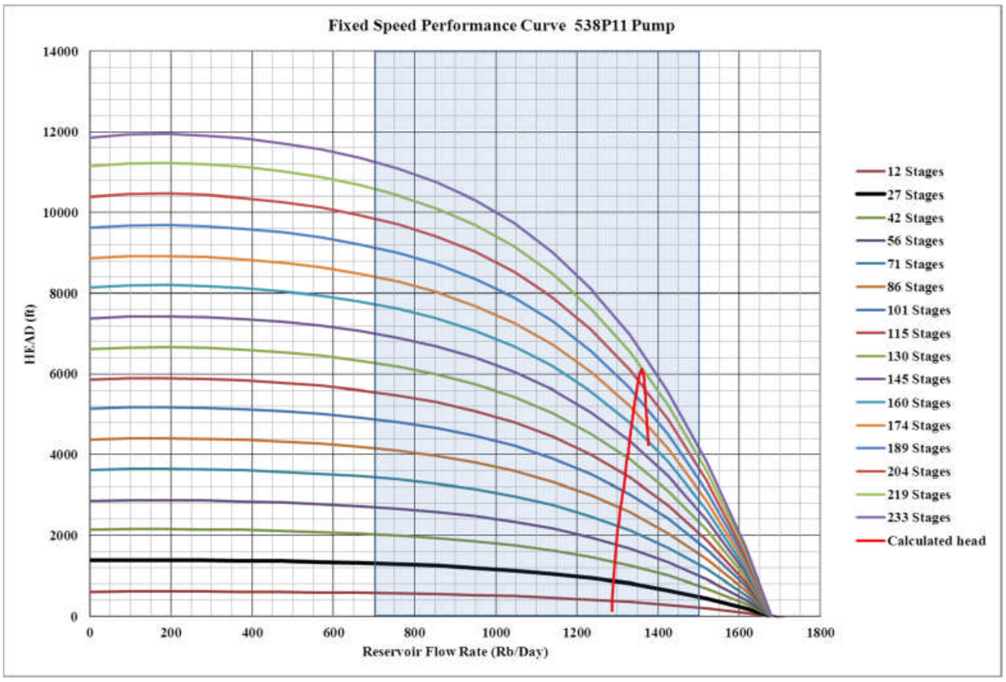

Figure 5.178: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 33.

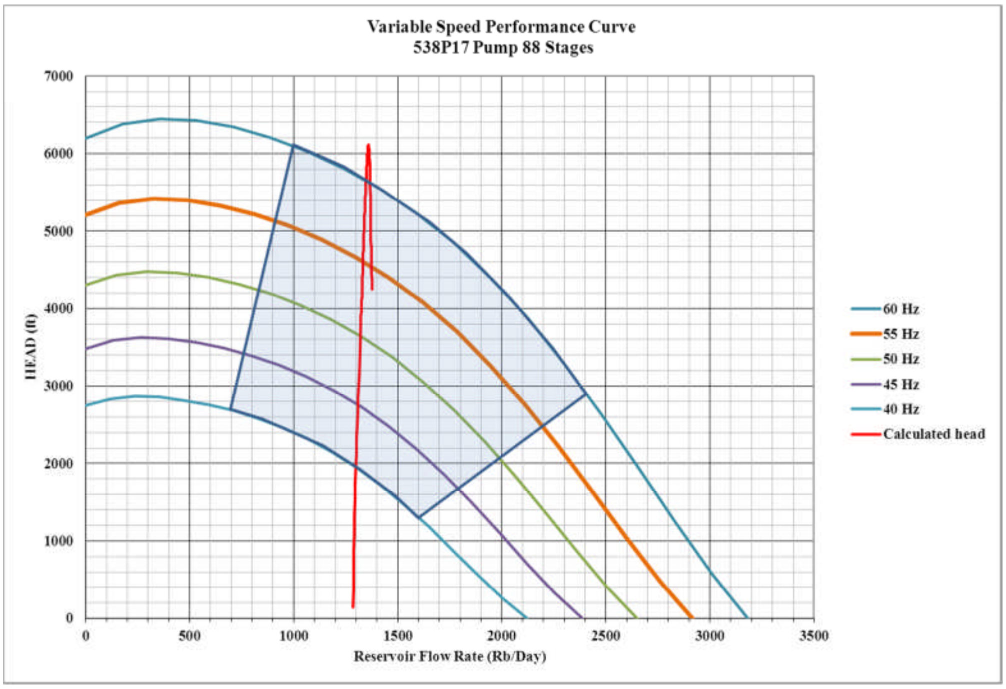

Figure 5.179: Variable speed pump design for 60-Hz 538P17 pump model for water-drive reservoir in case 33.

Case 34: 10PV Aquifer, reservoir pressure 4,400 psi, reservoir temperature 250°F, and initial solution GOR 100 scf/STB.

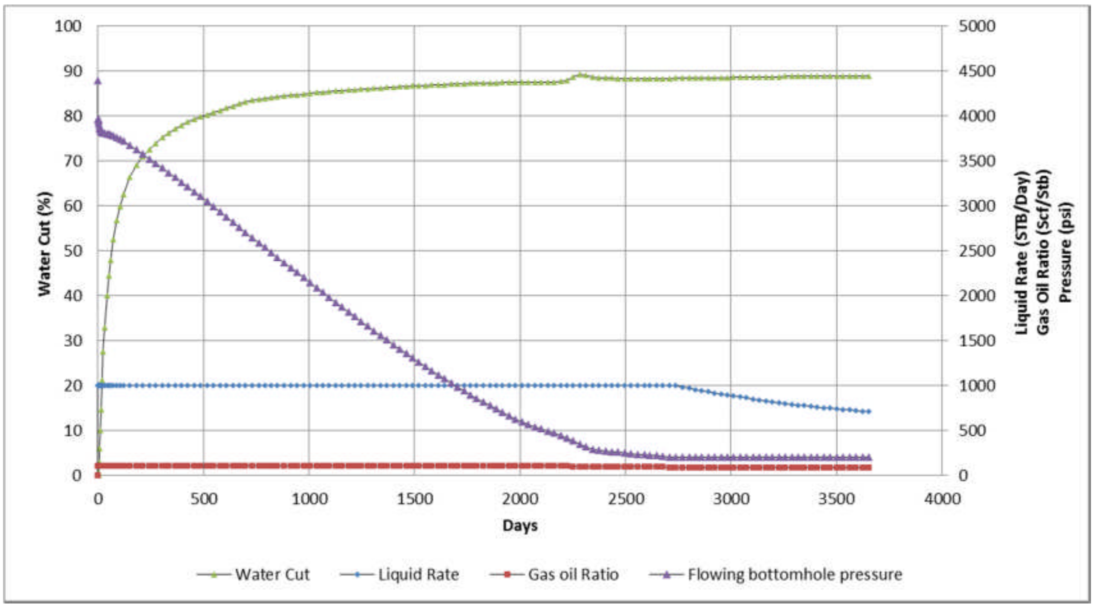

Figure 5.180: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 34.

In this scenario, the aquifer support is changed from 5 times to 10 times of the reservoir pore volume. As represented in Figure 5.180, the bottom-hole pressure steadily declines while the liquid production target rate can be sustained for 2,750 days. The water cut increases quickly since the beginning to around 80% within 500 days and reaches almost 90% at the end of production. In comparison to case 31, in which the aquifer size is 5PV, the water cut in this case is higher due to larger aquifer.

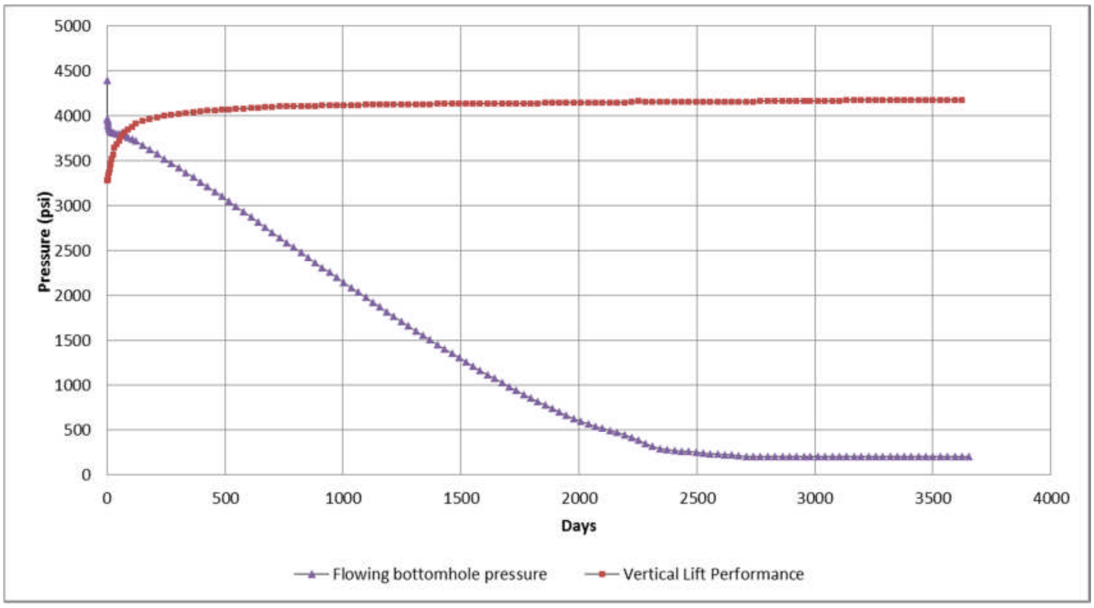

Figure 5.181: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 34.

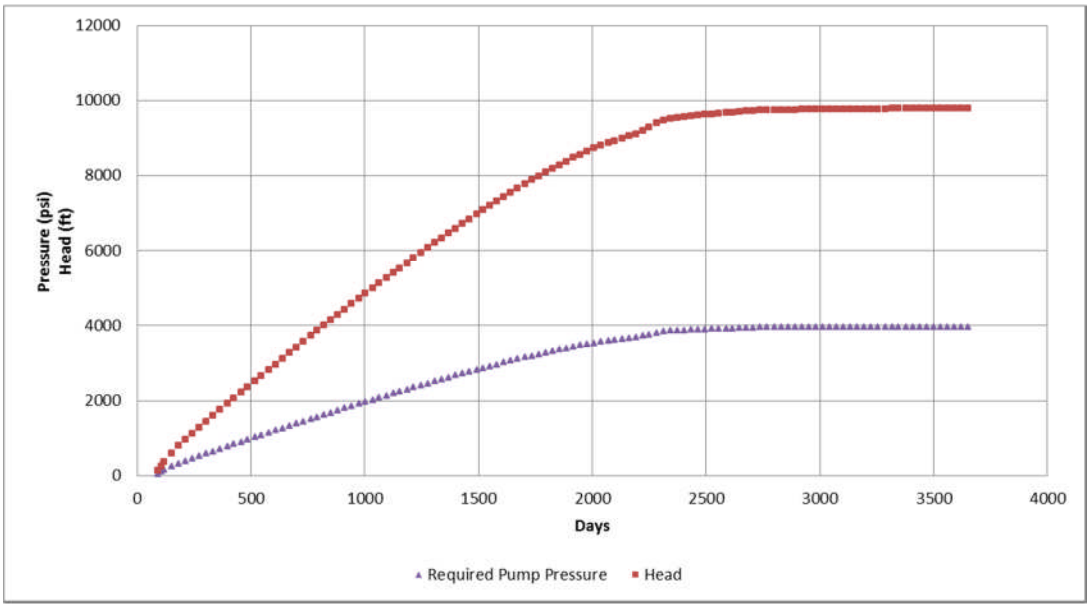

Figure 5.182: Required pump pressure and head for water drive reservoir in case 34.

The well cannot flow naturally at very short period as shown in Figure 5.115. The pressure from vertical lift performance is also high from the beginning and stays flat until the end but flowing bottom-hole pressure moderately declines until reaching the minimum as shown in Figure 5.181. The required pump pressure and head as depicted in Figure 5.182 rapidly increases at the beginning and remains unchanged after 2,200 days. In comparison to case 28 and 31, which have smaller aquifer sizes the head requirement in this case of 10PV aquifer is the highest.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 34 is P11 with 248 stages as shown in the Figure 5.183. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 248 stages as depicted in Figure 5.184.

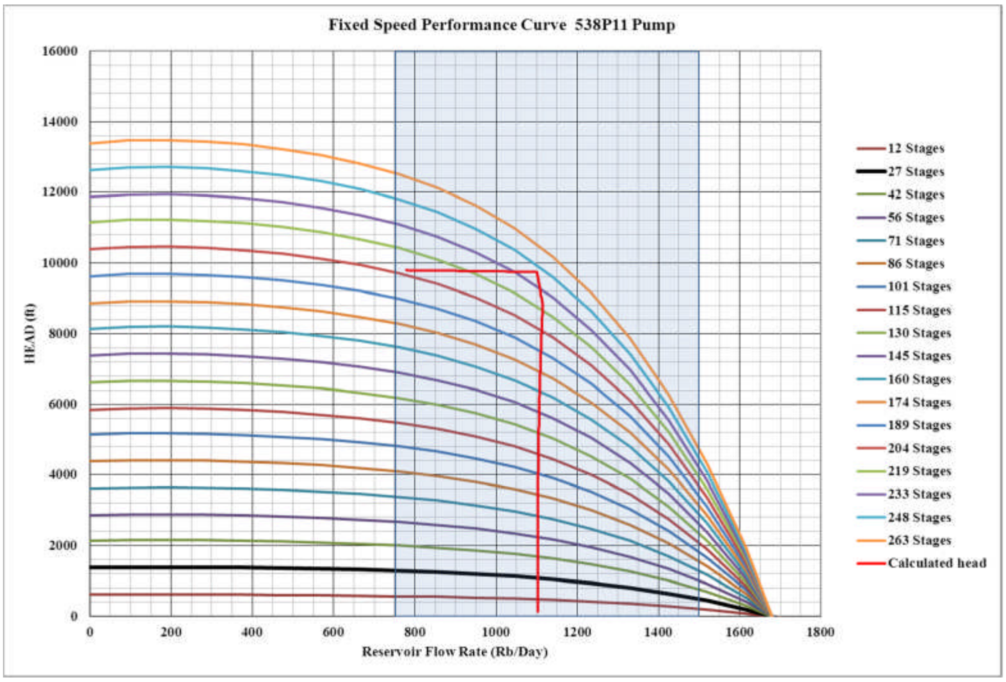

Figure 5.183: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 34.

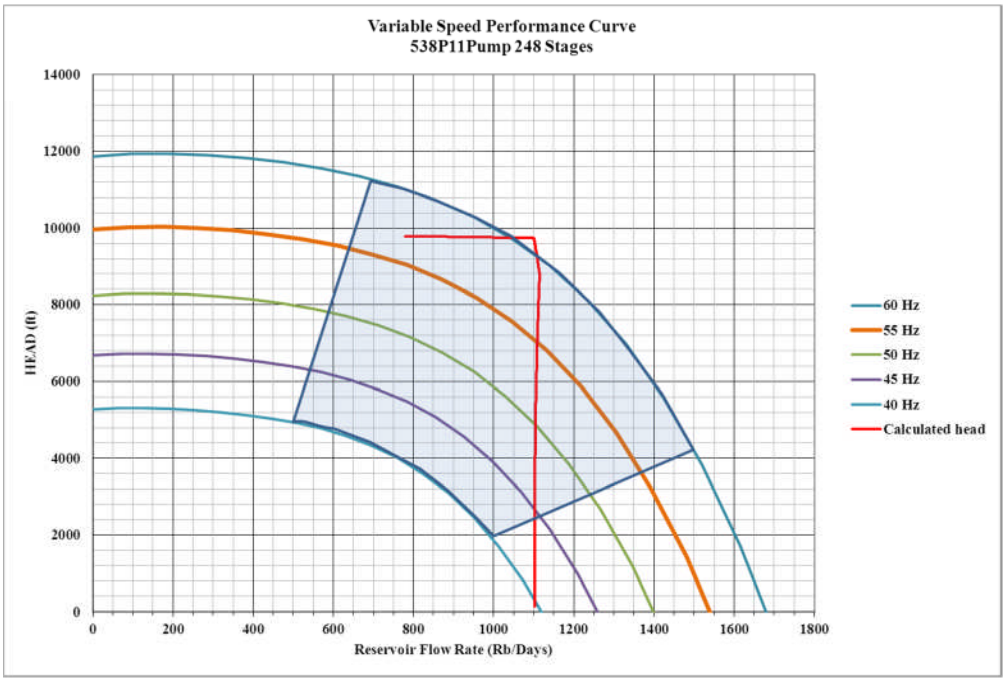

Figure 5.184: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 34.

Case 35: 10PV Aquifer, reservoir pressure 4,400 psi, reservoir temperature 250°F, and initial solution GOR 250 scf/STB.

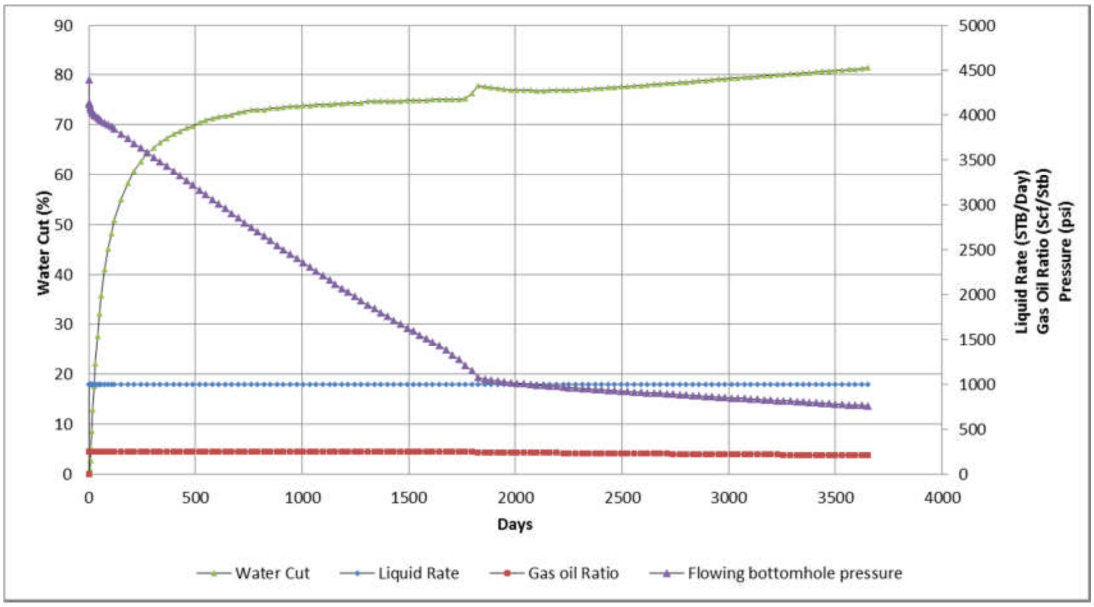

Figure 5.185: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 35.

In this case, the initial solution gas-oil ratio is altered to 250 scf/STB. The simulation results are shown in Figure 5.185. The production target rate remains stable at 1,000 STB/D for the entire life of simulation period because of strong aquifer support. The bottom-hole pressure steadily declines while the water cut rapidly increases to around 70% within 500 days and reaches over 80% at the end of production.

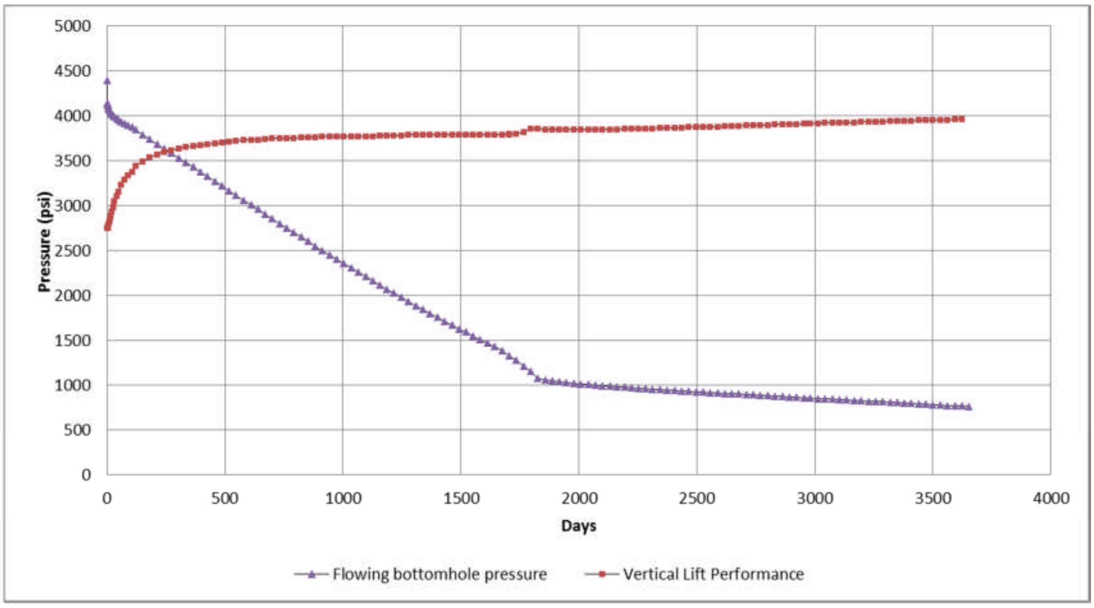

Figure 5.186: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 35.

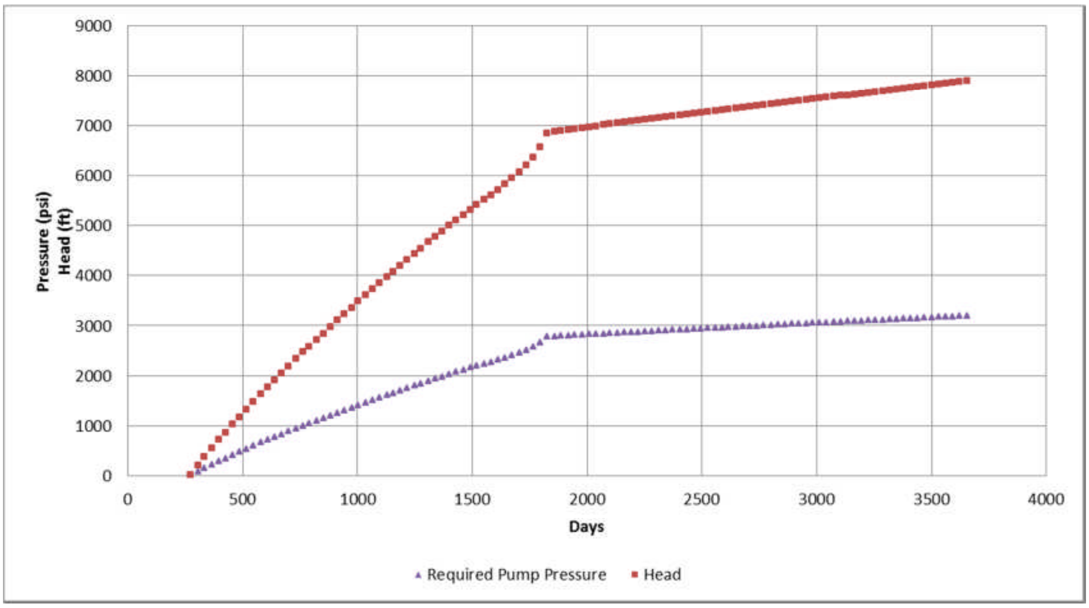

Figure 5.187: Required pump pressure and head for water drive reservoir in case 35.

From Figure 5.186, the well can flow naturally for around 250 days and the bottom-hole pressure from vertical lift performance is initially high and gradually increases after the water cut increases gradually. The differential pressure between flowing bottom-hole pressure and pressure from vertical lift performance is plotted in Figure 5.187 as a required pump pressure. In another word, it is the difference between the discharge pressure and suction pressure and after dividing by fluid gravity, it is plotted as head in the same trend. In contrast with case 29 and 32, the head does not decline at the late times due to constant producing gas-oil ratio.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 35 is P11 with 233 stages as shown in the Figure 5.188. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P11 with 219 stages as depicted in Figure 5.189.

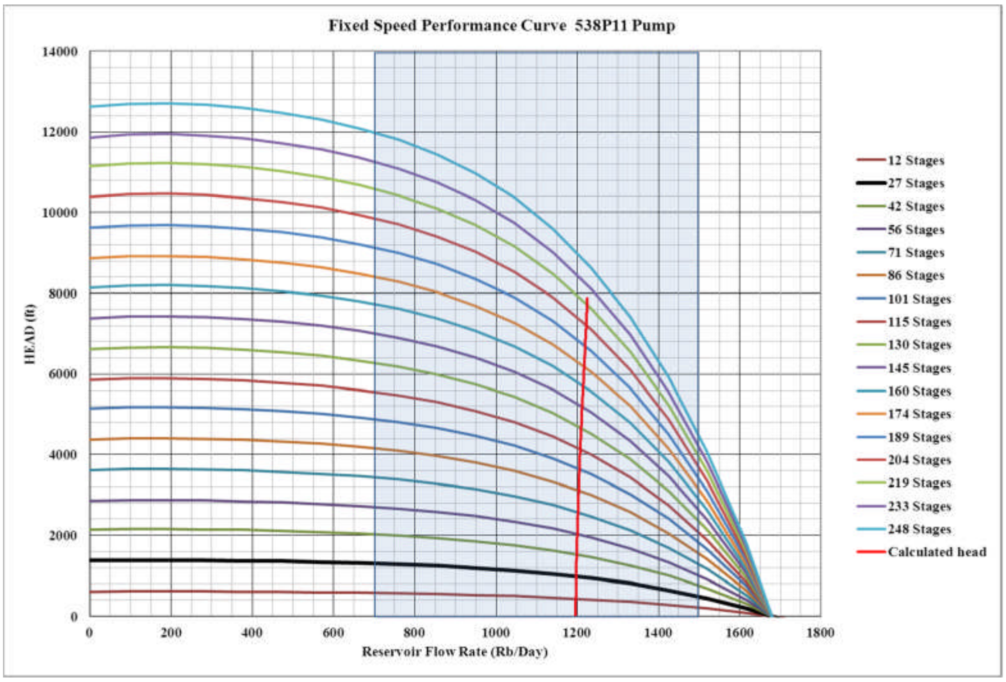

Figure 5.188: Fixed speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 35.

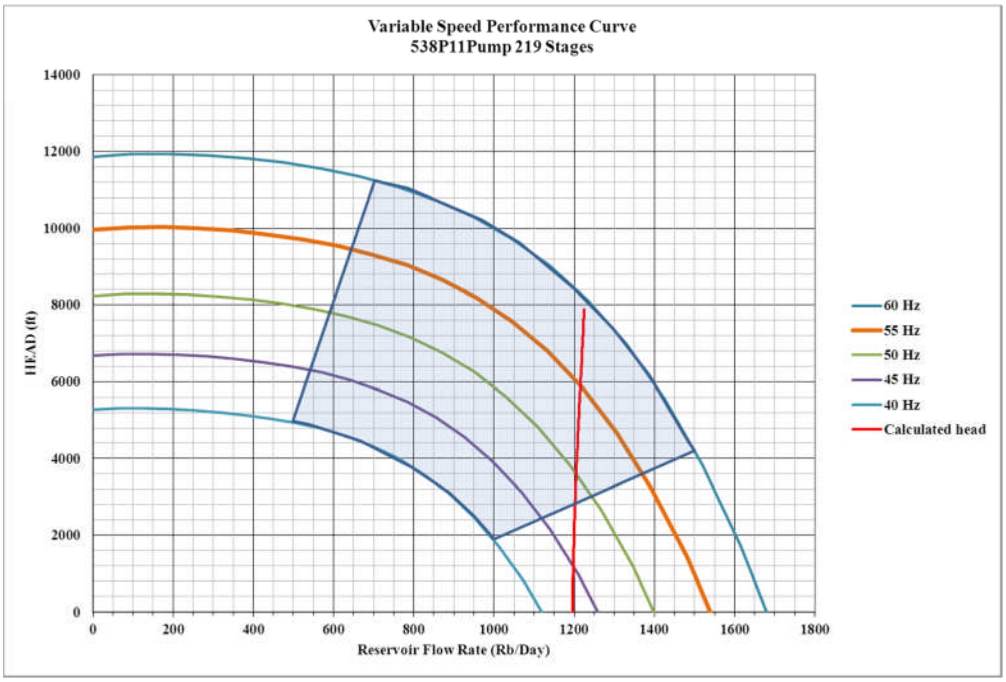

Figure 5.189: Variable speed pump design for 60-Hz 538P11 pump model for water-drive reservoir in case 35.

Case 36: 10PV Aquifer, reservoir pressure 4,400 psi, reservoir temperature 250°F, and initial solution GOR 500 scf/STB.

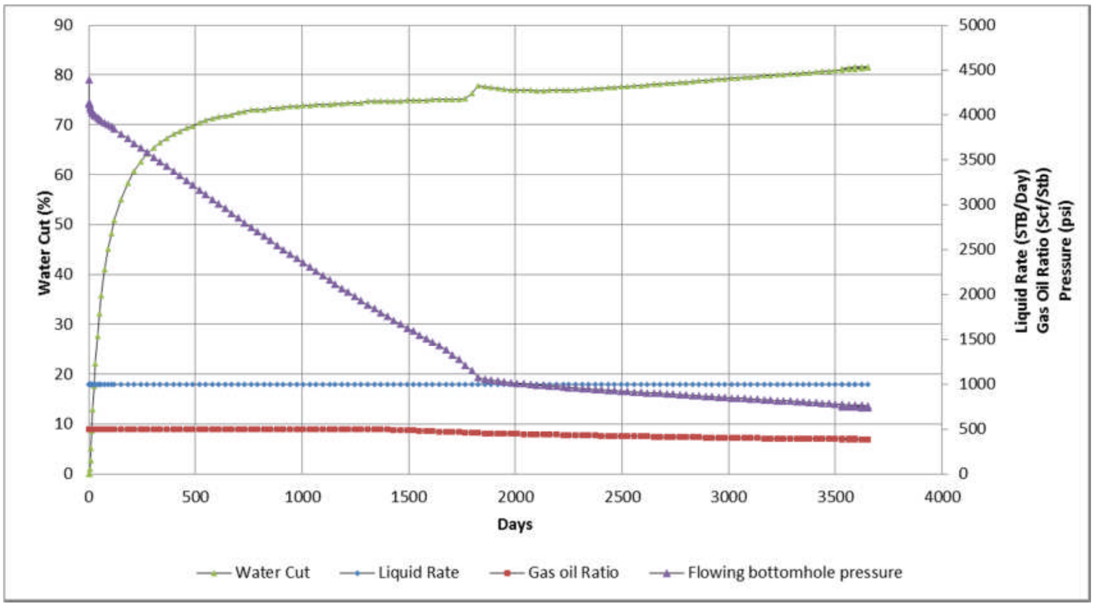

Figure 5.190: Liquid rate, gas-oil ratio, water cut, bottom-hole pressure profiles for water drive reservoir in case 36.

In this case, initial solution gas-oil ratio is changed to 500 scf/STB and it is considered as the last case of this thesis. As shown in Figure 5.190, Due to pressure support from water aquifer, the production target rate remains stable at 1,000 STB/D for the entire life of reservoir. The producing gas-oil ratio is more or less unchanged and for over 3,500 days. The bottom-hole pressure declines at a slow pace while the water cut increases quickly since the beginning to around 70% within 500 days and reaches over 80% at the end of production.

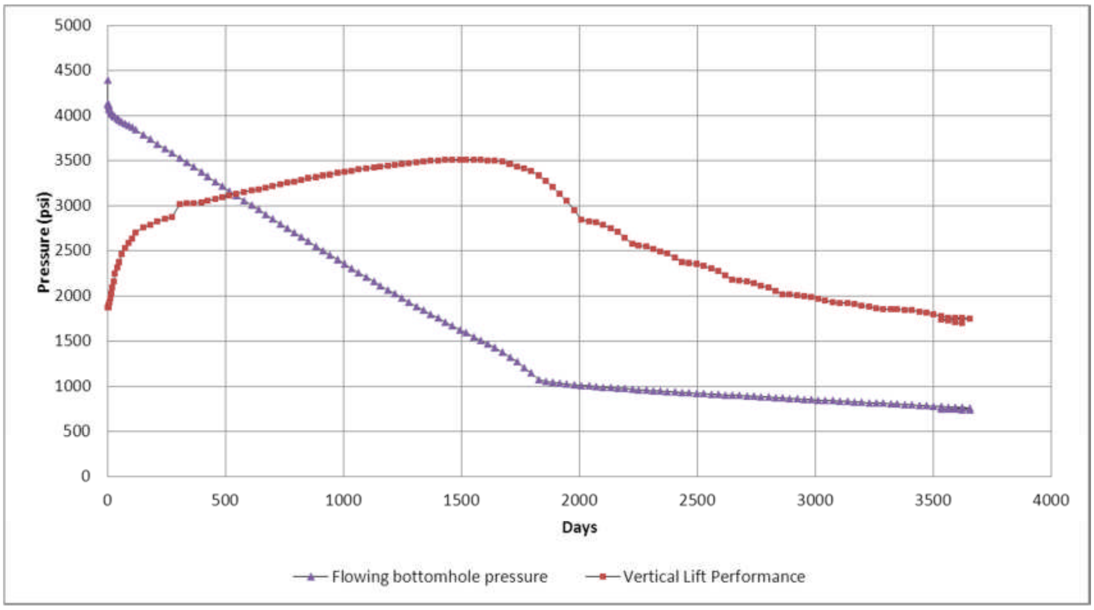

Figure 5.191: Bottom-hole pressures from ECLIPSE and Vertical Lift Performance for water drive reservoir in case 36.

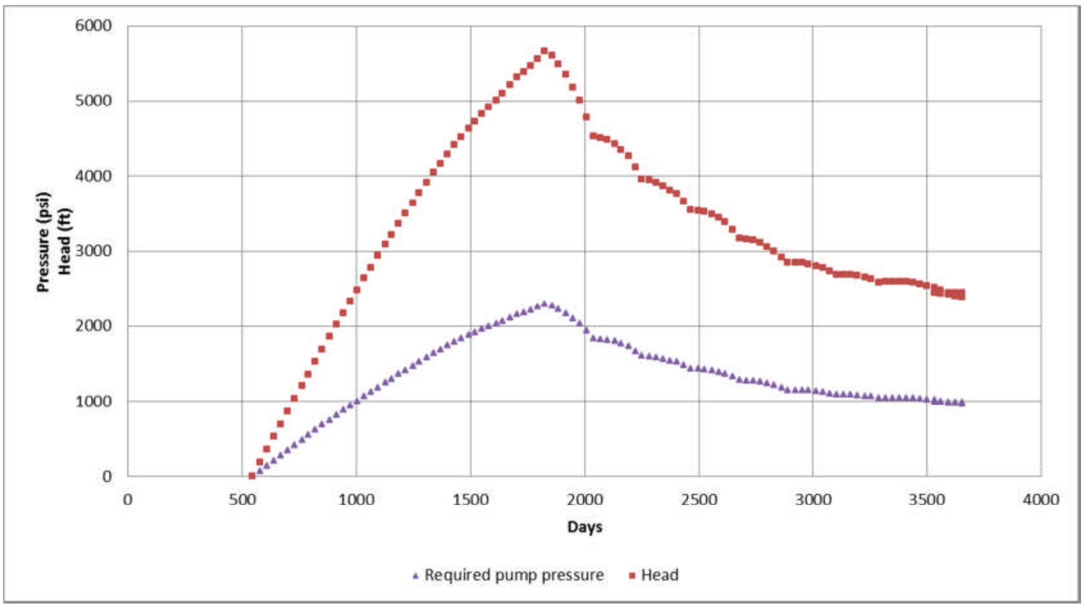

Figure 5.192: Required pump pressure and head for water drive reservoir in case 36.

From Figure 5.191, the well flows naturally for around 500 days. The flowing bottom-hole pressure declines at moderate rate while pressure required for vertical lift performance increases due to water production in the tubing. Later on, when more gas flows into the wellbore, the pressure for vertical lift performance deceases because a lighter fluid is produced in the tubing. The required pump pressure and head are shown in Figure 5.192. They steadily increase in the same style due to water production and afterward when more gas flows into the wellbore, they gradually decrease. In comparison to case 30 and 33, the head requirement in this case is the highest due to high water cut.

The design for fixed speed pump is performed by plotting the head as a function of downhole rate liquid on two pump characteristic curves. The chosen pump model in case 36 is P17 with 134 stages as shown in the Figure 5.193. Similarly, the variable speed pump is designed by plotting the head requirement versus downhole liquid rate on two variable speed pump characteristic. The design that suits best for the varying well and reservoir conditions is pump model P17 with 134 stages as depicted in Figure 5.194.

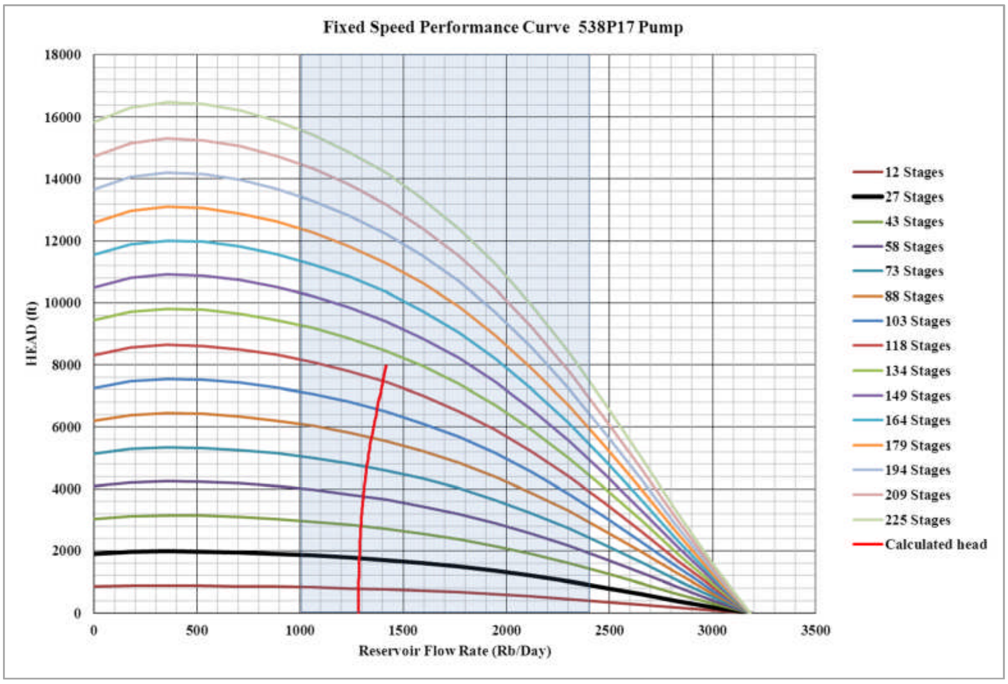

Figure 5.193: Fixed speed pump design for 60-Hz 538P17 pump model for water-drive reservoir in case 36.

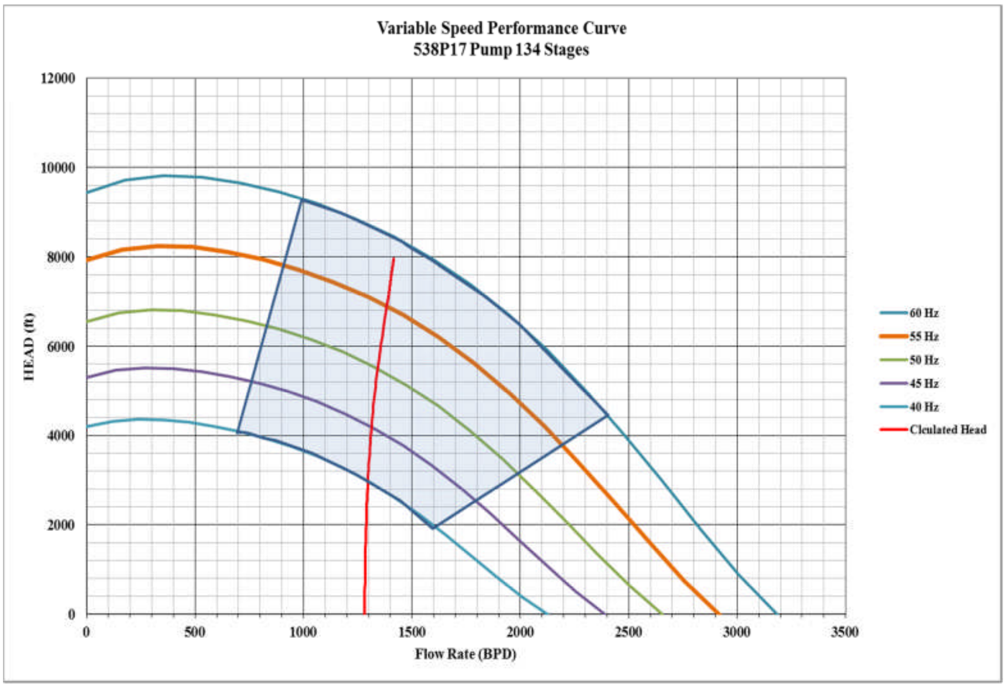

Figure 5.194: Variable speed pump design for 60-Hz 538P17 pump model for water-drive reservoir in case 36.

5.5 Design Comparison of Case Studies

In this section, conventional pump design method is applied all 36 scenarios presented in Sections 5.3 and 5.4. The conventional design is then compared with the design proposed in this study to determine whether the conventional design can satisfy all requirements.

In conventional design, static bottom-hole pressure is used to design the number of pump stages by applying reduction factors to reservoir pressure to predict number of pump stages. Typically, reduction factor of 10, 25, and 50 percent of the initial reservoir pressure is used. Future IPR may be based on Productivity Index or Vogel equation depending on the phase flowing in the reservoir. If gas is present in the reservoir, Vogel equation is used instead of Productivity Index.

Table 5.3 summarizes future reservoir pressure of three different reservoir depths for different reduction factor. For pump stage calculation in the conventional design. The future reservoir pressure will be used to calculate inflow performance and incorporate outflow performance tubing correlation to evaluate the number of pump stages. Note that all conventional design scenarios are performed by industrial commercial software.

Table 5.3: Future reservoir pressure for number of pump stage calculation.

Reservoir depth. (ft.)	Initial Reservoir pressure. (psia)	Reduction factor	Future reservoir pressure. (psia)
5,000	2,200	10%	1,980
		25%	1,650
		50%	1,100
7,000	3,300	10%	2,970
		25%	2,475
		50%	1,650
10,000	4,400	10%	3,960
		25%	3,300
		50%	2,200

5.5.1. Design Comparison at Reservoir Depth 5,000 ft.

The reduction factor of 10, 25, and 50 percent is applied to initial reservoir pressure to obtain the future reservoir pressure for pump design. The ultimate goal is to determine the actual number of pump stages and select the number of pump stages that are available from industrial catalog. The number of pump stage obtain from conventional design are compared with the design based simulation results for both drive mechanisms.

The results of design based on reservoir simulation and conventional design with three different reduction factors are shown in Table 5.4. For fixed speed design, 11 out of 12 simulation cases require the number of pump stages larger than the one based on 10% and 25% reduction factors. The only case that requires less number of stages is case 3, which is solution-gas drive reservoir with initial solution gas-oil ratio of 500 scf/STB with no aquifer. This means that conventional design based on 10% or 20% reduction factors would generally not satisfy the head requirement except when the fluid has high GOR in tubing. When 50% reduction factor is used, there are still four simulation cases which require larger number of pump stages than the ones in the conventional design. These four cases are case 10, 13, 14, and 17 which have water aquifer and small initial solution gas-oil ratio. In summary, the conventional design for fixed speed pump based on the reduction factor applied to reservoir pressure may underestimate the number of required pump stages, particularly, in the case of water drive reservoir which yields high water cut and in the case of low producing gas-oil ratio which results in high hydrostatic loss.

In the case of variable speed design, the conventional design based on 10% reduction factor can satisfy all cases of solution-gas drive reservoirs without water aquifer but in the case of high initial solution gas-oil ratio (case 3), the number of pump stages is over estimated. For reservoir with water drive, 4 out of 9 simulation cases require higher number of pump stages than those determined from conventional design with 10% reduction factor. When 25% and 50% reduction factors are applied, all of the conventional designs overestimate the number of pump stages. The overestimation is extremely high in the case of solution-gas drive reservoir, in which the requirement is between 27-86 stages for different initial solution gas-oil ratios while conventional design suggests 174 stage.

Table 5.4: Comparison of number of pump stages
for initial reservoir pressure 2,200 psia.

Scenario				No. of stages (catalog)			
Case no.	Drive mechanism	Solution GOR (scf/STB)	Aquifer size	Fixed speed	Pump model	Variable speed	Pump model
Case 1	Solution-gas-drive	100	No aquifer	86	P11	86	P11
Case 2	Solution-gas-drive	250	No aquifer	86	P11	71	P11
Case 3	Solution-gas-drive	500	No aquifer	42	P11	27	P11
Case 10	Water-drive	100	1 PV	115	P11	101	P11
Case 11	Water-drive	250	1 PV	101	P11	101	P11
Case 12	Water-drive	500	1 PV	86	P11	71	P11
Case 13	Water-drive	100	5 PV	115	P11	101	P11
Case 14	Water-drive	250	5 PV	115	P11	73	P17
Case 15	Water-drive	500	5 PV	86	P11	43	P17
Case 16	Water-drive	100	10 PV	101	P11	86	P11
Case 17	Water-drive	250	10 PV	115	P11	101	P11
Case 18	Water-drive	500	10 PV	86	P11	43	P17
10% reduction factor				56	P11	86	P11
25% reduction factor				71	P11	130	P11
50% reduction factor				101	P11	174	P11

5.5.2. Design Comparison at Reservoir Depth 7,000 ft.

In this section, the reduction factor of 10, 25, and 50 percent is applied to initial reservoir pressure to obtain the future reservoir pressure for pump design at depth 7,000 ft. The ultimate goal is to determine the actual number of pump stages and select the number of pump stages that are available from industrial catalog. The number of pump stage obtain from conventional design are compared with the design based simulation results for both drive mechanisms.

The number of pumps stages determined based on head requirement from simulation and that from conventional design for different reduction factors are shown in Table 5.5. For fixed speed design, all simulation cases require the number of pump stages larger than the one based on 10% reduction factors. In the case of 25% reduction factors, 11 out of 12 simulation cases still require larger numbers of pump stages than the ones in conventional design. For the cases of 50% reduction factor, 10 out of 12 simulation cases still have higher requirement of pump stages. This means that conventional design based on 10%, 25%, and 50% reduction factors would generally not satisfy the head requirement. In summary, the conventional design for fixed speed pump based on the reduction factor applied to reservoir pressure may underestimate the number of required pump stages, particularly, in the case of water drive reservoir with high water cut and in the case of low producing gas-oil ratio.

In the case of variable speed design, the conventional design based on 10% reduction factor cannot satisfy any cases at all. The design based on 25% reduction factor can satify only 4 cases while the design based on 50% reduction factor satisfy all cases but the numbers are overestimated. The overestimation is extremely high in the case of solution-gas drive reservoir, in which the requirement is between 56-115 stages for different initial solution gas-oil ratios while conventional design suggests 204 stages.

Table 5.5: Comparison of number of pump stages
for initial reservoir pressure 3,300 psia.

Scenario				No. of stages (catalog)			
Case no.	Drive mechanism	Solution GOR (scf/STB)	Aquifer size	Fixed speed	Pump model	Variable speed	Pump model
Case 4	Solution-gas-drive	100	No aquifer	130	P11	115	P11
Case 5	Solution-gas-drive	250	No aquifer	115	P11	101	P11
Case 6	Solution-gas-drive	500	No aquifer	56	P11	56	P11
Case 19	Water-drive	100	1 PV	160	P11	145	P11
Case 20	Water-drive	250	1 PV	145	P11	130	P11
Case 21	Water-drive	500	1 PV	130	P11	115	P11
Case 22	Water-drive	100	5 PV	160	P11	160	P11
Case 23	Water-drive	250	5 PV	160	P11	145	P17
Case 24	Water-drive	500	5 PV	145	P11	58	P11
Case 25	Water-drive	100	10 PV	174	P11	160	P11
Case 26	Water-drive	250	10 PV	160	P11	145	P11
Case 27	Water-drive	500	10 PV	130	P11	58	P17
10% reduction factor				27	P11	42	P11
25% reduction factor				56	P11	101	P11
50% reduction factor				115	P11	204	P11

5.5.3. Design comparison at reservoir depth 10,000 ft.

The reduction factor of 10, 25, and 50 percent is applied to initial reservoir pressure to obtain the future reservoir pressure for pump design at depth 10,000 ft. in the same fashion as the previous section. The ultimate goal is to determine the actual number of pump stages and select the number of pump stages that are available from industrial catalog. The number of pump stage obtain from conventional design are compared with the design based simulation results for both drive mechanisms.

The number of pump stages from simulation and conventional design are shown in Table 5.6. For fixed speed design, almost all simulation cases require the number of pump stages larger than the one based on 10%, 25% and 50% reduction factors. The only case that the conventional design meets the requirement is case 9 with reduction factor of 50%. This means that any conventional design based on 10%, 25%, and 50% reduction factors would not satisfy the head requirement. Even though 50% reduction factor is applied, almost all simulation cases which require larger number of pump stages than the ones in the conventional design, especially, in the cases which have water aquifer and initial solution gas-oil ratio. In summary, the conventional design for fixed speed pump based on the reduction factor applied to reservoir pressure may underestimate the number of required pump stages, particularly, in the case of water drive reservoir with high water cut and in the case of low producing gas-oil ratio.

In the case of variable speed design, the conventional design based on 10% reduction factor cannot satisfy any cases at all. The design based on 25% reduction factor can satisfy only three cases with initial solution GOR of 500 scf/STB (cases 9, 30,33). When 50% reduction factor is applied, all of the conventional designs overestimate the number of pump stages. The overestimation is extremely high in the case of water drive reservoir, in which the requirement is between 88-248 stages for different initial solution gas-oil ratios while conventional design suggests 263 stages.

Table 5.6: Comparison of number of pump stages
for initial reservoir pressure 4,400 psia.

Scenario				No. of stages (catalog)			
Case no.	Drive mechanism	Solution GOR (scf/STB)	Aquifer size	Fixed speed	Pump model	Variable speed	Pump model
Case 7	Solution-gas-drive	100	No aquifer	189	P11	189	P11
Case 8	Solution-gas-drive	250	No aquifer	174	P11	160	P11
Case 9	Solution-gas-drive	500	No aquifer	115	P11	58	P17
Case 28	Water-drive	100	1 PV	233	P11	233	P11
Case 29	Water-drive	250	1 PV	219	P11	219	P11
Case 30	Water-drive	500	1 PV	219	P11	88	P17
Case 31	Water-drive	100	5 PV	248	P11	233	P11
Case 32	Water-drive	250	5 PV	248	P11	233	P17
Case 33	Water-drive	500	5 PV	219	P11	88	P17
Case 34	Water-drive	100	10 PV	248	P11	248	P11
Case 35	Water-drive	250	10 PV	233	P11	219	P11
Case 36	Water-drive	500	10 PV	134	P17	134	P17
10% reduction factor				42	P11	71	P11
25% reduction factor				71	P11	130	P11
50% reduction factor				132	P11	263	P11

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

In this study, reservoir simulation was applied to predict the future performance of the fluid rate and bottom-hole pressure. The vertical lift performance is used to estimate the discharge pressure required to lift fluid to the surface. The results from reservoir simulation together with vertical lift performance are used to design the number of pump stages. Water and solution gas drive were considered to investigate the pressure behavior and determine the number of pump stages and the pump model.

6.1 Conclusions

After comparing the number of pump stages determined from conventional design and the one based on reservoir performance simulation which considers reservoir and tubing performance, the following conclusions can be drawn:

1. The specific gravity of fluid mixture in tubing has a significant influence to number of pump stages. In the case of water drive reservoir, the larger aquifer will require a higher number of pump stages than the one with small aquifer. Water production has a major effect on head requirement and number of pump stages required in the future. For solution-gas drive reservoir, the solution gas once vaporizes as free gas has a significant influence of reducing fluid density, resulting in head reduction.
2. In the fixed speed application, the numbers of pump stages calculated from conventional design with reduction factor are generally underestimated when compared with the results from the simulation. For fixed speed, the number of pump stage selected must be bases on the worst case scenario to accommodate varying well conditions thus whenever the well conditions change, the pump still fluid to the surface.

3. In the variable speed application, at reservoir depth of 5,000 ft, the conventional design with 25% reduction factor satisfy the minimum required number of pump stages for both drive mechanism. However, 50% reduction factor in the conventional design results in overestimation of pump stages compared to all simulation cases. At depth of 7,000 ft. and 10,000 ft., only design with 50% reduction factor can satisfy the requirement in all cases. However, overe design still happens in some cases.

6.2 Recommendations

In this research, the gas separator efficicnecy was assumed to be 100% efficiency. In other word, there is no gas flow into the first stage of pump and the head is not degradated by the effect of gas. Since free gas causes a certain level of head degration, it is highly recommended to extend this study by including the percentage of free gas that enters the pump and reevaluating the number of pump stages.

Tubing size. wellhead pressure, and addtional parameters that affect the total dynamic head need further anaysis for the pump stage design, especially, offshore in the case of offshore development project that certainly concerns with the footprint and size of platform to accommodate the topside equipments such as gernerator, swithch gear, variable speed drive, switchboard, step-up transformer and etc. This equipment needs to be sized based on number of pump stages and other downhole equipment.

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APPENDIX

APPENDIX A

A-1) Reservoir model

Two reservoir models are generated by entering required data into ECLIPSE 100 reservoir simulator. The model used in this study composes of 50 x 50 x 60 blocks in the x-, y- and z- directions.

A-2)Case definition

Simulator:	Black Oil	
Model dimensions:	Number of cells in the x-direction	50
	Number of cells in the y-direction	50
	Number of cells in the z-direction	60
Grid type:	Cartesian	
Geometry type:	Block centered	

A-3) Reservoir properties

<u>Grid</u>

Porosity		= 0.80
Permeability	k-x	= 100mD
	k-y	= 100mD
	k-z	= 10mD
X Grid block sizes		= 50 ft
Y Grid block sizes		= 50 ft
Z Grid block sizes		= 5 ft
Depth of top face (Top layer)		= 5,000, 7,000, 10,000 ft

A-4) SCAL

Gas/Oil relative permeabilities

where:

$k_{rg}$is relative permeability to gas

$k_{ro}$is relative permeability to oil

$k_{rw}$is relative permeability to water

S_w is saturation of water

$S_g$is saturation of gas

S_g	k_{rg}	k_{ro}
0.000	0.000	0.600
0.121	0.000	0.367
0.196	0.001	0.258
0.272	0.007	0.173
0.347	0.022	0.109
0.423	0.053	0.063
0.498	0.101	0.032
0.574	0.178	0.014
0.649	0.282	0.004
0.725	0.421	0.001
0.800	0.600	0.000
0.000	0.000	0.600
0.121	0.000	0.367
0.196	0.001	0.258
0.272	0.007	0.173
0.347	0.022	0.109
0.423	0.053	0.063
0.498	0.101	0.032
0.574	0.178	0.014
0.649	0.282	0.004
0.725	0.421	0.001

Oil/Water relative permeabilities

S_w	k_{rw}	k_{ro}
0.200	0.000	0.600
0.250	0.000	0.476
0.319	0.001	0.334
0.388	0.007	0.224
0.457	0.024	0.141
0.526	0.057	0.082
0.595	0.111	0.042
0.664	0.193	0.018
0.733	0.306	0.005
0.802	0.457	0.001
0.871	0.650	0.000
0.200	0.000	0.600
0.250	0.000	0.476
0.319	0.001	0.334
0.388	0.007	0.224
0.457	0.024	0.141
0.526	0.057	0.082
0.595	0.111	0.042
0.664	0.193	0.018
0.733	0.306	0.005
0.802	0.457	0.001
0.871	0.650	0.000

A-5) Schedule

Production well

Well Specification (P-01) [WELSPECL]

Well	P-01
Group	1
I location	25
J location	25
Datum depth	5,050/ 7,050/10,050 ft
Preferred phase	Liquid
Inflow equation	STD
Automatic shut-In instruction	Shut
Cross flow	Yes
Density calculation	SEG

Well Comp Data (P-01) [COMPDATL]

Well	P-01
I Location	25
J Locatioon	25
K upper	3
K lower	8
Open/Shut flag	Open
Well bore ID	0.70833 ft.
Direction	Z

Production well control (P-01) [WCONPROD]

Well	P-01
Open/Shut flag	Open
Control	LRAT
Liquid rate	1,000 STB/D
BHP target	200 psia

Production well economics limits [WECON]

Well	P-01
Water Cut	95%
Workover procedure	None
End run	No

VITAE

Thanudcha Khunmek was born in Bangkok, Thailand. He received his degree in Bachelor of Engineering in Civil Engineering from Sirindhorn International Institute of Technology, Thammasat University. He has been a graduate student in the Master’s Degree Program in Petroleum Engineering of the Department of Mining and Petroleum Engineering, Chulalongkorn University since 2009.