RESERVOIR SIMULATION USED TO PLAN DIATOMITE DEVELOPMENT IN MOUNTAINOUS REGION

A Thesis

by

RICHARD RAYMOND POWELL, III

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

MASTER OF SCIENCE

August 2012

Major Subject: Petroleum Engineering

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Approved by:

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Ding Zhu
Committee Member, Robert Lane
Head of Department, A. Dan Hill

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ABSTRACT

Reservoir Simulation Used to Plan Diatomite Development in Mountainous Region.

(August 2012)

Richard Raymond Powell, III, B.S., Texas A&M University

Co-Chairs of Advisory Committee: Dr. Maria Barrufet
Dr. Ding Zhu

In Santa Barbara County, Santa Maria Pacific (an exploration and production company) is expanding their cyclic steam project in a diatomite reservoir. The hilly or mountainous topography and cut and fill restrictions have interfered with the company's ideal development plan. The steep hillsides prevent well pad development for about 22 vertical well locations in the 110 well expansion plan. Conventional production performs poorly in the area because the combination of relatively low permeability (1-10 md) and high viscosity (~220 cp) at the reservoir temperature. Cyclic steam injection has been widely used in diatomite reservoirs to take advantage of the diatomite rocks unique properties and lower the viscosity of the oil. Some companies used deviated wells for cyclic steam injection, but Santa Maria Pacific prefers the use only vertical wells for the expansion. Currently, the inability to create well pads above 22 vertical well target locations will result in an estimated $60,000,000 of lost revenue over a five year period.

The target locations could be developed with unstimulated deviated or horizontal wells, but expected well rates and expenses have not been estimated. In this work, I use a thermal reservoir simulator to estimate production based on five potential development cases. The first case represents no development other than the cyclic wells. This case is used to calibrate the model based on the pilot program performance and serves as a reference point for the other cases. Two of the cases simulate a deviated well with and without artificial lift next to a cyclic well, and the final two cases simulate a horizontal well segment with and without artificial lift next to a cyclic well.

The deviated well with artificial lift results in the highest NPV and profit after five years. The well experienced pressure support from the neighboring cyclic well and performed better with the cyclic well than without it. Adding 22 deviated wells with artificial lift will increase the project’s net profit by an estimated $7,326,000 and NPV by $2,838,000 after five years.

ACKNOWLEDGEMENTS

I would like to thank my committee co-chair, Dr. Maria Barrufet for the she has provided me throughout my research, my co-chair Dr. Ding Zhu for helping me refine my research topic, and my committee member Dr. Robert Lane for his support.

Thanks to my fellow graduate students for offering their help with debugging software and navigating the hurdles to graduation.

Thanks to my father Ray and my mother Phyllis for their support throughout my life. I would not have gotten this far without both of you. To my wife Katie, you have provided me with an abundance of love and support despite a career of your own. Thank you for all you have done.

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CHAPTER I

INTRODUCTION

Diatomite reservoirs have a large concentration of oil per acre due to a high porosity, reservoir thickness and oil saturation. High viscosity at reservoir temperatures and 1-10 md permeability prevent the formation from being produced by conventional means, and operators have started producing by cyclic steam stimulation (CSS).

CSS is a process where steam is injected into a well, then the well is idled for a few days to let the steam soak into the formation, finally the well is put on production for several days up to a few years and the cycle is repeated as long as it remains profitable. CSS is not as dependent on economies of scale as steam flooding because it is less pattern dependent, but generally results in lower ultimate recovery factors. In 2009 there were over 14,500 CSS wells in California and the number of CSS wells in production been increasing year after year (Miller, 2010).

1.1 Problem

Cyclic steam injection only stimulates the near wellbore region and requires tight well spacing for optimal field development, but tight well spacing is difficult to achieve in some regions such as the Orcutt field in northern Santa Barbara County, California, because of the mountainous and environmentally sensitive terrain.

This thesis follows the style of *SPE Journal.*

Santa Maria Pacific (SMP) has been producing from a 20 well pilot program in Santa Barbara County and has plans to expand the 20 well project to 110 wells on mountainous terrain. Because of county restrictions on the amount of land that can be disturbed by cutting into the land and filling depressions with rock and soil (known as cut and fill), a portion of the project area will be undeveloped under the current development plan. Since the pilot program averaged 12.5 STB/D from each well and local oil prices are around 121 $/STB, the resulting loss of 22 well locations will result in an estimated $61,000,000 of lost revenue over a five year period. Northern Santa Barbara County has the potential for many similar diatomite projects that will all have to plan around the mountainous terrain.

1.2 Objectives

The principal objectives of this research are to:

- Create and calibrate a model of the diatomite reservoir based on field data and analog fields
- Forecast production from five different development plans (base case with no additional development, a deviated well with and without artificial lift and a horizontal well with and without artificial lift).
- Recommend development plan based on optimal net profit and NPV using the forecasted production

CHAPTER II

LITERATURE REVIEW

Many attempts have been made to optimize diatomite reservoir production. Early pilot programs were created to test the viability of thermal recovery mechanisms in the tight diatomite rocks. Murer compared production from wells before and after hydraulic fracturing and compared cyclic steaming to steam drive (Murer et al., 2000). Murer concluded from the pilot that propped hydraulic fractures and steam flooding combined for the highest production rates, but the pilot was limited to only one cyclic well, one continually steamed well and one producer.

One of the earliest works on simulating cyclic steam injection in a diatomite reservoir found that induced fracture dimension, matrix permeability and grid size near the injector are a few of the most important factors for properly simulating CSS wells (Kumar and Beatty, 1995). Ambastha and others later used numerical reservoir simulation to optimize well spacing and found reducing their wells to 5/16 acre spacing from 5/8 acre spacing could increase the reservoir recovery factor to 34% from 22% (Ambastha et al., 2001). They also determined that fractured wells could be produced by steam drive with a lower steam oil ratio and a higher ultimate recovery factor of 54%.

When simulating a diatomite reservoir it is also important to include the temperature effects on the residual oil and relative permeability of oil and water (Hascakir and

Kovscek, 2010). In a diatomite simulation, the oil production could be increased by 16% after introducing temperature-dependent relative permeability end-points.

Previous works focus on how to best simulate diatomite reservoirs and how to optimize individual wells or patterns, but none of these works discuss how to best produce a reservoir when the planned well pattern is disrupted by surface restrictions. I will look at different plans to develop the previously lost acreage by the use of un-stimulated deviated wells or a horizontal well to fill one row of a nine spot pattern.

CHAPTER III

BUILDING THE MODEL

I used Eclipse 300 for the thermal simulation. The gridding is based on pattern symmetry to reduce the run times. The lines of symmetry assume each well is being produced and injected on the same schedule and each well is producing and injecting at the same rates. While in the field this does not hold true, neighboring wells are generally not steamed at the same time to avoid fracturing, for the purposes of the simulation I will assume that the lines of symmetry hold. In **Fig. 1** and **Fig. 2** the simulated area is shown in relation to neighboring wells. The circles represent the wells and the black lines simply show the grid like pattern. In **Fig. 2** the center row of wells (connected with hashed lines) represents the locations that vertical wells cannot be drilled. I wanted to be able to simulate both the cyclic well and the added deviated or horizontal wells so I chose my grid area to include a quarter of both locations.

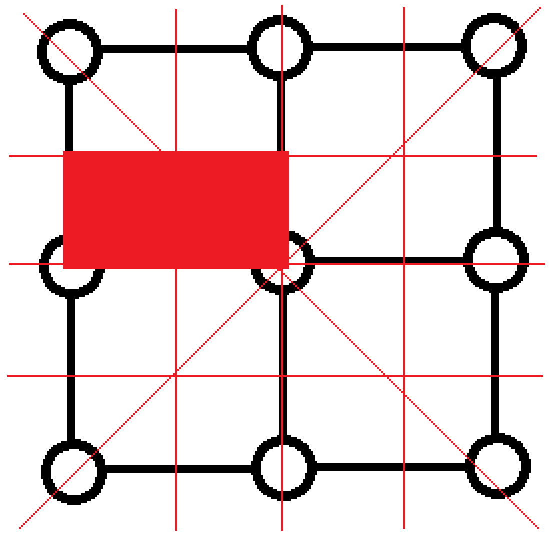

Fig. 1—The red rectangle represents the simulated reservoir area and follows the thin red lines of symmetry.

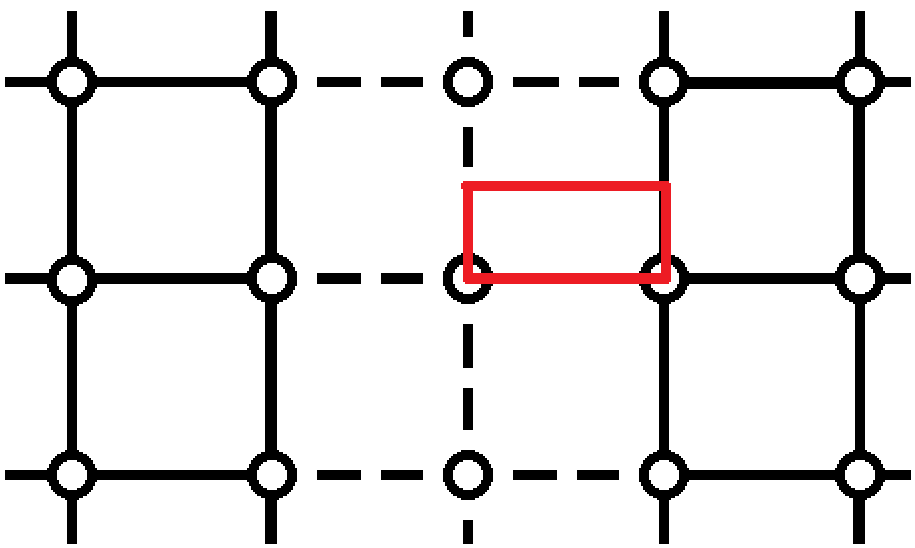

Fig. 2—The simulated element in the nine-spot pattern encompasses both a cyclic steam well and a prospective location for a deviated well or a portion of a horizontal lateral.

My model uses 15 cells in x direction, 8 in the y direction and 35 in the z direction. The cyclic well starts in the middle of the 1, 1, 1 cell and ends in the 1, 1, 35 cell. I used two wells to simulate the cyclic well. One well, SCYI is only on during the injection phase. After injection the well is shut off and the soak phase occurs. After the soak phase is completed and the well is ready for production the well SCYP is opened. When the production phase has ended, SCYP is shut and SCYI opens for another round of steam injection. The deviated wells start in the 15, 1, 1 cell and end in the 15, 1, 35 cell while the horizontal well starts in the 15, 1, 20 cell and ends in the 15, 8, 20 cell. The deviated well and cyclic well locations are shown in **Fig. 3**. Several layers in the z direction were removed to better view the well locations.

In the x direction, the cells are finest at either end where the wells are located. The cell widths in the y direction mirror the x direction. The faces of grid have half porosity and half permeability in both z direction and either the x or y direction depending on which edge. The edges have ¼ porosity and ¼ permeability in the z direction. Both the x and y direction permeability are ½ for the edge as well. These adjustments "trick" the simulator into placing the well location on a corner rather than in the middle of a grid block. The adjusted dimensions of the model are 120' by 60' by 175'. These dimensions are based on SMP's plan to drill wells approximately 120' apart and the primary diatomite zone thickness from pilot well logs. The gridding in the x direction is 1', 1.5', 3', 6', 11', 15', 15', 16', 15', 15', 11', 6', 3', 1.5' and 1'. For the y direction, the gridding is 1', 1.5', 3', 6', 11', 15', 15' and 16'. The unadjusted lengths in the x and y directions are 121’ and 68.5’ respectively. With the adjusted porosity and permeability, the corner cells function the same as a cell ¼ the size.

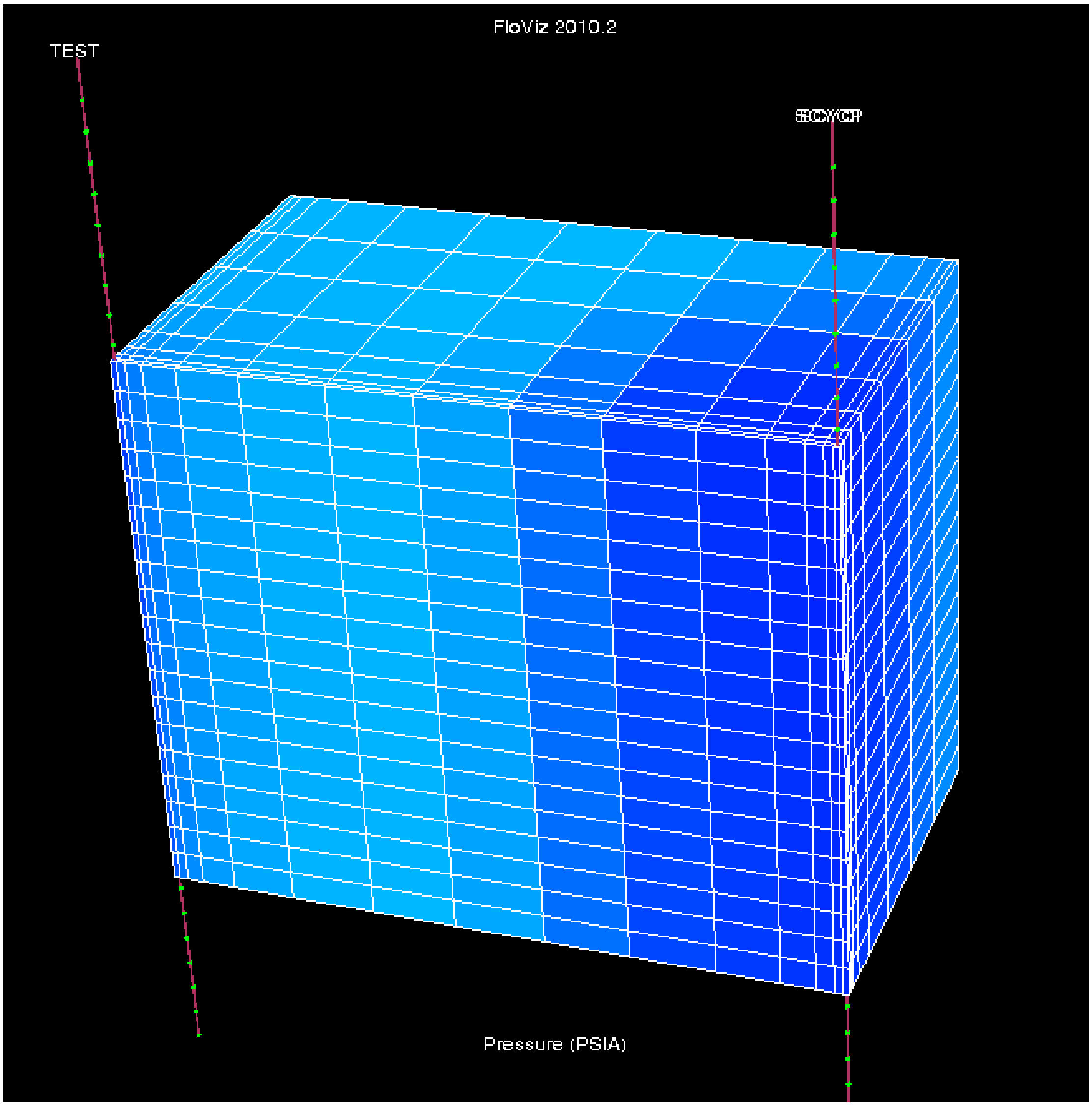

Fig. 3—The cyclic well (SCYP and SCYI) and deviated well (TEST) are located in the corners with the finest grid size in the x and y directions.

3.1 Data Gathering

I tried to get as much of the reservoir and fluid properties as I could from lab tests, logs and core samples from the field. I used the pilot program well logs to determine the reservoir thickness. Sidewall data was sent to me and included oil saturation and porosity. The core porosities are very high compared to most reservoir rocks, but are not unusual for diatomite rocks. In diatomite rocks there is porosity both between the grains and within the grains. The high porosity creates a large initial oil in place, but the grains are silt sized (Isaacs, 1984) so permeability is low. I did not have a direct measurement for the permeability, but from neighboring diatomite fields report permeability is between 1 md and 15 md. I used permeability as the primary variable to match the simulated well rate to the pilot program's average well rate.

SMP has taken sidewall cores from most of the pilot wells and sent them to a lab for oil saturation and porosity measurements. The oil saturation in the primary reservoir layers averaged 55% with a porosity of 60%. The porosity of the opal-A diatomite is much larger than most reservoir rocks. This is because the grains of diatomite rock are comprised of organic silica structures that have porosity. Since deposition, the opal-A diatomite rock has not gone through high temperatures and pressures that would crush and alter the silica structures and reduce the intragrain and intergrain porosity (Isaacs, 1984). The honeycomb like structure seen in **Fig. 4** is a diatom in opal-A diatomite (Strickland, 1985). The structure itself has porosity and contributes to the high porosity of the rock.

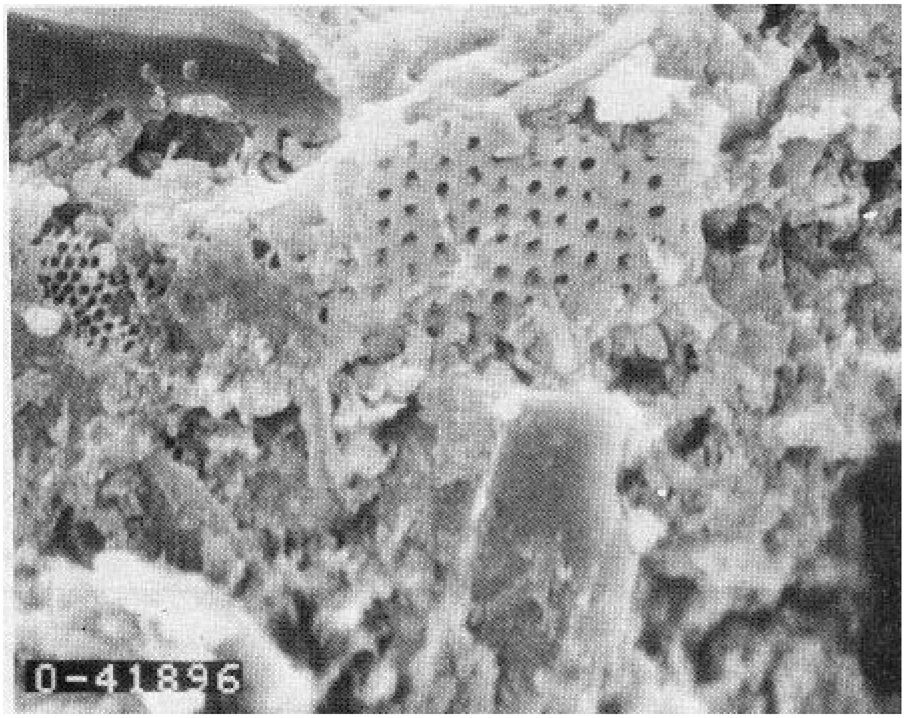

Fig. 4—Opal-A diatomite SEM photomicrograph shows diatomite structures.

Most of the rock mechanics, such as the rock compressibility and thermal conductivity were obtained from similar diatomite fields in Kern County (Fong et al., 2001). I also obtained the relative permeability curves from other diatomite studies because SMP has not had any relative permeability tests done (**Fig. 5** and **Fig. 6**).

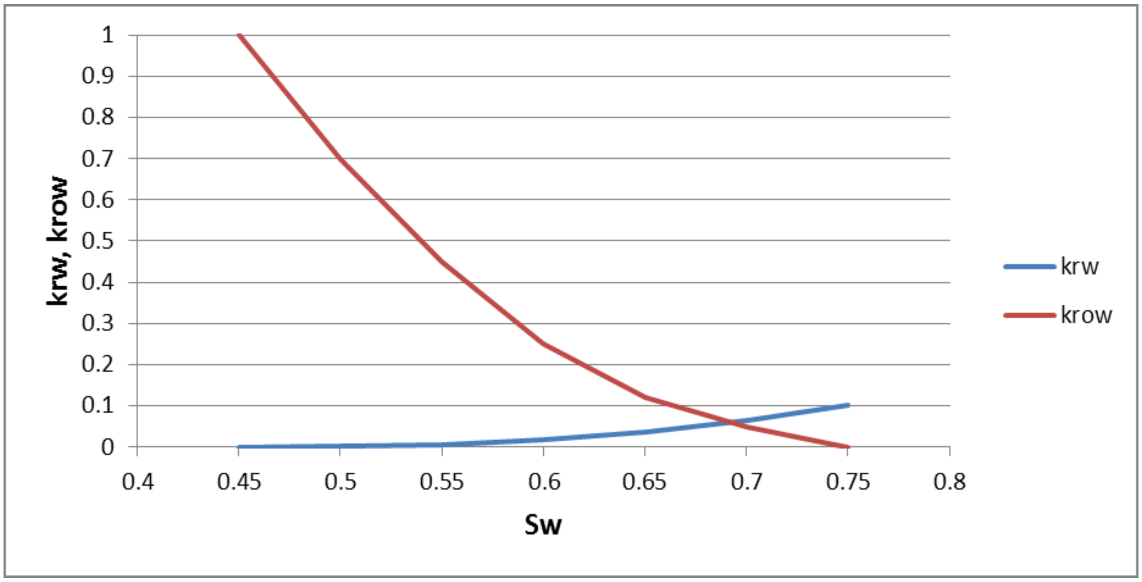

Fig. 5—Relative permeability curves for water and oil in diatomite rock.

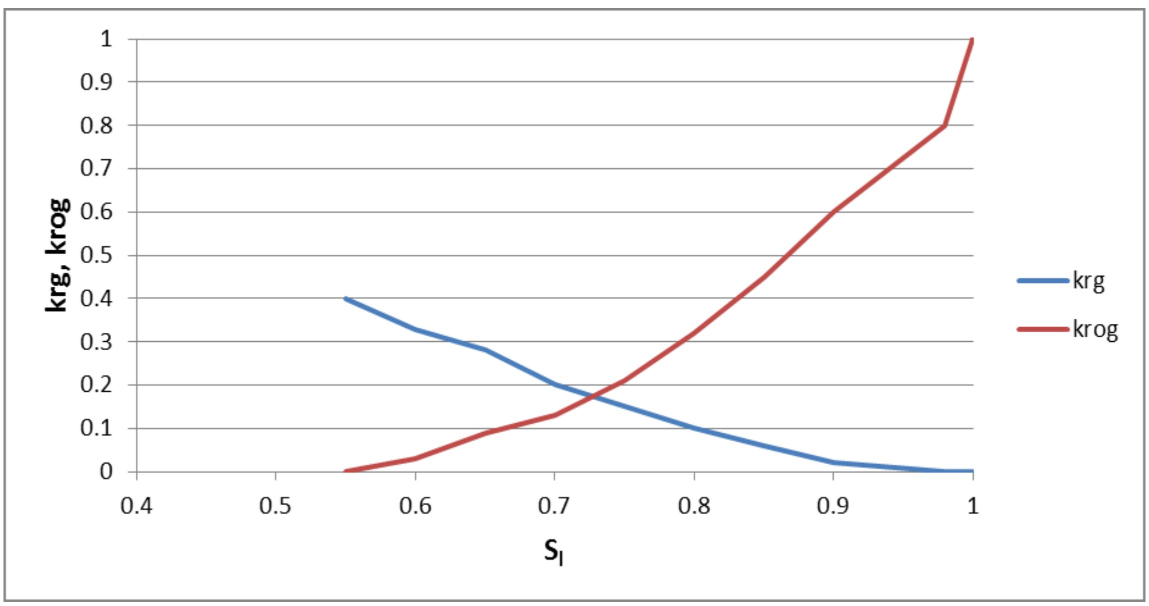

Fig. 6—Relative permeability curves for liquid and gas in diatomite rock.

One of the limitations to my work is the use of a homogeneous model. Most of the logs show three main layers within the 175’ I am modeling. On the top and bottom are the two quality reservoir layers while there is a small 10’ layer of lower quality rock between. Originally, I planned to test the effects of adding layering effects and heterogeneity on the model, but I was unable to simulate more than a few cycles because the simulator would crash. The change in the fluid flow direction as the well went from injection to soak to production caused the simulator to calculate negative temperatures between layers with different permeability. Based on the few cycles I could run there was little difference between runs with layering and the homogenous run if the weighted geometric average of the permeability was the same as the homogenous permeability, but any differences caused by the layering effects could become greater with longer simulation times because the high permeability layers would deplete faster than the low permeability layers and the lower permeability layers would receive less steam than the high permeability layers.

The oil saturated diatomite is very thick, 260’ based on **Fig. 7**, but currently plans are to target only the highest quality layers in the reservoir for completion. I originally worked on simulating the whole reservoir with only 175’ completed but the additional thickness and heterogeneity resulted in long run times. I found that reducing thickness of the reservoir did not significantly affect the production of the study, but did improve run times significantly. Because the layers that were removed were oil saturated, but unproductive, the recovery factors for the simulations increased and now represent the recovery factor from the primary layers rather than the field.

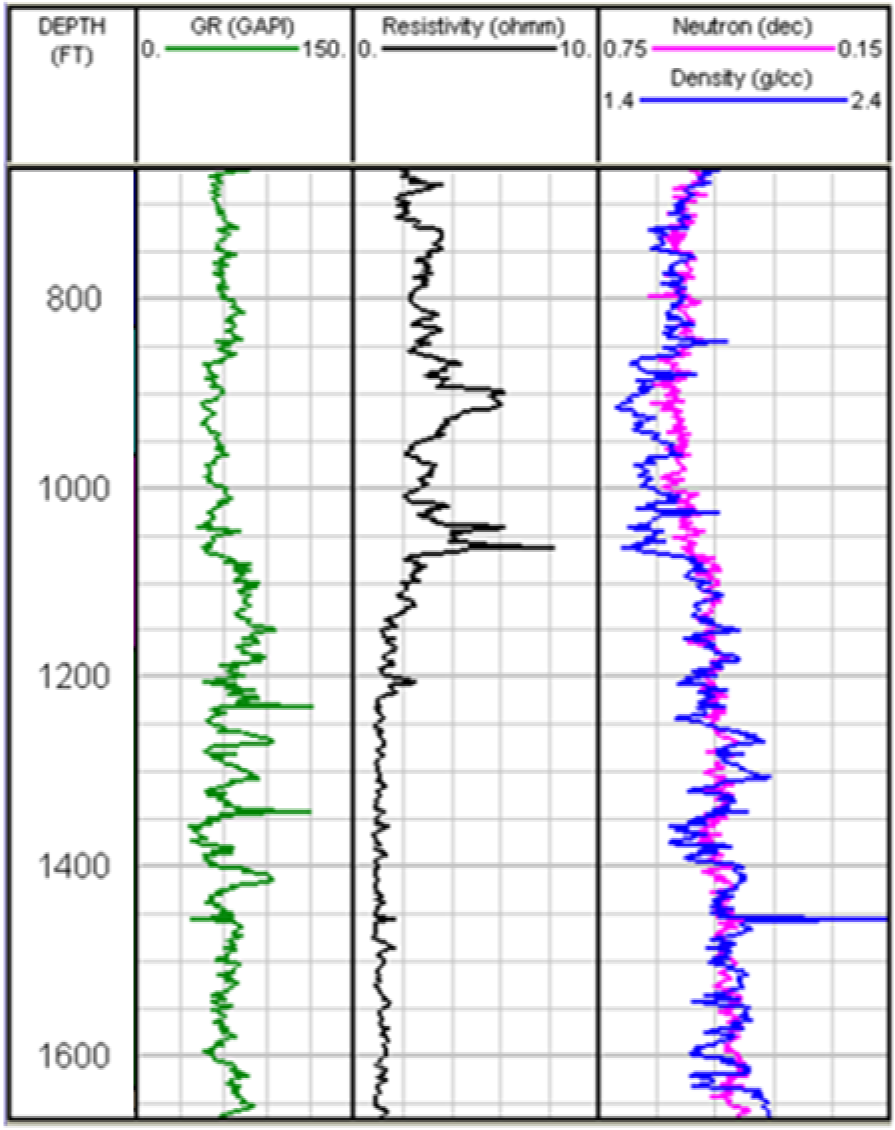

Fig. 7—Typical well log from pilot program shows oil saturated diatomite from 870' to 1,130'.

To get meaningful results from the study I needed to impute well operating constraints that are accurate for the field. To do this I first looked through the pilot well histories and found that we were able to consistently operate at a steam quality of 80% and a temperature of 500 °F. I made the assumption that a negligible amount of heat loss would occur during injection because the wells are very close to the steam generator, the piping is well insulated and the wells are shallow. Based on these assumptions, I was able to estimate a hydrostatic gradient during injection of 0.1 psi/ft. Using the gradient and one of the higher surface pressures that the pilot wells were operated at, I calculated a maximum bottomhole pressure of 1,550 psia during the injection phase. The maximum injection bottomhole pressure only constrains the injection rate during the first year. The steam injection is primarily limited by rate for most of the 5 years. Wells in the pilot program are steamed with about 1200 bbl CWE of steam in over a 3 day period. Because I am only simulating a quarter of the cyclic well I constrained the rate of injection to 100 bbl CWE/D. **Fig. 8** shows how rate is the primary constraint during steam injection.

The producing bottomhole pressure (BHP), 290 psia, for the cyclic well was also based on the pilot wells' surface pressures, temperatures, GORs (gas oil ratios), and WORs (water oil ratios) (**TABLE 1**). Based on these field inputs I estimated a BHP of 290 psia, for the cyclic well under typical flowing conditions using the Beggs-Brill method. I did the same for the deviated well producing BHP, 330 psia. For horizontal well I assumed that the BHP would be very similar to the vertical well because much of the horizontal well is vertical. For the wells under artificial lift, I assumed the casing pressure and the pump placement would be purposefully adjusted to create a BHP of 101 psia. There are concerns with the reservoir integrity under very low bottomhole pressures so a study into the formation integrity should be performed before deciding on the pump placement.

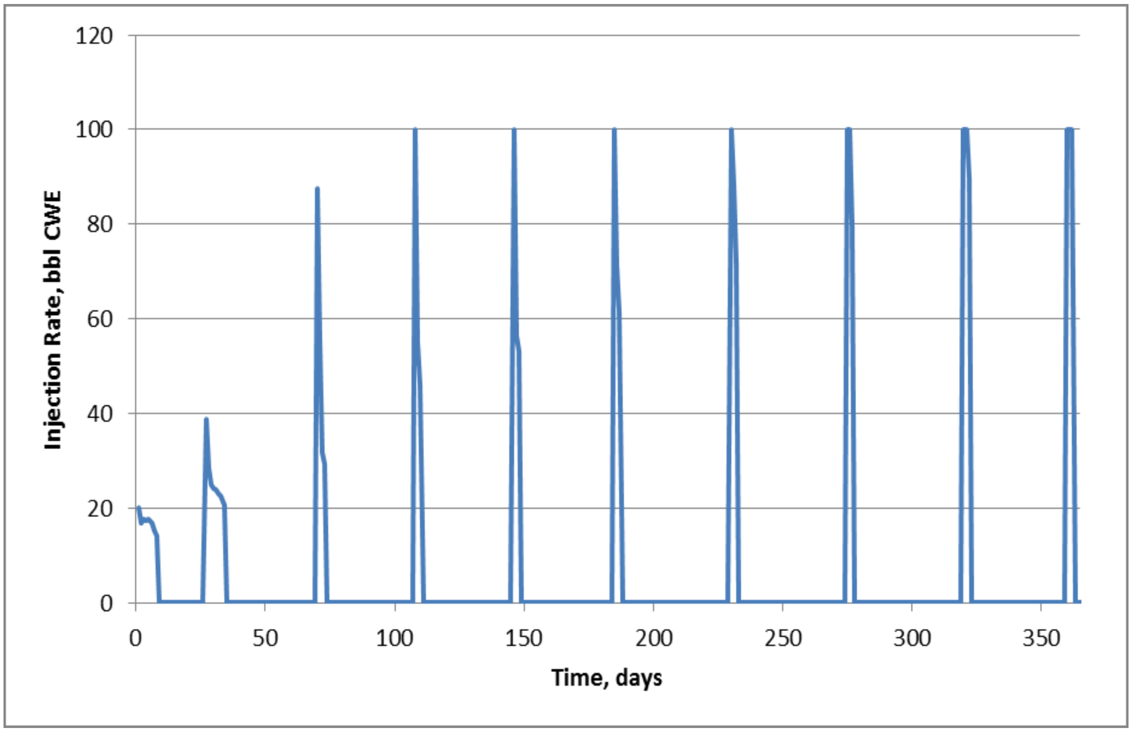

Fig. 8—Steam injection is constrained by both rate and bottomhole pressure.

TABLE 1—INPUTS FOR BHP CALCULATION USING BEGGS-BRILL

Tubing Inner Diameter, in	2.441
Depth, ft	888
Temperature, °F	295
Tubing Head Pressure, psig	45
Oil rate, STB/D	12.5
WOR, bbl/STB	2.2
GOR, scf/STB	330
Crude API Gravity, °API	18
Gas Specific Gravity	1.04
Water Specific Gravity	1.03

I based the injection, production and soak schedule for the cyclic well on the pilot program. In general there are about 30 days of production, 3 to 3.5 days of injection and

2 days of soak. For the first few cycles the injection and soak times were increased and the production time decreased to match field practice for the well cycles. The steam injection rate for these early cycles is limited by the constrained bottomhole pressure. As the near wellbore oil is produced and the reservoir is heated, the steam injection becomes constrained by injection rate. When the well is first switched from the soak phase to the production phase the oil and water production rates are very high. This is because the near wellbore region is at a high pressure and the oil viscosity is very low because of the increased near wellbore temperature (**Fig. 9** to **Fig. 12**).

All of the wells in each case start on the same day and run for the full 5 years. The injection and producing times are slightly altered for some cycles and have some differences between the cases (**TABLE 2**). This was to keep the overall reservoir pressure stable to reduce instability in the model. The average injection days ranged from 3.4 to 3.6 days for all the cases and the average producing days ranged from 30 to 33 days for all the cases. Longer injection times and shorter producing days worked to maintain reservoir pressure in the most productive case, the added deviated well with artificial lift since the most oil and water were produced under this development plan. **Fig. 13** shows a typical oil production response from the short injection periods.

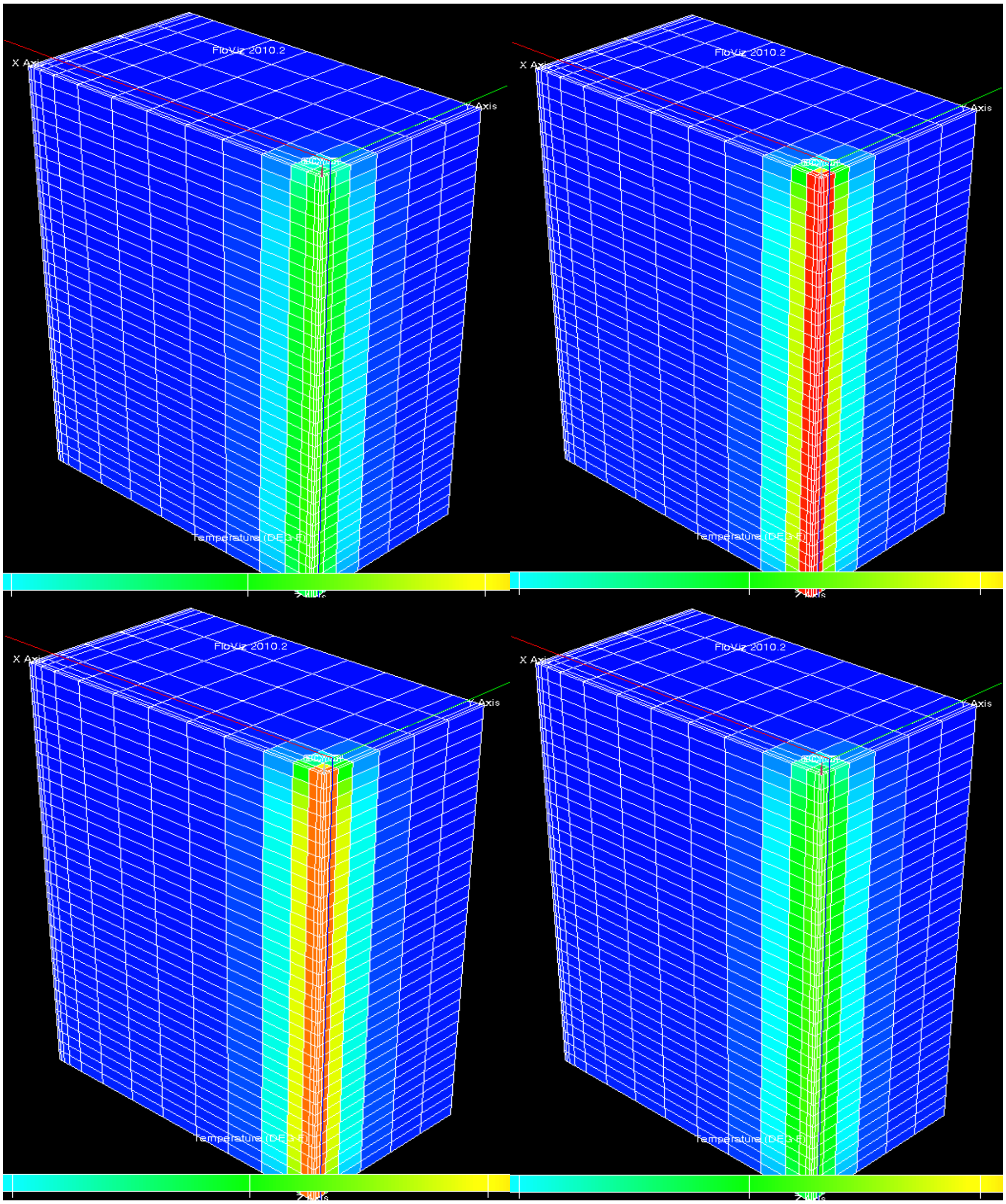

Fig. 9—Simulated cell temperatures before the cycle 10 steam injection (top left), after cycle 10 steam injection (top right), after cycle 10 soak (bottom left) and after cycle 10 production (bottom right) show how the near wellbore region heats up and cools down during a cycle.

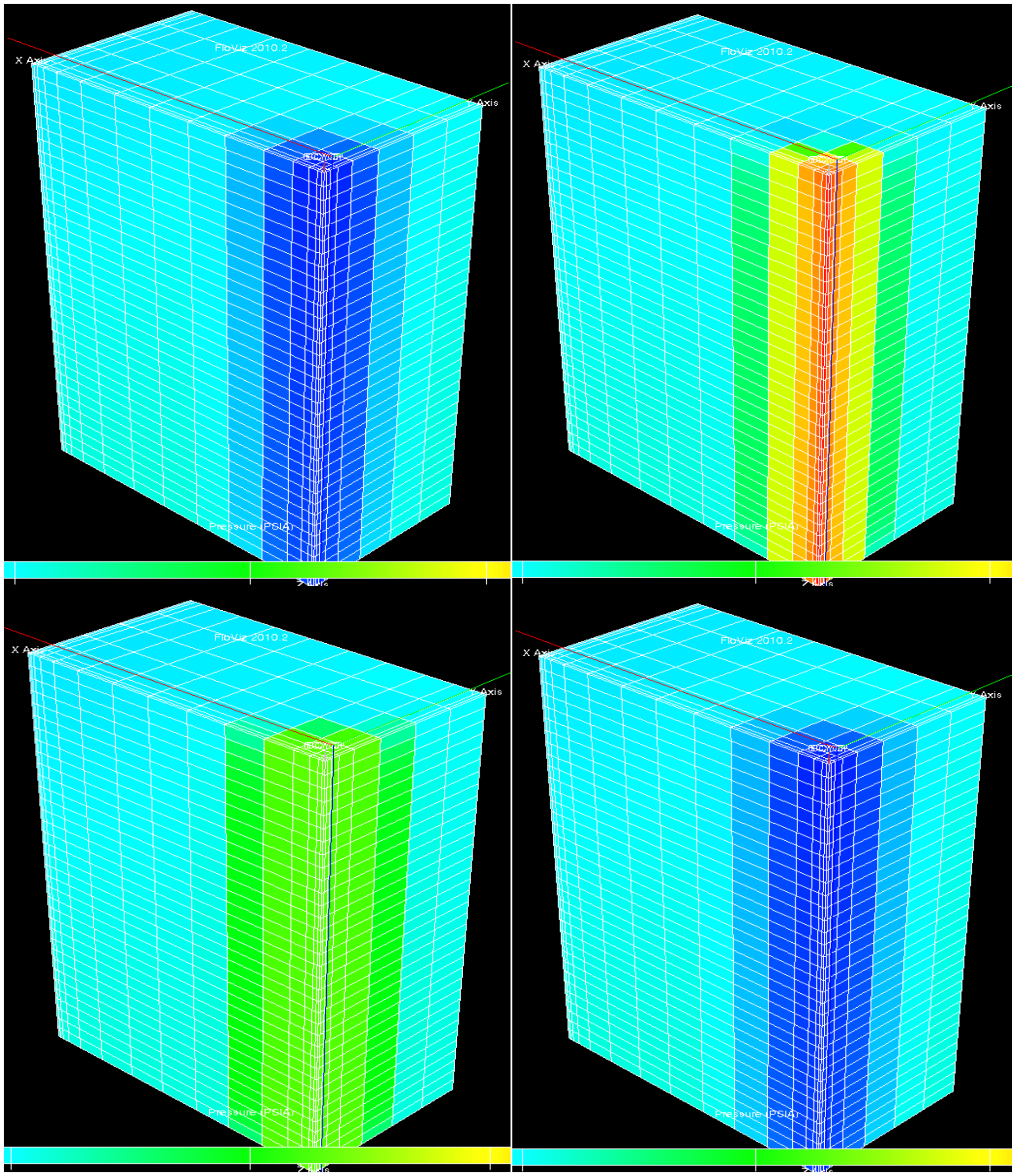

Fig. 10—Simulated cell pressures before the cycle 10 steam injection (top left), after cycle 10 steam injection (top right), after cycle 10 soak (bottom left) and after cycle 10 production (bottom right) show how the near wellbore region pressures up then depletes during a cycle.

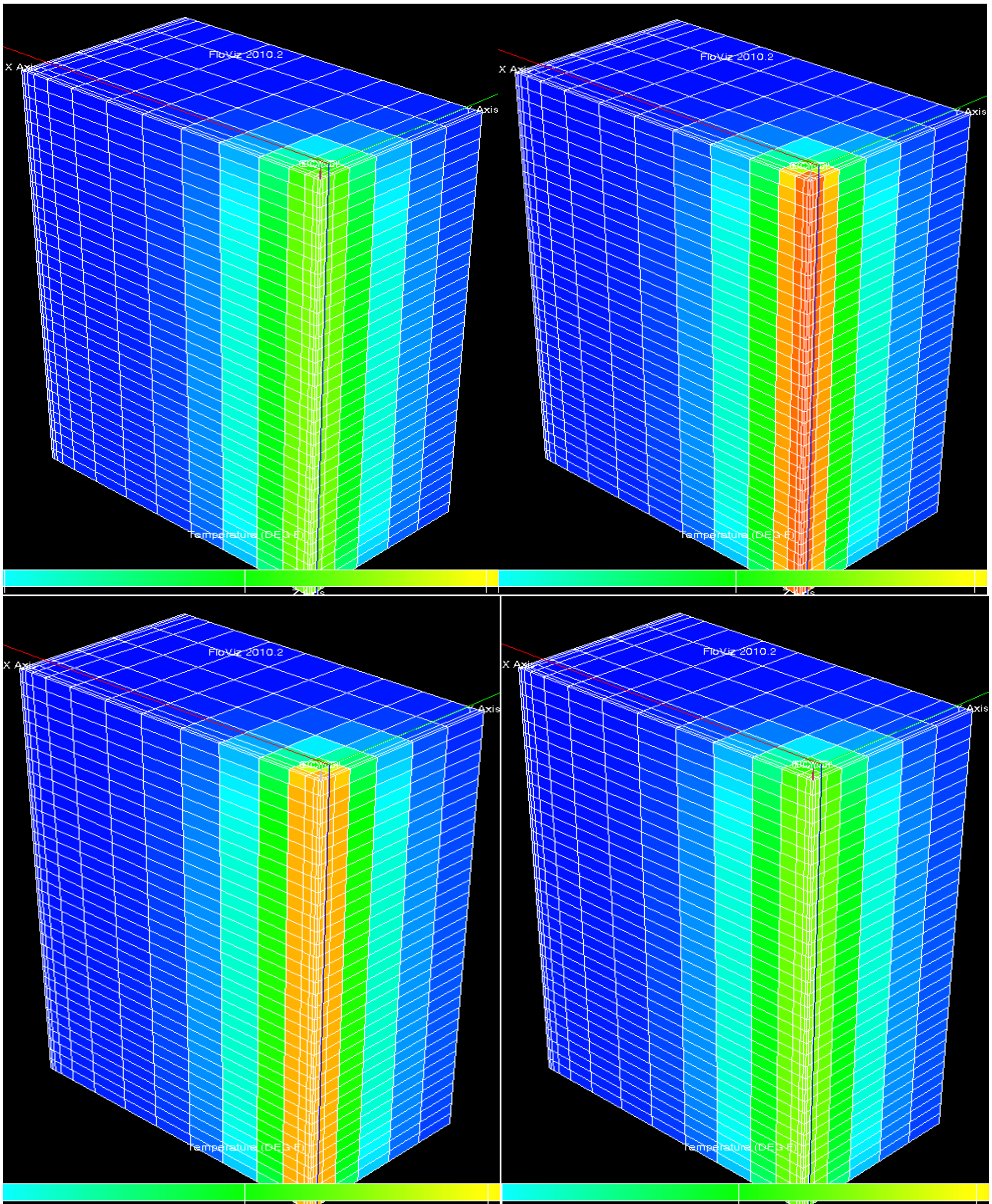

Fig. 11—Simulated cell temperatures before the last cycle's steam injection (top left), after the last cycle's steam injection (top right), after the last cycle's soak (bottom left) and after the last cycle's production (bottom right) show how the near wellbore region heats up and cools down during a cycle.

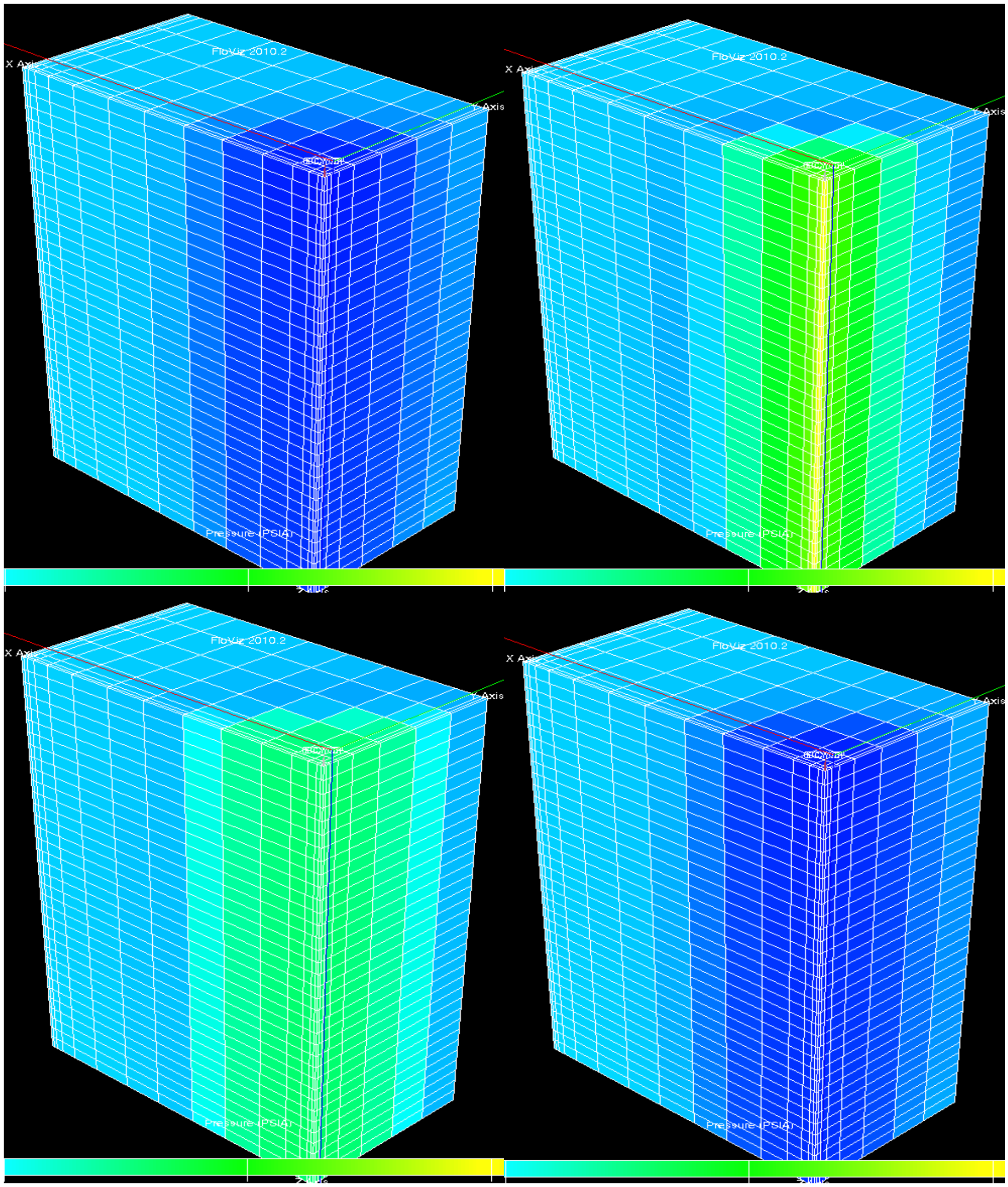

Fig. 12—Simulated cell pressures before the last cycle's steam injection (top left), after the last cycle's steam injection (top right), after the last cycle's soak (bottom left) and after the last cycle's production (bottom right) show how the near wellbore region pressures up then depletes during a cycle.

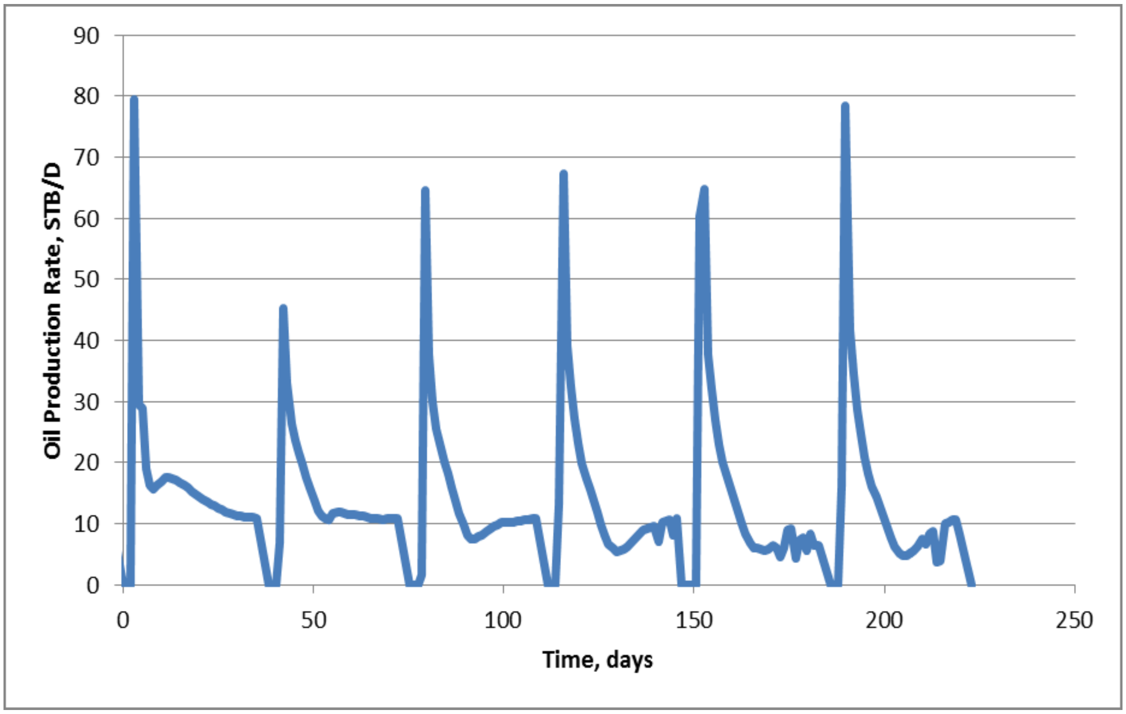

Fig. 13—Simulated oil rates give typical oil production response from a cyclic diatomite well.

TABLE 2—AVERAGE INJECTION, SOAK, AND PRODUCTION TIMES

	Injection (days)	Soak (days)	Production (days)
Base Case	3.4	2.0	33.4
Deviated with Rod Pump	3.6	2.0	31.2
Deviated Well	3.5	2.0	32.0
Horizontal with Rod Pump	3.5	2.0	30.5
Horizontal Well	3.4	2.0	33.5

I chose to forecast the production for five years for each case. The first reason for this choice is that the diatomite reservoir goes through significant expansion and contraction cycles as wells are steamed and then produced. The expansion and contraction of the reservoir often cause well failures and, therefore, shortens the expected producing life of the wells (**Fig. 14**). Because of the high well failure rates, it would be unrealistic to base my forecasts and project economics too far into the future without having an appropriate estimate for well failure rates non cyclic wells and the cost for remediation work. My second reason for choosing five years is the simulation. As the forecast time increases the simulation time becomes longer and forecasts become unstable. Longer simulation times would have also reduced the amount of cases I could have run in the same time frame and observing the effects of changing well and reservoir properties would have been more difficult.

SMP has sent a few oil samples to a lab for viscosity and API density measurements. Most of the samples have an API gravity of 18°. The viscosity measurements are unfortunately only at for fairly low temperatures (60°F, 120°F and 180°F) so I supplemented them with Kumar and Beatty's temperature and viscosity data for the Cymric diatomite oil shown in **Fig. 15** (Kumar and Beatty, 1995). I used two components to simulate the reservoir oil, dead oil and solution gas. SMP did not have a live oil composition for me to work with so I am making the assumption that the two components will adequately represent the actual reservoir oil. The primary reservoir properties that I assumed were constant are listed in **TABLE 3**. The original oil in place (OOIP) is for the simulated segment (120' x 60').

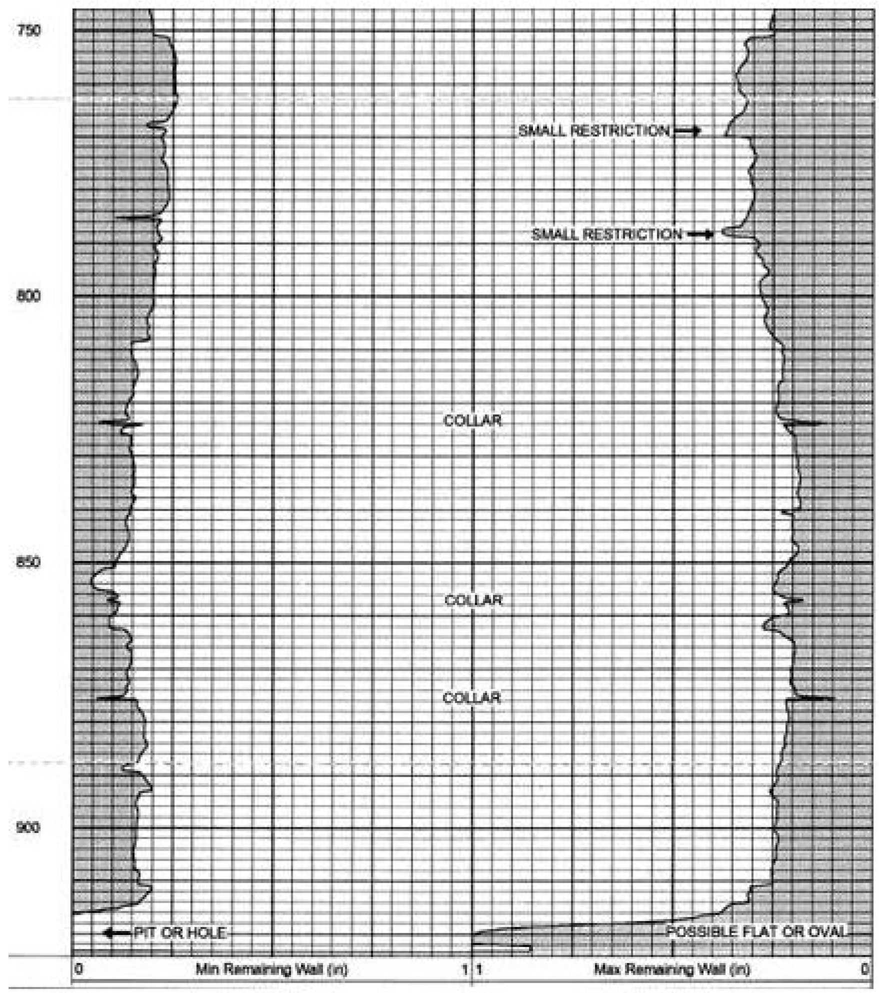

Fig. 14—Casing part at bottom of caliper log from expansion during steam injection and contraction during production.

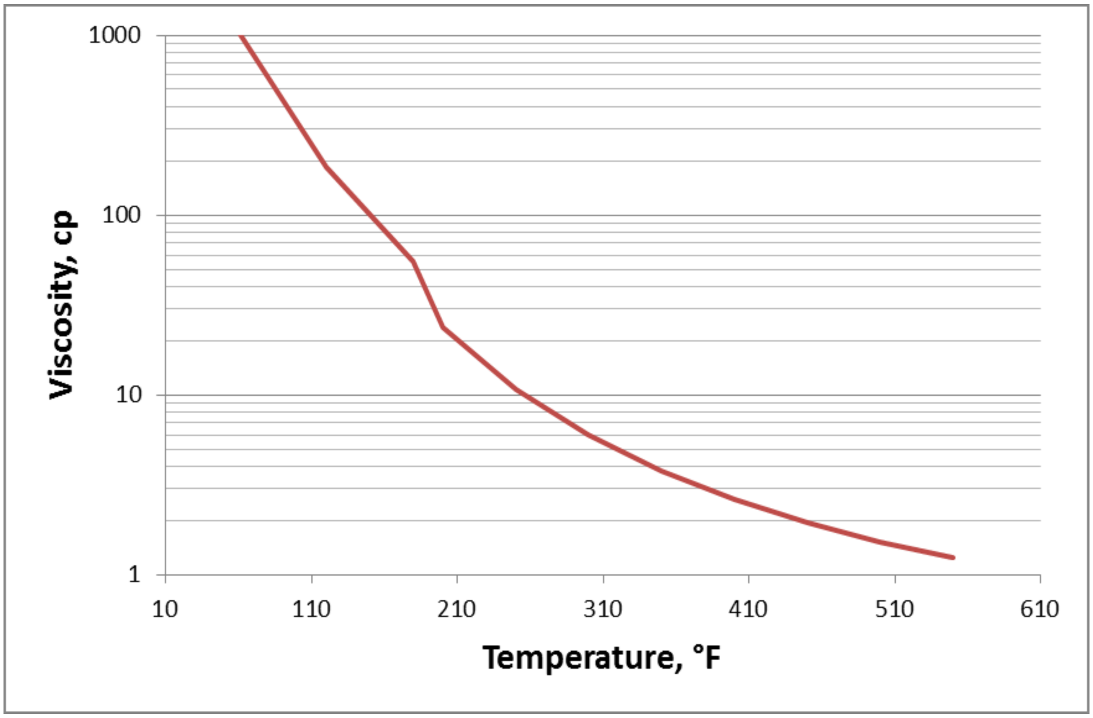

Fig. 15—Viscosity is reduced by almost two orders of magnitude as it is heated.

TABLE 3—CONSTANT RESERVOIR PROPERTIES

Permeability	10	md
Thickness	175	ft
Depth	800	ft
Pressure	585	psi
ϕ	0.6	
So	0.55	
Gravity	18	API
OOIP	73,940	STB

CHAPTER IV

CALIBRATING THE MODEL

The goal of my work was to forecast production for multiple cases in an undrilled portion of the reservoir. Much of the reservoir properties have significant uncertainty especially the permeability of the diatomite formation. To better forecast the production of the new wells I calibrated the model based on the pilot program. To do this I averaged the production of the pilot program wells and found the cumulative steam to oil ratio (SOR) for an analog edge well in the pilot program. The analog well has a SOR of 2.4 bbl CWE/STB and the pilot program has averaged about 12.5 STB/D from the pilot program wells.

I did not attempt to do a full history match to a single well because I am simulating a different location so I want to match the average properties of the field rather than a single well location. Further, individual oil and water rates from the pilot program are often inaccurate. The sources of the inaccuracies vary from difficulty measuring multiphase flow (oil, water, natural gas and steam) to a leaky valve that resulted in the flow meter malfunctioning for much of the first two years of the pilot. Each of the pilot wells share the same separation facility so the most accurate oil measurement that SMP collected was the cumulative field oil rates and the allocated monthly production for each well. To obtain an average rate for the project, I took the allocated monthly production for each of the original nine core pilot wells and discarded all months with less than 50 STB for each well. The average monthly production for each well was then converted into a daily rate.

While some wells in the pilot program have been more productive than others, the rates have a relatively low variance between wells, the most productive pilot well only outperforming the least productive well by 2.8 times (**TABLE 4**). Most of the pilot wells have rates very close to the average field rate of 12.38 STB/D and, after the first few cycles, the average oil rates for producing wells have varied primarily due to mechanical issues, but have maintained an even trend and have not shown a decline yet. Because the wells I have data for are all a part of the field pilot program, most of the wells have large shut in times at different points. Additions to the facilities have contributed to well down time and early well failures caused all of the pilot wells to have significant down time for remedial work. For these reasons, I looked to match the field average well rate rather than one individual well's rate.

TABLE 4—PILOT PROGRAM OIL RATES

Well	Rate (STB/D)
Pilot 1	6.44
Pilot 2	8.88
Pilot 3	10.39
Pilot 4	11.68
Pilot 5	11.92
Pilot 6	12.95
Pilot 7	14.60
Pilot 8	16.35
Pilot 9	18.20
Average	12.38

The cumulative SORs for the pilot wells have shown a strong correlation to well locations relative to adjacent wells (Elias et al., 2010). Interior wells had the lowest average cumulative SORs while step out wells and wells on the corner of the pattern had the highest SORs. For the model, I wanted to match an edge well's expected SOR since the cyclic well in my model is on an edge of the nine-spot pattern. The analog edge well has an SOR of 2.4 bbl CWE/STB after the initial startup period. Since most of the pilot wells have only been running for two years, I used the first two years of the simulation to match the production rate average and SOR of the edge well. The results from the first two years are very close to the target SOR and rate (**TABLE 5**). Since I did not have an accurate measurement of permeability from the field, the permeability was the primary variable I altered to calibrate the model.

TABLE 5—SIMULATED RESERVOIR SOR AND RATE

	SOR (CWE/STB)	Rate (STB/D)
Pilot	2.4	12.38
Simulated	2.4	12.39

CHAPTER V

ANALYZING PRODUCTION FROM DIFFERENT CASES

In each case I modeled an eighth of the nine-spot pattern and a quarter the cyclic well and any additional well I added. Unless otherwise noted, all rates and volumes I discuss will be for the eighth of the nine-spot pattern and for a quarter of each well discussed. This will allow me to compare the cases to each other while reducing some confusion.

5.1 Base Case

The base case was expected to have the lowest production over five years because it only has the one cyclic well. The cumulative oil curve steadily increases over the five years and does not have a strong bend over which indicates that there is a significant amount of oil still in the reservoir at the end of the simulated time. The recovery factor at the end of the five years confirms that the base case only produces a small portion of the original oil in place, 7.27%. The average oil rate for the base case is 3.2 STB/D, or 12.8 STB/D if the quarter of the well I simulated is converted to a whole well rate. The total water injected into the simulated segment is 15,592 bbl while the amount of water produced is 12,474 bbl. Over the five years 15,592 reservoir barrels of water are injected into the reservoir and 18,308 reservoir barrels of total fluid are produced. Because more fluids were produced from the reservoir than were injected, the reservoir pressure dropped to 485 psi after the 5 years. **Fig. 16** shows the cumulative oil production (FOPT), cumulative steam injection in bbl CWE (FWIT), and the cumulative water production (FWPT).

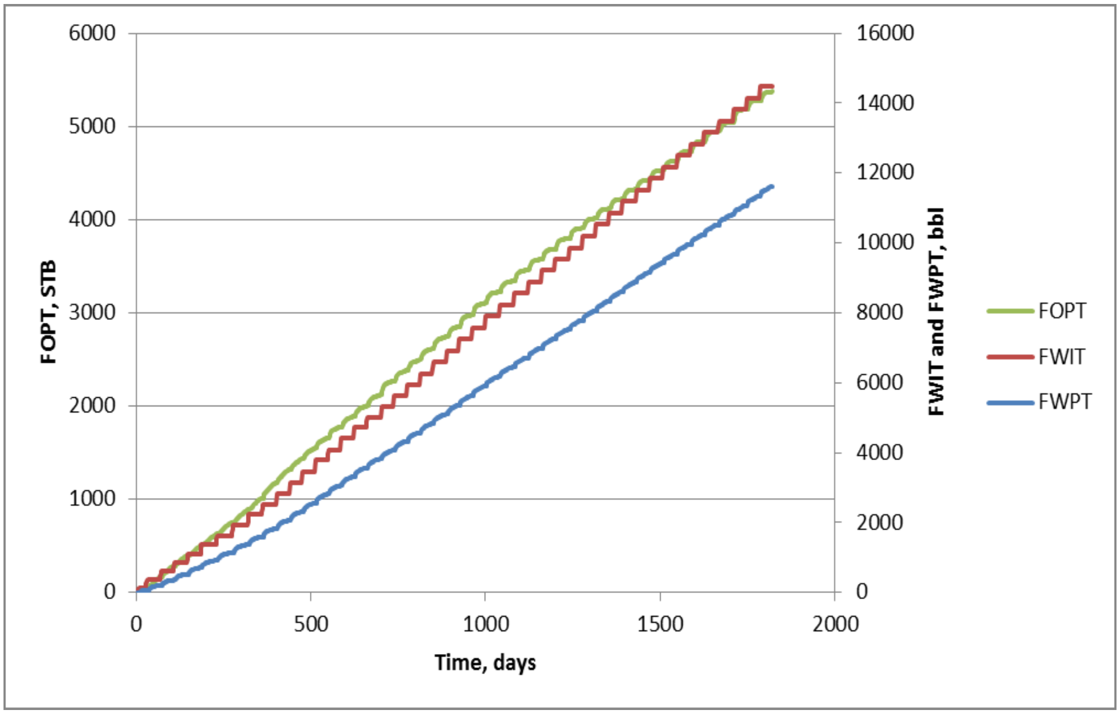

Fig. 16—Base case cumulative oil (FOPT), injected water (FWIT) and produced water (FWPT).

The pressure from the injection phase reaches out much further than the temperature does (**Fig. 9** and **Fig. 10)**. The temperature from the steam injection only affects the near wellbore region for the first cycles. At later cycles, the reservoir is heated in roughly a 30' radius from the cyclic well (**Fig. 11**). Because, the heat remains close to the well during the injection and soak phases, the oil has the highest temperature, and therefore the lowest viscosity, near the well. When the cyclic well is put on production the heated oil is quickly produced and the well's production quickly drops because the remaining oil is more viscous as seen from the reservoir model after the base case's last full production cycle (**Fig. 11**).

5.2 Horizontal Well Cases

For the horizontal well without artificial lift, the total production is similar to the base case. The total oil produced over the five years is 5,394 STB (**Fig. 17**). This case's water injection and production are also similar to the base case as shown in Error! Reference ource not found.. The horizontal well case produced only 20 STB more oil and 36 STB more water than the base case. This case's production is similar to the base case because the simulated segment of the horizontal well only produced 30 STB of oil during the five years. Because I only simulated a quarter of a 120' segment of the horizontal well the actual horizontal well's total production over five years is 713 STB since the total horizontal well lateral would be about 720'. Overall the production from an unstimulated horizontal well with no artificial lift is very low, especially when compared to the cyclic well or even the deviated well cases.

Stimulating the well with a propped hydraulic fracture or cyclic steam injection would increase the well's productivity, but Santa Barbara County has implemented a de facto ban on hydraulic fracturing at this time. Cyclic steamed horizontal wells have been successfully implemented in a few neighboring fields (Chona et al., 1996) and are a possibility later in the fields life, but currently SMP intends to develop the field with the more conventional cyclic vertical wells before looking at alternative well designs such as cyclic horizontal wells and cyclic deviated wells. Because of these limitations I looked at the effects of adding a rod pump to lower the BHP of the horizontal well.

The horizontal well with artificial lift simulated pattern segment produced 5,852 STB of oil during the five years, a 458 STB increase when compared to the horizontal well with no lift (**Fig. 18**). The horizontal well segment produced 49 STB of oil. While this is a slight improvement of the 30 STB from the horizontal well segment with no artificial lift, it is still only a small amount of production for five years. The larger increase in the total oil produced over the five years is probably primarily from changes in the scheduling of the cyclic between the cases since the horizontal well's production was so low for both horizontal well cases. In both cases, the horizontal well rates fall quickly before increasing slightly due to the cyclic well injection. When the injection pressure required to inject at 100 bbl CWE/D is lowered because the reservoir around the cyclic well is heated and depleted, the pressure of the reservoir segment begins to drop and therefore the horizontal wells' rates begin to drop once more (**Fig. 19**). Over five years of production, the total oil production from a 720' horizontal well with artificial lift is 1,177 STB based on the simulation.

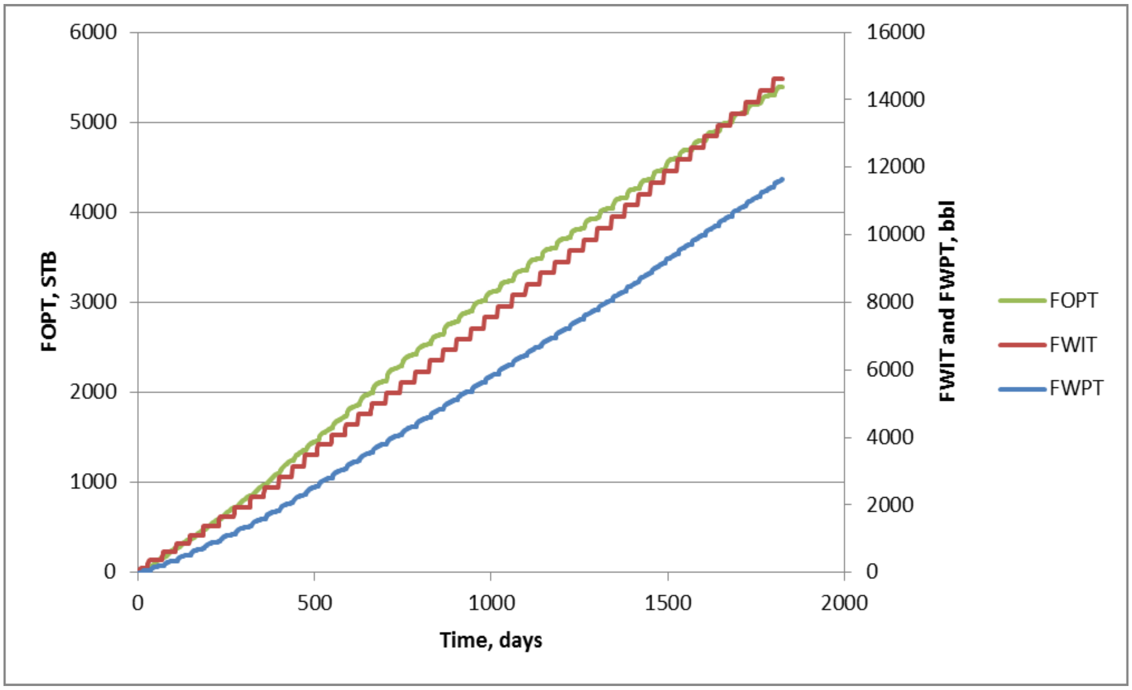

Fig. 17—Horizontal well no lift pattern segment.

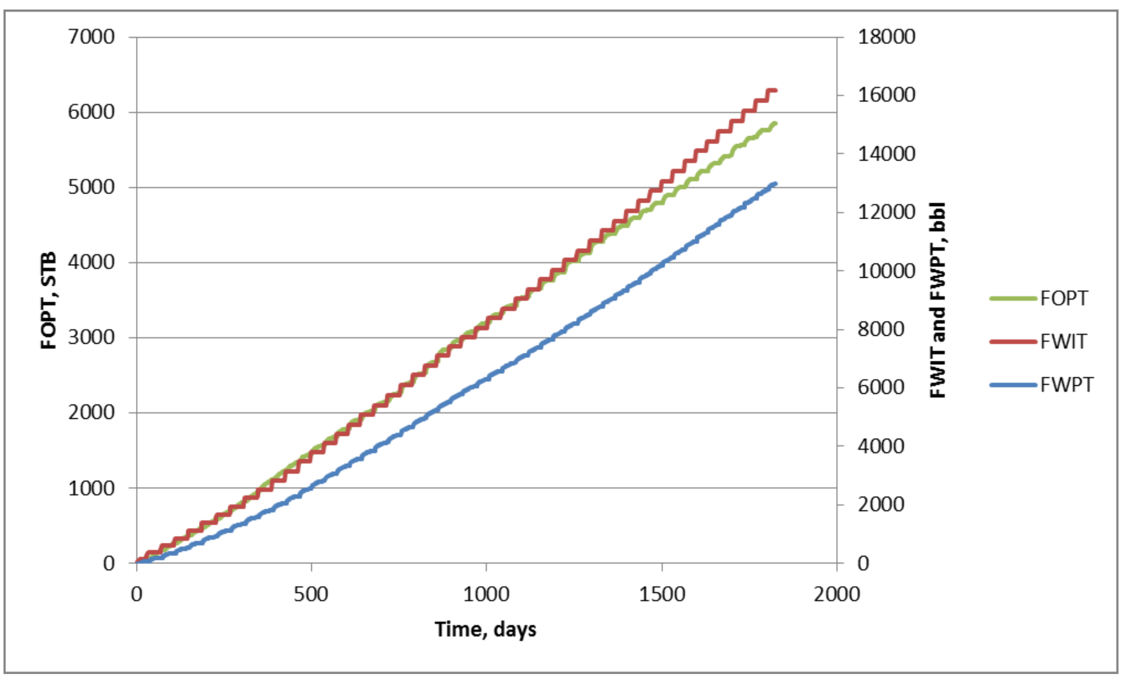

Fig. 18—Horizontal well with artificial lift pattern segment.

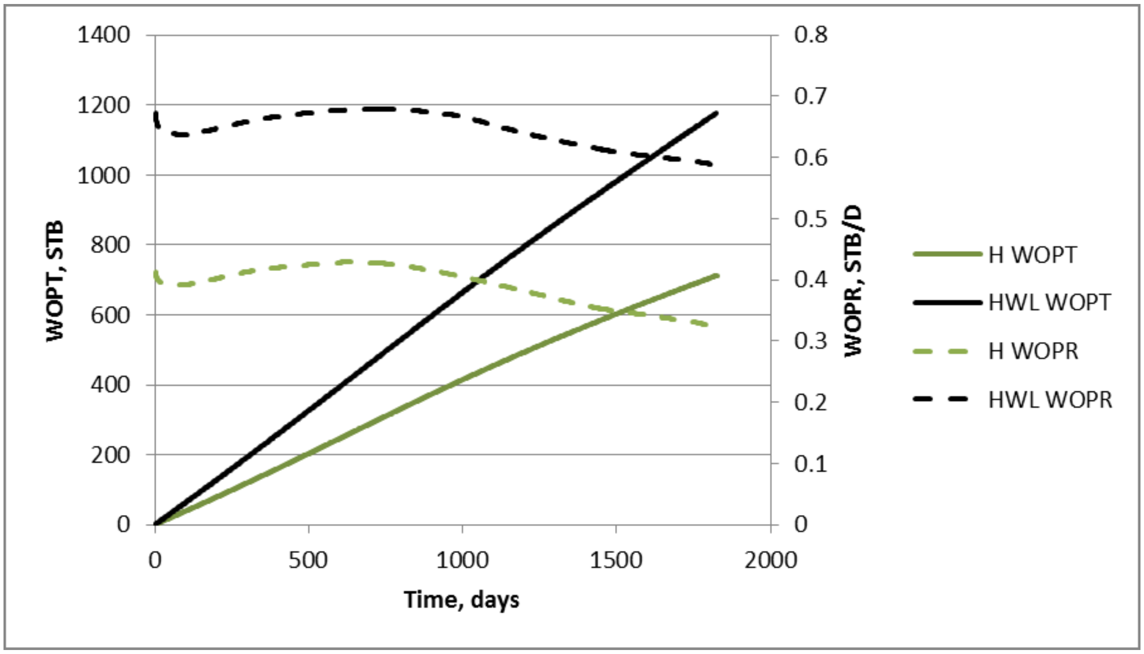

Fig. 19—Well cumulative oil production (WOPT) and well oil production rates (WOPR) for a full horizontal well (H) and a full horizontal well with artificial lift (HWL).

5.3 Deviated Well Cases

Both deviated well cases had a significant increase in cumulative production for five years compared to the base case. The deviated well without lift case increased the cumulative production of the simulated reservoir by 32.4% and the deviated well with artificial lift case increased the cumulative production by 14.4%. Water production also increased in both cases when compared to the base case. The deviated well without lift case increased the cumulative water production by 1,168 bbl and the deviated with artificial lift case increased the cumulative water production by 1,798 bbl. The cumulative production from both deviated wells, without the cyclic well's production included, was more than the production from either of the horizontal wells. An unstimulated deviated well in the middle of the cyclic steam project will produce an estimated 3,667STB of oil in five years. With artificial lift a deviated well will produce 7,266 STB. **Fig. 20** and **Fig. 21** show the cumulative oil, injected water and produced water for the deviated well without artificial lift case and the deviated with artificial lift respectively. The individual well rates and cumulative production for the deviated well and deviated well with artificial lift are included in **Fig. 22**.

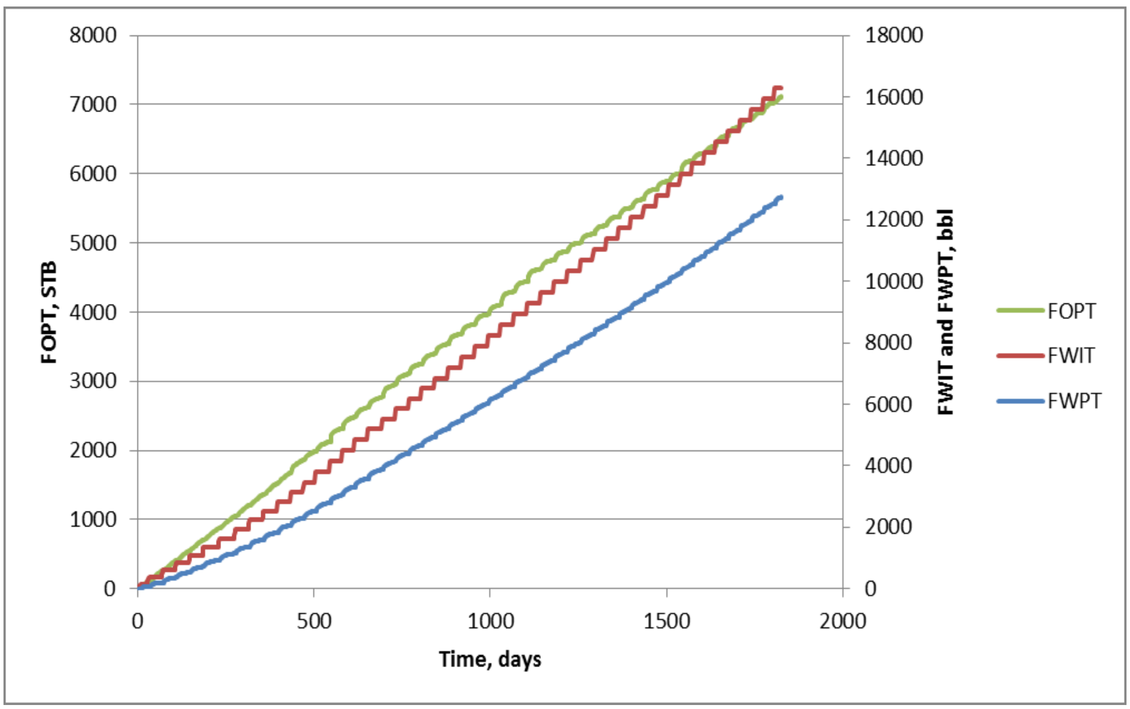

Fig. 20—Deviated well with artificial lift pattern segment.

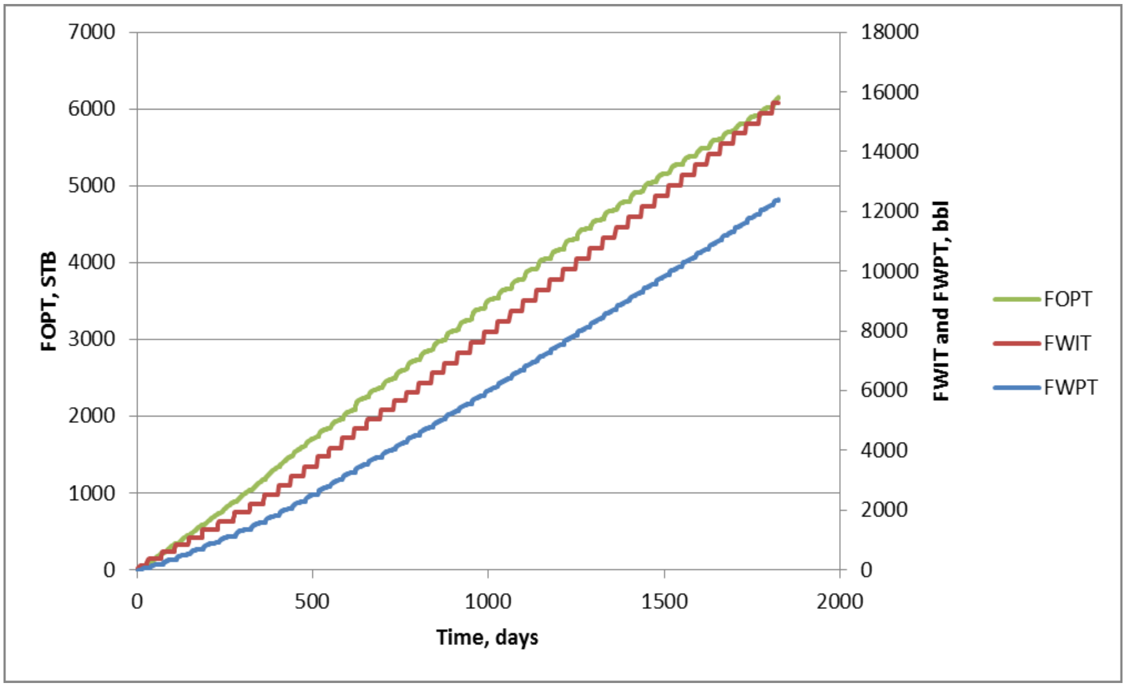

Fig. 21—Deviated well no lift pattern segment.

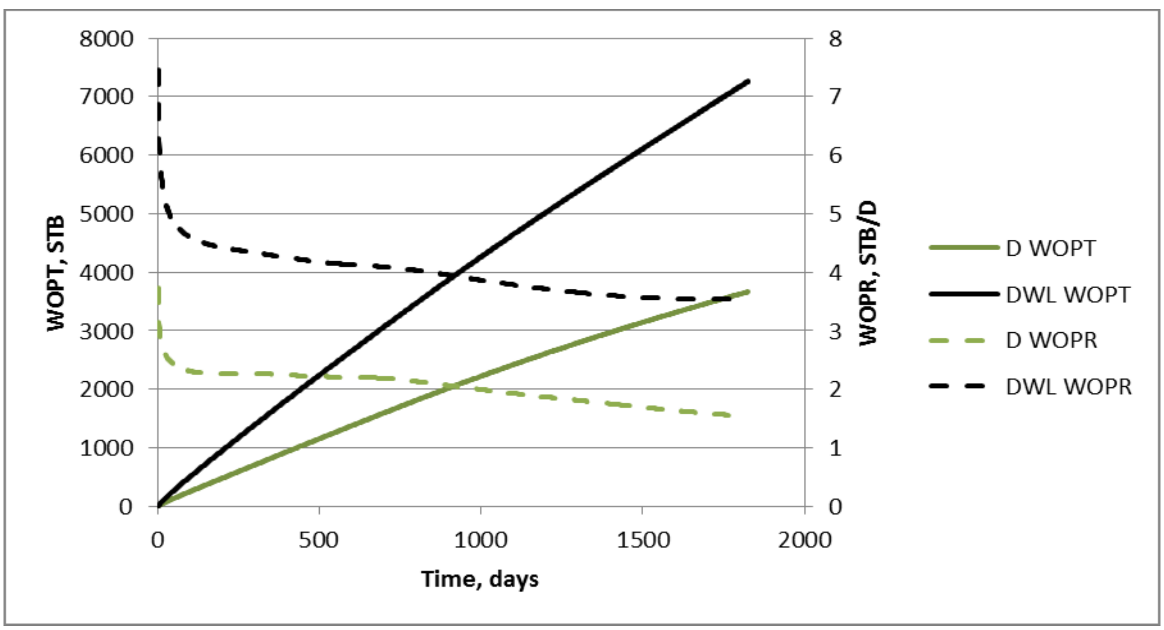

Fig. 22—Well cumulative oil production (WOPT) and well oil production rates (WOPR) for a full deviated well (D) and a full deviated well with artificial lift (DWL).

Each case's FOPT, FWIT and FWPT are included in **TABLE 6** and the FOPT for all of the cases is shown in **Fig. 23**. **TABLE 7** shows the cumulative oil, water and gas production from each well and is adjusted from the simulated volumes up to the full well volume. Deviated wells in the diatomite rock have much higher production than the simulated horizontal wells. Horizontal wells are normally used when the formation thickness is low and the long laterals can make up for the lower vertical permeability. Horizontal wells can also be used to take advantage of multiple hydraulic fractures, access areas that are otherwise inaccessible through vertical wells or even deviated wells and connect multiple small lens like reservoirs. Since diatomite reservoir in the prospective well location is thick (175'), continuous, and accessible via a slightly deviated well, the advantages that horizontal wells provide are not utilized and, therefore, are less productive than the deviated wells.

TABLE 6—5 YEAR CUMULATIVE UNADJUSTED VOLUMES FOR SIMULATED SEGMENT

	FOPT (STB)	FWIT (bbl CWE)	FWPT (STB)	SOR (CWE/STB)
Base Case	5,374	14,482	11,620	2.7
Deviated with Rod Pump	7,114	16,280	12,735	2.3
Deviated Well	6,147	15,650	12,387	2.5
Horizontal with Rod Pump	5,852	16,190	13,001	2.8
Horizontal Well	5,394	14,609	11,656	2.7

TABLE 7—ADJUSTED FULL WELL VOLUMES AFTER FIVE YEARS

	Oil (STB)	Water (STB)	Gas (MSCF)
Deviated with Rod Pump	7,266	204	31
Deviated Well	3,667	55	16
Horizontal with Rod Pump	1,177	4	5
Horizontal Well	713	3	3

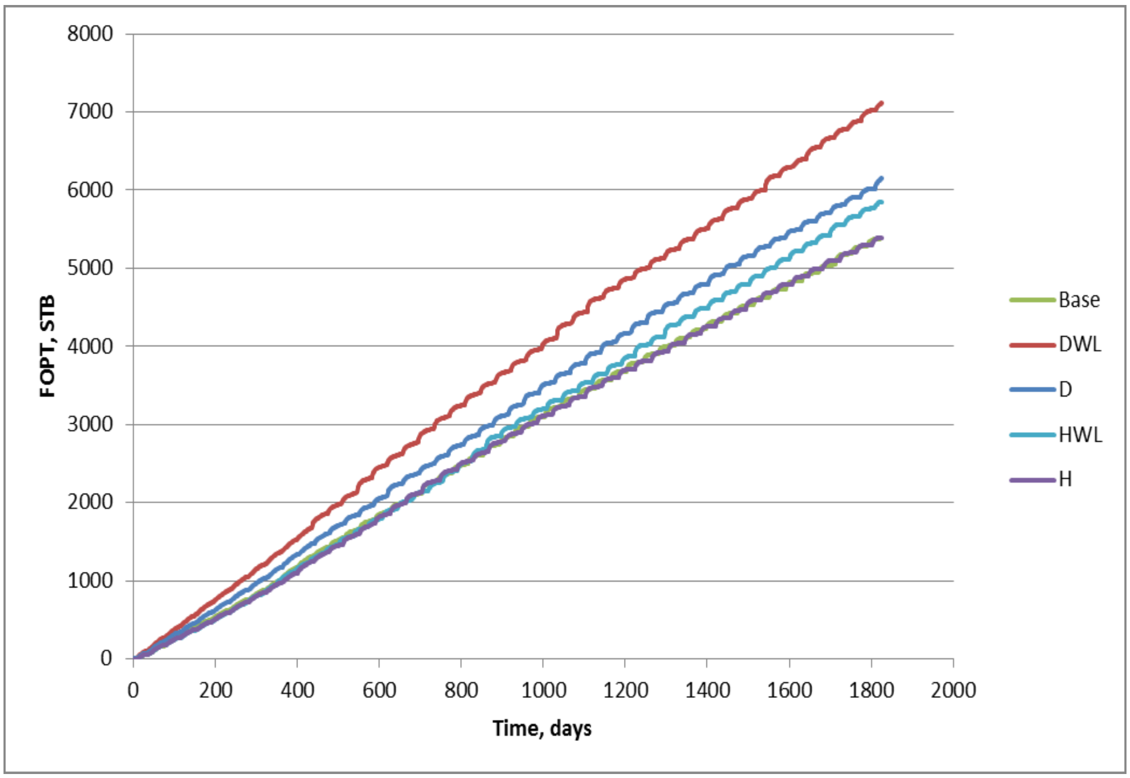

Fig. 23—Cumulative production for all cases.

5.4 Cyclic Well and Additional Well Interaction

The deviated and horizontal wells have increased production when simulated with the cyclic well compared to when they are simulated without the cyclic well (**TABLE 8**). The reason for this difference is primarily the pressure support provided by the cyclic well. The bottomhole pressure of the additional wells is higher when the cyclic well is present because of the steam injection. The temperature near the additional well is hardly changed so the heat cyclic well is likely not a contributing factor to the increase in production from the added wells. The 0.53 °F increase in temperature for the deviated with artificial lift well reduces viscosity by only 0.63%.

TABLE 8—PRODUCTION AND TEMPERATURE CHANGE WHEN CYLCIC WELL IS SIMULATED

	Production Increase (STB/D)	Production Increase (%)	Temperature Increase (°F)
Deviated with Rod Pump	829	12.9%	0.53
Deviated Well	429	13.3%	0.14
Horizontal with Rod Pump	33	2.8%	0.23
Horizontal Well	10	1.4%	0.14

For the deviated wells, the oil production rate is always higher with the cyclic well, but the horizontal wells only have increased production for roughly three of the five years (**Fig. 24** and **Fig. 25**). The rate increase occurs as the cyclic well is increasing the overall pressure of the reservoir by adding heat and volume. After the near wellbore region of the cyclic well has heated, the cyclic well begins to produce more oil and water than it injects, this causes the reservoir pressure to fall and the increased production decline that the deviated and horizontal wells experience towards the end of the forecast.

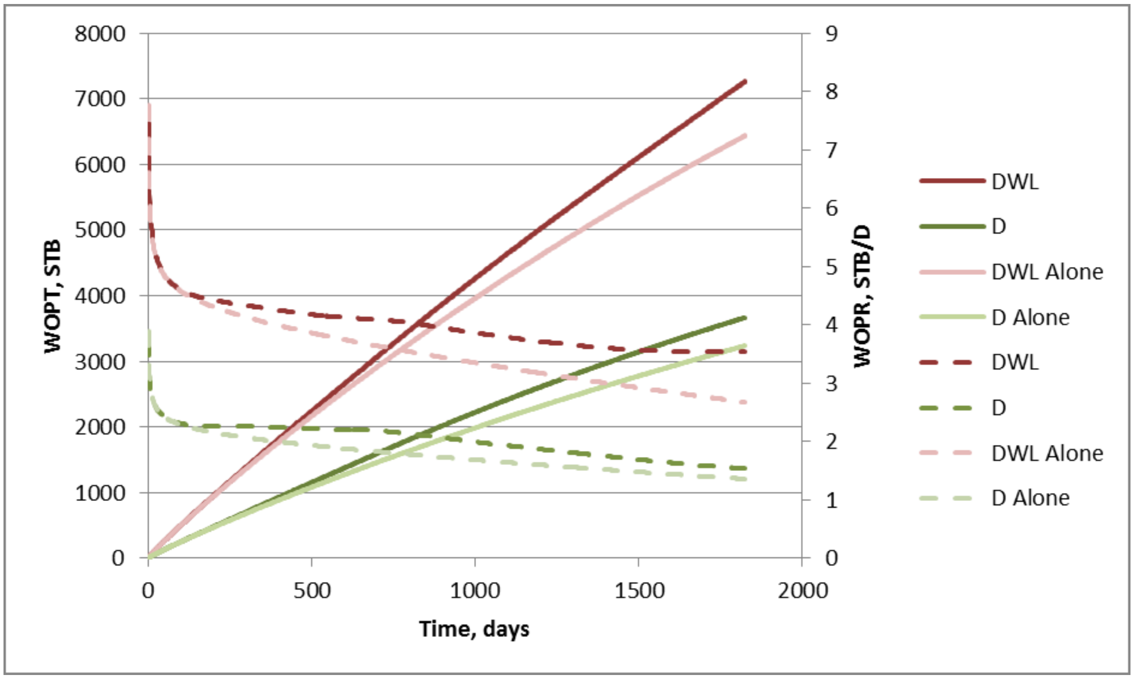

Fig. 24—Cyclic well increases deviated wells' production.

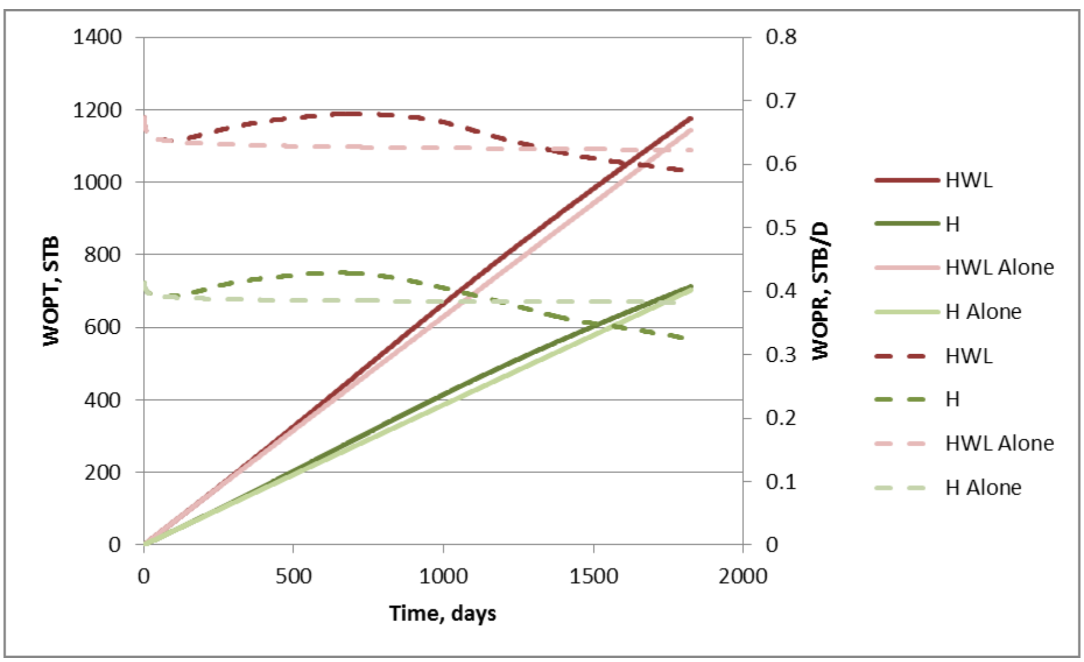

Fig. 25—Cyclic well has only slightly increases the horizontal wells' production.

CHAPTER VI

ESTIMATING DRILLING AND OPERATION COSTS

To identify the most profitable development scenario I first had to accurately estimate the costs of drilling new wells, adding infrastructure, waste water disposal and steam generation. As a part of the recent expansion plan development, I have accurate estimations for the cost of a new cyclic steam well and a steam generator. Based on our current steam generator fuel consumption and steam output I calculated the cost of steam injection to be about $0.78 for every barrel CWE. The steam generator costs $1,600,000, but only costs $34,600 on a per well basis because each steam generator supplies about 46 wells.

In the pilot program, oil treatments amount to $0.70 for every barrel produced and consist primarily of surfactants used as emulsion breakers in the separation process. This number is likely to be lower because of economies of scale for the expansion, but I will base my calculations on this pessimistic number because I cannot predict what the future savings will be if we will have any. Likewise water disposal costs were estimated using the pilot program cost of $0.20 for every barrel of waste water. Currently we dispose of all produced water into the lower Monterey formation. Because of restrictions on new water disposal wells and the increased water disposal needs of project, water disposal is one of the project risks. I will not attempt to address this issue within this thesis, but it is a subject that is being addressed and could result in a more expensive means of water disposal.

Recently 10 cyclic wells were newly drilled for the pilot program. These wells have identical completions to the wells in the expansion project and are good analogs for estimated the cost of drilling and completing wells in the field. Based on these wells I am estimating the cost of drilling and completing a new well to be $360,000. Drilling an “S” shaped well will cost more than a vertical well, the total cost of an “S” shaped well will be about $385,000. For the horizontal well, I do not have as accurate of an estimate, but based on a rig capable of drilling the 600’ lateral, a horizontal well would cost about $805,000 to drill and complete based on a ghost horizontal well in a neighboring field. The artificial lift case requires a rod pump that will cost an estimated $46,000 to install.

Facility costs for the expansion project are significant on a per well basis, but the facilities being built for the expansion will be able to adequately handle the additional 22 deviated wells or the three horizontal wells without upgrades and the cost of piping the wells to the facilities was included in the drilling and completion costs of a new well. Therefore, additional wells will not need additional infrastructure and have no cost added for facilities.

Oil and gas prices for the forecast are estimated at 121 $/STB and 2.09 $/MSCF. These prices are the current prices for mid-April, the time of this writing. Both of these commodities have a significant effect on profitability and are prone to significant price swings. Because I cannot predict what prices will be for the forecast, I will assume constant prices at 121 $/STB and 2.09 $/MSCF. I will perform a sensitivity analysis on both oil and gas prices in 7.4 Vertical Permeability.

All of the project expenses and commodity prices I used are included in **TABLE 9**. I assumed that any costs that I did not include were either not significant or not required for the additional wells.

TABLE 9—PROJECT COSTS

Cylcic Well	360,000	$
Deviated Well	385,000	$
Horiz Well by Segment	134,167	$/120ft
Rod Pump	46,000	$
Generator	34,600	$/well
Steam	0.78	$/bbl CWE
Oil Treatment	0.70	$/STB
Water Disposal	0.20	$/STB
Oil Price	121	$/STB
Gas Price	2.09	$/MCF

CHAPTER VII

RESULTS WITH WELL AND OPERATIONAL COSTS

With all of the cases forecasted through five years and reasonable estimates for drilling and operational costs I am able to determine the most profitable development plan. In this section I will compare all of the cases based on one prospective well location and one cyclic well. For the base case, the prospective well location is undeveloped and a quarter of the cyclic well is simulated. For the deviated well cases, a quarter of a deviated well is simulated in the prospective well location and a quarter of the cyclic well is simulated. For the horizontal well cases, only 1/24 of the horizontal well is simulated in the prospective well location and a quarter of the cyclic well is simulated. Therefore, all volumes and rates for the simulated reservoir will be multiplied by four to represent one prospective location and one cyclic well. The costs for the base case and the deviated well cases will then be whole well costs, but the horizontal well cost will only be for 1/6 of the well since one 720’ horizontal well stretches across six prospective well locations.

The deviated well with artificial lift produced the most cumulative oil production over five years while the base case produced the least; this does not mean that the deviated well with artificial lift was the most profitable and the base case the least though. The base case has the lowest total costs compared to all of the other cases and the deviated well with artificial lift has the highest (**TABLE 10**). In order to evaluate the different cases I need to select a method than includes the cost and revenues from the project. There are many different methods I can use to rank the cases and each method has its own advantages and limitations. I have chosen to evaluate the projects based on net profit and net present value (NPV) using a hurdle rate of 15% because both methods are commonly used in the industry. Net profit simply sums the expenditures and revenue for the project while NPV takes the opportunity cost of project expenditures into account.

TABLE 10—FIXED AND VARIABLE EXPENDITURES BY CASE

	Oil Treatments	Steam Generation	Water Disposal	Fixed	Total
Base Case	$ 15,046	$ 45,402	$ 9,296	$ 394,600	$ 464,344
Deviated with Rod Pump	$ 19,919	$ 51,037	$ 10,188	$ 800,600	$ 881,745
Deviated Well	$ 17,213	$ 49,063	$ 9,910	$ 754,600	$ 830,786
Horizontal with Rod Pump	$ 16,386	$ 50,755	$ 10,401	$ 528,767	$ 606,308
Horizontal Well	$ 15,104	$ 45,800	$ 9,325	$ 574,767	$ 644,996

The deviated well with artificial lift provided the highest cumulative production after five years. Likewise, both the net profit and the NPV for the deviated well with artificial lift case is the highest among the cases despite also having the highest cost per prospective location. Based on the simulation and the economic parameters, the deviated well with artificial lift case will increase net profit by $295,000 and NPV by $90,000 compared to the base case. The horizontal well with artificial lift case generates a net profit of $1,826,000 after five years, also an improvement over the base case net profit of $1,811,000, but the NPV is lower than the NPV of the base case. Both the net profit and the NPV for the horizontal and deviated well cases are lower than the base case because of the added well costs. **TABLE 11** summarizes the results of the net profit and NPV for the different development plans a cyclic well and prospective location pair.

TABLE 11—NET PROFIT AND NPV FOR CYCLIC WELL AND PROSPECT LOCATION

	Net Profit	NPV, 15%	RF
Base Case	$ 1,811,000	$ 1,208,000	7.27%
Deviated with Rod Pump	$ 2,106,000	$ 1,298,000	9.62%
Deviated Well	$ 1,748,000	$ 1,048,000	8.31%
Horizontal with Rod Pump	$ 1,826,000	$ 1,142,000	7.91%
Horizontal Well	$ 1,685,000	$ 1,073,000	7.30%

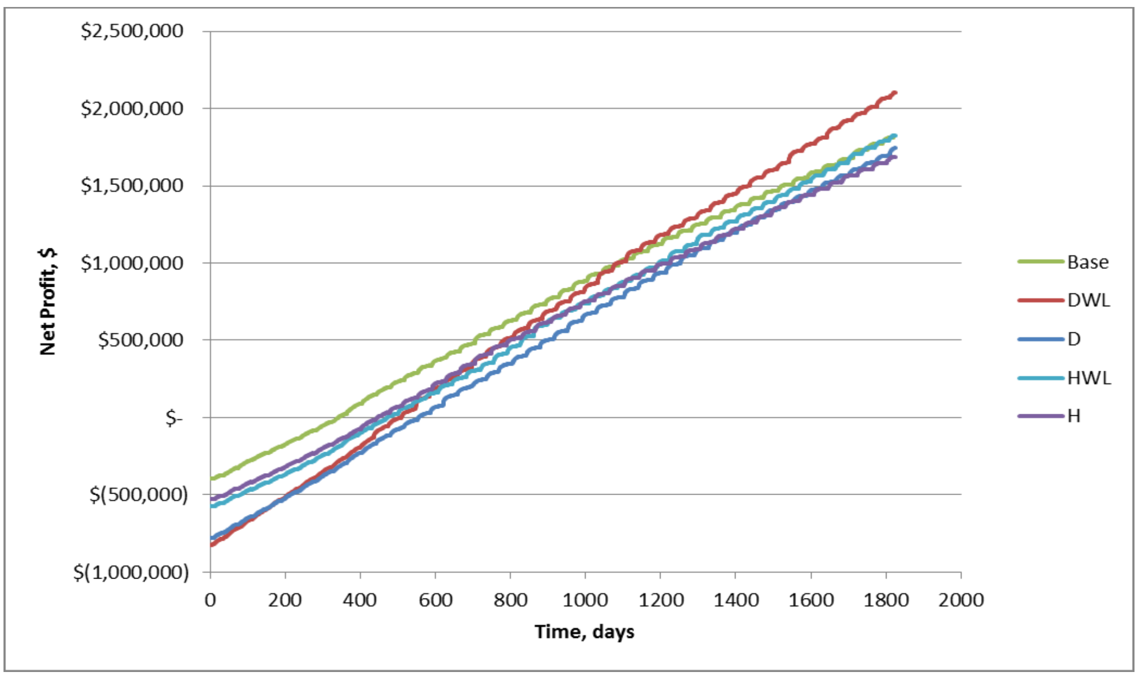

Fig. 26—Net profit over time shows the base case is the first simulated segment to payout (positive net profit).

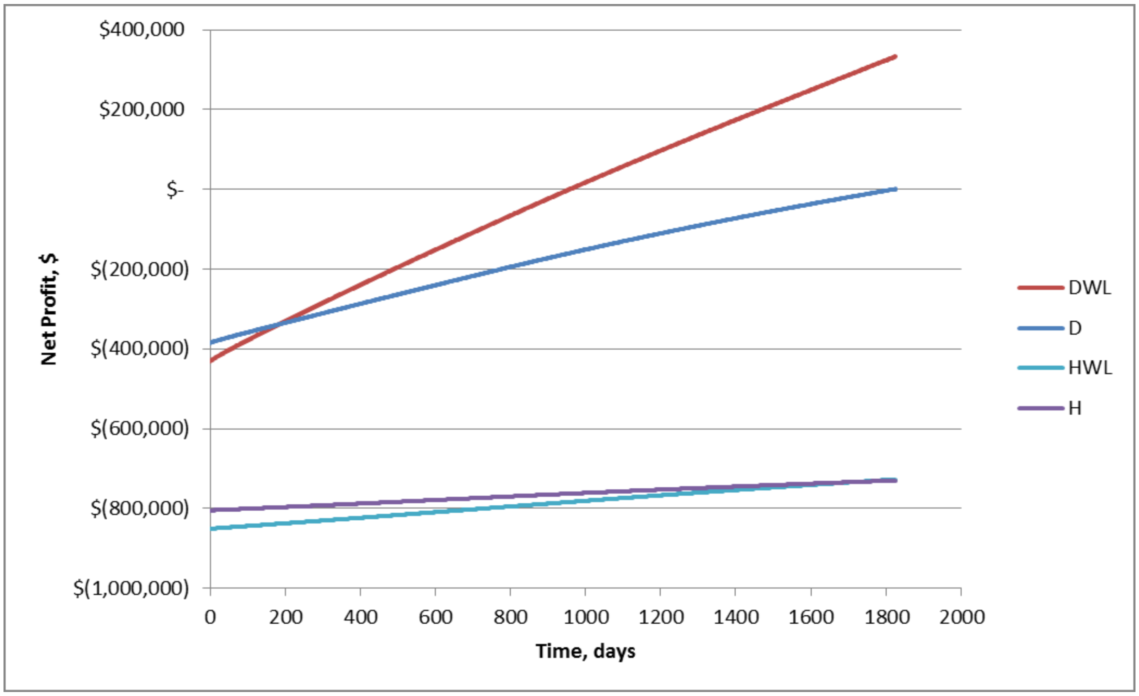

Fig. 27—Net profit over time shows the deviated well with artificial lift is the first well to payout and has the highest net profit after five years.

The time until payout is another important value for a company and its investors. Shorter payout times require less long term debt and provide positive cash flow for other projects. **Fig. 26** shows the net profit as a function of time for the prospective location and cyclic well pair and **Fig. 27** does the same for individual wells. The time until payout for the prospective location and each prospective well is included in **TABLE 12**.

TABLE 12—TIME TO PAYOUT

	Payout Pattern (days)	Payout well (days)
Base Case	341	341
Deviated with Rod Pump	509	957
Deviated Well	554	1821
Horizontal with Rod Pump	472	N/A
Horizontal Well	445	N/A

The deviated well with artificial lift increases profit by $333,000 over five years and the NPV by $129,000. Since there is the potential for 22 deviated wells to be drilled, the total increase in net profit for the project is $7,326,000 and the increase in NPV is $2,838,000 (**TABLE 13**). All of the other added wells have unattractive or negative profits over the forecasted time period. Overall, the most productive unstimulated well that I simulated only produces at a fraction of the rate of a cyclic well which is expected to increase net profit by $1,811,000 per well. The deviated wells with artificial lift do increase profit though, and, if all of the undeveloped well locations are developed, the profit increase for the project is not insignificant.

TABLE 13—PROFIT AND NPV FROM 22 DEVIATED WELLS AND 3 HORIZONTAL WELLS

	Profit ($M)	NPV, 15% ($M)
Deviated with Rod Pump	7,326	2,838
Deviated Well	22	-2,200
Horizontal with Rod Pump	-2,181	-2,283
Horizontal Well	-2,190	-2,250

CHAPTER VIII

SENSITIVITY ANALYSIS

Unfortunately all forecasts are based on estimates of rock and fluid properties. I have reasonable estimates for many of the properties, but some have a significant amount of uncertainty. Calibrating the model to the pilot program production helped to limit some of the uncertainty, but I only had a limited amount of information to base my match on. Further, the locations I am attempting to simulate are 600' to 1400' from the pilot program, and I am assuming a homogenous formation when in reality, the formation is more complex.

A sensitivity analysis will help identify the reservoir and well properties that have the greatest impact on production. Identifying the critical properties will help direct future core, fluid, and reservoir testing and analysis. This will result in a better use of company funds for refining the reservoir model. Identifying key economic parameters such as the effect of the price of oil is also important for the project. Oil price drops can be detrimental to projects with large initial investments and high operating costs.

To observe the effects of changing reservoir, fluid, and economic properties I ran the base case through 500 days changing one property at a time. In general, I ran one run with the selected property lower than the original base case and once with the property higher. I chose to run the cases for 500 days to reduce the run times and reduce the likelihood that the run would be unstable. In a few cases I had to reduce the injection rate to 90 or 95 BBL CWE/D, but this was fairly rare.

8.1 Permeability Changes

Under simple radial pseudo steady state and steady state flow, permeability is directly proportional to the flow rate. The simulation results for the different field wide permeabilities show cumulative oil production from the reservoir is close to being directly proportional to the permeability if the permeability is lower than 10 md (**TABLE 15** and **Fig. 28**). For 12 md, 20% greater permeability than the base case, production only increased by 11% after 500 days. Currently we believe that permeability in the field is fairly uniform aerially based on logs and the nature of the reservoir rock, but a positive or negative 20% to 25% change in permeability between the pilot program well area and the expansion area would not be surprising. Such a change in permeability could change the NPV and net profit rankings of the development plans, so it would be wise to take a few cores in the area or calculate the permeability from logs as the expansion wells are drilled.

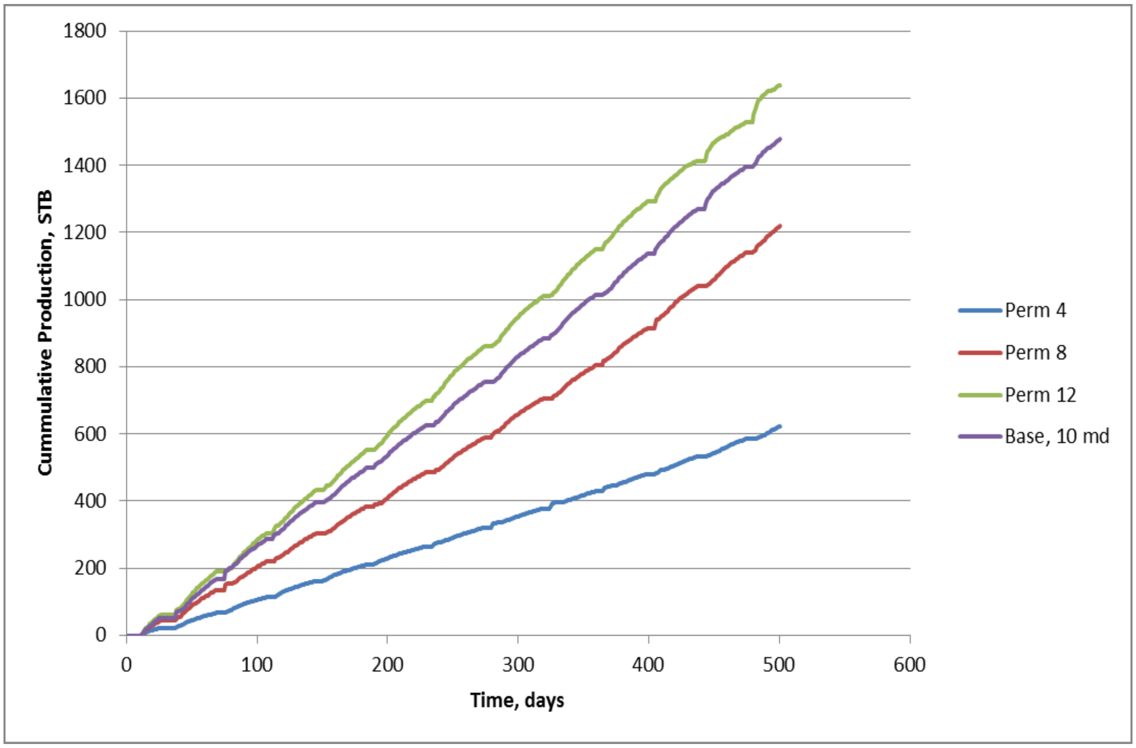

Fig. 28—Cumulative production increases as permeability increases.

8.2 Porosity Changes

Porosity is proportional to the OOIP and also impacted production over 500 days (**Fig. 30**). When I increased porosity to 70% from 60%, a 16.7% increase, cumulative production only increased by 4.2%. I expected a similar decrease in cumulative production when I decreased the porosity to 50%, but the cumulative production dropped by 9.2%. The difference in production responses from the changes in porosity may be a result of the cycle scheduling. The base case schedule was created by customizing the production interval to balance the reservoir pressure. A higher porosity means the reservoir pressure will increase less for a given injection volume and decrease less for a given produced volume. Over the 500 day period the reservoir pressure increases then decreases, and at the end of the 500 days the reservoir pressure is 599 psia for 70% porosity, 595 psia for the base 60% porosity and 589 psia for 50% porosity. The reservoir pressures at 500 days do not differ significantly between the cases, but there is a noticeable difference in the amplitude of the reservoir pressure peaks and troughs over a cycle (**Fig. 29** and **TABLE 14**).

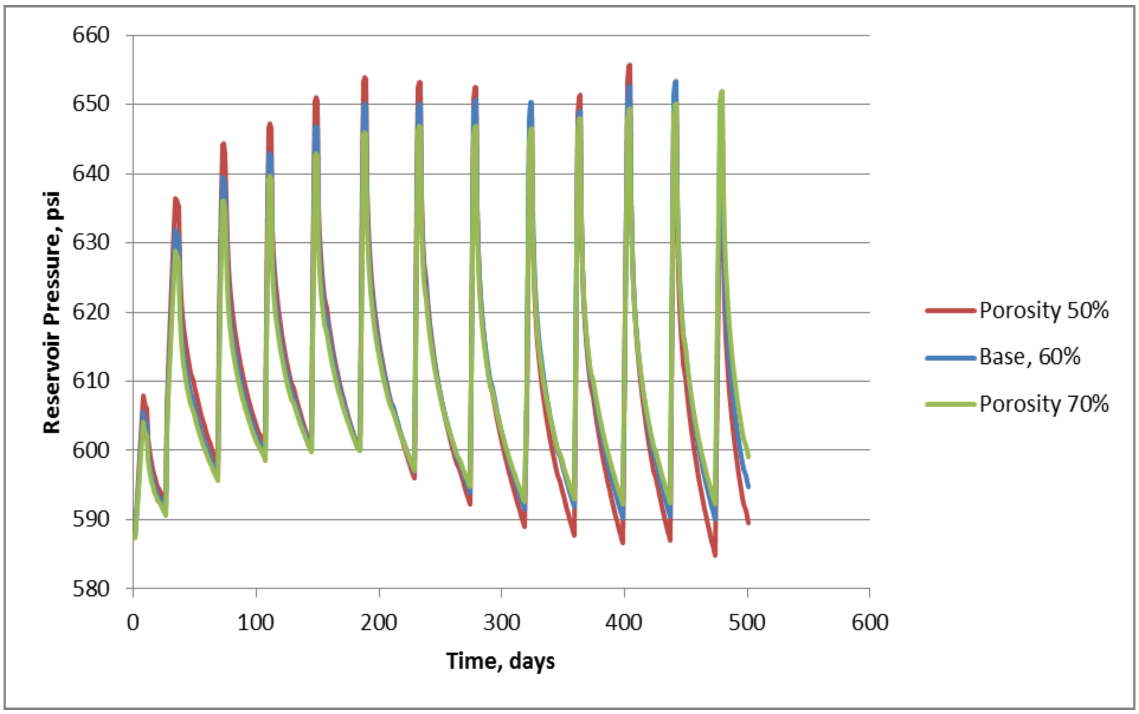

Fig. 29—Higher porosity results in lower pressure increases during injection and lower pressure decreases during production. After 500 days the reservoir pressure is similar between the three cases.

TABLE 14—CYCLE 5 RESERVOIR PRESSURE CHANGES

	ΔP Injection (psi)	ΔP Production (psi)
50% Porosity	50.0	-50.5
60% Porosity	46.4	-46.4
70% Porosity	42.8	-42.6

Porosity is one of the reservoir properties that we have the most data for. Each of the pilot wells has lab measured porosity on sidewall cores. Based on the sidewall cores, porosity is fairly uniform within the main production interval. Because the reservoir porosity is unlikely to differ significantly from my current estimate and changes in porosity alone has a modest impact on the cumulative production, additional investment in porosity data acquisition could be better spent on properties that have more uncertainty and a larger impact on production.

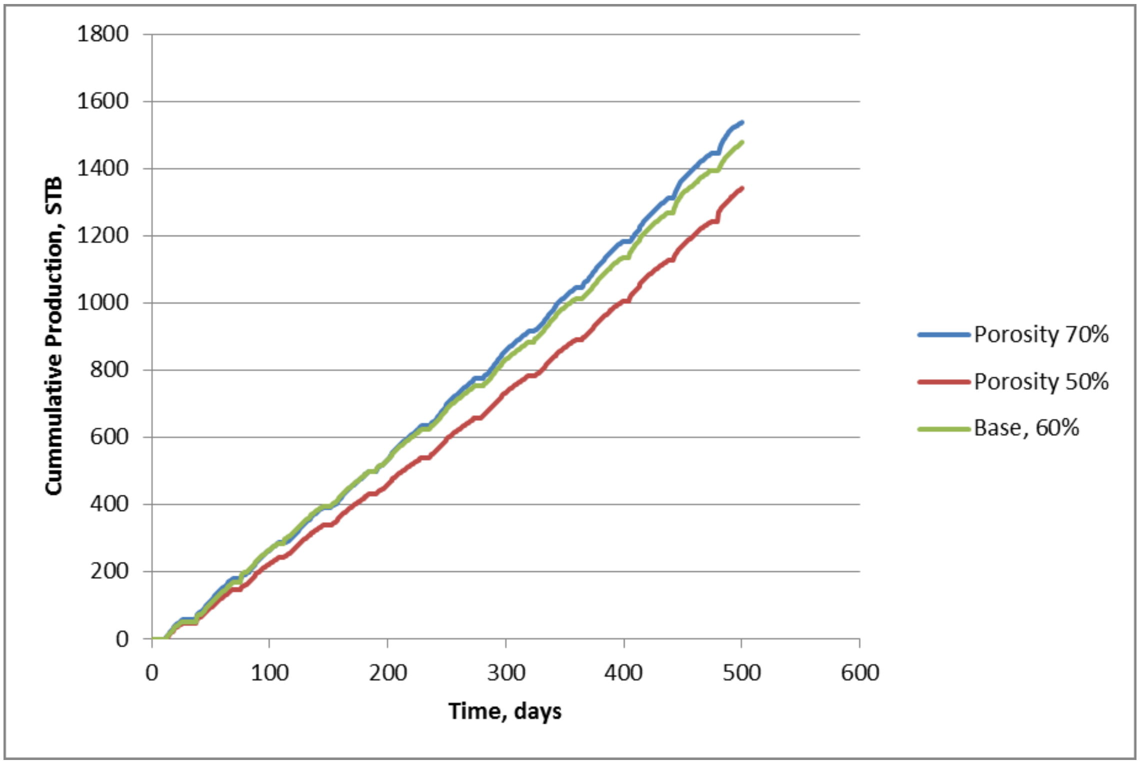

Fig. 30—Porosity changes do not have as great an impact on the cumulative production after 500 days as viscosity and permeability.

8.3 Viscosity Changes

The primary reason the project relies on cyclic steam injection is because of the high viscosity of the oil at the reservoir pressure and temperature. The viscosity of the oil has a large effect on the reservoir productivity, but the viscosity can be lowered with heat during steam injection. SMP has had several lab tests to measure the viscosity of oil samples at different temperatures (**Fig. 15**) so viscosity is one of the fluid parameters with a high degree of confidence, but even small errors in the viscosity measurements could have a sizeable impact on the project. Oil samples were taken from an unpressurized tank and are not pure wellhead samples with solution gas. This could cause some errors in the viscosity measurements. To determine the project's sensitivity to the oil viscosity I increased the viscosity by 20% at all temperatures for one run and then decreased the viscosity by 20% and ran the simulation. Changes in the viscosity and the resulting changes to the cumulative oil production are shown in **Fig. 31**. If the in-situ oil viscosity is 20% greater than the measured viscosity at all temperatures, a 14.3% drop in productivity can be expected.

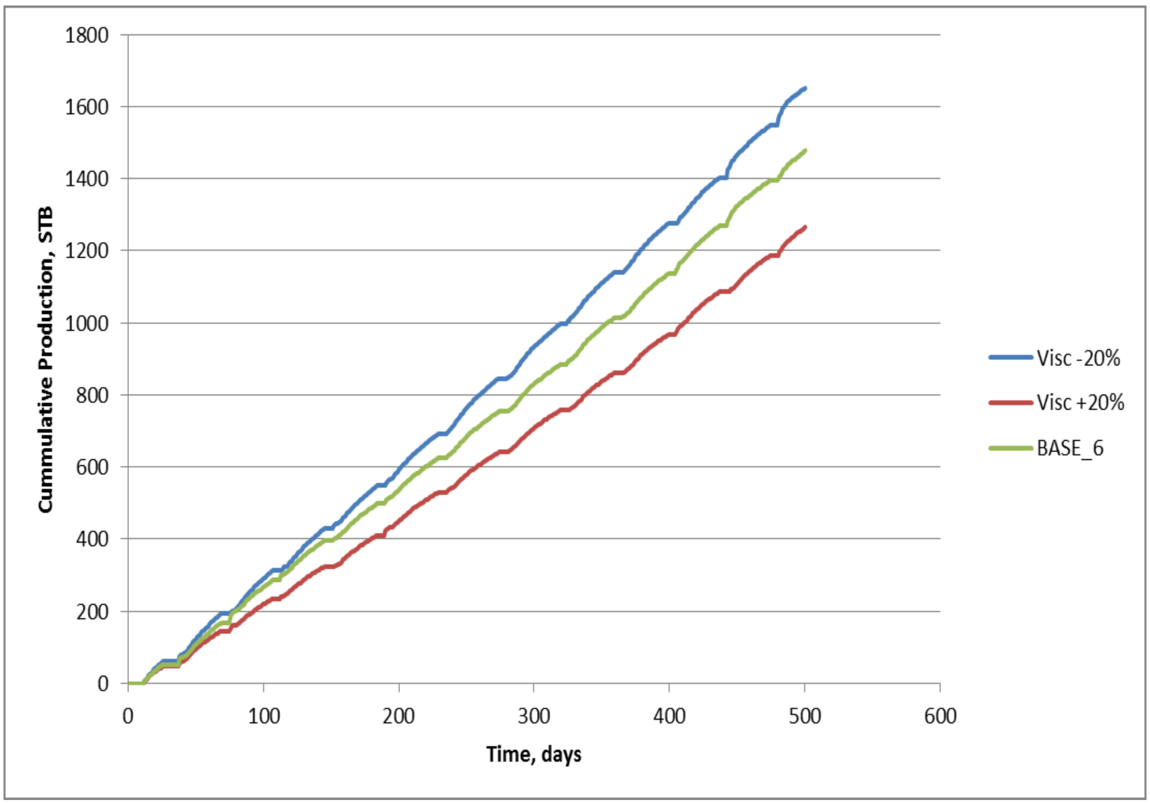

Fig. 31—Lower viscosity results in lower cumulative production.

TABLE 15—PROPERTY CHANGES AND CUMULATIVE PRODUCTION

	FOPT (STB)	Difference (%)
Base Case	1,477	
4 md Permeability	623	-57.8%
8 md Permeability	1,219	-17.5%
12 md Permeability	1,639	11.0%
50% Porosity	1,342	-9.2%
70% Porosity	1,539	4.2%
-20% Viscosity	1,652	11.9%
+20% Viscosity	1,265	-14.3%

8.4 Vertical Permeability

Vertical permeability was assumed to be 10% of the horizontal permeability, but the ratio of k_v/k_h is unknown. I ran the horizontal well with artificial lift case with two higher k_v/k_h ratios, 0.5 and 1.0 to observe how the additional horizontal well's production changes. Originally, a full unstimulated additional horizontal well with artificial lift produced 327 STB over a 500 day period. When the vertical permeability was increased to 5 md to create a k_v/k_h ratio of 0.5, production increased to 706 STB, a 116% increase. The horizontal well's production is shown in Table xxx and has a significant impact on the horizontal well's performance. Core tests can be used to estimate a k_v/k_h ratio and is critical for a full understanding of horizontal well performance in the field

.

TABLE 16—K_V/K_H RATIO EFFECT ON HORIZONTAL WELL PERFORMANCE

	WOPT (STB)	Difference (%)
kv/kh = 0.1	327	
kv/kh = 0.5	706	116%
kv/kh = 1.0	983	201%

8.5 Cyclic Horizontal Well

The unstimilated horizontal wells performed poorly, but there is the opportunity to cyclic steam the horizontal well. Without trying to optimize the production schedule other than increasing the injection time to eight days to compensate for the lower steam injection rates, I simulated a cyclic horizontal well with the same spacing as the unstimulated wells. I did not stimulate a base cyclic well at the same time as the horizontal well to reduce complications for the simulation. **TABLE 17** includes both the original unstimulated horizontal wells' production and the newly simulated cyclic horizontal well. The cyclic horizontal well outperforms the by a substantial amount. Unfortunately a cyclic horizontal well currently falls out of the scope of this expansion plan, but may be worth considering for future developments.

TABLE 17—HORIZONTAL WELL COMPARISONS

	Oil (STB)	Water (STB)
Cyclic Horizontal Well	44,160	140,106
Horizontal with Rod Pump	1,177	4
Horizontal Well	713	3

8.6 Oil Price

Oil price swings are common and greatly affect the profitability of the project. In the past year the price of Brent crude has had a low of 95 $/STB and a high of 125 $/STB. I have simplified the economic forecast for the project by assuming a constant oil price of 121 $/STB, but it is important to look the impact of different prices to understand how much risk in the project is associated to the oil price. If the project will become uneconomic at a lower oil price it may be in the company's best interest to hedge against the price of oil. To observe the effects of changing the oil price, I ran each development plan with the past years high and low oil prices (**TABLE 18**).

TABLE 18—OIL PRICE AND PATTERN PROFIT

	95 $/bbl		121 $/bbl		125 $/bbl	
	Profit ($M)	NPV, 15% ($M)	Profit ($M)	NPV, 15% ($M)	Profit ($M)	NPV, 15% ($M)
Base Case	1,322	853	1,811	1,208	1,887	1,262
Deviated with Rod Pump	1,459	829	2,106	1,298	2,206	1,376
Deviated Well	1,188	644	1,748	1,048	1,834	1,110
Horizontal with Rod Pump	1,294	761	1,826	1,142	1,908	1,200
Horizontal Well	1,195	718	1,685	1,073	1,761	1,128

For all three oil prices the deviated well with artificial lift performed the best, but the base case and the deviated well with artificial lift case are near equal based on NPV at 95 $/STB. For the base case, a 21.5% drop in the price of oil decreased the profit from the project by 27% and the NPV by 29.4%. A 3.3% increase in the price of oil increased the profit and NPV of the base case by 4.2% and 4.5% respectively. An oil price of 32.54 $/STB is breakeven point for the base case NPV at a 15% hurdle rate and the profit from the project has a breakeven at 24.69 $/STB. While the deviated well with artificial lift has the highest NPV and profit after 5 years at 121 $/STB, the NPV breakeven oil price and the profit breakeven oil price are much higher than for the base case. The NPV of the deviated well with artificial lift case breaks even at 47.59 $/STB and the profit breaks even at 35.41 $/STB. The oil price is very important to the bottom line of the project, but cannot be accurately projected into the future. If management wanted to avoid some of the risk of a large oil price decline the base case would be the best choice in development plans.

On an individual well basis, the deviated well with artificial lift has positive NPV and profit for the three oil prices I used (**TABLE 19**). The deviated well has a positive profit, but negative NPV at the 121 and 125 $/STB prices. At 95 $/STB the deviated will has a negative NPV and profit. The breakeven oil price for the deviated well with artificial lift well is 68.60 $/STB for profit and 93.27 $/STB for NPV (**TABLE 20**). If a rate of return of at least 15% is desired, an oil price drop below 93.27 $/STB would cause the deviated well with artificial lift to be a poor development choice. A deviated well is profitable at oil prices above 120.79 $/STB, but will not achieve a 15% rate of return unless the oil price increases to 163.32 $/STB. Both horizontal wells perform poorly at all of the observed oil prices and the breakeven oil prices for both horizontal wells is well over 500 $/STB.

TABLE 19—OIL PRICE AND WELL PROFIT

	95 $/bbl		121 $/bbl		125 $/bbl	
	Profit ($M)	NPV, 15% ($M)	Profit ($M)	NPV, 15% ($M)	Profit ($M)	NPV, 15% ($M)
Deviated with Rod Pump	168	8	333	129	359	149
Deviated Well	-83	-162	1	-100	14	-91
Horizontal with Rod Pump	-754	-781	-727	-761	-723	-758
Horizontal Well	-746	-762	-730	-750	-728	-749

TABLE 20—DEVIATED WELL OIL PRICE BREAKEVEN POINTS

	Profit Oil Price ($/bbl)	NPV Oil Price ($/bbl)
Deviated with Rod Pump	68.60	93.27
Deviated Well	120.79	163.32

8.7 Gas Price

The diatomite wells require natural gas to run the steam generators, but the amount of produced gas from the wells is almost negligible. Gas will be piped in from the local utility company to keep the steam generators running, but similar to the oil price, the gas price is always changing. Recently gas prices have been at historic lows because of the abundance of shale gas released through hydraulically fractured horizontal wells. It is possible for the price of gas to return to previous prices which would hurt the economics of this thermal project. **TABLE 21** shows the effect of 4 $/MCF and 6 $/MCF on the project economics. Nearly tripling the current price of natural gas only reduces the project NPV and profit by about 5% for the base case. Similar changes are seen in the other cases. The price of natural gas hardly affects the prospective wells because the produced gas is negligible and there is no steam injection.

TABLE 21—GAS PRICE AND PATTERN PROFIT

	2.09 $/MCF		4 $/MCF		6 $/MCF	
	Profit ($M)	NPV, 15% ($M)	Profit ($M)	NPV, 15% ($M)	Profit ($M)	NPV, 15% ($M)
Base Case	1,811	1,208	1,770	1,178	1,726	1,147
Deviated with Rod Pump	2,106	1,298	2,059	1,265	2,011	1,236
Deviated Well	1,773	1,073	1,728	1,041	1,681	1,008
Horizontal with Rod Pump	1,826	1,142	1,780	1,109	1,731	1,075
Horizontal Well	1,685	1,073	1,644	1,044	1,600	1,013

CHAPTER IX

CONCLUSIONS

In this study I used a homogenous reservoir model using field and analog data to simulate a quarter of a cyclic steam well and either a quarter of a deviated well or a quarter of a 120’ section of a horizontal well. The model simulates five years of production. Based on the reservoir simulation and the different cases I developed I came to the following conclusions.

- Inaccurate reservoir characterization and inaccurate price forecasts can significantly affect the project’s viability. The five year NPV of the deviated well with artificial lift breaks even at an oil price of 93.27 $/STB and a 20% decrease in the field’s permeability decreases the 500 day production forecast for the base case by 17.5%.
- Adding 22 deviated wells with artificial lift to the expansion development plan will increase net profit by $7,326,000 and NPV by $2,838,000 after five years by producing 7,266 STB for each additional well.
- Adding 22 deviated wells with artificial lift will add $9,482,000 to the project’s startup cost.
- Deviated wells without artificial lift payout after 1,821 days (just before the end of the five simulated years). With a longer project life, deviated wells could be a viable development method.
- Unstimulated horizontal wells perform poorly over the five years with only 294 STB cumulative oil production for each horizontal well with artificial lift, but can

produce from up to six prospective vertical well locations for each horizontal well which results in a lower initial investment compared to the deviated well cases. More research needs to be done on the viability of a hydraulically fractured horizontal well and a cyclic steam horizontal well.

Further testing of the reservoir model would increase the accuracy of forecasting and the validity of the study. Reservoir quality and oil characteristics are likely to vary between diatomite project locations. The model should be updated to reflect these changes before any conclusions are extrapolated to different project locations.

NOMENCLATURE

BHP	bottomhole pressure
BBL	barrels
CSS	cyclic steam stimulation
CWE	cold water equivalent
D	deviated well without lift
DWL	deviated well with artificial lift
FGPT	field gas production total
FOPT	field oil production total
FWPT	field water production total
H	horizontal well without lift
HWL	horizontal well with artificial lift
OOIP	original oil in place
SMP	Santa Maria Pacific
STB	stock tank barrels
WOR	water oil ratio

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APPENDIX A

Base Case DATA file:

```
RUNSPEC


TITLE

BASE CASE


FIELD


THERMAL


COMPS

2 /          2 hydrocarbon components, dead oil + solution gas


WATER


HWELLS


DIMENS

15 8 35 /    Grid dimensions
```

```
ROCKDIMS
2  /            Base and cap rock connections


WELLDIMS
1* 40 /         Max number of completions / well


EQLDIMS
1* 1* 1* /


START
 01 JAN 2012 /
------------------------------------------------------------------------------
GRID
------------------------------------------------------------------------------


TOPS
120*800.0 /


DXV
 1 1.5 3 6 11 15 15 16 15 15 11 6 3 1.5 1 /        x-length = 121 feet


DYV
```

```
 1 1.5 3 6 11 15 15 16 /                              y-length = 68.5 feet


DZ

4200*5 /                          z-height = 1052 feet


-- Properties with uniform values:


EQUALS

PORO    0.60 /                     porosity

PERMX   10    /                    kx, mD

PERMY   10   /                     ky, mD,  ky = kx

PERMZ   1   /                      kz, mD,  kv/kh = 0.66

HEATCR 34    /                     rock heat capacity Btu/ft**3/deg F

THCONR 12.5  /                     rock conductivity Btu/ft/Day/deg F

PORO    .30    1 1 1 8 1 35 /

PORO    .30    1 15 1 1 1 35 /

PORO    .30    1 15 8 8 1 35 /

PORO    .30    15 15 1 8 1 35 /

PORO    .15    15 15 8 8 1 35 /

PORO    .15    15 15 1 1 1 35 /

PORO    .15    1 1 8 8 1 35 /

PORO    .15    1 1 1 1 1 35 /
```

```
PERMX   5    1 15 8 8 1 35 /

PERMZ  .5    1 15 8 8 1 35 /


PERMX   5    1 15 1 1 1 35 /

PERMZ  .5    1 15 1 1 1 35 /


PERMY   5    1 1 1 8 1 35 /

PERMZ  .5    1 1 1 8 1 35 /


PERMY   5    15 15 1 8 1 35 /

PERMZ  .5    15 15 1 8 1 35 /


PERMZ  .25      15 15 8 8 1 35 /

PERMZ  .25      15 15 1 1 1 35 /

PERMZ  .25      1 1 8 8 1 35 /

PERMZ  .25      1 1 1 1 1 35 /


/
```

```
ROCKCON
--# I1 I2 J1 J2 K1 K2 Dir
 1  1 15  1 8  1  1 K- /                overburden  connections
 2  1 15  1 8 35 35 K+ /                 underburden connections
/

ROCKPROP
--# Temp (F) Cond (Btu/ft/Day/F) Heat capacity (kJ/m3/K)
 1 115      12.5                34  1* N /     overburden  properties
 2 130      12.5                34  1* N /     underburden properties
/


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

SWOF
--Sw            Krw       krow       Pcow
 0.450000    0.          1           0
 0.500000    0.001134    0.7         0
 0.550000    0.006415    0.45        0
```

0.600000	0.017678	0.25	0
0.650000	0.036289	0.12	0
0.700000	0.063394	0.05	0
0.750000	0.1	0.0	0
1.00000	0.4	0.0	0

/

SLGOF

--SL	krg	krog	Pcog
.5	1	0	0
.55	.4	0	0
.6	.33	0.03	0
.65	.28	0.09	0
.7	.2	0.13	0
.75	.15	0.21	0
.8	.1	0.32	0
.85	.06	0.45	0
.9	.02	0.60	0
.98	0	0.80	0
1	0	1.00	0

/

```
-- Stone 3-phase oil rel perm

STONE


-- Component gas viscosities

GASVISCT

--temp  visc

100  .0112  1

200  .0128  1

300  .0145  1

550  .016   1

/


-- Relative permeability endpoints vs temperature (deg F)

ENKRVT

-- temp Krwmax Krgmax Kromax Krwro  Krgro Krorg Krorw

   100  1*     1*     1*     0.1     1*    1*    1*

   200  1*     1*     1*     0.1     1*    1*    1*

   400  1*     1*     1*     0.1     1*    1*    1*

   600  1*     1*     1*     0.1     1*    1*    1*     /
```

```
-- Saturation endpoints vs temperature (deg F)

ENPTVT

-- temp  Swc  Swir  Swmax  Sgc  Sgr  Sgmax  Sorw  Sorg

   100   0.45 0.45  1*     1*   1*   1*     0.25   0.10

   200   0.50 0.50  1*     1*   1*   1*     0.20   0.08

   400   0.55 0.55  1*     1*   1*   1*     0.15   0.07

   600   0.60 0.60  1*     1*   1*   1*     0.10   0.05 /


-- Component oil phase viscosities cp

OILVISCT

 60  1046    1046

120   185     185

180    55      55

200    23.9    23.9

250    10.8    10.8

300     6      6.0

350     3.8    3.8

400     2.64   2.64

450     1.96   1.96

500     1.53   1.53

550     1.25   1.25

/
```

```
-- Crookston K-value coefficients
-- Propane

KVCR
--   SGAS  HEAVY
     3.167  1*
   170447    1*
     0      1*
    3062     1*
     0      1*
/

-- Heats of vapourisation Btu/lb
HEATVAP
350  0.0 /

-- Critical temperatures deg R
TCRIT
358 10000 /

-- Critical pressures psia
```

PCRIT

666.37 1* /

-- Component reference densities in oil phase lb/ft**3

DREF

58.5 58.5 /

-- Component compressibilities in oil phase 1/psi

CREF

0.00002 5.0E-06 /

-- Component specific heats Btu/lb/deg R

SPECHA

0.52 0.432 /

CNAMES

SGAS HEAVY /

MW

30.07 600 /

-- Thermal expansion coefficients 1/deg R

```
THERMEX1
.00035 .000315 /

-- oil component gas phase compressibilities 1/psi
ZFACTOR
0.95 /

-- Surface density of oil phase - lb/ft**3
DENSITY
59.0 /

-- Water properties
PVTW
--  Pref     Bw      Cw       Vw      Cvw
--  PSIA     RB/STB  1/PSI    CPOISE  1/PSI
    75.000   1.0     3.E-08   .3      7.E-09
 /

-- Ref press  rock compressibility
-- psia      1/psi
ROCK
100  7.0E-05  /
```

```
-- global mole fraction vs depth

ZMFVD

800 0.05 0.95 /


REGIONS


EQLNUM

4200*1 /


------------------------------------------------------------------------------

SOLUTION

------------------------------------------------------------------------------

EQUIL

--depth  psi  WOC cap_press  GOC  cap_p NA   NA  9    10

   800  550  2000    0       100     0   1*  1*  -10   1* /



TEMPVD

800   115

1050  130/
```

```
-- Output to print file

RPTSOL

PRES SOIL SGAS SWAT TEMP YMF XMF /


-- Output to restart file

RPTRST

PRES SOIL SGAS SWAT TEMP /


------------------------------------------------------------------------------

SUMMARY

------------------------------------------------------------------------------


-- Field vectors

FWIR

FWIT

FHLT

FOPR

FOPT

FWPR

FWPT

FGPR
```

```
FGPT

FSTPR

FPRP

FOE

FOIP



-- Performance data


PERFORMANCE


-- Run summary file


RUNSUM


-------------------------------------------------------------------------------

RPTONLY

SCHEDULE

-------------------------------------------------------------------------------

CVCRIT

 1* 15 6* 2 /
```

```
--RPTPRINT
-- 1 1 0 0 0  1 1 1 0 0 /
RPTSCHED
  TEMP  PRES  SOIL  SWAT  SGAS VOIL VGAS VWAT /
RPTRST
PRES TEMP SOIL SGAS SWAT VOIL VGAS VWAT /

WELSPECS
 SCYCI FIELD 1 1 1* LIQ /
 SCYCP FIELD 1 1 1* LIQ /
/

COMPDAT
-- 4 1/2 " diameter from Carpenter
--     I J K1 K2 ...  ... T   Diam   Kh Skin D  Dir Ro
 SCYCI  1 1 1 35 OPEN 1*  1*  0.375  1* 1*   1* 1*  1* /
--
 SCYCP  1 1 1 35 OPEN 1*  1*  0.375  1* 1*   1* 1*  1* /
/

WPIMULT
 SCYCI 0.25 /
```

```
 SCYCP 0.25 /
/

--TSCRIT
--initT    minT   maxT maxInc/Dec targTTE maxTTE TTPT MTPT TSCT MxWT
--   .05   0.0001  2   1.25   1*      1*     1*     1*  1*  1*  0.2 /

----------------- Cycle 1

WCONINJE
--Well  Type  ...   Init Rate  Res BHP
  SCYCI WATER OPEN  RATE 100.0 1*  1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
```

```
8*1 /


WELOPEN
 SCYCI  SHUT /
/

TSTEP
3*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
15*1 /

WELOPEN
 SCYCP  SHUT /
/
```

```
--------------------------- Cycle 2

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /

/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
8*1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
```

```
3*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
32*1 /

WELOPEN
 SCYCP  SHUT /
/



-------------------------- Cycle 3

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/
```

```
WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
4*1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
32*1 /
```

```
WELOPEN
 SCYCP  SHUT /
/

-------------------------- Cycle 4

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3*1 /

WELOPEN
 SCYCI  SHUT /
```

```
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
33*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 5

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
```

```
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3*1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/
```

```
TSTEP
34*1 /

WELOPEN
 SCYCP  SHUT /
/

------------------------------ Cycle 6

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3*1 /
```

```
WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
40*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 7

WCONINJE
```

```
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3*1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
```

```
/

TSTEP
40*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 8

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
```

```
3*1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
40*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 9
```

```
WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3*1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
```

```
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
35*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 10

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/
```

```
TSTEP
3*1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
35*1 /

WELOPEN
 SCYCP  SHUT /
/
```

```
----------------------------- Cycle 11

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /
```

```
WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
33*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 12

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/

WINJTEMP
--Well  SQ   T(F)
```

```
  SCYCI 0.8  500.0  /
/

TSTEP
3.1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
32*1 /

WELOPEN
```

```
 SCYCP  SHUT /
/

----------------------------- Cycle 13

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.2 /

WELOPEN
 SCYCI  SHUT /
/
```

```
TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
31*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 14

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/
```

```
WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.2 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
32*1 /
```

```
WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 15

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3*1 /

WELOPEN
 SCYCI  SHUT /
```

```
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
32*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 16

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
```

```
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.2 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/
```

```
TSTEP
32*1 /

WELOPEN
 SCYCP  SHUT /
/

------------------------------ Cycle 17

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.1 /
```

```
WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
32*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 18

WCONINJE
```

```
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3*1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
```

```
/

TSTEP
35*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 19

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
```

```
3.1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
32*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 20
```

```
WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
```

```
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
32*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 21

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/
```

```
TSTEP
3.1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
32*1 /

WELOPEN
 SCYCP  SHUT /
/
```

```
----------------------------- Cycle 22

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /
```

```
WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
32*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 23

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/

WINJTEMP
--Well  SQ   T(F)
```

```
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
35*1 /

WELOPEN
```

```
 SCYCP  SHUT /
/
----------------------------- Cycle 24

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
```

```
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
30*1 /

WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 25

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/

WINJTEMP
--Well  SQ   T(F)
```

```
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
31*1 /

WELOPEN
```

```
 SCYCP  SHUT /
/
---------------------------- Cycle 26

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
```

```
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
33*1 /

WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 27

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
```

```
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
35*1 /

WELOPEN
```

```
 SCYCP  SHUT /
/

----------------------------- Cycle 28

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/
```

```
TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
37*1 /

WELOPEN
 SCYCP  SHUT /
/
------------------------------ Cycle 29

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/

WINJTEMP
```

```
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
34*1 /
```

```
WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 30

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/
```

```
TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
34*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 31

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/
```

```
WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
33*1 /
```

```
WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 32

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.2 /

WELOPEN
 SCYCI  SHUT /
/
```

```
TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
35*1 /

WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 33

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/
```

```
WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.2 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
33*1 /
```

```
WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 34

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/
```

```
TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
33*1 /

WELOPEN
 SCYCP  SHUT /
/

----------------------------- Cycle 35

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/
```

```
WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
```

```
33*1 /

WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 36

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
```

```
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
33*1 /

WELOPEN
 SCYCP  SHUT /
/
------------------------------ Cycle 37

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/
```

```
WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
```

```
33*1 /

WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 38

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
```

```
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
33*1 /

WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 39

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*  1550 /
/
```

```
WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
```

```
34*1 /

WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 40

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
```

```
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
34*1 /

WELOPEN
 SCYCP  SHUT /
/
------------------------------ Cycle 41

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/
```

```
WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
```

```
34*1 /

WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 42

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
```

```
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
34*1 /

WELOPEN
 SCYCP  SHUT /
/
------------------------------ Cycle 43

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/
```

```
WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
```

```
36*1 /

WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 44

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
```

```
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
36*1 /

WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 45

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/
```

```
WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
```

```
33*1 /

WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 46

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
```

```
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
33*1 /

WELOPEN
 SCYCP  SHUT /
/
------------------------------ Cycle 47

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/
```

```
WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
```

```
33*1 /

WELOPEN
 SCYCP  SHUT /
/
----------------------------- Cycle 48

WCONINJE
--Well  Type  ...   Init Rate  Res BHP  THP
  SCYCI WATER OPEN  RATE 100.0  1*   1550 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
3.3 /

WELOPEN
 SCYCI  SHUT /
```

```
/

TSTEP
2*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
39*1 /

WELOPEN
 SCYCP  SHUT /
/
END
```

APPENDIX B

Deviated Well Case Difference

```
SCHEDULE

-----------------------------------------------------------------------------

CVCRIT
 1* 15 6* 2 /


--RPTPRINT
-- 1 1 0 0 0  1 1 1 0 0 /
RPTSCHED
  TEMP  PRES  SOIL  SWAT  SGAS VOIL VGAS VWAT /
RPTRST
PRES TEMP SOIL SGAS SWAT VOIL VGAS VWAT /


WELSPECS
 SCYCI FIELD 1 1 1* LIQ /
 SCYCP FIELD 1 1 1* LIQ /
 TEST  FIELD 1 1 1* LIQ /
/


COMPDAT
--      I J K1 K2 ...  ... T   Diam   Kh Skin D  Dir Ro
```

```
 SCYCI  1 1 1 35 OPEN 1*  1*  0.375  1* 1*   1* 1*  1* /
--
 SCYCP  1 1 1 35 OPEN 1*  1*  0.375  1* 1*   1* 1*  1* /
--
 TEST  15 1 1 35 OPEN 1*  1*  0.375  1* 1*   1* 1*  1* /
/

WPIMULT
 SCYCI 0.25 /
 SCYCP 0.25 /
 TEST  0.25 /
/

----------------- Cycle 1

WCONINJE
--Well  Type  ...   Init Rate  Res BHP
  SCYCI WATER OPEN  RATE 100.0 1*  1550 /
/

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
```

```
  TEST OPEN LRAT 1*  1*  1*  300 1* 330 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/



TSTEP
8*1 /



WELOPEN
 SCYCI  SHUT /
/

TSTEP
3*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
```

```
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
15*1 /

WELOPEN
 SCYCP  SHUT /
/
```

APPENDIX C

Deviated Well With Artificial Lift Case Difference

```
SCHEDULE

-------------------------------------------------------------------------------

CVCRIT

 1* 15 6* 2 /


RPTSCHED

  TEMP  PRES  SOIL  SWAT  SGAS VOIL VGAS VWAT /

RPTRST

PRES TEMP SOIL SGAS SWAT VOIL VGAS VWAT /


WELSPECS

 SCYCI FIELD 1 1 1* LIQ /

 SCYCP FIELD 1 1 1* LIQ /

 TEST  FIELD 1 1 1* LIQ /

/


COMPDAT

--      I J K1 K2 ...  ... T   Diam   Kh Skin D  Dir Ro

 SCYCI  1 1 1 35 OPEN 1*  1*  0.375  1* 1*   1* 1*  1* /

--
```

```
 SCYCP  1 1 1 35 OPEN 1*  1*  0.375  1* 1*   1* 1*  1* /
--
 TEST  15 1 1 35 OPEN 1*  1*  0.375  1* 1*   1* 1*  1* /
/

WPIMULT
 SCYCI 0.25 /
 SCYCP 0.25 /
 TEST  0.25 /
/

----------------- Cycle 1

WCONINJE
--Well  Type  ...   Init Rate  Res BHP
  SCYCI WATER OPEN  RATE 100.0 1*  1550 /
/

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  TEST OPEN LRAT 1*  1*  1*  300 1* 101 /
/
```

```
WINJTEMP

--Well  SQ   T(F)

  SCYCI 0.8  500.0  /

/

TSTEP

8*1 /

WELOPEN

 SCYCI  SHUT /

/

TSTEP

3*1 /

WCONPROD

--Well  ...  Init Oil Wat Gas Liq Res BHP

  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /

/
```

```
TSTEP
15*1 /

WELOPEN
 SCYCP  SHUT /
/
```

APPENDIX D

Horizontal Well Case Difference

```
SCHEDULE
-----------------------------------------------------------------------------
CVCRIT
 1* 15 6* 2 /


--RPTPRINT
-- 1 1 0 0 0  1 1 1 0 0 /
RPTSCHED
  TEMP  PRES  SOIL  SWAT  SGAS VOIL VGAS VWAT /
RPTRST
PRES TEMP SOIL SGAS SWAT VOIL VGAS VWAT /


WELSPECS
 SCYCI FIELD 1 1 1* LIQ /
 SCYCP FIELD 1 1 1* LIQ /
 TEST  FIELD 1 1 1* LIQ /
/


COMPDAT
--     I J K1 K2 ...  ... T   Diam   Kh Skin D  Dir Ro
```

```
 SCYCI  1 1 1 35 OPEN 1*  1*  0.375  1* 1*   1* 1*  1* /
--
 SCYCP  1 1 1 35 OPEN 1*  1*  0.375  1* 1*   1* 1*  1* /
--
 TEST  15 1 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 2 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 3 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 4 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 5 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 6 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 7 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 8 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
/

WPIMULT
 SCYCI 0.25 /
 SCYCP 0.25 /
 TEST  0.25 /
/

--TSCRIT
--initT    minT   maxT maxInc/Dec targTTE maxTTE TTPT MTPT TSCT MxWT
```

```
--   .05   0.0001  2   1.25   1*      1*     1*     1*  1*  1*  0.2 /

----------------- Cycle 1

WCONINJE
--Well  Type  ...   Init Rate  Res BHP
  SCYCI WATER OPEN  RATE 100.0 1*  1550 /
/

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  TEST OPEN LRAT 1*  1*  1*  300 1* 290 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
8*1 /
```

```
WELOPEN
 SCYCI  SHUT /
/

TSTEP
3*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
15*1 /

WELOPEN
 SCYCP  SHUT /
/
```

APPENDIX E

Horizontal Well With Artificial Lift Case Difference:

```
SCHEDULE
-------------------------------------------------------------------------------
CVCRIT
 1* 15 6* 2 /


--RPTPRINT
--  1 1 0 0 0   1 1 1 0 0 /
RPTSCHED
  TEMP  PRES  SOIL  SWAT  SGAS VOIL VGAS VWAT /
RPTRST
PRES TEMP SOIL SGAS SWAT VOIL VGAS VWAT /


WELSPECS
 SCYCI FIELD 1 1 1* LIQ /
 SCYCP FIELD 1 1 1* LIQ /
 TEST  FIELD 1 1 1* LIQ /
/


COMPDAT
-- 4 1/2 " diameter from Carpenter
```

```
--      I J K1 K2 ...  ... T    Diam   Kh Skin D  Dir Ro
 SCYCI  1 1 1 35 OPEN 1*  1*  0.375  1* 1*   1* 1*  1* /
--
 SCYCP  1 1 1 35 OPEN 1*  1*  0.375  1* 1*   1* 1*  1* /
--
 TEST  15 1 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 2 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 3 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 4 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 5 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 6 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 7 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
 TEST  15 8 20 20 OPEN 1*  1*  0.375  1* 1*   1* X   1* /
/

WPIMULT
 SCYCI 0.25 /
 SCYCP 0.25 /
 TEST  0.25 /
/

--TSCRIT
```

```
--initT    minT   maxT maxInc/Dec targTTE maxTTE TTPT MTPT TSCT MxWT
--   .05   0.0001  2   1.25   1*      1*     1*     1*  1*  1*  0.2 /

----------------- Cycle 1

WCONINJE
--Well  Type  ...   Init Rate  Res BHP
  SCYCI WATER OPEN  RATE 100.0 1*  1550 /
/

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  TEST OPEN LRAT 1*  1*  1*  300 1* 101 /
/

WINJTEMP
--Well  SQ   T(F)
  SCYCI 0.8  500.0  /
/

TSTEP
```

```
8*1 /

WELOPEN
 SCYCI  SHUT /
/

TSTEP
3*1 /

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP
  SCYCP OPEN LRAT 1*   1*  1* 300 1* 290 /
/

TSTEP
15*1 /

WELOPEN
 SCYCP  SHUT /
/
```

VITA

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