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PE 357- PETROLEUM PRODUCTION ENGINEERING I

PRODUCTION MODELLING PROJECT WORK

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EXECUTIVE SUMMARY

Project Overview: TRENCH Oil Company has discovered the JARVIS Oilfield off the coast of Tanzania, with substantial reserves estimated at over 390 million barrels, potentially reaching 2.0 billion barrels. The field's reservoir, situated at a water depth of 1,100 ft., presents an opportunity for offshore production using a floating, production, storage, and offloading (FPSO) vessel. The development plan entails the drilling of four production wells to tap into the field's resources.

Objective: This report outlines the well planning strategy devised by TRENCH's team for the JARVIS field development. The primary goal is to design four production wells capable of efficiently extracting oil from two distinct layers within the reservoir.

Approach: The well planning team has adopted a comprehensive approach to address the specific challenges and opportunities presented by the JARVIS Oilfield. Each aspect of well planning, from initial tubing size selection to completion configuration and sensitivity analyses, is meticulously considered to ensure maximum productivity and longevity of the production wells.

Key Considerations:

1. **Reservoir Dynamics:** Understanding the complex reservoir characteristics, including the presence of under-saturated oil in multiple layers, is crucial for optimizing production strategies.

2. **Technical Configuration:** The selection of optimal completion configurations and equipment is paramount to ensure efficient oil recovery while maintaining operational integrity.

3. **Operational Flexibility:** Given the offshore location, careful consideration of transportation logistics for oil, gas, and water disposal is essential for seamless operations.

4. **Long-Term Sustainability:** With a planned 20-year production lifespan, emphasis is placed on implementing strategies to mitigate risks and ensure the longevity and profitability of the production wells.

Tasks and Analysis: The report encompasses a range of analyses and sensitivities, including production tubing size optimization, gas-liquid ratio sensitivity, water cut sensitivity, reservoir depletion analysis, skin factor sensitivity, and wellhead pressure sensitivity. Each analysis provides valuable insights into optimizing production performance and addressing potential challenges throughout the field's lifespan.

INTRODUCTION

The JARVIS Oilfield, discovered by TRENCH Oil Company off the coast of Tanzania, holds significant promise for oil production. With vast reserves waiting to be tapped, TRENCH Oil Company is poised to embark on the development of this valuable resource. The field's recoverable reserves are estimated to be more than 390 million barrels, with an upside potential of 2.0 billion barrels. In anticipation of the field's development, TRENCH Oil Company plans to employ FPSO vessel for field production and processing, with stored oil transported to an onshore facility for further treatment and sales. This strategic choice allows for efficient handling of extracted oil, ensuring operational efficiency and maximizing the potential of the JARVIS Oilfield.

The purpose of this report is to outline the strategic approach undertaken by TRENCH's well planning team in designing the production wells for the JARVIS Oilfield. Our objective is to ensure efficient extraction of oil while considering the unique challenges posed by offshore drilling.

In addition to introducing the background of the oilfield, our report will delve into the various analyses and sensitivities to be conducted. These include:

- Initial production tubing size analysis: Evaluating the performance of each well under different tubing sizes to determine the optimal size for maximum productivity.
- Completion configuration: Designing the completion configuration for each well and justifying equipment selection based on reservoir characteristics and operational requirements.
- Gas-Liquid Ratio (GLR) sensitivity analysis: Assessing the impact of changing GLR on production rates and bottom hole pressures for each layer and combined production.
- Water Cut (WC) sensitivity analysis: Investigating the effects of increasing water production on well performance and recommending strategies to mitigate water breakthrough.
- Reservoir depletion sensitivity analysis: Analyzing the impact of reservoir depletion on production performance and determining abandonment pressures for each well.
- Skin factor sensitivity analysis: Evaluating the effect of formation damage on productivity and identifying wells in need of stimulation via matrix acidizing.
- Wellhead pressure sensitivity analysis: Assessing the influence of wellhead pressure on performance and recommending optimal pressure settings for downstream equipment requirements.

- By conducting these analyses and sensitivities, we aim to optimize production efficiency, mitigate risks, and ensure the long-term success of the JARVIS Oilfield development project.

METHODOLOGY

The development of the JARVIS Oilfield demands a meticulous approach to well planning, considering the unique challenges and opportunities inherent in offshore exploration.

In addition to conventional methods, the team employed a novel approach in their sensitivity analysis. We utilized the Darcy Reservoir model to gain insights into the individual performance of each well in the various layers of the reservoir. Furthermore, we utilized a multilayer pressure loss model for tasks involving simultaneous analysis of multiple wells, providing a holistic view of each well's contribution to overall production, while also accounting for the pressure reduction due to shale layer in between during simultaneous production from the two reservoir layers.

By integrating these analytical techniques alongside traditional methodologies, TRENCH Oil Company is well-equipped to navigate the complexities of the JARVIS Oilfield and optimize production efficiency over its anticipated lifespan.

Additionally, after gathering data for each well scenario using IPM Prosper software, we performed further analysis using computer programming in Python. This allowed us to generate comprehensive graphs, gain insights into trends, and provide explanations for observed phenomena. Moreover, it facilitated the justification of decisions made during the well optimization process.

RESULTS AND DISCUSSION

a. IPR and TPR Base case

PI serves as a key indicator of a well's efficiency in delivering fluids from the reservoir to the surface per unit pressure drop. It quantifies the well's ability to produce fluids under specific bottomhole pressure conditions, offering insights into its inherent reservoir properties and productivity potential. A higher PI suggests that the well can maintain or increase production rates with minimal pressure drawdown, indicating favorable reservoir characteristics and efficient fluid flow pathways.

On the other hand, AOF represents the maximum achievable flow rate of the well under natural flowing conditions, providing a crucial benchmark for assessing its ultimate productivity potential. It reflects the combined influence of reservoir properties, wellbore configuration, and fluid dynamics on the well's capacity to deliver fluids to the surface without artificial lift assistance. A higher AOF signifies greater reservoir deliverability and overall production potential.

Considering both PI and AOF allows for a comprehensive evaluation of well performance, accounting for both efficiency (PI) and maximum capacity (AOF). By comparing these metrics across different wells, we can identify the most productive and resilient assets within a field.

Based on the provided data and analysis, the ***Gamma well*** emerges as the best-performing well under the base case of 4.67 inches ID production tubing. With the highest combined AOF and relatively high PIs for both layers compared to other wells, the Gamma well demonstrates superior productivity potential and resilience to varying bottomhole pressures.

The completion configuration for each well was designed to maximize production efficiency and operational safety. A packer was placed at the end of Layer 1 to ensure zonal isolation, while tubing extends into Layer 2 for continued production. This tubing-annulus approach facilitates efficient fluid recovery. Additionally, a Surface Safety Shutdown Valve (SSSV) was included to enhance safety by enabling immediate shutdown of production flow in emergencies.

Well	Layer	Matched PVT Correlation	PI	Qo (STB/D)	Qg (MMSCF/D)	Qw (STB/D)	Pwf (Psia)	AOF (STB/D)
Alpha	1	Vasquez, Egbogah	57.47	23612.2	2.361	1242.7	5031.17	121091.8
	2	Petrosky et al Beggs et al	64.89	36559.2	7.312	1924.2	6148.47	205176.1
	1+2	Glaso Beal et al	60.45	32168.6	4.256	1693.1	4953.38	154857.2
Beta	1	Vasquez, Egbogah	77.71	26480.3	2.648	1393.7	5166.77	226721.5
	2	Lasater Egbogah	72.87	33395.6	6.679	1757.7	6269.76	214101.8
	1+2	Glaso Beal et al	44.41	28165.3	3.747	1482.4	4988.35	139850.7
Delta	1	Vasquez, Egbogah	78.71	25338.8	2.534	1333.6	5088.58	193143.6
	2	Lasater, Egbogah	78.02	35399.5	7.080	1863.1	6052.48	179575.5
	1+2	Glaso Beal et al	77.90	30256.3	3.908	1592.4	4884.69	177268.6
Gamma	1	Vasquez, Egbogah	68.09	26370.6	2.637	1387.9	5257.24	285897.9
	2	Vazquez-Beggs , Egbogah et al	56.97	19057.0	1.906	1003.0	6476.55	184478.6
	1+2	Glaso Beal et al	36.48	35989.1	3.599	1894.2	5787.66	133932.3

Table 1.Summary of results for the natural flowing well with assumed tubing size of 4.67 inches

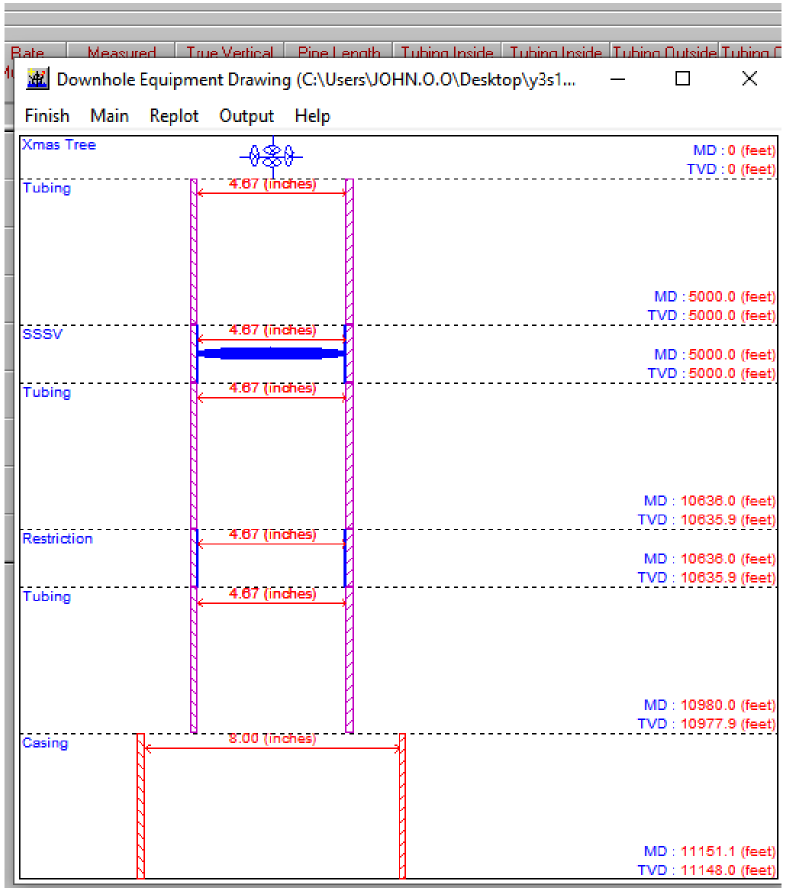


Figure 1. Summary of Downhole

b. Production Tubing Sensitivity

Well	Initial tubing size (inch)	Tubing size 1 (inch)	Tubing size 2 (inch)	Tubing size 3 (inch)	Tubing size 4 (inch)
Alpha	3.5	4.125	4.75	5.5	6
Beta	3.5	4.0	4.5	5.5	6
Delta	3.5	4.0	4.5	5.5	6
Gamma	3.5	4.125	4.75	5.5	6

Table 2.Summary of selected realistic production tubing sizes for each well

The observed trend is an increasing flow rate with increasing tubing diameter, with the worst-case scenario being no flow occurring at a larger tubing size.

The increase in flow rate with increasing tubing size is attributed to reduced frictional losses and improved fluid flow efficiency. As the diameter of the tubing increases, there is a larger cross-sectional area available for fluid flow, resulting in lower flow velocities and reduced frictional pressure losses along the tubing walls. This allows for a greater volume of fluid to be transported through the tubing, leading to higher flow rates.

This phenomenon is well-documented in reservoir engineering literature. For instance, (Terry et al., 2015) explained that larger tubing diameters result in lower frictional losses per unit length, allowing for increased flow rates at a given bottomhole pressure. Additionally, (Guo, 2011) discusses how optimizing tubing size can enhance production rates by minimizing flow restrictions and maximizing fluid flow efficiency.

Figure 2, extracted from the Python notebook "Group7model.ipnyb," illustrates the system analysis plot generated by the program. This plot provides insights into the relationship between tubing diameter, production rate, and bottomhole pressure for each well. The optimal tubing size is determined by the intersection of the two curves, balancing gravity and frictional losses to achieve maximum efficiency

Table 3 Summary of results of optimal conditions for each well

Well	Selected Tubing size (inch)	Layer	Qo (STB/D)	Qg (MMSCF/D)	Qw (STB/D)	Pwf (Psia)
Alpha	4.75	1	24259.4	2.426	1276.8	5007.50
		2	37895.8	7.579	1994.5	6108.13
		1+2	32861.7	4.257	1693.1	4953.38
Beta	4.5	1	24581.7	2.458	1293.8	5212.28
		2	30813.0	6.193	1621.7	6345.71
		1+2	28165.3	3.747	1482.4	4988.35
Delta	4.67	1	25338.8	2.534	1333.6	5088.58
		2	35399.5	7.080	1863.1	6052.48
		1+2	30256.3	3.908	1592.4	4884.69
Gamma	4.5	1	24474.9	2.447	1288.2	5296.36
		2	33342.4	3.334	1754.9	5895.4
		1+2	27821.3	3.665	1464.3	4936.74

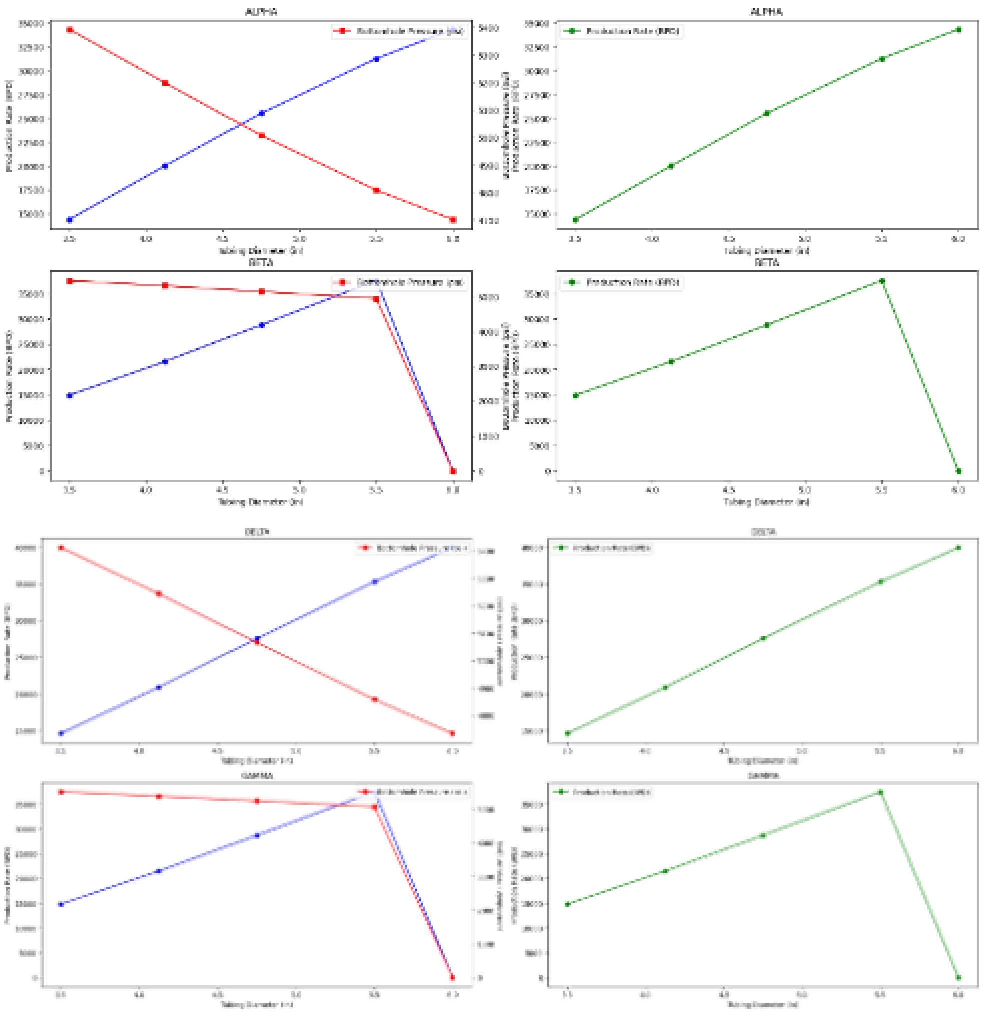


Figure 2. Tubing optimization

b. Gas Liquid Ratio (GLR) Sensitivity

The sensitivity analysis on GLR reveals a consistent trend across all wells: as GLR increases, flow rates decrease while bottomhole flowing pressures decrease. This trend aligns with expectations as higher gas-to-liquid ratios typically result in reduced flow efficiency and increased backpressure due to gas interference.

As GLR increases, the mixture density decreases owing to the lower gas pressure gradient. Initially, this benefits our wells by reducing holdup. However, at extreme conditions, such as excessively high GLR values, liquid slip occurs, leaving more liquid holdup in the production tube, thereby compromising production efficiency (Guo, 2011).

In the case of the Beta well, vertical lift remains feasible for both layers despite the GLR conditions. This is because the GLR values, although increasing, are not high enough to hinder vertical lift operations. Vertical lift becomes impossible when the gas-to-liquid ratio reaches excessively high levels, causing gas locking and inhibiting the ability to lift fluids to the surface efficiently(El Achkar et al., 2024).

Table 4. Summary of results of the effects of GLR for each well

Well	Layer	GLR 1	Qo1	Pwf 1	GLR2	Qo2	Pwf 2	GLR 3	Qo3	Pwf 3	GLR4	Qo4	Pwf4	GLR5	Qo5	Pwf 5
Alpha	1	50	24839.5	4986.29	100	25750.5	4952.95	200	26775.2	4915.49	400	27326.3	4895.34	600	27108.7	4903.3
	2	50	37376.5	6123.81	100	36893.4	6138.39	200	36076.5	6163.04	400	34848.3	6200.11	600	33381.7	6244.38
	1+2	50	28669.7	4791.98	100	31652.5	4914.90	200	34706.6	5456.6	400	30854.5	5546.87	600	27409.8	5690.35
Beta	1	50	25161.6	5198.38	100	25480.0	5190.75	200	25799.9	5183.08	400	25912.4	5180.38	600	25420.9	5192.16
	2	50	33073.7	6279.23	100	32738.6	6289.08	200	32169.1	6305.83	400	31452	6326.92	600	30401.2	6357.82
	1+2	50	25168.8	4828.22	100	27716.6	4948.51	200	30212.3	5467.12	400	26857.3	5560.53	600	23594.1	5603.66
Delta	1	50	26129.5	5066.33	100	26580.4	5053.65	200	27078.8	5039.62	400	27362.1	5031.65	600	26950.2	5043.24
	2	50	35003.8	6066.58	100	34547.0	6082.85	200	33728.3	6111.97	400	32647.8	6150.26	600	31489.4	6191.20
	1+2	50	26220.1	4687.14	100	29631.7	4838.79	200	33751.1	5553.29	400	30051.3	5678.3	600	26398.0	5747.12
Gamma	1	50	25283.7	5279.67	100	25859.1	5267.80	200	26386.0	5256.92	400	26402.3	5256.58	600	25958.6	5265.74
	2	50	32713.5	5920.93	100	32233.5	5940.46	200	31377.4	5975.29	400	30029.0	6030.15	600	28636.9	6086.79
	1+2	50	24266.2	4738.12	100	27049.0	4862.15	200	30138.3	5452.14	400	26817.9	5549.60	600	23564.6	5592.68

d. Water Cut (WC) Sensitivity

Water production is an inevitable aspect of oil and gas production, leading to eventual breakthrough into wells. The issues arising from water breakthrough are significant, impacting production rates, equipment integrity, and overall field economics. Running sensitivity analyses on water cut with optimum operating conditions as the base case can provide valuable insights.

The observed trend in the provided data shows that as the water cut (WC) increases, the oil production rates (Qo) generally decrease, while bottomhole flowing pressures (Pwf) tend to **increase** as well.

This trend can be attributed to the increasing proportion of water in the production fluid as the water cut rises. As more water is produced along with oil, the overall fluid density decreases, leading to reduced flow rates. Additionally, the presence of water in the reservoir and wellbore exerts less pressure compared to oil, resulting in lower bottomhole flowing pressures.

Furthermore, at higher water cut percentages, there may be instances where no oil production is observed (as indicated by Qo = 0), which contributes to the overall decrease in oil production rates. This can occur when the water cut surpasses a certain threshold, indicating that the reservoir is predominantly producing water rather than oil.

Overall, the trend signifies the impact of increasing water cut on oil production performance, highlighting the importance of managing water production to optimize overall well productivity.

(El Achkar et al., 2024).

To delay water breakthrough for each well, several future actions can be considered. Implementing zonal isolation techniques, such as cement squeeze treatments or mechanical packers, can help isolate water-producing zones and maintain reservoir pressure. Utilizing smart well technologies, like inflow control devices (ICDs) or interval control valves (ICVs), can manage water and oil production from different zones, delaying water breakthrough. Implementing enhanced oil recovery (EOR) techniques, such as polymer flooding or surfactant flooding, can displace and recover more oil, reducing the impact of water breakthrough. Regular monitoring of well performance and reservoir conditions is crucial to detect early signs of water breakthrough and take preventive actions (Ehlig-Economides et al., 1996).

Table 5 Summary of results for water cut

Well	Layer	WC 1	Qo1	Pwf 1	WC 2	Qo2	Pwf 2	WC3	Qo3	Pwf 3	WC4	Qo4	Pwf4	WC5	Qo5	Pwf 5
Alpha	1	10	18334.0	5186.95	15	13280.8	5351.86	20	8213.3	5538.01	25	0	0	30	0	0
	2	10	33525.2	6183.83	15	29439.4	6258.83	20	25621.5	6333.60	25	22042.8	6409.19	30	18602.4	6489.92
	1+2	10	28235	5001.8	15	24575.4	5049.49	20	21148.5	5096.94	25	17924.7	5146.09	30	14870.3	5197.66
Beta	1	10	18764.6	5264.05	15	13419.3	5356.22	20	8128.3	5493.71	25	0	0	30	0	0
	2	10	29698.6	6329.96	15	26212.2	6390.33	20	22909.2	6451.83	25	19781.6	6515	30	16774.4	6582.25
	1+2	10	24720.1	5033.29	15	22883.3	4858.60	20	23250.9	4848.58	25	23607.5	4840.47	30	23948.0	4833.59
Delta	1	10	19075.5	5160.20	15	13391.8	5279.91	20	7818.5	5453.99	25	0	0	30	0	0
	2	10	31510.7	6128.52	15	27881.2	6202.75	20	24468.9	6276.70	25	21248.6	6351.51	30	18177.7	6429.42
	1+2	10	26591.3	4937.93	15	23024.3	4989.91	20	19749.6	5042.87	25	16649.0	5096.82	30	13707.8	5154.73
Gamma	1	10	18497.4	5364.12	15	12906.3	5459.07	20	7193.2	5589.44	25	0	0	30	0	0
	2	10	29401.8	5989.21	15	25766.1	6080.25	20	22388.8	6170.20	25	19233.9	6260.68	30	16241.4	6355.11
	1+2	10	24202.9	4955.34	15	21054.5	5006.57	20	18110.7	5059.22	25	15330.0	5113.01	30	12688.8	5169.83

e. Reservoir depletion Sensitivity

The observed trend in the provided data reveals a consistent decrease in oil production rates as reservoir pressure diminishes. As reservoirs deplete over time, the declining pressure exerts a direct impact on the reservoir's ability to deliver fluids to the surface. Initially, when reservoir pressure is high, fluid flow is facilitated, enabling higher production rates. However, as pressure decreases due to reservoir depletion, the driving force for fluid movement diminishes, leading to reduced flow rates. This phenomenon occurs because the pressure differential between the reservoir and the wellbore decreases, resulting in decreased fluid mobility and ultimately lower production rates. Consequently, the observed trend underscores the critical relationship between reservoir pressure and production performance, highlighting the necessity for ongoing monitoring and management of reservoir depletion to optimize well productivity and maximize hydrocarbon recovery. The abandonment pressure for each layer is determined based on dead well conditions, where no economically viable production is possible due to extremely low pressures (Guo, 2011).

Table 6. Summary of reservoir depletion sensitivity

Well	Layer	PR1	Qo1	Pwf 1	WC1	PR2	Qo2	WC2	Pwf 2	PR 3	WC 3	Qo3	Pwf 3	PR 4	Qo4	Pwf 4	WC 4
Alpha	1	**5511.43**	13894.0	4983.97	10	**5221.36**	2522.9	15	5121.23	**4931.28**	20	0	0	**4641.21**	0	0	25
	2	**6961.81**	31863.4	5986.61	10	**6671.74**	26081.2	15	5860.68	**6381.66**	20	20444.3	5734.12	**6091.59**	14713.1	5615.55	25
	1+2	**d20**	26799.5	4811.34	10	**d40**	21651.9	15	4656.16	**d60**	20	16631.3	4489.1	**d80**	11679.7	4309.16	25
Beta	1	**5511.43**	15751.9	5065.56	10	**5221.36**	5080	15	5056.39	**4931.28**	20	0	0	**4641.21**	0	0	25
	2	**6961.81**	27978.4	6100.81	10	**6671.74**	22807.3	15	5939.9	**6381.66**	20	17747	5785.6	**6091.59**	12604.5	5644.29	25
	1+2	**D20**	23447.7	4839	10	**D40**	18940	15	4677.34	**D60**	20	15797.5	4368.18	**D80**	10239	4317.68	25
Delta	1	**5511.43**	15862.5	4984.39	10	**5221.36**	4440.8	15	5052.08	**4931.28**	20	0	0	**4641.21**	0	0	25
	2	**6961.81**	29912.7	5910.86	10	**6671.74**	24728.5	15	5768.46	**6381.66**	20	19760.6	5629.11	**6091.59**	14881.6	5499.0	25
	1+2	**D20**	25184.2	4760.05	10	**D40**	20275.4	15	4619.83	**D60**	20	15426.1	4465.35	**D80**	10542.3	4299.26	25
Gamma	1	**5511.43**	14801.4	5149.83	10	**5221.36**	2345.3	15	5155.30	**4931.28**	20	0	0	**4641.21**	0	0	25
	2	**6961.81**	30695.9	5743.93	10	**6671.74**	25655.6	15	5682.79	**6381.66**	20	20767.2	5607.52	**6091.59**	15887.4	5522.23	25
	1+2	**D20**	23153.8	4797.85	10	**D40**	18675.7 4646.57	15	4646.57	**D60**	20	14292.8	4482.5	**D80**	9959.4	4306.5	25

f. Skin factor sensitivity

The sensitivity analysis on formation damage reveals varying impacts on production rates across different layers. Negative values of S indicate increased formation damage, resulting in decreased production rates and higher bottomhole flowing pressures. Positive values of S indicate reduced formation damage, leading to improved production rates and lower bottomhole flowing pressures. Layers with lower values of S generally exhibit higher production rates and lower bottomhole pressures, indicating lesser formation damage and better reservoir connectivity.

The well that is most suitable for stimulation via matrix acidizing is determined by considering both the formation damage, indicated by the negative value of S, and the potential for production improvement. The well with the highest formation damage, denoted by the most negative value of S, typically exhibits the greatest potential for enhanced productivity through stimulation. Additionally, among wells with the same least skin factor, the one demonstrating the highest production rates under optimal conditions serves as a crucial factor in justifying the choice. From the data provided, Well Beta (S2 = -2) meets the criteria outlined. This approach ensures that the selected well not only suffers from significant formation damage but also possesses the capacity for substantial production enhancement, thereby maximizing the effectiveness of the stimulation treatment.

Table 7. Summary of Skin

Well	Layer	S1	Qo1	Pwf 1	S2	Qo2	Pwf 2	S3	Qo3	Pwf 3	S4	Qo4	Pwf4	S5	Qo5	Pwf 5
Alpha	1	-4	35681.3	5892.44	-2	32103.5	5599.66	1	27450.3	5266.61	5	22491.5	4969.51	8	19556.6	4822.50
	2	-4	0	0	-2	0	0	1	0	0	5	37895.8	421.14	8	35811.6	404.80
	1+2	-4	35199.8	5541.68	-2	34905.6	5380.89	1	33691.1	5166.01	5	31869.8	4914.33	8	30517.1	4746.77
Beta	1	-4	29623.4	5646.72	-2	28402.5	5534.79	1	26679.4	5384.27	5	24581.7	5212.28	8	23141.6	5102.20
	2	-4	0	0	-2	37843.2	6892.25	1	36110.2	6639.17	5	33924.3	6338.62	8	32386.3	6138.28
	1+2	-4	30702.0	5566.24	-2	30489	5426.27	1	29652.1	5234.8	5	28278.9	5006.53	8	27234.4	4852.3
Delta	1	-4	32484.5	5631.77	-2	31014.9	5510.26	1	28960.7	5348.59	5	26480.3	5166.77	8	24792.4	5052.32
	2	-4	0	0	-2	0	0	1	0	0	5	36907.8	6255.87	8	353399.5	6052.48

	1+2	-4	34635.5	5717.61	-2	34223.1	5522.28	1	33030.4	5247.48	5	31257.8	5021.23	8	29966.9	4845.33
Gamma	1	-4	29387.7	5680.25	-2	28326.7	5591.08	1	26800.5	5469.65	5	24916.7	5328.39	8	23613.8	5236.15
	2	-4	0	0	-2	0	0	1	36796.1	445.08	5	34454.1	418.42	8	32803.3	400.81
	1+2	-4	30701.2	5566.07	2	30488.9	5426.75	1	30266.4	536059	5	28279.1	5006.56	8	27234.5	4852.30

g. Wellhead pressure sensitivity

It's observed that increasing the wellhead pressure leads to a reduction in production rates for each well across all layers. This trend is consistent with the principles of reservoir engineering, where higher wellhead pressures impose greater backpressure on the reservoir, hindering fluid flow towards the wellbore. As the wellhead pressure increases, the pressure differential between the reservoir and the wellbore decreases, diminishing the driving force for fluid production. Consequently, production rates decrease, and bottomhole flowing pressures increase, indicating reduced well performance. However, the degree of production decline varies among wells and layers due to variations in reservoir properties and completion designs. Therefore, to optimize production while meeting operational requirements, the recommended wellhead pressure for downstream equipment requiring a pressure of 50 psia should be carefully selected to balance the trade-off between maximizing production and maintaining operational constraints. Further analysis in the python notebook.

Table 8. Summary of wellhead

Well	Layer	Pwh1	Qo1	Pwf 1	Pwh 2	Qo2	Pwf 2	Pwh 3	Qo3	Pwf 3	Pwh 4	Qo4	Pwf 4
Alpha	1	100	28074.6	4867.97	200	26982.3	4907.92	300	25845.5	4949.49	400	24698.6	4991.44
	2	100	31207.7	6802.75	200	30926.0	6806.8	300	30586.4	6811.69	400	30186.2	6817.45
	1+2	100	34323.9	4889.32	200	33910.1	4901.6	300	33349.5	4918.27	400	32782.2	4935.14
Beta	1	100	28570.2	5116.67	200	27683.8	5137.92	300	26737.9	5160.59	400	25695.9	5185.57

	2	100	35566	6205.93	200	35078.2	6220.27	300	34473.5	6238.06	400	33984.3	6252.45
	1+2	100	30039.4	4926.46	200	29671.4	4938.59	300	29195	4954.33	400	28696.4	4970.8
Delta	1	100	29789.3	4963.36	200	28776.0	4991.87	300	27727.4	5021.37	400	26561.2	5054.19
	2	100	37082.7	5992.28	200	36802.5	6002.32	300	36311.3	6019.92	400	35872.9	6035.61
	1+2	100	32379.1	4818.01	200	31969.1	4830.77	300	31416.5	4848.17	400	30855.9	4865.82
Gamma	1	100	28663.5	5209.9	200	27727.3	5229.24	300	26623.2	5252.02	400	25555.4	5274.06
	2	100	35295.9	5815.86	200	34863.4	5833.46	300	34367.2	5853.65	400	33865.2	5874.07
	1+2	100	29703.0	4870.71	200	29330.8	4883.81	300	28847.1	4900.83	400	28358.6	4918.02

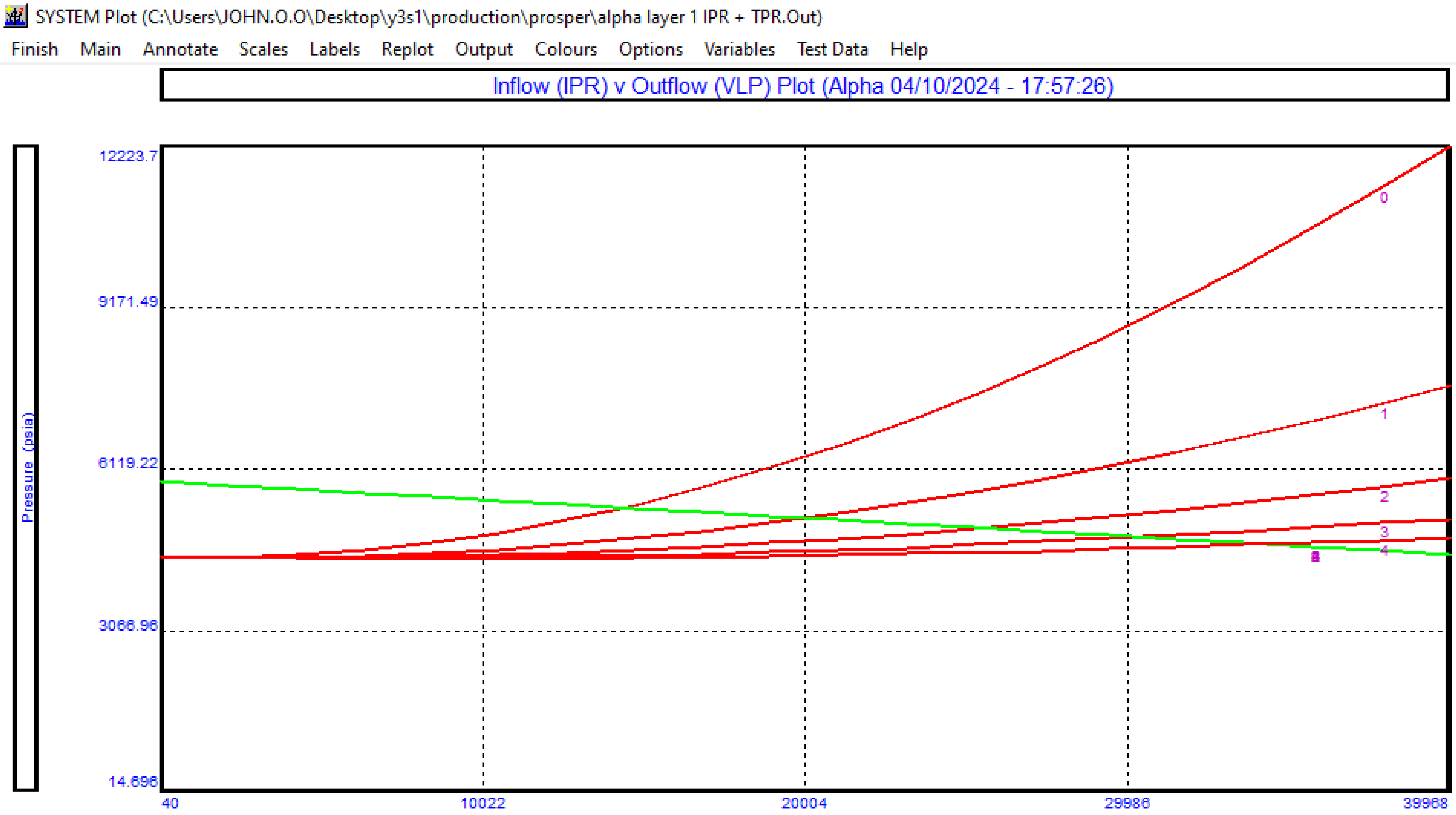
Recommendations and Conclusions

To delay increases in Water Cut (WC) and Gas-Liquid Ratio (GLR) during oil and gas production, various reservoir management and completion techniques are essential. Water injection and gas injection help maintain reservoir pressure, delaying water breakthrough and reducing GLR. Selective completion techniques, like intelligent completions and inflow control devices, enable operators to manage water and gas inflow effectively, thus delaying increases in WC and GLR. Additionally, employing artificial lift methods such as electric submersible pumps (ESPs) and implementing water shut-off techniques in mature fields can further optimize production and delay WC increases. Furthermore, regular well testing and optimized well placement aid in monitoring fluid composition and preventing early water and gas breakthroughs, contributing to sustained reservoir performance.

In conclusion, implementing a combination of reservoir management and completion techniques is crucial for delaying increases in WC and GLR during oil and gas production. Selective completion methods like intelligent completions and inflow control devices play a pivotal role in managing fluid inflow from different zones, while artificial lift and water shut-off techniques help optimize production and delay WC increases. By adopting these measures and ensuring regular monitoring, operators can effectively mitigate the impacts of water and gas breakthrough, maintaining optimal reservoir performance and maximizing oil recovery.

Glossary

Python directory: https://github.com/John-Oleka/Group-7-Sensitivities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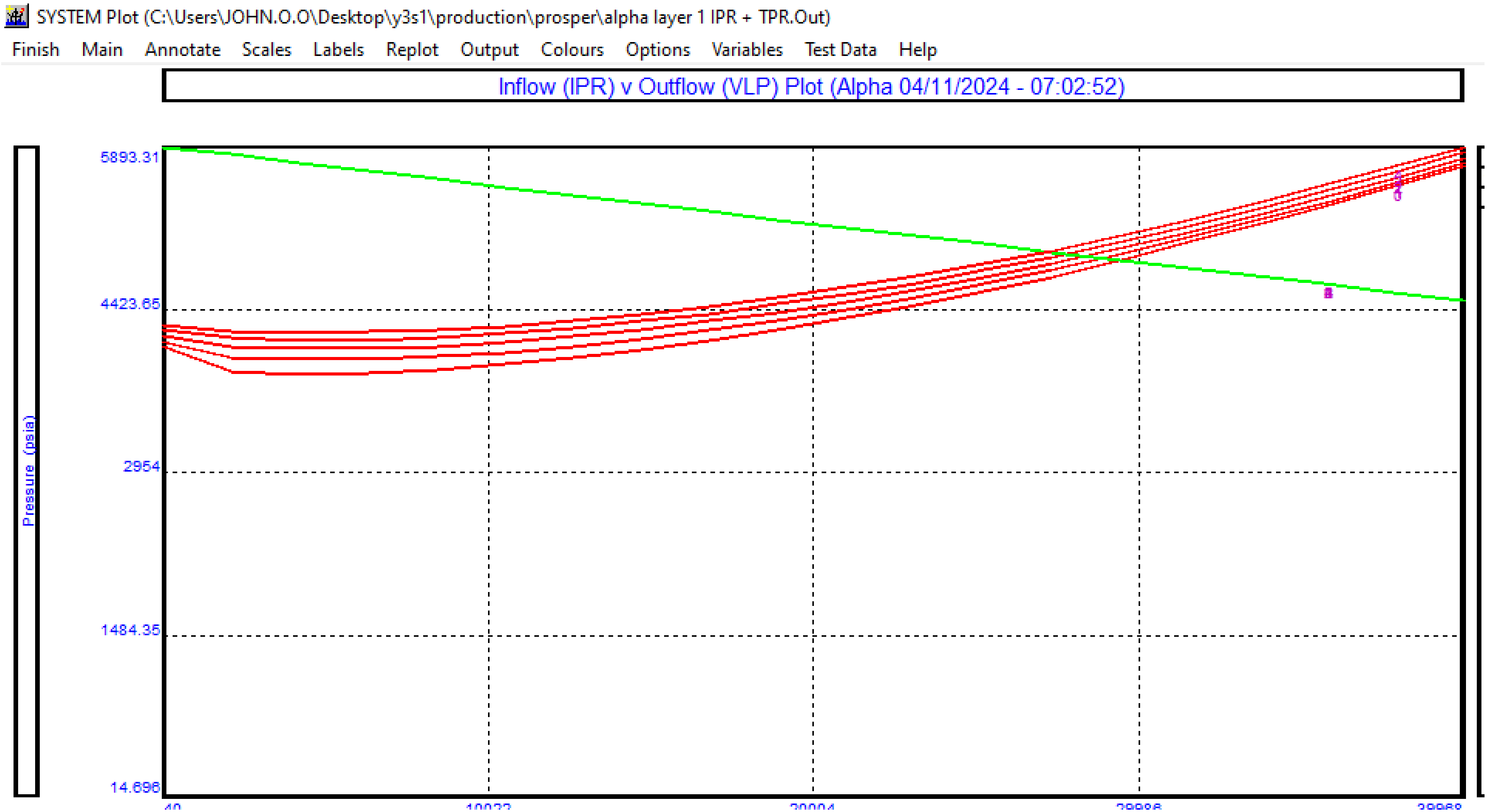
Finish Main Annotate Scales Labels Replot Output Colours Options Variables Test Data Help
Inflow (IPR) v Outflow (VLP) Plot (Alpha 04/10/2024 - 17:57:26)
Pressure (psia)
12223.7
9171.49
6119.22
3066.96
14.696
40
10022
20004
29986
39968
0
1
2
3
4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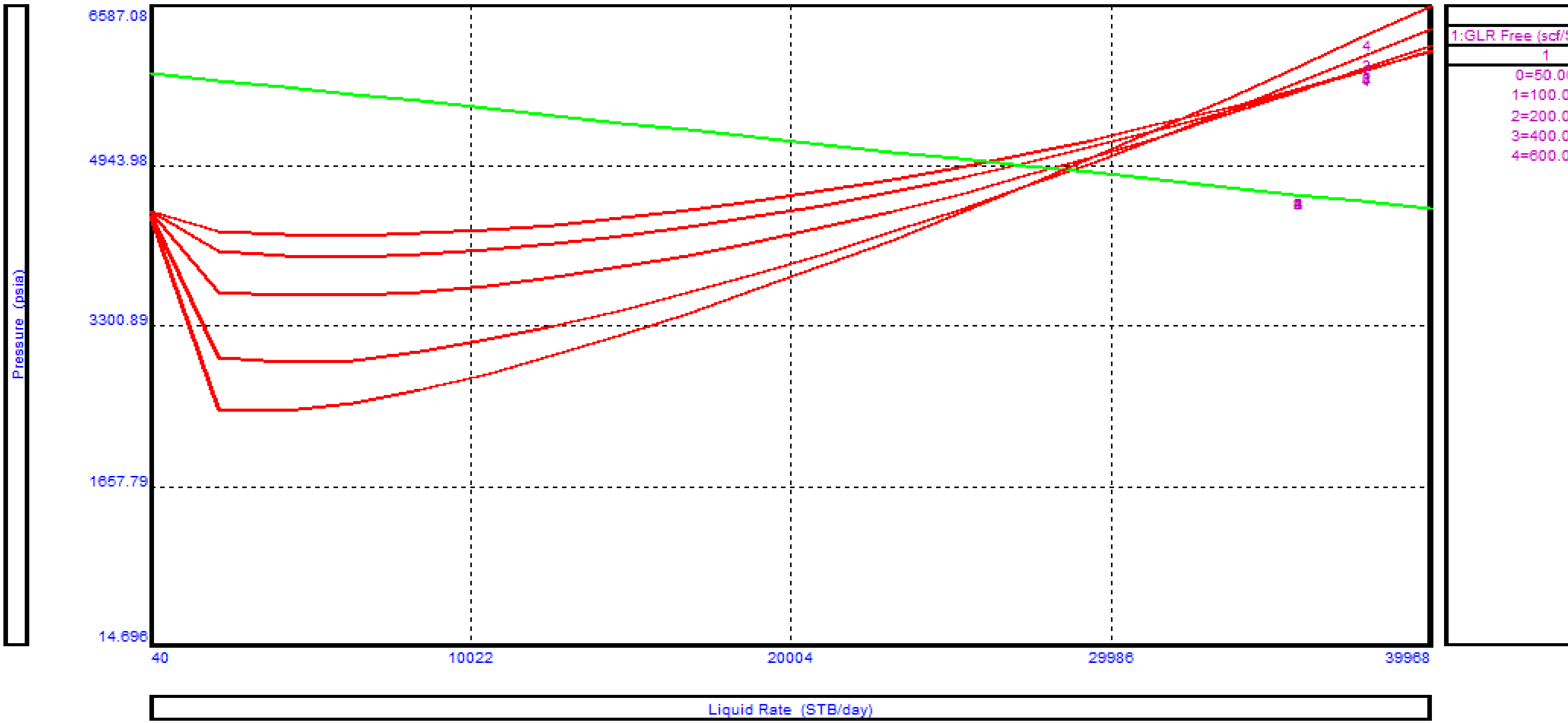
Inflow (IPR) v Outflow (VLP) Plot (Alpha 04/11/2024 - 07:02:52)
Pressure (psia)
5893.31
4423.65
2954
1484.35
14.696

SYSTEM Plot (C:\Users\JOHN.O.O\Desktop\y3s1\production\prosper\alpha layer 1 IPR + TPR.Out)

Finish Main Annotate Scales Labels Replot Output Colours Options Variables Test Data Help

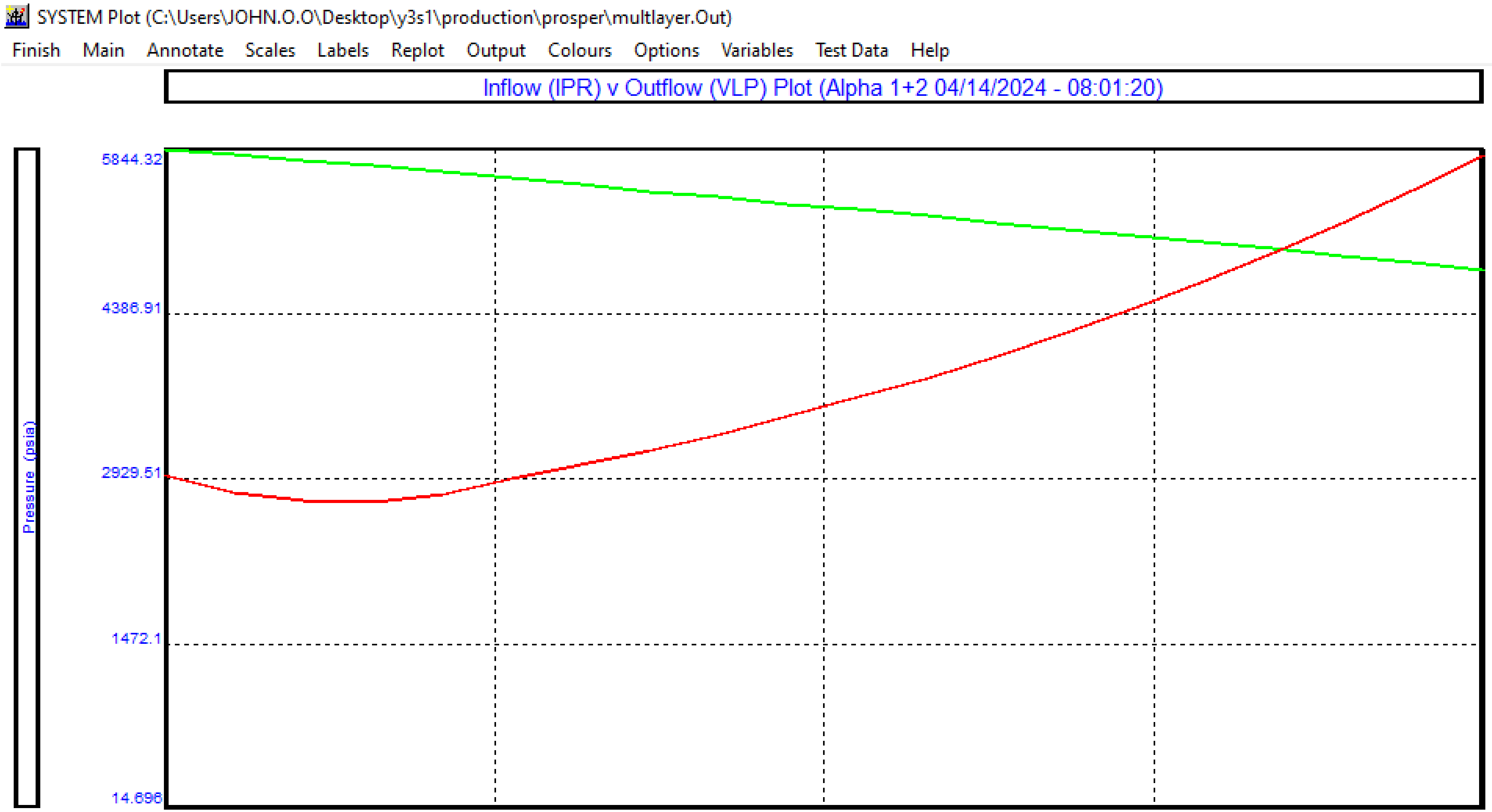
Inflow (IPR) v Outflow (VLP) Plot (Alpha 04/10/2024 - 18:07:18)

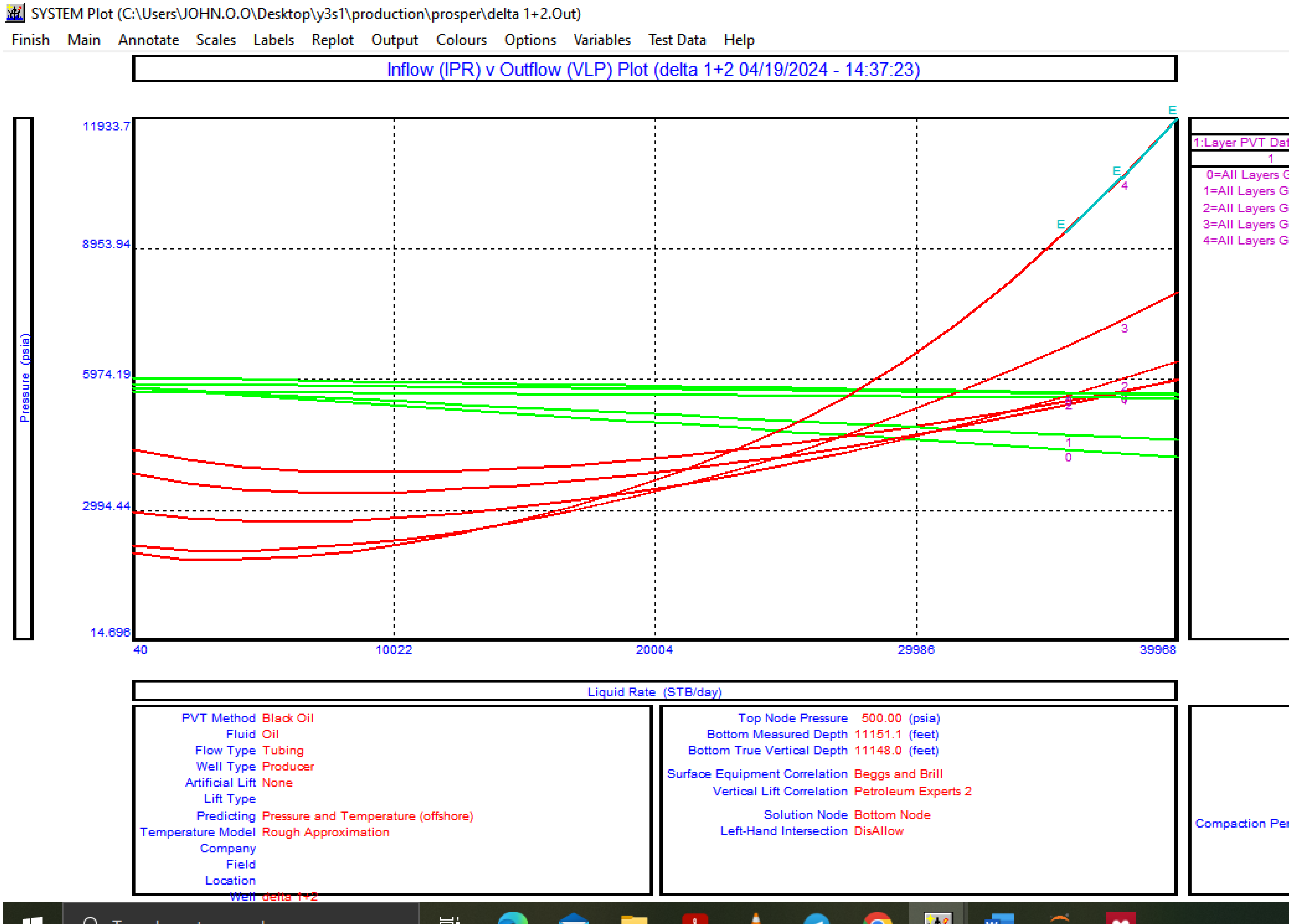


PVT Method	Black Oil
Fluid	Oil
Flow Type	Tubing
Well Type	Producer
Artificial Lift	None
Lift Type	
Predicting	Pressure and Temperature (offshore)
Temperature Model	Rough Approximation
Company	TRENCH OIL COMPANY LIMITED
Field	JARVIS OIL FIELD
Location	60Km offshore SE Tanzania
Well	Alpha

Top Node Pressure	500.00 (psia)
Water Cut	5.000 (percent)
Bottom Measured Depth	3248.0 (m)
Bottom True Vertical Depth	3248.0 (m)
Surface Equipment Correlation	Beggs and Brill
Vertical Lift Correlation	Petroleum Experts 2
Solution Node	Bottom Node
Left-Hand Intersection	DisAllow

Compaction Per


SYSTEM Plot (C:\Users\JOHN.O.O\Desktop\y3s1\production\prosper\multlayer.Out)
Finish Main Annotate Scales Labels Replot Output Colours Options Variables Test Data Help
Inflow (IPR) v Outflow (VLP) Plot (Alpha 1+2 04/14/2024 - 08:01:20)
5844.32
4386.91
2929.51
1472.1
14.696
Pressure (psia)



SYSTEM Plot (C:\Users\JOHN.O.O\Desktop\y3s1\production\prosper\delta 1+2.Out)
Finish Main Annotate Scales Labels Replot Output Colours Options Variables Test Data Help
Inflow (IPR) v Outflow (VLP) Plot (delta 1+2 04/19/2024 - 14:37:23)
Pressure (psia)
11933.7
8953.94
5974.19
2994.44
14.696
40
10022
20004
29986
39968
Liquid Rate (STB/day)
1:Layer PVT Dat
0=All Layers G
1=All Layers G
2=All Layers G
3=All Layers G
4=All Layers G
PVT Method Black Oil
Fluid Oil
Flow Type Tubing
Well Type Producer
Artificial Lift None
Lift Type
Predicting Pressure and Temperature (offshore)
Temperature Model Rough Approximation
Company
Field
Location
Well delta 1+2
Top Node Pressure 500.00 (psia)
Bottom Measured Depth 11151.1 (feet)
Bottom True Vertical Depth 11148.0 (feet)
Surface Equipment Correlation Beggs and Brill
Vertical Lift Correlation Petroleum Experts 2
Solution Node Bottom Node
Left-Hand Intersection DisAllow
Compaction Per

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