

Production Enhancement Using Prosper Software with Reference to Well Test Matching and Modeling for Good Financial Management [†]

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[†] Presented at the International Conference on Innovative Research in Renewable Energy Technologies, West Bengal, India, 16–17 March 2022.



Citation: Kudapa, V.K.; Iqbal, M.I.; Memon, S.; Azharuddin, S.; Rajawy, I.A. Production Enhancement Using Prosper Software with Reference to Well Test Matching and Modeling for Good Financial Management. *Mater. Proc.* **2022**, *10*, 7. <https://doi.org/10.3390/materproc2022010007>

Academic Editors: Sudipta Das, K. Vasu Babu, Samrat Paul and Kunal Chakraborty

Published: 27 July 2022

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Abstract: Everyone who works in the oil and gas industry wants to keep capital and operating costs down while also increasing cumulative oil production in the most cost-effective way for the whole field. There must be a logical consideration of all of the field's production systems, from the subsurface to its surface facilities, in order for true production optimization to take place. As a result, when an oil well does not flow on its own, an assisted lifting system must be used. Gas lift is one of the few artificial lift systems that can start up a well and keep it going for a long time. Gas lift works by lowering the hydrostatic pressure inside the production tubing by injecting lighter fluid into the annulus, which is the space between the production tubing and the well. Integrated production modeling is very important for well performance analysis and for optimizing the production system. It offers a way of assessing the effects of changes by looking at each individual aspect and how they work together in the field. This paper considers a best practice workflow that was used in an integrated production-modeling project. When creating a surface network model, steps can be taken to make it faster. They also show how to ensure the model is accurate. The main goals of this work were to speed up the development of a model that could be used for investigating the well flow in advanced stacked watercourse sand systems and to look for ways to increase production. The model is built and compared to real-world data, and then, the best fluid and well production correlations are chosen for the model and for the data. The use of this model will help improve production and clarify how the whole production system works.

Keywords: PROSPER; PVT; IPR; VLP; modeling; well test; PVT tuning; production system; optimization

1. Introduction

One of the most important parts of well analysis is determining which wells might be able to produce at a better rate than the current one. The well modeling software PROSPER is designed to assist in making sure that well models are accurate and consistent. It also allows the handling of every aspect of well modeling, PVT (fluid description), VLP correlations (for calculating flow-line and conduit pressure loss) and IPR (reservoir inflow) [1]. PROSPER has different ways of matching PVT, point flow correlations and IPR

to field data, so that the well model can be built before it is used in prediction sensitivity or artificial lift design. PROSPER allows the consideration of detailed surface pipeline performance and design in the following areas: flow regimes, pipeline stability, slug size and frequency. It works as follows. The options, PVT data, equipment data, IPR data and calculation outline are all on the main PROSPER screen, which is divided into five parts. When PROSPER is used to make well models, the concept of integrated production modeling IPM is used [1]. PROSPER is the link between the reservoir model and the surface model in well modeling. It connects the two. Among other things, it shows how the well works and how the reservoir and vertical rise work. Before using the well matching method, we will create a well model by putting incorrect information into the well check. The well analysis is then performed in each part of the assembly system to determine whether it is producing less than it should be. An important part of well analysis is the ability to show how well flow and performance are linked currently (IPR). It is important to use the right well check information and the right IPR model for the analysis in order to be successful. Well performance modeling is an important part of research in the field of crude oil engineering. In this model, the PVT model for the produced fluids, the reservoir IPR model and the VLP model are all combined to create one model that is a mix of them all [2,3].

Hydrocarbon deposits have been found thousands of feet below the surface of the earth. A link must be created between the surface and subsurface reservoirs in order for the hydrocarbons to be combined, which is a well group. It cannot be overstated how important it is to conduct research and determine how wells will perform. The period of the well's ability to supply the reservoir fluid is called the well performance. This is because the well's expected productive capacity, pressure drop or flow rate are all factors that affect how well it can do this for a certain amount of time [4]. As a result, well performance analysis is concerned with discovering how tubular size, wellhead and bottom-hole pressure, fluid properties, fluid production rate and reservoir deliverability all work together. An important part of fossil fuel engineering is the consideration of the pressure visit of oil and gas wells. This helps with the design of wells, the completion of wells and the production of more oil and gas. Fluid moves from the all-time bottom hole into the tubing or casing, from where it moves to the surface. The friction between the fluids and the tube walls, as well as the restrictions inside the tube, gravity and viscosity forces, all play a role in fluid movement. To perform a good well performance analysis, the well and its fluid model should be included, as well as the model of the fluid produced, the influx performance relationship model and the model of how well the fluid moves up and down. The PVT model is important because the produced fluid can have different properties at different pressures and temperatures. This is why it is important to have this model. Pressure and temperature changes cannot be avoided when fluid moves vertically upwards in a tube. This method is used to accurately predict what is occurring inside. The flow up the tube can be mixed at times [5]. Gas and liquid tend to separate and cannot usually move at the same speed. Calculating the pressure drop is very complicated and difficult. To determine how wells will deliver and how they will deplete, accurate pressure visit predictions for oil and gas wells are required. As a result, even though many people have proposed completely different multiphase flow correlations, none of them have tried to produce reasonable results for all the different situations that could occur when producing hydrocarbons. The tuned correlations are then used to predict how a well would perform in the future. This is carried out by simulating a well and then considering the results.

2. Literature Survey

Production modeling includes activities such as measuring, analyzing, modeling, prioritizing and implementing actions to improve the productivity of a reservoir, well or surface [6,7]. These activities are called "production modeling". Production optimization is an important step in making sure that the developed reserves can be recovered and that profits can be maximized. The PROSPER integrated oil reference states that PROSPER is a

well performance, style and optimization program that is part of the integrated production modeling toolkit, which is used to figure out how wells work and how to improve them (IPM). According to Shoaib et al. [8], IPM is a way to model the quality of a product from the time it is extracted from the ground to when it is delivered. At first, each fluid model will not behave the way it is supposed to, and it will need to be matched with information from research labs. This is often performed to make sure that the model does not change and behaves like a real reservoir fluid. After creating the PVT model, the wellbore model is created with the PROSPER software package. An important tool helps one figure out how to increase the output of a well when the pressure in the well drops. The flow performance curve (IPR) and the vertical raise performance curve can be used to conduct many different kinds of tests (VLP). Reservoir modeling can be used to see how current reservoirs are behaving by working with MBAL, a company that works with fossil fuels. This model can also be used to predict the reservoir's long-term future, except for figuring out how much it will run out of. The built model's reliability and accuracy depend on the pressure and production points that have been put into it over the years. In their opinion, Tejaswi et al. [9] say that integrated production modeling is very important for well performance analysis and for the growth of the production system. It is a way to figure out how changes will affect processes, such as field performance, by looking at individual elements in a structured way and then looking at how their interactions will affect field performance. This paper discusses a workflow that is used in integrated production modeling. When creating a surface network model, there are steps one can take to make it faster. They also show how to make sure the models are accurate. The main goals of this work were to speed up model development, review well flow performance in advanced stacked watercourse sand systems and look for ways to improve production by looking for ways to remove bottlenecks and drilling more wellbore. This is how the model is created and tested against real-world data. Then, the best fluid and well production correlations are chosen. Umut and other researchers came up with a five-step process for creating an integrated production model. Among them:

Step 1: Outline the problem and state the main technical assumptions that will affect the choice you make. This is called framing, and the whole project group is involved in it.

Step 2: Modeling is the next step. All of the technical information from the framing step is put into the different models and packages during this step.

Step 3: It is called the "Static Quality Check (Reservoir to Separator)". This is when an engineer looks at the rock and fluid and mechanically inputs their attributes into every model (subsurface well, surface network, and so on, if there are any) and compares them to standard information (well log, core, flow back check, fluid samples, unstable and others).

Step 4: "Link the Surface Network to the subsurface Model". The wells in the subsurface model are linked to their corresponding pairs in the surface model.

Step 5: "Dynamic Quality Check". The whole system is put through the full amount of prediction. If there are problems with convergence, they are fixed. If an associated anomaly is found, the same modeling step may be performed again.

The sixth step is forecasting. If one makes a big economic decision, one can use IPM in two ways. One way is where the whole IPM is forecasted for full-field predictions. A call on a smaller scale will not work because the bound module of IPM is removed in this case [10]. A study by Kerunwa et al. [11] stated that modeling well performance is an important part of crude engineering research. There are three models in this model: the fluid PVT model, the reservoir IPR model and the VLP model. They all work together. The objective is to figure out how much pressure is lost as the reservoir fluid moves from the bottom hole to the surface. Researchers have come up with many different ways to figure out how much pressure is lost, but none of them have been found to be the most accurate because the fluid flow inside the conduit can be complicated and polyphase. Polyphase flow correlations were changed by standardization in this work to fit the downhole pressure and rate from the assembly check, which was used to model the performance of the well under study. This was performed to make the correlations more accurate. Production tests are needed to

make sure the correlation is correct for the behavior that is found. For example, the pressure in the well is affected by how much water is cut off. At pressures less than 2900 psig, the well would not work at all if it were left in its original state (250 psig THP, 30% water cut and 2.875" conduit size).

3. Methodology

In order to make sure that well models are reliable and consistent, PROSPER is meant to be used for everything from fluid characterization to flow line and tubing pressure loss to IPR (reservoir inflow). It is possible for the user to test each model subsystem by adjusting the well system model to real-world data (PROSPER User Manual, 2008). When creating a well model, it is best to match well IPR and VLP knowledge when there is information from the investigation. Matching was performed for a period of time, which was the same length of time as the investigation. The well downhole diagrams were used to make sure that the instrument configuration was correct. To be able to copy any workovers, well models had to be changed. In this study, petrophysics and perforation summaries were used to compare the reservoir's permeability and formation thickness to their findings (from the production database). A lot of your time was spent "setting up" the well model. If one has already done some preparation, this time will be cut down. For example, if one has already done some preparation, this could speed up IPR/VLP matching. Following the development of the well model, the PVT modeling is performed by matching the PVT information from the lab tests to the available correlations. Nonlinear regression is used to change the correlations, so that they work best with lab-measured PVT data. When two factors are linked together, they each have their own value (parameter 1) and their own shift (parameter 2). In this example, the correlation that best matched the fluid was correct the least amount of time (Figure 1). The level of quality deviation shows how close are the results.

PVT - INPUT DATA (untitled)

Buttons: Done, Cancel, Match Data, Matching, Calculate, Save, Import, Export, Help, PVT is MATCHED, Use Tables, Tables

Input Data

Input	Options	Composition	Warnings
Solution GOR	800	scf/STB	
Oil Gravity	37	API	
Gas Gravity	0.76	sp. gravity	
Water Salinity	23,000	ppm	
Mole Percent H2S	0	percent	
Mole Percent CO2	0	percent	
Mole Percent N2	0	percent	
Pb, Rs, Bo Correlation	Glasco		
Oil Viscosity Correlation	Beal et al		

Pb, Rs, Bo Correlations

Correlation	Parameter 1	Parameter 2	Standard Deviation	Reset All
Bubble Point	1.00882	30.3398	0	Reset
Solution GOR	0.99145	-11.8394	0.57946	Reset
Oil FVF (Below Pb)	0.99299	0.0028888	0.0012159	Reset
Oil FVF (Above Pb)	1	0.14336		Reset

Oil Viscosity Correlations

Correlation	Parameter 1	Parameter 2	Standard Deviation	Reset All
Oil Viscosity	1.04383	-0.044779	0.035639	Reset

Matching

Match Data: Bubble Point Plot, Gas Oil Ratio Plot, Oil FVF Plot, Oil Viscosity Plot

Table 1: Temperature 210 deg F, Bubble Point 3500 psig

Point	Pressure (psig)	Gas Oil Ratio (scf/STB)	Oil FVF (RB/STB)	Oil Viscosity (centipoise)
1	4000	800	1.42	
2	3500	800	1.432	0.364
3	3000	655	1.352	0.35
4	2400	500	1.273	0.403
5	1000	190	1.12	0.7205

Other Data

Viscosity: Emulsion, Pump, Power Fluid

Viscosity Modelling: Viscosity Model Newtonian Fluid

Figure 1. Input window for PVT parameters.

PROSPER creates a well inflow performance relationship (IPR) curve after one builds the model one wants and enters the input parameters one wants. Darcy's model was used in this case because the reservoir was not full enough to hold all the water. As shown in Figure 2, PROSPER was also used to create the vertical raise performance (VLP) curves, and the intersection of these curves was used to report the production rates. Correlations were changed to match the measured pressures in the reservoir. There were some adjustments made in this case to make sure that the point flow correlations matched the downhole pressure and flow rate from the assembly check. When the correlations were a little off, PROSPER was used to improve them (VLP matching). If one has a matched VLP, one can match the IPR to the downhole pressure and rate measurements.

IPR plot Petroleum Experts (10 July 07 11:34)

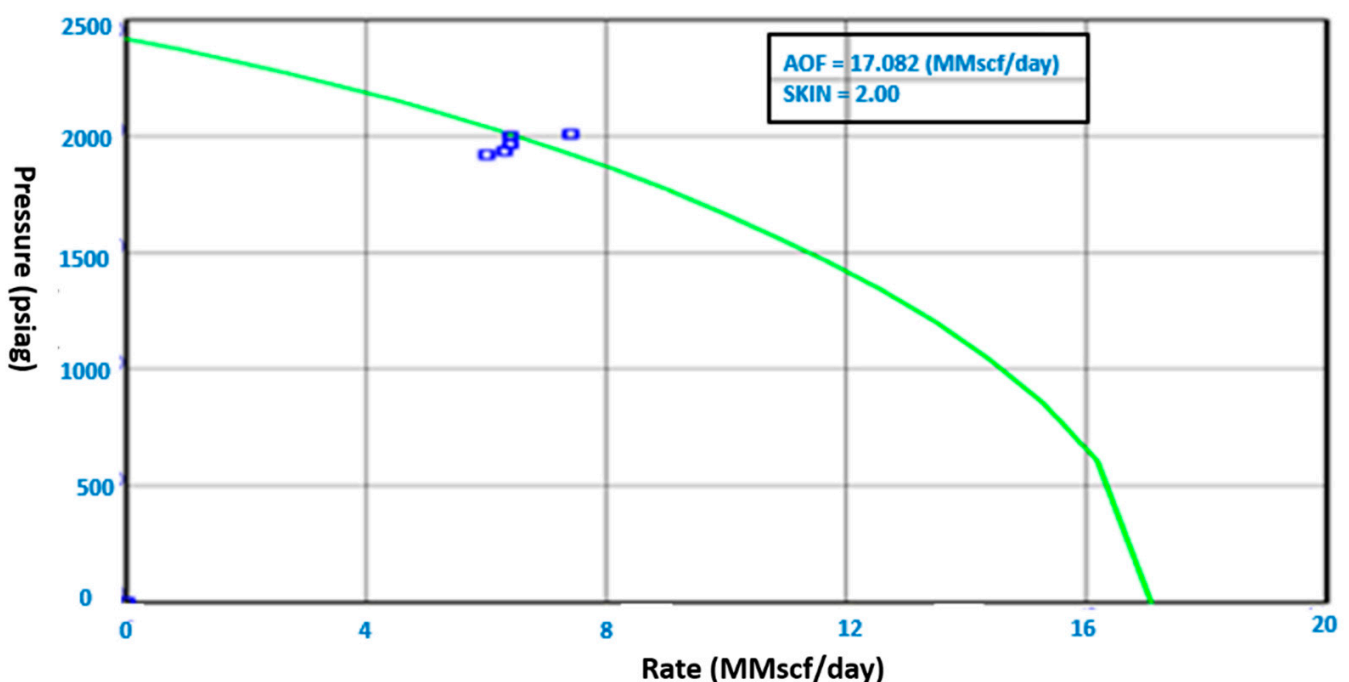


Figure 2. Constructed IPR with PROSPER.

Nonlinear regression is used to match the built and real IPRs in PROSPER. The error between the measured and calculated pressures is found through a correlation. In this way, the gravity and friction terms of the pressure loss equation are changed until the calculated and measured pressures match up at 1 psi or unit area intervals, at which point the iteration process is over after 50 rounds of changes. First, two parameters are changed. Then, the gravity and friction terms are calculated until they come up with a value that is 10% more than unity. This is what we found out when we looked at the VLP match. It was between 0.9 and 1.1, which means that the Duns and Ross correlation had changed. This makes the match even better.

4. Results and Discussion

After entering all of the mandatory information (Tables 1 and 2) into the desired field, the user determines whether the entered PVT data match or not. If the PVT information matches, the IPR section will proceed to the input file.

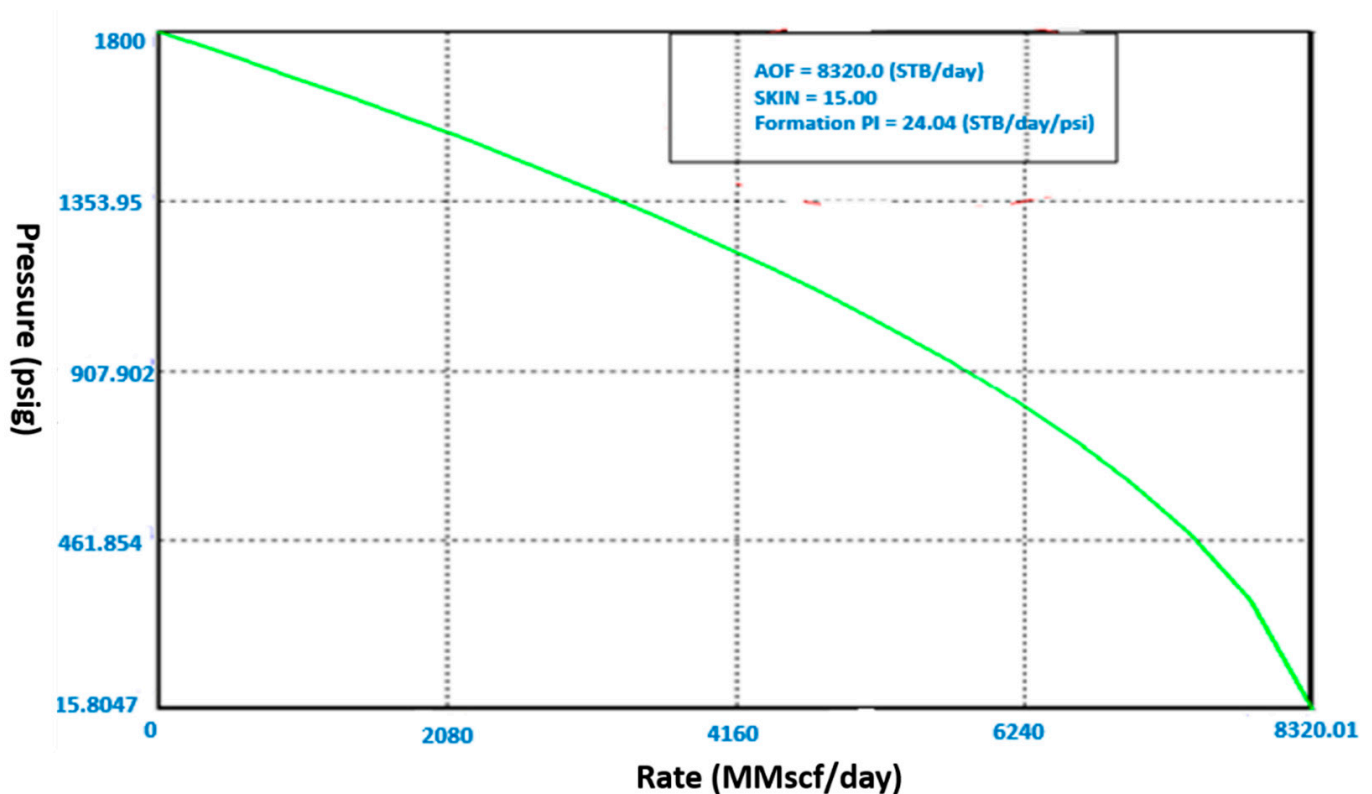
Table 1. Input data for the reservoir.

Pressure	2300 psia
Temperature	239 F
Net sand	10 m
Permeability	500 md
Porosity	24–30%
Tubing head pressure	550 psia

Table 2. Input data for fluid properties.

API	40
Gas Oil Ratio	440 scf/stb
Water cut	0 %

The IPR Darcy plot is based on the PROSPER model that was chosen. By looking at the values of the absolute open flow potential (AOF), the formation productivity index (PI) and the skin created, the user can figure out how the wells will work (Figures 3 and 4). The AOF is the amount of oil that the well can produce when the pressure at the bottom hole is at 0 pounds per square inch. The skin value can show whether a well is damaged or not.

**Figure 3.** Represents the IPR Darcy plot.

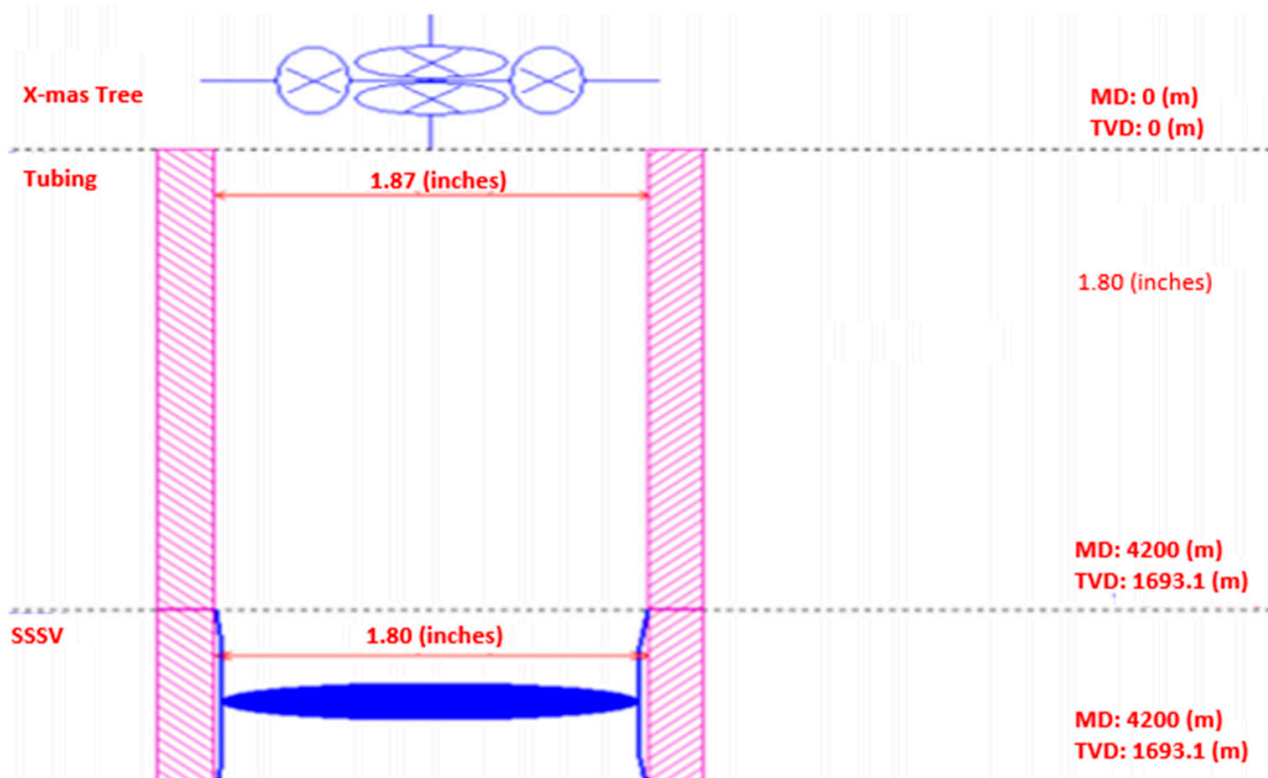


Figure 4. Represents the downhole system of the wellbore.

5. Sensitivity Analysis

A sensitivity analysis over the selected reservoir model is performed over the selected parameters. The ranges of those selected parameters are mentioned in Table 3.

Table 3. Different ranges of input parameters for sensitivity analysis.

Tubing size	2-7/8", 3-1/2" and 4-1/2"
Reservoir pressure	2300, 2000 (psia)
Water cut	0, 20 (%)
GOR	440, 600 and 800 (scf/stb)
Skin	0, 15

The first sensitivity analysis was performed based on tubing size, so that the best tubing size could be chosen for the project. Figure 5A shows that with bigger tubing, the rate of production also goes up. This is because more fluid is flowing through the tube. Figure 5B shows how well the tubing works with more water cut. In Figure 5A, red lined indicates the increase in productivity with increase in tubing size and green line indicates the decrease trend of GOR value. Flowing gradient survey (FGS) and GRE correlation were used to study the impact of tubing performance with increase in water cut (Figure 5B). Redlines in Figure 5B, indicates the increase in tubing performance with respect to FGS and GRE correlation. It was observed that the GRE correlation gives a better fit than FGS correlation. The green lines indicate the reduction in GOR for the above said two correlations.

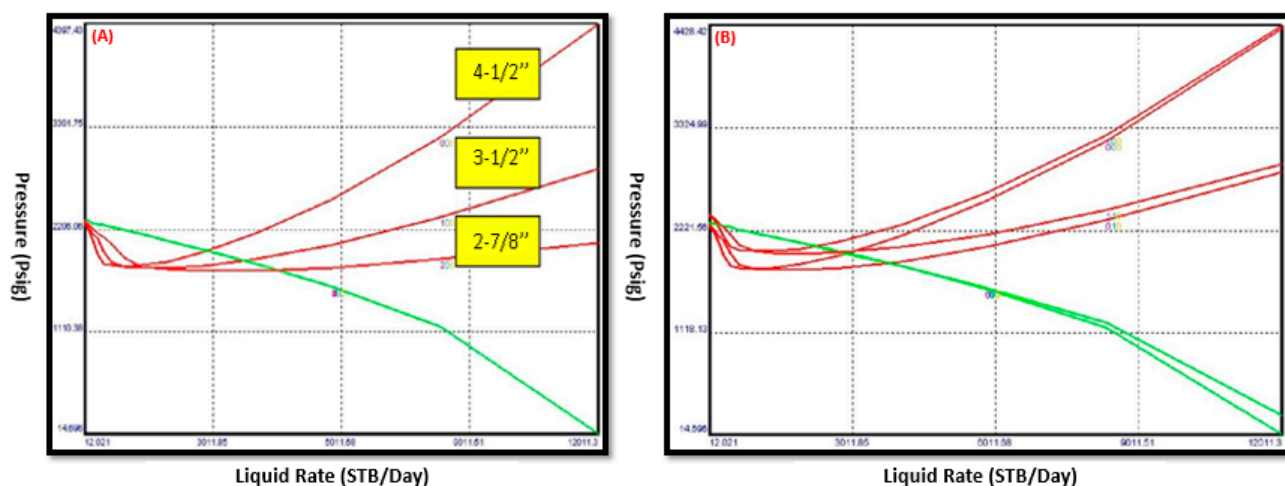


Figure 5. (A) Production variation with respect to tubing size; (B) Tubing performance variation with increase in water cut.

6. Conclusions

A reservoir wellbore model was created in PROSPER to figure out how much water was coming out of the well and to compare the production rates with different correlations. It was found that the Duns and Ross correlation was better at matching up with real-time data than the other correlation. In addition, a sensitivity analysis was also performed to look at how tubing size and the GOR ratio affect wellbore productivity. The study found that when the tubing size was bigger, the production rate increased. In addition, the effectiveness of the tubing could be increased by cutting more water from it.

Author Contributions: V.K.K.: Conceptualization, Writing—Original Draft Preparation; M.I.I.: Validation and Writing; S.M.: —Reviewing and Editing; S.A.: Resources and Formal Analysis; I.A.R.: Reviewing. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: Data will be made available when required.

Acknowledgments: I would like to acknowledge the support extended by UPES-Dehradun, University of Technology and Applied Sciences—Oman, Babasaheb Ambedkar Marathwada University, Aurangabad, and Lincoln University College—Malaysia for performing the simulation studies.

Conflicts of Interest: The authors declare no conflict of interest.

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