Digital Oil Recovery™
Questions and answers

Questions

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2. What machine learning techniques are used in behavioral modelling? Are the methods used for geological modelling of reservoir suitable for behavioral modelling? For example, A&N methods such as MLP may be used for estimating reservoir properties, but can the same tools be used in behavioral modelling?

3. What is meant by measured data? Interpreted datais derived from measured data. Does Foroil use only production rate and pressure data? You can't use Darcy law without incorporating G&G.

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Digital Oil Recovery™: Questions and answers

1. How can the Digital Oil Recovery model complement our existing reservoir models?

Digital Oil Recovery (DOR) technology is fundamentally a tool to find a better way to produce in a given field. It is based on learning how the field is behaving, but not meant to tell you why it is behaving like this. As a secondary result, it can help you better understand your reservoir, but the primary objective is to generate 15 million plans and find the best way to produce.

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2. What machine learning techniques are used in behavioral modelling? Are the methods used for geological modelling of reservoir suitable for behavioral modelling? For example, A&N methods such as MLP may be used for estimating reservoir properties, but can the same tools be used in behavioral modelling?

No, we are not using those techniques. The principle is to apply optimization algorithms, so we can solve in sequence two optimization problems. The first one is to find the best candidate model within that space of solutions, which will give you the best history match. There is no difference in principle with what you do in history matching an Eclipse model. The difference is that we do that in a different space. Once we have found the best model, which incidentally is unique in our case as opposed to an Eclipse system, then we have a given model which will be used to test, fully calculate, and rank 15 million plans. This is going to be the second optimization problem. We make sure to cover the vast domain of possibilities and find the best combination of parameters: where to drill, how whether to modify the production rates and injection rates, how much enhanced oil recovery (EOR) to inject, etc. Those are the levels that we are playing with and therefore the 15 million scenarios we generate, calculate, and rank.

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3. What is meant by measured data? Interpreted data is derived from measured data. Does Foroil use only production rate and pressure data? You can't use Darcy law without incorporating G&G.

We take all the measured data, and here's a brief list. We take production data and injection data well by well. We take all the pressure measurements made on the field. It can be bottom hole flowing pressure. It can be well head pressure or static pressure. All these measurements made on the field as they are. We will also take all the geological measurements made at the wells, at the cores, so porosity, permeability, everything. We will take all the PVT measurements made on the fluids. All the measured data will be taken as inputs, similar to a meshed model. We will not take the following as an input: interpreted data like seismic data, and geological model that you build yourself from your interpretation of the field.

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4. What is FDP?

An FDP is a Field Development Plan which is a step-by-step guide that includes all the recommended actions to optimize the production of a reservoir. These actions can include adjusting production and injection rates, converting producers to injectors, de-bottlenecking the surface, and drilling new wells.

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5. How are economics embedded into the optimization?

Our solution is not a software, so for each project we have developers coding specific lines for the particular field based on defined issues and needs. Regarding economics, we take into account all related costs and prices of oil. So we will code the cost of drilling, the cost of operating, and even the cost of debottlenecking surface equipment, because surface equipment is part of the optimization process. We will also embed the fiscal terms if requested, and will take the price of oil as a given. We also consider how parameters can vary over time. In the end we will code your specific objective function, which is the objective that you want to achieve—whether it is net present value, CAPEX per barrel, rate of return of your investments, or a combination of these. We can help optimize any objective that the client specifies.

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6. How reliable is this method on projects that do not have data related to what is going to be implemented in future?

There are three limitations:

1. Minimum number of wells,
2. Minimum number of years, and
3. Recommendations are based on actions that have been already implemented on the particular field in the past. So if your field had secondary recovery, then we can help optimize. But if there has not been enhanced oil recovery (EOR) on the field, then we cannot predict what the behavior will be with EOR. It is basically a machine learning process—learning the response of any draining technique on the field—so we require past information.

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7. How is physics included? Do you solve the flow equations?

Yes, we solve the flow equations within the space of solutions. We couple the space of solutions with data and find a best candidate model within that space of solutions.

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8. Do you have a success story for deepwater? Compared with unconventional, there are not many wells, but there is data available for deep water.

Yes, we have success stories for deepwater. There are some cases when there may not be a sufficient number of wells, for example some cases in the Gulf of Mexico and the North Sea. If there is the minimum number of wells and minimum years of production, the technology equally applies to deep offshore, offshore, or onshore.

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9. How long will it take to get a report for a field with 100 wells, that is 10 years old, and already unitized with gas and water injection?

It will likely take three months. In three months, we can set up the model, run our 15 million scenarios, find the best scenario for each type of strategy that you are interested in. What we call a type of strategy is for instance no investment, a 10 million USD investment, or a 20 million USD investment. For each strategy that you define, we can find the best plan which will take about three months. Next, we will go into the plan customization phase, which roughly takes a few weeks. During this time, you can ask us questions as we fine-tune the plan to make it more practical, taking on any additional constraints that we will have uncovered.

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10. Can your method be implemented in the optimization of tertiary recovery?

Yes. It depends on the number of wells and the number of years when the field has been under that form of recovery. If you think about it as a learning system, it needs a training data set to learn from (whether it is primary recovery, secondary recovery, or tertiary recovery), and then the tool can model and learn from the past behavior.

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11. How did you embed reservoir physics into the data?

Reservoir physics are not embedded in the data; they are embedded in the custom space of solutions. In that space of solutions, we apply all the physical equations—the same as you have in any mesh model—and then we use machine learning to find the best model within that space of candidate models to find the best history match.

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12. Can you apply uncertainty on your allocated production data to determine the impact on the forecast?

Yes. However, unlike a mesh model over five years which would typically have plus or minus 50% error or uncertainties attached to each well, our tool typically has uncertainty divided by 10, so plus or minus 5% at a well level. So the need for assessing uncertainty is less.

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13. What is the minimum number of required parameters?

The minimum number is a combination of the number of years the field has been producing and the number of wells. The rule of thumb is 10 years, but 20 years is better than 10, and then the number of wells. 10 to 15 wells would be minimum, but 30 wells or 50 wells is better. Prior to starting a project, we will ask some basic information regarding the field to test whether it is within the scope of our technology or not. This would also be prior to any signed contract.

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14. What is the margin of uncertainty?

A typical uncertainty is plus or minus 5% on a well-by-well basis over 5 years, as opposed to plus or minus 50% with the traditional mesh model. Based on dozens of projects the average error observed between our forecast and actual production is about 4%–7% on a well by well basis and 3%–5% on total cumulative production over a 4-year period.

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15. Do you use a third party or proprietary machine learning algorithm? If third party, which one?

No, the machine learning used is proprietary to FOROIL. It was originally developed for the nuclear and defense industries and subsequently modified for solving reservoir engineering challenges.

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16. What is the model based on where production data is used to train it?

The model is based on the same reservoir physics equations used in standard mesh models. The system learns the behavior of the reservoir using the historical production data and the information about previous actions taken in the reservoir. The forecaster tool can then calculate the production and the behavior of the reservoir when similar actions are applied in the future.

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17. How are Field Development Plans (FDPs) generated and provided to the algorithm for optimization?

That is part of the know-how: by solving the non-uniqueness issue we have complexified the optimization problem. Because the space of solutions does not have a nice shape in terms of mathematical algorithms that we can apply for optimization, we have developed a way to cover the vast domain of possibilities. So after having run 15 million scenarios, the output should not be too far from the absolute optimum. We cannot guarantee that we touch the optimum, but we can help: 1) cover the vast domain of possibilities, and 2) significantly increase the outputs of the field compared to the reference case.

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18. If your model can learn on its own and run overnight using HPTC, why does it take 3–4 months to run the solution?

Because the Forecaster model is custom built specifically for each individual reservoir, it can take 2–3 months to build and test. Once it is built, and the client's objectives and constraints have been defined, millions of potential field development scenarios can be run overnight.

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19. Are there any other limitations of the data physics model aside from the requirement of multi-year/decade production history?

Aside from the appropriate amount of data history, the reservoir needs to be conventional, and it needs to have enough wells (at least 15–20 minimum) to provide a rich enough dataset to work with.

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20. Has a study been conducted to compare your forecasts with forecasts based on reservoir simulation?

Deviations in our forecasts have been validated to an average range of 4%–7% on a well by well basis.

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21. How is the optimization model different from a typical reservoir or asset model?

There are numerous differences but the main ones are as follows:

1. The Forecaster model is a behavioral model of the reservoir. It focuses on describing what the reservoir "does" and how it behaves over time as activities are undertaken in the field. It does not attempt to describe what the reservoir "is". The standard simulator model describes in detail what the reservoir "is" but becomes much more complex which impedes its ability to produce accurate forecasts.
2. The forecaster model is built with the appropriate level of complexity relative to the data that is available. This process uses proven theorems of machine learning for the minimization of forecast error.

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22. Are there any simplifying assumptions in your model? For example, PVT, compressibility, or relative permeabilities.

The complexity of the space of solutions is adapted to the richness of the data set.

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23. Are well penetrations and completions in each reservoir zone or compartment required for model performance?

Yes, completion profile, intervals and well trajectories are required.

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24. Should this tool be on the desks of the Reservoir Engineers?

In a typical case, fully optimized field development plans are delivered containing specific sets of recommendations to be implemented in the field. However, if the client would like the ability to build models, and optimize FDPs on their desktops, technology transfer options are available.

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25. Has this technique been applied to Water alternating gas (WAG) developments?

We have applied the technology to fields where both gas and water were injected with excellent results in forecast and optimization.

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26. The behavior model depends on what is going on today. But will it change in 5 years as more hydrocarbons have been taken out?

Essential behaviors of the brown field are captured from its production history and are not expected to change much over the next 5 years. When fed with operational inputs, the field after 5 years will land close to FOROIL's model projection. The model is dynamic and can be modified as new wells are drilled and adjustments are made in the field. The optimizer can also be re-run to produce a modified and enhanced Field Development Plan incorporating the new contingencies.

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27. What specific simulator are you using?

The simulator is proprietary to FOROIL and custom built for each reservoir.

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28. Would it be correct to say that 'Digital Oil Recovery' is a workflow rather than a software?

Digital Oil Recovery is not a software, but it is more than a workflow. It uses proprietary software, and patented processes involving advanced mathematics, reservoir physics, and machine learning to produce a highly accurate forecast model and generate the best FDPs out of tens of millions tested.

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29. In case there is not enough available real data, how reliable would machine learning models based on synthetic simulation models be?

The corresponding data set would most likely be insufficient and lacking high frequency content, such an academic exercise would need special care.

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30. Do you have a plan to increase the infill drilling as the best option?

Yes, we discuss multiple economic scenarios with our clients and if they choose scenarios that involve capex then new drilling locations would more than likely be recommended as a component of the best plan.

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31. How much will it cost for the Foroil report for the 100 well fields example?

Digital Oil Recovery pricing is based on a small fraction of the value we deliver so it would depend on the specifics of the field in question. ROI for the client is typically in the 2000%–3000% range.

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32. Can you comment on the challenges around applying this model to unconventional reservoirs?

We do not foresee any specific difficulty but it still has not been realized until now.

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33. What machine learning technique is being used?

The machine learning is a custom and patented process that combines advanced mathematics and reservoir and well physics, as well as heuristic, deterministic, and non-deterministic approaches for our advanced hybridized optimization process.

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34. Can your method be applied to green field FDP development?

Digital Oil Recovery (DOR) technology does not typically apply to green field development as the process requires 7–10 years minimum of historical data to learn from. In addition, it does not attempt to recommend new "step out" drilling locations or activities that have not been previously performed in the field.

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35. Is the forecasting being done by FOROIL rather than the engineers working on the Asset? Can you explain how to operationalize the tool?

The forecast model is built by FOROIL's PhD mathematicians, reservoir engineers, data scientists and developers using the patented process and the available measured data. Daily and weekly activities —including surveillance of fluid levels, adjustment of pump rates, equipment maintenance and repair —should be carefully monitored and managed by the client's operations team. FOROIL's forecast is also reviewed with the client's reservoir engineering team on a monthly to quarterly basis to take into account events that are relevant to the reservoir management and incremental recovery (i.e. well drilling schedule, changes to surface capacities).

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36. Which well data do you need as a minimum?

We would need the following: production and injection volumes by well, by phase, by month, well test data, and temperature and pressure data.

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37. Can this technology be used to optimize the location and number of wells in an infill drilling campaign?

Yes. An optimized infill drilling campaign is designed by identifying the under drained, under swept, or over depleted areas of the reservoir, accounting for interactions between wells and ensuring compliance with the current and future capacities of surface facilities.

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38. Do you foresee problems with modeling steam recovery with gravity drainage?

No, we do not foresee any problems applying the technology to Steam Assisted Gravity Drainage (SAGD).

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39. Is your history matching technique based on experimental design?

Our history matching is an iterative process that uses machine learning to scale the model complexity up and down relative to the data available to produce a model that has the best history match and the lowest forecast error.

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Let's talk

Learn more about how Digital Oil Recovery™ can help you produce more oil, for less dollars, faster and with less risk. Visit www.deloitte.com/us/digital-oil-recovery.

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