ALBERTA INNOVATES

CLEAN RESOURCES FINAL REPORT PACKAGE

Project proponents are required to submit a Final Report Package, consisting of a Final Public Report and a Final Financial Report. These reports are to be provided under separate cover at the conclusion of projects for review and approval by Alberta Innovates (AI) Clean Resources Division. Proponents will use the two templates that follow to report key results and outcomes achieved during the project and financial details. The information requested in the templates should be considered the minimum necessary to meet AI reporting requirements; proponents are highly encouraged to include other information that may provide additional value, including more detailed appendices. Proponents must work with the AI Project Advisor during preparation of the Final Report Package to ensure submissions are of the highest possible quality and thus reduce the time and effort necessary to address issues that may emerge through the review and approval process.

Final Public Report

The Final Public Report shall outline what the project achieved and provide conclusions and recommendations for further research inquiry or technology development, together with an overview of the performance of the project in terms of process, output, outcomes and impact measures. The report must delineate all project knowledge and/or technology developed and must be in sufficient detail to permit readers to use or adapt the results for research and analysis purposes and to understand how conclusions were arrived at. It is incumbent upon the proponent to ensure that the Final Public Report **is free of any confidential information or intellectual property requiring protection**. The Final Public Report will be released by Alberta Innovates after the confidentiality period has expired as described in the Investment Agreement.

Final Financial Report

The Final Financial Report shall provide complete and accurate accounting of all project expenditures and contributions over the life of the project pertaining to Alberta Innovates, the proponent, and any project partners. The Final Financial Report will not be publicly released.

ALBERTA INNOVATES

CLEAN RESOURCES FINAL PUBLIC REPORT TEMPLATE

1. PROJECT INFORMATION:

Project Title:	**Online Optimization and Surveillance of SAGD Production Wells**
Alberta Innovates Project Number:	G2020000131
Submission Date:	
Total Project Cost:	$278425
Alberta Innovates Funding:	$111370
AI Project Advisor:	Vanessa White, Bryan Helfenbaum

2. APPLICANT INFORMATION:

Applicant (Organization):	**Madala Software**
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Applicant Representative Name:	Damien Hocking
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Email:	damien@madalasoftware.com

3. PROJECT PARTNERS

Please provide an acknowledgement statement for project partners, if appropriate.

RESPOND BELOW

This project would not have been possible without the support of Suncor Energy and Alberta Innovates. We would like to thank Udoka Nwabuike, Fernando Gaviria, Dorothy Chan, and Jeremy D'Mello from Suncor and Vanessa White and Bryan Helfenbaum from Alberta Innovates.

A. EXECUTIVE SUMMARY

Provide a high-level description of the project, including the objective, key results, learnings, outcomes and benefits.

RESPOND BELOW

The project delivered an automated Digital Twin pilot for production optimization. The objective was to deploy full-physics models of SAGD production wells in an online cloud-based environment, using parameter estimation to calibrate the models to real-time production data and nonlinear optimization to provide automated surveillance and production optimization advice. A production gain of 2 - 5% was targeted. The project was successful, exceeding the 5% production gain target and providing automated visibility into well tests and accurate virtual flow measurement (VFM) between well tests. Overall, an average production increase of 5% is worth slightly over $1 CDN/bbl *after* production costs, calculated on the total field rate. On a 50,000 bbl/d field, this becomes $18.25M CDN/yr free cash flow at current prices.

Three gas-lift wells of varying vintages and instrumentation levels were selected for the project: a very mature, manually controlled well with an older completion design (mature well); a midlife well with standard instrumentation (standard well), and a sophisticated, fully-instrumented and automated late vintage well with distributed temperature sensors and flow control devices (sophisticated well).

The production advice was field tested and was very successful. The mature well realized the largest gain, between 70 – 80%. The historical operating conditions had not been changed for some time and the optimized advice provided significant debottlenecking. The standard well realized a rate increase of 11% over the trial period based on small but significant operating changes. The production advice for the sophisticated well also indicated a potential production increase of several percent, but the well was found to be operating near an integrity constraint and the advice has not been field-tested as of the projects' conclusion. The integrity constraint was added to the optimization to explore the options for maximizing production while maintaining integrity.

For each well test on each well, typically every two weeks, the models are aligned with the test data to generate a calibrated physics model. Twice daily, a VFM workflow is run to estimate flowrates and update the model to recent changes. The updated model is then used in a short-term optimization workflow to provide advice on incremental changes to the current set points, also twice a day. With each well test, a long-term, large-change optimization is also run to determine the potential maximum opportunity available. The optimization cycles for each well are fully automated and run without user interaction or intervention, in a few minutes per well. A side benefit of the system is the ability to immediately identify possible outlier or failed well tests.

While the base calibration, VFM and optimization configurations are similar, some customization was required for each well model to generate valid, actionable results. This is related to the measurements available (or not available) and which variables can be adjusted for each well. This experience is invaluable for future projects and commercialization.

The application is cloud-deployed with a web interface, with workflows for well test analysis and comparison, VFM prediction and optimization uplift. There are also ad-hoc workflows for engineers to conduct offline what-if simulations.

B. INTRODUCTION

Please provide a narrative introducing the project using the following sub-headings.

- **Sector introduction:** Include a high-level discussion of the sector or area that the project contributes to and provide any relevant background information or context for the project.
- **Knowledge or Technology Gaps:** Explain the knowledge or technology gap that is being addressed along with the context and scope of the technical problem.

RESPOND BELOW

Sector Introduction

The project is in the Digital Oilfield sector. Digital Oilfield encompasses a broad range of themes, such as Operational Efficiency, Production Optimization, Collaboration, Decision Support, Data Integration and Workflow Automation. These themes apply to various domains and disciplines, for example Exploration, Drilling, Production, Logistics, Shipping, Sustainability and so on. The Digital Oilfield concept has made enormous progress in the last ten years, driven by massive increases in data and computing availability and concurrent changes in engineer experience (the crew change), decreases in resource discovery and increased cost of recovery with tighter margins. This has become a requirement to deliver more hydrocarbons, more economically from more challenging resources with reduced numbers of a less-experienced workforce. The only way to achieve this is through Digitization and Automation.

Specifically, the project is in the domain of Production Optimization, delivering automated Surveillance and Advisory workflows. Well-test analysis, virtual flow metering and production optimization advice is fully automated to present the production engineer with relevant, actionable information to enable “management by exception” operation, focus for troubleshooting and lower costs.

Knowledge or Technology Gap

The project addresses the identification, sustenance and maintenance of production optimization opportunities in SAGD. Production Engineering teams use engineering software to design better, more performant wells and analyze the performance of existing wells to realize production gains. Physics-based models are ideal for these activities because they are fully predictive and results can be traced to a physics-based explanation. To date, identification of these opportunities is a manual exercise; a production engineer reads data from a historian or other data service, likely conditions this data in Excel, manually transcribes the data into a production simulator, runs multiple simulations and hopefully can find a better operation point. These new setpoints are then sent to Operations for directives the following day. This is a time-consuming process. If an engineer is responsible for ten wells and each manual calibration and investigation takes half an hour per well (this is optimistic), over half the engineer's day is spent on manual surveillance activities and are not likely conducted on weekends.

Engineering team members now spend significantly more time performing project management and have less time for dedicated production optimization activities like these. With the recent economic downturn, staff levels are reduced while production is maintained or growing. Engineers are now responsible for more wells with less time to dedicate to each well. Software that consumes a significant number of engineering hours to deliver a useful result provides a strong disincentive for its use, which

in turn leaves opportunities and their value unrealized. This is true at all SAGD producers regardless of scale. In spite of the downturn and reduced staffing levels, AER data indicates that SAGD production increased by 500,000 bbl/d from 2013 to 2018. In 2019 SAGD production averaged approximately 1.4 million bbl/d under curtailment, whereas in 2018 it was approximately 1.6 million bbl/d. In 2022 the industry is expected to be back at 2018 levels as the pandemic recedes. At an average 1,000 bbl/d per well pair, there are 1,600 well pairs operating in Alberta, possibly not operating at their full potential because their optimal performance cannot be analyzed. SAGD production is forecast to reach 2.6 million bbl/d in the next 15 – 20 years, adding at least another 1,000 well pairs. Staffing levels are unlikely to match this growth rate as companies strive to deliver more production with less overhead.

Production engineers have used Madala SAGD to realize an extra 2 – 5% production on a SAGD well. The key is being able to sustain and maintain this advantage, which is the primary driver for the project. As wells are produced, the production performance changes and the optimum operating conditions change; last week's optimal setpoints may not be optimal for this week. Production Engineering teams will not spend 50 - 60% of their working hours on repetitive, manual activities regardless of the potential uplift. Operations teams will not do this either. Sustaining and maintaining uplifts must come from online, automated applications that minimize repetitive, manual activities for Engineers, provide them with high-value information and enable them to become proactive in a limited time span.

To our knowledge, there are no similar, successful applications of on-line physics models applied to SAGD production. In 2010, Schlumberger authored a paper, SPE 128426, An Integrated Framework for SAGD Real-Time Optimization. The overall optimization approach described in the paper is practical and the description of what is required and the potential benefits is comprehensive. The paper describes the use of a neural network model to condition and clean data and a SAGD reservoir simulator to perform well performance analysis. This was proposed specifically because of the lack of any other first-principles physics model being available for filtering or prediction. Applying a reservoir simulator to a field with a hundred wells in a production engineering team is impractical because of complexity and performance. A production team does not use a reservoir simulator to model their wells. With correct physics models, the neural net data filter is un-necessary; the filter and the predictor are the same physics model, used by the production team for design and offline analysis and redeployed to operations.

At the commencement of the project, the technological challenges were mostly related to assessing the pilot-scale performance with a view to large-scale commercial deployment:

1) Performance of the physics models. Madala's models are around three orders of magnitude faster than an equivalent reservoir simulator model. Running a few well models is straightforward, but a large field-wide deployment would require many thousands of evaluations a day.
2) Data Access and Movement. The amount of information to be moved around and at what frequency was unknown. On a small-scale pilot this is not likely to be challenging.
3) Data Quality. Even though a first-principles physics model is a powerful data filter, there will be situations where production measurements are inconsistent and cannot be aligned with the physics. We have encountered this in offline analysis where bad sensor data led to a flawed simulation with misleading results.
4) Automated Calibration and Optimization performance. We did not know if the well models could regularly be calibrated to the production data accurately enough, without human intervention, to then provide actionable setpoint changes, also without human intervention.

C. PROJECT DESCRIPTION

Please provide a narrative describing the project using the following sub-headings.

- **Knowledge or Technology Description:** Include a discussion of the project objectives.
- **Updates to Project Objectives:** Describe any changes that have occurred compared to the original objectives of the project.
- **Performance Metrics:** Discuss the project specific metrics that will be used to measure the success of the project.

RESPOND BELOW

Knowledge or Technology Description

Conventional gas lift production is well understood, to the point that there are published, standard design and operating guides readily available based on several decades of global experience. SAGD gas lift is not as well understood because of a comparatively short timeline of experience and a lack of good, predictive models operating in an optimization platform to perform analysis, instead of experimentation on the real production environment. Madala has spent several years developing advanced predictive models of SAGD production wells. The technology gap addressed in this project is moving these models to an online operation and optimization environment to enable alignment with and prediction against operating data.

The major project objectives were framed in reference to achieving Technology Readiness Levels:

TRL 4: Develop a suitable optimization engine and workflows to enable optimization of Madala's existing SAGD gas lift models, matching to production data.

TRL 5: Demonstrate the TRL 4 workflows in an online, cloud deployment.

TRL 6: Automate the online TRL 5 workflows and automate data retrieval from the Plant Information System (as described earlier, connection and data retrieval were brought forward to MS-1 and completed).

TRL 7: This is TRL 6 operating with minimal maintenance or intervention for one month.

Updates to Project Objectives

As the project progressed, we refined the workflows and modified the optimization constraints and targets. Originally, we anticipated two workflows, calibration for inflow and then production optimization for maximum rates. We also added a Virtual Flow Meter (VFM) workflow and divided the production optimization into short- and long-term objectives. Four optimization workflows are now automatically run on each well, with the ability for Production Engineers to run ad-hoc simulations and optimizations as well. A calibration workflow is run for each physical well test, typically every two weeks, which generates an inflow model. An unanticipated benefit of this workflow is the ability to identify outlier or faulty well tests. A VFM workflow is run every 12 hours based on the most recent inflow calibration, to generate a software flow meter valid between well tests. A short-term (small change) optimization is run every 12 hours to provide operating directives and long-term (large change) optimization is also run at each well test. Ultimately the long-term and short-term optimizations should align as wells are moved to their best operating points, however this is not guaranteed and subject to steam chamber and injection changes.

As part of the project metric to maintain the automated system with all wells for one month, the team also field-tested the optimization advice, initially on one well and when successful, the other two test wells. The short-term optimization advice yielded sustained production increases greater than 5% on two wells. Uplifts were also predicted on the third well, however the operating points would have pushed the well past an integrity constraint.

Performance Metrics

The project success metrics were:

- Calibrated model predictions against production data: The project target was to predict production data to within a 10% error and the commercialization goal was to predict within 5%. The commercialization goal was met during the project.
- Model calibration performance: The project target was to calibrate wells in less than 15 minutes and the commercialization goal was to calibrate in under 6 minutes. The commercialization goal was exceeded during the project, most calibrations complete in 1 – 2 minutes.
- Model optimization performance: The project target was to optimize wells in less than 15 minutes and the commercialization goal was to optimize in under 6 minutes. The commercialization goal was exceeded during the project, most optimizations complete in 2 - 3 minutes.
- All workflows cloud deployed: This has been achieved, the system is accessible and operable anywhere there is an internet connection. The system is usable on any device from a phone to a large screen, although the phone utility is limited.
- Automated workflows in continuous operation: This was achieved. Over the 6 months of the project, the system calibrated to 71 well tests across 3 wells and performed 730 automated calibration, VFM and optimization runs with no user interaction.

D. METHODOLOGY

Please provide a narrative describing the methodology and facilities that were used to execute and complete the project. Use subheadings as appropriate.

RESPOND BELOW

The project had three main deliverables, partly run concurrently:

1) Develop the advisory software platform, including the optimization engine, data retrieval, workflows and user interface.
2) Select three wells for the project from a group of candidates and build the simulation models.
3) Run the online system for at least one month and field-test the advice.

Of these, 1 and 3 required the most work, selecting the wells and building the simulation models was a straightforward exercise. The wells were selected on the basis of vintage and instrumentation sophistication. The team wanted an older, unsophisticated well, an average well and a newer, sophisticated well. The simulation models were built and tested in the Madala SAGD software product.

The field testing was conducted in gradual steps. Even though the advisory system ran twice a day, the team adopted a less aggressive approach to changes, updating setpoints every few days and waiting for the wells to stabilize. The VFM workflow provided a twice daily measurement of the well response and performance.

For software development we followed an iterative, agile process. Often in agile projects, team will follow a two-week iteration cycle. With such a small team, we shortened iterations to a few days when necessary for deliverables that required rapid turnaround and testing. There are five main components in the system: the production data source, data processing, the core software application, the calculation engine and the user interface. These can be distributed on different servers.

Production Data Source

The production data source comes from a server within the producer's automation group. The server sends batched production SCADA data to Madala's data processing server as a data push. Commercially this will vary from producer to producer.

Data Processing

The data processing service extracts the SCADA data and processes it with a time-series database. This is hosted in the cloud. This generates averaged simulation values for use in the optimization processes. The data processing service then pushes the simulation values to the core software application.

Core Software Application

This is the brain of the system, responsible for coordination of the data flows and the work. The application is hosted in the cloud. When new simulation values arrive, the application logic detects which well the data is from and if the data is from a well test. It then extracts the well completion data from another database and constructs the appropriate optimization workflow. The workflow is then sent to the calculation engine, which then sends results back to the application.

The development for these three components started at the Production Data Source, then to Data Processing and then to the Core Software Application, which follows the flow of information.

Calculation Engine

The calculation engine contains the physics models and solution engines for constructing and solving well models and the optimization engine that drives the well models. This is also hosted in the cloud. It operates as a stateless calculator, in that it takes a series of inputs, performs calculations on those inputs and generates a series of outputs.

The extra development for optimization was conducted at the beginning of the project, in order to prove that optimization of these was models was feasible. This was the majority of the first project milestone.

Once the Core Software Application and the Calculation Engine were independently functioning correctly, they were connected through their Application Programming Interfaces (APIs) and brought online.

User Interface (UI)

The interface presents filtered data for the production engineer, delivered from the core application. It is not a full production simulator interface, which would be too complicated for an automation application. The interface presents access to a graphical data historian, tabulated wellhead and downhole KPIs, well performance charts for important variables and tabulated optimization uplift and advisory values. It enables a production engineer to screen and analyze well performance much more quickly than a conventional production simulator. It also allows engineers to conduct ad hoc, offline simulations and optimization runs for investigation and what-if analyses. Different interfaces can be presented for different audiences.

The UI was refined over the course of the second milestone, based on user feedback and additional features and capabilities as they became possible.

E. PROJECT RESULTS

Please provide a narrative describing the key results using the project's milestones as sub-headings.

- Describe the importance of the key results.
- Include a discussion of the project specific metrics and variances between expected and actual performance.

RESPOND BELOW

Milestone 1

The success metrics for MS-1 were:

- Calibrated model predictions against production data: The project target was to predict production data to within a 10% error and the commercialization goal was to predict within 5%. The commercialization goal was met during the project.
- Model calibration performance: The project target was to calibrate wells in less than 15 minutes and the commercialization goal was to calibrate in under 6 minutes. The commercialization goal was exceeded during the project, most calibrations complete in 1 – 2 minutes.
- Model optimization performance: The project target was to optimize wells in less than 15 minutes and the commercialization goal was to optimize in under 6 minutes. The commercialization goal was exceeded during the project, most optimizations complete in 2 - 3 minutes.

The purpose of these metrics was to prove that the required calculations could be performed in a reasonable amount of time. If each workflow could be run in 15 minutes, with the two original project workflows described earlier, a well could be calibrated and new data presented in half an hour using a single CPU. While this is not very scalable for multiple pads of wells, it is enough to prove that the project concept works. At the time of the project's inception, we had no information about optimization performance, data quality or reliability or any other factors that might affect the results. The 6-minute commercial goal was set on the basis that a pad with 10 wells with two workflows per well, on a 4-CPU server would also complete in half an hour. With four workflows per well (calibration, VFM, short optimization, long optimization) and each one running in two minutes, we have considerably more flexibility and capability to explore more sophisticated workflows and analytics.

The 10% and 5% accuracy targets were set based on best industry practice in other resources and well types. For production engineering, +/- 20% is considered to be a reasonable match and +/- 10% is considered to be a good match to production data. This is combined with an engineer exercising judgement as to what the results mean. Our goal was a fully-automated system without human intervention or judgement and we set our targets to be stricter. A calibration that matches to +/- 20% will generate a VFM and an optimization to that level of accuracy, which then requires an engineer's interpretation. The majority of calibrations achieved less than 5% error, with some between 5 and 10%.

Milestone 2

The success metrics for MS-2 were:

- All workflows cloud deployed: This has been achieved, the system is accessible and operable anywhere there is an internet connection. The system is usable on any device from a phone to a large screen, although the phone utility is limited.
- Automated workflows in continuous operation for one month: This was achieved, all three wells were ultimately online for at least two months. Over the 6 months of the project, the system calibrated to 71 well tests across 3 wells and performed 730 automated calibration, VFM and optimization runs with no user interaction. As part of this objective, the optimization advisory setpoints were tested in the field on the wells, achieving an uplift greater than 5%.

A cloud-deployed system is much easier to maintain and update than a system deployed on internal company servers, particularly in a pilot project like this where settings and software were sometimes updated daily or on weekends. Cloud-based software is also easier to scale when designed correctly and it is much easier to move to a more powerful server in the cloud than it is in an IT group. The production engineer working on the project adopted the system for managing the three wells in the pilot for the trial period.

The ability to perform many hundreds of automated optimization runs without human intervention means that the overall design is robust. We believe the system as-is could handle hundreds of wells with an increase in server capacity.

Field testing of the advisory setpoints yielded significant production uplifts, greater than 5%. This is a valuable uplift. The team took a cautious approach to making operating changes; while the advisory system ran twice a day, changes were made every 24 – 48 hours to move the wells to their new operating points.

F. KEY LEARNINGS

Please provide a narrative that discusses the key learnings from the project.

- Describe the project learnings and importance of those learnings within the project scope. Use milestones as headings, if appropriate.
- Discuss the broader impacts of the learnings to the industry and beyond; this may include changes to regulations, policies, and approval and permitting processes

RESPOND BELOW

Project Learnings

To our knowledge this is the first application of its kind in SAGD. The key learning for the overall project is that it is possible to deploy full-physics SAGD wellbore models in an online environment and realize production gains.

The major learnings for the milestone are associated with the online trial, the other tasks in the milestone were low-risk implementation activities. The major learnings are discussed in the following paragraphs based on the results for each well. The optimization problem structure is described to provide context for the learnings on each well.

<u>Optimization Problem Structure</u>

The major measured variables for a typical dual-string SAGD well are wellhead temperature (WHT) and wellhead pressure (WHP) on each string. Most wells will also have a Flowing Bottom Hole Pressure (FBHP) measurement in the liner, which is five measured variables.

In a well test, the total well gas, oil and water rates are measured, but not separately for each string. In a well-test calibration, the optimizer adjusts the null flow point of the liner (NFP), which is the point in the liner that flow splits left or right to the short or long string, pressure at the NFP, inflow temperature at the NFP and inflow temperature at the heel and toe of the well. The inflow temperature profile is then set as an interpolation between the three adjusted temperatures. The inflow rate is assumed to be evenly distributed along the liner. Gas lift rates for the well test are known and fixed. A calibration optimization then solves a least-squares optimization of the five measured variables against the simulated values of those variables, using the five adjusted variables. Based on the pressure and temperature profile from the optimization, we then generate a distributed inflow model. Overall, the optimization uses flows to calibrate inflow pressure response and temperatures.

The VFM optimization uses the same five measured variables for the objective and the same five adjusted variables as the calibration. Gas lift rates are known and fixed for that VFM time window. The internal well model then uses the distributed inflow model to calculate the liner and string flowrates that meet the least-squares objective, along with updates to the inflow temperature to account for daily conditions and injection influences. Well test calibration and VFM together provide a strong quality check; if a VFM is run on the same data as a well test calibration, they should provide the same inflow model at the same rates and temperature profile. In practice there are very small deviations, because least-squares is a best fit, but we discovered that this is a good indicator for a bad optimization or inconsistent well-test data. The VFM generates a twice-daily flow measurement and updated inflow temperature profile for the well. Overall, the optimization uses pressures and temperatures to calibrate flow and inflow temperature.

In general, for least-squares data fitting to models such as calibration and VFM, an optimization should have at most the same number of adjusted variables as there are measured variables. If there are more adjusted than measured variables, the optimizer has too much flexibility to fit the data and can produce calibration values that do not correctly predict the effect of changes. This is a standard numerical guideline to force the algorithm to compromise.

The short-term optimization is based on a maximum-flowrate objective for the well, summing the oil rates for each string. The purpose is to identify a small change from current operation that will improve performance. Constraints are added for maximum and minimum WHP and subcool temperature limit. The lower limit for WHP is set as 20 kPa lower than the current operating point, or the minimum permitted for the well, whichever is greater. The subcool limit is typically a minimum 5 degrees C, this constraint exists to prevent the optimizer from generating advice that might lead to a steam breakthrough. The adjusted variables are the NFP, liner P, and gas lift rate per string. Gas-lift rate is allowed to move by +/- 20 std m^3/hr of the current operating point. The inflow model from the associated VFM run is used in the well simulation. Generally, this optimization moves WHP to their minimum and lift gas rates to their maximum. Overall, the optimization uses pressures and lift rate to determine maximum flow, subject to constraints, to identify the daily tactical opportunity.

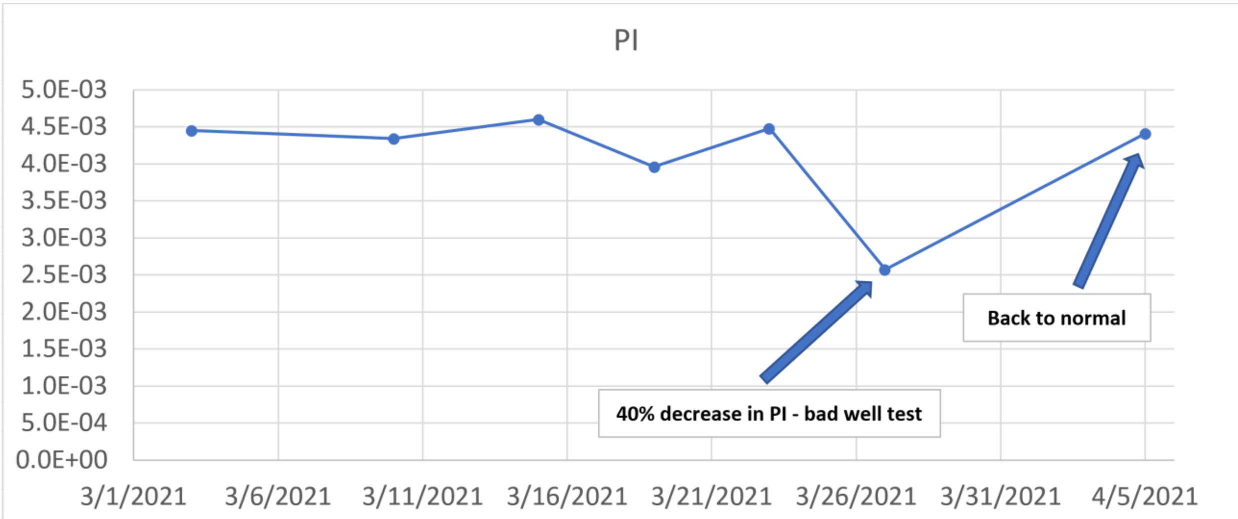
This series of three optimizations provides incremental, sequential updates for well performance and operation. The relatively infrequent well tests are used to calibrate inflow pressure and temperature response every two weeks. VFM runs then provide flow measurements and an updated inflow temperature each day. Short-term optimization runs then use the daily VFM inflow to provide an improved operating point.

The long-term optimization is run on each well test. The formulation is the same as the short-term, except that the lift gas limit is set to the maximum rate that is available for each string and the WHP is set to the minimum permitted for the well.

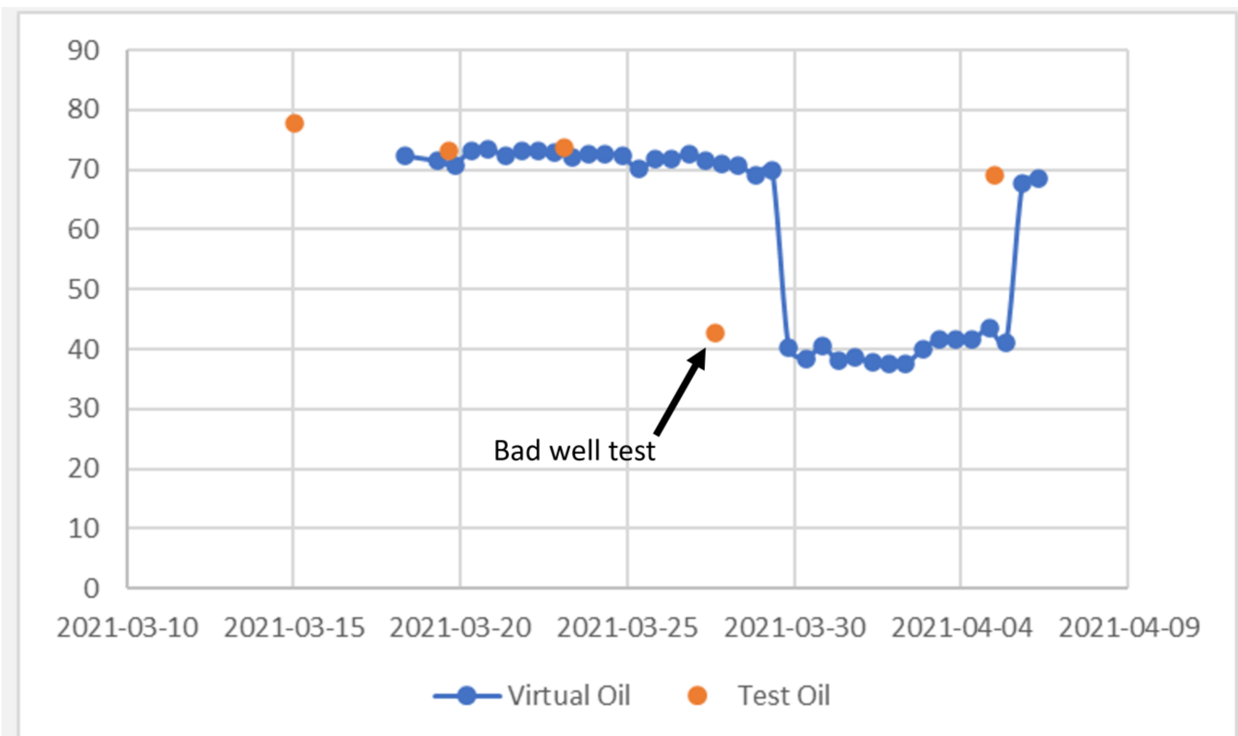
<u>Well 1 (Standard Well)</u>

Well 1 is a stable, well-instrumented well known to be consistent, selected as a reference case. It has WHP and WHT measurements for each string, gas lift measurement and control for each string and a FBHP measurement in the liner. The optimization workflows were initially developed using this well.

Calibration of the well model was reliable over the 7 months the well has been online. The chart below shows the average Productivity Index (PI) calculated from each well test. On March 27 there was a suspected bad well test, based on rates and the average PI calculated from the calibration run. This was the first indication that the system could be used to detect and advise of bad well tests.

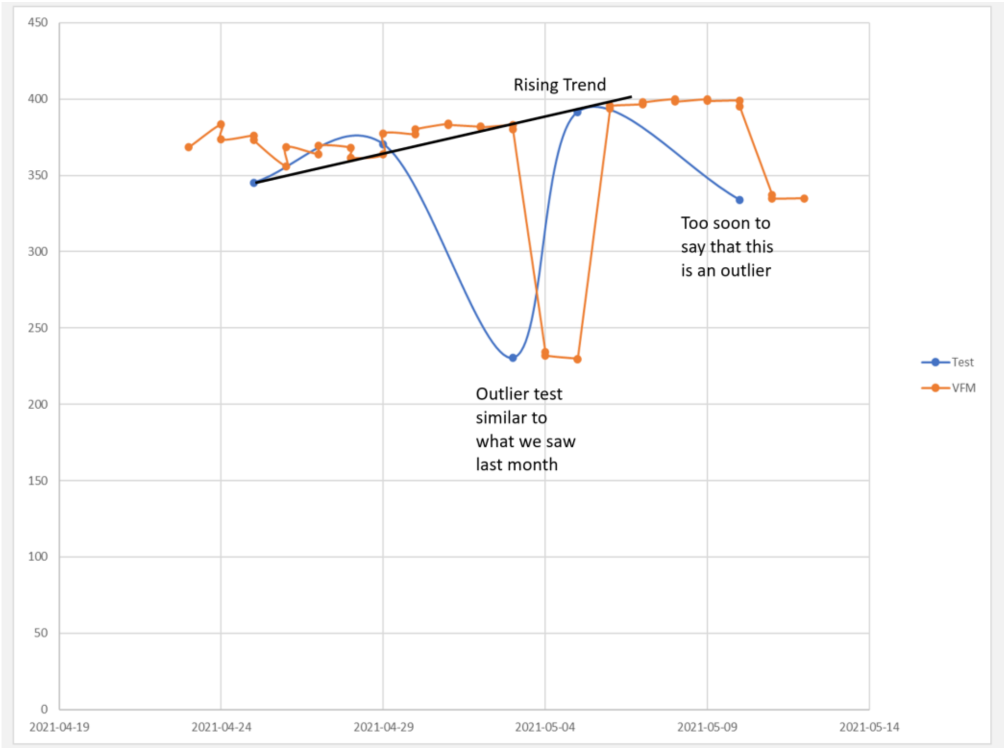


The chart below shows the performance of the same set of well test calibrations with the VFM in March 2021.



If the VFM had kept running based on the consistent well test from March 23rd, the VFM trend would have remained consistent also. In the event of a bad test, it is likely that the VFM can continue to provide good flow estimates if the most recent consistent well test is used.

In the April-May period, we began testing the short-term optimization advisory setpoints for Well 1 in the field. The VFM and well test responses to the operating changes are shown on the next chart.

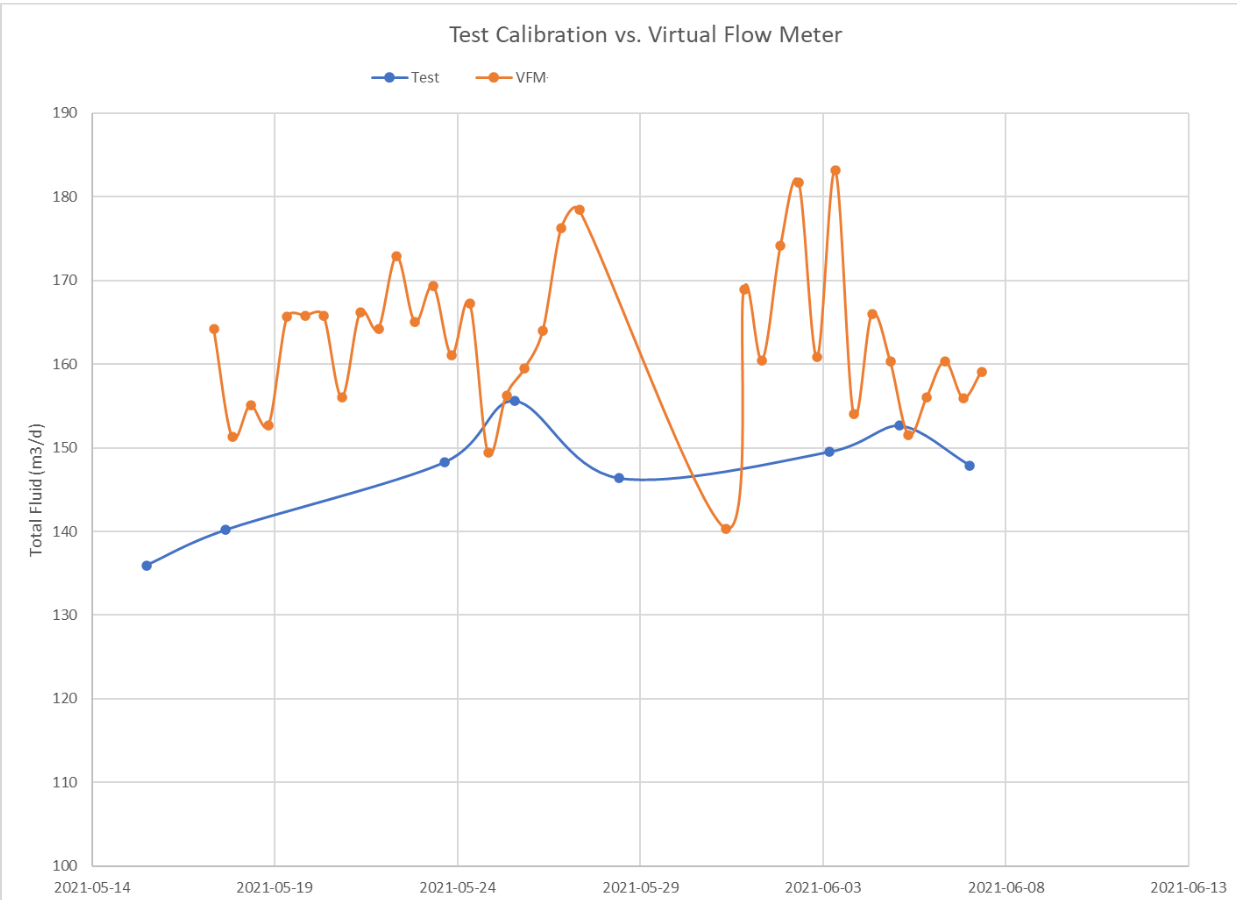


Over the period based on three tests, production increased by 11%. There was one failed well test in early April, and the well and test separator had some operational problems in May.

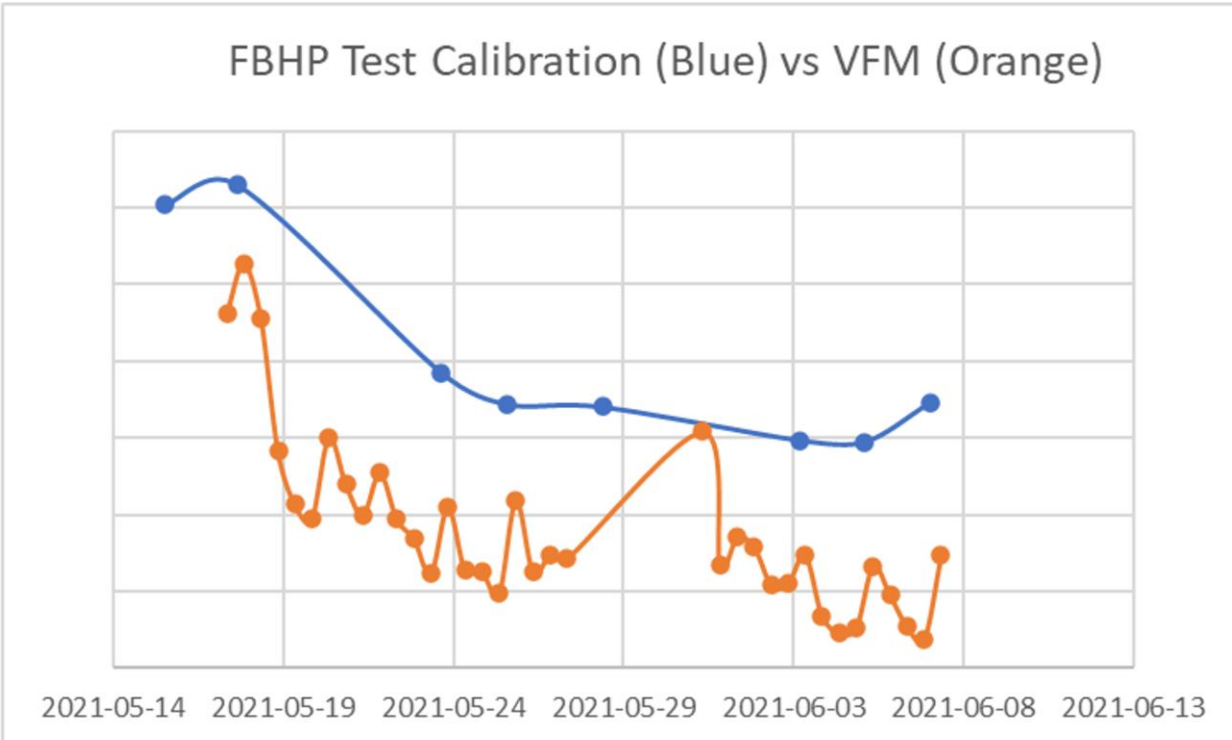
Well 2 (Mature Well)

Well 2 is a very mature, less instrumented well from the mid 2000s. It has manual gas lift split control and a total lift gas rate, without measurement for each string. FBHP is measured by shutting off lift gas to the short string and measuring the gas lift string pressure. This is an unreliable and inaccurate way to measure FBHP; the short string is not being lifted while the measurement is being taken and so the hydraulics to the liner will be different and it is possible that that section of the liner will not be flowing. This is not accurate enough to use for surveillance. We elected to exclude FBHP from the calibration and VFM optimizations to investigate if the system could still provide value, even though the wellhead to FBHP pressure balance is the largest driver of lift performance.

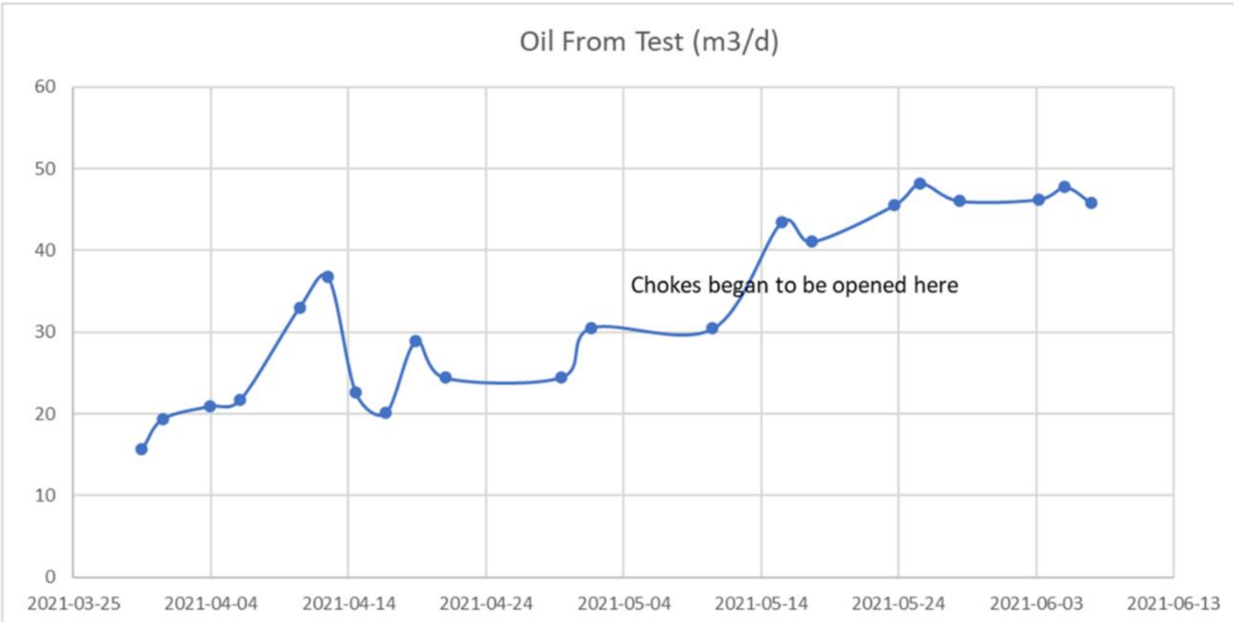
Over the course of testing, we saw that the VFM consistently over-estimated production against the well tests, as shown below.



On investigation, the VFM runs were consistently underestimating FBHP against the manual measurement, shown below. A lower FBHP means higher rates.



However, with a consistent and explainable deviation, the short-term optimization was able to provide good advice, which was to lower WHP by opening manual chokes as much as possible. The positive impact is shown below.



This is a 70 – 80% production increase, considerably more than expected. On discussion with production engineers, it was realized that this well had always been run as it was at the beginning of the trial, with no significant operational changes; nobody had attempted any manual optimization as they have on newer, better-instrumented wells.

<u>Well 3 (Sophisticated Well)</u>

Well 3 is the youngest, most-instrumented well in the project. It has WHP and WHT measurement, FBHP measurement at the heel and toe of the liner and DTS along the liner. It has gas lift control on each string and liner-deployed FCDs. The individual FCDs were not simulated, they were incorporated into the liner inflow model.

Our original calibration and VFM design was to use the standard calibration, with DTS and both FBHPs in the objective. We added distributed inflow temperature to the adjusted variables, to enable the optimizer to try and match the DTS profile. There were 11 adjusted variables to try and match 14 measured variables. In the initial trial period this was a complete failure. The calibration results gave a poor fit to the well test data and as a result the inflow model was wrong, which meant that the VFM and calibration were also not aligned and, in many cases, the short and long-term optimization predicted worse performance.

This was driven by the DTS temperatures and the two FBHP measurements. The liner temperatures are interdependent; the temperature at any given location is driven by the inflow at that location and also the inflows upstream of that location. Fundamentally, the optimizer was trying to compromise on matching all the DTS measurements, the WHTs, WHPs and both FBHPs. With wells running close to the subcool limit or flash point, there is a strong interaction between temperature and pressure.

Our first attempt at rectifying this was to reduce the weights of the DTS in the objective. This helped, but not enough. We then tested the 3-point temperature interpolation discussed earlier, which also improved results further. At this stage the temperature match was reasonable but the pressure match was still poor, particularly on the FBHPs. We then tried adding a multiplying factor to the multiphase pressure drop model and made this variable adjustable by the optimizer. This provided good calibration and VFM results and allowed matching of FBHP measurements, DTS and the wellhead conditions. An early June calibration is shown below.

Objective	Measured	Calibration	% err		DTS md	Measured	Calibration	% err
Short WHP	576	575	0.2%		500	177	170	3.7%
Long WHP	585	594	-1.6%		610	177	173	2.2%
Short WHT	147	145	1.4%		735	178	175	1.7%
Long WHT	153	153	-0.1%		860	179	177	1.1%
Long FBHP	1295	1295	0.0%		985	179	180	-0.3%
Short FBHP	1191	1191	0.1%		1110	181	180	0.4%
Heel T	170	177	-3.6%		1250	181	180	0.7%
Toe T	180	181	-1.1%		1375	182	180	1.5%

While this is a good match to the data, the multiplying factor is a compromise from a physics perspective. It is better for the optimizer to adjust model boundary conditions on a global physics model to match data. With a multiplying factor, the physics model potentially becomes a local physics model, although this is not clear until multiple sets of data have been fitted. The series of values of the factor becomes a KPI; if the value over several tests remains approximately constant, then there is some characteristic that the physics model is not describing, but the factor is consistent and so the physics model with that factor is still globally predictive for the particular well. This is similar to the flow offset in Well 2. If the factor changes significantly on each well test, then the physics model is local for that test and valid over a smaller range. This means that the short-term optimization should still be valid for the small changes it is permitted to make, but the long-term optimization may be less useful. We do not have enough well tests yet to determine if the factor is consistent.

One of the reasons that the factor is required may be that the liner FCDs and their pressure response were incorporated into the inflow model, meaning that the FCD pressure response is in the PI value. Proving or disproving this requires a more detailed model incorporating the FCDs.

With the better calibration and VFM performance, the short-term optimization was predicting increased production with different setpoints. These setpoints are unable to be tested because these would exceed a Total Fluid to Steam Ratio (TFSR) constraint. We have added this constraint to the short-term optimization but there are not enough data for conclusion at this point. This constraint makes optimization more challenging; the TFSR is a whole well constraint and if it is limiting then there are multiple ways to maximize production of the well. A more sophisticated, margin-based objective function is required.

Conclusions

We have generated significant know-how and knowledge around creating an on-line optimization platform for SAGD production wells:

Physics-based algorithms provide a strong basis for estimating production from producing SAGD wells as a Virtual Flow Meter.

Applying numeric optimization to simulation that leverages a VFM can viably generate more production or can be used to keep a well operating within its safe limits, such as TFSA or other KPIs.

There are important changes in algorithm design required, based on the available instrumentation and well vintage:

- Estimating the correct downhole temperature which then impacts the FBHP.
- Distributed downhole temperature readings coupled with distributed FBHP measurement can over-specify the problem. Knowhow on how to handle this was developed in the project.
- The lack of downhole temperature and FBHP readings requires a compromise that may not exactly match manual measurements but still provide significant uplift. Knowhow in this area was also developed.

Processes and procedures to commission and validate such a system have been generated for the overall platform and for well-by-well deployment, for example, how to monitor for data transmission, how to assess whether simulations commissioned for a particular well are running correctly and using the right data and how to present dense information in a straightforward UI.

G. OUTCOMES AND IMPACTS

Please provide a narrative outlining the project's outcomes. Please use sub-headings as appropriate.

- **Project Outcomes and Impacts:** Describe how the outcomes of the project have impacted the technology or knowledge gap identified.
- **Clean Energy Metrics:** Describe how the project outcomes impact the Clean Energy Metrics as described in the *Work Plan, Budget and Metrics* workbook. Discuss any changes or updates to these metrics and the driving forces behind the change. Include any mitigation strategies that might be needed if the changes result in negative impacts.
- **Program Specific Metrics:** Describe how the project outcomes impact the Program Metrics as described in the *Work Plan, Budget and Metrics* workbook. Discuss any changes or updates to these metrics and the driving forces behind the change. Include any mitigation strategies that might be needed if the changes result in negative impacts.
- **Project Outputs:** List of all obtained patents, published books, journal articles, conference presentations, student theses, etc., based on work conducted during the project. As appropriate, include attachments.

RESPOND BELOW

Project Outcomes and Impacts

The most important outcome for the project is the demonstration that it is possible to deploy full-physics SAGD wellbore models in an online environment and realize production gains.

As the industry continues the drive to do more with less, automated surveillance and analytics will become more and more important. Engineers do not have time to perform manual analysis of the wells they are responsible for. This project has demonstrated that it is possible to move to a factory performance model for SAGD: wells are production machines that can be monitored and analyzed with advanced models that provide status and advice on the machines' performance. The engineer then manages by opportunity and exception, to capitalize on opportunities and investigate and correct poor performance. Similar workflows and opportunities exist for ESP-lifted wells.

Clean Energy Metrics

Data-enabled innovation: We believe this is an industry-first application of full-physics SAGD well models in an online environment. The project uses real-time SCADA production data to calibrate the well models and provide a Virtual Flow Meter with production optimization.

Digital Transformation for Business innovation: The project has demonstrated that time-consuming, manual calibration of SAGD production well models is unnecessary and that flow measurement and optimized, advisory setpoints can be provided automatically. These activities are not conducted manually by production engineers because they do not have enough time and consequently miss value opportunities. The technology enables new workflows for engineers that increase value with a minimal time commitment.

Future Investment: The project demonstrated compelling production uplifts through automation. This is a strong basis for investment and commercialization.

Clients selling goods or services internationally: While SAGD production is largely based in Alberta, the workflows and processes are directly portable to other well and resource types produced internationally. Madala has initiated discussions with conventional gas-lift and ESP providers in Canada, the US and the EU. The technology is also directly applicable to ESP and solvent-based SAGD production.

Number of publications: The project will result in publication of at least one conference or journal paper.

Number of field pilots: This project is the first field pilot. We anticipate all clients will require a small-scale field pilot before a commercial commitment. Suncor has agreed to support Madala in evangelizing the technology.

Projected GHG emissions reductions from future deployment: This is difficult to quantify on a limited, 3-well pilot, however a potential emissions reduction is described in Section H.

Sector HQSP Trained: One EIT has been participating the project. The EIT has stated that they now use the system daily for surveillance and optimization of the three wells. In addition, a Senior Production Advisor and a Production Manager have been involved and attended the majority of team meetings. As the system is commercialized and scaled, more HQSP will be trained in the use of the system and gain insight into their production assets.

Existing Sector HQSP jobs retained: This is difficult to quantify on a pilot project. However, with an automated surveillance and advisory system, production engineers can assign more time to high-value work, including responding to the outputs of the system. Engineers with a better perspective and knowledge of their production assets can extract higher value from them, increasing their value to their employers.

New products/Services created: The project has delivered a successful pilot as the basis of a new, commercialisable product.

TRL Advancement: The technology supporting the project has reached TRL 7.

Program Specific Metrics

Number of collaboration partners: There are two partners.

$/bbl product uplift: The original uplift goal of the project was to determine if production could be increased 2 – 5%. This was exceeded. At the current WTI/Diluent price of $72 USD/bbl, a WCS price of $58/bbl and a blend of 30% diluent to 70% bitumen, the produced bitumen revenue is $52 USD/bbl, or $62.40 CDN/bbl. On 1,000 bbl/d and assuming a 5% uplift, this is an increase of 50 bbl/d, or $3120 CDN/d.

If cost of production is 2/3 of the gross revenue, the net revenue is $17.33/bbl and the realizable value is slightly over $1 CDN/bbl on the full field capacity.

Number of end users participating: Suncor was the producer participant, with the strong value proposition of the technology we intend to grow to the majority of SAGD producers.

Project Success Metrics

Calibrated model predictions against production data: We have met the commercialization performance target of a 5% error. The base project goal was 10%.

Model calibration performance: We have exceeded the commercialization performance target of 6 minutes, calibrations based on optimizations typically complete in 1 – 2 minutes.

Model optimization performance: We have exceeded the commercialization performance target of 6 minutes, optimizations typically complete in 1 – 2 minutes.

All workflows cloud deployed: This has been achieved, the system is accessible and operable anywhere there is an internet connection. The system is usable on any device from a phone to a large screen, although the phone utility is limited.

Automated workflows in continuous operation: This has been achieved.

H. BENEFITS

Please provide a narrative outline the project's benefits. Please use the subheadings of Economic, Environmental, Social and Building Innovation Capacity.

- **Economic:** Describe the project's economic benefits such as job creation, sales, improved efficiencies, development of new commercial opportunities or economic sectors, attraction of new investment, and increased exports.
- **Environmental:** Describe the project's contribution to reducing GHG emissions (direct or indirect) and improving environmental systems (atmospheric, terrestrial, aquatic, biotic, etc.) compared to the industry benchmark. Discuss benefits, impacts and/or trade-offs.
- **Social:** Describe the project's social benefits such as augmentation of recreational value, safeguarded investments, strengthened stakeholder involvement, and entrepreneurship opportunities of value for the province.
- **Building Innovation Capacity:** Describe the project's contribution to the training of highly qualified and skilled personnel (HQSP) in Alberta, their retention, and the attraction of HQSP from outside the province. Discuss the research infrastructure used or developed to complete the project.

RESPOND BELOW

Economic

The project has demonstrated that a 5% production uplift can be achieved. At current WTI prices, the post-payout royalty rate is 28% of net revenue. In a stable market with net bitumen revenue of $17.33 CDN/bbl, a 5% production increase generates an extra $31.6M/y on 100,000 bbl/d. This provides $8.8M/yr in royalties and almost $23M for reinvestment by the producer.

Environmental

The ability to optimize and increase production has the corresponding benefit of being able to reduce resource use for the same production target. The production increases in the project were achieved without changing steam injection rates. If the same production rate can be achieved with 5% less steam, there is a clear GHG benefit. Steam GHG footprint varies from producer to producer, but 53 kg CO_2e/bbl is a reasonable industry average. At a steam-oil ratio of 2.5, a 100,000 bbl/d field produces 13,250 tonnes CO_2e/d. A 5% reduction removes 663 tonnes CO_2e/d of emissions. On a passenger vehicle basis of 4.6 tonnes CO_2e/y (US EPA figures), this is the equivalent of taking 144 cars off the road for a year.

Social

The primary social benefit is entrepreneurship opportunities for the Province. The project has provided a de-risked pilot for online data exchange and performance optimization of Alberta's largest industry. Deploying and maintaining these kinds of software applications is challenging, in spite of the clear value proposition many companies struggle to realise the benefits. Alberta's advantage is that there is a common production technology spread across a relatively small land area with high production rates and a close community. This means that the benefits of a digital-based opportunity can be de-risked, deployed and commercialized more quickly than areas that have widely-varying production technologies. In addition, there are likely further opportunities in surveillance and optimization of other equipment types and facilities both inside and outside of Oil and Gas production. By establishing a successful, validated path to exploiting digital initiatives to optimize oil and gas production, the barrier to similar digital optimization deployments is lowered, as much of the software infrastructure, experience and knowledge can be reused.

Building Innovation Capacity

At the conclusion of the project there is one additional HQSP trained in production optimization in the partner organization. Madala's goal is to reach at least 60% market penetration for SAGD production, at 1.5 Mbbl/d production, 60% penetration is 900 kbbl/d. If one Production and one Operations engineer is required for every 10,000 bbl/d of production, there would be 180 HQSP that will be directly involved and fully trained in online production optimization. This number will likely be significantly higher as organizations cross-train and move personnel around. This then provides a strong capacity base and standardized knowledge based on this skillset which is important for resilience and viability of the SAGD industry. Producers will also benefit by having a broader, more stable pool of talent to draw on.

I. RECOMMENDATIONS AND NEXT STEPS

Please provide a narrative outlining the next steps and recommendations for further development of the technology developed or knowledge generated from this project. If appropriate, include a description of potential follow-up projects. Please consider the following in the narrative:

- Describe the long-term plan for commercialization of the technology developed or implementation of the knowledge generated.
- Based on the project learnings, describe the related actions to be undertaken over the next two years to continue advancing the innovation.
- Describe the potential partnerships being developed to advance the development and learnings from this project.

RESPOND BELOW

The long-term commercialization plan is to continue to develop the system and its capabilities to become the de-facto production surveillance and optimization tool for in-situ production in Alberta and Saskatchewan. There are approximately 600 gas-lift wells in production across the two Provinces, from Suncor, CNRL, Husky and smaller players.

Over the next two years, development will be progressed on two fronts. The first is to pursue and fund a major deployment across 50 – 60 wells at one producer, to reach 10% of the SAGD gas-lift market, prove the solution scalability and reach TRL 8. This would prove the full commercial viability. The second front will be conducted concurrently, focused on an equivalent ESP-lift solution. The ESP value proposition is slightly different than gas-lift; ESP wells have higher production performance but they are prone to pump failures. An ESP failure costs in the region of $400,000 an incident, with associated lost production and the CO2e emissions and risk exposure of heavy equipment and staff travelling to and from site. Madala already has full-physics ESP well models, which can be deployed online to predict installed ESP conditions, wear and potential lifetime to failure. There is an opportunity to optimize production and equipment reliability, the solution only has to save one ESP to prove value.

We anticipate partnerships with producers and equipment vendors. Many producers have digital initiatives, with their own proprietary analytics or processes that would be beneficial if linked with a physics-based surveillance platform. These can be integrated on a case-by-case basis. We are aware of ESP vendors that are interested in discovering more about how their equipment is used; with this kind of platform we can provide better visibility into operating conditions for vendors and producers in a common environment, enabling improvements in reliability for both groups.

J. KNOWLEDGE DISSEMINATION

Please provide a narrative outlining how the knowledge gained from the project was or will be disseminated and the impact it may have on the industry.

RESPOND BELOW

The project team has gained considerable knowledge in the online optimization of SAGD gas-lift production. The knowledge is deployed in a way to make it easily accessible to production engineers and enable off-line analysis. One of the key advantages of the system is that it provides a continuous optimization history of the wells. This is a form of knowledge retention and helps producers move staff around production teams, the optimization history is now in a software platform instead of locked in an engineer’s head. This aids HQSP career development and de-risks employee movement.

Part of the the Building Innovation Capacity subsection from Section H is repeated here: If one Production and one Operations engineer is required for every 10,000 bbl/d of production, there would be 180 HQSP that will be directly involved and fully trained in online production optimization. This number will likely be significantly higher as organizations cross-train and move personnel around. This then provides a strong capacity base and standardized knowledge based on this skillset which is important for resilience and viability of the SAGD industry. Producers will also benefit by having a broader, more stable pool of talent to draw on.

K. CONCLUSIONS

Please provide a narrative outlining the project conclusions.

- Ensure this summarizes the project objective, key components, results, learnings, outcomes, benefits and next steps.

RESPOND BELOW

The project delivered an automated Digital Twin pilot for production optimization. The objective was to deploy full-physics models of SAGD production wells in an online cloud-based environment, using parameter estimation to calibrate the models to real-time production data and nonlinear optimization to provide automated surveillance and production optimization advice. A production gain of 2 - 5% was targeted. The project was successful, exceeding the 5% production gain target and providing automated visibility into well tests and accurate virtual flow measurement (VFM) between well tests. Overall, an average production increase of 5% is worth slightly over $1 CDN/bbl *after* production costs, calculated on the total field rate. On a 50,000 bbl/d field, this becomes $18.25M CDN/yr free cash flow at current prices.

Key to the success of the project was the ability to calibrate the physics models within a few percent of the operating data. The less accurate the model, the more engineering judgement is required to interpret its results. Calibrating the models within a few percent of production data is critical for automated workflows because the advice from the system is generated based on the calibration; a weak calibration generates unreliable advice.

The project met or exceeded all the project success metrics, in particular calculation performance and accuracy and the entire automated system was deployed in a cloud environment. Over the course of the online trial, the system performed several hundred calibration, VFM and optimization runs on widely-varying data, without human intervention, proving robustness and viability of the approach.

Overall, physics-based algorithms provide a strong basis for estimating production from producing SAGD wells as a Virtual Flow Meter.

Applying numeric optimization to simulation that leverages a VFM can viably generate more production or can be used to keep a well operating within safe limits based on integrity KPIs.

There are important changes in algorithm design required, based on the available instrumentation and well vintage:

- Estimating the correct downhole temperature which then impacts the FBHP.
- Distributed downhole temperature readings coupled with distributed FBHP measurement can over-specify the problem. Knowhow on how to handle this was developed in the project.
- The lack of downhole temperature and FBHP readings requires a compromise that may not exactly match manual measurements but still provide significant uplift. Knowhow in this area was also developed.

Processes and procedures to commission and validate such a system have been generated for the overall platform and for well-by-well deployment, for example, how to monitor for data transmission, how to assess whether simulations commissioned for a particular well are running correctly and using the right data and how to present dense information in a straightforward UI.

The project has demonstrated that it is possible to move to a factory performance model for SAGD: wells are production machines that can be monitored and analyzed with advanced models that provide status and advice on the machines' performance. The engineer then manages by opportunity and exception, to capitalize on opportunities and investigate and correct poor performance. Similar workflows and opportunities exist for ESP-lifted wells.

There were several Clean Energy metrics for the project, most importantly Data-Enabled Innovation and Digital Transformation for Business Innovation. The project leveraged standard production measurements and data to deliver a first-of-a-kind physics-based surveillance, virtual flow meter and optimization workflows for SAGD. These workflows could not be performed manually by production engineers.

There are economic, environmental, social and innovation capacity benefits realizable from the project. The economic benefit based on post-payout royalties is almost \$23M to the producer and \$8.8M to the Province, based on 100,000 bbl/d production for a year. The environmental benefit on a 100,000 bbl/d field is estimated to be 663 tonnes CO_2e/d emission reduction. The social benefit is based on expanding entrepreneurial opportunities for the Province, by deploying a locally-developed innovation to improve production and environmental performance across an oil resource that has a standard recovery design. The innovation capacity benefit can be realized through large-scale deployment of the technology, educating HQSP in SAGD operations optimization and providing opportunities for the HQSP to keep adding value to their organizations.

Finally, the next steps to be taken are to pursue a much larger deployment of the project technology, of the order of 50 – 100 wells to prove final commercial viability and technology scale-up, to reach TRL 8 and 9. The technology will also be expanded to ESP fields, providing a combined surveillance, VFM, optimization and ESP reliability solution.