Successful Real-Time Optimization of a Highly Complex, Integrated Gas System

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Background

Traditionally important aspects of security of gas supply relate to reservoir management, development planning, and sustaining plant availability and integrity. With increased computing capabilities, increased attention is also given to non-CAPEX-intensive ways to provide additional, smaller scale improvements to the performance of an asset [11]. Production System Optimization (PSO) falls into this category, and the contents of this paper is an element of automated PSO.

To date, the Sarawak asset has experimented with a number of ways to improve continuous optimization of its production through model optimization. An implementation [9] of a Mixed-Integer Non-Linear Programming [7, 10] model has rendered valuable results on the Medium Term and Long Term planning horizons. The complexity of the network and the amount of optimization calculations required, obviates real-time application. Subsequent unsuccessful approaches included using rigorous Process Engineering simulation and optimization tools linked to the data historian. Also, two commercially available software packages were trialed, but none of these approaches produced the desired results in a way that was fast enough and sustainable by local staff.

This paper describes a more successful and pragmatic approach that features easier to apply and sustain data driven models in a software package that is a standard within Shell, and with which hundreds of users are familiar [4, 12]. The objective has been to provide a solution that is fast enough to be applied in the real-time domain, and simple enough to be used and maintained locally as part of the routine work processes. First the asset, its complexity and constraints are described, followed by a discussion of possible optimization approaches, and which approach has been applied. Then the optimization methodology is described, and how the solution is applied in the daily operational decision making process. Finally a prior-to-go-live testing approach is discussed, followed by a brief outline of other areas in which a similar optimization approach has been applied in Shell, and conclusions are given.

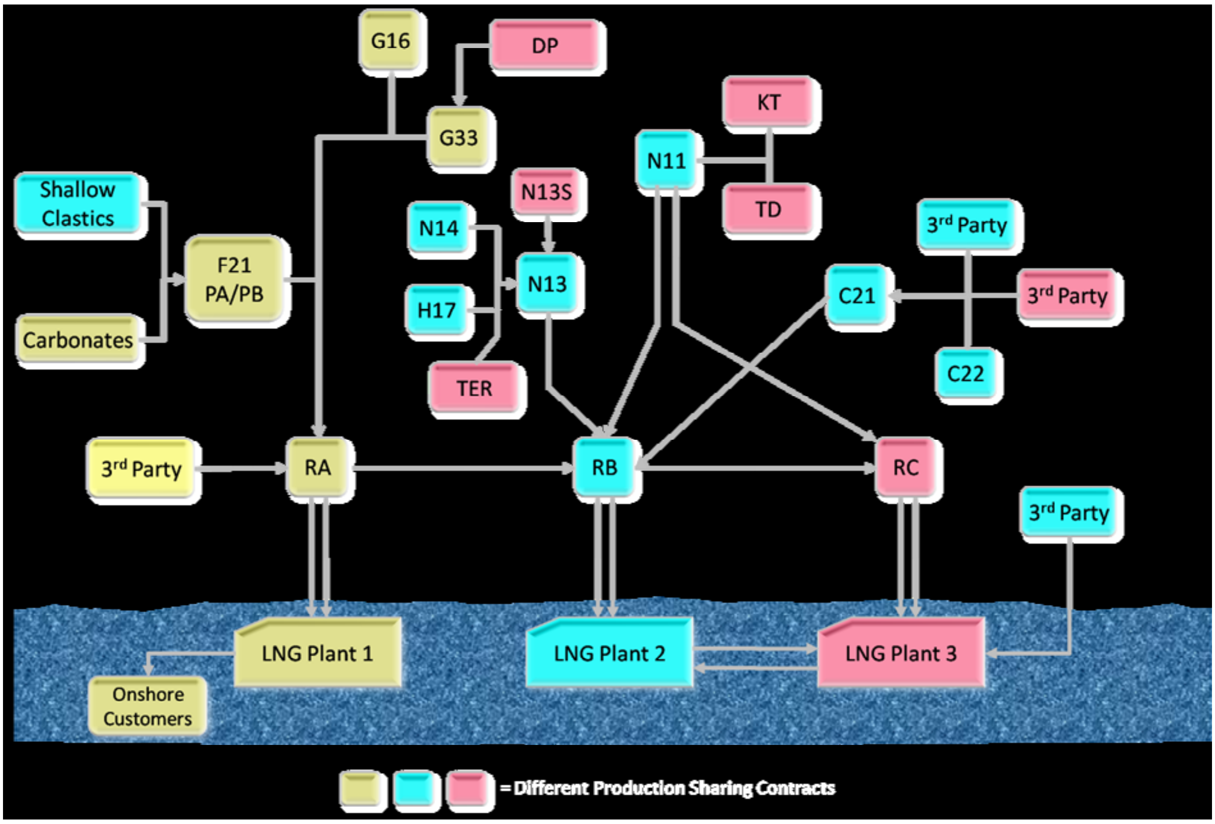

Figure 1 *Simplified overview of the integrated production system.*

The Sarawak integrated gas asset is located in the South China Sea off the coast of the state of Sarawak in East-Malaysia, and comprises of: 3 onshore LNG plants at the onshore LNG complex in Bintulu, 4 onshore customers and an LNG cargo export facility, 50+ offshore hubs and jackets, 100+ wells, numerous connecting pipelines, covered by 5 Production Sharing Contracts, and where a number of different operators are active - see Figure 1, above.

The asset produces offshore natural gas of variable composition that is blended in the source system pipelines and liquefied in the onshore LNG plants in Bintulu. Associated condensates are also collected and processed in the Bintulu complex. Constraints in the system are physical, planning, and contractual / commercial in nature:

Physical and Infrastructural Constraints

- Pipeline diameter, maximum flow and pressure
- Pipelines and risers routing
- Well and reservoir production envelopes (maximum drawdown, sand production)
- Facility capacity constraints (water handling, compressor capacity) [1)]
- LNG train handling capacity:
    - Gas volume (that vary depending on contaminant contents) [2)]

[1)] The system does not explicitly take into consideration equipment status or equipment constraints, but the operator can manually adjust the 1) overall, current platform capacity based on the latest operational information.

- CO_2, H_2S, C5+ handling
- Intake pressure
- Plant trips [1)]

Planning Constraints [3)]

- LNG demand and gas production nominations
- Shutdowns
- Well tests and wells interventions
- PSC expiry dates

Commercial Constraints

- Maximum allowable CO_2 percentage per LNG train as stipulated in the Gas Sales Agreements
- Gas quality / Gross Heating Value (GHV)
- Ultimate Recovery: long term it is important to ensure that sufficient sweet gas is available to blend with gas that contains a too high percentage of contaminants;
- Gas borrowing agreements between PSCs: if production of a PSC is in deficit of its PSC primary demand, gas can be borrowed from a PSC (in Priority of Supply order) that has excess capacity. [4)]
- Priority of Supply: stipulates which PSC and which field is 'allowed to' produce first, second, etc. to meet a demand.
- Supply ratios: in a situation where multiple operators produce into the same PSC, their production is constrained according to a static relative supply ratio: operator 1 can produce 2.5 times as much as operator 2 can produce 1.3 times as much as operator 3. The ratio is based on the operator capacity and overall average PSC demand level. If one or more operators are in deficit, the remaining operators can fill the gap, again according to their respective ratios.
- Economic, commercial, and financial stipulations in the PSC contracts. See next section.

All constraints mentioned above are part of the optimizer to ensure that the optimized advice is within the constraints that exist in the system.

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2) The system does not carry LNG train capacity constraints, but applies the gas demand as a constraint.

3) Monthly plan data can be copied into the model if the Excel scenarios interface is used. With the new real time optimization approach, user interface nominations and planning constraints are entered on a daily or as-required basis.

4) PSC producers are contractually mandated to produce their gas into the LNG plant of the same PSC, but physically this is not always possible. Between risers RA, RB, and RC pipelines are in place that enable gas flow from one riser to another to enable the contractual obligations to be met, and also to enhance the ability to manage gas supply/demand and quality.

Optimization Approaches

Besides taking a view on the balance between, and definitions of long -term and short -term optimization, three optimization levels were considered: financial, economical, and operational, as follows:

Financial – impractical

This constitutes the dollars that hit the bottom line at the end of the day: total profit after royalty, tax and interest. The dollars are generated from gas and condensate sales revenues at the going rates, minus taxes and the costs of investments and operations.

The calculations would include some or all PSC terms: operator shares, contractual pricing scheme, spot prices, the revenue or penalties associated with gas borrowing, cost recovery ullage or ceiling, PSC investment levels and capital cost recovery status, liquids allocation scheme, currency agreements, royalty, tax and profit gas percentages. It should in theory also include some accounting practices such as: assets and liabilities, cost and revenue categorization, exchange rates, asset depreciation, cost of capital, CAPEX and OPEX levels, and tax situation.

The complexity of this approach is compounded by operator participation in mid -stream and downstream assets PSCs.

Further drawbacks of this approach are: 1. the complexity to go from a daily production number to a bottom-line dollar, accounting for PSC rules and financial practices, is enormous and would make optimization practically impossible, and 2. it does not take into account the (long-term) time-value of gas and condensates production and reserves.

Economical – too theoretical

Perhaps a more correct, but also more theoretical approach would be to optimize on asset economical value [8]. This would take into account a slightly simplified version of the short -term financial approach, and augment it by placing the financial returns and expected returns in the context of the long term, and comparing the time value of money in real terms by applying a Nett Present Value of expected cash flow and assets.

This would shift the focus away from tomorrow's bottom line profits, and bring into the picture the value of expected Ultimate Recovery, and of gas that is left unproduced at the expiry date of a PSC, and the value of being able to produce the contaminated gas reservoirs for longer, due to the effect of good short -term sweet gas production decisions, inclusive of the cost and timing of planned shutdowns.

The drawback here is that this approach also makes the model too complex and too theoretical. Furthermore, when it comes to comparing the value of reserves versus a daily production decision of 100 MMscf/d more or less from one platform, the production variation becomes almost invisible in the bigger picture.

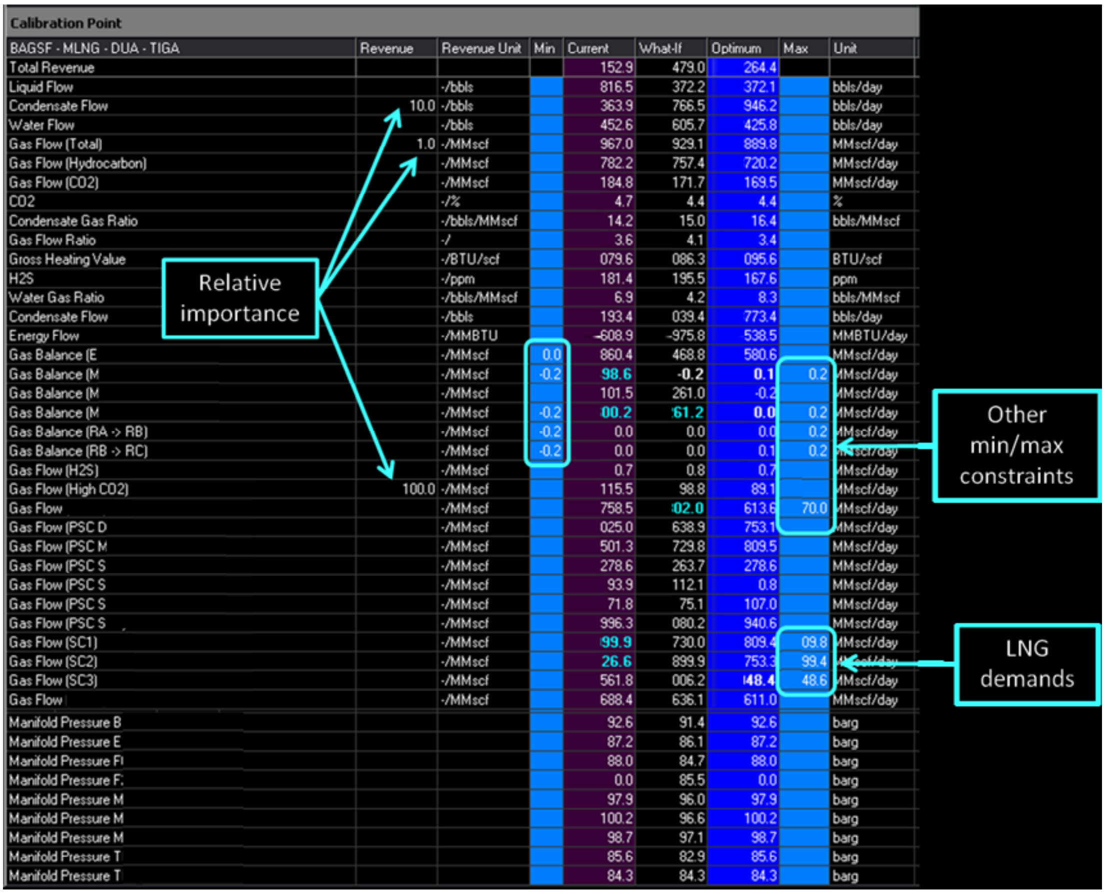
Operational – pragmatic and fits with the existing work processes

A more practical approach is to focus on daily production targets, actual production, and condensate/gas deferments – this is not as rigorous as the aforementioned Financial and Economical approaches, however, the data is measurable and exists in real-time without the need to invoke complicated calculations and assumptions, and output can easily be generated in terms that operational staff can work with.

Aims

In terms of the optimization objective of the optimizer in the solution, we have chosen to keep the optimization in the operational domain, but enhance it with the ability to apply relative factors to inputs, constraints, and target values.

This means for instance that we optimize not on MMscf/d production levels, but on production (MMscf/d) x quality (MMBtu/MMscf) x PSC gas price (US$/MMBtu). This resembles revenue more closely, and is more correct from an optimization perspective. We do not include the exact pricing and quality values, as this information is privileged, but setting relative factors to gas streams will skew the optimizer to 'prefer' producing more valuable gas.


Calibration Point

BAGSF - MLNG - DUA - TIGA	Revenue	Revenue Unit	Min	Current	What-If	Optimum	Max	Unit
Total Revenue				152.9	479.0	264.4		
Liquid Flow		-/bbls		816.5	372.2	372.1		bbls/day
Condensate Flow	10.0	-/bbls		363.9	766.5	946.2		bbls/day
Water Flow		-/bbls		452.6	605.7	425.8		bbls/day
Gas Flow (Total)	1.0	-/MMscf		967.0	929.1	889.8		MMscf/day
Gas Flow (Hydrocarbon)		-/MMscf		782.2	757.4	720.2		MMscf/day
Gas Flow (CO2)		-/MMscf		184.8	171.7	169.5		MMscf/day
CO2		-/%		4.7	4.4	4.4		%
Condensate Gas Ratio		-/bbls/MMscf		14.2	15.0	16.4		bbls/MMscf
Gas Flow Ratio		-/		3.6	4.1	3.4		
Gross Heating Value		-/BTU/scf		079.6	086.3	095.6		BTU/scf
H2S		-/ppm		181.4	195.5	167.6		ppm
Water Gas Ratio		-/bbls/MMscf		6.9	4.2	8.3		bbls/MMscf
Condensate Flow		-/bbls		193.4	039.4	773.4		bbls/day
Energy Flow		-/MMBTU		-608.9	-975.8	538.5		MMBTU/day
Gas Balance (E		-/MMscf	0.0	860.4	468.8	580.6		MMscf/day
Gas Balance (M		-/MMscf	-0.2	98.6	-0.2	0.1	0.2	MMscf/day
Gas Balance (M		-/MMscf		101.5	261.0	-0.2		MMscf/day
Gas Balance (M		-/MMscf	-0.2	00.2	61.2	0.0	0.2	MMscf/day
Gas Balance (RA -> RB)		-/MMscf	-0.2	0.0	0.0	0.0	0.2	MMscf/day
Gas Balance (RB -> RC)		-/MMscf	-0.2	0.0	0.0	0.1	0.2	MMscf/day
Gas Flow (H2S)		-/MMscf		0.7	0.8	0.7		MMscf/day
Gas Flow (High CO2)	100.0	-/MMscf		115.5	98.8	89.1		MMscf/day
Gas Flow		-/MMscf		758.5	02.0	613.6	70.0	MMscf/day
Gas Flow (PSC D		-/MMscf		025.0	638.9	753.1		MMscf/day
Gas Flow (PSC M		-/MMscf		501.3	729.8	809.5		MMscf/day
Gas Flow (PSC S		-/MMscf		278.6	263.7	278.6		MMscf/day
Gas Flow (PSC S		-/MMscf		93.9	112.1	0.8		MMscf/day
Gas Flow (PSC S		-/MMscf		71.8	75.1	107.0		MMscf/day
Gas Flow (PSC S		-/MMscf		996.3	080.2	940.6		MMscf/day
Gas Flow (SC1)		-/MMscf		99.9	730.0	809.4	09.8	MMscf/day
Gas Flow (SC2)		-/MMscf		26.6	899.9	753.3	99.4	MMscf/day
Gas Flow (SC3)		-/MMscf		561.8	006.2	48.4	48.6	MMscf/day
Gas Flow		-/MMscf		688.4	636.1	611.0		MMscf/day
Manifold Pressure B				92.6	91.4	92.6		barg
Manifold Pressure E				87.2	86.1	87.2		barg
Manifold Pressure F				88.0	84.7	88.0		barg
Manifold Pressure F				0.0	85.5	0.0		barg
Manifold Pressure M				97.9	96.0	97.9		barg
Manifold Pressure M				100.2	96.6	100.2		barg
Manifold Pressure M				98.7	97.1	98.7		barg
Manifold Pressure T				85.6	82.9	85.6		barg
Manifold Pressure T				84.3	84.3	84.3		barg

Figure 2 *The operator user interface where relative importance can be given to objective flows, min/max constraints can be set, what -if scenarios tested, and current - and optimum operating*

point are given. Numbers don't reflect actual data.

At the same time, and in the same way, it is possible to make certain, often conflicting, objectives relatively more important than others – see Figure 2. E.g.: it may be more important to maximize daily condensate revenue, than it is to produce as much contaminated gas as allowable within contractual limits, or the other way around. The optimizer provides a transparent way of including such priorities into the solution.

Our objective function is to maximize condensate revenue while meeting gas demand at maximum achievable gas revenue (value) without gas borrowing, whilst ensuring that CO_2 content is always at its allowable maximum percentage, and early PSC expiry fields are produced with 'preference'. This satisfies most short-term and long-term objectives.

The most important constraint is the gas demand at the three LNG plants. We found that there is bandwidth within which we can decide *how* we meet this demand, and therewith room for optimization, but it is limited as simply meeting the gas demand is 90% of the solution.

Matching contractual agreements with physical delivery

A set of linear constraints allow for balancing the production of the platforms with the demand from the LNG plants, such that the Production Sharing Contracts (PSCs) are satisfied.

The PSCs specify which field should contribute to the delivery of which MLNG plant. However in some cases physical delivery to the plant is impossible; the gas simply cannot flow to the appropriate LNG facility. This is either because of a difference in pressure regime, or because there is no physical route for the gas to travel.

And while these gas molecules may travel a different route, the contracts are only concerned about the total gas volumes delivered. So in fact it is possible to borrow gas from one end of the network and lend it back at another, while still maintaining a neutral balance and thus deliver the same amount of gas to the LNG plant as is produced by the platforms in the contract.

To manage production in the PSCs, a set of gas balances have been setup where the total physical delivery to the LNG plants is set against the contractual agreements. In normal practice, these balances should be neutral, such that the gas volume produced according to the contract is the same as the gas delivered to the LNG plant.

In some cases the 'contracted' gas cannot fulfill the demand of the LNG plants. In such case, gas can be borrowed from one of the other contracts. This can be facilitated by allowing either a positive ('borrowing') or a negative ('lending') balance. The reverse can be implemented to borrow back the gas when possible. By putting a penalizing factor on gas borrowing between PSCs, the optimizer will find solutions where gas borrowing is minimum. If certain borrowing/returning is required, operators can manually enter the amount of borrowing/returning into an Excel interface or into the new real-time optimization interface, or adjust the penalizing factor to allow the optimizer to advise optimized borrowing rates.

With the use of this automated gas balancing, managing the PSCs is easier than before and prevents back-allocating production at the end of the month.

Methods

The Sarawak RTO system has been configured using the FieldWare Production Universe (PU) software. PU is used extensively throughout the Shell Group. Originally developed to monitor and optimize the production of individual wells and platforms [1], more recent PU implementations have focused on asset-wide optimization [6]. PU exists in two flavors – PU RTM which estimates dry gas flow, CGR and WGR for all of the wells all of the time and PU RTO which combines well rate estimates with electronic bulk measurements to continuously maximize an objective function whilst simultaneously honoring real time constraints.

The requirement to apply optimization in the real-time environment translates into a number of key requirements for the solution. For one, the system needs to be 'fast': capable of delivering a new optimal production set point for the entire field in less than 6 minutes. Also, the system needs to be flexible enough to cope with sudden and unplanned events, such as a production platform, or LNG train trip. And the system needs to be user friendly, with an intuitive Graphical User Interface (GUI) and an easy means to change constraints or objectives.

Using the PU application as the vehicle to implement the asset-wide RTO system has advantages. All real-time monitoring and reporting capabilities of PU are already available at the Asset-Wide Monitoring level in PU-RTM. With the RTO system running online using real-time data available from the RTM system and the data historian, the users get a real-time overview of how the entire production network is performing, what the real-time well flow rates are, how the pressure profiles look, compositions of the various streams (CO_2, H_2S), how the current demand is matched by the current production, etc. The Exception Based Surveillance (EBS) [13] capabilities of PU can email diagnostic messages to field crew in case of faulty transmitters, or if certain constraints are violated. And daily reports and historical trends make it easy to analyze productivity and performance against plan on a daily basis.

At the core of the Sarawak RTO system there are three main components:

1. The topology of the production system;
2. The models for the wells, platforms, and pipelines;
3. The optimization engine with objective function.

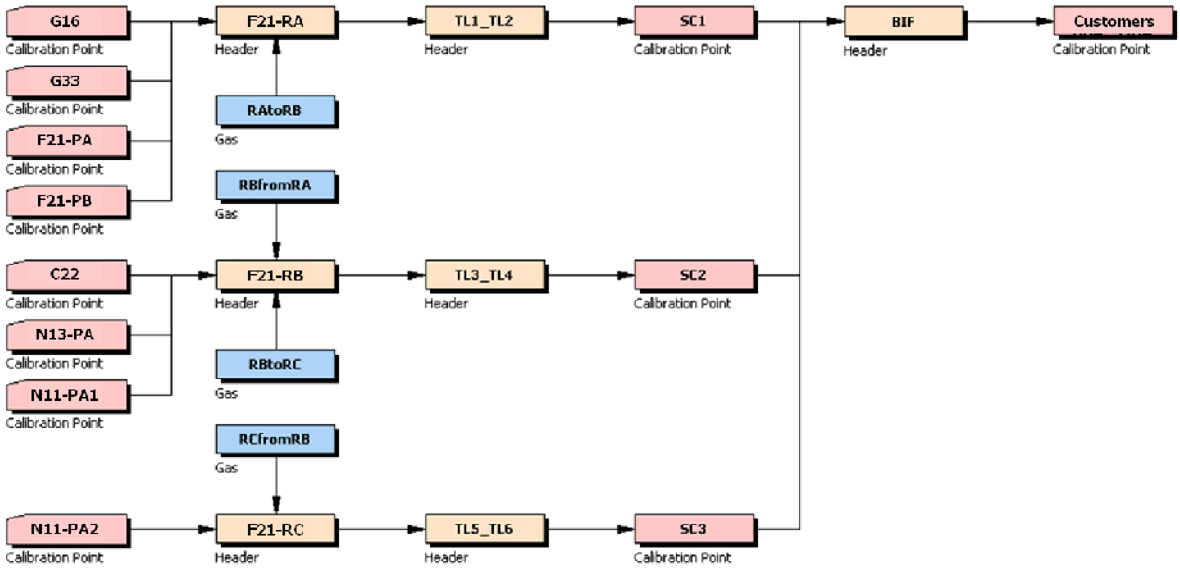


Figure 3 *Overall topology of the Sarawak network*

Topology
The entire Sarawak production system is represented in the PU topology, see Figure 3 and 4. Some wells, all platforms, interconnecting pipelines, riser platforms, down to the trunk lines that feed the MLNG plants are present. The topology is constructed such that it gives an accurate view of the production system. However, a number of simplifications have been implemented.

For the majority of the w ells there are no individual topological elements. Only if wells in a cluster or field have production of a unique composition, are they represented individually. For the majority of the fields the composition of the natural gas (CGR, CO_2, H_2S, BTU) is ass umed identical for all wells based on what we have seen in well tests. These wells are lumped together in the topology into a ‘platform object’.

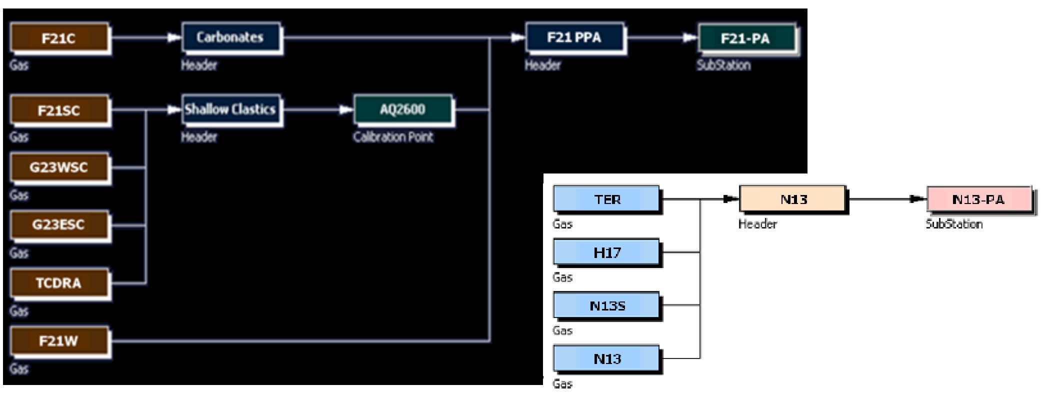


Figure 4 *Station topologies of the Sarawak Gas System. Wells from these fields are grouped in a cluster.*

Also the pipelines are represented in a simplified manner. Not every bend, restriction, change in elevation, diameter, nor the line pack, dynamic hold-up of liquids and slugs is modeled. The pipelines are simply represented by a model that relates pipeline flows to pressure drops across the pipe. The models are constructed using linear models with gas composition and the 'associated stream' feature of PU. The pressure-to-flow data is derived from the process historian, or from a pipeline simulator. Having these pipeline models allows the optimizer to take into account backpressure effects between platforms and wells.

For the optimization problem the pipelines are important, as they allow the user to set constraints on e.g. maximum CO_2 level (process constraint) or maximum flowrate (equipment constraint). Also, the pipeline topological element allows the user to monitor in real-time the flow and composition at the different nodes in the system. One aspect of the Sarawak topology that increases the complexity (and non-linearity) of the problem, are the cross-flows between the risers. Depending on the gas demand, there can be cross-flow from Riser A (RA) to RB, and from RB to RC. The RA, RB and RC riser platforms behave like multiplexer nodes where the flow can go down two paths.

Models

The PU RTO software was originally developed to optimize a cluster of wells, typically a platform or production station [4,12]. The optimization models for these wells are data-driven. They are constructed using historic well tests, well production variations, or multi-rate well tests to relate well productivity to changes in a real-time well head parameter and thus modeling the performance of each well. The RTO modeling engine uses the individual data driven well models to compute the objective function and constraints in real-time. This speeds up the optimization computation, and makes it more accurate.

The models are constructed in such a way that the relationship between the MV (Manipulated Variable) and the PV (Process Variable) is clear, and that the MV can easily be implemented by an operator in the field e.g. set point for a given well gas flow rate. The well and platform models contain the relationship between the measured wet gas flow (the MV of the system), and the total dry gas, CO_2 and condensate flows. Since the relationship between wet- or dry gas and CO_2 output is assumed linear, it can be translated straightforwardly into the model as a constraint to be tested against.

As mentioned, for fields where all well flows have the same composition, the wells are clustered into a single field object to simplify the model. The MV here is the total field wet gas flow (WGF). When the optimizer computes an optimal total WGF for a field, it is left to the Offshore Installation Manager how to distribute this demand over the available wells.

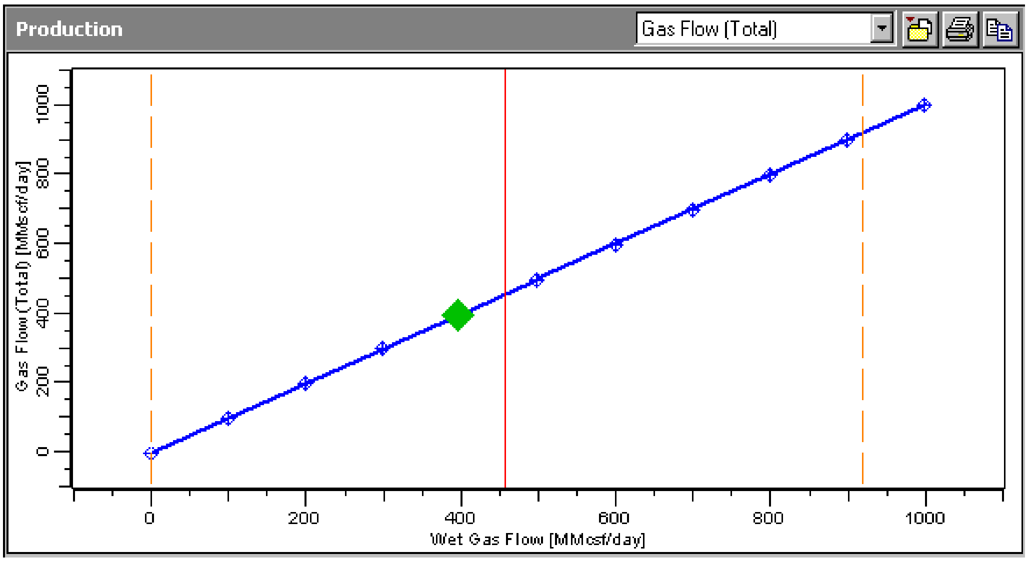


Figure 5 *A linear RTO model. The green diamond shows the current working point*

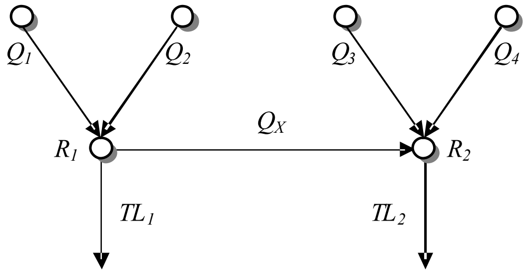
The last simplification is the assumption that there are no back-pressure effects between individual wells or between platforms. This is a reasonable assumption given that we use flow as the MV in the sys tem, and not pressure. PU does support back -pressure effects in its modeling engine, so this is something that could be added in the future if required.

The simplicity of the optimization models provides a beneficial robustness to the system: e.g. if the reservoir pressure declines, or there is scale deposition in the tubing, or the WGR increases, the CGR/CO_2/H_2S/BTU compositions stay valid. If required it is easy to change the corresponding ratios in the model.

Engine

The optimization engine is required to generate convex, stable and repeatable solutions in a short time, that are global, not local, optima. Some optimization approaches pose the risk of generating instable solutions: an advised flow rate distribution across the network where a large percentage of wells and platforms is required to change flow rate to achieve a marginal (and theoretical) increase in condensate output. This engine is required to provide set -points that are close to the current state of the network. With speed in mind, ideally this optimum solution is derived via linear programming techniques. The following describes why this is not feasible.

The 'standard' oil field optimization problem is non -linear to a degree, and the non -linearity increases in complexity when there is int eraction between wells, e.g. through backpressure effects in the production headers. Having assumed no backpressure interaction and linear flow response, still non-linearity is introduced into this optimization by the links between the riser platforms and the constraints on the composition of the gas through the trunk lines, as demonstrated with the following simple network.



It consists of 4 nodes; two pairs, each connected to one of the risers R_1 and R_2, which in turn are connected to the two trunk lines TL_1 and TL_2. The added complexity of this topology is the link X between the riser platforms. All gas properties (e.g. CO_2, H_2S, etc.) are assumed constant.

The composition of the gas through TL_1 can then be stated as a function of the contributing flows:

$$\gamma_{TL_1} = \frac{\gamma_1 Q_1 + \gamma_2 Q_2}{Q_1 + Q_2}$$

Similarly, the composition in TL_2 can be stated as a function of the contributing flows:

$$\gamma_{TL_2} = \frac{\gamma_X Q_X + \gamma_3 Q_3 + \gamma_4 Q_4}{Q_X + Q_3 + Q_4}$$

Where $\gamma_X Q_X$ is the same as the composition of the gas through TL_1. The expression for the composition constraint on the second trunk line then becomes:

$$\frac{\left(\frac{\gamma_1 Q_1 + \gamma_2 Q_2}{Q_1 + Q_2}\right) Q_X + \gamma_3 Q_3 + \gamma_4 Q_4}{Q_X + Q_3 + Q_4} \le c_{\gamma_{TL_2}}$$

This cannot be written in a linear form. This forces the application of more sophisticated techniques to handle this non-linear optimization problem, instead of the aforementioned linear programming techniques.

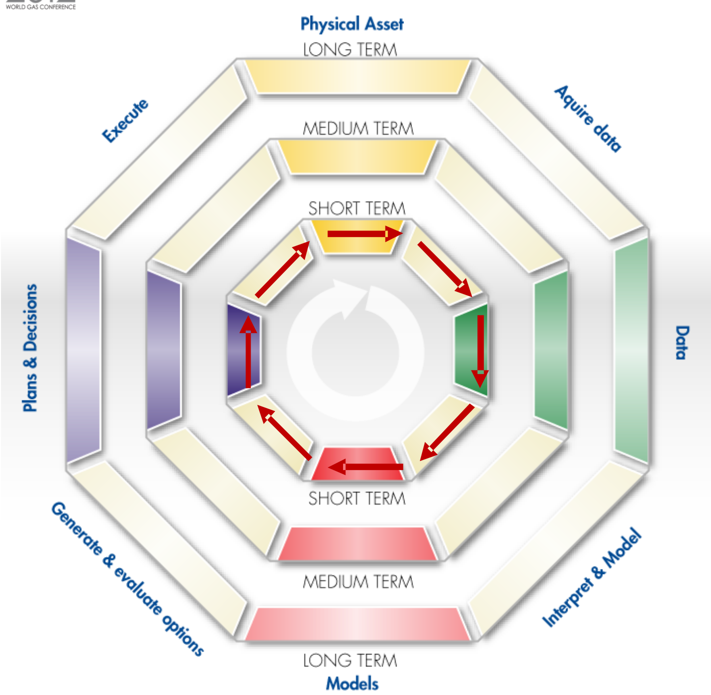


Figure 6 *The value loop for maximizing asset life cycle value in three time domains: short, medium and long term.*

The application in day-to-day operations

See Figure 6. Meeting the short-term and long-term objective through automated PSO effectively means improving day-to-day, short-term and very short-term decision making. Or, to put the latter in terms of the value loop in Figure 6: obtaining data from (the state of) your physical asset, filtering and interpreting this data to turn it into information, feeding this information into a modeling application for optimization, generating and evaluating options given by the optimizer, turning the options into a decision, and executing the decision.

Short-term planning is done by the Production Planner in the central office. The planner applies his experience and a rule set to comprise a 30-day plan with production nominations on a field and platform basis, based on the short-term demand forecast issued by the gas consumers. This 30-day plan is reviewed daily to take into consideration operational events and demand changes from the last 24 hours.

The very short-term decisions about which wells and platforms to produce from in order to meet gas demand and safeguard gas specifications, given operational events, are made at the Bintulu Operational and Coordination Center (BOCC), and are executed offshore. BOCC use the 30-day production plan as their main guide and are in frequent contact with the Production Planner. Most of Sarawak offshore production hubs are manned, and frequent visits are made to unmanned satellite platforms to perform normal operational duties inclusive of executing individual well set-point changes as directed by the BOCC.

A simplified production model in MS Excel is used to test Very Short-Term decisions regarding which wells and fields should be producing and at what rates. This model mainly ensures that production level decisions do not violate the maximum allowable CO_2 and other contaminant volume in the produced gas, because a CO_2 percentage that is higher than the specification will trip the LNG processing plants.

This workbook is not capable of optimizing cond ensate levels. Including all constraints and multiple objectives would make the file complex and slow and it would become impractical to use and difficult to maintain. It would increase the likelihood of errors, which are difficult to spot and correct. The complexity of the optimization problem is beyond what can be comfortably modeled and maintained in Excel.

The application of a dedicated RTO application in the operations environment constitutes a change in the current daily production planning and opera tions coordination work process. This change is managed mainly by involving the end users in the development of the solution, and via user training. The new solution mimics the interface of the existing solutions to minimize the impact of the change to operations staff. The planner will use a dedicated Excel interface to run monthly plans and scenarios. BOCC staff will use the new real-time optimization user interface to apply platform constraints and generate options just as they use the Excel file today.

Figure 7 *Screen showing current operating points and RTO calculated optimum set points. User can also enter their own parameters in 'What -If' to check the expected condensate production or gas quality (GHV, CO_2/H_2S). Numbers don't reflect actual data.*

Results

A single optimization run takes around 5 minutes, which is acceptable and much faster than the traditional optimization approaches that include physical models, where a single run on a fast computer requires at least 3 hours. The optimizer is tested in a number of ways:

Comparison of actual daily liquid volumes with model -predicted daily liquid volumes
As the model evaluates calculated alternatives to the current state to find a new optimum, it is important that the model calculations resemble the real data from the field for the optimized variables. The model values do not have to match the field values exactly, as long as the model tracks the field state behavior: if the model output is maximum, this should correspond to a maximum field output also.

In Figure 8 it can be seen that the model predicted values track the actual measured production well enough for the optimization purpose. It is noticeable that in the first eight months there were some discrepancies. This triggered a review of the reliability of the meters and instruments used as the basis for the mod el, and of the validity of the modeling assumptions. This has improved the understanding of the flaws in the system and models, and improved the tracking performance of the model.

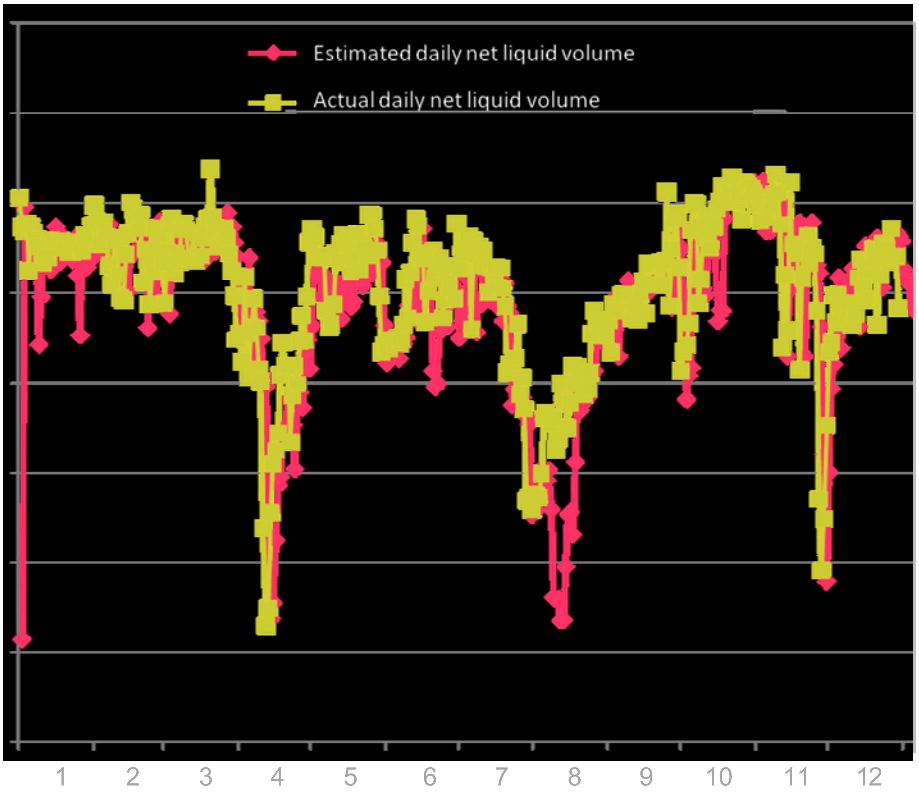


Figure 8 *PU estimated total liquid production from the models vs. actual recorded production. This proves that the simplified model follows reality closely enough to be used for optimization. Where discrepancies arise this is usually a good trigger to challenge the model assumptions, or more likely identify metering problems.*

Backtracking runs
A number of operational events from the past 12 months has been identified where a plant trip or change of state required BOCC to take corrective action in the network. The scenario was re-run in the optimizer, and the set points that were used at the time were compared to set point advise from the optimizer. Actual output from that day was compared to calculated output from the optimizer.

In this approach it has proven difficult to prevent the comparing of apples and oranges, for it requires detailed knowledge of the events of the day, available capacities, gas composition, 3rd party gas supply, and the set point advise that was given to platforms at the time. A lot of this is captured in the daily reports and activity logs, but to translate it into viable scenarios for the optimizer in a way that allows for like-for-like comparison of the results, has proven too impractical to be useful.

'Dry runs' using current real-time data
When entering current gas demand figures into the system and running the optimizer based on the current, real-time state of the system, this test indicates that the production system can render a production increase of up to 7% of additional (estimated) condensate per day depending on the amount of excess capacity in the system. However, unverified model inaccuracies and unforeseen constraints and limitations in the real production system may limit these gains, which is why the real test of the system is in the field trials.

Field trials
At the time of publishing the field trials are a few weeks away. At first the tool will be applied in parallel to the current, unchanged daily practice of the Short-Term Planner and the Very Short-Term BOCC Operations team to verify whether the tool and interface are robust enough to function in the live operating environment. If this is the case, gradually we will shift to applying the optimizer advise in the field in replacement of the current mechanism used.

Other applications
In the long term, this solution provides the possibility for 'closed-loop control' of the entire production system. With remotely operated chokes, the software could translate the optimum production levels into well choke movements. This would allow continuous, life cycle optimization incremental gains as depicted by the 'blue' area Figure 9 below.

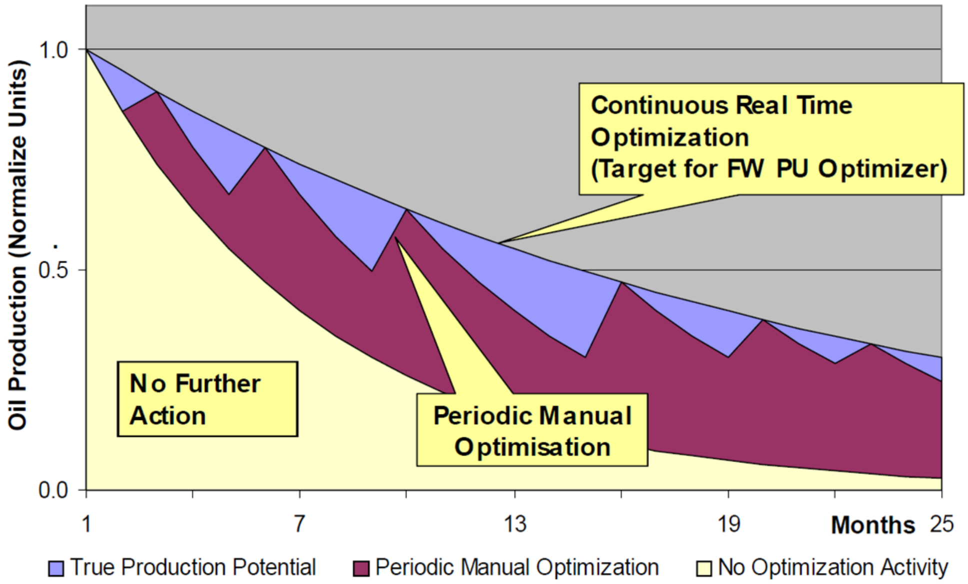


Figure 9 *Difference between continuous and manual optimization [1]*

At the moment, a similar optimization approach is applied in Shell operating units across the globe in the following areas:

- *Gas Lift Optimization*: better use of available lift gas, reduced compression requirements and compressor maintenance [1];
- *Optimizing the use of energy and fuel gas:* applying RTO to bean pumps, ESPs and gas lift results in this;
- *Use of chemicals*: PU continuously calculates required ppm of chemicals injected based on well flow rate estimates and advises operator accordingly;
- *Reducing FTEs*: applying of Real-Time Optimization has lead to the reduction of a team involved in optimization and allocation [3];
- *Reducing logistics exposure*: after introduction of PU and 'well intervention by exception', a Shell operator successfully eliminated one boat, saving some US$1mln per annum;
- *Emissions Reduction* [2]: PU estimates provide a real-time handle on flaring and fuel gas consumption levels. If correlated to plant output, the cost of emissions can be weighed against the output of the plant and optimized.

Future plans include true Asset-Wide Optimization, where the optimizer will be expanded to also include managing compressor suction levels, energy consumption, and other OPEX, while optimizing product quality and throughput. A combination of the above applications is required to successfully and optimally manage an EOR asset [8].

Conclusions

The real-time optimization solution is fast, adequate, and user -friendly enough to be deployed into the daily operations environment, and the complex constraints and dynamics of the network can actually be translated into the context of the optimization requirements. The calculation results are physically realistic, stable, close to the current state of the system, adhere to contractual and commercial constraints, and can be skewed to prefer either long-term or short-term objectives and specific input stream, as well as putting a preference on the relative importance of certain constraints. We found that there is bandwidth within which we can decide *how* we meet demand, and therefore there is room for optimization, but it is limited, so we expect gains to be marginal but big enough to be pursued.

The field trials are to prove the actual value derived from the application of this technology, and whether it is worth the investment. Based on preliminary data, and due to the relatively small investment associated with implementing this solution, there is an expected payback time in the order of a few months.

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Nomenclature

BOCC	Bintulu Operational and Coordination Center
CAPEX	Capital Expenditure
CGR	Condensate-to-Gas Ratio
CO_2	Carbon Dioxide
DOF	Digital Oil Field
EOR	Enhanced Oil Recovery
ESP	Electric Submersible Pump
FTE	Full-Time Equivalent
GHV	Gross Heating Value
GUI	Graphical User Interface
H_2S	Hydrogen Sulphide
LNG	Liquefied Natural Gas
MLNG	Malaysian Liquid Natural Gas
MMscf/d	Million Standard Cubic Feet per Day
MS	Microsoft
OPEX	Operating Expenditure
P	Pressure
PI	OsiSoft Plant Information – the real-time data historian
ppm	Parts per Million
PSC	Production Sharing Contract
PSO	Production System Optimisation
PU	FieldWare Production Universe

PU (RTM)	Production Universe (Monitoring version)
PU (RTO)	Production Universe (Optimization version)
Q	Flowrate
RA, RB, RC	Riser A, Riser B, Riser C
RTM	Real Time Monitoring
RTO	Real Time Optimization / Real Time Operations
SMEP	Shell Malaysia Exploration & Production
ST, MT, LT	Short-Term, Medium-Term, Long-Term
T	Temperature
THP	Tubing Head Pressure
TL	Trunk Line
WGF	Wet-Gas Flow
WGR	Water-to-Gas Ratio

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