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Integrated Surface and Sub-Surface Simulation Model in A Single Simulation Platform

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ABSTRACT

An integrated model between surface and sub-surface is typically done by interconnecting many process modelling platforms. PROSPER and GAP are the common steady state modelling platforms for sub-surface while VMGSim and HYSYS are typical steady state surface modelling platforms. A major issue of using multiple simulation platforms is the compatibility of thermodynamic physical properties calculations among the platforms. This situation makes the simulations difficult to converge to a consistent thermo physical properties values. This is due to different interaction parameters applied in each platform that impact flashing and the physical property values even though the same property package such as Peng Robinson is used. To overcome this convergence problem, a single simulation platform within iCON (PETRONAS's standard process simulation software, co-developed with VMG-Schlumberger) has been developed. This allows the use of one thermodynamic package across the integrated model. PROSPER sub-surface pressure-flow relationship results were automatically correlated and connected to surface models within the iCON environment. This integrated model was validated with data from operations and yielded about 1.23% average error tolerance. Based on this validated model, an optimization envelope can be developed with all possible well lineup configurations. This envelope covers set points for the operations where CAPEX free optimization can readily be applied.

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1. INTRODUCTION

Fossil fuel continues to be widely used worldwide as a primary energy resource due to slow development of sustainable energy resources. These conditions have motivated researches in the area of oil and gas production to explore new approaches to both maximize oil and gas productions and minimize production costs (Abas *et al*., 2015; Izadmehr *et al*., 2018).

Conventionally a standalone surface process model can only achieve production increment of up to 1% (Abidin & Hussein, 2014). Hence, In order to achieve higher production increment, an integrated surface process and subsurface model is required. This modeling technique requires the integration of different modeling platforms for reservoir, wells, headers, surface facility, interconnecting pipelines between platforms, and re-injection wells back to the reservoir. The main challenge is to develop a seamless interface communication between the different modeling platforms. Schlumberger and PETEX developed Integrated Asset Management (IAM) and RESOLVE system integrator respectively to integrate multiple simulation platforms. Lumping and delumping of the composition slate requires complex thermodynamic integration among the models every time it cross the platform (Abidin & Hussein, 2014).

An integrated surface and sub-surface model with optimization features play an important role during production because it can produce comprehensive operational recommendations. However, it presents some challenges in terms of efficient algorithms coupling the models with common optimization algorithms. Petroleum operation is considered a complex process as it is difficult to identify cause and effect without comprehensive model-based integration (Juell *et al.*, 2009). Apart from this, it also requires sufficient hardware capacities to run and solve the complex model. Typical process simulation applications for improving design and solving operational challenges have been reported elsewhere (Putra, 2016a; Putra, 2016b). Development of simulation models have also been applied in different processes (Andika & Valentina, 2016; Bhullar & Putra, 2017; Nayaggy & Putra, 2019).

Standalone surface optimization approach focuses mostly on equipment performances and their integration. There are two significant informations that must be understood in dealing with existing equipment: (i) changes are limited by the performance of the existing equipment and (ii) any changes in operation of the process cannot be considered in isolations (Nelson & Douglas, 1990; Rapoport *et al*., 1994). This include mainly separators and compressors efficiencies as well as stable operation via better process control strategies.

In this approach, current performances of the processing facilities are typically benchmarked against design capacities. The outcome of the study typically includes new operating separator pressure to ensure efficient gas and oil separation, new compressor speed or control configuration to meet gas export, gas lift/injection requirements, and new and/or improved control scheme with better tuning parameters for stable operations. By implementing the recommendations, the processing platform is expected to achieve more stable operations with minimal number of trips and unplanned shutdowns. Queipo *et al*., (2003) offered a solution methodology for the optimization of integrated oil production systems at the design and operational level which involving the combined execution of mathematical simulation models and optimization algorithm. **Figure 1** shows a typical methodology applied for standalone surface optimization.

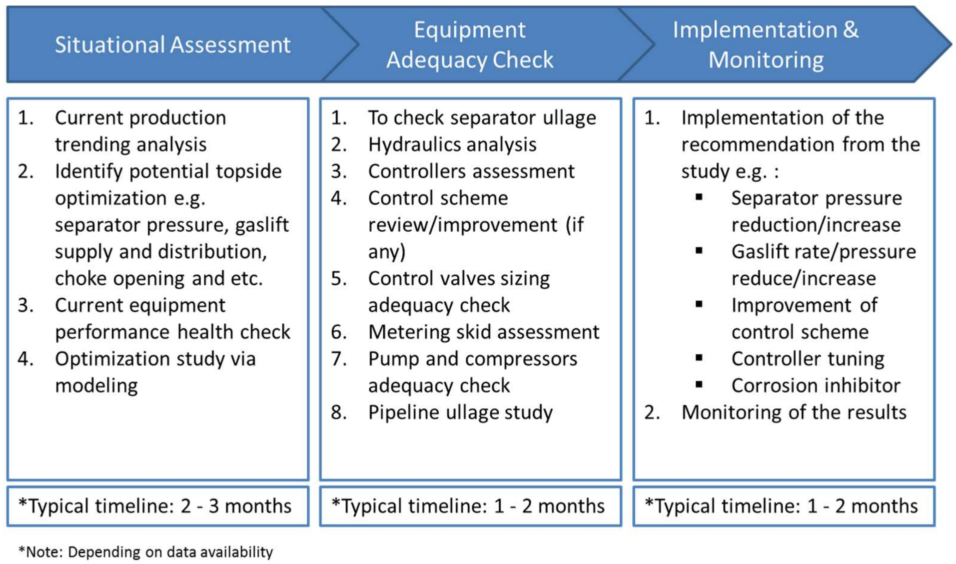

Figure 1. Typical methodology for standalone surface optimization study

On the other hand, the above standalone surface optimization approach does not indicate the impact of surface operations to subsurface and reservoir. Unstable production in multiphase production systems and pipelines can obviously cause serious operational problems for downstream receiving production facilities. This situation strengthens the argument of the necessity to have an integrated surface-subsurface optimization. Escalona *et al.*, (2014) developed a fully compositional integrated subsurface-surface model for the Production Unit Carito in order to support a future exploitation plan for the next 3 years by taking the consideration of maintaining the oil production plateau and an aggressive infill drilling. Miskar Field in Tunisia is one of the fields that have implemented the integrated model in order to maximize gas and liquid production and monitor the gas blend that is transferred to the shore is maintained within the current operational limitations (Madray *et al*., 2008).

Typically, production rates are set at the inlet of the surface process by adjusting the position of the production choke valves for each well. Due to large velocity gradients, the turbulence of the flow increases thus a pressure drop across the valve occurs. This pressure drop is used to regulate the production rate (Van der Z & Muntinga, 1999). There is no automatic feedback from the surface facility to where the production rates are set. Operators normally adjust these choke valves and hence, the performance will naturally vary depending on the operator's action. Rashid *et al*. (2011) developed a mixed integer nonlinear programming (MINLP) which includes dual control in each well, comprising gas-lift injection and certain choke setting. The same approach is used by Tavallali & Karimi (2016), which use MINLP in order to locate production wells, installing and connecting manifolds, planning capacity expansion of surface processing facilities, and determining the best oil production and water injection flows which successfully increase net present value (NPV) from the base case while considering the detailed dynamics of oil reservoirs. Several researchers have conducted research on various integration works. Bailey & Couet (2005); Cullick *et al.* (2003) discussed complex petroleum field projects applying uncertainty analysis. Their work, however, ignored the surface process facility. Integrated ECLIPSE and HYSYS simulators to model integrated field operation in a deep-water oil field has also been conducted. Application of integrated optimizations in a daily operations setting of LNG value chains was studied by Foss & Halvorsen (2009) To reduce the computational time, they used simple models for all system components. A sizable gain could be identified by integrating all models into one model platform as opposed to many modeling platforms. Integrated operation and optimization representing the value chain from reservoirs to export terminals was also studied by Rahmawati *et al*. (2010) using actual operation parameters. Then, Rahmawati *et al*. (2012) improved the work by including a simplified economic model to maximize the economic performance of the fields. In another case study, Nor *et al*. (2019) optimized well connections in an integrated subsurface and surface facilities using mathematical programming in GAMS.

So far, previous researchers have developed integrated models mostly focusing on sub-surface interactions of flow assurances between wells, reservoir behavior, and reservoir types. Other researchers have also attempted to connect surface with subsurface models with multiple and isolated software. However, this approach suffers inherent limitation of thermodynamic problem as mentioned above. It is observed that Peng Robinson property package use in suface model is different from Peng Robinson use in sub-surface model. This is due to different binary interaction parameters applied by respective modelling platform. Litvak *et al*. (2002) developed an integrated compositional model of the reservoir and surface facilities. This model used multiple modeling platforms and only valid for daily operations for small field due to unstable thermodynamic translation among the multiple platforms. Having multiple simulation platforms for integrated surface and sub-surface model will truncate the errors as the calculations proceed iteratively among the plaforms and slow down the simulation time and eventually diverge the model solution. Utilizing multiple simulation platforms also is not economically viable and difficult to maintain.

Lobato-Barradas *et al*. (2002) presented the results of implementation of integrated fully compositional model of 72 wells from six different fields which located in the southeast region of Mexico. Based on the implementation, the integrated compositional model is capable to give historical production and also to estimate future production. All the researchers focus on maximizing productions however integrated production optimization at CAPEX free point was not considered. In this first part of our paper, an integrated first principle model from wells to surface processes is developed in one simulation platform of iCON, PETRONAS' standard process simulation software co-developed with VMG. Having an integrated model and optimization in this single platform of iCON is the main contribution of this work. In this manner, consistent thermodynamic calculations between subsurface and surface process models is guaranteed.

Recent studies have presented multiple model platform that required suitable and accurate time stamp for optimization to work. Look up tables were also used to determine multiphase flow from each reservoir without considering surface facilities installed capacity as constraint variables. Potential revenue predicted from recent studies on integrated model were based on single point optimization without giving optimization validity envelope which is difficult to implement.

In this work, a single model platform iCON is used to ensure seamless data transfer, thermodynamic stability, and efficient optimization iteration to locate the CAPEX free implementation region. This is the main difference between previous works and this work. Multi variables multiphase flows Vertical Lift Performance curves will be generated for each well to cover a wide range of operating envelope to ease the implementation. Sub-surface and surface model integration is done via Visual Basic Application (VBA). In this integrated optimization works, iCON is used as a single surface and subsurface modelling, and optimizing production platform to link between PROSPER individual well sub surface data and iCON top side surface model. Visual Basic Application is used to generate the correlations of individual well data to estimate liquid and gas production rate which were used as an input in iCON. Gas to Oil ratio (GOR) and water cut (WC) or water to oil ratio values are used to optimize oil, water, and gas productions.

Due to confidentiality issue, field names, and associated wells are not disclosed in this paper. Reasonable names will be used throughout the paper.

2. METHODOLOGY

The flow chart of the methodology is shown in **Figure 2**. The methodology starts from gathering all input data from Process Flow Diagram (PFD), Process, and Instrumentation Diagram (P&ID), designed mass, and energy balance (MEB), daily production report (DPR), and individual well Inflow Performance Relationship (IPR) or Vertical Lift Performance (VLP) data that match respective well tests. The next step is regressing individual well IPR data with the influential variables such as Tubing Head Pressure (THP), water cut (WC), Gas Oil Ratio (GOR), and Gas Lift injection rates to calculate the corresponding liquid flowrates. All these sub-surface correlations are then linked with the surface steady state model in iCON. The surface steady state model is first developed and validated to match the design case. After validation, the steady state model is then linked with the individual well IPR correlations. This integrated model is further tuned to match DPR data at different well configurations.

Optimization formulation with the objective of maximizing oil productions is further setup in the model within the iCON environment. Existing process designs are taken as the constraints such as compressor speed and capacities, pump capacities, fuel gas max requirements, and flare gas capacity due to additional oil and gas productions.

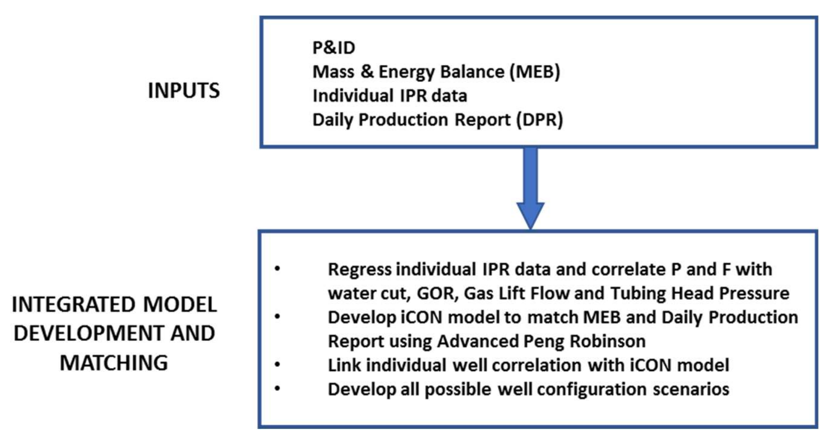

Figure 2. Flow chart of the methodology

2.1. Simulation basis

The developed methodology has been applied on Field A Platform. Several site visits to the platform were conducted in quarter 1 and 2 of 2018. During the site visits, the obtained PFD was verified and the operating condition were compiled and reconciled. Most of the pressure readings were available via transmitters. Temperature readings were mostly based on either the transmitters or manual reading using infrared.

Figure 3 shows the flow diagram of Field A based on the site visits. The actual process consists of HP Separator (V-100), MP Separator (V-200), LP Separator (V-300), and LP Surge Vessel (LPSV) (V-400). The LPSV was not considered in this study due to its usability or no longer operating in the field. Overall mass balance for the platform was developed using combination of daily gas balancing, daily production report, and individual well test data.

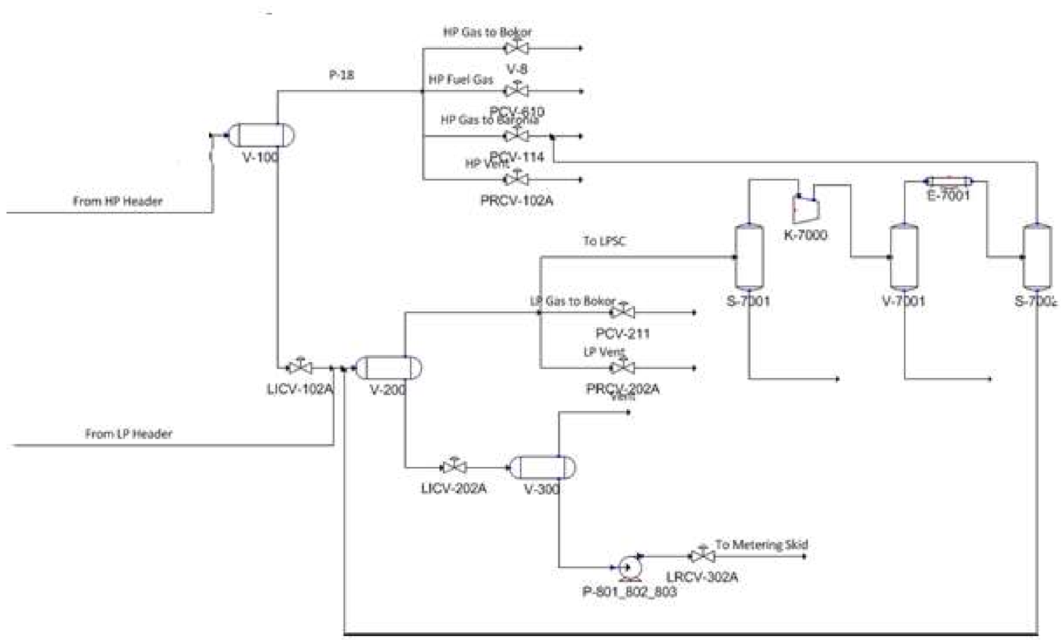

Figure 3. Simplified platform process flow diagram of Field A

Individual well IPR-VLP data coming from PROSPER results that matched well test data was used to generate individual well flow correlation. The correlation is a function of influential variables such as water cut, tubing head pressure, gas lift rate, and gas oil ratio. A typical PROSPER well simulation outputs are shown in **Table 1**. This output data is modified in the form of well pressure-flow relationship table format as shown in **Table 2**.

This data is then used as the input in developing multivariable regression of individual well that estimate the production flowrate as a function of the above variables. Some of the correlations are shown in **Figure 4**. These correlations are then coded using VBA within the iCON environment to connect this PROPER result with steady state surface model (explained below).

Table 1. Typical PROSPER outputs

++

+ Water Cut 55.000 (percent) +

+ First Node Pressure 50.00 (psig) +

++

Liquid Rate (STB/day)	Oil Rate (STB/day)	VLP Pressure (psig)	IPR Pressure (psig)
15	6.8	500.3	1684.6
21.6	9.7	461.92	1684.29
31.1	14	446.64	1683.84
44.7	20.1	441.62	1683.2
64.3	28.9	437.49	1682.27
92.4	41.6	406.84	1680.92
133	59.8	381.47	1678.96
191.2	86.1	362.27	1676.1
275.1	123.8	348.67	1671.91
395.7	178.1	343.73	1665.72
569.1	256.1	344.71	1656.47
818.6	368.4	359.12	1642.43
1177.5	529.9	397.01	1620.72
1693.7	762.2	474.84	1586.26
2436.2	1096.3	613.41	1529.81
3504.2	1576.9	843.54	1433.68
5040.4	2268.2	1210.43	1262.04
7250.1	3262.5	1797.41	936.83
10428.5	4692.8	2710.62	266.27
15000.2	6750.1	4094.09	-990.68

Table 2. Well VLP relationship modified from the output of the PROSPER

Plat-from A	**String 2**			**Unit**	**GL THP**	**MMSCFD psia**				
THP/GL	0.2	0.4	0.6	0.8	1	1.2	1.4	1.6	1.8	2
50	1577	1555.8	1533.3	1512.2	1486.9	1464.3	1441.8	1419.7	1398.3	1372.5
100	1562.3	1540.9	1520.6	1497.9	1474.5	1452.8	1428.9	1408	1383.8	1361.8
150	1540.8	1520.4	1495.9	1475.5	1453.5	1433.7	1407.6	1387.8	1363.3	1342.9
200	1511.6	1484	1462.2	1443.3	1423.8	1401.3	1382.1	1358.2	1339	1314.4
250	1460.8	1444.9	1425.6	1399.9	1382	1365.2	1348.4	1319.1	1300.7	1280.8
300	1384.	1369.	1354.	1399.	1324.	1308.3	1292.	1275.	1258.	1231.

Plat-from A	String 2			Unit	GL THP	MMSCFD psia				
	5	6	6	5	3		1	9	6	5
350	1302.5	1287.8	1273	1258.1	1243.1	1228.1	1213	1197.8	1182.6	1167.3
400	1211.8	1198.6	1185.2	1171.6	1157.9	1144.1	1130.1	1116.1	1101.9	1087.6
450	1117.6	1106	1094.1	1082	1069.6	1057	1044.2	1031.2	1018.1	1004.9
500	1020.4	1010,5	1000.1	989.2	977.3	965.1	952.8	940.4	927.8	915

Liq Flow (bbl/d) = 3131.2327 - 2.1451THP (Psia) - 0.0063GL (MSCFD)

=== RESULTS SUMMARY ===

Eqn(THP,GL) 1 = Liq Flow (bbl/d) = 3131.2327 - 2.1451THP (Psia) - 0.0063GL (MSCFD)

Eqn(THP,GL) 2 = Liq Flow (bbl/d) = 1701.5007 - 1.1405THP (Psia) - 0.0891GL (MSCFD)

Eqn(THP,GL) 3 = Liq Flow (bbl/d) = 1915.4743 - 1.1767THP (Psia) + 0.0116GL (MSCFD)

Eqn 1 ===> Avg Err = 1.2921 % Avg LiqFlow Err = 32.7468 bbl/d

Eqn 2 ===> Avg Err = 2.9897 % Avg LiqFlow Err = 38.5623 bbl/d

Eqn 3 ===> Avg Err = 0.9657 % Avg LiqFlow Err = 15.4961 bbl/d

Figure 4. Well VLP relationship developed from the output of PROSPER

The following basis are used when developing the surface steady state model in iCON process simulation software:

a) The model used Advanced Peng-Robinson (APR) thermodynamics package within the iCON package. This APR model has all the characteristics of the Peng-Robinson model plus volume translation for accurate liquid phase density estimation using the Peneloux (1980) idea as modified by Mathias *et al*. (1991). It deals with polar components that are seen in these areas in a more appropriate way than the Peng Robinson (PR) equation of state does. The developed iCON steady state surface model for Field A is shown in **Figure 5**.

b) Individual feed composition of oil, gas, and water used in the study are as per existing last known compositions due to unavailability of latest sampling. All other fields data are obtained from the site visits during the abovementioned period.

c) Heavy components are lumped as a pseudo component of C20+. Bulk properties of this pseudo component such as molecular weight, normal boiling point, and ideal density are tuned to match its reported viscosity. As one of the transport properties, matching the viscosity is important in ensuring the accuracy of pump calculations.

d) Pipe elevations and fittings from the isometric drawing are used to closely match actual condition of the pipe networks. Petalas and Colebrook methods are used to calculate the pressure drop of multiphase and single-phase flow, respectively. Pipe roughness value is tuned to match the actual field value. The pipe is assumed to operate in adiabatic condition.

e) The wells configurations used in the model are based on operation in April 2018. The details are shown in **Figure 6**. In the figure, THP is Tubing Head Pressure (psig), WC is the Water Cut for the respective wells (18L until 29L), and HP, MP, and LP are high, medium, and low-pressure headers, respectively, for pressure vessels.

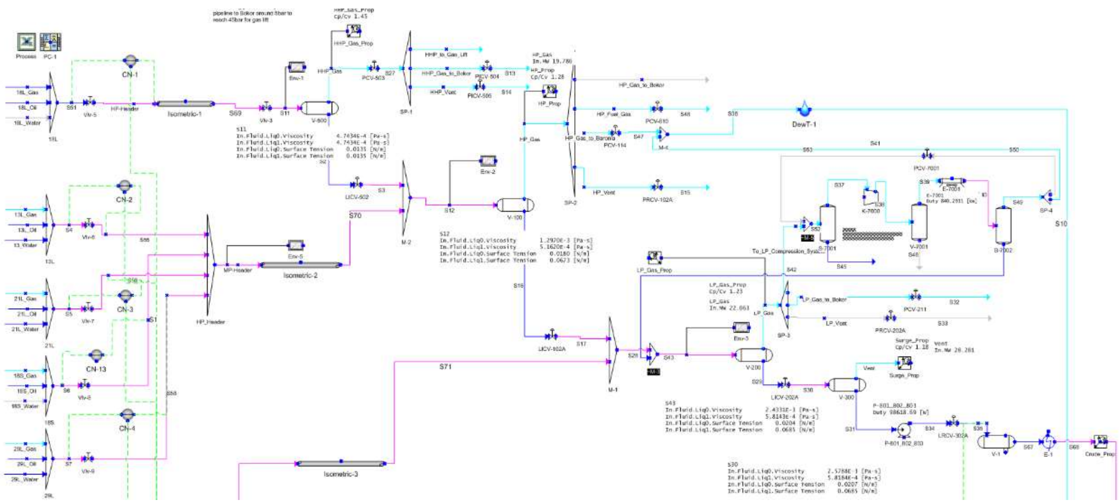

Figure 5. iCON steady state surface process model

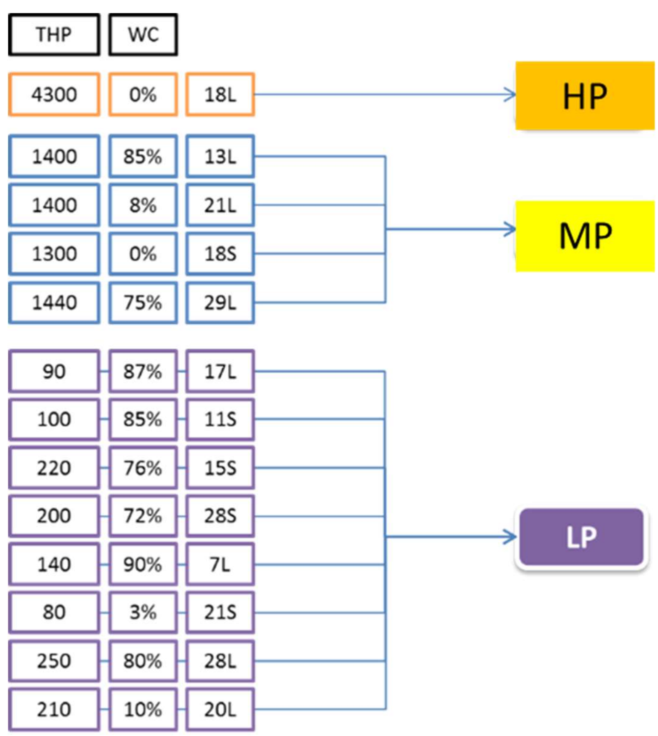

Figure 6. Well lineup configuration

3. RESULTS AND DISCUSSIONS

The obtained flow correlations from PROSPER results are shown in **Figure 7**. The decimal points are taken in such a way to maintain the precision of the estimation.

Table 3 shows the comparison results where the developed correlations show some reasonable accuracies and precisions. These flow correlations in **Figure 7** are validated against the actual data. **Table 3** shows the comparison between the results coming from the well tests and the developed correlations.

High pressure well: (Gas Well)

1 Gas flow rate of Well 18L (MMSCFD) = $-0.00000008026666666667THP^3 + 0.000248599999999995THP^2 - 0.232433333333241THP + 495.499999999932$

Medium pressure wells: (Oil+Water Wells)

2 Well 13L liquid flow (Std bbl/d) = $0.00000010833333333334THP^3 - 0.000513928571428 67THP^2 + 0.0485952380955305THP + 1,272.85714285689$

3 Well 21L Liquid Flow (sbbl/d) = $0.00000015365405429 7833THP^3 - 0.000752860754886536THP^2 + 0.509085719517854THP + 1,731.09083757835$

4 Well 18S Liquid Flow (sbbl/d) = $-0.00000008026666666667THP^3 + 0.000248599999999995THP^2 - 0.232433333333241THP + 495.499999999932$

5 Well 29L Liquid Flow (sbbl/d) = $-0.00000008786883784 82THP^3 - 0.0000541738792676355THP^2 - 1.49198854764436THP + 4,099.8456072 1931$

Low pressure wells: (Oil+Water Wells)

6 Well 17L Liquid Flow (sbbl/d) = $-0.000000001180831826157THP^4 + 0.000008479686557268 11THP^3 - 0.00306013562383397THP^2 - 0.472535563569049THP + 634.89710668903$

7 Well 7L Liquid Flow (sbbl/d) = $0.000000000761438145869THP^5 - 0.0000053451481956 1238THP^4 + 0.00147957339239824THP^3 - 0.20307418059086x^2 + 11.7512605476734THP + 1,280.53956684449$

8 Well 11S Liquid Flow (sbbl/d) = $-0.000000022478439260995THP^4 + 0.0000187238196310835THP^3 - 0.00617541405199251THP^2 + 0.00913343034412151THP + 1,438.57092772563$

9 Well 15S Liquid Flow (sbbl/d) = $-0.00000000002538239999 6THP^5 + 0.0000000272569599946 8THP^4 - 0.000109004693314782THP^3 + 0.0192683359905207THP^2 - 1.77540906312717THP + 867.682719632543$

10 Well 20L Liquid Flow (bbl/d) = $-1.09681663999237E-08THP^4 + 0.0000183800995165769THP^3 -0.0125487891157642THP^2 + 3.14617022983361THP + 794.080168311003$

11 Well 21S Liquid Flow (bbl/d) = $-0.00015927145649168THP^2 + 0.016590845402176THP + 188.360490551939$

12 Well 28L Liquid Flow (sbbl/d) = $0.0000000050666666665 1515THP^4 - 0.0000467999999983065THP^3 + 0.0139133333326946THP^2 - 1.66699999988897THP + 485.899999993365$

13 Well 28S Liquid Flow (sbbl/d) = $-0.00000248522666662643THP^3 - 0.00135105828573923THP^2 - 5.22392041904039THP + 4,535.82156799918$

Figure 7. Obtained flow correlations from PROSPER results

The developed steady state surface model is compared with the maximum design and actual cases. The comparison results are shown in **Tables 4** and **5** for the maximum design and actual running data, respectively. Turn down case is not conducted since the focus is on maximizing the oil production.

Table 3. Deviation between well tests and the developed correlations

			Deviation							
			THP	Water Cut	GOR	Liquid	Oil	Water	Gas
	String	**Date**	**Psig**	**%**	**mmscfd/bbl**	**bbl/d**	**bbl/d**	**bbl/d**	**mmscfd**
1	11S	2-Jan-18	100	0.00%	0.00%	11.00%	11.20%	11.00%	11.20%
2	13L	14-Feb-18	1400	0.10%	0.00%	0.10%	0.40%	0.20%	0.40%
3	15S	19-Jun-17	220	0.00%	0.00%	0.80%	0.60%	0.80%	0.60%
4	17L	5-Feb-18	90	0.10%	0.00%	3.60%	2.80%	3.70%	2.80%
5	18S	9-Feb-18	1300	-	0.00%	3.30%	3.30%	-	3.30%
6	18L	16-Feb-18	4300	-	0.00%	9.40%	9.40%	-	9.40%
7	20L	3-Feb-18	210	0.00%	0.00%	3.10%	3.10%	3.10%	3.10%
8	21L	10-Feb-18	1400	0.10%	0.00%	4.00%	4.40%	4.00%	4.40%
9	21S	24-Feb-18	80	1.20%	0.00%	1.20%	1.50%	0.00%	1.50%
10	28L	11-Nov-17	250	0.00%	0.00%	1.30%	1.40%	1.30%	1.40%
11	28S	2-Feb-18	200	0.40%	0.00%	0.10%	0.40%	0.40%	0.40%
12	29L	20-Feb-18	1440	0.00%	0.00%	6.00%	6.90%	6.00%	6.90%
13	7L	4-Feb-18	140	0.00%	0.00%	0.20%	0.20%	0.20%	0.20%

Table 4. Comparison of the model with maximum design case using design data

FEED STREAMS	MODEL Max Case (kg/hr)	OUT STREAMS	MODEL Design Case (kg/hr)	Surface Design Case (kg/hr)	Deviation (%)
HP Header	24000	HP Gas	4400	4425	0.56
MP Header	67200	HP Gas to Field B	11528	11486	0.37
LP Header	86000	HP Vent	0	0	
		MP Vent	4263	4289	0.61
		MP Fuel Gas	838	823	1.85
		MP Gas to Field C	21045	20913	0.63

FEED STREAMS	MODEL Max Case (kg/hr)	OUT STREAMS	MODEL Design Case (kg/hr)	Surface Design Case (kg/hr)	Deviation (%)
		MP Gas to Field B	10848	10926	0.71
		LP Gas to Field B	7123	7170	0.65
		LP Vent	0	0	
		LP Gas to Field C	14021	13898	0.88
		Oil Production	44667	44878	0.47
		Water Production	58429	58354	0.13
		Surge Vent	38	39	2.53
TOTAL	177200		177200	177200	Average = 0.85

Table 5. Comparison of the model with the actual case using operational data

FEED STREAMS	Actual Case (kg/hr)	OUT STREAMS	MODEL Actual Case (kg/hr)	Surface Actual Case (kg/hr)	Deviation (%)
HP Header	22478	HP Gas	4386	4418	0.72
MP Header	42966	HP Gas to Field B	10518	10122	3.91
LP Header	59180	HP Vent	0	0	
		MP Vent	493	496	0.60
		MP Fuel Gas	838	844	0.71
		MP Gas to Field C	21043	20829	1.03
		MP Gas to Field B	1308	1317	0.68
		LP Gas to Field B	7010	7057	0.67
		LP Vent	0	0	
		LP Gas to Field C	7521	7619	1.29
		Oil Production	31853	31961	0.34
		Water Production	39592	39896	0.76
		Surge Vent	62	65	4.62
TOTAL	**124624**		**124624**	**124624**	**Average = 1.39**

The model comparison with the maximum design data is basically the comparison of the simulation results of iCON and HYSYS. The observed deviation is considered small and this is mainly due to different property packages used in HYSYS compared with iCON. As mentioned above that the current work with iCON is using Advanced Peng Robinson model while that of HYSYS used Peng Robinson.

The observed average deviation of 1.39% with the actual case is higher compared to the design case of 0.85%. This is due to the assumptions made in the simulation basis to back blend the individual full well stream of oil, water, and gas phases separately based on available sampling points in the vessels. Furthermore, the gas balance distribution is solely based on Daily Gas Balancing and Production Allocation report. In this report, gas balance was calculated based online size and pressure drop, while its flowrate data is taken at the customer side.

This developed integrated model is further validated against actual conditions for the period of 2 years where five different network configurations were applied. One of those conditions are in February 2018 where all wells are in operation. The validated mass balance and production summary are shown in **Tables 6** and **7**, respectively.

Overall, average deviation of mass balance is 1.23% considering the whole five different well lineup configurations. It is observed that oil and gas production predicted in the model are always higher than the actual operational production values. This is due to unknown vented gases used in the gas balance calculations as explained previously.

To comply with PETRONAS Technical standard for integrated process model acceptance, the process models fidelity for steady-state accuracy of the predicted process variables shall be within +/-2% of transmitter range for flow related values. Therefore this deviation is considered small and the integrated model can be used for further optimization studies.

Table 6. Mass balance validation of the integrated model when all wells are in operation

Case 1: All Wells are Flowing

Well	Unit	Actual Choke Valve Opening	Model Choke Valve Opening	Deviation (%) Choke Valve Opening
18L	%	50	50	0
13L	%	50	50	0
21L	%	50	50	0
18S	%	50	50	0
29L	%	50	50	0
17L	%	50	50	0
11S	%	50	50	0
15S	%	50	50	0
28S	%	50	50	0
7L	%	50	50	0
21S	%	50	50	0
28L	%	50	50	0
20L	%	50	50	0
HP Header Pressure	(psig)	800	800	0
MP Header Pressure	(psig)	270	270	0
LP Header Pressure	(psig)	40	40	0
HP Gas	(kg/hr)	4418	4386	0.72
HP Gas to Field B	(kg/hr)	10122	10518	3.91
HP Vent	(kg/hr)	0	0	
MP Vent	(kg/hr)	496	493	0.60
MP Fuel Gas	(kg/hr)	844	838	0.71
MP Gas to Field C	(kg/hr)	20829	21043	1.03
MP Gas to Field B	(kg/hr)	1317	1308	0.68

Case 1: All Wells are Flowing

Well	Unit	Actual Choke Valve Opening	Model Choke Valve Opening	Deviation (%) Choke Valve Opening
LP Gas to Field B	(kg/hr)	6963	7010	0.67
LP Vent	(kg/hr)	0	0	
LP Gas to Field C	(kg/hr)	7425	7521	1.29
Oil Production	(kg/hr)	31961	31853	0.34
Water Production	(kg/hr)	40184	39592	1.47
Surge Vent	(kg/hr)	65	62	4.62
				Average Deviation
Mass Balance		**124624**	**124624**	**1.46%**

Table 7. Production summary when all wells are in operation

	Unit	February 2018 (actual)	iCON Model (Calculated)	Deviation (%)
HP Gas	MMSCFD	15.5	15.87	2.50%
MP Gas	MMSCFD	23.8	24.02	0.83%
LP Gas	MMSCFD	13.5	13.68	0.99%
Oil	bbl/d	5,650	5669.23	0.34%
Water	bbl/d	6136	6047.05	1.47%

4. CONCLUSION

Individual well Inflow Performance Relationship (IPR) data was successfully regressed and correlated for liquid flow as a function of Tubing Head Pressure (THP), water cut, gas to oil ratio (GOR), and gas lift flow. To complete the surface and subsurface integrated model, the individual well flow correlation was linked with iCON steady state model. The integrated model was benchmarked and matched with 5 wide range of operating conditions and productions as the final validation prior to optimization.

5. RECOMMENDATIONS

For future works and to fill the remaining gaps, several recommendations are suggested below:

a) Take fluid sample at each well to determine individual well composition for more accurate fluid properties calculation and products distribution.

b) De-lumping well bank simplification by using individual well flow correlation to generate maximum well lineup configuration for more granular operation matching.

c) Verify individual well flow assurance at maximum surface production rate via OLGA modelling to confirm each well can deliver additional flow gain.

d) Extend the optimization study by linking the integrated developed model with reservoir steady state model under one simulation and thermodynamic platform.

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7. AUTHORS' NOTE

The author(s) declare(s) that there is no conflict of interest regarding the publication of this article. Authors confirmed that the data and the paper are free of plagiarism.

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