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ANALYTIC HIERARCHY PROCESS (AHP) IN SELECTION OF WELL CONTROL EQUIPMENT FOR WORKOVER AND WELL SERVICE RIGS

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Abstract *PT BEI is a subsidiary of Bravo Corporation that holds 100 percent-owned and operated interest in Rocka PSC. PT BEI needs to improve the flexibility of its workover and well service rigs to be operated across the operating areas to deal with dynamic business plan and rig allocation as a strategy in entering the transition period to the end of concession of Rocka PSC. Well Control equipment associated with the rig contract Scope of Work (SOW) is identified as the main potential causes of why current rigs have less flexibility. A decision-making approach is utilized to find the solution. Well data mapping combined with existing business processes and applicable standards review are conducted to determine the minimum Well Control equipment requirement, selection criteria and alternatives. The Analytic Hierarchy Process (AHP) is utilized as the decision-making method to analyze the alternatives. As a result, a BOP Class II A1-R1 (Annular + Blind-Shear ram) is selected as the fit for purpose Well Control equipment to support the strategy of PT BEI. The solution implementation improves the rig flexibility and saves potential $ 90,000 investment cost per rig for the rig contractors and $ 77,000 cost avoidance per rig for PT BEI.*

Keywords*: Rig, Equipment, Flexibility, Decision Making, AHP*

1. Introduction

PT Bravo Energy Indonesia[#] (PT BEI) is a subsidiary of Bravo Corporation[#], which is a multinational oil and gas company that has operations around the globe. PT BEI operates the Rocka[#] block, a Production Sharing Contract (PSC) block located in Central Sumatra. PT BEI divides its operating area into 2 (two) main areas which are Heavy Oil (HO) and Sumatra Light Oil (SLO) areas which cover a total area of around 6,264 square kilometres. HO area covers an oil field that applied steam flood technology as the Enhanced Oil Recovery (EOR) method to produce the oil and SLO area covers 75 active oil and gas fields with primary recovery and waterflood EOR method that scattered from South to North area of the block. The main differences between the two main areas are formation characteristics, oil characteristics, well completion types, well job types and environment. In 2019, PT BEI delivered gross daily production for about 200,000 barrels of oil equivalent from all the fields.

Almost one century, the company has developed and implemented many practices including how the company run the business and operation. In 2018, after the Government of Indonesia (GOI) announced not to continue the PSC agreement of Rocka block with PT BEI, the company totally changed its business plan and strategy. PT BEI stop the drilling activities and put focus on workover and well service activities to maintain the oil production till the End of Concession (EOC) of Rocka PSC in 2021. As a strategy in entering the transition period of EOC, PT BEI implements dynamic resources allocation. To support the strategy, a decision-making approach is chosen to deliver the best alternative in a relatively short time owned by the company.

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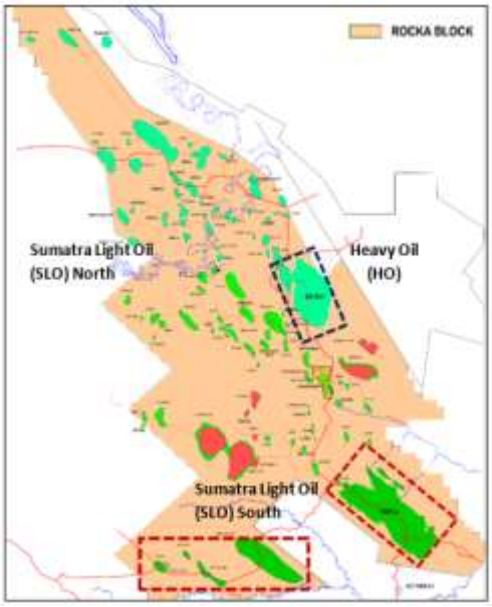

Figure 1. Operating Area of PT BEI (Source: Internal Data PT BEI)

The drilling and Completion (D&C) team is a core team in PT BEI that is fully responsible for drilling, workover and well services activities throughout the operating area. Historically, PT BEI ever operated 15 drilling rigs and 58 workover and well services rigs during the peak period between the years 2013 and 2015 to support the activities. In 2018, PT BEI started to decrease the rig number to align with the updated business plan and strategy. In 2019, PT BEI operated the remaining 41 workover and well service rigs and this rig number will be decreased gradually till the EOC.

Based on recent company's experience, the existing business process and operational practice are not appropriate to deal with the dynamic resource allocation. This matter is reflected by the recent operation issue that occurred where the company had difficulties to allocate 2 (two) rigs from HO to the SLO area to meet the business plan revision. This issue causes delayed execution of several good candidates that impact Loss Production Opportunity (LPO) and extra effort in terms of time and resources to perform the rig contract amendment process. An effort has been performed by the D&C team by developing several new rig contracts and bringing them to the phase of being ready to be awarded. However, this effort is still considered not optimum because there is uncertainty on the capability of rig contractors to commence the rig contract timely as requested by the company. Besides that, there is the possibility of early contract termination due to no more job candidates for the rig contract.

This research is aimed to improve the flexibility of workover and well service rigs so it can be operated across the operating areas of PT BEI. The result of this research is a solution to deal with the dynamic resources allocation to execute all good candidate's queues across the operating area by minimizing the rig contracting process. This solution also brings benefits both for PT BEI and rig contractors. In this case, PT BEI may avoid the potential additional charges due to rig contract revision while rig contractors may save investment cost in rig equipment.

2. Conceptual Framework

The conceptual framework of this research (see Figure 2) is established to understand what the problem is, what the current situation is and what the goal is. The root cause analysis will be conducted to identify potential causes of the problem. Decision-making analysis and implementation plans are developed to achieve the goal.

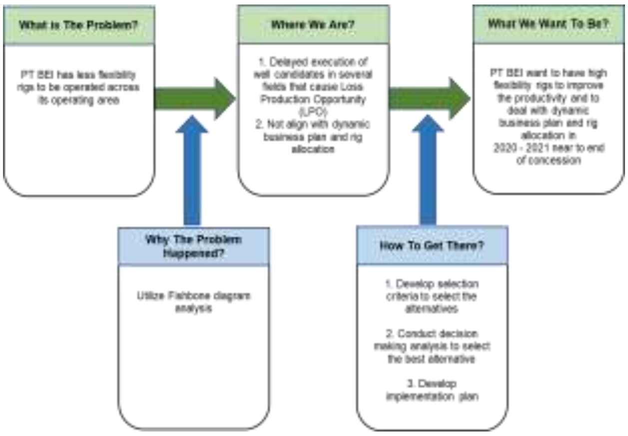

Figure 2 Conceptual Framework

3. Research Methodology

Research methodology (see Figure 3) is developed as a flow process to find the solution. As the result of root cause analysis (see section 3.1), the business problem in this research is to find the fit for purpose well control equipment for workover and well service rigs to improve rigs flexibility to be operated across operating areas of PT BEI.

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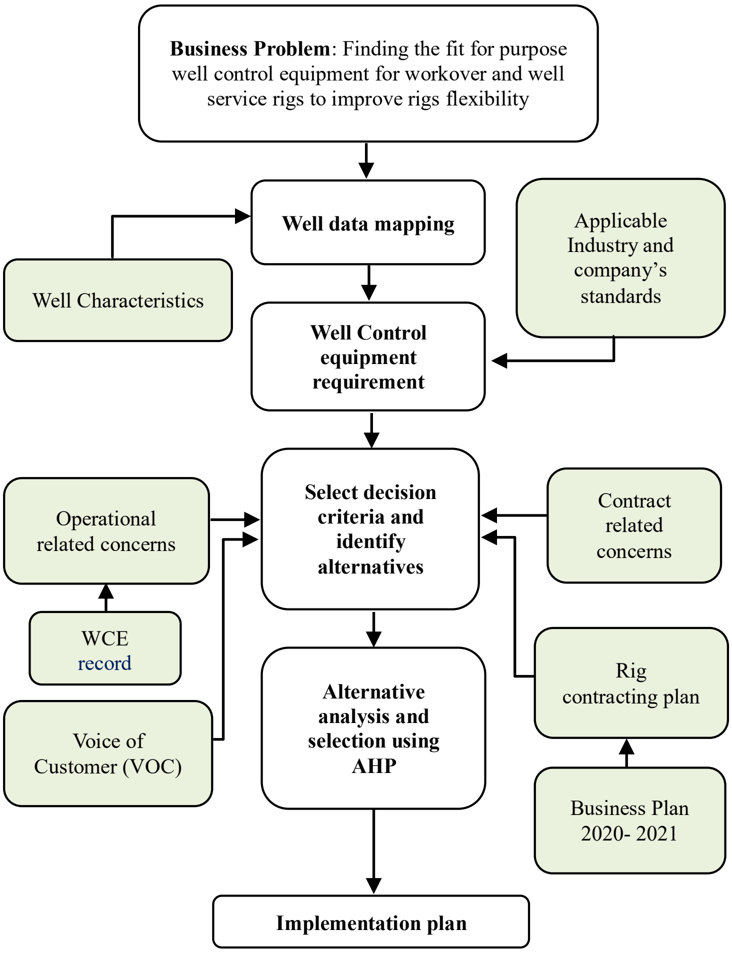

Figure 3. Research Methodology

3.1. Root Cause Analysis

In this research, a Fishbone diagram analysis is utilized to identify possible causes of "why current rigs have less flexibility to be operated across HO and SLO areas." The analysis of using this method was devised by Dr Kaoru Ishikawa in 1943. Therefore, this diagram is also known as Ishikawa Diagram. There are several steps to solve a problem using Fishbone diagram analysis (Mindtools, 2019, [1]) as follows:

1. *Identify the problem*. Identify what the problem is, who is involved and where and when it occurs.
2. *Work out the major factors involved*. In this case, 6M (Machine, Manpower, Measurement, Material, Method, and Mother Nature) categorization is used as a major factors category.
3. *Identify possible causes*. Conduct brainstorming to identify possible causes of the problem that may be related to the factor. Framing it as a "why" question will help in the brainstorming. Draw these possible causes as shorter lines coming off the "bones" of the diagram. If a cause is large, then it may be best to break it down into sub-causes then draw these as lines coming off each cause line.
4. *Analyze the diagram*. Investigate the most likely causes further. This method also tests possible causes identified, which possible causes contributing to the problem.

A Focus Group Discussion (FGD), which consists of Well Control subject matter experts and stakeholders (Representatives of D&C Operation, D&C Rig Hub, D&C Engineering, D&C Support), was established as a media for discussion and decision making in this research. During this research, several FGD were conducted in every step which needed decision making (see Appendix 1). Through the FGD, the team developed the Fishbone Diagram and

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identified several possible causes. All possible causes are then verified to determine which possible causes impact directly rig flexibility.

Combining the Fishbone diagram (see Appendix 2) and the possible causes verification (see Appendix 3), through the FGD, the team eliminated some possible causes then determined the remaining possible causes as potential causes. The possible causes that were eliminated were possible causes under the "Measurement" category which is most related to the business plan of the company while possible causes that are under the "Mother Nature (Environment)" category which is most related to the good characteristics and environmental situation of the operating area. The team considered those possible causes as part of the business issue of this research and factors that cannot be managed or controlled. Other possible causes that have a direct impact on rig flexibility are considered as the potential causes of less rig flexibility and it can be managed or controlled. The summary of potential causes can be seen in Appendix 4.

As the conclusion of root cause analysis, the main potential root causes of why current rigs have less flexibility are well-controlled equipment in relation to rig contract SOW. In further analysis, a fit for purpose well control equipment is determined, and rig contract SOW is improved so it can be utilized both in HO and SLO areas to improve rig flexibility.

3.2. Well Data Mapping

Well, data gathering and mapping are conducted to understand further the good characteristics across an operating area of PT BEI. Over the past decades, PT BEI has drilled over 16,000 wells in the Rocka block area. About 66% of the wells (11,000 wells) are in the HO area and the remaining 34% of the wells (5,000 wells) are in the SLO area. For well status, currently, 84% of the wells (13,600 wells) are in the active status, 12% of the wells have been Plug Abandoned (PA) and 4% of the wells are in Temporary Abandoned (TA) or inactive status.

HO applied steam flood EOR while SLO area applied waterflood EOR on several big fields and other fields still rely on primary recovery. For well type distribution, the HO area has 72.5% oil producer wells, 18.5% steam injector wells and the remaining wells are combinations of observation and disposal wells. SLO area has 79% oil producer wells, 14.5% water injector wells, 0.7% gas producer wells and the remaining wells are a combination of observation and disposal wells. From the data mapping, it was identified that only the SLO area has active gas producer wells (93 wells).

Figure 4. Well Status Distribution (Source: Internal Data PT BEI)

Well, completion types for HO and SLO areas are different. The good completion type selection depends on several factors such as formation characteristic of the field, subsurface condition related to the formation target and the purpose of the well. HO area uses Open Hole Gravel Pack (OHGP) completion for the oil producer wells considering formation characteristic in HO area which is unconsolidated sand while the steam injector wells use cased hole completion. The HO area also has several horizontal producer wells with perforated or pre-packed liners. Different from the HO area, the SLO area uses cased hole completion types for the oil producer, gas producer and water injector wells. SLO also has several horizontal oil producer wells to produce the oil from thin formation targets.

Almost all fields in the Rocka block area are depleted. The wells have a Maximum Anticipated Surface Pressure (MASP) range within 0 – 500 psi except for gas producer wells which have MASP of 500 – 1,000 psi. But most wells in both HO and SLO areas have MASP of 0 psi. For the artificial lift system types, the HO area uses Sucker Rod Pump (SRP) while the SLO area uses an Electric Submersible Pump (ESP) and some Progressive Cavity Pump (PCP). The selection of an artificial lift system depends on the fluid rate that can be produced for the wells. Related to production string size, wells in HO area use various production string sizes from 2.375 to 4.5 inch while wells in SLO

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area mostly use 3.5-inch string size and some use 4.5 inches. Types of artificial lift systems and the production string size directly affect the operational procedure of well control equipment

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Table 1. Main difference between HO and SLO Wells

Characteristics	HO	SLO
Oil Gravity (ºAPI)	21.5 (heavy crude)	35.0 (light crude)
Hydrocarbon Content	Oil (low to high H2S)	Oil and gas (mostly oil)
Well Depth (feet TVD)	300 – 800	500 – 9,000
Well Profile	Vertical, directional, horizontal (mostly vertical)	Vertical, directional, horizontal (mostly directional)
Well Completion Type	OHGP (producer wells) and Cased Hole (injector wells)	Cased Hole (producer and injector wells)
Oil Recovery	Steam flood	Primary and Waterflood
Artificial Lift System	Mostly SRP	Mostly ESP and some SRP and PCP

(Source: Internal Data PT BEI)

In the past 3 years (2017 – 2019), PT BEI maintained the number of good jobs executed at the level 6,200 – 6,700 jobs per year (see Figure 5). HO area has the highest portion of well jobs number compared to SLO area because of shorter moving distance (all wells in a field), shallow well depth, and simpler job types.

Based on the Pareto chart (see Figure 6 and Figure 7), the top primary job type executed in the HO and SLO area is a pump repair job. This job type takes up to 78% of total jobs executed. Pump repair job is a simple job type that only involves pump changing to put the well back on production without interfering with the well completion and configuration. SLO area has more various job types compared to HO area which expose the SLO area to more job risks. In addition, there are approximately 20 jobs routinely performed every year in gas producer wells across the SLO area. Performing workover and well services jobs in the gas producer wells will be a special concern because of the higher operational risk.

Figure 5. Jobs Completed and Rigs Number for Period: 2017 to Q3-2019 (Source: Internal Data PT BEI)

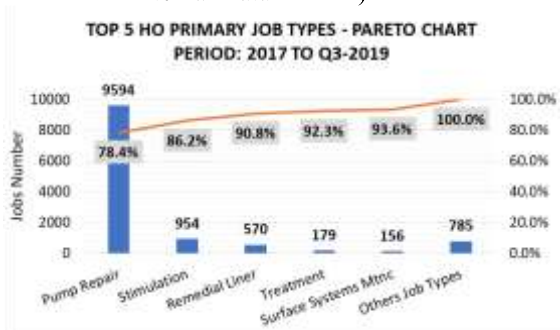

Figure 6. Top 5 HO Primary Job Types for Period: 2017 to Q3-2019 (Source: Internal Data PT BEI)

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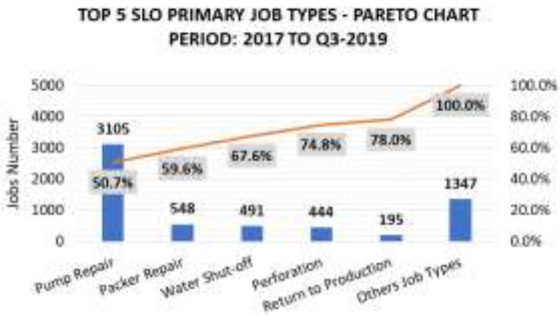

Figure 7. Top 5 SLO Primary Job Types for Period: 2017 to Q3-2019 (Source: Internal Data PT BEI)

The company has a record of Well Control Events (WCE) during the period of year 2017 – 2019. 10 WCE occurred in HO area which is Duro field and 12 WCE occurred in 7 of 75 active fields in SLO area. No WCE that caused severe or major loss of containment recorded during the period. See Appendix 5 for a data mapping summary.

3.3. Well Control Equipment Requirement

The minimum well control equipment requirement is determined by API Std 53 [2] and the company's standard – Global Technical Standard (GTS) Well Control System [3] and GTS Well Control Requirement [4]. Referring to those standards, well MASP and exposure to gas formation are the main points of consideration in determining the well control equipment requirement. API Std 53 (2018, p.26-27, [2]) highlights that for a MASP of 3,000 psi or less, a minimum BOP Class II with one Blind ram or Blind-Shear ram (BSR) shall be installed. A minimum BOP Class III shall be installed for wells with MASP of greater than 3,000 to 5,000 psi. While GTS Well Control System (2018, p.12-13, [3]) highlights that minimum BOP Class II shall be installed for wells with MASP of less than 500 psi. A minimum BOP Class III-A shall be installed for wells with MASP between 501 – 2,000 psi, or when gas zones are expected. A BOP Class III-B shall be installed for wells with MASP between 2,001 – 5,000 psi, or when gas zones are expected. For BOP Class III-B has a minimum one set of BSR.

Basically, the minimum Well Control equipment requirement both for HO and SLO area, refer to the industry standard API Std 53 and company's standard GTS – Well Control System, is BOP Class II. The BOP Class III is required when executing gas producer wells which are only found in the SLO area.

3.4. Decision Criteria and Alternatives

Operational related concerns

1. BOP must be able to shut-in the well quickly and properly regardless the well characteristics and job type
2. A BSR should be installed for HO rigs to cut and shut-in the well in case of steam kick present
3. Safety aspect and cycle time to install and uninstall the BOP
4. Several well candidates cannot be executed due to high wellhead height issues. BOP Class II is preferred than BOP Class III to execute this group of wells

Contract related concerns

PT BEI has not much time to prepare a new contracting process with new rig equipment specification. It is recommended to utilize the existing rig contract SOW or equipment specification that is available in the existing rig contract or owned by the existing rig contractors. Related to contract type, the conventional contract type provides more rig flexibility where additional required rig equipment can be added to the provision sum in the contract SOW and it can be utilized after the work order is issued. While the Technical Frame Contract (TFC) type provides less rig flexibility because of the rigid contract SOW.

Contracting plan

Rig number continues to be reduced gradually starting 2019 to 2021. This reduction aligns with the business plan revision to reduce the jobs number. The rig numbers reduction is up to 50% annually.

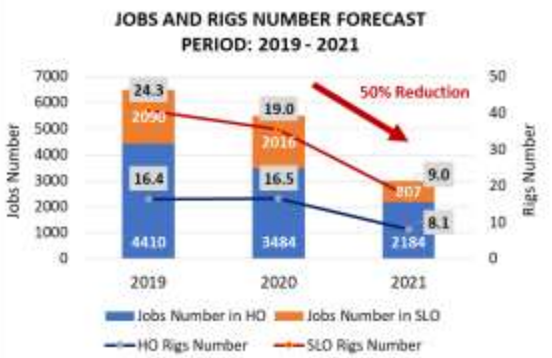

Figure 8. Jobs and Rig Number Forecast 2019 to

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2021 (Source: Internal Data PT BEI)

Voices of Customer (VOC)

1. The fit for purpose well control equipment is expected will increase the rig flexibility to be operated across HO and SLO area and improve rig operation performance including optimum BOP activities time and minimum risks during BOP installation and uninstallation process (by D&C Operation Superintendent)
2. The fit for purpose well control equipment is expected can support better well candidate execution especially for group of wells with high wellhead height (by D&C Engineering Team Manager)
3. The fit for purpose well control equipment is expected will simplify the contract SOW and can accommodate the rig operation requirement in both HO and SLO area contractually in facing the dynamic business plan and minimize the series of tiring contracting process in the future (by D&C Support Team Lead)
4. The fit for purpose well control equipment shall not reduce its functions to prevent loss of containment. As an operational consideration, the well control equipment, especially BOP, is expected to shut-in the well as fast as possible and be able to be used in various operation conditions. Another important one in determining the fit for purpose well control equipment is ensuring the well control equipment alternatives selection follow the applicable standards (by WellSafe Examiner and Well Control Instructor)

Decision Criteria

The decision criteria are defined through the FGD. There are 4 decision criteria selected for this research.

1. **Operational flexibility (highest priority)**. This criterion is to accommodate the operational concerns related to the ability of Well Control equipment that can be used to shut-in the wells properly for various wells conditions (tubular size, well completion types, artificial lift systems) in both HO and SLO area without problem.
2. **Contract flexibility**. This criterion considers Well Control equipment specification that is already available in the existing contracts and/ or owned by existing rig contractors. And, most possible specification for future rig contracts that can improve rigs flexibility.
3. **Installation/ uninstallation process**. This criterion includes sub-criteria of safety aspect and cycle time to install/ uninstall the Well Control equipment as VOC from D&C Operation team.
4. **High wellhead wells execution ability (lowest priority)**. This is another criterion that allows the execution of high wellhead wells as VOC from the D & C Engineering team.

Decision Alternatives

The decision alternatives are also defined through the FGD. There are 4 decision alternatives identified and will be further analyzed in this research:

1. **Alternative-1** (existing rig contract specification): BOP Class III A1-R2 (Annular + Blind and Pipe Rams) for SLO area and BOP Class II A1-R1 (Annular + Blind-Shear Ram) for HO area
2. **Alternative-2**: BOP Class III A1-R2 (Annular + Blind and Pipe Rams) for all area
3. **Alternative-3**: BOP Class II A1-R1 (Annular + Blind-Shear Ram) for all area
4. **Alternative-4**: BOP Class II R2 (Blind and Pipe Rams) for all area

Some key considerations to define the alternatives are as follows:

1. Minimum Well Control equipment requirement for HO and SLO area is BOP Class II (Well MASP 0-500 psi) except for gas producer wells which require BOP Class III.
2. As an existing operational practice, a Blind-Shear ram is used in HO area considering steam flood operation and shallow well depth.
3. Annular has an advantage compared to pipe ram where it can seal on a wide range of tubular size. It should be considered for a well completion type that uses a variation of tubular size.
4. Well Control equipment classification in the existing contract or owned by the existing rig contractor is strongly considered.

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5. Ability of the Well Control equipment to shut-in the well in the various well characteristics such as, wells that using ESP as its artificial lift system, wells with high wellhead height that cannot be executed using high BOP height like BOP Class III, and operating area that have wells with various size of production tubing.

The scope and limitation of the research are:

1. Covers all operating area of PT BEI in Rocka block area
2. Limited to workover and well service rigs operation (excluded drilling rigs operation)
3. Focused on fit for purpose well control equipment selection by considering applicable standards, contract and operational concerns to improve rig flexibility
4. Uses Analytic Hierarchy Process (AHP) as the decision-making method to determine the best alternative. This method is suitable for the case where AHP enables pairwise comparison to find the most critical alternative, do the consistency checking, and allow the use quantitative and qualitative data combination.

4. Analytic Hierarchy Process (AHP)

AHP is a structured method to analyze the alternatives for decision making. The AHP method was originally introduced and developed by Prof. Thomas L. Saaty in 1970's. This method allows the use of qualitative as well as quantitative criteria in the evaluation. Some small inconsistency is allowed in the judgement concerning qualitative criteria that is created from human thinking that is not always consistent. The AHP helps the decision makers to find one that best suits their goal and their understanding of the problem [5].

AHP is used as an organised way to make decisions and collect information relevant to the group by laying out all the important factors and negotiating their understanding, beliefs and values. The AHP is a theory of measurement through pairwise comparison and relies on the judgments of experts to derive priority scale (Saaty, 2008, [6]). Generally, AHP decomposes the decision into the following steps:

1. Develop a hierarchy of decision criteria. Define the problem, determine the criteria and identify the alternatives.
2. Make pairwise comparisons. Rate the relative importance between each pair of decision alternatives and criteria. Determine the relative weights of the decision criteria and the relative rankings (priority) of the alternatives.
3. Synthesize the results including the consistency checking to determine the best alternative.

4.1. AHP Hierarchy

The AHP hierarchy in this research is depicted in Figure 9.

1. Alternative-1: BOP Class III A1-R2 for SLO and BOP Class II A1-R1 for HO area
2. Alternative-2: BOP Class III A1-R2
3. Alternative-3: BOP Class II A1-R1
4. Alternative-4: BOP Class II R2

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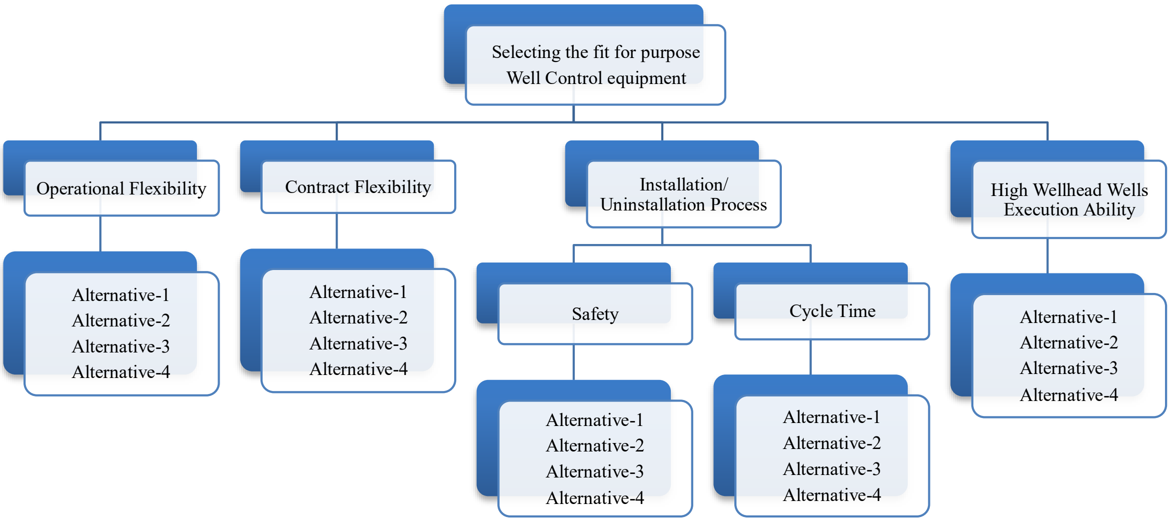

Figure 9. The AHP Hierarchy

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4.2. Pairwise Comparison

Pairwise comparison is performed through the FGD. The fundamental scale of absolute numbers (see Table 2) are utilized to develop pairwise comparison matrices.

Table 2. The Fundamental Scale of Absolute Numbers

Intensity of Importance	Definition	Explanation
1	Equal importance	Two activities contribute equally to the objective
2	Weak of slight	
3	Moderate importance	Experience and judgement slighly favour one activity over another
4	Moderate plus	
5	Strong importance	Experience and judgement strongly favour one activity over another
6	Strong plus	
7	Very strong or demonstrated importance	An activity is favoured very strongly over another; its dominance demonstrated in practice
8	Very, very strong	
9	Extreme importance	The evidence favouring one activity over another is of the highest possible order of affirmation

(Source: Saaty, 2008 [6])

Pairwise Comparison Criteria and Sub-criteria

Operational flexibility is strongly important than contract flexibility, very strongly more important than installation/ uninstallation process performance, and extremely more important than high wellhead wells execution ability. Contract flexibility is moderately more important than installation/ uninstallation process performance and strongly more important than high wellhead wells execution ability (see Table 3).

Comparing the sub-criteria safety and cycle time, sub-criteria safety is strongly more important than sub-criteria cycle time. And, installation/ uninstallation process performance is moderately more important than high wellhead wells execution ability (see Table 4).

Operational Flexibility

Alternative-1, the existing well control equipment in the current contract, is very strongly preferred than Alternative-2 and Alternative-4 considering the use of BSR that is recommended for HO wells with potential of steam kick. Alternative-1 is weaker than Alternative-3 considering the requirement to meet the standard when executing gas producer wells which need BOP Class III however statistically the number of gas producer wells executed per year is very small (~20 wells or < 0.3% of total jobs executed). Alternative-3 is very strongly preferred to Alternative-2 and Alternative-4 for similar reasons as Alternative-1 considering the use of BSR. Alternative-2 is moderately preferred than Alternative-4 considering the use of Annular which can accommodate most HO and SLO wells characteristics (see Table 5).

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Contract Flexibility

Alternative-1 is the existing rig contract condition. With the current contract condition, provision sum activation or contract amendment is required just in case the rig is moved from HO to SLO area or vice versa due to fixed contract SOW. In the current contract SOW, HO rigs utilize BOP Class II while SLO rigs utilize BOP Class III. Considering that situation also related to capability to be utilized almost for well jobs, Alternative-3 is strongly preferred than Alternative-1 and very strongly preferred than Alternative-2 and Alternative-4. Alternative-1 is considered moderately preferred than Alternative-2 and Alternative-4. While Alternative-2 is equally preferred than Alternative-4 (see Table 6).

Installation/ Uninstallation Process

Safety – Annular and ram come in separate sections. Rig crews need to do the installation/ uninstallation process in every rig up and rig down. The process includes the bolts and not installation/ uninstallation also lifting rigging activity from BOP skid to wellhead and vice versa. Specifically, for R2 (Blind Pipe), it comes in one body (double ram) so it has less bolts and nut installation/ uninstallation. Considering the number of bolts and nuts to be installed/ un (pinch points) and weight of the equipment (lifting rigging activity), Alternative-4 is very strongly preferred than Alternative-2, strongly preferred than Alternative-1 and Alternative-3. Alternative-3 is strongly preferred than Alternative-2 and moderately preferred than Alternative-1. Alternative-1 is weaker than Alternative-2 (see Table 7).

Cycle Time – Considering the number of sections including bolts and nuts to be installed/ uninstalled and lifting rigging time, Alternative-4 is very strongly preferred than Alternative-2, strongly preferred than Alternative-1, moderately preferred than Alternative-3. Alternative-3 is strongly preferred than Alternative-2 and moderately preferred than Alternative-1. Alternative-1 is weaker than Alternative-2 (see Table 8).

High Wellhead Execution Ability

Several wells with high wellheads have been identified in the SLO area. Those wells cannot be executed using BOP Class III. Considering this matter, Alternative-3 and Alternative-4 are very strongly preferred to Alternative-1 and Alternative-2. Alternative-3 is equally preferred than Alternative-4 and Alternative-1 is equally preferred than Alternative-2 (see Table 9).

Table 3. Pairwise Comparison Matrix of The Main Criteria

		Operational Flexibility	Contract Flexibility	Installation/ Uninstallation Process	High Wellhead Wells Execution Ability
Operational Flexibility		**1**	**5**	**7**	**9**
Contract Flexibility		**1/5**	**1**	**3**	**5**
Installation/ Uninstallation Process		**1/7**	**1/3**	**1**	**3**
High Wellhead Wells Execution Ability		**1/9**	**1/5**	**1/3**	**1**

Table 4. Pairwise Comparison Matrix for The Subcriteria with Respect to Installation/ Uninstallation Process

		Safety	Cycle Time
Safety		**1**	**5**
Cycle Time		**1/5**	**1**

Table 5. Relative Ranking of Alternatives – Operational Flexibility

Operational Flexibility		Alternative-1	Alternative-2	Alternative-3	Alternative-4

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Alternative-1		1	7	2	7
Alternative-2		1/7	1	1/7	3
Alternative-3		1/2	7	1	7
Alternative-4		1/7	1/3	1/7	1

Table 6. Relative Ranking of Alternatives – Contract Flexibility

Contract Flexibility		Alternative-1	Alternative-2	Alternative-3	Alternative-4
Alternative-1		1	3	1/5	3
Alternative-2		1/3	1	7	1
Alternative-3		5	7	1	7
Alternative-4		1/3	1	1/7	1

Table 7. Relative Ranking of Alternatives – Installation/ Uninstallation – Safety

Safety		Alternative-1	Alternative-2	Alternative-3	Alternative-4
Alternative-1		1	3	1/3	1/5
Alternative-2		1/3	1	1/5	1/7
Alternative-3		3	5	1	1/5
Alternative-4		5	7	5	1

Table 8. Relative Ranking of Alternatives – Installation/ Uninstallation – Cycle Time

Cycle Time		Alternative-1	Alternative-2	Alternative-3	Alternative-4
Alternative-1		1	3	1/3	1/5
Alternative-2		1/3	1	1/5	1/7
Alternative-3		3	5	1	1/3
Alternative-4		5	7	3	1

Table 9. Relative Ranking of Alternatives – High Wellhead Execution Ability

High Wellhead Execution Ability		Alternative-1	Alternative-2	Alternative-3	Alternative-4
Alternative-1		1	1	1/7	1/7
Alternative-2		1	1	1/7	1/7
Alternative-3		7	7	1	1
Alternative-4		7	7	1	1

4.3. Synthesizing Alternatives and Criteria

After the pairwise comparison matrix is determined then the synthesizing alternatives

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and criteria is performed covering pairwise comparison matrix, eigen factor calculation and consistency checking. The synthesizing procedures are as follows:

Step-1. Sum the values in each column.

Step-2. Divide each element of the matrix by its column total. Make sure all columns in the normalized pairwise comparison matrix now have a sum of 1.

Step-3. Average the elements in each row. The values in the normalized pairwise comparison matrix have been converted to decimal form. The result is usually represented as the relative priority vector (Eigenvector).

To ensure that the matrix is consistent, consistency needs to be done as the next step of the process. Consistency checking is required for n > 2. n is the number of pairwise comparison matrices. The consistency procedures are as follows:

Step-1. Multiply each value in the first column of the pairwise comparison matrix by the relative priority of the first item considered. Same procedures for other items. Sum the values across the rows to obtain a vector of values labeled "weighted sum".

Step-2. Divide the elements of the vector of weighted sums obtained in the Step-1 by the corresponding priority value.

Step-3. Compute the average of the values computed in Step-2. This average value is denoted as λ_{max}.

Step-4. Compute the **Consistency Index (CI)**
$CI = \frac{\lambda - n}{n-1}$
n = the number of elements being compared

Step-5. Compute the **Consistency Ratio (CR)**
$CR = \frac{CI}{RI}$
RI = random index, which is the consistency index of a randomly generated pairwise comparison matrix. RI depends on the size of pairwise comparison matrix

Table 10. The Random Index (RI)

n	RI
1	0.00
2	0.00
3	0.58
4	0.90
5	1.12
6	1.24
7	1.32
8	1.41
9	1.45
10	1.49

(Source: Golden and Wang, 1990 [7])

If the CR value less than 0.100 (≤ 0.100) means that the degree of consistency exhibited in the pairwise comparison matrix for an element is "acceptable" or consistent. Detailed synthesizing for each alternative and criteria can be seen in Appendix 6.

4.4. Ranking of Alternatives and Criteria

From the result of the synthesizing alternatives and criteria, the ranking of alternatives can be summarized in Table 11. While the ranking of criteria can be seen in Figure 10.

Alternative-3 BOP Class II A1-R1 (Annular + Blind-Shear Ram) is the best alternative compared to other alternatives. Alternative-3 is selected as fit for purpose Well Control equipment for HO and SLO area and included in the new rig contract SOW.

Table 11. Ranking of Alternative

		Score
Alternative-1 BOP Class III A1-R2 (Annular + Blind and Pipe Rams) for SLO and BOP Class II A1-R1 (Annular + Blind-Shear Ram) for HO area		**0.380**

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Alternative-2 BOP Class III A1-R2 (Annular + Blind and Pipe Rams) for all area		**0.082**
Alternative-3 BOP Class II A1-R1 (Annular + Blind-Shear Ram) for all area		**0.409**
Alternative-4 BOP Class II A1-R1 (Blind and Pipe Rams) for all area		**0.129**

5. Implementation and Results

As the solution, PT BEI selected BOP Class II A1-R1 (Annular + Blind-Shear Ram) as a default well control equipment in the rig contract SOW for all rigs in HO and SLO area. This BOP classification is already owned by most rig contractors working for PT BEI. The well control specification in the existing contract, minimum well control equipment requirement and proposed well control equipment can be seen in the Appendix 7.

The implementation of this solution was applied in a rig contract (conventional contract type) which consists of 3 rigs, in the beginning of 2020. The solution implementation resulted in flexibility to allocate the rigs from HO to SLO area or vice versa. Moreover, the rigs have capability to execute some well candidates with high wellhead height across the SLO area that evidently have high economic value. The actual financial benefits since the beginning of contract commencement are cost avoidance for PT BEI due to Well Control equipment revision (estimated $ 77,000 per year) and investment cost saving of Well Control equipment for rig contractor (estimated $ 90,000 per rig unit).

6. Conclusion and Recommendation

Some key points are concluded from this research which are:

1. FGD involving subject matter experts and stakeholders is an effective media for discussion and decision making.
2. AHP is an appropriate method to get an objective solution for the decision-making problem when quantitative and qualitative data combinations are used.
3. Well Control equipment associated with the rig contract SOW is identified as a rig component that significantly impacts the flexibility of workover and well service rigs in PT BEI.
4. The utilization of one BOP classification which is BOP Class II (Annular + Blind-Shear ram) as default well control equipment specification for HO and SLO area has improved rig flexibility to execute high wellhead height well candidates as well as be operated across operating area of PT BEI in Rocka PSC. As an exception for well jobs execution in gas producer wells (0.7% of total wells in SLO), BOP Class III (Annular + Blind and Pipe ram) is still required and included in the provision sum list of rig contracts.
5. Some rig accessories (i.e. elevators and subs size) are standardized and included together with the BOP Class II (Annular + Blind-Shear ram) as standard rig equipment in the new rig contract SOW.

As recommendations and next opportunities are:

1. Implement the solution to the next rig contracting process.
2. Develop a more conventional rig contract type instead of Technical Frame Contract (TFC) to have more flexibility for dynamic business situations.
3. Introduce a similar approach to solve any company's issues related to the decision making.

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APPENDIX 1. Focus Group Discussion (FGD) Schedule and Summary

FGD Session	Event Date	Participants	Discussion Topic
Session 1	20 Aug 2019	Well Control Instructor, WellSafe Examiner, D&C Engineering Team Manager, D&C Operation Superintendent, D&C Operation Team Lead, D&C Rig Hub Team Lead, D&C Support Team Lead	Root Cause Analysis: Develop fishbone diagram, verify the possible causes, determine the potential causes
Session 2	15 Oct 2019	Well Control Instructor, WellSafe Examiner, D&C Engineering Team Manager, D&C Operation Superintendent, D&C Operation Team Lead, D&C Rig Hub Team Lead, D&C Support Team Lead	Decision criteria selection and alternatives identification: gather Voices of Customer (VOC), discuss operational related concerns and contract related concerns, discuss business plan and rig contracting plan, select decision criteria and identify alternatives
Session 3	7 Nov 2019	Well Control Instructor, WellSafe Examiner, D&C Engineering Team Manager, D&C Operation Superintendent, D&C Operation Team Lead, D&C Rig Hub Team Lead, D&C Support Team Lead	Alternative analysis using AHP: pairwise comparison, synthesizing decision criteria and alternatives, ranking of alternatives, ranking of criteria
Session 4	19 Nov 2019	Well Control Instructor, WellSafe Examiner, D&C Engineering Team Manager, D&C Operation Superintendent, D&C Operation Team Lead, D&C Rig Hub Team Lead, D&C Support Team Lead, Planning Specialist	Project socialization
Session 5	9 Dec 2019	Well Control Instructor, WellSafe Examiner, D&C Engineering Team Manager, D&C Operation Superintendent, D&C Operation Team Lead, D&C Rig Hub Team Lead, D&C Support Team Lead, Planning Specialist	Project implementation

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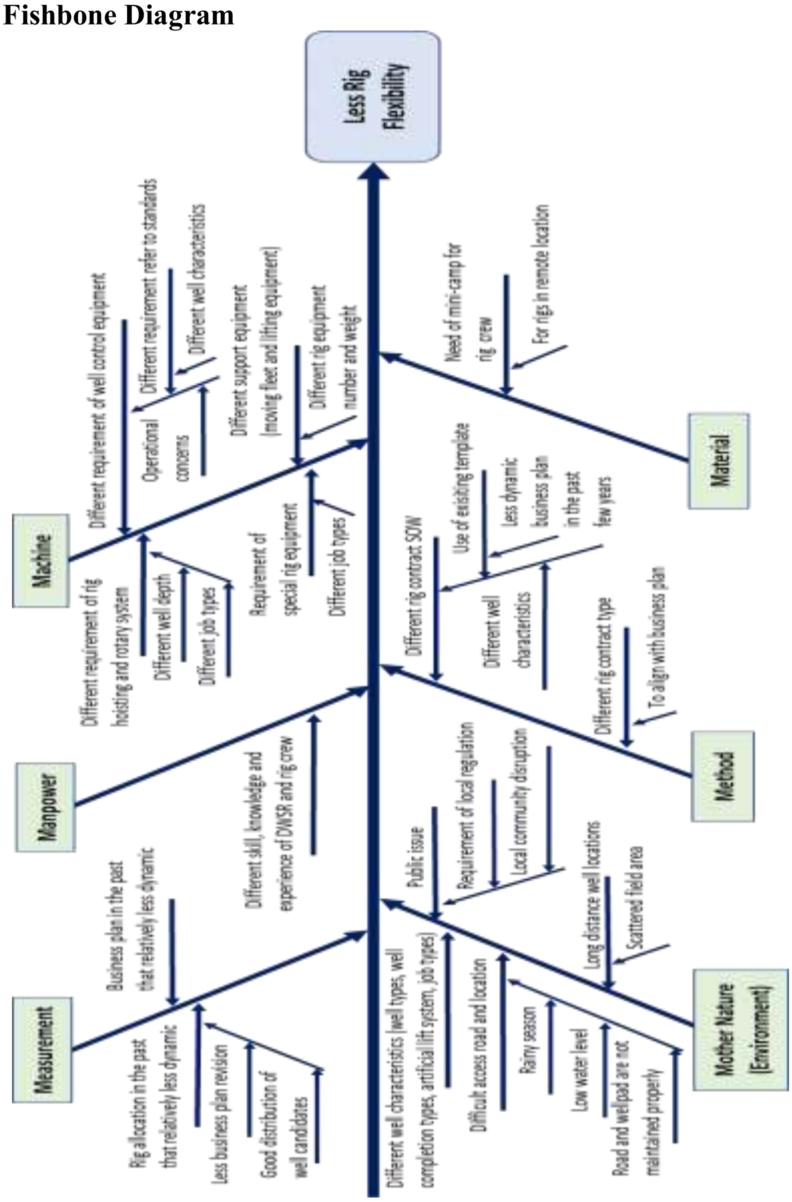
APPENDIX 2. Fishbone Diagram



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APPENDIX 3. The Possible Causes of Less Rig Flexibility

No.	Category	Possible Causes	Remarks	Impact to Rig Flexibility?	
				Y	N
1	Measurement	Business plan in the past that relatively less dynamic	This is the business issue	✓	
		Rig allocation in the past that relatively less dynamic – caused by less business plan revision	Situation in the past few years has led to complacency and conditioned the rigs to have less flexibility	✓	
		Rig allocation in the past that relatively less dynamic – caused by good distribution of well candidates	Situation in the past few years has led to complacency and conditioned the rigs to have less flexibility	✓	
2	Manpower	Different skill, knowledge and experience of DWSR and rig crew	This situation was normal. Learning curve occurred in every beginning of operation in a new area		✓
3	Machine	Different requirement of rig hoisting and rotary system – caused by different well depth	Current equipment specification can allow rigs to be operated for both HO and SLO area		✓
		Different requirement of rig hoisting and rotary system – caused by different job types	Current equipment specification can allow rigs to execute all job types for both HO and SLO area		✓
		Requirement of special rig equipment – caused by different job types	Many swabbing jobs are executed in SLO area that cause SLO rigs must have special equipment for swabbing job (swab tool, swab head, swab tank)	✓	
		Different requirement of well control equipment – caused by different requirement refers to standards that depend on the well characteristics	Well control equipment that utilized by HO rigs is BOP Class II A1-R1 while SLO rigs is BOP Class III A1-R2. PT BEI refers to API and company's standards	✓	
		Different requirement of well control equipment – caused by operational concerns	BSR is recommended to be utilized in HO rigs considering steam flood and shallow well depth	✓	

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		Different support equipment (moving fleet and lifting equipment) – caused by different equipment number and weight	HO and SLO rigs have same support equipment that can be operated both in HO and SLO area		✓
4	Mother Nature (Environment)	Different well characteristics (well types, well completion types, artificial lift system, job types)	This condition is given	✓	
		Difficult access road and location – caused by rainy season	This condition is given and normal. Typically, the support from road and maintenance team is required besides the need to standby dozer at rig site. It is also mitigated through rig scheduling		✓
	Mother Nature (Environment)	Difficult access road and location – caused by low water level	This condition is given and normal.		✓
		Difficult access road and location – caused by road or location were not maintained properly	This condition is normal and specifically for fields that have rarely well job execution. Road and maintenance team will repair the access road and location just before rig moving to the location		✓
		Public issue – caused by requirement of local regulation	As written in the national regulation and stated in the work procedure guidelines for oil and gas operation (PTK-007), rig contractors shall employ local people from the area where the rig is operated		✓
		Public issue – caused by local community disruption	This situation is uncontrollable. Need intensive engagement and communication among public relation team, security team, local government and local community prior to rig moving and during job execution in an area		✓
		Long distance well locations – caused by scattered field area	This situation is given for SLO – North area. The fields are scattered, and most rigs have long distance moving		✓
5	Method	Different rig contract SOW – caused by using existing template that still considered	The existing contract SOW still considers less dynamic business plan in the past few	✓	

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		less dynamic business plan in the past few years	years and not appropriate to deal with the current situation		
		Different rig contract SOW – caused by different well characteristics	Existing contract SOW was basically developed considering the well characteristics. HO and SLO has some differences in well characteristics	✓	
		Different rig contract type – caused by to align with the business plan	There are 2 types of rig contract that currently applied for workover and well service rigs. TFC and conventional contract type. Only conventional contract type that provide flexibility to operate the rigs across HO and SLO area. TFC contract type typically to cover the rigs number baseline/ minimum rigs number requirement in the business plan	✓	
6	Material	Needs of minicamp for rig crew – caused by remote location	The minicamp is must have facility for rig crew when working in the remote area		✓

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APPENDIX 4. The Potential Causes of Less Rig Flexibility

Category	No.	Potential Causes	Remarks
Machine	1	Requirement of special rig equipment – caused by different job types	Special equipment for swabbing job (requires swab tank, swab head, swab tool) is required for all SLO rigs and some HO rigs when executing specific jobs on disposal wells in HO area
	2	Different requirement of well control equipment – caused by different requirement refers to standards that depend on the well characteristics	As per rig contract SOW, HO rigs utilize BOP Class II A1-R1 (Annular + Blind-Shear Ram) and SLO rigs utilize BOP Class III A1-R2 (Annular + Blind and Pipe Rams)
	3	Different requirement of well control equipment – caused by operational concerns	Practice of using BSR for HO rigs considering shallow well depth and steam flood operation
Method	4	Different rig contract SOW – caused by using existing template that still consider less dynamic business plan	Different existing rig contract SOW template between HO and SLO rigs. This contract SOW still considers less dynamic business plan that occurred in the past few years and it is rigid
	5	Different rig contract SOW – caused by different well characteristics	Rig contract SOW was developed based on well characteristics. HO and SLO have area have different well characteristic
	6	Different rig contract type – caused by need to align with business plan	There are 2 types of rig contract that currently applied for workover and well service rigs. TFC and conventional contract type. Only conventional contract type that provide flexibility to operate the rigs across HO and SLO area. TFC contract type typically to cover the rigs number baseline/ minimum rigs number requirement in the business plan

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APPENDIX 5. Well Data Mapping Summary

Description	HO Area	SLO Area
Well drilled	~ 11,000 wells	~ 5,200 wells
Well depth	~ 300 – 800 ft TVD	~ 500 – 9,000 ft TVD
Enhanced Oil Recovery (EOR)	Steam flood	Primary, water flood
Well status	85% active wells, 11% permanent abandoned, 4% inactive/ temporary abandoned	84% active wells, 13% permanent abandoned, 3% inactive/ temporary abandoned
Well types	73% oil producers, 18% steam injectors, 8% observation wells, 1% disposal and evaluation wells	79% oil producers, 15% water injectors, 5.3% observation and disposal wells, **0.7% gas producers**
Well completion types (active oil and gas producer wells)	91% open hole gravel pack, 8% horizontal wells with perforated/ pre-packed liner, 1% cased hole	90% cased hole, 10% horizontal wells with perforated/ pre-packed liner
Artificial lift system (active oil and gas producer wells)	99.7% sucker rod pump, 0.3% progressive cavity pump and hydraulic pump	97% electric submersible pump, 2.5% sucker rod pump, 0.5% progressive cavity pump and hydraulic pump
Job types (2017 – 2019)	~ 4,300 jobs per year 78.5% pump repair, 7.7% stimulatiom, 4.7% remedial liner, 9.9% other jobs combination	~ 2,200 jobs per year 50.7% pump repair, 8.9% packer repair, 8% water shut-off, 7.2% perforation and re-perforation, 25.2% other jobs combination
Well Control Event (WCE) history (2017 – 2019)	10 (Duro)	5 (Bala So), 2 (Kotabata), 1 (Bango), 1(Peta), 1 (Seru), 1 (Sinto), 1 (Tandu)
Well Maximum Allowable Surface Pressure (MASP)	**0 - 500 psi**	**0 - 500 psi (gas producers: 500 – 1000 psi)**

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APPENDIX 6. Synthesizing Alternatives and Criteria

Operational Flexibility

Pairwise Comparison Matrix

Operational Flexibility		Alternative-1	Alternative-2	Alternative-3	Alternative-4
Alternative-1		1.000	7.000	2.000	7.000
Alternative-2		0.143	1.000	0.143	3.000
Alternative-3		0.500	7.000	1.000	7.000
Alternative-4		0.143	0.333	0.143	1.000
Column Total		**1.786**	**15.333**	**3.286**	**18.000**

Eigen Factor Calculation

Operational Flexibility		Alternative-1	Alternative-2	Alternative-3	Alternative-4	Row Average
Alternative-1		0.560	0.457	0.609	0.389	0.504
Alternative-2		0.080	0.065	0.043	0.167	0.089
Alternative-3		0.280	0.457	0.304	0.389	0.357
Alternative-4		0.080	0.022	0.043	0.056	0.050

Consistency Checking

Operational Flexibility		Weighted Sum				Total Weighted Sum	Total Weighted Sum divided by Eigen Factor
Alternative-1		0.504	0.622	0.715	0.351	2.192	4.353
Alternative-2		0.072	0.089	0.051	0.151	0.362	4.079
Alternative-3		0.252	0.622	0.357	0.351	1.582	4.427
Alternative-4		0.072	0.030	0.051	0.050	0.203	4.040

λ max = 4.225 n = 4 RI = 0.90
Consistency Index (CI) = 0.075
Consistency Ratio (CR) = 0.083 (less than 0.100)
The degree of consistency exhibited in the pairwise comparison matrix for Operational Flexibility is acceptable.

Contract Flexibility

Pairwise Comparison Matrix

Contract Flexibility		Alternative-1	Alternative-2	Alternative-3	Alternative-4
Alternative-1		1.000	3.000	0.200	3.000

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Alternative-2		0.333	1.000	0.143	1.000
Alternative-3		5.000	7.000	1.000	7.000
Alternative-4		0.333	1.000	0.143	1.000
Column Total		**6.667**	**12.000**	**1.486**	**12.000**

Eigen Factor Calculation

Contract Flexibility		Alternative-1	Alternative-2	Alternative-3	Alternative-4	Row Average
Alternative-1		0.150	0.250	0.135	0.250	0.196
Alternative-2		0.050	0.083	0.096	0.083	0.078
Alternative-3		0.750	0.583	0.673	0.583	0.647
Alternative-4		0.050	0.083	0.096	0.083	0.078

Consistency Checking

Contract Flexibility		**Weighted Sum**				**Total Weighted Sum**	**Total Weighted Sum divided by Eigen Factor**
Alternative-1		0.196	0.235	0.129	0.235	0.795	4.052
Alternative-2		0.065	0.078	0.092	0.078	0.314	4.019
Alternative-3		0.981	0.547	0.647	0.547	2.723	4.206
Alternative-4		0.065	0.078	0.092	0.078	0.314	4.019

λ max = 4.074 n = 4 RI = 0.90
Consistency Index (CI) = 0.025
Consistency Ratio (CR) = 0.027 (less than 0.100)
The degree of consistency exhibited in the pairwise comparison matrix for Contract Flexibility is acceptable.

Installation/ Uninstallation Process - Safety

Pairwise Comparison Matrix

Safety		Alternative-1	Alternative-2	Alternative-3	Alternative-4
Alternative-1		1.000	3.000	0.333	0.200
Alternative-2		0.333	1.000	0.200	0.143
Alternative-3		3.000	5.000	1.000	0.200
Alternative-4		5.000	7.000	5.000	1.000
Column Total		**9.333**	**16.000**	**6.533**	**1.543**

Eigen Factor Calculation

Safety		Alternative-1	Alternative-2	Alternative-3	Alternative-4	Row Average

Alternative-1		0.107	0.188	0.051	0.130	0.119
Alternative-2		0.036	0.063	0.031	0.093	0.055
Alternative-3		0.321	0.313	0.153	0.130	0.229
Alternative-4		0.536	0.438	0.765	0.648	0.597

Consistency Checking

Safety		**Weighted Sum**				**Total Weighted Sum**	**Total Weighted Sum divided by Eigen Factor**
Alternative-1		0.119	0.166	0.076	0.119	0.481	4.045
Alternative-2		0.040	0.055	0.046	0.085	0.226	4.083
Alternative-3		0.356	0.277	0.229	0.119	0.982	4.284
Alternative-4		0.594	0.387	1.146	0.597	2.724	4.565

λ max = 4.244 n = 4 RI = 0.90
Consistency Index (CI) = 0.081
Consistency Ratio (CR) = 0.091 (less than 0.100)
The degree of consistency exhibited in the pairwise comparison matrix for Installation/ Uninstallation Process - Safety is acceptable.

Installation/ Uninstallation Process – Cycle Time

Pairwise Comparison Matrix

Cycle Time		Alternative-1	Alternative-2	Alternative-3	Alternative-4
Alternative-1		1.000	3.000	0.333	0.200
Alternative-2		0.333	1.000	0.200	0.143
Alternative-3		3.000	5.000	1.000	0.333
Alternative-4		5.000	7.000	3.000	1.000
Column Total		**9.333**	**16.000**	**4.533**	**1.676**

Eigen Factor Calculation

Cycle Time		Alternative-1	Alternative-2	Alternative-3	Alternative-4	Row Average
Alternative-1		0.107	0.188	0.074	0.119	0.122
Alternative-2		0.036	0.063	0.044	0.085	0.057
Alternative-3		0.321	0.313	0.221	0.199	0.263

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Alternative-4		0.536	0.438	0.662	0.597	0.558

Consistency Checking

Cycle Time		Weighted Sum				Total Weighted Sum	Total Weighted Sum divided by Eigen Factor
Alternative-1		0.122	0.171	0.088	0.112	0.492	4.036
Alternative-2		0.041	0.057	0.053	0.080	0.230	4.041
Alternative-3		0.366	0.284	0.263	0.186	1.099	4.175
Alternative-4		0.609	0.398	0.790	0.558	2.356	4.222

λ max = 4.118 n = 4 RI = 0.90
Consistency Index (CI) = 0.039
Consistency Ratio (CR) = 0.044 (less than 0.100)
The degree of consistency exhibited in the pairwise comparison matrix for Installation/ Uninstallation Process – Cycle Time is acceptable.

High Wellhead Wells Execution Ability

Pairwise Comparison Matrix

High Wellhead Wells Execution Ability		Alternative-1	Alternative-2	Alternative-3	Alternative-4
Alternative-1		1.000	1.000	0.143	0.143
Alternative-2		1.000	1.000	0.143	0.143
Alternative-3		7.000	7.000	1.000	1.000
Alternative-4		7.000	7.000	1.000	1.000
Column Total		**16.000**	**16.000**	**2.286**	**2.286**

Eigen Factor Calculation

High Wellhead Wells Execution Ability		Alternative-1	Alternative-2	Alternative-3	Alternative-4	Row Average
Alternative-1		0.063	0.063	0.063	0.063	0.063
Alternative-2		0.063	0.063	0.063	0.063	0.063
Alternative-3		0.438	0.438	0.438	0.438	0.438
Alternative-4		0.438	0.438	0.438	0.438	0.438

Consistency Checking

High Wellhead Wells Execution Ability		Weighted Sum	Total Weighted Sum	Total Weighted Sum divided by Eigen Factor

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Alternative-1		0.063	0.063	0.063	0.063	0.250	4.000
Alternative-2		0.063	0.063	0.063	0.063	0.230	4.000
Alternative-3		0.438	0.438	0.438	0.438	1.750	4.000
Alternative-4		0.438	0.438	0.438	0.438	1.750	4.000

λ max = 4.000 n = 4 RI = 0.90
Consistency Index (CI) = 0.000
Consistency Ratio (CR) = 0.000 (less than 0.100)
The degree of consistency exhibited in the pairwise comparison matrix for High Wellhead Wells Execution Ability is acceptable.

Summary of Synthesizing Alternatives and Criteria

		Operational Flexibility	Contract Flexibility	Installation/ Uninstallation Process		High Wellhead Wells Execution Ability	Overall Priorities
Criteria		**0.643**	**0.208**	**0.101**		**0.048**	
Sub Criteria				Safety	Cycle Time		
Weights (Criteria x Sub-criteria)		**0.643**	**0.208**	**0.833**	**0.167**	**0.048**	
Alternative-1		0.504	0.196	0.119	0.122	0.063	**0.380**
Alternative-2		0.089	0.078	0.055	0.057	0.063	**0.082**
Alternative-3		0.357	0.647	0.229	0.263	0.438	**0.409**
Alternative-4		0.050	0.078	0.597	0.558	0.438	**0.129**

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APPENDIX 7. Well Control Equipment Specification

	Existing		Minimum Requirement		Proposed
Description	HO	SLO	HO	SLO	HO & SLO
BOP Class	Class II	Class III	Class II	Class II and Class III (for wells with MASP> 500 psi or when gas zones are expected)	Class II
BOP Configuration (top – down)	A1-R1: Annular + Single Ram (Annular + Blind-Shear Ram)	A1-R2: Annular + Double Ram (Blind and Pipe Rams)	A1-R1: Annular + Single Ram (Annular + Blind Ram/ Blind-Shear Ram), or R2: Double Ram (Blind and Pipe Rams)	A1-R1: Annular + Single Ram (Annular + Blind Ram/ Blind-Shear Ram), or R2: Double Ram (Blind and Pipe Rams) A1-R2: Annular + Double Ram (Blind and Pipe Rams) for wells with MASP > 500 psi or when gas zones are expected	A1-R1: Annular + Single Ram (Annular + Blind-Shear Ram) Note: Add BOP Class III A1-R2: Annular + Double Ram (Blind and Pipe Rams) in the provision sum list in the rig contract SOW As mitigation for executing well jobs in gas producer wells in SLO area.
BOP Rating	3,000 psi	3,000 psi	3,000 psi	3,000 psi	3,000 psi
Accumulator System	3,000 psi	3,000 psi	3,000 psi	3,000 psi	3,000 psi
Choke Manifolds	Class III, 3,000 psi rating, all manual valves (no remotely hydraulic valves)	Class III, 3,000 psi rating, all manual valves (no remotely hydraulic valves)	Class III, 3,000 psi rating, all manual valves (no remotely hydraulic valves)	Class III, 3,000 psi rating, all manual valves (no remotely hydraulic valves)	Class III, 3,000 psi rating, all manual valves (no remotely hydraulic valves)
Drilling Spool Available/ Required?	Yes	Yes	Yes	Yes	Yes
Shear Ram Available/ Required?	Yes	No	No	No	Yes