Workover Operation Improvement For Wells With High Wellhead Elevation At "Humaira" Area

Agung Budi Rudiantoro* and Mursyid Hasan Basri

School of Business and Management, Institut Teknologi Bandung, Indonesia

Email: agungbudi-rudiantoro@sbm-itb.ac.id

Abstract –**Commodity demand and the production costs strongly affect the oil price. For the industry, market price is considered as uncontrollable, while production cost is controllable. PT. Diamond Energy Indonesia (PT.DEI), one of the largest oil producers in Indonesia, operates "Humaira" oil field with more than 2,000 oil/gas production wells also strives to improve its competitiveness. The subject of this studyis the existence of oil wells having high wellhead elevation which occurred to approximately 6.7% from the population. This situation existed as result of surface erosion of the well site due to rainfall, but mainly due to the addition of wellhead component (retrofit) as low cost fixing to the failure of the existing wellhead design's sealing capability. This extra elevation,however, creates difficulty for the workover rig because of limited clearance below the working platform for the installation of the required blowout preventer (BOP) stack specification. Several alternative solutions were brainstormed by involving the highly experienced in-house personnel via focused group discussions. Kepner-Tregoe decision analysis was selected to seek the most optimum alternative solution for a safe operation that meets compliance, cost effectiveness and practicality as the business objective. The expected business implication of this study is a tangible saving based P50 Cost of Poor-Quality scenario of $742,220.00.**

Keywords: **alternative solution, BOP side outlet, cost effectiveness, high wellhead elevation, Kepner-Tregoe, workover operation**

1. INTRODUCTION

A. *Fossil Energy in Indonesia*

In Indonesia, fossil-based energy is still considered practical and economical to support various industries, transportation, and power generations.Mr. Jusuf Kalla (2019), said that fossil-based power generation was considerably lower cost compared to renewable energy based, despite the fossil-based energy required higher operational cost. This is opposite with renewable energy-based power generation where the initial investing cost will be very high despite lower operational cost. As an example, he compared several energy alternatives. The PLTU (Steam Powered Power Generator) costs 5.5 cent / kWh, geothermal 8-9 cent per kWh and Solar energy costs 10 cent per kWh. The projected energy supply in Indonesia is still dominated by oil and gas at 44% up until the year of 2050, followed by coal 25% and the remaining are renewable energy at 31%. The oil and gas demand in 2050 was estimated at 641 million ton of oil equivalent(CNBCIndonesia, 2019). The conclusion, oil and gas industry sector still crucial for the national development. The fact is however, as showed by the chart below, a continuous declination of oil production within the last 20 (ten) years is unavoidable due to mature oilfields, while on the other hand, the oil demand is kept increasing over the years.

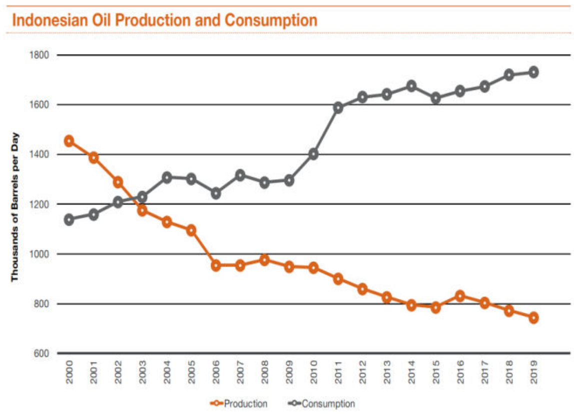

Fig.1. Indonesia Crude Oil Production VS Consumption (2000 - 2019)
(Source : https://www.pwc.com/id/en/energy-utilities-mining/assets/oil-and-gas/oil-gas-guide-2020.pdf*)*

B. *Diamond Energy Indonesia (PT.DEI)*

Diamond Energy Company (located in Central Sumatera) currently is the second largest oil producer in Indonesia, responsible to help the government to maintain the national oil production. As an oil company with mature fields, the production of the company has declined over the years. As part of their commitment to operational excellence, thecompanystrive to do their best to conduct safe and cost-effective operation.

C.*Problem Statement*

There are three critical success measures in workover operation:

- Incident Free Operation (IFO) ~ (0 accident, 0 spill, 0 non-productive time)
- Cost within the planned budget.
- Quality well (production rate, lifetime)

One of critical aspect of workover operation is maintaining the well under control. Failure to maintain

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the well under control could result in a well control situation and harm both people end environment. Blow out preventer (BOP) is a critical equipment which has function to shut in a well in case a kick occurred and close the well under pressure, prior to establish well killing operation. It is very important to assure that workover operation using correct BOP specification to support safe and reliable operation.

One ofunique operational challenge is working on wells withhigh wellhead elevation. Thesewells exist as result of either well pad erosion and/or wellhead modificationproject that was needed so that itsdesignmeet latest company's standard. The process is by adding a new component between the existing configuration, causingthe wellhead became taller from its original design. Unfortunately, this process causesoperational problemfor the rig to perform workover/well service job because of rig's working platform clearance limitation,resulting inability to install the BOP stack.

To overcome this situation, the team has to either installing smaller BOP stack (7-1/16" BOP) to reduce the overall height of the BOPE stack or altering the rig by installing concrete slabs underneath the rig carrier. Both solutions work however it constitute additional cost and challenges.

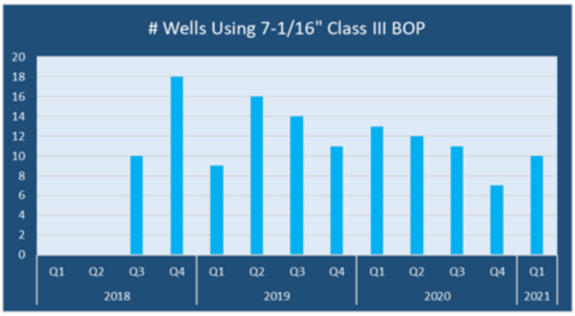

Fig.2. Job Distribution Using 7-1/16" Class III BOP Stack (2018-2021YTD)
(Source: Internal Data)

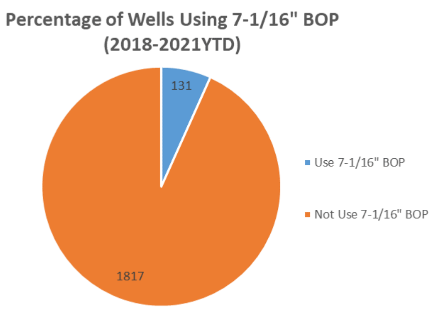

Fig.3. Percentage of 7-1/16" Class III BOP Stack VS Total Job (2018-2021YTD)
(Source: Internal data)

Based on historical workover job in Humaira area of operation within the period of 2018-2021 year-to date, there were in total of 131 wells or 40 wells per year in average that need 7-1/16" Class III 3M psi BOP stack due to tall wellhead. It is approximately 6.7% from the total workover job during the period. The 7-1/16" size BOP stack is currently not part of rig contract daily rate, means extra cost when using it. A workover job could be last between one to few days depend on whether the job was going normal as per plan or could be much longer than expected when certain operation problem occurs during the job execution.

The second alternative is installing concrete blocks underneath the rig carrierto add clearance so that the working platform able to accommodate the installation of 11" 3M psi BOP stack. Another complication is the Loss Production Opportunity due to delay in installing the concrete block because of limited resources. Based on last 2 years data, there were 23 wells workover backlog and had to utilize concrete block due to unavailability of 7-1/16" Class III 3M psi BOP stack.

This study is very important for the company since the business issue caused a considerably financial loss at approximately $742,220.00.

a. Conceptual Framework

An additional workover cost in this study is defined as an unnecessary expense on workover operation as result of accepting to work on an abnormal situation while failing to identify more effective work process. Below is the simplified diagram showing the contributing factors. To narrow the scope, this study will focus on the most significant and internally controllable aspect as represented by the dark blue circles in the diagram below.

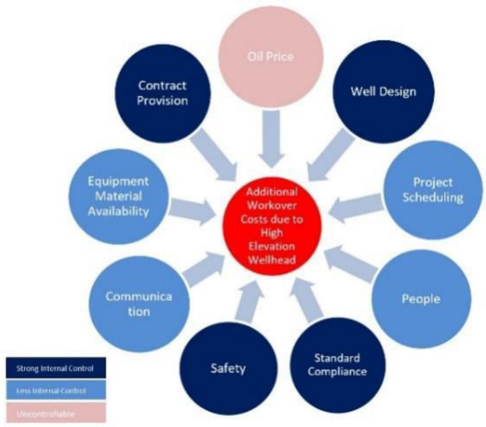

Fig.4. Project's Conceptual Framework
(Source: Author's analysis)

b.Analysis of Business Situation

- *Working Platform (WPF)*

For a light duty job such as well servicing (pump replacement job), a workover rig is equipped with smaller and foldable working platform.The function of WPF is to provide working space for the workers while enable installation of blowout preventer stack (BOP) underneath it.

- *Well Control Equipment*

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Well control equipment system consists of blow out preventers (BOP), choke manifold and accumulator system. The critical function of a well control system is to provide the ability to close the well in the event of well control situation.

- *Annular BOP*

An annular BOP capable of closing the well against tubular presence across the wellbore. An annular BOP is very common for both drilling and workover operation because it has flexibility to seal any size of tubular, except for non-sealable shaped tubulars such as drilling line.

- *Ram BOP*
  - *Pipe Ram*

A pipe ram BOP has the same function with an annular BOP to close the well. The difference is, a ram BOP is designed to only be able to seal the well against certain tubular size. A pipe ram BOP can be used as redundancy for an annular BOP in case it fails. Further, combining between an annular BOP with a pipe ram BOP will enable stripping operation.

  - *Blind / Blind Shear Ram*

A blind shear ram BOP is designed to close the well when no tubular across it. A blind shear ram is a blind ram BOP which is equipped with a shearing blade capable of cutting the tubular allowing the rig to free from the wellbore and move off location immediately.

The determination on whether a blowout preventer can be installed either in single or stack is based on the anticipated well's maximum anticipated surface pressure (MASP) (Stanley &Cummings, 2018). MASP is the maximum surface pressure when the well having full column of gas.

Fig.5. A Class III BOP Stack under WPFll
(Source: Internal documentation)

With the conceptual frameworks, this project is seekinga fit for purpose alternative solutions to reduce or possibly eliminate the workover extra cost for the well with high elevation wellhead while maintaining operational safety and compliance requirements toward the applicable standards

II. LITERATURE REVIEW

A. Well Kick Definition

A well kick is defined as unwanted entrance of reservoir fluid into the wellbore. During drilling and workover operation, it is critical to keep the reservoir fluid in its place. The only situation where the reservoir fluid is permitted to flow up to surface is during the production mode of the well, because it is safely contained in the well and flow through pipeline production system (Smith. J, 2018).

B. Well Control Standard

Well control standard contains references, guidelines, procedures of which the company adopt them to ensure safe and reliable operation based on common industry practices acceptance criteria. Well control standard could be adopted from independent external sources, including Industry Standards, Government Regulations, or Corporate Standards.

a. API S53

API S53 stands for American Petroleum Industry Standard. It is an example of industry standard that is widely adopted by oil and gas company around the world. API S53 provides general guidance for drilling and well servicing industry specific on well control equipment requirements It is not a standard operating procedure for an oil and gas company or replacing any local or state government regulations but facilitate well control equipment configurations that is based on risk assessment, sound engineering and technically proven in the field operations.

The followings are several subjects in the API S53 document which relevant to this research:

- Drilling Spools

The function of this spool is to allow flow / circulating path from the well bore to choke manifold, or from mud pump to killing line into the well bore. Drilling spools is governed in article 4.1.4.1. from the standard.

- Surface BOP Stacks

Article 5.1.1.1. governs the pressure rating of BOP based on maximum anticipated surface pressure (MASP). MASP could be due to full column of gas inside the well bore or from maximum anticipated well intervention load such as injection or fracturing job.

- BOP Stacks capability

Section 5.1.2 details the selection requirements of BOP stack. It must consider the capability, including the ability to shut in the well while having tubular or without tubulars, ability to cut/shear tubular under emergency, ability to hang off pipe when emergency evacuation, ability for stripping operation and circulate the wells under certain conditions.

- BOP Stack arrangement

Section 5.1.3 details how BOP stacks are categorized based on well's MASP and the arrangement / configuration of each BOP components including choke manifold and killing line configuration.

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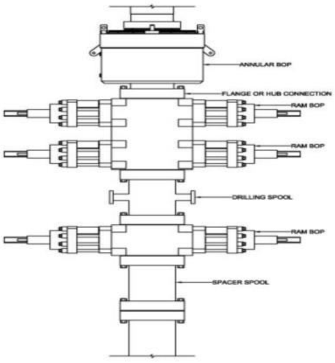

Fig.6. Diagram of A Class III BOP Stack
(Source: API Std 53)

b. API Specification 6A – Specification for Wellhead and Tree Equipment

API Specification 6A provide the requirement related to performance, dimension, design, materials, manufacturing process, inspection and testing of wellhead and tree equipment for oil and gas wells. The followings are some articles that relevant to this project.

- Adapter and Spools

Adapter and spools are both categorized as connectors for BOP stack. This adapter and spools could have different size and rating toward BOP components and enable combinations of different BOP ratings and connection to wellhead.

- Casing and Tubing Hangers

Casing and tubing hangers are components in the wellhead that have the function to hang and hold subsequent casing size while tubing hanger has function hanging the production tubing. The existing well in the Humaira area of operation are mostly under Group 3 where both casing and tubing hanger hangs pipe and seals from bottom and top but without mechanical / ring joint isolation. That is why the reliability of this design was considerably low with many leaks' occurrences.

c. Corporate Standard – Well Control Requirements

This technical standard provides minimum requirements that will be used to establish specific well control requirement procedure for every business unit. It contains assurance that the well control requirement in the business unit shall meet well control regulations in the location where the business unit operates (Stanley, 2017).

The most important and relevant aspect of this standard are the requirement of Kick Detection ability using the selected BOP stack specification, which is governed in the Well Barrier Design Standard DCM-ST-102006 article 3.1.2.4 and the Shut-In Preparedness in article 3.1.3.2. where the rig shall post the specific well shut-in procedure containing the information regarding the diagram of the BOP stack and the BOP element that is selected for closing the well upon a kick occurred. Another requirement that is relevant is article 3.1.3.6. regarding Well Kill Procedure that the uppermost BOP element must be used during well killing due to stripping ability feature. That means an annular BOP is required for any workover operation.

d. Corporate Standard - Well Control System

This technical standard governs the standardization of the well control equipment system technical and operational consideration for drilling and workover operation in the company with the objective is to ensure safe execution. The scope of this standard helps identifying limitations and capabilities as well as governing the installation, maintenance, and operation of the well control equipment system so that it will be auditable (Cummings, 2018). The Section 3.2 and, 3.7 of these standards govern the requirements of BOP stack arrangement and specification based on well's anticipated surface pressure and the drilling/workover fluid and other specific operational environment. This is shown in Appendix A of the standard.

e. Corporate Standard – Well Barrier

Well barrier is a mechanism in an oil or gas well that has main function to ensure no well control event occurred during intervention process or production mode. Well barrier could be a fluid inside the wellbore and/or mechanical devices, including BOP stack, tubing hanger and X-mast tree. The relevant subject from the standard area as follows:

- Barrier Requirements

In any situation a well, Well Barrier Standard requires minimum two barriers, both shall be independent. The critical consideration in these two independent barrier systems is, if one barrier fails, then the second barrier integrity shall not be compromised (Stanley, 2019). An example in this case, if the first barrier is downhole packer leaks, therefore tubing hanger and X-mast tree valves shall not leak, otherwise the hydrocarbon from the well cannot be contained.

Another requirement, that the barrier shall have integrity throughout the life of the well, means since the well is being constructed, up until during production cycle and during interventions, and must be capable to hold any anticipated design loads. It is important that if at any case a well loss one barrier, then the operation must be suspended and only be resumed if the second barrier have been re-established.

- Barrier Qualifications

The article 3.1.1. stated that barrier design shall meet with design verification for both grade and product service level based on anticipated loads and industry standards such American Petroleum Institute (API) standards and/or International Organization for Standardization (ISO). They must adhere QA/QC, inspection, testing process and Original Equipment Manufacturer (OEM) specifications manual.

f. Corporate Process Safety Standard "WELLSAFE®"

WELLSAFE is a corporate process safety that provide a reasonable maximum well control assurance for drilling and completion operation (Smith, 2018). WELLSAFE®establishes a certification program to ensure compliance with clearly defined requirements for personnel, procedures, and equipmentwith a direct impact on well control during well design, planning,

and operations, that are mandatory for well planning and execution purposes.
This study explored the above relevant literatures to demonstrate the opportunity for a workover cost optimization specific to high wellhead elevation case focusing on the well control equipment as subject of discussion.

III. METHODOLOGY

A.Decision Making Hierarchy

The decision process hierarchy to obtain fit for purpose solution are made based on the following sequences:

- Understanding the Root Causes
- Determine the acceptance criteria.
  - Must
    - Compliance
  - Wants
    - Safety
    - Practicality
    - Cost Effectiveness
- List alternative / possible solutions.
- Assess alternative solutions:
    - Subject Matter Expert (SME) professional opinion.
    - Pros and Cons analysis
    - Ranks and select the most optimum solutions ~ Kepner Tregoe method.
- Conclusion and Recommendations.

To solve the problem, we conducted focused group discussions to brainstorm the possible alternative solutions as well as establishing decision objectives. Both are categorized as qualitative information. A correspondence survey was generated to convert the qualitative information into a quantitative information of which the selection of the best alternative to be made using Kepner-Tregoe decision making analysis.
The SME role is very important to produce the most objective outcome of the study. Their function is to provide the ideas, concerns as well as suggestion during the brainstorming and acted as survey respondents. The SME consisted of highly experienced personnel who works as decision makers, advisors, project engineers as well as the service providers ranging from 15 – 25 years of working experience.
The following diagram describes the flow process of the research.

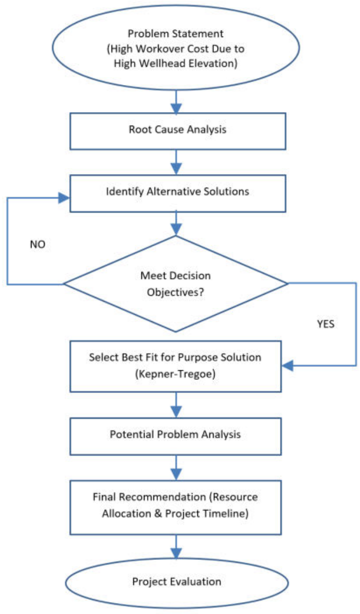

Fig. 7. Research process

A root cause analysis (RCA) was conducted to understand why the problem statement occurred. From this RCA, a brainstorming session involving the SME produced list of possible alternative solutions. A follow up discussion was held to determine the decision objectives. To establish the ranks of all available options, we utilized Kepner-Tregoe analysis. The best rank resulted from multi criteria decisions however could not produce a perfect solution without a minor trade off. A mitigation plan was established via potential problem analysis session to ensure the associated down sides are fully safeguarded. The final phase was establishing the recommendations along with resource allocation and project timeline. The project evaluation was planned for six months period of review to determine the continuity and to explore possible wider implementation.

IV. DISCUSSION AND BUSINESS SOLUTIONS

A. Discussions

- *Root Cause Analysis - Wells with High Wellhead Elevation*

What does it mean with “wells with high wellhead elevation?”. Why does this become the focus issue? There are two major contributing factors that causing a well having high elevation wellhead: tubing hanger design and well pad soil erosion.

- *Retrofitted Wellhead Design*.

Typical of an oil well configuration is as follows (from ground and above): Casing head/wellhead – casing spool/ tubing spool – tubing hanger – X-mast tree. Casing head/wellhead is a flange that is installed at the surface casing of the well. The function of a casing head was to enable installation of BOP stack prior to drill the next hole section. After completing the next hole section, an intermediate or production casing will be run and cemented. For more than two sections well configuration, a casing spool is then installed above the casing head to hang the intermediate casing and allow the BOP tack to be installed on the casing spool flange. For two-hole section configuration, a tubing spool is installed on top of the casing head/wellhead where later a production tubing hanger will be seated on. The last one, a X-mast tree will be installed and connecting the production tubing with production lines with master valves, swab valve and production valves interface. Each component from casing head/wellhead, casing spool/tubing spool, and X-mast tree are stacked, that resulting the well elevation measured from surface ground.

The original design of wellhead tubing hanger in Humaira area was very simple. The tubing hanger has a function to hang the production tubing in the wellbore and connected to the well *X-mast tree*. The specific area that become concern is the production wells having electric submersible pump (ESP) completion. An ESP is a centrifugal pump that is installed in the well and powered by electricity. As consequence, a power cable must connect the pump with the power source in the surface. The ESP cable consisted of three wires and protected with steel armor.

The cable runs all the way from the pump motor and clamped at the production tubing and pass through a port located at tubing hanger, called as cable penetrator. The original design of the cable penetrator had low reliability of sealing mechanism. Historically, there were many issues happened related to the old design such as leaking, spills, fire. The concern arose since the corporate established an assurance process called WELLSAFE® which governs process safety in the well construction matters. According to Barrier Standard, this original cable penetrator design was considered not meeting the requirement and shall be replaced with a new design with proven sealing mechanism.

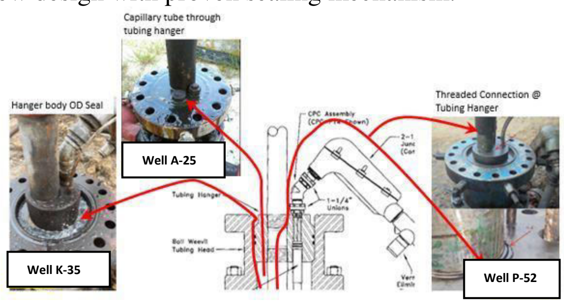

Fig.8. Examples of Legacy Wellhead Design Reliability Cases
(Source: Internal documentation)

There were approximately 2500 oil producer wells at Humaira area of operation having ESP completion type and 52% of them (around 1,300 wells)do not meet the Barrier Standard. The Asset and Drilling and Workover group put serious effort together to upgrade those old tubing hanger design to meet the newly adopted Barrier Standard.

The ideal way and straight forward methodology to make the wellhead design become comply with the standard is by changing out the old design wellhead and replaced with new wellhead design that meet the standard criteria however, this effort was deemed very expensive and would not be able to keep up with the approaching the end of concession contract timeframe that expire by Q3 2021. The joint study produced solution by designing a retrofit system that still using existing wellhead part but adding new component that enable secondary pressure containment with minimum additional cost. A retrofit design does not need to change the whole wellhead components from a well but instead inserting a retrofit spool above the existing tubing spool that enabled new tubing hanger design which have appropriate seal mechanism meeting the Barrier Standard. In addition to the retrofit design, the team also established project prioritization that focus on project economic aspect.

Fig.9. A Retrofit Wellhead with Cable Penetrator
(Source: Internal Documentation)

The below table compares the old wellhead design against wellhead retrofit system that was designed to reduce the recurring leaks cases and meeting the compliance to the new Barrier Standard.

TABLE 1. OLD WELLHEAD DESIGN VS RETROFIT TYPE

Aspects	Old Design	Retrofit Design	Y/N
Secondary containment	N/A	Tubing Head Adapter (THA)	Yes
ESP Cable Penetrator	Bypass tubing hanger body seal	Through hanger body	Yes
Redundancy	N/A	Dual body + extended neck seals	Yes
Sealing Mechanism	Through ESP cable penetration	Tubing bore and penetrator bore isolated into THA	Yes
Connections	Threaded	Studded	Yes

(Source: Autl Well X-52 ysis)

However, it created another challenge to the operational due to adding elevation as described by the schematic belows.

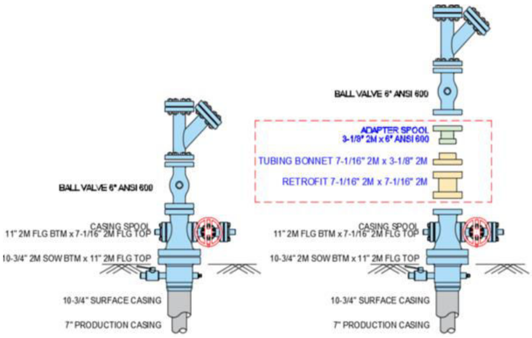

Fig.10. Basic Wellhead Diagram (Before VS After Retrofit)
(Source: Internal documentation)

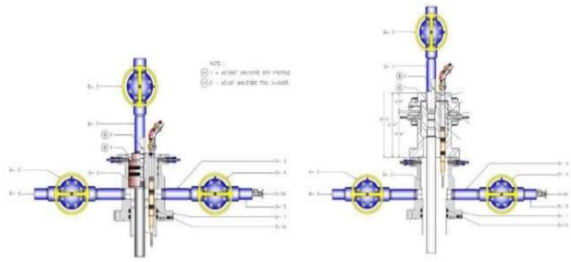

Fig.11. Cross-section Drawing of A Retrofit Wellhead (right pict.)
(Source: Internal documentation)

- *Soil Erosion*

A new well is constructed on an area called well pad where originally either clay hard soil or sometimes soft swampy location backfilled with sands, gravel, and dirt. The well components that can be seen from surface are the wellhead and the X-mast tree.The ground level is taken as depth reference from the WPF during the job on a well, later called as Rotary Kelly Bushing (RKB). This RKB is important to understand the actual depth of a tubulars or a wireline in the well. RKB measurement also important because it provides the clearancefor BOP installation since it seats on the wellhead. If the surface ground is eroded due to rainwater or flood, then the elevation of the well become higher.

A working platform is designed to have capability for elevation adjustment to accommodate different working elevation requirement. This design, however, has limitation towards structural safety in design considerations. Therefore, adding concrete slab is one of options even though the trade-off is also adding extra effort such as installation cost and, in many cases, delayed workover schedule due to limited resource on the concrete slab availability and prioritization. At the end, this delay causes lost production opportunity.

B. Scoping Business Situation Analysis into Business Solution

The focus of the discussion is about the additional workover cost that occurred as result of the existence of high wellhead elevation. Based on historical data, if the wellhead elevation is higher than 4.8 ft, or any height that exceed the WPF clearance of the assigned rig, then it is considered as high wellhead which cause extra workover cost, because the platform clearance just unable to accommodate the total height from wellhead and the BOP stack. There are two major root cause categories that contribute to the event.

- Design Failure
    - Old design wellhead technical issues
    - Rig WPF design limitation
- Strategic Planning
    - Retrofit wellhead program prioritization.
    - Limited availability of concrete blocks.
    - Not all rigs are equipped with 7-1/16" BOP stack.

The business solution in this project will focus on seeking another alternative that is meeting the value based objective criteria as follows:

- Compliance
    - Standard Operating Procedure
    - Industrial Standard
    - Applicable Regulations
- Feasibility
    - Safety
    - Operational ~ Fit for Purpose
- Project Economic

C. Alternative Business Solution

- *Change current wellhead design.*

Changing wellhead design that meet Barrier Standard could be the most ideal option because it will eliminate the need of retrofit component. Appropriate wellhead design will not requireretrofit component, so it will result in standard wellhead elevation where the rig could work on without the alteration of WPF.

- *Modify WPF elevation*

WPF is part of the integral design of the rig mast. If we could just alter the WPF elevation, it will helps accommodating existing provision of 11" Class III BOP stack underneath it.

- *Use Class II BOP stack*

It means the BOP stack component will use only combination of either Annular BOP + Single Ram BOP or use Double Ram BOP consisted of Blind/Shear Ram and Pipe Ram. Using Class II BOP stack will significantly reduce the need of working clearance underneath WPF should the well's MASP allows to use Class II BOP (Devid, 2020).

- *Use side outlet BOP to replace drilling spool.*

BOP side outlet is an outlet that is located built up in the Ram BOP body. For drilling and conservative workover operation, this side outlet is usually blocked with a blind flange and the circulation will be conducted through the drilling spool outlet instead to avoid eroding the internal body of the Ram BOP. Drilling spool is considered as disposable BOP stack components where normally being utilized for well circulation. If we can use the BOP side outlet, the drilling spool can be discarded therefore, the total elevation of the BOP stack will be reduced and eventually need lesser work clearance underneath WPF.

- *Fully Utilize 7-1/16" Class III 3M psi BOP stack.*

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As this subject already explained in the beginning g of Chapter II, the use of 7-1/16" Class III 3M psi BOP will reduce the total stack elevation during workover operation because of smaller and shorter dimension and proven to have works. This option also beneficial to eliminate the need of concrete slab.

- *Fully utilize concrete slab to alter the whole rig carrier / WPF.*

Installing concrete slab will add the elevation of the whole rig system including WPF, adding extra clearance under WPF. If we can use concrete slabs everytime we encounter high elevation wellhead, therefore the need of renting 7-1/16" Class III BOP stack can be eliminated.

- *Soil back-fill the well pad*

The objective of this alternative is essentially adding rig elevation similar with using concrete slab, but the different is instead of using concrete block, soil/dirt backfill is used.

- *Do Nothing ~ Combination of either 7-1/16" BOP stack or using concrete blocks.*

Current practice when encountering wells with high wellhead elevation is either using 7-1/16" Class III BOP stack or installing concrete blocks underneath the rig carrier. This method has been proven working despite we need to check the total cost of ownership comparing to other possible alternatives. By doing nothing means no effort need to be made rather than just maintaining the current practices.

D. Objective Criteria

Objective criteria is very important to understand the boundary of the alternative solution's feasibility and meeting the logical thought process.

- Safety

Safety is the topmost priority since it is the core value of the company. Protecting people and environment is an aspect that the company committed to take act at whatever cost it is because it related to corporate branding and reputation.

- Compliance

The company operates under certain regulations both internal and external. The proposed solution must be verified against the requirements such as law, standard, procedures, and regulations. Failing to meet this criterion will be categorized as illegal.

- Doability/Practicality

The practicality describes the level of effort will take place to do the proposed solution. The more practical a solution will help the human resources to carry out the task, hence the risk of error is lower.

- Cost Effectiveness

As part of business objectives, cost effectiveness always become an integral part of the equation because it directly affects the company profitability.

E.Decision Analysis ~ Kepner-Tregoe (KT) Method

The KT Decision making analysis divided objectives into two categories, MUST- *that guarantee a successful decision* and WANTs – *a sense of how alternatives perform relative to each other*(Kepner&Tregoe,1950).

From the four pre-determined objective criteria, the team decided that Compliance is categorized as MUST, while Safety, Doability/Practicality, and Cost Effectiveness are considered as WANTs. The logical reason to put Compliance as a MUST is because of the operation requirements shall meet the applicable standards and regulations. It has only "comply" or "not comply" option. While Safety, Practicality, and Effectiveness are relative parameters that comparable one to another, where the higher the ranks will be preferred option. Those are categorized into WANTs.

Compliance score is 10 because of absolute requirement, and classified as MUST factor, it will be taken as NO GO criteria. It means that for any option that could not satisfy 100% of the compliance factor will be rejected. As an example, if the alternative fails to comply with API S53 requirement, or any other relevant company standard, then we shall not proceed with the option.

For Safety, the team decided 10 as the weigh factor. This aligns with the company's value that "In conducting their operation, PT.DEI is willing to risk money, but will not risk their people". The team committed to assure that protecting people is the company value, therefore, any options that having better score on safety aspect will be considered as most preferred. The question is, why we do not consider Safety as a MUST factor aligns with Compliance? The rational for safety capability is a relative measure among options. There is no single solution that guarantee 100% safe operation. What we could do is, minimizing the likelihood of the event and reduce the severity of an incident.

After getting the agreement on each criteria objective, the next step is establishing ranks among alternative solutions via survey and interview to the selected Subject Matter Experts (SME) who were considered having sufficient experience in the design planning and operational supervision. The results are shown in the spider diagram belows:

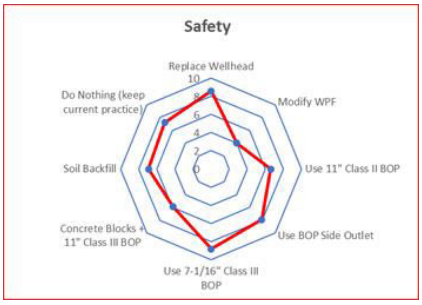

Fig.12. Acceptance Criteria Rating
(Source: Author's analysis)

Cost effectiveness is the second rank with 9 as weigh factor, aligns with the objective of the effort to seek the most cost-effective solution. It is important to understand that the cost effectiveness must be calculated based on total cost of ownership.

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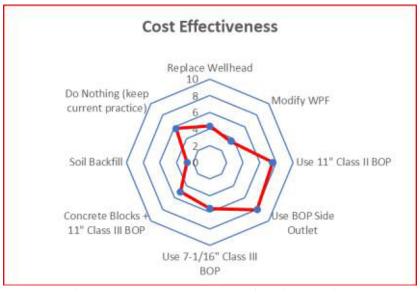

Fig.13. Acceptance Criteria Rating
(Source: Author's analysis)

The third aspect is Practicality with 8 as weigh factor. Practicality describes the level of simplicity of the solution. Implementation focuses on how easy a solution will be executed by the field personnel. The more simple and practical solution, the preferred it is since it will helps avoiding human error or operational failure.

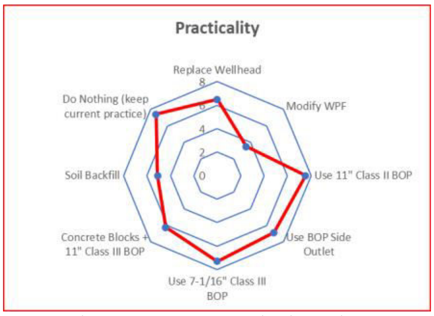

Fig.14. Acceptance Criteria Rating
(Source: Author's analysis)

The multi criteria objectives then were synthesized using Kepner-Tregoe decision analysis method to produce the final ranks from the available alternatives which result can be seen in the following table.

TABLE.2. SUMMARY OF KEPNER-TREGOE ANALYSIS

MUST		Replace Wellhead		Modify WPF		Use 11" Class II BOP		Use BOP Side Outlet		Use 7-1/16" Class III BOP		Concrete Blocks + 11" Class III BOP		Soil Backfill		Do Nothing (keep current practice)	
Satisfy Compliance to																	
Wellsafe GS-21		YES		YES		YES		YES		YES		YES		YES		YES	
Barrier Standard		YES		YES		YES		YES		YES		YES		YES		YES	
Well Control Requirements		YES		YES		NO		YES		YES		YES		YES		YES	
Well Control System		YES		YES		NO		YES		YES		YES		YES		YES	
API S53		YES		YES		NO		YES		YES		YES		YES		YES	
API 6A		YES		YES		YES		YES		YES		YES		YES		YES	
WANTS	Weight	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score
Safety	10	8.6	85.8	4.0	40.0	6.6	65.8	7.9	79.2	8.8	88.3	5.9	59.2	6.9	69.2	7.3	85.8
Cost Effectiveness	9	4.4	39.3	3.6	32.0	7.5	67.8	8.1	72.7	5.5	49.8	5.0	45.0	2.8	24.8	5.7	34.9
Practicality	8	6.5	52.0	3.5	28.0	7.5	60.3	6.8	54.8	7.3	58.5	6.2	49.8	5.1	40.6	7.4	58.5
			177.1		100.0		194.0		206.6		196.6		154.0		134.5		179.2

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V. CONCLUSION AND RECOMMENDATION

A. Conclusion

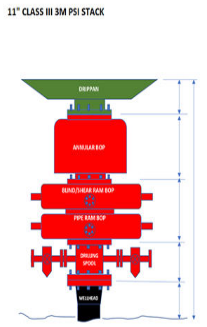
Basedon Kepner-Tregoe analysis of the alternative solutions, the use of side outlet BOP from existing contract (11" Class III 3M psi stack) scored the highest. This satisfies the original research question "Is there any fit for purpose solution for the wells having high wellhead elevation that is cost effective and maintain compliance to applicable industrial standards?", by several business implications:

- Eliminate rental cost of 7-1/16" 3M psi Class III BOP stack.
- Eliminate installation cost of concrete slab as back up if 7-1/16" 3M psi Class III BOP stack is not available
- Eliminate lost of production opportunity due to no delay on workover schedule.
- Maintain compliance to Well Control Equipment Standard Requirement.

The literature gap in this study is basically whether the use of side outlet BOP as an alternative port to conduct well circulation is acceptable for workover operation specifically for wells with high wellhead elevation. It is known that despite the use of side outlet BOP is allowed for circulation, but it is generally discouraged due to risks of accelerated wear because of internal component erosion during circulation. But in this case, the use of solid free fluid for workover and reverse circulation method during operation has become strong support point that the likelihood of the risk could be minimized.

B. Validation

Based on WPF and BOP height measurement of the workover rigs assigned for Humaira area, it was found that existing 11" 3M psi Class III BOP stack in the contract provision, resulted that the maximum workable wellhead elevation, between 2.72 ft– 6.4 ft.



FT	Rig 05	Rig 08	Rig 3516	Rig 3523	Rig 12
MAX WPF CLEARANCE	14	14	14.5	14	16.5
DRILLER CONSOLE ELEVATION	11.5	9.6	12.8	11.5	10.3
MAX SAFE WPF - CONSOLE ELEVATION	2.5	4	1.7	2.5	4
ACTUAL MAX WPF CLEARANCE	14	14	14.5	14	14.3
DRIP PAN	2	0.9	2.05	2.06	1.9
ANNULAR	3	2.8	3.08	3.35	3.2
DOUBLE RAM	3.2	2.45	3.27	2.29	4.73
DRILLING SPOOL	1.8	1.45	1.58	1.58	1.75
TOTAL STACK HEIGHT	10	7.6	9.98	9.28	11.58
ALLOWABLE WELLHEAD HEIGHT	4	6.4	4.52	4.72	2.72
TOTAL STACK MINUS DRL SPOOL	8.2	6.15	8.4	7.7	9.83
NEW ALLOWABLE WELLEHAD HEIGHT	5.8	7.85	6.1	6.3	4.47

Fig.15. Post BOP Stack Elevation
(Source: Author's analysis)

Historical cases showed that for wellhead elevation higher than 4.8 ft, then it required the installation of either installing concrete blocks under rig carrier or utilizing a 7-1/16" 3M psi Class III BOP stack. Eliminating drilling spool from BOP stack improves tolerance for high wellhead from 4.47 ft – 7.85 ft. This increased the WPF capability to handle high wellhead issue from 20% to 80% from the available rig fleet. Based on this figure the result from Kepner-Tregoe decision analysis is considered acceptable.

C. Recommendation

Utilize 11" 3M psi Class III BOP stack (embedded in existing contract), with procedure change:

- Take out drilling spool as original flow path for conducting well circulation.
- As replacement, well circulation will be conducted through Ram BOP side outlet.
- Potential Problem Analysisis established to recognize and mitigate potential risk from this this solution both from technical and field implementation point of view. (See Table 2 below)

TABLE 3. POTENTIAL PROBLEM ANALYSIS

Potential Problems	Possible Cause	Consequences	Mitigation	Contingency Plan
Misalignment connection of choke manifold line from BOP side outlet to the choke manifold unit	BOP side outlet position is significantly higher than choke manifold elevation	Unable to kill well during well control event due to inability to install the choke line	Use flexible high pressure hose connecting BOP to choke manifold	Alter choke manifold position to enable straight hardline choke manifold line configuration
Unable to install straight choke manifold hardline from BOP at well pad having multi wells	Narrow space between WPF to adjacent well block the direction of the choke manifold position	Unable to kill well during well control event	Use flexible high pressure hose connecting BOP to choke manifold	
High pressure hose replacing hard line choke manifold line premature damage	Extreme radius of curvature installation	Failure during well killing operation	Ensure appropriate length according to rig standard layout	Prepare back up unit
High sand content in the circulating fluid during circulation	Abrasion caused by the sand friction during circulation	Ram BOP body washed out causing BOP derating	• Completion fluid is a clear fluid. • Install correct screen shaker mesh size	• Conduct reverse circulation instead of forward circulation. • Only during casing scrapper operation, the circulation will be carried out forward flow
Premature damage to the side outlet part of the BOP	Human performance error during installation	• Major damage in the bolting system (broken thread, leaks) • Early abrasion in the side outlet flow path	• Develop new standard operating procedure. • Produce Management of Change document and discuss during plan of action.	Continuous socialization and coordination between office and rig site via video and conference call.

(Source: Author's analysis)

The picture below describes the changes on the BOP stack installation. The picture in the left side is the original BOP stack configuration where the well circulation is conducted through drilling spool, while picture at the right side is the BOP stack without drilling spool and the well circulation is conducted through BOP side outlet component.

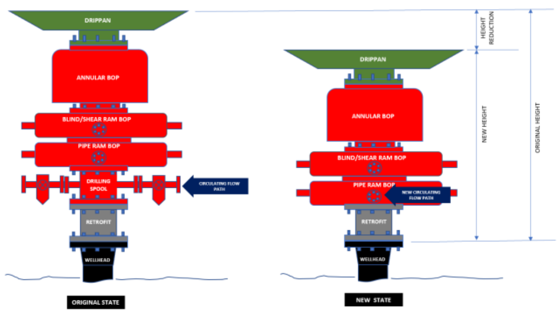


Fig.16. BOP Stack - Before VS After the Project
(Source: Author's analysis)

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D. Estimated Project Financial Benefit

Based on historical data that on average high wellhead elevation case that used 7-1/16" Class III 3M psi BOP stack was 40 wells per year (equal to$118,857.14/year). The cost of average 11 wells per year using concrete blocks to support the rig carrier combined with LPO resulted total $1,365,584.00/year. Combining both resulting total extra cost of $1,484,441.00 annually. Therefore, the estimated project cost saving based on P50 scenario is $ 742,220.00/year.

Fig.17. Pilot Project of The BOP Side Outlet Usage in a 11" Class III BOP Stack
(Source: Internal documentation)

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