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Ikatan Ahli Fasilitas Produksi Minyak dan Gas Bumi Indonesia

Innovation in Brownfield Operation



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VISI MISI
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1. Membangun knowledge database yang kedepannya diharapkan dapat menjadi referensi utama ilmu dan teknologi dibidang fasilitas produksi migas di Indonesia, serta referensi kondisi lokal untuk International Codes.

2. Mendorong para professional dan akademisi dibidang fasilitas produksi migas untuk menerbitkan karya dan pemikirannya sehingga kompetensi dan keahliannya terangkat ke permukaan dunia industri migas.

3. Menjalin jaringan keilmuan dan teknologi untuk mengembangkan industri nasional dibidang fasilitas produksi migas.

4. Mengangkat aktifitas sumberdaya pendukung industri infrastruktur migas ke permukaan.

Dari Redaksi



Alhamdulillah, Jurnal IAFMI telah memasuki edisi ke-13 dengan tema ***Innovation in Brownfield Operation***. Edisi ini merupakan edisi perdana di kepengurusan IAFMI periode 2022 – 2025. Tema ini dipilih karena kondisi fasilitas produksi di Indonesia sebagian besar berada pada fase *brownfield operation* dan merupakan *aging facilities*, sehingga diperlukan berbagai inovasi seperti dari segi manajemen integritas aset untuk memastikan aset fasilitas produksi dapat tetap handal dalam mendukung kinerja operasi.

Melalui Jurnal ini, IAFMI sebagai wadah para profesional fasilitas produksi migas di tanah air menampilkan beberapa makalah yang relevan diantaranya mengenai bagaimana melakukan optimisasi dengan intervensi fasilitas produksi di salah satu lapangan migas. Selain itu, terdapat *implementasi planning and scheduling* yang efektif untuk mengoptimalkan potensi lapangan *brownfield*.

Sebagai tambahan, Jurnal 13 IAFMI juga menghadirkan *sharing* bagaimana inovasi dilakukan di tahap konstruksi dalam instalasi fasilitas baru dan tentang perawatan *pipeline* secara menyeluruh. Terdapat juga ringkasan hal terbaru dalam standard API 610 yang menjadi acuan dalam desain dan operasinal *centrifugal pump* yang banyak terpasang di fasilitas produksi seluruh Indonesia.

Akhirnya, kami memberikan apresiasi kepada Tim Redaksi Jurnal IAFMI periode 2019-2022 yang telah bekerjasama menerbitkan jurnal dalam periode tersebut. Tidak lupa, kami mengucapkan terima kasih para pemakalah yang telah ikut berpartisipasi dalam Jurnal 13 IAFMI ini, semoga tulisan-tulisan yang disajikan dapat menambah ide baru bagi para pembaca.

Tidak lupa kami menunggu masukan yang konstruktif dan tulisan para Profesional IAFMI semuanya untuk edisi 14 berikutnya untuk bisa menjadi lebih baik. Karena menulis adalah pekerjaan untuk berkontribusi dan mengabadikan nama dalam sejarah.

Salam,

Redaksi

Kata Pengantar

Ketua Umum IAFMI



Atas nama pengurus periode 2022-2025 yang baru terpilih dan dilantik di bulan Desember 2022, saya menyampaikan apresiasi yang setinggi-tingginya kepada anggota IAFMI yang bersedia dan telah berkontribusi baik secara langsung ataupun tidak langsung pada penulisan makalah untuk penerbitan Jurnal IAFMI Edisi 13 yang mengusung tema ***"Innovation in Brownfield Operation"***.

Jurnal edisi kali ini mengangkat tema yang sangat relevan terhadap tantangan dalam mengelola lapangan *brownfield* dengan fasilitas produksi sudah lama beroperasi. Para profesional fasilitas produksi migas sudah selayaknya inovatif dalam memunculkan berbagai inisiatif yang dapat mempertahankan kinerja operasi secara handal dan efisien di fasilitas produksi lapangan *brownfield*. Inovasi dapat dilakukan dengan penerapan teknologi yang tengah berkembang ataupun melalui modifikasi terhadap fasilitas eksisting dalam sebuah alur produksi.

Inovasi sendiri merupakan hal yang esensial dalam semua tahap pengelolaan sebuah kegiatan usaha mulai dari tahap perencanaan, pengembangan hingga produksi. Khususnya di lingkungan industri migas, inovasi diharapkan mampu menjawab tantangan yang semakin kompleks untuk mengedepankan efisiensi biaya di tengah kondisi makro ekonomi dan harga yang dinamis.

Sebagi penutup, kegiatan inovasi membutuhkan dukungan kepemimpinan yang kuat. Dengan kepemimpinan, serta kemauan dan tekad seluruh anggota organisasi/ perusahaan, maka akan tercipta rangkaian strategi yang tepat hingga menjadi budaya yang mampu memberikan daya dorong tambahan dalam melaksanakan kegiatan operasi yang berkesinambungan.

Kepada Para Profesional IAFMI, mari terus semangat untuk melakukan inovasi untuk yang lebih baik!

Ir Taufik Aditiyawarman, MM, PMP, IPU

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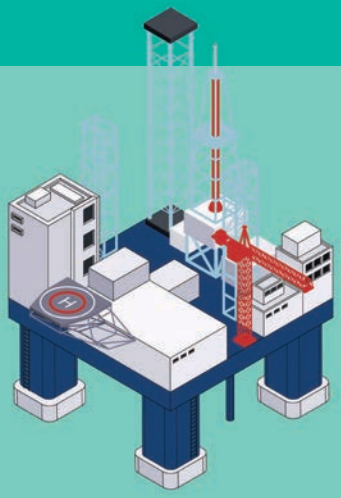
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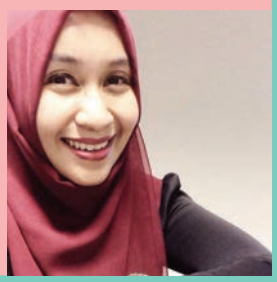
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INDONESIAN PETROLEUM ASSOCIATION (IPA)

Konvensi dan pameran yang diadakan oleh Indonesian Petroleum Association (IPA) merupakan wadah pertemuan para pelaku industri hulu minyak dan gas bumi (migas) di Indonesia. Tahun 2022 merupakan konvensi dan pameran ke-46 yang diselenggarakan oleh Indonesian Petroleum Association (IPA) yang diadakan secara hybrid, baik daring melalui platform http://convex.ipa.or.id/ dan luring di Jakarta Convention Center (JCC) pada tanggal 21-23 September 2022 yang diresmikan oleh Ketua Umum Asosiasi Daerah Penghasil Migas (ADPM) Dr. Mochamad Ridwan Kamil, ST, MUD. yang juga dihadiri oleh Menteri Energi dan Sumber Daya Mineral (ESDM) Ir. Arifin Tasrif, Direktur Jenderal Minyak dan Gas Bumi Kementerian ESDM yaitu Prof. Ir. Tutuka Ariadji, MSc, PhD dan Kepala SKK Migas Dr. Dwi Soetjipto. Tema besar yang diangkat pada gelaran konvensi dan pameran IPA ke-46 ini adalah “Addressing the dual challenge: Meeting Indonesia’s Energy Needs While Mitigating Risks of Climate Change”.

Dalam penyelenggaraannya, kegiatan ini terdiri dari Plenary Sessions, Special Sessions, High-Level Roundtable Talk, dan pameran yang melibatkan para pelaku di sektor migas baik dari dalam maupun luar negeri. Gelaran IPA tahun 2022 diikuti oleh 1.000 delegasi konvensi, 19.000 pengunjung, 95 perusahaan peserta pameran dari 22 negara di seluruh dunia. Selain itu, IPA Convex 2022 juga memiliki acara Breakfast Meeting untuk pada calon investor migas yang akan masuk ke Indonesia. Sebagai asosiasi di sektor fasilitas migas, IAFMI juga turut serta dalam pameran IPA Convex 2022. Dengan turut serta pada pameran ini, diharapkan bahwa para pelaku di industri migas menyadari bahwa dukungan fasilitas dan teknologi memiliki peran penting dalam mendorong kegiatan eksplorasi dan optimalisasi produksi migas di Indonesia. Sebagai asosiasi yang mewadahi para praktisi di sektor fasilitas migas, pada pameran ini IAFMI menunjukkan bahwa akan terus mewadahi dan mendukung para praktisi untuk terus memajukan teknologi fasilitas migas guna mendorong kegiatan eksplorasi dan optimalisasi produksi migas di Indonesia.

SUMMARY KEGIATAN FFPM 2022 DI BANDUNG

Forum Fasilitas Produksi Migas tahun 2022 (FFPM 2022) diselenggarakan atas kerjasama antara SKK Migas dan IAFMI sebagai asosiasi ahli fasilitas produksi di industri migas di Indonesia. Forum ini menjadi yang pertama diselenggarakan secara tatap muka setelah 2 (dua) tahun lamanya terkendala pandemic COVID-19 yang melanda dunia. Tema yang diangkat dalam FFPM 2022 adalah "Recovering & Transforming The Industry" yang mencerminkan semangat semua pihak di lingkungan fasilitas produksi migas untuk bangkit mengejar target dan peluang demi menuju produksi 1 juta barrel minyak dan 12 bcf gas.

FFPM 2022 berlangsung selama 3 hari dari tanggal 18-20 Oktober 2022 di Hotel Pullman Bandung. Kegiatan FFPM terbagi menjadi Konferensi & Pameran, Breakout Session, dan Business Forum. FFPM 2022 didukung oleh total 38 sponsor (3 sponsor Emerald, 2 Platinum, 9 Gold), 32 booth pameran, dan 5 sesi slot Technology Update. FFPM 2022 dihadiri oleh 689 orang peserta dari seluruh pemangku kepentingan meliputi institusi pemerintah (Kementerian ESDM dan SKK Migas), perusahaan hulu migas (KKKS), perusahaan hilir migas, konsultan engineering, kontraktor EPC, kontraktor penyedia barang dan jasa, serta akademisi dari berbagai perguruan tinggi. Forum ini menjadi sarana diskusi dan berbagi *best practices* dan *lesson learned* serta meningkatkan jejaring bagi para praktisi migas dalam usaha meningkatkan efisiensi dan optimasi fasilitas produksi migas.

Pada hari pertama, FFPM 2022 diawali oleh *Welcoming Speech* dari Gubernur Jawa Barat





yang juga Ketua Asosiasi Daerah Penghasil Migas dan Energi Terbarukan (ADPMET) Bapak Ridwan Kamil. Selanjutnya Keynote Speech dari Menteri ESDM yang diwakili oleh Dirjen Migas Bapak Tutuka Ariadji, dan sambutan serta pembukaan dari Kepala SKK Migas Bapak Dwi Soetjipto serta para panelis yang terdiri dari pemimpin perusahaan migas yang membawa topik sesuai tema besar sebagai landasan konferensi untuk acara 2 hari berikutnya.



Untuk lebih fokus dalam pembahasan maka pada hari kedua diselenggarakan serangkaian diskusi panel yang terbagi dalam 3 ruangan terpisah yaitu Panel-1 (Design & Technology), Panel-2 (Project Management) dan Panel-3 (Operation & Maintenance). Pada hari ketiga dilanjutkan dengan Business Forum yang membahas dukungan Industri Nasional Bagi Percepatan Proyek Migas Nasional.

Selain konferensi, yang tidak kalah penting selama FFPM 2022 juga diadakan pameran perkembangan aplikasi keilmuan dan teknologi fasilitas produksi migas, kemampuan dan teknologi konstruksi, penunjang fasilitas produksi berbasis digital, dan sebagainya dari para penyedia barang dan jasa migas.





KONGRES IAFMI
17 DESEMBER 2022, DI LORIN SENTUL HOTEL

Kongres IAFMI ke-4 dilaksanakan sejalan dengan berakhirnya kepengurusan 2019-2022, bertempat di Lorin Sentul Hotel Bogor, pada 17 Desember 2022 dan menetapkan bahwa Ketua Umum IAFMI Periode 4 tahun 2022-2025 adalah Ir. Taufik Aditiyawarman, MM, PMP, IPU.

Pemilihan dilakukan melalui musyawarah secara tertutup oleh anggota Kongres dengan Ketua Sidang Dr. Ir. Noezran Azwar, ST, MT, IPU dan Sekretaris Sidang Arnold Sanda Layuk, ST, MM. Kongres dinyatakan sah oleh Pimpinan Kongres Ir. Rudianto Rimbono, MT sesuai dengan ketentuan pada Anggaran Rumah Tangga IAFMI dan dituangkan dalam Ketetapan Kongres No. 12/IAFMI/Kongres/P3/12/2022 dan mulai berlaku pada tanggal 17 Desember 2022.



Pada acara yang sama, Ketua Umum IAFMI menyatakan menunjuk Ir. G. Daru P. Dewanto, ST, MM, MBA, IPM sebagai Sekretaris Jendral IAFMI Periode 4, 2022-2025.

RAPAT KERJA DAN PELANTIKAN PENGURUS IAFMI 2022-2025

12 FEBRUARI 2023
PONDOK CABE GOLF CLUB

Pada tanggal 12 Februari 2023 di Pondok Cabe Golf, Tangerang Selatan telah dilaksanakan Rapat Kerja dan Pelantikan Pengurus Ikatan Ahli Fasilitas Produksi Minyak dan Gas Bumi Indonesia (IAFMI) 2022-2025. Acara tersebut dihadiri oleh Dewan Penasehat, Dewan Tenaga Ahli, Ketua dan Wakil Bidang, serta Wakil Sekretariat Jendral.

Acara dibuka dengan sambutan Ketua Umum IAFMI 2022-2025 Ir. Taufik Aditiyawarman, MM, PMP, IPU, dan sambutan dari Ketua Dewan Pengawas IAFMI 2022-2025 Dr. Wahju Wibowo, ST.

Pada kesempatan ini juga diperkenalkan Dewan Penasehat IAFMI, Yaitu:

Dr. Ir. Dwi Soetjipto, MM,
Dr. Wahju Wibowo, ST,
Ir. Rudianto Rimbono,
Ir. Nanang Untung, IPU,
Ir. Ardiansyah, MPU, IPU,
Syaifudin, ST, MT,
Ir. Edwin Badrusomad

Acara dilanjutkan dengan Pengukuhan dengan prosesi penyematan PIN dan pemberian Surat Keterangan Pengurus, Dewan Penasehat, Dewan Tenaga Ahli Periode 2022-2025 oleh Ketua Umum IAFMI, Sekretaris Jendral IAFMI.Rapat kerja dimulai dengan pemaparan dan usulan program kerja masing-masing bidang.





PRE-JOINT CONVENTION 2023

"PELUANG DAN TANTANGAN HILIRISASI MINERAL"

Event ini dilaksanakan pada tanggal 18 – 19 Maret 2023 lalu di Hotel Novotel Pangkalpinang. Acara secara resmi dibuka oleh Dr. Ir. Ridwan Jamaludin MSC selaku Pj. Gubernur Bangka Belitung. Event terdiri dari seminar dan diskusi panel dengan pemateri terkemuka, diantaranya Direktur Pembinaan dan Pengusahaan Mineral KESDM Dr. Ir. Ediar Usman MT, Direktur Utama PT. Timah Tbk. Achmad Ardianto ST, MBA, Ketua Asosiasi Eksportir Timah Indonesia Harwendo Aditya Dewanto SH, dan Geologist Exploration dari Badan Riset dan Inovasi Nasional Dr. I Gde Sukadana ST, MEng, IPM.





Event ditutup dengan *informal dinner* bersama *Joint Convention Committee* dan IAGI *Funwalk* pada hari kedua.

Event ini merupakan *event* pembuka *(pre-event)* dari rangkaian acara Joint Convention 2023 yang pada tahun ini akan dilaksanakan di Pangkalpinang pada tanggal 23 – 26 Oktober 2023 mendatang.

Joint Convention merupakan *event* rutin dua tahunan yang diselenggarakan bersama oleh IAGI, IAFMI, HAGI dan IATMI. Pada Joint Convention tahun ini PERHAPI (Perhimpunan Ahli Pertambangan Indonesia) akan turut bergabung menjadi penyelenggara.

JOINT CONVENTION PANGKALPINANG (JCP) 2023

"MINERAL & ENERGY TRANSITIONS FOR ENVIRONMENTAL SUSTAINABILITY OF INDONESIAN NATURAL RESOURCES"

24 -26 OKTOBER 2023

Technical Event telah dimulai melalui *Call of Abstract Submission* yang secara resmi telah ditutup pada 14 April 2023 lalu. Lebih dari 750 *abstract* diterima dan 94 *abstract* diantaranya berasal dari member IAFMI dengan pilihan topik *Project Economics and Bussiness Development*, *Project Management and Engineering, Facility Design and Technology, Maintenance and Reliability Management,* dan *Operations and Integrity Management*.

Abstract yang lolos ke tahap berikutnya akan diumumkan pada tanggal 29 April 2023. *Stay tune* di channel resmi *Joint Convention* berikut ini untuk mengikuti informasi terkini *Joint Convention*!

FURTHER INFORMATION

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Scan for registration and further information about JCP 2023

PHENOMENA OF SCALING AND CORROSION ON CRUDE OIL PIPELINE WITH VELOCITY PROFILE IN FULLY DEVELOPED CONDITION APPROACH

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ABSTRACT

Scaling and corrosion phenomena always occur on the internal surface of the crude oil, gas, steam boiler and geothermal pipelines, which have an impact on the flow rate, shutdown frequency, target maintenance costs and the company's business. In general, this scaling and corrosion phenomenon occurs as a result of crude oil, geothermal, water, gas and steam containing CO_3, OH, HCO_3, Ca^{2+}, Mg^{2+} and Fe^{2+}, CO_3, CO_2, H_2S, O_2, H_2O ions and sulphide compounds respectively. In this paper, an investigation is carried out by mapping the critical areas for scaling and corrosion in the pipeline based on the crude oil velocity profile approach in steady and fully developed conditions. Based on the phenomenon of fluid flow, in steady and fully developed conditions, the velocity of crude oil forms a boundary layer where the maximum crude oil velocity is at the center of the pipe or pipe radius equal zero, while the interface shear stress of the crude oil-surface internal pipe system is close to zero, which means crude oil is stationary, not moving. In a stationary condition, immobile ion scaling undergoes deposition which has an impact on the reduction in the diameter of the pipeline and the rate of crude oil water. While at rest, corrosive species ions will react with the pipe surface. Both the formation of scaling and corrosion on the internal surface of the pipeline occur simultaneously and continuously. The mapping of critical areas of scaling and corrosion on the piping surface of the internal system is based on a velocity profile with fully developed conditions and confirmed with maintenance data. Based on the results of the treatment, it is possible to predict the rate of scaling and corrosion, determine the schedule for the maintenance period and the necessary actions to slow down and/or eliminate the process of scaling and corrosion formation, such as adjusting pH and/or adding inhibitors to crude oil. Processing and analyzing the results of the pipeline maintenance period data to predict the trend and rate of scaling and corrosion as well as the manufacture of a maintenance expert system, which is an integral part of excellent operation.

Keywords: Scaling and corrosion, ion species scaling, pipeline, excellent operation, expert system maintenance

INTRODUCTION

Corrosion of The Crude Oil Pipeline

Crude oil in the form of mud consists of a mixture of organic compounds, hetero atomic compounds (S, N, O), hydrocarbons (C, H), metals and organic compounds (Ni, V, Fe) and inorganic (Na^+, Ca^{2+}, Cl). (Dutton 2021)

Hydrocarbon compounds consist of the elements carbon and hydrogen and are the largest organic compounds found in petroleum. Hetero atomic compounds containing sulphur as a source of H_2S include mercaptan disulphides, sulphides, thiols, thiophenols, diphenyl sulphide thiophene and dibenzothiophene which are included in the form of organosulfur compounds. While heteroatomic compounds containing oxygen are carboxylic and phenolic, while organometallic compounds such as porphyrins.

Based on its density, crude oil is called light, medium, or heavy which is expressed in specific gravity, which according to the American Petroleum Institute (API) (Matar and Hatch 2001), is expressed by the equation

$$°\text{API} = \frac{141.5}{\text{Sp.gr}\frac{60}{60^\circ}} - 131.5 \qquad (1)$$

Specific Gravities of crude oils roughly range from 0.82 for lighter crudes to over 1.0 for heavier crudes (41 - 10 °API scale). °API gravity higher than 10 means the oil density is less dense than water and will float on it. API gravity lower than 10 means the density of oil is heavier than water and will sink in it. The content of heteroatomic, metallic and inorganic compounds is the species that causes scaling and corrosion on the surface of the internal pipeline.

In general, the problems of scale formation and corrosion and other degradation can be illustrated as shown in Figure 1. Based on Figure 1, the internal system piping interactions are affected by loading in terms of tensile, compression and bending in installations both on land and at sea. From loading and defects during manufacturing are fatigue and fracture mechanics. While the environment such as temperature, pressure, humidity, there are key species scaling and corrosive will have an impact on the occurrence of scaling and corrosion.

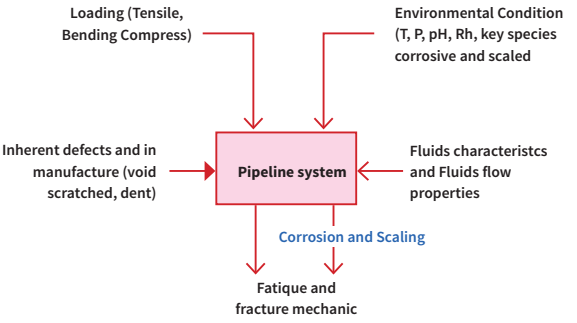


Figure *1. Mapping interaction pipeline and environmental condition*

On the internal pipe surface is exacerbated when the pipe surface roughness is getting rougher where species are trapped in the roughness valley. The same is true for the O_2, H_2S, H_2O, Cl^- species trapped in the roughness of the pipe, which results in corrosion, such as pitting corrosion, surface corrosion, stress corrosion cracking and others.

As it is known that corrosion and scaling processes are two factors that cause degradation in the pipeline, both for oil and gas as well as in geothermal and boiler pipes due to the interaction of corrosive key species, scaling or a combination thereof. Degradation in the form of thinning of pipe walls, well corrosion are many examples and are commonly found on the surface of internal pipes, while the formation of scale will have an impact on reducing the diameter of the pipeline which inhibits the flow rate of oil and gas or geothermal fluids.

Crude oil is flowed from the oil source reservoir through a pipeline to a refinery center, which is far from the oil source. The interaction of oil with the internal surface of the pipeline has an impact on the simultaneous occurrence of scale formation and corrosion, which is presented in Figure 2. As a result of scale formation and corrosion, the

diameter of the pipeline decreases and corrosion such as pitting, stress corrosion cracking, and surface corrosion is unavoidable. Conditions like this can disrupt the oil business, especially related to the transportation of crude oil to refinery centers such as the function and life of the pipeline.

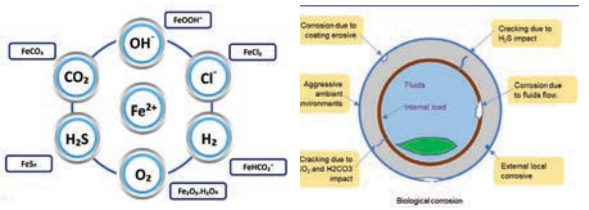


Figure 2. *Interaction (a) key species; (b) impact of corrosion and scaling formation*

The interaction process between fluids in the form of oil, gas and water vapor with the piping surface of the internal system, for example the simultaneous formation of scale and corrosion, originates from key species such as O_2, CO_2, H_2S, H_2O, Ca^{2+}, Cl^- and other elements contained in crude oil. This key species will interact with the internal surface of the pipe to form scale and corrosion simultaneously. The formation of scale due to the presence of CO_2 reacts with the internal surface of the pipe in the form of siderite, $FeCO_3$, calcite, $CaCO_3$, calcium silica $CaOSiO_2$, or ferro silica, $FeOSiO_2$ and other salts such as $BaCO_3$. Continuous deposition of key species scaling and corrosion processes causes local leakage, thinning of pipe thickness and narrowing of the pipe resulting in the flow rate of crude oil.

Mechanism of Scale Formation and Corrosion

Electrochemically, corrosion is a phenomenon of an oxidation reaction on the surface of the internal pipe (as a substrate) which degrades the anode according to the reaction. (Popoola et al. 2013)

$$Fe \rightarrow Fe^{2+} + 2e^- \quad (2)$$

On the surface of the internal steel pipe which contains water with a low concentration of O_2 becomes anodic and oxidized which causes corrosion. Under acidic conditions, if there is O_2 it is reduced according to the reaction

$$O_2 + 4\,H^+ + 4e^- \rightarrow 2H_2O \quad (3)$$

Under neutral or basic conditions, oxygen

$$0.5\,O_2 + H_2O + 2e^- \rightarrow 2OH^- \quad (4)$$

meanwhile, in an acidic solution,

$$2H^+ + 2e^- \rightarrow H_2 \quad (5)$$

Under conditions of neutral or alkaline water, a reaction occurs

$$2H_2O + 2e^- \rightarrow H_2 + 2OH^- \quad (6)$$

The equation for the reaction of the oxide with H_2S is as follows (Smith 1993):

$$Fe_2O_3 + 4H_2S^- \rightarrow 3FeS + 4H_2O + S \quad (7)$$

$$FeS + S \rightarrow FeS_2 \quad (8)$$

$$Fe_3O_4 + 6H_2S \rightarrow 3FeS_2 + 4H_2O + 2H_2 \quad (9)$$

When water combines with CO_2 and H_2S, the surface of the pipeline is represented by Fe^{2+} reaction:

$$Fe^{2+} + H_2CO_3 \rightarrow FeCO_3 + H_2 \quad (10)$$

$$Fe^{2+} + H_2S + H_2O \rightarrow FeS + 2H \quad (11)$$

$FeCO_3$ and FeS or FeS_2 form a thin layer on the internal surface of the pipeline to prevent further corrosion. In the oil and gas production industry, sweet corrosion, acid corrosion, oxygen corrosion, galvanic corrosion, crevice corrosion, erosion corrosion, microbiological corrosion, and stress corrosion cracking are found. Weet corrosion is corrosion that occurs due to CO_2. This CO_2 gas with water forms H_2CO_3 and will react with Fe to form Fe_3C, $FeCO_3$ or decompose greatly affecting pH.

The presence of CO_2 will have an impact on pitting and mesa corrosion which affects the pipe surface. As an illustration, the reaction process that occurs physically is shown in Figure 3.

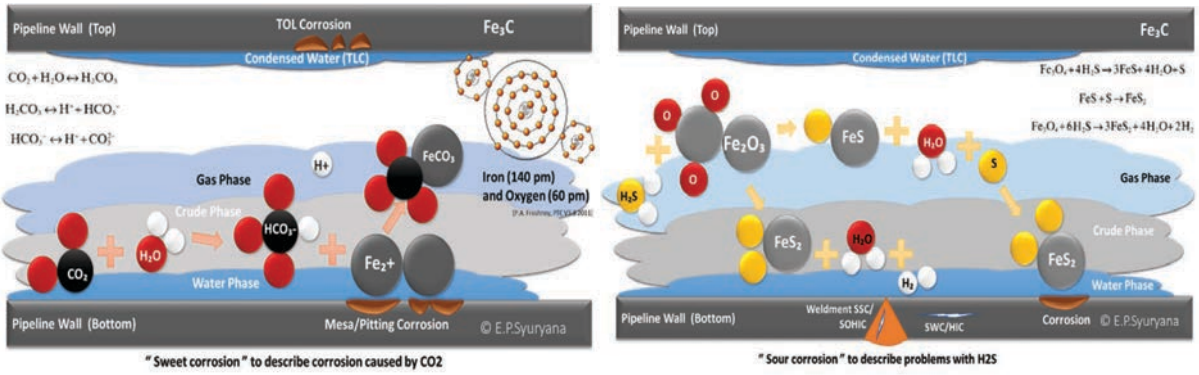


Figure 3. *Corrosion (a) pipeline wall upper; (b) pipeline wall bottom*

CO_2 gas is a gas dissolved in water and oil. In water, CO_2 dissolves to form carbonic acid:

$$CO_2 + H_2O \leftrightarrow H_2CO_3 \quad (12)$$

$$H_2CO_3 \leftrightarrow H^+ + HCO_3^- \quad (13)$$

$$HCO_3^- \leftrightarrow H^+ + CO_3^- \quad (14)$$

CO_2 gas reacts with water to form H_2CO_3. The presence of CO_2 and HCO_3^- is affected by pH. Corrosion caused by CO_2 (Ibraheem et al. 2012) gas is pitting, which can be found in turbulent areas.

The partial pressure of CO_2 can be used as a benchmark for predicting corrosion. The reaction rate is affected by temperature and pH.

The rate of the reaction can be expressed by the equation:

$$\frac{dS}{dt} = -3{,}000\, x[S_t]^2\, [H^+]^{1.06} x[I] \quad (15)$$

S = total dissolved sulfides in filtrate, ppm; t = time, min; H^+ = hydrogen ion concentration, moles/L; I = Ironite Sponge concentration, lb/bbl (0.351 x kg/m^3).

Transmission of sour gases must be preceded by drying to the dew point, which is below the minimum exposure temperature in the facility. Calculation of CO2 corrosion in a certain regime, according to the equation:

$$Log\,(R_{maks}) = 5.8 - \frac{1710}{T} + 0.67\, Log\,(P_{CO2}) \quad (16)$$

where

1. R_{max} is the corrosion rate (mm/year)
2. T is the temperature (°K)
3. P_{CO2} = P x m (CO_2)

CO_2 partial pressure: > 30 psi corrosion will occur, partial pressure (3-30) PSI corrosion can occur, while partial pressure < mild corrosion. In the case of drilling, CO_2 gas is removed by degassers and pH adjustment, with NaOH (Sami M and Lewis F H, 2000), to prevent the formation of carbonate scaling. The corrosion rate of steel is expressed by the equation (Chillingar et al. 2008)

$$mpy = (2.831 \text{ x } W)/ (A \text{ x } T) \quad (17)$$

where

W = weight loss (in grams), T = exposure time in days, and A = area of specimen in $inch^2$.

Characteristics and Properties of Fluids

Two important and critical properties that play a role in corrosion and scaling formation in pipelines are fluid parameters and crude oil fluid flow. The parameters in the fluid are the key corrosive species and scale that cause corrosion on the internal pipe surface, scaling formation and a combination of both. In a fluid flowing through the

pipeline, it is impossible for corrosion and scaling formation to occur. The process of corrosion and scaling formation is only possible when the fluid is at rest so that the key species interact with the internal pipeline surface.

In fluid mechanics, not all fluids move at the same speed in a pipe. The shape of the velocity curve depends on the flow pattern, namely laminar and turbulent. If the flow in the pipe is laminar, the velocity distribution across the cross section will be parabolic with the maximum velocity at the center about twice the average pipe velocity, as shown in Figure 4.

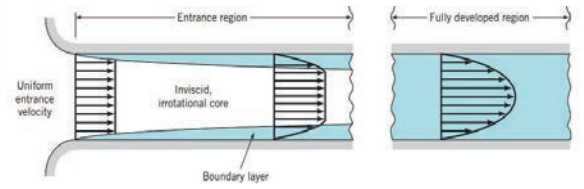


Figure *4. Fully developed velocity profile*

Based on Figure 4, there are 2 types of flow, namely viscous flow and convective flow. Convective crude oil flow is perpendicular to the flow direction, while viscous flow is radial. The two streams form a boundary layer. The convective flow velocity profile forms a para-sphere with the largest velocity at the center of the pipe with zero shear stress, while the largest viscous flow is at the crude oil-internal surface of the pipe. Geothermal fluid flow is distinguished by convective momentum in the direction of current and viscous momentum in the direction of radial. The shear force, is proportional to the fluid velocity gradient, expressed as

$$sv_z = \left(\frac{\Delta P}{L} \mp \rho g\right)\frac{R^2 - r^2}{4\eta} \qquad (18)$$

The boundary conditions, at r = 0, then the value of x becomes max, and the shear stress, x = 0; while the boundary conditions, at r = R, then the fluid flow velocity, x = 0, and the shear stress, x = max. The flow pattern in the bend pipe shows a turbulent area where friction and cavitation occur which have an impact on erosion-corrosion.

In simple terms crude oil and natural gas fluids characteristics and fluids flow properties as shown in Figure 5. Based on Figure 5, pH, temperature, moisture content and key species are important factors in the occurrence of corrosion and scaling formation. In addition, the density, viscosity and velocity, flow pattern, radius of the pipeline and the surface roughness of the internal pipeline are important factors in the corrosion process and the formation of scaling.

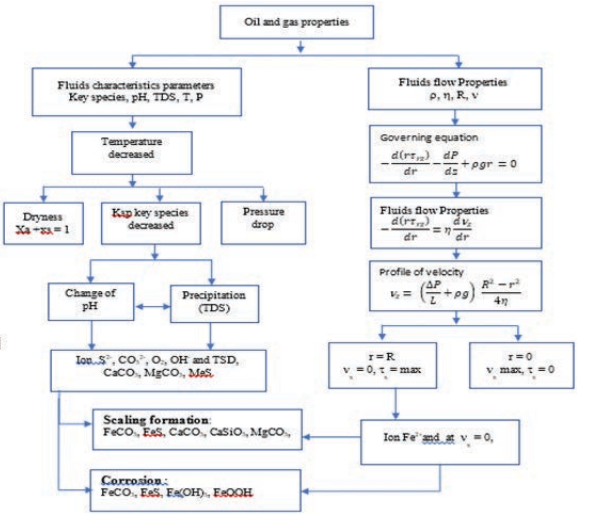


Figure 5. *Parameters and fluid flow properties of crude oil*

DATA AND METHOD

Crude and Corrosion Key Species Data

Key species analysis needs to be carried out to control the formation of scale and corrosion on a periodic and scheduled basis so that preventive measures can be taken immediately, as shown in Table 1., the required threshold (NAV).

Table 1. Key species of scale and corrosion

No	Key species	Kadar	Potential to
1	CO_3^{2-}, HCO_3	0.176-0,558	$CaCO_3$
2	Ba^{2+}	0.06-0,294	$BaCO_3$
3	Sr^{2+}	0.23-0.295	$SrCO_3$
4	Ca^{2+}	4.05-5.2251	$CaCO_3$
5	Mg^{2+}	0.367-576	$MgCO_3$
6	Cl^-	55.32-56.8	$FeCl_2$
7	K^{1+}	0.338-1.046	K2CO_3
8	Na^{1+}	44.409-96.500	$NaCO_3$
9	SO_4^{2-}	0.551-0.662	$BaSO_4$, Na_2SO_4
10	Fe	0.003-0.007	FeS, Fe_2O3
11	S	0.014-0.301	FeS
12	TSP	0.111-0.140	
13	COD	4.158-5.045	
14	NO^{3-}	0.000-0.004	
15	O_2	-	
16	pH	5.60-6.00	

Pipeline

The type of oil and gas pipe material must meet the dimensional requirements of 1) API 5L Specification, 2) API 5LC & 5LD Specification, 3) ASME B36.10M Welded and Seamless Forged Steel Pipe, and 4) ASME B36.19M Stainless Steel Pipe. The surface roughness of the internal pipe needs to be known to estimate the amount of fluid and total suspended solid buried in the roughness valley.

Flow of Fluid

The velocity or flow rate of fluids such as crude oil, viscosity or °API, TDS, key species, pressure, temperature need to be determined for head loss that occurs, especially the fluid-surface interface velocity of the internal pipe.

Parameter Proses

Pressure, bases, acids, water and organosulfur compounds and fluid velocity have an important effect on the process of scale formation and corrosion.

RESULT AND DISCUSSION

Key Species

The presence of key corrosive and scale species in crude oil will obviously degrade the function and service life of the existing pipeline. The corrosion process in the bag and bottom pipe is shown in Figure 6 and the scaling formation is triggered by corrosive key species such as CO_2, H_2S, O_2, Cl, while the key species for scaling formation are Ca^{2+}, Ba^{2+}, Sr^{2+} ions. Analysis of this method of organic matter must be carried out to ensure the content of key species elements. Besides that, it is also necessary to test Chemical Oxygen Demand (COD), Total Organic Carbon (TOC) and Total Suspended Solids respectively using the open reflux method per ASTM D 1252, high frequency infrared per GB/T13193 and filtration per GB/T 11901. The standard LOD is 1mg/Liter, 0, 5 mgr/Liter. As for ions such as Cl, basicity, ammonia, Ba, Ca, Fe, Mg, li, K, Na, Sr ions and S. Key species tests must be routine and the results must be processed and presented to interested parties, such as engineering maintenances used to determine periodic maintenance of pipelines.

Surface Roughness

The surface roughness of the pipeline plays an important role in the corrosion process and the formation of scale in the pipeline. The surface roughness of the internal pipeline will be a place for the accumulation of key species of corrosion and scale, especially in the valleys as shown in Figure 6. This accumulation of key species increases along with the roughness and in turn can accelerate the rate of corrosion and scale processes. The surface roughness of the pipeline in fluid mechanics also has an impact on head losses. Large head losses will cause the crude oil flow rate to be slow and require a lot of pumps and large energy.

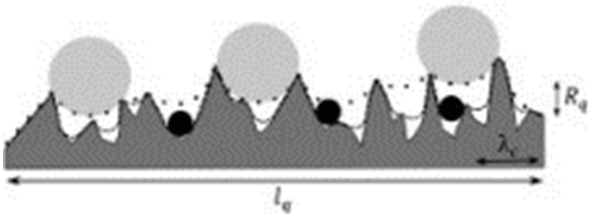


Figure 6. *Illustration key species and corrosion deposit on the internal surface roughness of the pipeline.*

Interaction Process Parameters

The effect of pH on steel corrosion depends on the metal composition, stress, oxygen concentration, and the type of acid that controls the pH. In the high alkaline state, the corrosion reaction is under anodic control and proceeds at high speed. In neutral state and in mild alkaline solution, the corrosion rate is under cathodic control, which provides corrosion protection. The actual corrosion rate depends on the diffusion of oxygen to the metal surface. Corrosion increases with increasing oxygen concentration and abrasion and in the presence of turbulent flow at high velocity. In addition to pH, the process parameters that affect corrosion are temperature, pressure, TDS as shown in Figure 5.

Crude Oil Flow Rate

As it is known that, the flowing fluid has a layered velocity forming a velocity profile like a parabola as shown in Figure 3 where the highest velocity is in the middle, while the lowest velocity is on the surface of the internal pipeline, according to Eq. (18). At r = 0, then the maximum speed, while at r = R, the velocity = 0, which occurs on the surface of the internal pipeline. At zero speed or at rest, the corrosion reaction process and the formation of scaling occur. The surface roughness of the internal pipe causes where key corrosive and scaling species are deposited in the roughness valley.

The flow velocity, density and diameter of the pipeline cause laminar or turbulent flow patterns. If the flow is laminar, then a thin layer that is formed such as siderite and FeS will prevent further corrosion processes. This is also the thin layer formed by the scale that will get thicker over time and reduce the pipe hole to shrink. It is recommended that if the flow pattern is turbulent as shown in Figure 4, then the layers of $CaCO_3$, FeS, and $FeCO_3$ formed will be peeled off and erosion will occur which causes thinning of the pipe thickness, especially this occurs in the elbow area (Figure 4). As mentioned earlier, that crude oil is in the form of mud because it will be possible to grow and breed bacteria that produce CO_2 and H_2S which are corrosive elements in the presence of H_2O. CO_2 and H_2S react to form $FeCO_3$ and FeS, or with Ca^{2+} to form $CaCO_3$ or with water to form H_2CO_3 which will dissociate into HCO_{3-} and CO_3^{2-} as in (1) to (12).

CONCLUSIONS

The interaction between key species, the surface of the internal pipeline, and parameter conditions such as pH and temperature caused a corrosion process and the formation of scaling that will have an impact on the function and service life of the pipeline. The surface roughness of the internal pipe will become a key species deposit so that the corrosion process and the formation of scaling occur. The process of corrosion and scaling formation is influenced by pH, temperature and water content, H_2S, CO_2 and sulphur. Under fully developed flow conditions, the fluid velocity at the crude oil fluid interface-the internal pipeline surface is zero. In other words, the key species is at rest and the corrosion reaction process and scaling formation occurs. To improve the function and general use of the pipe due to the corrosion process and scaling formation, it is necessary to apply an excellent operation, and an expert system.

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UNLOCKING POTENTIAL OF BROWNFIELDS THROUGH EFFECTIVE IMPLEMENTATION OF PLANNING & SCHEDULING

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ABSTRACT

Getting the best out of Brownfields, due to its marginal economics nature, requires accuracy and impactful collaboration in the execution of its activities & projects. Therefore process improvements become highly crucial inthe pursuit of operational excellence. This is exactly what is expected from the introduction of Operational Excellence, particularly in the Operating Efficiency Pillar. The focus will be on its sub-pillar which is Planning & Scheduling (P&S). Brownfield operations have long established processes and governance that provide an array of challenges when trying to introduce a new way of working. Therefore this paper tries to share the key learnings during the first year of implementing IP & S in Brownfield operation.

The foundational framework used is the PDCA framework of Plan-Do-Check-Adjust, and then within this framework, there are several elements specified even further with the expectations. The elements in the system basically relate to the establishment of strong Governance, People, Process, or Technology all working together in harmony. This paper will focus on the early stages of developing a solid planning & scheduling system in the organization, where the majority of the groundwork was oriented by the Operational Excellence maturity matrix. The matrix was then converted into actionable items and deliverables within the space of 11 months since the initiative was kicked off.

The foundational phase for the introduction & implementation of P&S was completed within 11 months. Action items and deliverables were produced, and both qualitative and quantitative benefits were gained. There was also a direct connection between P&S and helping the organization achieve its business objectives despite the global challenges that shook the oil & gas industry to its core. Challenges and difficulties were inevitable, but also becamethe key factor in creating a unified front. Overall, the organization-wide effort played a strong role in the mission ofimproving operational excellence with P&S as one of its key elements. Everyone was in the same boat, going through the same storm.

In times of unprecedented challenges, Operational Excellence and the Planning & Scheduling sub-pillar became the rock that solidified our organization. It is and shall be a leading practice that helps improve business sustainability, agility, and resilience. Making it a must-have for every organization in any industry wanting to survive and thrive. This paper provides leaders and changemakers with a usable framework in their efforts for the introduction and development of Planning & Scheduling, helping to achieve optimum results while gaining meaningful relationshipsand experiences along the way.

BACKGROUND

Getting the best out of Brownfields, due to its marginal economics nature, requires accuracy and impactful collaboration in the execution of its activities & projects. Therefore process improvements become highly crucial. This is exactly what is expected from the introduction of Operational Excellence (OE), particularly in the Operating Efficiency Pillar.

Medco's has four main pillars:

1. HSE: Health, Safety, and Environment
2. A&OI: Asset & Operating Integrity
3. CM: Cost Management
4. OEF: Operating Efficiency

Planning & Scheduling (P&S) is a sub-pillar that belongs in the Operating Efficiency pillar. It focuses on making sure all our efforts are constructed thoroughly, and timed accurately, in order to achieve the best possible outcome.

PROBLEM STATEMENT

The main challenge therefore focused on the early stages of implementation. Where it was critical that astrong foundation for further growth had to be established.

KEY FACTORS

There were several key factors that went into the equation. However all of them were covered and governed by this one internal system, called Medco's Operational Excellence Guideline. This became the basic reference to all our efforts. In it, is a maturity matrix filled with expectations that helped us build the system.

RECOMMENDATIONS

As mentioned above, the OE Guideline became the basic reference for our efforts. Within the guideline, is a maturity matrix, complete with elements and expectations in each level of maturity. This paper provides a recommendation for the most critical elements during the early stages of building the foundation for further growth of the OE culture, particularly for the P&S area.

The elements were grouped into the 4 main phases ofthe continuous improvement cycle more known asthe PDCA Framework, short for Plan-Do-Check- Adjust.

The details of how many elements and expectations exist in each can be found in Table 1. While the mostimportant elements during the early stages can be found in Table 2.

DATA AND METHOD

This paper shall cover two areas, the first is the 10 most critical elements in the early stages. The second is how the team addressed the most important element of any change initiative, the people. As Kotter (2007) listed in his article, there are 8 important steps in leading change.

Area number 2 was to 'Form a Guiding Coalition', which is built from reliable people having clear roles & responsibilities (Friedman, 2015 and Jones, 2014).

10 CRITICAL ELEMENTS OF EARLY-STAGE P & S PLAN

1. Planning & Scheduling Philosophy

A philosophy acts as the basis of all basics. Any vision, mission, objectives, or key results, must be in line with the main philosophy. In this case, the P&S philosophy essentially states that all of the organization's efforts to sustain the business, must be thoroughly planned & scheduled, so as to achieve the best possible outcome.

2. Governance, Roles and Responsibilities

An effective team is one where everyone

knows exactly what they are there for, what is demanded of them, and how they are expected to contribute to the team's mission. Therefore, clear responsibilities, with minimum overlaps, and well-quantified outputs from each key person was highly crucial.

3. Planning Components (Planning Tools)

This relates to technology as an enabler. Which essentially means, technology should follow the process. The principle in choosing a tool was something that was readily accessible, highly adjustable, and can serve the purpose. Spreadsheet application, despite all its shortcomings, was chosen.

4. Integrated Planning (Plan Input Standardization)

Consistency is key. Governance in how everyone would input their plans was nothing short of being critical. This aims to establish a minimum standard of quality, where there is a uniform and consistent method for inputting plans and activities. This goes as detailed as the structure (begins with a verb) of the action sentence.

DO

5. Planning Horizon (Medium Term Plan)

Medium to short term plan is where all the organization's efforts can be made or broken. Therefore, the focus was on the 1 year, down to 7 day planning & scheduling. This was seen as the tactical and operational planning horizon, where things get done and results are created.

6. P&S Communications

A plan is worthless if it is not communicated. Kotter (2007) also listed this as a critical step in leading change (Step #4. Communicate the Vision). The whole organization, especially the key executors must know exactly what is planned, why it is important, the impact it will bring, and how it will be executed.

7. Plan Visualization

Visualization supports the effective understanding of the plan, especially when being communicated. This covers quantification, conditional formattings, and other data visualization techniques aimed to ensure the message is clearly conveyed and understood.

CHECK

8. Plan Performance (Planning Compliance)

Creating a plan is one thing, actually committing and sticking to it, is another. Therefore, periodic reviews are imperative, aimed to ensure plan owners are in full compliance to what is planned at the start of the year. THis does not imply that plans cannot be altered, but changes must also follow a strict process.

9. Key Performance Indicators (KPI)

Reviews need a quantification system, and this is where planning KPIs come into play. This includes Schedule Attainment, Plan Utilization, and Manhour Utilization. All is measured to ensure the schedule is obliged, the plan is used accurately, and that no resource is wasted, therefore enhancing operational efficiency.

ADJUST

10. Planning Program Adjustment

As mentioned in the planning compliance section, adjustments are tolerable. Constraints occur, impacting the execution of a plan and schedule.

This however requires a structured approach, therefore minimizing any major disruptions to all the other activities in the approved plan.

BUILDING POWERFUL P&S PEOPLE

The core P&S team identified an imminent challengeduring the early stages. Building a culture, a system, or any effort, requires contribution from the key people involved. The OE initiative was robust and comprehensive, therefore the key players, in this case, the Asset Planners needed to be equipped with the right amount and quality of character, competency, and capability.

The 5Cs was utilized as the foundational framework. The following elaborates each C, and aims to provide practical examples for better understanding. The result was a team of Planners, consisting of 12 personnel that were previously secretaries/admins. This was the main achievement of all the efforts.

1. Care

An essential ingredient to begin with, we have to care enough before we can truly endeavour to improve our operations.

This is shown through the extra efforts taken by the core team in building the system in the beginning, and the constant offering of help.

2. Connection

Aims to build trust with the Planners. This was achieved through having 1-on-1 discussion with them, with the main objective to connect and to understand their strengths, improvement areas, and concerns. This connection was rather harder to be achieved if done through a group setting.

The sessions also involved knowledge sharing, helping them understand the oil & gas operations.

3. Clarity

When we understand what is expected of us, we can contribute better. Effectively managing expectations, provided a sense of clarity for the expected change. This was achieved through group sessions, aimed to explain the basics of OE and P&S. The desired impact was the Planners' understanding the P&S system before it was implemented to an organization-wide context.

To further assist the process of understanding the technical side of things, explanatory videos on oiland gas operations were also created and distributed.

4. Commitment

Through Connection and Clarity, comes Commitment. This is also shown in the weekly forum conducted with the sole purpose to provide a solid support system for the Planners. Answering anyquestions, solving any problems, and improving whatneeds to be improved.

The constant interaction within a nurturing environment significantly contributed in creating commitment. And likewise, through collective commitment, a nurturing environment is created.

5. Continuous Improvement (CI)

The CI mindset is key to any organization's long term success and sustainability (Chandrasekaran, 2019). Business processes that govern how CI is implemented is therefore crucial.

In this case, the PDCA cycle is always referred to. Should there be any problems/opportunities, this triggers a cycle of identifying the root cause, coming up with options, and then trying out which option works best.

Once proven, the existing guideline shall be updated and communicated, to ensure minimum standards are always raised and improved.

RESULT AND DISCUSSION

Key and notable results include the following:

1. 12 Asset Planners, gained from existing personnel, from previously secretaries.
2. 1 P&S Guideline document, developed together with the Planners.

3. MPRP (Monthly Performance Review & Planning), the ultimate ceremony for operational level P&S. This meeting became the core P&S communication event, gathering all key functions and operations, ensuring goals & objectives are well executed and managed.

Overall these 3 results contributed significantly towards the company's success in achieving 2020's business goals, despite the challenges faced globally in the form of COVID-19 pandemic.

CONCLUSIONS

The following points became the summary and key findings in this paper.

1. It is important to identify which elements are critical in each stage of building a system, especially for building a solidfoundation.
2. Key personnel must be provided with a strong support system, and effective framework for their professional development. The 5Cs helped with this.
3. P&S is a collective effort, therefore a gathering ceremony must exist, in the form of a monthly performance review and planning (MPRP) meeting.

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16 years of professional experience in the oil and gas industry, leading various multi-disciplinary projects, change intiatives, and strongly passionate in aligning and unlocking both people and business potential. Hold a B. Eng from Monash University and MBA from Robert Gordon University. Recently shifted career path from Eng & Ops at operating company to HR at an energy contractor.

Esi Marlini



10 years of experience in oil & gas company as secretary and planner. Pioneered the Planning & Scheduling (P&S) development in PT Medco E&P Indonesia's Onshore Assets, served as Coordinator of Operational Excellence sub-pillar P&S for South Sumatera Region and dedicating time and energy to share P&S practices to Assets' stakeholders. Currently pursuing a masters degree in PGRI University in Palembang.

COMPREHENSIVE PIPELINE MAINTENANCE

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ABSTRACT

The Rokan block is one of Indonesia's largest crude oil producers. Rokan block operates and maintains over 530 kilometres of main oil shipping pipelines to transport crude oil from the producing field to the Dumai terminal tank facility. There were pipeline integrity and operational issues in the main shipping lines: aging pipeline networks (more than 45 years old), heavy metal loss due to external corrosion from environment and soil contact, illegal road crossings (RC), Pipeline Hit Incidents (PHI) from public road proximity, and natural factors (land shift, fallen trees, erosion).

CPM Program (comprehensive pipeline repair and maintenance program) in Rokan Block was initiated in 2017 with core goal to continue safe pipeline operation, reduce risk of LOC and reduce the risk of social and environment impact due to pipeline integrity. CPM Program covered all aspects of pipeline maintenance start from inspection programs, life time analysis, priority ranking, planning and executions with main goal to maintain pipeline integrity in acceptable level of services. The focus of activities was to increase rate of proactive repairs (sleeving program), performed road crossing repairs, coating repairs, installed sacrificial anodes, and other interim mitigations until pipelines are either replaced or shut in.

The execution of CPM Program in Main Corridor from 2017 – 2020 has successfully maintain pipeline operation at safe margin (MAWP>MOP), extend pipeline Remaining Life Time (RFT), reduce damage rate from Pipeline Hit Incidents (PHI), reduce Loss Production Opportunity (LPO), and increase Mean Time Between Failure (MTBF).

Keywords: *comprehensive pipeline maintenance, MAWP, pipeline remaining life time, mean time between failure.*

INTRODUCTION

The Rokan Block is produce from approximately 75 active oil fields consisting of three major oil fields: Duri, Minas and Bekasap. There are two types of oil production, heavy oil and light oil. The pipeline is used to transport oil production from wells to gathering station for separation between oil, sand and water. Crude oil from the gathering station is transported by pipeline to Dumai storage tank, and then shipped to customers. The following figure shows the simplified process of crude oil transportation system in Rokan Block.

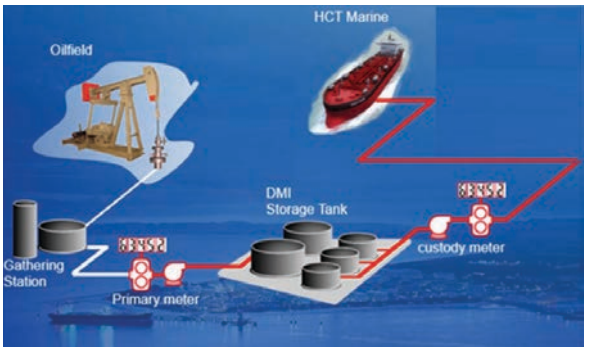


Figure 1 *Simplified process of crude oil transportation system*

The Rokan Block operates and maintains over 530 kilometres of oil main shipping pipelines ("Main Corridor") to transport crude oil from the producing field to the Dumai terminal tank facility. The existing Main Corridor pipelines were constructed more than 45 years ago located above ground with no community around the area. Current condition reveals that there are many pipeline segments that have been partially/fully buried without proper coating and/or cathodic protection to prevent corrosion.

As part of further pipeline integrity program, In-line Inspection (ILI) and Long-Range Ultrasonic Testing (LRUT) were conducted on the existing aging pipelines to be used as baseline data. The results indicated some pipeline segments were at high risks due to significant metal loss. The Comprehensive Pipeline Maintenance Program ("CPM") was then initiated by PT. Chevron Pacific Indonesia ("CPI") as Rokan Block Operator in 2017 to repair the pipelines and address other threats to support safe operation until lines replaced or shut in. The effort was completed in 2020.

This paper focus on the execution of CPM Program from Y2017 to Y2020 in Main Corridor which was executed by CPI as the Rokan Block Operator until August 2021. The Main Corridors consists of 8 segments as listed and shown in the simplified flow diagram below.

Table 1 *Main Corridor Segment*

PIPELINE SEGMENTS	SIZE (INCH)	LENGHT (KM)	BUILT
Balan - Bangko	10"	13	1972
Benar - Bangko	10"	10	1972
Bangko - Dumai	20" / 30"	80	1972
Duri CPS - Dumai	30" / 36"	54	1971
Duri CGS#3 - Dumai	24" / 30"	46	1958
Minas GS#1 - Duri	18" / 30"	76	1958
Libo - Mindal	10"	13	1982
Kotabatak - NBS	12"	33	1995



Figure 2 *Flow Diagram of Eight Segments Main Corridors*

SPECIFICS PROBLEM

The following are main integrity and operational issues for Pipeline in Main Corridors infrastructures:

1. Aging pipeline networks (more than 45 years old)
2. Public encroachment along pipeline Right of Way (RoW)
3. Heavy metal loss due to external corrosion from environment and soil contact
4. Illegal road crossings (RC)
5. Pipeline Hit Incidents (PHI) from public road proximity
6. Natural factors (land shift, fallen trees, erosion)

Considering inability to perform full pipeline replacement during the remaining time of Rokan PSC, the Rokan Block Operator was deploying a so-called Comprehensive Pipeline Maintenance (CPM) Program which covered all aspects of pipeline maintenance, starting from inspection programs,



Figure 3 *Integrity and operational issues in Main Corridors infrastructures*

lifetime analysis, priority ranking, planning to executions. The main goal of CPM program was to maintain pipeline integrity in acceptable level of services. The program was focused on activities related to increased rate of proactive repairs (sleeving program), performed road crossing repairs and coating application, installed sacrificial anodes installation, and other interim mitigations until pipelines are either replaced or shut in.

DATA AND METHOD

CPM Program (comprehensive repair and maintenance program) was initiated to allow safe pipeline operation, reduce risk of LOC and reduce the risk of social and environment impact due to pipeline integrity during operation. As part of CPM Program, The Rokan Block Operator utilized Pipeline Integrity Management System (PIMS) and implemented Risk Based Inspection tools to prioritize the asset integrity program.

1. Pipeline Integrity Management System ("PIMS")

The PIMS is pipeline management system in Rokan Block to provide an Integrity Management System for pipelines system that will ensure that all pipelines are designed, installed, operated, maintained, and decommissioned in a manner that protects the safety and health of people, protects the environment, and allows the inherently safe, high quality and cost-effective delivery of the product.

Picture below shows the Pipeline Integrity Flow Process to maintain the pipeline integrity. The main asset integrity pipeline activities including Risk Assessment, Inspection, Monitoring & Testing, Integrity Assessment, and Mitigation & Repair.



Figure 4: *Pipeline Integrity Flow Process to maintain the pipeline integrity*

In addition to implementing PIMS, Rokan block operator performed Risk Based Inspection Assessment to prioritize asset integrity program as illustrate on the figure below.

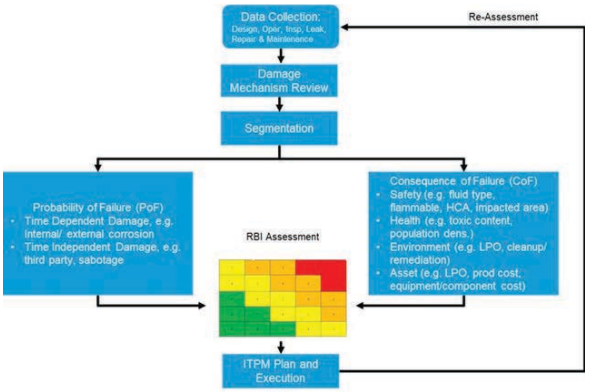


Figure 5 *Risk Based Inspection Assessment*

2. CPM - Proactive Repair Program

This section describes the objectives of program repair criteria and key highlighted results related to sleeve installation, sectional replacement, road crossing improvement, coating application and guard rail installation.

A. Sleeve Installation

- Objective : Maintain/improve MAWP rating that supports safe operation.
- Repair criteria: Red & orange anomalies based on projection of latest inspection result.

Metal Loss (%)	$MAWP_{current}$	Anomaly Category
>80%	≤ 1.10 $MAWP_{Limit}$	Red
>60% - 80%	> 1.10 – 1.25 $MAWP_{Limit}$	Orange
> 40% - 60%	> 1.25 – 1.50 $MAWP_{Limit}$	Yellow
<40%	> 1.50 $MAWP_{Limit}$	Green

Table 2 *Anomaly Category based on MAWP*

- Results: Installed sleeve quantity (2018 – 2020) 4,652 pairs (~1.7% total main corridor length).

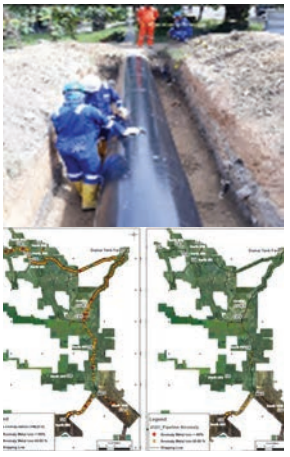


Figure 6 *Sleeve Installation on main corridor line*

Visualization of Main Corridors Before and After CPM Program:

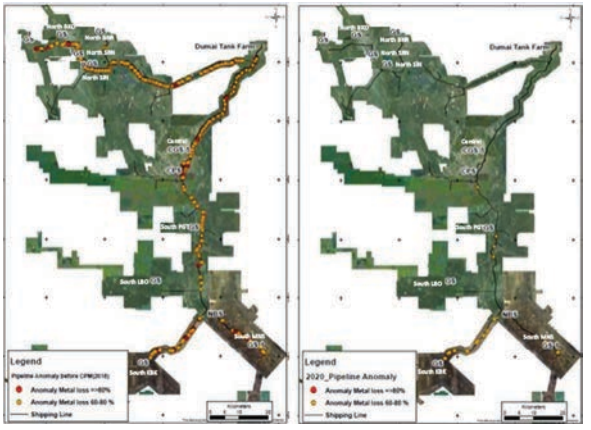


Figure 7 *Main Corridor Anomalies Condition Before and After CPM Program*

B. Road Crossing Improvement

- Objective : Provide protection against external load/impact on illegal road crossings.
- Criteria : On-site visual inventory for pipe condition (half-buried/buried), road crossing width (vehicle load), and HCA (high consequences area) class.
- Results: Installed sleeve reinforcement and cathodic protection with proper backfill on total 1,580 spots (~3% of total main corridor length).



Figure 8 *Road Crossing Improvement*

C. Coating Application

- Objective : Provide protection against external corrosion and mitigate corrosion growth.
- Criteria : Based on projection of latest inspection result on buried/-half-buried pipeline with 50-60% metal loss.
- Results: Applied external coating and installed sacrificial anode cathodic protection along 20.2 km (~6.2% total main corridor length~).



Figure 9 *Coating Application on Buried Line*

D. Guard Rail Installation

- Objective : Provide protection against pipe hit incident due to vehicle traffic.
- Criteria : Criticality prioritization based on past incidents, road condition, and pipeline position.
- Results: Installed 30.1 km standardized guard rail.



Figure 10 *Guard Rail Installation*

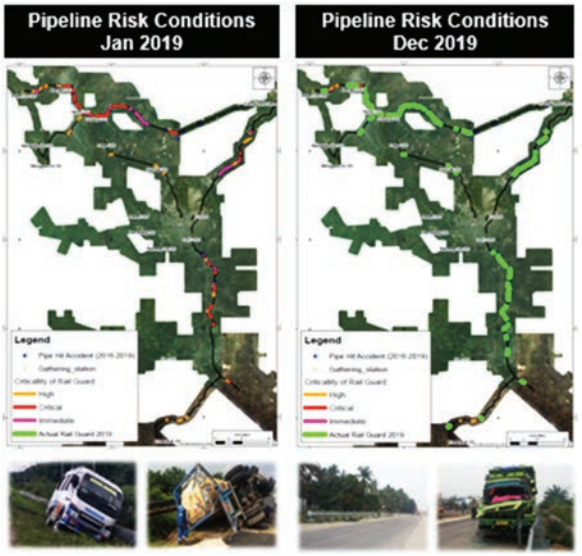


Figure 11 *Pipeline Risk Condition Improvement*

E. Sectional replacement

Sectional replacement is cut and replace method.

- Objective: Pipeline repair by replacing the red & orange anomalies segmental pipes based on projection of latest inspection result.
- Criteria:
  - Permanent repairs to replace previous temporary repairs (watermelon, sleeve over sleeve).
  - Environmental or constructability constraints and other technical matters. In example to repair anomalous pipes under public National Road.
  - Long anomalous pipe conditions.

Deliverables or Result of CPM Program (2018 – 2020)

This section summarized the accomplishment of CPM Program from 2018 to 2020 in ensuring safe pipeline operation (MAWP > MOP), extending pipeline Remaining Life Time, reducing damage rate from PHI, reducing loss production opportunity (LPO), and increasing mean time between failure (MTBF).

1. Maintain MAWP above MOP to support safe pipeline operation. After CPM program, all of main corridor segment demonstrates MAWP improvement in 2019 if compare with projected MAWP without CPM program. In addition, degradation of MAWP below required operating pressure due to aging pipeline has been avoided.

Table 3 *MAWP Improvement*

Segment	Remaining Life Time - Akhir 2017 Sebelum Perbaikan (Year)	Remaining Life Time - Akhir Tahun 2019 Setelah Perbaikan (Year)	Est MAWP (Block Flow) Akhir Tahun 2017	Est MAWP (Block Flow) Akhir Tahun 2019 (Tanpa Program CPM)	MOP	Cluster	MAWP (Block Flow) Akhir Tahun 2019 (Setelah Program CPM 2018 - 2019)
10" North #1 GS - BD	-3.3	2.5	350	180	240	A	290*
10" North #2 GS - BD	-1.8	3.6	300	150	270	B	350**
20" North Segment #3	-3.8	2.7	300	150	300	B	350**
30" North Segment #4 - Dumai	-3.9	1.1	300	150	300	B	350**
30" Central CPS Segment CGS	-5.7	4.5	200	90	170	C	400
36" Central CGS - Dumai	-0.7	6.8	200	90	170	C	400
24" Central Inter CGS	-2.3	7.5	170	145	1175	D	300
30" Central CGS - Dumai	-6.1	2.1	170	145	170	D	300
18" South GS - South NBS	2	5.6	200	180	200	E	250
30" South NBS - Central	-6.6	2.2	140	120	140	F	400
10" South Infield L	-8.8	4.9	140	120	150	F	400
12" South Infield K	-2.8	5.6	140	120	225	F	400

2. Maintain pipeline services until end of Rokan PSC or until pipeline is replaced.

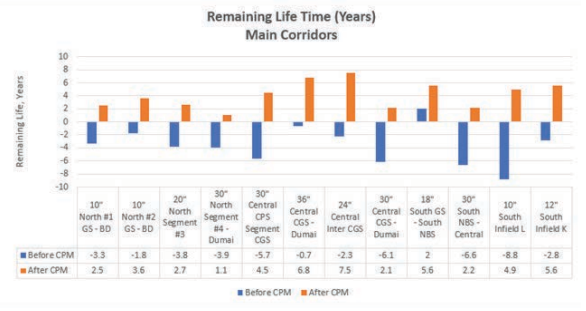


Figure 12 *Remaining Life Time Improvement*

3. Reduce pipeline failure due to integrity issue.
    - Reduced frequent of leak incidents since 2017 (~20% annually).
    - Improve MTBF and mitigate decline rate in 2019 until 2021
    - Reduced oil spill incidents and mitigate spill volume increase.

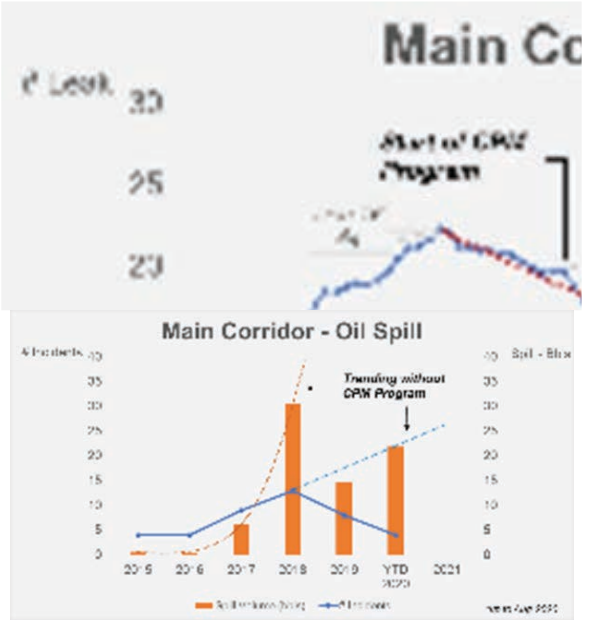


Figure 13 *Main Corridor MTBF and Oil Spill Improvement*

4. More flexibility in mitigating congeal event resulting from sustained MAWP.

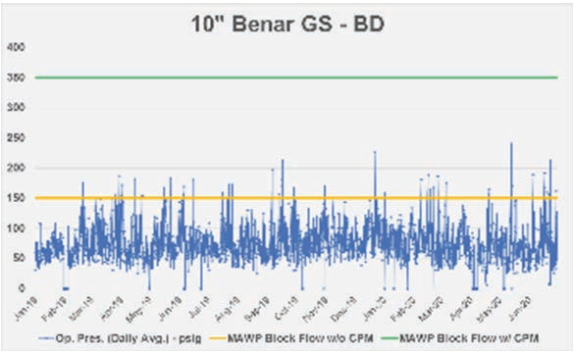


Figure 14 *Improvement of MAWP margin for congeal line*

5. Reduce LPO due to congeal.



Figure 15 *LPO reduction due to congeal*

6. Reduce number of damaged inflicted to the pipeline resulting from vehicle strike/accident.

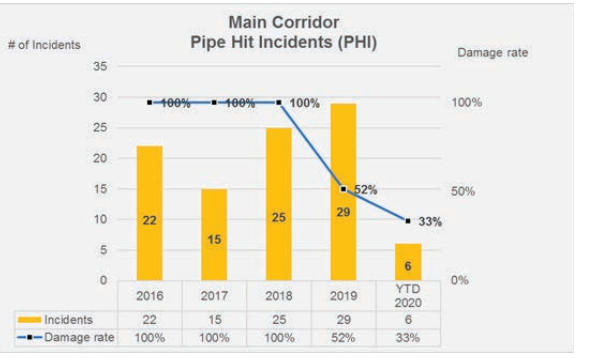


Figure 16 *Reduce PHI*

7. Reduce associated repair cost resulting from pipe hit incidents.

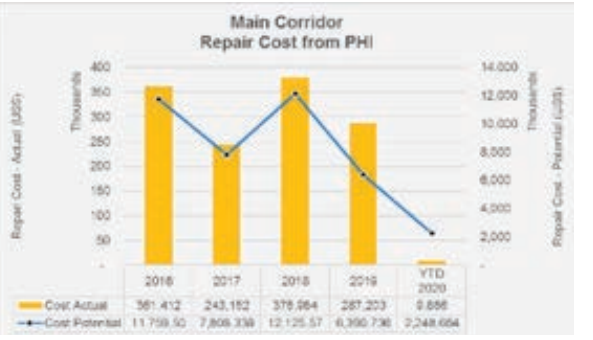


Figure 17 *Reduce Repair Cost*

CONCLUSIONS

The program to restore pipeline integrity on a campaign basis has proven to be one of the good solutions to contain the massive failure rate. When compared with new replacements, it can be compared in general has several advantages, including:

1. Significant capital cost savings and converted into operational costs.
2. Minimizing social risks, and increase the safety factor.
3. Preventing lost production with an even greater effect.
4. Generating baseline improvements with good learning for future activities.

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MATURE GAS FIELD AS NEW CHALLENGE FOR NEW OPERATOR AT BLOCK B ACEH BY GENERATING SURFACE PRODUCTION FACILITY INTERVENTIONS FOR OPTIMIZATION (INCREASING GAS SALES AND FUEL EFFICIENCY)

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ABSTRACT

Mature gas field optimization shall begin with main production problems identification, for Block B operation, the main problem is the production facility equipment needto be modified by intervention through surface production facility to adapt the current operating conditions. Excessivefuel own use has more challenging for new operator inBlock B.

First and foremost, generating surface production facility intervention programs that directly contribute to reduce fuelown use should be put on priority.

There are two projects where located in Point B (Ex-Arun LNG) processing area that will be executed to reducing fuelown use and increasing sales gas. Firstly, replace existing TEG Dehydration and Regeneration Package suitable with current operating condition, and secondly replacement for Booster Compressor.

The new TEG Dehydration and Regeneration package will reduce fuel gas consumption in amount of 5 MMSCFD. Thisproject will contribute the revenue for new operator toincrease the amount of sales gas. While the Booster Compressor will reduce fuel consumption in amount of 4 MMSCFD. Therefore, the amount of total fuel own use thatcould be reduced is ± 9 MMSCFD. This portion is divided between PGE and PHE NSO based on throughput feed gas.In the next stage, several surface facility interventions will be selected to additionally offer utilized innovations in various units, such as power generation system and gas compressor in APO field and other ageing facility.

INTRODUCTION

Arun field is well-known for its remarkable hydrocarbon resource in Indonesia. Discovered in 1971, the field has supported Liquefied Natural Gas (LNG) sales to Asian market (Pathak, 2004). The Arun field has been producing since 1977. Currently more than 99% of expected ultimate gas recovery has been produced. Surface facilities were designed for a peak capacity of 3,500 MMSCFD with multiple well clusters and production trains. (Avida, 2013). First gas was produced in July 1977, and the first condensatewas exported in October 1977 and the first LNG tanker was loaded in October 1978 (Pathak, 2004).

Since 17 May 2021, this field has been operated by PT PemaGlobal Energi (PGE) as a new operator (Production SharingContractor) to Aceh Upstream Oil and Gas Management Agency (hereinafter called "BPMA"). Previously, the fieldhad been operated by PHE-NSB.

The production field area consists of Arun, South Lhok Sukon A (SLS-A) and South Lhok Sukon D (SLS-D), (Luthfi, 2019). Gas production from the fields will be transported via 42-inch pipeline 32 km to Point B treating unit ex.PT Arun NGL and PHE-NSO Onshore for blending and further process with gas from PHE-NSO and from Triangle Pase Indonesia.

This study describes intervention surface production facilities to reduce fuel own use consumption. The effectiveimplementation of the concept to reduce cost and fuel own use shall be analyze comprehensively. In the next stage, several surface facility interventions will be selected to additionally offer utilized innovations in various units, such as power generation system and gas compressor in Aceh Production Operation (APO) field and other ageing facility. The issue of aging facilities leading to an increased risk of loss of containment and other failures due to plant and equipment deterioration. The significance of deterioration and damage relates to the potential effect on the equipment'savailability and reliability. Aging facilities which are no longer considered fully fit for purpose due to obsolescence in its integrity or functional performance (P Horrock, 2010). The traditional approaches to reduce the cost production and fuel consumption is to change the existing surface production facility which appropriate with the current operating condition.

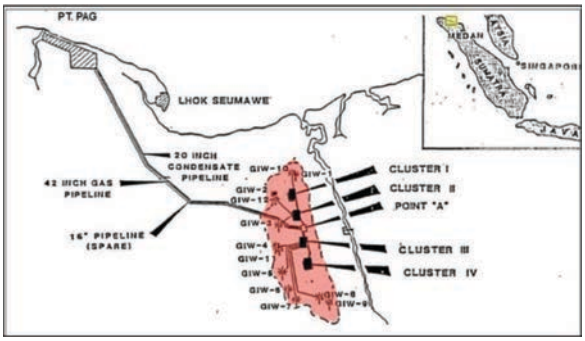


Figure 1: *Arun Field Map (Suhendro, 2017)*

DATA AND METHOD

Currently, the production from PGE (APO) approximately is 50 MMSFD and 1000 barrels of stabilized condensate perday.

The APO field information as shown in Table. 1

Table 1. *APO Field Information*

Field Information	Arun	SLS-A	SLS-D
Discovery	1971	1972	1991
No. of Wells	141	14	16
No. Active Wells	43	2	8
IGIP (Bscf)	14,112	306	696
Gp (Bscf)	13,267	286	616
Rem. Reserve (BCF)	56	1	3
Gas Prod. (MMscf/d)	36.62	2.18	6.19
RF (%)	94	94	89

The Arun field consist of Cluster I, II, III and IV and each cluster consisted of production wells and other surface facilities. Gas from SLS-A, SLS-D delivered to Cluster IV as well as gas from Cluster I, II and III. In cluster IV, stream gas undergoes a three-phase separation and then refrigerated de-

hydration unit. Dry gas and separated condensate are thendelivered to metering station in Point A by Booster compressor K-4920 (located in Cluster-IV) before transfer to the Point B (Avida, 2013).

Feed gas from the PGE (APO field) still contains impurities.Feed gas from PGE and PHE NSO (outlet SRU unit) will be commingled shared facilities booster gas compressor (KGT-2601), the feed gas will require further purification and processing to remove impurities and condensate stabilization before delivered to the buyer. Gas purification and processing in this step causes a large consumption of fuel for its own use (FOU).

The operation scheme at Point B using Facility Sharing Agreement (FSA) and the FSA is operated by PHE-NSO. Inaddition, there are cost for utilities service that provided by PT. PAG in this area. The utilities services are intended for two main area, namely Sulfur Recovery Unit (dedicated for PHE-NSO) and the other Gas Treating and Condensate Treating Unit (share between PGE and PHE NSO). For GasTreating unit, the allocation of cost sharing will be based onratio of the volume of feed gas rate. And for condensate treating unit, the allocation cost will be based on the ratio ofthe rate of volume of the condensate.

Table 2. *Gas Composition From APO*

No.	Component	Composition Mol Fraction
1	N2	0.0045
2	CH4	0.6845
3	H2S	0.000
4	CO2	0.2156
5	C2H6	0.0514
6	C3H8	0.0203
7	iC4H10	0.0051
8	nC4H10	0.0063
9	iC5H12	0.0033
10	nC5H12	0.0021
11	C6H14+	0.0069
TOTAL		**1.0000**

After purified, gas is then delivered to buyer according to gas nomination. This gas is also used for operational needs at Point B. On the other hand, to support operating gas purification and processing, both parties need additional items including services and consumable such as manpower, chemical & catalyst, lubricant, and other supporting utilities. Different strategies were created by previous operator (ExxonMobil) to maintain profitability of mature field. Arun Cluster Project Consolidation Project (ACCP) were started in 2004 to centralize gas dehydration and booster compression facilities into one cluster. The benefit from this project is reduced active assets by 60%, reducing operating expense by $350K annually, and saving fuel gas consumption by 9 MMSCFD by deactivated 2-unit gas turbine booster compressor. The ACCP was followed by the Liquid Handling Project (LHP) to consolidate liquid separation and transfer facilities from four clusters into two. Deactivation of two condensate pumps enabled until 20% reduction of power consumption. In addition to the condensate pumps, the LHP also eliminated several other types of equipment, including condensate-water separators, produced water treatment tanks, and produced water transfer pumps (Avida, 2013).

Cost Sharing, Feed Gas and Gas Supply

The treated gas that is flowed from the shared facility to allbuyers is a commingled gas sale of the parties. Sales gas each party is measured based on feed gas after deduction with fuel consumption.

Gas for fuel is taken from treated gas from shared facilities, the fuel gas is used for power plants, steam generators, gas turbine for booster compressor and NSO facilities. Measurement of fuel consumption is carried out at the measuring point of each equipment.

Fuel consumption for NSO treating unit will be borne by NSO, and the fuel consumption used for

PGE treating unit (APO field) is also fully borne by PGE.

Gas from the parties entering the sharing facilities is measured at the Gas Transition Point in volume units (MMSCFD) using the following measuring tools:

PGE gas is measured flow meter FQI-56001/2 which is a as flow meter PGE. Gas from NSO is measured as the difference from the combined gas measured by flow meter FQI-2602A that located down stream of booster compressorunit-26.

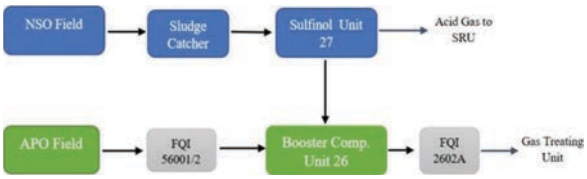


Figure 2: *Commingle of Feed Gas*

Gas for fuel is taken from the gas that has entered the shared facility, which will be used as fuel for booster compressor (Unit-26). The fuel consumption for booster compressor will be charged to each party (PGE and NSO) proportionally based on the feed gas volume of each party. Fuel consumption for power plants and steam generators is charged on a prorated basis based on the use of electricity and use of steam by each party. Feed gas volume from eachparty is measured by flow meter. The recording of the feed gas volume measurement is carried out on daily at 00:00-24:00. Analysis of gas composition to determine the GHV value is carried out on a weekly basis.

The volume of gas sales to each buyer is commingle gas sales by PGE and NSO, measured by the flow meter as shown in Table 3.

Table 3. *Custody Meter Supply Gas*

Tag Number	Services	Remark
FQI-6751	Total Treated Gas	
FQI-1905	Gas to Arbel	KIM and Jargas Lhoksukon
M-401/402	PT Pupuk Iskandar Muda	
M-403/404	PT Kertas Kraft Aceh (KKA)	PLN-KKA
CM	Jargas Aceh Utara	
CM	Jargas Lhokseumawe	

The recording of the sales gas volume measurement iscarried out on daily at 00:00 - 24:00. Analysis of gas composition to obtain the GHV value will be carried out periodically in accordance with the agreement with each buyer. Recording and reading of gas usage in the system is carry out on each daily, weekly, and monthly.

Sales gas for each party's is calculated prorated based on thecomparison of each party's feed gas after deducting for fuelconsumption (PGE and NSO) as described below.

Sales Gas PGE.

$$Total\ gas\ sales\ x\ \frac{Feed\ Gas\ PGE - Fuel\ PGE}{(Feed\ Gas\ NSO - Fuel\ NSO) + (Feed\ Gas\ PGE - Fuel\ PGE)}$$

Sales Gas NSO.

$$Total\ gas\ sales\ x\ \frac{Feed\ Gas\ NSO - Fuel\ NSO}{(Feed\ Gas\ NSO - Fuel\ NSO) + (Feed\ Gas\ PGE - Fuel\ PGE)}$$

The calculation of fuel own use is carried out in energy units.The measurement of the volume of gas fuel own use and heating value at the measuring point is described in Table 4below.

Table 4. *Measuring Point of Fuel Own Use*

No.	Equipment	Meter	Remark
1	Condensate Stripper	FI-2760	Dedicated NSO
2	SRU Plant	FI-6702	Dedicated NSO
3	HRSG	FI-9239	Share base on using of steam
4	Power Generation	FI-9001	Share base on electricity consumption after deduction with load of PAG.
5	KGT-2601	FI-5731	Sahre base on feed gas volume
6	KGT-4501	FI-4562	Share base on feed gas volume

In many mature gas fields, the production and fuel own use is a big issue. For APO field, optimal use of existing surface facilities or by intervention of surface equipment including install the new facilities to adapt with current condition is the key to reducing production costs and increase economic value.

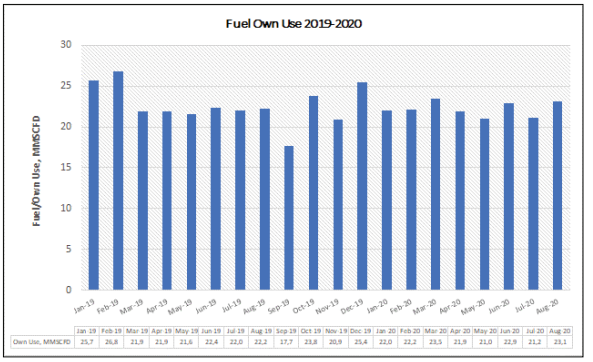


Figure 3. *Fuel Own Use 2019-2020*

RESULT AND DISCUSSION

The Arun and SLS A/D fields are mature fields with the oiland gas depletion rate reaching by 94%. The carbonate reservoir drain rate is generally below 80%. The rate of decline in natural production from year to year reaches 20%. Apart from that, along with decline of gas production and excessive fuel own use in Block B cause on production life becomes shorter and at certain times, all the production will be used for fuel gas only.

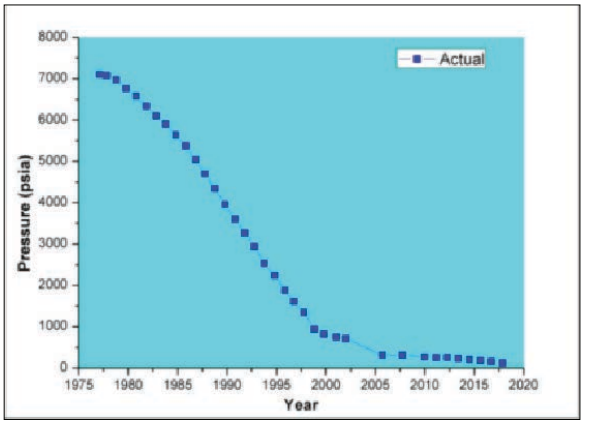


Figure 4. *Arun Field Reservoir Pressure (Luthfi, 2019)*

With the existing operating conditions, economic value of the Arun field will be negative in 2022/2023. To prevent this event, PGE as new operator should define the objective to be achieved, including prioritization and identify effectiveness of production cost.

Average production of gas from APO field is 48 MMSCFD (August 2021), and total fuel consumption at APO field is

8.25 MMSCFD. In this field, the biggest consumption is for booster compressor KGT-4920 that consume 3.7 MMSCFD. After deduction with fuel own use in APO field,feed gas be delivered to Point B in amount of 41 MMSCFD.At point B, feed gas form APO field will commingle with gas from NSO (outlet of unit 27), with the amount 21MMSCFD and from TPI is 1.42 MMSCFD only. The total feed gas commingled at Point B is 63 MMSCFD.

From the amount of feed gas, 20,24 MMSCFD is used for fuel own use, and this is heavily influencing the commercialization of sales gas from WK-B. The biggest fuel own use in Point B is treating unit that consume 10 MMSCFD and following by power generator consume 7.5 MMSCFD. The amount of impurities gas is 18,44 MMSCFD. Finally, total amount sales gas is 21.3 MMSCFD with 15.05 MMSCFD for PGE portion, 5,25 MMSCFD for NSO and 0.99 for TPI. (This data base on PGE daily report August 2021).

First and foremost, generating surface production facility intervention programs that directly contribute to reduce fuelown use (efficiency) should be put on priority. In this scenario, there are two projects that located at Point Bprocessing area that will be executed to reducing fuel own use and increasing sales gas.

TEG DEHYDRATION & REGENERATION PACKAGE

First project is to optimize the system in Unit 45 (liquefaction system) with deactivated the Scrubbing & Refrigeration System and deactivated Fuel Gas CompressorUnit and replace the existing Gas Dehydration Unit (Molecular-Sieve Drier) with a new TEG dehydration unit that suitable with current condition. The existing refrigeration system consume fuel gas 5.7 MMSCFD meanwhile fuel gas compressor unit requires power of 4.2MW or

equivalent to 1.3 MMSCFD of fuel gas.

The new TEG Dehydration package will be installed with a capacity of 60 MMSCFD. This equipment is required to replace the existing unit. This scenario will contribute gas treating unit becomes more efficient. TEG Dehydration package easier to operate and requires less fuel gas consumption compared to existing (Mole-Strainer Dehydration System).

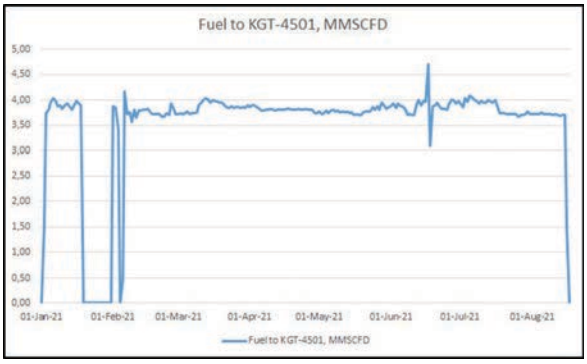


Figure 5. *Fuel Consumption KGT-4501*

From this optimization, it is expected that there will be a fuel savings by installing this TEG Dehydration unit can reach ± 5 MMSCFD. The saving of this gas fuel can be additional sales gas and revenue for both parties.



Figure 6. *Modified TEG Dehydration Unit*

REPLACEMENT BOOSTER COMPRESSOR K-2601

Second project is replacing the existing Booster Compressor (Unit-26) which has a design capacity of 450 MMSCFD with a new booster compressor unit that adjusts to the total feed in amount of 60 MMSCFD.

Unit 26 is a booster compressor (K/KGT-2601) which aims to increase feed gas pressure for the treating unit and dehydration unit. The feed gas comes from PGE gas and NSO gas. Existing K-2601 is a centrifugal compressor that has two stages of compression with a gas turbine driven.

The current condition of feed gas to K-2601 is 60 MMSCFD. The inlet pressure is 265 psig and outlet pressure is 738 psig. To compress this amount of untreated gas, K- 2601 requires treated gas fuel of 6.3 MMSCFD which the amount of fuel is not much different from the design fuel requirement.

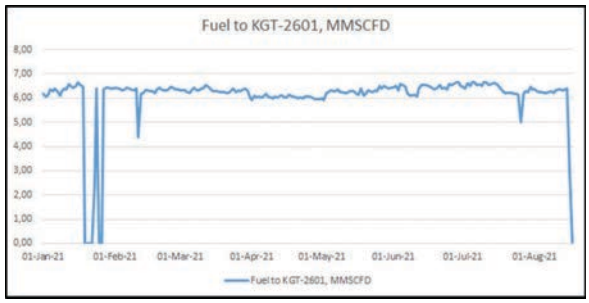


Figure 7. *Fuel Consumption KGT-2601*

By reducing fuel gas consumption at the booster compressor unit by replacing the booster compressor with a smaller capacity, adjusts to the current amount of gas feed. Decrease in fuel gas consumption can be used as additional gas sales to increase gas revenue. The new booster compressor will be selected with fuel gas consumption maximum 2 to 3 MMSCFD, therefore will be a fuel saving from this unit can reach 4 MMSCFD and this fuel saving can be additional sales gas.

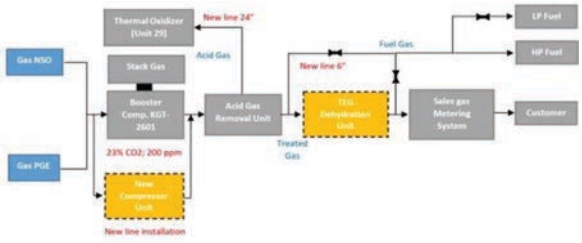


Figure 8. *Modified New Booster Compressor Unit*

Raise in economically viable awareness of current operationmode have led to increased fuel efficiency at point B processing and treating unit for almost 9 MMSCFD. This fuel saving provides economic advantage for PGE and NSO.This portion is divided between PGE and PHE NSO based on throughput feed gas.

A SUSTAINABLE EFFICIENCY EFFORT OF EACH PARTIES

In the next option, several surface facility interventions willbe selected to additionally offer utilized innovations in various units, such as power generation system, gas compressor and gas purification and treating unit in APO field.

This scenario will focus on APO Field only. Existing surface production will be changed or modified. This program optimizing production facilities by reducing the fuel own use.

Average production of raw gas at SLS is 8-9 MMSCFD, meanwhile average sales gas is 2.22 MMSCFD. Average fuel consumption at SLS is 0.89 MMSCFD, this fuel is using for power generation system. To reduce fuel consumption, all power supply for SLS will be provide from PLN and EDG as backup. In addition, this option will reduce costs for the operation and maintenance of gas turbines and fuel gas compressors.

Estimate gain from this project will increase of sales gas by 0.6 MMSCFD from SLS field.

At Point A, existing power generator generate by gas turbine generator package PGT-503/504 (GE Frame 3). The power generator consumes 2 MMSCFD of fuel and actual load power required at Point A is 3 MW. In other hand, the power generator in point A is an aging equipment. To optimize fuel gas consumption, the existing unit will be replaced with gas engine generator (GEG). configuration the GEG is 3 x 1500 kW and led to 0,8 MMSCFD in saving of fuel gas.

Booster compressor KGT-4920 located at Cluster IV, the compressor is used to delivered dry gas to the Point B with discharge pressure 380 psig. The existing compressor is centrifugal multistage compressor driven by gas turbine with fuel consumption 3.7 MMSCFD. To optimize fuel consumption at Cluster IV, the existing compressor will be replaced with reciprocating/screw type compressor with discharge pressure 800 psig. 2.2 MMSCFD fuel gas saving will be obtained from this scenario. The compressed gas from Cluster IV will be not delivered to point B for blending with gas from NSO and then through processing and treating purpose to meet buyer requirement. Gas purification unit will be installed at Cluster IV.

As mentioned above, gas purification unit will be installed at cluster IV. Cluster IV is designed to treat raw gas and then deliver to Point B for further process. Currently, portion of PGE fuel at point B is 13 MMSCFD. This project optimization includes installation of CO2 removal unit, TEG Dehydration Unit, H_2S removal. Sales point of gas from PGE is located at Point A (Custody Meter). Potential customer to sales gas directly from APO field is PT PIM or PTGN. This scenario will provide economic benefits for PGE which can increase gas sales by 12 MMSCFD. This option should be seriously considered to prevent economical issue of APO field production and the application of new concept has generated numerous opportunities to extend field life.

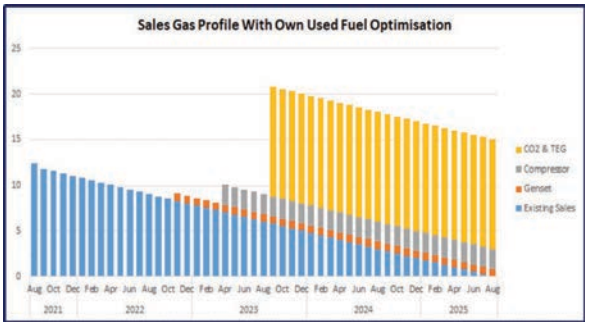


Figure 9. *Sales Gas Fuel Optimization APO Field*

In addition, with this scenario there will be saving cost $ 6 million annually for utilities services at Point B. It is important to understand the cost reduction at Point B is called cost avoidance. This is one of the right cost reductionstrategies to survival and growth for mature gas field. Reduction of fuel gas consumption and cost savings at Point B as a cost reduction strategy enables to PGE to achieve their planned gas production at reduced costs.

CONCLUSIONS

1. PGE as a new operator has a lot of challenge to operate Arun mature field. The new operator should be seriously considered innovative method by generating surface facilities to reduce excessive fuel own use and intervention for mature equipment to expand life of production profile.
2. Optimize of existing surface facilities or by intervention of surface equipment including install the new facilities to adapt with current condition is the key to reducing production costs and increase economic value
3. Without facility intervention program to reduce excessive fuel own use, at certain time all the production from this field will be used for fuel gas only.
4. Reduce in fuel consumption and cost reduction for utilities service at Point B is a cost reduction strategy and this is a key to a new operator to dealing with economic issue in mature gas field.
5. Excessive fuel own use and ageing facilities also have more challenging for field operation, either for availability or reliability issue and functional performance.

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WHAT'S NEW IN API 610 12TH EDITION?

Suharto | *PT Duraquipt Cemerlang*

ABSTRACT

A centrifugal pump standard, API 610 12th edition was just published in January 2021. This is still quite fresh and it will take time for the API 610 pumps manufacturers and end users to adapt to this new API 610 standard.

There are few International Standards for pumps which are used in Oil & Gas Industry. But, API 610 is the most popular pump standard and used widely all over the world, especially in the Oil & Gas Industry.

This paper is trying to discuss several things that are new in API 610 12th edition when compared to previous API 610 11th edition, including:

1. BB1 pumps. In the previous API 610, there is only 1 type of BB1 pump. But, now it is divided into 2 types, namely BB1-A: Foot Mounted and BB1-B: Near-centerline Mounted.
2. Hierarchy of Requirements. The hierarchy of the documents shall be stated by the purchaser.
3. Equipment Reliability. If requested by the purchaser, only field-proven pumps, as defined by the purchaser are accepted.
4. Parallel operation. Pumps with a discharge size greater than 3 inches that are operated in parallel, there is an additional requirement that in the preferred operating range (POR), the head different shall be within 3% of each pump.
5. Head rise to shut off (HRTSO). It is noted that pumps with head curve that continues to rise towards the shut off (stable curve) are preferred for all applications. However, this is not possible for all types of pumps.
6. Couplings. In API 610 11th edition, the coupling should be balanced with grade G6.3, but in 12th edition, the balancing grade is not stated, but it should be specified by the purchaser.
7. Shaft guards. In addition to the coupling guard installed between the driver and the pump, a shaft guard shall also be installed between the bearing housing and the mechanical seal.
8. Baseplates. The baseplate for the OH2 pump shall have nothing (auxiliaries or seal flush plan) mounted beside or above the coupling or bearing housing.
9. Performance test. The distance of each test point in the allowable operating range (AOR) should not be more than 35% of the rated flow. Hence, the test point is increased from 6 to 9 points.
10. Material Classes. Bronze, Ni-Resist and cast iron materials are no longer used for either the casing or impeller. Minimum material for casing and impeller is carbon steel.
11. Special-purpose Centrifugal Pumps. A special-purpose centrifugal pump is a pump that meets one or more of the following criteria:
    a. Operating in a severe, critical application;
    b. A prototype;
    c. High energy levels.

INTRODUCTION

API 610 Pump Standard 12th edition was just published in January 2021. This is still quite fresh and it will take time for API 610 pumps manufacturers and users to adapt to the new API 610 standard.

In addition to the API 610 Pump standard (Centrifugal Pump) there are several other pump standards that are used in the Oil and Gas industry, namely API 674 (Reciprocating Pumps), API 675 (Controlled volume/Metering/Dosing pumps), API 676 (Rotary pumps), API 685 (Sealless Centrifugal Pumps) and ANSI/ASME B73.1 (Centrifugal Pump).

API 610 Pump Standard is the most popular pump standard in the oil and gas industry. API 610 Pump Standard was first published in 1954. Table 1 shows the years of publication of the API 610 standard from 1st edition to the last edition, which is 12th edition.

Edition	Year of publication	Title	Number of pages	Years between editions
1	1954	API Specifications for Pumps for General Refinery Services	20	
1	Jan-55	Supplementary 1 Mechanical Seals	1	
1	Jan-55	Supplementary 2 Vertical Pumps	3	
2	Jan-57	Centrifugal Pumps for General Refinery Service	22	2
3	Jan-60	Centrifugal Pumps for General Refinery Service	26	3
4	Jul-65	Centrifugal Pumps for General Refinery Service	26	5
5	Mar-71	Centrifugal Pumps for General Refinery Service	35	6
6	Jan-81	Centrifugal Pumps for General Refinery Service	62	10
7	Feb-89	Centrifugal Pumps for General Refinery Service	139	8
8	Aug-95	Centrifugal Pumps for Petroleum, Heavy Duty Chemical, and Gas Industry Services	193	6
9	Dec-02	Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries	192	7
10	Oct-04	Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries	184	2
11	Sep-10	Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries	205	6
12	Jan-21	Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries	223	11

Compared to other pump standards, the API 610 standard is the most popular pump standard and the most frequently updated.

DATA AND METHOD

Most of data in this paper are taken from API 610 12th and 11th edition. Method used in this paper is comparative, i.e. comparing API 610 12th edition with the previous API 610 11th edition.

RESULT AND DISCUSSION

In API 610 12th edition there are several things that are new when compared to API 610 11th edition, including the following. To make it easier to check in API 610 12th edition, the API 610 paragraph is provided in parentheses.

1. BB1 PUMPS (4.2.2.8)

BB1 pump type, which previously only has 1 type, is now divided into 2 types, namely BB1-A: Foot Mounted and BB1-B: Near-centerline Mounted. See figure 1a & 1b respectively. BB1-A pumps may be used for service temperature below 150 ^{O}C.

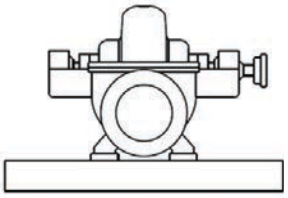


Figure 1a. *BB1-A: Foot Mounted*

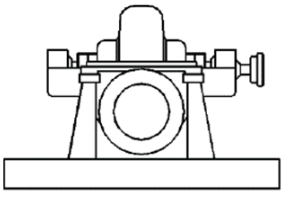


Figure 1b. *BB1-B: Near-centerline Mounted*

2. HIERARCHY OF REQUIREMENTS (5.3.3)

In API 610 12th edition there is an addition that the hierarchy of documents shall be specified by purchaser. This is certainly very useful to avoid any conflicts that may occur between one document and another. So it is clear that the document with the highest hierarchy shall be used as a reference. In case of conflict between the standard and the inquiry, the inquiry shall govern. At the time of the order, the purchase order shall govern.

3. EQUIPMENT RELIABILITY (6.1.1)

In API 610 11th edition, pumps shall be designed and manufactured for a minimum of 20 years of service life (excluding normal wear of parts specified in Table 20 of API 610 11th edition) and a

minimum of 3 years of uninterrupted operation. Whereas In API 610 12th edition, if requested by the purchaser, only field-proven pumps, as determined by the purchaser, are acceptable.

Purchaser can use their engineering judgment in determining what equipment is field-proven. API 691 can be used as a reference.

If specified, the vendor shall provide documentation to demonstrate that all proposed equipment qualifies as field proven.

If the equipment is not available, vendors shall submit an explanation of how their proposed equipment can be considered field-proven. A possible explanation is that all the components that make up the assembly machine meet field-proven definitions.

4. Parallel operation (6.1.13)

Pumps with a discharge nozzle size greater than 3 inches that are operated in parallel, there is an additional requirement that in the preferred operating range (POR), the head values must be within 3% of each pump. This means that the head difference of each pump which is operated in parallel cannot be more than 3%.

5. Head rise to shut off (HRTSO) (6.1.15)

It is noted that pumps with a head curve that continues to rise towards the shut off (stable curve) are preferred for all applications. However, this is not possible for all types of pumps. The shape of the head curve is dependent on several factors specific to the hydraulic design of the pump.

6. Couplings (7.2.2.g)

In API 610 11th edition, if specified, the couplings shall be balanced according to ISO 1940-1 grade G6.3, but in 12th edition major coupling components (hubs and spacer/flex element) shall be balanced in accordance with ISO 21940-11, but the balance grade is determined by the purchaser.

Balancing grade G6.3 is good enough for the coupling. So far so good, no problem.

7. Shaft guards (7.3.3)

In addition to coupling guard between driver and driven equipment (pump), a shaft guard shall also be installed between bearing housing and mechanical seal.

The shaft guard shall sufficiently vented to prevent the accumulation of seal emissions, liquid, or vapor and allow visual inspection of the seal without removal of guard.

8. Baseplates (7.4.6)

Baseplates for OH2 pumps shall have nothing (auxiliaries or seal flush plan) mounted beside or above the coupling or bearing housing. If the auxiliaries or seal flush plan shall be mounted on the baseplate, the increased length standard baseplate shall be used and the auxiliaries and/or seal flush plan shall be mounted adjacent to the suction nozzle. See figure 2.

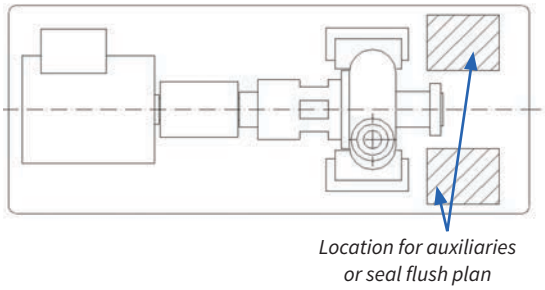


Figure 2. *Baseplate for OH2 Pumps*

This is intended that the auxiliary systems will not block access when maintain the pump, motor, and coupling.

Baseplate size in API 610 12th edition starts with the baseplate size number 2.5 – 12, while in the previous edition the size starts from the number 0.5 – 12. See Table 2.

Table 2. *Dimensions of Standard Baseplates*

Baseplate number	Number of holes per side	l_1 ±13 (0,5)	l_2 ±25 (1,0)	l_3 ±3 (0,12)	l_4 ±3 (0,12)	l_5 ±3 (0,12)
0.5		These baseplate numbers are deleted in API 610 12th edition				7,0)
1						7,0)
1.5						7,0)
2						
2.5	3	915 (36,0)	1 535 (60,5)	615 (24,25)	615 (24,25)	840 (33,0)
3	3	915 (36,0)	1 840 (72,5)	770 (30,25)	770 (30,25)	840 (33,0)
3.5	4	915 (36,0)	2 145 (84,5)	920 (36,25)	615 (24,16)	840 (330)
4	4	915 (36,0)	2 450 (96,5)	1 075 (42,25)	715 (28,16)	840 (33,0)
5	3	1 065 (42,0)	1 840 (72,5)	770 (30,25)	770 (30,25)	990 (39,0)
5.5	4	1 065 (42,0)	2 145 (84,5)	920 (36,25)	615 (24,16)	990 (39,0)
6	4	1 065 (42,0)	2 450 (96,5)	1 075 (42,25)	715 (28,16)	990 (39,0)
6.5	5	1 065 (42,0)	2 755 (108,5)	1 225 (48,25)	615 (24,12)	990 (39,0)
7	4	1 245 (49,0)	2 145 (84,5)	920 (36,25)	615 (24,16)	1 170 (46,0)
7.5	4	1 245 (49,0)	2 450 (96,5)	1 075 (42,25)	715 (28,16)	1 170 (46,0)
8	5	1 245 (49,0)	2 755 (108,5)	1 225 (48,25)	615 (24,12)	1 170 (46,0)
9	4	1 395 (55,0)	2 145 (84,5)	920 (36,25)	615 (24,16)	1 320 (52,0)
9.5	4	1 395 (55,0)	2 450 (96,5)	1 075 (42,25)	715 (28,16)	1 320 (52,0)
10	5	1 395 (55,0)	2 755 (108,5)	1 225 (48,25)	615 (24,12)	1 320 (52,0)
11	4	1 550 (61,0)	2 145 (84,5)	920 (36,25)	615 (24,16)	1 475 (58,0)
11.5	4	1 550 (61,0)	2 450 (96,5)	1 075 (42,25)	715 (28,16)	1 475 (58,0)

9. Performance test (8.3.3.4.1)

The distance of each test point in the allowable operating range (AOR) shall be no more than 35% of the rated flow. The number of test points is 9. See figure 3.

Table 3 shows the differences in its test points between API 610 11th and 12th editions.

Table 3. Comparison of test points of API 610 11th edition vs 12th edition.

11th Edition	12th Edition
1. Shutoff;	1. Shutoff;
2. Minimum continuous stable flow;	2. Minimum continuous stable flow;
	3. Halfway between minimum continuous stable flow and minimum preferred operating flow;
	4. Minimum preferred operating flow;
	5. Halfway between minimum preferred operating flow and rated flow;
3. Between 95 % and 99 % of rated flow;	6. Between 95 % and 99 % of rated flow;
4. Between rated flow and 105 % of rated flow;	7. Between rated flow and 105 % of rated flow;
5. Approximately BEP flow (if rated flow is not within 5 % of BEP flow);	
6. End of allowable operating region.	8. End of preferred operating region;
	9. End of allowable operating region if different from the end of the preferred operating region.

For pumps with low capacity, below 50 gpm (11 m^3/hr), test points no. 3 and 5 are not required.

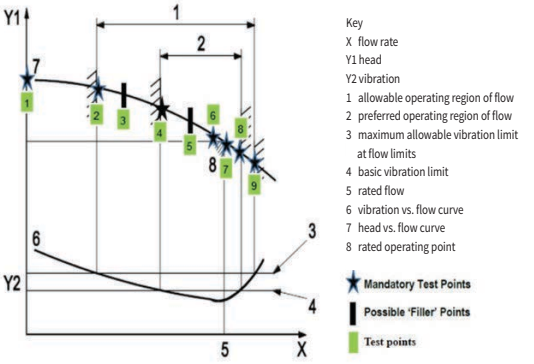


Figure 3. *Test points*

10. Material Classes (Table H.1)

In API 610 12th edition, bronze, Ni-Resist and cast iron materials are no longer used for either casing or impeller. Minimum material for casing and impeller is now carbon steel. So the material class starts from S-4. Material classes I-1, I-2, S-1 and S3 are removed from the API 610 12th edition.

For the last few years back, the requirement of cast iron material for API 610 pump is very seldom. Cast iron is fragile and not suitable for high pressure. Moreover, it is difficult to repair when welding is required.

11. Special-purpose Centrifugal Pumps (Annex O)

A special-purpose centrifugal pump is a pump that meets one or more of the following criteria:

a. Operating in a severe, critical application;

b. A prototype – a design that is sufficiently different from existing designs to warrant, in either the manufacturer's or the purchaser's opinion, the extent of engineering analysis and manufacturing process specified in Annex O of API 610 12th edition;

c. High energy levels.

High energy is a term that has been used by some in the oil and gas industry to define if a design requires more attention to engineering

and manufacturing than is required by API 610. High energy has many definitions (shaft power, power per stage, head per stage, pressure rise per stage, value of first stage impeller inlet peripheral velocity), none of which are sufficiently encompassing to qualify as a single definition.

CONCLUSIONS

This paper has highlighted some significant new requirement in API 610 12th edition. Both pumps manufacturers and end users shall adapt their pumps design and requirement to this new API 610 12th edition.

There is no change in bare pump design like: maximum allowable working pressure (MAWP), corrosion allowance, bearing life, shaft deflection, etc.

The significant changes are occurred in pump requirement like: pump reliability, parallel operation, head rise to shut off, performance test, material classes & special purpose pumps, and also pump accessories like: coupling, shaft guard & baseplate.

API 610 12th edition provides more attention on safety and ease of maintenance accessibility.

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Suharto, 2016, POMPA SENTRIFUGAL Panduan Lengkap: Standarisasi, Teori, Pemilihan, Pembelian, Pengoperasian, *Maintenance* dan *Troubleshooting*.

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Pada tahun 2001 penulis mulai bertugas sebagai Direktur di PT. Duraquipt Cemerlang sampai dengan saat ini. PT. Duraquipt Cemerlang adalah sebuah perusahaan yang bergerak dibidang manufaktur dan perawatan/ perbaikan untuk pompa ANSI/ASME B73.1, Pompa API 610 dan Fire Pumps NFPA 20.

Penulis menyelesaikan pendidikan D-3 dan S-1 Teknik Mesin di Institut Sains dan Teknologi APKRIND, Yogyakarta, dan program Pasca Sarjana (S-2) bidang Teknik Industri pada Institut Sains dan Teknologi Nasional, Jakarta. Gelar Insinyur Teknik Mesinnya diperoleh di Institut Teknologi Bandung.

Penulis sering memberikan presentasi mengenai berbagai jenis produk pompa dan memberikan pelatihan-pelatihan yang berhubungan dengan pompa.

Penulis telah menulis buku dengan judul: Pompa Sentrifugal - Panduan Lengkap: Standarisasi, Teori, Pemilihan, Pembelian, Pengoperasian, Maintenance dan troubleshooting.

Saat ini penulis menjabat sebagai Sekretaris BKM-PII (Badan Kejuruan Mesin-Persatuan Insinyur Indonesia).

A STUDY OF COMPARISON OF THE EFFECTIVENESS BETWEEN THE PROCESS SAFETY MANAGEMENT PROGRAMS DEPLOYED BY E&P COMPANIES IN INDONESIA

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ABSTRACT

Oil and gas production has always been a high-risk process, involving highly flammable substances, toxic materials and waste, heavy equipment, and in some areas even hazard by wildlife. Human involvement in this industry is integral, and keeping the workers safe is a challenge that every company has to face. In Indonesia, exploration and production companies are implementing their own Process Safety Management (PSM) program for every aspect of the company to adhere to fit the company's standard of safety. Even a tiny neglect of the PSM may cause material loss of containment, fire, and explosion, some leading to catastrophic events that result in loss of assets. Added to that, fines, sanctions, and stricter regulations may give negative feedback for the respective company. Thus, the importance of proper PSM programs is not to be underestimated.

Process safety management program comprises commitment to process safety, understanding hazards involved, managing risks that may occur, and learning from documentations of previous accidents or near misses. It is a comprehensive program that encompasses every essential element involved. Still, some companies' PSM programs held better safety records than others.

The aim of this paper is to compare and give recommendations for the more robust PSM program to be implemented by companies. To be more precise, this paper focuses on PSM programs that are implemented by oil and gas exploration and production companies in Indonesia. The authors focus on more recently updated accident data and latest implementation of the PSM program, as the foregoing program may be outdated and may lead to inaccurate results.

The authors aim for this paper to be taken for consideration for further iterations of the PSM program to be implemented by oil and gas companies that operate around the globe, as some of the cases mentioned here might be similar to conditions faced by the company. Furthermore, may this

paper spark the spirit of safety culture to the professionals of the industry and establish the need of safety transparency to the eyes of the public. All of this effort may result in a better safety assurance for the workers involved and industry-wide, erasing the connotation of oil and gas as a 'dirty and unsafe' industry. The implementation of a robust PSM program will act as a catalyst for a better oil and gas industry in the future.

Keywords: *Process Safety Management, Surface Facilities, Safety Culture*

INTRODUCTION

Oil and gas production has always been a high-risk process, involving highly flammable substances, toxic materials and waste, heavy equipment, and in some areas even hazard by wildlife. Human involvement in this industry is integral, and keeping the workers safe is a challenge that every company has to face. In Indonesia, exploration and production companies are implementing their own Process Safety Management (PSM) program for every aspect of the company to adhere to fit the company's standard of safety. Even a tiny neglect of the PSM may cause material loss of containment, fire, and explosion, some leading to catastrophic events that result in loss of assets. Added to that, fines, sanctions, and stricter regulations may give negative feedback for the respective company. Thus, the importance of proper PSM programs is not to be underestimated.

Research shows that the incidence rate of failure in the oil and gas industry has increased over the years (Platt & Platt, 1989). From these studies, there are incidents that cannot be predicted so that a preventive technique approach is needed instead of a reactive technique for failures that occur (Nwankwo et al., 2020). One example occurred on the Deepwater Horizon in 2010 which spilled 4 million barrels of crude oil into the Gulf of Mexico. This incident has an impact on the marine environment, abandoned refinery businesses, and led to criminal charges against British Petroleum (BP) of up to 60 billion US Dollars (Norazahar et al., 2014). Other cases also occurred in the Piper Alpha disaster in 1988 which caused the death of 167 people, the Alexander Kielland collapse incident in 1980 which caused the death of 123 people and the BP explosion in Texas in 2005 which resulted in 15 deaths and 180 injuries (Ismail et al., 2014). The root cause of these incidents occurred in process safety failures which consisted of lack of communication, asset problems, poor company management and human factors (Hsu et al., 2015). This can be prevented by implementing Process Safety Management (PSM) in all process facilities (Bridges & Tew, 2010). In this study, a comparative study of the effectiveness of Process Safety Management was conducted based on incidents that had occurred in the oil and gas industry.

20 ELEMENTS OF PSM BASED ON CCPS

The Center for Process Safety (CCPS) was established by the American Institute of Chemical Engineers (AIChE) in 1985 to research and disseminate technical information for the avoidance of significant chemical catastrophes (Hanida & Azmi, 2017). Risk-based Process Safety (RBPS) was developed by CCPS and named as the framework for the next generation of Process Safety Management (PSM). Figure 1 lists the features of RBPS, which are based on four pillars : commit to process safety, understand hazards and risk, manage risk and learn from experience (*Comparison of Process Safety Management System: CCPS Risk-Based & OSHA PSM*, 2019). Based on the perceived needs, resource requirements, and existing safety culture of the institution, very diverse RBPS actions may arise (NJ, 2007).

a. Process safety culture: Process safety culture has been defined as, “the combination of group values and behaviors that determine the manner in which process safety is managed”. Employees at all levels are dedicated to process safety in this positive environment. This starts at the highest levels of organization and is shared by everyone. Leaders in the field of process safety encourage it.

b. Compliance with standards: A system for identifying, developing, acquiring, evaluating, disseminating, and providing access to process safety-related standards, rules, regulations, and legislation. Internal and external standards, as well as national and international codes and standards, industry association guidelines and practices, and municipal, state, and federal rules and laws, are all addressed by the standards system.

c. Process Safety Competency: To control its process dangers, the firm needs the necessary skills and resources in the right areas. Confirmation that the organization as a whole have certain abilities and resources. This knowledge may be put to use in succession planning and change management.

d. Workforce Involvement: Actively committing to established safety standard

e. Stakeholder Outreach: A method for finding, interacting with, and sustaining positive connections with external stakeholder groups. This includes the local community, raw material suppliers, customers, government agencies and regulators, professional societies, contractors, and others.

f. Process Knowledge Management: Documentations and records of any accident

g. Hazard Identification and Risk Analysis: Process safety threats and their possible effects are identified. The dangers associated by various hazard situations are defined. Recommendations for reducing or eliminating risks, reducing possible consequences, and reducing the frequency with which they occur. Depending on the amount of risk, the analysis might be qualitative or quantitative.

h. Operating Procedures: Written instructions for a manufacturing process that explain how the activity should be carried out properly, the consequences of departure from procedures, important safeguards, and exceptional situations and emergencies.

i. Safe Work Practices: Process and operational status monitoring, especially on maintenance and non-routine practices

j. Asset integrity and reliability
Management of operational interfaces. Ensures that critical equipment stays fit for its intended function throughout its service life.

k. Contractor management
Practices to guarantee that contract personnel can execute their tasks safely and that contracted services do not contribute to or exacerbate operational hazards at the site.

l. Training and Performance Assurance
Ensure that workers meet performance standards and identify where additional training is required.

m. Management of Change
Any changes to a process do not inadvertently introduce new hazards.

n. Operational Readiness

Before starting or restarting a process, it must be evaluated to verify that it can be started safely. This rule applies to facilities that have been shut down or idled, as well as process modifications and maintenance. This is also true for the start-up of new facilities.

o. Conduct of Operations
Means of carrying out the necessary managerial and operational responsibilities for process safety in a thoughtful, faithful, and systematic

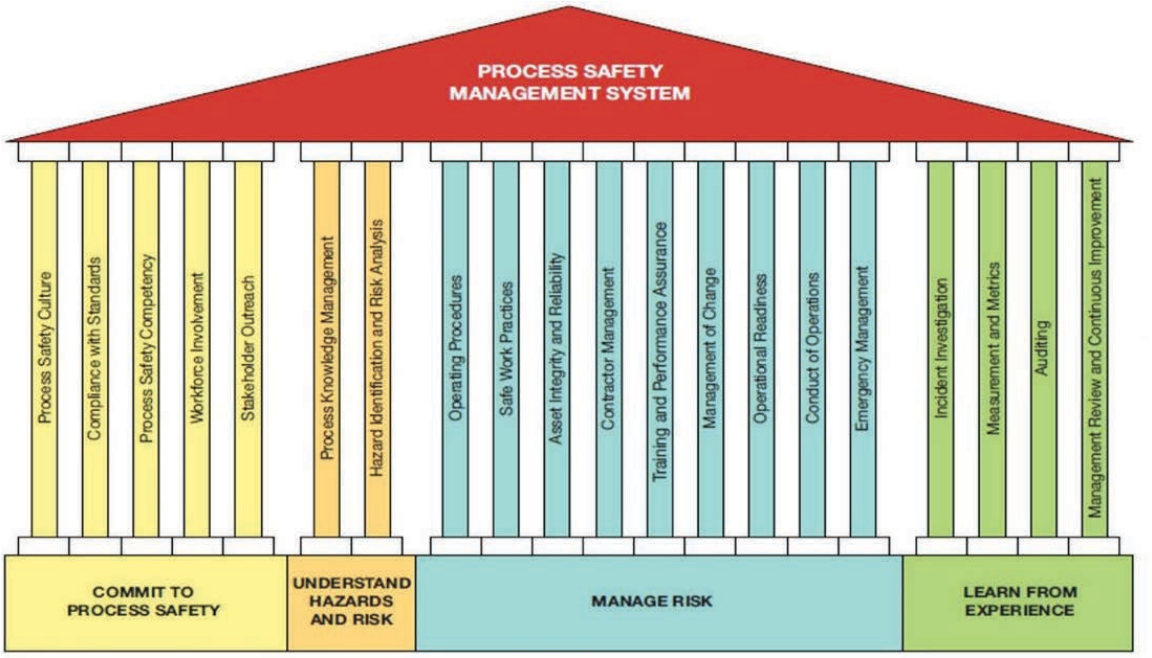


Figure 1: *4 pillars and 20 elements of PSM*

manner. Managers ensure that employees complete essential tasks and that performance does not deviate from expectations.

p. Emergency Management
Emergency planning that defines actions in an emergency (routes, continuous improvement of strategies) and responses (trainings, how to notify an accident).

q. Incident Investigation
Reporting, tracking, investigating incidents. Provides data for resolution and documentation of recommendations generated by the investigations.

r. Measurements and Metrics
Incidence and near-miss rates, as well as measures that demonstrate how well essential process safety aspects are executed, are leading and lagging indicators of process safety performance. This data is utilized to promote process safety improvements.

s. Auditing
Evaluation of safety management system.

t. Management Review and Continuous Improvement Routine evaluation of whether management systems are performing as intended. Continuously improve the current safety system.

RISK & HAZARD POTENTIAL

Potential hazards are abundant in upstream oil and gas operations. A hazard is defined simply as something that can cause harm, for example gas release, toxic chemical, and live electric line. When combined with the likelihood of exposure to the hazard, it becomes a risk. A risk is the probability, high or low, that any hazards will actually cause harm to personnel, environment or assets. Risk can be calculated by multiplying the likelihood of the hazard occurring with the magnitude of the hazard impact. Table 1 shows some of the major hazards and their associated causes normally encountered in upstream operations. These hazards will be the basis for the incident collection used to measure the effectiveness of PSM program in this study.

OVERVIEW SURFACE FACILITY OPERATION AND ITS ASSOCIATED HAZARDS

The surface facility operation is very important in the oil and gas industry. It is responsible to process and treat the product from well specification to commercial specification. Simplified diagram of the surface facility process can be seen in Figure – 2.

The first process carried out is the separation of gas from liquid and the separation of water from oil using separator. The separator is a fixed pressure tank that is used to separate the streamflow from the well into gas, oil, and water-based on the density of each substance. There are 3 types of separators used in general at surface facilities, namely High Pressure (HP) Separator, Intermediate Pressure (IP) Separator, and Low Pressure (LP) Separator. The streamflow from the well will first enter the HP Separator and then be separated into gas and liquid phase. The gas which has a low density will flow into the top to flow as the sales product and the liquid which has a heavier density will go down to the bottom of the vessel and enter the next process at the IP Separator. In this equipment, further separation between gas and liquid phase is also carried out. The gaseous phase will come out to the top towards the compressor to increase its pressure to the sales product pressure. The liquid will come out through the bottom of the vessel to the LP Separator. This LP Separator is used to separate 3 phases, so this separator is commonly called a 3 phase Separator. The LP Separator is separated into 3 phases, namely oil, water, and gas. The gas will exit through the top and enter the compressor to increase the pressure so that it meets the sales product pressure. Liquid phase consisting of oil and water will be separated in the LP Separator equipment. Because the separation of oil and water may not be perfect, then the oil produced from the LP Separator will enter the Oil Treating process. In this process, heating is carried out to reduce the viscosity of the oil so that there is an evaporation of water in the oil. Meanwhile, the water which is separated from the oil will enter the Water Treating process. In this process, the oil still contained in the water is separated. The oil must be separated from the oil at a certain level before it can finally be discharged. From the surface facility description, there are many potential hazards. Referring to API RP 14J, the hazards can be summarized in the Hazard Tree shown in Figure 3.

DATA AND METHOD

In this study, 2 types of data were used to evaluate the PSM program used by the exploration and production (E&P) companies, namely incident data as an indicator of the success of the PSM program and data on the PSM program run by each company. Data on incidents that occurred in oil and gas companies in Indonesia were obtained from the media in the form of news from the last 10 years. Data on the PSM program run by each company was obtained from various kinds of literature such as the company's official website and journals.

RESULT AND DISCUSSION

The research was conducted by collecting data in the form of incidents that have occurred based on the potential hazards in the production facilities that have been described previously. The study involved the analysis of each company's method of managing process safety in the facility and clustering to each of the 20 elements and 4 pillars of RBPS process safety management. Some of the companies have multiple items that can be categorized in the same pillar, while at the same time do not have any items to support the other pillars. A total of 5 companies were selected for this study, and the number of publicly covered accidents in the last 10 years were documented to investigate the relationship -if any- between the number of accidents and the elements supported in the process safety management system.

The comparative framework used within this study uses 20 elements and 4 pillars of RBPS PSM.

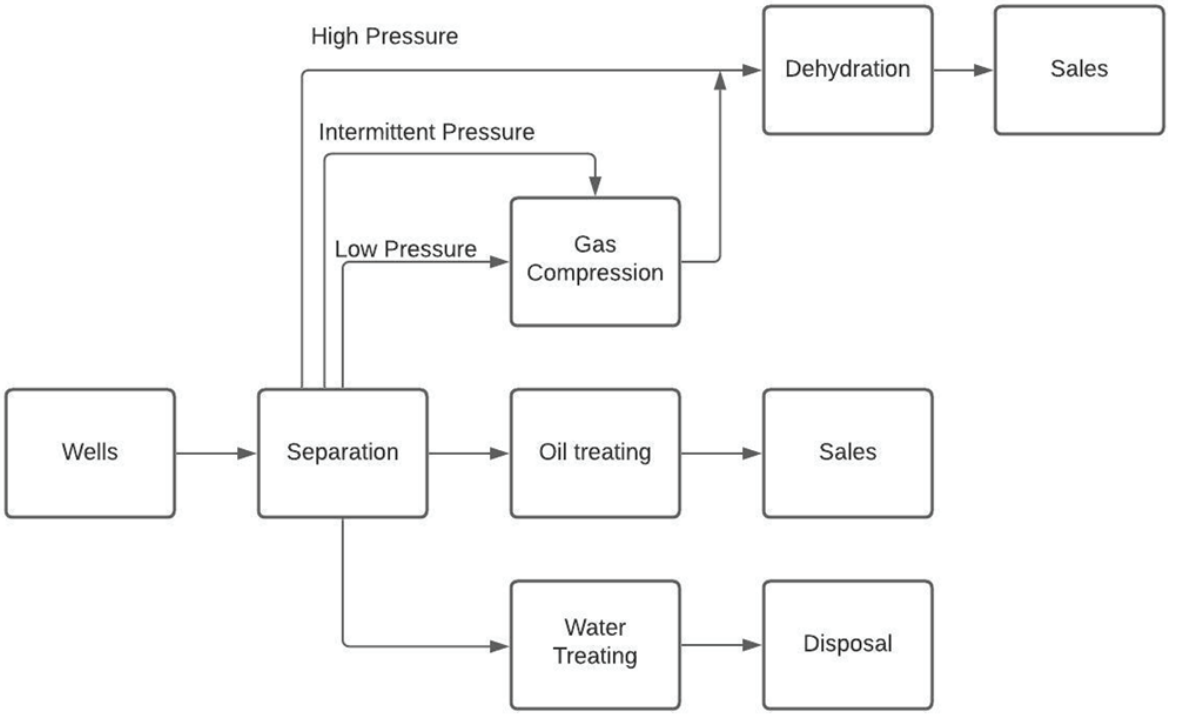


Figure 2: *Block Flow Diagram Surface Facility Operation*

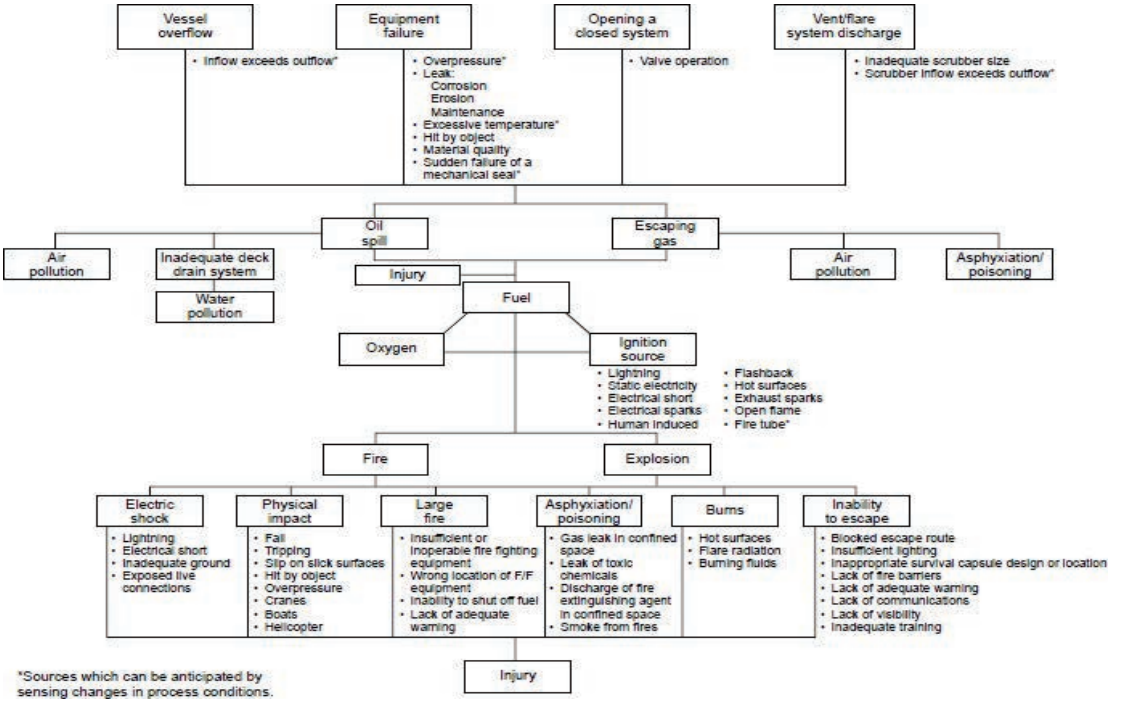


Figure 2: *Hazard Tree Surface Facility Operation*

- Under the Commit to Process Safety: Process Safety Culture, Compliance with Standards, Process Safety Competency, Workforce Involvement, and Stakeholder Outreach.
- Under the Understand Hazards and Risk: Process Knowledge Management and Hazard Identification and Risk Analysis.
- Under Manage Risk: Operating Procedures, Safe Work Practices, Asset Integrity and Reliability, Training and Performance, Management of Change, Operational Readiness, and Emergency Management.

Under Learn from Experience: Incident Investigation, Measurement and Metrics, Auditing, and Management Review and Continuous Improvement.

Accident data used for this study were sourced from public news coverage and excluding close calls/near-misses or tier 3 events. There is no other information regarding accidents that are not publicized and close call reports from any employees of the selected companies. All of the authors of this study are independent and impartial, which does not give any advantage or disadvantage to any of the companies assessed. The accident covered in this study is limited to the last 10 years to filter out the possibility of obsolete data as the result of the out-of-date process safety management system employed by the companies prior to the newest.

Table 2 reveals the PSM program E&P companies in Indonesia. Categorized by the four pillars of 20 elements of RBPS process safety management, it appears that all companies have at least one of the elements for each pillars of process safety management. With exception to Pertamina Hulu Energi who does not have its own Engineering Standards yet.

Based on the count of publicly released incident data visualized in Figure 4, Shell Indonesia leads with 0 public incident. Shell's success is mainly caused by its strong process safety culture reflected by its robust process safety fundamentals and its strong commitment to safety through its Get Zero principles and Safety Culture Awareness program. From fundamental design standpoint, Shell Engineering Standards, the DEP provides detail and clear guidance on good engineering practices to design and construct a safe facility. However, this does not mean other E&P companies in scope of the study lacks strong process safety culture and commitment. Other companies in scope also have strong PSM programs. However, the implementation may need to be improved, especially in the process safety culture awareness section. This can be done by having a strong, fit

RISK AND HAZARD POTENTIAL	POSSIBLE CAUSE
Fire and Explosions	Presence of highly combustible hydrocarbons from loss of containment, oxygen and igniter
Exposure to Harsh Chemicals	Chemicals used in daily operations tend to be hazardous. Long-term exposure to hazardous and volatile chemicals and gases can cause respiratory and mental health issues in employees. In fact, chronic exposure to a common molecule known as hydrogen sulphide has been linked to leukaemia, paralysis, and even death.
Electrical and Other Hazardous Energy	If equipment is not designed, installed, and maintained appropriately, workers may be exposed to uncontrolled electrical, mechanical, hydraulic,or other sources of dangerous energy.
High Pressure Lines and Equipment	Workers may be exposed to compressed gases or high-pressure lines, which pose a risk. Internal line degradation could cause leaks or line bursts, exposing employees to high-pressure threats posed by compressed gases or high-pressure lines. Struck-by risks could be created if connections securing high-pressure lines fail.

Table 1: *Risk and Hazard Potential for Production Facility (Insurance, 2021; Safety and Health Management System in Oil and Gas Industry, 2021; Safety Hazards Associated with Oil and Gas Extraction Activities, 2021; Suda et al., 2015)*

PSM Pillar Aspects (CCPS RBPSBased)		PSM Program at E&P Companies in Indonesia			
		Pertamina Hulu Energi	Conoco Phillips	Chevron	Shell
Commit to Process Safety	Process Safety Culture	SUPREME	SPIRIT	Operational Excellence	Safety Culture Awareness
	Compliance with Standards	-	COPSAS	Chevron Engineering Standards (CES)	Shell Design & Engineering Practices (DEP)
	Process Safety Competency	KOMET	COPI ProcessSafety Fundamental	Process Safety Organizational Capability	Shell Process Safety Fundamental
	Workforce Involvement	Process Safety Campaign	Process Safety Campaign	Process Safety Campaign	Process Safety Campaign
	Stakeholder Outreach	Community Outreach	Community Outreach	Community Awareness & Outreach	Community Outreach
Understand Hazards and Risk	Process Knowledge Management	Process Safety Information	Process Safety Information	Process Safety Information	Process Safety Information
	Hazard Identification and Risk Analysis	Risk Identification (HAZOP/HAZID / QRA)	Risk Assessment	Process Hazard Analysis	Hazard Identification and Risk Analysis
Manage Risk	Operating Procedure	Standard Operating Procedure	Operating Proce ures	Operating Procedure and Standard Operating Procedure	Operating Procedures
	Safe Work Practices	Corporate Life Saving Rules	Life Saving Rules	Managing Safe Work	Safe Work Process
	Asset Integrity and Reliability	Process Safety & Asset Integrity Management System	Asset and Operating Integrity	Surface Equipment Reliability & Asset Integrity Practices	Asset Integrity &Process Safety Management
	Training and Performance	Training	Training	Training	Training
	Management of Change	Management of Change	Management of Change	Management of Change	Management ofChange
	Operational Readiness	Pre Start-Up Safety Review	Pre Start-Up Safety Review	Pre Start-Up Safety Review	Pre Start-Up Safety Review
	Emergency Management	Emergency Planning andR sponse	Emergency Preparedness	Emergency Management	Emergency Management
Learn from Experience	Incident Investigation	Accident/Incident Investigation	Incident Reporting andInvestigation	Incident Investigation	Incident Investigation
	Measurement and Metrics	Performance Measurement	Process Safety Leading & Lagging Indicators	PSM Visible Scorecards	Performance Monitoring &Reporting
	Auditing	SUPREME Audit	HSEMS Audits	OEMS Audit	SEMS Element Audit
	Management Review and Continuous Improvement	Management Walkthrough	Process SafetyBoards	PSM Leadership Engagement	Leadership F2F Engagement

for operations process safety fundamentals that is routinely communicated and campaigned topped with strong focus in continuously improving process safety competencies at every level in the organization. Building a strong process safety culture is a long game, therefore the earlier the process starts the better.

CONCLUSIONS

A major inference from this study is no one-size-fits-all approach to process safety management. Companies should be thorough when deciding the right system that will be the most suited to the scope of their operations. There is a relation

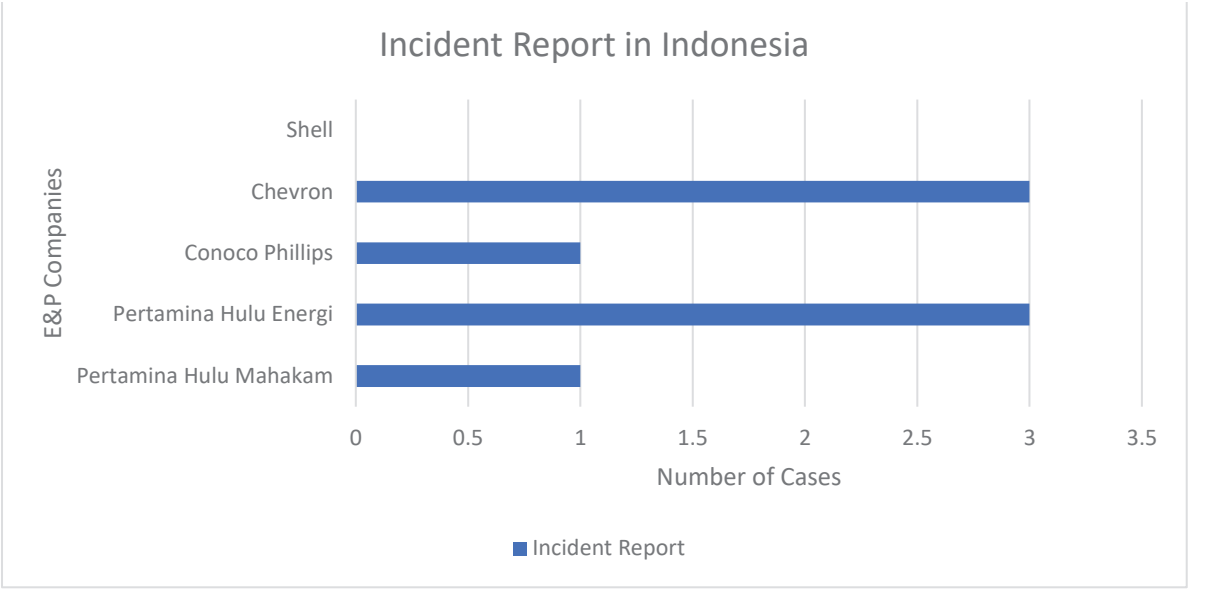


Figure 4: *Incident report from several E&P Companies in Indonesia*

between more pillars covered and lack of accidents, however, every company should thrive to have all pillars in an RBPS process safety management system to maximize the managed area covered by the system.

This study has limitations, namely, the accidents included in the study are public -and by the result, major- accidents. This results in some blind spots for minor reported accidents that do not get coverage by media and close calls which are not reported as accidents but may be beneficial to indicate the weakness in the process safety management in the respective company. Another area to be improved is testimonials from companies studied that can provide insights that are not represented by the number of accidents, namely: the efficiency of the system, the responsiveness of the system, and the process shutdown caused by false trip that is detected.

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A POTENTIAL PLANT OPTIMIZATION CASE STUDY: THE USE OF EXTRACTIVE HEATING THERMAL OXIDIZERS IN GAS PROCESSING PLANTS FOR OPERATIONAL SAFETY IMPROVEMENT AND ENERGY CONSERVATION

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ABSTRACT

The conservation of energy through the utilization of Waste Heat Recovery Units (WHRUs) in Gas Processing Plants (GPPs) presents both a challenge and an opportunity for enhancing efficiency and reducing costs in Field Operations. This activity falls under the category of plant optimization and involves the identification, capture, and transfer of excess energy to selected equipment, resulting in effective energy usage in the production process.

Thermal Oxidizers (TOx) in GPPs are a prime example of equipment that generates excess energy in the form of heat. TOx is used to maintain the quality of gas released to comply with the regulations set forth by the State Minister of Environment. In this process, acid gas is purified through thermal oxidation, which is maintained at a specific time and high temperature under an oxygen-rich environment to ensure optimal oxidation efficiency and prevent the release of harmful gases into the environment. The excess heat generated from this process can be efficiently utilized to heat Hot Oil using WHRUs.

This paper outlines an iterative process of a plant optimization case study. It involves the identification of the source of excess heat, selection of appropriate technology to capture the heat, and improvement of the configuration of TOx and WHRUs to ensure safe operation and cost reduction.

Keywords: Energy conservation, Waste Heat Recovery Units (WHRUs), Gas Processing Plants (GPP), Thermal Oxidizers (TOx), Plant Optimization.

1. INTRODUCTION

The need for stricter environmental regulations in Gas Processing Plants (GPPs) is on the rise. The public is increasingly aware of the detrimental effects of harmful gas emissions on the environment. Therefore, GPP owners must continuously adapt to the evolving environmental regulations set by the government. To comply with emission regulations, Thermal Oxidizers (TOx) are being utilized in various ways.

In a typical gas processing plant, a Gas Separation Unit is present to separate gas from other liquids such as free water or condensate. The water and condensate undergo further processing where water is transported to the produced water system for impurity removal before injection into the injection well. Condensate, on the other hand, is transported to the condensate tank or another containment unit. Based on its composition, gas streams can be classified as either sweet or sour gas. Sweet gas contains fewer impurities and can be sold as is, while sour gas has impurities such as acid gas in the form of H2S or CO2, which must be removed to provide a clean/sweet gas to customers.

The Acid Gas Removal Unit (AGRU) in Gas Processing Plants (GPPs) typically uses chemical solvents to absorb acid gas from the gas stream. These solvents must then be regenerated to recycle them back into the AGRU stream and absorb another stream of acid gas. Regenerating the solvents requires a high temperature medium to heat the solvent and release the absorbed acid gas.

Another essential process is dehydration, which removes dissolved water from the gas stream. The water content of sales gas is typically around 10 lb/mmscf, but some buyers may require lower than that to prevent issues during transportation and processing such as gas hydrate formation, ice formation, and increased corrosion potential.

After capturing the acid gas, it must be purified, usually through a sulfur recovery unit. In this case study, a Biological Sulfur Recovery Unit (BSRU) was utilized, although chemical or physical Sulfur Recovery Units are also available. The sulfur is then oxidized in thermal oxidizers. In Gas Processing Plants equipped with incinerators or thermal oxidizers, excess heat is typically generated due to the high-temperature combustion required to fully oxidize the sulfur into SOx. This situation provides an opportunity for plant operators to harness the energy and utilize it for solvent regeneration.

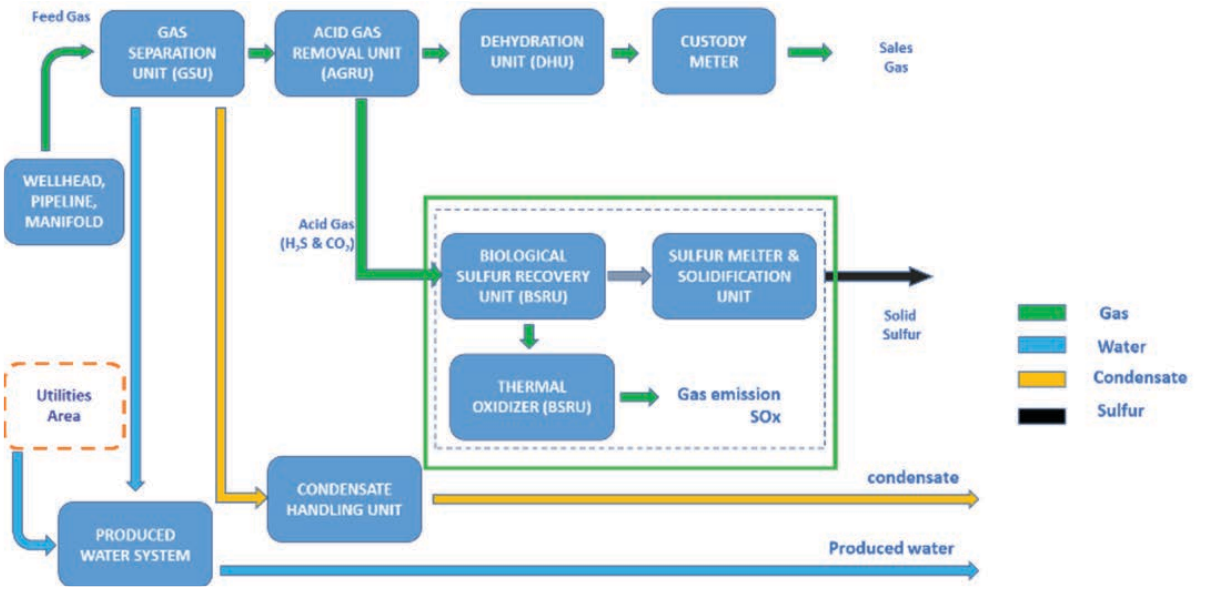


Figure 1. *Typical Gas Processing Plant Process Block Diagram*

The solvent regeneration process involves delivering heated Hot Oil into the regenerative system. To achieve this condition, GPPs may introduce a heat recovery system in the TOx system to satisfy the heat requirements for solvent regeneration while also reducing overall operating costs by using excess heat from TOx instead of Hot Oil Heater generated by diesel or fuel gas.

2. DEFINITION AND METHOD

2.1. Thermal Oxidizers (TOx)

Thermal oxidizers are an essential component in the oil and gas industry for controlling air emissions, particularly volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) generated during various industrial processes. They are pollution control systems that use high temperatures to break down and eliminate harmful air pollutants by oxidizing them into carbon dioxide and water vapor.

Thermal oxidizers work by creating a high-temperature environment within a combustion chamber, where the pollutants are exposed to temperatures between 800 and 1,200 degrees Celsius. The high temperature causes the pollutants to undergo thermal oxidation, which is the process of breaking down the pollutants into simpler, less harmful substances.

There are different types of thermal oxidizers used in the oil and gas industry, including regenerative thermal oxidizers (RTOs), catalytic thermal oxidizers (CTOs), and thermal recuperative oxidizers. RTOs use a bed of ceramic media to absorb and release heat between two chambers, while CTOs use catalysts to lower the temperature required for oxidation to occur. Thermal recuperative oxidizers use a heat exchanger to transfer heat from the exhaust stream to the incoming air or fuel, reducing the energy required to maintain the high temperature needed for thermal oxidation.

Thermal oxidizers are crucial for maintaining compliance with air pollution regulations in the oil and gas industry. They help to protect the environment and public health by removing harmful air pollutants before they can be released into the atmosphere.

2.2. Waste Heat Recovery Units (WHRUs)

In the oil and gas industry, waste heat recovery units (WHRUs) are devices used to capture and reuse the heat generated during various industrial processes, such as oil refining, gas processing, and power generation. The heat that is produced during these processes is typically considered waste and is often vented to the atmosphere or discharged into the environment. However, WHRUs allow for the recovery of this waste heat and its conversion into useful energy that can be utilized for heating or power generation, reducing overall energy consumption and costs.

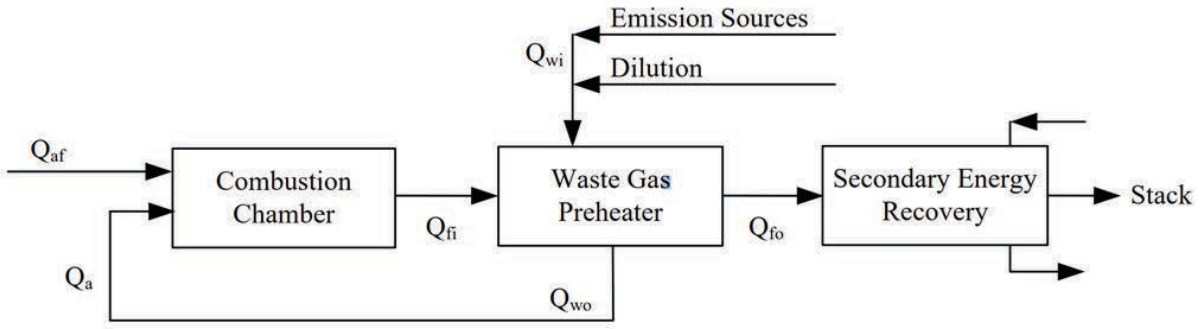


Figure 2. *Thermal Oxidizers General Case*

WHRUs can be designed and integrated into a variety of industrial systems, including thermal oxidizers, boilers, and gas turbines, to name a few. The recovered heat can be used to generate steam or hot water for use in other industrial processes, as well as for heating buildings or powering generators. WHRUs typically consist of a heat exchanger, which extracts the waste heat from the exhaust stream of a process, and a power generation system, which converts the captured heat into useful energy.

Overall, waste heat recovery units are an important component of many industrial processes in the oil and gas industry, helping to reduce energy consumption, improve efficiency, and lower operating costs.

In this paper, a Shell and Tube Heat Exchanger (STHE) act as WHRU to harness excess heat and transfer it to hot oil. STHE provides an effective solution for transferring heat between the hot flue gas and the Hot Oil stream. In this process, the hot gas passes through the shell while the Hot Oil is circulated within the tube, creating an indirect contact that heats the Hot Oil to the desired temperature. This enables the Hot Oil to be used effectively for regenerating the solvent in the AGRU.

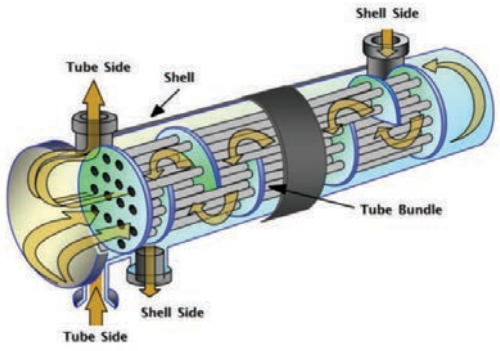


Figure 3. *Typical Shell and Tube Heat Exchanger Configuration*

2.3. Plant Optimization Step

Plant optimization in the oil and gas industry involves several steps to increase efficiency and reduce operating costs. One critical aspect of plant optimization is managing excess energy, which refers to energy produced by the plant that is not being utilized in the production process.

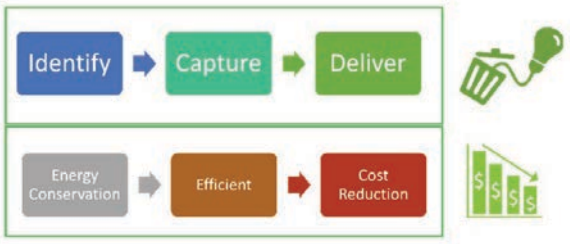


Figure 4. *Typical Plant Optimization Step*

Below are detailed steps recommended to assess the potential of excess energy utilization.

1. Conduct an energy audit: This involves identifying areas in the plant where energy is being wasted or not being utilized effectively. An energy audit may involve analyzing energy usage data, reviewing plant processes, and assessing equipment performance.
2. Implement energy-efficient technologies: Once areas of energy waste have been identified, energy-efficient technologies can be implemented to reduce energy consumption. This may include upgrading equipment, installing variable speed drives, and implementing process improvements.
3. Recycle waste heat: Excess energy can be used to generate additional steam or hot water through waste heat recovery systems. This can then be used in other parts of the plant, such as heating or cooling processes, or to generate electricity.
4. Optimize process control: Process control can be optimized to ensure that equipment is operating efficiently, and that energy is being used effectively. This may involve implementing advanced control systems, monitoring equipment performance, and adjusting process parameters.

5. Monitor and analyze energy usage: Regular monitoring and analysis of energy usage can help identify areas for improvement and track progress over time. This may involve implementing an energy management system, setting energy performance indicators, and regularly reviewing energy usage data.

By implementing these steps, plant operators can optimize excess energy in the oil and gas industry, reduce energy consumption, and improve operating efficiency.

In this paper, the author highlights the identification of excess heat generated in the combustion chamber of thermal oxidizers as a potential source of excess energy. To efficiently harness this energy, a heat exchanger technology is utilized to transfer the excess heat as a heating medium to heat hot oil circulation in the plant process. AGRU in a GPP utilized hot oil for solvent regeneration is a widespread practice in GPP. GPPs that have an excess of fuel gas can utilize a fired heater to heat the Hot Oil. However, if fuel gas is limited, a Waste Heat Recovery Unit (WHRU) can be installed in the TOx to minimize fuel gas costs.

The primary purpose of a Thermal Oxidizer Package equipped with a Waste Heat Recovery Unit (WHRU) is twofold. Firstly, it aims to oxidize acid gas and harmful hydrocarbons to produce safer flue gas. Secondly, it provides a heating medium for hot oil that can be utilized for process purposes.

The usual setup of a TOx and WHRU is direct heating or straight-through. In this configuration, all the flue gas generated by the TOx will pass through the WHRU since it is located in a straight line to the outlet stack.

The vertical arrangement of Radiant section, convective section, and stack is utilized in this design. WHRU is installed at the top of the convective section. Depending on the space available inside the GPP, the configuration can also be arranged horizontally.

The acid gas from the process area will enter the TOx package from the bottom of the stack (burner) along with the fuel gas from the other direction. Air intake fan feeds air from the environment to the burner. In the bottom of the TOx, these three gases (acid gas, fuel, and air) will be mixed. The burner will then burn the mixture of these gases at a high temperature, preferably above 800 degrees Celcius to ensure that all harmful gases (H2S and hydrocarbon) are burned and perfectly oxidized.

The heat energy from the combustion will be absorbed by WHRU to heat the hot oil as the hot gas rises. Due to the heat exchange phenomenon, this hot gas will have a lower temperature and will be discharged to the environment as flue gas that has already fulfilled the government's environmental requirements.

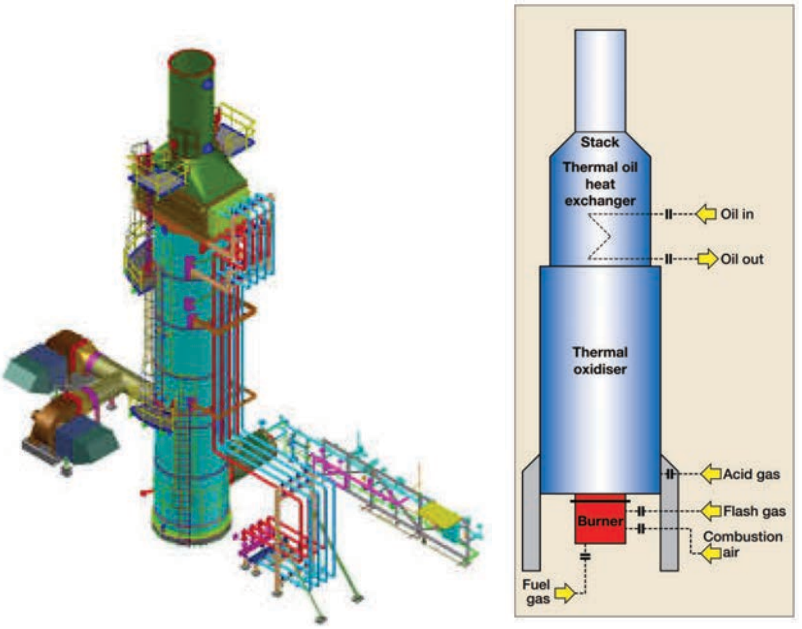


Figure 5. *Straight Through Configuration Thermal Oxidizers*

At this point, we have satisfied the plant optimization step, but can we improve it further? Looking at the straight-through design, a potential risk arises. What if the tube inside the heat exchanger leaks, ruptures or breaks? Direct contact of the hot gas with the hot oil will raise the temperature and, at some point, will reach the hot oil flash point, creating a chain reaction of explosion and damaging the property as well as putting the operators at risk. To minimize this risk, plant optimization engineers need to find another configuration to harness the heat.

To minimize potential risks and improve plant optimization, an extractive design can be used to harness the heat. This design utilizes a coil placed outside of the main flue gas path. An induced draft fan pulls the flue gas, which is then used to heat the Hot Oil at a lower level. This configuration not only provides easier maintenance, but also ensures safer operability.

The benefits of using this configuration include the ability to operate at different temperatures without affecting the performance of the oil system, having a predictable and well-defined operation range, and being able to continue operating even when the hot oil is out of service. However, it is important to note that there is an added capital cost associated with this configuration, which includes ducting, fans, and flue gas control.

3. RESULT AND DISCUSSION

The optimization of plant operations presents a challenging endeavor, as it necessitates a delicate balance between the desired outcomes and associated costs. Specifically, in this scenario, the desired outcome is to comply with governmental regulations regarding gas emissions, which requires the development of equipment capable of harnessing and utilizing excess heat. Further, it is necessary to enhance plant safety protocols without undermining the goal of cost reduction in production. An iterative process of equipment design could improve the plant operational safety and energy conservation. In the future, the author hopes there will be more studies in Thermal Oxidizers configurations that can satisfy both safety improvement and cost reduction.

4. CONCLUSION

The potential for Waste Heat to be utilized for various applications is considerable, and this form of Energy conservation can contribute to enhanced plant operation safety and reduced costs. However, the choice of Heat utilization strategy requires careful consideration of numerous factors. For example, Direct Heating or Straight Through Thermal Oxidizer designs are known to offer smaller footprints and lower capital costs,

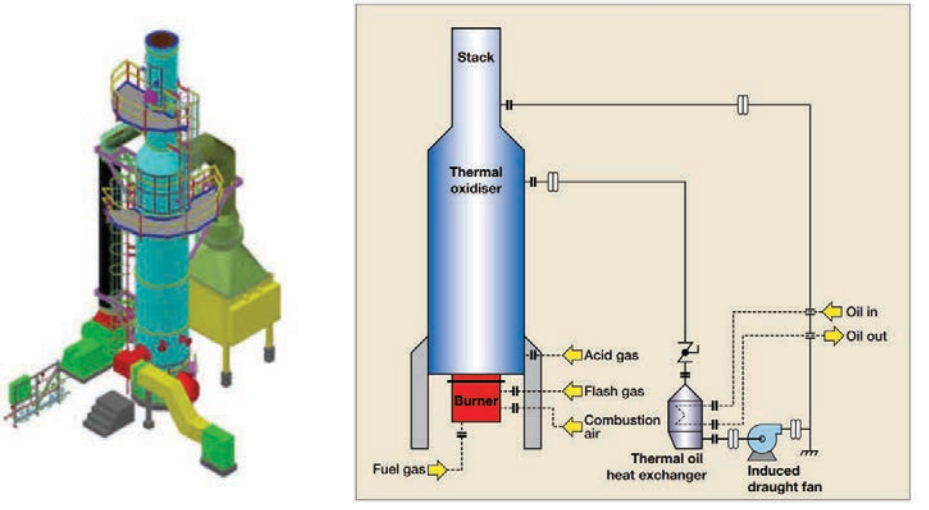


Figure 6. *Extractive Heating Configuration Thermal Oxidizers*

but the associated Waste Heat Recovery Units (WHRUs) may be at risk of damage, leading to plant shutdown. In contrast, Extractive Heating Thermal Oxidizers provide greater flexibility in operation and improved safety, but entail additional capital costs, such as those related to ducting, fans, and flue gas control. Hence, an iterative process is essential to refine plant optimization strategies, and further research is necessary to identify alternative sources of excess energy that can be leveraged to optimize production costs.

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INNOVATIVE REVERSE ENGINEERING APPROACH IN THE DESIGN AND CONSTRUCTION OF A NEW GAS PROCESSING FACILITY IN BROWN FIELD BLOCK.
CASE STUDY: FIELD X ASSOCIATED GAS RECOVERY PROJECT

Ir. Muhammad Riandhy Anindika Yudhy, ST, MEng, IPM, ACPE

ABSTRACT

Project management success boils down to successfully and efficiently managing resources in order to achieve the project's cost and timeline. The capacity to properly manage projects becomes increasingly critical as Production Sharing Contracts (PSC) blocks expire. The longer it takes to execute a project, the greater the project capital and the lower the capital recovery. According to the results of various big capital facility projects, the fundamental problem in meeting project costs and schedules is the procurement of long lead materials and essential process equipment. There is a chance to undertake reverse engineering in brownfield blocks by optimally utilizing extra materials in the warehouse and idle/unused process equipment to tackle the primary challenges. As an added bonus, reusing excess materials and idle process equipment will enhance inventory management and capital stewardship because the cost of relocating and modifying the equipment is substantially lower than the cost of purchasing new equipment.

The Field X Associated Gas Recovery Project (AGRP) served as an excellent case study of a successful reverse engineering method in the design and building of a new gas processing facility in a brownfield block. Field X AGRP is designed to recover and process associated gas from the X field for use as fuel gas in the internal Power Generation Plant's gas turbines. However, based on prior experience, the cost of building and installing a new gas processing facility utilizing new construction materials and process equipment is prohibitively expensive in the current oil price scenario. As a result, in order to make the project financially viable, the project team must design the use of available excess material in the warehouse and idle/unused equipment. The project team evaluated many facilities around the concession area in order to collect equipment specification data for idle process equipment and the size of accessible excess materials. The design of the gas processing facility was reverse-engineered in order to make the best use of idle process equipment and extra resources.

The use of idle equipment and excess material in the construction of the gas processing facility resulted in cost savings of up to five times the project cost by eliminating the procurement of new equipment and construction materials. The project successfully recovered associated gas at a rate of 0.5 MMSCFD for use as fuel for the gas turbine, and the gas-liquid separation process generated 60 BOPD condensates.

BACKGROUND

Field X has been producing associated gas at a rate of up to 1.2 MMSCFD, with a heating value of approximately 720 BTU/scf. (refer to Table 1 for the detailed gas properties). However, the gas was constantly flared before the project was completed. With the internal power generator capable of processing the associated gas with a minimum of 700 BTU/scf as fuel, there was an opportunity to recover the associated gas and use it as fuel for the power generator.

Table 1 *– Field X Gas Properties*

Variable	Unit	Field X Associated Gas
Vapor Fraction		0.981542
Temperature	F	150
Pressure	psig	5
Molar Flow	MMSCFD	1.2
Mass Flow	lb/day	101689
Std Ideal Liq Vol Flow	barrel/day	474
Lower Heating Value	Btu/SCF	720.80

Because Field X lacked a gas processing plant to extract the associated gas, a new gas processing facility must be built to fully capitalize on the opportunity. However, the opportunity was recognized in late 2016, when the oil price was low (50 USD/barrels) and the window for gaining a return on investment was short because the concession region will be returned to the states in less than 5 years. To guarantee that the decision to invest in building a new facility was justified, a detailed economic study must be conducted. In the economic study, the variables to be compared were the cost and schedule of constructing the facility using all new materials, the cost and schedule of constructing the facility using available excess materials and existing spare/unused equipment from inactive facilities, and the operating cost savings from using the associated gas for power generator fuel. According to the study, the cost of establishing the gas processing facility using entirely new materials will be 5 times more than using excess resources, and it will take 700 days longer due to the extra contracting and procurement process for the same operating cost savings. As a result, the most cost-effective option was to build the facility with accessible extra materials and existing spare/unused equipment from inactive operations.



Figure 1 *Project Cost Comparison*

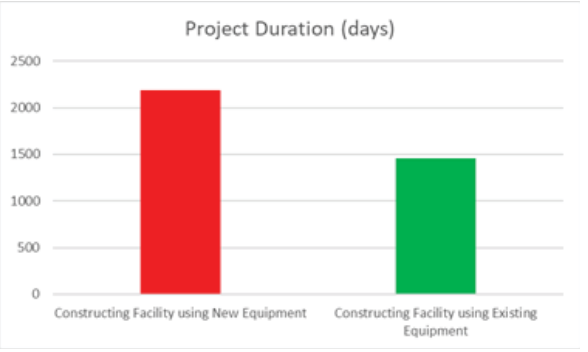


Figure 2 *Project Schedule*

Using existing materials and equipment to construct a facility posed 3 unique technical challenges that the Project team must be able to solve:

1. The first and most important challenge was the available excess materials or spare equipment size might not match the required equipment size from engineering calculation.
2. The second challenge was the existing equipment condition that might not be at its prime to be used for the facility since it was inactive for a long time with minimal maintenance.

3. The last challenge was equipment relocation from the individual equipment location that was scattered all over the concession area to Field X. The concession area was ~150 km^2 in a very wide area. The longest distance for equipment relocation travel was more than 100 km.

The creative solutions brought up by the Project team to solve these technical challenges will be discussed further in this paper.

REVERSE ENGINEERING

To address the issue of equipment and material size, the first step was to create a Front-End Engineering Design (FEED) of the facility using new equipment as the baseline. Assuming new equipment will ensure that the FEED's primary goal of maximizing dry gas and condensate output from processing feed-associated gas is met. In developing the FEED, 3 proprietary simulation software were used:

- A proprietary pipe network simulation software was used to determine the pressure dynamics in the gas pipeline network. The result of the simulation will set the target for the minimum discharge pressure of the gas processing facility to be able to flow to the power generation facility.
- A proprietary process simulation software was used to generate FEED details, such as equipment size and the optimal operating range for the process variables.
- A proprietary gas compressor simulation software was used to design the optimum configuration of the gas compressor.

Based on the simulation, the best design for the baseline was a three-stage compression process with two stages of separation and cooling for the gas before entering the gas compressor, two stages of separation for the liquid phase, and throttling for Joule - Thompson cooling at the gas compressor's outlet to extract the remaining liquid in the gas before shipping to the power generation facility. Figures 3 and 4 depict the resulting basic design for the gas plant facility and the gas compressor.

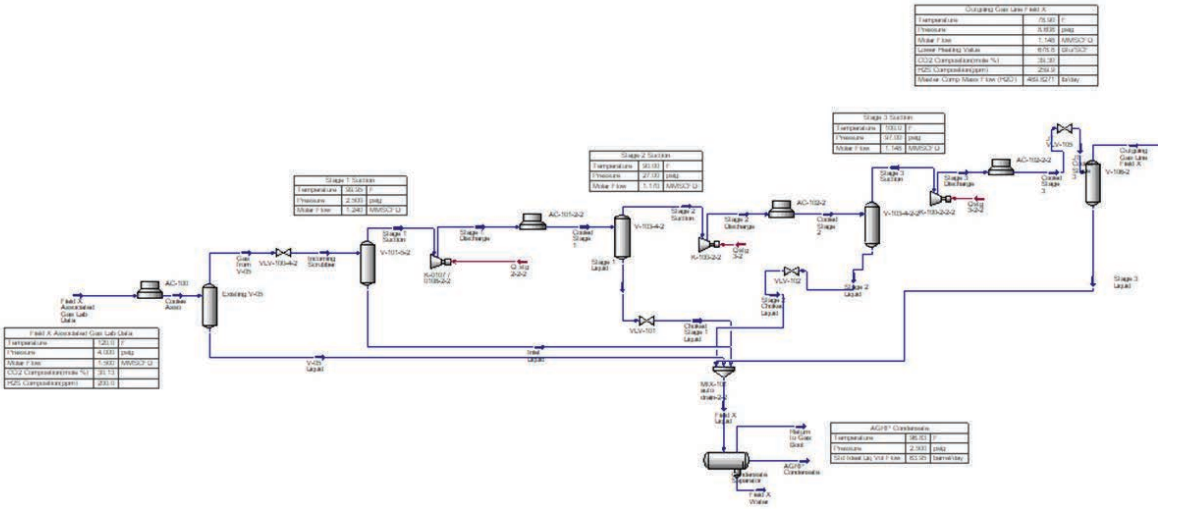
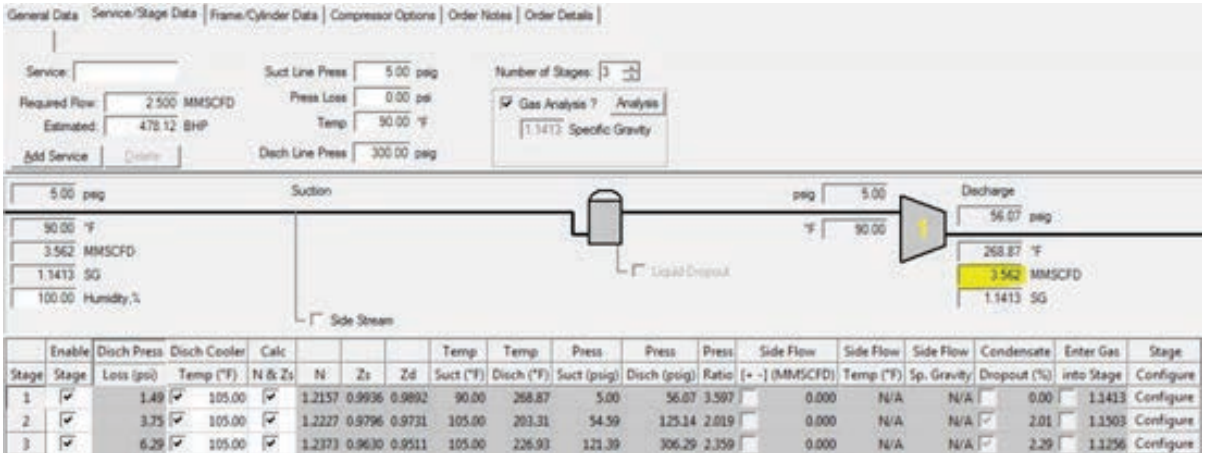


Figure 3 *Process Simulation Design for FEED*



Stage	Enable Stage	Disch Press Loss (psi)	Disch Cooler Temp (°F)		Calc N & Zs	N	Zs	Zd	Temp Suct (°F)	Temp Disch (°F)	Press Suct (psig)	Press Disch (psig)	Press Ratio	Side Flow [+ -] (MMSCFD)	Side Flow Temp (°F)	Side Flow Sp. Gravity	Condensate Dropout (%)		Enter Gas into Stage	Stage Configure
1	☑	1.49	☑	105.00	☑	1.2157	0.9936	0.9892	90.00	268.87	5.00	56.07	3.597	☐ 0.000	N/A	N/A	☐	0.00	☐	1.1413 Configure
2	☑	3.75	☑	105.00	☑	1.2227	0.9796	0.9731	105.00	203.31	54.59	125.14	2.019	☐ 0.000	N/A	N/A	☑	2.01	☐	1.1503 Configure
3	☑	6.29	☑	105.00	☑	1.2373	0.9630	0.9511	105.00	226.93	121.39	306.29	2.359	☐ 0.000	N/A	N/A	☑	2.29	☐	1.1256 Configure

Figure 4 *Compressor Simulation Design for FEED*

Following the development of the baseline, the Project team re-simulated the process by altering the size of the major equipment and pipelines to the available stock sizes and comparing the simulation result to the baseline result. As an example, the available materials and equipment included a 2-stage gas compressor skid with coolers, 2 fin-fan coolers, 2 positive displacement pumps, many 2' diameter vessels, and couplings of 4", 6", and 8" pipes. Multiple material combination situations were simulated. Surprisingly, the simulated scenario with available materials produced the same production profile as the baseline case, indicating that the available materials and equipment were sufficient for the facility's construction. Additional inspections were performed to ensure that the gas compressors, pipework and pipelines, mechanical and structural construction met appropriate engineering standards. Some of the industry engineering standards utilized to determine the FEED's suitability were as follows::

- API 618 Reciprocating Compressors for Petroleum, Chemical, and Gas Industry Services
- API RP 14E Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems
- API RP 686 Machinery Installation and Installation Design
- API Spec 6D Specification for Pipeline and Piping Valves
- API RP 520 Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries
- API RP 1110 Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide
- API RP 500 Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1, and Division 2
- PIP PNC00003 Process Unit and Offsite Layout Guide
- ASME B31.1 Power Piping
- ASME B31.3 Process Piping
- ASME B31.4 Pipeline Transportation Systems for Liquids and Slurries
- ASME B31.8 Gas Transmission and Distribution Piping Systems
- ASME Section VIII, Division 1, Rules for Construction of Pressure Vessels
- NACE MR0175 Petroleum and Natural Gas Industries—Materials for Use in H_2S-Containing Environments in Oil and Gas Production
- AISC 325 Steel Construction Manual
- AISC 326 Detailing for Steel Construction

The gas compressor was a more fascinating case of re-engineering. The available gas compressor was a two-stage gas compressor with a cooler positioned on the skid. To achieve the highest possible output from the feed-associated gas, the facility's gas compressor must be a three-stage gas compressor. The reason for this was that the pressure ratio of the feed-associated gas to the target discharge pressure required to transport the gas to the production header exceeded the maximum pressure ratio authorized by the gas compressor. If this was permitted, the discharge temperature would climb over the temperature limit that the compressor materials could bear, resulting in material failure and serious damage to the gas compressor. As a result, the available gas compressor must be upgraded to accept an additional stage in order to avoid such damage to the gas compressor and recover the optimal gas production.

To establish the necessary modification for the gas compressor, the Project team conducted a complete engineering analysis. According to the findings of the study, the cylinder bores of Throw 1 and Throw 3 of the gas compressor should be changed from 13" to 19.5", while the cylinder bore of Throw 2 should be changed from 9.25" to 13". The changes were based on a three-stage compressor design that was modeled using proprietary gas compressor simulation software and approved by the gas compressor manufacturer's lead engineer for additional technical design assurance. Figure 5 depicted the changes in the cylinder. The dimensions of the suction and discharge bottles from each stage must be changed in order to use the four throws of a three-stage compressor. The increased bottle size was determined using proprietary gas compressor simulation software and the simulation result for a three-stage compressor. Figure 6 depicts the variations in bottle size dimensions. A third-party contractor did manual field verification to guarantee that the bottles could survive the pulsation induced by the compressor and to validate the simulation results. Figure 7 depicts a summary of the results of the verification. The calculated bottle size dimension was confirmed to be able to endure the pulsation from gas compressor operation because the measured vibration was below the API limit. Additional manual calculations were undertaken to ensure that the existing pressure vessels in the compressor skid could accommodate the condensate generated during compression. The calculated result was then compared to the predicted liquid dropout at each stage of the simulation, as shown in Table 2. According to the calculations, the holding capacity was significantly more than the projected liquid drop.

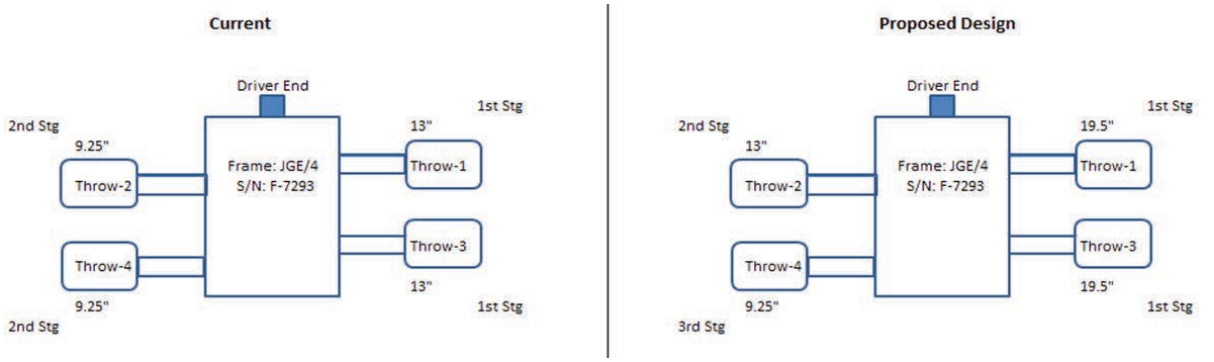


Figure 5 *Gas Compressor Cylinder Modification*

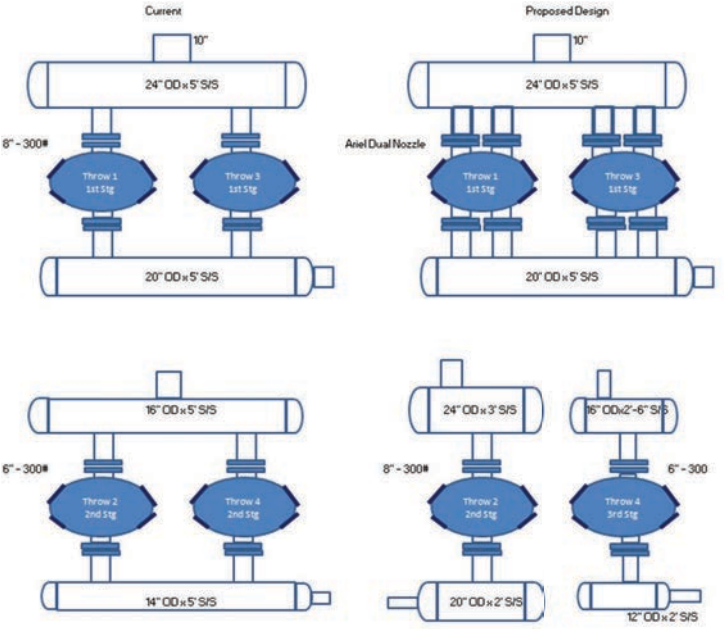


Figure 6 *Gas Compressor Bottle Modification*

Within the table highest values over the driving speed range will be shown.

Definition:
LC-S/D ... line connection flange suction/discharge side
CC-S/D ... cylinder connection flange suction/discharge side

Location		Basic design	Mod 1 to API limit	Mod 2 empty dampers	Basic design	Mod 1 to API limit	Mod 2 empty dampers
		pk -pk [%]			comparison with API [%]		
1st stage	LC-S	1.6	1.6	-	28	28	-
	CC-S	7.2	7.2	-	100	100	-
	CC-D	7.0	6.2	-	100	89	-
	LC-D	3.0	1.8	-	190	82	-
2nd stage	LC-S	0.34	-	1.5	12	-	64
	CC-S	3.9	-	3.7	59	-	56
	CC-D	4.2	-	3.3	63	-	49
	LC-D	1.5	-	1.5	72	-	73
3rd stage	LC-S	0.79	0.79	1.2	40	40	78
	CC-S	3.3	3.3	2.4	47	47	35
	CC-D	3.5	2.8	2.7	51	39	39
	LC-D	1.7	0.91	0.97	160	79	88

Shaking forces on pulsation damper
Shell – S/D ... forces of entire damper in damper axis suction/discharge side
CP-S/D ... shaking force at cylinder connection flange suction/discharge side

Location		Basic design	Mod1 to API limit	Mod2 empty damper
		kN pp		
1st stage	Shell-S	1.8	1.8	-
	CP-S	0.41	0.41	-
	CP-D	2.0	1.7	-
	Shell-D	8.2	4.5	-
2nd stage	Shell-S	0.49	-	1.9
	CP-S	1.2	-	0.82
	Baffle-S	3.9	-	-
	CP-D	2.4	-	1.6
	Shell-D	3.4	-	0.57
3rd stage	Shell-S	0.94	0.92	1.0
	CP-S	0.81	0.71	0.65
	Baffle-S	3.5	3.1	-
	CP-D	3.8	1.7	1.7
	Shell-D	2.7	2.4	0.70

Figure 7 *Pulsation Study*

Table – 2 *Pressure Vessel Capacity*

Vessel	Diameter (in)	Height (ft)	Liquid volume (bbls)	Retention time	Calculated capacity (BOPD)	Simulated Liquid dropout (BOPD)
Inlet Scrubber	28	8.00	2.03	5	584.55	15
1st Stage discharge scrubber	28	7.30	1.85	5	533.41	50
2nd Stage discharge scrubber	28	7.30	1.85	5	533.41	20
3rd Stage discharge scrubber	28	7.00	1.78	5	511.48	15

A reliability study was conducted utilizing Reliability Block Diagram (RBD) modeling and the reliability statistics of the selected equipment to assure the spare equipment will be reliable during the facility's operational phase. The reliability data was computed using the failure history of the equipment and verified using the Maintenance inspection, testing, and preventative maintenance (ITPM) records. The Society of Maintenance and dependability Professionals (SMRP) Best Practice recommended a baseline of world-class dependability of 90%. Figure 8 depicted the RBD modeling results as well as the computed system reliability.

Equipment	Inlet Cooler	Inlet separator	Inlet Scrubber	Stage 1 Compressor	Stage 1 Cooler	Stage 1 Discharge Scrubber	Stage 2 Compressor	Stage 2 Cooler	Stage 2 Discharge Scrubber	Stage 3 Compressor	Stage 3Cooler	Stage 3 Discharge Scrubber	JT Valve	Low Temperature Separator	System Reliability
Reliability	0.98	1	1	0.95	0.98	1	1	0.99	1	1	1	1	1	1	0.9032562

Figure 8. *Equipment Reliability Analysis*

The combination of selected spare equipment yield a system reliability of 90.32%, which means they were adequate to sustain a reliable operation.

EQUIPMENT MODIFICATION AND RECONDITIONING

Based on FEED, several pieces of equipment shall be modified to be able to perform their intended function. The major modification was done for the gas compressor, with minor modifications on the piping or pipeline to accommodate the usage of excess materials. There were 6 main tasks for the compressor modification, comprised of mechanical modification and control system modification:

1. Cylinder bore modification
2. Pulsation bottles modification
3. Re-staging of the gas compressor using a new cylinder bore and new pulsation bottles
4. Connection lines for additional cooling for the additional stage
5. Control system upgrade from pneumatic controls to electronic controls
6. Installation, testing, and commissioning.

The cylinder bores and pulsation bottles were adjusted in accordance with the engineering study results, then fitted back into the gas compressor frame for re-staging, as shown in Figure 9. To maintain isentropic compression and recover more condensate, the additional compression stage required an additional cooling stage, so an additional line was built to connect the discharge line from one of the compressor's outlets to the additional cooling stage assembly (cooler and scrubber), as shown in Figure 10. The pneumatic control system of the gas compressor was converted to an electronic control system to improve control and integration between gas compressor control systems and the overall plant control system. The new electronic control system is equipped with the following features:

- Air-fuel ratio control (AFR) system: to optimize the combustion in the engine and reduce the amount of unburnt fuel the AFR system is required to control the amount of fuel entering the engine. The system operates by sensing the amount of oxygen in the engine exhaust before the catalyst. By analyzing the amount of oxygen that exits the combustion chamber, the system can obtain information on the characteristics of the combustion in the cylinder, whether there is too much fuel (too rich) or not enough fuel (too lean). After obtaining the information, the system will adjust the amount of fuel that flows to the carburetor of the engine
- Electronic ignition control system: in contrast to the existing mechanical ignition system, the

electronic ignition system will provide better control of how the engine will burn. The ignition control system will be able to be more accurate when setting the ignition timing for the engine. This will be useful in maintaining the NOx emission, as the ignition timing is one of the factors that contribute to the NOx formation. By advancing the timing, combustion occurs earlier in the cycle, which increases the peak pressure. This resulted in higher peak temperatures in the engine cylinders causing higher NOx formation rates. However, by retarding the ignition timing, the peak pressure and temperature will decrease, and it will reduce NOx formation. The ignition control system will be able to better control the ignition timing and consequently the NOx formation.

- Pyrometer and detonation sensors at the engine: Primarily, this device will be used to monitor the engine cylinder temperatures and adjust ignition timing when detonation occurs in the cylinder, to avoid damage to power cylinders
- Integration with new PLC system to control sequence and process within engine and compressor as well as process control in the gas plant facility



Figure 9. *Gas Compressor Restaging*



Figure 10. *Additional line to the additional cooling stage*

To fully utilize the excess building materials, a modest adjustment was performed to the pipe connection to the equipment. To study the impact on pressure drop, the impact of alteration was simulated using proprietary pipe network modeling software. The simulation result showed no substantial pressure reduction from the adjustment, therefore it was safe to use. Figure 11 depicts some examples of these adjustments. We noticed a 10" to 8" pipe reduction and a 2" to 6" pipe expansion at the junction between the pipes and the equipment.



Figure 11 *Example of Modified Piping Connection*

Some of the spare equipment transported to the AGRP did not require modification, but it did need to be reconditioned to return to its original state. Repair, replacement of broken components, and repainting were all part of the reconditioning process. The reconditioning was seen on the vessels and coolers in Figures 9, 10, and 11, where the vessels and coolers had been restored to their original condition.

FIELD RESULT

The AGRP's ability to extract associated gas and condensate is the major indicator of technical success, and the project attained that goal. The measured gas production and condensate production trends in Figures 12 and 13 reveal that AGRP was able to recover an average of 0.5 MMSCFD-associated gas and 60 BOPD condensate. While the amount of recovered gas was less than projected in the first analysis, the 20 BOPD increase in condensate output more than compensated. The return on investment from the reduction in operating costs is estimated to break even in two years of operation at this output rate.

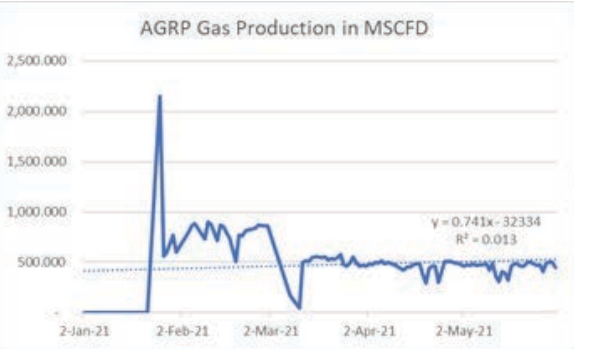


Figure 12. *AGR Daily Gas Production*

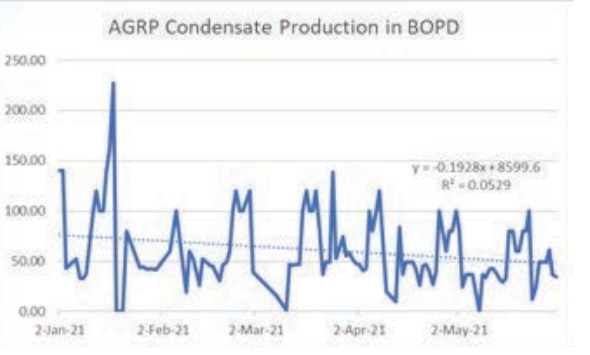


Figure 13. *AGRP Condensate Daily Production*

Because many of the bulk materials used to build the facility were leftovers, the warehouse was able to cut its inventory by 8559 pieces, a considerable amount. The total savings from lower inventory costs and cost avoidance from purchasing fresh bulk materials exceeded USD 350,000. Another advantage of better inventory management was a lower sole cost to the company. The Company's region of operations adopted the PSC system, under which the Company will be back-charged if it purchases something it does not utilize to improve production.

CONCLUSION

By avoiding the acquisition of new equipment and building materials, the use of idle equipment and excess material in the construction of the gas processing facility has effectively created cost savings of up to five times the project cost. Excess materials and idle process equipment can also be used to improve inventory management and capital stewardship because the cost of relocating and modifying the equipment is substantially lower than the cost of purchasing new equipment. The facility built with surplus materials and spare equipment performed admirably as well, recovering associated gas at a rate of 0.5 MMSCFD for use as fuel in the gas turbine and producing 60 BOPD condensate from the gas-liquid separation process. All of this was made feasible by the project team's ingenuity and the strong multi-functional coordination amongst support departments.

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PENILAIAN KEHANDALAN OPERASI PIPA GAS PADA LPG STATION AMURANG DENGAN PERANGKAT LUNAK CAESAR II

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ABSTRAK

PT Elnusa Petrofin merupakan perusahaan yang bergerak di bidang produk dan jasa migas. Untuk memenuhi kebutuhan produksi bahan bakar dan gas LPG, PT Elnusa Petrofin mengoperasikan Terminal LPG dengan pipa penyalur yang berada di Amurang, Sulawesi Utara. TLPG tersebut akan dikaji terkait sisa umur dari pipa tersebut. Tujuan dari penelitian ini adalah menganalisis tegangan yang terjadi pada pipa penyalur gas LPG. Selain itu, penelitian ini dilakukan agar dapat mengetahui sisa umur dari pipa penyalur tersebut dan menjamin keamanan serta operasi berkelanjutan dari peralatan tersebut. Pengujian dilakukan secara numerik menggunakan perangkat lunak CAESAR II untuk menganalisis tegangan yang terjadi pada pipa penyalur tersebut. Pengujian dilakukan menggunakan jenis beban data desain dan data operasional. Nilai tegangan yang didapatkan hasil dari simulasi dibandingkan dengan nilai tegangan hasil perhitungan teoretis menggunakan rumus. Lalu, dari perhitungan tersebut dapat ditentukan jika pipa dalam kondisi aman sesuai dengan standar. Kemudian, untuk menghitung sisa umur dari pipa tersebut harus didapatkan data aktual dari pipa penyalur. Data tersebut nantinya akan digunakan untuk perhitungan sisa umur dari pipa penyalur yang akan dianalisis.

Kata kunci: Tegangan, sisa umur, pipa penyalur.

ABSTRACT

PT Elnusa Petrofin is a state-owned company engaged in oil and gas products and services. PT Elnusa Petrofin is building an LPG terminal with a pipeline located in Amurang, South Sulawesi, to meet fuel and gas production needs. LPG Terminal has not been studied in relation to the remaining life of the pipe. This study aims to analyze the stress in the channel, in this case, the LPG gas channel. In addition, this study is conducted to determine the remaining life of the channel. The test is carried out numerically using CAESAR II software, requested by the company to analyze the stress that occurs in the channel. Tests were carried out twice using the same type of load but using design data and operational data. The stress values obtained from the simulation results are compared with the stress values obtained from theoretical calculations using the formula. Then, the stress can be considered safe based on the allowable stress of the conduit based on existing standards. Then, to calculate the remaining life of the pipe, actual data from the channel pipe are utilized.

***Keywords**: Stress, remaining life, pipe.*

1. PENDAHULUAN

Indonesia memiliki sumber daya energi migas yang sangat besar, sehingga dapat mendominasi pasar energi global. Salah satu bukti nyatanya adalah cadangan sumber daya energi yang dimiliki oleh Indonesia pada tahun 2019 sebanyak 7,5 miliar barel minyak dan 135,55 TSCF gas [1]. Saat ini penggunaan gas alam banyak digunakan untuk kebutuhan industri, rumah tangga maupun sebagai sumber daya pembangkit listrik. Penyaluran gas alam tersebut hingga dapat digunakan baik untuk kebutuhan industri maupun untuk kebutuhan rumah tangga menggunakan jaringan pipa sebagai sarana pendistribusian.

Jaringan pipa adalah bagian dalam suatu proses *flow* diagram suatu industri gas dan pipa rentan memiliki risiko kegagalan yang perlu diperhitungkan sehingga perlu dilakukan pemeriksaan. Pada industri migas, bagian yang paling perlu mendapatkan perhatian serius adalah pipa penyalur. Hal ini dikarenakan pipa penyalur merupakan bagian yang sering berkontak langsung dengan fluida yang mengalir di dalamnya sehingga potensi kegagalannya pun lebihbesar bila dibandingkan dengan *equipment* lain [2].

Material baja karbon adalah material yang banyak digunakan untuk pembuatan pipa pada industri eksplorasi dan produksi minyak dan gas alam. Material baja memiliki sifat keuletan yang tinggi, harga terjangkau, dan mudah untuk proses *machining*. Kelemahan dari material ini adalah kekerasannya yang relatif rendah dan ketahanan terhadap korosi yang relatif rendah [3].

Salah satu contohnya adalah terminal LPG (*Liquefied Petroleum Gas)* milik PT Elnusa Petrofin yang berada di Amurang, Kabupaten Minahasa Selatan, Sulawesi Utara. Terminal tersebut merupakan tempat penyimpanan LPG yang kemudian akan didistribusikan ke SPBE. PT Elnusa Petrofin merupakan perusahaan yang bergerak di bidang produk dan jasa migas, di mana PT Elnusa Petrofin yang juga merupakan bagian dari perusahaan PT Pertamina (Persero).

Terminal tersebut perlu dilakukan perhitungan terkait sisa umur dari jaringan pipa tersebut. Pada kesempatan ini juga, penulis bekerja sama dengan PT Elnusa Petrofin untuk melakukan penelitian mengenai sisa umur pipa gas LPG dan memastikan tetap aman untuk menjalankan operasi dari depot milik Pertamina di Amurang, Sulawesi Utara.

2. KAJIAN PUSTAKA

2.1. TEGANGAN

Tegangan adalah besaran vektor yang selain memiliki nilai juga memerlukan arah. Nilai dari tegangan di definisikan sebagai gaya (F) per satuan luas (A) (Persamaan 1).

$$\sigma = \frac{F}{A} \qquad (1)$$

Dalam menerapkan *code* dan *standard* desain, kita harus mengerti prinsip dasar dari tegangan pipa dan hal-hal yang berhubungan dengannya. Sebuah pipa dinyatakan mengalami kegagalan jika tegangan dalam yang terjadi pada pipa melebihi tegangan batas yang diizinkan. Dari definisi yang sederhana ini ada dua istilah yang harus dipahami dengan benar yaitu tegangan dalam pipa dan tegangan batas yang diizinkan [4].

Tegangan yang terjadi dalam sistem perpipaan dapat dikelompokkan ke dalam dua kategori, yakni Tegangan Normal *(Normal Stress)* dan Tegangan Geser *(Shear Stress)* [5].

Tegangan normal terdiri dari tiga komponen tegangan, yang masing-masing adalah:

- Tegangan *Longitudinal (Longitudinal Stress)*, yaitu tegangan yang searah panjang pipa.
- Tegangan Tangensial *(Circumferential Stress atau Hoop Stress)*, yaitu tegangan yang searah garis singgung penampang pipa.

- Tegangan Radial *(Radial Stress)*, yaitu tegangan searah jari-jari penampang pipa.

Tegangan Geser terdiri dari dua komponen tegangan, yang masing-masing adalah:

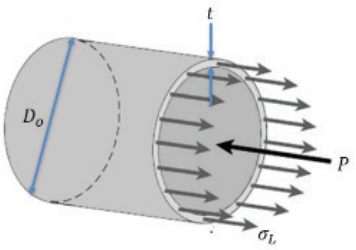
- Tegangan Geser *(Shear Stress)*, yaitu tegangan akibat gaya geser.
- Tegangan Puntir atau Tegangan Torsi *(Torsional Stress)*, yaitu tegangan akibat momen puntir pada pipa

2.2. API 5L GR B

Pipa API (*American Petroleum Institute*) 5L Grade B memiliki kandungan karbon 0,28% C. Kandungan karbon yang dimiliki oleh API 5 L Grade B mengkategorikan bahwa pipa ini termasuk pada jenis *medium carbon steel*, dimana *medium carbon steel* merupakan baja dengan kandungan karbon 0,25%-0,55% C [6]. Baja jenis ini memiliki kemampukerasan yang rendah. Adanya penambahan chrom, nikel, dan *molybdenum* dapat meningkatkan kemampuan paduan ini untuk diberikan perlakuan panas sehingga memiliki kekuatan dan keuletan yang beragam. *Heat treated alloy* ini memiliki kekuatan yang lebih baik dibandingkan dengan *low carbon steel*, namun keuletan dan ketangguhan tidak sebaik *low carbon steel*. Selain itu, pipa juga dibedakan berdasarkan NPS *(nominal pipe size dan schedule)* / (ketebalan pipa) [7]. Hal ini berdasarkan pada ANSI *(American National Standard Institute)* / ASME B.36.10. Ukuran mewakili diameter tertentu, sedangkan *schedule* mewakili rasio antara tekanan operasi dengan tekanan yang diperbolehkan. Jika ukuran tetap, maka semakin besar *schedule* maka ketebalan semakin besar.

2.3. *LONGITUDINAL STRESS*

Tegangan longitudinal atau tegangan aksial adalah tegangan yang arahnya sejajar dengan sumbu longitudinal. Untuk mempermudah melihat ada gaya apa saja yang bekerja seperti Gambar 1 di bawah ini [5].



Gambar 1. *Longitudinal Stress*

Tekanan yang ada di dalam pipa tersebut menghasilkan sebuah gaya. Besar dari gaya tersebut dapat ditentukan dengan Persamaan 2) .

$$F = P.A \qquad (2)$$

Keterangan:

P = Tekanan di dalam pipa (MPa)

A = Luas permukaan pipa (mm^2)

Lalu, dari tekanan yang terjadi di dalam pipa menghasilkan tegangan longitudinal (*longitudinal stress*). Maka dari itu, nilai *longitudinal stress* dapat dinyatakan Persamaan 3 sebagai berikut.

$$\sigma_L = \frac{P.D_i}{4t} \qquad (3)$$

Keterangan:

= Tegangan Longitudinal (MPa)

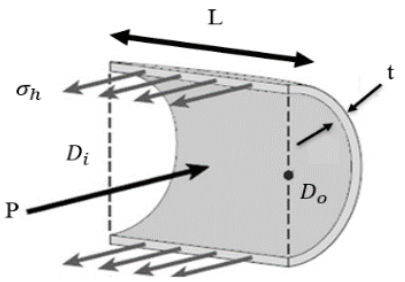
P = Tekanan di dalam pipa (MPa)

= Diameter dalam pipa (mm)

t = Tebal pipa (mm)

2.4. HOOP STRESS

Hoop stress merupakan tegangan yang terjadi tegak lurus terhadap terhadap sumbu dari pipa. Untuk mempermudah melihat ada gaya apa saja yang bekerja, pipa dibelah menjadi dua seperti Gambar 2 di bawah ini.



Gambar 2. *Hoop Stress*

Tekanan yang terjadi di dalam pipa tersebut menghasilkan sebuah gaya. Besar dari gaya tersebut dapat ditentukan dengan Persamaan 4 berikut.

$$F = P.\,Di.\,L \qquad (4)$$

Keterangan:

P = Tekanan di dalam pipa (MPa)

Di = Diameter dalam pipa (mm)

L = Panjang pipa (mm)

Lalu, dari tekanan yang terjadi di dalam pipa menghasilkan tegangan tangensial *(hoop stress)*. Maka dari itu, nilai *hoop stress* dapat dinyatakan dalam Persamaan 5.

$$\sigma_H = \frac{F}{2t.L} \qquad (5)$$

Keterangan:

σ_H = *Hoop stress* (MPa)

F = Gaya pipa (N)

t = Tebal pipa (mm)

L = Panjang pipa (mm)

Tekanan dalam pipa akan mempengaruhi besar gaya yang akan dihasilkan oleh pipa tersebut. Gaya yang dihasilkan oleh pipa akan memengaruhi nilai dari tegangan tangensial dari pipa. Maka dari itu nilai *hoop stress* Persamaan 6 [5].

(6)

2.5. SISA UMUR JARINGAN PIPA

Dalam perhitungan sisa umur jaringan pipa, konsep yang digunakan sebagai dasar perhitungan adalah konsep tegangan di mana tegangan merupakan gaya per satuan luas Persamaan 7.

$$\sigma = \frac{F}{A} \qquad (7)$$

Kemudian, prinsip ini diturunkan menjadi tegangan pada pipa, di mana tegangan pada pipa dibagi menjadi beberapa jenis tegangan. Nilai tegangan dapat dicari menggunakan turunan rumus dari rumus dasar tegangan seperti contoh sebelumnya.

Setelah mendapat nilai tegangan tangensial hasil dari persamaan sebelumnya, ketebalan minimum pipa untuk mencari sisa umur pipa dapat dicari dengan rumusdalam Persamaan 8..

$$t_{req} = \frac{P.D_i}{2.0.72.E.SMYS} \qquad (8)$$

Keterangan:

t_{req} = Minimum tebal dinding pipa yang minimum (mm)

σ_{allow} = Tegangan Izin *Hoop Stress* (MPa)

E = *Weld Joint Factor*

SMYS = *Specific Minimum Yield Strength* (MPa)

Nilai sisa umur pipa bergantung pada nilai laju korosi pipa tersebut. Laju korosi dapat dirumuskan dalam Persamaan 9 sebagai

berikut.

$$Cr = \frac{t_{sch\,80} - t_{actual}}{\Delta T} \qquad (9)$$
[8]

Keterangan:

Cr = *Corrosion Rate* (mm/tahun)
$t_{sch\,80}$ = Tebal aktual pada saat inspeksi pertama (mm)
t_{actual} = Tebal aktual pada saat ini (mm)
ΔT = Rentang waktu antara inspeksi pertama dan saat ini (tahun)

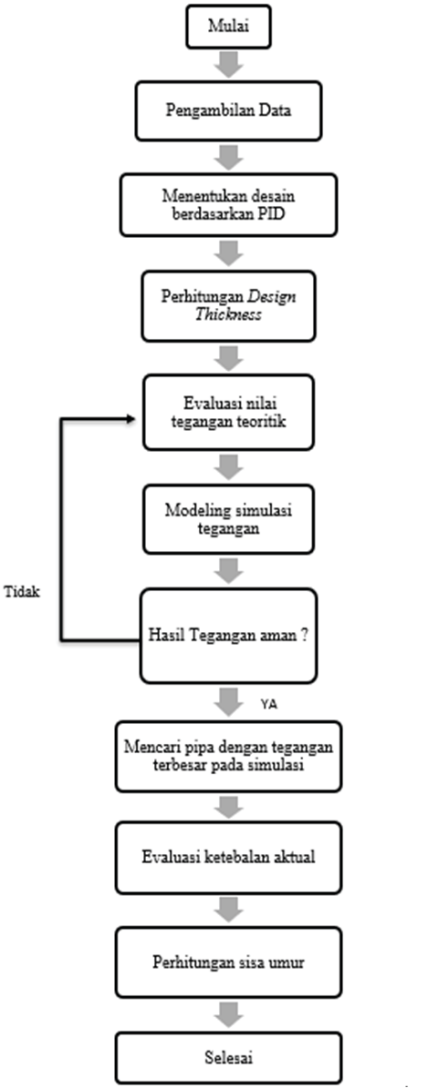
Sisa umur pipa merupakan waktu penggunaan pipa sebelum pipa tersebut melewati batas aman dari pipa tersebut. Sisa umur pipa dapat dirumuskan dalam persamaan 10 sebagai berikut [8].

Keterangan:

RL = *Remaining Life* (tahun) (10)
Cr = *Corrosion Rate* (mm/tahun)
t_{actual} = Tebal aktual pada saat ini (mm)

3. METODE PERANCANGAN ALAT

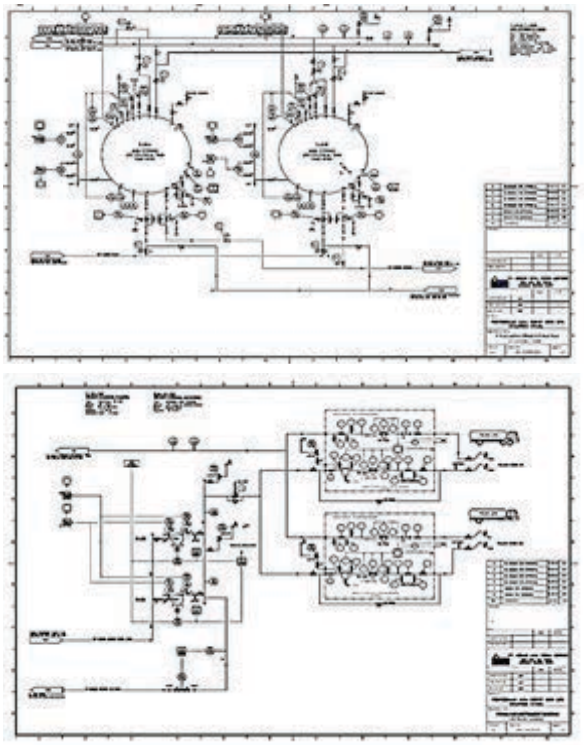
Penelitian simulasi ini akan dilakukan di PT Elnusa Petrofin dengan bantuan arahan dari dosen pembimbing Prodi Teknik Mesin Unika Atma Jaya. Metode penelitian yang akan digunakan dalam penelitian ini adalah dengan melakukan simulasi numerik dengan menggunakan *software* CAESAR II sebagai *software* yang akan digunakan untuk mengolah data. Pada tahap awal dilakukan studi literatur mengenai konsep tegangan secara umum dan tegangan pada pipa. Kemudian, akan ditentukan jaringan pipa yang akan dianalisis, evaluasi sisa umur jaringan pipa tersebut menggunakan *software* CAESAR II. Tahapan penelitian ini dapat dilihat pada sebuah diagram alir pada Gambar 3.



Gambar 3. *Diagram Alir Tahapan Penelitian*

3.1 P&ID *(Piping & Instrument Diagram)*

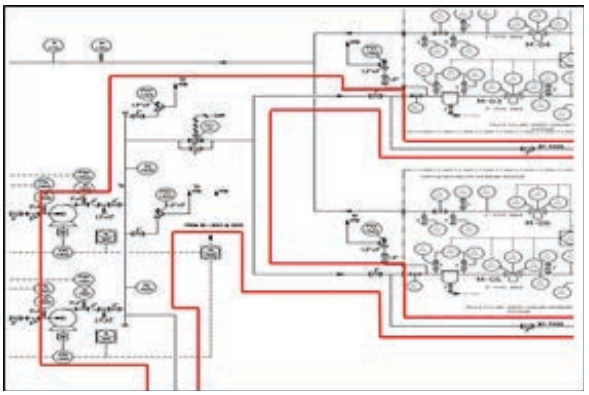
Dalam menentukan jaringan pipa yang akan dianalisis, diperlukan beberapa dokumen untuk menjelaskan jaringan pipa tersebut. Salah satunya adalah P&ID (*Piping & Instrument Diagram*). P&ID digunakan sebagai petunjuk informasi mengenai jalur pipa proses distribusi gas dan instrumen yang ada dalam jaringan pipa tersebut. Diagram ini digunakan oleh teknisi di lapangan untuk memahami proses dan instrumen yang ada di lapangan seperti pada Gambar 4 di bawah ini.



Gambar 4. *P&ID (Piping & Instrument Diagram)*

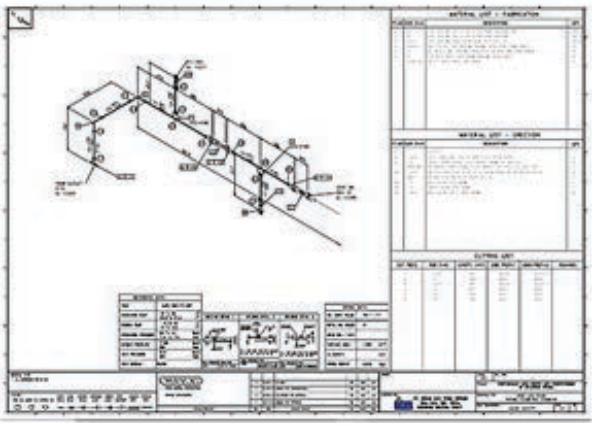
Berikut ini merupakan bagian dari P&ID yang akan dilakukan desain dan simulasi pada perangkat CAESAR II seperti pada Gambar 5.

Gambar 5. *Jalur yang akan dianalisis*

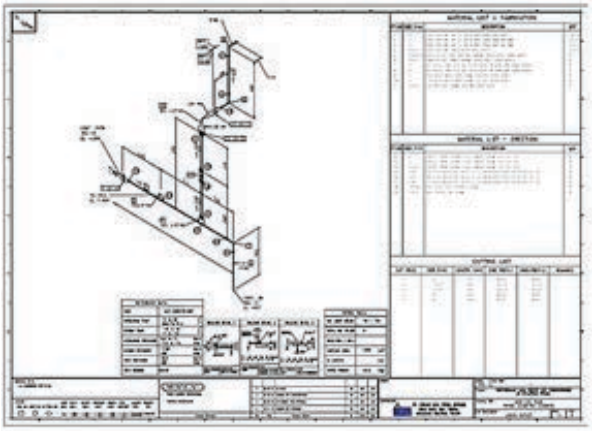


3.2 Isometric Drawing

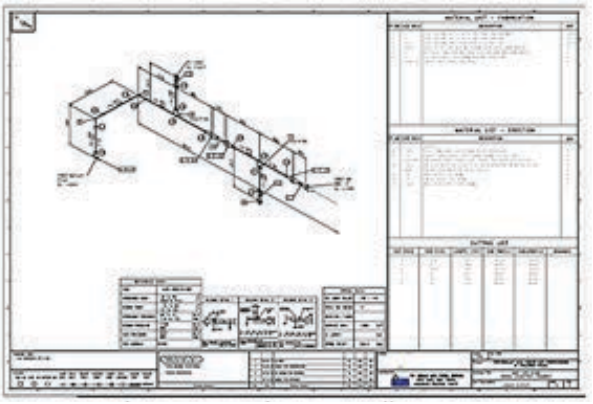
Dalam proses pemodelan, gambar isometrik merupakan dokumen yang digunakan sebagai acuan dalam proses desain di *software* sebelum dilakukan simulasi. Gambar isometrik juga dapat menggambarkan posisi jalur pipa yang ada di lapangan sehingga dapat membantu teknisi dalam melakukan inspeksi di lapangan. Contoh dari gambar isometrik jalur pipa seperti pada Gambar 6-13.



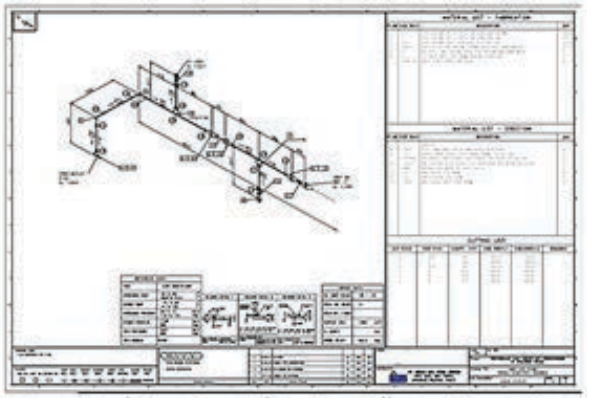
Gambar 6. *Mini LPG Plan Piping Isometric Drawing 1*



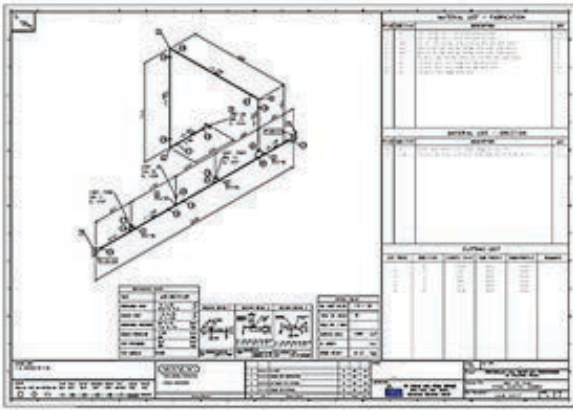
Gambar 7. *Mini LPG Plan Piping Isometric Drawing 2*



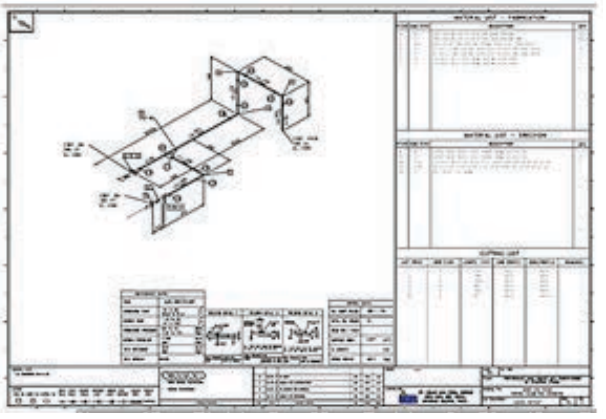
Gambar 8. *Mini LPG Plan Piping Isometric Drawing 3*



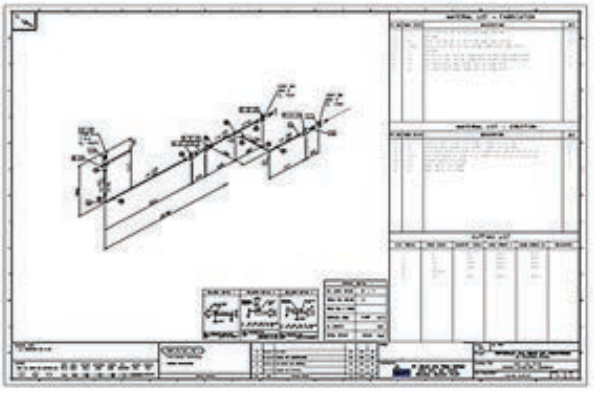
Gambar 9. *Mini LPG Plan Piping Isometric Drawing 4*



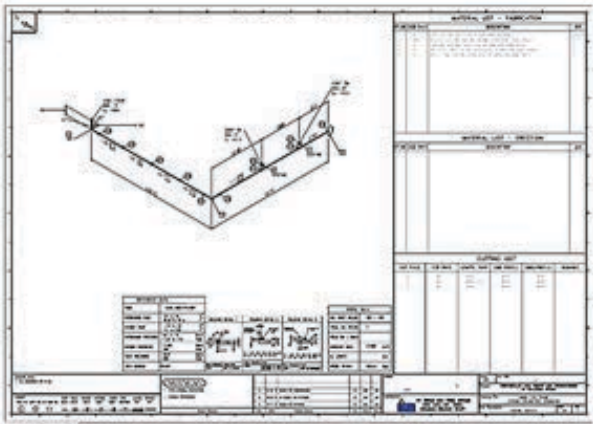
Gambar 10. *Mini LPG Plan Piping Isometric Drawing 5*



Gambar 11. *Mini LPG Plan Piping Isometric Drawing 6*



Gambar 12. *Mini LPG Plan Piping Isometric Drawing 7*



Gambar 13. *Mini LPG Plan Piping Isometric Drawing 8*

3.3 *Piping Plant*

Piping plant merupakan gambaran hasil dari jalur pipa yang ada di lapangan. Dokumen ini digunakan dalam proses pemodelan dalam *software*. Berikut contoh gambar *piping plant* yang akan digunakan dalam pemodelan.

3.4 Data Karakteristik Pipa

Data karakteristik pipa yang akan dianalisis diambil dari *piping code* ASME 31.8 yaitu *Gas Transmission and Distribution Piping Systems*. Berikut di bawah ini Tabel 1. merupakan tabel data *properties* dari jaringan pipa yang akan dilakukan simulasi dan analisis menggunakan *software* CAESAR II [9].

Tabel 1. *Data Karakteristik Pipa*

No	Parameter	Nilai	Satuan
1	Jenis Pipa	Pump Discharge Isometric 10-14, 18-22	
2	Material	Sch 80 (API 5L / A106 Gr B ERW)	
3	Tensile Allow	413000	KPa
4	Yield Allow	241000	KPa
5	Stress Allow	174000	KPa
6	Density LPG	0,525	kg/cm3
7	Weld Joint Factor	1	
8	Fluid Density	0,525	kg/cm3
9	Pump Density	0,00783	kg/cm3
10	Corrosion Allowance	3,175	
11	Poison Ratio	0,292	
12	Modulus Elastic		KPa

3.5 Dimensi Pipa

Data dimensi pipa didapat berdasarkan jaringan pipa yang akan dilakukan simulasi dan dianalisis. Berikut di bawah ini Tabel 2. merupakan tabel data dimensi pipa yang akan digunakan pada proses simulasi dan analisis.

Tabel 2. *Data Dimensi Pipa*

Diameter (inch)	Diameter dalam (mm)	Diameter luar (mm)	Ketebalan Pipa
0,75	18,85	26,67	3,91
1	24,3	33,4	4,55
1,5	38,1	48,26	5,08
2	49,24	60,32	5,54
2,5	59	73,02	7,01
3	73,66	88,9	7,62
4	97,18	114,3	8,56
6	146,33	168,27	10,97
8	193,67	219,07	12,7

3.6 Data Operasional dan Desain

Data operasional dan desain yang dimasukkan ke dalam simulasi adalah data tekanan dan temperatur. Data tersebut merupakan data yang diberikan oleh pihak PT Elnusa Petrofin berdasarkan kondisi aktual jaringan pipa LPG di station Amurang.

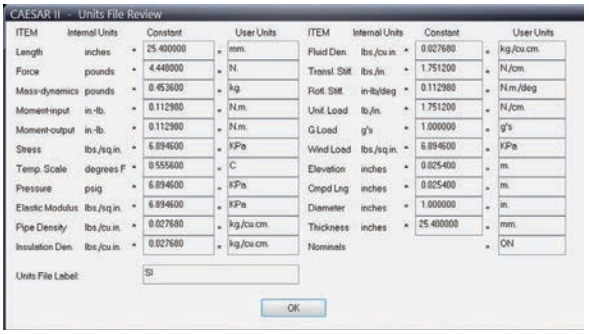
Berikut di bawah ini Tabel 3 merupakan data lengkap operasional dan parameter dari jaringan pipa LPG di station Amurang.

Tabel 3. *Data Operasional dan Desain*

Parameter	Nilai	Satuan
Design Pressure	1800	KPa
Operating Pressure	1200	KPa
Design temperature	50	°C
Operating temperature	33	°C

3.7 *Input Software*

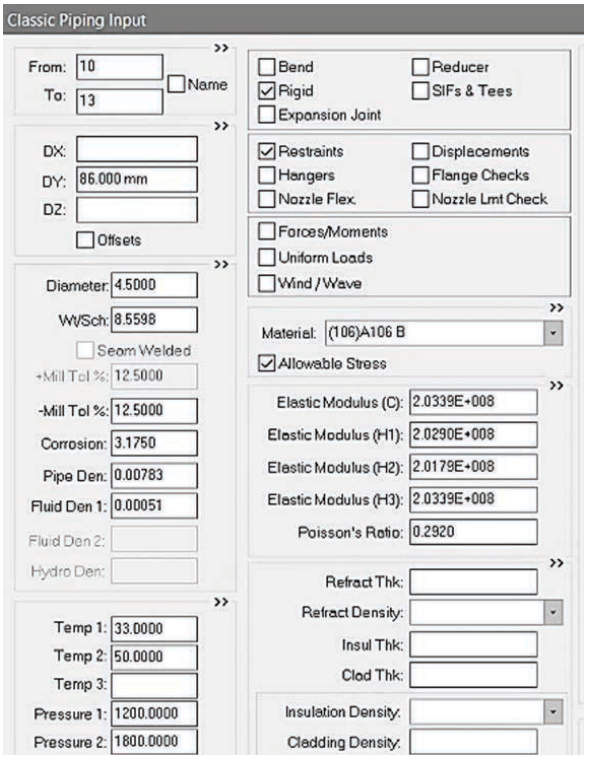
Sebelum melakukan desain dan simulasi, perlu diketahui beberapa data sebagai input desain tersebut sebelum dilakukan simulasi. Berikut merupakan satuan yang akan digunakan pada saat proses desain dan simulasi seperti pada Gambar 14 di bawah ini.



Gambar 14. *Input Data Satuan untuk Desain dan Simulasi*

3.8 Proses *Software*

Pada bagian ini, semua data yang ada akan dimasukkan ke dalam *software* tersebut untuk detail analisis. Berikut contoh data yang diperlukan dalam proses desain seperti pada Gambar 15.



Gambar 15. *Input Data Desain pada Software*

Pada pengujian ini beban yang dipilih adalah beban *sustained*. Beban *sustained* adalah beban akibat berat pipa, berat fluida, dan tekanan dalam pipa. Akibat dari beban tersebut nantinya akan menghasilkan tegangan (*stress*) yang akan dijadikan hasil data untuk dianalisis.

3.9 *Output Software*

Setelah desain dan simulasi dilakukan, *software* tersebut akan menghasilkan data untuk di setiap *node*. Jadi untuk setiap node akan diberikan nilai tegangan yang terjadi. Ada beberapa jenis tegangan yang akan ditampilkan seperti *hoop stress, bending stress, torsion stress, axial stress*. Semua hasil simulasi dapat dijabarkan dengan detail, baik dari tegangan terbesar, tegangan rata-rata berada di *node* berapa. Berikut Gambar 16. di bawah ini merupakan beberapa data yang bisa dicari pada proses simulasi.

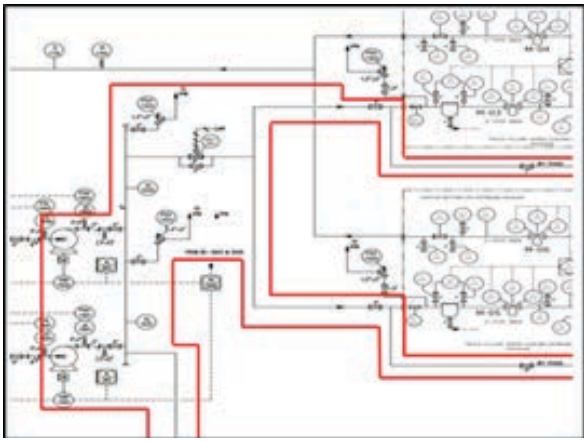


Gambar 16. *Standard Reports*

Pada penelitian ini ada poin *hoop stress* yang akan diambil sebagai acuan untuk perhitungan sisa umur dari pipa tersebut. Nilai tegangan terbesar akan diambil dari masing-masing simulasi dan akan digunakan sebagai perbandingan dengan nilai dengan perhitungan teoritik.

4. PERANCANGAN DAN PERWUJUDAN DESAIN

Pada bab ini akan dipaparkan desain dari jaringan pipa yang dianalisis serta hasil simulasi dari desain tersebut. Pembahasan dari hasil simulasi akan dicari nilai tegangan terbesar dari jaringan pipa tersebut. Lalu, akan masuk ke perhitungan untuk menghitung sisa umur dari pipa dengan tegangan terbesar dalam jaringan pipa yang dianalisis. Proses desain dilakukan dengan *software* CAESAR II. Data desain dapat dilihat berdasarkan P&ID *(Piping & Instrument Diagram)* dan *Piping Plant* yang diberikan oleh pihak PT Elnusa Petrofin. Lalu setelah itu untuk memodelkan jaringan pipa lewat *software*, data *Isometric Drawing* yang akan digunakan sebagai data untuk memodelkan jaringan pipa yang akan dianalisis seperti pada Gambar 17. dibawah ini.

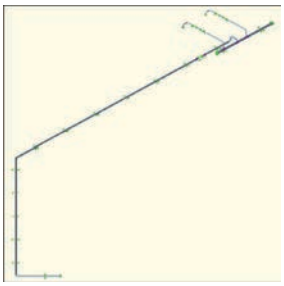


***Gambar 17**. Jalur Pipa yang dianalisis*

Pertama, menentukan daerah jalur pipa yang akan dianalisis berdasarkan P&ID. Jalur yang akan dianalisis adalah jalur pipa *output* dari pompa dengan isi *liquid* yang sebelumnya berasal dari tangki penyimpanan sampai dengan sebelum masuk ke *truck loading metering.*

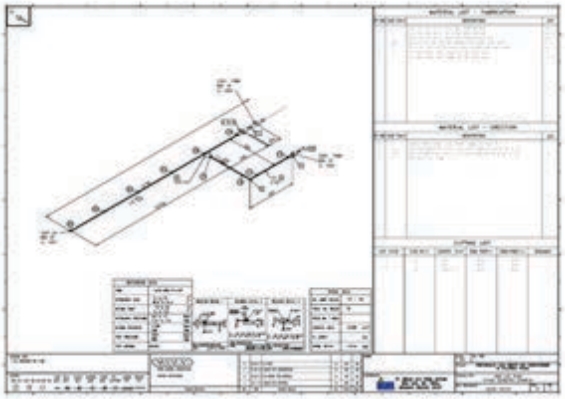
4.1 Desain

Jalur pipa terbagi menjadi beberapa gambar isometrik yang akan digabungkan dan dianalisis menggunakan *software* CAESAR II, kemudian ingin mengetahui sisa umur dari pipa tersebut dengan data dari PT Elnusa Petrofin. Gambar 18. merupakan hasil desain berdasarkan gambar isometrik pada Gambar 19. menggunakan *software* CAESAR II.

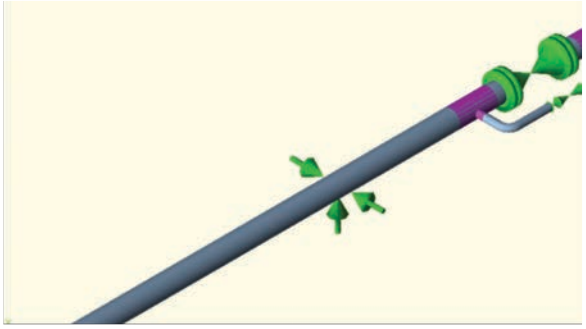


***Gambar 18.** Desain Jaringan Pipa*

Berdasarkan gambar isometrik diatas, proses untuk desain menggunakan software CAESAR II akan menghasilkan model berawal seperti Gambar 19 di bawah ini. Kemudian, desain tersebut dimasukkan ke dalam *software* seperti pada Gambar 20.

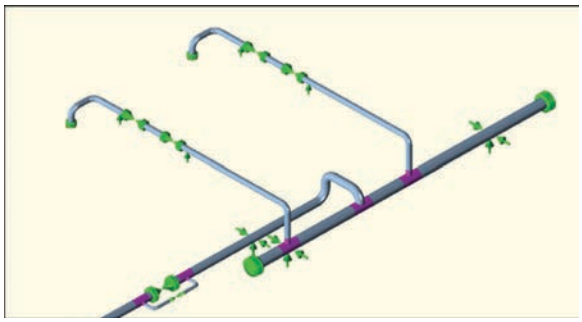


***Gambar 19.** Isometric Drawing*

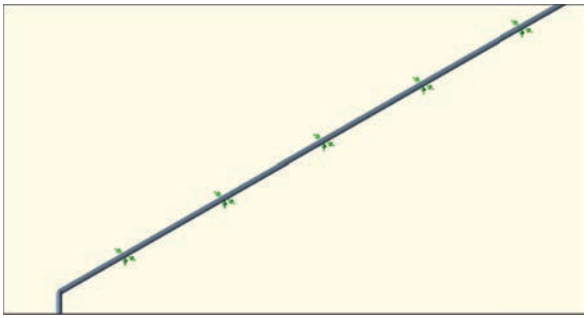


***Gambar 20.** Desain Hasil Gambar Isometrik*

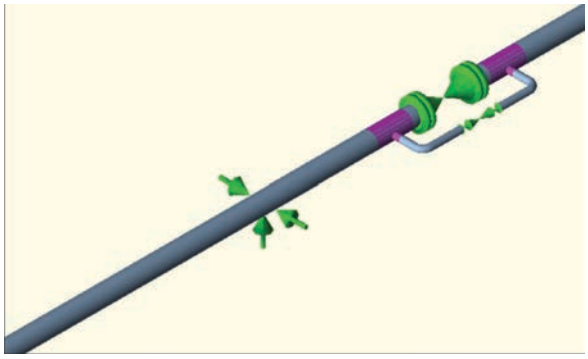
Selain itu, data pendukung lainnya dalam proses modeling selain gambar isometrik adalah *piping plant*. *Piping plant* menggambarkan komponen-komponen yang tidak terdapat pada gambar isometrik seperti *support* dan *guide* yang menjadi penopang pipa dan juga mengurangi terjadinya *stress*. Berikut ini merupakan gambaran desain jalur pipa yang akan dianalisis beserta dengan komponen lainnya dapat dilihat pada Gambar 21-24.



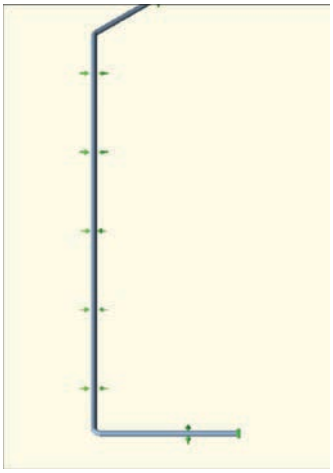
Gambar 21. *Desain 1*



Gambar 22. *Desain 2*



Gambar 23. *Desain 3*



Gambar 24. *Desain 4*

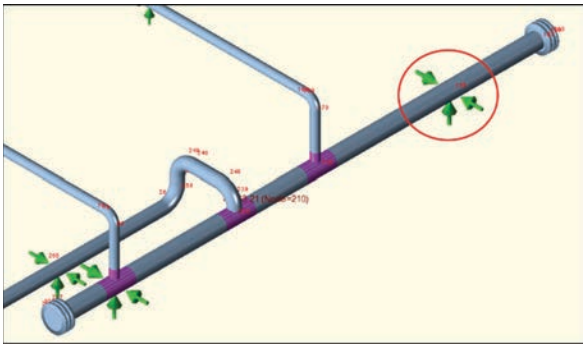
4.2 Simulasi

Setelah *modeling* selesai dibuat, simulasi dengan *software* CAESAR II dapat dijalankan dengan menentukan parameter yang akan digunakan. Pada *software* CAESAR II terdapat beberapa *load case* (beban) yang dapat dipilih untuk menjalankan simulasi. Berikut merupakan jenis *load case* yang dapat dijalankan pada *software* CAESAR II:

- (OPE) *Operating*: *Stress* yang terjadi akibat beban kombinasi antara *sustain load* dan *expansion load* dimana biasa terjadi pada kondisi operasional.
- (OCC) *Ocassional*: *Stress* yang terjadi hanya dalam waktu relatif singkat akibat beban *sustain load* + *ocassional loading* (seperti angin, *wave*, dll.)
- (SUS) *Sustained*: *Stress* yang terjadi secara terus menerus selama umur operasi akibat tekanan dan berat pipa & fluida.
- (EXP) *Expansion*: *Stress* yang terjadi akibat adanya perubahan temperatur.
- (HYD) *Hydrotest*: *Stress* akibat tekanan air saat dilakukan *hydrotest.*

Jenis beban yang akan digunakan pada proses simulasi kali ini adalah beban *Sustained*. Jenis beban ini seperti yang sudah dijelaskan di atas merupakan beban yang menghasilkan *stress* secara terus menurus akibat tekanan dan berat pipa dan fluida yang ada di dalam pipa selama

pipa tersebut masih dapat beroperasi. Selain itu simulasi dijalankan dengan dua jenis simulasi *sustained*. Pertama, parameter yang dimasukkan adalah beban keseluruhan (berat pipa + berat fluida) ditambahkan dengan besar tekanan desain. Parameter berikutnya adalah beban keseluruhan ditambahkan dengan besar tekanan operasional. Berikut di bawah ini merupakan hasil simulasi menggunakan kedua parameter di atas.



Tabel 4. *Hasil Simulasi W+P1 pada software CAESAR II*

CODE STRESS CHECK PASSED: LOAD-CASE 3 (SUS) W+P1
Highest Stresses: (KPa)
Ratio (%): 12.7 @Node 210
Code Stress: 16607.0
Allowable Stress: 130307.9
Axial Stress: 4340.0 @Node 210
Bending Stress: 12312.7 @Node 210
Torsion Stress: 484.3 @Node 238
Hoop Stress: 9150.0 @Node 185
Max Stress Intensity: 24677.9 @Node 300

Berdasarkan hasil simulasi W+P1 di mana beban yang diberikan adalah beban keseluruhan ditambahkan dengan tekanan operasional. Hasil yang didapatkan dari modeling yang sudah dibuat kemudian dilakukan simulasi dengan kondisi yang ada didapatkan beberapa data-data seperti di atas. Nilai-nilai di atas merupakan nilai tegangan terbesar yang terjadi pada pipa dengan masing-masing jenis tegangan yang terjadi pada pipa tersebut. Untuk kondisi beban *sustained* (W+P1), nilai *hoop stress* terbesar adalah 9150 KPa pada *node* nomor 185 seperti pada Gambar 25.

Gambar 25. *Hoop Stress Maksimal pada Beban nomor 3*

Tabel 5. *Hasil Simulasi W+P2 Pada software CAESAR II*

CODE STRESS CHECK PASSED: LOAD-CASE 4 (SUS) W+P2
Highest Stresses: (KPa)
Ratio (%): 14.4 @Node 210
Code Stress: 18753.8
Allowable Stress: 130307.9
Axial Stress: 6486.7 @Node 210
Bending Stress: 12312.7 @Node 210
Torsion Stress: 484.3 @Node 238
Hoop Stress: 13725.0 @Node 185
Max Stress Intensity: 29304.2 @Node 300

Kemudian, hasil simulasi W+P2 di mana beban yang diberikan adalah beban keseluruhan ditambahkan dengan tekanan desain. Untuk kondisi W+P2, nilai *hoop stress* terbesar adalah 13725 KPa pada node nomor 185. Nilai maksimal untuk setiap posisi jenis tegangan maksimal sama untuk kedua kasus di atas dikarenakan memang desainnya pun sama hanya bebannya saja yang diubah. Nilai dengan tekanan desain akan lebih besar dibandingkan dengan nilai tekanan operasional karena untuk faktor keamanan dan tentunya ketahanan dari pipa tersebut.

4.3 Perhitungan Tegangan Manual Pipa

Setelah mengetahui nilai *hoop stress* paling besar pada simulasi, maka kali ini akan dicari *hoop stress* menggunakan perhitungan manual. Berikut adalah perhitungan pada *node* 185.

Diketahui:

Kasus: 3 (*Sustained* = W + P1)

Diketahui:
Kasus: 3 (*Sustained* = W + P1)
P = 1200 KPa
Di = 8 inch = 193,67 mm
$t_{sch\ 80}$ = 12,7 mm

$$\sigma_{185} = \frac{P.Di}{2t}$$

$$\sigma_{185} = \frac{1200\ \text{KPa}.193{,}67\ \text{mm}}{2.\ 12{,}7\ mm}$$

$$\sigma_{185} = 9149{,}76378\ \text{KPa}$$

4.4 Data Aktual Jalur Pipa

Untuk menghitung sisa umur pipa, maka dibutuhkan beberapa data seperti kondisi tebal aktual pipa. Lalu setiap pengukuran di posisi yang akan diukur dilakukan pengukuran di empat lokasi yaitu atas, bawah, kiri, kanan (90 derajat antar sisi). Berikut merupakan data aktual pipa di TBBM LPG di Amurang.

Tabel 6. *Data Aktual dari Isometrik 1 & 2*
Design thickness 4" Sch 80 = 8.56 mm
Actual Thickness

No	NPS 4" (Isometrik 1)		NPS 4" (Isometrik 2)
	1	2	1
atas	7,33	6,9	6,66
bawah	7,27	6,57	7,27
kanan	7,11	7,18	7,12
kiri	6,93	6,65	6,82

Tabel 6. di atas merupakan hasil pengukuran data aktual teknisi PT Elnusa Petrofin dari masing-masing gambar isometrik jalur pipa. Gambar isometrik 1 & 2 dilakukan dua kali pengukuran di mana pipa yang diukur adalah pipa dengan ukuran 4 inci dengan nilai ketebalan pipa paling kecil ada di posisi kiri pipa untuk pengukuran pertama dengan tebal 6,93 mm dan pengukuran kedua di posisi bawah pipa dengan dengan tebal 6,57 mm. Lalu gambar isometrik nomor 11 dilakukan satu kali pengukuran dengan ukuran pipa yang sama yaitu 4 inci dengan nilai paling kecil ada di posisi atas dengan ketebalan 6,66 mm.

Tabel 7. *Data Aktual Isometrik 5*
Design thickness 8" Sch 80 = 12.7 mm
Actual Thickness

No	NPS 4" (Isometrik 5)
	1
atas	11,74
bawah	11,18
kanan	11,21
kiri	11,57

Gambar isometrik 5 dilakukan satu kali pengukuran di mana pipa yang diukur adalah pipa dengan ukuran 8 inci dengan nilai ketebalan pipa paling kecil ada di posisi kiri pipa untuk pengukuran pertama dengan tebal 11,18 mm.

Tabel 8. *Data Aktual Isometrik 6*
Design thickness 6" Sch 80 = 10.97 mm
Actual Thickness

No	NPS 6" (Isometrik 6)	
	1	2
atas	9,41	8,93
bawah	9,62	9,05
kanan	9,56	9,32
kiri	9,29	9,41

Gambar isometrik 6 dilakukan dua kali pengukuran di mana pipa yang diukur adalah pipa dengan ukuran 6 inci dengan nilai ketebalan pipa paling kecil ada di posisi kiri pipa untuk pengukuran

pertama dengan tebal 9,29 mm. Sementara untuk pengukuran kedua nilai ketebalan pipa paling kecil ada di posisi atas dengan nilai 8,93 mm.

Tabel 9. *Data Aktual Isometrik 7.1*
Design thickness 6" Sch 80 = 10,97 mm
Actual Thickness

No	NPS 6" (Isometrik 7)			
	1	2	3	4
atas	8,57	9,26	9,65	9,62
bawah	8,78	9,65	8,93	9,44
kanan	9,26	9,48	8,9	9,56
kiri	8,87	9,35	9,2	9,02

Tabel 10. Data Aktual Isometrik 7.2
Design thickness 2" Sch 80 = 5,54 mm
Actual Thickness

No	NPS 2" (Isometrik 7)
	1
atas	4,28
bawah	3,24
kanan	4,19
kiri	3,66

Gambar isometrik 7 dilakukan empat kali pengukuran pipa dengan ukuran 6 inci dan 1 kali pengukuran pipa dengan ukuran 2 inci. Nilai ketebalan pipa paling kecil untuk ukuran 6 inci ada di posisi atas pipa untuk pengukuran pertama dan kedua dengan tebal 8,57 mm dan 9,26 mm. Sementara untuk pengukuran ketiga nilai ketebalan pipa paling kecil ada di posisi kanan dengan nilai 8,9 mm. Pengukuran keempat nilai ketebalan pipa paling kecil ada di posisi kiri dengan nilai 9,02 mm. Sementara untuk ketebalan pipa paling kecil untuk ukuran 2 inci ada di posisi bawah dengan tebal 3,24 mm.

Tabel 11. *Data Aktual Isometrik 8*
Design thickness 6" Sch 80 = 10.97 mm
Actual Thickness

No	NPS 6" (Isometrik 8)			
	1	2	3	4
atas	8,9	9,44	10,45	9,08
bawah	8,69	9,29	9,59	9,14
kanan	9,32	9,62	9,62	9,82
kiri	9,17	9,38	9,38	9,91

Gambar isometrik 8 dilakukan empat kali pengukuran di mana pipa yang diukur adalah pipa dengan ukuran 6 inci dengan nilai ketebalan pipa paling kecil ada di posisi bawah pipa untuk pengukuran pertama dan kedua dengan tebal 8,69 mm dan 9,29 mm. Sementara untuk pengukuran ketiga nilai ketebalan pipa paling kecil ada di posisi kiri dengan nilai 9,38 mm. Pengukuran keempat nilai ketebalan pipa paling kecil ada di posisi kiri dengan nilai 9,08 mm.

Berdasarkan hasil pengukuran pipa secara aktual di lapangan, dapat dijabarkan data untuk setiap dimensi pipa yang akan dianalisis dengan kondisi nilai paling kecil untuk setiap ukurannya seperti pada Tabel 12.

Tabel 12. *Data Tebal Pipa Paling Kecil*

Dimensi	2"	4"	6"	8"
T Sch 80	5,54 mm	8,56 mm	10,97 mm	12,7 mm
Nilai t aktual min	3,24 mm	6,57 mm	8,57 mm	11,18 mm
Selisih	2,2 mm	1,99 mm	2,4 mm	1,52 mm

Untuk dimensi 4 inci, nilai tebal aktual paling kecil berada di angka 6,57 mm, selisih 1,99 mm dengan standar ukuran awal pipa tersebut. Dimensi 6 inci untuk nilai tebal aktual paling kecil adalah 8,57 mm berselisih 2,4 mm dari ukuran awal pipa. Sementara untuk dimensi 8 inci, nilai tebal aktual pipa paling kecil ada di angka 11,18 mm berselisih 1,52 mm dari tebal awal pipa tersebut.

4.5 Perhitungan *Remaining Life*

Sisa umur dari pipa dapat ditentukan dengan rumus dari standar yaitu kode standar API (*American Petroleum Institute*) 570. Perhitungan sisa umur pada pipa digunakan oleh para teknisi dengan tujuan untuk memperkirakan berapa lama pipa tersebut dapat digunakan secara operasional, sehingga sebelum masa waktu dari pipa tersebut habis atau melewati batas waktunya dapat diganti dengan pipa baru. Berdasarkan proses pengambilan data aktual ketebalan pipa serta data lain yang diperlukan, maka dapat ditentukanlah estimasi waktu pipa tersebut dapat digunakan sebagai pipa penyalur. Berikut merupakan contoh perhitungan tebal minimum pipa sebagai berikut.

Diketahui:

$$\sigma_{allow} = 0{,}72 \,.\, E \,.\, SMYS$$
$$\sigma_{allow} = 0{,}72 \,.\, 1 \,.\, 241000\ KPa$$
$$\sigma_{allow} = 173520\ KPa$$
$$P = 1800\ \text{KPa}$$
$$Di = 6\ \text{inch} = 146{,}33\ \text{mm}$$

$$\sigma = \frac{P.Di}{2t} \qquad (6)$$
$$t = \frac{P \,.\, Di}{2\sigma_{allow}}$$
$$t = \frac{1800\ \text{Kpa} \,.\, 146{,}33\ \text{mm}}{2 \,.\, 173520\ KPa}$$
$$t_{req} = 0{,}7\ \text{mm}$$

Nilai *t* di atas merupakan nilai ketebalan minimum yang diizinkan dengan ukuran pipa 6 inci untuk kondisi seperti di atas.

Kemudian dilanjutkan dengan perhitungan nilai laju korosi *(corrosion rate)* yang akan digunakan selanjutnya pada perhitungan sisa umur.

Diketahui:

$$t_{awal\ sch\ 80} = 10{,}97\ \text{mm}$$
$$t_{actual} = 8{,}57\ \text{mm}$$
$$tahun\ sekarang = 2019$$
$$tahun\ dibuat = 2014$$

$$Cr = \frac{t_{awal\ sch\ 80} - t_{actual}}{tahun\ sekarang - tahun\ dibuat} \qquad (9)$$
$$Cr = \frac{10{,}97\ \text{mm} - 8{,}57\ \text{mm}}{2019 - 2014}$$
$$Cr = \frac{2.4\ \text{mm}}{5\ tahun}$$
$$Cr = 0{,}48 \frac{\text{mm}}{tahun}$$

Nilai laju korosi yang terjadi pada pipa dengan ukuran 6 inci adalah 0.48 mm / tahun.

Setelah mendapatkan nilai laju korosi pada pipa, sisa umur pipa dapat dihitung menggunakan rumus di bawah ini.

Diketahui:

$$t_{actual} = 8{,}57\ \text{mm}$$
$$t_{req} = 0{,}7\ \text{mm}$$
$$\text{Cr} = 0{,}48\ \text{mm/tahun}$$

$$RL = \frac{t_{actual} - t_{req}}{Cr} \qquad (10)$$
$$RL = \frac{8{,}57\ \text{mm} - 0{,}7\ \text{mm}}{0.48\ mm/tahun}$$
$$RL = 16{,}2\ \text{tahun}$$

Nilai sisa umur pipa dengan ukuran 6 inci menggunakan data ketebalan aktual dari pipa saat ini dapat diprediksi umur pipa tersebut dapat bertahan 16 tahun.

4.6 Analisis

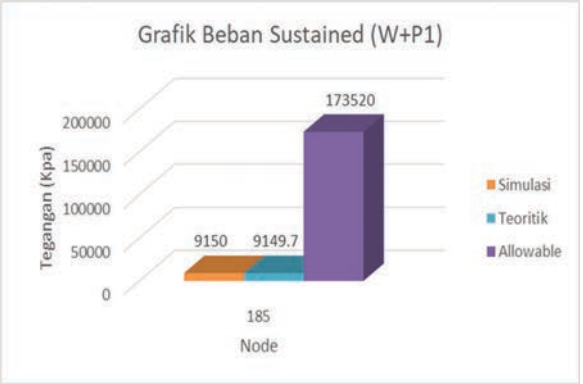
Dalam bagian ini, analisis yang akan dilakukan adalah membandingkan antara nilai tegangan yang dihasilkan oleh simulasi dengan nilai tegangan hasil perhitungan teoritik menggunakan

rumus. Berikut di bawah ini merupakan hasil perbandingan kedua nilai tegangan tersebut pada Tabel 13.

Tabel 13. *Perbandingan Hasil Simulasi & Teoretis*

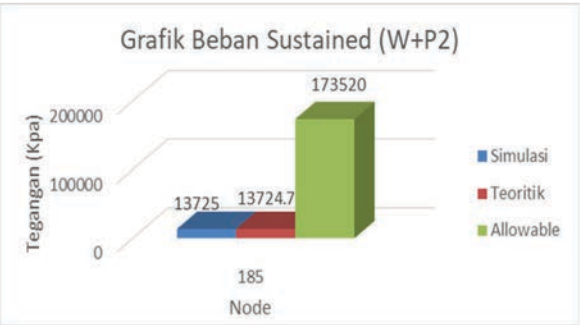
Load Case	Node	Simulasi (KPa)	Teoretis (KPa)	Allowable Stress (MPa) (KPa)	Ratio (%)	Status
Sustained (W+P1)	185	9150	9149,7	174	12,7	OK
Sustained (W+P2)	185	13725	13724,6	174	14,4	OK

Berdasarkan tabel di atas, dapat dilihat dilakukan dua kali simulasi dengan menggunakan beban *sustained*. Jenis beban yang digunakan adalah beban keseluruhan sistem ditambah dengan tekanan operasional dan beban *sustained* menggunakan beban keseluruhan sistem ditambah dengan tekanan desain. Dapat dilihat dari simulasi pertama, bahwa nilai tegangan maksimal yang dialami oleh jaringan pipa adalah sebesar 9150 KPa. Sementara, hasil perhitungan teoritik dengan menggunakan rumus dengan data yang ada adalah 9149,763 KPa. Secara keseluruhan kedua nilai tersebut tidak lebih besar dari tegangan yang diizinkan berdasarkan kode dan standar ASME 31,8 yaitu sebesar 174000 Kpa seperti pada Gambar 26 dibawah ini.



Gambar 26. *Grafik Beban Sustained (W+P1)*

Pada simulasi kedua, nilai tegangan maksimal yang dialami oleh jaringan pipa adalah sebesar 13725 KPa. Sementara, hasil perhitungan teoritis dengan menggunakan rumus dengan data yang ada adalah 13724.6457 KPa. Secara keseluruhan kedua nilai tersebut tidak lebih besar dari tegangan yang diizinkan berdasarkan kode standar ASME 31.8 yaitu sebesar 174000 KPa. Jadi untuk kedua percobaan tersebut baik menggunakan simulasi dan perhitungan teoritik dapat dikatakan aman seperti pada Gambar 27 dibawah ini.



Gambar 27. *Grafik Beban Sustained (W+P2)*

5. SIMPULAN DAN SARAN

5.1. simpulan

Berdasarkan hasil penelitian dan analisis tegangan pada pipa LPG Station Amurang terhadap umur pipa dengan perangkat lunak CAESAR II dapat disimpulkan bahwa:

1. Hasil simulasi LPG station di Amurang menyatakan bahwa sisa umur pipa dapat dihitung menggunakan kode standar API 570 dengan hasil yang berbeda untuk setiap dimensinya. Berikut merupakan penjabaran untuk setiap dimensinya seperti pada Tabel 14.

Tabel 14. Remaining Life *Pipa Berbagai Dimensi*

Dimensi	2”	4”	6”	8”
Sisa Umur	± 9 tahun	± 15 tahun	± 16 tahun	± 33 tahun

2. Secara keseluruhan, simulasi dilakukan sebanyak dua kali dengan beban *sustained*. Kedua simulasi tersebut menghasilkan nilai tegangan simulasi dan teoritik yang tidak melebihi nilai tegangan izin dari kode standar ASME 31.8.

5.2. Saran Pengembangan

Berdasarkan penelitian yang telah dilakukan, fasilitas pipa LPG Station Amurang masih sangat layak beroperasi dan memiliki kegiatan perawatan yang rutin dijalankan. Adapun saran yang dapat diberikan untuk pengembangan penelitian lebih lanjut sebagai berikut:

1. Perlu dilakukan inspeksi berkala dan pengontrolan berkelanjutan terhadap tekanan operasional, serta nilai ketebalan pipa.
2. Pengujian lanjutan disarankan agar dapat melakukan perbandingan data dengan penelitian seperti *risk based inspection dan fitness for service* lanjutan.

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PENULIS

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THE PERFORMANCE OF SUBSEA FLEXIBLE RISERS WITH DISTRIBUTED BUOYANCY MODULES CONFIGURATION IN THE OIL AND GAS BROWNFIELD (CASE STUDY : KAKAP NATUNA FIELD)

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Abstract

Distributed Buoyancy Modules (DBM), a relatively new riser structure technology, are rarely used on flexible risers in Indonesia Oil and Gas Fields which are dominated by brown fields. When compared to conventional subsea structures like Mid-Water Arches (MWA), DBM has a number of advantages. DBM provides lower budget spending due to the shorter period and easier method in installation phase. The paper presents engineering design of DBM operation and installation in Kakap Field, Natuna Sea, Indonesia to replace the existing KH and KG Risers. This research analysed a number of instances to simulate the behaviours of risers using DBM.. According to static analysis, the maximum effective tension for KH and KG risers during operation with an acceptable value of less than 1530 KN are 100.7 KN and 83.4 KN, respectively. Meanwhile, the minimum bending radius for the risers when they are being operated are above the allowable value of 3.926 m which are 6.6 m and 6.7 m for KH and KG Riser in turn. The analysis indicates the both of risers are safe to operate during their life period.

1. INTRODUCTION

In the offshore oil and gas production process, exploited hydrocarbon resources are delivered from sea well to the offshore floating storage station called Floating Production Storage and Offloading (FPSO) [1]. This storage is crucially tied to flexible risers that are fitted with buoyancy modules, making them extremely complex and subject to technical or even environmental hazards that could result in increased costs. Due to the brownfield's short remaining life, cost is one of the primary issues.

The choice of the buoyancy mechanism that keeps the flexible riser "floating" at mid-water level may have a significant impact on the riser's configuration [1,2]. One option for producing effective risers with an uncomplicated configuration, simple installation process, and minimal equipment is to use Distributed Buoyancy Modules (DBM) [2,3]. In addition to helping create desired configurations and shapes, buoyancy modules are used to ensure the best structural performance against topside or tension loads of deepwater flexible risers [1,4]. Lazy Wave Riser Configuration is one of the most popular

configurations because it has superior resistance to dynamic conditions than the traditional Steel Catenary Riser (SCR)[1]. With the use of many design engineering simulations, it is possible to identify and analyze the high stress and fatigue damage reactions brought on by the dynamic conditions of a specific riser configuration.[4]

Based on the actual scenario, this paper discusses the performance of flexible risers after they have been connected with DBMs to produce the required Lazy Wave riser configuration. New risers and the DBM buoyancy system were installed on the 2 (two) sets of flexible risers, KH & KG risers. Interference evaluation, static condition analysis, and dynamic condition analysis are performed and addressed in the examination of the installed risers. These flexible risers with DBM have desirable structural performance against potential force due to bending and tension, which demonstrates that their arrangement might support operation safely. This is demonstrated by dynamic simulation and analysis. This installation carried out at Kakap Natuna Sea, Indonesia.

2. DATA AND CONFIGURATION

2.1. Riser Parameters

A lazy-wave configuration will be used for both KG and KH 10" risers with the length of 199 m and 175 m respectively. This configuration utilizes distributed buoyancy modules along a determine section of the riser length to provide a multi-curve/wavy shape to the catenary. This aims at reducing the riser weight hanged from the platform, minimize bending moment at the sag bend near the seabed and stress along the riser length and connections.

A section of the flexible will be stationary on the seabed in depth of 92.52 m (Mean Sea Level), followed by a buoyant section where the buoyancy modules are distributed. This induces a hog bend into the flexibles, followed by a sag bend and with the final hanging catenary terminating into a flange at the SPM. Bend stiffeners for both risers are located at the topside SPM hang-off point. The general riser configuration along with the SPM mooring lines which have 6 chains are shown in Figure 1. The chains are divided into 2 sections which are Segment A (at SPM) and Segment B (at Anchor) with the length of 165 m and 289 m as well as R4 and ORQ for their grade respectively. In addition, detailed parameters of the flexible pipe for both the KG & KH riser are shown in Table 1. Note that KG and KH risers are identical in characteristic and properties. The nomenclatures of KG and KH Flexible Risers are described in Figure 2.3. The other environment parameters with respect to coming direction (wave origin direction) are shown in Table 2.2, 2.3. 2.4. and 2.5.

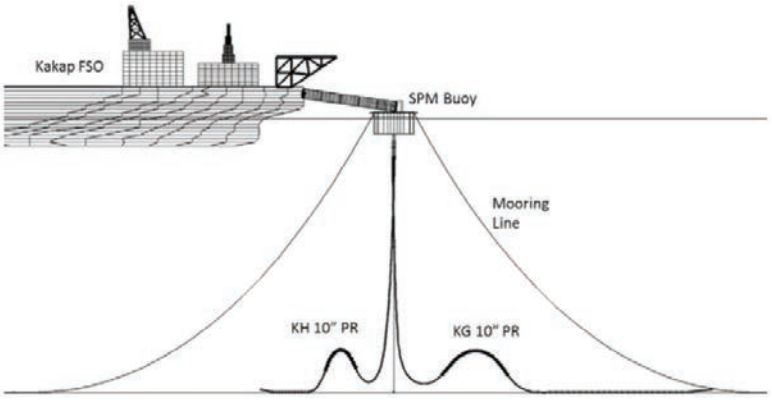


Figure 1. *Flexible risers & mooring line configuration elevation view.*

Table 1. *KH & KG Flexible Riser Configuration.*

Flexible Riser	SBM to PLEM horizontal distance	Lower Catenary Length	Buoyant Section Length	Upper Catenary Length	Number of Buoyancy Modules	Buoyancy Module Centre to Centre Spacing
KH	88.5 m	44 m	30 m	101 m	14 m	2.19 m
KG	106 m	60 m	46 m	93 m	21 m	2.19 m

Table 2. (a) *Extreme wave 100yr RP sea state parameters.*

Parameter	Unit	N (0°)	NE (45°)	E (90°)	SE (135°)	S (180°)	SW (225°)	W (270°)	NW (315°)
H_{max}	[m]	9.5	12.5	9.3	6.0	7.6	8.5	7.1	8.7
T_{lower}	[s]	8.2	9.4	8.1	6.5	7.3	7.7	7.0	7.8
T_{mean}	[s]	9.1	10.4	9.0	7.2	8.1	8.6	7.8	8.7
T_{upper}	[s]	10.0	11.4	9.9	7.9	8.9	9.5	8.6	9.6
H_s	[m]	5.1	6.7	5.0	3.2	4.1	4.6	3.8	4.7
T_p	[s]	9.9	11.3	9.8	7.9	8.8	9.3	8.5	9.5
T_z	[s]	7.7	8.8	7.6	6.1	6.9	7.3	6.6	7.4

Table 2. (b) *Extreme wave 1yr RP sea state parameters, Ref Error! Reference source not found. Table 3-18*

Parameter	Unit	N	NE	E	SE	S	SW	W	NW
		0°	45°	90°	135°	180°	225°	270°	315°
H_{max}	[m]	7.2	9.1	6.7	4.2	5.4	6.4	5.2	6.4
T_{lower}	[s]	7.1	8.0	6.8	5.5	6.2	6.8	6.0	6.8
T_{mean}	[s]	7.9	8.9	7.6	6.1	6.9	7.5	6.7	7.5
T_{upper}	[s]	8.7	9.8	8.4	6.7	7.6	8.3	7.4	8.3
H_s	[m]	3.9	4.9	3.6	2.3	2.9	3.4	2.8	3.5
T_p	[s]	8.6	9.7	8.3	6.6	7.5	8.1	7.3	8.1
T_z	[s]	6.7	7.5	6.4	5.1	5.8	6.3	5.7	6.3

Table 2. (c) *Extreme 100yr RP current parameters, Ref Error! Reference source not found. Table 3-21*

Depth [m]	N	NE	E	SE	S	SW	W	NW
	0°	45°	90°	135°	180°	225°	270°	315°
0.0	0.60	0.60	0.60	1.00	1.10	0.90	0.40	0.50
23.1	0.40	0.40	0.40	0.80	0.90	0.80	0.30	0.30
46.3	0.20	0.20	0.30	0.70	0.80	0.60	0.20	0.20
69.4	0.20	0.10	0.20	0.60	0.70	0.50	0.10	0.10
91.5	0.10	0.10	0.10	0.40	0.40	0.30	0.10	0.10

Table 2. (d) *Extreme 1yr RP current parameters, Ref Error! Reference source not found. Table 3-23*

Depth [m]	N	NE	E	SE	S	SW	W	NW
	0°	45°	90°	135°	180°	225°	270°	315°
0.0	0.50	0.50	0.50	0.90	1.00	0.80	0.40	0.40
23.1	0.40	0.30	0.40	0.80	0.90	0.70	0.30	0.30
46.3	0.20	0.20	0.30	0.70	0.80	0.60	0.20	0.20
69.4	0.20	0.10	0.20	0.60	0.70	0.50	0.10	0.10
91.5	0.10	0.10	0.10	0.40	0.40	0.50	0.10	0.10

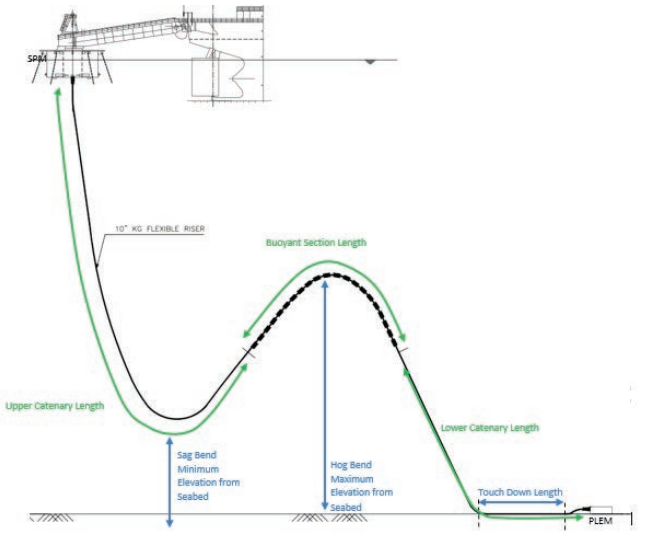


Figure 2. *KH & KG Flexible Riser Lazy Wave Configuration Nomenclature*

2.2. Vessel Parameters

Kakap Natuna Floating Storage Offloading (KN FSO) Vessel is the vessel that will be used during the operation of risers. The vessel has an adequate stability due to large size with the length of 314.64 m, 43.40 m width and 8.49 m ballasted draught. The vessel Response Amplitude Operator (RAO) for Kakap FSO are extracted from analyses performed in Moses of the vessel, for both ballasted and loaded.

3. METHODOLOGY

The design methodology for this paper will be based on applicable standard and company specification. Figure 3 shows the workflow adopted for the KG & KH riser replacement design. The workflow is primarily driven by the requirement to provide regular interface deliverables for detailed design engineering phase. Analysis will be performed by Analysis was performed using Moses and Orcina's Orcaflex™ Version 10.1C and it was assisted by Third-party.

3.1 Mooring Analysis

There are two stages to carry out mooring analysis. The first stage is to get the motion response of the FSO. The analysis will be performed by employing diffraction approach to obtain the first-order (high frequency) motion responses under the excitation of regular waves, the second-order (low frequency) motion responses and motion statistics of the vessel under the excitation of random waves. Further, the hydrodynamic motion properties of the FSO will be obtained

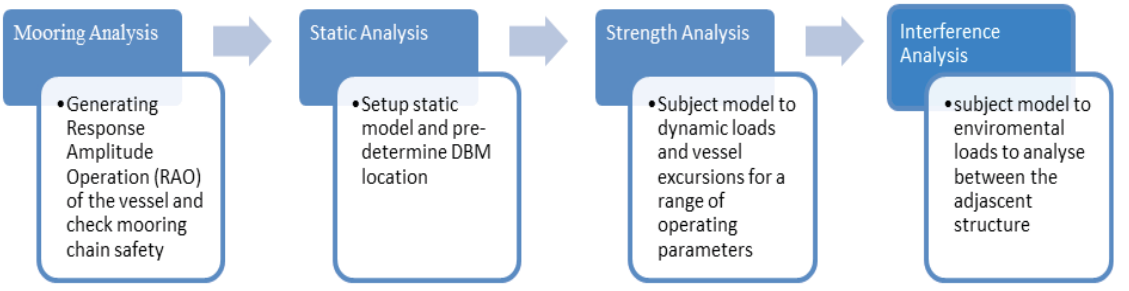


Figure 3. *Workflow.*

based on the result of environmental loading. This analysis will be carried out in MOSES.

The second stage is the computation of mooring line tension and buoy excursion. A moored structure can be characterized as a dynamical system subject to the various environmental conditions with low and high frequency excitation as result of the wind, waves and current acting on the system. The reaction forces are a combination of added mass forces, wave drift damping forces, viscous forces and combined restoring and damping forces interacting with mooring lines. The buoy and mooring line tension are simulated using ORCAFLEX based on the excitation and reaction for simulating the buoy excursion and mooring line tension.

3.2 Static Analysis

The static analysis is the analysis step to ensure the correct design of the DBM. The basics of the static analysis are to:

- Insert input data from basis of design document into finite element analysis software;
- Re-adjust and iterate the location, spread, etc of the DBMs along the flexible riser to ensure visibly correct lazy-wave configuration of both risers.
- Perform static / quasi-static analysis, and re-adjust DBMs as per above point.

3.3 Strength Analysis

The dynamic analysis is performed as time domain analysis. Each of load case is analysed based on the current profile and regular waves. The relevant extreme regular wave height Hmax and associated period Tass is derived from significant wave height, peak period and spectral shape. Morrison's equation is used to calculate the hydrodynamic action on the riser and distributed buoyancy modules. The extreme load case matrix considers the following parameters. If any items in the load case are shown to be non-critical, these may be excluded during detailed design.

1. System State. Two states are considered in the analysis. Start of Life (SOL) is characterised by initial as-built conditions of riser system. End of Life (EOL) is based on the changes occurred in the riser system (e.g. Marine Growth development and water ingress).
2. Contents Density. Minimum and maximum density during operation are considered in the analysis.
3. Environment (Wave-Current). The directionality of the environmental conditions is applied in accordance with the associated vessel offset and vessel loading condition. Note that the environmental conditions are given for the 8 compass directions N, NE, E, SE, S, SW, W and NW. 100 year and 1 year environmental conditions are considered in the analysis.
4. Riser Temperature and Pressure. Critical combinations of riser pressure and temperature will be analysed. In general, a pressurized cold state will give the highest interface loads, while a depressurized hot state will give the highest utilization of minimum bending radius of the flexible riser.
5. Vessel Offset. Vessel excursion is considered in the analysis to ensure that all aspects of interference and structural design criteria are sufficiently investigated.

3.4 Interference Analysis

During the interference analysis, the extreme load case matrix (Table 17) is investigated by extracting relevant clearance between risers and adjacent structures. Furthermore, visual inspection of critical load cases is carried out.

The following cases are investigated:

1. Mooring line interference: Clearances

between risers and mooring lines are extracted for all load cases.

2. Seabed interference: Clearances between risers and mooring lines are extracted for all load cases.

SPM buoy body interference: Clearances between risers and buoy body are extracted for all load cases. Interference between risers and the buoy body is not allowed at any times.

4. ANALYSIS AND DISCUSSION

4.1. Mooring Analysis

4.1.1 FSO RAOs and Combined System Motions

The Kakap Natuna FSO vessel Response Amplitude Operators (RAOs) have been generated based on the vessel characteristics (geometry and dead weight) and body linesplan to accurately model the hull shape. A set of environmental loads were applied to the model and the dynamic responses of the vessel body have been calculated in all six (6) degrees of freedom. The analysis and motions calculations were performed using the commercial software MOSES. As the FSO is attached to a Single Point Mooring structure it was necessary to create a combined model of FSO and SPM linked by a rigid structure with hinged connection to generate the motions of FSO plus SPM.

4.1.2 FSO and SPM Mooring Analysis

The analysis study was carried out in two phases. Phase one relates to 3D diffraction analysis performed in MOSES to obtain the motion responses of the FSO in free floating condition. Phase two relates to the coupled time domain analyses performed using ORCAFLEX, with the motion responses obtained from Phase one.

Two mooring configurations were applied (in-line and between-line) as per Figure 4(a) and 4(b) for two FSO draughts. For each analysis condition, Ultimate Limit State (ULS) with "all line intact" and Accidental Limit State (ALS) with "one line damaged case" are considered as per statutory requirement. Intact indicates that the mooring system is operating normally (vessel excursions are controlled), whilst Damaged means that one (1) mooring leg has failed (vessel excursions are more prominent). The survival condition with 100 years return period of environmental load and operating condition with 1 year return period of environmental load have been considered. All environmental elements (wave, current, and wind) are assumed collinear as conservative approach.

From the analysis results, maximum mooring lines tension and maximum excursion of the FSO plus SBM are summarized in the Table 3 and Table 4.

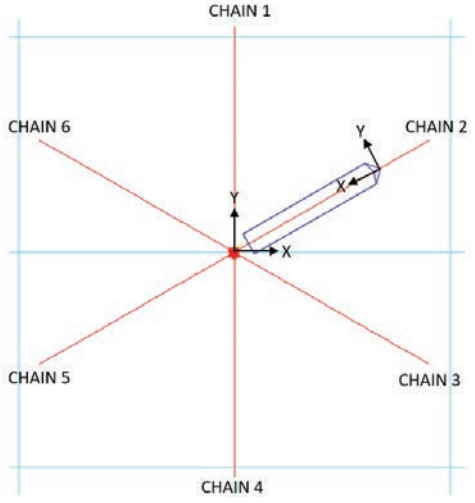


Figure 4. (a) *In-Line Mooring Configuration*

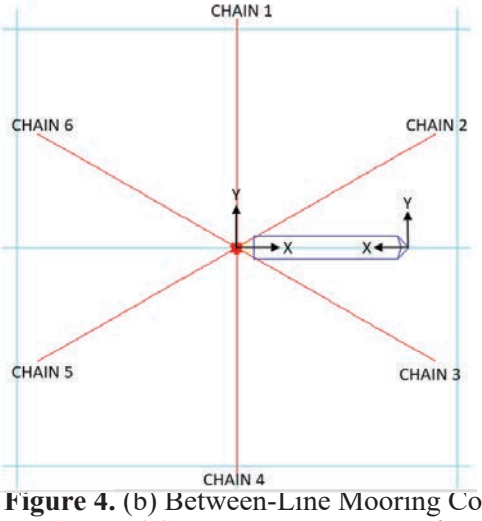


Figure 4. (b) Between-Line Mooring Configuration

Figure 4. (b) *Between-Line Mooring Configuration*

Table 3. *Mooring Analysis Results Summary for Intact Condition*

Environmental Load	Vessel Condition	Condition	Mooring Line Tensions			Maximum SBM Excursion
			Max.	SF	Remark(1)	
Survival Condition (1 YRP)	Ballast	In-Line	59.33 MT	8.00	OK	6.16 m
		Between-Line	53.87 MT	8.81	OK	7.47 m
	Fully Loaded	In-Line	83.51 MT	5.68	OK	15.65 m
		Between-Line	93.58 MT	5.07	OK	14.33 m
Operating Condition (100 YRP)	Ballast	In-Line	101.71 MT	4.67	OK	8.39 m
		Between-Line	84.71 MT	5.60	OK	10.60 m
	Fully Loaded	In-Line	281.72 MT	1.68	OK	20.99 m
		Between-Line	228.82 MT	2.07	OK	22.66 m

Notes:

1. The mooring lines strength assessment criteria are 60% and 80% of minimum breaking load for intact and on-line damage case [11]. SF for Safety Factor.
2. The minimum breaking load calculation is based on de-rated capacity considering 38 years of service life.

Table 4. *Mooring Analysis Results Summary for One-Line Damage Condition.*

Environmental Load	Vessel Condition	Condition	Mooring Line Tensions			Maximum SBM Excursion
			Max.	SF	Remark(1)	
Survival Condition (1 YRP)	Ballast	In-Line	80.16 MT	5.92	OK	8.52 m
		Between-Line	85.50 MT	5.55	OK	8.96 m
	Fully Loaded	In-Line	108.55 MT	4.37	OK	21.39 m
		Between-Line	136.24 MT	3.48	OK	14.82 m
Operating Condition (100 YRP)	Ballast	In-Line	112.12 MT	4.23	OK	13.77 m
		Between-Line	125.39 MT	3.78	OK	13.79 m
	Fully Loaded	In-Line	252.09 MT	1.88	OK	31.97 m
		Between-Line	346.20 MT	1.37	OK	19.07 m

4.2. Static Analysis

The static analysis [1] is considered to be the foundation of subsequent dynamic analyses and aims to establish the equilibrium configuration of the riser system due to weight, buoyancy, tension and current. In this analysis, Finite Element Analysis was conducted in Orcaflex based on provided flexible data and hang-off / tie-in locations which were modelled as fix. Vessel excursions (herein called "Offsets") of the SPM & FSO are categorized into three (3) types: Nominal offset, Far Offset and Near Offset which are depicted at Figure 5. The Far Offset is categorized into two (2) subsets: Intact and Damaged. The load case matrix for the static analysis is shown in Table 5.

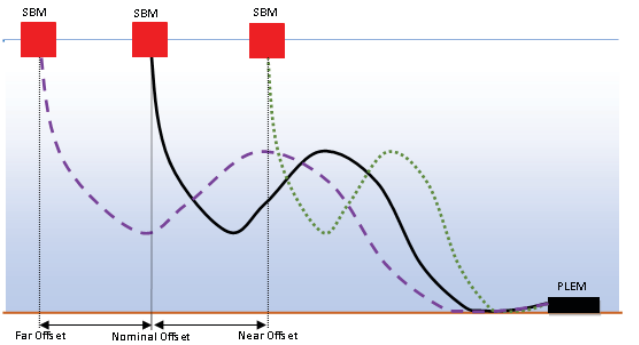


Figure 5. *Nominal, Far & Near Offset Descriptions*

Table 5. *Flexible Riser Configuration Analysis Load Case Matrix.*

Flexible Riser	Service	Riser Content Density [kg/m3]	Riser Content Pressure [barg]	Vessel Excursion	Current Loading[3]
KH & KG	Start of Life	Operational Mean (796)	Operational Maximum (28.3)	- None(1) - Damaged Near & Far(2)	100yr RP

Analysis results for the KH and KG flexible riser configuration static assessment are presented in Table 6 and Table 8 respectively, with interface loads at the hang-off position at the SPM and subsea tie-in at the PLEM presented in Table 7 and 9 in turn. For all considered flexible riser integrity critical results, the KH and KG flexible riser in its current configuration is acceptable.

Table 6. *KH Flexible Riser Results (Static).*

Position	Offset [m]	Maximum Effective Tension [kN]	Minimum Effective Tension [kN]	Minimum Bending Radius [m]	Touch Down Length [m]	Sag Bend Minimum Seabed Clearance [m]	Hog Bend Maximum Elevation from Seabed [m]
Nominal	0	96.7	5.8	8.4	14.9	15.0	32.5
Near	38.85	94.6	-2.8	6.6	12.7	15.1	37.7
Far	38.85	100.7	20.1	10.3	15.0	17.8	25.6
Allowable [12]		< 1530	> -50	> 3.926	> 0	> 0	< 67.5
Acceptable		þ	þ	þ	þ	þ	þ

Table 7. *KH Flexible Riser Hang Off and Subsea Interface Loads (Static).*

Position	Offset [m]	Maximum Hang Off Tension [kN]	Maximum PLEM Connector Tension [kN]	Maximum Hang Off Bending Moment [kN.m]	Maximum PLEM Connector Bending moment [kN.m]
Nominal	0	96.7	7.6	7.0	54.1
Near	38.85	94.6	-0.4	9.3	19.7
Far	38.85	100.7	20.6	22.7	53.2
Allowable [12]	-	< 300	< 300	< 150	< 150
Acceptable	-	þ	þ	þ	þ

Table 8. *KG Flexible Riser Results (Static).*

Position	Offset [m]	Maximum Effective Tension [kN]	Minimum Effective Tension [kN]	Minimum Bending Radius [m]	Touch Down Length [m]	Sag Bend Minimum Seabed Clearance [m]	Hog Bend Maximum Elevation from Seabed [m]
Nominal	0	80.7	8.1	9.3	15.9	29.9	56.5
Near	38.85	78.1	0.3	6.7	16.0	25.7	60.62
Far	38.85	83.4	19.45	14.4	15.9	31.62	48.42
Allowable [12]		< 1530	> -50	> 3.926	> 0	> 0	< 67.5
Acceptable		þ	þ	þ	þ	þ	þ

Table 9. *KG Flexible Riser Hang Off and Subsea Interface Loads (Static).*

Position	Offset [m]	Maximum Hang Off Tension [kN]	Maximum PLEM Connector Tension [kN]	Maximum Hang Off Bending Moment [kN.m]	Maximum PLEM Connector Bending moment [kN.m]
Nominal	0	80.7	9.8	13.0	52.4
Near	38.85	78.1	3.4	3.5	53.1
Far	38.85	83.4	21.9	26.0	32.8
Allowable [12]	-	< 300	< 300	< 150	< 150
Acceptable	-	þ	þ	þ	þ

4.3. Strength Analysis

The vessel offsets for the strength analysis are applied in 5 directions for each riser, Near, Quartering Near, Transverse, Quartering Far and Far with respect to the plane of the flexible riser (Figure 6). This in turn examines each flexible riser for maximum vessel offsets conditions and a complete strength overview is analyzed. The offset used is both intact and damaged vessel excursions. The load case matrix for the strength assessment is shown in Table 10.

Table 10. *Strength Assessment Load Case Matrix.*

Operating Conditions	Service	Riser Content Density [kg/m3]	Riser Content Pressure [barg]	Vessel Excursion	Environmental Loading
Normal (Intact Mooring) Abnormal (Damaged Mooring)	Start of Life End of Life Marine Growth Sensitivity	Operational Mean (796) Operational Max (1000)	Operational Min. (0) Operational Max. (28.3)	Near Far Transverse Quartering Near Quartering Far	Directional 100yr RP Wave and Current

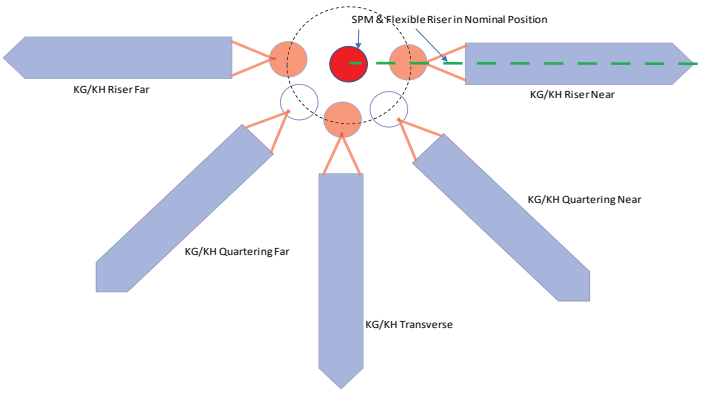


Figure 6. *Vessel Offset and Environmental Directions (Strength Analysis)*

4.3.1 KH and KG Flexible Riser Strength Analysis Results

The structural integrity of the KH and KG flexible risers are maintained and acceptable throughout the analysis. Results pertaining to the MBR, tension and interface loads are presented in the following three (3) sections, presented below.

4.3.1.1 KH and KG Flexible Riser Minimum Bending Radii

The overall MBRs of the KH and KG flexible risers are presented in Table 11 This MBR represents the minimum bending radius that the flexible riser experienced throughout the analysis, at any length along the risers. All MBRs presented are above the stipulated minimum MBR as per the acceptance criteria stated in the Supplier Specification. The MBR occurs in the sag bend of the flexible riser, during "Near" vessel offset conditions.

Table 11. KH and KG Flexible Riser MBR.

Operating Condition	Mooring Condition	FSO Condition	Overall Minimum Bend Radius	
			KH [m]	KG [m]
Normal	Intact	Fully Loaded	4.98	4.63
		Ballasted	4.63	4.12
Abnormal	Damaged	Fully Loaded	5.17	4.36
		Ballasted	4.94	4.38
Allowable [12]			3.926	

4.3.1.2 KH and KG Flexible Riser Tension

Overall maximum and minimum tensions of the KH and KG flexible riser are presented in Table 12. The overall minimum tension within the flexible pipe is negative, indicating compression. This compression is within allowable limitations. Likewise, the overall maximum tension is within the structural allowable limitations of the flexible.

Table 12. KH and KG Flexible Riser Tensions.

Operating Condition	Mooring Condition	FSO Condition	Overall Min. Tension		Overall Max. Tension	
			KH [kN]	KG [kN]	KH [kN]	KG [kN]
Normal	Intact	Fully Loaded	-9.03	-7.39	185.73	161.44
		Ballasted	-15.57	-11.82	178.28	154.04
Abnormal	Damaged	Fully Loaded	-7.83	-9.02	182.84	155.60
		Ballasted	-14.70	-11.33	169.08	146.49
Allowable			-50		1530	

4.3.1.3 KH and KG Flexible Risers PLEM & SPM Hang-Off Interface Loads

The maximum KH and KG flexible pipe interface loads at the SPM hang-off and PLEM tie-in are presented in Table 13 and Table 14, respectively. All interface loads are within the allowable limitations.

Table 13. KH Flexible Riser Interface Loads.

Operating Condition	Mooring Condition	FSO Condition	SPM Hang Off Interface		PLEM Tie-In Interface	
			Max. Tension [kN]	Max. Bending Moment [kN.m]	Max. Tension [kN]	Max. Bending Moment [kN.m]
Normal	Intact	Fully Loaded	185.73	27.45	26.43	65.36
		Ballasted	178.28	39.24	34.54	75.06
Abnormal	Damaged	Fully Loaded	182.84	26.71	32.50	74.43
		Ballasted	169.08	37.94	37.94	68.02
Allowable [12]			300	150	300	150

Table 14 *KG Flexible Riser Interface Loads.*

Operating Condition	Mooring Condition	FSO Condition	SPM Hang Off Interface		PLEM Tie-In Interface	
			Max. Tension [kN]	Max. Bending Moment [kN.m]	Max. Tension [kN]	Max. Bending Moment [kN.m]
Normal	Intact	Fully Loaded	161.44	24.76	24.76	82.47
		Ballasted	152.89	31.76	31.76	93.10
Abnormal	Damaged	Fully Loaded	155.60	29.21	29.21	87.14
		Ballasted	146.49	26.29	26.29	87.27
Allowable [12]			300	150	300	150

4.3.2. Marine Growth Sensitivity

The worst load case for MBR of the KG flexible riser was selected and the full Marine Growth profile applied to the DBM and flexible riser. The results of this load case are presented in Table 1, alongside the sensitivity assessment utilizing Marine Growth.

Table 15. *KG Flexible Riser Marine Growth Sensitivity – MBR.*

Marine Growth Included	Operating Condition	Mooring Condition	FSO Condition	Vessel Offset and Environmental Loading Direction	Overall Minimum Bend Radius
No	Normal	Intact	Ballasted	KH Riser Quartering Near	4.12 m
Yes	Normal	Intact	Ballasted		5.25 m
Allowable [12]					3.926

As can be seen by Figure 2, Table 15 and Table 16, the minimum bend radius and maximum effective tension increase because the marine growth adds the weight of risers. It leads to hog bend elevation decrease and sag bend elevation increase. With the assumption of SPM and PLEM are the fixed points of riser, the additional weight results bigger tension on the riser to seabed. In this simulation, the marine growth is assumed to have 30 mm thickness and 1325 kg/sq.m for its density.

Table 16. *KG Flexible Riser Marine Growth Sensitivity – Tension.*

Marine Growth Included	Operating Condition	Mooring Condition	FSO Condition	Vessel Offset and Environmental Loading Direction	Overall Max. Effective Tension
No	Normal	Intact	Fully Loaded	KG Quartering Far	185.73 kN
Yes	Normal	Intact	Fully Loaded		198.28 kN
Allowable [12]					1530

4.3.3 Flexible Riser Design Pressure Sensitivity

A sensitivity study utilizing the maximum design pressure of the flexible pipe has been performed the results shown in Table for KG Riser and KH Riser. The study was conducted under fully loaded FSO at KG Quartering Far Position as well as normal mooring and operating condition because the maximum pressure could be reached in this condition. It is to be noted that the design pressure cases of 206 barg are meant to be performed using a 1yr RP environment. For conservatism, the same 100yr RP environment as used for the remainder of the study reported in this document was utilized. The worst MBR load case for the KG riser was selected to be presented as a comparison to the 206 barg internal pressure case.

Table 17. KG Flexible Riser Design Maximum Pressure Sensitivity.

Riser Internal Pressure	Overall Minimum Tension [kN]		Overall Maximum Tension [kN]		Minimum Bending Radius [m]	
	KG	KH	KG	KH	KG	KH
28.3	-8.30	4.55	139.09	162.08	4.66	8.58
206	-8.31	4.57	139.07	162.13	4.66	8.60
Allowable [12]	-50		1530		3.926	

As can be seen in the results tables, differences between the normal operating pressure and maximum design pressure on the riser response characteristics are numerically insignificant

4.4. Interference Analysis

Interference analysis has a significant role to make sure clashing energy among the subsea structure below the limit. The excess clashing energy could produce the riser broken then cause hydrocarbon spill which is harm for the environment. The load case matrix for interference analysis is shown in Table 8.

Table 18. Interference Assessment Load Case Matrix.

Operating Conditions	Service	Riser Content Density [kg/m^3]	Riser Content Pressure [barg]	Vessel Excursion	Environmental Loading
Normal (Intact Mooring) Abnormal (Damaged Mooring)	Start of Life End of Life Marine Growth Sensitivity	Operational Mean (796) Operational Max (1000)	Operational Minimum (0) Operational Maximum (28.3)	Near Far North North East South East South South West North West	Directional 100yr RP Wave and Current

The interference analysis results summarizing the general findings of the KH & KG flexible riser clashing with adjacent mooring lines is presented in Table below. The results shown in this table are the minimum clearance distances that have been obtained from the FEA analysis for all considered load cases. The results are divided into two analysis categories, quasi-static and dynamic analysis.

- For normal operating conditions, no clashing is observed for all considered load cases. The minimum clearance observed between a flexible riser and a mooring line after the exposure of an extreme environment to the riser system is 0.10m. It is to be reiterated that this result is conservative.
- For abnormal operating conditions and with a fully loaded FSO, contact is observed. This contact is already observed in the quasi-static analysis, as such the dynamic analysis does not differ as is anticipated. For a ballasted FSO, no contact between the flexible risers and mooring lines is observed.

For all cases considered and as shown in Table 9 below, the quasi-static analysis shows larger clearances than the dynamic analysis, which is expected.

Table 19. *Analysis Results Summary.*

Operating Condition	Mooring Condition	FSO Loading Condition	Minimum Clearance between Flexible Risers (KH & KG) to all six (6) Mooring Lines	
			Quasi-Static Analysis	Dynamic Analysis
Normal	Intact	Fully Loaded	1.62 m	0.10 m
		Ballasted	2.86 m	0.41 m
Abnormal	Damaged	Fully Loaded	Contact	Contact
		Ballasted	3.83 m	0.59 m

Figure (a) on the following page present the quasi-static minimum clearances between each flexible riser and the adjacent mooring lines for each load case (720 total load cases). A separation line between normal and abnormal operation conditions is shown to ease the interpretation of this graphic. Points scattered within this plot are representative of the minimum clearances between both KH & KG risers and their nearest adjacent mooring lines. A plot point above the zero (0) clearance distance (shown as a red dotted line) indicates that no clashing has been observed. It is clear from the graphic that for abnormal operating conditions and certain load cases, the flexible risers are in contact with the mooring lines. No contact is observed for normal operating conditions.

Figure shows the dynamic analysis, following the quasi-static analysis in the preceding image. As can be observed in the figure, most clearance values have decreased (i.e.: flexible risers are closer to the mooring lines) during the dynamic analysis. This is to be expected, as wave loading will contribute to motion of the flexible risers & mooring lines. As with the quasi-static analysis, no clashing is observed for normal operating conditions and only a limited amount of load cases show clashing (plot points below zero (0) clearance) for abnormal operating conditions.

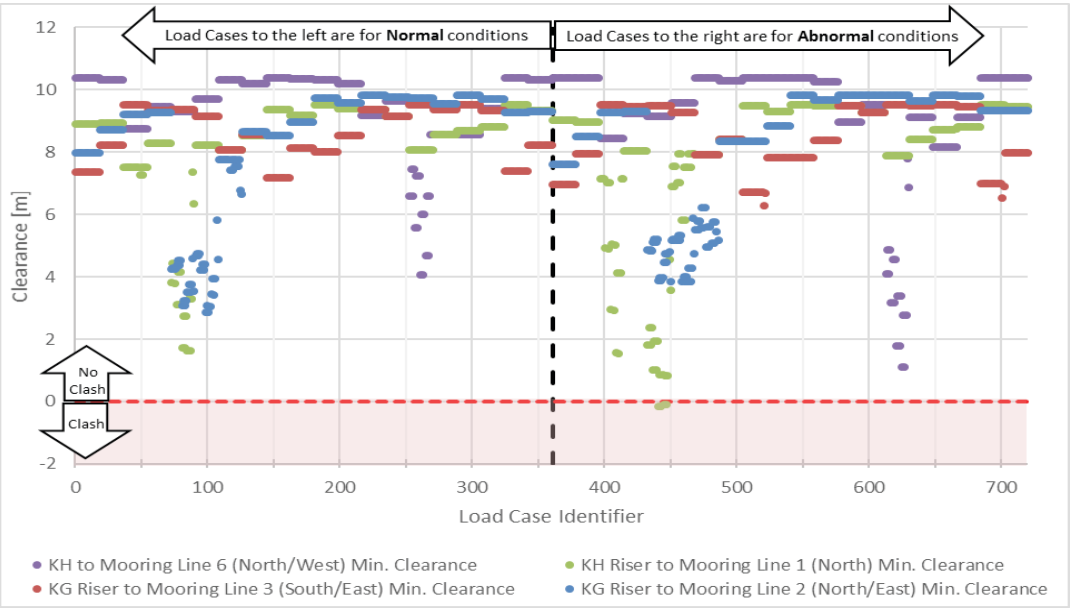


Figure 7(a) *Quasi-Static Analysis Minimum Clearance Plot*

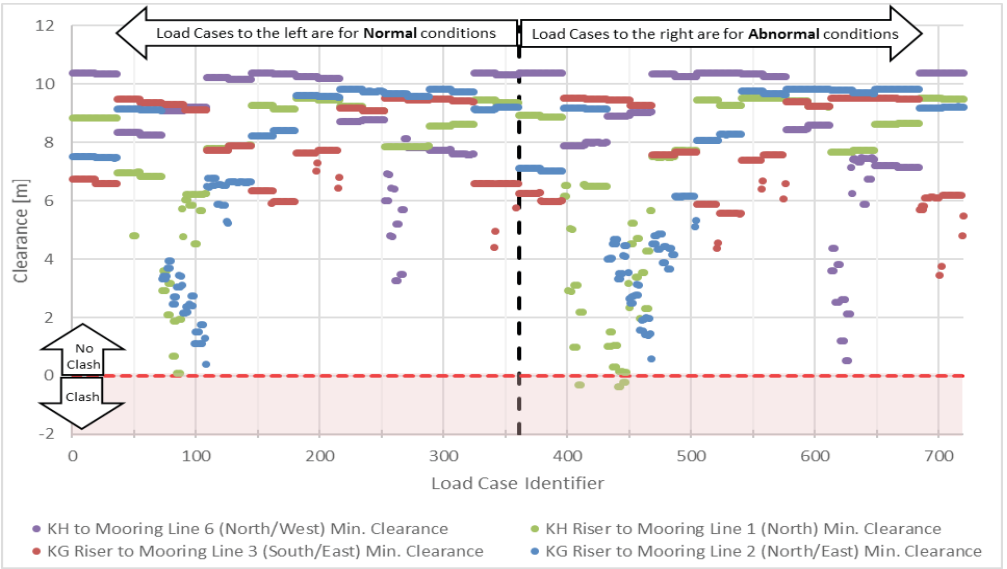


Figure 7(b) *Analysis Minimum Clearance Plot*

4.4.1 KH Flexible Riser Clashing Energy Analysis

Due to the KH flexible riser exhibiting contact with mooring line #1 in some of the analyses, a clashing energy assessment is herein performed and reported. Clashing assessments are very computational intensive, as such only load cases which exhibit clashing have been analyzed. A total of 6 load cases out of 720 (i.e.: 0.8%) exhibited contact. The load cases to which clashing is isolated to, are the fully loaded FSO, single line mooring failure and end of life system configurations. The maximum clashing energy between the KH flexible riser and mooring line #1 are reported in Table 20. The maximum clashing energies exhibited by the analysis are small, indicating that the flexible riser contact impact with the mooring line is very light. In general engineering practice, a clashing energy value of less than 2 kJ of a flexible pipe is deemed to be acceptable [12].

Table 20. *KH Flexible Riser Clashing Energy.*

Operating Condition	Mooring Condition	FSO Condition	Riser System Life Cycle	Vessel Offset and Environmental Loading Direction	Maximum Clashing Energy [kJ]
Abnormal	Damaged	Fully Loaded	EOL	KH Riser Near North	0.083 0.032

5. CONCLUSION

This paper presents an engineering design of flexible risers with distributed buoyancy modules configuration. After conducting several analysis namely mooring analysis, static analysis and strength analysis, the designed flexible riser could meet allowable values. In theory, distributed buoyancy module could be consider as the one of alternative to replace conventional subsea structure in the harsh environment (Natuna Sea) due to its advantage in installation process. The interference analysis results in several cases, KH riser will clash with mooring line 1 but the energy is insignificant. It means that the clashing will not harm the equipment in the field which are dominated by aging ones.

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