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Ohio, United States

For Directorate General of Oil and Gas, Ministry of Energy and Mineral Resources, Republic of Indonesia (DG MIGAS)

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TA-9189 INO: Pilot Carbon Capture and Storage Activity in the Natural Gas Processing Sector

Gundih Block Feasibility Design and Costing

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Executive Summary

This document presents an updated feasibility study for the Gundih pilot carbon capture and storage project, which is authorized under the Asian Development Bank (ADB) Technical Assistance TA-9189 "Pilot Carbon Capture and Storage (CCS) Project in the Natural Gas Processing Sector (49204-002)" for evaluation and development of carbon capture and storage (CCS) technologies for mitigation of carbon dioxide (CO_2) emissions from anthropogenic sources. This feasibility study provides a near-final design for a two-year, 100,000 tonne, CO_2 capture and storage project at a site in Central Java, Indonesia. The project outlined in this document represents a major revision to the original pilot project design, which was documented in ITB (2015). The major differences are: the target CO_2 mass for the two-year project has been increased to 100,000 tonnes from 20,000 tonnes; CO_2 will be transported from the source (Gundih Central Processing Plant) to the injection site via pipeline rather than truck; and injection will take place at a new location in close proximity to the CPP, requiring a new injection well. Selection of a new injection site was conducted by ITB as part of their scope under their Center of Excellence (COE) contract with ADB. This feasibility study document provides a design, operations and maintenance requirements, subsurface monitoring plan, and a cost estimate for the two-year pilot CCS project. The pilot system includes the following functional components:

- Surface facility (source gas treatment (H2S removal, dehydration, and compression);
- Pipeline;
- Flow measurement facility;
- Injection well;
- Supervisory Control and Data Acquisition (SCADA) control system (computers, networked data communications and graphical user interfaces) for high-level process supervisory management;
- Subsurface monitoring infrastructure (in-well and above-ground monitoring equipment and instrumentation, multiple geophysical arrays cemented in shallow boreholes).

This Feasibility Study document is one of three documents that together provide an executable plan for the Gundih pilot CCS project. The other two companion documents are:

- **TA 9189 Gundih CCS Project** – PROJECT MANAGEMENT AND ASSURANCE PLAN (project risk assessment, project delivery plans, and project assurance framework)
- **TA 9189 Gundih CCS Project** – CCS PILOT PROJECT TENDERING AND PROCUREMENT BRIDGING STRATEGY (procurement documents suitable for soliciting budgetary quotes).

Collectively, this information will enable the ADB Board to determine whether the project should proceed to the field execution phase.

Section 1. Introduction

The Asian Development Bank (ADB) is providing technical assistance to the Republic of Indonesia under TA-9189 INO: Pilot Carbon Capture and Storage Activity in the Natural Gas Processing Sector (49204-002) for evaluation and development of carbon capture and storage (CCS) technologies for mitigation of carbon dioxide (CO_2) emissions from anthropogenic sources. As part of this effort, Battelle (Battelle's team members include Trimeric Corporation, Elnusa, and Serenity West Pacific Corp.) was selected in April 2018 to provide technical advisory support for the project. In the initial phase of work, Battelle conducted a due diligence and state of readiness review of the proposed Gundih pilot storage project as described in the original feasibility study for the project (ITB, 2015). As a part of the initial phase of work, Battelle also reviewed other information and documents that became available after the 2015 feasibility study was released that proposed modifications to the original project design. A list of documents and information reviewed is provided in Battelle (2018).

Based on the recommendations made by Battelle (2018) following the initial project review, ADB directed Battelle to conduct a more detailed due diligence assessment of the Gundih Project. The primary objectives of the current phase of work are to: 1) update the Gundih pilot project feasibility study (reference) to reflect changes in the injection well location and other aspects as needed, 2) prepare a project risk assessment, project delivery plans, and a project assurance framework consistent with the technical approach defined in the feasibility study; and 3) develop procurement documents suitable for soliciting budgetary quotes (typically +/- 20% accuracy).. Collectively, this information will enable the ADB Board to determine whether the projects should proceed to field execution phase.

This document presents the updated feasibility study; the other requirements described above, i.e., objective 2) (project risk assessment, project delivery plans, and a project assurance framework and objective 3) (procurement documents suitable for soliciting budgetary quotes) are each provided in a separate companion document to this feasibility study. This document includes the following information:

- Surface facility design
- Transport facility design
- Injection site design
- Operation and monitoring requirements
- Cost estimate

1.1 Gundih CCS Pilot Design Overview

The concept of the Gundih CCS pilot project as described in the original Feasibility Study (ITB et al., 2015) has three primary components as illustrated in Figure 1-1. These include CO_2 capture (separation) and treatment/conditioning for truck transport, transport to the injection well site via truck, and deep well injection with monitoring. Battelle's review/analysis of the feasibility study recommended modifications to the design, which are identified in

Table 1-1, along with the final design decision incorporated in this document. Battelle (2018) recommendations include identifying a new injection site that is closer to the CPP with amenable properties for the injection test, so that the cost of CO_2 pipeline transport would be more comparable to truck transport, and the cost and risk associated with truck transport can be reduced. Battelle also recommended a cost-benefit analysis to select the best-suited transportation option. This was done as part of the current study, and as a result, the pipeline option was selected. This reduces treatment at the central processing plant (CPP) because liquefaction is eliminated, and handling requirements are essentially eliminated both at the CPP and the injection site. In exchange, compression of the CO_2 at the CPP is added for the pipeline option. In this study, the “tap point” for obtaining CO_2 at the Gundih CPP, a subject of extensive discussion due to inconsistent performance of the Bio-SRU (sulfur removal unit), is downstream of the H_2S absorber so the source gas to the pilot project has a lower hydrogen sulfide (H_2S) concentration. This assumes that the Bio-SRU performance becomes consistent at its design treatment H_2S concentration of 3,000 ppm. ADB has indicated that they will not support the pilot study if the Bio-SRU cannot be operated consistently to achieve this level.

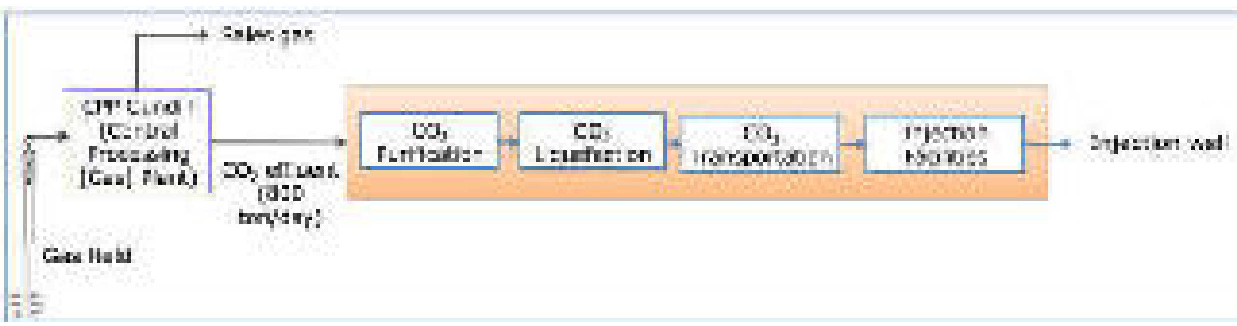


Figure 1-1. Conceptual schematic of the original Gundih Pilot Project Design (from ITB et al., 2015).

Table 1-1. Components of the Gundih CCS pilot Project (ITB et al. 2015), recommendations from Battelle (2018), and final design incorporated in the current study.

Key Component
• Capture 30 tonnes of CO_2 per day (20,000 tonnes over two years) from the Gundih natural gas central processing plant (CPP) in Central Java, • Transport the CO_2 via truck to the Jepon field about 60 km away where it would be injected into an existing well (Jepon-1), and • Conduct subsurface and surface monitoring in the vicinity of the injection site for two years.
Recommendations from Battelle (2018)
• The location of the tap point for the source gas will have a significant impact on the pilot project design. Assuming the Bio-SRU performance becomes consistent at its design outlet H_2S concentration of 3,000 ppm, the tap point should be downstream of the H_2S absorber (see location 2 in Figure 1-2) so the source gas to the Pilot Project has a lower H_2S concentration. A lower H_2S concentration translates into lower operating costs and a better fit for a solid scavenger system. If the operating costs can be kept reasonable, the lower capital cost of a scavenger system can be a good fit for a pilot project. • Transportation: trucking over large distances is not recommended; try to locate the new injection site close to the CPP so that both trucking and pipeline are both viable; • The Jepon-1 well is not recommended for use as the injection well due to integrity issues. Furthermore, the geology of the area around the Jepon-1 well is not suitable for a pilot injection test. A new injection site closer to the CPP needs to be selected so that CO_2 transport via pipeline could be considered as an alternative to trucking. In the case of the pipeline option, the CO_2 capture process would not require a liquefaction step and the dehydration method could be with glycol. Both actions would result in less capital and operating cost for the pilot. • Conduct subsurface and surface monitoring in the vicinity of the injection site for two years but adjust monitoring design to new site geology/conditions.
Final Design Incorporated in the current Feasibility Study Document
• The tap point for the source gas will downstream of the H_2S absorber (see location 1 in Figure 1-2). • CO_2 transport via pipeline • A new injection site has been selected at the Gundih CPP. Injection rate for the Pilot increased from 30 t/d (20,0000 tonnes over 2 years) to 150 t/d (100,000 tonnes over 2 years). • Subsurface and surface monitoring will be conducted in the vicinity of the injection site for two years.

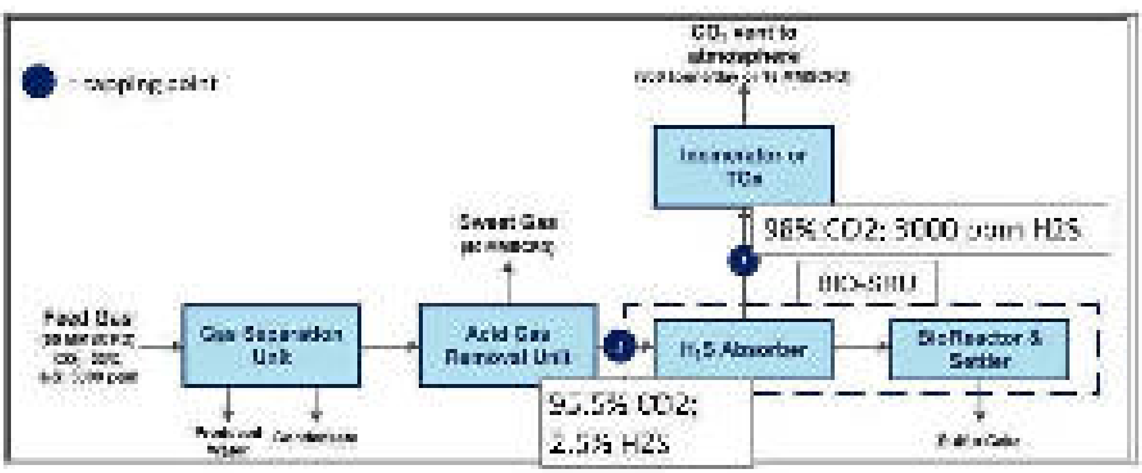


Figure 1-2. Gundih gas processing plant schematic showing possible tap points for the pilot-scale treatment system.

1.2 New Injection Well Location

The injection site for the Gundih CCS Pilot test is a critical component of the test. A site was sought that is close to the source of CO_2 so that transportation is affordable and that has requisite reservoir properties (injectivity, thickness) necessary to minimize spreading of CO_2 (i.e., plume area), which reduces monitoring requirements, and requisite caprock properties (permeability, capillary pressure, thickness, absence of fractures and faults) to permanently contain the plume within the intended injection reservoir. Selection of a new injection site was conducted by ITB as part of their scope under their Center of Excellence (COE) contract with ADB. The new site was visited by the project team and the report can be found in appendix D. The new site is briefly described below and elsewhere in this document, however, the reader interested in more details should consult the complete ITB (2019) study. As part of their study, ITB (2019) conducted numerical modeling to simulate the injection, spreading, and containment of 100,000 tonnes of CO_2.

The location for the proposed Injection well is within the Gundih Area, which is comprised of three separate gas fields: KTB (Kedung Tuban), RBT (Randu Blatung), and KDL (Kedung Lusi). developed in the Kujung Formation. Figure 1-3 shows the location of the Gundih Area in Central Java.

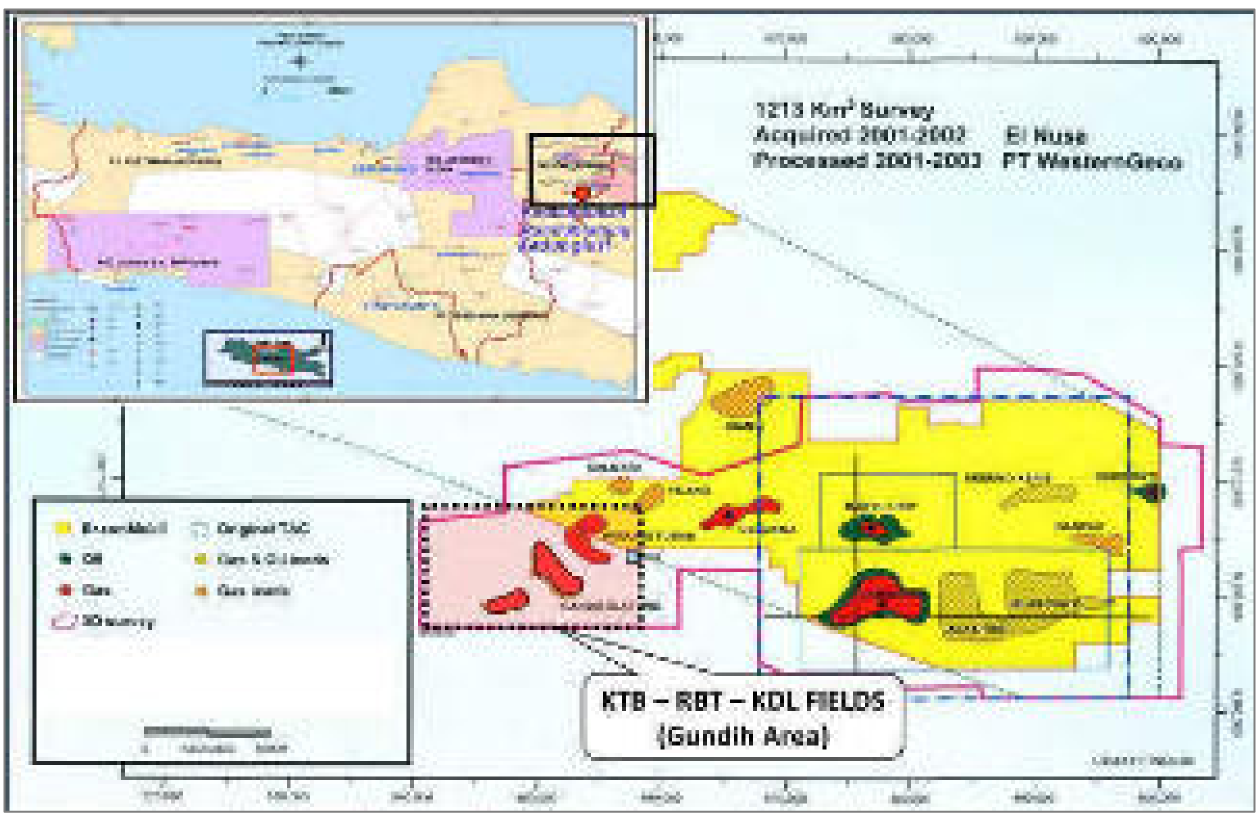


Figure 1-3. Location of the Gundih Area showing the three gas fields KTB, RBT, and KDL.

To determine the best location for the injection well, ITB (2019) modeled CO_2 injection and spreading at three locations each with multiple injection rates. The three candidate injection locations were chosen based on properties of the reservoir, including i.e. porosity, permeability, and distance of well to reservoir target. In all simulations, the CO_2 was injected near the bottom of the reservoir to minimize the potential for CO_2 injection to adversely affect production of methane gas from the upper portion of the reservoir. The three injection locations are referred to as INJ-2, INJ-3, and INJ-4. Three injection rates were simulated for each of the three well locations, including 0.57 MMSCFD for two years (30 tonnes/day), 2.85 MMSCFD for two years (100 tonnes/day), and 15 MMSCFD for 10 years (800 tonnes/day). The second scenario (2.85 MMSCFD for two years) is the design case for the Pilot Test. The first rate (0.57 MMSCFD for two years) was the injection design included in the original feasibility study (ITB et al., 2015) and was reevaluated by ITB for the purpose of comparing the quality of the new sites under consideration to the original Jepon-1 well site. The third injection rate (2.85 MMSCFD for 10 years) was evaluated by ITB to assess the feasibility of injecting 100% of the CPP plant CO_2 emissions.

The surface location for all three candidate injection wells is the well pad for the existing KTB-4 production well; however, the trajectory for each of the wells is different and consequently so is the bottomhole depth (total well depth includes horizontal and vertical lengths), and location, as shown in Figure 1-4.

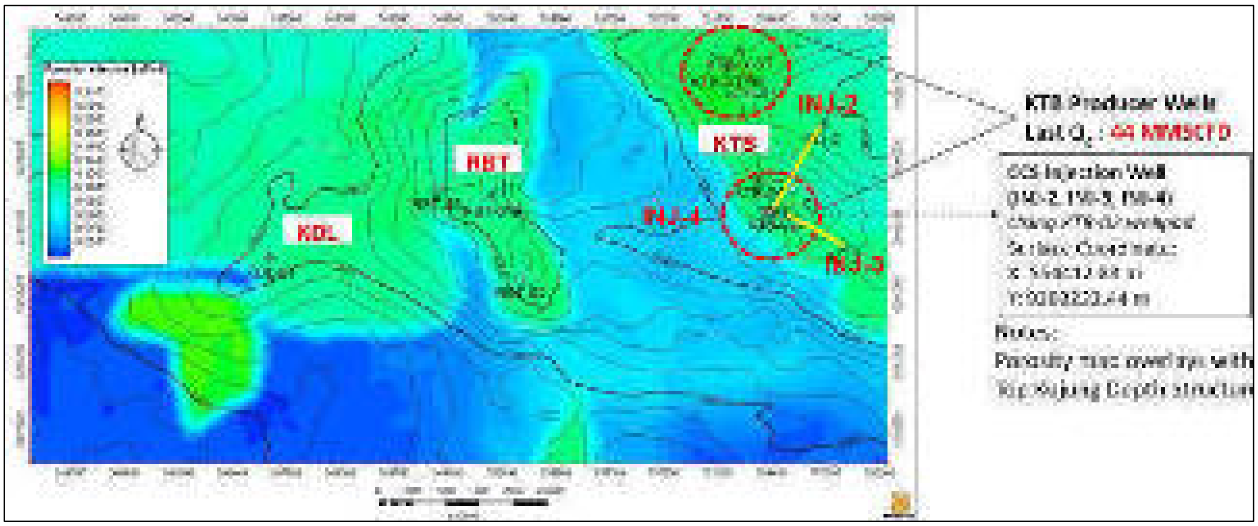


Figure 1-4. The three candidate injection well locations evaluated by ITB (2019): INJ-2 (directional well), INJ-3 (directional well) and INJ-4 (vertical well).

The rationale for INJ-2 was to locate the injector well far from the productive gas zones, although the permeability is not highly favorable (average permeability near INJ-2 well is 14 mD). On the other hand, INJ-3 and INJ-4 are both located in areas with better porosity and permeability, but closer to the productive gas zone. The rationale for INJ-04 (vertical well) is to minimize total well depth and therefore cost relative to INJ-2 and INJ-3.

Figure 1-5, Figure 1-6, and Figure 1-7 are the cross section of simulated CO_2 movement for the most conservative scenario for each of the three wells (plotted in CO_2 mole fraction grid) for the design injection rate of 100,000 tonnes over two years (2.85 MMSCFD for two years). The light blue grid is the gas productive zone, the dark blue is the water zone / aquifer and the red is the CO_2 injected. Other model scenarios are provided in the ITB (2019) report. Based on these results and other factors (e.g. proximity to the CPP, injection well INJ-02 was selected for the purpose of developing an injection well design and cost estimate for this feasibility study)(note: INJ-2 was selected because initially ITB only modeled this well location and the modeling results for the INJ-3 and INJ-4 locations were not available in time to develop a well design for this report. However, using the information provided in this report, a well design and cost estimate could easily be developed for these other two locations).

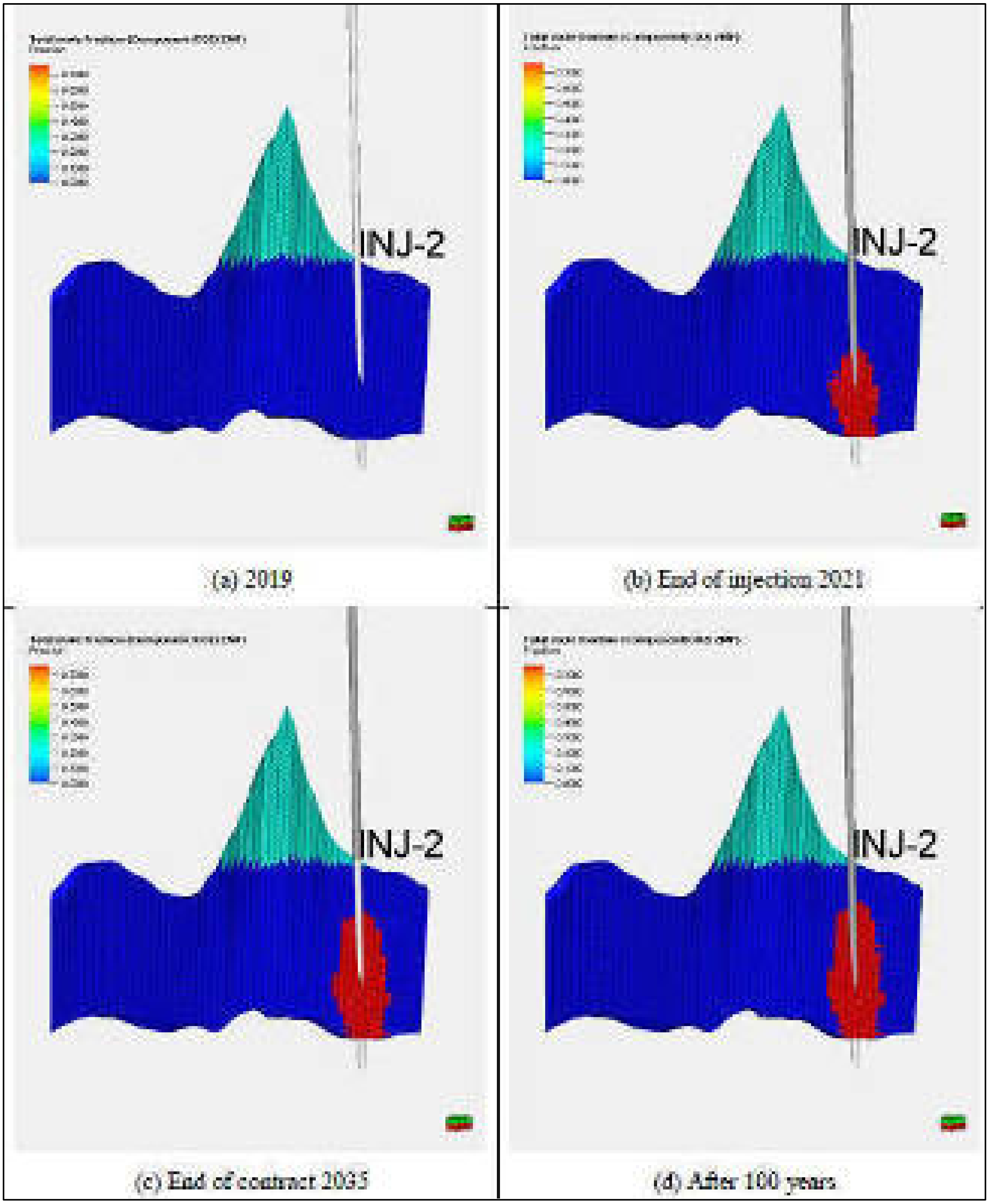


Figure 1-5. Total mole fraction CO_2 case 2C kv/kh 0.5 (a) initial; (b) end of injection 2021; (c) end of contract 2035; (d) after 100 years (source: ITB, 2019).

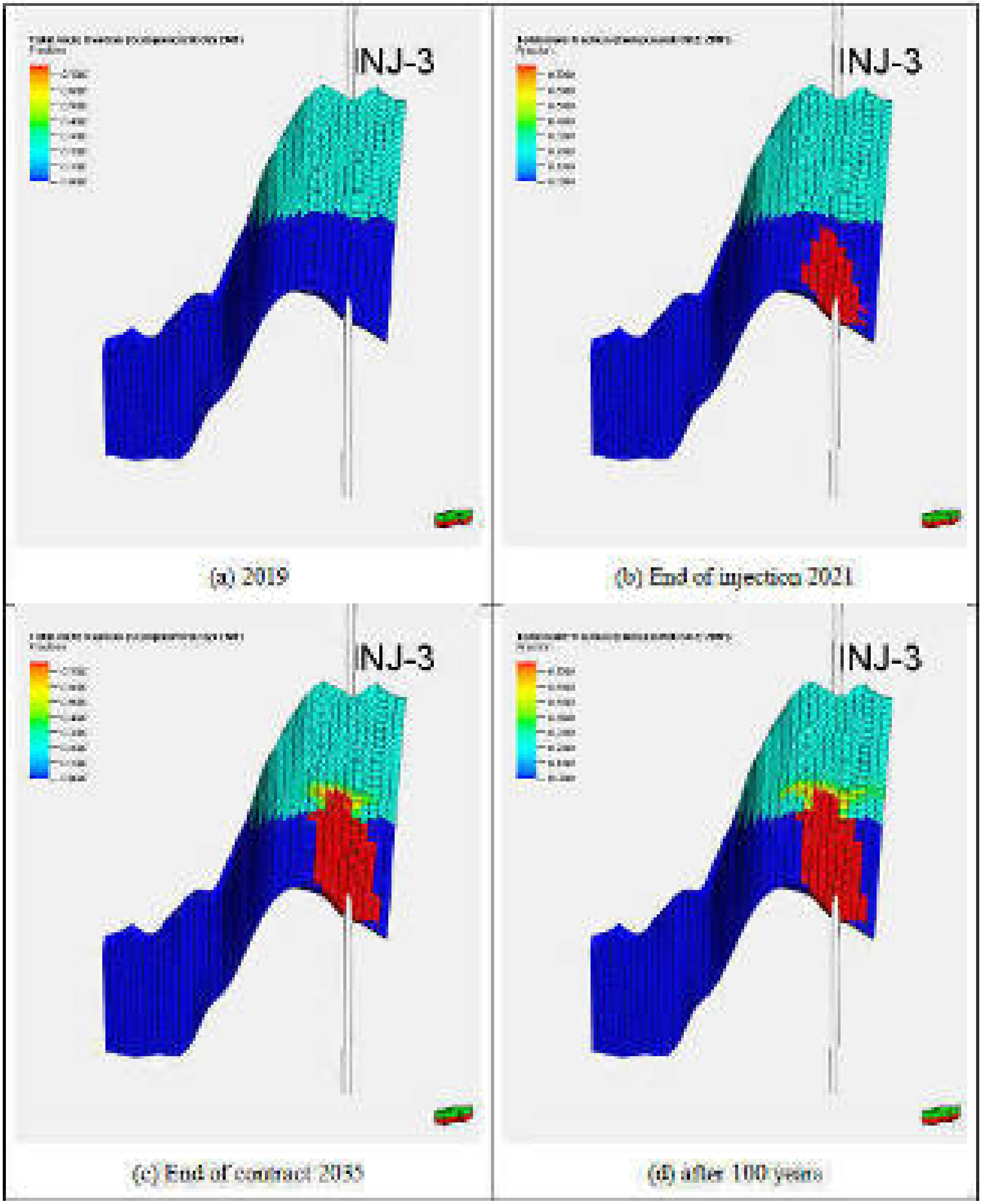


Figure 1-6. Total mole fraction CO_2 case 2B kv/kh 0.5 (a) initial; (b) end of injection 2021; (c) end of contract 2035; (d) after 100 years (source: ITB, 2019)

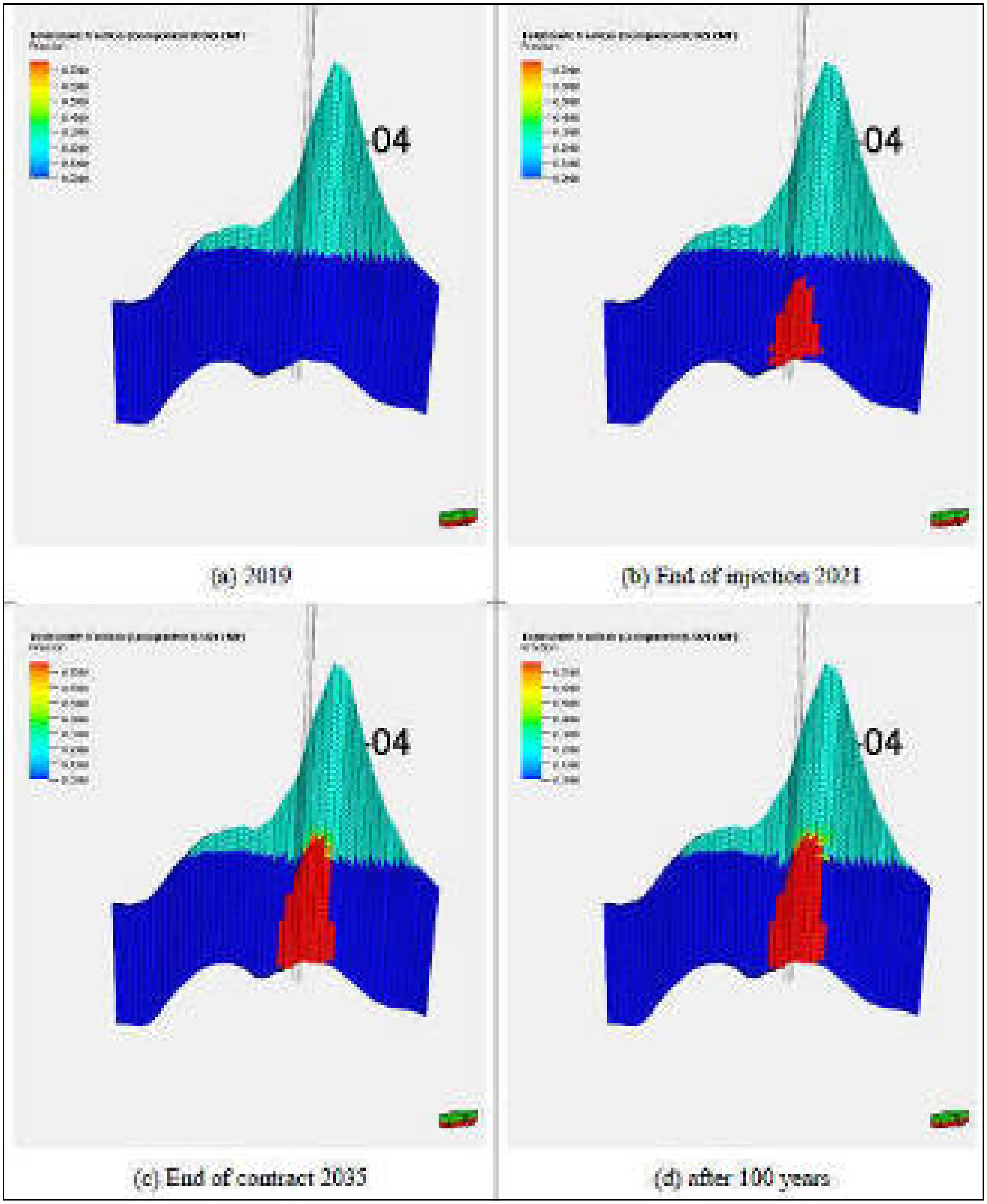


Figure 1-7. Total mole fraction CO_2 case 2A kv/kh 0.5 (a) initial; (b) end of injection 2021; (c) end of contract 2035; (d) after 100 years (source: ITB, 2019).

Section 2. Surface Facilities Design

2.1 Introduction

The Gundih CPP is a significant source of CO_2 that can be used for an injection project. The CO_2 is from the removal of CO_2 and H_2S from natural gas (NG) production by an acid gas removal unit (AGRU). The AGRU vent has a CO_2 flow rate of about 800 tpd and H_2S concentration of 2.5%. At the CPP, the majority of the H_2S is removed in an H_2S absorber and then routed to a thermal oxidizer that converts the remaining H_2S to SO_2. This process arrangement at the Gundih CPP is shown in Figure 2-1.

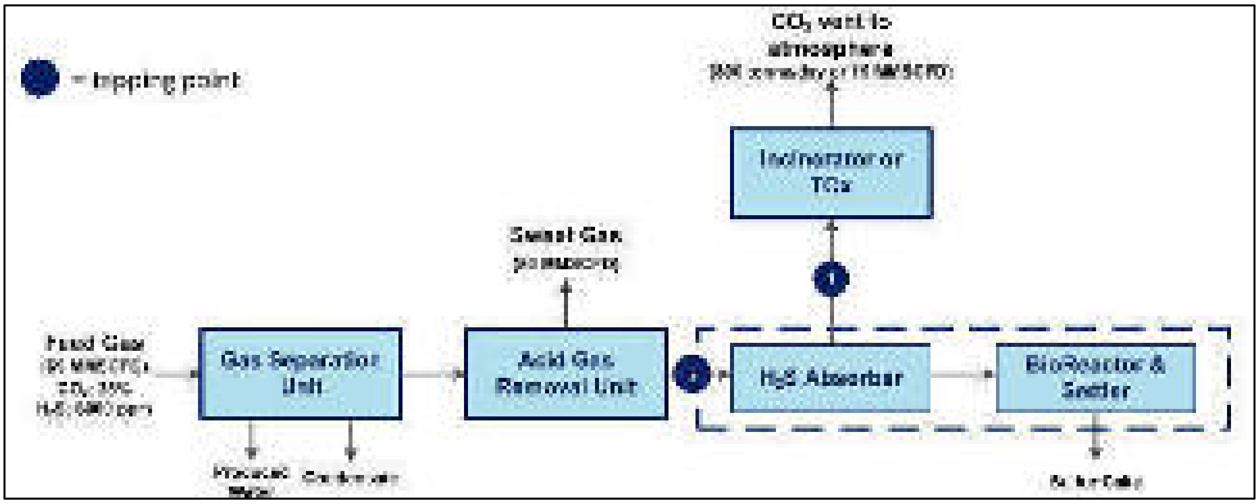


Figure 2-1. Process arrangement displaying H_2S absorber outlet as CO_2 tapping point.

Past studies have evaluated the process and cost benefits of selecting take-off location 1 (downstream of the H_2S absorber) for the CO_2 source or take-off location 2 (upstream of the H_2S absorber). The cost of H_2S removal has been shown to be a significant component of the pilot project and the H_2S concentration at location 1 is about 10% of location 2. Using take-off point 1 for the pilot takes advantage of the existing H_2S treatment at the Gundih CPP and reduces the overall equipment size and cost of H_2S treatment required for the pilot project. The CO_2 source and process design outlined in this report represent a balance between capital and operating costs for the pilot project, keeping the overall costs reasonable for a two-year injection period.

2.2 Basis of Design

The surface equipment of the pilot project for the treatment and transport of the CO_2 source stream from the Gundih CPP was designed and evaluated for two (2) injection flow rates, 30 tons/day (0.58 MMSCFD) and 150 tons/day (2.85 MMsSCFD). Reservoir evaluation identified an injection well for the project ~4.3 km from the Gundih CPP. A review of surface conditions confirmed there was an existing right-of-way available for a pipeline. The use of a pipeline to transport CO_2 was selected based on previous transport analysis and the benefits of simplifying the process and operations of the surface equipment.

The major equipment and process flow of the surface equipment is shown in Figure 2-2. The compressor, H_2S scavenging system, and glycol dehydration are available as equipment packages; this can reduce the cost and schedule of site construction activities. The design and specification of equipment for suppliers to develop commercial offerings is discussed in the next section.

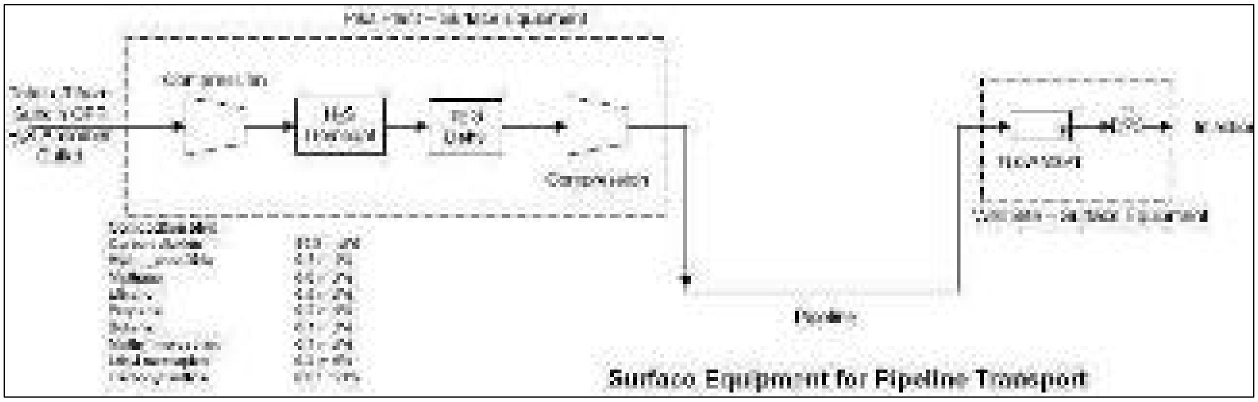


Figure 2-2. Surface equipment process flow.

The gas composition and conditions used for the surface equipment design is based on the data in the 2017 ICoE report. The composition (dry basis) of this stream is shown in the figure, but the stream is water saturated from the Gundih CPP.

The process equipment was also designed to meet the CO_2 product specification of:

- Water content less than 30 lb H2O / MMscf
- H2S less than 50 ppmv
- Injection pressure and temperature: 2,000 psig /100° F.

In addition, available utilities at the plant site included power, fuel gas, and instrument air. Some provisions for connecting to the infrastructure are assumed. The overall utility usage from the pilot project is small in comparison to existing Gundih CPP operations.

2.3 Design Specification

Information developed during the design specification phase of a project depends on the type of equipment associated with the process. In general, the level of information developed must be sufficient to communicate the equipment details of the process such that a supplier can develop budgetary cost proposals. The equipment types associated with the CO_2 Pilot Project are common in the oil and gas industry and are packaged by suppliers with a standard approach for skid layout or equipment arrangement. The information developed included process description, process simulation results, process flow diagrams, and technical scope documents for cost proposals. The technical scope documents developed for suppliers can be found in the tender documents prepared for this project.

An abbreviated description of the major equipment package skids and specific process details are included in this discussion. The process flow diagram of the surface facilities associated with the pilot project is shown in Figure 2-3. Material balance information for select streams is shown based on process simulation results from Virtual Materials Group's Simulator, VMGSim. Internal checks of the CO_2 property estimates have been done on previous CO_2 projects and there is a high confidence in the results.

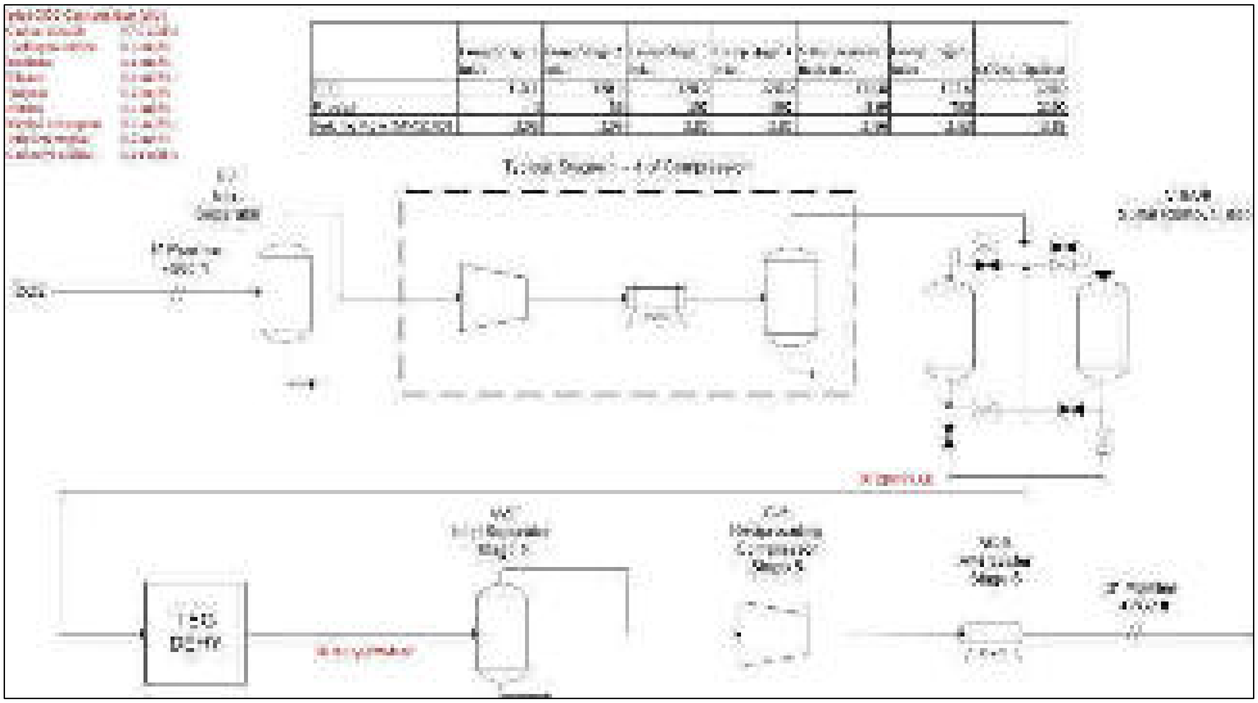


Figure 2-3. Diagram displaying the process flow of the surface facilities associated with the pilot project.

2.4 Process Description

The CO_2 source at the Gundih CCP is at low pressure (5 psig); therefore, an 8-inch diameter, 500 foot pipeline will be required to transport the gas from the source to the pilot facility to limit pressure drop in the line. The first unit operation of the pilot project is compression. A 5-stage reciprocating compressor will be used to raise the pressure from about 4 psig to about 2,100 psig. The sour CO_2 stream will be compressed sequentially through four (4) stages and then diverted after the stage 4 discharge cooler to the H_2S scavenger and TEG dehydration units. The interstage pressure for H_2S and water removal is approximately 850 psig. H_2S removal is the first process step, because the scavenger material is more effective on a water saturated stream.

The selected H_2S removal method is a solid bed adsorbent scavenger; SulfaTreat 2242 material is the basis for vessel design and operating cost. Liquids from the CO_2 stream are removed in a separator before entering the H_2S removal system to prevent fouling of the material (gas should be water saturated, but without any liquids). The H_2S scavenger system consists of two (2) pressure vessels operating in series in a lead-lag configuration, in the top and out the bottom of each vessel. When H_2S concentrations begin to approach 500 ppmv leaving the lead vessel, plans should be made to change the lag vessel to serve as the lead vessel and to replace the scavenger material in the original lead vessel. Each vessel will be capable of meeting the 50 ppmv limit on its own, therefore CO_2 will be processed in a single bed while the spent material is removed and replaced.

After H_2S removal, water is removed from the CO_2 in a triethylene glycol (TEG) dehydration process. TEG systems are very common in natural gas processing applications, and those used in CO_2 service are similar with a few modifications to the materials of construction. The basic configuration includes a contactor to remove water from the CO_2 and a regenerator to remove the absorbed water from the TEG so it can be returned to the absorber and reused. The wet gas stream flows up the contactor (with internal trays or structured packing) while TEG flows down, countercurrent to the gas flow in the vessel. Dehydrated CO_2 leaves the top of the vessel, while rich TEG (TEG that contains the dissolved water) leaves the bottom of the vessel. There is typically a pressure reduction step in a flash vessel that releases some CO_2 (usually vented, but can be routed to lower suction stage of compressor), followed by one (1) or more heat exchange steps between the rich TEG on its way to the regenerator and the lean TEG on its way from the regenerator back to the absorber.

Following water removal, the dry CO_2 stream from the contactor is routed back to the compressor and the 5th stage of compression boosts the stream to 2,100 psig for transport to the injection well. The discharge of the compressor is higher than the required injection pressure of 2,000 psig to account for pressure drop loss that can occur in measurement and the pipeline. The flow rate into and out of the pipeline will be measured to provide a means of continuously monitoring the integrity of the line.

Equipment Description

Select process information is listed below for the major equipment to provide context to the requirements of the surface equipment of the pilot project.

5-stage reciprocating compressor

- Boosts pressure from about 4 psig to about 2,100 psig, power requirement estimated at 915 HP.
- Each stage of compression consists of a vertical two-phase suction separator, suction pulsation bottle, one (1) or more cylinders, discharge pulsation bottle, and an air-cooled heat exchanger (intercooler for stages 1 through 4 and final cooler after stage 5).
- A typical setup for this application would be a 5-stage, 6-throw reciprocating compressor. There would be two (2) cylinders for stage 1 and one (1) cylinder each for stages 2 through 5.
- The main driver could be an electric motor or NG engine. For estimating operating costs for this equipment, a NG engine was used. Equipment costs would be similar for either driver type.
- The skid will include a control panel, PLC (programmable logic controller), and instruments such as pressure transmitters, temperature transmitters, and vibration sensors needed to monitor and control the operation of the reciprocating compressor system.
- Materials of construction prior to H2S and water removal are typically 304L or 316L stainless steel on the cold, suction side of each stage (upstream of the cylinder(s)). Carbon steel can be used from the discharge of the cylinder(s) to the inlet to the air cooler, because the gas is well above its water dew point

H_2S Scavenger System

- Two (2) pressure vessels operating in series in a lead-lag configuration, CO_2 flows down through each bed.
- Vessel design and scavenger usage rates are based on Schlumberger SulfaTreat 2242 performance data
- Vessel size and change out frequency
- 8-ft diameter x 24-ft Seam to Seam (S/S), 19 day bed life for 150 TPD
- 6-ft diameter x 24-ft S/S, 45 day bed life for 30 TPD
- Operations to make plans for bed change out when H_2S out of lead vessel at 500 ppmv

- Each vessel is designed to meet the 50 ppmv requirement on its own, flow through one (1) vessel during bed change out
- Vessel isolation venting pressure for bed change out is manual operation
- Spent scavenger is disposed of following waste disposal testing; material is not regarded as a hazardous waste in similar applications
- Two (2) bed system will handle upsets (periods of higher H_2S levels) and still meet the product specification, but the time between change outs would be reduced
- Materials of construction (MOC) for the scavenger vessels for sour, water saturated CO_2 are typically 304L or 316L stainless steel

TEG Dehydration System

- TEG dehydration systems are a common unit operation in oil and gas operations
- Size of the pilot unit equipment is small compared to standard units. Approximate sizing are
- 1-ft contactor diameter
- 1 gpm lean glycol flow
- 100,000 Btu/hr reboiler size
- Process configuration of TEG system for CO_2 service is similar to natural gas service with the addition of 316L SS material for vessel MOC and rich TEG streams.
- A PLC was included in the specification for monitoring TEG flow/pressure/temperature and controlling reboiler operation. Many small dehydration units of this size operate as stand-alone systems without PLC control, and this could be an option to consider during final design

2.5 Control Philosophy

The control philosophy used to define the level of instrumentation for the pilot project was based on common industry practice for operational control of equipment with consideration of safety systems. The expected level of instrumentation detail was included in the technical scope information provided to suppliers for budgetary equipment quotation. However, a formal review of instrumentation or safety systems has not been performed for the project. In the next phase of the project, cause and effect diagrams would be developed and process hazard review meetings would occur to formally review the safety systems and instrumentation requirements of the project.

The general approach taken for instrumentation and control of the surface equipment associated with the pilot project is described below.

- No automation of the isolation valve at the take-off location inside the Gundih CPP facility. If pilot plant operations shut down, manual valve to the pilot unit will be closed and CO_2 source flow will route to thermal oxidizer as today.
- Emergency shutdown valves (ESV) will be located on the inlet gas to the pilot process, at the inlet to the pipeline, and at the outlet of the pipeline. These valves will operate to isolate the system in case of an operational upset.
- Inlet H_2S concentration will not be measured, the data from the Gundih CPP will be used to track this parameter.
- The performance of the H_2S treatment system will be monitored with an online analyzer in the process area or at the pipeline inlet.
- The performance of the TEG dehydration system will be monitored with an online analyzer in the process or at the pipeline inlet.

- The compressor package will include a PLC unit to monitor and control the operation.
- The H_2S removal system will not have automation.
- The TEG dehydration system will include a PLC unit to monitor and control operation.
- The flow into and out of the pipeline will be measured through orifice meters and the surface injection condition monitored at the well site.
- Data from the well site and the injection well will be transferred to the pilot surface facility location via fiber optic cable.
- PLC data and instrumentation from site and injection location will be integrated into HMI (human machine interface) screens for operators to monitor injection and a data historian will pull and store required information.

The control approach will be further defined during the detailed engineering phase of the project. In addition, the site specifications and company specifications (mechanical, electrical, civil, instrumentation, and other areas) of Pertamina will be referred to in order to refine the equipment packages and be the basis of the onsite work performed by the general contractor or EPC.

Section 3. Transport Facilities Design

3.1 Introduction

A pipeline will transport CO_2 from the surface equipment adjacent to the Gundih CPP to the injection well (4.3 km distance). The surface equipment will condition and deliver the CO_2 to the pipeline at a design pressure of 2,100 psig. The project team performed several site visits and determined an existing right-of-way could be used for routing the pipeline to the well. Figure 3-1 and Figure 3-2 depict the planned route of the flowline.

Figure 3-1. Layout of Pipelines (yellow line) from Gundih CPP to the INJ-2 injection well.

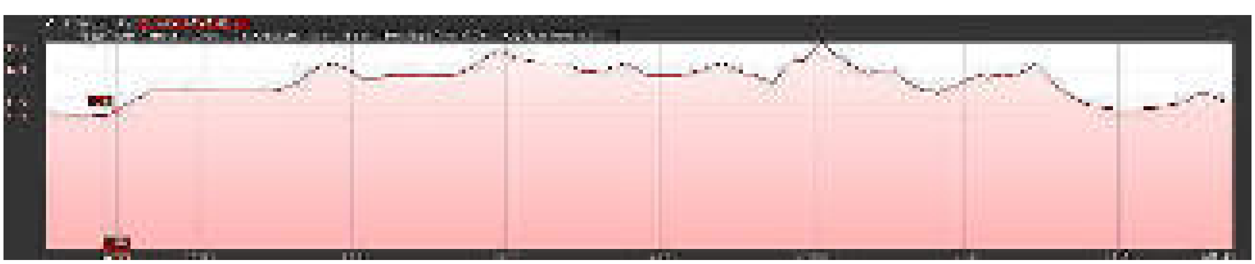


Figure 3-2. Elevation Profile Route from the INJ-2 injection site to the Gundih CPP.

3.2 Basis of Design

The pipeline design was based on the following conditions:

- Design pressure of 2,100 psig and temperature of 120° F
- Two (2) flow cases: 30 ton/day (TPD) (0.58 MMSCFD) and 150 TPD (2.9 MMSCFD)
- Hydraulic loss through the pipeline to be less than 20 psi

At this condition, the CO_2 will be in the supercritical fluid phase. It will be important to confirm flow measurement devices (flow computers) have a good thermodynamic properties package and calculation method for adjusting to the correct CO_2 density.

3.3 Design Specification

Hydraulic calculations performed identified a 2-in. diameter schedule 80 pipe would be sufficient for transport of 30 TPD and a 3-in. schedule 80 pipe would be sufficient for transport of 150 TPD. For the purposes of this project, the pipe diameter was increased one (1) pipe size for each for defining costs. The CO_2 entering the pipeline contains less than 30 lb H_2O/MMSCF, allowing for normal carbon steel for materials of construction.

The following list provides an example scope of supply for the pipeline contractor:

- Mobilization, demobilization, loading, hauling, clearing, grading, stringing, cutting, beveling, welding, valve installations, coating, holiday detection and repair, ditching, horizontal directional drilling, lowering in, backfilling, hydrostatic testing, gauging, inspection, dewatering, cleaning, drying, final cleanup, and right-of-way and site restoration.
- Furnish all labor, supervision, tools, equipment, and materials as required, except material specifically furnished by Company. The pipeline contractor is expected to provide the following items:
  - All temporary and permanent fencing and gate materials
  - All skids for use on the pipeline rights-of-way
  - All water and pumps, blinds, gaskets, etc. required for pressure testing the pipeline and related appurtenances
  - All welding equipment and supplies, including oxygen, acetylene and welding rod
  - All pigs and other material and equipment required for gauging, filling with water and cleaning the pipeline
  - All foam pigs, brush pigs, air compressors, dehydrators, monitors and controls required for drying the pipeline
  - All coating material and primer and/or fusion bond epoxy (FBE) coating machines, sand blasting materials and epoxy powder required for field joints and coating repairs on FBE coated line pipe including tools and equipment necessary for proper application
  - All epoxy/urethane coating material including tools and equipment necessary for proper application on field joints on FBE coated pipe used in auger bore, slick bore and horizontal directional drilled installations and concrete coated pipe installations
  - All coating material and equipment necessary for proper application on underground fabricated piping
  - All paint, primer and sandblast material required for the above grade portions of the project
  - All sack breakers
  - All water and other material required for dust control in the pipeline right-of-way and on all other construction sites

- All material required by the Environmental Control Plans
- All timber construction mats.

Examples of items furnished by the Company for projects of this type include:

- A central pipe/ware yard for execution of the project
- Radiographic and other nondestructive testing (NDT) of field welding during the fabrication and construction of the pipeline. Contractor shall provide a sufficient amount of time to company for scheduling NDT services
- Source of water for pipeline hydrotest.

The equipment required for CO_2 measurement at either end of the pipeline and for the injection of CO_2 into the well is limited to mostly piping and valves that are connected to a flow meter. Figure 3-3 shows the pipe and valve arrangement for flow measurement at each project location. The flow measurement shown in the diagram consists of a Daniels type or similar orifice meter tube. The specific design and size of the meter tube will depend on flow conditioning devices and the flow capacity at each location. Each measurement tube will be equipped with pressure and temperature instrumentation used to calculate the density of the CO_2 at the measurement location and the differential pressure across the orifice plate. A flow computer associated with the meter tube uses the differential pressure across the plate and calculates the density of the fluid at the locally measured temperature and pressure to calculate the mass flow rate of CO_2 through the meter. Flow and pressure data will be communicated via fiber optic cable from the well location to the pilot plant data system to monitor conditions on the pipeline and at the well.

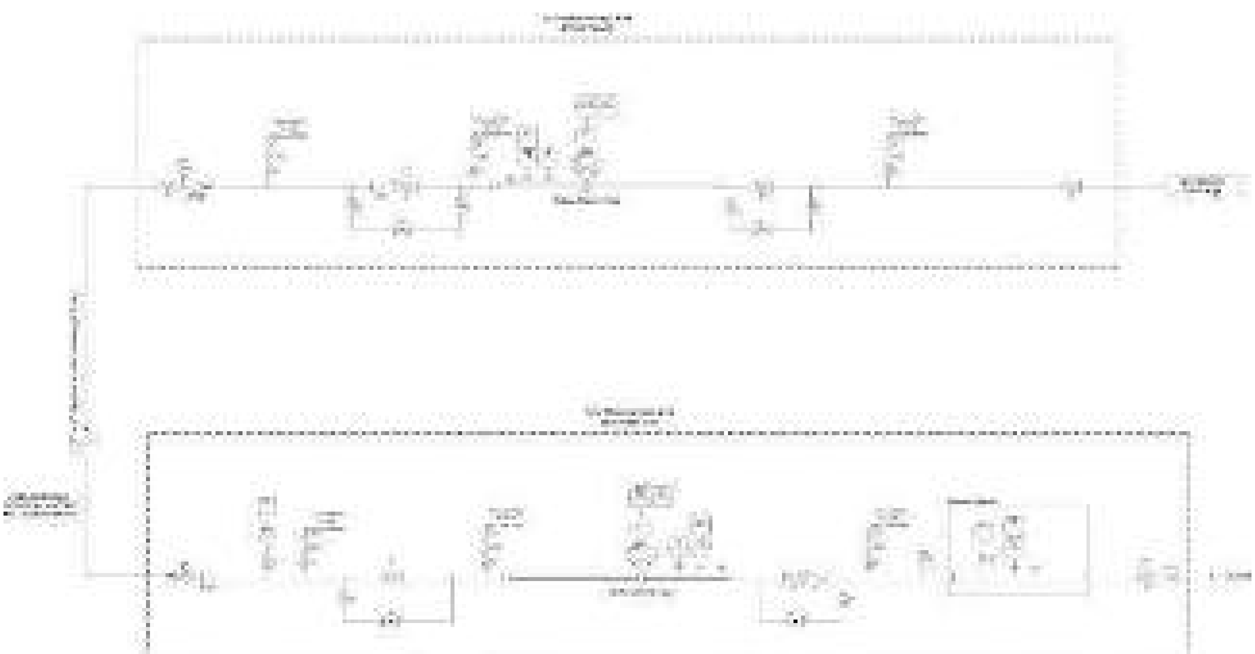


Figure 3-3. Diagram displaying pipe and valve arrangement for flow measurement at each project location.

Section 4. Subsurface Facilities Design

4.1 Geologic Overview of the Injection Well Location

A comprehensive description of the geology of the Gundih Block, including the proposed injection well location, is provided in ITB (2019). A brief review of the geology is provided here. The Gundih block (oilfield) is in the Randublatung physiographic province of east Java and is composed of three reef structures developed in the Kujung Formation. From east to west and increasing depth, these are KTB (Kedung Tuban), RBT (Randu Blatung), and KDL (Kedung Lusi). The thicknesses of the Kujung in each reef structure are as follows: KTB ~2,300 ft.; RTB ~2,300 ft.; and KDL ~1,115 ft. Calciturbidites drape on the SW flank of some of these reef buildups and compose of a secondary reservoir target. These calciturbidites form in the lowermost section of the Tuban Formation, which overlies the Kujung, can be up to ~130 ft thick, and are composed mostly of calcium carbonate. These form when tropical carbonate platforms or reefs are flooded or exposed and cause a sharp increase in sedimentation. The Tuban is over-pressured and the strata returns to normal lithostatic pressure in the Kujung. Overpressure is seen in the KDL-1 well at 4,377 ft. MD in the Ngrayong and Tuban, based on the sonic log detection and increase in mudweight. The KTB-1 well also saw overpressure in the Tuban. Hydrocarbon (gas) production occurs from the Kujung Formation within these local structural highs (Figure 4-1). In order to avoid disturbing gas production in the reefs, CO_2 injection will occur in the water leg on the southern flank of the KTB reef. Figure 4-1 is a contour map of the top of the Kujung Formation. The Gundih CPP (central processing plant) for hydrocarbon production from the nearby well pads (Figure 4-1) is situated between the RBT and KTB structures.

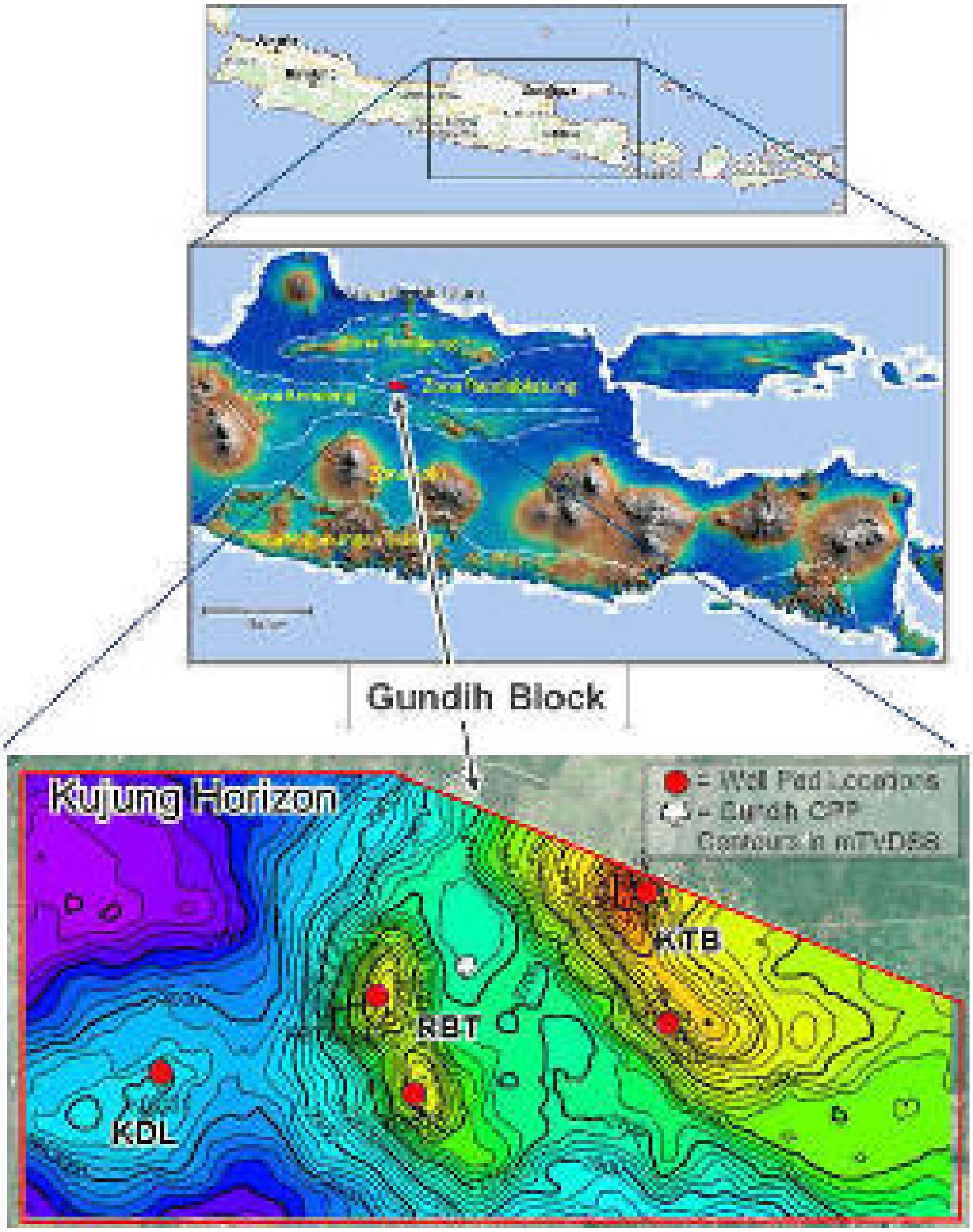


Figure 4-1. The Gundih Block is comprised of three structural culminations (KDL, RBT, KTB) within the Randublatung physiographic province of east Java. The contoured structural map of the Kujung Formation surface reveals three reefal structures.

Good CO_2 storage potential exists at all three structures but the KTB area was selected to host the CO_2 injection well because of its close proximity to the Gundih CPP (less than 2 miles or 3.2 km). Additionally, the Kujung occurs at a shallower depth compared to the other two structures (therefore well costs will be lower) yet deep enough so that the CO_2 will exist as a supercritical liquid when injected. (Figure 4-2). The reservoir rock is overlain by the Tuban Formation, an interlayered claystone and limestone, which has served as a seal for hydrocarbons in this reef. The stratigraphic column in Figure 4-2 shows the lithostratigraphy for this potential storage site.

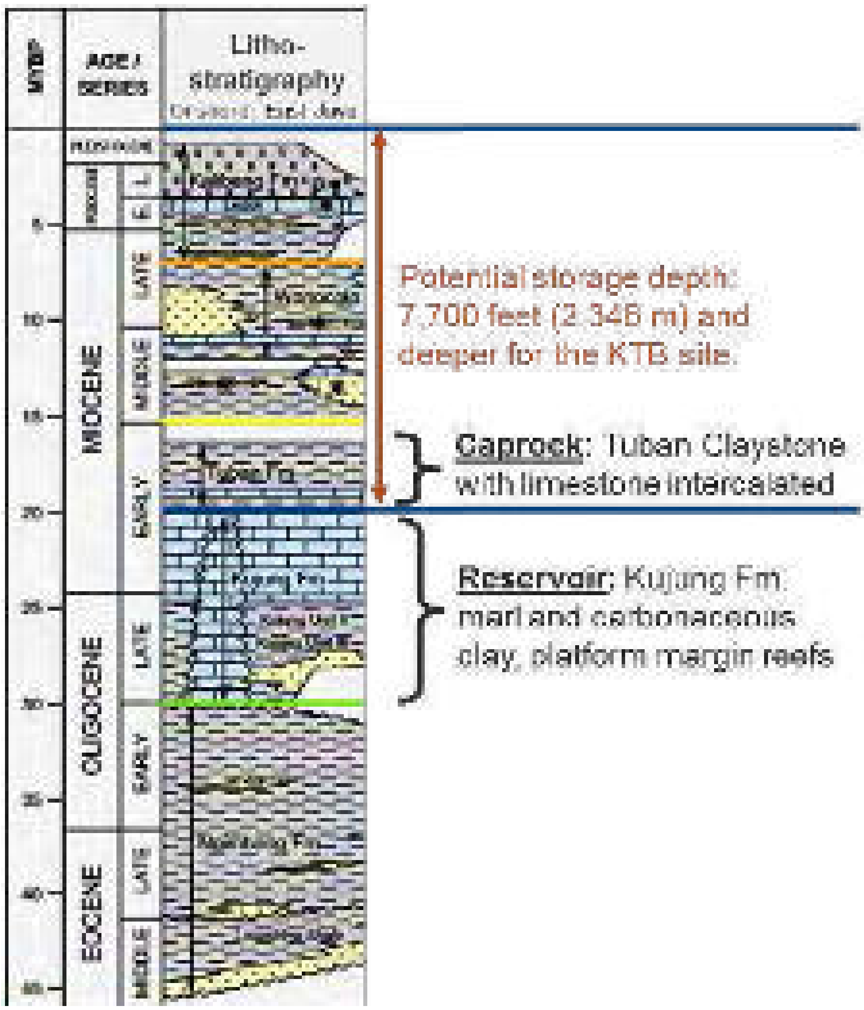


Figure 4-2. Stratigraphic column for the Gundih Block with caprock and reservoir depicted. Depth indicated is for top of Kujung Formation. Actual CO_2 storage depth is potentially deeper depending on injection location within or adjacent to the reef.

Example well logs for the KBT-2 well indicate that the reservoir rock in the vicinity of the proposed injection well location is largely comprised of clean limestone (Figure 4-3). Effective porosity (track 9 in Figure 4-3) averages 5% with frequent peaks as high at 10%. The gamma ray log (track 4 in Figure 4-3) indicates an abrupt transition from the Kujung Formation into the overlying Tuban claystone (caprock). Three drill stem tests (DSTs) were conducted in the KBT-2 well within the reservoir (tracks 2 and 3 in Figure 4-3); however, these were only for the purpose of collecting fluid samples and not for determining reservoir hydraulic properties. The Tuban caprock is generally lacking data. Formation testing, coring, advanced logging, and packer testing will be conducted within the caprock and reservoir, if borehole conditions allow, to better characterize the injectivity, storage, and containment potential of the formations.

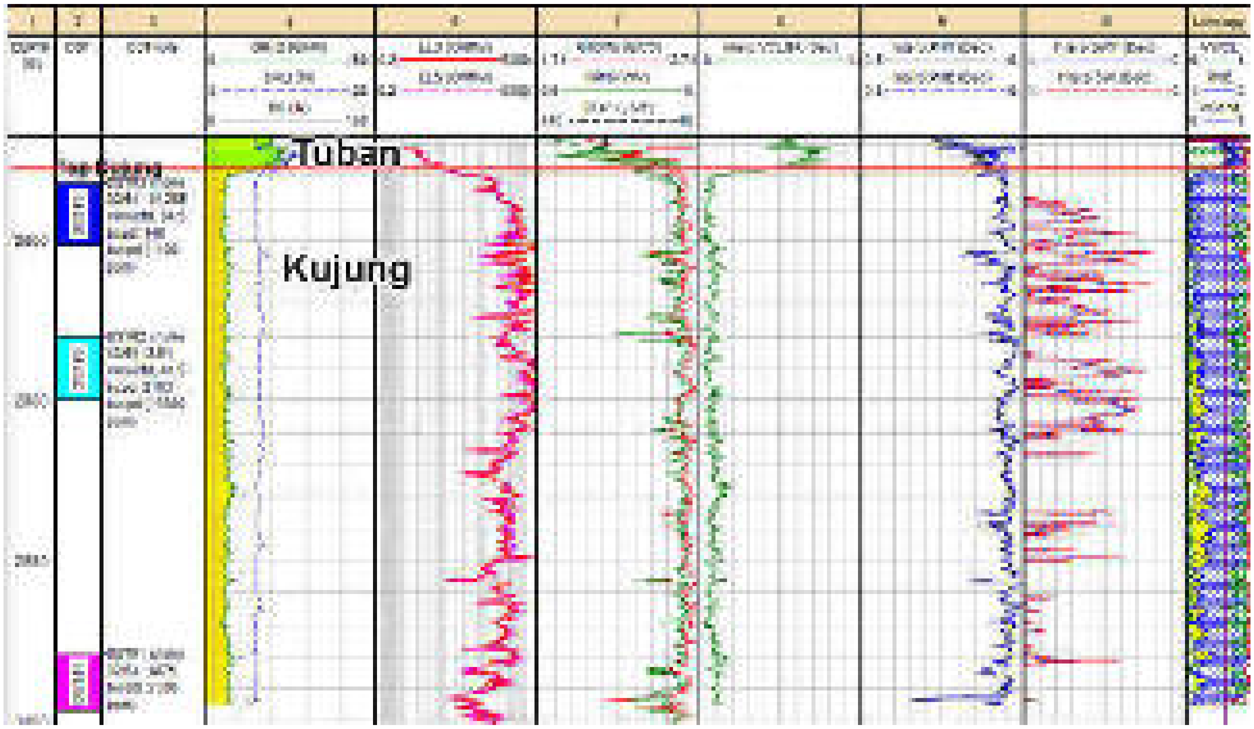


Figure 4-3. Example well logs for the KTB site from the KTB-2 well.

Significant static earth modeling has already been conducted (ITB, 2019) for the Gundih block and this work provides the necessary background for selecting a potential injection well location. Water saturation modeling (Figure 4-4) reveals where hydrocarbons have accumulated in the structural traps in the Kujung (below the Tuban claystone, not shown). Facies modeling for the KTB site shows that it is largely comprised of platform marine reef carbonates (Figure 4-4).

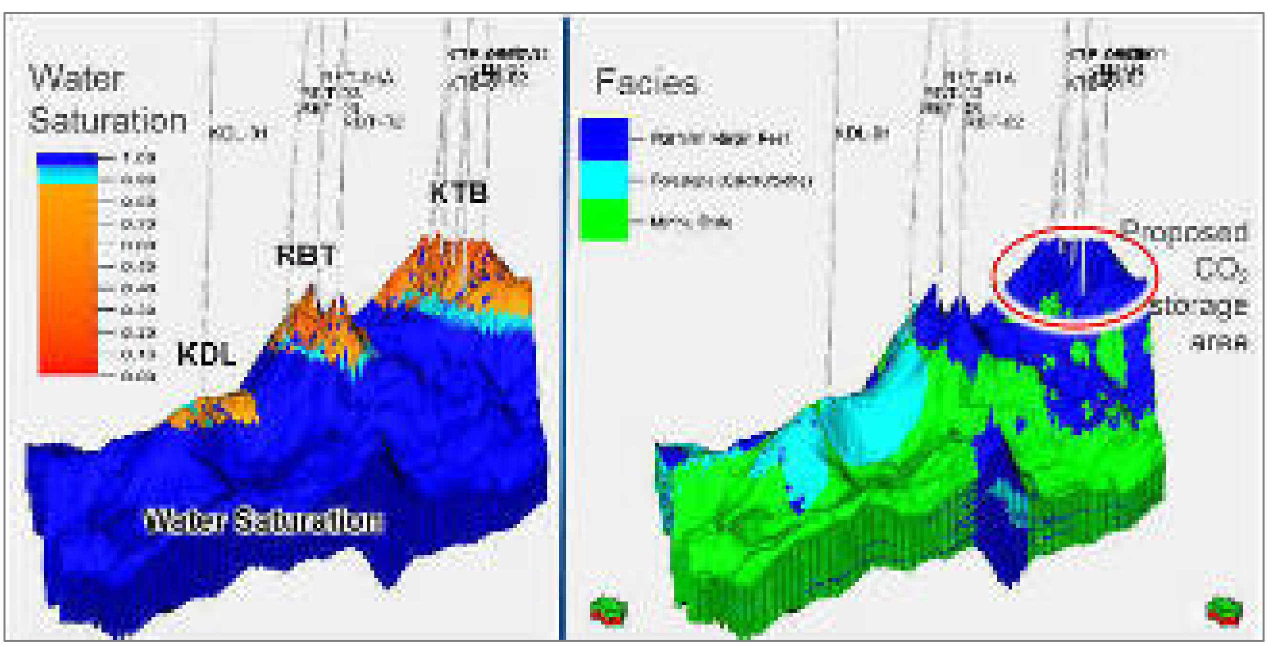


Figure 4-4. Example static earth models for the Gundih Block. At left, the water saturation model implies where gas accumulation (orange color) occurs up-dip within the reef structures. At right, the platform margin reef facies provide good opportunity for CO_2 storage.

4.2 Injection Well Basis of Design

This basis of design (BOD) for the Gundih CCS Pilot Injection well is a collection of requirements that dictate the well's design. The BOD requirements are presented in Table 4-1. As shown, the criteria can be grouped into groups according to the aspect of the well that is affected – e.g., location, size (diameter), materials of construction, operational considerations, and other requirements.

Table 4-1. Basis of design requirements for the Gundih pilot CO_2 injection well.

	Criteria	Criteria Value
Location and trajectory of injection well	• Inject into Kujung Formation but do not interfere with gas production	Avoid injected CO_2 from reaching gas zone
	• Start from existing well pad at Gundih field	Well INJ-02 was chosen for the purpose of developing a well design for this feasibility study (proposed location for INJ-02 is the well pad for existing production well KTB-04 – see Figure 1-4 for location; see Figure 4-5 below for trajectory)
	• Preferred bottomhole target location	Based on modeling (ITB, 2019)
	• Well perforation interval – (3896 to 3916 m MD) –	Based on modeling (ITB, 2019)
Well size	CO_2 total injection amount during two-year pilot study	100,000 tonnes (2.85 MMSCFD; assumes 20,805 MMSCF/tonne)
	Daily CO_2 injection rate: • minimum daily injection rate assumes continuous injection over two-year period; • upper bound daily injection rate assumes well is operational only 75% of the time.	137 to 183 tonnes/day
	• Packer and tubing string required	Size (diam.) of (injection tubing must be able to accommodate design injection rate without excessive friction head loss
	• Accommodate subsurface (in-well) monitoring instrumentation – Real-time bottom-hole P/T monitoring – fiber optic cable outside deep casing string	2-7/8 in. diam tubing inside 5-1/2 in. diam. casing; 8-1/2 in. diam. borehole.
	• Borehole large enough to accommodate wireline testing tools (e.g., Schlumberger MDT; Baker RCX)	Minimum 7-7/8 inch diam.

Table 4-1 (continued). Basis of design requirements for the Gundih pilot CO_2 injection well.

	Criteria	Criteria Value
Materials of construction	CO_2 Injectate Composition	CO_2%; H_2O%; H_2S%, other %
	• Required well service life	5 yrs (assumes 2 year injection period, 1 to 2 year post-injection monitoring, well is installed 1 year before injection begins)
	• Casing materials based on mechanical load scenarios	Schlumberger well design software (DrillPlan) used to determine casing specs
	• Bottomhole pressure and temperature	Based on modeling (ITB, 2019)
Operational Considerations	Surface Pressure and Temperature of CO_2 (wellhead)	Pressure and temperature will be such that CO_2 is not gas phase when it enters the injection well.
	Automatic shutdown (Control Philosophy)[A]	Injection wells must be able to halt injection automatically if criteria are met (e.g., injection pressure exceeds threshold) Requires automated vales on wellhead; requires that wellhead valves are connected to common capture/injection SCADA
Other Considerations	Emplace continuous cement fill from total depth to surface the annulus between the 5-1/2 inch casing and the 8-1/2 inch borehole	
	Pore pressure, fracture pressure, temperature	
	Characterization of caprock and reservoir properties is required during drilling, including geophysical logging, coring, and packer tests in the Tuban, Calcitubidite, Kujung. borehole Inclination shall be <30˚ to allow gravity conveyance of tools (i.e., avoid pipe-conveyed logging)	

A. Data from the well site and the injection well will be transferred to the pilot surface facility location via fiber optic cable; PLC data and instrumentation from site and injection location will be integrated into HMI (human machine interface) screens for operators to monitor injection and a data historian poll and store required information.

4.2.1 Location and Trajectory

As previously mentioned in Section 1.4, well location INJ-2 was chosen as the preferred injection well location and therefore was used to develop a well design for this feasibility study (proposed location for INJ-2 is the well pad for existing production wells KTB-02 and KTB-04 – see Figure 1-4 for location). The target bottom-hole location for the well is horizontally offset from the well pad, which is situated directly above the gas production zone, by a considerable distance and vertically offset beneath the gas production zone to minimize the potential for CO_2 mixing with the natural gas resource. in fact, the proposed injection interval is near the bottom of the Kujung These requirements necessitate that the injection well is deviated. It is desirable to keep the amount of deviation below 30 degrees so that logging and testing tools can be conveyed by gravity. Figure 4-5 illustrates the trajectory and depth of the well based on the INJ-2 location.

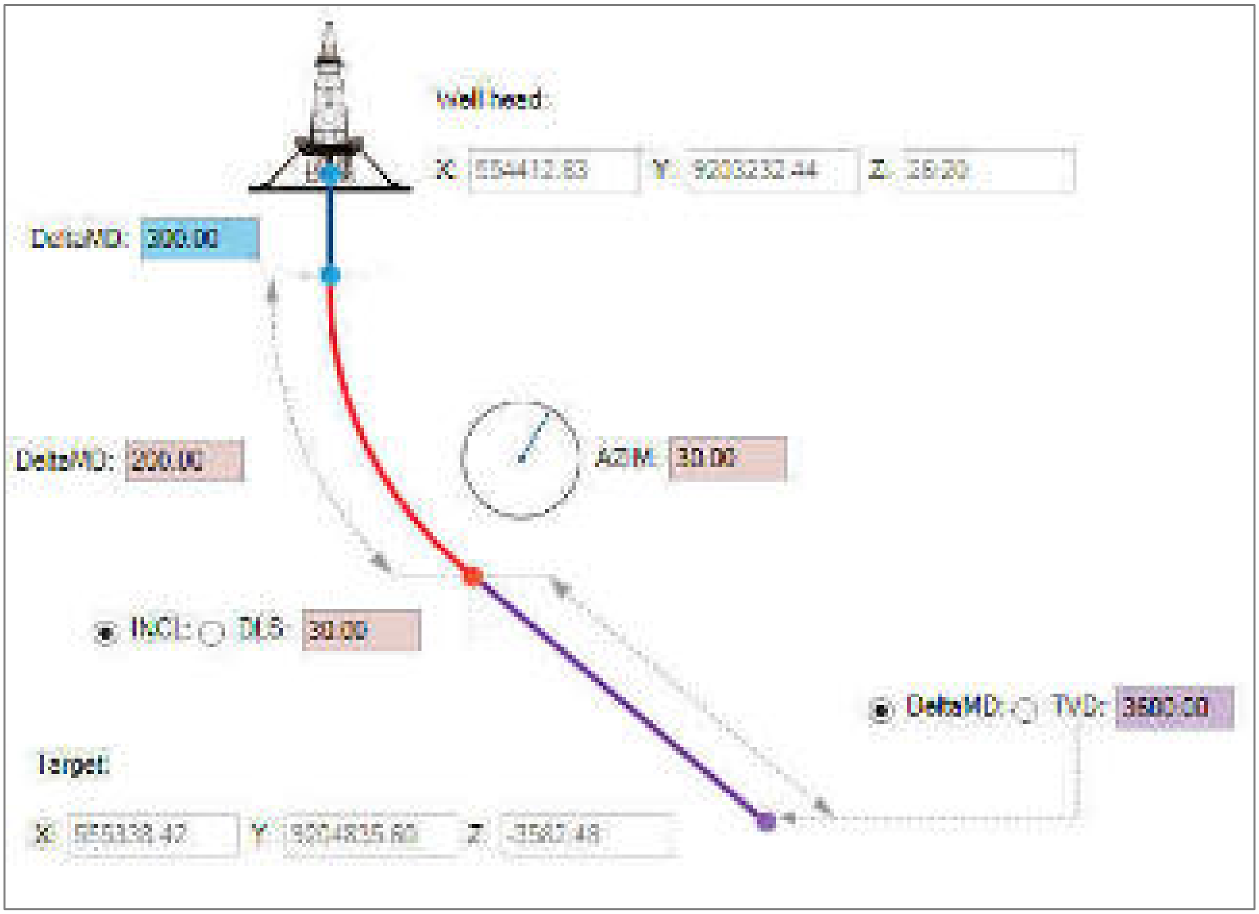


Figure 4-5. Trajectory and depth of proposed injection well at the INJ-02 location (ITB, 2019). (Note that the bottomhole delta MD value should be 4100 m rather than 3600 m)

4.2.2 Well Size

A major factor that affects the well size (diameter) is the amount (rate) of CO_2 injection. It is desirable for the tubing string to be large enough so that the frictional pressure drop is minimal. For the planned rate of injection, a 2-7/8 inch outside diameter tubing string is sufficient. Other factors that influence well diameter is the desire or need to install pressure gauges, temperature gauges or other hardware in the well. in this case, one or more fiber optic cables will be installed on the deepest casing string and real-time readout pressure and temperature sensors will be placed in the annular space between the tubing and deepest casing. This necessitated a 5-1/2 inch outside diameter casing string. To accommodate the fiber optic cable and to allow wireline logging and testing tools to be used in the deepest section of the well (i.e., across the reservoir), the deepest borehole was specified as 8-1/2 inches.

4.2.3 Materials of Construction

The main factor that determines the materials of construction is the composition of the CO_2 injection stream. CO_2 in the presence of water will produce a corrosive environment. Furthermore, H_2S present in the CO_2 stream is also corrosive. Although the CO_2 will be dehydrated before it is injected, selected components of the wellhead valves that come into contact with the CO_2 were specified to be made of CO_2 corrosion resistant materials. No special materials were specified for the tubulars (tubing, casing) because of the anticipated short service life of the well and low levels of H_2S (<50 ppm).

4.2.4 Operational considerations

To allow for the most efficient injection conditions, the pressure and temperature of the CO_2 in the pipeline will be maintained such that CO_2 will be supercritical liquid when it enters the injection well. this will ensure single phase flow in the tubing string and as the CO_2 enters the reservoir. Another important operational requirement is the ability of the injection well to halt injection automatically if criteria are met (e.g., injection pressure exceeds threshold). This requires automated vales on the wellhead (tree) and that the wellhead valves are connected to a common capture/injection SCADA.

4.2.5 Other Considerations

Other well design constraints include, for example, the need to cement the fiber optic cable in place, (by filling the annulus between the 5-1/2 inch casing and the 8-1/2 inch borehole from total depth to surface) in order to achieve good acoustic coupling between the fiber and formation. If it cannot be cemented to surface, the cement column should extend to above the caprock at minimum. Characterization of caprock and reservoir properties is an important objective during drilling, therefore, measures will be taken to facilitate logging, coring, and open borehole testing, to the extent possible. For example, the borehole diameter shall be sufficient to accommodate geophysical logging, coring, and packer testing tools in the Tuban, Calcitubidite, and Kujung intervals intersected by the borehole. Similarly, the borehole inclination shall be <30˚ to allow gravity conveyance of tools (i.e., avoid pipe-conveyed logging).

4.3 Site Characterization

4.3.1 Objectives

A geologic characterization program will be implemented in the injection well borehole during drilling to better characterize the distribution of important reservoir and caprock properties. These properties will be incorporated into the site-specific reservoir model, which will be used to help decide certain well completion details (e.g., perforation intervals) and to forecast the lateral and vertical spreading of the injected CO_2. Because no monitoring wells are planned for this project, extra reliance will be placed on the model to forecast/track the CO_2 plume during the operational period. Hence, it is essential that the model accurately represents the subsurface geology, which requires detailed characterization data.

The objectives of this Site Characterization Plan are to summarize the existing data available to the Gundih CCS project and to identify the types of data that will be collected for the project as part of the borehole characterization effort. The rationale is to conduct a detailed characterization of near wellbore geology to identify CO_2 injection interval(s) and confining units in support of the development of an accurate reservoir model. The borehole characterization program elements include geophysical logging, coring, core testing and analysis, packer testing, stress measurements (mini-frac testing), borehole seismic, and other reservoir testing methods.

4.3.2 Existing Data

Within the Gundih Field study area, there are nine existing wells that penetrate the formations of interest (i.e., Tuban and Kujung Formations) and have varying degrees of geophysical and reservoir data associated with them. In addition to the borehole data, 3D and 2D seismic data exists across the study area and have been used, along with the borehole data, to generate the initial static earth model created by ITB (2019). The tables below summarize the relevant existing data in the Gundih field. These tables also identify data gaps that are to be filled by the data collection program for the proposed injection well. A more complete overview of the existing data in the Gundih Field and the modeling work that has been done to date can be found in ITB (2019).

Table 4-2. Summary of available general well data in the Gundih Field.

Data Type		Well KDL-1	Well KTB-1	Well KTB-2	Well KTB-3TW	Well KTB-4	Well KTB-6ST	Well RBT-1A	Well RBT-2	Well RBT-3ST
Petrophysical & Core Data	Well Logs	✔	✔	✔	✔	✔	✔	✔	✔	✔
	Petrographic Analysis	✔	✔	---	---	---	---	---	---	---
	Scanning Electron Microscope & X-ray Diffraction Analysis	---	---	---	---	---	---	---	---	---
	Mud Log	✔	✔	✔	✔	✔	✔	✔	✔	✔
	Routine Core Analyses	---	---	---	---	---	---	---	---	---
	Special Core Analysis	---	---	---	---	---	---	---	---	---
Well & Reservoir Data	Well Report: Cutting, Mud Drilling	✔	✔	---	✔	✔	✔	✔	---	---
	Completion/Well Design	✔	✔	✔	✔	✔	✔	✔	---	✔
	Static Pressure Survey	✔	---	---	---	---	---	---	---	---
	Well Test	✔	✔	✔	✔	✔	✔	✔	✔	✔
	PVT	✔	✔	✔	---	✔	✔	✔	✔	---

*See section 8.4.4 Core Analyses for explanation of routine and special core analysis.

Table 4-3. Summary of the available geophysical log data in the Gundih Field.

Well	Running Depth (m)	GR	CAL	SP	Induction Resistivity Deep	Induction Resistivity Med.	Induction Resistivity Shallow	Laterolog Deep	Laterolog Med	RHOB	NPHI	DT	PE
KDL-1	1848.45-238	✓	✓	---	✓	✓	✓	---	---	---	---	✓	---
	3335.88-1728.5	✓	✓	---	✓	✓	✓	---	---	---	---	✓	---
	3499.25-3207.4	✓	✓	---	---	---	---	✓	✓	---	---	✓	---
	3681.37-3316.22	✓	✓	---	---	---	---	✓	✓	✓	✓	---	✓
KTB-1	1600-328	✓	✓	✓	✓	✓	---	---	---	---	---	✓	---
	2351.52-1506.89	✓	✓	✓	✓	✓	---	---	---	---	---	✓	---
	2736.02-2208.72	✓	✓	✓	✓	✓	---	---	---	---	---	✓	---
	3300-2585	✓	✓	✓	---	---	---	✓	✓	✓	✓	✓	✓
KTB-2	2830.3-1121	✓	✓	✓	✓	✓	✓	---	---	---	---	✓	---
	3020.7-2746.4	✓	✓	✓	---	---	---	✓	✓	✓	✓	---	✓
KTB-3TW	1203.50-284	✓	---	---	✓	✓	---	---	---	---	---	✓	---
	2208.27-1119.70	✓	---	---	✓	✓	---	---	---	---	---	✓	---
	2734-2180	✓	---	---	✓	---	---	✓	✓	---	---	---	---
	2969.07-2685.28	✓	✓	---	✓	✓	✓	✓	✓	✓	✓	---	✓
KTB-4	2772.97-1195	✓	---	---	✓	✓	✓	---	---	---	---	---	---
	2772.9-2185	✓	---	---	✓	✓	✓	---	---	---	---	---	---
	2969.66-2765	✓	---	---	---	---	---	✓	✓	✓	✓	---	✓
KTB-6ST	2752.8-894	✓	✓	---	✓	✓	✓	---	---	✓	✓	---	✓
RBT-1A	3092.95-2937.05	✓	✓	✓	---	---	---	✓	✓	---	---	---	---
RBT-2	1484.4-252.6	✓	✓	---	✓	✓	✓	---	---	---	---	---	---
	2948.79-1385.32	✓	✓	---	✓	✓	✓	---	---	✓	---	✓	✓
	3378-3236	✓	✓	✓	---	---	---	✓	✓	✓	✓	✓	✓
	3236.5-2848.05	✓	✓	✓	---	---	---	✓	✓	✓	✓	✓	✓
RBT-3ST	3237.28-1494.43	✓	✓	---	✓	✓	---	---	---	---	---	✓	---
	3662-3038.85	✓	✓	✓	---	---	---	✓	✓	✓	✓	---	✓

4.3.3 Open Borehole Geophysical Logging Program

A comprehensive suite of geophysical logs will be obtained during drilling. Geophysical logs will be the main method used to identify potential CO_2 injection intervals and caprock intervals for subsequent packer testing and caprocks in the well. The petrophysical logging program will build upon information from the existing wells in the field as well as the new characterization well.

4.3.3.1 Mudlogging

A mud log will be compiled during drilling. Mud loggers inspect formation cuttings produced during drilling and identify which formation was being drilled, approximate elevations for the formation’s top and bottom, and the formation’s lithology. They work closely with the rig crew to develop this information and to use it for more efficient drilling. The mud loggers also monitor gas production from the well. This information is used by the mud engineers to formulate the drilling fluid, and to help to ensure safety of the crews against the presence of harmful gasses.

4.3.3.2 Petrophysical Logging Program

The petrophysical logging program consists of basic and advanced log suites in a combination of logging while drilling (LWD) and open hole wireline logging. The triple combo log suite (i.e., resistivity, neutron porosity, bulk density, caliper, gamma ray, and photo-electric factor logs) will be logged while drilling to prevent any well integrity issues due to pressure differentials from affecting the data quality. All other logs will be open hole or cased wireline logs. The triple combo logs will be run a second time, pending sufficient well integrity, as open hole wireline logs to capture the bottom ~100 ft. of the borehole that the long LWD tools cannot access. In addition to the basic log suite, the following advanced wireline logs will be run open hole: dipole sonic, resistivity imager, and elemental spectroscopy. Pulsed Neutron Capture logging will be run after casing is set along with an ultrasonic cement imager and then again after tubing is set to create two baseline measurements (all cement bond logs will be run after casing, prior to tubing). Table 4-4 summarizes the logging program and includes formations that will be encountered, and which logs will be run at each interval.

Table 4-4. Summary of recommended petrophysical logs and logging intervals.

Parameter	Logging Tool	Wonocolo	Ngrayong	Tuban (Caprock)	Kujung (Reservoir)
Basic petrophysical properties – porosity, permeability, density, resistivity, photo-electric effect, etc.	Triple Combo	✔	✔	✔	✔
Acoustic velocities, rock mechanical properties, horizontal stress orientation (azimuth) and anisotropy, and velocity modeling update	Dipole Sonic	✔	✔	✔	✔
Identification of depositional features, bedding planes, dip, vugular/secondary porosity, fractures, faults, stress orientation (from break-outs and drilling-induced fractures)	Resistivity Imager	---	---	✔	✔
Fluid type/saturation	Pulsed Neutron Capture	---	---	✔	✔
Cement evaluation	Ultrasonic Cement Imager	✔	✔	✔	✔

Additional geophysical borehole characterization data will be collected via a vertical seismic profile (VSP) gather that will be performed post well completion.

4.3.4 Coring Program

Coring is a key element of the proposed characterization program. However, it is highly uncertain pending an assessment of borehole stability during drilling whether core data would be collected and used to calibrate geophysical logs in the determination of reservoir properties. Such data include routine core analyses as well as special core analysis. Secondly, measurements such as relative permeability and pore volume compressibility provide input for reservoir computer simulation. Core analysis data are also used to determine injectivity and to quantify acoustic rock properties.

The recommended coring program includes up to 240 ft of whole core and up to 120 sidewall core samples from the caprock and reservoir intervals

Table 4-5. Summary of proposed core acquisition details.

Formation		Whole Core	Sidewall Core
Tuban	Caprock (upper interval)	1 x 60 ft run	30 samples
	Calciturbidite (lower interval)	1 x 60 ft run	30 samples
Kujung	Upper Interval	1 x 60 ft run	30 samples
	Lower Interval	1 x 60 ft run	30 samples

4.3.4.1 Core Analyses

Core samples, if they are able to be obtained, will be subjected to the array of core tests described in Table 4-6. These tests will identify lithology/lithologic features and laboratory analyses (i.e., routine and special core analyses) will be performed on both whole core and sidewall core samples.

Routine core parameters include porosity, grain density, horizontal and vertical permeability, and a lithologic description. Routine parameters will be measured at a high frequency (e.g. every foot).

Table 4-6. Summary of proposed core analyses.

		Tuban		Kujung	
Core Test / Analysis	Purpose	Upper Caprock	Calciturbidite	Upper Section	Lower Section
Standard core descriptions for all whole core (macro descriptions)	Identify depositional environment, high porosity zones, fractures, etc.	✔	✔	✔	✔
Petrographic analysis (micro descriptions)	Mineral ID, porosity typing, and porosity development	✔	✔	✔	✔
Routine core analyses (whole and sidewall core)	Characterize porosity, permeability of reservoir and caprock; develop statistically sound poro-perm transforms for reservoir interval; calibrate/verify porosity and permeability logs	✔	✔	✔	✔
Specialized core tests (MICP, relative permeability)	Mercury injection capillary pressure (MICP) data is needed to model fluid diffusion into the caprock; relative permeability to CO_2 is an input model parameter for the reservoir	✔	✔	✔	✔

Special core analysis refers to any measurements that are not part of routine core analysis. Reservoir properties measured include relative permeability and capillary pressure. Petrographic and mineralogical studies include thin sections and X-ray diffraction. These measurements are usually made in selected intervals and formations.

The core analysis program for the Gundih CCS Project will build upon information from the current wells at the Gundih Field.

4.3.5 Reservoir Hydraulic and Geotechnical Testing

If borehole stability is favorable, open borehole reservoir (packer) tests will be conducted in the injection well to define reservoir properties needed to assess the viability of injecting and storing the target CO_2 quantity (approximately 100,000 tonnes over two years) and the ability of the caprock system to contain the injected CO_2 and prevent unwanted out-of-zone migration. Therefore, testing will be necessary both in the reservoir intervals and the caprock. The Kujung Formation is the primary candidate reservoir for this program and the calciturbidite interval near the base of the Tuban Formation is a potential secondary candidate reservoir for this program. The tests are referred to as packer tests because they entail using either a straddle (double) packer or single packer to isolate a test interval for either hydraulic or stress (geomechanical) hydraulic.

Geophysical logging data obtained for the open borehole section across the caprock and reservoir will be used to identify zones for packer testing. The type(s) of reservoir packer tests to be conducted varies for the reservoir and caprock. Reservoir tests, which are conducted with a wireline-deployed straddle-packer tool, inflatable packers placed in the borehole, can be designed to evaluate much longer (i.e., thicker) specialized core tests (MICP, relative permeability). MICP data allows for more accurate water saturation model and provides inputs for reservoir simulation. Relative permeability can be updated to refine the rock -fluid model used in dynamic simulation for the reservoir and caprock.

4.4 Injection Well Design

As part of the Gundih pilot CCS project, a well will be installed to characterize the site and eventually used for the injection of 20,000 MT of CO_2. The pilot well will be drilled to evaluate the CO_2 storage potential of the Lower Kujung Formation (below the water contact depth), Tuban reservoir-caprock system (Figure 4-6). In addition, the calciturbidite sequence located at the base of the Tuban Formation (at the transition between the Tuban and Kujung Formations) will be evaluated for CO_2 sequestration. See Appendix C for full drillling prognosis report. Table 4-7 presents the prognosis for the geologic formations of interest that will be encountered during the drilling of the characterization/injection well. If the formations are stable enough to allow open-borehole logging, coring and packer testing, specific characterization activities to be performed during installation of the well would include:

- Collection of geophysical logs
- Collection of full-hole core or sidewall core samples.
- Measurement of fluid pressures.
- Injectivity testing of potential CO_2 injection intervals identified from geophysical log data.

Additionally, formation resistivity will be monitored during the drilling of the well below the surface casing using the Near-Bit Resistivity (NBR) tool, This will enable the identification of the upper Kujung boundary before drilling proceeds beyond this depth so that the deep intermediate (9-5/8 inch) casing can be set in the lowermost Tuban. The NBR tool is only applicable when coupled with the rotary steering technology and is located approximately 1.5 m from the bit.

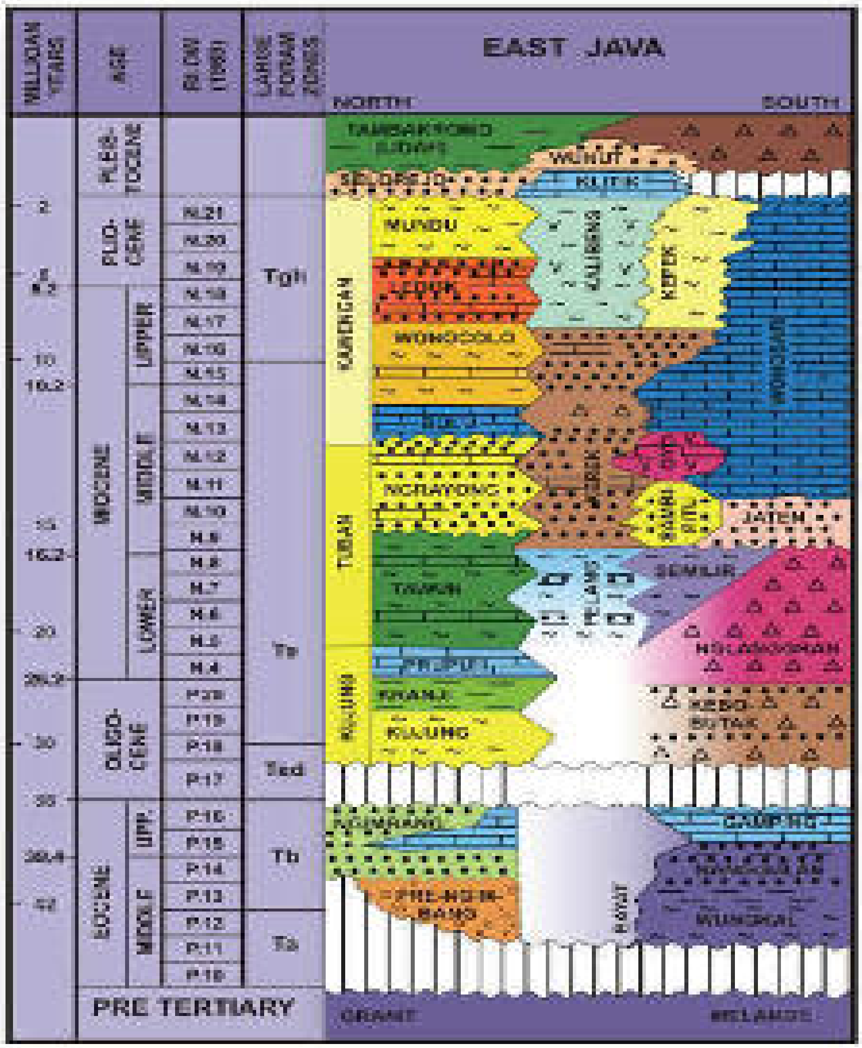


Figure 4-6. Generalized Stratigraphy of the East Java Basin.

Table 4-7. Prognosis for the geologic formations to be encountered during drilling.

Formation Name	Pilot Well Prognosis	RBT-01A Well
Lidah	Surface	Surface
Mundu	NA	515.87 m TVD
Ledok	NA	773.10 m TVD
Wonocolo	284 m TVD	1022.60 m TVD
Ngrayong	1006 m TVD	1528.90 m TVD
Tawun/Tuban	1596 m TVD	2151.0 m TVD
Kujung	2964 m TVD	2939.60 m TVD
Ngimbang	3490 m TVD	NA

4.4.1 Directional Drilling Plan

The pilot well will be drilled from the KTB-2 well pad and will be oriented deviated to the northeast (30 degrees) to reach the target the appropriate location in the injection zone. Table 4-8 presents the details of the directional drilling plan. After setting the surface casing, the well will be deviated N30°E at an angle of 30° to achieve the correct trajectory. Figure 4-7 shows the planned trajectory for the injection well at the INJ-2 location. Note that the well is vertical to a depth of approximately 300 m below that depth and will be deviated using either a rotary steerable or a downhole motor. A rotary steerable system (RSS) is preferred because it will drill the well more efficiently and less time will be spent adjusting/orienting the tool face with aggressive bit usage (issues with a motor when trying to control the tool-face) and maximizing drilling parameters.

Table 4-8. Details for the directional drilling plan.

Parameters	Well Detail	
UTM Zone 49S Coordinates surface location:	9203232.44 m S	554412.83 m E
Azimuth:	30°	
Vertical Section (KOP):	300 m TVD	
Build Section:	300 m TVD	500 m TVD
Maximum Deviation:	30°	4.5°/30 m BUR
Tangent Section:	500 m TVD	~3,582.5 m TVD
Measured Total Depth:	~4,100 m MD	
True Vertical Total Depth:	~3,582.5 m TVD	
Target bottomhole Coordinates:	9204836 m S	555338.4 m E
Target Tolerance	TBA	

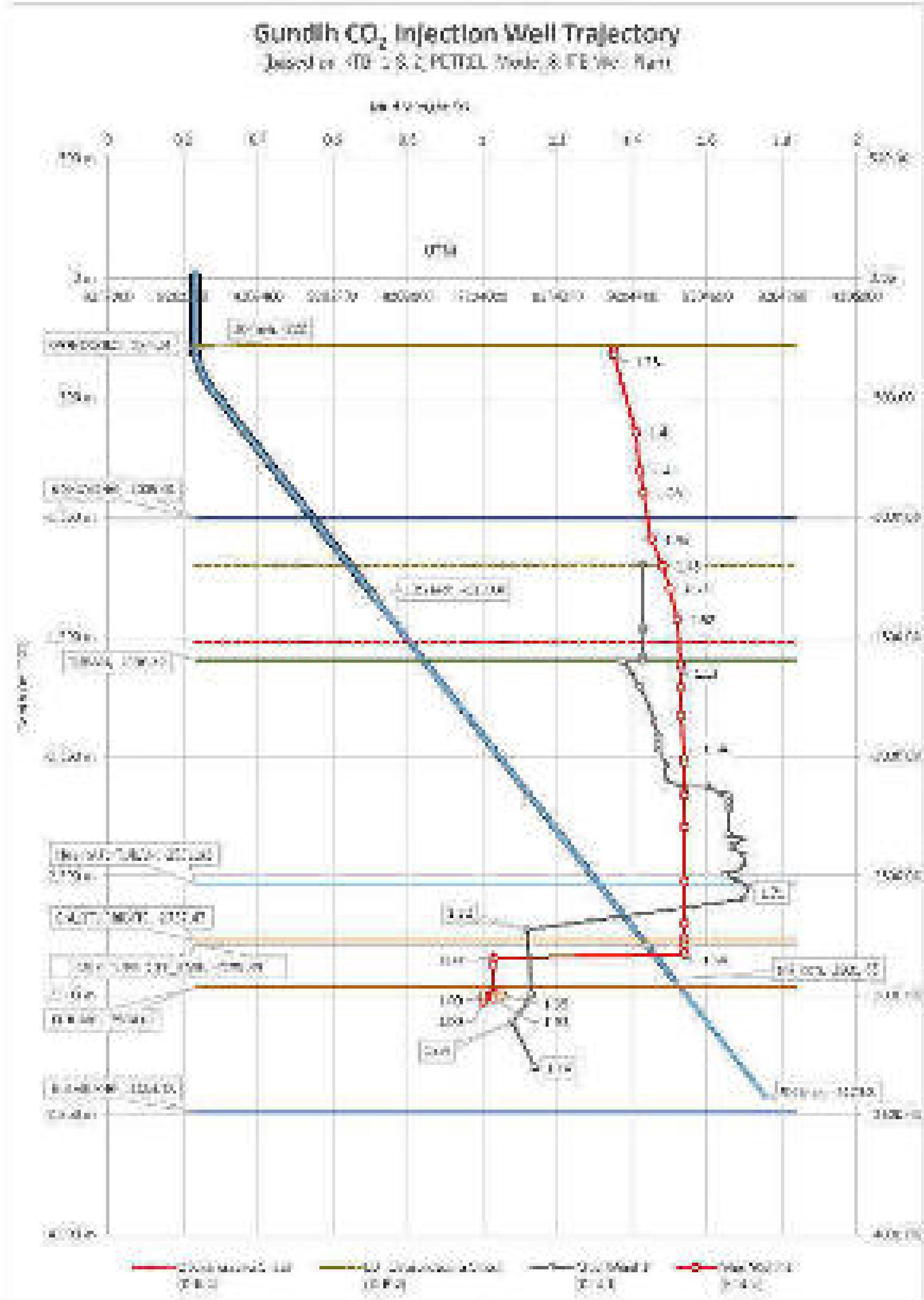


Figure 4-7. Planned well deviation in cross-sectional view showing mud weights used for wells KTB-1 and KTB-2.

Sliding with a mud motor could pose challenges due to weight stacking. The weight stacking is more profound when water-based mud (WBM) is used because the friction factor is higher than the synthetic oil-based mud (SOBM). Another advantage of using a RSS is that it will result in a smoother borehole and therefore make it easier to install casing. This will also aid in improved borehole conditions, which is important for the extensive logging and formation evaluation program. A mud motor creates "micro-doglegs" which increase the tortuosity of the hole section which, depending on the severity, will increase the chance the drilling assembly becomes stuck due to key-seating. RSS continuous rotation and higher rotating speed will also help improve hole cleaning of the well.

4.4.2 Casing Design

The pilot well will consist of five casing strings to reach the Ngimbang Formation at approximately 3,490m TVD. However, a sixth (contingency string) has been engineered and will be installed if over-pressure zones are encountered in the Tuban Formation. If an over-pressure situation is encountered, the 9⅝-inch casing would need to be set early due to potentially unstable hole conditions. Table 4-9 and 4-13 present the casing plan for the well, including the contingency string. The pilot well will be completed with a 5½-inch casing string in an 8½-inch borehole at total depth to allow for the passage of characterization tools in the deep zone to provide adequate annular space for fiber optic cable(s) on the outside of the 5-1/2 in. casing, to accommodate a tubing string of sufficient diameter for efficiently injecting the CO_2 (i.e., minimal friction), and to accommodate real-time bottom-hole pressure/temperature sensor between the tubing string and the 5-1/2 in. casing. (Figure 4-8).

Table 4-9. Borehole and casing depths and diameters for the pilot well in the Gundih Field.

Hole Size (inches)	Casing/Liner Diameter (Inches)	Shoe Depth (m MD)	Formation Setting Depth
Driven/Drilled	30	30	Surface
26	20	300	Wonocolo
17 ½	13 ⅜	1094	Ngrayong
12¼ x 14¾.	11 ¾[a]	TBD	Tuban
12 ¼	9 ⅝[b]	2346 - 3356	Tuban
8 ½	5 ½	0 – 4100	Kujung

a. Contingency casing liner
b. Casing liner

Table 4-10. Casing specifications.

Section	Type	Description	OD in.	ID in.	Drift ID in	Start MD ft	End MD ft	TOC ft	Grade	Connection
36 in	Conductor	30’ Casing 196.08 lbm/ft	30.000	28.750	28.5625	0.00	98.43	0.00	X52	MIJ
26 in	Casing	20’ Casing 133 lbm/ft	20.000	18.730	18.5425	0.00	984.00	0.00	K55	BTC
17.5 in	Casing	13.375’ Casing 77 lbm/ft	13.375	12.275	12.11875	0.00	3592.52	0.00	L80	MTC
14.75 in	Liner	11.75’ Casing 71 lbm/ft	11.750	10.586	10.42975	3559.71	7729.66	3559.71	L80	BTC
12.25 in	Liner	9.625’ Casing 53.5 lbm/ft	9.625	8.535	8.5	7696.85	11010.50	7696.85	P110	LTC
8.5 in	Production	5.5’ Casing 23 lbm/ft	5.500	4.670	4.545	0.00	13451.44	500.00	P110	MTC

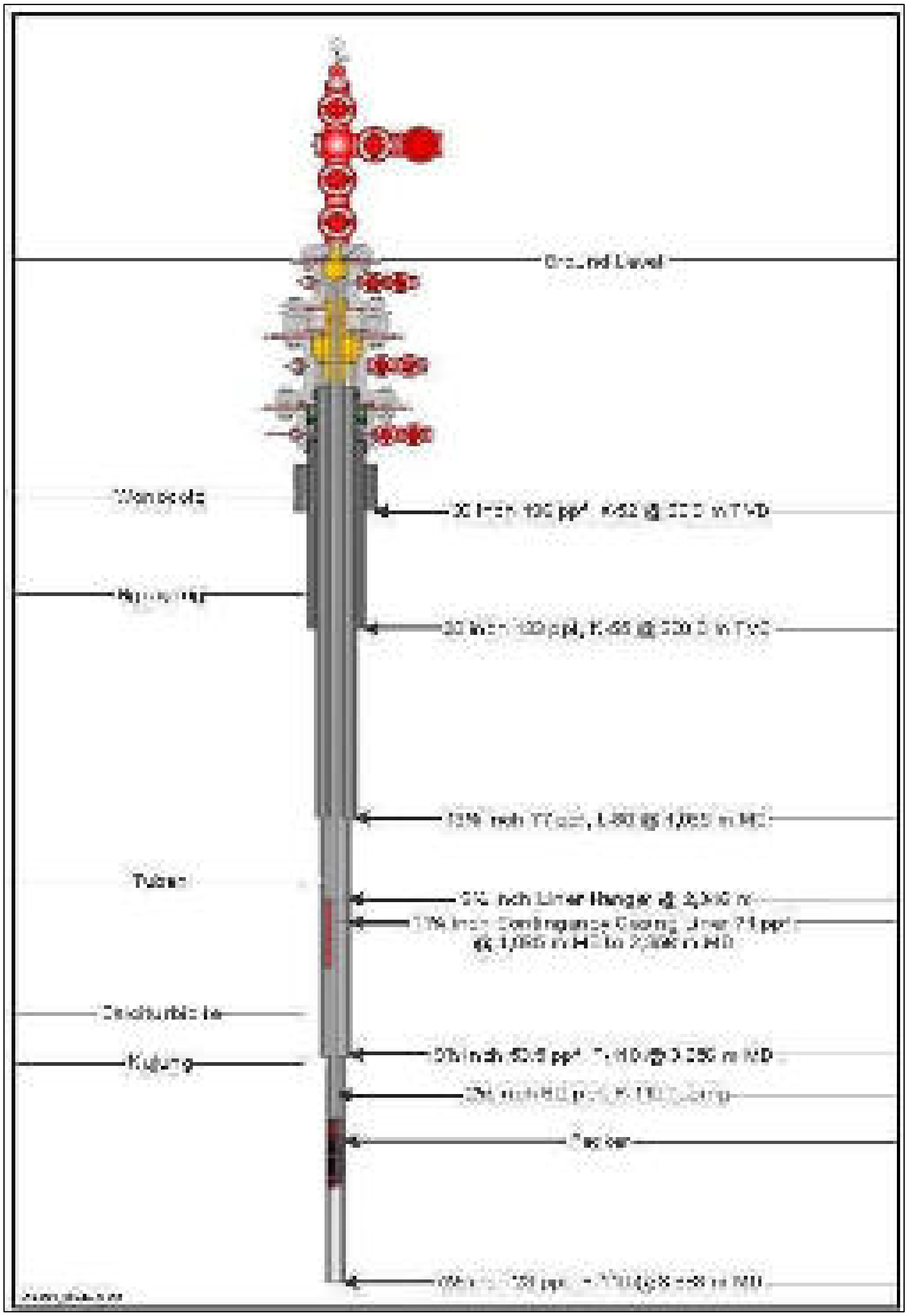


Figure 4-8. Diagram of casing details for the Gundih Field pilot CO_2 Injection well.

Conductor Casing String

The conductor casing string will extend from the ground surface to approximately 30 m MD. Installation of this string is necessary to isolate unconsolidated formations and protect against shallow gas. The conductor casing string will consist of 30-inch X52 MIJ, 196 lb/ft casing (or similar (e.g., 0-inch B, MIJ, 118.6 lb/ft) inside of a 36-inch borehole.

The 36-inch borehole hole section will initially be drilled with a 17½-in. pilot hole using a WBM. It will then be opened up with a 17½-in. bull nose x 26-in. x 36-in. hole opening assembly. At total depth the hole will be back reamed and a 30 bbl Hi-Vis pill will be pumped and displaced with WBM gel.

The conductor string section will be cemented with approximately 80 barrels (bbl) of 1.9 specific gravity slurry, that will cement the entire length (surface to 30 m MD) of the casing string.

Surface Casing String

Surface string will extend from the land surface to 300 m MD. The purpose of surface string casing is to provide protection from blowouts and prevent lost circulation. The casing material will be 20-inch, K-55, BTC, 133 lb/ft or similar (e.g., 20-inch, K-55, BTC, 106.5 lb/ft) set in a 26-inch diameter borehole.

The hole section will be drilled using 1.05 – 1.10 specific gravity potassium chloride (KCl) partially hydrolyzed polyacrylamide (PHPA) polymer mud. The surface string will be cemented throughout the entire length).

Shallow Intermediate Casing String

Shallow intermediate string casing will extend from the land surface to 1094 m MD. This casing will be necessary to provide protection against the caving of potentially weak or abnormally pressured formations. The casing material will be 13⅜-inch, L-80, MTC, 77 lb/ft (or similar) set inside a 17¾-inch hole.

The borehole for the shallow intermediate string casing will be drilled with a saline OBM ranging from 1.13 to 1.46 specific gravity. Casing for this section will be cemented throughout the entire length.

Contingency Casing Liner

A contingency casing string may be required to be set near the base of the Tuban Formation prior to penetrating the Kujung Formation. Installation of the contingency string casing may be necessary to accommodate the downhole pressure increases that may occur in the transient pressure zone. The exact placement (in terms of depth) of the contingency string casing will be determined during well construction. Casing material will be 11¾-inch, L-80, BTC, 71 lb/ft liner will be used as contingency string casing and will be set in a 14¾-inch diameter borehole. Casing for this section will be cemented throughout the entire length of the liner.

Deep Intermediate Casing Liner

The deep intermediate casing (liner) string will extend from the bottom of the shallow intermediate casing string (1,094 m MD) (if contingency string not used) to the base of the Tuban Formation (3,356 m MD). If a contingency string is used, the deep intermediate casing (liner) string will extend from the bottom of the contingency liner casing string to the base of the Tuban Formation (3,356 m MD). The placement of the liner at this depth will reduce the potential of significant mud loses. The liner string will consist of 9⅝-inch, P-1q10, 53.5 lb/ft, LTC casing inside a 12¼-inch borehole.

Using the offset well drilling approach as a reference, this section of the well will likely be drilled using a SOBM with a mud weight ranging from approximately 1.53 to 1.71 specific gravity. This mud weight would be satisfactory to maintain well control and borehole stability if over-pressure zones are not encountered and the contingency string is not needed. Due to the relatively high temperature gradient in this well, a mud cooling unit may be needed in the deeper sections of the well.

This section of the well will likely be cemented using a single stage cement job with a 1.68 specific gravity lead slurry followed by a 1.9 specific gravity tail slurry. The annular space will be cemented along the entire length of the liner.

Injection Casing String

The deep/injection casing string will be completed to just below the base of the Kujung Formation at a depth of approximately 3,917 m MD and will be used to case off the lower portion of the well and allow for CO_2 injection into the Kujung Formation. The casing material to be used for this section will have the following specifications (or similar): 5½-inch, P-110, 23 lb/ft, MTC.

4.4.3 Completion Details

Perforations

The well will be perforated to allow communication/injection into the selected zones. The perforation details, including depths, density [holes per foot], hole diameter and penetration distance) will be determined after the well has been drilled and the characterization activities have been completed.

Tubing

Using the U.S. EPA Class VI regulations as guidance, the CO_2 will be injected into the desired formation(s) through tubing. The tubing diameter will likely be 2⅞-inch to allow sufficient injection into the reservoir and will be compatible with the carbon dioxide stream. The tubing will also be designed with burst strength to withstand the injection pressure and the collapse strength to withstand the pressure in the annulus between the tubing and the casing. Consideration should be given to a metal-to-metal seal tubing connection due the higher than normal temperature fluctuation that can occur in the Gundih Field. The precise length/depth of tubing required will be determined once the injection zones have been selected.

Annular Fluid

The annular space above the packer between the 5½-inch injection casing and the 2⅞-inch injection tubing will be filled with fluid to provide structural support for the injection tubing. If required, a small positive pressure can be applied at the surface and continuously monitored to ensure there are no leaks in the tubing, packer or casing. The maximum annulus surface pressure will not exceed a value that would result in a pressure at the top of the packer that is greater than the pressure inside the tubing when the bottom-hole injection pressure is at the maximum allowable pressure.

The annular fluid will be a diluted salt solution such as KCl, NaCl, $CaCl_2$, or similar. The fluid will be mixed onsite using dry salt and clean fresh water or delivered pre-mixed. The fluid will also be filtered to ensure that solids do not settle at the packer or other components installed in the annulus. In addition, the annular fluid will contain additives and inhibitors including a corrosion inhibitor, biocide/bactericide (to prevent harmful bacteria), and an oxygen scavenger

Wellhead

The wellhead and Christmas tree will meet the requirements of API SPEC 6A – Specification for Wellhead and Christmas Tree Equipment Twenty-First Edition (2019) The wellhead and Christmas tree will be composed of materials compatible with the injected fluid to minimize corrosion. All components that are in contact with the CO_2 injection fluid will be made of a corrosion resistant alloy or a conventional material with a corrosion resistant inlay for flow wetted component surfaces. The wellhead and Christmas tree will also be designed to withstand the pressure and temperature conditions expected. Table 4-11 presents the specifications for the wellhead and Christmas tree and Figure 4-9 presents an example diagram of the wellhead/Christmas tree construction.

Table 4-11. Proposed wellhead and Christmas Tree API design specifications.

Section	Bottom Connection (inches)	Top Connection (inches)	Pressure Rating (psi)	Material Classification	Temperature Rating
Section A	20	21 ¼	3,000	TBD	TBD
Section B	21 ¼	11	5,000	TBD	TBD
Section B2*	11	11	5,000	TBD	TBD
Section C**	11	11	5,000	TBD	TBD
THA***	11	4 $^{1}/_{16}$	5,000	TBD	TBD
Xmas Tree	4 $^{1}/_{16}$	-	5,000	TDB	TBD

*Section B2 Casing annulus monitoring instrumentation ported section

**Section C Tubing annulus monitoring instrumentation port access incorporated into tubing head adapter and ported tubing hanger.

*** THA Tubing Head Adapter

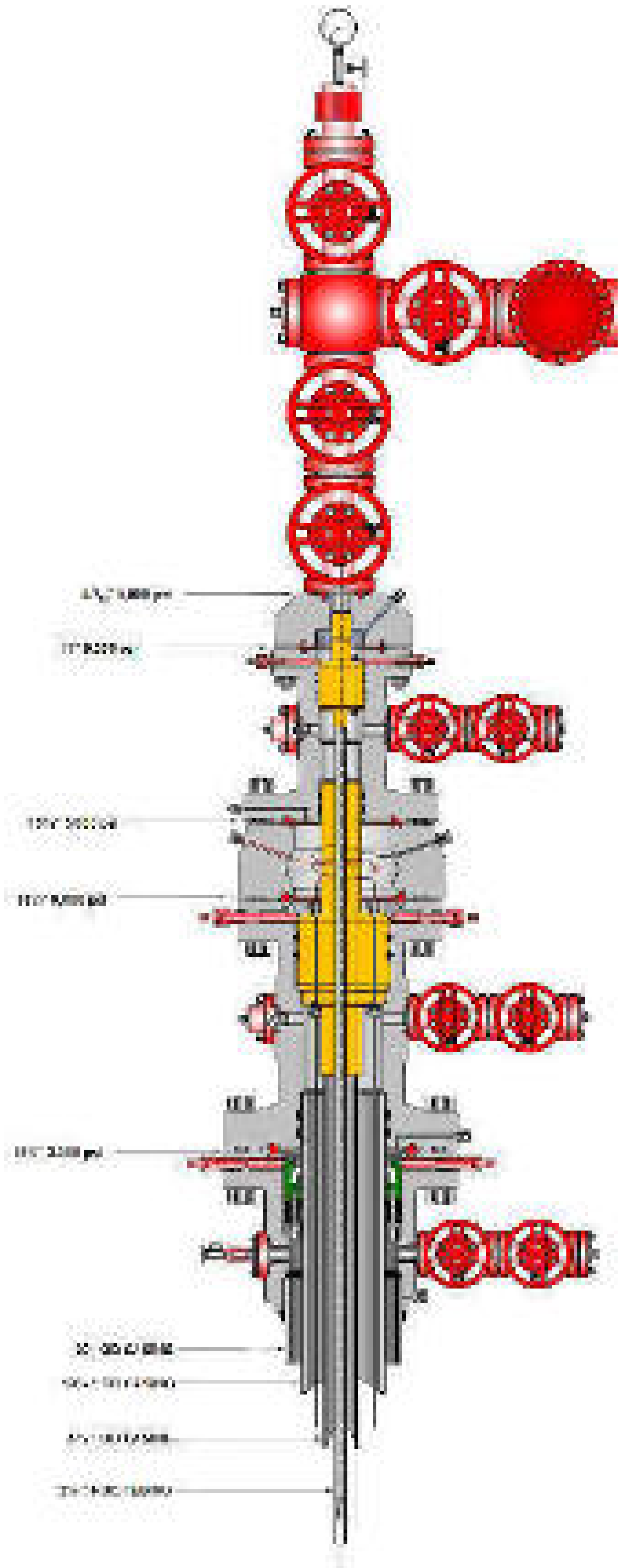


Figure 4-9. Example wellhead and Christmas tree design.

The well will be equipped with fiber optic cable(s) outside the 5-1/2 in. casing and real-time bottom-hole pressure and a temperature monitoring sensor on the outside of the tubing string. This will require the inclusion of ported adaptor flange sections that will incorporate pressure sealing ports. An example is shown in Figure 4-10.

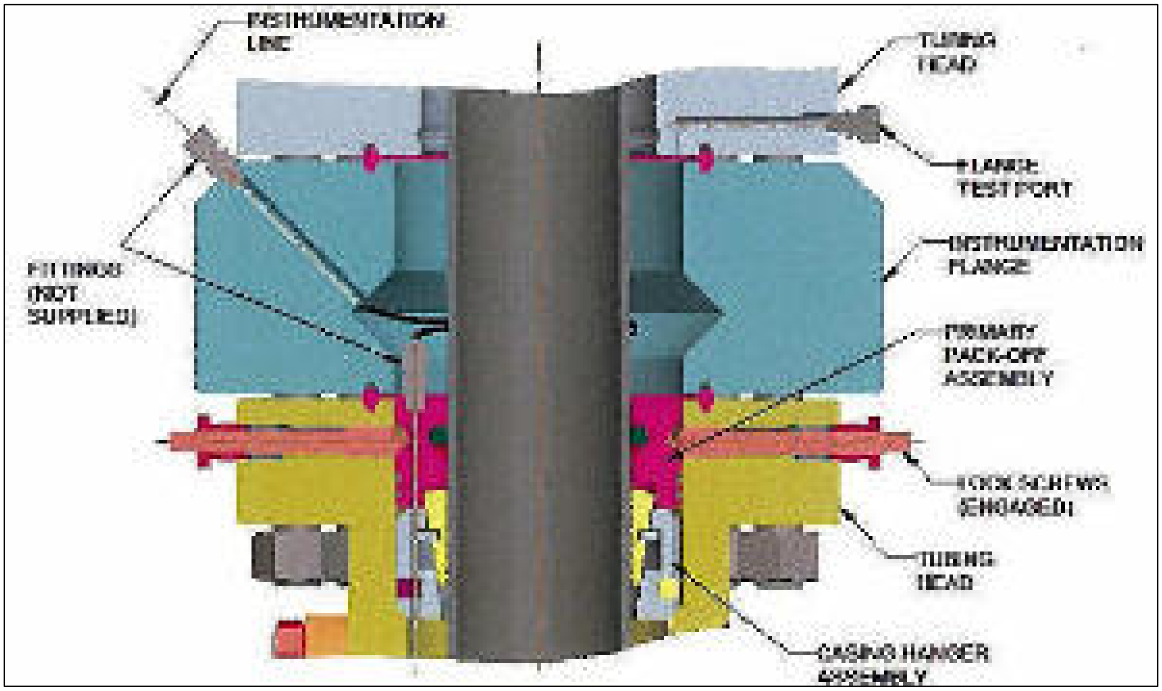


Figure 4-10. Example Instrumentation Flange Showing Penetration for Instrument Line.

Well Monitoring Equipment

During the completion of the pilot well, the well will be equipped with monitoring systems to examine the injection of CO_2 during the operational phase. There will be two main data source locations. The well will be equipped with a fiber optic cable(s) (containing fibers for Distributed Temperature Sensing [DTS], Distributed Acoustic Sensing [DAS], and Distributed Strain Sensing [DSS]) outside the 5-1/2 in. casing and real-time bottom-hole pressure and temperature monitoring sensor on the outside of the tubing string. The annular space outside of the 5½-inch casing will be cemented to the extent possible to surface, permanently cementing the externally mounted fiber optic cable in the well. An electronic cable will be mounted on the tubing string with the cable residing between the 2⅞-inch tubing and the 5½-inch casing. The cable will terminate on bottom a short distance above the packer into a ported sub-assembly providing access to tubing pressure and temperature.

4.4.4 Well Plugging and Abandonment

At the termination of the CO_2-injection pilot program, which is planned to last two years, the well will be permanently plugged and abandoned.

Indonesia does not have regulations or requirements governing well plugging and abandonment; therefore, guidance from the U.S. Environmental Protection Agency Underground Injection Control (UIC) Class VI (CO_2 Injection wells) Rule will be followed. These requirements can be found in 40 CFR §146.92 “Injection Well Plugging”. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, to resist the corrosive aspects of carbon dioxide/water mixtures, and protect any USDWs. Any necessary revisions to the well plugging plan, to address new information collected during logging and testing of the well will be made after construction, logging and testing of the well have been completed.

After injection has been terminated, the well will be flushed with a kill weight brine fluid. A minimum of three tubing volumes will be injected without exceeding the fracture gradient/pressure. The bottom hole pressure will be measured, and the well will be logged and pressure tested to ensure mechanical integrity, inside and outside the casing, prior to plugging. At least one of the following logs, as described in 40 CFR §146.92(a), will be conducted to verify external mechanical integrity prior to plugging operations:

- Temperature Log
- Noise Log
- Oxygen Activation Log

Should a loss of mechanical integrity be discovered, the well will be repaired prior to proceeding with plugging operations. The anulus of all casing strings extending to surface will have been cemented to surface during the well construction phase and will not be retrievable at abandonment. When injection has been terminated permanently, the injection tubing and packer will be retrieved and the well plugged with either, balanced cement plugs or a combination of cement retainers and cement plugs. In the event the packer cannot be retrieved, the tubing will be cut with an electric line tubing cutter leaving the packer in the well after which a cement retainer will be used for plugging the injection formation below the packer.

All casing strings will be cut off approximately three feet subgrade, in accordance with regulatory requirements, and a blanking plate with the well information welded to the cutoff casing.

4.5 Operations and Maintenance

Once the pilot well, separation and compression system, and transfer piping have been completed, the overall system will be ready for injection of CO_2 into the potential reservoirs, beginning the operation and maintenance phase.

In general, the O&M burden for the injection well should be minimal for a two-year injection period. The equipment covered by the injection well O&M activity include all equipment downstream of the Christmas Tree/pipeline connection, including wellhead and Christmas Tree valves, downhole equipment (i.e., packers, tubing, seating nipples, etc.), and the pressure/temperature monitoring equipment (surface and bottomhole). For a typical (e.g., >10-year) injection program, a schedule detailing the timeline of operations and maintenance activities would be developed and included as part of the Class VI UIC permit. Due to the short duration of this project, an operations and maintenance schedule has not been developed. Instead, O&M will be performed proactively or on an as-needed basis. The following text describes potential O&M needs.

Wellhead Equipment

The wellhead (including Christmas Tree) components will need to be checked for leaks, proper function, and general condition on a daily or weekly basis. This should be completed with visual and audible inspections. The wellhead will be visually inspected for cracks, fluid flow out of the wellhead, and the general condition of the wellhead components for oxidation or ill-fitting connections. In addition, localized frost-covered equipment can provide an indication of a leak in the wellhead or piping. Often even small leaks are audible, and the operator should listen to the surface equipment for any indication of leaks. Automated valves controlling the flow of CO_2 into the well should also be checked for acceptable condition. Any leaks or improper function should be reported. Periodically, the automated and manually operated valves should be checked for proper operation. The valves should be fully closed and fully opened to confirm the valves hold pressure and allow proper CO_2 flow to the well. The electronic relays or physical actuators on automated valves should be checked to confirm that they “trip” properly. The inspection of the valves should be performed according to the manufacturer’s recommendations. All moving parts and seals should be properly lubricated according to the manufacturer’s specifications.

Downhole Equipment

Annular pressure monitoring/testing can provide data to monitor the integrity of the well. Annular pressure testing is performed on the annular space between the injection tubing and injection casing to examine the integrity of the tubing, packer, and long casing string before injection commences and following any workover event that involves removing the tubing/packer. Monitoring/testing can also be performed between the individual casing strings in order to confirm the integrity of the outer casing strings and cement between the strings.

After the tubing string and packer have been set at the desired depth and the annular space has been filled with fluid, an annular pressure test (mechanical integrity test) should be conducted to confirm proper sealing of the equipment prior to commencing injection. During the test, the tubing/casing annulus should be increased to an appropriate value (e.g., the U.S. EPA regulations require a test pressure between 300 and 2,000 psi but is dependent upon the maximum allowable injection pressure), an appropriate duration (e.g., 15 minutes to one hour) to detect changes that could indicate leakage. A maximum pressure loss or gain of 5% would indicate acceptable integrity.

During injection operations, annulus pressure will be maintained at a small positive pressure; therefore, an annular pressure maintenance system is required to control the pressure in the annular space. O&M activities should include regular inspection of the annular pressure maintenance system components (e.g., air/nitrogen cylinders, tubing, gauges, transducer, data logger, etc.).

The interior condition of the tubing must be maintained to prevent plugging and interference of CO_2 injection. Indicators of plugged tubing would be an increase in wellhead tubing pressure without a corresponding increase in the tubing pressure at the depth of the reservoir. Depending on the cause of the plugging (hydrates, lubricants from the compressors, or corrosion) actions can be made to remedy the issue. Hydrates are often addressed with the injection of methanol into the injection lines and organic lubricants can often be remedied with an organic solvent. Corrosion of the tubing may require replacement of sections of the tubing or the entire tubing string.

Pressure/Temperature Monitoring Equipment

The injection well will use an electronic P&T sensor with real-time surface readout capability to monitor the surface and bottomhole (just above packer) pressure and temperature. These sensors will be calibrated before installation. The surface sensor can be re-calibrated periodically; however, the bottomhole sensor can only be recalibrated if the tubing/packer is removed. Routinely, the data will be analyzed for evidence of drift (e.g., increasing/decreasing trend). These systems generally are low maintenance devices and historically have only had problems related to electrical power supply.

4.6 CO_2 Monitoring Program

A subsurface monitoring program has been developed for the Gundih pilot CCS project that includes multiple monitoring methods aimed at achieving several key monitoring objectives, as outlined in Table 4-12. Upon ADB approval of this project to advance to the execution phase, a detailed monitoring plan will be developed that provides more information about each monitoring method.

The monitoring responsibility has been divided into two categories, including: monitoring processes at the point of injection (i.e., in the injection well);and monitoring the subsurface environment outside of/away from the injection well. Reportedly, funding for the latter category will come from JICA (Japan International Cooperation Agency) whereas ADB will provide the funding for the remainder of the monitoring program. Per discussions with ADB, ITB will be responsible for executing the JICA funded monitoring methods, whereas, the ADB contractor will implement the monitoring methods at/in the injection well.

Table 4-12. Subsurface Monitoring Objectives and Methods for the Gundih Pilot-Scale CCS Project.

Monitoring Focus	Objective	Method
Point of Injection	Monitor/document the chemical composition and physical properties (e.g., pH, density, viscosity) of the injection fluid	Periodically sample CO_2 fluid and submit to commercial laboratory or analyze on site
	Monitor/document surface and bottomhole injection pressure and temperature data during the two-year injection period	P&T sensors with real-time readout and data logging capability will be used to record continuous data stream
	Monitor pressure buildup in the injection reservoir Monitor injection well skin for indication of plugging or other obstructions	Injection fall-off tests conducted periodically (e.g., every 3 months)
	Detect vertical leakage of CO_2 or brine from the injection reservoir to overlying layers via the well-formation annulus	Pulsed Neutron Capture log monitoring or Continuous DTS monitoring for temperature anomalies
Reservoir monitoring	Monitor lateral and vertical spreading of CO_2 in the injection reservoir	DAS; DSS; DTS
	Detect changes in shallow groundwater aquifer chemistry due to CO_2 or brine leakage	Periodically collect and sample samples of the shallow groundwater. and analyze
	Detect pressure/CO_2 impact to existing gas-production well	Monitor produced fluids for increase in CO_2
	Detect induced seismicity	Multiple shallow boreholes will be instrumented with geophone array that will continuously monitor seismicity.

Section 5. Cost Information

This section provides a summary of estimated costs for the pilot-scale CCS project. Costs are summarized separately for surface facilities (i.e., capture, treatment), transportation (i.e., pipeline), and subsurface facilities (i.e., deep CO_2 injection well).

5.1 Surface Facilities Costs

The purchased costs for the major equipment and skids were estimated based on budgetary quotes and engineering estimates based on project experience. Budgetary quotes were received from Indonesian suppliers for all major equipment except for compressors. As of the time of this report, no response has been received from out of country vendors with operations in Indonesia (Germany, France, and Austria), so the compressor cost shown is from a USA project with import costs applied. Below is a summary of the cost basis for each equipment package (150 ton/day basis):

- Compressor – USA quote basis from multiple CO_2 compressor projects (include import duty)
- H_2S removal – Vertis quote (four vessel system adjusted to represent two vessel system)
- Dehydration – Vertis quote
- Pipeline – Elnusa quote

Minor process components listed below were estimated based on previous project experience:

- Piping required between CPP Gundih and injection well (500-ft of 8-in. pipe for 150 TPD)
- Shutdown valve (SDV), moisture analyzer, and flow measurement for pipeline and injection well site
- Piping and instrumentation costs for pipeline flow measurement and injection well site
- Fiber optic cable for installation into ditch during pipeline construction

A summary of the major purchased equipment cost data used in the cost analysis is shown below in Table 5-1.

Table 5-1. Major purchased equipment cost data.

	30 TPD	150 TPD	Base Cost	Base Scale	Notes
Piping from CPP to Pilot Injection Site	$60,000	$72,500	$72,500	150 TPD	500-ft of 8" Sch. 10 pipe
Compressor Package	$731,100	$2,398,600	$2,398,600	150 TPD	$2,230/HP (150 TPD), 3400/HP (30 TPD); + duty
H_2S Scavenger System	$548,800	$775,000	$1,550,000	150 TPD	Vertis quote was 2x size required
Dehydration	$213,200	$560,000	$560,000	150 TPD	Vertis quote for 1 gpm TEG system
Flow measurement and SDVs (two locations)	$100,000	$100,000	$50,000	150 TPD	Estimate for 2" Daniel meters / SDVs
Total capital - process area and well location	**$1,553,100**	**$3,806,100**			

The basis for budgetary quotes was 150 TPD, the equipment estimates for 30 TPD were extrapolated using the ratio of design capacity or characteristic size to the 0.6 power (the 6/10 rule). For the H_2S scavenging system the Vertis quote of four vessels was reduced by 50% to serve as the cost basis. A two-vessel system would still have a bed life of 19 days; this change out frequency is acceptable for a two-year test period, and the capital savings is significant. The budgetary quote for the dehydration system was four to five times the expected cost for equipment of this size based on USA project experience. A second quote was not available, so the quote obtained is used for the project cost basis. Consideration should be given to fabrication of the dehydration system in the USA if the Indonesian estimate does not change significantly.

The total project costs were estimated using a conventional, early project phase factored method. Factors are included for installation at the plant (piping, labor, etc.) as well as taxes, freight, and fees; a 20% contingency is also included. The total project cost estimates are summarized in Table 5-2 for 150 TPD. The spreadsheet calculations are provided in Appendix A. Lower installation factors were applied to the equipment as most are packaged systems and much of what would be installation costs (e.g., most of the piping, instrumentation, and engineering) for loose equipment are included in the packaged system purchased costs.

At the lower end of the table, the initial fill of H_2S scavenger and glycol are listed. These costs and the pipeline costs are not part of the contingency that is listed below the subtotal of project costs. A contingency of 20% is shown for the project to reflect the level of cost uncertainty and not having full scope definition or firm quotes for all project components.

Table 5-2. Total project cost estimates for 150 TPD scenario.

	150 TPD Capture Costs	Pipeline & Well Site Costs	Total
Major Equipment			
Piping from CPP to Pilot	$72,500		$72,500
Compressor Package	$2,398,600		$2,398,600
H_2S Scavenger System	$775,000		$775,000
Dehydration	$560,000		$560,000
Metering		$100,000	$100,000
Total Major Equipment	$3,806,100	$100,000	$3,906,100
Installation			
Site/Foundations	$228,400	$40,000	$268,400
Structural/Lifts	$304,500	$25,000	$329,500
Piping	$570,900	$60,000	$630,900
Instrumentation	$304,500	$40,000	$344,500
Electrical	$228,400	$25,000	$253,400
Total Installation	$1,636,700	$190,000	$1,826,700
Tax/Freight/Fees	$939,200	$67,800	$1,007,000
Other			
Engineering	$255,300	$32,600	$287,900
Inspection/Oversight	$127,600	$24, 500	$152,100
SulfaTreat 2242 Fill	$140,600		$140,600
Glycol Fill	$15,000		$15,000
Pipeline (TIC)		$303,000	$303,000
Fiber Optic Cable		$50,000	$50,000
Subtotal	$6,920,500	$767,900	$7,688,400
Contingency	$1,276,400	$81,600	$1,358,000
Total	**$8,196,900**	**$849,500**	**$9,046,400**

The total project cost was also estimated for a pilot facility to capture and transport 30 TPD. Although this flow rate is lower than the size required to inject 100,000 tons of CO_2 in a two-year test period, comparing costs of the different plant capacities provides some context for how projects costs change with the different injection rates. For 30 TPD capacity, the installed cost for the capture equipment was estimated at $4,190,000. For the pipeline and well location, the installed cost was estimated at $761,900. The total installed project cost for the 30 TPD pilot was estimated at $4,951,900. As shown in Table 5-2, the total project cost for 150 TPD was estimated at $9,046,400. Although the flow rate of the 30 TPD pilot is 20% the rate of the 150 TPD pilot, the estimated cost is roughly 55% of the 150 TPD pilot.

The operating expenses estimated for the surface facility equipment include scavenger costs, power costs (NG and electricity), and maintenance costs (Table 5-3). The largest of these costs is for the scavenger used to remove H_2S from the gas stream.

Table 5-3. Annual Operating Costs for surface facility equipment.

Annual Operating Costs	150 TPD	30 TPD
H_2S Scavenger	$1,811,000	$394,200
NG/Fuel Gas	$116,500	$44,400
Power/kilowatts	$56,100	$11,200
Labor	$232,100	$96,900
Facilities	$76,100	$31,100
Maintenance	$152,200	$62,100
Total	**$2,444,000**	**$639,900**

5.2 Transportation

The project costs for CO_2 transport included two flow measurement facilities (inlet and outlet of pipeline) and a 4.3 km pipeline. The installed cost for the pipeline was estimated by Elnusa based on current material pricing and cost experience from similar pipeline projects. For the flow measurement facilities, the total projects costs were estimated using the early project phase factored method discussed previously. The total project cost estimates for the CO_2 pipeline and well site component of the pilot project are summarized above. Additional cost information for the analysis is included in Appendix A.

5.3 Subsurface Costs

The subsurface component of the pilot project involves the drilling, completion, and operation and maintenance of a CO_2 injection well during the pilot project. The well will be used to inject CO_2 for a period of two years and to support various monitoring activities during the two-year injection period and during a follow-on monitoring only period after completion of CO_2 injection (note – the post injection monitoring period was assumed to be one to two years in duration, however, it may need to be longer if the injected CO_2 plume is not stable after this time. The total estimated cost for the subsurface facilities component of the pilot project is $22.7 million, which includes $17.7 million for the injection well (installation and operation for two years and plugging/abandonment at the end of the project) and $5 million for monitoring (Table 5-4).

Drilling/well work is inherently expensive and will involve multiple contractors. A breakdown of costs associated with the injection well is shown in Figure 5-1 (same data is presented in Table 5-4). The biggest costs are drilling services, formation testing/evaluation (e.g., logging while drilling, open-hole logging, sidewall coring), tangible items such as casing, wellhead, etc., drilling services, formation testing/evaluation (e.g., logging while drilling, open-hole logging, sidewall coring), drilling rig fuel, completion, and monitoring. Cost estimates for the well drilling/completion components were obtained from historical Pertamina authorization for expenditure (AFE) documents and recent vendor quotes. A comprehensive and detailed cost breakdown for the injection well is provided in Appendix B to this document. Note that the monitoring costs included in the estimate in Table 5-4 ($5,000,000) is a lump sum estimate of all monitoring (borehole seismic, surface seismic, microseismic, surface atmospheric monitoring, pressure and temperature monitoring, etc.). The assumption is made that the funding for monitoring would be provided by JICA (Japan International Cooperation Agency).

Table 5-4. Estimated cost for subsurface component of pilot project.

Cost Element	Cost $
casing and tubing	1,516,333
well equip. surface	313,548
well equip. subsurface	240,340
site prep.	128,180
contract rig/crew	4,918,325
drilling fluids/svc.	650,185
cement	1,507,900
casing installation	428,086
directional drilling	1,924,882
equip. rentals	506,595
bits, reamers, core heads	147,000
water, inspections	34,000
coring	269,950
mudlogging	282,874
open-hole logging	1,764,180
cased-hole logging	235,828
perforating	52,500
supervision	197,549
insurance, permits, fees	33,000
land/other transportation	55,085
fuel	1,339,187
camp facilities	51,331
overheads - field office/Jakarta	52,000
abandonment	989,913
Total Cost without monitoring	**17,638,770**
Monitoring costs	**5,000,000**
Total Estimated Cost with Monitoring	**22,638,770**

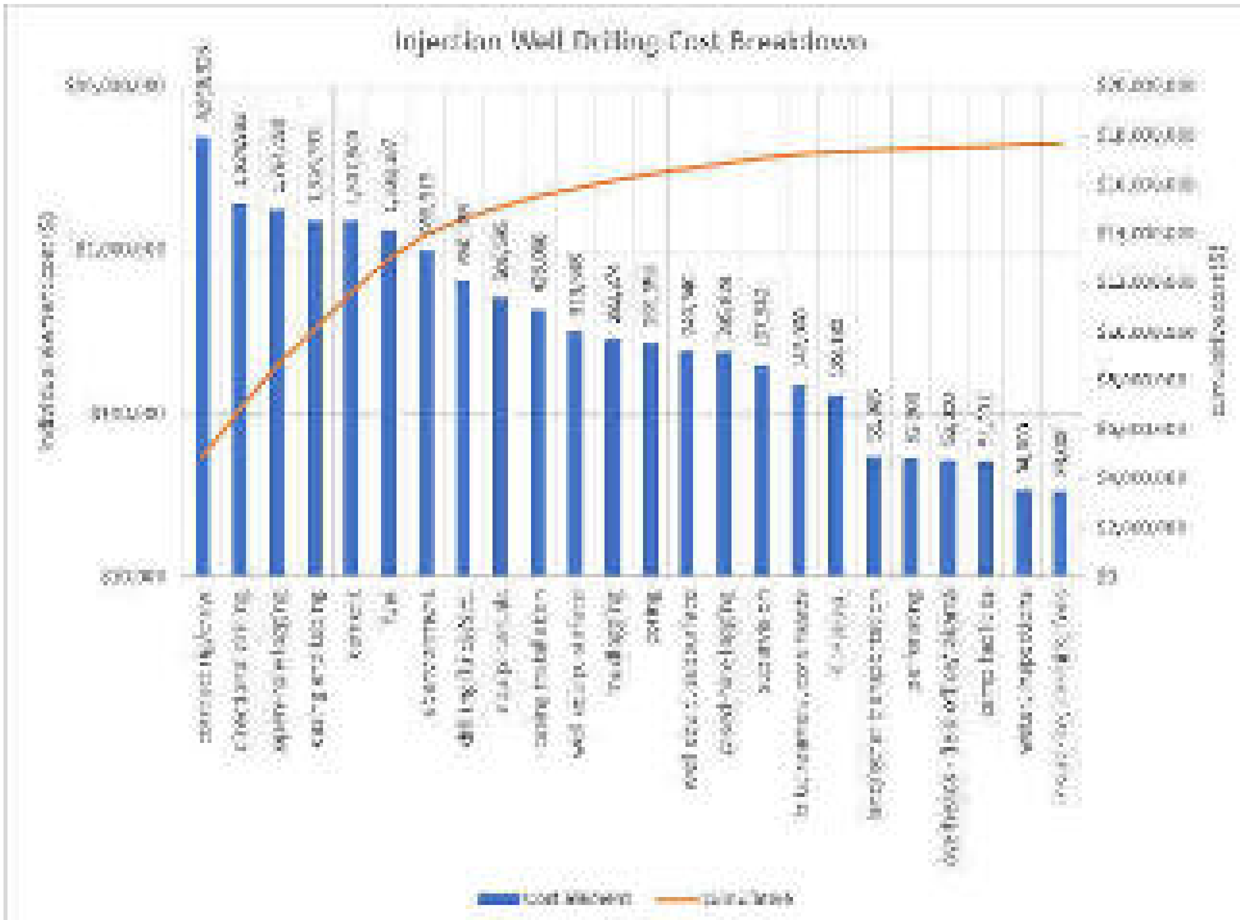


Figure 5-1. Injection Well Costs totaling $17,638,770 (does not include monitoring)

5.4 Summary

The total combined costs for the two-year 150 t/d pilot project is estimated to be $$36,573,170. A breakdown of costs into major categories is provided in Figure 5-2.

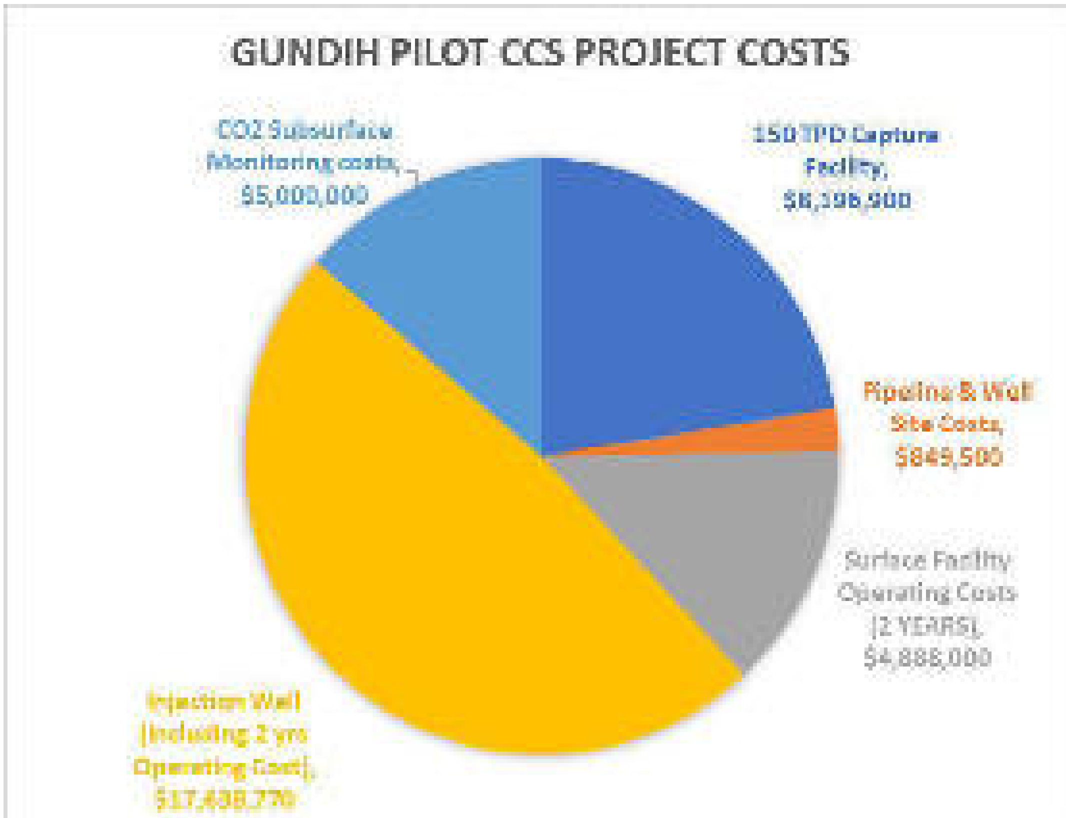


Figure 5-2. Total Project Cost Estimate for the Gundih 2-year 150 t/d Pilot CCS Project

Section 6. Environmental Safeguards & Regulatory Requirements

Details regarding environmental safeguards and regulatory requirements can be found in Section 7 of the Gundih Project Management and Assurance Plan (Battelle, 2019).

References

American Petroleum Institute (API). (2019). Specification for Wellhead and Christmas Tree Equipment Twenty-First Edition

Battelle (2018). “TA-9189 INO: Pilot Carbon Capture and Storage Activity in the Natural Gas Processing Sector Review of Proposed Pilot CO_2 Capture and Storage Project in Gundih Field”; prepared for Asian Development Bank under ADB Contract – 137806-S53178, Executing Agency – Directorate General of Oil and Gas, Ministry of Energy and Mineral Resources, Republic of Indonesia (DG MIGAS).

Battelle (2019). Gundih Project Management and Assurance Plan for ADB.

Institut Teknologi Bandung (ITB). (2015). Technical Report of CCS Gundih Pilot Project Feasibility Study for ADB. ITB: Bandung.

Institut Teknologi Bandung (ITB) Indonesia Center of Excellence of CCS and CCUS. (2019). ADB-ITB Knowledge Partnership Program. ITB: Bandung.

Appendix A. Total Project Cost Estimates

TITLE: **Battelle - ADB: Gundih Pilot Project**
DESC: **Capital cost estimate for CO2 Capture and Treatment**
OPTION 1: 30 TPD Capacity

Ver 0 ########
Trimeric Corporation

MAJOR EQUIPMENT AND COST	(MEC)				**COMMENTS**
TOTAL EQ COST				$1,553,045	Vendor Budgetary Quotes, skidded equipment only
	TOTAL = A			$1,553,045	
	TYPICAL				
INSTALLATION COSTS	RANGE	FACTOR			
SITE/FOUNDATIONS	0.06-0.2	0.1 X A		$155,305	Use low end of range, eq is skidded mostly
STRUCTURES	0.15-0.3	0.08 X A		$124,244	Limited need for structure for skids, use low value
EQUIPMENT ERECTION	0.15-0.3	0.04 X A		$62,122	Mostly putting skids in place, use low number
PIPING	0.4-1.1	0.2 X A		$310,609	Limited piping needs, low value
INSULATION	0-0.06	X A		$0	
PAINT	0.05-0.1	0.04 X A		$62,122	Skids should be painted, low end value
FIRE PROTECTION	0.01-0.06	0.015 X A		$23,296	H2S present in existing plant at tie-in
INSTRUMENTS	0.4-0.8	0.15 X A		$232,957	Low value, skids instrumented
ELECTRICAL	0.15-0.4	0.1 X A		$155,305	skids pre wired, use lower value, but add some for switchgear
	TOTAL INSTALLATION			$1,125,958	
PIPELINE - CPP TO INJECTION					
B = BASE COST = A + INSTALLATION		=		$2,679,003	
VAT TAX + Income tax 0.1A+0.025(B-A)			$183,453		default values
FREIGHT 0.05A			$77,652		default values
CONTRACTORS FEES 0.2(B-A)			$225,192		default values
			$486,297	$486,297	
C= SUBTOTAL = B+TAX+FREIGHT+FEES				$3,165,300	
ENGINEERING	FACTOR =	0.06 X SUBTOTAL		$189,918	use low value since skid cost includes vendor engr
INSPECTION/OVERSIGH	FACTOR =	0.03 X SUBTOTAL		$94,959	
CONTINGENCIES	FACTOR =	0.2 X SUBTOTAL		$633,060	Use typical pre-FEED contingency
TOTAL C+ENGR+CONTINGENCIES				$4,083,237	
Additional Equipment without associated installation costs Subtract the value here of any salvage used equipment					
PROJECT COST - TIC ************************				**$4,083,237**	OVERALL FACTOR = 2.6
			SulfaTreat 2242	91,730	
			Glycol Fill	15,000	
			Installation		
TOTAL PROJECT COST ********************************				**$4,189,967**	

TITLE:	**Battelle - ADB: Gundih Pilot Project**		Ver 0 ########	
DESC:	**Capital cost estimate for CO2 Capture and Treatment**		Trimeric Corporation	
	OPTION 2: 150 TPD Capacity			

MAJOR EQUIPMENT AND COST	(MEC)				**COMMENTS**
TOTAL EQ COST				$3,806,104	Vendor Budgetary Quotes, skidded equipment only
	TOTAL = A			$3,806,104	
	TYPICAL				
INSTALLATION COSTS	RANGE	FACTOR			
SITE/FOUNDATIONS	0.06-0.2	0.06 X A		$228,366	Use low end of range, eq is skidded mostly
STRUCTURES	0.15-0.3	0.05 X A		$190,305	Limited need for structure for skids, use low value
EQUIPMENT ERECTION	0.15-0.3	0.03 X A		$114,183	Mostly putting skids in place, use low number
PIPING	0.4-1.1	0.12 X A		$456,732	Limited piping needs, low value
INSULATION	0-0.06	X A			
PAINT	0.05-0.1	0.02 X A		$76,122	Skids should be painted, low end value
FIRE PROTECTION	0.01-0.06	0.01 X A		$38,061	H2S present in existing plant at tie-in
INSTRUMENTS	0.4-0.8	0.08 X A		$304,488	Low value, skids instrumented
ELECTRICAL	0.15-0.4	0.06 X A		$228,366	skids pre wired, use lower value, large engines to be NG drive
	TOTAL INSTALLATION			$1,636,625	
PIPELINE - CPP TO INJECTION					
B = BASE COST = A + INSTALLATION		=		$5,442,729	
VAT TAX + Income tax	0.1A+0.025(B-A)		$421,526		default values
FREIGHT	0.05A		$190,305		default values
CONTRACTORS FEES	0.2(B-A)		$327,325		default values
			$939,156	$939,156	
C= SUBTOTAL = B+TAX+FREIGHT+FEES				$6,381,885	
ENGINEERING	FACTOR =	0.04 X SUBTOTAL		$255,275	use low value since skid cost includes vendor engr
INSPECTION/OVERSIGH	FACTOR =	0.02 X SUBTOTAL		$127,638	
CONTINGENCIES	FACTOR =	0.2 X SUBTOTAL		$1,276,377	Use typical pre-FEED contingency
TOTAL C+ENGR+CONTINGENCIES				$8,041,175	
Additional Equipment without associated installation costs Subtract the value here of any salvage used equipment					
PROJECT COST - TIC ************************				**$8,041,175**	OVERALL FACTOR = 2.1
			SulfaTreat 2242	140,611	
			Glycol Fill	15,000	
			Installation		
TOTAL PROJECT COST ********************************				**$8,196,786**	

TITLE: Battelle - ADB: Gundih Pilot Project
DESC: Capital cost estimate for CO2 Capture and Treatment Well Location

Ver 0 ########
Trimeric Corporation

					COMMENTS
MAJOR EQUIPMENT AND COST	(MEC)				
TOTAL EQ COST				$100,000	Estimate of meter and SDV Both Sites
	TOTAL = A			$100,000	
INSTALLATION COSTS	TYPICAL RANGE	FACTOR			
SITE/FOUNDATIONS	0.06-0.2	0.4 X A		$40,000	
STRUCTURES	0.15-0.3	0.15 X A		$15,000	pipe supports or vent
EQUIPMENT ERECTION	0.15-0.3	0.1 X A		$10,000	
PIPING	0.4-1.1	0.5 X A		$50,000	open area, limited piping
INSULATION	0-0.06	0 X A		$0	
PAINT	0.05-0.1	0.1 X A		$10,000	limited piping
FIRE PROTECTION	0.01-0.06	0 X A		$0	
INSTRUMENTS	0.4-0.8	0.4 X A		$40,000	flow and P/T msmst
ELECTRICAL	0.15-0.4	0.25 X A		$25,000	
	TOTAL INSTALLATION			$190,000	
Communication - Fiberoptic				$50,000	
B = BASE COST = A + INSTALLATION		=		$340,000	
VAT TAX + Income tax 0.1A+0.025(B-A)			$14,750		default values
FREIGHT 0.05A			$5,000		default values
CONTRACTORS FEES 0.2(B-A)			$48,000		default values
			$67,750	$67,750	
C= SUBTOTAL = B+TAX+FREIGHT+FEES				$407,750	
ENGINEERING	FACTOR =	0.08 X SUBTOTAL		$32,620	use low value since skid cost includes vendor engr
INSPECTION/OVERSIGH	FACTOR =	0.06 X SUBTOTAL		$24,465	
CONTINGENCIES	FACTOR =	0.2 X SUBTOTAL		$81,550.00	Use typical pre-FEED contingency
TOTAL C+ENGR+CONTINGENCIES				$496,385	
Additional Equipment without associated installation costs Subtract the value here of any salvage used equipment					
PROJECT COST - TIC ************************				**$496,385**	OVERALL FACTOR = 5.0
TOTAL PROJECT COST ********************************				**$496,385**	

Appendix B. Subsurface Authorization for Expenditure

SKK MIGAS

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER

OPERATOR : Pertamina EP
CONTRACT AREA : Gundhi Field
CONTRACT AREA № : Pertamina Asset IV

PROJECT TYPE : CCS Pilot Injection Well
WELL NAME : CCS - 1
WELL TYPE : Onshore CCS Pilot Injection Well
PLATFORM/TRIPOD : Onshore Drilling Unit
FIELD/STRUCTURE : Gundih Field/Kedung Tuban
BASIN : Java Basin

AFE № : TBA
DATE : 27-Aug-2019

IN US DOLLARS

LOCATION : KTB-B V
WATER DEPTH : N/A
SURFACE LAT : 7°12'18.28"S
ELEVATION : TBA
LONGITUDE : 111°29'34.27"E
CONTRACTOR : TBA
UBSURFACE LAT : TBA
RIG NAME : TBA
LONGITUDE : TBA
RIG TYPE : Land Rig

SPUD DATE : TBA
COMPLETION DATE : TBA
PLACED IN SERVICE : TBA
DRILLING DAYS : TBA

	PROGRAM		ACTUAL	
RIG DAYS :	70.42	days		days
TOTAL DEPTH (ft.) :	13,451	feet		feet
WELL COST PER FOOT :	$1,230.90	US$/ft		US$/ft
WELL COST PER DAY :	$235,114.23	US$/Day		US$/Day

CLOSE OUT DATE :
COMPLETION TYPE : CO_2 Injection & Monitoring Completion
WELL STATUS :

LINE №	DESCRIPTION	WORK PROGRAM AND BUDGET	REVISED BUDGET	FINAL BUDGET	ACTUAL EXPENDITURES: PRIOR YEARS	ACTUAL EXPENDITURES: COMMITTED	ACTUAL EXPENDITURES: EXPENDITURE TO DATE	ACTUAL OVER /(UNDER) BUDGET	PERCENTAGE OVER /(UNDER) BUDGET
		1	2	3	4	5	6	7	8
1	TANGIBLE COSTS								
2	CASING	1,313,659						(1,313,659)	(100.00)
3	CASING ACCESSORIES	58,570						(58,570)	(100.00)
4	TUBING	144,104						(144,104)	(100.00)
5	WELL EQUIPMENT - SURFACE	313,548						(313,548)	(100.00)
6	WELL EQUIPMENT - SUBSURFACE	239,415						(239,415)	(100.00)
7	OTHER TANGIBLE COSTS	0						0	
8								0	
9	TOTAL TANGIBLE COSTS	$2,069,296	-	-	-	-	-	(2,069,296)	(100.00)
10									
11	INTANGIBLE COSTS								
12	PREPARATION AND TERMINATION								
13	SURVEYS	6,000						(6,000)	(100.00)
14	LOCATION STAKING AND POSITIONING	36,816						(36,816)	(100.00)
15	WELLSITE AND ACCESS ROAD PREPARATION	65,000						(65,000)	(100.00)
16	SERVICE LINES& COMMUNICATIONS	20,364						(20,364)	(100.00)
17	WATER SYSTEMS	0						0	
18	RIGGING UP / RIGGING DOWN	0						0	
19								0	
20	SUBTOTAL	$128,180	-	-	-	-	-	(128,180)	(100.00)
21									
22	DRILLING / WORKOVER OPERATIONS								
23	CONTRACT RIG	4,918,325						(4,918,325)	(100.00)
24	DRILLING RIG CREW / CONTRACT RIG CREW	0						0	
25	MUD, CHEMICAL & ENGINEERING SERVICES	650,185						(650,185)	(100.00)
26	WATER	7,000						(7,000)	(100.00)
27	BITS, REAMERS AND CORE HEADS	147,000						(147,000)	(100.00)
28	EQUIPMENT RENTALS	506,595						(506,595)	(100.00)
29	DIRECTIONAL DRILLING AND SURVEYS	1,924,882						(1,924,882)	(100.00)
30	DIVING SERVICES	0						0	
31	CASING INSTALLATION	428,086						(428,086)	(100.00)
32	CEMENT, CEMENTING AND PUMP FEES	1,507,900						(1,507,900)	(100.00)
33	INSPECTIONS	27,000						(27,000)	(100.00)
34									
35	SUBTOTAL	$10,116,972	-	-	-	-	-	(10,116,972)	(100.00)
36									
37	FORMATION EVALUATION								
38	CORING	269,950						(269,950)	(100.00)
39	MUD LOGGING SERVICES	282,874						(282,874)	(100.00)
40	DRILLSTEM TESTS	0						0	
41	OPEN HOLE ELECTRICAL LOGGING SERVICES	1,764,180						(1,764,180)	(100.00)
42									
43	SUBTOTAL	$2,317,004	-	-	-	-	-	(2,317,004)	(100.00)
44									
45	COMPLETION								
46	CASING, LINER AND TUBING INSTALLATION	0						0	
47	CEMENT, CEMENTING AND PUMP FEES	0						0	
48	CASED HOLE ELECTRICAL LOGGING SERVICES	145,280						(145,280)	(100.00)
49	PERFORATING AND WIRELINE SERVICES	52,500						(52,500)	(100.00)
50	STIMULATION TREATMENT	0						0	
51	PRODUCTION TESTS	0						0	
52									
53	SUBTOTAL	$197,780	-	-	-	-	-	(197,780)	(100.00)
54									
55	GENERAL								
56	SUPERVISION	197,549						(197,549)	(100.00)
57	INSURANCE	3,000						(3,000)	(100.00)
58	PERMITS AND FEES	30,000						(30,000)	(100.00)
59	MARINE RENTAL AND CHARTERS	0						0	
60	HELICOPTERS AND AVIATION CHARGES	0						0	
61	LAND TRANSPORTATION	30,000						(30,000)	(100.00)
62	OTHER TRANSPORTATION	25,085						(25,085)	(100.00)
63	FUEL AND LUBRICANTS	1,339,187						(1,339,187)	(100.00)
64	CAMP FACILITIES	51,331						(51,331)	(100.00)
65	ALLOCATED OVERHEADS - FIELD OFFICE	7,000						(7,000)	(100.00)
66	ALLOCATED OVERHEADS - JAKARTA OFFICE	45,000						(45,000)	(100.00)
67	ALLOCATED OVERHEADS - OVERSEAS	0						0	
68	TECHNICAL SERVICES FROM ABROAD	0						0	
69									
70	SUBTOTAL	$1,728,151	-	-	-	-	-	(1,728,151)	(100.00)
71									
72	TOTAL INTANGIBLE COSTS	$14,488,088	-	-	-	-	-	(14,488,088)	(100.00)
73									
74	T O T A L C O S T S	$16,557,383	-	-	-	-	-	(16,557,383)	(100.00)
75									
76	TIME PHASED EXPENDITURES								
77	THIS YEAR 2019					-	-	0	
78	FUTURE YEARS 2020	$16,557,383							
79	TOTAL	$16,557,383							

OPERATOR
APPROVED BY :
POSITION :
DATE :

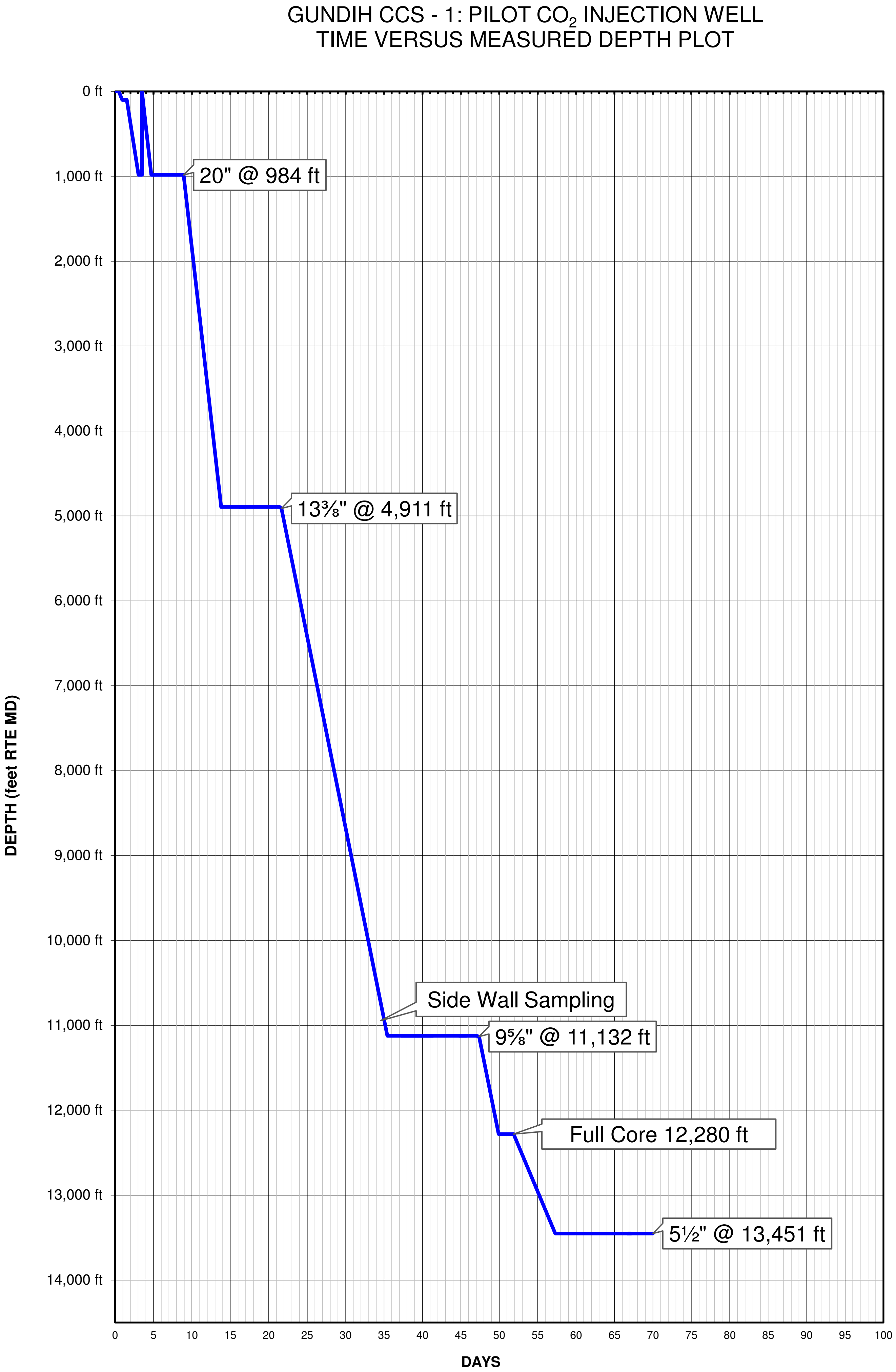
SKK MIGAS
APPROVED BY :
POSITION :
DATE :

REMARKS

CCS PILOT WELL DRILLING, EVALUATION & COMPLETION BUDGETARY AFE (feet)

Revision Print Date: 27-Aug-19

SKK MIGAS


GUNDIH CCS - 1: PILOT CO2 INJECTION WELL
TIME VERSUS MEASURED DEPTH PLOT
20" @ 984 ft
13⅜" @ 4,911 ft
Side Wall Sampling
9⅝" @ 11,132 ft
Full Core 12,280 ft
5½" @ 13,451 ft
0 ft
1,000 ft
2,000 ft
3,000 ft
4,000 ft
5,000 ft
6,000 ft
7,000 ft
8,000 ft
9,000 ft
10,000 ft
11,000 ft
12,000 ft
13,000 ft
14,000 ft
DEPTH (feet RTE MD)
0
5
10
15
20
25
30
35
40
45
50
55
60
65
70
75
80
85
90
95
100
DAYS

SKK MIGAS

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER

SCHEDULE №. 19

OPERATOR	: Pertamina EP	PROJECT TYPE :	CCS Pilot Injection Well	AFE № :	TBA
CONTRACT AREA	: Gundhi Field	WELL NAME :	CCS - 1		
CONTRACT AREA №	: Pertamina Asset IV	WELL TYPE :	Onshore CCS Pilot Injection Well	DATE :	27-Aug-2019
		PLATFORM/TRIPOD :	Onshore Drilling Unit		
		FIELD/STRUCTURE :	Gundih Field/Kedung Tuban		
		BASIN :	Java Basin		IN US DOLLARS

LOCATION :	KTB-B V	SURFACE LAT :	7°12'18.28"S	LONGITUDE :	111°29'34.27"E	UBSURFACE LAT :	TBA	LONGITUDE :	TBA
WATER DEPTH :	N/A	ELEVATION :	TBA	CONTRACTOR :	TBA	RIG NAME :	TBA	RIG TYPE :	Land Rig

			PROGRAM		ACTUAL	
SPUD DATE :	TBA	RIG DAYS :	70.42	days		days
COMPLETION DATE :	TBA	TOTAL DEPTH (m.) :	4,100	meters		meters
PLACED IN SERVICE :	TBA	WELL COST PER METER :	$4,038.39	US$/m		US$/m
DRILLING DAYS :	TBA	WELL COST PER DAY :	$235,114.23	US$/Day		US$/Day
CLOSE OUT DATE :		COMPLETION TYPE :	CO_2 Injection & Monitoring Completion	WELL STATUS :		

LINE №	DESCRIPTION	WORK PROGRAM AND BUDGET	REVISED BUDGET	FINAL BUDGET	ACTUAL EXPENDITURES: PRIOR YEARS	COMMITTED	EXPENDITURE TO DATE	ACTUAL OVER /(UNDER) BUDGET	PERCENTAGE OVER /(UNDER) BUDGET
		1	2	3	4	5	6	7	8
1	TANGIBLE COSTS								
2	CASING	1,313,659						(1,313,659)	(100.00)
3	CASING ACCESSORIES	58,570						(58,570)	(100.00)
4	TUBING	144,104						(144,104)	(100.00)
5	WELL EQUIPMENT - SURFACE	313,548						(313,548)	(100.00)
6	WELL EQUIPMENT - SUBSURFACE	239,415						(239,415)	(100.00)
7	OTHER TANGIBLE COSTS	0						0	
8								0	
9	TOTAL TANGIBLE COSTS	$2,069,296	-	-	-	-	-	(2,069,296)	(100.00)
10									
11	INTANGIBLE COSTS								
12	PREPARATION AND TERMINATION								
13	SURVEYS	6,000						(6,000)	(100.00)
14	LOCATION STAKING AND POSITIONING	36,816						(36,816)	(100.00)
15	WELLSITE AND ACCESS ROAD PREPARATION	65,000						(65,000)	(100.00)
16	SERVICE LINES& COMMUNICATIONS	20,364						(20,364)	(100.00)
17	WATER SYSTEMS	0						0	
18	RIGGING UP / RIGGING DOWN	0						0	
19								0	
20	SUBTOTAL	$128,180	-	-	-	-	-	(128,180)	(100.00)
21									
22	DRILLING / WORKOVER OPERATIONS								
23	CONTRACT RIG	4,918,325						(4,918,325)	(100.00)
24	DRILLING RIG CREW / CONTRACT RIG CREW	0						0	
25	MUD, CHEMICAL & ENGINEERING SERVICES	650,185						(650,185)	(100.00)
26	WATER	7,000						(7,000)	(100.00)
27	BITS, REAMERS AND CORE HEADS	147,000						(147,000)	(100.00)
28	EQUIPMENT RENTALS	506,595						(506,595)	(100.00)
29	DIRECTIONAL DRILLING AND SURVEYS	1,924,882						(1,924,882)	(100.00)
30	DIVING SERVICES	0						0	
31	CASING INSTALLATION	428,086						(428,086)	(100.00)
32	CEMENT, CEMENTING AND PUMP FEES	1,507,900						(1,507,900)	(100.00)
33	INSPECTIONS	27,000						(27,000)	(100.00)
34									
35	SUBTOTAL	$10,116,972	-	-	-	-	-	(10,116,972)	(100.00)
36									
37	FORMATION EVALUATION								
38	CORING	269,950						(269,950)	(100.00)
39	MUD LOGGING SERVICES	282,874						(282,874)	(100.00)
40	DRILLSTEM TESTS	0						0	
41	OPEN HOLE ELECTRICAL LOGGING SERVICES	1,764,180						(1,764,180)	(100.00)
42									
43	SUBTOTAL	$2,317,004	-	-	-	-	-	(2,317,004)	(100.00)
44									
45	COMPLETION								
46	CASING, LINER AND TUBING INSTALLATION	0						0	
47	CEMENT, CEMENTING AND PUMP FEES	0						0	
48	CASED HOLE ELECTRICAL LOGGING SERVICES	145,280						(145,280)	(100.00)
49	PERFORATING AND WIRELINE SERVICES	52,500						(52,500)	(100.00)
50	STIMULATION TREATMENT	0						0	
51	PRODUCTION TESTS	0						0	
52									
53	SUBTOTAL	$197,780	-	-	-	-	-	(197,780)	(100.00)
54									
55	GENERAL								
56	SUPERVISION	197,549						(197,549)	(100.00)
57	INSURANCE	3,000						(3,000)	(100.00)
58	PERMITS AND FEES	30,000						(30,000)	(100.00)
59	MARINE RENTAL AND CHARTERS	0						0	
60	HELICOPTERS AND AVIATION CHARGES	0						0	
61	LAND TRANSPORTATION	30,000						(30,000)	(100.00)
62	OTHER TRANSPORTATION	25,085						(25,085)	(100.00)
63	FUEL AND LUBRICANTS	1,339,187						(1,339,187)	(100.00)
64	CAMP FACILITIES	51,331						(51,331)	(100.00)
65	ALLOCATED OVERHEADS - FIELD OFFICE	7,000						(7,000)	(100.00)
66	ALLOCATED OVERHEADS - JAKARTA OFFICE	45,000						(45,000)	(100.00)
67	ALLOCATED OVERHEADS - OVERSEAS	0						0	
68	TECHNICAL SERVICES FROM ABROAD	0						0	
69									
70	SUBTOTAL	$1,728,151	-	-	-	-	-	(1,728,151)	(100.00)
71									
72	TOTAL INTANGIBLE COSTS	$14,488,088	-	-	-	-	-	(14,488,088)	(100.00)
73									
74	T O T A L C O S T S	$16,557,383	-	-	-	-	-	(16,557,383)	(100.00)
75									
76	TIME PHASED EXPENDITURES								
77	THIS YEAR 2019					-	-	0	
78	FUTURE YEARS 2020	$16,557,383							
79	TOTAL	$16,557,383							

OPERATOR

APPROVED BY :

POSITION :

DATE :

SKK MIGAS

APPROVED BY :

POSITION :

DATE :

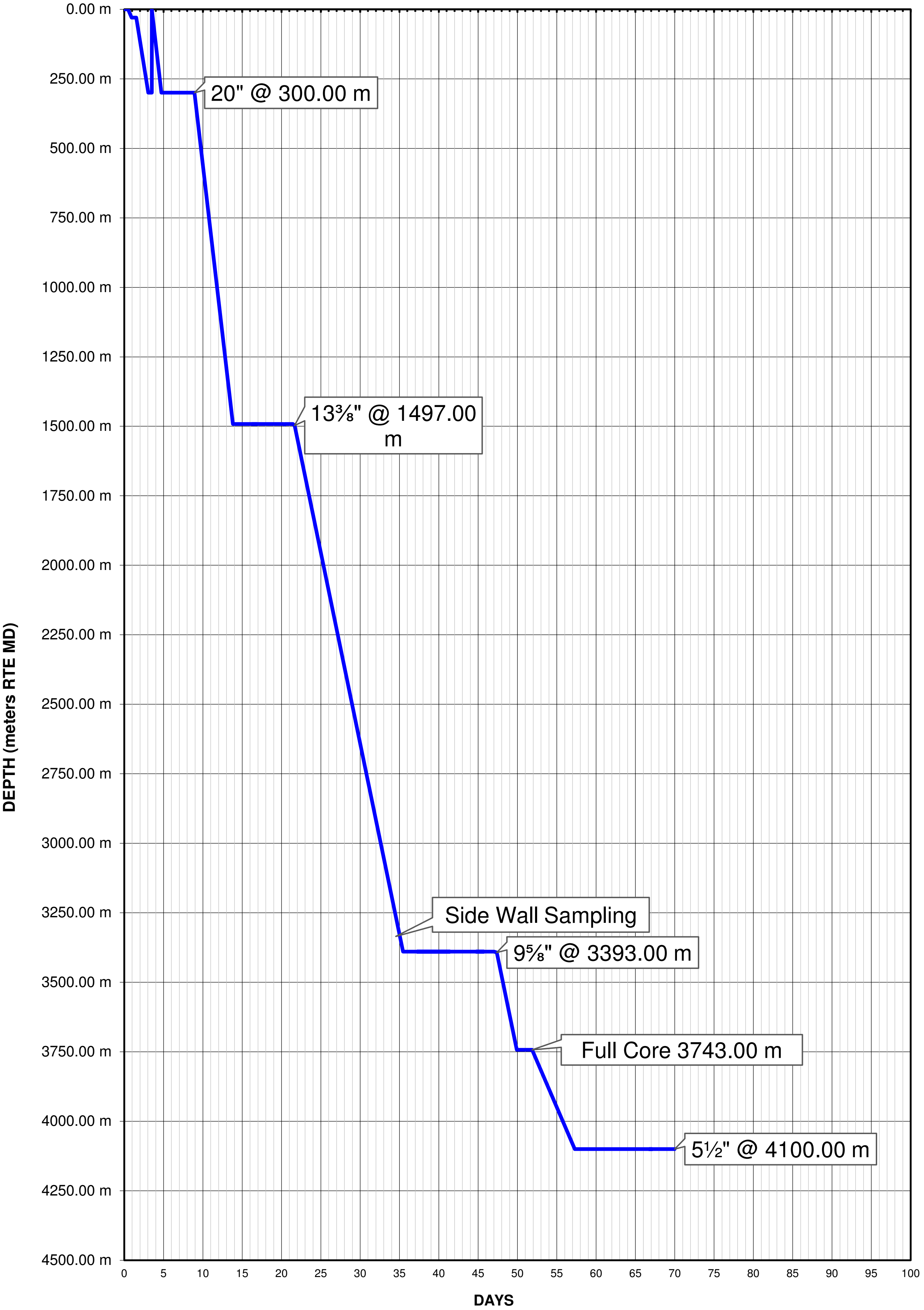
REMARKS

CCS PILOT WELL DRILLING, EVALUATION & COMPLETION BUDGETARY AFE (meters)

Revision Print Date: 27-Aug-19

SKK MIGAS

GUNDIH CCS - 1: PILOT CO_2 INJECTION WELL
TIME VERSUS MEASURED DEPTH PLOT



SKK MIGAS

PRODUCTION SHARING CONTRACT

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER MATERIAL LIST

OPERATOR	:	**Pertamina EP**	PROJECT TYPE	:	**CCS Pilot Injection Well**	AFE No. :	**TBA**
CONTRACT AREA	:	**Gundhi Field**	WELL TYPE	:	**Onshore CCS Pilot Injection Well**		
CONTRACT AREA	:	**Pertamina Asset IV**	FIELD STRUCTURE	:	**Gundih Field/Kedung Tuban**	DATE :	**27-Aug-19**
			WELL NAME	:	**CCS - 1**		

Line №	DESCRIPTION		BUDGET			ACTUAL							ACTUAL OVER/UNDER		SURPLUS MATERIAL	
						ISSUED FROM STOCK			NEW PURCHASES							
		UNIT OF ISSUE	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	GRAND TOTAL	QUANTITY	AMOUNT	QUANTITY	DISPOSITION
		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	TANGIBLES															
	CASING															
	Size Grade Connection															
1	30 inchCasing	feet	90	$372.00	$33,480											
2	30 inch Drive Sub	each	1	$16,900.00	$16,900											
3	Drive Shoe Joint	each	1	$15,700.00	$15,700											
4	20 inch Cas 133 ppf, K-55 BTC	feet	1,082	$113.00	$122,311											
5	20 inch Float Shoe BTC	each	1	$11,300.00	$11,300											
6	Float Shoe Stinger BTC	each	1	$2,600.00	$2,600											
7	13⅜ inch Ca 68 ppf, K-55 BTC	feet	4,993	$82.00	$409,418											
8	9⅝ inch line 53.5 ppf, N-80 LTC	feet	6,629	$56.00	$371,230											
	with 500 ft overlap into 13 ⅜ inch casing															
9	5½ inch 20 ppf, P110 LTC	feet	10,335	$32.00	$330,720											
	long string to surface															
	CASING COST				**$1,313,659**											
	VALUE ADDED TAX (VAT)		0%		$0											
	TOTAL FOR CASING				**$1,313,659**											

Operator

Approved By: ____________ Position: ____________ Date: August 27, 2019

Approved By: ____________ Position: ____________ Date: ____________

SKK MIGAS

Approved By: ____________ Position ____________ Date: ____________

SKK MIGAS

PRODUCTION SHARING CONTRACT

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER MATERIAL LIST

BUDGET SCHEDULE No. 20

OPERATOR	:	**Pertamina EP**	PROJECT TYPE	:	**CCS Pilot Injection Well**
CONTRACT AREA	:	**Gundhi Field**	WELL TYPE	:	**Onshore CCS Pilot Injection Well**
CONTRACT AREA	:	**Pertamina Asset IV**	FIELD STRUCTURE	:	**Gundih Field/Kedung Tuban**
			WELL NAME	:	**CCS - 1**

AFE No. : **TBA**

DATE : **27-Aug-19**

Line №	DESCRIPTION		BUDGET			ACTUAL							ACTUAL OVER/UNDER		SURPLUS MATERIAL	
						ISSUED FROM STOCK			NEW PURCHASES							
		UNIT OF ISSUE	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	GRAND TOTAL	QUANTITY	AMOUNT	QUANTITY	DISPOSITION
		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2	**CASING ACCESSORIES**															
1	20 inch Stab-In Float Shoe	each	1	3744	$3,744											
2	20 inch Drill Pipe Centralizers	each	8	329	$2,632											
3	13⅜ inch float shoe	each	1	1,291	$1,291											
4	13⅜ inch float collar	set	1	2,582	$2,582											
5	13⅜ inch top & bottom plugs	set	1	1,911	$1,911											
6	13⅜ inch centralizers & stop collars	each	20	359	$7,180											
	11-3/4 inch float shoe	each		2,800	$0											
	11-3/4 inch floar collar & accessories	set		3,250	$0											
	11-3/4 inch centralizers	each		138	$0											
7	9⅝ inch float shoe	each	1	2,300	$2,300											
8	9⅝ inch float collar	set	1	3,750	$3,750											
9	9⅝ inch positive stand-off centralizers	each	40	228	$9,120											
10	5½ inch float shoe	each	1	2,000	$2,000											
11	5½ inch float collar	each	1	2,500	$2,500											
12	5½ inch multi-tage cement collar	each	1	15,000	$15,000											
13	5½ inch cement plugs	each	1	1,000	$1,000											
14	5½ inch positive stand-off centralizers	each	20	178	$3,560											
	CASING ACCESSORIES COST				**$58,570**											
	VALUE ADDED TAX (VAT)		0%		$0											
	TOTAL FOR CASING ACCESSORIES				**$58,570**											

Operator

SKK MIGAS

Approved By: ____________ Position: ____________ Date: **27-Aug-19**

Approved By: ____________ Position ____________ Date: ____________

Approved By: ____________ Position: ____________ Date: ____________

SKK MIGAS
PRODUCTION SHARING CONTRACT
AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER MATERIAL LIST

BUDGET SCHEDULE №. 20

OPERATOR : Pertamina EP
CONTRACT AREA : Gundhi Field
CONTRACT AREA : Pertamina Asset IV

PROJECT TYPE : CCS Pilot Injection Well
WELL TYPE : Onshore CCS Pilot Injection Well
FIELD STRUCTURE : Gundih Field/Kedung Tuban
WELL NAME : CCS - 1

AFE № : TBA
DATE : 27-Aug-19

Line №	DESCRIPTION		BUDGET			ACTUAL							ACTUAL OVER/UNDER		SURPLUS MATERIAL	
						ISSUED FROM STOCK			NEW PURCHASES							
		UNIT OF ISSUE	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	GRAND TOTAL	QUANTITY	AMOUNT	QUANTITY	DISPOSITION
		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
3	**TUBING**															
1	2⅞ inch 8.6 ppf N-80, NUE	ft	13,451	$10.71	$144,104											
	TOTAL TUBING				**$144,104**											

Operator

Approved By: ____ Position: ____ Date: 27-Aug-19

Approved By: ____ Position: ____ Date: ____

SKK MIGAS

Approved By: ____ Position ____ Date: ____

SKK MIGAS

PRODUCTION SHARING CONTRACT

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER MATERIAL LIST

OPERATOR : **Pertamina EP**
CONTRACT AREA : **Gundhi Field**
CONTRACT AREA : **Pertamina Asset IV**

PROJECT TYPE : **CCS Pilot Injection Well**
WELL TYPE : **Onshore CCS Pilot Injection Well**
FIELD STRUCTURE : **Gundih Field/Kedung Tuban**
WELL NAME : **CCS - 1**

AFE No. : **TBA**
DATE : **27-Aug-19**

Line №	DESCRIPTION		BUDGET			ACTUAL							ACTUAL OVER/UNDER		SURPLUS MATERIAL	
						ISSUED FROM STOCK			NEW PURCHASES							
		UNIT OF ISSUE	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	GRAND TOTAL	QUANTITY	AMOUNT	QUANTITY	DISPOSITION
		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
4	**WELL EQUIPMENT SURFACE**															
1	Wellhead Casing Head Assembly	set	1	35,732	$35,732											
2	Unihead Assembly specified for CO_2 injection & monitoring	set	1	77,860	$77,860											
2	Xmas Tree specified for CO_2 injection & monitoring	set	1	199,956	$199,956											
	TOTAL WELL EQUIPMENT SURFACE				**$313,548**											

Operator

Approved By: ____________ Position: ____________ Date: August 27, 2019

Approved By: ____________ Position: ____________ Date ____________

SKK MIGAS

Approved By: ____________ Position ____________ Date: ____________

SKK MIGAS

PRODUCTION SHARING CONTRACT

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER MATERIAL LIST

BUDGET SCHEDULE№. 20

OPERATOR	: **Pertamina EP**	PROJECT TYPE	: **CCS Pilot Injection Well**	AFE№. :	**TBA**
CONTRACT AREA	: **Gundhi Field**	WELL TYPE	: **Onshore CCS Pilot Injection Well**		
CONTRACT AREA No.	: **Pertamina Asset IV**	FIELD STRUCTURE	: **Gundih Field/Kedung Tuban**	DATE :	**27-Aug-19**
		WELL NAME	: **CCS - 1**		

Line №	DESCRIPTION		BUDGET			ACTUAL							ACTUAL OVER/UNDER		SURPLUS MATERIAL	
						ISSUED FROM STOCK			NEW PURCHASES							
		UNIT OF ISSUE	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	GRAND TOTAL	QUANTITY	AMOUNT	QUANTITY	DISPOSITION
		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
5	**WELL EQUIPMENT SUB-SURFACE**															
1	Liner Hanger															
	9⅝ x 13⅜ inch Liner hanger, liner top packer & accessories	set	1	$161,415.00	$161,415											
2	Subsurface Safety Valve															
	SCSSSV - CO_2 Injection Specification	each	1	$50,000.00	$50,000											
	Control Line ¼ inch SS 316	foot	500													
3	Packer															
	5½ inch Non-feed through CO_2 Resistant, Re-settable 300 °F	each	1	$28,000.00	$28,000											
4	CO_2 Monitoring Equipment															
	Downhole Pressure/Temperature Monitoring Gauges	set														
	DAS Cable	foot														
	Single Conductor Encapsulated DTS 200 °C	foot														
	Cross-coupling Cable Protectors	each														
5	2⅞ inch Completion Equipment															
	Shear Out Ball Seat Sub w/wireline re-entry guide	each														
	Seating Nipplea (No-Go Profile)	each														
	Sliding Sleeve	each														
	Gauge Carrier	each														
	TOTAL WELL EQUIPMENT - SUBSURFACE				**$239,415**											

Operator

Approved By: ______________ Position: ______________ Date: **27-Aug-19**

Approved By: ______________ Position: ______________ Date ______________

SKK MIGAS

Approved By: ______________ Position ______________ Date: ______________

SKK MIGAS

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER

SCHEDULE №. 19

OPERATOR : Pertamina EP
CONTRACT AREA : Gundhi Field
CONTRACT AREA № : Pertamina Asset IV

PROJECT TYPE : CCS Pilot Injection Well
WELL NAME : CCS - 1
WELL TYPE : Onshore CCS Pilot Injection Well
PLATFORM/TRIPOD : Onshore Drilling Unit
FIELD/STRUCTURE : Gundih Field/Kedung Tuban
BASIN : Java Basin

AFE № : TBA
DATE : 27-Aug-2019

IN US DOLLARS

LOCATION : KTB-B V | SURFACE LAT : 7°12'18.28"S | LONGITUDE : 111°29'34.27"E | UBSURFACE LAT : TBA | LONGITUDE : TBA
WATER DEPTH : N/A | ELEVATION : TBA | CONTRACTOR : TBA | RIG NAME : TBA | RIG TYPE : Land Rig

		PROGRAM		ACTUAL	
SPUD DATE : TBA	RIG DAYS :	15.00	days		days
COMPLETION DATE : TBA	TOTAL DEPTH (m.) :		meters		meters
PLACED IN SERVICE : TBA	WELL COST PER METER :		US$/m		US$/m
DRILLING DAYS : TBA	WELL COST PER DAY :	$65,994.18	US$/Day		US$/Day

CLOSE OUT DATE :
COMPLETION TYPE : CO_2 Injection Well Abandonment
WELL STATUS : Abandoned

LINE №	DESCRIPTION	WORK PROGRAM AND BUDGET	REVISED BUDGET	FINAL BUDGET	ACTUAL EXPENDITURES: PRIOR YEARS	ACTUAL EXPENDITURES: COMMITTED	ACTUAL EXPENDITURES: EXPENDITURE TO DATE	ACTUAL OVER /(UNDER) BUDGET	PERCENTAGE OVER /(UNDER) BUDGET
		1	2	3	4	5	6	7	8
1	TANGIBLE COSTS								
2	CASING							0	
3	CASING ACCESSORIES							0	
4	TUBING							0	
5	WELL EQUIPMENT - SURFACE							0	
6	WELL EQUIPMENT - SUBSURFACE	50,000						(50,000)	(100.00)
7	OTHER TANGIBLE COSTS							0	
8								0	
9	TOTAL TANGIBLE COSTS	$50,000	-	-	-	-	-	(50,000)	(100.00)
10									
11	INTANGIBLE COSTS								
12	PREPARATION AND TERMINATION								
13	SURVEYS							0	
14	LOCATION STAKING AND POSITIONING							0	
15	WELLSITE AND ACCESS ROAD PREPARATION	29,250						(29,250)	(100.00)
16	SERVICE LINES& COMMUNICATIONS							0	
17	WATER SYSTEMS							0	
18	RIGGING UP / RIGGING DOWN							0	
19								0	
20	SUBTOTAL	$29,250	-	-	-	-	-	(29,250)	(100.00)
21									
22	DRILLING / WORKOVER OPERATIONS								
23	CONTRACT RIG	491,832						(491,832)	(100.00)
24	DRILLING RIG CREW / CONTRACT RIG CREW							0	
25	MUD, CHEMICAL & ENGINEERING SERVICES	97,528						(97,528)	(100.00)
26	WATER							0	
27	BITS, REAMERS AND CORE HEADS							0	
28	EQUIPMENT RENTALS	50,659						(50,659)	(100.00)
29	DIRECTIONAL DRILLING AND SURVEYS							0	
30	DIVING SERVICES							0	
31	CASING INSTALLATION							0	
32	CEMENT, CEMENTING AND PUMP FEES							0	
33	INSPECTIONS							0	
34									
35	SUBTOTAL	$640,020	-	-	-	-	-	(640,020)	(100.00)
36									
37	FORMATION EVALUATION								
38	CORING							0	
39	MUD LOGGING SERVICES							0	
40	DRILLSTEM TESTS							0	
41	OPEN HOLE ELECTRICAL LOGGING SERVICES							0	
42									
43	SUBTOTAL	$0	-	-	-	-	-	0	
44									
45	COMPLETION								
46	CASING, LINER AND TUBING INSTALLATION							0	
47	CEMENT, CEMENTING AND PUMP FEES	128,172						(128,172)	(100.00)
48	CASED HOLE ELECTRICAL LOGGING SERVICES							0	
49	PERFORATING AND WIRELINE SERVICES	42,300						(42,300)	(100.00)
50	STIMULATION TREATMENT							0	
51	PRODUCTION TESTS							0	
52									
53	SUBTOTAL	$170,472	-	-	-	-	-	(170,472)	(100.00)
54									
55	GENERAL								
56	SUPERVISION	9,877						(9,877)	(100.00)
57	INSURANCE							0	
58	PERMITS AND FEES							0	
59	MARINE RENTAL AND CHARTERS							0	
60	HELICOPTERS AND AVIATION CHARGES							0	
61	LAND TRANSPORTATION	5,100						(5,100)	(100.00)
62	OTHER TRANSPORTATION	2,508						(2,508)	(100.00)
63	FUEL AND LUBRICANTS	66,959						(66,959)	(100.00)
64	CAMP FACILITIES	8,726						(8,726)	(100.00)
65	ALLOCATED OVERHEADS - FIELD OFFICE	7,000						(7,000)	(100.00)
66	ALLOCATED OVERHEADS - JAKARTA OFFICE							0	
67	ALLOCATED OVERHEADS - OVERSEAS							0	
68	TECHNICAL SERVICES FROM ABROAD							0	
69									
70	SUBTOTAL	$100,172	-	-	-	-	-	(100,172)	(100.00)
71									
72	TOTAL INTANGIBLE COSTS	$939,913	-	-	-	-	-	(939,913)	(100.00)
73									
74	T O T A L C O S T S	$989,913	-	-	-	-	-	(989,913)	(100.00)
75									
76	TIME PHASED EXPENDITURES								
77	THIS YEAR 2019					-	-	0	
78	FUTURE YEARS 2020	$989,913							
79	TOTAL	$989,913							

OPERATOR

APPROVED BY :
POSITION :
DATE :

SKK MIGAS

APPROVED BY :
POSITION :
DATE :

REMARKS

CCS PILOT WELL ABANDONMENT BUDGETARY AFE
(meters)

Revision Print Date: 27-Aug-19

SKK MIGAS

Appendix C. Drilling Prognosis Report

GUNDIH CCS PILOT WELL DRILLING PROGNOSIS

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DOCUMENT CONTROL*

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Rev C	28 June 2019	Updated Draft	David Jackman	DJJ
Rev B	2 June 2019	Updated Draft	David Jackman	DJJ
Rev A	27 May 2019	Draft	David Jackman	DJJ
Rev	**Date**	**Amendment/Addition**	**Author**	**Initial**

*Draft documents are designated Rev A, B C, D etc.
Final Document issued is Rev 0
Revisions after Document 0 are designated Rev. 1, 2, 3, 4 etc.

Preamble

The Gundih pilot CCS project is intended to store 20,000 MT up to 100,000 MT of CO_2 over a two year period. Gundih project assets are owned and operated by Pertamina EP Asset IV and the project is funded by a Technical Assistance facility, Pilot Carbon Capture and Storage Activity in the Natural Gas Processing Sector (49204-002) from the Asian Development Bank (ADB) to the Republic of Indonesia for the purpose of evaluation and development of Carbon Capture and Storage (CCS) technologies for mitigation of CO_2 emissions from anthropogenic sources.

This drilling prognosis and conceptual well design is primarily based on KTB – 01, RBT – 03 & KDL - 01 well data and associated reports available and is intended to provide insight into the subsurface drilling challenges that can be expected when drilling a well in the geological structures found in the Gundih Field area.

In support in the selection of a bottom-hole target zone extensive subsurface geological modelling has been conducted by Institut Teknologi Bandung (ITB) in conjunction with Battelle Memorial Institute, in an effort to determine an optimum CO_2 geological storage structure that will provide the capability to monitor CO_2 storage and retention.

Additionally, focus is placed on current casing, drilling and cementing practices and where significant improvements can be made to enhance drilling performance and well integrity.

Objectives

Primary Objective

To drill, core and evaluate the carbon storage potential of the Kujung Formation below the known water contact depth in the Lower Kujung. On successful evaluation the well is to become a pilot carbon dioxide (CO_2) injection well.

This will involve:

(a) Log analysis of any potential CO_2 injection reservoir section(s).
(b) Full core or sidewall sampling of potential CO_2 injection zones and effective sealing cap rock.
(c) Sampling of fluid pressures from potential CO_2 injection, hydrocarbon and water bearing zones.
(d) Comprehensive injectivity testing of any potential CO_2 injection formations should analysis prove encouraging.

Secondary Objective

Upon reaching the 12¼-inch hole section TD at the base of the Tuban Formation and prior to setting the 9⅝-inch casing, evaluate the calciturbidite sequence typically found at the transition between the Tuban and Kujung Formations for potential for CO_2 sequestration.

This will involve:

(e) Log analysis of any potential CO_2 injection reservoir section(s).
(f) Sidewall sampling of potential CO_2 injection zones and effective sealing cap rock.
(g) Sampling of fluid pressures from potential CO_2 injection, hydrocarbon and water bearing zones.
(h) Comprehensive injectivity testing of any potential CO_2 injection formations should analysis prove encouraging.
(i) Comprehensive evaluation of the sealing cap rock in the lower Tuban Formation.

Generalized East Java Basin Stratigraphy

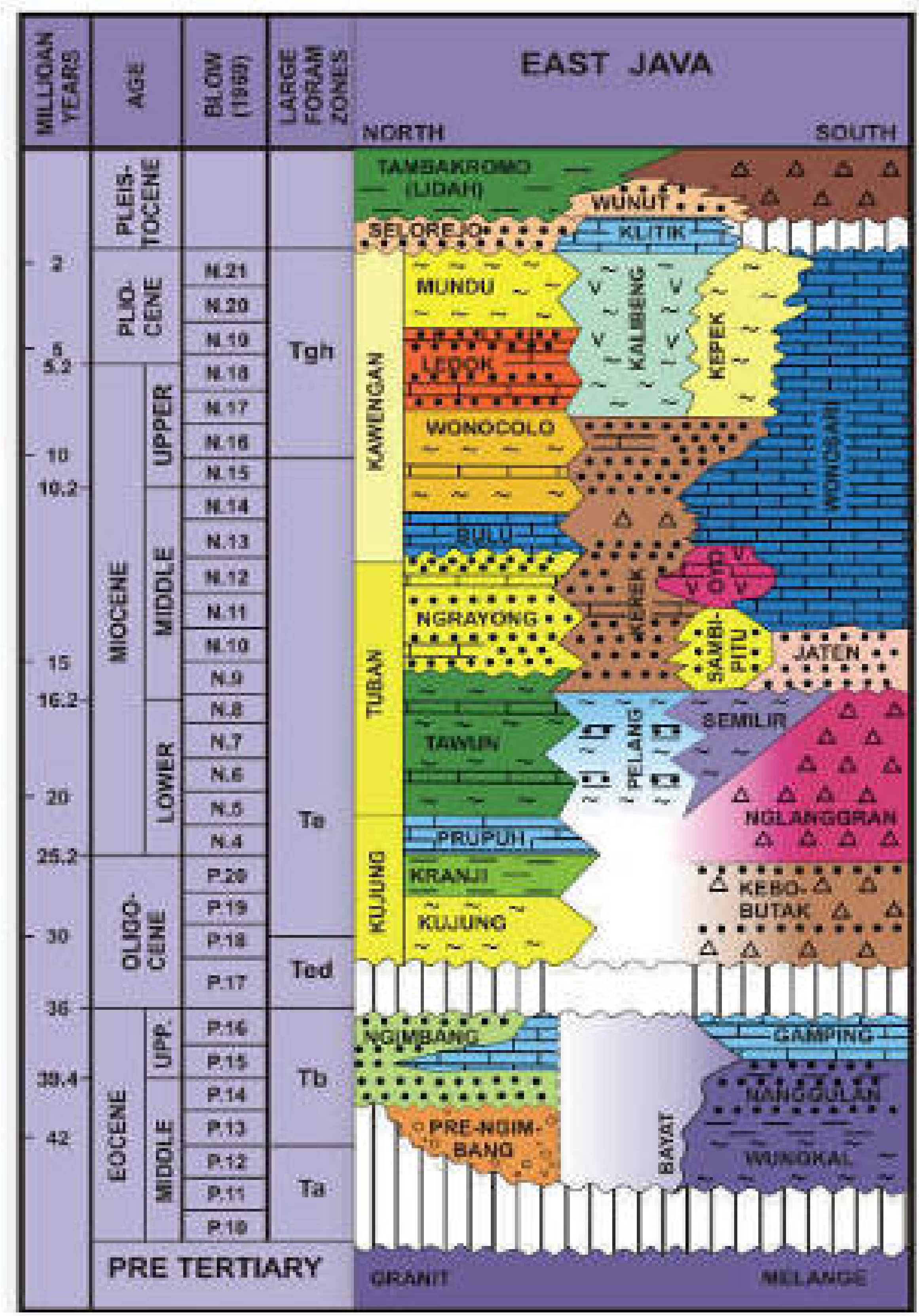


Figure 1 Generalized East Java Basin Stratigraphy

Pore Pressure

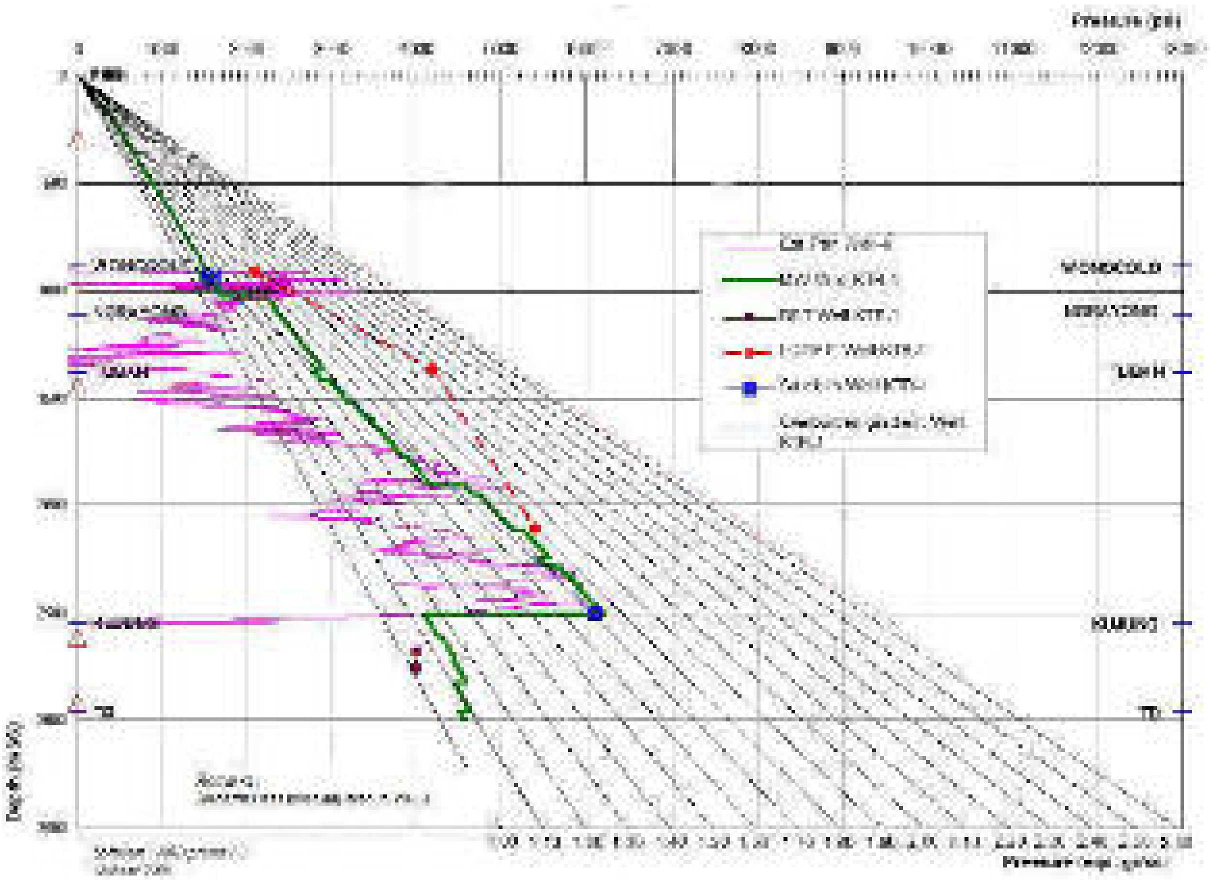


Figure 2 Pore Pressure/Mud Weight based on KTB-01 Well

Based on the KTB-1 Pressure Profile provided above, the overpressure commencing in the Wonocolo and continuing through the Ngrayong and Tuban formations above the Kujung reservoir section, could pose issues, in that event, 9⅝-inch casing would be required to be set early due to over-pressured and potentially unstable hole conditions. Whereby drilling to TD would have to be conducted in 6-inch hole and a 4½-inch liner run in which case any MDT or equivalent hole size logging could not be conducted.

In this transient pressure zone (Wonocol-Nrayong-Tuban) it is felt an 11¾-inch contingency liner may be required for potential setting at the onset of the second pressure increase, as indicated in Fig 2 above. In the KTB-01 well the pressure increase can be considered significant, based on mud weight. Pore pressure then drops back to slightly above normal pressure in the Kujung. The 9⅝-inch casing is required set at the base of the Tuban formation prior to penetrating the Kujung Formation in an effort to avoid significant mud losses. The secondary objective calciturbidite transition sequence, prior to the 8½-inch hole section, is required evaluated and either cored or, if not possible, side-wall core samples obtained.

Overpressure

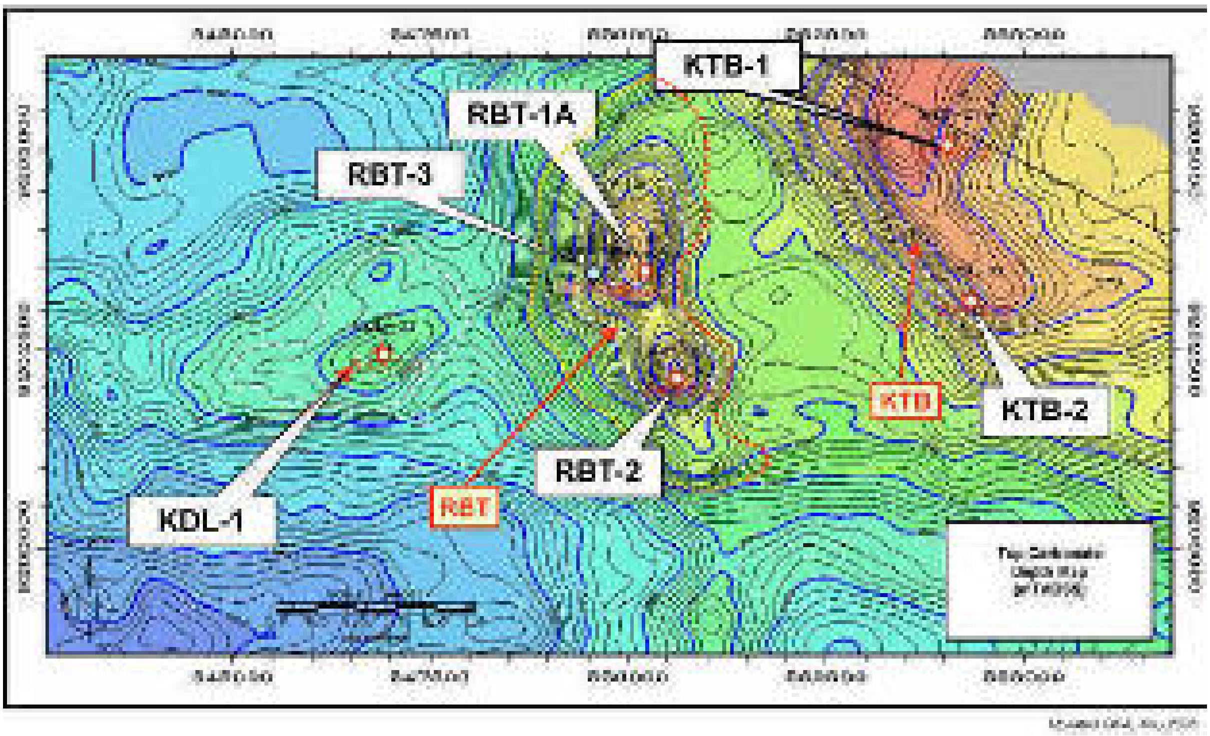


Figure 3 Kujung Formation Tops Map

Overpressure onset depth (TVDSS) varies between the three main Gundih structures:

• Kedung Tuban	KTB – 1 Well	1520 m
• Randu Blatung	RBT – 3 Well	1805 m
• Kedung Lusi	KDL – 1 Well	1350 m

Geothermal Gradient

Based on the highest recorded Bottom Hole Static Temperature (BHST) of 165 °C (330 °F) in the KDL – 01 Well and a surface ambient temperature of 28°C (82°F). The geothermal gradient has been calculated to be;

- 3.836 °C/100 m
- 2.104 °F/100 ft.

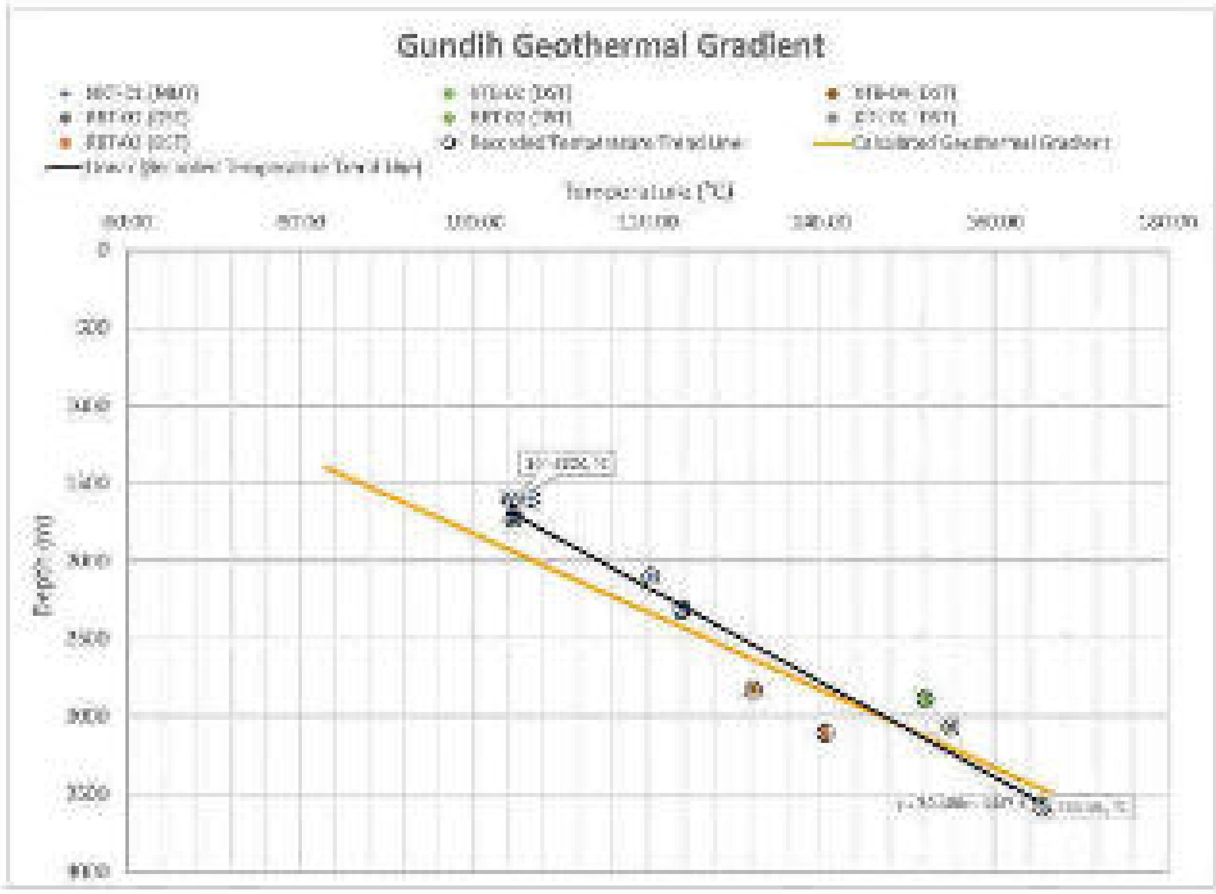


Figure 4 Gundih Geothermal Gradient

Formation Tops

Top of Formation	*Prognosed Depth Pilot CCS Well*	*Offset Well Depth RBT – 01A*
Lidah	Surface	Surface
Mundu		515.87m TVD
Ledok		773.10m TVD
Wonocolo	284 m TVD	1022.60m TVD
Ngrayong	1006 m TVD	1528.90m TVD
Tawun/Tuban	1596 m TVD	2151.0m TVD
Kujung	2964 m TVD	2939.60m TVD
Ngimbang	3490 m TVD	

Well Sections

It is planned that the well be drilled in 4 sections with a driven surface conductor and contingency liner as summarized below:

Hole Size (inches)	*Casing/Liner Size (Inches)*	*Shoe Depth (m TVD/MD)*	*Formation Setting Depth*
Driven/Drilled	30”	30 m	Surface
12¼”/26”	20”	300 m	Wonocolo
17 ½”	13 ⅜”	1596 m /1776 m	Ngrayong
*12¼” x 14¾“****	11 ¾”*	TBA	Tuban
12 ¼”	9 ⅝”	2964 m/3356 m	Tuban
8 ½”	5 ½”	3490 m/3963 m	Kujung

*Contingency Liner

Casing Design

The construction materials selected for the casing and the casing design must be appropriate for the fluids and stresses encountered at the site-specific down-hole environment. Carbon dioxide in combination with water forms carbonic acid, which is corrosive to many materials. Native fluids can also contain corrosive elements such as brines and hydrogen sulfide (H_2S). In CO_2 injection wells, the annular spaces between the long string casing and the intermediate casing, and between the intermediate casing and the surface casing as well as between the casings and the geologic formation are required to be filled with cement, along all casings.

Formation Tops have been based on existing offset wells in the area and will be revised on completion of the static earth and dynamic geological modelling. Casing sizes and setting depths have been selected from:

(a) Actual pore pressures and temperatures based on offset wells

(b) A requirement to have an 8 ½-inch hole to TD (Kujung Formation).

(c) Pressure and stress loading as a result of CO_2 injection.

(d) CO_2 (Carbonic Acid) corrosion resistance.

Casing Connections

Buttress Thread Connections (BTC) are typically used on the casing strings found in the Gundih Field.

Casing connections should satisfy several functional and operational requirements.

Consideration should be given to a metal-to-metal seal casing connection for the long/production casing string due the higher than normal temperature fluctuation that can occur in the Gundih Field

Functional Aspects

- to provide a leak resistance to internal or external fluid pressures
- to have sufficient structural rigidity to transmit externally applied loads

- to have good geometry in order not to increase the outer diameter or reduce the inner diameter of the casing string significantly

Operational Aspects

- easy to make-up in the field
- easy to break-out in the field
- reusable

To fulfil these aspects, the connections are provided, in almost all cases, with connection threads. Connections based on welding or gluing techniques and snap-on connectors are available for casing but will not be utilized, in this case.

For many years the API thread connections, with or without a resilient seal ring, have been the standard in well casing strings. These standardized connections are:

- API round thread connection for casing application;
- API buttress thread connection for casing application;
- API extreme line connection for casing application.

However, during the last decades there has been a shift away from relatively simple and inexpensive shallow wells to complicated completions for deep, often corrosive and high pressure/temperature wells. This trend entailed the need for connections with better seals than the API connections, and led to the development of the so-called Premium connections.

All connections that have one or more special features, such as higher strength, better sealing properties, faster make-up, smaller outer diameter of the coupling, internally streamlined and recess free, etc. as compared with API connections, are collectively called Premium connections.

Threaded casing connections can be divided in two groups, namely the integral connections and the threaded and coupled connections. Each group can further be divided into several types, depending on the sealing mechanism and the existence of a torque shoulder.

Integral and Threaded/Coupled Connections

In recent years there has been a move away from integral type connections, towards the use of threaded and coupled connections. Listed below are the characteristics of the integral connections and those of the threaded and coupled connections:

Integral Connections

- integral connections halve the number of threaded connections, and thus the number of potential leakage paths.

- there is no possibility of receiving a coupling made of a different, and thus wrong, material

- in general, the integral type of connections has higher torque capacity than the threaded and coupled connection. This is because integral connections are generally designed with an external torque shoulder, while for most threaded and coupled connections the torque shoulder is located at the pin nose.

- there is a risk of "ringworm" corrosion. This corrosion can occur at the upset region of joints in the presence of CO_2. During the upsetting process the pipe ends are heated and heavily deformed, which results in a difference in steel microstructure compared to the pipe. It has been found that this microstructure is highly sensitive to CO_2 corrosion so that pits can form quite rapidly. The observed corrosion has a characteristic morphology called ringworm attack. To avoid this problem it is necessary to use tubulars which have been fully heat treated after upsetting.

Threaded and Coupled Connections

- threaded and coupled connections are generally cheaper to produce and the pipe ends can be re-cut should the threads be damaged.
- the manufacturing process of threaded and coupled connections is a lot simpler than that of integral connections as no upsetting or swaging is required.
- with threaded and coupled connections there is less risk of leakage due to geometric errors in the machined connection parts. Generally, the geometric error in machined couplings is smaller than the error in machined pipe ends. Pins and boxes, machined on long tubulars, may show geometry errors in the shape of a clover leaf. This is usually caused by movements of the long unsupported section of the casing joint.
- there has also been a move towards the use of more highly alloyed steel grades which cannot be satisfactorily hot-worked to produce the upset pipe ends necessary for an integral connection.

Thread Forms

The following thread forms are commonly manufactured today:

- API round type thread, a tapered thread with stabbing and loading flanks of 30° and rounded crests and roots.
- API buttress type thread, a tapered thread with stabbing and loading flanks of 10° and 3° respectively, and flat crests and roots, parallel to the thread cone.
- API extremeline thread, a tapered thread with stabbing and loading flanks of 6°, and flat crests and roots parallel to the pipe axis.

Modified buttress threads used for Premium connections. Several thread forms have been developed which are provided with one of the following modifications or combinations thereof: the thread profile has thread crests and roots parallel to the pipe axis rather than being parallel to the thread cone; a clearance at the pin thread crest, in order to ensure a better control of the thread friction during make-up; a change in the angle of the stabbing flank, ranging from +10° to +45° in order to improve the connection stabbing performance; a change in the angle of the loading flank, ranging from +3° to -15° in order to increase the tensile capacity of the connection; a change in the pitch of the threads (single or double pitch change) in order to provide a more uniform stress distribution in the connection threads under tensile or compressive loads.

Two step thread has two sections of different diameter, each provided with free running, non-interfering, threads either straight or tapered. A design with three shoulders which has the advantage of an increased over-torque capacity. In contrast, a non-interfering thread has the risk of inadvertently backing-out of the connection.

Wedge shape thread is based on an interlocking dovetail thread profile. The loading flank is machined with a greater pitch than the stabbing flank to produce a thread that wedges together during make-up, eliminating the need for an additional torque shoulder. The applicable make-up torques of these connections tend to be higher than that of connections with modified buttress thread profiles and a shoulder.

Load Case Scenarios

20 inch, 133 ppf, K-55, BTC – Surface Casing

Load Case	Burst	Collapse	Tension	Compression	Von Mises	Buckling
As Cemented		8.39	37.40	16.61	19.19	No
⅓ replacement to gas(2)	6.30		15.49	68.55	7.06	No
Pressure Test(1)	2.73		9.56		2.97	No
Gas Kick(2)	6.72		13.86	2.06	2.42	No
⅓ replacement to gas circulating(2)	6.30		19.66	2.08	2.39	No
⅓ evacuation(2)		3.09	37.40	10.15	7.02	No
Green Cement Pressure Test	2.65		5.56		2.96	No
Minimum Design Factor	1.100	1.100	1.400	1.250	1.250	
Depth						
(1)983.99 ft.						
(2)3592.52 ft.						

13 ⅜ inch, 68 ppf, K-55, BTC – Intermediate Casing

Load Case	Burst	Collapse	Tension	Compression	Von Mises	Buckling
As Cemented		4.52	14.40	12.13	4.41	No
⅓ replacement to gas(2)	3.02		6.93		2.16	No
⅓ replacement to gas(3)	2.28		5.93		2.54	No
⅓ replacement to gas(4)						
Pressure Test(1)	2.58		6.76		2.60	No
Pressure Test(2)	1.64		6.76		1.75	No
Pressure Test(3)						
Gas Kick(2)	2.54		7.16	9.89	2.21	No
Gas Kick(3)	1.98		6.08	11.06	2.08	No
Gas Kick(4)	2.67		7.40	9.55	2.32	No
⅓ replacement to gas circulating(2)	3.02		9.08	9.91	2.51	No
⅓ replacement to gas circulating(3)	2.28		9.67	13.75	2.08	No
⅓ replacement to gas circulating(4)	2.44		10.52	12.44	2.19	No
⅓ evacuation(2)		3.06	14.40	13.19	4.17	No
⅓ evacuation(3)		2.17	14.40	9.11	4.17	No
⅓ evacuation(4)		2.13	14.40	8.95	4.17	No
Green Cement Pressure Test	3.42		5.56		3.20	No
Minimum Design Factor	1.100	1.100	1.400	1.250	1.250	
Depth						
(1)3592.52 ft.						
(2)7729.66 ft.						
(3)11010.50 ft.						
(4)13451.44 ft.						

11¾ inch, 71 ppf, L-80, BTC – *Contingency Liner*

Load Case	Burst	Collapse	Tension	Compression	Von Mises	Buckling
As Cemented		11.60	16.10	8.73	8.52	No
⅓ replacement to gas(2)	3.62	184.10	5.42	4.35	4.01	No
⅓ replacement to gas(3)	6.05	4.50	5.61	3.58	4.72	No
Pressure Test(1)	1.65		3.94	7.31	1.82	No
Pressure Test(2)	1.75		4.03	6.62	1.93	No
Gas Kick(2)	2.11		5.22		2.34	No
Gas Kick(3)	2.98		5.97	55.48	3.29	No
⅓ replacement to gas circulating(2)	3.63	182.18	7.08	35.82	3.98	No
⅓ replacement to gas circulating(3)	5.97	4.51	7.41	13.09	5.55	No
⅓ evacuation(2)		1.57	22.67	2.70	2.29	No
⅓ evacuation(3)		1.16	23.06	2.42	1.78	No
Green Cement Pressure Test	6.24		7.11	49.21	5.24	No
Minimum Design Factor	1.100	1.100	1.400	1.250	1.250	

Depth

(1)7729.66 ft.
(2)11010.50 ft.
(3)13451.44 ft.

9⅝ inch, 53.5 ppf, P-110, LTC – Intermediate Liner

Load Case	Burst	Collapse	Tension	Compression	Von Mises	Buckling
As Cemented		16.23	193.03	9.16	14.08	No
⅓ replacement to gas(3)	6.23	8.56		4.38	3.97	No
Pressure Test(2)	1.89		34.84	7.57	1.81	No
Gas Kick(3)	3.56		15.40	529.15	3.88	No
⅓ replacement to gas circulating(3)	6.41	8.46	35.20	27.96	7.02	No
⅓ evacuation(3)		1.74		2.68	2.47	No
Green Cement Pressure Test	9.80		14.30	23.39	8.60	No
Minimum Design Factor	1.100	1.100	1.400	1.250	1.250	

Depth

(1)7729.66 ft.
(2)11010.50 ft.
(3)13451.44 ft.

5½ inch – 23 ppf, P-110, MTC – Production Casing

Load Case	Burst	Collapse	Tension	Compression	Von Mises	Buckling
As Cemented		11.28	3.72	9.19	2.95	No
Surface Tubing Leak - Hot(1)	2.54	106.10	5.57	4.20	2.71	No
Surface Tubing Leak – Static(1)	2.62	106.10	1.97	4.20	1.81	No
Full Evacuation(1)		1.92	2.29	2.73	1.98	No
Green Cement Pressure Test	8.99		3.12	19.57	2.78	No
Minimum Design Factor	1.100	1.100	1.400	1.250	1.250	

Depth

(1)13451.44 ft.

Evaluated Load Scenarios

Load Name	Description	Casing String
As Cemented	Casing filled with drilling fluid at the density it was run with; cement outside casing; static temperature profile	All
⅓ replacement to gas	Casing is filled with 0.0 psi/ft. gas to a depth equal to one-third the depth of the next casing point (below this, mud is present with weight used to drill subsequent section) natural pore pressure gradient outside of the casing; static and circulating temperature profiles are both considered.	S, I
Pressure Test	Casing is filled with the mud weight with which the casing was run in and surface and surface pressure applied that produces a pressure at the casing shoe equal to the fracture pressure plus a margin of safety (0.2 ppg); natural pore pressure gradient outside the casing; static temperature profile	S, I, P
Gas Kick (50 bbl)	Simulates gas kick of specified volume; internal pressure profile depends on size of gas bubble and natural pore pressure gradient outside the casing; temperature profile is based on correlation by Kutasov and Taighi (Schlumberger 2006)	S, I
⅓ replacement to gas circulating	Casing is filled with 0.0 psi/ft. gas to a depth equal to one-third the depth of the next casing point while circulating; natural pore pressure gradient outside of the casing; static and circulating temperature profiles are both considered.	S, I, P
⅓ evacuation	Casing is filled with mud with weight it was run in with; cement outside casing; static temperature profile.	
Surface Tubing Leak	Surface Tubing Leak – The internal pressure profile is created by placing the shut-in tubing pressure on top of the packer fluid from the wellhead to the packer. Below the packer, bottom-hole pressure conditions exist. Pore pressure is used for the external pressure and static temperature is used for the temperature profile.	P
Green Cement Pressure Test	Casing filled with drilling fluid at the density it was run with; un-hydrated cement outside casing; static temperature profile	All
Full Evacuation	Tubing is completely evacuated; external pressure is the hydrostatic pressure due to the packer fluid in the annulus surrounding the tubing; static temperature profiles.	P

S = Surface Casing; I = Intermediate Casing; P = Production Casing; T = Tubing

Casing Accessories

Float Equipment

Casing float equipment and cement plugs required are to meet or exceed the casing specification and temperature rating. Cement plugs are to be rated for the expected temperature and casing test pressure of 80% of the maximum rated casing pressure.

Multi-Stage Cementing

In some cases, cementing along the well casing from the injection zone up to the ground surface in a single stage may not be possible. The pressure exerted by the cement column increases as the height of the column increases. In very deep wells the pressure may become so great that the cement pumps can no longer maintain the pressure, or the pressure from the cement column under construction may fracture weaker formations. In some cases, highly fractured formations or formations with large voids may not allow cement to circulate to the surface, as the cement will flow into the fractures and voids in the formation instead of stacking vertically in a column up to the ground surface. If single stage cementing cannot be successfully performed, multi-staged cementing may be used [40 CFR §146.86(b) (4)]. Multi-staged cementing can be two-stage, three-stage, or continuous two-stage cementing.

Two – Stage Cementing

Two-stage cementing is performed similarly to single stage cementing, except that a cement collar with cement ports is installed at an appropriate point in the well. The cement collar allows cement to be injected into the annulus between the casing and formation at some point in the column under construction other than the bottom of the well. Figure 5 shows a schematic of a two-stage cementing process. EPA recommends that an appropriate point for the cement collar may be the halfway point of the well or just above a fractured zone where the cement circulation might be lost.

To successfully accomplish two-stage cementing, the cement is pushed out of the well bore using a fluid. Two plugs, often referred to as bombs because of their shape, are then dropped. The first plug closes the section of the well below the collar and stops cement from flowing into the lower portion of the well. The second plug (or opening bomb) opens the cement ports in the collar allowing cement to flow into the annulus between the casing and formation through the cement collar. Cement is then circulated down the well bore, out the cement ports, into the annulus between the casing and formation, and up to the ground surface. Once cementing is complete, a third plug is dropped to close the cement ports (Lyons and Plisga, 2005). If the time between the first and second stage is long enough for the cement to begin to set, care should be taken that the first stage is stopped significantly below the cement ports.

Continuous Two-Stage and Three-Stage Cementing

In continuous two-stage cementing, there is no break between the injection of cement between the first and second stages. Continuous two-stage cementing requires less time than regular two- stage cementing, but it requires a more precise knowledge of the cement level to avoid plugging the cement ports. Three-stage cementing is very similar to two-stage cementing, except that two cement collars are used instead of one. The method used will largely be determined by the characteristics of the well bore. If there are two weak formations where circulation is lost or the well is very deep, three-stage cementing may be advantageous.

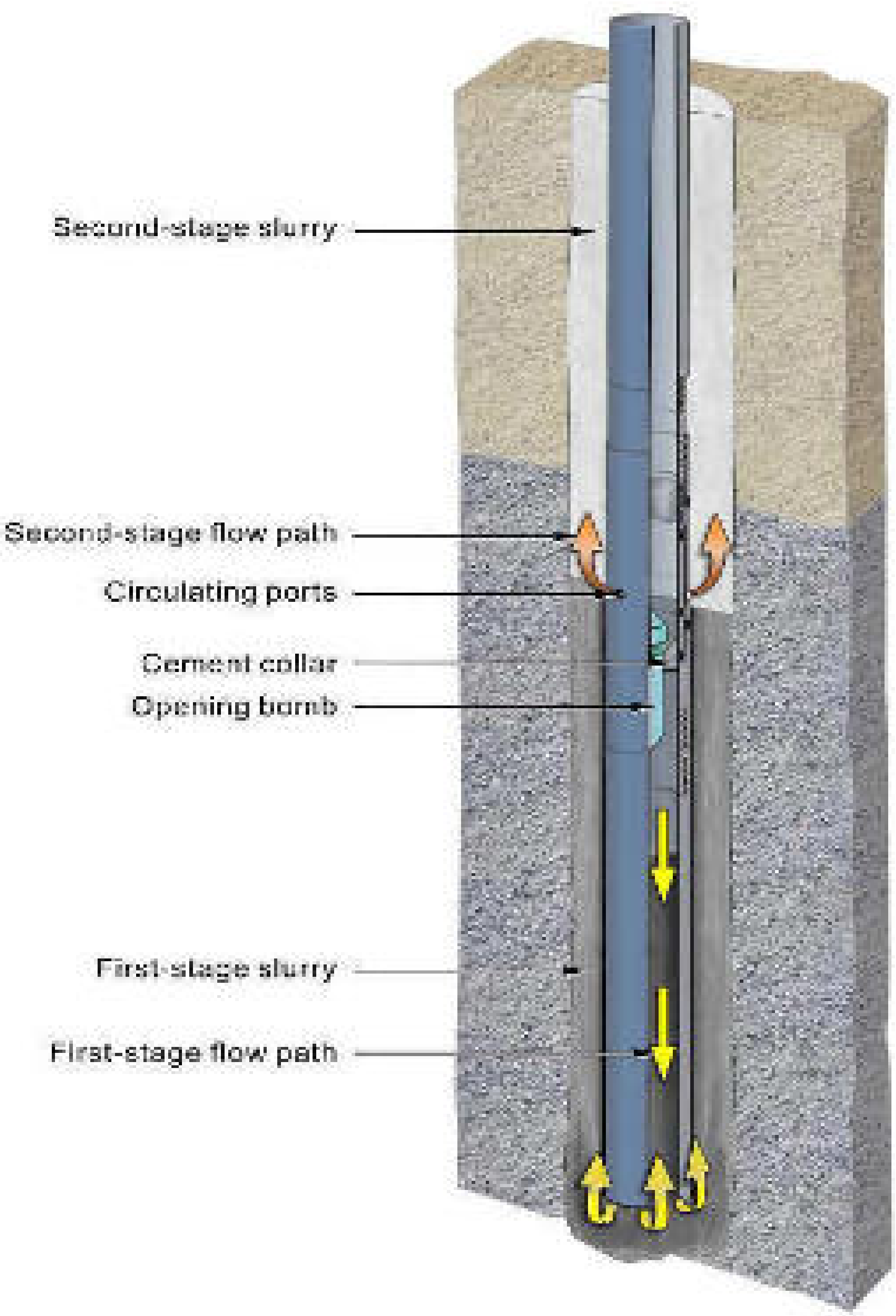


Figure 5Two - Stage Cementing Schematic

Downhole Deployment Valve (DDV) and Rotating Control Device (RCD)

DDV's coupled with an RCD have successfully been employed in the area and provided the safety sought in similar well conditions, however, further planning is required to integrate the technology into this particular well and geological environment.

Liner Hanger

There are no specific regulations for liner hangers in this application, however in this instance, the regulatory requirements that govern the selection of packer materials and technical requirements is applicable.

Tubing

U.S. EPA Class VI regulations require that injection occur through tubing. The tubing must be compatible with the carbon dioxide stream [40 CFR §146.86(c) (1)]. Tubing materials are generally similar to the casing well materials. The tubing should also be designed with the same types of stresses in mind. The tubing must be designed with burst strength to withstand the injection pressure and the collapse strength to withstand the pressure in the annulus between the tubing and the casing [40 CFR §146.86(b) (1)]. Consideration should be given to a metal-to-metal seal tubing connection due the higher than normal temperature fluctuation that can occur in the Gundih Field.

Tubing Specifications & Load Cases

2⅞ inch, 6.4 ppf, L-80, NUE, Seamless, R3 has been selected as the tubing to be utilized for CO_2 injection. Tubing movement modelling has not been included in the casing Load Case Scenarios and is required conducted upon selection of the tubing packer to model the packer loads in various scenarios encountered during CO_2 injection, well shut-in conditions and any potential flow. The injection tubing is subject to contraction and expansion caused by variations in temperatures, and to tension, compression, and hydraulic pulsation effects. Therefore, to comply with 30 TAC §331.62(a)(1)(B)(vii), modelling of adequate safety factors is necessary when designing for tubing and packer installation.

Tubing Packer

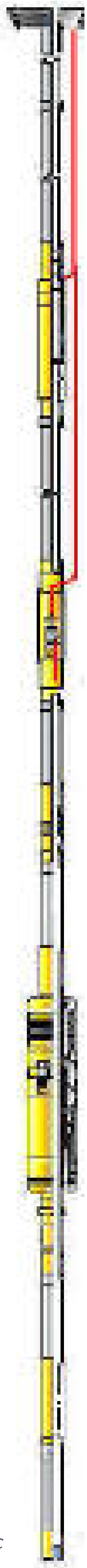
U.S. EPA Class VI regulations also require that injection occur through a packer, set opposite a cemented interval at a depth approved by the UIC Program Director, and compatible with the carbon dioxide stream [40 CFR §146.86(c)(1) and (2)].

Packers are often made from a hardened rubber such as Buna-N or nitrile rubbers and are nickel plated. Proper materials for packers are important as they are likely to come into contact with corrosive fluids such as carbon dioxide or corrosive brines at some point during the project life. The packer must be compatible with any fluids it may come into contact with [40 CFR §146.86(c)(1)]. Placement of the packer can also be an important consideration, influenced by numerous factors. If the packer is placed above the confining layer, it will allow logs to be run next to the casing through the confining layer without having to pull the tubing. Alternatively, placing the packer close to the perforations may allow instruments used for carbon dioxide plume tracking, such as geophones, to be placed closer to the expected plume. Packer placement can also affect how mechanical integrity tests are conducted and may affect the stress placed on well components. Consideration should be given to these factors, in order to select the best location for the packer according to project and site specific circumstances.

Completion Equipment

The well completion equipment, from bottom up, (Fig 6) will comprise:

- Shear Out Ball Seat Sub w/wireline re-entry guide
- Seating Nipple (No-Go Profile)
- Re-settable 2⅞ x 5½ inch packer
- Sliding Sleeve
- Gauge Carrier
- Single Conductor Encapsulated DTS 200 °C Working Temperature
- Surface Controlled Sub-surface Safety Valve (SCSSSV)
- SCSSSV Control Line
- Tubing hanger with Back Pressure Valve (BPV) profile.



Annular Fluid

The annular space above the packer between the 5½-inch long string casing and the 2⅞-inch injection tubing will be filled with fluid to provide structural support for the injection tubing. If required, fluid pressure measure at the surface within the annulus will be maintained so as to exceed the maximum injection pressure within the injection tubing at the elevation of the injection zone. Under this requirement, the maximum annulus surface pressure will not exceed a value that is more than ~200 psi greater than injection pressure at surface. Alternatively, the maximum annulus surface pressure will not exceed a value that would result in a pressure at the top of the packer that is greater than the pressure inside the tubing when the bottom-hole injection pressure is at the maximum allowable pressure.

The annular fluid will be a diluted saline solution such as potassium chloride (KCl), sodium chloride ($NaCl^-$), calcium chloride ($CaCl_2$), or similar solution. The fluid will be mixed onsite using dry salt and clean fresh water. The fluid is also to be filtered to ensure that solids do not settle at the packer or on other components installed in the annulus.

The annular fluid will contain additives and inhibitors including a corrosion inhibitor, biocide/bactericide (to prevent harmful bacteria), and an oxygen scavenger.

Wellhead and Xmas Tree

API SPEC 6A – Specification for Wellhead and Xmas Tree Equipment Twenty-First Edition (2019) is the specification required to be adhered to for the Wellhead and Xmas Tree. Specifications listed below are defined in API Spec 6A:

- Material Class – with specific attention to wetted surfaces subject to CO_2 and H_2S exposure.
    - As defined by NACE MR 0175
- Performance Requirement (PR)
- Pressure Rating
- Product Specification Level (PSL)
- Temperature Classification
- Nonmetallic Requirements

Figure 6: CCS Completion Schematic

The wellhead and Xmas tree will be composed of materials compatible with the injected fluid to minimize corrosion. All components that are in contact with CO_2 injection fluid will be made of a corrosion resistant alloy or a conventional material with a corrosion resistant inlay for flow wetted component surfaces.

Valve actuators are to be installed on those valves designated to be included in an automated system to close the valve when certain criteria are met e.g. injection pressure.

Specific to CO_2 monitoring requirements will be the inclusion of ported adaptor flange sections to the wellhead that will incorporate pressure sealing ports for monitoring instrumentation and control lines. An example is shown in Figure 6 below.

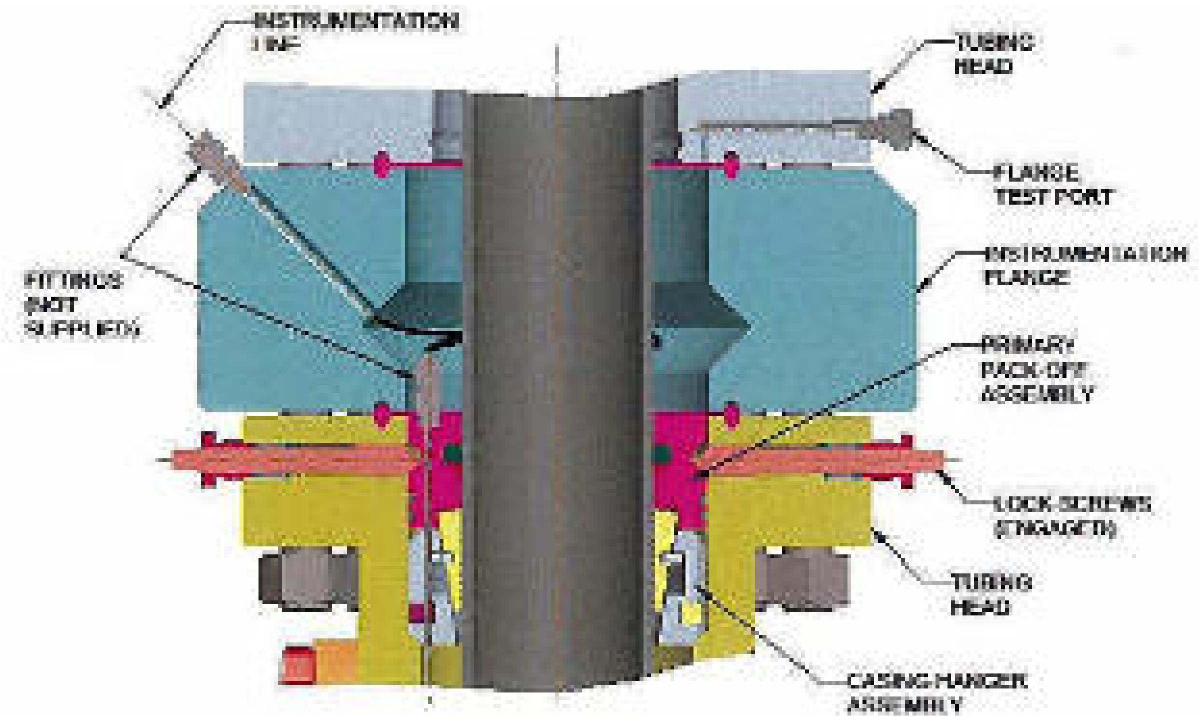


Figure 7 Typical Instrumentation line penetrator wellhead flange

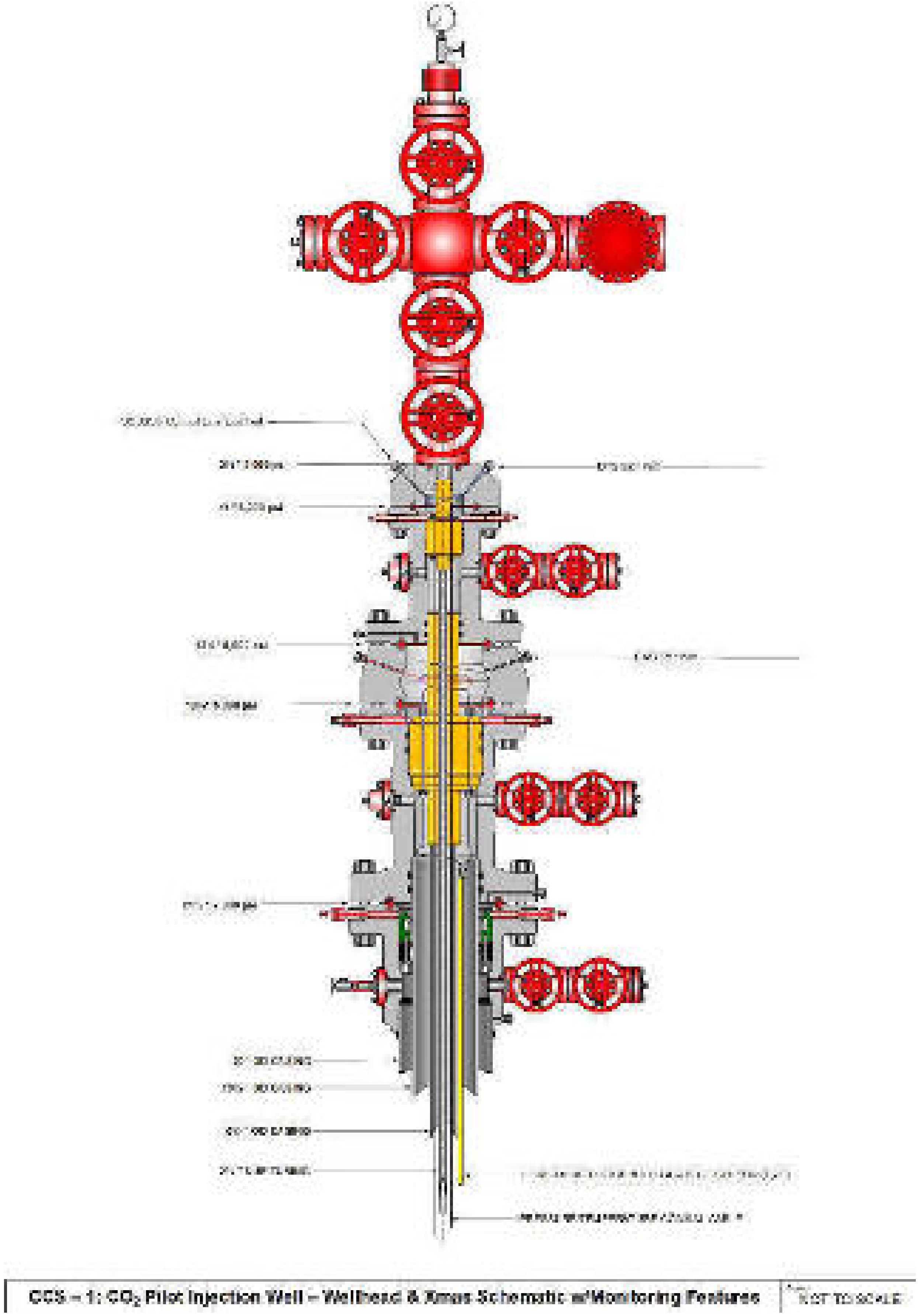


Figure 7 Example of CCS Multiple Monitoring Configured Conceptual Wellhead & Xmas Tree

Proposed Wellhead and Xmas Tree API 6A (Latest Edition) Specifications:

Section	*Bottom Connection*	*Top Connection*	*Pressure Rating*	*Material Classification*	*Temperature Rating*	*PSL*	*PR*
Section A	20”	21 ¼ “	2,000 psi	DD	U	3	2
Section B	21 ¼”	11”	5,000 psi	EE	U	3	2
Section B2[1]	11”	11”	5,000 psi	EE	U	3	2
Section C[2]	11”	11”	5,000 psi	EE	U	3	2
Tubing Hanger Assy.			5,000psi	FF 1.5	X	3	2
THA[3]	11”	3⅛”	5,000 psi	FF	X	3	2
Xmas Tree	3 ⅛”		5,000 psi	FF	X	3	2F

[1]Section B2 Spacer Spool monitoring instrumentation ported access section

[2]Section C Tubing annulus monitoring instrumentation and SCSSSV ported access incorporated into tubing head adapter and ported tubing hanger.

[3]THA Tubing Head Adapter

CO_2 Downhole Well Monitoring Equipment

Distributed Acoustic Sensor (DAS)/Distributed Temperature Sensing (DTS)

At the time of writing this drilling prognosis, research and development of the monitoring plan continued. Conceptually, there will be two (2) main data source locations; the first source will be situated in the annulus of the 5½-inch x 9⅝/13⅜-inch casing strings with the 9⅝-inch casing run as a liner in an effort to save time and reduce the number of wellhead sections. The 5½-inch casing will be cemented as close as practically possible to surface, permanently cementing the externally mounted Distributed Acoustic Sensor (DAS) reservoir monitoring cable in the well. This cable is the sensor and is not typically run with any other equipment other than cross-coupling protectors similar to the one shown in Figure 8 below. It should be noted that the typical temperature rating for fiber optic cable in this application is 150 °C (302 °F). Bottomhole temperature in the Gundih Field can extend above 150 °C (302 °F) as indicated in Geothermal Gradient page 9 of this document.

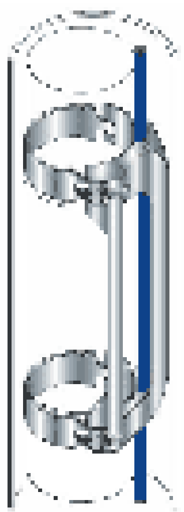


Figure 8: Cross-coupling Cable Protector

Coaxial Pressure & Temperature Monitoring Cable

The second monitoring location will be the annulus of the 2⅞-inch tubing x 5½-inch casing where the Coax Pressure & Temperature monitoring cable will be strapped to the 2⅞-inch tubing and extend, from a ported carrier-assembly installed above the packer depth, to surface, providing access to tubing pressure coupled with access to annulus pressure, along with temperature.

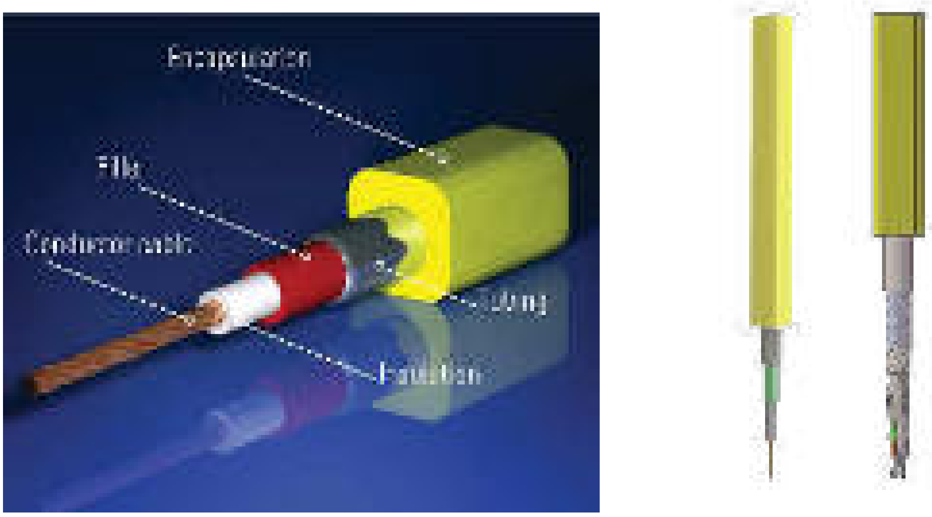


Figure 9: Examples of Single Permanent Downhole Monitoring (DTS) Cable

Multi-Conduit and Monitoring Cable Flat-Pack

In the event geophones are selected as part of the monitoring program and run, a more complex flat-pack monitoring conduit may be utilized that incorporates the features as shown Figure 10 below.

Figure 10 Flat Pack Multi-Core Monitoring Cable

Downhole Monitoring Equipment

Figure 11 Typical Geophone and Flat Pack Installation on CO_2 injection tubing.

Well Integrity

Cement and Its Degradation Due to CO_2 Injection

Portland cement systems are used conventionally for zonal isolation in oil or gas production wells. It is thus crucial to study how such cement behaves at depth in CO_2-rich fluids and understand the chemical interactions between injected CO_2 and existing cements that could potentially lead to leakage. Portland cement is thermodynamically unstable in CO_2-rich environments and can degrade rapidly upon exposure to CO_2 in the presence of water. As CO_2-laden water diffuses into the cement matrix, the dissociated acid (H_2CO_3) reacts with the free calcium hydroxide and the calcium-silicate-hydrate gel. The reaction products are soluble and migrate out of the cement matrix. Eventually, the compressive strength of the set cement decreases and the permeability and porosity increase leading to loss of zonal isolation.

There are mainly three different chemical reactions involved in cement-CO_2 interaction: (1) formation of carbonic acid, (2) carbonation of calcium hydroxide and/or cement hydrates, and (3) dissolution of calcium carbonate ($CaCO_3$)

Cement is important for providing structural support of the casing, preventing contact of the casing with corrosive formation fluids, and preventing vertical movement of carbon dioxide. Some of the most current research indicates that a good cement job is one of the key factors in effective zonal isolation.

The proper placement of the cement is critical, as errors can be difficult to fix later on. Failing to cement the entire length of casing, failure of the cement to bond with the casing or formation, not centralizing the casing during cementing, cracking, and alteration of the cement can all allow migration of fluids along the wellbore. If carbon dioxide escapes the injection zone through the wellbore because of a failed cement job, the injection process must be interrupted to perform costly remedial cementing treatments. In a worst case scenario, failure of the cement sheath can result in the total loss of a well.

During the injection phase, cement will only encounter dry CO_2. However, after the injection phase and all the free CO_2 around the wellbore had been dissolved in the brine, the wellbore will be attacked by carbonic acid (H_2CO_3). The carbonic acid will only attack the reservoir portion of the production (long string) casing, therefore special consideration of CO_2 cement needs only to be considered for the reservoir, the primary seal and a safety zone above the reservoir. Regular cement should be placed over the CO_2-resistant cement. However since two different cement slurries will be used, CO_2-resistant cement that is compatible with regular Portland cement has to be used to prevent flash setting. The cement must be able to maintain a low permeability over lengthy exposure to reservoir conditions in a CO_2 injection and storage scenario. Long-term carbon sequestration conditions include a contact of set cement with supercritical CO_2 (>31 °C at 1059 psi) and brine solutions at increased pressure and temperature and decreased pH.

Underground gas storage operations and CO_2 sequestration in aquifers rely on both proper wellbore construction and sealing function of the cap rock. The potential leakage paths are the migration CO_2 along the wellbore due to poor cementation and flow through the cap rock. The permeability and integrity of the cement will determine how effective it is in preventing leakage. The integrity of the cap rock is assured by an adequate fracture gradient and by sufficient cement around the casing across the cap rock and without a micro-annulus.

Well integrity has been identified as the biggest risk contributing to leakage of CO_2 from underground storage sites. Wellbore represents the most likely route for the leakage of CO_2 from geologic carbon sequestration. Abandoned wells are typically sealed with cement plugs intended to block vertical migration of fluids. In addition, active wells are usually lined with steel casing, with cement filling the outer annulus in order to prevent leakage between the casing and formation rock.

Several potential leakage pathways can occur along active injection well and/or abandoned well. These include leakage: through deterioration (corrosion) of the tubing (1), around packer (2), through deterioration (corrosion) of the casing (3), between the outside of the casing and the cement (4), through deterioration of the cement in the annulus (cement fractures) (5), leakage in the annular region between the cement and the formation (6), through the cement plug (7), and between the cement and the inside of the casing (8) .

The permeability and integrity of the cement in the annulus and in the wellbore will determine how effective the cement is in preventing fluid leakage.

The greatest risk for the escape of CO_2 may come from other wells, typically for oil and gas, which penetrate the storage formation. Such wells need to be properly sealed in order to ensure that they do not provide pathways for the CO_2 to escape into the atmosphere. Planning for geologic storage must take such wells into account. The escaping of CO_2 through water wells is much more unlikely since water wells are usually much shallower than the storage formation.

Casing Pressure Testing

Casing is required to be pressure tested to 80% of the casing pressure rating after the top plug has been bumped and prior to the cement setting. This procedure is in an effort to reduce the potential for a micro-annulus being generated between the cement and casing when test pressure is released after the cement has already hydrated. Casing pressure testing using traditional methods is typically conducted after the cement setting time has been achieved and increases the incidence of micro-annulus formation as the casing contracts, as a result of the internal casing pressure being released.

Formation Integrity Testing (FIT)

A Formation Integrity Test will be conducted when it is decided to test the casing shoe and immediate formation to a specific design pressure. The pressure is typically below the formation fracture pressure and is the preferred method, reducing the potential of damaging the cement bond and formation at the casing shoe thus reducing the potential for uncontrolled sub-surface flow while continuing drilling to the hole section TD.

Leak Off Test (LOT)

In the event it is required to know the formation fracture gradient a Leak Off Test is conducted where the pressure in the well below the previous casing shoe is increased to the fracture point providing actual fracture pressure/gradient data.

Annulus Pressure Test (APT)

Standard Annulus Pressure Test to be conducted during well completion operations and prior to commencing CO_2 injection operations.

Cementing Program

All casing strings, with the exception of liners, will be cemented back to surface in accordance with the requirements EPA UIC Class VI regulations (10 CFR §146.87).

Positive stand-off casing centralizers will be used on casing strings that extend to surface and liners exposed to annuli that extend to surface, in accordance with a centralizer spacing and placement simulation, with the exception of the surface conductor and intermediate casing string. A temperature rated, PDC drillable float/guide shoe will be run on the bottom of the first joint with a temperature and casing test pressure rated double-float collar above the second casing joint to provide sufficient separation between the cement slurry and displacement fluid. The minimum two (2) joint shoe track is intended to ensure a competent and uniform cement slurry surrounds the casing shoe.

All casing strings and liners with a potential for exposure to CO_2, H_2S and associated fluids will be cemented with a CO_2 corrosion resistant cement. In an effort to effectively remove drilling fluid filter cake from both the casing and formation, and reduce the potential for micro-annulus formation, an effective “Mud Removal Spacer Fluid” for both the OBM and Water Based drilling fluids is to be included as part of the cementing program.

After running a casing string that extends to the deeper higher temperature formations of the well a pre-determined casing circulating period is required in an effort to reduce formation temperature in the immediate wellbore at that particular depth. This is in an effort to reduce any downhole temperature anomalies that may be present.

The 5½-inch production casing is currently planned to be cemented back to surface in a multi-stage process. The placement of a multi-stage cementing tool will be defined after further reservoir data acquisition, engineering and analysis.

Note: As shown in the reservoir pressure profiles there is a distinct pressure regression (~1.54 SG – 1.00 SG [~12.86 ppg – 8.34 ppg]) after exiting the Tuban Formation and penetrating the Kujung. In this case a full column of conventional weight cement, to surface, is not considered feasible.

A high temperature (~149 °C [~300 °F]), lite-weight, CO_2 corrosion resistant cement slurry design is required to cement the 5½-inch long string in a single stage cement job that exhibits the necessary properties to conduct the cementation in a single stage whereby, eliminating the requirement for multi-stage cementation of the 5½-inch casing string thus eliminating the potential for failure during the multi-stage process and, a saving in rig time.

Potential Drilling Constraints

Drilling Unit

A well of this nature and depth requires the use of a heavy land drilling unit with a drawworks hook load capacity to handle the casing weights, in dry air and, a minimum of three (3) large capacity mud pumps that are capable of delivering continuously, 1,200 gallons per minute (gpm) at pump pressures up to 3,000 psig. Additionally, a Top Drive System (TDS) is to be made available. The equipment is to be suitably prepared for the formation temperatures expected encountered. It is important that the drilling contractor be experienced in drilling wells of the type described in this prognosis.

Formation Temperature

KDL-01 well, recorded a bottomhole temperature of 165 °C (330 °F). The geothermal gradient for the area has been established at 3.836 °C/100 m (2.104 °F/100 ft.). Recorded RBT – 01A well mud flowline temperature increased from 149 °C (300 °F) to 156 °C (313 °F) through the Kujung interval (2962.0m MD/2939.6m TVD – 3112.0m MD/3090.3m TVD). Use of a drilling fluid capable of withstanding these temperatures is a point for consideration. Additionally, surface handling equipment (e.g. TDS, TDS hose, mud manifold, choke manifold etc.) and surface pumping equipment and BOP elastomers are to be rated for temperatures of this magnitude. Should drilling fluid temperature be deemed excessive consideration is to be given to the installation of a mud cooling unit for the deeper sections of the well. Temperature of this magnitude require that all equipment and materials used on the well be ***"Fit for Purpose"***.

Drilling Fluids Conditioning

Temperature and solids content are two factors with the greatest potential to cause serious drilling fluid and well control issues. A "Mud Cooler" should be considered to provide the reduction in drilling fluid circulating temperature required. The primary concern being the temperature limitations of the BOP elastomers. Additionally, an effective solids control system is also a requirement. In an effort to provide consistent fluid density during drilling operations

Lost Circulation

The risk of a "blowout" increases significantly when severe lost circulation is encountered. The potential for major drilling fluid cost overruns and drilling delays are substantially increased. Alternative methods of combating lost circulation are to be made available at the drilling location. Such systems are to be in place to allow fast replenishment of drilling mud, i.e. bulk barite and bentonite storage, shearing equipment and additional surface drilling fluid storage.

Well Control

The combination of high pressure, high temperature, lost circulation and long hole sections between casing points increases the risk of a well control incident. Procedures are to be developed to handle risk management. In addition the provision of high rate water supply and large reserve drilling mud storage.

Note: RBT – 01A recorded flowline temperature up to 156 °C (313 °F) when nearing TD of the well. Standard BOP elastomers are rated for up to 93 °C (200 °F) with standard spherical (annular) BOP elastomers rated for 77 °C (170 °F). BOP elastomers are to be rated for the temperatures anticipated. High temperature BOP elastomeric components are available for up to 177 °C (350 °F) and spherical (annular) BOP elastomer elements up to 107 °C (225 °F).

Formation Injectivity Testing

U.S. EPA Class VI Rule requires that the injection pressure not exceed 90 percent of the injection zone fracture pressure except during stimulation [40 CFR §146.88(a)].

Maintaining the injection pressure below 90 percent of the injection zone fracture pressure is a conservative requirement that prevents the injection zone from being fractured and diminishes the likelihood of fracturing the confining zone which could result in fluid movement out of the injection zone. In some cases, a well stimulation program may be necessary to achieve the desired injectivity of the Class VI injection well.

Stimulation usually occurs during completion of the well and may also be conducted if injectivity decreases over the course of the injection project.

Some stimulation methods can induce and propagate fractures. If stimulation is to be performed, the proposed stimulation method must demonstrate that it will not fracture the confining zone or otherwise allow injection or formation fluids to endanger USDWs [40 CFR §146.88(a)]. This can be accomplished by modeling pressures and showing that the fracture pressure of the confining zone is never exceeded.

The modeled pressures can be confirmed using technologies such as tilt-meters and micro-seismic monitoring to monitor and refine the model; however, these technologies are still experimental and may not be applicable in all circumstances. If additional chemicals are to be used in stimulation it should be shown that they will not react with the confining layer. Information on calculating the fracture pressure of a formation can be found in the *Draft UIC Program Class VI Well Site Characterization Guidance*. The API Guidance Document RF1 – Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines also contains information on ways to perform stimulation without fracturing the confining layer. Additionally, the *Draft UIC Program Class VI Well Testing and Monitoring Guidance* provides additional information on how to monitor injection pressure.

Injection between the casing and the formation is not allowed [40 CFR §146.88(b)], as it would provide no barrier between the carbon dioxide and the formation. The Class VI Rule requires the space between the casing and the formation to be cemented [40 CFR §146.86(b)(2) and 146.86(b)(3)].

Toxic and Poisonous Gases

Carbon dioxide (CO_2) and hydrogen sulfide (H_2S) are present in the Gundih Field. Equipment is to be made available at the well site for the detection and monitoring of such gases.

Mud scavengers are also to be available as part of the drilling fluids program.

Surface and sub-surface equipment are to be “fit for purpose” in an environment containing CO_2 and H_2S.

Safety equipment including 30 minute air-packs, 15 minute egress packs, breathing air compressors, wind direction indicators and warning signs are to be made available for all personnel on location.

H_2S and toxic gas training of all relevant personnel is to be conducted.

A contingency plan with respect to the local population, surrounding farm and agricultural life is to be developed.

Drilling Parameters and Well Data Monitoring

A mud logging unit and associated service personnel will be made available, on location, while drilling the well. The purpose of which is to identify potential CO_2 injection zones as they are penetrated.

Additional parameters to be monitored include BOP/wellhead and flowline temperatures, annulus pressures and solids control equipment performance.

RBT – 01A recorded flowline temperature up to 156 °C (313 °F) when nearing TD of the well. Standard BOP elastomers are rated for up to 93 °C (200 °F) with spherical (annular) BOP elastomers rated for 77 °C (170 °F). BOP elastomers are to be rated for the temperatures anticipated. High temperature BOP elastomeric components are available for up to 177 °C (350 °F) and spherical (annular) BOP elastomer elements up to 107 °C (225 °F).

Electric Logging

The electric logging program is designed to confirm the identity of potential CO_2 storage zones. Tools and logging cable are to be suitable for high temperatures (>149 °C/300 °F). In addition electric logging services may be required to conduct intermediate VSP's and pressure measurements of candidate zones.

Casing Wear

Procedures are required developed to check; steel recovery in the drilling fluid and tool joint hard banding inspection specification. And, should casing wear be suspected a casing caliper log and additional pressure testing of casing conducted.

Casing and Annulus Pressure Testing

Casing pressure testing is to be conducted when the last plug is bumped after the cement is in place and prior to setting. This is in an effort to reduce the formation of a micro-annulus between the casing and cement. Typically, the pressure test is to a minimum of 80% of casing pressure rating.

Annulus Pressure Testing will be conducted in accordance with §40 CFR §146.8(b)(2)

Hazardous Operations (HAZOP's)

Surface equipment is to be ***fit for purpose*** in an environment where H_2S and CO_2 are present.

Safety equipment including 30 minute air packs, 5 minute egress pack, breathing air compressors, wind direction indicators, warning signs will be made available.

Training of all relevant personnel is to be conducted.

A contingency plan with respect to the local population and surrounding farm life is to be developed.

All drilling personnel both office based and rig based involved in the decision making and/or supervisory capacity are to have attended a recognized well control course. These courses, typically well specific, are designed to provide the participants with a working knowledge of the procedures and techniques required for a CO_2 injection well. Generally, broken into two training sessions, firstly for supervisory personnel and secondly training directed at drilling crews and service company personnel. The second course will be conducted in the field and cover drilling issues and well control procedures to be used plus, practical drills in implementing procedures.

Surface Location

Figure 12: CCS-1: Pilot CO_2 Injection Well Surface Location KTB-B well pad approximately 4.0 km east of Gundih CPP

The Gundih CPP and producing wells are located near the town of Cepu, Central Java. The area is predominantly agricultural with rural villages that rely on ground water for irrigational and domestic use. The proposed surface well location is approximately 4.0 km east of the Gundih CPP at the KTB – B well pad.

Directional Drilling and Deviation

A deviated well (CCS – 1) is planned from the KTB – B well pad location designated with the following surface location and sub-surface target parameters:

UTM Zone 49S Coordinates:	9203232.44 m S	554412.83 m E
Latitude/Longitude	7°12'18.28"S	111°29'34.27"E
Azimuth:	30° E	
Vertical Section (KOP):	300 m TVD	
Build Section:	300 m TVD	500 m TVD
Maximum Deviation:	30°	4.5°/30 m BUR
Tangent Section:	500 m TVD	~3,582.5 m TVD
Measured Depth:	~4,100 m MD	
True Vertical Depth:	~3,582.5 m TVD	
Target Coordinates:	9204836 m S	555338.4 m E
Target Tolerance	200 m.	
Dog Leg Severity (DLS)	1.06°/30 m.	

Directional Drilling Method Selection

Either rotary steerable or downhole motor will be considered for the directional drilling phase.

A Rotary Steerable System (RSS) will drill the well faster with less time wasted on orienting the tool face with aggressive bit usage (issues with a motor when trying to control the tool-face), and maximizing drilling parameters.

Sliding with a mud motor in could pose challenges due to weight stacking. The weight stacking is more profound when Water Base Mud (WBM) is used as the friction factor is higher than the SOBM. A highly experienced Directional Driller (DD) is required if it is selected to drill with a motor.

An RSS will result in a smoother borehole for casing run in both 12¼-inch and 8½-inch hole section as doglegs are even distributed in the borehole. This will also aid in improved borehole conditions for the extensive logging and formation evaluation program. A mud motor creates "micro-doglegs" which increase the tortuosity of the hole section if not managed well. Micro-dogleg depending on the severity will increase the chance of the drilling assembly becoming stuck due to key-seating.

RSS continuous rotation and higher rotating speed will improve hole cleaning of the well. Mud motors, however, have rotary speed limitations due to the deviation. Improved hole cleaning will reduce the risk of stuck pipe and enable faster tripping.

Near bit Resistivity While Drilling will enable the selection of an optimum geological point at the base of the Tuban and casing setting point for the 9⅝-inch casing and is only applicable when coupled with RSS technology. The RSS Near Bit Resistivity is approximately 1.5 m from the bit whereas when using a mud motor, the Resistivity Tool is at least 15.0 m above the bit.

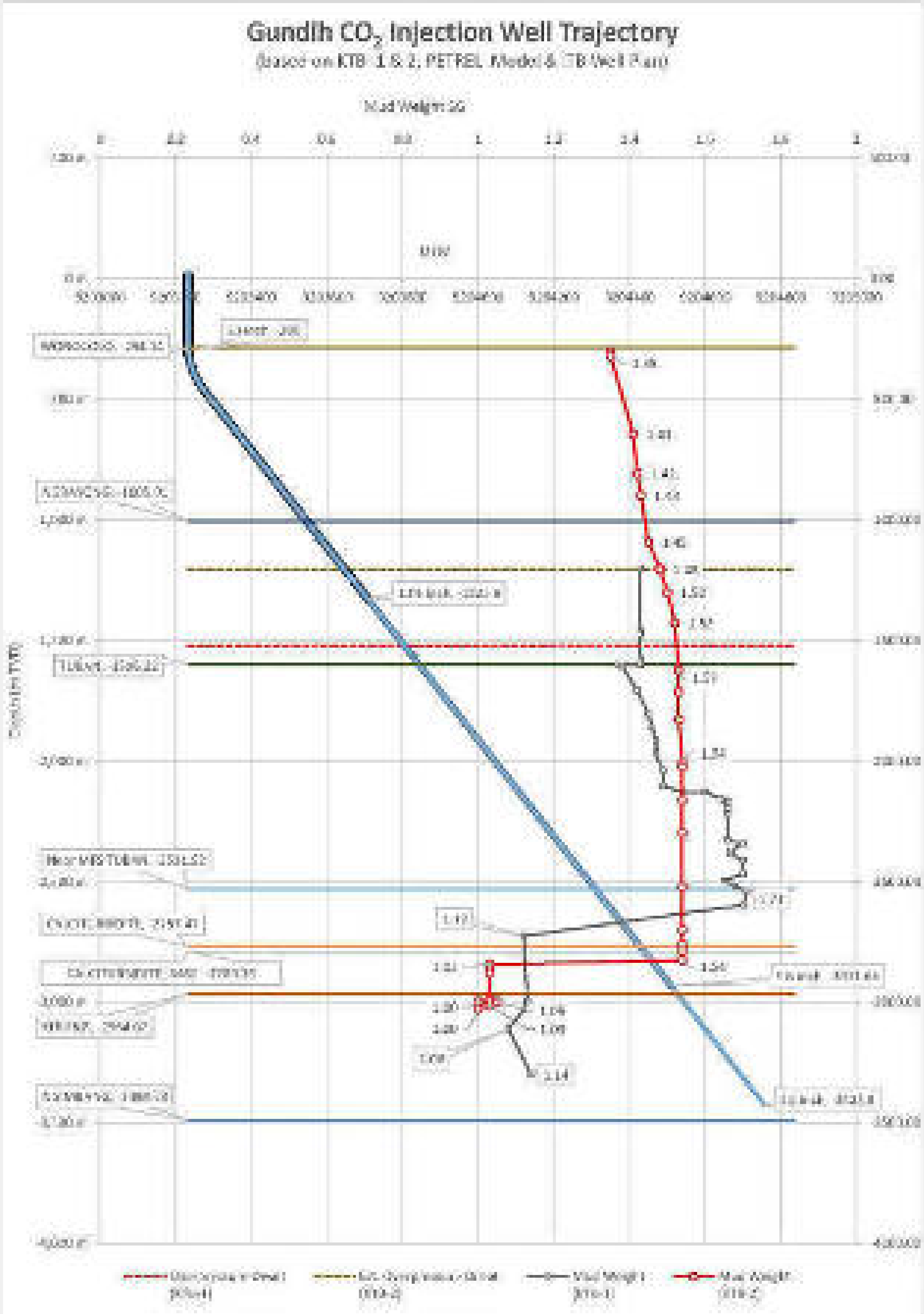


Figure 13 Gundih Pilot CO_2 Injection Well Trajectory, Geological Formations & Estimated Pressure Profiles

Formation Data

Geological Summary – Based on RBT – 1A Offset Well

The location of Randublatung RBT-1A offset well was proposed to be drilled within the Blue Horizon objective of the limestone reservoir layer in the Kujung Formation exhibiting a porosity ranging from 19% - 24%. The reservoir trap is a barrier reef (reefal) shelf edge increasingly controlled by basement faulting since the Eocene period.

Primary Ngimnbang formation hydrocarbon source migration occurred in Miocene – Mid-Miocene where the structural trap of the Kujung Formation was formed. Faulting, in the Middle Miocene penetrated the Kujung Formation. It is expected the shale formation that matures in the Tuban Formation will provide an effective seal.

Offset Well: RBT – 1A

Formation	Drilling
	36" Hole Section: Surface – 30m MD The 36" hole section was initially drilled with a 17½ pilot hole using a water base gel mud then opened up with a 17 ½" bull nose x 26" x 36" hole opening assembly from surface to 30m. At TD the hole was back reamed and a 30 bbl Hi-Vis pill was pumped and displaced with water base gel mud. No gas was recorded due to pump and dump mud returns. 30-inch B, MIJ, 118.6ppf casing was run to 30m and cemented with 76 bbl 1.9 SG slurry
Lidah Formation Surface – 518.0m MD/515.87m TVD Claystone interbedded with sandstone, siltstone and streaks of limestone	26" Hole Section: 30 – 309m MD The 26" hole section was drilled from 30m – 309m with 1.05 – 1.10 SG KCl PHPA Polymer mud. Formation encountered included sandstone interbedded with claystone, limestone and siltstone. Trace gas was recorded from 30m – 240m between 0 – 2 units. Below 240m gas increased from 2 – 8 units with a gas composition comprising mostly methane. No connection gas was recorded in this section. No connection gas was recorded in this section. Maximum trip gas recorded was 63 units after circulating bottoms up prior to pulling out of the hole. 20-inch, K-55, 106.5ppf, BTC casing was run to 308m followed by 7 – 10bbls chemical wash, 50 bbls Mud Push II, lead slurry 268 bbls 1.62 SG, tail slurry 132 bbls, 1.90 SG then displaced with 17 bbls water.

Offset Well: RBT – 1A

Formation	Drilling
Mundu Formation 518.0m MD/515.87m TVD – 787.0m MD/773.1m TVD Sandstone interbedded with layers of siltstone, claystone and marl.	17½"Hole Section: 309 – 1724m MD This section was drilled from 309 – 1724m MD with 1.13 – 1.46 SG SOBM. Mud weight was increased at 354m from 1.13 – 1.25 SG, when background gas increased to 20 – 50 units. At 471m was increased from 1.25 – 1.4 SG as background gas increased and again from 1.4 – 1.46 SG at 585m where background gas stabilized between 60 – 80 units. From 585m MD to hole section TD at 1724m MD background fluctuated between 50 – 120 units. Maximum gas recorded in this section was217 units in a sandstone at 526m MD. Maximum recorded trip gas was 146 units while circulating the hole clean at 1456m MD. Gas in this section consisted mostly of methane with traces of ethane and propane. At hole section TD (1724m MD) the mud weight was increased from 1.46 – 1.49 SG prior to pulling out of the hole (POOH) and gas reduced to 25 units. Mud losses encountered were, 7 bbls of mud were lost pulling out of the hole, 6 bbls at the centrifuge and 7 barrels at the desilter. The 17½"open hole logging suite comprised AITH-MCFL-GR-PEX (Schlumberger). Two gyro run were also made. The hole was then cased and cemented with 13⅜", L-80, 68ppf & 72ppf (connection type not available) with the casing shoe being set at 1722.05m MD/1701.0m TVD.
Ledok Formation 787.0m MD/773.1m TVD – 1043.5m MD/1022.6m TVD. Claystone interbedded with sandstone and siltstone	
Wonocolo Formation 1043.5. MD/1022.6m TVD – 1551.0m MD/1528.9m TVD Predominantly claystone interbedded with siltstone, sandstone and limestone.	
Ngrayong Formation 1551.0m DM/1528.9m TVD – 2174.0m MD/2151.0m TVD Predominantly shale interbedded with sandstone, claystone and siltstone in the upper portion and intercalation with marl and limestone in the middle and lower section.	12¼" Hole Section: 1724 – 2959m MD The 12 ¼" hole section was drilled from 1724 – 2959m MD with Saline Oil Base Mud (SOBM) ranging in mud weight from 1.55 – 1.61 SG. There is no record of the LWD/MWD tools that were used to a depth of 2914m MD where tool failure occurred and drilling continued without LWD/MWD. The tools used and data obtained are not available A VSP was conducted at 2830m. Background gas for the entire section ranged from 50 –

Offset Well: RBT – 1A

Formation	Drilling
Tuban Formation 2174.0m MD/2151.0m TVD 2962.0m MD/2939.6m TVD Shaley claystone and shale interbedded with sandstone and siltstone in upper portion with intercalation shale, siltstone and limestone streaks in the lower part.	150 units with a maximum gas reading of 297 units at 1907m MD and trip gas of 362 units at 2830m MD. At 2959.5m MD. Recovered samples showed approximately 50% limestone and 50% shale. Temperature increased with depth and ranged from 88 °C (191 °F) to 100 °C (212 °F) through the 12¼" hole section The hole was cased with 9⅝", L-80, 53.5 ppf, BTC casing with the shoe set at 2959m MD. The cementing program comprised; 2 bbls water ahead, 50 bbls Mud Push II, 239 bbls 1.68 SG Lead Slurry followed by 100 bbls 1.9 SG Tail slurry
Kujung Formation 2962.0m MD/2939.6m TVD – 3112.0m MD/3090.3m TVD. Predominantly limestone to occasional dolomite.	8⅜" Hole Section: 2960 – 3112m MD The 8⅜" hole section was drilled from 2960 – 3112m MD with 5% KCl Polymer drilling fluid ranging in weight from 1.35 – 1.1 SG. A flow check was conducted at 2973m MD due to dynamic losses of 20 bph at 450 gpm and high gas of 3203 units from 3035m MD. An LCM pill was spotted and POOH 6 stands. Static losses were 6 bph. RIH to 3045m MD and spotted cement plug. Continued drilling from 3045 – 3095m MD. Total losses encountered. Maximum gas encountered while drilling, 1309 units from 3079m MD. Pumped LCM and spotted cement plug. Drilled out cement. Maximum gas, 4050 units from 3079m MD. Circulated to condition hole and monitored for losses, well static. Continued drilling to 3112m MD. Maximum encountered 3096 units from 29776m MD, 3203 units from 3035m MD. Encountered 60 bph losses that increased to 100 bph. Pumped LCM and spotted cement plug with Zone Lock solution to combat losses. Drilled out cement, unsuccessful in combating losses. Spotted another cement plug. Reduced mud weight to 1.1 SG. Drilled out cement plug and continued drilling with losses dropping from 0 – 9 bph. Flowline temperature increased from 149 °C (300 °F) to 156 °C (313 °F) through the interval Open hole logging conducted; Log # 1 DLL – SRT – SP – CAL – GR, Log # 2 LDT – CNL – GR, Log # 3 DSI – GR, Log # 4 FMI – GR, Log # 5 VSP The 7", L-80, 32.0 ppf, BTC liner was run to 3090 m MD and the cement pumping program that followed comprised; 30 bbl 1.24 SG Mud Push II, 30 bbls 1.38 LiteCRETE followed by 183 bbls of displacement mud.

Operations Summary

Operations associated with the drilling of CCS Pilot Well can be broken down into the following discrete steps:

1. Move in drilling unit and associated service equipment and rig up.
2. Drive 30-inch conductor or drill 36-inch hole and run 30-inch casing and cement. Install diverter equipment if shallow gas is considered to be a possibility.
3. Drill 12¼-inch pilot hole to the 20-inch casing setting depth taking returns to the cellar with cellar pump returns to mud system.
4. Log pilot hole as required.
5. Open pilot hole to 26-inch
6. Run and cement 20-inch casing using "water bushing" and drill pipe inner string.
7. Rig down diverter equipment, if it has been installed, cut off 30-inch conductor at cellar floor. Cut off 20-inch casing at pre-determine height and weld on 21¼-inch 3,000 psi WP x 20-inch SOW casing head flange. Leak test weld. Install 21¼-inch, 3,000 psi BOP stack. Test 21¼-inch BOP stack and associated surface equipment in accordance with the approved BOP Test Procedures.
8. Make-up 17½-inch drilling assembly. RIH and drill out the 20-inch casing shoe. Drill 4.0m of new formation and perform a Formation Integrity Test (FIT) to the predetermined value.
9. Directionally drill 17½-inch hole to 13⅜-inch casing setting depth.
10. Conduct wiper trip to 20-inch casing shoe and POOH.
11. Log as required.
12. Run and cement 13⅜-inch casing.
13. Remove 21¼-inch 3,000 WP BOP's and install the 21¼-inch x 13⅝-inch Casing Head Assembly (CHA) and pressure test CHA cavities. Install 13⅝-inch 5,000 psi WP BOP stack and associated surface equipment in accordance with the approved BOP Test Procedures.
14. Make up 12¼-inch drilling assembly. RIH and drill out 13⅜-inch casing shoe. Drill 4.0m of new formation and perform a Formation Integrity Test (FIT) to the predetermined value.
15. Drill 12¼-inch hole to the base of the Tuban Formation.
16. *<u>11¾-inch Contingency Liner</u>*
    a. ***In the event hole conditions are unfavorable in this hole section,*** *POOH, make up 14¾-inch hole opening drilling assembly and open up the hole to 14¾-inch to the 11¾-inch contingency liner setting depth.*
    b. *Conduct wiper trip to 13⅜-inch casing shoe.*
    c. *Log as required.*
    d. *Run and cement the 11¾-inch contingency liner.*
    e. *Make up 9⅞ x 12¼-inch drilling assembly. RIH and drill out 11¾-inch contingency liner shoe. Drill 4.0m of new formation and perform a Formation Integrity Test (FIT) to the predetermined value. Drill to 9⅝-inch casing setting depth at the base of the Tuban Formation. POOH.*
    f. *Conduct wiper trip to the 11¾-inch liner shoe.*
17. Conduct wiper trip to the 13⅜-inch casing shoe.
18. Log as required and conduct formation dynamics tests of any potential CO_2 injection formations along with Side Wall Core (SWC) sampling.
19. Run and cement 9⅝-inch liner.

20. Nipple down 13⅝-inch 5,000 psi WP BOP stack. Install 13⅝-inch 5,000 psi x 11-inch 5,000 psi CHA and pressure test CHA cavities. Install 13⅝-inch 5,000 psi WP BOP stack and associated surface equipment in accordance to the approved BOP Test Procedures.
21. Make up 8½-inch drilling assembly. RIH and drill out 9⅝-inch casing shoe. Drill 4.0 m of new formation and perform a Formation Integrity Test (FIT) to the predetermined value.
22. Control drill 8½-inch hole and penetrate the Kujung Formation. Continue drilling to the water zone, at the base of the Kujung Formation and prior to penetrating the Ngimbang Formation, where it is planned to conduct full-hole coring of the target injection zone. POOH.
23. RIH with core barrel assembly and core the lower portion of the Kujung Formation. POOH.
24. Conduct wiper trip from TD to the 9⅝-inch liner shoe. POOH
25. Log as required and conduct formation dynamics tests of potential CO_2 injection formations below the water contact.
26. Run 5½-inch "long string" casing and external down-hole monitoring equipment and cement utilizing a multi-stage light weight cementing process. On completion of the first stage cementation, land 5½ inch mandrel casing hanger and conduct second stage cementation taking returns through wellhead Section B side outlets.
27. Nipple down 13⅝-inch 5,000 psi WP BOP stack. Install 11-inch 5,000 psi x 11-inch 5,000 psi tubing hanger section with temperature and pressure ports. Install 13⅝-inch 5,000 psi WP BOP stack and associated surface equipment in accordance to the approved BOP Test Procedures.
28. Install bull plug in tubing No-Go nipple, run 2⅞-inch tubing, isolation packer, associated completion equipment and tubing hanger pressure testing tubing every 5 stands.
29. Land tubing hanger in wellhead section, secure and set packer.
30. Pressure test tubing/packer annulus and temperature/pressure exit ports.
31. Retrieve bull plug from No-Go profile.
32. Install BPV in tubing hanger.
33. Nipple down BOP equipment.
34. Demobilize drilling unit and associated service equipment.
35. Install Xmas tree and pressure test. Including monitoring sensor DAS cable ports.
36. Rig Down and Rig Release
37. Restore site.

The well will be perforated at a later date on assessment and interpretation of the data acquired over the zone of interest.

Time – Depth Curve

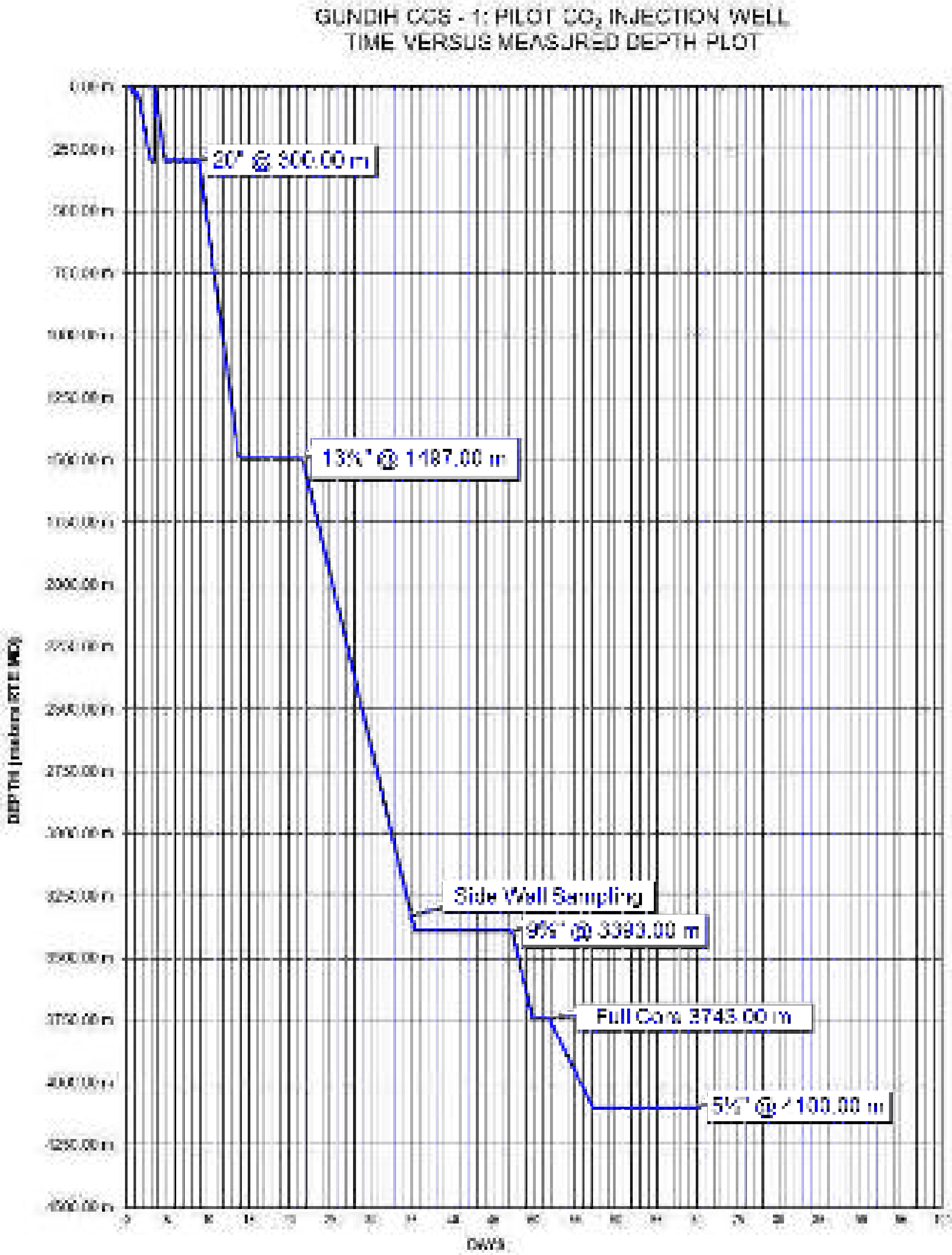


Figure 14 Estimated Time - Depth Curve with 30% NPT

Formation Evaluation

Borehole Characterization

Rationale

- Conduct a detailed characterization of near wellbore geology to identify CO_2 injections interval(s) in support of the development of an accurate reservoir model.
- Model accuracy is critical in the prediction of CO_2 spreading/behavior.
- Modelling is a monitoring method (particularly in the case, when monitoring wells are not available).

Borehole Characterization Program Elements

- Geophysical logging.
- Coring, core sampling, core testing and analysis.
- Packer testing.
- Stress measurements (mini-frac testing).
- Borehole seismic (tentative).
- Data analysis, interpretation and modelling.

Open Borehole Logging Program

17½ inch Hole Section - 13⅜ inch Casing

Log № 1 - Parameters
Basic Properties:

- Resistivity
- Neutron Porosity
- Bulk Density
- Caliper
- Gamma Ray
- Photo-Electric Factor

Acoustic Velocities:

- Rock Mechanical Properties
- Horizontal Stress Orientation (azimuth) and anisotropy
- Velocity Modelling Update

Log № 1A Cased Hole Logging

- Cement Evaluation Log

Hole Depth (TVD)/Formation
Surface – 1,324 m TVD/1492 m MD

Logging Tools:

- Triple Combo or Platform Express*
- Dipole Sonic

Formation:

- Wonocolo
- Ngrayong

Wonocolo

Ngrayong

14¾ inch Hole Section - 11¾ inch Contingency Liner

Contingency Log Parameters
Basic Properties:

- *Resistivity*
- *Neutron Porosity*
- *Bulk Density*
- *Caliper*

Hole Depth (TVD)/Formation
1,324 m – TBA

Logging Tools:

- *Triple Combo or Platform Express**

Ngrayong

- *Gamma Ray*
- *Photo-Electric Factor*

Acoustic Velocities:

- *Rock Mechanical Properties*
- *Horizontal Stress Orientation (azimuth) and anisotropy*
- *Velocity Modelling Update*
  Identify depositional features, bedding, dip, vugular porosity, fractures, faults and stress orientation (if break-outs or drilling induced fractures are present.
- *Acoustic Resistivity*

Contingency Cased Hole Logging

- *Cement Evaluation Log*

- *Dipole Sonic*

Formation:

- *Ngrayong*
- *Tuban*

Tuban

12¼ inch Hole Section - 9⅝ inch Liner

Log № 2 - Parameters

Basic Properties:

- Resistivity
- Neutron Porosity
- Bulk Density
- Caliper
- Gamma Ray
- Photo-Electric Factor

Acoustic Velocities:

- Rock Mechanical Properties
- Horizontal Stress Orientation (azimuth) and anisotropy
- Velocity Modelling Update
  Identify depositional features, bedding, dip, vugular porosity, fractures, faults and stress orientation (if break-outs or drilling induced fractures are present.
- Acoustic Resistivity

Mineralogy

- Elemental Spectroscopy (tentative)
- Rotary Sidewall Core Sampling

Log № 2A Cased Hole Logging

- Cement Evaluation Log

Hole Depth (TVD)/Formation
1,324 – 2,932 m TVD

Logging Tools:

- Triple Combo or Platform Express*
- Dipole Sonic
- Resistivity (LWD) geo-stop

Formation:

- Ngrayong
- Tuban

Ngrayong

Tuban

8½ inch Hole Section - 5½ inch Production Casing

Log № 3 Parameters
Basic Properties:
- Resistivity
- Neutron Porosity
- Bulk Density
- Caliper
- Gamma Ray
- Photo-Electric Factor

Acoustic Velocities:
- Rock Mechanical Properties
- Horizontal Stress Orientation (azimuth) and anisotropy
- Velocity Modelling Update
  Identify depositional features, bedding, dip, vugular porosity, fractures, faults and stress orientation (if break-outs or drilling induced fractures are present.
- Acoustic Resistivity

Permeability
- Nuclear Magnetic Resonance

Fluid Type/Saturation
- Pulsed Neutron Capture

Mineralogy
- Elemental Spectroscopy (tentative)
- Coring/Rotary Sidewall Core Sampling

Log № 3A Cased Hole Logging
- Cement Evaluation Log

**Schlumberger Nomenclature*

Hole Depth (TVD)/Formation
2,932 – 3,424 m TVD

Logging Tools:
- Triple Combo or Platform Express*
- Dipole Sonic
- NMR*
- PNC*

Formation:
- Kujung

Kujung

Measurement While Drilling (MWD)

A Rotary Steerable System (RSS) is employed, in wells over 20° deviation, by the operator along with the associated MWD requirements.

Resistivity Imaging While Drilling (LWD)

A minimum LWD requirement, Resistivity While Drilling is to be included with the selected directional drilling method for the casing setting point identification e.g. Geo-stop (this tool has an accuracy of 1.0 – 1.5 meters). Other LWD requirements are to be established on the availability of tools.

Coring & Sidewall Core Sampling

Full Hole Coring Primary Objective – Lower Kujung

Coring operations are planned to be conducted in the target CO_2 injection reservoir section. All downhole coring equipment is to be temperature rated for reservoir conditions and exposure to a CO_2 and H_2S environment.

The point at which coring will commence is to be determined in conjunction with the Drilling Supervisor and Well Site Geologist and conveyed to Company for final concurrence. As with any coring operations, the utmost care is to be taken when operations are conducted in a high temperature, H_2S environment of this nature. As a primary concern, the well is to be confirmed in a stable state prior to commencement of coring operations.

Upon recovery, the core is to be catalogued, packaged in an approved method and sent to a laboratory for analysis.

Side Wall Sampling Secondary Objective – Lower Tuban Calciturbidite

Rotary sidewall core sampling is planned as part of the 12¼-inch hole section open hole logging program to sample the calciturbidite sequence above the Kujung Formation as a potential secondary CO_2 injection zone prior to setting the 5½-inch production casing. As in the full hole coring equipment is to be temperature rated and suitable for working in an H_2S and CO_2 environment.

This phase will also include sidewall core sampling of the cap rock above the reservoir section in the Tuban Formation.

Characterization Program

Well and Reservoir Hydraulic and Geo-mechanical Testing

Phase 1 – Flowmeter Logging (mechanical spinner meter logging tool) survey of the open borehole section across the reservoir to identify candidate CO_2 injection zones.

This phase of testing includes a baseline fluid logging survey conducted under static (no injection) conditions and additional surveys conducted while injecting brine at increasing rates (e.g. 2, 4 and 6 bpm).

Phase 2 – Straddle Packer Tests of candidate CO_2 injection horizons and other discrete intervals with the intervals being isolated utilizing a straddle packer testing tool.

This phase will include Hydraulic Pumping (withdrawal/build-up) tests to characterize formation hydraulic properties (transmissibility, permeability).

Stress Test pumping (injection/fall-off) tests will be conducted to create mini hydraulic fractures to characterize horizontal stress directions and formation fracture pressure.

Well Schematic

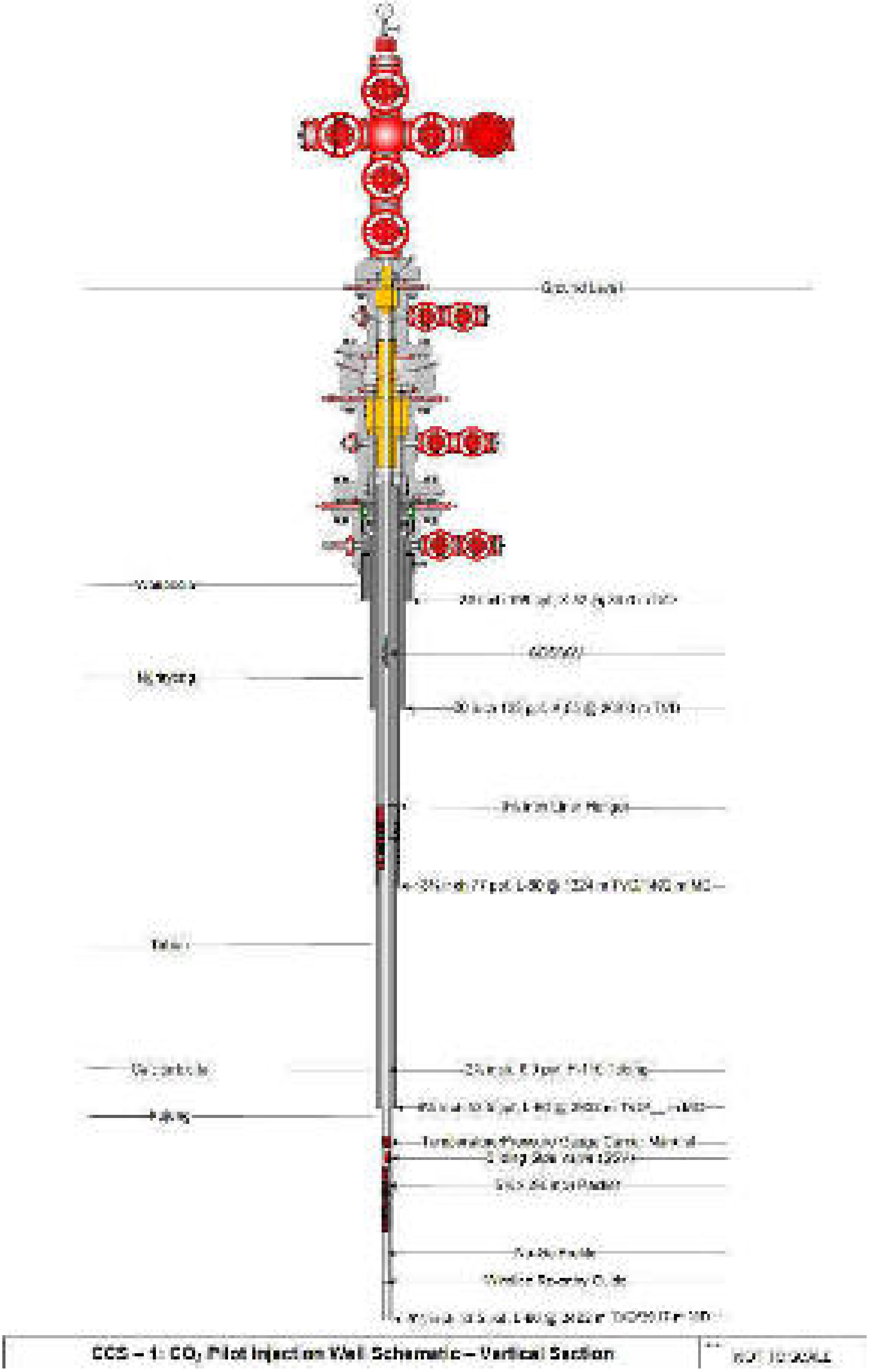


Figure 15 CCS Conceptual Well Schematic – Vertical Section

Well Suspension/Abandonment

At the termination of the CCS pilot program, that is expected to endure for approximately 2 years, the decision to suspend or abandon the well will be made.

Should there be a potential for the well to either remain a CO_2 injection well or a production well the well will be suspended and left in a usable state, providing no safety or environmental concerns are violated, i.e. Xmas Tree, production tubing, safety valve and completion packer remain in place.

In the event the well is plugged and abandoned, procedures will meet the requirements of 40 CFR §146.92. Plugging procedure and materials will be designed to prevent any unwanted fluid movement, to resist the corrosive aspects of carbon dioxide/water mixtures, and protect any USDW's. Any necessary revisions to the well plugging plan, to address new information collected during logging and testing of the well will be made after construction, logging and testing of the well have been completed.

After injection has been terminated, the well will be flushed with a kill weight brine fluid. A minimum of three (3) tubing volumes will be injected without exceeding the fracture gradient/pressure. Bottom hole pressure will be taken and the well will be logged and pressure tested to ensure mechanical integrity, inside and outside the casing, prior to plugging. Should a loss of mechanical integrity be discovered, the well will be repaired prior to proceeding with plugging operations. A detailed plugging procedure is to be compiled. All casing strings extending to surface will have been cemented to surface during the well construction phase and will not be retrievable at abandonment. When injection has been terminated permanently, the injection tubing and packer will be retrieved and the well plugged with either, balanced cement plugs or a combination of cement retainers and cement plugs. In the event the packer cannot be retrieved, the tubing will be cut with an electric line tubing cutter leaving the packer in the well after which a cement retainer will be used for plugging the injection formation below the packer.

All casing strings will be cut off in accordance with regulatory requirements and a blanking plate with the well information welded to the cutoff casing.

Company will record bottom hole pressure from a downhole pressure gauge to determine kill fluid density. At least one (1) of the following logs, as required by 40 CFR §146.92(a), will be conducted to verify external Mechanical Integrity (MI) prior to plugging operations:

- Temperature Log
- Noise Log
- Oxygen Activation Log

Cement formulated for plugging operations shall be resistant to the carbon dioxide stream.

The suspension or abandonment of the CCS – 1 Pilot Well is to adhere to Badan Standar Nasional Indonesia SNI 13-6910 – 2002: Drilling Operation for Safe Conduct of Onshore and Offshore in Indonesia – Implementation. Specifically, Article 6.10 Abandonment of Wells; Sub-sections 6.10.3 Permanent Abandonment and 6.10.4 Temporary Abandonment (Suspension). It should be pointed out that a well that is temporarily abandoned (suspended) shall be permitted by Pertamina as per Government Regulation № 17/1974 (Ref: SNI 13-6910 – 2002 Appendix C1)

WELL ABANDONMENT – STANDAR NASIONAL INDONESIA SNI 13 – 9610 – 2002

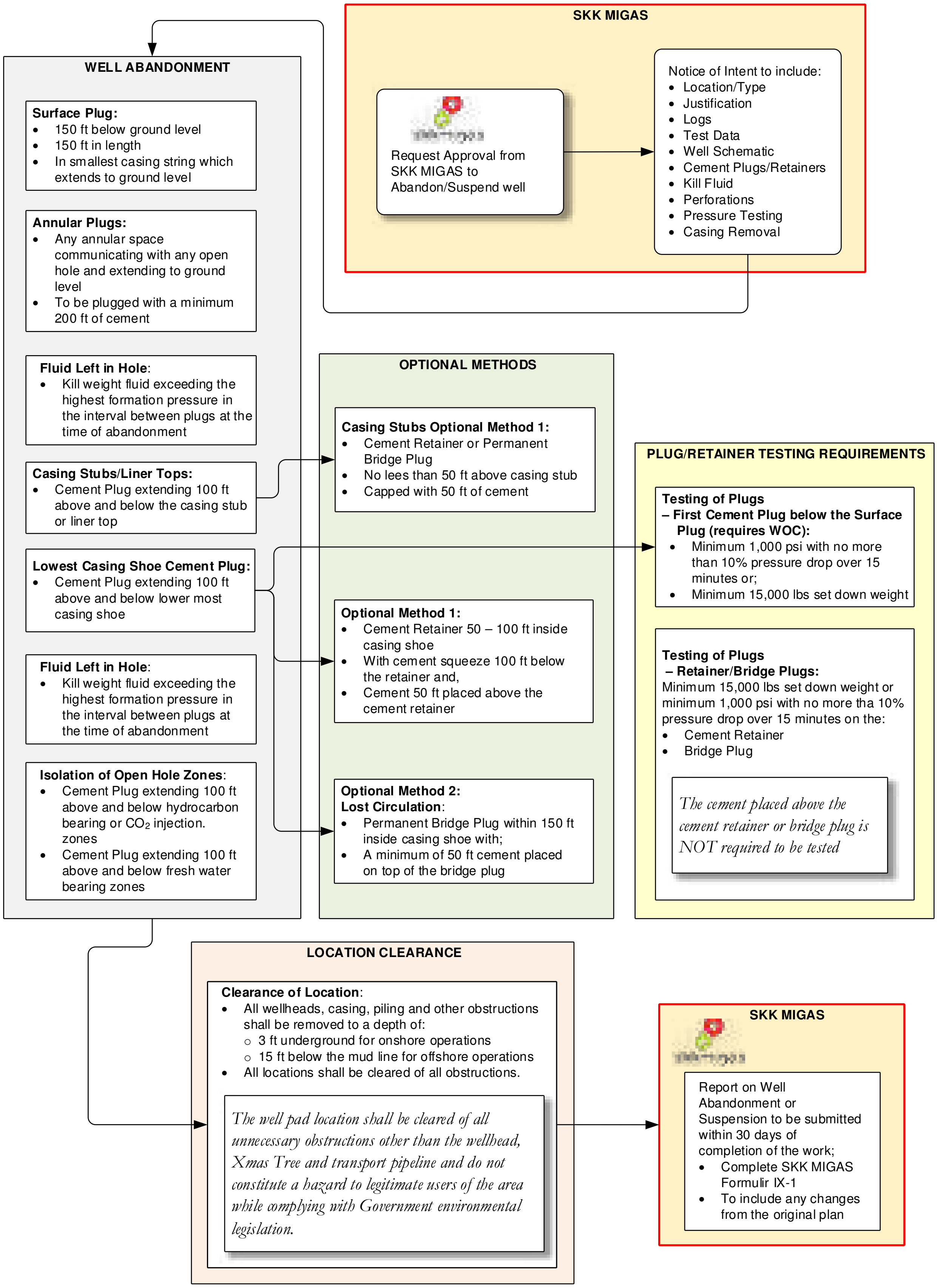


Figure 16: Well Suspension/Abandonment Flowchart

Nomenclature

API	American Petroleum Institute
bbl	Barrel
BHST	Bottom Hole Static Temperature °C (°F)
BOP	Blow-Out Preventer
bph	Barrels per Hour
bpm	Barrels per Minute
BPV	Back Pressure Valve
BTC	Buttress Thread Connection
BUR	Build Up Rate
°C	Degrees Celsius
CAL	Caliper Log
Cap Rock	The shale layers above a reservoir that provide geological isolation to upward migration of CO_2 and provide the primary seal
CBL	Cement Bond Log
CHA	Casing Head Assembly
CO_2	Carbon Dioxide
CPP	Central Processing Plant
DAS	Distributed Acoustic System
DLS	Dog Leg Severity
DST	Drill Stem Test
DTS	Distributed Temperature System
°F	Degrees Fahrenheit
ft.	feet
gpm	gallons per minute
GR	Gamma Ray Log
H_2S	Hydrogen Sulfide
HAZOPS	Hazardous Operations
KCl	Potassium Chloride
KOP	Kick Off Point
LCM	Lost Circulation Material
m	meters
MD	Measure Depth – m (ft.)
MDT	Modular Dynamic Tester (Schlumberger)

MI	Mechanical Integrity
MMSCFD	Million Standard Cubic Feet per Day
MT	Metric tons
NACE	National Association of Corrosion Engineers
NMR	Nuclear Magnetic Resonance Log
NPHI	Neutron Porosity Log
OBM	Oil Base Mud
PDC	Polycrystalline Diamond Compact (drill bit)
PEF	Litho-Density Log
PHPA	partially-hydrolyzed polyacrylamide
PNC	Pulsed Neutron Capture Log
POOH	Pull Out Of Hole
ppf	Pounds Per Foot
PR	Performance Requirement
psig	pounds per square inch, gauge
psi WP	pounds per square inch Working Pressure
PSL	Product Specification Level
OBM	Oil Base Mud
RCX	Reservoir Characterization Explorer (Baker)
RES	Resistivity Log
RHOB	Neutron Density Log
RIH	Run In Hole
RSS	Rotary Steerable System
RTE	Rotary Table Elevation
SG	Specific Gravity
SOBM	Synthetic Oil Base Mud
SONIC	Sonic Log
SOW	Slip-on Weld
SSSCSV	Sub Surface, Surface Controlled Safety Valve
SSV	Surface Safety Valve
SWC	Side Wall Core
TBA	To be advised
TD	Total Depth (measured) – m (ft.)
TDS	Top Drive System

TVD	True Vertical Depth – m (ft.)
TVDSS	True Vertical Depth, Sub Sea - m (ft.)
USIT	Ultrasonic Imaging Tool
VDL	Variable Density Log
VSP	Vertical Seismic Profile
WBM	Water Base Mud
WP	Working Pressure

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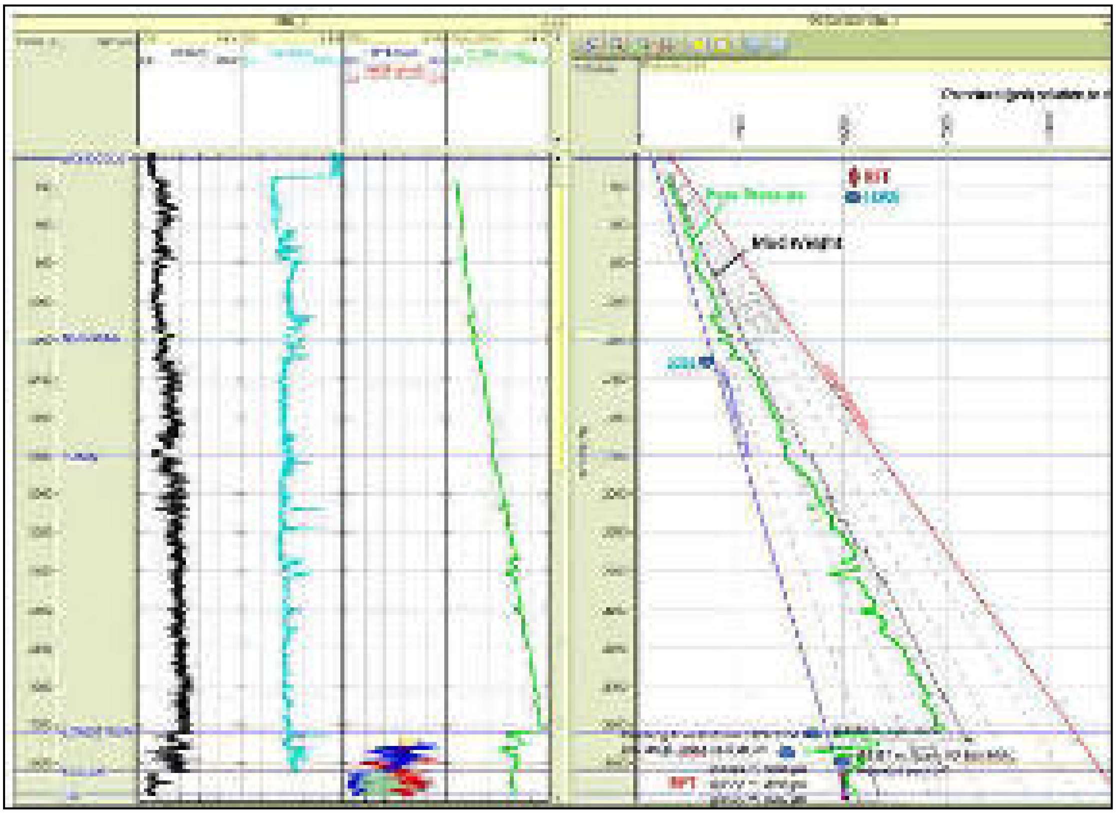

Figure 17: KDL-1 Well Data Profile

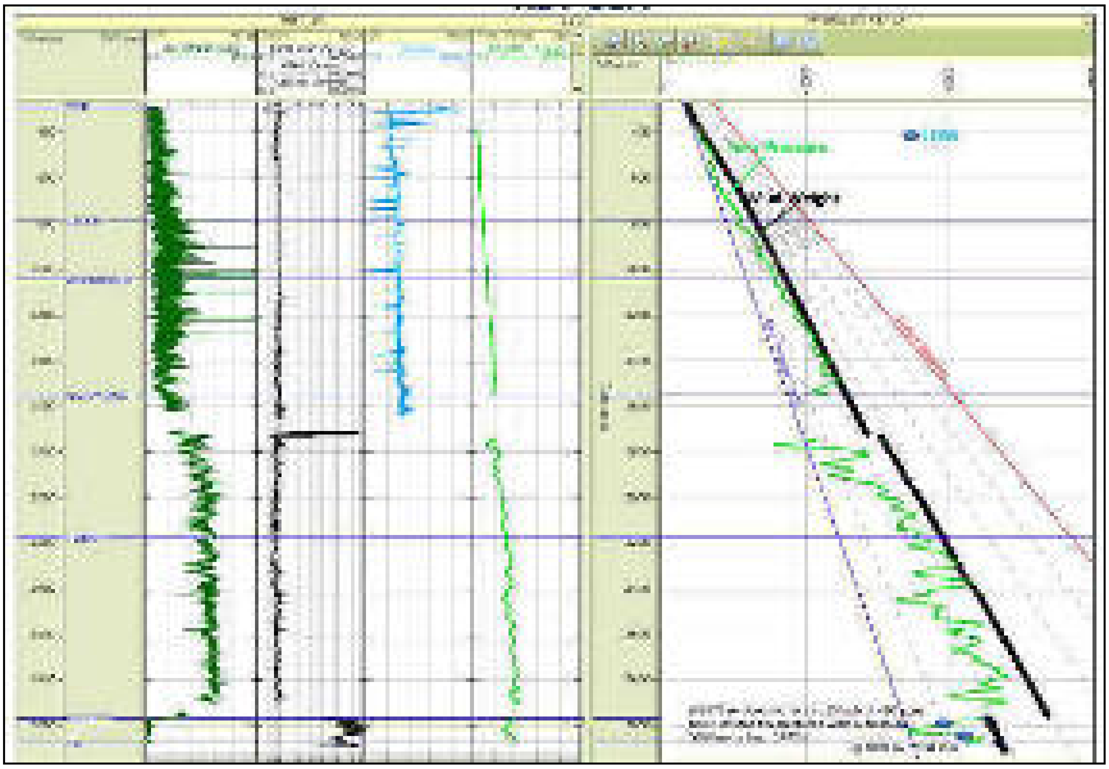

Figure 18: RBT-1A Well Data Profile

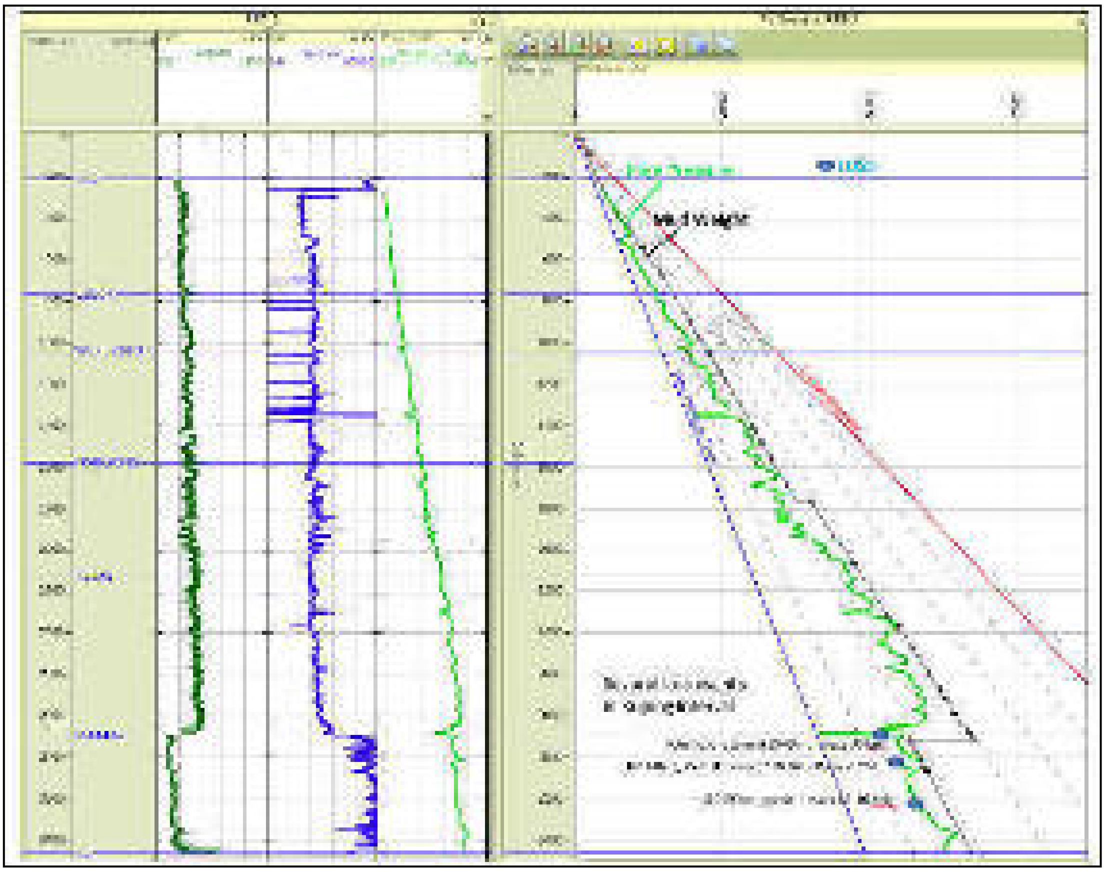

Figure 19: RBT-2 Well Data Profile

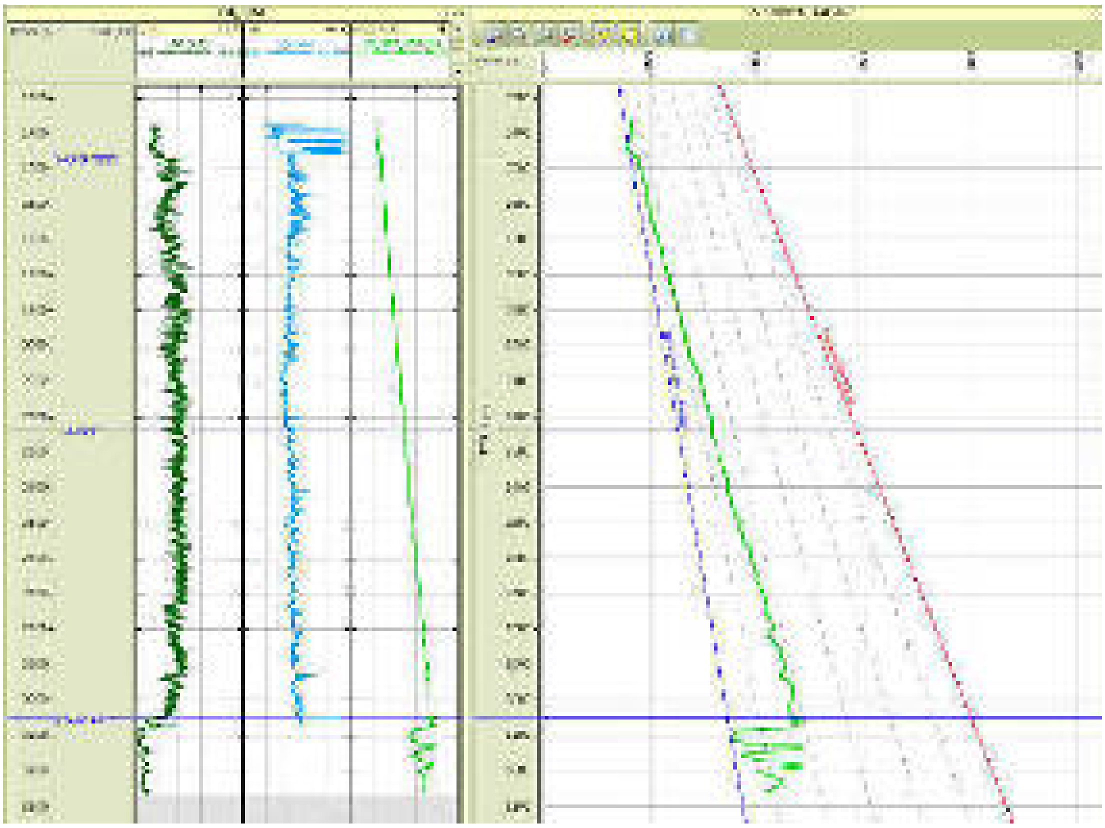

Figure 20: RBT-3Well Data Profile

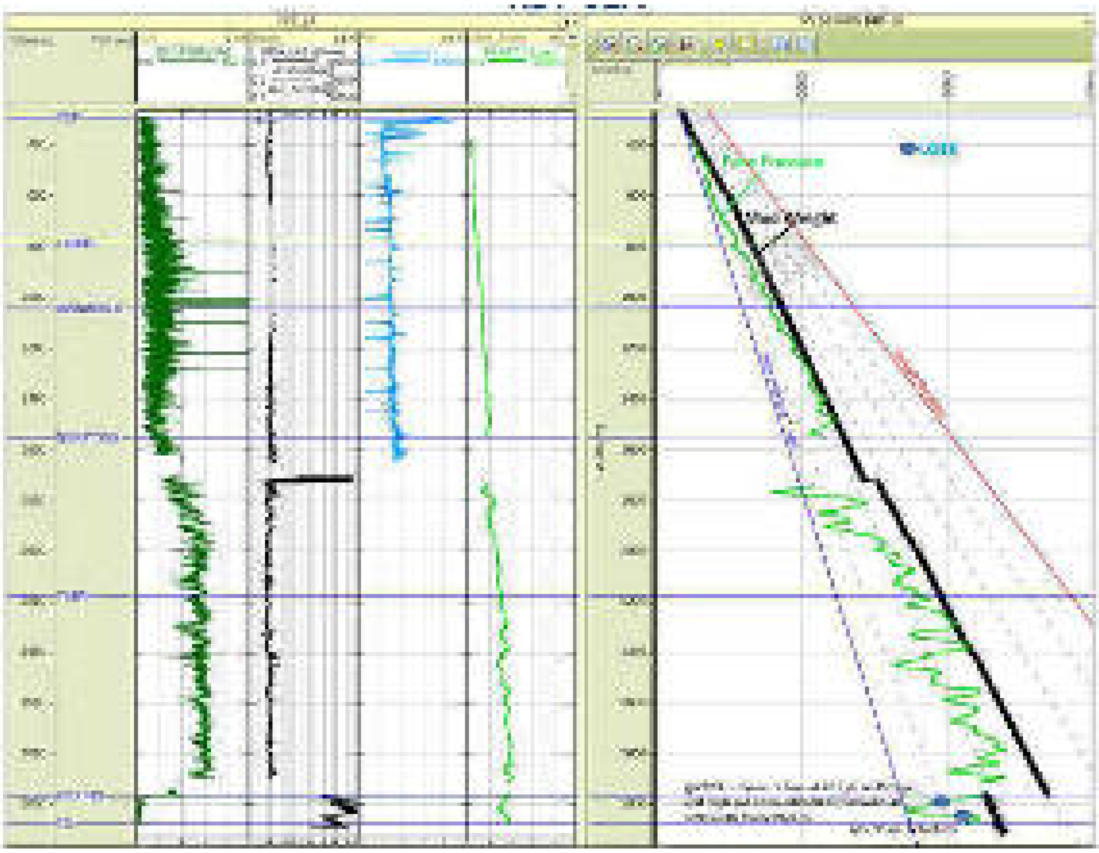

Figure 21: KBT-1 Well Data Profile

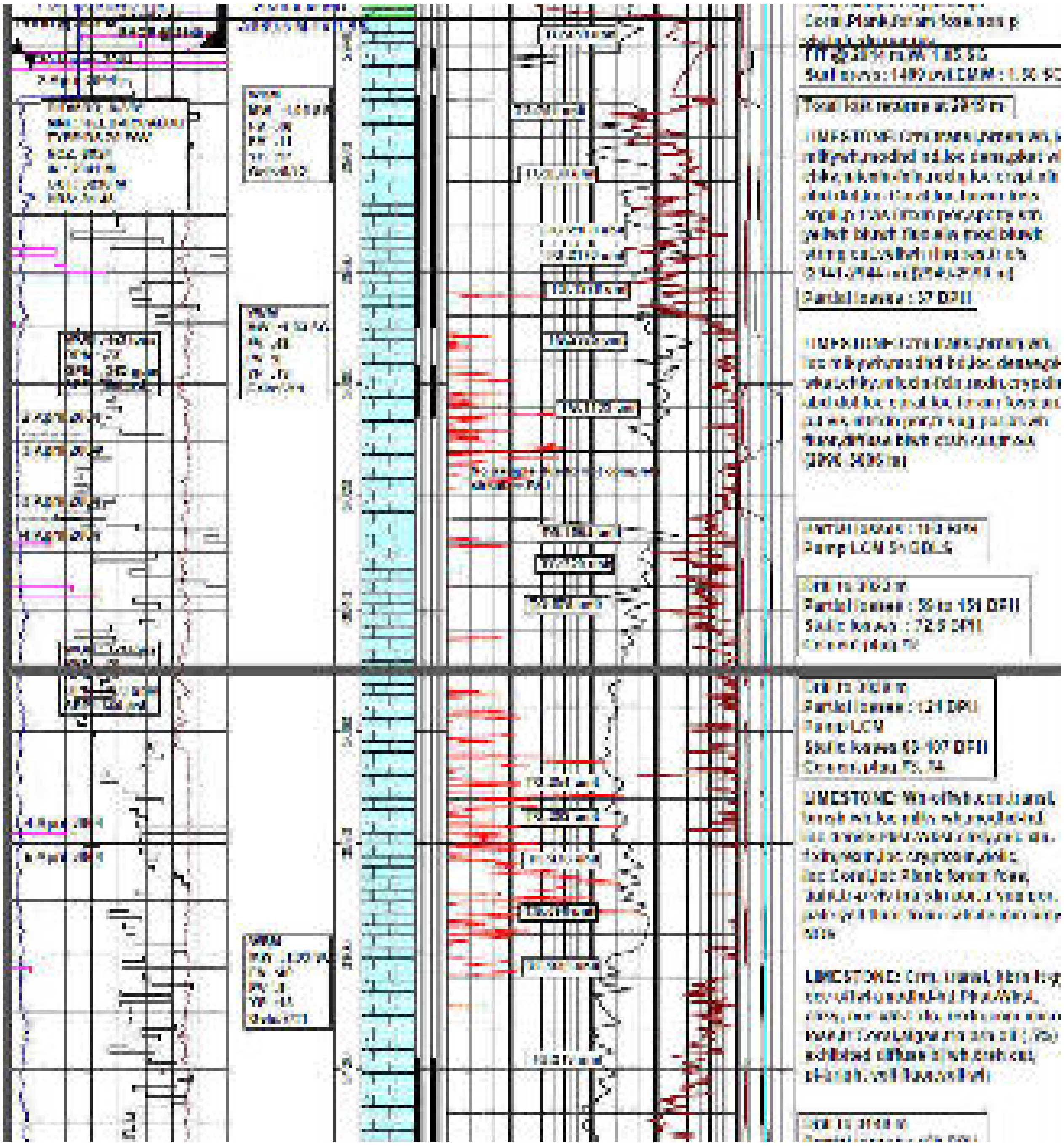

Figure 22: RBT-2 Mud Log

Appendix D. Gundih Site Visit Report

GUNDIH SITE VISIT REPORT

13 & 14th February 2019

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RBT – A Well Pad: RBT-01A and RBT-03ST Wells 3
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KTB – B Well Pad: KTB-02 & KTB-04 Wells 11
Gundih Central Processing Plant (CPP) 14

Preamble

The second Gundih site visit took place 13th & 14th February 2019 and covered the well pad locations, pipeline right-of-ways and Gundih Central Processing Plant.

The visit team comprised, representatives of Asian Development Bank, Battelle Memorial Institute, Institute Technology Bandung, Elnusa and Pertamina.

Commencing, initially, with a meeting at Pertamina Asset Offices, Cepu, followed by a site visits to, Gundih well pad locations and some pipeline right-of-ways and the central processing plant.

The site visit focused on potential candidate surface well locations for use as a CO_2 pilot injection well site. There are five (5) well pad locations in the Gundih Field; KDL, RBT – A, RBT – B, KTB – A and KTB – B.

Figure 1: Gundih CPP, Well Pads and Pipeline ROWs

RBT – A Well Pad: RBT-01A and RBT-03ST Wells

RBT Well Pad A is the closest well location west of the Gundih Central Processing Plant and is approximately 32,269 m^2 in size. The pipeline right of way is approximately 1,450 meters in length and crosses the provincial highway at the entrance to both the CPP and RBT Well Pad A where; producing well RBT - 01 and, water injector well RBT – 03 are located.

Three pipelines traverse this right of way, 2 – 6 inch steel pipelines and 1 – HDPE PN 110.

Figure 2: Pipeline ROW RBT-3ST to Gundih CPP and RBT-A Well Pad approximately 32,269 m^2

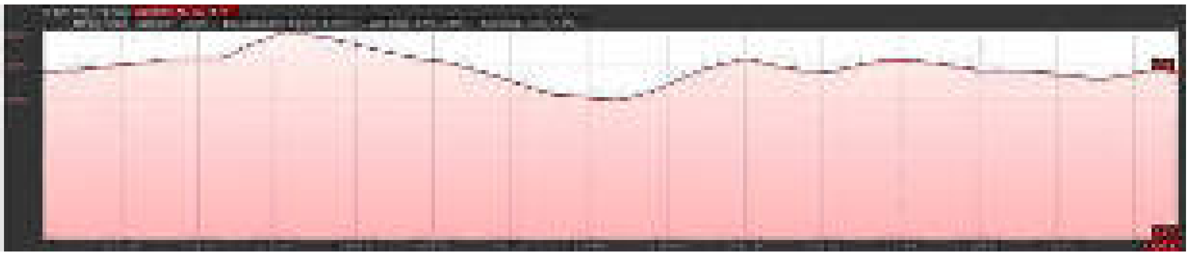
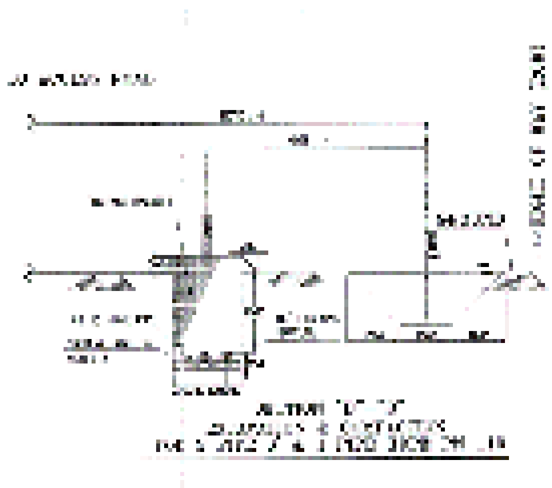


Figure 3: Elevation Profile ROW: RBT-A Well Pad to Gundih CPP



Three pipelines traverse this right of way, 2 – 6 inch steel pipelines and 1 – HDPE PN 110.

Figure 4: ROW Cross Section RBT-A Well Pad to Gundih CPP

Figure 5: Peting - Menden Provincial Road Crossing RBT-A to Gundih CPP

Figure 6: RBT-01 and RBT-03ST (water injection) Wellheads

KDL – A Well Pad: KDL-01 Well

The most western well pad KDL – A, 23,520 m^2 in size, is currently not a viable option as a CO_2 injection well location, however, it is shown to indicate the challenges of being selected as a potential candidate.

A single 6 inch flowline is contained in the pipeline right of way that passes from KDL Well Pad A to RBT Well Pad A, through a complex agricultural rural area and river crossings onto the CPP via the access road pipeline right of way, a distance of approximately 6,470 meters.

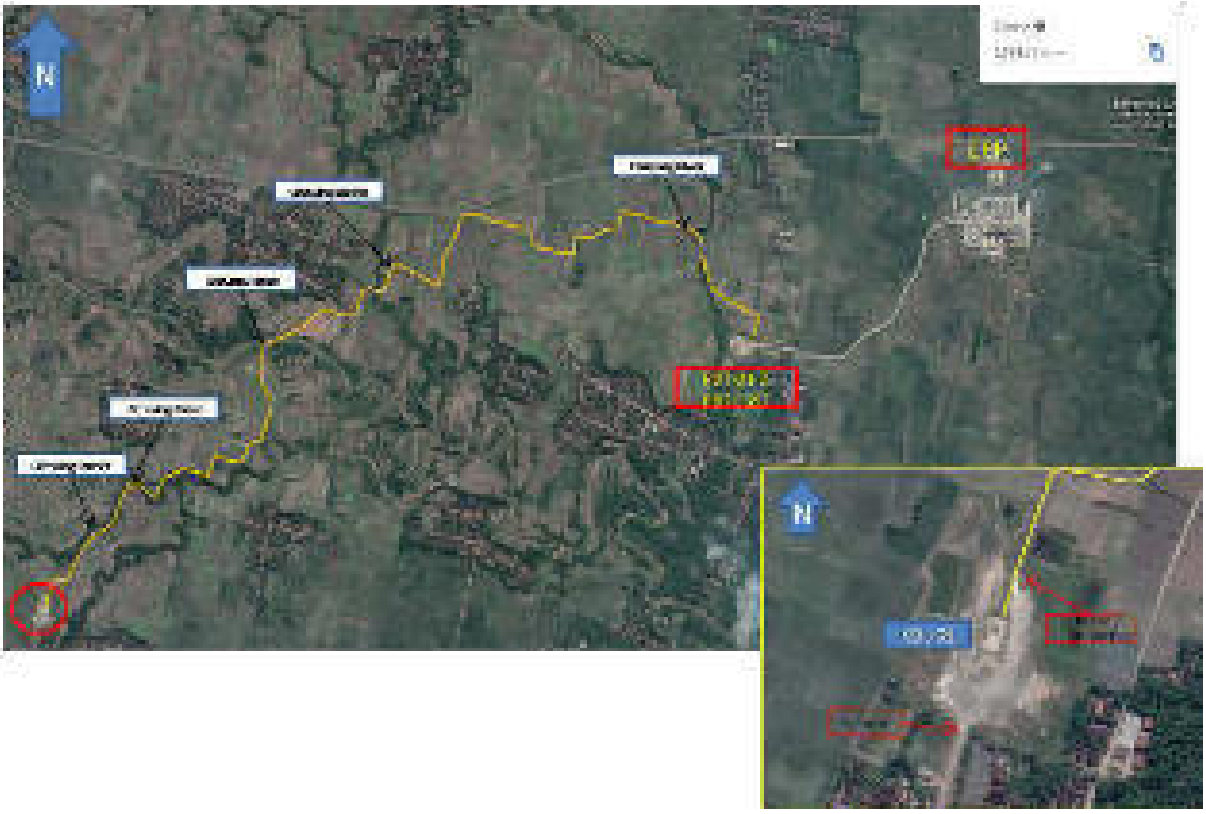
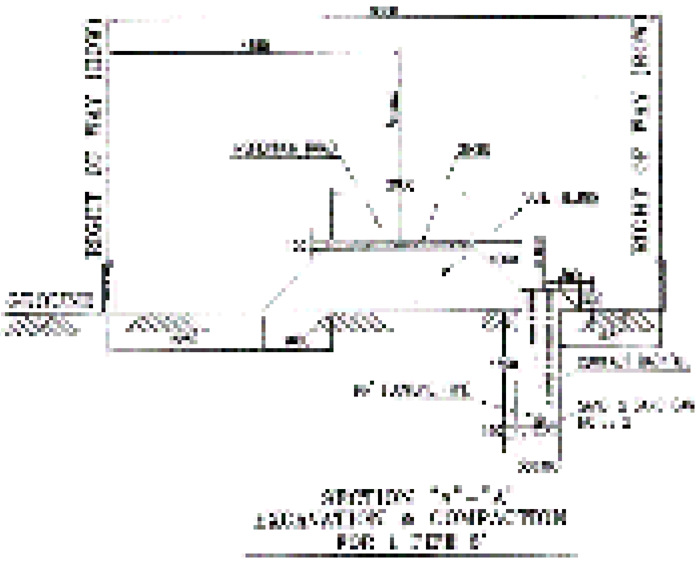


Figure 7: KDL-A Well Pad Location (23,520 m²) & Pipeline ROW

Figure 8: Pipeline ROW Elevation Profile: KDL-A Well Pad to RBT-A Well Pad



A single 6 inch flowline from KDL-01 traverses this ROW

Figure 9: ROW Cross Section: KDL-A Well Pad to RBT-A Well Pad

Figure 10: KDL-o1 Wellhead and Controls

RBT – B Well Pad and RBT-02 Well

RBT Well Pad B, 24,950 m^2 in area, is the next well location in close proximity to the CPP and is where RBT – 02 well is located. This well pad is subject to flooding of up to 1.5 meters during the wet season. Artificial water containment ponds have been constructed on the well pad areas closest in proximity to a nearby tributary of the Bengawan Solo River.

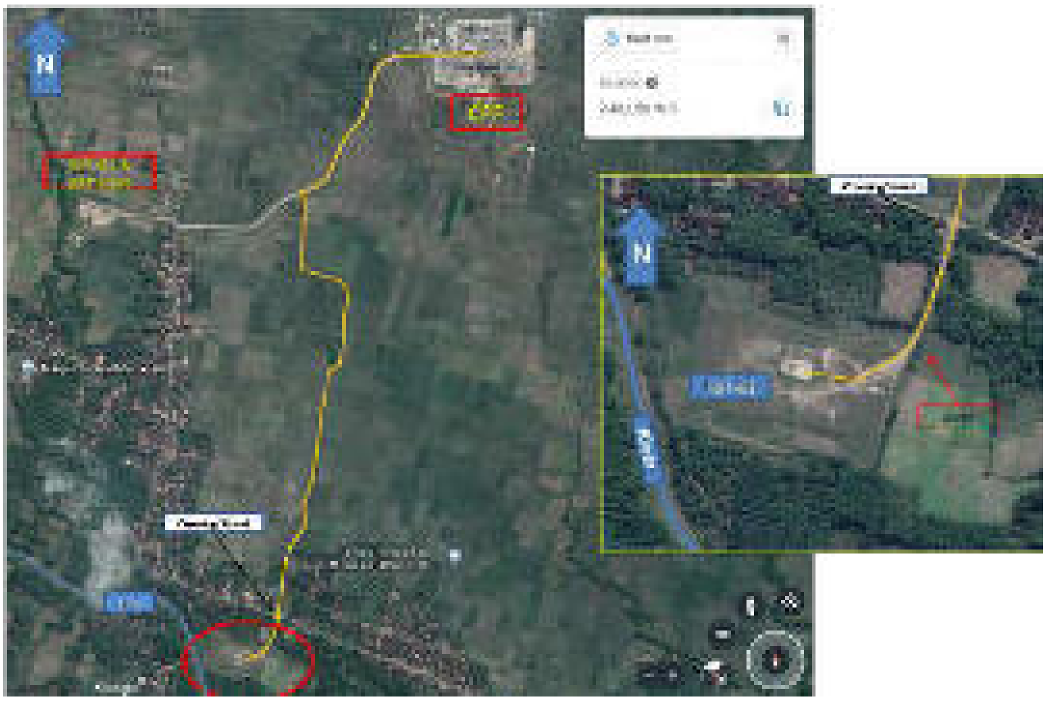


Figure 11: RBT-B Well Pad Location & Pipeline ROW intersecting at Gundih CPP access road.

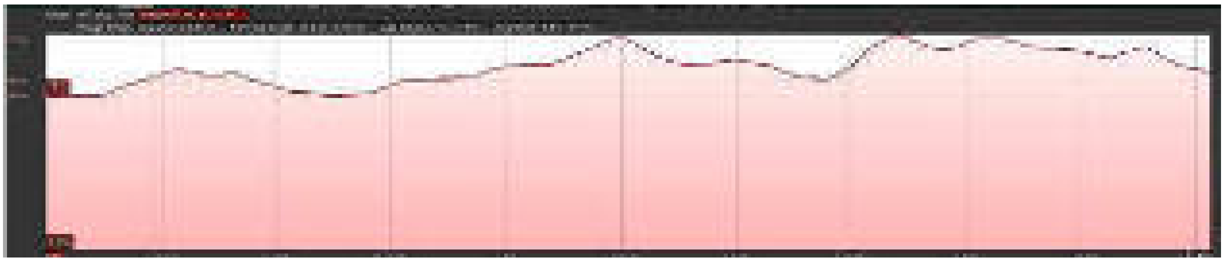
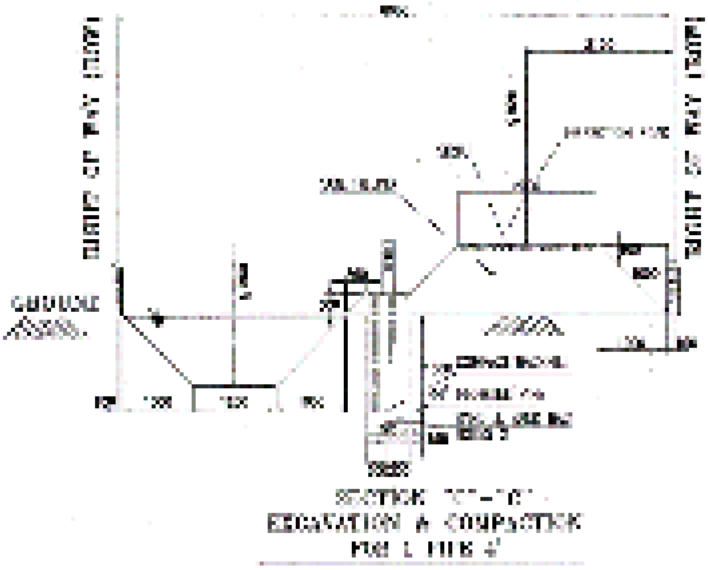


Figure 12: RBT-B Pipeline Elevation Profile: RBT-B to Gundih CPP Junction Point



The associated pipeline right of way is approximately 2,465 meters in length and has a 4 inch single flowline from RBT-02

The 4 inch RBT-02 flowline merges with the 2 – 6 inch flowlines from RBT – 3 and KDL-01 and the single water injection HDPE line to RBT-03.

Figure 13: ROW Cross Section: RBT-B to Gundih CPP Junction Point

Figure 14: RBT-02 Wellhead

Figure 15: Elevated Well Control Panel & Water Containment Pond area.

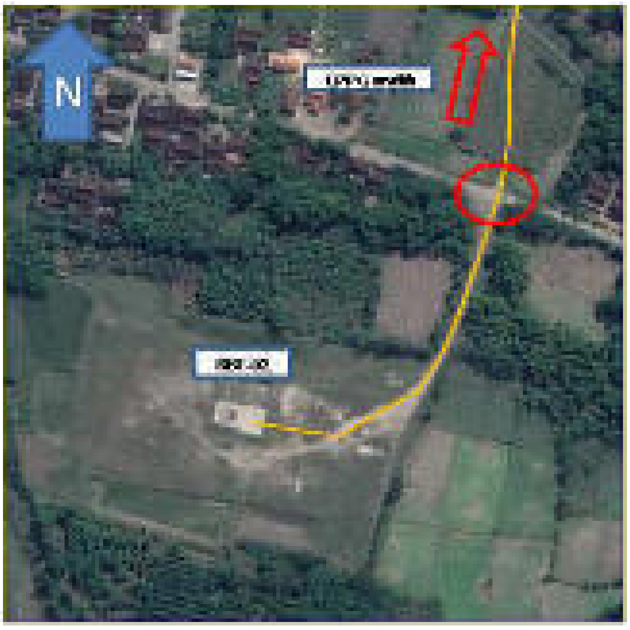


Figure 16: RBT-B to Gundih CPP Provincial Road Crossing Point

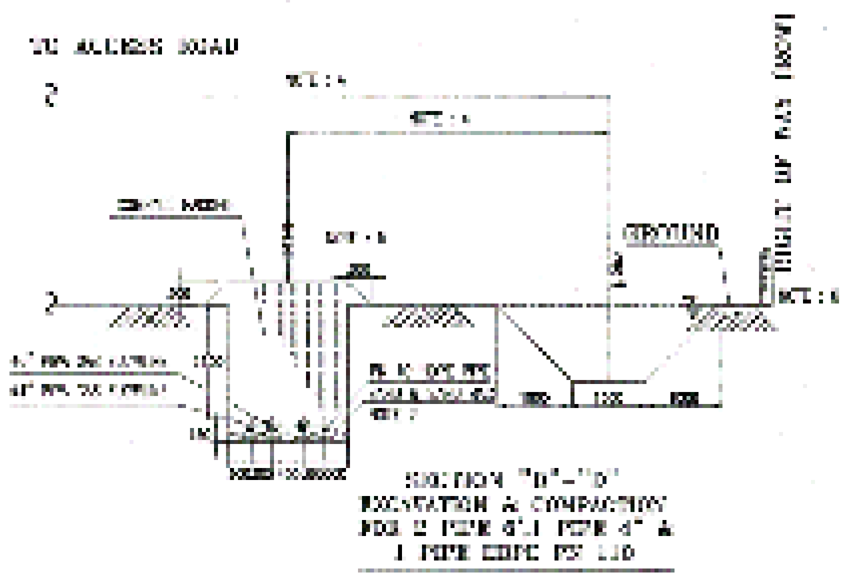


Figure 17: ROW Cross Section KDL/RBT-A/RBT-B Junction Point to Gundih CPP

KTB – A Well Pad: KTB-01, KTB-03TW & KTB-06ST Wells

KTB Well Pad A, an area of approximately 20,024 m^2, is located north east of the CPP and is where KTB – 01, KTB - 03 TW and KTB – 06 ST are located. The associated pipeline right of way from KTB Well Pad A to the CPP crosses underneath the provincial rail way line.

Figure 18: KTB-A Well Pad Location and Pipeline ROW

Figure 19: KTB-A to Gundih CPP Elevation Profile

Figure 20: KTB-01 & KTB-03TW Wellheads

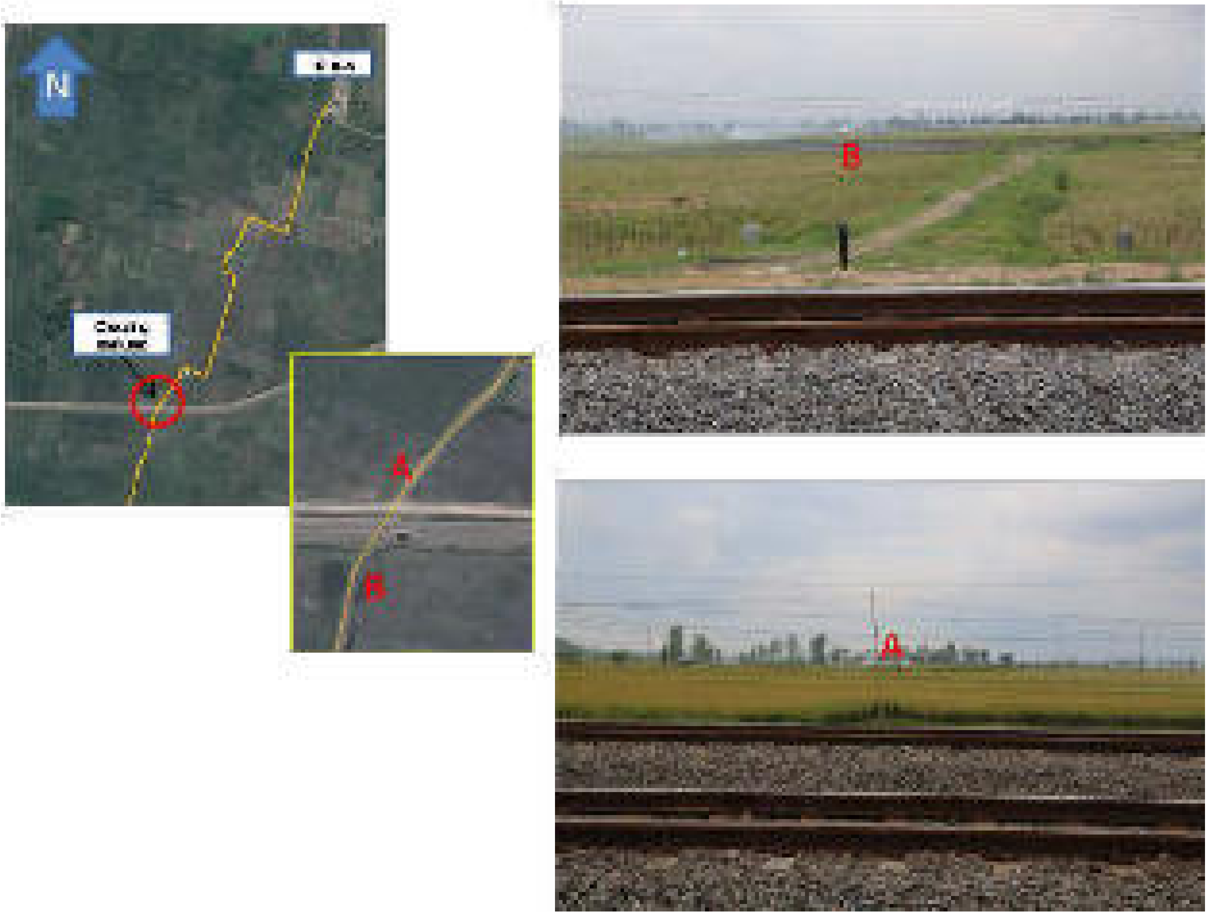


Figure 21: KBT-A to Gundih CPP Pipeline ROW Underground Railway Crossing

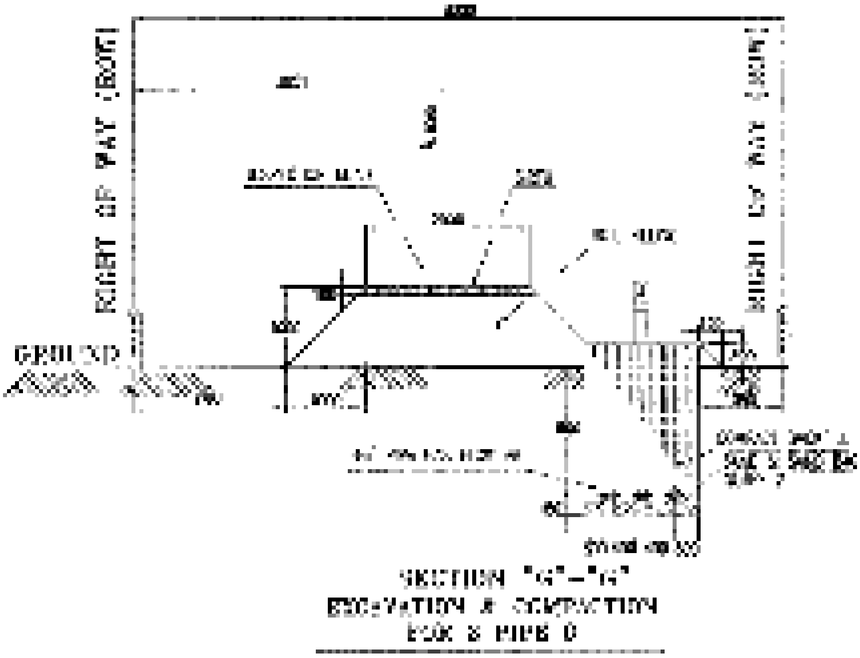


Figure 22: ROW Cross Section: KTB-A to Gundih CPP

Three 6 inch flowlines traverse the pipeline right of way from KTB Well Pad A to the CPP and cross under the provincial railway line a distance of approximately 3,900 meters. These flowlines are from KTB – 01, KTB- 03 TW and KTB – 06 ST wells.

KTB – B Well Pad: KTB-02 & KTB-04 Wells

KTB – B is the most eastern, well pad location, 24,134 m2 in area is where KTB – 02 & 04 wells are located. The well pad is located in an agricultural area similar to KTB Well Pad A with an associated pipeline right of way to the eastern perimeter of the CPP also, a distance of approximately 3,900 meters. The pipeline right of way merges with the KTB - A, flow lines along this route.

There are 2 – 6 inch flow lines from the wells at KTB – B Well Pad to the CPP.

KTB – B well pad location has been selected as the CO_2 pilot injection candidate well location and all planning both surface and subsurface have been made from this location.

Figure 23: KTB-B Well Pad Location and Pipeline ROW

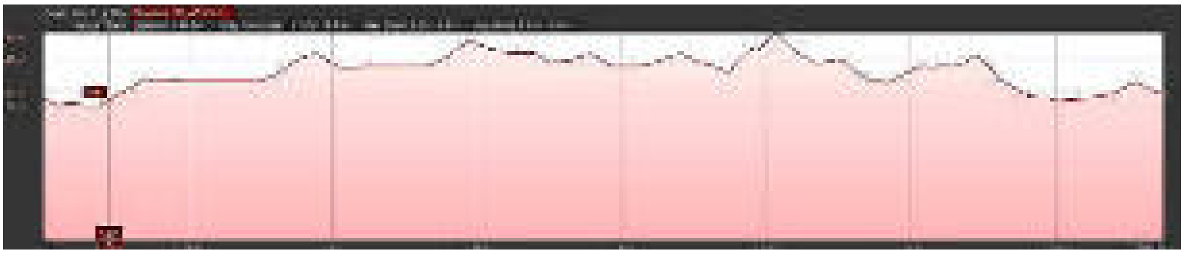


Figure 24: KTB-B to Gundih CPP Elevation Profile

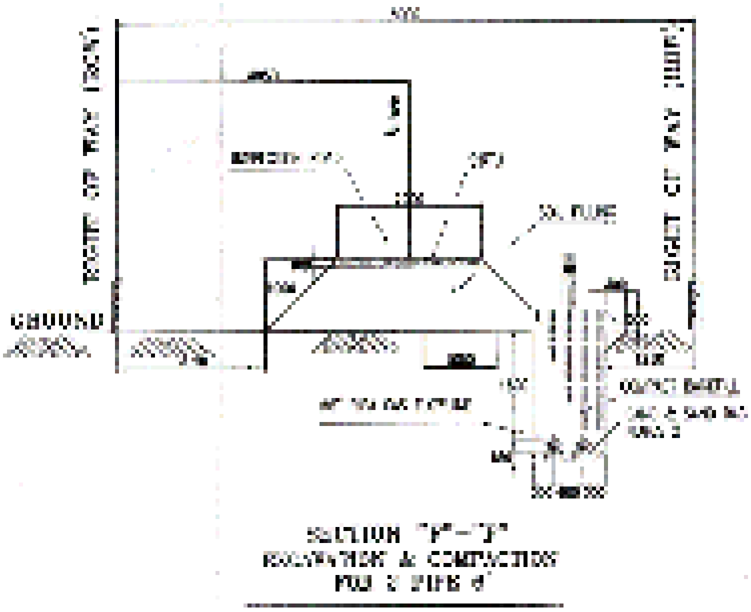


Figure 25: ROW Cross Section: KTB-B to Gundih CPP

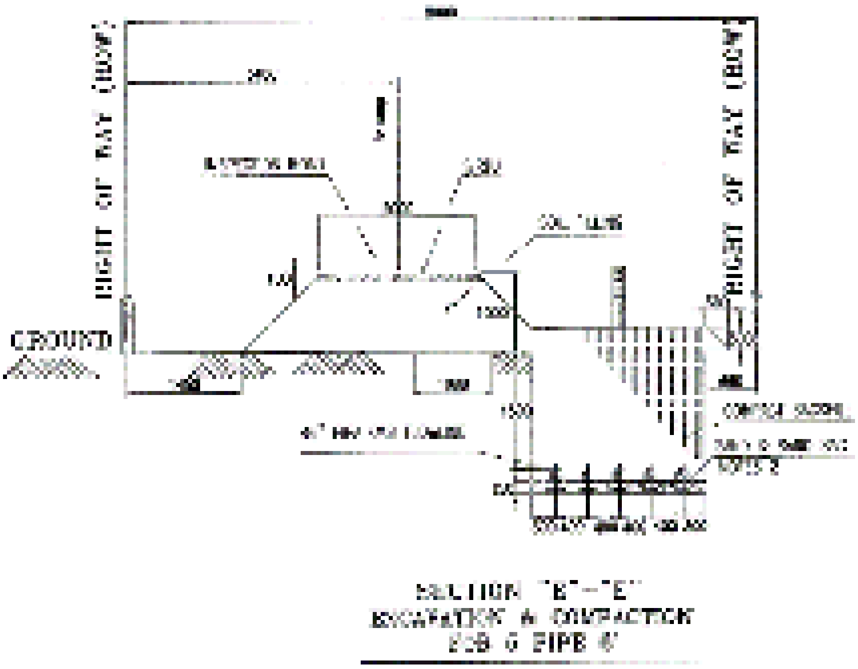


Figure 26: ROW Cross Section KTB-A/KTB-B Junction Point to Gundih CPP

The flowlines from KTB – A & B well pads merge at the junction shown and five flowlines continue to the CPP perimeter boundary and production manifold.

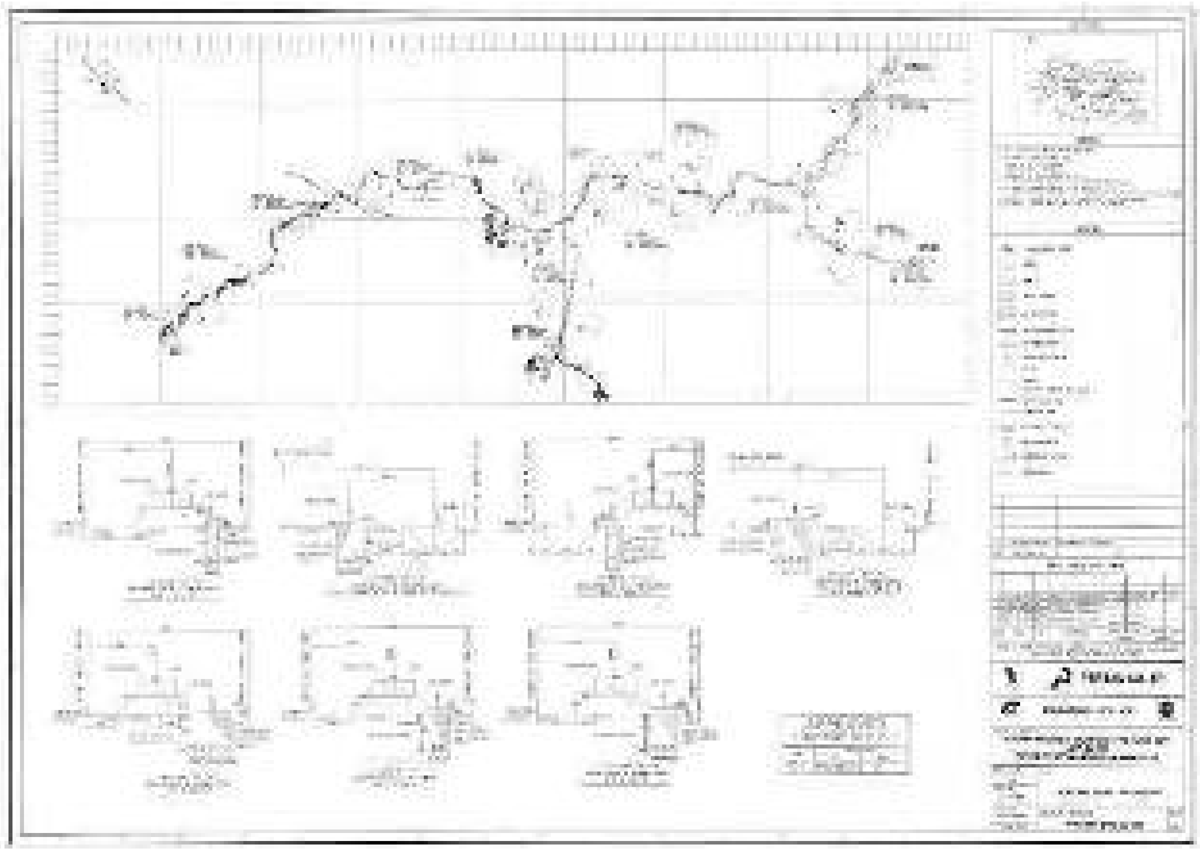


Figure 27: Gundih General Flowline & ROW Layout

Gundih Central Processing Plant (CPP)

Construction of the Gundih CPP started June 2011 and operations commenced December 2013. The CPP has now been operating for slightly over 4 years, at the time of writing, and is designed to process 70 mmscfd. Typical feed gas comprises 23% CO_2 and 6,000 ppm H_2S (Varying values of H_2S concentration have been reported in the feed gas. Actual H_2S values need to be confirmed for process design purposes). 50 mmscfd of sales gas is piped to Tambaj Lorok Power Plant, Semarang located approximately 140 kilometers from the Gundih CPP.

Gundih CPP is estimated to produce 800 metric tons per day (MT/day) of emitted CO_2 (15.2 mmscfd). Prior to emitting acid gas to atmosphere it is passed through a Bio-Sulfur Recovery Unit (Bio-SRU) process that converts the H_2S to elemental sulfur that is bagged and packaged. The remaining gases are oxidized in the Thermal Oxidizing System to comply with environmental regulations for gas emissions (max. 2,600 ppm SO_2). Bleed water from the Bio-SRU is treated in the Wet Air Oxidization Unit along with the caustic spent in the Caustic Treatment Unit. This water is then treated for disposal well injection along with produced water from the Gas Separation Unit.

Two CO_2 streams have been identified, at Gundih CPP, as potential feed streams for CO_2 capture. These streams are the outlet of the Bio-SRU (Stream 1) and the outlet of the Thermal Oxidation Unit (TOX) (Stream 2). The outlet stream of the Bio-SRU contains 95% CO_2, though odorous sulfur compounds (H_2S and mercaptans) are present in small quantities and are required to be removed before releasing the CO_2 to the atmosphere. These odorous, sulfur compounds are oxidized (converted to SO_2) in the TOX. As it is the outlet of a combustion system, the stream consists of CO_2 diluted with air (N_2 and excess O_2) and SO_2 in small quantities.

The Bio-SRU (Stream 1) emits a high CO_2 stream with diluted impurities although additional CO_2 purification is required to remove odorous sulfur components and waste water before the CO_2 conditioning unit. A post combustion capture unit such as an amine capture column is required should the TOX (Stream 2) be selected to separate CO_2 from the associated gases such as N_2, O_2 and SO_2. An economic evaluation is required, based on the outlet discharge of Stream 1 and 2 to determine which method is the most feasible taking into account all operational factors.

Depending on the technically feasible option selected there is sufficient available land area to install a CO_2 Purification Unit, CO_2 Compression/Liquefaction Unit, and CO_2 storage along with the selected mode of CO_2 transportation at the Gundih CPP site. The exact location at the CPP site has yet to be determined, however, there are a number of location options available within the CPP.

Figure 28: Gundih CPP Layout

BATTELLE

It can be done

TITLE: **Battelle - ADB: Gundih Pilot Project**
DESC: **Capital cost estimate for CO2 Capture and Treatment**
OPTION 1: 30 TPD Capacity

Ver 0 ########
Trimeric Corporation

					COMMENTS
MAJOR EQUIPMENT AND COST	(MEC)				
TOTAL EQ COST				$1,553,045	Vendor Budgetary Quotes, skidded equipment only
	TOTAL = A			$1,553,045	
	TYPICAL RANGE	FACTOR			
INSTALLATION COSTS					
SITE/FOUNDATIONS	0.06-0.2	0.1 X A		$155,305	Use low end of range, eq is skidded mostly
STRUCTURES	0.15-0.3	0.08 X A		$124,244	Limited need for structure for skids, use low value
EQUIPMENT ERECTION	0.15-0.3	0.04 X A		$62,122	Mostly putting skids in place, use low number
PIPING	0.4-1.1	0.2 X A		$310,609	Limited piping needs, low value
INSULATION	0-0.06	X A		$0	
PAINT	0.05-0.1	0.04 X A		$62,122	Skids should be painted, low end value
FIRE PROTECTION	0.01-0.06	0.015 X A		$23,296	H2S present in existing plant at tie-in
INSTRUMENTS	0.4-0.8	0.15 X A		$232,957	Low value, skids instrumented
ELECTRICAL	0.15-0.4	0.1 X A		$155,305	skids pre wired, use lower value, but add some for switchgear
	TOTAL INSTALLATION			$1,125,958	
PIPELINE - CPP TO INJECTION					
B = BASE COST = A + INSTALLATION		=		$2,679,003	
VAT TAX + Income tax	0.1A+0.025(B-A)		$183,453		default values
FREIGHT	0.05A		$77,652		default values
CONTRACTORS FEES	0.2(B-A)		$225,192		default values
			$486,297	$486,297	
C= SUBTOTAL = B+TAX+FREIGHT+FEES				$3,165,300	
ENGINEERING	FACTOR =	0.06 X SUBTOTAL		$189,918	use low value since skid cost includes vendor engr
INSPECTION/OVERSIGH	FACTOR =	0.03 X SUBTOTAL		$94,959	
CONTINGENCIES	FACTOR =	0.2 X SUBTOTAL		$633,060	Use typical pre-FEED contingency
TOTAL C+ENGR+CONTINGENCIES				$4,083,237	
Additional Equipment without associated installation costs Subtract the value here of any salvage used equipment					
PROJECT COST - TIC ************************				**$4,083,237**	OVERALL FACTOR = 2.6
			SulfaTreat 2242	91,730	
			Glycol Fill	15,000	
			Installation		
TOTAL PROJECT COST ********************************				**$4,189,967**	

TITLE:	**Battelle - ADB: Gundih Pilot Project**				Ver 0 ########
DESC:	**Capital cost estimate for CO2 Capture and Treatment**				Trimeric Corporation
	OPTION 2: 150 TPD Capacity				
MAJOR EQUIPMENT AND COST	(MEC)				**COMMENTS**
TOTAL EQ COST				$3,806,104	Vendor Budgetary Quotes, skidded equipment only
	TOTAL = A			$3,806,104	
	TYPICAL				
INSTALLATION COSTS	RANGE	FACTOR			
SITE/FOUNDATIONS	0.06-0.2	0.06 X A		$228,366	Use low end of range, eq is skidded mostly
STRUCTURES	0.15-0.3	0.05 X A		$190,305	Limited need for structure for skids, use low value
EQUIPMENT ERECTION	0.15-0.3	0.03 X A		$114,183	Mostly putting skids in place, use low number
PIPING	0.4-1.1	0.12 X A		$456,732	Limited piping needs, low value
INSULATION	0-0.06	X A			
PAINT	0.05-0.1	0.02 X A		$76,122	Skids should be painted, low end value
FIRE PROTECTION	0.01-0.06	0.01 X A		$38,061	H2S present in existing plant at tie-in
INSTRUMENTS	0.4-0.8	0.08 X A		$304,488	Low value, skids instrumented
ELECTRICAL	0.15-0.4	0.06 X A		$228,366	skids pre wired, use lower value, large engines to be NG drive
	TOTAL INSTALLATION			$1,636,625	
PIPELINE - CPP TO INJECTION					
B = BASE COST = A + INSTALLATION		=		$5,442,729	
VAT TAX + Income tax 0.1A+0.025(B-A)			$421,526		default values
FREIGHT 0.05A			$190,305		default values
CONTRACTORS FEES 0.2(B-A)			$327,325		default values
			$939,156	$939,156	
C= SUBTOTAL = B+TAX+FREIGHT+FEES				$6,381,885	
ENGINEERING	FACTOR =	0.04 X SUBTOTAL		$255,275	use low value since skid cost includes vendor engr
INSPECTION/OVERSIGH	FACTOR =	0.02 X SUBTOTAL		$127,638	
CONTINGENCIES	FACTOR =	0.2 X SUBTOTAL		$1,276,377	Use typical pre-FEED contingency
TOTAL C+ENGR+CONTINGENCIES				$8,041,175	
Additional Equipment without associated installation costs					
Subtract the value here of any salvage used equipment					
PROJECT COST - TIC *************************				**$8,041,175**	OVERALL FACTOR = 2.1
			SulfaTreat 2242	140,611	
			Glycol Fill	15,000	
			Installation		
TOTAL PROJECT COST ************************************				**$8,196,786**	

TITLE: Battelle - ADB: Gundih Pilot Project
DESC: Capital cost estimate for CO2 Capture and Treatment Well Location

Ver 0 ########
Trimeric Corporation

					COMMENTS
MAJOR EQUIPMENT AND COST	(MEC)				
TOTAL EQ COST				$100,000	Estimate of meter and SDV Both Sites
	TOTAL = A			$100,000	
	TYPICAL				
INSTALLATION COSTS	RANGE	FACTOR			
SITE/FOUNDATIONS	0.06-0.2	0.4 X A		$40,000	
STRUCTURES	0.15-0.3	0.15 X A		$15,000	pipe supports or vent
EQUIPMENT ERECTION	0.15-0.3	0.1 X A		$10,000	
PIPING	0.4-1.1	0.5 X A		$50,000	open area, limited piping
INSULATION	0-0.06	0 X A		$0	
PAINT	0.05-0.1	0.1 X A		$10,000	limited piping
FIRE PROTECTION	0.01-0.06	0 X A		$0	
INSTRUMENTS	0.4-0.8	0.4 X A		$40,000	flow and P/T msmst
ELECTRICAL	0.15-0.4	0.25 X A		$25,000	
	TOTAL INSTALLATION			$190,000	
Communication - Fiberoptic				$50,000	
B = BASE COST = A + INSTALLATION		=		$340,000	
VAT TAX + Income tax 0.1A+0.025(B-A)			$14,750		default values
FREIGHT 0.05A			$5,000		default values
CONTRACTORS FEES 0.2(B-A)			$48,000		default values
			$67,750	$67,750	
C= SUBTOTAL = B+TAX+FREIGHT+FEES				$407,750	
ENGINEERING	FACTOR =	0.08 X SUBTOTAL		$32,620	use low value since skid cost includes vendor engr
INSPECTION/OVERSIGH	FACTOR =	0.06 X SUBTOTAL		$24,465	
CONTINGENCIES	FACTOR =	0.2 X SUBTOTAL		$81,550.00	Use typical pre-FEED contingency
TOTAL C+ENGR+CONTINGENCIES				$496,385	
Additional Equipment without associated installation costs Subtract the value here of any salvage used equipment					
PROJECT COST - TIC ************************				**$496,385**	OVERALL FACTOR = 5.0
TOTAL PROJECT COST ********************************				**$496,385**	

SKK MIGAS

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER

SCHEDULE №. 19

OPERATOR	: Pertamina EP	PROJECT TYPE :	CCS Pilot Injection Well	AFE № :	TBA
CONTRACT AREA	: Gundhi Field	WELL NAME :	CCS - 1		
CONTRACT AREA №	: Pertamina Asset IV	WELL TYPE :	Onshore CCS Pilot Injection Well	DATE :	27-Aug-2019
		PLATFORM/TRIPOD :	Onshore Drilling Unit		
		FIELD/STRUCTURE :	Gundih Field/Kedung Tuban		
		BASIN :	Java Basin		IN US DOLLARS

LOCATION :	KTB-B V	SURFACE LAT :	7°12'18.28"S	LONGITUDE :	111°29'34.27"E	UBSURFACE LAT :	TBA	LONGITUDE :	TBA
WATER DEPTH :	N/A	ELEVATION :	TBA	CONTRACTOR :	TBA	RIG NAME :	TBA	RIG TYPE :	Land Rig

			PROGRAM		ACTUAL	
SPUD DATE :	TBA	RIG DAYS :	70.42	days		days
COMPLETION DATE :	TBA	TOTAL DEPTH (ft.) :	13,451	feet		feet
PLACED IN SERVICE :	TBA	WELL COST PER FOOT :	$1,230.90	US$/ft		US$/ft
DRILLING DAYS :	TBA	WELL COST PER DAY :	$235,114.23	US$/Day		US$/Day

CLOSE OUT DATE :

COMPLETION TYPE : CO_2 Injection & Monitoring Completion

WELL STATUS :

LINE №	DESCRIPTION	WORK PROGRAM AND BUDGET	REVISED BUDGET	FINAL BUDGET	ACTUAL EXPENDITURES PRIOR YEARS	ACTUAL EXPENDITURES COMMITTED	ACTUAL EXPENDITURES EXPENDITURE TO DATE	ACTUAL OVER /(UNDER) BUDGET	PERCENTAGE OVER /(UNDER) BUDGET
		1	2	3	4	5	6	7	8
1	TANGIBLE COSTS								
2	CASING	1,313,659						(1,313,659)	(100.00)
3	CASING ACCESSORIES	58,570						(58,570)	(100.00)
4	TUBING	144,104						(144,104)	(100.00)
5	WELL EQUIPMENT - SURFACE	313,548						(313,548)	(100.00)
6	WELL EQUIPMENT - SUBSURFACE	239,415						(239,415)	(100.00)
7	OTHER TANGIBLE COSTS	0						0	
8								0	
9	TOTAL TANGIBLE COSTS	$2,069,296	-	-	-	-	-	(2,069,296)	(100.00)
10									
11	INTANGIBLE COSTS								
12	PREPARATION AND TERMINATION								
13	SURVEYS	6,000						(6,000)	(100.00)
14	LOCATION STAKING AND POSITIONING	36,816						(36,816)	(100.00)
15	WELLSITE AND ACCESS ROAD PREPARATION	65,000						(65,000)	(100.00)
16	SERVICE LINES& COMMUNICATIONS	20,364						(20,364)	(100.00)
17	WATER SYSTEMS	0						0	
18	RIGGING UP / RIGGING DOWN	0						0	
19								0	
20	SUBTOTAL	$128,180	-	-	-	-	-	(128,180)	(100.00)
21									
22	DRILLING / WORKOVER OPERATIONS								
23	CONTRACT RIG	4,918,325						(4,918,325)	(100.00)
24	DRILLING RIG CREW / CONTRACT RIG CREW	0						0	
25	MUD, CHEMICAL & ENGINEERING SERVICES	650,185						(650,185)	(100.00)
26	WATER	7,000						(7,000)	(100.00)
27	BITS, REAMERS AND CORE HEADS	147,000						(147,000)	(100.00)
28	EQUIPMENT RENTALS	506,595						(506,595)	(100.00)
29	DIRECTIONAL DRILLING AND SURVEYS	1,924,882						(1,924,882)	(100.00)
30	DIVING SERVICES	0						0	
31	CASING INSTALLATION	428,086						(428,086)	(100.00)
32	CEMENT, CEMENTING AND PUMP FEES	1,507,900						(1,507,900)	(100.00)
33	INSPECTIONS	27,000						(27,000)	(100.00)
34									
35	SUBTOTAL	$10,116,972	-	-	-	-	-	(10,116,972)	(100.00)
36									
37	FORMATION EVALUATION								
38	CORING	269,950						(269,950)	(100.00)
39	MUD LOGGING SERVICES	282,874						(282,874)	(100.00)
40	DRILLSTEM TESTS	0						0	
41	OPEN HOLE ELECTRICAL LOGGING SERVICES	1,764,180						(1,764,180)	(100.00)
42									
43	SUBTOTAL	$2,317,004	-	-	-	-	-	(2,317,004)	(100.00)
44									
45	COMPLETION								
46	CASING, LINER AND TUBING INSTALLATION	0						0	
47	CEMENT, CEMENTING AND PUMP FEES	0						0	
48	CASED HOLE ELECTRICAL LOGGING SERVICES	145,280						(145,280)	(100.00)
49	PERFORATING AND WIRELINE SERVICES	52,500						(52,500)	(100.00)
50	STIMULATION TREATMENT	0						0	
51	PRODUCTION TESTS	0						0	
52									
53	SUBTOTAL	$197,780	-	-	-	-	-	(197,780)	(100.00)
54									
55	GENERAL								
56	SUPERVISION	197,549						(197,549)	(100.00)
57	INSURANCE	3,000						(3,000)	(100.00)
58	PERMITS AND FEES	30,000						(30,000)	(100.00)
59	MARINE RENTAL AND CHARTERS	0						0	
60	HELICOPTERS AND AVIATION CHARGES	0						0	
61	LAND TRANSPORTATION	30,000						(30,000)	(100.00)
62	OTHER TRANSPORTATION	25,085						(25,085)	(100.00)
63	FUEL AND LUBRICANTS	1,339,187						(1,339,187)	(100.00)
64	CAMP FACILITIES	51,331						(51,331)	(100.00)
65	ALLOCATED OVERHEADS - FIELD OFFICE	7,000						(7,000)	(100.00)
66	ALLOCATED OVERHEADS - JAKARTA OFFICE	45,000						(45,000)	(100.00)
67	ALLOCATED OVERHEADS - OVERSEAS	0						0	
68	TECHNICAL SERVICES FROM ABROAD	0						0	
69									
70	SUBTOTAL	$1,728,151	-	-	-	-	-	(1,728,151)	(100.00)
71									
72	TOTAL INTANGIBLE COSTS	$14,488,088	-	-	-	-	-	(14,488,088)	(100.00)
73									
74	T O T A L C O S T S	$16,557,383	-	-	-	-	-	(16,557,383)	(100.00)
75									
76	TIME PHASED EXPENDITURES								
77	THIS YEAR 2019					-	-	0	
78	FUTURE YEARS 2020	$16,557,383							
79	TOTAL	$16,557,383							

OPERATOR

APPROVED BY :

POSITION :

DATE :

SKK MIGAS

APPROVED BY :

POSITION :

DATE :

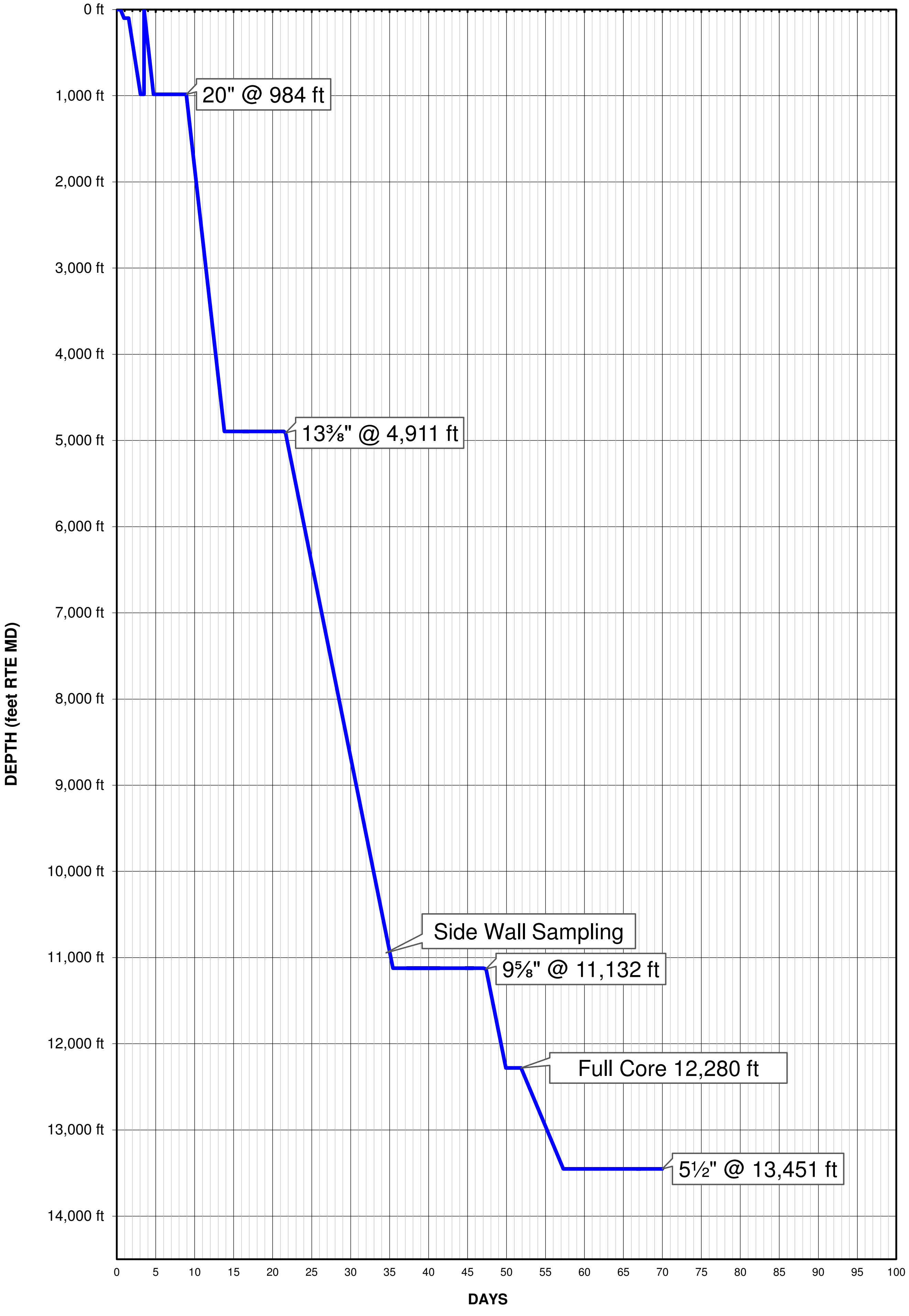
REMARKS

CCS PILOT WELL DRILLING, EVALUATION & COMPLETION BUDGETARY AFE (feet)

Revision Print Date: 27-Aug-19

SKK MIGAS

GUNDIH CCS - 1: PILOT CO_2 INJECTION WELL
TIME VERSUS MEASURED DEPTH PLOT



SKK MIGAS

SCHEDULE №. 19

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER

OPERATOR	: Pertamina EP	PROJECT TYPE :	CCS Pilot Injection Well	AFE № :	TBA
CONTRACT AREA	: Gundhi Field	WELL NAME :	CCS - 1		
CONTRACT AREA №	: Pertamina Asset IV	WELL TYPE :	Onshore CCS Pilot Injection Well	DATE :	27-Aug-2019
		PLATFORM/TRIPOD :	Onshore Drilling Unit		
		FIELD/STRUCTURE :	Gundih Field/Kedung Tuban		
		BASIN :	Java Basin		IN US DOLLARS

LOCATION :	KTB-B V	SURFACE LAT :	7°12'18.28"S	LONGITUDE :	111°29'34.27"E	UBSURFACE LAT :	TBA
LONGITUDE :	TBA						
WATER DEPTH :	N/A	ELEVATION :	TBA	CONTRACTOR :	TBA	RIG NAME :	TBA
RIG TYPE :	Land Rig						

			PROGRAM		ACTUAL	
SPUD DATE :	TBA	RIG DAYS :	70.42	days		days
COMPLETION DATE :	TBA	TOTAL DEPTH (m.) :	4,100	meters		meters
PLACED IN SERVICE :	TBA	WELL COST PER METER :	$4,038.39	US$/m		US$/m
DRILLING DAYS :	TBA	WELL COST PER DAY :	$235,114.23	US$/Day		US$/Day

CLOSE OUT DATE :

COMPLETION TYPE : CO_2 Injection & Monitoring Completion

WELL STATUS :

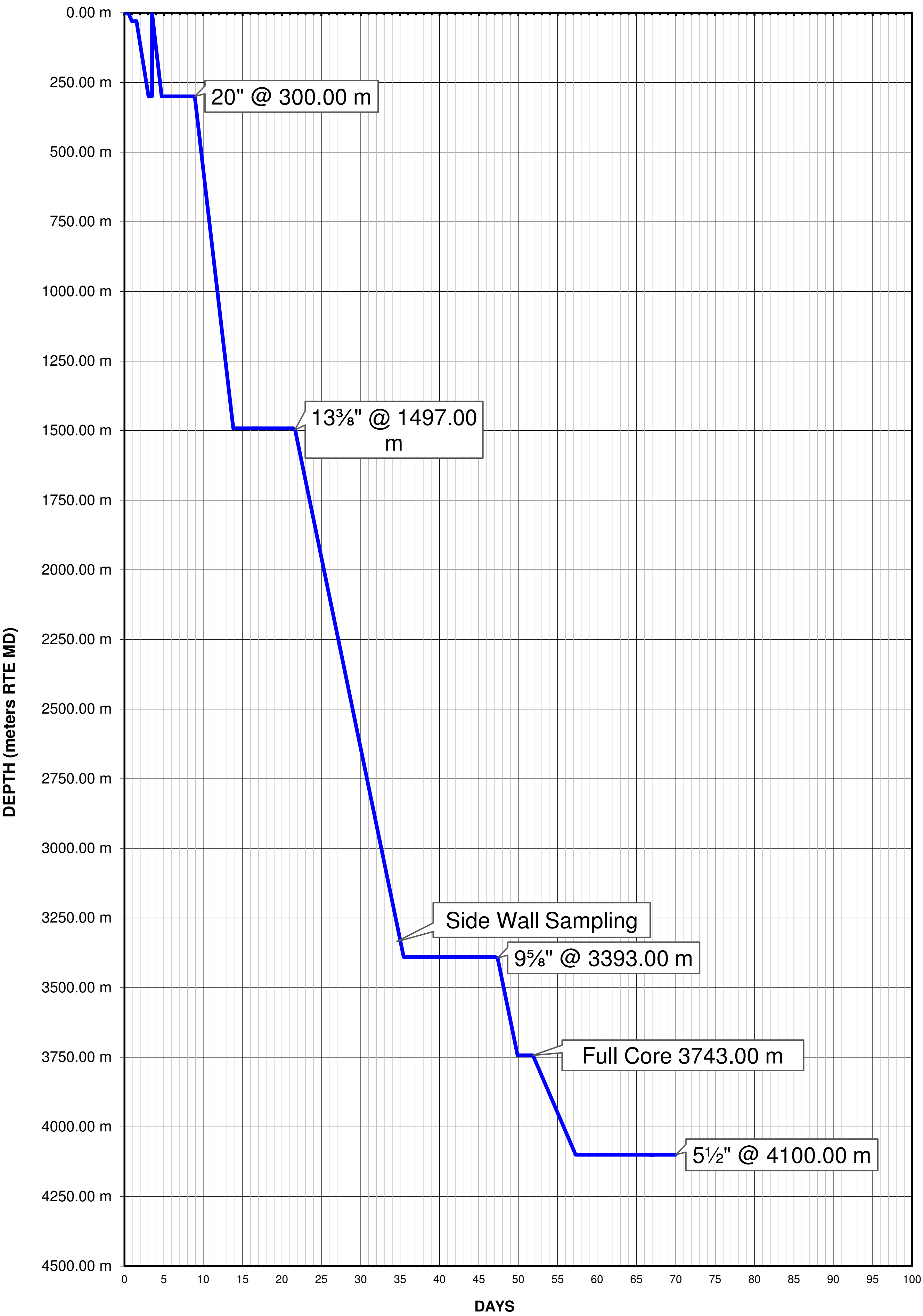
LINE №	DESCRIPTION	WORK PROGRAM AND BUDGET	REVISED BUDGET	FINAL BUDGET	ACTUAL EXPENDITURES: PRIOR YEARS	ACTUAL EXPENDITURES: COMMITTED	ACTUAL EXPENDITURES: EXPENDITURE TO DATE	ACTUAL OVER /(UNDER) BUDGET	PERCENTAGE OVER /(UNDER) BUDGET
		1	2	3	4	5	6	7	8
1	TANGIBLE COSTS								
2	CASING	1,313,659						(1,313,659)	(100.00)
3	CASING ACCESSORIES	58,570						(58,570)	(100.00)
4	TUBING	144,104						(144,104)	(100.00)
5	WELL EQUIPMENT - SURFACE	313,548						(313,548)	(100.00)
6	WELL EQUIPMENT - SUBSURFACE	239,415						(239,415)	(100.00)
7	OTHER TANGIBLE COSTS	0						0	
8								0	
9	TOTAL TANGIBLE COSTS	$2,069,296	-	-	-	-	-	(2,069,296)	(100.00)
10									
11	INTANGIBLE COSTS								
12	PREPARATION AND TERMINATION								
13	SURVEYS	6,000						(6,000)	(100.00)
14	LOCATION STAKING AND POSITIONING	36,816						(36,816)	(100.00)
15	WELLSITE AND ACCESS ROAD PREPARATION	65,000						(65,000)	(100.00)
16	SERVICE LINES& COMMUNICATIONS	20,364						(20,364)	(100.00)
17	WATER SYSTEMS	0						0	
18	RIGGING UP / RIGGING DOWN	0						0	
19								0	
20	SUBTOTAL	$128,180	-	-	-	-	-	(128,180)	(100.00)
21									
22	DRILLING / WORKOVER OPERATIONS								
23	CONTRACT RIG	4,918,325						(4,918,325)	(100.00)
24	DRILLING RIG CREW / CONTRACT RIG CREW	0						0	
25	MUD, CHEMICAL & ENGINEERING SERVICES	650,185						(650,185)	(100.00)
26	WATER	7,000						(7,000)	(100.00)
27	BITS, REAMERS AND CORE HEADS	147,000						(147,000)	(100.00)
28	EQUIPMENT RENTALS	506,595						(506,595)	(100.00)
29	DIRECTIONAL DRILLING AND SURVEYS	1,924,882						(1,924,882)	(100.00)
30	DIVING SERVICES	0						0	
31	CASING INSTALLATION	428,086						(428,086)	(100.00)
32	CEMENT, CEMENTING AND PUMP FEES	1,507,900						(1,507,900)	(100.00)
33	INSPECTIONS	27,000						(27,000)	(100.00)
34									
35	SUBTOTAL	$10,116,972	-	-	-	-	-	(10,116,972)	(100.00)
36									
37	FORMATION EVALUATION								
38	CORING	269,950						(269,950)	(100.00)
39	MUD LOGGING SERVICES	282,874						(282,874)	(100.00)
40	DRILLSTEM TESTS	0						0	
41	OPEN HOLE ELECTRICAL LOGGING SERVICES	1,764,180						(1,764,180)	(100.00)
42									
43	SUBTOTAL	$2,317,004	-	-	-	-	-	(2,317,004)	(100.00)
44									
45	COMPLETION								
46	CASING, LINER AND TUBING INSTALLATION	0						0	
47	CEMENT, CEMENTING AND PUMP FEES	0						0	
48	CASED HOLE ELECTRICAL LOGGING SERVICES	145,280						(145,280)	(100.00)
49	PERFORATING AND WIRELINE SERVICES	52,500						(52,500)	(100.00)
50	STIMULATION TREATMENT	0						0	
51	PRODUCTION TESTS	0						0	
52									
53	SUBTOTAL	$197,780	-	-	-	-	-	(197,780)	(100.00)
54									
55	GENERAL								
56	SUPERVISION	197,549						(197,549)	(100.00)
57	INSURANCE	3,000						(3,000)	(100.00)
58	PERMITS AND FEES	30,000						(30,000)	(100.00)
59	MARINE RENTAL AND CHARTERS	0						0	
60	HELICOPTERS AND AVIATION CHARGES	0						0	
61	LAND TRANSPORTATION	30,000						(30,000)	(100.00)
62	OTHER TRANSPORTATION	25,085						(25,085)	(100.00)
63	FUEL AND LUBRICANTS	1,339,187						(1,339,187)	(100.00)
64	CAMP FACILITIES	51,331						(51,331)	(100.00)
65	ALLOCATED OVERHEADS - FIELD OFFICE	7,000						(7,000)	(100.00)
66	ALLOCATED OVERHEADS - JAKARTA OFFICE	45,000						(45,000)	(100.00)
67	ALLOCATED OVERHEADS - OVERSEAS	0						0	
68	TECHNICAL SERVICES FROM ABROAD	0						0	
69									
70	SUBTOTAL	$1,728,151	-	-	-	-	-	(1,728,151)	(100.00)
71									
72	TOTAL INTANGIBLE COSTS	$14,488,088	-	-	-	-	-	(14,488,088)	(100.00)
73									
74	T O T A L C O S T S	$16,557,383	-	-	-	-	-	(16,557,383)	(100.00)
75									
76	TIME PHASED EXPENDITURES								
77	THIS YEAR 2019					-	-	0	
78	FUTURE YEARS 2020	$16,557,383							
79	TOTAL	$16,557,383							

OPERATOR	APPROVED BY : POSITION : DATE :	REMARKS
SKK MIGAS	APPROVED BY : POSITION : DATE :	CCS PILOT WELL DRILLING, EVALUATION & COMPLETION BUDGETARY AFE (meters)

Revision Print Date: 27-Aug-19

SKK MIGAS

GUNDIH CCS - 1: PILOT CO_2 INJECTION WELL
TIME VERSUS MEASURED DEPTH PLOT



BUDGET SCHEDULE № 20

SKK MIGAS

PRODUCTION SHARING CONTRACT

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER MATERIAL LIST

OPERATOR :	**Pertamina EP**	PROJECT TYPE :	**CCS Pilot Injection Well**	AFE No. :	**TBA**
CONTRACT AREA :	**Gundhi Field**	WELL TYPE :	**Onshore CCS Pilot Injection Well**		
CONTRACT AREA :	**Pertamina Asset IV**	FIELD STRUCTURE :	**Gundih Field/Kedung Tuban**	DATE :	**27-Aug-19**
		WELL NAME :	**CCS - 1**		

Line №	DESCRIPTION	UNIT OF ISSUE	BUDGET QUANTITY	BUDGET UNIT PRICE	BUDGET TOTAL	ACTUAL – ISSUED FROM STOCK QUANTITY	ISSUED FROM STOCK UNIT PRICE	ISSUED FROM STOCK TOTAL	ACTUAL – NEW PURCHASES QUANTITY	NEW PURCHASES UNIT PRICE	NEW PURCHASES TOTAL	GRAND TOTAL	ACTUAL OVER/UNDER QUANTITY	ACTUAL OVER/UNDER AMOUNT	SURPLUS MATERIAL QUANTITY	SURPLUS MATERIAL DISPOSITION
		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	TANGIBLES															
	CASING															
	Size Grade Connection															
1	30 inchCasing	feet	90	$372.00	$33,480											
2	30 inch Drive Sub	each	1	$16,900.00	$16,900											
3	Drive Shoe Joint	each	1	$15,700.00	$15,700											
4	20 inch Cas 133 ppf, K-55 BTC	feet	1,082	$113.00	$122,311											
5	20 inch Float Shoe BTC	each	1	$11,300.00	$11,300											
6	Float Shoe Stinger BTC	each	1	$2,600.00	$2,600											
7	13⅜ inch Ca 68 ppf, K-55 BTC	feet	4,993	$82.00	$409,418											
8	9⅝ inch line 53.5 ppf, N-80 LTC	feet	6,629	$56.00	$371,230											
	with 500 ft overlap into 13 ⅜ inch casing															
9	5½ inch 20 ppf, P110 LTC	feet	10,335	$32.00	$330,720											
	long string to surface															
	CASING COST				**$1,313,659**											
	VALUE ADDED TAX (VAT)		0%		$0											
	TOTAL FOR CASING				**$1,313,659**											

Operator

Approved By: ____________ Position: ____________ Date: August 27, 2019

Approved By: ____________ Position: ____________ Date: ____________

SKK MIGAS

Approved By: ____________ Position ____________ Date: ____________

BUDGET SCHEDULE No. 20

SKK MIGAS

PRODUCTION SHARING CONTRACT

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER MATERIAL LIST

OPERATOR	:	**Pertamina EP**	PROJECT TYPE	:	**CCS Pilot Injection Well**
CONTRACT AREA	:	**Gundhi Field**	WELL TYPE	:	**Onshore CCS Pilot Injection Well**
CONTRACT AREA	:	**Pertamina Asset IV**	FIELD STRUCTURE	:	**Gundih Field/Kedung Tuban**
			WELL NAME	:	**CCS - 1**

AFE No. : **TBA**

DATE : **27-Aug-19**

Line №	DESCRIPTION		BUDGET			ACTUAL							ACTUAL OVER/UNDER		SURPLUS MATERIAL	
						ISSUED FROM STOCK			NEW PURCHASES							
		UNIT OF ISSUE	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	GRAND TOTAL	QUANTITY	AMOUNT	QUANTITY	DISPOSITION
		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2	**CASING ACCESSORIES**															
1	20 inch Stab-In Float Shoe	each	1	3744	$3,744											
2	20 inch Drill Pipe Centralizers	each	8	329	$2,632											
3	13⅜ inch float shoe	each	1	1,291	$1,291											
4	13⅜ inch float collar	set	1	2,582	$2,582											
5	13⅜ inch top & bottom plugs	set	1	1,911	$1,911											
6	13⅜ inch centralizers & stop collars	each	20	359	$7,180											
	11-3/4 inch float shoe	each		2,800	$0											
	11-3/4 inch floar collar & accessories	set		3,250	$0											
	11-3/4 inch centralizers	each		138	$0											
7	9⅝ inch float shoe	each	1	2,300	$2,300											
8	9⅝ inch float collar	set	1	3,750	$3,750											
9	9⅝ inch positive stand-off centralizers	each	40	228	$9,120											
10	5½ inch float shoe	each	1	2,000	$2,000											
11	5½ inch float collar	each	1	2,500	$2,500											
12	5½ inch multi-tage cement collar	each	1	15,000	$15,000											
13	5½ inch cement plugs	each	1	1,000	$1,000											
14	5½ inch positive stand-off centralizers	each	20	178	$3,560											
	CASING ACCESSORIES COST				**$58,570**											
	VALUE ADDED TAX (VAT)		0%		$0											
	TOTAL FOR CASING ACCESSORIES				**$58,570**											

Operator

Approved By: ____________ Position: ____________ Date: **27-Aug-19**

Approved By: ____________ Position: ____________ Date: ____________

SKK MIGAS

Approved By: ____________ Position ____________ Date: ____________

SKK MIGAS

PRODUCTION SHARING CONTRACT

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER MATERIAL LIST

OPERATOR	: **Pertamina EP**	PROJECT TYPE	: **CCS Pilot Injection Well**	AFE №	: **TBA**
CONTRACT AREA	: **Gundhi Field**	WELL TYPE	: **Onshore CCS Pilot Injection Well**		
CONTRACT AREA	: **Pertamina Asset IV**	FIELD STRUCTURE	: **Gundih Field/Kedung Tuban**	DATE	: **27-Aug-19**
		WELL NAME	: **CCS - 1**		

Line №	DESCRIPTION		UNIT OF ISSUE	BUDGET			ACTUAL							ACTUAL OVER/UNDER		SURPLUS MATERIAL	
							ISSUED FROM STOCK			NEW PURCHASES							
				QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	GRAND TOTAL	QUANTITY	AMOUNT	QUANTITY	DISPOSITION
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
3	**TUBING**																
1	2⅞ inch	8.6 ppf N-80, NUE	ft	13,451	$10.71	$144,104											
	TOTAL TUBING					**$144,104**											

Operator

Approved By: ____________ Position: ____________ Date: **27-Aug-19**

Approved By: ____________ Position: ____________ Date: ____________

SKK MIGAS

Approved By: ____________ Position ____________ Date: ____________

SKK MIGAS

BUDGET SCHEDULE No. 20

PRODUCTION SHARING CONTRACT

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER MATERIAL LIST

OPERATOR	: Pertamina EP	PROJECT TYPE	: CCS Pilot Injection Well	AFE No.	: TBA
CONTRACT AREA	: Gundhi Field	WELL TYPE	: Onshore CCS Pilot Injection Well		
CONTRACT AREA	: Pertamina Asset IV	FIELD STRUCTURE	: Gundih Field/Kedung Tuban	DATE	: 27-Aug-19
		WELL NAME	: CCS - 1		

Line №	DESCRIPTION		BUDGET			ACTUAL							ACTUAL OVER/UNDER		SURPLUS MATERIAL	
						ISSUED FROM STOCK			NEW PURCHASES							
		UNIT OF ISSUE	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	GRAND TOTAL	QUANTITY	AMOUNT	QUANTITY	DISPOSITION
		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
4	**WELL EQUIPMENT SURFACE**															
1	Wellhead Casing Head Assembly	set	1	35,732	$35,732											
2	Unihead Assembly specified for CO_2 injection & monitoring	set	1	77,860	$77,860											
2	Xmas Tree specified for CO_2 injection & monitoring	set	1	199,956	$199,956											
	TOTAL WELL EQUIPMENT SURFACE				$313,548											

Operator

SKK MIGAS

Approved By: ____________ Position: ____________ Date: August 27, 2019

Approved By: ____________ Position ____________ Date: ____________

Approved By: ____________ Position: ____________ Date ____________

SKK MIGAS BUDGET SCHEDULE№. 20

PRODUCTION SHARING CONTRACT

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER MATERIAL LIST

OPERATOR	:	**Pertamina EP**	PROJECT TYPE	:	**CCS Pilot Injection Well**	AFE№. : **TBA**
CONTRACT AREA	:	**Gundhi Field**	WELL TYPE	:	**Onshore CCS Pilot Injection Well**	
CONTRACT AREA No.	:	**Pertamina Asset IV**	FIELD STRUCTURE	:	**Gundih Field/Kedung Tuban**	DATE : **27-Aug-19**
			WELL NAME	:	**CCS - 1**	

Line №	DESCRIPTION		BUDGET			ACTUAL							ACTUAL OVER/UNDER		SURPLUS MATERIAL	
						ISSUED FROM STOCK			NEW PURCHASES							
		UNIT OF ISSUE	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	QUANTITY	UNIT PRICE	TOTAL	GRAND TOTAL	QUANTITY	AMOUNT	QUANTITY	DISPOSITION
		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
5	**WELL EQUIPMENT SUB-SURFACE**															
1	Liner Hanger															
	9⅝ x 13⅜ inch Liner hanger, liner top packer & accessories	set	1	$161,415.00	$161,415											
2	Subsurface Safety Valve															
	SCSSSV - CO_2 Injection Specification	each	1	$50,000.00	$50,000											
	Control Line ¼ inch SS 316	foot	500													
3	Packer															
	5½ inch Non-feed through CO_2 Resistant, Re-settable 300 °F	each	1	$28,000.00	$28,000											
4	CO_2 Monitoring Equipment															
	Downhole Pressure/Temperature Monitoring Gauges	set														
	DAS Cable	foot														
	Single Conductor Encapsulated DTS 200 °C	foot														
	Cross-coupling Cable Protectors	each														
5	2⅞ inch Completion Equipment															
	Shear Out Ball Seat Sub w/wireline re-entry guide	each														
	Seating Nipplea (No-Go Profile)	each														
	Sliding Sleeve	each														
	Gauge Carrier	each														
	TOTAL WELL EQUIPMENT - SUBSURFACE				**$239,415**											

Operator

Approved By: ____________ Position: ____________ Date: **27-Aug-19**

Approved By: ____________ Position: ____________ Date ____________

SKK MIGAS

Approved By: ____________ Position ____________ Date: ____________

SKK MIGAS

SCHEDULE №. 19

AUTHORIZATION FOR EXPENDITURE - DRILLING AND WORKOVER

OPERATOR : Pertamina EP
CONTRACT AREA : Gundhi Field
CONTRACT AREA № : Pertamina Asset IV

PROJECT TYPE : CCS Pilot Injection Well
WELL NAME : CCS - 1
WELL TYPE : Onshore CCS Pilot Injection Well
PLATFORM/TRIPOD : Onshore Drilling Unit
FIELD/STRUCTURE : Gundih Field/Kedung Tuban
BASIN : Java Basin

AFE № : TBA
DATE : 27-Aug-2019

IN US DOLLARS

LOCATION : KTB-B V
WATER DEPTH : N/A
SURFACE LAT : 7°12'18.28"S
ELEVATION : TBA
LONGITUDE : 111°29'34.27"E
CONTRACTOR : TBA
UBSURFACE LAT : TBA
RIG NAME : TBA
LONGITUDE : TBA
RIG TYPE : Land Rig

		PROGRAM		ACTUAL	
SPUD DATE : TBA	RIG DAYS :	15.00	days		days
COMPLETION DATE : TBA	TOTAL DEPTH (m.) :		meters		meters
PLACED IN SERVICE : TBA	WELL COST PER METER :		US$/m		US$/m
DRILLING DAYS : TBA	WELL COST PER DAY :	$65,994.18	US$/Day		US$/Day

CLOSE OUT DATE :
COMPLETION TYPE : CO_2 Injection Well Abandonment
WELL STATUS : Abandoned

LINE №	DESCRIPTION	WORK PROGRAM AND BUDGET	REVISED BUDGET	FINAL BUDGET	ACTUAL EXPENDITURES: PRIOR YEARS	ACTUAL EXPENDITURES: COMMITTED	ACTUAL EXPENDITURES: EXPENDITURE TO DATE	ACTUAL OVER /(UNDER) BUDGET	PERCENTAGE OVER /(UNDER) BUDGET
		1	2	3	4	5	6	7	8
1	TANGIBLE COSTS								
2	CASING							0	
3	CASING ACCESSORIES							0	
4	TUBING							0	
5	WELL EQUIPMENT - SURFACE							0	
6	WELL EQUIPMENT - SUBSURFACE	50,000						(50,000)	(100.00)
7	OTHER TANGIBLE COSTS							0	
8								0	
9	TOTAL TANGIBLE COSTS	$50,000	-	-	-	-	-	(50,000)	(100.00)
10									
11	INTANGIBLE COSTS								
12	PREPARATION AND TERMINATION								
13	SURVEYS							0	
14	LOCATION STAKING AND POSITIONING							0	
15	WELLSITE AND ACCESS ROAD PREPARATION	29,250						(29,250)	(100.00)
16	SERVICE LINES& COMMUNICATIONS							0	
17	WATER SYSTEMS							0	
18	RIGGING UP / RIGGING DOWN							0	
19								0	
20	SUBTOTAL	$29,250	-	-	-	-	-	(29,250)	(100.00)
21									
22	DRILLING / WORKOVER OPERATIONS								
23	CONTRACT RIG	491,832						(491,832)	(100.00)
24	DRILLING RIG CREW / CONTRACT RIG CREW							0	
25	MUD, CHEMICAL & ENGINEERING SERVICES	97,528						(97,528)	(100.00)
26	WATER							0	
27	BITS, REAMERS AND CORE HEADS							0	
28	EQUIPMENT RENTALS	50,659						(50,659)	(100.00)
29	DIRECTIONAL DRILLING AND SURVEYS							0	
30	DIVING SERVICES							0	
31	CASING INSTALLATION							0	
32	CEMENT, CEMENTING AND PUMP FEES							0	
33	INSPECTIONS							0	
34									
35	SUBTOTAL	$640,020	-	-	-	-	-	(640,020)	(100.00)
36									
37	FORMATION EVALUATION								
38	CORING							0	
39	MUD LOGGING SERVICES							0	
40	DRILLSTEM TESTS							0	
41	OPEN HOLE ELECTRICAL LOGGING SERVICES							0	
42									
43	SUBTOTAL	$0	-	-	-	-	-	0	
44									
45	COMPLETION								
46	CASING, LINER AND TUBING INSTALLATION							0	
47	CEMENT, CEMENTING AND PUMP FEES	128,172						(128,172)	(100.00)
48	CASED HOLE ELECTRICAL LOGGING SERVICES							0	
49	PERFORATING AND WIRELINE SERVICES	42,300						(42,300)	(100.00)
50	STIMULATION TREATMENT							0	
51	PRODUCTION TESTS							0	
52									
53	SUBTOTAL	$170,472	-	-	-	-	-	(170,472)	(100.00)
54									
55	GENERAL								
56	SUPERVISION	9,877						(9,877)	(100.00)
57	INSURANCE							0	
58	PERMITS AND FEES							0	
59	MARINE RENTAL AND CHARTERS							0	
60	HELICOPTERS AND AVIATION CHARGES							0	
61	LAND TRANSPORTATION	5,100						(5,100)	(100.00)
62	OTHER TRANSPORTATION	2,508						(2,508)	(100.00)
63	FUEL AND LUBRICANTS	66,959						(66,959)	(100.00)
64	CAMP FACILITIES	8,726						(8,726)	(100.00)
65	ALLOCATED OVERHEADS - FIELD OFFICE	7,000						(7,000)	(100.00)
66	ALLOCATED OVERHEADS - JAKARTA OFFICE							0	
67	ALLOCATED OVERHEADS - OVERSEAS							0	
68	TECHNICAL SERVICES FROM ABROAD							0	
69									
70	SUBTOTAL	$100,172	-	-	-	-	-	(100,172)	(100.00)
71									
72	TOTAL INTANGIBLE COSTS	$939,913	-	-	-	-	-	(939,913)	(100.00)
73									
74	T O T A L C O S T S	$989,913	-	-	-	-	-	(989,913)	(100.00)
75									
76	TIME PHASED EXPENDITURES								
77	THIS YEAR 2019					-	-	0	
78	FUTURE YEARS 2020	$989,913							
79	TOTAL	$989,913							

OPERATOR
APPROVED BY :
POSITION :
DATE :

SKK MIGAS
APPROVED BY :
POSITION :
DATE :

REMARKS

CCS PILOT WELL ABANDONMENT BUDGETARY AFE (meters)

Revision Print Date: 27-Aug-19

SKK MIGAS

GUNDIH CCS PILOT WELL DRILLING PROGNOSIS

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DOCUMENT CONTROL*

Rev 1	27 August 2019	Updated Completion Equipment	David Jackman	DJJ
Rev 0	22 August 2019	Final for Issue	David Jackman	DJJ
Rev D	17 August 2019	Updated Draft	David Jackman	DJJ
Rev C	28 June 2019	Updated Draft	David Jackman	DJJ
Rev B	2 June 2019	Updated Draft	David Jackman	DJJ
Rev A	27 May 2019	Draft	David Jackman	DJJ
Rev	**Date**	**Amendment/Addition**	**Author**	**Initial**

*Draft documents are designated Rev A, B C, D etc.
Final Document issued is Rev 0
Revisions after Document 0 are designated Rev. 1, 2, 3, 4 etc.

Preamble

The Gundih pilot CCS project is intended to store 20,000 MT up to 100,000 MT of CO_2 over a two year period. Gundih project assets are owned and operated by Pertamina EP Asset IV and the project is funded by a Technical Assistance facility, Pilot Carbon Capture and Storage Activity in the Natural Gas Processing Sector (49204-002) from the Asian Development Bank (ADB) to the Republic of Indonesia for the purpose of evaluation and development of Carbon Capture and Storage (CCS) technologies for mitigation of CO_2 emissions from anthropogenic sources.

This drilling prognosis and conceptual well design is primarily based on KTB – 01, RBT – 03 & KDL - 01 well data and associated reports available and is intended to provide insight into the subsurface drilling challenges that can be expected when drilling a well in the geological structures found in the Gundih Field area.

In support in the selection of a bottom-hole target zone extensive subsurface geological modelling has been conducted by Institut Teknologi Bandung (ITB) in conjunction with Battelle Memorial Institute, in an effort to determine an optimum CO_2 geological storage structure that will provide the capability to monitor CO_2 storage and retention.

Additionally, focus is placed on current casing, drilling and cementing practices and where significant improvements can be made to enhance drilling performance and well integrity.

Objectives

Primary Objective

To drill, core and evaluate the carbon storage potential of the Kujung Formation below the known water contact depth in the Lower Kujung. On successful evaluation the well is to become a pilot carbon dioxide (CO_2) injection well.

This will involve:

(a) Log analysis of any potential CO_2 injection reservoir section(s).
(b) Full core or sidewall sampling of potential CO_2 injection zones and effective sealing cap rock.
(c) Sampling of fluid pressures from potential CO_2 injection, hydrocarbon and water bearing zones.
(d) Comprehensive injectivity testing of any potential CO_2 injection formations should analysis prove encouraging.

Secondary Objective

Upon reaching the 12¼-inch hole section TD at the base of the Tuban Formation and prior to setting the 9⅝-inch casing, evaluate the calciturbidite sequence typically found at the transition between the Tuban and Kujung Formations for potential for CO_2 sequestration.

This will involve:

(e) Log analysis of any potential CO_2 injection reservoir section(s).
(f) Sidewall sampling of potential CO_2 injection zones and effective sealing cap rock.
(g) Sampling of fluid pressures from potential CO_2 injection, hydrocarbon and water bearing zones.
(h) Comprehensive injectivity testing of any potential CO_2 injection formations should analysis prove encouraging.
(i) Comprehensive evaluation of the sealing cap rock in the lower Tuban Formation.

Generalized East Java Basin Stratigraphy

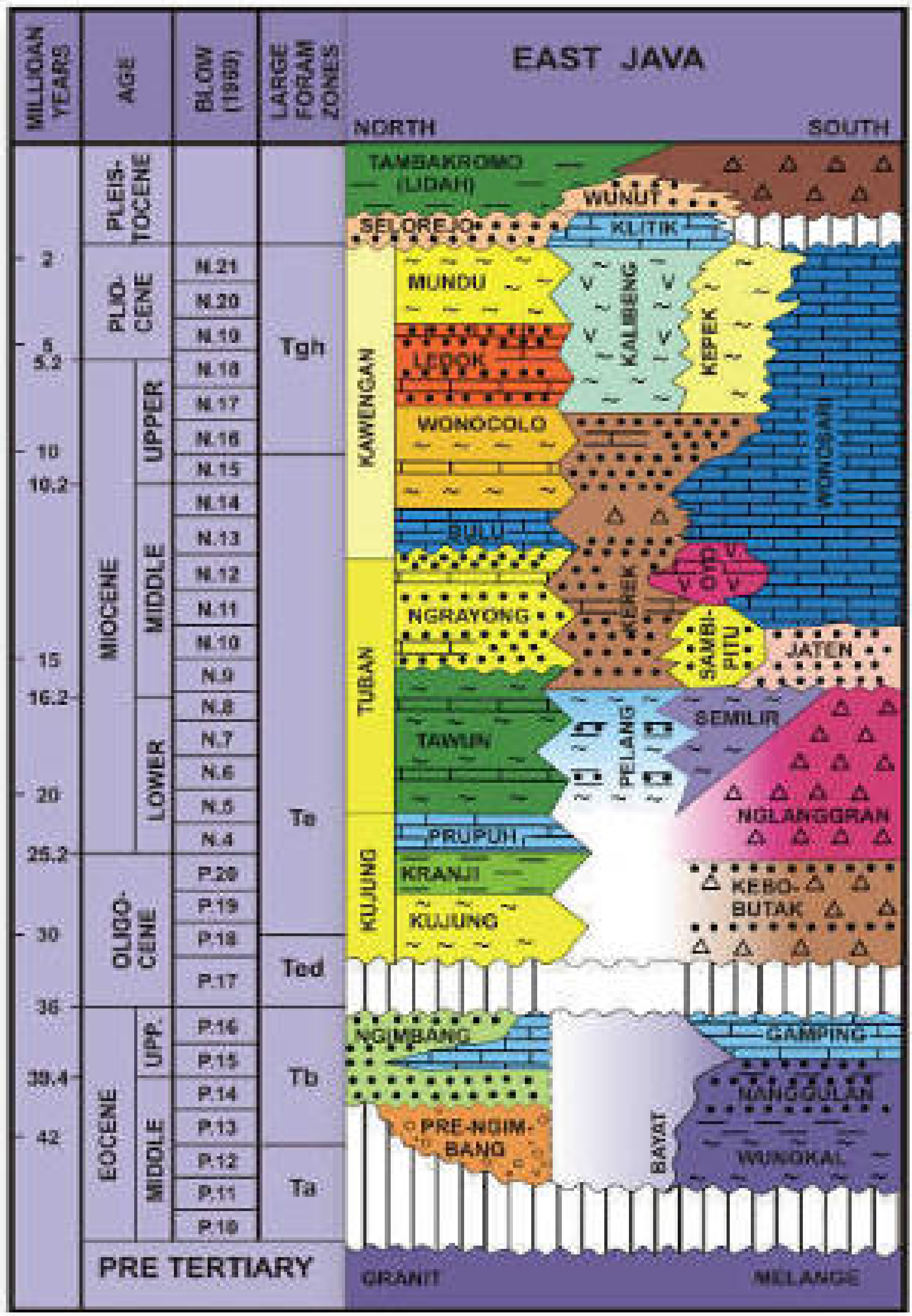

Figure 1 Generalized East Java Basin Stratigraphy

Pore Pressure

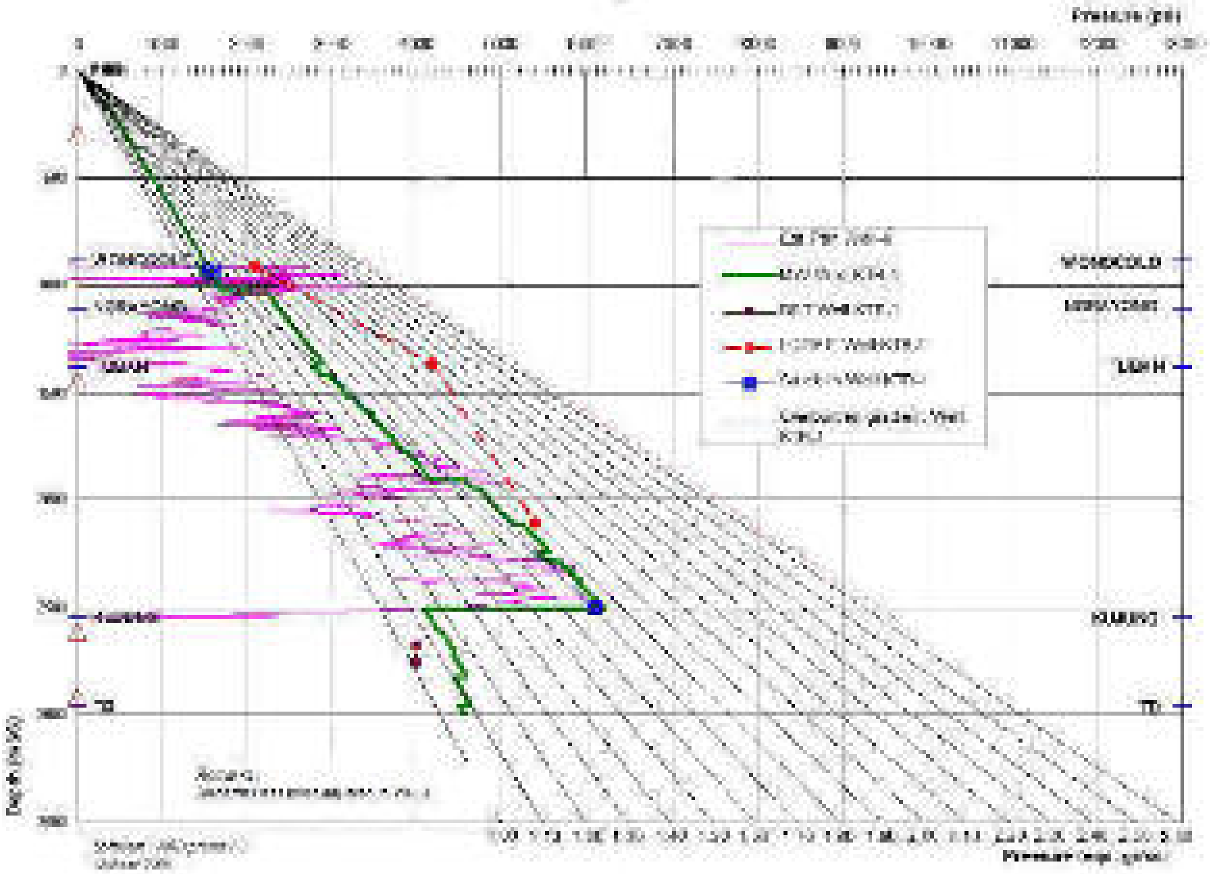

Figure 2 Pore Pressure/Mud Weight based on KTB-01 Well

Based on the KTB-1 Pressure Profile provided above, the overpressure commencing in the Wonocolo and continuing through the Ngrayong and Tuban formations above the Kujung reservoir section, could pose issues, in that event, 9⅝-inch casing would be required to be set early due to over-pressured and potentially unstable hole conditions. Whereby drilling to TD would have to be conducted in 6-inch hole and a 4½-inch liner run in which case any MDT or equivalent hole size logging could not be conducted.

In this transient pressure zone (Wonocol-Nrayong-Tuban) it is felt an 11¾-inch contingency liner may be required for potential setting at the onset of the second pressure increase, as indicated in Fig 2 above. In the KTB-01 well the pressure increase can be considered significant, based on mud weight. Pore pressure then drops back to slightly above normal pressure in the Kujung. The 9⅝-inch casing is required set at the base of the Tuban formation prior to penetrating the Kujung Formation in an effort to avoid significant mud losses. The secondary objective calciturbidite transition sequence, prior to the 8½-inch hole section, is required evaluated and either cored or, if not possible, side-wall core samples obtained.

Overpressure

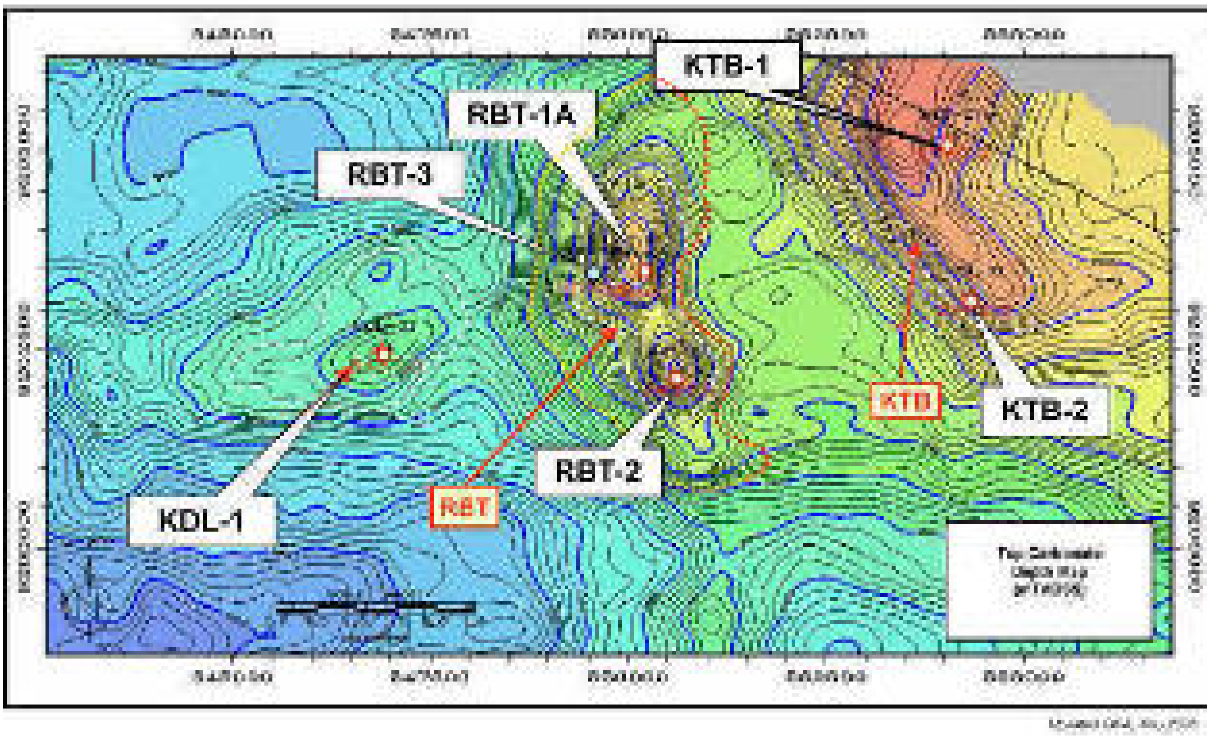

Figure 3 Kujung Formation Tops Map

Overpressure onset depth (TVDSS) varies between the three main Gundih structures:

- Kedung Tuban KTB – 1 Well 1520 m
- Randu Blatung RBT – 3 Well 1805 m
- Kedung Lusi KDL – 1 Well 1350 m

Geothermal Gradient

Based on the highest recorded Bottom Hole Static Temperature (BHST) of 165 °C (330 °F) in the KDL – 01 Well and a surface ambient temperature of 28°C (82°F). The geothermal gradient has been calculated to be;

- 3.836 °C/100 m
- 2.104 °F/100 ft.

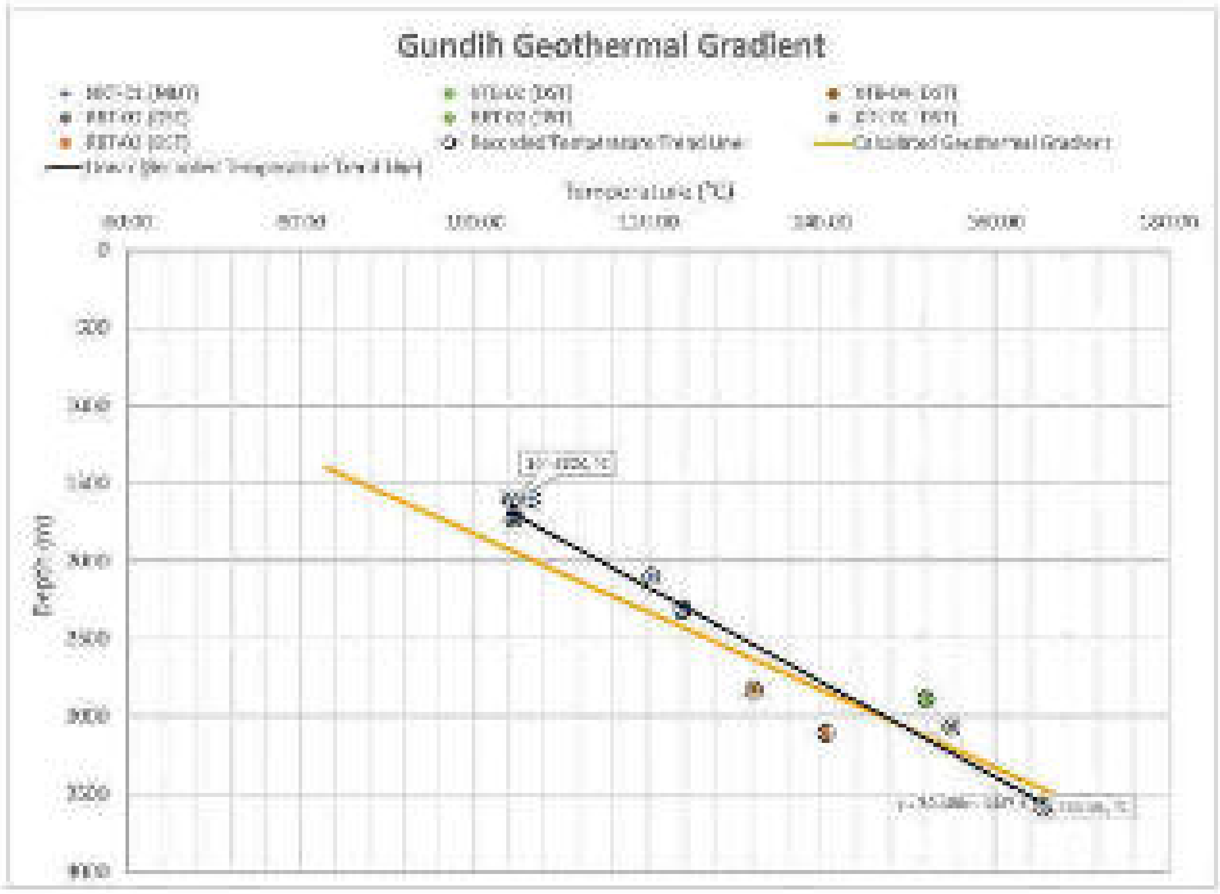

Figure 4 Gundih Geothermal Gradient

Formation Tops

Top of Formation	*Prognosed Depth Pilot CCS Well*	*Offset Well Depth RBT – 01A*
Lidah	Surface	Surface
Mundu		515.87m TVD
Ledok		773.10m TVD
Wonocolo	284 m TVD	1022.60m TVD
Ngrayong	1006 m TVD	1528.90m TVD
Tawun/Tuban	1596 m TVD	2151.0m TVD
Kujung	2964 m TVD	2939.60m TVD
Ngimbang	3490 m TVD	

Well Sections

It is planned that the well be drilled in 4 sections with a driven surface conductor and contingency liner as summarized below:

Hole Size (inches)	*Casing/Liner Size (Inches)*	*Shoe Depth (m TVD/MD)*	*Formation Setting Depth*
Driven/Drilled	30”	30 m	Surface
12¼”/26”	20”	300 m	Wonocolo
17 ½”	13 ⅜”	1596 m /1776 m	Ngrayong
*12¼” x 14¾“**	11 ¾”*	TBA	Tuban
12 ¼”	9 ⅝”	2964 m/3356 m	Tuban
8 ½”	5 ½”	3490 m/3963 m	Kujung

*Contingency Liner

Casing Design

The construction materials selected for the casing and the casing design must be appropriate for the fluids and stresses encountered at the site-specific down-hole environment. Carbon dioxide in combination with water forms carbonic acid, which is corrosive to many materials. Native fluids can also contain corrosive elements such as brines and hydrogen sulfide (H_2S). In CO_2 injection wells, the annular spaces between the long string casing and the intermediate casing, and between the intermediate casing and the surface casing as well as between the casings and the geologic formation are required to be filled with cement, along all casings.

Formation Tops have been based on existing offset wells in the area and will be revised on completion of the static earth and dynamic geological modelling. Casing sizes and setting depths have been selected from:

(a) Actual pore pressures and temperatures based on offset wells

(b) A requirement to have an 8 ½-inch hole to TD (Kujung Formation).

(c) Pressure and stress loading as a result of CO_2 injection.

(d) CO_2 (Carbonic Acid) corrosion resistance.

Casing Connections

Buttress Thread Connections (BTC) are typically used on the casing strings found in the Gundih Field.

Casing connections should satisfy several functional and operational requirements.

Consideration should be given to a metal-to-metal seal casing connection for the long/production casing string due the higher than normal temperature fluctuation that can occur in the Gundih Field

Functional Aspects

- to provide a leak resistance to internal or external fluid pressures
- to have sufficient structural rigidity to transmit externally applied loads

- to have good geometry in order not to increase the outer diameter or reduce the inner diameter of the casing string significantly

Operational Aspects

- easy to make-up in the field
- easy to break-out in the field
- reusable

To fulfil these aspects, the connections are provided, in almost all cases, with connection threads. Connections based on welding or gluing techniques and snap-on connectors are available for casing but will not be utilized, in this case.

For many years the API thread connections, with or without a resilient seal ring, have been the standard in well casing strings. These standardized connections are:

- API round thread connection for casing application;
- API buttress thread connection for casing application;
- API extreme line connection for casing application.

However, during the last decades there has been a shift away from relatively simple and inexpensive shallow wells to complicated completions for deep, often corrosive and high pressure/temperature wells. This trend entailed the need for connections with better seals than the API connections, and led to the development of the so-called Premium connections.

All connections that have one or more special features, such as higher strength, better sealing properties, faster make-up, smaller outer diameter of the coupling, internally streamlined and recess free, etc. as compared with API connections, are collectively called Premium connections.

Threaded casing connections can be divided in two groups, namely the integral connections and the threaded and coupled connections. Each group can further be divided into several types, depending on the sealing mechanism and the existence of a torque shoulder.

Integral and Threaded/Coupled Connections

In recent years there has been a move away from integral type connections, towards the use of threaded and coupled connections. Listed below are the characteristics of the integral connections and those of the threaded and coupled connections:

Integral Connections

- integral connections halve the number of threaded connections, and thus the number of potential leakage paths.
- there is no possibility of receiving a coupling made of a different, and thus wrong, material
- in general, the integral type of connections has higher torque capacity than the threaded and coupled connection. This is because integral connections are generally designed with an external torque shoulder, while for most threaded and coupled connections the torque shoulder is located at the pin nose.
- there is a risk of "ringworm" corrosion. This corrosion can occur at the upset region of joints in the presence of CO_2. During the upsetting process the pipe ends are heated and heavily deformed, which results in a difference in steel microstructure compared to the pipe. It has

been found that this microstructure is highly sensitive to CO_2 corrosion so that pits can form quite rapidly. The observed corrosion has a characteristic morphology called ringworm attack. To avoid this problem it is necessary to use tubulars which have been fully heat treated after upsetting.

Threaded and Coupled Connections

- threaded and coupled connections are generally cheaper to produce and the pipe ends can be re-cut should the threads be damaged.
- the manufacturing process of threaded and coupled connections is a lot simpler than that of integral connections as no upsetting or swaging is required.
- with threaded and coupled connections there is less risk of leakage due to geometric errors in the machined connection parts. Generally, the geometric error in machined couplings is smaller than the error in machined pipe ends. Pins and boxes, machined on long tubulars, may show geometry errors in the shape of a clover leaf. This is usually caused by movements of the long unsupported section of the casing joint.
- there has also been a move towards the use of more highly alloyed steel grades which cannot be satisfactorily hot-worked to produce the upset pipe ends necessary for an integral connection.

Thread Forms

The following thread forms are commonly manufactured today:

- API round type thread, a tapered thread with stabbing and loading flanks of 30° and rounded crests and roots.
- API buttress type thread, a tapered thread with stabbing and loading flanks of 10° and 3° respectively, and flat crests and roots, parallel to the thread cone.
- API extremeline thread, a tapered thread with stabbing and loading flanks of 6°, and flat crests and roots parallel to the pipe axis.

Modified buttress threads used for Premium connections. Several thread forms have been developed which are provided with one of the following modifications or combinations thereof: the thread profile has thread crests and roots parallel to the pipe axis rather than being parallel to the thread cone; a clearance at the pin thread crest, in order to ensure a better control of the thread friction during make-up; a change in the angle of the stabbing flank, ranging from +10° to +45° in order to improve the connection stabbing performance; a change in the angle of the loading flank, ranging from +3° to -15° in order to increase the tensile capacity of the connection; a change in the pitch of the threads (single or double pitch change) in order to provide a more uniform stress distribution in the connection threads under tensile or compressive loads.

Two step thread has two sections of different diameter, each provided with free running, non-interfering, threads either straight or tapered. A design with three shoulders which has the advantage of an increased over-torque capacity. In contrast, a non-interfering thread has the risk of inadvertently backing-out of the connection.

Wedge shape thread is based on an interlocking dovetail thread profile. The loading flank is machined with a greater pitch than the stabbing flank to produce a thread that wedges together during make-up, eliminating the need for an additional torque shoulder. The applicable make-up torques of these connections tend to be higher than that of connections with modified buttress thread profiles and a shoulder.

Load Case Scenarios

20 inch, 133 ppf, K-55, BTC – Surface Casing

Load Case	Burst	Collapse	Tension	Compression	Von Mises	Buckling
As Cemented		8.39	37.40	16.61	19.19	No
⅓ replacement to gas(2)	6.30		15.49	68.55	7.06	No
Pressure Test(1)	2.73		9.56		2.97	No
Gas Kick(2)	6.72		13.86	2.06	2.42	No
⅓ replacement to gas circulating(2)	6.30		19.66	2.08	2.39	No
⅓ evacuation(2)		3.09	37.40	10.15	7.02	No
Green Cement Pressure Test	2.65		5.56		2.96	No
Minimum Design Factor	1.100	1.100	1.400	1.250	1.250	
Depth						
(1)983.99 ft.						
(2)3592.52 ft.						

13 ⅜ inch, 68 ppf, K-55, BTC – Intermediate Casing

Load Case	Burst	Collapse	Tension	Compression	Von Mises	Buckling
As Cemented		4.52	14.40	12.13	4.41	No
⅓ replacement to gas(2)	3.02		6.93		2.16	No
⅓ replacement to gas(3)	2.28		5.93		2.54	No
⅓ replacement to gas(4)						
Pressure Test(1)	2.58		6.76		2.60	No
Pressure Test(2)	1.64		6.76		1.75	No
Pressure Test(3)						
Gas Kick(2)	2.54		7.16	9.89	2.21	No
Gas Kick(3)	1.98		6.08	11.06	2.08	No
Gas Kick(4)	2.67		7.40	9.55	2.32	No
⅓ replacement to gas circulating(2)	3.02		9.08	9.91	2.51	No
⅓ replacement to gas circulating(3)	2.28		9.67	13.75	2.08	No
⅓ replacement to gas circulating(4)	2.44		10.52	12.44	2.19	No
⅓ evacuation(2)		3.06	14.40	13.19	4.17	No
⅓ evacuation(3)		2.17	14.40	9.11	4.17	No
⅓ evacuation(4)		2.13	14.40	8.95	4.17	No
Green Cement Pressure Test	3.42		5.56		3.20	No
Minimum Design Factor	1.100	1.100	1.400	1.250	1.250	
Depth						
(1)3592.52 ft.						
(2)7729.66 ft.						
(3)11010.50 ft.						
(4)13451.44 ft.						

11¾ inch, 71 ppf, L-80, BTC – *Contingency Liner*

Load Case	Burst	Collapse	Tension	Compression	Von Mises	Buckling
As Cemented		11.60	16.10	8.73	8.52	No
⅓ replacement to gas[2]	3.62	184.10	5.42	4.35	4.01	No
⅓ replacement to gas[3]	6.05	4.50	5.61	3.58	4.72	No
Pressure Test[1]	1.65		3.94	7.31	1.82	No
Pressure Test[2]	1.75		4.03	6.62	1.93	No
Gas Kick[2]	2.11		5.22		2.34	No
Gas Kick[3]	2.98		5.97	55.48	3.29	No
⅓ replacement to gas circulating[2]	3.63	182.18	7.08	35.82	3.98	No
⅓ replacement to gas circulating[3]	5.97	4.51	7.41	13.09	5.55	No
⅓ evacuation[2]		1.57	22.67	2.70	2.29	No
⅓ evacuation[3]		1.16	23.06	2.42	1.78	No
Green Cement Pressure Test	6.24		7.11	49.21	5.24	No
Minimum Design Factor	1.100	1.100	1.400	1.250	1.250	
Depth						
[1]7729.66 ft.						
[2]11010.50 ft.						
[3]13451.44 ft.						

9⅝ inch, 53.5 ppf, P-110, LTC – Intermediate Liner

Load Case	Burst	Collapse	Tension	Compression	Von Mises	Buckling
As Cemented		16.23	193.03	9.16	14.08	No
⅓ replacement to gas[3]	6.23	8.56		4.38	3.97	No
Pressure Test[2]	1.89		34.84	7.57	1.81	No
Gas Kick[3]	3.56		15.40	529.15	3.88	No
⅓ replacement to gas circulating[3]	6.41	8.46	35.20	27.96	7.02	No
⅓ evacuation[3]		1.74		2.68	2.47	No
Green Cement Pressure Test	9.80		14.30	23.39	8.60	No
Minimum Design Factor	1.100	1.100	1.400	1.250	1.250	
Depth						
[1]7729.66 ft.						
[2]11010.50 ft.						
[3]13451.44 ft.						

5½ inch – 23 ppf, P-110, MTC – Production Casing

Load Case	Burst	Collapse	Tension	Compression	Von Mises	Buckling
As Cemented		11.28	3.72	9.19	2.95	No
Surface Tubing Leak - Hot[1]	2.54	106.10	5.57	4.20	2.71	No
Surface Tubing Leak – Static[1]	2.62	106.10	1.97	4.20	1.81	No
Full Evacuation[1]		1.92	2.29	2.73	1.98	No
Green Cement Pressure Test	8.99		3.12	19.57	2.78	No
Minimum Design Factor	1.100	1.100	1.400	1.250	1.250	
Depth						
[1]13451.44 ft.						

Evaluated Load Scenarios

Load Name	Description	Casing String
As Cemented	Casing filled with drilling fluid at the density it was run with; cement outside casing; static temperature profile	All
⅓ replacement to gas	Casing is filled with 0.0 psi/ft. gas to a depth equal to one-third the depth of the next casing point (below this, mud is present with weight used to drill subsequent section) natural pore pressure gradient outside of the casing; static and circulating temperature profiles are both considered.	S, I
Pressure Test	Casing is filled with the mud weight with which the casing was run in and surface and surface pressure applied that produces a pressure at the casing shoe equal to the fracture pressure plus a margin of safety (0.2 ppg); natural pore pressure gradient outside the casing; static temperature profile	S, I, P
Gas Kick (50 bbl)	Simulates gas kick of specified volume; internal pressure profile depends on size of gas bubble and natural pore pressure gradient outside the casing; temperature profile is based on correlation by Kutasov and Taighi (Schlumberger 2006)	S, I
⅓ replacement to gas circulating	Casing is filled with 0.0 psi/ft. gas to a depth equal to one-third the depth of the next casing point while circulating; natural pore pressure gradient outside of the casing; static and circulating temperature profiles are both considered.	S, I, P
⅓ evacuation	Casing is filled with mud with weight it was run in with; cement outside casing; static temperature profile.	
Surface Tubing Leak	Surface Tubing Leak – The internal pressure profile is created by placing the shut-in tubing pressure on top of the packer fluid from the wellhead to the packer. Below the packer, bottom-hole pressure conditions exist. Pore pressure is used for the external pressure and static temperature is used for the temperature profile.	P
Green Cement Pressure Test	Casing filled with drilling fluid at the density it was run with; un-hydrated cement outside casing; static temperature profile	All
Full Evacuation	Tubing is completely evacuated; external pressure is the hydrostatic pressure due to the packer fluid in the annulus surrounding the tubing; static temperature profiles.	P

S = Surface Casing; I = Intermediate Casing; P = Production Casing; T = Tubing

Casing Accessories

Float Equipment

Casing float equipment and cement plugs required are to meet or exceed the casing specification and temperature rating. Cement plugs are to be rated for the expected temperature and casing test pressure of 80% of the maximum rated casing pressure.

Multi-Stage Cementing

In some cases, cementing along the well casing from the injection zone up to the ground surface in a single stage may not be possible. The pressure exerted by the cement column increases as the height of the column increases. In very deep wells the pressure may become so great that the cement pumps can no longer maintain the pressure, or the pressure from the cement column under construction may fracture weaker formations. In some cases, highly fractured formations or formations with large voids may not allow cement to circulate to the surface, as the cement will flow into the fractures and voids in the formation instead of stacking vertically in a column up to the ground surface. If single stage cementing cannot be successfully performed, multi-staged cementing may be used [40 CFR §146.86(b) (4)]. Multi-staged cementing can be two-stage, three-stage, or continuous two-stage cementing.

Two – Stage Cementing

Two-stage cementing is performed similarly to single stage cementing, except that a cement collar with cement ports is installed at an appropriate point in the well. The cement collar allows cement to be injected into the annulus between the casing and formation at some point in the column under construction other than the bottom of the well. Figure 5 shows a schematic of a two-stage cementing process. EPA recommends that an appropriate point for the cement collar may be the halfway point of the well or just above a fractured zone where the cement circulation might be lost.

To successfully accomplish two-stage cementing, the cement is pushed out of the well bore using a fluid. Two plugs, often referred to as bombs because of their shape, are then dropped. The first plug closes the section of the well below the collar and stops cement from flowing into the lower portion of the well. The second plug (or opening bomb) opens the cement ports in the collar allowing cement to flow into the annulus between the casing and formation through the cement collar. Cement is then circulated down the well bore, out the cement ports, into the annulus between the casing and formation, and up to the ground surface. Once cementing is complete, a third plug is dropped to close the cement ports (Lyons and Plisga, 2005). If the time between the first and second stage is long enough for the cement to begin to set, care should be taken that the first stage is stopped significantly below the cement ports.

Continuous Two-Stage and Three-Stage Cementing

In continuous two-stage cementing, there is no break between the injection of cement between the first and second stages. Continuous two-stage cementing requires less time than regular two- stage cementing, but it requires a more precise knowledge of the cement level to avoid plugging the cement ports. Three-stage cementing is very similar to two-stage cementing, except that two cement collars are used instead of one. The method used will largely be determined by the characteristics of the well bore. If there are two weak formations where circulation is lost or the well is very deep, three-stage cementing may be advantageous.

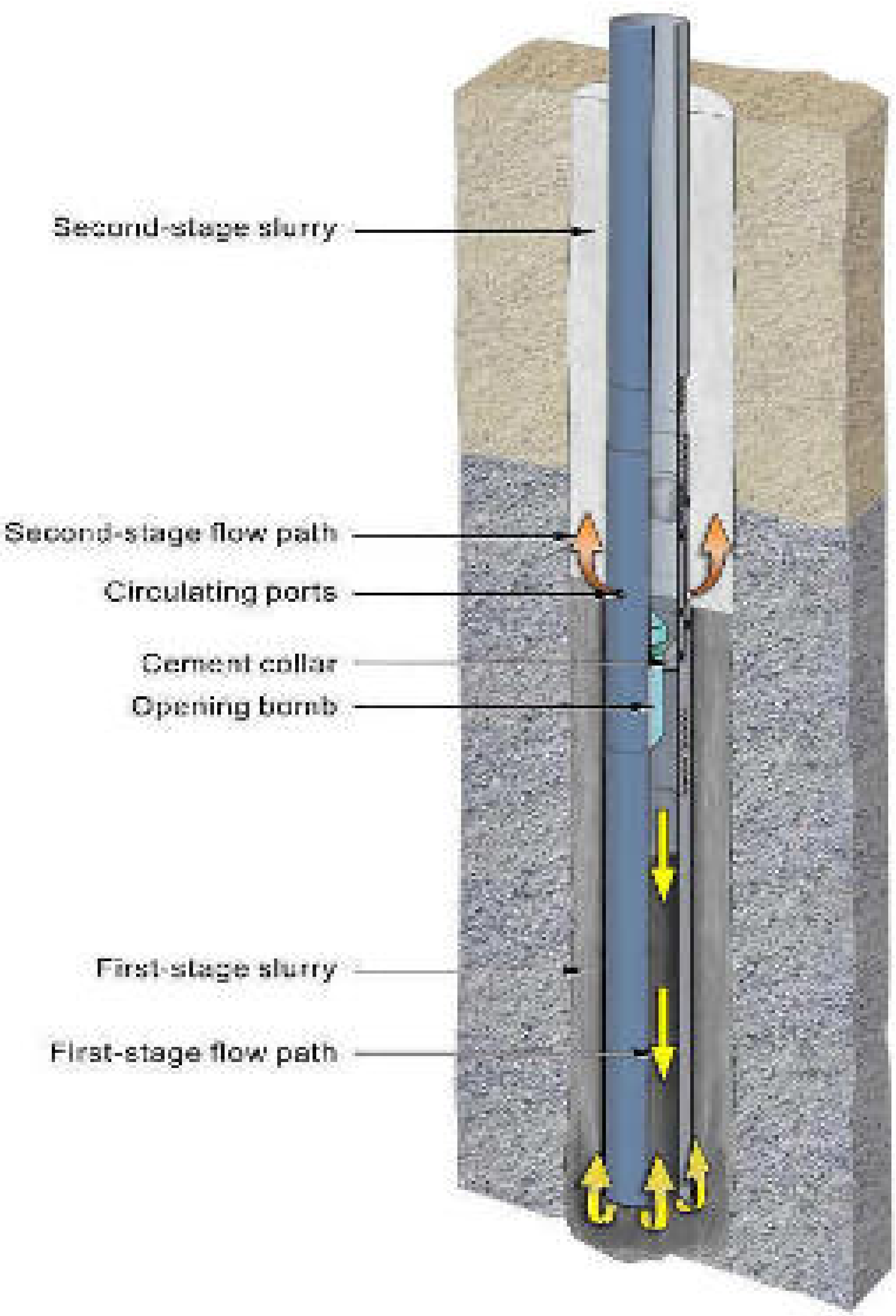

Figure 5Two - Stage Cementing Schematic

Downhole Deployment Valve (DDV) and Rotating Control Device (RCD)

DDV's coupled with an RCD have successfully been employed in the area and provided the safety sought in similar well conditions, however, further planning is required to integrate the technology into this particular well and geological environment.

Liner Hanger

There are no specific regulations for liner hangers in this application, however in this instance, the regulatory requirements that govern the selection of packer materials and technical requirements is applicable.

Tubing

U.S. EPA Class VI regulations require that injection occur through tubing. The tubing must be compatible with the carbon dioxide stream [40 CFR §146.86(c) (1)]. Tubing materials are generally similar to the casing well materials. The tubing should also be designed with the same types of stresses in mind. The tubing must be designed with burst strength to withstand the injection pressure and the collapse strength to withstand the pressure in the annulus between the tubing and the casing [40 CFR §146.86(b) (1)]. Consideration should be given to a metal-to-metal seal tubing connection due the higher than normal temperature fluctuation that can occur in the Gundih Field.

Tubing Specifications & Load Cases

2⅞ inch, 6.4 ppf, L-80, NUE, Seamless, R3 has been selected as the tubing to be utilized for CO_2 injection. Tubing movement modelling has not been included in the casing Load Case Scenarios and is required conducted upon selection of the tubing packer to model the packer loads in various scenarios encountered during CO_2 injection, well shut-in conditions and any potential flow. The injection tubing is subject to contraction and expansion caused by variations in temperatures, and to tension, compression, and hydraulic pulsation effects. Therefore, to comply with 30 TAC §331.62(a)(1)(B)(vii), modelling of adequate safety factors is necessary when designing for tubing and packer installation.

Tubing Packer

U.S. EPA Class VI regulations also require that injection occur through a packer, set opposite a cemented interval at a depth approved by the UIC Program Director, and compatible with the carbon dioxide stream [40 CFR §146.86(c)(1) and (2)].

Packers are often made from a hardened rubber such as Buna-N or nitrile rubbers and are nickel plated. Proper materials for packers are important as they are likely to come into contact with corrosive fluids such as carbon dioxide or corrosive brines at some point during the project life. The packer must be compatible with any fluids it may come into contact with [40 CFR §146.86(c)(1)]. Placement of the packer can also be an important consideration, influenced by numerous factors. If the packer is placed above the confining layer, it will allow logs to be run next to the casing through the confining layer without having to pull the tubing. Alternatively, placing the packer close to the perforations may allow instruments used for carbon dioxide plume tracking, such as geophones, to be placed closer to the expected plume. Packer placement can also affect how mechanical integrity tests are conducted and may affect the stress placed on well components. Consideration should be given to these factors, in order to select the best location for the packer according to project and site specific circumstances.

Completion Equipment

The well completion equipment, from bottom up, (Fig 6) will comprise:

- Shear Out Ball Seat Sub w/wireline re-entry guide
- Seating Nipple (No-Go Profile)
- Re-settable 2⅞ x 5½ inch packer
- Sliding Sleeve
- Gauge Carrier
- Single Conductor Encapsulated DTS 200 °C Working Temperature
- Surface Controlled Sub-surface Safety Valve (SCSSSV)
- SCSSSV Control Line
- Tubing hanger with Back Pressure Valve (BPV) profile.

Annular Fluid

The annular space above the packer between the 5½-inch long string casing and the 2⅞-inch injection tubing will be filled with fluid to provide structural support for the injection tubing. If required, fluid pressure measure at the surface within the annulus will be maintained so as to exceed the maximum injection pressure within the injection tubing at the elevation of the injection zone. Under this requirement, the maximum annulus surface pressure will not exceed a value that is more than ~200 psi greater than injection pressure at surface. Alternatively, the maximum annulus surface pressure will not exceed a value that would result in a pressure at the top of the packer that is greater than the pressure inside the tubing when the bottom-hole injection pressure is at the maximum allowable pressure.

The annular fluid will be a diluted saline solution such as potassium chloride (KCl), sodium chloride ($NaCl^-$), calcium chloride ($CaCl_2$), or similar solution. The fluid will be mixed onsite using dry salt and clean fresh water. The fluid is also to be filtered to ensure that solids do not settle at the packer or on other components installed in the annulus.

The annular fluid will contain additives and inhibitors including a corrosion inhibitor, biocide/bactericide (to prevent harmful bacteria), and an oxygen scavenger.

Wellhead and Xmas Tree

API SPEC 6A – Specification for Wellhead and Xmas Tree Equipment Twenty-First Edition (2019) is the specification required to be adhered to for the Wellhead and Xmas Tree. Specifications listed below are defined in API Spec 6A:

- Material Class – with specific attention to wetted surfaces subject to CO_2 and H_2S exposure.
  - As defined by NACE MR 0175
- Performance Requirement (PR)
- Pressure Rating
- Product Specification Level (PSL)
- Temperature Classification
- Nonmetallic Requirements

Figure 6: CCS Completion Schematic

The wellhead and Xmas tree will be composed of materials compatible with the injected fluid to minimize corrosion. All components that are in contact with CO_2 injection fluid will be made of a corrosion resistant alloy or a conventional material with a corrosion resistant inlay for flow wetted component surfaces.

Valve actuators are to be installed on those valves designated to be included in an automated system to close the valve when certain criteria are met e.g. injection pressure.

Specific to CO_2 monitoring requirements will be the inclusion of ported adaptor flange sections to the wellhead that will incorporate pressure sealing ports for monitoring instrumentation and control lines. An example is shown in Figure 6 below.

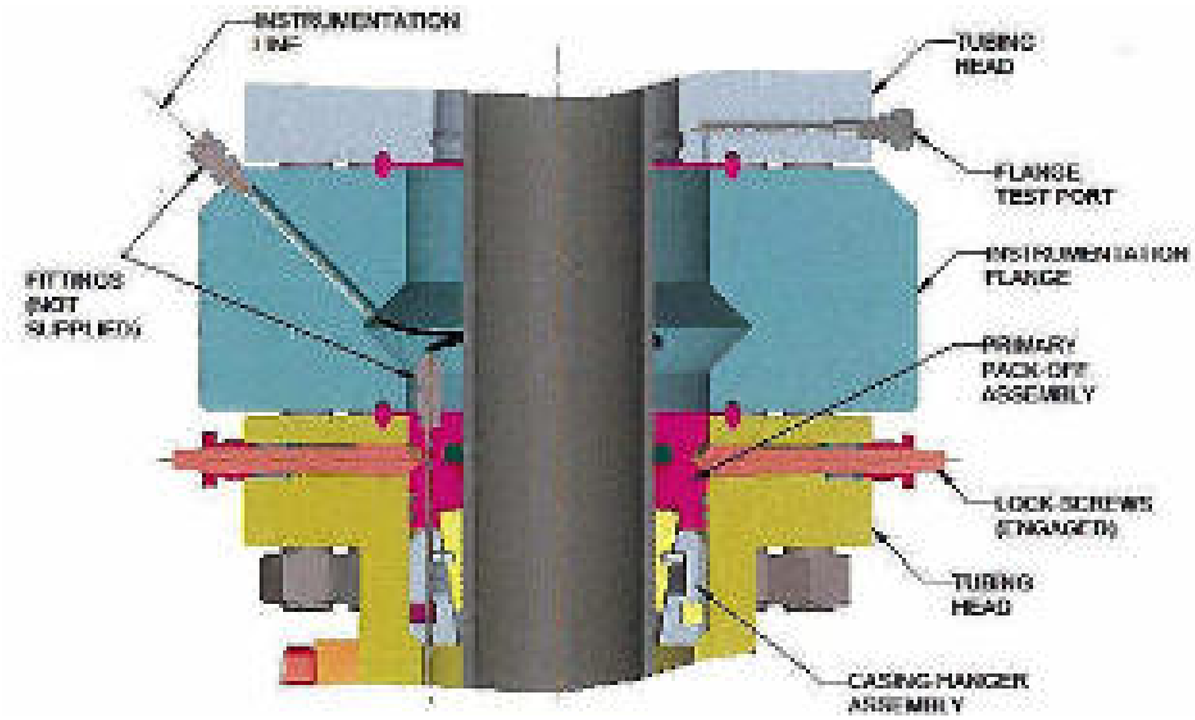

Figure 7 Typical Instrumentation line penetrator wellhead flange

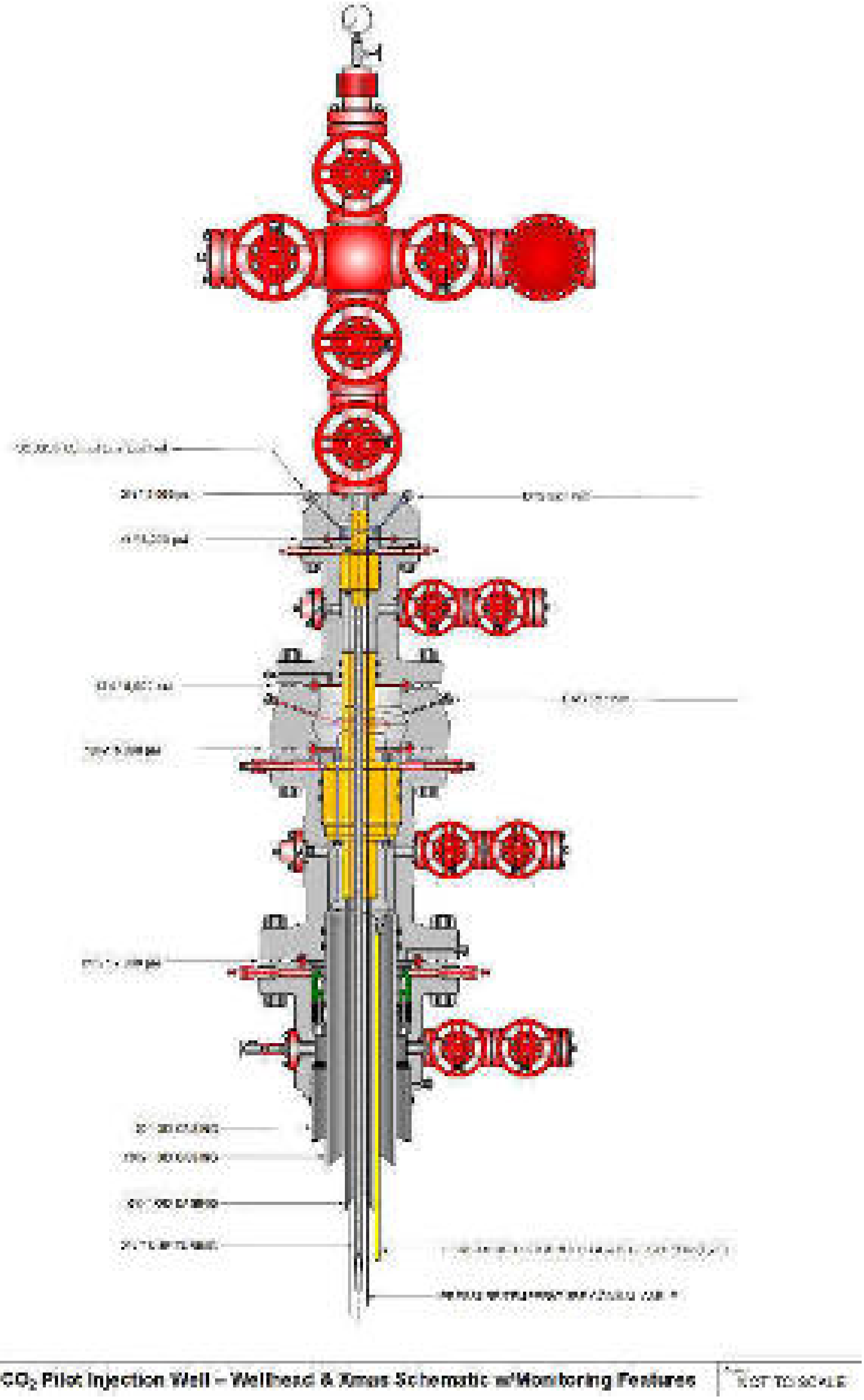

Figure 7 Example of CCS Multiple Monitoring Configured Conceptual Wellhead & Xmas Tree

Proposed Wellhead and Xmas Tree API 6A (Latest Edition) Specifications:

Section	*Bottom Connection*	*Top Connection*	*Pressure Rating*	*Material Classification*	*Temperature Rating*	*PSL*	*PR*
Section A	20”	21 ¼ “	2,000 psi	DD	U	3	2
Section B	21 ¼”	11”	5,000 psi	EE	U	3	2
Section B2[1]	11”	11”	5,000 psi	EE	U	3	2
Section C[2]	11”	11”	5,000 psi	EE	U	3	2
Tubing Hanger Assy.			5,000psi	FF 1.5	X	3	2
THA[3]	11”	3⅛”	5,000 psi	FF	X	3	2
Xmas Tree	3 ⅛”		5,000 psi	FF	X	3	2F

[1]Section B2 Spacer Spool monitoring instrumentation ported access section

[2]Section C Tubing annulus monitoring instrumentation and SCSSSV ported access incorporated into tubing head adapter and ported tubing hanger.

[3]THA Tubing Head Adapter

CO_2 Downhole Well Monitoring Equipment

Distributed Acoustic Sensor (DAS)/Distributed Temperature Sensing (DTS)

At the time of writing this drilling prognosis, research and development of the monitoring plan continued. Conceptually, there will be two (2) main data source locations; the first source will be situated in the annulus of the 5½-inch x 9⅝/13⅜-inch casing strings with the 9⅝-inch casing run as a liner in an effort to save time and reduce the number of wellhead sections. The 5½-inch casing will be cemented as close as practically possible to surface, permanently cementing the externally mounted Distributed Acoustic Sensor (DAS) reservoir monitoring cable in the well. This cable is the sensor and is not typically run with any other equipment other than cross-coupling protectors similar to the one shown in Figure 8 below. It should be noted that the typical temperature rating for fiber optic cable in this application is 150 °C (302 °F). Bottomhole temperature in the Gundih Field can extend above 150 °C (302 °F) as indicated in Geothermal Gradient page 9 of this document.

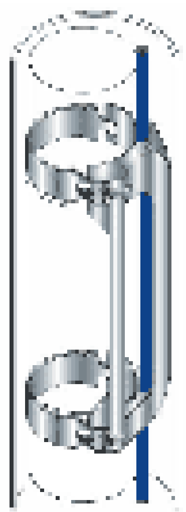

Figure 8: Cross-coupling Cable Protector

Coaxial Pressure & Temperature Monitoring Cable

The second monitoring location will be the annulus of the 2⅞-inch tubing x 5½-inch casing where the Coax Pressure & Temperature monitoring cable will be strapped to the 2⅞-inch tubing and extend, from a ported carrier-assembly installed above the packer depth, to surface, providing access to tubing pressure coupled with access to annulus pressure, along with temperature.

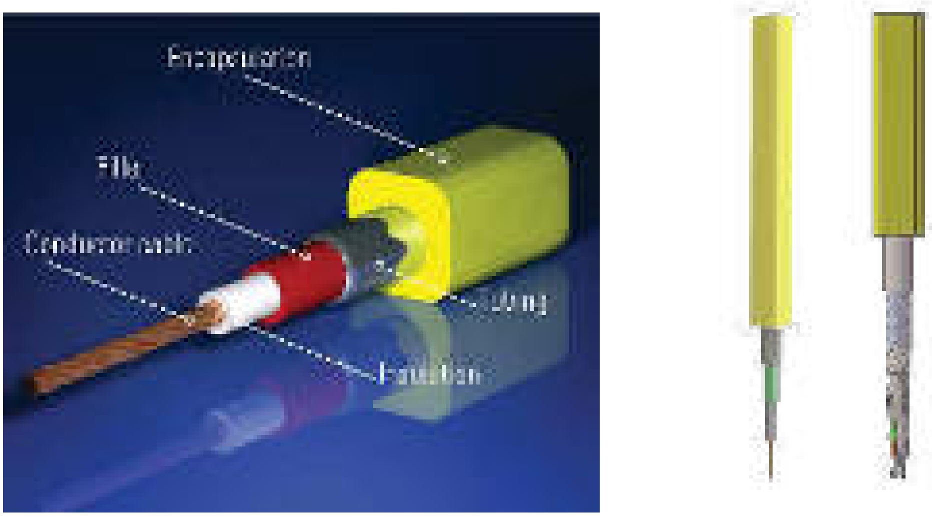

Figure 9: Examples of Single Permanent Downhole Monitoring (DTS) Cable

Multi-Conduit and Monitoring Cable Flat-Pack

In the event geophones are selected as part of the monitoring program and run, a more complex flat-pack monitoring conduit may be utilized that incorporates the features as shown Figure 10 below.

Figure 10 Flat Pack Multi-Core Monitoring Cable

Downhole Monitoring Equipment

Figure 11 Typical Geophone and Flat Pack Installation on CO_2 injection tubing.

Well Integrity

Cement and Its Degradation Due to CO_2 Injection

Portland cement systems are used conventionally for zonal isolation in oil or gas production wells. It is thus crucial to study how such cement behaves at depth in CO_2-rich fluids and understand the chemical interactions between injected CO_2 and existing cements that could potentially lead to leakage. Portland cement is thermodynamically unstable in CO_2-rich environments and can degrade rapidly upon exposure to CO_2 in the presence of water. As CO_2-laden water diffuses into the cement matrix, the dissociated acid (H_2CO_3) reacts with the free calcium hydroxide and the calcium-silicate-hydrate gel. The reaction products are soluble and migrate out of the cement matrix. Eventually, the compressive strength of the set cement decreases and the permeability and porosity increase leading to loss of zonal isolation.

There are mainly three different chemical reactions involved in cement-CO_2 interaction: (1) formation of carbonic acid, (2) carbonation of calcium hydroxide and/or cement hydrates, and (3) dissolution of calcium carbonate ($CaCO_3$)

Cement is important for providing structural support of the casing, preventing contact of the casing with corrosive formation fluids, and preventing vertical movement of carbon dioxide. Some of the most current research indicates that a good cement job is one of the key factors in effective zonal isolation.

The proper placement of the cement is critical, as errors can be difficult to fix later on. Failing to cement the entire length of casing, failure of the cement to bond with the casing or formation, not centralizing the casing during cementing, cracking, and alteration of the cement can all allow migration of fluids along the wellbore. If carbon dioxide escapes the injection zone through the wellbore because of a failed cement job, the injection process must be interrupted to perform costly remedial cementing treatments. In a worst case scenario, failure of the cement sheath can result in the total loss of a well.

During the injection phase, cement will only encounter dry CO_2. However, after the injection phase and all the free CO_2 around the wellbore had been dissolved in the brine, the wellbore will be attacked by carbonic acid (H_2CO_3). The carbonic acid will only attack the reservoir portion of the production (long string) casing, therefore special consideration of CO_2 cement needs only to be considered for the reservoir, the primary seal and a safety zone above the reservoir. Regular cement should be placed over the CO_2-resistant cement. However since two different cement slurries will be used, CO_2-resistant cement that is compatible with regular Portland cement has to be used to prevent flash setting. The cement must be able to maintain a low permeability over lengthy exposure to reservoir conditions in a CO_2 injection and storage scenario. Long-term carbon sequestration conditions include a contact of set cement with supercritical CO_2 (>31 °C at 1059 psi) and brine solutions at increased pressure and temperature and decreased pH.

Underground gas storage operations and CO_2 sequestration in aquifers rely on both proper wellbore construction and sealing function of the cap rock. The potential leakage paths are the migration CO_2 along the wellbore due to poor cementation and flow through the cap rock. The permeability and integrity of the cement will determine how effective it is in preventing leakage. The integrity of the cap rock is assured by an adequate fracture gradient and by sufficient cement around the casing across the cap rock and without a micro-annulus.

Well integrity has been identified as the biggest risk contributing to leakage of CO_2 from underground storage sites. Wellbore represents the most likely route for the leakage of CO_2 from geologic carbon sequestration. Abandoned wells are typically sealed with cement plugs intended to block vertical migration of fluids. In addition, active wells are usually lined with steel casing, with cement filling the outer annulus in order to prevent leakage between the casing and formation rock.

Several potential leakage pathways can occur along active injection well and/or abandoned well. These include leakage: through deterioration (corrosion) of the tubing (1), around packer (2), through deterioration (corrosion) of the casing (3), between the outside of the casing and the cement (4), through deterioration of the cement in the annulus (cement fractures) (5), leakage in the annular region between the cement and the formation (6), through the cement plug (7), and between the cement and the inside of the casing (8) .

The permeability and integrity of the cement in the annulus and in the wellbore will determine how effective the cement is in preventing fluid leakage.

The greatest risk for the escape of CO_2 may come from other wells, typically for oil and gas, which penetrate the storage formation. Such wells need to be properly sealed in order to ensure that they do not provide pathways for the CO_2 to escape into the atmosphere. Planning for geologic storage must take such wells into account. The escaping of CO_2 through water wells is much more unlikely since water wells are usually much shallower than the storage formation.

Casing Pressure Testing

Casing is required to be pressure tested to 80% of the casing pressure rating after the top plug has been bumped and prior to the cement setting. This procedure is in an effort to reduce the potential for a micro-annulus being generated between the cement and casing when test pressure is released after the cement has already hydrated. Casing pressure testing using traditional methods is typically conducted after the cement setting time has been achieved and increases the incidence of micro-annulus formation as the casing contracts, as a result of the internal casing pressure being released.

Formation Integrity Testing (FIT)

A Formation Integrity Test will be conducted when it is decided to test the casing shoe and immediate formation to a specific design pressure. The pressure is typically below the formation fracture pressure and is the preferred method, reducing the potential of damaging the cement bond and formation at the casing shoe thus reducing the potential for uncontrolled sub-surface flow while continuing drilling to the hole section TD.

Leak Off Test (LOT)

In the event it is required to know the formation fracture gradient a Leak Off Test is conducted where the pressure in the well below the previous casing shoe is increased to the fracture point providing actual fracture pressure/gradient data.

Annulus Pressure Test (APT)

Standard Annulus Pressure Test to be conducted during well completion operations and prior to commencing CO_2 injection operations.

Cementing Program

All casing strings, with the exception of liners, will be cemented back to surface in accordance with the requirements EPA UIC Class VI regulations (10 CFR §146.87).

Positive stand-off casing centralizers will be used on casing strings that extend to surface and liners exposed to annuli that extend to surface, in accordance with a centralizer spacing and placement simulation, with the exception of the surface conductor and intermediate casing string. A temperature rated, PDC drillable float/guide shoe will be run on the bottom of the first joint with a temperature and casing test pressure rated double-float collar above the second casing joint to provide sufficient separation between the cement slurry and displacement fluid. The minimum two (2) joint shoe track is intended to ensure a competent and uniform cement slurry surrounds the casing shoe.

All casing strings and liners with a potential for exposure to CO_2, H_2S and associated fluids will be cemented with a CO_2 corrosion resistant cement. In an effort to effectively remove drilling fluid filter cake from both the casing and formation, and reduce the potential for micro-annulus formation, an effective “Mud Removal Spacer Fluid” for both the OBM and Water Based drilling fluids is to be included as part of the cementing program.

After running a casing string that extends to the deeper higher temperature formations of the well a pre-determined casing circulating period is required in an effort to reduce formation temperature in the immediate wellbore at that particular depth. This is in an effort to reduce any downhole temperature anomalies that may be present.

The 5½-inch production casing is currently planned to be cemented back to surface in a multi-stage process. The placement of a multi-stage cementing tool will be defined after further reservoir data acquisition, engineering and analysis.

Note: As shown in the reservoir pressure profiles there is a distinct pressure regression (~1.54 SG – 1.00 SG [~12.86 ppg – 8.34 ppg]) after exiting the Tuban Formation and penetrating the Kujung. In this case a full column of conventional weight cement, to surface, is not considered feasible.

A high temperature (~149 °C [~300 °F]), lite-weight, CO_2 corrosion resistant cement slurry design is required to cement the 5½-inch long string in a single stage cement job that exhibits the necessary properties to conduct the cementation in a single stage whereby, eliminating the requirement for multi-stage cementation of the 5½-inch casing string thus eliminating the potential for failure during the multi-stage process and, a saving in rig time.

Potential Drilling Constraints

Drilling Unit

A well of this nature and depth requires the use of a heavy land drilling unit with a drawworks hook load capacity to handle the casing weights, in dry air and, a minimum of three (3) large capacity mud pumps that are capable of delivering continuously, 1,200 gallons per minute (gpm) at pump pressures up to 3,000 psig. Additionally, a Top Drive System (TDS) is to be made available. The equipment is to be suitably prepared for the formation temperatures expected encountered. It is important that the drilling contractor be experienced in drilling wells of the type described in this prognosis.

Formation Temperature

KDL-01 well, recorded a bottomhole temperature of 165 °C (330 °F). The geothermal gradient for the area has been established at 3.836 °C/100 m (2.104 °F/100 ft.). Recorded RBT – 01A well mud flowline temperature increased from 149 °C (300 °F) to 156 °C (313 °F) through the Kujung interval (2962.0m MD/2939.6m TVD – 3112.0m MD/3090.3m TVD). Use of a drilling fluid capable of withstanding these temperatures is a point for consideration. Additionally, surface handling equipment (e.g. TDS, TDS hose, mud manifold, choke manifold etc.) and surface pumping equipment and BOP elastomers are to be rated for temperatures of this magnitude. Should drilling fluid temperature be deemed excessive consideration is to be given to the installation of a mud cooling unit for the deeper sections of the well. Temperature of this magnitude require that all equipment and materials used on the well be ***"Fit for Purpose"***.

Drilling Fluids Conditioning

Temperature and solids content are two factors with the greatest potential to cause serious drilling fluid and well control issues. A "Mud Cooler" should be considered to provide the reduction in drilling fluid circulating temperature required. The primary concern being the temperature limitations of the BOP elastomers. Additionally, an effective solids control system is also a requirement. In an effort to provide consistent fluid density during drilling operations

Lost Circulation

The risk of a "blowout" increases significantly when severe lost circulation is encountered. The potential for major drilling fluid cost overruns and drilling delays are substantially increased. Alternative methods of combating lost circulation are to be made available at the drilling location. Such systems are to be in place to allow fast replenishment of drilling mud, i.e. bulk barite and bentonite storage, shearing equipment and additional surface drilling fluid storage.

Well Control

The combination of high pressure, high temperature, lost circulation and long hole sections between casing points increases the risk of a well control incident. Procedures are to be developed to handle risk management. In addition the provision of high rate water supply and large reserve drilling mud storage.

Note: RBT – 01A recorded flowline temperature up to 156 °C (313 °F) when nearing TD of the well. Standard BOP elastomers are rated for up to 93 °C (200 °F) with standard spherical (annular) BOP elastomers rated for 77 °C (170 °F). BOP elastomers are to be rated for the temperatures anticipated. High temperature BOP elastomeric components are available for up to 177 °C (350 °F) and spherical (annular) BOP elastomer elements up to 107 °C (225 °F).

Formation Injectivity Testing

U.S. EPA Class VI Rule requires that the injection pressure not exceed 90 percent of the injection zone fracture pressure except during stimulation [40 CFR §146.88(a)].

Maintaining the injection pressure below 90 percent of the injection zone fracture pressure is a conservative requirement that prevents the injection zone from being fractured and diminishes the likelihood of fracturing the confining zone which could result in fluid movement out of the injection zone. In some cases, a well stimulation program may be necessary to achieve the desired injectivity of the Class VI injection well.

Stimulation usually occurs during completion of the well and may also be conducted if injectivity decreases over the course of the injection project.

Some stimulation methods can induce and propagate fractures. If stimulation is to be performed, the proposed stimulation method must demonstrate that it will not fracture the confining zone or otherwise allow injection or formation fluids to endanger USDWs [40 CFR §146.88(a)]. This can be accomplished by modeling pressures and showing that the fracture pressure of the confining zone is never exceeded.

The modeled pressures can be confirmed using technologies such as tilt-meters and micro-seismic monitoring to monitor and refine the model; however, these technologies are still experimental and may not be applicable in all circumstances. If additional chemicals are to be used in stimulation it should be shown that they will not react with the confining layer. Information on calculating the fracture pressure of a formation can be found in the *Draft UIC Program Class VI Well Site Characterization Guidance*. The API Guidance Document RF1 – Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines also contains information on ways to perform stimulation without fracturing the confining layer. Additionally, the *Draft UIC Program Class VI Well Testing and Monitoring Guidance* provides additional information on how to monitor injection pressure.

Injection between the casing and the formation is not allowed [40 CFR §146.88(b)], as it would provide no barrier between the carbon dioxide and the formation. The Class VI Rule requires the space between the casing and the formation to be cemented [40 CFR §146.86(b)(2) and 146.86(b)(3)].

Toxic and Poisonous Gases

Carbon dioxide (CO_2) and hydrogen sulfide (H_2S) are present in the Gundih Field. Equipment is to be made available at the well site for the detection and monitoring of such gases.

Mud scavengers are also to be available as part of the drilling fluids program.

Surface and sub-surface equipment are to be “fit for purpose” in an environment containing CO_2 and H_2S.

Safety equipment including 30 minute air-packs, 15 minute egress packs, breathing air compressors, wind direction indicators and warning signs are to be made available for all personnel on location.

H_2S and toxic gas training of all relevant personnel is to be conducted.

A contingency plan with respect to the local population, surrounding farm and agricultural life is to be developed.

Drilling Parameters and Well Data Monitoring

A mud logging unit and associated service personnel will be made available, on location, while drilling the well. The purpose of which is to identify potential CO_2 injection zones as they are penetrated.

Additional parameters to be monitored include BOP/wellhead and flowline temperatures, annulus pressures and solids control equipment performance.

RBT – 01A recorded flowline temperature up to 156 °C (313 °F) when nearing TD of the well. Standard BOP elastomers are rated for up to 93 °C (200 °F) with spherical (annular) BOP elastomers rated for 77 °C (170 °F). BOP elastomers are to be rated for the temperatures anticipated. High temperature BOP elastomeric components are available for up to 177 °C (350 °F) and spherical (annular) BOP elastomer elements up to 107 °C (225 °F).

Electric Logging

The electric logging program is designed to confirm the identity of potential CO_2 storage zones. Tools and logging cable are to be suitable for high temperatures (>149 °C/300 °F). In addition electric logging services may be required to conduct intermediate VSP's and pressure measurements of candidate zones.

Casing Wear

Procedures are required developed to check; steel recovery in the drilling fluid and tool joint hard banding inspection specification. And, should casing wear be suspected a casing caliper log and additional pressure testing of casing conducted.

Casing and Annulus Pressure Testing

Casing pressure testing is to be conducted when the last plug is bumped after the cement is in place and prior to setting. This is in an effort to reduce the formation of a micro-annulus between the casing and cement. Typically, the pressure test is to a minimum of 80% of casing pressure rating.

Annulus Pressure Testing will be conducted in accordance with §40 CFR §146.8(b)(2)

Hazardous Operations (HAZOP's)

Surface equipment is to be ***fit for purpose*** in an environment where H_2S and CO_2 are present.

Safety equipment including 30 minute air packs, 5 minute egress pack, breathing air compressors, wind direction indicators, warning signs will be made available.

Training of all relevant personnel is to be conducted.

A contingency plan with respect to the local population and surrounding farm life is to be developed.

All drilling personnel both office based and rig based involved in the decision making and/or supervisory capacity are to have attended a recognized well control course. These courses, typically well specific, are designed to provide the participants with a working knowledge of the procedures and techniques required for a CO_2 injection well. Generally, broken into two training sessions, firstly for supervisory personnel and secondly training directed at drilling crews and service company personnel. The second course will be conducted in the field and cover drilling issues and well control procedures to be used plus, practical drills in implementing procedures.

Surface Location

Figure 12: CCS-1: Pilot CO_2 Injection Well Surface Location KTB-B well pad approximately 4.0 km east of Gundih CPP

The Gundih CPP and producing wells are located near the town of Cepu, Central Java. The area is predominantly agricultural with rural villages that rely on ground water for irrigational and domestic use. The proposed surface well location is approximately 4.0 km east of the Gundih CPP at the KTB – B well pad.

Directional Drilling and Deviation

A deviated well (CCS – 1) is planned from the KTB – B well pad location designated with the following surface location and sub-surface target parameters:

UTM Zone 49S Coordinates:	9203232.44 m S	554412.83 m E
Latitude/Longitude	7°12'18.28"S	111°29'34.27"E
Azimuth:	30° E	
Vertical Section (KOP):	300 m TVD	
Build Section:	300 m TVD	500 m TVD
Maximum Deviation:	30°	4.5°/30 m BUR
Tangent Section:	500 m TVD	~3,582.5 m TVD
Measured Depth:	~4,100 m MD	
True Vertical Depth:	~3,582.5 m TVD	
Target Coordinates:	9204836 m S	555338.4 m E
Target Tolerance	200 m.	
Dog Leg Severity (DLS)	1.06°/30 m.	

Directional Drilling Method Selection

Either rotary steerable or downhole motor will be considered for the directional drilling phase.

A Rotary Steerable System (RSS) will drill the well faster with less time wasted on orienting the tool face with aggressive bit usage (issues with a motor when trying to control the tool-face), and maximizing drilling parameters.

Sliding with a mud motor in could pose challenges due to weight stacking. The weight stacking is more profound when Water Base Mud (WBM) is used as the friction factor is higher than the SOBM. A highly experienced Directional Driller (DD) is required if it is selected to drill with a motor.

An RSS will result in a smoother borehole for casing run in both 12¼-inch and 8½-inch hole section as doglegs are even distributed in the borehole. This will also aid in improved borehole conditions for the extensive logging and formation evaluation program. A mud motor creates "micro-doglegs" which increase the tortuosity of the hole section if not managed well. Micro-dogleg depending on the severity will increase the chance of the drilling assembly becoming stuck due to key-seating.

RSS continuous rotation and higher rotating speed will improve hole cleaning of the well. Mud motors, however, have rotary speed limitations due to the deviation. Improved hole cleaning will reduce the risk of stuck pipe and enable faster tripping.

Near bit Resistivity While Drilling will enable the selection of an optimum geological point at the base of the Tuban and casing setting point for the 9⅝-inch casing and is only applicable when coupled with RSS technology. The RSS Near Bit Resistivity is approximately 1.5 m from the bit whereas when using a mud motor, the Resistivity Tool is at least 15.0 m above the bit.

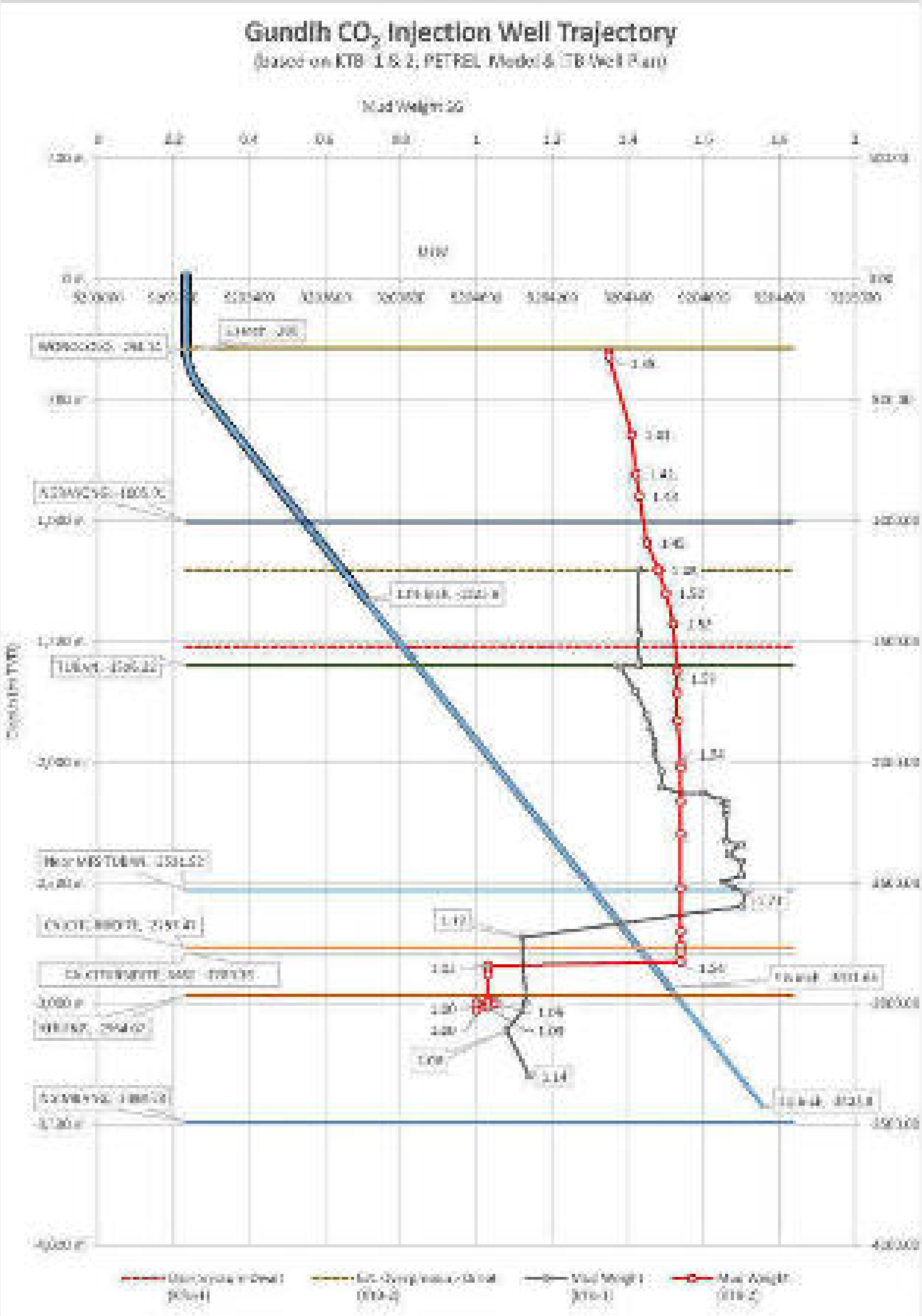

Figure 13 Gundih Pilot CO_2 Injection Well Trajectory, Geological Formations & Estimated Pressure Profiles

Formation Data

Geological Summary – Based on RBT – 1A Offset Well

The location of Randublatung RBT-1A offset well was proposed to be drilled within the Blue Horizon objective of the limestone reservoir layer in the Kujung Formation exhibiting a porosity ranging from 19% - 24%. The reservoir trap is a barrier reef (reefal) shelf edge increasingly controlled by basement faulting since the Eocene period.

Primary Ngimnbang formation hydrocarbon source migration occurred in Miocene – Mid-Miocene where the structural trap of the Kujung Formation was formed. Faulting, in the Middle Miocene penetrated the Kujung Formation. It is expected the shale formation that matures in the Tuban Formation will provide an effective seal.

Offset Well: RBT – 1A

Formation	Drilling
	36" Hole Section: Surface – 30m MD The 36" hole section was initially drilled with a 17½ pilot hole using a water base gel mud then opened up with a 17 ½" bull nose x 26" x 36" hole opening assembly from surface to 30m. At TD the hole was back reamed and a 30 bbl Hi-Vis pill was pumped and displaced with water base gel mud. No gas was recorded due to pump and dump mud returns. 30-inch B, MIJ, 118.6ppf casing was run to 30m and cemented with 76 bbl 1.9 SG slurry
Lidah Formation Surface – 518.0m MD/515.87m TVD Claystone interbedded with sandstone, siltstone and streaks of limestone	26" Hole Section: 30 – 309m MD The 26" hole section was drilled from 30m – 309m with 1.05 – 1.10 SG KCl PHPA Polymer mud. Formation encountered included sandstone interbedded with claystone, limestone and siltstone. Trace gas was recorded from 30m – 240m between 0 – 2 units. Below 240m gas increased from 2 – 8 units with a gas composition comprising mostly methane. No connection gas was recorded in this section. No connection gas was recorded in this section. Maximum trip gas recorded was 63 units after circulating bottoms up prior to pulling out of the hole. 20-inch, K-55, 106.5ppf, BTC casing was run to 308m followed by 7 – 10bbls chemical wash, 50 bbls Mud Push II, lead slurry 268 bbls 1.62 SG, tail slurry 132 bbls, 1.90 SG then displaced with 17 bbls water.

Offset Well: RBT – 1A

Formation	Drilling
Mundu Formation 518.0m MD/515.87m TVD – 787.0m MD/773.1m TVD Sandstone interbedded with layers of siltstone, claystone and marl.	17½"Hole Section: 309 – 1724m MD This section was drilled from 309 – 1724m MD with 1.13 – 1.46 SG SOBM. Mud weight was increased at 354m from 1.13 – 1.25 SG, when background gas increased to 20 – 50 units. At 471m was increased from 1.25 – 1.4 SG as background gas increased and again from 1.4 – 1.46 SG at 585m where background gas stabilized between 60 – 80 units. From 585m MD to hole section TD at 1724m MD background fluctuated between 50 – 120 units. Maximum gas recorded in this section was217 units in a sandstone at 526m MD. Maximum recorded trip gas was 146 units while circulating the hole clean at 1456m MD. Gas in this section consisted mostly of methane with traces of ethane and propane. At hole section TD (1724m MD) the mud weight was increased from 1.46 – 1.49 SG prior to pulling out of the hole (POOH) and gas reduced to 25 units. Mud losses encountered were, 7 bbls of mud were lost pulling out of the hole, 6 bbls at the centrifuge and 7 barrels at the desilter. The 17½"open hole logging suite comprised AITH-MCFL-GR-PEX (Schlumberger). Two gyro run were also made. The hole was then cased and cemented with 13⅜", L-80, 68ppf & 72ppf (connection type not available) with the casing shoe being set at 1722.05m MD/1701.0m TVD.
Ledok Formation 787.0m MD/773.1m TVD – 1043.5m MD/1022.6m TVD. Claystone interbedded with sandstone and siltstone	
Wonocolo Formation 1043.5. MD/1022.6m TVD – 1551.0m MD/1528.9m TVD Predominantly claystone interbedded with siltstone, sandstone and limestone.	
Ngrayong Formation 1551.0m DM/1528.9m TVD – 2174.0m MD/2151.0m TVD Predominantly shale interbedded with sandstone, claystone and siltstone in the upper portion and intercalation with marl and limestone in the middle and lower section.	12¼" Hole Section: 1724 – 2959m MD The 12 ¼" hole section was drilled from 1724 – 2959m MD with Saline Oil Base Mud (SOBM) ranging in mud weight from 1.55 – 1.61 SG. There is no record of the LWD/MWD tools that were used to a depth of 2914m MD where tool failure occurred and drilling continued without LWD/MWD. The tools used and data obtained are not available A VSP was conducted at 2830m. Background gas for the entire section ranged from 50 –

Offset Well: RBT – 1A

Formation	Drilling
Tuban Formation 2174.0m MD/2151.0m TVD 2962.0m MD/2939.6m TVD Shaley claystone and shale interbedded with sandstone and siltstone in upper portion with intercalation shale, siltstone and limestone streaks in the lower part.	150 units with a maximum gas reading of 297 units at 1907m MD and trip gas of 362 units at 2830m MD. At 2959.5m MD. Recovered samples showed approximately 50% limestone and 50% shale. Temperature increased with depth and ranged from 88 °C (191 °F) to 100 °C (212 °F) through the 12¼" hole section The hole was cased with 9⅝", L-80, 53.5 ppf, BTC casing with the shoe set at 2959m MD. The cementing program comprised; 2 bbls water ahead, 50 bbls Mud Push II, 239 bbls 1.68 SG Lead Slurry followed by 100 bbls 1.9 SG Tail slurry
Kujung Formation 2962.0m MD/2939.6m TVD – 3112.0m MD/3090.3m TVD. Predominantly limestone to occasional dolomite.	8⅜" Hole Section: 2960 – 3112m MD The 8⅜" hole section was drilled from 2960 – 3112m MD with 5% KCl Polymer drilling fluid ranging in weight from 1.35 – 1.1 SG. A flow check was conducted at 2973m MD due to dynamic losses of 20 bph at 450 gpm and high gas of 3203 units from 3035m MD. An LCM pill was spotted and POOH 6 stands. Static losses were 6 bph. RIH to 3045m MD and spotted cement plug. Continued drilling from 3045 – 3095m MD. Total losses encountered. Maximum gas encountered while drilling, 1309 units from 3079m MD. Pumped LCM and spotted cement plug. Drilled out cement. Maximum gas, 4050 units from 3079m MD. Circulated to condition hole and monitored for losses, well static. Continued drilling to 3112m MD. Maximum encountered 3096 units from 29776m MD, 3203 units from 3035m MD. Encountered 60 bph losses that increased to 100 bph. Pumped LCM and spotted cement plug with Zone Lock solution to combat losses. Drilled out cement, unsuccessful in combating losses. Spotted another cement plug. Reduced mud weight to 1.1 SG. Drilled out cement plug and continued drilling with losses dropping from 0 – 9 bph. Flowline temperature increased from 149 °C (300 °F) to 156 °C (313 °F) through the interval Open hole logging conducted; Log # 1 DLL – SRT – SP – CAL – GR, Log # 2 LDT – CNL – GR, Log # 3 DSI – GR, Log # 4 FMI – GR, Log # 5 VSP The 7", L-80, 32.0 ppf, BTC liner was run to 3090 m MD and the cement pumping program that followed comprised; 30 bbl 1.24 SG Mud Push II, 30 bbls 1.38 LiteCRETE followed by 183 bbls of displacement mud.

Operations Summary

Operations associated with the drilling of CCS Pilot Well can be broken down into the following discrete steps:

1. Move in drilling unit and associated service equipment and rig up.
2. Drive 30-inch conductor or drill 36-inch hole and run 30-inch casing and cement. Install diverter equipment if shallow gas is considered to be a possibility.
3. Drill 12¼-inch pilot hole to the 20-inch casing setting depth taking returns to the cellar with cellar pump returns to mud system.
4. Log pilot hole as required.
5. Open pilot hole to 26-inch
6. Run and cement 20-inch casing using “water bushing” and drill pipe inner string.
7. Rig down diverter equipment, if it has been installed, cut off 30-inch conductor at cellar floor. Cut off 20-inch casing at pre-determine height and weld on 21¼-inch 3,000 psi WP x 20-inch SOW casing head flange. Leak test weld. Install 21¼-inch, 3,000 psi BOP stack. Test 21¼-inch BOP stack and associated surface equipment in accordance with the approved BOP Test Procedures.
8. Make-up 17½-inch drilling assembly. RIH and drill out the 20-inch casing shoe. Drill 4.0m of new formation and perform a Formation Integrity Test (FIT) to the predetermined value.
9. Directionally drill 17½-inch hole to 13⅜-inch casing setting depth.
10. Conduct wiper trip to 20-inch casing shoe and POOH.
11. Log as required.
12. Run and cement 13⅜-inch casing.
13. Remove 21¼-inch 3,000 WP BOP’s and install the 21¼-inch x 13⅝-inch Casing Head Assembly (CHA) and pressure test CHA cavities. Install 13⅝-inch 5,000 psi WP BOP stack and associated surface equipment in accordance with the approved BOP Test Procedures.
14. Make up 12¼-inch drilling assembly. RIH and drill out 13⅜-inch casing shoe. Drill 4.0m of new formation and perform a Formation Integrity Test (FIT) to the predetermined value.
15. Drill 12¼-inch hole to the base of the Tuban Formation.
16. *<u>11¾-inch Contingency Liner</u>*
    a. ***In the event hole conditions are unfavorable in this hole section,*** *POOH, make up 14¾-inch hole opening drilling assembly and open up the hole to 14¾-inch to the 11¾-inch contingency liner setting depth.*
    b. *Conduct wiper trip to 13⅜-inch casing shoe.*
    c. *Log as required.*
    d. *Run and cement the 11¾-inch contingency liner.*
    e. *Make up 9⅞ x 12¼-inch drilling assembly. RIH and drill out 11¾-inch contingency liner shoe. Drill 4.0m of new formation and perform a Formation Integrity Test (FIT) to the predetermined value. Drill to 9⅝-inch casing setting depth at the base of the Tuban Formation. POOH.*
    f. *Conduct wiper trip to the 11¾-inch liner shoe.*
17. Conduct wiper trip to the 13⅜-inch casing shoe.
18. Log as required and conduct formation dynamics tests of any potential CO_2 injection formations along with Side Wall Core (SWC) sampling.
19. Run and cement 9⅝-inch liner.

20. Nipple down 13⅝-inch 5,000 psi WP BOP stack. Install 13⅝-inch 5,000 psi x 11-inch 5,000 psi CHA and pressure test CHA cavities. Install 13⅝-inch 5,000 psi WP BOP stack and associated surface equipment in accordance to the approved BOP Test Procedures.
21. Make up 8½-inch drilling assembly. RIH and drill out 9⅝-inch casing shoe. Drill 4.0 m of new formation and perform a Formation Integrity Test (FIT) to the predetermined value.
22. Control drill 8½-inch hole and penetrate the Kujung Formation. Continue drilling to the water zone, at the base of the Kujung Formation and prior to penetrating the Ngimbang Formation, where it is planned to conduct full-hole coring of the target injection zone. POOH.
23. RIH with core barrel assembly and core the lower portion of the Kujung Formation. POOH.
24. Conduct wiper trip from TD to the 9⅝-inch liner shoe. POOH
25. Log as required and conduct formation dynamics tests of potential CO_2 injection formations below the water contact.
26. Run 5½-inch "long string" casing and external down-hole monitoring equipment and cement utilizing a multi-stage light weight cementing process. On completion of the first stage cementation, land 5½ inch mandrel casing hanger and conduct second stage cementation taking returns through wellhead Section B side outlets.
27. Nipple down 13⅝-inch 5,000 psi WP BOP stack. Install 11-inch 5,000 psi x 11-inch 5,000 psi tubing hanger section with temperature and pressure ports. Install 13⅝-inch 5,000 psi WP BOP stack and associated surface equipment in accordance to the approved BOP Test Procedures.
28. Install bull plug in tubing No-Go nipple, run 2⅞-inch tubing, isolation packer, associated completion equipment and tubing hanger pressure testing tubing every 5 stands.
29. Land tubing hanger in wellhead section, secure and set packer.
30. Pressure test tubing/packer annulus and temperature/pressure exit ports.
31. Retrieve bull plug from No-Go profile.
32. Install BPV in tubing hanger.
33. Nipple down BOP equipment.
34. Demobilize drilling unit and associated service equipment.
35. Install Xmas tree and pressure test. Including monitoring sensor DAS cable ports.
36. Rig Down and Rig Release
37. Restore site.

The well will be perforated at a later date on assessment and interpretation of the data acquired over the zone of interest.

Time – Depth Curve

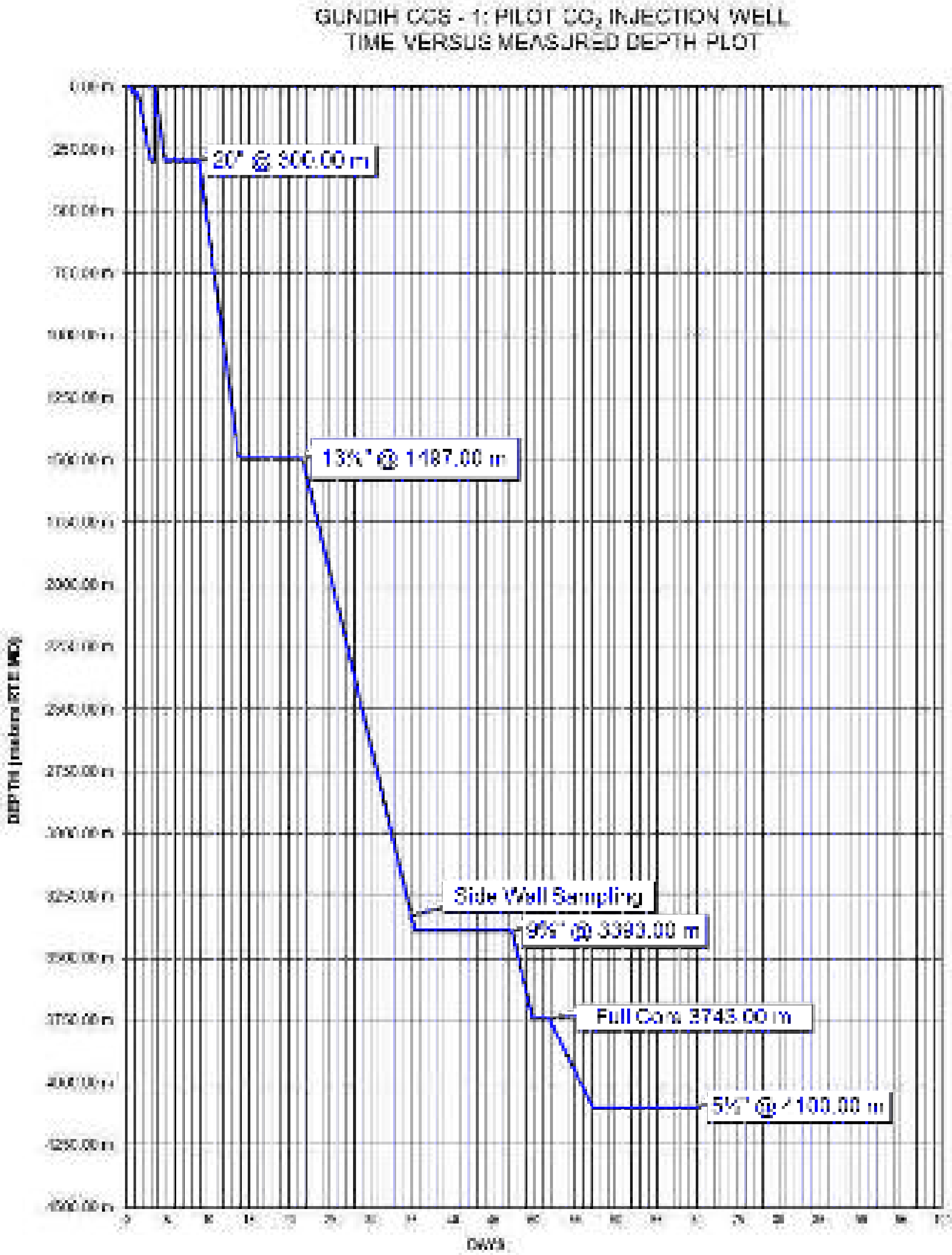

Figure 14 Estimated Time - Depth Curve with 30% NPT

Formation Evaluation

Borehole Characterization

Rationale

- Conduct a detailed characterization of near wellbore geology to identify CO_2 injections interval(s) in support of the development of an accurate reservoir model.
- Model accuracy is critical in the prediction of CO_2 spreading/behavior.
- Modelling is a monitoring method (particularly in the case, when monitoring wells are not available).

Borehole Characterization Program Elements

- Geophysical logging.
- Coring, core sampling, core testing and analysis.
- Packer testing.
- Stress measurements (mini-frac testing).
- Borehole seismic (tentative).
- Data analysis, interpretation and modelling.

Open Borehole Logging Program

17½ inch Hole Section - 13⅜ inch Casing

Log № 1 - Parameters
Basic Properties:

- Resistivity
- Neutron Porosity
- Bulk Density
- Caliper
- Gamma Ray
- Photo-Electric Factor

Acoustic Velocities:

- Rock Mechanical Properties
- Horizontal Stress Orientation (azimuth) and anisotropy
- Velocity Modelling Update

Log № 1A Cased Hole Logging

- Cement Evaluation Log

Hole Depth (TVD)/Formation
Surface – 1,324 m TVD/1492 m MD

Logging Tools:

- Triple Combo or Platform Express*
- Dipole Sonic

Formation:

- Wonocolo
- Ngrayong

Wonocolo

Ngrayong

14¾ inch Hole Section - 11¾ inch Contingency Liner

Contingency Log Parameters
Basic Properties:

- *Resistivity*
- *Neutron Porosity*
- *Bulk Density*
- *Caliper*

Hole Depth (TVD)/Formation
1,324 m – TBA

Logging Tools:

- *Triple Combo or Platform Express**

Ngrayong

- *Gamma Ray*
- *Photo-Electric Factor*

Acoustic Velocities:

- *Rock Mechanical Properties*
- *Horizontal Stress Orientation (azimuth) and anisotropy*
- *Velocity Modelling Update*
  Identify depositional features, bedding, dip, vugular porosity, fractures, faults and stress orientation (if break-outs or drilling induced fractures are present.
- *Acoustic Resistivity*

Contingency Cased Hole Logging

- *Cement Evaluation Log*

- *Dipole Sonic*

Formation:

- *Ngrayong*
- *Tuban*

Tuban

12¼ inch Hole Section - 9⅝ inch Liner

Log № 2 - Parameters

Basic Properties:

- Resistivity
- Neutron Porosity
- Bulk Density
- Caliper
- Gamma Ray
- Photo-Electric Factor

Acoustic Velocities:

- Rock Mechanical Properties
- Horizontal Stress Orientation (azimuth) and anisotropy
- Velocity Modelling Update
  Identify depositional features, bedding, dip, vugular porosity, fractures, faults and stress orientation (if break-outs or drilling induced fractures are present.
- Acoustic Resistivity

Mineralogy

- Elemental Spectroscopy (tentative)
- Rotary Sidewall Core Sampling

Log № 2A Cased Hole Logging

- Cement Evaluation Log

Hole Depth (TVD)/Formation
1,324 – 2,932 m TVD

Logging Tools:

- Triple Combo or Platform Express*
- Dipole Sonic
- Resistivity (LWD) geo-stop

Formation:

- Ngrayong
- Tuban

Ngrayong

Tuban

8½ inch Hole Section - 5½ inch Production Casing

Log № 3 Parameters
Basic Properties:
- Resistivity
- Neutron Porosity
- Bulk Density
- Caliper
- Gamma Ray
- Photo-Electric Factor

Acoustic Velocities:
- Rock Mechanical Properties
- Horizontal Stress Orientation (azimuth) and anisotropy
- Velocity Modelling Update
  Identify depositional features, bedding, dip, vugular porosity, fractures, faults and stress orientation (if break-outs or drilling induced fractures are present.
- Acoustic Resistivity

Permeability
- Nuclear Magnetic Resonance

Fluid Type/Saturation
- Pulsed Neutron Capture

Mineralogy
- Elemental Spectroscopy (tentative)
- Coring/Rotary Sidewall Core Sampling

Log № 3A Cased Hole Logging
- Cement Evaluation Log

**Schlumberger Nomenclature*

Hole Depth (TVD)/Formation
2,932 – 3,424 m TVD

Logging Tools:
- Triple Combo or Platform Express*
- Dipole Sonic
- NMR*
- PNC*

Formation:
- Kujung

Kujung

Measurement While Drilling (MWD)

A Rotary Steerable System (RSS) is employed, in wells over 20° deviation, by the operator along with the associated MWD requirements.

Resistivity Imaging While Drilling (LWD)

A minimum LWD requirement, Resistivity While Drilling is to be included with the selected directional drilling method for the casing setting point identification e.g. Geo-stop (this tool has an accuracy of 1.0 – 1.5 meters). Other LWD requirements are to be established on the availability of tools.

Coring & Sidewall Core Sampling

Full Hole Coring Primary Objective – Lower Kujung

Coring operations are planned to be conducted in the target CO_2 injection reservoir section. All downhole coring equipment is to be temperature rated for reservoir conditions and exposure to a CO_2 and H_2S environment.

The point at which coring will commence is to be determined in conjunction with the Drilling Supervisor and Well Site Geologist and conveyed to Company for final concurrence. As with any coring operations, the utmost care is to be taken when operations are conducted in a high temperature, H_2S environment of this nature. As a primary concern, the well is to be confirmed in a stable state prior to commencement of coring operations.

Upon recovery, the core is to be catalogued, packaged in an approved method and sent to a laboratory for analysis.

Side Wall Sampling Secondary Objective – Lower Tuban Calciturbidite

Rotary sidewall core sampling is planned as part of the 12¼-inch hole section open hole logging program to sample the calciturbidite sequence above the Kujung Formation as a potential secondary CO_2 injection zone prior to setting the 5½-inch production casing. As in the full hole coring equipment is to be temperature rated and suitable for working in an H_2S and CO_2 environment.

This phase will also include sidewall core sampling of the cap rock above the reservoir section in the Tuban Formation.

Characterization Program

Well and Reservoir Hydraulic and Geo-mechanical Testing

Phase 1 – Flowmeter Logging (mechanical spinner meter logging tool) survey of the open borehole section across the reservoir to identify candidate CO_2 injection zones.

This phase of testing includes a baseline fluid logging survey conducted under static (no injection) conditions and additional surveys conducted while injecting brine at increasing rates (e.g. 2, 4 and 6 bpm).

Phase 2 – Straddle Packer Tests of candidate CO_2 injection horizons and other discrete intervals with the intervals being isolated utilizing a straddle packer testing tool.

This phase will include Hydraulic Pumping (withdrawal/build-up) tests to characterize formation hydraulic properties (transmissibility, permeability).

Stress Test pumping (injection/fall-off) tests will be conducted to create mini hydraulic fractures to characterize horizontal stress directions and formation fracture pressure.

Well Schematic

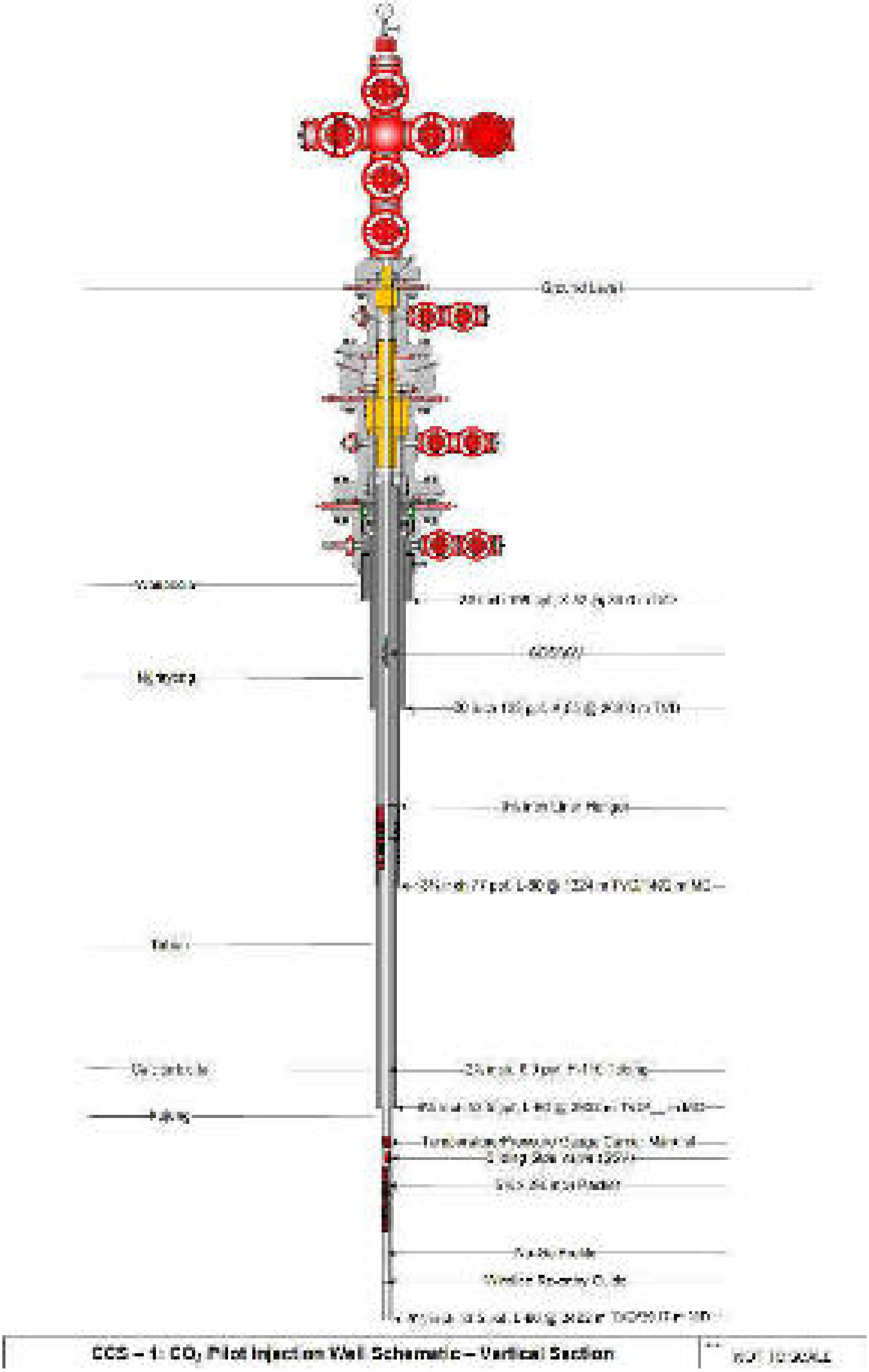

Figure 15 CCS Conceptual Well Schematic – Vertical Section

Well Suspension/Abandonment

At the termination of the CCS pilot program, that is expected to endure for approximately 2 years, the decision to suspend or abandon the well will be made.

Should there be a potential for the well to either remain a CO_2 injection well or a production well the well will be suspended and left in a usable state, providing no safety or environmental concerns are violated, i.e. Xmas Tree, production tubing, safety valve and completion packer remain in place.

In the event the well is plugged and abandoned, procedures will meet the requirements of 40 CFR §146.92. Plugging procedure and materials will be designed to prevent any unwanted fluid movement, to resist the corrosive aspects of carbon dioxide/water mixtures, and protect any USDW's. Any necessary revisions to the well plugging plan, to address new information collected during logging and testing of the well will be made after construction, logging and testing of the well have been completed.

After injection has been terminated, the well will be flushed with a kill weight brine fluid. A minimum of three (3) tubing volumes will be injected without exceeding the fracture gradient/pressure. Bottom hole pressure will be taken and the well will be logged and pressure tested to ensure mechanical integrity, inside and outside the casing, prior to plugging. Should a loss of mechanical integrity be discovered, the well will be repaired prior to proceeding with plugging operations. A detailed plugging procedure is to be compiled. All casing strings extending to surface will have been cemented to surface during the well construction phase and will not be retrievable at abandonment. When injection has been terminated permanently, the injection tubing and packer will be retrieved and the well plugged with either, balanced cement plugs or a combination of cement retainers and cement plugs. In the event the packer cannot be retrieved, the tubing will be cut with an electric line tubing cutter leaving the packer in the well after which a cement retainer will be used for plugging the injection formation below the packer.

All casing strings will be cut off in accordance with regulatory requirements and a blanking plate with the well information welded to the cutoff casing.

Company will record bottom hole pressure from a downhole pressure gauge to determine kill fluid density. At least one (1) of the following logs, as required by 40 CFR §146.92(a), will be conducted to verify external Mechanical Integrity (MI) prior to plugging operations:

- Temperature Log
- Noise Log
- Oxygen Activation Log

Cement formulated for plugging operations shall be resistant to the carbon dioxide stream.

The suspension or abandonment of the CCS – 1 Pilot Well is to adhere to Badan Standar Nasional Indonesia SNI 13-6910 – 2002: Drilling Operation for Safe Conduct of Onshore and Offshore in Indonesia – Implementation. Specifically, Article 6.10 Abandonment of Wells; Sub-sections 6.10.3 Permanent Abandonment and 6.10.4 Temporary Abandonment (Suspension). It should be pointed out that a well that is temporarily abandoned (suspended) shall be permitted by Pertamina as per Government Regulation № 17/1974 (Ref: SNI 13-6910 – 2002 Appendix C1)

WELL ABANDONMENT – STANDAR NASIONAL INDONESIA SNI 13 – 9610 – 2002

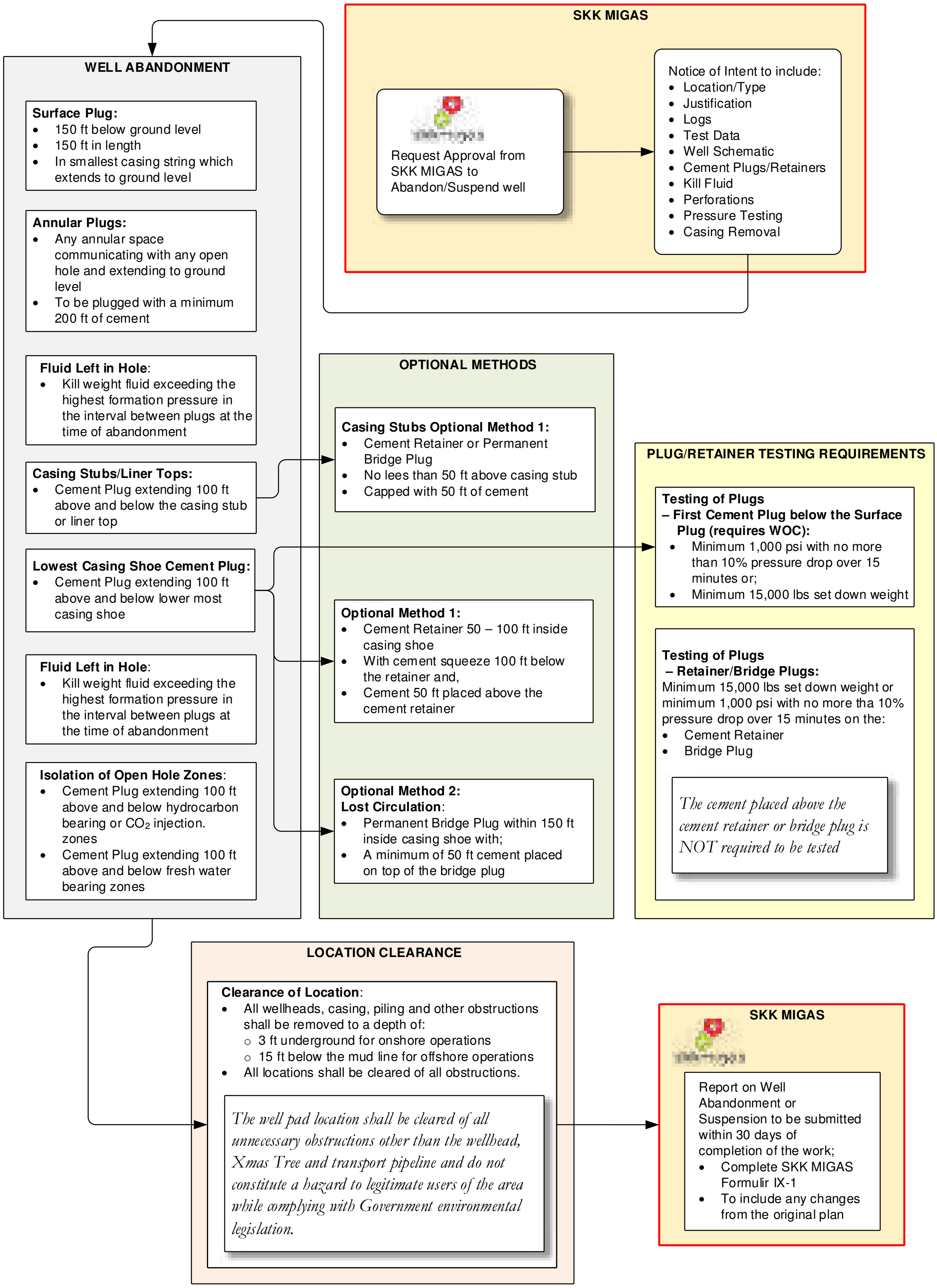

Figure 16: Well Suspension/Abandonment Flowchart

Nomenclature

API	American Petroleum Institute
bbl	Barrel
BHST	Bottom Hole Static Temperature °C (°F)
BOP	Blow-Out Preventer
bph	Barrels per Hour
bpm	Barrels per Minute
BPV	Back Pressure Valve
BTC	Buttress Thread Connection
BUR	Build Up Rate
°C	Degrees Celsius
CAL	Caliper Log
Cap Rock	The shale layers above a reservoir that provide geological isolation to upward migration of CO_2 and provide the primary seal
CBL	Cement Bond Log
CHA	Casing Head Assembly
CO_2	Carbon Dioxide
CPP	Central Processing Plant
DAS	Distributed Acoustic System
DLS	Dog Leg Severity
DST	Drill Stem Test
DTS	Distributed Temperature System
°F	Degrees Fahrenheit
ft.	feet
gpm	gallons per minute
GR	Gamma Ray Log
H_2S	Hydrogen Sulfide
HAZOPS	Hazardous Operations
KCl	Potassium Chloride
KOP	Kick Off Point
LCM	Lost Circulation Material
m	meters
MD	Measure Depth – m (ft.)
MDT	Modular Dynamic Tester (Schlumberger)

MI	Mechanical Integrity
MMSCFD	Million Standard Cubic Feet per Day
MT	Metric tons
NACE	National Association of Corrosion Engineers
NMR	Nuclear Magnetic Resonance Log
NPHI	Neutron Porosity Log
OBM	Oil Base Mud
PDC	Polycrystalline Diamond Compact (drill bit)
PEF	Litho-Density Log
PHPA	partially-hydrolyzed polyacrylamide
PNC	Pulsed Neutron Capture Log
POOH	Pull Out Of Hole
ppf	Pounds Per Foot
PR	Performance Requirement
psig	pounds per square inch, gauge
psi WP	pounds per square inch Working Pressure
PSL	Product Specification Level
OBM	Oil Base Mud
RCX	Reservoir Characterization Explorer (Baker)
RES	Resistivity Log
RHOB	Neutron Density Log
RIH	Run In Hole
RSS	Rotary Steerable System
RTE	Rotary Table Elevation
SG	Specific Gravity
SOBM	Synthetic Oil Base Mud
SONIC	Sonic Log
SOW	Slip-on Weld
SSSCSV	Sub Surface, Surface Controlled Safety Valve
SSV	Surface Safety Valve
SWC	Side Wall Core
TBA	To be advised
TD	Total Depth (measured) – m (ft.)
TDS	Top Drive System

TVD	True Vertical Depth – m (ft.)
TVDSS	True Vertical Depth, Sub Sea - m (ft.)
USIT	Ultrasonic Imaging Tool
VDL	Variable Density Log
VSP	Vertical Seismic Profile
WBM	Water Base Mud
WP	Working Pressure

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    d. National Energy Technology Laboratory, Albany, OR 97322, United States
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    f. Pacific Northwest National Laboratory, Richland, WA 99354, United States
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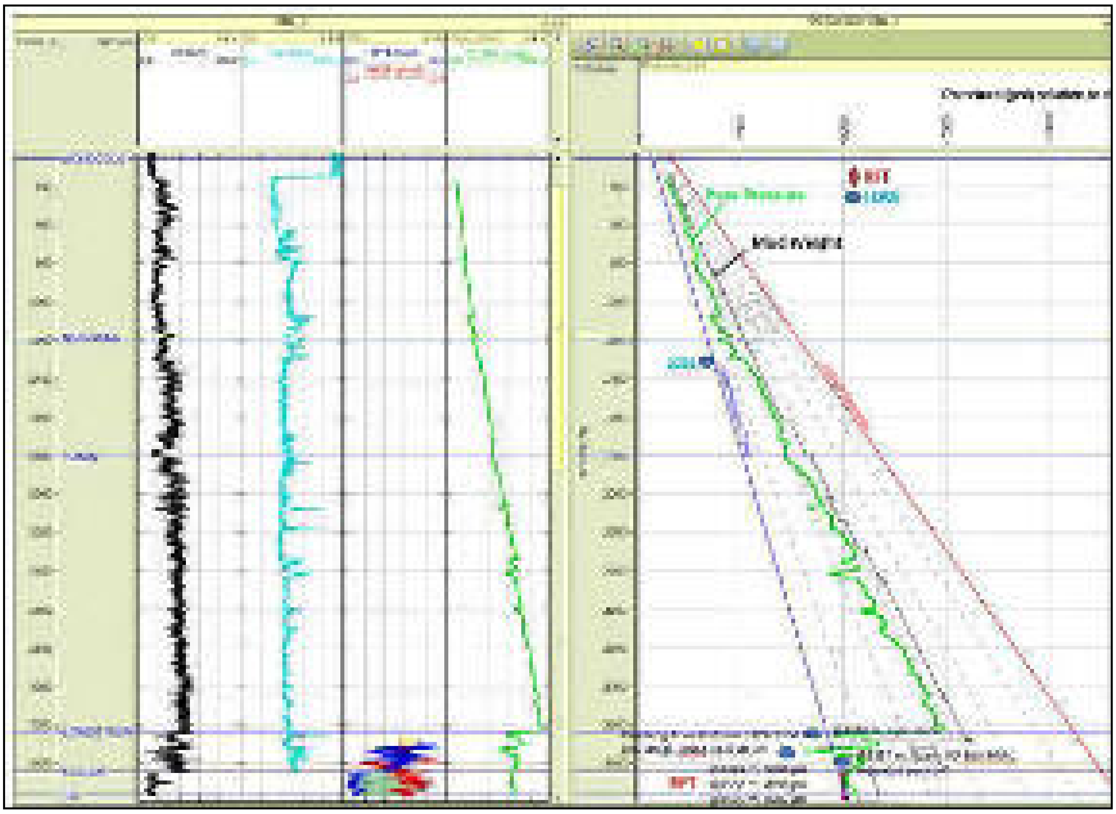

Figure 17: KDL-1 Well Data Profile

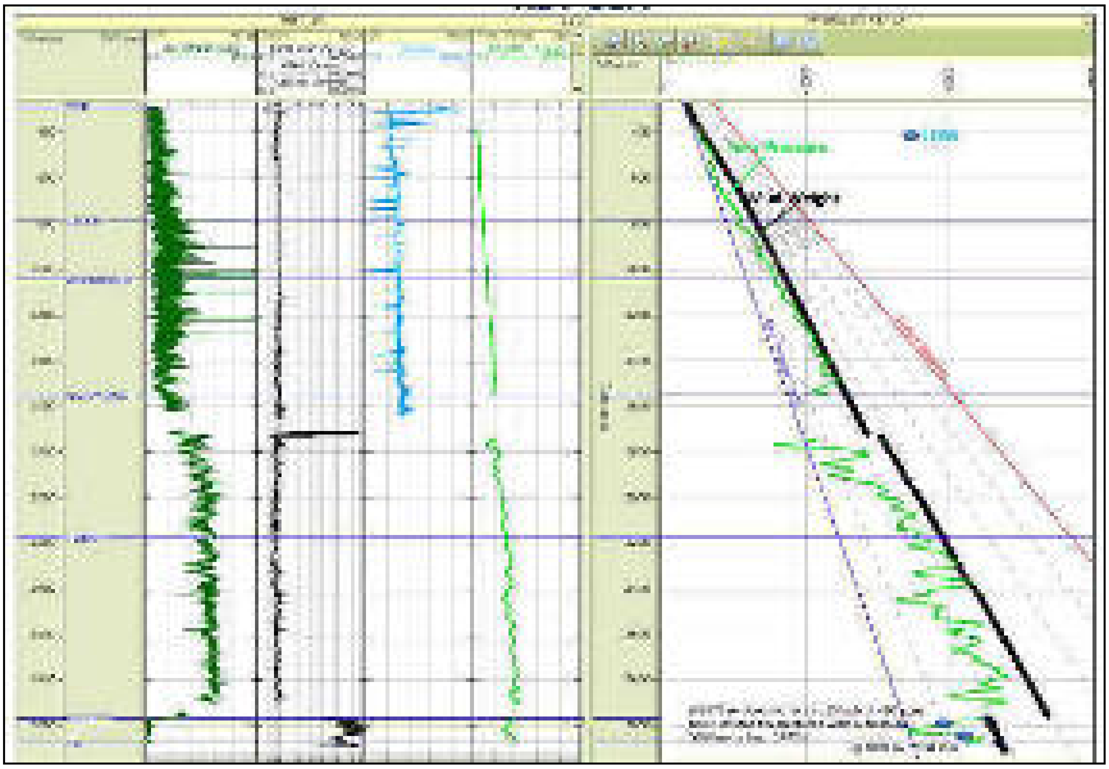

Figure 18: RBT-1A Well Data Profile

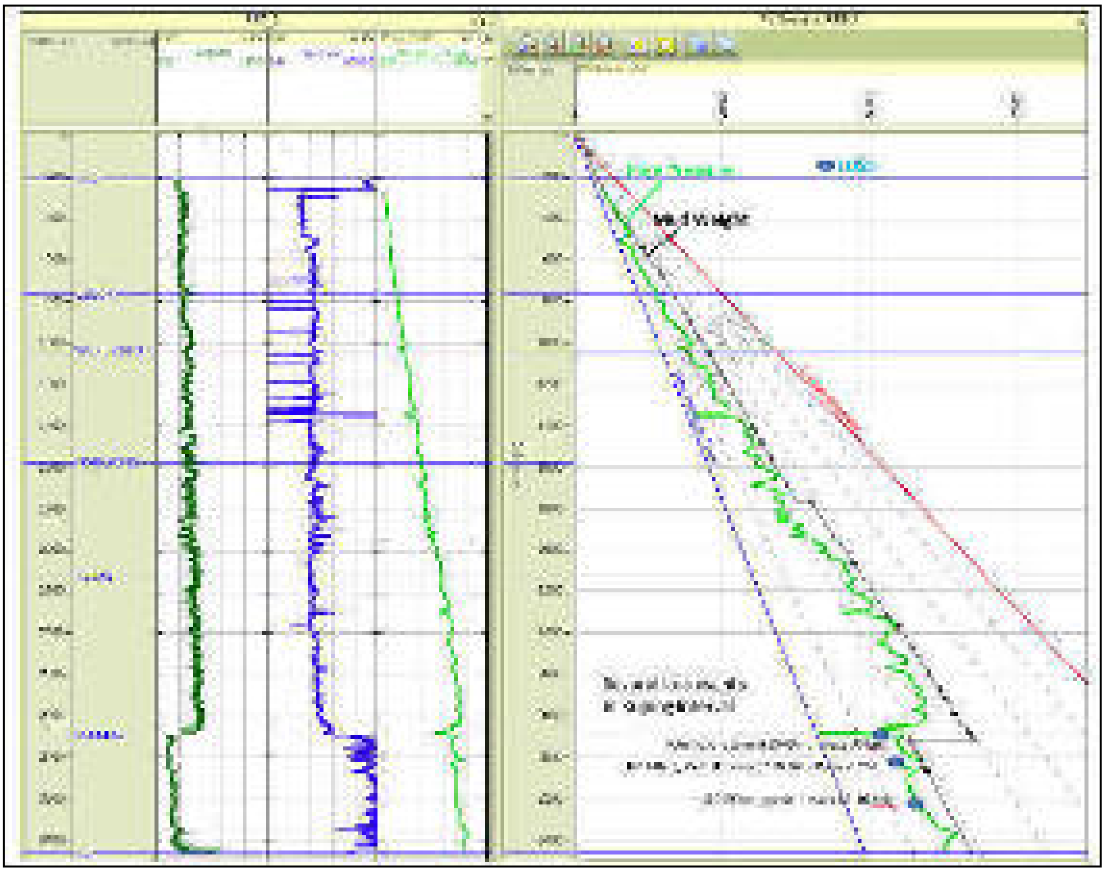

Figure 19: RBT-2 Well Data Profile

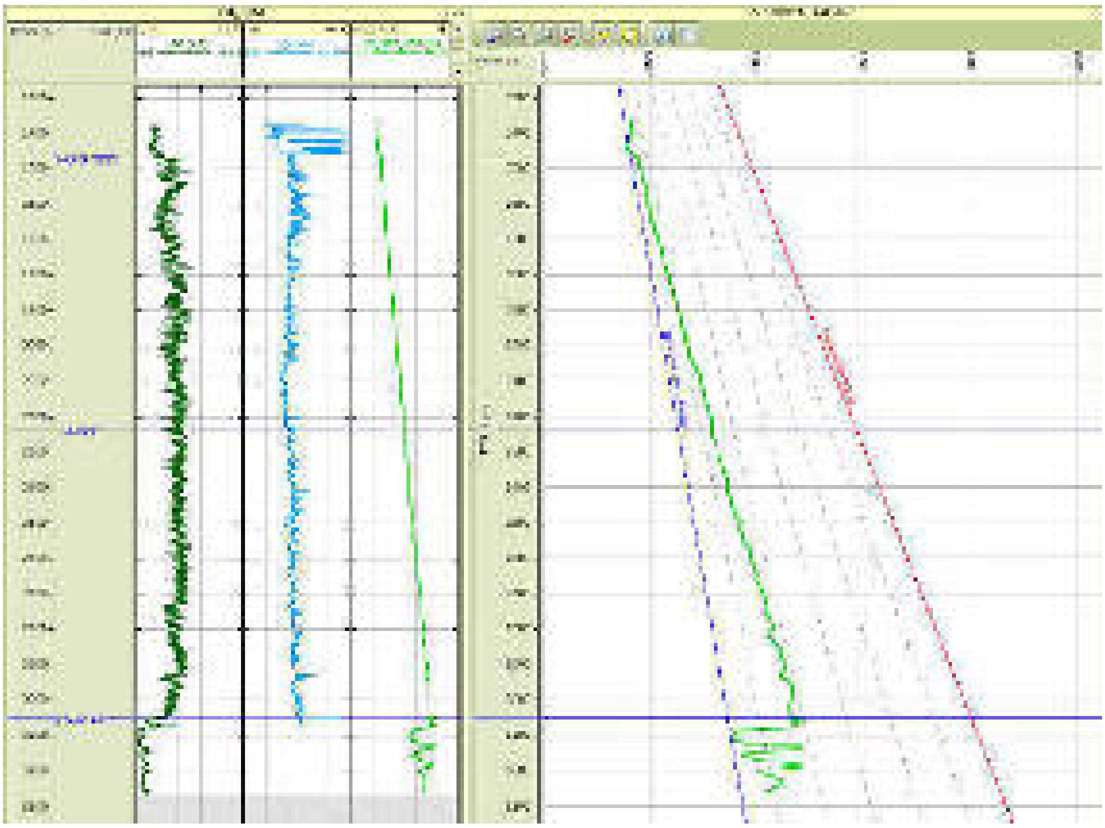

Figure 20: RBT-3Well Data Profile

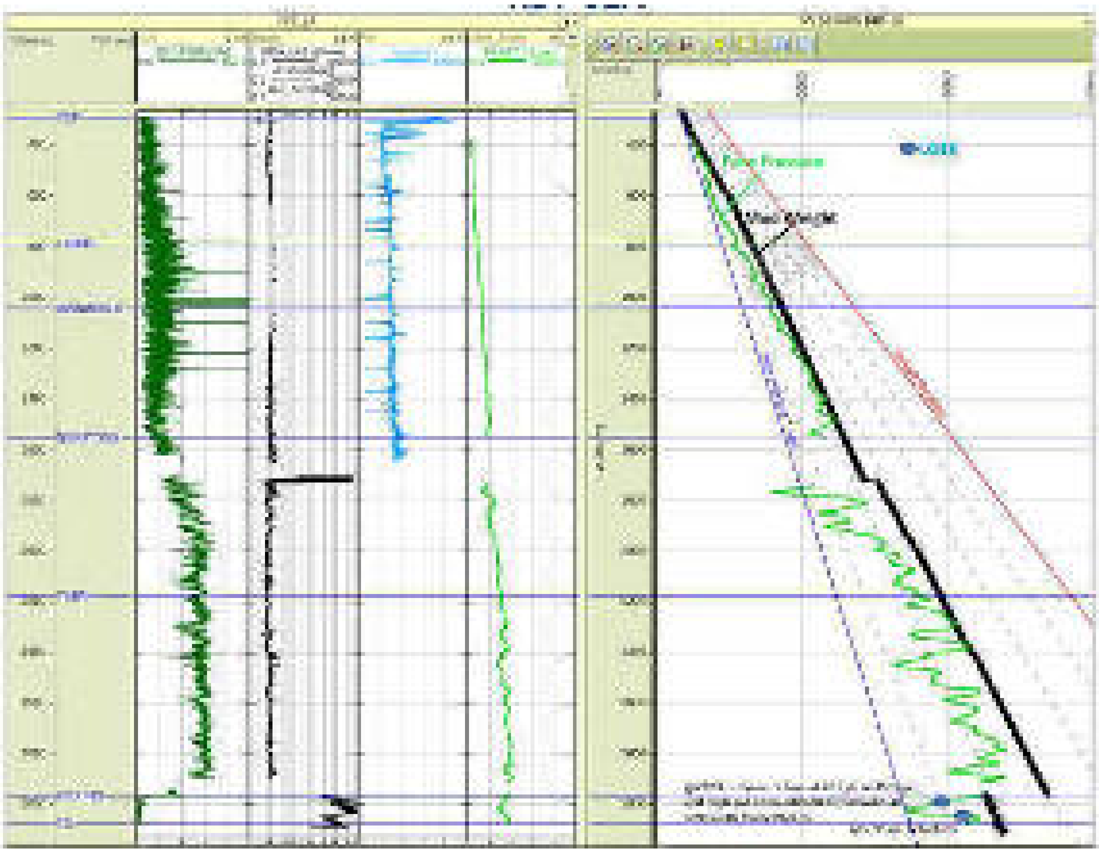

Figure 21: KBT-1 Well Data Profile

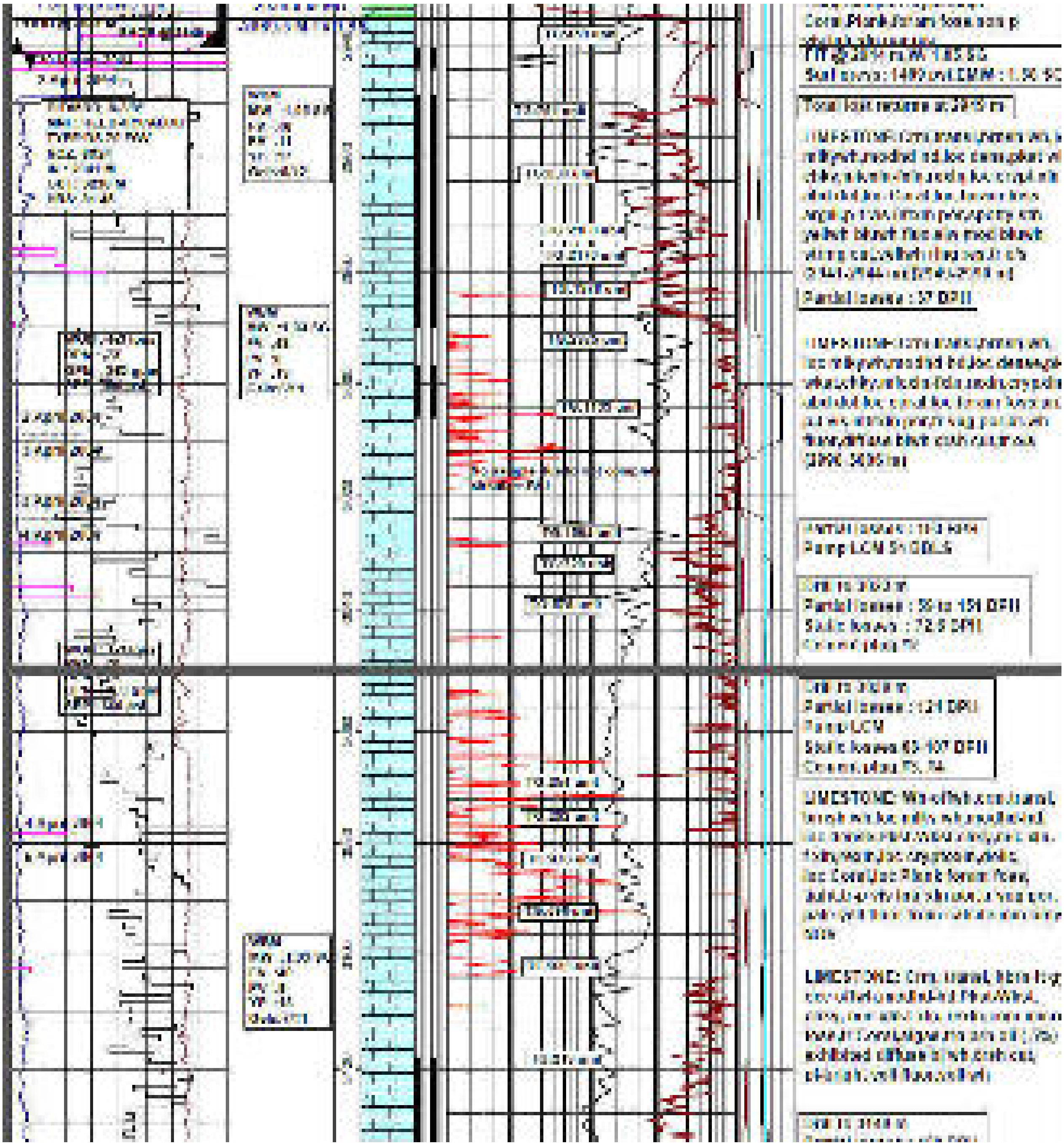

Figure 22: RBT-2 Mud Log

GUNDIH SITE VISIT REPORT

13 & 14th February 2019

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RBT – B Well Pad and RBT-02 Well 6

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KTB – B Well Pad: KTB-02 & KTB-04 Wells 11

Gundih Central Processing Plant (CPP) 14

Preamble

The second Gundih site visit took place 13th & 14th February 2019 and covered the well pad locations, pipeline right-of-ways and Gundih Central Processing Plant.

The visit team comprised, representatives of Asian Development Bank, Battelle Memorial Institute, Institute Technology Bandung, Elnusa and Pertamina.

Commencing, initially, with a meeting at Pertamina Asset Offices, Cepu, followed by a site visits to, Gundih well pad locations and some pipeline right-of-ways and the central processing plant.

The site visit focused on potential candidate surface well locations for use as a CO_2 pilot injection well site. There are five (5) well pad locations in the Gundih Field; KDL, RBT – A, RBT – B, KTB – A and KTB – B.

Figure 1: Gundih CPP, Well Pads and Pipeline ROWs

RBT – A Well Pad: RBT-01A and RBT-03ST Wells

RBT Well Pad A is the closest well location west of the Gundih Central Processing Plant and is approximately 32,269 m^2 in size. The pipeline right of way is approximately 1,450 meters in length and crosses the provincial highway at the entrance to both the CPP and RBT Well Pad A where; producing well RBT - 01 and, water injector well RBT – 03 are located.

Three pipelines traverse this right of way, 2 – 6 inch steel pipelines and 1 – HDPE PN 110.

Figure 2: Pipeline ROW RBT-3ST to Gundih CPP and RBT-A Well Pad approximately 32,269 m^2

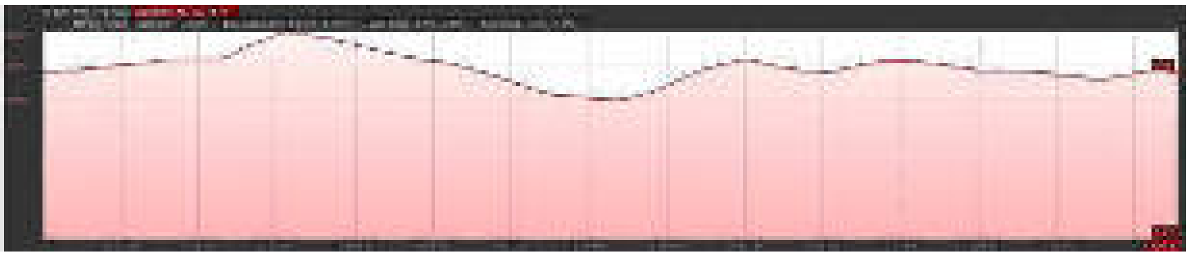
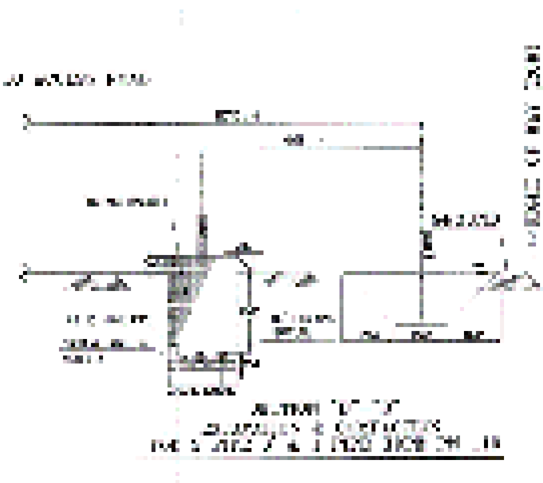


Figure 3: Elevation Profile ROW: RBT-A Well Pad to Gundih CPP



Three pipelines traverse this right of way, 2 – 6 inch steel pipelines and 1 – HDPE PN 110.

Figure 4: ROW Cross Section RBT-A Well Pad to Gundih CPP

Figure 5: Peting - Menden Provincial Road Crossing RBT-A to Gundih CPP

Figure 6: RBT-01 and RBT-03ST (water injection) Wellheads

KDL – A Well Pad: KDL-01 Well

The most western well pad KDL – A, 23,520 m^2 in size, is currently not a viable option as a CO_2 injection well location, however, it is shown to indicate the challenges of being selected as a potential candidate.

A single 6 inch flowline is contained in the pipeline right of way that passes from KDL Well Pad A to RBT Well Pad A, through a complex agricultural rural area and river crossings onto the CPP via the access road pipeline right of way, a distance of approximately 6,470 meters.

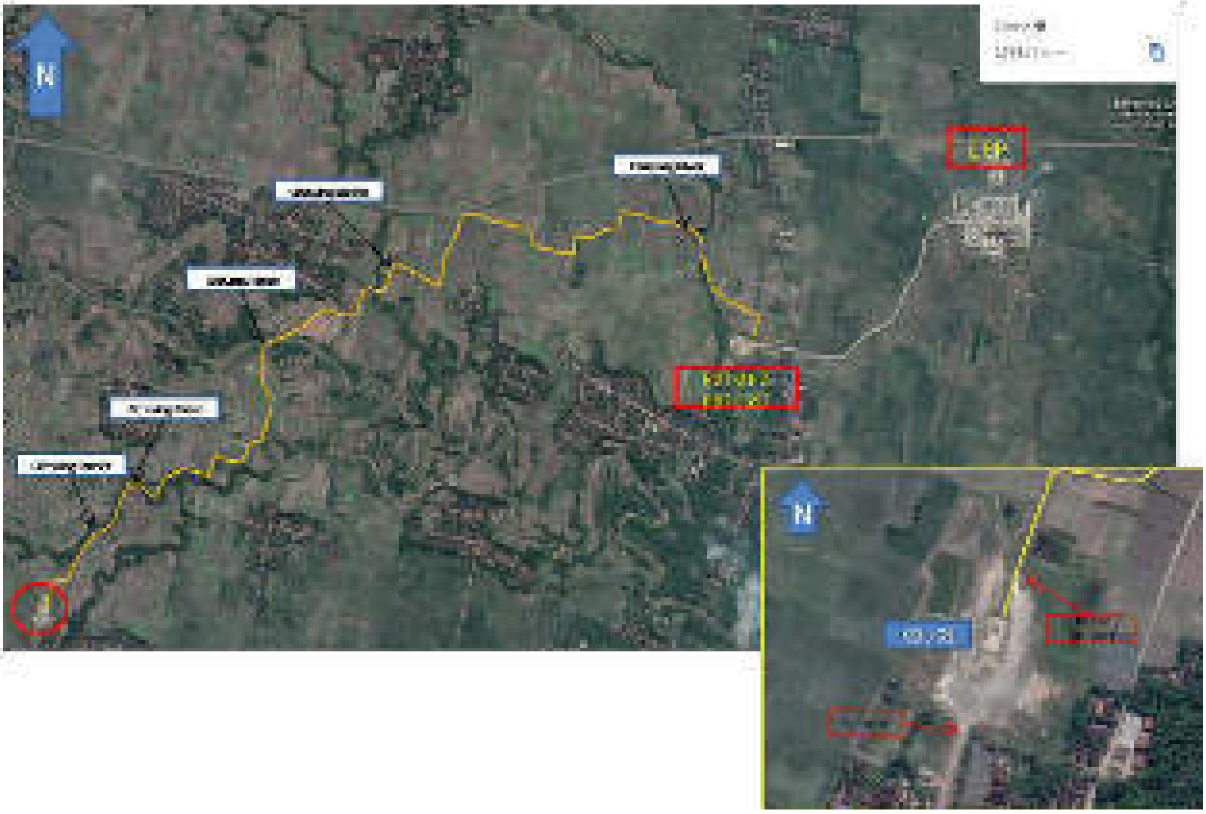
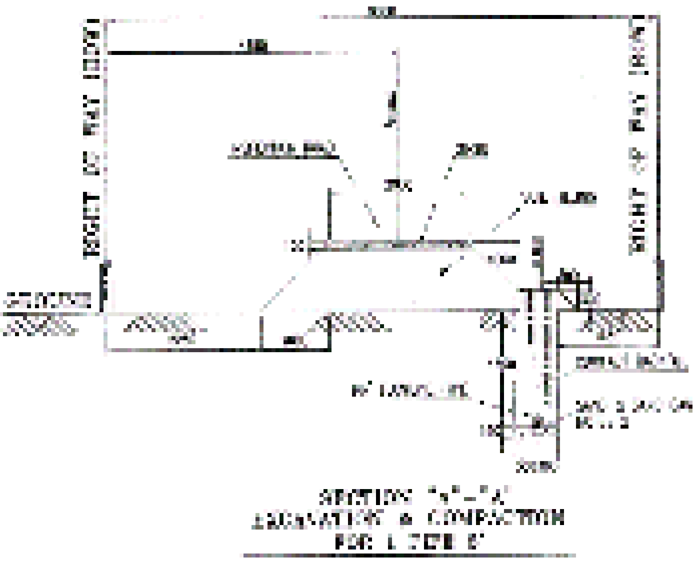


Figure 7: KDL-A Well Pad Location (23,520 m^2) & Pipeline ROW

Figure 8: Pipeline ROW Elevation Profile: KDL-A Well Pad to RBT-A Well Pad



A single 6 inch flowline from KDL-01 traverses this ROW

Figure 9: ROW Cross Section: KDL-A Well Pad to RBT-A Well Pad

Figure 10: KDL-o1 Wellhead and Controls

RBT – B Well Pad and RBT-02 Well

RBT Well Pad B, 24,950 m^2 in area, is the next well location in close proximity to the CPP and is where RBT – 02 well is located. This well pad is subject to flooding of up to 1.5 meters during the wet season. Artificial water containment ponds have been constructed on the well pad areas closest in proximity to a nearby tributary of the Bengawan Solo River.

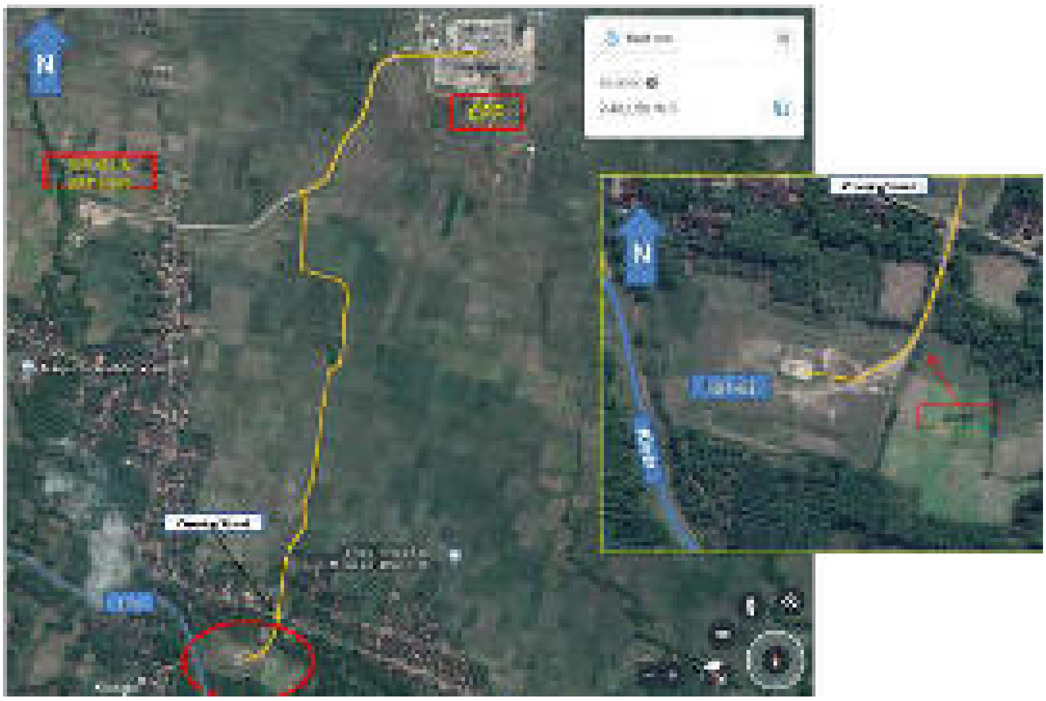


Figure 11: RBT-B Well Pad Location & Pipeline ROW intersecting at Gundih CPP access road.

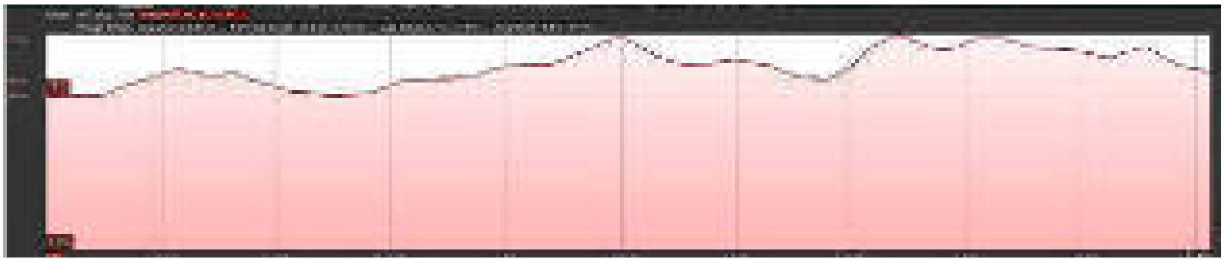
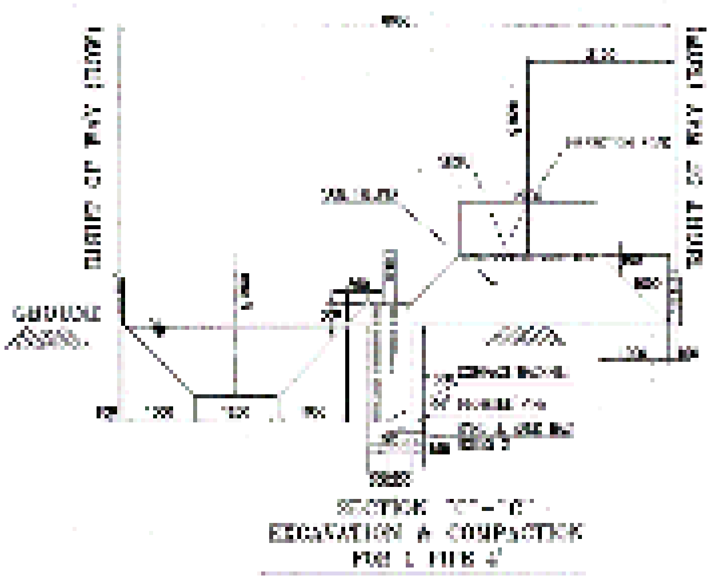


Figure 12: RBT-B Pipeline Elevation Profile: RBT-B to Gundih CPP Junction Point



The associated pipeline right of way is approximately 2,465 meters in length and has a 4 inch single flowline from RBT-02

The 4 inch RBT-02 flowline merges with the 2 – 6 inch flowlines from RBT – 3 and KDL-01 and the single water injection HDPE line to RBT-03.

Figure 13: ROW Cross Section: RBT-B to Gundih CPP Junction Point

Figure 14: RBT-02 Wellhead

Figure 15: Elevated Well Control Panel & Water Containment Pond area.

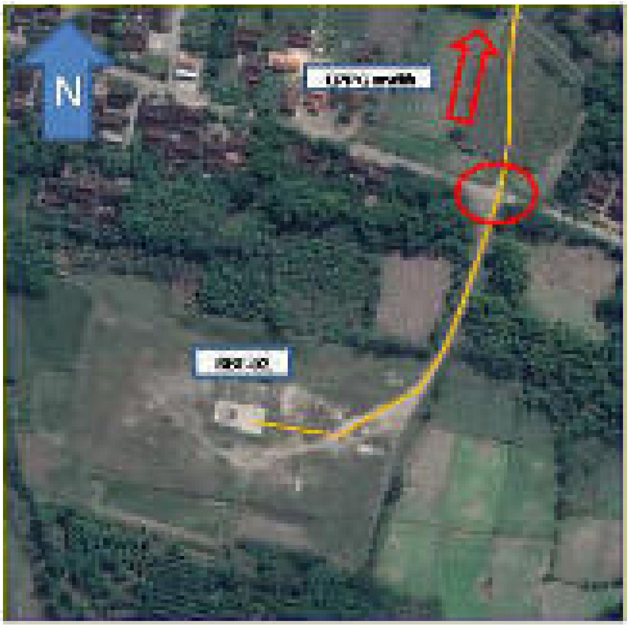


Figure 16: RBT-B to Gundih CPP Provincial Road Crossing Point

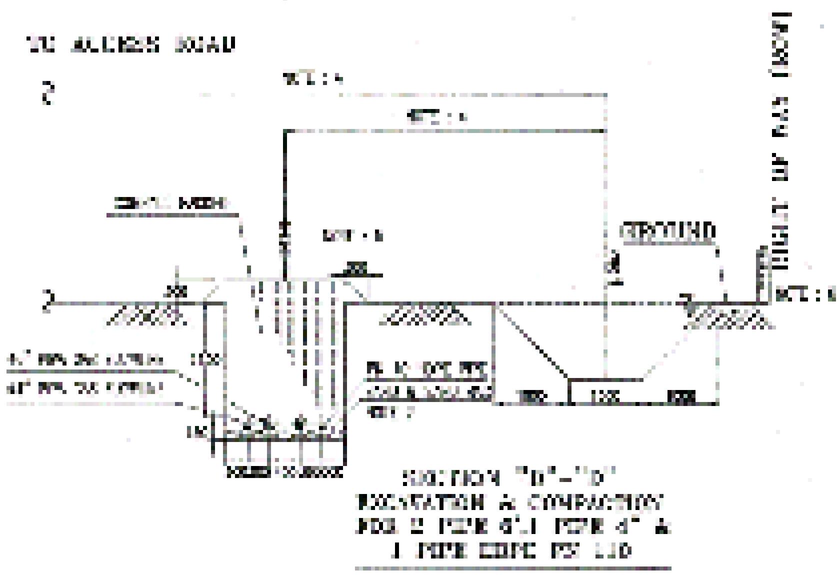


Figure 17: ROW Cross Section KDL/RBT-A/RBT-B Junction Point to Gundih CPP

KTB – A Well Pad: KTB-01, KTB-03TW & KTB-06ST Wells

KTB Well Pad A, an area of approximately 20,024 m^2, is located north east of the CPP and is where KTB – 01, KTB - 03 TW and KTB – 06 ST are located. The associated pipeline right of way from KTB Well Pad A to the CPP crosses underneath the provincial rail way line.

Figure 18: KTB-A Well Pad Location and Pipeline ROW

Figure 19: KTB-A to Gundih CPP Elevation Profile

Figure 20: KTB-01 & KTB-03TW Wellheads

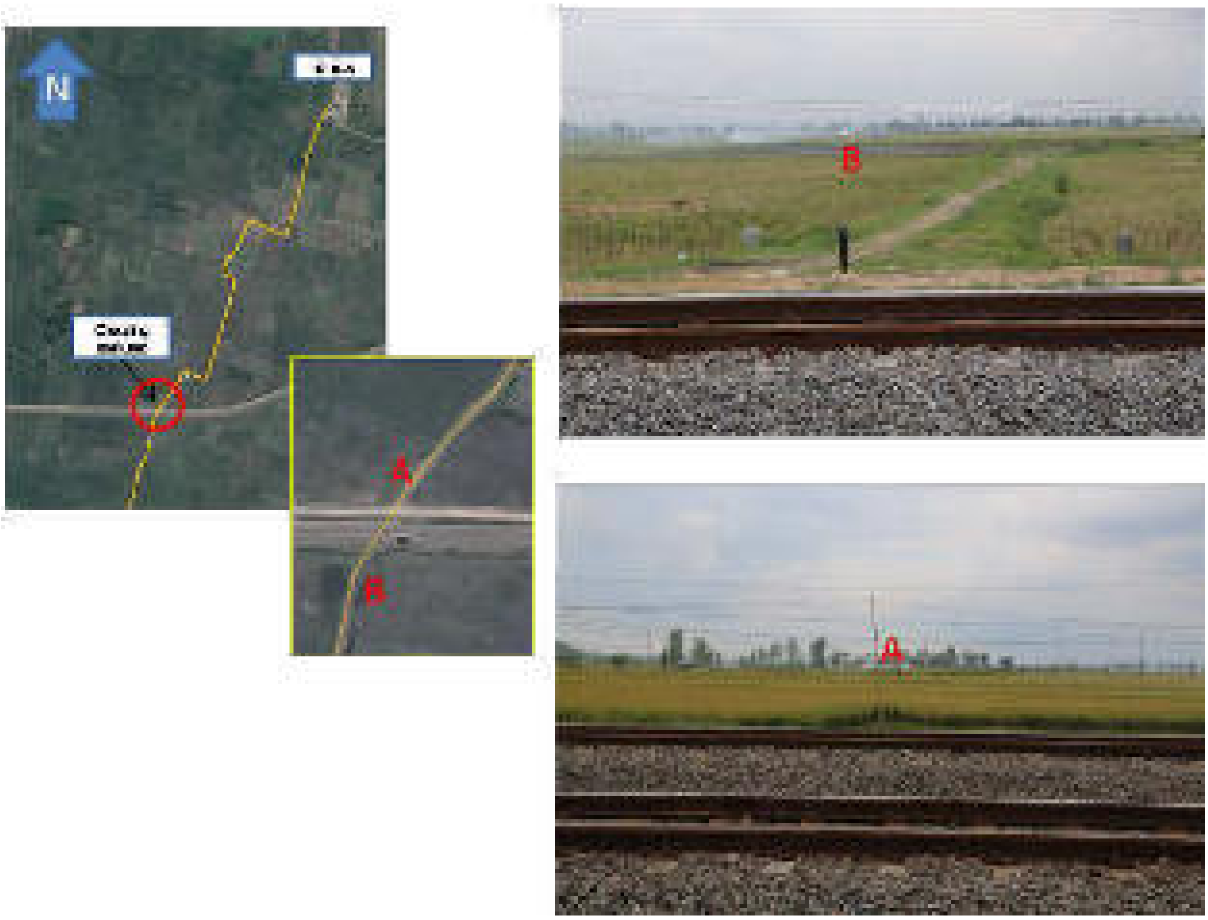


Figure 21: KBT-A to Gundih CPP Pipeline ROW Underground Railway Crossing

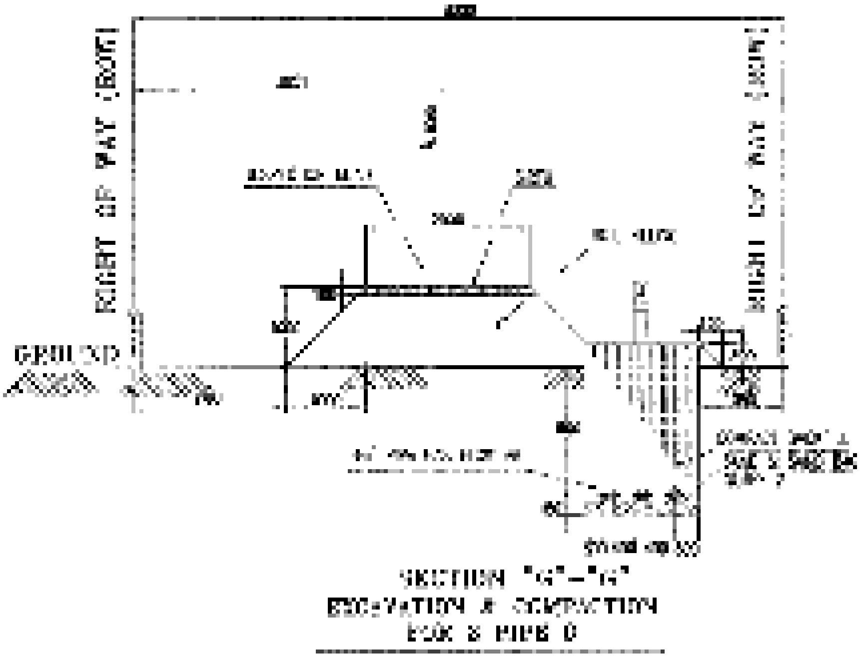


Figure 22: ROW Cross Section: KTB-A to Gundih CPP

Three 6 inch flowlines traverse the pipeline right of way from KTB Well Pad A to the CPP and cross under the provincial railway line a distance of approximately 3,900 meters. These flowlines are from KTB – 01, KTB- 03 TW and KTB – 06 ST wells.

KTB – B Well Pad: KTB-02 & KTB-04 Wells

KTB – B is the most eastern, well pad location, 24,134 m2 in area is where KTB – 02 & 04 wells are located. The well pad is located in an agricultural area similar to KTB Well Pad A with an associated pipeline right of way to the eastern perimeter of the CPP also, a distance of approximately 3,900 meters. The pipeline right of way merges with the KTB - A, flow lines along this route.

There are 2 – 6 inch flow lines from the wells at KTB – B Well Pad to the CPP.

KTB – B well pad location has been selected as the CO_2 pilot injection candidate well location and all planning both surface and subsurface have been made from this location.

Figure 23: KTB-B Well Pad Location and Pipeline ROW

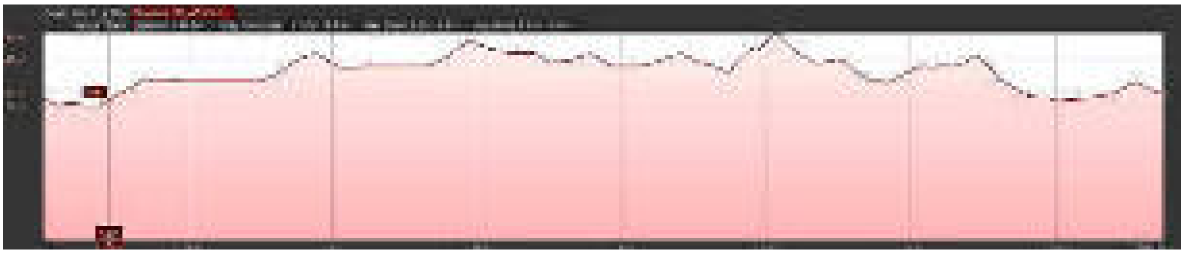


Figure 24: KTB-B to Gundih CPP Elevation Profile

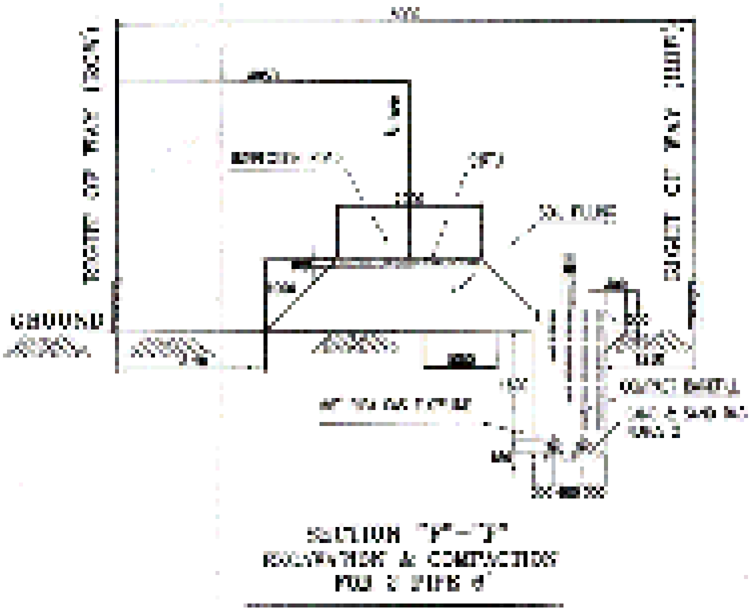


Figure 25: ROW Cross Section: KTB-B to Gundih CPP

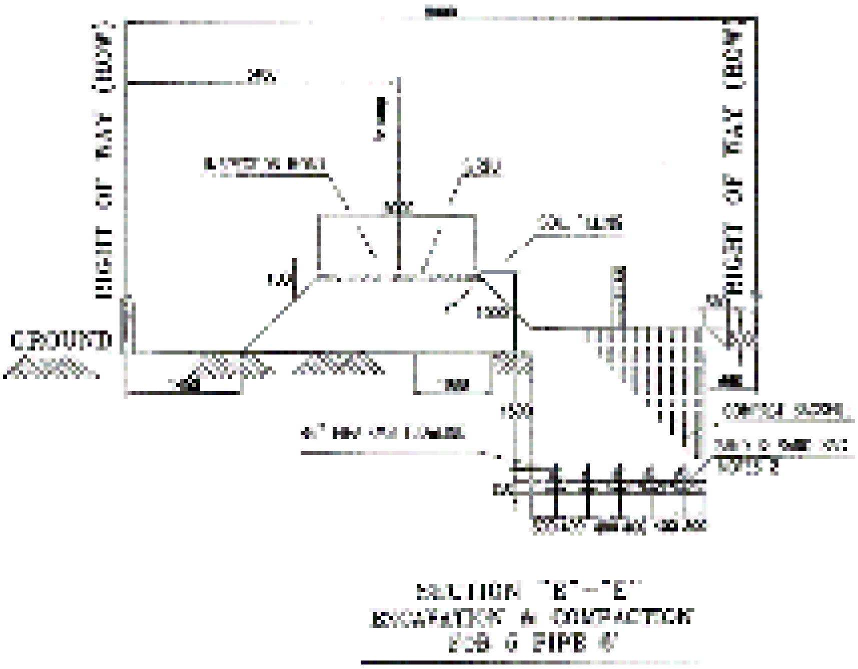


Figure 26: ROW Cross Section KTB-A/KTB-B Junction Point to Gundih CPP

The flowlines from KTB – A & B well pads merge at the junction shown and five flowlines continue to the CPP perimeter boundary and production manifold.

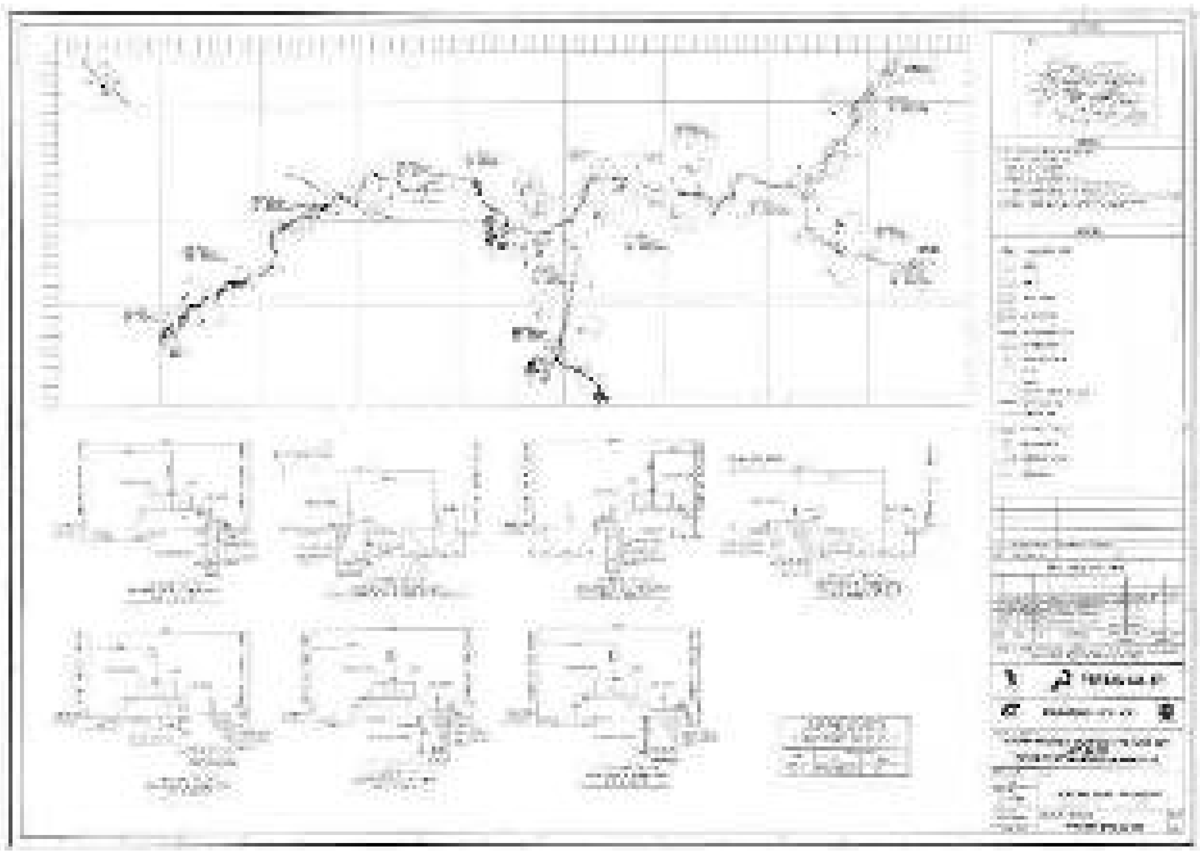


Figure 27: Gundih General Flowline & ROW Layout

Gundih Central Processing Plant (CPP)

Construction of the Gundih CPP started June 2011 and operations commenced December 2013. The CPP has now been operating for slightly over 4 years, at the time of writing, and is designed to process 70 mmscfd. Typical feed gas comprises 23% CO_2 and 6,000 ppm H_2S (Varying values of H_2S concentration have been reported in the feed gas. Actual H_2S values need to be confirmed for process design purposes). 50 mmscfd of sales gas is piped to Tambaj Lorok Power Plant, Semarang located approximately 140 kilometers from the Gundih CPP.

Gundih CPP is estimated to produce 800 metric tons per day (MT/day) of emitted CO_2 (15.2 mmscfd). Prior to emitting acid gas to atmosphere it is passed through a Bio-Sulfur Recovery Unit (Bio-SRU) process that converts the H_2S to elemental sulfur that is bagged and packaged. The remaining gases are oxidized in the Thermal Oxidizing System to comply with environmental regulations for gas emissions (max. 2,600 ppm SO_2). Bleed water from the Bio-SRU is treated in the Wet Air Oxidization Unit along with the caustic spent in the Caustic Treatment Unit. This water is then treated for disposal well injection along with produced water from the Gas Separation Unit.

Two CO_2 streams have been identified, at Gundih CPP, as potential feed streams for CO_2 capture. These streams are the outlet of the Bio-SRU (Stream 1) and the outlet of the Thermal Oxidation Unit (TOX) (Stream 2). The outlet stream of the Bio-SRU contains 95% CO_2, though odorous sulfur compounds (H_2S and mercaptans) are present in small quantities and are required to be removed before releasing the CO_2 to the atmosphere. These odorous, sulfur compounds are oxidized (converted to SO_2) in the TOX. As it is the outlet of a combustion system, the stream consists of CO_2 diluted with air (N_2 and excess O_2) and SO_2 in small quantities.

The Bio-SRU (Stream 1) emits a high CO_2 stream with diluted impurities although additional CO_2 purification is required to remove odorous sulfur components and waste water before the CO_2 conditioning unit. A post combustion capture unit such as an amine capture column is required should the TOX (Stream 2) be selected to separate CO_2 from the associated gases such as N_2, O_2 and SO_2. An economic evaluation is required, based on the outlet discharge of Stream 1 and 2 to determine which method is the most feasible taking into account all operational factors.

Depending on the technically feasible option selected there is sufficient available land area to install a CO_2 Purification Unit, CO_2 Compression/Liquefaction Unit, and CO_2 storage along with the selected mode of CO_2 transportation at the Gundih CPP site. The exact location at the CPP site has yet to be determined, however, there are a number of location options available within the CPP.

Figure 28: Gundih CPP Layout