4 Options Assessed

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4.1 Introduction

The design options assessment process has been aligned with the BP's Capital Value Process (CVP) to allow consistency across all major projects within BP's portfolio. Figure 4.1 illustrates the key requirements for each CVP stage.

Figure 4.1 BP Capital Value Process

Appraise:	**Select:**	**Define:**	**Execute:**	**Operate:**
• Determine project feasibility & alignment with business strategy; • Understand project drivers; and • Identify viable opportunities to pursue.	• Perform technical definition and evaluation of prioritised project options; • Develop initial cost and schedule estimates for the options; • Compare options by focusing on uncertainties, risks, flexibility and associated economic criteria; • Recommend preferred option and further develop technical definition, cost schedule and production estimates.	• Develop the selected option to an appropriate level of detailed technical definition and planning required to freeze the scope of the project; and • Confirm cost, schedule and production estimates.	• Produce an operating asset consistent with scope, cost and schedule, including; • Detailed engineering; • Procurement; • Follow-on engineering; • Site support; and • Project management services.	• Evaluate asset to ensure performance is to specification including; • Feedback of facilities availability; and • Production performance.

As Figure 4.1 demonstrates, conceptual design options are analysed in terms of their feasibility during the Appraise stage of the CVP. Recommended design options then pass onto the Select stage during which the preferred option for development is further studied and selected. During the Define stage, the scope of the preferred option is more fully defined and final design decisions are made.

The key options assessed during the SD2 Project design development have focused on:

- Concept definition;
- The selection of the offshore strategy to exploit the SD reservoir; and
- Identification of technically and economically feasible design options to reduce, and where possible avoid, adverse environmental impacts, primarily associated with:
    - Discharges to the marine environment;
    - Emissions to atmosphere;
    - Onshore noise; and
    - Waste.

Throughout the CVP to date, environmental evaluation of the project options has been undertaken alongside technical and economic evaluation and consultation with stakeholders including SOCAR and SD partners[1].

This Chapter presents a summary of the options that have been assessed to support the current design base case which is defined as follows:

- Subsea development concept incorporating 26 wells;
- Fixed standalone offshore SDB Platform Complex comprising Production and Risers Platform (SDB-PR) and Quarters and Utilities Platform (SDB-QU) bridge linked to SDB-PR located in shallow water to the north of the Contract Area;

[1] Chapter 8: Consultation and Disclosure provides details of the consultation undertaken and proposed specifically with regard to the SD2 Project ESIA

- Receiving and processing facilities at Sangachal Terminal (ST); and
- New subsea gas, condensate and chemical pipelines between the onshore receiving facilities and the SD Contract Area.

The decision to include new subsea gas and condensate export pipelines as well as additional facilities at the ST for SD2 facilities was made at the project outset as there is insufficient capacity within the existing SD1 export pipelines and SD1 onshore facilities to accommodate the predicted throughput associated with the SD2 Project.

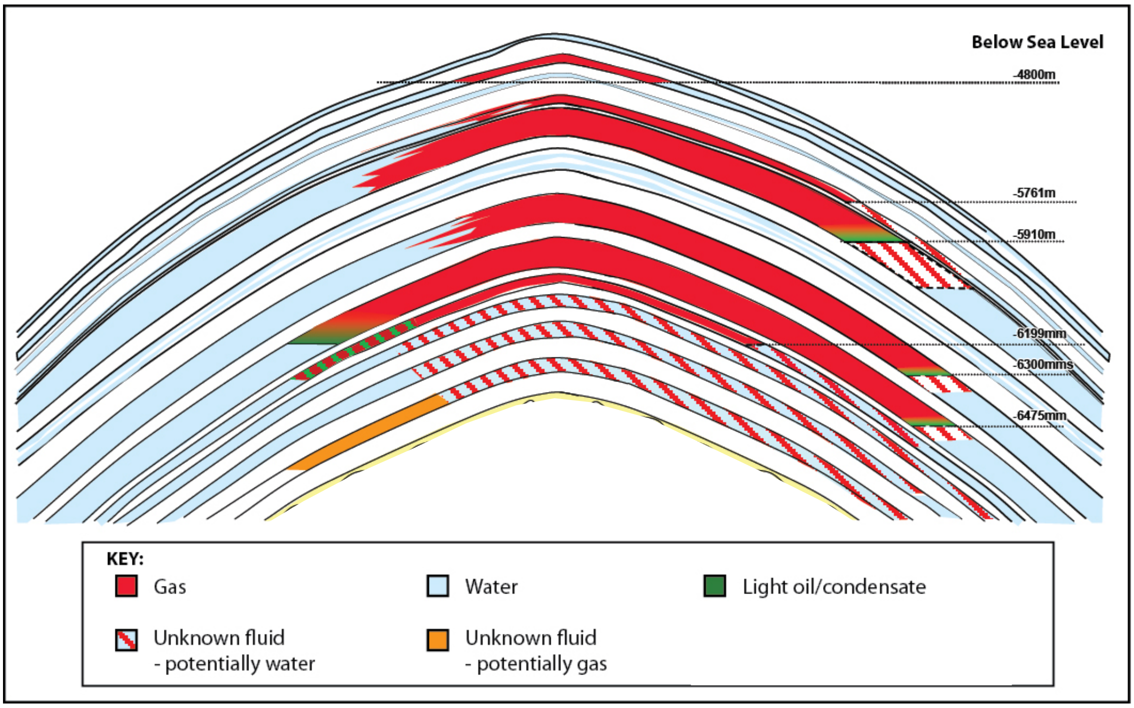
The option of not developing the SD2 Project has also been considered. The decision to not proceed would result in a reduction of potential revenues to the Azerbaijan government with a resultant inability to deliver the associated benefits to the Azerbaijan economy. Pursuing the SD2 Project will result in employment creation for national citizens during both the construction phase and operational phase of the development, as well as increased use of local facilities, infrastructure and suppliers. The option of not proceeding was therefore disregarded when considered against these socio-economic benefits.

4.2 Concept Selection: Multiple Platforms versus Subsea Development

During the Appraise stage, a number of development concepts were identified for assessment including a number of deepwater platforms, platform drilling options, multiphase tie-back to shore and subsea development concepts. The options assessment was primarily informed by drilling conditions, seabed depths and reservoir characteristics across the Contract Area:

- Drilling conditions - The geological structure of the Contract Area rises to a crest or “anticline” through its centre, restricting where wells can be located (refer to Figure 4.2). Due to the abnormally high pressures present in the crest of the structure, drilling and cementing is extremely difficult. Experience from elsewhere in the world has shown that drilling crestal wells has led to rock fracturing and downhole drilling fluids losses. Therefore the single option which included crestal drilling was rejected during the Appraise stage. Options which considered drilling directional wells from the flanks of the crest structure were retained.

Figure 4.2 Cross-Section Through SD Crest Structure



- Reservoir characteristics - Anticipated reservoir characteristics informed the number and location of wells required to achieve the planned production rate for the SD2 Project. An analysis was then undertaken to determine the feasibility of drilling these wells from fixed platforms as opposed to drilling from a mobile rig and subsequent subsea tie-in. The analysis took into account the maximum step out anticipated for platform wells (assumed to be approximately 5km) and for subsea wells (assumed to be approximately 3km) and water depths and the number of wells per subsea manifold (assumed to be four) and concluded that, for the planned production rates, platform drilling concepts were not economically feasible.

- Seabed depths - Minimum water depths across the Contract Area vary from approximately 60m to the north-east to a maximum of almost 700m in the south-east. Due to the perceived technical risks and associated high costs, options which included platforms within the southern part of the Contract Area (i.e. deepwater platforms) were rejected at the Appraise stage.

Further analysis of the reservoir characteristics indicated the potential requirement for offshore compression to achieve the planned production rates for both SD1 and SD2.

Based on the considerations above, the concept taken into the Select stage comprised:

- Subsea development concept incorporating 24 wells;
- Fixed SDB production and quarters facilities located in shallow water to the north of the Contract Area; and
- An offshore compression platform (denoted SDC), tied in to both the SD1 and SD2 offshore facilities.

From an environmental perspective, the subsea concept has the following advantages over the multiple platforms option:

- Reduction in materials required for jacket and topside construction and associated reduction in potential construction waste, emissions and discharges; and
- Increased opportunity for optimisation of production facilities and utilities, as compared to multiple production facilities and utilities on different platforms, resulting in lower waste, emissions and discharges.

4.3 Offshore Compression

Early in the Select stage, a study was undertaken to consider an “Offshore Compression” concept (with the SDC platform providing compression for both SD1 and SD2) and an alternative “No Offshore Compression” concept with the compression facilities located onshore.

Comparison of these two concepts showed that the “No Offshore Compression” case delivers a similar gas sales profile to the “Offshore Compression” case and has the following key benefits:

- Reduces the total offshore topsides installation weight by approximately 12,000 tonnes;
- Significantly reduces the offshore system complexity and improves overall system operability by transfer of offshore compression to the onshore terminal;
- Removes all safety and project delivery risk associated with the construction, installation, operation and decommissioning of the SDC platform after first gas;
- Eliminates the production shutdown (60-80 days) required for the future installation of the SDC platform;
- Minimises the Stage 1 offshore brownfield modification scope by removing the need for offshore gas interconnector pipelines. This eliminates a 35-day shutdown of SD-A;
- Total compression duty is reduced by ~35 Megawatts (MW) by more efficient utilisation of the hydraulic capacity of the marine gas pipelines at the end of field-life;
- Eliminates additional seabed disturbance; and

- Provides an opportunity to improve overall energy efficiency due to potential for heat and power integration onshore.

On this basis, the SD2 Project adopted the “No Offshore Compression” concept into the SD2 Base Case design.

4.4 Hydrate Management

During the design development, assessments were undertaken to establish the preferred options to manage hydrate formation in the SD2 subsea facilities. The three options identified during the Select stage to manage the potential for hydrates forming in the SD2 subsea production system (SPS), flowlines and risers were:

- Continuous mono ethylene glycol (MEG) injection (Option 1);
- Continuous injection of Anti Agglomerate low Dosage Hydrate Inhibitors (AA LDHI) (Option 2); and
- Direct Electrical Heating (DEH) (Option 3).

Due to the significant quantities of salty MEG, which would require a plant more than 10 times (by volume) the size of the SD1 MEG treatment plant at the Terminal, Option 1 was eliminated from further assessment.

The use of AA LDHI chemicals was not found to be effective for the anticipated water cut rates. In addition, the resultant hydrate slurry would require processing at the offshore facilities, which poses risks as the technology options to process the slurry are immature and would require a large scale test programme to prove the technology.

Option 3 (DEH) was therefore adopted as the primary means of hydrate management. This technology involves direct heating of the flowlines to maintain the temperature of the production fluids above that where hydrates form (approximately 26°C).

From the environmental perspective, the DEH option offers the following key benefits when compared with a chemical management approach:

- Minimising the offshore chemical inventory and waste streams; and
- Minimising flaring and associated emissions due to quicker recovery from shutdowns.

Further details of the DEH system and associated MEG system adopted within the SD2 Base Case are provided within Chapter 5 Section 5.11.2.

4.5 Power

4.5.1 Power from Shore

At the start of the Select stage, the SD2 Base Case assumed that onshore and offshore power would be generated by two separate independent systems. In May 2011, an assessment was undertaken to investigate an option for a single system based onshore, providing power to the onshore and offshore facilities via subsea cabling.

Both High Voltage Direct Current and Alternating Current options were considered. The options were evaluated against five key criteria; capital cost, operating cost, production availability, environmental impact and technical risk. The assessment showed the option to provide the Power from Shore did not offer significant operating cost benefits to offset the significantly increased capital costs (3–5 times more than separate independent systems) and increased technical risk.

Modelling of greenhouse gas (GHG) (as CO_2) and NO_X emissions and fuel usage for the options over the Life of Field (LoF) was completed to evaluate environmental benefits. The study showed a slight reduction in GHG emissions and fuel gas usage for the Power from

Shore option (by ~1%) as compared to the Base Case. NO_X emissions for the Power from Shore option, however, were more than 88% greater than for the Base Case.

On the basis of the technical, cost and environmental criteria assessed the Power from Shore option was not adopted. Separate onshore and offshore power generation systems have been retained as the Base Case for SD2.

4.5.2 Onshore Power and Heat Generation

4.5.2.1 Process and Utilities Power

To meet the SD2 onshore power demand for utilities and process systems, a number of power generation options and configurations were considered. These included a standalone power generation system for SD2 with one main and one spare gas turbine, and a system integrated with the existing ST facilities.

These options were assessed on the basis of technical feasibility, availability, efficiency and capital cost. For all the criteria considered, the integrated option was shown to be the best option with increased availability and efficiency, resulting in lower fuel use and hence lower emissions. The integrated power generation and distribution system is designed to provide power for the SD2 process plant and utilities, with SD2 power provided by a single 28MW ISO machine and back-up power provided by the existing gas turbines at the Terminal and/or the national grid.

4.5.2.2 Compression Power

In addition to the power demand for process and utilities systems, power is also required for the gas export compression system.

The project Base Case of using 3 x 50% gas turbines to drive the gas export compressors was compared with an option of using electric drives. A comparative assessment of CO_2 and NO_X emissions was undertaken using industry standard emissions estimating software, PI Forecaster. The estimates showed that the Base Case (direct drives) was expected to result in slightly lower GHG (as CO_2) and NO_X emissions when compared with the electric drive option (by ~2% and ~8% respectively). The assessment therefore supported the project Base Case of using dedicated turbines to drive the export compressors.

4.5.3 Onshore Heat Integration

At the start of the Select stage, the Base Case assumed use of hot oil heaters to provide the heat demand for the SD2 onshore facilities. An assessment, using the PI Forecaster software, was undertaken to consider whether use of waste heat recovery to provide the heat demand would result in lower GHG (as CO_2) and NO_X emissions. The following scenarios were investigated:

- Two 40MW fuel gas fired Hot Oil Heaters and one spare (3x50%);
- Waste Heat Recovery Units (WHRUs) on all Gas Turbines;
- WHRUs on all Compression Gas Turbines; and
- WHRUs on Power Gas Turbine only.

The assessment showed the greatest reduction in emissions, as compared with hot oil heaters, was obtained assuming WHRUs on all Gas Turbines (a reduction of 23% in CO_2 emissions and 5% in NO_X emissions). However, given that the SD2 power gas turbine will be part of the ST integrated power system and as such will be used as a back-up machine in certain operating scenarios, it was not considered feasible to fit this turbine with a WHRU.

As a result, the option of WHRUs installed on the Compression Gas Turbines was adopted as the SD2 Base Case. This option showed a reduction of CO_2 and NO_X emissions of 19% and 4% respectively when compared with using hot oil heaters.

4.5.4 Offshore Power

To determine the optimal generator size and configuration for offshore power generation, a total of six generator types were selected for assessment. The assessment criteria included:

- Technology suitability and lessons learned;
- Weight and layout considerations; and
- Target machine loading[2].

The assessment concluded that the 15MW ISO machines were preferable based on the technical criteria considered.

A further assessment using production and power profiles over the LoF as well as performance curves for the selected generators, was completed to compare the predicted GHG (as CO_2) and NO_X emissions for the preferred option and alternatives.

The results showed that, while the difference between the CO_2 emissions for the options considered was marginal, 15MW ISO turbine resulted in significantly lower NO_X emissions compared to the other options assessed.

Based on technical and environmental assessments, the 15MW ISO option was subsequently adopted as the SD2 Base Case.

4.6 Flare

4.6.1 Ground versus Elevated Flare

During the Select stage, an assessment was undertaken to identify the Best Practicable Environmental Option (BPEO) for the SD2 flare design at the Terminal from the options identified by the Project. The two types of flare systems, i.e. ground and elevated flare, were assessed based on the following categories:

- Environmental – noise, air quality, light and visual intrusion;
- Legal and policy compliance;
- Process Safety;
- Operability; and
- Capital cost.

The results of the assessment were as follows:

- Environmental (Noise) – Noise modelling studies were undertaken for both the elevated and ground flare using anticipated flaring scenarios and vendor noise data specific to the flaring scenarios. The flaring scenarios, which were developed by the SD2 Project Team, included expected events (e.g. trips, plant upsets leading to flaring), flaring flowrates, frequency and the duration of flaring per event. Predicted noise levels at the community receptors surrounding the ST (Sangachal Town, Umid, Azim Kend and Masiv 3) for each scenario were compared for the two options. The modelling predicted that the ground flare would be marginally noisier than the elevated flare at flaring rates up to moderate flaring rates (by up to four dB(A)). However, the elevated flare would be marginally noisier for the emergency depressurisation scenario (by up to three dB(A). Overall, however, it was concluded that there was no significant differentiation between the two flare options;
- Environmental (Air Quality) – An air dispersion modelling screening study was undertaken for both the elevated and ground flare for average and emergency depressurisation flaring scenarios. The study focused on predicting the NO_2 concentrations at the community receptors surrounding the ST. The modelling showed

[2] Turbines should have a minimum loading of 50% during normal operation and a minimum of two generators should be in operation at one time.

that for both modelling scenarios there was an insignificant difference between predicted annual average NO_2 concentrations at all modelled receptors for both the elevated and ground flare options. It was therefore concluded that there was no preference with regards to the two flare options;

- Environmental (Light/Visual Intrusion) – A screening assessment was undertaken to establish the visibility of the ground and elevated flares from the area surrounding the Terminal. The screening assessment, which took into account the proposed height and location of the flare options, was undertaken using viewshed analysis, in which the likely visibility of an object from selected viewpoints can be determined (taking into account topography but not existing structures or buildings). The assessment showed that the elevated flare would be significantly more visible, particularly under non routine flaring conditions, than the ground flare at the community receptors, although significant visual impacts were not anticipated given that the existing Terminal facilities already dominate the view from the local communities. Significant light impacts were also not anticipated although they were predicted to be less from the ground flare as the ground flare enclosure would screen the flare from the surrounding receptors. The ground flare option was therefore shown to be preferable with regards to light and visual intrusion.
- Legal and Policy Compliance – Noise modelling results for both flare options were compared to the applicable project noise limits[3]. No difference between the elevated and ground flare options in terms of the number and duration of noise limit exceedances was predicted. It was shown that noise limits would be met for at least 95% of the time per year for all years, which is in compliance with the project requirements. In addition air quality modelling showed that relevant air quality limits[4] were predicted to be met for both the ground and elevated flare options. Both the elevated and ground flare options were shown to be in compliance with applicable legal and policy requirements and no difference between the options was identified.
- Process Safety – A preliminary review of process safety including the size of the radiation sterile area and consequences of flare upsets was undertaken for both flare options. The review concluded that the elevated flare is preferable from the process safety perspective due to due to reduced risks of ignited release and issues associated with ground level radiation.
- Operability – A comparison between operability aspects associated with the two options considered planned and unplanned maintenance and reliability. It concluded that the elevated flare is the preferred option.
- Capital Cost – Vendor cost data, obtained for both flare options, showed that capital costs were lower for the elevated flare option.

Based on the assessments undertaken, the elevated flare option was therefore identified as the BPEO recommendation on safety, operability and cost grounds. This option was therefore incorporated into the SD2 Base Case design as discussed in Chapter 5 Section.

4.6.2 Offshore Flare Gas Recovery

The SD2 onshore flare system will be provided with a flare gas recovery (FGR) system. FGR is proposed for the HP system to handle blowdown and control valves discharges. For the low pressure (LP) system FGR is proposed for tank breathing from all large tanks and MEG regeneration. The option of incorporating offshore FGR was also investigated, taking into account technical feasibility, operability/maintenance, cost, safety and environmental considerations. It was concluded that, while the FGR option was feasible and had the potential to further reduce GHG emissions by approximately 85 ktonnes over the LoF, the FGR package would add 37 tonnes to the platform weight and introduce additional safety risks. In addition, the associated costs indicated that offshore FGR was not economically feasible. Offshore FGR was therefore not incorporated into the SD2 Base Case design.

[3] 55dB daytime limit (07:00 to 22:00) and 45dB nightime limit (22:00 to 07:00) to be achieved 95% of the time that plant is operating, calculated as a proportion of annual operating hours.
[4] NO_2 annual average limit of 40 µg/m^{3}and 1 hour limit (not to be exceeded more than 18 times per year) of 200 µg/m^3.

4.7 Produced Water

A number of options were considered for the disposal of produced water during the initial stages of SD2 planning. The options not taken forward for further assessment during the initial stages of SD2 planning included:

- Offshore and onshore separation and treatment of produced water and re-injection of water into subsurface formations within the offshore SD Contract Area. Residual water recovered onshore would be routed back offshore to the SD Contract Area and re-injected. This was not adopted for the following reasons:
  - HSSE risks associated with high pressure water injection in the challenging subsurface conditions found within the SD Contract Area
  - Uncertainties associated with the availability of a suitable reliable subsurface injection target; and
  - Capital and operational costs for drilling a dedicated water injection disposal well, and the need for additional produced water treatment process plant at the Terminal to support re-injection offshore.
  - The delay to ramp up production well delivery whilst drilling water injection wells

- Offshore and onshore separation and treatment of produced water and disposal of water into the Caspian Sea at the SDB platform complex location. This was not adopted for the following reasons:
  - HSSE risks associated with acquiring and maintaining permissions to discharge treated produced water to the Caspian on a continuous basis;
  - Technical challenges and space/weight limitations associated with offshore treatment and limited experience of operating an offshore treatment unit capable of treating to an appropriate standard; and
  - Capital and operational costs associated with additional produced water treatment process plant at the Terminal to support re-injection offshore.

A number of support studies, including trials of produced water treatment at third party (i.e. external non BP company) offsite treatment contractor facilities, treatability trials of SD2 water using the existing ACG produced water treatment plant and assessment of pond design and pre-treatment options were completed during the final selection process of produced water handling options. In order to mitigate risks associated with disposal of produced water the SD2 Project has adopted the following produced water handling hierarchy:

1. First Option: Utilise ACG produced water treatment and disposal options when available
2. Second Option: SD2 produced water will be sent off site for treatment and disposal at a third party treatment contractor site
3. Third Option: During emergency situations, when option 1 and 2 are not available and there is no produced water tank storage capacity at Sangachal including the new SD2 produced water storage tank, SD2 produced water will be sent to a new storage pond.

4.8 Subsea Pipeline Pre-Commissioning

Following pipelay, all pipelines and flowlines will undergo pre-commissioning comprising cleaning, hydrotesting, inspecting and dewatering. These activities will be completed using seawater, treated with chemicals to prevent biological growth and corrosion within the pipelines and flowlines. Following each pre-commissioning activity, treated seawater will either be discharged at a temporary subsea pig trap in the vicinity of the SDB platform complex or via the SDB-PR open drains caisson (refer to Chapter 5 Sections 5.8.4 and 5.9.4 for anticipated volumes discharged). If the SD2 Project were to adopt the same approach as used for the SD1 marine subsea pipelines, the SD2 pipelines would be dewatered by propelling a pig through them using the product that would be ultimately transported through the lines (e.g. gas, condensate or MEG), followed by a MEG conditioning pig train, designed to remove any remaining water in the lines. The pigs would be launched from the Sangachal

Terminal to the offshore facilities. This approach requires the offshore facilities to be operational prior to dewatering.

It is anticipated that some of the SD2 subsea pipelines may be mechanically complete more than 2 years before the SDB platform complex is installed and commissioned. The chemicals within the treated seawater will be qualified for a minimum protection period of 2 years. After this period it will be necessary to empty and refill the pipelines with treated seawater. When the dewatering does take place there would be requirement to contain and ship to shore large quantities of MEG used for final conditioning for treatment and/or disposal.

The project has therefore considered an alternative whereby dewatering will be accomplished by propelling air through each line (which will dry the line) following which the dried lines will be filled with inert nitrogen gas. Fluids used to hydrotest the shore approach and onshore sections of the export and MEG subsea pipelines will be recovered and removed by tanker for disposal off-site; this will avoid any risk of discharges to Sangachal Bay and nearshore waters. The approach, which minimises the volume of MEG for disposal and is expected to reduce the potential for refilling of pipelines due to degradation of the preservation chemicals, has been adopted as the SD2 Base Case.

4.9 Subsea System Decisions

While there are numerous subsea production systems globally, the SD2 subsea production system will be the first in the Caspian Sea and one of the largest in the world.

The key decisions with respect to the selection of the subsea control systems were:

- Hydraulic versus electrical actuation of production control valves: the valves which control the flow of production fluids could be opened and closed either by hydraulic pressure, or by electrically-operated solenoids;
- For hydraulic control: open versus closed loop systems; in an open system, the control fluid is discharged to sea when valves operate, while in closed loop systems the fluid flows to the platform via return lines; and
- Selection of control fluid: after considering the relative merits of the options, laboratory studies were carried out to select the most environmentally benign control fluid.

4.9.1 Hydraulic versus Electrical Control Systems

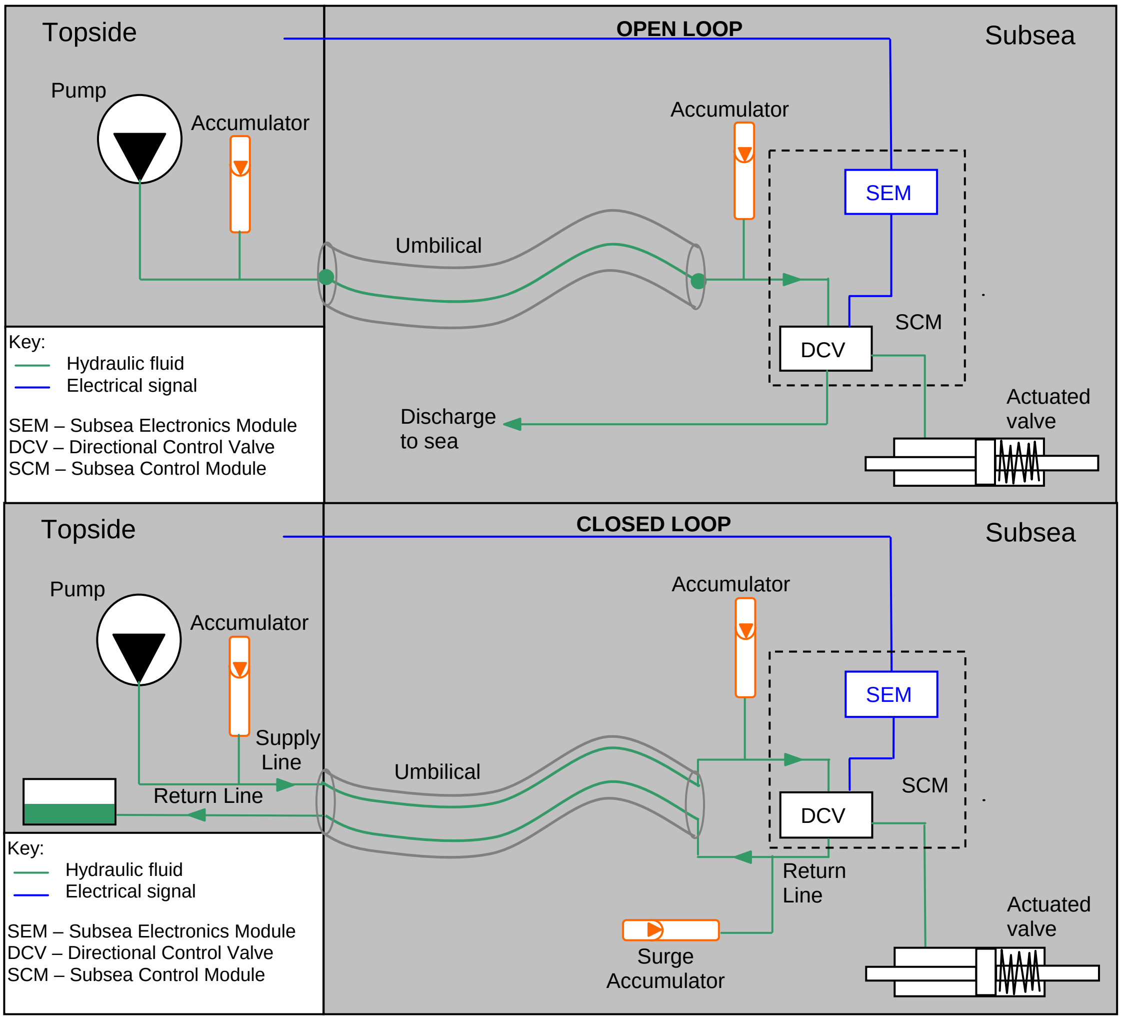
In an electrical system, electric power rather than hydraulic control fluid is used as the energy source to operate the well and manifold valves. While a number of manufacturers have developed electric control systems, the reliability of these systems has not been proven and they have not previously been used in the Caspian Sea. It is understood that an electrical High Integrity Pressure Protection System (HIPPS), which is the Base Case overpressure safety measure for SD2, has never been installed anywhere worldwide.

Analysis showed that no “all electric” system has yet been developed. A hydraulic system would still be required to operate downhole safety valves associated with the production wells. While discharges from such a system would be lower when compared with a hydraulic control system, overall technical feasibility could be affected due to increased complexity (i.e. additional umbilicals/controls required for the electrical and hydraulic systems). This option was therefore discounted.

4.9.2 Open and Closed Loop Hydraulic Systems

The key feature of a subsea open loop hydraulic system is that the control fluid is discharged to the marine environment when any subsea actuated valves are closed or when chokes used to regulate flow are stepped. Figure 4.3 shows a typical flow path for open and closed loop control systems.

Figure 4.3 Typical Open Loop and Closed Loop Hydraulic Systems



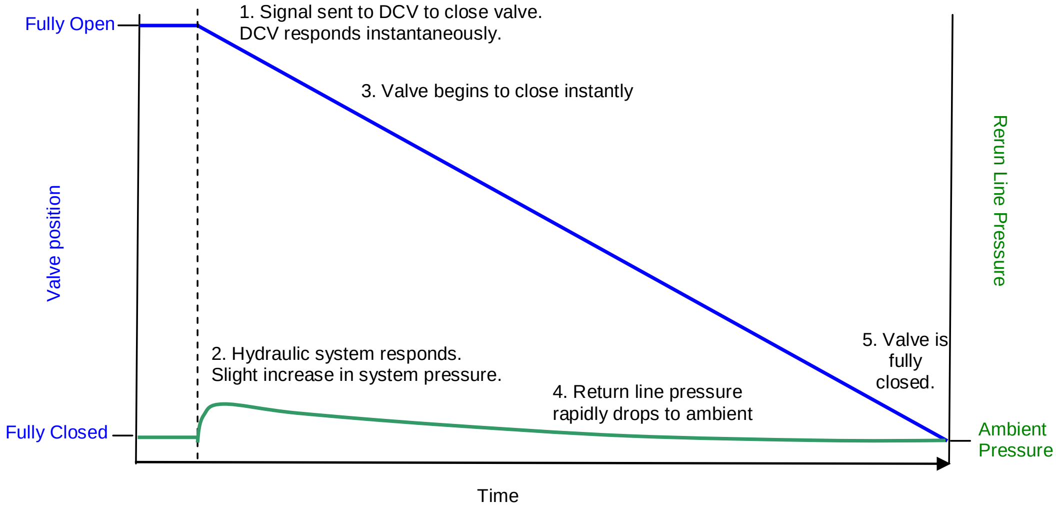
In an open loop system, discharge to sea occurs when the spring within the actuated valve returns the valve to the closed position, forcing the control fluid to discharge to sea. In a closed loop system hydraulic fluids are not discharged but are transferred back to the topside via return lines. In addition to the hydraulic fluid return line, the closed loop system also includes a surge accumulator; the function of which is to limit pressure build up in the return line.

A variation to the closed loop hydraulic system, in which a pump is integrated into the closed loop design to drive the returned control fluid from the valve when closed, was also considered. The purpose of the technology is to improve the response time for the valves within the closed loop system. However, the technology is in the earlier stages of development (used at only a few installations to date) and is proprietary to one supplier. On the basis of unproven reliability this option was therefore discounted.

4.9.2.1 Operability and Response Times

The operability of the open and closed loop systems was determined by comparing valve response time characteristics. Figure 4.4 shows how the pressure in the open loop system changes and the valve responds once the signal to close has been received.

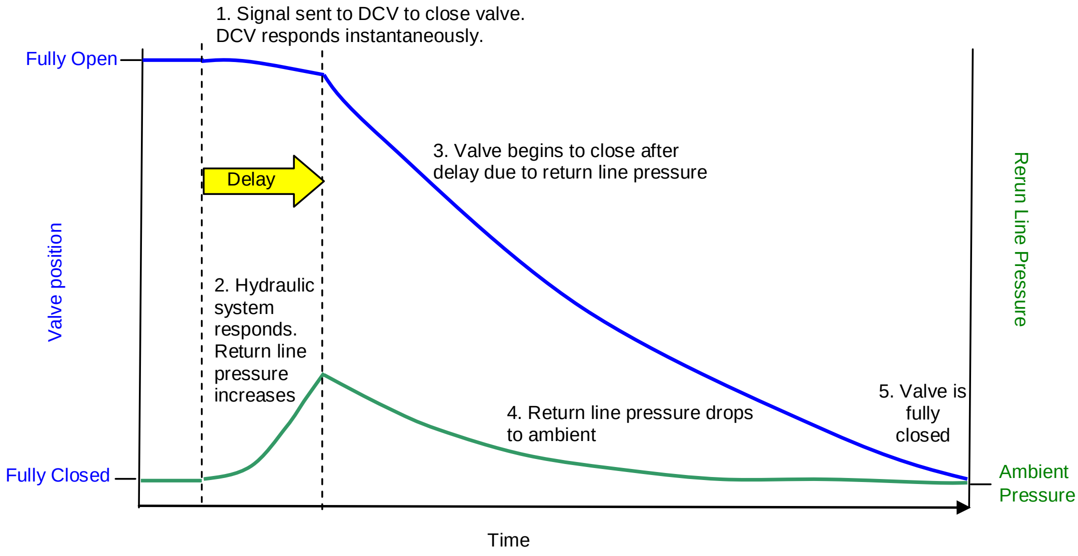
Figure 4.4 Indicative Valve Closure and Pressure Changes in an Open Loop System



The figure shows that when the valve is operated there is an initial slight build up of back pressure within the system, which rapidly dissipates as the control fluid is discharged to sea. Modelling of the activities required to close the safety critical HIPPS valve showed that a closure time in the order of six seconds could be achieved for the open loop system.

Figure 4.5 shows how the valve responds once the signal to close has been received within the closed loop system.

Figure 4.5 Indicative Valve Closure and Pressure Changes in a Closed Loop System



In the closed loop system, back pressure builds up in the system which has the effect of delaying the closure time. This is because the control fluid is being forced through the return line, which restricts the fluid flow. While the system includes a surge accumulator to relieve this effect, the delay cannot be avoided. Modelling of the HIPPS valve showed that a closure time in the order of 250 seconds would be expected for the closed loop system. This is greater than the 30 seconds maximum response time determined from the project safety criteria. The 30 second response time represents the 15 second HIPPS design closure time with a safety margin.

In addition, one of the major disadvantages of a closed loop system is the requirement for the system to return the fluid back to the surface. For developments in shallower waters this is generally a simple operation; however, for longer and deeper developments there is insufficient energy to push against the tube restriction and/or additional hydrostatic head (water pressure). There are two options to resolve this issue:

- Increase the spring strength in actuators. This, however, pushes up the required control system pressures and increases the valve opening times; or
- Increase the diameter of return lines as this will help to reduce the tubing restrictions. This is not considered an option for SD2 as it makes it infeasible to manufacture, transport to and install the SD2 subsea control system components in the SD Contract Area using the vessels and transportation routes available, which is a project requirement.

The option of a hybrid system involving an open loop system for the HIPPS valves and a closed loop system for all the other valves was also investigated. However, this was not considered feasible as:

- The valve reaction time for the closed loop valves is much slower than for the open loop HIPPS valves. As a result, when all the well and manifold valves are instructed to close a pressure build up would occur between the well and the HIPPS. This would affect the reliability of the HIPPS and as such the hybrid system would not meet the safety criteria required; and
- Manufacturing, installation and transportation of the return lines are infeasible, as for the closed loop system.

4.9.2.2 Reliability

Both the open and closed loop systems are considered reliable, proven technology. However, the closed loop control fluids, which are synthetic based, are considered to be more sensitive to potential contamination, in particular from seawater and particulates, resulting in poor performance. The open loop system fluids, which are water based, are not affected by seawater in the same way and particulate build up is avoided as a proportion is discharged with the fluids.

4.9.2.3 Logistics and Installation

The subsea umbilicals, which include all chemical, hydraulic and electrical supplies from the platform to the manifolds and wells, are manufactured under controlled conditions, and are shipped as continuous fabrications on carousels. The closed loop system requires both supply and return hydraulic lines within the subsea umbilicals and therefore the size and weight of the closed loop umbilicals is greater than for the open loop. The only practicable method of importing the umbilicals is via the canal system. Transportation vessels are therefore limited by width and weight restrictions. It is anticipated that it is unlikely the closed loop system umbilicals can be transported through the canal system.

4.9.2.4 Environmental Issues

For the open system, water-based control fluids would be discharged to sea as a result of:

- Valve actuator movements or choke operations required for flow control of the wells. Choke operations account for the majority of the control fluid discharged. Under normal operating conditions, the closed loop system is not designed to discharge control fluids;
- Directional control valve (DCV) discharge – In addition to discharges associated with valve/choke movements, discharges would also occur on a continuous basis from the DCVs. To maintain the integrity of the production system, it is necessary to select highly reliable valves that will continue to function for the duration of the project.

HIPPS is an integral part of the subsea control system to ensure the safety criteria are met and to minimise the potential for uncontrolled releases of hydrocarbons to the marine environment. A maximum response time of 30 seconds (including safety margin) has been determined for the HIPPS. Note that the HIPPS design closure time is 15 seconds. As demonstrated in the analysis of the open and closed loop systems, the closed loop system is unable to meet this criterion.

4.9.2.5 Summary

The key reasons for the selection of an open loop hydraulic control system are provided below:

- A hydraulic system has been selected for SD2 because electrical systems are unproven and therefore the risks of system failure are unacceptably high;
- The closed loop system does not meet safety criteria for critical valve closure times to ensure isolation and containment of the reservoir fluids within the subsea production system, avoiding spillages and over pressure events on the new offshore platform; and
- Transportation and installation logistics render closed loop umbilicals infeasible due to the limitations on importing material through the canal system to the Caspian Sea as well as the limitations of the offshore installation vessels available within the Caspian.

4.9.3 Open Loop System Control Fluid Selection

To support the decision of an open loop system, work was completed to select a control fluid with the least environmental impact. Four candidate fluids that are accepted by OSPAR countries, within the Gulf of Mexico and in Australia, were considered:

- Castrol Transaqua HC10;
- Castrol Transaqua HT2;
- Niche Products Pelagic 100; and
- MacDermid Oceanic HW760R.

All fluids are classified ‘Gold’[5] under the UK regulatory system and approved for discharge to sea, indicating they have least environmental impact. Based on fluid composition data provided by the vendor, screening was undertaken to ensure that the products did not contain any components which were:

- Bioaccumulative;
- Persistent; or
- Likely to cause specific or chronic effects.

All candidate fluids successfully passed this screening process, and were therefore included in a preliminary programme of toxicity testing. Caspian species were used to conduct the toxicity tests which are directly comparable to the OSPAR algal and herbivore species[6] (Table 4.1). All tests were carried out in conjunction with the same quality assurance (QA)/quality control (QC) procedures as are used for OSPAR tests. The design and execution of the tests differed from OSPAR tests only in the species used, and in the use of Caspian seawater; test conditions, equipment and duration were otherwise consistent with OSPAR procedures.

Table 4.1 Summary of Caspian Toxicity Test Species

Test Species	Type	OSPAR Equivalent	Test Temperature (ºC)	Test Duration
Calanipeda aquae dulcis	Herbivore	*Acartia tonsa*	20 (+/- 2ºC)	48h
Chaetoceros tenuissimus	Alga	*Skeletonema costatum*	20 (+/- 2ºC)	72h

[5] Hazard Quotients are assigned to 1 of 6 categories and "GOLD" is the least hazardous category.
[6] Refer to Chapter 2 for an explanation of the OSPAR ecotoxicity testing procedure.

The four candidate products were tested concurrently on three separate occasions to ensure the reliability of the results. Test results are summarised in Table 4.2.

Table 4.2 Toxicity Test Results

Fluid	Zooplankton 48h LC50[1] (mg/l)				Phytoplankton 72h EC50[2] (mg/l)			
	1	2	3	Average	1	2	3	Average
HC10	6,199	6,160	6,373	6,244	2,694	2,732	2,460	2,629
HT2	6,496	6,306	6,553	6,452	2,836	2,414	2,256	2,502
100C	3,642	3,803	3,434	3,626	607	659	581	616
HW760R	5,244	5,943	6,306	5,831	582	678	640	633

Notes
1. LC50 - Lethal Concentration 50 is the estimated concentration of a substance required to cause death in 50% of the test organisms in a specified time period.
2. EC50 - Effective Concentration 50 is the concentration of a substance that has a specified non-lethal effect on half of the test organisms within a specified period of time. Effects measured are often the number of young produced, time to reproduction, etc.

Table 4.2 indicates that the HC10 and HT2 products were of similar, and consistently lower, toxicity. Based on the toxicity test results and the technical performance of the product, HC10 was selected as the control fluid for the SD2 subsea control system.

The results of the toxicity tests were used to carry out an ecotoxicological risk assessment. An initial step in the risk assessment process was to confirm the no-effect concentration of the control fluid.

The no-effect concentration for the selected fluid was estimated by applying safety factors to the toxicity test results. A factor of 100 was used for the continuous DCV discharge. For intermittent actuator valve discharges, a safety factor of 10 was used, to reflect the short duration of the events (maximum 45 seconds) in relation to the test duration (48-72 hours). The application of these safety factors provided the basis for estimating the degree of fluid dilution required to avoid biological harm.

To support the ecotoxicological risk assessment, control fluid discharge scenarios were defined, and fluid dispersion was modelled. This included both continuous discharge (from DCVs) and intermittent discharge (from events in which the tree and manifold actuator valves are operated). The modelling output was expressed as the linear dimension and volume of the ‘plumes’ at the no-effect dilution.

The ecotoxicological risk assessment demonstrated that:

- For DCV discharge (combining all DCVs for a single tree or manifold) the plumes were too small to visualise graphically and that the maximum volume was approximately $5m^3$. This is equivalent to a radius of just more than one metre. The assessment is based on the assumption of constant exposure; the small size of the plume and the presence of a concentration gradient within the plume mean that in practice the radius of potential effect will be less than one metre from the point of discharge.
- For the actuator valve discharges, the maximum plume volume was $84m^3$, and the maximum plume persistence at concentrations above the no-effect level was approximately 18 minutes. Short-duration toxicity tests (0.5h) indicated that, for this duration of persistence and exposure, toxicity was 4-5 times lower than over the standard (48-72h) test durations, and therefore that a more realistic estimate of the maximum volume would be less than approximately $20m^3$.

The risk assessment concluded, on the basis of these results, that the discharge of water-based control fluid would have minimal environmental impact within a very small distance from the discharge locations (DCVs and actuator valves).

4.10 Drilling

Well tests are undertaken to evaluate well performance characteristics and are considered only when identified as necessary by the project. The duration of the well tests will be dependent upon how well the various sand layers are connected to each other. A cleanup flow period will be performed first to remove any “slugs” of drilling fluid and perforation debris. The well will then be flowed at a steady state through a range of chokes at various rates for a period of time. The well will then be “shut-in” for a pressure build up period. The time taken for the Pressure Build Up (PBU) will indicate how well connected the reservoir sands are and give an indication of what impact the “Fault Feature” has on the reservoir performance.

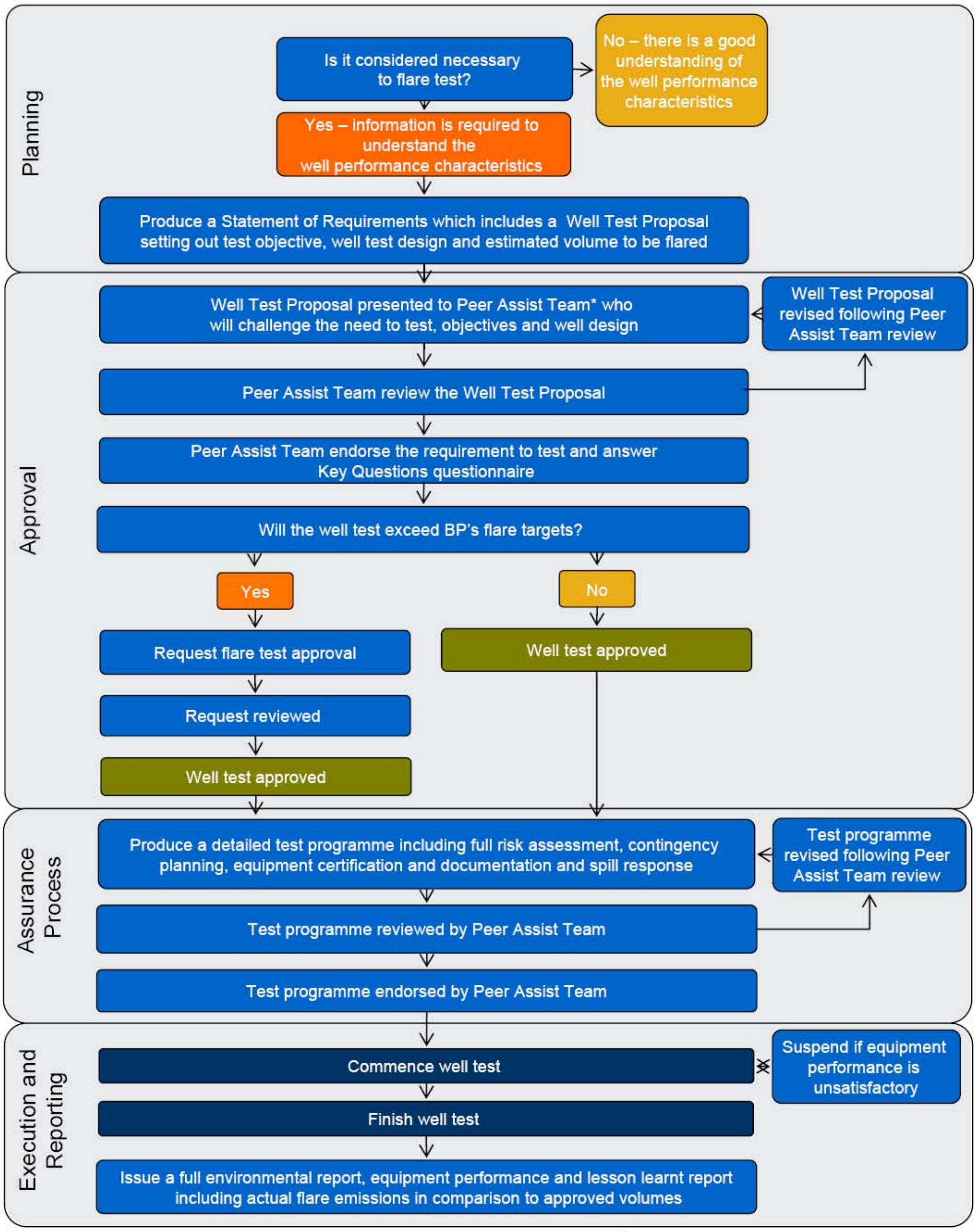
In addition to obtaining reservoir productivity and sustainability data, fluid samples will be taken to study wax formation temperatures. This will potentially affect the design of the subsea equipment.

The majority of the well test period is associated with PBU. However, flaring of reservoir fluids will be undertaken following each PBU period. Alternatives to flaring are not considered feasible as the reservoir fluids will be predominantly gas. Flaring is therefore the most technically practicable and safest means of disposing of the reservoir fluids.

BP has committed to minimise well test flare emissions globally. This commitment has been considered during well planning for the SD2 Project. Well testing will be undertaken in accordance with the Well Testing Assurance Process as shown in Figure 4.6.

There are four key stages to the Well Testing Assurance Process which aims to minimise flare emissions while maximising the value of the well test data. BP has set target well test emission levels and if a test is planned to flare more than these targets, then the approval process must be followed to ensure that a robust review by an internal expert team (known as the Peer Assist Team) is undertaken to test the justification for exceeding the emission targets. The process aims to ensure that well testing is planned and undertaken efficiently, with emissions minimised.

Figure 4.6 Well Testing Assurance Process



* Peer Assist Team includes representatives from the following:
- Well test operations specialists;
- Fluids sampling and production chemistry specialists;
- Test data analysts;
- Reservoir Engineers and
- Subsea support team.

4.11 Base Case Optimisation

The design of the SD2 facilities will be further optimised during the Define stage of the project. It is not anticipated, however, that there will be any significant changes to the current design Base Case.

Should the optimisation result in a change to the SD2 Base Case design as assessed within this ESIA, the SD2 Management of Change Process will be followed as detailed within Chapter 5 Section 5.16.