

NOVEMBER 2020

CARBON CAPTURE AND STORAGE HUB STUDY

PREPARED FOR THE GOVERNMENT OF THE NORTHERN TERRITORY OF AUSTRALIA

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EXECUTIVE SUMMARY

The Opportunity

Middle Arm in Darwin Harbour has the potential to host an industrial Carbon Capture and Storage (CCS) hub mitigating carbon dioxide (CO₂) emissions from current and future natural gas processing operations and supporting the creation of new low emissions industries that use natural gas as a feedstock, including clean hydrogen production. CO₂ captured at Middle Arm could be transported via pipeline to a geological storage resource located in the Petrel Sub-basin (Bonaparte Basin) in the Joseph Bonaparte Gulf, approximately 180km west of Darwin. Reviews of the Petrel Sub-basin completed over the past two decades indicate that it is highly prospective for geological storage, with a capacity to receive up to 20 million tonnes per year of CO₂ with several hundred million tonnes of total storage resources.

The cost of capturing reservoir CO₂ from natural gas processing facilities is extremely low because near-pure CO₂ gas streams are currently available and vented to the atmosphere. The cost of compression, transport and storage of CO₂ in the Petrel Sub-basin depends on the pipe route selected (i.e., length of the onshore and offshore pipeline), the mass of CO₂ transported and stored per year (i.e. capacity and utilisation of infrastructure and energy required for compression), the cost of energy and the cost of capital. Three pipeline routes and a range of CO₂ capacities from 2.2Mtpa to 17.3Mtpa were considered. One pipeline route was ultimately not recommended due to high cost. Estimates of the total cost of compression, transport and storage of CO₂ for the remaining two pipeline routes were generally between AUD40/tCO₂ and AUD50/tCO₂.

The geological storage of reservoir CO₂ that would otherwise be vented to atmosphere from gas processing facilities at Middle Arm could reduce the Northern Territory's greenhouse gas emissions by between 6 and 10Mtpa at a cost of approximately AUD45/tCO₂. Costs

would be reduced if the cost of injection and monitoring was less than AUD10/tCO₂ or the cost of electricity for compression was less than AUD115/MWh, or the cost of capital was lower than 6% (e.g., through concessional finance provided by Government). In all cases, larger-scale delivers economies of scale that reduce the unit cost.

The cost of capturing CO₂ from natural gas power generation, ammonia production, methanol production, ethylene production, condensate refining and titanium vanadium refining at Middle Arm was also estimated. These are higher-cost capture options due to low CO₂ partial pressure in gas streams. The cost of capture from these processes was estimated at between AUD70 to AUD90 per tonne of CO₂. The cost would reduce by almost AUD10/tCO₂ if the cost of capital was reduced from 6% to 2%. Lower energy costs can further reduce capture costs by a similar amount. Compression, transport and storage costs would add approximately AUD45/tonne CO₂ as described in the previous paragraph.

The cost of clean hydrogen production via steam methane reformation with CCS at Middle Arm was estimated to be slightly more than AUD2/kg of hydrogen. A small hydrogen production capacity of 82,000 tonnes per year was assumed. This low-cost clean hydrogen production at this small scale is only possible at Middle Arm as part of a CCS hub with a total CO₂ capacity of a few million tonnes per annum (or more) as it depends upon economies of scale which significantly reduce the unit cost of CO₂ transport and storage.

The cost of clean hydrogen production could be reduced through a lower cost of capital, and/or a lower cost of electricity or natural gas and/or a lower cost of CO₂ injection as previously described. There is also new technology; the Allam-Fetvedt cycle integrated power and hydrogen production cycle that is progressing through feasibility studies in New Zealand that promise even lower hydrogen production costs. Conversely,

higher gas costs could increase clean hydrogen production costs. For example, if gas cost was AUD6/GJ instead of AUD4/GJ assumed in this study, the cost of clean hydrogen production would increase to approximately AUD2.50/kg.

Blueprint of Actions

These opportunities will not be realised unless government acts to address the commercial barriers and

risks that currently prevent private sector investment and participation in the development of a CCS hub at Middle Arm. A coordinated effort by the Northern Territory and Commonwealth Governments is most likely to deliver the best outcome at the lowest overall cost. A high-level Blueprint of Actions has been developed to describe the first steps the NT government could take to initiate the development of a CCS Hub at Middle Arm. Later actions will need to be defined based on the outcomes of the first actions described in the blueprint. The blueprint actions are summarised in the following pages.

BUILD A PARTNERSHIP WITH THE COMMONWEALTH GOVERNMENT MONTH 0 TO MONTH 3	CONSULT INDUSTRY & THE COMMUNITY MONTH 0 TO MONTH 6	STAGE GATE 1: GO OR NO-GO FOR PRE-FEASIBILITY STUDIES MONTH 7	OBTAIN A GREENHOUSE GAS ASSESSMENT PERMIT MONTH 7 TO MONTH 19
Actions 1a: Engage with the Commonwealth Government to develop a shared vision for a CCS hub to support the existing LNG industry and the development of new low emission industries at Darwin. 1b: Propose a development pathway to the Commonwealth to focus discussion and identify specific policy measures that may implemented. 1c: Consult the Commonwealth Department of Industry, Science, Energy and Resources (DISER) to request the release of Acreage encompassing the Area of Interest shown in Section 1.4 of this report. Resources Required • NT Government industrial development policy personnel and possibly minor external resources (consultancy) to support policy development. • Consultancy support may cost \$20k	Actions 2a: Develop and issue a Request for Information (or similar process) seeking submissions from industry that address specific questions or issues related to a proposed CCS hub at Middle Arm. 2b: Establish a dedicated communication function with appropriate resources to serve the project. An early priority should be collecting data on community concerns and attitudes to inform the development and implementation of a Community Engagement Plan. Resources Required • Dedicated Senior Community Engagement Specialist plus operational expenses. • Operational expenses (excluding the specialist) for the Community Engagement Programme may cost \$10k	Actions 3: Decide whether to proceed with a prefeasibility study for a CCS hub at Middle Arm.	Actions 4: Prepare a greenhouse gas storage exploration work programme and apply for a Greenhouse Gas Assessment Permit. This programme should include the collection of 3D seismic data over the Area of Interest followed by the drilling of an exploration/appraisal well. Resources Required • Support from a specialist in offshore subsurface exploration. • External support may cost around \$50k

ESTABLISH A CCS HUB PROJECT TEAM	DEFINE THE SCOPE AND PLAN FOR EXECUTION OF THE PREFEASIBILITY STUDY	COMPLETE PRE-FEASIBILITY STUDY INCLUDING STORAGE SITE APPRAISAL	STAGE GATE 2: GO OR NO-GO FOR FEASIBILITY STUDY AND CHOICE OF DEVELOPMENT OPTION
MONTH 16 TO MONTH 19	MONTH 20	MONTH 21 TO MONTH 33	MONTH 34
Actions 5: Establish a CCS Hub Project Team staffed by individuals with the requisite skills and experience. Resources Required The team will require high level competence in at least the following disciplines: • industrial feasibility study management • project management • gas production and processing • gas pipelines and compression (engineering) • offshore subsurface exploration & development • community engagement & public relations • indigenous heritage management • compliance management • financial & commercial analysis • health, safety and environmental management	Actions 6: Develop a scope and plan for completion of a prefeasibility study. Resources Required • The CCS Hub Project Team • Probably support from an engineering firm experienced in developing prefeasibility studies for industrial and oil/gas production projects.	Actions 7: Undertake the pre-feasibility study including the exploration programme under the approved Greenhouse Gas Assessment Permit Resources Required • The CCS Hub Project Team • Probably support from an engineering firm experienced in developing prefeasibility studies for industrial and oil/gas production projects. • Storage site appraisal may cost around \$20 million for acquisition and analysis of 3d seismic data plus around \$50 million for an offshore appraisal well, sampling and analysis. • The remainder of the prefeasibility study, including study scope definition and planning may cost around \$3 million.	Actions 8: Decide whether to proceed with a feasibility study and if so, choose the development option for study.

1.0 GEOLOGICAL STORAGE RESOURCE ASSESSMENT

1.1 Introduction

This study reviews the CO₂ storage potential of the Petrel Sub-Basin (PSB) based on previous analysis. An area of interest (AOI) proposed in this study has a higher potential for success in identifying a viable storage formation for a CCS project. Success criteria include:

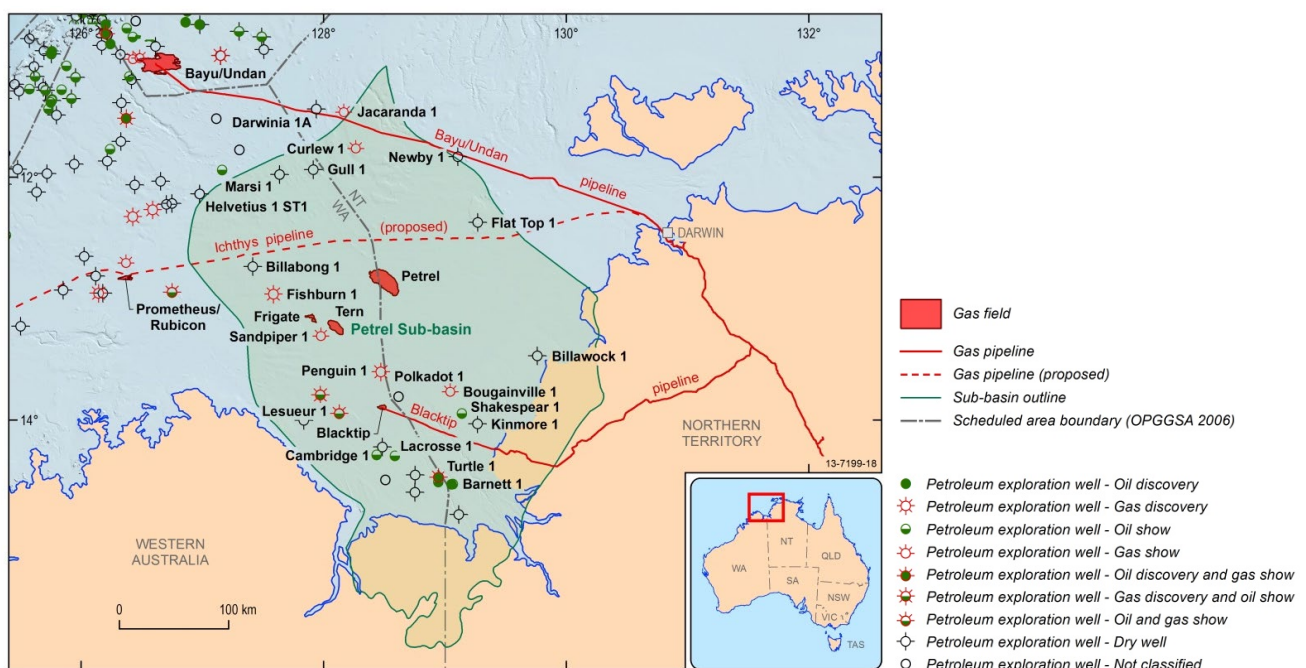
- Geology: meets capacity and containment requirements
- Economics: minimise pipeline length and wells

The target storage formation within the AOI is the Plover-Elang formations.

1.2 Petrel Sub-Basin geology

The PSB occupies the majority of the Bonaparte Gulf in water depths averaging 100m (Figure 1). The entire sedimentary package of the PSB is over 15 kilometres thick. The package thickens to the northwest, gradually thinning to the south, where it extends onshore (Figure 1). The PSB is an asymmetric syncline which dips northerly. Bounded by large faults on the eastern and western margins, the base of syncline roughly follows the central part of the Gulf.

Figure 1. Petrel Sub-Basin including petroleum wells, fields and existing infrastructure (From: Consoli et al. 2014).

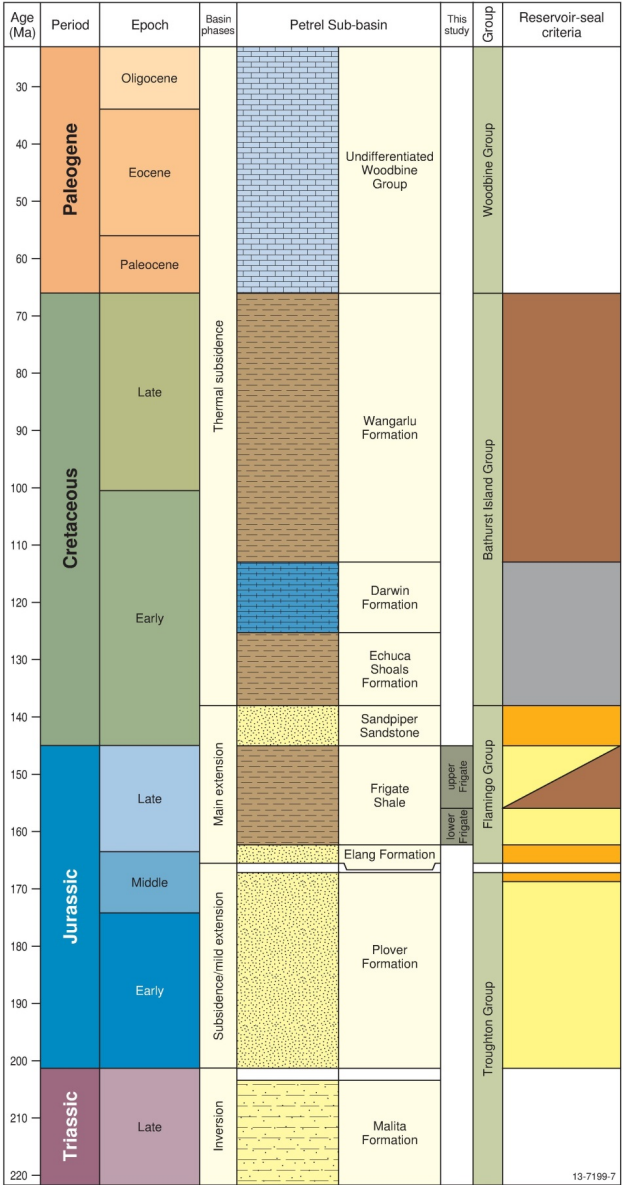


The Jurassic-aged Plover and Elang formations lithologically are a single unit but are separated by a time-gap, known as the Callovian Unconformity (Figure 2). The Plover-Elang formations are the main storage reservoirs within the AOI of this study. The Jurassic formations overlie the Triassic Malita Formation, which forms a low permeability barrier under the storage formation.

The reservoirs are succeeded by the Jurassic-aged Frigate Formation – the caprock in the AOI. The caprock is then proceeded by the Cretaceous Sandpiper Sandstone and Bathurst Island Formation; potentially a secondary reservoir-seal pair in the AOI. The Bathurst Island Formation is the regional seal for the basin.

This entire sequence of rocks was deposited as a series of fluvial and delta sediments, with increasing shallow marine influence before deep marine mudstones of the Bathurst Island Formation. For more information on the geology of the PSB the reader is referred to Consoli et al. (2014).

Figure 2. Geological stratigraphy if the Petrel Sub-basin for this study (After: Consoli et al. 2014).



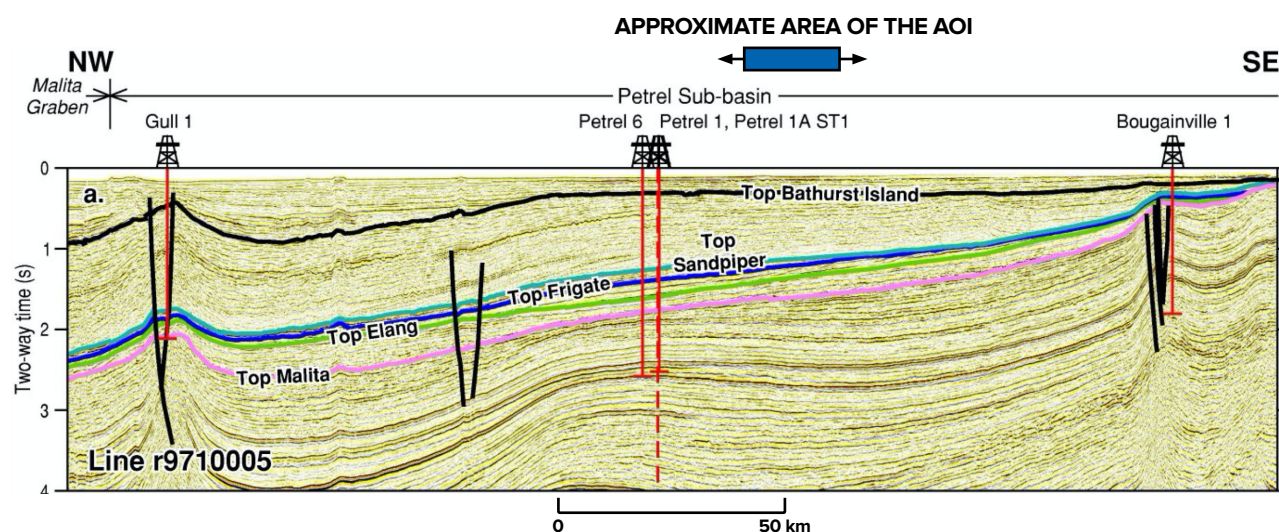
RESERVOIR-SEAL CRITERIA RESERVOIR

- HIGHLY SUITABLE
- SUITABLE

SEAL

- HIGHLY EFFECTIVE
- EFFECTIVE

Figure 3. Seismic line (r9710005) showing the location of the approximate Area of Interest (AOI). The seismic line shows the seismic horizons tops of the formations (coloured lines) and tectonic faults (in black) discussed in this study. See inset map for the location of the seismic line (in dark blue line) (Modified from: Consoli et al. 2014).



1.3 Evaluation History

In 1999, the PSB was identified as a potential CO₂ storage basin. Since that time, reviews of the PSB have been almost continual, all confirming the Plover-Elang and Sandpiper formations as the most prospective formations for storage.

GEODISC (1999-2004)

GEODISC was an Australia-wide assessment to identify storage sites based on regional and then site-scale geology. The initial phase identified over 50 sites, known as Environmentally Sustainable Sites for CO₂ Injection (ESSCI) (Cook, Rigg & Bradshaw 2000; Rigg et al. 2001; Bradshaw et al. 2002). The study was undertaken by a consortium of groups including the former bodies of Geoscience Australia and the CO₂CRC.

The outputs of GEODISC included a ranked assessment based on the geological suitability of the ESSCIs, including storage resources and containment properties. Also, the estimated capital costs and proximity to emission sources are ranked. GEODISC identified the PSB Plover-Elang and Sandpiper as 'possible', specifically in two sites – the Tern and Petrel gas fields. As far as this author is aware, no additional data was acquired during this assessment.

The PSB was shortlisted for a comprehensive assessment as part of GEODISC Phase Two.

Phase Two of GEODISC included a complete reinterpretation of existing well and seismic data and the construction of a geological model. Phase Two also completed core analysis, including mineralogy

and seal containment analysis, as well as petrophysical and hydrodynamic analysis. The Plover – Elang and Sandpiper ESSCIs had a combined capacity exceeding ~50 GtCO₂.

Two prospective areas using the Plover – Elang and Sandpiper ESSCIs include:

1. The central part of the basin Gull-1 and the Petrel Field (Figure 1) that was also found as the cheapest option.
2. The second site is up-dip from the Petrel Field, comparable to the Area of Interest (AOI) of this study. The authors identified that the second option will not conflict with the future production of the Petrel Gas Field.

Carbon Storage Taskforce (2008-2009)

The Carbon Storage Taskforce, guided by the Geosequestration Mapping Taskforce (the Chief Geoscientists and their representatives from the national and state geological surveys), directed Geoscience Australia to complete an Australia-wide study of basins. Initially examining around 100 basins, a shortlist was created using a qualitative Basin Ranking system, modified from (Bachu 2003). The Taskforce ranked the Plover – Elang and Sandpiper formations 12th of all basins in Australia. The Taskforce found:

- Plover – Elang and Sandpiper formations ranked as 'suitable' storage formations
- Storage resource of 55.3 GtCO₂ (P50).

The outputs included a series of tables and graphs summarising key data critical for storage and a series of data acquisition recommendations for the PSB (called the Bonaparte- NT in the report). The Taskforce did not acquire any new data but utilised existing well data and formation mapping.

The PSB was identified as a potential CCS hub, based on the suitability of the geology and LNG industries in Darwin at a rate of 5 Mtpa, ready for start-up in 2021. However, the PSB was not recommended in their pre-exploration programme by the Taskforce.

National Emissions Coal Initiative -Geoscience Australia (2014-2015)

Geoscience Australia completed this pre-competitive data acquisition and assessment on the PSB after the release of ten greenhouse gas (GHG) storage areas for exploration in March 2009.

The goal of the assessment was to de-risk factors identified in previous studies over a region released for GHG exploration leases on the eastern flank of the PSB. The year-long study completed by Geoscience Australia was part of the National Emissions Coal Initiative and formed part of a series of regional studies.

The new data acquired included:

- 2D seismic over a significant gap in data on the eastern flank of the PSB.
- Seafloor marine sampling, bathymetry, sonar identifying existing seafloor leaks and provide baseline marine data.
- Core analysis including seal capacity, mineral mapping, fluid inclusion analysis, amongst others

This new data was utilised to re-map the sequence stratigraphy, confirm the position of faulting and enable new well log analysis. That data was included in a geological model and dynamic simulation. Key findings from the simulation study include:

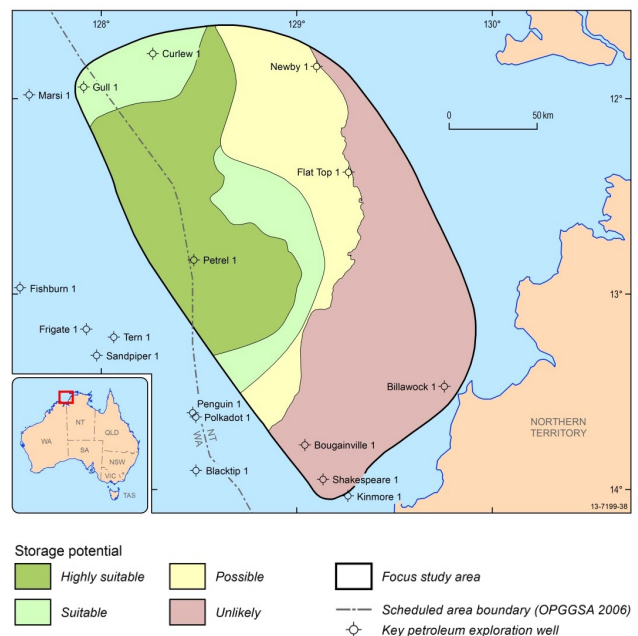
- The injection of CO₂ would not result in the reactivation of faults.
- Long migration pathway means CO₂ will not flow out of the reservoir due to hydrodynamic trapping

- The caprock will not fracture under high CO₂ accumulation rates
- The injection rate of 14 Mtpa in a small section of the Plover-Elang and Sandpiper formations north of the existing Petrel Field
 - Nine wells are required to reach these targets
 - CO₂ only flowed 5 kilometers during injection (20 years); virtually stopped after cessation of injection.
 - 50% trapped of CO₂ trapped by residual and dissolution trapping (permanent methods) after 100 years.
- Total storage resource of 15.9 GtCO₂ of the entire Plover-Elang and Sandpiper formations

The assessment concluded that the central part of the PSB was highly suitable for CO₂ storage (Figure 4). Migration-assisted trapping is the primary method for trapping across the two storage formations. Finally, the Plover – Elang and Sandpiper, are both are effectively sealed by proven overlying caprocks.

The AOI of the current study sits within this highly suitable zone of the Geoscience Australia assessment.

Figure 4. CO₂ storage potential of the study area. (Source: Consoli et al. 2014).



Northern Australia CCS RD&D Fund (2016-2020)

The purpose of this study was to review the central PSB for CO₂ captured from the Evans Shoal Field, a high CO₂ gas field to the north of Darwin. This study commenced mid-2016 led by Shell as the then operator of Evans Shoal Field permit, NT/RL7. In December 2017, Eni Australia became the operator of the permit and completed the assessment along with analysis by CSIRO.

The targeted assessment's objectives included:

- De-risk factors identified from previous studies
- Identify a suitable storage AOI
- Model the injection of CO₂
- Define the infrastructure required, included indicative specifications on compression, CO₂ pipelines, injection operations.

New seismic data was incorporated into a revised assessment of seismic mapping exercise that included new sequence stratigraphy and formation mapping, as well as fault mapping (Johnstone & Torres 2017). The additional analysis included geomechanics, paleogeographic mapping and core analysis.

Five shortlisted potential storage sites include:

- The Evans Shoal Field itself
- Proximal to the Evans Shoal Field
- Southern margin of the Caldita Graben
- Darwin Shelf
- PSB

The PSB is the most suitable target according to the study, and once again, the Plover-Elang and Sandpiper were identified as the best storage formations.

Shell and ENI identified an AOI that met all the objectives and found:

- The Plover-Elang is the only required formation
- Faults would not be reactivated on injection
- A rate of up to 5 Mpta (the flow rate of CO₂ from Evans Shoal gas processing facility) is achievable
- CO₂ migrates only 12 kilometres southeast
- 50 to 90% of the injected CO₂ trapped by residual and dissolution over 200 years.
- An estimated total storage resource of 130 MtCO₂ stored (approximately 30 years of injection)

The Northern Australia CCS RD&D Fund found five specific sites to review, all on the southern flank, southeast of the Petrel Field.

1.4 Area of Interest

The AOI is approximately 180 kilometres west of Darwin and 77 kilometres from the closest shoreline (Figure 5). The water depth is approximately 65-70 metres in the area. Geologically, the AOI lies midway along the eastern flank of the PSB. The areal extent of the AOI is 2,200 kilometers¹.

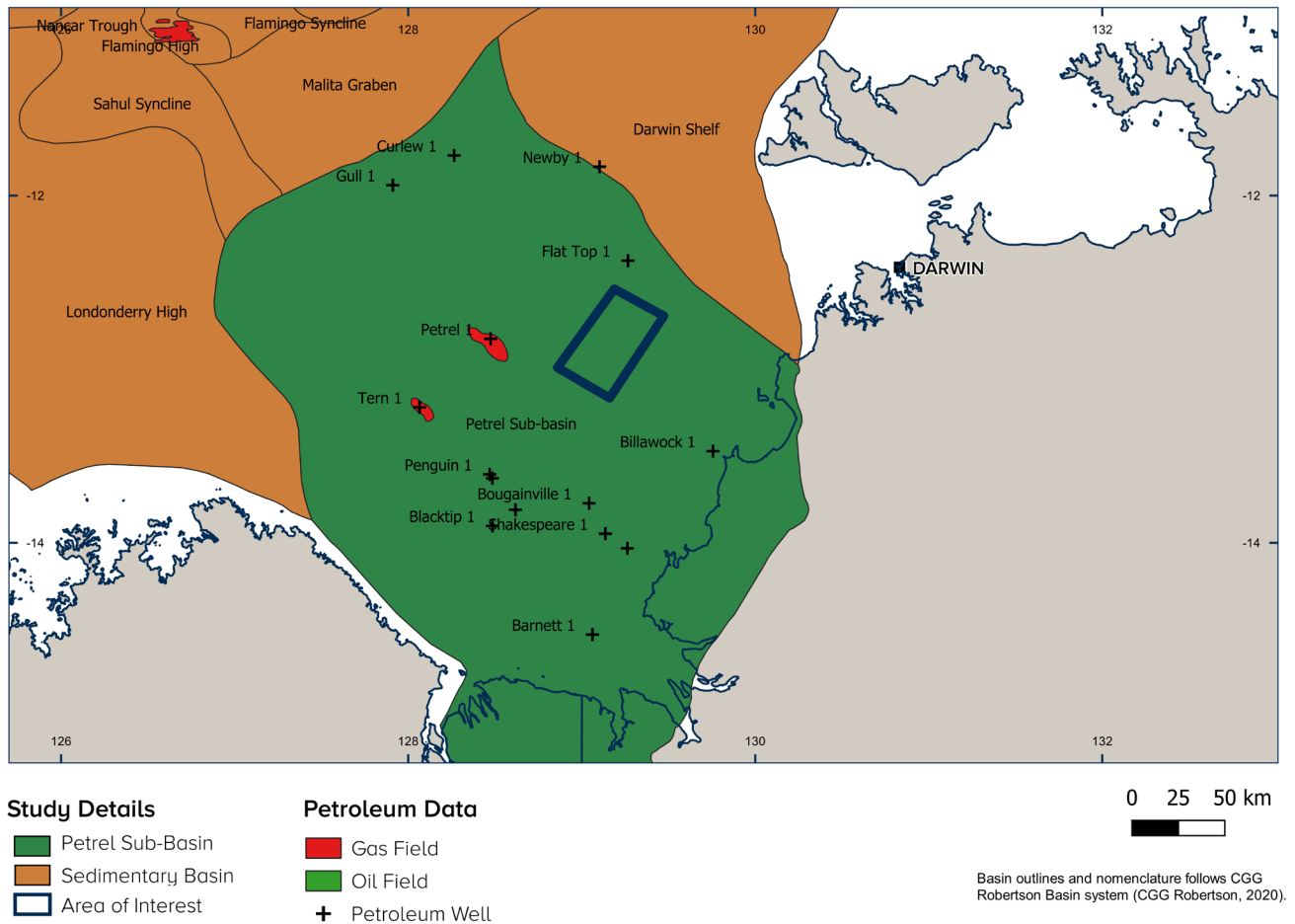
The storage formation's pore volume for the reservoir is defined as the base of Plover Formation to the top Elang Formation (Figure 2).

The caprock is mapped as the top of the Elang Formation to the top of the Frigate Formation. According to the current seismic interpretation, no geological structures (such as anticlines¹) lie within AOI. The lack of structures means the predominant trapping mechanisms will be residual and dissolution trapping; collectively known as migration-assisted trapping.

Previous studies indicate that migration-assisted trapping in the Plover-Elang formations can permanently store between 5 and 14 Mpta (Stalker et al. 2020; Clennell 2019; Consoli et al. 2014; Johnstone and Torres 2017).

¹ Anticline is a folded, arch-like structure. For CO₂ storage, the arch would have the reservoir on the inner, and seal on the outer.

Figure 5. The area of interest of this study.



1.5 Storage Formation Characteristics

The reservoir characteristics are derived from the nearest set of wells in the Petrel Field and surrounding wells (Bougainville-1 and Flat Top-1) (Table 1, Table 2, Table 3) and analyses from previous studies (Clennell et al. 2017; Dewhurst et al. 2019; Consoli et al. 2014; Stalker et al. 2020; Johnstone and Torres 2017).

Table 1. Properties of the Plover – Elang formations (After: Consoli et al. 2014).

WELL	GROSS THICKNESS (M)	NET RESERVOIR THICKNESS (M)	NET / GROSS	NET RESERVOIR POROSITY (%)	NET RESERVOIR PERMEABILITY (MD)	NET RESERVOIR WATER SATURATION (%)
Bougainville 1	67.1	65.0	0.97	29.8	4022	99
Flat Top 1	196.1	178.4	0.91	23.9	622	100
Petrel 1	410.1	370.6	0.87	16.9	65	99
Petrel 3	423.0	370.6	0.88	17.0	67	100

Primary reservoir

The Plover-Elang formations are the primary CO₂ storage reservoirs in the AOI. The formations are laterally extensive, continuous sand bodies extending across much of the PSB. The CO₂ is injected into a depth of around 1400 meters below mean sea level (sea level depth in AOI is ~80m).

The Plover Formation was deposited in a sand-rich fluvial system. This depositional environment results in a high sand ratio (80-90% sand) and excellent reservoir properties for CO₂ storage (Table 1). The likelihood for baffles (thin layers (<1-meter scale) of mudstone) is also high in this environment. Baffles enable the CO₂ to better distribute throughout the reservoir, maximising utilisation of the pore space.

The Plover-Elang reservoir has a gross thickness (top to bottom of reservoir) of around 400 m with a permeability range from 65 to over 4000 mD and a porosity of 15-25% range (Table 1). Given the location of the AOI, mid ranges of the porosity and permeability are most likely.

Secondary reservoir

The Plover-Elang storage reservoir is likely to meet injection and storage capacity requirements for the current rates of CO₂ capture. However, if expansion is required, the Sandpiper Sandstone Formation overlies the Plover-Elang storage reservoir in the AOI and could potentially serve as a secondary reservoir. If not utilised, the Sandstone will act as a buffer mitigating storage leakage risk assessment.

In addition, the new interpretation of the Northern Australia CO₂ Storage Project (Torres, Johnstone & Bennett 2016) suggests the Sandpiper Sandstone is hydraulically connected to the Plover-Elang formations. The reservoirs may merge up-dip and outside the AOI. The merging of reservoirs means the Sandpiper Sandstone could alleviate pressure concerns acting as pressure buffer in the later stages of a storage operation, when pressure may become an issue.

Table 2. Depth of the top of the formations of interest from Petrel-1 and Petrel-3 petroleum wells. Note: the top of the secondary seal is not provided, as the section can be over 1000 meters thick. After: Consoli et al. 2014).

WELL	FORMATION			
	SANDPIPER SANDSTONE (TOP OF THE SECONDARY RESERVOIR)	FRIGATE (TOP OF THE PRIMARY SEAL)	ELANG - PLOVER (TOP OF THE PRIMARY RESERVOIR)	MALITA (BASE OF THE PRIMARY RESERVOIR)
Bougainville 1	315	365	400	465
Flat Top 1	784	790	826	985
Petrel 1	1330	1575	1900	2230
Petrel 3	1240	1415	1740	2070

1.6 Storage Containment Characteristics

The Frigate Shale provides vertical containment of CO₂ in the primary reservoir. Within the AOI the Frigate was deposited in a marine environment as an argillaceous mudstone. This sealing facies of the Frigate is relatively thick (100-200 m) in the AOI according to the mapping of Consoli et al. (2014) and extends around 40 kilometres up-dip from the centroid of the AOI. Based on the limited core of the Petrel-1, low CO₂ column heights of approximately 65-143 m using mercury injection capillary pressure (MICP). Beyond that facies and south of the AOI, the depositional environment shallows and there is potential for fine sandstone layers indicating some permeability in the seal.

Secondary containment

The secondary reservoir, the Sandpiper Sandstone, is overlain by the Bathurst Island Formation. The Bathurst Island Formation is the regional seal extending across much of the basin, including all the reservoirs mentioned. The regional seal is 500-700 m thick in the AOI. The latest seal capacity testing using the core of the seal contained a CO₂ column height of around 137-365 m (average 225.8 m). The regional seal provides further assurance against the risk of leakage, either vertically or laterally within the Plover-Elang prospect.

The Bathurst Island Formation does host extensive polygonal faulting that warrants more review if the regional seal was to become the primary containment unit for the storage formation.

1.7 Storage Resource

This current study did not calculate the storage resources of the AOI. Six separate calculations have been completed over the AOI, but consider the broader PSB.

The storage resources are divided into:

- **Static:** typically volumetric calculations using a defined formula. The formula takes into account the pore volume (thickness, area of the reservoir), CO₂ density and an efficiency factor. The latter predicts how much of the pore volume the CO₂ occupies. The formula most used within the PSB are those of the Department of Energy, US Government. For more details on the calculation method, the reader is referred to US DoE/NETL (2015). Overall, static calculations provide only a theoretical estimate of final storage capacity.
- **Dynamic simulation:** uses computer modelling to predict injection and storage rate, as well as wells required to meet targets. The method uses localised reservoir characteristics (taken from well data) and well design and optimisation to predict the rate and movement of CO₂ within a geological model. Dynamic simulations are a more accurate reflection on actual injection and storage rates. The accuracy is dependent on the resolution and precision of the data inputted into the simulation.

Previous static calculations have shown that across the PSB, the Plover-Elang formations have substantial storage resources in the scale of gigatonnes of CO₂ storage resources (See Table 3).

With regards to dynamic simulations, Clennell et al. (2017) completed a study over the AOI and found injection rates of between 2.0 - 7.5 Mtpa for 30 years. Using between 1 - 4 wells, depending on the injection rate, CO₂ ultimately stored was only limited by well design and the CO₂ capture rate. That study found no pressure-induced impacts on the reservoir or seal. Also, fault reactivation did not occur during the injection.

Through dynamic simulation studies, Consoli et al. (2014) reached a CO₂ injection rate of 14 Mtpa using nine wells in a site to the north of the Petrel Field. Comparable to the previous study, CO₂ capture rates were the limiting factor. Injection rates did not impact caprock integrity or result in fault reactivation. The overall conclusion from both volumetric and dynamic simulations, it that the required CO₂ injection rates and ultimate storage capacity can be achieved within the Plover-Elang formations.

Storage Resource Management System

This study has classified previous resource estimates according to the Storage Resource Management System (SRMS) classification (Society of Petroleum Engineers 2017) (Table 3). The SRMS is comparable to the Petroleum Resource Management System (PRMS) to define existing resources according to their commercial maturity. The SRMS creates consistency of terminology to support investor, regulatory and operator's communication of storage resources. The SRMS contrasts to previous storage resource classification methods that focussed on the method of calculation and geology.

A project-led terminology and classification method of resource maturity considers:

- Development of the storage resource based on data and assessment status
- Regulatory system
- The internal project decision-making process
- Status of development, operation and end of injection

A flow chart, developed by PBDE, is shown below. The flowchart, alongside the SRMS classification system, shows the maturation of storage resources through key steps (Figure 6).

According to the classification of the SRMS, the AOI has proceeded through each stage of the SRMS to the stage of being "drill ready". However, without an exploration/appraisal well, the resource will not mature to 'discovered' status. An exploration/ appraisal well requires a commercial driver, which at this point does not exist.

Upon successful appraisal, the storage site in the AOI could rapidly mature with few barriers in place before deployment.

Figure 6. A flow chart describing the steps required to categorise the Storage Resource Management Scheme (After: Pale Blue Dot Energy 2020)

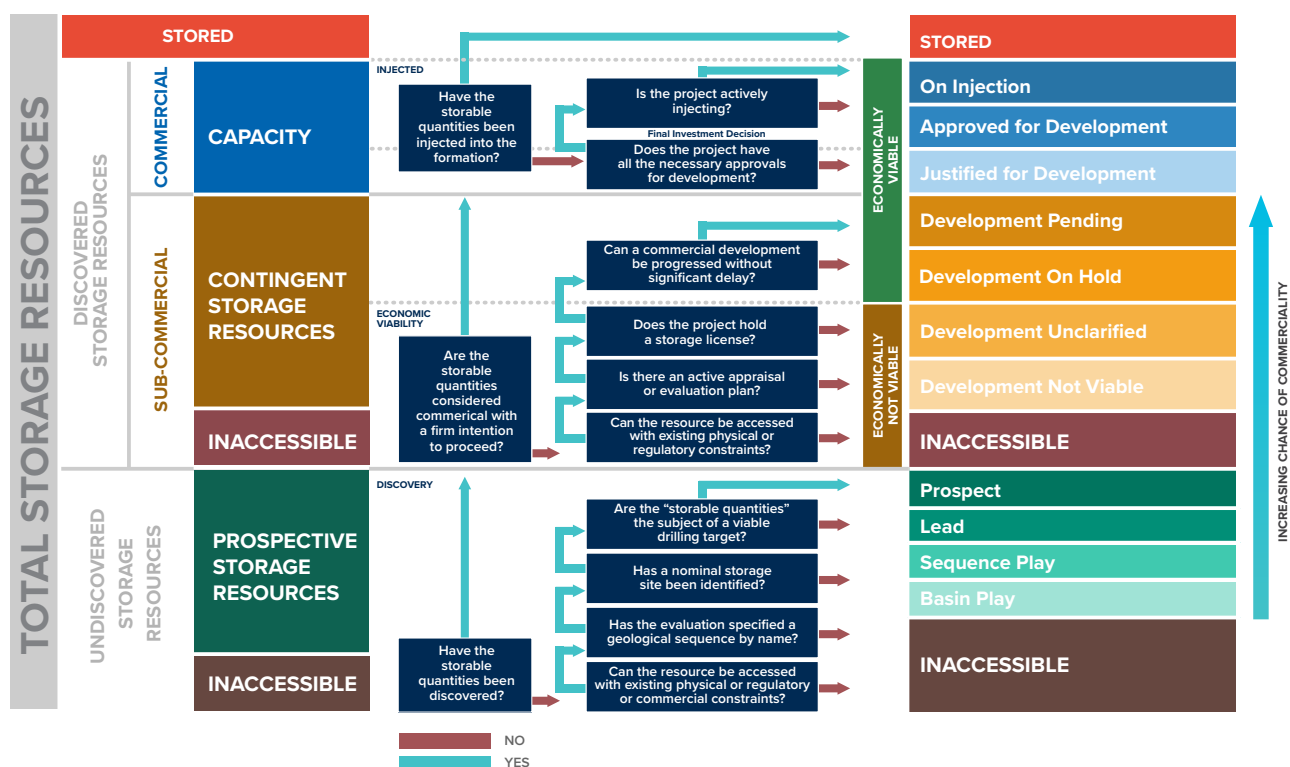


Table 3. Previous reviews of the Plover-Elang and Sandpiper PSB according to the Storage Resource Management System (2017).

PUBLISHED RESOURCE	SCALE	RESOURCE MT	RESOURCE VALUATION METHOD	SRMS (2017) CLASSIFICATION
Gibson-Poole (2009)	Formation	193,464	Static- Volumetric based on geological model	Sequence Play
Carbon Storage Taskforce (2010)	Formation	55,300	Static- Volumetric based on total pore volume	Basin Play
Consoli et al. (2014)	Formation	15,930 (6,480)	Static- Volumetric based on geological model	Sequence Play
Consoli et al. (2014)	Site	570 (420)	Dynamic simulation based on injection rate of 21 Mtpa over 30 years	Lead
Northern Australia CO ₂ storage (2018-2020)	Site	(75-223)	Dynamic simulation based on injection rate of ~2-7.5 Mtpa over 30 years	Lead

Injectivity Assessment

The injectivity assessment below is taken from the outcomes and analysis of Consoli et al. (2014) and unpublished reports of the Northern Australia studies, primarily Seldon et al. (2017).

The top of the Plover-Elang reservoir is approximately 1400 metres deep meaning that any CO₂ stored in the reservoir will remain in the dense phase. This improves the efficiency of stored CO₂ in the pore space, and CO₂ plume migration is more predictable and potentially more constrained.

According to dynamic simulations of the Plover-Elang in the AOI from unpublished sources of the Northern Australia Study, it is predicted that:

1. 130 Mt is injected and stored, at a rate of just under 5 Mtpa CO₂
2. After 200 years, 50-90% of CO₂ is permanently trapped through dissolution and residual trapping
3. CO₂ migrates between ~5-20 kilometres up-dip (Northeast) from the injection wells after 100 years
4. CO₂ migrates between ~15-30 kilometres (Northeast) after 500 years

The ranges above reflect the model inputs. To further

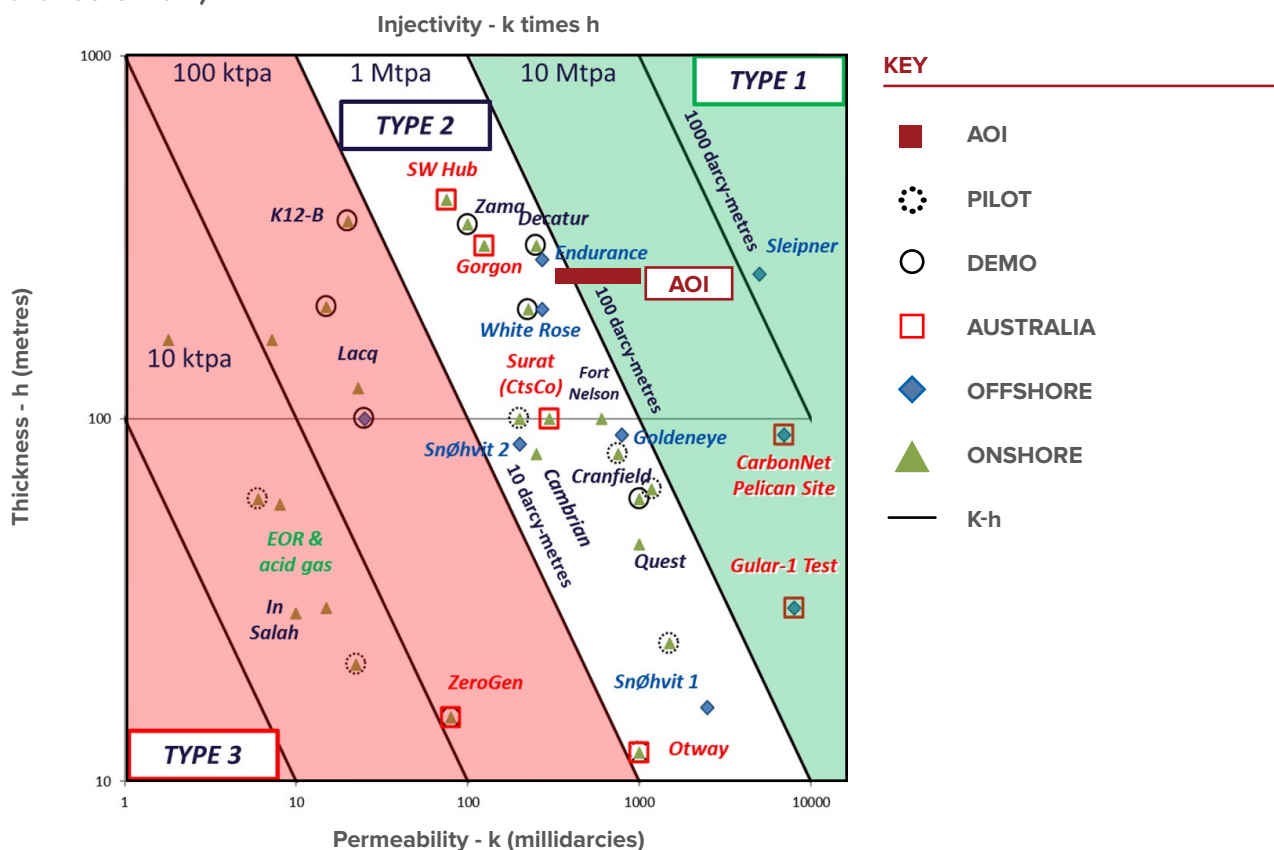
support those simulation results, Consoli et al. (2014) found:

- At the end of 30 years of injection, 420 Mt has been stored in the Plover-Elang
- After 100 years 50% of the CO₂ is permanently trapped through dissolution and residual trapping
- At the end of injection, the CO₂ migrates northeast from 5 kilometres and then up to 34 kilometres after 3200 years.

Collectively, the migration and permanent trapping mechanisms within the dynamic simulations suggest that the reservoir-seal pair within the AOI are extensive enough to store and contain the injected CO₂.

Comparing the Plover – Elang storage formation in the AOI to other CCS projects globally (Figure 7), the injectivity rate in AOI is comparable to other major CCS projects. The AOI also sits within the 'Type 1' Injectivity category. The CarbonNet Project (2015) states that these sites typically have high injectivity with a low number of simple wells, with low overall project costs. The negative aspects of Type 2 projects is a large monitoring footprint due to high CO₂ mobility. Reviewing Figure 7, it should be noted that the Gorgon CCS project lies to the left (lower permeability) than the Plover – Elang storage formation. Gorgon, via nine wells, will reach an annual injection rate of 3-4 Mtpa of CO₂.

Figure 7. Injectivity of the Plover - Elang storage formation in the AOI. The range of the Area of Interest is based on low-medium-high permeability scenarios of the simulations (After: The CarbonNet Project 2015; Seldon, Lynn and Tucker 2017)



Storage Integrity

The integrity of storage formation refers to both pre-existing conditions and factors that can impact a storage formation during the injection.

The AOI does not contain any existing petroleum wells (Figure 5). There is a very low likelihood that the CO₂ plume migrates to a nearby well, with the closest petroleum well (Billawock-1) up-dip from the AOI being over 100 kilometres away. The geology also dictates that the plume is unlikely to migrate northwest to the Petrel Field which contains six wells or Flat Top-1 to the northeast.

The highest risk for most storage operations is pre-existing wells. If the well intersects the storage formation, it may provide a direct conduit to the surface. Therefore, it is important to note that most wells in the immediate region have not been abandoned to specifications that would prevent CO₂ leakage up the well.

The subsurface mapping of faults has been reviewed extensively by previous authors (Dave Dewhurst et al. 2019; B. Clennell et al. 2017; Consoli et al. 2014; D. Dewhurst et al. 2019). Within the current seismic coverage, all known faults have been mapped. These include:

- large bounding faults on the edge of the basin
- a series of normal faults to the north and northeast of the Petrel Field
- polygonal faulting at the base of the Bathurst Island Formation.

There is no evidence of faulting in the AOI that intersect the storage formation and through the secondary seal -

the Bathurst Island Formation. The nearest faults to the AOI are the series of normal faults that lie to the north and north-east of the AOI. Once again, the geology indicates that the CO₂ is unlikely to migrate north.

Numerous geomechanical studies reviewed the faults of PSB. These studies have found that under realistic CO₂ injection scenarios (up to 20 Mtpa), the major faults in the PSB and the polygonal faults within the Bathurst Island Formation do not reactivate (Seebeck et al. 2015; Zhang et al. 2018; Consoli et al. 2014; Dewhurst et al. 2019)

Hydrocarbons

Although no well data exists within the AOI, the likelihood of hydrocarbons within the storage formations is very low. The nearby Petrel Gas Field (not producing) lies within the stratigraphically lower Kinmore Group. Any petroleum accumulations in the AOI are likely to be in the formations of that Group.

Titles, Leases and Licences

The AOI spans across several Commonwealth petroleum titles and is briefly described here (Table 4). For more information and analysis, the reader is referred to Section Two. The southern end of the AOI covers a Special Prospecting Area for the acquisition of geophysics. The majority of the AOI spans the 2019 acreage release. The operator of that title is still unknown. The northern tip also covers the potential 2020 acreage, which is in the consultation phase.

Table 4. Commonwealth Petroleum Titles in the Area of Interest.

TITLE	NAME	OPERATOR	STATUS	EXPIRY	NOTE
Special Prospecting Area	NT-05-SPA	Polarcus Seismic Ltd.	Active	08/05/2020	Geophysical acquisition only; no wells
Special Prospecting Area	WA-44-SPA	Polarcus Seismic Ltd.	Active	07/03/2020	Geophysical acquisition only; no wells

Required Exploration Programme

The main recommendation is the acquisition of 3D seismic over a small prospect within the AOI on the southern flank of the PSB. The primary aim of the 3D seismic survey is to identify a target for drilling an exploration well.

The 3D seismic survey over the AOI also enables:

- Construction of a detailed geological and dynamic models
- Identification of unknown faults
- A better definition of the lithostratigraphy including the extent of the Frigate Shale and merging of the two reservoirs

Ultimately, the 3D seismic survey enables a future well programme.

There is no well control over the AOI or on the eastern flank of the PSB more broadly. Therefore an exploration well is required. In addition to standard well data acquisition, a successful storage-focussed exploration well should complete:

- A coring programme over the intervals of interest to test the seal and reservoir properties
- A leak-off test (or equivalent) to define the flow rate and communication of the reservoir(s)
- Geomechanic and geochemical analysis

The completion of an exploration well will confirm the ultimate injection rate and capacity of the Plover-Elang formations in the PSB, advancing towards final investment decision.

1.8 Potential Injection Design

The final injection and infrastructure requirements can only be confirmed through the appraisal process of Front End Engineering Design and ultimately, the Final Investment Decision.

The current concept below is taken from Seldon et al. (2017) and ENI (2018) Northern Australia CCS Reports. The concept below is only presented to guide the costs and design of this current study. The main modification below is the number of wells (from four to eight) and diameters of tubing and pipes (selected the maximum size).

- Uncrewed well head Platform
 - Well bays
 - Piping and manifold for the CO₂ injection
 - Utilities and infrastructure to support platform operations
 - Helideck
- Vertical CO₂ injection wells
 - 1400 m vertical depth
 - Eight injection wells, two back-ups used as a pressure/seismic monitoring well
 - 7" or larger tubing thickness
 - Cement to ensure conformance to CO₂

A platform removes the need for onshore connection of power and hydraulics to the wellhead. Alternative options exist, including subsea facilities. An extensive review of alternative injection strategies is beyond the scope of this study. However, the Northern Lights Project in the North Sea of Norway is using sub-sea infrastructure including satellite wells, with tie-in points to a hub connecting a subsea pipeline. Northern Lights is only using one well but has provisions for additional wells. They state the subsea system lowers the cost of storage, but no comparison with platforms is provided (Equinor 2019).

1.9 Conclusion and recommendations

The PSB has been almost consistently reviewed over the past two decades. Within this time no new wells have been drilled in the prospective region. Also, only a limited number of 2D and 3D seismic surveys were acquired.

New desktop studies will not progress the development of the PSB for CCS.

An exploration programme, acquiring new subsurface data is required. The exploration programme, including the acquisition of 3D seismic and an exploration well, will progress the deployment of CCS in the PSB. The first injection and storage project in the PSB will de-risk future projects.

2.0 OVERVIEW OF THE REGULATORY FRAMEWORK GOVERNING THE GEOLOGICAL STORAGE OF CO₂ IN COMMONWEALTH WATERS

2.1 The Regulation of Carbon Capture and Storage in Australia

The Australian system of government affords both the Commonwealth and the state governments jurisdiction, to regulate Carbon Capture and Storage (CCS) activities. The Commonwealth Government retains regulatory responsibility for activities in offshore waters, extending from three nautical miles to the edge of Australia's continental shelf. Onshore activities and those conducted in coastal waters, up to the three nautical mile limit and which are adjacent to a state or territory, remain the responsibility of a respective state or territory.

In 2005 a set of national guiding principles for a CCS-specific regulatory framework, the 'Carbon Dioxide Capture and Geological Storage Australian Regulatory Guiding Principles' were published. The Principles were endorsed by the former Ministerial Council on Mineral and Petroleum Resources (MCMPR) and developed following an extensive period of consultation with a

wide range of Australian stakeholders. The Principles sought to ensure a consistent legislative approach was adopted across all Australian jurisdictions and they have been considered by both Commonwealth and State governments, in the design and implementation of their legal and regulatory frameworks for the technology.

The provisions of the Commonwealth government's 2006 Act provide one of the world's first examples of CCS-specific legislation. The Act, together with its accompanying regulations, amend the existing Commonwealth petroleum regime and introduce a CCS-specific model to regulate pipeline transportation, injection and storage activities within the offshore area.

At the state level, the states of Victoria, Queensland, South Australia and Western Australia have all now enacted legislation to regulate the geologic storage of greenhouse gases, or other discrete aspects of the CCS process. Together with the enactment of the Commonwealth Act these regulatory activities have resulted in three distinct Australian storage frameworks; state or territory onshore legislation; state or territory offshore legislation and the Commonwealth offshore legislation.

2.2 Commonwealth offshore storage regime

The Offshore Petroleum and Greenhouse Gas Storage Act 2006 (OPGGGS Act) is the central aspect of the Commonwealth government's regime for the regulation of offshore storage activities. The CCS-specific provisions of this Act, which were enacted in 2009, introduce several changes to the existing Commonwealth petroleum regime and implement a new system of titles for greenhouse gas (GHG) storage operations. The Act has been amended several times in recent years to accommodate policy developments and to address particular challenges in the legislation; the most recent, enacted in early 2020, enables the grant and administration of single greenhouse gas (GHG) titles that straddle the boundary between Commonwealth waters and state or Northern Territory coastal waters.

The Act regulates the exploration process, construction and operation of infrastructure facilities and the injection of GHG substances in Commonwealth waters². Operators are required to secure the appropriate form of tenure to undertake activities throughout the project lifecycle and the legislation introduces a permitting model that enables exploration for a suitable storage site, through to eventual injection operations.

Under the Act, an operator seeking to undertake exploration for a potential storage site in Commonwealth waters, will be required to obtain a 'GHG assessment permit'. The permit enables the holder to conduct exploration activities for potential GHG storage formations and potential GHG injection sites, within the designated permit area.

An assessment permit may be transitioned to a 'GHG holding lease', where a declaration of an identified GHG storage formation is made and an operator wishes to delay injection and storage activities. In other instances, following the declaration of an identified GHG storage formation, injection and permanent storage activities are subsequently authorised under a 'GHG injection lease'.

Detailed CCS-specific provisions are introduced to address the closure of a storage site, several of which are similar to those applicable to the existing petroleum scheme. The Act, however, also includes new provisions which address the long-term liabilities associated with CCS operations and apportion responsibilities to both the storage site operator and the Commonwealth government following the closure of a storage site. The potential for post-closure transfer of responsibility for a storage site, to the Commonwealth Government, is a further significant development under the CCS-specific provisions of the Act.

Secondary regulations provide further detail to the permitting regime and processes established under the Act. Amongst other items, the regulations provide further detail of the content of environment plans, health and safety requirements and the interaction of oil and petroleum titles with the newly created CCS tenures. The four key supporting regulations are:

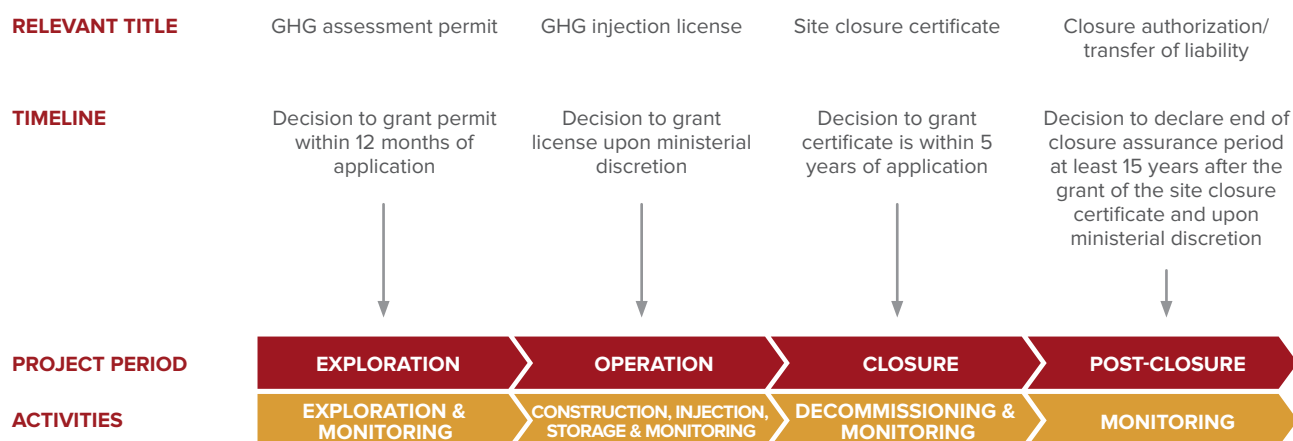
- Offshore Petroleum and Greenhouse Gas Storage (Greenhouse Gas Injection and Storage) Regulations 2011
- Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011
- Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009
- Offshore Petroleum and Greenhouse Gas Storage (Safety) Regulations 2009

2.2.1 CCS Project lifecycle

The Commonwealth Act introduces a series of individual tenures to regulate the lifecycle of CO₂ storage operations, from initial site selection and appraisal through to injection and storage activities. The diagram below identifies each of the key permits, necessary through each of the project phases and milestones.

² Note that the Act uses the term 'Greenhouse Gas Substance', which includes carbon dioxide (in a gaseous or liquid state), other prescribed greenhouse gases or a mixture of substances, as defined by the Act (Section 7).

Figure 8. Diagram of CCS project lifecycle and accompanying titles



2.2.2 Site selection and characterisation activities

The Commonwealth Act introduces a series of individual tenures to regulate the lifecycle of CO₂ storage operations, from initial site selection and appraisal through to injection and storage activities. Figure 8. identifies each of the key permits, necessary through each of the project phases and milestones.

The identification of a suitable storage site under the Commonwealth model, starts with securing suitable acreage for exploration. The following sections set-out the processes and stages necessary for obtaining the relevant approvals that will enable exploration and identification of a storage site.

Acreage release

The Commonwealth retains sovereign rights over the waters beyond the coastal waters of the States, including Australia's exclusive economic zone and continental shelf for the purpose of exploring for and exploiting natural resources. The Commonwealth Act also prohibits the conducting of any exploration and injection activities in offshore Commonwealth waters, without first obtaining the relevant statutory titles established by the Act.

The Department of Industry, Science, Energy and Resources (DISER), of the Commonwealth government, has been charged with regulating CCS activities in the Commonwealth offshore areas. In accordance with Section 695A of the Act, the Secretary to the DISER appoints the National Offshore Petroleum Titles

Administrator (NOPTA) to administer the process of granting the relevant statutory titles to conduct GHG exploration and storage operations in Commonwealth offshore areas. The statutory titles are currently granted by the responsible Commonwealth Minister, who is the Minister for Industry, through NOPTA.

The release of acreage, within the Commonwealth's offshore waters, is the starting point for the site selection process and provide an opportunity for project operators to obtain access to and conduct exploration for potential CO₂ storage sites within a specific area. The acreage release process for offshore GHG storage operations is intended to reflect the model used for petroleum activities.

The selection of prospective acreage for release, begins with a call for the nomination of areas from interested parties, including private companies and State and Territory governments. Following these nominations, a series of sites is shortlisted as potential sites for GHG exploration. GeoScience Australia, the government's advisory agency in relation to geoscientific research, then prepares geological data for each proposed storage site, which will include details of the location and type of any petroleum wells that have been drilled in the area and whether there are any overlapping petroleum titles. Information on previous seismic work carried out for the area, as well as the location of any defence or shipping interests will also be provided³. Where such interests do overlap, a stakeholder consultation is to be carried out, prior to the selected acreage being released and following the approval of the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA).

To-date, there have been two greenhouse gas storage acreage release processes.

³ Chapter 2, Down Under: Greenhouse Gas Storage, Report of the Standing Committee on Primary Industries and Resources on the Inquiry into the Draft Offshore Petroleum Amendment (Greenhouse Gas Storage) Bill, August 2008.

Interactions with other titles under the Act

An important aspect of the Act is the consideration given to the impact upon petroleum exploration and production activities, when granting statutory GHG titles. As such, the Act includes extensive provisions regarding the interaction between these titles and the management of any impacts of key GHG operations upon existing or future petroleum titles.

The Act distinguishes between two types of petroleum titles; pre-commencement petroleum titles and post-commencement petroleum titles. Pre-commencement titles are those titles that were in existence prior to the entry into effect of the amendments to the Act in November 2008, while all other subsequent titles are post-commencement titles.

Where there is a potential conflict between a GHG statutory title and a pre-commencement petroleum exploration title, the Minister assesses whether the GHG title to be granted will have a 'significant risk of a significant adverse impact (SRSAI)' on the pre-commencement title, in which case the GHG title will not be approved. Alternatively, the Minister will also consider if there is a commercial agreement between the two titleholders before granting approval.

In the case of a conflict at the stage of granting a GHG injection license or a post-commencement title, the Minister will decide on which activity should proceed based on the public interest. However, once post-commencement titles have been granted, the Minister will apply the SRSAI test to determine whether a GHG title should be granted in respect of the conflicting area.

Exploration – GHG Assessment Permit

In order to explore for a potential GHG storage formation, an application must first be made to the Minister for a 'GHG assessment permit'. Subsequent approval and award of this permit will then enable the holder to undertake exploration for a suitable geological storage formation, as well as conduct other more intrusive activities, within the permit area. It is an offence to explore in an offshore area for a potential greenhouse gas storage formation, or a potential greenhouse gas injection site, without the correct authorisation.

The Minister will advertise invitations for applications for the grant of a greenhouse gas assessment permit in one of two ways, on either a work-bid or a cash-bid basis. Under the former, applicants are required to provide detail of their proposed work and expenditure in relation to the advertised block(s), as well as information on the

applicant's technical qualifications and the availability of technical and financial resources, amongst other requirements. The latter category of assessment permits requires applicants to specify the amount they would be prepared to pay for a permit, in addition to information relating to their technical and financial capabilities. The Act sets out clear processes governing the procedures for both forms of application, as well as the approach to be adopted by the Minister in selecting and approving applications.

Once an assessment permit is awarded the holder is entitled, subject to any conditions, to undertake a range of activities within the permit area. The Act specifies the following may be undertaken:

- Exploration for a potential greenhouse gas storage formation
- Exploration for a potential greenhouse gas injection site
- Injection of a greenhouse gas substance into a part of a geological formation, on an appraisal basis
- Storage of a greenhouse gas substance into a part of a geological formation, on an appraisal basis
- Injection or storage of air, petroleum; or water; into a part of a geological formation, on an appraisal basis
- Recover petroleum in the permit area for appraising a discovery of petroleum, but only where its discovery was an incidental consequence of exploration or injection activities.

A further feature of the Act's regulatory model is the requirement for a further set of approvals from the Minister, in addition to the grant of a licence, lease or permit. The additional obligation is to ensure that full consideration is given to the impact upon petroleum exploration and production activities and that there is no significant risk of a significant adverse impacts. A condition of the award of a GHG assessment permit, therefore, is that a 'key GHG operation' must not be carried out without approval from the Minister. A GHG assessment permittee must not therefore carry out, amongst other activities, injection and storage, seismic and other surveys, monitoring and sampling from the seabed or subsoil; without first obtaining additional approval. Failure to obtain this approval, prior to these activities being undertaken, is grounds for cancellation of the permit.

The accompanying Commonwealth Regulations place further obligations upon titleholders. The holder of an assessment permit, for example, is required under the Environment Regulations⁴ to provide an environment plan prior to undertaking a GHG activity. Operations

⁴ Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009

must also not continue, where new or increased environmental risks are identified. The plan is to be provided to the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) for approval and must conform with the minimum standards set out in the Environment Regulations.

Assessment permits are granted for a period of six years; however, they may be renewed for a further three-year period.

Declaration of a storage formation

The Act enables the holder of an Assessment Permit, to apply to the Minister for a declaration of an identified GHG storage formation, where they have reasonable grounds to believe that:

- part of a geological formation is an eligible formation; and
- that part is wholly situated in the permit area.

The formal grant of a declaration, by the Minister, is recognition of an eligible greenhouse gas storage formation for the purposes of the Act and is required prior to an application for a GHG injection licence, or a GHG holding lease. Holders of either a GHG injection licence or holding lease, may also apply for a declaration.

The Act, together with the 2011 Regulations, sets out the application requirements and procedure for granting a declaration⁵. The accompanying NOPTA Guidance, notes that applicants will be required to define the 'fundamental suitability determinants' for the eligible storage formation, which will include the following:

- the amount of GHG substance that may be stored, noting that it must be at least 100,000 tonnes
- the particular GHG substance for which the storage formation is suitable to store
- the proposed injection point or points
- the proposed injection period
- any proposed engineering enhancements (if any) required
- the effective sealing feature, attribute or mechanism of the storage formation that enables permanent storage.⁶

Applicants will be required to demonstrate that the formation meets the requirements of an 'eligible storage formation'. An application will therefore include the fundamental suitability determinants, such as the suitability of the formation for the permanent storage of at least 100,000 tonnes of CO₂ (greenhouse gas substance), with or without engineering enhancements, and its spatial extent. Details of the spatial extent of an eligible formation are to be determined; notably the expected migration pathway(s) from the starting date of injection, up to a notional site closure date.

Schedule 1 of the 2011 Regulations provides further detail as to the information to be submitted in support of an application, including; information on to the geological features and integrity of the storage formation, plume migration, any engineering enhancements and the estimated spatial extent of the storage formation.

Where satisfied that the requirements of the Act and Regulations have been met, the Minister must declare, in writing, that a site is an eligible storage formation and its spatial extent is in accordance with that estimated in the application. The Minister must also state that the fundamental suitability determinants specified in the application, are the fundamental suitability determinants of the identified greenhouse gas storage formation.

In instances where the Minister is not satisfied that the proposed part of the geological formation is suitable for the permanent storage of CO₂, they must inform the applicant and offer them the opportunity to amend and re-submit their application. The Act also includes provisions for varying or revoking a declaration,

The Minister is required to publish a copy of the declaration, as well as maintain a 'Register of Identified Greenhouse Gas Storage Formations'. The register is required to contain information of all declarations made under the Act, as well as details of any variations and revocations of declarations.

2.2.3 Regulation of injection and storage activities

The operational phase of a CCS project, notably the injection of GHG substances into an eligible storage formation, is managed through the GHG injection licence. The Commonwealth regime also includes provision for a further form of title, in instances where an operator may not be in a position to start injection at the site.

⁵ Chapter 3, Part 3.2, Offshore Petroleum and Greenhouse Gas Storage Act 2006; Part 2, Offshore Petroleum and Greenhouse Gas Storage (Greenhouse Gas Injection and Storage) Regulations 2011.

⁶ National Offshore Petroleum Titles Administrator, Offshore Greenhouse Gas Guideline, Declaration of Storage Formation, A Guideline in relation to the Offshore Petroleum and Greenhouse Gas Storage Act 2006, Prepared by the Australian Government Department of Industry, Science, Energy and Resources, November 2015.

GHG holding lease

The Commonwealth Act allows the holder of either a GHG assessment permit, a GHG injection licence, or a petroleum retention lessee, to apply for a GHG holding lease, where:

- there is an identified GHG storage formation wholly located within the proposed lease area
- the applicant is not currently in a position to inject and store a GHG substance
- the applicant is likely to be in such a position within 15 years.

The award of a holding lease provides the lessee with similar rights to those held under a GHG assessment permit. While the holding lease is in effect, a lessee is entitled to explore in the lease area for a potential GHG injection site and to inject and store on an appraisal basis. The lease holder is also entitled to recover petroleum in the lease area for appraising a discovery of petroleum, but only where its discovery was an incidental consequence of exploration or injection activities.

The application process for the lease varies, depending upon whether the applicant holds a GHG assessment permit, an injection licence (but has yet to carry out any injection activities), or a petroleum retention licence. A further process is applicable to those seeking a 'special greenhouse gas holding lease', in instances where an applicant has been unsuccessful in obtaining a greenhouse gas injection licence, because of the risks posed to petroleum interests and the relevant titleholder has refused consent to the grant of an injection licence. An applicant for this category of holding lease must already hold either a GHG assessment permit or a holding lease.

The Minister may grant a GHG holding lease, subject to any conditions the Minister deems appropriate. A condition of a GHG holding lease, however, is that separate approval be obtained for any 'key GHG operations' that the lessee intends to undertake. In a manner similar to the approach adopted in the case of an GHG assessment permit, the Minister must consider the impact of granting an approval where there is a 'significant risk of a significant adverse impact' posed, to either existing or future petroleum titles, and the petroleum titleholder does not consent to the operation.

A holding lease will remain in force for a period of 5 years, whereas a special greenhouse gas holding lease remains in force indefinitely. The lessee may apply to the Minister to renew a holding lease, providing the required information and within the timeframe specified within the Act. Where the Minister is satisfied that the applicant

is likely to be in a position to inject and store GHG substances within ten years, a renewal may be granted.

Injection licence

The award of an injection licence entitles the holder to inject a GHG substance into an identified GHG storage formation within the licence area, provided that the injection well is situated within the licence area. The licence authorises the permanent storage of the injected GHG, as well as the equivalent rights to exploration and appraisal activities, which are afforded under either an assessment permit or a holding lease. Similar to all other forms of title under the Act, it is an offence to undertake these activities without authorisation.

An application for an injection licence may be made by holders of a GHG assessment licence, holding lease or a petroleum production licence. The Act again includes detailed provisions regarding process and the considerations to be given to holders of various petroleum-related titles under the Act. In a similar manner to the approach adopted for the award of both the injection permit and the holding lease, the Minister is required under the Act to consider the significant risk of a significant adverse impact upon these titles. Under these provisions, for example, the Minister may in the case of existing or future post-commencement petroleum titles, grant an injection licence if satisfied that the award is in the public interest.

Where a licence is in effect, further protection is also offered to petroleum interests. The Minister may direct the holder of a licence to eliminate or manage the risks posed to petroleum interests, where an injection licence overlaps with a pre-commencement petroleum title and petroleum is discovered in the area of overlap. The Minister's powers to protect the petroleum apply where they are convinced that there is a significant adverse impact upon operations to recover the petroleum; or the commercial viability of the recovery of the petroleum. In these instances, the Minister may issue directions to the licence holder obliging them to eliminate the risks posed by their operations, or in some instances, suspend or cancel the injection licence.

The Act and accompanying regulations include further provisions regarding the application procedure to be followed by an applicant for a licence. Two specific pathways are proposed under the Act, the first is for those awarded an assessment permit or holding lease, while the second is for the holders of a petroleum production licence. In the case of the former, an application must set out, for each of the identified storage formations, details of the information to be specified in the licence, including:

- the GHG substance to be injected
- the origins of the GHG substance
- the proposed period of injection
- the total volume of GHG substance to be injected.

The application is to be accompanied by details of the applicant's proposals for work and expenditure, the technical and financial resources available to the applicant as well as a draft site plan.

The preparation and submissions of plans is a further aspect of the application procedure and the approval of their content an integral aspect of the approval process. Three plans are to be submitted and approved as part of the approvals process:

- Site plan
- Decommissioning plan
- Environmental plan

The 2011 Regulations provide further detail regarding the site and decommissioning plans. Under the Act, an injection licensee must not carry on any operations in relation to an identified greenhouse gas storage formation specified in the licence unless an approved site plan is in force in relation to the formation. Once the Minister approves a draft site plan, the approved site plan will come into force at the time of the injection licence approval. The Regulations set out the information to be provided in a site plan, which in turn, is divided into two parts. Part A sets out predictions for the behaviour of the stored CO₂ and Part B provides further detail regarding the project's management and the approach to be taken to technical issues such as risk assessment, monitoring and the operation of the site.

A provisional decommissioning plan is also to be submitted at the time of applying for an injection licence. The plan will set out the applicant's approach to the decommissioning of structures and equipment, and remediation of the site, following the cessation of injection activities. The Minister must approve the contents of the plan prior to the award of an injection licence. The decommissioning plan is to be reviewed throughout the lifetime of CCS operation, notably at least once in every 10 years during the injection phase of the project. A final version of the plan is to be submitted at least 12 months prior to the cessation of injection.

As a GHG activity, an environment plan is again required to be submitted by the applicant and approved by NOPSEMA prior to activities commencing under the injection licence.

The Minister may grant a licence subject to whatever conditions they determine are appropriate. An injection licence remains in force indefinitely; however, it may be terminated by the Minister where no injection activities have taken place during a continuous period of at least 5 years.

2.2.4 Cessation of injection activities and closure of a site

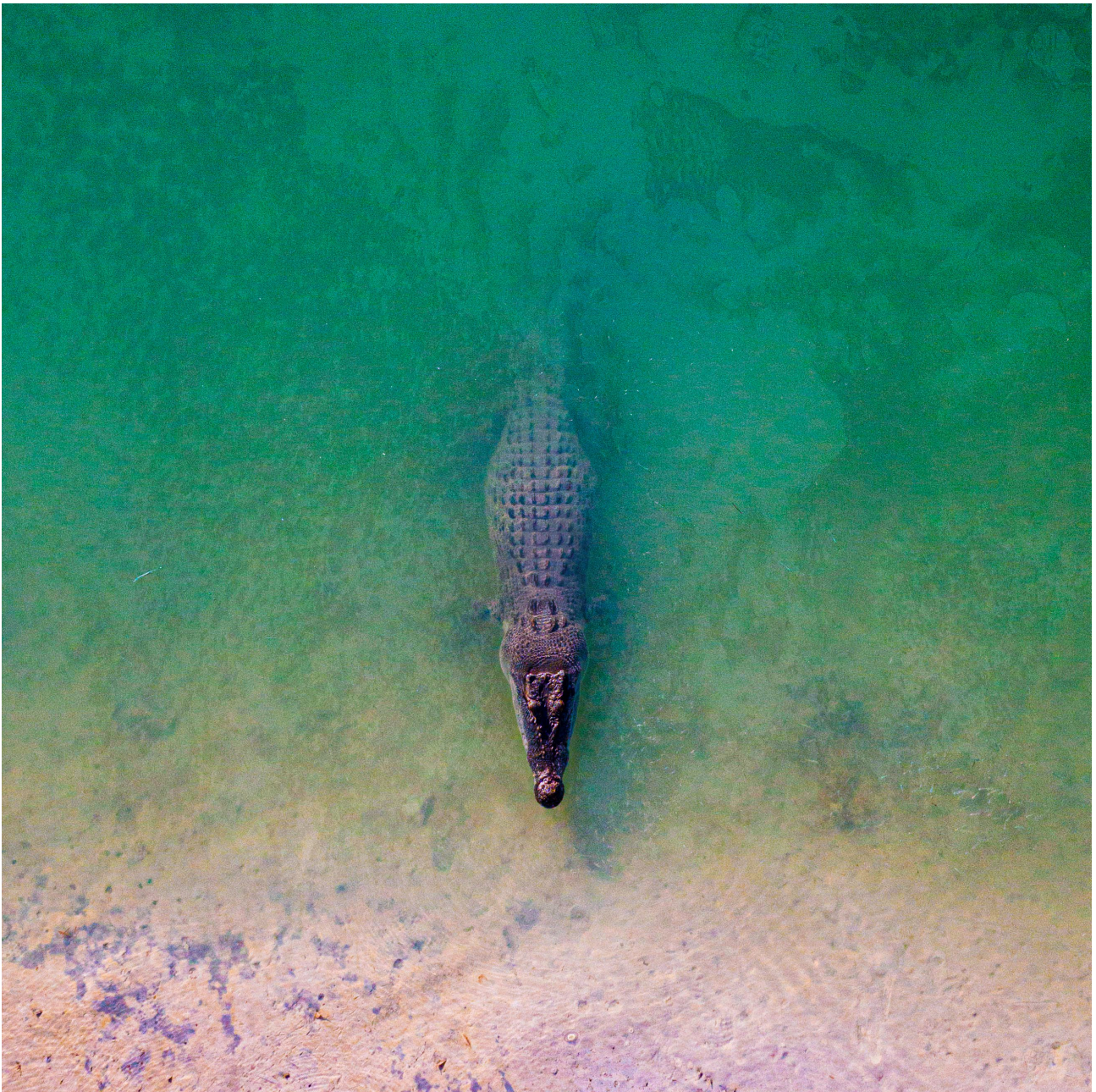
Under the Commonwealth Act a formal procedure is established for the closure of a storage site. While based upon the existing petroleum model, these provisions were introduced by the Commonwealth government to address some of the novel challenges of the CCS process.

Site closure certificate

Upon completion of injection activities, the holder of an injection licence must apply to the Minister for a site closure certificate, in relation to the storage formation specified in the licence. A site closure certificate must be sought where the injection licence is tied to a petroleum retention lease or production licence that has ceased to be in force; or where there are grounds for cancellation of the licence.

The application must set out details of the following:

- a written report on modelling of the behaviour of the injected GHG substance, including the applicant's analysis of information relevant to this modelling, and;
- a written report detailing the applicant's assessment of the behaviour of the injected GHG substance, including, expected migration pathways, and the short and long-term consequences of migration of the substance(s); and
- the applicant's suggestions to the Commonwealth on the approach that should be taken towards monitoring after the issue of a site closure certificate.



In accordance with the provisions of the Act governing the surrender of authorities, once an application is made to the Minister, they may also direct the holder of the injection licence to:

- remove all property from the relevant area
- plug or close off all wells made in the surrender area
- make provision for the conservation and protection of the natural resources in the surrender area
- make good any damage to the seabed or subsoil in the surrender area, which were caused by the operations permitted under the licence

Where the Minister is satisfied that injection operations have ceased in accordance with the requirements of the Act, they may issue a pre-certificate notice, which confirms that the Minister is prepared to issue to the applicant a site closing certificate in relation to the storage site. The notice includes detail of the monitoring role to be assumed by the Commonwealth upon surrender and the security to be paid by the applicant to cover the costs of this role.

Once a notice has been issued and the applicant has paid the required security, then a site closure certificate must be issued. Within five years of an operator's application, a Minister must make an assessment of whether or not to grant a certificate.

2.2.5 Post-closure period

The Act includes provision for the management of the post-closure phase of a CCS project and includes comprehensive provisions regarding the management of long-term liabilities.

Under the Act, an operator will bear statutory and common law liabilities throughout the lifetime of a CCS project, but will be afforded the opportunity to transfer these liabilities to the Commonwealth government following a successful closure operation and the formal declaration of the completion of a 'closure assurance period'.

Closure assurance period and the transfer of liability

As described in section 2.2.4 above, the process for obtaining a declaration, begins with the completion of injection and storage activities and the operator formally applying for a 'site closure certificate'. Where a certificate is issued and a further period of at least 15 years has elapsed, an operator may then request that the Minister declare the end of the closure assurance period. Taken together with the five-year period, commencing with the cessation of injection and concluding with the issue of a site closure certificate, the entire process will see a licensee retain liability for the site for at least 15 to 20 years following the end of operations.

The Minister's declaration of the closure assurance period will effectively conclude the operator's liability for the site, with the Commonwealth government also indemnifying the former operator against a number of specific liabilities, including under the common law. The Commonwealth's liability is however, limited by the following conditions:

- the liability is a liability for damages;
- the liability is attributable to an act done or omitted to be done in the carrying out of operations authorised by the licence in relation to the formation;
- the liability is incurred or accrued after the end of the closure assurance period in relation to the formation;
- such other conditions (if any) as are specified in the regulations.

A former operator will, therefore, retain some liabilities, in circumstances not addressed by the Commonwealth's indemnification.

2.2.6 Responsible authorities

The chart below, provides an overview of the approval and administration of GHG storage titles and activities throughout the CCS project lifecycle.

Table 5. Responsible authorities for approval and administration of GHG titles.

	ACREAGE RELEASE	GHG ASSESSMENT PERMIT	DECLARATION OF AN IDENTIFIED GHG STORAGE FORMATION	GHG HOLDING LEASE	GHG INJECTION LICENSE	SITE CLOSURE CERTIFICATE	DECLARATION OF CLOSURE ASSURANCE PERIOD
DISER*	✓						
RCM**		✓	✓	✓	✓	✓	✓
NOPTA***		✓	✓	✓	✓	✓	✓
GEO SCIENCE AUSTRALIA	✓						
NOPSEMA****		✓ ✓		✓ ✓	✓ ✓		



Responsible for Approval



Administering Authority



Advisory Role



Approvals for requirements such as environment health and safety plans

* Department of Industry, Science, Energy and Resources

** Responsible Commonwealth Minister (currently the Minister for Resources and Northern Australia)

*** National Offshore Petroleum Titles Administrator

**** National Offshore Petroleum Safety and Environmental Management Authority

2.3 Overarching legal and regulatory context

The exclusive focus of this overview, has been the regulation of a storage project, operating entirely within the Commonwealth's offshore waters. A CCS project will also, however, be subject to a wider body of national and territory legislation throughout the entirety of its lifecycle. The diagram below is indicative of the variety of legal and regulatory regimes and provisions that are likely to be applicable to a CCS project, from the planning phase, through to its eventual closure and decommissioning.

Table 6. Summary of applicable legislation.

CAPTURE	TRANSPORT	STORAGE
TERRITORY SELECTION • Environmental protection legislation (floral and fauna) • Environmental water or waste legislation • Planning legislation • Construction legislation • Native title or heritage considerations • Health and safety legislation • Operational requirements	TERRITORY LEGISLATION (ONSHORE AND OFFSHORE - 3 MILE LIMIT) • Legislation governing permitting and construction of pipeline or any proposed hub • Legislation covering licensing of pipeline operations • Health and Safety legislation • Native title or heritage considerations • Wider environmental licensing or environmental protection legislation • Fisheries legislation • Maritime legislation covering vessels, navigational right or obligations COMMONWEALTH LEGISLATION (OFFSHORE + MILE LIMIT) • Pipeline requirements within Commonwealth offshore legislation (OPGGSA) • Maritime legislation covering vessels navigational rights or obligations	COMMONWEALTH LEGISLATION • Offshore Petroleum and Greenhouse Gas Storage Act (OPGGSA) • Environmental Protection (Sea Dumping) Act 1981

2.3.1 Legislation applicable to the entirety of a CCS project

In addition to legislation governing the capture, transport and storage aspects of a project, further Commonwealth acts are likely to be applicable to the entirety of a CCS operation. Two acts, governing environmental protection and the reporting of information concerning greenhouse gas emissions, are potentially relevant to those seeking to undertake CCS operations in Australia.

The Environmental Protection and Biodiversity Conservation Act 1999 ("The EPBC Act")

The EPBC Act constitutes the primary legal framework for the protection of the environment in Australia. The Act prohibits projects and activities that could potentially impact heritage sites, wetlands, flora and fauna and other communities within the ecosystem, which have been identified as matters of national environmental significance, from proceeding without the approval of the responsible Commonwealth Minister.

The Act provides for the referral of a project to the responsible Minister to assess the likelihood of negative impacts on any matter of environmental significance under the EPBC Act. The Minister is empowered to utilise a variety of approaches to conduct the assessment, such as an accredited assessment process, a public environmental report, or an environmental impact statement.

Once the report of the assessment is submitted to the Minister, the Minister will decide whether to approve the project or activity and what conditions are to be attached to the approval.

The Department of Agriculture, Water and the Environment is charged with the administration of the environmental assessment and approval process under the EPBC Act. The Minister for Environment is the responsible Commonwealth Minister under the EPBC Act, who is assisted by the Department to provide the necessary approvals as required by the Act.

National Greenhouse and Energy Reporting Scheme legislation

The National Greenhouse and Energy Reporting (NGER) Scheme is Australia's national GHG accounting model and is an important element of the national framework which supports international and domestic reporting commitments. The National Greenhouse and Energy Reporting Act 2007 established the Scheme and together with the accompanying regulatory instruments, sets out a framework for company-level GHG emissions accounting.

The scheme sets out the rules as to which organisations are required to register and report their greenhouse gas emissions, the type of emissions to be reported and where this data is to be published and used.

The NGER scheme was amended to explicitly recognise the role of CCS and the 2008 NGER Regulations include specific provisions regarding the treatment of emissions and CCS operations. Further guidance is also set out in the 2008 Measurement Determination and the accompanying Technical Guidelines, which offer further detailed methodological and measurement provisions to enable reporters to appropriately report emissions from those facilities employing CCS during a reporting year. Crucially, the Regulations allow for the deduction from the emissions estimates, of a relevant source of CO₂ which has been captured and permanently stored.

The Regulations require facilities engaged in CCS activities to report the opening and closing stocks of

stored CO₂, the amount of CO₂ that has been captured, imported and stored, as well as the amount of any fugitive emissions from transport and injection operations and the storage site.

Parts 1.2 and 3.4 of the Measurement Determination expand further on these obligations, with provisions to address the CCS-specific requirements and fugitive emissions from CCS operations respectively.

2.3.2 Commonwealth legislation

In addition to the storage-specific provisions of the OPGGS Act, there are other provisions within both the offshore Act and wider Commonwealth legislation that will be applicable to a CCS project operating in Commonwealth waters.

Chapter 2 of the OPGGS Act, as well as the accompanying regulations, include detailed provisions applicable to infrastructure development and pipeline construction and operation in Commonwealth waters. The Act establishes an offence for conducting activities without the correct authorisation(s) and sets out procedures for obtaining infrastructure and pipeline licences. In both instances, the relevant Joint Authority will be responsible for granting authorisations. In the Northern Territory, the Joint Authority for the Principal Northern Territory offshore area is constituted by the responsible Northern Territory Minister; and the responsible Commonwealth Minister⁸.

The Commonwealth's Environment Protection (Sea Dumping) Act 1981 implements the requirements of the London Protocol within Australian law. In accordance with the dumping provisions of the London Protocol, the injection of CO₂ streams in a sub-seabed geological formation will require a permit under the Act. The Department of Agriculture, Water and Environment are responsible for the administration of the Act.

The London Protocol will also be relevant in instances where CO₂ is proposed to be transported from another nation into Australian territorial waters for the purpose of geological storage. In October 2009, an amendment to the Protocol was adopted by the Parties (including Australia) to enable the transboundary movement of CO₂ for storage, however, an insufficient number of Parties have ratified this amendment.

At the recent meeting of the Contracting Parties to the Protocol, in October 2019, a proposed resolution to address this situation was jointly submitted by the governments of the Netherlands and Norway. Under the proposal, the Parties would allow the 'provisional

⁸ The Principal Northern Territory area is defined by the Act to mean "so much of the offshore area of the Northern Territory as does not consist of the Eastern Greater Sunrise offshore area".

application' of the 2009 amendment, which in turn would enable them to "consent to cross-border transport of carbon dioxide for the purpose of geological storage without entering into non-compliance with international commitments". Formal agreement to allow the provisional application of the 2009 amendment, as an interim solution, was reached at the October 2019 meeting. Provisional application will now allow those Contracting Parties, who wish to export or to receive CO₂ for storage to do so, subject to their depositing of a declaration of provisional application and notification of any agreements or arrangements with the International Maritime Organization (IMO).

Effectively, this means that Contracting Parties will implement the provisions of the 2009 amendment in advance of it entering into force. Noting that Australia is a Contracting Party to the Protocol, there would need to be consideration of the status of the exporting country.

2.3.3 Territory legislation

A substantial and diverse body of legislation will be applicable to the development and operation of capture and transport infrastructure, both onshore and within the Territory's territorial waters. While it is not possible within this review to offer a detailed description of this legislation, Table 6 provides examples of the categories of legislation that regulators will have to consider when regulating the entirety of a CCS operation.

Policymakers, regulators and project proponents will likely be familiar with the application of these regimes to other major industrial and infrastructure activities. In the case of both capture and pipeline operations, there are likely to be many aspects of these processes which will prove familiar to regulators and existing legislation will therefore require little amendment.

2.4 Conclusions and recommendations

The Commonwealth offshore legislation offers a well-characterised and detailed framework for regulating CO₂ storage activities within Commonwealth waters. Similarly, it is likely that many aspects of the capture and transport elements of the CCS process may be adequately addressed by existing Commonwealth and Territory legislation.

Absent a CCS-specific regulatory framework in the Territory, however, it is recommended that the Northern Territory government undertake a comprehensive review of the scope and adequacy of their existing regulatory models. A review of this nature would consider not only the ability of existing models to address all relevant aspects of the capture and transport processes, but also the current administrative processes which support these legal and regulatory frameworks. The ultimate aim of the exercise would be to identify any remaining obstacles within the Territory's existing framework, as well as opportunities for improving or 'streamlining' the regulatory process. It is suggested that a version of the Institute's 'Regulatory Test Toolkit' be deployed in the near term.

The location of a potential storage site will determine the next step in the process for obtaining an injection licence. Where a proposed site does not currently sit within an existing licence area, the Territory government or project proponent should engage in the acreage release nomination process.

A further option is for existing petroleum title holders to apply for the relevant declaration or authority, where a proposed greenhouse gas acreage release overlaps their licence area or lease, or they believe their petroleum title contains a potential storage formation.

3.0 PIPELINE, INJECTION AND MONITORING INFRASTRUCTURE

The Middle Arm hub is based on a hub model of CO₂ transport infrastructure. This means it brings together multiple sources of CO₂ to a single location (the hub) for compression before flowing to a shared transmission pipeline to the storage site.

Key advantages of a hub model include:

- Reduced per-tonne compression costs through economies of scale at the compression hub
- Flexibility in compression train operation across multiple sites, including better turndown to enable lower CO₂ flows when necessary – for example, when one or more upstream facilities are offline.
- Using cheaper low-pressure gas-phase lines to transport CO₂ from each source facility to the hub results in lower cost piping overall.

The design of piping and compression will be set to match this base case with no pumping between the compression hub and the storage site.

2. A “boosted” case will identify the maximum throughput available through the system designed for the base case. This will be done by maximising pump discharge pressure at the hub and incorporating an additional booster pump at the coast.
3. A third case would add one additional 4.5 Mtpa LNG train at each of the Inpex and DLNG facilities, exploiting the same reservoirs as in the base case. Therefore, the CO₂ captured from these plants would be identical to the quantities captured in the base case.

3.1 Basis of design

On discussion with NT government representatives, the following bases for the proposed designs was agreed:

1. The base case involves capture of reservoir CO₂, gas turbine CO₂ and industrial CO₂ from the following sources:
 - a. One (1) new 4.5 Mtpa LNG facility at Inpex, operating on Browse gas
 - b. One (1) new 4.5 Mtpa LNG facility at Darwin LNG, operating on Evans Shoal gas.
 - c. 1.1 Million tonnes per year of CO₂ representing emissions from one or more gas manufacturing plants. This will represent the possible range of future industrial CO₂ captured from various gas industries (as outlined in Sections 6 and 7).

Base case CO₂ flow

This report is based on assumed newly developed LNG trains at DLNG and Inpex. As such it is assumed they will be forward looking with an eye for best practice LNG design.

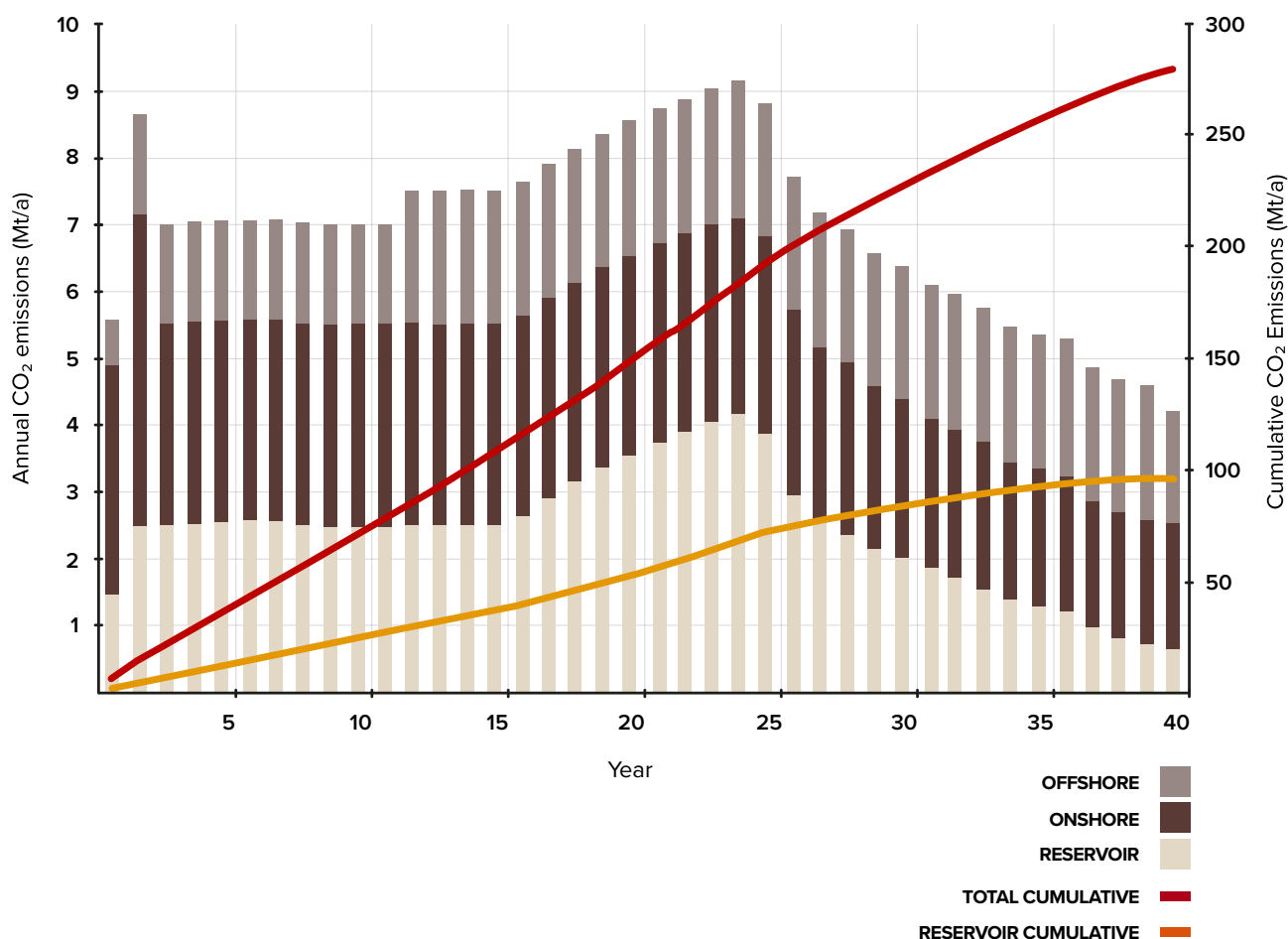
DLNG’s existing plant uses open-cycle gas turbines for on-site power generation and to drive refrigeration compressors. While lower cost, these are much less efficient than combined-cycle gas turbines (as were installed at the newer existing Inpex facility).

The choice of turbine types (open cycle or combined cycle) has a direct influence on CO₂ production from the gas turbines. Given the cost associated with CO₂ capture from gas turbines (outlined in Section 5), good engineering practice would first optimise (minimise) CO₂ production from the source before sizing the capture plant. As such it is assumed that best-practice combined-cycle gas turbines are used, as these minimise CO₂ production per MWh of power produced.

As Inpex uses combined cycle gas turbines and is a newer plant, its emissions profile was used as a basis to project emissions from future LNG trains – both at DLNG and at Inpex.

Inpex has supplied the Institute with information on anticipated CO₂ production from its existing LNG facility. This was summarised in their draft EIS (INPEX 2009) and was confirmed by Inpex to be a reasonable approximation of CO₂ emissions by Inpex over the existing trains' operating lives. The key chart is shown in Figure 9 below.

Figure 9. Inpex existing LNG plant CO₂ emissions profile (INPEX 2009, fig 9–3)



Inpex is moving over time to a higher CO₂ field (Plover) from a lower CO₂ field (Brewster). This explains the steady increase over time in the reservoir gas emissions numbers. At its peak in year 23, the reservoir gas will be 4.1 Mtpa of CO₂ from the existing trains, and onshore emissions will be 3 Mtpa of CO₂. As Plover is reasonably close to the CO₂ content of the proposed LNG operations, it is assumed that the onsite emissions are

a reasonable basis for estimating emissions from a new trains. Reservoir emissions will be estimated separately (see below).

Base case LNG plants (as provided by NT Government): 2 x new LNG trains of 4.5 Mtpa of LNG. One at Inpex running on Plover gas, the other at DLNG running on average Evans Shoal Gas.

Power generation emissions basis – per LNG train

Not all onshore combustion emissions from LNG are from power generation or refrigeration compressors (the source of CO₂ for capture). A portion of these onshore emissions are from other sources, such as flaring.

Inpex (2009, p.421) in their draft EIS provide the following split of onshore emissions:

Refrigeration compressor gas turbines: 1.4 Mtpa CO₂

Power generation gas turbines: 0.9 Mtpa CO₂

Total onshore emissions: 2.8 Mtpa CO₂

From this we estimated that $(1.4 + 0.9) / 2.8 = 82\%$ of onshore emissions are from gas turbines for capture.

The Inpex emissions estimates are based on 8.9 Mtpa of LNG capacity.

Each LNG train in this study has a capacity of 4.5 Mtpa of LNG, or 50.6% of the Inpex reported figures.

It is assumed that the power generation and refrigeration energy required by each LNG train is in proportion to its capacity (i.e. combustion emissions per tonne of LNG are the same).

This means power plus refrigeration CO₂ for each LNG train is:

3.0 (total onshore emissions from Inpex) x

82% (proportion of onshore that are from gas turbines) x

50.6% (scaling down from 8.9 to 4.5 Mtpa)

= 1.25 Mtpa CO₂.

So 1.25 Mtpa of CO₂ is the basis of CO₂ produced from gas turbines at each LNG train.

Reservoir gas CO₂ emissions basis – per LNG train

Raw gas from offshore contains CO₂ that must be removed in each LNG train's AGRU (acid gas removal unit).

The analysis of raw gas for each of DLNG and Inpex trains are different. They are summarised in Table 7. The C number refers to the number of carbon atoms in each species, so C1 is methane (CH₄), C2 is ethane (C₂H₆) and so on:

Table 7. Raw gas analysis (averages) for new Inpex and DLNG LNG trains (NT government supplied)

INPEX (PLOVER)	MOL %	MW	DLNG (EVANS SHOAL AVERAGE)	MOL%
C1	75.00	16	C1	78.14
C2	4.00	30	C2	2.20
CO ₂	17.0	44	CO ₂	17.6

Heavier fractions (propane, butane and heavier) are assumed to be recovered in condensate and not take part in gas combustion.

Inpex indicated that raw gas after CO₂ removal (i.e. C1 and C2) is the fuel used on-site for all gas combustion. Hence the plants are combusting a mixture of methane and ethane.

These compositions were used to estimate how much raw gas was required to not only produce the LNG plant's 4.5 Mtpa of LNG production, but also how much additional raw gas is required to supply the gas turbines with fuel. This additional gas also means that more CO₂ is carried to the plant as reservoir gas.

The resulting raw gas flows and quantities of CO₂ in reservoir gas were estimated as shown in Table 8.

Table 8. CO₂ in raw gas to each LNG plant. The final line represents estimate of reservoir CO₂ captured in the each train's AGRU.

	INPEX LNG TRAIN		DLNG LNG TRAIN	
CO ₂ mass from combustion (including flaring and miscellaneous sources)	1.50	Mtpa CO ₂	1.50	Mtpa CO ₂
C1 from raw gas used as fuel	0.500	Mtpa C1	0.524	Mtpa C1
C2 from raw gas used as fuel	0.0500	Mtpa C2	0.0276	Mtpa C2
LNG product mass (LNG plant capacity)	4.5	Mtpa (C1 + C2)	4.5	Mtpa (C1 + C2)
C1 in product gas	4.09	Mtpa (C1)	4.27	Mtpa (C1)
C2 in product gas	0.409	Mtpa (C2)	0.225	Mtpa (C2)
C1 total in raw gas	4.59	Mtpa	4.80	Mtpa
C2 total in raw gas	0.459	Mtpa	0.253	Mtpa
Total raw gas C1 and C2	5.05	Mtpa	5.05	Mtpa
CO ₂ to C1+c2 ratio (mass)	0.567		0.588	
CO ₂ in raw gas	2.84	Mtpa	2.95	Mtpa

CO₂ from industrial sources

There are many possible combinations of downstream gas industries that could contribute to a future Darwin CCS hub. For the purposes of this study, a single hydrogen plant, capturing 1.1 Mtpa of CO₂ was selected.

Summary of CO₂ flows to the hub

In summary, CO₂ flows have been estimated from each source/plant (Table 9).

It is assumed that the capture plants on the gas turbines are able to capture 90% of the CO₂ produced by gas combustion.

Table 9. CO₂ flows under the base case

SOURCE	CO ₂ FLOW (Mtpa)
Hydrogen plant capture facility	1.10
Inpex reservoir gas (100% captured)	2.84
Inpex captured gas from gas turbines (90% captured)	1.13
DLNG reservoir gas (100% captured)	2.95
DLNG captured gas from gas turbines (90% captured)	1.13
TOTAL CO ₂ to hub (slight difference due to rounding)	9.14

So base case CO₂ flows in the CCS hub system are:

Total from DLNG	4.08 Mtpa
Total from INPEX	3.96 Mtpa
Total from Hydrogen plant	1.10 Mtpa

Total to compression hub and storage 9.14 Mtpa

These flows were selected as the basis for sizing pipelines, modelling pressure drops and estimating the duty and cost of compression systems in the base case.

Boosted flow and 2nd pipeline cases

The NT Government requested an assessment of the capacity of pipelines, sized for the base case, if additional pressure was used to boost flow through the system. This is the “boosted” case.

This pressure can come from two sources:

1. Increase pressure at the Compression hub, up to a maximum of 227.7 bar (pipeline pressure limit)
2. Including a booster pump part-way along the pipeline, providing an additional boost for pressure. This is not reasonable for route 1 (all offshore) as

the costs of a platform and power supply in an offshore location are prohibitive. So this option is only assessed for Route 2 and 3.

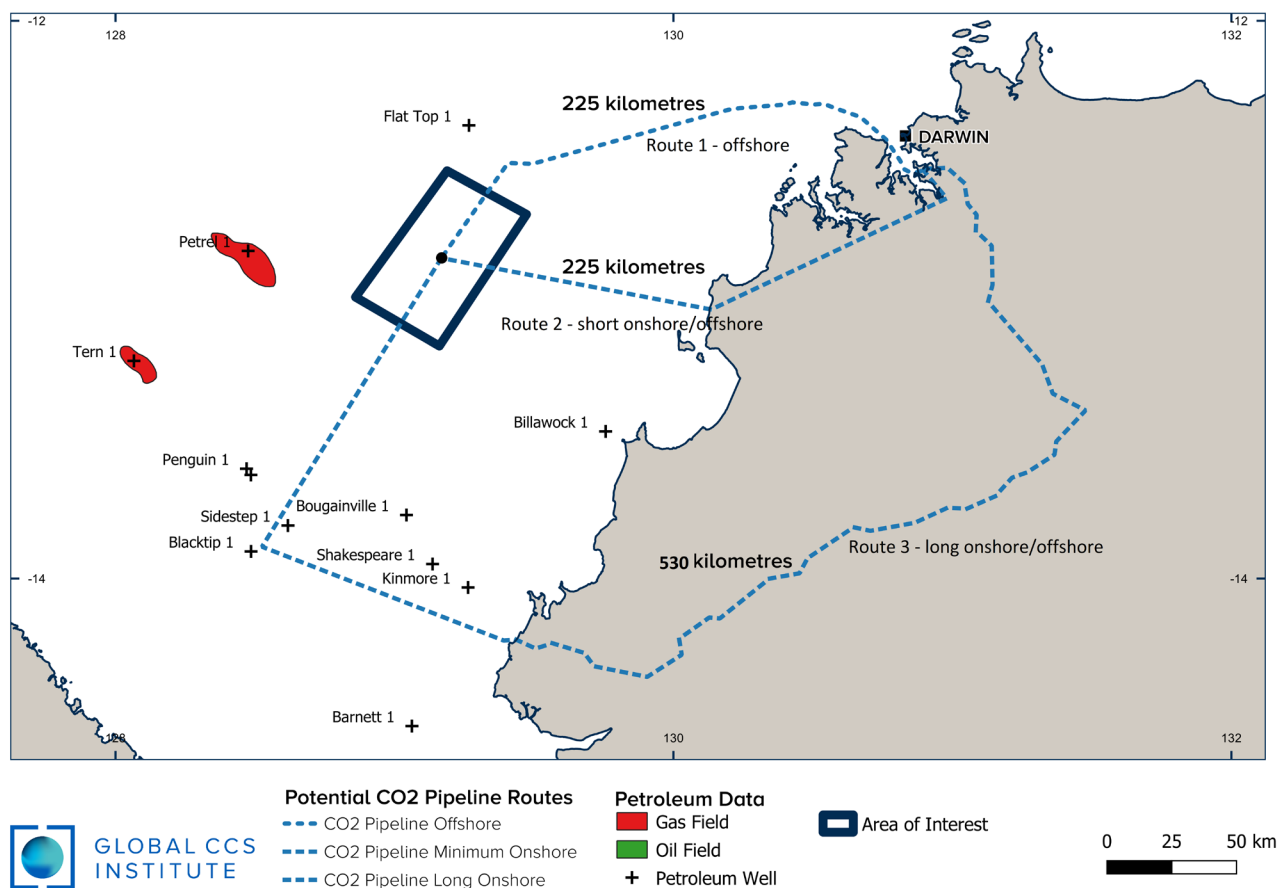
For the 2nd pipeline case, identical amounts of CO₂ flow from the second LNG trains at DLNG and Inpex (4.08 Mtpa from DLNG, 3.96 Mtpa from Inpex). This adds an additional 8.1 Mtpa over the base case, or 17.3 Mtpa total.

The distribution of this 17.3 Mtpa of CO₂ across both pipelines has several options. The first pipeline can operate in a boosted configuration, meaning a smaller flow is required for the 2nd pipeline. Or the first pipeline can drop back to an unboosted condition (base case) with all CO₂ from the 2nd set of LNG plants flowing in the second pipeline.

Main trunk line – alternative routes, sizes and parameters for design

The main capital cost item for the project will be the main trunk line carrying high flows of CO₂ at supercritical (or dense phase) conditions from the Middle Arm hub to the offshore storage site.

Figure 10. Shows approximate pipeline routes for the offshore and both onshore/offshore options.



Three key routes were identified:

Route 1: Offshore route – avoids issues with land access, but requires a significant investment in offshore piping which is more expensive per inch-km than onshore piping

Route 2: Short Onshore/offshore route – same distance as offshore route. Has advantages of a shorter offshore pipeline length and also provides the option of a pumping/boosting station at the coast. However the feasibility of this pipeline corridor will need to be investigated and confirmed in a future study.

Route 3: Long onshore/offshore route – longer distance. Pipeline follows existing piping routes (known to have pipeline easements) and existing roads, which may make for fewer risks around land and construction. Distance is much longer than first two options, adding to pressure drop and energy costs.

Routes 1 and 2 are very close in length. The offshore route is assumed to be all offshore. The onshore route runs for 117km onshore and 106km offshore. Both routes have been selected to minimise overall pipe length.

Route 3 is much longer – 530 kilometres; 375km of it is onshore, 155 km offshore. This option is not preferred

due to the much longer pipeline and associated capital cost, as well as the increased pressure drop and associated compression/pumping energy losses. However, it was considered as it follows existing piping routes and roads for most of its onshore length, and thus has the potential to be built more easily. It will be shown that the high costs for this route preclude it from serious consideration.

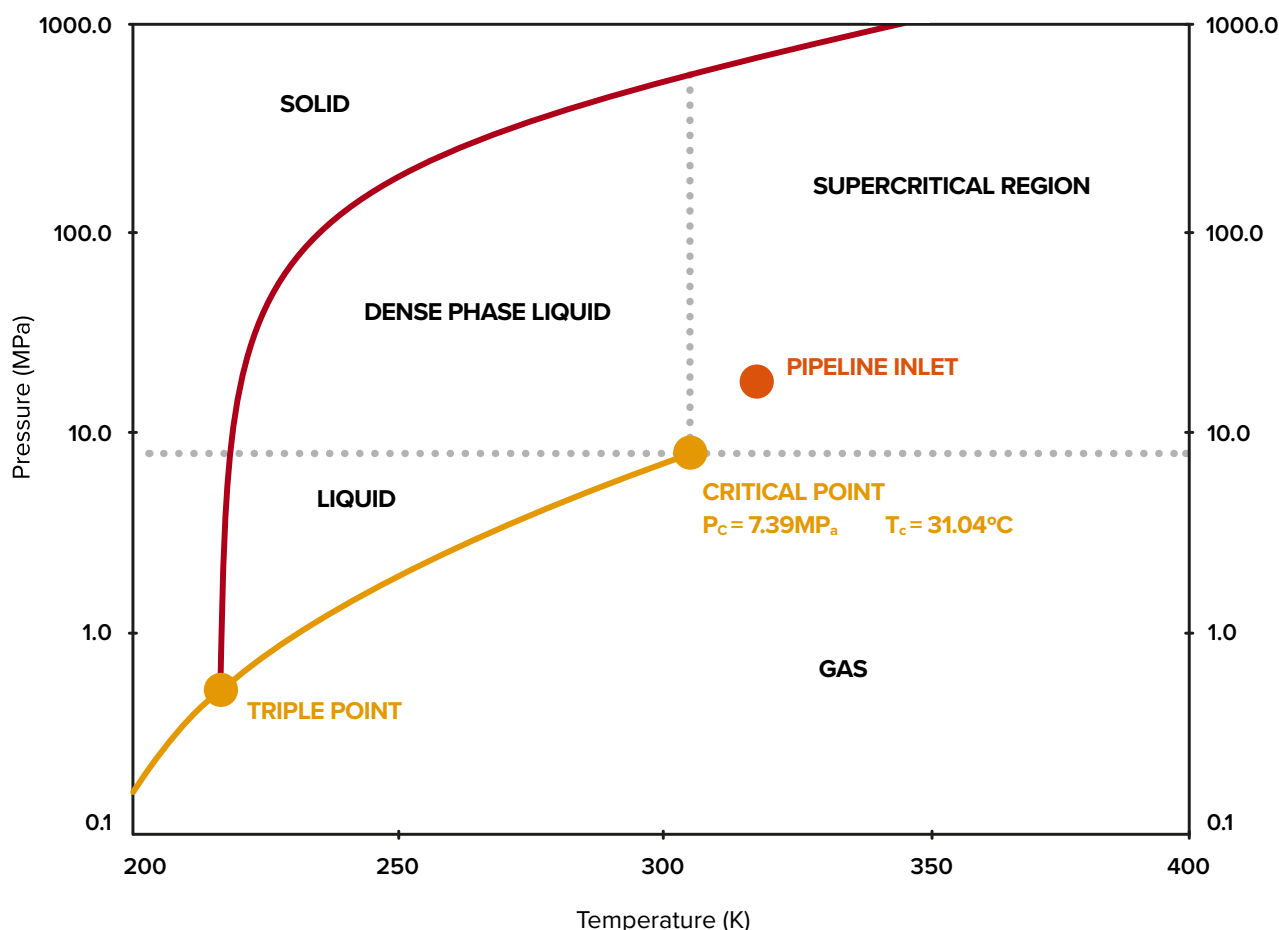
CO₂ transport properties and design philosophy:

CO₂ hub design is an emerging area of engineering. Though the general intent is clear – to provide high rates of CO₂ flow for compression for economies of scale – the precise design of how CO₂ is transported from each source plant to the hub and onwards to storage is flexible.

Phase and properties of CO₂:

CO₂ is an unusual substance in that it exhibits quite different phases and physical properties under varying temperature and pressure conditions. Figure 11 shows a phase diagram of pure CO₂.

Figure 11. Phase diagram of CO₂ (Witkowski, Majkut & Rulik 2014, p.119)



Under low pressure and moderate to high temperatures, CO₂ is a gas. Gas-phase pipeline transport has the advantage that relatively thin-walled pipelines can be used to handle low-pressure gas (say under 1-5 MPa). Consideration in subsequent phases of work could be given to constructing gas phase lines from plastic, which could further reduce pipeline costs compared to steel.

Gas-phase transport's main disadvantage is CO₂'s very low density, which means it physically occupies a large volume per tonne. This causes high pressure drop in pipelines, which really makes gas-phase transport suitable only for shorter distances (Zero Emissions Platform 2011, p.12). It also requires large pipe diameters. This is an acceptable and lowest-cost option for feeder pipelines from each CO₂ source to the compression hub, where distances from the source plant to the hub are modest.

Gas-phase transport of CO₂ is a lower-cost option for shorter piping runs of less than 50km. It is assumed all sources of CO₂ for this project will be much less than 50km from the compression hub.

A key risk in any CO₂ transport system is water. Most CO₂ capture plants employ water-based solvents, meaning that CO₂ from capture plants are typically saturated with water vapour and may contain entrained liquid water. CO₂ forms highly acidic solutions with liquid water

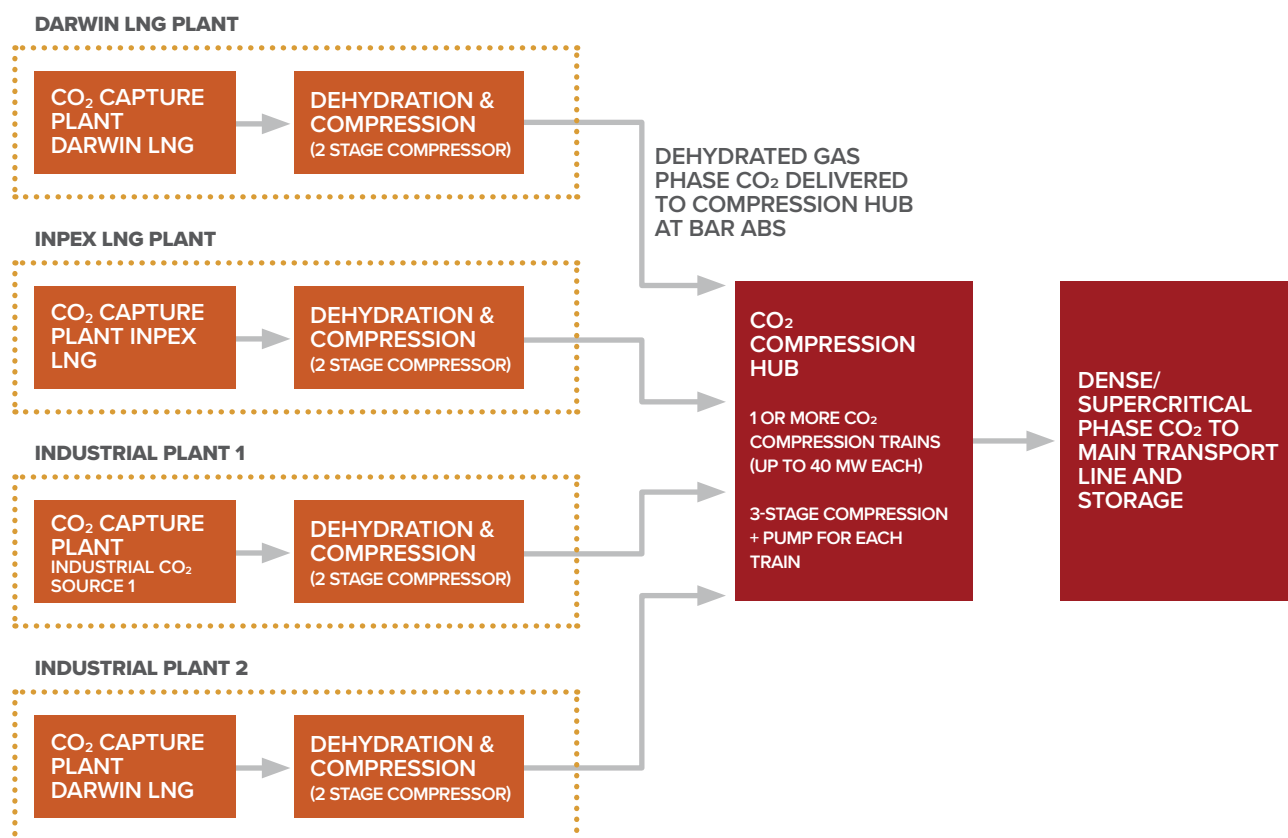
which can attack and damage piping and compression systems and cause integrity risks. To minimise this risk, water must be removed to very low levels; less than 200 ppm water in line with the ISO standard for CO₂ transport (International Standards Organisation 2016a, p.22). This will ensure that any residual water remains in the vapour phase and cannot condense to form low pH liquids.

Although this project did not delve deeply into dehydration system design, it typically involves a combination of compressed CO₂ cooling (which causes some water to condense) followed by either a glycol-based solvent drying unit or an adsorption dryer. Dehydration is included implicitly in the costs of the compression systems estimated in this work. It is typically a very small part of capital and operating costs for a compression and transport system.

3.2 Proposed design:

Figure 12 shows the proposed design of the CO₂ transport system. As an example, two generic industrial CO₂ sources are included. More could be added as additional gas industry capture plants are added to the Middle Arm complex.

Figure 12. Block diagram of CO₂ compression and transport



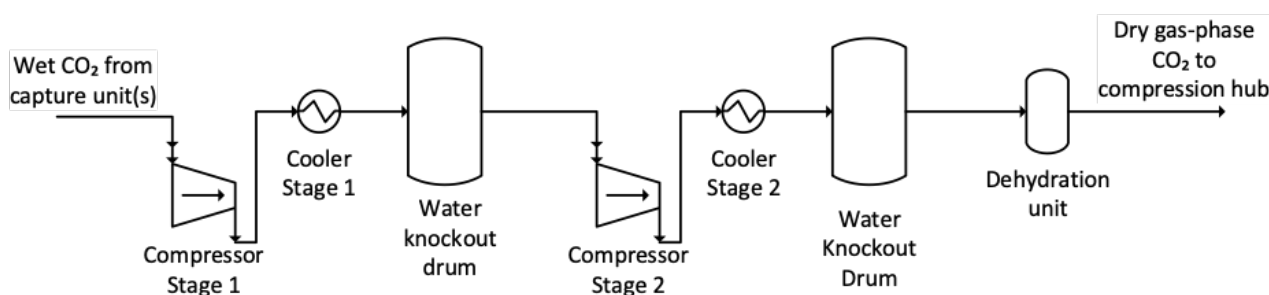
CO₂ transport by pipeline has been selected to be done in two main steps:

1. Piping from each source plant (LNG facility, industrial plant etc) is compressed modestly on-site at each capture facility and remains as a gas. Two-stage compression is employed, sufficient to deliver CO₂ to the main compression hub at 5 bar abs (4 bar gauge). This typically requires 8-9 bar of pressure at the compressor discharge, to allow for pressure drops in the gas-phase lines (over ~ 10km) in the range of 4-5 bar (calculated). CO₂ is dehydrated at each of these smaller source CO₂ compression

stations to ensure no liquid water forms in any downstream CO₂ pipelines (gas or dense phase). Target water levels are below 200ppm, consistent with ISO standards (International Standards Organisation 2016b, sec. Annex A). This prevents liquid water condensation (preventing corrosion) and avoids the risk of hydrate formation.

Figure 13 shows the typical configuration of gas-phase CO₂ compression and dehydration at each upstream CO₂ plant.

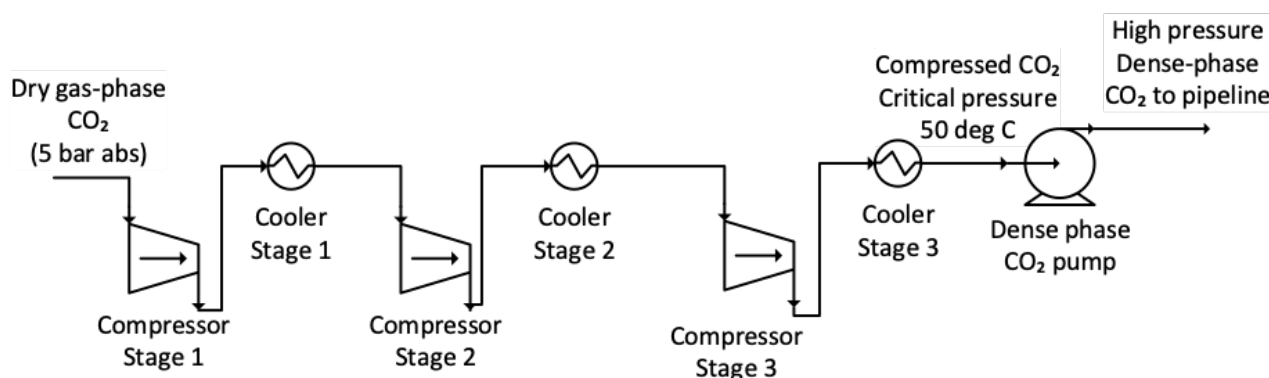
Figure 13. Gas-phase two-stage compression and dehydration located at each upstream CO₂ source plant



2. The CO₂ compression hub aggregates CO₂ from all source plants. Using one or more CO₂ compression trains, CO₂ is compressed in a 3-stage compression system to the critical pressure (73.8 bar). Above P_{crit} it is dense-phase (similar to a liquid) and can

be pumped to the required final pressure (180 bar or higher depending on the case). Pumping is much less energy intensive than compression for the same change of pressure.

Figure 14. Three-stage compression and pumping arrangement at main compression hub.



Pipeline selection and conditions:

- The main transport pipeline must maintain CO₂ well above the critical pressure at all points along the line.
- Gas-phase CO₂ lines sized for 30 m/s CO₂ velocity at an assumed pipe end pressure of 5 bara (Sinnott & Towler 2009, p.259)
- Dense-phase CO₂ lines sized for 2 m/s CO₂ velocity

at an assumed pipe end pressure of 10 MPa (Peletiri, Rahmanian & Mujtaba 2018, p.6)

- Steel schedule 160 piping was selected for dense/supercritical phase CO₂. With a maximum allowable working pressure of 253 bar (Atlas Steels 2010), this pipe has thicker walls than conventional schedule 40 piping and is suitable for the pressures seen in CO₂ transport.

- Dense/supercritical phase operations must stay between two limits:
 - Pressure must be well above the critical pressure to avoid two-phase behaviour which can introduce mechanical stress and risk to piping integrity. In this work that minimum pressure has been selected as 100 bar.
 - Pressure must remain below the safe operating pressure for the pipeline. This has been taken as 10% below the 253 bar maximum allowable working pressure, or 227.7 bar.
 - Hence the pressure must be within the range 100-227.7 bar at all points along the line.

Key assumptions and data

1. Compression station elevation is 10m above sea level.
2. End-point of trunk line is 80m below sea level (sea floor)
3. Destination pressure target is 100 bar abs (ENI S.p.A 2018b, p.10)
4. Discharge temperature of CO₂ at the compression hub is 50 degrees C.
5. Seawater temperature is 25 degrees C (affects CO₂ cooling in offshore line)
6. Overall heat transfer coefficient for the pipeline in seawater is 44.7 W/m²/K (Drescher et al. 2013, p.3055). This is used to model cooling in offshore pipelines.
7. Soil temperature is 25 degrees C (for CO₂ cooling in buried onshore line)
8. 20% was added to route length to account for fittings losses when calculating pressure drop
9. Pressure ratio of each stage of compression is assumed to be the same.
10. CO₂ is cooled to 50 degrees C after each stage of compression. This is a reasonable outcome given the high ambient temperatures in the Darwin region. The high humidity rules out conventional cooling towers for cooling. It is anticipated that either air-cooling or seawater cooling will be used.
11. Maximum power consumption for a compression train (all stages / pumps) is 40 MW. For cases requiring more power than this, multiple trains were used to keep individual power consumption below 40 MW (Mccollum & Ogden 2006a, p.3)

Capital cost estimating of compression facilities

The key reference used for capital cost estimation was Mccollum & Ogden (2006). This extensive techno-economic reference itself derived CO₂ compression cost estimates from an earlier IEAGHG report (Woodhill Engineering Consultants 2002a). We have validated this against verbal advice on CO₂ compression pricing in Australia and found its estimates are comparable.

CO₂ compression systems are unusual in that they are usually divided into two parts – compression (for pressures below and up to the critical pressure of CO₂, 73.8 bar) and pumping (for pressures above the critical pressure).

Compressors are staged (multiple stages of compression, each followed by an aftercooler). It was assumed the maximum pressure ratio is 3.0.

The capital cost of a compression facility was estimated using Equation C-1 (Mccollum & Ogden 2006b):

Equation C-1. Capital cost of compression system (USD 2005)

$$C_{\text{comp}} = m_{\text{train}} N_{\text{train}} \left[0.13 \times 10^6 (m_{\text{train}})^{-0.71} + 1.40 \times 10^6 (m_{\text{train}})^{-0.60} \ln(P_{\text{cut-off}}/P_{\text{initial}}) \right]$$

Where:

C_{comp} = cost of compression system (US dollars, 2005)

m_{train} = mass flowrate through compression train (kg/s)

N_{train} = number of compression trains in compression system (integer)

$P_{\text{cut-off}}$ = the discharge pressure of the system (absolute) (any pressure units)

P_{initial} = the inlet (initial) pressure of the system (absolute) (same pressure unit at $P_{\text{cut-off}}$)

The term inside square brackets is the capital cost per kg/s.

Capital cost estimation for compression to the critical pressure only requires knowing the mass rate per train, the number of trains, and the inlet and outlet pressures.

It was assumed the maximum power demand for a compression train was 40,000 kW (Woodhill Engineering Consultants 2002b). For systems requiring more power than this, multiple trains are required.

Hence if 60,000 kW of compression power is needed, two trains would be required to keep them both under the 40,000 kW threshold. It should be noted that this threshold is now almost 20 years old and it is possible that more compression could occur within one train. However we have retained this limit for this work, as the cost equation has only been validated up to 40,000 kW.

To check the threshold, capital cost requires the work (energy) of the compression system to be estimated.

Work (energy) of compression is a linear function with mass flow. As such, specific (per kg) work of compression can be calculated, and simply scaled up or down with flowrate for all systems. Work of compression was calculated using the following assumptions:

- Aftercooling to 50°C after each stage.
- 75% adiabatic efficiency for each compression stage and for pumping.
- 90% drive (motor & gearbox) efficiency (i.e. 90% of energy fed to the motor is transferred to the compressor shaft). This makes electricity consumption $1/0.9 = 1.11$ times higher than the compression energy.
- Pressure ratio of each stage is the same

The engineering application HYSYS (by AspenTech) was used to estimate work of compression and pumping for all four kinds of compression/pumping systems in this report. A 1 Mtpa flow was used in the modelling, with linear scaling to get estimates of energy for each application's flowrate.

Using the energy consumptions for each system and multiplying by the number of million tonnes per year of CO₂, we can obtain the power consumption of each compression system. This enables the number of trains to be calculated (whole trains of 40,000 kW or less).

The location, currency and inflation conversions were based on:

Australia location factor: 1.2 (Richardson)

USD/AUD exchange rate: 0.70 (assumed)

GDP Deflator 2015 USA: 86 (<https://tradingeconomics.com/united-states/gdp-deflator>)

GDP Deflator 2020 USA: 113 (<https://tradingeconomics.com/united-states/gdp-deflator>)

Adjustment factor to convert capex in Equation C-1 is $1.2 / 0.7 \times 113 / 86 = 2.253$.

Operating cost of compression systems

Opex for compression/pumping systems is dominated by energy cost. Compressor and pump power estimates are already available from the capital cost estimation section.

Energy operating cost

A flat 11.5 cents/kWh price was assumed for energy. Energy price was estimated by multiplying this price by kWh for the year for each compression system, in turn assuming 24/7/365 operation. In practice this will be a slight overestimate as most compression facilities will have some planned downtime.

Other operating costs

Annual operation and maintenance (O&M) costs were estimated at 4.0% of total capital cost (Mccollum & Ogden 2006b).

Capital cost estimating of pipelines - onshore

Once length, pipe diameter and schedule were determined, cost estimates were made for each pipeline in this study. An AEMO-published report on gas production and transmission costs (Core Energy Group 2015, p.10), regressed from the costs of 11 major gas transmission lines across 5 states, was used as the source of pipeline costs (in 2015 AUD):

Cost of steel line pipe:	2,500/tonne
Coating cost:	45.00/square metre
Construction cost:	30,000/inch-kilometre
Other (insurance, engineering, legal etc.)	15%
Contingencies	10%

All costs were calculated per metre of pipe length. As inputs, the following were calculated or obtained:

- Pipe weights were obtained online for all pipes ('Steel pipes schedule 40 chart: wall thickness and weight' 2020; 'Steel pipes schedule 160 chart: wall thickness and weight' 2020). This enabled steel pipe cost per metre to be estimated for all line sizes.

- Surface area was calculated based on outside diameter of each pipe, as obtained from online charts mentioned above. This enabled coating cost to be estimated for all line sizes
- Inch-kilometres are simply nominal pipe sizes in inches (mm size divided by 25) multiplied by pipe length. This enabled construction cost to be estimated.
- Other and Contingencies are simple percentages based on the sum of piping, coating and construction costs.

Estimates were converted to 2020 Australian Dollars using the GDP Deflator for Australia – 95.5 in 2015, 105.7 in 2020 ('Australia GDP Deflator' 2020).

Table 10 summarises per-metre costs of pipelines of dense phase (schedule 160) piping using the above approach. Only sizes used in this report have been included.

Table 10. Dense phase piping (Schedule 160) costs per metre

Pipe size (nominal mm)	300	350	400	450	500	550	600
Pipe ID (actual mm)	257.16	284.18	325.42	366.52	407.98	451.04	490.92
Pipe OD (actual mm)	323.8	355.6	406.4	457	508	559	610
Weight/ m (kg/m)	238.76	281.7	365.35	459.37	564.81	672.26	808.22
Surface area (m ² /m)	1.017	1.117	1.277	1.436	1.596	1.756	1.916
Inch km / m	0.012	0.014	0.016	0.018	0.02	0.022	0.024
Pipe Cost (\$/m)	596.90	704.25	913.38	1148.43	1412.03	1680.65	2020.55
Paint (\$/m)	45.78	50.27	57.45	64.61	71.82	79.03	86.24
Construction (\$/m)	360.00	420.00	480.00	540.00	600.00	660.00	720.00
Other (\$/m)	150.40	176.18	217.62	262.95	312.58	362.95	424.02
Contingency (\$/m)	100.27	117.45	145.08	175.30	208.38	241.97	282.68
Total (\$/m) (2015)	1253.35	1468.15	1813.54	2191.29	2604.80	3024.60	3533.48
Total (\$/m) (2020)	1387.21	1624.96	2007.23	2425.33	2883.01	3347.64	3910.88

Table 11 summarises per-metre costs of pipelines of gas phase (schedule 40) piping using the above approach. Only sizes used in this report have been included.

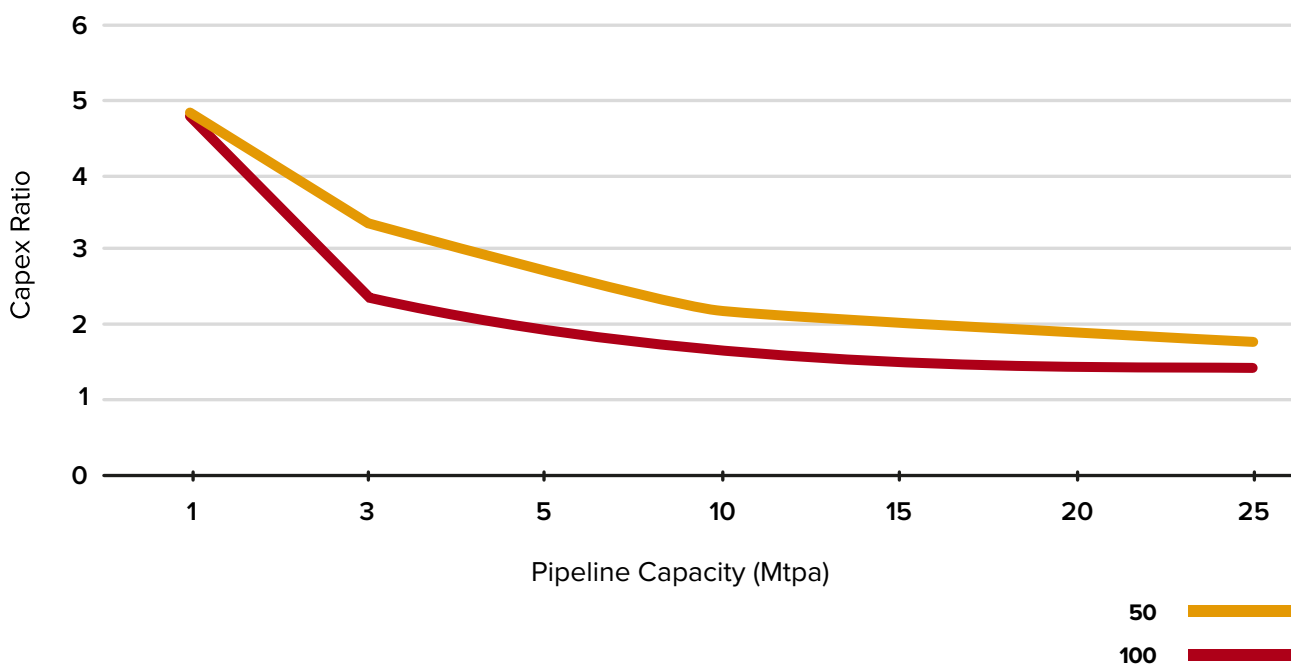
Table 11. Gas-phase piping (Schedule 40) costs per metre

Pipe size (nominal)	500	850
Pipe ID (actual) (mm)	477.82	829.04
Pipe OD (actual) (mm)	508	864
Weight/m (kg/m)	183.42	364.9
Surface area (m ² /m)	1.596	2.714
Inch km / m	0.02	0.034
Pipe cost (\$/m)	458.55	912.25
Paint (\$/m)	71.82	122.15
Construction (\$/m)	600.00	1020.00
Other (\$/m)	169.56	308.16
Contingency (\$/m)	113.04	205.44
Total (\$/m) (2015)	1412.96	2567.99
Total (\$/m) (2020)	1563.87	2842.27

A final factor in cost estimation is onshore vs offshore pipelines. The public data on offshore pipelines is much more variable than that for onshore due to offshore factors like ocean floor topography and depth. The Institute's experience is that offshore piping costs can be highly variable and that accurate estimates can be obtained only through detailed bottom-up costings. Additionally, there is some anecdotal evidence that offshore pipeline costs have been falling over the past twenty years.

One comparative source of data on offshore piping costs is from the Australian Power Generation Technology Report (CO₂CRC & Gamma Energy Technology 2015a). This report gave pipeline cost estimates for onshore and offshore lines of various flow capacities and lengths. Figure 15, derived from this report, shows the ratio of offshore to onshore capital costs (per km) for pipelines across a range of capacities. The orange line represents a pipe length of 50 km, and the red line a length of 100 km.

Figure 15. Offshore to onshore capital cost ratio for pipelines



In the range of capacities of interest in this study (> 5 Mtpa, and over 100 km) then it is conservative to say that offshore lines will be 2.0 times the cost of equivalent onshore lines. For this report, offshore line capital costs per metre are estimated in the same manner as onshore lines, then multiplied by 2.0.

Operating cost of pipelines

A straightforward estimate of 1% of capex was used as the annual fixed operations and maintenance (O&M) operating cost for all pipelines in this study (CO₂CRC & Gamma Energy Technology 2015b). Pipelines have little or no variable O&M operating costs, so these were taken to be zero.

3.3 Results for transport systems

All designed systems were set up to deliver CO₂ at the storage hub at a pressure of 100 bar.

The following cases were modelled:

- Base case – 9.1 Mtpa. Supports CO₂ from two LNG trains (1 at Inpex, 1 at DLNG) and CO₂ from a hydrogen plant. Flow results in Table 12.
- Boosted case(s) – using a pumping station and/or higher compression to maximise flow through the pipelines designed for case a. Flow results in Table 13.
- 2nd pipeline case – 17.3 Mtpa. Supports CO₂ from four LNG trains (2 at Inpex, 2 at DLNG) and CO₂ from a hydrogen plant. Flow results in Table 14.

Note that no boosting is assumed for the 2nd pipeline case.

HYSYS was used to calculate pressure drop along the pipelines. 20% extra was added to pipe length for pressure drop calculations to account for pressure drop across system fittings and bends.

Table 12. Route 1 pressures and flows – all offshore (222 km long)

CASE	PRESSURE AT COMPRESSION HUB (INLET TO TRANSMISSION PIPELINE) (BAR) (FROM HYSYS)	CO ₂ FLOW IN LINE (Mtpa)	TOTAL FLOW OF CO ₂ (Mtpa)	LINE DIAMETER (mm)	BOOSTER PUMP PART-WAY ALONG PIPELINE?
a. Base case	183	9.1	9.1	600	No
b. Boosted	227.7	11.3	11.3	600	No
c. 2nd pipeline on top of case a	204	8.2	17.3	550	No
d. 2nd pipeline on top of case b	193.6	6.0	17.3	500	No

Table 13. Route 2 pressures and flows – shorter onshore/offshore (117km onshore, 106km offshore, 223 km total)

CASE	PRESSURE AT COMPRESSION HUB (INLET TO TRANSMISSION PIPELINE) (BAR) (FROM HYSYS)	CO ₂ FLOW IN LINE (Mtpa)	TOTAL FLOW OF CO ₂ (Mtpa)	LINE DIAMETER (mm)	BOOSTER PUMP PART-WAY ALONG PIPELINE?
a. Base case	184.1	9.1	9.1	600	No
b. Boosted	227.7	11.3	11.3	600	No
c. Boosted with booster pump	227.7	15.1	15.1	600	Yes
d. 2nd pipeline on top of case a	205	8.2	17.3	550	No
e. 2nd pipeline on top of case b	195.9	6.0	17.3	500	No
f. 2nd pipeline on top of c	181.4	2.2	17.3	350	No

Table 14. Route 3 pressures and flows – longer onshore/offshore route (375 km onshore, 155 km offshore, 530km total)

CASE	PRESSURE AT COMPRESSION HUB (INLET TO TRANSMISSION PIPELINE) (BAR) (FROM HYSYS)	CO ₂ FLOW IN LINE (Mtpa)	TOTAL FLOW OF CO ₂ (Mtpa)	LINE DIAMETER (mm)	BOOSTER PUMP PART-WAY ALONG PIPELINE?
a. Base case (only possible with booster pump)	227.7	9.1	9.1	600	Yes
b. Boosted with maximum booster pump	227.7	10.1	10.1	600	Yes
c. 2nd pipeline on top of case a	Not applicable (case does not work)				
d. 2nd pipeline on top of case b	Not applicable (case does not work)				

In summary we have a total of 4 (route 1) + 6 (route 2) + 2 (route 3) = 12 cases that were assessed for the main trunk line.

In addition, the upstream gas-phase lines were also assessed. These route CO₂ from the 2-stage compressors at each upstream site to the CCS compression hub at middle arm. See Table 15.

Table 15. Gas-phase pipeline pressures and flows

GAS-PHASE LINE	PRESSURE AT COMPRESSION HUB (INLET TO TRANSMISSION PIPELINE) (BAR) (FROM HYSYS)	CO ₂ FLOW IN LINE	LINE DIAMETER (mm)
From Inpex 4.5 Mtpa LNG train to hub (10.2 km)	8.3	3.99	850
From DLNG 4.5 Mtpa LNG train to hub (13.3 km)	9.3	4.10	850
From H ₂ plant (10 km assumed)	7.3	1.1	500

Pipeline cost summary

Pipeline capex was estimated on a length basis, with a 2.0 factor included for the offshore sections.

In order to estimate the pipeline cost per tonne, capital cost was annualised. This uses the Capital Recovery Factor (CRF) of 7.26%, derived from an assume cost of capital of 6%. Total capex multiplied by the CRF gives the total annual cost required to service the cost of capital and depreciation over the life of the asset – assumed in this case to be 30 years.

The summary of pipeline costs is shown in Table 21.

Compression cost summary

Table 22 summarises the costs of compressor capex (total and annualised) as well as the cost of energy to run compression at the compression hub. Total compression cost per tonne is also summarised.

Upstream piping and compression costs

The costs of transporting gas-phase CO₂ from each LNG plant and the hydrogen plant to the central CCS hub are summarised in Table 23 and Table 24. Also included are the weighted average costs of pipeline and compression per tonne of CO₂ across all three facilities, as costs vary significantly from source to source.

3.4 Potential Injection Design

The final injection and infrastructure requirements can only be confirmed through the appraisal process of Front-End Engineering Design and ultimately, the Final Investment Decision.

The current concept below is taken from the Northern Australia CCS Reports (ENI SpA 2019; Seldon, Lynn & Tucker 2017; ENI S.p.A 2018a). The concept below is only presented to guide the costs and design of this current study. The main modification below is the number of wells and diameters of tubing and pipes, see Results for transport systems above.

The design is as follows:

- 600mm nominal diameter subsea pipeline that would start from Darwin
- Un-crewed wellhead platform (Figure 16)
 - Well bays
 - Piping and manifold for the CO₂ injection
 - Utilities and infrastructure to support platform operations
 - Helideck
- Vertical CO₂ injection wells (Figure 17)
 - 1400 m vertical depth
 - Number dependent on injection rate, See Table 16; Table 17; Table 18.
 - Consists of between 8-12 injection wells and one spare well
 - 7" or larger tubing thickness
 - Cement to ensure conformance to CO₂
- Vertical CO₂ monitoring well
 - Spare well will be used as monitoring well also.

A platform removes the need for onshore connection of power and hydraulics to the wellhead. Alternative options exist, including subsea facilities. An extensive review of alternative injection strategies is beyond the scope of this study. Reviewing offshore, greenfield injection strategies globally (comparable to PSB AOI), the general strategy is un-crewed platforms. However, the Northern Lights Project in the North Sea of Norway is using sub-sea infrastructure including satellite wells,

with tie-in points to a hub connecting a subsea pipeline. Northern Lights is only using one well but has provisions for additional wells. They state the subsea system lowers the cost of storage, but no comparison is provided (i.e. platforms) (Equinor 2019) (Global CCS Institute 2020). The Petrobras CCS EOR project also uses subsea injection and production wells connected to the floating production, storage and offloading ships (Global CCS Institute 2020).

Figure 16. Platform design for Northern Australia CCS Project, from ENI (2018b).

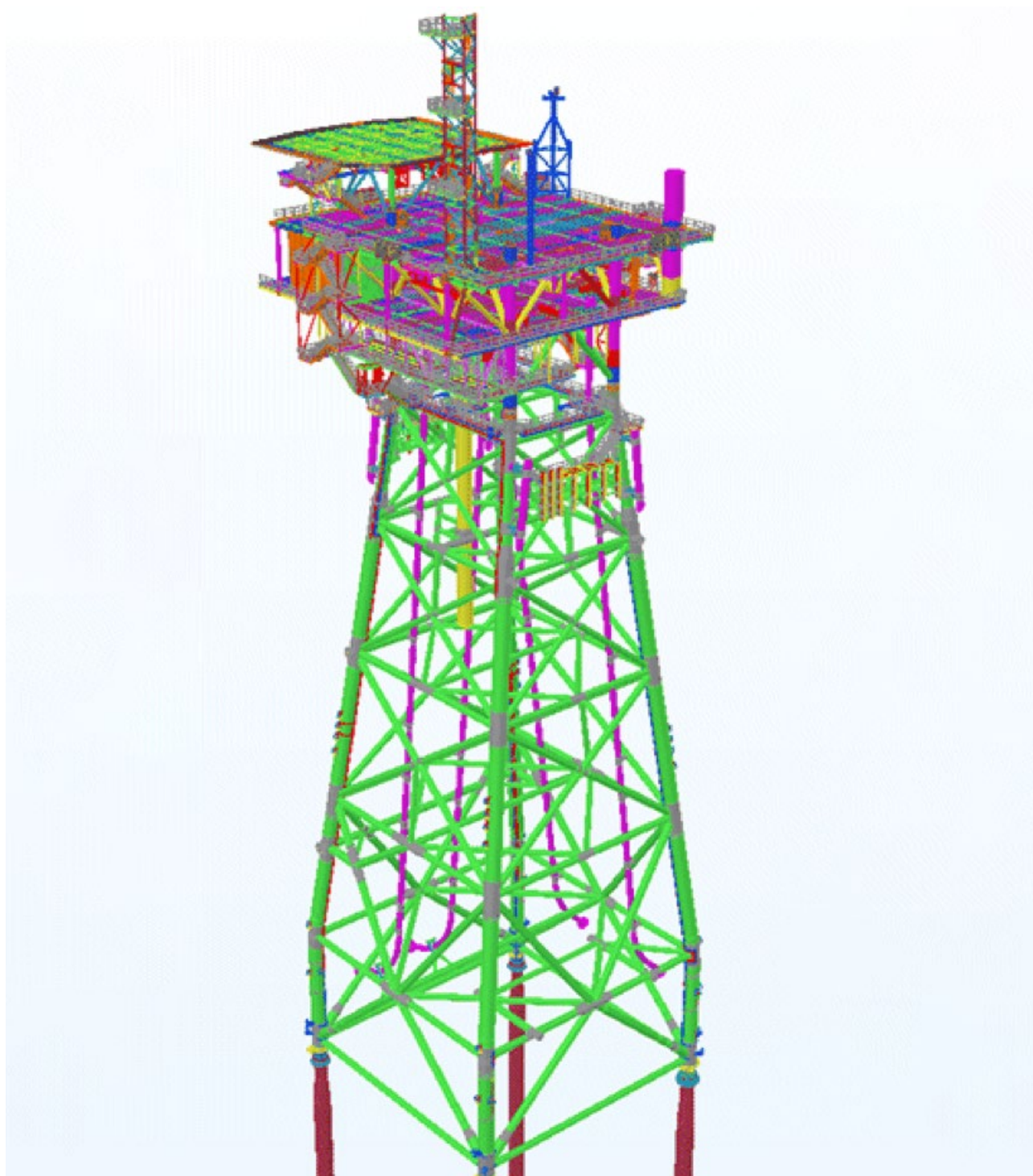


Figure 17. Potential Well Design, from ENI SpA (2019)

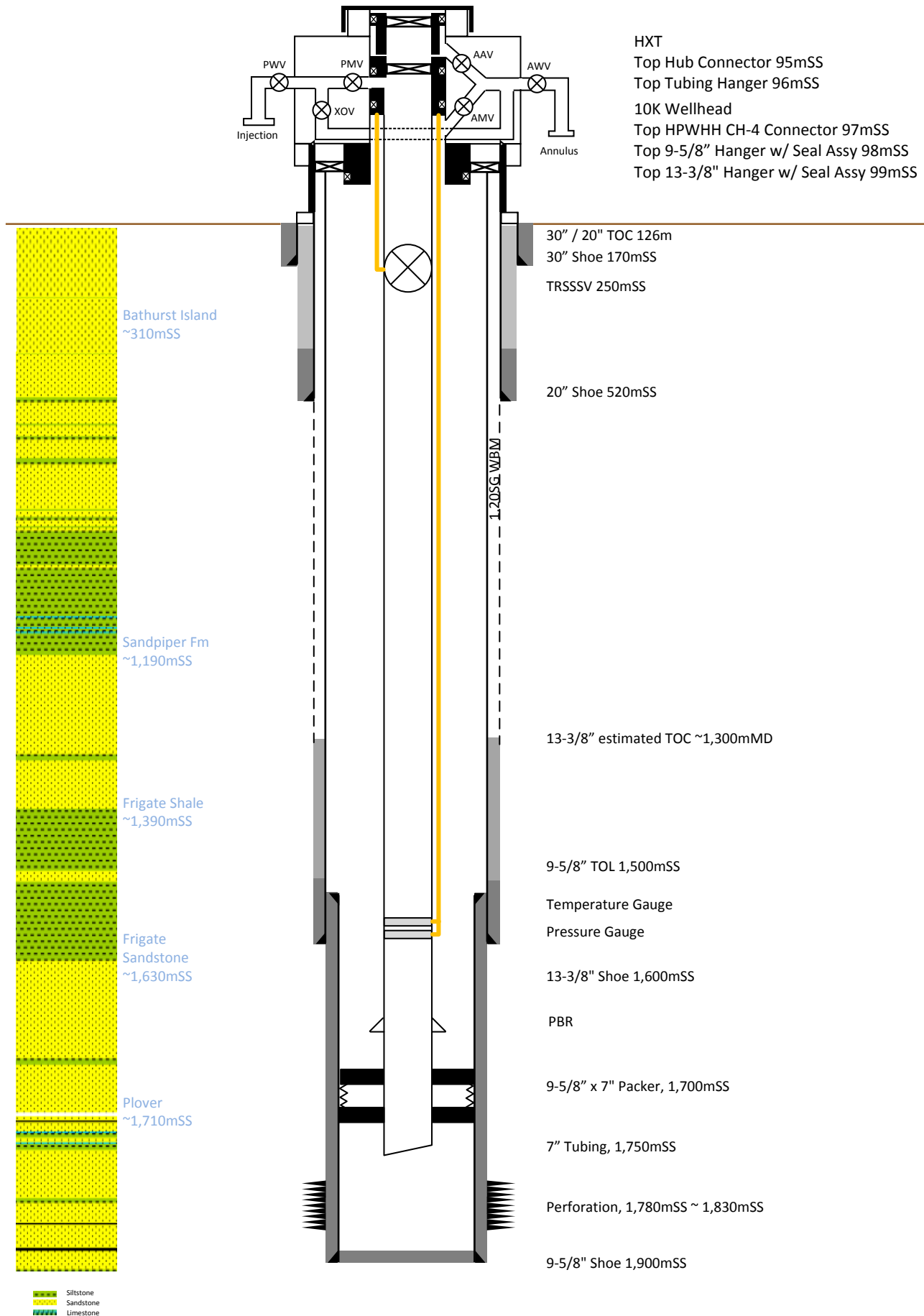


Table 16. Potential well count based on various cases for Route 1: All offshore (222 km long).

CASE	TOTAL FLOW OF CO ₂ (Mtpa)	NUMBER OF WELLS (BASED ON 80-90 MMscfd PER WELL)
a. Base case	9.1	8 (6 injection, 1 spare, 1 monitoring)
b. Boosted	11.3	9 (7 injection, 1 spare, 1 monitoring)
c. 2nd pipeline on top of case a	17.3	12 (10 injection, 1 spare, 1 monitoring)
d. 2nd pipeline on top of case b	17.3	12 (10 injection, 1 spare, 1 monitoring)

Table 17. Potential well count based on various cases for Route 2: Shorter onshore/offshore (117km onshore, 106km offshore, 223 km total).

CASE	TOTAL FLOW OF CO ₂ (Mtpa)	NUMBER OF WELLS (BASED ON 80-90 MMscfd PER WELL)
a. Base case	9.1	8 (6 injection, 1 spare, 1 monitoring)
b. Boosted	11.3	9 (7 injection, 1 spare, 1 monitoring)
c. 2nd pipeline on top of case a	15.1	11 (9 injection, 1 spare, 1 monitoring)
d. 2nd pipeline on top of case b	17.3	12 (10 injection, 1 spare, 1 monitoring)
e. 2nd pipeline on top of case b	17.3	12 (10 injection, 1 spare, 1 monitoring)
f. 2nd pipeline on top of c	17.3	12 (10 injection, 1 spare, 1 monitoring)

Table 18. Potential well count based on various cases for Route 3 – longer onshore/offshore route (375 km onshore, 155 km offshore, 530km total)

CASE	TOTAL FLOW OF CO ₂	NUMBER OF WELLS (BASED ON 80-90 MMscfd PER WELL)
a. Base case (only possible with booster pump)	9.1	8 (10 injection, 1 spare, 1 monitoring)
b. Boosted with maximum booster pump	10.1	9 (10 injection, 1 spare, 1 monitoring)

3.5 Monitoring

The following section focusses on the latest developments and best practice in CO₂ monitoring in an offshore environment. The requirements are drawn from the latest operations, notably the Tomakomai Project in Japan. The Japan Project, although small-scale (<100,000 tonnes of CO₂ stored), represents the latest in technology under stringent regulatory requirements in an offshore environment.

An offshore CO₂ storage operation requires three phases of monitoring:

1. Baseline: pre-injection characterisation to understand environmental variability (spatial and temporal) including CO₂ levels, existing leaks, seafloor mapping (seafloor movement, sediment and habitat types, as well as biota). The baseline period will also include 3D seismic, either vertical seismic profiling (VSP) or ship-based seismic acquisition.

2. Operational monitoring (see Table 19 for preliminary list): the focus is on CO₂ plume injection and movement, including:
 - Containment assurance: Prove injection and storage performance and ensure free-phase CO₂ plume does not move beyond the storage formation.
 - Conformance assurance: confirms that the CO₂ plume within the storage formation is performing as expected, to reduce the uncertainty of adverse impacts to storage performance, health and the environment
3. Post-injection: according to the regulatory requirements (See Section 2 for full details on the regulation), at least 15 to 20 years of monitoring is required following the end of the operation. Periodic 3D VSP or standard ship-based 3D seismic, potentially five years apart are the primary monitoring activities. Seafloor sensors may also be required.

Table 19. Potential monitoring activities during the operation of an offshore CO₂ storage project.

EQUIPMENT	MONITORING	OBSERVATION FREQUENCY
Injection Well	Downhole: • Temperature and pressure gauges; • Optical fibres: distributed acoustic sensing (DAS) for vertical seismic profiling (VSP) • Distributed temperature sensing (DTS) for thermal sensing Wellhead: • Pressure, injection rate gauges	Continuous
Monitoring Well (spare wells can be used as monitoring well also)	Downhole: • Temperature and pressure gauges; • Optical fibres: Seismic (VSP) through DAS) • DTS for thermal sensing	Continuous
Ocean bottom cable	Micro-seismicity and natural earthquakes	Continuous
3D seismic survey	Downhole VSP or ship-based seismic acquisition	Periodic
Seafloor sensors	Acoustic and chemical proximal to injection and monitoring wells	Periodic

Costs of Injection and Monitoring

The latest significant analysis of the cost of storage in Australian offshore waters was through the Carbon Storage Taskforce (2010). The only offshore storage site modelled was the Gippsland Basin. Its clear from

the table below that the per tonne cost of injection and monitoring is significantly reduced as scale increases. Costs are also sensitive to the capital cost of drilling and completing wells, and the number of wells required. For the purposes of this early stage study, we have assumed a cost per tonne for storage and monitoring of \$10.

Table 20. Offshore cost of CO₂ injection wells from Gippsland Basin, from:(Carbon Storage Taskforce 2010).

DISTANCE FROM HUB	CO ₂ FLOWRATE (Mtpa)	NO. WELLS	TOTAL CAPITAL COST OF WELLS (\$AUD, MILLIONS, 2015)	CAPITAL COST PER WELL	MMV ANNUALISED COSTS (\$AUD, MILLIONS, 2015)	\$AUD/t CO ₂ AVOIDED (2015)
Nearshore	1	1	22	22	0.1	26
Nearshore	5	3	65	22	0.1	9.1
Nearshore	10	5	149	30	0.1	6.2
Intermediate	10	5	210	42	0.9	8.3
Central	10	5	210	42	4.5	13.8
Central	15	8	337	42	4.5	11.5
Central	20	10	217	22	4.5	9.1

Table 21. Pipeline costs for all cases (main trunk line(s))

PIPE ROUTE	CASE	FLOWRATE	DIAMETER (mm)	PIPE INLET P (BAR)	PIPELINE COST PER M (ONSHORE)	LENGTH (m)	PIPELINE CAPEX (\$M)	PIPELINE CAPEX ANNUALISED (\$M/Y)	PIPELINE OPEX (\$M/Y)	TOTAL PIPELINE ANNUAL COST (\$M/Y)	PIPELINE COST PER TONNE CO ₂ (\$/TONNE)
Route 1: All offshore	a. Base	9.1	600	183.1	3910.88	222	1736.4	126.1	17.364	143.4	15.76
	b. Boosted at hub	11.3	600	227.7	3910.88	222	1736.4	126.1	17.364	143.4	12.70
	c. 2nd pipe from base	8.2	550	204	3347.64	222	1486.4	107.9	14.864	122.8	15.03
	d. 2nd pipe from boosted	6.0	500	193.6	2883.01	222	1280.1	92.9	12.801	105.7	17.69
Route 2: Onshore/ offshore (short)	a. Base - Route 2	9.1	600	184.1	3910.88	223	1286.7	93.4	12.867	106.3	11.68
	b. Boosted at hub (no booster pump)	11.3	600	227.7	3910.88	223	1286.7	93.4	12.867	106.3	9.44
	c. Boosted at hub plus booster pump	15.1	600	227.7	3910.88	223	1286.7	93.4	12.867	106.3	7.03
	d. 2nd pipe from base	8.2	550	205	3347.64	223	1101.4	80.0	11.014	91.0	11.13
	e. 2nd pipe from base (no booster pump)	6.0	500	195.9	2883.01	223	948.5	68.9	9.485	78.3	13.02
	f. 2nd pipe boosted (booster pump)	2.2	350	181.4	1624.96	223	534.6	38.8	5.346	44.2	20.43
Route 3: Onshore/ offshore (long)	a. Boosted at hub plus booster pump	9.1	600	227.7	3910.88	530	2679.0	194.5	26.790	221.3	24.32
	b. Boosted at hub plus max booster pump	10.1	600	227.7	3910.88	530	2679.0	194.5	26.790	221.3	21.93

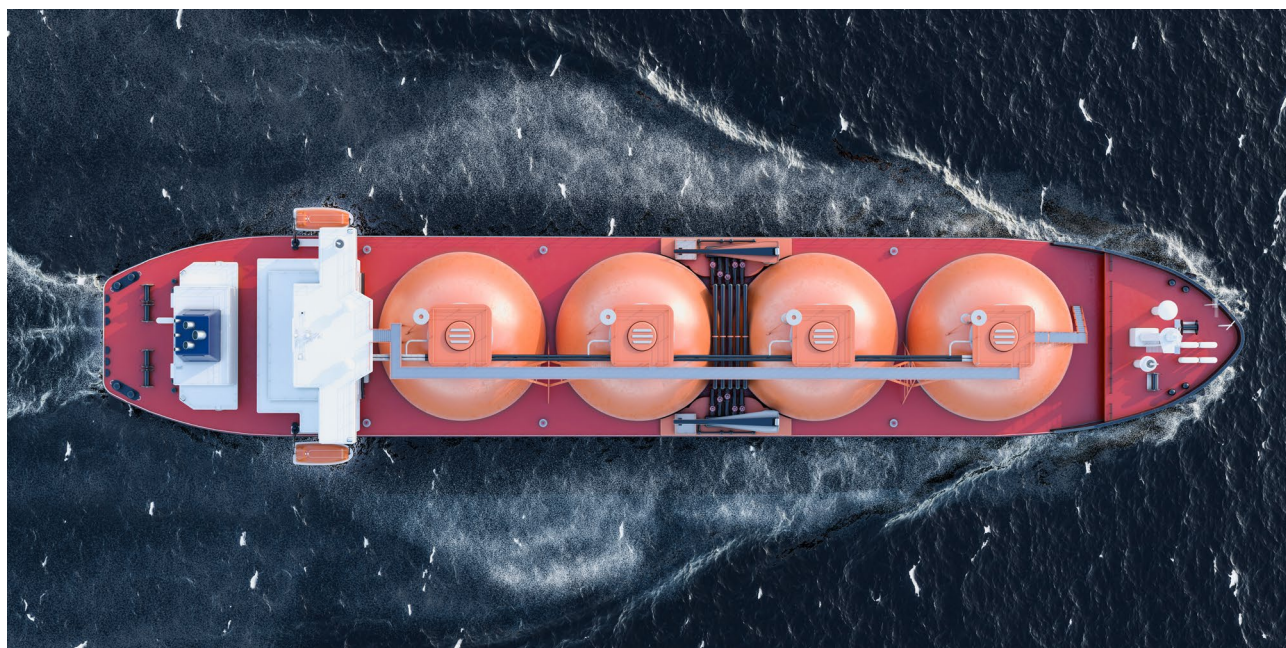


Table 22. Compression costs for all cases (Compression Hub)

PIPE ROUTE	CASE	COMPRESSION POWER (kW)	BOOSTER PUMP POWER (kW)	TRAINS 1/40000 (kW)	POWER PER TRAIN (kW)	COMPRESSION CAPEX PER TRAIN (\$M)	COMPRESSION CAPEX TOTAL (\$M)	BOOSTER PUMP CAPEX (\$M)	ANNUALISED CAPEX (\$M/Y)	ELECTRICITY OPEX (\$M/Y)	OTHER OPEX - 4% OF CAPEX PER YEAR (\$M/Y)	TOTAL OPEX (\$M/Y)	TOTAL ANNUAL COST (\$M/Y)	TOTAL COMPRESSION COST PER TONNE (\$/TONNE)
Route 1: All offshore	a. Base	96,500	-	3	32166.8	74.2	222.7	0.0	16.2	97.2	8.9	106.1	122.3	13.44
	b. Boosted at hub	131,991	-	4	32997.6	79.0	315.9	0.0	22.9	133.0	12.6	145.6	168.5	14.92
	c. 2nd pipe from base	90,791	-	3	30263.6	73.4	220.0	0.0	16.0	91.5	8.8	100.3	116.2	14.23
	d. 2nd pipe from boosted	64,907	-	2	32453.5	75.5	151.0	0.0	11.0	65.4	6.0	71.4	82.4	13.78
Route 2: Onshore/offshore (short)	a. Base - Route 2	96,723	-	3	32241.0	74.4	223.3	0.0	16.2	97.4	8.9	106.4	122.6	13.47
	b. Boosted at hub (no booster pump)	131,530	-	4	32882.5	78.8	315.2	0.0	22.9	132.5	12.6	145.1	168.0	14.93
	c. Boosted at hub plus booster pump	176,589	9,162	5	35317.9	82.3	411.3	23.1	31.5	187.1	17.4	204.5	236.0	15.62
	d. 2nd pipe from base	90,991	-	3	30330.2	73.5	220.6	0.0	16.0	91.7	8.8	100.5	116.5	14.26
	e. 2nd pipe from base (no booster pump)	65,676	-	2	32838.0	76.2	152.5	0.0	11.1	66.2	6.1	72.3	83.3	13.85
	f. 2nd pipe boosted (booster pump)	22,832	-	1	22832.3	61.4	61.4	0.0	4.5	23.0	2.5	25.5	29.9	13.84
Route 3: Onshore/offshore (long)	a. Boosted at hub plus booster pump	106,359	3,893	3	35452.9	82.5	247.4	9.9	18.7	111.1	10.3	121.4	140.0	15.59
	b. Boosted at hub plus max booster pump	117,947	6,877	3	39315.8	87.8	263.4	17.4	20.4	125.7	11.2	137.0	157.4	15.59

Table 23. Pipeline costs for upstream plants (gas-phase CO₂)

PIPE ROUTE	CASE	FLOWRATE	DIAMETER (mm)	PIPE INLET P (BAR)	PIPELINE COST PER M (ONSHORE)	LENGTH (km)	PIPELINE CAPEX (\$M)	PIPELINE CAPEX ANNUALISED (\$M/Y)	PIPELINE OPEX (\$M/Y)	TOTAL PIPELINE ANNUAL COST (\$M/Y)	PIPELINE COST PER TONNE CO ₂ (\$/TONNE)
Inpex to hub (base)	Base	3.99	850.0	8.3	2842.27	10.2	29.0	2.1	0.290	2.4	0.60
DLNG to hub (base)	Base	4.10	850.0	9.3	2842.27	13.9	39.6	2.9	0.396	3.3	0.80
Industrial (H ₂) to hub	Base	1.1	500.0	7.25	1563.87	10	15.6	1.1	0.156	1.3	1.17

Table 24. Compression costs for upstream plants (gas-phase CO₂)

PIPE ROUTE	COMPRESSION POWER (kW)	BOOSTER PUMP POWER (kW)	TRAINS 1/40000 (kW)	POWER PER TRAIN (kW)	COMPRESSION CAPEX PER TRAIN (\$M)	COMPRESSION CAPEX TOTAL (\$M)	BOOSTER PUMP CAPEX (\$M)	ANNUALISED CAPEX (\$M/Y)	ELECTRICITY OPEX (\$M/Y)	OTHER OPEX - 4% OF CAPEX PER YEAR (\$M/Y)	TOTAL OPEX (\$M/Y)	TOTAL ANNUAL COST (\$M/Y)	TOTAL COMPRESSION COST PER TONNE (\$/TONNE)
Inpex to hub (base)	27,848	-	1	27,848.0	48.0	48.0	0.0	3.5	28.1	1.9	30.0	33.5	8.39
DLNG to hub (base)	30,102	-	1	30,102.3	50.5	50.5	0.0	3.7	30.3	2.0	32.3	36.0	8.79
Industrial (H ₂) to hub	3,697	-	1	3,696.9	20.5	20.5	0.0	1.5	3.7	0.8	4.5	6.0	5.49

3.6 Summary of costs

A summary of transport and storage costs for all routes and cases is given in Table 25. For this summary, the assumed storage cost is \$10/tonne.

Table 25. Summary of transport and storage costs

	Mtpa CO ₂	UPSTREAM PIPING (AVERAGE) (\$/tCO ₂)	UPSTREAM COMPRESSION (AVERAGE) (\$/tCO ₂)	HUB COMPRESSION (\$/tCO ₂)	MAIN CO ₂ PIPELINE (\$/tCO ₂)	STORAGE (ASSUMED \$10/TONNE) (\$/tCO ₂)	TOTAL (\$/tCO ₂)
1a. Base	9.1	0.76	8.22	13.44	15.76	10.00	48.18
1b. Boosted at hub	11.3	0.76	8.22	14.92	12.70	10.00	46.60
1c. 2nd pipeline from base (incremental cost of 2nd line only)	8.2	0.76	8.22	14.23	15.03	10.00	48.23
1d. 2nd pipe from boosted (incremental cost of 2nd line only)	6.0	0.76	8.22	13.78	17.69	10.00	50.45
1c. Average costs across both pipelines	17.3	0.76	8.22	13.81	15.41	10.00	48.20
1d. Average costs across both pipelines	17.3	0.76	8.22	14.53	14.43	10.00	47.93
2a. Base	9.1	0.76	8.22	13.47	11.68	10.00	44.13
2b. Boosted at hub	11.3	0.76	8.22	14.93	9.44	10.00	43.35
2c. Maximum flow case (with booster pump)	15.19.18.2	0.76	8.22	15.62	7.03	10.00	41.63
2d. 2nd pipeline from base (incremental cost of 2nd line only)	6.0	0.76	8.22	14.26	11.13	10.00	44.37
2e. 2nd pipeline from boosted at hub (no booster pump)	2.2	0.76	8.22	13.85	13.02	10.00	45.85
2f. 2nd pipeline from boosted at hub (with booster pump)	17.3	0.76	8.22	13.84	20.43	10.00	53.25
2d. Average costs across both pipelines	17.3	0.76	8.22	13.84	11.42	10.00	44.24
2e. Average costs across both pipelines	17.3	0.76	8.22	14.55	10.69	10.00	44.22
2f. Average costs across both pipelines	17.3	0.76	8.22	15.40	8.71	10.00	43.09
Route 3 - base case (not possible)	N/A						
Route 3 - booster pump (match base case flow)	9.1	0.76	8.22	15.39	24.32	10.00	58.68
Route 3 - booster pump (max flow)	10.1	0.76	8.22	15.39	21.93	10.00	56.50

3.7 Discussion

The first key decision was around route 3. As can be seen in tables 21 and 22, the costs of pipelines and cost of compression are both significantly higher than both route 1 and route 2. Base case pipeline cost is \$8-12 more expensive per tonne, and compression is \$2 per tonne more expensive than the base case for this route, mainly due to the necessity of more compression.

The decision was made to not pursue route 3 for the boosted and 2nd pipeline cases. The elevated costs will only become even higher. The small benefit of known pipe easements and roads does not justify the large additional cost of this route.

The compression costs per tonne are quite similar between cases. This is because energy is over 90% of compression cost per tonne, and energy costs scale linearly with flow, meaning costs per tonne are fairly steady. There are small savings per tonne from economies of scale in the non-energy part, but they work out to be trivial.

It is in pipelines that considerable economies of scale are available. By increasing flow in the single 600mm pipeline (e.g. Route 2, case c), pipeline costs as low as \$7/tonne can be obtained – less than half the per-tonne cost of the base case in the offshore route. Of course this is only possible if sufficient CO₂ demand exists to support these economies of scale.

In all cases, route 2 pipeline costs are lower, reflecting the lower per-metre costs of piping onshore vs offshore. In addition, route 2 offers the option of a booster pump at the coast, greatly increasing the potential flow through this pipeline (15.1 Mtpa vs 9.1 Mtpa in the base case). So route 2 is not only lower cost but is more flexible than route 1.

Note the distinction between incremental and average costs for the 2nd pipeline options (routes 1 and 2). Incremental costs represent the additional costs only for installing and operating the second pipeline – they do not include any costs from the original pipeline. Average costs are a weighted average, spreading the costs of both pipelines across the total flow in both pipelines.

As investment decisions are made at the margin, route 2 becomes of interest. If the capacity of the first pipeline is boosted to its maximum extent (case 2c) then a flow of 15.1 Mtpa can be achieved. This is only a small amount below the total 17.3 Mtpa required for the 2nd pipeline cases. As such, a second pipeline in this instance would be much smaller capacity (only 2.2 Mtpa). This significantly boosts the pipeline marginal cost per tonne for the second pipeline, though when averaged across the total flow the impact is not so severe.

In summary – CCS compression, transport and storage benefit significantly from economies of scale. However, the single biggest component of system cost (compression energy) does not vary (in \$/tonne) with flowrate, and effectively sets a floor under total system cost.



4.0 CAPTURE OF RESERVOIR CO₂ FROM ONSHORE GAS PROCESSING FACILITIES

In Section 3, a base case was outlined that included the basis for reservoir CO₂ produced from future LNG trains at the Inpex and DLNG sites. To reiterate, the quantities are as described in Table 26.

Reservoir gas is processed in LNG trains through a sequence of operations to separate hydrocarbon liquids (condensate), remove impurities (CO₂, H₂S) and moisture, before a sequence of refrigeration operations cool and liquefy LNG for export. Almost all of this reservoir gas CO₂ must be removed from the natural gas to ensure it does not solidify during the LNG refrigeration and

liquefaction process. As such, CO₂ capture of reservoir gas is very high – practically 100%.

CO₂ and H₂S are collectively known as acid gases for their tendency to form acidic solutions in water. The LNG operation that removes them is known as the acid gas removal unit (AGRU) or sometimes the “amine” unit (in recognition of the solvent used). Figure 18 is a typical representation of an amine-based acid gas removal unit. All LNG plants already include one (or more) of these units. Raw gas enters as “sour gas” (bottom left) and purified acid gas exits top-right.

Table 26. Reservoir gas CO₂ (per LNG train)

FACILITY	GAS FIELD (ASSUMED)	RAW GAS CO ₂ CONCENTRATION (MOL%)	RAW GAS CO ₂ TONNAGE (Mtpa)
Inpex – 4.5 Mtpa LNG capacity	Plover	17.0	2.84
DLNG – 4.5 Mtpa LNG capacity	Evans Shoal	17.6	2.95

Discussions with Inpex yielded their typical composition and operating conditions for the acid gas stream. These conditions are typical for captured acid gas and have been used for the remainder of this task. Table 27 summarises the Inpex acid gas stream leaving their AGRU (Loden 2020). Also included are recommended

limits/levels from the ISO 27913 standard - Carbon Dioxide capture, transportation and geological storage - Pipeline transportation systems (International Standards Organisation 2016, Annex 1) – which outlines recommended compositions for various species in CO₂ for pipeline transport.

Figure 18. Typical gas plant acid gas removal unit

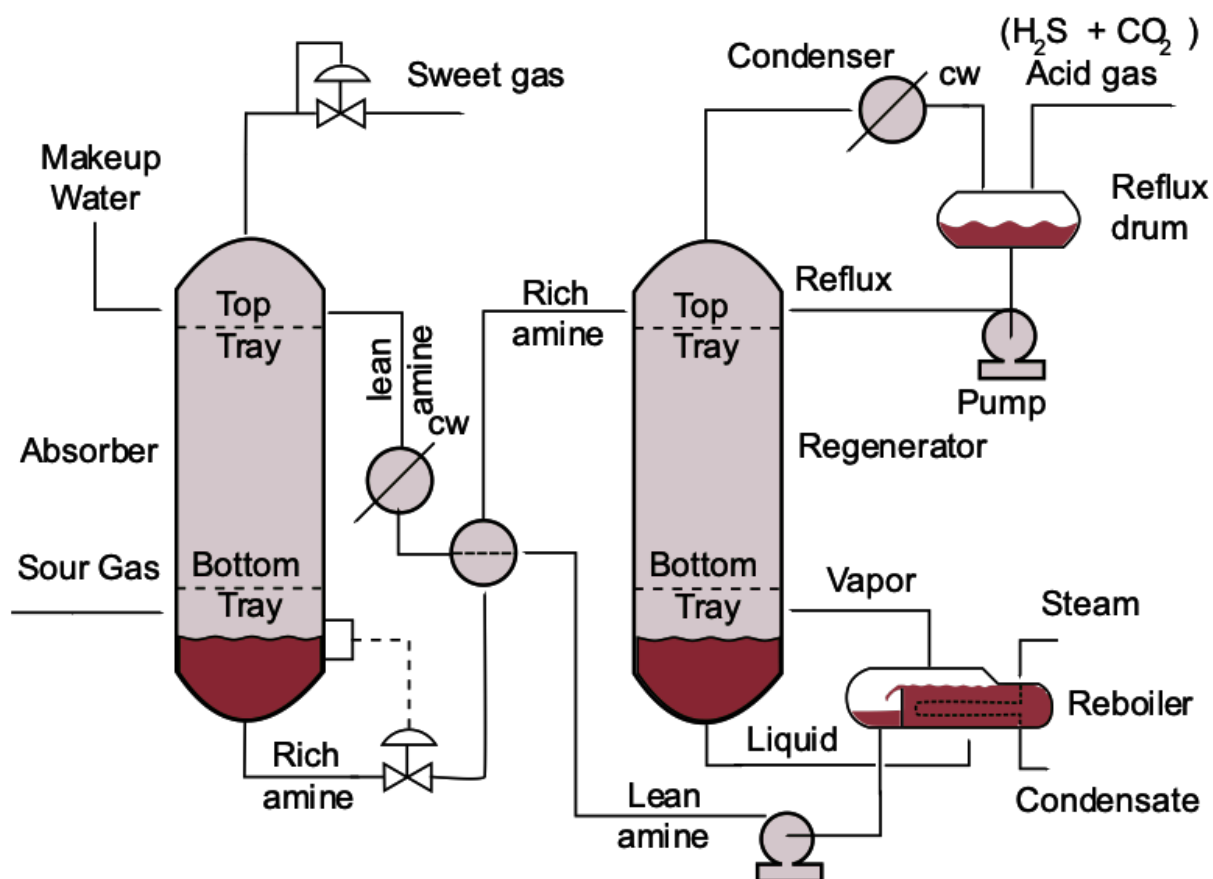


Table 27. Inpex-supplied acid gas composition (dry basis)

ACID GAS COMPOSITION (DRY BASIS)	TYPICAL VALUE	ISO 27913 RECOMMENDED LIMIT/RANGE
CO ₂	99.73 mol%	> 95 mol%
Methane (C1)	0.12 mol%	< 4 mol% for all non-condensable gases (including methane)
Ethane (C2)	0.03 mol%	< 2.5 mol% for all C2+ hydrocarbons
Propane (C3)	0.01 mol%	
Hydrogen Sulphide (H ₂ S)	0.07 mol% (max)	< 200ppm (0.02 mol%)
Benzene, Toluene, Ethylbenzene and Xylene (BTX)_	200-400 ppm (vol)	Not stated
Water	Saturated	< 200 ppm (0.02 mol%) to avoid hydrate formation < 630 ppm (0.063 mol%)

Presently, acid gas from the Inpex AGRU flows to an acid gas combustor. This thermally oxidises residual hydrocarbons and H₂S before venting – ensuring VOC and H₂S atmospheric emissions remain acceptable.

In a future operation, this gas will instead flow to the new CCS system and not be vented. As such, gas will need a degree of basic processing before it can be sent to pipelines.

4.1 Review of specification vs captured CO₂ composition

CO₂ composition from solvent-based AGRUs are more than acceptable. CO₂ purity is very high at over 99 mol% – much higher than the ISO minimum of 95 mol%.

Non-condensable species (methane) and heavier hydrocarbons are well within ISO limits for pipeline transport.

The composition of raw gas to future LNG processing plants will be broadly similar to those currently being seen. H₂S levels are not expected to rise: Evans Shoal (future source for DLNG) has been quoted with zero H₂S, and Plover is very close to the H₂S content of Inpex's current supplies from Brewster.

H₂S limit in the ISO standard is not a hard limit. One facility mentioned in the ISO standard footnotes – Weyburn pipeline – operates with 9000 ppm (0.9 mol%) H₂S without difficulty on the proviso that the CO₂ is adequately dried.

As such, the only remaining component that needs management is water. Acid gas removal units use a water-based solvent (MEA or similar aqueous solutions). Hence acid gas is in intimate contact with this solvent water, and becomes saturated (100% relative humidity). Inpex advised that acid gas leaving the AGRU is at approximately atmospheric pressure (101 kPa) and around 50-60 degrees C.

The partial pressure of water at 60 degrees C is 20 kPa. This corresponds with a volume percentage of $20/101 = 19.8$ vol % (mol%). Almost all this water must be removed.

In Section 3, the on-site compression and dehydration system was described for acid gas from each LNG train. This will be a shared compression and dehydration system for CO₂ from the AGRU and from capture plants on the gas turbines. No dedicated dehydration unit will be used for reservoir gas – it is a shared service across all site CO₂ streams.

Condensed water from gas treatment will be contaminated by low levels of hydrocarbons and H₂S. It can be treated in a conventional wastewater treatment plant before discharge into Darwin Harbour. It should be noted that present LNG operations vent much of this water as vapour, so it is entering the local environment untreated. Water treatment will improve local sulphur and hydrocarbon emissions.

In terms of on-site CO₂ flow, it is recommended that the CO₂ compression and dehydration system is located physically close to both the AGRU and the gas turbine CO₂ capture units. CO₂ streams are quite large and require large piping. The costs of this can be minimised by reducing pipe lengths to the compression and dehydration plant.

4.2 Equipment requirements

No specific equipment is required for handling captured reservoir CO₂, simply large diameter piping to transport AGRU CO₂ to the on-site compression and dehydration system. This is described in Section 3. Stainless steel piping is recommended until water has been removed to prevent corrosion.

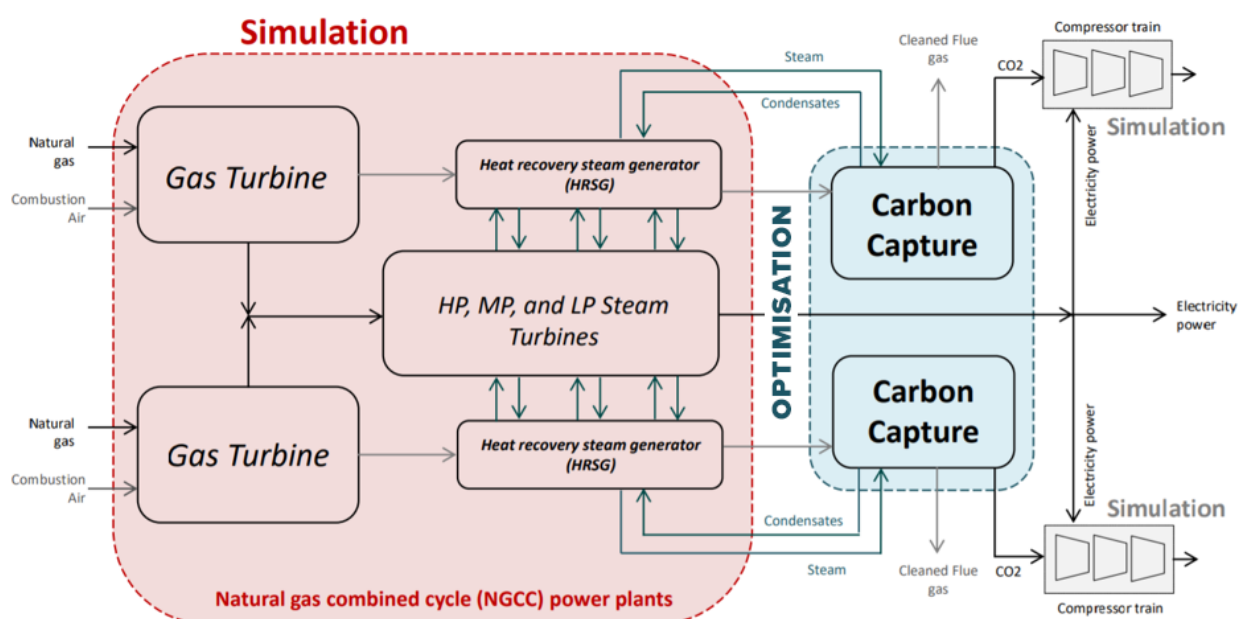
5.0 CARBON CAPTURE IN NATURAL GAS COMBINED CYCLE PLANTS

5.1 Background and Methodology

A typical Natural Gas Combined Cycle (NGCC) with carbon capture process layout is shown in Figure 19. NGCC plants utilise gas and steam turbines in series to achieve higher thermal efficiency than other conventional power generation systems. A NGCC plant contains a sequential gas turbine system generating electricity from the combustion flue gas. The exhausted

flue gas subsequently passes through a three-stage heat recovery steam generator (HRSG). The HRSG produces superheated steam for the three pressure staged steam turbine system to generate electricity. The steam turbine system consists of a high-pressure turbine (HPT) with steam entering at $\sim 580^\circ\text{C}$ 160 bar, a medium-pressure turbine (MTP) at $\sim 580^\circ\text{C}$ and 25 bar and a low-pressure turbine (LPT) typically around $\sim 300^\circ\text{C}$ (Feron, Cousins, Jiang, et al. 2019). After the heat exchange in the HRSG, the flue gas enters the pre-treatment process for particulates and NO_x control, before entering the CO₂ capture system.

Figure 19. Process flow chart of the natural gas-fired combined cycle (NGCC) with carbon capture (Sharifzadeh & Shah 2016)



Carbon capture is increasingly being applied to decarbonise the power sector and other industries with low-concentration dilute gas streams. Table 28 lists the chemical solvent-based carbon capture technologies available commercially or near commercialisation, and their current technology readiness level. TRL in this table stands for Technology Readiness Level, a qualitative indicator of the commercialisation of a technology. TRL 1 represents basic principles of operation being observed, through to TRL 9 representing proven full-scale commercial operation of the technology. Technology risk declines as TRL rises. A summary of TRL ratings is given in at the end of this chapter.

The chemical solvents, especially the amine-based solvents, are the current state-of-art technologies for

carbon capture from the flue gas of natural gas turbines. The US Department of Energy (DOE) has set targets to improve state-of-the-art capture technologies to reduce the cost of capture from dilute gas streams. (Miller et al. 2016). The second-generation technologies, yet to be deployed commercially, are targeted to reduce costs by 20 per cent from current state-of-the-art technologies. Second generation capture technologies are expected to be available for demonstration by 2025. Transformational technologies are targeted to reduce costs by 30 per cent from the first of a kind technology and be available for demonstration in the 2030 timeframe. There have been concerted efforts to drive down the cost and energy requirement of chemical solvent technologies.

Table 28. TRL assessment and key technology vendors of the CO₂ capture chemical solvent technologies. Global CCS Institute analysis and IEAGHG 2014.

TECHNOLOGY	KEY VENDORS	TRL 2014	TRL 2018
Conventional amine solvents	Fluor, Shell, MHI	9	9
Benfield process and variants	UOP	-*	9
Advanced amine solvent (sterically hindered amine)	MHI, Carbon Clean Solutions, Toshiba, CSIRO	6-8	6-9
Chilled ammonia process	GE	6*	6-7
Water-Lean solvent	Ion Engineering, RTI	4-5	4-6
Phase change solvents	IFPEN/Axens	4	5-6
Amino acid based solvent	Siemens	-*	5
Precipitating solvents	GE	4-5	4-5

The 30 wt% monoethanolamine (MEA) solvent technology is used for carbon capture in this report. The impact of heat-stable salt is also considered by including 2 wt% formate and acetate in the amine formulation (MEA alkalinity remains the same). This represents most operational amine plants. MEA solvent technology is widely used as the reference technology for capturing CO₂ from flue gases with low CO₂ partial pressure.

A rigorous, rate-based model developed in Aspen Plus® was applied to evaluated technical performance. This is a bottom-up approach based on a detailed process flow sheet. The latest process integration using intercooling and rich amine split processes were incorporated to technically improve the capture process and reduce energy consumption. The whole amine CO₂ capture process is described below and shown in Figure 20:

1. The flue gas is initially cooled in the direct contact cooler using the water wash.
2. The cooled flue gas is then fed to the bottom of the absorber column, which consists of packed beds in the CO₂ absorption section(s), and a water wash section.
3. The flue gas is contacted with a semi-lean amine solvent in the packed bed where the CO₂ in the flue gas is absorbed. The intercooling process situated in the middle to the middle-lower section of the absorber improves the efficiency of the absorption process.
4. The flue gas leaving the CO₂ absorption section is scrubbed in the topwater wash section and passes through a demister section to remove any MEA and/or degraded solvent.

5. The rich amine solvent leaves the bottom of the absorber. This is divided into two different streams (rich amine split process). The first rich amine stream enters the Lean-Rich Heat Exchanger and is heated by the hot lean amine coming from the bottom of the desorber. The heated rich amine is then sent to the top of the desorber. The second rich amine stream is sent directly to the top of the desorber above the first rich amine stream.
6. The rich amine solvent is regenerated in the desorber column which is heated by a reboiler situated at the base of the desorber column. The reboiler is heated by the low-pressure steam.
7. Periodically, some of the circulating amines are sent to the filtration unit to remove any heat-stable salts and trace impurities. Fresh MEA from the amine storage tanks is added to replenish the lost solvent.
8. The overhead vapour from the desorber column passes through a demister and is sent to the condenser which is cooled by the cooling water. The wet CO₂ is separated in a reflux drum, while the separated liquid is recycled back to the column as reflux or water storage tank for water balance.

A comprehensive techno-economic analysis model was used to determine the required capital investment and economic performance using the Aspen Capital Cost Estimator (ACCE) V11.0, based on the equipment parameters, materials and energy balance from process simulation. ACCE uses the equipment models contained in the Icarus Evaluation Engine to generate preliminary equipment designs and simulate vendor-

costing procedures to develop detailed cost estimates. The association for the Advancement of Cost Engineers (AACE) international Recommended Practice (Class IV) and the DOE economic analysis were used here to guide estimates of capital costs and calculate the total capital investment within an expected accuracy range of $\pm 40\%$.

The basis, key assumptions and design decisions are as follows:

- The design basis for cooling is an air-water cooling system with 35°C cooling water supply temperature and 45°C return temperature in a tropical climate in Darwin.
- Approach temperature for the lean-rich heat exchangers and reboilers has been set at a minimum of 15°C (Feron, Cousins, Jiang, et al. 2019). This in turn determines the saturated steam temperature (and pressure) used in the reboilers.
- Carbon steel was the material of construction in all cases except where specifically required for corrosion control, e.g. 304 stainless steel in the heat exchanger rich amine side, column cladding and packing material of absorption/desorption towers, etc.
- Column packing is Mellapak™ M250X structured packing (Feron, Cousins, Jiang, et al. 2019), manufactured by Sulzer. It is constructed of stainless steel and is well established in packed column service. Alternative packings would likely perform at a similar level.

Figure 20. Conventional aqueous amine solvent plant process flowsheet integrated with process optimisation using the intercooling and rich split processes.

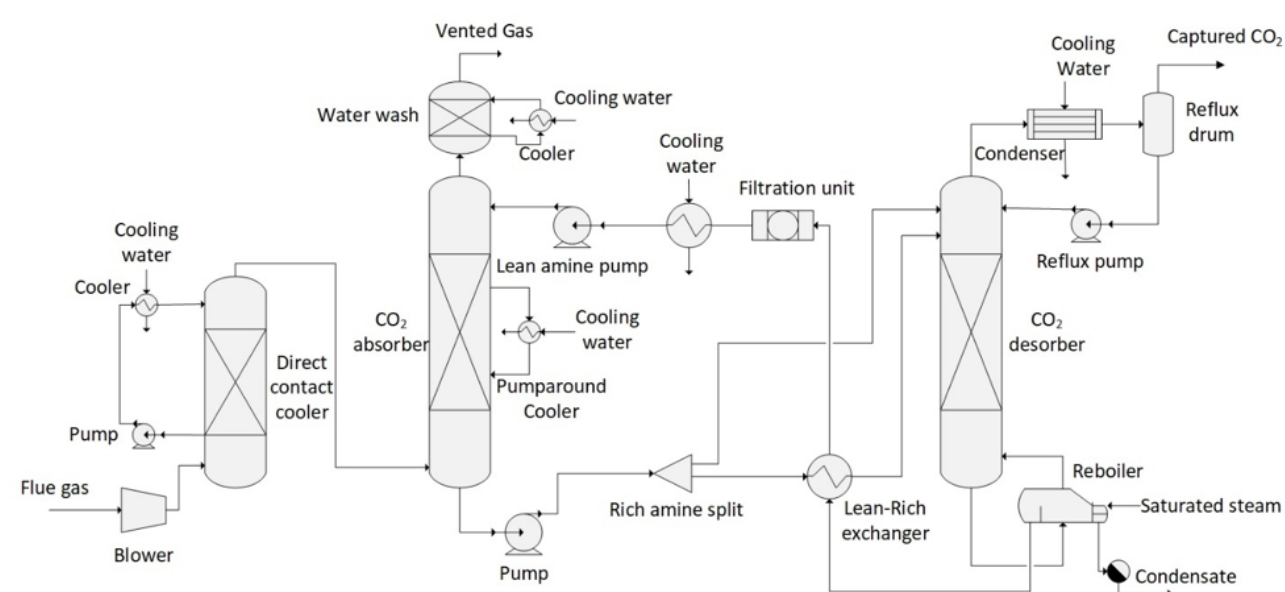


Table 29. Main assumptions for techno-economic analysis of CO₂ capture plants

PARAMETER	VALUE
Location	Darwin, Northern Territory Australia
Present Value	2018 USD cost basis
Exchange rate	0.70 USD/AUD
NT AU: Texas US Equipment cost index	1.21
NT AU: Texas US Material cost index	1.21
Escalation rate from base year to the 2020 study year	2.2% ⁹ per year
Cost Recovery Factor (CRF) – this is equivalent to a WACC of 6%	7.26 %
Construction years	3
Operating life	30 years
Capacity factor	85%
CO ₂ capture rate	90%
Natural gas price	AUD 4 / GJ

Due to the dilute CO₂ concentration in NGCC flue gas that impacts the physical size of the capture towers, 2 capture units are required to capture 1.25 million tonnes CO₂ per LNG train. Table 30 provides the flue gas conditions entering one post-combustion capture plant

and the gas streams exiting the capture plant. Table 31 shows the column properties and key performance results used in the capture simulations, with a calculated reboiler duty of 4.94 GJ/tonne CO₂ at 90% capture rate similar to published data.

Table 30. Inlet and outlet stream conditions in the process simulation of the single train post-combustion CO₂ capture in NGCC power plant

		INLET STREAM	OUTLET STREAM	OUTLET STREAM
STREAM NAME	UNIT	FLUE GAS FROM STEAM CRACKER	CLEANED FLUE GAS TO STACK	CAPTURED CO ₂
Temperature	°C	85.2	46.0	50
Pressure	bar	1.02	1.01	2
Total Mole Flow	kmol/sec	10.72	10.46	0.43
Total Mass Flow	kg/sec	304.73	289.53	18.34
Mole Fraction				
MEA		0.00%	0.6 ppm	0.004 ppm
H ₂ O		8.5%	10.11%	6.26%
CO ₂		4.2%	0.43%	93.63%
N ₂		74.4%	76.24%	0.08%
O ₂		12.0%	12.30%	0.03%
Ar		0.90%	0.91%	20 ppm
NO		25 ppm	26 ppm	0.08 ppm

⁹ Using the average escalation value of the 2011-2018 per cent change over time within The Handy-Whitman Index of Public Utility Construction Costs, 1912 to January 1, 2018 – Cost Trends of Gas Utility Construction across the six regions. (Whitman, Requardt and Associates 2018)



Table 31. Process performance results of CO₂ capture plant in the NGCC post-combustion capture plant

PARAMETER	UNIT	VALUE
Liquid/gas ratio	kg amine/kg flue gas	1.21
Reboiler Duty	GJ/t CO ₂	4.94
Power penalty due to steam extraction for reboiler*	MW	24.8
Cooling requirement	GJ/t CO ₂	5.41
Auxillary power (electricity use, excluding cooling water, steam extraction)	MW	3.89
Amine content in the exhaust	Part per million (ppm)	0.6 ppm

*Steam extraction from NGCC power plant is converted to the equivalent electric power loss based on the method from (Ystad, Bolland & Hillestad 2012).

5.2 Capital Cost

Table 32 shows the capital investment and detailed individual equipment costs of one post-combustion CO₂ capture unit at 90% capture (0.5625 million tonnes per annum) for NGCC, including all the major equipment for flue gas treating and cooling process, CO₂ absorption and desorption process. The total fixed capital investment of the single post-combustion plant train is AUD 299 million.

Table 32. Process performance results of one CO₂ capture unit for the post-combustion capture in NGCC

NAME	PURCHASED EQUIPMENT COST AUD 1,000	DIRECT COST AUD 1,000*	SPECIFICATIONS
FLUE GAS TREATING AND COOLING PROCESS			
Flue gas blower	5,231	6,511	346,733 L/sec x 3 trains
Direct contact cooler (DCC) tower (packed)	7,628	10,611	Φ10.7 x 10 m
DCC cooler	3,049	4,785	11,902 m ²
Pump	91	459	682 L/sec
CO₂ CAPTURE PROCESS			
CO ₂ absorption tower with water wash (packed)	17,076	23,676	Φ10.0 x 20 m (Φ8.2 x 4 m)
Intercooling cooler and pump	2,540	3,439	3,862 m ²
Water wash cooler	794	1,219	2,991 m ²
Water wash process tank	126	456	49 m ³
Water pump	22	139	111 L/sec
Solvent pump	80	620	405 L/sec
Lean rich heat exchanger	3,091	4,664	4,849 m ²
CO ₂ desorption tower (packed)	2,041	3,082	Φ4.5 x 10 m
Reboiler	2,840	3,689	2,934 m ²
Reflux pump	15	120	9 L/sec
Condenser	444	803	642 m ²
Condenser knockout drum	48	214	3.2 m ³
Solvent makeup tank	406	1,136	147 m ³
Lean solvent cooler	1,179	1,776	4,532 m ²
AUXILIARY UNITS**			
Solvent filtration system	59	286	
Cooling system	3,189	4,494	
Other equipment***	2,331	7,026	
Initial startup cost for chemicals		504	
Others		22,751	
G&A overheads		2,862	
Contract fees		3,261	
INVESTMENT COST CALCULATION			
Total direct cost (TDC)		109,315	
Total indirect cost		21,863	0.2 TDC
Bare erected cost (BEC)		131,178	TPC+TIC
Engineering and contractor		35,418	0.27 BEC
Engineering procurement and construction (EPC)		166,596	1.27 BEC
Process contingency		32,795	0.25 BEC
Project contingency		39,878	0.2 EPC+0.05 BEC
Total plant cost (TPC)		239,269	1.2 EPC +0.3 BEC
Owner's cost		35,890	0.15 TPC
Total capital investment (TIC) in AUD2018		275,159	1.15 TPC
Total capital investment (TIC) in AUD2020		299,387	

* Direct cost includes purchased equipment, equipment setting, piping, civil, structural steel, instrumentation, electrical, insulation and paint

** Solvent reclaiming cost are included in variable O&M cost based on techno-economic results of thermal reclaiming technology from

*** other equipment include minor equipment such as solvent storage tank, water storage tank and pumps etc

5.3 Operation & Maintenance (O&M) Cost

Table 33 shows the detailed O&M cost of the single post-combustion CO₂ capture unit for NGCC. The total variable O&M expense is around AUD 13.5 million. The fixed O&M cost is around AUD 8.6 million per CO₂ capture unit.

Table 33. Detailed capital and O&M cost of one post-combustion CO₂ capture unit for NGCC in Darwin Port

NGCC POST COMBUSTION CAPTURE PLANT UNIT		
CO ₂ Capture Capacity	Tonnes per annum	562,500
CAPITAL COST		
Total Capital Investment	AUD	180,984,707
VARIABLE O&M		
Water Cost	AUD per year	194,738
Capture plant Chemicals Cost	AUD per year	3,857,948
Special Waste Disposal & Sewage Cost	AUD per year	590,609
Auxiliary amine reclaiming cost	AUD per year	583,393
Fuel Cost	AUD per year	8,318,950.73
Total Variable O&M	AUD per year	13,545,639
FIXED O&M		
Operators	Number	5
Operator Wage	AUD per annum	425,000
Administrative/support labour cost	AUD per year	947,042
Maintenance Material and Labour	AUD per year	5,263,920
Insurance and Tax	AUD per year	1,977,430
Fixed O&M	AUD per year	8,613,392
Levelised Cost of CO₂ capture (exclude dehydration & compression)	AUD per tonne CO₂ captured	78.1

A summary of total costs for CO₂ capture at one NGCC train (1.25 million tonne CO₂ per annum) for the LNG industry in Darwin is provided in Table 34.

Table 34. Economic performance results of CO₂ capture plant in one NGCC train

ECONOMIC PARAMETER	UNIT	VALUE
Number of capture units	unit	2
Total capital requirement	million AUD	598.77
Fixed O&M	million AUD per year	17.23
Energy cost	million AUD per year	16.64
Other variable O&M	million AUD per year	10.45
CO ₂ captured	Tonnes per annum	1,125,000
Levelised cost of CO ₂ capture (exclude dehydration & compression)	AUD per tonne CO ₂	78.1

5.4 Sensitivity analysis

The cost of capital also has a significant impact on the cost of CO₂ capture. This study assumes a cost of capital of 6% (capital recovery factor of 7.26%). Figure 21 shows the impact of the cost of capital and illustrates the opportunity to bring costs down through the provision of low-cost finance. At an interest rate of 2% (CRF of 4.5%) the cost of CO₂ capture (excluding dedhydration & compression) would reduce from \$78/tonne CO₂ to \$63/tonne CO₂.

The levelised cost of CO₂ capture is also dependent on the natural gas price for NGCC. In this case, the price of natural gas assumed is the opportunity cost of using the gas to provide the energy required to run the capture processes instead of selling it. The simplest

approach is to simply assume that the price at which the gas would have been sold is the opportunity cost. However, this is likely to overstate the cost as some costs that would be incurred in the process of selling the gas (eg liquefaction) are avoided for gas that is instead used on-site. According to Core Energy & Resources Pty Limited (2019), the current wholesale delivered price to generators in Northern Territory is AUD6.8/GJ. This is very likely to be significantly higher than the price of gas sold to export customers from the DLNG and Ichthys facilities, however we have assumed this price for the purposes of this study. Figure 22 shows the impact of price on the levelized cost of capture across a broad range of LNG prices. Lower actual gas prices could reduce the cost of capture towards \$70/tonne CO₂. Higher prices could raise the cost of capture towards \$100/tonne CO₂.

Figure 21. The sensitivity of the levelised cost of CO₂ capture (excluding dehydration & compression) to the cost of capital

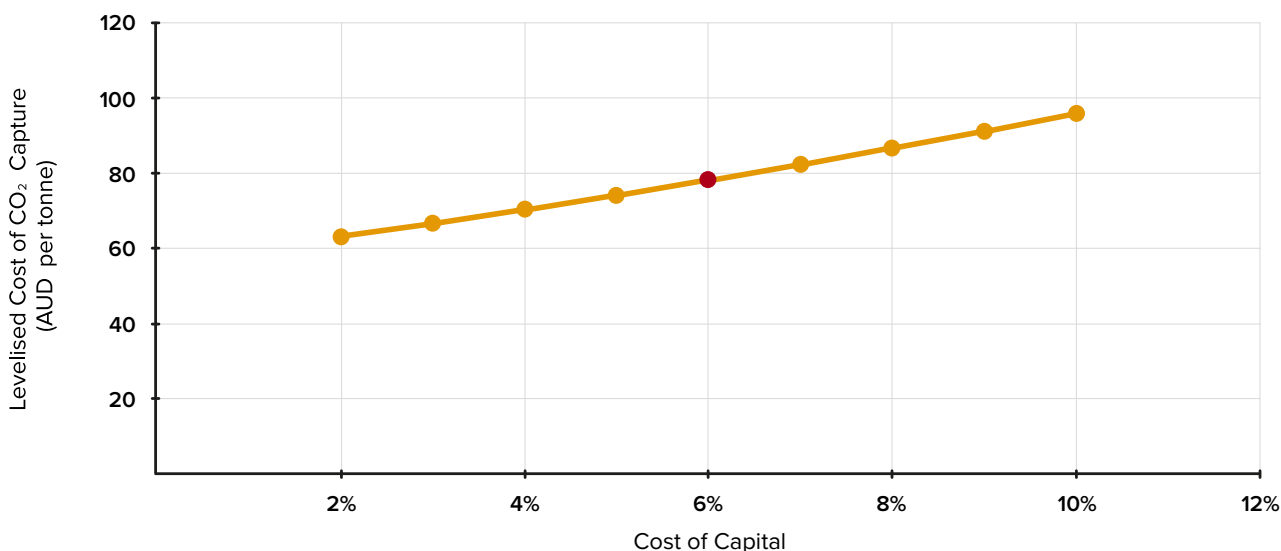
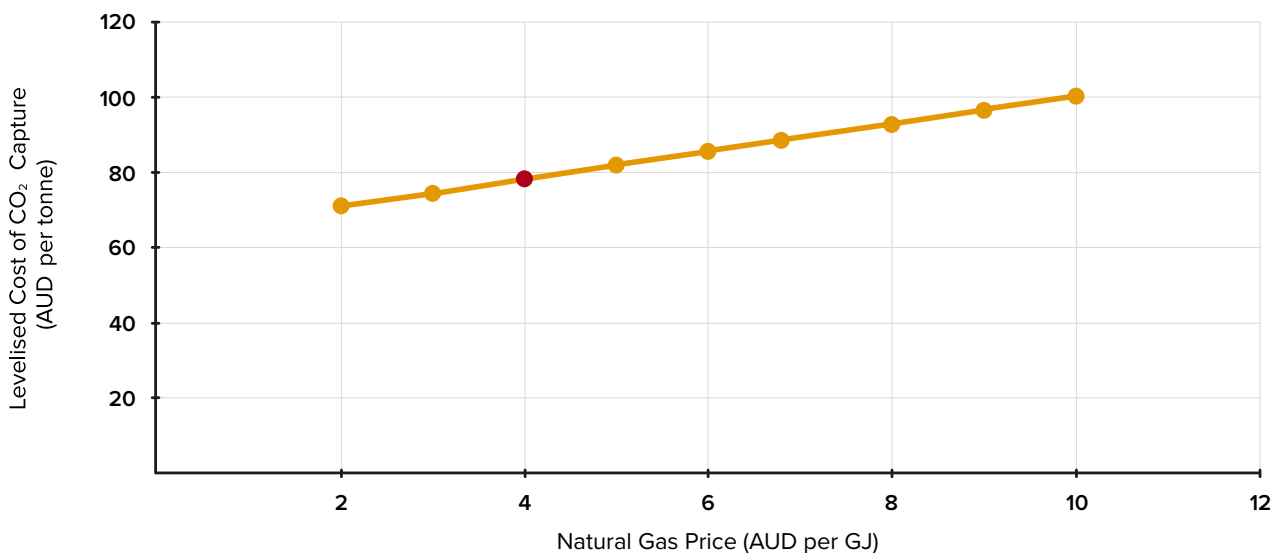


Figure 22. The sensitivity of the levelised cost of CO₂ capture (excluding dehydration & compression) to wholesale delivered natural gas price.



5.5 Technology Readiness Levels

The technology readiness levels in Table 35 below are adapted from those published by the US Department of Energy (Zimmermann & Schomäcker 2017, p.853). Other similar TRL tables have been published by NASA, the United States Air Force and the European Union.

Table 35. Technology Readiness Level descriptions

TRL	US DOE DEFINITION
1	basic principles observed and reported
2	technology concept and/or application formulated
3	analytical and experimental critical function and/or characteristic proof of concept
4	component and/or system validation in laboratory environment
5	laboratory scale, similar system validation in relevant environment
6	engineering/pilot-scale, similar (prototypical) system validation in relevant environment
7	full-scale, similar (prototypical) system demonstrated in a relevant environment
8	actual system completed and qualified through test and demonstration
9	actual system operated over the full range of expected conditions



6.0 CARBON CAPTURE IN GAS MANUFACTURING INDUSTRIES

6.1 Background and Methodology

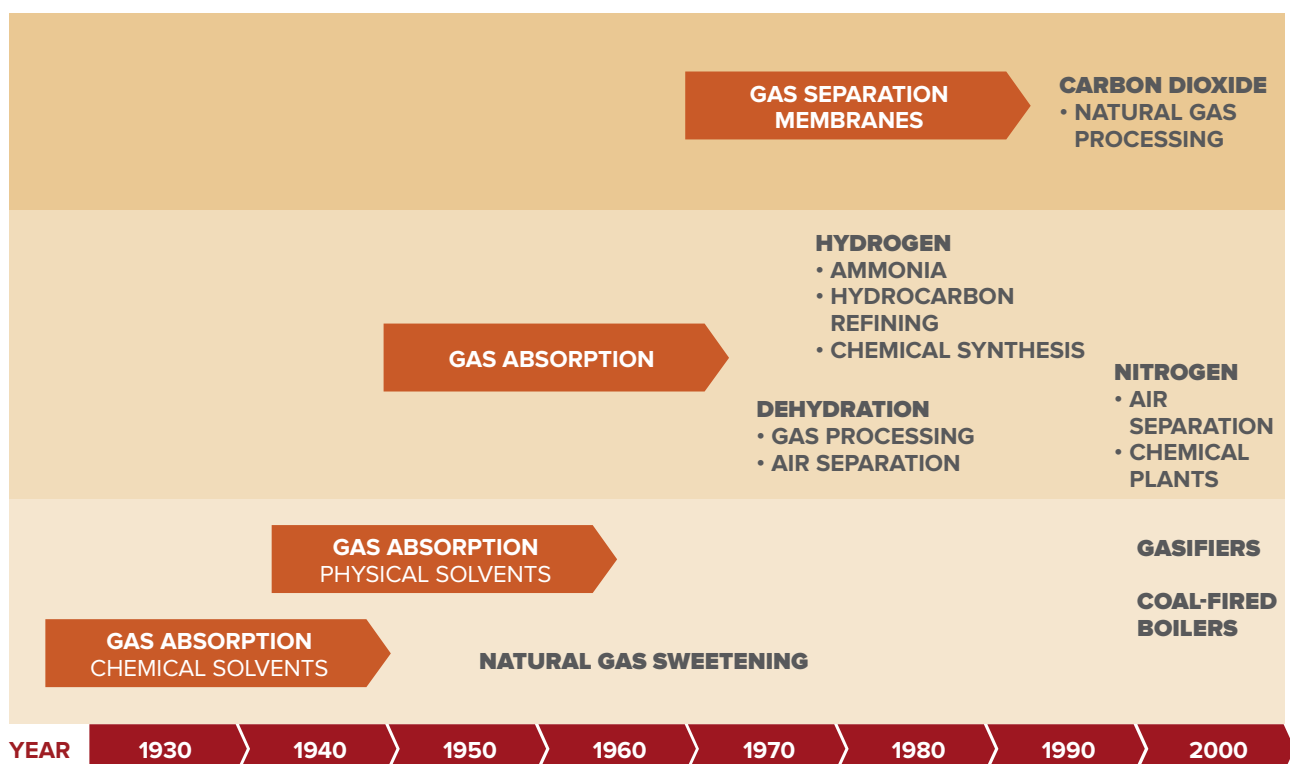
In gas manufacturing industries, CO₂ is directly emitted in the form of the process flue gas and/or combustion flue gas. Combustion emissions arise from burning carbon-based fuels, while process emissions represent all other CO₂ released as part of the chemical reaction. For example, in an ammonia production plant, both process CO₂ emissions from the water gas shift reaction and combustion emission are produced. In a titanium/

vanadium concentrate plant, both CO₂ emissions from the process gas from ore reduction and combustion flue gas are produced.

The deployment of carbon capture in industrial processes dates back to the 1930s, when CO₂ absorption using chemical solvents, such as amines in aqueous solutions, were used in the natural gas industry to separate CO₂ from methane (Figure 23) (Global CCS Institute 2016a).

Starting in the 1940s, processes using physical solvents emerged for CO₂ capture from process gas streams that contained higher CO₂ concentrations (25 to 70 per cent) and under higher-pressure conditions (approximately

Figure 23. Development of carbon captures technologies (Global CCS Institute 2016a).



100 bar). Two commercial examples of physical solvents are Selexol™ and Rectisol®. These solvents are used at gasification plants using coal, petroleum coke, and biomass feedstocks.

In the 1950s and 1960s, adsorption processes using solid sorbents, such as pressure swing adsorption (PSA), enabled gas separation in hydrogen production (refineries), nitrogen production, and dehydration applications (Siqueira et al. 2017). In the 1970s and 1980s, membranes were developed to capture CO₂ for use in natural gas processing.

Table 36 summarises the composition of typical flue gas streams from proposed gas manufacturing industries at the Darwin Port. The relatively pure CO₂ stream from water gas shift process in ammonia production plant can be sent to the dehydration unit without any further processing. The process conditions of other gas streams were used as the basis for the CO₂ capture process simulation using monoethanolamine (MEA) solvent-

based CO₂ capture. The 30wt% MEA solvent technology as discussed in Section 5 is widely considered as the reference technology for capturing CO₂ from flue gases with low CO₂ partial pressure. The equipment list for the amine CO₂ capture plant described in the NGCC Chapter also applies to all gas manufacturing industries, except there is no need for flue gas blow in ethylene industry where the flue gas is at a higher pressure.

Table 37 lists the parameters of the main assumptions for the techno-economic analysis of CO₂ capture. Detailed economic parameters are presented in the Appendix.

A higher 95% carbon capture rate rather than 90% is targeted for gas manufacturing industries to reduce the average emissions intensity. However, the determination of the detailed design capture rate would need to be explored fully in the detailed engineering study, i.e. FEED.

Table 36. Summary of process characteristics of flue gas streams for the gas manufacturing industries in Northern Territory Darwin Port

INDUSTRY	CO ₂ CONCENTRATE (VOL%)	FLUE GAS PRESSURE (BAR)	CO ₂ PROCESS UNIT	TEMPERATURE (°C)	FLUE GAS COMPONENT	REFERENCE
Ammonia Production	88.4%	1.5	Water gas shift for H ₂ purification	50	H ₂ O, CO ₂ , N ₂ , O ₂ , CO, H ₂ , CH ₄ , Ar	(Aspen Technology 2015; Mok 1982; IEAGHG 2017a)
	7.8%	1.013	Process heater	148	H ₂ O, CO ₂ , N ₂ , O ₂ , Ar	
Ethylene production	6.3%	1.42	Steam cracking	150	H ₂ O, CO ₂ , N ₂ , O ₂ , Ar	(The Lindgren Group 2013)
Methanol production	10.3%	1.013	Process heater	155	H ₂ O, CO ₂ , N ₂ , O ₂ , Ar	(IEAGHG 2017b)
Refinery Condensate	8.5%	1.013	Process heaters	135	H ₂ O, CO ₂ , N ₂ , O ₂ , Ar	
Titanium Vanadium Concentrate	20.0%	1.1	Reduction process	50	CO ₂ , N ₂	(TNG limited 2019)
	7.8%	1.013	Process heaters	148	H ₂ O, CO ₂ , N ₂ , O ₂ , Ar	

Table 37. Main assumptions for techno-economic analysis of CO₂ capture plants

PARAMETER	VALUE
Location	Darwin, Australia
Present Value	2018 USD cost basis
Exchange rate	0.70 USD/AUD
Escalation rate from base year to the 2020 study year	2.2% ¹⁰
Cost Recovery Factor (CRF) – this is equivalent to a WACC of 6%	7.26 %
Construction years	3
Operating life	30 years
Capacity factor	90%
CO ₂ capture rate	95%

6.2 Ammonia Plant

As illustrated in Figure 24, ammonia is commonly synthesised using hydrogen generated via steam methane reforming (Bains, Psarras & Wilcox 2017). The natural gas feedstock and steam enter the primary reformer, which produces CO and H₂ at a temperature of 730 °C. The produced syngas then enters the secondary reformer. Compressed air is injected into the secondary reformer reactor to obtain an optimised ratio of hydrogen: nitrogen atoms for ammonia production. The product stream enters the water gas shift reactor. The produced gas exiting the shift reaction contains around 60 per cent of the total CO₂ produced in a typical ammonia plant, while the remaining 40 per cent is mainly produced from the combustion of the additional fuel gas (normally natural gas) to heat up the steam reformer (700 – 1,000 °C) (Global CCS Institute 2016b, 2016a).

In an integrated ammonia-urea fertiliser plant, the CO₂ generated after the water gas shift reaction is captured in an integrated process after the water gas shift process. Part of the captured CO₂ is used to react with the synthesised ammonia for urea production while the rest is vented. The integrated CO₂ capture plants for urea-yield-boosting have been commercially used since the late 1990s.

The proposed ammonia production capacity in Darwin

port is up to 1 million tonnes per annum (Mtpa). The ammonia is subsequently used to produce approximately 1.4 Mtpa urea and 0.4 Mtpa ammonium phosphates.

The typical process conditions for the reformer heating flue gas stream and captured CO₂ stream from the process gas are presented in Table 38. The downstream urea production consumes ~0.74 kg CO₂ per kg urea (Aspen Technology 2015; Mok 1982). This means 64 wt% of the captured CO₂ from process gas is consumed in urea production, leaving 15.9 kg/sec captured CO₂ sent directly to the CO₂ dehydration unit before entering the pipeline system.

The CO₂ capture plant treating the flue gas from reformer heating unit was modelled using Aspen Plus targeting 95% capture. The captured CO₂ stream condition is shown in Table 38. The CO₂ capture plant performance results from Aspen Plus simulation are shown in Table 39.

¹⁰ using the average escalation value of the 2011-2018 per cent change over time within The Handy-Whitman Index of Public Utility Construction Costs, 1912 to January 1, 2018 – Cost Trends of Gas Utility Construction across the six regions. (Whitman, Requardt and Associates 2018)

Figure 24. Simplified ammonia/urea production flow diagram(Bains, Psarras & Wilcox 2017)

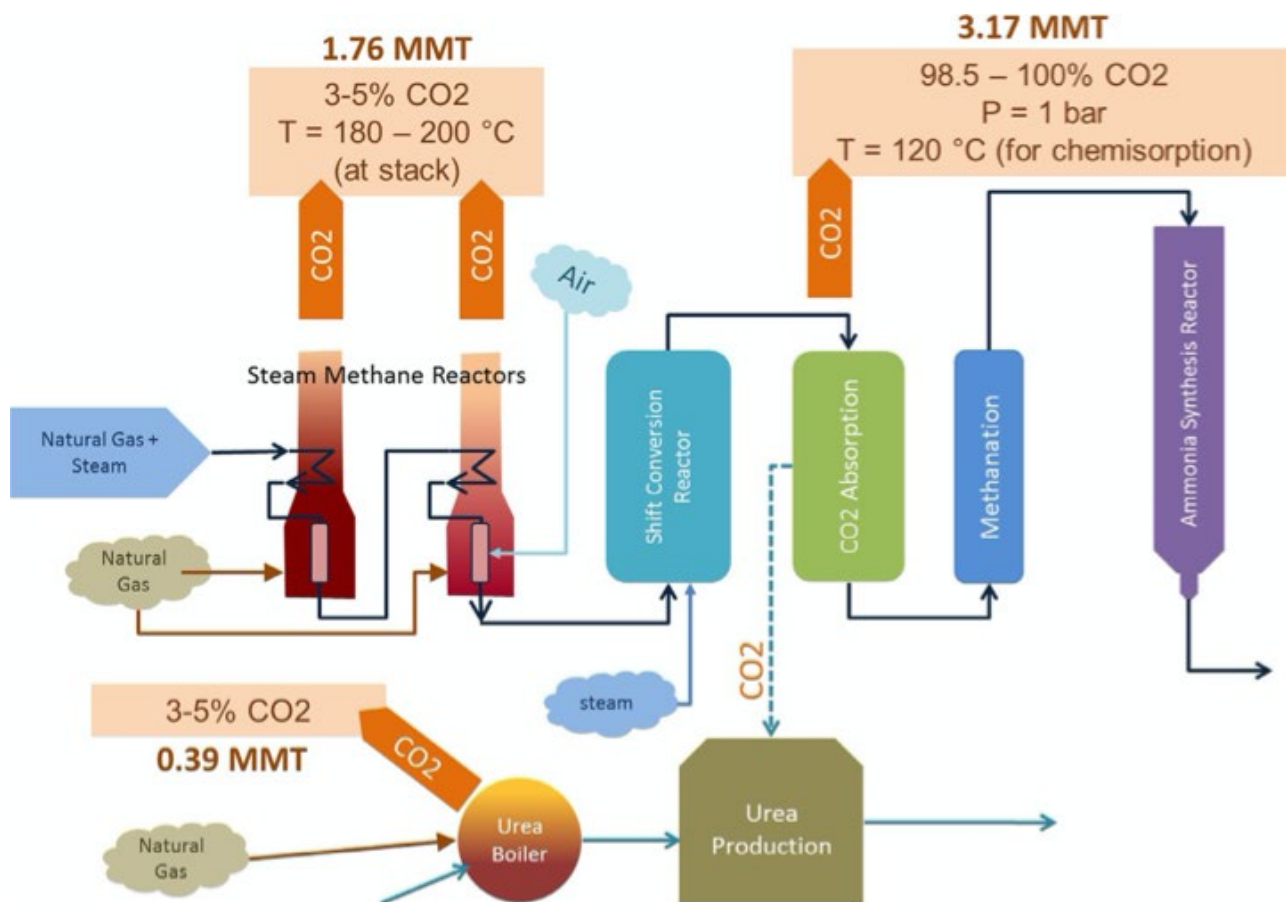


Table 38. Inlet and outlet stream conditions in the CO₂ capture facility in the ammonia plant – reformer heating unit

STREAM NAME	UNIT	INLET STREAM		OUTLET STREAM	
		REFORMER HEATER FLUE GAS	CAPTURED CO ₂ FROM PROCESS GAS (TOTAL)	CAPTURED CO ₂ FROM REFORMER HEATER FLUE GAS	CAPTURED CO ₂ FROM PROCESS GAS (TO DEHYDRATION)
Temperature	C	148	50	50	50
Pressure	bar	1.03	1.5	2	1.5
Total Mole Flow	kmol/sec	4.55	1.08	0.36	0.39
Total Mass Flow	kg/sec	125.83	44.90	15.23	16.14
Mole Fraction					
MEA		0.00%	0.00%	0.004 ppm	0.00%
H ₂ O		18.27%	3.78%	6.26%	3.78%
CO ₂		7.81%	88.43%	93.65%	88.43%
N ₂		71.02%	6.59%	0.09%	6.59%
O ₂		1.80%	0.00%	0.00%	0.00%
CO		0.00%	0.12%	0.00%	0.12%
H ₂		0.00%	0.00%	0.00%	0.00%
CH ₄		0.00%	0.90%	0.00%	0.90%
Ar		1.10%	0.17%	0.00%	0.17%

Table 39. Process performance results of CO₂ capture plant in the ammonia plant – reformer heating unit

PARAMETER	UNIT	VALUE
Pre-treatment direct contact cooler (DCC) diameter	metre	7.5
DCC tower packed height	metre	5
Absorber diameter	metre	7.1
Absorber packed height	metre	15
Absorber water wash diameter	metre	5.0
Absorber water wash packed height	metre	3
Desorber diameter	metre	4.4
Desorber packed height	metre	10
Liquid/gas ratio	kg amine/kg flue gas	2.95
Reboiler duty (steam @150 °C)	GJ/tonne CO ₂	5.42
Amine content in exhaust	Part per million (ppm)	0.62 ppm

Table 40. Economic performance results of CO₂ capture plant in the ammonia plant

ECONOMIC PARAMETER	UNIT	VALUE
Total capital requirement	million AUD	172.23
Fixed O&M	million AUD per year	6.17
Energy cost	million AUD per year	15.94
Other variable O&M	million AUD per year	2.68
CO ₂ captured	Tonnes per annum	469,000
Levelised cost of CO ₂ capture (exclude dehydration & compression)	AUD per tonne CO ₂	83.9

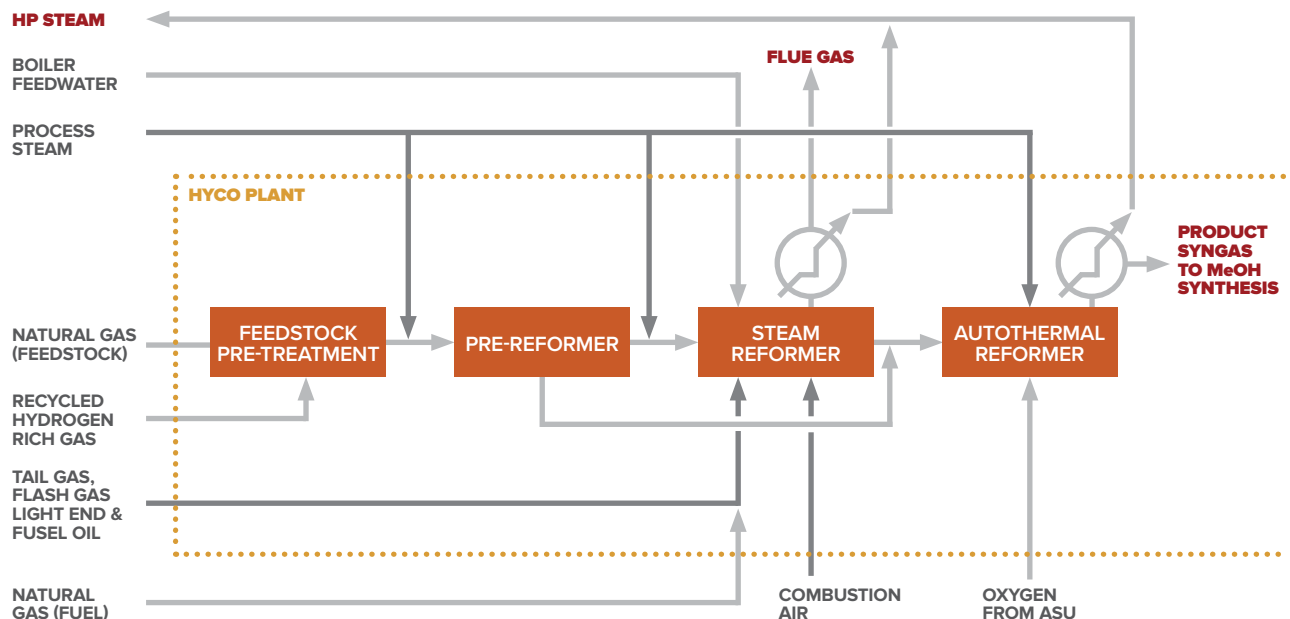
6.3 Methanol Plant

According to IEAGHG's 2017 study (IEAGHG 2017a), most methanol production plants use the syngas from SMR in tandem with oxygen blown autothermal reforming (ATR). In Figure 25, the natural gas feedstock mixes with a slipstream of the hydrogen purge gas from the downstream hydrogen recovery unit and enters the pretreatment unit. The treated feedstock is then mixed with steam and enters the pre-reformer which mainly converts any heavy hydrocarbons in the feed to CH₄,

CO₂, CO or H₂. The outlet gas from the pre-reformer is divided; one stream enters the primary SMR unit, and the other stream is mixed with the syngas from the SMR before being fed into the ATR at around 670 °C.

The SMR is the primary steam reformer providing most of the hydrogen in the syngas. The main fuel for the SMR furnace heaters consists of the tail gas from hydrogen recovery unit, recycled fuel gas from methanol synthesis and natural gas. The ATR optimises the content of CO₂, CO and H₂ to ensure the minimum requirement of methane input. The bulk of the CO₂ in the process gas would end up in the methanol product.

Figure 25. Simplified methanol production flow diagram (IEAGHG 2017a)



The proposed methanol production capacity in Darwin port is approximately 2 Mtpa. The methanol would subsequently be used to produce downstream materials such as formaldehyde and acetic acid. The typical process conditions of the flue gas stream from SMR reformer heaters are presented in Table 41. The CO₂ capture plant performance results from Aspen Plus simulation are shown in Table 42.

Table 41. Inlet and outlet stream conditions in CO₂ capture facility in methanol production

STREAM NAME	UNIT	INLET STREAM	OUTLET STREAM
		FLUE GAS FROM REFORMER HEATING	CAPTURED CO ₂
Temperature	°C	155	50
Pressure	bar	1.03	2
Total Mole Flow	kmol/sec	4.96	0.52
Total Mass Flow	kg/sec	138.0	21.9
Mole Fraction			
MEA		0.00%	0.004 ppm
H ₂ O		20.04%	6.26%
CO ₂		10.26%	93.66%
N ₂		67.27%	0.08%
O ₂		1.34%	0.00%
CO		0.00%	0.00%
H ₂		0.00%	0.00%
CH ₄		0.00%	0.00%
Ar		1.09%	0.00%

Table 42. Process performance results of CO₂ capture plant in the methanol plant

PARAMETER	UNIT	VALUE
Pre-treatment direct contact cooler (DCC) diameter	metre	7.8
DCC tower packed height	metre	5
Absorber diameter	metre	7.5
Absorber packed height	metre	15
Absorber water wash diameter	metre	5.0
Absorber water wash packed height	metre	3
Desorber diameter	metre	4.9
Desorber packed height	metre	10
Liquid/gas ratio	kg amine/kg flue gas	3.44
Reboiler duty (steam @150 °C)	GJ/tonne CO ₂	4.90
Amine content in exhaust	Part per million (ppm)	0.16 ppm

A summary of the total costs for carbon capture at the methanol plant (2 Mtpa methanol capacity) is provided in Table 42.

Table 43. Economic performance results of CO₂ capture plant in the methanol plant

ECONOMIC PARAMETER	UNIT	VALUE
Total capital requirement	million AUD	216.36
Fixed O&M	million AUD per year	7.31
Fuel cost	million AUD per year	19.33
Other variable O&M	million AUD per year	6.71
CO ₂ captured	Tonnes per annum	671,000
Levelised cost of CO ₂ capture (exclude dehydration & compression)	AUD per tonne CO ₂	73.2

6.4 Ethylene/propylene Plant

Shown in Figure 26, in natural gas-based olefins (ethylene/propylene) production process, the hydrocarbon feed, e.g. ethane and propane, enters the steam cracker for pyrolysis reaction to produce double-bonded and lighter single-bonded hydrocarbons (Bains, Psarras & Wilcox 2017). The steam crackers basically are furnaces with feedstock running through heated tubes in the combustion chamber. After the steam cracking, the cracked gaseous products are immediately quenched at 400 °C. Further water injection into the product stream cools it further down. The product stream is compressed and fractionated to yield pure streams of ethylene, propylene, butadiene etc. The liquid stream flows out from the bottom of the column and goes through further processing and distillation.

The combustion of natural gas and the recycled off-gas is the major CO₂ emission source in an ethylene/propylene plant. It provides heat for the steam crackers and other processes. The typical process conditions of the flue gas stream from the process heaters of the ethylene/propylene plant are presented in Table 44.

The proposed ethylene/propylene production capacity in Darwin port is approximately 1 Mtpa. The ethylene and propylene have the potential to produce downstream plastic materials such as high-density polyethylene (HDPE), low-density polyethylene (LDPE), linear low-density polyethylene (LLDPE) and polypropylene. The CO₂ capture plant performance results from Aspen Plus simulation are shown in Table 45.

Figure 26. Olefins (ethylene/propylene) process

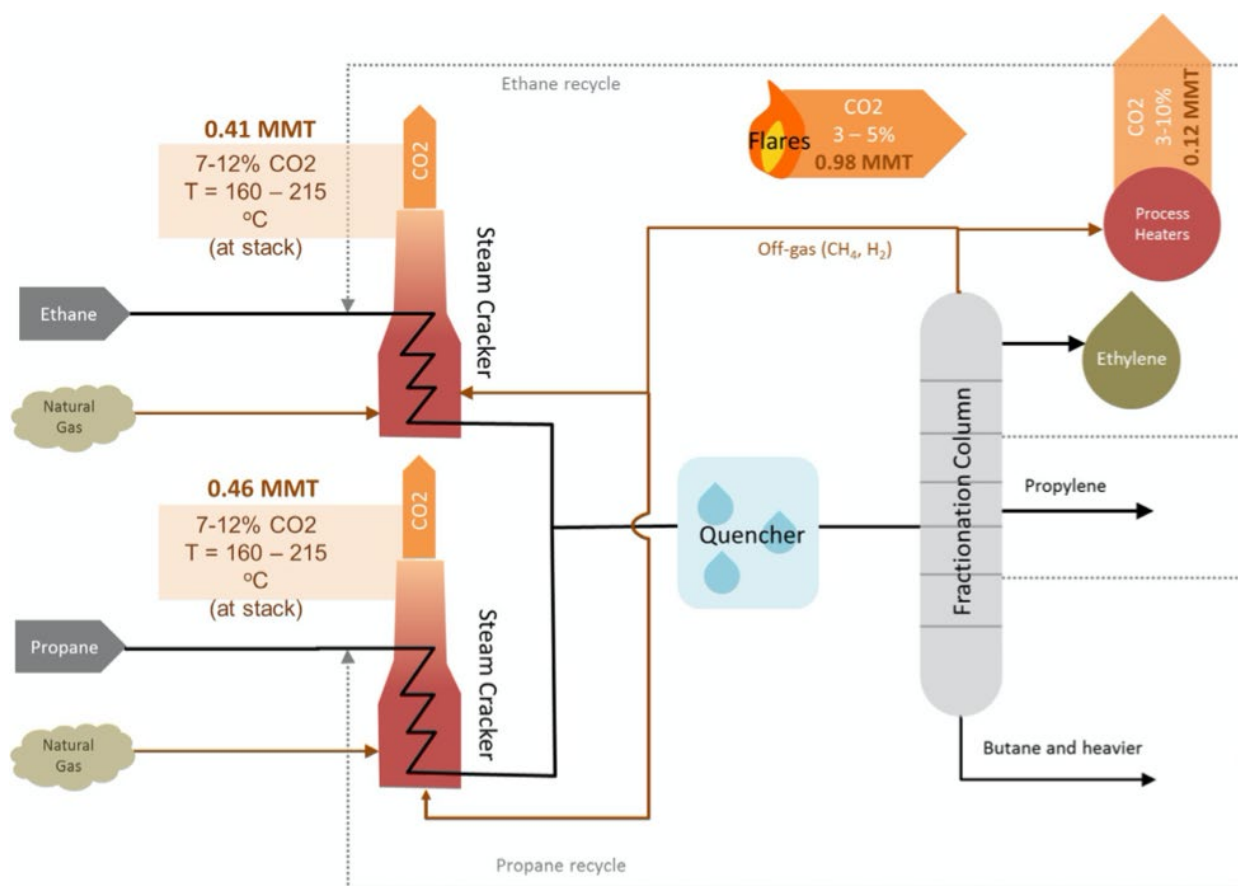


Table 44. Inlet and outlet stream conditions in CO₂ capture facility in ethylene/propylene production. (Bains, Psarras & Wilcox 2017)

STREAM NAME	UNIT	INLET STREAM	OUTLET STREAM
		FLUE GAS FROM STEAM CRACKER	CAPTURED CO ₂
Temperature	°C	150	50
Pressure	bar	1.42	2
Total Mole Flow	kmol/sec	11.0	0.71
Total Mass Flow	kg/sec	315.7	29.9
Mole Fraction			
MEA		0.00%	0.004 ppm
H ₂ O		7.48%	6.26%
CO ₂		6.32%	93.60%
N ₂		76.07%	0.11%
O ₂		10.13%	0.02%
CO		0.00%	0.00%
H ₂		0.00%	0.00%
CH ₄		0.00%	0.00%
Ar		0.00%	0.00%

Table 45. Process performance results of CO₂ capture plant in the ethylene/propylene plant

PARAMETER	UNIT	VALUE
Pre-treatment direct contact cooler (DCC) diameter	metre	10.6
DCC tower packed height	metre	10
Absorber diameter	metre	10.4
Absorber packed height	metre	15
Absorber water wash diameter	metre	7.6
Absorber water wash packed height	metre	3
Desorber diameter	metre	5.9
Desorber packed height	metre	10
Liquid/gas ratio	kg amine/kg flue gas	2.14
Reboiler duty (steam @150 °C)	GJ/tonne CO ₂	5.27
Amine content in exhaust	Part per million (ppm)	0.29 ppm

A summary of the total costs for carbon capture at the ethylene/propylene plant (1 Mtpa ethylene/propylene production capacity) is provided in Table 46.

Table 46. Economic performance results of CO₂ capture plant in the ethylene/propylene plant

ECONOMIC PARAMETER	UNIT	VALUE
Total capital requirement	million AUD	263.42
Fixed O&M	million AUD per year	9.67
Fuel cost	million AUD per year	26.49
Other variable O&M	million AUD per year	8.72
CO ₂ captured	Tonnes per annum	917,000
Levelised cost of CO ₂ capture (exclude dehydration & compression)	AUD per tonne CO ₂	69.8

6.5 Condensate Refining Plant

Condensate is a mixture of light liquid hydrocarbons and H₂S. It is typically separated out of a natural gas stream. Condensate refining plant mainly involves three steps: water washing, condensate stabilisation and condensate treating (Mokhatab, Poe & Mak 2019). In the water washing section, the condensate is treated to remove any salts and additives. Then the condensate goes to the condensate stabilisation unit, where the amount of intermediate (C3 to C5) and heavy (C6+) components in the condensate is maximised. After the stabilisation

step, the produced condensate stream is treated to remove any heavy mercaptans and other undesirable contaminants to produce a marketable liquid product to be sold as “natural gasoline”. The main CO₂ emission source is from fuel gas combustion, which provides heat for steam generations and other preheating units.

The proposed refined fuels production capacity of the condensate refining plant in Darwin port is approximately 100,000 barrels per day (BPD). The typical process conditions of flue gas stream from the process heaters of the condensate refining plant are presented in Table 47. The CO₂ capture plant performance results from Aspen Plus simulation are shown in Table 48.

Table 47. Inlet and outlet stream conditions in CO₂ capture facility in condensate refining

STREAM NAME	UNIT	INLET STREAM	OUTLET STREAM
		FLUE GAS FROM REFORMER HEATING	CAPTURED CO ₂ FROM REFORMER HEATING FLUE GAS
Temperature	C	135	50
Pressure	bar	1.03	2
Total Mole Flow	kmol/sec	3.01	0.26
Total Mass Flow	kg/sec	83.6	11.0
Mole Fraction			
MEA		0.00%	0.004 ppm
H ₂ O		17.23%	6.26%
CO ₂		8.51%	93.65%
N ₂		71.78%	0.08%
O ₂		2.48%	0.01%
CO		0.00%	0.00%
H ₂		0.00%	0.00%
CH ₄		0.00%	0.00%
Ar		0.00%	0.00%

Table 48. Process performance results of CO₂ capture plant in the condensate refining plant

PARAMETER	UNIT	VALUE
Pre-treatment direct contact cooler (DCC) diameter	metre	6.0
DCC tower packed height	metre	5
Absorber diameter	metre	5.9
Absorber packed height	meter	15
Absorber water wash diameter	metre	4.4
Absorber water wash packed height	metre	3
Desorber diameter	metre	3.8
Desorber packed height	metre	10
Liquid/gas ratio	kg amine/kg flue gas	3.20
Reboiler duty (steam @150 °C)	GJ/tonne CO ₂	5.48
Amine content in exhaust	Part per million (ppm)	0.12 ppm

A summary of the total costs for carbon capture at the condensate refining plant is provided in Table 49.

Table 49. Economic performance results of CO₂ capture plant in the condensate refining plant

ECONOMIC PARAMETER	UNIT	VALUE
Total capital requirement	million AUD	135.64
Fixed O&M	million AUD per year	5.22
Fuel cost	million AUD per year	11.29
Other variable O&M	million AUD per year	3.36
CO ₂ captured	Tonnes per annum	338,000
Levelised cost of CO ₂ capture (exclude dehydration & compression)	AUD per tonne CO ₂	87.9

6.6 Titanium/vanadium condensate processing Plant

The proposed processing capacity of the titanium/vanadium concentrate processing plant in Darwin port is approximately 0.75 Mtpa from ~2 Mtpa ore inputs. TNG Limited currently operates the processing plant. Based on their 2019 Environmental Impact Statement (EIS) of a similar magnetite concentrate processing facility in development (TNG limited 2019), the CO₂ emission from the process sources is 76,149 tonnes per annum (tpa) CO₂ in the titanium/vanadium concentrate processing plant at the availability of 8,000 hours per year (TNG limited's typical process facility). The process CO₂

emission accounts for residual CO₂ emitted from the use of natural gas and coke as a reductant in multiple processes. The CO₂ concentration is assumed at 20 mol% at atmospheric pressure in this report. The other emission is from natural gas combustion to provide the heat. The CO₂ combustion emission is 861,165 tpa calculated from the TNG limited's reported total GHG emission.

The detailed process conditions of the flue gas stream from the process heaters of the titanium/vanadium concentrate processing plant are presented in Table 50. The process gas and flue gas from combustion heater are mixed together for CO₂ capture. The CO₂ capture plant performance results from Aspen Plus simulation are shown in Table 51.

Table 50. Inlet and outlet stream conditions in CO₂ capture facility in titanium/vanadium concentrate processing

STREAM NAME	UNIT	INLET STREAM		OUTLET STREAM
		PROCESS GAS	FLUE GAS FROM COMBUSTION HEATER	CAPTURED CO ₂ FROM REFORMER HEATING FLUE GAS
Temperature	C	50	148	50
Pressure	bar	1.03	1.03	2
Total Mole Flow	kmol/sec	0.27	7.9	0.69
Total Mass Flow	kg/sec	8.6	219.6	29.1
Mole Fraction				
MEA		0.00%	0.00%	0.004 ppm
H ₂ O		0.00%	18.27%	6.26%
CO ₂		20.00%	7.81%	93.65%
N ₂		80.00%	71.02%	0.08%
O ₂		0.00%	1.80%	0.00%
CO		0.00%	0.00%	0.00%
H ₂		0.00%	0.00%	0.00%
CH ₄		0.00%	0.00%	0.00%
Ar		0.00%	1.10%	0.00%

Table 51. Process performance results of CO₂ capture plant in the titanium/vanadium concentrate processing plant

PARAMETER	UNIT	VALUE
Pre-treatment direct contact cooler (DCC) diameter	metre	10.0
DCC tower packed height	metre	10
Absorber diameter	metre	9.4
Absorber packed height	metre	20
Absorber water wash diameter	metre	8.3
Absorber water wash packed height	metre	4
Desorber diameter	metre	5.6
Desorber packed height	metre	10
Liquid/gas ratio	kg amine/kg flue gas	2.48
Reboiler duty (steam @150 °C)	GJ/tonne CO ₂	4.52
Amine content in exhaust	Part per million (ppm)	0.1 ppm

A summary of the total costs for carbon capture at the condensate refining plant is provided in Table 49.

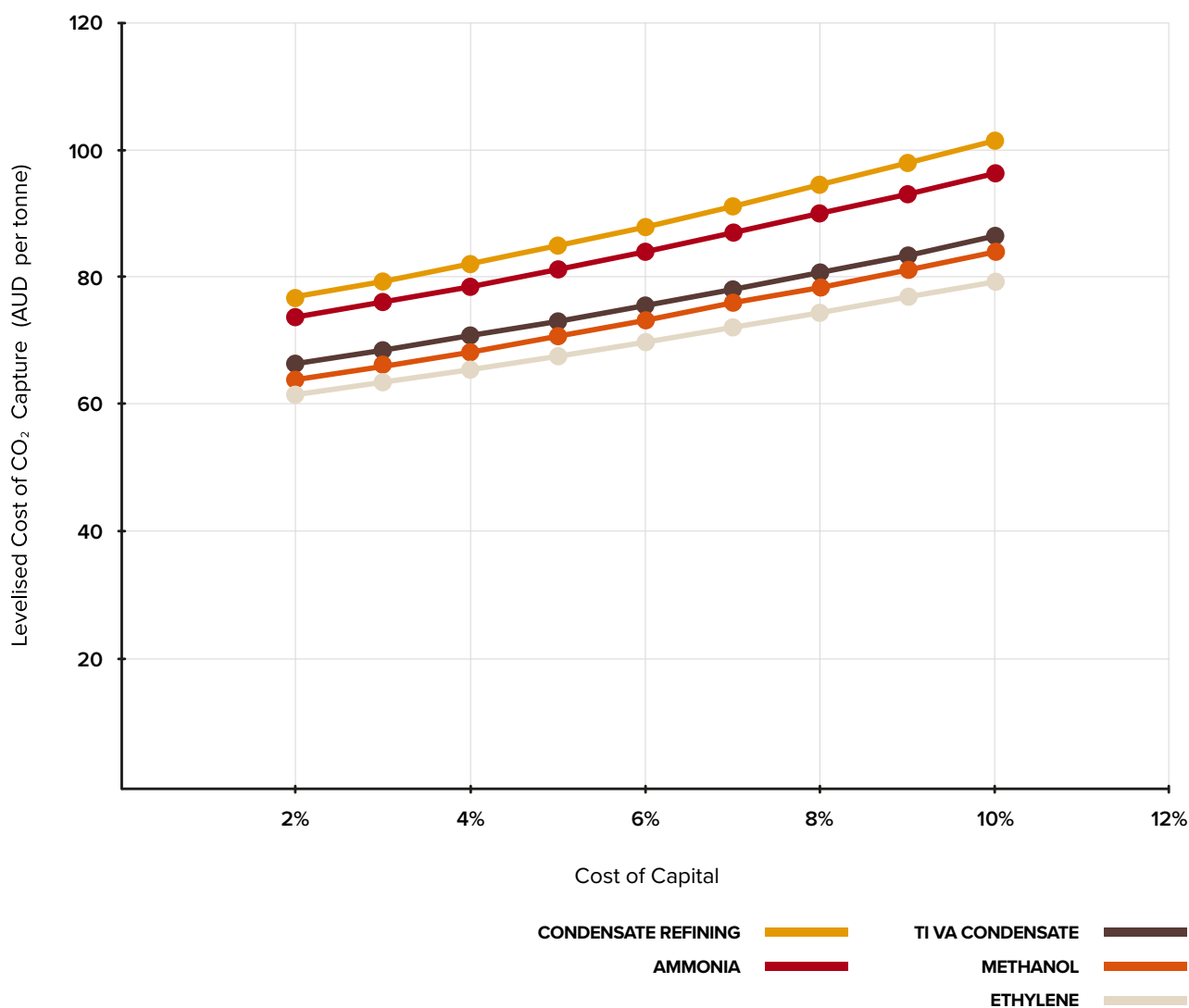
Table 52. Economic performance results of CO₂ capture plant in the titanium/vanadium concentrate processing plant

ECONOMIC PARAMETER	UNIT	VALUE
Total capital requirement	million AUD	290.99
Fixed O&M	million AUD per year	10.10
Fuel cost	million AUD per year	26.88
Other variable O&M	million AUD per year	8.9
CO ₂ captured	Tonnes per annum	890,000
Levelised cost of CO ₂ capture (exclude dehydration & compression)	AUD per tonne CO ₂	75.3

Sensitivity analysis

Again, through the sensitivity analysis in Figure 27, it presents the same trend as discussed in the NGCC section. The cost of capital has a significant impact on the cost of CO₂ capture in the gas manufacturing industries. Opportunities exist in bringing costs down through the public support of low-cost finance.

Figure 27. The sensitivity of the levelised cost of CO₂ capture (exclude dehydration & compression) to the cost of capital

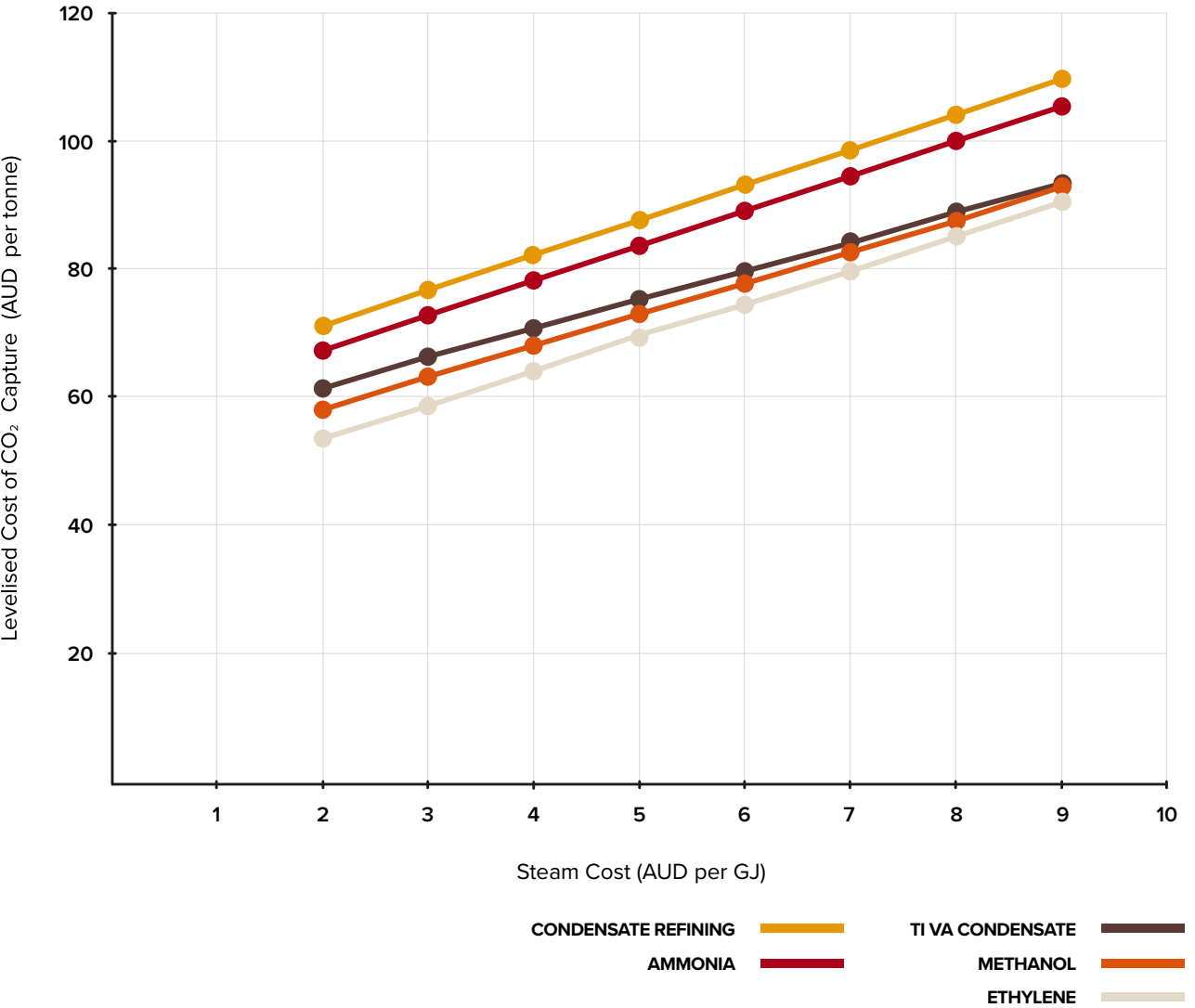


The second sensitivity analysis was performed using the cost of low-pressure steam which provides process heat for solvent regeneration. At the indicative price of AUD5 per GJ steam (150 °C), the levelised costs of CO₂ capture are AUD83.9, AUD73.2, AUD69.8, AUD87.9 and AUD75.3 per tonne CO₂ for carbon capture for the ammonia plant, methanol plant, ethylene/propylene plant, condensate refining plant and titanium/vanadium

processing plant respectively. A lower steam cost at AUD2 per GJ can substantially reduce the levelised costs of CO₂ capture by 18 – 22%.

Results of this second sensitivity analysis are shown in Figure 28. This shows the opportunity in cost reduction via waste heat utilisation in the gas manufacturing industries.

Figure 28. The sensitivity of the levelised cost of CO₂ capture (excluding dehydration & compression) to low pressure steam price.



6.7 Summary

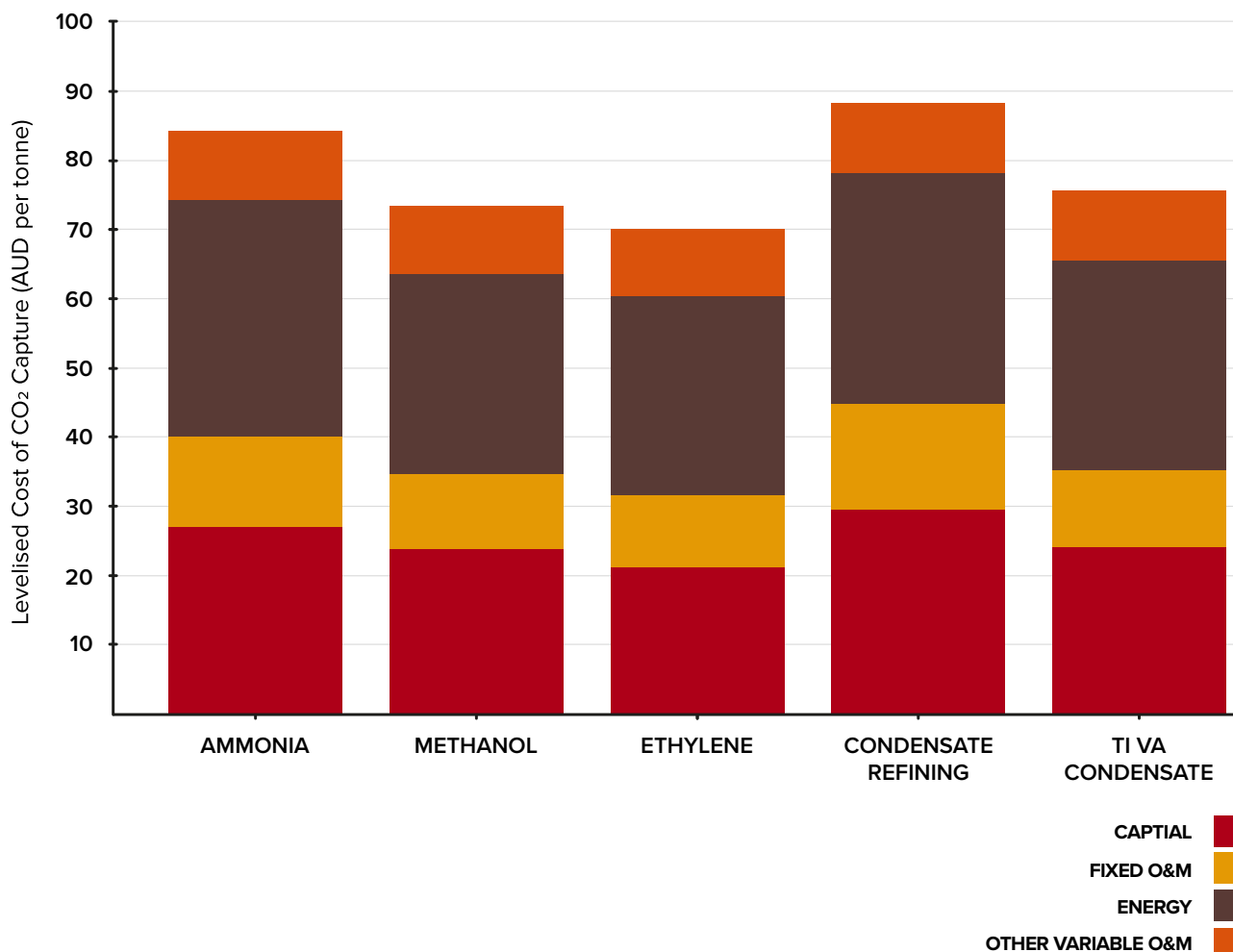
This section evaluated the technical feasibility and techno-economic performance associated with the implementation of amine-based carbon capture technology considering the current level of process integration at the five prospective industrial plants in Darwin Port, Northern Territory.

Based on the process simulation and cost modelling, the specific capital investments of carbon capture plants were estimated to be AUD172.2 million, AUD216.4 million, AUD263.4 million, AUD135.6 million and AUD291.0 million at the ammonia plant, methanol plant, ethylene/propylene plant, condensate refining plant and titanium/vanadium processing plant respectively.

The levelised CO₂ capture costs (excluding dehydration and compression) are AUD83.9, AUD73.2, AUD69.8, AUD87.9 and AUD75.3 per tonne CO₂ respectively shown in Figure 29.

For future development, it is recommended that the CO₂ capture system for each industrial plant can be competitively bid to obtain detailed site-specific design and performance evaluation, and competitive pricing from various technology providers. A more in-depth detailed engineering, such as FEED, is also expected to be conducted to advance the project development. Carbon capture technologies have substantially advanced over the last decade, due to R&D, modularisation and process optimisation. The new emerging CO₂ capture technologies are expected to reduce further the costs of CO₂ capture into the future.

Figure 29. Components of levelised cost of CO₂ capture (excluding dehydration and compression) in the studied gas manufacturing industries in Darwin Port.



6.8 Detailed capital and O&M cost of CO₂ capture at the gas manufacturing industries in Darwin Port

INDUSTRIAL PLANT

Industry		Ammonia plant	Methanol plant	Ethylene plant	Condensate refining plant	Ti/Va condensate processing plant
CO ₂ Capture Capacity	Tonnes per annum	469,000	671,000	917,000	338,000	890,000

CAPITAL COST

Total Direct Cost	AUD	62,886,588	79,000,692	100,272,800	49,526,701	106,247,523
Engineering Procurement and Construction	AUD	95,839,159	120,397,055	152,815,747	75,478,693	161,921,225
Total Plant Cost (TPC)	AUD	137,646,163	172,916,715	219,477,105	108,404,044	232,554,578
Owner's Cost	AUD	20,646,924	25,937,507	32,921,566	16,260,607	34,883,187
Total Capital Investment	AUD	172,230,909	216,363,211	263,422,483	135,641,054	290,985,566

VARIABLE O&M

Capture plant Chemicals Cost	AUD per year	1,174,369	4,558,426	6,246,550	2,297,974	6,062,182
Special Waste Disposal & Sewage Cost	AUD per year	772,921	1,109,303	1,046,973	539,824	1,455,289
Auxiliary amine reclaiming cost	AUD per year	728,944	1,043,523	1,427,214	525,998	1,384,197
Total Energy Cost (cooling water+electricity+steam)	AUD per year	15,937,972	19,331,780	26,491,972	11,291,350	26,878,279
Total Variable O&M	AUD per year	20,634,627	26,043,031	35,212,709	14,655,147	35,779,947

FIXED O&M

Operators	Number	10	10	15	10	15
Operator Wage	AUD per annum	850,000	850,000	1,275,000	850,000	1,275,000
Administrative/support labour cost	AUD per year	1,150,319	1,227,273	1,753,859	1,086,518	1,782,392
Maintenance Material and Labour	AUD per year	3,028,216	3,804,168	4,828,496	2,384,889	5,116,201
Insurance and Tax	AUD per year	1,137,572	1,429,064	1,813,860	895,901	1,921,939
Total Fixed O&M Cost	AUD per year	6,166,106	7,310,504	9,671,216	5,217,308	10,095,531

6.9 Economic Parameters

TOTAL CAPITAL INVESTMENT (TCI)¹¹

Total Direct Cost (TIC)	Equipment cost+ installation cost+labour cost
Total Indirect Cost (TIC)	0.2 TDC
Bare Erected Cost (BEC)	TDC + TIC
Engineering and Contractor	0.27 BEC
Engineering Procurement and Construction (EPC)	1.27 BEC
Process Contingency	0.25 BEC
Project Contingency	0.2 EPC + 0.05 BEC
Total Plant Cost (TPC)	1.2 EPC + 0.3 BEC
Owner's Cost	0.15 TPC
Total Capital Investment (TCI)	1.15 TPC

CONSTRUCTION TIME

All gas manufacturing industry capture plant	3 years
Capital Expenditure Schedule	
All gas manufacturing industry capture plant	20%/45%/35% of TPC for year 1-3
Cost Recovery Factor (CRF)	
Plant construction and operation	7.26% based on 6% discount rate

OPERATION LIFE

Years of operation	30 years
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FIXED OPERATING COST

Maintenance costs	2.2% of TPC/year
Maintenance labour	40% of maintenance costs
Maintenance materials	60% of maintenance costs
Operating labour cost	AUD 85,000/person-year
Number of operators	2 (base case)
Number of shifts	5
Administrative/support labour	30% operating labour + 12% of maintenance cost
Insurance cost	0.5% TPC
Local taxes and fees	0.5% TPC

VARIABLE OPERATING COST

Raw process water	AUD1.96 /cubic metre ¹²
Activated carbon	AUD3.8/kg
Diatomaceous Earth	AUD4.8/kg
MEA amine	AUD2.8/kg
Corrosion Inhibitor	AUD11.4/kg
Soda ash	AUD1.0/kg
Special waste disposal costs (non-hazardous)	AUD700/tonne ¹³
Sewage cost	AUD1/cubic metre ¹⁴

ENERGY COST

Electricity	AUD0.115/kWh
Steam	AUD5/GJ

¹¹ Parameters used to calculate the total capital investment were under guideline of Association for the Advancement of Cost Engineers International Recommended Practice (AACE 2011) and the United States Department of Energy economic analysis(US DoE/NETL 2011).

¹² Raw process water price sourced from Northern Territory Water pricing and tariffs (PowerWater 2020)

¹³ Amine and other chemicals disposal cost takes the sludge neutralisation and thermal treatment cost from (Marsden Jacob Associates 2014)

¹⁴ There is a future potential to reduce the overall water usage via recycling and treatment of discharge water from the direct contact cooler

7.0 HYDROGEN PRODUCTION

7.1 Background

Hydrogen is an industrial and energy commodity most commonly manufactured using the steam-methane reforming (SMR) process. A simple flow diagram representation of a typical SMR process is shown in Figure 30.

7.2 Technology routes for hydrogen production

Presuming the hydrogen is to be manufactured from natural gas, there are two key pathways that could be used:

- Steam-methane reforming (SMR) with water-gas shift (WGS) (as described above)
- Autothermal reforming (ATR)

The chemical reactions in both processes are identical. The main difference is the source of heat.

In SMR/WGS, heat for the reforming reaction is provided by burning natural gas in a furnace while the process gas runs inside tubes inside that furnace. The fuel gas and feedstock gases never come into direct contact and remain as discrete streams. SMR-based hydrogen production is a mature technology, having been used for many decades in the oil refining, chemicals and related industries.

In ATR, fuel and oxygen is mixed with the feedstock gases. As such the whole operation is carried out in one mixed phase inside reactor tubes. The potential advantage of ATR is that it can boost the CO₂ concentration in the outlet gas, relative to that seen in SMR. This could in principle reduce the costs of carbon capture.

However, reliable mass and energy balance data for ATR coupled with CCS is not available in the public domain. Also, ATR has a much shorter operating history in industrial plants.

To minimise risk and facilitate reliable results, the SMR/WGS route with CCS was assessed for this chapter.

In SMR/WGS plants, hydrogen is manufactured in two discrete reactors.

The first reactor is the methane reformer.

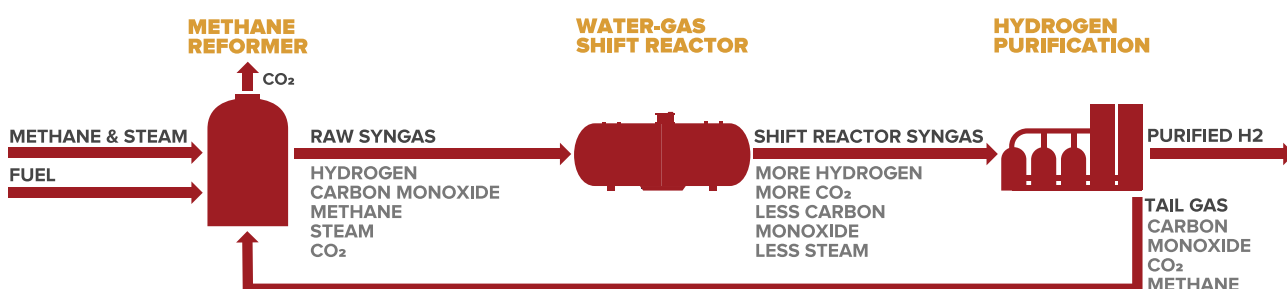
Equation 1. Methane reforming reaction



Here, methane and water (as steam) react at high temperature on a nickel catalyst with the following reaction. Hydrogen gas (H₂) and carbon monoxide (CO) are formed.

The reaction is endothermic (i.e. it absorbs heat). A substantial amount of natural gas must be combusted outside the reactor tubes to provide the heat of reaction and to get the reactants up to temperatures that favour hydrogen production (700-1000°C).

Figure 30. Flow diagram of conventional SMR process for hydrogen manufacturing (Global CCS Institute 2019)



Not all the methane reacts, so some unreacted methane leaves the reformer. The mix of hydrogen, carbon monoxide, unreacted methane, unreacted steam and small amounts of CO₂ (collectively “raw syngas”) flow to the second reactor: the water-gas shift reactor.

In the water gas shift reactor, carbon monoxide reacts with steam to form CO₂ and more hydrogen. This reaction is slightly exothermic, so no or little fuel is required to keep the mix at the required temperature.

Equation 2. Water-gas shift reaction



From the water-gas shift reactor, the shift reactor syngas is a mix of hydrogen, unreacted methane and steam, CO₂, and carbon monoxide. A pressure swing adsorption (PSA) unit is used to separate out purified hydrogen gas (> 99% pure). The remaining gases are typically sent back to the reformer for combustion as fuel – this consumes the carbon monoxide and unreacted methane.

7.3 Basis

The NT Government has not stipulated a specific capacity of hydrogen plant for this report. This report estimated a reasonable scale based on an existing hydrogen plant with CCS.

The example of Air Products’ hydrogen plant (with

CCS) at Port Arthur in Texas, USA was used as a basis. Each reformer at Port Arthur (there are two) produces 100 MMscfd (million standard cubic feet per day) of hydrogen. With a standard hydrogen volume of 423.3 scf/kg (Universal Industrial Gases 2017), that is 236.2 tonnes per day. At 95% availability, that is 81,916 tonnes of hydrogen per year.

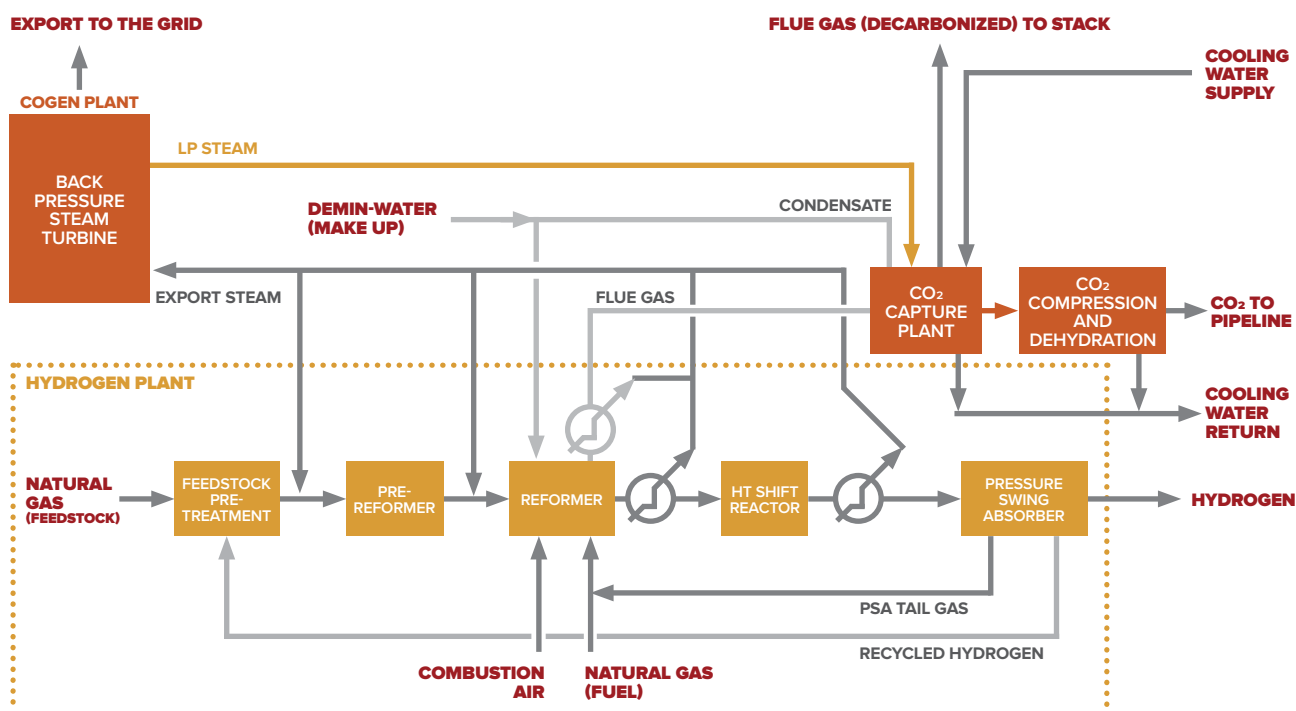
So the hydrogen plant capacity used in this report is 81,916 tonnes per year.

7.4 Data source for mass and energy balance and financial information

Key data for this report section has been obtained from the IEAGHG study Techno - Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS (IEAGHG 2017b). This report provides detailed flowsheets, costings and mass and energy balance data for SMR plants that incorporate CCS.

The IEAGHG report contains multiple assessments of SMR plants with varying degrees of CO₂ capture – from only tail gas, from only raw syngas. This study wanted to be comprehensive, so “Case 3” from the IEAGHG report was used – this case involves MEA-based solvent capture of CO₂ from reformer flue gas. This includes process CO₂ as well as CO₂ from fuel combustion. The block flow diagram from the IEAGHG report is shown as Figure 31.

Figure 31. Block flow diagram of the SMR plant with CO₂ capture from flue gas and process sources



Key points on this process arrangement:

- SMR plants produce high-pressure steam as a byproduct. This is used to produce electricity for the process in backpressure steam turbines, with the resulting low-pressure steam used to provide heat in the capture plant. The heat and electricity are sufficient to meet the energy requirements of the CO₂ capture plant, so no additional external energy supplies are required.
- The capture fraction of the process is 90%. This means that 90% of the CO₂ produced by the SMR plant (including combustion of fuel) is captured in the CO₂ capture plant and sent to storage.

7.5 Gas stream for capture

In the IEAGHG Case 3 process, all CO₂ is captured from the combined tail gas / fuel gas combustion products leaving the reformer. A summary of properties and composition of this stream are given in Table 53 (IEAGHG 2017, Heat and Material Balance Case 3). The flow is scaled from the IEAGHG case to match the capacity used in this report.

Table 53. Composition of combined flue gas sent to capture plant

DESCRIPTION	VALUE
Temperature (deg C)	136
Pressure (kPag)	20
Flowrate (kg/h)	342,477
Compositions (mol fraction)	
CO ₂	0.1897
Nitrogen	0.6282
Oxygen	0.0109
Water	0.1712

A substantial fraction of the water content of the gas stream is knocked out by cooling and condensation.

The advantage of doing CO₂ capture from the combined flue gas (as described above) is that only a single source of gas needs to be processed.

In alternative capture arrangements, separate capture

plants are required for flue gas (combustion) and process gas, with different CO₂ compositions. They also require substantial additional gas processing to remove carbon monoxide. The option selected here ensures carbon monoxide is converted to CO₂ by combustion in the reformer burners. It also ensures that useful heat is recovered from this conversion.

7.6 Capital cost estimate – plant excluding CO₂ compression

Costs in this report have been scaled, currency-converted and inflated from those in the IEAGHG report.

The IEAGHG Case 3 hydrogen basis was 8.994 tonnes/h of hydrogen production (IEAGHG 2017b, sec.7.7). At a 95% availability, that is an annual production of 74848 tonnes of hydrogen.

As our basis (81916 t/y) is slightly more than the IEAGHG Case 3 basis (74848 t/y) the capital cost figures in the IEAGHG report have been scaled.

The “rule of six-tenths” or “0.6 scaling factor” have been used to scale the IEAGHG capital costs up to match our basis. The “rule” is approximate, but it’s generally suitable when scaling by modest amounts.

This rule uses Equation 3:

Equation 3. Applying rule of six-tenths to estimate capital cost of plant 2 based on capex and capacity of plants 1 and 2

$\text{Capex}_{\text{plant 2}} =$

$\text{Capex}(\text{plant 1}) \times (\text{Capacity}_{\text{plant 2}} / \text{Capacity}_{\text{plant 1}})^{0.6}$

IEAGHG case location: Netherlands.

IEAGHG total Capital cost (IEAGHG 2017b, fig.7): 398.48 million Euro (2015 basis).

Note that this cost includes CO₂ compression, which for this report has been estimated separately.

IEAGHG compression cost: 9.18% of base plant cost.

So IEAGHG total capital cost (excluding CO₂ compression) = (1-0.0918) x 398.48 = 361.89 million Euro

Scaling this up to capacity of our plant (81,916 t/y): 361.89 x (81916/74848)^{0.6} = 382.02 million Euro (2015)

Adjustment for currency, location and inflation

Exchanger rate (June 2015): 1.44 AUD / Euro (from xe.com)

Inflation adjustment used the CEPCI (Chemical Engineering Plant Cost Index):

June 2015: 555.05 (Chemical Engineering 2015)

End 2019 (lastest available): 592.1 (Chemical Engineering 2019)

Location factors used closest available locations for IEAGHG Basis (Rotterdam, Netherlands) and Darwin (in this case, Sydney Australia).

Richardson location factor (Amsterdam for Netherlands): 1.20 (Richardson Products 2008a)

Richardson location factor (Sydney for Darwin): 1.19 (Richardson Products 2008b)

Adjusted plant cost: $382.02 \times 1.44 \times (592.1 / 555.05) \times (1.19 / 1.20) = 581.95$ million AUD.

7.7 Capital cost – CO₂ compression, dehydration and pipeline

The CO₂ captured in the IEAGHG basis is 0.8004 tonnes CO₂ / 1000 Nm³ H₂.

The H₂ flow is 100,000 Nm³/h. So captured CO₂ flow is $0.8004 \times 100000/1000 = 80.004$ t/h (22.22 kg/s)

The compression system is sized for instantaneous flow, not flow over a year that includes availability (i.e. downtime). This is a 100% availability equivalent flow of 738,053 tonnes per year.

(Note that section 3 uses 1.1 million tonnes / year for an “industrial” H₂ plant. It infers either more hydrogen capacity or an additional gas industry capture plant on top of the one in this part of the report).

The capital cost of a compression facility was estimated (including integrated dehydration) using Equation C-1 (Mccollum & Ogden 2006b):

Equation 4. The capital cost of compression system (USD 2005)

$$C_{\text{comp}} = m_{\text{train}} N_{\text{train}} \left[0.13 \times 10^6 (m_{\text{train}})^{-0.71} + 1.40 \times 10^6 (m_{\text{train}})^{-0.60} \ln(P_{\text{discharge}}/P_{\text{initial}}) \right]$$

Where:

C_{comp} = cost of compression system (US dollars, 2005)

m_{train} = mass flowrate through compression train (kg/s)

N_{train} = number of compression trains in compression system (integer) – one (1) in this case

$P_{\text{discharge}}$ = the discharge pressure of the system (absolute) (any pressure units)

P_{initial} = the inlet (initial) pressure of the system (absolute) (same pressure unit at Pcut-off)

The term inside square brackets is the capital cost per kg/s.

In this instance, CO₂ is produced from the capture plant at 1.6 bar absolute – this is the initial pressure. Final pressure was conservatively estimated at 9 bar for gas-phase transport to the CCS compression hub.

The resulting capital cost of compression and dehydration was calculated as USD 9.617 million (2005).

Adjusting for:

- exchange rate (assumed 0.70 USD / AUD)
- location factor (1.19 in Darwin, 1.0 in USA), and
- Using the US GDP deflator for inflation adjustment (86 in 2005, 113 in 2020) (tradingeconomics.com)

the converted compression & dehydration capital cost estimate is: AUD 21.48 million (2020).

Total capital cost for H₂ plant with CCS (including CO₂ compression):

AUD 581.95 + AUD 21.48 = AUD 603.43 million

7.8 Operating costs

The IEAGHG paper gives the consumption of various utilities: electricity, water, cooling and natural gas for the hydrogen plant.

Fuel and utilities (variable operating costs)

Because the plant produces electricity from high pressure steam as a byproduct, and the resulting low pressure steam meets the needs of the capture plant, the net utility requirements are relatively modest. Table 54 summarises these (scaled from the IEAGHG case 3 example):

Table 54. Net utility requirements for hydrogen plant with CCS (including compression)

UTILITY	NET RATE REQUIRED (EXCLUDES SELF- GENERATION) (NEGATIVE MEANS EXPORT FROM PLANT)	AUD / UNIT	AUD/ HOUR	ANNUAL COST (AUD MILLION/ YEAR) @ 95% AVAILABILITY
Net electricity purchased (includes using net power from on-site generation)	3230 kW	0.115 \$/kWh	371.45	3.091
Raw water	46 tonne/h	\$1.9613/tonne	90.37	0.752
Natural gas	1918 MJ/h	\$4/MJ	7,673	63.858
Cooling duty*	191.8 MJ/h	See below	767.3	6.386
Total				74.086

* Cooling duty was inferred from the IEAGHG utility (seawater) with a temperature rise of 7 degrees C (as per IEAGHG assumptions).

This application would most likely use air cooling rather than seawater cooling. Little reliable data was found for air cooling, so an assumed value of 10% of gas costs was inferred. Cooling duty rises and falls with gas consumption, so gas costs are a reliable basis for estimating cooling costs.

The sale price of electricity was assumed to be AUD 50 / MWh, just under half the industrial price for purchasing (assumed AUD 115 / MWh in Section 3).

Raw water price was as quoted on the Power and Water Corporation website (Power and Water Corporation 2020) for commercial water customers.

Natural gas price was taken to be AUD 4.00 / GJ (AEMO 2019).

7.9 Fixed Operations and maintenance

Fixed operations and maintenance (Fixed O&M) include costs such as wages/salaries of staff, spare parts and chemicals, warehousing, and other costs that do not rise and fall with production.

The IEAGHG report is very Netherlands-specific with these costs. As a broad assumption, this report takes fixed O&M to be 4% of capex every year, consistent with this figure used for the CO₂ compression operations (Section 3) (CO₂CRC & Gamma Energy Technology 2015a, p.188). This fixed O&M is for compression systems, which are considered to be as complex as the overall SMR plus capture plant, so this percentage is reasonably conservative.

So fixed O&M is 4% x 602.48 = AUD 24.1 million

7.10 Costs of hydrogen production (including carbon capture & compression)

To estimate costs per unit of hydrogen, the capital cost must be annualised.

A 6% cost of capital was assumed. This gives a capital recovery factor of 7.26%.

So annualised capex (AUD/y) = 0.0726 x 603.43 = 43.81 million AUD

Utilities + variable opex = 74.086 million AUD

Fixed operations & maintenance = 24.1 million AUD

The CO₂ transport and storage cost varies by pipeline route and overall CO₂ flow. If the base case using the short onshore/offshore route (option 2a) from Section 3 is used, this gives AUD 35.91 / tonne CO₂ stored (this is AUD 44.13 but excludes the average AUD 8.22/tonne cost for upstream compression from Section 3, as this is included already in the hydrogen production cost).

Tonnes of CO₂ per year captured for the H₂ plant is 89.7 tonnes/h, or 746,770 tonnes per year at 95% availability.

So CO₂ transport and storage cost = 746,770 x 35.91 = AUD 26.8 million / year

The costs are summarised in Table 55

Table 55. Summary of hydrogen plant costs

COST ITEM	AUD MILLION/YEAR
Annualised capital cost	43.8
Utilities / variable opex (excluding natural gas)	10.2
Natural gas cost (@\$4/GJ)	63.9
Fixed operations & maintenance	24.1
CO ₂ transport and storage	26.8
Total	168.9

Total annual cost for H₂ production, including CO₂ transport and storage = 168.9 million AUD

Hydrogen production per year (95% availability) = 81,916 tonnes/year.

So cost of decarbonised hydrogen = $168.85 \times 106 / 81,916$ = AUD 2061 / tonne = AUD 2.06 / kg

The cost of decarbonised H₂ on an energy basis is AUD 14.72 / GJ (@140 MJ/kg HHV)

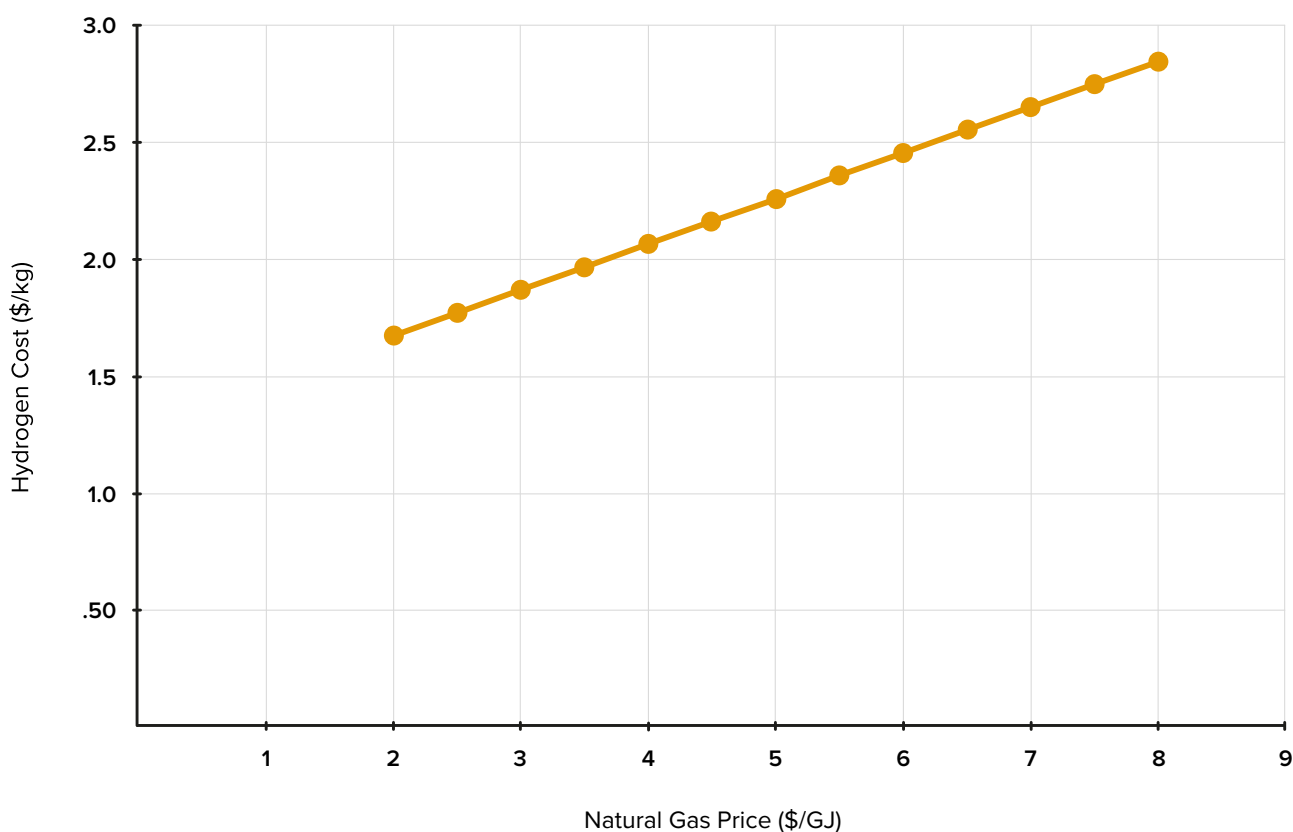
7.11 Sensitivity of hydrogen cost to natural gas prices

A substantial fraction of hydrogen production costs are from purchases of natural gas, as a feedstock and as a fuel for the reformer. In Table 46 the natural gas price was \$4 per GJ.

The sensitivity of decarbonised hydrogen production cost to natural gas price was assessed. This is shown in Figure 32.

The resulting range of hydrogen prices spans \$1.67 / kg to \$2.84 / kg for a natural gas price range of \$2-8/GJ. The relationship is linear and assumes all other costs remain constant (including externally-supplied electricity).

Figure 32. Sensitivity of decarbonised hydrogen cost to natural gas price





7.12 Emissions intensity of decarbonised hydrogen

The hydrogen plant CO₂ capture unit is sized to capture 90% of the CO₂ produced from the hydrogen plant, or 746,770 tonnes of CO₂ captured and stored.

This leaves residual (uncaptured) CO₂ emissions of 82,974 tonnes of CO₂ per year. Hydrogen production is 81,916 tonnes/year.

So the emissions intensity of decarbonised hydrogen is 1.01 tonnes CO₂ per tonne of hydrogen.

On an energy basis, that is 7.2 kg of CO₂ emissions per GJ of hydrogen energy.

This compares with 51.2 kg of CO₂ emissions per GJ when combusting natural gas (excluding very small amounts of other GHGs). So using this hydrogen will be 85% less emissions intensive than combusting natural gas.

Importantly, this analysis is based on a CO₂ capture fraction of 90%. If a higher fraction (95%) were used – something shown by recent IEAGHG analysis to be possible at modest additional cost (Feron, Cousins, Hla, et al. 2019) - the emissions intensity of the hydrogen could be halved to 3.6 kg CO₂ per GJ of hydrogen – 93% lower than from combusting natural gas.

8.0 POLICY OPTIONS

8.1 Introduction

This section of the report describes policy and regulatory options to incentivise private investment in a CCS hub at Middle Arm. It first summarises common barriers to CCS investments, and the range of policy options available to governments to address those barriers. It then reviews the policy and regulatory framework in the Northern Territory to identify potential gaps. It concludes with an assessment of other mechanisms that could be implemented, along with information on key stakeholders who the Northern Territory Government should consult to explore, develop and ultimately implement the policy options described.

8.2 Barriers to CCS investment

There are several barriers to the deployment of CCS which, if not addressed, will lead to underinvestment in CCS. These barriers arise from a variety of economic market failures. The main barriers include:

- **Insufficient value on CO₂ emission reductions.** For a potential capture plant developer, the main impediment to investment is often the lack of a clear price signal that places a sufficient value on emissions reductions. Without this, there is no incentive for a developer to incur the costs of constructing and operating the capture plant, even though it may be beneficial from a broader societal perspective in helping to meet climate targets cost effectively. In addition, consumers have traditionally been unwilling to pay a premium for products with a lower carbon footprint, such as steel produced with CCS. This makes it difficult for manufacturers to pass on the cost of CCS without a loss in competitiveness.
- **Interdependency of the CCS value chain.** CCS projects require the coordination of multiple investment decisions, each with long lead times. Decisions to develop each element of the CCS chain are taken before there is full certainty that the capture plant will have access to transport and storage infrastructure, and the transport and storage infrastructure will be sufficiently utilised. Once projects are operational the interdependency remains, as the failure of one of the components to deliver on their obligations may affect the costs and revenues of others and prevent the value chain performing as a whole. This is often referred to as cross-chain risk.
- **High capital costs of CCS projects and natural monopoly of T&S networks.** Building CCS facilities is capital intensive. Most of the costs of a project are incurred upfront and financed over all or part of the operational lifetime of the infrastructure. For industries that are perceived to be higher risk and that have low credit ratings, the limited access to low cost capital acts as a barrier to investment in capturing CO₂. CCS projects may also have to compete for capital with more established technologies. For transport and storage projects, the high upfront costs make it cheaper for one firm to provide the transport or storage infrastructure than two or more competing firms due to the cost of replicating infrastructure. Transport and storage providers can use this natural monopoly advantage to charge a high fee for using their infrastructure, knowing that a competitor cannot provide the service at a lower cost. If priced inefficiently, this would add to the costs of a project and further erode the business case for investment.
- **Knowledge spillovers from early adopters.** Early adopters of capture technologies generate knowledge that supports the development of the industry. Similarly, the success and failure of storage site developers in identifying appropriate sites improves the understanding of storage resources in the location the storage exploration is conducted. This knowledge can be used by other project developers, at no additional cost, to improve the design and operation of future capture plants, and the location of storage sites. While these knowledge spillovers help to reduce the unit costs of CCS over the longer-term, they increase the risk of asset stranding for early movers. This may encourage a 'wait and see' approach in anticipation of being able to achieve better value for money by learning from the success and failures of others.
- **Information market failures.** While the capture and safe storage of CO₂ has been technically proven over many decades, there remain relatively few large-scale CCS projects in operation. Banks have typically priced in a high-risk premium on lending

to CCS projects due to the lack of operational data compared to mature industries. Similarly, insurance providers are likely to charge high premiums to cover the lack of business volume that would otherwise be relied on to generate capital to cover pay-outs in the event of any low probability high impact event, such as CO₂ leakage. Storage operators are unlikely to be willing to take on an uncapped and indefinite liability for CO₂ leakage, especially if there are no insurance options available.

There are a range of other, technical and operating constraints that can hamper investment in CCS. These could include constraints on space available for capture facilities, the hidden cost of downtime for plants designed to run close to full capacity and the challenges of integrating the capture facility with the power or industrial plant.

8.3 Overview of policy options available to address the barriers to CCS investment

The presence of multiple market failures highlights the need for a comprehensive policy framework for CCS that is tailored to address the specific barriers to investment. Well-designed policy can set the conditions that make CCS a commercially viable proposition, by minimising costs, supporting stable revenues and allocating risks efficiently. This ultimately enables the CCS market to operate more efficiently and helps to deliver climate mitigation targets cost effectively.

Policies supporting CCS can also help to achieve other government objectives. For example, unlocking investment in CCS can support high-value jobs and economic growth, and help establish new industrial sectors in the Northern Territory, such as low-carbon hydrogen production. Investment in CCS can also facilitate a just transition by enabling existing industries to make a sustained contribution to the economy of the

Northern Territory as it transitions to a low carbon future. This can alleviate the challenges associated with the potential mismatch in the timing and geographic spread of job losses and gains during the transition. This is particularly relevant to the LNG industry in the Northern Territory. In the Bayu-Udan, Ichthys, Barossa, Evans Shoal and Greater Sunrise gas fields alone, there is an estimated 175 to 200 million tonnes of reservoir CO₂. The development of these fields and other economic opportunities in the Northern Territory, will likely only be feasible within emissions reductions targets if their development includes CCS.

There are several policy options available to address the barriers to investment in CCS. These include financial incentives and grants, loans and loan guarantees, economic and market-based instruments, regulatory obligations and standards, and the provision of information and guidance. The relative merits of different instruments depends on the context in which they are deployed and the specific barrier they are intended to address. Figure 33 below provides a high-level summary of the policy options available alongside the specific barrier they are intended to address.

From a policymakers perspective, the list of barriers and potential policy responses highlights the following areas as important components of any CCS policy framework:

- Establishing a bankable value on CO₂ emissions reductions for CCS projects
- Supporting early adoption of new capture technologies and detailed appraisal of prospective storage resources
- Investing in T&S networks
- Providing access to low-cost debt for industries that are capital constrained
- Establishing regulatory frameworks, particularly to address issues around storage liability

Figure 33. Potential policy response to address main barriers to CCS deployment

BARRIER	DESCRIPTION	EXAMPLES OF POTENTIAL POLICY RESPONSE
Insufficient value on CO ₂ emissions	The value on reducing CO ₂ emissions is insufficient, resulting in a mismatch between the private and social costs of emitting CO ₂	Introduce a value on CO ₂ emissions reductions, for example through a carbon tax, tax credit, emissions trading scheme, CCS obligation, emissions performance standard or through government procurement standards
	CCS adds to the costs of production and leads to a loss in competitiveness	Design any value on CO ₂ emissions to limit effects on competitiveness, or consider introducing, for example, a border adjustment tariff
Knowledge spillovers from early adopters	Early adopters of capture technologies generate knowledge that supports the development of the industry	Provide time-limited capital support for early adopters of new capture technologies to support their commercialisation and compensate early adopters for broader industry benefits delivered
	Storage site appraisal involves high upfront costs and some benefits of exploration fall to industry as a whole	Support coordinated efforts for early appraisal of storage sites, with results made available publicly to encourage development
Interdependency of the CCS value chain	Emitters may have to take investment decisions for the capture facility before a transport and storage solution is operational	Provide capital support to enable the development of shared T&S networks, with a focus on integrated hubs and clusters where economies of scale can reduce unit costs and a diversified source of emissions can reduce the risk of asset stranding
	T&S providers have uncertain demand for their network ahead of taking final investment decisions	
High capital costs of CCS projects	The capital costs of building T&S infrastructure are high	
	The emitter is in an industry that is seen as higher risk with lower credit ratings, limiting their ability to access finance	Provide capital support, such as loan guarantees, as part of broader initiatives to improve access to finance for industry for investment in climate mitigation technologies
Information market failures	Banks price in a high-risk premium on lending to CCS projects due to the lack of operational data	
	Storage operators are unable to take on uncapped storage liabilities	Consider transfer of liabilities after a period of time and a collective industry insurance fund
Political risks	Uncertainty around the policy framework weakens case for investment	Provide a clear and stable policy environment for CCS
	Local communities object to T&S in their area	Facilitate community-level engagement in CCS projects to improve public perception and, where possible, site projects away from areas of local opposition

8.4 International examples of CCS policies that have supported investment

There are currently twenty large-scale CCS facilities in operation and three under construction. These have been enabled through a mix of supportive policy and favourable project conditions. They provide a valuable insight into how the barriers described in Figure 33 have been overcome to make CCS a commercially viable proposition. While the specific mechanisms used to overcome the market failures have differed, there are common features that are reflected across a number of projects.

Figure 34. The main policies and project characteristics that have enabled large-scale facilities

									
Policies & project characteristics	Carbon tax	Tax credit or emissions credit	Grant support	Provision by government or SOE	Regulatory requirement	Enhanced oil recovery	Low cost capture	Low cost transport and storage	Vertical integration
US									
Terrell						●	●	●	
Enid Fertiliser						●	●	●	
Shute Creek					●	●	●	●	
Century Plant		●				●	●		
Air Products SMR		●	●			●			
Coffeyville		●				●	●		
Illinois Industrial		●	●				●	●	●
Great Plains						●	●		
ZEROS Project*		●				●			
Canada									
Boundary Dam			●	●	●	●		●	
Quest		●	●						●
ACTL Agrium			●			●	●		
ACTL Nutrien			●			●	●		
Brazil									
Petrobras Santos				●		●	●	●	●
Norway									
Sleipner	●			●			●	●	●
Snøhvit	●			●	●		●		●
UAE									
Abu Dhabi CCS				●		●		●	
Saudi Arabia									
Uthmaniyah				●		●	●	●	●
China									
CNPC Jilin				●		●	●	●	●
Sinopec Qilu*				●		●	●	●	
Yanchang*				●		●	●		
Australia									
Gorgon			●		●		●	●	●

* In Construction

Creating a sufficient value for CO₂

There are a variety of ways in which a value for CO₂ has been created for CCS projects. These have either been through the use of CO₂ for Enhanced Oil Recovery (EOR) or from policy mechanisms.

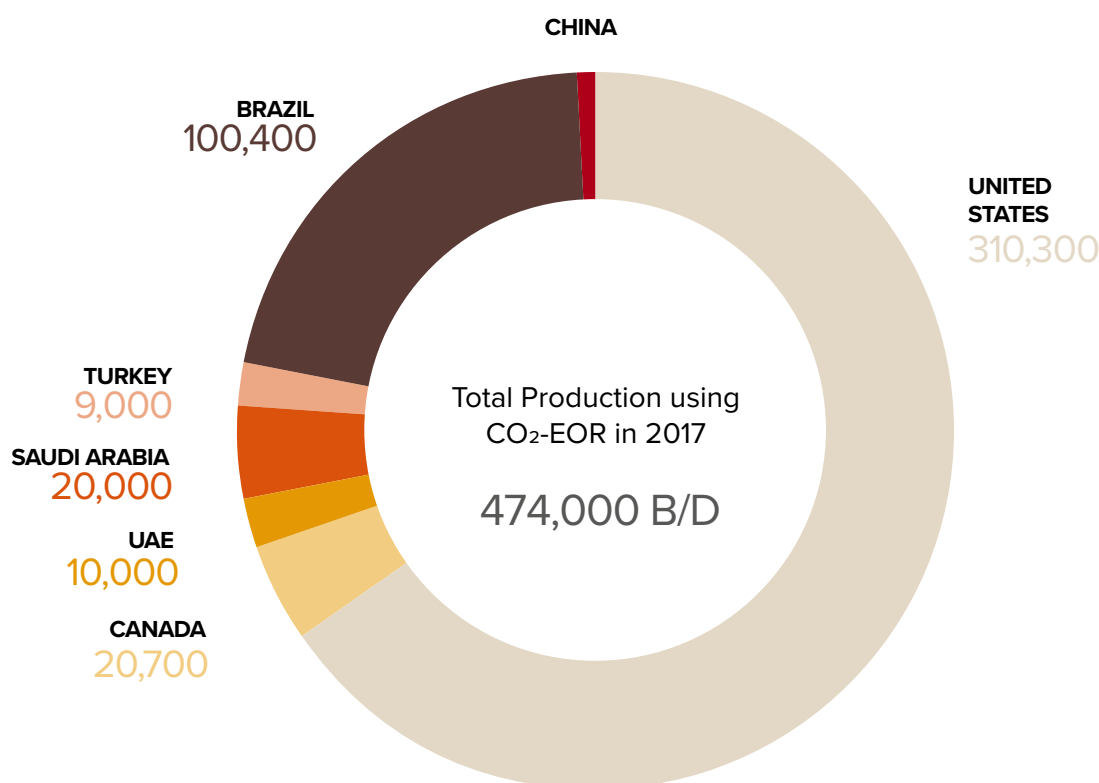
The use of CO₂ for Enhanced Oil Recovery

EOR is a process whereby a fluid is injected into an oil reservoir to increase its production. It has been common practice to use CO₂ as a fluid for EOR (CO₂-EOR) because, in addition to increasing reservoir pressure, CO₂ can decrease the viscosity of the oil

improving its mobility. The injection of CO₂ into an oil well increases its production which in turn improves economic performance. Around 474,000 barrels of oil per day were produced in 2017 using CO₂ enhanced oil recovery (EOR), utilising between 70 and 80 Mt CO₂ per year. The largest producer of oil using CO₂-EOR is the United States, which accounted for 310,000 barrels of oil per day (65 per cent) of global production in 2017, followed by Brazil (21 per cent), Canada (4 per cent) and Saudi Arabia (4 per cent).

While most of the CO₂ that is used for EOR around the world is naturally occurring¹⁵, the use of anthropogenic CO₂ has been ongoing since the early seventies, and its share of oil recovered using CO₂-EOR has been increasing in recent years.

Figure 35. Oil production (barrels per day) using Enhanced Oil Recovery



Where a readily available supply of naturally occurring CO₂ is not available, CO₂ may be captured from large proximate anthropogenic sources and supplied via pipeline. This requires the installation of CO₂ capture equipment at the source and access to, or construction of, a pipeline. Revenue is generated either through the sale of CO₂ to the oil well operator by way of an offtake agreement, or through additional oil production, where the oil field and the capture facility are combined as a single investment.

In interviews performed with financiers that have engaged with CCS projects in the US, specifically the Permian Basin, the pricing for CO₂-EOR has historically been indexed to oil. Usually this would be as a percentage of the West Texas Intermediate (WTI) benchmark that is central to commodities trading, settled on the monthly average price. A thousand cubic feet (mcf) – equivalent to 28.3 m³ – of CO₂ would be priced at between 1.5% and 2.5% of the price of a barrel of oil, with financiers observing that most contracts have been priced at circa 2% of WTI. For example, at an oil price

¹⁵ CO₂ is produced from natural geological accumulations.

of \$75 per barrel and a 2% contract, the price of CO₂ would be \$27 per tonne. In other regions, these have been lower, sometimes as low as 1%. This ends up being about 35% of the price of a barrel of oil in short tons or 38% in metric tonnes. With the advent of contracts for anthropogenic CO₂, these contracts sometimes have a floor price of between \$0.50 and \$1.00 per mcf of CO₂. This floor price is designed to limit the downside for the project and help in securing financing.

CO₂-EOR has been an important motivator for investments in CCS facilities. In fact, the main way through which a value has been placed on capturing CO₂ has been in its use for EOR rather than through any individual policy mechanism. Of the twenty projects currently in operation, fifteen sell CO₂ for EOR.

Example of EOR-based CCS Project: Petra Nova

In recent times, the price of oil has fallen substantially. This has diminished the economic performance of CCS projects relying on the steady revenues provided by EOR opportunities. While some projects are relatively sheltered by way of offtake agreements, those that are directly invested in both the capture and EOR activities have been particularly sensitive to the oil price. The most notable example of such projects is Petra Nova, which was launched in 2017 and suspended its capture operations in 2020 as a result of prolonged, low oil prices. CO₂ capture will resume when oil prices recover.

Petra Nova is a post-combustion retrofit project. The capture unit is attached to the WA Parish coal fired power station owned by NRG in Texas, USA. At 240MW, Petra Nova is the world's largest power-based CCS facility. Before operations were suspended, it captured and stored 1.4 million tonnes of CO₂ per year. Petra Nova differed from most other large-scale CCS facilities because it was able to attract significant levels of non-recourse debt financing during its development. The project was the result of a joint venture between NRG and JX Nippon, a Japanese oil and gas company. Together, they invested in the CCS facility as well as buying a 50% stake in an aged oil field, West Ranch, 130 km away from the capture facility (Jenkins 2015). This made the design of the project unique because, unlike other post combustion capture projects, Petra Nova made direct use of CO₂ for EOR rather than selling it to a third party.

Typically, CO₂ sold for EOR has been priced at USD10-35 per tonne (OECD-IEA-UNIDO, 2011). The actual value of CO₂ is greater than this because the project proponents of Petra Nova projected that its direct use would enable

the extraction of an additional USD150-300 worth of oil for each tonne of CO₂ delivered to West Ranch. The economics of the project were, therefore, centred on the additional oil production from the well.

At the same time, the CCS component of the project would also generate a smaller revenue stream through tax credits issued under section 45Q of the Internal Revenue Code. Along with USD167M of grant funding from the US Department of Energy, which covered approximately 16% of project costs (Shimokata 2018), the projected revenues from additional oil production and 45Q tax credits attracted debt financing from JBIC and NEXI.

It is understood that the Petra Nova project increased the production of oil at the West Ranch oil field from 300 barrels a day to 4,000 barrels a day (Jenkins 2015). The precedent set by this project is that risk tolerant financiers, such as JBIC and NEXI, were willing to provide debt financing to a full chain CCS project so long as long term and sufficient revenue from a reliable source was assured. Capture technology, therefore, was not considered to be as great a risk as revenue uncertainty by the financiers that provided debt financing for Petra Nova.

Policy Mechanisms

While CO₂-EOR has played an important role in supporting CCS deployment, most CCS investments have been driven by a variety of government policies. These have come in the form of direct investments to support capital requirements as well as through different mechanisms that place a sufficient value on CO₂. A summary of the different policies that have enabled projects to reach positive FID is described below.

Tax Credit

One proven example is Tax credits, which have been an important enabler of the six large-scale CCS facilities that have commenced operation in the USA since 2011. In the USA, tax credits are issued under section 45Q of the Internal Revenue Code. The credits can be used to reduce a company's tax liability or, if they have no tax liability, can be transferred to the company that disposes of the CO₂ or can be traded on the tax equity market. Tax credits have the benefit of being well established in the context of climate change mitigation in the USA, having been used to drive significant investment in renewables over the past two decades. They provide a predictable effective revenue stream for each tonne of CO₂ stored (or utilized).

Figure 36. The 45Q Tax Credit

TYPE OF CO ₂ STORAGE/USE	MINIMUM SIZE OF ELIGIBLE CARBON CAPTURE PLANT BY SIZE (KtCO ₂ /YR)			RELEVANT LEVEL OF TAX CREDIT GIVEN IN OPERATIONAL YEAR (USD/tCO ₂)										
	POWER PLANT	OTHER INDUSTRIAL FACILITY	DIRECT AIR CAPTURE	2018	2019	2020	2021	2022	2023	2024	2025	2026	LATER	
DEDICATED GEOLOGICAL STORAGE	500	100	100	28	31	34	36	39	42	45	47	50	INDEX LINKED	
STORAGE VIA EOR	500	100	100	17	19	22	24	26	28	31	33	35		
OTHER UTILISATION PROCESSES*	25	25	25	17	19	22	24	26	28	31	33	35		

*Each CO₂ source cannot be greater than 500 ktCO₂/yr. Any credit will only apply to the portion of the converted CO₂ that can be shown to reduce overall emissions.

The recent extension and increase in the value of the 45Q tax credit has incentivized the next wave of CCS investments in the USA, with more than ten new projects currently progressing through feasibility or front end engineering and design studies.

Carbon Tax

A carbon tax is a fixed cost that is imposed on CO₂ emissions. The pricing of the tax can be optimised to drive investments in CCS technology. This could be achieved by pricing the tax above the cost of doing CCS. At the same time, the tax cannot be priced too high, otherwise businesses will simply move their operations to jurisdictions where the tax is not enforced or is significantly lower than the cost of investing in CCS.

It was a carbon tax introduced by the Norwegian government in 1991 that incentivised the development of the Sleipner and Snøhvit CCS projects. At USD17/ tCO₂, the cost of injecting and storing CO₂ for the Sleipner project was much less than the USD50/ tCO₂ tax penalty at the time for CO₂ vented to the atmosphere (Herzog 2016).

Regulatory Requirement

Instead of imposing a tax on emitters, governments can implement regulatory measures. These can take shape in numerous forms, such as emissions performance standards or a simple requirement to do CCS.

In Saskatchewan, Canada, SaskPower made the decision to retrofit its coal-fired power station, Boundary Dam, with CCS. The main driver for the investment in the capture facility at Boundary Dam was the enactment of

a federal regulation that limited the amount of CO₂ that could be released from coal-fired power generation. This performance standard, 'Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations', limits CO₂ emissions to 420 tonnes per GWh (CCS Knowledge Centre 2015), which is equivalent to the emissions intensity of a modern, high efficiency, base load Natural Gas Combined Cycle (NGCC) power plant.

Boundary Dam faced two choices to stay in operation. These were either to implement a CCS retrofit to their coal-fired power plant or to repower the facility with NGCC. Given the other drivers available to the development of a CCS facility – notably, the sale of CO₂ for EOR to a nearby oil well; the sale of other by-products (fly ash and sulphuric acid); and capital support from the federal government — a decision was made to go ahead with the development of a CCS retrofit at Boundary Dam.

Gorgon, Australia

Chevron recognised the need to reduce CO₂ emissions from its Gorgon LNG project in Australia and included CCS in its Environmental Impact Statement. The approval of the project by the Western Australian Government subsequently included a mandatory condition to inject at least 80% of the reservoir CO₂ produced by the gas processing operations. Gorgon is the world's largest dedicated CO₂ storage facility with a capacity of 4 million tonnes of CO₂ per year (Chevron 2019). As one of the largest natural gas projects in the world, the additional cost of compressing and storing CO₂ was manageable in the context of the project as a whole, adding less than 5% to the total project costs.

Overcoming High Capital Cost of CCS

CCS facilities are capital intensive requiring hundreds of millions, or sometimes billions of US dollars in investment. Moreover, the market failures described in Figure 33 translate into hard to reduce risks. Investors that are exposed to these risks will find it difficult to commit significant capital, either through debt or equity, to projects. In cases for which private capital is raised for CCS projects, investors' perception of hard to reduce risks translates to high capital costs. Despite several projects reaching positive FID, very few projects have managed to attract debt financing. Given the relatively high cost of capital from equity investors and general unavailability of debt financing, projects have had to rely significantly on public subsidies to reach positive FID. These subsidies have been applied to projects in the form capital grants for project development or as incentives during the operational phase of projects. Grant funding reduces the private capital requirement and thereby increases the return on private capital enabling investment. It also mitigates the disincentive to be a first mover by rewarding early investors for the knowledge they create that can be used by future project developers. Capital support from government will be most efficient where applied to the highest risk components and phases of projects where the cost of private capital would otherwise be the highest.

Funding Programmes

In North America, where projects have a tendency to be developed and owned by the private sector rather than state owned enterprises, government support has taken shape in the form of funding programmes. These programmes are part of a broader strategy to enable CCS deployment in parts of the economy where the technology is most needed.

Canada: Alberta Program (Carbon Capture and Storage Fund) and Federal Government Capital Grants (Natural Resources Canada)

The Pan Canadian Framework on Climate Change has set an ambitious target to reduce national GHG emissions by 30% from 2005 levels by 2030. The manner in which each province chooses to reduce its GHG emissions inventory is at its discretion with the sole exception of coal-fired power generation. Regarding coal, Canada's 2012 update to the Environmental Protection Act required new coal plants to be compliant with an emissions limit of 420 tonnes of CO₂ emitted per GWh of electricity produced, as well as existing plants

when they turn 40 years old (Herzog 2016).

In the province of Alberta, the government recognised that its economy and emissions are both heavily tied to the oil and gas sector as well as trade-exposed heavy industries. The government made the decision to build a strategy around CCS so as to shield these sectors from climate risks. In 2008 it launched a CAD2 billion Carbon Capture and Storage Fund to support large-scale CCS projects. Four awards were made in 2009. Two of these reached positive FID and are now in operation, namely the Shell Quest Project and the Alberta Trunk Line project.

At the federal level, Natural Resources Canada's Clean Energy Fund (2009-2014) had budgeted CAD205M for funding towards CCS projects, most of which was spread across the Shell Quest and Alberta Trunk Line projects. The Government of Canada has also provided direct grant funding of CAD240M towards the Boundary Dam project.

Shell Quest: Derisking through high subsidies and demonstration

The Shell Quest CCS facility near Edmonton, Alberta, is attached to Shell's hydrogen gasification facility and has been operational since 2015. It is a vertically integrated project that injects the CO₂ captured into a geological formation for permanent storage. In 2008, Shell Canada, along with its Athabasca Oil Sands Project joint-venture partners, received grant funding from the Government of Alberta's Carbon Capture and Storage Fund to develop the Shell Quest CCS project. Additional grant funding was also obtained through the federal government's Clean Energy Fund. The overall proportion of direct grant funding amounts to some 64% of project cost. In addition to capital support, the government also awards carbon credits to the project on a performance basis at a ratio of two credits transferred to the project for every tonne of CO₂ sequestered. The combination of significant capital grants as well as a secure revenue line obtained from carbon credits was sufficient incentive for the project to reach positive FID.

The Shell Quest project has contributed significantly to the CCS learning curve. This is because one of the conditions of the funding agreement with the government is that all project data and learning outcomes are published in the public domain.

Alberta Carbon Trunk Line: Derisking through infrastructure investments in shared transportation

Situated in Alberta's industrial heartland, the Alberta Carbon Trunk Line (ACTL) is the world's largest capacity pipeline for carrying anthropogenic CO₂, capable of transporting up to 14.6M tonnes of CO₂ per year. The ACTL project involves multiple project partners. The pipeline connects two emitters, North West Refinery and

Nutrien, to a storage operator, Enhance Energy. The CO₂ that is captured is compressed and transported by the pipeline's owner and operator, Wolf Midstream. Enhance Energy utilises the CO₂ for EOR purposes. The pipeline is oversized so as to allow additional emitters and storage operators to connect to it over time. It covers a distance of 240km, passing through an area where multiple other CO₂ emitters operate, and could eventually join the network, which in turn could connect to other oil fields and storage sites.

This operating model – known as a hub and cluster model – directly addresses one of CCS' hard to reduce risks, the interdependency or cross-chain risk. It also allows project partners to benefit from economies of scale, reducing the cost of transport and storage of CO₂. The first investors in the transport and storage network, however, face all the costs and risks of a single source – single sink business model until others join the network which exposes them to the original cross-chain risks. This is a significant barrier to the initial investment but can be overcome if capital support is made available.

The role of the Alberta government was, therefore, to ensure that the ACTL could be oversized at no additional cost to private sector partners. To achieve this, the Alberta and federal governments provided capital grants of CAD495m and CAD63 respectively. This led to the project partners being able to reach positive FID on the basis of CO₂-EOR revenues.

Boundary Dam

While the Boundary Dam project was mainly driven by an emissions regulation, it was also supported by way of a one-time CAD240 million grant from the federal government, representing approximately 22% of the initial projected cost of the project. This grant, coupled with the sale of CO₂ for EOR, combined to create a project with a Levelised Cost of Electricity (LCOE) equivalent to building a new NGCC plant at that time (International CCS Knowledge 2018).

USA: Department of Energy Funding Program: Derisking through provision of capital subsidies

Like Canada, the U.S. has also built a climate strategy that includes CCS. The U.S. has the highest number of operational CCS projects in the world, as well as some of the largest. While the 45Q tax credit plays an important role in generating revenue for CCS projects, capital support was also provided. Capital grants are made available through the U.S. Department of Energy (DOE), which administers the Clean Coal Power Initiative (CCPI). The CCPI works under the condition that a minimum 50% cost sharing is provided by the project developers.

Awards are issued to projects by way of request for proposals that take place as and when funds become available to the CCPI.

Three operational large-scale CCS projects, Air Products SMR, Illinois Industrial and Petra Nova, received grant support from the DOE to advance towards a positive FID.

Air Products SMR

Air Products SMR is a post-combustion CCS project. Air Products partnered with Denbury Onshore LLC to capture and sequester CO₂ from existing steam methane reformers. The project was made possible because of relatively low-cost transportation due to the relative proximity of the capture facility and an existing pipeline, the Green Pipeline, operated by Denbury. This made it possible for the project to sell the captured CO₂ to oil fields in eastern Texas. The project received USD284m in grant funding as a contribution towards the overall capital cost of USD431m.

Illinois Industrial

The Illinois Industrial plant produces bioethanol from corn. Since a relatively pure stream of CO₂ is produced in this process, the cost of capture is very low. The other significant costs were therefore compression and transportation of the CO₂, which was also low since the location of the facility is directly above a suitable geological formation. The project reached positive FID with significant grant support – it received a USD141 million investment from DOE, matched by over USD66 million in private-sector cost share from the investor – and also relies on the 45Q tax credit for revenue generation.

State Owned Enterprises

An alternative to providing grant funding to projects is for governments to support the construction of CCS facilities through State Owned Enterprises (SOE). Such an approach can also avoid the need for creating an enabling environment through policies.

Sponsoring projects through SOEs has several advantages for these countries. State ownership is a way of directly supporting the development of infant industries like CCS. Governments can borrow at relatively low interest rates, helping to bring down the effective cost of capital of projects. Some elements of CCS also lend themselves well to state ownership due to their natural monopoly characteristics, such as the development of transport and storage infrastructure. The governments of UAE and Saudi Arabia have adopted this approach, which led to the development of Abu Dhabi CCS Project and Uthmaniyah facilities.

Overcoming Long Term Storage Liability Risk

Liability has long been raised as a significant barrier to the wide scale deployment of CCS. In the unlikely event that there is CO₂ leakage at the site of a CCS facility, the operator could be liable for the cost of actions to stop the leakage. Further, the operator could also be liable for any damages claimed by parties as a consequence of the leakage, and any fines or sanctions applied under legislation including the cost of purchasing emission allowances at the price in effect at that time. While it is possible – and a well-established practice – for companies to assume a rising carbon price when assessing potential investments, it is very difficult for private sector investors to accept essentially unlimited and perpetual liabilities, particularly in emerging industries like CCS where experience is limited. Of the

CCS projects that have reached positive FID, these have occurred in countries where legal and regulatory (L&R) frameworks are well-characterised. This made it clear to project developers what potential liabilities they could face. Further, these L&R frameworks have generally placed limits on the investors' exposure to any long-term storage liabilities by transferring these to the state after a specified period of post-closure. Each jurisdiction specifies a different number of minimum years for which operators must continue to monitor the site post-closure.

Table 56 provides an overview of the different approaches to liability undertaken across Australia, Canada, United States and the European Union, including support and conditions at both Federal and State level or equivalent.

Table 56. Overview of liability provisions for CCS activities. Adapted from (Havercroft 2019)

	AUSTRALIA		CANADA		UNITED STATES		EUROPEAN UNION	
	FEDERAL	STATES	FEDERAL	STATES	FEDERAL	STATES	DIRECTIVE	MEMBER STATES
Liability to be borne by the operator during the operational phase	✓	✓	-	✓	✓	✓	✓	✓
Transfer of liability	✓	✓	-	✓ Alberta only	✗	✓ Montana, Texas, North Dakota	✓	✓
Conditions for transfer	✓	✓	-	✓ Alberta only	✗	✓ Montana, Texas, North Dakota	✓	✓
Post-closure time limit for transfer	✓ 20 years	✓	-	✓ As per regulations in Alberta – no explicit statutory requirement regarding length of time yet	✗	✓ Between 10-15 years (North Dakota, Montana)	✓ Minimum 20 years	✓

8.5 The current policy framework supporting CCS in the Northern Territory

The Commonwealth government has committed to an economy-wide emissions reduction target of 26 to 28 per cent below 2005 levels by 2030 under the Paris Agreement, and agreed to adopt progressively more ambitious emissions reductions targets beyond 2030. Achieving these emissions reductions targets will require the deployment of a range of technologies, including CCS.

In recognition of the need for CCS, the Commonwealth government has supported the development of CCS in Australia for the past two decades. During that period the government has introduced several policies that partly or potentially address the barriers to CCS deployment. However, there remain several gaps as shown in Table 57. In its current form the policies in place are not sufficient to incentivise investment in CCS consistent with meeting the goals of the Paris Agreement.

The remainder of this section describes the relevant policies in place in more detail and the extent to which they address the policy action required to support large-scale CCS deployment.

Table 57. Summary of existing policies supporting CCS in the Northern Territory

POLICY ACTION REQUIRED	RELEVANT POLICIES IN PLACE	EXTENT TO WHICH POLICIES ADDRESS ACTION REQUIRED TO SUPPORT CCS DEPLOYMENT	COMMENTS
Establish a bankable value on CO ₂ emissions reductions for CCS projects	Emissions Reduction Fund		Currently does not support CCS, but Commonwealth Government consulting on its inclusion
	Safeguard Mechanism		Unlikely to support CCS in its current form as its focus is on limiting rises in emissions rather than achieving significant emissions reductions
Support early adoption of new capture technologies and detailed appraisal of prospective storage resources	Various funding initiatives (see list in text)		Funding has previously been provided for studies, but a 3D seismic survey followed by a well is required to appraise potential storage sites in the NT.
Invest in T&S networks	North Australia Infrastructure Fund		Could be used to support investment in T&S networks in Northern Australia, but not yet tested
	Clean Energy Finance Corporation		Currently does not fund/finance CCS projects, but Commonwealth Government announced plans to amend CEFC Act to include CCS
Provide access to low-cost debt for industries that are capital constrained	As above for investment in T&S networks	N/A	N/A
Establish regulatory frameworks, particularly to address issues of storage liability	See section 2 of this report		An established regulatory framework is in place for offshore CO ₂ storage but not for other aspects of the CCS chain (e.g. pipeline transport)

Emissions Reduction Fund

The Emissions Reduction Fund (ERF) is the primary mechanism through which the Commonwealth Government has incentivised emissions reductions outside of the power sector in recent years. It is an AUD2.55 billion fund used by the government to purchase emissions abatement from project developers. The fund is administered by the Clean Energy Regulator,

which runs a reverse auction process into which project developers bid to deliver a specified amount of emissions abatement at a specified price. The lowest cost bids are selected and successful project developers enter into a contract with the government, with the auction price being paid on verified delivery of emissions abatement.

As of March 2020, the government has committed AUD2.3 billion of the ERF, purchasing 193 million tonnes of greenhouse gas emissions abatement at an average



cost of around AUD12 per tonne of CO₂-equivalent. Nearly all of the credits have been awarded to projects in the agriculture and waste sectors. Fifteen of the 475 projects supported by the fund have been in the Northern Territory.

In 2019, the Government announced that it would continue purchasing low-cost abatement through the Climate Solutions Fund, an AUD2 billion fund intended to build on the success of the ERF. The fund was announced as part of the Government's Climate Solutions Package, an AUD3.5 billion package designed to deliver on Australia's 2030 climate change commitments.

CCS is currently not included in the projects that are eligible to participate in the ERF. However, in May 2020, the government accepted a recommendation of the King Review to introduce legislative amendments to enable the development of a CCS method within the ERF. If designed effectively, the inclusion of CCS in the ERF could provide an incentive for low-cost CCS projects.

In July 2020, the government issued a consultation paper seeking industry feedback on various elements of the method for crediting CCS projects under the ERF. The paper highlights several areas where the current conventions and standards of the ERF may need to be amended to take account of the specific aspects of CCS investments. Four issues in particular will need careful consideration by the government if the ERF is to provide a bankable value on emissions reductions for CCS projects:

- **The timeline between registering and generating emissions credits needs to reflect the lead-time for CCS projects.** As with other large infrastructure projects, a CCS facility follows a phased process with decision gates that determine and guide its development. The process of moving from concept to operation takes time. Evidence from the Institute's CCS facility database shows it has taken 6-8 years on average for CCS projects to progress through the full development cycle, from identification to operation. In contrast, the ERF only allows an 18 month window between a project being registered and emissions reductions being delivered. This would require project developers to take final investment decisions and start construction before knowing whether they would receive any revenue to cover the CO₂ emissions reductions delivered. As well as creating commercial challenges, this could place projects at risk of not meeting additionality criteria.
- **The crediting period under the ERF should reflect the abatement delivered by CCS projects.** The standard crediting period under the avoidance pathway of the ERF is 7 years. CCS projects, on the other hand, are typically designed to have a lifetime of 30 years or more, meaning that the long-lasting emission reduction services of a CCS project are not appropriately recognised. This would prevent positive investment decisions in projects that are not viable without longer term financial reward for

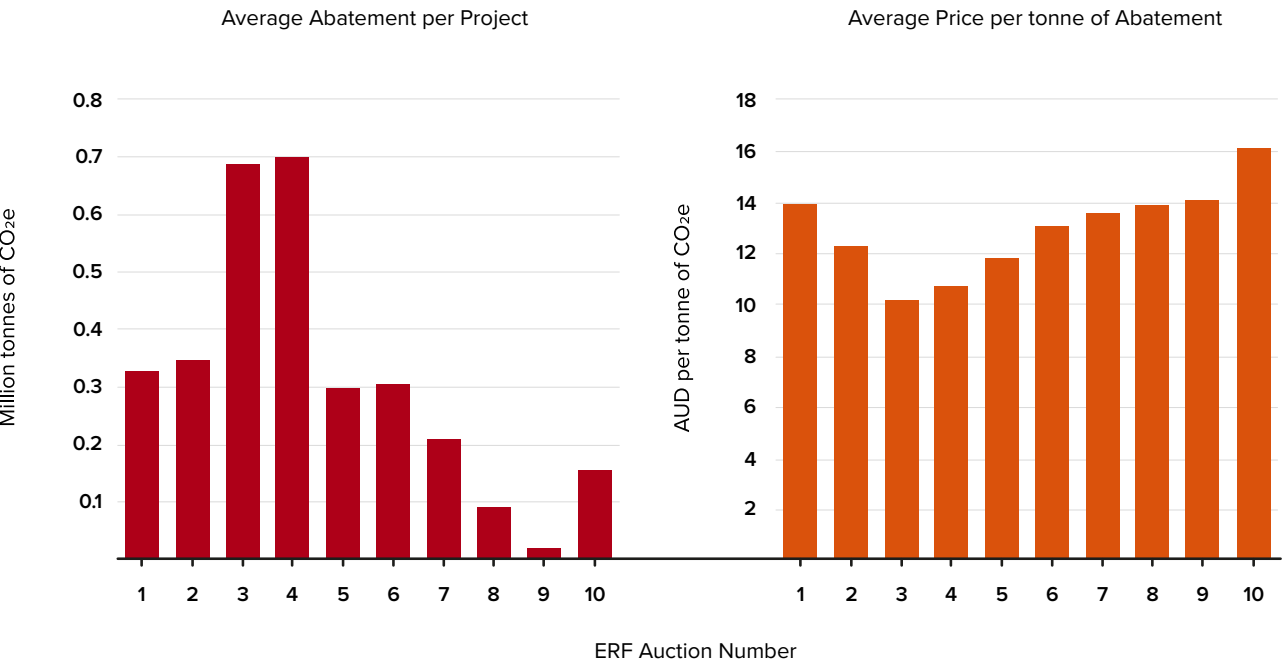
the emissions abatement they deliver. In the US, the crediting period adopted for the 45Q tax credit is 12 years. The combination of this longer crediting period, the higher incentive (up to USD50/tonne, indexed after 2026), and other government support has enabled several projects to reach operation and incentivised about a dozen more to start development studies. In other policy frameworks, such as the Low Carbon Fuel Standard in California, CCS projects are credited for the duration that they sequester CO₂.

- Given the current total value of the ERF, the number of credits available under the ERF could be a barrier to CCS investment.** Assuming a future clearing price of AUD20 a tonne, the total number of credits available under the Climate Solutions Fund would be only 100 million tonnes of CO₂. A single moderately sized CCS facility could deliver more than this level of abatement over its 30 year lifetime. A typical CCS facility would have the capacity to capture and permanently store between 1 and 5 million tonnes of CO₂ per annum. A CCS hub may have the capacity to store more than 20 million tonnes of CO₂ per year. Over the lifetime of

a single project, cumulative emissions reductions would typically be 30 to 150 million tonnes of CO₂. This could mean that a very small number of CCS facilities could use up all of the credits available. In the US, the cap on 45Q tax credits acted as a barrier to take up once project developers realised the cap was likely to be breached. The recent removal of the cap and increase in the value of credits has contributed to around a dozen new CCS projects entering the pipeline in the USA.

- The current price of emissions credits is too low to support deployment of most CCS opportunities.** The design of the ERF ensures the lowest cost abatement opportunities are funded by the government. The average price paid for credits under the ERF has been AUD12/tCO₂, although credit prices have been on a gradually increasing trend (Figure 37). As emissions reductions targets become more stringent, the price paid for credits is likely to increase. However, at current prices, the ERF is unlikely on its own to provide a sufficient value on CO₂ emissions reductions to encourage the scaling up of CCS required.

Figure 37. Average CO₂ abatement per project and credit price under the ERF



Safeguard Mechanism

A separate component of the ERF is the Safeguard Mechanism, which places emissions intensity limits on electricity, mining and industrial emitters in Australia. The mechanism applies to large scale emitters with scope 1 emissions that exceed 100,000 tonnes CO₂e per year, covering around a quarter of Australia's total emissions.

The emissions intensity limits, known as baselines, are designed to ensure there is no significant increase in emissions above business as usual levels, rather than promote emissions reductions. Emissions intensity limits are based on historic emissions for existing facilities, and best practice emissions intensities for new facilities (by facility type). There are various compliance mechanisms available for facilities whose emissions intensity are above the limits, including the ability to acquire Australian Carbon Credit Units or use over-achievement from another entity or period to offset emissions.

In its current form, the Safeguard Mechanism is unlikely to provide a strong enough signal to encourage investment in CCS. CCS delivers significant emissions reductions, whereas incremental emissions reductions are likely to be sufficient for entities to meet their obligations under the current framework.

Various funding initiatives for the early adoption of capture technologies and for CO₂ storage assessments

Over the past decade and a half, the Australian government has established and delivered a range of initiatives to support the early adoption of CCS technologies and encourage the exploration of storage sites. This includes:

- The low emissions technology fund, which provided AUD60 million to the Gorgon CCS project.
- The Carbon Capture Flagships Programme, which provided funding to a range of prospective CCS projects, including CarbonNet, the SouthWest Hub project and Otway Geological Storage and Demonstration Project.
- The ANLEC R&D¹⁶ research institution, which has funded over AUD100 million to various research initiatives, including research in CO₂ storage in the Surat, Gippsland and Southern Perth Basin.
- The National CO₂ Infrastructure Plan, which provided funding of AUD50 million to the Carbon Storage Taskforce which developed the plan to speed up

the process of identification and development of potential CO₂ storage sites.

- The CCS Research, Development and Demonstration (RD&D) Fund, which has provided support for a range of storage projects.

In Northern Australia, the Northern Australia CCS Project identified a series of drill-ready targets within the Petrel Sub-basin. Along with work completed by Geoscience Australia, the Project identified two viable, proven reservoir-seal pairs. Further appraisal work is needed to collect well and 3D seismic data from the prospective storage sites identified in the Petrel sub-basin before they are commercialised.

Northern Australia Infrastructure Facility

The Northern Australia Infrastructure Facility (NAIF) is a \$5 billion lending program aimed at providing loans to major infrastructure projects in Northern Australia. The loans cover up to 100% of the project's debt on concessional terms, subject to appropriate risk sharing arrangements.

Eligible projects include economic infrastructure projects associated with transporting people, goods, services or information, and increasing economic activity in the region. To qualify, projects need to meet a range of criteria. Projects must:

- involve the construction or material enhancement of Northern Australian economic infrastructure;
- be of public benefit;
- be located in, or have significant benefit for, Northern Australia;
- require a loan that is able to be repaid or refinanced; and
- have an indigenous engagement strategy.

As of April 2020, the NAIF had committed around AUD2 billion in loans to a range of transport, energy and other infrastructure projects. There are no CCS facilities in the funding pipeline, but CCS projects in Northern Australia could feasibly meet the eligibility criteria listed.

Clean Energy Finance Corporation

The CEFC, established by the Clean Energy Finance Corporation Act 2012 (Cth), uses debt and equity funding

¹⁶ Note that ANLEC R&D is jointly funded 50/50 by the Commonwealth Government and the Australian black coal industry.

to promote investment in clean energy technologies. As of June 2019, the CEFC had made cumulative investment commitments of \$7.2 billion to projects worth over \$24 billion, in relation to reducing emissions from energy and industrial processes and investments in solar energy and energy storage. The CEFC administers a number of funds including the Clean Energy Investment Fund, the Sustainable Cities Program, the Grid Reliability Fund and the Advancing Hydrogen Fund.

The CEFC Act currently prohibits the CEFC from investing in CCS projects. However, in May 2020, following an expert panel review on methods to support low cost emissions abatement options, the government has agreed-in-principle the recommendation of the panel to introduce legislative amendments to include CCS within the investment mandate of the CEFC. Investments by the CEFC will be guided by the Technology Investment Roadmap. The Government is currently consulting on the development and implementation of the Roadmap, and considering the merits of amending the CEFC's legislation through that process.¹⁷

8.6 Additional mechanisms and priority actions for the Northern Territory

Considering the analysis above, the policies that the Northern Territory has the powers to implement, and recognising the challenges associated with introducing significant new funding sources for CCS, it is clear that amendments and improvements to the existing policy framework could go a long way to providing the enabling framework for CCS. With this in mind, the following identifies potential steps the Northern Territory government could take to facilitate the development of a CCS hub in the Northern Territory.

1. Work with the Commonwealth Government to establish a Special Purpose Vehicle to develop a CCS hub in the Northern Territory

The creation and optimisation of a CCS hub requires the coordination of several actors with different commercial interests and drivers. While the Northern Territory government is not best placed to directly develop a CCS hub, it is very well placed to support its development at a strategic level alongside the Commonwealth Government. This can be achieved through the creation of a government owned and funded company, a Special Purpose Vehicle (SPV). Such a vehicle would be staffed

by individuals with relevant private sector experience. It could be a national body but with a focus on advancing specific regional CCS opportunities, such as at Middle Arm.

The SPV could perform a range of roles with respect to the Northern Territory, depending on the preferred approach taken to developing a hub in the region. In the early stages of the development, the purpose of the SPV could include:

- Developing and communicating the economic case for a CCS hub in the Northern Territory, with a focus on the role a hub could play in meeting Australia's emissions reductions targets at least cost, creating and retaining jobs, providing clean growth opportunities, and supporting a just transition in Northern Australia.
- Consulting with large emitters in the Northern Territory, all levels of government and other important stakeholders to understand the barriers to the development of a CCS hub, to build support for a CCS Hub and to coordinate actions where relevant to support its development. This would include the development and implementation of a Community Engagement Program.
- Identifying potential developers and operators of the transport and storage network in the Northern Territory, noting that the SPV itself could take on that role.

Many of the CCS hubs in development in Europe and the US are being coordinated through a similar set up, albeit some are joint-ventures between private companies only that are responding to policies that make CCS a commercially viable proposition in those regions. An SPV, owned and funded by the Territory and Commonwealth Governments, could pursue the development of a CCS hub in a way that meets government long-term objectives. Government backing/ownership would provide it with greater credibility, a clear sense of political will to support CCS, and help manage the trade-offs between different commercial and community interests.

2. Seek funding for storage site appraisal in the Petrel Sub-basin

Investment in storage resource appraisal is at-risk capital, similar to mineral exploration, but currently without the expectation of a return on investment. Consequently, the development of storage resources in most cases will not occur without government support.

¹⁷ See <https://www.industry.gov.au/sites/default/files/2020-05/government-response-to-the-expert-panel-report-examining-additional-sources-of-low-cost-abatement.pdf>.

While existing initiatives have identified drill-ready sites in the Petrel Sub-basin, there is still the need for detailed site appraisal, including the drilling of exploration and testing wells and modelling of 3D seismic data, before CO₂ can be safely injected at those sites.

The appraisal of offshore sites can cost in the mid to high tens of millions of dollars for greenfield, saline aquifers, and around ten million for depleted oil and gas reservoirs. The Northern Territory should explore with the Commonwealth Government the possibility of grant funding to support the appraisal of sites in the Petrel Sub-basin. The Commonwealth Government would be well placed to manage any appraisal work given its expertise and previous work it has funded. The SPV (if established) could also play a coordinating role.

Grant funding addresses the lack of capital available for early-stage projects that are too risky for the private sector and would therefore be more effective in supporting storage appraisal than a low-cost loan under the NAIF.

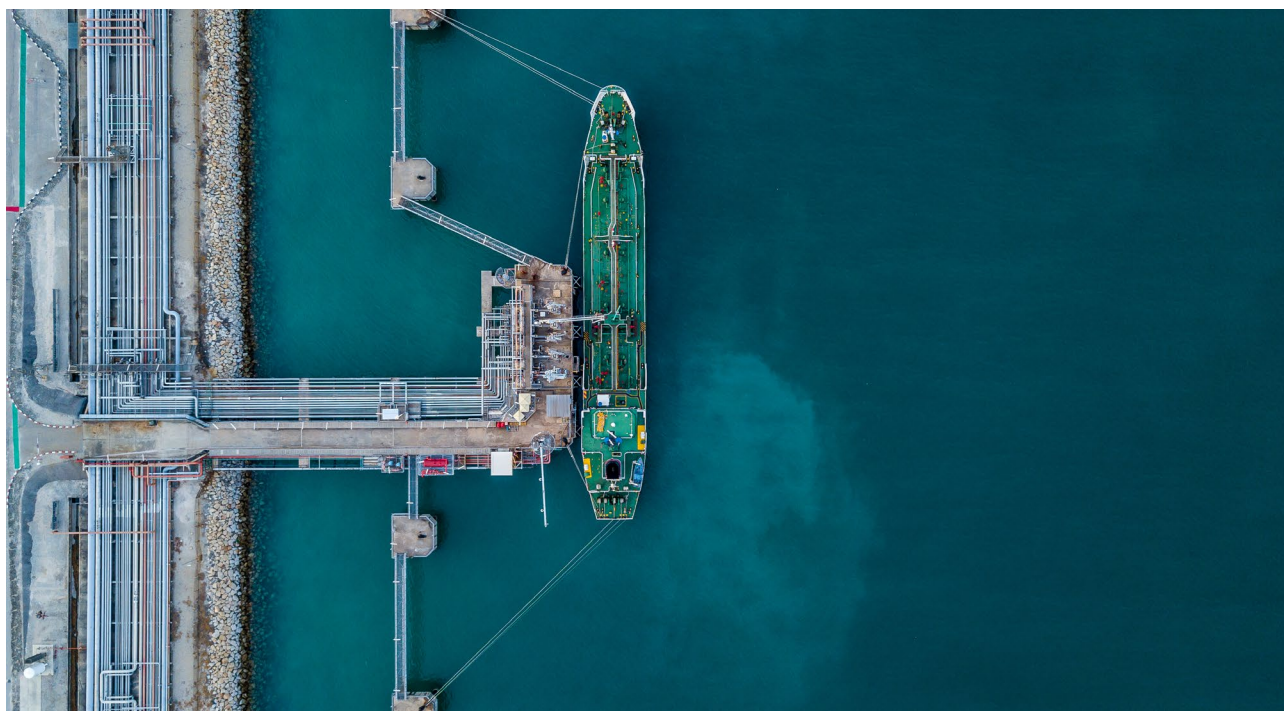
3. Seek funding for the development of shared T&S infrastructure in Northern Australia

The Northern Territory government should seek funding from the Commonwealth to complete feasibility studies into the construction of shared CO₂ transport and storage infrastructure. The feasibility studies could be undertaken by the SPV previously recommended, and would consider the likely demand for the infrastructure and all technical requirements. This would require consultation with potential users of the infrastructure,

such as LNG producers, which the Northern Territory would be well placed to coordinate. It would also require consultation with the Commonwealth Government to determine how to incentivise existing and new emitters to use the infrastructure if it were constructed. An option to encourage utilisation is discussed in Step 4 below.

Subject to the findings of feasibility studies being positive, the Northern Territory Government could seek funding from the Commonwealth Government for the construction of transport and storage infrastructure, which would be managed and operated by the SPV. The Northern Australian Infrastructure Facility (NAIF) is an obvious option to fund the development of a shared CO₂ transport and storage network. However, the NAIF alone is unlikely to provide sufficient capital to support a shared CO₂ transport and storage network. The capital cost of the compression and pipeline aspects of the network alone in Middle Arm are estimated to cost around AUD2 billion, whereas the NAIF currently has only AUD3 billion of funding remaining. The Northern Territory government should monitor developments in the CEFC and explore whether equity funding or loan finance from that vehicle could be utilised alongside any capital from private investors that is committed to the project.

The NAIF and/or CEFC could also support investment in capturing CO₂, where it is required, that is not covered under the transport and storage solution. The Northern Territory Government could have a role to play in making emitters aware of the latest developments in the policies and helping them to access the funding available.



4. Support the establishment of a bankable value on CO₂ emissions reductions

Even if infrastructure were available for the transport and storage of CO₂, the current policy framework in Australia does not provide a sufficient value on CO₂ emissions reductions to incentivise its use by emitters. In the absence of a clear price signal to reduce CO₂ emissions, it is far cheaper for emitters to vent CO₂ than capture it, even though investment in CCS may be beneficial for achieving longer-term targets at the lowest cost.

The Northern Territory government should keep track of the latest developments in the amendments to the ERF and liaise with the Commonwealth government on the design of the methodology for crediting CCS projects under the ERF. As one of the regions with low-cost CCS opportunities, the Northern Territory would have a lot to gain from ensuring the design of the ERF reflects the needs of CCS projects. Some of the issues that the Commonwealth government will need to address are identified in Section 8.5. In addition, the Northern Territory government should liaise with large emitters in the region to ensure the ERF reflects the commercial complexities of deploying CCS.

New Policy Options

Options to establish new policies beyond the ERF, as currently constituted, also exist. Ultimately, any new policy must provide a financial reward (or avoid a financial penalty) which is sufficiently large to incentivise private investment in CCS. Currently, the value of certificates under the Renewable Energy Certification Scheme is equivalent to a CO₂ value of approximately AUD45/tonne.¹⁸ It would not be unreasonable to consider establishing a scheme that paid a financial reward for each tonne of CO₂ stored to incentivise investment in CCS in the same way that the REC scheme has incentivised investment in renewable energy. If government funded the construction and operation of the transport and storage infrastructure, the value of the incentive would only need to be sufficiently high to cover the costs of compression (by the emitter) and relatively minor associated pipeline infrastructure between the emitters site and the CCS hub.

Consider the hypothetical case of an Incentive of AUD25 per tonne of CO₂. The cost to LNG producers of compressing the pure CO₂ they are currently venting (gas phase only, as necessary to transport it to the central

compression hub) and piping it to a central hub is around AUD10/tonne CO₂. If they received a financial reward of AUD25/tonne for CO₂ which is ultimately stored from a Commonwealth Government programme, the SPV (or operator of the transport and storage infrastructure) could charge a tolling fee of AUD15/tonne CO₂ resulting in a net cost to the LNG producer of zero. It is very likely that LNG producers would utilise this service if the net cost was very low or zero. This would provide the SPV with an ongoing revenue stream that could support its operational costs. If the capital for the infrastructure was granted to the SPV by the government, this revenue stream should be sufficient for the SPV to be profitable. Government, which would own the SPV, would then have the option of selling it to a private sector operator to recoup some of its initial investment. This option is worthy of further investigation, consultation and development.

In addition to or instead of providing price incentives, the Commonwealth government could consider introducing regulations that require new, large industrial facilities to meet an emissions performance standard that encourages investment in CCS. Chevron recognised the need to reduce CO₂ emissions from its Gorgon LNG project and included CCS in its Environmental Impact Statement. The approval of the project by the Western Australian Government subsequently included a mandatory condition to inject at least 80% of the reservoir CO₂ produced by the gas processing operations. The project is the world's largest dedicated CO₂ storage facility currently in operation with the ability to store up to 4 million tonnes of CO₂ per year.

One drawback of this approach is the potential impact on the short-term competitiveness and commercial viability of the investment in the industrial facility, particularly where it is producing a globally traded commodity. Financial penalties and regulation must be applied with caution to prevent perverse outcomes such as the movement of production capacity, and its associated emissions, to another jurisdiction with less stringent climate policy. In the case of the Gorgon LNG project, as one of the largest natural gas projects in the world, the additional costs of compressing and storing CO₂ were manageable, adding less than five per cent to the total project costs. The Northern Territory Government could have an important role to play in these considerations, by facilitating the consultation between the Commonwealth Government and emitters in the Northern Territory.

¹⁸ Assuming a REC value of approximately \$39/MWh and that the renewable electricity supported by the RECs displaces black coal generation with an emissions intensity of 0.88tCO₂/MWh.

8.7 Policy Update – Technology Investment Roadmap

Following the completion of the previous policy sections of this report, the Commonwealth Government announced its new Technology Investment Roadmap (TIR). The TIR contains significant new initiatives of relevance to CCS, although implementation is subject to the passage of necessary legislative amendments through the Commonwealth Parliament, and are thus not yet certain.

In summary, the TIR (amongst other things):

- Defines clean hydrogen and CCS as priority low emission technologies
- Sets stretch goals for clean hydrogen production at less than AUD2/kg and CO₂ compression, transport and storage at less than AUD20/t
- Authorises the Clean Energy Finance Corporation and the Australian Renewable Energy Agency (ARENA) to invest in a broader range of technologies including CCS
- Establishes an additional AUD1.9B in funding for priority technologies including
 - AUD1.6B for ARENA
 - AUD74.5M for Future Fuels (hydrogen is in scope)
 - AUD70.2M to support establishment of regional hydrogen export hubs
 - AUD50M to support the scale up of CCS commercial operations.

The TIR states that:

“The Government will invite expressions of interest from industry and state government to establish a regional hydrogen export hub. This will be a region in Australia where clean hydrogen users and exporters are co-located, creating efficiencies in supply and focal points for innovation and skills development.”

(Department of Industry Science Energy and Resources 2020)

Subject to passage of the necessary legislative amendments through the Commonwealth Parliament, the TIR establishes significant additional funding mechanisms that would be relevant to the creation of a CCS hub at Middle Arm. The Northern Territory could bid for support for the establishment of a regional hydrogen export hub, and/or could apply to access new funds made available under the TIR to support the completion of pre-feasibility studies. In any case, the Northern Territory Government should open a dialogue with the Commonwealth Government to discuss the opportunity to establish a CCS hub at Middle Arm, and to identify how the Commonwealth and Territory Governments could work together to realise this opportunity.

9.0 BEST PRACTICE COMMUNITY ENGAGEMENT

International best practice on the successful management of carbon capture and storage (CCS) projects is very clear:

“All successful projects integrate communication and public outreach activities into the project planning process from the beginning, treating stakeholder and community engagement as a critical component of project delivery”

(Ashworth et al. 2010).

The international CCS community has learned valuable lessons from the well-publicised failings of a few early CCS projects that experienced long, expensive, delays and often cancellation, due to serious public opposition because of a failure to properly consult and engage with influential stakeholders and local communities (Feenstra, Mikunda & Brunsting Petten (Netherlands)] 2010). In more recent years, as practices have improved, several great examples have emerged of highly successful stakeholder and community engagement programs, that have gone beyond simply mitigating the risk of public opposition, to enhance the relationships and reputation of project developers (Pragnell 2013).

The Barendrecht CO₂ storage project is an example of a failed CCS project due to public opposition. Although Shell did public engagement at Barendrecht, this happened reactively, once protests had already begun. The Barendrecht and Carson (US) projects have similarities in terms of public perception – they were perceived as being ‘top-down’ and ‘private’, and this perception contributed to their fate.

More successful projects in terms of public engagement outcomes had government participation during the site

selection phase and involved local stakeholders from the beginning; with a key contributing factor for public consent being the ability to influence the project’s decision-making.

Public engagement should involve all stakeholders that are impacted by the decision. Having a diverse stakeholder group and a participative method can significantly improve the quality of risk identification, risk analysis and decision making by drawing on different viewpoints, knowledge and values. A more participative approach to public engagement can lead to improved relationships and sustainable and innovative outcomes, primarily when public concerns and values feed into decision making at the early stages of the project (Ilinova, Cherepovitsyn & Evseeva 2018). The ‘Big Sky’ CCS demonstration project faced opposition but support improved when engagement activities ‘explored the value basis for the opposition and then involved communities in decision-making’ (Ilinova, Cherepovitsyn & Evseeva 2018).

Some significant risks or challenges when undertaking CCS specific public engagement could include:

- miscommunication risk,
- climate change scepticism,
- perceptions of CCS being ‘greenwash’,
- ‘not in my backyard’ mentality and
- lack of CCS and subsurface awareness.

The perception of risk and benefit will depend in part on the socio-cultural background of the various communities. The differing perspectives both within and across communities’ influence what is viewed as important policy issues, what approach and engagement processes are preferred as well as the perceived benefits associated with the project (Ashworth et al. 2012)

Lessons learned from CCS experts with direct public engagement experience include the need to explain the necessity for CCS, followed by tailored information

appropriate to each specific audience using useful visualisations and analogies. The most important factors (in decreasing priority) are:

- explaining why we need CCS with emphasis on decarbonisation (as opposed to focusing on 'how' it is done),
- using trusted communicators and information,
- gauging audience needs and addressing these appropriately,
- providing government leadership and consistency and
- open and direct communication using good visualisation and analogies (Ilinova, Cherepovitsyn & Evseeva 2018).

Experts with direct experience also stress the need to build relationships through early and on-going

engagement; explicitly tailored to the cultural and contextual requirements of the project. It is essential to find people the communities trust and enable them to become champions by providing them with clear facts, useful presentations and materials that are memorable and make it easy for them to communicate with others (Ilinova, Cherepovitsyn & Evseeva 2018).

9.1 Common Success Factors

The site-specific nature of engagement for a CCS project makes it difficult to define globally applicable lessons on "the right way" to engage and communicate with stakeholders. However, there are common themes that have emerged from successful early projects, and common challenges that CCS developers and social researchers have worked hard to overcome.

Figure 38. Common Success Factors

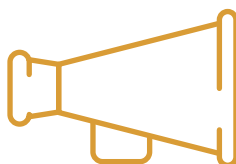
COMMON SUCCESS FACTORS

SHARED VISION



Project developers and funders share and communicate a common vision.

CORE COMMUNICATION FUNCTION



Communication engagement experts are embedded in a project team from outset.

UNDERSTAND SOCIAL CONTEXT



Thorough analysis of local environment stakeholders, sensitivities and opportunities undertaken at project outset.

THESE COMMON SUCCESS FACTORS ARE ALL ABOUT BUILDING TRUST...

EARLY & CONTINUOUS ENGAGEMENT



Early, open inspection with key stakeholders and efforts to maintain a visible trusted presence throughout the project's life.

TARGETED MESSAGING



What and how messages are communicated impact on project perceptions. Great communicators listen first.

EDUCATE & CREATE TANGIBLE EXPERIENCES



Investment in a program of ongoing engaging, educational and tangible outreach experiences.

9.2 Shared Vision

The site-specific nature of engagement for a CCS project makes it difficult to define globally applicable lessons on “the right way” to engage and communicate with stakeholders. However, there are common themes that have emerged from successful early projects, and common challenges that CCS developers and social researchers have worked hard to overcome.

As with most large scale and complex infrastructure projects, there tend to be many different groups of people involved with the design and delivery of a CCS facility: public and private investors, the facility developers (who very often span different industries and ways of working), and all the enabling stakeholders, such as local governments, trade unions, regulators and ENGOs.

Successful communication and engagement campaigns have presented a shared vision across the main project proponents, of what a project involves and why it is important. During the early development stages of multi-partner projects, this can be a challenging. When project partners and funders publicly use inconsistent messaging and have different ideas on the scope and value of a project, it creates a sense of uncertainty and confusion. This provides a prime opportunity for project critics to plant seeds of misinformation that breed fear and increase perception of risk.

A learning from the early UK CCS FEED studies for the Longannet Project was the intense effort that was required to co-ordinate communication and engagement activities across a multi-partner full-chain (capture, transport and storage) CCS Project:

“At the outset of FEED each Consortium Partner maintained their separate corporate positions and approaches to communications. The result was an, at times, disjointed communications program which in turn led to tensions between the communications leads from Partner organisations as they sought to protect their respective corporate reputations rather than take a collective approach in the development of the reputation of the Consortium.”

A clear structure, strong working relationships and a shared understanding of the responsibility or ownership of communications must be shared between Consortium Partners from the outset of any project work. If functioning properly, the communications workstream should be able to create a collegiate public-facing entity, in which Partners can adapt their communications approaches to operate on behalf of the Consortium as a whole.”

(ScottishPower CCS Consortium, 2011).

The Norwegian Full-Scale CCS Project is a more recent example of a multi-partner project that has been very successful in maintaining this shared public vision. Despite many different partners responsible for different parts of this project, all the project communication and engagement activity is run by Gassnova – a Norwegian State-owned enterprise established to ensure that CCS technology is implemented and becomes an effective climate mitigation measure. The Norwegian Full-Scale CCS Project recently held a ‘CCS Safari’ for influential, mainstream, international journalists. They were each able to visit and hear from representatives across various speciality areas. However, the overall vision and purpose of the project was presented by the Gassnova CEO – presenting a strong united front even between competing industry participants and the Government on the need for CCS in Norway.

From case studies like Barendrecht (Feenstra, Mikunda & Brunsting Petten (Netherlands)] 2010) Jämschwalde (Pragnell 2013), and the Carson Project (Bradbury & Wade 2010) in California, we can see clear examples of misalignment between different levels of government or a general ‘politicising’ of projects proving exceptionally difficult for developers.

9.3 Core Communication Function

A fundamental learning from all successful projects is the importance of embedding communication and engagement expertise within the team from the outset of a project. This is to ensure that the social, economic and political factors influencing a project are adequately represented when vital technical and commercial decisions are being made.

A telling example is drawn by Prangnell (2013), between the fierce public opposition experienced by the Barendrecht CCS Project that led to an effective moratorium on onshore CO₂ storage in the Netherlands, while just 50km from this project, the Rotterdam Opslag and Afvang Demonstratieproject (ROAD project) managed to achieve full project permissions with minimal upset. In analysing the differences between the two projects, Prangnell highlights the inclusion of an experienced stakeholder management resource at an executive level within the project team as an essential contributing factor to the differing fortunes of the two projects. To be clear, the ROAD project had such an experienced stakeholder management resource at the executive level and the Barendrecht project, which failed, did not.

9.4 Understand the Social Context

The most common public engagement mistakes tend to be made at the beginning of projects, with developers and funders not investing enough time and resource to mapping and gaining a full understanding of important project stakeholders, their current environment, perceptions and their potential issues or concerns.

The unexpected challenges faced by the project team at Barendrecht - a technically simple project - are frequently cited as a hard lesson in the importance of looking beyond technical and commercial elements of a project to understand the social context in which you are operating.

While producing a set of CCS guidance documents for the Global CCS Institute in 2011, social researchers Judith Bradbury, Sarah Wade and Sally Greenberg coined the term ‘Social Site Characterisation’ to help explain their recommended approach to understanding the social situation in which a potential CCS site may have to operate. The term was used to help technical and commercial teams working on early CCS projects relate to the process of gathering social data “just as physical site characterisation informs efforts to design a project to suit the local geologic and other physical conditions; social site characterisation can be used to design effective stakeholder engagement to suit local conditions” (Anderson, K. Bradbury, J. Greenberg, S. Klinkhammer, R. & Wade 2017).

In their 2011 toolkit, ‘Social Site Characterisation: From Concept to Application’ Wade and Greenberg (2011) give comprehensive explanations and recommendations of social science methodologies to gather general information about the project context, identify stakeholders and their perceptions and roles, and to analyse potential areas of concern or opportunity related to CCS projects.

Just like physical site characterisation, the process of gathering social data must be iterative throughout site selection, project design, and project operation. The social data is used to monitor changes in stakeholder behaviour proactively and to be mindful of external influences that could impact a project. Due to the long development lead times associated with most CCS projects, changes in social circumstances are inevitable; therefore, it is essential to monitor the situation and keep key stakeholders well informed of project developments.

The SouthWest Hub Project in Bunbury, Western Australia, experienced some community engagement challenges when it came to gaining land access and permissions. This quote was a lesson shared by the Project Manager, emphasising the importance of comprehensive baseline data to allow future monitoring that would stand up to scrutiny:

“If we could turn back the clock, I think we would invest in a more comprehensive community profile. Many of the challenges we face now have very little to do with CCS safety and more with legacy issues. Comprehensive baseline data would support regular monitoring for changes in behaviour and help us better target our messaging and engagement activities.”

(Dominique van Gent, South West Hub Project, Australia (Global CCS Institute 2013) Pg 140)

A key lesson from rolling out the social site characterisation toolkit to different projects was the importance of having engagement and a sense of responsibility for stakeholder identification and management across the entire project team. Occasionally there is a temptation to pass off all the ‘softer’ stakeholder related activities to communication staff, but this results in relatively poor-quality stakeholder mapping, social data and stakeholder feedback not being prioritised when decisions are being made, and challenges in building stakeholder trust in a project developer if the project’s technical staff are never visible.

9.5 Early and Continuous Engagement

The timing of a project's stakeholder engagement has been shown to have a decisive influence on the acceptance of a project. Early engagement with impacted or influential stakeholder groups (local communities, regulators, interested academics, environmental NGO groups, local councils, industry bodies and sometimes local media organisations) has emerged as the best approach to facilitate meaningful participation and to instil a sense of empowerment or affinity with the project within these different stakeholder groups.

“Project developers need to engage in meaningful dialogue with stakeholders and the public well in advance of project plans being finalised, making use of trusted advocates within different stakeholder groups.”

(Ashworth et al. 2013)

Early engagement should not be confused with early media activity or promotion before a project has been appropriately defined. Despite a relatively comprehensive public engagement strategy, the Carson Project in Los Angeles County, California, experienced challenging public backlash centred around air quality concerns and then on the unknown impacts of CO₂ storage. Later studies into the reactions to this project determined that many stakeholder groups felt that the project made a premature, high-profile media launch, before clarifying important areas of the project and ensuring local community awareness and support (Bradbury & Wade 2010).

Early engagement is about identifying influential and impacted stakeholders and engaging with a genuine intent to give them some influence over aspects of project development.

The recommendation is to involve influential stakeholders in the actual stakeholder identification and analysis process – bringing in representatives from different stakeholder groups to sit with project teams in mini focus group sessions to help give insight into their interests, concerns and preferred methods of engagement. This kind of early engagement is mutually beneficial - helping establish a much deeper understanding and often a sense of loyalty towards a project from influential stakeholders and helping a project team to gain much richer stakeholder data to create a better-targeted engagement strategy. However, this kind of activity is labour intensive, and once a trusted relationship is established with a stakeholder group it must be maintained.

Involving communities at some level of project decision making has helped some projects to progress smoothly through local permissions, and for communities to gain real benefits from a potential project siting. The Quest Project in Alberta, Canada found that involving impacted communities in the site selection for parts of their CO₂ pipeline was an extremely beneficial investment. They made a total of 30 changes to the initial pipeline route to take account of community feedback, resulting in positive responses from the community during their public hearing. The Longannet Project created a bi-monthly forum for all consenting regulatory bodies to come together with all project proponents to discuss and work through regulatory challenges based on the best available knowledge from the project operators.

9.6 Targeted Communication

One of the most common mistakes in communicating with local communities and stakeholders is to try and push out approved and memorised key messages, rather than listening to what stakeholders are asking. While supporting technical experts to communicate in an accessible manner, we had witnessed examples of project developers listing all the facts they had memorised to justify why someone should not be concerned about induced seismicity, when they were initially asked about likely noise pollution from building works.

Well-planned communication activity should be written from a stakeholder point of view, with staff trained to listen to what stakeholders are interested in or concerned about. The project staff should then adapt the messaging into a context that makes sense for that stakeholder.

‘Hot-seating’ and stakeholder role play are two beneficial training techniques to improve a project team’s level of empathy and understanding of stakeholder groups. Here, a member of the team is asked to take the ‘hot seat’ and respond to questions from colleagues who are taking on the roles of certain key stakeholder groups – forcing them to think about the kind of issues that concerns this group and the kind of questions they might ask.

Small stakeholder focus groups are an effective method for testing messaging and communication resources – again this is mutually beneficial as it will result in improved project resources and a more engaged set of stakeholders that are likely to be strong public champions for the project.

It is important to ensure messages come from trusted, sympathetic sources such as independent groups like ENGOs and academics, as well as the technical staff who have been trained to communicate. The public engagement team on the Peterhead Project in the UK created opportunities where senior technical and commercial project staff could meet with stakeholders and local communities, building their confidence and supporting them to become excellent ambassadors for the Project.

Although engineers, scientists and academics have a terrible reputation as communicators, in our experience, with some support their natural passion and enthusiasm for the topic combined with the authority of expert knowledge can be a handy communication tool. Independent advocates can be hugely influential but should be treated carefully. It is important to remember that they are independent and may hold views quite contrary to a project’s ambitions.

9.7 Educate and Create Tangible Experiences

Lack of awareness and understanding is one of the key barriers to engagement, not just with CCS, but also on more basic subjects like energy, material production,

CO₂ and climate change that are fundamental to understanding the importance of CCS technology.

Although CCS technology is increasingly recognised as a critically important climate mitigation technology in the international climate dialogues, CCS remains stubbornly in the shadows of public awareness.

Some great work has been done with projects and through organisations like the Institute, to improve the way we communicate about CCS – using resources that do not assume technical knowledge and help create a memorable and engaging experience of CCS to help overcome the distinct lack of iconic imagery for the technology.

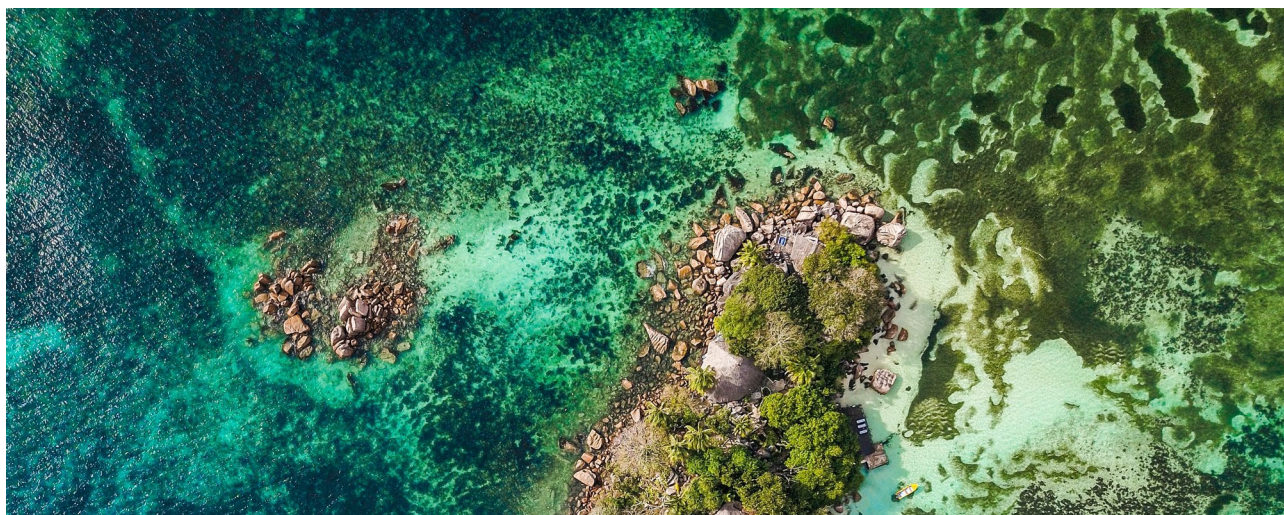
Also, successful projects that are in operation or under construction are now actively encouraged to publicly celebrate significant milestones and take the opportunity to engage a broader audience on CCS.

9.8 Building Trust

Central to each of these success factors is the practice of building trust. In their 2013 ‘Synthesis of Social Research’ Report, Ashworth et al. (2013) nicely sum up the many areas affecting CCS deployment.

“The various contexts that surround CCS are key determinants for acceptance, be it the economic context that affects how people perceive the use of public funds, the political context that can determine how CCS is framed in public discourse, or the socio-cultural context that informs ideas of what the ‘right’ way is to treat the environment”.

Similarly, the research has found that trust is vital. Not just trust in the capability of operators to carry out CCS safely, but also trust in the motivations of those delivering the CCS message. The way in which trust is developed and information is communicated will influence the levels of risk an uninformed public perceives in relation to a project.”



9.9 Project Case Study Building Trust

Title: Quest Project

Project lead: Shell

Country: Alberta, Canada

Status:

Operational since November 2015, in July 2020 Quest had captured and stored over 5 million tonnes of CO₂

The Project

- A fully integrated CCS project in Alberta, Canada, developed as part of the Athabasca Oil Sands Project (AOSP).
- The respective ownership interests of AOSP assets in aggregate, directly and indirectly, are 70% Canadian Natural Resources Limited and an affiliate, 20% Chevron Canada Limited and 10% Shell Canada Limited through certain subsidiaries..
- Quest captures 1.2 Million tonnes of CO₂ per year from steam methane reformer units at the Scotford Upgrader (a facility that produces hydrogen and other chemicals from the Athabasca tar sands in Alberta).
- A 64km pipeline transports CO₂ to an onshore deep saline formation for storage 2km below ground.
- Shell has worked hard to fully understand and engage with community leaders and key stakeholders on this project, including a challenging ENGO community and with the possibility for additional EOR.

Key Learnings

- Quest went to considerable effort to identify and understand who the influential people and groups within impacted communities are, particularly along the pipeline corridor and storage site.
- Independent public opinion surveys were used to flag any potential areas of challenge.
- The Project engagement strategy set out to maximise benefits to stakeholders and build on existing relationships in communities.
- Following an initial announcement and early 'open house' events, a more focused engagement strategy began to target key stakeholders (landowners, regulators and local authorities, indigenous communities).
- Quest actively involved local ENGO groups like the Pembina Institute in helping shape the project and its communication activity.
- Learning from Barendrecht, this project was consultative and accommodating to stakeholder feedback – with multiple changes made to pipeline routes to meet stakeholder needs.
- The project team made a conscious effort to be present at community events and festivals.
- A great deal of effort was put into aligning and simplifying the project messaging – setting the project firmly in the context of climate change and emission reductions.
- Shell created a CCS lift simulator and a VR Goggle experience to help with communication and engagement efforts on Quest and CCS more generally.
- The Quest Team worked hard to create a welcome presence in local communities and build trust in the project.

10.0 BLUEPRINT OF ACTIONS

The purpose of this Blueprint is to summarise the next steps the NT Government would be required to take to develop a CCS hub at Darwin harbour. The next phase is to determine whether to proceed to the completion of a prefeasibility study, and then to complete the study. The Blueprint is described below and summarised, together with the first approximation of schedule and resource requirements in Figure 33. Blueprint of Actions.

10.1 Build a Partnership with the Commonwealth Government.

The most significant barriers to the establishment of a CCS hub in Darwin arise from the market failures described in 8.2. Collectively, these market failures result in the absence of an appropriate risk-weighted return for private sector actors who might consider investing in CCS. Consequently, as has been the case for the development of many other industries, there is a role for government to implement policy to correct market failures and align private investment incentives with the broader long-term public interest.

The development of a CCS hub in Darwin would serve the interests of both the Northern Territory and Commonwealth governments. It would support increased production of LNG at Darwin in the medium to long term, facilitate the establishment of new low emissions industries in northern Australia, and make a material contribution towards meeting Australia's long-term climate mitigation commitments under the Paris Agreement. The Commonwealth Government has already implemented a suite of relevant policies and programmes and has recently introduced new initiatives specifically targeting support for carbon capture and storage in Australia. The Commonwealth has very significant resources and relevant experience and expertise. Whilst it is possible for the Northern Territory to support the development of a CCS hub alone, active support from the Commonwealth would improve efficiency and increase the probability of success. Now is the time to engage the Commonwealth Government

to create a shared vision for the development of a CCS hub at Darwin and to create a partnership designed to deliver that vision.

Action 1a: Engage with the Commonwealth Government to develop a shared vision for a CCS hub to support the existing LNG industry and the development of new low emission industries at Darwin.

There are many possible pathways towards the development of a CCS hub at Darwin. Ultimately, any pathway that efficiently corrects the market failures described in 8.2 will be successful. Section 8.6 suggested one potential pathway based upon an analysis of the current policy environment, an understanding of existing market failures, and what has worked elsewhere. This framework could be offered as one potential solution to focus discussion with the Commonwealth Government.

Action 1b: Propose a development pathway to the Commonwealth to focus discussion and identify specific policy measures that may be implemented. One possible framework for discussion is summarised below.

- a. Establish a government-funded Special Purpose Vehicle (SPV) to develop a CCS hub in the Northern Territory
- b. A government-funded programme to appraise storage resources in the Petrel Sub-basin is implemented. The programme could be managed by the SPV.
- c. The SPV is funded by the Commonwealth to construct, own and operate CCS hub infrastructure and to charge users a fee for CO₂ storage services.
- d. A financial reward, which is paid per tonne of CO₂ stored to incentivise current and future operators at Middle Arm to utilise transport and storage infrastructure, is created through a Commonwealth government policy measure. If the CCS hub infrastructure was constructed, owned and operated by a government-funded SPV, an incentive less than \$25/tonne could be sufficient. The value of the incentive and the value of the fee for utilising the infrastructure could be calibrated such that:

- i. there is a strong business case for current operators to store their CO₂ using the CCS hub.
- ii. Middle Arm is an attractive location to establish new industries that will benefit from the availability of CO₂ storage services.

The first step in securing the right to undertake exploration for greenhouse gas storage resources is the release of acreage by the National Offshore Petroleum Titles Administrator (NOPTA). It would be wise to seek to initiate this process as soon as possible so as not to introduce unnecessary delays in the project development schedule.

Action 1c: Consult the Commonwealth Department of Industry, Science, Energy and Resources (DISER) to request the release of Acreage encompassing the Area of Interest shown in Section 1.4 of this report.

10.2 Consult Industry Stakeholders

Any CCS hub can only be a success with the active participation of private sector emitters. That participation could be through direct investment in the CCS hub infrastructure or as a customer of the CO₂ storage services it offers. Operators of the DLNG and Ichthys gas processing facilities have a critical commercial interest in any proposed CCS hub. To be successful, a CCS hub must integrate effectively with the LNG facilities without reducing their operability, and there must be a sound business case for its utilisation. The same applies to industrial facilities that may be established at Middle Arm in the future, including additional gas processing facilities or gas manufacturing industries. Further, industry cooperation will be necessary to inform future feasibility studies, and it is probably true that strong industry opposition will make the development of a CCS hub extremely difficult at best, and most likely impossible.

To ensure engagement is substantive and focused, a Request for Information (or similar process) could be issued where the Territory government describes the CCS hub concept it is considering and then requests submissions from industry addressing specific questions or issues. This would be the first step of an ongoing industry consultation process as consideration of the hub develops.

Action 2a: Develop and issue a Request for Information (or similar process) seeking submissions from industry that address specific questions or issues related to a proposed CCS hub at Middle Arm.

10.3 Establish a Community Engagement Programme

CCS is generally not well understood by the community. It is often confused with hydraulic fracturing or is perceived to be experimental, unproven or even dangerous. It is essential that the community be informed and involved in planning for any significant industrial development, especially one that involves unfamiliar processes like CCS. As described in section 9, the integration of communication and public outreach activities into project planning processes from the beginning is essential to mitigate the risk of strong public opposition halting or at least delaying the project. This programme should commence in parallel with consultation with industry stakeholders.

Action 2b: Establish a dedicated communication function with appropriate resources to serve the project. An early priority should be collecting data on community concerns and attitudes to inform the development and implementation of a Community Engagement Plan. It is critical that community consultation and engagement commence in parallel with industry consultation.

10.4 Stage-Gate 1: Go or No-Go for Prefeasibility Studies

At this point, considering the progress of discussions with the Commonwealth Government, industry and local communities, the NT government should form a view on whether a CCS hub at Middle Arm is likely to prove feasible as the following steps will require the commitment of significant resources.

Action 3: Decide whether to proceed with a prefeasibility study for a CCS hub at Middle Arm.

10.5 Obtain a Greenhouse Gas Assessment Permit

It is necessary to undertake storage site appraisal to confirm the suitability of the geological structure and precise injection location for CO₂ storage activities. As described in section 2.2 of this report, those activities can only be undertaken in Commonwealth waters under a Greenhouse Gas Assessment Permit issued under the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (OPGGGS Act).

Once acreage is released, the award of a Greenhouse Gas Assessment Permit is a competitive process. DISER will publish the criteria on which applications will be judged. Generally, bidders will be required to prepare an exploration work programme describing the exploration activities it intends to undertake within the acreage, and/or the value of the programme it intends to implement.

Action 4: Prepare a greenhouse gas storage exploration work programme and apply for a Greenhouse Gas Assessment Permit. This programme should include the collection of 3D seismic data over the Area of Interest followed by the drilling of an exploration or appraisal well.

10.6 Establish a CCS Hub Project Team

Assuming a decision to proceed is reached at the first stage-gate, a Project Team with access to relevant specialist expertise and experience will be required to manage further studies. Key disciplines in which the Project Team will require high levels of competence will include at least the following:

- industrial feasibility study management
- project management
- gas production and processing
- gas pipelines and compression (engineering)
- offshore subsurface exploration & development
- community engagement & public relations
- indigenous heritage management
- compliance management
- financial & commercial analysis
- health, safety and environmental management

Action 5: Establish a CCS hub Project Team staffed by individuals with the requisite skills and experience.

10.7 Define the Scope and a Plan for Execution of the Prefeasibility Study

One of the first deliverables of the CCS Hub Project Team should be the definition of the scope of the prefeasibility study and a plan for its execution. The storage site appraisal is a critical component of the broader prefeasibility study.

Completing the prefeasibility study is a major undertaking. In addition to the many significant desktop analyses required, this prefeasibility study will require significant field work including the acquisition of 3D seismic data by a specialist ship, and then the drilling of an exploration/appraisal well. Development of the scope and plan for the prefeasibility study requires highly skilled and experienced personnel.

Action 6: Develop a scope and plan for completion of a prefeasibility study.

10.8 Complete Prefeasibility Study including Storage Site Appraisal

Note that in addition to compliance with the provisions of the OPGGS Act and regulations, the implementation of greenhouse gas storage site exploration and appraisal activities will be subject to various other Commonwealth and NT legislation. This will include legislation related to environmental protection, indigenous heritage, workplace health and safety, planning and other operational requirements.

As previously mentioned, completing this prefeasibility study is a major activity including significant field work required to collect geological data on the Area of Interest.

Action 7: Undertake the prefeasibility study including the exploration programme under the approved Greenhouse Gas Assessment Permit.

10.9 Stage Gate 2: Go or No Go for Feasibility Study and Choice of Development Option

After completion of the prefeasibility study, the NT government will know, with low uncertainty, whether a CCS Hub at Middle Arm is feasible, and if so, will be in a position to choose a preferred development option for more detailed feasibility studies.

Action 8: Decide whether to proceed with a feasibility study and if so, choose the preferred development option for study.

Figure 39. Blueprint of Actions

BUILD A PARTNERSHIP WITH THE COMMONWEALTH GOVERNMENT MONTH 0 TO MONTH 3	CONSULT INDUSTRY & THE COMMUNITY MONTH 0 TO MONTH 6	STAGE GATE 1: GO OR NO-GO FOR PRE-FEASIBILITY STUDIES MONTH 7	OBTAIN A GREENHOUSE GAS ASSESSMENT PERMIT MONTH 7 TO MONTH 19
Actions 1a: Engage with the Commonwealth Government to develop a shared vision for a CCS hub to support the existing LNG industry and the development of new low emission industries at Darwin. 1b: Propose a development pathway to the Commonwealth to focus discussion and identify specific policy measures that may implemented. 1c: Consult the Commonwealth Department of Industry, Science, Energy and Resources (DISER) to request the release of Acreage encompassing the Area of Interest shown in Section 1.4 of this report. Resources Required • NT Government industrial development policy personnel and possibly minor external resources (consultancy) to support policy development. • Consultancy support may cost \$20k	Actions 2a: Develop and issue a Request for Information (or similar process) seeking submissions from industry that address specific questions or issues related to a proposed CCS hub at Middle Arm. 2b: Establish a dedicated communication function with appropriate resources to serve the project. An early priority should be collecting data on community concerns and attitudes to inform the development and implementation of a Community Engagement Plan. Resources Required • Dedicated Senior Community Engagement Specialist plus operational expenses. • Operational expenses (excluding the specialist) for the Community Engagement Programme may cost \$10k	Actions 3: Decide whether to proceed with a prefeasibility study for a CCS hub at Middle Arm.	Actions 4: Prepare a greenhouse gas storage exploration work programme and apply for a Greenhouse Gas Assessment Permit. This programme should include the collection of 3D seismic data over the Area of Interest followed by the drilling of an exploration/appraisal well. Resources Required • Support from a specialist in offshore subsurface exploration. • External support may cost around \$50k

Figure 39. Blueprint of Actions (continued)

ESTABLISH A CCS HUB PROJECT TEAM MONTH 16 TO MONTH 19	DEFINE THE SCOPE AND PLAN FOR EXECUTION OF THE PREFEASIBILITY STUDY MONTH 20	COMPLETE PRE-FEASIBILITY STUDY INCLUDING STORAGE SITE APPRAISAL MONTH 21 TO MONTH 33	STAGE GATE 2: GO OR NO-GO FOR FEASIBILITY STUDY AND CHOICE OF DEVELOPMENT OPTION MONTH 34
Actions 5: Establish a CCS Hub Project Team staffed by individuals with the requisite skills and experience. Resources Required The team will require high level competence in at least the following disciplines: • industrial feasibility study management • project management • gas production and processing • gas pipelines and compression (engineering) • offshore subsurface exploration & development • community engagement & public relations • indigenous heritage management • compliance management • financial & commercial analysis • health, safety and environmental management	Actions 6: Develop a scope and plan for completion of a prefeasibility study. Resources Required • The CCS Hub Project Team • Probably support from an engineering firm experienced in developing prefeasibility studies for industrial and oil/gas production projects.	Actions 7: Undertake the pre-feasibility study including the exploration programme under the approved Greenhouse Gas Assessment Permit Resources Required • The CCS Hub Project Team • Probably support from an engineering firm experienced in developing prefeasibility studies for industrial and oil/gas production projects. • Storage site appraisal may cost around \$20 million for acquisition and analysis of 3d seismic data plus around \$50 million for an offshore appraisal well, sampling and analysis. • The remainder of the prefeasibility study, including study scope definition and planning may cost around \$3 million.	Actions 8: Decide whether to proceed with a feasibility study and if so, choose the development option for study.

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