Life Cycle Carbon Footprint Study of Onshore Shale Gas in the Northern Territory

Undertaken by Lifecycles

Tim Grant

March 2022

Citation

Grant T.F. (2022) Life Cycle Carbon Footprint Study of Onshore Shale Gas in the Northern Territory. Life Cycle Carbon Footprint. Lifecycles, Melbourne, Australia.

Copyright

Important disclaimer

Version	Revision	Author	Reviewed by	Comments
Draft	1.0	Tim Grant	Anna Boyden	Draft for comment
Draft	1.9	Tim Grant		From Tim Baynes comments
Draft	2.0	Tim Grant		Send for Review
Draft	3.05	Tim Grant		Responses for review
Final	3.06	Tim Grant		Final release
Final	3.07	Tim Grant		Minor editorial fixes
Final	3.08	Tim Grant		Minor Reviews edits
Final	3.09	Tim Grant		Additional references and clarification of

Contents

Figures

Tables

Glossary

Term	Definition (including source)
Allocation	Partitioning the input or output flows of a process or a product system between the product system under study and one or more other product systems (ISO 14040).
Carbon dioxide equivalent (CO_2 e)	Unit for comparing the radiative forcing of a greenhouse gas to that of carbon dioxide (ISO/TS 14067).
Carbon footprint (CFP)	Sum of greenhouse gas emissions and removals in a product system, expressed as CO_2 equivalents and based on a life cycle assessment using the single impact category of climate change (ISO/TS 14067).
Characterisation factor	Factors derived from a characterisation model are applied to convert an assigned life cycle inventory analysis result to the common unit of the category indicator (ISO 14040).
Critical review	Process intended to ensure consistency between a life cycle assessment and the principles and requirements of the international standards on life cycle assessment (ISO 14040).
Cut-off criteria	Specification of the amount of material or energy flow, or the level of environmental significance associated with unit processes, or product system, to be excluded from a study (International Organization for Standardization 2006).
Determining product	A determining product of an activity is defined as a product for which a change in demand will affect the production volume of the activity. It is also sometimes called a "reference product" (e.g. in ecoinvent terminology).
Fossil carbon	Carbon contained in fossilised material (ISO 2018).
Functional unit	Quantified performance of a product system for use as a reference unit (ISO 14040).
Global warming potential (GWP)	Characterisation factor describing the radiative forcing impact of one mass-based unit of a given greenhouse gas relative to that of carbon dioxide over a given period of time (ISO 2018).
Greenhouse gas (GHG)	Natural or anthropogenic gaseous constituent of the atmosphere that absorbs and emits radiation at specific wavelengths within the spectrum of infrared radiation emitted by the earth's surface, the atmosphere and clouds (International Organization for Standardization 2015).
Life cycle assessment (LCA)	Compilation and evaluation of the inputs, outputs and the potential environmental impacts of a product system throughout its life cycle (ISO 14040).
Life cycle impact assessment (LCIA)	Phase of life cycle assessment aimed at understanding and evaluating the magnitude and significance of the potential environmental impacts for a product system throughout the life cycle of the product (ISO 14040).

Life cycle inventory (LCI)	Phase of life cycle assessment involving the compilation and quantification of inputs and outputs for a product throughout its life cycle (ISO 14040).
Risked resource	The resource availability after accounting for the probability of success of resource extraction at the well.
System boundary	Set of criteria specifying which unit processes are part of a product system (ISO 14040).

Acronyms used in this report

AusLCI	Australian Life Cycle Inventory Database
bbl	Barrel (petroleum) = 42 gallons
Bcf	Billion cubic feet
CCS	Carbon capture and storage
Cft	Cubic foot
EUR	Estimated ultimate recovery
GHG	Greenhouse gas
GTP	Global temperature potential
GWP	Global warming potential
HHV	Higher heating value
IPCC	Inter-governmental Panel on Climate Change
LCA	Life cycle assessment
LCI	Life cycle inventory
LCIA	Life cycle impact assessment
LNG	Liquified natural gas
LPG	Liquified petroleum gas
MEA	Monoethanolamine
MEE-MVR	multiple-effect evaporation with mechanical vapour recompression
MJ	Megajoule = 10^6 joules
Mt	Megatonne = 10^6 tonnes
NGER	National Greenhouse and Energy Reporting Scheme
NT	Northern Territory
PJ	Petajoule = 10^{15} joules
SMR	Steam methane reforming
Tcf	Trillion cubic feet
UK	United Kingdom
US	United States

Executive Summary

The study documents the Carbon Footprint (CFP) study which quantifies the greenhouse gas emissions of proposed Northern Territory Beetaloo Sub-basin shale gas project. The key objective of this CFP is to establish the size and timing of the life cycle GHG emissions offsets required to make onshore shale gas extraction in the Northern Territory climate neutral. Note that the CFP does not include the process for offsetting emissions or comparisons with alternative energy sources.

The product from the proposed Northern Territory Beetaloo Sub-basin shale gas projects is an energy commodity functionally equivalent to natural gas, which is typically greater than 90% methane with small components of other hydrocarbons. This product is suitable, after treatment of any contaminants, for use as distributed gas, industrial feedstock for processes such as ammonia and hydrogen production and, after compression and refrigeration, as liquified natural gas (LNG) for export and use in overseas markets.

The extraction process for shale gas involves vertical and horizontal drilling to access gas trapped in shale sediments, which are between approximately 1,500 to 3,000 metres below ground. To access the gas, the layers need to be fractured with high-pressure liquid, which contains mostly water as well as a small amount of sand and chemicals.

The main consumables are steel and cement lining for the wells to avoid contamination of other ground water layers, and the water itself with the sand and chemical additives. The outputs from the process include valuable products, mainly gas and some condensates, as well as products for waste treatment such as the blow back water that is released from the fracking process. There is also fugitive methane and vented carbon dioxide when the gas is extracted. Once extracted, the gas needs to be cleaned and dried before being transported to end-use markets or compressed and liquefied to LNG for export.

Table 1 shows the five production scenarios included in the CFP - four of which are based on total annual production of 365 PJ per annum for 25 years with different mixes of utilisation technology, and a fifth scenario which is based on 1,130 PJ per Anum including all technologies previously tested.

Table 1 Scenarios assessed in CFP study

Scenario name	Output (PJ/year)	Domestic gas supply (PJ/year)	Refinery products (PJ/year)	LNG for export (PJ/year)	Methanol (PJ/year)	Ammonia (PJ/year)	Hydrogen (PJ/year)
Sc1 Dom. gas & LNG	365	45		320			
Sc2 Dom. gas, LNG & refinery	365	45	120	200			
Sc3 Dom. gas, LNG & chemicals	365	45		200	60	60	
Sc4 Dom. gas, LNG & hydrogen	365	45		200			120
SC 5 All	1,130	45	120	725	60	60	120

The system boundary in a CFP study describes the processes included in the study. Four boundaries are used in the study which progressively broaden the inclusions at each stage. They are:

1. Shale gas production – extraction and processing
2. Shale gas production and manufacturing (natural gas products such as LNG, H_2 etc)
3. Shale gas production, manufacturing and domestic use
4. Shale gas production, manufacturing and use globally (domestic and international)

The fourth option here is what would be included and a cradle to grave CFP study boundary.

Results

Before calculating the impacts of each scenario in total, the impacts of each end use of the shale gas were calculated per GJ of raw shale gas input to help understand how the end use will effect the impacts of different scenarios.

Figure 1 provides the impact profiles for the extraction, production, and utilisation of 1 GJ of raw shale gas to different destinations and technologies. Of the six destinations five of them involve the complete release of carbon embodied in the shale gas at some point in the production chain. For this reason, the total emission from those five destinations is relatively similar, ranging between 57 and 80 kg CO_2 e per GJ. The scenario for methanol holds some of the carbon in the final product; however, depending on the ultimate use of the methanol this may eventually be released to the environment.

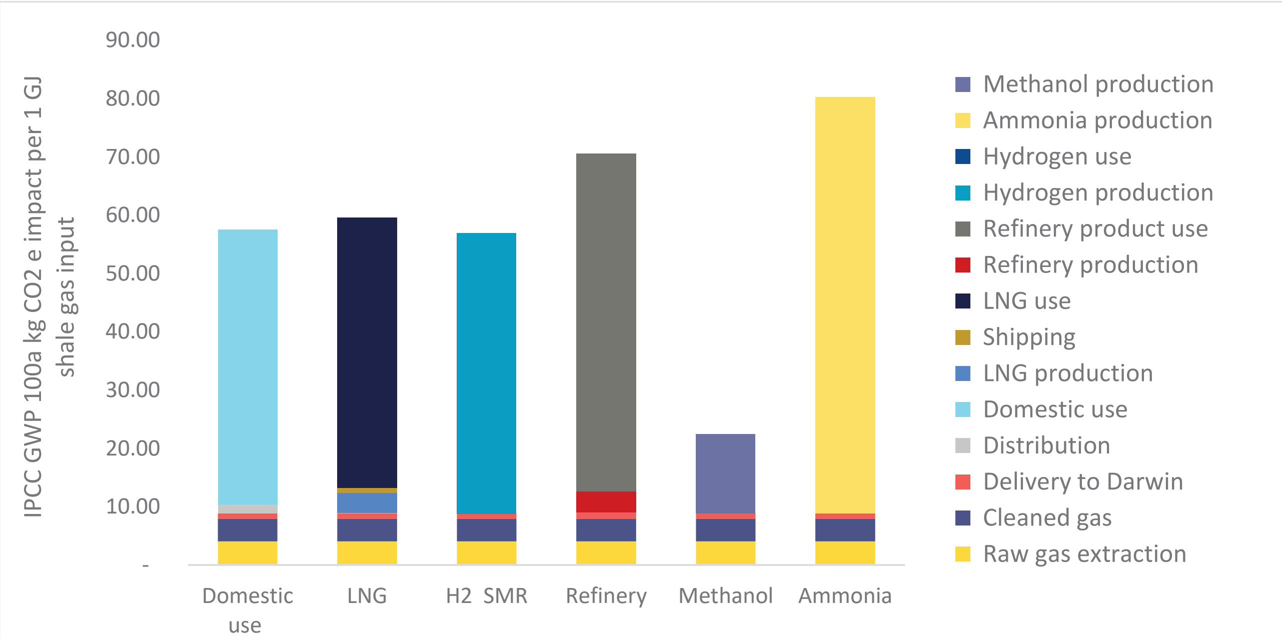


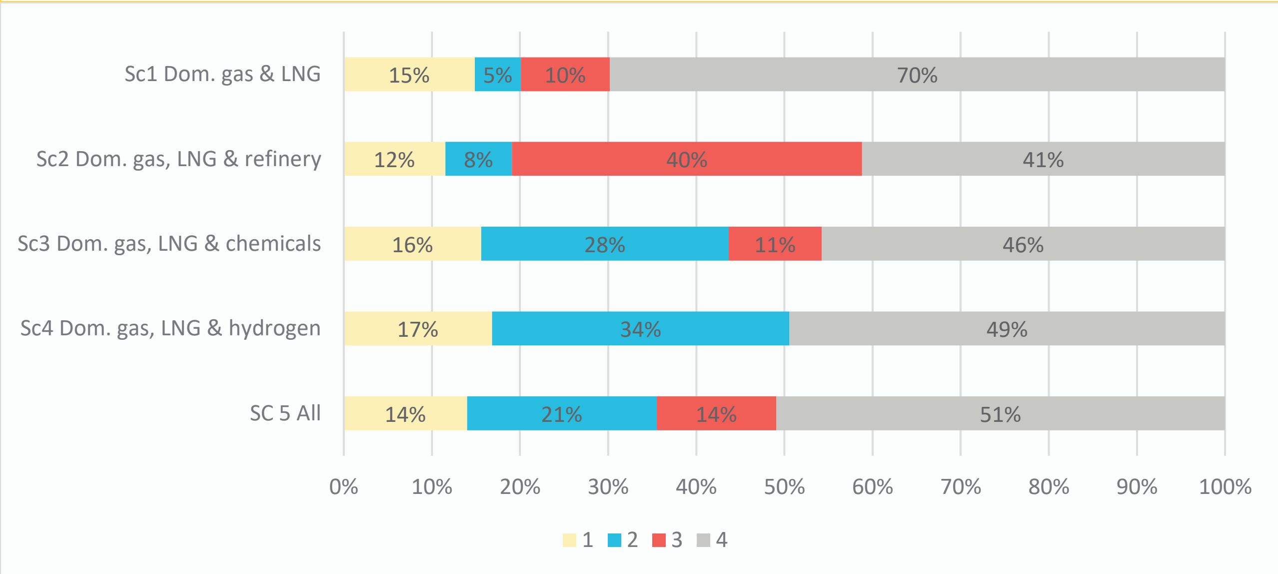
Figure 1 Climate change kg CO_2 e impact per 1 GJ shale gas input.

Table 2 shows the results for all scenarios using 4 different boundary conditions as well as the percentage impacts added in each progressive expansion of the boundary.

Because of the large volume of shale gas which is destined to overseas use via LNG production and export, the fourth system boundary described (all gas production, manufacturing and use globally) adds between 41% and 70% depending on the scenario.   It adds more than half the total emissions in scenario 5 with more than 34MT of CO2 e being from use of LNG in overseas markets.

Table 2 Greenhouse gas emission by scenario in Mt CO_2 e over 25-year life for four different system boundaries and percentage of emissions added by each expansion of the boundary.

	1 Shale gas production	2 Shale gas production and product manufacturing	3 Shale gas production, manufacturing and domestic use	4 Shale gas production, manufacturing and use globally
Sc1 Dom. gas & LNG	3.23	4.36	6.55	21.7
Sc2 Dom. gas, LNG & refinery	2.65	4.39	13.53	23.0
Sc3 Dom. gas, LNG & chemicals	3.23	9.04	11.23	20.7
Sc4 Dom. gas, LNG & hydrogen	3.23	9.71	9.71	19.2
SC 5 All	9.43	23.89	33.03	67.3



While the single point value calculated for the total CFP for scenario 5 was 67.3 Mt CO_2 using an uncertainty assessment the CFP for scenario 5 are estimated to be between 65 and 76 Mt CO_2 e using a 95% confidence internal (95% of Monte Carlo simulations fall withing these values). The uncertainty analysis is based on estimated probability distributions used for calculation parameters as well as uncertainty of all background data. The other scenarios show a similar spread to scenario 5.

1 Introduction

This document presents a life cycle carbon footprint (CFP) study of potential new onshore natural gas projects in the Northern Territory.

The key objective of this CFP is to establish the size and timing of the life cycle GHG emissions offsets required to make onshore shale gas extraction in the Northern Territory climate neutral.

The CFP does not include the process for offsetting emissions or comparisons with alternative energy sources, which may be required if shale gas projects are not implemented.

The CFP will be based primarily on ISO 14067 International Standard "Greenhouse Gases – Carbon Footprint of Products – Requirements and Guidelines for Quantification (International Organization for Standardization 2018). The study also draft on guidance from the International Standard on Life Cycle Assessment (International Organization for Standardization 2019b) which provides the high-level framework for undertaking an CFP.

2 Goal and scope

2.1 Goal

The goal of the CFP is to establish the life cycle GHG emissions from the proposed development of onshore gas from the Northern Territory Beetaloo Sub-basin for the purpose of then developing offset projects to mitigate these emissions.

The report is intended to be used to help design the offset strategy but could beyond this form part of the scientific basis for carbon neutral certification under the national Climate Active initiative or similar.

The audience for the study will be the research team at CSIRO examining potential offset projects. In addition to this, the CFP will be disseminated to a range of stakeholders including Aboriginal and Torres Strait Land Councils, senior officers from the Northern Territory Government and representatives of the carbon offset industry.

The report will not include any comparative assertions on the superiority or otherwise of shale gas compared with alternative energy sources; however, it is expected that the results from the report will be compared with alternatives, and therefore the CFP will follow the requirements of ISO14044 for comparative assertions.

2.2 Scope

2.2.1 Product system under study

The product from the proposed Northern Territory Beetaloo Sub-basin shale gas projects is an energy commodity functionally equivalent to natural gas, which is typically greater than 90% methane with small components of other hydrocarbons.

This product is suitable, after treatment of any contaminants, for use as distributed gas, industrial feedstocks for processes such as ammonia and hydrogen production and, after compression and refrigeration, as liquified natural gas (LNG) for export and use in overseas markets.

The exact composition of the shale gas is not known given but the scientific enquiry noted that "Shale gas in the Beetaloo Sub-basin contains very low levels of corrosive gases such as CO_2 and H_2S (Scientific Enquiry 2018b).

The extraction process for shale gas involves vertical and horizontal drilling to access gas trapped in shale sediments, which are between approximately 1,500 to 3,000 metres below ground. To access the gas the layers need to be fractured with high-pressure liquid, which contains mostly water and a small amount of sand and chemicals. The main consumables are steel and cement lining for the wells to avoid contamination of other ground water layers, and the water itself with the sand and chemical additives. The outputs from the process include valuable products, mainly gas and some condensates, and products for waste treatment such as the blow back water that is released from the fracking process. There is also fugitive methane and vented carbon dioxide from the gas extracted.

Once extracted, the gas needs to be cleaned and dried before being transported to end-use markets or compressed to LNG for export.

2.2.2 Temporal scope

Product life cycle

The time frame for the product system is based on the anticipated life of the projects under consideration. The CFP will cover onshore shale gas extraction from the Beetaloo Sub-basin from 2025 to 2050. Different scenarios for the production levels will be used over this time span.

The time frame for calculation of global warming potential (GWP) will be 100 years following the recommendations from the *IPCC Fifth Assessment Report* (IPCC 2013). A sensitivity analysis will be performed to examine the impacts of using updated values for GWP over 20 years, GWP for 100 years and a global temperature potential (GTP) for 100 years as recommend in the UN Environment Programme/Society for Environmental Toxicology and Chemistry Life Cycle Initiative (Frischknecht and Jolliet 2016).

The timing of GHG emissions will be presented; however, the GWPs will be applied as if all emissions occur at the beginning of the project. That is to say, there will be no use of time sensitive GWPs that allow for lower GWPs for delayed emissions.

2.2.3 Geographical scope

Extraction

The geographical scope of the CFP focuses on extraction of shale gas from the area referred to as the Beetaloo Sub-basin, as shown in Figure 2. According to Falcon Oil and Gas, there is a technically recoverable resource of 89,000 PJ (85 Tcf) (Falcon Oil & Gas Ltd 2021). This is the maximum possible quantity of gas considered available for extraction, noting that it is highly uncertain how much of this is economically feasible to extract and that less than 7,000 PJ (7.4%) has been identified as a Contingent Resource.(Origin Energy Limited 2021)

Given this uncertainty, the total quantity of gas extracted over the study period (25 years) will not be based on Reserves, but rather assumed rates of extraction at levels which, in the estimation of the *Scientific Inquiry*, are suitable for an environmental impact risk assessment (See Chapter 9 p. 229 of the *Scientific Inquiry into Hydraulic Fracturing in the Northern Territory* (2018)).

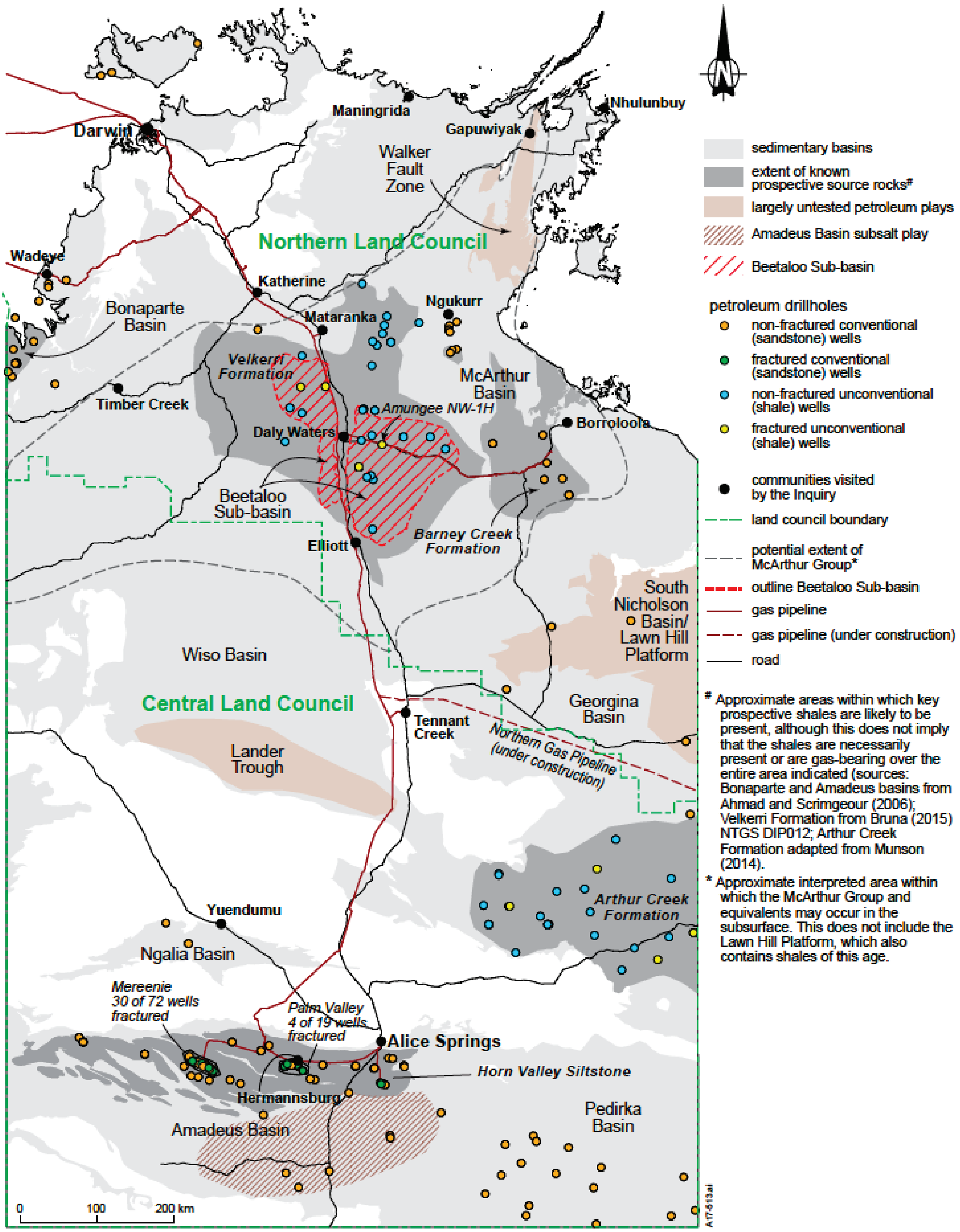


Figure 2 Location and boundary of the Beetaloo Sub-basin from Chapter 6 of the *Scientific Inquiry into Hydraulic Fracturing in the Northern Territory – Final Report* (2018), © The Northern Territory of Australia.

Production

The processing of extracted gas into various energy and chemical products is expected to take place in the Northern Territory. The two main products will be domestic gas supply to the Northern Territory and LNG for export markets, which are predominantly in Asia. Ammonia and hydrogen products could also be produced in the Northern Territory from the extracted gas. If the gas extraction includes significant liquid fractions, such as oils and condensates, these could either be refined in the Northern Territory for the petroleum market or exported for refining elsewhere in Australia or overseas.

Use

The use of products is expected to be a mix of domestic consumption in the Northern Territory and other parts of Australia, and overseas consumption. For a complete CFP scope, emissions will be calculated for all uses of products from Beetaloo Sub-basin, but differentiated by end markets from the Northern Territory, the rest of Australia and the rest of the world. The actual carbon offsetting will could be based on Australian emissions only, so the emissions from overseas utilisation of gas will not be included in the carbon offset. However, as the report may provide insights to alternative scenarios, it is important to include the complete carbon footprint of the project from cradle to grave.

2.2.4 Functional unit

ISO 14044 describes the functional unit as defining what is being studied, and states that all results should be relative to the functional unit. The definition of the functional unit needs to clearly articulate the functionality or service that is under investigation. The functional unit is common for all scenarios being assessed in the study.

The goal of the study is the calculation of the carbon footprint of shale gas products under different development scenarios.

While the product in this CFP is predominately natural gas, the aim of this CFP focuses on the requirements for offsetting the emissions from the project. The different scenarios being assessed will have vastly different quantities of product, which makes a common quantitative reference, such as 1 PJ of gas, impractical. What is common between all scenarios is that they will represent the total production from the Northern Territory Beetaloo Sub-basin *between 2025 and 2050.*

Therefore, the functional unit used for this assessment is:

"the product supply and use of all proposed shale gas products from the Northern Territory Beetaloo Sub-basin between 2025 and 2050."

2.2.5 Scenarios

In the development of scenarios to test the CFP, three variables are being assessed:

- scale of development
- type of play – gas only (dry gas) or liquids-rich gas (wet gas)
- mix of products to be made from the extracted gas and liquids.

Scale of development

As part of the *Scientific Inquiry* (Scientific Enquiry 2018b), overall scale of production was modelled with three scenarios referred to as “breeze”, “wind” and “gale”. Each scenario represented increasing levels of production, with breeze the lowest level and gale the highest level. Note that two other scenarios were modelled for the economic analysis but did not include any production from the Betaloo Sub-basin, so are not included in the CFP.

For the purpose of this CFP the two scales of development have been included – one at 365 PJ per year and larger scale at 1130 PJ per year.

Dry gas/wet gas

The type of gas to be extracted is determined in part by the type of “play”. In gas/oil development a “play” represents a group of petroleum accumulations that occur in the same region and are controlled by the same set of geological circumstances (Satter and Iqbal 2016).

According to Côté, Richards et al. (2018), five different unconventional play types have been identified within the Beetaloo Sub-basin that have the potential to bring petroleum to market within a time frame of five to ten years:

- dry gas hosted in the Velkerri Formation shales
- liquids-rich gas hosted in the Velkerri Formation shales
- liquids-rich gas hosted in the Kyalla Formation shales
- the hybrid Kyalla Formation play (including tight sands adjacent to the organic-rich shale intervals)
- tight gas, condensate and potentially volatile oil within the Hayfield Sandstone member of the Hayfield Mudstone in the overlying Neoproterozoic units.

An estimate of the potential yield of petroleum products and liquids-rich gas plays has been made using the data on the respective resource quantities published by the US Department of Energy (U.S. Department of Energy 2015).

Table 3 shows that the risked recoverable gas in the Beetaloo Sub-basin is 22.2 Tcf for Velkerri Shale and 21.5 Tcf for Kyalla Shale, which adds up to a total of 46,106 PJ of total recoverable gas in the Beetaloo Sub-basin.[1] Table 4 shows that the recoverable petroleum resources are 1.39 bbl and 3.26 bbl for Velkerri Shale and Kyalla Shale respectively, which adds up to 28,400 PJ of recoverable petroleum products.[2] This suggests that in the liquids-rich scenarios it is not unreasonable to expect approximately at least one-third of the energy products to be petroleum based.

---

[1] (22.2+21.5)*1.055*1,000,000,000,000/1,000,000,000, which is conversion from cubic foot of gas to MJ * unit multiplier for Tcf to Cft/MJ to PJ conversion.

[2] (1.39+3.26)*6,120*1,000,000,000/1,000,000,000, which is conversion from barrel oil equivalent of oil to MJ and unit conversions for barrels of oil to billion barrels of oil and MJ to PJ.

Table 3 Gas resources in the Beetaloo Sub-basin.

	Velkerri Shale			Kyalla Shale		
Gas phase	Associated gas	Wet gas	Dry gas	Associated gas	Wet gas	Dry gas
Risk gas in place (Tcf)	9.6	32.7	52	23.5	44.5	32.5
Risked recoverable (Tcf)	1	8.2	13	2.3	11.1	8.1

Source: (U.S. Department of Energy 2015)

Table 4 Petroleum resources in the Beetaloo Sub-basin.

	Velkerri Shale		Kyalla Shale	
Oil phase	Oil	Condensate	Oil	Condensate
Risked oil in place (B bbl)	22.1	5.7	54.4	10.7
Risked recoverable (B bbl)	1.11	0.28	2.72	0.54

Source: (U.S. Department of Energy 2015)

Product mix

The mix of end products will affect the whole-of-life GHG emissions even if they are based on the same volume of gas/liquids extracted. Current options for utilisation of the gas are:

- domestic use as reticulated gas to industry and households in the Northern Territory
- Liquefication to LNG for export
- production of ammonia for use in the chemical industry, such as fertiliser production
- production of hydrogen for export and/or domestic use.

For the liquids-rich plays the potential end products would be refinery products such as petrol, diesel, fuel oil and aviation kerosene. This could supply domestic markets, since Australia is a net importer of refinery products(Department of Industry 2021b) or it could be exported.

Five scenarios have been selected and outlined in Table 5 to cover the three main variables identified previously: scale, gas type and product end mix. The first scenario is taken directly from *Scientific Enquiry* and is based on dry gas production under the "Gale" scenario. The end use assumes a fraction going to domestic uses in the Northern Territory. The Northern Territory currently uses 91 PJ/year, so allowing for half of this coming from the Beetaloo Sub-basin, this has nominally been set at 45 PJ/year noting we are not taking into account existing contractual supply arrangements. The remainder in this scenario will be exported as LNG.

The second scenario assumes the same production as gale but with 33% of the extracted energy being liquids destined for refinery production. It is assumed that the output would be used in the Australian market.

Scenario 3 is the same as scenario 2 but with one-third of the extracted gas being diverted to an ammonia and methanol plant (50/50) and the remainder being exported as LNG.

Scenario 4 is the same as scenario 3 but with one-third of the extracted gas being diverted to hydrogen production for sale in export markets.

Scenario 5 is a combination of scenarios 2, 3 and 4 with much higher gas production and a range of product technologies being included.

Table 5 Proposed scenarios for assessment in the CFP.

Scenario name	Output (PJ/year)	Domestic gas supply (PJ/year)	Refinery products (PJ/year)	LNG for export (PJ/year)	Methanol (PJ/year)	Ammonia (PJ/year)	Hydrogen (PJ/year)	Source comment
Sc1 Dom. gas & LNG	365	45		320				Production level based on “Gale” scenario from ACIL Allen (Acil Allen Consulting 2017)assuming dry gas extraction only with some supply to domestic gas market and the balance to LNG production for export.
Sc2 Dom. gas, LNG & refinery	365	45	120	200				Production level based on “Gale” scenario from ACIL Allen (Acil Allen Consulting 2017)assuming high liquid gas extraction with some supply to domestic gas market assuming one-third of extracted energy in as liquids process to petroleum products and the balance to LNG production for export.
Sc3 Dom. gas, LNG & chemicals	365	45		200	60	60		Production level based on “Gale” scenario from ACIL Allen (Acil Allen Consulting 2017)assuming dry gas extraction only with some supply to domestic gas market, one-third to ammonia manufacture and the balance to LNG production for export.
Sc4 Dom. gas, LNG & hydrogen	365	45		200			120	Production level based on “Gale” scenario from ACIL Allen (Acil Allen Consulting 2017)assuming dry gas extraction only with some supply to domestic gas market, one-third to hydrogen manufacture and the balance to LNG production for export.
SC 5 All	1,130	45	120	725	60	60	120	Product level based on 3X ~4.5MTPA LNG plant already operational in NT and the potential for expansion. Also includes extensive industrial development in the planned new industrial chemical plant at Middle Arm.

2.2.6 System boundary

The system boundary in an CFP describes which unit processes are included in the calculation

The system boundary should, at a minimum align with and respond to the recommendations of the *Scientific Inquiry*. The enquiry noted that " the Panel has formed the view that the life cycle GHG emissions must have a 'low' risk and meet the acceptability criteria. These objectives can be achieved by seeking to offset the life cycle GHG emissions to ensure that there is no net increase in life cycle GHG emissions in Australia from any onshore shale gas produced in the NT." (Scientific Enquiry 2018b)

From this definition there are a range of boundaries which could be drawn.

- Emission from the production of shale gas produced in the NT (no including its use)
- Emission from production of shale gas and other products made from shale gas in the NT
- Emission from production of shale gas and its products and domestic (in Australia) use of these gases
- Emission from production of shale gas, and its production and all its use regardless of location

Rather than set one of these boundaries as the correct one, all four boundaries will be reported against in the results.

Figure 3 shows the system boundary for the CFP with four concentric boundaries working outwards from the shale gas production boundary, the domestic shale gas manufacturing boundary, the domestic shale gas manufacturing and consumption boundary and finally a full system boundary, which included both domestic and overseas emissions from extraction right through to consumption.

- Note that ammonia and methanol are not modelled past their production point as there are many potential end markets for these products, with ammonia having no downstream emission (typically used in fertiliser manufacture) while methanol may be used in formaldehyde production.

The system boundary for domestic shale gas production (most inner boundary in black in Figure 3) includes all GHG emissions from:

- an expected number of wells, including drilling, well completion and maintenance
- collection lines and new pipeline infrastructure
- energy and emissions for the gas treatment facility
- energy and emissions relating to water treatment facilities
- pumping and pipeline transport

The system boundary for domestic shale gas production and manufacturing (second most inner boundary in red in Figure 3) includes impacts from prior boundary and includes

- liquefaction and storage for export from current or anticipated Darwin capacity
- production of associated liquid fuels from condensate co-produced with the shale gas
- production of chemicals and hydrogen in the Northern Territory.

The system boundary for domestic shale gas production and use (third most inner boundary in blue in Figure 3) includes impacts from prior boundary and includes emissions from the

use of hydrogen in Australia,
consumption of domestic natural gas in Northern Territory; and
consumption of liquid fuels from refinery in the Northern Territory.

The system boundary for all shale gas production and use (the outer boundary in green in Figure 3) includes impacts from prior boundary and includes emissions from the

- transport of LNG from shale gas to overseas markets
- consumption of LNG from shale gas in overseas markets.

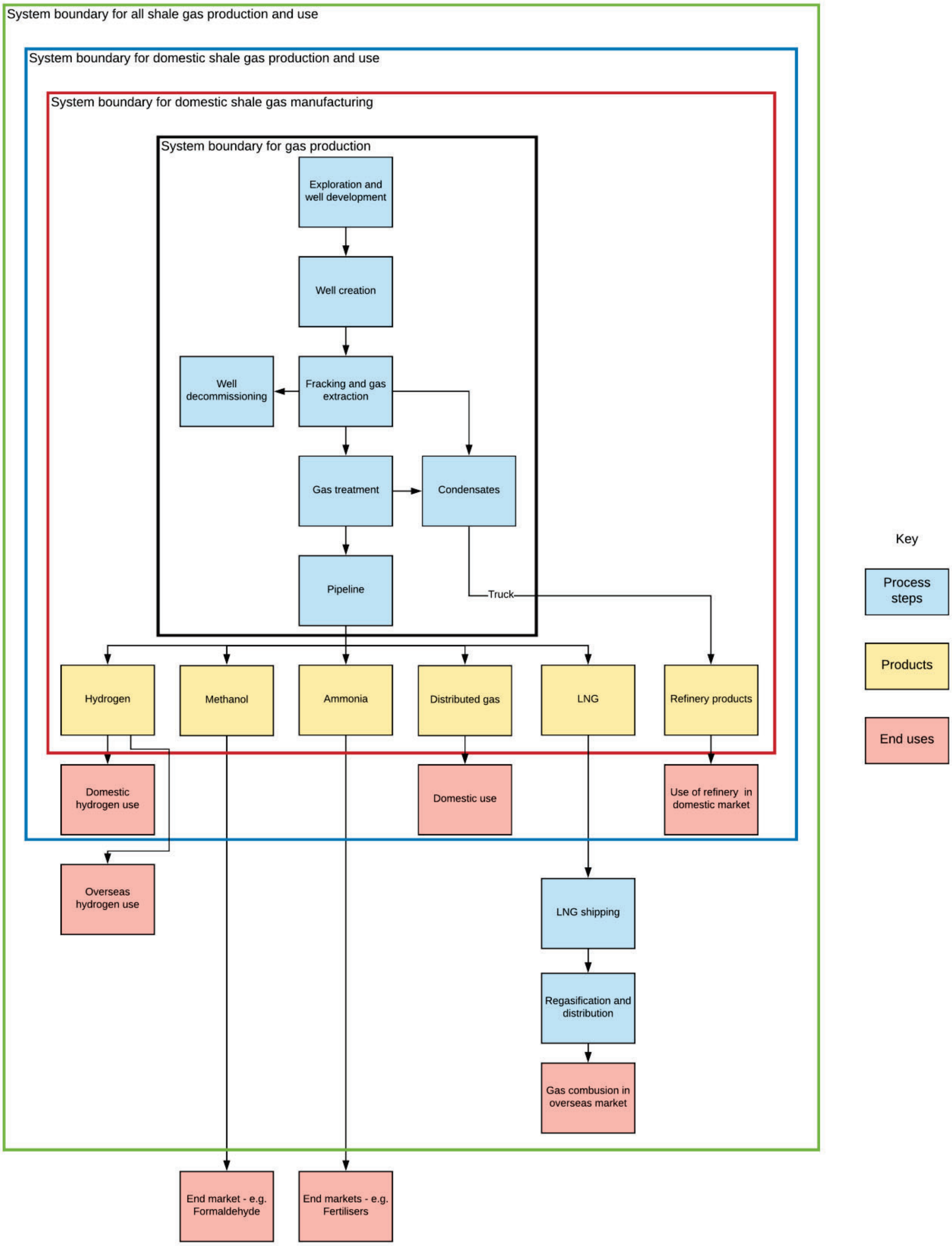


Figure 3 System boundaries for life cycle assessment and carbon offset boundary.

2.2.7 Cut-off criteria

The system boundary allows for the exclusion from the inventory of any flows expected to be less than a specified percent of the threshold for inclusion. In this study this has been set at 0.5% of total contribution to final scenario results.

No specific exclusions have been made, however small flows which may be required with specific technologies have been excluded. For example, administration, safety equipment, worker transport has been excluded. In the chemical manufacturing processes such as ammonia, hydrogen and methanol all flows included in the ecoinvent database are included in the study however minor processes chemicals may have been omitted. Natural gas transport to Darwin and for export shipping are included however transfers and storage for other natural gas users is not included.

2.3 Data quality requirements

Data quality will be assessed for all input data to the CFP and ranked in terms its fitness for purpose.

The key data quality criteria for the study are:

- reliability
- time-related coverage
- geographical coverage
- technology coverage
- representativeness.

The indicators of data quality are shown in Table 6 for each of the criteria. All major data points in the CFP above 5% net contribution to climate change impacts will be assessed according to these criteria.

Table 6 Data quality assessment framework.

	Poor	Fair	Good	Very good
Reliability	Non-qualified estimate	Qualified estimate	Modelled data	Primary measured data
Time-related coverage	From past production >5 years old	From current production data <5 years old	From near future production	From future production averages from time period 2025–2050
Geographical coverage	From distinctly dissimilar region	From global average	From similar region	From region of interest

Technology coverage	From old or dissimilar technology	Generic technology average	From technology specific to region	From actual technology used
Representativeness	Unknown coverage	Sample from small part of target region	Sample covers >50% of target region	Representative of entire target region

2.4 Data modelling

CFP studies can be calculated in different ways depending on the goal of the study. There are two main approaches: those designed for decision support and those for accounting purposes. For decision support, in particular meso and macro level decision support, consequential modelling is recommended (European Commission Joint Research Centre and Institute for Environment and Sustainability 2010) because it attempts to identify the consequences of one course of action compared with another. This is done by following the cause-and-effect change connected to each action and by modelling the different production systems and environmental flows affected.

The method is the equivalent to marginal economic costing, which is used to determine the change in cost for changes in production (Turvey 1969).

For accounting purposes an attributional modelling approach is recommended, which seeks to determine the emissions associated with a group of activities. The calculation of a carbon footprint is an accounting exercise in that it is an attempt to determine all the emissions linked to the extraction and use of non-conventional gas.

For attributional modelling the most appropriate data source for upstream supply is from the actual supplies to the process being studied, however this is not always available or practical in an CFP. The hierarchy for selection of data source for upstream supply is:

- actual supplier – e.g. specific manufacturer when these data are available
- average supply from the actual market – e.g. if electricity inputs are required for use in the Northern Territory then the current Northern Territory grid would be used
- global supply – where the source of the supply is not known then global supply would be used when it is available
- regionalised version of supply from different region – e.g. where data are only available from a region known to not be the supplying region, the data will be regionalised to the local or global regions that best represent the actual supply.

2.5 Multifunctionality

Multifunctionality occurs when a single process or group of processes produces more than one usable output, or “co-product”. A co-product is defined in ISO 14040 (International Organization for Standardization 2019a) as “any of two or more products coming from the same unit process or product system”. A product is any good or service, so by definition it has some value for the user. This is distinct from a “waste”, which is defined in ISO 14040 as “substances or objects which the holder intends or is required to dispose of”, and therefore has no value to the user.

As an CFP identifies the impacts associated with a discrete product or system, it is necessary to separate the impacts of co-products arising from multifunction processes.

The ISO 14044 LCA standard provides a four-step hierarchy for solving the issue of multifunctionality:

1a **Avoid allocation by subdividing systems** – wherever possible, allocation should be avoided by dividing the unit process into sub-processes.

1b **Avoid allocation by system expansion** – expanding the product system to include the additional functions related to the co-products.

2 **Allocation by underlying physical relationships** – the inputs and outputs of the system should be partitioned between its different products or functions in a way that reflects the underlying physical relationships between them.

3 **Allocation between co-products** – the inputs should be allocated between the products and functions in a way that reflects other relationships between them. For example, data may be allocated between co-products in proportion to the economic value of the products.

(adapted from text in International Organization for Standardization (2019b))

However, as this assessment is focusing on an attributional approach for modelling, options 1a, 2 and 3 will be used as option 1b is better suited to consequential LCA modelling.

Table 7 describes the co-products in the foreground system of this LCA and the allocation approach to be used in the LCA.

Table 7 Co-production in the CFP foreground and allocation used.

Process	Determining product	Co-product	Allocation approach
Gas extraction at well	Raw natural gas	Condensate for refinery processing	Energy allocation uses as both products represent raw input to energy supply chains
LNG processing	LNG	LPG	Energy allocation
Petroleum refining	Diesel, petrol & aviation kerosene	LPG, fuel oil	Energy allocation

The background data from the AusLCI database and ecoinvent contain multifunctionality and by default this is dealt with through economic allocation and in some instances physical allocation. Some exceptions to this are in complex multi-product processes. For example, oil refineries in the ecoinvent database include a mix of physical allocation of crude oil content, process allocation of refining processes to the products they refine, and value allocation to differentiate between intended and non-intended products.

2.6 Data sources and literature review

Sourcing data for the CFP is challenging as there is no existing shale gas industry in the Northern Territory with the only commercial scale facility being one developed by Santos near Moomba, South Australia (Scientific Enquiry 2018a). However, there are a range studies based on overseas shale gas production that can be used to supplement local data collection and modelling.

Foreground data for specific emissions will be sourced from national and international GHG emission reports including:

- the emissions factors in the National Greenhouse Accounts (2020), notably Sections 2.4.2.6 to 2.4.2.9
- National Greenhouse Inventory Reports (Commonwealth of Australia 2020b), Section 3.9 generally, and Section 3.10
- methods on natural gas production used in the National Greenhouse and Energy Reporting (NGER) Scheme (Commonwealth of Australia 2020a)
- IPCC Guidelines Volume 2 Chapter 4.2 (IPCC 2006a), with 2019 updates (IPCC 2019)
- the Australian life cycle inventory (AusLCI) databases (ALCAS 2020)
- the ecoinvent life cycle inventory database (Weidema, Bauer et al. 2019).

Calculations will use SimaPro™ software version 9.11, with the main background data model being AusLCI data from version 1.35 embedded with ecoinvent version 3.6, linked using the recycling cutoff system model. This system model is an attributional database using predominantly economic allocation throughout except for recycling commodities, where a cutoff allocation that effectively draws a system boundary at the end of the recycling stage, without providing any credit for recycling activities, is used.

2.7 Impact assessment categories

While there are a range of LCA impacts associated with gas extraction and use, McConnell and Grant (2020) included four indicators in the assessment of natural gas extraction and use from North West Shelf in Western Australia: climate change, particulate matter, acidification and photochemical ozone creation. However, the purpose of this study is restricted to calculation of GHG emission offsets so the climate change impacts will be the only indicator assessed. It will, however, be assessed using multiple methods:

- 100-year GWPs used by the Australian government in the NGER and climate active programs (Department of Industry 2021a)
- 20-year GWP, which focuses on the cumulative impact of GHGs assessed over 20 years (Frischknecht and Jolliet 2016)
- the latest GWP 100 values recommended by the IPCC at this time (Frischknecht and Jolliet 2016)
- GWP 100 values, which measure the longer term impacts of climate change by estimating the impact in 100 years' time rather than the cumulative impact over the next 100 years(Frischknecht and Jolliet 2016).

2.8 Sensitivity analysis

The sensitivity analysis is driven in part by examination of the most critical data points in the study. The six scenarios being assessed against the functional unit are already covering a range of variables relating to the type and scale of production. In the impact method a sensitivity will be included using the 20-year GWP method as opposed to the 100-year GWP. In addition to these, sensitivity analysis will be undertaken on:

- fugitive emissions from wells, pipelines and LNG processing equipment

- number of wells required to achieved desired gas production
- onsite mitigation such as electrification and renewable energy supply to equipment.

2.9 Uncertainty analysis

All data points in the foreground of the study will be characterised with uncertainty estimates. These estimates will be based on published ranges provided with data points and in the absence of these data uncertainty will be estimated based on the data quality assessment of each data point. This will be based on the pedigree matrix uncertainty estimation approach outlined in Muller, Lesage et al. (2016).

In the interpretation of the results each of the main scenarios will be analysed using Monte Carlo simulation to determine how the uncertainty of the input data propagate through to uncertainty in the outputs results. The results of this will provide a mean value and 95% confidence limits of the climate change impacts.

2.10 Critical review

The CFP has been reviewed by

- Andrew Moore, Principal Sustainability Scientist at Life Cycle Logic,
- Associate Professor Wahidul Biswas Sustainable Engineering Group Curtin University; and
- Associate Professor Ahmed Barifcani, Department of Chemical Engineering Curtin University.

3 Inventory

The inventory is construction of individual unit processes for each step of gas production and utilisation. Between each process there are flows, which account for inherent losses along the supply chain. – for example gas is used to make gas and this internal utilisation is included in the unit processes.

3.1 Well establishment and completion

Wells are constructed through drilling and linking with steel lining, cement and concrete. In this CFP the amount of construction material is assumed to be proportional to total length of the well. Construction materials and construction energy have been taken from Bista, Jennings et al. (2019) and is shown in Table 8.

The typical depth of wells has been estimated based on the locations of the different shale formations as shown in Figure 4. For Velkerri the vertical depth is estimated to be 2,500 m, while for Kyalla the vertical depth is estimated to be 1,500 m. For both formations the horizontal drilling distance is 2,500 m, which is similar to the value used in Bista, Jennings et al. (2019).

Table 8 Inputs for production of 1 well 5753m long.

Inputs from technosphere: materials/fuels	Unit	Amount	
Steel, low-alloyed	kg	327600	Bista, Jennings et al. (2019)
ordinary portland cement	kg	2099564	Bista, Jennings et al. (2019)
concrete 25 MPa	m3	2077700	Bista, Jennings et al. (2019)
Sand	kg	1215000	Bista, Jennings et al. (2019)
Drilling fluid	l	1000000	Bista, Jennings et al. (2019)
Well pads	p	0.08	12 wells per well pad.
electricity	MJ	945705	For steel fabricationBista, Jennings et al. (2019)
Diesel, burned in diesel-electric generating set, 10MW	GJ	10036	Bista, Jennings et al. (2019)

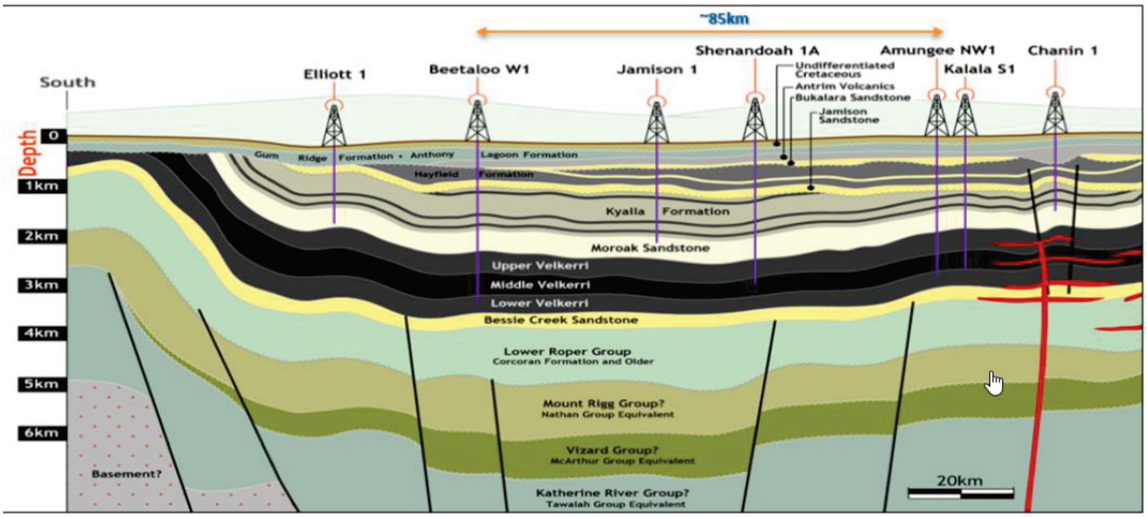


Figure 4 Representation of the depth of geological layers in the Beetaloo Sub-basin. Source (Orr ML, Bernardel G et al. 2020).

3.2 Fracturing

3.2.1 Number of fracturing operations

The *Scientific Inquiry* notes evidence from the US suggesting that "recent long horizontal wells require 30–40 fracturing stages" (Scientific Enquiry 2018b). Based on an industry estimate (Kernke 2021), the study uses 25 fracturing stages, which has been assumed as a midpoint, with 20 as the lower value and 40 as the upper estimate.

3.2.2 Hydraulic fracturing fluid

Water use per fracturing stage is estimated by the inquiry to be between 9 and 22 ML per stage based on a study by (Clark, Horner et al. 2013); however, industry estimates have water use at 1.5 ML, with a lower value of 1 ML and an upper value of 2 ML (Kernke 2021) which we have used in this study..

The *Scientific Inquiry* cites US EPA data (USEPA 2016) that typical water-based hydraulic fracturing fluid is 90% to 97% water, 1% to 10% proppant, and 1% or less of chemical additives (Table 9). According to the USEPA (2015), proppant is most likely to be quartz sand (in 98% of cases), so for this study sand will be taken as the proppant.

The water recovered from fracturing can be treated and reused. Jiang, Michael Griffin et al. (2011) estimate water reuse to be between 30% and 60% of total input water.

Water is assumed to be source from groundwater and the groundwater depth is estimated to be 80m based on bore depths reported in Fulton and Knapton (2015).

Table 9 Estimates for hydraulic fracturing fluid.

Component	Best estimate	Low value	High value
Nett water volume per stage	1.5 ML	1 ML	2 ML

Water	95%	90%	97%
Proppant (sand)	4%	3%	9%
Polyamides	1%	0%	2%
Water table depth (m)	80	50	120

3.3 Well pads

A well pad is the surface installation where wells are located. Well pads consist of between 1 to 16 wells (Jiang, Michael Griffin et al. 2011), the infrastructure used in drilling and fracturing the wells, as well as tanks and/or ponds for managing waste water and water treatment.

Section 7.3.1.4 of the *Scientific Inquiry* suggests that the gas industry's 25-year development scenario of between 1,000 and 1,200 wells is associated with around 150 well pads. From this it is assumed that the number of wells per well pad will range from 6 to 8 wells per well pad, which aligns with estimates by Jiang, Michael Griffin et al. (2011).

Jiang, Michael Griffin et al. (2011) estimate that each well pad occupies an area of 2 ha (5 acres). It is assumed the site will need to be cleared of vegetation.

3.3.1 Energy use in fracturing operations

Stephenson, Valle et al. (2011) estimate 2 hours of water injection per fracturing event, at 12,250 HP. Jiang, Michael Griffin et al. (2011) estimate the pumping power to be 34,150 HP (25 MW), with an operation time of between 10 and 30 hours for a multistage fracturing operation, which would be equivalent to 2 hours per fracturing event if there are an average of 15 fracturing events.

The 2 hours per fracturing event has been used with the larger horsepower value of 34,150 HP, which translates to 25.5 MW, or 51 MWh for each fracturing event. This is the hydraulic energy requirement, so assuming a pumping efficiency of 75% and diesel motor efficiency of 45%, the diesel requirement in GJ is 51 MWh/0.75/0.45*3.6 GJ/MWh = 544GJ of diesel.

Jiang, Michael Griffin et al. (2011) estimate that the average lateral length of a well is 4,000 m, so the energy use values are divided by 4,000 to derive an energy use per kilometre of lateral well based on the assumption that the volume of fracturing fluid and energy would be relative to the lateral length of the well. The resulting energy use per metre of lateral well length is therefore 544/4000 = 0.136 GJ/m. Assuming that 10 to 30 hours represents the uncertainty, the low and high values are 0.068 GJ/m and 0.204 GJ/m respectively.

3.3.2 Wastewater treatment

Caballero, Labarta et al. (2020) provide data on options for primary and secondary wastewater treatment of fracturing fluid, which is shown in Table 10. For this study only primary treatment is assumed. If secondary treatment is required, it would add 2.3% to the footprint of clean gas production and less than 0.35% to the footprint of gas production and utilisation.

Table 10 Wastewater treatment inputs per M3 of wastewater

Inputs from technosphere: materials/fuels	Unit	Amount	
High-density polyethylene	kg	1.6E-04	Primary treatment
Electricity, low voltage	kWh	4.34	Primary treatment
Steel	kg	8.8E-04	Primary treatment
High-density polyethylene	kg	5.8E-06	Primary treatment
Concrete	m^3	1.0E-05	Primary treatment
Glass fibre reinforced plastic	kg	4.5E-04	Primary treatment
Quicklime	kg	0.199	Primary treatment
Soda ash	kg	0.57	Primary treatment
Polypropylene	kg	4.3E-05	Primary treatment
Electricity, low voltage	kWh	29	Secondary treatment (MEE-MVR)

Source: (Caballero, Labarta et al. 2020)

3.3.3 Methane fugitives from fracturing

Estimate of fugitive methane emissions vary significantly from different literature sources.

Howarth, Santoro et al. (2011) estimate total fugitive methane emissions from unconventional gas to be between 3.6% and 7.9%.

Stephenson, Valle et al. (2011) provide a shale gas estimate of fugitives from well completions as 0.45%, with a low value of 0.09% and a high value of 1.94%. Burnham, Han et al. (2012) provide a similar mean value for shale gas well completions with fugitives at 0.46%, with a low value of 0.006% and a high value of 2.75%.

There is an expectation with new shale wells that emissions control will be vastly improved based on the greater emphasis on GHG emission reduction. For this reason, the values from Stephenson, Valle et al. (2011), Burnham, Han et al. (2012) have been used in this CFP.

3.3.4 Carbon dioxide venting from fracturing

The shale gas fracturing yields a mix of gases which including a small fraction of carbon dioxide which is vented to atmosphere.

Table 11 Carbon dioxide content assumptions from shale gas production.

Well Source	CO2 content Mol%	Source/comment
Kyalla	0.91%	Origin energy estimate (Kernke 2021)
Velkerri	4.0%	Origin energy estimate (Kernke 2021)

3.3.5 Gas processing

Gas processing involves removal of moisture and separation of any liquid fractions including C3 and C4 hydrocarbons to liquified petroleum gas (LPG) and heavier fractions to condensate. Contaminants such as acid gasses and heavy metals such as mercury may also need to be removed when present. Data for gas processing is presented in Table 12 and is based on ecoinvent inventory with is derived primarily from a study by NREL in 2007. Also included in this inventory is ethylene glycol , methanol and natural gas onshore field infrastructure taken directly from an ecoinvent processes .

Table 12 Data for energy use in gas processing.

Energy input	Unit		Source/comment
Electricity	kWh/t	65	Ecoinvent data listed as 0.0457 kWh of electricity. The gas density of 0.702 kg/m3.
Energy from natural gas	GJ/t	2.96	Ecoinvent data 2.08MJ of energy from natural gas per m3 of gas. The gas density of 0.702 kg/m3

Fugitives from gas processing have been calculated according to the National Inventory Report (Commonwealth of Australia 2021), which uses the relationship between the size of the facility to the rate of fugitive emission developed by (Mitchell, Tkacik et al. 2015) using the formulae shown below.

$$Fugitives\ (t) = 0.6369X^{-0.48}$$

Where X is the processing capacity of the gas processing plant in tonnes per annum.

Assuming 365 PJ of gas processing, the emissions would be 0.000323 tonnes per tonne of gas processed ($0.6369*(365PJ/50.16Mt/PJ*10^{6})^{-0.48}$).

3.3.6 Gas transmission

The pipeline transmission emissions are taken from the National Inventory Report (Commonwealth of Australia 2021) (Table 13).

Table 13 Data assumptions for gas transmission.

Item	Flow	Unit	Source/comment
Pipeline length	470	km	Estimate based on locations
Energy use	1.2%		From AusLCI based on 23.2 PJ per 1,916 PJ (ABARE 2011)
Carbon dioxide	0.02	t/km.year of pipeline	Table 3.46 Fugitive emission factors for natural gas
National Greenhouse Gas Inventory (2013)	0.41	t/km.year of pipeline	Table 3.46 Fugitive emission factors for natural gas

3.4 Shale gas utilisation

3.4.1 Domestic use

Domestic gas utilisation was assumed to consist of distributions throughout the Darwin region and also assumed combustion in some form of stationary equipment.

Distribution emissions are taken from AusLCI data for the Northern Territory, which is based on the National Inventory Report and ABARE (Table 14).

Table 14 Data assumptions for domestic gas use.

Item	Flow	Unit	Source/comment
Pipeline length	470	km	Estimate based on locations
Energy user	0.0227	MJ/MJ	From AusLCI based on 14 PJ for 617 JP distributed (ABARE 2011)
Methane	16.2	kg CH_4/GJ	Table 3.47 Natural gas composition and emission factors for Amadeus Basin, NT

3.4.2 LNG production and use

Likely to be one of the main end destinations, LNG is produced from cleaned[3] natural gas through compression and cooling to a liquid product. The product is destined for export to

[3] Clean refers to natural gas processing which removed contaminants such as acid gasses and heavy metals and separation of liquid hydrocarbons fractions as well as moisture)

different destinations in Asia where the most likely end use is in gas grid or electricity generation.

Pospíšil, Charvát et al. (2019) provide values for different LNG processes of between 0.25 kWh per kg LNG up to 0.350 kWh per kg LNG. Khan, Karimi et al. (2017) provide a specific range of energy use of 0.29 kWh per kg LNG to 0.35 kWh per kg LNG, which has been used in this study, with 0.32 kWh per kg LNG used as the mid value (Table 15).

Table 15 Data assumptions for LNG production per kilogram of LNG.

Item	Flow	Unit	Source/comment
Shale gas, high pressure, delivered to Darwin	1	kg	Estimate based on locations
Natural gas, burned in gas motor, for storage [AU-NT]	0.32	kWh	Process is based on ecoinvent with high-pressure shale gas in Darwin replacing conventional natural gas supply. Assumes 40% conversion effiency from fuel LHV to electrical energy. (Goldstein, Hedman et al. 2003)
Natural gas processing plant [GLO]	1.22 E-12	p	Infrastructure process from ecoinvent and assuming 25-year life
Waste natural gas, sweet [GLO] treatment of, burned in production flare	0.195	kg	Ecoinvent value for LNG production

3.4.3 Hydrogen production

Hydrogen production from shale gas is assumed to be produced from a steam methane reforming (SMR) method. The assumptions on efficiency of hydrogen production have been sourced from Salkuyeh, Saville et al. (2017), which includes energy use from SMR with and without carbon capture (Table 16).

Table 16 Data assumptions for production of 1 kg of hydrogen production using steam methane reforming without carbon capture.

Item	Unit	Without CC	With CC	Source/comment
High pressure clean shale gas at Darwin	kg	*3.88*	5.3	Based on Salkuyeh, Saville et al. (2017)
- Used as feedstock	kg	0.455	0.455	Based on stoichiometry of H in methane ending use as H_2. Carbon from this feedstock is assumed to be oxidised to carbon dioxide

- Shale gas combusted	kg	3.345	4.845	Calculated by difference from total after account for feedstock gas
Electricity	kWh	0.17	0.17	Based on data estimate by CSIRO
Water	litres	5.5	5.5	Based on data estimate by CSIRO
Catalyst	kg	0.00031	0.00031	Mix of minor flows representing catalyst in steam reformer – data based on methanol steam reforming from ecoinvent
MEA consumption	kg	0	0.034	Consumption of mono ethanolamine is taken from Grant, Anderson et al. (2014)
Carbon dioxide captured	kg	0	12.5	Based on Salkuyeh, Saville et al. (2017)

3.4.4 Methanol production

Methanol production data have been taken on ecoinvent data for methanol production based on synthesis gas mixtures (carbon monoxide and hydrogen), which can be combined to produce methanol. The inventory has 0.5 kg of gas required to produce 1 kg of methanol. The only adaptation to the inventory is to change the electricity input to the Northern Territory and to change the deionised water to also be produced from Northern Territory electricity.

3.4.5 Ammonia production

Ammonia production data have been taken from ecoinvent data for ammonia production via steam reforming. The inventory has 0.42 kg of gas required to produced 1 kg of ammonia. The only adaptation to the inventory is to change the electricity input to Northern Territory and the deionised water to also be produced from Northern Territory electricity.

3.4.6 Refinery production

Petroleum refinery production data have been taken from ecoinvent data for a refinery model based on refining crude oil. The liquids inputs from shale gas extraction are assumed to be the same as crude oil input in terms of refinery processes. The inventory has 1.08 kg of liquids input to produce 1 kg of diesel. For simplicity it is assumed that all production is towards diesel, and this is used in the heavy transport industry. The only adaptation to the inventory is changing the input of crude oil to condensate and changing the electricity input to the Northern Territory.

Shale gas liquids are assumed to be trucked from Beetaloo Sub-basin to a refinery in Darwin. The energy content is assumed to be 46.5 GJ/t higher heating value (HHV) (Department of Energy and Environment 2020) and the physical density is assumed to be 0.65 kg/litre.

Allocation between clean shale gas and shale gas liquids is based on the energy content of each product.

3.4.7 Summary of key assumptions

Parameter	Unit	Value	Low est.	High est.	Alternate values data sources, and comments
Shale gas production					
Gas production per well	Bcf	4	3	6	Origin Energy suggest gas per well would need to be above 3 Bcf to be economic and likely to be between 3 and 6
Number of wells over 25 years	no.	2,406	1,604	3,208	To produce 365 PJ for 25 years – calculated from Bcf per well
Land area occupied by well pad	ha	5	2	8	5.5 Suggested by Origin Energy, lower value taken from Jiang, Michael Griffin et al. (2011) upper value author estimate
Carbon loss from wellpad clearing	t/ha	25	11	43	Range taken from (Jiang, Michael Griffin et al. 2011).
Wells per well pad	no.	12	6	16	Based on estimate from Origin energy
Fractures per well	no.	25	20	40	Estimate various sources
Vertical well depth Kyalla	m	1,500			Estimated from diagram showing formation depth
Horizontal well length Kyalla	m	2,500			
Vertical well depth Valkerri	m	2,500			Estimated from diagram showing formation depth
Horizontal well length Valkerri	m	2,500			
Contribution from Valkerri	%	50%			Estimate

Contribution from Kyalla	%	50%			Estimate
Energy per Fracturing per m of lateral well	GJ	0.136	0.068	0.204	Diesel GJ is based on 25.5 MW for 2 hours for 4,000 m lateral (Jiang, Michael Griffin et al. 2011)
Fracturing fluid per fracturing	ML	1.5	1	2	Clark, Horner et al. (2013) suggest 15 ML. Origin suggests 1.5 ML
Water supply pumping head	m	80	50	120	(Fulton and Knapton 2015)
WW pre-treatment energy	kWh/m^3	4.34			Caballero, Labarta et al. (2020)
Water reuse rate	%	45	30	60	
Carbon dioxide vent from Kyalla	1	0.91			CA suggest 0.91 CO_2 of Kyalla gas vented when drilling
Carbon dioxide vent from Velkerri	% mol	4%			CA suggest 4% mol CO_2 Velkerri gas evented when drilling
Methane fugitive at well completion (% of gas produced)	%	0.45%	0.09%	1.94%	Stephenson, Valle et al. (2011)
Gas processing					
Electricity from GT genset	kWh/t	65			Ecoinvent 2021 based on NREL 2007. +/- 10% used for uncertainty
Gas used in compressors	GJ/t	2.98			Ecoinvent 2018, Uncertainty value of 1.13 SSD lognormal
Fugitives from gas processing (% of gas produced)	%	0.032%			From National Inventory Report method (Commonwealth of Australia 2021) based on Mitchell, Tkacik et al. (2015)
Pipeline length to Darwin	km	570			
Transmission energy use GJ/GJ of gas	Fraction	0.012			NGGI (2013)

Fugitives from transmission of pipeline	t per t.km per year	11.6			(Department of Energy and Environment 2020)
Liquefaction energy requirement	kWh/kg	0.32	0.29	0.35	(Khan, Karimi et al. 2017)
Product yields					
Tonne liquids per tonne of refinery products	t/t	1.2			Derived from CFP model
GJ raw gas per tonne for methanol	GJ/t	27.5			Derived from CFP model
GJ raw gas per tonne for ammonia	GJ/t	23.1			Derived from CFP model
GJ raw gas per tonne for hydrogen without CCS	GJ/t	213			Derived from CFP model
GJ raw gas per tonne for hydrogen with CCS	GJ/t	293			Derived from CFP model
GJ raw gas per GJ electricity generated	GJ/GJ electricity	3.77			Derived from CFP model

4 Results and interpretation

4.1 Shale gas production

Figure 5 shows the greenhouse gas results for 1 GJ of raw shale gas input delivered to Darwin via high-pressure pipeline, noting that 3.2% of this gas is utilised in processes and transmission. The total emission result is 8.85 kg CO_2 e raw gas production impact (4.0 kg CO_2 e), gas processing makes up 3.9 kg CO_2 eof which 0.2 kg CO_2 e are from fugitive methane emissions from processing. Transmission of gas to Darwin is also 1 kg CO_2 e. Raw gas impacts are made up of CO_2 venting (0.5kg CO_2), methane fugitives (2.5kg CO_2 e), with the remainder being the impact of creating the fracturing the wells. The main impacts of well completions is cement and concrete contributions at 0.46 kg CO_2 e.

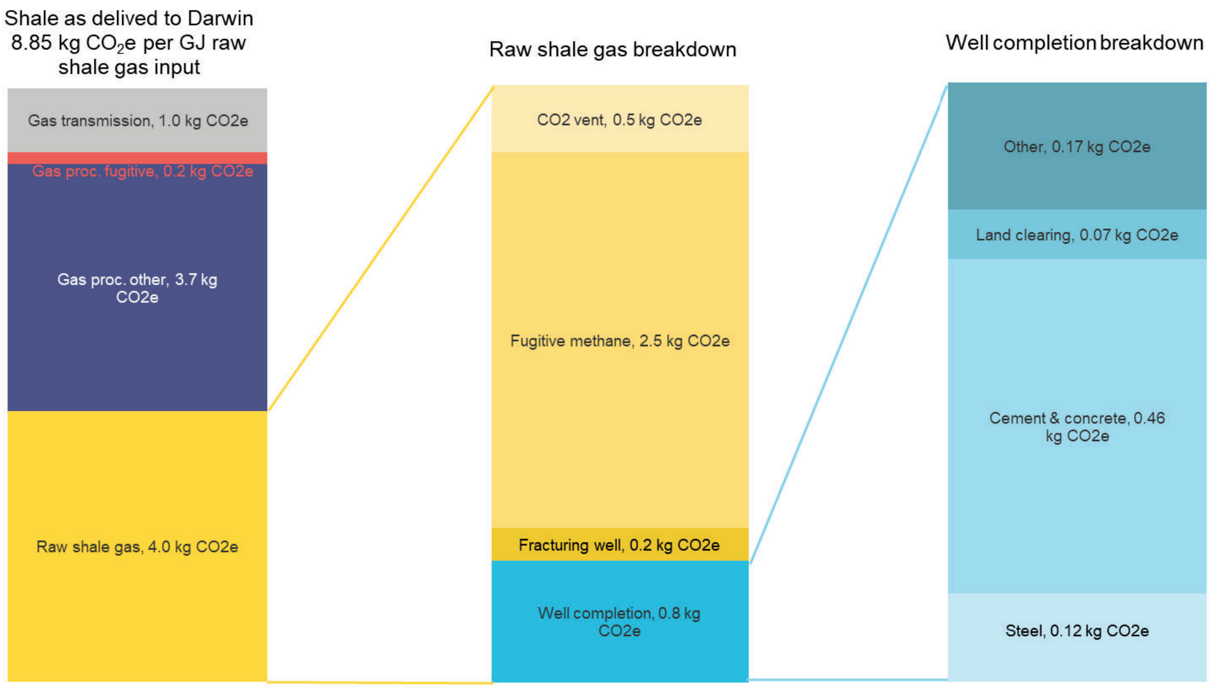


Figure 5 Climate change results for 1GJ shale gas delivered to Darwin.

4.2 Shale gas utilisation

Before examining the different scenarios on how much gas will be extracted, Table 17 and

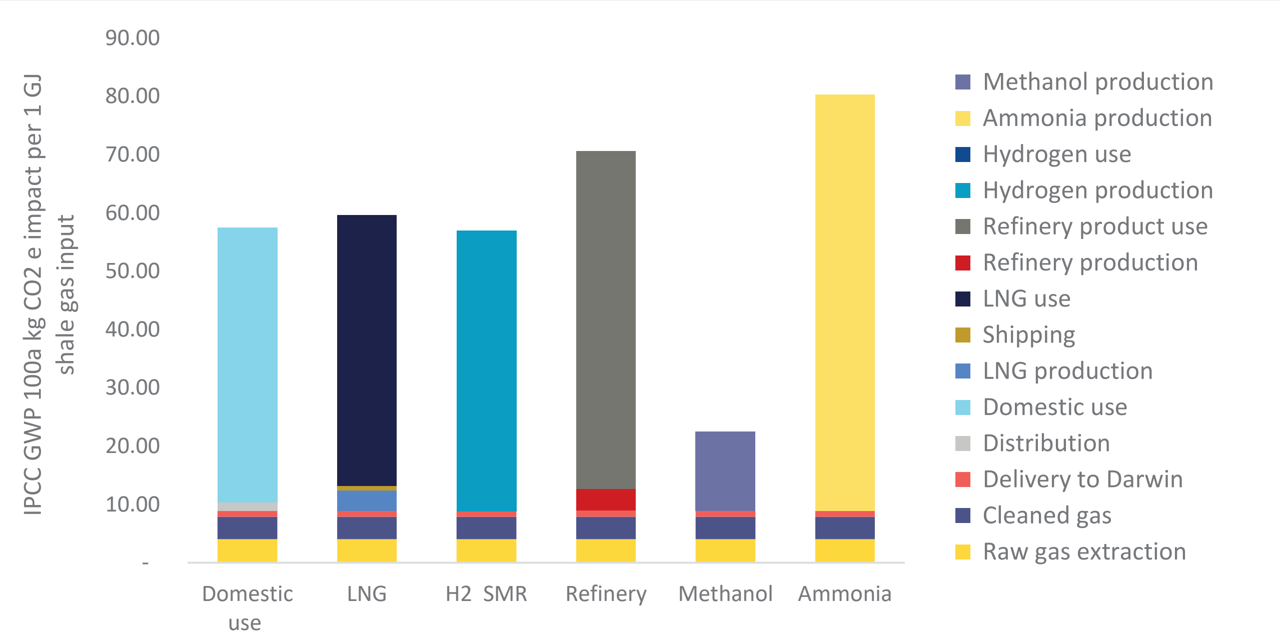


Figure 6 provide the impact profiles for the utilisation of shale gas to different destinations and technologies. Of the six destinations for the shale gas, five of them involve the complete release of carbon embodied in the shale gas at some point in the production chain. For this reason, the total emission from those five destinations is relatively similar, ranging between 57 and 80 kg CO_2 e per GJ. The scenario for methanol holds some of the carbon in the final product; however, depending on the ultimate use of the methanol this may eventually be released to the environment. Ammonia production has the highest impact due to energy inputs in the ammonia production process as well as the release of carbon dioxide, which is liberated from that process. Note that in some circumstances this carbon dioxide is captured and used in urea production, however this is only temporary storage as the carbon dioxide will be released when urea is placed on farms as a fertiliser (see section 11.4 IPCC (2006b).

The hydrogen process is based on steam methane reforming and does not include carbon capture and storage; however, this is tested in a sensitivity analysis later in the report. The higher impacts of the refinery are due to the higher emission factor from diesel in use as well as the impacts of refinery production. Note the refinery production model is based on conventional crude oil inputs and may be lower when refining shale gas liquids.

Table 17 Climate change kg CO_2 e impact per 1 GJ shale gas input.

	Raw gas extraction	Cleaned gas	Delivery to Darwin	Distribution / shipping	Manufacture	Use	Total
Domestic use	4.0	3.9	1.0	1.5	-	47.1	57.5
LNG	4.0	3.9	1.0	0.9	3.5	46.4	59.6
H_2 SMR	4.0	3.9	1.0	-	48.1	-	57.0
Refinery	4.0	3.9	1.1	-	3.6	57.9	70.6

Methanol	4.0	3.9	1.0	-	13.6	-	22.5
Ammonia	4.0	3.9	1.0	-	71.4	-	80.2

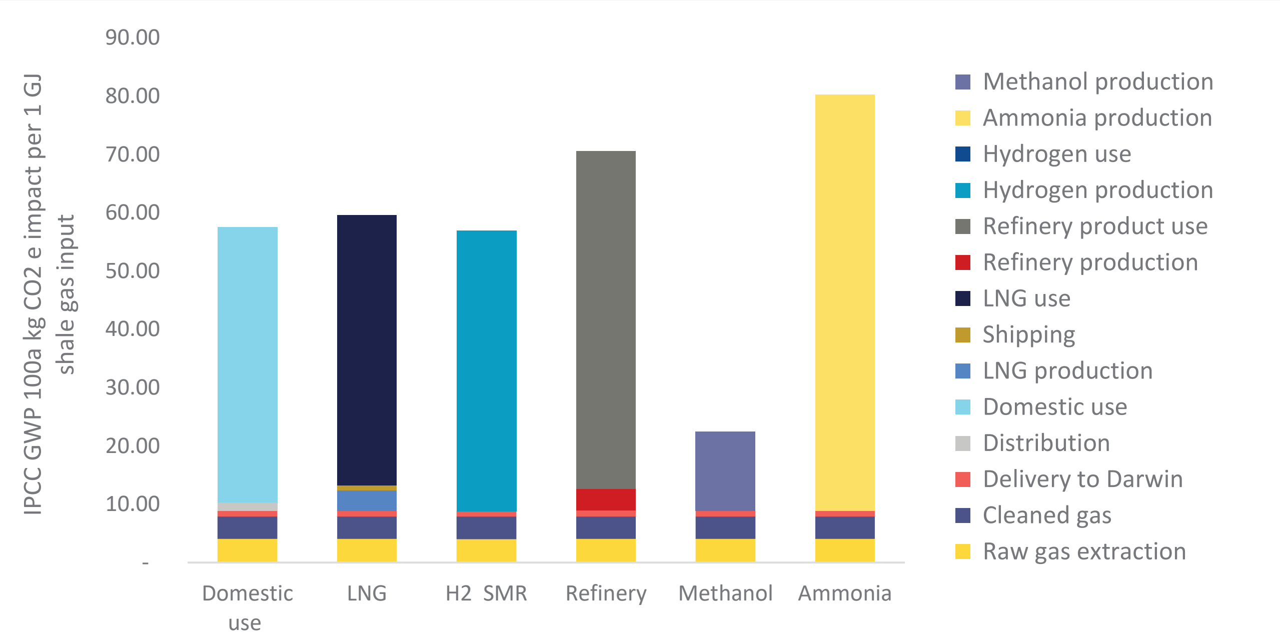


Figure 6 Climate change kg CO_2 e impact per 1 GJ shale gas input.

4.3 Shale gas utilisation scenarios

The different production/utilisation scenarios for shale gas from Beetaloo Sub-basin are shown in Table 5 Section 2.2.5. The emission results from these scenarios are shown in Table 18 and Figure 7.

Table 18 Greenhouse gas emission by scenario in Mt CO_2 e over 25-year life.

	Gas production	Transmission	Manufacturing	Domestic use	Overseas use	Total

Sc1 Dom. gas & LNG	2.88	0.35	1.13	2.19	15.11	21.7
Sc2 Dom. gas, LNG & refinery	2.42	0.23	1.74	9.14	9.44	23.0
Sc3 Dom. gas, LNG & chemicals	2.88	0.35	5.80	2.19	9.44	20.7
Sc4 Dom. gas, LNG & hydrogen	2.88	0.35	6.48	-	9.44	19.2
SC 5 All	8.46	0.96	14.46	9.14	34.24	67.3

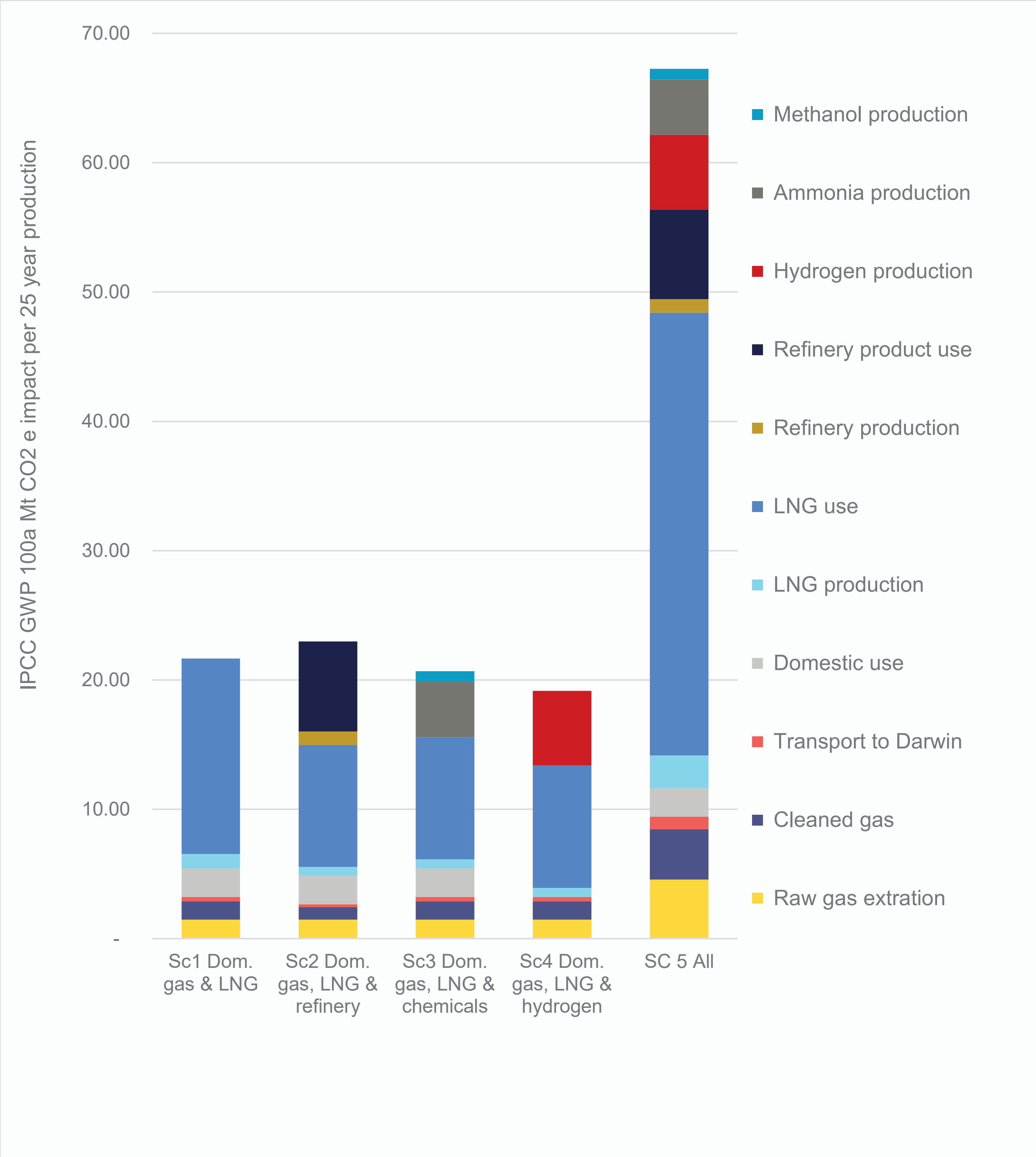


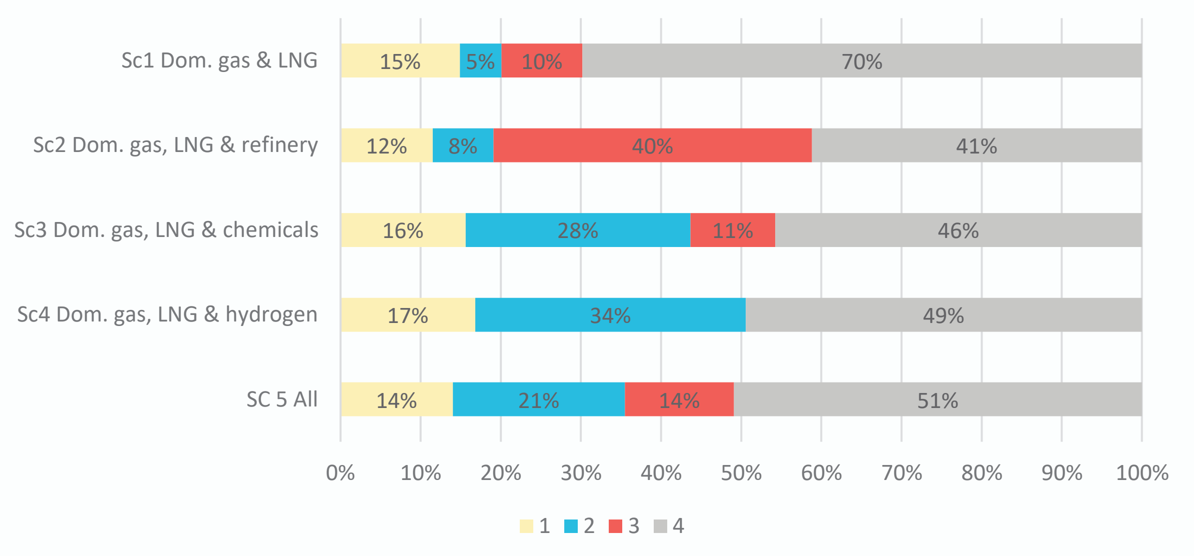
Figure 7 Greenhouse gas emission by scenario in MT CO_2 e over 25-year life.

Table 19 shows the results for all scenarios using 4 different boundary conditions outlined in the system boundary section.

1. Production of shale gas produced in the NT (not including its use)
2. Production of shale gas and other products made from shale gas in the NT
3. Production of shale gas and its products and domestic (in Australia) use of these products
4. Production of shale gas, and its production and all its uses regardless of location

Table 19 Greenhouse gas emission by scenario in Mt CO_2 e over 25-year life for four different system boundaries and percentage of emissions added by each expansion of the boundary.

	1 Shale gas production	2 Shale gas production and product manufacturing	3 Shale gas production, manufacturing and domestic use	4 Shale gas production, manufacturing and use globally
Sc1 Dom. gas & LNG	3.23	4.36	6.55	21.7
Sc2 Dom. gas, LNG & refinery	2.65	4.39	13.53	23.0
Sc3 Dom. gas, LNG & chemicals	3.23	9.04	11.23	20.7
Sc4 Dom. gas, LNG & hydrogen	3.23	9.71	9.71	19.2
SC 5 All	9.43	23.89	33.03	67.3



Because of the large volume of shale gas which is destined to overseas use via LNG production and export, the fourth system boundary described (all gas production, manufacturing and use globally) adds between 41% and 70% depending on the scenario. It adds more than half the total emissions in scenario 5 with more than 34MT of CO2 e being from use of LNG in overseas markets.

4.4 Sensitivity analysis

The sensitivity analysis examines the specific method and data choices in the CFP to determine how they affect the results. Note that the cumulative effect of uncertainty of input data on the results is tested in the next section with the uncertainty analysis.

Sensitivity analyses have been undertaken on the following choices:

- electrification of diesel gensets with renewable energy
- carbon capture and storage included with hydrogen production
- different global warming potentials.

There is also a sensitivity analysis of individual parameters involved in gas extraction and processing.

4.4.1 Electrification of diesel gensets with renewable energy

Electrification has been tested in four parts of the production chain:

- replacing diesel energy used in fracturing (pumping)
- replacing genset gas electricity generators at gas processing
- replacing gas compressors at gas processing
- replacing gas compressors at LNG manufacture.

All replacements have been undertaken using solar electricity, open field installation using average generation from solar energy inputs to grid mix (based on ecoinvent process Electricity, low voltage [AU]| electricity production, photovoltaic, 570kWp open ground installation, multi-Si | Cut-off).

In reality, the production of energy from solar will not match the timing of demands from the shale gas operations which typically run 24 hours per day. This may be resolved through trading electricity credits or power storage, and this is not taken account of in this sensitivity.

For the purpose of the sensitivity the efficiency of electric motors and compressors are assumed to be similar to gas compressors and diesel genset. It is likely this would overestimate the electricity demand as electric motors tend to be more efficient than gas compressors and diesel generation sets.

Table 20 shows the results of the sensitivity analysis for shale as delivered to Darwin. It shows the influence of renewable energy is most significant at the gas processing stage where it leads to a 26.7% reduction in the overall footprint. If solar energy is implemented at all four points of the production chain the total impact is a reduction of 47%.

Table 21 shows the influence of renewable energy use at processing on scenario 5. The total reduction for scenario 5 with solar energy replacements at all four points in the supply chain is 7.9%.

Table 20 Sensitivity result for 1 kg of LNG at the port when implementing renewable energy at different parts of shale gas and LNG production chain.

	kg CO2 e	% reduction
Baseline	0.722	
Solar replacing diesel at well head	0.582	19.5%
Solar replacing gas genset at processing	0.713	1.3%
Solar replacing gas compressor at gas processing	0.530	26.7%
Solar replacing compressor at LNG	0.713	1.3%
All solar	0.382	47.1%

Table 21 Sensitivity result Mt CO_2 e for scenario5 implementing renewable energy at different parts of shale gas and LNG production chain.

	Mt CO2 e	% reduction
Baseline	67.26	
Solar replacing diesel at well head	64.54	4.0%
Solar replacing gas genset at processing	67.09	0.3%
Solar replacing gas compressor at gas processing	64.87	3.6%
Solar replacing compressor at LNG	67.08	0.3%
All solar	61.95	7.9%

4.4.2 Carbon capture used on hydrogen

Carbon capture is assumed to use monoethanolamine (MEA) and to be 90% effective, and no storage or utilisation impacts are included in the calculation. The energy data for carbon capture were taken from Salkuyeh, Saville et al. (2017). Note that the practicality of storage and utilisation are also not assessed here.

Figure 8 shows the impacts without carbon capture are 12.1 kg CO_2 e per kg H_2 and with carbon capture it is 6.4 kg CO_2 e per kg H_2, representing a 47% reduction in overall carbon footprint.

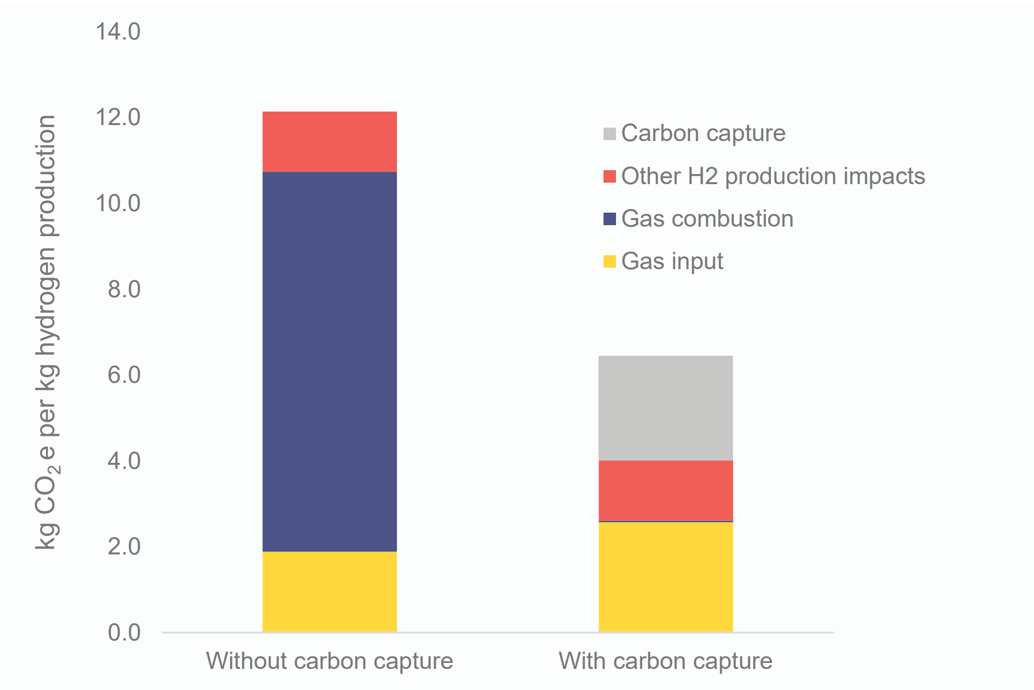


Figure 8 Impact difference between hydrogen production with and without carbon capture and storage.

4.4.3 Results with different global warming potentials

There are different metrics used to measure climate change impacts published by the Intergovernmental Panel Climate Change (IPCC). The default method used in this CFP is GWP 100, which stands for global warming potential 100 years, and assesses the cumulative warming impact of different gases released into the atmosphere over a 100-year timeframe. This method is used for international commitments by nations and Australian Government programs such as NGERs and Climate Active.

In this study we used the current values published in the National Greenhouse Factors which are based on the IPCC 5th Assessment Report. There is a 6th Assessment Report which has a slightly lower value for methane over 100-year GWP (from 30.5 to 29.8).

While the IPCC doesn't make specific recommendations on which metrics should be used, the Life Cycle Initiative Global Guidance of Life Cycle Impact Assessment (Frischknecht and Jolliet 2016) recommends two alternative metrics in addition to the GWP 100 (Table 22). They are:

- GWP 20 – cumulative impacts over 20 years (Table 23), which represents short-term climate warming impacts, and
- GTP 100 (Table 24Table 24 Comparison of results using GTP 100 compared to GWP 100.), which is the global temperature potential that is the instantaneous temperature effect in 100 years and represents the long-term impacts of climate change.

The characterisation factors shown in Table 22 show that the value for methane varies most between the different methods. This is important as the main non-CO_2 contributor from the shale gas life cycle in methane. Table 23 shows gas production impacts increase by 67%-77% in the GWP 20 scenario although over the full lifecycle the increase is closer to 10 to 13 percent.

Table 24 shows the reverse trend in the GTP 100 long term scenario with gas production impacts reducing by 20 to 24 percent and overall reduction in life cycle impacts of 3-4 percent.

Table 22 Characterisation factors for different climate change metrics.

	GWP 100[1]	GWP 20[3]	GTP 100[4]
Carbon dioxide	1	1	1
Methane (fossil)	30.5[2]	85.4[2]	13
Nitrous oxide	265	264	297

1 GWP 100 values based on National Greenhouse Accounts (Department of Climate Change 2022)with exception of fossil methane which is adjusted as per note 2.

2 Includes impacts of remaining fossil based carbon dioxide remaining after degradation of methane according to the approach provided in Muñoz and Schmidt (2016)

3 Based on value published in table 8.7 of Myhre (2013) except for methane based on note 2 all excluding climate carbon feedback.

4 Based on values published in by Frischknecht and Jolliet (2016). These include the climate carbon feedback.

Table 23 Results using GWP 20 for each scenario in Mt CO_2e for 25 years.

Results using GWP 20						
	Gas production	Trans.	Manufacture	Domestic use	Overseas use	Total
Sc1 Dom. gas & LNG	4.8	0.6	1.2	2.2	15.3	24.1
Sc2 Dom. gas, LNG & refinery	4.3	0.4	1.8	9.2	9.6	25.3
Sc3 Dom. gas, LNG & chemicals	4.8	0.6	6.1	2.2	9.6	23.3
Sc4 Dom. gas, LNG & hydrogen	4.8	0.6	6.6	-	9.6	21.5
SC 5 All	14.4	1.6	15.0	9.2	34.7	74.9
Results using GWP 100						
Sc1 Dom. gas & LNG	2.88	0.35	1.13	2.19	15.11	21.7
Sc2 Dom. gas, LNG & refinery	2.42	0.23	1.74	9.14	9.44	23.0
Sc3 Dom. gas, LNG & chemicals	2.88	0.35	5.80	2.19	9.44	20.7
Sc4 Dom. gas, LNG & hydrogen	2.88	0.35	6.48	-	9.44	19.2
SC 5 All	8.46	0.96	14.46	9.14	34.24	67.3
Percentage increase in with GWP 20 compared to GWP 100 results						
Sc1 Dom. gas & LNG	67%	64%	2%	1%	1%	11%
Sc2 Dom. gas, LNG & refinery	77%	64%	6%	1%	1%	10%
Sc3 Dom. gas, LNG & chemicals	67%	64%	5%	1%	1%	13%
Sc4 Dom. gas, LNG & hydrogen	67%	64%	1%		1%	12%
SC 5 All	70%	64%	4%	1%	1%	11%

Table 24 Comparison of results using GTP 100 compared to GWP 100.

Results using GTP 100						
	Gas production	Trans.	Manufacture	Domestic use	Overseas use	Total
Sc1 Dom. gas & LNG	2.3	0.3	1.1	2.2	15.1	20.9
Sc2 Dom. gas, LNG & refinery	1.8	0.2	1.7	9.1	9.4	22.2
Sc3 Dom. gas, LNG & chemicals	2.3	0.3	5.7	2.2	9.4	19.8
Sc4 Dom. gas, LNG & hydrogen	2.3	0.3	6.5	-	9.4	18.4
SC 5 All	6.6	0.8	14.3	9.1	34.1	64.9
Results using GWP 100						
Sc1 Dom. gas & LNG	2.88	0.35	1.13	2.19	15.11	21.7
Sc2 Dom. gas, LNG & refinery	2.42	0.23	1.74	9.14	9.44	23.0
Sc3 Dom. gas, LNG & chemicals	2.88	0.35	5.80	2.19	9.44	20.7
Sc4 Dom. gas, LNG & hydrogen	2.88	0.35	6.48	-	9.44	19.2
SC 5 All	8.46	0.96	14.46	9.14	34.24	67.3
Percentage increase (negative is decrease) GTP 100 relative to GWP 100 results						
Sc1 Dom. gas & LNG	-21%	-20%	-1%	0%	0%	-4%
Sc2 Dom. gas, LNG & refinery	-24%	-20%	-2%	0%	0%	-3%
Sc3 Dom. gas, LNG & chemicals	-21%	-20%	-2%	0%	0%	-4%
Sc4 Dom. gas, LNG & hydrogen	-21%	-20%	0%		0%	-4%
SC 5 All	-22%	-20%	-1%	0%	0%	-4%

4.4.4 Sensitivity to gas production parameters

To test the sensitivity of the gas production and use results to individual gas production parameters

Table 25. It shows the methane fugitive and energy use in gas processing are the two most sensitive parameters affecting the emission profile of shale. Respectively these increase the emission profile of processed gas by 3.1% and 4.3% for a 10% increase in the default value for the parameter. The effect of either of these impacts on the final emission total is between 0.44% and 0.64% depending on which scenario is being assessed. Gas yield per well and fraction of gas requiring drying have around 1% change in emission profile of gas while all other parameters are below 1%.

Table 25 Change in emissions arising from 10% increase in different gas production parameters

	Effect on emission of gas delivered to Darwin.	Effect on total emissions of scenario 1	Effect on total emissions of scenario 5
Gas yield per well	-1.15%	-0.16%	-0.17%
Wells per well pad	0.00%	0.00%	0.00%
Fracs Per Well	0.27%	0.04%	0.04%
Well depth	0.44%	0.06%	0.07%
Well width	0.82%	0.12%	0.12%
Fracking diesel use	0.22%	0.03%	0.03%
Frac fluid volume	0.05%	0.01%	0.01%
Water supply pumping head	0.00%	0.00%	0.00%
Primary wastewater energy use	0.03%	0.00%	0.01%
Fracking water reuse fraction	0.00%	0.00%	0.00%
Methane fugitive from fracking	3.09%	0.44%	0.46%
CO2 Venting from fracking	0.55%	0.08%	0.08%
Gas processing energy	4.29%	0.61%	0.64%
Fugitive from gas processing	0.00%	0.00%	0.00%
Fraction of gas requiring drying	1.25%	0.18%	0.19%

As the methane fugitive is value is demonstrated as a sensitive parameter an additional sensitivity on the fugitive methane fraction from Burnham, Han et al. (2012) is shown in Table 26 using a lowest value of 0.006% and a highest value of 2.75%. It demonstrates that at the upper limit of the Burnham, Han et al. (2012) range the footprint of gas could more than double and the overall footprint of scenarios could increase by 22%.

Table 26 Change in emissions arising from highest estimate from % increase in different gas production parameters

	Effect on emission of gas delivered to Darwin.	Effect on total emissions of scenario 1	Effect on total emissions of scenario 5
Low estimate from Burnham, Han et al. (2012)	-22.9%	-3%	-3%
High estimate from Burnham, Han et al. (2012)	146%	22%	22%

4.5 Uncertainty analysis

The uncertainty analysis consists of two parts. The first part is specifying the uncertainty ranges on important values in the CFP. The summary of key parameters in the inventory section describes the values used. The background data in the CFP already have uncertainty specified by the database developers.

The second part of the uncertainty analysis is to run the Monte Carlo simulation, which runs the CFP many times while randomly setting each value within its specified distribution. This results in a probability distribution for the output results of the CFP. The uncertainty of the results can be set based on 95% confidence limits (the upper and lower bounds in which 95% of sampled results fall between).

The results for 1 GJ of gas delivered to Darwin is shown in Table 27, with the mean value being 9.4 kg CO_2 e per GJ. The value calculated on best estimates was 8.86 kg CO_2 e per GJ.

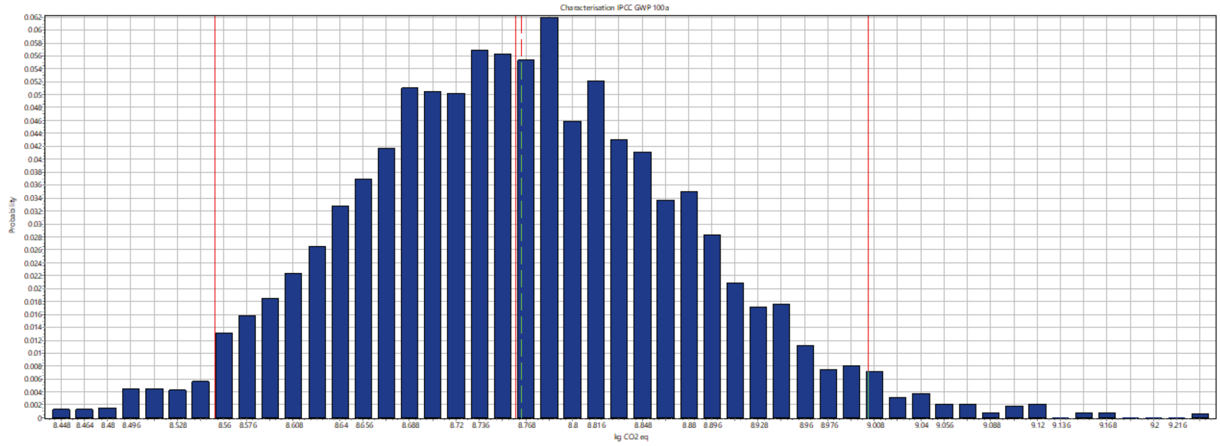


Figure 9 shows the probability distribution of the Monte Carlo. The Monte Carlo analysis shows the fraction of runs that occur at different value points for the 2,000 Monte Carlo runs. The results reveal that the higher values above the mean are more widespread on the right of the graph. This is a property of log normal distributions and is also the result of some key uncertainties, which were defined with a bias to the right.

Table 27 Uncertainty assessment results for 1 GJ of gas production delivered to Darwin.

	Mean	Standard deviation	Lower 95% tile value	Upper 95% tile value

1 GJ of gas delivered to Darwin	9.4kg CO_2 e	0.12 kg CO_2 e	9.16kg CO_2 e	9.82 kg CO_2 e

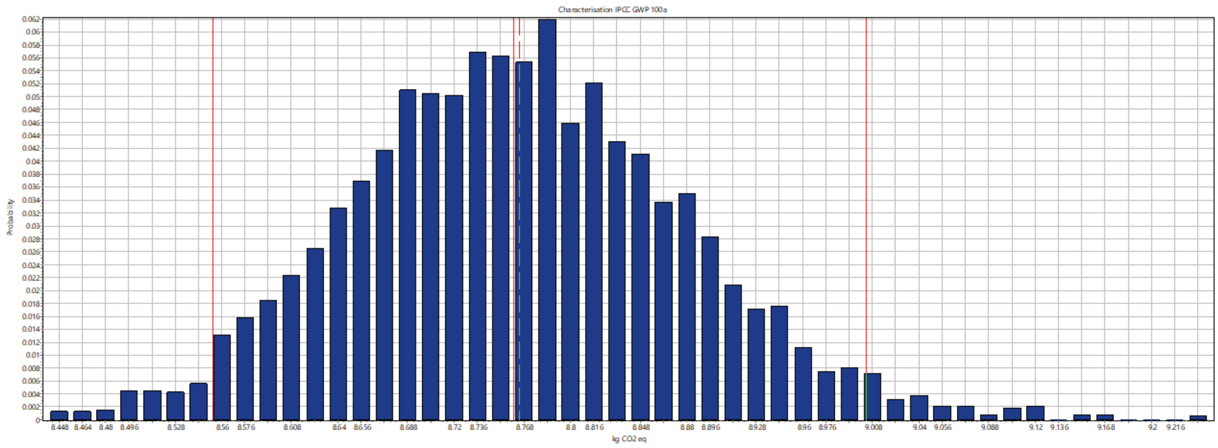


Figure 9 Probability distribution from Monte Carlo analysis of 1 GJ of shale gas delivered to Darwin.

Table 28 and Figure 10 show the uncertainty results for each of the scenarios. Similar to the results for shale gas production, the values are skewed to the right giving mean values slightly higher than the best estimate calculation. The overall uncertainty for the scenario is lower than for the gas production alone – as there is less uncertainty about the combustion emissions from shale gas which dominate the total value of the scenarios.

Table 28 Uncertainty assessment results in Mt CO_2 e for 25 years of production under each scenario.

	Mean Mt CO2 e	Standard deviation Mt CO2 e	Lower 95% tile value Mt CO2 e	Upper 95% tile value Mt CO2 e
Sc1 Dom. gas & LNG	22	1.1	20.7	24.6
Sc2 Dom. gas, LNG & refinery	24	1.0	22.2	25.8
Sc3 Dom. gas, LNG & chemicals	21	1.0	19.6	23.6
Sc4 Dom. gas, LNG & hydrogen	22	1.0	20.6	24.1
SC 5 All	70	3.1	64.6	76.2

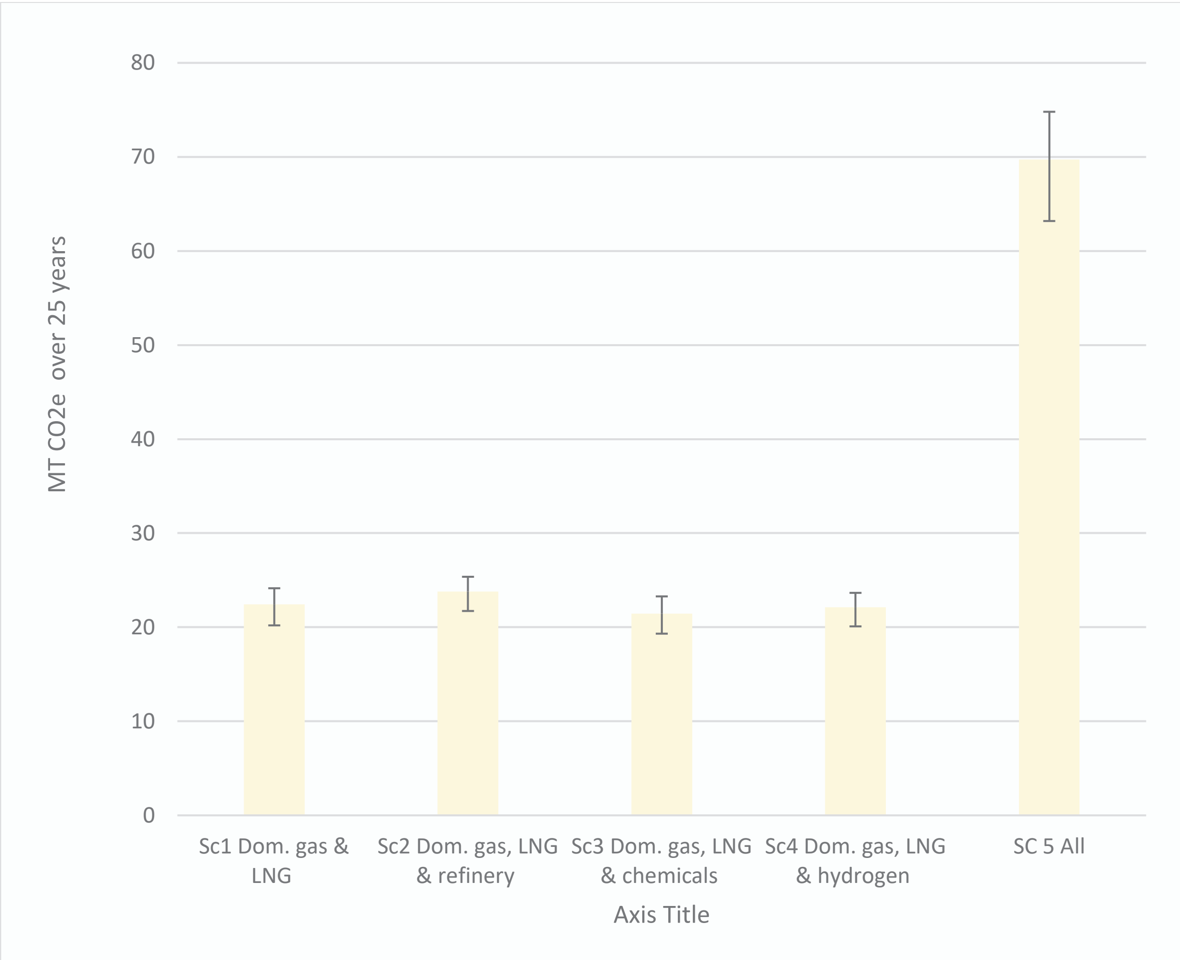


Figure 10 95% confidence limits for each of five scenarios over 25 years.

4.6 Data quality assessment

The data quality assessment (Table 29) provides a qualitative review of the data used in the study and aims to highlight the strengths and weaknesses of data inputs. The data quality indicators were established in the goal and scope stage of the study and are shown in Section 2.2.7.

Table 29 Data quality assessment.

	Reliability	Time-related coverage	Geographical coverage	Technology coverage	Representative ness	Comment
Gas production per well	Good	Good	Good	Good	Fair	Industry estimates based on similar mine configurations
Number of wells over 25 years	Fair	Good	Good	Good	Fair	Industry estimates based on similar mine configurations
Land area occupied by well pad	Good	Good	Good	Good	Fair	Industry estimates based on similar mine configurations
Wells per wellpad	Good	Good	Good	Good	Fair	Industry estimates based on similar mine configurations
Fractures per well	Good	Good	Good	Good	Fair	Industry estimates based on similar mine configurations
Vertical well depth Kyalla	Good	Good	Very good	Very good	Good	From map of geological formation
Horizontal well length Kyalla	Good	Good	Very good	Very good	Good	Estimate based on current and emerging practice
Vertical well depth Valkerri	Good	Good	Very good	Very good	Good	From map of geological formation
Horizontal well length Valkerri	Good	Good	Very good	Very good	Good	From map of geological formation
Contribution from Valkerri	Fair	Good	Good	Good	Fair	Estimate based on available reserves in each
Contribution from Kyalla	Fair	Good	Good	Good	Fair	Estimate based on available reserves in each
Energy per Fracturing per m of horizonal well	Fair	Fair	Good	Good	Fair	From literature extrapolated to per m horizontal value

Fracturing fluid per fracturing	Fair		Good	Good	Fair	From industry estimate
Water supply pumping head	Poor	Fair	Fair	Fair	Fair	Author estimate
WW pre-treatment energy	Fair	Good	Good	Good	Fair	From literature value
Water reuse rate	Fair	Good	Good	Good	Fair	Industry estimates based on similar mine configurations
Carbon dioxide vent from Kyalla	Good	Good	Good	Good	Good	Industry values from tests on CO_2 content
Carbon dioxide vent from Velkerri	Good	Good	Good	Good	Good	Industry values from tests on CO_2 content
Methane fugitive at well completion (% of gas produced)	Good	Good	Good	Good	Good	From literature estimates and verified with industry

4.7 Limitations of the study.

This study only covers greenhouse gas emissions calculated for the purpose of estimating what offsets would be required at different scales of development. It cannot be used to compare shale gas production against other fuel types or energy systems. It does not provide any detail other impacts such as water depletion, toxicity, damage, or biodiversity. The study also does not provide any assessment of the sustainability of these greenhouse gas emissions in the context of any climate change targets or international agreements.

The study calculates the impacts of future potential extraction and use of shale gas resource in the Beetaloo sub-basin over the next 30 years. However, the only data available for the extraction, processing and utilisation of the gas is based on historic data between 2 and 15 years old. This is likely to overestimate total emissions with newer plant and equipment likely to be more efficient than existing equipment however this is not a certainty

The focus of the study has been on the extraction and processing data for shale gas while the technology models for utilisation of the gas as hydrogen and chemical production are more general models and do not intend to represent an actual design of these technologies in the Northern Territory. These are intended to indicate the total emission difference between different end use options and not be a feasibility assessment of the technology themselves.

End markets for LNG are modelled as electricity in China when in reality this could be exported to other countries in Asia and elsewhere which would change the shipping distance and potentially the types of end uses.

5 Conclusions

The study aimed to calculate the total climate change impact of different gas utilisation scenarios which may need to be offset using different boundary conditions.

The CFP has successfully modelled the climate change impacts using a 100-year global warming potential result for Beetaloo Sub-basin under a variety of production scenarios. At the maximum production scenario, the impacts are estimated to be between 65 and 76 Mt CO_2 e with the mean being 70.5Mt while the best estimate is 67Mt (the value calculated without uncertainty).

Using a 20-year global warming potential, scenario 5 increases to 75Mt and using a GTP 100 approach reduces the impact to 65Mt.

In the shale gas production stage, the main contributing factors are fugitive methane and vented carbon dioxide from fracturing which contribute half of the impacts of gas delivery to Darwin. The majority of impacts however are in the utilisation of shale gas both domestically and internationally. Use as LNG assumed to be destined to energy markets form most of these impacts while other technologies has similar impact profiles with the possible exception of methanol – assuming it used in non-combustion application and hydrogen production with carbon capture.

References

ABARE (2011). Energy in Australia 2011. Canberra ACT, ABARE, Australian Bureau of Agricultural Reseach Economics.

Acil Allen Consulting (2017). The Economic Impacts of a Potential Shale Gas Development in the Northern Territory. Perth.

ALCAS (2020). Australian Life Cycle Inventory Database (AusLCI) Version 1.35. A. L. C. A. Society. Melbourne.

Bista, S., P. Jennings and M. Anda (2019). "Comprehensive environmental impacts and optimization of onshore shale gas development and delivery." Energy Technology **7**(5): 1800871.

Burnham, A., J. Han, C. E. Clark, M. Wang, J. B. Dunn and I. Palou-Rivera (2012). "Life-cycle greenhouse gas emissions of shale gas, natural gas, coal, and petroleum." Environmental science & technology **46**(2): 619-627.

Caballero, J. A., J. A. Labarta, N. Quirante, A. Carrero-Parreño and I. E. Grossmann (2020). "Environmental and Economic Water Management in Shale Gas Extraction." Sustainability **12**(4): 1686.

Clark, C. E., R. M. Horner and C. B. Harto (2013). "Life cycle water consumption for shale gas and conventional natural gas." Environmental science & technology **47**(20): 11829-11836.

Commonwealth of Australia (2020a). Measurement Determination of the Clean Energy Regulator for National Greenhouse and Energy Regulation Scheme.

Commonwealth of Australia (2020b). National Inventory Report 2018 Volume 1. Australian National Greenhouse Accounts. Canberra**:** 352.

Commonwealth of Australia (2021). National Inventory Report 2019 Volume 1. Australian National Greenhouse Accounts. Canberra**:** 352.

Côté, A., B. Richards, C. Altmann, E. Baruch and D. Close (2018). "Australia’s premier shale basin: five plays, 1 000 000 000 years in the making." The APPEA Journal **58**(2): 799-804.

Department of Climate Change, E., the Environment and Water,, (2022). National Greenhouse Accounts Factors. Canberra, Department of Climate Change, Energy, the Environment and Water,

Commonwealth of Australia.

Department of Energy and Environment (2020). National Greenhouse Accounts Factors. Canberra, Department of the Energy and Environment, Commonwealth of Australia.

Department of Industry, S., Energy and Resources,, (2021a). National Greenhouse Accounts Factors. Canberra, Department of Industry, Science, Energy and Resources, Commonwealth of Australia.

Department of Industry, S., Energy and Resources. (2021b). Australian Petroleum Statistics. Canberra, Commonwealth of Australia. **10**.

European Commission Joint Research Centre and Institute for Environment and Sustainability (2010). International Reference Life Cycle Data System (ILCD) Handbook - General guide for Life Cycle Assessment - Detailed guidance. Luxembourg.

Falcon Oil & Gas Ltd. (2021). "Declaration of Material Gas Resource."   Retrieved 6th December 2021, 2021, from **https://www.falconaustralia.com.au/declaration-of-material-gas-resource/**.

Frischknecht, R. and O. Jolliet, Eds. (2016). Global Guidance for Life Cycle Impact Assessment Indicators Volume 1. Paris, France, United Nations Environment Programme, 2016.

Fulton, S. and A. Knapton (2015). Beetaloo'Basin'Hydrogeological'Assessment, CloudGMS.

Goldstein, L., B. Hedman, D. Knowles, S. I. Freedman, R. Woods and T. Schweizer (2003). Gas-fired distributed energy resource technology characterizations, National Renewable Energy Lab., Golden, CO.(US).

Grant, T., C. Anderson and B. Hooper (2014). "Comparative life cycle assessment of potassium carbonate and monoethanolamine solvents for CO2 capture from post combustion flue gases." International Journal of Greenhouse Gas Control **28**(0): 35-44.

Howarth, R. W., R. Santoro and A. Ingraffea (2011). "Methane and the greenhouse-gas footprint of natural gas from shale formations." Climatic Change **106**(4): 679-690.

International Organization for Standardization (2006). International Standard, ISO 14040, Environmental Management Standard- Life Cycle Assessment, Principles and Framework. Switzerland.

International Organization for Standardization (2015). ISO/CD 13065:2015, Sustainability criteria for bioenergy,. Switzerland, ISO.

International Organization for Standardization (2018). International Standard ISO 14067:2018, Greenhouse gases — Carbon footprint of products — Requirements and guidelines for quantification. Geneva, Switzerland, ISO**:** 58.

International Organization for Standardization (2019a). International Standard, ISO 14040, Environmental Management Standard- Life Cycle Assessment, Principles and Framework. Switzerland.

International Organization for Standardization (2019b). International Standard, ISO 14044, Environmental Management Standard- Life Cycle Assessment, Requirements and Guidelines. Switzerland.

IPCC (2006a). 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Volume 2: Energy, IPCC.

IPCC (2006b). 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Volume 4: Agriculture, Forestry and Other Land Use, IPCC.

IPCC (2013). Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. C. U. Press. Cambridge, United Kingdom and New York, NY, USA.**:** 1535.

IPCC (2019). 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Volume 2: Energy, IPCC.

ISO (2018). ISO 14067:2013, Greenhouse gases — Carbon footprint of products — Requirements and guidelines for quantification. Geneva, Switzerland, International Organization for Standardisation.

Jiang, M., W. Michael Griffin, C. Hendrickson, P. Jaramillo, J. VanBriesen and A. Venkatesh (2011). "Life cycle greenhouse gas emissions of Marcellus shale gas." Environmental Research Letters **6**(3): 034014.

Kernke, M. (2021). Responses to "Summary of key assumptions for LCA Draft". T. Grant.

Khan, M. S., I. A. Karimi and D. A. Wood (2017). "Retrospective and future perspective of natural gas liquefaction and optimization technologies contributing to efficient LNG supply: A review." Journal of Natural Gas Science and Engineering **45**: 165-188.

McConnell, P. and T. Grant (2020). Comparative Life cycle assessment: Browse and Scarborough. Perth, ERM.

Mitchell, A. L., D. S. Tkacik, J. R. Roscioli, S. C. Herndon, T. I. Yacovitch, D. M. Martinez, T. L. Vaughn, L. L. Williams, M. R. Sullivan and C. Floerchinger (2015). "Measurements of methane emissions from natural gas gathering facilities and processing plants: Measurement results." Environmental science & technology **49**(5): 3219-3227.

Muller, S., P. Lesage, A. Ciroth, C. Mutel, B. P. Weidema and R. Samson (2016). "The application of the pedigree approach to the distributions foreseen in ecoinvent v3." The International Journal of Life Cycle Assessment **21**(9): 1327-1337.

Muñoz, I. and J. H. Schmidt (2016). "Methane oxidation, biogenic carbon, and the IPCC's emission metrics. Proposal for a consistent greenhouse-gas accounting." The International Journal of Life Cycle Assessment **21**(8): 1069-1075.

Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, (2013). Anthropogenic and Natural Radiative Forcing. Cambride, United Kingdom and New York, US, Cambridge University Press.

Origin Energy Limited. (2021). "Beetaloo Basin drilling results indicate material gas resource." Retrieved 7th December 2021, 2021, from **https://www.originenergy.com.au/about/investors-media/beetaloo-basin-drilling-results-indicate-material-gas-resource/**.

Orr ML, Bernardel G, Owens R, Hall LS, Skeers N, R. B and W. M (2020). Geology of the Beetaloo GBA region. Technicalappendix for the Geological and Bioregional Assessment: Stage 2. Australia, Department of the Environment and Energy, Bureau of Meteorology, CSIRO and Geoscience Australia, Australia.

Pospíšil, J., P. Charvát, O. Arsenyeva, L. Klimeš, M. Špiláček and J. J. Klemeš (2019). "Energy demand of liquefaction and regasification of natural gas and the potential of LNG for operative thermal energy storage." Renewable and Sustainable Energy Reviews **99**: 1-15.

Salkuyeh, Y. K., B. A. Saville and H. L. MacLean (2017). "Techno-economic analysis and life cycle assessment of hydrogen production from natural gas using current and emerging technologies." International Journal of hydrogen energy **42**(30): 18894-18909.

Satter, A. and G. M. Iqbal (2016). 7 - Reservoir life cycle and role of industry professionals. Reservoir Engineering. A. Satter and G. M. Iqbal. Boston, Gulf Professional Publishing**:** 127-136.

Scientific Enquiry (2018a). Final Report of the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory. Darwin, Australia.

Scientific Enquiry (2018b). Summary of the Final Report of the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory. Darwin, Australia.

Stephenson, T., J. E. Valle and X. Riera-Palou (2011). "Modeling the relative GHG emissions of conventional and shale gas production." Environmental science & technology **45**(24): 10757-10764.

Turvey, R. (1969). "Marginal cost." The Economic Journal **79**(314): 282-299.

U.S. Department of Energy (2015). Technically Recoverable Shale Oil and Shale Gas Resources: Australia. Washington, DC 20585, Independent Statistics & Analysis U.S. Department of Energy.

USEPA (2015). "Analysis of hydraulic fracturing fluid data from the FracFocus chemical disclosure registry 1.0." Development, O. o. R. a., Ed. Washington, DC.

USEPA (2016). Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States.

Weidema, B. P., C. Bauer, R. Hischier, C. Mutel, T. Nemecek, J. Reinhard, C. O. Vadenbo and G. Wernet (2019). Overview and methodology. Data quality guideline for the ecoinvent database version 3. Ecoinvent Report 1(v3.6). St. Gallen, The ecoinvent Centre.

lifecycles.

CONTACT US

Life Cycle Strategies Pty Ltd (Lifecycles)

t **+61 (0)3 9417 1190**

e **info@lifecycles.com.au**

w **www.lifecycles.com.au**