ANALYSIS OF BEETALOO GAS BASIN EMISSIONS & CARBON COSTS

Australian carbon advisory, October 2021

RepuTex ENERGY

CONTENTS

ABOUT THIS REPORT

RepuTex has been engaged by Lock the Gate to evaluate the scale and implications of potential greenhouse gas (GHG) emissions and carbon costs from the proposed development of the Beetaloo and McArthur shale gas basins in the Northern Territory (NT).

Specifically, analysis quantifies potential GHG emissions from NT gas basin projects between 2025-2045 for the purpose of evaluating expected demand for Australian Carbon Credit Unit (ACCU) offsets in line with the Northern Territory Offsets Principles, along with the potential costs of carbon offset procurement for liable entities. Analysis also considers the compatibility of proposed developments with Australia's obligations under the Paris Agreement, and the gas industry's pathway to net-zero emissions.

Analysis is presented in the following sections:

- Background to the Beetaloo and McArthur shale gas basins;
- Analysis of the estimated costs of resource extraction and estimated gas production scenarios;
- Analysis of potential GHG emissions from proposed NT gas basin projects between 2025-2045;
- Calculation of the carbon cost for liable entities to offset their GHG emissions in line with the Northern Territory Offsets Principles;
- Summary of results and implications.

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1.

Background

Introduction to the McArthur Basin and Beetaloo Sub-basin

BACKGROUND

The Beetaloo Sub-basin is located approximately 500 kilometres south of Darwin in the Northern Territory, with the boundaries of the sub-basin incorporating the Katherine-Daly and Barkly Regions. The Sub-basin lies within the larger McArthur Basin and spans around 30,000 square kilometres.

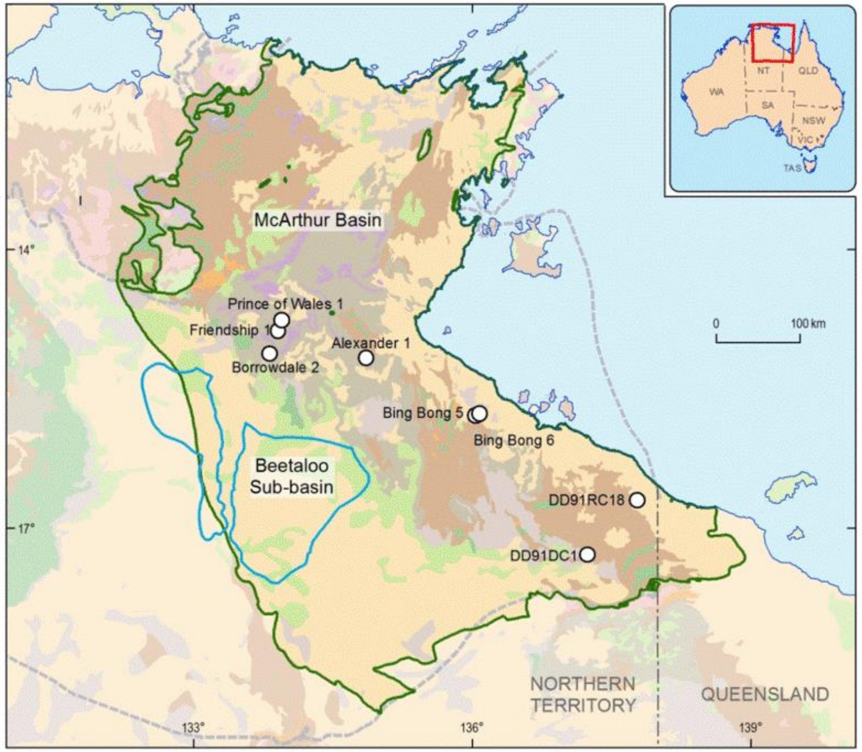
Due to its size, the Beetaloo Sub-basin has gained significant interest both politically and commercially. It is estimated that the Sub-basin contains approximately 70 per cent of the Territory's prospective shale gas resources. As a result, it has been the source of around 50 per cent of the total A$505 million of exploration investment in the NT since 2010 (Pepper 2018). The Sub-basin is comparable with several of the major US shale gas basins and its shale gas resources are most recently estimated at up to 295,700 petajoules (263 Trillion cubic feet). (DISER and GA 2021). As a result, the Sub-basin is larger than any of the North-West Shelf conventional gas resources, or over 500 times current annual domestic consumption in Australia.

In response to environmental concerns, the NT Government suspended hydraulic fracturing in September 2016, with the moratorium lifted in April 2018 following the Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs (the Pepper Inquiry). The Pepper Inquiry made several recommendations to manage the environmental risks associated with onshore gas development, including a commitment to ensure no net increase in lifecycle emissions (in Australia) from NT onshore shale gas, subsequently adopted by the NT Government.

Significant exploration activity is now underway in the Sub-basin with Origin Energy, Santos, Falcon Oil and Gas, and Empire Energy all investigating key unconventional targets. Initial results indicate that the Sub-basin is prospective for petroleum and is estimated to contain significant technically recoverable gas and liquid resources, particularly from shale gas plays.

Recoverable resources are proposed to be developed to supply the East Coast Gas Market (the Australian Capital Territory, New South Wales, Queensland, South Australia, Tasmania, and Victoria) or be used as feedstock for LNG projects in the NT gas market. In January 2021, the Australian Government released its Beetaloo Strategic Basin Plan, which aims to accelerate exploration and development in the Sub-basin. Around 20-40 appraisal wells are anticipated to be drilled in the next four years, followed by around 200-300 wells each year during development, with full production continuing for 20-40 years (DISER 2021b).

There is still a large degree of uncertainty as to the volumes and consistency of the gas and liquids in the basin, which is not likely to be settled until 2022. While initial results from horizontally drilled test wells are promising (Macdonald-Smith 2021), the resource has several stages to progress prior to commercial or investment decisions being made.



Source: Northern Territory Geological Survey (2017)

2.

Production and emissions estimates

Estimated gas volumes and potential greenhouse gas emissions

ESTIMATED COSTS OF RESOURCE EXTRACTION

Estimated costs of resource extraction in the Beetaloo Sub-basin, commissioned by the Australian Energy Market Operator (AEMO), conducted by Core Energy, indicate a range between A$7-$10/GJ, with the estimated cost of exports to north-east Asia ranging between A$11-$12/GJ, shown in the figures below.

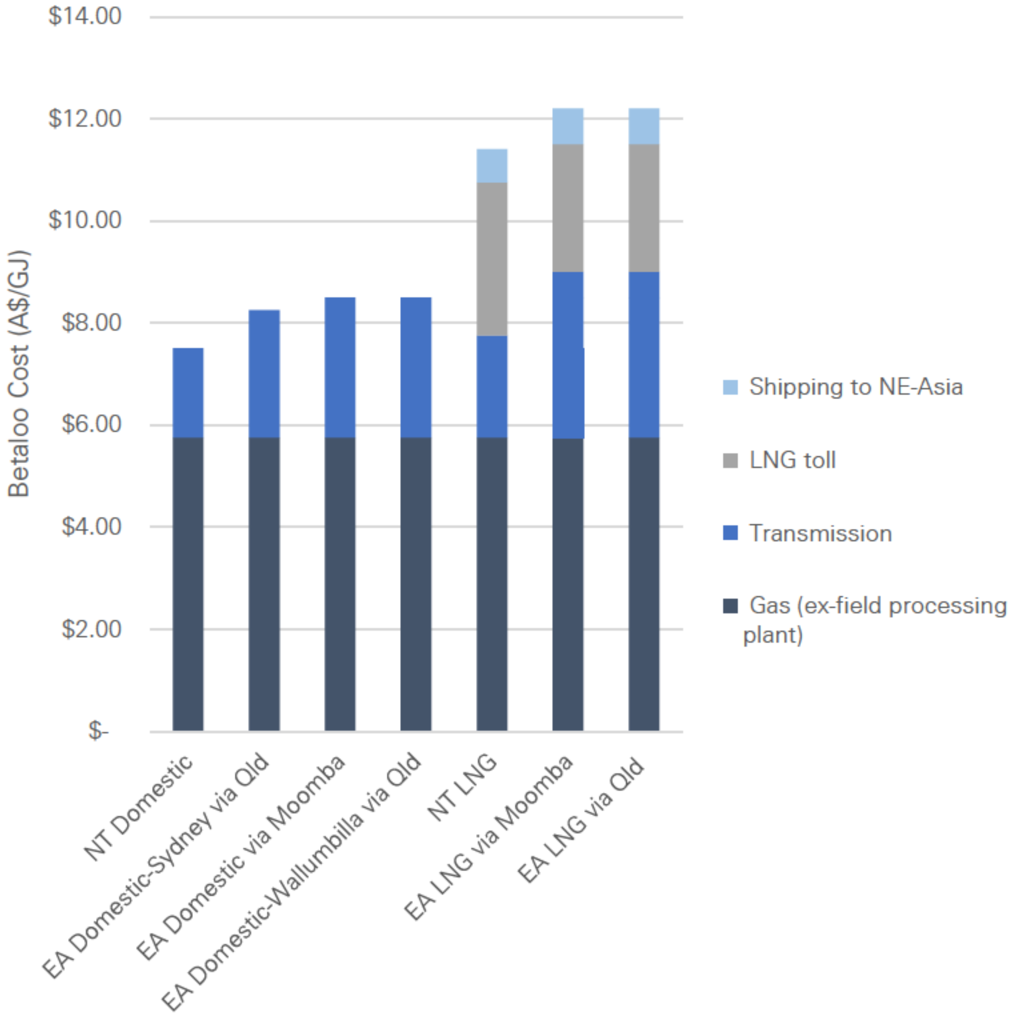
The bulk of the costs associated with developing Beetaloo's unconventional gas resources are associated with deep horizontal drilling, fracking, and collection of gas, which is more expensive than conventional gas production. The Beetaloo Sub-basin gas is also in a remote location, and in most scenarios would necessitate field processing facilities and other infrastructure to be developed including gas transmission pipelines at the appropriate mature daily rates (TJ/d) to the closer Northern Territory (NT) and/or various routes to the further Eastern Australia (EA) markets. Additional costs would be associated with export from Darwin and/or Gladstone including liquification and shipping.

Figure 2: Contingent and Prospective Gas Resources and extraction costs

Project / Supply Region	OPEX, Well Cost & Existing Plant Cost, Royalty & Tax | AUD/GJ	OPEX, Well Cost & New Plant Cost, Royalty & Tax | AUD/GJ	Including Appraisal, Acquisition & Exploration Cost | AUD/GJ
Bass Basin	6.02		6.84
Casino, Henry and Netherby	3.51-4.63		0.00
Cooper Eromanga Basin	7.12		7.63
GBJV & Turrum & Kipper	6.29		7.43
Longtom & Sole	5.80		6.51
Moranbah	5.24	5.71	6.91
QLD CSG - Arrow Energy (excl. Moranbah)	6.61	7.55	0.00
QLD CSG - BG / QCLNG	6.45	7.39	0.00
QLD CSG - GLNG	8.44	9.44	0.00
QLD CSG - Ironbark / ORG	5.18		
QLD CSG - ORG / APLNG	6.60	7.47	7.93
QLD CSG - Other	0.00	8.87	9.38
Gippsland Basin - Other	6.77-8.30	7.28-9.36	7.28-9.87
Clarence-Moreton Basin - Other			
Gunnedah Basin - Other			
Galilee Basin - Other			
Adavale Basin - Other			
Otway Basin - Other			
Central Petroleum Amadeus			
Falcon Oil & Gas (Georgina Basin)			
Cash Maple			
Beetaloo Basin			
Gloucester Basin			
Coxco Dolomite			

Source: Core Energy and Resources, 2019.

Figure 3: Beetaloo cost estimates for extraction of gas to Northern Territory (NT) and Eastern Australia (EA) markets.



Source: Average values from Deloitte, 2020 based on optimal (non fragmented) infrastructure development. If numerous gas processing facilities are built instead of common, shared infrastructure, total costs may be increased by in excess of A$2 billion, increasing tariffs by approximately A$0.50/GJ, potentially significant in a market sensitive to price differences of $1/GJ.

ESTIMATED GAS PRODUCTION SCENARIOS

Below we present three scenarios for the development of the Beetaloo Sub-basin, reflecting the High, Mid and Low scale up of resource production. Scenarios account for the early stage of exploration in the Sub-basin and uncertainty over the scale of and composition of economically recoverable resources, either dry or liquids rich gas.

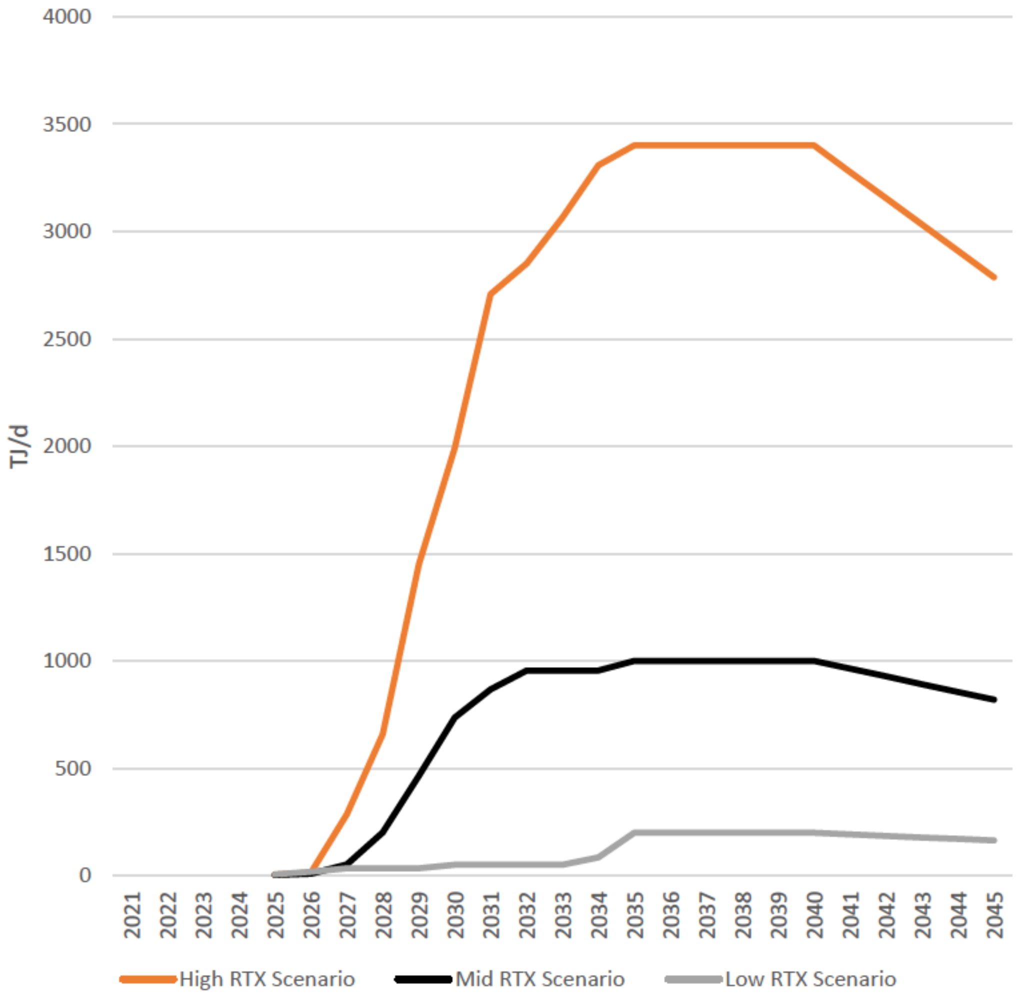
Production estimates draw on industry input to the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (Pepper Inquiry), which assumes potential shale gas fields will have production in the range of 100-200 TJ/day for a small development, 800-1,100 TJ/day for a large gas field development, and production of 3,400 TJ/day for a later development scenario, with 2,740 TJ/day used for LNG export and 660 TJ/day for domestic gas consumption.

The three scenarios describe a significant increase in gas production from the Beetaloo Sub-basin (and consequently Australia) beginning in 2024, with peak production achieved in 2035. A summary of the cases is outlined below:

- **High scenario (3,400 TJ per day):** The Sub-basin is developed and reaches peak production in 2035. An 80% share of gas is sold to the LNG export market, e.g., via Gladstone LNG, Darwin LNG and Ichthys (2,740 TJ/day).
- **Mid scenario (1,000 TJ per day):** The Sub-basin is developed and reaches peak production in 2035. Gas is sold principally to the NT, and Australian east coast markets via new pipelines to Queensland and Moomba.
- **Low scenario (200 TJ per day):** The Sub-basin is developed and reaches peak production in 2035. Gas is sold predominantly into the east coast market via Northern Gas Pipeline, and into the Northern Territory.

The shape of RepuTex's 20-year production curves are derived from similar dry gas scenarios modeled in Deloitte's 2020 Report on the Development of the Beetaloo Sub-basin, with degradation of 3.6% assumed to occur after the first five years of full production.

Figure 4: Beetaloo Sub-basin Gas Production Scenarios



Source: RepuTex Energy 2021

ANALYSIS OF LIFECYCLE EMISSIONS FROM NT GAS BASIN PROJECTS

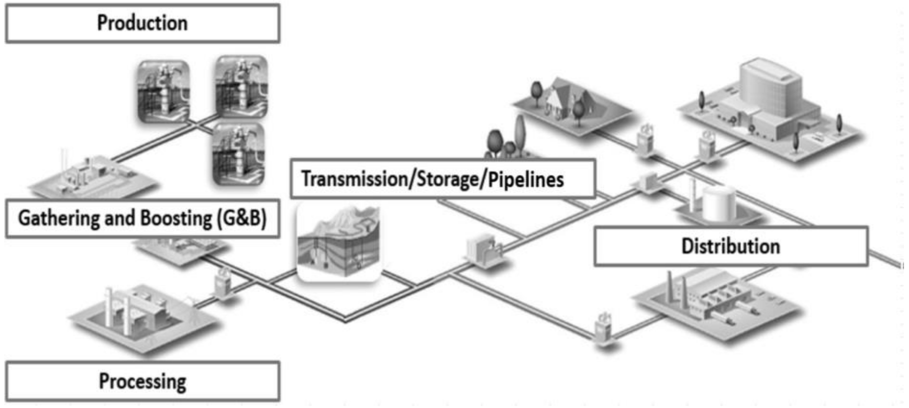
In July 2020, the NT Government set a new climate response and offset reform agenda, along with a Three-Year Action Plan for policy development including a goal for the NT to achieve net zero emissions by 2050, and policy for the mitigation of emissions from new and expanding large GHG emitters.

The framework includes the development of a Greenhouse Gas Emissions Offsets Policy to guide the application and administration of carbon offsets by mid-2022; and confirmation of a commitment to Recommendation 9.8 of the Pepper Inquiry to ensure there is no net increase in lifecycle emissions (in Australia) from any onshore shale gas produced in the NT.

Calculation of lifecycle emissions

Life-cycle analysis considers the full fuel cycle of gas production, from construction, production, processing, transport and final use (combustion).

Figure 5: Supply Chain Stages that compose life-cycle emissions



Source: Adapted from American Gas Association literature (AGA, 2014)

The life cycle of gas is then aggregated into two stages:

1. The upstream stage, which comprises natural gas production, processing, transmission, and transportation; and
2. The downstream stage of the energy conversion of natural gas for commercial or industrial or domestic purposes.

Analysis of lifecycle greenhouse gas emissions applies current industry assumptions for the calculation of carbon dioxide equivalence from methane emissions, based on the following assumptions:

- Analysis considers a 20-year study period 2025 to 2045;
- Analysis applies the Australian Government's IPCC assessment report five (AR5) 100-year global warming potential (GWP) for methane of 28 g CO2;
- Export emissions that occur overseas are excluded from Australian lifecycle offset calculations.
- Gas production is assumed to follow the shape of the 20-year production curves outlined in the previous section (Figure 4), derived from Origin Energy (2017), ramping up over an initial 'Development' portion of a gas project (2025 to 2035), reaching full production or steady state 'Harvest' production (2035 to 2040) before declining after 2040);
- A GHG emissions value of 64 g CO2e/MJ is applied to gas sent to domestic markets; while the Australian GHG emissions value of 19 g CO2e/MJ is applied to gas sent to export markets as the transport, regasification, and combustion/use emissions occur overseas.
- Analysis applies an upstream GHG emissions value of 13 g CO2e/MJ, and an additional 6 g COe/MJ for the conversion of export gas to LNG, in line with the Pepper Inquiry (Pepper 2018), converted from a GWP of 36;
- Analysis applies an emissions value of 51.53 g CO2e/MJ for downstream gas combustion in line with National Greenhouse Accounts Factors (DISER 2021);

Please refer to the following section for discussion of uncertainty in methane emissions calculations.

ACCOUNTING FOR UNCERTAINTY IN METHANE EMISSIONS CALCULATIONS

The scale and duration of the impact of GHG emissions such as carbon dioxide, methane and nitrous oxide (referred to as the global warming potential (GWP)) vary. To simplify comparison, individual effects are converted to a standard unit called a 'carbon dioxide equivalent' or CO_2e.

GWP measures how much energy the emissions of a 1 tonne of a gas will absorb over a given period, relative to the emissions of 1 tonne of carbon dioxide (CO2). This is commonly considered over a 100-year period; however, alternative 20-year metrics are increasingly being used in some analysis when the impact of GHGs with shorter lives than CO2 are important..

For example, a 20-year GWP for methane (CH4) is sometimes used as an alternative to a 100-year GWP. GWPs based on a shorter timeframe are larger for gases with lifetimes shorter than that of CO2. For example, for CH4, the 100-year GWP of 28–36 is less than the 20-year GWP of 84–86. The Intergovernmental Panel on Climate Change's (IPCC) Fifth Assessment Report (AR5) noted that fossil sources of methane can be up to 36 times worse than carbon dioxide, while methane from other sources – such as livestock and waste – can be up to 34 times worse (Nicholls and Baxter 2020). It should be noted that some uncertainty remains in this area with recent assessments such as Etminan et al. 2016, suggesting a further revision of fossil methane and other methane sources could increase consensus GWP values for fossil methane to around 40 times CO2 in later assessments.

The NT government's draft GHG Emission Management for New and Expanding Large Emitters, however, prescribes that industrial project proponents should use emissions measurement factors and methodologies provided by the Clean Energy Regulator when estimating emissions. From 1 July 2020, amendments to the National Greenhouse and Energy Reporting Regulations 2008 and the National Greenhouse and Energy Reporting (Measurement) Determination 2008 mean that GWPs for methane (CH4) have been updated, increasing from 25 to 28 from 2020-21 onwards. (CER 2021)

Therefore, in this analysis, we apply a GWP of 28 over a 100-year timeframe, in line with updated Australian National Greenhouse Accounts Factors (DISER 2021). For example, if 1 gram of methane is emitted, for a 100-year timeframe with a GWP of 28, the equivalent emission is calculated as 28 g CO2e.

In doing so we note that this approach is conservative, or "best case" for industry, with an alternative use of a 20-year timeframe (GWP of 84 to 86) to result in significantly higher emissions outcomes. For example, at a methane GWP of 28, we calculate upstream GHG emissions factor for shale gas with an low CH4 leakage rate of 1.8% to be 13 g CO2e/MJ. Refer to Appendix A for discussion of the risks of a higher methane leakage rate.

If a 20-year GWP of 84 to 86 is used, however, the upstream GHG emissions factor increases to between 31.4 g COe/MJ to 32.0 g COe/MJ, with a corresponding increase in GHG emissions. See Appendix A for an example of life cycle GHG emission estimates based on a 20-year GWP = 86.

In line with Recommendation 9.8 of the Pepper Inquiry, adopted by the NT Government, the scope of analysis considers lifecycle emissions - ensuring there is no net increase in life cycle emissions emitted in Australia from any onshore shale gas produced in the NT. This position has been supported by the Australian Department of the Environment and Energy (now the Department of Industry, Science, Energy and Resources), which noted that it "understands life cycle emissions include emissions associated with the extraction, processing, transport and use within Australia" (DoEE 2019).

ESTIMATED LIFECYCLE EMISSIONS FROM NT GAS BASIN PROJECTS BY PHASE

Scenarios

For the purposes of this analysis, we consider three scenarios for potential lifecycle GHG emissions from Beetaloo Sub-basin projects, reflecting high, mid and low gas production, along with the use of gas for domestic versus international purposes. These scenarios are described below:

- High scenario (use of gas in Australia and overseas): 3,400 TJ/day (2,740 TJ/day for LNG export and 660 TJ/day for domestic consumption)
- Mid scenario (use of gas in Australia): 1,000 TJ/day
- Low scenario (use of gas in Australia): 200 TJ/day

Modelled outcomes

GHG emissions vary with production, however around 20%, of emissions from shale gas occur 'upstream', largely associated with the compression of gas during processing, fugitive methane emissions vented during well completions, and operational leakage during gas transport. The remaining 80% of GHG emissions occur 'downstream' at the point of use, typically involving combustion into CO2.

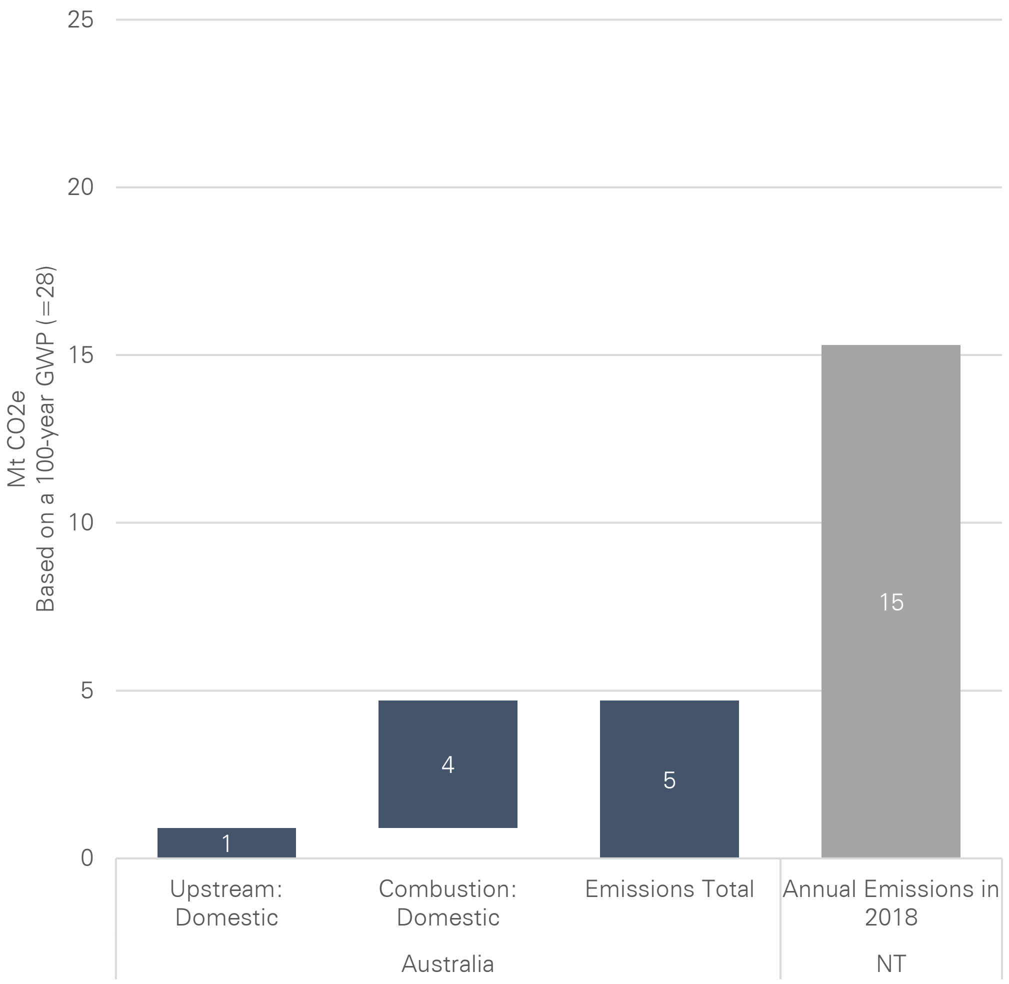
At 200 TJ/day, our Low scenario is anticipated to result in around 5 Mt CO2e (Mt) p.a., equivalent to approximately one-third of current NT emissions (before the Ichthys LNG project). Cumulatively, this translates to 59 Mt over the first 20-years. At 1,000 TJ/day, our Mid scenario is calculated to result in approximately 24 Mt p.a., equivalent to current NT annual emissions (after Ichthys). Cumulatively, this is calculated to be 368 Mt over the first 20 years.

At 660 TJ/day, our High scenario (Australia-only) is calculated to result in approximately 34 Mt p.a. in Australia. Cumulatively, this translates to 523 Mt over the first 20 years, equivalent to more than Australian annual current net-emissions. This also constitutes approximately 27% of Australia's carbon budget remaining to limit warming to 1.5°C (or 5% of a 2°C budget). At 3,400 TJ/day, our High scenario (Australia and overseas) is estimated to result in approximately 89 Mt p.a.. Cumulatively, this is estimate to be 1.4 billion tonnes over the first 20 years, equivalent to more than 2.5 times Australia's total annual emissions.

Figure 6: Annual lifecycle emissions from Beetaloo Sub-basin projects by scenario in Million tonnes of carbon dioxide equivalent (Mt), based on a 100-yr GWP for methane = 28. See Appendix A for life cycle GHG emissions based on a 20-yr GWp for methane = 86.

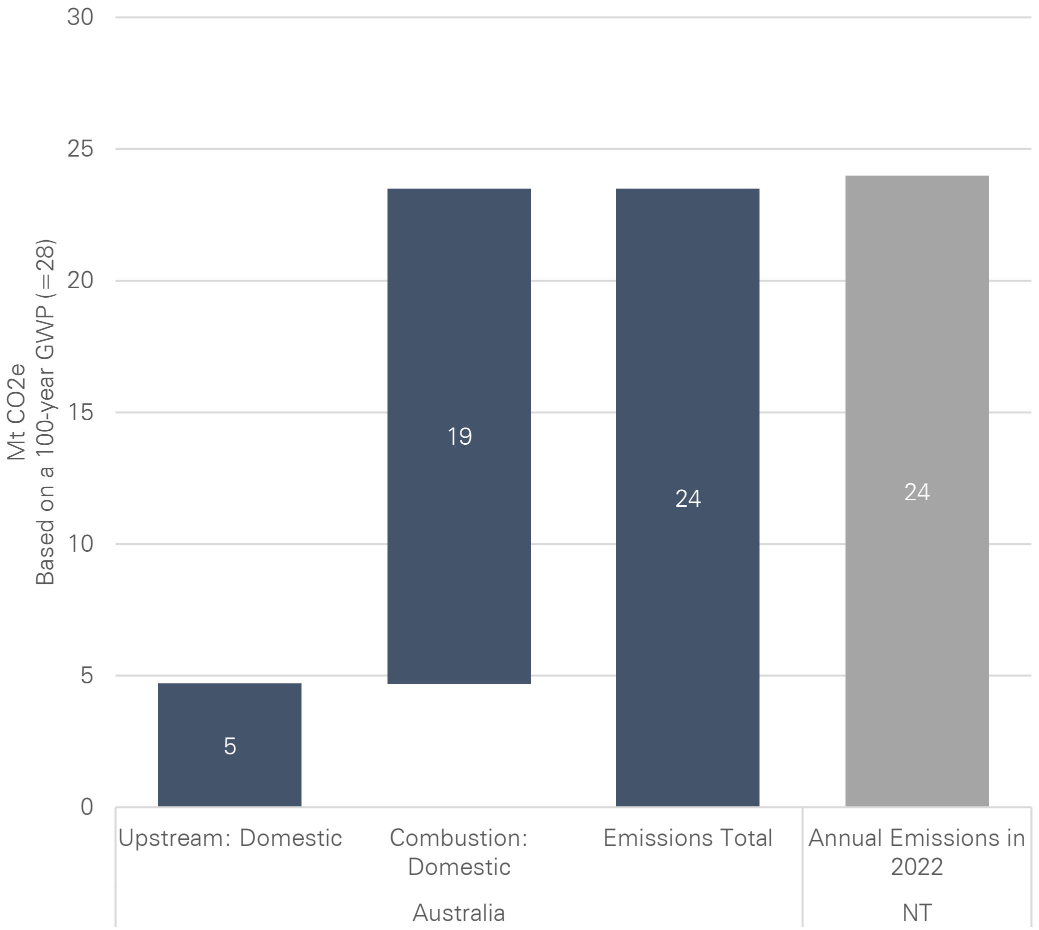
	Upstream (Mt p.a.)	Conversion to LNG (Mt p.a.)	Transport (Mt p.a.)	Regasification (Mt p.a.)	Combustion (Mt p.a.)	Full production lifecycle emissions (Mt p.a.)	Total lifecycle emissions (Cumulative Mt over 20-years)
High scenario (Australia and overseas)	16	6	2	1	64	89	1,358
Use of gas in Australia (660 TJ/day)	16	6			12	34	523
Mid scenario (use of gas in Australia)	5				19	24	368
Low scenario (use of gas in Australia)	1				4	5	59

Figure 7: Annual Beetaloo lifecycle emissions at full production (Low case). Note emissions comparison is for actual annual NT emissions in 2018.



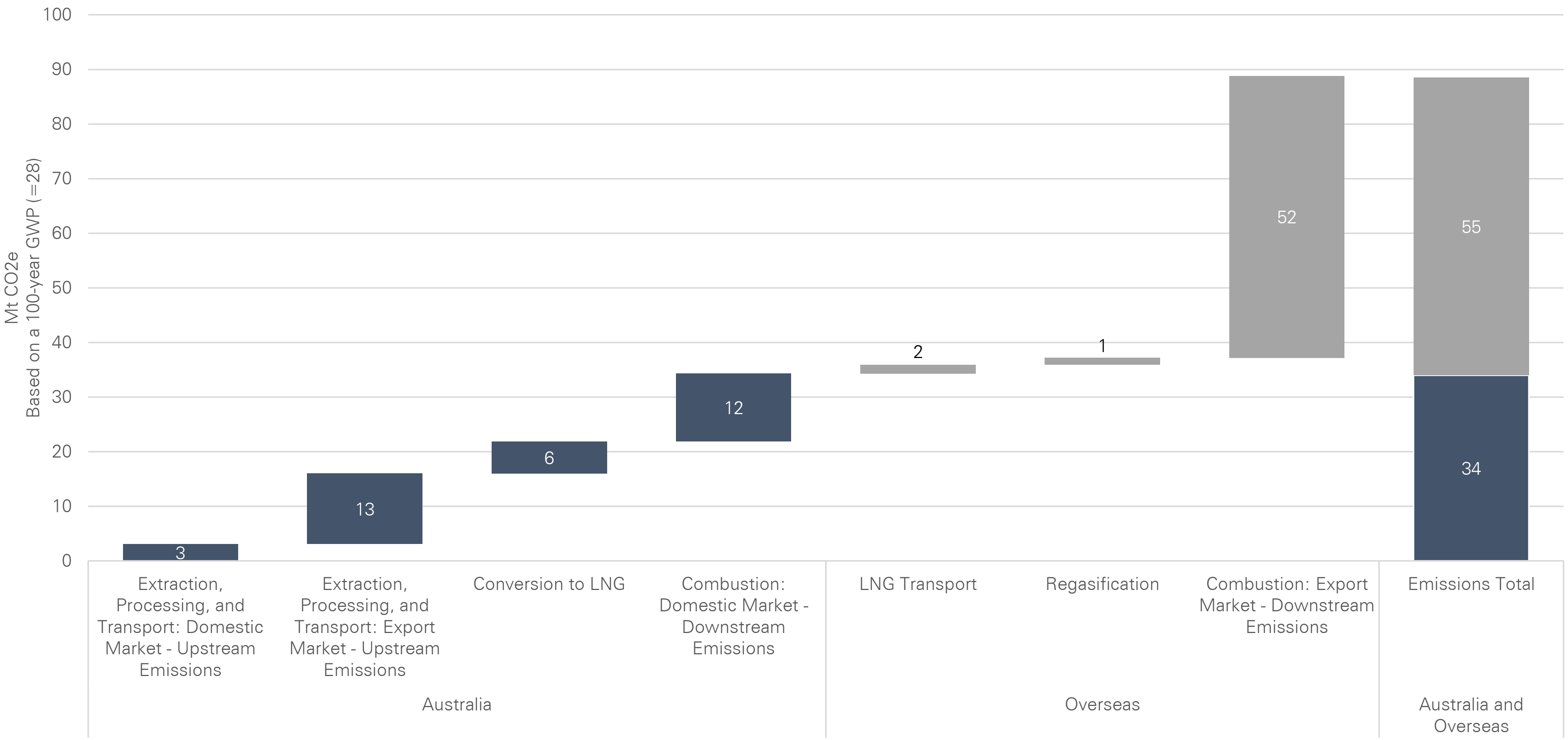
Source: RepuTex Energy, 2021

Figure 8: Annual Beetaloo lifecycle emissions at full production (Mid case). Note emissions comparison has increased to 24 Mt CO2e in 2022 due to Ichthys Project increases (NT Gov 2018).



Source: RepuTex Energy, 2021

Figure 7: Annual Beetaloo lifecycle emissions at full production for gas use in Australia and overseas (High case)



Source: RepuTex Energy, 2021

3.
Carbon cost analysis

The cost for liable entities to offset their GHG emissions

NORTHERN TERRITORY CLIMATE POLICY AND CARBON OFFSET PRINCIPLES

In July 2020, the NT Government set a new climate response and offset reform agenda, along with a Three-Year Action Plan for policy development including a goal for the NT to achieve net zero emissions by 2050, and policy for the mitigation of emissions from new and expanding large GHG emitters.

The framework includes the development of a Greenhouse Gas Emissions Offsets Policy to guide the application and administration of carbon offsets by mid-2022; and confirmation of a commitment to Recommendation 9.8 of the Pepper Inquiry to ensure there is no net increase in lifecycle emissions emitted in Australia from any onshore shale gas produced in the NT.

Northern Territory Offsets Principles

The Northern Territory Offsets Principles outline the framework for the use of carbon offsets in the NT. According to the policy, the use of an offset may only be considered when avoidance and mitigation measures have been exhausted and residual impacts remain. The offsets framework is underpinned by the use of Biodiversity offsets and GHG emissions offsets, which may be required for development activity or statutory approval process. The Principles provide that:

- Offsets must contribute to relevant NT emissions targets.
- Offsets must be delivered in the NT and be designed to deliver environmental, and wherever possible social, benefits in the affected region.
- Where offsets are not available within the NT, the proponent will need to demonstrate lack of availability and negotiate an alternative approach that ensures benefits are maximised within the Australian context.
- Offsets must be additional to what is already required under existing legislation and not already funded under another scheme.
- Offsets should last at least as long as the residual impacts of the project.

GHG abatement and the role of Carbon Capture and Storage (CCS)

In September 2021, the NT government released draft consultation on GHG emissions management for new and expanding large emitters, along with draft carbon offsets policy and guideline. The draft guidance notes that proponents of large-emitting projects in the NT may be required to develop a Greenhouse Gas Abatement Plan (GGAP). This may include the use of carbon offsets to manage residual emissions, however, all reasonable and practical measures to mitigate emissions are expected to be undertaken in the first instance.

Carbon Capture and Storage (CCS) is an emerging technology to capture, transport and store GHG emissions from gas fields by injecting the captured GHG back into the ground, albeit unproven at scale. A final investment decision is currently pending on Santos' proposed Moomba CCS project, which has the potential to be one of the lowest cost CCS projects globally with a lifecycle cost of A$33 per tonne of CO2 (Lewis 2021). Santos' Northern Australia and Timor-Leste CCS hub is also planning to repurpose existing wells to re-inject CO2.

The role of CCS at the Beetaloo Sub-basin remains uncertain, however, with Beetaloo shale gas containing carbon dioxide concentrations of around 3% (Middleton 2021). This is significantly lower than Australian convention gas fields being developed offshore, which may limit the potential application of CCS to reduce CO2 emissions from fugitive gas venting.

Given the expectation that CCS abatement at Beetaloo may be limited, the procurement of external carbon offsets is assumed to be the major source of emissions reductions for proponents of large-emitting projects in the NT. While we note the potential for CCS re-injection to become eligible for ACCU issuance, the cost per tonne of these developments is assumed to be broadly equivalent to our forward carbon offset price assumptions (refer to the following section), suggesting that carbon offset prices will also be similar irrespective of the project that ACCUs originate from.

CALCULATION OF CARBON COSTS

In calculating the carbon cost of potential GHG emissions for NT gas basins, we assume that a liability to offset lifecycle emissions is implemented in line with Recommendation 9.8 of the Pepper Inquiry and the NT Government's July 2020 climate response and offset reform agenda. Specifically, 100 per cent of Australian lifecycle emissions are assumed to be offset utilising domestic carbon offset units over the study period between 2025 - 2045, with typical gas production and lifecycle emissions assumed to continue but be in decline by 2045, as noted within the modelled production curve.

In doing so, a demand curve is created for the procurement of carbon offsets in line with our modelled High, Mid and Low production scenarios. Australian Carbon Credit Units (ACCUs) are then assumed to be utilised to fulfil demand. In line with current ACCU issuance, vegetation projects (55% of total ACCU issuance in FY21) are forecast to remain the dominant source of supply.

While ACCU issuance for vegetation projects ceases after 25 years, the carbon stocks sequestered by a project should be maintained for at least 100 years (in line with the CO2 equivalence of methane emissions), even if the business that originally surrendered the offsets is no longer in operation.

Forward carbon offset price assumptions

The ACCU spot price has grown 40% calendar year-to-date, reaching over $23/t (as of Sep 2021). For the purposes of this analysis, we assume liable entities bypass the spot market and enter into long-term offtake agreements for ACCUs (vegetation projects) over a 20-year term, for more cost-effective procurement.

In line with in-house modelling and feedback from market participants, we anticipate the current availability of ACCUs at the required scale between $35-40/t. This is applied as a conservative estimate, with ACCU spot prices forecast to be approximately double this level over the period under some scenarios. Meanwhile, the International Energy Agency forecasts that carbon prices will be required to rise on average to US $130/t by 2030 (A$175) to reach net-zero compatible targets, and to US $250/t (A$340) by 2050 (Sirna 2021).

ESTIMATED COSTS OF CARBON OFFSET PROCUREMENT

Demand for GHG emissions abatement

In line with our modelled scenarios for potential lifecycle GHG emissions from NT gas basin projects, and assumed production curves, cumulative demand for GHG emissions abatement is estimated to fall between 59 and 523 Mt of abatement. Specifically, this is calculated as 59 Mt in the Low scenario, 368 Mt in the Mid scenario, or 523 Mt in the High scenario. Should the export of gas to overseas markets be considered (High scenario: Australia and overseas), cumulative demand is forecast to reach 1,358 million over the forecast period.

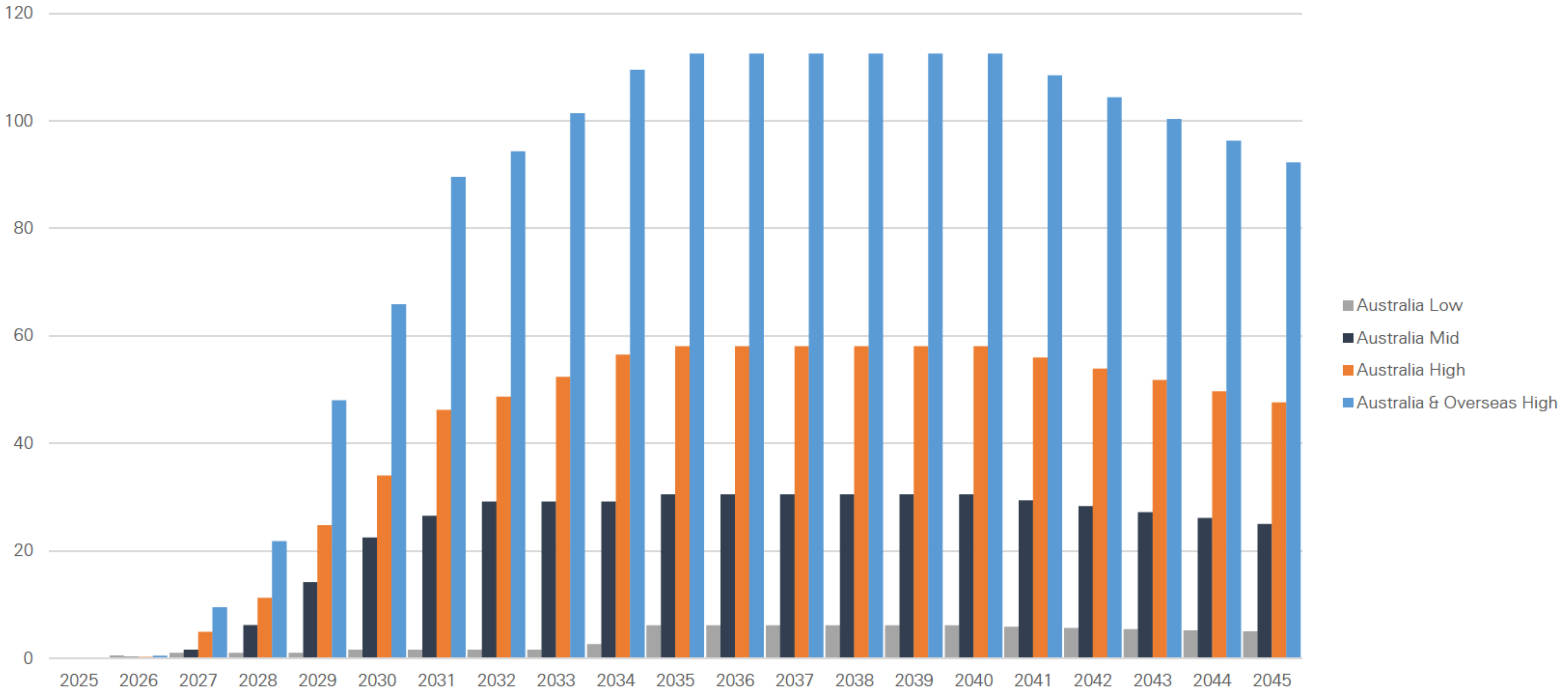
As noted, lifecycle emissions analysis applies the Australian Government's AR5 100-year global warming potential factor (GWP) for methane (28 g CO2), considered to be a conservative or "best case" assessment. Should analysis apply a higher 20-year GWP value (84 g CO2), demand for GHG emissions abatement is modelled to grow to 76 Mt (Low), 474 Mt (Mid) or 875 Mt (High).

Figure 8: Total demand for abatement (cumulative)

Scenario	Annual Peak (Mt CO2e p.a.)	Cumulative over 20 y. (Mt CO2e)
Low	5	59
Mid	24	368
High	34	523
High (Australia & Overseas)	89	1,358

Source: RepuTex Energy, 2021

Figure 9: Demand for abatement per annum (million tonnes) assuming 100-year GWP for methane



Source: RepuTex Energy, 2021

Estimated costs of ACCU procurement

As shown in Figure 10 (over page), in line with an assumed ACCU price range of $35-40, analysis indicates that cumulative demand for GHG emissions abatement of between 59 and 523 Mt would translate into a carbon liability of between $3 billion to $22 billion over a 20-year period, or an annual average of between $140 million and $1.1 billion.

Under a Low scenario, cumulative demand for GHG emissions abatement of 59 Mt (up to 5 Mt per annum) is modelled to translate into a carbon liability of $3.0 billion over 20-years, or up to $185 million per annum.

Under this scenario, Savanna Burning, Energy Efficiency, and Agriculture ACCUs are modelled to linearly scale up from 0.9 Mt in 2025 to 5 Mtpa from 2035 onwards. This assumes a combination of emissions abatement though savanna fire management, industrial electricity and fuel efficiency, and beef cattle herd management. Offsets are anticipated to be available at $35/t, in line with feedback from market participants and in-house expectations.

Under a Mid scenario, cumulative demand for GHG emissions abatement of 368 Mt (up to 24 Mt per annum) is modelled to translate into a carbon liability of $15.1 billion over 20-years, or up to $921 million per annum.

Under this scenario, vegetation ACCUs are modelled to linearly scale up from 4 Mt in 2025 to 24 Mt p.a. from 2035 onwards. This assumes environmental and plantation forestry projects covering an additional 246,000 ha pa, for 12 years (to match assume peak gas production in 2035), totaling almost 3 million ha by 2035 (almost as large as the portion of Australia covered in rainforest (or 2.5-3% of the Australian native forest area). Offsets are anticipated to be available at $38/t, in line with feedback from market participants and in-house expectations.

Under a High scenario, cumulative demand for GHG emissions abatement of 523 Mt (up to 34 Mt per annum) is modelled to translate into a carbon liability of $22.3 billion over 20-years, or up to $1.360 billion per annum.

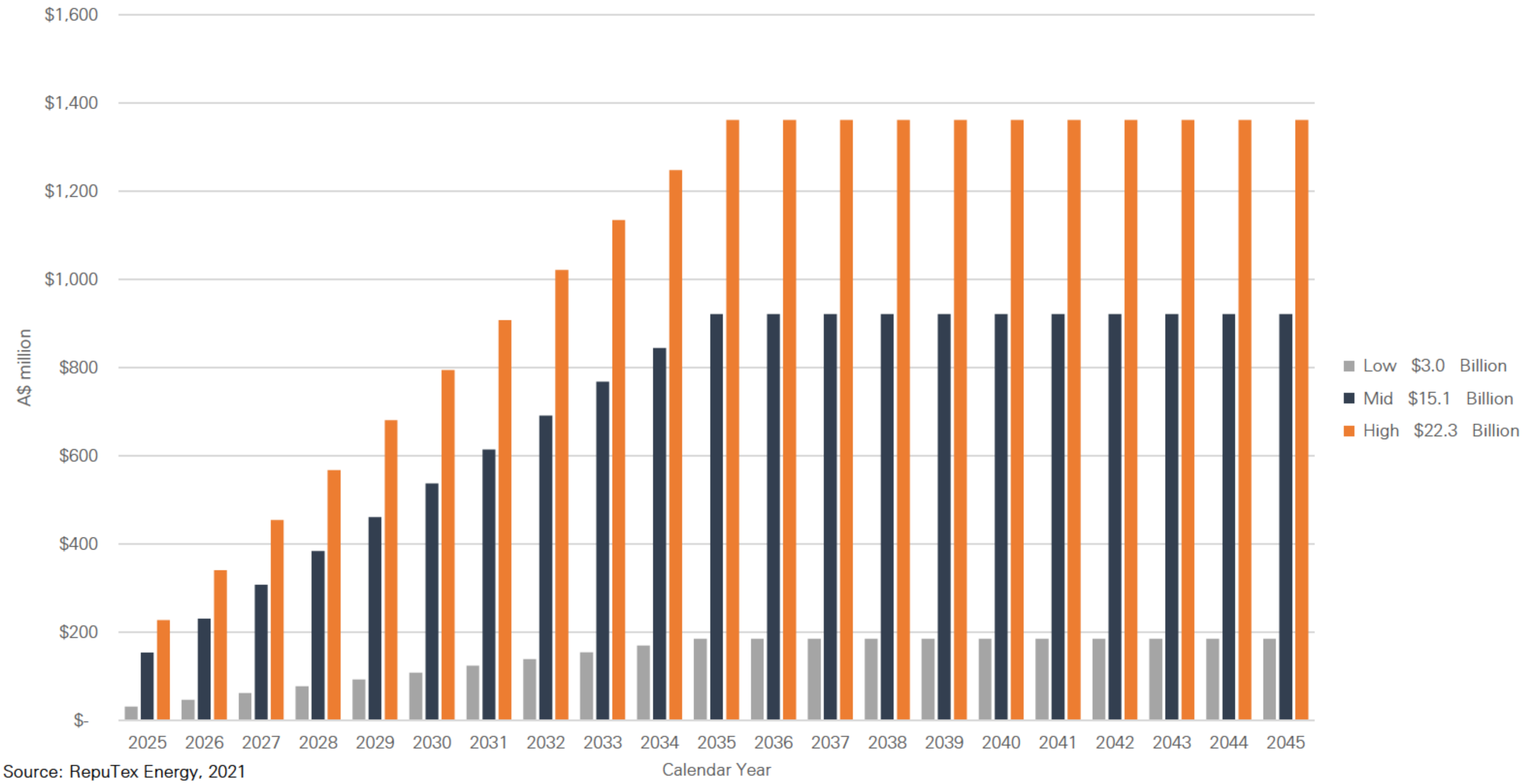
Under this scenario, vegetation ACCUs are modelled to linearly scale up from 5.7 Mt in 2025 to 34 Mtpa from 2035 onwards. This assumes a combination of environmental and plantation forestry projects covering an additional 348,000 ha pa, for 12 years, totaling 4.2 million ha by 2035 (about the same as the amount of previously undisturbed primary tropical forests lost globally in 2020 alone). Offsets are anticipated to be available at $40/t, in line with feedback from market participants and in-house expectations.

Figure 11: Estimated costs of ACCU procurement (all scenarios)

Scenario	Per annum carbon cost $/t	Cumulative carbon cost (first 20 years)
Low	$35	**$3 billion**
Mid	$38	**$15 billion**
High	$40	**$22 billion**

Source: RepuTex Energy, 2021

Figure 10: Annual estimated costs of ACCU procurement: Direct Contracting



Source: RepuTex Energy, 2021

4. Summary of results

Summary of results and implications

SUMMARY OF KEY RESULTS

Carbon costs and commercial implications

In line with NT policy and Recommendation 9.8 of the Pepper Inquiry, the inclusion of carbon costs is likely to have significant implications for the commercial viability of Northern Territory gas basin projects, with potential for emissions liabilities to add between $1-$2.5 per GJ to the cost of Beetaloo basin gas, varying with the modelled production scenario.

» **Low production scenario: $6 Billion gas value**. Assuming Beetaloo field costs of A$6-7/GJ under this scenario, in line with economic analysis undertaken by Deloitte, abatement costs of $3 billion over 20 years, or $140 million per year are modelled to increase abated gas unit costs to $8.50-$9.50/GJ, a 47-55% increase in project costs. At this level, economic analysis suggests "it is unlikely that it will be a competitive source of supply without some form of government subsidy or incentive" (Deloitte 2020).

» **Mid production scenario: $31 Billion gas value**. Assuming Beetaloo field costs of A$5-6/GJ under this scenario abatement costs of $15 billion over 20 years, or $720 million per year are modelled to increase abated gas unit costs to $7.50-$8.50/GJ, a 44-53% increase in project costs. In line with the Low scenario, economic analysis suggests that Beetaloo is again unlikely to be a competitive source of supply without some government subsidy.

» **High production scenario: $95 Billion gas value**. Assuming Beetaloo field costs of less than A$5/GJ under this scenario, abatement costs of $22 billion over 20 years, or $1.1 billion per year are modelled to increase abated gas unit costs to above $6/GJ, a 24% increase in project costs. At this level, economic analysis suggests that "the likely market will be less than 250 PJ per year" (Deloitte 2020), indicating that the market is not anticipated to need as much as 80% of the 1,240 PJ per year of gas assumed for this scenario.

Carbon costs may be higher outside of modelled "best-case" assumptions

While carbon costs are forecast to be material, we note that costs have potential to be higher outside of our modelled 'best-case' assumptions should alternative assumptions be applied in place of more conservative inputs. Alternative assumptions could include:

- A 20-year GWP for methane of 84-87 g CO2 instead of the applied 100-year GWP value of 28 g CO2.
- A common 40-year life for gas projects instead of a 20-year study period.
- Abatement valued in line with annual spot price purchases, or higher carbon price pathways, rather than wholesale ACCU contracting.
- Assumptions for gas production to ramp up over the first half of the study period, reaching maximum harvest levels for only six years of the 20-year study period.
- Methane leakage rates higher than 1.8%
- The application of an upstream GHG emissions value from the Pepper Inquiry (15.5 g CO2e/MJ), or the latest calculations from larger and more precise U.S. lifecycle modelling (19.9 g CO2e/MJ, See Littlefield et al. 2019) instead of our assumed 13 g CO2e/MJ.
- The application of the higher end AR5 GWP range for fossil methane (commonly calculated as 36 rather than 28).
- The application of the Pepper Inquiry's 57 g/MJ downstream gas combustion value in place of the Commonwealth's 51.5 g CO2e/MJ.
- The exclusion of export emissions that occur overseas, which make up most of the total lifecycle gas emissions.

High risk of stranded assets

In calculating the carbon costs for a broad range of Beetaloo Sub-basin development scenarios, from 200 TJ/day to 3,400 TJ/day, outcomes indicate that – in each case – the overlay of carbon costs to offset the Australian component of lifecycle emissions implies a high risk of developed shale gas assets becoming economically stranded.

An interim report from CSIRO's Gas Industry Social and Environmental Research Alliance (GISERA - a collaboration between CSIRO, Commonwealth and state governments and the gas industry) into the use of offsets for lifecycle GHG emissions for onshore gas in the NT has similarly signalled that "the cost of offsetting Australian emissions from consumption of NT gas would be prohibitive" for scenarios considering offsetting more than >200 PJ/year (548 TJ/day) of domestic consumption (GISERA 2021).

Impact on Australia's progress in meeting Paris Agreement commitments

Beetaloo basin gas emissions represent a large source of additional GHG emissions entering the Australian economy at a time when rapid global emission reductions are necessary to limit the effects of global warming. To this end, new oil and gas fields from 2021 have been modelled by the IEA to be inconsistent with a net-zero pathway (IEA 2021b).

The development of the Beetaloo Sub-basin under a mid to high scenario, resulting in 368-523 Mt of GHG emissions over 20 years, is likely to have a significant impact on Australia's remaining carbon budget, with modelled outcomes representing between 3 to 5 per cent of Australia's remaining carbon budget remaining (2°C scenario). For a 1.5°C scenario Beetaloo Sub-basin gas could represent 10 to 27 per cent of Australia's total carbon budget.

The Commonwealth Department of Environment and Energy (now Department of Industry, Science, Energy and Resources) has subsequently recognised that GHG emissions from the development of onshore shale gas in the Northern Territory may be difficult to offset, and could impact on Australia's progress in meeting Paris Agreement commitments, noting:

> "Offsetting emissions of this quantum [5 Mt to 39 Mt CO2-e per year] would be challenging, and they would add to Australia's Paris Agreement task if they occur before 2030 and are not offset. Under the Paris Agreement, Australia is expected to progressively tighten our targets every five years. If emission from NT shale occur post 2030 and are not offset, they will add to the task to meet the post 2030 target (which is due to be set by 2025)." (DoEE 2019)

Updated climate science contained in the Intergovernmental Panel on Climate Change's (IPCC) 6th assessment (Aug 2021) highlights that methane emissions are a critical and urgent issue, with the central findings demonstrating that the earth's climate system is locked into at least 1.5 degrees of warming in the next several decades, resulting in significant physical impacts. The report also emphasises that the near-term elimination of carbon dioxide emissions, and reductions in methane emissions, would play a large role in limiting temperature rises above 1.5 or 2 degrees, avoiding the worst impacts of climate change.

Figure 12: Carbon budgets for Australia.

Global temperature	67% chance of meeting temperature goal (Gt CO2e 2021-2050)	50% chance of meeting temperature goal (Gt CO2e 2021-2050)
1.5 °C	2	4
2.0 °C	11	

Source: RepuTex 2021 based on Global carbon budgets from IPCC SR15Chapter 2, 'Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development'

5. Appendix A

Methodology notes and references

CONVERTING GWP = 36 TO GWP = 28

At present these is a lack of data and analysis of leakage rates in Australia giving rise to concerns that actual loss rates could be much higher than the 0.5% estimated in present Australia inventories (Lalfeur et al. 2016). For example, Australian work by Bista et al., estimates a possible loss rate of 6.5% from upstream components of the natural gas production system (Hare 2018), if best practices are not properly enacted to reduce fugitive methane emissions from unconventional gas development. The risk of higher leakage rates are discussed in many estimates of life cycle emissions from unconventional gas resources, with estimates of emissions from hydraulic fracking uncertain and heavily debated, ranging between 1.7% and 17%.

For the purposes of GHG emissions estimates, the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory assumed total upstream emissions to be 15.5 g CO2e/MJ (with a 90% confidence interval of 14 – 18 g CO2e/MJ) for a representative US shale gas-field (the large and geologically similar 'Appalachian' field). Methane accounted for 11.9 g CO2e/MJ of these emissions, equivalent to a methane emissions rate of 1.8% of the natural gas production, representing 77% of total upstream emissions (Pepper 2018). The Pepper Inquiry estimate is calculated based on a common assumption of 100-yr fossil methane GWP = 36, however, in line with the Australian Government National Greenhouse Account Factors all methane is assumed to have a GWP of just 28 (DISER 2021). Therefore, our analysis makes the following conversion:

- Upstream emissions factor: 15.5 g CO2e/MJ = 3.6 g CO2e/MJ (carbon dioxide component) + 11.9 g CO2e/MJ (methane component)
- 11.9 g CO2e/MJ / 36 g CO2e per g CH4 * 28 g CO2e per g CH4 = 9.3 g CO2e (methane component)
- 3.6 g CO2e/MJ (carbon dioxide component) + 9.3 g CO2e (methane component) = 12.9 g CO2e/MJ Upstream emissions factor

Therefore, while the same assumption for upstream emissions is applied as the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, this is converted from a GWP of 36 to 28. Thus, GHG emissions estimates for this analysis are based on an upstream emissions factor of 12.9 g CO2e/MJ (rather than 15.5 g CO2e/MJ), which accounts for depicted annual GHG estimates being lower than the Pepper Inquiry, despite using the same production scenarios.

As the Pepper Inquiry recommended, it is critical to measure fugitive emissions during the development phase of a gas basin, implementing best practices to reduce GHG emissions, and monitoring for inadvertent methane leaks. Caution should be used when relying on assumptions for low methane leakage rates as upstream GHG emissions from shale gas development are specific to the resource in each basin, and the emissions reduction measures implemented in developing that resource, which will remain uncertain until a basin is developed.

CALCULATIONS: GWP = 86

As a relatively short-lived gas, most of methane's warming effect occurs early within the 100-yr convention. In some instances it can therefore be insightful to calculate near-term warming effects based on a 20-year timeframe. In these cases, the 20-yr methane GWP of 84 to 86 results in an increased GHG estimate when presented as a CO2 equivalent value. Similar to the Pepper Inquiry, we have also provided the quantity of life cycle GHG emissions based on a 20-year GWP = 86 below.

Note that if more than approximately 3% of produced methane is emitted into the atmosphere, the climate impact of the 20-year timescale of the emitted methane is larger than the climate impact of the remaining combusted methane (Lafleur et al. 2016).

Figure A: Annual lifecycle emissions from Beetaloo Sub-basin projects by scenario in Million tonnes of carbon dioxide equivalent (Mt), using a 20-yr GWP for methane of 86.

	Upstream (Mt p.a.)	Conversion to LNG (Mt p.a.)	Transport (Mt p.a.)	Regasification (Mt p.a.)	Combustion (Mt p.a.)	Full production lifecycle emissions (Mt p.a.)	Total lifecycle emissions (Cumulative Mt over 20-years)
High scenario (Australia and overseas)	40	6	2	1	64	113	1,717
Use of gas in Australia (660 TJ/day)	40	6			12	58	886
Mid scenario (use of gas in Australia)	12				19	31	478
Low scenario (use of gas in Australia)	2				4	6	77

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