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SUPPLEMENTARY REPORT TO THE EIS

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Bowen Gas Project SREIS

AUSTRALIA

Supplementary Greenhouse Gas Technical Report

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Prepared by	Stuart Bennett Dr Dina Makarynska		February 2014	Senior Associate Environmental Scientist Associate Environmental Scientist
Checked by	Dr. Chris Taylor		February 2014	Senior Associate Environmental Scientist
Approved by	Dan Simmons		March 2014	Senior Associate Environmental Scientist

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Client Contact Details:

Arrow Energy Pty Ltd
Level 39,
111 Eagle Street,
Brisbane 4000

Issued by:
URS Australia Pty Ltd
Level 17, 240 Queen Street
Brisbane, QLD 4000
GPO Box 302, QLD 4001
Australia

T: +61 7 3243 2111
F: +61 7 3243 2199

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ABBREVIATIONS

Abbreviation	Description
API	American Petroleum Institute
AR2	Second Assessment Report of the IPCC
AR4	Fourth Assessment Report of the IPCC
AR5	Fifth Assessment Report of the IPCC
Arrow	Arrow Energy Pty Ltd
ATP	Authority to prospect
ATPA	Authority to prospect application
BGP	Bowen Gas Project
CGPF	Central gas processing facility
CH_4	Methane
COP	Code of Practice
CO_2	Carbon dioxide
CO_2-e	Carbon dioxide equivalent
CSG	Coal seam gas
CPM	Carbon pricing mechanism
DCCEE	Department of Climate Change and Energy Efficiency
DERM	Department of Environment and Resource Management
EHP	Department of the Environment and Heritage Protection
DIDO	Drive-in / drive-out
EEO	Energy Efficiency Opportunities
EIS	Environmental Impact Statement
EPCM	Engineering procurement construction management
FCF	Field compression facility
FEED	Front end engineering design
FIFO	Fly-in / fly-out
GHG	Greenhouse gas
GJ	gigajoule
GWP	Global warming potential
IPF	Integrated processing facility
IPCC	Intergovernmental Panel on Climate Change
kg	kilogram
kL	kilolitre
km	kilometre
km^2	square kilometre
kt	kilotonne
kW	kilowatt
kVA	Kilovolt Ampere
LFL	Lower flammability limit
LNG	Liquefied natural gas
Mt	Megatonne

Abbreviation	Description
mtpa	Million tonnes per annum
MW	Megawatt
MWh	Megawatt hour
N_2O	Nitrous oxide
NGER	National Greenhouse and Energy Reporting
NGER Act	*National Greenhouse and Energy Reporting Act 2007*
SREIS	Supplementary Report to the Environmental Impact Statement
t	tonne
TJ	Terajoules or 10^{12} Joules
ToR	Terms of Reference
URS	URS Australia Pty Ltd
US EPA	United States Environmental Protection Agency
VKT	Vehicle kilometres travelled

EXECUTIVE SUMMARY

URS Australia Pty Ltd was engaged by Arrow Energy Pty Ltd (Arrow) to undertake a Greenhouse Gas (GHG) assessment in the preparation of an Environmental Impact Statement (EIS) for the proposed development of the Bowen Gas Project (the Project) in the Bowen Basin, Queensland. Since publication of the EIS for public comment, Arrow's field development plan and conceptual design for the Project has advanced.

Arrow is required to submit a Supplementary Report to the EIS (SREIS) to present information on refinements to the project description, address issues identified in the EIS as requiring further consideration and/or assessment, and address stakeholder submissions. This report also addresses regulatory changes that have occurred since the EIS.

Regulatory Framework

Changes to international, national and state legislation and policy since the submission of the EIS are described. Under current legislation, the Project would be required to report its emissions under the *National Greenhouse and Energy Reporting Act 2007* each year. The Project would be captured by the Carbon Pricing Mechanism, a key component of the *Clean Energy Act 2011*. Under the *Clean Energy Act 2011* the proponent must report its emissions and hold emission permits at the end of each annual reporting period. Although changes to this legislation have been proposed, Australia remains committed to a 5% reduction in GHG emissions from 1990 levels by 2020, which represents a 23% reduction on business as usual.

Project Refinements

The key refinements to the project description include changes to major infrastructure components, electrical power supply options, power requirements for Project facilities, power generation equipment and the use of flaring. The refined project description shows that the Project is expected to be five years shorter and production rates are expected to increase during ramp-up and decrease during operation and ramp-down more sharply.

This supplementary report describes changes to the GHG assessment resulting from the refinements and the inclusion of updated and new datasets. The emissions inventory update shows that total Project emissions are likely to be lower than reported in the EIS by 4%. However, the refinements have made a significant difference to the source, profile and intensity of GHG emissions through the Project.

Project 'direct' (Scope 1) GHG emissions are defined as emissions that occur from within the Project boundary. Project 'indirect' (Scope 2) emissions result from the use of energy products (electricity). These emissions physically occur at the point of electricity generation, rather than the facility that consumes the electricity. 'Other indirect' (Scope 3) emissions are a consequence of the activities of an entity, but occur outside of the Project boundary. The extraction and production of purchased materials, transportation of purchased fuels, and use of sold products and services are examples of Scope 3 emissions. These definitions have been applied to the SREIS and are consistent with the EIS.

Scope 1 emissions for the Project are significantly lower than calculated in the EIS. This is mainly a result of Project refinements. Electrical power will now be largely obtained from the grid, rather than generated locally as assumed in the EIS. It should be noted however that power demand and hence calculated emissions for the possible alternative temporary power generation scenario in 2018 and 2019 are based on a full capacity power demand for each facility, and hence are deemed to be highly conservative. Through detailed design the installed capacity of any required temporary power generation will be optimised.

Project emissions are now dominated by Scope 2 emissions, which result from the use of electricity from the national grid. The principal challenge in preparing emissions forecasts for the Project is modelling the future emissions associated with grid electricity use. Future grid emission intensity is dependent on the generation mix employed and is subject to future state and federal policy changes. Emissions from electricity generation across all sectors in Queensland have been decreasing from a peak in 2009. Queensland Scope 2 emission factors in 2011 were more than 8% lower than in 2009; this is reflected in the emission factors applied to the Project. As energy production is the source of approximately 75% of Australia's total GHG emissions, reducing emissions from this sector will be required for Australia to achieve its commitment to reduce emissions by 5% by 2020. It is likely therefore, that Scope 2 and total emissions from the Project will be lower than calculated in this report.

Scope 3 or 'other indirect' emissions for the Project include emissions associated with the end-use of produced gas, third party infrastructure required to export gas as liquefied natural gas (LNG), emissions from workplace travel based on fly-in / fly-out and drive-in / drive-out arrangements and emissions associated with LNG product shipping. However, the majority of Scope 3 emissions result from the combustion of the product gas. Scope 3 emissions are calculated to be lower than in the EIS as total gas production is predicted to be lower.

The report confirms that the emission estimates applied in the EIS are still relevant after the project description refinements and that the mitigation measures applied for the EIS are still appropriate to address identified impacts.

Response to Stakeholder Comments

This report provides supplementary information in response to comments from the stakeholders on the EIS. This report details climate change adaptation in planning and design, construction, operation and decommissioning phases of the Project. This includes developing preventative and responsive measures for extreme weather events and designing and constructing production facilities in accordance with current Australian standards to withstand extreme events. Arrow is committed to taking a cooperative approach with government, industry and other sectors to address adaptation to climate change.

This report provides additional explanation around fugitive emission assessment methodology. Forecasts have been developed in line with existing Commonwealth reporting methodologies and consistent with the methodology applied in the EIS. However, the SREIS includes Global Warming Potential values from the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. This reflects the latest scientific understanding of the relative impact of GHGs on global warming.

A description of Arrow's approach to determining GHG emissions associated with well activities, described under the *National Greenhouse and Energy Reporting (Measurement) Determination* and subsequent amendments, is provided. Arrow is committed to reporting its emissions under the scheme in accordance with the principles set out: transparency, comparability, accuracy and completeness.

1 INTRODUCTION

URS Australia Pty Ltd (URS) was engaged by Arrow Energy Pty Ltd (Arrow) to undertake a greenhouse gas (GHG) assessment in the preparation of an Environmental Impact Statement (EIS) for the proposed development of the Bowen Gas Project (the Project).

A conceptual description of the Project was developed to inform the EIS. The project description formed the basis for which all initial baseline environmental studies were undertaken and guided the approach for how impact assessment studies were conducted for the EIS.

Since publication of the EIS for public comment, Arrow's field development plan and conceptual design for the Project has advanced. This progression is the result of ongoing exploration activities that have improved Arrow's understanding of the gas resource, and the evolution of Arrow's planning and operational processes. Refinements to the basis of design, including revised typical arrangements, configurations, construction methods and coal seam gas (CSG) infrastructure design are being undertaken by Arrow to prepare for the front-end engineering design (FEED) phase and incorporate new design elements to improve efficiencies and reduce the Project's disturbance footprint. Until Project-specific design details have been determined during FEED, this refined project description will remain largely conceptual (see Project Description chapter (Section 3) in the supplementary report to the EIS (SREIS)).

This report describes the changes to the GHG assessment for the EIS (Arrow, 2012) resulting from refinements to the project description, the inclusion of updated and new datasets and supplementary information requested by stakeholders. The report provides an evaluation as to whether the emission estimates applied in the EIS are still relevant after the project description refinements and whether the mitigation measures applied for the EIS are still appropriate to address identified impacts.

Environmental values, potential impacts and mitigation measures are outlined in the Greenhouse Gas Emissions chapter (Section 10) of the EIS. The Greenhouse Gas Technical Report (Appendix I, Section 3.3) of the EIS provides a description of GHG emission 'Scopes' defined for the purpose of GHG accounting and reporting. Project 'direct' (Scope 1) GHG emissions are defined as emissions that occur from within the Project boundary. Project 'indirect' (Scope 2) emissions result from the use of energy products (electricity). These emissions physically occur at the point of electricity generation, rather than the facility that consumes the electricity. 'Other indirect' (Scope 3) emissions are defined as those emissions that are a consequence of the activities of an entity and occur outside of the Project boundary. The extraction and production of purchased materials, transportation of purchased fuels, and use of sold products and services are examples of Scope 3 emissions. These definitions have been applied to the SREIS and are consistent with the EIS.

1.1 Summary of Updates to the GHG Assessment

An improved understanding of gas reserves of the Project tenements has resulted in the refinement of the field development plan and basis for design of CSG extraction infrastructure. This has enabled the GHG assessment to be updated. This section provides a description of the changes as a result of refinements to the project description, the inclusion of updated and new datasets, and supplementary information requested by stakeholders.

1.1.1 *Refinements to the SREIS Project Description*

The refinements that are applicable to the GHG assessment are discussed in Sections 1.1.1.1 to 1.1.1.4.

1.1.1.1 *Major Infrastructure Components*

Major infrastructure components include:

- The location of development areas, construction sequencing and yearly gas production have been revised.
- There are no longer any integrated processing facilities (IPFs), previously four had been assumed.
- The number of central gas processing facilities (CGPFs) has reduced from three to two. The CGPFs will have co-located water treatment facilities (WTFs). The reduction in major high pressure facility numbers is reflected in a significant increase in capacity of the two proposed CGPFs.
- The number of field compression facilities (FCFs) has increased from 10 to 33 (as a result of each drainage area radius being reduced from 12 km to 6 km).
- The planned number of production wells has reduced from 6,625 to approximately 4,000 wells. Wells will be clustered together onto common well pads where possible, with a maximum of 12 wells per pad (six production and six lateral wells).

1.1.1.2 *Electrical Power Supply Options*

Base Case

Grid power supply based on connection to existing electricity infrastructure is the preferred (base case) SREIS power supply scenario. However, it may not be feasible to connect some remote wells to the electricity grid. Therefore, local gas fired power generation would be used to supply power to the remote wells if required. Local well head power generation has been assumed conservatively for 10% of the wells from the third year onwards.

Alternative Case

Temporary power generation using CSG at the Project facilities (CGPFs and FCFs) for the first two years of Project life, with connection to the existing electricity network from the third year onwards, is considered as an alternative power supply scenario if grid connection is not completed on time. The temporary power installed at the FCFs over the first two years will provide power for the wells through an overhead distribution network and if required underground. In specific cases, power for the remote wellheads (up to 10% of total number of wells) will be generated locally by gas fired engines.

1.1.1.3 Power Requirements for Project Facilities

The power requirements for Project facilities are as follows:

- In the EIS, the maximum power requirement for the CGPFs was 60 MW, FCFs 19 MW and the IPF 58 MW. A worst-case power generation scenario was assessed. This scenario assumed internal gas usage of 10% of the maximum gas produced to power the FCFs, CGPFs and IPFs, with 100% wellhead power requirements supplied from the well head.
- In the SREIS, CGPFs have a 44 MW maximum power requirement, including power supplied to WTFs, and FCFs 35 MW maximum power requirement. For the preferred base case power scenario, grid power will be connected to existing electricity infrastructure and partial gas fired power generation will be used at remote wellheads (10% of total number of wells) for the life of the Project. Note that power demand and hence calculated emissions for the possible alternative temporary power generation scenario in 2018 and 2019 are based on a full capacity power demand for each facility, and hence are deemed to be highly conservative. Through detailed design the installed capacity of any required temporary power generation will be optimised.
- The maximum power demand for wellheads has decreased from 75 kW assessed in the EIS to 20 kW for the SREIS. Only vertical production wells will require power. In the EIS, the power requirement of 75 kW was assumed to be the same for the lifetime of the wellheads, with a wellhead engine utilisation (capacity) factor of 28% over the life of the well. Furthermore, the wells were assumed to be operational for the whole year and wellheads to be powered by electricity from the grid. In the SREIS, for both power generation scenarios (base case and alternative), 10% of wells were conservatively assumed to be powered by local gas fired engines.

1.1.1.4 Project Flaring Options

Project flaring options include:

- Under the current development scenario there is no requirement for ramp-up flaring at compression facilities;
- Flaring during well completions and workovers has been included in the SREIS assessment; and
- Upset condition / operational flaring rates have been updated.

1.1.2 New and Updated Datasets

To account for the refinements to the project description detailed in Section 1.1.1, new and updated datasets for gas production, Project activities, flaring and electricity usage data were used in this assessment. The following additional datasets were also used.

1.1.2.1 Transport Data

In the EIS, direct (Scope 1) diesel consumption in light and heavy vehicles for the construction, operation and maintenance, and decommissioning of well pads was estimated. These emissions were calculated for gathering infrastructure and facilities using emission factors applied to the quantity of diesel used. These diesel quantities have been updated based on the revised transport model for the Project, which is described in the Road Impact Assessment (Appendix K) of the SREIS.

For Scope 3 emissions, fly-in / fly-out (FIFO) and drive-in / drive-out (DIDO) activity rates were estimated.

1.1.2.2 *Land Clearance*

Emission calculations from land clearance have been updated to reflect the new Project infrastructure footprint and revised associated land clearance requirements described in Section 1.1.1.1.

1.1.2.3 *Drilling Emissions*

Scope 1 GHG emissions associated with diesel combustion from well drilling operations were not included in the EIS. GHG emissions from drill rigs for each year of the Project life have been included in the updated emissions inventory. These emissions were assessed using the default energy content factor for diesel, default emission factors for CO_2, N_2O and CH_4 and activity data consistent with the updated project description. Further detail on the assessment methodology for GHG emissions from diesel used in drilling activity can be found in Appendix A.1.3.

1.1.2.4 *Updated Guidance Documents*

A number of the reference documents that were used to develop the EIS emissions inventory are updated on a periodic basis. Since completion of the EIS emissions inventory, a number of these documents have been updated. These are described in Section 3.2.

1.1.2.5 *Global Warming Potential Value*

The Fourth Assessment Report (AR4) of the Intergovernmental Panel on Climate Change (IPCC) (IPCC, 2007) global warming potential (GWP) values for methane and nitrous oxide have been used in the emissions inventory update. The National Greenhouse and Energy Reporting (NGER) (Measurement) Amendment Determination 2013 (No. 1) Explanatory Statement outlines the intention to adopt these values from 2017 onwards. Table 1-1 shows a comparison between the GWP values used in the EIS (Second Assessment Report of the IPCC (AR2)) and those applied in the SREIS.

Table 1-1 Global Warming Potential Values

Pollutant	EIS (AR2)	SREIS (AR4)
Nitrous oxide	310	298
Methane	21	25

All Project emissions estimates in the SREIS were made using the AR4 GWP values in advance of their adoption for NGER in 2017. The use of AR4 GWPs represents the latest scientific understanding. It is particularly relevant to the Project as the GWP for methane has increased.

1.1.3 Supplementary Information Requested by Stakeholders

1.1.3.1 Transport Emissions

In response to a submission from Isaac Regional Council, the assessment of GHG emissions from the FIFO and DIDO workforce for the Project has been incorporated into the emissions inventory update.

1.1.3.2 Climate Change Adaptation

In response to a submission from the Department of Environment and Heritage Protection (EHP), further details on climate change adaptation are provided, which relate to Project planning and the need for adaptive management. This information is provided in Section 7.

1.1.3.3 Fugitive Emissions

In response to a submission from the Doctors for the Environment Australia, additional explanation as to the method of assessment of fugitive emissions is provided. This information is provided in Section 8.

1.2 Comparison to EIS

A summary of the key changes to the EIS is presented in Table 1-2.

Table 1-2 Summary of Key Changes to the EIS

Project Aspect	EIS	SREIS	Basis for Change
Number of CGPFs	3	Two with co-located WTFs.	Project description refinement.
Number of FCFs	10	33	Project description refinement - field radius has been reduced from generally 12 km to 6 km.
IPFs	4	Removed	Project description refinement
Number of vertical production wells	6,625	Approximately 4,000 (up to 12 wells per pad, six vertical production and six lateral wells).	Project description refinement.
Traffic data	Vehicle kilometres travelled (VKT) from EIS traffic model.	Improved estimates of VKT from updated traffic model.	Updated/new information.
Power supply	<u>Base Case</u> In field power generation based on 10% of the maximum CSG produced to meet 100% of Project needs.	<u>Base Case</u> Grid power supply based on connection to existing electricity infrastructure with partial gas fired power generation at remote wellheads (10% of total number of wells) from the third year onwards if required.	Project description refinement. An assessment was made between the preferred 'Base Case' power option and a temporary power supply option (Section 3.4.3). It was determined that the

Project Aspect	EIS	SREIS	Basis for Change
	Worst Case In field power generation based on 10% of the maximum CSG produced to meet a portion of the Project needs. Purchased electricity to supply 100% of well heads.	Temporary Power Supply In field power generation at the facilities using CSG for first two years. Partial gas fired power generation at remote wellheads if required (10% of total number of wells) from the third year onwards.	temporary power supply option was the most conservative option and this is reported.
CGPF power requirement	60 MW maximum power requirement.	44 MW maximum power requirement, including power supplied to WTFs.	Project description refinement.
FCF power requirement (largest)	19 MW	35 MW	Project description refinement.
Production wellhead power requirement	75 kW	20 kW	Project description refinement.
Land clearance	Assessed	Updated	Project description refinement.
Drill rig emissions	Not included	Included in SREIS (four diesel generators with 1,000 kVA engines).	Updated / new information.
Ramp up flaring	Assessed	Not required	Project description refinement.
Flaring during well completions and workovers	Not included	Assessed	Project description refinement.
Upset condition / operational flaring rates	Based on maximum worst-case rate.	Based on updated maximum worst-case rate.	Project description refinement.
Updated guidance Documents	--	See Section 3.2	Updated/new information.
New guidance documents	--	For the estimation of FIFO and DIDO emissions.	
GWP values	21 for CH_4 and 310 for N_2O.	25 for CH_4 and 298 for N_2O.	Updated/new information.
Transport emissions (FIFO and DIDO)	Not included	Included in updated inventory.	Stakeholder submission.
Climate change	Climate change impact assessment included.	Further detail on adaptation provided (Section 7).	Stakeholder submission.

Project Aspect	EIS	SREIS	Basis for Change
Fugitive emissions	Scope 1 emission calculated for facility level production and processing, gas transmission and flaring. Expressed in carbon dioxide equivalent (CO_2-e).	Addition of a description of Arrow's fugitive methane emissions sampling program (Section 8).	Stakeholder submission.

2 UPDATES TO LEGISLATIVE AND POLICY CONTEXT OF THE ASSESSMENT

This section describes the changes to the relevant aspects of legislation and policy since the submission of the EIS. At the time of EIS submission, the initial 'fixed price' phase of the Carbon Pricing Mechanism (CPM), described in the Greenhouse Gas Technical Report (Appendix I, Section 2.2.2) of the EIS was in effect. Arrow will be a direct participant in the CPM and, as part of the stationary energy sector, will report its GHG emissions under the *National Greenhouse and Energy Reporting Act 2007* (NGER Act). This means that Arrow must report its emissions and hold emission permits at the end of each period. Amendments to the Energy Efficiency Opportunities (EEO) Program were also made and Australia is in its second commitment period under the Kyoto Protocol.

2.1 International Policy

2.1.1 The Kyoto Protocol

The Kyoto Protocol first commitment period ended on 31 December 2012. On 9 December 2012, at the United Nations climate change conference in Doha, it was announced that Australia has agreed to a second commitment period under the Kyoto Protocol. The second commitment period of the Kyoto Protocol was scheduled to commence on 1 January 2013 and end in 2020 in line with the start of a new global agreement. Australia agreed a Kyoto target to reduce its emissions to 5% below 2000 levels by 2020. However, the option to increase the target to up to 25% might be considered, depending on the scale of global action (Australian Government, 2012a, 2012b and 2012c).

2.2 Australia's Climate Change Legislation

2.2.1 Proposed Repeal of the Carbon Pricing Mechanism

Section 2.2.2 of the EIS described the *Clean Energy Act 2011*, which was implemented under the Government's Clean Energy Plan. The Clean Energy Plan incorporated a CPM intended to impose a cap on emissions from covered sectors of the economy. As the Project would exceed emissions of covered sources of 25,000 tonnes of CO_2-e per year, it would create a liability for the proponent under the CPM.

On 14 November 2013, the Senate referred the Clean Energy Legislation (Carbon Tax Repeal) Bill 2013 and related bills to the Environment and Communications Legislation Committee for inquiry and report by December 2013 (Australian Government, 2013a). If the Clean Energy Legislation (Carbon Tax Repeal) Bill 2013 is passed, 2013-14 would be the last financial year of the carbon price in its current form. As the ramp-up phase of the Project is likely to begin in 2017, under this scenario, the proponent would not incur any carbon liability under the *Clean Energy Act 2011*.

The proponent will still be required to report Project emissions under the NGER Act if the CPM is repealed.

2.2.2 Energy Efficiency Opportunities

The *Energy Efficiency Opportunities Act 2006* is described in the Greenhouse Gas Technical Report (Appendix I, Section 2.2.2) of the EIS. The EEO regulations, which came into effect in July 2012, have been amended since publication of the EIS.

2.2.2.1 *Energy Efficiency Opportunities Amendment Regulation 2012*

Under the amended EEO regulations, corporations are allowed to align their assessment liability with their NGER liability (Australian Government, 2012d).

Under the Energy Efficiency Opportunities Amendment Regulation 2012 (Australian Government, 2012d) from July 2013, the EEO Program was expanded to include new developments and expansion projects. The amendment provides specific definitions for a new development or expansion project and what will be considered to be future energy use. The regulation defines future energy use as the energy that a new development or expansion will use, on average and calculated on an annual basis, after commercial operation has commenced. Corporations will be subject to participation thresholds for new projects and those corporations not registered for EEO whose projects meet these thresholds will be required to participate.

As the Project is a new development which will utilise more than 0.5 PJ of energy per financial year, it will be subject to an EEO Program assessment under the EEO Act. As a result, the proponent will be required to submit an assessment plan for the Project or seek an exemption on the basis that it can demonstrate systems and processes that meet the intent of the six key elements.

The Assessment Framework is made up of six requirements (formerly key elements), which contain:

- Specific actions controlling corporations must meet to demonstrate they have satisfied the intent of each requirements; and
- Evidence that must be kept to show they have met the actions.

Table 2-1 shows the six key elements of the EEO program and a summary of evidence for the Project.

Table 2-1 Six Key Elements of the EEO Program

Requirement	Evidence
Key Element 1—Leadership	Visible leadership and commitment from senior management provides clear direction and purpose to the assessment throughout the design stage through to commercial operation. Senior management supports, motivates and values the efforts of staff and other stakeholders (for example, project managers, design teams, equipment suppliers, engineering procurement construction management (EPCM) and operation staff) involved in the identification and implementation of energy efficiency opportunities.

Requirement	Evidence
Key Element 2—People	Skilled and knowledgeable people, and people with direct and indirect influence on the operational energy use of the new development or the expansion through design and development decisions are involved in the assessment. The relevant people or similar relevant people are included in a process to improve the energy productivity of the new development or the expansion. Responsibilities and accountabilities are suitably allocated and team diversity is encouraged.
Key Element 3—Information, data and analysis	Predominately relating to early design stages, an analysis is conducted on the whole site which includes energy productivity, to identify a cost effective facility design from an operational and capital cost perspective. Relating to design stages prior to construction, predicted energy data, and relating to optimisation, measured energy data, is analysed from different perspectives to understand the relationship between activity and consumption, and to identify energy efficient design features or areas to be optimised. A site-wide analysis, connecting and communicating data between different operations, systems and sections of the site, and between other sites, where appropriate, is investigated. Sufficient design data, operational data, or both, in suitable forms, is used to estimate, model and understand future and current energy use, identify and quantify energy savings and improve energy productivity. Models of the design are likely to incorporate energy-mass flows or other relevant modelling tools. Provisions are made to track performance and outcomes during operation. This may include appropriate provisions for metering to enable ongoing performance tracking and improvement of energy productivity. Data accuracy is appropriate to the stage of the design and available data sources. The accuracy is considered when deciding the suitability of the model, assumptions and analysis to make the appropriate project choices. Processes are put in place to ensure adequate transfer of relevant information, data and potential energy savings initiatives between different design gates through to commercial operation. If the design involves the provision of a service, site, or supporting infrastructure that is not within the control of the registered corporation, then an investigation of the possibility of a mutual agreement with the entity providing the services, site or supporting infrastructure is conducted, so that a financial benefit can be realised, based on energy savings achieved through design or operational changes.
Key Element 4—Identification and evaluation of energy savings	An effective process is undertaken to identify potential cost-effective energy productivity improvements. This process covers all stages of the design through to commercial operation and is broad, open-minded and encourages innovation. Sufficient time is taken for the design team to understand and review the information and data from Key Element 3 and the range of perspectives provided by relevant people indicated in Key Element 2 to cooperatively identify and evaluate a range of ideas. Adequate time is scheduled to allow energy productivity improvements to be identified and incorporated into the design. Relevant ideas are analysed to a sufficient level appropriate to the stage of design. The process allows design aspects that require more detailed investigation to transfer across design stages. A whole-of-business evaluation is undertaken to enable decision-makers to make informed business decisions about energy efficiency design. Where relevant, the design process will results in the optimum solution being identified, evaluated and included in the design without alternatives considered. This is particularly relevant for minor design aspects. Where relevant, energy impacts are included in the evaluation of “off the shelf” equipment.

Requirement	Evidence
	Examples of energy savings identified in the assessment include: Grid Power Generation - the assumed base case is that the power (to power 10% of total number of wells at remote locations) can be generated by reciprocating gas engines with improved efficiency and reduced emissions for the size of generation required (emissions reduction technology, e.g. catalyst). Temporary Power Generation - temporary power generation using CSG at the Project production facilities (CGPFs and FCFs) will use high efficiency, low emission reciprocating gas engines or other high efficiency technology options. Distribution Lines - power distribution lines will be co-located with gathering and medium pressure pipelines to minimise the use of energy for land clearance.
Key Element 5—Decision making	Management responsible for resource allocation for the development or the expansion should make informed energy efficiency decisions based on investment quality information, which may include but is not limited to data accuracy, capital costs, maintenance costs, and calculated risks. These decisions and their rationale should be recorded. Mechanisms for reviewing, monitoring, tracking through design gates and reporting on outcomes are established to learn from experience and enable public reporting.
Key Element 6—Communicating outcomes	Senior management responsible for the new development or the expansion are aware of the outcomes of the assessment in a strategic business context (including the corporation's risk management, corporate social responsibility, major investment decisions and energy productivity). Senior management is made aware of capital and operational cost savings as a result of the assessment. The board reviews and notes the content for the registered corporation's public report in the context of relevant business information. Relevant outcomes of each stage of design or development are communicated to the design team indicating what decisions were made and why. Where relevant, achievements in relation to any objectives identified in Key Element 1 that were set by the design teams, relevant stakeholders, government and senior management responsible for the development or the expansion are communicated.

The government report will also require energy use and sources, broken down by fuel type.

2.2.3 *Proposed Direct Action Plan*

The Australian Government intends to implement a climate change strategy called the Direct Action Plan. It is expected that the Direct Action Plan will include initiatives to reduce CO_2 emissions by 5% by 2020. A key initiative of the Direct Action Plan is expected to be the Emissions Reduction Fund.

2.2.3.1 *Emissions Reduction Fund*

The Emissions Reduction Fund would work together with other incentives under the Direct Action Plan and the Renewable Energy Target (under review) to help meet Australia's emissions reduction target.

The fund would include the following initiatives:

- The Government will purchase low-cost abatement through reverse auctions or 'abatement buy-back'. The proponent will be incentivised to find the lowest cost approach to reduce emissions as high cost abatement will not be purchased by the Government.
- Incentives for abatement activities across the Australian economy in conjunction with the Carbon Farming Initiative.
- Community input will be invited on potential sources of low-cost abatement and on key design features such as auctions, baselines and contract arrangements.

The Terms of Reference for the Emissions Reduction Fund remain under review at this time (Australian Government, 2013c).

2.3 State Policy and Initiatives

Section 2.3 of the EIS described ClimateSmart2050, which was the Queensland Climate Change Strategy; it included a number of state policies and initiatives intended to reduce GHG emissions.

These were:

- Smart Energy Savings Program;
- Queensland Future Growth Fund;
- Queensland Gas Scheme; and
- ClimateQ.

Since the EIS, significant changes have been made to these policies and initiatives as follows:

2.3.1 Smart Energy Savings Program

Under the Queensland government formed in April 2012, the Smart Energy Savings Program was discontinued to reduce regulatory burden on Queensland businesses. However, this has no effect on the GHG assessment because the Project will be required to report under the EEO Program.

2.3.2 Queensland Future Growth Fund

The Queensland Future Growth Fund was created to provide funding for infrastructure and initiatives that would benefit the economy and environmental sustainability of Queensland, such as investment in clean coal technologies. The *Future Growth Fund Act 2006* has been repealed and the fund closed effective from July 2013 (Queensland Treasury and Trade, 2013).

2.3.3 Queensland Gas Scheme

Under the ClimateSmart2050 strategy, the Queensland Government announced its intention to transition the Queensland Gas Scheme into a national emissions trading scheme. With the advent of the CPM in July 2012, the Queensland Government reviewed the Queensland Gas

Scheme and identified that it would provide an advantage to gas-fired generators and likely duplicate the expected impacts of the CPM.

The Queensland Gas Scheme will close at the end of the 2013 liable year. There will be no further Gas Electricity Certificate creation or liability after 31 December 2013. However, administration of the scheme and the registry will continue until the penalty imposition day of 30 June 2014 (Department of Energy and Water Supply, 2013).

After stakeholder consultation by the Department of Energy and Water Supply, amendments to the *Electricity Act 1994* will be made through the Energy Red Tape Reduction (Amendment and Repeal Bill) 2013 (Queensland Government, 2013).

2.3.4 Climate Change Strategy

The climate change strategy ClimateQ: toward a greener Queensland has been replaced by a new approach to managing climate change by the Queensland Government. The Queensland Government has committed to managing the impact of climate change through supporting adaptation measures with the aim of building community resilience, protecting ecosystems and enhancing industry productivity in a cost-effective way (EHP, 2013).

2.4 Summary of Relevant Policies

A summary of the relevant policies relating to emissions of GHGs and electricity consumption/generation from the Project is presented in Table 2-2.

Table 2-2 GHG Emissions Policies Relevant to the Project

Level	Policy	EIS	SREIS
International	Kyoto Protocol	INDIRECT. As the Project is planned to be commissioned after 2013, emissions will count towards Australia's Kyoto target for the 2008-2012 period. Section 2.1.1.	INDIRECT. As the Project is planned to be commissioned after 2013, emissions will count towards Australia's Kyoto target for the 2013-2020 as part of the second commitment period. Section 2.1.1.
Australia	National Greenhouse Energy Reporting	MANDATORY. Proponent already participates in NGER and will have to annually report GHG emissions and energy consumption/production associated with the Project. Section 2.2.1.	MANDATORY. The assessment has incorporated updates to the NGER Technical Guidelines in the estimation of emissions. Section 3.2.
	Energy Efficiency Opportunities Program	MANDATORY. It is expected that Proponent will report energy usage and EEOs associated with the Project. Section 2.2.3.	MANDATORY. The EEO Program has been expanded to include new developments and expansion projects. Section 2.2.2.

Level	Policy	EIS	SREIS
	Carbon Price Mechanism	MANDATORY. Proponent is a participant in the CPM and will have to annually report emissions from the Project and hold emission permits equivalent to its covered emissions at the end of each period. Assistance from the government will potentially be given if gas production qualifies as an Emissions Intensive Trade Exposed industry.	PROPOSED. Proposed repeal for which 2013-14 will be the last financial year that the carbon tax will apply.
	Direct Action Plan	--	PROPOSED. The potential implications of the proposed Direct Action Plan for the Project are not yet known.
Queensland	Smart Energy Savings Programme	NONE. Proponent will only have to report energy efficiency data from the Project if it does not do so under the EEO Program.	NONE. Discontinued in 2012.
	Queensland Gas Scheme	INDIRECT. The Project will not be a direct participant in the trading of Gas Electricity Certificates.	NONE. Closed at end of 2013 under the Energy Red Tape Reduction (Amendment and Repeal Bill) 2013.
	Climate Change Strategy	--	INDIRECT. The Queensland Government is committed to supporting adaptation and building resilience to climate change in communities and ecosystems.

3 UPDATED GREENHOUSE GAS EMISSIONS ESTIMATION METHODOLOGY

3.1 Introduction

An updated GHG emissions inventory (the inventory update) has been developed for each year of the life of the Project. The inventory update includes all Project activities delineated by the physical CSG field comprising Authority to Prospect Application (ATPA) 742, ATPA 749, Authority to Prospect (ATP) 1103, ATP 759, ATP 1025P and ATP 1031P and the areas where associated gas gathering infrastructure is required by the Project. The inventory excludes emissions associated with the gas transmission pipeline to Gladstone and the liquified natural gas (LNG) facility, which are subject to separate Environment Impact Assessments.

All calculations and results for the SREIS are shown in Appendix A as described in Table 3-1.

Table 3-1 Appendix Guide

Section	Scope	Emission source
A.1 to A.3		**Scope 1 Emissions – Construction, Operation and Decommissioning**
A.1		**Scope 1 Emissions – fuel combustion**
A.1.1		Fuel combustion – gas fired power generation
A.1.2		Fuel combustion – diesel used in vehicles for transport and construction energy
A.1.3		Fuel combustion – diesel used in drilling activities
A.2	1	Scope 1 emissions – construction
A.2.1		Fugitive emissions
A.2.2		Vegetation clearing
A.3		Scope 1 emission – operation
A.3.1		Fugitive emissions – process flaring
A.3.2		Facility level fugitive emissions from production and processing
A.3.3		Gathering lines
A.4	2	**Scope 2 – Construction, Operation and Decommissioning**
A.5		**Scope 3 Emissions – Construction, Operation and Decommissioning**
A.5.1		Full fuel cycle emissions
A.5.2	3	End use of gas
A.5.3		Emissions associated with third party infrastructure required to export CSG
A.5.4		Emissions from FIFO and DIDO operations

3.2 Updated and New Reference Documents

This updated estimate of GHG emissions is based on the latest methodologies; some of these have been updated or introduced since the EIS. A summary of the documents used in the EIS and the SREIS is provided in Table 3-2.

Table 3-2 Updated and New Reference Documents

EIS	SREIS	Justification
The Australian Government Department of Climate Change and Energy Efficiency. The NGER Technical Guidelines 2011 (Australian Government, 2011a).	The Australian Government Department of Industry, Innovation, Climate Change, Science Research and Tertiary Education. The NGER Technical Guidelines 2013 (Australian Government, 2013d).	Update
The Australian Government Department of Climate Change and Energy Efficiency. National Greenhouse Accounts Factors 2011 (Australian Government, 2011b).	The Australian Government Department of Industry, Innovation, Climate Change, Science Research and Tertiary Education. National Greenhouse Accounts Factors 2013 (Australian Government, 2013e).	Update
The Australian Government Office of Parliamentary Counsel. The National Greenhouse and Energy Reporting (Measurement) Determination 2008 as amended – Reporting Year 2011-12 (Energy Reporting (Measurement) Determination) (Australian Government, 2011c).	The Australian Government Office of Parliamentary Counsel. The National Greenhouse and Energy Reporting (Measurement) Determination 2008 as amended – Reporting Year 2012-13 (Energy Reporting (Measurement) Determination) (Australian Government, 2013f).	Update
The World Resources Institute / World Business Council for Sustainable Development Greenhouse Gas Protocol (Greenhouse Gas Protocol) (WRI and WBCSD, 2004).	The World Resources Institute / World Business Council for Sustainable Development Greenhouse Gas Protocol (Greenhouse Gas Protocol) (WRI and WBCSD, 2004).	No change
--	Technical Guidance for Calculating Scope 3 Emissions (version 1.0), Category 6: Business Travel; The Greenhouse Gas Protocol (WRI and WBCSD, 2013).	Submission response requesting the assessment of Scope 3 emissions from FIFO and DIDO staff.
--	Climate Leaders: Greenhouse Gas Inventory Protocol Core Module Guidance: Optional Emissions from Commuting, Business Travel and Product Transport (US EPA, 2008).	Submission response requesting the assessment of Scope 3 emissions from FIFO and DIDO staff.

The documents used in the EIS are described in the Greenhouse Gas Technical Report (Appendix I, Sections 3.2 to 3.5) of the EIS. The new documents used to assess emissions from FIFO and DIDO Project staff are described in Sections 3.2.1 and 3.2.2.

3.2.1 Technical Guidance for Calculating Scope 3 Emissions (version 1.0)

Airline and vehicle travel is included in the assessment as an indirect or Scope 3 GHG emission as a result of FIFO and DIDO working arrangements. The Technical Guidance for Calculating Scope 3 Emissions (version 1.0) (WRI and WBSC, 2013) provides practical guidance in support of the GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard. In this document, Category 6: Business Travel provides a methodology for the assessment of emissions from the transportation of employees for business-related activities in vehicles owned or operated by third parties such as aircraft, trains, buses and passenger cars.

3.2.2 Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance

The emission factors for the FIFO and DIDO emission calculations are included in Table A.5-11. Emission factors are based on United States Environment Protection Agency (US EPA) Climate Leaders GHG Inventory Protocol (US EPA, 2008).

3.3 Project Greenhouse Gas Emission Sources

Updated activity data used to determine GHG emissions for this assessment were provided by Arrow. Based on the updated activity data, Project GHG sources were identified and reviewed. For details of the activity data and methodology used for emission calculations refer to Appendix A of this report.

The sources of GHG emissions and corresponding activities during the construction, operation and decommissioning phases of the Project for the EIS and SREIS are compared in Table 3-3 and Table 3-4.

Table 3-3 Summary of Scope 1 and Scope 2 Emission Sources

Project Phase	Category	Source of GHG Emission	EIS	SREIS
Construction, Operation and Decommissioning	1	Water storage and treatment.	✓	✓
Construction	1	Power generation from generation sets which provide power to construction activities.	✓	✓
		Diesel fuel consumption during construction and drilling.	✓	✓
		Vegetation losses as a result of land clearing for the gas well heads, nodes, and gas gathering infrastructure.	✓	✓
		Vertical production well installation.	✓	✓
		Gas and water gathering infrastructure installation.	✓	✓
		Water transmission infrastructure.	✓	✓
		Road construction to production facilities.	✓	✓
		Dam construction associated with each WTF.	✓	✓
		Ramp-up flaring.	✓	×

Project Phase	Category	Source of GHG Emission	EIS	SREIS
		Accommodation camp construction.	✓	✓
		Diesel combustion from drill rigs.	×	✓
		Flaring during well completions.	×	✓
Operation and Maintenance	1	Gas combustion in gas fired engines for power generation.	✓	✓
		Diesel consumption in light and heavy vehicles for: • Well site operation and maintenance including well workovers; • Gathering infrastructure operation and maintenance (water and gas); and • Facility operation and maintenance.	✓	✓
		Fugitive emissions through water gathering system (high point vents, water dams), gas gathering lines, drilling and fugitive releases associated with each facility.	✓	✓
		Flaring during upset conditions at the facilities.	✓	✓
		Emissions associated with self-generated electricity production from power generation.	✓	✓
		Power supply to facilities and well heads via distribution lines.	✓	✓
		Flaring during well workovers.	×	✓
	2	Electricity purchased from the grid.	✓	✓
Decommissioning and rehabilitation	2	Earth moving and fuel usage.	✓	✓
		Gathering infrastructure.	✓	✓
		Facility site.	✓	✓

Table 3-4 Summary of Scope 3 Emissions

Project Phase	Category	Source of Greenhouse Gas Emission	EIS	SREIS
Construction, Operation and Decommissioning	3	End use (consumption of gas).	✓	✓
		Full fuel cycle (diesel).	✓	✓
		Full fuel cycle (electricity).	✓	✓
		Third party infrastructure – CSG transmission to Arrow LNG plant.	✓	✓
		Third party infrastructure – CSG downstream processing.	✓	✓
		FIFO and DIDO.	×	✓

3.4 Assumptions and Parameters Applied in SREIS

This section provides a summary of the assumptions and parameters applied in the SREIS which results from the refinements to the project description, updates and inclusion of new datasets and requirement for supplementary information as described in Section 1.1.

3.4.1 Project Phases

GHG emissions were estimated in the inventory update on an annual basis for three distinct phases in the Project: ramp-up (2017 – 2023), operation (2024 – 2053), and ramp-down (2054 – 2058). In compiling the inventory update, it was assumed that construction will commence in 2017 and the Project will be 42 years, including decommissioning.

3.4.2 Worst Case Year

Based on the results for each year of the Project, a worst case year (year that generates the highest GHG emissions) was selected for each phase of the Project in order to represent the most conservative estimates.

3.4.3 Power Generation

3.4.3.1 Options Considered in the Assessment

Based on the updated project description, two power options were considered in this assessment.

Grid Power Supply (preferred base case)

The 'base case' involves grid power supply based on connection to existing electricity infrastructure from the start of the Project. Partial gas fired power generation at remote wellheads (10% of total number of wells) is required from year three. As a long term power supply option, electricity from the grid will generally be supplied to CGPFs from where it will be distributed to FCF's and water transfer stations with further distribution to the wells from the FCF's.

The methodology for calculations of Scope 2 emissions from electricity purchased from the grid were based on Arrow's forecast electricity demand for the Project.

Temporary Power Generation (worst case)

Temporary gas-fired power will be generated at the production facilities in the first two years. Connection to the electricity network is assumed from the third year onwards, with 10% of total number of wells powered locally by gas fired engines, as it may not be feasible to connect some of the wells to the electrical distribution network.

The fuel consumption rates in Table 3-5 were used for temporary power generation. A rating of 11.43 GJ/MWh was adopted for the assessment, as provided by Arrow. This is equivalent to an assumed engine efficiency of 31.5%.

Table 3-5 Gas Consumption for Temporary Power Generation

Application	Power required	Unit Model	Rating	Heat Rate	Manufacturer
Temporary power (1)	50 MW	C1160 N5C	1,160 kW	9.474 GJ/MWh	CUMMINS
Temporary power (2)	50 MW	TAURUS 60	5,670 kW	11.430 GJ/MWh	CATERPILLAR-SOLAR TAURUS 60

3.4.3.2 *Selection of Power Option for Reporting*

A comparison of total Project emissions, estimated for both power options using AR4 global warming potentials, was made to determine the most conservative approach to estimating emissions for the purpose of the supplementary assessment. A summary is shown in Table 3-6.

Table 3-6 A Comparison of Project Emissions for the Power Generation Options

Scenario	Scope 1 (t CO_2-e)	Scope 2 (t CO_2-e)	Total (t CO_2-e)
Base case (100% grid) (10% local power for well heads)	19,689,388	57,673,060	77,362,448
Temporary power generation in first 2 years then grid (10% local power for well heads)	22,762,248	56,498,000	79,260,248
Difference	16%	2%	2%

Table 3-6 shows that total GHG emissions were higher for temporary power generation by 2%. As a result, estimates of GHG emissions from the temporary power generation option are presented in this report as they represent the worst case emissions. However, it should be noted that grid power supply (base case) remains the preferred option. In the event that temporary power generation is not used, the emissions are likely to be lower than those shown in this report.

Potential Decrease in Project Emissions

Australia has committed to reduce national GHG emissions by 5% on 2000 levels by 2020 under the Kyoto Protocol. This represents a 23% reduction below business as usual (Australian Government, 2013g). As energy production is the source of approximately 75% of Australia's total GHG emissions, reducing emissions from this sector will be necessary to meet this commitment. The SREIS has shown that the Project will source electricity from the national grid for the majority of its power needs, which means its Scope 2 GHG emissions are the most significant Project emissions. Therefore, Project emissions will depend on the emissions associated with purchased electricity and therefore on state and federal policies on electricity generation. Emissions from electricity generation across all sectors in Queensland have been decreasing from a peak in 2009. Queensland emissions per unit of electricity generated in 2011 were more than 8% lower than in 2009; this is reflected in the most recent Scope 2 emission factors applied to the Project. If emissions per unit of electricity generated in Queensland continue to fall, Project emissions will be lower than predicted in the SREIS.

3.4.3.3 Drilling

Additionally, the GHG emissions from diesel generators that supply power for well drilling and completions operations were assessed. These calculations were based on the methodology used in the Surat SREIS (Arrow, 2013).

3.4.4 Generic Parameters

Appendix B presents a summary of the generic parameters for the Project, including information on the Project life, facility life, number of facilities, well configurations, pipelines, overhead power lines, Project infrastructure footprint, CSG composition and GWP values applied to the SREIS.

3.4.5 Construction Worker Camps

Scope 2 emissions attributable to construction worker camps and other limited infrastructure were not considered in this study as they are likely to be negligible compared to total GHG emissions resulting from the Project. An allowance of 3 km^2 was made for worker camps in the clearance footprint for the purposes of calculations in the SREIS.

3.4.6 Land clearing

A conservative approach was used in this study to calculate Scope 1 emissions associated with vegetation clearing for the following reasons:

- Emissions from land clearing have been estimated based on data presented in the Project Description chapter (Section 3, Table 3-2) of the SREIS. As the precise locations for clearing of vegetation cannot be determined at this stage of the Project, site-specific emission factors cannot be generated. As an alternative approach, the general biomass densities that have been used by Australian Greenhouse Office for land clearing inventory purposes used in this assessment as per the Project EIS, Surat EIS (Arrow, 2011) and Surat SREIS (Arrow, 2013).
- The estimated emissions do not take into account the planned rehabilitation of all areas cleared for Project purposes. Therefore, Scope 1 emissions from land clearing are likely to be significantly lower than those estimated in this assessment.
- An assumption that 50% of the biomass in any given area is carbon has been made. In reality, this value differs between each species in the range of 40-50% which is consistent with the EIS.

3.4.7 Flaring

3.4.7.1 Well Completions and Workovers

Gas released during the course of regular well completion and well intervention (workovers) operations is disposed of at the well site via a flare. Individual well characteristics and the type and duration of well intervention activities will significantly affect the duration and intensity of any gas flared. Arrow expects total average flaring of 400 m^3 of gas per well completion or workover.

There are two possible sources of emissions from completion of wells:

- Well completion – it is estimated that 400 m³ of gas will be produced and flared per well completion; and
- Well workover –production well workover emissions are typically flared; however, vertical production wells associated with the Project will only be tested for production when connected to gas gathering lines.

The frequency of well workovers is assumed to be once every two years whilst well completions occur once within the lifetime of each well.

3.4.7.2 Ramp-Up Flaring

In order to minimise gas flaring and associated impacts from the Project, the Bowen gas commissioning strategy will use gas from the Arrow Bowen Pipeline, backfilled from the Gladstone Gas Hub, for commissioning of wells, FCFs and CGPFs. Using this approach, emissions associated with the upstream Project ramp-up in the SREIS case for the Project are lower than the EIS case. This strategy negates the need to use gas from Bowen wells for commissioning FCFs and CGPFs and minimises the possibility of excess gas being flared during commissioning of the upstream facilities. Therefore, ramp-up flaring has not been included in the assessment. However, it remains an option to flare during ramp-up if a deviation from the commissioning strategy is required.

In the SREIS, it is assumed that each FCF will be commissioned by gas from the CGPFs, and no well commissioning will take place until the relevant FCF is commissioned. Therefore, under this current development concept no ramp-up flaring is required at facilities.

3.4.7.3 Pilot Flame for Flare

Under normal operating conditions the flares require a pilot flame that will be continuously lit. Continuous pilot flaring will occur at FCFs and CGPFs, with a rate of 0.02 TJ/d/facility, as in the EIS.

3.4.7.4 Maintenance / Upset Conditions Flaring

Flaring at FCFs and CGPFs may occur due to upset conditions throughout the operational phase of the Project. Table 3-7 shows forecast flaring rates for the entire Arrow gas field in the Bowen Basin (not per compression facility). It should be noted that maintenance flaring cannot occur at all facilities simultaneously.

Table 3-7 Estimated Maintenance Flaring Conditions

Total duration per year (hours)	Number of occurrences per year	Total amount of gas flared per year (TJ)
6	0.05	1
12	15	75
18	53	1,380
24	24	1,240
Total		**2,696**

3.4.8 Scope 3 Emissions

Scope 3 or 'other indirect' emissions occurring outside the Project boundary include emissions associated with the end-use of produced gas, third party infrastructure required to export gas as LNG, emissions from workplace travel based on FIFO and DIDO arrangements and emissions associated with LNG product shipping. Scope 3 emissions exclude waste products management and construction material embedded energy. Other Scope 3 sources that have not been calculated explicitly are not expected to be material to the overall inventory.

In order to be conservative in estimating the Scope 3 emissions from third party infrastructure, the Scope 1 and Scope 2 emissions associated with the worst-case emissions scenario for the Arrow LNG Plant were used. This worst case scenario is defined as the use of four LNG trains sourcing power from the national grid exclusively. These estimates were then scaled according to the currently expected fraction of gas supplied by the Project.

4 UPDATED GREENHOUSE GAS EMISSION ESTIMATES FOR THE PROJECT

This section provides a summary of the results of the inventory update. The results presented are those for the temporary power generation option, which was shown in Section 3.4.3 to represent higher emissions than the preferred base case grid power option. The Project emissions inventory is summarised in Section 4.6. A detailed description of the emissions estimation methodologies adopted for Project and non-Project sources can be found in Section 3 and Appendix A of this report.

4.1 Greenhouse Gas Project Emission Estimates for the Life of the Project

Figure 4-1 shows the estimated GHG emissions released for each year of the Project.

Figure 4-1 Project (Scope 1 and Scope 2) GHG Emissions in t CO_2-e for each Year from 2017 to 2058

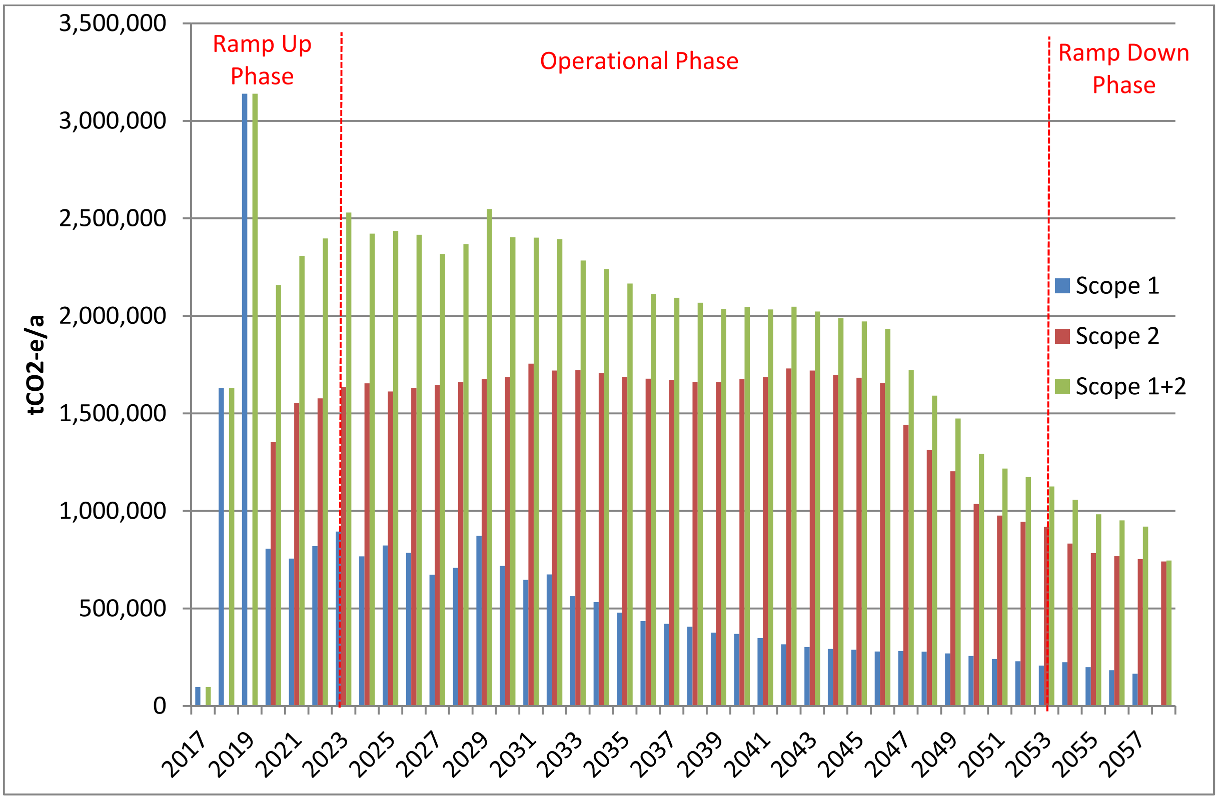

Figure 4-1 shows that direct Project emissions (Scope 1) in the ramp-up phase are higher than indirect Project (Scope 2) emissions for the first three years of the Project. Total emissions are expected to be highest during the year 2019, assuming the worst case scenario of requiring temporary power generation, and consist entirely of direct (Scope 1) emissions. For the remainder of the Project, the proportion of indirect emissions from the purchase of electricity are greater than the proportion of direct emissions. In the operational phase, the production plateau is expected to last until 2046. From 2046, direct and indirect Project emissions gradually decline to the end of the ramp-down phase. In the EIS, direct emissions were estimated to be greater than indirect emissions for the whole Project.

The inventory updates shows that overall Project emissions are likely to reduce by 4% from 82.9 Mt CO_2-e (EIS) to 79.3 Mt CO_2-e (SREIS).

4.2 Ramp-Up Period Project Emissions (Scope 1 and Scope 2)

Scope 1 and Scope 2 GHG emissions associated with the ramp-up period (2017 – 2023) of the Project are shown in Table 4-1 for the worst-case year with the highest emissions (2019).

Table 4-1 Predicted GHG Emissions for Worst-Case Year (2019) of Ramp-Up Period

Category	Activity	GHG Emissions (t CO_2-e)
Scope 1 Emissions	Fuel combustion – gas fired power generation	1,921,913
	Fuel combustion – diesel powered drilling	35,981
	Fuel combustion – diesel used in vehicles for transport and construction energy	12,174
	Vegetation clearing	843,026
	Gathering lines	25,474
	Fugitive emissions (facility level) - production and processing	140,995
	Fugitive emissions - flaring during well completions and workovers, pilot lights and upset conditions flaring	159,411
Total Scope 1 Emissions		**3,138,973**
Scope 2 Emissions	Electricity consumption wellheads	0
Total Scope 2 Emissions		**0**
Total (Scope 1 and Scope 2) Emissions		**3,138,973**

Direct (Scope 1) emissions for 2019 were estimated to be 3.1 Mt CO_2-e, comprising all of the emissions in that year. Scope 1 ramp-up emissions are associated with fuel combustion (to run construction activities, the construction camp and transport), land clearing, and fugitive emissions from gas processing and maintenance of the vertical production wells. Table 4-1 shows the majority of Scope 1 emissions are from gas combustion for power generation. Note that power demand and hence calculated emissions for the possible alternative temporary power generation scenario in 2018 and 2019 are based on a full capacity power demand for each facility, and hence are deemed to be highly conservative. Through detailed design the installed capacity of any required temporary power generation will be optimised.

Indirect (Scope 2) emissions for the worst-case year 2019 were estimated to be zero in the ramp up phase as all power will be provided from combusted gas at Project facilities.

The total (Scope 1 and Scope 2) Project emissions for the worst-case year (2019) of the ramp-up period were estimated to be 3.1 Mt CO_2-e, which is almost double the estimate made in the EIS. The main reason for this difference is the increased rate of fuel combustion for gas fired power generation and addition of drilling, and an increase in the vegetation clearance (Scope 1 emissions).

4.3 Operational Project Emissions (Scope 1 and Scope 2)

Scope 1 and Scope 2 GHG emissions associated with the operational period (2024 – 2053) of the Project are shown in Table 4-2 for a year with the highest emissions (2029).

Table 4-2 Predicted GHG Emissions for Worst-Case Year (2029) of Operational Period

Category	Activity	GHG Emissions ($t\ CO_2$-e)
Scope 1 Emissions	Fuel combustion – gas fired power generation	34,501
	Fuel combustion – diesel powered drilling	14,247
	Fuel combustion – diesel used in vehicles for transport and construction energy	10,930
	Vegetation clearing	339,199
	Gathering lines	84,354
	Fugitive emissions (facility level) - production and processing	221,808
	Fugitive emissions - flaring during well completions and workovers, pilot lights and upset conditions flaring	166,964
Total Scope 1 Emissions		**872,004**
Scope 2 Emissions	Electricity consumption wellheads	1,676,080
Total Scope 2 Emissions		**1,676,080**
Total (Scope 1 and Scope 2) Emissions		**2,548,084**

The total (Scope 1 and Scope 2) Project emissions for 2029 were estimated to be 2.5 Mt CO_2-e, which is approximately 20% higher than the peak operational year in the EIS.

Scope 1 emissions for 2029 were estimated to be 0.9 Mt CO_2-e, which represents 34% of the total. These emissions are lower than those estimated for the worst-case year in the EIS as power is now assumed to be supplied by the grid. In contrast to the EIS, the majority of Scope 1 emissions are from vegetation clearing and fugitive emissions and not fuel combustion for power generation and drilling. The estimate of gas combustion for power generation in the SREIS is 3.5% of the EIS estimate.

Scope 2 emissions for 2029 were estimated to be 1.7 Mt CO_2-e, which represents 65% of the total. Scope 2 operational emissions are associated with electricity consumed to meet most of the power requirements. Project related Scope 2 emissions in the operational phase are 73% higher than the estimate in the EIS.

4.4 Ramp-Down Period Project Emissions (Scope 1 and Scope 2)

Scope 1 and Scope 2 GHG emissions associated with the ramp-down period (2054 – 2058) of the Project are shown in Table 4-3 for the year with the highest emissions (2054).

Table 4-3 Predicted GHG Emissions for Worst-Case Year (2054) of Ramp-Down Period

Category	Activity	GHG Emissions ($t\ CO_2$-e)
Scope 1 Emissions	Fuel combustion – gas fired power generation	5,143
	Fuel combustion – diesel powered drilling	0
	Fuel combustion- diesel used in vehicles for transport and construction energy	12,787
	Vegetation clearing	0

Category	Activity	GHG Emissions ($t\ CO_2$-e)
	Gathering lines	17,104
	Fugitive emissions (facility level) - production and processing	35,823
	Fugitive emissions - flaring during well completions and workovers, pilot lights and upset conditions flaring	153,615
Total Scope 1 Emissions		**224,472**
Scope 2 Emissions	Electricity consumption wellheads	833,120
Total Scope 2 Emissions		**833,120**
Total (Scope 1 and Scope 2) Emissions		**1,057,592**

The total (Scope1 and Scope 2) Project emissions for the worst-case year of the ramp-down period 2054 were estimated to be 1.1 Mt CO_2-e, which is 40% lower than the worst-case ramp-down year in the EIS.

Scope 1 emissions for 2054 were estimated to be 0.2 Mt CO_2-e, which represents 21% of the total Project emissions. Scope 1 ramp-down emissions are mostly associated with fugitive emissions from flaring during completion and maintenance of the vertical production wells. Scope 1 emissions from fuel combustion are less than 1% of the ramp-down period emissions in the EIS as power is now assumed to be supplied by the grid.

Scope 2 emissions for 2054 were estimated to be 0.8 Mt CO_2-e, which represents 79% of the total. This is almost three times higher than the EIS estimate. Scope 2 ramp-down emissions are associated with electricity consumed to meet most of the power requirements.

4.5 Scope 3 Emissions

Scope 3 or 'other indirect' emissions are produced by the end-use of produced gas, full fuel cycles of diesel and electricity, the third party infrastructure required to export gas as LNG and workplace travel based on FIFO and DIDO operations. Table 4-4 shows the Scope 3 emissions associated with the worst case year for each phase of the Project.

Table 4-4 Predicted Annual Scope 3 Greenhouse Gas Emissions during Ramp-Up, Operational and Ramp-Down Period Worst-Case Year 2019, 2029, 2054)

Activity	Ramp-up (2019) ($t\ CO_2$-e)	Operational (2029) ($t\ CO_2$-e)	Ramp-down (2054) ($t\ CO_2$-e)
End use (combustion of gas)	9,224,474	14,511,673	2,343,719
Full fuel cycle (diesel)	923	829	969
Full fuel cycle (electricity)	0	286,160	142,240
Third party infrastructure – CSG transmission to Arrow LNG plant	6,538	6,538	6,538
Third party infrastructure – CSG downstream processing	1,395,619	2,195,621	354,497
FIFO/DIDO operations	4,649	2,327	2,234
Total Scope 3 Emissions	**10,632,203**	**17,003,148**	**2,850,197**

The annual Scope 3 GHG emissions associated with the ramp-up period (2017 - 2023) of the Project have been estimated to be 10.6 Mt CO_2-e for the worst-case year, 2019. This is approximately the same as estimated in the EIS. For the operational period (2024 - 2053) the annual Scope 3 emissions were estimated to be 17.0 Mt CO_2-e in 2029, which is 35% higher than the EIS. For the ramp-down period Scope 3 emissions were estimated to be 2.9 Mt CO_2-e in 2054, which is almost 68% less than the EIS.

The majority of Scope 3 Project emissions are associated with the end use of the produced gas. The expected total gas production is lower for the SREIS reference case than for the EIS reference case.

4.6 Summary of Emissions

Table 4-5 summarises the estimated Project total GHG emissions during each phase of the Project, including Scope 3 emissions.

Table 4-5 Total Greenhouse Gas Emissions Estimated for Each Phase of the Project by Scope

Type	Scope	Ramp-up Period (t CO_2-e)		Operational Period (t CO_2-e)		Ramp-Down Period (t CO_2-e)	
		EIS 2016-2022	SREIS 2017-2023	EIS 2023-2056	SREIS 2024-2053	EIS 2057-2062	SREIS 2054-2058
Project (direct)	**1**	8,817,223	8,143,317	51,335,961	13,841,885	7,497,589	777,046
Project (indirect)	**2**	978,432	6,116,380	13,366,019	46,501,380	876,606	3,880,240
Total	**1+2**	**9,795,655**	**14,259,697**	**64,701,980**	**60,343,265**	**8,374,196**	**4,657,286**
Non-Project (indirect)	**3**	43,807,678	79,524,884	350,651,846	267,800,894	26,021,718	6,095,394

Table 4-5 shows that indirect scope 3 GHG emissions are higher than both the Project direct (Scope 1) and indirect (Scope 2) emissions combined. This finding is unchanged from the EIS.

4.6.1 Ramp-Up Period

In the ramp-up period, Project emissions (Scope 1 plus Scope 2) are significantly higher in the SREIS than the EIS. This is a result of significantly higher Scope 2 emissions from the purchase of electricity for power requirements in the period 2020 to 2023.

Ramp up period Scope 3 emissions are almost double the EIS estimate, which is a result of increased gas field production and a subsequent increase in downstream gas combustion.

4.6.2 Operational Period

In the operational period, direct Project emissions are lower in the SREIS than the EIS. Direct Scope 1 emissions are 73% lower than the EIS estimate, which is a result of the reduction in fuel consumption for power requirements in the SREIS. Conversely, indirect Project emissions are more than three times higher in the SREIS as a result of the use of purchased electricity to meet Project power requirements. The net result of the changes made in the SREIS assessment is to lower Project emissions by approximately 7%.

Operational period Scope 3 emissions are 24% lower than the EIS. This is directly proportional to the reduction in estimated gas production from 7.1 million TJ (EIS) to 5.8 million TJ (SREIS), and the corresponding reduction in emissions from downstream processing and combustion.

4.6.3 Ramp-Down Period

In the ramp-down period, Project Scope 1 and Scope 2 emissions are 1.8 times lower than those estimated in the EIS as a result of lower gas production. However, it should be noted that the SREIS conceptual ramp-down period is one year shorter than the EIS equivalent period.

SREIS direct Project emissions are approximately 10% of those estimated in the EIS and the indirect Project emissions are more than four times greater as a result of the use of purchased electricity to meet Project power requirements during ramp-down.

In the ramp-down period, SREIS Scope 3 emissions are approximately a quarter of those estimated in the EIS.

5 IMPACT OF GREENHOUSE GAS EMISSIONS FROM THE PROJECT

5.1 Updated Estimate of Potential Impacts

Sections 5.1.1, 5.1.2 and 5.1.3 present a comparison of the predicted Project emissions with the estimates of global (2010), Australian (2011) and Queensland (2011) emissions shown in Table 5-1. Section 5.1.4 presents a summary of GHG emissions compared to Australia and Queensland emissions.

Table 5-1 Estimates of Greenhouse Gas Emissions

Geographic Area	Source	Year	Emissions
Global*	Consumption of fossil fuels	2010	31,387 Mt CO_2
Australia+	Total (including Land Use, Land Use Change and Forestry (LULUCF) activities)	2011	563.1 Mt CO_2-e
Australia+	Energy sector	2011	422.0 Mt CO_2-e
Queensland+	Total (including LULUCF activities)	2011	155.5 Mt CO_2-e
Queensland+	Energy sector	2011	99.5 Mt CO_2-e

* http://mdgs.un.org/unsd/mdg/Search.aspx?q=Carbon%20dioxide%20emissions&Provider=Data. Data for 2010 was the latest year of data available when the site was accessed on 18/11/2013. Australia's total emissions inventory in 2011 is compared to the 2010 global inventory and should therefore be considered indicative.

+ http://www.ageis.greenhouse.gov.au/. Accessed 18/11/2013.

The aggregate Scope 1 and Scope 2 emissions from the Project associated with the worst case year (2019) represent approximately 0.01% of global 2010 fossil fuel consumption emissions (see Table 5-1).

5.1.1 Comparison with Australian Emissions

The National Greenhouse Gas Inventory 2011 (Australian Government, 2013h) is the latest available national account of Australia GHG emissions. Australian GHG emissions across all sectors totalled 563.1 Mt CO_2-e in 2011, with the energy sector being the largest emitter at 422.0 Mt CO_2-e. Approximately 41.3 Mt CO_2-e of energy sector emissions were attributable to fugitive emissions from fuels, representing approximately 10% of the national total from the energy sector.

The total Project Scope 1 and Scope 2 emissions for 2019 equal to approximately 0.6% of Australia Emissions and 0.7% of emissions from the Australian energy sector.

5.1.2 Comparison with Queensland Emissions

For the peak year 2019, annual Scope 1 and Scope 2 GHG emissions from the Project were predicted to be approximately 3.1 Mt CO_2-e. These emissions are equal to 2.0% of the 2011 state inventory and 3.2% of the state energy sector inventory. However, the proportion of the state inventory is lower when the annual average for the life of the Project is considered. For the Project life, the annual average emissions (1.9 Mt CO_2-e) are 1.2% of the state inventory and 1.9% of the state energy sector inventory.

5.1.3 Summary of GHG Emissions Compared to Australia and Queensland Emissions

Table 5-2 and Table 5-3 present a summary of the Project GHG emission contribution to Australia and Queensland GHG emissions for net GHG emissions and energy sector emissions.

When compared with Australia 2011 emissions, Project emissions for 2019 are equivalent to 0.6% of Australia total emissions and 0.7% of Australia emissions from the energy sector. The peak year emissions represent approximately 2.0% of the total GHG emissions for Queensland (2011) and approximately 3.2% of the emissions from the Queensland Energy sector for the same year.

Table 5-2 Comparison of Project GHG Emissions for the Worst-Case Year (2019) with Australian and Queensland Total Annual GHG Emissions (2011)

Category	Project Emissions (Mt CO_2-e/year)	% Australian Emissions	% Queensland Emissions
Scope 1	3.1	0.6	2.0
Scope 2	0.0	0.0	0.0
Total Scope 1 & 2	**3.1**	**0.6**	**2.0**

Table 5-3 Comparison of Project GHG Emissions for the Worst-Case Year (2019) with Australian and Queensland Annual GHG Emissions from Energy Sector (2010)

Category	Project Emissions (Mt CO_2-e/year)	% Australian Emissions	% Queensland Emissions
Scope 1	3.1	0.7	3.2
Scope 2	0.0	0.0	0.0
Total Scope 1 & 2	**3.1**	**0.7**	**3.2**

When compared with Australia 2011 emissions, average Project emissions (1.9 Mt CO_2-e/year) are equivalent to 0.3% of Australia total emissions and 0.4% of Australia emissions from the energy sector. Average emissions represent approximately 1.2% of the total GHG emissions for Queensland (2011) and approximately 1.9% of the emissions from the Queensland Energy sector.

The same approach to representing typical GHG emissions for the Project has been applied as used in the EIS. Project emissions used in the analysis are conservative as they are based on the results for a year with the highest emissions and represent a worst case scenario (see Section 4.1). This is particularly pertinent to the SREIS estimates as Scope 1 emissions from the ramp-up phase (2019) have been used to represent Project emissions. In 2019, Scope 1 emissions as a result of gas usage are approximately three times the highest emission estimate for the operational phase which occurs in 2023.

Emission factors are used to calculate Scope 2 emissions from the generation of the electricity purchased and consumed by an organisation as kilograms of CO_2-e per unit of electricity consumed. Scope 2 emission factors are dependent on the State, territory or electricity grid in which the consumption occurs. Each year, the NGER Guidelines are updated to include the latest Scope 2 emission factors, and to reflect changes made to the Measurement Determination. However, emissions per unit of electricity generated across all sectors in Queensland have been decreasing from a peak in 2009. Queensland Scope 2 emission factors in 2011 were more than 8% lower than in 2009 (Australian Government, 2013e). In line with standard industry practice, the current emission factor has been used for the lifetime of the Project. However, the observed trend is expected to continue as action is taken to reduce Australian GHG emissions to achieve the policy objective of a 5% reduction by 2020. As purchased electricity accounts for the majority of Project emissions, actual Scope 2 Project emissions are likely to be significantly lower than estimated here.

A conservative approach was also used to calculate emissions associated with land clearing (see Section 4). Therefore, the total Project emissions are likely to be lower than those predicted in this assessment. Implementing the additional abatement measures described in Section 6 may also reduce direct GHG emissions from the Project.

The SREIS emission estimate comparisons against global, Australian and Queensland emissions are similar to the EIS.

5.2 Updated Greenhouse Gas Intensities

A GHG emissions intensity is defined in Section 5.2 of the Greenhouse Gas Technical Report (Appendix I) of the EIS as GHG as a measure to benchmark Projects and/or industries against other practices or facilities. GHG intensities are presented as the quantity of GHG emitted during delivery and supply of the product or service per unit of product or service provided. For the energy sector, this is calculated as CO_2-e/GJ. The National Greenhouse Gas Accounts Factors (Australian Government, 2013e) provides Scope 3 emission factors for gaseous, liquid and solid fuels. These Scope 3 emission factors are in fact GHG intensities, i.e. the quantity of upstream emission per unit of energy supplied.

The refined project description shows that the Project will be five years shorter than the EIS and production rates will increase during ramp-up and decrease during operation and ramp-down more sharply than the EIS. It can therefore be expected that emissions intensities will be higher at the beginning and end of the Project in the SREIS.

The Project average emissions intensity has been calculated for the Project as the sum of upstream Scope 1 emissions (gas combustion for upstream facilities, flaring, fugitive losses, gas gathering system maintenance, land clearance, drilling and vehicle transportation) and Scope 2 emissions from the consumption of electricity.

Table 5-4 presents a comparison between the Project average emissions intensities for the EIS and SREIS.

Table 5-4 A Comparison of Emissions Intensity

Fuel	Emissions Intensity (kg CO_2-e /GJ)	
	EIS	SREIS
Project average	11.7	13.7

Table 5-4 shows that in the SREIS the GHG intensity averaged over the Project is 13.7 kg CO_2-e /GJ. This is higher than the EIS (11.7 kg CO_2-e /GJ) and can be expected because the reduction in forecast gas production is greater than the predicted reduction in GHG emissions. However, the following should be noted:

- Conservative assumptions have been used to assess GHG emissions such as, but not limited to, the assessment of emissions from temporary power generation under the full capacity scenario instead of the likely optimised required capacity for the Project.
- Despite the expected increase in intensity of GHG emissions during the life of the Project after the project description refinements, the inventory update shows that overall Project emissions are likely to reduce from 82.9 (EIS) to 79.3 Mt CO_2-e (SREIS) which is a reduction of 4.3%.

The end-use of gas for electricity production results in much lower GHG emissions than other fossil fuels. The use of gas for energy production (Scope 3 emissions) produces much higher GHG emissions than Project related activities and processes. Hence, electricity sourced from gas has a significant advantage over other fossil fuels with respect to full cycle emissions, which include emissions from the extraction, production and transport of the fuel, and the emissions associated with combustion. For instance, each unit of electricity generated from gas produces approximately 50% lower full-cycle GHG emissions than conventional coal-fired electricity (Arrow, 2012). Recent studies in the Australian context focused on exports to Asia of Australian conventional gas, CSG and coal (Arrow, 2012). These studies have concluded generally that LNG has lower overall lifecycle GHG emissions than coal, when power generation technologies of similar efficiency or application are compared. Open cycle gas technology, using LNG from CSG produces 27% less emissions over its life cycle than sub-critical coal fired technology.

6 GHG ABATEMENT, MANAGEMENT AND MITIGATION MEASURES

The Project is subject to international, national, state and corporate GHG policies with abatement objectives and performance standards as discussed in Section 2. Arrow will comply with all mandatory international and national objectives, state objectives and remains committed to the mitigation measures described in the Greenhouse Gas Technical Report (Appendix I, Table 6-1) of the EIS and the climate change adaptation commitments described in Section 7 of this report.

Arrow has committed to the ongoing measurement and monitoring of the Project's emissions, energy consumption and production through schemes which include:

- National Greenhouse Emissions Reporting System; and
- Energy Efficiency Opportunities.

Arrow will continue to investigate GHG abatement measures for on-going monitoring and maintenance program at the site-level, reducing fugitive emissions from equipment leaks and investigating new technologies as they become available.

As electricity consumption is an important contributor to life cycle emissions, it is recommended that electrical equipment e.g. motors, pumps and compressors are regularly monitored and maintained as part of a comprehensive energy efficiency improvement program for the Project. These measures will be consistent with the EEO Program activities.

Arrow is a direct participant in the CPM. This means that if the Clean Energy Legislation (Carbon Tax Repeal) Bill 2013 is passed, Arrow will not be required to submit permits equivalent to its liability beyond 30 June 2014. However, Arrow will be a participant in the Direct Action Plan and the Project will be included in the federal government's program to meet its emission reduction commitments. If the CPM is not repealed, Arrow will continue to acquit liability under the *Clean Energy Act 2011*.

7 CLIMATE CHANGE IMPACT ASSESSMENT

7.1 Stakeholder Submission

EHP made a submission in response to the EIS regarding adaptation to climate change. The submission is as follows:

> *"Although Sections 8.5.1 to 8.5.4 discuss the role of climate change on the design of the Project, insufficient information has been provided regarding the planning for climate change in the short and long terms to determine how these changes will be managed. It is not clear what adaptation strategies will be implemented to account for those impacts.*
>
> *Limited discussion has been provided for the following example matters:*
>
> - *how extreme climate events may impact on the project and local environment*
> - *given that floods and cyclones increase in frequency as a result of climate change, it is not clear what measures will be taken to minimise impacts to the project and local environment as a result of those extreme weather events*
>
> *Commitments to undertake a cooperative approach with government, industry and other sectors to address adaptation to climate change are not made or are unclear."*

7.2 Arrow Response

7.2.1 Review of EIS Climate Change Impact Assessment

The climate change impact assessment in the EIS was based on climate change scenarios described in the fourth IPCC report, AR4. The Fifth Assessment Report (AR5) will provide a clear view of the current state of scientific knowledge relevant to climate change. A final draft of AR5 has been released and will be published in January 2014. Therefore the assessment of the impact of climate change on the Project has not been updated.

7.2.2 Impacts of Extreme Climate Events

In 2012 the IPCC released the Special Report for Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation (SREX report) which brings together the latest research on climate change and extreme events. The key findings from the SREX report which are relevant to the Project include:

- Australia has already observed an increase in warm days and a decrease in cold days. This trend is projected to continue with large scale increases in the number of days over 35^{o}C and 40^{o}C and an increase in heatwave duration.
- Extreme rainfall events are projected to increase.
- Tropical cyclones are likely to become more intense and shift southwards; however the frequency of tropical cyclones could remain unchanged or even decrease.
- Since the 1950s there has been an observed increase in drought over the south west and south east of Australia with projections indicating this could continue.

- The most effective adaptation and disaster risk reduction actions for extreme events are those that offer development benefits in the relatively near term, as well as reductions in vulnerability over the longer term.

Potential impacts on the Project and local environment that may occur as a result of climate-related hazards are shown in Table 7-1.

Table 7-1 Potential Impacts

Climate-related hazards	Potential impact
Extreme temperatures and heatwaves	Heat-related health impacts
	Increased energy demand
	Heat-induced damage to infrastructure.
	Increased risk of bushfire
	Increased invasive weed and pest species
Increase in rainfall intensity and flooding	Degradation and failure of essential infrastructure
	Exceed capacity of water management facilities
	Increased mosquitos
More frequent droughts	Water shortage
	Increased dust
	Soil shrinkage and movement
	Decreased groundwater levels
	Pressures on rehabilitation
Increase in storms events and intensity of cyclones	Increased damage to Project infrastructure
	Increased workforce injuries
	More frequent and prolonged interruptions to operations

Further explanation on the impact of extreme climate change events on the Project is provided in the Climate chapter (Section 8) of the EIS.

7.2.3 Adaptation Commitments

Arrow considers climate change adaptation in planning and design, construction, operation and decommissioning phases of the Project. This includes developing preventative and responsive measures for extreme climatic events and designing and constructing production facilities in accordance with current Australian standards to withstand extreme occurrences of these events, as described in the SREX report.

Arrow operates a Crisis and Emergency Management System which includes a Corporate level Emergency Management Standard and Crisis and Emergency Management System Description. As a major asset, operations in the Bowen Basin are subject to the Bowen Basin Emergency Management Plan, which includes emergency management actions for the management of risks from bush fires and flooding.

Floods and cyclones are the predominant weather events likely to have an impact on the Project. However, under current design of upstream facilities all the proposed drainage areas for the Project will be located in non-cyclonic regions (Standards Australia/Standards New

Zealand, 2002), with only some supporting sites located within 50 km off the coast within a Cyclonic region C.

Arrow is committed to the following actions to mitigate the extreme weather effects on the Project:

- Design to address increased intensities of storm events;
- Incorporate seasonal and weather forecasts for planning Project activities;
- Consider future climate change effects in emergency response planning; and
- Repair damaged infrastructure based on higher standards to withstand local climate extremes with contingency for climate change, where possible.

Risk management measures that will be adopted in the development of the Project are described in Section 7.7.3 of the EIS Greenhouse Gas Technical Report (Appendix I). Furthermore, Arrow is committed to taking a cooperative approach with government, industry and other sectors to address adaptation to climate change.

8 FUGITIVE EMISSIONS

8.1 Stakeholder Submission

Doctors for the Environment Australia made a submission in response to the EIS regarding fugitive emissions from the Project. The submission is as follows:

> *"Scope 1 emissions - Fugitive emissions should include a realistic assessment based on current science and on findings in other gas fields such as Tara in Australia and large gas fields in the USA."*

8.2 Arrow Response

8.2.1 Fugitive Emissions

Under the NGER legislation the following sources are considered as fugitive emissions:

- Exploration and production flaring;
- General leaks; and
- Venting, including emissions from the following sources: glycol dehydrator, cold process vents, gas driven pneumatic drives, chemical injection pumps, mud degassing, vessel blowdowns, compressor starts and blowdowns, gas well workovers, gathering gas pipeline blowdowns and pressure relief valves.

Fugitive emissions have been defined in the same way for the purpose of this assessment which provides consistency between the SREIS and the reporting requirements of the NGER Act.

8.2.2 SREIS Fugitive Emissions Assessment

The emissions presented in Table 4-3 and Appendix A were estimated using the methodology described in the Greenhouse Gas Technical Report (Appendix I, Section A.3.2) of the EIS and a number of conservative assumptions specific to the updated project description, as described in Section 3-4. The method uses:

- American Petroleum Institute of Greenhouse Gas Methodologies for the Oil and Gas Industry default facility level average emission factor modified to represent the Project site (Appendix A.3.2);
- Method 1 of the National Greenhouse and Energy Reporting System Measurement Technical Guidelines 2013 (Australian Government, 2013d);
- AR4 GWP values; and
- National Greenhouse Accounts Factors (Australian Government, 2013e) for gas gathering.

8.2.3 Fugitive Emissions Assessment Approach

Section A.2 and A.3 show the estimated CH_4 emissions associated with facility level fugitives from production and processing in tonnes of CO_2-e for each year of the Project. The methodologies and specific parameters applied in their estimation are shown in Table 8-1.

Table 8-1 Fugitive Emissions Assessment Approach

Project phase	Activity	Method	Appendix
	Flaring during well completions and workovers	Method 1 (Part 3.3, division 3.3.2) of Australian Government (2013d) AR4 GWP values applied	A.2.1
Operation	Process flaring (exploration pilot)	Method 1 (Part 3.44) of Australian Government (2013d) Site specific energy content factor 0.03729 GJ/m^3 AR4 GWP values applied	A.3.1
	Process flaring (production or processing pilot)	Method 1 (Part 3.58) of Australian Government (2013d) Site specific energy content factor 0.03729 GJ/m^3 AR4 GWP values applied	A.3.1
	Process flaring (maintenance/upset conditions)	Method 1 (Part 3.39) of Australian Government (2013d) AR4 GWP values applied	A.3.1
	Fugitive leaks Facility level emissions from production and processing (excluding venting and flaring)	Conversion of API default emission factors to site specific emission factors Default emission factor for general methane leaks from Section 3.72 of the Technical Guidelines, Australian Government (2013d) Specific methane facility-level average fugitive emission factor associated with gas processing plants based on AR4 GWP value for methane	A.3.2
	Compressor blowdowns, maintenance leaks and accidents Gathering system	Method 1 (Division 3.37, Section 3.76, Method 1 – natural gas transmission, Australian Government, 2013d). AR4 GWP values applied	A.3.3

Table 8-1 shows that the methodologies applied in the SREIS are consistent with the latest fugitive GHG emissions assessment methodologies. The assessment methodology used in the SREIS considered the use of the following API compendium fugitive emission factors to represent emissions from production facilities:

- Facility-level average fugitive emissions for gas processing plants to represent leaks from all aspects of gas processing based on the API Compendium methodology (API, 2009). It is important to note that this methodology is conservative as the API emission factor (0.0339 t CO_2-e/t CSG processed) is more than 25 times higher than the emission factor (0.0012 t CO_2-e/t CSG processed) recommended by the Technical Guidelines (Australian Government, 2013d).
- Facility-level average fugitive emissions for on-shore gas production (0.0302 t CO_2-e/t CSG processed) – to represent leaks specifically from gas wells, heaters, separators, small reciprocating compressors, meters/piping and pipelines.

As a conservative approach the facility-level average fugitive emissions associated with gas processing plants has been applied in the SREIS assessment on the assumption that any leaks not accounted for in the on-shore gas production factor are included. Furthermore, the application of the AR4 GWP values to the factor (Appendix A.3.2) adds further conservatism to the emission factor applied (0.0403 t CO_2-e/t CSG processed) is reflecting the latest scientific understanding of the relative impact of GHGs on global warming in advance of their adoption into NGER.

8.2.4 Fugitive Emissions Management

Arrow monitors and manages well head emissions in accordance with the Code of Practice for Coal Seam Gas Well Head Emissions Detection and Reporting (COP) (Queensland Government, 2011) as required under Schedule 1 of the Petroleum and Gas Regulations 2004. The requirements of well head monitoring are detailed in a formal Leak Management Plan.

Arrow has conducted a risk assessment to identify risks posed by leaks from well sites and has implemented appropriate actions to reduce these risks to as low as reasonably practicable as required under the *Petroleum and Gas (Production and Safety) Act 2004*. These actions are incorporated into Arrow's Leak Management Plan. Mandatory requirements of the Leak Management Plan include (but are not limited to):

- Ensure formal integrity audits are conducted on 20% of the total number of gas well site per annum.
- Ensure a formal integrity audit is conducted on every operating gas well site facility at least once every five years.
- Undertake formal integrity audits on individual gas well site facilities at an increased frequency as determined by the risk assessment and in consideration of previous audit/inspection findings for those specific facilities.

Leaks detected that are greater than 10% of the lower flammability limit (LFL) of CSG sustained for a period of 15 seconds, measured at 150 mm from the source are considered reportable leaks and are reported to the Petroleum and Gas Inspectorate immediately if over 100% LFL and within 24 hours if above 10% LFL. Unplanned releases that fall outside these parameters are classified as internally reportable well head leaks and are reported to the Petroleum and Gas Inspectorate on an annual basis. Detected leaks are repaired as soon as practical in line with the requirements of Arrow’s Leak Management Plan.

9 CONCLUSIONS

The project description was developed to inform the Project EIS. Since publication of the EIS for public comment in Q1 2013, the proponent's field development plan and project description have been refined. The emissions inventory for the Project has been updated to reflect these refinements incorporating updated and new guidance documents and Project data sources. These updates and revised estimates of GHG emissions from the construction, operation and decommissioning of the Project have been reported. They are supplemented by new information about the Project in response to stakeholder submissions.

The SREIS assessment has used the same methodologies as the EIS, but has been updated to include the latest guidance documents and emission factors. This includes the application of GWP values for methane and nitrous oxide from AR4 of the IPCC. The application of the latest GWP values is an approach that reflects the latest scientific understanding of the relative impact of GHGs on global warming, in advance of the adoption of these data into NGER.

The project description refinements and resulting inventory updates indicate an approximately 4% reduction of Project emissions compared with the EIS estimate. However, the refinements have altered the source, profile and intensity of GHG emissions through the Project. The changes include a five year reduction in Project duration, reduction in total forecast gas production and a greater production rate incline and decline during the ramp-up and ramp-down phases of the Project, respectively.

A worst case scenario for power supply was adopted, which conservatively assumed infield CSG power generation for the first two years of Project, with connection to the electricity network from the third year onward. Direct Project emissions (Scope 1) in the ramp-up phase are higher than indirect Project (Scope 2) emissions for the first three years of the Project in the worst-case scenario. This is a result of the combustion of gas for facility power generation. Scope 1 emissions are lower and Scope 2 emissions are higher in the preferred base case, which assumed power supply from grid and 10% of wells gas powered locally.

As in the EIS, emissions were presented for the whole life of the Project and for a year that generates the highest GHG emissions based on the worst-case scenario. The year of the highest emissions for the Project is expected to be 2019 when direct Project emissions from gas fired power generation are at their highest. Note that power demand and hence calculated emissions for this year and year 2018 are based on a full capacity power demand for each facility, and hence are deemed to be highly conservative. Through detailed design the installed capacity of any required temporary power generation will be optimised. For the remainder of the Project, indirect emissions are greater than direct emissions because power requirements for the Project are predominantly met by purchased electricity. In the operational phase, the production plateau is expected to last until 2046.

Although total emissions for the Project are predicted to be lower than in the EIS, the overall emissions intensity for the Project has increased from the EIS estimate. However, highly conservative assumptions have been used to assess GHG emissions, such as but not limited to, the assessment of emissions from temporary power generation under the full capacity scenario instead of the likely optimised required capacity for the Project. It should also be noted that the inventory update shows that overall Project emissions are likely to reduce by 4.3%.

Australia has committed to reduce national GHG emissions by 5% on 2000 levels by 2020 under the Kyoto Protocol. This represents a 23% reduction below business as usual (Australian Government, 2013g). As energy production is the source of approximately 75% of Australia's total GHG emissions, reducing emissions from this sector will be necessary to meet this commitment. The Project will source electricity from the national grid for the majority of its power needs, which means Scope 2 GHG emissions are the most significant Project emissions. Therefore, actual Project emissions will depend on future state and federal policies on electricity generation. Emissions from electricity generation across all sectors in Queensland have been decreasing from a peak in 2009. Queensland emissions per unit of electricity generated in 2011 were more than 8% lower than in 2009; this is reflected in the most recent Scope 2 emission factors applied to the Project. Further falls will be required if Australia is to meet its commitment to reduce national GHG emissions. If emissions per unit of electricity generated in Queensland continue to fall, Project emissions will be lower than predicted in the SREIS.

Scope 3 emissions are predicted to be lower than in the EIS throughout the Project because of lower gas production rates.

The Project remains subject to international, national, state and corporate GHG policies with abatement objectives and performance standards. The proponent remains committed to the mitigation measures described in EIS. The proponent is a direct participant in the CPM and is liable for carbon emissions under the *Clean Energy Act 2011*. Although changes to this legislation have been proposed, Australia remains committed to a 5% reduction in GHG emissions from 1990 levels by 2020.

Arrow has committed to the ongoing measurement and monitoring of the Project's emissions and energy consumption and production through schemes which include:

- National Greenhouse Emissions Reporting System; and
- Energy Efficiency Opportunities.

The proponent will continue to investigate GHG abatement measures for on-going monitoring and maintenance program at the site-level, reducing fugitive emissions from equipment leaks and high level investigations into new technologies as they become available.

As electricity consumption is an important contributor to life cycle emissions, it is recommended that electrical equipment, e.g. engines, turbines, pumps and compressors are regularly monitored and maintained as part of a comprehensive energy efficiency improvement program for the Project. These measures will be consistent with the EEO Program activities.

The proponent considers climate change adaptation in planning and design, construction, operation and decommissioning phases of the Project. This includes developing preventative and responsive measures for extreme climatic events and designing and constructing production facilities in accordance with current Australian standards to withstand extreme occurrences of these events. Arrow is committed to taking a cooperative approach with government, industry and other sectors to address adaptation to climate change.

It is considered that the mitigation measures applied for the EIS are still appropriate to address identified impacts.

10 REFERENCES

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11 LIMITATIONS

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APPENDIX A GENERIC ASSESSMENT PARAMETERS, GREENHOUSE GAS EMISSION ESTIMATION METHODOLOGY AND RESULTS

The greenhouse gas emissions estimates presented in this Appendix were calculated for the Temporary power generation scenario. The emissions factors for methane and nitrous oxide used in calculations are based on the updated GWP values, which were published in the IPCC in the Physical Science Basis (Cambridge, UK: Cambridge University Press, 2007). The NGER (Measurement) Amendment Determination 2013 (Explanatory Statement) outlines the intention to adopt these values from 2017 onwards.

A.1 Scope 1 Emissions – Construction, Operation and Decommissioning

A.1.1 Fuel Combustion – Gas Fired Power Generation

Grid power supply based on connection to existing electricity infrastructure is the preferred SREIS power supply option. However, temporary power generation using CSG at the Project production facilities (CGPFs and FCFs) will be retained as a power supply option for the first two production years (2018 and 2019) of Project life. No local power generation using gas fired engines will be required at wellheads during this period. The temporary power installed at the CGPFs and FCF's over the first two years will provide power for the wells through an overhead and if required underground distribution network.

Grid power supply based on connection to existing electricity infrastructure will be provided from the third production year (2020) onwards. In specific cases, power for the remote wellheads (10% of total number of wells) will be generated locally by gas fired engines.

To determine the GHG emissions for CO_2, CH_4 and N_2O the following equation was used following the guidelines outlined in Method 1 of the Technical Guidelines (Division 2.3.2, Australian Government, 2013d).

$$\mathrm{Ej} = \frac{\mathrm{Q} \times \mathrm{EF}}{1000}$$

$\mathrm{Ej} = \text{Estimated emission of gas type (j)from gas combustion (tonnes (t) } \mathrm{CO_2}\text{-e per year)}$

$\mathrm{Q} = \text{Quantity of CSG combusted in the year (GJ/year)}$

$\mathrm{EF} = \text{Emission factor for each gas type (j) (kg } \mathrm{CO_2}\text{-e/t GJ)}$

Emission factors for gas combustion in stationary sources were sourced from Table 2.3.2A of the Technical Guidelines (Australian Government, 2013d) and are listed in Table A.1-1. Data from Table A.1-2 were used to calculate the estimated quantity of gas combusted in the year based on conservative estimate of fuel usage (11.43 GJ/MW-h) provided by Arrow. Estimated fuel (CSG) combustion for power generation is presented in Table A.1-3. The resulting GHG emissions produced from gas combusted in stationary sources are listed in Table A.1-4.

Table A.1-1 Emission Factors Associated with Gas Combusted in Stationary Engines

Method Used	Constant	Current Value	Updated Value	Units
Method 1	Scope 1 CO_2 emission factor	51.10		
Method 1	Scope 1 CH_4 emission factor	0.20[a]	0.24[d]	t CO_2-e/GJ
Method 1	Scope 1 N_2O emission factor	0.03[b]	0.03[e]	
Method 1	Scope 1 overall emission factor	51.33[c]	51.37[f]	

a. Based on current AR2 GWP values for CH_4 (21).

b. Based on current AR2 GWP values for N_2O (310).

c. Based on current AR2 GWP values for CH_4 (21) and N_2O (310).

d. Based on updated AR4 GWP values for CH_4 (25). This emission factor was used in calculations of Project emissions.

e. Based on updated AR4 GWP values for N_2O (298). This emission factor was used in calculations of Project emissions.

f. Based on updated AR4 GWP values for CH_4 (25) and N_2O (298). This emission factor was used in calculations of Project emissions.

Table A.1-2 Activity Data Associated with Gas Combusted in Stationary Power Generation

Facility	Onstream date 1st Jan	Facility installed capacity (TJ/d)	Total power demand (MW)	No. of 5 MW units
CGPF1/ WTF1 (co-located with CGPF1)	2018	450	44	9
CGPF2/ WTF 2 (co-located with CGPF2)	2018	360	36	8
FCF01	2018	120	30	6
FCF02	2018	120	30	5
FCF04	2018	60	15	3
FCF08	2018	60	15	3
FCF12	2019	40	10	2
FCF19	2019	60	15	3
FCF20	2019	80	20	4
FCF22	2019	60	15	3
FCF27	2018	60	15	3
FCF28	2019	60	15	3
FCF29	2019	60	15	3
FCF31	2019	80	20	4
FCF36	2019	100	25	5
FCF38	2018	40	10	2
FCF39	2018	60	15	3

Facility	Onstream date 1st Jan	Facility installed capacity (TJ/d)	Total power demand (MW)	No. of 5 MW units
FCF40	2018	40	10	2
Total		**355**	**344**	

Table A.1-3 Estimated Fuel (CSG) Combustion for Power Generation

Year	Cumulative power demand (MW)			Total power demand (MW)	Total power demand per year (MWh/year)	Fuel (CSG) combustion (GJ/year)
	FCF	CGPF	Wells			
2017	0	0	0	0	0	0
2018*	140	80	4	224	1,960,313	22,406,375
2019*	275	80	19	374	3,273,437	37,415,383
2020	0	0	2	2	21,620	247,113
2021	0	0	3	3	26,140	298,778
2022	0	0	4	4	31,291	357,653
2023	0	0	4	4	37,388	427,341
2024	0	0	5	5	41,417	473,400
2025	0	0	5	5	44,974	514,051
2026	0	0	6	6	48,548	554,903
2027	0	0	6	6	50,948	582,337
2028	0	0	6	6	53,594	612,576
2029	0	0	7	7	58,762	671,651
2030	0	0	7	7	59,796	683,466
2031	0	0	7	7	60,304	689,273
2032	0	0	7	7	60,724	694,079
2033	0	0	7	7	60,129	687,270
2034	0	0	7	7	59,445	679,460
2035	0	0	7	7	59,971	685,468
2036	0	0	7	7	60,111	687,070
2037	0	0	7	7	60,321	689,473
2038	0	0	7	7	60,532	691,876
2039	0	0	7	7	57,518	657,433

Year	Cumulative power demand (MW)			Total power demand (MW)	Total power demand per year (MWh/year)	Fuel (CSG) combustion (GJ/year)
	FCF	CGPF	Wells			
2040	0	0	6	6	56,169	642,013
2041	0	0	6	6	53,226	608,370
2042	0	0	5	5	47,006	537,280
2043	0	0	5	5	44,203	505,240
2044	0	0	5	5	42,066	480,809
2045	0	0	5	5	42,066	480,809
2046	0	0	5	5	40,173	459,182
2047	0	0	5	5	40,173	459,182
2048	0	0	5	5	40,051	457,780
2049	0	0	4	4	37,563	429,344
2050	0	0	4	4	33,498	382,885
2051	0	0	3	3	28,207	322,408
2052	0	0	3	3	23,862	272,745
2053	0	0	2	2	15,435	176,423
2054	0	0	1	1	8,760	100,127
2055	0	0	1	1	6,658	76,096
2056	0	0	0	0	0	0
2057	0	0	0	0	0	0
2058	0	0	0	0	0	0
Total	415	160	203	777	6,806,397	77,797,122

*Note: Power demand and hence calculated emissions for the possible alternative temporary power generation scenario in 2018 and 2019 are based on a full capacity power demand for each facility, and hence are deemed to be highly conservative. Through detailed design the installed capacity of any required temporary power generation will be optimised.

Table A.1-4 GHG Emissions Associated with Gas Combusted in Stationary Engines for Construction, Operation and Decommissioning Power

Year	Emissions (t CO_2-e/year)			
	CO_2	CH_4	N_2O	Total
2017	0	0	0	0
2018*	1,144,966	5,335	646	1,150,947
2019*	1,911,926	8,908	1,079	1,921,913
2020	12,627	59	7	12,693

Year	Emissions (t CO_2-e/year)			
	CO_2	CH_4	N_2O	Total
2021	15,268	71	9	15,347
2022	18,276	85	10	18,372
2023	21,837	102	12	21,951
2024	24,191	113	14	24,317
2025	26,268	122	15	26,405
2026	28,356	132	16	28,504
2027	29,757	139	17	29,913
2028	31,303	146	18	31,466
2029	34,321	160	19	34,501
2030	34,925	163	20	35,108
2031	35,222	164	20	35,406
2032	35,467	165	20	35,653
2033	35,120	164	20	35,303
2034	34,720	162	20	34,902
2035	35,027	163	20	35,210
2036	35,109	164	20	35,293
2037	35,232	164	20	35,416
2038	35,355	165	20	35,540
2039	33,595	157	19	33,770
2040	32,807	153	19	32,978
2041	31,088	145	18	31,250
2042	27,455	128	15	27,598
2043	25,818	120	15	25,953
2044	24,569	114	14	24,698
2045	24,569	114	14	24,698
2046	23,464	109	13	23,587
2047	23,464	109	13	23,587
2048	23,393	109	13	23,515
2049	21,939	102	12	22,054
2050	19,565	91	11	19,668

Year	Emissions (t CO_2-e/year)			
	CO_2	CH_4	N_2O	Total
2051	16,475	77	9	16,561
2052	13,937	65	8	14,010
2053	9,015	42	5	9,062
2054	5,116	24	3	5,143
2055	3,889	18	2	3,909
2056	0	0	0	0
2057	0	0	0	0
2058	0	0	0	0
Total	**3,975,433**	**18,523**	**2,244**	**3,996,200**

*Note: Power demand and hence calculated emissions for the possible alternative temporary power generation scenario in 2018 and 2019 are based on a full capacity power demand for each facility, and hence are deemed to be highly conservative. Through detailed design the installed capacity of any required temporary power generation will be optimised.

A.1.2 Fuel Combustion – Diesel used in Vehicles for Transport and Construction Energy

Due to the large distances expected to be travelled by the workforce for the construction, operation and decommissioning of the vertical production wells, processing plants and other infrastructure, a significant quantity of diesel will be used by passenger vehicles for transport (light vehicles). Diesel will also be consumed in industrial vehicles (heavy vehicles).

Assumptions on traffic and the specific types of vehicles selected for this Project are based on the Road Impact Assessment (Appendix K) of the SREIS. Light vehicles were classified as sedans, wagons, vans, utilities, and 4WDs, while any other types of vehicles were considered as heavy vehicles. Emissions were estimated using Method 1 of the Technical Guidelines (Division 2.4.2, Australian Government, 2013d). The following equation was used to calculate GHG emissions associated with fuel combustion in diesel engines.

$$\mathrm{Ej} = \frac{\mathrm{Q} \times \mathrm{Ec} \times \mathrm{EFjoxec}}{1000}$$

$\mathrm{Ej} = \text{Estimated emission of gas type (j) from diesel combustion}\ \ (\text{t } \mathrm{CO_2}\text{-e/year})$

$\mathrm{Q} = \text{Estimated quatity of diesel combusted in light or heavy vechicles}\ \ (\text{kilolitres (kL)/year})$

$\mathrm{EC} = \text{Emission factor for diesel (GJ/kL)}$

$\mathrm{Efjoxec} = \text{Emission Factor for each gas type}\ \ (\text{kg } \mathrm{CO_2}\text{-e/GJ})$

The default energy content factor for diesel and the default emission factor for each greenhouse gas were sourced from Table 2.4.2B, of the Technical Guidelines (Australian Government, 2013d) and are listed in Table A.1-5. Activity data associated with diesel combustion are presented in Table A.1-6 and parameters associated with diesel combustion are shown in Table A.1-7. GHG emissions are shown in Table A.1-8.

Table A.1-5 Activity Data Associated with Diesel Combustion in Vehicles

Method Used	Constant	Current Value	Updated Value	Units
-	Default energy content factor	38.6		GJ/kL
Method 1	Scope 1 CO_2 emission factor	69.20		kg CO_2-e/GJ
Method 1	Scope 1 CH_4 emission factor	0.20[a]	0.24[d]	
Method 1	Scope 1 N_2O emission factor	0.50[b]	0.47[e]	
Method 1	Scope 1 overall emission factor	69.90[c]	69.91[f]	

a. Based on current AR2 GWP values for CH_4 (21).

b. Based on current AR2 GWP values for N_2O (310).

c. Based on current AR2 GWP values for CH_4 (21) and N_2O (310).

d. Based on updated AR4 GWP values for CH_4 (25). This emission factor was used in calculations of Project emissions.

e. Based on updated AR4 GWP values for N_2O (298). This emission factor was used in calculations of Project emissions.

f. Based on updated AR4 GWP values for CH_4 (25) and N_2O (298). This emission factor was used in calculations of Project emissions.

The following equation was used to estimate quantity of diesel consumed in light and heavy vehicles in the year, Q, (kL/year), based on activity data presented in Table A.1-6 and diesel consumption rates presented in Table A.1-7:

$$Q = \frac{D \times Rc}{1000}$$

$Q = \text{Quantity of diesel consumed in light and heavy vehicles in the year (kL/year)}$

$D = \text{Total kilometres travelled in the year (kilometres (km) /year)}$

$Rc = \text{Average rate of diesel consumption of light or heavy vehicles (litres (L)/km)}$

Table A.1-6 Activity Data Associated with Diesel Combusted in Light (LV) and Heavy Vehicles (HV)

Year	Total km travelled (HV)	Total km travelled (LV)	Total Fuel Consumption (kL)
2017	1,934,714	3,066	1,082
2018	1,855,778	594,341	1,110
2019	7,925,335	653,946	4,511
2020	17,983,001	899,054	10,163
2021	7,592,158	758,869	4,337
2022	7,904,615	733,321	4,509
2023	9,044,946	730,238	5,146
2024	10,741,312	803,053	6,103
2025	7,920,367	740,268	4,519
2026	8,360,255	861,692	4,779
2027	7,560,543	982,796	4,347

Year	Total km travelled (HV)	Total km travelled (LV)	Total Fuel Consumption (kL)
2028	7,231,926	729,435	4,132
2029	7,071,949	785,902	4,050
2030	10,571,434	896,526	6,020
2031	8,123,570	920,509	4,654
2032	6,796,156	922,838	3,913
2033	7,491,696	967,806	4,307
2034	5,660,265	867,381	3,271
2035	5,514,559	861,867	3,189
2036	5,001,620	836,016	2,899
2037	4,238,776	748,057	2,461
2038	4,005,752	721,461	2,328
2039	4,008,198	720,256	2,329
2040	3,817,761	710,469	2,222
2041	4,314,375	824,446	2,513
2042	4,294,164	747,746	2,492
2043	4,138,808	865,715	2,420
2044	4,532,009	931,156	2,648
2045	4,339,928	787,701	2,523
2046	3,567,996	681,533	2,078
2047	7,241,563	645,788	4,127
2048	7,230,694	684,022	4,126
2049	7,164,723	650,292	4,085
2050	6,769,377	633,419	3,862
2051	7,405,425	721,205	4,228
2052	7,953,582	744,657	4,538
2053	8,095,657	764,144	4,619
2054	8,329,051	666,736	4,738
2055	7,153,421	789,871	4,096
2056	8,431,989	1,321,135	4,876
2057	1,803,033	1,402,828	1,180
2058	3,057,457	374,012	1,755
Total	**274,179,938**	**32,685,573**	**157,287**

Table A.1-7 Parameters Associated with Diesel Combusted in Vehicles Estimation

Data Required	Value*	Units
Average rate of diesel consumption of passenger vehicles (light vehicles)[a]	0.123	L/km
Average rate of diesel consumption of passenger vehicles (heavy vehicles)[b]	0.559	L/km

a. Australian Bureau of Statistics (2008). The rate of fuel consumption for passenger vehicles was selected to represent the light vehicles.

b. Australian Bureau of Statistics (2008). As a conservative assumption, the rate of fuel consumption for articulated trucks was used to represent the heavy vehicles (i.e., higher fuel consumption per kilometre).

Table A.1-8 GHG Emissions Associated with Diesel Combusted in Light and Heavy Vehicles

Year	CO_2 (t CO_2-e/year)	CH_4 (t CO_2-e/year)	N_2O (t CO_2-e/year)	Total (t CO_2-e/year)
2017	2,890	10	20	2,920
2018	2,966	10	21	2,997
2019	12,049	41	84	12,174
2020	27,147	93	189	27,429
2021	11,586	40	80	11,706
2022	12,044	41	84	12,169
2023	13,745	47	95	13,888
2024	16,302	56	113	16,472
2025	12,070	42	84	12,195
2026	12,766	44	89	12,899
2027	11,612	40	81	11,733
2028	11,038	38	77	11,153
2029	10,818	37	75	10,930
2030	16,079	55	112	16,246
2031	12,432	43	86	12,561
2032	10,451	36	73	10,559
2033	11,504	40	80	11,624
2034	8,737	30	61	8,827
2035	8,517	29	59	8,606
2036	7,743	27	54	7,823
2037	6,575	23	46	6,643
2038	6,218	21	43	6,283
2039	6,222	21	43	6,286
2040	5,934	20	41	5,996

Year	CO_2 (t CO_2-e/year)	CH_4 (t CO_2-e/year)	N_2O (t CO_2-e/year)	Total (t CO_2-e/year)
2041	6,713	23	47	6,783
2042	6,658	23	46	6,727
2043	6,464	22	45	6,531
2044	7,073	24	49	7,146
2045	6,739	23	47	6,809
2046	5,551	19	39	5,609
2047	11,025	38	77	11,139
2048	11,021	38	77	11,136
2049	10,912	38	76	11,025
2050	10,316	35	72	10,423
2051	11,294	39	78	11,412
2052	12,121	42	84	12,246
2053	12,339	42	86	12,467
2054	12,656	44	88	12,787
2055	10,941	38	76	11,054
2056	13,024	45	90	13,160
2057	3,153	11	22	3,186
2058	4,688	16	33	4,737
Total	**420,132**	**1,446**	**2,918**	**424,496**

A.1.3 Fuel Combustion – Diesel used in drilling activities

Diesel is combusted in drilling rigs during well construction. Emissions of CO_2, CH_4 and N_2O were estimated using Method 1 (Division 2.4.2, *Method 1- emissions of carbon dioxide, methane and nitrous oxide from liquid fuels other than petroleum based oils or greases* of the *Technical Guidelines* (Australian Government, 2013d)).

The default energy content factor for diesel and the default emission factor for each gas were sourced from Table 2.4.2B of the *Technical Guidelines* and are listed in Table A.1-9. The activity data associated with diesel combusted in drill rigs are presented in Table A.1-10 and the resulting greenhouse gas emission estimates are presented in Table A.11.

Table A.1-9 GHG Emissions Factors Associated with Diesel Combusted for Drilling

Method Used	Constant	Current Value	Updated Value	Units
-	Default energy content factor	38.60		GJ/kL
Method 1	Scope 1 CO_2 emission factor	69.20		kg CO_2-e/GJ
Method 1	Scope 1 CH_4 emission factor	0.10[a]	0.12[d]	
Method 1	Scope 1 N_2O emission factor	0.20[b]	0.19[e]	
Method 1	Scope 1 overall emission factor	69.50[c]	69.51[f]	

a. Based on current AR2 GWP values for CH_4 (21).

b. Based on current AR2 GWP values for N_2O (310).

c. Based on current AR2 GWP values for CH_4 (21) and N_2O (310).

d. Based on updated AR4 GWP values for CH_4 (25). This emission factor was used in calculations of Project emissions.

e. Based on updated AR4 GWP values for N_2O (298). This emission factor was used in calculations of Project emissions.

f. Based on updated AR4 GWP values for CH_4 (25) and N_2O (298). This emission factor was used in calculations of Project emissions.

Table A.1-10 Diesel Consumption Associated with Drilling

Year	Total wells commissioned in year	Total diesel consumption (kL)[a]
2017	0	0
2018	189	3,402
2019	745	13,410
2020	300	5,400
2021	258	4,644
2022	294	5,292
2023	348	6,264
2024	230	4,140
2025	271	4,878
2026	239	4,302
2027	139	2,502
2028	161	2,898
2029	295	5,310
2030	159	2,862
2031	110	1,980
2032	142	2,556
2033	62	1,116
2034	59	1,062

Year	Total wells commissioned in year	Total diesel consumption (kL)[a]
2035	30	540
2036	8	144
2037	12	216
2038	12	216
2039	2	36
2040	8	144
2041	5	90
2042	0	0
2043	0	0
2044	0	0
2045	0	0
2046	0	0
2047	0	0
2048	0	0
2049	0	0
2050	0	0
2051	0	0
2052	0	0
2053	0	0
2054	0	0
2055	0	0
2056	0	0
2057	0	0
2058	0	0
Total	**4,078**	**73,404**

a. Average quantity of diesel consumed per well drilled (18 kL/well) was adopted from the Surat Project SREIS assessment (Arrow, 2013).

Table A.11 Greenhouse Gas Emissions Associated with Drilling

Year	Scope 1 emissions (t CO_2-e/year)			
	CO_2	CH_4	N_2O	Total
2017	0	0	0	0
2018	9,087	16	25	9,128

Year	Scope 1 emissions (t CO_2-e/year)			
	CO_2	CH_4	N_2O	Total
2019	35,820	62	100	35,981
2020	14,424	25	40	14,489
2021	12,405	21	34	12,460
2022	14,136	24	39	14,199
2023	16,732	29	46	16,807
2024	11,058	19	31	11,108
2025	13,030	22	36	13,088
2026	11,491	20	32	11,543
2027	6,683	11	19	6,713
2028	7,741	13	22	7,776
2029	14,184	24	39	14,247
2030	7,645	13	21	7,679
2031	5,289	9	15	5,313
2032	6,827	12	19	6,858
2033	2,981	5	8	2,994
2034	2,837	5	8	2,849
2035	1,442	2	4	1,449
2036	385	1	1	386
2037	577	1	2	580
2038	577	1	2	580
2039	96	0	0	97
2040	385	1	1	386
2041	240	0	1	241
2042	0	0	0	0
2043	0	0	0	0
2044	0	0	0	0
2045	0	0	0	0
2046	0	0	0	0
2047	0	0	0	0
2048	0	0	0	0
2049	0	0	0	0

Year	Scope 1 emissions (t CO_2-e/year)			
	CO_2	CH_4	N_2O	Total
2050	0	0	0	0
2051	0	0	0	0
2052	0	0	0	0
2053	0	0	0	0
2054	0	0	0	0
2055	0	0	0	0
2056	0	0	0	0
2057	0	0	0	0
2058	0	0	0	0
Total	**196,071**	**337**	**545**	**196,953**

A.2 Scope 1 Emissions – Construction

A.2.1 Fugitive Emissions – Flaring

Flaring during Well Completions and Workovers

Gas released during the course of regular well completion and well intervention (workovers) operations is disposed of at the well site via a lit flare. Individual well characteristics and the type and duration of well intervention activities will significantly impact the duration and intensity of any gas flared. An average well intervention is anticipated to take up to two days, with total average flaring per well intervention expected to be in the order of 400 m^3. Emissions from flaring during well completions and workovers were estimated based on Method 1 (Part 3.3, division 3.3.2) of the Technical Guidelines (Australian Government, 2013d); the emissions factors are presented in Table A.2-1.

Table A.2-1 Emission Factors Associated with Well Completions and Workovers Flaring

Method Used	Constant	Current Value	Updated Value	Units
Method 1	Scope 1 CO_2 emission factor	2.80		t CO_2-e/t gas flared
Method 1	Scope 1 CH_4 emission factor	0.70[a]	0.83[d]	
Method 1	Scope 1 N_2O emission factor	0.03[b]	0.03[e]	
Method 1	Scope 1 overall CO_2 emission factor	3.53[c]	3.66[f]	

a. Based on current AR2 GWP values for CH_4 (21).

b. Based on current AR2 GWP values for N_2O (310).

c. Based on current AR2 GWP values for CH_4 (21) and N_2O (310).

d. Based on updated AR4 GWP values for CH_4 (25). This emission factor was used in calculations of Project emissions.

e. Based on updated AR4 GWP values for N_2O (298). This emission factor was used in calculations of Project emissions.

f. Based on updated AR4 GWP values for CH_4 (25) and N_2O (298). This emission factor was used in calculations of Project emissions.

The following equation was used to determine quantity of gas flared.

$$Q = \frac{Qe \times Pcsg}{1000}$$

$Q = \text{Quantity of gas flared}$ (t/year)

$Qe = \text{Quantityof gas flared in the year}$ (m^3/year)

$Pcsg = \text{Gas density}$ (kg CSG/Sm^3)

Table A.2-2 Parameters Associated with the Estimation of the Quantity of Gas Flared

Data Required	Value	Units
CSG density at standard conditions [a]	0.726	kg/Sm^3

a Advised by Arrow based on the Greenhouse Gas Assessment for the Surat Basin (Coffey Environments, 2011)

Table A.2-3 Activity Data Associated with Well Completions and Workovers Flaring

Year	Number of Commissioned wells	Gas flared during completions (m^3)	Number of Workover wells	Gas flared during workovers (m^3)	Total gas flared (m^3)	Total gas flared (t)
2017	0	0	0	0	0	0
2018	189	75,600	0	0	75,600	55
2019	745	298,000	0	0	298,000	216
2020	300	120,000	189	75,600	195,600	142
2021	258	103,200	745	298,000	401,200	291
2022	294	117,600	300	120,000	237,600	172
2023	348	139,200	447	178,800	318,000	231
2024	230	92,000	1,039	415,600	507,600	369
2025	271	108,400	648	259,200	367,600	267
2026	239	95,600	574	229,600	325,200	236
2027	139	55,600	1,310	524,000	579,600	421
2028	161	64,400	887	354,800	419,200	304
2029	295	118,000	701	280,400	398,400	289
2030	159	63,600	1,445	578,000	641,600	466
2031	110	44,000	1,182	472,800	516,800	375
2032	142	56,800	786	314,400	371,200	269
2033	62	24,800	1,260	504,000	528,800	384
2034	59	23,600	1,324	529,600	553,200	402
2035	30	12,000	848	339,200	351,200	255
2036	8	3,200	1,221	488,400	491,600	357
2037	12	4,800	1,354	541,600	546,400	397
2038	12	4,800	856	342,400	347,200	252
2039	2	800	1,059	423,600	424,400	308
2040	8	3,200	1,366	546,400	549,600	399
2041	5	2,000	858	343,200	345,200	251
2042	0	0	915	366,000	366,000	266
2043	0	0	1,071	428,400	428,400	311
2044	0	0	600	240,000	240,000	174
2045	0	0	730	292,000	292,000	212

Year	Number of Commissioned wells	Gas flared during completions (m^3)	Number of Workover wells	Gas flared during workovers (m^3)	Total gas flared (m^3)	Total gas flared (t)
2046	0	0	1,071	428,400	428,400	311
2047	0	0	600	240,000	240,000	174
2048	0	0	621	248,400	248,400	180
2049	0	0	923	369,200	369,200	268
2050	0	0	568	227,200	227,200	165
2051	0	0	517	206,800	206,800	150
2052	0	0	642	256,800	256,800	186
2053	0	0	231	92,400	92,400	67
2054	0	0	189	75,600	75,600	55
2055	0	0	189	75,600	75,600	55
2056	0	0	72	28,800	28,800	21
2057	0	0	43	17,200	17,200	12
2058	0	0	0	0	0	0
Total	**4,078**	**1,631,200**		**11,752,400**	**13,383,600**	**9,716**

Presented in Table A.2-4 are the GHG emissions associated with well completions and workovers flaring.

Table A.2-4 Greenhouse Gas Emissions Associated with Well Completions and Workovers Flaring

Year	Emissions (t CO_2-e/year)			
	CO_2	CH_4	N_2O	Total
2017	0	0	0	0
2018	154	46	2	201
2019	606	180	6	792
2020	398	118	4	520
2021	816	243	8	1,067
2022	483	144	5	632
2023	646	192	7	845
2024	1,032	307	11	1,350
2025	747	222	8	977
2026	661	197	7	865

Year	Emissions (t CO_2-e/year)			
	CO_2	CH_4	N_2O	Total
2027	1,178	351	12	1,541
2028	852	254	9	1,115
2029	810	241	8	1,059
2030	1,304	388	13	1,706
2031	1,051	313	11	1,374
2032	755	225	8	987
2033	1,075	320	11	1,406
2034	1,125	335	12	1,471
2035	714	212	7	934
2036	999	297	10	1,307
2037	1,111	331	11	1,453
2038	706	210	7	923
2039	863	257	9	1,128
2040	1,117	333	12	1,461
2041	702	209	7	918
2042	744	221	8	973
2043	871	259	9	1,139
2044	488	145	5	638
2045	594	177	6	776
2046	871	259	9	1,139
2047	488	145	5	638
2048	505	150	5	660
2049	751	223	8	982
2050	462	137	5	604
2051	420	125	4	550
2052	522	155	5	683
2053	188	56	2	246
2054	154	46	2	201
2055	154	46	2	201
2056	59	17	1	77
2057	35	10	0	46

Year	Emissions (t CO_2-e/year)			
	CO_2	CH_4	N_2O	Total
2058	0	0	0	0
Total	**27,206**	**8,097**	**280**	**35,583**

A.2.2 Vegetation Clearing

The common method used to determine GHG emissions associated with land clearing is the FullCAM model from the National Carbon Accounting Toolbox. However, because the areas to be cleared were unknown, the FullCAM model could not be used. Instead assumptions have been used based on the various technical reports from the former Australian Greenhouse Office (AGO, 1999, 2000, 2002 and 2003). These assumptions have been used to predict land clearing emission generated from the Project. Table A.2-5 provides the emission factor used to calculate greenhouse gas emissions from land clearing.

Table A.2-5 Emission factor Associated with Vegetation Clearance

Constant	Value	Units
Default Emission factor for vegetation clearance [a]	3.67	t CO_2 / t carbon

a. AGO (1999, 2000, 2002 and 2003)

Presented in Table A.2-6 are activity data associated with vegetation clearing.

Table A.2-6 Activity Data Associated with Vegetation Clearing

Item	Length (m)	Width (m)	Area (m^2)	Area (km^2)	Area (ha)
CGPF					
CGPF (including WTF)	500	250	125,000	0.13	13
Dams at CGPF	775	775	600,000	0.60	60
Temp. power generation (CGPF)	150	80	12,000	0.01	1
Main substation (CGPF)	200	150	30,000	0.03	3
FCF					
FCF(including WTS)	200	380	76,000	0.08	8
Temp. power generation (FCF)	150	80	12,000	0.01	1
Medium pressure Pipelines per FCFs	25,000	10	250,000	0.25	25
Overhead lines per each of the selected strategic FCFs (2)	30,000	6	180,000	0.18	18
FCF substation	150	100	15,000	0.02	2
Wells					
4 wells pad	130	175	22,750	0.02	2

Item	Length (m)	Width (m)	Area (m^2)	Area (km^2)	Area (ha)
8 wells pad	130	235	30,550	0.03	3
12 wells pad	130	295	38,350	0.04	4
Gathering pipeline per well pad	8,000	10	80,000	0.08	8
Overhead lines per each of the selected well pads	5,760	6	34,560	0.03	3
Low pressure pipelines per well	2,200	10	22,000	0.02	2
Other facilities					
Other facilities (including weather stations, workshops, warehouses, offices, etc.)	1,732	1,732	3,000,000	3.00	300

Based on the '*Synthesis of Allometrics, review of Root Biomass and Design of Future Woody Biomass sampling Strategies*' (AGO, 2000), an open forest system was adopted for the Project site. This provided a biomass density of 90 tonnes per hectare (t/ha). Fifty per cent of the biomass in the area has been assumed as carbon based (AGO, 2000). Therefore, an emission factor of 45 t CO_2-e per hectare per year was assumed. The estimated greenhouse gases over the life of the Project associated with land clearing are presented in Table A.2-7.

Table A.2-7 Estimated Greenhouse Gas Emissions Associated with Vegetation Clearing

Year	GHG emissions (t CO_2-e) for well pads, pipelines, overhead lines, other facilities	GHG emissions (t CO_2-e) for CGPFs, WTFs, dams, main substations	GHG emissions (t CO_2-e) for FCFs, WTFs, pipelines, overhead lines, substations	Total (t CO_2-e/year)
2017	24,773	25,334	44,657	94,763
2018	238,641	0	52,584	291,225
2019	843,026	0	0	843,026
2020	339,473	0	0	339,473
2021	291,947	0	5,384	297,331
2022	332,684	0	16,152	348,836
2023	393,789	0	10,768	404,557
2024	260,263	0	10,768	271,031
2025	306,658	0	16,152	322,809
2026	270,447	0	5,384	275,831
2027	157,289	0	5,384	162,673
2028	182,184	0	10,768	192,952
2029	333,816	0	5,384	339,199
2030	179,921	0	5,384	185,305

Year	GHG emissions ($t\ CO_2$-e) for well pads, pipelines, overhead lines, other facilities	GHG emissions ($t\ CO_2$-e) for CGPFs, WTFs, dams, main substations	GHG emissions ($t\ CO_2$-e) for FCFs, WTFs, pipelines, overhead lines, substations	Total ($t\ CO_2$-e/year)
2031	124,474	0	0	124,474
2032	160,684	0	0	160,684
2033	70,158	0	0	70,158
2034	66,763	0	0	66,763
2035	33,947	0	0	33,947
2036	9,053	0	0	9,053
2037	13,579	0	0	13,579
2038	13,579	0	0	13,579
2039	2,263	0	0	2,263
2040	9,053	0	0	9,053
2041	5,658	0	0	5,658
2042	0	0	0	0
2043	0	0	0	0
2044	0	0	0	0
2045	0	0	0	0
2046	0	0	0	0
2047	0	0	0	0
2048	0	0	0	0
2049	0	0	0	0
2050	0	0	0	0
2051	0	0	0	0
2052	0	0	0	0
2053	0	0	0	0
2054	0	0	0	0
2055	0	0	0	0
2056	0	0	0	0
2057	0	0	0	0
2058	0	0	0	0
Total	**4,664,120**	**25,334**	**188,766**	**4,878,221**

A.3 Scope 1 Emission – Operation

A.3.1 Fugitive Emissions – Process Flaring

Fugitive Emissions – Pilot Flaring

Flaring will not be used for disposal of process gas within the facilities; however, under normal operating conditions the flares require a pilot flame that will be continuously lit to ensure their readiness state should there be an event due to upset conditions. Pilot flaring is only to occur at FCFs and CGPFs, with the same rate of 0.02 TJ/d/facility and duration of 365 days per year as in the EIS.

The following equation was used to calculate emissions from flaring.

$$\mathrm{Ej} = \mathrm{Q} \times \mathrm{Efj}$$

$\mathrm{Ej} = \text{Emissions of gas type (j)from CSG flared in the year } (\mathrm{t\ CO_2\text{-}e/year})$

$\mathrm{Q} = \text{Quantity of CSG flared in the year } (\mathrm{t\ CSG\ flared/year})$

$\mathrm{Efj} = \text{Scope 1 emission factor for gas type } (\mathrm{t\ CO_2\text{-}e/\ t\ CSG\ flared})$

In order to determine the quantity of gas flared from each facility, the energy content and activity data provided in Table A.3-1 and Table A.3-3 were used. The data were sourced from Arrow and the Technical Guidelines (Australian Government, 2013d, section 3.44 for exploration flaring and section 3.58 for production flaring). Flaring will occur during start up and operational phases of the Project. Therefore, the following equation was used to calculate emissions from the time period 2017-2054.

$$\mathrm{Q} = \frac{\mathrm{R} \times \mathrm{Nf} \times \mathrm{D} \times \mathrm{PCSG}}{\mathrm{Ecss}}$$

$\mathbf{Q = Quantity\ of\ gas\ flared\ in\ the\ year}\ (\mathrm{t\ CSG\ flared/year})$

$\mathrm{R} = \text{Flare light rate } (\mathrm{TJ/day/facility})$

$\mathrm{Nf} = \text{Number of processing or gas field facilities on line (facilities)}$

$\mathrm{D} = \text{Duration of pilot flaring (days/year)}$

$\mathrm{PCSG} = \text{Site specific CSG demnsity at standard conditions } (\mathrm{kg\ CSG/Sm^3\ CSG})$

$\mathrm{Ecss} = \text{Site specific energy content factor of CSG } (\mathrm{GJ/Sm^3})$

Table A.3-1 Energy Content Factor and Emission Factors Associated with Pilot Flaring

Category	Method Used	Constant	Current Value	Updated Value	Units
Both		Site specific energy content factor [g]	0.03729		GJ/m^3
Exploration flaring	Method 1	Scope 1 CO_2 emission factor	2.80		t CO_2-e/t gas flared

Category	Method Used	Constant	Current Value	Updated Value	Units
		Scope 1 CH_4 emission factor	0.70[a]	0.83[d]	
		Scope 1 N_2O emission factor	0.03[b]	0.03[e]	
		Scope 1 overall emission factor	3.53[c]	3.66[f]	
Production or processing flaring	Method 1	Scope 1 CO_2 emission factor	2.70		t CO_2-e/t gas flared
		Scope 1 CH_4 emission factor	0.10[a]	0.12[d]	
		Scope 1 N_2O emission factor	0.03[b]	0.03[e]	
		Scope 1 overall emission factor	2.83[c]	2.85[f]	

a. Based on current AR2 GWP values for CH_4 (21).

b. Based on current AR2 GWP values for N_2O (310).

c. Based on current AR2 GWP values for CH_4 (21) and N_2O (310).

d. Based on updated AR4 GWP values for CH_4 (25). This emission factor was used in calculations of Project emissions.

e. Based on updated AR4 GWP values for N_2O (298). This emission factor was used in calculations of Project emissions.

f. Based on updated AR4 GWP values for CH_4 (25) and N_2O (298). This emission factor was used in calculations of Project emissions.

g. Advised by Arrow based on the Greenhouse Gas Assessment for the Surat Basin (Coffey Environments, 2011)

Table A.3-2 Activity Data Associated with Pilot Flaring

Data Required	Value	Units
Site-specific gas density at Standard conditions [a]	0.726	kg CSG/Sm^3 CSG
Flare pilot light rate per facility [a]	0.020	TJ/d/facility
Duration of pilot flaring [b]	365	days/year
Total energy flared per facility - pilot flaring [c]	7.300	TJ/year/facility

a. Advised by Arrow based on the Greenhouse Gas Assessment for the Surat Basin (Coffey Environments, 2011)

b. URS assumption; worst case scenario

c. URS calculation

Presented in A.3-3 are the greenhouse gas emissions associated with pilot flaring for the Project.

Table A.3-2 Activity Data Associated with Pilot Flaring

Year	Number of field compression facilities (FCF)	Total amount of gas flared at FCFs (TJ/year)	Total amount of gas flared at FCFs (t/year)	Number of processing facilities (CGPF)	Total amount of gas flared at CGPFs (TJ/year)	Total amount of gas flared at CGPFs (t/year)
2017	0	0	0	0	0	0
2018	8	58	1,137	2	15	284
2019	16	117	2,274	2	15	284
2020	16	117	2,274	2	15	284
2021	16	117	2,274	2	15	284
2022	17	124	2,416	2	15	284
2023	20	146	2,842	2	15	284
2024	22	161	3,127	2	15	284
2025	23	168	3,269	2	15	284
2026	26	190	3,695	2	15	284
2027	27	197	3,837	2	15	284
2028	28	204	3,979	2	15	284
2029	30	219	4,264	2	15	284
2030	30	219	4,264	2	15	284
2031	30	219	4,264	2	15	284
2032	29	212	4,122	2	15	284
2033	28	204	3,979	2	15	284
2034	27	197	3,837	2	15	284
2035	27	197	3,837	2	15	284
2036	27	197	3,837	2	15	284
2037	27	197	3,837	2	15	284
2038	27	197	3,837	2	15	284
2039	25	183	3,553	2	15	284
2040	24	175	3,411	2	15	284
2041	21	153	2,985	2	15	284
2042	17	124	2,416	2	15	284
2043	15	110	2,132	2	15	284
2044	14	102	1,990	2	15	284
2045	14	102	1,990	2	15	284

Year	Number of field compression facilities (FCF)	Total amount of gas flared at FCFs (TJ/year)	Total amount of gas flared at FCFs (t/year)	Number of processing facilities (CGPF)	Total amount of gas flared at CGPFs (TJ/year)	Total amount of gas flared at CGPFs (t/year)
2046	13	95	1,848	2	15	284
2047	13	95	1,848	2	15	284
2048	13	95	1,848	2	15	284
2049	12	88	1,705	2	15	284
2050	10	73	1,421	2	15	284
2051	8	58	1,137	2	15	284
2052	7	51	995	2	15	284
2053	6	44	853	2	15	284
2054	6	44	853	2	15	284
2055	6	44	853	2	15	284
2056	6	44	853	2	15	284
2057	6	44	853	2	15	284
2058	0	0	0	0	0	0
Total			**104,745**	**80**	**584**	**11,370**

Table A.3-3 Greenhouse Gas Emissions Associated with Pilot Flaring

Year	CO_2 (t CO_2-e/year)	CH_4 (t CO_2-e/year	N_2O (t CO_2-e/year)	Total CO_2-e (t CO_2-e/year)
2017	0	0	0	0
2018	3,951	981	41	4,973
2019	7,135	1,929	74	9,137
2020	7,135	1,929	74	9,137
2021	7,135	1,929	74	9,137
2022	7,533	2,047	78	9,658
2023	8,726	2,403	90	11,219
2024	9,522	2,639	98	12,260
2025	9,920	2,758	102	12,781
2026	11,114	3,113	115	14,342
2027	11,512	3,232	119	14,863
2028	11,910	3,350	123	15,383

Year	CO_2 (t CO_2-e/year)	CH_4 (t CO_2-e/year	N_2O (t CO_2-e/year)	Total CO_2-e (t CO_2-e/year)
2029	12,706	3,587	131	16,424
2030	12,706	3,587	131	16,424
2031	12,706	3,587	131	16,424
2032	12,308	3,468	127	15,903
2033	11,910	3,350	123	15,383
2034	11,512	3,232	119	14,863
2035	11,512	3,232	119	14,863
2036	11,512	3,232	119	14,863
2037	11,512	3,232	119	14,863
2038	11,512	3,232	119	14,863
2039	10,716	2,995	111	13,822
2040	10,318	2,876	107	13,301
2041	9,124	2,521	94	11,740
2042	7,533	2,047	78	9,658
2043	6,737	1,810	70	8,617
2044	6,339	1,692	66	8,096
2045	6,339	1,692	66	8,096
2046	5,941	1,574	61	7,576
2047	5,941	1,574	61	7,576
2048	5,941	1,574	61	7,576
2049	5,543	1,455	57	7,055
2050	4,747	1,218	49	6,014
2051	3,951	981	41	4,973
2052	3,553	863	37	4,453
2053	3,155	744	33	3,932
2054	3,155	744	33	3,932
2055	3,155	744	33	3,932
2056	3,155	744	33	3,932
2057	3,155	744	33	3,932
2058	0	0	0	0
Total	**323,986**	**88,641**	**3,349**	**415,976**

Fugitive Emissions – Flaring due to Maintenance / Upset Conditions

GHG emissions associated with upset flaring conditions were determined using Method 1 (Part 3.3.9, Division 3.85, Method 1 – gas flared from natural gas production and processing) sourced from the Technical Guidelines (Australian Government, 2013d). Note that according to regulations natural gas includes CSG. Both were

The following equation was used to calculate emissions from flaring.

$$\mathrm{Ej} = \mathrm{Q} \times \mathrm{Efj}$$

$\mathrm{Ej} = \text{Emissions of gas type (j) from CSG flared in the year (t CO}_2\text{-e/year)}$

$\mathrm{Q} = \text{Quantity of CSG flared in the year (t CSG flared/year)}$

$\mathrm{Efj} = \text{Scope 1 emission factor for gas type (t CO}_2\text{-e/ t CSG flared)}$

Flaring will occur during emergency and maintenance activities of the Project. The same conservative amount of gas (2,696 TJ/year) was assumed to be flared in each year of Project life.

Table A.3-4 Energy Content Factor and Emission Factors Associated with Flaring Due to Maintenance / Upset Conditions

Category	Method Used	Constant [a]	Current Value	Updated Value	Units
Production or processing flaring	Method 1	Scope 1 CO_2 emission factor	2.70		t CO_2-e/t gas flared
		Scope 1 CH_4 emission factor	0.10[a]	0.12[d]	
		Scope 1 N_2O emission factor	0.03[b]	0.03[e]	
		Scope 1 overall emission factor	2.83[c]	2.85[f]	

a. Based on current AR2 GWP values for CH_4 (21).

b. Based on current AR2 GWP values for N_2O (310).

c. Based on current AR2 GWP values for CH_4 (21) and N_2O (310).

d. Based on updated AR4 GWP values for CH_4 (25). This emission factor was used in calculations of Project emissions.

e. Based on updated AR4 GWP values for N_2O (298). This emission factor was used in calculations of Project emissions.

f. Based on updated AR4 GWP values for CH_4 (25) and N_2O (298). This emission factor was used in calculations of Project emissions.

Table A.3-5 Activity Data Associated with Flaring Due to Maintenance / Upset Conditions

Year	Total amount of gas flared per year (TJ/year)	Total amount of gas flared (t/year)
2017	0	0
2018	2,696	52,488
2019	2,696	52,488
2020	2,696	52,488

Year	Total amount of gas flared per year (TJ/year)	Total amount of gas flared (t/year)
2021	2,696	52,488
2022	2,696	52,488
2023	2,696	52,488
2024	2,696	52,488
2025	2,696	52,488
2026	2,696	52,488
2027	2,696	52,488
2028	2,696	52,488
2029	2,696	52,488
2030	2,696	52,488
2031	2,696	52,488
2032	2,696	52,488
2033	2,696	52,488
2034	2,696	52,488
2035	2,696	52,488
2036	2,696	52,488
2037	2,696	52,488
2038	2,696	52,488
2039	2,696	52,488
2040	2,696	52,488
2041	2,696	52,488
2042	2,696	52,488
2043	2,696	52,488
2044	2,696	52,488
2045	2,696	52,488
2046	2,696	52,488
2047	2,696	52,488
2048	2,696	52,488
2049	2,696	52,488
2050	2,696	52,488
2051	2,696	52,488
2052	2,696	52,488

Year	Total amount of gas flared per year (TJ/year)	Total amount of gas flared (t/year)
2053	2,696	52,488
2054	2,696	52,488
2055	2,696	52,488
2056	2,696	52,488
2057	2,696	52,488
2058	0	0
Total	**107,840**	**2,099,540**

Presented in Table A.3-6 are the GHG emissions associated with upset flaring conditions from the Project.

Table A.3-6 Greenhouse Gas Emissions Associated with Flaring Due to Upset Conditions

Year	CO_2 (t CO_2-e/year)	CH_4 (t CO_2-e/year)	N_2O (t CO_2-e/year)	Total CO_2-e (t CO_2-e/year)
2017	0	0	0	0
2018	141,719	6,249	1,514	149,481
2019	141,719	6,249	1,514	149,481
2020	141,719	6,249	1,514	149,481
2021	141,719	6,249	1,514	149,481
2022	141,719	6,249	1,514	149,481
2023	141,719	6,249	1,514	149,481
2024	141,719	6,249	1,514	149,481
2025	141,719	6,249	1,514	149,481
2026	141,719	6,249	1,514	149,481
2027	141,719	6,249	1,514	149,481
2028	141,719	6,249	1,514	149,481
2029	141,719	6,249	1,514	149,481
2030	141,719	6,249	1,514	149,481
2031	141,719	6,249	1,514	149,481
2032	141,719	6,249	1,514	149,481
2033	141,719	6,249	1,514	149,481
2034	141,719	6,249	1,514	149,481
2035	141,719	6,249	1,514	149,481
2036	141,719	6,249	1,514	149,481

Year	CO_2 (t CO_2-e/year)	CH_4 (t CO_2-e/year)	N_2O (t CO_2-e/year)	Total CO_2-e (t CO_2-e/year)
2037	141,719	6,249	1,514	149,481
2038	141,719	6,249	1,514	149,481
2039	141,719	6,249	1,514	149,481
2040	141,719	6,249	1,514	149,481
2041	141,719	6,249	1,514	149,481
2042	141,719	6,249	1,514	149,481
2043	141,719	6,249	1,514	149,481
2044	141,719	6,249	1,514	149,481
2045	141,719	6,249	1,514	149,481
2046	141,719	6,249	1,514	149,481
2047	141,719	6,249	1,514	149,481
2048	141,719	6,249	1,514	149,481
2049	141,719	6,249	1,514	149,481
2050	141,719	6,249	1,514	149,481
2051	141,719	6,249	1,514	149,481
2052	141,719	6,249	1,514	149,481
2053	141,719	6,249	1,514	149,481
2054	141,719	6,249	1,514	149,481
2055	141,719	6,249	1,514	149,481
2056	141,719	6,249	1,514	149,481
2057	141,719	6,249	1,514	149,481
2058	0	0	0	0
Total	**5,668,758**	**249,945**	**60,548**	**5,979,251**

A.3.2 Facility Level Fugitive Emissions from Production and Processing, and Gas Transmission

Facility – Level Fugitives from Production and Processing (other than venting and flaring)

The primary GHG released in fugitive leak emissions is methane (CH_4). The best available method for estimating fugitive level emissions from production and processing plants is outlined in the American Petroleum Institute of greenhouse Gas Estimation Methodologies for Oil and Gas Industry Compendium (API) 2009 (API, 2009). The API Compendium emission factor associated with onshore gas production includes leaks from gas wells, separators, heaters, small reciprocating compressors, meters and pipelines.

In order to convert API default emission factors to site specific emission factors the following equation was used.

$$\mathrm{Efss(CH_4)} = \frac{\mathrm{Efd} \times \mathrm{GWP} \ \frac{\mathrm{mol\%ss}}{\mathrm{mol\%d}}}{\mathrm{PCSG}} \times 1000$$

$\mathrm{Efss(CH4)}$ = Site specific CH_4 facility level average fugitive emission factor (t CO_2-e/t CSG processed)

Efd = Default CH_4 facility level average fugitive emission factor(t CH_4/Sm^3 CSG processed)

GWP = Global warming potential of CH_4(t CH4/Sm^3 CSG processed)

$\mathrm{mol\%ss}$ = Site specific CH_4 mole percentage of gas processed(mol%)

$\mathrm{mol\%d}$ = Default CH_4 mole percentage of gas processed (mol%)

PCSG = CSG density at standard conditions (kg CSG/Sm^3 CSG)

Table A.3-7 to Table A.3-10 below present the emission factors and activity data associated with fugitive emissions from production and processing at the Project.

Table A.3-7 Parameters for Facility –Level Fugitive Emission Factors (Site-Specific) Estimation

Data Description	Value	Units
Site-specific CH_4 molar percentage of CSG processed [a]	98.690	mol%
GWP CH_4 [b]	25.000	t CO_2-e/ t CH_4
CSG density at standard conditions [a]	0.726	kg/ Sm^3 CSG processed
Default CH_4 facility-level average fugitive emission factor associated with gas processing plants (at standard conditions) [c]	1.03×10^{-6}	t CH_4/ Sm^3 CSG processed
Default CH_4 mole percentage of CSG processed [c]	86.80	mol%

a. Advised by Arrow based on the previous Greenhouse Gas Assessment for the Surat Basin (Coffey Environments, 2011)

b. Appendix C, Australian Government (2013d)

c. Table 6-2, API (2009)

Arrow have advised that information gathered for the previous greenhouse gas assessment carried out for the Surat Gas Project should be used in the assumptions for calculating emission generated from fugitive emissions from production and processing. Based on the Surat Project, 5% of the gas produced from the well will come out in the water gathering system. Eighty per cent of this will be captured by applying down-hole and surface separators. Therefore 4% of the gas produced from the well that has come out in water stream will be captured and 1% will be lost into the gathering system. Ninety-nine per cent of the lost gas will be captured in high point valves and returned to the gathering system resulting in 0.01% of gas produced from the well escaping as saturated gas.

To provide a worst case scenario, these losses will be used in the estimation of GHG emissions from fugitive sources for both processing and gas field facilities.

GHG emissions were estimated using equation below. This equation applies for both CH_4 and CO_2

$$E = \frac{Q \times MW \times GWP \times \left(\frac{mol\%ss}{100}\right)}{PCSG \times V}$$

$EF =$ Site specific CO_2/ CH_4 facility level average fugitive emission factor(t CO_2-e/t CSG processed)

$Q =$ Total Quantity of gas processed in the year (t CSG/year)

$GWP =$ Global warming potential of CH_4 / CO_2 (t CH_4/Sm^3 CSG processed)

$MW =$ Molecular weight of CH_4/CO_2 (kg CO2/CH_4 / kmole CO_2/CH_4)

$mol\%ss =$ Default CH_4/CO_2 mole percentage of gas processed (mol%)

$PCSG =$ CSG density at standard conditions (kg CSG/Sm^3 CSG)

$V =$ Volume of 1 kilomole of gas at standard conditions (${Sm}^3$/kmole)

Table A.3-8 Facility – Level Fugitive Emission Factors

Data Description	Value	Units
Default CH_4 emission factor for general leaks [a]	0.0012	t CO_2-e/t CSG processed
Site – specific CH_4 facility-level average fugitive emission factor associated with gas processing plants (at standard conditions) [b]	0.0403	

a. Section 3.72 of the Technical Guidelines (Australian Government, 2013d)

b. Calculated by URS based on updated AR4 GWP values for CH4 (25)

Table A.3-9 Assumed Percentage of Gas Losses

Data Description	Value	Units
Percentage of gas losses from water gathering system [a]	0.01	%

For conservativeness purposes, it was assumed that the API Compendium emission factor of 0.0403 t CO_2-e/t CSG processed associated with gas processing plants covers all fugitive emissions from gas processing and compression. It is important to note that this factor is higher than the emission factor of 0.0012 t CO_2-e/t CSG processed recommended by the Technical Guidelines (Australian Government, 2013d).

Table A.3-10 Activity Data Associated with Facility Level Fugitive Emissions from Gas Production and Processing

Data Description	Value	Units
Site – specific CO_2 mole percentage of gas processed [a]	0.220	mol%
Molecular weight of CO_2 [b]	44.010	kg CO_2/kmole CO_2
Molecular weight of CH_4 [b]	16.040	kg CO_2/kmole CO_2
GWP of CO_2 [c]	1.000	t CO_2-e/t CO_2
Volume of 1 kilomole of gas at standard conditions [d]	23.640	Sm^3/kmole

a. Advised by Arrow Energy based on the previous Greenhouse Gas Assessment for the Surat Basin (Coffey Environments, 2011)

b. Section 2.22 (1), Australian Government (2013d)

c. Appendix C, Australian Government (2013d)

d. Section 2.22 (3), Australian Government (2013d)

Presented in Table A.3-11 are the GHG emissions associated with facility level fugitives from production and processing.

TableA.3-11 Greenhouse Gas Emissions Associated with Facility level Fugitives from Production and Processing

Year	CSG Out Total (TJ/year)	CSG Out Total (t/year)	CO_2 Emissions (t CO_2-e/year)	CH_4 Emissions (t CO_2-e/year)	Total CO_2-e (t CO_2-e/year)
2017	0	0	0	0	0
2018	18,980	369,522	0	14,902	14,902
2019	179,580	3,496,248	2	140,993	140,995
2020	281,415	5,478,876	3	220,946	220,949
2021	281,415	5,478,876	3	220,946	220,949
2022	281,780	5,485,982	3	221,232	221,235
2023	282,510	5,500,195	3	221,805	221,808
2024	282,510	5,500,195	3	221,805	221,808
2025	281,415	5,478,876	3	220,946	220,949
2026	282,510	5,500,195	3	221,805	221,808
2027	283,240	5,514,407	3	222,379	222,382
2028	282,875	5,507,301	3	222,092	222,095
2029	282,510	5,500,195	3	221,805	221,808
2030	281,050	5,471,770	3	220,659	220,662
2031	274,115	5,336,752	3	215,214	215,217
2032	264,260	5,144,885	3	207,477	207,480
2033	243,455	4,739,832	3	191,142	191,145
2034	215,715	4,199,761	2	169,363	169,365

Year	CSG Out Total (TJ/year)	CSG Out Total (t/year)	CO_2 Emissions (t CO_2-e/year)	CH_4 Emissions (t CO_2-e/year)	Total CO_2-e (t CO_2-e/year)
2035	189,435	3,688,115	2	148,730	148,732
2036	167,170	3,254,637	2	131,249	131,251
2037	144,540	2,814,053	2	113,482	113,483
2038	126,290	2,458,743	1	99,153	99,155
2039	111,690	2,174,496	1	87,691	87,692
2040	98,915	1,925,779	1	77,661	77,662
2041	85,410	1,662,850	1	67,057	67,058
2042	71,905	1,399,920	1	56,454	56,455
2043	62,780	1,222,265	1	49,290	49,291
2044	55,845	1,087,248	1	43,845	43,846
2045	51,465	1,001,973	1	40,406	40,407
2046	45,990	895,381	1	36,108	36,108
2047	43,070	838,531	0	33,815	33,816
2048	39,420	767,469	0	30,950	30,950
2049	34,675	675,088	0	27,224	27,225
2050	30,295	589,814	0	23,785	23,786
2051	24,090	469,009	0	18,914	18,914
2052	19,710	383,735	0	15,475	15,475
2053	12,775	248,717	0	10,030	10,030
2054	45,627	888,313	1	35,823	35,823
2055	25,460	495,681	0	19,989	19,990
2056	13,400	260,885	0	10,521	10,521
2057	6,700	130,442	0	5,260	5,260
2058	0	0	0	0	0
Total	**5,805,992**	**113,037,012**	**64**	**4,558,424**	**4,558,488**

A.3.3 Emissions from Gas Gathering System

Additional potential emissions of methane can be a result of:

- Compressor blow downs for maintenance at compressor stations;
- Maintenance on pipelines;

- Leakage; and
- Accidents.

GHG emissions associated with gas transmission were determined using Method 1 (Division 3.37, Section 3.76, Method 1 – natural gas transmission, Australian Government, 2013d).

Note that emissions associated with gas transmission from the Project to Gladstone are beyond the scope of this study.

The following equation was used to calculate emissions from gas transmission. The default emission factors are listed in Table A.3-12 and the activity data associated with gas transmission in Tables A.3-13-A.3-14. Table A.3-15 presents the estimated GHG emissions associated with gas transmission for the Project.

$$\mathrm{Ej} = \mathrm{Q} \times \mathrm{Efj}$$

$\mathrm{Ej} =$ Emissions of gas type (j) from natural gas transmission (t CO_2-e/year)

$\mathrm{Q} =$ length of the pipeline system relevant to the study (km/year)

$\mathrm{Efj} =$ emission factor for gas type (t CO_2-e/km)

TableA.3-12 Emission Factors Associated with Emissions from Gathering System

Method Used	Constant	Current Value	Updated Value	Units
Method 1	Scope 1 CO_2 emission factor	0.02		t CO_2/km
	Scope 1 CH_4 emission factor	8.70[a]	10.36[b]	
	Scope 1 overall emission factor	8.72[a]	10.38[b]	

a. Based on current AR2 GWP values for CH_4 (21).

b. Based on updated AR4 GWP values for CH_4 (25). This emission factor was used in calculations of Project emissions.

Table A.3-13 Activity Data Associated with Calculation of Emissions from Gathering System

Data Required	Value	Units
Average length of medium pressure gas pipelines from FCFs [a]	25.0	km/FCF
Average length of low pressure gas pipelines from wells [a]	2.2	km/well

a. Advised by Arrow

Table A.3-14 Estimated GHG Emissions from Gathering System

Year	Cumulative number of wells	Cumulative number of FCF	Cumulative length of low pressure pipelines from wells (km)	Cumulative length of medium pressure pipelines from FCF (km)	Total length of gas pipe-lines (km)	CO_2 (t CO_2-e/year)	CH_4 (t CO_2-e/year)	Total CO_2-e (t CO_2-e/year)
2017	0	0	0	0	0	0	0	0
2018	189	8	416	200	616	12	6,378	6,390
2019	934	16	2,055	400	2,455	49	25,425	25,474
2020	1,234	16	2,715	400	3,115	62	32,260	32,323
2021	1,492	16	3,282	400	3,682	74	38,139	38,213
2022	1,786	17	3,929	425	4,354	87	45,097	45,184
2023	2,134	20	4,695	500	5,195	104	53,803	53,907
2024	2,364	22	5,201	550	5,751	115	59,562	59,677
2025	2,567	23	5,647	575	6,222	124	64,446	64,571
2026	2,771	26	6,096	650	6,746	135	69,871	70,006
2027	2,908	27	6,398	675	7,073	141	73,252	73,393
2028	3,059	28	6,730	700	7,430	149	76,952	77,100
2029	3,354	30	7,379	750	8,129	163	84,191	84,354
2030	3,413	30	7,509	750	8,259	165	85,536	85,701
2031	3,442	30	7,572	750	8,322	166	86,196	86,363
2032	3,466	29	7,625	725	8,350	167	86,484	86,651
2033	3,432	28	7,550	700	8,250	165	85,451	85,616

Year	Cumulative number of wells	Cumulative number of FCF	Cumulative length of low pressure pipelines from wells (km)	Cumulative length of medium pressure pipelines from FCF (km)	Total length of gas pipe-lines (km)	CO_2 (t CO_2-e/year)	CH_4 (t CO_2-e/year)	Total CO_2-e (t CO_2-e/year)
2034	3,393	27	7,465	675	8,140	163	84,303	84,466
2035	3,423	27	7,531	675	8,206	164	84,987	85,151
2036	3,431	27	7,548	675	8,223	164	85,169	85,333
2037	3,443	27	7,575	675	8,250	165	85,442	85,607
2038	3,455	27	7,601	675	8,276	166	85,716	85,881
2039	3,283	25	7,223	625	7,848	157	81,279	81,436
2040	3,206	24	7,053	600	7,653	153	79,265	79,418
2041	3,038	21	6,684	525	7,209	144	74,661	74,805
2042	2,683	17	5,903	425	6,328	127	65,536	65,662
2043	2,523	15	5,551	375	5,926	119	61,372	61,491
2044	2,401	14	5,282	350	5,632	113	58,334	58,446
2045	2,401	14	5,282	350	5,632	113	58,334	58,446
2046	2,293	13	5,045	325	5,370	107	55,614	55,721
2047	2,293	13	5,045	325	5,370	107	55,614	55,721
2048	2,286	13	5,029	325	5,354	107	55,454	55,561
2049	2,144	12	4,717	300	5,017	100	51,960	52,060
2050	1,912	10	4,206	250	4,456	89	46,156	46,245
2051	1,610	8	3,542	200	3,742	75	38,756	38,831
2052	1,362	7	2,996	175	3,171	63	32,847	32,910

Year	Cumulative number of wells	Cumulative number of FCF	Cumulative length of low pressure pipelines from wells (km)	Cumulative length of medium pressure pipelines from FCF (km)	Total length of gas pipe-lines (km)	CO_2 (t CO_2-e/year)	CH_4 (t CO_2-e/year)	Total CO_2-e (t CO_2-e/year)
2053	881	6	1,938	150	2,088	42	21,628	21,670
2054	681	6	1,498	150	1,648	33	17,071	17,104
2055	380	6	836	150	986	20	10,212	10,232
2056	200	6	440	150	590	12	6,111	6,123
2057	100	6	220	150	370	7	3,832	3,840
2058	0	0	0	0	0	0	0	0
Total						**4,389**	**2,272,693**	**2,277,081**

A.4 Scope 2 – Construction, Operation and Decommissioning

Scope 2 emissions arise from electricity acquired from sources that do not form part of the facility. Arrow provided electricity usage data for each year of Project life as presented in Table A.4-2.

Scope 2 emissions from the Project were estimated following method 1 outlined in the Technical Guidelines (Australian Government, 2013d), Division 7.2. The following equation was used to calculate Scope 2 emissions for each year of Project life.

$$Y = Q \times \left(\frac{Efs2}{1000}\right)$$

$Y =$ Scope 2 greenhouse gas emissions in the year (t CO_2-e/year)

$Q =$ Quantity of electricity purchased from the grid in the year (kilowatt hours (kWh)/year)

$Efs2 =$ Default Scope 2 emission factor specific to state or Territory in which consumption occurs (kg CO_2-e/kWh)

The default energy content factor and the greenhouse gas emission factor in units of CO_2-e are provided in Table A.4-1. URS adjusted the greenhouse gas emission factor using the updated GWP values for methane and nitrous oxide. However, it was found that greenhouse emission factor for electricity consumption is not sensitive to the change in the GWP values for methane and nitrous oxide. This can be attributed to the fact that there is no significant production of methane and nitrous oxide from combustion of fuels for power generation. Methane emissions result from incomplete combustion, which if persistent is both inefficient and uneconomic. Nitrous oxide is generally formed under low temperature and as a consequence its concentration is normally very low in power plants. Therefore, the adjusted factor using AR4 GWPs is equal to the greenhouse gas emission factor using AR4 GWPs and is presented in Table A.4-1. The resulting GHG from Scope 2 emissions are presented in Table A.4-4.

Table A.4-1 Energy Content and Emission Factors Associated with Scope 2 Emissions

Variable	Value	Units
Energy Content factor [a]	0.0036	GJ/kWh
CO_2-e Emission factor [b]	0.8200	kg CO_2 – e/kWh

a. Section 6.3, Australian Government (2013d)

b. Table 7.2, Australian Government (2013d)

Note that there is no electricity usage from the electricity network in the years 2017-2019 as the Temporary Power Generation scenario assumes that, during this period, power for the Project will be generated locally using gas fired engines.

Table A.4-2 Activity Data Associated with Electricity Consumption from the Grid

Year	Electricity Usage (MWh/year)	Electricity Usage (kWh/year)
2017	0	0
2018	0	0

Year	Electricity Usage (MWh/year)	Electricity Usage (kWh/year)
2019	0	0
2020	1,649,000	1,649,000,000
2021	1,893,000	1,893,000,000
2022	1,923,000	1,923,000,000
2023	1,994,000	1,994,000,000
2024	2,017,000	2,017,000,000
2025	1,966,000	1,966,000,000
2026	1,989,000	1,989,000,000
2027	2,006,000	2,006,000,000
2028	2,024,000	2,024,000,000
2029	2,044,000	2,044,000,000
2030	2,055,000	2,055,000,000
2031	2,140,000	2,140,000,000
2032	2,097,000	2,097,000,000
2033	2,099,000	2,099,000,000
2034	2,082,000	2,082,000,000
2035	2,058,000	2,058,000,000
2036	2,046,000	2,046,000,000
2037	2,039,000	2,039,000,000
2038	2,026,000	2,026,000,000
2039	2,024,000	2,024,000,000
2040	2,044,000	2,044,000,000
2041	2,055,000	2,055,000,000
2042	2,110,000	2,110,000,000
2043	2,097,000	2,097,000,000
2044	2,069,000	2,069,000,000
2045	2,052,000	2,052,000,000
2046	2,018,000	2,018,000,000
2047	1,757,000	1,757,000,000
2048	1,600,000	1,600,000,000
2049	1,468,000	1,468,000,000
2050	1,264,000	1,264,000,000

Year	Electricity Usage (MWh/year)	Electricity Usage (kWh/year)
2051	1,191,000	1,191,000,000
2052	1,152,000	1,152,000,000
2053	1,120,000	1,120,000,000
2054	1,016,000	1,016,000,000
2055	956,000	956,000,000
2056	937,000	937,000,000
2057	919,000	919,000,000
2058	904,000	904,000,000
Total		**68,900,000,000**

Table A.4-3 Scope 2 Greenhouse Gas Emissions

Year	Scope 2 Emissions (t CO_2-e /annum)
2017	0
2018	0
2019	0
2020	1,352,180
2021	1,552,260
2022	1,576,860
2023	1,635,080
2024	1,653,940
2025	1,612,120
2026	1,630,980
2027	1,644,920
2028	1,659,680
2029	1,676,080
2030	1,685,100
2031	1,754,800
2032	1,719,540
2033	1,721,180
2034	1,707,240
2035	1,687,560
2036	1,677,720

Year	Scope 2 Emissions (t CO_2-e /annum)
2037	1,671,980
2038	1,661,320
2039	1,659,680
2040	1,676,080
2041	1,685,100
2042	1,730,200
2043	1,719,540
2044	1,696,580
2045	1,682,640
2046	1,654,760
2047	1,440,740
2048	1,312,000
2049	1,203,760
2050	1,036,480
2051	976,620
2052	944,640
2053	918,400
2054	833,120
2055	783,920
2056	768,340
2057	753,580
2058	741,280
Total	**56,498,000**

A.5 Scope 3 Emissions – Construction, Operation and Decommissioning

A.5.1 Full Fuel Cycle Emissions

Indirect emissions from exploration, processing and transport are associated with diesel that has been used during the construction, operation and decommissioning of the Project. The consumption of purchased electricity also has associated Scope 3 emissions, these emissions have been generated through the extraction, production and transport of fuel combusted at generation and the indirect emissions associated to the electricity lost in the delivery in the transmission and distribution network.

To calculate GHG emissions from full life cycles, the total amount of fuel combusted and electricity purchased from the grid are required. The equation below was used to calculate Scope 3 emissions associated with fuel combustion.

$$\mathrm{E} = \frac{\mathrm{Q} \times \mathrm{EC} \times \mathrm{EFs3}}{1000}$$

$\mathrm{E}=$ Scope 3 emissions of GHG from fuel combustion ($\mathrm{t\ CO_2\text{-}e/year}$)

$\mathrm{Q}=$ Quantity of fuel combusted (kL/year)

$\mathrm{EC} =$ Energy content factor

$\mathrm{EFs3} =$ Scope 3 Emissions factor

The equation below was used to calculate Scope 3 emissions associated with electricity consumption.

$$\mathrm{E} = \frac{\mathrm{Q} \times \mathrm{EFs3}}{1000}$$

$\mathrm{E} =$ Scope 3 emissions of GHG from electricity consumption in the year ($\mathrm{t\ CO_2\text{-}e/year}$)

$\mathrm{Q}=$ Quantity of fuel combusted in the year (kL/year)

$\mathrm{EFs3} =$ Default Scope 3 Emissions factor specific to state or territory in which consumption occurs

Activity data associated with the full life cycle for the total amount of fuel combusted and electricity purchased from the grid are provided below in Table A.5-1.

Table A.5-1 Activity Data Associated with Full Fuel Cycles

Variable	Value	Units
Energy Content factor of diesel [a]	38.60	GJ/kL
Scope 3 emission factor of diesel [b]	5.30	kg CO_2-e/GJ
Scope 3 emission factor of electricity in QLD [c]	0.14	kg CO_2-e/kWh

a.Table 2.4.2B (Australian Government, 2013e)

b Table 40, (Australian Government, 2013e)

c Table 41, (Australian Government, 2013e)

GHG emissions from full fuel cycle of diesel are presented in Table A.5-2. Scope 3 GHG emissions from full fuel cycle of electricity are outlined in Table A.5-3.

Table A.5-2 GHG Emissions from Full Fuel Cycle of Diesel

Year	Total fuel consumption for the year (kL/year)	GHG Emissions from Full fuel Diesel (t CO_2-e /year)
2017	1,082	221
2018	1,110	227
2019	4,511	923
2020	10,163	2,079
2021	4,337	887
2022	4,509	922
2023	5,146	1,053
2024	6,103	1,249
2025	4,519	924
2026	4,779	978
2027	4,347	889
2028	4,132	845
2029	4,050	829
2030	6,020	1,232
2031	4,654	952
2032	3,913	800
2033	4,307	881
2034	3,271	669
2035	3,189	652
2036	2,899	593
2037	2,461	504
2038	2,328	476
2039	2,329	477
2040	2,222	454
2041	2,513	514
2042	2,492	510
2043	2,420	495
2044	2,648	542

Year	Total fuel consumption for the year (kL/year)	GHG Emissions from Full fuel Diesel (t CO_2-e /year)
2045	2,523	516
2046	2,078	425
2047	4,127	844
2048	4,126	844
2049	4,085	836
2050	3,862	790
2051	4,228	865
2052	4,538	928
2053	4,619	945
2054	4,738	969
2055	4,096	838
2056	4,876	998
2057	1,180	241
2058	1,755	359
Total	**157,287**	**32,178**

Table A.5-3 Scope 3 GHG Emissions from Full Fuel Cycle of Electricity

Year	Total Electricity used for Year (kWh/year)	GHG Emissions from Full fuel electricity (t CO_2-e/year)
2017	0	0
2018	0	0
2019	0	0
2020	1,649,000,000	230,860
2021	1,893,000,000	265,020
2022	1,923,000,000	269,220
2023	1,994,000,000	279,160
2024	2,017,000,000	282,380
2025	1,966,000,000	275,240
2026	1,989,000,000	278,460
2027	2,006,000,000	280,840
2028	2,024,000,000	283,360

Year	Total Electricity used for Year (kWh/year)	GHG Emissions from Full fuel electricity (t CO_2-e/year)
2029	2,044,000,000	286,160
2030	2,055,000,000	287,700
2031	2,140,000,000	299,600
2032	2,097,000,000	293,580
2033	2,099,000,000	293,860
2034	2,082,000,000	291,480
2035	2,058,000,000	288,120
2036	2,046,000,000	286,440
2037	2,039,000,000	285,460
2038	2,026,000,000	283,640
2039	2,024,000,000	283,360
2040	2,044,000,000	286,160
2041	2,055,000,000	287,700
2042	2,110,000,000	295,400
2043	2,097,000,000	293,580
2044	2,069,000,000	289,660
2045	2,052,000,000	287,280
2046	2,018,000,000	282,520
2047	1,757,000,000	245,980
2048	1,600,000,000	224,000
2049	1,468,000,000	205,520
2050	1,264,000,000	176,960
2051	1,191,000,000	166,740
2052	1,152,000,000	161,280
2053	1,120,000,000	156,800
2054	1,016,000,000	142,240
2055	956,000,000	133,840
2056	937,000,000	131,180
2057	919,000,000	128,660
2058	904,000,000	126,560
Total	**68,900,000,000**	**9,646,000**

A.5.2 End Use of Gas

Emissions associated with the end use of gas refer to the full combustion of product gas. End use of the product gas will be the most significant Scope 3 source of emissions associated with the Project. It is assumed that no fugitive emissions will occur after the product gas leaves the Project facilities.

When calculating the GHG emissions from the end use of the CSG the following equation was used.

$$E = \frac{Q \times EFs3}{1000}$$

E = Emissions of GHG from end use of gas produced ($t\ CO_2$-e/a)

Q= Quantity of gas combusted in a year (GJ/a)

$EFs3$ = Scope 1 Emissions factor for CSG ($t\ CO_2$-e/GJ)

The energy content factor and Scope 3 emission factors and GHG emissions associated with the end use of gas are outlined in Table A.5-3 and Table A.5-4.

Table A.5-3 Emission Factors Associated with End-Use of Gas

Method Used	Constant	Current Value	Updated Value	Units
Method 1	Scope 1 CO_2 emission factor	51.10		$t\ CO_2$-e/GJ
Method 1	Scope 1 CH_4 emission factor	0.20[a]	0.24[d]	
Method 1	Scope 1 N_2O emission factor	0.03[b]	0.03[e]	
Method 1	Scope 1 overall emission factor	51.33[c]	51.37[f]	

a. Based on current AR2 GWP values for CH_4 (21).

b. Based on current AR2 GWP values for N_2O (310).

c. Based on current AR2 GWP values for CH_4 (21) and N_2O (310).

d. Based on updated AR4 GWP values for CH_4 (25). This emission factor was used in calculations of Project emissions.

e. Based on updated AR4 GWP values for N_2O (298). This emission factor was used in calculations of Project emissions.

f. Based on updated AR4 GWP values for CH_4 (25) and N_2O (298). This emission factor was used in calculations of Project emissions.

Table A.5-4 GHG Emissions associated with End-Use Gas

Year	Total gas production (GJ/year)	GHG Emissions from End use of gas (t CO_2-e/year)
2017	0	0
2018	18,980,000	974,944
2019	179,580,000	9,224,474
2020	281,415,000	14,455,426

Year	Total gas production (GJ/year)	GHG Emissions from End use of gas (t CO_2-e/year)
2021	281,415,000	14,455,426
2022	281,780,000	14,474,175
2023	282,510,000	14,511,673
2024	282,510,000	14,511,673
2025	281,415,000	14,455,426
2026	282,510,000	14,511,673
2027	283,240,000	14,549,170
2028	282,875,000	14,530,421
2029	282,510,000	14,511,673
2030	281,050,000	14,436,677
2031	274,115,000	14,080,447
2032	264,260,000	13,574,226
2033	243,455,000	12,505,537
2034	215,715,000	11,080,618
2035	189,435,000	9,730,695
2036	167,170,000	8,587,010
2037	144,540,000	7,424,577
2038	126,290,000	6,487,130
2039	111,690,000	5,737,173
2040	98,915,000	5,080,960
2041	85,410,000	4,387,250
2042	71,905,000	3,693,539
2043	62,780,000	3,224,816
2044	55,845,000	2,868,586
2045	51,465,000	2,643,599
2046	45,990,000	2,362,365
2047	43,070,000	2,212,374
2048	39,420,000	2,024,885
2049	34,675,000	1,781,148
2050	30,295,000	1,556,161
2051	24,090,000	1,237,429

Year	Total gas production (GJ/year)	GHG Emissions from End use of gas (t CO_2-e/year)
2052	19,710,000	1,012,442
2053	12,775,000	656,213
2054	45,627,000	2,343,719
2055	25,460,000	1,307,802
2056	13,400,000	688,317
2057	6,700,000	344,158
2058	0	0
Total	**5,805,992,000**	**298,236,008**

A.5.3 Emissions Associated with Third Party Infrastructure Required to Export CSG

GHG Emissions associated with third party infrastructure required to export gas as LNG refer to gas losses through the transmission and losses due to emissions associated with downstream processing of the gas that results in the production and export of LNG (refer to Scope 1 and Scope 2 emissions associated with the "all electrical" scenario in Arrow's LNG Plant EIS Greenhouse Gas chapter http://www.arrowenergy.com.au/page/Community/Project_Assessment_EIS/Arrow_LNG_Plant_EIS).

Gas Transmission

Gas transmission losses can occur due to maintenance on pipelines and leakage of emissions. The Arrow Bowen Pipeline consists of approximately 475 km of pipelines (without laterals), which will convey CSG for subsequent export as LNG and associated above ground infrastructure. The purpose of the Project is to deliver CSG from Arrow's gas fields in the Bowen Basin to a proposed Arrow gas gathering hub in the Aldoga precinct of the Gladstone State Development Area for further transmission to Arrow's proposed Arrow LNG Plant on Curtis Island. For the purposes of this assessment, the total pipeline length (Arrow Bowen Pipeline plus pipeline laterals to connect facilities of total length 155 km) of 630 km was assumed for each year to represent a worst-case scenario, as outlined in Table A.5-5. Emissions factors associated with gas transmission are outlined in Table A.5-6. In order to calculate Scope 3 emissions caused from gas transmission, the equation below was used in accordance with Method 1 of the Technical Guidelines (Division 3.3.7, *Natural gas transmission*, (Australian Government, 2013d): GHG emissions calculated for Scope 3 transmission are presented in Table A.5-7.

$$\mathrm{Ej} = \mathrm{Q} \times \mathrm{EFj}$$

Ej = Emissions of gas type from natural gas transmission (t CO_2-e/year)

Q= Total length of pipeline relevant to the study (km/year)

EFj= Emissions factor for gas type (t CO_2-e/km)

The calculated emissions are presented in Table A.5-7.

Table A.5-5 Activity data Associated with Gas transmission to Arrow LNG Plant (Scope 3)

Data Required	Value	Units
Maximum length of high pressure pipelines from CGPFs and IPFs to Arrow LNG plant[a]	630	km

[a] URS estimation is based on the maximum pipeline length worst case scenario.

Table A.5-6 Emission Factors Associated with Gas Transmission

Method Used	Constant	Current Value	Updated Value	Units
Method 1	Scope 1 CO_2 emission factor for CSG[a]	0.02		T CO_2/ GJ
	Scope 1 CH_4 emission factor for CSG [a]	8.70[a]	10.36[b]	
	Scope 1 overall emission factor for CSG [b]	8.72[a]	**10.38[b]**	

a. Based on current AR2 GWP values for CH_4 (21).

b. Based on updated AR4 GWP values for CH_4 (25). This emission factor was used in calculations of Project emissions.

Table A.5-7 GHG Emissions Associated with Scope 3 Gas Transmission

Year	CO_2 (t CO_2-e /year)	CH_4 (t CO_2-e /year)	Total CO_2-e (t CO_2-e /year)
2017	0	0	0
2018	13	6,525	6,538
2019	13	6,525	6,538
2020	13	6,525	6,538
2021	13	6,525	6,538
2022	13	6,525	6,538
2023	13	6,525	6,538
2024	13	6,525	6,538
2025	13	6,525	6,538
2026	13	6,525	6,538
2027	13	6,525	6,538
2028	13	6,525	6,538
2029	13	6,525	6,538
2030	13	6,525	6,538
2031	13	6,525	6,538

Year	CO_2 (t CO_2-e /year)	CH_4 (t CO_2-e /year)	Total CO_2-e (t CO_2-e /year)
2032	13	6,525	6,538
2033	13	6,525	6,538
2034	13	6,525	6,538
2035	13	6,525	6,538
2036	13	6,525	6,538
2037	13	6,525	6,538
2038	13	6,525	6,538
2039	13	6,525	6,538
2040	13	6,525	6,538
2041	13	6,525	6,538
2042	13	6,525	6,538
2043	13	6,525	6,538
2044	13	6,525	6,538
2045	13	6,525	6,538
2046	13	6,525	6,538
2047	13	6,525	6,538
2048	13	6,525	6,538
2049	13	6,525	6,538
2050	13	6,525	6,538
2051	13	6,525	6,538
2052	13	6,525	6,538
2053	13	6,525	6,538
2054	13	6,525	6,538
2055	13	6,525	6,538
2056	13	6,525	6,538
2057	13	6,525	6,538
2058	0	0	0
Total	**504**	**261,000**	**261,504**

Emissions Associated with Downstream Processing of CSG

To estimate the GHG emission associated with the downstream processing of CSG to produce and export LNG, Scope 1 and 2 associated with all electrical scenarios were incorporated, so as to predict a worst case emission. Scope 1 emissions for methane and nitrous oxide were adjusted using the updated values of global warming potentials.

Scope 3 emissions were based on the Arrow LNG Plant estimated Scope 1 and 2 annual emissions for all the electrical option for four LNG trains were scaled down to the amount of CSG delivered by the Project using the following equation:

$$\mathrm{Ej,s3} = \mathrm{Ej,s1\&2} \times \frac{\mathrm{Qupstream}}{\mathrm{Qdownstream}}$$

$\mathrm{Ej,s3}$ = Scope 3 emissions of gas type (j) associated with downstream gas processing in the year (t CO_2-e/year)

$\mathrm{Ej,s1\&2}$ =
Scope 1 and 2 emissions of gas type (j) assocaited with gas processing at the Arrow LNG PLant in the year (t CO_2-e/year)

Qupstream = Total amount of gas fed to the Arrow LNG project (Sm^3/year)

Qdownstream = Total amount of gas processed downstream for four LNG trains (Sm^3/year)

The following equation was used to determine the total amount of gas fed to Arrow LNG plant from the Project.

$$\mathrm{Qupstream} = \frac{(\mathrm{CSGp} - \mathrm{CSGT})\mathrm{x}1000}{\mathrm{ECss}}$$

Qupstreeam = Total amount of gas fed to Arrow LNG project (Sm^3/year)

CSGp= Cumulative total gas produced by the project in the year (TJ/year)

CSGT = Total leaks of CO_2 and CH_4 during transmission to Arrow LNG Plant in the year (TJ/year)

ECss = Site Specific energy content of CSG (GJ/Sm^3 CSG)

Parameters used for calculation of CSG losses during transmission for the Arrow Project are outlined in Table A.5-8. To convert CO_2 equivalents emissions from gas transmission to a volume of gas the following equation was used:

$$\mathrm{CSGT} = \frac{\frac{\mathrm{CSGt,CO_2}}{\mathrm{GWPCO_2}} + \frac{\mathrm{CSGt,CH_4}}{\mathrm{GWPCH_4}}}{\mathrm{PCSG}} \text{ x ECss}$$

CSGT = Total leaks of CO_2 and CH_4 during transmission to Arrow LNG Plant (TJ/year)

$\mathrm{CSGt,CO_2}$ = Total leaks of CO_2 during transmission (t CO_2-e/year)

$\mathrm{GWPCO_2}$ = Global warming potential of CO_2 (t CO_2/t CO_2)

$\mathrm{CSGt,CH_4}$= Total leaks of CO_2 during transmission in theyear (t CO_2-e/year)

$\mathrm{GWPCH_4}$ = Global warming potential of CH_4 (t CO_2/t CO_2)

ECss = Site Specific energy content of CSG (GJ/Sm^3CSG)

PCSG = Site specific CSG density at Standard conditions (kg CSG/Sm^3 CSG)

The subsequent GHG associated with downstream processing are presented in Table A.5-9.

Table A.5-8 Parameters Associated with the Estimation of the Volume of CSG Losses during Transmission to the Arrow LNG Plant

Variable	Value	Units
Site specific CSG density [a]	0.72600	kg/Sm^3
Site-specific energy content factor [a]	0.03729	GJ/m^3
GWP of CO_2 [b]	1	t CO_2-e/t CO_2
GWP of CH_4 [b]	25	t CO_2-e/t CH_4

a. As advised by Arrow based on the Surat Basin Report

b. IPCC (2007)

Table A.5-9 GHG Emissions Associated with Downstream Processing of CSG

Year	Cumulative total gas produced by project (TJ/year)	Amount of CSG losses through transmission (TJ/year)	Amount of Gas Fed to Arrow	GHG Emissions (t CO_2-e /year)
2017	0	0	0	0
2018	18,980	14	508,606,782	147,409
2019	179,580	17	4,815,322,966	1,395,619
2020	281,415	17	7,546,215,967	2,187,110
2021	281,415	17	7,546,215,967	2,187,110
2022	281,780	17	7,556,004,114	2,189,947
2023	282,510	17	7,575,580,408	2,195,621

Year	Cumulative total gas produced by project (TJ/year)	Amount of CSG losses through transmission (TJ/year)	Amount of Gas Fed to Arrow	GHG Emissions (t CO_2-e /year)
2024	282,510	17	7,575,580,408	2,195,621
2025	281,415	17	7,546,215,967	2,187,110
2026	282,510	17	7,575,580,408	2,195,621
2027	283,240	17	7,595,156,702	2,201,294
2028	282,875	17	7,585,368,555	2,198,458
2029	282,510	17	7,575,580,408	2,195,621
2030	281,050	17	7,536,427,820	2,184,273
2031	274,115	17	7,350,453,028	2,130,372
2032	264,260	17	7,086,173,060	2,053,776
2033	243,455	17	6,528,248,683	1,892,074
2034	215,715	17	5,784,349,515	1,676,471
2035	189,435	17	5,079,602,934	1,472,215
2036	167,170	17	4,482,525,969	1,299,165
2037	144,540	17	3,875,660,858	1,123,278
2038	126,290	17	3,386,253,510	981,433
2039	111,690	17	2,994,727,632	867,958
2040	98,915	17	2,652,142,489	768,667
2041	85,410	17	2,289,981,051	663,702
2042	71,905	17	1,927,819,614	558,737
2043	62,780	17	1,683,115,940	487,815
2044	55,845	17	1,497,141,148	433,914
2045	51,465	17	1,379,683,384	399,872
2046	45,990	17	1,232,861,180	357,319
2047	43,070	17	1,154,556,004	334,623
2048	39,420	17	1,056,674,535	306,255
2049	34,675	17	929,428,624	269,375
2050	30,295	17	811,970,861	235,332
2051	24,090	17	645,572,363	187,105
2052	19,710	17	528,114,599	153,063
2053	12,775	17	342,139,807	99,162
2054	45,627	17	1,223,126,667	354,497

Year	Cumulative total gas produced by project (TJ/year)	Amount of CSG losses through transmission (TJ/year)	Amount of Gas Fed to Arrow	GHG Emissions (t CO_2-e /year)
2055	25,460	17	682,311,435	197,753
2056	13,400	17	358,900,333	104,020
2057	6,700	17	179,227,498	51,945
2058	0	0	0	0
Total	**5,805,992**	**662**	**155,680,619,190**	**45,120,712**

A.5.4 *Emissions from FIFO and DIDO Operations*

Arrow's preference is to provide local employment; however, due to the high demand by mining companies and low unemployment rates, Arrow recognises that labour will likely need to be sourced from further afield.

Airline and vehicle travel is included in the assessment as an indirect or Scope 3 GHG emission as a result of FIFO and DIDO working arrangements. Workers will FIFO from Brisbane airport to Moranbah. DIDO business travels are included in the assessment based on data from the SREIS Road Impact Assessment (Appendix K). DIDO travels were assumed to be conducted by vehicles fuelled by diesel.

It is assumed that 90% of construction workforce will be working on FIFO basis and other 10% will be working on DIDO basis (Table A.5-10). It is assumed that 80% of operational workforce will be working on FIFO and DIDO, with 60% out of 80% FIFO (Table A.5-10).

Table A.5-10 FIFO and DIDO Activity Data

Item	Value	Units
Distance between Brisbane and Moranbah (round trip)	2,100	km
FIFO construction workers	90	%
DIDO construction workers	10	%
FIFO operational workers	48	%
DIDO operational workers	32	%
Number of trips per person in year	12	

The emission factors for the airline and vehicle travel are included in Table A.5-11. Emission factors are based on U.S. EPA Climate Leaders GHG Inventory Protocol, "Optional Emissions from Commuting, Business Travel and Product Transport" (available at: http://www.epa.gov/stateply/documents/resources/ in commute_travel_product.pdf).

The number of trips and kilometres travelled as well as subsequent GHG associated with FIFO and DIDO are presented in Table A.5-12 and Table A.5-13 respectively.

Table A.5-11 Emission Factors for Airline Business Travel (passenger-km) for Short Haul Distances

GHG	Emission factor (aircraft) based on current GWP	Emission factor (aircraft) based on updated GWP	Emission factor (vehicle) based on current GWP	Emission factor (vehicle) based on updated GWP	Units*
CO_2	0.1721	0.0665			kg CO_2-e/passenger-km
CH_4	0.0001[a]	0.0002[d]	7.829E-06[a]	9.321E-06[d]	
N_2O	0.0016[b]	0.0015[e]	0.0001[b]	9.010E-05[e]	
Overall	0.1739[c]	0.1738[f]	0.0666[c]	0.0666[f]	

*Emission factors have been converted from kg CO_2-e/passenger-mile to kg CO_2-e/passenger-km

a. Based on current AR2 GWP values for CH_4 (21).

b. Based on current AR2 GWP values for N_2O (310).

c. Based on current AR2 GWP values for CH_4 (21) and N_2O (310).

d. Based on updated AR4 GWP values for CH_4 (25). This emission factor was used in calculations of Project emissions.

e. Based on updated AR4 GWP values for N_2O (298). This emission factor was used in calculations of Project emissions.

f. Based on updated AR4 GWP values for CH_4 (25) and N_2O (298). This emission factor was used in calculations of Project emissions.

Table A.5-12 FIFO and DIDO Workforce, Number of Trips and Travelled Kilometres

Year	Construction workforce per day	Operational workforce per day	FIFO workforce	Number of trips/year per person	Total trips/year per FIFO person	km travelled by aircraft (round trip)	km travelled by vehicle (round trip)[a]
2017	1,000	0	900	12	10,800	22,680,000	24,758
2018	2,450	300	2,349	12	28,188	59,194,800	555,340
2019	1,000	300	1,044	12	12,528	26,308,800	1,125,639
2020	900	300	954	12	11,448	24,040,800	3,001,676
2021	900	300	954	12	11,448	24,040,800	1,656,540
2022	900	300	954	12	11,448	24,040,800	1,483,677
2023	900	300	954	12	11,448	24,040,800	1,545,301
2024	900	300	954	12	11,448	24,040,800	2,218,862
2025	900	300	954	12	11,448	24,040,800	1,642,313
2026	900	300	954	12	11,448	24,040,800	2,607,727
2027	900	300	954	12	11,448	24,040,800	3,357,600
2028	400	300	504	12	6,048	12,700,800	1,538,776
2029	400	300	504	12	6,048	12,700,800	1,787,749
2030	400	300	504	12	6,048	12,700,800	2,681,548

Year	Construction workforce per day	Operational workforce per day	FIFO workforce	Number of trips/year per person	Total trips/year per FIFO person	km travelled by aircraft (round trip)	km travelled by vehicle (round trip)[a]
2031	400	300	504	12	6,048	12,700,800	2,891,369
2032	400	300	504	12	6,048	12,700,800	2,556,563
2033	400	300	504	12	6,048	12,700,800	2,689,069
2034	400	300	504	12	6,048	12,700,800	2,026,365
2035	400	300	504	12	6,048	12,700,800	2,009,899
2036	400	300	504	12	6,048	12,700,800	1,657,267
2037	400	300	504	12	6,048	12,700,800	1,576,849
2038	400	300	504	12	6,048	12,700,800	1,591,634
2039	400	300	504	12	6,048	12,700,800	1,595,284
2040	400	300	504	12	6,048	12,700,800	1,499,207
2041	400	300	504	12	6,048	12,700,800	1,493,445
2042	400	300	504	12	6,048	12,700,800	1,442,625
2043	400	300	504	12	6,048	12,700,800	1,348,916
2044	400	300	504	12	6,048	12,700,800	1,217,690
2045	400	300	504	12	6,048	12,700,800	1,139,164
2046	400	300	504	12	6,048	12,700,800	1,074,798
2047	400	300	504	12	6,048	12,700,800	1,070,673
2048	400	300	504	12	6,048	12,700,800	1,017,040
2049	400	300	504	12	6,048	12,700,800	1,012,200
2050	400	300	504	12	6,048	12,700,800	1,009,381
2051	400	300	504	12	6,048	12,700,800	907,862
2052	400	300	504	12	6,048	12,700,800	822,301
2053	400	300	504	12	6,048	12,700,800	668,029
2054	400	300	504	12	6,048	12,700,800	387,951
2055	400	300	504	12	6,048	12,700,800	360,399
2056	400	300	504	12	6,048	12,700,800	102,564
2057	400	300	504	12	6,048	12,700,800	699,139
2058	400	300	504	12	6,048	12,700,800	24,500

a. Based on the SREIS Road Impact Assessment (Appendix K) (November 2013).

Table A.5-13 GHG Emissions Associated with FIFO and DIDO

Year	CO_2 (t CO_2-e/year)	CH_4 (t CO_2-e/year)	N_2O (t CO_2-e/year)	Total (t CO_2-e/year)
2017	3,905	4	36	3,945
2018	10,226	10	93	10,329
2019	4,603	4	42	4,649
2020	4,338	4	38	4,380
2021	4,248	4	38	4,290
2022	4,237	4	38	4,279
2023	4,241	4	38	4,283
2024	4,286	4	38	4,327
2025	4,247	4	38	4,289
2026	4,311	4	38	4,353
2027	4,361	4	38	4,403
2028	2,288	2	20	2,311
2029	2,305	2	20	2,327
2030	2,364	2	20	2,387
2031	2,378	2	20	2,401
2032	2,356	2	20	2,378
2033	2,365	2	20	2,387
2034	2,321	2	20	2,343
2035	2,320	2	20	2,342
2036	2,296	2	20	2,319
2037	2,291	2	20	2,313
2038	2,292	2	20	2,314
2039	2,292	2	20	2,314
2040	2,286	2	20	2,308
2041	2,285	2	20	2,308
2042	2,282	2	20	2,304
2043	2,276	2	20	2,298
2044	2,267	2	20	2,289
2045	2,262	2	20	2,284
2046	2,258	2	20	2,280

Year	CO_2 (t CO_2-e/year)	CH_4 (t CO_2-e/year)	N_2O (t CO_2-e/year)	Total (t CO_2-e/year)
2047	2,257	2	20	2,279
2048	2,254	2	20	2,276
2049	2,253	2	20	2,276
2050	2,253	2	20	2,275
2051	2,246	2	20	2,269
2052	2,241	2	20	2,263
2053	2,231	2	20	2,253
2054	2,212	2	20	2,234
2055	2,210	2	20	2,232
2056	2,193	2	20	2,215
2057	2,233	2	20	2,255
2058	2,188	2	20	2,210
Total	**123,559**	**113**	**1,098**	**124,770**

APPENDIX B GENERIC ASSESSMENT PARAMETERS

Description	Parameters assumed	Source of information
Project life		
Project life	35-40 years	Project Description chapter (Section 3) of the SREIS
Ramp-up period	2018-2023	
Operational period	2024-2053	
Ramp-down period	2054-2058	
Facilities life		
Facility:	Facility life:	Project Description chapter (Section 3) of the SREIS
CGPF	25-40 years	
FCF	25-40 years	
Well	15-30 years	
WTF	25-40 years	
Number of facilities		
Facility:	Number of facilities:	Project Description chapter (Section 3) of the SREIS. As in the EIS, a conservative number of substations (ten) were assumed for land clearance.
CGPF	2	
Dam (2xraw, 2xtreated, 2xbrine)	6	
FCF	33	
Vertical Production Wells	Up to 4000	
Substations	10	
Well configurations		
Well pad configurations:	Percentage of well pad configurations:	Project Description chapter (Section 3) of the SREIS A 12 well pad implies 6 vertical production wells only. An 8 well pad implies 4 vertical production wells only.
4 wells pad	71%	
8 wells pad	21.5%	
12 wells pad	7.5%	
Each well pad will contain 50% of vertical production wells and 50% of lateral wells. Only the vertical production wells will require power.		
Pipelines		
Pipeline:	Length	No change to EIS.
Gathering pipeline per well pad	8 km	
Medium pressure pipeline per FCF	25 km	
Overhead electricity transmission lines		
Transmission lines.	Length	6 x FCF's and 2 x CGPFs will each have a main substation
Per FCFs (66 kV)	15 km	
Per pad (from FCFs, 11 kV)	8 km	
Number of strategic FCFs and CGPFs with a main substation	8	

Description	Parameters assumed	Source of information
The following logic is used for vegetation clearance calculations of overhead lines. 80% of power distribution lines will be co-located with gathering and medium pressure lines. Wells with local power generation (10% or 400) must be excluded. Only strategic FCFs and CGPFs as above (8) should be taken into account This means that (2231-223) x 0.2=402 well pads and 8x0.2=2 FCFs will have overhead lines not co-located with pipelines. Additional land area needs to be cleared for these overhead lines. The 223 well pads are those which are powered locally and therefore which don't require overhead lines.		
Project Infrastructure Footprints (for vegetation clearance calculations)		
Facility: CGPF (including WTF)	Area: 500 x 250 m	No change to EIS
Dams at CGPFs	0.6 km^2	Assumed
FCF(including WTS)	200 x 380 m	
4 wells pad	130 x 175 m	
8 wells pad	130 x 235 m	
12 wells pad	130 x 295 m	
Main substation	200 x 150 m	
FCF substation	150 x 100 m	
Temporary power generation at each CGPF and strategic FCF (8)	150 x 80 m	
Low pressure Pipelines per well	2,200 x 10 m	
Medium pressure Pipelines per FCFs	25,000 x 10 m	
Overhead lines per each of the selected strategic FCFs (two)	30,000 x 6 m	
Overhead lines per each of the selected well pads	5,760 x 6 m	
Other facilities (including weather stations, workshops, warehouses, offices, etc.)	3 km^2	
CSG composition and properties		
GSG energy content factor	0.03729 GJ/m^3	No change to EIS
CSG density at standard conditions	0.726 kg/Sm^3	
CH_4 molar percentage of CSG	98.69 mol%	
CO_2 molar percentage of CSG	0.22 mol%	
Non-methane VOCs composition of CGG	0.04 mol%	
Molecular weight of CSG	16.24 kg/kmol	
GWP Value		
CH_4 (methane)	25	The updated AR4 GWP values for

Description	Parameters assumed	Source of information
N_2O (nitrous oxide)	298	CH_4 and N_2O have been applied (IPPC, 2007). The NGER (Measurement) Amendment Determination 2013 (Explanatory Statement) outlines the intention to adopt these values from 2017 onwards. Note that current NGER (2013) values are different: 21 for CH_4 and 310 for N_2O.

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URS Australia Pty Ltd
Level 17, 240 Queen Street
Brisbane, QLD 4000
GPO Box 302, QLD 4001
Australia

T: +61 7 3243 2111
F: +61 7 3243 2199

www.urs.com.au