HyNet CCUS Pre-FEED

Key Knowledge Deliverable

WP1: Full Chain Basis of Design

HyNet North West

EXECUTIVE SUMMARY

The Basis of Design Report was generated as part of the Preliminary Front End Engineering and Design (pre-FEED) study for the HyNet Industrial CCUS Project. The HyNet CCUS pre-FEED project commenced in April 2019, and was funded under grant by the Department for Business, Energy and Industrial Strategy (BEIS) under the Carbon Capture Utilisation and Storage (CCUS) Innovation Programme.

Delivery of the project was through a consortium formed between Progressive Energy Limited, Essar Oil (UK) Limited, CF Fertilisers UK Limited, Peel L&P Environmental Limited, University of Chester, and Cadent Gas Limited.

The main project objectives are as follows;

- To determine the technical feasibility of a full chain Industrial CCUS scheme comprising anchor loads from Stanlow Refinery and Ince Fertiliser Plant and storage in Liverpool Bay fields.
- To determine the optimised trade-off position between lowest initial cost and future scheme growth
- To determine capital and operating costs for the project to +/- 30% to support HMG development of a policy framework and support mechanism
- To undertake environmental scoping and determine a programme of work for the consent process

This document is one of a series of Key Knowledge Deliverables (KKD's) to be issued by BEIS for public information, as follows;

- HyNet CCUS Pre-FEED KKD WP1 - Basis of Design
- HyNet CCUS Pre-FEED KKD WP1 - Final Report
- HyNet CCUS Pre-FEED KKD WP2 - Essar Refinery Concept Study Report
- HyNet CCUS Pre-FEED KKD WP2 - Hydrogen Production Plant
- HyNet CCUS Pre-FEED KKD WP3 - Fertiliser Capture Report
- HyNet CCUS Pre-FEED KKD WP4 - Onshore CO2 Pipeline Design Study Report
- HyNet CCUS Pre-FEED KKD WP4 - CO2 Road Rail Transport Study Report
- HyNet CCUS Pre-FEED KKD WP5 - Flow Assurance Report
- HyNet CCUS Pre-FEED KKD WP6 - Offshore Transport and Storage
- HyNet CCUS Pre-FEED KKD WP7 - Consenting and Land Strategy

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1.0 INTRODUCTION

1.1 Project Background

HyNet is a project conceived and supported by numerous stakeholders, including the partners in this project, to decarbonise heat, power and transport in the North West industrial cluster. The project produces hydrogen from natural gas feedstock using a reforming process, captures and stores the resultant carbon dioxide (CO_2) offshore, and transports the hydrogen to industrial consumers using a newbuild pipeline with additional blending of hydrogen with natural gas for domestic consumers.

The initial project feasibility study was published in 2017, and a subsequent follow-up report was issued in 2018 (www.hynet.co.uk). As Government policies on CCUS and hydrogen deployment are still being formulated consideration has been given to the approach of focusing on a subset of the proposed HyNet Project in the first instance which provides material industrial emissions reduction, creates expandable CCUS (Carbon Capture Utilisation and Storage) infrastructure and is no regrets in terms of Government commitment. Notable uncertainties to be resolved include funding and regulatory structures and technical approval for use of hydrogen blends. A 'phased' approach allows material decarbonisation at the earliest possible point, and importantly increases confidence that the cost reduction associated with closure of the currently operating gas fields to be used as CO_2 stores can be captured.

The proposed phasing of HyNet is as follows:

- Phase 1: Industrial CCUS. This phase will capture existing emissions from Stanlow Refinery (Essar) and Ince Fertiliser Plant (CF Fertilisers), and, using principally existing, repurposed infrastructure, transport the carbon dioxide offshore and store it in the depleted Liverpool Bay fields.
- Phase 2: Hydrogen Production and Distribution. This phase will construct a hydrogen production plant and a pipeline to transport hydrogen to industrial consumers. Additionally, hydrogen will be blended with natural gas to materially reduce the carbon intensity of domestic heat.
- Phase 3: Enabling of the Hydrogen Economy. This phase will further expand hydrogen production and distribution infrastructure in the region, to include flexible power, construction of vehicle refuelling hubs and underground hydrogen seasonal storage facilities.

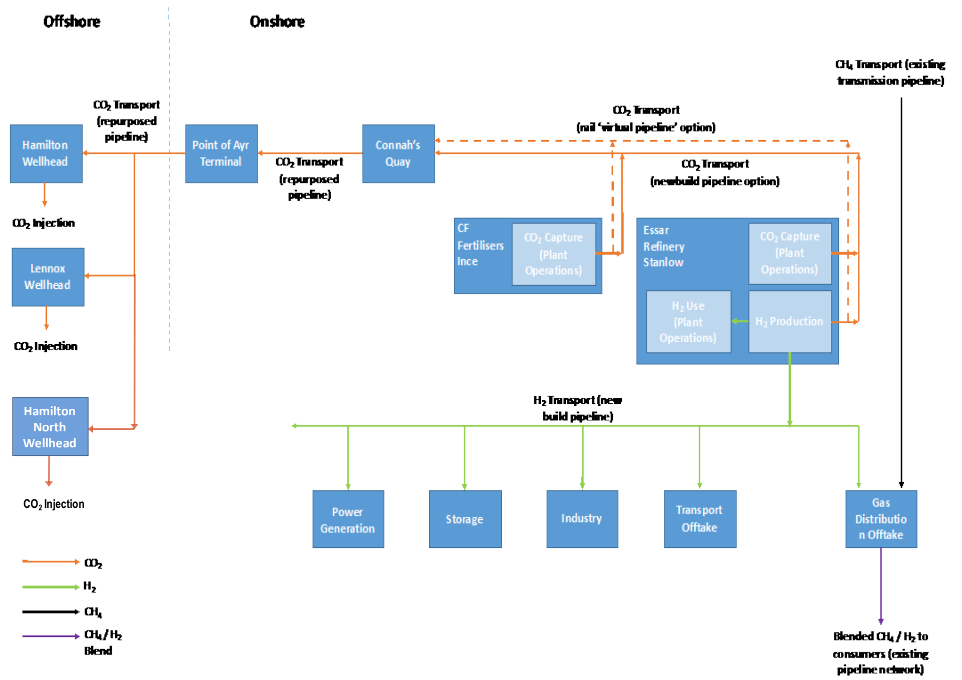


Figure 1 - HyNet Full Project Schematic

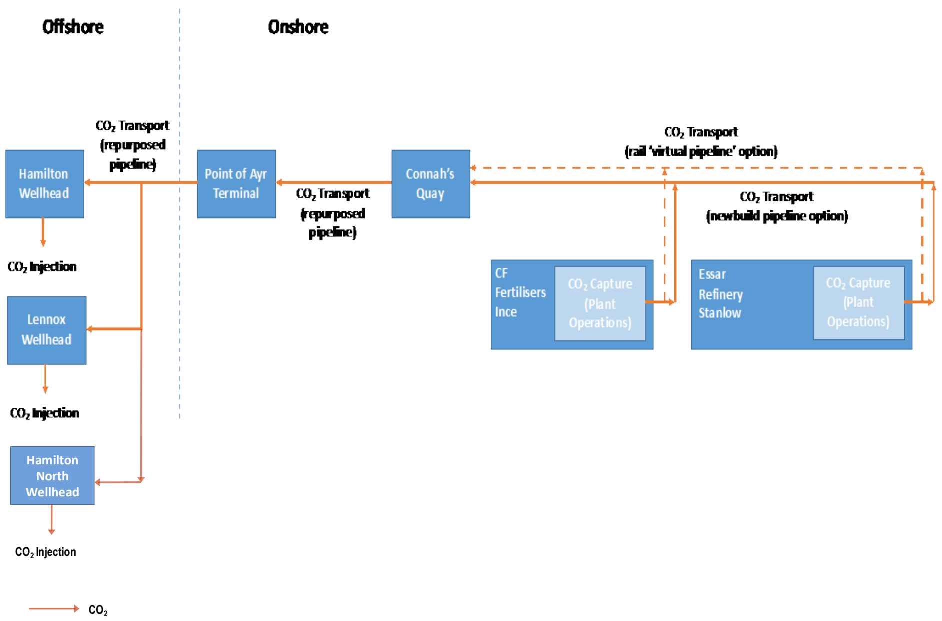


Figure 2 - HyNet Phase 1 Project Schematic

1.2 Project Scope

The objectives of the pre-FEED study are as follows:

- To determine the technical feasibility of a full chain Industrial CCUS scheme comprising anchor loads from Stanlow Refinery and Ince Fertiliser Plant and CO_2 storage in Liverpool Bay fields (see Figure 2 above);
- To determine the optimised trade-off position between lowest initial cost and future scheme growth which includes capture from additional industrial facilities and hydrogen production (see Figure 1 above);
- To determine capital and operating costs for the project to +/- 30% to inform HMG development of a policy framework and support mechanism;
- To determine a programme of work for the FEED study (scheduled from 2020-2022); and
- To undertake environmental scoping and determine a programme of work for the consent process.

The pre-FEED study will concentrate on developing a low-risk, low-cost, deliverable CCUS project based on emissions from Phase 1 and Phase 2 (see Section 1.1), but with optionality for future expansion.

1.3 Project Development Process and Timescales

It is intended that the project follows the development process as set out below:

- Pre-FEED: April 2019 to April 2020
- FEED: April 2020 to April 2022
- Onshore Pipeline Consent Determination (DCO): April 2022
- Offshore Storage License: April 2022
- Financial Investment Decision (FID): June 2022
- Construction and Commissioning: June 2022 to June 2024
- Capture Operations (Fertiliser Plant): June 2024 onwards
- Capture Operations (Refinery): December 2024 onwards
- Capture Operations (Hydrogen Production): June 2025 onwards

All timelines are indicative and subject to determination of policy and investment framework, consents and licenses etc.

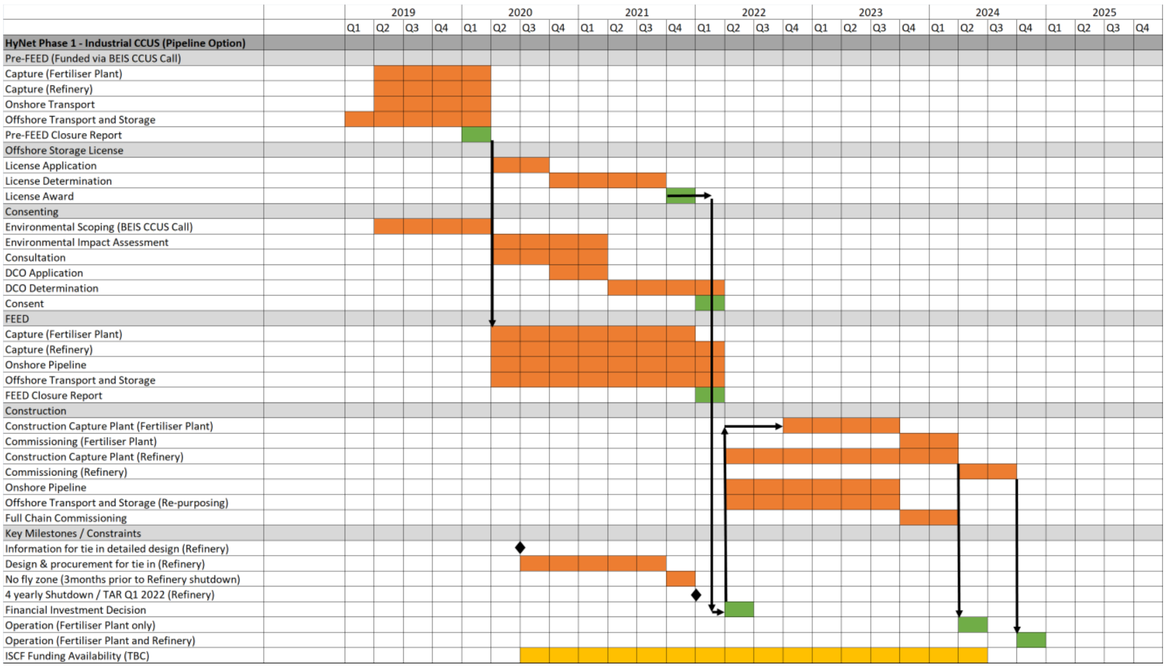


Figure 3 - Indicative Project Timeline (excluding Hydrogen Production Plant)

1.4 Project Participants

The following parties will participate in the project:

- Progressive Energy – Lead Project Partner
- Essar Oil UK – Project Partner, owner and operator of Stanlow Refinery
- CF Fertilisers – Project Partner, owner and operator of Ince Fertiliser Plant
- Peel – Project Partner
- Cadent – Project Partner
- University of Chester – Project Partner
- Eni – Project Collaborator, owner and operator of Liverpool Bay fields and associated infrastructure

1.5 Project Structure

The project is structured into 7 work packages:

- Work Package 1 – Project Management and Integration
- Work Package 2 – CO_2 Capture (Refinery)
- Work Package 3 – CO_2 Capture (Fertiliser Plant)
- Work Package 4 – CO_2 Transport (Onshore)
- Work Package 5 – Full Chain Flow Assurance
- Work Package 6 – CO_2 Transport (Offshore) and Storage
- Work Package 7 – Land and Planning

2.0 FULL CHAIN INTEGRATION

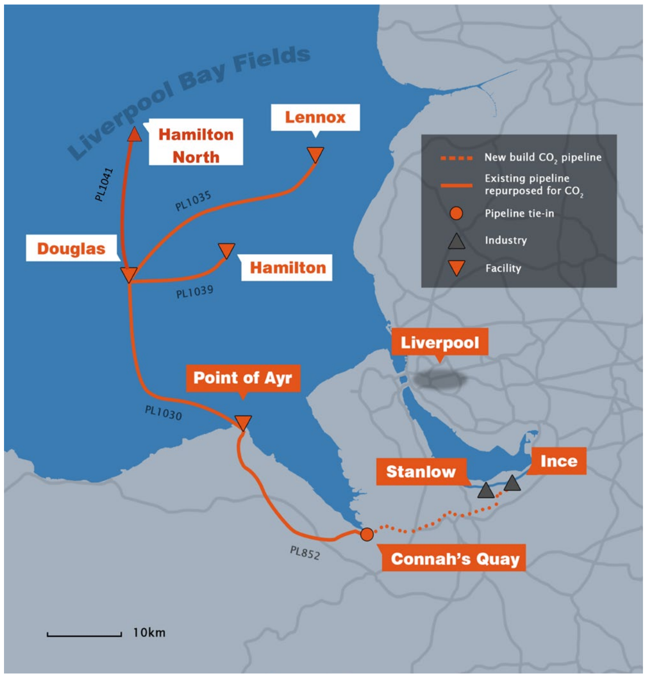
2.1 Project Location

The project is located in the North West of England and focuses on CO_2 emissions capture from existing industrial facilities in the Merseyside region, alongside capture from new-build industrial facilities and hydrogen production plant.

Initial capture sources are at Ince Fertiliser Plant (SJ473765) and Stanlow Refinery (SJ436751), both located between Ellesmere Port and Runcorn between the M56 and the Mersey. For the purposes of the pre-FEED it is assumed that the hydrogen production plant will be co-located at Stanlow Refinery and that new-build industrial facilities with CO_2 capture will be located at Protos (SJ465765).

CO_2 emissions from these sources will be transported along a new-build pipeline which will connect Ince Fertiliser Plant with Stanlow Refinery and then run from Stanlow Refinery to the south of Chester, and then north to Connah's Quay. At Connah's Quay the new-build pipeline will connect to the existing natural gas import pipeline at the existing gas processing facility adjacent to the Connah's Quay power station (SJ276712). The existing gas import pipeline is currently owned and operated by Eni.

Figure 4 - Map of HyNet Phase 1



The existing onshore natural gas import pipeline (PL852) will be re-purposed to become a CO_2 export pipeline and will transport the CO_2 to the existing Point of Ayr gas terminal (SJ121839)

From the Point of Ayr gas terminal, the existing offshore natural gas import pipeline (PL1030 / P908) will be re-purposed to become a CO_2 export pipeline and will transport the CO_2 to the Douglas complex.

From the Douglas complex, CO_2 will be transported along re-purposed natural gas pipelines initially to the Hamilton platform (PL1039) for injection into the Hamilton reservoir, to the Hamilton North platform (PL1041) for injection into the Hamilton North reservoir, and subsequently to the Lennox platform (PL1035, PL1036A and PL1034) for injection into the Lennox reservoir.

Compression facilities may be required along the pipeline route. The baseline configuration includes compression plants adjacent to, or co-located at Stanlow Refinery and Point of Ayr.

2.2 System Battery Limits and Design Authority

System Battery limits and relevant Design Authorities are set as follows:

Refinery Capture: Outlet from capture plant compressor. Essar Oil UK is the Design Authority for the refinery capture plant.

Fertiliser Plant Capture: Outlet from capture plant compressor. CF Fertilisers is the Design Authority for the fertiliser capture plant.

Hydrogen Production Plant Capture: Outlet from capture plant compressor. The future operating entity of the hydrogen production plant is currently unknown, but as Progressive Energy is the Lead Partner in a project undertaking a pre-FEED / FEED study of the plant they will be designated Design Authority for the hydrogen production plant capture plant for this pre-FEED study.

Protos Plant Capture: Outlet from capture plant compressor. At present, there is no specific industrial capture facility at Protos, and, as such, it will be included as a mass flow rate into the pipeline sizing and flow assurance modelling, but no capture plant engineering is required.

New-build Pipeline: Outlet from capture plant compressor at the Refinery and Fertiliser plant to tie-in point to existing natural gas pipeline (PL852) at Connah's Quay. Progressive Energy is the Design Authority for the new-build pipeline.

Existing onshore and offshore pipelines and offshore facilities: Tie-in point on PL852 at Connah's Quay. Eni is the Design Authority for the existing onshore and offshore pipelines and offshore facilities.

In addition to the above System Battery Limits which delineate physical interfaces, Progressive Energy will be Design Authority for full-chain integration, ensuring operability of the end to end system and specification and design of compression facilities.

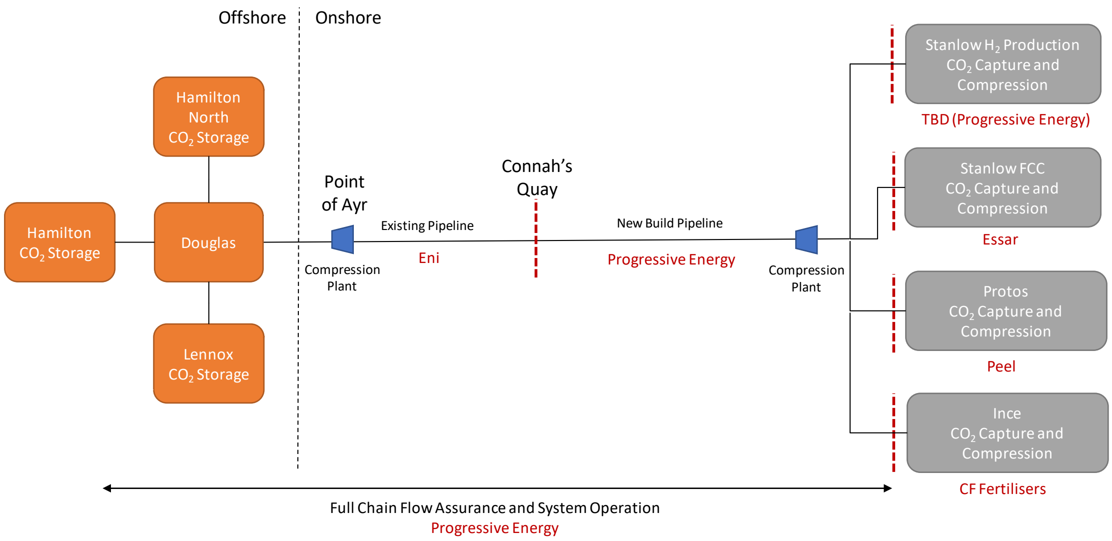


Figure 5 - Project Battery Limits

2.3 Units

Parameters	Units
Pressure	barg
Density	kg/m^3
Conductivity	W/m-°C
Heat Capacity	J/kg-°C
Wall Thickness	mm
Pipe Roughness	mm
Temperature	°C
Erosion Velocity	m/s
Pipe Length	km
Pipeline Diameter	Inches
Gas volume	Nm^3
Particle Content	ppmv, mol %
Mass Flowrate	kg/s
	$MtCO_2$/year where 1$MtCO_2$/year = 35.2 kg/s (see below)

Throughout the Basis of Design, and the wider project, units of mass flow rate will be both $MtCO_2$/year and kg/s. The $MtCO_2$/year will assume a 90% availability from all sources, so the corresponding rate of instantaneous flow will be 11.1% higher, 1$MtCO_2$/year therefore corresponds to a mass flow rate of 35.2kg/s.

2.4 Full Chain Operation

The operating modes for the capture plants and the transport and storage system will be start-up, part load, base load and shutdown. The flow assurance study will also assess various emergency shutdown modes.

The system will be designed to be operated with any combination of the three baseline capture plants operating in any of the operating modes. By extension, the system will also be designed to operate with new sources of CO_2 (see Section 2.10.3) which operate independently of other capture sources.

Given that this is being designed as a flexible system with multiple sources of CO_2, rather than a point to point system, a System Operator function will be required, either fulfilled by one of the actors or an independent entity. The control philosophy will reflect the System Operator role.

The anticipated operating sequence is as follows:

- Capture Plant: On start-up existing flue gases / CO_2 streams will be directed from the stack to the capture plant. When the processed CO_2 meets the required specification, it will be directed to the inlet of the transport and storage system once the system has confirmed it is ready to accept the CO_2.
- Transport and Storage System: On start-up, the CO_2, with confirmation of being within composition limits, will proceed through the pipeline system to the injection wellhead platform. In the initial stage of operation CO_2 will be transported in the gas phase and no additional system compression will be required. In the later stage of operation CO_2 will be transported in liquid phase and further system compression may be required. This is set out further in Section 2.5. Heating may be required at the wellhead prior to injection (see Section 4.4).

The design intent of the system is for the capture plants and the transport and storage system to operate continuously subject to pre-planned maintenance windows. It is anticipated that system maintenance windows will be aligned, wherever possible, with capture plant outages, and this alignment will be part of the role of the SO.

The proposed operation of the storage system will depend on the actual injection profile.

For the Baseline Scenario (see Figure 12 below) the storage capacity offered by the Hamilton field could be sufficient to store the total amount of injected CO_2.

However, in the case of higher injection profiles, the Hamilton North and Lennox fields would additionally be required to store the expected total amount of CO_2.

The transition from gas to liquid phase injection will depend on the reservoir storage capacity, the selected numbers of wells, the well completion sizes and well head P and T conditions. In the case of "Mid" and "High" injection scenarios, both sequential filling and parallel filling of the fields will be considered. The relative merits of providing system redundancy by filling a single field with multiple wells, versus parallel filing of more than one field will be explored.

In the parallel case having two or more operational storage reservoirs allows them to be transitioned from gas phase to liquid phase sequentially without any overall system downtime.

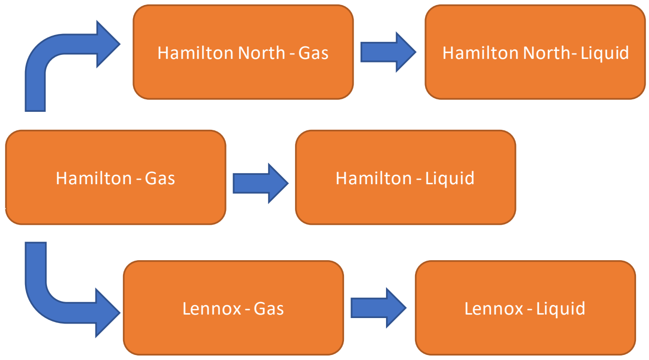


Figure 6 - Reservoir Fill Sequence (Option 1)

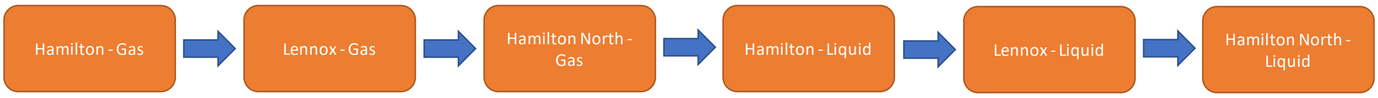


Figure 7 - Reservoir Fill Sequence (Option 2)

2.5 CO_2 Phases

The project will initially operate in gas phase to minimise capital investment requirements. Operating pressures for this regime are set out in Section 2.6.

At a future point, the project will transition to liquid phase flow for the offshore section of the system (beyond Point of Ayr). This part of the system will therefore be designed for both gas phase and liquid phase flow.

The trigger point for transition to liquid phase flow will be one of the following:

- Storage reservoir pressures increase to the point that liquid phase flow is required to continue to store. This will be a function of cumulative storage of CO_2.
- System flow rates increase to the level that flow in the existing pipeline is constrained. Preliminary calculations indicate that this occurs in PL852 at approximately 3.5MtCO_2/year 123.3kg/s).

This study will not undertake pre-FEED related to new assets required specifically to undertake the future transition from gas phase to liquid phase flow. For example, e.g. a replacement onshore pipeline for PL852 (which is assessed to be unsuitable for the pressures associated with liquid phase flow) will be required, and while this will be modelled for flow assurance purposes, its detailed routing, design and configuration will not be assessed. The environmental scoping and planning and consent assessment will also determine what consents would be required for the future replacement of this pipe.

2.6 Baseline System Configurations

Optimal system configuration will be determined as an iterative process during the pre-FEED through operational scenario workshops and flow assurance modelling. In order to provide a baseline system configuration for initial assessment, the following baseline scenarios have been established based on preliminary pipeline pressure loss calculations.

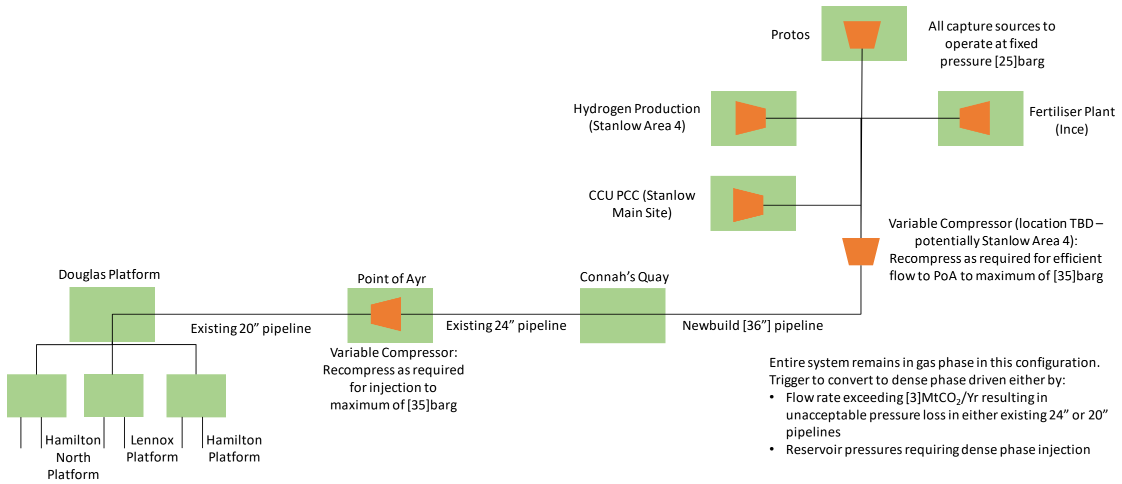


Figure 8 - Baseline System Configuration (Gas Phase)

The baseline system configuration (gas phase) set out above has the following key features:

- A low pressure 'collector' network, between capture plant and central variable compressor, operating in gas phase at fixed pressure [25barg] allowing all capture plants to operate at this pressure throughout the project life.
- A variable compressor located somewhere in the vicinity of the Stanlow site which is the control point for the System Operator to set the downstream system pressure for transport to Point of Ayr.
- A newbuild 36" pipeline from Stanlow to Connah's Quay, sufficient to transport up to [10]MtCO_2/year (maximum design mass flow rate) in gas phase.
- A tie-in to the existing 24" pipeline at Connah's Quay
- Further variable compression located at Point of Ayr which is the control point for the System Operator to set the downstream system pressure for injection.

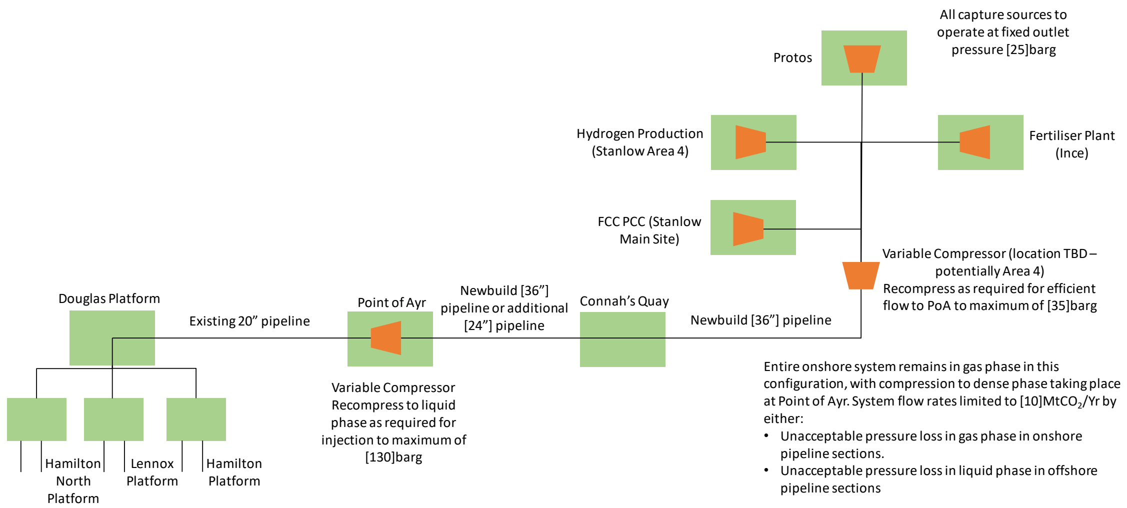


Figure 9 - Baseline System Configuration (Liquid Phase)

After a period of operation, the system will be reconfigured for liquid phase flow offshore. The transition to liquid phase will be determined either by mass flow rates in the existing 24" or 20" pipelines leading to unacceptable pressure loss in the system, or reservoir pressures requiring liquid phase for injection.

The baseline system configuration for liquid phase has the same low pressure 'collector' network as the gas phase configuration. System differences are as follows:

- Replacement of the existing 24" onshore pipeline with a new 36" pipeline, or the installation of a new 24" pipeline alongside retaining operation of the existing pipeline. This decision will be determined by economic and consenting considerations.
- Upgrading of the Point of Ayr compression facility to allow compression to liquid phase, allowing the offshore system to run at pressures up to [130]barg.

2.7 CO_2 System Pressures

2.7.1 Gas Phase

System operating pressures will be controlled to prevent the onset of two-stage flow. The system pressure margins will be set with reference to the Dew Point as follows:

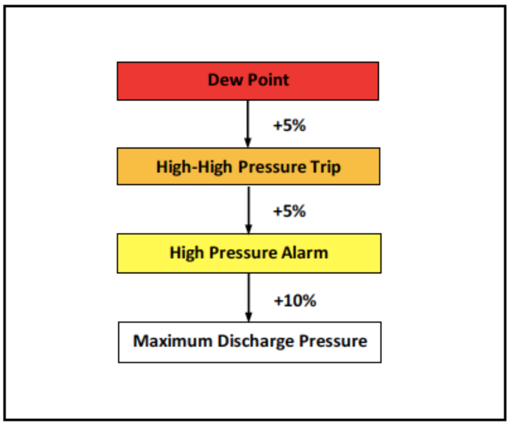


Figure 10 – System pressure margins (gas phase)

At the start of operations, reservoir pressure for Hamilton will be approximately [8]barg. Expected reservoir pressures for Lennox and Hamilton North will be calculated by Eni as part of their scope of work.

Injection pressure will therefore be set to [10]barg at the wellhead for Hamilton, Hamilton North and Lennox reservoirs (subject to further evaluation of Lennox and Hamilton North) and will progressively increase as reservoir pressure increases with increased storage volume.

Flow assurance modelling will determine optimal compression requirements at Stanlow and Point of Ayr to deliver the required injection pressure at the wellhead.

The following two normal operating modes for the gas phase flow will be assessed in the flow assurance modelling to set the system operating envelope:

1. Gas Low Pressure Mode (GLP) – Minimum operating pressure required to deliver gas at each of the two wellheads with no pressure losses at the wellhead choke(s).
2. Gas High Pressure Mode (GHP) – Maximum operating pressure possible, while maintain the CO_2 mixture in the gas phase subject to normal operational margins (see Figure 10). The upper pressure limit is ultimately constrained by the fluid dew point.

2.7.2 Liquid Phase

As set out in Section 2.5, the project will transition to liquid phase when one or both of the triggers are reached. At this point, system operating pressures will be set so as to minimise the risk of hydrogen break-out of the CO_2 mix. A maximum system operating pressure of [130]barg will be set although this will be reviewed during the project based on reservoir modelling and evaluation of existing offshore pipelines.

Pressure margins will be calculated with reference to the Bubble Point as follows:

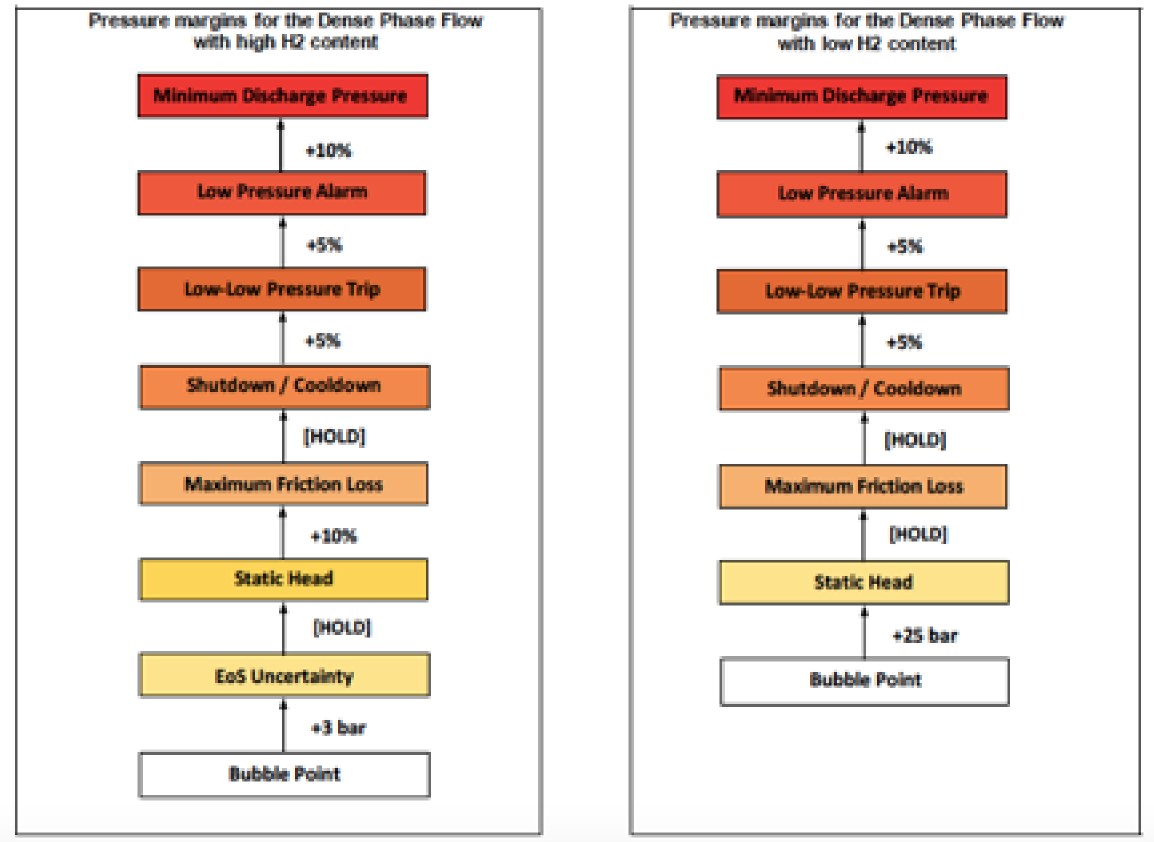


Figure 11 – System pressure margins (liquid phase)

High and low H_2 content are defined in Section 2.13.

The following two normal operating modes for the dense phase flow will be assessed in the flow assurance modelling to set the system operating envelope:

1. Dense Low Pressure Mode (DLP) – Minimum operating pressure required to prevent gas break-out from the CO_2 mixture, subject to normal operational margins (see Figure 11). The minimum operating pressure during dense phase is ultimately governed by the bubble point. There are two operating cases to be considered under DLP mode, one for each hydrogen content compositional case. The high hydrogen composition has a significantly higher bubble point than the base case, therefore this will impact the minimum operating pressure required to prevent gas breakout.
2. Dense High Pressure Mode (DHP) – Initial maximum operating pressure to be used in flow assurance modelling is 130 barg, not including normal operational margins.

2.8 System Compression

The baseline system configuration includes compression plant at both Stanlow and Point of Ayr. The compression plant at Point of Ayr will be utilised to compress to liquid phase when this becomes necessary.

2.9 System Venting Requirements

All capture plants will be designed to have onsite recirculation / vent capability in the event of emergency closure of the ROV (for example, in the event that CO_2 goes out of specification, or the transport and storage system is unable to accept CO_2).

The system will have vent capability at the wellhead and at an intermediate point on the onshore pipeline network. In the event of out of specification CO_2 flowing into the system, flow assurance modelling will determine the distance travelled by the gas prior to full closure of the ROV. This will determine the minimum distance along the pipeline from the capture plant for a possible vent location.

Depressurisation of the onshore and offshore pipelines would only be performed when absolutely necessary. The intention would be to retain the pipeline transportation system in a pressurised state over the 40 year design life.

Consideration will be given in the pre-FEED assessment process to the potential locations and configurations for vent locations and the requirement for vent stacks to be either permanent or temporary.

2.10 CO_2 Flowrates

2.10.1 Sources of CO_2

The HyNet project will capture CO_2 from a number of sources. One of the key elements of the project is to offer expandability to provide connection opportunities for sources beyond the initially identified sites. For the HyNet project, sources of CO_2 fall into two categories:

Industrial Capture: This is capture of CO_2 from existing and future industrial processes, such as steel manufacture, oil refining, fertiliser manufacture and cement manufacture. CO_2 will be captured using process plant retrofitted to existing facilities, and, in the case of new facilities, integrated into the core process.

Hydrogen Production Capture: This is capture of CO_2 from the manufacture of hydrogen using reformation of methane. It is anticipated that there will be a growing demand for hydrogen in the North West region and this is the heart of the HyNet vision. The hydrogen will be used for industrial fuel conversion, distribution network blending, flexible power generation and transport.

It is not anticipated at this point that there will be post combustion capture from power generation as part of the HyNet project.

2.10.2 Baseline Mass Flow Rate Scenario

A project baseline mass flow rate scenario has been generated which will form the primary design scenario for the project. This includes capture from existing industrial Stanlow Refinery and Ince Fertiliser Plant, capture from newbuild processes (e.g. at Protos site), and the CO_2 capture from two hydrogen production units (each unit is rated at 350MW and captures 0.62MtCO_2/year (21.8kg/s)). This baseline scenario is in line with the data supplied to Eni in Technical Note WP1.003 in February 2019 and is the reference injection profile for reservoir modelling.

2.10.3 Future CO_2 Emitters

It is anticipated that the HyNet project could expand substantially beyond the mass flow rates given above, particularly if the wider hydrogen economy accelerates. This would primarily include additional Hydrogen production plants, but would also include capture from additional industrial facilities:

- Hydrogen Blending at 20% by volume into the gas distribution network across the North West
- Substantial deployment of hydrogen fuelled heavy transport, particularly road and rail
- Conversion / new-build hydrogen power stations (CCGT – Combined Cycle Gas Turbines)

Beyond the baseline scenario described in Section 2.10.2 three additional scenarios have been set out in Section 0 below to provide an envelope for pre-FEED assessment. The 'High' scenario has been derived from a capacity assessment of the existing offshore pipeline (PL1030). Pressure loss increases substantially at higher flow rates and [10]MtCO_2/year (352.3kg/s) is an appropriate upper limit to maintain acceptable system pressures without requiring intermediate compression.

2.11 Mass Flow Rate Scenarios for Modelling

The mass flow rates described in this section are included as a table of annual flow rates in Appendix A.1.0. It should be noted that these scenarios are indicative only and don't represent actual projects under development.

Scenario	Maximum Flow Rate ($MtCO_2$ / Year)	Maximum Flow Rate (kg/s)	Phase	Cumulative Storage ($MtCO_2$)	Assumptions					
					Industrial CO_2 Capture	Hydrogen for Industrial Fuel Switching	Hydrogen for Blending	Hydrogen for Transport	Hydrogen for Flexible Power Generation	Maximum number of Hydrogen Units (350MW / 0.62$MtCO_2$ per unit)
Basecase Scenario	3.0	105.7	Gas transitioning to Liquid in 2035/36 (triggered by reservoir volume)	70.3	100% Capture at Stanlow CCU 100% Capture at Ince Fertiliser Plant 0% Capture of other Industrial CO_2 emissions in region (e.g. Cement) 50% Capture at newbuild sources (e.g. Protos)	25% of total hydrogen switching demand in NW is achieved (BEIS 2030 estimate)	50% of total hydrogen blending demand (at 20% volume) in NW is met	None	Approx 1x300MW CCGT converted to H_2 at 50% load factor	3
Low	1.2	42.3	Gas	28.7	100% Capture at Stanlow CCU 100% Capture at Ince Fertiliser Plant	None	None	None	None	0
Mid	5.9	207.7	Gas transitioning to Liquid in 2029/30 (triggered by pipeline capacity)	128.0	100% Capture at Stanlow CCU 100% Capture at Ince Fertiliser Plant 25% Capture of other Industrial CO_2 emissions in region (e.g. Cement) 50% Capture at newbuild sources (e.g. Protos)	50% of total hydrogen switching demand in NW is achieved (BEIS 2030 estimate)	100% of total hydrogen blending demand (at 20% volume) in NW is met (seasonal storage required)	25% of total NW region HGV energy demand is met by hydrogen	Approx 3x300MW CCGT and converted to H_2 at 50% load factor	7
High	10.0	352.5	Gas transitioning to Liquid in 2029/30 (triggered by pipeline capacity)	193.0	100% Capture at Stanlow CCU 100% Capture at Ince Fertiliser Plant 50% Capture of other Industrial CO_2 emissions in region (e.g. Cement) 100% Capture at newbuild sources (e.g. Protos)	100% of total hydrogen switching demand in NW is achieved (BEIS 2030 estimate)	100% of total hydrogen blending demand (at 20% volume) in NW is met (seasonal storage required)	50% of total NW region HGV energy demand is met by hydrogen	Approx 6x300MW CCGT converted to H_2 at 50% load factor	13

Figure 12 - Mass Flow Rate Scenarios for Modelling

Charts of annual and cumulative flow rates for these scenarios are set out below:

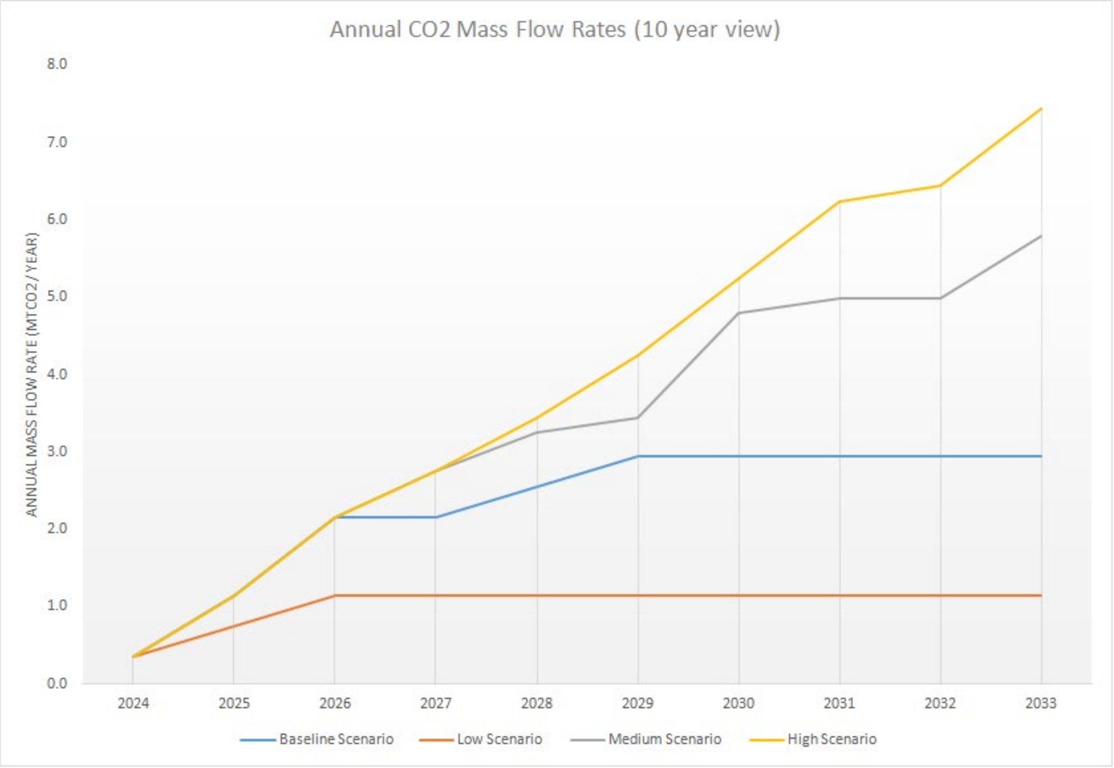


Figure 13 - Annual CO_2 Mass Flow Rates (10 year view)

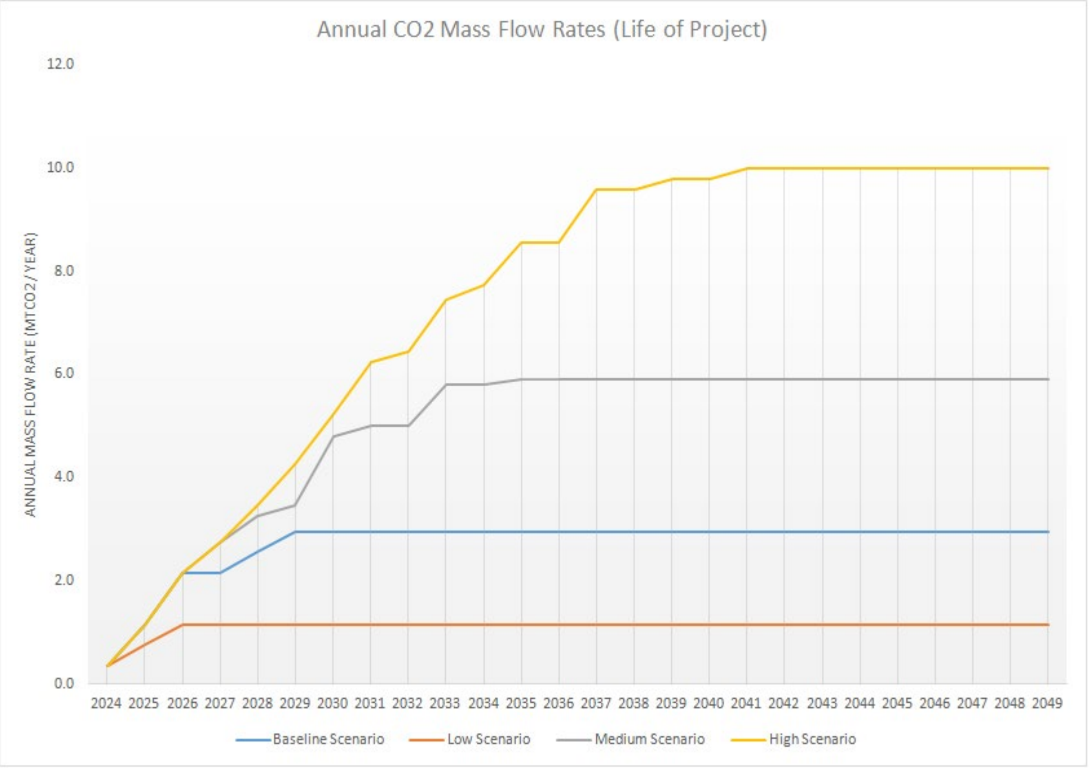


Figure 14 - Annual Mass Flow Rates by Source Type - Baseline Scenario

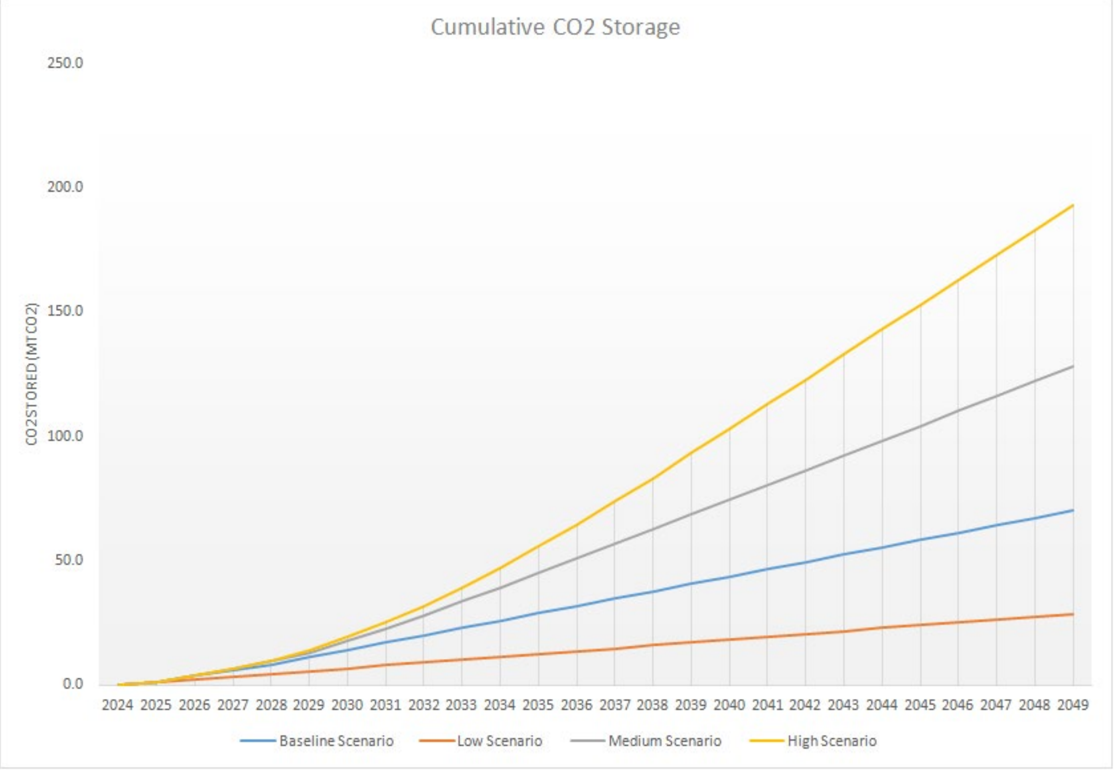


Figure 15 - Annual CO_2 Mass Flow Rates (Life of Project)

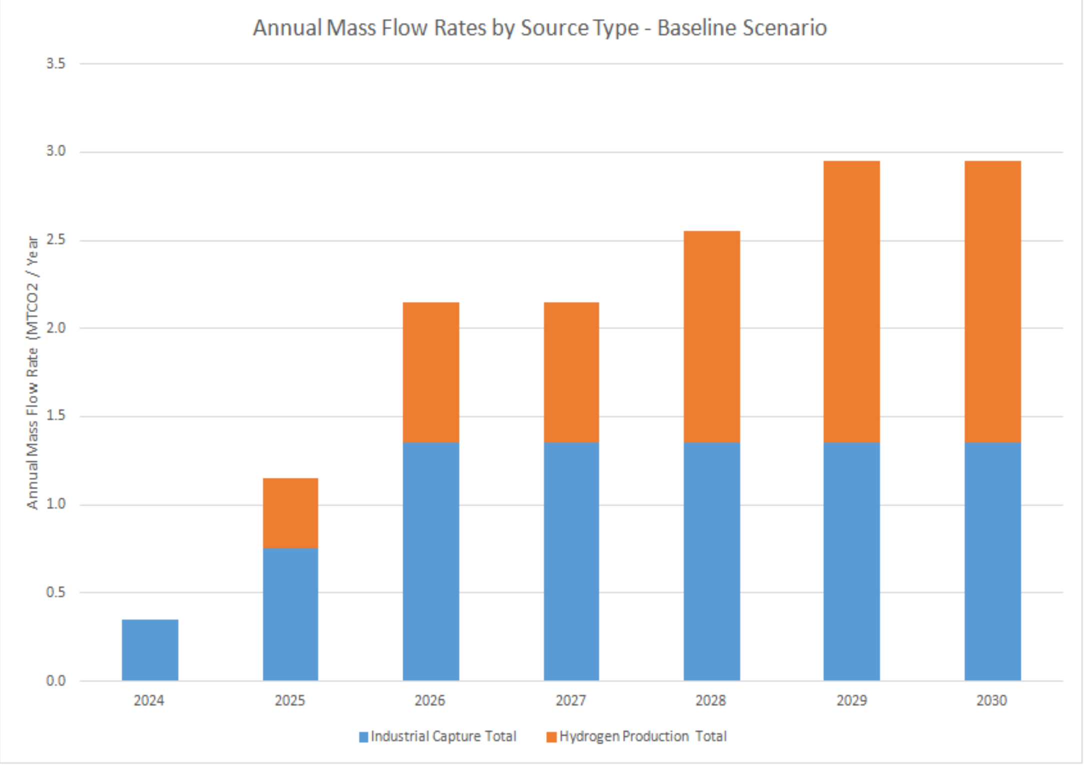


Figure 16 - Cumulative CO_2 Storage (Life of Project)

2.12 Locations of CO_2 Sources

Locations of the CO_2 sources in the Baseline Scenario are as follows:

- Fertiliser Plant Capture – Ince
- Catalytic Cracker Unit Post Combustion Capture – Stanlow Site
- Hydrogen Production Capture – Stanlow Site
- New Sources of CO_2 – Protos site, with connection to the pipeline between Ince and Stanlow

Additional sources of CO_2 in the Mid / High Scenarios are as follows:

- All additional Hydrogen Production Units assumed to be located at Stanlow
- All additional industrial sources assumed to connect to CO_2 pipeline at Stanlow at an appropriate pressure with the exception of Padeswood Cement (Part of the 'Other Existing Sources' line item in the Mass Flow Rate table in Annex A at 0.4MtCO_2/year (14.1kg/s)) which is assumed to be connected to the CO_2 pipeline at Connah's Quay at appropriate pressure.

2.13 CO_2 Composition

2.13.1 Baseline Composition – Low H_2

Capture plant CO_2 specifications are determined by specifications for transport and storage. All four capture plants in the Baseline Scenario(refinery, fertiliser plant, Protos and hydrogen production plant) will operate to the same specification, but, recognising that any individual capture plant may yield CO_2 of higher purity and that the CO_2 in the pipeline at any given time will be a blend from the four sources, this specification presents the worst case CO_2 purity envelope for consideration in the transport and storage assessment. All future sources will be required to meet the same specification.

Species	Limit
Ash	<1mg/Nm³, <1µm [7]
C_2+	<2.5mol % [1]
Carbon dioxide (CO_2)	>95 mol%
Carbon Monoxide (CO)	0.2% [5, 9]
Hydrogen (H_2)	<0.75 mol% [3, 9]
Water (H_2O)	<250 ppmv [2, 10]
Hydrogen Sulphide (H_2S)	<200 ppmv [1, 4, 9, 10]
Non-condensables (N_2, Ar, CH_4, etc.)	<4 mol% [8, 9]

Nitrogen oxides (NOx)	<50 ppmv [1]
Sulphur oxides (SOx)	<50ppmv [1]
Oxygen (O_2)	<10ppmv [6, 9]

Notes:

1. **BS ISO 27913:2016 Table A1**
2. **Avoidance of CO_2 hydrate formation, ref. "Evaluating the risk of hydrate formation in CO_2 pipelines under transient operation", International Journal of Greenhouse Gas Control, Vol 14, May 2013 pp 177-182**
3. **The bubble point for hydrogen within the CO2 stream should be determined for the lowest pressure and highest temperature in the pipeline. A design margin should be introduced such that the normal operating temperature is 10 % less than this, or the normal operating pressure is 5 % higher than this. (BS ISO 27913:2016 section C4).**
4. **"Effects of impurities on Geological Storage of CO_2", IEAGHG report 2011/4, June 2011.**
5. **At this level the impact on respiration is less than that of the CO_2 itself, and is equivalent to a 110ppm CO-in Natural Gas SLOT exposure time of 120 minutes**
6. **Avoidance of SRB production, ref. "Selection of an active souring management solution for a Gulf of Mexico waterflood", 'Corrosion' periodical 2004 ref. 04759**
7. **Levels to avoid pore blocking are not known. These figures set by manufacturers of CO_2 compressors.**
8. **Avoidance of running ductile fracture ref. "Pipeline transport for CO_2 mixtures: models for transient simulation", Aursand, Hammer, Munkejord, Wilhelmsen, SINTEF energy Research, Norway**
9. **Avoidance of running ductile fracture ref. "CO_2 pipeline integrity: Comparison of a fluid-structure model and uncoupled two-curve methods", Aursand, Dørum, Hammer, Morin, Munkejord, Norghagen, Energy Procedia 2014, 51 pp382-391**
10. **Changes to these Design Basis figures are captured in KKD WP1 Final Report**

Figure 17 - CO_2 specification

2.13.2 Alternative Composition – High H_2

Flow assurance modelling will also consider a 'High H_2' composition. Differences to the baseline composition are as follows (all other components remain the same):

Component	Base composition (mol %)	High hydrogen (mol %)
CO_2	97.25	96.0
H_2	0.75	2.0

Figure 18 - High H_2 composition

2.14 Turndown

The minimum mass flow rate will be 0.2MtCO_2 / year 7.0kg/s), calculated on 50% load from the single smallest source (Fertiliser Plant).

2.15 Ramp Rate

The system will accommodate a ramp rate of 2% / minute from each individual source in normal operation. Emergency shutdown at the capture plant, wellhead or any intermediate valve will be considered to reduce flow at that location from 100% to 0% in [1] minute.

2.16 System Availability and Reliability

Each capture plant will be designed to have an availability of [90%], averaged over a multi-year period to reflect periodic shutdowns. It is assumed that maintenance of the transport and storage system will be aligned with capture plant maintenance wherever possible.

The transport and storage system will operate with a reliability of [99%].

2.17 Metering and Monitoring

Monitoring is a fundamental requirement of the project requiring a range of metering, instrumental measurement, analytical measurement, observation, recording and reporting. These functions collectively must satisfy as minimum two sets of requirements:

- Real time
    - Safety;
    - Control;
- Retrospective and longer term
    - Regulatory;
    - Commercial.

2.17.1 Onshore Metering

CO_2 volumetric and mass flow rates will be measured to a fiscal standard prior to their exit from the capture plant. Consideration will be given to a range of technical metering solutions. CO_2 composition will also be measured at this point to ensure it is acceptable for entry into the Transport and Storage system.

2.17.2 Offshore Metering

CO_2 volumetric and mass flow rates will be measured to a fiscal standard at each wellhead prior to injection. Consideration will be given to a range of technical metering solutions. CO_2 composition will also be measured at this point to ensure it is acceptable for injection into the reservoir.

2.17.3 Subsurface Monitoring

A Monitoring Plan, the parameters to be monitored, and the technology required will be devised by Eni so as to be consistent with the requirements of Appendix 2 of the OGA Carbon dioxide storage permit application guidance (Reference) and Annex II of European Parliament and Council Directive 2009/31/EC.

2.18 Safety and Control

Given that there are multiple sources of CO_2 entering the transport and storage system, a central control system will be implemented to be operated by a System Operator function.

Operational control of each individual capture plant will remain with the relevant entity, but connection to the transport and storage system will be subject to 'dispatching' by the System Operator.

A System Operator controlled Remotely Operable Valve (ROV) will be installed at the battery limit between the capture plant and the transport and storage system to allow for system control and remote shutdown if required.

Sufficient instrumentation, metering and monitoring systems will be included in the system design to allow the system to operate safely in all routine and foreseeable upset conditions. Such systems should be sufficiently robust as to give an adequate level of confidence in the long-term safe operation of chain elements and the Full Chain;

2.19 Project Design Life

All pipelines in the full-chain will be designed for a 40 year operational life. All other system assets, including capture plants, heaters, compressors (if required) will be designed for a 25 year operational life, assuming commencement of operation in 2024 and cessation of operation in 2049.

Existing pipelines will require a recent intelligent pig run for each of the lines to be re-used, and an assessment of the corrosion rate for the new CO_2 service, to prepare a formal fitness for service assessment and to calculate the remaining life. This will then have to be agreed with the HSE Pipelines Inspectorate.

2.20 Decommissioning

Consideration should be applied to decommissioning methodology for all project assets during the pre-FEED phase. This is particularly applicable for offshore assets, where existing Oil and Gas Authority (OGA) assessment methodologies should be applied.

2.21 Planning, Consents and Land Access

Work Package 4 (WP4) will identify and progress the consent process for the newbuild onshore CO_2 pipeline, which is expected to be a DCO (Development Consent Order). This consent will consider both gas phase and liquid phase operation and will also assess what planning requirements, if any are required for the change of use of the existing onshore pipeline (PL852) between Connah's Quay and Point of Ayr.

In parallel, Work Package 7 (WP7) will identify any other project planning requirements and consider land access requirements for all project assets.

3.0 CAPTURE

3.1 Industrial Capture at Fertiliser Plant

The Ince Ammonia plant generates Carbon Dioxide as a by-product of the Steam Methane Reforming (SMR) of the natural gas feedstock, which is carried out to produce hydrogen for ammonia manufacture. The Carbon Dioxide is already removed from the process by a two stage capture process using an amine solution. Approximately 1.2 tonnes of this process CO_2 is produced per tonne of ammonia produced.

A portion of this process CO_2 is recovered, purified and liquefied on site for sale into the industrial gas market. This is carried out within a 3rd party owned plant and the maximum capacity of the plant is approximately 30% of the total process CO_2 emission. The remaining CO_2 is currently vented to atmosphere.

An additional emission of approximately 0.6 tonnes of CO_2 per tonne of Ammonia occurs in flue gas from the SMR. However, it has been decided not to include recovery of the combustion CO_2 in the initial scheme, as this will require the construction of a high cost CO_2 absorption and stripping system in the ammonia plant flue gas system. This project will therefore concentrate on capture of the process CO_2 only.

3.1.1 Existing Plant CO_2 Composition

The typical composition of the recovered CO_2 is[1]:

Component	Typical Content (Dry mole % basis)	Expected Operating Range (Dry mole % basis)
Carbon Dioxide	97.8	balance
Hydrogen	2.0	1.2 – 3.0 %
Nitrogen	0.2	0.1 – 1 %
Methane	0.01	
Carbon Monoxide	0	Negligible
Argon	0	Negligible

Figure 19 - Existing Plant CO_2 Composition

The gas steam will be saturated with water vapour, the water content is expected to be 15 - 20% on a mass basis, dependent on operating temperature.

[1] All gas composition data to be confirmed in WP3 Basis of Design Document

The main contaminants of the stream are expected to be Ammonia, Methanol, and Ethanol, (expected levels to be confirmed, in the detailed WP3 Basis of Design document).

All of these are highly water soluble and the majority of the contaminant will be removed along with condensate in cooling prior to and post compression. However a portion will pass through to the drying section.

3.1.2 Existing Plant CO_2 Mass Flow Rate and Pressure

Currently the maximum production rate is 1150 tonnes/day of Ammonia, which generates 1393 tonnes/day (58 tonnes/hour) of process CO_2. At typical operating rates on the Ammonia plant and CO_2 liquefaction plant, the expected flowrate of CO_2 available for capture would be 40 tonnes/hour)

A preliminary basis of design would be 3 x 20 tonne CO_2/hour compression systems, providing 50% redundancy when the CO_2 liquefaction plant is operating, but able to cope with the maximum capture rate if all 3 compressors are available.

The compressor capacity should include a suitable design margin [10 %] for potential future expansion and variations in natural gas composition and operating conditions.

The CO_2 is currently vented to atmosphere, with the only backpressure being that imposed by the vent nozzle.

The new system should be designed to maintain the pressure in the line leaving the top of the CO_2 Flash Column C1303 at [HOLD] mbarg (to be confirmed in WP 3 Basis of Design Document).

3.1.3 Plant Overview and Capture Plant Location

The proposed location of the compression plant and associated connection points is shown in the aerial view below.

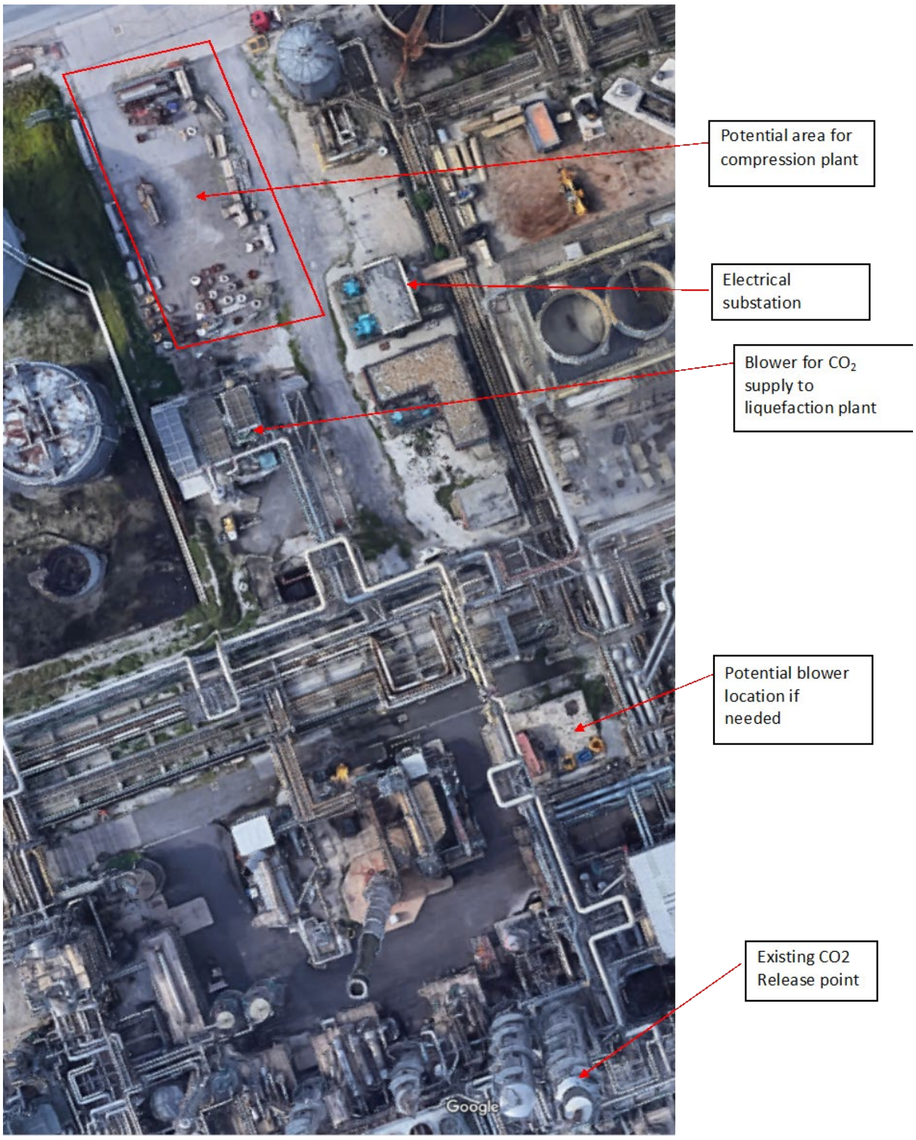


Figure 20 Proposed equipment locations

3.2 Industrial Capture at Refinery

The majority of capturable emissions from Stanlow Refinery are contained within the flue-gas from the Catalytic Cracker Unit (CCU). The proposed capture plant is a Post Combustion Capture (PCC) plant co-located adjacent to the existing CCU. This plot is heavily space constrained as illustrated in Figure 24, and Essar have recommended utilising a location directly south of the CCU for the PCC.

3.2.1 Post Combustion Capture Plant Proposed Configuration

The Post Combustion Capture plant will take existing flue-gas from the CO boiler outlet. This outline process will then raise steam through a waste heat steam generator, remove sulphur dioxide using a limestone scrubber, capture the CO_2 from the stream using an amine chemical solvent and compress the CO_2 to the required pressure for transport and storage. Additional dehydration may also be required. This process is subject to modification through the pre-FEED process.

3.2.2 Catalytic Cracker Unit Annual Emissions

The mass flow rate assumed for pipeline design, flow assurance and storage assessment is 0.8MtCO_2/year, which represents a capture rate of 90-95% based on historic annual emissions.

3.2.3 Catalytic Cracker Unit Flue-Gas Composition

Details redacted

3.2.4 Catalytic Cracker Unit Flue-Gas Mass Flow Rate, Temperature and Pressure

Details redacted

3.2.5 Plant Overview and Capture Plant Location

The location of the CCU unit on the Stanlow Site is as follows:

Figure 21 - Stanlow Site showing location of Catalytic Cracker Unit (CCU)

Space constraints in the existing plot are illustrated as follows:

Figure 22 - Stanlow Catalytic Cracker Unit (CCU) illustrating plot constraints

3.3 Hydrogen Production Capture

A hydrogen production plant pre-FEED and FEED programme of work is underway led by Progressive Energy and in partnership with Johnson Matthey plc (JM) and SNC Lavalin UK Ltd (SNCL).

The project is based on employing JM's Gas Heated Reformer (GHR) Auto-Thermal Reformer (ATR) technology and the proposed plant location is at Stanlow Refinery.

The size of unit shall be such as to produce 100,000 Nm^3/h of hydrogen when using 100% natural gas as a feedstock and CO_2, suitable for export, transportation and long-term geological storage. This size has been chosen to ensure that sufficient hydrogen is produced to make a material contribution to decarbonisation of the NW region and to secure economies of scale for the ATR configuration.

Each ATR unit has the following specification:

- Thermal Rating: 350MW (HHV) / 300MW (LHV)
- Utilisation: 95%
- Output: 3TWh H_2 / year
- CO_2 Captured: 0.62MtCO_2 / year (21.8kg/s)

The initial HyNet project assumptions call for two such units to be built to supply approximately 6 TWh of hydrogen per annum (LHV basis), of which 2/3 will be utilised directly to supply industry and the remainder will be blended into the local distribution network to reduce the carbon intensity of domestic heat. Over time, the HyNet project envisages multiple such plants to provide hydrogen for industry, distribution network blending, flexible power generation and transport across the region.

4.0 TRANSPORT AND STORAGE

4.1 Transport and Storage Design Concept

Captured CO_2 emissions will be transported along a new-build pipeline which will connect Ince Fertiliser Plant with Stanlow Refinery and then run from Stanlow Refinery to the south of Chester, and then north to Connah's Quay. At Connah's Quay the new-build pipeline will connect to the existing natural gas import pipeline currently owned and operated by Eni.

The existing onshore natural gas import pipeline (PL852) will be re-purposed to become a CO_2 export pipeline and will transport the CO_2 to the existing Point of Ayr gas terminal.

From the Point of Ayr gas terminal, the existing offshore natural gas import pipeline (PL1030 / P908) will be re-purposed to become a CO_2 export pipeline and will transport the CO_2 to the vicinity of the Douglas complex, where it will either be routed over the Douglas platform or more likely, through a new subsea cross-connection to connect with re-purposed natural gas pipelines initially to the Hamilton platform (PL1039) for injection into the Hamilton reservoir, and subsequently to the Lennox platform (PL1035, PL1034 and PL1036A) for injection into the Lennox reservoir, and to the Hamilton North Platform (PL1041) for injection into the Hamilton North reservoir.

The system will make use of existing assets wherever possible, including pipelines and offshore platforms.

The pipeline from Ince to Stanlow will always operate in gas phase. When the project transitions to liquid phase, additional compression will be utilised on the Stanlow site. No additional compression is envisaged at the Fertiliser Plant.

As set out in Section 2.8, no intermediate compression between Stanlow and Hamilton / Hamilton North / Lennox fields is envisaged either in the gas phase or the liquid phase stages of the project.

In gas phase the system will operate between 10-30barg and in liquid phase between 75-110barg (see Section 2.6).

4.2 Pipeline Description

The existing pipelines that can be potentially re-used are listed here below:

Pipeline	From	To	Diameter (in)	Wall Thickness (mm)	MAOP (bar)	Length (km)
PL852	CQY	PoA	24	11.1	70	26.4
PL1030	PoA	DD	20	20.6	130	32.1

PL1039	DD	HH	20	15.9	70	11.4
PL1041	DD	HN	14	12.7	95.5	14.6
PL1035	DD	LNX	16	11.9	70	32.1
PL1034	DD	LNX	14	11.1	75	32.1
PL1036A	DD	LNX	12	22.2	140	31.8

Figure 23 - Existing Pipelines

Where:

- CQY Connah's Quay
- PoA Point of Ayr
- DD Douglas Platform
- HH Hamilton Platform
- LNX Lennox Platform
- HN Hamilton North Platform

The current operating pressures are shown in Figure 24:

Pipeline	From	To	MAOP (barg)	Current operating pressure (barg)
PL852	CQY	PoA	70	**45**
PL1030	PoA	DD	130	**70**
PL1039	DD	HH	70	**TBC**
PL1035	DD	LNX	70	**51**
PL1034	DD	LNX	75	**42**
PL1036A	DD	LNX	140	**42**
PL1041	DD	**HN**	**95**	TBC

Figure 24 - Existing Pipeline Operating Pressures

Maximum Operating Pressure (MAOP) will be confirmed for all existing pipelines as part of the pre-FEED activity.

Re-use of existing pipelines can only be confirmed after definition of operating conditions in the network and associated Flow Assurance simulations.

The new-build pipeline section will run from Stanlow to Connah's Quay, as per the following preliminary route map (with tie-in point to P852 expected to be within the

Connah's Quay gas processing plant exact location to be decided as a part of this FEED and in discussion with the operators):

Figure 25 - Preliminary Onshore Pipeline Route (Stanlow to Connah's Quay)

The baseline design specification of the newbuild pipeline will be a MAOP of 130Bar to accommodate liquid phase flow and a diameter of 24in (600mm) to allow continuous pigging of the onshore pipeline from Stanlow to Point of Ayr through the tie-in point at Connah's Quay. Maximum flow-rates and pressure loss should be calculated for this design as part of the pre-FEED, and, if flow-rates are not able to meet the 10MtCO_2 / year 352.3kg/s) requirement a preliminary study of a larger pipe diameter will be undertaken. It should be noted that any economic benefit of this approach would be partially offset by the need to install separate pigging facilities at Connah's Quay.

There is an existing 6" pipeline between Ince Fertiliser Plant and Stanlow Refinery (YP4017), and, while analysis demonstrates that the pipe is of sufficient strength to meet pressure requirements, its diameter is not sufficient to meet flow rate requirements. A new pipeline will therefore be required. Preliminary calculations indicate that an 8" pipe will be appropriate to accommodate mass flow rates from Ince, but this will be revisited during the pre-FEED in light of additional potential connections from the Protos site.

The new pipeline will use, if possible, the existing easement.

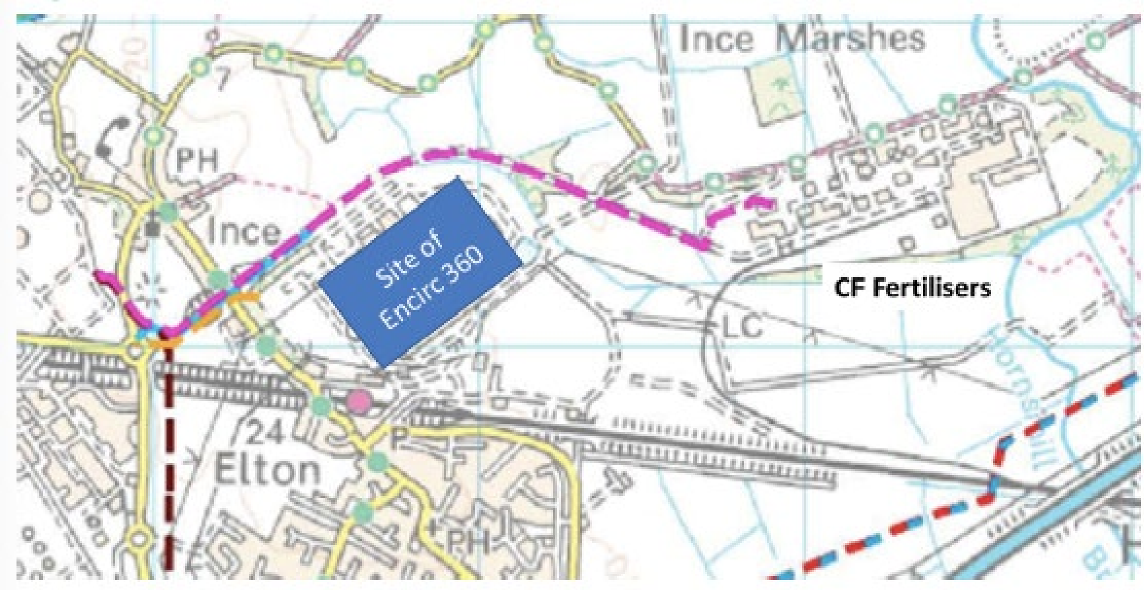


Figure 26 - Pipeline easement from Ince Fertiliser Plant to Stanlow

4.3 Onshore CO_2 Transport Alternative Options Description

The pre-FEED study will consider alternative CO_2 transport options (rail / road) from Stanlow / Ince to Point of Ayr to provide a counterfactual for the pipeline baseline scenario. This assessment will be undertaken to provide a technical and economic assessment of the viability of rail / road transport and it will also provide a fall back scenario for the project should the pipeline encounter consenting challenges.

The pre-FEED study will assume liquid phase transport, and hence there will be a requirement for liquefaction at source (the baseline will be a single liquefaction facility at either Stanlow or Ince, with a pipeline between the two sites). A buffer store will be required at source, and potentially at the pipeline connection point such that continuous flow can be achieved from the capture plants and for injection into the transport and storage network.

The study will consider alternative transport solutions between Stanlow / Ince and Connah's Quay, and between Stanlow / Ince and Point of Ayr.

4.4 Offshore Facilities Description

The offshore facilities to be used in the project[2] are as follows:

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[2] The baseline assumption is that the existing Douglas Process Platform will be by-passed to allow decommissioning.

Platform	Type	Water Depth [m]	Inst. Year	Design Life [years]	Planned End of Life
Lennox (LD)	Wellhead & Process Platform	8.5	1995	30	2025
Hamilton (HH)	Wellhead Platform	25.8	1995	30	2025
Hamilton North (HN)	Wellhead Platform	25.0	1995	30	2025

Figure 27 - Existing Offshore Platforms

All of the existing pipelines identified in Section 4.2 have flanged tie-in spools, and so these can be used to make a subsea cross-connection, and thereby avoid having to retain the Douglas DD platform.

Initial assessment of these platforms by Eni has indicated that lifetime extension in line with projected project lifetime is feasible, although more detailed work is required. The assessment also indicates that existing facilities can accommodate up to 200t of additional topside weight if required.

Additional process equipment maybe required on the wellhead platform potentially including measuring and monitoring equipment and heating to ensure that the injected CO_2 remains at an appropriate temperature as pressures reduce from pipeline pressure to reservoir pressure. Eni will assess this requirement in conjunction with the Flow Assurance modelling.

The requirement for wellhead heating during the gas phase stage of the project has not yet been determined. It is assumed that heating will be required during the liquid phase stage of the project, as pipeline pressure will be significantly greater than reservoir pressure for a period of time and rapid cooling will ensue when the pressure reduces on injection.

The requirement for wellhead heating will be determined from the results of flow assurance modelling. Progressive Energy will then determine an appropriate heater configuration and provide this space and mass requirement to Eni for evaluation.

4.5 Reservoir Description

4.5.1 Hamilton

The Hamilton depleted gas field site is one of the largest of a series of fields located in the Liverpool bay area of the East Irish Sea. It is located around 40km south of the large Morecambe Bay gas field and is some 23km from landfall at Merseyside. The field was discovered in June 1990 with first gas delivered in February 1997. Hamilton is notable for its significant pressure depletion and its shallow depth, which has resulted in it being identified as one of the most suitable CO_2 storage sites in UK waters[3].

The field has high storage efficiency and is estimated to have a total storage potential of 125 $MtCO_2$ in liquid phase. Hamilton's capacity to securely store CO_2 in liquid phase will be subject to further assessment in the pre-FEED study.

4.5.2 Lennox

Lennox in an oil field with a gas cap. It is part of the Liverpool Bay complex of fields in the East Irish Sea and is located around 20 km east of Hamilton field, and around 15km from shore.

Lennox was discovered in June 1990 with first production early in 1996. Lennox oil production is exported via offshore loading directly into tankers, and its gas production from the gas cap is exported via Douglas.

The gas depleted gas cap provides a storage volume, with an estimated total storage potential of 80 $MtCO_2$ in liquid phase[4]. Lennox's capacity to securely store CO_2 in liquid phase will be subject to further assessment in the pre-FEED study.

4.5.3 Hamilton North

Hamilton North is a depleted gas field, 8km to the north of the Hamilton field.

First production was in December 1995. The field is estimated to have a total storage potential of 23 $MtCO_2$ in liquid phase[5]. Hamilton North's capacity to securely store CO_2 in liquid phase will be subject to further assessment in the pre-FEED study.

4.6 Well Configuration

The required number of wells will change according to the assumed injection profile and the completion size selection. Considering the Baseline Scenario volumes, and existing well completions, 3-4 wells could be necessary for gaseous phase injection and just 1 well for dense phase injection. Redundancy can be achieved by adding an additional well or injecting in parallel in two or more reservoirs. Higher injection rates can be reached with additional wells or different size completions.

System redundancy will be guaranteed either considering multiple wells per reservoir or two or more reservoirs operating in parallel.

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[3] Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource, Energy Technologies Institute, April 2016

[4] Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource, Energy Technologies Institute, April 2016

[5] Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK, Report No. COAL R308, DTI/Pub URN 06/2027, October 2006

Eni's review will address the feasibility of re-use of existing well stock.

4.7 Offshore Environmental Data

[HOLD]

A.1.0 GLOSSARY

A.1.1 DEFINITIONS

ATR	Auto Thermal Reformation
CCUS	Carbon Capture Utilisation and Storage
CCU	Catalytic Cracker Unit
DCO	Development Consent Order
FEED	Front End Engineering Design
HHV	Higher Heating Value
HMG	Her Majesty's Government
LHV	Lower Heating Value
MAOP	Maximum Allowable Operating Pressure
OGA	Oil and Gas Authority
PCC	Post Combustion Capture
SO	System Operator

A.2.0 MASS FLOW RATES – ANNUAL BREAKDOWN

HyNet CO2 Mass Flow Rate Scenarios

Baseline Scenario	**Source**	**Proportion of maximum captured**	**Maximum**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**
	Industry Capture																												
	Stanlow FCC	100%	0.80	0.0	0.4	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	Ince Ammonia Plant	100%	0.35	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Other Existing Sources (e.g. Cement)	0%	0.60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other New Sources (e.g. Protos)	50%	0.40	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Industrial Capture Total			0.4	0.8	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
	Hydrogen Production Capture																												
	Industry Hydrogen Fuel Switching	25%	1.70	0.0	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Hydrogen Flexible Power Generation		3.84	0.0	0.0	0.0	0.0	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	Hydrogen Blending	50%	0.89	0.0	0.2	0.4	0.4	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	Hydrogen Transport	0%	1.42	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hydrogen Production Total			0.0	0.4	0.8	0.8	1.2	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
	Annual Total			0.4	1.2	2.2	2.2	2.6	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
	Cumulative Total			0.4	1.5	3.7	5.8	8.4	11.3	14.3	17.2	20.2	23.1	26.1	29.0	32.0	34.9	37.9	40.8	43.8	46.7	49.7	52.6	55.6	58.5	61.5	64.4	67.4	70.3
	Number of Hydrogen ATR Units			0	1	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Low Scenario	**Source**	**Proportion of maximum captured**	**Maximum**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**
	Industry Capture																												
	Stanlow FCC	100%	0.80	0.0	0.4	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	Ince Ammonia Plant	100%	0.35	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Other Existing Sources (e.g. Cement)	0%	0.60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other New Sources (e.g. Protos)	0%	0.40	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Industrial Capture Total			0.4	0.8	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
	Hydrogen Production Capture																												
	Industry Hydrogen Fuel Switching	0%	1.70	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hydrogen Flexible Power Generation			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hydrogen Blending	0%	0.89	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hydrogen Transport	0%	1.42	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hydrogen Production Total			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Annual Total			0.4	0.8	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
	Cumulative Total			0.4	1.1	2.3	3.4	4.6	5.7	6.9	8.0	9.2	10.3	11.5	12.6	13.8	14.9	16.1	17.2	18.4	19.5	20.7	21.8	23.0	24.1	25.3	26.4	27.6	28.7
	Number of Hydrogen ATR Units			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Medium Scenario	**Source**	**Proportion of maximum captured**	**Maximum**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**
	Industry Capture																												
	Stanlow FCC	100%	0.80	0.0	0.4	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	Ince Ammonia Plant	100%	0.35	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Other Existing Sources (e.g. Cement)	50%	0.60	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Other New Sources (e.g. Protos)	50%	0.40	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Industrial Capture Total			0.4	0.8	1.4	1.4	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	Hydrogen Production Capture																												
	Industry Hydrogen Fuel Switching	50%	1.70	0.0	0.2	0.4	0.4	0.4	0.4	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	Hydrogen Flexible Power Generation	50%	3.84	0.0	0.0	0.0	0.6	0.6	0.6	1.2	1.2	1.2	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
	Hydrogen Blending	100%	0.89	0.0	0.2	0.4	0.4	0.6	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
	Hydrogen Transport	50%	1.42	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.4	0.4	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
	Hydrogen Production Total			0.0	0.4	0.8	1.4	1.6	1.8	3.1	3.3	3.3	4.1	4.1	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
	Annual Total			0.4	1.2	2.2	2.8	3.3	3.5	4.8	5.0	5.0	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
	Cumulative Total			0.4	1.5	3.7	6.4	9.7	13.1	17.9	22.9	27.9	33.7	39.5	45.4	51.3	57.2	63.1	69.0	74.9	80.8	86.7	92.6	98.5	104.4	110.3	116.2	122.1	128.0
	Number of Hydrogen ATR Units			0	1	2	3	3	3	6	6	6	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
High Scenario	**Source**		**Maximum**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**
	Industry Capture																												
	Stanlow FCC	100%	0.80	0.0	0.4	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	Ince Ammonia Plant	100%	0.35	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Other Existing Sources (e.g. Cement)	100%	0.60	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	Other New Sources (e.g. Protos)	100%	0.40	0.0	0.0	0.2	0.2	0.2	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Industrial Capture Total			0.4	0.8	1.4	1.4	1.7	1.7	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
	Hydrogen Production Capture																												
	Industry Hydrogen Fuel Switching	100%	1.70	0.0	0.2	0.4	0.4	0.6	0.6	0.8	1.0	1.2	1.4	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	Hydrogen Flexible Power Generation	100%	3.84	0.0	0.0	0.0	0.6	0.6	1.2	1.2	1.8	1.8	2.4	2.4	3.0	3.0	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
	Hydrogen Blending	100%	0.89	0.0	0.2	0.4	0.4	0.6	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
	Hydrogen Transport	100%	1.42	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.4	0.4	0.6	0.6	0.8	0.8	1.0	1.0	1.2	1.2	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
	Hydrogen Production Total			0.0	0.4	0.8	1.4	1.8	2.6	3.1	4.1	4.3	5.3	5.6	6.4	6.4	7.4	7.4	7.6	7.6	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
	Annual Total			0.4	1.2	2.2	2.8	3.5	4.3	5.2	6.2	6.4	7.4	7.7	8.5	8.5	9.6	9.6	9.8	9.8	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
	Cumulative Total			0.4	1.5	3.7	6.4	9.9	14.1	19.3	25.6	32.0	39.5	47.2	55.8	64.3	73.9	83.5	93.2	103.0	113.0	123.0	133.0	143.0	153.0	163.0	173.0	183.0	193.0
	Number of Hydrogen ATR Units			0	1	2	3	3	5	5	7	7	9	10	11	11	12	12	13	13	13	13	13	13	13	13	13	13	13