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North Sea
Transition
Authority

TECHNICAL NOTE

Bacton Energy Hub Supply SIG – Green Hydrogen Technology Readiness Report

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ABBREVIATIONS

Bbls	Barrels
BoP	Balance of Plant
BCA	Bacton Catchment Area
CAPEX	Capital expenditure
CO_2	Carbon Dioxide
CTR	Cost Time Resource
CUFT	Cubic Feet
FID	Final Investment Decision
GW	Giga Watt
H_2	Hydrogen
H&MB	Heat and Material Balance
HHV	Higher Heating Value
K	Thousand
MMcm	Million Cubic Meters
MW	Megawatt
MWh	Megawatt Hours
NSTA	North Sea Transition Authority
NTP	Normal Temperature and Pressure
OEM	Original Equipment Manufacturer
OGA	Oil and Gas Authority
R&D	Research & Development
SIG	Special Interest Group
TWh	Terawatt Hours
UK	United Kingdom

HOLDS LIST

HOLD	SECTION	DESCRIPTION
01	1.1	Introduction background text template for all reports as defined by the NSTA
02		
03		

1.0 INTRODUCTION

1.1 Background [HOLD 1]

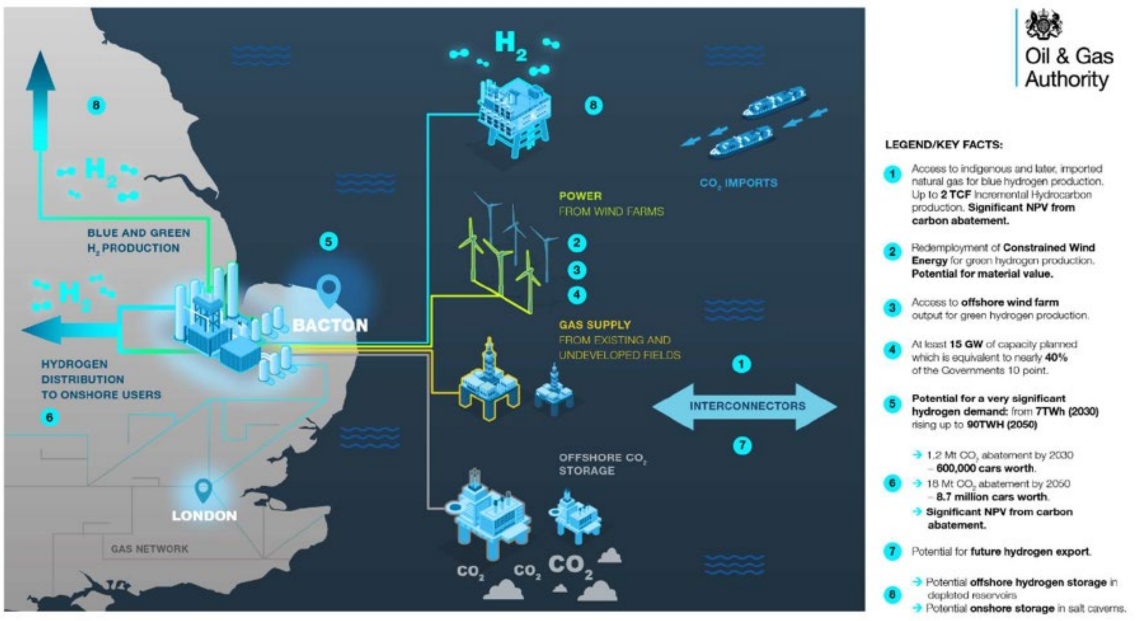
In 2021 the UK North Sea Transition Authority ("NSTA", formally known as the Oil & Gas Authority) commissioned a future vision for the Southern North Sea and Bacton considering the potential role of hydrogen in supporting the delivery of Maximising Economic Recovery and Net Zero. The study area, which is described as the Bacton Catchment Area ("BCA") comprises the Southern North Sea, and the onshore areas defined by National Grid's East of England and North Thames areas.

Bacton is ideally positioned to become a significant hydrogen production facility for London and the South East. It has a number of critical advantages:

- Access to indigenous and, later, imported natural gas for blue hydrogen production
- Access to offshore wind farm output for green hydrogen production
- Availability of offshore structures for carbon dioxide (CO_2) and hydrogen (H_2) storage
- Ample land for development of hydrogen production
- Excellent gas connections to London and the South East of England

These factors combine to make Bacton ideally situated for development as a low carbon hub.

Figure 1-1 Bacton Energy hub Potential Development Scheme



LEGEND/KEY FACTS:

1. Access to indigenous and later, imported natural gas for blue hydrogen production. Up to **2 TCF** Incremental Hydrocarbon production. **Significant NPV from carbon abatement.**
2. Redemployment of **Constrained Wind Energy** for green hydrogen production. **Potential for material value.**
3. Access to **offshore wind farm** output for green hydrogen production.
4. At least **15 GW** of capacity planned which is equivalent to nearly **40%** of the Governments 10 point.
5. **Potential for a very significant hydrogen demand:** from **7TWh (2030)** rising up to **90TWH (2050)**
6. → 1.2 Mt CO_2 abatement by 2030 – **600,000 cars worth**.
   → 18 Mt CO_2 abatement by 2050 – **8.7 million cars worth**.
   → **Significant NPV from carbon abatement.**
7. Potential for **future hydrogen export**.
8. → Potential **offshore hydrogen storage** in depleted reservoirs
   → Potential **onshore storage** in salt caverns.

Hydrogen production at Bacton could help to decarbonise not just the study area, which comprises nearly 20% of the UK population, but also to contribute to decarbonisation in London and South East more widely.

This development would contribute to the UK's decarbonisation targets, and to the recently published "Ten Point Plan for a Green Industrial Revolution", specifically by supporting objectives 1 ("Advancing Offshore Wind"), 2 ("Driving the Growth of Low Carbon Hydrogen") and 8 ("Investing in Carbon Capture, Usage and Storage").

It is recognised that there are a multitude of scenarios that are credible, however detailed scenarios will ultimately be required to be explored by the consortium in the future phases of the project. Therefore, maturing an extensive list of scenarios at this stage of the project will add little value when considering the key objective for this phase. It is not the intention of this phase of the project to define the technical specification or detailed basis of design of the hub, but rather propose a development concept supported by a scoping level design outline to help frame the potential.

1.2 Study Objective

This study objective is to define a concept supported by a "scoping level design" for a 2.1 GW green hydrogen plant. The basis is underpinned by the "BEH Scenario Summary" (see Appendix B) as outlined:

- 2040: 1 x 2.1 GW Electrolyser
- 2050: 1 x 2.1 GW Electrolyser + 2 x 2.1 GW Electrolyser plants
- Green Hydrogen feedstock assumptions: dedicated wind/solar plus connection to (green) grid (2050)

The study work will focus on a single 2.1 GW plant with a repeated design for 2050.

Three key deliverables are part of the required scope of work (refer to the green hydrogen CTR in Appendix A) as listed below:

1. Production facility technology readiness report
    - Review and identify Green Hydrogen technologies
    - Technology availability and anticipated development (upscaling)
    - Discussion of Bacton phasing and how the right technology may change before FID is reached or even between development phases
2. Production facility sizing/scoping
    - Phasing
    - Storage
3. Production profiles for Green Hydrogen, phased
    - Will be part of deliverable 2 above.

1.3 Document Purpose

The purpose of this report is to outline the production facility technology readiness scope.

This report is agnostic, and no preference is given to vendors. It is assumed technology and vendor selection will be performed in the subsequent phases of the BEH development. No costs have been included other than a relative cost.

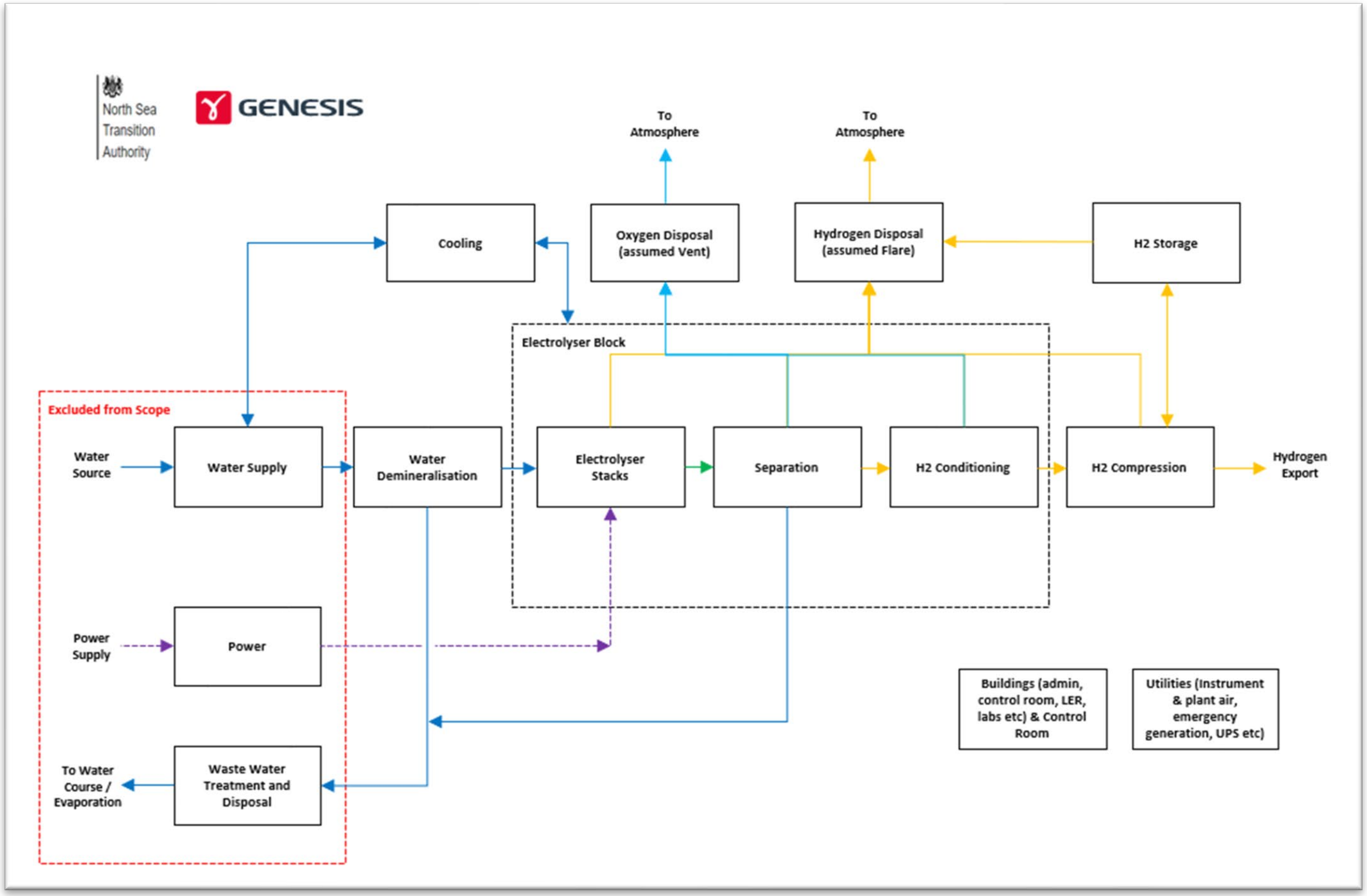
The battery limits of the report are illustrated in Figure 1-2 below and covers specifically:

- Electrolyser Technology
- Hydrogen compression
- Water Demineralisation
- Hydrogen Storage

All data in this report is publicly available, as referenced throughout the report.

The data held in this report is current upon the issue date of the report. Technologies in green hydrogen production are evolving and innovating rapidly and data may be superseded shortly. The view held in this report is based on current understanding of market analysis and trends, but not necessarily the view of the NSTA.

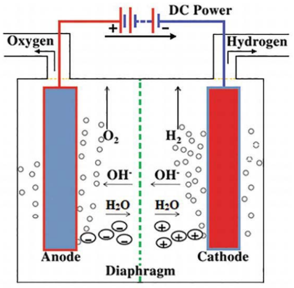
Figure 1-2 Bacton Green Hydrogen Plant Battery Limits



2.0 ELECTROLYSER

Electrolysis is a process in which electricity from renewable sources is used to split water (H_2O) into its component molecules - hydrogen (H_2) and oxygen (O_2) - in systems known as electrolysers. Electrolysers contain an anode and a cathode that are separated by an electrolyte [Ref. 2].

Figure 2-1 Typical Electrolyser Sketch



2.1 Electrolyser Types

There are three main types of electrolysers based on the electrolyte material involved:

- Alkaline Water Exchange (AWE)
- Polymer electrolyte membrane (PEM)
- Solid-oxide electrolysers cell (SOEC)

In addition, there are the less mature technologies including:

- Anion exchange membrane (AEM)
- Electrochemical Thermally Activated Chemical (E-TAC)
- Supercritical.

2.1.1 Alkaline

Alkaline electrolysers include “cells” that consist of an anode, cathode and membrane, and are typically assembled in stacks. The system uses a liquid electrolyte solution such as potassium hydroxide (KOH) or sodium hydroxide (NAOH), and water. By applying current on the cell stack, the hydroxide ions (OH-) move from the cathode to the anode of each cell. This leads to the production of hydrogen gas bubbles at the cathode and oxygen gas on the anode side. [Ref. 2]

2.1.2 PEM

The electrolyte in a PEM electrolyser is a solid speciality plastic material. In this type of systems, on the anode side water reacts to form oxygen and positively charged hydrogen ions, or protons, which then move across the PEM to the cathode side and combine with electrons from the external circuit to form hydrogen gas. [Ref. 2]

2.1.3 SOEC

SOEC electrolysers are a less mature technology that uses a solid ceramic material as the electrolyte. In these systems, water on the cathode side combines with electrons from the external circuit to form hydrogen gas and negatively charged oxygen ions. Then, these oxygen ions pass through the solid ceramic membrane and react on the anode side to form oxygen gas and generate electrons for the external circuit. [Ref. 2]

2.1.4 AEM

On paper, AEM combines the simplicity and efficiency of a PEM electrolyser with the less harsh environment in which alkaline electrolysers operate but enables the use of non-noble catalysts and titanium-free components. It is the latest of the main technologies to be developed and as such is still dealing with unstable lifetime profiles caused by chemical and mechanical stability issues. [Ref. 2]. The design is in R&D phase and also testing electrolyser fluid with brine.

2.1.5 E-TAC

Also in R&D, E-TAC is a new membrane-less technology which operates in a batch mode. During the first batch sequence hydrogen is evolved from the anode while oxygen is absorbed onto the cathode. During the second step the electrolyte is replaced with a hot electrolyte and oxygen is chemically evolved from the cathode at which point the sequence re-starts. Key advantages are the elimination of hydrogen and oxygen separation, elimination of the high-cost membrane and operation at elevated pressure (100barg+). [Ref. 3]

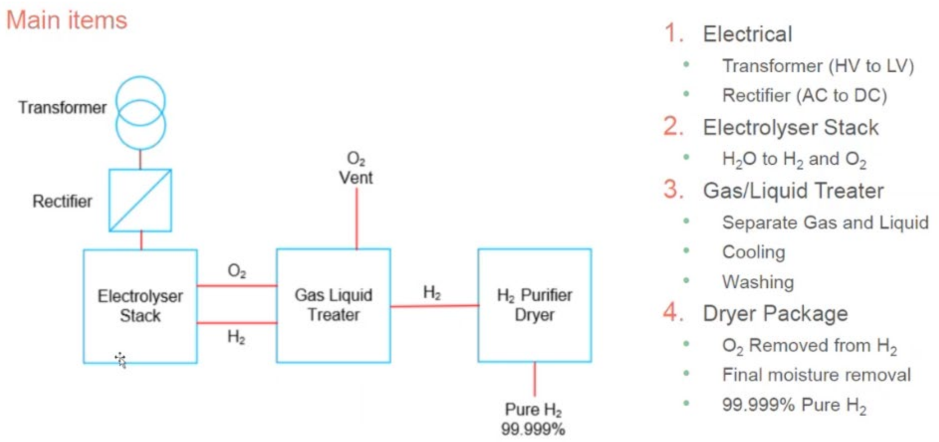
2.1.6 Supercritical

Limited information is available on the theory behind super critical electrolysis however it is believed that operation at high temperature and pressure changes (above the critical point) the behaviour of the water allowing for higher efficiency operation of the stack. Beyond this the high operating pressure results in a high product pressure eliminating the requirement for compression for onward pipeline transport. [Ref. 4]

2.1.7 Typical Electrolyser Package

The figure below illustrated the main building blocks for a typical electrolyser package. This package is often referred to “Balance of Plant (BOP)” or “Balance of Stack”. The exact building blocks in the package varies depending on the vendor. The illustrations in this section are typical.

Figure 2-2 Typical Electrolyser Package Building Blocks

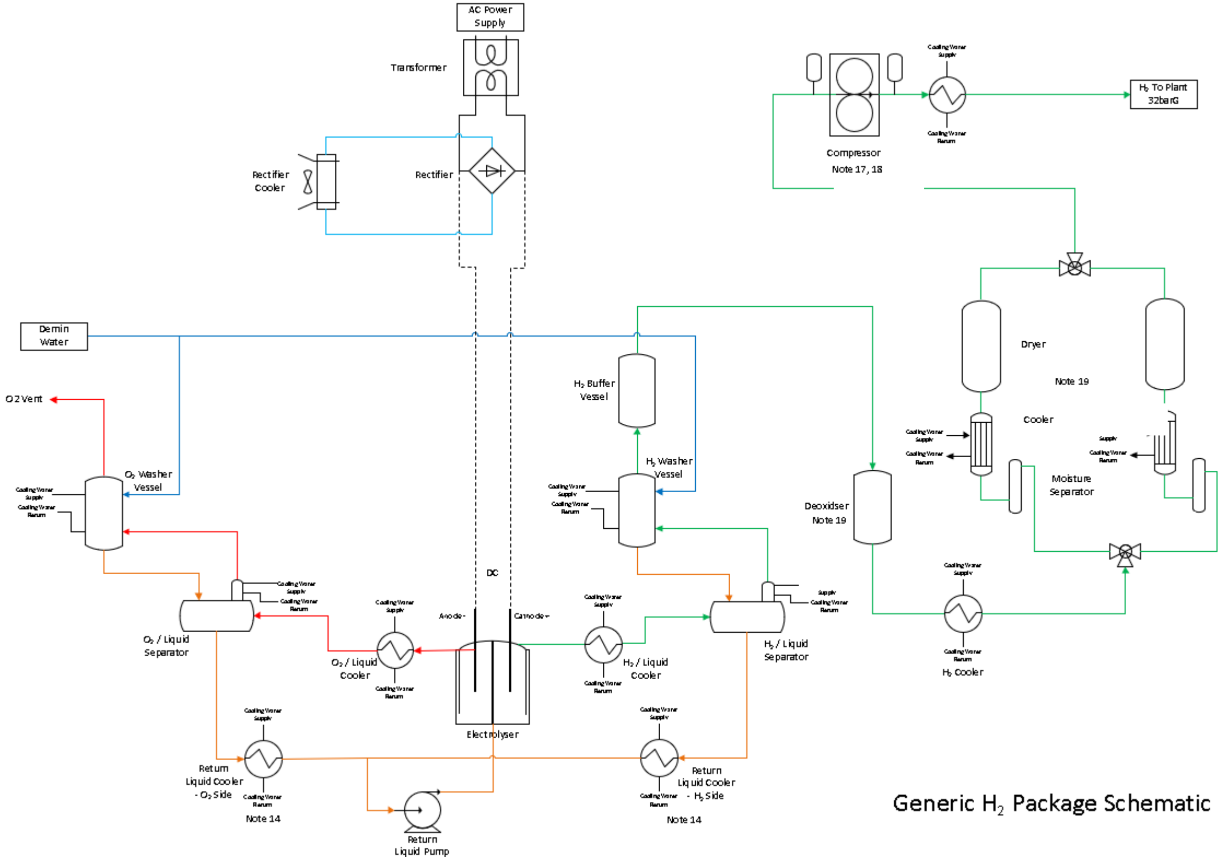


Main items

1. Electrical
   - Transformer (HV to LV)
   - Rectifier (AC to DC)
2. Electrolyser Stack
   - H_2O to H_2 and O_2
3. Gas/Liquid Treater
   - Separate Gas and Liquid
   - Cooling
   - Washing
4. Dryer Package
   - O_2 Removed from H_2
   - Final moisture removal
   - 99.999% Pure H_2

The figure below shows the typical vendor electrolyser package in further detail.

Figure 2-3 Typical Electrolyser Package PFD



Note, Nitrogen needed on startup and shutdown.

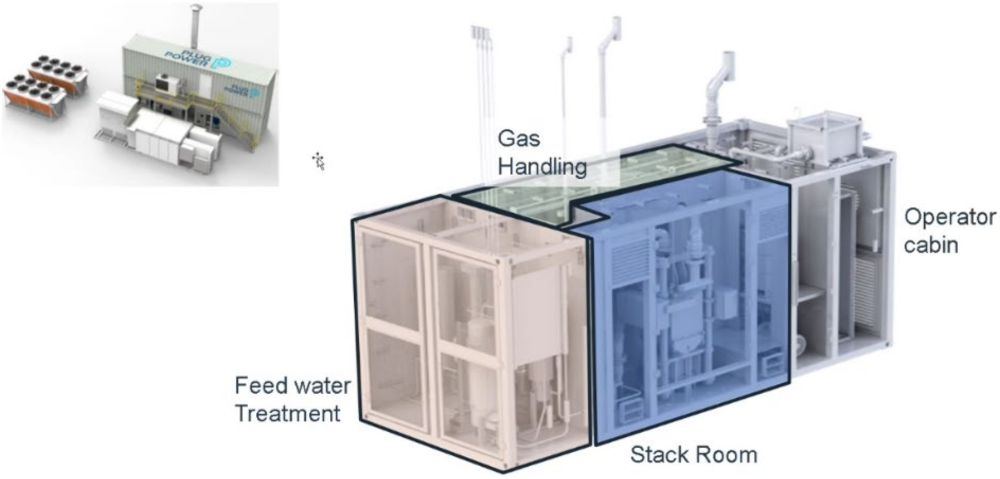
It is the convention to state the capacity of the electrolyser in power (kW, MW or GW), not the heating value of the hydrogen produced. The source power supplied to the electrolyser is AC. Its voltage is then stepped-down via transformer and a major part is converted to DC (for the stacks) via the rectifier. Note that the BoP and any auxiliaries are AC. The electrolyser starts to degrade as soon as it begins operation due to losses in electrical efficiency. Either the developer needs to accept less hydrogen production over time, or the design need to increase power demand to maintain constant hydrogen production rate.

The “balance of plant” power is the power consumed by auxiliaries associated with a set of stacks (or modules) associated with a common BoP set. The figures below show various 5 MW stacks with their BoP.

Figure 2-4 5 MW Electrolyser Packages (Ref. open-source data)

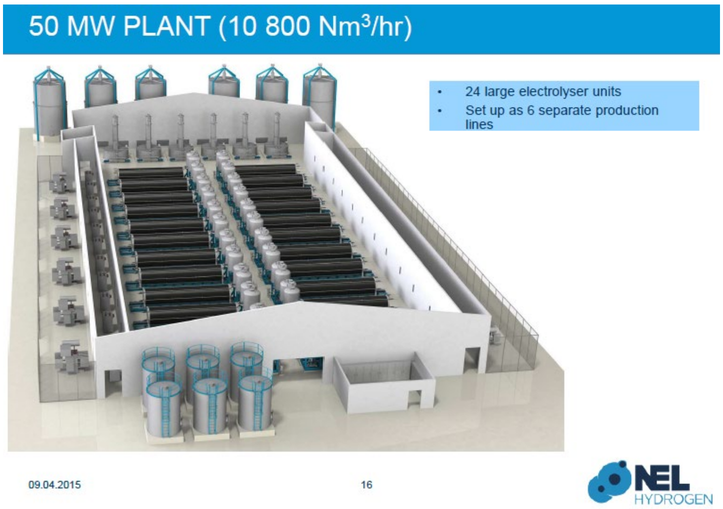
These packages can be open (typical for alkaline) or containerised (typical for PEM) design. The figure below illustrates containerised PEM (2MW from ITM Power).

Figure 2-5 Containerised Electrolyser Package (Ref. ITM Power)



In order to scale green hydrogen production, the electrolyser packages (or units) are modularised into multiple production lines and then repetition of the design into arrays. The figure below shows a typical layout for a 50 MW plant. Note, package design and production line design will vary from vendor to vendor and the size of green hydrogen plant.

Figure 2-6 Typical Electrolyser Modules (Ref. NEL)



50 MW PLANT (10 800 Nm^3/hr)

- 24 large electrolyser units
- Set up as 6 separate production lines

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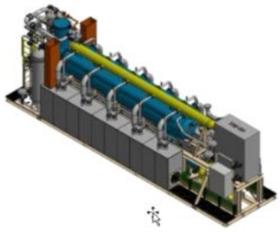
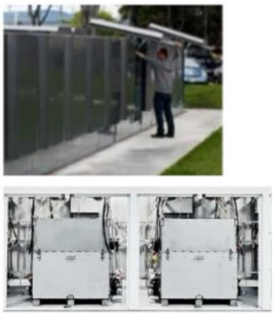
The figure below illustrates current relative designs of modules for each electrolyser type.

Figure 2-7 Electrolyser Type Assembly


10 MW PEM Array

(slightly bigger than a 40' container)


5 MW AWE Module


3 MW SOEC Module

(40' container)


1 MW AEM Array

(40' container)

*For a like for like capacity, alkaline is 30-50% higher footprint than PEM.

2.1.8 Electrolyser Selection Criteria

The selection of technology or vendor for a prospective green hydrogen project should be based on a series of factors or criteria.

- **Technology or Product Specific**:
    - **Technology Readiness Level (TRL):** *Generally, the maturity of a technology gives an indication of the likelihood that it will be able to be reliably deployed for the project in question (e.g. Alkaline is considered a relatively mature, well understood technology at small scale). Beyond the general level of development of a technology, a supplier's individual product may have defining features which lead to a different TRL (e.g. specific membrane technology);*
    - **Power to Hydrogen Efficiency**: *Critical to the business case is amount of power which must be used to generate a specific quantity of hydrogen. Where projects are operating at large scale and in competitive markets higher efficiency can offset increased capital cost.*
    - **Turndown**: *The ability to operate the stacks at low load when there is an insufficient supply of power is critical to cost effective green hydrogen production from intermittent renewable sources;*
    - **Ramp Up/Down and Cyclical Operation**: *As with the ability to "turn-down" the electrolysers the ability to quickly ramp-up hydrogen production is also important as power becomes available. The resistance to cyclical operation is also an important consideration as varying power supply may result in stacks needing to be shut-down and restarted regularly.*
    - **Start-up Time**: *The time to bring warm or cold stacks back on line is also a key consideration. Stacks which can be quickly brought back on line can produce hydrogen more quickly when power is available.*

  - **Hydrogen production pressure:** *The product pressure is a key consideration – lower product pressure will require more compression equipment which is both costly to install and to operate;*
  - **Feedwater Requirements:** *the ability to tolerate impurities in the feedwater is a key consideration. Technology with better resistance to feedwater impurities will typically have longer stack life and will reduce the installation and operating cost of the feedwater purification systems;*
  - **Product Purity:** *this will dictate the amount of purification steps (and their associated capital and operating/overall efficiency costs that must be added to the electrolyser itself);*
  - **Capital Cost:** *Capital cost is a key consideration as it dictates the initial financial cost of the project;*
  - **Lifetime and Stack Replacement:** *Stack lifetime is important as the plant will typically operate for many years longer than the life of an individual stack. Planning for stack replacements is a critical activity as these are high cost activities during which time the stacks are not available to produce hydrogen.*
  - **Size of Largest Single Stack:** *Typically larger fewer high-capacity stacks will provide a more cost effective solution;*
  - **Materials of Manufacture:** *A number of technologies use scarce commodities (such as rare earth metals) these technologies can be considered to be at higher risk of unexpected price escalation.*
- **Supplier Specific**;
  - **Manufacturing Capability & Capacity:** *The ability of a company to produce the product at the scale required for the project in question is critical;*
  - **Future Manufacturing Capability:** *It is important to understand what the capability of the manufacturer will be at the point of order for the project;*
  - **Track Record:** *Where a company has successfully supplied their product previously this gives a good indication of ability to do so again. Also an indication of R&D budget to continuously improve their product;*
- **Installation Specific**:
  - **Footprint:** *Larger plant will require additional footprint which will increase the cost of real estate, associated civil (groundworks) and architectural (buildings) works;*
  - **Weight:** *Heavier single items may result in more complex logistical arrangements to deliver to site and have higher foundation/civil costs;*
  - ***Constructability & Logistics:*** *Ability to transport equipment to site, bottlenecks may result in constructability issues preventing modular design and installation.*

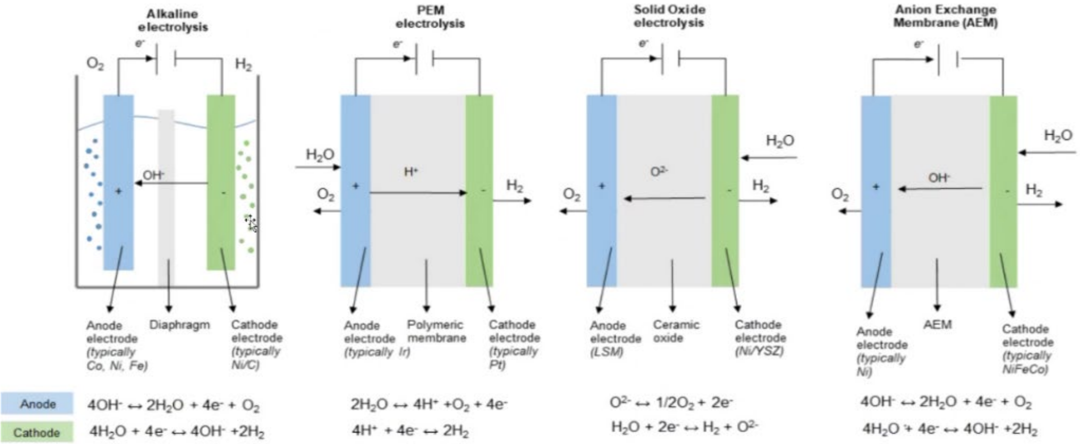
Due to the recent increase in activity in the electrolyser market there are now over 18 companies offering electrolyser technologies as an original equipment manufacturer (OEM) this is distinct from companies re-selling or packaging products manufactured by others. The full list of considerations outlined above is unlikely to be available for each and every manufacturer during early project phases and typically the final supplier selection may not occur until shortly before the final investment decision (FID) is taken. At this stage however it is useful to provide an overview of the current technology and suppliers and the direction in which we anticipate it may move.

The following sub-sections provide a summary of Genesis' insights into both the technology and the supplier landscape and are summarised with a section looking forward to the likely implementation dates for the Bacton Green Hydrogen project phases. Note, this review Is not exhaustive and are based on publicly vendor sourced claims.

2.1.9 Technology and Electrolyser Suppliers Comparisons

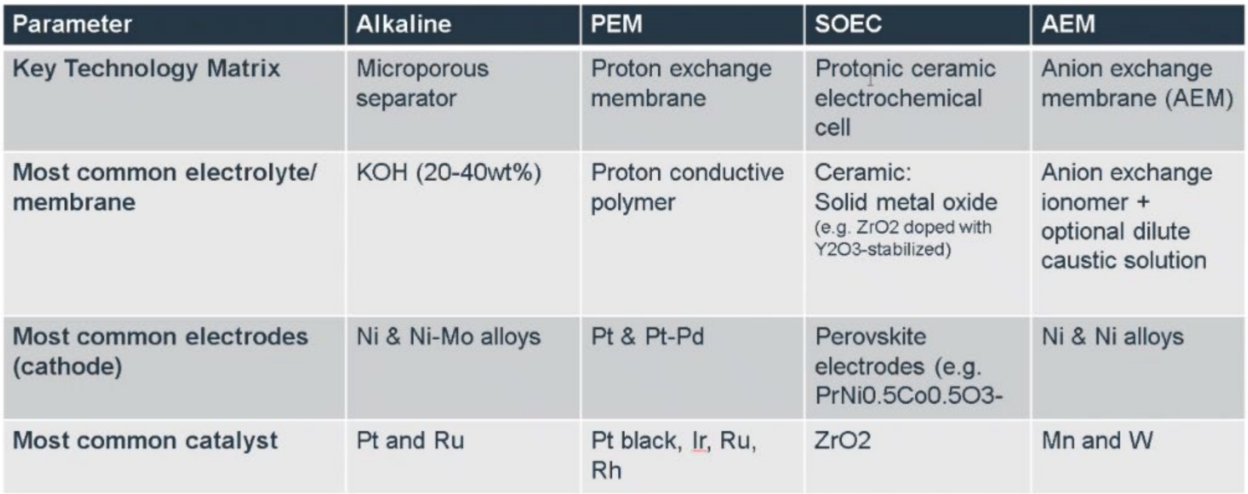
Key differences between the technology types are the separation/membrane and electrode materials, catalysts and the electro-chem reactions as shown in the table below.

Figure 2-8 Electrolyser Technology Illustrations



This review focuses on the key four technologies illustrated above. A comparison of material is shown below in the table below.

Table 2-1 Electrolyser Type Material Comparison



Parameter	Alkaline	PEM	SOEC	AEM
Key Technology Matrix	Microporous separator	Proton exchange membrane	Protonic ceramic electrochemical cell	Anion exchange membrane (AEM)
Most common electrolyte/ membrane	KOH (20-40wt%)	Proton conductive polymer	Ceramic: Solid metal oxide (e.g. ZrO2 doped with Y2O3-stabilized)	Anion exchange ionomer + optional dilute caustic solution
Most common electrodes (cathode)	Ni & Ni-Mo alloys	Pt & Pt-Pd	Perovskite electrodes (e.g. PrNi0.5Co0.5O3-	Ni & Ni alloys
Most common catalyst	Pt and Ru	Pt black, Ir, Ru, Rh	ZrO2	Mn and W

Tables comparing electrolyser technology (operating conditions and performance per electrolyser type) and vendor comparison is provided in the following tables.

Table 2-2 Technology Comparison Table

	Alkaline	PEM	SOEC	AEM[2]
Manufacturers	Cockerill, McPhy, Hydrogen Pro, Thyssenkrupp, Sunfire, NEL Hydrogen, GHS, Cummins	H-Tec, NEL Hydrogen, Cummins, H-Tec (MAN), Siemens, ITM, Ohmium, Plug Power, Elogen	Sunfire, Haldor Topsoe, Bloom	Enapter, Hydrolite
Efficiency	70-75% (Typical)	70-75% (Typical), 75% (Siemens)	90% (Haldor), 90%+ (Bloom)	88% (Hydrolite)
TRL	9	9	7	7
Start Time (Warm/Cold)	5 min / 60 min (Typical)	30s / 5min (Plug)	6min / 15hr (Bloom)	“Fast” (Hydrolite)
Operational Flexibility	40-100% (Cummins)	10-100% (Siemens) 5-125% (Cummins)	10-100% (H-T)	“Good” (Hydrolite)
Product Pressure	30barg (Cockerill) 30barg (McPhy) Atm (Thyssenkrupp, Nel)	20-30barg (ITM) 40barg (Plug)	Atm (Bloom) 2barg (H-T)	35barg (Enapter)
Lifetime / Stack Replacement	10yr (Sunfire)	10yr (Siemens)	5yr (Bloom)	10yr (Hydrolite)
Purity	99.8 (Cockerill) 99.99 (after drying)	99.999 (ITM), 99.999 (Plug)	99.99 (after drying)	99.999 (Hydrolite)
Capital Cost ($/kW)	Moderate	High	High	Low Claimed (Hydrolite)
Feedwater Quality Requirement	Flexible	High	High	Flexible
Size / Weight	45m^2/MW	25-30m^2/MW	~45m^2/MW	Note 1

Notes:

1. Insufficient information exists in the public domain to provide more detailed view;
2. Few instances of AEM's being used beyond pilot scale applications and therefore many of these assessments are claimed by the manufacturers rather than demonstrated at scale.
3. In general, publicly available data can vary. The table above is a guide only.
4. E-TAC and Super Critical are still at lab scale therefore it is not possible to provide a full overview of their pros and cons. Both are sold as offering improved efficiency and product pressure over established products (typically PEM and Alkaline) however it is not clear whether other considerations such as conditioning or feedwater specification would offset these gains.

Table 2-3 Electrolyser Supplier Comparison Table – Public Domain Data (Supplier Websites & Ref. 2)

		John Cockerill	McPhy Energy	Thyssenkrupp	Hydrogen Pro	Green Hydrogen Systems	Stiesdal	NEL Hydrogen	Cummins	Elogen	Hoeller	ITM Power	Plug Power	Siemens	H-Tec (Man)	Sunfire Gmbh	Bloom	Haldor Topsoe	Enapter	Hydrolite
Current	Technology[1]	A	A	A	A	A	A	A / P	A / P	P	P	P	P	P	P	A / S	S	S	AE	AE
Current	Single Largest Unit (MW)	6.5	4.0	5.0	4.4	0.4	3.0	22.3	4.3	10.0	1.5	2.0	5.0	17.5	1.0	10[3]	<	<	0.002	0.001
Current	Manuf. Capacity (MWpa)	350	300	1,000	300	75	-	550	-	400	375	1,000	500	-	-	500	600	-	-	-
Current	TRL of Units	9	9	9	9	9	7	9	-	-	-	9	-	-	8	-	-	-	-	-
Current	Largest Project[2] (MW)	110	6.0	9.0	9.0	12.0	-	-	-	-	-	24.0	-	-	-	-	-	-	-	-
Current	Installed Capacity (MW)	>600	168	-	-	-	-	-	-	-	-	-	-	-	-	-	500+	-	-	-
Current	Level of Activity	Mod	Mod	High	Mod	Mod	Mod	High	High	Mod	Mod	High	Mod	Mod	Mod	Mod	Mod	Mod	Mod	Mod
Future	Single Largest Unit (MW)	-	-	20.0	-	-	10+	-	-	-	3.0	5.0	10.0	-	-	-	-	100	-	-
Future	Near Term Capacity (MWpa)	700 (2023)	-	-	-	400 (2023)	-	-	500 (2023)	-	375+ (2024)	5,000 (2024)	-	-	-	500 (2023)	1,000 (2022)	500 (2024)	200 (2023)	-
Future	Long Term Capacity (MWpa)	4,000+	1,300	5,000	1,000	1,000	-	2,050	1,230	-	-	5,000+	3,000+	-	-	1,000	-	5,000	-	-

Future	Largest Project[2] (MW)	2,000	100	2,000	800	100	-	-	-	-	-	-	-	200	-	-	-	100	-	-

Notes:

1. A: Alkaline, P: PEM, S: SOEC, AE: AEM, E: E-TAC
2. Current largest project is treated as Post FID, future is treated at pre-FID
3. 10MW refers to alkaline units, SOEC units are currently available at 3.0MW capacity

2.1.10 Outlook – A View

2022-2030

The electrolyser market is moving quickly with two currently dominant technologies: Alkaline and PEM. These technologies offer different benefits with PEM more expensive but offering more operational flexibility (very important if power source is not stable) and higher product quality (without conditioning). At present both technologies have a significant global manufacturing capability with plans for a number of “giga-factories” for both technologies. It is clear that at present, for projects looking for sanction in the next 2-3 years the choice will be between flexibility and efficiency. Many players are making claims of increases in efficiency within the decade, particularly PEM.

Operators are starting to construct testing facilities (>15MW) to understand electrolyser performance, beyond vendor claims. For the “first of class” green hydrogen plants, it is possible that that “hybrid plants” of both Alkaline & PEM electrolysers are developed to utilise PEM to handle variation in power supply and alkaline provide the base load.

SOEC is likely to offer the only major disruption to this duopoly in the near future with the offer of significant further efficiency gains at the cost of reduced flexibility with some manufacturers claiming 10-30% increase in efficiency compared to PEM/Alkaline systems already on the market. SOEC could start to displace Alkaline systems providing relatively inflexible “base load” production, particularly where other derivatives of hydrogen are produced such as ammonia and synthetic fuels as SOEC works well with other industrial processes where waste heat is available.

Towards the end of the decade, and subject to overcoming challenges with cell durability, AEM has the potential to displace both PEM and Alkaline as it is claimed to offer the operational flexibility of PEM, cheaper materials than PEM and the efficiency of Alkaline. It also has the side benefit of much higher tolerance to feedwater specification with some manufacturers claiming that even brines could be used as feedwater. Current commercialisation plans by the AEM suppliers talk about delivering at commercial scale by mid-2020s however full-scale manufacturing capability at the level required to service multiple GW scale projects would likely not be until the early 2030s. This technology could be a game changer for developments with water quality challenges.

Lastly, other green hydrogen technology disruptors will be extremely important for electrolyser development, particularly hydrogen storage (either power storage or hydrogen storage). Any technology advances in storage may mitigate requirement for electrolyser flexibility, strengthening a position for Alkaline.

2030-2040

In the following decade there may be further disruptive technologies: E-TAC has the potential to offer a further efficiency gain over PEM & Alkaline. Supercritical stacks may eliminate the requirement for compression while offering very high stack efficiencies (although at this stage these are claims based on lab-scale systems and it’s not clear if there are higher power or costs which will need to be weighed out against that of eliminating compression). Based on the expected time to market for AEM, gigawatt scale manufacture of any of these technologies may not be until the early to mid-2030s.

If all these technologies offer very high efficiency, then they may supplant PEM, Alkaline or SOEC. Although, as indicated above, a view is SOEC may dominate the green ammonia or synthetic fuels market as it could provide a neat integrated technology with ammonia synthesis (high temperatures and heat integration).

In this point of time, technologies may segregate into specific markets based on hydrogen uses with new emerging technologies starting to scale.

2040+

From 2040 onwards the green hydrogen market is likely to be mature with most of the currently discovered technologies having reached commercial gigawatt scale deployment. At this point in time there will likely be clear "winners" with preferred technologies for both base-load (i.e. high efficiency) and peaking (i.e. high flexibility) with an outside possibility that one of the currently nascent technologies will fulfil both of these roles.

Another possibility is that if the cost of "buffering" power upstream of the hydrogen plant or the cost of storing hydrogen downstream of the plant fall sufficiently far there will be little to no requirement for flexibility in the hydrogen production facility itself. In this case the dominant "flexible" technology may be limited to small scale plants (for example island networks) where there is no real base-load requirement.

Any new technologies at this point will face an uphill battle to penetrate the market as there are already technologies offering high flexibility) and others which are likely to offer efficiency in the mid-90% range. The gains in either area is likely to be marginal at this stage so a new technology would likely either need to significantly reduce cost or provide both flexibility and high efficiency (if this is not already available).

Bacton Build-out

The first phases of Bacton are expected to be implemented in 2040 and at this point in time it is expected that there will be a clear market leader in electrolyser technology. Bacton will have the benefit of learning from earlier large-scale developments to incorporate into technology the selection.

Technology Watch

Many technology claims are being announced as this market rapidly evolves and verification of performance will be key as technology evolves. In March 2022 alone, two claims were announced, both in lab testing phases and the technology will need to be closely monitored:

- Hysata Electrolyser: claims their 'capillary-fed electrolysis cell' can produce green hydrogen from water at 98% cell energy efficiency, well above International Renewable Energy Agency's (IRENA) 2050 target and significantly better than existing electrolyser technologies [Ref. 5].
- Honeywell Electrolyser: announced that it has developed new green hydrogen production technology based on a "catalyst-coated membrane" which have shown to bring on improved electrolyser efficiency and a higher electric current density.

Close monitoring of the market will be essential over the next few years.

3.0 H_2 COMPRESSION

Following hydrogen production through electrolysis, and depending on the electrolyser technology in use, hydrogen needs to be compressed for either supply or storage, depending on the end user application. The majority of current technologies currently produce hydrogen at around 30barg (SOEC is the exception which produces very low pressures of ~0-2barg or atmospheric alkaline electrolysers). The main markets envisaged for hydrogen are:

- Highly compressed for mobility (fuel cell) use: *typically 300-700barg*
- Moderately compressed for delivery by pipeline: *typically 60-100barg*

3.1 Compression Types

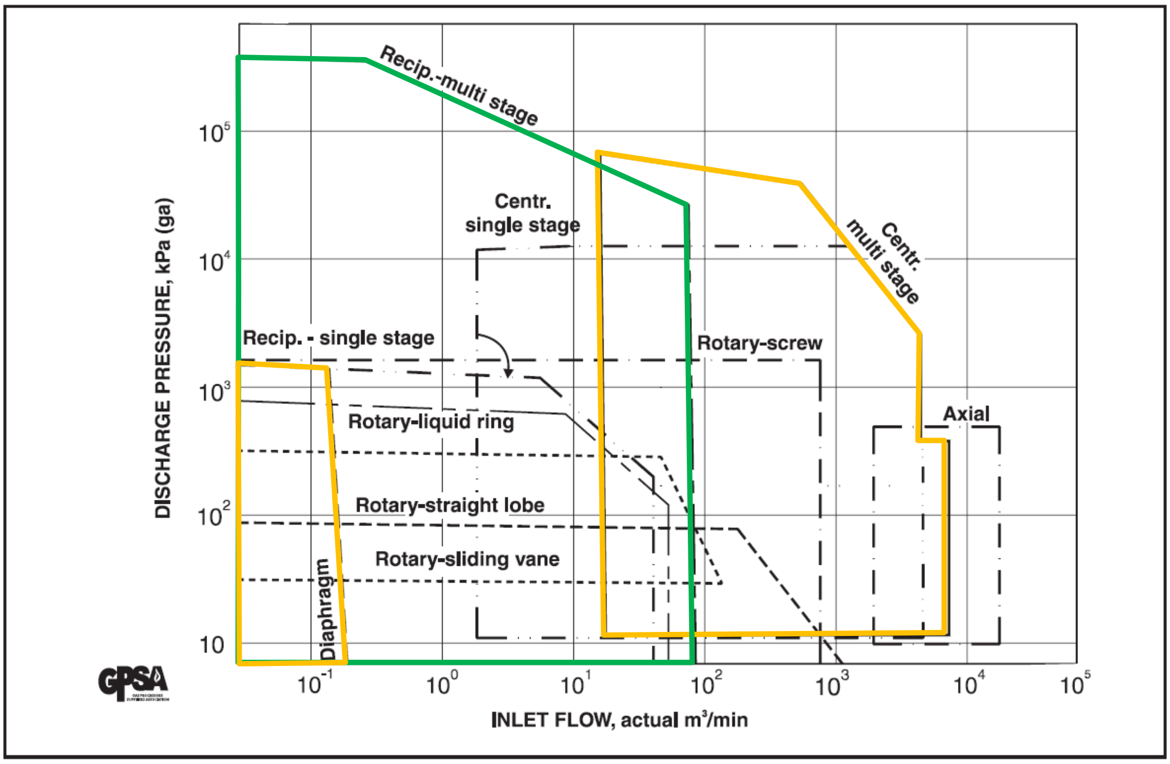
There are a number of compression technologies in use in the process gas industry which can be broadly broken down into four categories:

- Reciprocating
  - Diaphragm and ionic compressors can be seen as derivatives of reciprocating;
- Rotary
  - This includes screw, lobe, sliding vane and liquid ring type compressors;
- Centrifugal
  - This includes both traditional and integrally geared centrifugal compressors;
- Axial

For wider process gas compression (rather than specifically hydrogen) applications a chart similar to that shown in Figure 3-1 is typically used to select the most appropriate technology for a given application. This is driven by the parameter on each axis which dominate the selection:

- Discharge pressure
- Inlet actual volume flow

Figure 3-1 Compressor Selection Chart [Ref. GPSA Section 13 12th Edition]



For hydrogen compression there are a number of different factors which have to be considered over standard process gas compression in particular:

- **The molecular weight of the gas** – *for hydrogen this is low which makes aerodynamic acceleration more difficult to achieve*;
- **The diffusivity of the gas** – *this means hydrogen has an increased propensity to leak*;

And the following factors should also be considered:

- Flow rates & Compression ratios
- Load variation, turndown parameters
- Power and cooling requirements

The following sub-sections give a summary of each compression type, its track record in the hydrogen industries and the future outlook.

3.2 Reciprocating Compressors

Reciprocating compressors draw hydrogen into the cylinder through the suction inlet, compressing the gas in through a piston mechanism. To date reciprocating compressors have been preferentially selected for hydrogen applications as they have advantages with respect to efficiency and leakage for low molecular weight gases such as hydrogen.

Reciprocating compressors have demonstrated their application in industry currently, therefore reciprocating compressors use in the future is likely to continue with advancements of technology. Reciprocating compressors are more suitable for scenarios with higher pressure ratios and low volume flow.

3.3 Rotary Compressors

Rotary compressors typically involve a fixed inlet volume which through the rotary action of the compressor is sequentially reduced in volume through to the discharge point. Rotary compressors are not currently used in the hydrogen industry. Rotary compressors rely on the tolerance between the moving and stationary parts being small enough that backwards leaks are minimal. Due to the diffusivity of H_2, these leaks are large and severely impact on performance. Future developments to reduce internal clearances may create a market for these however that is uncertain, and therefore the application of rotary compressors in the future is doubtful. Rotary compressors at present, occupy a fairly niche subset of compression duty already; where flow is not large enough to justify a centrifugal application and required pressure is not sufficient to need a reciprocating compressor. In the hydrogen value chain this would be low-capacity pipelines which could be equally well served by integrally geared centrifugal compressors.

3.4 Centrifugal Compressors

The four main features of a centrifugal compressor are the inlet, centrifugal impeller, diffuser and outlet. Centrifugal compressors work by utilising high-speed rotation of impellers to impose high velocity to the hydrogen and to use the kinetic energy generated by the impellers to increase the pressure of the hydrogen. Gas is accelerated outwards from the central shaft and then decelerated at the diffuser recovering the energy as pressure; the compressed gas then leaves via the outlet.

At present for hydrogen compression, centrifugal compressors require a significant number of stages, and if the discharge pressure is high, multiple casings are required, resulting in a limited uptake of the technology. Compressor manufacturers have identified centrifugal compressors as a potential improved solution for compression in the hydrogen energy market, if the pressure rise per stage can be increased. Improving the pressure rise per stage could be achieved through the development of impeller blade design.

Centrifugal compressors are typically more suitable for higher volume flows than reciprocating compressors. Centrifugal compressors are the preferred option for high volume flow and lower pressures. Centrifugal compressors will likely be the dominant technology for pipeline hydrogen transmission.

3.5 Axial Compressors

Axial compressors are comprised of a chamber with rotating blades. Gas is drawn the chamber axially parallel to the axis of the rotating blades of the compressors. Kinetic energy is increased by the rotation of the blades, increasing the velocity within the chamber. As the gas flows through the chamber, the gas is met with stationary blades converting the kinetic energy and increasing the pressure of the gas. Similar to centrifugal compressors, axial compressor require several axial stages for large pressure applications. Axial compressors can process large volume flows.

There is very little information on the use of axial compressors for hydrogen compression. Compressor manufactures are yet to demonstrate whether axial compressor will be a cost-effective viable option for the future.

3.6 Future Technologies

3.6.1 Ionic Compressors

Ionic compressors operate in a similar fashion to reciprocating compressors however the metal piston is replaced by a moving ionic fluid. By using a fluid piston, it is possible to eliminate some of the seals and moving parts which are typically at fault in reciprocating designs.

3.6.2 Metal Hydride Compressors

Metal hydride compressors were originally developed during the 1970's for storage of hydrogen however the thermodynamic fundamentals lend themselves well to compression applications. The process involves a low pressure-low temperature absorption step (during which heat is given out) and a high pressure high temeprature desorption step (where heat is applied) during which high pressure hydrogen is evolved.

Compressors of this type are currently manufactured on a small-scale basis (up to 12 Nm^3/hr) by Hystorsys for residential applications and can achieve a compression ratio of 10:1 with the low temperature side at 20°C and the high temperature side at 90°C with maximum pressures of up to 250barg.

The key advantage is the lack of moving parts which makes them ideal for environments where maintenance is difficult. The key disadvantage is the efficiency with as much as 10kWh/kgH$_2$ required for a 2-stage high pressure compression application. This technology could be particularly attractive however if waste heat from other parts of the process was used to run the "hot" side as then the compression is effectively free.

3.6.1 Supplier Comparison

Table 3-1 Compressor Supplier Comparison

Manufacturer	Siemens	Baker Hughes	Howden	PDC Machine	Hystorsys
Type	Reciprocating and Centrifugal	Reciprocating	Reciprocating and Diaphragm compressors	Diaphragm compressors	Metal Hydride
Maximum Discharge Pressure (barg)	~200	700+	700+	700+	250

3.6.2 Outlook – A View

2020-2030

Due to its established track record and the scale of currently planned hydrogen projects, reciprocating compressors are likely to dominate the hydrogen compression market in the early to mid-2020s for both fuel cell and pipeline applications.

As centrifugal compressor manufacturers start to see larger projects reaching investment decision in the late 2020's they will likely have prepared new higher rotating velocity designs to account for the lower molecular weight of H_2. At this point the cost, footprint and maintenance benefits of a centrifugal design will out-weight the track record of reciprocating compressors and the majority of pipeline discharge projects will likely utilise centrifugal compressors.

Depending on the scale of the project either traditional or integrally geared centrifugal designs will be used with the former being more suited to larger projects and the latter smaller projects.

The only possible disruption to this pattern may be maturation of diaphragm designs which may displace some of the reciprocating market due to its superior sealing technology.

2030+

The patterns observed towards the end of the 2020s will likely continue through the 2030s and onwards.

For pipeline delivery if system capacities become sufficiently large there may be application for axial compressors which offer even higher capacities and similar advantages to centrifugal compressors. As with centrifugal compressors there will be a period where manufacturers will need to update their designs and qualify them for operation with hydrogen.

For higher pressure applications (such as fuel cell use) the most likely disruptive technologies will be ionic compressors (which remove some of the disadvantages of traditional reciprocating designs) or metal hydride compressors (in particular where there is a source of waste heat).

The key aspect to all of these systems will be the integration of the heat of compression (the power consumed by the compression process that is converted to heat rather than pressure) into the electrolyser system to increase system efficiency.

Elimination of Compression Requirement

The major change likely as a result of changes to electrolyser technology could be the elimination of compression requirement. Both E-TAC and super-critical electrolysers (if feasible) would remove the requirement for compressors.

Bacton Build-out

For the Bacton build-out phases where gas export is by pipeline (assumed for this phase of development) it is likely that centrifugal compressors will have reached relative maturity by the early phases and will be considered to be the most appropriate technology. This is likely to persist throughout the build-out phases unless capacities are reached where axial compressors offer better economics.

4.0 WATER DEMINERALISATION

4.1 Summary

The electrolysers require a supply of demineralised water for electrolysis (typically 10.5 kg/ Kg hydrogen produced). Water quality is a central factor to ensure long-life operation of an electrolyser. Impurities can accumulate in the cell, and deposit on the electrode surface and in the membrane, thus hindering mass and charge transfer. This will influence the lifetime of the electrolysis technologies.

For AWE, the highly alkaline environment in the electrolysis cell requires the concentrations of magnesium and calcium ions to be sufficiently low to avoid precipitation of their hydroxides. In addition, when the current density exceeds the so-called limiting current of hydroxyl ions, chloride ions present in solution are oxidized to chlorine at the anode surface, which is extremely corrosive to most metallic components of the electrolyser.

For PEM, poor water quality is one of the main reasons for stack failure. Many elements are quickly affected due to impurities such as membrane, ionomer in the catalyst layer, catalysts. ASTM type II water (see table below) is the minimum requirement for intake water to the electrolyser cells.

PEM requires higher purity demin water compared to Alkaline. Note, exact specifications must always be confirmed with the confirmed with electrolyser suppliers on the feedwater specifications.

There is little in the literature on the impacts of water quality on SOEC electrolyser. It is, however, expected to be less sensitive when compared to AWE or PEM electrolysers. SOEC needs boiler feed water quality as it is steam based.

Table 4-1 Water quality parameters for ASTM types, (ASTM D1193-06, 2018)

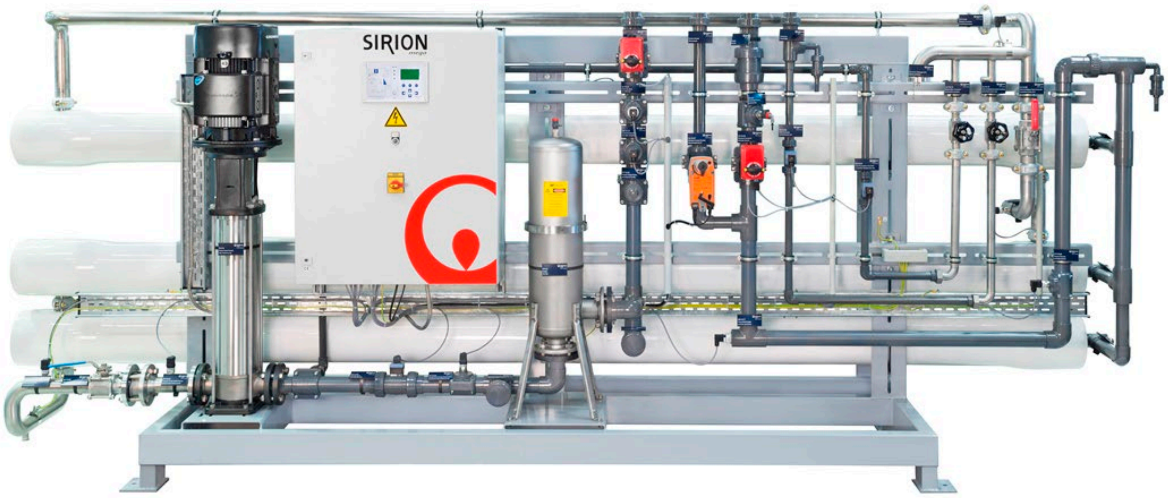
Parameter	Type I*	Type II**
Conductivity (µS/cm) at 25 °C, max	0.056	1
Resistivity (MΩ-cm) at 25 °C, max	18	1
pH at 25 °C	–	–
TOC (µg/l), max	50	50
Sodium (µg/l), max	1	5
Silica (µg/l), max	3	3
Chloride (µg/l), max	1	5

*Requires use of 0.2 µm membrane filter; **Prepared by distillation;
***Requires the use of 0.45 µm membrane filter.

The dominant technology for the production of demineralised water is Reverse Osmosis (RO). These packages are considered to be technologically mature due to their application in a range of other industrial sectors including power generation (for boiler feed water), waste water treatment and generation of high specification feedwater.

Figure 4-1 shows a typical package which can be configured to supply up to 100m^3/hr of demineralised water. Similar systems are available from a number of other manufacturers.

Figure 4-1 Typical Reverse Osmosis Package [https://www.veoliawatertechnologies.co.uk/]



The technology associated with demin water treatment is mature and therefore not further discussed in this review.

5.0 HYDROGEN STORAGE

Due to its low density, any significant hydrogen storage will require very large storage volumes that could comprise a significant proportion of the total overall plant costs. Storage may be required to provide a buffer for supply, owing either to the intermittency of the hydrogen generation from renewables or to variations in demand. This can be small scale (daily fluctuations), however seasonal storage may also be required. In either case, large scale storage hydrogen is currently immature in the UK, and innovation is required beyond geological storage.

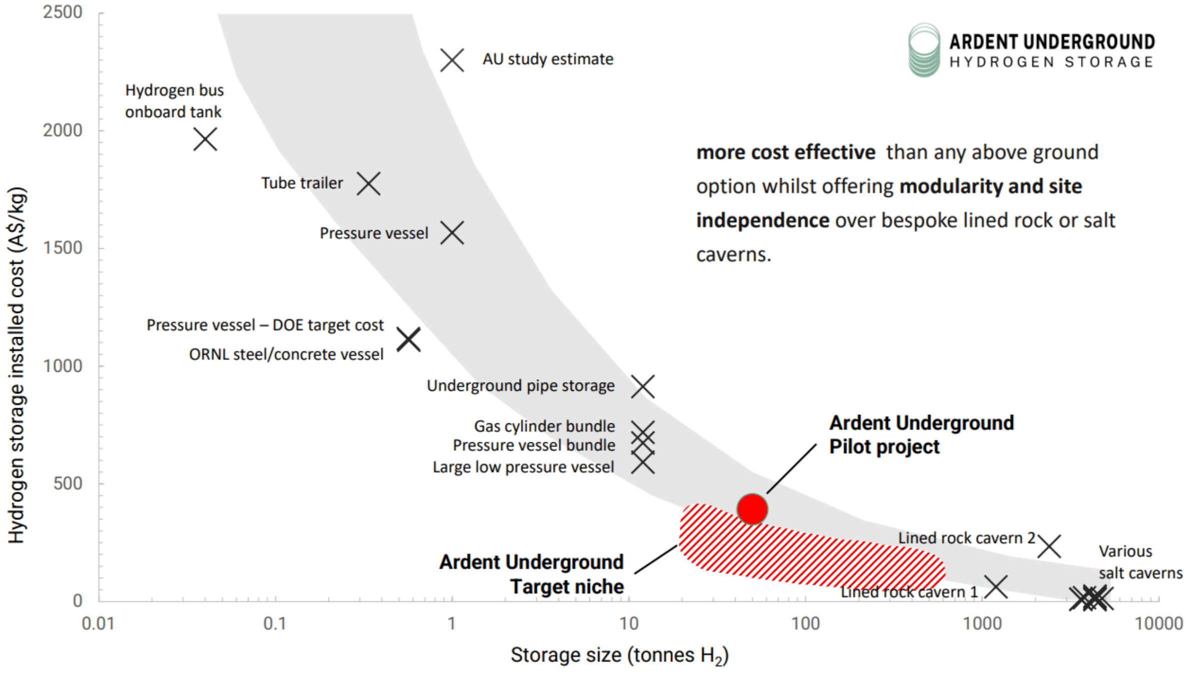
5.1 Storage Types

The key technologies for hydrogen storage are considered to be:

- Cylinders or tube trailers
- Pressure Vessels (Steel or Composite)
- Coiled Pipe/Underground Pipelines
- Line Pack
- Vertical Bored Shafts
- Underground Caverns (Lined Rock and Salt)
- Liquid Storage.

Figure 5-1 gives an overview of the typical storage sizes and costs (in Australian Dollars) per kilogram from work done by Ardent Underground (Nb. Ardent are a provider of hydrogen storage and the values in this chart have not been fully assured however it is broadly representative).

Figure 5-1 Storage Options



5.1.1 Cylinders

Compressed gas cylinders are a well-established technology and have been used in hydrogen for many years. They are able to achieve very high pressures however the key drawback is the limited volume stored. Even with multiple cylinders in a bundle the total volume is typically only 2-10 te H_2. They also rely on very high pressures to achieve this storage, so compression losses are high.

Figure 5-2 Gas Cylinders [Ref.6]

5.1.2 Pressure Vessels

Larger typically steel pressure vessels can also be used for storage of hydrogen (small scale) however, they are limited by the trade-off between high pressure (gives more hydrogen storage) and steel mass (increase cost and makes transportation and installation more complicated). There are also limitations on the grade of steels that can be used with higher strength steel typically subject to embrittlement failure mechanisms.

Alternatives are currently being investigated including the use of composite construction where an inner steel layer provides the embrittlement resistance and lower cost materials (including high strength steels and concrete) provide the pressure containment. These designs have the potential to significantly reduce cost.

5.1.3 Coiled Pipe / Underground Pipeline

Large bore pipe suitable for hydrogen service is already manufactured at scale. Rather than installing vessels mounted above ground with associated civil works an alternative approach is to install multiple runs of straight or coiled pipeline underground.

In addition to this it may be possible to convert existing pipelines to hydrogen service however care has to be taken over the materials of construction. Many pipelines use high strength grade steels which are susceptible to embrittlement in H_2 service.

5.1.4 Line Pack

Line pack method is widely used in the current natural gas network for the compensation of small daily variations. However, characteristics of hydrogen cause that storage possibilities via line packing are only one third compared to natural gas within the same grid. Furthermore, hydrogen pressure changes lead to higher deterioration of the pipes. Therefore, additional costs for reinforcements, maintenance, and replacement may be required. New hydrogen infrastructure could be designed to overcome these disadvantages, but then the possibility of reusing the natural gas infrastructure is dismissed [Ref. 5].

5.1.5 Vertical Shaft

One solution offering potential large-scale storage of hydrogen where natural cavities do not exist is the creation of vertical bored shafts. These shafts, typically 2-7m in diameter and up to 1,000m in depth are created by boring shafts and then installing a steel liner pipe with the space between the liner and surrounding rock grouted. In this way the steel liner provides the containment and the surrounding rock provides the strength.

Fuels cells for mobility require hydrogen to be pressurised to around 300 – 700 bar. Vertical shaft / underground cavities have been demonstrated as an option for storing hydrogen at the required high pressures.

5.1.6 Underground Cavity

The use of underground cavities for the storage of hydrogen is well establish with a number of multi-GWh facilities already in operation (e.g. US). Salt caverns can be used as storage facilities for large volume of hydrogen and facilitate in daily balancing on a large scale and seasonal balancing [Ref. 5].

Salt caverns are the preferred option as the rock salt typically has a very low permeability to hydrogen leading to good containment. The main drawback is the physical location as salt caverns may not exist in proximity to the facility under development in which case the cost of piping hydrogen to/from the cavity could be prohibitive.

Finally engineered caverns where an existing cavern is either lined or created (through the dissolution of rock) present a possible future technology however these are relatively poorly developed at present.

Alternatives to salt caverns are porous media storage including depleted hydrocarbon reservoirs and aquifers offshore. Specific challenges of offshore sites include the degradation of the hydrogen. It is currently unclear whether storage in the gas fields is feasible, however, Centrica are currently looking at re-purposing Rough for Hydrogen storage in the UK.

5.1.7 Liquefied Storage

Liquefied hydrogen can be stored in cryogenic tanks after cooling hydrogen to -259.9 degree Celsius. Current technologies only provide small-scale liquefied hydrogen storage possibilities for daily fluctuations; technical development is needed to scale-up. Moreover, the cooling process requires significant amounts of energy, and the tanks are relatively expensive [Ref. 5]. In addition, liquefaction is not typically considered as a storage mechanism unless there is a requirement for onward transportation of the H_2 in liquid form (typically over large distances) this is due to the high cost of plant and energy penalty for liquefaction. While some of these may improve in future there will remain a large thermodynamic penalty for liquefaction that will almost certainly make it unattractive for buffer storage of H_2.

Another liquefied hydrogen storage method is binding hydrogen to a hydrogen carrier (LOHC). Recently, Vopak, the largest storage facilitator of the port of Rotterdam, invested in the further development of this technology (Hydrogenious) [Ref. 5].

Figure 5-3 Liquefied Storage [Ref. 7]

5.2 Storage Comparison

A summary overview of storage options for hydrogen are shown in the table below.

Table 5-1 Hydrogen Storage Options

Storage Type	Typical Pressure (barg)	Typical Volume (m^3)	Hydrogen Stored (kg)
Cylinder	350 - 750	1 - 10	10 - 50
Pressure Vessels	Up to 199 / Up to 799 (Note 2)	10- 70	1,000
Underground Pipes	40 to 85	800 – 3,000	10,000
Bored Shafts	199 - 299	1,500 -15,000	50 – 500
Caverns (Note 3)	50 - 200	5,000 – 500,000	1,000 – 50,000
Liquefied[1]	10 - 30	3 – 100	200 – 7,000

Notes:

1. There is a significant energy penalty associated with hydrogen liquefaction.
2. Up to 200 bar for steel cylinders and up to 800 bar for composite tanks.
3. Storage is based on the geological structure of the cavern, values presented are typical.
4. Underground pipelines can be stored in pressures up to 140 bar in specific cases.

6.0 RECOMMENDATIONS

Recommendations pertaining to the technology readiness for the Bacton Energy Hub are:

- Monitor and keep abreast of technology development and supply chain maturity.
- Monitor UK Government policy towards investment in green hydrogen.
- Keep abreast of hydrogen storage options in the area, particularly with regard to geological storage options (i.e. Rough or disused hydrocarbon reservoirs).
- Be aware of long lead times for green hydrogen facilities deployment and manage Bacton build-out scenarios to suit.
- Monitor global developments in green hydrogen investment.
- Develop more detailed uses and market cases for produced green hydrogen at Bacton.
- Keep abreast of any private investment cases in region.

7.0 REFERENCES

REFERENCES	
Ref 1	Progressive energy, SNS-Bacton Energy Hub A Vision for the Future Redacted for Commercial Sensitivity, 2021
Ref 2	Electrolyser Case Studies - Intelligence Report, Dec 2021
Ref 3	https://www.h2pro.co/technology
Ref 4	https://www.supercritical.solutions/
Ref 5	Position Paper ROTTERDAM HYDROGEN HUB, https://smartport.nl/wp-content/uploads/2019/09/SmartPort-Position-paper-Rotterdam-Hydrogen-Hub-1.pdf
Ref 6	https://www.tenaris.com/en/products-and-services/industrial-and-mechanical/gas-cylinders
Ref 7	https://www.pv-magazine.com/2022/02/07/large-scale-storage-options-for-compressed-hydrogen/
Ref 8	
Ref 9	

APPENDIX A- GREEN HYDROGEN CTR

CTR Cost, Time, Resource

Project: BEH Supply SIG	Contract No.:	Work Order No.:
Planned Start:	Planned Finish:	Duration:
CTR No.: 002b	Title: Green Hydrogen Production	Date: Rev: By:

Objective:
Review Green Hydrogen Technology availability, scalability and demand requirements
Activity Description:
Review Green Hydrogen technologies. Determine sizing requirements and phasing of different technology solutions and current technology providers. Generate likely development concepts: - Sizing - Phasing Blending requirements Storage Technology availability and anticipated development (upscaling)
Input Requirements:
Demand SIG production requirements (use OOM for early screening) Supplier engagement and data Existing public domain data and studies
Output/Deliverables:
Production facility sizing/scoping Production facility technology readiness report Production profiles for Green Hydrogen, phased
Notes/Assumptions:
Must consider the output and interfaces with CTR’s 002a and 002c

Prepared By:
Name:……………………………………….
Signature:…………………………………..
Date:………………………………………….

Checked By:
Name:……………………………………….
Signature:…………………………………..
Date:………………………………………….

APPENDIX B – BEH SCENARIOS

Bacton Energy Hub Area Plan Grounding Scenarios

Context

As set out in the Bacton Energy Hub (BEH) vision statement, the overarching goal is to 'Establish a sustainable hydrogen system to ensure Bacton remains a key regional Energy Hub with a low carbon future '. The first stage in doing this is to demonstrate that a credible project exists that presents a value-add opportunity worth the investment to take the hub concept forward to execution.

The objective of this phase of the project and the SIGs is to work towards **building a foundation on which a credible project can emerge**. The basis of this will be the work scopes as set out in each of the SIG TORs. The work scopes will be matured to frame the value proposition and develop a business opportunity document to articulate the potential that the BEH could unlock.

It is recognised that there are a multitude of scenarios that are credible, however detail scenarios will ultimately be required to be explored by the consortium in the future phases of the project. Therefore, maturing an extensive list of scenarios at this stage of the project will add little value when considering the key objective for this phase. It is **NOT** the intention of this phase of the project to define the technical specification or detailed basis of design of the hub. But rather propose a development concept supported by a scoping level design outline to help frame the potential.

The decision has been taken to focus this phase of the project on two key grounding scenarios:

- **Core Project**: which aims to represent the minimum potential / minimum value proposition of a hydrogen hub at Bacton.
- **Build Out:** which aims to represent how you would build from the minimum potential to a hub which delivers what we believe is a base analogous with a P50 development case.

The intent of the scenarios as defined below is to provide a framework to help prioritise work scopes and make best use of available resource and time to complete them to a meaningful conclusion. Also, to concentrate activity on areas which deliver on reducing the key uncertainties around the core case and therefore present a basis for the BEH vision that carries a high confidence supporting the credibility of the project to a future consortium.

Note:

1. There has been discussion on whether an early green hydrogen production scheme could be incorporated in the scenario. To avoid over complicating and distracting from the key objective it has been decided that although this is potential value opportunity it will be considered in parallel rather as a core component to the grounding scenarios.
2. The expectation is that the key information in the table below which details the base assumptions for the scenarios is a first pass and the SIGS will work to validate and refine and or expand the key assumptions as appropriate as the studies and assessment progress.
3. Key Assumptions / Critical Givens below demonstrate some of the potential areas of uncertainty however it will be critical for each SIG to consider the key uncertainties further, that need addressing to inform their prioritisation of work scopes.

		Core Project	Build-out
Demand	**Demand Base Assumption**	Supply Driven Domestic Only	Balanced supply / demand scenario Domestic Only 70% of current domestic gas demand is met with hydrogen (by 2040)
	Maximum Demand (TWh)	7.9 TWh (2030), 58.2 TWh (2040), 90.3 TWh (2050)	7.9 TWh (2030), 58.2 TWh (2040), 90.3 TWh (2050)
	Maximum Blend %	Assumed 20% blend in 2030 increasing to 100% hydrogen in some parts of region in 2040, all 100% hydrogen in 2050	
	Phasing Description	Assumes blending into NTS by 2030. 2030 demand dominated by blend into NTS/LDZ supply for domestic/commercial; full conversion to 100% hydrogen over time	
Supply	**Supply Base Assumption (Blue, Green, Blue + Green)**	Blue Only*	Blue + Green
	Blue / Green Phasing Description	1 (or 3 depending on demand at the time) x 355MW SMR/ATR Plant, no additional investment	2030: 3 x 355 MW SMR/ATR plants 2040: 3 x 355 MW SMR/ATR + 2 x 1.8 GW upscaled SMR/ATR + 1 x 2.1 GW Electroliser 2050: 2 x 1.8 GW upscaled SMR/ATR + 1 x 2.1 GW Electroliser + 2 x 2.1 GW Electroliser plants (NB 3 x 355MW SMR/ATR retired)
	Maximum Supply from Blue Hydrogen (TWH / %?)	3 TWh – 100% of demand	9 TWh – 100% of Demand (2030), 39 TWh – 54% of demand (2040) 30 TWh – 33% of demand (2050)
	Maximum Supply from Green Hydrogen (TWH / %?)	Zero	0 TWh – 0% of demand (2030) 18 TWh – 46% of demand (2040) 54 TWh – 80% of demand (2050)
	Blue Hydrogen Feedstock Assumptions	Producing and Reserves (Requires approx. 30 mmscf/d). Availability of indigenous supply to be confirmed by SIG	Producing and Reserves + Undeveloped discoveries for Hydrogen with possible import 2040 onwards. Estimated hydrocarbon feedstock: 82 mmscf/d (2030) 356 mmscfd (2040) 274 mmscfd (2050) NB All figures to be verified by SIG, and assessment of indigenous vs imported supply
	Green Hydrogen Feedstock Assumptions	N/A	Dedicated wind/solar plus connection to (green) grid (2050)
	Export Yes / No?	No	No
	CS Yes / No?	Yes	Yes
	Hydrogen Storage Yes / No?	No	Yes
	Land requirement	Within existing plant	Blue hydrogen within existing plant boundary with potential re-use of