THE SHELL BLUE HYDROGEN PROCESS

Helping heavy industries, refiners and resource holders to meet their net-zero-emission ambitions through the integration of proven technologies for affordable greenfield blue hydrogen production

WHITE PAPER

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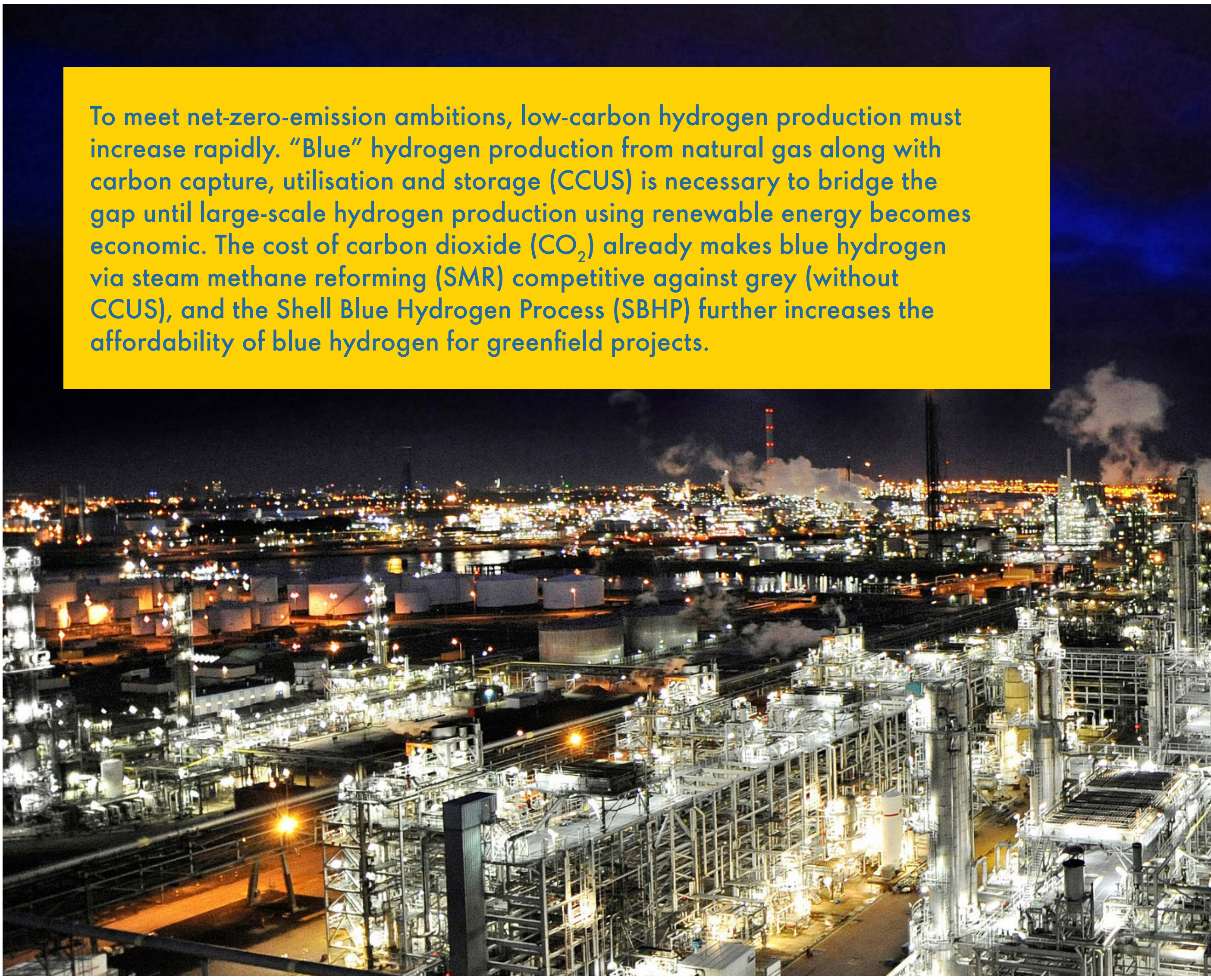

To meet net-zero-emission ambitions, low-carbon hydrogen production must increase rapidly. "Blue" hydrogen production from natural gas along with carbon capture, utilisation and storage (CCUS) is necessary to bridge the gap until large-scale hydrogen production using renewable energy becomes economic. The cost of carbon dioxide (CO_2) already makes blue hydrogen via steam methane reforming (SMR) competitive against grey (without CCUS), and the Shell Blue Hydrogen Process (SBHP) further increases the affordability of blue hydrogen for greenfield projects.

Are you…

…under pressure to decarbonise your existing operations?

…a resource holder looking for ways thrive through the energy transition and to create value from natural gas by becoming a low-carbon energy producer?

The SBHP improves the cost-effectiveness of greenfield blue hydrogen production, thereby making it an attractive investment option.

1. WHY BLUE HYDROGEN?

A growing number of national governments and energy companies, including Shell [Ref 1], have announced net-zero-emission ambitions. Although renewable electricity is expanding rapidly, without low-carbon hydrogen as a clean-burning, long-term-storable, energy-dense fuel, a net-zero goal is difficult to achieve, especially when it comes to decarbonising fertiliser production and hard-to-abate heavy industries such as steel manufacturing and power generation. Hydrogen also has potential as a transport and heating fuel that could repurpose existing gas distribution infrastructure or be introduced into existing natural gas supplies.

Consequently, hydrogen plays an important part in many green strategies. The EU's hydrogen strategy [Ref 2] published in July 2020 describes it as "essential to support the EU's commitment to reach carbon neutrality by 2050 and for the global effort to implement the Paris Agreement while working towards zero pollution".

Momentum is building with a succession of commitments to hydrogen by various companies and governments. For example, in June 2020, Germany announced a €9-billion hydrogen strategy [Ref 3], and the International Energy Agency says that "now is the time to scale up technologies and bring down costs to allow hydrogen to become widely used" [Ref 4]. Over the last three years, the number of companies in the international Hydrogen Council, which predicts a tenfold increase in hydrogen demand by 2050 [Ref 5], has jumped from 13 to 81 and includes oil and gas companies, automobile manufacturers, trading companies and banks.

In 2018, global hydrogen production was 70 Mt/y [Ref 4]. Today's demand is split between being used for upgrading refined hydrocarbon products and as a feedstock for ammonia production for nitrogen fertilisers. Nearly all production comes from fossil fuels: it accounts for 6% of natural gas and 2% of coal consumption, and 830 Mt/y of CO_2 emissions [Ref 6] – more than double the UK's emissions [Ref 7]. "Grey" hydrogen is a major source of CO_2 emissions.

If hydrogen is to contribute to carbon neutrality, it needs to be produced on a much larger scale and with far lower emission levels.

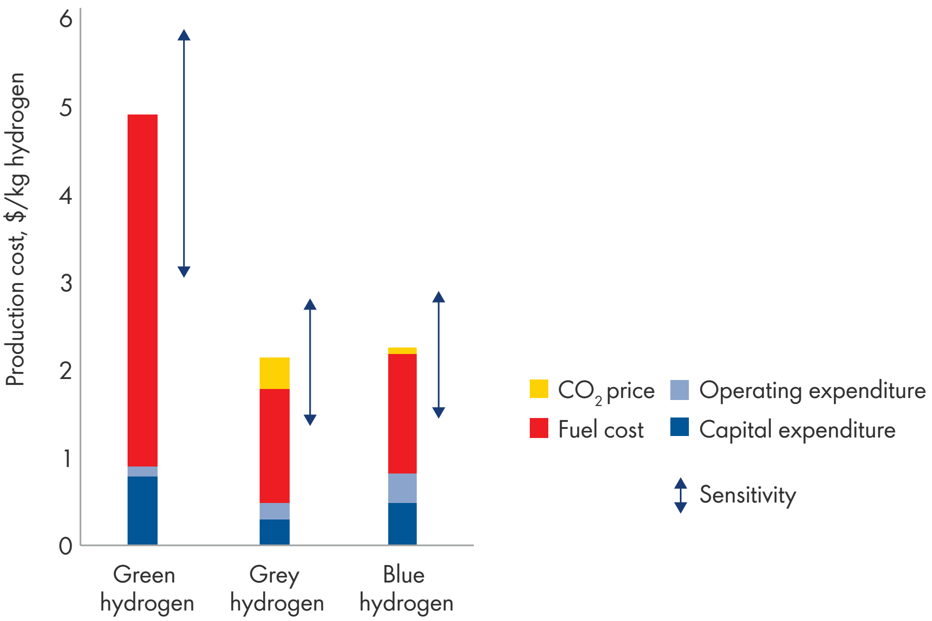

Figure 1: Hydrogen production costs in 2030.

Long term, the answer is likely to be "green" hydrogen, which is produced from the electrolysis of water powered by renewable energy. This supports the integration of renewable electricity generation by decoupling production from use. Hydrogen becomes a convertible currency enabling electrical energy to be stored and for use as an emissions-free fuel and chemical feedstock.

Green hydrogen projects are starting. For example, a Shell-led consortium is at the feasibility stage of the NortH2 wind-to-hydrogen project in the North Sea, and a Shell–Eneco consortium secured the right to build the 759-MW Hollandse Kust Noord project at a subsidy-free Dutch offshore wind auction in July 2020; this project will include a green hydrogen technology demonstration.

However, electrolysis alone will not meet the forecast demand. It is currently expensive and there is insufficient renewable energy available to support large-scale green hydrogen production. To put the scale of the task into perspective, meeting today's hydrogen demand through electrolysis would require 3,600 TWh of electricity, more than the EU's annual use [Ref 4]. Moreover, using the current EU electricity mix would produce grey hydrogen from electrolysis with 2.2 times the greenhouse gas emissions of producing grey hydrogen from natural gas [Ref 8].

An alternative is blue hydrogen produced from natural gas along with CCUS. Hydrogen production via electrolysis has a similar efficiency to blue hydrogen production, but the levellised cost of production is significantly higher for electrolysis at €66/MWh compared with €47/MWh for SMR–CCUS [Ref 9].

In addition, it is widely acknowledged that scaling up blue hydrogen production will be easier than delivering green hydrogen. For example, the EU strategy [Ref 2] says that **"other forms of low-carbon hydrogen [i.e., blue] are needed, primarily to rapidly reduce emissions... and support the parallel and future uptake of renewable [green] hydrogen".**

The strategy goes on to say that neither green nor blue hydrogen production is cost-competitive against grey: the hydrogen costs[1] estimated for the EU being €1.5/kg for grey, €2.0/kg for blue and up to €5.5/kg for green [Ref 4].

With the cost of CO_2 at $25–35/t, blue hydrogen becomes competitive against grey, even with higher capital costs, and **green hydrogen may still be more than double the price of blue hydrogen by 2030 [Ref 4]. Some forecasts indicate cost parity will occur in about 2045 [Ref 10].**

[1] Based on an assumed natural gas price for the EU of €22/MWh, an electricity price of €35–87/MWh and capacity costs of €600/kW

2. GREENFIELD TECHNOLOGY OPTIONS

This paper considers three technology options for greenfield blue hydrogen projects: SMR, autothermal reforming (ATR) and Shell gas partial oxidation (SGP) technology (Figure 2).

GOOD

SMR

- Catalytic
- Indirect heating
- Non-oxygen-based with steam
- Multitubular with external firing

Proven for grey hydrogen, but the alternatives may be better suited for blue hydrogen

BETTER

ATR

- Catalytic
- Direct heating
- Oxygen-based with steam
- Refractory-lined reactor with catalyst bed

As an oxygen-based system, more cost-effective than SMR for blue hydrogen

BEST

SGP technology

- Noncatalytic
- Direct heating
- Oxygen-based without steam
- Refractory-lined reactor

Offers key advantages over ATR, for example, for a 500-t/d hydrogen production unit:

- **$30 million/y lower operating expenditure;**
- **35% less power import; and**
- **10–25% lower levellised cost of hydrogen**

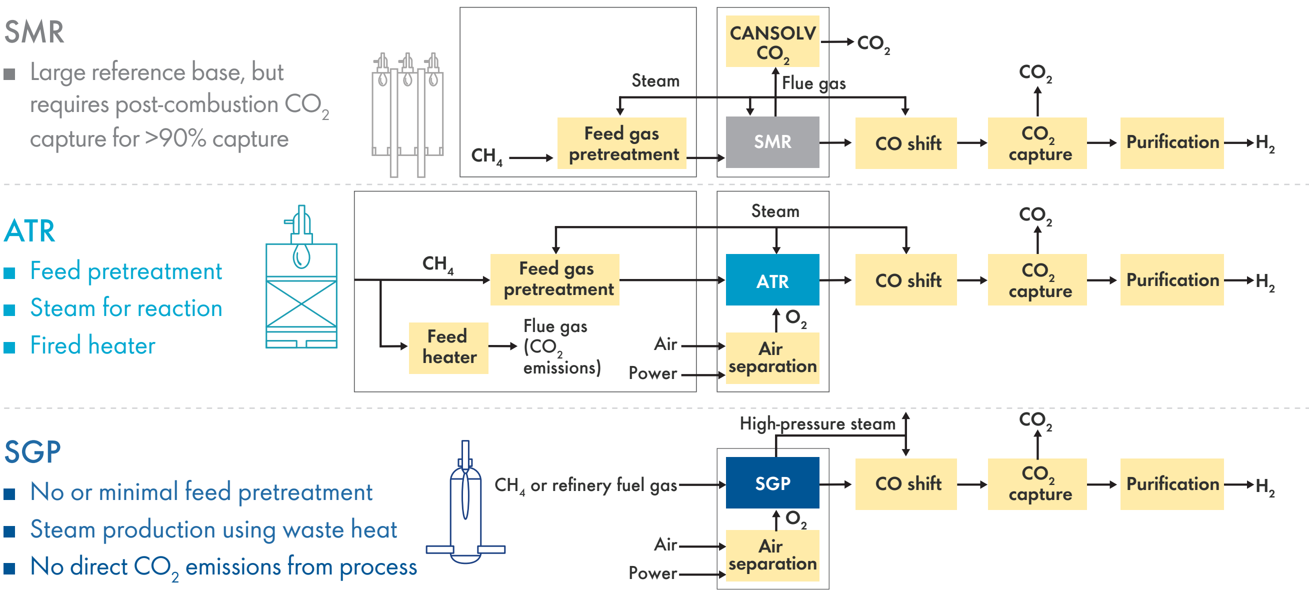

Figure 2. Blue hydrogen technologies and process line-ups.

SMR

SMR, a proven catalytic technology widely applied for grey hydrogen production, uses steam in a multitubular reactor with external firing for indirect heating. Post-combustion carbon capture can be retrofitted to convert grey hydrogen production to blue. For example, the Shell CANSOLV[2] CO_2 Capture System is proven to capture nearly all the CO_2 (99%) from low-pressure, post-combustion flue gas.

However, for greenfield blue hydrogen applications, oxygen-based systems such as ATR and SGP technology are more cost-effective than SMR (Figure 3), a conclusion backed by numerous studies and reports [Ref 11]. Note that the cost of CO_2 makes grey hydrogen via SMR more expensive than blue hydrogen from SGP technology. The cost advantage of oxygen-based systems over SMR increases with scale because the relative cost of the air separation unit decreases with increasing capacity. Another advantage is that more than 99.9% of the CO_2 can be captured using the lower-cost, pre-combustion Shell ADIP ULTRA solvent technology.

ATR

ATR uses oxygen and steam with direct firing in a refractory-lined reactor with a catalyst bed. It is more cost-effective than SMR, but requires a substantial feed gas pretreatment investment and the fired heater produces CO_2 emissions (Figure 2).

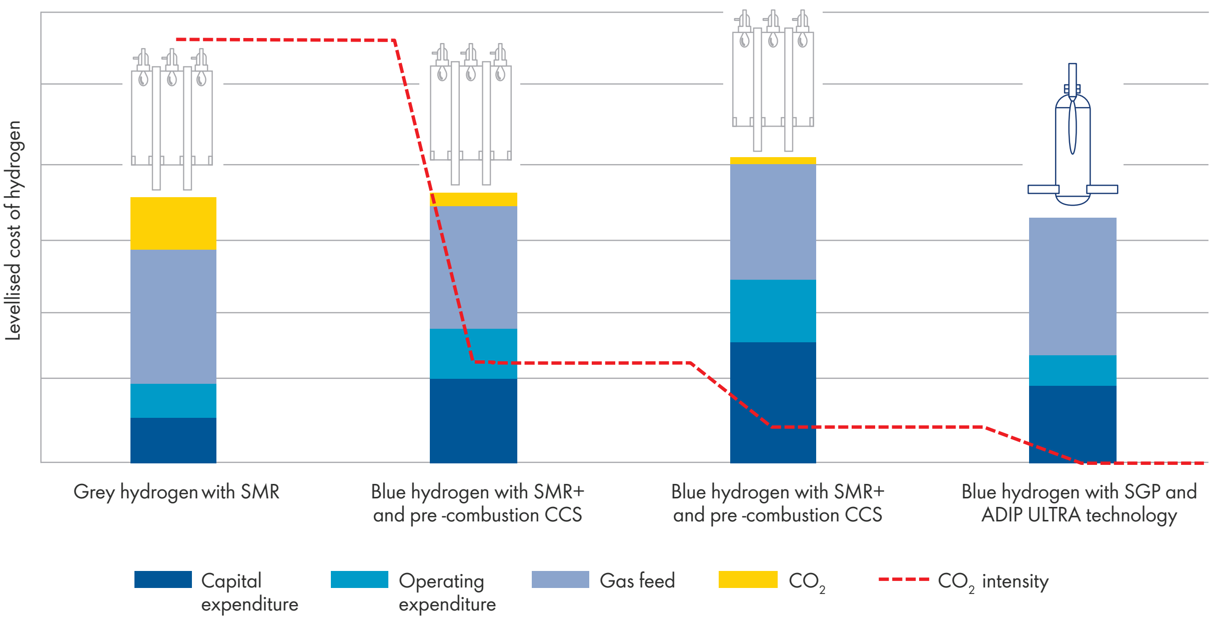

Figure 3: Relative CO_2 intensity and cost of grey and blue hydrogen via SMR with pre- and post-combustion capture, and blue hydrogen via SGP and ADIP ULTRA technology.

[2] CANSOLV is a Shell trademark.

SGP TECHNOLOGY

SGP technology is also an oxygen-based system with direct firing in a refractory-lined reactor, but it is a noncatalytic process that does not consume steam and has no direct CO_2 emissions. Compared with SMR, SGP technology saves money by maximising carbon-capture efficiency and simplifying the process line-up, both of which offset the cost of oxygen production (Figure 4).

A key advantage of SGP technology over ATR is that the partial oxidation reaction does not require steam as a reactant. Instead, high-pressure steam is generated by using waste heat from the reaction, which can satisfy the steam consumption within the SBHP as well as some internal power consumers. With no need for feed gas pretreatment, SGP technology has a far simpler process line-up than ATR (Figure 2) and, as a noncatalytic, direct-fired system, it is robust against feed contaminants such as sulphur and can thereby accommodate a large range of natural gas quality, and thus give refiners greater feed flexibility to decarbonise refinery fuel gas.

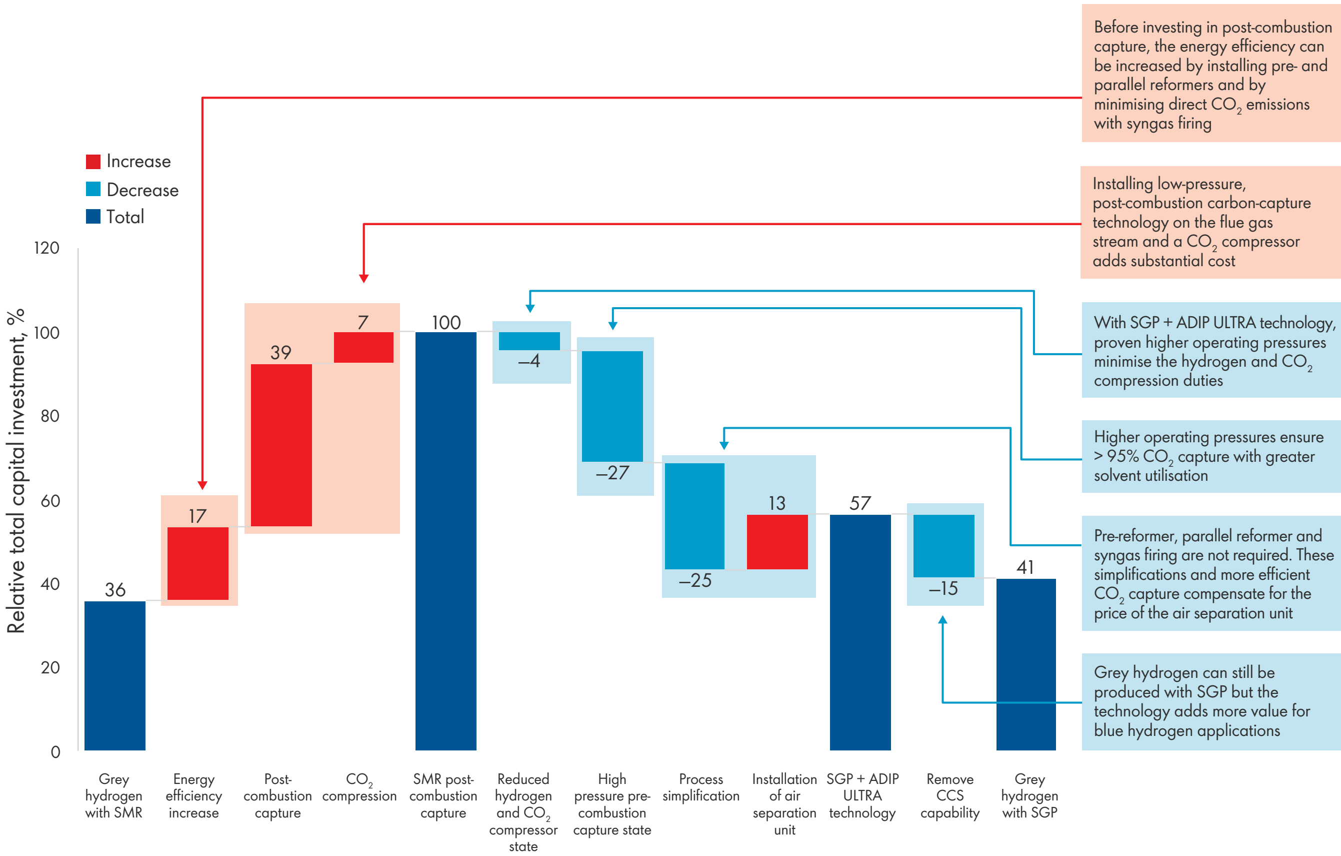

Figure 4: Relative capital investment comparison between grey and blue hydrogen via SMR and SGP technology.

SGP technology provides substantial savings compared with ATR: a 22% lower levellised cost of hydrogen (Figure 5). This saving comes from a 17% lower capital expenditure owing to the potential for a higher operating pressure leading to smaller hydrogen compressor (single-stage compression), CO_2 capture and CO_2 compressor units, and a 34% lower operating expenditure (excluding the natural gas feedstock price) from reduced compression duties and more steam generation for internal power. SGP technology consumes 6% more natural gas, but this is offset by power generation from the excess steam.

The SBHP is an end-to-end line-up that maximises the integration of SGP and ADIP ULTRA technologies. Compared with an ATR unit, modelling shows that a SBHP line-up producing 500 t/d of pure hydrogen would have:[3]

- **$30** million/y lower operating expenditure;
- **35%** less power import;
- >**99%** CO_2 capture; and
- a **10–25%** lower levellised cost of hydrogen.

The SBHP is the best option for large-scale blue hydrogen projects. Figure 6 shows the principle advantages of integrating the SBHP with other Shell and open-source technologies.

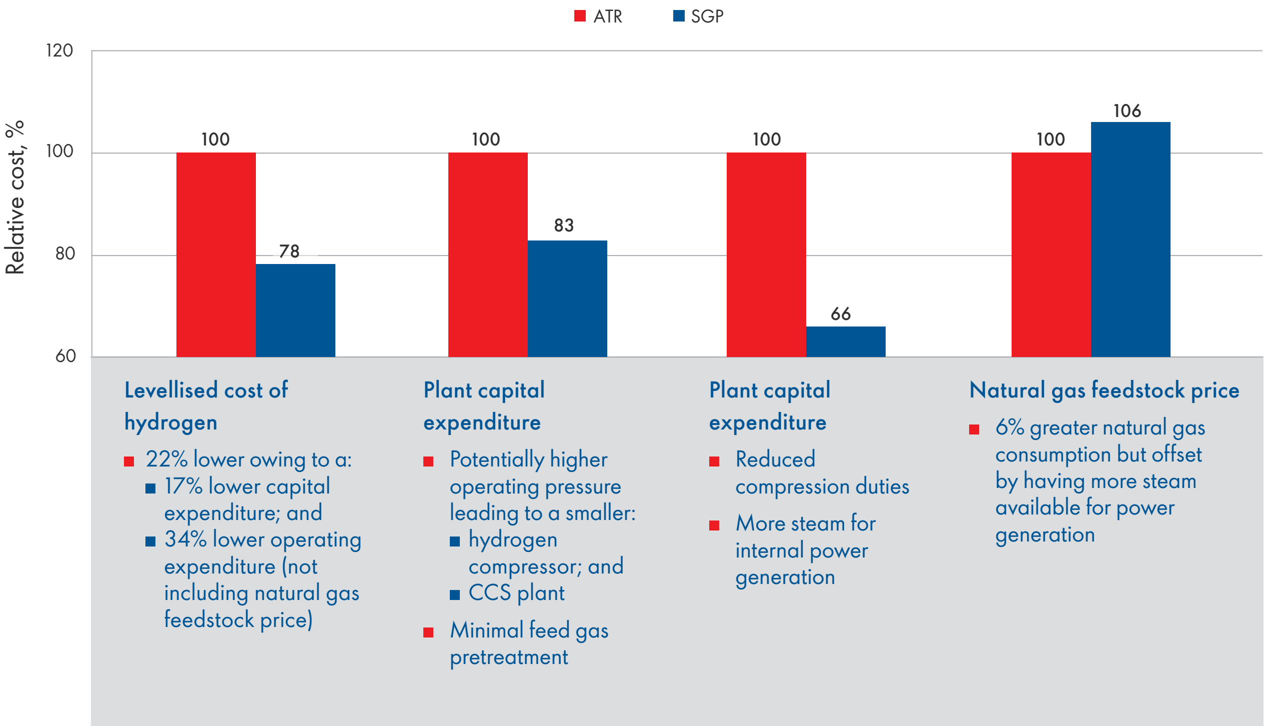

Figure 5: The cost of SGP technology relative to ATR.

[3]Excluding inerts, methane, CO_2 and carbon monoxide, which will also be present, depending on the final purification step: based on costs of $396/te for natural gas, $8.4/te for demineralised water and $86/MWh for power import; estimated costs for solvent, triethylene glycol and catalyst; hydrogen discharge pressure of 72 bara and CO_2 discharge pressure of 150 bara; and 95% plant availability

The choice between a methanator or pressure-swing absorption unit for the hydrogen purification step depends on the required hydrogen purity. For example, a pressure-swing absorption unit is necessary to achieve the >99.97% purity required for the hydrogen used in fuel cells. The off-gas is predominantly hydrogen with trace containments such as carbon monoxide, CO_2 and nitrogen. In the ATR process, this off-gas is typically burned to preheat the natural gas, which produces direct CO_2 emissions.

In a methanator, the purity of the final hydrogen is lower (>98%, depending on the feed gas properties). However, it avoids direct the CO_2 emissions from burning the pressure-swing absorption off-gas. The main advantage of choosing a methanator is that hydrogen is not lost via the pressure-swing absorption off-gas. Consequently, it reduces natural gas consumption for the same hydrogen production. In addition, a methanator is commonly applied in industry, as it satisfies the hydrogen purity requirements of most industrial consumers.

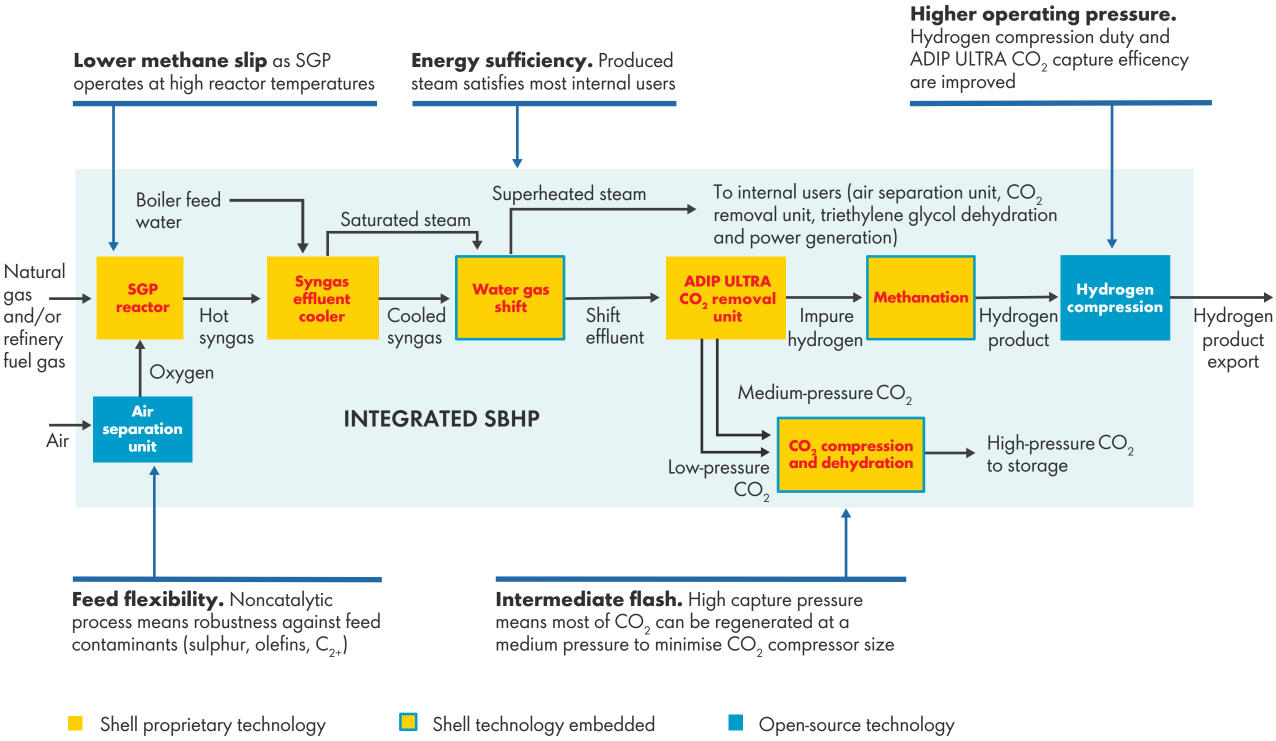

Figure 6: The advantages of integrating the SBHP with other technologies, with Shell as the master licensor.

3. THE HISTORY OF SGP TECHNOLOGY

SGP is a mature (TRL9), “low-carbon” technology eligible for government funding.

Shell has a long history of developing SGP technology, beginning with research in the 1950s (Figure 7). Today, SGP has over 30 active residue and gas gasification licensees, and more than 100 SGP gasifiers have been built worldwide.

For example, in the Pearl gas-to-liquids plant, Qatar, 18 SGP trains, each with an equivalent pure hydrogen production capacity of 500 t/d have been operating since 2011.[4] Since 1997, Pernis refinery, the Netherlands, has been operating at a 1-Mt/y CO_2 capture capacity using SGP technology: the CO_2 is used in local greenhouses. The CO_2 stream is an essential part of the Pernis CCS project (Figure 8).

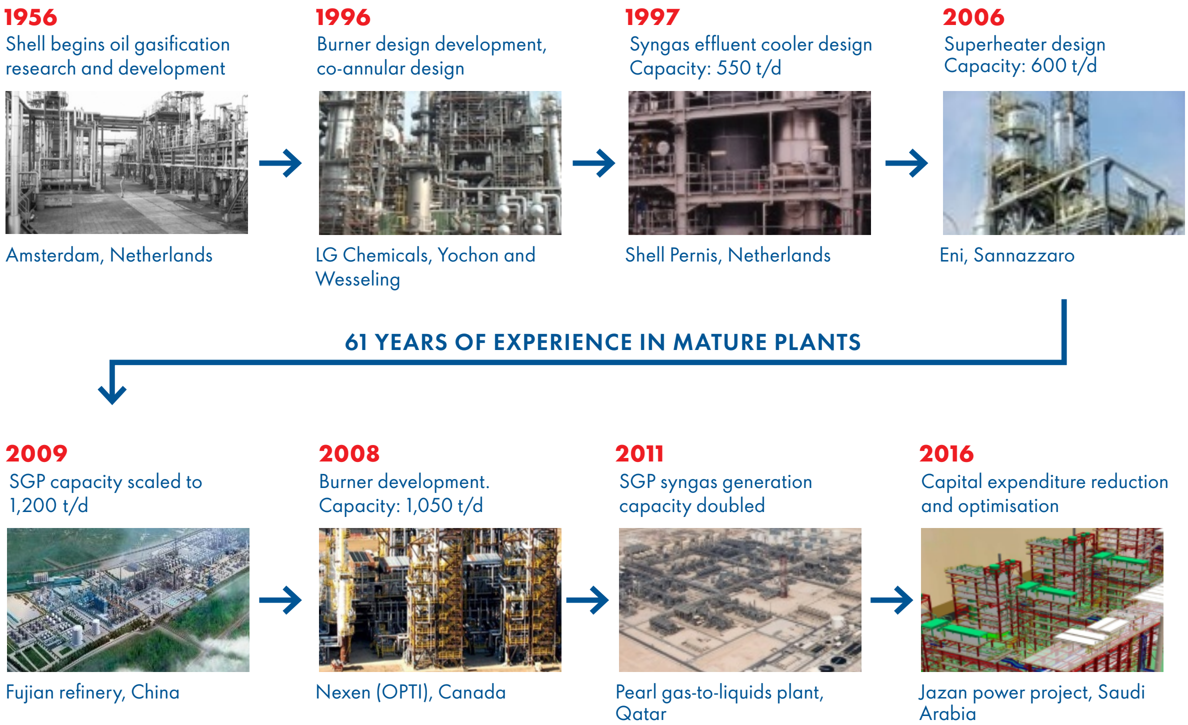

Figure 7: SGP development.

[4] Defined as pure hydrogen production, i.e., not including any inerts, methane, CO_2, or carbon monoxide, which will also be present, depending on the final purification step

4. CCUS EXPERIENCE

No matter how cost-effective the hydrogen production and carbon capture technologies, without sequestering the CO_2 directly or through enhanced oil recovery, the hydrogen remains grey.

Shell has growing experience in CCUS through its long-term involvement in multiple CCUS projects in different phases of development (Figure 8), and can offer key insights into each of the four major steps in CCUS:

1. **Capture** – Shell Catalysts & Technologies has two proven carbon-capture technologies: ADIP ULTRA solvent technology and the CANSOLV CO_2 Capture System.
2. **Compression** – The captured CO_2 is compressed into liquid form for transport using commercial, fully available technology.
3. **Transport** – The CO_2 is moved from the industrial site where it is produced to its storage site, which could be on- or offshore. It is generally pumped through a pipeline, but ship transport may also play a role.
4. **Utilisation and storage** – The CO_2 is either injected deep underground into the microscopic spaces in porous rocks or it is sold for uses such as in the beverage industry or in greenhouses. Although the market size for those applications is small, this is highly relevant for those refiners located near other industries that need CO_2.

In addition, Shell has worked with customers on other crucial aspects, including location identification and measuring, monitoring and verification to ensure that the CO_2 is permanently stored.

Figure 8: Shell CCUS experience.

5. KEY TAKEAWAYS

Hydrogen will be part of the future energy mix and there are several mature technologies available for producing cost-effective, low-carbon blue hydrogen.

For greenfield applications, SMR is an inefficient method of producing blue hydrogen owing to poor CO_2 recovery and scalability: oxygen-based systems offer better value (an independently backed conclusion).

The SBHP, which integrates Shell SGP and ADIP ULTRA technologies, offers key advantages over ATR, including a 10–25% lower levellised cost of hydrogen, a 20% lower capital expenditure, a 35% lower operating expenditure (excluding natural gas feedstock price), >99% CO_2 captured and overall process simplicity.

Shell has a long, proven record in blue hydrogen production with Shell SGP technology at the 500-t/d scale and is a market leader in developing full-scale CCUS projects. The SBHP is now available to third-party refiners.

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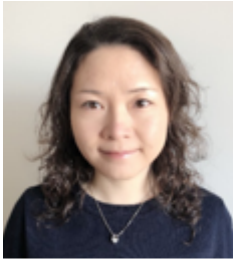
6. ABOUT THE AUTHOR



Nan Liu, Licensing Technology Manager Gasification, Shell Catalysts & Technologies

Nan Liu has fulfilled roles throughout the project life cycle, from initial feasibility and front-end development to project execution and plant operations, on major capital projects around the globe.

These include the startup of the gasification unit at the Fujian refinery and ethylene project in China, and performance optimisation at the gasification and hydrogen plant at Shell's Pernis refinery in the Netherlands. Nan has a strong commercial mindset and is a keen advocate of gasification as a value-adding investment.

7. ABOUT SHELL CATALYSTS & TECHNOLOGIES

Shell Catalysts & Technologies supports Shell and non-Shell businesses by working with them to co-create integrated, customised solutions comprising licensed technologies, refining and petrochemical catalysts, and technical services.

It was formed by combining Shell Global Solutions, a technology licensor with a track record of delivering pioneering process schemes and innovative configurations; Criterion Catalysts & Technologies, the world's largest hydroprocessing catalyst supplier; and CRI Catalyst Company, a pioneer in the petrochemical catalyst sector.

It operates across the energy value chain, from upstream, gas processing and liquefied natural gas through to downstream refining and petrochemicals.

The fact that Shell Catalysts & Technologies supports Shell's global downstream network means that it has already addressed many of the challenges that its third-party customers face; the catalysts and technologies that it licenses have been developed in response to the same challenges.

For further information, please visit our website at **www.shell.com/ct.**