Chapter 7. Conclusions

Using low-carbon hydrogen and ammonia in fossil fuel power plants can play an important role to help ensure electricity security in clean energy transitions

Governments around the world are faced with the challenge of ensuring electricity security and meeting growing electricity uses while simultaneously cutting emissions. The significant increase in renewables and electrification of end-uses plays a central role in clean energy transitions. However, due to the variable nature of solar PV and wind, a secure and decarbonised power sector requires other flexible resources on a much larger scale than currently exists today. These include low-carbon dispatchable power plants, energy storage, demand response and transmission expansion. The availability and cost of these technologies depends on local conditions, social acceptance and policies.

Thermal generation is the largest source of power and heat in the world today, also providing key flexibility and other system services that contribute to the security of electricity supply. Countries that rely strongly on fossil fuel-based power generation will be required to make very significant efforts to achieve decarbonisation objectives to comply with the Paris Agreement or Net Zero targets, where applicable.

The possibility to combust high shares of low-carbon hydrogen and ammonia in fossil fuel power plants provides countries with an additional tool for decarbonising the power sector, while simultaneously maintaining all services of the existing fleet. The relevant technologies are progressing rapidly. Co-firing up to 20% of ammonia and over 90% of hydrogen has taken place successfully at small power plants, and larger-scale test projects with higher co-firing rates are under development.

The value of low-carbon fuels in the power sector depends on system contexts and regional conditions

By 2030, thermal power plants using low-carbon fuels could play a growing role as a dispatchable resource for covering peaking needs when the value of the produced electricity is high, and for providing a range of system services to ensure energy security and capacity adequacy to avoid costly disruptions in the energy supply.

Low-carbon fuels can play an especially important role in countries or regions where the thermal fleet is young, or when the availability of low-carbon dispatchable resources is constrained. In these settings, they can enable continued operation of existing assets even when climate regulations are tightened, thereby diminishing the risk of creating stranded assets. This is particularly the case in the East and Southeast Asia.

Production costs of low-carbon fuels must decrease further

Today, the cost of producing low-carbon fuels is still significantly higher than the cost that fossil fuel power plants generally pay for their fuels. However, the need to decarbonise hard-to-abate sectors like industry and transport is fostering the production of hydrogen and hydrogen-derived fuels, and this is expected to lead to cost reductions due to scale benefits and learning.

Natural gas with CCUS is currently the least-cost production route for low-carbon hydrogen and ammonia in regions with cheap natural gas, and access to CO_2 storage. By 2030, the economic attractiveness of the CCUS route could improve further, though it remains exposed to fossil fuel price variations.

Due to continuing reductions in the cost of renewable electricity and scale benefits in electrolysers, the costs of the electrolytic route decrease faster, and by 2030 the costs of low-carbon fuels from renewables become comparable with those of fossil fuels in the CCUS route, and can become the lowest cost route in regions with excellent wind and solar resources. However, in the absence of a price on carbon, low-carbon hydrogen and ammonia are still expected to remain more expensive than coal and natural gas in 2030.

Full value chains, including transport and storage, must be considered when comparing the cost of using different low-carbon fuels

An extensive transport and storage infrastructure is a prerequisite for establishing global value chains based on hydrogen and ammonia, and connecting low-cost production regions with users of low-carbon fuels. Such infrastructure involves massive investments combined with concerted and coordinated efforts across many stakeholders, including duly addressing health & safety risks.

The storage and long-distance transport of low-carbon fuels can lead to a substantial increase in the cost of delivered fuel. In the case of hydrogen, liquefaction is a very energy- and capital- intensive process that contributes to high transport costs which can significantly impact the cost difference between hydrogen and ammonia, and in some cases tilts the overall balance in favour of ammonia.

The use of low-carbon fuels in fossil fuel power plants must lead to significant and measurable life-cycle emission reductions

There are currently no internationally agreed rules or standards on the maximum allowable limit of GHG emissions that can be associated with the production of hydrogen and/or hydrogen-derived fuels. Standards are however needed to create end-user confidence towards fuels that are carbon-free at the point of consumption, but might be associated with significant GHG emissions along the supply chain, from production to transport and final distribution.

In the case of the CCUS route, as it will dictate minimum eligible CO_2 capture rates and put limits on the maximum allowable upstream emissions because they cannot be captured at the production plant.

At the same time, such rules and standards are also relevant for the electrolytic route if the use of grid electricity is allowed for the production plants, as the power mix will significantly influence life-cycle emissions.

A versatile mix of supply routes for low-carbon fuels will enhance diversification and security of supply while contributing to cost predictability

Our cost analysis indicates clear differences among the production costs of different production technologies. Despite possible rapid cost reductions for electrolysers, in most locations the renewable route is likely to remain more expensive than fossil fuels with CCUS in 2030.

However, the lowest cost production route is subject to location conditions and – as supply chains struggle to meet rapidly growing demand – a diverse mix of supply locations and technologies can help enhance the security of supply for end-users. The costs of the renewable route are more predictable and can help to balance possible disruptions in the supply of natural gas and swings in commodity prices, to which the fossil fuel-based routes are exposed.

Early opportunities for low-carbon hydrogen and ammonia production are identified in places where production can be built on existing infrastructure and demand. There also exist possibilities to integrate the two approaches into a hybrid plant that can offer increased efficiency and potentially also require lower capital investment requirements.

If the biomass feedstock is sustainably produced, capturing by-product CO_2 from a biomass conversion plant would enable the production of carbon-negative hydrogen and ammonia. This form of BECCS configuration would lead to increases in production costs. However, if the plant received revenue from negative emissions (i.e., from permanent storage of biogenic CO_2), this would significantly improve the economics of biomass-based fuels under high carbon price jurisdictions.

For the above-mentioned reasons, the overall strategies and policies incentivising the deployment of low-carbon fuels should be kept open for different technology options so long as basic sustainability criteria are met. This is likely to increase competition and accelerate cost reductions, while contributing to increased diversification and security of supply

A portfolio of policies is required to compensate for cost gaps and foster uses that maximise system value

By 2030, low-carbon hydrogen and ammonia are likely to remain expensive energy carriers for power generation. Power markets should be redesigned to reward flexibility and capacity contributions from low-carbon thermal power plants.

This could be accompanied by support measures such as carbon pricing and/or other complementary policies and regulatory frameworks to further decrease the remaining cost gap with incumbent generation. Support measures should be tailored towards cost-effective system integration and maximising the value of low-carbon dispatchable generation. They should also aim at fostering competition and improving environmental performance over time.

In any case, given the expected increasing competition from other forms of low-carbon dispatchable resources as well as other flexibility and storage options, the availability, feasibility and competitiveness of low-carbon thermal power plants will need to be continuously and carefully assessed.

Developing markets for low-carbon fuels and their supply chains by 2030 will establish significant opportunities in many countries and sectors of the economy

It is vital that economies with strong drivers for low-carbon fuel use are successful in creating demand, bringing down the costs and stabilising value chains by 2030. Only their success will open up opportunities to expand the use of low-carbon fuels in the emerging economies of the world.

This is particularly relevant to countries that have young fossil fuel fleets, and have already implemented and utilised most of their existing flexibility resources, such as grids and interconnections, storage and demand-side measures.

Ultimately, using large volumes of low-carbon hydrogen and ammonia in the power sector will help establish supply chains and drive down costs through economies of scale and technological improvements, thereby complementing and mutually reinforcing the use of low-carbon in fuels in other hard-to-abate sectors such as long-haul transport and industry.

Annexes

Annex A - Dynamical modelling of hydrogen and ammonia costs from a mix of wind and solar via water electrolysis

The cost and availability of electricity governs the cost of fuels produced via the electrolytic route. By connecting the electrolyser plant directly to a mix of wind and solar PV power plants, a fully renewable fuel production process can be established. Because the solar and wind resources are distributed unevenly across the globe, certain locations are better suited for producing low-cost fuels via electrolysis.

For the purposes of this report, the levelised cost of hydrogen (LCOH) and the levelised cost of ammonia (LCOA) have been dynamically modelled and analysed following a methodology explained in more detail in the paper: "Flexible production of green hydrogen and ammonia from variable solar and wind energy: Case study of Chile and Argentina".

The table below summarises the capacity factors (CFs) and LCOE estimates for wind and PV for selected locations in 2030. The capacity factors for solar electricity range from 15.1% (Magallanes, Chile) to 32.5% (Taltal, Chile) while for wind generation the CFs range from 15.3% (Rajasthan, India) to 51.8% (Magallanes, Chile). The resulting LCOEs for solar PV range from USD 16 to 51/MWh and for wind from USD 25 to 77/MWh.

Levelised cost of electricity estimates for selected locations in 2030

	Taltal	Magallanes	Gujarat	Karnataka	Rajasthan	Port Headland, Australia	Aqaba, Saudi Arabia	Abu Dhabi
CF solar (%)	32.5	15.1	23.7	24.1	23.2	25.2	27.1	27.6
CF wind (%)	43.8	51.8	45.6	43.9	15.3	42.2	48.0	29.2
LCOE solar (USD/MWh)	24	51	31	16	17	30	23	22
LCOE wind (USD/MWh)	37	30	30	25	77	40	36	67

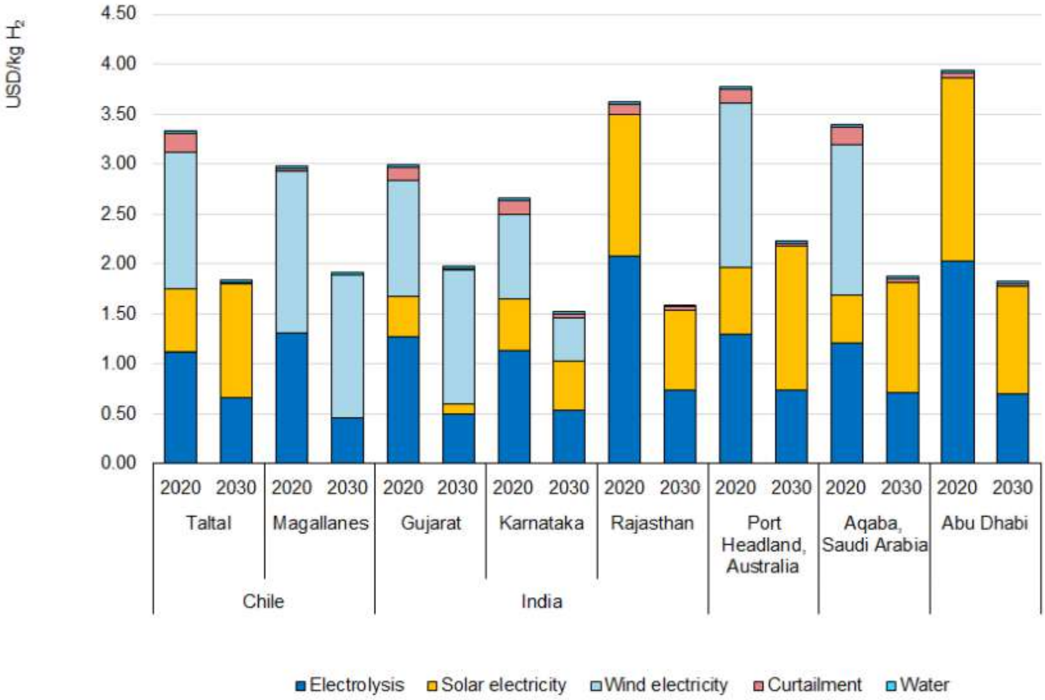
Based on local conditions, as summarised in the form of CFs and LCOEs, the LCOH has been dynamically modelled and summarised in the table below. By optimising the solar (P_{solar}) and wind farm capacities (P_{wind}) relative to the size of the electrolyser unit (P_{H2}), the electrolyser's capacity factor (CF hybrid) as well as the total curtailment of electricity (electricity generation that exceeds electrolyser capacity) can be calculated. Out of the examined locations, the lowest LCOH of USD 1.52/kg is achieved in Karnataka, followed by USD 1.59 /kg in Rajasthan.

The cost reduction from hybridisation, i.e. from optimising the wind/PV mix is limited for most of the examined hydrogen cases, though for Karnataka an almost 3% cost reduction can be achieved. Higher hybridisation gains can be generally achieved when the local daily and yearly cycles of solar and wind combine favourably, leading to an increased capacity factor for the electrolyser. On the other hand, at lower electrolyser CAPEX the hybridisation gains are also lower.

Process parameters and production cost estimates for electrolytic hydrogen from locally optimised mixes of solar PV and wind in 2030

	Taltal	Magallanes	Gujarat	Karnataka	Rajasthan	Port Headland, Australia	Aqaba, Saudi Arabia	Abu Dhabi
P_{solar}/P_{H2}	1.25	0	0.145	1.45	1.64	1.45	1.45	1.44
P_{wind}/P_{H2}	0	1.18	1.16	0.436	0	0	0	0
CF hybrid (%)	40.5	61.2	55.9	52.1	36.4	36	37.7	38.5
curtailment (%)	0.83	0.12	1	4	4.2	1.9	4.3	2.9
Hybridisation gain (%)	0	0	0.2	1.8	0	0	0	0
LCOH	1.84	1.91	1.97	1.52	1.59	2.23	1.88	1.83

Cost breakdown of LCOHs in 2020 and 2030 for selected regions



Similarly to LCOHs, the LCOAs have also been optimised for local conditions and summarised in the table below. However, dynamical modelling of an electrolytic ammonia plant is substantially more complex than modelling a hydrogen electrolyser. In the HB process, the produced hydrogen is combined with nitrogen captured from the air using a cryogenic air separation unit (ASU), and catalytically converted to ammonia under elevated pressure and temperature. The Haber-Bosch synthesis loop is much less flexible than an electrolyser, thus an intermediate storage of hydrogen is used to stabilise the flow of hydrogen to the ammonia synthesis. For this purpose, steel tanks for compressed hydrogen storage were considered, which is quite costly, but currently commercially available. The additional electricity consumption caused by the ASU and HB is based as much as possible on wind and solar generation, but is complemented with "firm-up" electricity purchased either from the grid or generated locally at a cost of about USD 100/MWh when wind or solar are not available.

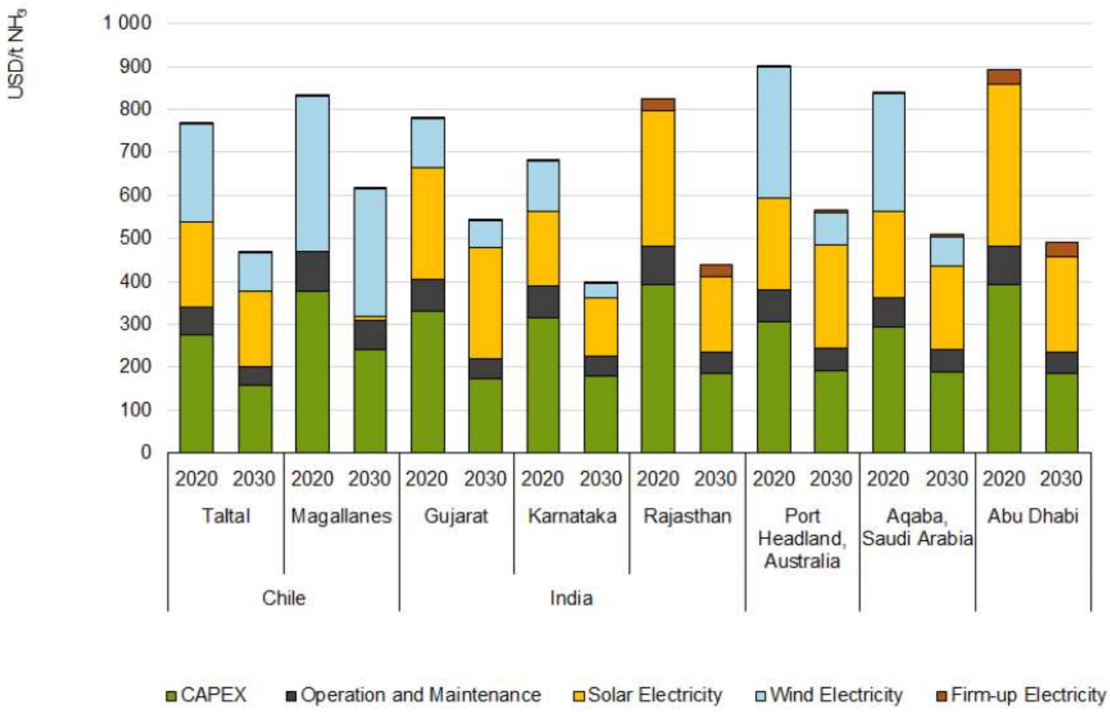
The LCOA depends, as the LCOH, on the sizes of wind and solar power plants relative to the electrolyser capacity P_{H2}, but additionally on the capacity of the HB synthesis reactor relative to P_{H2}, which is described by the oversizing of the HB capacity relative to the mean hydrogen flow. When HB oversizing equals 1, the H_2 buffer storage manages to absorb all of the fluctuations in upstream hydrogen production so that the ammonia synthesis can operate the whole year at a constant nominal load. This is however not the optimal configuration due to the high cost of H_2 storage to achieve perfectly continuous H_2 supply to the HB reactor.

The results show that hybridisation gains are higher for electrolytic ammonia than for electrolytic hydrogen, providing cost reductions up to 8.0% (Gujarat). A second observation relates to the large hydrogen storage requirements for locations like Magallanes (7.4 days of H_2 production) where wind variability is very strong. Due to the high cost of H_2 storage, an optimal configuration requires substantial oversizing of the renewable power supply, leading to an electrolyser capacity factor of 64.7% and a large 5.5% share of curtailed electricity. Of the examined locations, the lowest LCOA of USD 400/tNH3 (USD 77/MWh) is achieved in Karnataka, followed by USD 439 /tNH3 (USD 85/MWh) in Rajasthan.

Process parameters and production cost estimates for electrolytic ammonia from a locally optimised mix of solar PV and wind in 2030

Optimisation results	Taltal	Magallanes	Gujarat	Karnataka	Rajasthan	Port Headland, Australia	Aqaba, Saudi Arabia	Abu Dhabi
P_{solar}/P_{H2}	1.31	0.09	1.71	1.6	2.01	1.51	0	1.57
P_{wind}/P_{H2}	0.31	1.4	0.23	0.14	0	0.2	1.36	0.2
HB oversizing	1.1	1.34	1.16	1.08	1.13	1.13	1.16	1.13
Hybrid CF (%)	50.8	64.7	43.9	40.4	39	41.8	44.3	39.6
Curtailment (%)	3.6	5.5	7.4	3.5	13.2	3.8	9.0	6.6
H2 storage (days of H2 production)	1.1	7.4	1.1	1.3	1.4	2.3	2.3	1.5
HB-ASU firm-up elec. (%)	6.6	3.9	3.2	8.2	51.2	6.0	9.3	49.3
Hybridisation gain (%)	6.4	0.2	8.0	4.5	0.0	5.0	1.5	0.0
# stops HB	0	0	0	0	0	0	0	0
LCOA (USD/tNH3)	471	617	544	400	439	565	511	490
LCOA (USD/MWh)	91	119	105	77.3	84.8	109	98.7	94.6

Cost breakdown of LCOAs in 2020 and 2030 for the selected regions



Annex B - Assumptions

This annex collects the various assumptions that underpin the analyses throughout the *The Role of Low-Carbon Fuels in the Clean Energy Transitions of the Power Sector* report. The analysis is based on the IEA Sustainable Development Scenario (SDS).

General

- Weighted average cost of capital, WACC: 5%
- CAPEX range: ±15%
- Learning to 2030: 2% (Commercial technologies)
- Learning to 2030: 20% (Biomass technologies)
- Runtime of thermal fuel production: 8000 hours/year
- Plant lifetime: 25 years

Main investment cost assumptions

Electrolyser	Unit	Today	2030 SDS
CAPEX	USD/kW$_e$	1477	562
OPEX	% of CAPEX	1.5	1.5
Lifetime	years	28	30
Stack lifetime	Operating hours	95000	95000
Efficiency (LHV)	%	64	69

Solar PV – Large-scale	Unit	Today	2030 SDS
Brazil (Latin America) *			
CAPEX	USD/kW$_e$	1250	720
Annual O&M	USD/kW$_e$	18	16
India			
CAPEX	USD/kW$_e$	610	360
Annual O&M	USD/kW$_e$	12	8
Australia			
CAPEX	USD/kW$_e$	1220	700
Annual O&M	USD/kW$_e$	18	16

* Used for Chile

Wind - Onshore	Unit	Today	2030 SDS
Brazil (Latin America) *			
CAPEX	USD/kW$_e$	1560	1460
Annual O&M	USD/kW$_e$	38	38
India			
CAPEX	USD/kW$_e$	1060	1000
Annual O&M	USD/kW$_e$	26	26
Australia			
CAPEX	USD/kW$_e$	1560	1440
Annual O&M	USD/kW$_e$	38	36

* Used for Chile

Main transport assumptions

Nautical distances	Unit		
Australia to Japan	km		8,000
Saudi Arabia to Japan	km		12,000
Saudi Arabia to Indonesia	km		9,000
Chile to Japan	km		20,000
Shipping parameters	**Unit**	**LH_2 carrier**	**NH_3**
Ship speed	km/h	30	30
Ship capacity	m^3	160,000	86,700
Ship CAPEX	M$	412	89
Ship OPEX	USD/day	10,000	10,000
Loading flash rate	%	1	0.1
Propulsion energy demand	GJ/km	4	4
Unloading flash rate	%	1	0.1
Export terminal parameters	**Unit**	**LH_2 carrier**	**NH_3**
Tank capacity	m^3	192,000	104,000
CAPEX	M$	1161	209
OPEX	% of CAPEX	2	2
Electricity consumption	kWh/kg	0.2	0.001
Duration one loading	days	1.5	1.5
Time between loadings	days	15	15
Import terminal parameters	**Unit**	**LH_2 carrier**	**NH_3**
Tank capacity	m^3	200,000	81,000
CAPEX	M$	1271	291
OPEX	% of CAPEX	2	2
Electricity consumption	kWh/kg	0.2	0.001
Boil-off rate	%	0.1	0.1
Duration one loading	days	1.5	1.5
Time between loadings	days	15	15
Liquefaction parameters	**Unit**		
Size of liquefier unit	t/d	115	
Liquefier unit CAPEX	M$	195	
Liquefier unit OPEX	% of CAPEX	2	
Electricity consumption	kWh/kg	6	

Cost assumptions based on data from the Institute of Applied Energy (Japan) report: "Economical Evaluation and Characteristic Analyses for Energy Carrier Systems (FY 2014–FY 2015) Final Report". Link: www.nedo.go.jp/library/seika/shosai_201610/20160000000760.html

Main fuel cost and power plant assumptions

2030 prices in the SDS		Japan			Australia			Indonesia			India			Saudi Arabia			USA		
Item	Unit	*L*	*C*	*H*	*L*	*C*	*H*	*L*	*C*	*H*	*L*	*C*	*H*	*L*	*C*	*H*	*L*	*C*	*H*
Coal	USD/t	52	65	79	12	15	18	35	44	53	40	50	60		n/a		27	34	41
NG	USD/GJ	4.4	5.5	6.6	3.6	4.5	5.4		n/a			n/a		1.1	1.3	1.6	1.7	2.1	2.5
CO_2	USD/tCO_2	66	82	98	66	82	98	0	0	0	0	0	0	0	0	0	66	82	98
Biomass (wood chips)	USD/t		n/a			n/a			n/a			n/a			n/a		50	75	100

Efficiency		Japan	Australia	Indonesia	India	Saudi Arabia	USA
Item	Unit						
NGCC efficiency (young)	% (LHV)	51	52	n/a	n/a	n/a	45
Coal plant efficiency (USC)	% (LHV)	44	n/a	40	40	n/a	n/a
NGCC OPEX	USD/MW$_{th}$h				2		
USC OPEX	USD/MW$_{th}$h				4		

Carbon price for advanced economies in SDS 2030 is 74-90 USD/tCO_2. The letters *L*, *C*, and *H* in the table refer to Low, Central and High values, respectively. Coal price is for an assumed LHV value of 6000 kcal/kg.

Hydrogen production

Pathway	Parameter	Unit	Now	2030
NG reforming with CCUS	CAPEX	USD/kW$_{H2}$	1470	1440
	OPEX	% of CAPEX	4	4
	Efficiency (LHV)	%	74	74
Coal gasification with CCUS	CAPEX	USD/kW$_{H2}$	2040	2000
	OPEX	% of CAPEX	5	5
	Efficiency (LHV)	%	58	58
Biomass w/ and w/o CCUS*	CAPEX	USD/kW$_{H2}$	5410	4330
	OPEX	% of CAPEX	5	5
	Efficiency (LHV)	%	62	62

*Cost impact of adding CCS to the biomass plant is accounted through capture costs.

Ammona production

Pathway	Parameter	Unit	Now	2030
NG reforming with CCUS	CAPEX	USD/kW_{NH3}	2830	2770
	OPEX	% of CAPEX	4	4
	Efficiency (LHV)	%	63	63
Coal gasification with CCUS	CAPEX	USD/kW_{NH3}	3500	3430
	OPEX	% of CAPEX	5	5
	Efficiency (LHV)	%	49	49
Biomass w/ and w/o CCUS*	CAPEX	USD/kW_{NH3}	7470	6170
	OPEX	% of CAPEX	5	5
	Efficiency (LHV)	%	53	53

***Cost impact of adding CCS to the biomass plant is accounted through capture costs.**

Main CCUS and GHG emissions assumptions

CCUS parameter	Unit	Value
Capture rate from ATR and gasification	%	95
Capture costs, concentrated streams	USD/tCO_2	25
Capture costs, concentrated and diluted streams	USD/tCO_2	40
Cost of transport and storage	USD/tCO_2	20

Abbreviations and acronyms

ASU	air separation unit
ATR	autothermal reforming
BECCS	bioenergy with carbon capture and storage
BEV	battery electric vehicle
BF-BOF	blast furnace-basic oxygen furnace
CAES	compressed air energy storage;
CAPEX	capital expenditure
CCGT	combined-cycle gas turbine
CH3OH	methanol
CF	Capacity factor
CNG	compressed natural gas
CO	carbon monoxide
CSP	Concentrated solar power
CO2	carbon dioxide
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CNG	compressed natural gas
CSA	Central and South America
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAC	direct air capture
DLN	Dry Low NOx
DRI	direct reduced iron
DRI-EAF	direct reduced iron-electric arc furnace
EAF	electric arc furnace
ECBM	Enhanced coal-bed methane
EOR	enhanced oil recovery
FC	fuel cell
FCEV	fuel cell electric vehicle
FGD	Flue gas desulphurisation
FLH	fuel load hours
FT	Fischer-Tropsch
GT	Gas turbines
HB	Haber-Bosch
HFO	Heavy fuel oil
HRSG	Heat recovery steam generator
LCOA	Levelised cost of ammonia
LCOE	Levelised cost of energy
LCOH	Levelised cost of hydrogen
LOHC	Liquid organic hydrogen carriers
LPG	Liquefied petroleum gas
MP	Methane pyrolysis
PC	Pulverised coal
PEM	Polymer electrolyte membrane

PSA	Pressure swing adsorption
SCR	Selective catalytic reduction
SDS	Sustainable Development Scenario
SMR	Steam methane reforming
SOEC	Solid oxide electrolyser cells
UAN	Urea ammonium nitrate
VALCOE	Value-adjusted levelised cost of energy
VRE	Variable renewable energy
WEM	World Energy Model

Glossary

bbl	barrel
bbl/d	barrels per day
bcm	billion cubic metres
bcm/yr	billion cubic metres per year
cm/s	centimetres per second
gCO2	gram of carbon dioxide
gCO2/kWh	grams of carbon dioxide per kilowatt hour
GJ	gigajoule
Gt/yr	gigatonnes per year
GtCO2	gigatonne of carbon dioxide
GtCO2/yr	gigatonnes of carbon dioxide per year
GW	gigawatt
GWh	gigawatt hour

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