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BUSINESS MODELS FOR LOW CARBON HYDROGEN PRODUCTION

Background annexes

BEIS research paper number: 2020/026

August 2020

CONTENTS

ANNEX A TECHNOLOGIES

A.1 Characteristics of technologies

A.1.1 Methane Reformation

Methane reformation is the reaction of natural gas and steam to produce hydrogen and carbon dioxide. Steam Methane Reformation (SMR) and Auto-Thermal Reformation (ATR) are different types of methane reformation technology. Methane reformation plants have the following characteristics, relevant to the development of business models.

Reliance on methane inputs. Under the assumptions used in this report, methane input costs make up 60% of total levelised costs[1].

- **Requires CCS to be low carbon.** The process produces emissions so CCS is required for the hydrogen to be low carbon. As carbon capture is required, a methane reformation plant would be heavily dependent on carbon dioxide transport and storage infrastructure. It would be preferable for a methane reformation plant to be placed near CO_2 storage facilities to reduce costs and avoid leaks.
- **Produces residual emissions.** SMR relies on an external heat source, from which it is difficult to capture the carbon dioxide produced. Carbon capture for the whole system, therefore, could be in the range 70-90%.[2] ATR does not require this heat source, and therefore only needs to capture the carbon dioxide from the syngas, which is why carbon capture rates of 95-98% are more feasible.[3] CO_2 intensity levels are estimated to be 45-120 gCO_2/kWh for SMR with CCS and 29-99 gCO_2/kWh for ATR with CCS.[4]
- **Relatively inflexible production.** A methane reformation plant cannot easily turn its production up or down; it would need to operate at least 70% capacity at all times and could only alter production by 10% in a 24-hour period.[5]
- **Economies of scale.** Methane reformation plants are associated with economies of scale, and larger plants are more cost efficient. Currently the largest reformation plants have a capacity around 1000MW, but the minimum efficient scale differs for SMR and ATR at about 150MW and 300MW respectively.[6]

[1] Element Energy & Jacobs, (2018), *Hydrogen supply chain evidence base* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

[2] Ibid.

[3] Element Energy & Jacobs, (2018), *Hydrogen supply chain evidence base* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

[4] The Committee on Climate Change, (2018), *Hydrogen in a low-carbon economy* - https://www.theccc.org.uk/wp-content/uploads/2018/11/Hydrogen-in-a-low-carbon-economy.pdf

[5] Element Energy & Jacobs, (2018), *Hydrogen supply chain evidence base* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

[6] Ibid.

- **Maturity.** SMR is a mature hydrogen production technology – 8 out of 9 in terms of technology readiness level (TRL) - however it has not yet been combined with carbon capture and storage (CCS) at scale. ATR is less mature than SMR, and also has never been combined with CCS at scale.

A.1.2 Biomass Gasification

Biomass gasification is the reaction of heating biomass without combustion to produce hydrogen and carbon dioxide. Biomass gasification plants have the following characteristics, relevant to the development of business models.

- **Reliance on feedstock.** Under the assumptions used in this report, feedstock costs are estimated to make up 50% of levelised costs and the scale of a biomass gasification plant is limited by the amount of feedstock available (typical plants are between 50-500MW). Being located near the source of its feedstock would be beneficial for a biomass gasification plant.
- **Negative emissions with CCS.** Biomass gasification without CCS would be carbon neutral, because of the CO_2 absorption of the feedstock during its life. When CCS is included, the CO_2 absorption by the feedstock still occurs, and therefore the CO_2 that is captured during gasification is considered a net negative emission. As carbon capture is required, a biomass gasification plant would be dependent on CO_2 transport and storage infrastructure for it to deliver negative emissions.
- **Maturity.** Biomass gasification technology is still at demonstration level, and has never been combined with CCS at scale.

A.1.3 Electrolysis

Electrolysis is when electricity is applied to water, separating the hydrogen and oxygen molecules, which can then be collected. Alkaline electrolysis and PEM electrolysis are different types of electrolysis technology. Electrolysers have the following characteristics when used for production of hydrogen for industrial purposes, relevant to the development of business models.

- **Small economies of scale.** Electrolysers can operate at a small scale and are modular, meaning that larger scale plants are created by linking multiple electrolysers together. This means there is only economies of scale in production and purchase of electrolysers, and not additional economies of scale in the use of electrolysers to produce hydrogen with increasing plant size.
- **Flexible production.** Electrolysers can either be connected to the grid for electricity, or linked to a dedicated renewable energy source. PEM electrolysers especially are becoming increasingly suitable for use with renewables as they can operate intermittently, and can be cycled from 0% to 100% in minutes.[7] This is less the case with alkaline electrolysers.
- **No emissions.** Electrolysis itself does not produce any carbon emissions. Therefore if the electricity used in the process is green, then no carbon emissions will have been produced when producing hydrogen.

[7] Element Energy & Jacobs, (2018), *Hydrogen supply chain evidence base* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

- **Maturity.** Alkaline electrolysis is a more mature form of electrolysis compared to PEM electrolysis, though the latter is developing quickly.

Figure 1 Technology characteristics summary table

Group	Technology	Maturity	Scale	Pattern of Output	Carbon capture	Other constraints
Methane reformation	SMR with CCS	SMR mature but CCS not	150 - 1000 MW	Baseload	70-90%	Best placed near CCS T&S
	ATR with CCS	ATR has high TRL but has not been tested at scale; CCS is not mature	300 – 1000 MW	Baseload	95-98%	Best placed near CCS T&S
Gasification	Biomass Gasification with CCS	Biomass gasification has not been demonstrated at scale; CCS is not mature	50 – 500 MW	Baseload	Negative emissions	Availability and sustainability of biomass – dependent on waste policies
Electrolysis	Alkaline	Reasonably mature	No minimum scale	Baseload for grid electricity; Intermittent for renewable electricity	N/A	
	PEM	Demonstration level but has not been tested at scale	No minimum scale	Baseload for grid electricity; Intermittent for renewable electricity	N/A	

Source: Frontier Economics

Note: Carbon Connect, (2018), Producing Low Carbon Gas – Future Gas Series: Part 2 – https://www.policyconnect.org.uk/research/producing-low-carbon-gas-future-gas-series-part-2 ;

Element Energy & Jacobs, (2018), Hydrogen supply chain evidence base – https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf ;

The Royal Society, (2018), Options for producing low-carbon hydrogen at scale – Policy Briefing – https://royalsociety.org/topics-policy/projects/low-carbon-energy-programme/hydrogen-production/.

A.2 Costs of technologies

The aim of this work was not to determine new estimates for the costs of hydrogen production technologies. We therefore used existing estimates in the literature as our input assumptions. BEIS confirmed that we were to take the assumptions in the Element Energy report[8] as our default cost assumptions, and supplement with

[8] Element Energy & Jacobs, (2018), *Hydrogen supply chain evidence base* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

other assumptions either from BEIS directly, or in the remaining literature where necessary. The sourced input assumptions used for each technology are in Annex E.

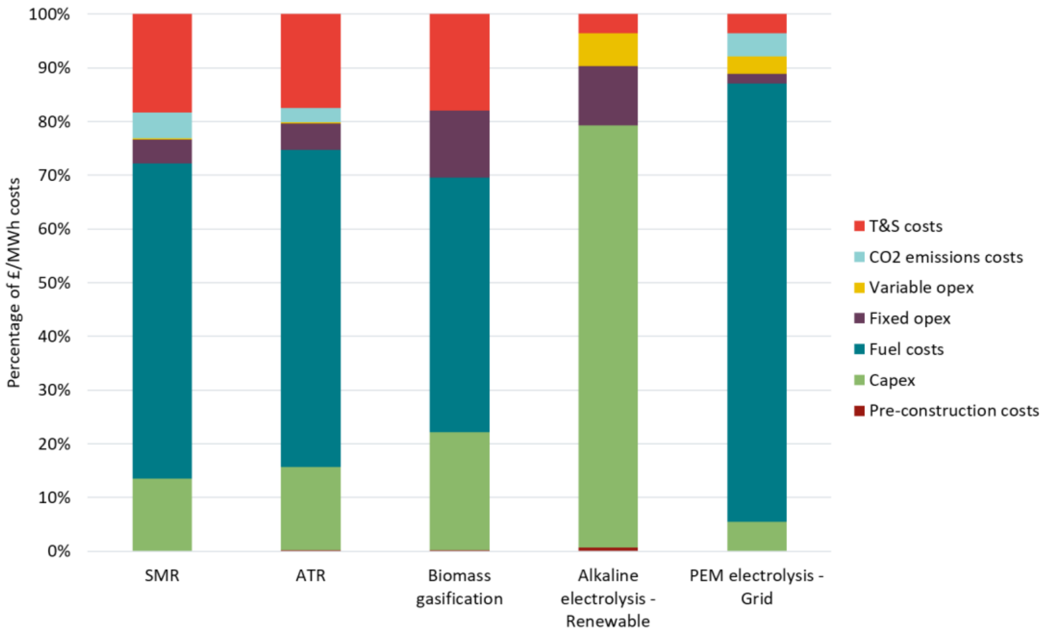
We have analysed alkaline and PEM electrolysis both with a grid connection and with a dedicated renewable. There are different ways to model the costs of electrolysis with dedicated renewables. We have followed the approach of Element Energy in assuming the electrolyser is exclusively connected to a dedicated onshore wind farm. Our assumption is that the electrolyser takes all of the output produced by the wind farm, and that there is storage between the two to smooth the flow of electricity such that the electrolyser is always working at baseload. Therefore capex and opex cover the capital and operating expenditures of the electrolyser, the wind farm and the storage unit, but there are no electrolyser fuel costs. Under these assumptions, the electrolyser will use all of the electricity output from the wind farm, and will not require any extra electricity from the grid. Therefore neither the wind farm nor the electrolyser would be used for grid balancing, in this scenario.

Combining the input assumptions with BEIS time series estimates of carbon price, electricity emissions factor, electricity price and natural gas price, produces annual production cost estimates for each technology.

Taking the net present value of these production estimates given a social discount factor of 3.5%, and converting these costs into £/MWh terms, produces the chart in Figure 2. It should be noted that in Figure 2 alkaline electrolysis uses renewable electricity and PEM electrolysis uses grid electricity. This distinction is merely to show the difference in cost structure of the two different energy sources, as either electrolysis technology could be powered by electricity from either source.

The number above each bar represent the net present value of the production costs in £/MWh terms.

Figure 2 Comparison of levelised costs across technologies



Source: Frontier Economics

Notes: The above chart omits negative carbon costs from BECCS. If negative emissions are valued at the carbon price suggested by the Green Book Supplementary Guidance, this could offset more than 70% of costs.

Figure 2 can be used to compare the cost structures of the different technologies. It is clear that for all technologies - apart from electrolysis with dedicated renewables – fuel costs dominate, accounting for at least 60% of total costs for these technologies, under our assumptions. In the case of electrolysis with dedicated renewables, capex replaces fuel costs as the dominant cost, accounting for almost 80% of all costs.

Both methane reformation technologies have very similar cost structures, with only small changes resulting from ATR's superior carbon capture ability. Biomass gasification has higher capex and fuel costs than either methane reformation technology, however the negative CO_2 emissions could be a big source of revenue[9].

Grid electricity fuel costs are larger than either natural gas or biomass costs, and variable opex is significantly more for electrolysis of either source than for any of the other technologies..

[9] This estimate assumes that hydrogen producers using biomass gasification are rewarded for negative emissions at the current carbon price.

ANNEX B LITERATURE REVIEW

We systematically created a longlist of 46 papers using key search terms. This ensured that we covered the relevant literature rather than only looking at the 'usual suspects'. We supplemented the search results with a wider set of 14 non-UK papers and reports. Of these 60 papers, we reviewed 23 in detail for our shortlist.

To reach our systematic longlist of papers we searched five key terms into Google, and then every paper that was in the first three pages of search results was added to our list. The key search terms were:

- low-carbon hydrogen production;
- low-carbon hydrogen production investment;
- low-carbon hydrogen production barriers to investment;
- low-carbon hydrogen production support mechanisms; and
- low-carbon hydrogen production business models.

Having agreed the longlist of papers with BEIS, we read a summary[10] of the papers and determined whether to include them in the shortlist.

To be included in the shortlist the papers needed to have discussed the barriers to hydrogen production – specifically thinking about the application to industry - and any possible solutions to those barriers. We looked through the 60 longlisted papers and narrowed this down to 23 papers for our shortlist which we reviewed in detail. Having agreed the shortlist of paper with BEIS, we conducted a review which brought out the barriers, challenges and risks to hydrogen production that were discussed in the papers, and any possible solutions that were recommended.

Shortlisted papers reviewed

Element Energy/Equinor, (2019), Hy-Impact Series – Study 4: Hydrogen in Yorkshire & the Humber.

Energy UK, (2019), Energy UK Response to the BEIS Consultation on Business Models for Carbon Capture, Usage and Storage.

CCUS Advisory Group (CAG), (2019), Investment Frameworks for Development of CCUS in the UK – Final Report.

Element Energy/Equinor, (2019), Hy-Impact Series – Study 2: Net-zero hydrogen.

E4tech/UCL Energy Institute, (2015), Scenarios for deployment of hydrogen in contribution to meeting carbon budgets and the 2050 target – Final Report

Frontier Economics/BEIS, (2018), Market and Regulator Frameworks for a Low Carbon Gas System.

IRENA, (2019), Hydrogen: A renewable energy perspective.

French operators, (2019), Technical and economic conditions for injecting hydrogen into natural gas networks.

[10] This summary either consisted of the abstract, executive summary, or introduction and conclusion of the paper.

Hydrogen Europe, (2019), Hydrogen Europe Vision on the Role of Hydrogen Gas Infrastructure on the Road Toward a Climate Neutral Economy – A Contribution to the Transition of the Gas Market.

Low Carbon Innovation Coordination Group, (2014), Technology Innovation Needs Assessment – Hydrogen for Transport Summary Report.

IEA, (2019), The Future of Hydrogen – Seizing today's opportunities.

IRENA, (2018), Hydrogen from Renewable Power – Technology Outlook for the Energy Transition.

Frontier Economics, (2019), The Value of Gas Infrastructure in a Climate-Neutral Europe.

Frontier Economics, (2018), International Aspects of a Power-to-x Roadmap.

European Union, Hydrogen Roadmap Europe – A Sustainable Pathway for the European Energy Transition.

Committee on Climate Change, (2018), Hydrogen in a low-carbon economy.

BEIS, (2019), Business Models for Carbon Capture, Usage and Storage.

Carbon Connect, Producing Low Carbon Gas – Future of Gas Series: Part 2.

Cornwall Insight/WSP, (2019), Market based frameworks for CCUS in the power sector.

E4tech/Element Energy, (2016), Hydrogen and Fuel Cells: Opportunities for Growth – A Roadmap for the UK

Element Energy/Equinor, (2019), Hy-Impact Series – Study 3: Hydrogen for Power Generation.

Element Energy/BEIS, (2018), Industrial carbon capture business models.

Low Carbon Contracts Company, (2019), Non-Confidential Response to the Consultation on CCUS Business Models.

Development and Infrastructure Committee, (2019), Orkney Hydrogen Strategy – Report by Executive Director of Development and Infrastructure.

The Royal Society, (2018), Options for producing low-carbon hydrogen at scale.

World Energy Council, (2019), Innovation Insights Brief – New Hydrogen Economy: Hope of Hype?

Longlisted papers (not reviewed in detail)

Committee on Alternatives and Strategies for Future Hydrogen Production and Use, (2004), The Hydrogen Economy – Opportunities, Costs, Barriers and R&D Needs, The National Academic Press (Washington).

Cadent, (2019), HyMotion – Network-supplied hydrogen unlocks low carbon transport opportunities.

Staffell et al., (2019), The role of hydrogen and fuel cells in the global energy system.

Element Energy, (2018), Hydrogen Mobility in Europe: Overview of progress towards commercialisation.

Element Energy/Equinor, (2019), Hy-Impact Series – Study 1: Hydrogen for economic growth.

Element Energy/Equinor, (2019), Hy-Impact Series – Hydrogen in the UK, from technical to economic.

Hydrogen Council, (2017), Hydrogen scaling up – A sustainable pathway for the global energy transition.

Ministere de la Transition Ecologique et Solidaire, Plan de depoiement de l’hydrogene pour la trransition energetique.

Hydrogen Europe, (2018), Hydrogen, Enabling a Zero Emission Europe – Technology Roadmaps Full Pack.

Hydrogen London, (2016), LONDON: a capital for hydrogen and fuel cell technologies – Executive Summary.

Element Energy/Hydrogen Mobility Europe, Energy Conclusions – 5. Summary of H2MEprojects achievement and emerging conclusions.

Element Energy/Hydrogen Mobility Europe, D2.4 Summary of solutions adopted to resolve outstanding network and precommercial issues around hydrogen fuel retailing (H2ME).

Hydrogenics, (2016), Importance of a Well-Designed Hydrogen Certification Mechanism for the Take-Off of the Hydrogen Economy.

IEA Hydrogen, 2018 Annual Report – IEA Agreement on the Production and Utilization of Hydrogen.

IEA Hydrogen, (2017), Global trends and outlook for hydrogen,

The Institute of Engineering and Technology, Transitioning to hydrogen – Assessing the engineering risks and uncertainties.

IHS Markit, (2019), Hydrogen as the Enabler: Meeting China’s Energy Challenge?

Interreg, Renewable Smart Hydrogen for a Sustainable Future.

IRENA, (2018), Global Energy Transformation – A Roadmap to 2050.

Navigant/ENA, (2019), Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain.

OGUK, (2019), Energy Transition Outlook 2019 – The UK oil and gas industry and the low-carbon future.

Policy Exchange/Burke, J., and Rooney, M., Fuelling the Future – Hydrogen’s role in supporting the low-carbon economy.

Pöyry Management Consulting, (2019), Hydrogen from natural gas – The key to deep decarbonisation.

Smart Living Wales, (2017), Hydrogen Reference Group – Hydrogen Pathway for a Smarter Low Carbon Wales Paper.

Government of South Australia, South Australia’s Hydrogen Action Plan.

World Energy Council, (2018), Hydrogen an enabler of the grand Transition – Future Energy Leader position paper.

CEFIC, (2019), CEFIC Vision on Hydrogen.

GIE, Hydrogen – A pillar for achieving the EU Commission's 2050 vision.

Hydro Tasmania, (2019), Tasmania's 'green hydrogen' opportunity.

Kanellopoulos, K., (2019), The potential role for H2 production in a sustainable future power system – An analysis with METIS of a decarbonised system powered by renewables in 2050.

Chaczykowski, M., and Osiadacz, A. J., (2017), Power-to-gas technologies in terms of the integration with gas networks.

NREL, (2013), Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues.

Asset Project, (2018), Sectorial integration – long-term perspective in the EU Energy System.

EASE, (2019), Recommendations on Certification of Renewable and Low-Carbon Hydrogen.

Wind Europe, (2019), Wind-to-X – A position paper on how to achieve net-zero emissions through a renewables-based electrification.

ANNEX C STAKEHOLDER INTERVIEWS

We spoke to a range of stakeholders from industrial clusters, financial organisations, and industry bodies.

Figure 3 Stakeholders

Group	Organisation	Interviewees
Mitsubishi UFG Financial Group (MUFG)	Mitsubishi UFG Financial Group (MUFG)	Andrew Doyle
Acorn industrial cluster	Pale Blue Dot	Dewi ab Iorwerth, Martin Edwards, Tim Dumenil
	Chrysaor	Gary Hughes
	Shell	Matthew Livingston
	Total	Mark Tandy, Raffaele Luce
Teeside industrial cluster	British Petroleum (BP)	Ian Hunter, Amr El Zanfally, Teodora Lekic, Andres Guevara
Committee on Climate Change (CCC)	Committee on Climate Change (CCC)	Mike Hemsley, Aaron Goater
Humber industrial cluster	Equinor	Kristofer Hetland, Dan Sadler, Tormod Tønnessen, Håvard Hellvik Kvadsheim
HyNet industrial cluster	Progressive Energy	Adam Bladdeley, Chris Mason-Whitton
	Cadent	Richard Court
Johnson Matthey	Johnson Matthey	Sam French
Energy Networks Association (ENA)	Energy Networks Association (ENA)	Matthew Hindle
Gigastack	ITM	Marcus Newborough
	Phillips 66	Michael Wailes
	Ørsted	Andrew Ho
University College London (UCL)	University College London (UCL)	Paul Dodds

ANNEX D CASE STUDIES

We looked at six case studies from a range of countries and markets, outlined in Figure 4.

Figure 4 Case studies

	Case study	Key features	Key differences to low carbon hydrogen sector
Renewable electricity producer subsidies	UK CfD German renewables	▪ Subsidies are for production facilities that produce carbon savings and learning ▪ Approaches vary over time, becoming more technology-neutral ▪ Successful in driving investment and bringing down costs	▪ Homogenous product ▪ Generally more capital-intense and lower marginal costs than hydrogen production (taking account of fuel inputs)
Cross sectoral subsidies for low carbon energy production	SDE++	▪ Subsidy is focussed on rewarding carbon saved ▪ Applies to hydrogen production as well as other technologies	▪ Covers hydrogen production, but has not yet been implemented
Regulated returns on energy network infrastructure	RAB on gas networks Cap and floor for electricity inter-connectors	▪ Well established methodology ▪ Very effective at reducing risk for investors for capital intensive infrastructure	▪ More capital-intense than hydrogen production technologies (taking account of fuel inputs) ▪ Natural monopoly characteristics (gas networks)
User subsidies	EV grants in the UK	▪ User subsidies leave the choice up to consumers	▪ Targeted at domestic consumers

For each case study group, we describe the models and the key implications for low carbon hydrogen business models. We look at value produced, markets, and technologies.

Renewable electricity producer subsidies

The UK CfD covers electricity generation by renewables, but with different categories for established and less established technologies. Support is allocated through an auction process based on strike price bids, however when the scheme started in 2013 support was allocated on a first-come-first-served basis with strike prices set out by the Government.

The German RSE-E feed in premium has a similar structure whereby support is allocated in technology-specific auctions. Participants bid on tariff levels which informs the premium.

Key implications:

- **Value produced.** Non-market value including learning is rewarded. This will be an important externality for immature hydrogen production technologies.
- **Markets.** Uncertainty over demand is mainly transferred away from investors, except when there is a big risk of sustained negative price periods. However, one key difference to hydrogen is that generators sell electricity into a liquid market, which would not exist for low carbon hydrogen.
- **Technologies.** There is increasing technology-neutrality over time in the UK, which is achieved over different allocation rounds. The cost profiles of renewable electricity technologies are capex-heavy, which differs substantially to the opex dominated low carbon hydrogen technologies.

Cross sectoral subsidies for low carbon energy production

The SDE++ is a CfD that covers renewable energy production, CCS, and hydrogen from electrolysis. It aims to reward carbon abatement directly through a technology-neutral auction. Bids are submitted for subsidy per tonne of CO_2 abated, which is measured as the difference between the amount of CO_2 produced with the current technology and the amount of CO_2 that would have been produced by a counterfactual technology. For example, the counterfactual technology for hydrogen production is SMR. The first round will be in autumn 2020.

Key implications:

- **Value produced.** Non-market value including learning is rewarded. This will be an important externality for immature hydrogen production technologies.
- **Markets.** Uncertainty over demand remains with producers. This is likely to be an unmanageable risk for low carbon hydrogen producers.
- **Technologies.** Although the model aims to provide a technology-neutral subsidy, it may be too early for technology-neutrality in the low carbon hydrogen production context. Producers are exposed to more wholesale price risk than under a power CfD.

Regulated returns on energy network infrastructure

Under RAB-based regulation, network companies are issued a licence to own and operate gas grids. Ofgem determines an allowed revenue at periodic price reviews which includes any changes to the RAB, the speed at which it is depreciated, and the return that can be earned on it. Revenue is collected from charges levied on gas shippers, which are passed through to consumers' gas bills.

The GB cap and floor regime sets a maximum and minimum annual revenue that can be earned by an interconnector developer. The cap and floor are set by Ofgem using detailed information on costs which are benchmarked. These remain fixed for 25 years.

Key implications:

- **Value produced.** This model does not automatically incentivise efficient production levels, which would need to be built in to the regulatory design.

- **Markets.** Demand uncertainty is only a risk for producers when there is a risk that demand falls below a level where the resulting prices are no longer cost competitive.
- **Technologies.** Both the RAB and Cap and Floor are focussed on delivering a stable return to investors for long-lived assets. The more significant opex is relative to capex, the less applicable these models are likely to be.

User subsidies

Low-emissions vehicles are subsidised by a grant which aims to overcome the higher upfront cost of buying an electric vehicle relative to a petrol vehicle. The grant is included in the price of the vehicle at the dealer, so consumers do not need to take any action. The grant is applied to six different vehicle types on a list of approved models. This policy interacts with fuel duties which raise the price of petrol relative to electricity, thereby giving low-emissions vehicles lower running costs.

Key implications:

- **Value produced.** Non-market value is rewarded by allowing producers to charge a higher price for their product.
- **Markets.** Demand is stimulated but the subsidy does not tackle related issues such as charging infrastructure requirements. In the low carbon hydrogen context, switching costs may need to be subsidised in addition to carbon reductions. Subsidising users may not create sufficient certainty for early hydrogen producers.
- **Technologies.** The grant is technology specific, down to specific EV models.

D.1 Renewable electricity producer subsidies

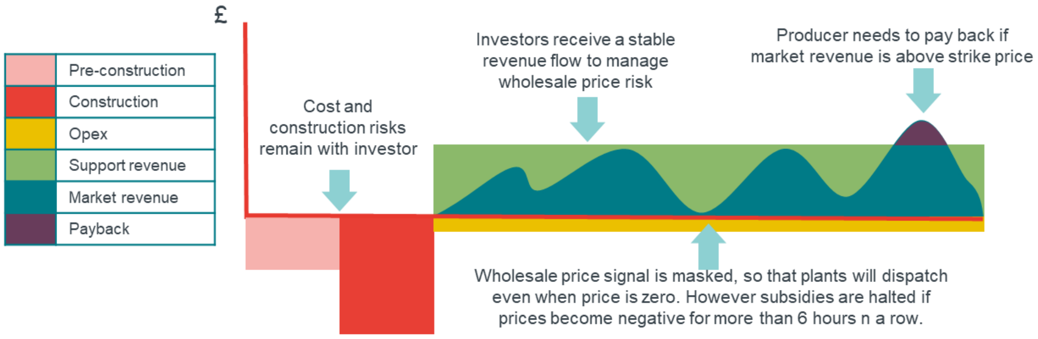
D.1.1 UK CfD for low carbon electricity generation

The aim of UK CfDs is to give greater certainty and stability of revenues to electricity generators, while protecting consumers from paying for higher support costs when electricity prices are high.

UK CfDs cover electricity generation by renewables, but with different categories for established and less established technologies.

For each allocation round, bids are ordered in terms of strike price from lowest to highest. The winning bids are the bids for eligible projects that fall below the budget and output cut-offs. The strike price that is awarded to all bids in that auction is the highest strike price that was submitted by one of the winning bids.

Figure 5 CfD illustrative cost and revenue profiles



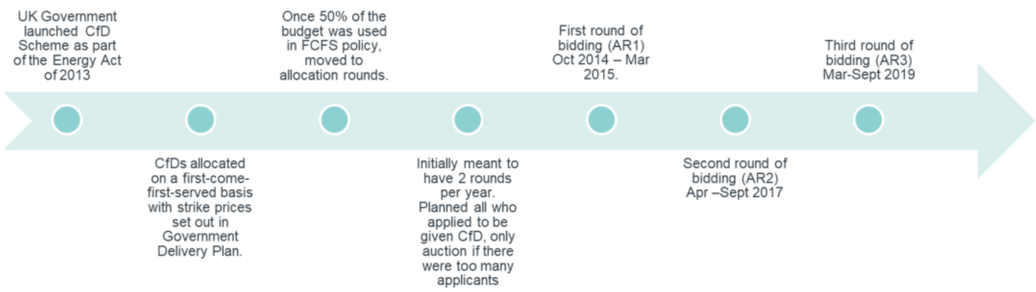
Source: Frontier Economics

Prices have fallen significantly over each allocation round, particularly for offshore wind. The model has also evolved over time to introduce greater competition between investors.

Figure 6 CfD allocation rounds

Allocation Round	Technology	Output (MW)	£/MWh
Allocation Round 1 (AR1)	Advanced Conversion Technologies	62	£119.89
	Energy from Waste with CHP	95	£80.00
	Offshore Wind	1,162	£119.89
	Onshore Wind	749	£82.50
	Solar PV	72	£79.23
Allocation Round 2 (AR2)	Advanced Conversion Technologies	64	£74.75 for 2021/22; £40.00 for 2022/23; £57.50 for 2022/23 offshore wind
	Dedicated Biomass with CHP	86	
	Offshore Wind	3,196	
Allocation Round 3 (AR3)	Advanced Conversion Technologies	34	£39.65 for 2023/24; £41.61 for 2024/25
	Remote Island Wind	275	
	Offshore Wind	5,466	

Figure 7 CfD timeline



Source: Frontier Economics

Note:

CfDs have become more technology-neutral over time both in terms of budget and output allocation.

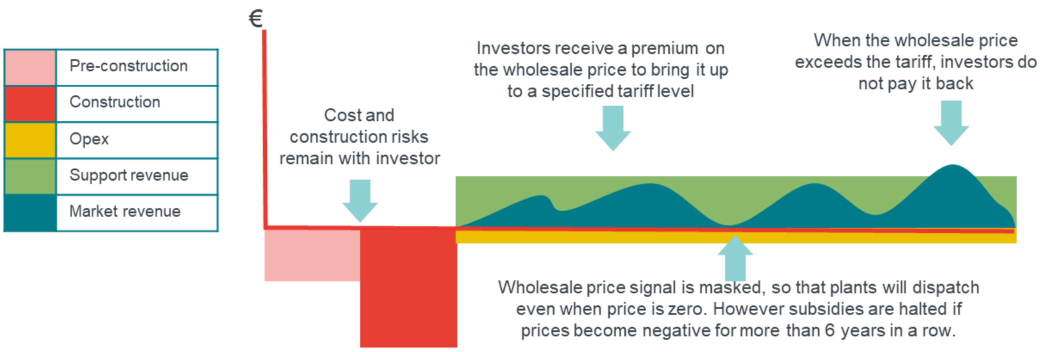
- Budget allocation by technology.
  - AR1 had a budget of £65m for established technologies (on-shore wind and solar) and £235m for less-established technologies, with delivery dates 2016/17 – 2021/22.
  - Established technologies were removed from allocation rounds and could no longer receive the CfD subsidy after AR1.
- Output allocations by technology.
  - AR1 had minimum constraints (e.g. 10MW minimum per project on wave and tidal technologies in AR1), and maximum constraints on a group of technologies that are below the total allocation round output maximum (e.g. 150MW maxima put on fuelled technologies).
  - AR3 had no minimum or maximum.

D.1.2 German RES-E support scheme (Feed in premium)

Figure 8 RES-E key features

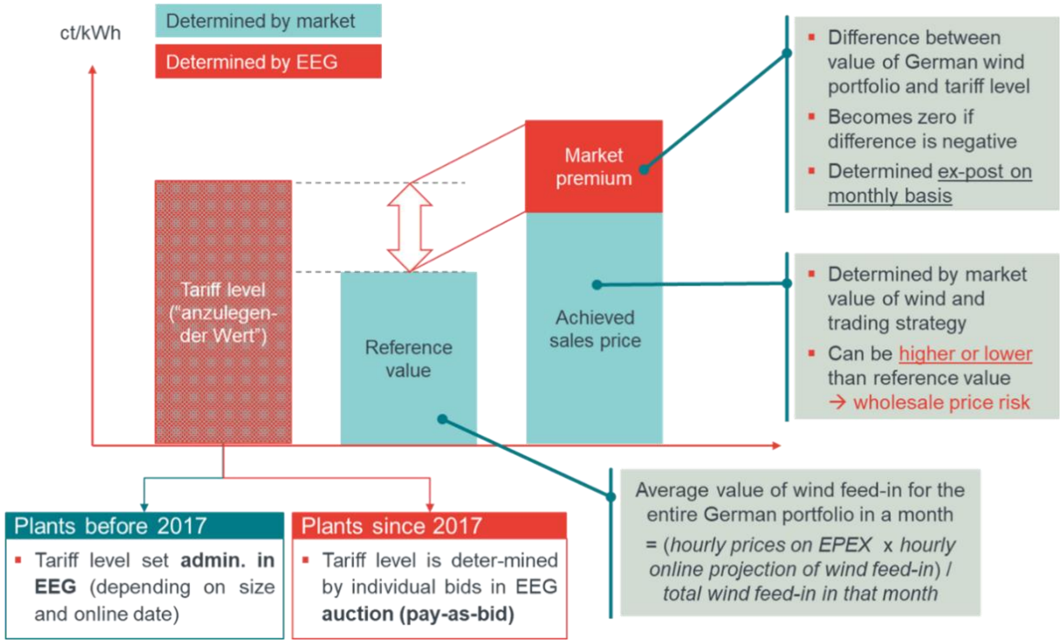
Aim	▪ Incentivise investment in renewable electricity
Technologies covered	▪ Largescale renewable energy production
Allocation	▪ Large plants (> 750 kW) participate in technology-specific auctions. The bids in this auction determine the tariff level, which informs the premium (the difference between the renewables portfolio for the relevant technology and the tariff level) ▪ Multiple auctions occur each year (see figures for 2020 below) ▪ Wind onshore: 7 ▪ Solar PV: 7 ▪ Biomass (new): 2 ▪ Joint solar PV & wind onshore: 2 ▪ Offshore: 0 (next auction schedules for 2021)
Non-realisation risk	▪ Escalating penalties, on a technology specific basis ▪ penalty increases with time of delay ▪ beyond a date, bid is cancelled and full penalty (= bid bond for successful bidders) is imposed.
Risk borne by investors	▪ Tariff is fixed for 20 years (beyond that there is full market exposure. ▪ Reference value is determined monthly ex-post for entire portfolio. The resulting market premium is individual to each plant. Producers bear risk/change to the extent individual sales price differs from portfolio-wide reference price. ▪ 6-hour-rule, i.e. no market premium paid if more than 6 consecutive hours with negative spot prices (day-ahead)

Figure 9 German RES-E illustrative cost and revenue profiles



Source: Frontier Economics

Figure 10 German RES-E description



Source: Frontier Economics

D.2 Cross sectoral subsidies for low carbon energy production

D.2.1 SDE ++

SDE++ is a CfD that covers renewable energy production, CCS, and hydrogen from electrolysis. It aims to reward carbon abatement directly, rather than to promote low carbon energy generation.

Figure 11 SDE++ key features

Aim	▪ Directly reward carbon savings
Technologies covered	▪ Renewable energy production, CCS, and hydrogen from electrolysis.
Allocation	▪ By technology-neutral auction. ▪ The bids in each auction will be ranked by subsidy per tonne of CO2 abated, where the administrative strike price (the maximum subsidy considered) is EUR 300/mtCO2.
Measurement of abatement	▪ Each technology is allocated an emissions intensity. ▪ The savings are measured relative to a counterfactual technology (SMR for hydrogen, CCGT for electricity).

The amount of carbon abated is measured as the difference between the amount of carbon produced with the current technology and the amount of carbon that would have been produced by a counterfactual technology.

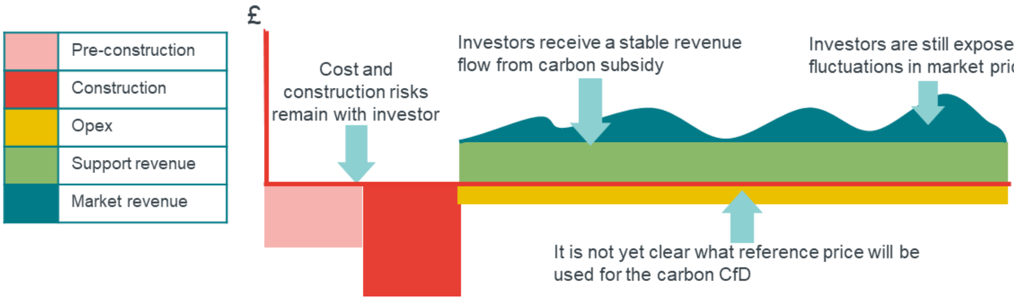
The counterfactual technology for electricity is gas and the counterfactual technology for hydrogen is SMR. Emissions intensities for each low carbon technology are also specified.

The bids in each auction will be ranked by subsidy per tonne of CO_2 abated, where the administrative strike price (the maximum subsidy considered) is EUR 300/mt CO_2.

The first SDE++ auction will be in Sept-Oct 2020, and will have four rounds with increasing maximum subsidy per metric tonne of CO_2 abated. The total budget for the whole auction round will be €5 billion.

Hydrogen from electrolysis was initially allocated an intensity based on grid electricity.

Figure 12 SDE++ illustrative cost and revenue profiles



Source: Frontier Economics

D.3 Regulated returns on energy network infrastructure

D.3.1 RAB for the UK gas network

RAB-based regulation provides a way to determine revenues for natural monopolies with long-lived assets. It has been an important factor in minimising the cost of capital for attracting investment in network sectors.

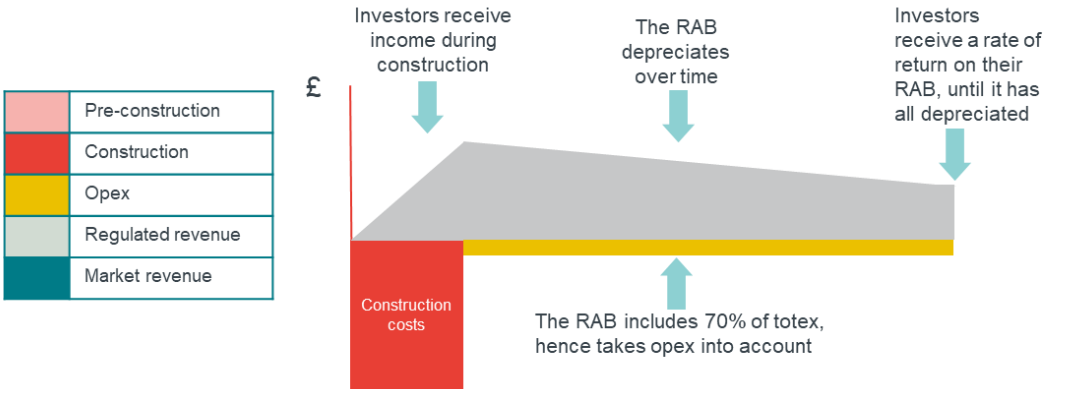
A license is issued to network companies to own and operate the gas grids. At periodic price reviews Ofgem determines a level of allowed revenue for the GDNs, which includes any changes to the RAB, the speed at which it is depreciated and the return that can be earned on it. The licenses are modified to implement the new control. Licensees can appeal licence modifications to the CMA – e.g. to prevent Ofgem arbitrarily reducing the value of their investments.

Gas networks were privatised in 1986 and began using RAB-based regulation shortly after. There have been four gas distribution price reviews since then, usually every five years. The most recent is RIIO-GD1 in 2013 (which set allowances for eight years to 2021).

As part of RIIO, Ofgem sets a certain percentage (currently 70%) of total cost which is capitalised each year into the RAB, regardless of whether this was spent on opex or capex.

Revenue is collected from charges levied on gas shippers, which are passed through to consumers' gas bills. Network charges are primarily capacity based but some revenue is also derived from volume based charges. In any year, a gas network could earn above or below its allowed revenue because of differences between forecast and actual demand, but its allowed revenue for a future year will be adjusted up or down accordingly.

Figure 13 RAB illustrative cost and revenue profiles



Source: Frontier Economics

D.3.2 GB cap and floor regime

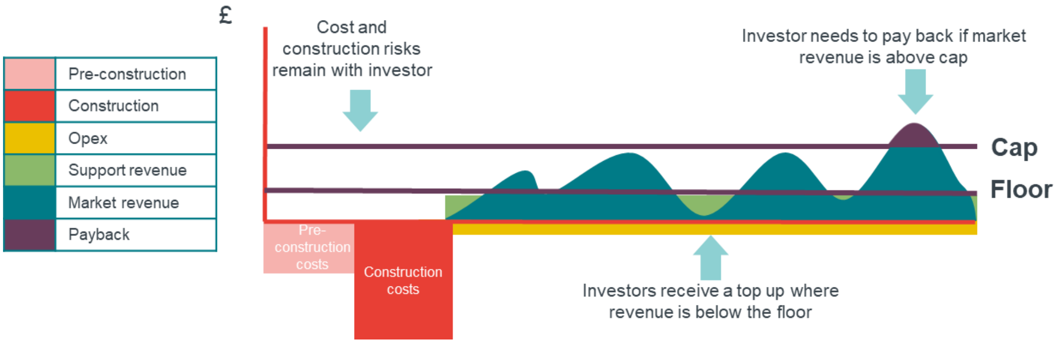
The cap and floor regime was designed to encourage investment in electricity interconnectors by setting the maximum and minimum amounts of annual revenue for an interconnector developer

The cap and floor are set at different stages in operation (capital, operating and decommissioning) and these remain fixed in real terms for the duration of the regime of 25 years (though operating costs can be reset 10 years into the regime)

In setting the costs that are considered efficient Ofgem looks at detailed information from developers on construction, development, spares and replacement expenditure (for capex) as well as operating and decommissioning costs. Ofgem then benchmarks financing costs such as interest during construction and transaction costs.

Investors apply to Ofgem to be allocated the cap and floor support.

Figure 14 Cap and floor illustrative cost and revenue profiles



Source: Frontier Economics

The cap and floor are set as follows:

- **Floor.** The level of return at the floor assumes 100% debt financing and uses a cost of debt benchmark (iBoxx). This is aimed at incentivising developers to incur efficient debt costs.
- **Cap.** The level of return at the cap assumes 100% equity financing, calculated in line with the capital asset pricing model (CAPM) where the parameters are defined based on independent evidence.

Ofgem allows for developers to request variations to the default regime relating to financing (such as the methodology for compensating for financing costs, allowed return estimation, revenue assessment period, inflation indexation and other parameters) if it can be shown that these variations would be in the interest of consumers.

D.4 User subsidies

D.4.1 UK low-emission vehicles grant

The aim of the low-emission vehicles grant is to overcome the higher upfront cost of buying an electric vehicle compared to a petrol vehicle.

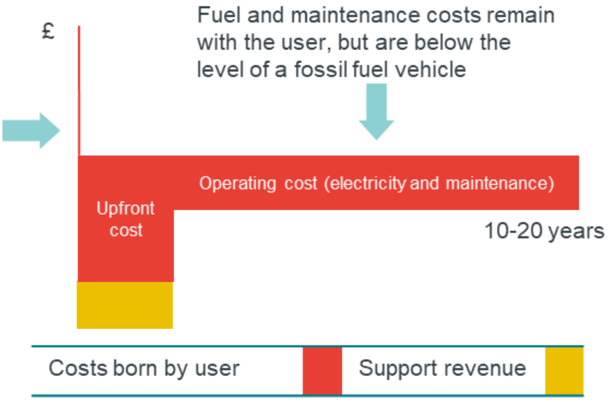
The grant is included in the price of the vehicle at the dealer, so consumers do not need to do anything to be awarded the grant.

The grant applies to six different vehicle types, and will subsidise a percentage of the cost of the vehicle up to a limit. This percentage and maximum limit differs between the six vehicle types. In order to qualify for the subsidy, the vehicle purchased must be on a list of approved models.

Fuel duties are also in place which raise the price of petrol relative to electricity, so make operating a low-emission vehicle relatively cheaper.

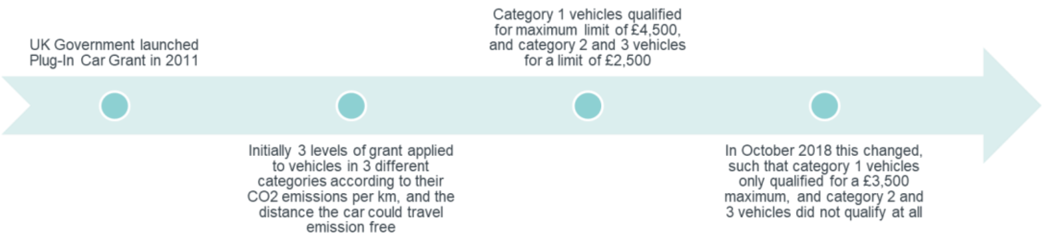
Figure 15 EV grant description

Vehicle Type	Grant % of vehicle price	Maximum grant (£)
Car	35%	£3,500
Motorbike	20%	£1,500
Moped	20%	£1,500
Van	20%	£8,000
Taxi	20%	£7,500
Truck	20%	£8,000



Source: Frontier Economics

Figure 16 EV grant timeline



Source: Frontier Economics

ANNEX E GLOSSARY OF TERMS

- **Steam Methane Reformation (SMR).** A technology that coverts methane to hydrogen and carbon dioxide in the presence of steam.
- **Auto-Thermal Reformation (ATR)**. A technology which converts methane to hydrogen and carbon dioxide in the presence of steam.
- **Biomass Gasification. A** technology which converts biomass into hydrogen and carbon dioxide in the presence of heat.
- **Alkaline Electrolysis. A** technology which converts water to oxygen and hydrogen using electricity.
- **Proton Exchange Membrane (PEM) Electrolysis,** A technology which coverts water to oxygen and hydrogen using electricity.
- **Contract for Difference (CfD)**. : A long-term contract set at a fixed level under which variable payments are made to top-up the level of payment to the producer to an agreed strike price. The payment is made to producers in addition to the generator's revenues from selling hydrogen in the market. The CfD is a two-way mechanism that has the potential to see producers return money to taxpayers/billpayers if low carbon hydrogen prices in the market are higher than the agreed tariff.
- **Premium Payments** are an additional payment that producers receive on top of the market price of their product for each unit that they sell.
- **Regulated Asset Base (RAB).** A RAB model is a type of economic regulation typically used in the UK for monopoly infrastructure assets such as water, gas and electricity networks. The company receives a licence from an economic regulator, which grants it the right to charge a regulated price to users in exchange for provision of the infrastructure in question. The charge is set by an independent regulator who holds the company to account to ensure any expenditure is in the interest of users[11].
- **Upside risk.** The risk of that producers could end up with a greater net present value (NPV) than expected, either due to reduced costs or increased revenue.
- **Downside risk.** The possibility that producers could end up with a lower NPV than expected, either due to increased costs or reduced revenue.
- **Outturn demand.** The level of demand that is realised in the market, as opposed to what is expected.
- **Index.** The value of one or multiple goods and/or services. In practice an index could be the price of a specific good (e.g. natural gas) or the price of a basket of goods (e.g. Consumer Price Index [CPI]). If a price is linked to an index, this means that if the value of the index goes up then the price goes up, and vice versa if the value of the index falls.

[11] This definition is taken from BEIS (2019), *RAB Model for Nuclear*, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/825119/rab-model-for-nuclear-consultation.pdf

- **Revenue stabilisation.** The process of smoothing income generation over time.
- **Backstop**. Where the government would act as a 'buyer of last resort' and would buy all the remaining units that a producer produces which they cannot sell on the market. This prevents producers from having large amounts of capacity that they cannot monetise.
- **Externalities.** The difference between the value of a good or service to society, and the value of the good or service to the individuals involved in the transaction. An example in transport is pollution. A car owner is likely to think of only the cost of petrol and of the value of being able to travel a certain distance when filling up their car. However, driving a car also releases pollution which has a negative effect on society that the car owner does not necessarily factor into their decision. Pollution is therefore a negative externality.
- **Business models**. The systems of actors, infrastructure, financing for development and operation costs, use of revenues and profits, and risk ownership required for hydrogen production infrastructure to be developed and operated.
- **Industrial clusters.** A geographical area where a number of organisations in different industries operate together in a collaborative way.
- **Transport & Storage (T&S). The** infrastructure that is used to connect a producer or supplier of gas (in this case) to its customers. For example, the hydrogen transport and storage operator would provide the infrastructure that would connect hydrogen producers with their industrial customers.
- **Shippers.** A licensed company that buys and sells gas and arranges for the transportation of gas through networks owned by gas transporters
- **End users.** The final users of a good in the supply chain. In this case end users would be the industrial customers who use the hydrogen as a fuel or ingredient in their industrial processes.
- **Gross Value Added (GVA)**. A measure of the value of goods and services produced in an area, industry or sector of an economy.
- **Spillovers.** When a benefit or detriment spreads from one area to another as a consequence of activity. In this case, if developing skills and infrastructure that benefit the production of hydrogen were also used to further the development of other low carbon industries, then this would be a positive spillover.

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