European Commission

ASSET Study on

Geolocation of hydrogen production in the EU

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About ASSET

ASSET (Advanced System Studies for Energy Transition) is an EU funded project, which aims at providing studies in support to EU policymaking, including for research and innovation. Topics of the studies will include aspects such as consumers, demand-response, smart meters, smart grids, storage, etc., not only in terms of technologies but also in terms of regulations, market design and business models. Connections with other networks such as gas (e.g. security of supply) and heat (e.g. district heating, heating and cooling) as well as synergies between these networks are among the topics to study. The rest of the effort will deal with heating and cooling, energy efficiency in houses, buildings and cities and associated smart energy systems, as well as use of biomass for energy applications, etc. Foresight of the EU energy system at horizons 2030, 2050 can also be of interests.

The ASSET project will run for 36 months (2017-2019) and is implemented by a Consortium led by Tractebel with Ecofys and E3-Modelling as partners.

Disclaimer

The study is carried out for the European Commission and expresses the opinion of the organisation having undertaken them. To this end, it does not reflect the views of the European Commission, TSOs, project promoters and other stakeholders involved. The European Commission does not guarantee the accuracy of the information given in the study, nor does it accept responsibility for any use made thereof.

Authors

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1 Goal of the study

The modelling underpinning the scenarios for the EU long-term strategy did not include hydrogen trade. The assumption was that each Member State (MS) supplies its own needs for hydrogen and synthetic fuels.

The goal of this study is to develop a model to undertake optimal geolocation of hydrogen production between MS, including the possibility to trade hydrogen and therefore use the RES potential more optimally and decrease energy system costs at EU level.

Specifically, the new model helps to identify the geo-location of:

1. Renewable energy production (PV, wind, biomass, hydro)

2. Location of RES and hydrogen production facilities

3. Storage infrastructure, also for natural gas, and storage technologies, i.e., batteries, pumping etc.

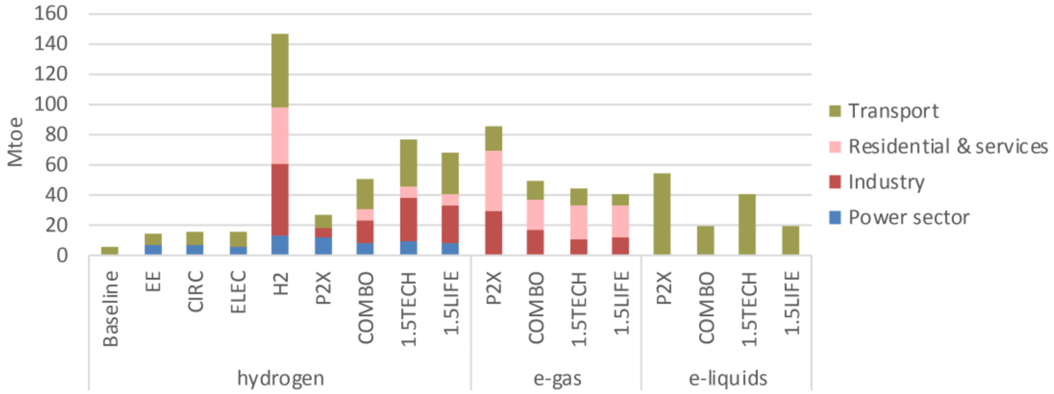
4. Infrastructure by road and pipeline

2 Introduction

The transition to carbon neutrality signals a significant progressive reduction in the use of fossil natural gas and oil products, which could be replaced by carbon-neutral gaseous fuels, including biomethane, hydrogen, biofuels, synthetic liquids, chemical compounds and synthetic methane (from now on "clean methane").

In the carbon neutrality context, hydrogen is expected to grow in importance acting either as *energy carrier* or *feedstock* for the production of other more complex synthetic fuels or for providing *storage* means. Many industrial sectors would need to shift to hydrogen in order to reduce both energy-related and process-related CO_2 emissions. More so, to meet the carbon neutrality objectives, hydrogen would need to be produced through electrolysis from Renewable Energy Sources (RES). Different scenario paradigms explored as part of the EU Long-Term Strategy show a moderate to significant increase in hydrogen consumption (Figure 1).

Figure 1: Consumption of new fuels by sector in 2050



Note: Baseline, EE, CIRC, ELEC and H2 scenarios do not produce e-gas or e-liquids.

Source: PRIMES.

Determining the optimum geolocation of clean-fuel production and storage facilities and the injection points is challenging, as a number of parameters need to be factored in:

1. **Proximity to resources**: Proximity to resources used as feedstock for the production of the respective clean fuels is critical. In the case of hydrogen, locations close to power generation sites, including abundant RES, will be favoured, as this implies no further expansion of power transmission systems and hence lower costs. However, there is a trade-off between transporting electricity or gaseous fuels over long distances. Given the transition towards carbon-free electricity generation, regions with significant RES, nuclear, and CCS capacity/potentials are, at first glance, attractive for hydrogen and e-fuel production.

2. **Economics of scale**: Concentrated production capacity lowers average costs of production while grouping different facilities in a specific location with sizeable consumption centres helps scale up hydrogen production. An important aspect of economies of scale has to do with the possibility to merge renewables of different but complementary variability profiles so as to feed electricity with a close-to-base-load profile to hydrogen production. Obviously, mesh and long transmission networks are necessary for this purpose. Thus, the achievement of economies of scale has to account for both inputs and outputs of the production facility.

3. **Resilience to congestions and disruptions:** High geographic concentration of the facilities for alternative fuels and hydrogen puts resilience into the spotlight. Resilience highly depends on the network infrastructure that supports the input, e.g., electrolysers feeding into the system) and output supply system, e.g., network supplying alternative fuels and hydrogen to demand centres via domestic, as well as import and export routes. The more interconnected an area is, the least sensitive it is to potential disruptions in the infrastructure. For instance, if clean fuel production takes place in north Europe, countries in the south would be dependent on pipelines on the north-south corridor to transfer hydrogen over this axis. Currently, the network capacity over this corridor is limited, thus, unless new infrastructure is built, not only congestions might occur but southern countries might face important outages if a pipeline is not operational, with important implications for their economy and their citizens. For this reason, security of supply criteria need to be taken into consideration, similar to the 'n-1' principle applied to electric or gas networks.

4. **Gas infrastructure transformation**: Gas infrastructure includes high, medium and low-pressure pipelines, storage facilities, natural gas liquefaction (LNG) and re-gasification terminals (at present LNG liquefaction plants for international shipping do not exist in Europe). The economic optimality of the geographic localization of the facilities producing the non-fossil gases will determine the size and density of the gas distribution system (low- and medium-pressure pipelines). Large- and medium-scale hubs producing such gases and distributing them locally, e.g., in heavy-duty refuelling stations in transport, industrial areas, and densely populated urban areas, will compete against distribution networks as developed today. For hydrogen in particular, to inject large amounts in the gas distribution network will require an overhauling of the gas network and storage infrastructure. Another driver of the reconfiguration of the gas infrastructure is the possible reduction of gas consumption in the residential and buildings sector, resulting in stranded assets also in the distribution network.

5. **Co-existence of physical and virtual networks**: It is likely that pipeline and vehicle transport networks will co-exist for the supply of hydrogen and alternative fuels to final consumption. A physical network uses pipelines and compressors, whereas a virtual network uses trucks or rail for transportation and in the case of gaseous fuels, liquefaction/compression and regasification stations. Depending on the (LTS) scenario configuration and the volume of the specific markets by sector, the optimal mix of physical and virtual networks will differ. It is also interesting, that this optimal mix may also differ during the dynamic transition towards a system dominated by alternative fuels. A scenario that foresees use of hydrogen only in specific sectors may use virtual networks rather than physical ones (for hydrogen). Conversely, it may be worth developing a full-scale hydrogen pipeline system in a scenario involving large use of hydrogen in highly dispersed applications. Even in this case, it is reasonable to develop hub applications of hydrogen in the early stages and develop hydrogen pipelines in a later stage.

6. **Liquefaction-transport-gasification-fuelling chains:** For hydrogen and gas refuelling for mobility, in particular for heavy-duty transport means, it may be economically appropriate to develop chains of liquefaction-transport-gasification and fuelling at hubs. This may also apply in large industrial areas. The development of small- and medium-scale infrastructure of liquefaction, transportation in liquid form and regasification of clean gases is part of the future supply of such fuels to the transport sector, mainly for long-haul transport modes, including maritime. In that respect, the research aims at providing a

high-level stylized technoeconomic analysis of the possibilities and market prospects.

7. **Economies of scale and transport trade-offs**: For large hydrogen and gas use hubs, it may be appropriate to locate the electrolyzers at the same place rather than in other areas. Thus, there is trade-off between economies of scale in hydrogen production and the costs (or burden) of transporting hydrogen. However, when the electrolysers serve electricity storage needs (and thus the produced hydrogen is used for power generation), it may be appropriate that there are located close to electricity generation areas rather than close to consumption. This is another trade-off to be considered.

These parameters have been addressed by the improvements made in the PRIMES model in the past year. Specifically PRIMES now includes:

1. Hydrogen uses to reduce energy and process emissions in the industrial sectors and refineries.

2. A trade mechanism for hydrogen to allow for production of hydrogen in areas of high-RES potential with or without local hydrogen demand.

The report at hand outlines the developments on the second point. It provides an extensive literature review, which informed the developments and a brief overview of the new modelling feature, which has been included in the PRIMES model and used for the scenarios included in the “Fit for 55” Package.

3 Literature review

The study is supported by literature review that covers **(i)** an overview of the technologies used for the production of synthetic fuels, the transmission, distribution and storage of different energy forms and **(ii)** an overview of modelling tools used to simulate the evolution of the energy system into the future.

3.1 Energy system technologies

3.1.1 RES integration into the electricity system

The first legislative framework to achieve climate neutrality (European Commission, 2020a) was proposed in 2020. The complete decarbonisation of the power sector is expected to play a key role in the transition to a climate neutral energy system. The transformation of the power generation system requires the integration of RES on a large scale. The ever-decreasing unit costs of photovoltaic and wind energy sources make investments in the sector increasingly attractive (IEA, 2019b). Although the production of electricity from RES contributes to the achievement of climate change mitigation targets, it also presents challenges (IEA, 2019b). Their variable nature requires high levels of reserves and flexibility. Traditionally, this flexibility was met by thermal plants, hydropower plants, interconnections and demand response. Today, most of the flexibility is covered by thermal stations and only 10% of the other technologies (IEA, 2018). However, with the increasing need for flexibility in the system, this is expected to change rapidly in the future.

The possibility to have power systems with high penetration of RES is referenced by researchers in Europe (Bussar et al., 2016; Child et al., 2019; Zappa et al., 2019) and globally (IRENA, 2019b). As the energy transition requires the phasing out of thermal plants, which until now have covered all flexibility needs, interconnections and storage units come under the spotlight. Storage units have the ability to meet different types of flexibility; batteries are suitable for short-term needs while hydrogen can meet long-term needs (Blanco & Faaij, 2018).

Storage needs are clearly linked to the level of RES penetration into the power grid (Cebulla et al., 2018). It is necessary to analyze both the mix of different storage technologies required (e.g. batteries, Power-to-X, hydrogen) and the optimal location of these units to meet the needs of the network. Combining RES with storage units will minimize RES curtailing, thereby improving their performance both economically and technically (Lyseng et al., 2017).

3.1.2 Storage technologies

The rapid deployment of RES implies a significant increase in flexibility requirements of the system. In mid-2017, Pumped Hydro Systems (PHS) dominated global storage technologies, reaching 96% of the 176 GW of total installed power of electricity storage technologies. Other electricity storage technologies worldwide included 3.3 GW of thermal storage, 1.9 GW of batteries and 1.6 GW of other storage systems (IRENA, 2017). The rapid development of storage technologies needs to be supported through ambitious research and development (R&D) programmes, innovation and competitiveness combined with regulatory changes in market design and energy policy.

Energy storage systems can be classified into two main categories based on:

- the form in which they store energy, i.e., mechanical storage, heat storage, electrical storage, electrochemical storage and chemical storage technologies;

- the duration for which they store energy, i.e., **(a)** short-term storage technologies (short-term storage) and **(b)** long-term storage technologies (long-term or seasonal storage). The duration of energy storage also determines the different services they offer in the energy system, as well as the various needs they cover (e.g., voltage adjustment, coverage of power and energy needs, etc.) (Elshurafa, 2020).

Short-term storage is used to cover balancing services of the electrical system either at central or decentralised level, within one day, at any time. Its role in ensuring voltage stability both at system and distribution level is crucial. Short-term storage technologies include batteries, flywheels, super capacitors, pumped storage systems and Compressed Air Energy Systems (CAES) (EASE & EERA, 2017; Koohi-Fayegh & Rosen, 2020; WEC-World Energy Council, 2016).

Long-term or seasonal storage technologies can store energy for days or months. For this reason, they are used to absorb the seasonal surplus of electricity generated by wind turbines or photovoltaic systems and give it back to the later to meet the given demand. The need for seasonal storage is becoming increasingly important, a trend that will intensify as electrification progresses and RES penetration accelerates (Blanco & Faaij, 2018). The most widely used long-term storage technologies are hydro reservoirs and Power-to-X synthetic fuel production technologies. For example, converting electricity into hydrogen or synthetic methane is expected to be one of the most competitive solutions in 2050 combined with the use of gas infrastructure that already exists. The downside of long-term storage is that it faces significant cost challenges, mainly because storage volume is used for a limited number of days over time.

Power-to-X technologies use electricity to produce synthetic fuels (hydrogen, synthetic methane and synthetic hydrocarbons). The process of storing these fuels differs from that of liquid fuels (e.g. petrol, oil). For hydrogen it is necessary to reduce its volume through either high pressure (remaining gas) or by reducing its temperature (liquefaction) (WEC-World Energy Council, 2016). Today, in industry mainly, hydrogen is stored in liquid or gaseous form using cylindrical tanks (IEA, 2015). In the case of liquefaction, it is stored in cryogenic tanks to maintain its liquefied form (IEA, 2015). The main advantage of liquefied gas is that it is easy to transport. However, high costs are required for its liquefaction, as well as for the construction of the storage tank, in relation to the compressed hydrogen storage tank (EASE & EERA, 2017; Ogden, 1999).

Both synthetic methane and hydrogen can be stored in large quantities and for a long time in underground infrastructures. For the large-scale storage of hydrogen salt caves are currently considered the preferred option, as their yield is close to 100% (Ogden, 1999), followed by depleted gas fields and natural aquifers, while rock caverns and depleted oil deposits are characterized by higher uncertainties (Blanco & Faaij, 2018). Hydrogen in gaseous form, i.e. synthetic methane, can be transported through but also stored in the existing gas transmission and distribution network. Hydrogen can be mixed up to 15-20% (IEA, 2019b; Melaina et al., 2013) at volume levels in the existing gas network, without modifications to the gas transmission infrastructure and device change of final consumers (Maroufmashat & Fowler, 2017). However, pilot projects in England (H21 Project) are exploring the feasibility, both technical and economical, of making existing gas networks carry 100% hydrogen (IEA, 2019b).

3.1.3 Energy transmission and distribution systems

Reflecting the approach adopted by different models and used widely in literature, the distinction is made between *physical* and *virtual* energy transmission and distribution systems. Physical networks include the electricity transmission and distribution network and gas (gas or hydrogen) transmission infrastructures. Pipelines, cables, substations, compressors, etc. are used to distribute energy to final consumers. Virtual networks include the means of transporting energy products, namely trains, ships, trucks, tankers, etc. There is no physical infrastructure, such as the electricity transmission grid, but transport is conducted via road and sea.

Virtual networks

The railway network offers significant geographical flexibility, allowing to transport the products in a short period of time and to different regions. Railway infrastructure can be almost always built or expanded much faster than pipelines or the road network. In fact, railways offer a viable solution to the rapid expansion of the transport network, allowing to keep up with the increased production or investments in new fuels (e.g. hydrogen or biofuels). Rail services, however, can be affected by adverse weather conditions and so specific care must be taken for the safety of products that are flammable.

For the transport via road, trucks are used for solid fuels and tankers for liquid fuels. Tankers have a tank built into their frame and are designed to transport liquid fuels and liquefied gases (e.g. hydrogen). Both are used widely to supply areas that are not connected to pipelines or have no rail network and at the same time are far from the sea. They are also used as intermediate carrier for the supply of service stations, industries, and houses. Trucks and tankers have the greatest flexibility thanks to the road network, which is constantly expanding and can cover remote areas. Accidents are often because lorries move through busy highways. Moreover, since trucks can carry a limited volume of products, the number of trucks required is greater than the number of trains to carry the same quantity of product, which results in an increase in carbon dioxide emissions if conventional vehicles are used. Fuel transport by sea is carried out by large tankers for long distances or by smaller vessels in the case of islands. Mainly liquefied natural gas (LNG) and crude oil are transported by sea. Transport costs per tonne transported are significant and operating costs include fuel costs, port charges and insurance costs. Finally, safety rules are key to avoiding accidents that may lead to significant oil spills into the marine environment.

Physical Networks

Physical networks include the electricity and gas transmission and distribution networks. The growing interlinkages between energy and the economy point to the need to strengthen investment in energy networks, including for their digitisation, to ensure they operate efficiently and are subject to robust competition rules, offering consumers more alternatives to the supply of energy resources (IEA, 2017).

Natural gas and electricity systems have some similarities in their topology, as both systems have transmission and distribution networks. In addition, electricity and gas networks are subject to the laws of physics, which may limit the energy transferred (electricity or gas flows) causing network losses, electrical losses or falls in the pressure of the natural gas pipeline (Deane et al., 2017). The two networks have significant differences also. First, in terms of response time. Electricity is transferred almost instantly, while gas at a much lower speed, resulting in a time delay between the injection point and the delivery point, which can range from a few hours to some days, depending on the distance. Second, unlike the electricity grid, the gas network is a powerful tool for providing flexibility to the energy system (line-pack flexibility). Since gas is a fluid that can be compressed, pipelines have the ability to incorporate quantities larger than what the system really needs for short- or long-term storage purposes. This means that the quantities that flow (inflow) to and from the conductors do not have to be in balance at all times, as is the case with the electrical grid (Belderbos, 2019). Another important element worth considering is that transition to a climate-neutral economy may require blending clean fuels such as hydrogen, synthetic methane and biomethane into the (existing) gas network, where in theory, a 100% replacement of natural gas currently flowing into the grid by a mixture of gases with zero-climate footprint could be possible.

3.1.4 Production technologies and uses for hydrogen

Current global hydrogen production is in the order of 70 million tonnes, with the EU share being close to 15% (IEA, 2019a). Over 90% of hydrogen is used in industry, of which 63% is consumed for the production of ammonia and methanol (chemical industry), 30% in refineries and the remaining percentage for metal processing (Blanco, Nijs, Rufc, et al., 2018; CertifHy, 2015).

The role of hydrogen in the energy system is threefold: as a *fuel* in final demand sectors and for the cogeneration of heat and electricity; as *chemical storage* of electricity; and as *raw material* to produce methane and liquid hydrocarbons (Evangelopoulos et al., 2019). Storing hydrogen represents a key challenge, since compressing a large quantity into a limited-sized tank is difficult, due to the high pressures required to achieve liquefaction. Another disadvantage is its low calorific power per unit volume. The calorific power of hydrogen in volume (MJ/m3) is equal to 1/3 of the High Heating Value (HHV) of natural gas (Blanco & Faaij, 2018). Therefore, the amount of energy that can be stored in relation to the corresponding amount of methane is reduced. As an energy product, hydrogen can be mixed into existing gas networks as a percentage (in the order of 10%-15% by volume, with exact limits varying by country). However, any further increase in its involvement in the network creates the need to upgrade both network infrastructure and replace consumer devices (IEA, 2019b).

Currently, hydrogen is produced mainly through Steam Methane Reforming (SMR) in many industrial plants, i.e., chemical and refineries. The production of hydrogen through SMR (grey hydrogen) releases CO_2. If combined with CCS, the carbon footprint is significantly reduced (blue hydrogen). In a decarbonisation context the main option to produce hydrogen through electrolysis, using water as raw material and electricity as fuel. This implies zero carbon footprint, when electricity has been produced from zero-emission sources (green hydrogen) such as RES, nuclear power, or conventional stations with CCS. Still though, fossil-CCS still produces limited emissions as the capture rate is not 100%. Another hydrogen production technology is methanol pyrolysis, which produces hydrogen and carbon in solid form that can be easily stored; however, this technology has yet to be proven on an industrial scale.

3.1.5 Production technologies and uses of synthetic methane & hydrocarbons

Synthetic methane is a type of gas that can be produced in several ways: from fossil fuels (lignite, coal, shale gas, coal-to-gas plants), biomass or RE (Kopyscinski et al., 2010). It has similar molecular properties with mineral methane, which is the main component of natural gas, and could make use of the same infrastructure and appliances as natural gas, thus reducing the need for additional expenditure. However, synthetic methane is the product of controlled chemical processes, as opposed to the natural formation of fossil natural gas from biomass being stored in underground reservoirs for millions of years. Synthetic methane can have zero carbon footprint, if the following conditions apply:

- Hydrogen used in the process has zero carbon footprint (green hydrogen).
- Carbon sources have net zero climate footprint, i.e. direct air capture, biomass, or CO_2 as by-product of upgrading biogas to bio-methane.
- Fuels used in all processes are climate neutral.

Several small synthetic methane production plants currently operate in Europe and their number is expected to increase in the future. At present, synthetic methane is at least two to three times more expensive than natural gas (Evangelopoulos et al., 2019). Moreover, the amount of electricity required to produce synthetic methane is significant and surpasses the amount required for hydrogen production. If global demand for natural gas is replaced by synthetic methane, huge amounts of electricity will be required. For this reason, the energy efficiency of the energy system as a whole and of the production process of each fuel must be significantly improved (Evangelopoulos et al., 2019).

Synthetic liquid hydrocarbons (synthetic kerosene, synthetic diesel and synthetic gasoline) produced from electricity and used for chemical storage of electricity are meant to drive the decarbonisation of the transport sector. Contrary to what is the case of hydrogen, a key advantage of synthetic hydrocarbons is that they can be distributed and used within existing infrastructures, reducing extensive infrastructure spending and the cost of transporting energy forms. Synthetic liquid fuels also combine high calorific power (energy per volume), maintaining the properties of conventional fuels.

3.1.6 Production technologies for bioenergy

Biomass plays an important role in the transition towards a low- or net-zero emissions energy system. It can be used directly for combustion (e.g., for heating buildings) and in industrial processes and can be also converted into biofuels or biogas. Biogas can be then upgraded to biomethane and replace natural gas (Rotunno et al., 2017). Moreover, biomass and biogas are used to capture and store carbon dioxide in underground formations to achieve net negative emissions, which are required to compensate for remaining non-CO2 emissions from non-energy sectors.

Biomass conversion technologies can be thermochemical, e.g., gasification/Fischer-Tropsch, catalytic cracking, or biochemical. Provided that these technologies are developed on an industrial scale and that the market is organized in a way that allows for the creation of economies of scale in the production and supply chain of energy crops, then it will be able to produce new generation advanced biofuels at competitive prices in the future.

Biofuels, i.e., biodiesel, ethanol, biokerosene, are mainly consumed in transport, a sector that is 90% dependent on petroleum products and thus very difficult to decarbonize (Haasz et al., 2018). Aviation, shipping and road transport (heavy trucks) are the most difficult to electrify and thus the segments that dependent the most on petroleum. The development of biofuel production, conventional -1st generation biofuels- and new generation -advanced biofuels- has great potential for the European economy (Hamelin et al., 2019). Conventional biofuels are derived from crops such as sunflowers, sugar beets and are produced through the processes of fermentation and transesterification (Callegari et al., 2020). They have reached high levels of maturity (Naik et al., 2010), which allows them to compete against new generation biofuels. However, their main disadvantage is that they compete with crops for food production. Advanced biofuels aim to solve this problem, as their production uses lignocellulosic raw materials (e.g., wood) or waste (e.g., frying oils). They are projected to achieve full technological maturity after 2030 (Chiaramonti & Goumas, 2019; Oh et al., 2018).

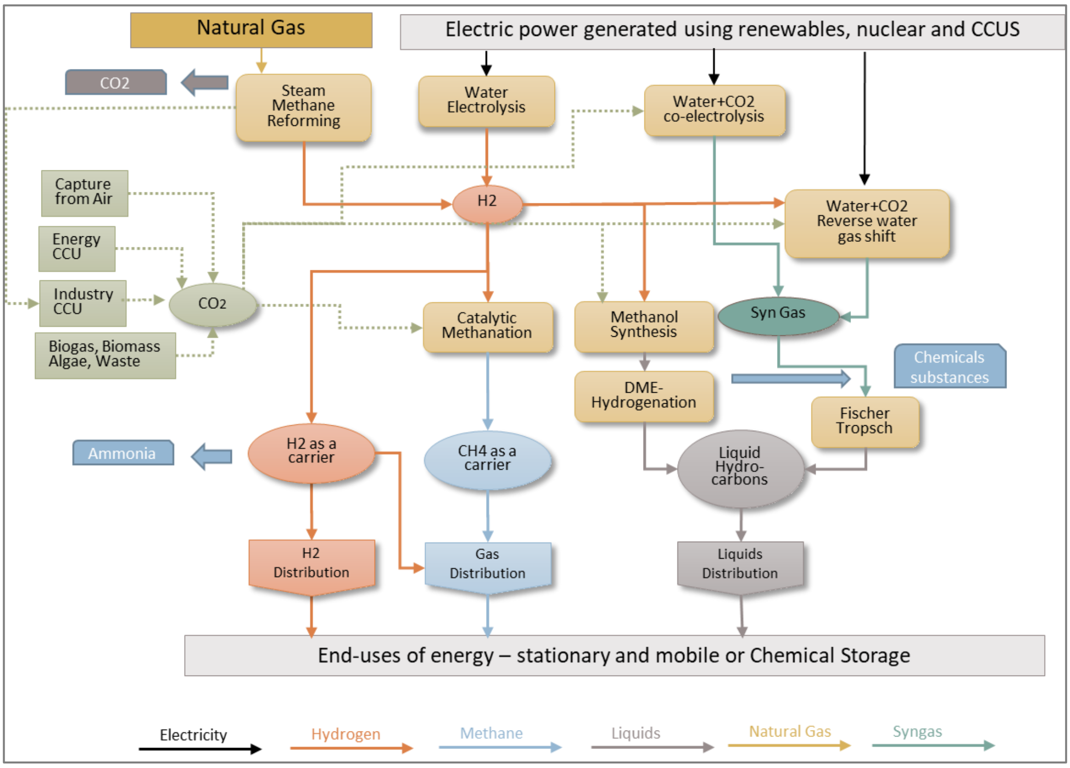
The main challenge associated with the large-scale exploitation of biomass is ensuring the uninterrupted and safe supply of industries and power generation. Regulation mandating the blending of bio-methane in the distribution network of natural gas can drive the development and upgrading of biogas into bio-methane and ensure the capturing of carbon dioxide for other uses.

3.1.7 Synergies between technologies

Significant synergies between many low- or zero-carbon footprint technologies exist. The ultimate goal of simulating these synergies is to make an accurate and detailed representation of the energy system in order to find the best way to meet the demand of all forms of energy and all sectors of consumption.

Hydrogen can be produced through different processes, such as electrolysis or SMR (Figure 2). It can be used either as a final or intermediate product for the production of methane and synthetic liquid hydrocarbons. Hydrogen and synthetic methane can be both injected into the gas network, while being generated through electricity. These different production chains represent a link between the two sectors. Synergies occur also between bioenergy production and the gas sector. Biomethane for instance, produced either via anaerobic digestion or gasification, can be injected into the gas network too and reduce the carbon footprint of the final mix. Furthermore, during the biogas upgrade process carbon dioxide can be captured and used either in industrial processes or in the production of liquid and gaseous synthetic fuels. In fact, carbon dioxide is an intermediate product in industry for the production of materials (e.g. petrochemicals), but also for the production of synthetic methane and synthetic liquid hydrocarbons, regardless of their production process. At the same time, carbon dioxide is released during power generation and industrial processes and can be captured and reused. Tapping the synergies between the different uses of carbon dioxide in the future will lead to the creation of an additional market, a carbon dioxide market meeting the needs of different energy and non-energy sectors.

Figure 2: Flow chart of energy and non-energy forms



Source: E3M

The Levelized Cost of Electricity (LCOE) has been used to estimate the cost of synthetic fuels produced and compare them with the corresponding conventional fossil fuels. In this case, the index is called LCOX and represents the selling price of the X product and is expressed in Euros per action of the X product produced (ENEA, 2016). More specifically, it expresses in present value prices the cost required for the production of energy product throughout the life of a unit, weighted in relation to the total energy production, considering all the individual cost components (investment, operation, fuel, lending, insurance costs etc.).

Table 1 summarizes the estimated weighted cost of synthetic fuels, factoring in future technology progress and economies of scale. For the calculation of the estimated fuel cost, the technology costs were used, and various considerations were made for the cost of electricity (70 Euros / MWh), the reduction rate (8.5%) and the emission allowance prices (from 30 Euros / ton CO2 in 2030 and 100 Euros / ton CO2 for 2050). Learning curves enabled by technological progress have led to a decline in weighted energy costs of electrolysis and methanolization technologies over time. Although water electrolysis is the most expensive hydrogen production process today, mainly due to the increased electricity required, the total cost is expected to decrease significantly, given the high efficiency of the new systems and the integration of RES, which can be combined with the specific process. Capital costs are expected to halve over the next decade, mainly for PEM electrolysis. The economic figures will be further improved, with the expected future mass production (economies of scale) of small electrolysis devices, which can be converted from small to large units, using cheap RES energy.

Table 1: Weighted cost of hydrogen production (Euro / MWh) for various technologies

Hydrogen Production Technologies	2015	2030	2050
Alkaline Electrolysis (AEL) – large scale	92	89	90
PEM Electrolysis (PEM) – large scale	99	85	90
SOEC Electrolysis (SOEC) – large scale	120	114	100
Steam Methane Reconstruction (SMR) – large scale	48	91	229
Steam Methane Reconstruction (SMR) with CCS – large scale	107	133	267
Alkaline Electrolysis (AEL) – small scale	102	91	94
PEM Electrolysis (PEM) – small scale	120	97	95
SOEC Electrolysis (SOEC) – small scale	143	128	105

Source: Evangelopoulou et al., 2019

The cost of electricity is the main element in the cost structure of synthetic fuels. Next comes the cost of capital, which has the potential to decrease further, if technologies develop on a large scale. Still however, electricity remains the primary cost factor. Generating electricity at times when RES is abundant and the marginal cost of the electricity system is low can bring production cost down. The same goes for the SMR technology, as it is a mature technology and no further significant drop in capital costs is expected. On the contrary, the cost of hydrogen production in this case depends to a large extent on the future price of gas.

As explained, gray hydrogen has a significant carbon footprint, which can be significantly reduced if combined with CCS, resulting in blue hydrogen. Nonetheless, CCS leads to higher capital and operating costs the CO2 storage capabilities are limited. On top, the unit cost of hydrogen produced through this process depends on emission allowance prices. The EU Emission Trading System prices increase significantly in the period 2030-2050 driven by the Market Stability Reserve (MSR). Nowadays, the unit cost of hydrogen produced by conventional technologies is less than that of electrolytes. However, in the future the production of "green hydrogen" will be more profitable. Finally, synthetic fuel producers can meet flexibility needs with potential revenue for this service, further reducing production costs.

Summing up, in a future decarbonized energy system, electricity-based climate-neutral fuels are an important complementary element to the direct use of RES. The main synthetic fuel is hydrogen. It can be used directly as a fuel for final consumers, as a means of storing electricity, or as a raw material for the production of other synthetic fuels such as methane. It can also be used to produce heavier synthetic hydrocarbons (synthetic diesel, synthetic gasoline, synthetic kerosene), but also as a raw material in a range of industries, such as refineries and petrochemical, ammonia and aluminum plants.

Synthetic fuels offer a number of advantages over the direct use of electricity to final consumers. Thanks to their energy density, they can be easily stored and transported. At the same time, the compatibility of synthetic fuels with existing infrastructure is a clear argument in favor of their development, as it does not imply major changes to existing infrastructure and systems in the industrial, building and transport sectors. A key advantage of synthetic fuel plants is the ability to produce different products for different sectors, while offering storage services (either indirectly or directly). As such, synthetic fuels will be an important factor in reducing carbon levels in industry, the domestic sector, as well as the transport sector. The capital costs of the technologies are expected to decrease significantly in the future, owing to their development on a large scale. However, in order for synthetic fuel production technologies to be cost-effective, a high degree of utilization and widespread use of cheap electricity from RES is required. A major drawback of synthetic fuel plants is their low energy efficiency. Meanwhile, climate-neutral fuels increase the volume of electricity generation and lead to the development of RES in inaccessible areas at relatively high costs. Finally, the high volumes of renewable energy required for the production of synthetic fuels, in case they cannot be produced within a country or within Europe, should be imported.

3.2 Modelling and simulation tools of the energy system

The implementation of climate policies is expected to have an impact on the structure of the global energy system and the evolution of economic activity. Mathematic models help to study the interlinkages between the energy and economy systems and evaluate the possible future effects of climate policies thereof.

Energy system models were developed mainly in the second half of the twentieth century, after the 1970 oil crisis, to support optimal energy management planning. The liberalization of energy markets during the 1980s and 1990s created new needs and international organizations started to use a number of different energy system models: International Energy Agency (World Energy Model- WEM) (OECD / IEA, 2020); European Commission (POLES, PRIMES) (POLES, 2018; E3Mlab of ICCS / NTUA, 2018); US Department of Energy / EIA (NEMS) (Energy Information Administration, 2019); OECD (Markal) (Loulou et al., 2016); IIASA (MESSAGE) (Krey et al., 2016).

In essence, what energy models do is to investigate possible future scenarios of the energy system. They do not deliver a forecast but rather a projection of the future outlook of the energy system under different policy assumptions and exogenous parameters. The quantification of the scenarios through the use of each model leads to the analysis and evaluation of the effects of the policies on carbon dioxide emissions, the system costs, the fuel mixture, the technologies etc.

The main distinction is made between models that represent technologies and techno-economic elements (technological approach, bottom-up approach) in detail and macroeconomic models (economic approach, top-down approach). A third category are hybrid models, which combine the representation of technologies and microeconomic behavior of consumers with macroeconomic variables. The interconnection of the models is achieved through iterations with iterative information feedback (Helgesen, 2013). In addition, there are models that combine different sub-models (modules) into one hybrid. Each of the sub-models describes the behavior of a sector of the energy system (e.g. representation of final consumer demand, representation of electricity generation, hydrocarbon extraction, etc.). The specialized mathematical sub-models are interconnected through an algorithm, which decides the equilibrium values for energy products and equilibrium volumes, after balancing supply and demand by industry and by fuel, in order to produce projections for different scenarios. Some typical examples of such hybrid models are the PRIMES (E3Mlab of ICCS / NTUA, 2018) for the modelling of the European energy system, the NEMS for the USA (Energy Information Administration, 2019) and the CIMS for Canada (Canadian Integrated Modelling System) (Bataille & Jaccard, 2004). These models obtain GDP forecasts for each sector of the economy through their connection to a CGE model, since they do not contain a detailed representation of the economy.

As we move to a climate neutral economy, it is necessary to include in the modelling the trade of liquid fuels with zero carbon footprint (e.g., liquefied hydrogen). Models that cover the energy system of the EU-27 and make endogenous investment decisions in power plants and storage technologies are TIMES and PRIMES models. Extensions of these models with the integration of modelling of Power-to-X technologies enable the evaluation of the potential and operational implications of all storage technologies in the context of an integrated energy system analysis.

The latest version of the PRIMES sub-model for the power generation and production of steam, heating and synthetic fuels solves a problem by minimizing costs. The period of analysis is 2015-2070. The improved model covers all areas of supply and demand and covers alternative processes and technologies for the production of hydrogen, synthetic methane and liquid hydrocarbons, carbon dioxide capture and electricity storage. The model considers consumer behavior, and uses non-linear curves to simulate the difficulty of investing in various technologies, as well as the availability of resources.

As the energy system is in a process of transformation, itself, the importance of storage changes too. New technologies are entering the market and it is necessary to monitor the ever-decreasing investment costs. Therefore, the process of modelling storage units is becoming more and more complex. Studies have confirmed the need for spatial and temporal modelling of energy storage. This way long-term design models will be able to include phenomena that occur in the energy system for short periods of time in different sub-regions. (Bistline et al., 2020).

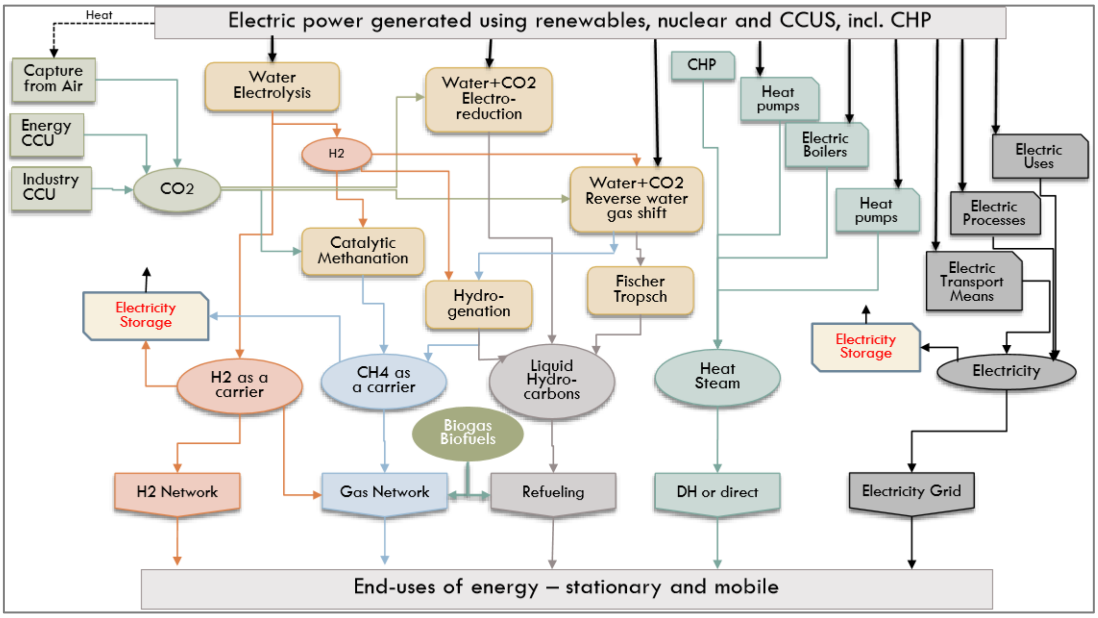
So far, no clear definition of integrated energy system models or Multi Energy System models (MES) has been provided (Kriechbaum et al., 2018; Mancarella, 2014). The most comprehensive description is based on four axes (Mancarella, 2014): 1) spatial axis 2) multi-sector axis 3) multi-energy, i.e., fuel, axis 4) grid axis. The spatial axis includes the spatial analysis that can be done at the level of city, region, country or group of countries (e.g., Europe of 27). The multi-sector axis includes the modelling of different sectors of the energy system and the modelling of synergies between them (electricity sector - transport, electricity sector - production of synthetic fuels, electricity sector - storage systems, etc.). The axis of multiple energy carriers-fuels is related to the fuels analyzed in the model (e.g. electricity, gas, oil, coal, biofuels, hydrogen) while the axis of the energy networks (electricity, steam, gas, hydrogen) or/and non-energy products such as CO2, focuses on connecting consumers and producers and allows the study of their interactions.

A summary flow chart of the PRIMES energy model is presented in Figure 3. The model combines the production of different forms of energy and includes a large number of interactions of energy sectors and technologies. The model includes supply and demand sub-models of all sectors of the energy system, which interact with each other. It also integrates the modelling of all technologies for the production of electricity, steam, biofuels, hydrogen and synthetic fuels, endogenously calculating their final values. It examines the energy system at the country level but also the Europe of 27. The modelling of electricity transmission is done using an equivalent direct current network and for the transmission of gas a transmission problem is solved. However, the above models do not simulate the transport of gas through pipelines. In particular, they consider the gas network as a storage medium of infinite available capacity and in the case of injection of synthetic methane, hydrogen and biogas into the pipelines, no technical constraints are considered nor is the storage capacity of the gas network and the flexibility to provide to the system.

Economies of scale contribute to finding the optimal size and optimal installation locations for energy technology investments in the energy system. With the increasing penetration of RES units, greater congestion is expected in the transmission networks that connect areas with high RES production demand centers. By factoring in economies of scale, the increased spatial detail in the simulation of the electricity system will help select the investment points of the stations that will improve the system, also by upgrading in the transmission network (IRENA, 2019a).

With regards to Power-to-X technologies, not many studies have examined how to optimally locate them in the energy system. The majority has used GIS combined with multi-criteria analysis. (Nielsen & Skov, 2019) investigate the optimal location of these units considering the proximity to the electricity transmission network or gas network. However, they fail to consider economies of scale, which are expected to play an important role in the future energy system.

Figure 3: PRIMES energy model flow chart



4 The hydrogen location module of PRIMES

The version of PRIMES used for the Clean Planet for All strategy foresaw the possibility to produce hydrogen and other new fuels domestically. As a result, countries were obliged to develop their own power generation capacity (mainly RES) and electrolyser capacity. This obviously increased the required generation in some countries and in some cases resulted in high costs of hydrogen and e-fuels. The new expansion, which was used in the Fitfor55 policy assessment, includes hydrogen trading and simulates a more plausible development of hydrogen and RES deployment by country. This allows for a better use of resources and a reduction of prices, particularly in the longer term where in carbon neutrality scenarios the share of hydrogen and e-fuels increases.

The hydrogen-related development of PRIMES modelling aims at determining the location, energy origin, transport, and cross-border trade of hydrogen within the European energy scenarios. The projections derive from economic and technical optimality in the context of long-term planning, depending on resources, developments in the power sector and policies regarding price signals, such as ETS, technology costs and infrastructure.

The hydrogen module of PRIMES optimises the matching between hydrogen production locations and demand. The hydrogen location model considers transport routes, ground and sea, and builds infrastructure endogenously, by optimizing the matching with demand, the transport costs and possibilities and the RES cost-potential relationships with increasing slopes. The consumption of hydrogen by country is projected endogenously by the rest of the PRIMES model. The RES potential by country is based on the potential available in the PRIMES model and projected into the future (not only the effective RES, but also the potential).

Going towards carbon, neutrality hydrogen trade will most likely occur between countries with high RES potential, thus better positioned to produce "green" hydrogen compared to countries with fewer RES resources. In the currently developed version of the hydrogen location module, the regions are specified at NUTS0 level (country level).

4.1 Structure of the model

4.1.1 Hydrogen demand in PRIMES

In PRIMES demand for hydrogen is computed endogenously based on sectoral demand and is produced with the purpose of storing excess-produced electricity. Hydrogen is also the basic feedstock for the production of other synthetic fuels: e-methane and different forms of e-liquids (RFNBOs). Hydrogen either competes with other fuels directly in the open market, blended in the gas grid, or further transformed into other e-fuels.

In the PRIMES model, hydrogen is available for direct use in the supply side (power generation) and refineries, as well as in all sectors of the demand side. In the supply side, hydrogen is produced for storage purposes of electricity, as well as to meet the demand from final energy demand sectors and the energy branch. Hydrogen can then be utilised by power plants to generate in peak demand times generally in CCGT plans blended with natural gas.

In the energy branch, hydrogen is used in refineries – currently through Steam Methane Reforming facilities. In the transition to carbon neutrality, refineries will buy green hydrogen from electrolysis to reduce the consumption of fossil fuel (FCH JU study).

In the demand side, hydrogen can be used in transport as well as in stationary demand. The PRIMES-TREMOVE transport model has been improved to include hydrogen in almost all transport modes, where it is feasible according to current technological perspectives: cars, light duty vehicles, heavy duty vehicles, rail, and navigation. The technology to use hydrogen is considered to be the fuel cell; the use of hydrogen in ICEs is not considered due to the low efficiency.

For the stationary demand side hydrogen can be used directly in several industrial sectors (Iron and Steel, Chemicals) or in blended form in the gas grid in all stationary demand forms. Hydrogen is theoretically available as a pure form also in the residential and services sectors. However, this is but currently not part of any scenario, as the main assumption is that hydrogen will be distributed in blended form through the existing gas grid, rather than through a new, independent, hydrogen-only distribution grid.

In the iron and steel sector no use of hydrogen takes place,[1] nonetheless it is expected that hydrogen could be used for direct reduction processes, therefore directly injected in the production of iron, substituting iron production using blast furnace.

At present, primary chemicals, such as ammonia and other chemical substances for the petrochemical industry come from naphtha and natural gas reforming procedures (to hydrogen) and thus imply industrial process emissions of carbon dioxide. However, in a carbon neutrality context, these substances are expected to be produced using hydrogen.

4.1.2 Hydrogen supply in PRIMES

Treatment of hydrogen in the energy balances

Hydrogen in the EU is currently produced mainly within industries and refineries for "non-energy" purposes. In the energy balances, hydrogen is not considered an energy product. Moreover, traded hydrogen for non-energy purposes is not included in the energy balances, contrary to petroleum products, which are included as "non-energy" products in the energy balances.

Hydrogen produced on-site through Steam Methane Reforming is also not explicitly included in the balances: only the natural gas required by industry (for unspecified purposes) is included therein. In the future, to meet the carbon neutrality objectives, these uses will be increasingly met through green hydrogen. These quantities have now been included in the energy balances of PRIMES under "transformation output" for the production and under "energy branch consumption" for refineries and final energy demand.

Hydrogen and e-fuel production

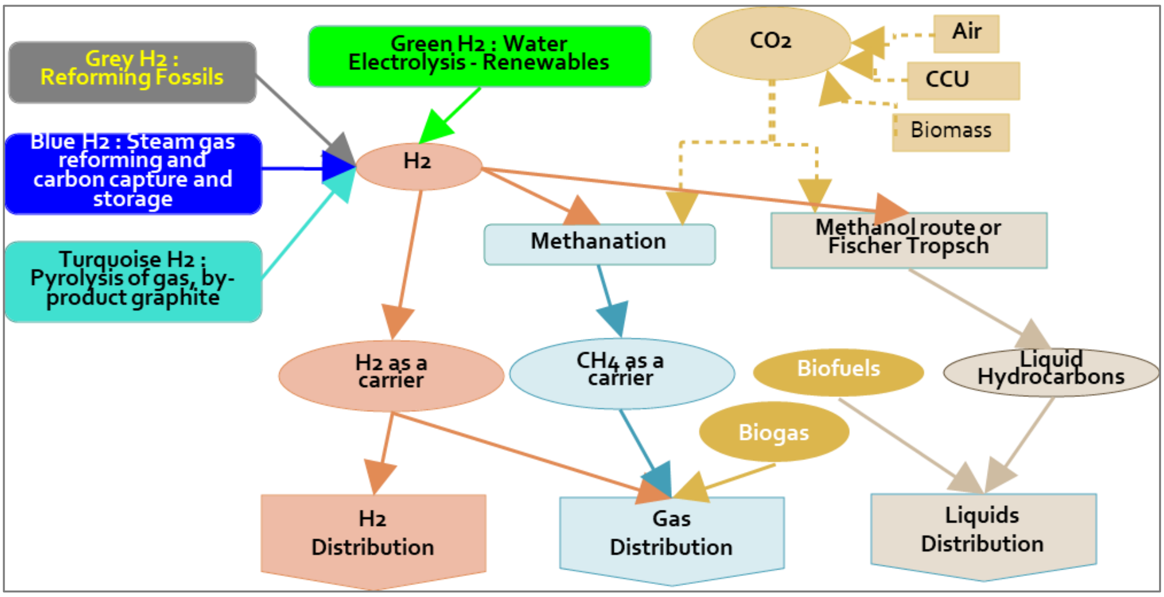
In the scenarios for carbon neutrality PRIMES introduces hydrogen production through electrolytic processes. The model includes both the production of hydrogen as well as

[1] IN August 2021, according to various news sites the first batch of "Green Steel" was dispatched in Sweden. https://www.theguardian.com/science/2021/aug/19/green-steel-swedish-company-ships-first-batch-made-without-using-coal

the further transformation of hydrogen into chemically more complex compounds, such as synthetic methane and synthetic liquids. The electrolysers consume electricity which is provided by the grid; the additionality principle as defined in RED II is verified for the production of RFNBOs for the transport sector.

The techno-economic characteristics for hydrogen and other synthetic fuel production as well as for key infrastructure elements required for hydrogen production are included in the Reference Scenario 2020 publication.

Figure 4: Possible hydrogen pathways



Source: E3M

In terms of economic readiness, green hydrogen is now two to three times more costly than grey hydrogen, while blue hydrogen is not a choice except in niche markets. Green hydrogen costs mainly depend on electricity costs but considering that hydrogen helps the power system to reduce balancing costs and maximize the use of RES, costs are projected to decrease in the future.

Poor energy efficiency of synthetic hydrocarbon production chain is the main limitation in the future, while distribution and storage are feasible. The least-cost route is to start with biomass-origin of gas, liquids and then CO_2. However, total potential is still limited.

In terms of technology readiness, the different synthetic fuels present the following characteristics:

- Methanation, Methanol Route, Fischer-Troops: industrial maturity expected
- CO_2 capture from air: immature and uncertain technology
- Biogenic CO_2: feasible but not ready at an industrial scale
- Hydrogen distribution: feasible, large investment
- Green gas blending: feasible in the short term – regulation and incentives needed
- Steam reforming of Natural Gas and CCS: no underground storage of CO_2

- Gas pyrolysis producing H_2 and graphite: not yet mature

4.2 Assumptions for the modelling

The techno-economic characteristics for hydrogen and other synthetic fuel production as well as for key infrastructure elements required for hydrogen production are included in the Reference Scenario 2020 publication. Renewable energy potentials in PRIMES have been updated in accordance with the ENSPRESO database of JRC.[2] The classes of the different types of RES have also been modified to better capture both cost and capacity factor differences for the different options. The new categorisation can be found in **Error! Reference source not found.**.

Table 2: New classification of renewable energy sources for power generation in PRIMES

Wind onshore			
Wind onshore - low resource area, high hub height	Wind onshore - medium resource area, medium height	Wind onshore - high resource area, medium height	Wind onshore - very high resource area, low hub height
Wind offshore			
Wind offshore Power, Shallow, Near-shore, Low	Wind offshore Power, Shallow, Near-shore, High	Wind offshore Power, Shallow, Far-shore, Low	Wind offshore Power, Shallow, Far-shore, High
Wind offshore Power, Deep, Near-shore, Low	Wind offshore Power, Deep, Near-shore, High	Wind offshore Power, Deep, Far-shore, Low	Wind offshore Power, Deep, Far-shore, High
Solar PV			
Solar PV Residential Low	Solar PV Residential Medium	Solar PV Residential High	Solar PV Residential Very High
Solar PV Commercial Low	Solar PV Commercial Medium	Solar PV Commercial High	Solar PV Commercial Very High
Solar PV Utility Low	Solar PV Utility Medium	Solar PV Utility High	Solar PV Utility Very High

The endogenous hydrogen trade module includes the development of the necessary infrastructure for the transportation of the produced hydrogen; it includes ground and sea trading options.

Hydrogen trade is allowed in the current version within the EU MS and with the UK[3]: currently the scenarios modelled do not include the import of hydrogen and other synthetic fuels from non-EU countries, but these could be included provided that cost-potential curves were available.

[2] https://publications.jrc.ec.europa.eu/repository/handle/JRC116900
[3] The UK continues to be fully modelled in PRIMES runs.

4.3 Model logic

The hydrogen geolocation module runs in a formal linkage with the power sector model of PRIMES. The coupled hydrogen and power sector models run within the overall modelling of demand and supply interaction. The model coupling uses an iterative process to converge towards economic equilibrium.

Before running the hydrogen model, all other models of PRIMES have determined demand for hydrogen as an energy product consumed in specific sectors directly and as a feedstock in the production of synthetic fuels. Therefore, the derived demand for hydrogen has locational (countries) and temporal (years and time slices) specifications.

The demand for hydrogen depends on prices by sector, year and country that the model estimates based on a complex pricing methodology, which aims at recovering levelized total costs that include the effects of anticipated learning-by-doing and at defining prices by sector (long-run marginal cost pricing principle) in inverse proportion of price elasticities (Ramsey pricing principle). At first approximation, the hydrogen prices depend on domestic resources and costs and have not yet included the cost-saving effects of cross-border trade.

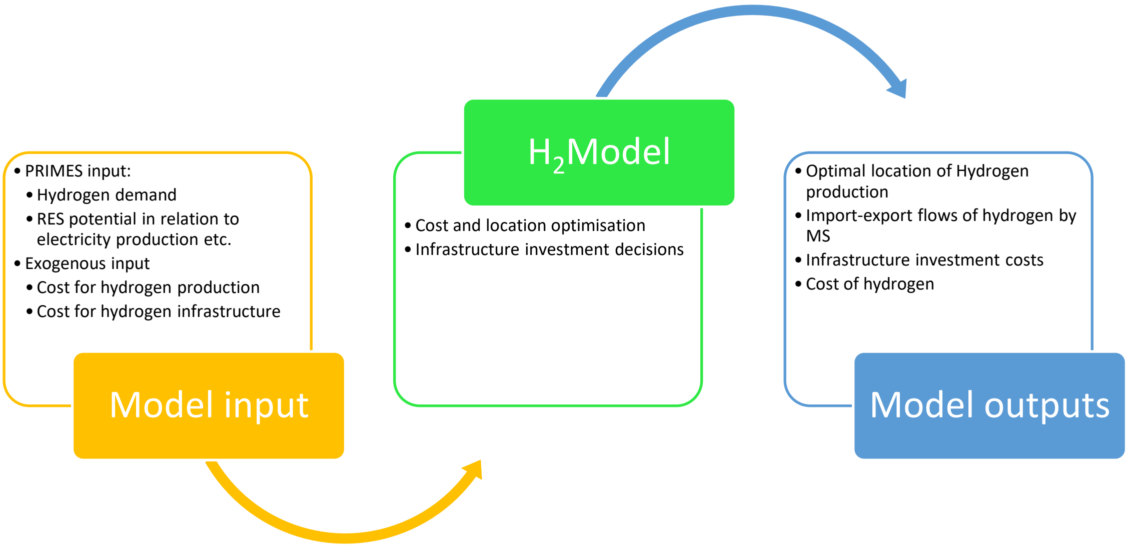
Then, the hydrogen geolocation and trade model operates to determine hydrogen's domestic production by origin, development of transport infrastructure, and cross-border trade. The hydrogen model considers as given a set of cost-potential curves concerning resources that potentially can produce hydrogen, such as solar energy, wind power, nuclear energy, steam reforming with CCS, etc. The cost-potential curves are country-specific and evolve over time. In addition, the modelling considers that the resource potentials also produce electricity for many uses other than hydrogen.

The model represents investment in hydrogen transport infrastructure endogenously. It is simultaneous with the determination of hydrogen production location and origin. The transport infrastructure distinguishes between pipelines, road and sea transport. The costs depend on transport mode, geographical features and distances. The potential transport infrastructure has limitations depending on policies and technical possibilities. The coverage of transport routes is very broad and includes origins outside the European continent. Parameters reflecting import dependency policies may restrict or penalize certain routes.

After running the hydrogen geolocation and trade model, the power sector model gets the results as constraints regarding the location, origin, and cross-border transport of hydrogen. So the model re-optimizes the power sector and re-determines the costs and prices, including for hydrogen. Cross-border trade of hydrogen is beneficial for reducing prices and costs of hydrogen, particularly for countries less endowed than others for hydrogen-producing resources. Then, the demand models of PRIMES operate to re-determine demand and close the overall model loop.

Then the model delivers a number of outputs which provide a clear picture as to where and at what cost hydrogen may be produced, along with the hydrogen trade flows between EU MS.

Figure 5: A representation of the H_2 PRIMES model



5 Overview of model results

5.1 Modelling context of updated CTP[4] scenarios

The MIX scenario design combines regulatory-based measures with economic measures such as carbon pricing to achieve the 55% GHG emission reduction target (expanded scope to LULUCF, as in the CTP). Carbon pricing applies the EU ETS mechanism, whereas the bottom-up policies are of a moderate intensity. The scenario assumes integration of buildings and road transport sectors into the ETS system ("new" ETS sectors). The unified market of allowances implies that a single carbon price shall apply to both "old" and "new" ETS market segments. The pricing of carbon emissions acts as a driver for energy efficiency and RES in the demand sectors. It thus complements bottom-up measures to achieve the same overall emissions target. A similar conception of the measures applies to the transport sector regarding the CO_2 standards (slightly less ambitious in the MIX than in the REG) and the promotion of modal shifts. The scenario includes policies for increasing the renovation rate, but at a lower level than the REG. Renewables in buildings and industry include incentives for the uptake of RES in heating and cooling -particularly heat pumps- in line with a binding RES H&C target for 2030. In power generation, the MIX scenario assumes a reduced risk for offshore wind projects to mimic the offshore wind strategy.

The scenario includes CO_2 standards for LDVs and HDVs in conjunction with recharging and refuelling infrastructure (review of the AFID and TEN-T Regulation & funding) and development of alternative fuels. The scenario includes a medium ambition increase in fuel policies (Renewable and low carbon fuels mandate). The ReFuelEU aviation and FuelEU maritime initiatives are again part of this scenario.

[4] Climate Target Plan https://ec.europa.eu/clima/policies/eu-climate-action/2030_ctp_en

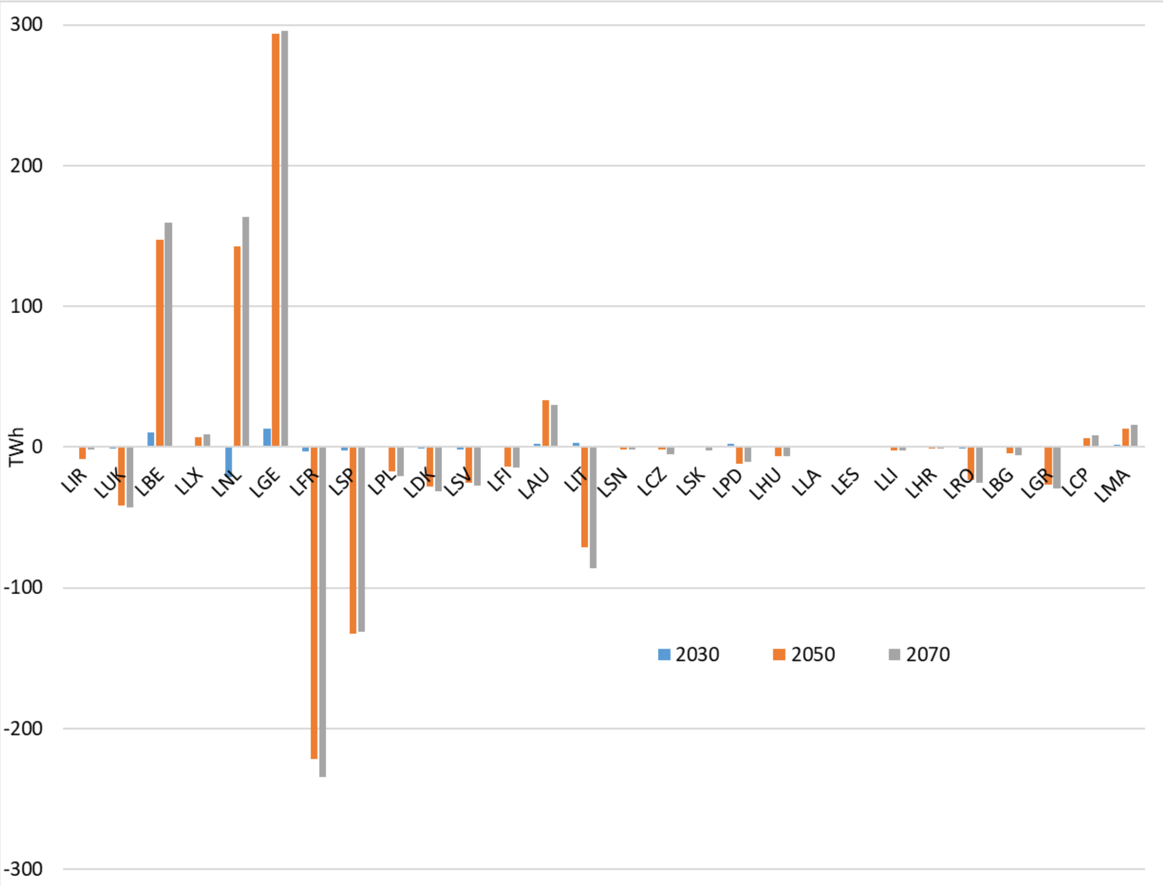
5.2 Exemplary Model results

The new module can estimate hydrogen curtailment, domestic supply, net imports as well as the split between ground and sea transportation requirements in terms of capacity and their use. The module also computes costs for the hydrogen supply system, as well as the additional electricity supply system costs.

The

The model is able to produce results about the flows of hydrogen between countries. Figure 6 shows the net imports of hydrogen under a decarbonisation scenario: countries with limited RES potential such as Germany or Belgium will be importing hydrogen whereas countries with higher RES potential and zero carbon installed capacity -such as France or Spain- will be producing and exporting hydrogen.

Figure 6: Net imports of hydrogen (Exemplary results from the new hydrogen module)[5]



Islands (Malta and Cyprus) will rely almost exclusively on imports; whereas larger countries will have their own production. Depending on the size of the demand, including from industry, supply may not be sufficient to cover demand and so imports will be required; this affects particularly Belgium, Netherlands and Germany according to the preliminary model simulations (see Table 3). Model results for 2030 have attempted to

[5] The values in this graph are exemplary from a draft scenario and should not be used as indication of future projections for net imports.

simulate existing plans for hydrogen production, whereas 2050 results are more illustrative of a stable market in a net zero context.

Table 3: Share of domestic supply of hydrogen

	2030	2050		2030	2050
AT	60%	53%	**IE**	97%	130%
BE	30%	20%	**IT**	80%	132%
BG	120%	126%	**LT**	110%	110%
CY	20%	9%	**LU**	5%	5%
CZ	110%	101%	**LV**	94%	110%
DE	70%	26%	**MA**	0%	6%
DK	180%	180%	**NL**	200%	43%
EE	110%	110%	**PL**	75%	107%
ES	115%	155%	**PT**	115%	145%
FI	80%	138%	**RO**	130%	145%
FR	115%	175%	**SE**	129%	140%
GR	103%	150%	**SI**	75%	124%
HR	75%	109%	**SK**	110%	97%
HU	110%	114%	**UK**	108%	110%

Simulations using the endogenous trade module for hydrogen ensure a more realistic projection of hydrogen production by country and for the system overall: as with cross-border trade of electricity, optimising the trade of hydrogen leads to overall cost savings for the entire energy system in the order ranging between 0.5% and 0.6% cumulatively in the time period 2020-2050 (equals to over 330 or 335bn€); depending on the initial scenario. Scenarios with endogenous trade show reductions in GIC up to 2.7% over the projection period.

Hydrogen trade within the EU27+UK is simulated to 1248TWh in 2050 of which approximately 20% would be sea transportation and the remaining 80% by land. The share of hydrogen transported by sea is projected to rise over the projection period. Electricity for hydrogen production is expected to rise from 252TWh in 2030 to 3357TWh in 2050 in a net zero CO_2 context.

Table 4: Hydrogen trade transportation shares

	2030	2035	2040	2045	2050
Land	86%	85%	80%	80%	79%
Sea	14%	15%	20%	20%	21%

6 Summary and Conclusion

The PRIMES model has been extended with a new module that determines the location, energy origin, transport, and cross-border trade of hydrogen across EU countries. The new module allows to better assess developments in the sector and to use renewable energies more efficiently in each MS.

The model results show that intra-EU trade, as expected, will lead to benefits in terms of costs and primary energy resource use, which are both lower in model runs which include the trade module.

The use of the module in the scenarios for the evolution of the EU energy system shows that trade occurs mainly between countries with high RES potential, while countries with low RES potentials tend to be importers; the size of the industrial sector and therefore the size of hydrogen demand also play a role. Smaller countries with limited RES endowment such as Malta, Cyprus or Luxembourg are projected to have very limited domestic production and are expected to have access to hydrogen, allowing additional options for emission mitigation in the modelling. Hydrogen transport is expected to occur mainly by land, with approximately 20% of trade occurring over sea in the longer time period.

The model represents a significant improvement of the PRIMES energy system model, enhancing its capabilities to better simulate the energy system, particularly in the context of the energy transition and aim to net zero, where hydrogen and e-fuels are expected to play an increasingly important role. The model can be expanded to include extra-EU hydrogen trade, if required.

Attempts at scaling the model below NUTS0 level were attempted but have not yet reached sufficient maturity; further research is planned in this regard to improve the modelling even further.

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8 Annex: Typical costs

Costs assumed in PRIMES based on literature review and stakeholder consultation

	Total cost (EUR/kg H2 LHV)	
	Currently	Long-term
Hydrogen from		
natural gas steam reforming centralised - Large Scale	1.5	2.9
natural gas steam reforming small Scale	3.4	5.2
natural gas steam reforming centralised - Large Scale with CCS	2.7	4.0
electrolysis PEM- Large Scale	2.8	2.4
electrolysis PEM small-medium scale	3.4	2.9
electrolysis Alkaline - Large Scale	2.7	2.4
electrolysis Alkaline small-medium scale	3.0	2.8
high temperature electrolysis SOEC	3.6	3.0
high temperature water electrolysis SOEC small scale	4.2	3.6
H2 compression station	0.2	0.2
Hydrogen Liquefaction plant	0.4	0.3
H2 liquid to gas refuelling station	0.6	0.6
H2 refuelling station Small	0.7	0.7
H2 refuelling station Medium	0.4	0.4
H2 refuelling station Large	0.3	0.3

	SEC - Natural gas	SEC - Electricity	Overnight investment cost (EUR per kW-output)		Variable and emissions cost (EUR/MWh-output)		Total cost (EUR/MWh-output)	
			Currently	Long-term	Currently	Long-term	Currently	Long-term
Hydrogen from								
natural gas steam reforming centralised - Large Scale	1.33	0.094	535	485	42	87	52	98
natural gas steam reforming small Scale	1.53	0.094	885	1554	102	97	115	173
natural gas steam reforming centralised - Large Scale with CCS	1.33	1.094	1864	835	47	155	89	132
electrolysis PEM- Large Scale		1.27	1145	475	78	80	95	82
electrolysis PEM small-medium scale		1.35	1485	630	83	84	113	96
electrolysis Alkaline - Large Scale		1.32	920	434	80	84	91	80
electrolysis Alkaline small-medium scale		1.32	1290	435	80	85	99	92
high temperature electrolysis SOEC		1.59	1358	743	97	95	118	100
high temperature water electrolysis SOEC small scale		1.62	2320	1210	99	96	138	121
H2 compression station		0.07	110	99	4	5	6	7
Hydrogen Liquefaction plant		0.02	723	582	1	1	13	11
H2 liquid to gas refuelling station		0.07	826	702	4	5	20	19
H2 refuelling station Small		0.07	966	854	4	5	23	22
H2 refuelling station Medium		0.07	503	402	4	5	14	13
H2 refuelling station Large		0.07	302	218	4	5	10	9

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