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HYDROGEN TECHNOLOGY

WORKSHOP SUMMARY

TECHNICAL REPORT

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Executive summary

On the 15th and 22nd of April, the Florence School of Regulation held two online workshops that shed valuable light on the state of technological development regarding renewable and decarbonised/low-carbon hydrogen.[1] They were organised in the context of the European Commission's preparations for its 'Energy System Integration' initiative. As DG ENER Deputy Director-General Klaus-Dieter Borchardt explained, the objective of this upcoming Communication is twofold: first, it aims to further develop the EU energy regulatory framework so that the different forms and vectors of energy in the widest sense are able to find optimal places in the EU's future decarbonised energy market. Second, it will determine how the EU should promote the development of renewable and decarbonised hydrogen.

Our workshops aimed to discuss data and evidence which can support the rationale for an energy system integration strategy. We have extracted some key points emerging from the debates which show how important it is to maintain an evidence-based approach if the EU is to develop a policy that meets decarbonisation targets and at the same time delivers a cost-effective job-creating strategy:

- In determining the measures that might be taken to promote the development of a 'clean' hydrogen economy, it is vital to know the ETS price levels at which clean hydrogen can enter the market and displace grey hydrogen (produced from fossil fuels with the resulting CO_2 being vented).[2]
- There are essentially three methods to produce low/zero-carbon hydrogen; (i) 'green' hydrogen, produced from the electrolysis of water using renewable electricity, (ii) 'blue' hydrogen, produced from natural gas using steam methane reforming, with the CO_2 then being stored (CCS) or used (CCU), and (iii) 'blue' hydrogen, produced from natural gas using pyrolysis, with the CO_2 being rendered into solid carbon and used in industrial processes or stored (CCUS).

  It is essential to have an objective understanding of the well-to-wheel CO_2 content of the hydrogen produced by these different technologies.

[1] For more information, refer to
https://fsr.eui.eu/event/online-workshop-on-renewable-hydrogen/ and
https://fsr.eui.eu/event/very-low-decarbonised-hydrogen-from-natural-gas/

[2] This should have a strong influence on the scale of any support schemes. If, for example, an ETS price of 50 euros would already lead to significant substitution, a short-term policy of R&D/demonstration support and tenders for production would make sense. If a 150 euros price is necessary, it would makes sense to limit support to R&D/demonstration projects in the short-term to get the technological costs down before providing production subsidies.

- It is equally important to understand the costs and expected cost trajectory of these different forms of hydrogen production.
- Externalities other than CO_2 also need to be identified. For example, green hydrogen requires significant quantities of water. Will this mean serious limitations as to where it can be produced? CCS involves CO_2 storage. Where can this take place and is it a long-term safe solution?
- Finally, other potential constraints need to be taken into account when assessing the potential role that the different types of hydrogen might play. For example, how much renewable electricity would the EU need to generate if it was to cover both its electrification needs and its hydrogen requirements? Should 'clean' hydrogen be imported, and if so, from where?

While answers to these questions will in many cases be open to interpretation and subject to future developments that cannot be perfectly predicted (technological development, future gas and renewable electricity costs, for example), they are crucial in developing a coherent policy with respect to the EU Energy System Integration Strategy and the policy measures needed to develop the 'clean' hydrogen market. These issues will no doubt be at the very heart of the Commission's Impact Assessment, which it will prepare in advance of legal proposals on Energy Sector Integration currently scheduled for June 2021.

The online workshops were therefore established to provide some first answers to these vital questions. While this is a first step, and the FSR will follow up with further research and discussions, the following observations can be made from the interventions.

- We can expect a broad use of hydrogen across different energy sectors. Hydrogen could supply up to 20% of energy demand by 2050. The particular challenge is that a hydrogen economy requires a new customer base with new infrastructure. The process could be accelerated with more stringent emission standards for heavy transport and industrial decarbonisation policies. The scale of production matters greatly in the production of 'clean hydrogen'.
- The political focus today is very much on renewable hydrogen, but decarbonised hydrogen from natural gas will also play a significant role. Different technologies have different additional advantages. Methane pyrolysis does not need water. Autothermal reforming of methane with the use of CCS could be more efficient than SMR with CCS. Some companies have already had some experience with these processes and have announced CCS projects.

The production of ‘blue’ hydrogen could be done at scale already now, saving the 830 Mt CO_2/year that is currently being emitted with the production of ‘grey’ hydrogen. New technologies are being developed like ‘hydrogen stripping using microwave-initiated catalysis’ in which energy transfer happens without heat transfer. The use of renewable electricity and biogas to produce hydrogen can provide ‘negative’ emissions[3], which can give an input in achieving carbon neutrality. Blue/green hydrogen use will vary by region, depending on the availability/costs of resources and public acceptance. An EU ETS price of 55€/tCO_2 by 2030 can enable the conversion of 125TWh of grey to blue hydrogen.

- For the development of renewable hydrogen, the price of renewable electricity and the costs of electrolysers are of crucial importance. The technology today is substantially more energy consuming than ‘blue’ hydrogen technologies. Efficiency will increase with the scale of use. By 2050 two thirds of the hydrogen used will be ‘green’ hydrogen. One way to support the early stage development of hydrogen and economies of scale could be to inject ‘clean’ hydrogen in the existing gas grids. Blending methane with up to 10-20% of hydrogen does not require major changes in infrastructure and end use applications.
- Sector integration, in particular of the power and gas sectors, could bring important advantages. The recovery initiatives in response to the Covid-19 crisis could significantly accelerate ‘clean’ hydrogen penetration in the European economy. Scaling up the capacity of electrolysers, adapting gas networks for the transport of hydrogen and increasing storage capacity could be measures to get support from recovery instruments. There are plans to install 40 GW electrolysis capacity in the EU and 40 GW in North Africa and Ukraine. Important private investments have also been announced. On the demand side, there is an interesting technological development of trucks with fuel-cell technology. The EU’s research programmes are supporting projects from the production of renewable hydrogen using advanced electrolysis to renewable hydrogen used in hard-to-abate carbon sectors.

[3] By ‘negative emissions’ we mean here that some gas production processes remove CO_2 from the atmosphere or the environment rather than emitting it.

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Annexe 1: Reasons for the workshops

It is widely accepted that renewable and decarbonised hydrogen will need to play a major role in the EU's future decarbonised energy market. The technological solutions to produce it exist. However, the costs are high and the production capacity is small. How to drive down costs and catalyse sufficient capacity in time for the 2050 decarbonisation deadline? How to ensure that the principles of the internal gas market are retained? How to link the electricity and gas markets? How could ETS accelerate the process? These are the questions to answer to design the policy framework. The EU should strive to achieve the climate goals in an efficient and cost-effective way, taking into account the competitiveness of European industries and paying attention to security of supply. Some of the issues where an evidence-based approach is vital are: the likely costs of renewable and decarbonised hydrogen; what needs to be done to get costs down; how robust future price curves are; and the ETS price at which consumers of 'grey' hydrogen would be likely to switch to renewable or decarbonised hydrogen.

The Florence School of Regulation proposed two online workshops to examine and discuss these issues in depth. One focused on decarbonised hydrogen produced from natural gas; the other examined the potential of renewable hydrogen.

Annexe 2: Highlights from the workshops

Technology development for pyrolysis

Nowadays, natural gas pyrolysis is widely seen as another developing technology for blue hydrogen production that has a remarkable potential to facilitate deep decarbonisation of the European gas sector, the major part of the European energy economy. Pyrolysis is the thermal decomposition of materials at elevated temperatures in the absence of oxygen. Considering that natural gas is a hydrocarbon gas mixture primarily consisting of methane, natural gas pyrolysis is methane decomposition into gaseous hydrogen and solid carbon. Different methane technologies have been developed since the 1950s. Kværner Carbon Black&Hydrogen technology based on a high-temperature plasma approach, for example, was commercialised in the 1990s. Although natural gas is a fossil fuel, hydrogen production without CO_2 emissions brings a new opportunity for pyrolysis to be considered a leading technology in the energy transition. In recent years, beside Kværner, other technologies have been developed such as continuous chemical vapor deposition (ccCVD) and H_2 stripping using microwave-initiated catalysts. The technology readiness level (TRL) of such technologies is not above 6, basically meaning that scaling up from lab/pilot scale to large scale still has to be done, especially taking into account the projection that hydrogen demand could increase ten times by 2050.

Compared to other pathways for hydrogen production, such as SMR (+CCS/CCU) and water electrolysis (the carbon footprint depends on the electricity source), natural gas pyrolysis could have some advantages. The methane pyrolysis reaction requires less energy than SMR or electrolysis, and this energy can be provided by renewable electricity. The solid carbon that is produced in the process is easy to store and transport. The heat generated can be utilised too. There is no need for investment in and development of a costly CO_2 transportation and storage infrastructure. Water consumption is not required. A potential for negative emissions is present if biogas (biomethane) is used, which is mostly produced from agricultural and food waste.

Some studies indicate that methane pyrolysis is potentially a key future technology whose production costs depend on the price and availability of natural gas, the value of carbon by-products and the scale of production. Nevertheless, some technical issues (reactor design, solid carbon removal, process optimisation) and the economic benefits of viable industrial implementation of carbon will be challenging.

Technology development for the use of CCS

Europe has a very competitive edge regarding natural gas (methane) reforming compared to other continents. Several companies have long experience of carbon capture and storage (CCS), which is essential in blue hydrogen production. CCS is a technology that prevents CO_2 emissions being released into the atmosphere and instead allows them to be safely stored deep underground.

Steam methane reforming (SMR) is the method most developed at scale for hydrogen production. Gaseous hydrogen and CO_2 are produced in the endothermic reaction (requiring energy) between methane and steam (H_2O) at 40-50 bar.

In autothermal reforming (ATR), hydrogen is produced in an exothermic reaction between methane, steam (H_2O) and oxygen at 40-80 bar. The higher pressure during ATR means that the CO_2 capture rate is higher (95-97%) compared to SMR (90-92%), and the process is cheaper.

There are difficulties regarding scaling SMR. Compared to ATR, where the single-line capacity is from 1500 to 2000 MW, SMR has a line capacity from 400 to 500 MW. Systems based on ATR have higher efficiency (75-80%) compared to systems based on SMR without capture (70-75%). The capital expenses (CAPEX) have more or less similar values: 700-800 €/kW H_2 HHV (higher heating value) for SMR and 600-700 €/kW H_2 HHV for ATR.
A study was mentioned that proves that it is possible to combine different 'clean' hydrogen-producing technologies without ending up with a lot of stranded assets and wasted investment. The point of view was expressed that there is no need for competition between different technologies at the moment. Blue hydrogen could be produced at scale, and it facilitates green hydrogen technologies.

Technology development for renewable hydrogen

To achieve the goals of 'The European Green Deal,' it is expected that renewable hydrogen will play a vital role in the progressive decarbonisation of the gas sector. Renewable hydrogen, sometimes called green hydrogen, is produced using renewable electricity through water electrolysis. This is a technology that decomposes water into gaseous hydrogen and oxygen.
There is broad acceptance of this technology. Nevertheless, there are still ongoing questions related to the current status of the technology, scaling, cost projections, production potential, applications and the role of governments in accelerating deployment.
Hydrogen electrolysers are at the stage in their development where wind and solar were in 2008-2009 and have the potential to become the decade's break-out technology. Significant investment is needed to scale it up to 0.1-1 GW. To achieve these dimensions it is vital to bring down costs and make green hydrogen an attractive commercial opportunity.
One of the next steps is a proposal to demonstrate large-scale electrolysers (100 MW) as part of the Green Deal call in H2020 and the 2 x 40 GW initiative (40 GW in Europe, 40 GW outside Europe).
There is a need for hydrogen-dedicated pipelines. Various salt caverns around Europe could be used for hydrogen storage.
Identifying where hydrogen is needed, and where other energy carriers cannot be used, is crucial for the demand side. For example, synthetic fuels are a major part of the game and hydrogen is one step in the whole process. Many speakers agreed that blue hydrogen will have to play a complementary role in the energy transition until over time it is overtaken by

green hydrogen. Blue/green competitiveness will vary by region depending on the availability of advantaged resources (renewables for green/natural gas and CCS for blue) and policy preferences.

Annexe 3: Answers to questions from the participants

Very-low/decarbonised hydrogen from natural gas – Q&A

Stefan Petters, Christopher Brandon and Alexander Barnes provided answers on the following questions:

- Is CCS/CCU a valid option for hydrogen production in the EU?

  While Europe's prudence on sequestration is deemed totally warrantable because the vulnerability of deep-set cavity tectonic fitness to seismic plate displacements is prohibitive for continental CCS, it should be more worthwhile to concentrate on CCU.

  For CCU there are two possibilities:

  - Capture CO_2 and re-use it through MeOH or polystyrol synthesis and in very small volumes of high purity CO_2 in green house agriculture or the beverage industry. So called power-to-X CO_2 resurrection attempts require water equivalent to 0.6 per capita dietary irrigation needs and 2.5 times the achievable energy yield.

  - Recovering carbon prior to it being converted into CO_2 in directly reusable morphology is 2.5 times more energy efficient and water neutral. Methane is nature's sole repository of residual energy stored in matter and carbon can be recovered from it through thermal methane dissociation [TMD] technologies (favourably by controlling its morphology towards specific surfaces >100m²/g). Whether the co-produced hydrogen is sold to end-users or looped back for methanation of decomposition CO_2 gas (coinciding in the transformation of matter into gases) yielding water as a by-product may be a logistic choice.

  The fact is, however, that recovered (high specific surface) carbon from methane has a commercial value of ~1% per barrel (long-term average) of the crude oil price per kg. While every tonne of CO_2 triggers a carbon replenishment of 2.5 barrels of crude oil, high specific surface carbon can substitute up to 2 litres of oil per kg.

- How can we make sure that electrolysers only use electric energy that is not necessary for other electric technologies?

  Looking at the non-nuclear decarbonisation options for the EU grid, the first task to solve is volatility back-up. Hydrogen electrolysis can facilitate 30% of a wind or PV installation's excess electricity production as back-up without installing additional capacity just for back-up (at a first kWh cost!). As of 2020, the EU27 still needs to decarbonise 43% of utilities and any additional electricity demand from shifting combustion processes to electric heating (or work) comes on top. If for industry 24/365 availability is a must and given the above-mentioned back-up gap, there is no free lunch electrolysis hydrogen beyond the captive grid back-up.

- What can be done in Zimbabwe about hydrogen technologies? Any ideas?

  Zimbabwe shows a 60% energy use of biomass. Rather than burning biomass converting its ~40%wt carbon content into CO_2 under co-firing 50%wt water, generating water vapor in addition, biomass should be undertaken as an accelerated decomposition into energy-rich gases, as cited above under CCU.

  If the country wanted to go for a hydrogen economy, regenerative carbon co-producing ⅓wt green hydrogen could be undertaken using a water-gas reaction. High specific surface carbon can be brought up to chemical reactivity level at very low ambient temperatures with microwaves (see the paper at the ICPS2019 conference in Vienna). Hence, the chemical energy stored in the carbon, which is easily storable and not hazardous to transport (not inflammable or self-igniting) could deliver hydrogen on demand (electricity for the microwave can be drawn from a buffer battery until a slipstream from downstream fuel-cell electricity takes over). Given the higher electric efficiency of hydrogen there is a significant primary energy saving from going to hydrogen.

- Up to 40% of current gas consumption is outside of the EU ETS and not subject to a carbon price. How to ensure alternatives (H_2, efficiency, electrification) can compete fairly in those areas?

  With NG-power burning CH_4 versus fuel-cell utility from its hydrogen content (dissociated from its carbon by TMD) only, there is no need to combust the carbon. TMD processes providing adequate carbon morphology allow the carbon to be used in crude oil substitute applications. In EUI workshop slides (#12) there is an example that was explored in more depth at the Hypothesis XIII conference in Singapore, including the economics of such sector coupling. By improving the total carbon efficiency across both sectors by 64%, at arm's length competitiveness should make the ETS just nice to have, but not necessarily relevant for doing what makes sense.

- Could you please compare CAPEX/OPEX for SMR and pyrolysis? What is the technology readiness level for pyrolysis?

  Concerning TRLs, it can be refered to EUI workshop slides (#4). Before taking our prototype TRL7 reactor to industrial operation (small-scale special materials) we worked with an equipment supplier of R.A.G. and the chief engineer of OMV's Schwechat refinery on an add-on to their SMR to recover 20% additional hydrogen from their equilibrium methane in the off-gas. That study showed that in the case of our ccCVD CAPEX is about half of SMR. However, in OPEX we need 50% more methane input than SMR, need only 60% process energy and spend 3-5 times the catalyst cost (which, however, can be offset by selling our carbon yields at arm's length).

- Pyrolysis is an endothermic reaction. Is it still that competitive given that a part of the hydrogen produced should be burnt to fuel the process?

  Why should the enthalpy be energised by burning hydrogen? It is much more efficient to burn the ~10% of methane going in for splitting, which is just about 50% CO_2 of using EU27 grid electricity instead. This idea of burning part of the hydrogen output seems very hypocritical given that electrolysis connected to the grid has a hydrogen CO_2 footprint of 2 times SMR hydrogen today!

- What is to be expected on hydrogen in the post-corona recovery plan? The audio was not good when this was mentioned.

  Given the financial stress in European economies struck by the Covid-19 pandemic, one would expect the hydrogen concepts discussed so far to be contemplated without complying with energy efficiency principles and taking water as an abundant resource (although it's scarce and it should be stressed that groundwater levels trigger soil carbon depletion at a rate of 1.38t CO_2 per m³ surface water drain). Of course, there is a large electric system OEM home in Europe's economically strongest member state which can supply the wind turbines and at least maintain nuclear power stations and deliver electrolysis and water desalination plants – greedily using the same lobbying channels as the dieselgate people did to hype an all-electric electric society and advocate for add-on power-to-X abatement of continued CO_2 squandering by more of the same practices. It costs twice the CAPEX and dislocates ~10m³ water per tonne of usable hydrogen (potential soil carbon flux of 13.8t CO_2), maintains unnecessary carbon replenishment costs at > €100.-/t CO_2 and achieves just 40% of the decarbonisation effect. It has been outlined in EUI workshop slides (#8).

Hopefully, the post-corona recovery plan will be open to more frugal (by achieving as promptly as possible significant enough effects from using what's there) hydrogen concepts! It will be decisive for Europe's competitiveness against Asian countries (not only China) and most likely the US. If EU energy-policy continues to presume that water is an abundantly available resource (whether at home or in countries envisaged as exporters of green hydrogen), the next immigration waves and shut-down due to water scarcity will be pre-programmed! And after Covid-19 we cannot take another crisis in the next decade.

- How does CO_2 emission for pyrolysis include upstream emissions?

  The enthalpy energy requirement is ~10% of the methane split. Depending on the catalyst system used there might be another single digit percentage upstream. Hence, we're talking about 10-15% max of SMR.

- Do we have enough economic use of solid carbon to match the volumes of large-scale pyrolysis or do we end up needing to store it?

  - This is a question of the carbon morphology yielded. For a specific surface >100m²/g there are vast non-combustion oil or coal substitute applications in synthesis- or REPE-Chemistry and terra preta soil-improving pyrolytic carbon additives for microbial composting practices. The higher the specific surface the better (our 300m²/g carbon could also be used as active carbon filters, electrode graphite, battery ion spacers or super capacitor foil coatings, which, however, can never accommodate enough). Given the competitive price of high grade carbon yields from large-scale hydrogen energy applications, many light-weight composite materials could gradually make their way into steel- or even copper-substituting markets (which are the areas in which we made many feasibility studies and developed numerous processing technologies 10-15 years ago, given where we had been coming from originally).

    - The largest carbon markets are carbon black, somewhere in the order of 15 million metric tons per year, followed by needle coke at about 2 million MT. All the specialised carbon markets – graphite, carbon fibre, etc. – are much smaller but with correspondingly higher prices. As these markets increase there is an opportunity for the prices to drop significantly and for adoption in a much wider range of applications to emerge. That being said, for very large-scale pyrolysis, sequestering the resulting carbon by-product may have to be seriously considered.

- How does the CO_2 price impact on the competition between pyrolysis and SMR?

  CO_2 is always lost carbon (~2.5 barrel crude oil equivalents) value that CCU in chemically re-usable morphologies can preserve. In the first place that is already a penalty nobody seems to notice yet. The chemical reaction regime of SMR cannot mitigate the formation of CO_2 so it squanders the carbon value by disposal into air. Pyrolysis with a marketable (uniform high specific surface) carbon yield can offset part of the hydrogen production cost through carbon sales. In doing so at arms' length, crude oil prices (1% of a barrel's long-term average price per kg of carbon). Pyrolysis can be 25-30% (depending on the applicable NG price) more economic than SMR.

  - Are these technologies suitable for economically producing H_2 (in the future) or its by-products?

    - We started out to develop the carbon product and welcomed the hydrogen by-product. As a special material solution provider to the semiconductor, microsystems and photonics industries we always had to drive down the cost of processes and so we did with our TMD.

    - The immediate opportunity is for producing its by-products. However, in the future it should be possible to produce H_2 at scale more economically. This is primarily as a result of the much lower energy requirement to split fossil fuels and the lower capex for pyrolysis technologies than CCS alternatives.

  - Is the problem of black carbon clogging still present?

    - I guess that for people who do not control the morphology of their carbon by-product the answer is yes. From our own experience, however, I would add unnecessarily.

    - Carbon deposition is a challenge that remains. However, there are numerous engineering solutions with respect to reactor design that are being explored, including fluidised/moving bed reactors, liquid metal bubblers, a 2-step catalyst bed, etc.

- Does the carbon set on the catalyst? Does this lead to a reduction of the catalyst's effectivity?

    - Yes, the carbon extrudes away from the metal surface and the further it gets, the slower it grows (helping to get a reasonably uniform particle spectrum at discharge). In contrast to SMR, the catalyst exits, but can be recycled for re-introduction into the process (depending on the catalyst system chosen for controlling the carbon growth in the process).

    - Carbon does set on the catalyst and reduces catalytic conversion. We are exploring various methods of harvesting the carbon and catalytic regeneration to overcome this challenge.

- Which is the CO_2 price range underlying your SMR cost estimation?

  I refer to my comments to the first question about CCS before. Does it really matter? Looking at Japan's or Korea's hydrogen strategy you could take another view. For distributed HFC CHP-HVAC or mobility (LDV, HDV, ships), a transition to SMR hydrogen cuts 40-60% of CO_2 emissions and (what is important for 100% primary energy importers) approximately halves primary energy consumption. Hence, they do not worry about the "colour of hydrogen"! They go for the CO_2 saving and for the foreign currency retention for saved primary energy imports now! It pays off at no matter what CO_2 penalty.

- Pyrolysis/thermal/microwave decomposition – how should we see the coming 5 years? 1. scaling up and an applicability of economies of scale, 2. installed capacity cost, 3. (warranty of) lifetime, efficiency (and where possible compared to the most up-to-date electrolysis for the coming 5 years and not using the old 200x/201x figures that the photo-electro chemical water-splitting people also always compare to old electrolyser figures)?

    - We filed a cold-wall reactor patent 21 years ago. It works great for small batches or in the laboratory provided you can control the behaviour of how your carbon falls out from the methane. In high volume we refrained from using it (for the TMD – differently though in making use of the, in our case, very uniformly high specific surface carbon).

Electrolysis is a wonderful technology for shaving NRE peaks, which as I mentioned above is never sufficient to captively cover associated back-up requirements. Only, within that application the water needed to be consumed can be terrestrially returned locally by the fuel cell using the buffer storing hydrogen. Producing hydrogen from first kWh extra installed electricity will never be able to compete with a good TMD.

- The realistic time scale for this should see a large pilot unit within 5 years. For an idea of scale, a 1MW power plant would generate some 300kg of hydrogen per hour, with therefore nearly a ton of carbon by-product. Rough estimates by BASF and others suggest this would be the cheapest form of hydrogen production at that scale. Without significant support in this nascent technology, however, commercial units would be unlikely till the late 2020s, and the focus therefore would remain on carbon materials production in the interim.

- If we use air, then the capture rate is quite low. Right?

  Not everything technically doable makes sense ecologically or economically. If this question refers to power-to-X carbon recovery for, e.g., the chemical industry, one has to understand that, in order to neutralise all of the EU27 CO_2 emissions, 6 times the EU27's dietary irrigation water equivalent would be needed to be displaced. We should let plants live as well, otherwise we'll starve.

- What we do with the captured CO_2?

  Boost tree nurseries for faster afforestation, while mitigation of CO_2 emissions by blue hydrogen and a grave-to-cradle carbon circular economy can be implemented.

- When discussing the potential for hydrogen in the energy mix one needs to distinguish between different issues:

  1) The aim of the Green Deal is decarbonisation, not the support of renewables. Renewables will play a significant part in our energy future but as Klaus-Dieter Borchardt indicated there are issues concerning cost and the roll-out of the significant amount of additional renewable generation that would be required to make

green hydrogen a successful means to decarbonise. Therefore, it would be sensible to enable other decarbonised approaches to be used if they also help reduce emissions in a practical and cost-effective way. All the means for producing hydrogen have their challenges at the moment, but it is too early to say which will prevail if there is a level playing field. The policy framework should therefore focus on emissions not on a chosen technology. This includes ensuring that the sectors of the economy not covered by the ETS (which is emissions-focused) are also subject to a framework which is emissions-driven. At the moment, RED II and the 2030 targets are technology-driven because they set targets for renewables. As the German experience has shown, this can skew policymaking and risk a failure to meet emissions (as opposed to renewables) targets.

2) Recognition that the current gas regulatory framework is aimed at enabling competition in a well-established mature industry where there is potential for market failure due to economies of scale/natural monopolies in networks. However, there is no comparable EU-wide hydrogen industry. This raises the question of whether the current approach to gas regulation will enable potential suppliers to invest. Whilst the EU Commission's focus on sectoral coupling may help enable greater efficiencies across gas and electricity networks, it does not address the fundamental issue of what approach to take for hydrogen overall. Put simply, you cannot have market failure if there is no market. By contrast, the electricity regulatory framework can accommodate more renewables as it is simply a case of building a more renewable generation and additional transmission capacity. In electricity one is simply substituting one form of generation (renewables) in the place of another (fossil fuels) but all the other factors (means of transmission, type of product etc.) remain the same. This is not the case for hydrogen replacing natural gas. However, this does not diminish hydrogen's advantages as an energy carrier compared to electricity.

3) There is no business case for renewables, including green hydrogen or blue hydrogen, in the absence of the need to decarbonise the economy. Renewables have succeeded in the past few years in power generation thanks to carbon pricing (e.g. ETS), subsidies (CfD, FIT) and mandatory targets. The same approach can be taken to decarbonise the 75% of emissions not covered by power generation. But, as noted above, the focus should be on decarbonisation not specific technologies. So, for example, targets for replacing natural gas with low or zero

carbon heating could provide the incentive for consumers to switch (or utilities to convert networks on their behalf). This could be via electrification (heat pumps) or by converting to hydrogen, which may be simpler and more cost effective for consumers. In turn, this would ensure that potential suppliers of low carbon energy solutions would know they would have a market for their product. It may be tempting to choose a particular route when setting such targets, e.g. green hydrogen or electrification. However, this runs the risk of choosing a more expensive solution and thereby not meeting the Energy Union's priority of affordable, as well as sustainable, energy. A high enough ETS price would also create the incentive for industry to choose the optimal decarbonisation route – but current levels are not high enough to enable the full-scale switching needed. If they were, it would have happened already.

4) Policymakers should focus more on understanding the risks of different approaches rather than picking winners. All the papers which outline future scenarios for decarbonisation rest on assumptions about costs and the build-up of supply chains etc. Whilst these are all sound approaches, they remain based on assumptions none the less, and reality can prove different. 15 years ago, nuclear seemed a good option for decarbonisation but EdF's new Finnish, French and UK plants are massively delayed and over budget. So policymakers should avoid the temptation to put all their eggs in one basket and instead focus on how they can create a framework that means they are not dependent on a single pathway. This should allow industry and consumers to invest in technologies which they believe will give them the best outcome. Some will get this wrong and some will get this right but this is a better outcome than everyone getting it wrong. Engineers have the concept of a 'single point of failure,' which means that a whole structure or system (e.g. a bridge) can fail if one part fails. Betting on one technology or approach, as the Commission seems to want to do, risks a similar weakness. In this case, if green hydrogen proves more costly or difficult to achieve in sufficient quantity, the EU will miss its decarbonisation targets. It is ironic that the Commission has rightly focussed on creating markets for natural gas so different suppliers compete to get the best deal for customers but wishes to take a different approach for hydrogen.

Online workshop on Renewable Hydrogen – Q&A

Ronnie Belmans, Dolf Gielen and Catrinus Jepma provided answers on the following questions:

- What about blue H_2?

  For blue hydrogen, the greenhouse gas situation of the extraction and transport of methane has to be taken into account. 1% of CH_4 losses leads to 25% equivalent CO_2 exhaust. A detailed comparison has to be done and it is far from simple.

- I see some contradiction between saying that targets would only be considered at demand level (for specific sectors) and then that we should look first at production within the EU and not at imports from North Africa. On top of that, both internal production and imports seem to be needed according to most of the projections. Could you clarify this?

  A real calculation of the need for hydrogen to produce synthetic fuels and for feedstock in the industry is needed to see whether sufficient renewable energy is available in Europe as such. If the answer is yes, the cost has to be compared with imports. The greening of hydrogen is potentially very well possible.

- Is the availability of water a potential constraint on green H_2?

  Regarding the water needs for hydrogen, that is a myth. You need 16 l of water per kg of H_2. So for 30 EJ hydrogen per year (our global TES scenario for 2050) you need 4 million m^3 water. Our annual water consumption is about 500 l/person/day, so that's the water consumption of the Netherlands for half a day, or four big desalination plants operating for a day.

- On blue vs green hydrogen: how can we ensure we move quickly away from blue hydrogen to green hydrogen?

  This is a double problem. First, the cost is determining the choice between green and blue. Second, the greenhouse content of 'blue' (including methane leakage) and 'green' (the energy mix in the power system) has to be assessed correctly.

- Can guarantees of origin be used to manufacture green hydrogen?

  Guarantees of origin have to be combined with correct measures of the greenhouse gas content.

- Taking into account the relatively low efficiency of hydrogen production, the argument that delivering end-user energy in the form of hydrogen is more efficient than using electricity seems doubtful. So far, the numbers show that conversion to hydrogen is the least efficient use of surplus electricity. Is it possible to see the calculations behind your statements?

  A good overview may be found in our FSR paper (Vingerhoets/Belmans).

- Some sources say transporting H_2 in pipelines is efficient only up to 1500km. Do you have evidence for/against?

  Pipelines as such are always very efficient as a gas transport system.

- What are the views of the panellists on imposing a quota for clean (preferably green) gases in Europe towards 2030 that would also apply to hydrogen and industrial hydrogen?

  - Look at applications first. Why push hydrogen to places where it is not efficient (both technically and economically)?

  - Imposing carbon-neutral or green gas mandatory quotas in one way or another (e.g. mandatory 10% admixing with the option to do so by way of GoOs) would automatically create a market for green gasses boosting supply. I fully endorse this view, which is why I have mentioned the example in the Netherlands where mandatory admixing of green kerosene for aviation turns out to immediately stimulate investment in producing it. The market is apparently convinced that as soon as mandatory admixing is the rule, green kerosene market prices are likely to satisfy acceptable business conditions, and that it may pay to be first mover.

- IRENA’s Global Renewables Outlook: Energy transformation 2050 does not mention hydrogen as part of the second (of five) technology pillar, ‘increased power system flexibility.’ Isn't IRENA too electricity-focused?

  The GRO has significant green hydrogen consumption. For the first time, it shows the critical role of green hydrogen in deep decarbonisation perspective analysis. Electrification is listed as one of the five pillars and green hydrogen (from renewable electricity) is also listed as a separate pillar. It is therefore considered in the context of sector integration. Indeed, IRENA thinks that direct electrification is initially preferable for economic and efficiency reasons, but we will also need significant amounts of hydrogen for deep decarbonisation.

- Gas for Climate recommends a binding 10% target for suppliers (demand targets, not production). Why?

  Mandatory admixing is a much easier and cheaper policy device than keeping subsidising supply, because subsidies are always difficult to end once they are introduced, especially it they relate to both CAPEX and OPEX (as was and is the case with regard to renewable energy production).

- Is the hydrogen demand use of hydrogen as such or an intermediate for synthetic fuels, for instance for air transport?

  As an energy carrier, hydrogen as such is less important. Hydrogen has a number of physical characteristics that make it very difficult to use as an energy carrier. When electricity can be used directly, never change it to another carrier. For mobility applications, other molecules, synthetic fuels (methanol, ethanol, methane, ethane, ammonia) are a far better choice, and also for long distance transport (from deserts or Australia to Europe). See the paper at https://fsr.eui.eu/publications/?handle=1814/66205

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