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POLICY BRIEF

The Regulatory Approach to Power-to-Gas Facilities

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Highlights

- "Clean hydrogen", one of the main pillars of the EU decarbonisation strategy, will be mostly produced by power-to-gas facilities.
- The regulatory and ownership rules applicable to power-to-gas facilities are to be defined. A competitive setting is to be preferred. However, in an initial period, in case the market were not to show sufficient interest, the involvement of TSOs/DSOs to kick-start the green hydrogen sector could be considered.
- One possibility for such an involvement could be an approach similar to that envisaged in the Clean Energy Package for electric vehicle charging and electricity storage facilities.
- This Policy Brief proposes a variant of that approach that would introduce competition in the production and (wholesale) supply of green hydrogen, even while power-to-gas facilities are operated by TSOs/DSOs.

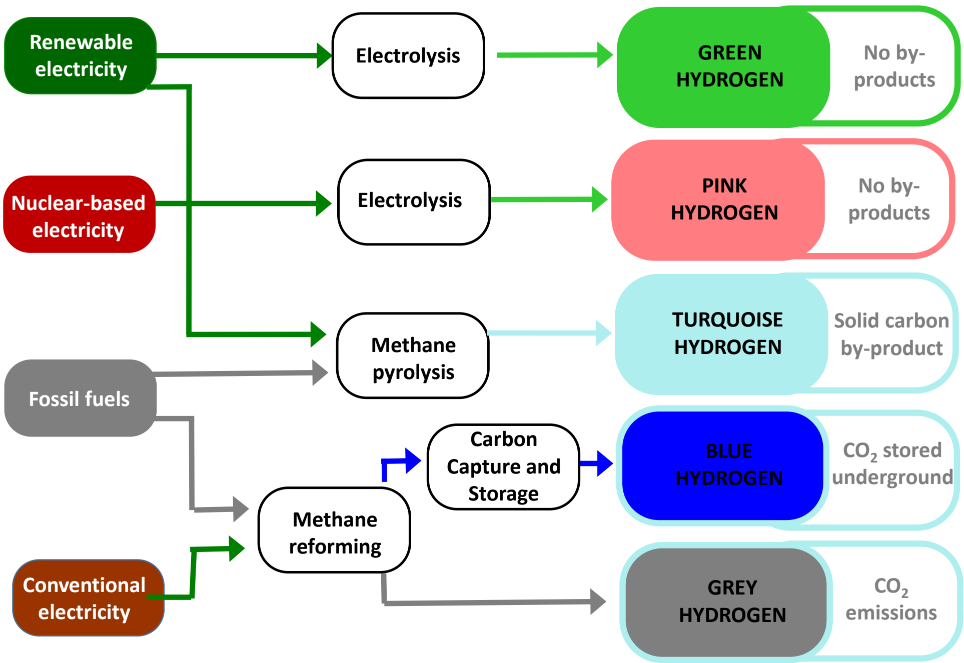
1. The author is grateful for comments received on the draft of this Policy Brief from many colleagues at the Florence School of Regulation, including Leonardo Meeus, Ilaria Conti and Tim Schittekatte, as well as from Ronnie Belmans of KU Leuven.

Green Hydrogen and its Production in Power-to-Gas Facilities

"Clean hydrogen" will be one of the main contributors to the EU decarbonisation strategy, the other pillars being energy efficiency and a greater electrification of energy consumption using electricity produced from renewable energy sources.

Hydrogen cannot be found as such in nature, but needs to be produced through chemical processes. The carbon footprint of hydrogen depends on the process used for its production and several colours – green, blue, turquoise, grey, brown, black, yellow, pink - have been associated with hydrogen produced by different processes.

The following chart shows some of the processes which can be used to produce hydrogen and the colour which has been associated with each of them.



Adapted from: L. Strohmeier, Grey, Blue, Green, Turquoise – The Colours of Hydrogen, delphidata, 10 December 2020.

The carbon-neutral scenario that the European Commission envisages for 2050 is based mostly on green hydrogen, the only carbon-free "colour", at least at the process level[2]. Green hydrogen can be produced through electrolysis[3]. This is a well-known process where electricity is used to split water into

2. Blue hydrogen production with carbon capture and storage/use, as a process, can reduce the hydrogen carbon footprint by approximately 90% compared to grey hydrogen production. Turquoise hydrogen production produces solid carbon as a by-product and therefore, as long as the carbon remains fixed in its solid form, can achieve a similar carbon footprint performance.

3. Green hydrogen can also be produced, *inter alia*:

- by microalgae, which convert water and carbon dioxide into hydrogen through a biochemical process using sunlight. However, while this process was discovered more than eighty years ago, it has until recently remained a biological curiosity and it is still far from reaching commercial viability. Moreover, it competes with the use of algae in the cosmetic industry, where it currently delivers higher value added;
- from biomass gasification. If combined with affective carbon capture and storage, this process might in fact have a negative carbon footprint. However, the economics of this process makes its commercial viability still uncertain.

oxygen and hydrogen. If the electricity is produced from renewable energy sources, there are greenhouse gas emissions neither in the production of electricity, nor from the chemical reaction in the electrolyser. Efforts are now being made to increase the capacity of electrolysers so that they can reach "network scale"[4].

Green hydrogen will be used to replace natural gas – and, gradually, hydrogen with higher carbon footprint - in hard-to-abate processes. Green hydrogen could also play a role in providing some of the increasing flexibility required by the electricity system in the face of a greater penetration of renewable-based generation, by storing energy over longer periods of time and transporting it over longer distances, more efficiently than it could be done with electricity.

In its Hydrogen Strategy[5], the European Commission refers to market analysts' forecasts of up to 8.7 GW of electrolyser capacity by 2030, of which 57% in Europe. However, reaching the ambitious energy and climate targets to which the European Union (EU) is committing requires harnessing all the opportunities associated with hydrogen, for which a strategic approach is needed. In this context, in the same Strategy, the European Commission launched a plan to reach 80 GW of electrolyser capacity by 2030, half of which within the EU and the other half in Europe's neighbourhood, with export of green hydrogen to the EU.

The envisaged massive increase in electrolyser capacity in the EU calls for clarity on the regulatory approach to these installations and, more generally, to power-to-gas facilities. At the moment there is significant interest among Transmission System Operators (TSOs), particularly in the gas sector, to develop power-to-gas facilities, which they somehow consider as part of the network infrastructure. This claim is supported by the need for coordination between the deployment of these facilities and the development of the electricity and gas networks. This is especially the case for those power-to-gas facilities which are mainly aimed at providing flexibility to the electricity system.

Interestingly, in its recent proposal for the revision of the TEN-E Regulation[6], the Commission has included electrolysers among the energy infrastructure categories being eligible for Project of Common Interest (PCI) status. All the other categories refer to network infrastructure or storage facilities.

Unbundling

Unbundling has been one of the main tenets of the energy sector liberalisation process in the EU. The rationale for unbundling is clear: operators of regulated activities – such as TSOs - should not have the possibility of using their monopoly position in such activities to distort competition in other, contiguous, segments of the energy value chain, which are instead suitable for a competitive market structure. If the rationale is clear, its implementation in EU legislation has been more difficult. Increasingly stringent unbundling requirements for electricity and gas TSOs were introduced by the three legislative packages of 1996-98, 2003 and 2009. For the 2009 (Third) Energy Package, the Commission pro-

4. At present, the largest electrolysers being developed in power-to-gas projects are in the order of 100MW, while most of them are in the tens of MW range. See, for example, IRENA, *Hydrogen: a renewable energy perspective*, September 2019, available at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf.

5. Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions: A hydrogen strategy for a climate-neutral Europe, Brussels, 8.7.2019, COM (2020) 301 final.

6. Proposal for a Regulation of the European Parliament and of the Council on guidelines for trans-European energy infrastructure and repealing Regulation (EU) No 347/2013, Brussels 15.12.2020, COM(2020) 824 final.

posed strict ownership unbundling rules, but, in the end, a "third way" - the Independent Transmission Operator (ITO) model - was added for pre-existing vertically-integrated undertakings. In this model, transmission system operation remains part of the vertically-integrated undertaking, but subject to stringent structural and behavioural requirements.

Now, with the expected rapid increase in the penetration of power-to-gas facilities in the EU energy sector, the question arises of which unbundling requirements should be envisaged for them. The answer to this question requires answering another question: should these facilities be considered as network infrastructure?

In principle, there seems to be no good reason to consider power-to-gas facilities as network infrastructure. They are energy conversion facilities, similar in nature to the facilities converting energy in the opposite direction – from gas-to-power: the well-known gas-fired power plants. In fact, power plants typically produce electricity by converting other forms of energy (chemical energy in fossil fuel-based thermal power plants, potential or kinetic energy in hydroelectric power plants, …). And it has never been suggested that gas-fired power plants – or any other electricity production facility – be considered as network infrastructure.

So, what is it so special about electrolysers and, more generally, power-to-gas facilities that different views have emerged about their regulatory treatment?

One difference is clear. When the unbundling debate started – in the 1990s in the EU, earlier in some national jurisdictions, such as the UK – electricity generating plants at network scale had been around for more than a century[7]. Therefore, not only the technology, but also its economic parameters and commercial viability were well-know and rehearsed, and investors could be attracted to develop generation capacity even in an unbundled setting, i.e. even without regulatory support.

Instead, while electrolysis was discovered more than two centuries ago, there is still significant uncertainty over the future trend of its costs and therefore on whether and when it will become competitive with respect to other hydrogen producing technologies and natural gas (which hydrogen is expected to replace in hard-to-abate processes). In its Hydrogen Strategy, the European Commission reports that electrolyser's costs, which already decreased by 60% over the last ten years, are expected to halve by 2030. It also reckons that, in regions with cheap renewable electricity, electrolysers are expected to be able to compete with fossil-based hydrogen by 2030. However, a recent Report by the Florence School of Regulation, reviewing the state of play with hydrogen production technologies, found a wide variation in forecasts of future production costs for green and blue hydrogen[8]. The competitiveness of green hydrogen will also depend on the way in which some policy tools to promote decarbonisation and renewable energies - such as the EU Emission Trading System (ETS) and renewable-support schemes – will be implemented and which price signals they will provide[9].

These uncertainties on the future costs of producing (green) hydrogen may discourage independent operators to enter the hydrogen production business at this early stage and invest in electrolysers, for sure not to the extent required to reach the scale which

7. The world's first electricity generating stations were opened in 1882 at Holborn Viaduct in London and at Pearl Street in Manhattan, New York City. In both cases, DC current was used to power street lighting.

8. A. Piebalgs, C. Jones, P.C. Dos Reis, G. Soroush, J.-M. Glachant, *Cost-Effective Decarbonisation Study*, 24 November 2020. Available at: Cost-effective decarbonisation study | Florence School of Regulation (eui.eu)

9. With respect to grey hydrogen, which is the standard hydrogen production at the moment, blue hydrogen will not incur most of the costs associated with the need to procure EU ETS allowances. Green hydrogen, beyond not being charged under the EU ETS, will also be likely to benefit from renewable support schemes.

will, in turn, deliver the expected significant reduction in electrolyser production costs.

Another difference between gas-fired power plants and power-to-gas facilities is that the latter, as already mentioned, may be able to provide flexibility to the electricity system. Therefore, while in most cases, the need for coordination of the siting of power-to-gat facilities with network development is very similar to that of new power stations, to the extent that power-to-gas facilities provide flexibility to the electricity system, greater coordination of their deployment with the needs of such a system might be needed.

These considerations should inform the choice of the most appropriate pathway for the regulation of power-to-gas facilities.

Possible Regulatory Approaches

In principle, there are several possible regulatory approaches which could be applied to power-to-gas facilities. The following two are at the extremes of what is probably a continuum of options:

- Assigning the operation of power-to-gas facilities to TSOs (and Distribution System Operators – DSOs), on the assumption that these facilities are part of the network infrastructure. This approach would then require power-to-gas activities to be regulated as any other network activity;
- Consider power-to-gas as a competitive activity and therefore, under the existing unbundling provisions, prevent TSOs (and DSOs) from owning and/or operating them.

The choice of approach in turn influences the mechanism which could be adopted to support power-to-gas activities, in case such a support is deemed necessary. In a competitive setting, the experience of renewable energy support over the last twenty and more years provides plenty of guidance on how to structure, calibrate and allocate such a support and on the mistakes to avoid. Instead, under a regulated setting, support to power-to-gas activities could be provided through the determination of the allowed revenues of the TSOs and DSOs. This note does not focus on whether support to power-to-gas activities is warranted, even though it seems difficult that the fast pace of deployment of these technologies required to meet the ambitious energy and climate targets could be achieved without some level of policy intervention, at least in the initial development stage. Here instead we focus on which organisational and regulatory structure could best accompany this activity towards its maturity. It is to be hoped that, once maturity is reached, power-to-gas activities would achieve commercial viability, within the general policy framework aimed at promoting decarbonisation, but without the need for specific additional support.

In general, when considering whether to regulate a new activity, the burden of proof should be on those who claim that such an activity could not be developed in a competitive setting, since competition, where possible, is the first-best solution for efficient resource allocation and for maximising benefits for consumers. Power-to-gas should be no exception in this respect.

However, to the extent that the market is unable to develop power-to-gas facilities at the pace required for the EU to meet its decarbonisation goals, some form of regulatory intervention may have to be considered. In this context, beyond the extreme approaches outlined above, a hybrid one might consider power-to-gas a potentially competitive activity, but also recognise that, during an initial period, it might require regulatory support. Under this approach, if no interest by independent operators to enter into the power-to-gas business is detected, including though the use of tendering procedures for the allocation of support, TSOs and, possibly, DSOs could be allowed to build, own and operate power-to-gas facilities, under regulated conditions. The market would then be tested at regular intervals and, as soon as interest from market parties is detected, TSOs and DSOs would have to divest and let market forces work. This approach would be similar to the one introduced for electric vehicle charging infrastructure and electricity storage by the Clean Energy for All Europeans package[10].

The Virtual Power-to-Gas Plant Model

However, there is also a variant of this hybrid approach which might promote competition in hydrogen production from electrolysers at an early stage, while sheltering independent actors from the risks associated with a still developing technology, at least when it comes to network-scale installations. In this variant, TSOs and DSOs would still be allowed to develop power-to-gas facilities until the market shows interest in developing them. However, TSOs and DSOs would be required to auction the capacity off to market actors who, having title to (renewable) electricity, could use such capacity to produce (green) hydrogen. The installation would still be owned and technically run by the TSOs and DSOs, but the commercial decisions – on when and how much hydrogen to produce and where to sell it – would be taken by the market actors who were assigned the capacity in the auctions.

In this way, independent actors will not be required to face the risk associated with investing in a technology which, at network scale, is still in its development stage, and which is likely to see significant cost reductions in the coming years. Such a risk, and any stranding of costs due to technological progress, would be absorbed by the TSOs and/or the DSOs and covered by regulation. The reserve price in the auctions would have to cover the cost of capital (return of capital and return on capital), as well as the operating costs for the power-to-gas facility. In this respect, the reserve price might usefully have a two-part structure to reflect the cost structure of the electrolysers: a fixed part, covering the (fixed) capital and maintenance costs and charged on an allocated-capacity basis, and a variable part, covering the operational costs[11] and charged on a utilisation basis. Over time, the regulators might decide that the auction reserve price be adjusted, at least partially to reflect the costs of the latest electrolyser technology. The extent of this adjustment would have to consider the trade-off between maintaining a level of competitiveness of the TSO/DSO power-to-gas facilities, while, at the same time, still leaving headroom for independent developers to enter into the power-to-gas business.

Beyond paying the (two-part) auction clearing price, the market actors to which the electrolyser capacity is assigned in the auctions would have to procure and pay for the electricity required to produce the hydrogen in the electrolyser and will receive the title to such hydrogen which they can then sell in the nascent hydrogen market, in which this approach will favour the entry of a multiplicity of sellers. It would also be possible that different assignees of the electrolyser capacity produce hydrogen of different shades, by feeding the electrolysers with electricity produced from different sources. A statutory system of Guarantees of Origin with an enhanced role, as proposed in a

10. Article 33 (for electric vehicle recharging points) and articles 36 and 54 (for electricity storage) of Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast). The possible involvement of network operators in power-to-gas projects was already mentioned in a report commissioned by the European Commission and published in 2019: *Potentials of sector coupling for decarbonisation - Assessing regulatory barriers in linking the gas and electricity sectors in the EU*. Available at: Potentials of sector coupling for decarbonisation: Assessing regulatory barriers in linking the gas and electricity sectors in the EU | Energy (europa.eu).

11. But not the cost of the electricity used to produce hydrogen, see further on in the text.

Report[12] recently published by the Florence School of Regulation, could enable such a possibility.

Note that this approach is not conceptually new, as it mimics, in its logic, the Virtual Power Plant (VPP) schemes which were successful in dealing with wholesale market concentration issues in the early stages of the energy sector liberalisation[13]. While the VPP concept is now mostly associated with the aggregation of small-scale, typically decentralised resources, including renewable-based generation, it was historically used to refer to the auctioning off of the commercial operation of generation capacity of incumbent undertakings, to limit their market power and to facilitate market entry by independent actors[14].

As in the case of the "historic" VPPs, the variant outlined above would also be robust to the appearance of independent hydrogen producers investing in new power-to-gas facilities alongside the TSO/DSO-owned facilities. If the terms under which the capacity of TSO/DSO-owned facilities is allocated were adjusted over time to maintain their competitiveness in the face of technological developments, or to the extent that some of this capacity were left unallocated, full cost recovery could not be guaranteed and the gap would have to be covered by other TSO/DSO revenues, subsidies or grants. This could be in any case in line with the stated EU policy of promoting and incentivising a fast-paced development of the hydrogen sector. In fact, for some facilities which play a role in providing flexibility for the electricity system, it might be a more efficient way of doing it than subsidising the independent development of power-to-gas facilities, at least until the sector reaches some level of maturity.

Power-to-gas and sector coupling

From another perspective, the variant outlined above could be considered in some ways similar to the explicit allocation of the capacity of cross-border electricity interconnectors. In this case the capacity is owned and operated by the TSOs, but the right to use it is assigned through auctions and the assignees of such capacity determine its use through nominations. The explicit allocation of interconnection capacity has now been replaced by the implicit allocation through market coupling and therefore one could be tempted to ask whether power-to-gas facilities owned and run by TSOs/DSOs, with the capacity auctioned off to market actors, could be an initial stage of longer-term arrangements enabling the integration of the electricity and hydrogen sector through a form of "sector-coupling" similar to cross-border electricity market coupling. This is clearly an interesting proposition. However, while cross-border electricity exchanges are clearly a network activity and do not involve any energy transformation, but only the transmission of electricity over potentially-congested network elements, power to gas is a process, an energy transformation – as already indicated, not too dissimilar, in nature, from (gas-fired) power generation – and there is no reason why, in the longer run when this technology matures also at network scale and its commercial viability is more established, competition should not be let to develop and TSO/DSOs leave this activities to market forces.

12. A. Pototschnig, I. Conti, *Upgrading Guarantees of Origin to promote the achievement of the EU renewable energy target at least cost*, Research Project Report, January 2021. Available at: QM-03-21-034-EN-N.pdf (eui.eu)

13. A somewhat similar approach, applied to electricity storage was proposed in T. Brijs, D. Huppmann, S. Siddiqui, R. Belmans, *Auction-based allocation of shared electricity storage resources through physical storage rights*, Journal of Energy Storage, 7 (2016) 82–92.

14. For example, in the context of the acquisition, in 2000, of 34.5% of EnBW by Electricité de France (EdF), which was judged anti-competitive by the European Commission, EdF agreed, as a remedy, to provide competitors with generation capacity through a VPP (thus avoiding capacity divestment which was opposed by the government and the public, as it would have meant the breaking up of the French nuclear park). Later on, VPPs in the same meaning were implemented by Electrabel in Belgium in 2003 and 2006, by Endesa/Iberdrola in Spain in 2007 and by E.ON in Germany also in 2007.

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