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Blending hydrogen from electrolysis into the European gas grid

A joint modelling assessment of the European Power and Gas systems with METIS

Kanellopoulos K., Busch S., De Felice M., Giaccaria S., Costescu A.

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Abstract

In 2020, the European Commission launched a hydrogen strategy for a climate-neutral Europe, setting out the conditions and actions for mainstreaming clean hydrogen, along with targets for installing renewable hydrogen electrolysers by 2024 and 2030. Blending hydrogen alongside other gases into the existing gas grid is considered a possible interim first step towards decarbonising natural gas. In the present analysis we modelled electrolytic hydrogen generation as a process connecting two separate energy systems (power and gas). The analysis is based on a projection of the European power and gas systems to 2030, based on the EUCO3232.5 scenario. Multiple market configurations were introduced in order to assess the interplay between diverse power market arrangements and constraints imposed by the upper bound on hydrogen concentration. The study identifies the maximum electrolyser capacity that could be integrated in the power and gas systems, the impact on greenhouse gas emissions, and the level of price support that may be required for a broad range of electrolyser configurations. The study further attempts to shed some light on the potential side effects of having non-harmonised H_2 blending thresholds between neighbouring Member States.

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Authors

Konstantinos Kanellopoulos

Sebastian Busch

Matteo De Felice

Sergio Giaccaria

Anca Costescu

Executive Summary

In 2020, the European Commission launched a hydrogen strategy for a climate-neutral Europe, setting out the conditions and actions for mainstreaming clean hydrogen, along with targets for installing renewable hydrogen electrolysers by 2024 and 2030. Blending green hydrogen alongside other gases into the existing gas grid is considered a possible interim first step towards decarbonising natural gas. Some EU countries have already defined blending targets for 2030.

In the present analysis, we model electrolytic hydrogen generation as a process connecting two discrete, and as yet not integrated, energy systems (power and gas). Within the various configurations analysed, electrolysers are operated under diverse market arrangements in the power system but are always limited by the quality requirements in the gas system.

Recent literature suggests that hydrogen can be injected into the gas grid up to about 5-10% vol in the immediate future, without the need for major modifications to transmission infrastructure and end-consumer installations. Towards the end of the decade we could see an increase to 15-20% vol, after making the necessary changes to the infrastructure and affected consumer installations.

With a 5% blending threshold, we calculate that up to 18.4 GW electrolyser capacity could be integrated EU-wide. This is three times the EU target for 2024. With a 20% blending threshold, the figure rises to 40-70.8 GW. These figures are in the same order of magnitude as the capacities quoted in the EU Hydrogen Strategy and in published national strategies of several Member States (ES, NL, FR, IT, DE, PT), and satisfy the EU target for 2030 of 40 GW.

The volume of hydrogen produced by electrolysis that may be introduced into the gas grid, considering a fixed upper threshold (i.e 20%), is largely dependent on the way the electrolysers are integrated into the power market and, in the case of purely market-driven arrangements, on the level of price support.

To take stock of this, a significant number of alternative electrolyser configurations were considered, based on arrangements where electrolysers are either connected to renewable electricity (wind or solar driven configurations) or are operated based on price signals from the power market. Although the cost of producing hydrogen via electrolysis is expected to fall sharply, it is not expected to compete, without support, with natural gas by 2030 (based on long-term cost projections). We therefore also considered alternative price support mechanisms in the purely market-driven configurations.

The modelled scenarios give us a wide range of values of the annual volumes of hydrogen produced and potentially blended with natural gas. When electrolysers are operated on the basis of market signals, this is affected primarily by the price support. We found that a price support of 30-50 Euro/MWh_e would lead to substantial electrolyser operation. On the other hand, when electrolysers are linked, either directly or contractually, to renewable generation, the operating hours are primarily affected by the type of renewable resource (wind or solar), and the contractual arrangements (type of linkage, as described below, and the willingness to pay in the case of a hybrid arrangement).

We find that due to the temporal correlation of gas demand and wind/solar availability, only a fraction (50-85%) of the available green electricity can be converted to hydrogen and blended into the gas network. This fact determines the maximum hydrogen production that can be blended into EU gas systems, with a threshold of 20% volume, to around 4.5 million tonnes. At this threshold, almost half of the 10 million tonnes of hydrogen to be produced according to the EU Hydrogen Strategy could be blended into the gas system.

Our analysis shows that wind consistently yields higher outputs over solar and market-driven dispatch. Market-based setups (market-driven or hybrid) lead to both lower costs and lower carbon-intensity for hydrogen, while for the renewable-driven setups, our conclusions are mixed: wind allows for potentially lower cost, while solar allows for hydrogen with lower carbon intensity. Adding further renewable capacity to the power system lowers both the cost and the carbon intensity of hydrogen production. In fact, we found that emissions of CO_2 increase if electrolysers are introduced without adding new renewable capacity, except for purely market-driven setups with no price support. In this case hydrogen would be generated from electricity that would otherwise be curtailed. In all other cases, additional electricity production from conventional sources would be required, causing an overall (EU-wide) increase of CO_2 emissions. However, our modelling suggests that a buffer storage of just a few hours can reduce the carbon intensity of hydrogen produced with electrolysis and blended into the gas network by as much as 40%.

Lastly, the presence of non-harmonised hydrogen thresholds in neighbouring countries, where important gas trade takes place, could induce significant trade barriers and constraints to the upstream grid. This can be addressed by minimising the differences in rules related to the maximum allowed concentration of hydrogen

in gas networks in order to avoid distortions, especially for neighbouring countries with high gas exchange volumes.

Report highlights:

- Approximately 40-70.8 GW of electrolysers could be integrated EU-wide, if allowed to inject hydrogen into the gas grid up to a 20% blending threshold. The corresponding maximum hydrogen production would be approximately 4.5 million tonnes under the most favourable wind-driven configuration.
- Maximum H_2 production is severely limited by the fact that only a fraction (50-85%) of the available green electricity (in RES linkage schemes) can be converted to H_2 due to the temporal correlation of gas demand and wind/solar availability constraints.
- Market-driven or hybrid schemes lead to a lower H_2 carbon intensity compared to direct linkage with the RES resource. As additional RES capacity is introduced, the carbon intensity of hydrogen (additional CO_2 due to the operation of the electrolysers) drops significantly.
- A buffer storage of just a few hours can reduce the carbon intensity of hydrogen produced with electrolysis and blended into the gas network by as much as 40%.
- The presence of non-harmonised H_2 thresholds in neighbouring countries, where important gas trade takes place, could induce significant trade barriers or hydrogen injection constraints to the upstream grid. This could largely be avoided if efforts were dedicated to harmonising, where, possible, the rules related to the maximum allowed concentration of hydrogen in gas networks, particularly for neighbouring countries with significant cross-border flows.

Introduction

Hydrogen is a strategic priority for the implementation of the European Green Deal. Its potential to store carbon-free energy in chemical form makes it an energy carrier option particularly suited for hard-to-decarbonise sectors such as industrial processes or heavy-vehicle transport, as a vector for renewable energy storage, or for stand-alone applications. However, today hydrogen is mostly produced from fossil fuels and represents only a small fraction of the European energy mix.

To capitalise on the future prospects of the EU Green Deal in a comprehensive manner and to spur economic recovery from the COVID-19 crisis at the same time, the European Commission launched a hydrogen strategy for a climate-neutral Europe in 2020 (1) that sets out framework conditions and a list of actions for mainstreaming clean hydrogen. It also includes milestone targets for installing at least 6 GW of renewable hydrogen electrolysers in the EU by 2024 and 40 GW of renewable hydrogen electrolysers by 2030. It is expected that elements of a new hydrogen infrastructure will be created gradually and that in the initial phase, demand will be met by production close to consumption sites. The strategy also considers the blending of hydrogen in the natural gas network at a limited percentage as a further option to facilitate – in particular during a transitional phase – the uptake of hydrogen. A range of studies and reports indicate that the presence of hydrogen in the gas grid up to a maximum of approximately 5-10% vol would be feasible without major modifications in the gas infrastructure and end consumer installations. A further increase to 15-20% vol appears feasible after modifications on system components based on current knowledge. Raising the content of hydrogen beyond that would require R&D for some categories of consumers and could be considered for the mid to long term.

Technical challenges aside, the regulatory framework must be in place for the strategy to achieve its goals. Enabling the access of renewable gases to the gas grid was marked as one of the key priorities in the European Gas Regulatory Forum in Madrid[1], which called for the creation of a market for renewable and low-carbon gases. The conclusions also proposed rules for the deployment of infrastructure along various pathways, including blending in the grid to guarantee broader availability of renewable and low-carbon gases for end-users.

Considering the capacity of the gas system to store energy as methane, injecting hydrogen into the gas grid might allow for an increased penetration of renewable energy in the system, in the form of green hydrogen (2). Many EU countries are considering allowing the injection of hydrogen into their natural gas network, some of them defining blending targets to be reached in 2030 (3).

[1] https://ec.europa.eu/info/sites/info/files/energy_climate_change_environment/events/documents/34th_mf_conclusions_final.pdf

1 Overview of the methodology and input

The current study is an assessment, based on modelling, of the potential for renewable and low-carbon hydrogen admixtures in the European gas system as an interim first step towards decarbonising gas. The study aims to identify the maximum electrolyser capacity that could be integrated with technical or economic criteria, the costs and benefits, the level of price support that may be required, as well as the impact of potential barriers, such as the existence of non-harmonised H_2 blending threshold levels between member states. In particular the following questions are addressed:

1. What are the electrolyser capacities that could be integrated under multiple assumptions on blending thresholds of H_2 content in the gas networks? What is the optimal local H_2 buffer storage at electrolyser facilities that will allow electricity generation and hydrogen production to match the constraints in the respective systems? How do these results relate to recently published H_2 figures such as the H_2 strategy?
2. What will be the operating profile of the electrolysers in the above scenarios under (a) different market integration schemes and (b) varying assumptions of price support?
3. What could be the implications of non-harmonised H_2 threshold levels between member states on cross border trade and/or H_2 generation?

Note : All results referring to the cost of hydrogen via electrolysis in the present study hold under the EUCO3232.5 scenario fuel and CO_2 price assumptions and thus should not be considered as valid in market conditions such as those witnessed in the second half of 2021, when the unprecedented surge of the natural gas price occured.

1.1 Scenario setup and admixture thresholds

The study is conducted with METIS, by simulating the European power and gas systems jointly on a context based on the EUCO3232.5 scenario in 2030. The proposed modelling approach is based on one-node-per-country, Europe-wide representation of the transmission networks of power and natural gas. The analysis focuses on the inter-linkages between power and natural gas transmission networks, and does not consider the interaction between transmission and distribution systems.

The scenarios are parametrised in order to provide answers to the main questions posed above. This parametrisation is based on the following:

1. The thresholds of H_2 content in the gas network
2. The market integration schemes
3. Required price support schemes
4. The adoption of non-harmonised H_2 concentration levels

1.1.1 Thresholds considered for the admission of H_2 into existing gas infrastructure

The technical readiness of existing gas infrastructure and end use equipment to handle safely and reliably hydrogen-natural gas mixtures is a topic of ongoing debate and research. The technical association of the European Gas industry (4) recently published their views on the actual and mid-term future readiness of various components of the gas network to accept hydrogen-natural gas admixtures. In particular, major components of the gas network and end-uses are able to accept 5-10vol% (depending on the end use) in natural gas without modification. After modifications and retuning of equipment this concentration is deemed possible to increase to 15-20%. In power generation, gas fired gas turbines are sensitive to the gas composition, affecting the Wobbe Index, which is permitted to fluctuate in a given pre-set range. Information provided by two major gas turbine manufacturers (5) (6) affirm the capability of a wide range of their gas turbine models to operate with natural gas – hydrogen admixtures at or above 15%vol. It is however stated that the "associated fuel system for the combustors are typically only configured for a maximum of 5%vol hydrogen and would require upgrading".

Table 1. Admixture threshold levels

	% vol	% HHV
Level-1 (Early)	2-5	0.6-1.6
Level-2 (Mid)	15-20	5.1-7.1
Level-3 (Advanced)	50	23.4

Source: JRC, 2021.

Based on the above there appears to be some consensus on what could be considered as threshold levels in terms of their applicability in the short – mid and longer term. These listed in Table 1 above.

Level-1 thresholds may be adopted without major technical or regulatory interventions at the transmission and distribution level. This level of thresholds could be considered in a first-transitory phase which could take place in the immediate future.

Level-2 thresholds appear to be possible without major adaptation of the existing gas infrastructure (4). However the impact of H_2 on the Wobbe Index (and other gas quality parameters) may require modifications of end-use appliances on certain types of consumers, most notably transformation assets in power generation and sensitive industrial end-users. The second level of thresholds could be considered in a second-transitory phase towards the end of the decade.

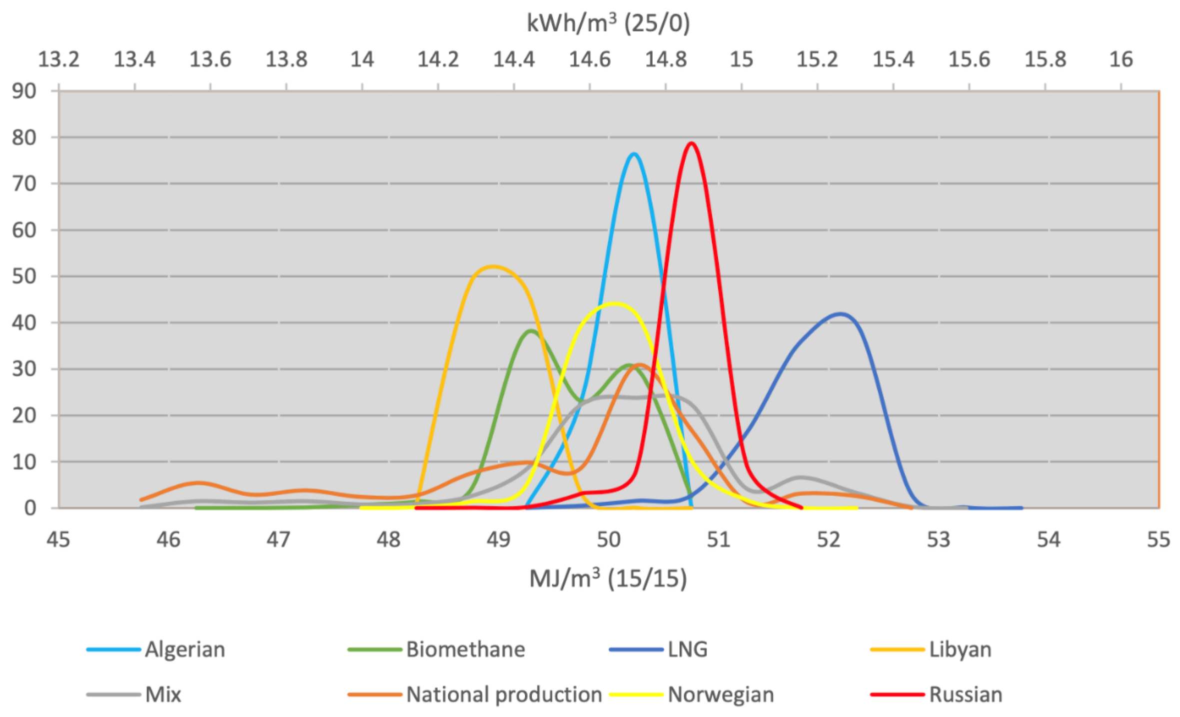
Level-3 thresholds could be a final interim step towards a hydrogen grid. Studies show technical feasibility at the distribution level. It is likely that this level of hydrogen concentration would not be equally feasible for all types of networks/end uses. The present analysis has not looked into hydrogen content at the level-3 thresholds since it focuses on 2030, by which time hydrogen production capacity is unlikely to have scaled up to the level required to support such concentration levels.

1.1.2 Wobbe Index bandwidth constraints

One further constraint not clearly delineated in the available literature on H_2 admixtures in the gas network is a lower bound for H_2 concentrations in the gas system. The lower bound would be dictated by the requirement by TSO/DSOs to maintain the variation of the gas Wobbe index (WI) at a bandwidth which is permissible by consumer installations.

ENTSOG (European Network of Transmission System Operators for Gas) reports: "Gas quality values are not uniform on the supply side. While several sources are characterized by a narrow WI range (Algerian, Russian, Libyan …), their average values are different. In addition, other sources are characterized by a much wider WI range (national production – EU Domestic, biomethane …) (7). This situation is illustrated in Figure 1.

Figure 1. Frequency distribution of Wobbe Index



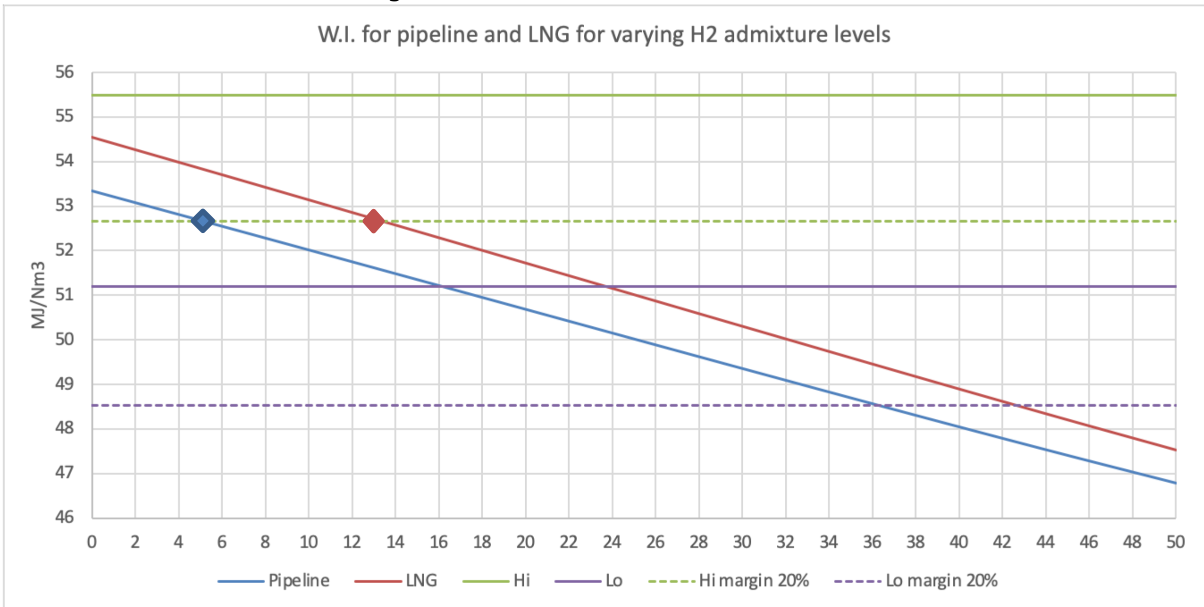
Source: ENTSOG, 2017.

On the demand side, adaptability to the WI varies. Modern gas turbines can adapt to varying gas compositions to a certain extent. Supported deviations of the Wobbe index are reported to be in the range of ±5%. Similarly, household appliances appear capable of operating within a certain Wobbe bandwidth (4-5 MJ/Nm^3 for older appliances and 8 MJ/Nm^3 for newer installations)[2].

The addition of H_2 to natural gas lowers the blend's WI. The impact of increased H_2 concentration in the gas network is illustrated for two distinct gas types (Russian pipeline gas and LNG) in Figure 2. The green and purple lines denote the thresholds, observing a 4.3 MJ/Nm^3 (0,0) bandwidth, with limits symmetrical around an average WI value based on pipeline gas. At 20% vol H_2 the mixture (based on pipeline gas) has a WI of 50.7, already below the established threshold (51.19 MJ/Nm^3). We assume that in order for this scenario to take place adjustments would have been implemented, lowering the "target gas" WI value (band central value), and therefore establishing new thresholds. If the new "target gas" WI the bandwidth of permissible WI values remains the same, this would lead to the applicability of a lower bound for the permissible values of H2 content in the admixture.

These new thresholds, still confining a band of permissible WI values of 4.3 MJ/Nm^3, are denoted Figure 2 by the horizontal dashed lines. The H_2 – gas admixture WI value would cross the upper threshold value at 5% H_2 content, in the case of pipeline gas and at 13% H_2 content for LNG. When H_2 content is below the respective values the admixture WI is above the green dashed line, and therefore outside the range of permissible values. Therefore, depending on the gas supply mix (LNG or pipeline) the H_2 would need to be above 5-13% vol, if the WI is to remain in the admissible range of values.

Figure 2. WI as a function of H_2 admixture %vol



Source: JRC, 2021.

Based on the reasoning and example presented above we opted for the use of the following three threshold levels (Table 2) to assess the impact of hydrogen admixtures on the power and gas markets.

Table 2. Admixture thresholds used in the present study

Level	**Higher %vol (%HHV)**	**Lower %vol (%HHV)**
T1	5 (1.6)	0
T2	20 (7.2)	0
T2L	20 (7.2)	5 (1.6)

Source: JRC, 2021.

(2) DNV GL – Report No. 74106553

1.2 Integration schemes

Hydrogen demand today is estimated at 8.3Mt (327 TWh) serving predominantly chemical/process industrial processes in refineries, as well as in ammonia and methanol production facilities (3). Renewable and low-carbon hydrogen set to serve this demand would most likely not be blended in the gas network. It would instead be produced on-site and consumed locally or transported in the form of pure hydrogen (e.g. per dedicated hydrogen pipelines). Therefore, the current industrial consumer paradigm is not the basis considered here. Instead, we consider the electrolysers as assets integrated in the power system and linked to the power and gas markets, according to the two schemes provided in Table 3.

Table 3. Electrolyser market configuration schemes

Name	**Power consumption**	**H_2 injection**
Market driven	Price-driven	Price-driven
RES driven	RES profile-following	RES profile -driven
Hybrid	RES profile-following limited by a WTP price	RES profile / price driven

Source: JRC, 2021.

The market-driven scheme assumes that electrolysers will be connected to the power grid with then their use, as the name suggests, influenced by market price spread between gas and electricity.

The RES-driven scheme differs from the market-driven scheme, in that the power/gas market price is no longer the driver for operational decisions. Instead, electrolysers are considered linked to renewable generating facilities and their consumption (and consequent hydrogen generation) is bounded by the renewable resource (wind or solar) availability (see Table 4).

Finally, a hybrid scheme, using elements of both is assessed. In the hybrid scheme electrolysers are still linked to renewable generating facilities but they stop consuming when the market price is above a certain predefined price, linked to the willingness to pay (WTP) of the electrolyser operator.

Furthermore all RES-driven setups (pure and hybrid alike) are analysed under two different configurations with regard to the capacities linked:

- Linking RES installed capacity and electrolysers on a one-to-one basis(linked).
- Linking RES installed capacity and electrolysers on a ratio of 3.3/1 (partially-linked, i.e. 1 GW electrolyser with 3.3 GW of RES). In this case the RES facility feeds the electrolysis process on a priority basis up to 1 GW. Excess generation (beyond 1 GW) is fed to the power grid.

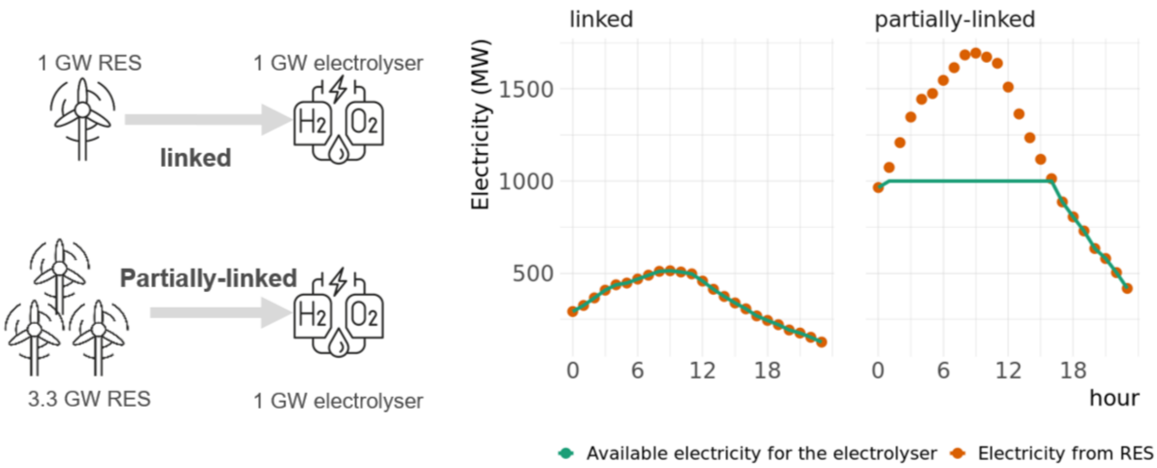
Table 4. RES driven configurations

Scheme	**Name**	**Power consumption**	**H_2 injection**
Wind driven	Wind	Wind profile-following	Wind-driven
Solar driven	Solar	Solar profile-following	Solar-driven
Wind partially-linked	Wind 3.3	Saturated wind profile-following	Wind-driven
Solar partially-linked	Solar 3.3	Saturated solar profile-following	Solar-driven

Source: JRC, 2021.

The difference between linked and partially-linked is illustrated in Figure 3.

Figure 3. Scheme illustrating the difference between linked and partially-linked RES-driven setups.



Source: JRC, 2021.

One further variation in the RES-based scenarios analysed concerns the integration of the RES capacity linked to electrolysers, in the EUCO scenario. In the BASE assumption we consider no additional RES capacity. In the ADD scenarios we assume that RES capacity linked to electrolysers is added to the system.

1.2.1 Assumptions of potential price support

Without a price support scheme hydrogen would not (yet) be dispatched on pure economic terms in the gas market as another source of gas. Renewable and low-carbon hydrogen today could be produced at a cost ranging between 2.5 and 5.5 €/kg (2) (63-140 €/MWh - HHV), and although costs are expected to fall sharply, it's highly unlikely that it will compete by 2030 with natural gas on the spot market.

We will therefore consider the following incentivising schemes. The first one (PS1) is based on the avoided cost of CO_2 emissions by reducing the carbon content of gas. The second and third (PS2 & PS3) the level of support required to reach price parity with natural gas or SMR-based hydrogen. A fourth level PS4 is considered assuming a level of support equivalent to existing schemes for biomethane. Further details are provided in ANNEX 1 and paragraph 2.1.1.

1.2.1.1 Techno-economic assumptions for electrolyser fleet

The modelling of the electrolyser fleet requires the definition of asset specific parameters. In principle, electrolysis can be conducted by different technologies such as alkaline, electrolyte membrane or solid oxide electrolysers which differ in terms of costs and conversion efficiencies. However, since we are only modelling a generic electrolyser fleet the parameters either have to correspond to a specific technology choice or be based on a composite indicator. Since our analysis focuses on the situation in the year 2030, we assume that electrolysis capacity will mostly be provided by alkaline electrolysers as the currently only mature option. A comprehensive overview of techno-economic parameters compiled by the ASSET study (8) is provided in the annex.

The table below lists 400 k€ per MW as investment costs for alkaline electrolysis by 2030 as reported in the draft Strategic Research and Innovation Agenda document (9). For the use in the METIS model the cost values have to be annualised which requires assumptions on the lifetime of the electrolyser system and the stack and the weighted average cost of capital, which gives an annualised cost of 37 820 € per MW_{el}.

Table 5. Technology cost and performance assumptions of electrolysers in 2030

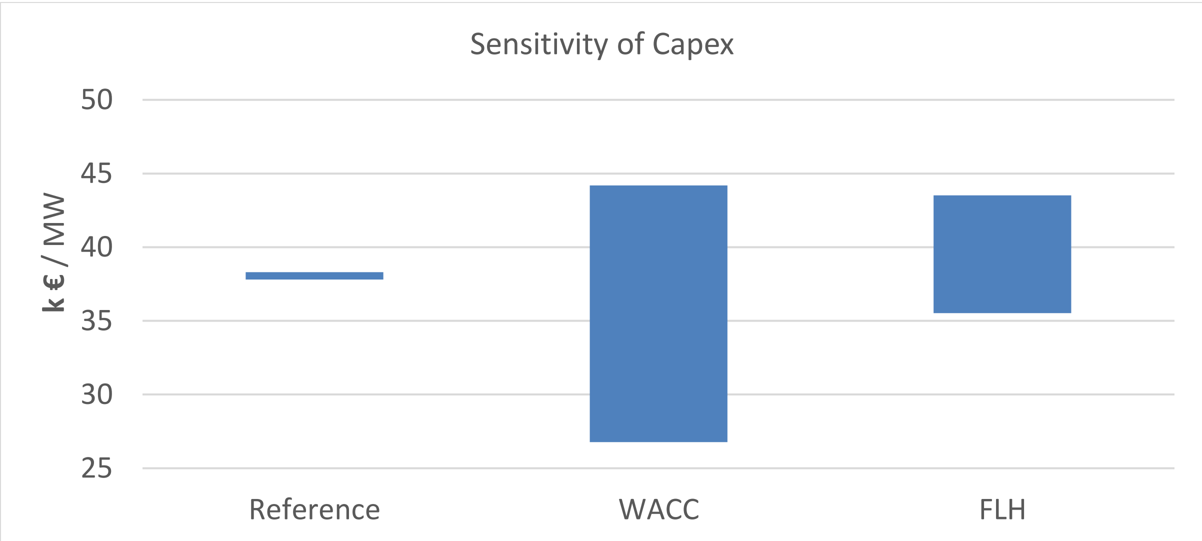
Technology	AEL	PEM	SOE	Source
NPV 2030 Investment Costs (k€ per MW)	400	500	520	(9)
NPV Stack Replacement Costs (k€ per MW)	26	45	0	

NPV 2030 System Costs (k€ per MW)	426	545	520	
Annualized System Costs (k€ per MW)	37.8	48.4	60.8	…
Annualized Storage Costs (k€ per MWh_{H2})	4.00	4.00	5.26	
Efficiency (LHV)	66%	69%	81%	
Capital Recovery Factor	9%	9%	12%	
Weighted Average Cost of Capital	8%	8%	8%	(10)
Stack Replacement Interval - Years	24	20	23	
System Lifetime - Years	30	30	15	(11)
Stack Lifetime Hours (thousands)	95	78	90	
Full Load - Hours (thousands)	4	4	4	

Source: JRC, 2021.

To further put these values into perspective, the subsequent figure displays a sensitivity analysis of the annualised cost of alkaline electrolysis for ranges of the WACC between 4 and 10 percent and ranges of the full load hours (FLH) between 2 000 and 8 000 per year, where higher FLH go along with shorter replacement intervals of the stack.

Figure 4. Annualised CAPEX sensitivity on WACC and full load hours



Source: JRC, 2021.

1.3 Non-harmonised H_2 threshold levels

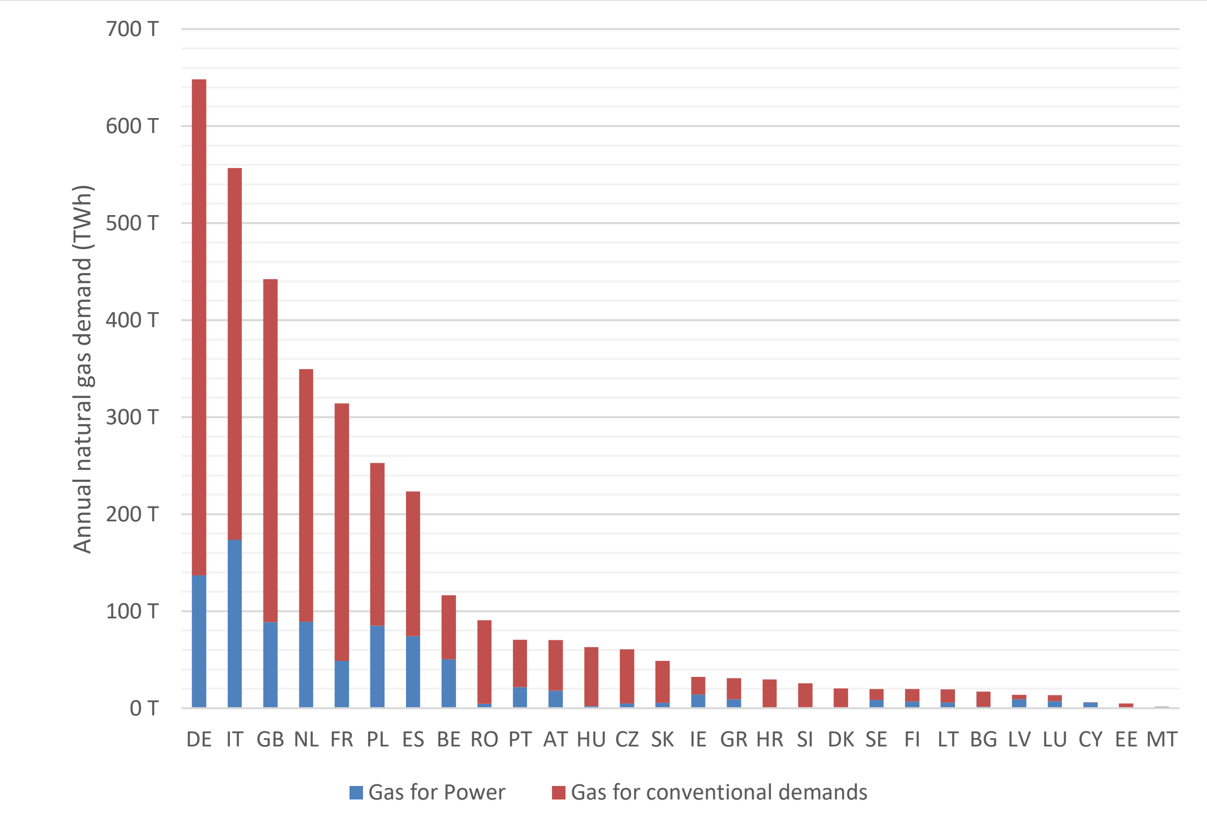
It is among this report's objectives to assess the compatibility of zonal hydrogen injections from renewable powered electrolysis with cross-zonal hydrogen blending constraints. The correct assessment of these effects would require the use of a 'physical model' that accounts for all stocks and flows of the energy vector hydrogen. This moreover would imply that the ratio of blending gas with hydrogen at each time step and zone would be an endogenous variable of the model. Such features however are currently addressed in the ongoing development of the METIS model but are not included in the METIS version 1.4.1 used for this analysis. Instead, we propose a simplified ex-post analysis that does not capture all the elements of the endogenous modelling, but as we believe sufficiently mimics broadly applicable patterns to reveal insights on the compatibility of blending thresholds. The ex-post analysis takes as input parameters H_2 injections from renewable electrolysis, the gas demands, the gas exports, as well as the upper and lower blending thresholds respectively. These parameters are applied in a boolean indexing to identify gas exports that would ex-post have been infeasible. Based on this information possible adaptation strategies entailing a curtailment of electrolyser injections or gas exports respectively are devised. A detailed description of the methodology is provided in Annex 4.

1.4 Description of the baseline scenario

The baseline scenario in the present study is based on the EUCO3232.5 in 2030. This scenario, simulated using a power & gas system model, leads to a total consumption of natural gas in the EU countries (for all uses) of 3 120 TWh.

The annual demand of natural gas for all the simulated countries, disaggregated by users (power or conventional) is visible in Figure 5. From the visualisation are excluded the simulated countries not using natural gas, namely Bosnia-Herzegovina (BA), Switzerland (CH), Montenegro (ME).

Figure 5: Annual demand of natural gas in EU+UK countries used in the simulation



Source: JRC, 2021.

The maximum amount of hydrogen that can be blended in the gas grid is based on natural-gas demand curves, as explained in Section 1.1.1.

Table 6 displays the amount of hydrogen that can be blended according the two thresholds used in this study (Table 1).

Table 6: Maximum amount of hydrogen that can be annually blended into the gas grid according the two thresholds used in this study. The countries are shown from the highest to the lowest value.

Country	Maximum amount of annual hydrogen blended with threshold 5% vol	Maximum amount of annual hydrogen blended with threshold 20% vol
Germany (DE)	10.3 TWh	46.1 TWh
Italy (IT)	9 TWh	40.7 TWh
Netherlands (NL)	5.6 TWh	25.1 TWh
France (FR)	5.3 TWh	22.6 TWh
Poland (PL)	4 TWh	18.1 TWh
Spain (ES)	3.5 TWh	15.9 TWh
Rest of the EU	12 TWh	51.3 TWh
Total EU	49.5 TWh	220 TWh

Source: JRC, 2021.

1.5 Capacity and Storage optimisation

The maximum technical H_2 production capacity that may be connected to the respective gas grid was optimised by selecting the capacity / storage pair with the lowest total (H_2 production system) cost, among a set of pairs of electrolyser capacity and local buffer storage, sufficient to serve each of the two considered admixture thresholds (T1 and T2).

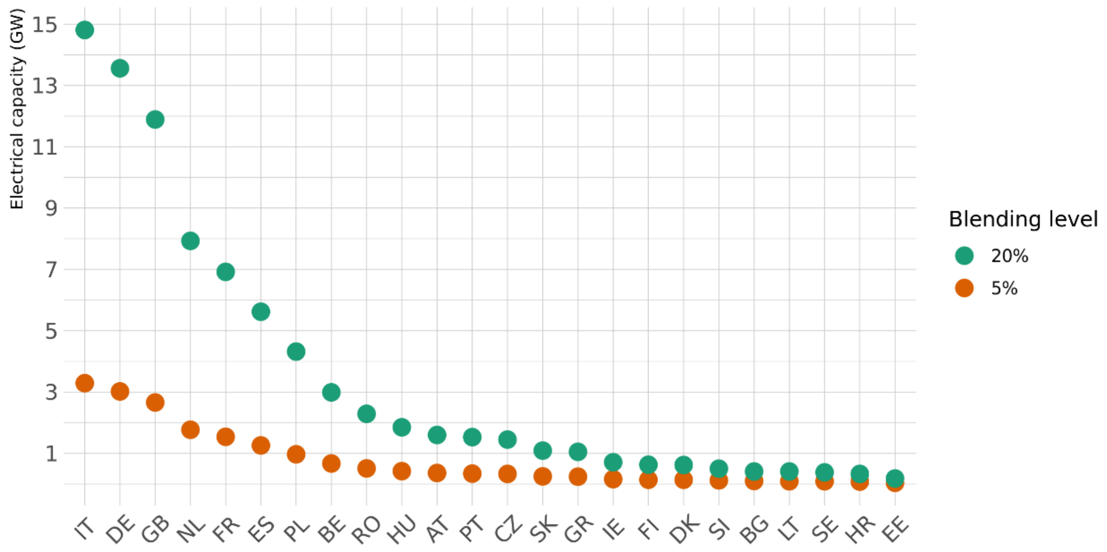
This is implemented by means of a linear optimisation procedure of the capacity and storage parameters by simulating the electrolysers' operations (electricity consumption, storage, gas generation) over one year with an hourly timestep. For this process it is assumed that the electrolysers operate as needed to supply hydrogen at a rate required to maintain the 5 and 20% threshold at all times.
A grid search on a set of values for the capacity and the storage is carried out returning the combinations that are feasible, i.e., the combinations representing an electrolyser able to maintain the target level of hydrogen in the network. Once found the set of feasible solutions, a cost function is applied to each of them calculating then the cost of the capacity/storage combination.

1.6 Results

Figure 6 **in the following page provides the resulting maximum electrolyser capacity per member state that could technically connect to the gas grid, for the two H_2 blending thresholds (5% and 20% vol). Satisfying the demand of hydrogen as reported in**

Table 6 leads to equivalent full-load hours of electrolysers between 2 700 and 4 200. As the methodology above indicates, this capacity is solely constrained by the gas demand temporal pattern because the optimisation procedure finds the least-cost capacity/storage combination able to reach the maximum blending threshold at each time-step..

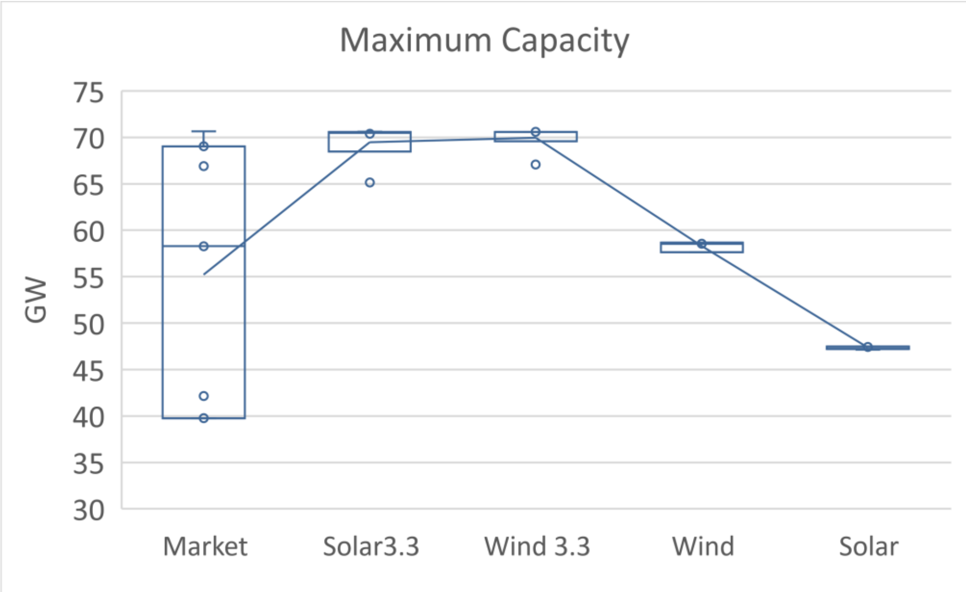
Figure 6. Maximum technical capacity that may operate under a blending regime when considering only the gas grid upper threshold constraints



Source: JRC, 2021.

The results above are driven by the gas demand and the applied upper threshold. No constraints are present on the supply of electricity to the electrolysers. In reality this may not always be true. In the scenarios analysed in the present study the resulting operating profiles of the electrolyser fleets revealed the supply side constraints which depend on the market integration scheme (RES – driven or market driven), the hybridisation arrangement (Electricity WTP price) and the level of price support. The maximum capacity that may be installed, when considering also the supply side limitations is in the range of 40-71 GW for the 20% vol blending threshold scenarios and depends on the market configuration of the electrolysers. Figure 7. illustrates the range of this capacity (EU figure) for five setups. Our analysis shows that the maximum electrolyser capacity is heavily dependent on the price support levels, under a pure market-based arrangement. Under a RES–driven approach we find that the electrolyser capacity is primarily affected by the type of linkage with the renewable fleets (solar or wind and electrolyser capacity ratios) and to a much lesser extent on the hybrid pricing arrangements (WTP).

Figure 7. Maximum technical capacity that may operate under a blending regime for the different market integration schemes considered

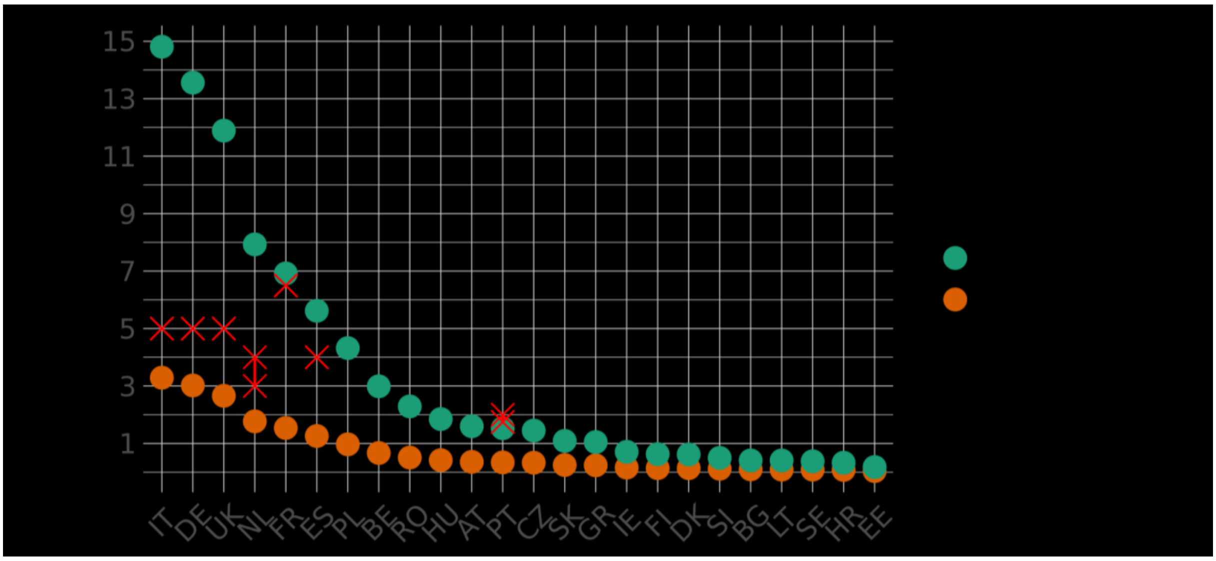


Source: JRC, 2021.

1.7 Comparison with published strategy document capacities

Several European countries have published national hydrogen roadmaps providing figures of planned electrolysers' capacity in 2030. Figure 8 illustrates the capacities in the published national strategies alongside the capacities derived in Section 1.6. It is evident that for most countries the (National) target installed capacity lies between the calculated maximum electrolyser capacity for the 5% and the 20% upper thresholds. This means that instituting a hydrogen blending threshold above 5% would allow a significant part – if not all - of the 2030 target electrolyser capacity to connect to the gas grid. In the following chapter we analyse the volume of hydrogen that may be produced by electrolysers under different electrolyser market configurations, and introduced in the gas network.

Figure 8: Summary of the electrolyser capacities found by the optimisation procedure (Section 3.3) and the national strategies.



Source: JRC, 2021.

Table 7: Electrolyser target capacity in H_2 National strategies vs capacity to supply 5% and 20% thresholds.

Country	Electrolyser Capacity in 2030 according to the National Strategy documents	Maximum technical capacity used in this study (range 5-20% blending level	Source
Germany	5 GW	3-13.6 GW	The National Hydrogen Strategy (12)
Netherlands	3-4 GW	1.8-7.9 GW	Government Strategy on Hydrogen (13)
France	6.5 GW	1.5-6.9 GW	Stratégie nationale pour le développement de l'hydrogène décarboné en France (14)
Italy	5 GW	3.3-14.8 GW	Piano Nazionale di Ripresa e Resilienza (PNRR) (15)
Portugal	1.75 – 2 GW	0.3-1.5 GW	EN-H2 Estratégia Nacional para o Hidrogénio (16)
Spain	4 GW	1.3-5.3 GW	Hoja de Ruta del Hidrógeno: una apuesta por el hidrógeno renovable (17)
United Kingdom	5 GW	2.7-11.9 GW	The Ten Point Plan for a Green Industrial Revolution (18)

Source: JRC, 2021.

2 Electrolyser operation and costs

In this section the results based on power & gas simulations focusing on the operation of the electrolysers are presented under multiple market configurations, following the methodology outlined in section 1.

2.1 Scenario overview

As mentioned previously, all scenarios explored in this study can be divided in two configurations: market-driven (explained in Section 2.1.1) and RES-driven (Section 2.1.2). The full list of all the simulations is given in Section 2.1.3.

2.1.1 Market driven

In the market-driven setup electrolysers are modelled as price-sensitive consumers in the power market and producers in the gas markets. In this formulation, they consume electricity only when the electricity to gas price ratio is such that it is economical to generate and dispatch hydrogen into the gas grid. The above description describes accurately the mechanism if there is no storage. In the setup of this analysis most electrolyser fleets include a very small buffer storage of 1-2 hours, which can mildly optimise the interaction between the two markets.

Since the main driver for the operation of the electrolysers in this mode is the electricity/gas price ratio, we executed a range of scenarios to analyse the effect of a price support mechanism. The range of scenarios is provided in Table 8.

Table 8. Price-support levels

Scheme	**Name**	**Value**
PS1	CO_2 driven	3.8 €/MWh_e
PS2	Gas price-parity	33-45 €/MWh_e
PS3	SMR H2 – parity	28-40 €/MWh_e
PS4	Biomethane parity	17-90 €/MWh_e
10-50	-	10-50

Source: JRC, 2021.

The price support scheme simulated in scenario PS1 is equivalent to a subsidy of the average electricity price with a common value applied to the EU regions: the produced mixture of gas and hydrogen is remunerated with the gas market price plus an additional amount of 3.8 Euro/MWh_e on the energy input of the electrolysers[3].

The price support scheme simulated in scenario PS2 is equivalent to a subsidy of the average electricity price required to make electrolytic hydrogen price-competitive with natural gas. The PS2 support is country specific and it's calculation is based on the average annual electricity and gas marginal costs (both calcutaed by the model).

The price support scheme simulated in scenario PS3 is equivalent to a subsidy of the average electricity price required to make electrolytic hydrogen price-competitive with natural gas aims at levelling the playing field between a baseline hydrogen production technology (the steam methane reforming, or SMR) and the electrolytic production.

Given existing subsidy schemes supporting biomethane production[4], we simulated their expansion to hydrogen in the PS4 scenario, by applying the same country-specific incentive to produce biomethane, to the production of hydrogen.

[3] See Appendix for a detailed calculation of the support scheme value.
[4] Values based on Decorte et al, 2020, available at https://www.regatrace.eu/wp-content/uploads/2020/04/REGATRACE-D6.1.pdf

Further details with the formulas used to calculate the values are provided in Annex 1. Besides the PS1-PS4 schemes, we also conducted a parametric evaluation of price support levels in increments of 10 €/MWh_e from 10 to 50 €/MWh_e applied equally in all the countries.

2.1.2 RES driven

In the renewables-driven setup (RES-driven) electrolysers are considered coupled to renewable generation (wind or solar) in two different schemes (1 to 1 or 1 to 3.3 as described in Section 1.2). The following two variations extend the wind and solar – drive setups:

- Possible hybrid arrangements where we de-couple the operation of the electrolysers from the RES source when the power market price exceeds a certain price.
- Adding additional RES capacity (wind or solar) to the system coupled to the electrolyser capacity.

The first aspect is addressed in scenarios using the suffix HYB 40/HYB 50 where a WTP value of 40 or 50 is used respectively.

The second aspect is addressed in scenarios defined with the suffix ADD (SolarADD, WindADD). In those scenarios the RES source used by the electrolyser is an additional source on top of the existing RES fleet in the EUCO scenario. The additional capacity is equal to the capacity of electrolysers (i.e. with 1 GW of electrolyser we add a 1 GW of wind or solar to the system) or is equal to 3.3 times the capacity of electrolysers in case of the scheme 1 to 3.3 (see Section 1.2).

2.1.3 Summary of scenarios

Table 9. **Scenario overview** provides the list of scenarios summarising the scenario configuration related to the three aspects outlined above.

Table 9. Scenario overview

Scenario name	Hydrogen integration	Price support	Added capacity
BASE solarADD	No electrolysers		Solar - 71 GW
BASE solarADD3.3	No electrolysers		Solar - 234 GW
BASE windADD	No electrolysers		Wind - 71 GW
BASE windADD3.3	No electrolysers		Wind - 234 GW
BASE	No electrolysers		0
PS1	Market	CO2 – compensated	0
PS2	Market	Gas – parity	0
PS3	Market	SMR – parity	0
PS4	Market	Biomethane parity	0
T1m	Market		0
T2Lm	Market		0
T2m-sub40	Market	SUB40	0
T2m-sub50	Market	SUB50	0
T2m	Market		0
SolarADD HYB 40	Solar	HYB	Solar - 71 GW
SolarADD HYB 50	Solar	HYB	Solar - 71 GW
SolarADD	Solar		Solar - 71 GW
SolarADD 3.3 HYB40	Solar3.3	HYB	Solar - 234 GW
SolarADD 3.3 HYB50	Solar3.3	HYB	Solar - 234 GW
SolarADD 3.3	Solar3.3		Solar - 234 GW
Solar	Solar		0
Solar HYB 40	Solar	HYB	0
Solar HYB 50	Solar	HYB	0
Solar 3.3 HYB 40	Solar3.3	HYB	0
Solar 3.3 HYB 50	Solar3.3	HYB	0
Solar 3.3	Solar3.3		0
Wind ADD HYB40	Wind	HYB	Wind - 71 GW
Wind ADD HYB50	Wind	HYB	Wind - 71 GW
Wind ADD	Wind		Wind - 71 GW

Wind ADD 3.3 HYB40	Wind 3.3	HYB	Wind - 234 GW
Wind ADD 3.3 HYB50	Wind 3.3	HYB	Wind - 234 GW
Wind ADD 3.3	Wind 3.3		Wind - 234 GW
Wind 3.3 HYB 40	Wind 3.3	HYB	0
Wind 3.3 HYB 50	Wind 3.3	HYB	0
Wind 3.3	Wind 3.3		0
Wind	Wind		0
Wind HYB 40	Wind	HYB	0
Wind HYB 50	Wind	HYB	0

Source: JRC, 2021.

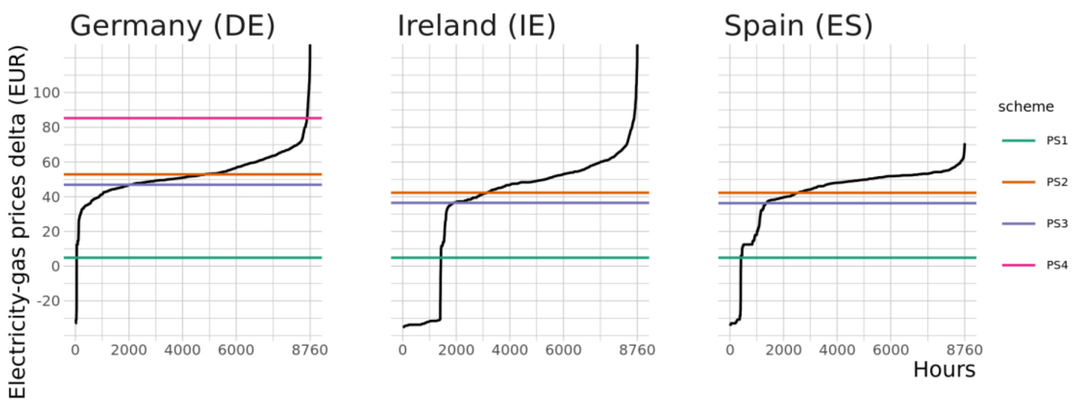
2.2 Analysis of electrolyser operation

2.2.1 Operating profile

In the market-driven configurations, the operation of electrolysers is mainly influenced by the marginal costs of electricity and gas. In this setup the electrolyser injects hydrogen into the gas grid when the cost of electricity (taking into account then the efficiency of the electrolyser) is lower than the cost of gas.

In the base scenario analysed (EUCO3232.5/2030) the average difference between electricity and gas prices throughout the year in the EU is 51.8 €/MWh_g[5]. This value corresponds to the gas price in increase that would make electrolysis-based hydrogen competitive to gas on average during the year. Figure 9 shows this difference for three selected countries, overlaying also as horizontal coloured lines the expected bids from electrolysers to consume power under each price support scheme (PS1-PS4).

Figure 9. Electricity and gas price spread duration curve for three countries (black lines). The horizontal lines show the value of the PS1-PS4 support schemes.

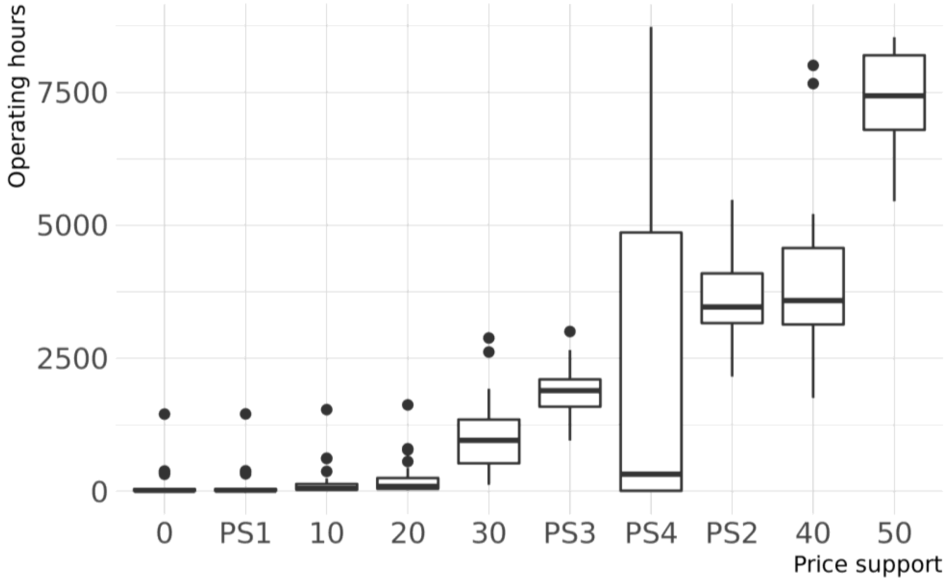


Source: JRC, 2021.

The abscissa of the intersection of the horizontal coloured lines with the price duration curve gives the expected operating hours of the electrolysers under each scheme. It becomes immediately evident that the dispatching of electrolysers is very sensitive to price support above a certain value. Figure 10 provides an indication of the sensitivity of electrolyser dispatching to the price support level (all the schemes in Table 8). While with zero subsidies a small group of countries appear to have favourable market conditions (due to curtailment), the tipping point for most countries is above 30 MWh_e. At a price support of 40€/MWh_e the median time of electrolyser operation across the EU is approaching 4 000 hours. A further subsidy increase to 50€/MWh_e would dispatch electrolysers as baseload demand (median of 7 500 hours).

[5] The average is computed considering a weighted average among the EU countries using annual electricity generation as weight. The electricity price is divided by the efficiency of the electrolysers (0.78)

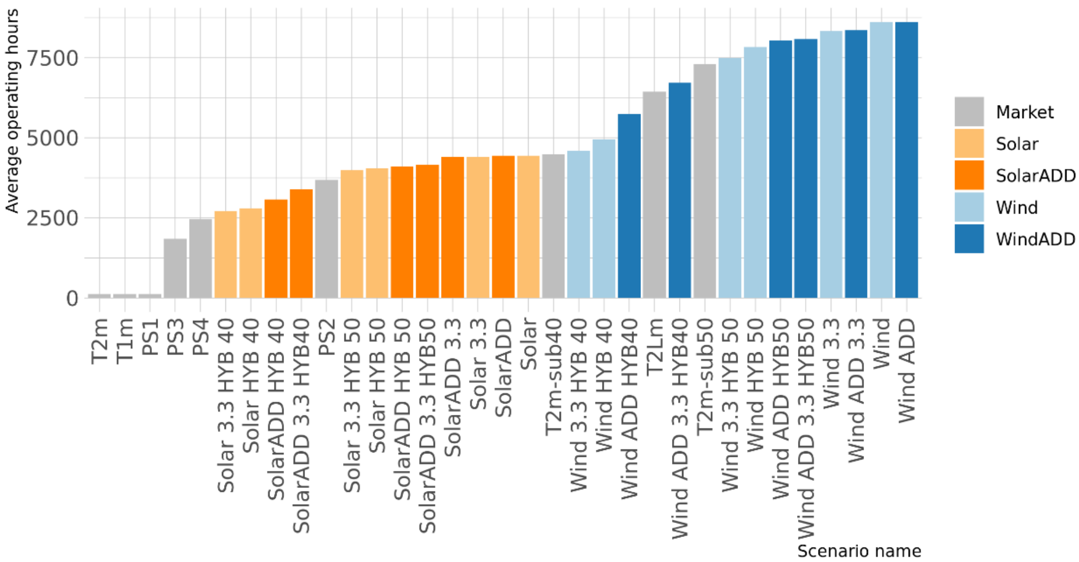
Figure 10. Maximum technical capacity operating hours with different price support schemes. This plot considers only scenarios market-driven without additional capacity.



Source: JRC, 2021.

The operating hours for the computed scenarios are provided in Figure 11. The scenarios are classified in five groups: market-driven (grey), RES-driven with solar (dark and light orange for scenarios with and without added solar capacity) and RES-driven with wind (dark and light blue for scenarios with and without added wind capacity). Electrolysers driven by wind power have the highest number of operating hours, with solar in general showing about half of the operating hours. Both show a large variability in numbers considering the various price schemes, and – as we will see later in the section – with some variation between EU countries.

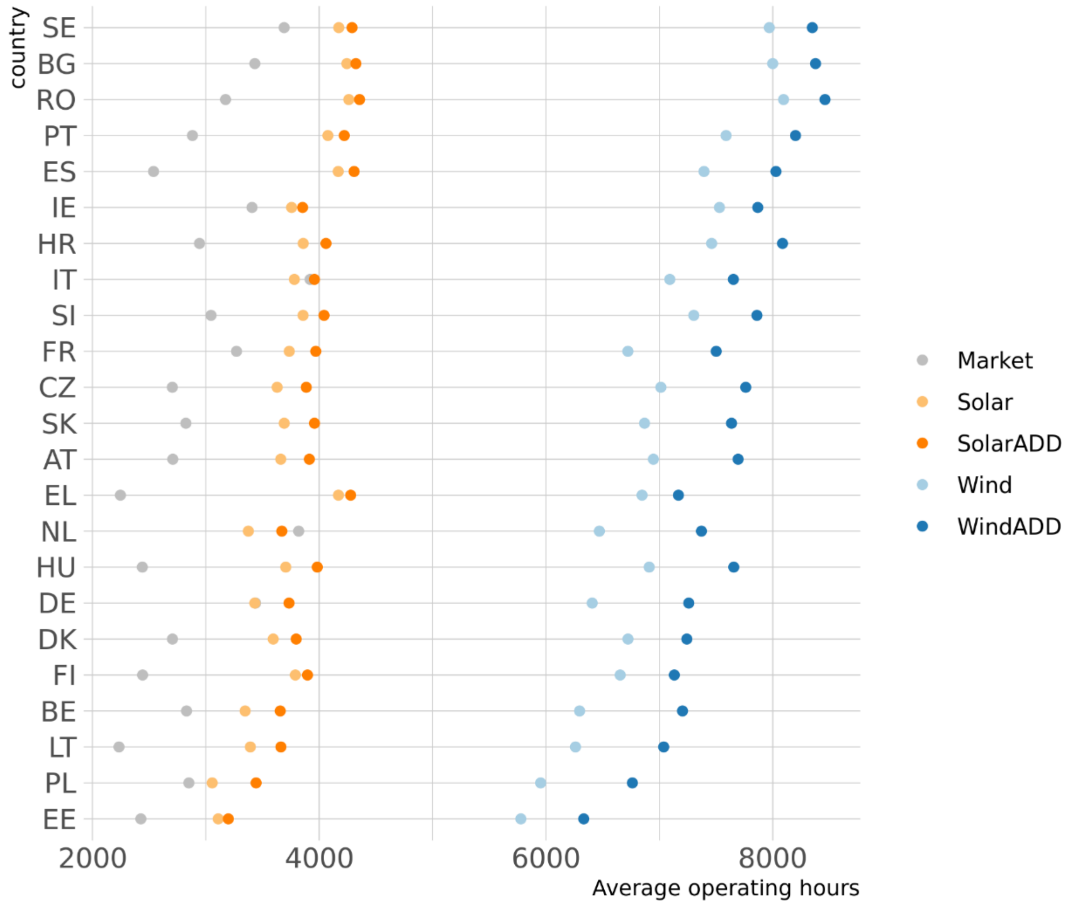
Figure 11. Average number of operating hours



Source: JRC, 2021.

Results shown in Figure 11 can be disaggregated to illustrate the differences and the characteristics in EU countries. Figure 12 shows the average of the five groups (i.e. the five colours) used in Figure 11.

Figure 12. Average number of operating hours per country. Countries are sorted by total average hours.

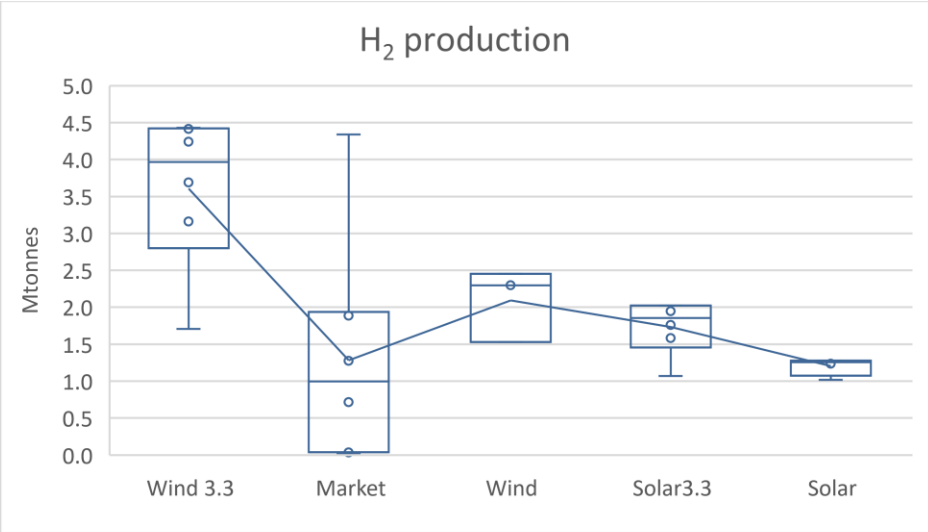


Source: JRC, 2021.

2.2.2 Hydrogen production and cost

As the results on the operating hours previously indicated, hydrogen production is highly dependent on the electrolyser market configuration and the level of price support applied. The maximum hydrogen production that may be blended in the gas systems EU-wide under a threshold of 20 % vol is approximately 4.5 million tonnes. This could materialise in RES-driven scenarios where wind capacity is partly linked to the electrolysis (1 to 3.3. linkage scheme). Figure 13 provides the calculated hydrogen production annually in 5 groups of scenarios. Linkage with wind, especially in a partly-linked scheme can give consistently higher hydrogen production than solar, and most of the market-driven scenarios we analysed.

Figure 13. H_2 production ranges under the various market schemes



Source: JRC, 2021.

The operation of electrolysers in a purely market-driven mode, is highly dependent on the price support scheme. The volumes calculated annually, while respecting a blending threshold of 20% are the following:

a) 0.04 Mtonnes (1.5 TWh) under the CO_2 driven scheme (PS1)

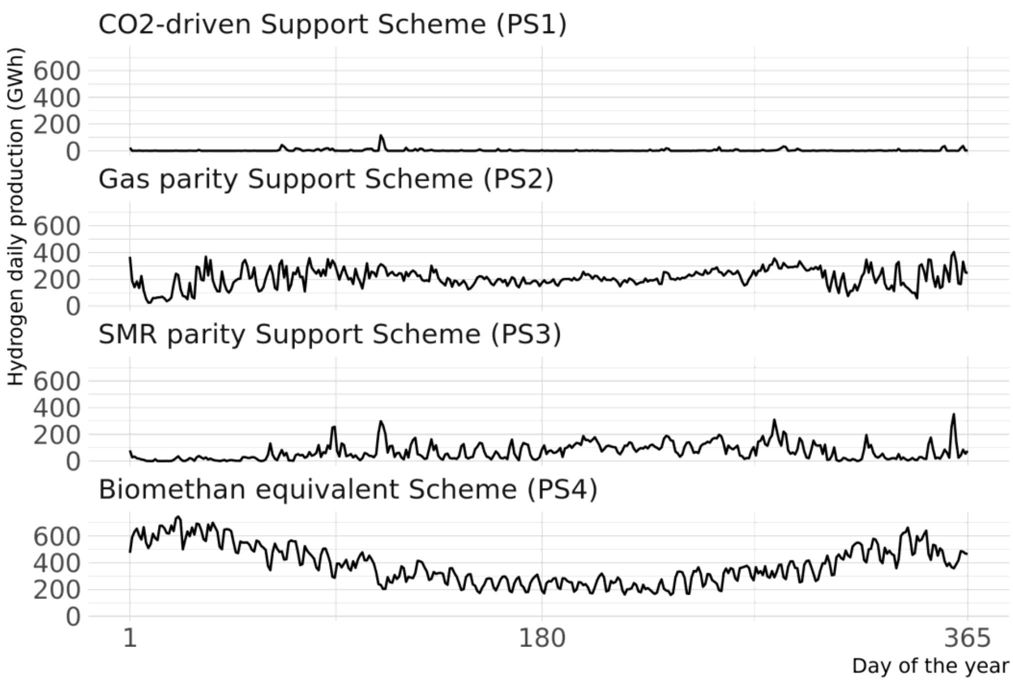
b) 1.95 Mtonnes (76.8 TWh) under the Gas parity scheme (PS2)

c) 0.72 Mtonnes (28.3 TWh) under the SMR parity scheme (PS3)

d) 3.56 Mtonnes (140 TWh) under the Biomethane equivalent support scheme (PS4)

By observing the production time series (Figure 14) we witness the gradual transition from an electricity-constrained production profile (periods of low electricity price) in PS1 to a gas-constrained pattern (20%vol threshold) in PS4, where due to the very high subsidy, constraints on the electricity side are no longer present.

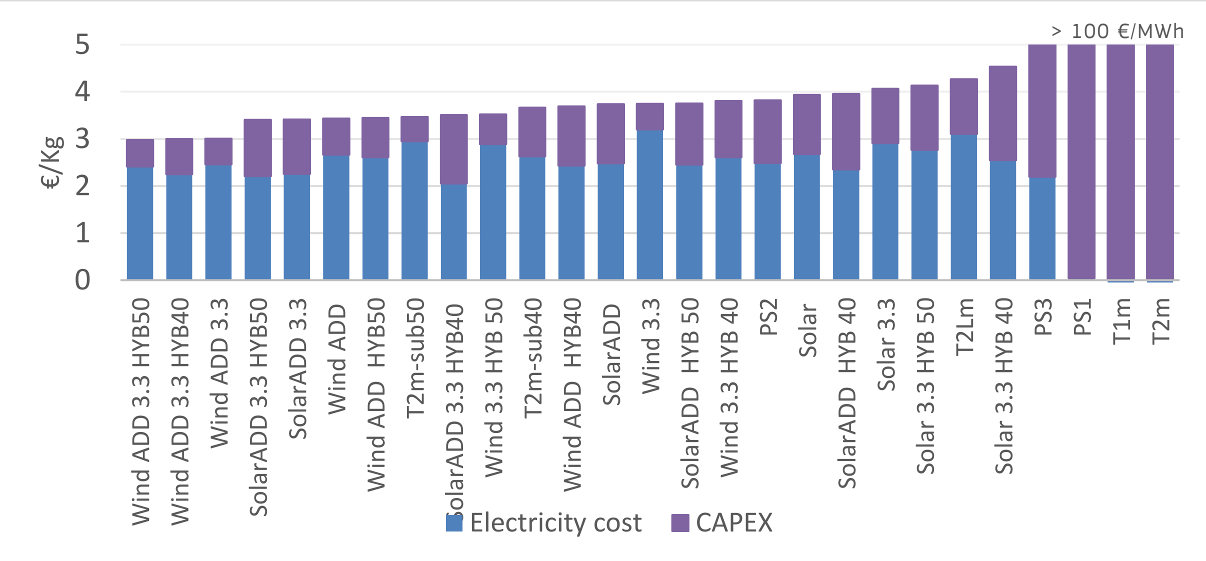
Figure 14. Daily generation of hydrogen in EU with the four price-support schemes



Source: JRC, 2021.

Based on the cost of electricity procured from the power market and the annualised investment cost we calculated the levelised cost of hydrogen across scenarios. Figure 15 provides the calculated H_2 cost split in variable and fixed components. Our analysis shows that while the CAPEX and variable cost components vary considerably, their sum in all but three scenarios (PS1, T1m and T2m) considered in the present study ranges between 3 and 4 €/kg[6] H_2. In these three outliers the operation of the electrolysers is severely limited, to hours of near zero or negative electricity prices, which under the assumptions used in our model runs for 2030 are not enough to justify the capital investment (and hence the very high CAPEX component).

Figure 15. H_2 production cost split in variable and fixed component



Source: JRC, 2021.

The figure above provides evidence that the following choices can lead to a lower hydrogen production cost :

- The addition of renewable capacity in the power system.
- Linkage to wind.
- Application of a hybrid RES-market configuration.
- Linkage of electrolysers to renewable capacity that is a multiple of their own installed capacity (i.e. Wind 3.3.).

2.2.3 The interplay of gas and electricity constraints

In the present analysis we model electrolytic hydrogen generation as a process connecting two separate energy systems (power and gas). Within the alternative setups electrolysers are bounded by diverse market arrangements in the power market and must always observe an upper bound on hydrogen production imposed by the quality requirements in the gas system.

The modelling results help us undestand the way that the identified system contraints on both sides (power and gas) impose themselves on the operation of electrolysers. The following results, refering to annual hydrogen production, can help us understand the effect of these constraints:

a) The maximum theoretical annual production potential of the electrolyser fleet

b) The maximum annual production of hydrogen that may be injected into the gas grid

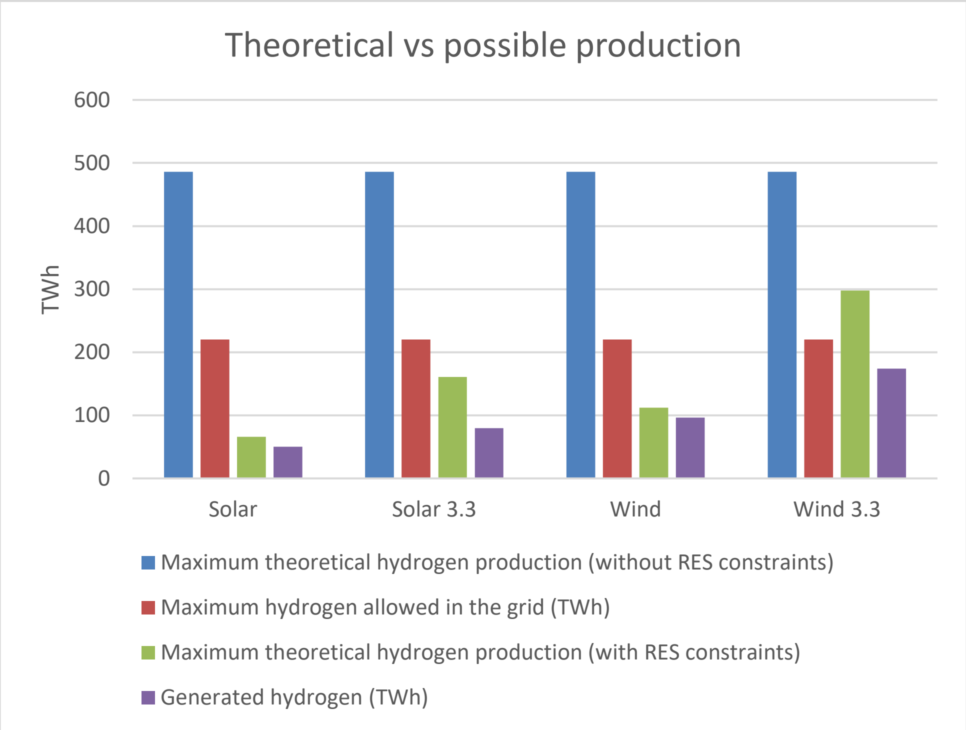
c) The maximum theoretical production considering RES availability (for RES-driven scenarios)

d) The annual production of hydrogen in the market configuration analysed

[6] This result is valid under the EUCO3232.5 scenario fuel and CO2 price assumptions and thus should not be considered as valid in market conditions such as those witnessed in the second half of 2021, when the unprecedented surge of the natural gas price occurred.

The first three values may be calculated externally to the model and are the result of the application of the constraints mentioned earlier individually. The fourth value is based on modelling results and are the result of applying all imposed constraints. Figure 16 illustrates the significant effect that the (power and gas) system constraints impose on the volumes that may eventually be injected into the gas gird. The data behind the graph are provided in Annex 3.

Figure 16. Effect of gas quality and renewable generation constraints

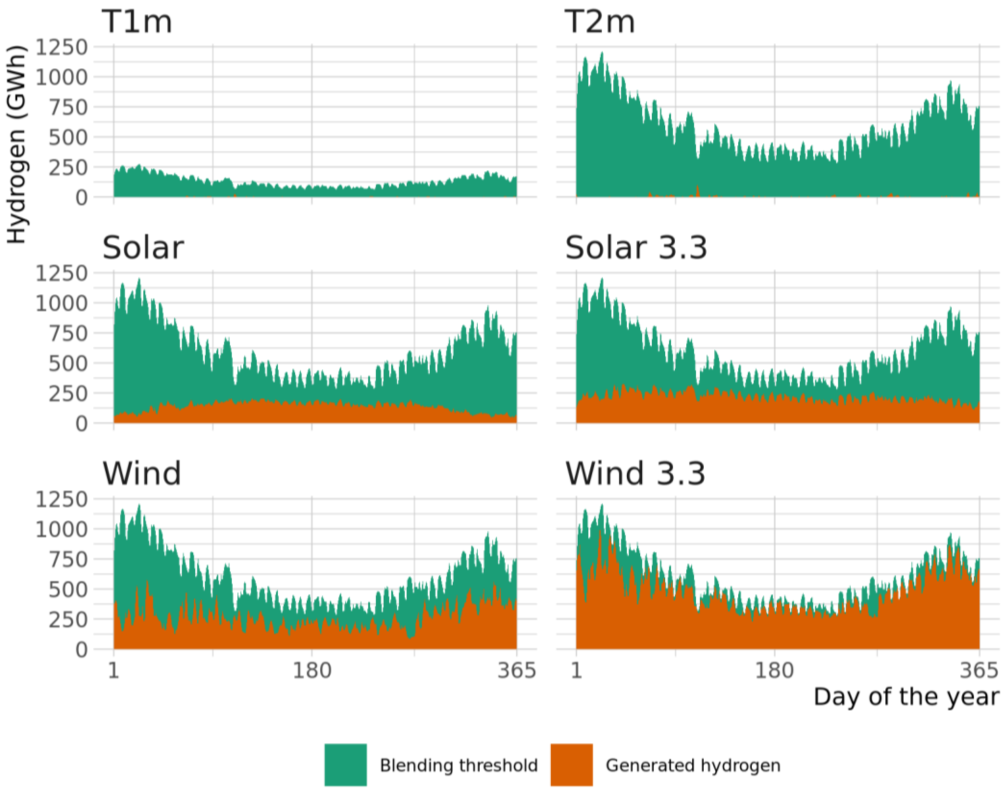


Source: JRC, 2021.

We can see that while the gas grid has significant potential to absorb green H_2, only a fraction of the full electrolyser potential can be converted to green hydrogen and a fraction of that may be blended. That fraction is 50-85%, leaving at least 15-50% available renewable electricity for dedicated H_2 (not introduced into the gas system).

So far we have been discussing annual results. By zooming in the temporal dimension we can see the mechanisms in place. The daily generation of hydrogen in EU is shown in Figure 17 and compared with the blending threshold. As expected, in the market-driven setups the H_2 production is barely visible while for the RES-driven configurations we can observe a clear difference between solar (less production, more pronounced during summer periods) and wind (more available during the winter period).

Figure 17. Daily production of hydrogen in EU with respect to the maximum allowed in the grid in six scenarios.



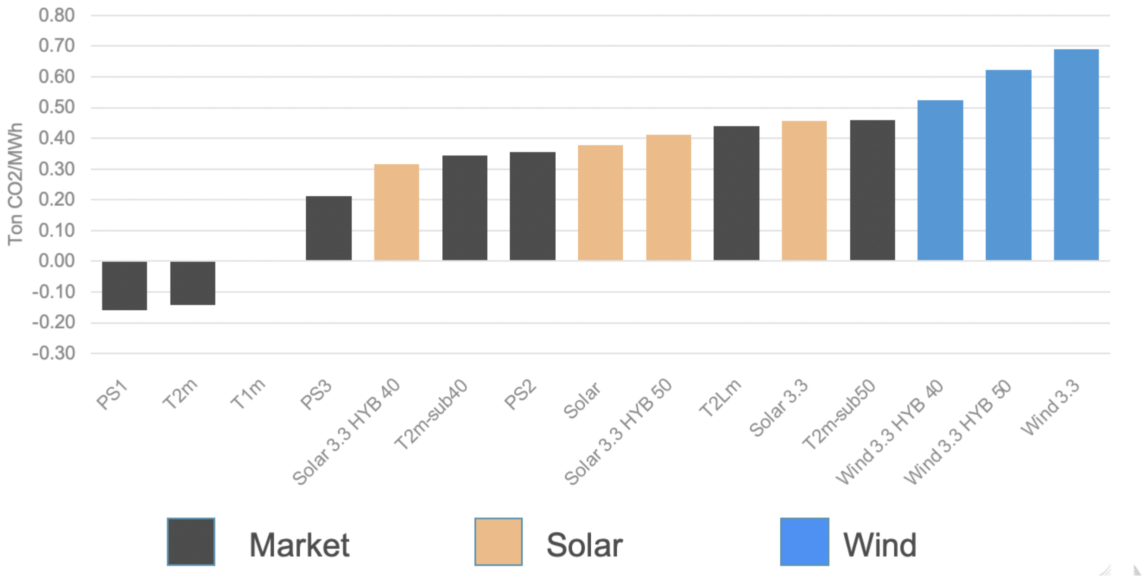
Source: JRC, 2021.

2.3 CO_2 emissions

Throughout this analysis we found that emissions of CO_2 increase, compared to the BASE scenario, if electrolysers are introduced without adding new renewable capacity. Exceptions to this general conclusion are the market-based scenarios without subsidy, as well as the marginally subsidized PS1 (the market-based scenario where a minimal subsidy, internalising CO_2 abatement benefits is included). This is illustrated in Figure 18, which provides the calculated carbon intensity[7] of hydrogen produced as the difference in total CO_2 emissions between the BASE and the respective blending scenario.

[7] With the term carbon intensity we refer to the carbon content determined through the holistic calculation of the impact of hydrogen production on CO2 emissions on the power and gas systems, expressed per tonne of hydrogen produced. The carbon intensity values will by default be completely different in project or sectoral assessments where sourcing of green electricity is assumed without considering impacts to the rest of the energy system.

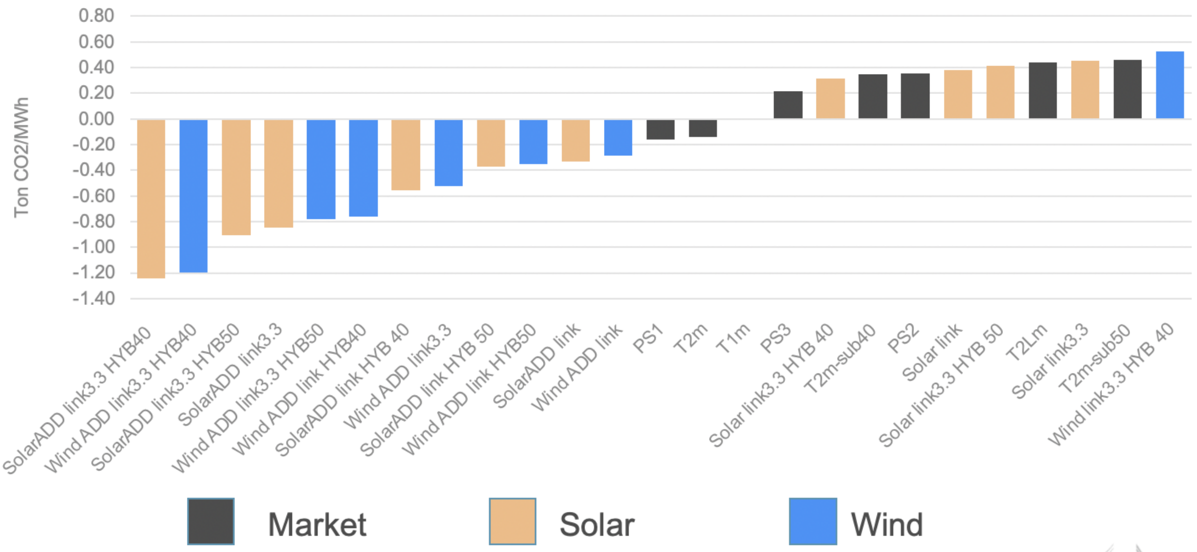
Figure 18. Carbon intensity of H_2 without additional RES



Source: JRC, 2021.

We observe that market mechanisms and linkage to solar capacity appear to assist in achieving a lower carbon intensity, compared to linkage to wind. One further observation is that when it comes to RES-driven setups, it is hybrid arrangements that achieve the lowest carbon intensity. This is an expected result, since in these arrangements dispatching RES energy to the grid takes precedence over the electrolysers at times when the power market clears at a price higher than the WTP (caused by the need for more expensive supply resources to balance demand). Figure 19 below, additionally provides the same indicator for the -ADD scenarios where additional 71/234 GW of solar or wind generation capacity – linked to electrolysers - are added to the EU energy system.

Figure 19. Carbon intensity of H_2 of all analysed scenarios

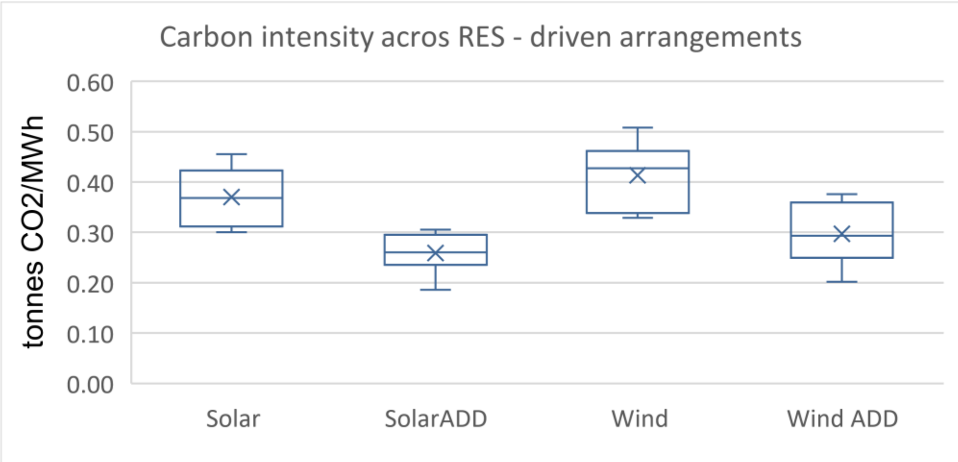


Source: JRC, 2021.

Similarly, we notice that hybrid variations offer, among similar setups, the lowest carbon intensity. The scenarios positioned on the left side of the chart have all negative emissions, when compared to the BASE scenario, due to the additional renewable generating capacity introduced in these scenarios,out of which, due to the quality constraints in the gas system, only 49.4-86% of the total available renewable generation may be converted to H_2 and injected to the gas grid. This excess renewable generation, if absorbed by the power system, leads to a significant reduction of system-wide CO_2 emissions in all the -ADD scenarios by displacing fossil-based generation.

In order to gain further insight on the impact of the opposite effect of additional renewable capacity and additional electrolytic hydrogen production capacity it is useful to compare the carbon intensity of H_2, generated in the -ADD scenarios, using the respective adjusted BASE-ADD scenario which includes the additional wind/solar capacity (without any H_2 production). This is reflected in the figure below.

Figure 20. Carbon intensity of H_2 for RES based scenarios



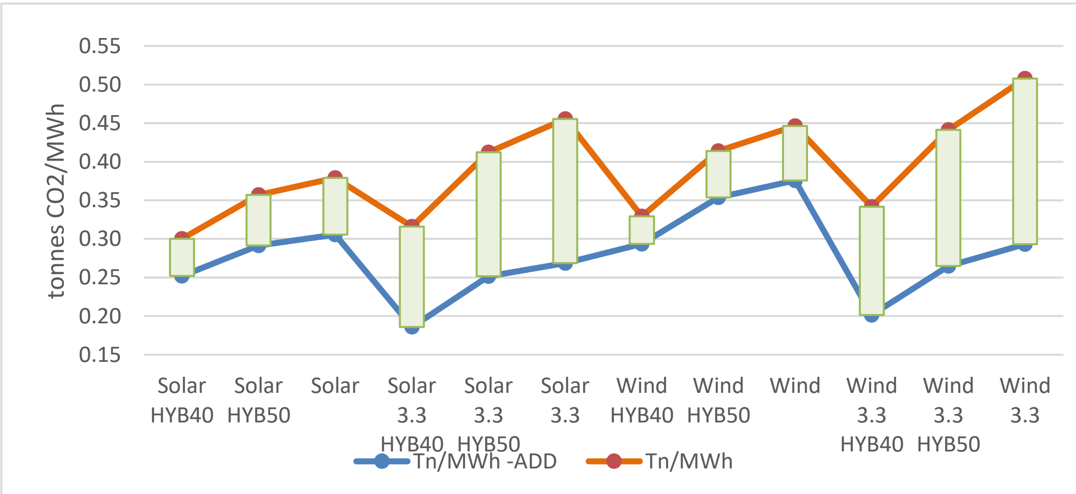
Source: JRC, 2021.

We observe that the -ADD scenarios (introducing additional wind/solar capacity) lead to lower carbon intensity H_2. This effect is more pronounced in the -ADD3.3 scenarios (where the additional RES capacity Is higher). This is further evidenced in Figure 21, where two distinct patterns are clearly visible:

i. A lower WTP value (Hybrid setups) consistently leads to lower CO_2 intensity of hydrogen produced (and blended).

ii. Adding more wind/solar capacity linked to the electrolysers lowers the CO_2 content in the H_2 produced. This is due to the fact that as we add more renewables the power system experiences higher curtailment, and less nuclear power generation. The subsequent activation of electrolysers leads to higher CO_2 emissions but at a significantly lower rate, compared to the scenarios without additional RES capacity.

Figure 21. Greening effect of introducing additional RES



Source: JRC, 2021.

The lowest carbon intensity values are achieved in the Solar and Wind base hybrid schemes operated with a WTP at 40 €/MWh and they are 7.3 and 7.9 $kgCO_2/kg\ H_2$ respectively. Both values are lower than the EU ETS benchmark for free allocation of allowances (8.85 $kgCO_2/kg\ H_2$) but higher than the EU Taxonomy threshold for sustainable hydrogen manufacturing (5.8 $kgCO_2/kg\ H_2$) (3).

2.4 The influence of a lower threshold

In all scenarios considered in this study, but one, we assumed that H_2 concentrations can fluctuate freely between zero and the upper threshold value. However, as explained in paragraph 1.1.2, respecting the Wobbe Index bandwidth may require the presence of a lower threshold value. Such a constraint was modelled in the scenatio T2L, where a lower hard threshold of permissible H_2 concentration was considered, equal to 5% vol. This lower threshold practically imposes a minimum load on the electrlolysers, leading to a substantial number of operating hours in a market-based setup, even without any financial incentive to produce.

In terms of annual H_2 production this scenario is comparable to three solar-driven and one wind driven hybrid scenario. Table 10 provides some key indicators across scenarios with similar to the hydrogen production in the T2L scenario.

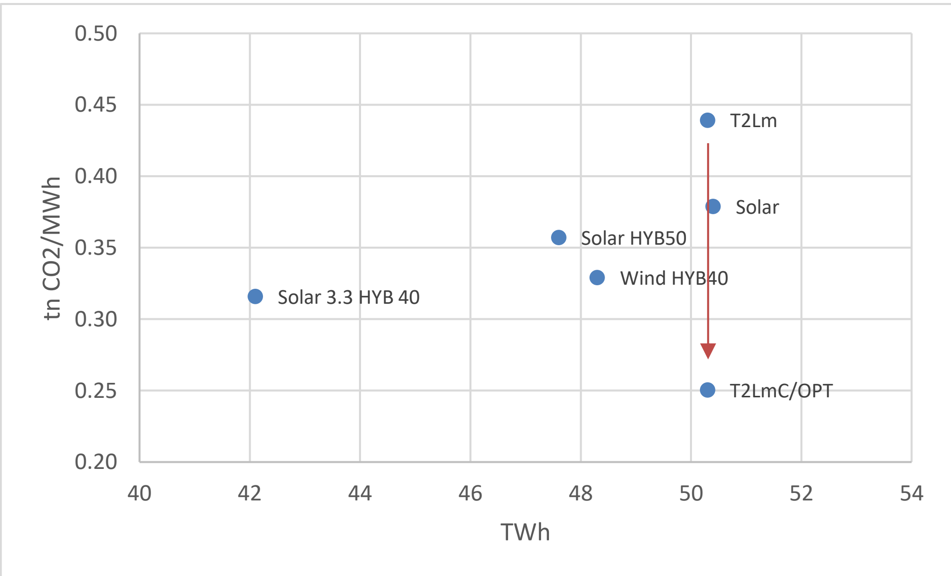
Table 10. Market-based operation with lower threshold compared to RES-driven scenarios

Scenario	H_2 production TWh	H_2 production ktonnes	Carbon intensity kg CO_2/kg H_2	Carbon intensity CO_2Tn/MWh
T2Lm	50.3	1277	17.3	0.44
Solar	50.4	1279	14.9	0.38
Solar3.3 HYB40	42.1	1068	12.5	0.32
Solar HYB50	47.6	1210	14.0	0.36
Wind HYB40	48.3	1227	13.0	0.33

Source: JRC, 2021.

We notice a significantly higher carbon intensity (0.44 tons per MWh) in this scenario, compared to the RES driven scenarios (0.32-0.38). This is due the fact that the lower threshold constraint imposes the injection of hydrogen and the consequent consumption of electricity at times when the power system is using more carbon intensive resources. We therefore proceeded with an optimisation of the storage volume to mitigate this effect. The reduction potential possible by increasing the buffer storage, alongside the respective values of the other scenarios is visualised in Figure 22.

Figure 22. Production (TWh) vs carbon intensity across scenarios



Source: JRC, 2021.

The optimised resulting storage volume more than doubles, increasing to 51.9 GWh from 21.4 GWh. This corresponds to an average storage time of 1.2h hours at the nominal electrolyser output, or 5 hours at 25% of the electrolyser installed capacity corresponding to the minimum load required to observe the 5% min threshold. The effect of the optimised storage on the carbon intensity of produced hydrogen is rather remarkable: A reduction of 43% from 0.44 to 0.25 tnCO2/MWh (17.3 to 9.9 kg CO_2/kg H_2) is possible. This is due to the fact that the optimised hydrogen storage allows a less carbon-intensive power generation mix much of the time that the lower threshold constraint is activated.

3 Possible Impact of non-harmonised approaches

In this section the methodology introduced in section 2.4 is applied in case studies to illustrate potential implications of non-harmonised H_2 blending thresholds. For reasons of complexity reduction, these initial exploratory case studies will focus on a smaller subset of Member States (equivalently referred to as zones). In choosing a suitable group of EU Member States to analyse through a case study we take into account a set of considerations. One essential question regards the levels of lower and upper blending thresholds that are considered for each zone. As of today, maximum blending thresholds have only been established in a small number of Member States (ACER, 2020) and not (yet) necessarily with a view to enable the blending of H_2. A further necessary condition to observe cross-border impacts of blending thresholds is that the considered zones are linked through interconnectors and that actually (significant) volumes of gas flows take place on these interconnectors. Based on these considerations we have selected two initial case studies: One focusing on Austria, France, Germany and Spain and a second one on Austria, Italy and Slovenia. Each of the case studies is based on the T1m scenario. However, to ensure a sufficient electrolyser dispatch and thus variability of the blending ratios the PS2 subsidy levels have been applied which provide for gas price parity.

3.1 Case Study: Austria, France, Germany, Spain

In this case study the blending thresholds have been defined based on currently valid H_2 blending thresholds as reported in the ACER Report on NRAs Survey (19) which could thus constitute a plausible scenario in the near term. The criteria for the inclusion of a country in the case study thus have been that in a candidate country a current H_2 blending threshold is in place and that it shares a gas network interconnection with another candidate country. This led to the inclusion of Austria, France, Germany and Spain in the case study, which are also the four countries with the highest reported current H_2 blending thresholds in the ACER report.

3.1.1 Input parameters

In addition to the parameters based on the T1m scenario, the parameters displayed in Table 11 have been defined specifically for the case study. Blending thresholds are set according to the ACER report and electrolyser capacities have been re-scaled in accordance with these blending thresholds. Subsidy levels correspond to the PS2 subsidy level of gas price parity.

Table 11. Input parameters for AT-DE-ES-FR case study.

Zone	Blending Thresholds		Electrolyser capacity MW	Subsidy level EUR/MWh
	% vol	% HHV		
AT	4	1.28	288	42.92
DE	10	3.35	6 223	43.48
ES	5	1.6	1 876	35.74
FR	6	1.95	1 260	40.54

Source: JRC, 2021.

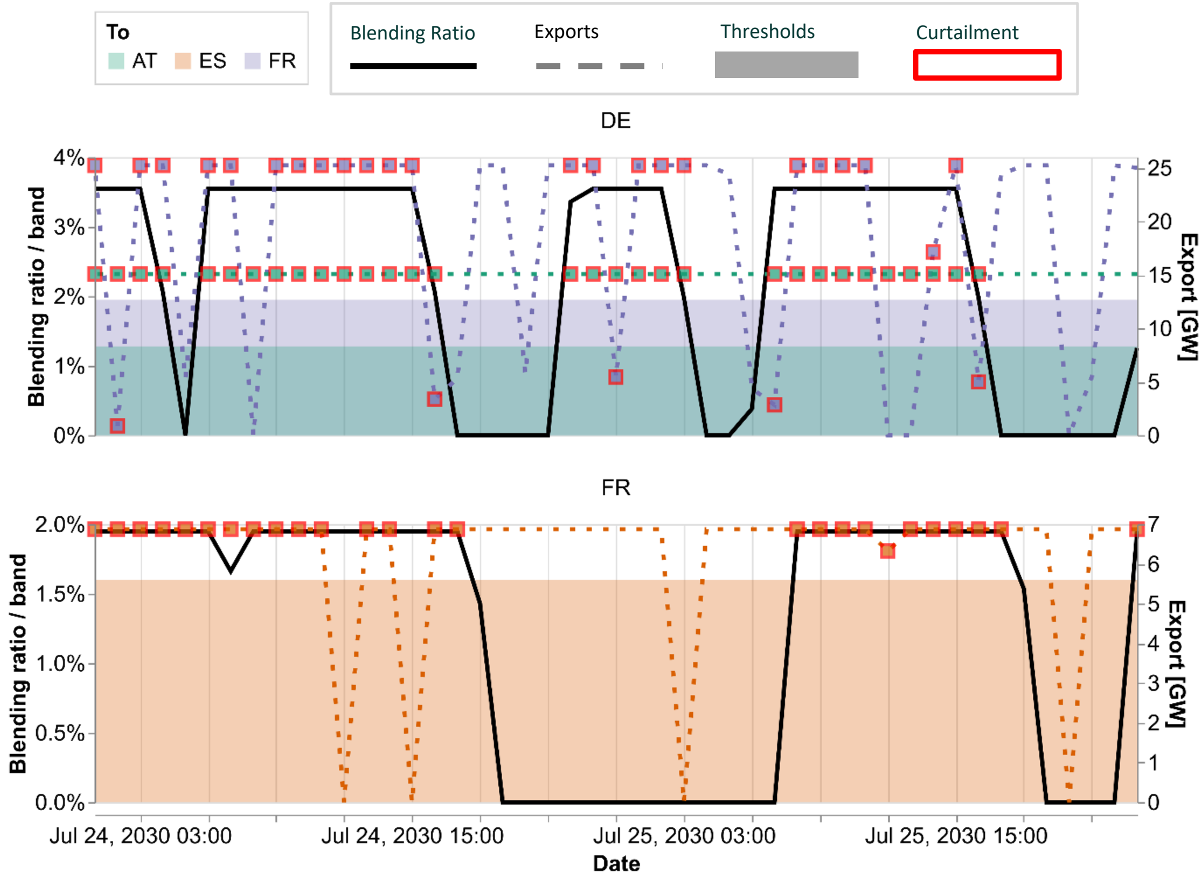
3.1.2 Hourly snapshot of adaptation strategies

Following the methodology, the two principal strategies that can be considered in case the H_2 blending ratio in one zone violates the feasible band in an adjacent zone to which it is exporting would be the curtailment of electrolyser output or respectively gas exports. In terms of order we start this section by first looking at the curtailment of gas exports revealing the constraints at the root of the incompatibility problem and then look at the impacts from curtailing electrolyser injections. For each of these strategies the following two figures illustrate their behaviour for a snapshot of two days in January. In these two figures the left vertical axis shows in percentage terms the variable blending ratios (black line) and the tolerable bands of H_2 blending in the adjacent zones (coloured areas). The dashed coloured lines show the flow of exports in GW to the adjacent zones that are displayed on the secondary vertical axis.

3.1.2.1 Curtailment of exports

Figure 23 illustrates the curtailment that could be imposed on exports from France and Germany. Germany is exporting to Austria and France is exporting to Spain. During the snapshot Germany is exporting a constant flow of 15 GW to Austria whereas exports from Germany to France are cycling between 0 and 25 GW. The blending ratio from H_2 injections is also alternating between 0% and the max. value 3.35 % which is above the maximum blending thresholds in Austria and France of 1.28% and 1.95% respectively. As a consequence, during hours of peak blending ratio in Germany, exports to both Austria and France would be curtailed, whereas in the remaining hours exports would be feasible.

Figure 23. Snapshot of curtailment of gas exports at hourly level. DE is exporting to AT and FR and FR is exporting to ES. H_2 blending ratios and thresholds denoted on primary vertical axis by black lines and shaded areas respectively; exports denoted by dashed lines on secondary vertical axis; curtailment denoted by red frames.



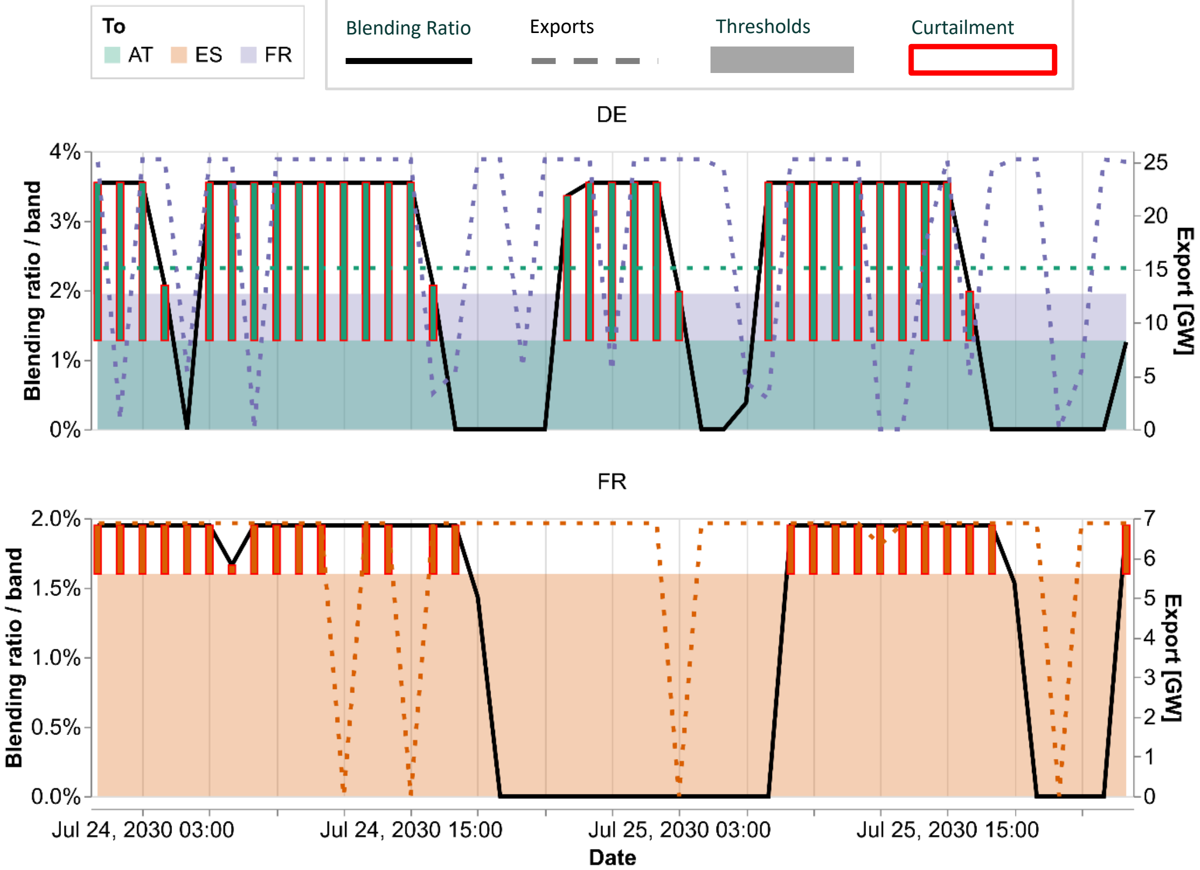
Source: JRC, 2021.

A similar situation can be observed for exports from France to Spain. The blending ratio in France is alternating between 0% and the max value of 1.95% which exceeds the maximum threshold of Spain. Therefore, in hours where a peak blending ratio and simultaneous exports of gas are present in France curtailments would take place. This graph also indicates that the blending ratio mostly appears to switch between the maximum threshold value and zero. However also some intermediate working points can be detected where H_2 injections take place at partial capacity.

3.1.2.2 Adjustment of electrolyser injections

Figure 24 displays the adjustment of electrolyser injections as the rate of change needed to respect the blending threshold(s) of the zone(s) to which exports take place. The interventions obviously take place during the same hours as for the alternate strategy of curtailing exports.

Figure 24. Snapshot of adjustment of electrolyser injections at hourly level. DE is exporting to AT and FR and FR is exporting to ES. H2 blending ratios and thresholds denoted on primary vertical axis by black lines and shaded areas respectively; exports denoted by dashed lines on secondary vertical axis; adjustment of electrolyser injections denoted by red frames.



Source: JRC, 2021.

One further effect can be observed for the case of Germany which is violating the maximum blending threshold of both Austria and France during hours of peak blending ratio. During those hours the injection of hydrogen has to be reduced to meet the requirements of both Austria and France, the rate of reduction is however solely determined by the lower threshold level that has to be reached, which in this case is Austria. A problem would only arise if France had induced a lower blending threshold level that would be above the Austrian maximum threshold level so that the two corresponding bands would not overlap which is not the case here. Then it would not be possible to adjust the output in Germany in a way that exports to both countries would feasible.

3.1.3 Yearly results

Next, we take a look at the results at yearly level which are displayed in Table 12. The first indicator shows the mean blending ratio throughout the year in percentage terms which ranges between 0.50% in Spain and 2.47% in Germany. The divergence in blending ratios can be attributed both to the different threshold levels shown in the second row and to different utilization rates of these threshold levels. The latter is displayed in the following row with shares ranging between 31.5% in Spain and 76.3% in Austria. The lower utilization ratio in Spain compared to Austria is resulting from overall lower operating hours.

Gas exports in this scenario only originate from France and Germany and the yearly mean ranges between 1.64 GW on the FR-ES interconnector and 13.6 GW on the DE-FR interconnector. The hours of threshold violation during which gas exports take place range between 1,459 on the FR-ES border and 4,416 on the DE-AT border. During those hours an adaptation strategy needs to be executed to enable trade. In case curtailing exports would be the applied strategy this would translate into a yearly mean curtailed volume from France to Spain of 1.12 GW. In comparison the curtailment of gas exports from Germany in absolute terms would be higher by a factor 7-9 due to the higher export volumes. The alternative strategy of curtailing injections would affect substantially lower energy volumes. The mean throughout the year would be 0.8 GW for Germany and for France 0.01 GW.

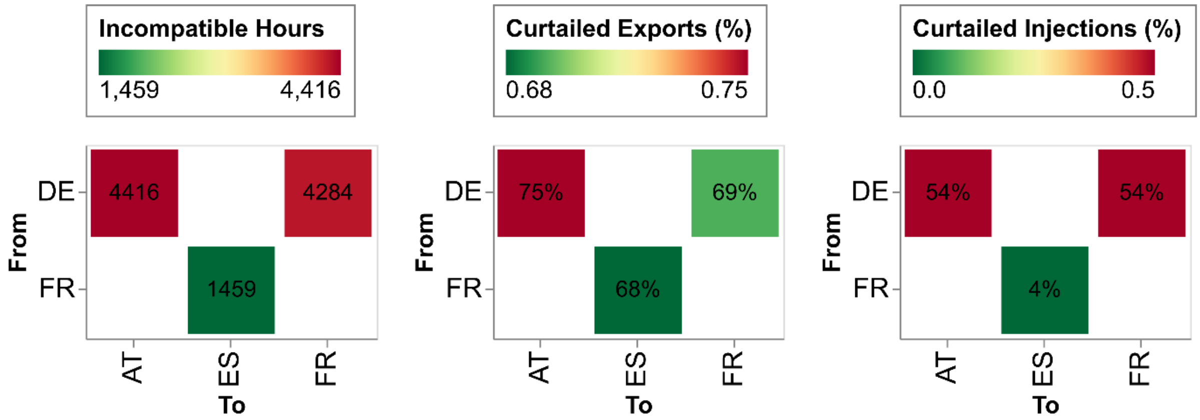
Table 12. Selected result indicators at yearly level for AT-DE-FR-ES case study.

From	**DE**	**DE**	**FR**	**AT**	**ES**
To	**AT**	**FR**	**ES**		
Mean Blending Ratio [% HHV]	2.5%	2.5%	1.13%	0.98%	0.50%
Blending Ratio Max. Threshold [% HHV]	3.6%	3.6%	1.95%	1.3%	1.6%
Blending Ratio - Share of Max	69.5%	69.5%	58.2%	76.3%	31.5%
Mean Exports [GW]	9.5	13.6	1.6		
Threshold Violation Hours	4 416	4 284	1 459		
Mean Curtailed Exports [GW]	7.1	9.4	1.1		
Mean Curtailed Injections [GW]	0.80	0.80	0.01		

Source: JRC, 2021.

A further perspective of the impacts of hours with blending threshold violations is provided in Figure 25, which displays the curtailed volumes in relative terms as share of gas exports or H_2 production respectively. It shows those volumes come out high ranging between around two-thirds and three-quarters in terms of total flows concerned. This is the case due to the high capacity factors of electrolysers in France and Germany which raises the blending ratio in most of the hours, when exports take place, above the blending threshold level of the importing country. High capacity factors of electrolysers are however essential for their economic viability. Thus, in the presence of non-harmonised blending thresholds there would potentially exist a trade-off between the levels of capacity factors of electrolysers and the curtailment of exports. Therefore, the alternative strategy of curtailing electrolyser injections may be the more viable one. While curtailment levels generally are lower in comparison to exports, a level of 54% for Germany is a very high value that cannot be considered as feasible when real-world supply contractual obligations are considered. On the other hand, the level of 4% of curtailed injections for France is a much more modest value and therefore appears more practicable. The main reason for these differences – besides the lower number of hours with gas exports from France compared to Germany – is the significantly smaller difference in blending threshold levels. The 0.35 percentage points the blending ratio in France would need to be lowered from its maximum to meet the threshold level in Spain translates into a 18% reduction which compares small to the about 60% reduction needed for Germany to meet the Austrian threshold level. Thus, it would appear advisable - if non-harmonised blending thresholds cannot be avoided - to keep the differences at a small amount in order to keep electrolyser curtailment at affordable levels. In such a case the strategy of curtailing injections would perform superior to curtailing exports in terms of minimizing trade-offs due to the smaller rate of adjustment needed.

Figure 25. Selected result indicators at yearly level for AT-DE-FR-ES case study.



Source: JRC, 2021.

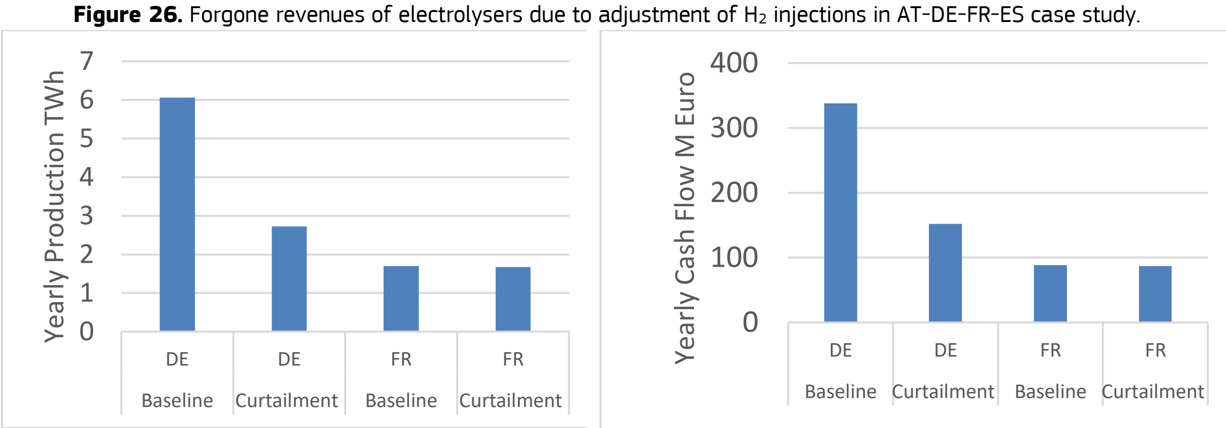
3.1.4 Economic impacts of curtailing electrolyser output

The intervention through curtailing electrolyser output leads to a deviation from the market dispatch which bears some economic costs. We now take a closer look at the differential impacts on forgone market revenues and welfare, comparing the effects of a scenario with curtailment to the baseline case with no curtailment.[8]

3.1.4.1 Forgone revenues of electrolysers

First, we focus on the forgone market revenues in Figure 26. The left-hand panel of the figure below compares the yearly H_2 production between the baseline case and the case where output is curtailed. For Germany this results in a substantial reduction of 55% from around 6 TWh down to less than 3 TWh whereas in France the reduction is much smaller in the order of 1.5%. The main reason for this is again that the average rate of curtailment needed to enable exports from France to Spain is much smaller than what is needed to enable export from Germany to Austria and France. Due to the forced curtailment the cash flows of electrolysers would be reduced in Germany by about 186 M Euro and in France by around 1.3 M Euro.

Figure 26. Forgone revenues of electrolysers due to adjustment of H_2 injections in AT-DE-FR-ES case study.



Source: JRC, 2021. Source: JRC, 2021.

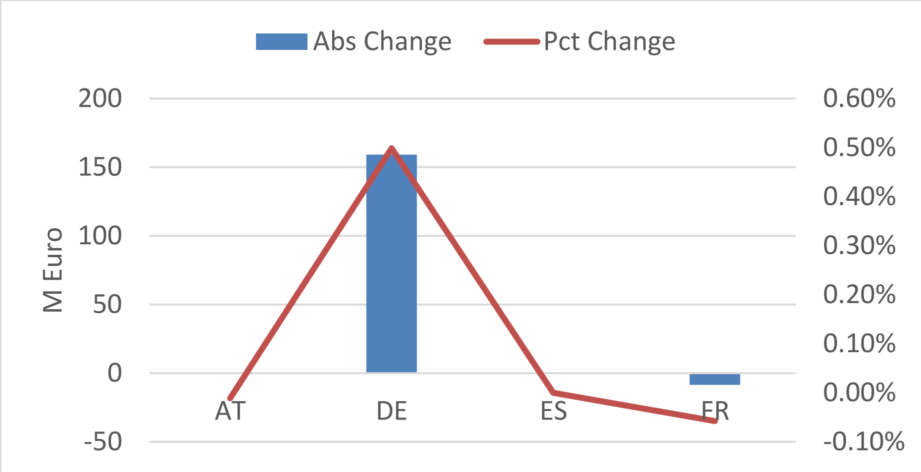
3.1.4.2 Welfare Change

Overall, the change in net welfare in the curtailment scenario with curtailment is positive, however small compared to the baseline case as can be seen from the percent change displayed on the secondary vertical axis in Figure 27. In Germany, where the highest curtailment would take place welfare would increase by about half a percent compared to the baseline. This positive change can be explained by an increase in

[8] For more details on the approach please see Annex 4.

producer surplus as (subsidized) and under given parameters not yet cost-efficient substitution of gas by green hydrogen is avoided. It should however be noted that benefits linked to H_2 production which could potentially (over-) compensate the relative welfare losses in the baseline scenario, such as CO_2 avoidance or future cost reductions, are not accounted for in this perspective. All other rents do not see a noteworthy change.

Figure 27. Welfare change due to adjustment of H_2 injections in AT-DE-FR-ES case study.



Source: JRC, 2021.

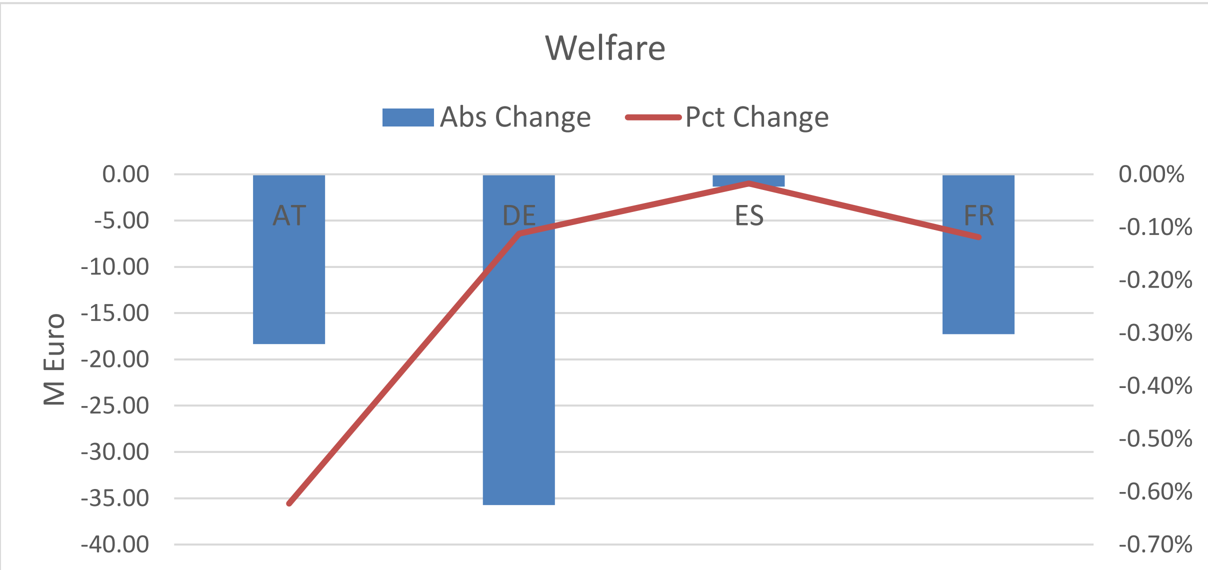
3.1.5 Economic impacts of curtailing exports

This section takes a closer look at the impacts that could derive from curtailing exports.

3.1.5.1 Welfare Change

Figure 28 below shows the absolute (primary vertical axis) and relative changes (secondary vertical axis) of welfare compared to the baseline case without curtailment. In all member states curtailment of exports would lead to a reduction of welfare. In absolute terms the reduction would be highest in Germany with about 35 M Euro whereas in relative terms Austria would see the highest reduction with a decrease of about 0.6 %.

Figure 28. Welfare change due to curtailment of exports in AT-DE-FR-ES case study.

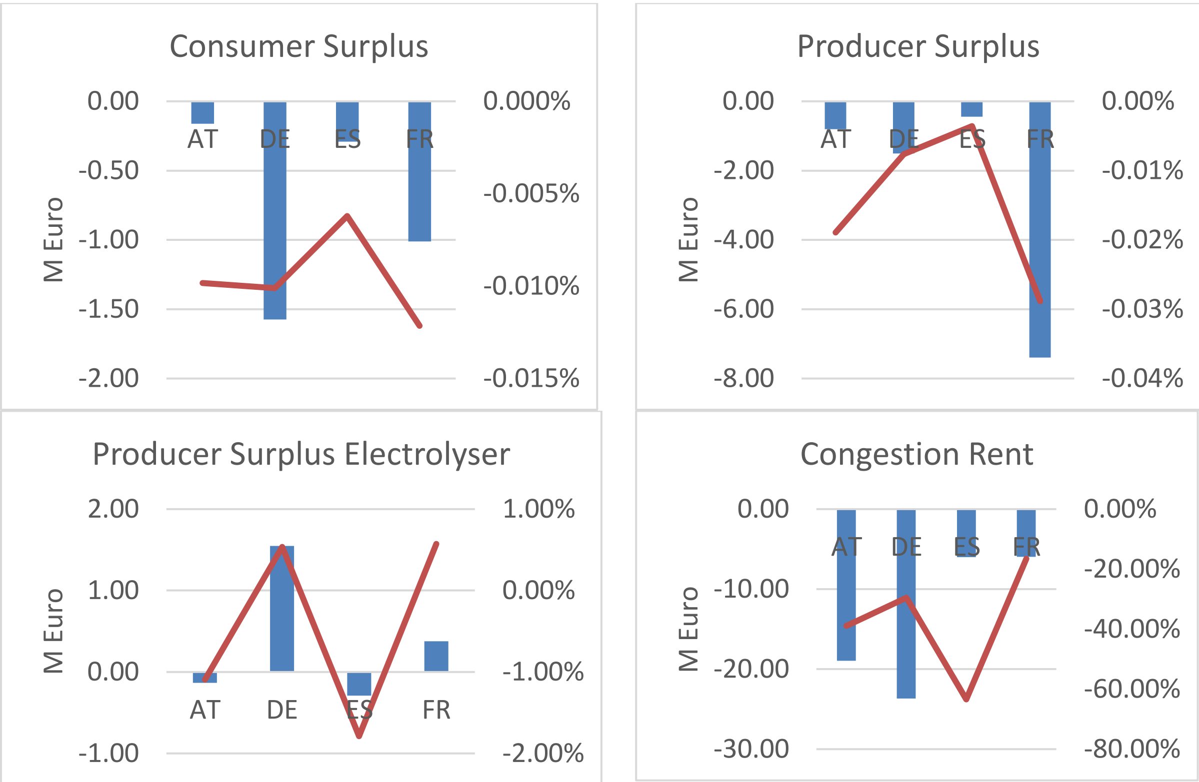


Source: JRC, 2021.

3.1.5.2 Rent Changes

The change of welfare is composed of the changes in different rents that are discussed next with the help of Figure 29. The values do not exactly add up since (smaller) welfare changes in other EU countries modelled with METIS here are not accounted for. As can be seen from the top-left panel consumer surplus would decrease in all member states, the change in relative terms would however be very low. The next panel shows the change in producer surplus. Here the biggest change both in absolute and relative terms would occur in France. The bottom left panel zooms in specifically on the change in producer surpluses of electrolysers. Here it can be seen that the effect is slightly positive in member states that act as gas exporters whereas the opposite is the case in importing member states. This result could appear counter-intuitive at first sight as, ceteris paribus, lower exports should lead to higher gas prices in the importing member state and lower prices in the exporting member state. It can be explained when considering that electrolyser production in this scenario is not yet competitive in terms of market prices and needs to be incentivised through subsidies, which is not accounted for in the calculation of producer surplus. Thus, when electrolyser output is lowered as reaction to lower gas prices also non-cost-effective generation is avoided and vice versa. Finally, the bottom-right panel displays the results for changes in congestion rents which by far accounts for the biggest changes of rents in absolute and relative terms and thus also for changes in welfare. The effects result from the restriction of welfare enhancing trade and are highest on the AT-DE interconnection where the highest volume of curtailed gas flows would have taken place.

Figure 29. Rent changes due to curtailment of exports in AT-DE-FR-ES case study.



Source: JRC, 2021.

Source: JRC, 2021.

3.2 Case Study: Austria, Italy and Slovenia

For the three member states three different levels of maximum blending thresholds have been selected which are displayed in Table 13 on a per volume (vol) and calorific (HHV) basis. These values should be considered exploratory since no official blending ratios have been established yet, however a value of 20% for Italy and 10% for Austria have been stipulated in discussions. In addition, the column to the right displays the electrolyser capacities that have been re-scaled from the T1m scenario to be able to supply the blending thresholds.

Table 13. Input parameters for AT-IT-SI case study.

MS	% vol	% HHV	Electrolyser capacity MW
AT	10	3.35	788
IT	20	7.1	14,810
SI	5	1.6	120

Source: JRC, 2021.

3.2.1 Cross border trade

The total trade volume in this scenario between the three member states is in the order of 57 TWh and the corresponding breakdown for the individual borders is displayed in the table below. Slovenia is not exporting, and the bulk of exports originate from Austria.

Table 14. Gas trade shares between Austria, Italy and Slovenia (modelling results).

Export Share	To			
From	AT	IT	SI	Grand Total
AT	0.00%	49.88%	38.43%	88.31%
IT	6.15%	0.00%	5.54%	11.69%
Grand Total	6.15%	49.88%	43.97%	100.00%

Source: JRC, 2021.

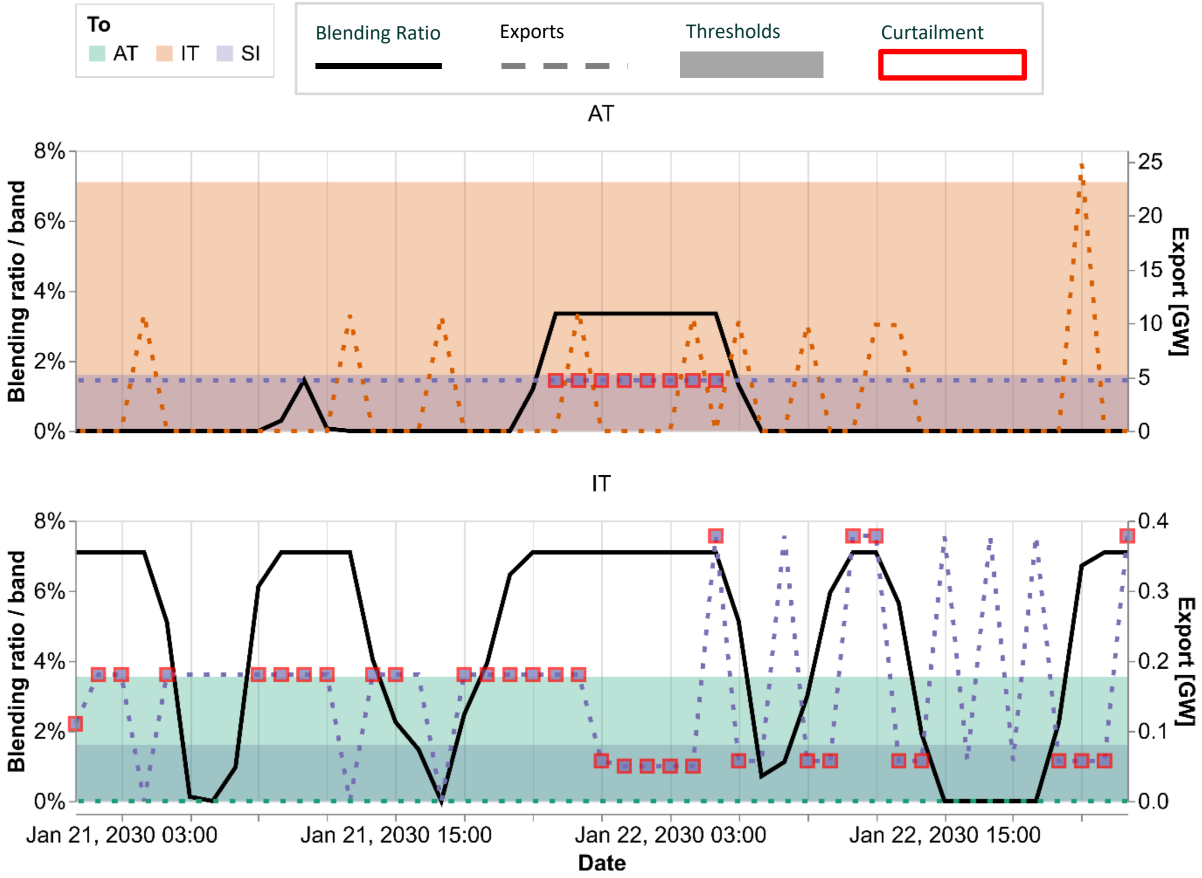
3.2.2 Hourly snapshot of adaptation strategies

This section again first illustrates the behavior at hourly granularity during two days in January. Except for the changed countries the same notation applies as for the first case study.

3.2.2.1 Curtailment of exports

In this strategy, in Figure 30 a curtailment of exports is denoted by a square with a red frame and the colour of the zone to which it is exporting. During the snapshot this occurs both for exports taking place from Austria and from Italy.

Figure 30. Snapshot of curtailment of gas exports at hourly level. AT is exporting to IT and SI and IT is exporting to AT and SI. H_2 blending ratios and thresholds denoted on primary vertical axis by black lines and shaded areas respectively; exports denoted by dashed lines on secondary vertical axis; curtailment denoted by red frames.



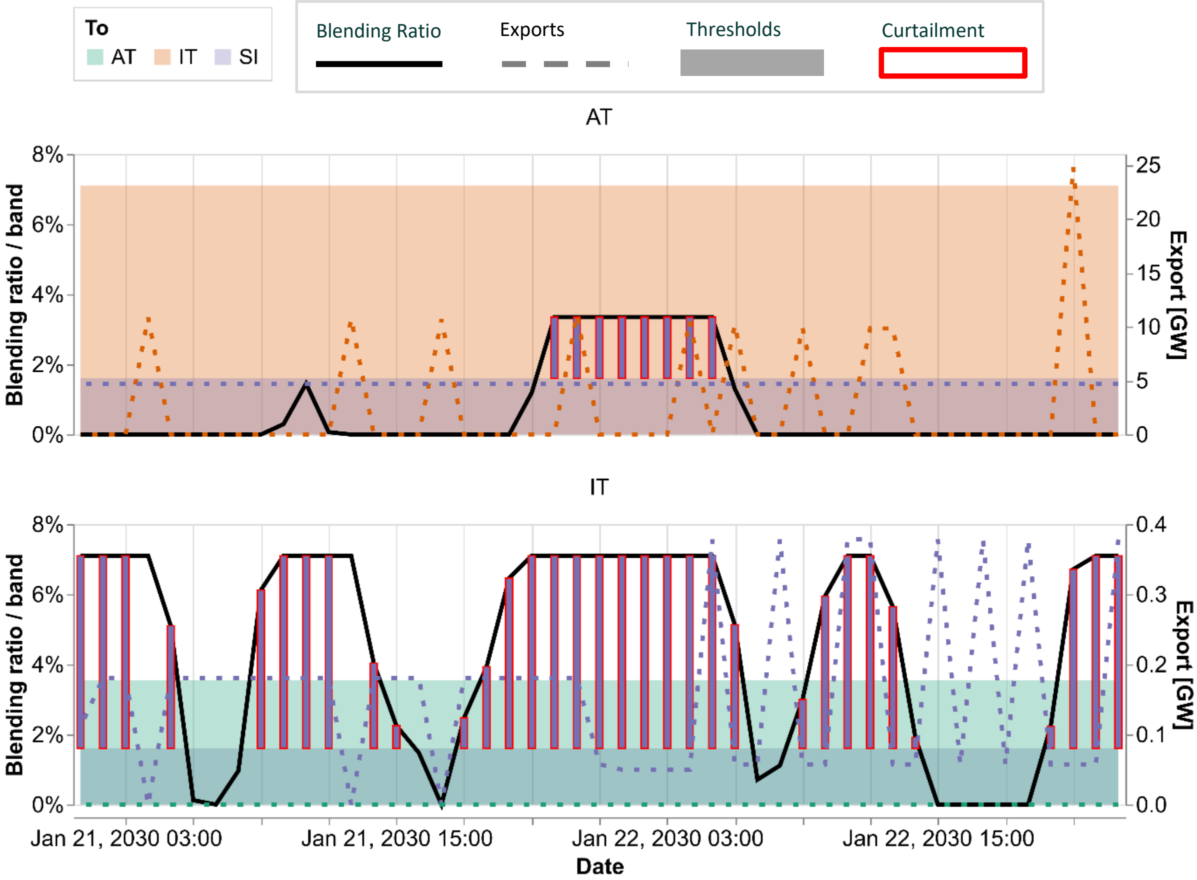
Source: JRC, 2021.

Austria is exporting a constant flow of 5 GW to Slovenia, however during the end of January 21 the H_2 injection in Austria is ramped out to its maximum, which collides with the blending threshold in Slovenia such that during these hours gas exports would have to be curtailed. A similar observation can be made for Italy where both H_2 injections and exports to Slovenia are quite cyclic over the course of the two days. Consequently, when the blending ratio in Italy surpasses the tolerable threshold of 1.6% in Slovenia exports are curtailed.

3.2.2.2 Adjustment of electrolyser injections

In this strategy an adjustment of the electrolyser injections into the gas grid to meet compatible blending ratios as required for gas trade with the adjacent zones is denoted in **Figure 31** by the bars with the red frames. One can observe that this strategy would affect Italy proportionally much stronger since the adjustment of the electrolyser output to meet the requirements of Slovenia would be much higher than in Austria due to the higher domestic maximum blending threshold whereas the export volumes that would be enabled by this would be significantly lower. These observations, which are based on a snapshot of two days, are instructive to illustrate the effects at play at a high granularity. However, these patterns alrady hint at some characteristics embodied in structural patterns as can be ascertained from the table of yearly summary statistics below.

Figure 31. Snapshot of adjustment of electrolyser injections at hourly level. AT is exporting to IT and SI and IT is exporting to AT and SI. H_2 blending ratios and thresholds denoted on primary vertical axis by black lines and shaded areas respectively; exports denoted by dashed lines on secondary vertical axis; adjustment of electrolyser injections denoted by red frames.



Source: JRC, 2021.

3.2.3 Yearly results

The mean blending ratios differ across the three zones in accordance with the diverging maximum thresholds as can be seen from

Table 15. For Italy the mean ratio is closest to the maximum threshold level in relative terms which implies the highest utilisation rate of the electrolyser capacity among the three countries. Since Italy is also the country with the highest absolute blending threshold a high utilisation generally can be expected to have implications for the compatibility with lower thresholds levels in adjacent zones. Looking at the next indicator it shows that the gas exports from Austria are a couple of magnitudes higher than those from Italy, while Slovenia is not exporting to either of the two neighbouring countries.

Table 15. Selected result indicators at yearly level for AT-IT-SI case study.

From	AT	AT	IT	IT	SI
To	IT	SI	AT	SI	
Blending Ratio - Mean	2.49%	2.49%	6.09%	6.09%	0.77%
Blending Ratio - Threshold	3.55%	3.55%	7.10%	7.10%	1.60%
Blending Ratio -	70.02%	70.02%	85.71%	85.71%	48.02%

Share of Max					
Exports [GW] - Mean	3.26	2.52	0.40	0.36	
Threshold Violation - Hours	0	6,519	436	2,657	
Curtailed Exports [GW] - Mean	0.00	1.65	0.39	0.34	
Curtailed Injections [GW] - Mean	0.08	0.08	0.88	0.88	

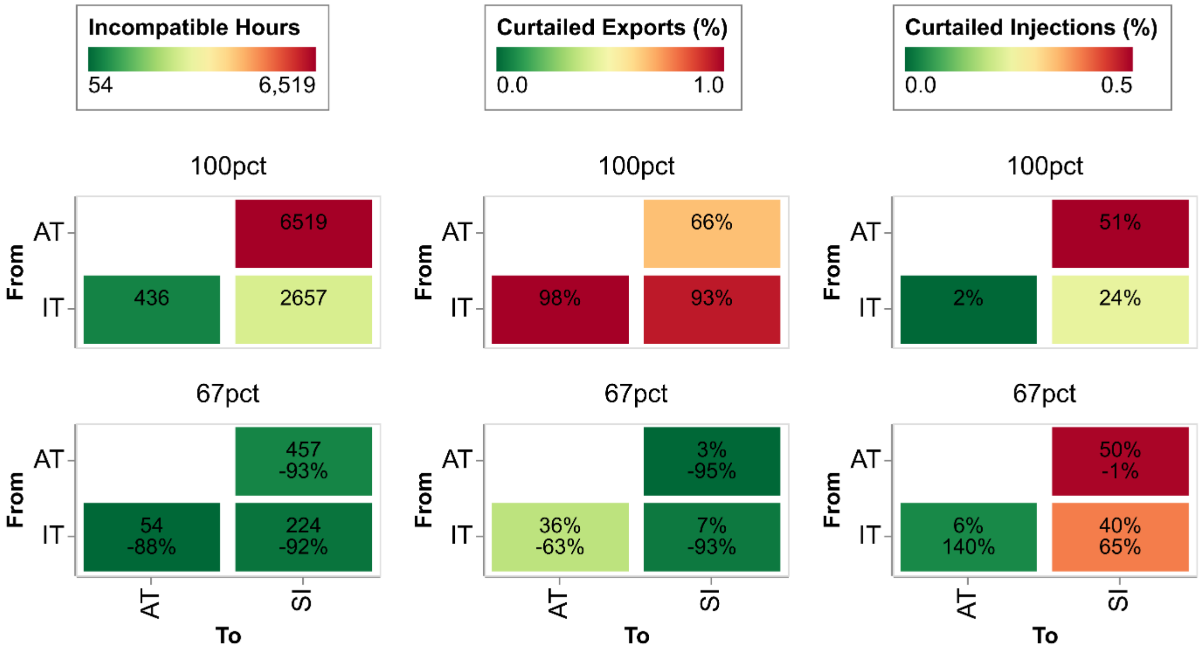
Source: JRC, 2021.

Next, we look at three indicators illustrating specifically the impact of non-harmonised blending thresholds. The first one tracks the number of hours where exports would have led to a violation of required blending ratios. For exports from Austria to Italy this is never the case which can be explained by the higher blending threshold present in Italy whereas for exports from Austria to Slovenia the value of 6 519 incompatible hours is the highest. The latter is due to the high injection levels from electrolyser capacity in Austria in conjunction with the lower maximum blending threshold in Slovenia. For Italy, which has the highest blending threshold gas quality incompatibilities exist both with Austria and Slovenia, whereby the number of hours is higher for the Slovenian border. The number of incompatible hours subsequently translates into curtailed exports by weighting it with the volume of exports. In comparison to curtailed exports, curtailed injections are lower in Austria, but higher in Italy, where two factors come into play: the higher magnitude between the maximum blending threshold in Italy and Slovenia require a higher adjustment rate to reach compatibility and the higher installed electrolyser capacity in Italy compared to the gas interconnection capacity makes each percentage point of adjustment more expensive in terms of gas volumes required.

A complementary perspective is offered by the first row of Figure 32, which shows the curtailed exports as share of total exports and curtailed injections as share of the yearly electrolyser output. One can see that while the numbers of incompatible hours for Italy is much lower compared to Austria the share of curtailed exports is higher and close to the maximum meaning that the bulk of export volumes form Italy would have to be curtailed. This is the case since during those hours the blending ratio in Italy almost consistently is too high due to the high blending threshold paired with high levels of electrolyser operating hours and injections. For Austria this ratio is somewhat proportional suggesting that during the remainder of hours where exports take place to Slovenia no blending ratio violation is present. On the curtailed injection indicator, the figure reveals that in percentage terms Austria would be affected more strongly than Italy – despite a lower absolute mean value on the AT-SI border – accounting for the fact that the absolute electrolyser injection volume in Italy is much higher in relation to the blending threshold.

The second row displays the results of a sensitivity analysis where the subsidy is lowered to 67 percent of its initial level, which leads to substantially lower electrolyser operating hours and injection volumes. As a result, the amount of incompatible hours and the share of curtailed exports would be reduced strongly. The share of curtailed injections on the other hand would not change in Austria and would even increase significantly in Italy. The reason is that production output from the electrolysers is reduced at least at the same rate as the curtailment of injections in absolute terms.

Figure 32. Selected result indicators at yearly level for AT-IT-SI case study. Second row displays sensitivity for lower subsidy level.



Source: JRC, 2021.

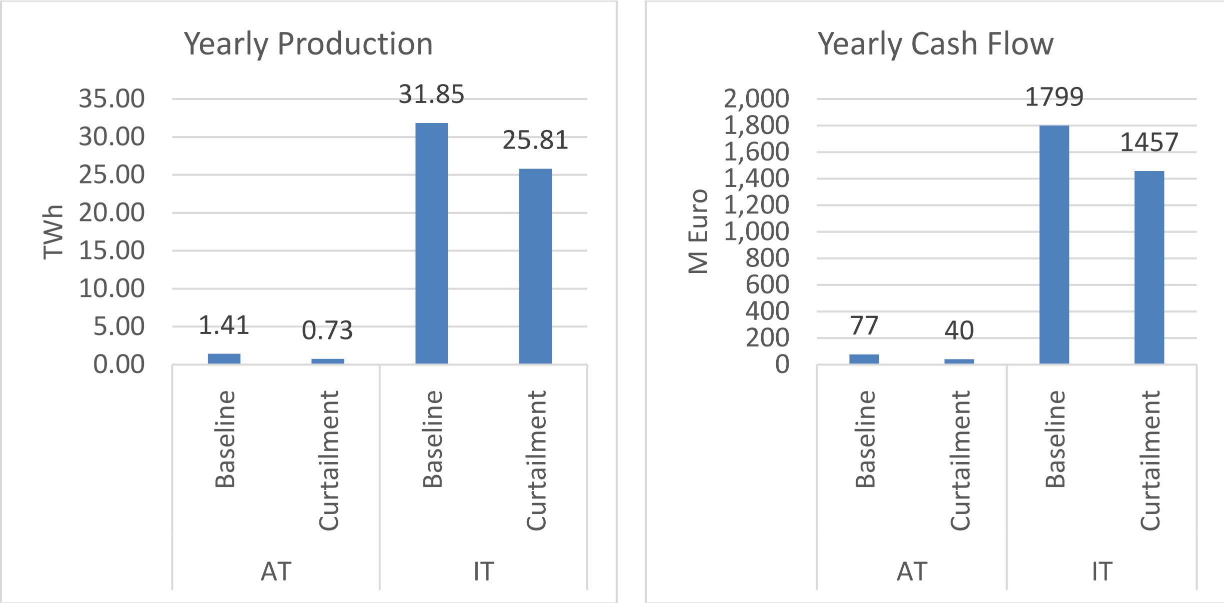
3.2.4 Economic impacts of curtailing electrolyser injections

Next, we look again how the deviation from the market dispatch through the curtailment of electrolyser injections affects economic indicators. We look how they may influence forgone market revenues and welfare.

3.2.4.1 Forgone revenues of electrolysers

Figure 33 displays again the differences between the scenarios with regards to yearly electrolyser production and the resulting impact on their cash-flows. In this case study only production capacities situated in Austria and Italy, which are exporting gas to Slovenia, would be affected. It can be seen again that due to the higher gas demand and blending thresholds the yearly production in absolute terms is much higher in Italy. Thus, also the reduction of output in the order of 6 TWh would be much higher compared to Austria. However, in relative terms the reduction in Austria would be significantly more pronounced and lead almost to a halving. These forced reductions in output are also reflected in the reduced cash flows of electrolysers which would affect their ability for cost recovery. Combined for both member states the reductions would amount to almost 400 M Euro.

Figure 33. Forgone revenues of electrolysers due to adjustment of H_2 injections in AT-IT-SI case study.



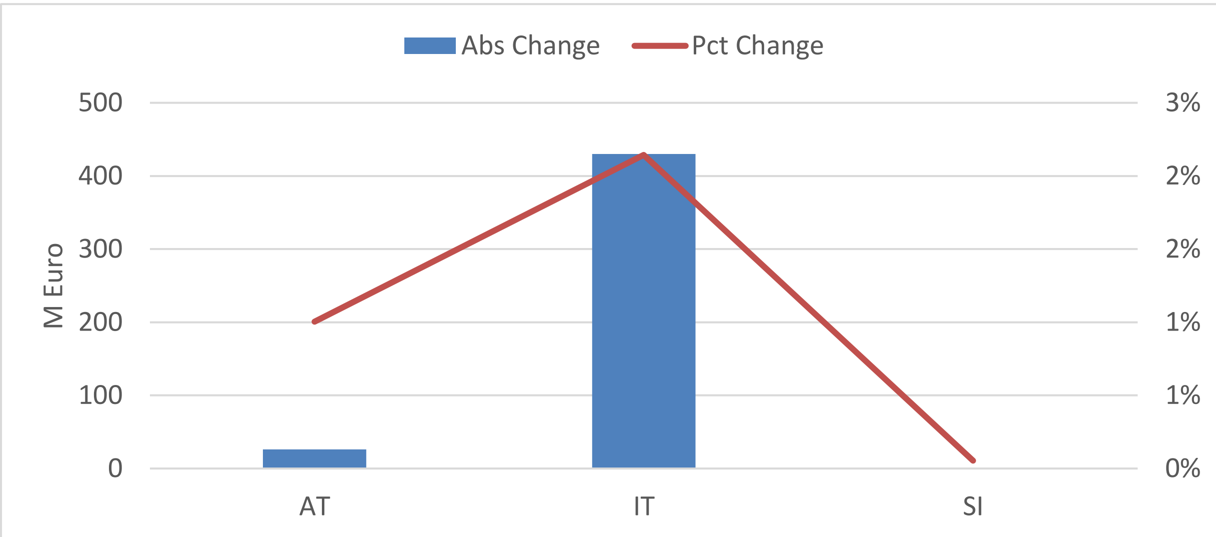
Source: JRC, 2021.

Source: JRC, 2021.

3.2.4.2 Welfare Change

For welfare a similar pattern can be detected as for the first case study as can be seen from Figure 34. The avoidance of not yet cost-effective electrolyser output increases the welfare in all three member states. This obviously again is a static perspective that does not account for external and future benefits of electrolyser hydrogen production.

Figure 34. Welfare change due to adjustment of H_2 injections in AT-IT-SI case study.



Source: JRC, 2021.

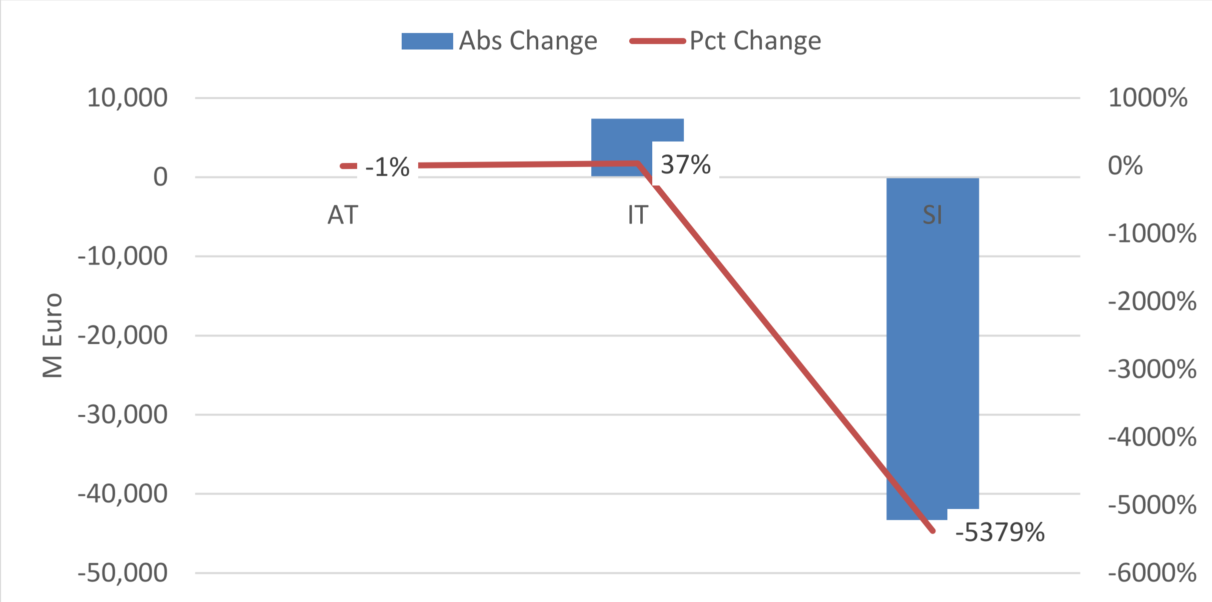
3.2.5 Economic impacts of curtailing exports

This section looks at the impacts of the alternative strategy of curtailing exports, which in this case study would trigger loss of load for gas demand in Slovenia in a high number of hours (~6 000). Therefore, it should be noted that this presents an extreme case which realistically would not be pursued in practice. It however serves to highlight possible drastic consequences in case (unintended) curtailment actions would need to be undertaken.

3.2.5.1 *Welfare Change*

We start by looking at the impacts from curtailing exports on welfare in the figure below. In this case study the curtailment of gas exports from both Austria and Italy to Slovenia would have an extremely negative impact on welfare in Slovenia. Due to a lack of alternative connections to substitute the gas import a loss of load would take place in quite a high number of hours in Slovenia which would translate into the steep, more than fiftyfold reductions in welfare.

Figure 35. Welfare change due to curtailment of exports in AT-IT-SI case study.

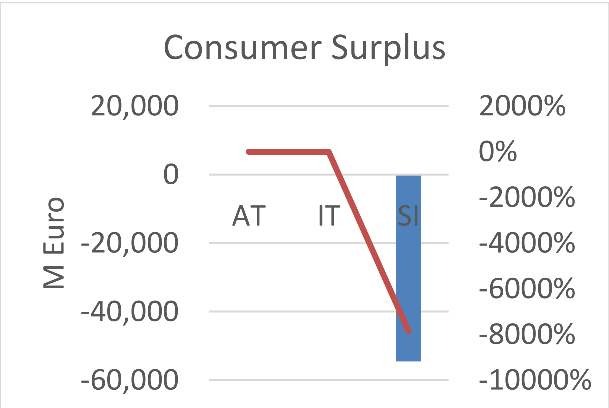


Source: JRC, 2021.

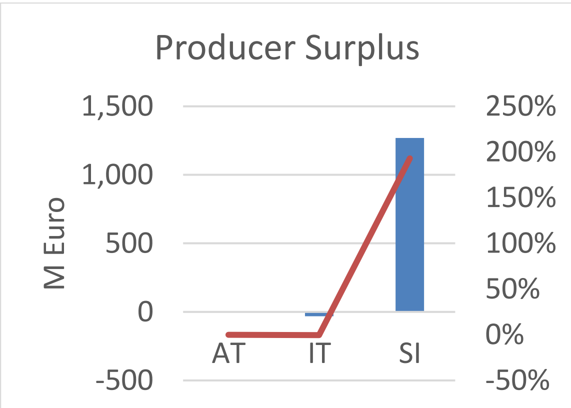
3.2.5.2 *Rent Changes*

Next, Figure 36 displays a breakdown of the welfare changes into the different rent changes. It can be seen that the welfare loss is triggered by the loss of consumer surplus in Slovenia as gas demand cannot be satisfied. On the other hand, Austria and Italy would experience a negligible increase in consumer surplus as gas becomes slightly cheaper due to the curtailed exports. The loss in consumer surplus would be partially offset by net increases in producer surplus and congestion rents, however as the change in welfare shows by far not sufficient to mitigate a net welfare loss. Electrolysers in Slovenia would gain from the higher gas prices whereas producer rents in Austria and Italy would be slightly reduced. Congestion rent would tremendously increase on the IT-SI intrconnector where exports would still take place. This increase would however not be sufficient to converge price levels due to the missing volumes from Austria where the cross-border capacity would not be available in most of the hours.

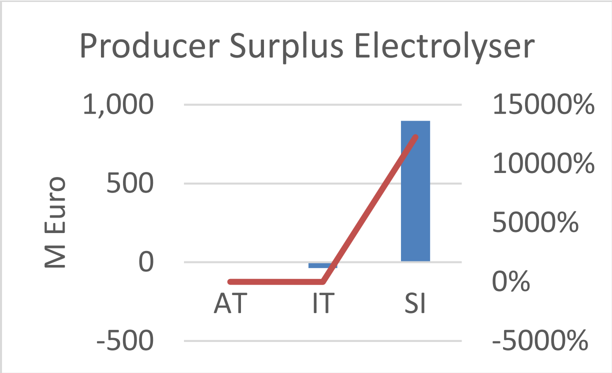
Figure 36. Rent changes due to curtailment of exports in AT-IT-SI case study.



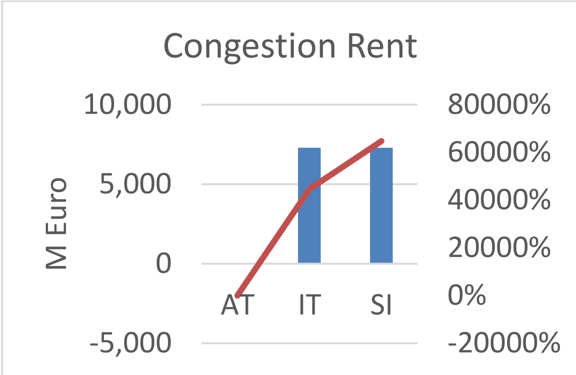
Source: JRC, 2021.



Source: JRC, 2021.



Source: JRC, 2021.



Source: JRC, 2021.

Box 1. *Key take-aways on non-harmonised thresholds*

- In the presence of non-harmonised blending thresholds incompatible gas quality may be present for a significant number of hours.
- The number of hours with incompatible gas quality depend on the relative difference between the blending thresholds, the volume of gas trade between the concerned zones and the volume of electrolyser injections.
- Two intervention strategies were modelled in order to assess the potential costs of enabling hydrogen injections into the gas grid with a different upper threshold of maximum allowed concentration of hydrogen. These are (a) the curtailment of electrolyser injections and (b) the curtailment of exports, when hydrogen content is beyond the specified upper threshold.
- The first strategy, the curtailment of electrolyser injections tends to be affected over-proportionally by high differences of blending thresholds.
- The second strategy, curtailment of gas exports tends to be affected over-proportionally by high volumes of export gas flows.
- Both strategies are affected by the number of operating hours of the electrolysers. High capacity factors are however essential for the economic viability of electrolysers.
- As expected curtailing electrolyser H_2 injections, entails significantly lower distortions than curtailing exports of gas with hydrogen concentrations exceeding the downstream threshold.
- A practical recommendation would be to keep the differences between blending thresholds – if not avoidable – at a small amount in order to avoid larger distortions, in particular for countries with high export volume of gas.

4 Conclusions

In this analysis we modelled electrolytic hydrogen generation as a process linking two separate energy systems (power and gas) formerly connected only with one link, the gas-fired power generation fleet. Multiple market configurations were introduced in order to assess the interplay between diverse market arrangements in the power market and the constraints imposed by the upper bound on hydrogen production, due to gas quality requirements. What follows is a summary of the main findings.

1. Hydrogen blending thresholds in the natural gas grid is a matter of ongoing research/debate. Our literature review led us to consider two threshold levels, 5%vol and 20% vol, as potentially applicable in the mid term (2030 onwards).
2. With a 5% blending threshold up to 18.4 GW electrolyser capacity could be integrated EU-wide. This figure rises to 40-70.8 GW with a 20% blending threshold, depending on the electrolyser configuration scheme. Electrolyser capacities for a 20% vol threshold are in the same order of magnitude as the capacities quoted in the EU Hydrogen Strategy and in the published national strategies of several member states (ES, NL, FR, IT, DE, PT).
3. H_2 production is largely dependent on the electrolyser configuration and price support mechanisms (if available) in the case of purely market-driven arrangements. The maximum hydrogen production that may be blended into gas systems EU-wide under a threshold of 20 % vol is approximately 4.5 million tonnes. This value is attainable with a wind-driven configuration. This means almost half of the 10 million tonnes of hydrogen to be produced according to the EU Hydrogen Strategy could be blended into the gas system.
4. This is also due to the fact that only a fraction (50-85%) of the available green electricity (in RES linkage schemes) can be converted to H_2 due to the temporal correlation of gas demand and wind/solar availability constraints.
5. On average, wind consistently yields higher outputs over solar and market-driven dispatch in terms of H_2 production and capacity factors, resulting in lower on-average production costs.
6. Emissions of CO_2 increase if electrolysers are introduced without the addition of renewable capacity. Exceptions to this general conclusion are the market-based scenarios without subsidy, as well as the marginally subsidised PS1 (the market-based scenario where a minimal subsidy is included, thus internalising CO_2 abatement benefits).
7. Market-driven or hybrid schemes lead to a lower H_2 carbon intensity (calculated based on system-wide CO_2 emission change, compared to the counterfactual with no H_2) compared to direct linkage with the RES resource. As additional RES capacity is introduced, the carbon intensity of hydrogen (additional CO_2 due to the operation of the electrolysers) drops significantly.
8. The lowest values achieved in the solar and wind-based hybrid schemes are 7.3 and 7.9 kg CO_2/kg H_2. Both values are lower than the EU ETS benchmark for free allocation of allowances (8.85 kg CO_2/kg H_2) but higher than the EU Taxonomy threshold for sustainable hydrogen manufacturing (5.8 kg CO_2/kg H_2) (3).
9. Modelling results in one of the scenarios point to the conclusion that providing flexibility with a buffer storage in the order of a few hours can significantly lower the carbon intensity of hydrogen produced with electrolysis and blended with natural gas.
10. While CAPEX and variable cost components of hydrogen blended in the gas network vary considerably, their sum, in all but three scenarios considered in the present study, ranges between 3 and 4 €/kg[9] H_2.
11. The presence of non-harmonised H_2 thresholds in neighbouring countries, where important gas trade takes place, could induce significant trade barriers or hydrogen injection constraints to the upstream grid.

[9] This result is valid under the EUCO3232.5 scenario fuel and CO2 price assumptions and thus should not be considered as valid in market conditions such as those witnessed in the second half of 2021, when the unprecedented surge of the natural gas price occurred.

12. A practical recommendation would be to minimise differences in rules related to the maximum allowed concentration of hydrogen in gas networks in order to avoid distortions, especially for neighbouring countries with high gas exchange volumes.

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List of abbreviations and definitions

CAPEX	Annuity related to Capital investment
HHV	Higher heating (calorific) value
RES	Renewable energy resource (generation)
WI	Wobbe Index
WTP	Willingness to pay

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Annexes

Annex 1. Price Support

The PS2 support is country specific and is equal to the difference in the electricity versus gas marginal costs, weighted by the electrolysers efficiency. as follows:

$FIP_{PS2i}\ P_{eli} - P_{gi} \times n_{elz}$

Where

FIP_{PS2i} Feed in premium PS2 in country i

P_{eli} is the electricity marginal cost in country i

P_{gi} is the gas marginal cost in country i

n_{elz} is the conversion efficiency of the electrolyser

The scheme simulated by the scenario PS3 aims at levelling the playing field between a baseline hydrogen production technology (the steam methane reforming, or SMR) and the electrolytic production. The PS3 feed in premium is calculated according to the following:

$FIP_{PS3i}=P_{eli} - (P_{gi} \times n_{elz} / n_{SMR} + cf \times P_{CO2})$

FIP_{PS3i} Feed in premium PS3 in country i

P_{eli} is the electricity marginal cost in country i

P_{gi} is the gas marginal cost in country i

n_{SMR} is the energy efficiency of the reforming process

cf : Carbon intensity of the SMR process with natural gas

P_{CO2} : The carbon price

Table 16. Price-support levels

Scheme	Name	Value
PS1	CO_2 driven	3.8 €/MWh_e
PS2	Gas price-parity	33-45 €/MWh_e Pel – Pg x nelz
PS3	SMR H2 – parity	28-40 €/MWh_e $\mathrm{Pel} - \left(\mathrm{Pg}\frac{\eta_{elz}}{\eta_{SMR}} + \mathrm{cf} \times \mathrm{PCO2}\right)$
PS4	Biomethane parity	Country €/MWhe AT 17 BE 35 DK 35 EE 80 FR 90 DE 66.5 IT 60 SE 30 NL 70.5 UK 63
10-50	-	10-50

Source: JRC, 2021.

Annex 2. Electrolysers

Table 17. Estimates of techno-economic parameters of electrolyser technologies

Technology	Year	Investment cost min (million EUR2019/MWH2out)	Investment cost mid (million EUR2019/MWH2out)	Investment cost max (million EUR2019/MWH2out)	Efficiency min (system; LHV)	Efficiency mid (system; LHV)	Efficiency max (system; LHV)	Source
Green - Alkaline electrolysers (ALK)	2020	0.628	1.292	1.955	63%	67%	70%	(IEA, 2019)
	2020	0.444	0.696	0.947	63%	66%	68%	(H21 NoE, 2018)
	2020	1.395	1.395	1.395	51%	51%	51%	(IRENA, 2018)
	2020	1.158	1.998	2.837	49%	59%	69%	(Schmidt, 2017)
	2030	0.496	0.824	1.151	65%	68%	71%	(IEA, 2019)
	2030	0.361	0.551	0.740	68%	69%	69%	(Hydrogen Europe, 2020)
	2030	0.700	0.700	0.700	65%	65%	65%	(IRENA, 2018)
	2030	0.736	1.134	1.531	52%	63%	73%	(Schmidt, 2017)
	2050	0.220	0.550	0.880	70%	75%	80%	(IEA, 2019)
	2050	0.289	0.289	0.289	69%	69%	69%	(Hydrogen Europe, 2020)
Green - Polymer Electrolyte Membrane electrolysers (PEM)	2020	1.613	2.221	2.828	56%	58%	60%	(IEA, 2019)
	2020	1.997	1.997	1.997	57%	57%	57%	(IRENA, 2018)
	2020	1.474	2.438	3.402	55%	59%	63%	(JRC, 2019)
	2020	1.266	2.431	3.596	52%	58%	63%	(Schmidt, 2017)
	2030	0.841	1.468	2.095	63%	66%	68%	(IEA, 2019)
	2030	1.037	1.037	1.037	64%	64%	64%	(IRENA, 2018)
	2030	0.998	1.728	2.457	59%	64%	68%	(JRC, 2019)
	2030	0.772	1.756	2.739	52%	61%	69%	(Schmidt, 2017)
Green - Solid Oxide Electrolysers (SOEC)	2020	3.041	4.850	6.658	74%	78%	81%	(IEA, 2019)
	2020	1.066	1.066	1.066	76%	76%	76%	(JRC, 2019)
	2020	2.132	2.898	3.664	80%	80%	80%	(Schmidt, 2017)
	2030	0.838	2.019	3.199	77%	81%	84%	(IEA, 2019)
	2030	0.582	0.582	0.582	80%	80%	80%	(JRC, 2019)
	2030	0.799	2.065	3.331	80%	80%	80%	(Schmidt, 2017)
	2050	0.489	0.816	1.143	77%	84%	90%	(IEA, 2019)
	2050	0.388	0.388	0.388	80%	80%	80%	(JRC, 2019)

Blue - CCS for existing Steam Methane Reforming (SMR) plant	2020	0.701	0.701	0.701	N/A	N/A	N/A	(Jakobsen & Åtland, 2016)
Blue - New Steam Methane Reforming (SMR) plant & CCS	2020	1.650	1.650	1.650	N/A	N/A	N/A	(Jakobsen & Åtland, 2016)
	2020	0.963	0.963	0.963	N/A	N/A	N/A	(ASSET, 2018)
	2020	1.594	1.594	1.594	69%	69%	69%	(IEA, 2019)
	2020	0.792	1.100	1.408	N/A	N/A	N/A	(IEA, 2019)
	2030	0.909	0.909	0.909	N/A	N/A	N/A	(ASSET, 2018)
	2030	1.290	1.290	1.290	69%	69%	69%	(IEA, 2019)
	2050	0.856	0.856	0.856	N/A	N/A	N/A	(ASSET, 2018)
	2050	1.214	1.214	1.214	69%	69%	69%	(IEA, 2019)
Blue - CCS for existing Autothermal Reforming (ATR) plant	2020	0.688	0.688	0.688	N/A	N/A	N/A	(Jakobsen & Åtland, 2016)
Blue - New Autothermal Reforming (ATR) plant & CCS	2020	1.498	1.498	1.498	N/A	N/A	N/A	(Jakobsen & Åtland, 2016)
	2020	0.952	0.952	0.952	N/A	N/A	N/A	(H21 NoE, 2018)

Source: ASSET consortium.

Annex 3. Detailed data on electrolyser operation

Table 18 provides the annual electrolyser output (column d) for two market-driven and four RES-driven scenarios, as well as the theoretical values (a) - (c).

Table 18: Hydrogen that may be blended in the gas grid compared to the maximum theoretical (TWh)

Scenario name	Maximum theoretical hydrogen production (without RES constraints)	Maximum hydrogen allowed in the grid (TWh)	Maximum theoretical hydrogen production (with RES constraints)	Generated hydrogen (TWh)	Share generated vs Max allowed into the grid (%)	Share of available renewable electricity that may be converted into hydrogen and introduced into the gas network
	(a)	(b)	(c)	(d)	(d)/(b)	(d)/(c)
T1m	109	49.5	-	0.4	0.8%	-
T2m	486	220	-	1.4	0.7%	-
Solar	486	220	66.2	50.4	22.9%	76%
Solar 3.3	486	220	161	79.7	44%	49.4%
Wind	486	220	112	96.6	36.3%	86%
Wind 3.3	486	220	298	174	79.1%	58.4%

Source: JRC, 2021.

Annex 4. Methodology for assessing impacts of non-harmonised H_2 threshold levels

Table 18 below displays the nomenclature used in the description of the approach.

Table 19. Nomenclature for ex-post analysis

Sets	
$t \in T$	…time step
$n, nn \in N$	…zones
$s \in S$	…scenarios [base, curtailment]
Parameters	
$Q_{t,n}$	…H_2 production at time step t in zone n [$MWhH_2$]
$D_{t,n}$	…Gas demand at time step t in zone n [$MWhCH_4$]
$\bar{Q}_{t,n}$	…Normalised H_2 production [0,1]
$X_{t,n,nn}$	…Gas exports at time step t from zone n to zone nn [$MWhCH_4$]
$B\_max_{t,nn}$	…Max blending threshold in time step t in (importing) node nn
$B\_min_{t,nn}$	…Min blending threshold in time step t in (importing) node nn
$\overline{B\_max}_{t,nn}$	…Normalised max blending threshold [0,1]
$\overline{B\_min}_{t,nn}$	…Normalised min blending threshold [0,1]
$Avail_{t,n,nn}^{s}$	Availability of gas cross-border transmission capacity in time step t and scenario s, between nodes n and nn
Result Variables	
$Curtail\_X_{t,n,nn}$	…Curtailment of gas exports from zone n to zone nn [$MWhCH_4$]
$Curtail\_Q_{t,n,nn}$	…Curtailment of electrolyser output in zone n to comply with thresholds in zone nn [$MWhH_2$]
Boolean Variable	
$Bool_{t,n,nn}$	…Boolean Variable [True, False]

Source: JRC, 2021.

For each zone n, nn and time step t the ex-post analysis takes as input parameters H_2 injections from the renewable electrolysis ($Q_{t,n}$), the gas demand ($D_{t,n}$), the gas exports ($X_{t,n,nn}$), as well as the upper ($B\_max_{t,n}$) and lower ($B\_min_{t,n}$) blending thresholds respectively. To ensure comparability across zones H_2 production and blending thresholds are normalized by division through the zonal gas demand in each time step.

To analyse the compatibility of H_2 injections in each zone derived from the model simulation with the blending thresholds of the adjacent zones all the data is organized in a table structure where the rows account for the hourly observations corresponding to all feasible combinations of the sets T and N and the columns refer to the different input parameters. That is, for each time step and possible pair of zones the table contains the corresponding values of H_2 production, gas exports and H_2 blending thresholds.

Table 20. Sets and parameters

Sets			**Parameters**			
t	n	nn	$\bar{Q}_{t,n}$	$X_{t,n,nn}$	$\overline{B\_max}_{t,nn}$	$\overline{B\_min}_{t,nn}$
	⋮				⋮	

Source: JRC, 2021.

Then for each row a script is executed that conducts a Boolean indexing where

$$Bool_{t,n,nn} = \begin{cases} \text{True}, & \text{if } \bar{Q}_{t,n} \geq \overline{B\_min}_{t,nn} \, and \, \bar{Q}_{t,n} \leq \overline{B\_max}_{t,nn} \\ \text{False}, & otherwise. \end{cases}$$

Adaptation strategies

In cases where the blending ratio resulting from the H_2 production in zone n violates the tolerable band of blending thresholds in zone nn the Boolean variable is set to False. If this is the case and (ex-post infeasible) gas exports would have taken place two adaptation strategies can be considered. The two strategies, a curtailment of H_2 injections or a curtailment of gas exports, relate to the binary nature of the ex-post approach. In practice also more targeted options like a de-blending facility might be potential strategies. These however are typically associated with a cost function (rather than a binary decision) which cannot be modelled with the ex-post approach. Since the here considered strategies are always available as options (of last resort) they can be considered benchmarks against which alternate strategies have to compete in terms of impacts.

Curtailment of H_2 Injections

A first strategy would consist of harmonizing the blending ratio in the exporting zone *n* with the gas quality requirements in the importing zone *nn*. Here, in principle two situations are possible. If the blending ratio would be too high electrolyser injections would have to be curtailed. This appears to be the more likely case. If the blending ratio would be too low, which could be the case if lower blending thresholds are installed, hydrogen injection would have to be increased meaning that curtailment could also take a negative value. This would however only be possible if sufficient electrolyser and/or storage capacity would be available to ramp-up the injection. The resulting calculation for the variable $Curtail\_Q_{t,n}$ that refers to output adaptation of the electrolyser in the exporting zone are shown in the equation below. In both cases the level of curtailment is determined by the biggest distance between the blending ratio in comparison to the blending thresholds of all adjacent, importing zones.

$$Curtail\_Q_{t,n} = \begin{cases} \max\limits_{nn}\left(\bar{Q}_{t,n} - \overline{B\_max}_{t,nn}\right) \times D_{t,n}, & \text{if } \; Bool_{t,n,nn} = False \; and \; \bar{Q}_{t,n} > \overline{B\_max}_{t,nn} \; \forall \; nn \\ \min\limits_{nn}\left(\bar{Q}_{t,n} - \overline{B\_min}_{t,nn}\right) \times D_{t,n}, & \text{if } \; Bool_{t,n,nn} = False \; and \; \bar{Q}_{t,n} < \overline{B\_min}_{t,nn} \; \forall \; nn \\ & and \text{ if } \overline{B\_min}_{t,nn} \leq \overline{B\_max}_{t,n} \; \forall \; nn \\ 0, & otherwise. \end{cases}$$

Curtailment of gas exports

In the second strategy all exports from zone *n* to zone *nn* in time step *t* would be curtailed to avoid the mixing of incompatible gas quality standards. The variable $Curtail\_X_{t,n,nn}$ counts all the instances and amounting quantities of such a setting, i.e. the whole (ex-post infeasible) volume of exports that would have taken place are accounted as curtailed in the respective hour.

$$Curtail\_X_{t,n,nn} = \begin{cases} X_{t,n,nn}, & \text{if } \; Bool_{t,n,nn} = False \\ 0, & otherwise. \end{cases}$$

Economic impacts of curtailments

In a subsequent step the curtailment information from the two adaptation strategies can also be assessed in monetary terms through an (ex-post) analysis of the effects on economic welfare and/or forgone revenues. Welfare in METIS is computed as key performance indicator for each scenario separately, however more revealing is the change in welfare in comparison to a counterfactual baseline scenario. Let us therefore denote the counterfactual scenario with no curtailment *base* and the scenario with curtailment *curtail*.

In the first strategy of curtailing electrolyser output the *curtail* scenario could be derived for the two situations as follows.

In the situation where the blending ratio would be too high to respect the maximum blending threshold in zone *n*, in each hour the threshold would be reduced by subtracting the level of curtailment required to make gas exchanges feasible. This parameter would then be passed to the *curtail* scenario METIS run.

$$B\_max_{t,n}^{curtail} = B\_max_{n}^{base} - Curtail\_Q_{t,n}$$

In the other situation where the blending ratio would be too low the curtailment variable would be subtracted from the lower blending threshold. Please note that in this situation the blending variable would take a negative value so that the minimum blending threshold in the *curtail* scenario would be overall increased.

$$B\_min_{t,n}^{curtail} = B\_mix_{n}^{base} - Curtail\_Q_{t,n}$$

For the alternative strategy of curtailing gas exports, a curtail scenario can be set up as follows, where the parameter $Avail_{t,n,nn}^{s}$ denotes the availability of the gas transmission interconnection capacity between the zones *n* and *nn* in time step *t*.

$$Avail_{t,n,nn}^{curtail} = \begin{cases} 0, & \text{if } Bool_{t,n,nn} = False \\ Avail_{t,n,nn}^{base}, & otherwise. \end{cases}$$

The change in economic welfare for both strategies then can simply be derived as the difference between the two scenarios and if demands are inelastic corresponds to the difference in total system production costs.

$$\Delta Welfare = Welfare^{curtail} - Welfare^{base}$$

For the strategy of adjusting electrolyser output however the impact on overall welfare can be expected to be rather small as long as the output accounts for small share of overall energy consumed. From a static perspectiveit might even turn positive if subsidies, required to incentivise the not yet economic dispatch, would be avoided. Therefore, a complementary indicator could be to compare the forgone revenues of electrolysers resulting from their forced curtailment. The analogy here would be given by the case of re-dispatch where power plants are paid to adjust their output in order to overcome grid congestion. Re-dispatch costs typically are borne by the electricity consumers.

$$\Delta Revenue = Revenue^{curtail} - Revenue^{base}$$

Limitations of the ex-post approach

The ex-post analysis approach can be expected to deviate from the more refined, endogenous modelling approach due to several limitations:

- The assumption that all injections take place in transmission network could lead to an overestimation of the blending ratio.
- Flows are only considered indirectly (as shares of hourly gas demand, thus implicitly all stocks and flows are replenished each hour) and stocks are neglected. Thus, the higher the actual share of stocks (for instance gas stored in pipelines) to flows the more skewed the analysis gets.
- The static nature of the approach does not consider the simultaneous impact of changes in different flows and stocks, e.g. when electrolyser output is reduced for compatibility with a neighbouring zone this would also change the compatibility with all other zones.

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