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From Natural Gas to Hydrogen

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The energy price implications of infrastructural investments based on a shadow price approach

By

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Preface

As a civil engineer I have a profound interest in the built environment surrounding us, and especially the vital infrastructure that upholds civilization as we know it. After the years I spent studying how to design these infrastructures, as a graduate student I decided to focus my thesis research on the higher level decision-making support preceding the realization of these projects. During my time as a designer I learnt from the experience of my more senior colleagues how much policy can dictate our everyday work as engineers, yet how little influence they felt in providing guidance for the progress of the regulatory environment. This experience motivated me in choosing my topic and executing this research.

The sudden, unfortunate and more often than not dreadful geopolitical developments of this year provided an unwelcome topicality to the subject addressed in this thesis. On 31 December 2021 the Dutch TTF Gas Futures price – the leading pricing benchmark for North-West Europe – stood on 65.0 EUR/MWh. By 20 May 2022 it reached 90.5 EUR/MWh and it reached an all-time high at 346.5 EUR/MWh on 26 August 2022. Currently (28 September 2022) it stands at 207.2 EUR/MWh. This increase and volatility of energy prices in Europe is unprecedented, disruptive and ultimately harmful not just in an abstract way – it affects all of us in our lives, in the end of every month, paying the utility bills.

This research explores the transmission infrastructure's role in the price formation of hydrogen for a future, carbon-free economy, aiding the decision-makers by providing insight on the different options' potential to mitigate price volatility, promote grid stability and ultimately transport hydrogen in a less expensive way.

Gergely Boldizsár
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Contents

Executive summary

Climate change, unfavourable geopolitical developments and resource scarcity pushes the fossil fuel based energy sector in the direction of renewable, carbon-neutral resources. The volatile nature of these, however, created new, technical needs for increased storage capacity and interconnectedness of demand and supporting grid, providing flexibility options. Hydrogen re-emerged as a possibility in the scientific discussion because as a potentially green energy carrier it is easy to store, transport and convert to and from electricity. The economic advantages of transporting hydrogen in its original, molecular form via pipelines rather than relying simply on the electric transmission grid are connected to the amount of energy that needs to be transported – the pipeline transportation usually requiring larger upfront investment but operating with lower unit costs. The uncertainty, however, regarding the competitiveness of hydrogen in possible end-use applications translates into unpredictability in its penetration of the future economy, bringing the return on investment of pipeline transportation options into question.

This thesis, using a quantitative analysis, compares the advantages and disadvantages of the identified, technologically possible transmission options – electric transmission, blended natural gas-hydrogen transmission, or the virtual, retrofitted and dedicated pipeline options – through the resulting average hydrogen price, volatility and grid stability of the Dutch energy grid and market under different penetration scenarios. By formulating the research as a constrained optimization problem, and using the Calliope framework to find an optimal (minimum cost) solution, it is possible to extract the shadow prices of the relevant constraints and use them as an indicator for hydrogen price and grid stability.

The important, societal conclusions of this study can be summarized as follows:

1. Based on the initial literature review, while there is great uncertainty regarding the future penetration of hydrogen in the economy, at least the vehicular transportation/virtual pipeline options can be excluded from further consideration on the international transmission scale in the focus of this research, as even the most pessimistic expectations regarding hydrogen's role would render this option uneconomical.
2. Blending 10% hydrogen in the natural gas does not contribute in any measurable way to decreasing the average price or price volatility of hydrogen. Therefore, the value of this option should be determined based on other relevant criteria not investigated as part of this research – such as investment cost/CO_2 emission reduction ratio, or its contribution to achieve the economies of scale in hydrogen production.
3. While the newly-built, dedicated hydrogen infrastructure is always outcompeted by the retrofitted infrastructure, in both the 2030 and 2050 timeframes even this option has considerable price advantages – 7.1-9.3% price reduction by 2030 and 6.9-7.6% reduction by 2050 – compared to electric transmission and – strictly only from a hydrogen price perspective – could become a viable option where retrofitting itself is not possible.

4. The retrofitted natural gas infrastructure, however, is more attractive than electric transmission in both the base-line and the elevated penetration scenarios providing 10.0-21.3% reduction by 2030, and 11.5-16.6% reduction in the average hydrogen price by 2050.
5. None of the pipeline infrastructure options proved to be effective against price volatility, however, and both of these options resulted in a less utilised grid in every scenario, other than the highest penetration option by 2050.
6. The electric transmission grid is a safe choice of investment because of its versatility – resulting in the most stable and well-utilised grid in almost all of the investigated scenarios. While the electric grid seems to be more evenly utilized just based on the outcomes of this research, its technical qualities also make it more sensitive to volatility than the natural gas/hydrogen grid is.

This thesis is an advancement on the existing research in demonstrating:

1. a simple representation and tested integration of the natural gas/hydrogen pipeline infrastructure and selected end-use applications in the existing Calliope framework,
2. a way to extract and process the dual variable/Lagrange-multiplier/shadow price of the modelling constraints of interest using a model built in the Calliope framework, and how to use them as a shadow price for energy carriers/capacities, creating useful insights based on the resulting timeseries outputs,
3. how the different infrastructure investment options can be compared to each other in terms of resulting modelled hydrogen/capacity expansion prices, creating a useful comparison for the decision-maker based on a set of identified performance indicators,
4. the biggest risks where further research in the modelling methodology is necessary to obtain more accurate and reliable results in the future; up to 25% deviation in the results are to be expected from the weather input data, while another considerable uncertainty was confirmed to be the newly-built pipelines' CAPEX resulting in a 4.7% deviation in average price.

While some of the conclusions above are unsurprising based on the existing knowledge – like blending options having limited effects on hydrogen price due to the limited amount of H_2 being actually blended in – the findings also provide deeper insight on the infrastructural investment options in a comparative manner scarcely found in literature. The research set out to identify the trade-offs between the competing alternatives in transportation of the green hydrogen supply of the future Dutch energy market, and found that while both the repurposed and newly-built pipeline options offered a considerable average price reduction compared to electric transmission, the electric grid showed better utilization patterns overall. Furthermore, both the pipeline and the electric transmission options performed appropriately in resulting hydrogen prices relative to hydrogen's prevalence in the energy mix – in perfect alignment with existing literature.

Acknowledgements

This report is a conclusion of an arduous journey. More than academic knowledge, the entire graduation process was a test of perseverance and patience. Special thanks goes to my friends for bearing with me during my entire academic journey at TU Delft – including but not limited to Samuel Lorenzo Paul Kizito Timmers, Paula Maria Götz, Jin Rui Yap, Ashok Ireton Willis, Sahiti Sarva, Xander Frank Smits, Mila Hendrikse, Eva Brink Carvalho, Francien Oguljemal Maria Baijanova and Ignasi Cortés Arbués. Their support helped me through the long days and months.

I am also thankful for the guidance my chairperson and first supervisor, Gerdien de Vries and Stefan Pfenninger provided throughout the entire process. This research would not have been half as happy and interesting without them. I am particularly grateful for the keen interest my external advisor, Francesco Lombardi took in this research. His dedication, positivity and always on-point feedback in our weekly meetings was a major driving force behind this final success.

Finally, I am thankful for the interest any reader takes in my thesis and hope that it proves to be as educational for you as it was for me.

List of figures and tables

Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
BEL	Belgium
CAPEX	capital expenditure
CBS	Statistics Netherlands (Centraal Bureau voor de Statistiek)
DEA	Danish Energy Agency
DEU	Germany
DNK	Denmark
EC	European Commission
ENTSOG	European Network of Transmission System Operators for Gas
EP	European Parliament
ETM	Energy Transition Model
EU	European Union
EUROSTAT	European Statistical Office
EV	electric vehicle
EZK	Ministry of Economic Affairs and Climate Policy (Ministerie van Economische Zaken en Klimaat)
FCHJU	Fuel Cells and Hydrogen Joint Undertaking
FRA	France
GBR, UK	United Kingdom
GDP	Gross Domestic Product
GHG	greenhouse gas
GIE	Gas Infrastructure Europe
GNI	Gas Networks Ireland
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRL	Ireland
KNMI	Royal Netherlands Meteorological Institute (Koninklijk Nederlands Meteorologisch Instituut)
LCOE	levelized cost of energy
LNG	Liquified Natural Gas
LUX	Luxembourg
NCA	National Climate Agreement
NECP	National Energy and Climate Plan
NL, NLD	the Netherlands
NOR	Norway
NS	North Sea
NSEC	The North Seas Energy Cooperation
OPEX	operational expenditure
PV	photovoltaics
RES	renewable energy source
SA	sensitivity analysis
SWE	Sweden
TNO	Netherlands Organization for Applied Scientific Research (Nederlandse Organisatie voor toegepast-natuurwetenschappelijk onderzoek)
TSO	Transmission System Operator
UK	United Kingdom
VRES	variable renewable energy sources
WTO	World Trade Organization

1 Background

Our modern economy is critically dependent on the long-distance transmission of a large amount of energy. With the onset and current progression of the energy transition – incited by global warming, current geopolitical developments, the subsequent de-carbonization effort and the accelerated European endeavor to decouple the continent's energy sector from Russia's fuel supply and influence – society faces new challenges.

1.1. Climate change and energy crisis

The effects of the ongoing climate change are well-documented – more frequent droughts, floods, storms, heat waves, melting glaciers/ice caps, and rising sea levels to name a few. Since the mid-1990s public concern around humanity's rising CO_2 emissions started to dominate the discourse (Covert et al., 2016). The period between 2018 and 2020 brought a drought of unprecedented intensity in Europe, setting a completely new benchmark for these weather extremities. Climate simulations based on current developments suggest that the continent will keep experiencing similar intensity droughts in the future but with durations unprecedented in the past 250 years (Rakovec et al., 2022). At present, 50 million Europeans live in 470.000 km^2 of low elevation coastal zones, threatened directly by rising sea levels – 70% of them in the Netherlands, Germany, the UK, Italy, Spain, or Russia (Rakovec et al., 2022). Other phenomena, like wildfires, desertification and ocean acidification are threatening to wipe the living space of countless species, leading to biodiversity loss and potentially tipping the entire ecosystem. While the planet has experienced gradual changes in its climate before, the contemporary global warming is scientifically accepted to be caused (or heavily exacerbated) dominantly by human activity (IPCC, 2022). The Paris Agreement, signed in 2015 defines legally binding climate goals for all the signatories – among them the Netherlands and the EU itself. The overarching aim of the agreement is to keep the global temperature rise 'well-below' 2 degree Celsius compared to pre-industrial levels. Meeting these goals comes with challenges for the energy sector as well.

Furthermore, the ongoing conflict between Ukraine and the Russian Federation proved to be a tough wakeup call and a reminder for European leaders of the risks posed by the continent's extreme dependence on (Russian) fossil fuels. The uneven geographical distribution and mismatch between the need and availability of these energy sources – especially oil and natural gas, 50% of the known global reserves being concentrated in just three countries (Singh et al., 2012) – has long been a source of geopolitical tension. While the coal markets remained largely domestic throughout the centuries, the superior transportability of liquid and gaseous fossil fuels created dependencies among international actors with a desire to control the chokepoints of the supply chain (Blondeel et al., 2021). The de-carbonization effort changes these power dynamics as well – in the case of Europe, offering an alternative, local source of power instead of the now so 'weaponized' Russian oil and natural gas imports.

Moreover, fossil fuels are non-renewable, and the reserves are limited (Scholten, 2018). The exact timeline for the global reserves to finally run out, is highly uncertain (Singh et al. 2012) and has been a topic of significant speculation over the past decades, however Martins et al. (2019) estimates that by 2050 only about 14% of oil, 72% of coal, and 18% of the proven natural gas reserves of Europe (excluding Russia) will remain without significant de-carbonization in an average energy consumption scenario. These estimations are, however, subject to a high level of uncertainty because of continuous discoveries of new reserves and technological development making previously unavailable resources economically viable for extraction. In fact, governments keep investing in fossil fuel production all around the World despite the declared carbon-goals and there seems to be no strategy in sight for curbing the production itself (Piggot et al., 2020).

Regardless, the energy transition is and has been an ongoing, structural change for decades now, transforming the current fossil fuel based energy sector into a carbon-neutral, sustainable operation. The share of renewables in the gross final energy consumption more than doubled in Europe between 2004 (9.6%) and 2020 (22.1%) according to Eurostat (2022). As seen on Figure 1 below, the energy sector is responsible for about three quarters of humanity's global GHG emission. This means that de-carbonizing the sector is one of the most important steps in fighting the adverse effects of global climate change.

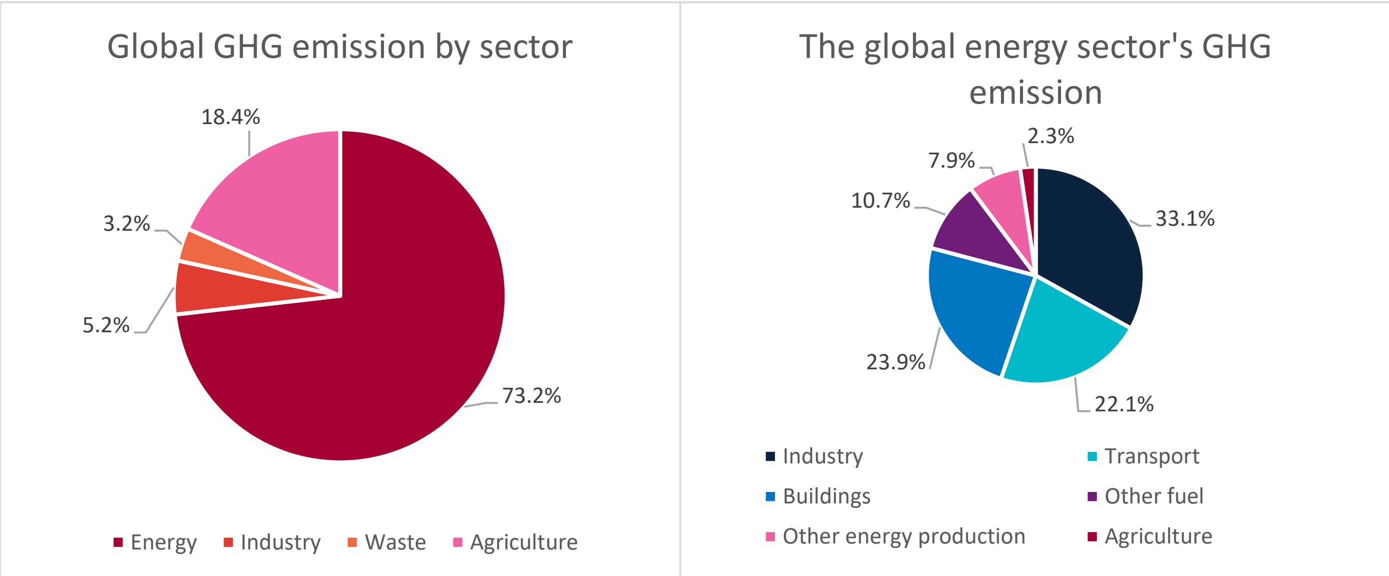

Figure 1 The share of the energy sector in global GHG emissions [Source: Our World in Data]

The necessary steps to make this transition happen include turning from fossil fuel generation by deploying renewable technologies exploiting carbon-neutral energy sources, like wind and solar power and making a shift from fossil fuel based end-user applications, like internal combustion engines and methane boilers to vehicles and appliances running on 'green' energy carriers – like electricity or hydrogen.

The challenges this energy transition faces are both technical and social in nature. Technical challenges include deploying renewable capacities fast and in large enough quantities by improving the efficiency of these technologies in their utilisation of the power source – the sun, wind, etc. Another technical challenge is guaranteeing the stability of the entire power system by creating either storage or carbon-neutral base-load capacities to complement the volatile renewable generation.

On the other hand, social challenges also emerge with the energy transition. One of the geopolitical and economic side-effects of switching from fossil fuels to renewables is that many oil-rich countries continuously failing to diversify their economies will slide into recession and possibly poverty (Lenferna, 2018). In every country, the most vulnerable, economically disadvantaged people are the most at risk of relapsing (back) into energy poverty as a result of the forced energy transition. Dong et al. (2021) in their study found that 1% increase in natural gas consumption leads directly to a reduction of 0.014% in energy poverty in China. Indeed, the single-minded sustainability approach does not always create the most socially just outcomes (Ciplet et al., 2019) and the so-called 'Global South' remains an understudied region from the perspective of energy transition (Cantarero, 2020). This transition is once again expected to perpetuate the global divide between rich and poor countries by splitting them between the technologically developed nations currently leading the transition, and the countries lacking the money to invest and innovate, therefore lagging behind (Hafner et al., 2020). Political pushback, both domestically and internationally, can be expected if the price of the energy transition is reflected too heavily on the end-users' utility bills.

1.1.1. Climate goals

Contributing to the global effort as proposed by the Paris Agreement in combatting climate change, the EU aims to decrease its carbon emissions by 55% before the end of 2030 and achieve carbon neutrality by 2050. In line with the Union's agenda, the National Climate Agreement of the Netherlands proposed by the Dutch Government in June 2019 requires the CO_2 emissions of the country to be decreased by at least 49% compared to the 1990's level before 2030. The document estimates that 70% of the electricity supply will come from renewable sources as a mean/result of this effort (NCA, 2019), which means a rapid development and a drastic change in the energy sector from the current 7% of renewable production (IEA, 2020). Specific and separate goals are set for the built environment, mobility sector, industry, agriculture, and electricity generation of the country. For the building heating sector the document states that better insulation and an imminent discontinuation of the natural gas heating for at least the newly-built dwellings is in the plans. As an alternative, the document considers district heating for the densely populated areas – for the rest, either electrification or the utilization of the existing natural gas connections for hydrogen heating is considered an option. The National Climate Agreement (2019) states that in order to achieve the climate goals, hydrogen must be utilized and promoted by the government in 5 focus areas; (1) as a carbon-neutral feedstock for the industry, (2) as high temperature heat-source for the process industry, (3) as a storage option and a vehicle for long distance energy transport, (4) in mobility, especially regarding passenger cars, (5) in heating the portion of the built environment that otherwise cannot be made carbon-neutral.
Relevant parameters of the Dutch climate plan are summarized in Table 1 below.

Table 1 Summary of the relevant Dutch policy goals and timeline [Source: NCA, 2019]

	2020	2030	2050
Installed electrolysis capacity [GW]	-	3-4	-
CO2 reduction [%]	24.5-25.0	49.0-55.0	95.0-100
Electrolysis cost reduction (CAPEX) [%]	0	65.0	-
Electrolysis cost [Million EUR/MW]	1.00	0.35	-
Wind energy price on land [EUR/MWh]	59.0	-	-
PV energy price [EUR/MWh]	83.0	-	-
Installed offshore wind [TWh]	22	49-85	525
Installed onshore renewable [TWh]	-	35-71	-

Furthermore, the European Commission (EC) in response to the outbreak of war between Ukraine and Russia in early 2022 announced its intentions to accelerate the Union's energy transition in an effort not only to meet its climate goals, but also to establish its strategic energy independence from the Russian Federation (EC, 2022). For the Netherlands, being historically reliant on natural gas, and with the government's pre-existing determination to scale down domestic production closing the unpopular and seismic Groningen gas field, this means a shift to either more import of liquified natural gas (LNG) or an even speedier decarbonization of the economy.

1.1.2. Sector coupling

The integration of the variable renewable energy sources (VRES) into the existing network, however, is a particularly complicated task. The changeability and often unpredictability of the carbon-free, renewable resources – like wind and solar energy, expected to dominate the energy mix of future carbon-free economies – and the uneven distribution of these new sources of power, the temporal and geographical mismatch between supply and demand are complications the current energy system is unequipped to handle.

While from an efficiency perspective it would be highly preferable to consume the energy as close as possible to the point of production, some areas lack the resources – sufficiently strong wind or sunshine –, others lack the physical space or social support to install large enough renewable generation capacities on-site. Generally speaking, the densely populated areas often having the highest energy demand lack the capacity the most for installing space-intensive solar or wind farms – forcing the energy and utility sector to rely on storage and long-distance transmission instead. Furthermore, the variability of renewable resources means that an often-changing energy demand has to be matched with a now uneven and unreliable supply. While generation in the Netherlands already can exceed demand by as much as an order of magnitude at times (Infrastructure Outlook 2050, 2019), the limitations of the current energy storage technologies make an accelerating switch in energy production to renewable sources an increasingly significant and rather pressing problem. Electricity stored directly in batteries is an effective, technologically possible option, however, it is economically unfeasible for long-term large-scale storage, and it has serious material limitations resulting in concerns regarding its sustainability (Elberry et al., 2021). Pumped hydro storage, while both technologically and economically a mature solution, it has serious geographical limitations – making it unsuitable for countries and regions without natural elevation differences – like the Netherlands. In the research of Acar (2018) chemical energy storage options, like hydrogen production, the power-to-gas concept, performed best on the average of all the selected and examined criteria (flexibility, arbitrage, balancing, congestion management, environmental impact and power quality) – surpassing even these mechanical storage options. The Energy Report of 2016, developed by the Ministry of Economic Affairs of the Netherlands further emphasizes the importance of chemical energy storage and the power-to-gas concepts in their superior transportability attributes compared to the options of storing energy in batteries.

Scientific and political consensus seems to be in support of electricity becoming the main carrier of energy in the future economy. It can be generated completely carbon-free and a large portion of appliances in commercial use today already runs directly on it – meaning that additional investment in research, infrastructure and the replacement costs of end-user equipment, as well as conversion losses to and from electricity can be avoided. However, in the case of especially large, mobile power applications – like shipping and transportation on land, sea and in air, requiring high energy density fuel – other, chemical options will likely play a larger role in the future than electricity itself (DeSantis et al., 2021) through sector-coupling.

Sector coupling is the purposeful connection and integration of energy sectors and demands through technological solutions – including electricity, gas, heat, cooling, traffic, industry, building heating – to increase the flexibility of supply, demand, and storing (Fridgen et al., 2020). Examples of this concept are the coupling of the electricity and heat sectors in building heating through electric heat pumps, the coupling of electricity, gas and heat sectors through combined heat and power plants, the coupling of hydrogen and natural gas sectors through steam methane reforming, and the coupling of the biomass and hydrogen sectors through biomass gasification. In centre of this research is the power-to-gas concept, an example of it being the production of hydrogen from electricity through electrolysis.

Hydrogen, as a versatile energy carrier, can be used in a number of different ways in various sectors of the economy – including transportation, building heating, the chemical industry and the power sector, making it an important link for the energy transition and sector-coupling. 98% of the current hydrogen demand worldwide comes from the heavy and chemical industry, hydrogen playing an already crucial – if limited – role in today's economy. In the transportation sector, it can be utilized to power both conventional combustion engines (with some necessary modifications) and fuel cells. Historically, hydrogen has mainly been a competitor in the market segment of passenger cars but recent interest turned toward the utilization in public transportation due to the range constraints of battery-electric vehicles (BEVs). Generally, future applications of hydrogen in mobility – either in its own form, or as a source for synthetic fuels – could include fueling motorbikes, ships, airplanes, railways or agricultural machinery, as hydrogen shows the biggest potential in decarbonizing the transportation sector (Hafner and Luciani 76).

Hydrogen also has a potential for a rapid decarbonization of the heating sector in both small-scale, private dwellings and the larger-scale commercial-industrial building stock, as existing natural gas boilers – after the necessary modifications – are expected to be suitable to run on hydrogen as well. There is considerable institutional experience accumulated on the execution of a switch like this – the shift first from town gas and then from low-calorific gas demonstrates how a successful transition can be managed by the system operators in cooperation with the end-users. However, the normally low price of natural gas and the low exergetic efficiency makes the combustion of hydrogen a less preferred utilization option, and the existing hydrogen technologies are still far behind in cost-competitiveness when it comes to domestic applications (Hafner and Luciani 79).

Hydrogen is, however, an undoubtedly promising opportunity to meet the energy demands in non-electrifiable segments of the economy, enhancing energy security and local industries in many countries (Noussan et al., 2020). The Hydrogen Council predicts 'large scale' utilization of hydrogen by 2030 and 18% of the world's final energy consumption to be met by hydrogen in 2050. In its long-term vision presented to parliament in

2018, the EC presupposes a 13-14% share of hydrogen in the European energy mix by 2050 (EC, 2018 [1]). The new hydrogen strategy presented to the European Parliament (EP) in 2020 projects an even bigger role for hydrogen worldwide – meeting 24% of the world's final energy demand by 2050. Almost all EU member states included hydrogen in their respective National Energy and Climate Plans (NECP) in some way, 26 member states signed the 'Hydrogen Initiative' committing themselves for further research and investment, some already published a dedicated hydrogen strategy (EC, 2020). In conclusion, the energy transition of the coming decades is expected to result not only in a larger share of electricity being produced by renewable sources, as well as a larger share of electricity overall in the total energy consumption – but also, a larger share for renewable gases, such as hydrogen itself, with a greater level of system integration between these two carriers, providing flexibility options (Koirala et al., 2021).

1.2. Research gap and objectives

As stated above, the potential in hydrogen as a medium to store and transport energy is well-understood and researched already. The Infrastructure Outlook 2050 (2019) itself published as a joint initiative by Gasunie and TenneT – the natural gas and electricity network operators of the Netherlands (and Germany) – expects a 24-38% share of hydrogen in the final energy demand of the Dutch economy by 2050. Detz et al. (2019), however, in their report reflected not just on the potential but also the great uncertainty around the future demand for hydrogen in the Netherlands and Europe. By reviewing 18 studies of the recent past from 2014 to 2019, including research papers, industry and policy documents, they found the estimations of a potential hydrogen economy to run from 0 to 1900 PJ/year – from hydrogen playing an insignificant role to covering basically the entire energy need of the Netherlands in 2050. They categorized the reviewed papers based on their methodologies into quantitative 'model' and qualitative 'vision' studies, and found that the ones in the latter category estimated more than twice as big a demand for the future on average – but even the modelled scenarios demonstrated significant deviations in their assumptions and themselves produced the 3rd and 4th highest projections of demand of all studies as a direct consequence of the uncertainty.

Academics have historically been conservative in their view on hydrogen. In most of its possible applications, hydrogen has strong competitors – pumped hydro in storage, electric vehicles (EVs) in mobility, heat pumps in building heating are all technologically and economically already mature solutions. In their literature review on the potential of hydrogen for decarbonizing the heating sector, Dodds et al. (2015) found that '…in some parts of Europe, the debate on low-carbon heat has largely neglected hydrogen…'. Böhm et al. (2021) states that 'despite an obvious potential for heat utilization from electrolysis-based hydrogen production, the topic is hardly covered in available literature.'. Building heating accounting for half of global final energy consumption, this is a large limitation on the potential future penetration of hydrogen. In a more recent and very extensive review, Fonseca et al. (2019) found that out of a 106 research papers concerning hydrogen as an energy vector, two-thirds considered hydrogen as a storage option only, one-third considered other end-use applications, including mobility and heating (without specifying the ratio between studies concentrating on mobility only), and only about one in ten research investigated hydrogen-natural gas blending as an option, implying general purpose utilization. They further concluded that the research effort so far predominantly focused on techno-economic issues and '…there is a lack of approaches including data uncertainties in weather conditions, prices and demands that can affect the performance of the system.'. Skepticism of the viability of hydrogen's general purpose utilization seems to stem mainly from the high conversion losses the current technology displays and the consequently uncompetitive price of (green) hydrogen.

Historically, interest in hydrogen peaked always as a result of soaring oil and gas prices, and this interest was concentrated exclusively on transportation (IEA, 2019). Hydrogen stepped into the spotlight of policy first in the 1970's oil crisis, and fell out of favor immediately when the crisis resolved via other means. Resources for hydrogen research were reallocated again in the 1990s, and then in the early 2000s because of the growing climate concerns but a breakthrough never happened because of the consistently low oil prices (IEA, 2019, Noussan et al., 2020). As of 2020, low-carbon hydrogen was not cost-competitive against its fossil-fuel based equivalents (Noussan et al., 2020), however, with the rising natural gas prices in Europe accelerated by a drawn-out conflict between Russia and Ukraine, green hydrogen already became competitive in regions where green electricity is in abundance. With the declining electrolysis costs and the economies of scale, green hydrogen is expected to outcompete grey hydrogen globally by 2030 (EC, 2020).

This uncertainty around the future hydrogen demand leads to a dilemma in the decision-making process; whatever role hydrogen is going to play in the energy transition, it needs a supporting infrastructure throughout its entire value chain – electrolysis capacities for production, caverns or insulated tanks for storage, trucks, pipelines or the electricity network for transmission, and retrofitted or newly installed end-user equipment to utilize its power. The realization of this takes time – years, or even decades in the case of large, supranational infrastructures. To integrate this value chain into the future economy, while also meeting the stringent decarbonization goals by 2030 and 2050, investment decisions need to be made presently not just by private stakeholders but by national governments as well.

The uncertainty around the penetration hydrogen might take up in powering the future economy affects the transmission leg of the value chain particularly. The Hydrogen Insights (2021) report states that 'with hydrogen production costs falling, transmission and distribution costs are the next frontier when it comes to reducing delivered hydrogen costs'. In this opaque hawk-dove game, however, the regulator and private sector stakeholders seem to be mutually waiting for each other to make the necessary first steps. In a report ordered by the Fuel Cells and Hydrogen Joint Undertaking, one of the main barriers of the deployment of a hydrogen transportation infrastructure is 'the lack of enabling regulation to stimulate the deployment of hydrogen applications and the use of existing methane infrastructure…' (FCHJU, 2020). On the other hand, in its own report, the EU agency of energy regulators states that 'given the uncertainties at this stage regarding hydrogen development, market commitments and interest should trigger repurposing of networks for pure hydrogen, and not the other way around…' (ACER, 2021). Most of the current hydrogen demand in the Netherlands is met by either on-site production, or by hydrogen delivered via vehicular transportation options. This is possible because of the comparatively low and localized demand that can be served by an existing natural gas infrastructure and local steam methane reforming. However, with a greater and more dispersed future patterns of consumption, and the decarbonization of hydrogen production, other options like pipeline transportation of hydrogen itself might make more economic sense. The European Union Agency for the Cooperation of Energy Regulators (ACER) in its recent report (2021) on the transportation options of hydrogen identifies 10 tonnes/day of hydrogen transported for no more than 200 km distance as a tipping point over which pipeline transportation becomes cost-competitive against vehicular transportation options. The existing Dutch annual industrial demand of a 180 PJ hydrogen already surpasses this comfortably, meaning that even a dedicated hydrogen pipeline network should prove competitive at least against this option, also depending on other, individual factors evaluated on a case by case basis. The other technological possibilities – dedicated or retrofitted pipeline, extending the electric grid or producing hydrogen on-site – however, require further evaluation on relevant criteria. According to DeSantis et al. (2021), there is little literature of the sort available right now drawing a comparison between energy transmission by electricity and transmission by other types of energy carriers. Koirala et al. (2021) in their research presented an integrated electricity, hydrogen and methane market model useful for exploring price-volume interactions between these markets as a function of generation capacities, and recommended further transmission capacity expansion planning and investment decision-support research based on their shadow price approach. Since the Netherlands has a sizeable natural gas transmission and distribution network completely suitable for 100% hydrogen transportation with comparatively small modifications and investments (Wang et al., 2020) this dilemma ties well into the greater issues of unused capacities, stranded assets, and the so-called carbon bubble as well. Löffler et al. (2019) found that in the power generation sector only, the most optimistic baseline scenario of decarbonization – if realized – will result in a 50 billion EUR investment loss in Europe alone. The most pessimistic scenario foresees a 200 billion EUR devaluation of the fossil-fuel based energy and utility companies and their assets in Europe, and a 4 trillion US$ wealth loss worldwide – representing 4% of the global GDP in 2021 – as a direct result of decarbonization. This compelled the authors to call for 'strong and clear signals from policy makers' to guide future investments in the energy sector and to prevent future market failures. Making informed decisions when it comes to investing in a legacy infrastructure – i. e. retrofitting the natural gas pipeline network for hydrogen transportation – therefore, is crucially important in financing the energy transition either way; by saving the otherwise stranded assets, or by avoiding unnecessary and wasteful investments in a dying fossil fuel sector.

This means that the most frequently used, traditional approaches concentrating on investment cost as the main decision-making criterion are, in this case, insufficient. To support and accelerate the decision-making process from all social and political aspects, we need more clarity not just on the investment costs but also on the (1) end-user price and demand implications, the resulting (2) price variability, and (3) grid stability coming with the different technologically possible hydrogen transportation investment options. Nonetheless, in the case of such previously untraded commodities like hydrogen, acquiring reliable price data is not a straight-forward task. The constrained linear programming formulation of the optimization problem, however, gives us the opportunity to exploit the duality principle, and use the Lagrange-multipliers of constraints as a shadow price.

1.3. Research question

The aim of this research is to support the Dutch governmental decision-makers of the infrastructure sector by quantifying and comparing how the different infrastructural investment opportunities effect the price of hydrogen in the country. The central research question, therefore, is as follows:

What are the trade-offs between the competing alternatives in transportation of the green hydrogen supply of the future Dutch energy market based on modelled energy carrier price outputs?

To explore the main research question completely, three sub-questions were formulated. These are:

1. How can the hydrogen network and important utilisation technologies (hydrogen boilers) be modelled and integrated in the existing Calliope framework?
2. What can be learnt from modelled shadow prices regarding the energy grid?
3. How does the modelled price of hydrogen change in pre-defined high and low penetration scenarios with different transportation options?

1.4. The structure of this document

Chapter 2 discusses the methodological background of the modelling, data gathering and processing used to answer the research questions detailed above. The related principles of multi-energy system modelling and open energy modelling are introduced and the motivation behind selecting the modelling framework (Calliope) is also detailed partially based on the introduced principles. A short background on shadow pricing is also included, explaining the theory in broad strokes behind the selected pricing method and comparing it to other, prevailing methods in energy modelling. This chapter also details the scenarios that were investigated as part of the modelling process and the necessary extensions added to the existing modelling framework to carry out the entire research. The data needs, sources and collection process is followed by the identified uncertainties. Chapter 3 summarizes the outcomes of the modelling effort detailing the results of the testing process and the model instantiations. Furthermore, the outcomes of the sensitivity analysis can also be found here. Finally, Chapter 4 provides an interpretation of these results with an in-depth analysis and reflection on their real-life implications based on the performance indicators; average price, hydrogen price variability, grid stability. The concluding remarks of this chapter reflect on the sensitivity of the results, the limitations of this research and the recommendations for policy-makers and researchers.

2 Methods

This research requires a quantitative experimental approach by nature to see if the different hydrogen technologies can be implemented and integrated in an existing modelling framework in a realistic way. To test the behaviour of shadow price time-series outputs of carriers – namely hydrogen – and compare them against expectations, assessing their useability and appropriateness in modelling real carrier prices, and to analyse the effect different pre-defined hydrogen penetration scenarios have on the modelled prices with different transmission systems, a mathematical model of sorts is ultimately necessary. The modelling is rooted in and established by a literature review, followed by data collection and initial data analysis, data processing and input data generation. The outcome of the research is then a thorough analysis of the results – combining the findings of the literature and data review with the modelling effort and its outputs. Figure 2 shows a simple flow chart of the research plan.

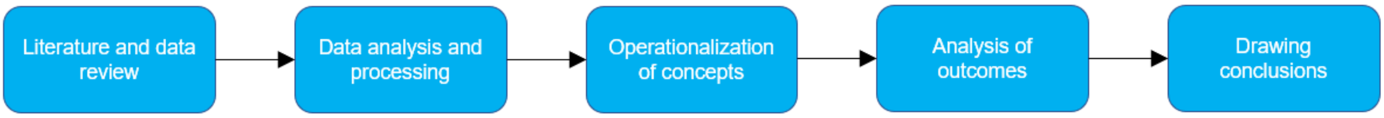

Figure 2 Simplified flow chart of the research steps

2.1. Multi-energy system modelling

The energy transition and the consequent sector-coupling – as described in Section 1.1.2 – has a profound effect on the way energy systems need to be modelled in order to provide the useful guidance in the decision-making process.

Multi-energy system modelling refers to a new approach of optimization by extending the analysis to the energy system as a whole – by including more than a single energy sector in the analysis, as opposed to the traditional approach, where the different sectors of the energy system have been de-coupled from each other due to their limited interconnectedness (Mancarella et al. 2014). This approach is gaining momentum in the scientific community due to the increasing interactions between the various energy sectors through technological development. Sector-coupling is providing additional flexibility options through increased conversion possibilities – leading to more optimal solution through the deployment of the most favourable energy carriers offering OPEX and CAPEX savings, increased energy efficiency and emission reduction (Capuder et al., 2014). Sector-coupling is also, in some cases, the only pathway for de-carbonization – like in the case of long-distance freight transport, or air travel (Mancarella et al., 2014) where green electricity is not expected to become a technologically feasible solution even in the long-term future. This all means that the decision-making in a de-carbonized future with a sector-coupled energy system requires a multi-energy modelling approach.

2.2. Open energy modelling

Furthermore, the field of energy system modelling suffers from a lack of openness and is lagging behind other fields in transparency (Pfenninger et al., 2017). This ends in researchers often working in parallel isolation, wasting resources, ultimately producing over-lapping and lower quality results. For the purposes of this thesis, an open modelling approach was followed, meaning that an open access model built exclusively on publicly available data was used as a primary tool to answer the research questions. Important advantages of relying on openly available models and data include enhanced transparency and reproducibility, and consequently an increased credibility and legitimacy for the research. Not only the outcomes but also the open data sources and written code/modelling extensions are being published attached to this document – making it possible for everyone to replicate the entire research. From a practical point-of-view, an open source model was also necessary due to the resource constraints of this study. Figure 3 below shows a decision-making chart in the selection of the modelling framework based on a preliminary assessment of the modelling needs, rooted in the information presented in previous sections of this document.

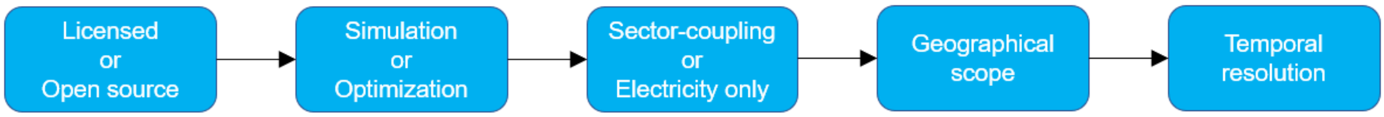

Figure 3 The model selection flow chart

More than 70 open source energy models are recorded on the OpenMod initiative's website and after the above consideration, 7 seems to cover some or most needs of this research – these are Calliope, Ficus, Oemof, OpenTUMFlex, PyPSA, Switch and URBS. Calliope is the most referenced among these, but the models Switch, URBS, PyPSA, Oemof and Ficus seem to have similar capabilities, therefore probably also capable of supporting this research. OpenTUMFlex is built with a different research area in mind.

2.3. Model framework

Based on the concepts described above, in order to come to meaningful conclusions, a linear optimisation problem was formulated and solved using the Calliope modelling framework. Calliope is a tool designed with a bottom-up approach in mind to support the investment and operation decisions – like the ones addressed in the main research question – regarding the energy transition in systems with a high share of renewable energy generation capacities. It was written in Python using human-readable text formats, with an open-source code to promote transparency and access, making it ideal for general purpose research. Calliope has a modular structure, which allows for easy alterations and extensions, with a separation of model code and input data. The framework defines a given energy system by resources, carriers, technologies, and locations – where resources are any form of energy coming from outside the boundaries of the considered system, becoming carriers upon entering said system, and technologies determine the supply, storage, demand, and transmission capacities between locations – themselves defined by a pair of coordinates. The spatial and temporal resolution is user-defined, the granularity is freely set based on the availability of input data, the computational needs and capacities of the user. The modelling horizon is flexible but the model itself is static. Calliope covers all relevant conventional and renewable generation capacities on the supply side, and incorporates an aggregated representation of inelastic demand for the produced energy. The modelled cost build-up covers investment, operation and maintenance, fuel and carbon costs, but neglects others, such as taxes and balancing costs. Figure 4 illustrates the structure and internal logic of the Calliope modelling framework.

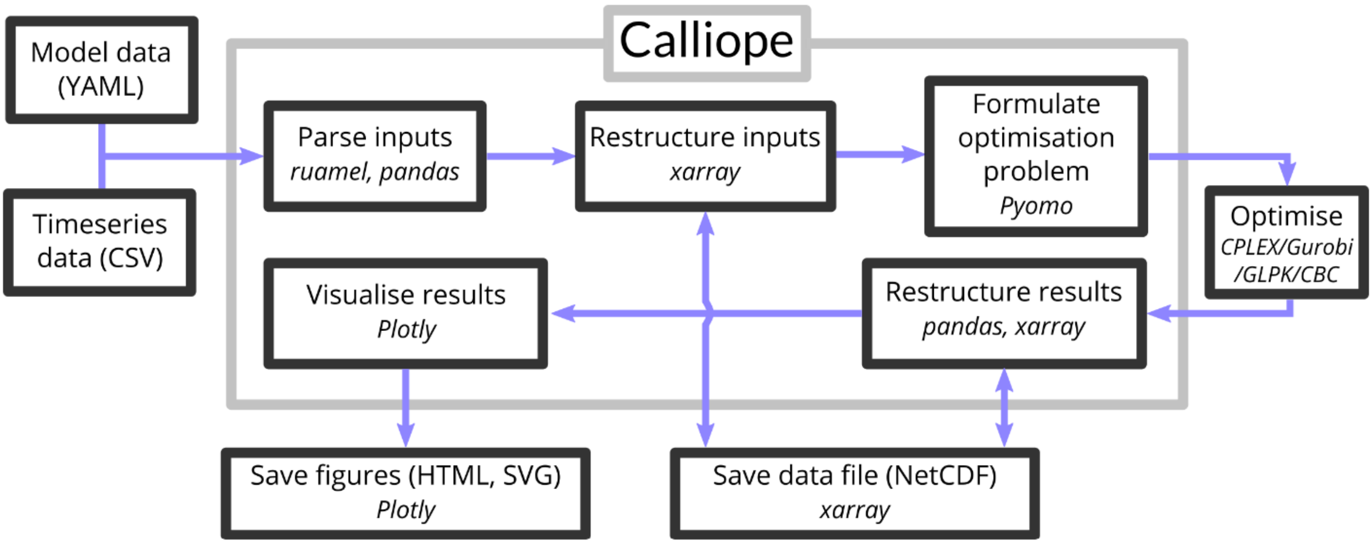

Figure 4 Model workflow [Source: Calliope Documentation 0.6.8]

2.3.1 Strengths

The Calliope framework is optimal for the purposes of this research and was selected against other state-of-the-art models of the kind for this study because:

- its modular structure makes it practical for projects that require more flexibility than what an out-of-the-box model offers,
- being written in Python, its interface is user-friendly for researchers with a wide background, promoting reproducibility,
- it provides simple dataset outputs that can easily be converted into Pandas structures, facilitating a simpler workflow for analysis of the results,
- the open-access nature of it makes it available for general-purpose research, and allows for the possibility to check and reproduce the results, which is particularly important in studies expected to end with otherwise hardly verifiable outputs,
- the pre-existing research done using this modelling framework provides valuable basis and groundwork for this research.

2.3.2 Short-comings

However, the perfect model does not exist, therefore, the trade-offs have to be carefully considered based on the purposes the model needs to serve when it comes to the model choice. Calliope's particular weaknesses include:

- it being a bottom-up, engineering type model, not covering economic interactions – i.e. behavioural economics, demand price elasticity – in as rich a detail, as other, top-down models would,

- it being a deterministic model, when stochastic models ‘almost always outperform the deterministic optimization methods in terms of social, technical, and economic aspects of renewable energy systems.’ (Zakaria et al., 2020),
- it being a static model, optimizing the investment in one step for the selected target year, with a perfect foresight approach, when a step-wise, myopic optimization would probably yield more realistic results.

Most of the short-comings of the model can be linked directly to the limited computational capacity; this research requires a complex, technologically detailed, sector-coupled model that is capable of capturing the high variability of renewable energy generation in sufficient detail and able to model the consequently variable energy prices. Some of the short-comings of the model can be mitigated by good practices, i. e. the uncertainty inherent to deterministic models can be reduced by sensitivity analyses. This is reflected in the research design and presented results of this study.

2.4. Shadow pricing

Hydrogen is a historically untraded commodity simply by the virtue of technological development and it not being in commercial use ever before. This means that relying on more conventional methods, i.e. using historical data and regression analyses is not an option for modelling future hydrogen market prices – raising the question of how to support the decision-makers in gaining more clarity in this field. Most of the current hydrogen pricing studies utilise a simple cost-plus (mark-up) pricing method, which is in many ways inaccurate, tend to cause deviations from the actual market value, has a strong time-lag, and lacks competitiveness (Zheng et al., 2022). In a research like this one, concentrating on a system with high renewable generation capacity and green hydrogen specifically, consistency between the highly variable electricity prices and the consequently volatile hydrogen prices is crucially important – rendering the cost-plus pricing method ultimately unsuitable.

Figure 5 below demonstrated the difference in results the price calculation/modelling method makes. The presented price profiles were all calculated based on the exact same 2050 model instantiation, but the blue-orange lines represent the levelized cost of energy and a simple, cost-plus pricing for hydrogen – calculated based on the model’s variable and investment cost input and produced electricity/hydrogen output with a fixed profit margin –, whereas the grey line shows the modelled shadow price – the meaning of which is explained further below.

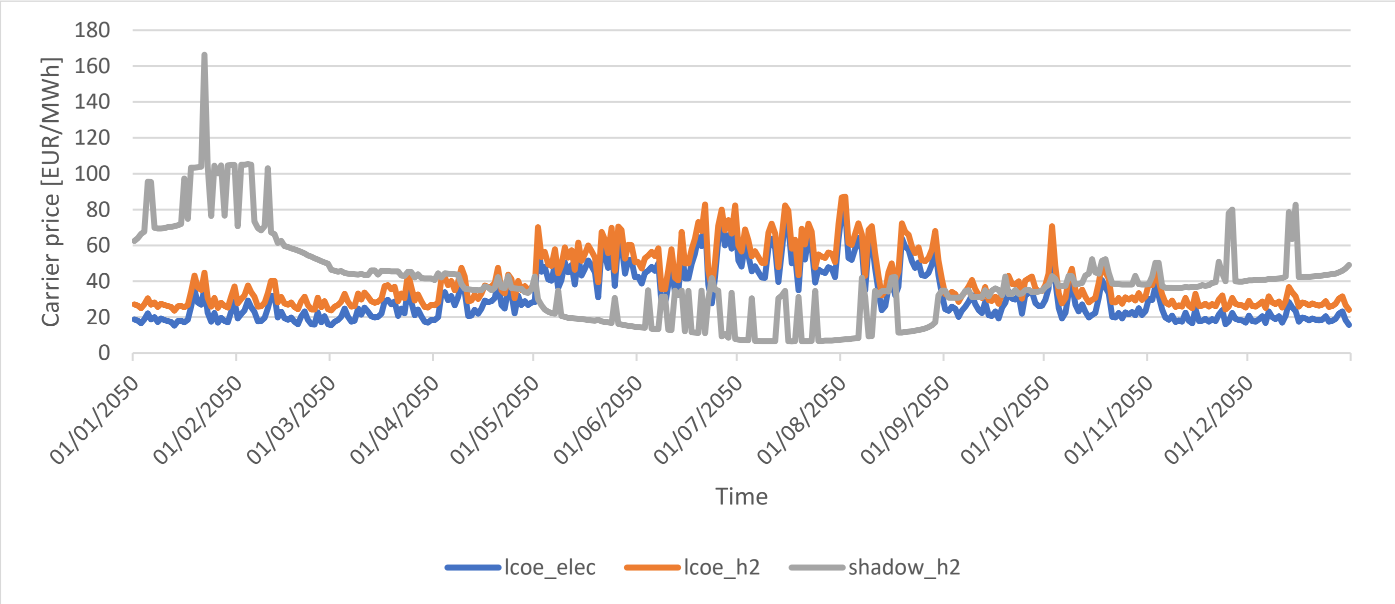

Figure 5 The difference between pricing methods

It is clear based on this figure that the choice of pricing method fundamentally influences the outcomes of this study. The cost-plus pricing results in a price peak in the mid-summer period for hydrogen – somewhat counterintuitively for a fuel present in the model as a heating option – supporting the referenced statement from Zheng et al. (2022) about the time-lag and lack of represented competitiveness. It also means that an applied cost-plus pricing would result not just in different average prices, but also altered price volatility and grid stability patterns.

The formulation of the problem as a constrained linear model, however, presents the opportunity to exploit the duality concept. Duality in linear programming is a unifying theory that proposes a relationship between the linear program in question – the primal problem – and another linear program related to the original problem – the so-called dual problem. Every variable in the primal problem is a constraint in the dual problem aa every constraint in the primal problem becomes a variable in the dual problem, while the direction of the objective is also reversed. In the economic interpretation of the duality theory the primal problem becomes a resource allocation problem and its dual problem a resource valuation problem, with the so-called shadow price representing the unit value of an infinitesimal change in the constraining resources.

The duality can be expressed in mathematical terms the following way:

- If the primal objective is to maximize function (Equation 1)

Equation 1

$$z = \sum_{j=1}^{n} c_j x_j$$

- Within the constraints of (Equation 2 and Equation 3)

Equation 2

$$\sum_{j=1}^{n} a_{ij} x_j \leq b_i \text{, } where\ i = 1, 2, \ldots, m$$

Equation 3

$$x_j \ \geq 0, where\ j = 1, 2, \ldots, n$$

- Then, the dual objective function is to minimize (Equation 4)

Equation 4

$$v = \sum_{i=1}^{m} b_i y_i$$

- Within the constraints of (Equation 5 and Equation 6)

Equation 5

$$\sum_{i=1}^{m} a_{ij} y_i \geq c_j, where\ j = 1, 2, \ldots, n$$

Equation 6

$$y_i \geq 0, where\ i = 1, 2, \ldots, m$$

Visually representing this constrained optimization problem, the optimal solution will lie where the constraint functions are tangential to the objective function – therefore maximizing the objective but not crossing the constraining lines. At this tangential point, the gradient vector of the objective function – expressing the direction of fastest increase in the objective function, by definition perpendicular to the function itself – is a linear combination of the constraint functions' gradients – themselves perpendicular to the constraint functions, and this way perpendicular to the objective function as well. Logically follows that there exists a weight with which these gradients are proportional to each other. This weight is called the Lagrange-multiplier. Since the change in utility/objective function can be calculated – as described above – by multiplying this number with the change in the constraining resource, the Lagrange-multiplier can be interpreted as a price in the ordinary sense for the constraining resource. This way, by assuming a unit increase in any given constraint of the problem, the Lagrange multiplier represents a unit price for the constraint, and a marginal-cost pricing method can be implemented. The (shadow) price, formally represented by the Lagrange-multiplier, is then the marginal utility of relaxing a constraint in the optimization problem, and therefore the price the problem-owner should theoretically pay for one additional unit of the constraining resource in question. Each constraint in an optimization problem has a shadow price.

Other than its already demonstrated advantages in modelling a more accurate free market behavior, shadow pricing has further advantages in its versatility. The dual variables of other constraints also have economic meaning, and this way, the shadow prices can provide a more detailed picture of other components of the end-user energy prices, and in fact, the utilization of the entire energy grid. The shadow price of transmission system capacities for example represents the congestion tariffs TSOs charge for providing system stability services (Koirala et al., 2021). If, for example, the demand on the transmission network is higher than anticipated, the TSOs are forced to commission new generation capacities to the extent of covering the difference and thereby keeping the system pressure/frequency stable at a desirable level. Failing to do so leads to blackouts and service disruptions. Figure 6 presents an example of the behavior of the dual variable linked to the transmission system capacity constraint, in relation to the levels of utilization of the same capacity over time.

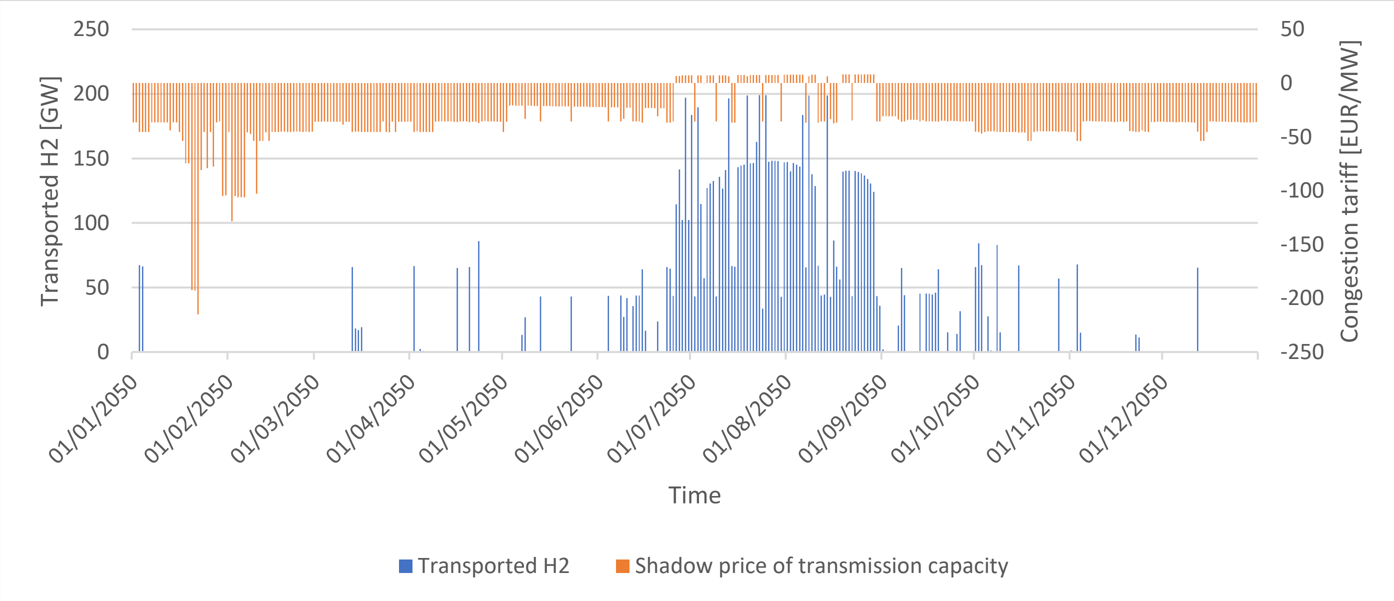

Figure 6 The relationship between the utilization of transmission capacity and its shadow price

The upper half of the figure with the right hand scale represent the shadow price of the transmission capacity – often in the negative, and the lower half of the figure with the left hand scale shows the daily amount of hydrogen flowing through the same pipeline. The correlation between a higher shadow price and the higher levels of utilization shows clearly in the July-September period of the year, when a small congestion in the pipeline actually appears and the shadow price of the transmission capacity turns positive.

2.5. Scope of the research

The importance of carrier price modelling in the energy sector is detailed in Chapter 1, and particularly how the price of hydrogen and competing fossil fuels played a decisive role in the past on the deployment of hydrogen infrastructure. All earlier attempts and research invested in hydrogen proved to be futile once the price of its competitors stabilized on a lower level than hydrogen itself.

This research, therefore, is aimed at uncovering some of the monetary implications of the infrastructural decisions and possibilities concentrating on the price of hydrogen itself – it does not take into account other important decision-making factors like safety, social acceptance, and so on. Until an understanding of the exact circumstances under which hydrogen can become cost-competitive is reached, the deployment of it remains a chicken-or-the-egg problem; the supply and the infrastructure does not exist because there is no secure demand, and demand cannot reach a level that justifies infrastructure because there is no supply. To break a vicious cycle, policy intervention is necessary and policy-makers need a better understanding of the possible effect of the actions available to them on securing a demand for hydrogen. While this research is restricted to this goal – to investigate this most basic, entry requirement for a possible future hydrogen economy, further research can shed a broader light on the full set of decision criteria.

2.5.1 Geographical and technical scope

The EU being one of the most industrialized regions and biggest polluters historically (Ritchie, 2019), is now also a front-runner in the energy transition and encourages decarbonization on every national and international level (Fragkos et al., 2021, Galiffa et al., 2022). The North Sea (NS) region is currently Europe's most significant oil and gas production hub, displaying an enormous potential for onshore/offshore wind energy and hydro storage, with an extensive legacy oil and gas transportation infrastructure. In 2017, the aggregated CO_2 emission of 2.20 Gt of this region accounted for more than half of the total carbon emission of the EU-28 (Maruf, 2019), meaning that the NS region has a huge role to play in meeting the EU's carbon emission goals. On this fertile ground of technological and economical possibilities, important stakeholder cooperation and policy support already started to develop, resulting in the North Seas Energy Cooperation (NSEC) and North Sea Energy initiatives, formal governmental and research programs aiming to develop a shared vision for the energy transition by 2050. The Netherlands' Hydrogen Strategy, published in 2020, reiterates the importance of this international cooperation, at least on the integrated 'Northwest European' energy market as a necessity for an economically feasible adaptation of hydrogen (Government Strategy on Hydrogen, 2020). The NSEC currently consists of Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway, Sweden and the European Commission itself, with the United Kingdom's withdrawal from the EU and the cooperation officially in 2020. The summarized GDP of these countries still equals to 8.5 trillion EUR without the UK, which is around 47% that of the EU's. All of them being net contributors to the Union's budget, it can be concluded that the NS countries form an economically robust region – well placed for further innovation and investment in a large scale hydrogen economy.

These are all important factors because ultimately, for green hydrogen to meet its potential in decarbonizing the economy on a global scale, it needs to become cost-competitive against its fossil based counterparts. The current price (5USD/kg or 150USD/MWh) does not allow that. The Hydrogen Council (2020) estimates that with a price of 2.5USD/kg (75USD/MWh), green hydrogen can meet 8% of the global energy demand, and by 1.8USD/kg (54USD/MWh), 15% of the final energy demand can be 'unlocked' for the carbon neutral energy carrier. To achieve this, however, further investment in technology and production is necessary reaching the economies of scale where hydrogen becomes cost-competitive. This requires a lot of funding – raising the questions around a just energy transition as well. The Lofoten declaration of 2017 states that global distributive justice requires the historically big polluters, who benefitted the most from fossil fuel extraction and therefore have the most parallel developmental pathways available to them to take climate leadership and bear the lion-share of burdens coming with the de-carbonization effort. Closing the economic gap – the gap between the current hydrogen price with today's technology, scale of production and the price where hydrogen becomes competitive – requires actors to front a significant and, for the time, unprofitable investment. The NS countries seem to be economically well-placed, ethically responsible, and politically willing to bear this burden. As stated above in Chapter 1, a number of NS countries are severely threatened by the effects of global warming and stand a lot to gain from mitigating its effects and preventing further deterioration.

From a technological and resource perspective, the price gap for green hydrogen is currently smallest for wind power generation. Table 2 below provides a summary of the CAPEX, operation costs, the resulting levelized cost of electricity and the availability of the different potential resources for hydrogen generation.

Table 2 Comparison table for PtH systems based on source of electricity supply [Source: Ozturk et al., 2021]

Source	CAPEX	Fixed Costs	LCOE	Availability
Solar	2.9	4.12	–	1.5
Onshore Wind	3.55	7.25	2.17	2.5
Hydro (run of river)	2.58	8.82	4.35	8
Hydro (Conventional)	4.19	8.82	6.09	8.5
Biomass	0	0	–	8
Geothermal	1.94	7.25	6.21	7
Lignite	4.19	3.33	2.92	7.5
Hard Coal	3.87	1.18	2.86	7.5
Natural Gas	7.42	8.82	0	7.5

From this data it is clear that (1) none of the renewable, carbon-neutral alternatives can compete with the price of wind energy based power-to-hydrogen systems and (2) the supply is volatile, making the storage and transportation of this energy all the more important.

The potential for wind power utilization also happens to be the highest in the NS countries on the European continent. Figure 7 shows the distribution of wind power potential around the entire continent.

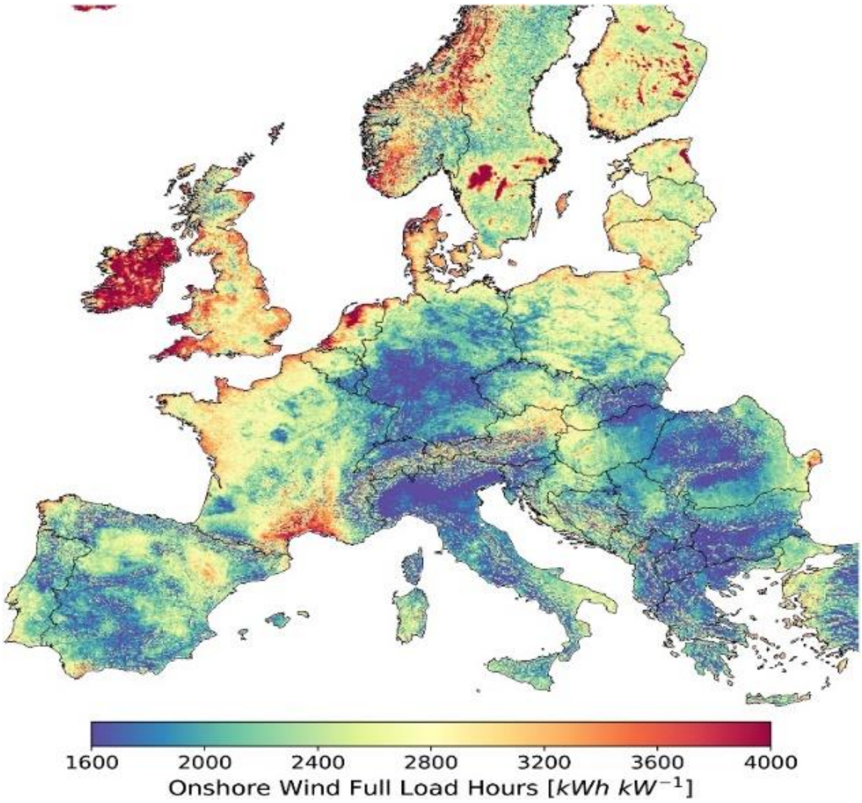

Figure 7 Average annual capacity factor mapped around Europe [Source: Ryberg et al., 2019]

In previous works of Tröndle et al. (2020), the Calliope framework was used to build an electricity system model of Europe (Euro-Calliope v1.0), which then was expanded into a sector-coupled model by Pickering et al. (2022) – adding household, industrial and commercial heat demand, passenger and freight transport technologies, and energy consumption in all other sectors, including agriculture and industrial feedstock. A national level of this pre-built Euro-Calliope model was further reduced in its original pan-European geographic scope – in the North Sea Calliope model 10 modelled nodes represent 10 countries; Belgium, Denmark, France, Germany, Ireland, Luxemburg, the Netherlands, Norway, Sweden, and the United Kingdom – all current or former parties to the NSEC.

The NS region and NSEC countries were selected as a topic and geographic scope for this study based on the information detailed above – they are economically developed, historically big polluters, with an existing infrastructure, international cooperation and political will to front the investment building the currently non-existent economies of scale in hydrogen production, necessary to bring down the prices to cost-competitive levels.

This means that production of energy carriers in these countries and the transmission of electricity and gas between them – including physical transmission capacities – are modelled in detail. However, the imported energy coming from outside this geographical scope is modelled as domestic production, without any care for the actual flow. Even though the main research question is aimed at the implications of the choice of infrastructure on the future price of hydrogen in the Netherlands, the Dutch infrastructure itself is not modelled in greater detail, and is neglected in favor of a larger geographical scope based on the information provided by the Dutch TSOs – the Netherlands' local distribution infrastructure is not expected to become a bottleneck in the future, therefore the investment decisions should be aimed at the larger, international transmission infrastructure. Furthermore, the relatively uniform climate of the country in combination with the utilization patterns of hydrogen means that a greater detail in the modelling of the Dutch infrastructure would not contribute proportionally to the results.

On the North Sea regional aggregation too, this research focuses solely on the transmission level of the electrical and gas infrastructure and omits the distribution network because of the vastly different, non-comparable purpose, technical attributes and economics of these different levels of infrastructure, keeping in line with the time and resource limitations. Since the focus of this research is quantifying the effects of the choice in transportation infrastructure has on the future price of hydrogen in the North Sea region, the transmission network connecting this region is the most logical starting point for analysis. Moreover, the unit cost of transportation generally shows a steep decline with the increase in transportation length and volume, reaching a more or less stagnant level only on the transmission level of infrastructure (DeSantis et al., 2021). This promises a more accurate result and a more appealing business case for hydrogen with this research applied on the transmission network first, without getting into complexity the time and resource limitations would anyway forbid. In the shorter distance transportation, a more detailed research would be necessary in an incremental, more progressive manner based on transportation length – but only if the transportation of hydrogen proves to be competitive on the higher level investigated in this research. From an economic point of view, with the probable decentralization of the energy supply system and the possible electrification of many end-use applications in the future, locally produced electricity can reasonably be assumed to be more competitive in short distance transportation than any other energy vector due to the high conversion costs – making the central research question rather less relevant for distribution levels of energy transportation – but further research should be directed on quantifying the exact effect the distribution network plays on the results presented in this report.

Parallel research operating under similar assumptions, conducted within the same research group and expected to be published the same time this research concludes already arrived to the conclusion that hydrogen is not becoming competitive in the transportation sector, at least as it is modelled in Calliope right now. This is somewhat contradicting expectations based on the literature review, however, within the same limitations this research is expected to arrive to the same conclusions – guiding this study to focus solely on hydrogen's role in the building heating sector instead.

2.5.2 Temporal scope

The research experiments are structured based on the declared policy goals of the problem-owner – the Dutch government – and the investigated time horizons are selected accordingly; the scenarios are set up with the 2030 and 2050 de-carbonization goals in mind already detailed in previous sections of this document.

2.6. Investigated scenarios

The literature review revealed an uncertainty around the prevalence of the possible end-use applications of hydrogen, leading to an uncertainty of its penetration in the future economy. The investigated scenarios address this uncertainty by simulating a wide range of hydrogen penetrations in the investigated 2030 and 2050 timelines. The 2030 horizon is worth investigating separately because unlike for the more distant future in 2050 the Dutch government (and the EC) has defined and very tangible goals – detailed also with regards to the hydrogen production – for the near future ending with 2030.

The scenarios are established with a base-line scenario produced via an initial model run – the basic NS Calliope model's optimal solution. The lower/upper bounds of the investigated scenarios were then determined by goals and expectations based on policy documents as described in the literature review. All the different transportation options – electricity, mixed hydrogen-natural gas, dedicated hydrogen and retrofitted hydrogen network – have been tested under the different penetration assumptions in one or both time horizons. Table 3 summarizes the investigated scenarios.

Table 3 The setup of investigated scenarios

Transportation options	Time horizon	H2 penetration	Capacity
Electric transmission	2030, 2050	All	Expandable, with minimum
Natural gas-hydrogen blend	2030	All	Fixed
Retrofitted infrastructure	2030, 2050	All	Fixed
Dedicated infrastructure	2030, 2050	All	Expandable, without minimum

The natural gas-hydrogen blends are not investigated on a 2050 timeline because in the decarbonized future – which is a presumption of this study – the fossil natural gas supply chain will not exist in the form it exists today, and the biomethane production/consumption/distribution problem with its uncertainties and complexities is worthy of a separate research. The existing literature considers the role of blending – if at all – a transition pathway, not an end-goal.

2.6.1 2030 scenarios

In its official climate policy action plan submitted to the EC the Dutch government laid out clear goals regarding renewable and hydrogen generations by the year 2030. The Dutch government wishes to establish 3-4 GW electrolyser capacity itself (NCA, 2019), very well complementing the European 2×40 GW goal promoted by the EC – out of which 40 GW is from import and 40 GW should come from domestic production (EC, 2020). The investigated scenarios are comparing the optimal model solution, considered to be the 'base-line' scenario, and the effects of infrastructure on achieving the declared European/governmental goals. The separation of scenarios based on the 2030/2050 timeline gives also an opportunity to explore hydrogen transportation options that would otherwise not make sense by 2050, like the natural gas-hydrogen blending options.

As established earlier, the NS region is responsible for around half of the entire EU's CO_2 emissions, and produces 47% of its GDP – the electrolysis capacity goal had been allocated accordingly in the 'Goal (50%)' scenario. Moreover, it is also established, that the most promising renewable potential for hydrogen production is concentrated in this region, therefore a 'Goal (100%)' scenario had also been established for further comparison. Table 4 below summarizes the setup parameters of the scenarios investigated on the 2030 time horizon.

Table 4 The summary of the 2030 scenarios

Scenario	Hydrogen penetration 2030 [10^5 MWh]
Base-line	0.287
Goal (50%)	1750
Goal (100%)	3500

As shown above, the base-line scenario represents a really small penetration – coincidentally in a great alignment with the recent findings and projections of Odenweller et al. (2022) predicting a 'less than 1%' penetration of hydrogen in the EU by 2030 even with the current, very ambitious plans materialized. Based on an exponential expansion model they argue that even with a fast ramp-up of electrolysis capacity, the high annual growth rates will translate into market share with a delay only – achieving a breakthrough point only by 2036 in Europe and by 2043 globally.

2.6.2 2050 scenarios

The first 2050 scenario is considered to be the 'base-line scenario', representing the optimal penetration of hydrogen calculated by the model in its original setup. Then, the hydrogen penetration is manipulated by an incrementally elevating/decreasing fashion, using the model's built-in carrier_prod_min and carrier_prod_max group constraints to force larger/smaller amounts of hydrogen output on the electrolysis technology. The scenario setup with the exact parameters is explained in the table below.

Table 5 The summary of the 2050 scenarios

Scenario	H2 penetration 2050 [10^5 MWh]
Decreased (90%)	16000
Base-line (100%)	17500
Elevated (150%)	26250

The North Sea countries consumed around 2.7 million GWh of energy in the form of natural gas in 2020 according to Eurostat, meaning that in the base-line model run hydrogen achieved 65% of the penetration of natural gas' penetration by 2050. This means that the 'Elevated' scenario with 150% of the modelled optimal, base-line scenario represents a future where hydrogen replaces natural gas in every possible way and takes its place by 2050. The 'Decreased' penetration future represents the EC's own prediction and expectations regarding the future hydrogen penetration in the EU by providing only about 15% of the 10.5 million GWh total energy supply.

2.7. Extension of the existing model

In the existing sector-coupled Euro-Calliope model hydrogen has already been established as an energy carrier. The production of hydrogen in the model is possible via electrolysis only, after which it is either used for combined heat and power generation, as industry feedstock, stored in dedicated storage tanks or as electricity, or converted into synthetic fuels, like kerosine, diesel, methanol or methane via the modelled transformation technologies.

2.7.1 The necessary extensions

Based on the research question, identified sub-questions and the documented standard capabilities of the North Sea Euro-Calliope software, on preliminary consideration the model needs to be extended and tested;

- with all relevant transmission systems capable of transporting hydrogen in its pure form – including the legacy natural gas infrastructure with its existing parameters,
- with a realistic representation of transmission and consumer technologies to transport and utilize natural gas-hydrogen blends,
- with additional dedicated end-use applications of hydrogen, covering theoretically possible options and sectors of the economy, like building heating – i. e. via hydrogen boilers,
- with a realistic representation of the natural gas production and import of the region,
- and with a function capable of extracting and processing the shadow price information of transmission capacities to gain information on grid stability and the transmission component of hydrogen prices.

The motivation behind these extensions is explained below.

Transmission system

This research is centered around quantifying the difference the various hydrogen transportation options have on the carrier price, this way motivating investment in one or the other option. These options include virtual (vehicular transportation), dedicated, retrofitted or blended hydrogen-natural gas pipeline options, or an expansion of the electric grid. Out of all of these options, only the electric grid had any sort of representation in the model prior to this research. The literature review revealed that the virtual pipeline/vehicular transportation options are only competitive in quantities lower than even the most pessimistic projections of hydrogen demand in the future, and interesting in a regional distribution role only, expected to be marginal, limited to a few odd cases – posing no interest for the national level problem owner this research aims to address and out of the geographical aggregation level the modelling requires for all other options.

The existing natural gas network and the dedicated hydrogen pipelines were modelled based on the built-in transmission technology type. For both, a ‘parent’ technology group was specified (ng_transmission, h2_transmission) to cover an onshore and offshore transmission pipeline technology (ng_onshore_transmission, ng_offshore_transmission, h2_onshore_transmission, h2_offshore_transmission, h2p_onshore_transmission, h2p_offshore_transmission). A differentiation was made between the onshore and offshore options based on geographical considerations because of the considerably higher investment and OPEX costs coming with the construction and operation of marine pipelines. If a pipeline connected two countries divided by a large water body, the worse-case investment offshore pipeline scenario was assumed.

Natural gas production and import

The sector coupled North Sea Euro-Calliope model does not extend into a realistic representation of the fossil fuel supply of the region. Methane, coal and petroleum products appear in the system on demand from an endless supply, placing the national natural gas production and import capacities, with their limitations out of the scope of the original model. For the purposes of this research, this is a potentially crucial oversimplification because methane itself is a competitive alternative – through technologies like methane boilers, or the hydrogen_to_methane technology built in the model – to hydrogen in some of its applications on the modelled 2030 time horizon. A limitless supply of methane, therefore, has a potential to influence hydrogen's expected price and market share. To avoid these market distorting effects, a limit needs to be implemented on the natural gas supply – logically this limit could be the actual technological supply capacity of the region. To model this natural gas supply, two sources were considered; domestic production and import. A built-in functionality of the model makes it possible to implement production by defining the production capacity (energy_cap_equals constraint); for this purpose, the maximum of the 10-year period before the year 2020 of the primary production data was used to reflect the volatility of the natural gas supply. The effect of implementing these real production and import values on the overall behaviour of the model and produced results were then promptly tested to validate the necessity of this addition. The modifications were implemented as a separate, 'natural_gas_supply' scenario.

Natural gas – hydrogen blends

Based on the literature review, a realistic transition pathway – and a transportation option for hydrogen – from the current energy system to a carbon-neutral economy might include the blending of hydrogen to the natural gas mix as a transient measure to realize immediate but limited carbon emission reduction without further investment (Klatzer et al., 2022). Studies and expert opinions differ on the exact amount of hydrogen that can be blended into the transported gas without necessitating adjustment or replacement in the end-user equipment. It appears that the technical possibility lies between 5% and 15% hydrogen/natural gas volumetric ratio, and the current regulation in European countries makes it possible to blend 0.1-12% H_2 into the natural gas grid (Ogden et al., 2018). The original model did not include options to model this pathway, therefore, following the internal logic of the model, a new hydrogen-natural gas blend carrier (ng_h2_blend), a complex converting technology to produce this new carrier using methane and hydrogen as an inflow (ng_h2_blender), furthermore a transmission system capable of transporting this blend (blend_transmission parent technology group, blend_onshore_transmission, blend_offshore_transmission technologies), and a technology formally converting the blend back to methane (ng_h2_deblender) were added to the model.

Dedicated hydrogen end-use technologies

The original sector coupled North Sea Euro-Calliope model already includes hydrogen as a carrier but does not include a modelled hydrogen demand to the level of detail necessary to carry out this research. Other than the already existing industrial feedstock demand, and energy storage option, hydrogen is explicitly expected to become a major source of energy in mobility, and possibly in building heating – dedicated hydrogen applications, therefore, need to be included in the model to cover these areas as well. However, parallel research in the same research group found that hydrogen is not becoming competitive in mobility applications as modelled in the Calliope framework, therefore, building this result, only the hydrogen boiler technology was included in this research.

Transmission system congestion costs

As explained above, the shadow price of transmission system capacities carry additional information regarding the energy grid's stability. As demonstrated in Section 2.4, a higher utilization of the transmission line leads to an elevated shadow price of the same capacity. The TSO's are obliged to keep the energy grid in balance. The cost of this is reflected in a congestion fee built in the transfer component of energy prices. To be able to reflect on these 'system stability costs' in different system settings, the modelling framework needs to be extended to process this information. The PYTHON script performing this task, added to the pre-processing stage of the framework's *utils.py* file can be found in Appendix C.

2.7.2 Testing process of the necessary extensions

The first sub-research question is addressing the methodological groundwork necessary for the entire further research. This section with the related, detailed results in Section 3.1 provides the answer for the first sub-question of this thesis. Since the research necessitates altering the dynamics of the existing model in the above described way, in order to gain confidence in the results, both integration and system level testing is important. Integration testing was carried out in an incremental way, after the implementation of every new extension, while a system testing was done with all the above mentioned extensions together. The results are detailed and interpreted in Chapter 3.

2.8. Data need and gathering process

This section explains in greater detail the data gathering process and the used sources for the above detailed extensions of the model. Figure 8 below shows a simplified flow diagram summarizing the process.

Figure 8 The data pipeline

2.8.1 Data need

The first step in the modelling process was to identify the potential data points that – implemented in the model correctly – would provide a close enough approximation of the physical and economical attributes of the extensions. This data need is summarized in Table 6 below based on an understanding of the model's operational needs and the literature review.

Table 6 The identified data need

Model extension	Data need
Transmission system	Physical capacity, geographical location, technical lifetime, efficiency, CAPEX and OPEX costs
Natural gas production and import	Production and import figures per NS country per source
Natural gas - hydrogen blends	Possible blending ratios
Dedicated hydrogen end-use technologies	Efficiency, technical lifetime, CAPEX and OPEX costs

2.8.2 Data sources

After delineating the data need, the data sources were gathered. As a general rule, in order to preserve the model's internal coherence and transparency, where possible, the original data sources of the model were used as a source to extend the model as well. The next step in the data gathering process, therefore, was to identify these sources as presented in Table 7 below.

Table 7 The data sources used to build the sector coupled model [Source: Pickering et al., 2022]

Original data sources	Type of data
Eurostat	Energy data, consumption, demand
Joint Research Centre	Attribution of consumed resources to end-users per subsector Location of existing generation
Swiss Federal Office for Energy	Disaggregation of demand
Danish Energy Agency	Technological and operational costs

The second step in collecting the data sources was to identify the emerging data need that is not covered by the existing data sources, and to determine the potential sources where this data can be collected from. The outcome of this exercise is summarized in Table 8 below.

Table 8 Potential sources for the model extensions

Type of data	Potential data sources
Physical capacity and location	ENTSOG, GIE
H_2 end-use data (lifetime, efficiency, costs)	Research papers, manufacturers
Future RES/hydrogen penetration	Policy documents, grey literature

2.8.3 Data collection and processing

Natural gas production and import data of the region was gathered from Eurostat. The natural gas production data of European countries is published on a monthly basis, while the import data is aggregated on a yearly temporal resolution and is disaggregated by partner/source country. The mismatch between the two datasets was resolved by the monthly production data being processed into yearly average production figures. To account for the high volatility of the natural gas output, the data of the 10-year period preceding the modelled years between 2009 and 2019 was collected, and the maximum of the period was implemented using the model's built-in energy_cap_equals constraint functionality, therefore, allowing the supply to reach the 10-year maximum but otherwise choose the production level freely depending on the need. Furthermore, the import data for all NS countries was divided between source countries that are themselves NS countries, and source countries outside of the geographical scope of the model. The import from countries in the latter category was accounted for and added as domestic production of the investigated countries, while the import data from NS countries to NS countries was used to validate the separately obtained infrastructural capacity data and to reflect on the amount of unused capacity. All obtained values were converted into the 10^5 MW unit, used by the model. The calculated national production figures are presented below by country in Table 9 and the existing interconnection capacities are in Table 10. The exact Eurostat dataset used in obtaining the specific datapoints can be found in Appendix B.

Table 9 Implemented natural gas production by NS country [Source: Eurostat]

NS countries	Modelled capacity [10^5 MW]
BEL	0.103
DEU	1.423
DNK	0.117
FRA	0.400
GBR	1.063
IRL	0.005
LUX	0.007
NLD	1.140
NOR	1.356
SWE	0.001

Table 10 The existing physical infrastructure capacity matrix between NS countries [Source: ENTSOG]

To [10^5 MW] \ From [10^5 MW]	BEL	DNK	DEU	IRL	FRA	LUX	NLD	SWE	NOR	GBR
BEL	x	-	0.165	-	0.113	-	0.582	-	0.203	0.272
DNK	-	x	0.057	-	-	-	-	-	-	-
DEU	0.135	0.002	x	-	-	-	0.530	-	0.520	-
IRL	-	-	-	x	-	-	-	-	-	0.161
FRA	0.363	-	0.256	-	x	-	-	-	0.238	-
LUX	0.020	-	0.011	-	-	x	-	-	-	-
NLD	0.138	0.022	0.248	-	-	-	x	-	0.401	0.070
SWE	-	0.022	-	-	-	-	-	x	-	-
NOR	0.203	-	-	-	-	-	0.401	-	x	-
GBR	0.335	-	-	-	-	-	0.206	-	0.625	x

In the absence of a central database, the length of the modelled transmission lines were collected separately, on a case by case basis from their respective operators, as shown in Appendix B. The summarized information used in the model is found in Table 11.

Table 11 The modelled natural gas transmission pipelines [Source: see Appendix B]

Connection		Name	Length [km]	Comment
BEL	DEU	TENP	25	Fraction of TENP (Eynatten-Stolberg)
BEL	GBR	Interconnector	235	
BEL	LUX	TENP	100	Charleroi-Luxemburg
BEL	NLD	-	75	Antwerp-Rotterdam
BEL	NOR	Zeepipe	814	
DEU	DNK	DEUDAN	111	
DEU	FRA	MEGAL Nord	908	
DEU	LUX	TENP	37	Fraction of TENP (Luxemburg-Trier)
DNK	SWE	Dragör-Malmö	25	
FRA	BEL	Dunkirk-Zeebrugge	74	
GBR	IRL	Multiple pipelines	687	
NLD	DEU	TENP	40	Fraction of TENP (Maastricht-Stolberg)
NLD	DNK	Tyra West - F3	100	
NLD	GBR	Balgzand Bacton Line (BBL)	235	
NLD	NOR	NOGAT	264	Assumed
NOR	DEU	Europipe	1318	
NOR	FRA	Franpipe	840	
NOR	GBR	Langeled	1166	

The technical data to describe the natural gas and hydrogen transmission system was collected from the Danish Energy Agency (DEA). DEA data was used extensively for building the original model, and their data projections extend to hydrogen technologies – regarding energy loss, investment, OPEX costs and lifetime, with a 2050 time horizon. The loss and investment data is published based on the amount of transported energy, making it possible to conduct a more precise calculation. The table below summarizes the collected data – the losses and investment costs were handpicked from the dataset based on Table 10 above and Table 12 below. Since the natural gas network is an already existing part of the infrastructure, its investment costs were neglected in the model and only operation and maintenance costs were considered. The obtained data then was turned into the units of 10^5 MW and km used by the model.

Table 12 The technical data describing the existing and future natural gas and hydrogen infrastructures [Source: DEA]

	Natural gas main distribution line	H_2 main distribution line
Energy losses [%]	0.1	1.5
Technical life time [years]	50	50
Investment costs [EUR/MW/m]	1-11	0.2-4.7
Fixed OPEX [EUR/MW/km/year]	0.12	0.5
Variable OPEX [EUR/MWh/km]	1.1×10^{-5}	0

2.8.4 Challenges

Since most of the hydrogen technologies in applications of the future economy and investigated in this study are still under development, in research, and therefore unavailable for commercial use, data for them is scarcely available – most of this data is hypothetical and obtained from research papers or other academic publications under some assumptions and simplifications.

As already mentioned in previous chapters, there was a mismatch between the geographical and temporal resolutions of some of the EUROSTAT datasets of the natural gas supply and transportation system which also needed to be resolved in a statistically satisfying way.

Furthermore, infrastructural investment decisions are virtually impossible to model reliably because of the financial aspects of these projects. The CAPEX of infrastructural investment depends on several independent variables – the highest contribution (around 50%) of it coming from labour costs (Palgrave, 2022). For this, and other reasons the cost-estimation of projects is highly dependent on individual factors, unique and has to be done on a case-by-case basis, the uniformizing simplifications – however necessary – for studies like these are hard to make and justify.

The natural gas infrastructure and the actual natural gas flows are hard to follow and connect in a reliable way. The actual data concerning this topic is sometimes confidential and constitutes a trade secret of privately owned companies (or even state secrets in the case of international natural gas purchasing treaties). Some educated assumptions had to be made connecting the natural gas import data with the physical infrastructure in existence between countries based on the collected infrastructure capacity data and the import/export data.

Those weaknesses of the data gathering and processing deemed to be most influential in forming the results of this study were tested in the sensitivity analyses to obtain a clearer picture of the inherent risks to these modelling decisions and to provide clarity on the limitations of the results. Results of these can be found in Section 3.3, and discussed in Section 4.4.

2.9. Uncertainties and sensitivity of results

The deterministic nature of the applied methods in this research and the uncertainties around data quality detailed in the above sections of this same chapter mean that sensitivity analyses are necessary to quantify the uncertainties around the results of this study and conclusions based on them. The sensitivity analyses, carried out as described below, are meant to establish the robustness of the outputs and to build confidence in the conclusions and recommendations of this research, while also possibly signalling the directions for further research. Results of the sensitivity analyses are published in Section 3.3 and discussed in Section 4.4.

2.9.1. Weather year

The Calliope model takes weather data as an input to establish the renewable capacities of the modelled energy system. Since the weather is extremely changeable by nature this is an expected weakness and source of uncertainty in modelling any energy system with a high share of renewable generation capacities. By default, to conserve computational capacity and speed up the modelling process – which consists of many iterations of the same model run –, a single weather year is being used as an input – therefore the optimization and the presented results account for the annual/seasonal weather changes only. However, there is no way to guarantee that the selected weather year is representative of the modelled time horizon spanning multiple years, or decades, especially since the underlying motivation of this study is provided by a rapidly changing climate. To decrease the interannual weather uncertainty, either multiple model years need to be fed to the model as an input, greatly increasing the computational demand, or time slices of different weather years need to be sampled randomly (Blanco et al., 2022).

2.9.2. Hydrogen technology and pipeline costs

Techno-economic attributes of the modelled hydrogen appliances and transportation options, such as efficiency and lifetime are highly uncertain due to the recent technological developments and the investigated time frame. Since the commercialization of these technologies is still underway, researchers right now cannot rely on manufacturers' or empirical data, like day-to-day experiences of customers. Some of the data used in this study like pipeline costs are a result of significant simplifications, since the variability displayed in 'real-life' would result in complexity this thesis cannot cover. Pipeline CAPEX costs are virtually impossible to estimate, since they are determined by factors such as length, capacity – its diameter and operational pressure –, material, labour costs, terrain, environmental and safety standards that are hard to simplify and uniformize in one model covering a large geographical and temporal area.

The summary of technical and economic attributes of the added technologies that were tested in a sensitivity analysis is displayed in Table 13. The 'SA1' and 'SA2' columns displayed the lower and upper bound of each property that was tested – selected based on the literature review (in the case of efficiency and lifetime, methane boilers taken as an example) and available data sources (in the case of investment costs).

Table 13 The technical and economic properties subjected to sensitivity analysis

Technology variable	Original value	SA1	SA2
h2_onshore_transmission investment cost	0.05	-	1.20
h2_offshore_transmission investment cost	0.10	-	2.05
h2p_onshore_transmission investment cost	0.20	-	4.10
h2p_offshore_transmission investment cost	0.35	-	7.20
hydrogen_boiler energy efficiency	0.97	0.90	1.00
hydrogen_boiler lifetime	13	10	20

The sensitivity model runs were set up accordingly on a 2050 time horizon, since the uncertainty, as described above, is expected to increase in the long-term future mainly. A 'minimum cost' and a 'maximum cost' model run was defined bundling the pipeline costs of onshore and offshore transmission lines together, resulting in 4 additional sensitivity model runs. The lowest investment costs of transmission pipelines were tested in the original model runs, and therefore only the higher bound estimation are implemented in the sensitivity analyses, for comparison.

2.9.3. Demand projections

The energy demand of a country is influenced by factors like economic performance, the size of its population, technological development, and even the weather. The inability to control these factors translates into unpredictability, which accumulates into a significant uncertainty regarding the world's energy demand in the coming decades. There are projections for some of these factors, like population change and economic growth, however, these are extremely unreliable in the long-term future. CBS expects a continuous growth in population of the Netherlands, and 19.63 million inhabitants by 2050 with 18.8 and 22.2 million as a lower and upper bound estimation (CBS, 2020), however also admits to 'many uncertainties' – like fluctuations in migration patterns, which for instance was severely disrupted in the years 2020 and 2021 due to previously unforeseen circumstances. Instead of trying to rely on inherently unreliable projections, this study addresses the uncertainty by exploring the sensitivity of its results to a change in energy demand.

To estimate the growth in energy demand due to CBS's estimation of population growth, the Energy Transition Model (ETM) was used. The model uses the demographic data as input, and generates projections of resulting energy demand. Table 14 and Table 15 summarizes the information gained this way, by the different sectors based on the aforementioned lower and upper bound estimations of population growth by CBS.

Table 14 Change in energy demand as a result of demographic uncertainty by 2050 - lower bound estimation

	2019 [PJ]	2050 [PJ]	Change [%]
Heat	279.9	303.3	108
Electricity	94.8	103.1	109
Cooking	8.4	9.2	110

Table 15 Change in energy demand as a result of demographic uncertainty by 2050 – upper bound estimation

	2019 [PJ]	2050 [PJ]	Change [%]
Heat	279.9	365.0	130
Electricity	94.8	121.7	128
Cooking	8.4	10.8	129

According to the ETM, a 10-30% energy demand growth can be expected based on CBS's demographic projections, and so the input data in the cooking-demand.csv, heat-demand.csv and the electricity-demand.csv input files of the model was changed accordingly.

3 Results

The following sections describe the results of the modelling process. These results are grouped into three main sections. The results of the testing process are presented in Section 3.1, answering the first, methodological sub-question of this research on how to extend the model to be capable of answering the rest of the research questions. The results of the model instantiations are in Section 3.2, answering the second and third sub-question set up with final data and according to the described scenarios in Chapter 2. Finally, the Section 3.3 contains the sensitivity analyses, reflecting on the robustness and weaknesses of this research and providing further insight into future research needs.

3.1. Testing of the model extensions

Due to the existing time and resource constraints, the research was heavily dependent on a pre-built sector-coupled energy system model. A summarized description of this model is entailed in Chapter 2 of this document, with the rationale behind selecting this specific software, the expected advantages and disadvantages, and the anticipated difficulties. Calliope is one of the most referenced open-source energy system models available and capable of supporting this research – according to the information provided by the OpenMod initiative. A detailed handbook is readily available and a hyperlink leading to the online development environment is provided in the bibliography of this thesis. While Calliope is an open-source model built with full transparency in mind, a complete understanding of all its capabilities, limitations and inner mechanisms could not possibly be obtained within the time constraints of this research alone. With this in mind, it was deemed important to take additional care in implementing the extensions and modifying the model mechanisms to maintain trust in the results. This paragraph provides information on the 'black-box' tests that were set up in order to provide certainty in observing the step by step implementation of new elements.

3.1.1 Integration testing

The Euro-Calliope and North Sea Calliope models built using the Calliope modelling framework are by no means black-box models in the classical sense. However, since the model itself is an extensive and very complicated tool, to maintain the trust in the modelling process and to make sure that the research draws well-grounded, verifiable and replicable conclusions, the extension process was done in incremental steps accompanied by a testing process. Calliope is a well-referenced modelling tool, its existing features have already been tested extensively but it is important to make sure that the extended version used for the purposes of this research works in a sensible way as well.

Transmission system

The most important extension to the model is the addition of pipeline transmission systems – the existing natural gas network with its technical attributes, and the possibility to repurpose this network into a blended natural gas-hydrogen network, or a dedicated hydrogen transportation system. To first test simply the model's own sensitivity to adding a pipeline infrastructure, a simplified network was modelled without adding any unnecessary complexity to the standard model. The hydrogen price information was then extracted from a 2050 model run, and compared to the original modelled price timeseries output – with the existing and already tested electric transmission system – of the same model year. The result is shown below in Figure 9.

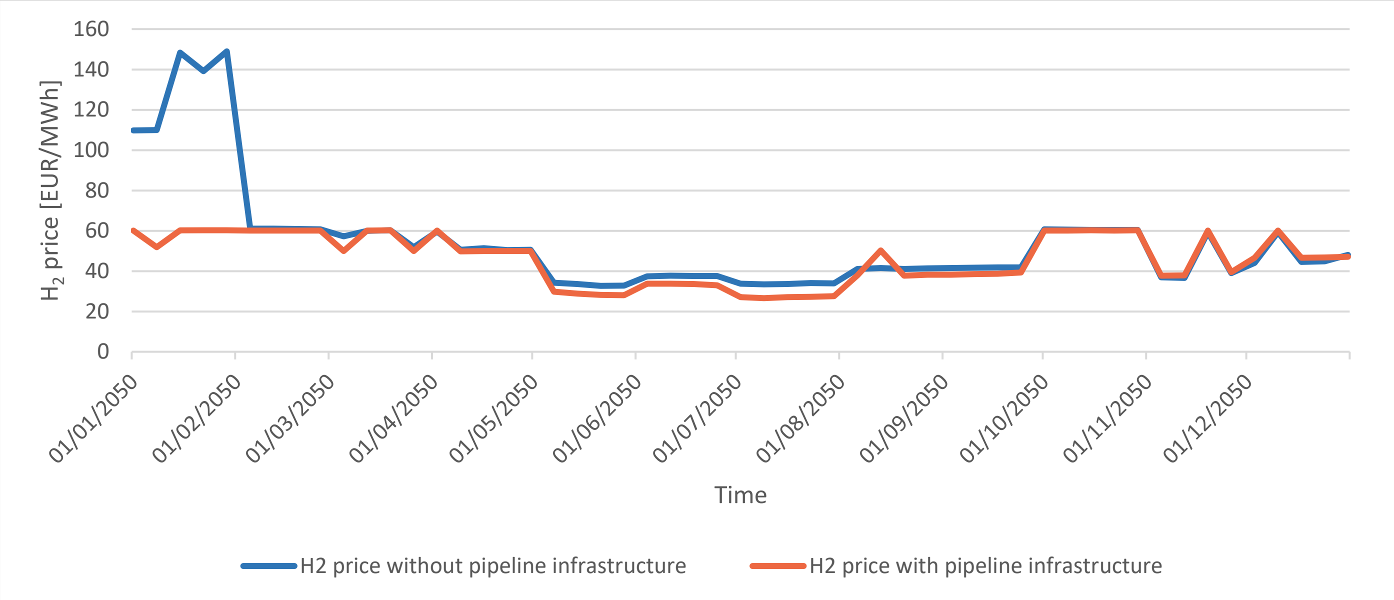

Figure 9 Testing the model's pipeline extension

The price timeseries output of hydrogen transported (partially) via this dedicated pipeline system is compared to the option of transforming hydrogen entirely into electricity for transmission purposes, coming with the default model. The difference – in fact, advantage – of using a pipeline shows clearly, especially in the first month of the year. This proves that the model itself is sensitive to the addition but provides very little further information. Investigating the role infrastructure plays in the forming of the future price of hydrogen, intuitively, the investment costs and the amount of gas being transported through the pipeline should play a role, as described in previous sections. Further experiments, therefore, were set up to test whether these relationships work in the modelled environment.

To see if the transported amounts of hydrogen has a role to play in the price formation, a 'regular' model run was compared against a model setup in which the electrolyser output of hydrogen were forced to reach 150% of the optimal amount calculated by the model in the 'regular' model run, using the carrier.prod.min group constraint. Table 16 summarizes and compares the information learnt from this experiment, and Figure 10 below shows that the expected relationship between the transported amount and the resulting hydrogen price stands.

Table 16 The set parameters and the optimal outcomes of the high penetration test model run

	'Regular' model run	Forced high H_2 output
Installed electrolyser capacity [10^5 MW]	2.46	3.6
Produced amount H_2 [10^5 MWh]	17449	26250
Installed pipeline capacity [10^5 MW]	2.2	2.2
Transported via pipeline [10^5 MWh]	97.67	3408.63
Average price [EUR/MWh]	44.48	26.58

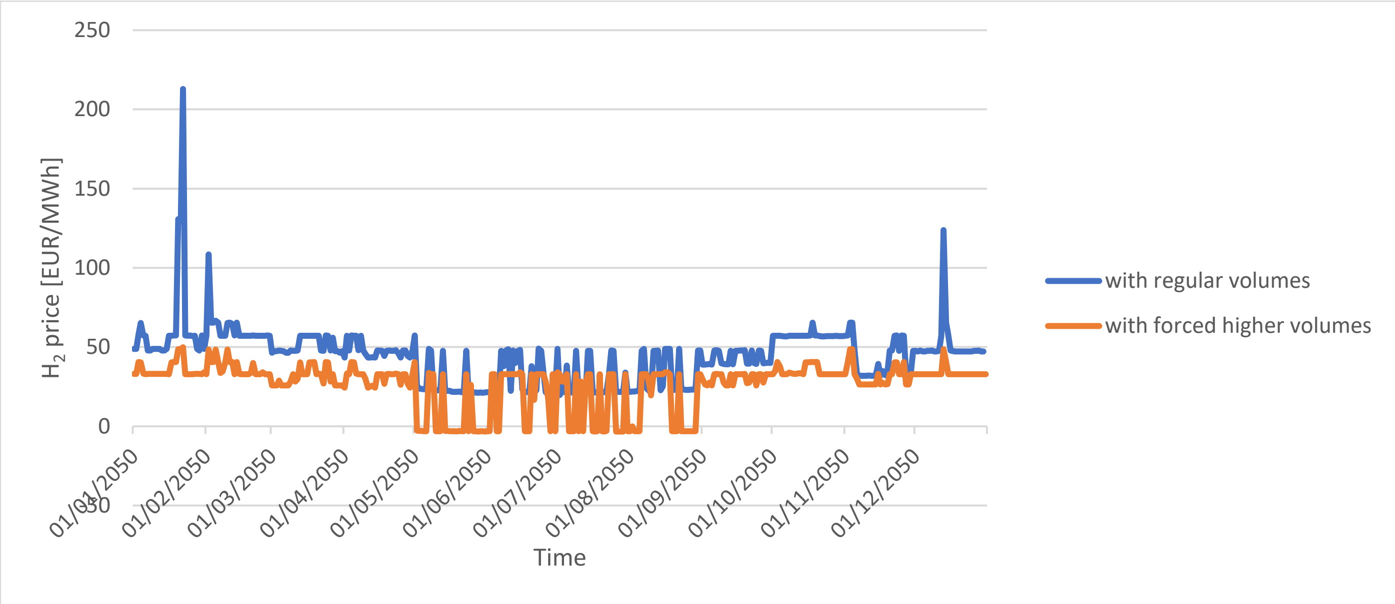

Figure 10 Testing the modelled price results' sensitivity to the transported volume

Going further, to see if the CAPEX costs of the transmission system result in the expected price increase, the hydrogen prices were extracted from a model run with (1) a newly-built gas transmission infrastructure, (2) a retrofitted infrastructure – with accordingly lowered CAPEX costs – and (3) an electric transmission system. The results are presented in Figure 11. As can be seen, the difference in price between the new infrastructure and the retrofitted infrastructure remains very much below expectations. Intuitively, the higher CAPEX costs should result in elevated hydrogen prices, and while there is a detectable difference between the two cases, this difference in prices – as shown also in the average – is practically negligible. This result is in contrast with the expectations based on the literature review, and therefore requires deeper analysis and attention before drawing any conclusions.

To gain more clarity in understanding these results, the model run was repeated with only one modification – the pipeline investment costs were altered to reach the higher end of estimation provided by the same source (DEA). The resulting hydrogen prices are shown on Figure 12. The difference shows clearly, and with the prices in the scenario with newly built infrastructure and therefore highest CAPEX surpassing both the electric transmission and the retrofitted infrastructure prices, the results are much more consistent with a priori expectations and the literature itself.

Possible explanations of this come from the modelling decisions and data quality - in reality the CAPEX of pipeline projects is composed of variable and non-variable components. Some of these components, like labour costs – accounting for as much as 50% of investment costs of pipeline infrastructures – do not display a linear relationship with the extension capacity, meaning that a smaller pipeline will be disproportionally expensive compared to a larger pipeline. It is reasonable to assume that the data – even though accounting for this effect by providing brackets of decreasing unit costs by the increasing capacity – does not follow this curve perfectly by just the small number of datapoints provided. These results show that (1) the modelling method works as intended, since the price changes in the expected direction with increased investment costs, (2) the uncertainty around the investment costs data is high, and therefore a sensitivity analysis is necessary.

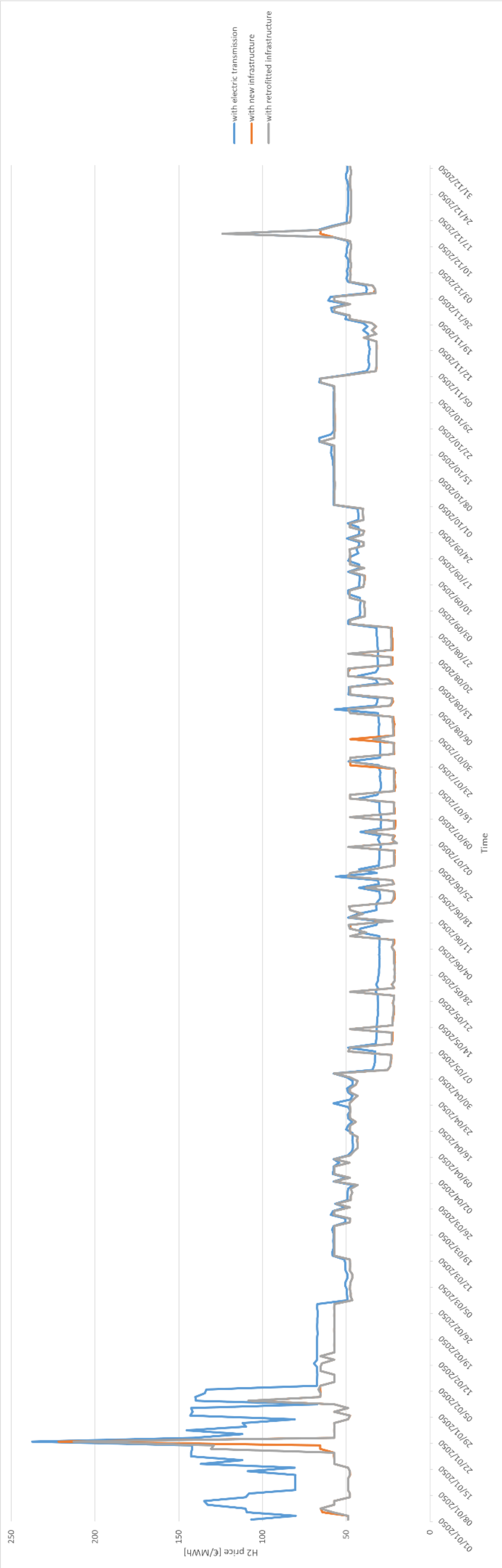

Figure 11 The H_2 price with low investment costs

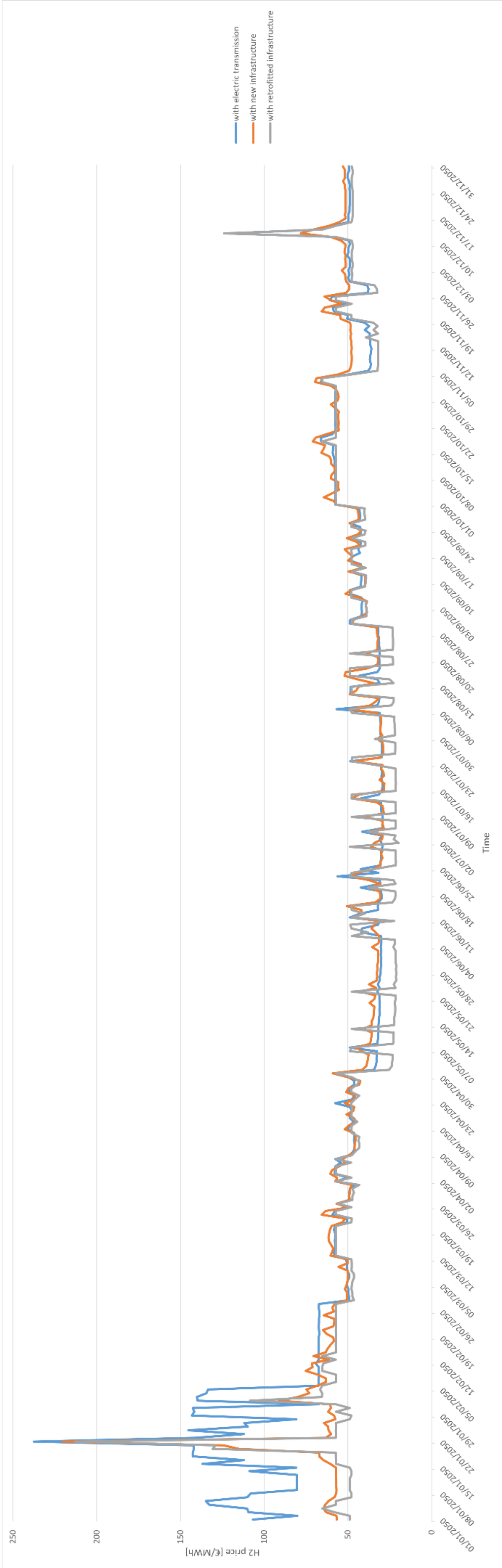

Figure 12 The H_2 price with high investment costs

In a similar fashion, the test was repeated with a lowered level of hydrogen penetration. Anticipating similar problems as in the previous test, to confirm the theory behind the reason why, the electrolysis technology was disabled in all locations but one, forcing a higher volume of hydrogen being transported despite low penetration.

Since lowering the hydrogen penetration to its minimum creates scarcity, the astronomical jump in price (2250-2300 EUR/MWh) is to be expected. The important conclusion based on Figure 13 below is that the model behaves the way it should, the newly built infrastructure resulting in an elevated hydrogen price compared to the already built and reutilized infrastructure, presumably because of the modelled CAPEX costs.

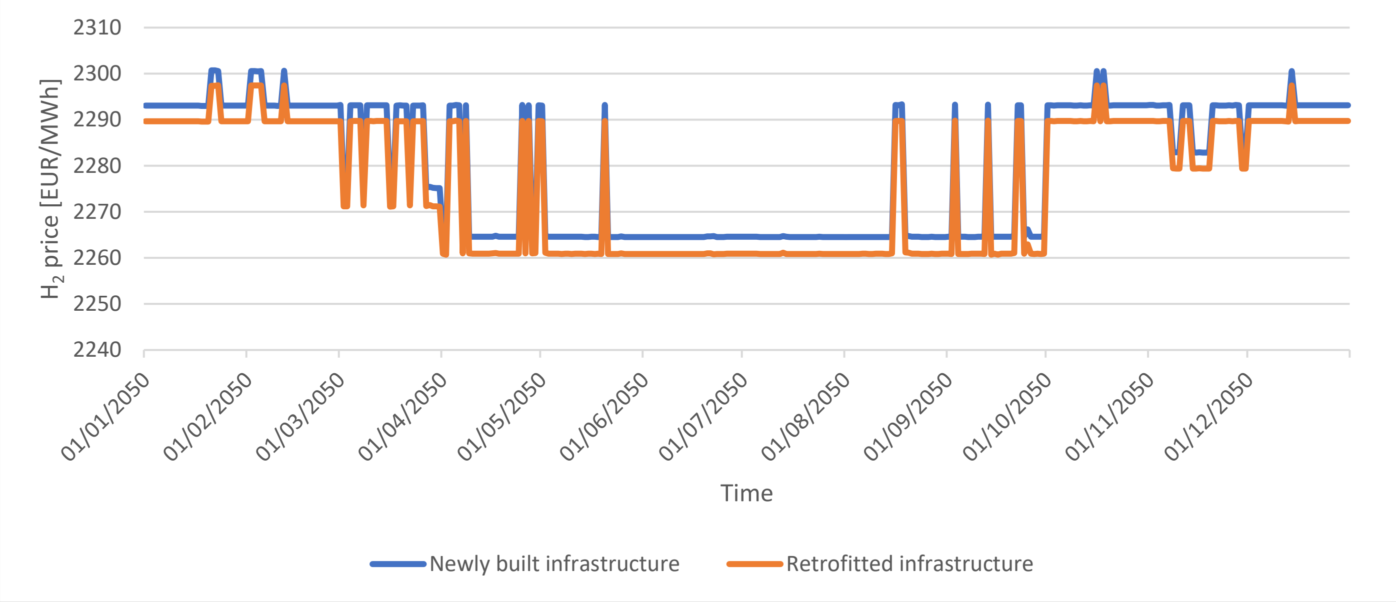

Figure 13 Hydrogen price with low penetration transported in different infrastructures

To summarize how much difference the lower and higher modelled CAPEX makes, the average price over the entire year was also calculated, as shown in Table 17. It can be concluded that the price reacted to the elevated investment costs the way it was expected.

Table 17 The average H_2 price in relation to differing investment costs

		Test 1	Test 2
Investment cost [EUR/MW/m]		0.02-0.035	0.41-0.72
Average H_2 price [EUR/MWh]	Electric transmission	53	53
	Retrofitted infrastructure	44	44
	Dedicated infrastructure	44	49

Natural gas production and import

Since the hydrogen and methane flows are interconnected in the model and work as competing options through a number of modelled technologies, it might prove important to fix the market distorting effect of an unlimited methane supply. For this purpose, the realistic methane supply of the NS region has been modelled in the way described above in Chapter 2. To test the model extension, and whether it works the way intended, a 2030 model run with and without it was executed. The resulting price of methane and hydrogen can be seen on the figure below (Figure 14).

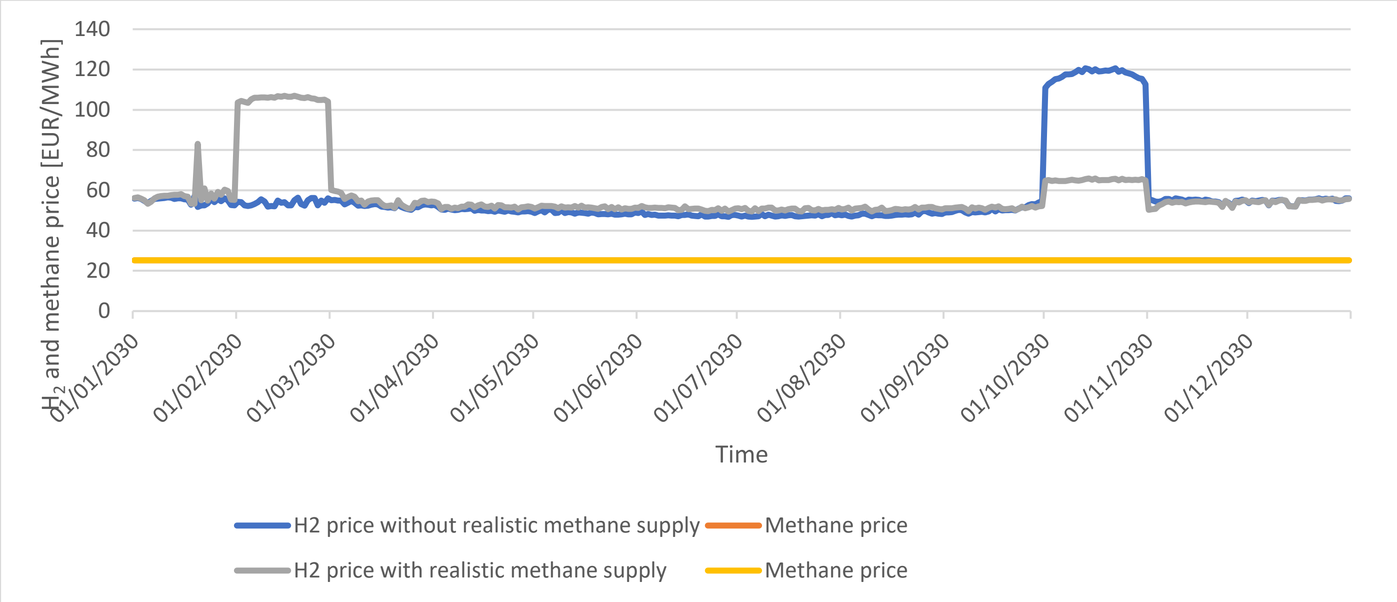

Figure 14 The impact of realistically modelled natural gas supply on the modelled H_2 price

The methane price itself remained constant in both model runs, the limit on the natural gas supply does not affect the methane prices itself but the effect on the hydrogen price can clearly shows – therefore, it is fair to conclude that the implementation of this extension is necessary in any model run on the 2030 time horizon. The 2050 model runs naturally exclude any level of fossil fuel production, therefore this extension does not make a difference in the 2050 scenarios.

Natural gas-hydrogen blends

The model setup for the natural gas-hydrogen blending option was detailed in previous sections. The four additional technologies that have been added to the model were tested in a new model run to see if they have been integrated into the model and whether they are functional. Table 18 below summarizing the newly installed capacities shows that the additions are indeed working, and a blended natural gas-hydrogen gas is flowing through the model.

Table 18 Summary of the installed optimal capacities of the newly integrated technologies

	Installed capacity [10^5 MW]
Fictional 'blender'	1.55×10^{-5}
Fictional 'de-blender'	9.73×10^{-6}
Offshore pipeline	0.699
Onshore pipeline	1.498

Hydrogen end-use applications

The hydrogen boiler was introduced as a new end-user technology, and tested to work the way expected. Table 19 shows the installed capacity in the optimal model solution in a 2050 model run, and Table 20 the produced heat by this technology in every location, as intended.

Table 19 Summary of the installed optimal capacities of the newly integrated hydrogen boiler

Technology	Installed capacity [10^5 MW]
Hydrogen boiler	0.025

Table 20 Produced heat by the newly introduced hydrogen boiler technology

Location	**Hydrogen heat production [10^5 MW]**
BEL	0.17
DEU	0.11
DNK	0.2
FRA	397.03
GBR	0.15
IRL	0.12
LUX	0.13
NLD	0.19
NOR	0.14
SWE	0.17

3.1.2 System testing

After all the different added elements of the extended model have been tested separately, and verified to work as expected, the entire model's coherence was tested with the new additions. It is impossible to verify the model's outputs in a traditional way for multiple reasons; in the case of hydrogen, there is no real historical market price data to which they could be compared. Furthermore, it is not the intention of this research to predict market prices – the outputs of the modelling effort are shadow prices rather representing the limits of an economically conscious decision. This way, even in the presence of reliable historical data, these would only be helpful to compare them to real actors' decision-making and the resulting price curves. Any difference between them could be explained with imperfect information/decision-making, which would not necessarily discredit the outputs of the model or the conclusions of the research. Moreover, important to note that this research is concerned with modelling the energy carrier prices in a future, therefore a non-existent energy system, which does not necessarily compare to the current one. This research does not aim to establish a perfect representation of the future energy system – not even as it is currently envisioned by decision-makers and the general public in the years 2030 or 2050. It is possible to aim for a better simulation of the energy sector based on a set of assumption – like already set and above described policy agendas for the future – but it is out of the scope of this research. This study aims to establish the relative effects of hydrogen transmission infrastructure on the modelled carrier prices, therefore it addressed strictly the necessary modelling need – the extensions that were expected to effect one type of hydrogen infrastructure disproportionately compared to other types of infrastructure, therefore distorting the relative relationship of hydrogen price outputs between them.

To test whether the additions work together as expected, additionally to the conclusions of the integration testing in the previous section, the hydrogen price outputs were compared to the electricity prices produced by the model. The result is shown in Figure 15 below.

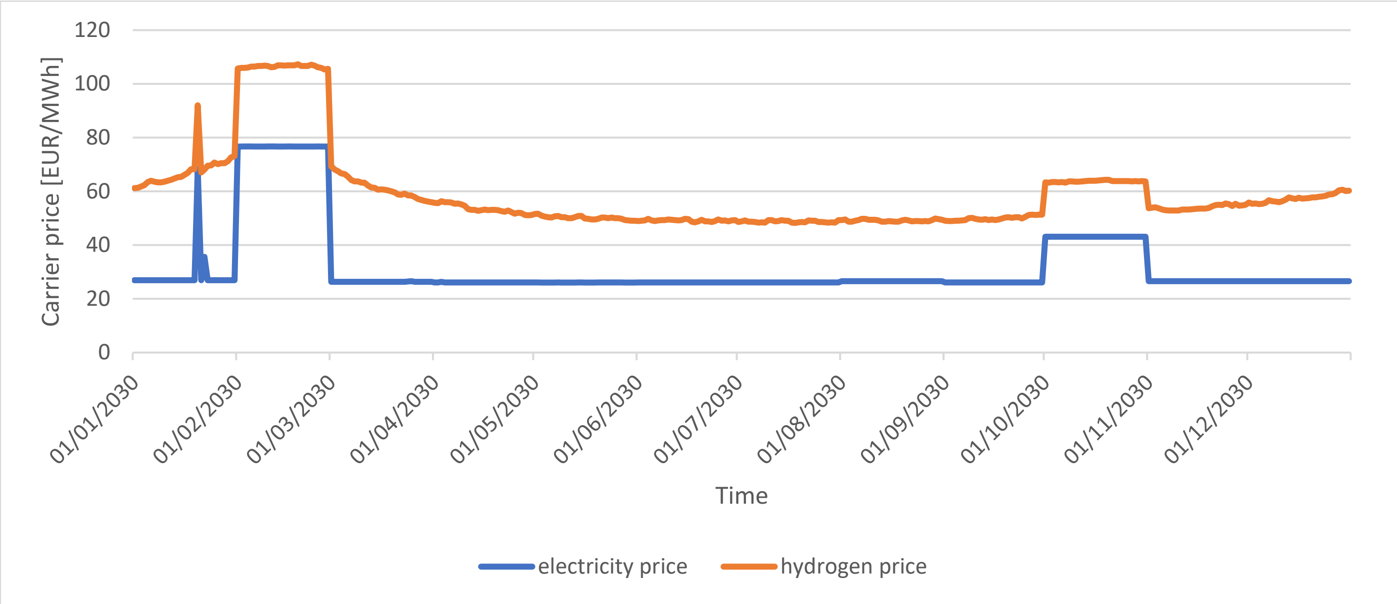

Figure 15 The correlation between H_2 and electricity prices in a 2030 model run

Based on the figure above the hydrogen price shows a strong correlation with the electricity price produced by the model, which satisfies the expectations. Since hydrogen is produced via electrolysis, the resulting hydrogen price should be coupled to electricity prices.

3.2. The model runs

After the model and its additions have been tested to work separately and together in a number of dummy calibrations, the model runs were set up using these additions with the input data published in Section 2.8, and according to the scenarios described in Section 2.6. The outcomes of these runs – price timeseries outputs, price duration curves, and the calculated statistical variability indicators – are detailed in the following sections, the results grouped according to the 2030 and 2050 time horizons, facilitating the comparative analysis based on them. Additionally, the shadow price of transmission capacities has been extracted in the model runs with a 2050 time horizon, as the utilization and the following grid stability is becoming an important issue in a fully de-carbonized energy system without (sufficient) base-load power generation to fall back on.

3.2.1 The 2030 model runs

Figure 16 shows the price timeseries output of hydrogen in the base-line hydrogen penetration scenario with electric transmission, blended natural gas-hydrogen transportation, retrofitted natural gas pipeline and a newly-built, dedicated hydrogen transmission network. Figure 17 shows the price duration curves for the same model instantiation with the same input data.

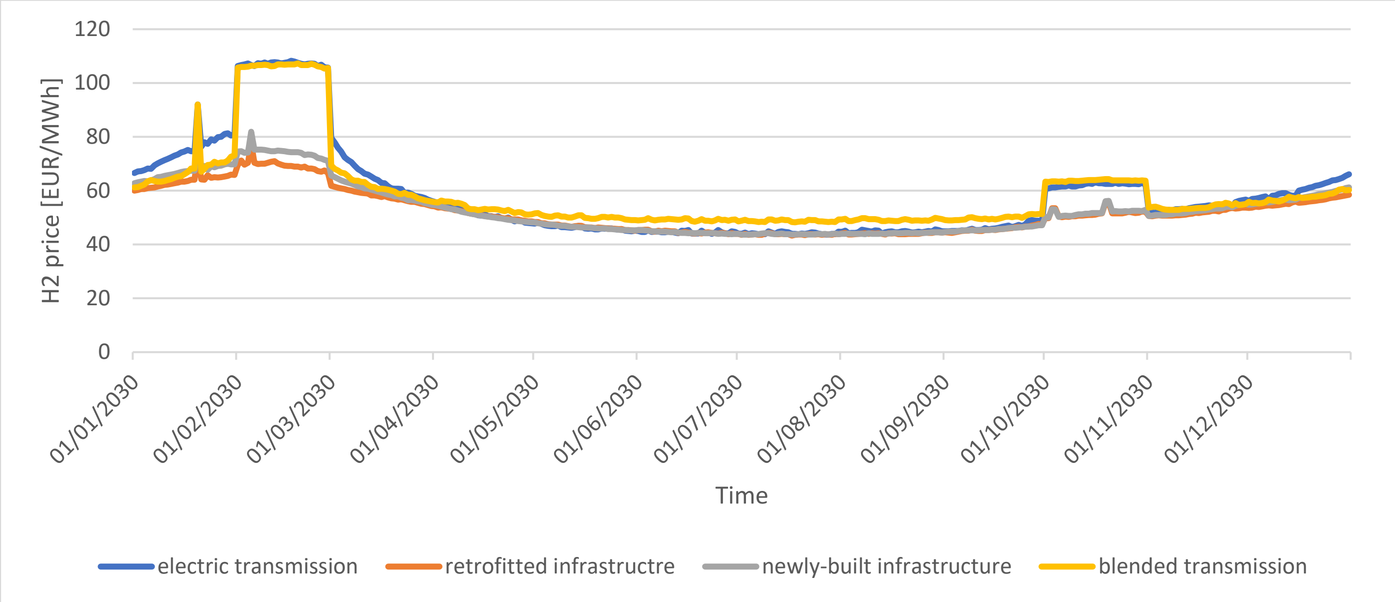

Figure 16 The H_2 price in the 'Base-line' scenario 2030

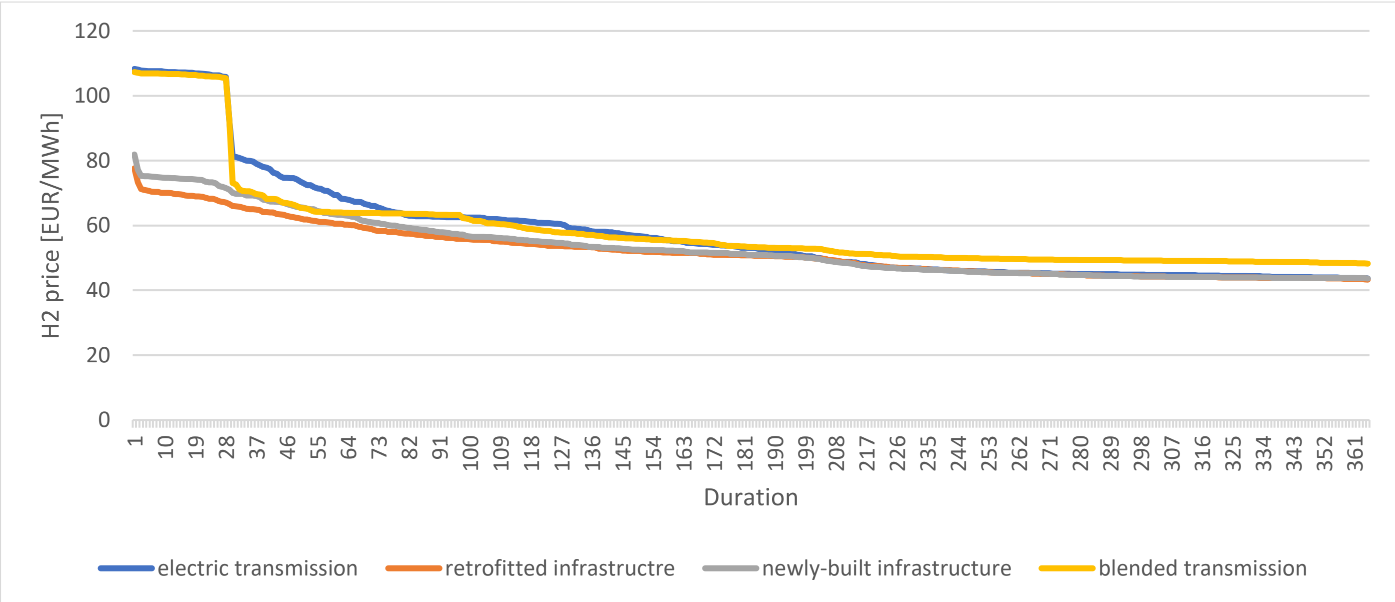

Figure 17 The H_2 price duration curves in the 'Base-line' scenario 2030

Figure 16 shows, that in line with expectations, the price of hydrogen – a fuel used partially for heating purposes in the model – is on the rise during the first three months of the year, and then again, in the last two months. The retrofitted infrastructure with the newly-built infrastructure, and the blending option with the electric transmission option produce similar patterns in the price outputs during the same times of the year – the main difference being the mitigating effect of the former two on price spikes. This is corroborated by Figure 17. In about exactly one half of the year the retrofitted and newly-built pipeline options produced a consistently lower price than the other two options, and the price difference was significant for at least about 30 days of the year.

Table 21 shows the relevant variability indicators of the timeseries data with different infrastructural options. The meaning of these is explained in Chapter 4.

Table 21 Relevant statistical indicators of the variability in the price timeseries 'Base-line' 2030

	electric	retrofit	newly-built	blend
RANGE [EUR/MWh]	64.6	34.3	38.2	59.1
STANDARD DEVIATION [EUR/MWh]	17.2	7.9	9.4	15.2

Figure 18 shows the resulting hydrogen prices with the same, already described transportation options, in the case of achieving the EU's declared domestic hydrogen production goals; an installed 20GW electrolysis capacity in the NS region based on its economic weight within the Union. Figure 19 contains the price duration curves of the same model setup.

Figure 18 The H_2 price in the 'Goal (50%)' scenario 2030

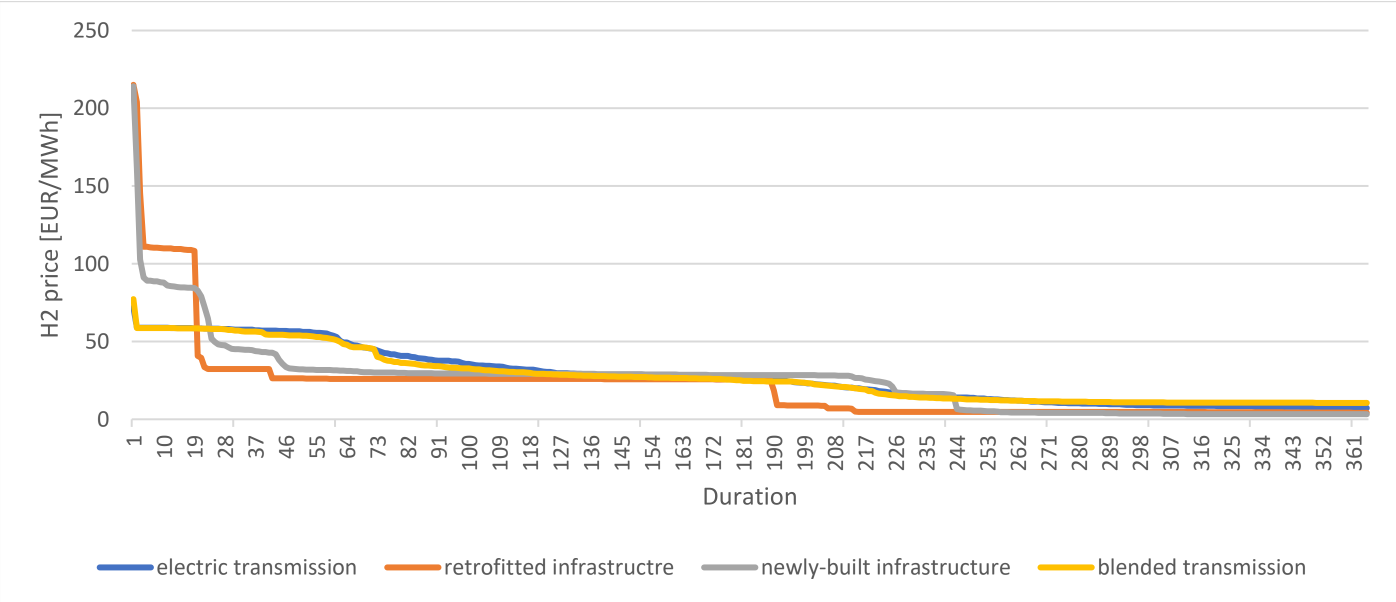

Figure 19 The H_2 price duration curves in the 'Goal (50%)' scenario 2030

Figure 18 and Figure 19 shows a significantly different outcome than what can be seen on Figure 16 and Figure 17 – the newly-built and retrofitted infrastructures proved to be less resistant to price spikes with the increased levels of hydrogen penetration, producing higher prices than electric transmission in 20-28 days of the year.

Table 22 summarizes the statistical variability of the dataset to facilitate the analysis and comparison between options.

Table 22 Relevant statistical indicators of the variability in the price timeseries ‘Goal (50%)’ 2030

	electric	retrofit	newly-built	blend
RANGE [EUR/MWh]	64.7	210.8	210.8	66.7
STANDARD DEVIATION [EUR/MWh]	17.3	26.9	23.4	16.3

Since the EC’s – otherwise very ambitious – goals for ramping up the electrolysis capacities can reasonably be expected to concentrate disproportionately in the NS region because of its comparatively high potential for wind energy, the highest penetration possibility was also considered with the results on Figure 20. Figure 21 contains the price duration curve for the same hydrogen penetration goal with the different infrastructural investment options.

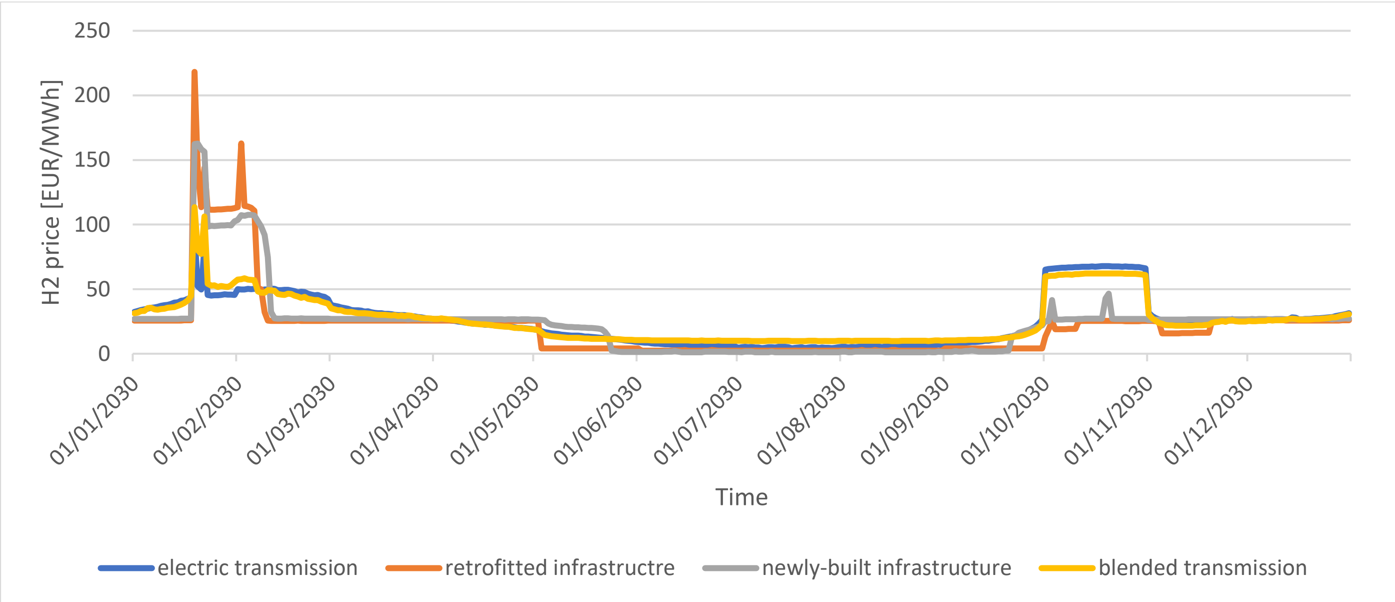

Figure 20 The H_2 price in the ‘Goal (100%)’ scenario 2030

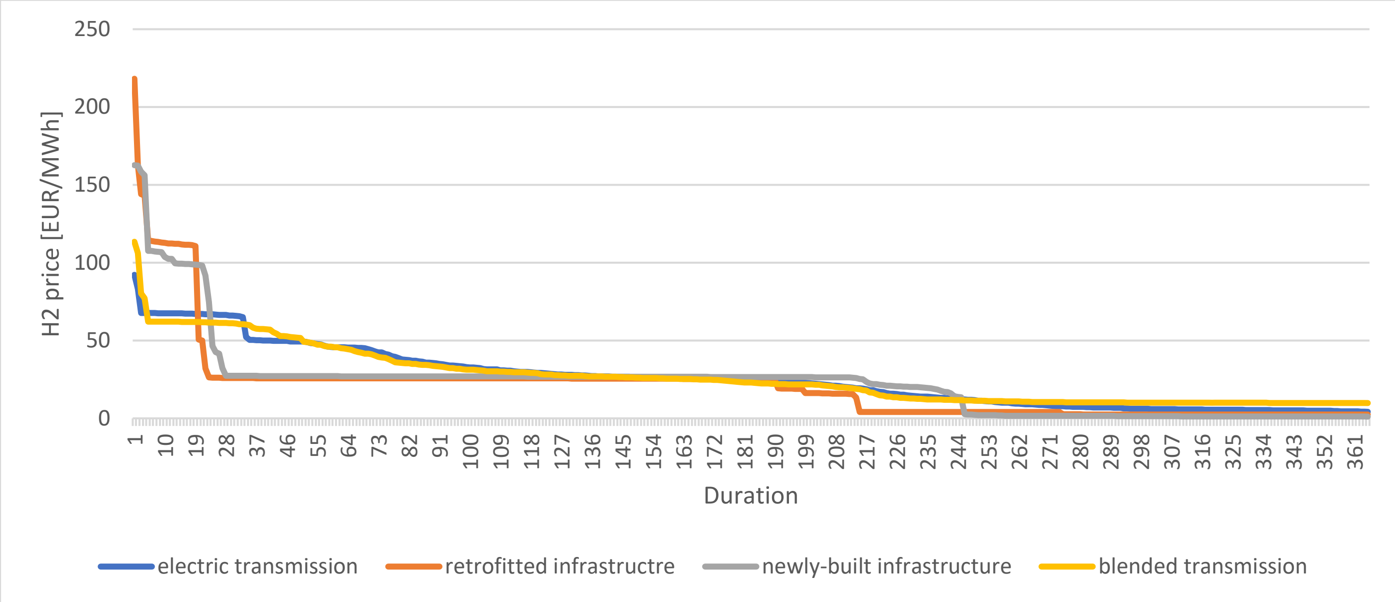

Figure 21 The H_2 price duration curves in the ‘Goal (100%)’ scenario 2030

Based on the figures above, a tendency can be identified; the pipeline infrastructures proven mitigating effect on average price and volatility seems to become much less clear with the increasing penetration in the 2030 timeline. With the increased penetration in both the ‘Goal (50%)’ and ‘Goal (100%)’ scenarios, the pipeline options seem to shows the same pattern – distinctively different than the smallest, base-line penetration scenario. The exact conclusions can be drawn based on the relevant statistical indicators of the dataset only. Table 23 below contains the relevant indicators expressing the variability in the resulting dataset.

Table 23 Relevant statistical indicators of the variability in the price timeseries ‘Goal (100%)’ 2030

	electric	retrofit	newly-built	blend
RANGE [EUR/MWh]	88.0	215.7	161.5	103.6
STANDARD DEVIATION [EUR/MWh]	19.0	27.2	26.2	18.0

3.2.2 The 2050 model runs

Figure 22 below shows the resulting hydrogen prices in the first, ‘Decreased’ 2050 penetration scenario with different infrastructural options – electric transmission only, retrofitted natural gas pipeline infrastructure and a newly built, dedicated hydrogen pipeline infrastructure. The natural gas-hydrogen blending options are not supported on a 2050 timeline anymore, as it is expected that the end-use applications will either be fully electrified or running on pure hydrogen in a fully de-carbonized economy.

Table 24 provides a summary of the other, more important indicators of the model run as well. Furthermore, Figure 23 contains the price duration curves resulting in this scenario.

Table 24 Summary of the output from the 2050 ‘Decreased’ model run

	2050 ‘Decreased’ H_2 penetration			
Transmission infrastructure	Average H_2 price [EUR/MWh]	Produced H_2 NL [10^5 MWh]	Transported H_2 [10^5 MWh]	Installed pipeline capacity [10^5 MW]
electric transmission	3326.3	0.3	-	-
retrofitted infrastructure	3328.7	0.6	0.3	2.2
newly built infrastructure	3328.1	0.3	0.1	2.6×10^{-5}

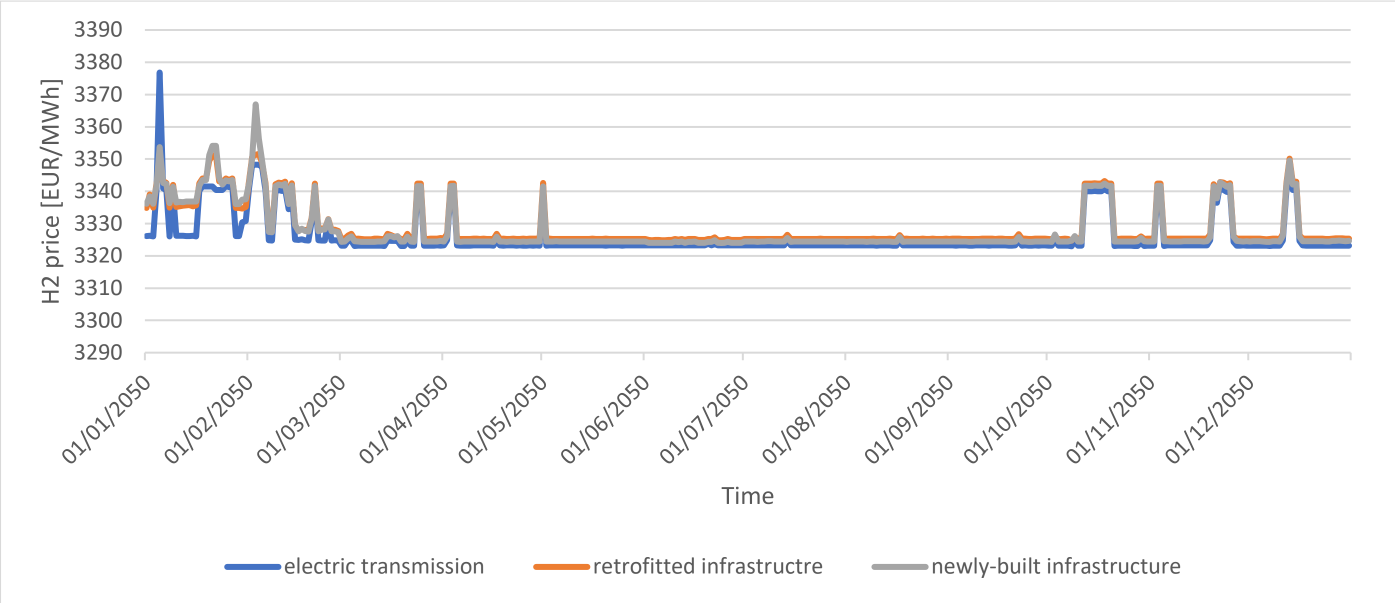

Figure 22 H_2 price in the 'Decreased' scenario 2050

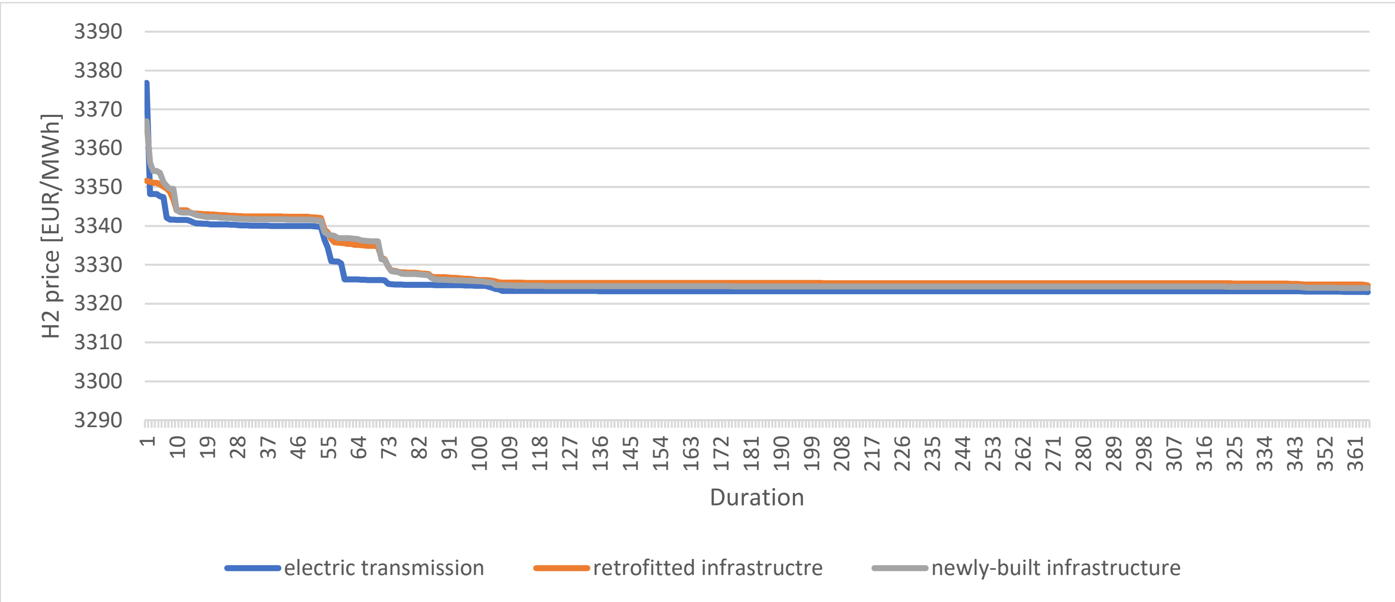

Figure 23 The H_2 price duration curves in the 'Decreased' scenario 2050

With the low penetration achieved in the model run, the transmission system couldn't achieve its intended role and the price dynamics were driven mainly by the scarcity of the resource – resulting in an unrealistically high hydrogen price. The curves display a very similar pattern, as can be expected, based on the low amount of hydrogen being transported through them. Table 25 below shows the statistical variability of the timeseries output above.

Table 25 Variability indicators 2050 'Decreased' scenario

	electric	retrofit	newly-built
RANGE [EUR/MWh]	53.9	26.9	43.0
STANDARD DEVIATION [EUR/MWh]	6.9	6.8	7.4

Table 26 contains the outputs of this model runs concerning the shadow price of the infrastructural capacity – not the transported hydrogen – itself. The meaning of this data with regards to grid stability and the infrastructure's utilization is explained in Chapter 4.

Table 26 The statistical data of transmission lines connecting NLD to the rest of the NS region in a 2050 'Decreased' model run

			Average price [EUR/MWh]	Range [EUR/MWh]	Standard deviation [EUR/MWh]
2050 'Decreased'	GBR	electric	-10.4	602.2	50.5
		retrofitted	-3328.7	26.9	6.8
		dedicated	-3336.3	29.9	6.5
	DEU	electric	-18.4	624.2	68.7
		retrofitted	-3328.7	26.9	6.8
		dedicated	-3334.5	44.2	7.7
	NOR	electric	-10.4	603.4	50.6
		retrofitted	-3328.7	26.9	6.8
		dedicated	-3336.7	29.6	6.5
	DNK	electric	-13.6	602.2	65.0
		retrofitted	-3333.7	29.0	6.9
		dedicated	-3334.7	47.8	7.5
	BEL	electric	-14.0	602.2	65.1
		retrofitted	-3328.7	26.9	6.8
		dedicated	-3338.8	44.0	7.5

The presented infrastructural options' effect on the price timeseries in the base-line penetration scenario is shown on Figure 24 below. All other relevant information extracted from the model run is also summarized in Table 27. Figure 25 shows the price duration curves resulting from the base-line scenario in each infrastructural option.

Table 27 Summary of the output from the 2050 'Base-line' model run

	2050 'Base-line' H_2 penetration			
Transmission infrastructure	Average H_2 price [EUR/MWh]	Produced H_2 NL [10^5 MWh]	Transported H_2 [10^5 MWh]	Installed pipeline capacity [10^5 MW]
electric transmission	54.1	0.2	-	-
retrofitted infrastructure	44.2	101.3	97.7	2.2
newly built infrastructure	49.6	0.3	3412.9	1.7×10^{-5}

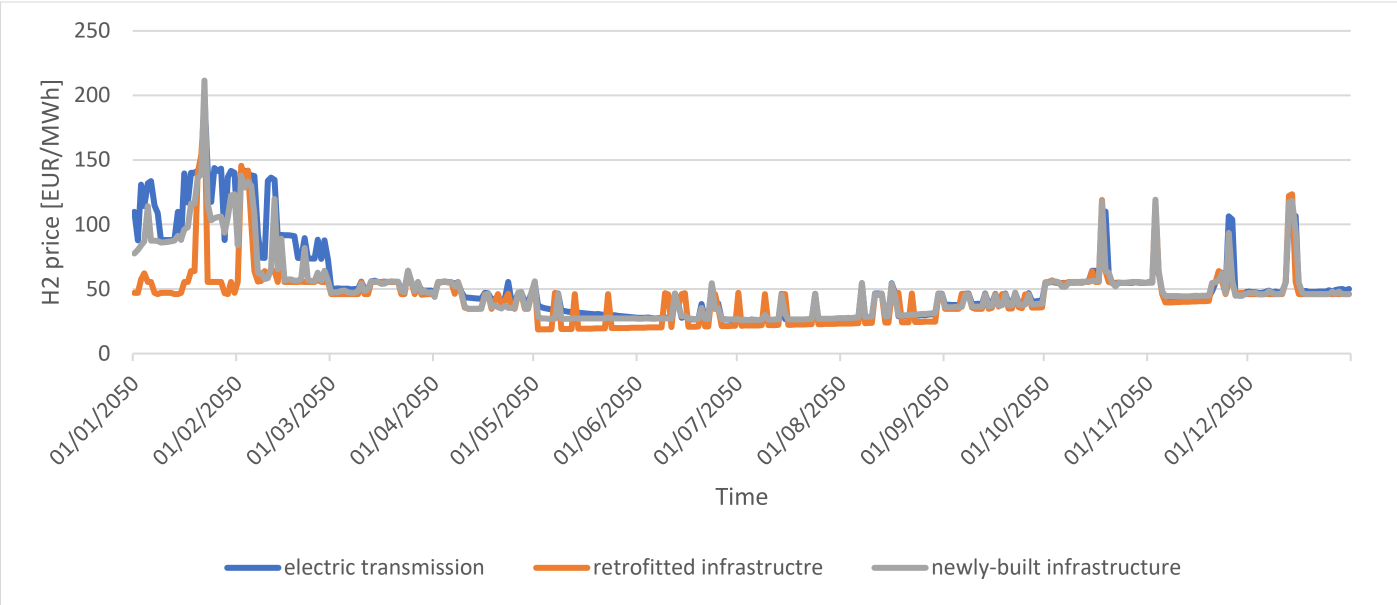

Figure 24 The H_2 price in the 'Base-line' scenario 2050

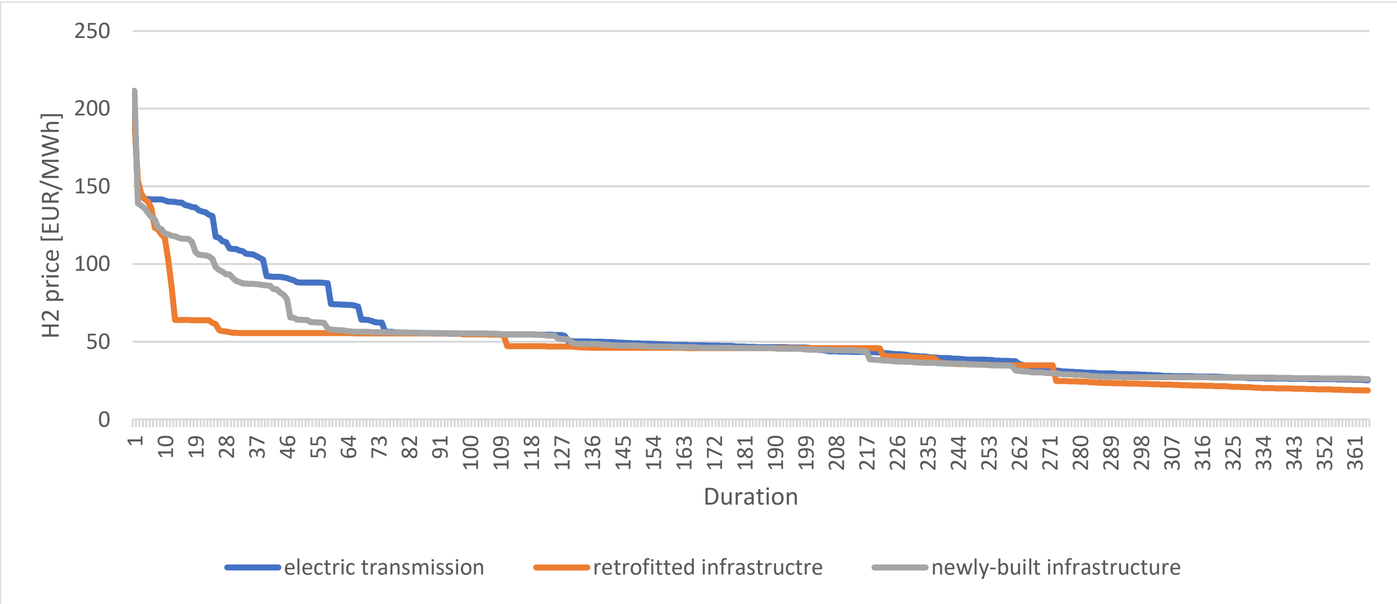

Figure 25 The H_2 price duration curves in the 'Base-line' scenario 2050

The base-line scenario shows a much bigger variance in pattern between the different infrastructure options with the retrofitted option being clearly the most advantageous, and the newly-built infrastructure still providing a lower prices in about 65 days of the year than electric transmission. Table 28 below shows the statistical variability of the timeseries output and Table 29 the shadow price and variability indicators of the infrastructure.

Table 28 Variability indicators 2050 'Base-line' scenario

	electric	retrofit	newly-built
RANGE [EUR/MWh]	175.5	173.2	185.6
STANDARD DEVIATION [EUR/MWh]	30.7	21.4	25.5

Table 29 The statistical data of transmission lines connecting NLD to the rest of the NS region in a 2050 ‘Base-line’ model run

			Average price [EUR/MWh]	Range [EUR/MWh]	Standard deviation [EUR/MWh]
2050 'Base-line'	GBR	electric	-29.4	272.4	30.4
		retrofitted	-44.2	173.2	21.4
		dedicated	-47.1	185.4	22.2
	DEU	electric	-36.8	280.5	37.6
		retrofitted	-44.2	173.2	21.4
		dedicated	-47.6	182.3	23.8
	NOR	electric	-30.0	272.4	30.3
		retrofitted	-44.2	173.2	21.4
		dedicated	-47.4	182.4	21.7
	DNK	electric	-28.2	275.6	29.7
		retrofitted	-44.2	173.4	21.4
		dedicated	-46.8	182.9	23.3
	BEL	electric	-33.9	275.0	34.0
		retrofitted	-44.2	173.2	21.4
		dedicated	-47.9	182.0	23.9

The third investigated scenario is the ‘Elevated’ penetration scenario with a forced 150% amount of hydrogen being produced with the electrolysers compared to the base-line scenario. The hydrogen price implications are shown in the timeseries outputs on Figure 26, the summarized information in Table 30 below. Figure 27 shows the price duration curves resulting from the elevated hydrogen penetration in each infrastructural investment option.

Table 30 Summary of the output from the 2050 ‘Elevated’ model run

Transmission infrastructure	2050 ‘Elevated’ H_2 penetration: Average H_2 price [EUR/MWh]	Produced H_2 NL [10^5 MW]	Transported H_2 [10^5 MW]	Installed pipeline capacity [10^5 MW]
electric transmission	39.5	0.1	-	-
retrofitted infrastructure	34.3	3417.9	3408.8	2.2
newly built infrastructure	36.2	0.3	3342.0	1.7×10^{-5}

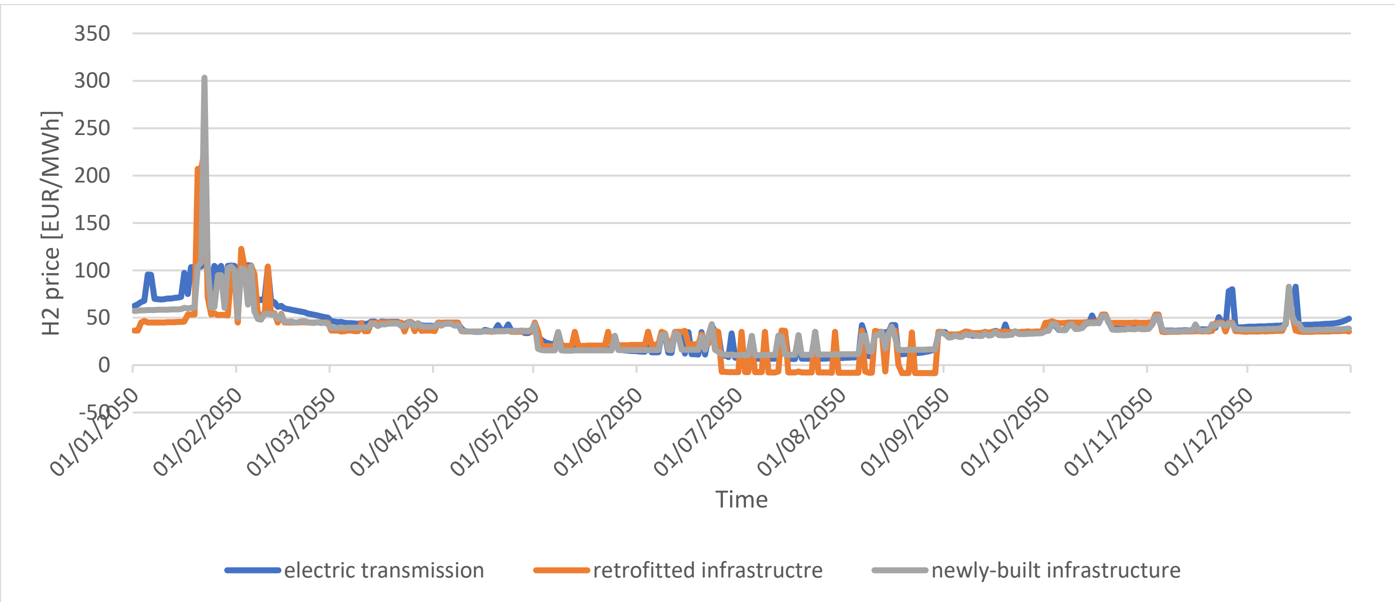

Figure 26 The H_2 price in the ‘Elevated’ scenario 2050

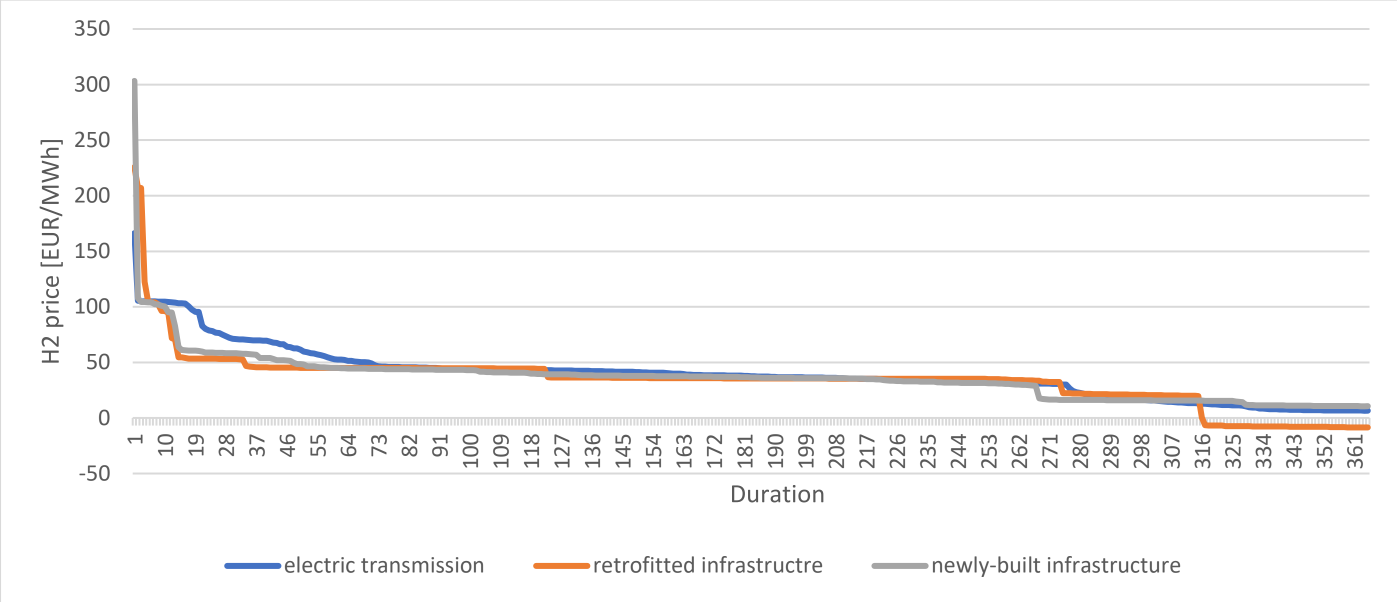

Figure 27 The H_2 price duration curves in the 'Elevated' scenario 2050

Based on the price duration curve above, the advantage of the retrofitted infrastructure seems to be disappearing compared to both the dedicated and the electric transmission system with the increasing hydrogen penetration. Table 31 below shows the statistical variability of the timeseries output and Table 32 shows the price and stability indicators of the transmission system capacity.

Table 31 Variability indicators 2050 'Elevated' scenario

	electric	retrofit	newly-built
RANGE [EUR/MWh]	159.8	234.3	292.7
STANDARD DEVIATION [EUR/MWh]	23.4	26.2	22.9

Table 32 The statistical data of transmission lines connecting NLD to the rest of the NS region in a 2050 'Elevated' model run

			Average price [EUR/MWh]	**Range [EUR/MWh]**	**Standard deviation [EUR/MWh]**
2050 'Elevated'	GBR	electric	-33.7	286.6	23.2
		retrofitted	-34.3	234.3	26.2
		dedicated	-40.0	300.4	21.7
	DEU	electric	-34.6	286.4	23.9
		retrofitted	-34.3	234.3	26.2
		dedicated	-35.9	293.6	22.8
	NOR	electric	-34.5	292.5	22.7
		retrofitted	-34.3	234.3	26.2
		dedicated	-36.2	306.3	21.9
	DNK	electric	-34.6	286.8	24.2
		retrofitted	-33.7	234.6	25.7
		dedicated	-34.2	298.0	22.0
	BEL	electric	-33.3	238.2	24.3
		retrofitted	-34.3	234.3	26.2
		dedicated	-36.3	289.8	22.4

3.2.3 Summary of the results

Table 33 summarizes the information of calculated average price for the different scenarios in both 2030 and 2050 timelines and transmission systems to facilitate comparison between them. The meaning of all the output data is discussed in Chapter 4.

Table 33 Summary of the resulting average hydrogen prices

	Average H_2 price [EUR/MWh]			
	electric transmission	blended transmission	retrofitted transmission	dedicated transmission
2030 'Base-line' [EUR/MWh]	58.1	61.6	52.4	54.0
2030 'Goal (50%)' [EUR/MWh]	27.2	26.8	21.4	25.1
2030 'Goal (100%)' [EUR/MWh]	25.7	26.3	21.0	23.3
2050 'Decreased' [EUR/MWh]	3341.4	-	3334.4	3334.4
2050 'Base-line' [EUR/MWh]	57.8	-	48.2	53.4
2050 'Elevated' [EUR/MWh]	43.3	-	38.3	40.3

Based on the detailed results in Table 26, Table 29 and Table 32 it can be concluded that all of the pieces of infrastructure connecting the Netherlands to neighbouring NS countries display the same pattern of behaviour in the data regarding their utilisation, so appropriate conclusions can be made based on the aggregated results of these tables in Table 34 below.

Table 34 Summary of the shadow prices of transmission infrastructure capacity in 2050

	2050 'Decreased'			2050 'Base-line'			2050 'Elevated'		
	Average price [EUR/MW]	Range [EUR/ MW]	Standard deviation [EUR/MW]	Average price [EUR/MW]	Range [EUR/ MW]	Standard deviation [EUR/MW]	Average price [EUR/MW]	Range [EUR/ MW]	Standard deviation [EUR/MW]
electric transmission	-13.4	606.8	60.0	-31.7	275.2	32.4	-34.1	278.1	23.7
retrofitted transmission	-3329.7	27.3	6.8	-44.2	173.2	21.4	-34.2	234.4	26.1
dedicated transmission	-3336.2	39.1	7.1	-47.4	183.0	23.0	-36.5	297.6	22.2

3.3. Sensitivity analyses

The limitations of the methodology and available data have been identified and described in detail in Chapter 2. To reflect on and quantify the uncertainty coming from the weaknesses and limitations of this research, sensitivity analyses have been carried out according to Section 2.9 of this document.

3.3.1 Weather year

To account for the uncertainty in the annual weather data, either multiple weather years need to be tested or weather data from multiple years need to be randomly sampled. The former is technically simpler but more resource consuming, therefore a first attempt was made with this approach to explore its feasibility.

To reflect on the results' sensibility to the weather year used as an input, first a 5-year period in the weather data was tested as an input between 2010-2015. This attempt proved to be unsuccessful because of technical resource constraints, as shown by the resulting error message on Figure 28 below.

```
MemoryError: Unable to allocate 10.9 GiB for an array with shape (6, 290,
52584) and data type <U32
```

Figure 28 Memory error as a result of the 5-year model run

With the existing computational limitations, a model run based on 3-years of weather data proved to be the upper limit, which still provides sufficient information on the sensitivity of the model results to the input weather year. Figure 29 shows the resulting price profile outputs.

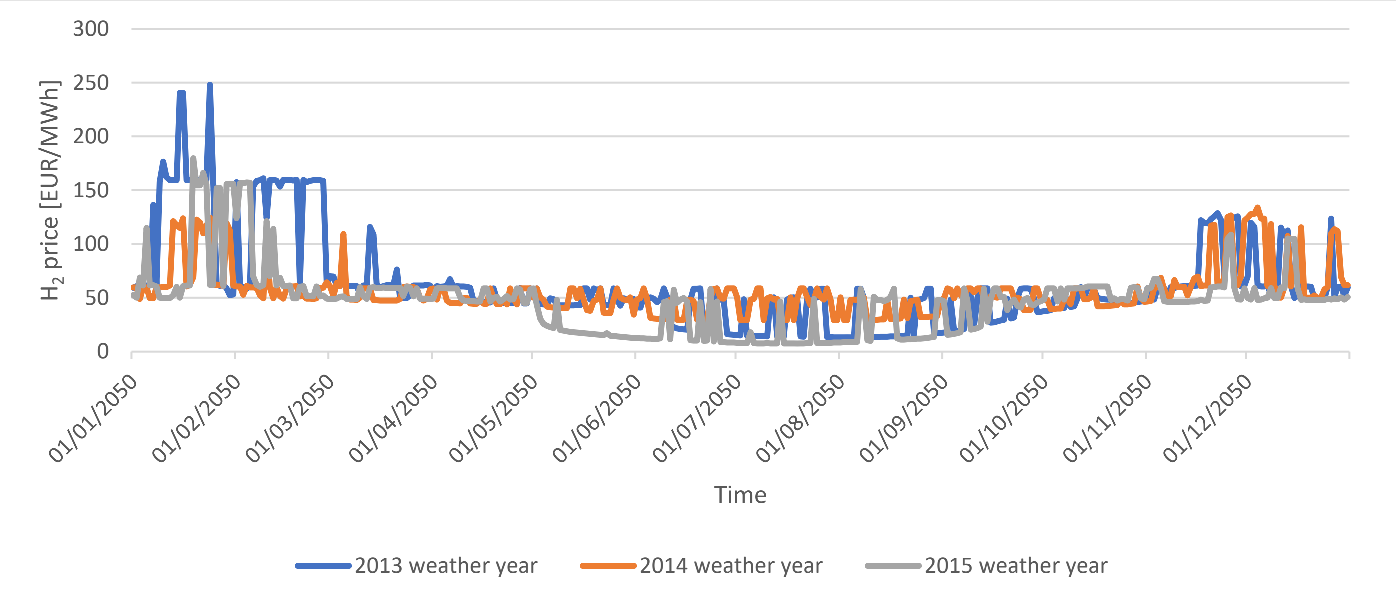

Figure 29 The difference in H_2 price based on different weather years

The blue line represents the resulting hydrogen price based on the 2013 weather input – with higher price extremities in the first 3 (winter) months of the year than in the other two years. Figure 30 below shows the minimum temperature data obtained by the Rotterdam station of KNMI in the same years.

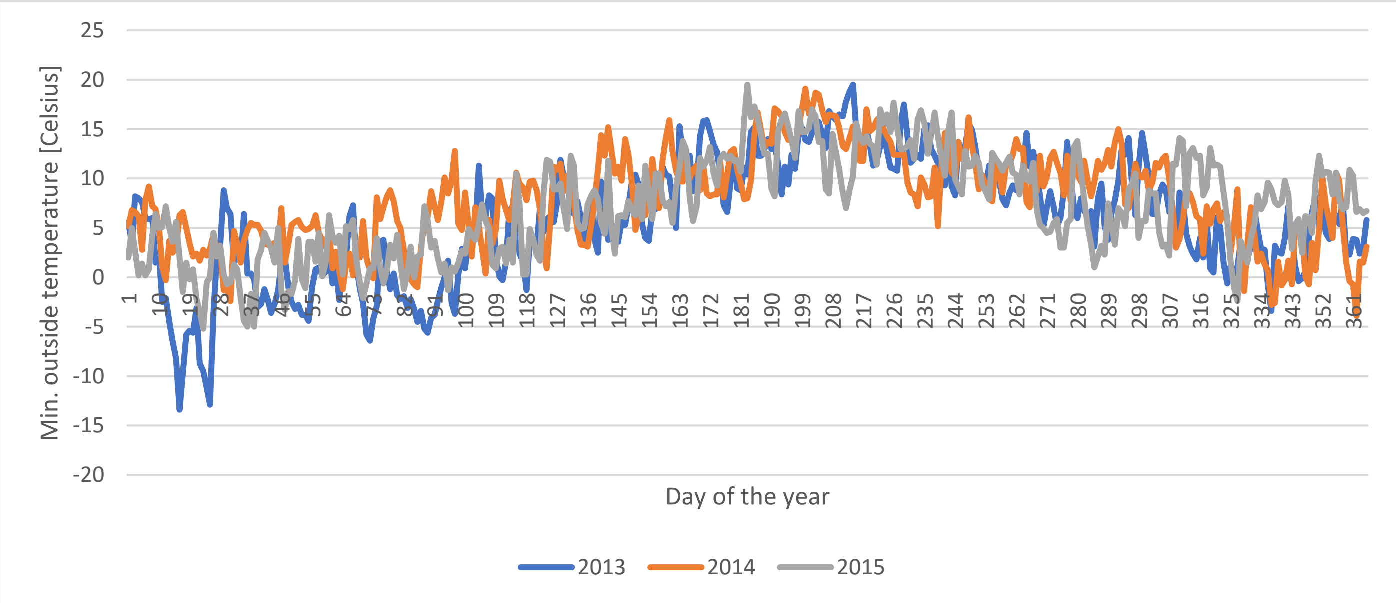

Figure 30 Temperature data of Rotterdam in the investigated years [Source: KNMI]

A strong correlation can be seen between the spikes of the modelled hydrogen price and the outside temperature, aligning perfectly with the expectations based on hydrogen's role as an energy carrier for building heating in the model. This correlation also supports that the variation in the obtained results is not random – or caused by modelling error – but indeed results from change in the weather input.

Table 35 shows the summarizing information regarding the average price and the price volatility in each year.

Table 35 The statistical indicators of the resulting dataset

	2013	2014	2015
AVERAGE PRICE [EUR/MWh]	62.8	55.5	46.8
RANGE [EUR/MWh]	234.8	104.8	172.3
STANDARD DEVIATION [EUR/MWh]	42.9	21.5	31.3

3.3.2 Hydrogen technology and pipeline costs

To test the price outputs' sensitivity to the modelled hydrogen technologies' uncertain properties, the sensitivity tests were set up according to Section 2.9.2 of this document with the following results.
Figure 31 shows the results for a change in the hydrogen boiler's efficiency. The exact values of the efficiency parameters tested are provided in Section 2.9.2 above.

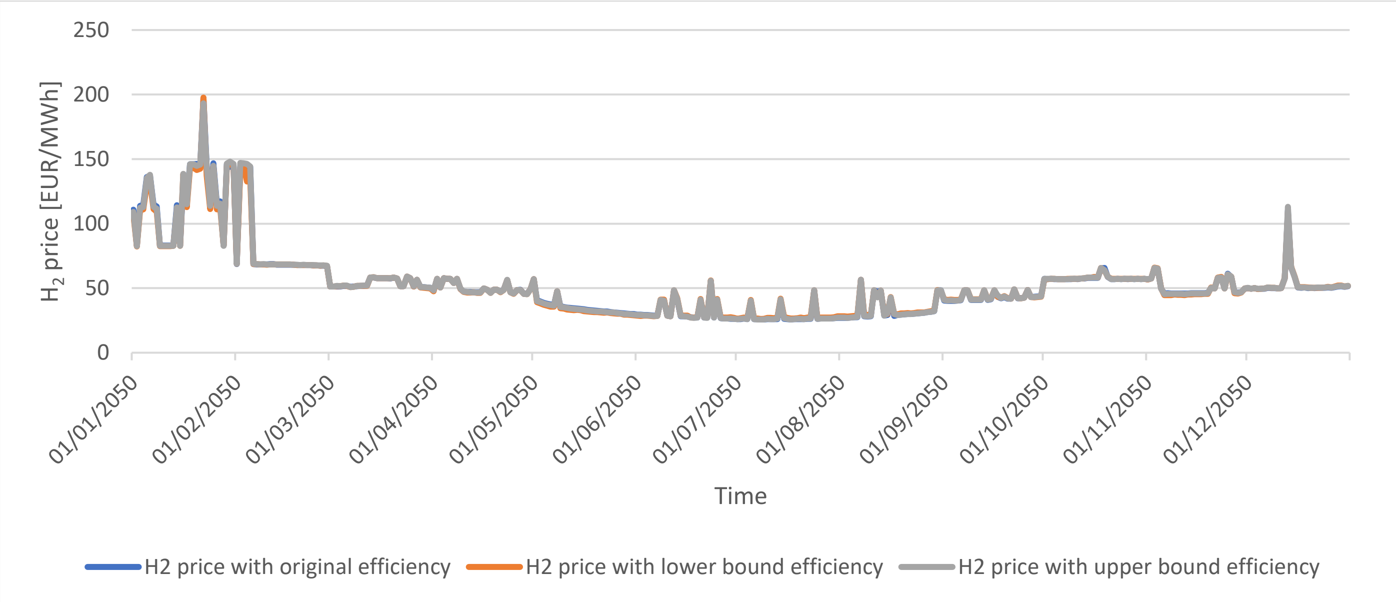

Figure 31 The modelled H_2 price's sensitivity for the hydrogen boiler's efficiency

Table 33 summarizes the statistical information of the resulting dataset.

Table 36 Results of the sensitivity analysis for the boiler's efficiency

Standard [EUR/MWh]	52.8
SA1 [EUR/MWh]	52.6
SA2 [EUR/MWh]	52.8
Deviation1 [%]	0.4
Deviation2 [%]	0

The results of the sensitivity test for the same boiler's lifetime are displayed on Figure 32 below. The values of the minimum and maximum deviation from the standard lifetime used in the model runs are detailed in Chapter 2.

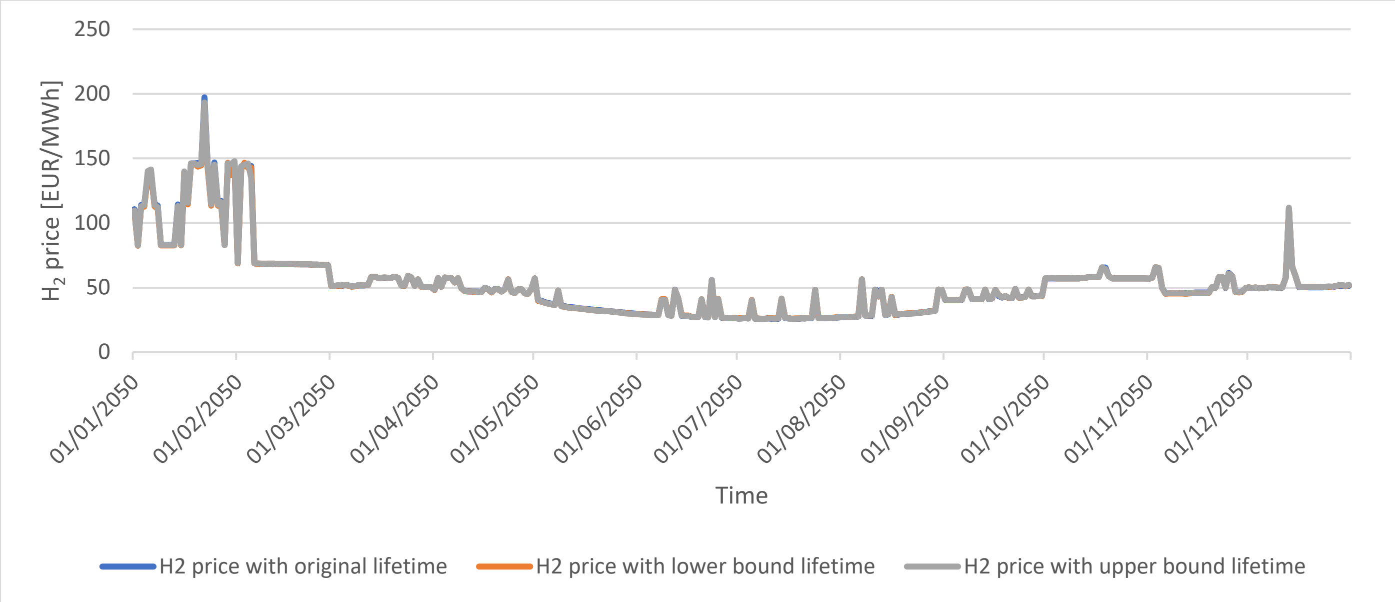

Figure 32 The modelled H_2 price's sensitivity for the hydrogen boiler's lifetime

Table 35 below summarizes the outcome of the sensitivity test in statistical terms.

Table 37 Results of the sensitivity analysis for the boiler's lifetime

Standard [EUR/MWh]	52.8
SA1 [EUR/MWh]	52.7
SA2 [EUR/MWh]	52.8
Deviation1 [%]	0.2
Deviation2 [%]	0

The hydrogen price's sensitivity to the changed investment costs' of a retrofitted pipeline network is displayed below, on Figure 33. The implemented CAPEX values (minimum and maximum) are presented in Chapter 2.

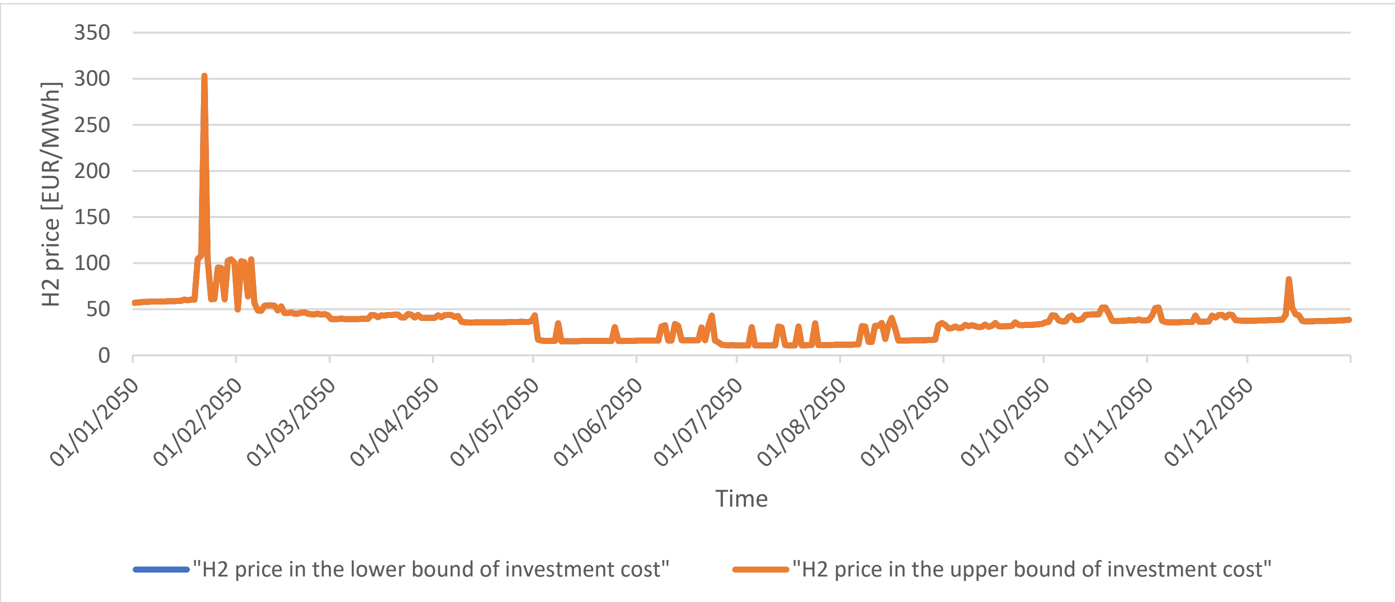

Figure 33 The modelled H_2 price's sensitivity for the retrofitted pipeline's investment costs

Table 38 below provides the exact values of average prices for the standard and the sensitivity model run, with the calculated deviation in values.

Table 38 Results of the sensitivity analysis for the retrofitted pipeline CAPEX

Standard [EUR/MWh]	36.2
SA [EUR/MWh]	36.2
Deviation [%]	0

Figure 34 shows the price sensitivity to a change in the newly-built infrastructure CAPEX, on the extreme values as found in the data source given in the related sections of Chapter 2.

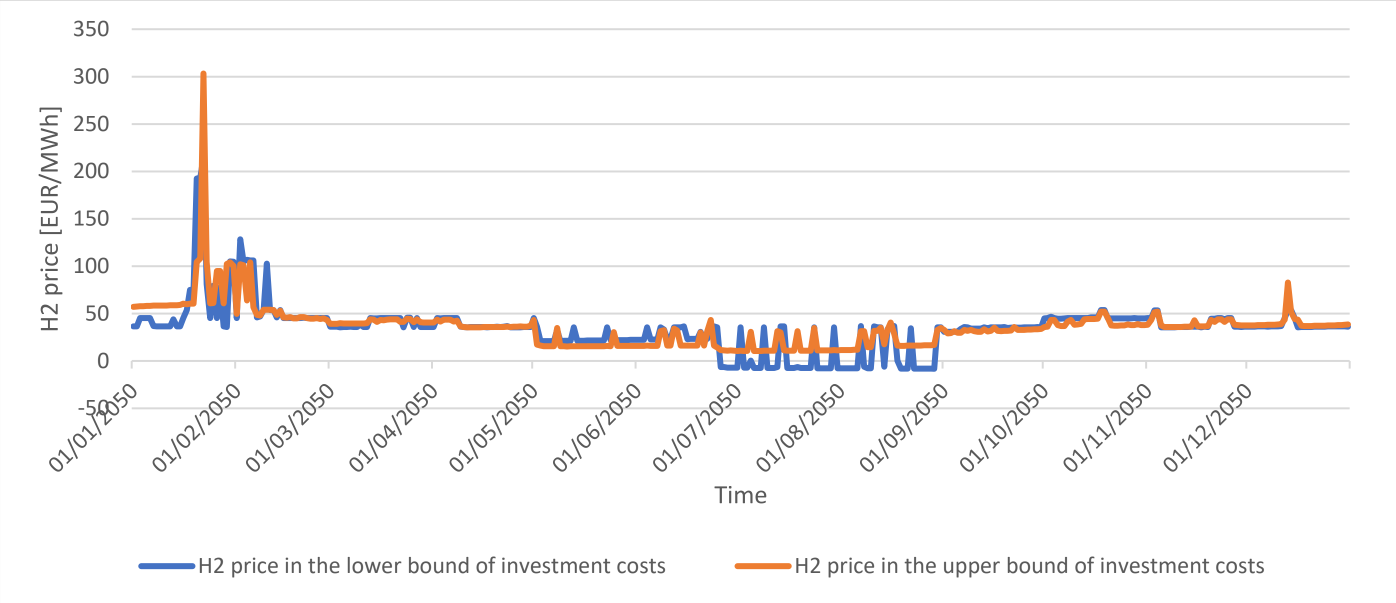

Figure 34 The modelled H_2 price's sensitivity for the newly-built pipeline's investment costs

Table 39 compares the outcomes of the standard and the sensitivity model run.

Table 39 Results of the sensitivity analysis for the dedicated pipeline CAPEX

Standard [EUR/MWh]	38.4
SA [EUR/MWh]	40.3
Deviation [%]	-4.7

3.3.3 Demand projections

Figure 35 compares the price timeseries outputs resulted by applying the energy demand projections as described in Section 2.9.3. Table 40 summarizes the resulting average price and the deviations in each projections.

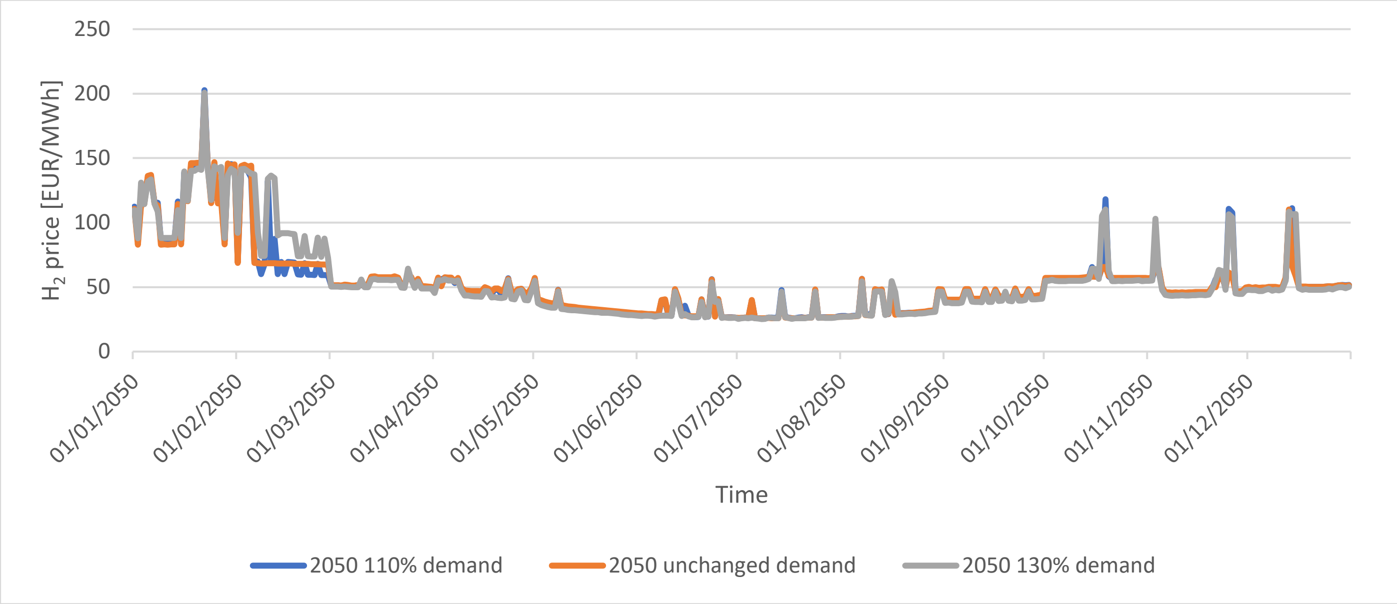

Figure 35 The modelled H_2 price's sensitivity to the projected future demand in 2050

Table 40 The average price and deviations in different energy demand projections

Average normal [EUR/MWh]	52.8
Average 110% [EUR/MWh]	53.1
Average 130% [EUR/MWh]	54.1
Deviation110 [%]	0.4
Deviation130 [%]	2.3

4 Discussion

This research explored the role different infrastructural investment options play in the price formation of hydrogen under different future penetration assumptions. The resulting price timeseries outputs are presented in Chapter 3 of this document. The analysis of the results is structured around a number of already identified key performance indicators – resulting average hydrogen price, price variability and grid stability – expressing the advantages and disadvantages of the alternative investment options. This chapter ends with a reflection on the sensitivity these performance indicators display regarding the already identified uncertainties in the data or the methodology of this research and with concluding remarks on what the results mean in relation to policy and future research.

4.1. Average price

The results are interpreted below separated based on the investigated 2030 and 2050 timelines, the investment options compared against the default, electric transmission option one-by-one.

4.1.1 2030 timeline

From a price perspective, on the 2030 timeline, based on the information summarized in Table 33 above, the blended options are strictly dominated by all other options regardless of the amount of hydrogen that needs to be transported. It is less competitive than any other pipeline option and offers virtually no decrease in price compared to the electric transmission either. Since the literature review revealed that a 10-20% hydrogen and natural gas blending is a technological limitation of this scenario, and a 10% blending is a regulatory upper limit as of now, this finding is not particularly surprising given how limited the transported amount of hydrogen is even in a high hydrogen penetration scenario. The hypothesized relationship between the transported amount of hydrogen and its price has been established during the testing of the model extensions in Chapter 3 (see Figure 10). However, this also gives some further certainty regarding its evaluation as a transition pathway with a low to no upfront investment cost. Natural gas-hydrogen blending options should be considered or discarded based on other relevant criteria not investigated in this research, like budgetary limitations, expected (imminent) emission reductions, or its contribution to achieving the economies of scale required for hydrogen to become cost-competitive in the long run.

The dedicated transmission option offered 7.1-9.3% average price reduction compared to electric transmission, however, it performed worse in every penetration scenario than the retrofitted pipeline options. The latter result is entirely in line with expectations based on the elevated CAPEX of newly-built infrastructure compared to the repurposed ones, however dedicated pipelines still performing better than electric transmission already gives options for the decision-makers where repurposing the existing natural gas infrastructure is not possible (yet).

The retrofitted pipeline options performed best in an average price perspective out of all the investigated options, in every penetration scenario, providing a 10.0-21.3% average price reduction. This means that on the 2030 timeline, retrofitting proved to be the single best option when it comes to resulting average price output, signing a clear policy direction for the decision-makers.

4.1.2 2050 timeline

The relevant figures in Table 33 show that dedicated pipelines offered a respectable 6.9-7.6% average price reduction against electric transmission. However, once again, the retrofitted pipeline option outperformed the dedicated pipelines and electric transmission both – offering a 11.5-16.6% reduction compared to the electric transmission only. This is an expected outcome based on the established relationship between CAPEX and hydrogen price, see Figure 13 – however, with other considerations at play this finding could still prove to be interesting. It can be concluded, that the retrofitted infrastructure provides robust average price reduction, dominating all other options in all investigated scenarios – other than the lowest, 'Decreased' scenario in 2050 – based on the relevant entries of Table 33, compared to relying solely on the electric grid. The diminished price reduction in the 'Decreased' 2050 scenario can be attributed to the hydrogen scarcity generated by the lower production setting. Table 24 shows how minimal the transported hydrogen is compared to the same column of Table 27 and Table 30, meaning that the otherwise substantial hydrogen production barely meets the local demand itself and no hydrogen is left for transportation in a cost-minimal solution of the modelling problem. Therefore, the price reducing advantage of a pipeline infrastructure cannot materialize in this scenario. Important to note here that the model has complete freedom in installing electrolysis capacities in whichever node it deems the most cost-competitive. This assumption makes sense for the current geographical limitation of the NS region with very high renewable (wind) power capacities, as established in Chapter 1 (see the relevant Figure 7). Further expanding the research into a pan-European geographical scope however, the role of the transmission infrastructure in question expands into servicing countries where renewable resources for electrolysis are not as abundantly available, and therefore a higher amount of hydrogen might require transportation – justifying the retrofitted infrastructure even in this decreased penetration scenario.

4.2. Price variability

It is expected that a better connected and integrated energy sector would result in less volatility and more stable prices. Volatile energy prices can trigger wider macroeconomic effects, such as inflation and recession, promote speculation, increasing risks of business investment failure. Stable energy prices on the other hand promote predictability and aid strategic long-term planning. Furthermore, the inflating energy price filtrates into the price of every other economic output and product, jeopardizing energy and food security and creating political instability. The increased variability also creates a need for extra supporting infrastructure capacities, such as in storage and transportation – requiring a larger investment from governments and potentially antagonizing other policy efforts, such as energy conserving measures.

To express the price stabilising effects of the different infrastructure options, relevant statistical parameters of the price timeseries outputs – its range and standard deviation – were calculated.

4.2.1 2030 timeline

As can be expected, the blending option only worked in favour on price stability on a modest penetration level in the 'Base-line' scenario of 2030 (Table 21) resulting in an 8.5% decrease in the range between minimum and maximum hydrogen prices, which is understandable given the small extent to which hydrogen can be blended in accordance with current regulation.

Based on the indicators found in Table 21, Table 22 and Table 23, however, it can also be concluded that the retrofitted and dedicated pipeline options performed in favour of mitigating price spikes also only in the lowest penetration scenario – resulting in a 41-47% reduction in range and a 45-55% reduction in standard deviation respectively compared to electric transmission. They, however, proved not only ineffective but outright harmful for price volatility compared to electric transmission in higher penetration scenarios (Table 22 and Table 23).

4.2.2 2050 timeline

Similarly to the findings in the 2030 instantiation of the model, both the retrofitted and the dedicated pipeline options showed positive effect on price volatility in the 2050 timeline on the lowest penetration scenario (Table 25) but proved to be disruptive in the highest penetrations (Table 31). The newly-built pipelines had a 20%, and retrofitted infrastructure had a 50% moderating effect on the distance between the price extremities compared to electric transmission in the 'Decreased' scenario, and given how minimal the transported amount of energy was in this model run, this finding seems to be in alignment with the 2030 findings. The three options performed equally in the base-line penetration scenario, no clear advantage being realized in the price range but some reduction being achieved by both the retrofitted option (30%) and the dedicated transmission (17%) in the standard deviation of the dataset (based on Table 28).

4.3. Grid stability

The shadow price of the transmission capacity conveys important information regarding the infrastructure's utilisation rate. Especially by 2050, when the fossil-fuel base-load generation capacities – currently acting as stabilization reserve – will be decommissioned, grid stability is becoming a critically important question. Table 26, Table 29 and Table 32 summarize this information by piece of infrastructure connecting the Netherlands to its neighbouring NS countries and Table 34 shows the average values.

None of the infrastructure options were overutilized on average – resulting in negative shadow prices of further capacity expansion –, but both the retrofitted and dedicated pipeline options experienced congestions in the 'Elevated' penetration scenario in at least parts of the year.

Table 26 quantifies an important advantage of the electricity grid. In the lowest expected hydrogen utilization/transportation scenario, it is still relatively well utilised compared to the pipeline options as shown by its relatively high average shadow price. This is explained by the electricity grid's more universal role in connecting supply and demand of the entire model. Based on Table 34, the electric transmission system is still the most well-utilised option on average in the base-line scenario, however, in the elevated penetration scenario, the retrofitted and dedicated pipeline capacities becomes just as well-utilized. The retrofitted pipeline displays also consistently the smallest difference between its maximum and minimum utilisation, meaning that it probably requires the least effort to stabilise.

The shadow price outputs of this research give useful information regarding the relative utilisation of the infrastructure, however, to draw definitive conclusions, a better understanding of the electric grid and the pipeline network's buffer capacity needs to be established first. Pipeline networks transporting molecules are easier to keep in a stable condition because of their own storage capacity – therefore, in the cases where the pipeline network displays more even utilisation patterns in relative terms based on their shadow price, it can already be concluded that the resulting grid itself is also more stable – which is not the case the other way around. However, this still does not mean that either of the options is unstable per se, in absolute terms.

4.4. Sensitivity

Table 35 summarizes the outcomes of the sensitivity analysis regarding the change in input weather year. The change in average price between the higher and lower end of outcomes is 25%. This means that the results of this study are highly dependent on the choice of weather year, and great care needs to be taken to reflect on this uncertainty drawing conclusions. The same holds for the conclusions regarding the price stability, as for example, standard deviation in the resulting price profile outputs doubled if the weather year 2013 was taken as an input instead of 2014.

Figure 31 displays the result of the sensitivity analysis regarding the uncertainty in the data sources for hydrogen boilers' expected efficiency. Based on manufacturers' statements, the hydrogen boilers in the future can be expected to operate on a similar technological background as the existing methane boilers, with only a few additional elements. The literature review revealed no further expectation regarding lesser technological efficiency either – the expected limitations of hydrogen in building heating arise from the costs of conversion and transportation, not inefficient burning. For these reasons, the lower bound of the sensitivity analyses were set to 90% – a generally low efficiency for state-of-the-art boilers –, and the tested upper bound were set to a theoretical limit of 100%. The results show that there is a very limited effect on the price formation – the average price being lowered 0.2 EUR/MWh with lowered efficiency due to smaller 'demand' generated in the optimal solution of the modelling problem found by Calliope. This means that the uncertainty in the boiler efficiency data is 0.4-0.7%, and therefore has a limited effect on the validity of the results.

Figure 32 shows the results' sensitivity to the modelled boiler's lifetime. The upper and lower bound technological properties were selected based on similar consideration as described in the case of efficiency. The results show that the price output is basically insensitive to the lifetime of the modelled boiler – decreasing the average price value by only 0.1 EUR/MWh in the case of lower expected lifetime as a result of lower built-in capacity, possibly due to slightly decreased competitiveness of the technology in the optimal solution. This means that the uncertainty amounts only to 0.2-0.3% in the results due to this particular limitation in the data quality.

Figure 33 shows the H_2 price sensitivity to the lower and upper limits of estimations for retrofitted pipeline CAPEX. Table 38 show that the deviation between the two optimal solutions on average remains negligible, therefore the results are robust regardless of the uncertainty in CAPEX data/input of the retrofitted infrastructure.

Figure 34 shows the price sensitivity for the lower and upper estimations of a newly-built pipeline's CAPEX. Table 39 contains the calculated deviation of the average price as a result of the uncertainty in input data. Relying on the lower bound estimation for the CAPEX costs resulted in a 4.7% reduction in average price compared to what was assumed in the original model runs. This is makes a difference in the conclusions of this research, as it puts the dedicated pipeline options on par with the retrofitted option in terms of produced price outcomes.

Figure 35 and Table 40 shows the results of the sensitivity test regarding the different demand projections calculated by as described in Section 2.9.3 of this document. The results show that the sensitivity of average hydrogen price is very low, 0.4% for a 10% increase in the energy demand, while for the upper bound estimation of 30% increase in demand, the average price increase is still a moderate 2.3%.

4.5. Limitations

This research has been carried out relying on existing modelling tools with some computational and time-limitations in mind. For resource-saving purposes, and in the absence of a readily and freely available model of a sector-coupled energy system with detailed natural gas/hydrogen transportation networks included, an existing linear optimisation model was selected based on careful deliberations of the needs of the study, and extended as part of this research. A more accurate model of hydrogen networks capturing their physical properties (and especially differences compared to an electric transmission grid) would almost certainly be non-linear, including equations accounting for friction and pressure drops – i.e. the Weymouth equation – and the line pack of gas transmission systems – i. e. the single or multi-phase methods –, etc. Not only the implementation of these takes a considerable amount of time and expertise but solving these equations and finding an optimal solution would have also increased the computational time of the model significantly. However, in the absence of modelled physical properties providing additional flexibility/robustness to the gas transmission systems compared to the electric grid, like the line pack itself, some conclusions of this research concerning grid stability remain only half the picture – reflecting on the changing utilisation levels of the infrastructure but not on the robustness of it to absorb the effects of this volatility.

While the costs of these transmission networks – and in fact, the largest cost factor at least in the retrofitted pipeline options – comes from the CAPEX and OPEX of pressure stations, this research with the above limitations cannot fully capture the effects of this dynamic either without extending into a higher level model with higher level equations – providing more accurate information on the investment needs/number of pressure stations actually required to keep the transmission system in balance. The importance of this limitation is also reflected in the results' demonstrated sensitivity (17.5%) to investment costs.

Additionally, the model is limited to a one-step optimization with a perfect foresight approach, and its own results show how a step-wise, myopic approach would perhaps result in a different and globally more efficient solution, by exploring the consequences of allocating investments in further, incremental steps. Reproducing this same research implemented in other modelling tools already identified – i.e. the Switch model – could provide an interesting comparison to the resulting conclusions.

Furthermore, all of the model runs were carried out on a 24h timestep for computational capacity reasons, however, parallel research of the same research group already shows that the feasible model space becomes wider with higher (hourly) resolution – i. e. lower hydrogen penetration scenarios already infeasible in the 24h model runs proved to be feasible on an hourly resolution. This means that a more accurate result in a limited number of scenarios on a 2050 time horizon can be obtained. Nevertheless, the 24h resolution proved to be enough to identify the directions and relative relationships in price movements in a straightforward way between infrastructure options at least on the chosen NS geographic scope. Based on the results of this research, decreasing the hydrogen levels anywhere below the optimum level ends in hydrogen being consumed locally rather than being transported, rendering the transmission network superfluous and its effect on price negligible.

Limiting the geographical scope of the research to the most viable locations in Europe from the perspective of hydrogen production – the North Sea region –, however, proves to be a limitation itself this way – restricting the role of transmission infrastructure to transport the unused hydrogen between otherwise potentially self-sufficient regions. The role of the infrastructure should be confirmed on a wider geographic scope with lower timestep (hourly) model runs as well.

The advantages of shadow pricing and the motivation behind relying on it compared to other methods have been discussed in Section 2.4 already. However, this market representation is not without its own limitations either. Following the definition of the shadow price, it is the utility increase in the objective function, and therefore logically the maximum amount of money that should be given in exchange by a rational actor for a unit of given resource causing the utility increase. But while this study has been setup with a single problem owner – the Dutch government – in mind, the real, European liberalised market is populated by a number of other, very different actors with differing objectives. The modelled shadow prices of this study hold only as long as the objective is to minimize the entire system cost, therefore, they represent the prices the government – or actors with the exact same objective – should be willing to pay. The shadow prices in this study are entirely valid only in a fictional, monopolistic or highly distorted market, where the government acts as a ‘buyer-of-last-resort’ for hydrogen.

4.6. Recommendations for decision-makers

One of the main conclusions of this research from a policy perspective is that blending never contributed to any amount of decrease in price or volatility – meaning that the implementation of a policy based on natural gas-hydrogen blending needs to happen on different considerations not investigated as part of this research. Blending is still an easy, cost-effective solution, requiring relatively small intervention and achieving some

GHG emission reduction. Further investigation of these benefits against their price is necessary and recommended.

Another important conclusion is that the pipeline transportation options – both retrofitted and dedicated – achieved significant average price reductions against the electric transmission option, the retrofitted pipeline options being the obvious frontrunners in every selected scenario. From the resulting hydrogen price perspective, repurposing the existing natural gas network for hydrogen transportation in the future is a recommendable, robust policy action. Furthermore, since transporting hydrogen or transporting natural gas are usually mutually exclusive options, and the newly-built hydrogen pipelines still outperformed the electric grid, in the case of specific pieces of infrastructure not easily retrofitted for hydrogen – because of other, relevant considerations, like servicing industrial users – it is still worth considering building a separate, dedicated hydrogen pipeline. This is especially interesting on the 2030 timeline, since it is unlikely that natural gas can be phased out by then. This finding could be a basis of further investigation in the form of a no-regret analysis – even more so because the infrastructural investments made by 2030 will naturally have an effect on the 2050 decisions. In this case, if a considerable part of the network gets built now for this advantage, the rest of the dedicated network might also become competitive with a lower CAPEX in the future. This, however, needs to be independently confirmed and probably determined on a case-by-case basis.

The Hydrogen Council in its 2020 study estimated that a 54 EUR/MWh price would lead to 15% utilisation of hydrogen in the global economy – which is perfectly aligned with the findings of this study, showing that in the 2050 timeline, a 16.5% penetration of hydrogen results in 48.2 - 57.8 EUR/MWh price – not considering ancillary costs. In this sense, accepting these estimations as a basis, while the pipeline infrastructures make a clear difference in the resulting price, the electric transmission also already comes close to the target price. The trade-off between the electric grid and the pipeline options, therefore, seems to lie with better utilisation in the case of the electric grid against lower resulting hydrogen prices with the pipeline options.

4.7. Recommendations for future research

Given the presented results, discussed vulnerabilities and limitations of the research, there are a number of avenues to continue and expand the scope of this study.

The chosen price modelling method – shadow pricing – is by definition connected to a single objective function. To explore the compound effect of different objectives of different actors on a more realistic, liberalised energy market, the model used in this study should be considered one sub-model representing one actor – the government – perspective only. Further sub-models with other important actors' – i.e. TSOs, industrial and domestic consumers, producers – objective functions can be constructed and linked together to create a more accurate representation of a liberalised energy market, resulting in a more complete hydrogen price.

The role of transmission infrastructure in this study is distorted by the geographical scope – representing a sort of minimum utilisation – transporting the superfluous hydrogen between otherwise high-potential production areas only. This geography is an ideal starting point for research but characteristically the most crucial role of transmission networks is supplying the regions where the resource is unavailable. Figure 7 shows that especially the Central-European region's supply is an interesting future question as a continuation of this study, as Southern-Germany, Northern-Italy, Austria, Hungary, the Czech Republic, Slovakia and Romania seem to lack at least the wind-power potential to produce hydrogen as cost-efficiently as the NS region. Some of these countries are also landlocked and the most reliant on Russian natural gas right now in the entire EU, making it a promising extension to the geographical scope of this thesis.

Additionally, further research should be concentrated on the trade-offs between increased resource needs and a physically more accurate representation of the gas transmission systems. A comparative study between the results and resource demands of this thesis and the outputs of a higher level model of a natural gas/hydrogen transmission system with increased computational demands would be a natural next step in this direction.

This research used a quantitative experimental technique to approach the problem of how to support the decision-makers in hydrogen infrastructure investment when the crucial piece of information on hydrogen's prevalence in the future economy is in doubt. Further research relying on different techniques would complement and strengthen the validity or identify the short-comings of this study. This same problem could be approached with a more qualitative technique via a combination of opportunity and scenario assessments based on expert and stakeholder interviews. A bottom-up, qualitative opportunity assessment involving expert interviews from the field of hydrogen research and industrial stakeholders could result in reliable timelines for hydrogen technology deployments, to which penetration scenarios can be attached. A higher level economic analysis applied to the different infrastructure options based on a mark-up pricing method would then result in the same average price output in different scenarios. Other, top-down economic models can be applied to the same problem as well.

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Appendix

Appendix A The list of extensions as present in the model

A summarizing list of added elements can be found here. The detailed implementation of these with the original YAML script is attached in Appendix B.

Addition	Explanation
tech_groups	
ng_transmission	parent technology for all natural gas transmission technologies
blend_transmission	parent technology for all blended transmission technologies
h2_transmission	parent technology for all hydrogen transmission technologies
techs	
ng_onshore_transmission	onshore natural gas transmission pipeline
ng_offshore_transmission	offshore natural gas transmission pipeline
blend_onshore_transmission	onshore blended gas pipeline
blend_offshore_transmission	offshore blended gas pipeline
h2_onshore_transmission	repurposed natural gas onshore hydrogen pipeline
h2_offshore_transmission	repurposed natural gas offshore hydrogen pipeline
h2p_onshore_transmission	newly built onshore hydrogen pipeline
h2p_offshore_transmission	newly built offshore hydrogen pipeline
ng_h2_deblender	fictional technology for producing blended gas
hydrogen_boiler	heating technology using hydrogen
ng_h2_blender	fictional technology for turning blended carrier back to methane

Appendix B Model script

All the changes to the model itself were implemented in a single YAML file to facilitate transparency and reproducibility. The changes made to the NS Euro-Calliope model written in YAML can be found below:

```yaml
tech_groups:
# Definition of natural gas transmission system technology groups
    ng_transmission:
        exists: false
        essentials:
            name: "Natural gas transmission pipeline"
            parent: transmission
            carrier: methane
        constraints:
            energy_eff: 0.999 # from [@DEA]
            lifetime: 50 # from [@DEA]
        costs:
            monetary:
                om_annual_investment_fraction: 0.00012 # from [@DEA]
# Definition of natural gas - hydrogen blend transmission system technology groups
    blend_transmission:
        exists: false
        essentials:
            name: "Natural gas-hydrogen blend transmission pipeline"
            parent: transmission
            carrier: ng_h2_blend
        constraints:
            energy_eff: 0.999 # from [@DEA]
            lifetime: 50 # from [@DEA]
        costs:
            monetary:
                om_annual_investment_fraction: 0.00012 # from [@DEA]
# Definition of hydrogen transmission system technology groups
    h2_transmission:
        exists: false
        essentials:
            name: "Hydrogen transmission pipeline"
            parent: transmission
            carrier: hydrogen
        constraints:
            energy_eff: 0.9985 # from [@DEA]
            lifetime: 50 # from [@DEA]
        costs:
            monetary:
                om_annual_investment_fraction: 0.0005 # from [@DEA]
techs:
# Definition of natural gas transmission system technologies
    ng_onshore_transmission:
        exists: false
        essentials:
            name: 'Natural gas underground transmission pipeline'
            parent: ng_transmission
    ng_offshore_transmission:
        exists: false
        essentials:
            name: 'Natural gas subsea transmission pipeline'
            parent: ng_transmission
# Defition of natural gas - hydrogen blend transmission system technologies
    blend_onshore_transmission:
        exists: false
        essentials:
            name: 'Natural gas-hydrogen underground transmission pipeline'
            parent: blend_transmission
```

```yaml
    blend_offshore_transmission:
        exists: false
        essentials:
            name: 'Natural gas-hydrogen subsea transmission pipeline'
            parent: blend_transmission
# Definition of retrofitted hydrogen transmission system technologies
    h2_onshore_transmission:
        exists: false
        costs:
          monetary:
            energy_cap_per_distance: 0.005 #(10.000EUR/MW/km) calculated based on [DEA
and McKinsey (2021): 0.02/3.5, also: 0.04/3.5, 0.08/3.5, 0.11/3.5, 0.18/3.5, 0.41/3.5]
        essentials:
            name: 'Hydrogen underground transmission pipeline'
            parent: h2_transmission
    h2_offshore_transmission:
        exists: false
        costs:
          monetary:
            energy_cap_per_distance: 0.01 #(10.000EUR/MW/km) calculated based on [DEA,
Palgrave Handbook of Energy Economics, McKinsey (2021): 0.02×1.75/3.5, also:
0.04×1.75/3.5, 0.08×1.75/3.5, 0.11×1.75/3.5, 0.18×1.75/3.5, 0.41×1.75/3.5]
        essentials:
            name: 'Hydrogen subsea transmission pipeline'
            parent: h2_transmission
# Definition of newly-built hydrogen transmission system technologies
    h2p_onshore_transmission:
        exists: false
        costs:
          monetary:
            energy_cap_per_distance: 0.41 #(10.000EUR/MW/km) from [@DEA: 0.02, also:
0.04, 0.08, 0.11, 0.18, 0.41]
        essentials:
            name: 'Dedicated H2 underground transmission pipeline'
            parent: h2_transmission
    h2p_offshore_transmission:
        exists: false
        costs:
          monetary:
            energy_cap_per_distance: 0.72 #(10.000EUR/MW/km) calculated based on [DEA,
Palgrave Handbook of Energy Economics: 0.02×1.75, also: 0.04×1.75, 0.08×1.75,
0.11×1.75, 0.18×1.75, 0.41×1.75]
        essentials:
            name: 'Dedicated H2 subsea transmission pipeline'
            parent: h2_transmission
# Definition of natural gas - hydrogen dummy blending and 'de-blending' technologies
    ng_h2_blender:
        exists: false
        essentials:
            name: ng_h2_blending
            carrier_in: methane
            carrier_in_2: hydrogen
            carrier_out: [ng_h2_blend]
            primary_carrier_in: methane
            parent: conversion_plus
        constraints:
            carrier_in:
              carrier_ratios:
                carrier.in.methane: 0.9 # based on existing regulation, see Section
3.5.1
                carrier.in.hydrogen: 0.1 # based on existing regulation, see Section
3.5.1
    ng_h2_deblender:
        exists: false
```

```yaml
        essentials:
            name: ng_h2_deblending
            carrier_in: ng_h2_blend
            carrier_out: methane
            parent: conversion
# Definition of hydrogen end-user technologies
    hydrogen_boiler:
        exists: false
        essentials:
                name: Hydrogen boiler
                parent: conversion
                carrier_in: hydrogen
                carrier_out: hydrogen_heat
        constraints:
                energy_eff: 0.97 # value based on Euro-Calliope, see Section 3.7.2
                lifetime: 13 # from [@ETM]
        costs:
                monetary:
                    energy_cap: 4.02  # (10,000 EUR2015/MW_heat/year) from [@ETM]
                    om_annual: 2.45  # (10,000 EUR2015/MW_heat/year) from [@ETM]
links:
# Definition of transmission links, capacities and lengths for natural gas, newly built
/ repurposed hydrogen, and natural gas-hydrogen blends
    BEL,DEU.techs:
        ng_onshore_transmission:
            exists: false
            distance: 25 # (km) from [@Fluxys]
            constraints:
                energy_cap_equals: 0.300  # (100,000 MW) from [@GIE]
                one_way: false
        blend_onshore_transmission:
            exists: false
            distance: 25 # (km) from [@Fluxys]
            constraints:
                energy_cap_equals: 0.300  # (100,000 MW) from [@GIE]
                one_way: false
        h2_onshore_transmission:
            exists: false
            distance: 25 # (km) from [@Fluxys]
            constraints:
                energy_cap_equals: 0.300  # (100,000 MW) from [@GIE]
                one_way: false
        h2p_onshore_transmission:
            exists: false
            distance: 25 # (km) from [@Fluxys]
            constraints:
                one_way: false
    BEL,GBR.techs:
        ng_offshore_transmission:
            exists: false
            distance: 235 # (km) from [@Fluxys]
            constraints:
                energy_cap_equals: 0.607  # (100,000 MW) from [@GIE]
                one_way: false
        blend_offshore_transmission:
            exists: false
            distance: 235 # (km) from [@Fluxys]
            constraints:
                energy_cap_equals: 0.607  # (100,000 MW) from [@GIE]
                one_way: false
        h2_offshore_transmission:
            exists: false
            distance: 235 # (km) from [@Fluxys]
            constraints:
```

```yaml
            energy_cap_equals: 0.607  # (100,000 MW) from [@GIE]
            one_way: false
    h2p_offshore_transmission:
        exists: false
        distance: 235 # (km) from [@Fluxys]
        constraints:
            one_way: false
BEL,LUX.techs:
    ng_onshore_transmission:
        exists: false
        distance: 100 # (km) from [@Fluxys]
        constraints:
            energy_cap_equals: 0.020  # (100,000 MW) from [@GIE]
            one_way: true
    blend_onshore_transmission:
        exists: false
        distance: 100 # (km) from [@Fluxys]
        constraints:
            energy_cap_equals: 0.020  # (100,000 MW) from [@GIE]
            one_way: true
    h2_onshore_transmission:
        exists: false
        distance: 100 # (km) from [@Fluxys]
        constraints:
            energy_cap_equals: 0.020  # (100,000 MW) from [@GIE]
            one_way: true
    h2p_onshore_transmission:
        exists: false
        distance: 100 # (km) from [@Fluxys]
        constraints:
            one_way: false
BEL,NLD.techs:
    ng_onshore_transmission:
        exists: false
        distance: 75 # (km) from [@Fluxys]
        constraints:
            energy_cap_equals: 0.720  # (100,000 MW) from [@GIE]
            one_way: false
    blend_onshore_transmission:
        exists: false
        distance: 75 # (km) from [@Fluxys]
        constraints:
            energy_cap_equals: 0.720  # (100,000 MW) from [@GIE]
            one_way: false
    h2_onshore_transmission:
        exists: false
        distance: 75 # (km) from [@Fluxys]
        constraints:
            energy_cap_equals: 0.720  # (100,000 MW) from [@GIE]
            one_way: false
    h2p_onshore_transmission:
        exists: false
        distance: 75 # (km) from [@Fluxys]
        constraints:
            one_way: false
BEL,NOR.techs:
    ng_offshore_transmission:
        exists: false
        distance: 814 # (km) from [@Gassco]
        constraints:
            energy_cap_equals: 0.203  # (100,000 MW) from [@GIE]
            one_way: false
    blend_offshore_transmission:
        exists: false
```

```yaml
            distance: 814 # (km) from [@Gassco]
            constraints:
                energy_cap_equals: 0.203  # (100,000 MW) from [@GIE]
                one_way: false
        h2_offshore_transmission:
            exists: false
            distance: 814 # (km) from [@Gassco]
            constraints:
                energy_cap_equals: 0.203  # (100,000 MW) from [@GIE]
                one_way: false
        h2p_offshore_transmission:
            exists: false
            distance: 814 # (km) from [@Gassco]
            constraints:
                one_way: false
    DEU,DNK.techs:
        ng_onshore_transmission:
            exists: false
            distance: 111 # (km) from [@Gasunie]
            constraints:
                energy_cap_equals: 0.058  # (100,000 MW) from [@GIE]
                one_way: false
        blend_onshore_transmission:
            exists: false
            distance: 111 # (km) from [@Gasunie]
            constraints:
                energy_cap_equals: 0.058  # (100,000 MW) from [@GIE]
                one_way: false
        h2_onshore_transmission:
            exists: false
            distance: 111 # (km) from [@Gasunie]
            constraints:
                energy_cap_equals: 0.058  # (100,000 MW) from [@GIE]
                one_way: false
        h2p_onshore_transmission:
            exists: false
            distance: 111 # (km) from [@Gasunie]
            constraints:
                one_way: false
    DEU,FRA.techs:
        ng_onshore_transmission:
            exists: false
            distance: 908 # (km) from [@GRTGaz]
            constraints:
                energy_cap_equals: 0.256  # (100,000 MW) from [@GIE]
                one_way: true
        blend_onshore_transmission:
            exists: false
            distance: 908 # (km) from [@GRTGaz]
            constraints:
                energy_cap_equals: 0.256  # (100,000 MW) from [@GIE]
                one_way: true
        h2_onshore_transmission:
            exists: false
            distance: 908 # (km) from [@GRTGaz]
            constraints:
                energy_cap_equals: 0.256  # (100,000 MW) from [@GIE]
                one_way: true
        h2p_onshore_transmission:
            exists: false
            distance: 908 # (km) from [@GRTGaz]
            constraints:
                one_way: false
    DEU,LUX.techs:
```

```yaml
        ng_onshore_transmission:
            exists: false
            distance: 37 # (km) from [@Fluxys]
            constraints:
                energy_cap_equals: 0.011  # (100,000 MW) from [@GIE]
                one_way: true
        blend_onshore_transmission:
            exists: false
            distance: 37 # (km) from [@Fluxys]
            constraints:
                energy_cap_equals: 0.011  # (100,000 MW) from [@GIE]
                one_way: true
        h2_onshore_transmission:
            exists: false
            distance: 37 # (km) from [@Fluxys]
            constraints:
                energy_cap_equals: 0.011  # (100,000 MW) from [@GIE]
                one_way: true
        h2p_onshore_transmission:
            exists: false
            distance: 37 # (km) from [@Fluxys]
            constraints:
                one_way: false
    DNK,SWE.techs:
        ng_offshore_transmission:
            exists: false
            distance: 25 # (km) from [@Swedegas]
            constraints:
                energy_cap_equals: 0.022 # (100,000 MW) from [@GIE]
                one_way: false
        blend_offshore_transmission:
            exists: false
            distance: 25 # (km) from [@Swedegas]
            constraints:
                energy_cap_equals: 0.022 # (100,000 MW) from [@GIE]
                one_way: false
        h2_offshore_transmission:
            exists: false
            distance: 25 # (km) from [@Swedegas]
            constraints:
                energy_cap_equals: 0.022 # (100,000 MW) from [@GIE]
                one_way: false
        h2p_offshore_transmission:
            exists: false
            distance: 25 # (km) from [@Swedegas]
            constraints:
                one_way: false
    FRA,BEL.techs:
        ng_onshore_transmission:
            exists: false
            distance: 74 # (km) from [@Fluxys]
            constraints:
                energy_cap_equals: 0.475  # (100,000 MW) from [@GIE]
                one_way: false
        blend_onshore_transmission:
            exists: false
            distance: 74 # (km) from [@Fluxys]
            constraints:
                energy_cap_equals: 0.475  # (100,000 MW) from [@GIE]
                one_way: false
        h2_onshore_transmission:
            exists: false
            distance: 74 # (km) from [@Fluxys]
            constraints:
```

```yaml
            energy_cap_equals: 0.475  # (100,000 MW) from [@GIE]
            one_way: false
    h2p_onshore_transmission:
        exists: false
        distance: 74 # (km) from [@Fluxys]
        constraints:
            one_way: false
GBR,IRL.techs:
    ng_offshore_transmission:
        exists: false
        distance: 687 # (km) from [@GNI]
        constraints:
            energy_cap_equals: 0.161  # (100,000 MW) from [@GIE]
            one_way: true
    blend_offshore_transmission:
        exists: false
        distance: 687 # (km) from [@GNI]
        constraints:
            energy_cap_equals: 0.161  # (100,000 MW) from [@GIE]
            one_way: true
    h2_offshore_transmission:
        exists: false
        distance: 687 # (km) from [@GNI]
        constraints:
            energy_cap_equals: 0.161  # (100,000 MW) from [@GIE]
            one_way: true
    h2p_offshore_transmission:
        exists: false
        distance: 687 # (km) from [@GNI]
        constraints:
            one_way: false
NLD,DEU.techs:
    ng_onshore_transmission:
        exists: false
        distance: 40 # (km) from [@Fluxys]
        constraints:
            energy_cap_equals: 0.778 # (100,000 MW) from [@GIE]
            one_way: false
    blend_onshore_transmission:
        exists: false
        distance: 40 # (km) from [@Fluxys]
        constraints:
            energy_cap_equals: 0.778 # (100,000 MW) from [@GIE]
            one_way: false
    h2_onshore_transmission:
        exists: false
        distance: 40 # (km) from [@Fluxys]
        constraints:
            energy_cap_equals: 0.778 # (100,000 MW) from [@GIE]
            one_way: false
    h2p_onshore_transmission:
        exists: false
        distance: 40 # (km) from [@Fluxys]
        constraints:
            one_way: false
NLD,DNK.techs:
    ng_offshore_transmission:
        exists: false
        distance: 100 # (km) from [@Maersk]
        constraints:
            energy_cap_equals: 0.022 # (100,000 MW) from [@GIE]
            one_way: false
    blend_offshore_transmission:
        exists: false
```

```
        distance: 100 # (km) from [@Maersk]
        constraints:
            energy_cap_equals: 0.022 # (100,000 MW) from [@GIE]
            one_way: false
    h2_offshore_transmission:
        exists: false
        distance: 100 # (km) from [@Maersk]
        constraints:
            energy_cap_equals: 0.022 # (100,000 MW) from [@GIE]
            one_way: false
    h2p_offshore_transmission:
        exists: false
        distance: 100 # (km) from [@Maersk]
        constraints:
            one_way: false
NLD,GBR.techs:
    ng_offshore_transmission:
        exists: false
        distance: 235 # (km) from [@BBL]
        constraints:
            energy_cap_equals: 0.276 # (100,000 MW) from [@GIE]
            one_way: false
    blend_offshore_transmission:
        exists: false
        distance: 235 # (km) from [@BBL]
        constraints:
            energy_cap_equals: 0.276 # (100,000 MW) from [@GIE]
            one_way: false
    h2_offshore_transmission:
        exists: false
        distance: 235 # (km) from [@BBL]
        constraints:
            energy_cap_equals: 0.276 # (100,000 MW) from [@GIE]
            one_way: false
    h2p_offshore_transmission:
        exists: false
        distance: 235 # (km) from [@BBL]
        constraints:
            one_way: false
NLD,NOR.techs:
    ng_offshore_transmission:
        exists: false
        distance: 264 # (km) from [@GDF Suez]
        constraints:
            energy_cap_equals: 0.401 # (100,000 MW) from [@GIE]
            one_way: false
    blend_offshore_transmission:
        exists: false
        distance: 264 # (km) from [@GDF Suez]
        constraints:
            energy_cap_equals: 0.401 # (100,000 MW) from [@GIE]
            one_way: false
    h2_offshore_transmission:
        exists: false
        distance: 264 # (km) from [@GDF Suez]
        constraints:
            energy_cap_equals: 0.401 # (100,000 MW) from [@GIE]
            one_way: false
    h2p_offshore_transmission:
        exists: false
        distance: 264 # (km) from [@GDF Suez]
        constraints:
            one_way: false
NOR,DEU.techs:
```

```yaml
    ng_offshore_transmission:
        exists: false
        distance: 1318 # (km) from [@Gasunie]
        constraints:
            energy_cap_equals: 0.520 # (100,000 MW) from [@GIE]
            one_way: true
    blend_offshore_transmission:
        exists: false
        distance: 1318 # (km) from [@Gasunie]
        constraints:
            energy_cap_equals: 0.520 # (100,000 MW) from [@GIE]
            one_way: true
    h2_offshore_transmission:
        exists: false
        distance: 1318 # (km) from [@Gasunie]
        constraints:
            energy_cap_equals: 0.520 # (100,000 MW) from [@GIE]
            one_way: true
    h2p_offshore_transmission:
        exists: false
        distance: 1318 # (km) from [@Gasunie]
        constraints:
            one_way: true
NOR,FRA.techs:
    ng_offshore_transmission:
        exists: false
        distance: 840 # (km) from [@Gassco]
        constraints:
            energy_cap_equals: 0.238 # (100,000 MW) from [@GIE]
            one_way: true
    blend_offshore_transmission:
        exists: false
        distance: 840 # (km) from [@Gassco]
        constraints:
            energy_cap_equals: 0.238 # (100,000 MW) from [@GIE]
            one_way: true
    h2_offshore_transmission:
        exists: false
        distance: 840 # (km) from [@Gassco]
        constraints:
            energy_cap_equals: 0.238 # (100,000 MW) from [@GIE]
            one_way: true
    h2p_offshore_transmission:
        exists: false
        distance: 840 # (km) from [@Gassco]
        constraints:
            one_way: false
NOR,GBR.techs:
    ng_offshore_transmission:
        exists: false
        distance: 1166 # (km) from [@Gassco]
        constraints:
            energy_cap_equals: 0.624 # (100,000 MW) from [@GIE]
            one_way: true
    blend_offshore_transmission:
        exists: false
        distance: 1166 # (km) from [@Gassco]
        constraints:
            energy_cap_equals: 0.624 # (100,000 MW) from [@GIE]
            one_way: true
    h2_offshore_transmission:
        exists: false
        distance: 1166 # (km) from [@Gassco]
        constraints:
```

```
                energy_cap_equals: 0.624 # (100,000 MW) from [@GIE]
                one_way: true
        h2p_offshore_transmission:
            exists: false
            distance: 1166 # (km) from [@Gassco]
            constraints:
                one_way: false
overrides:
# Activating natural gas supply
    natural_gas_supply:
        locations:
                BEL.techs.methane_supply.constraints.energy_cap_equals: 0.103 #(100000 
MW) from [@Eurostat nrg_103m]
                DEU.techs.methane_supply.constraints.energy_cap_equals: 1.423 #(100000 
MW) from [@Eurostat nrg_103m]
                DNK.techs.methane_supply.constraints.energy_cap_equals: 0.117 #(100000 
MW) from [@Eurostat nrg_103m]
                FRA.techs.methane_supply.constraints.energy_cap_equals: 0.400 #(100000 
MW) from [@Eurostat nrg_103m]
                GBR.techs.methane_supply.constraints.energy_cap_equals: 1.063 #(100000 
MW) from [@Eurostat nrg_103m]
                IRL.techs.methane_supply.constraints.energy_cap_equals: 0.005 #(100000 
MW) from [@Eurostat nrg_103m]
                LUX.techs.methane_supply.constraints.energy_cap_equals: 0.007 #(100000 
MW) from [@Eurostat nrg_103m]
                NLD.techs.methane_supply.constraints.energy_cap_equals: 1.140 #(100000 
MW) from [@Eurostat nrg_103m]
                NOR.techs.methane_supply.constraints.energy_cap_equals: 1.356 #(100000 
MW) from [@Eurostat nrg_103m]
                SWE.techs.methane_supply.constraints.energy_cap_equals: 0.001 #(100000 
MW) from [@Eurostat nrg_103m]
# Activating the above defined natural gas technologies and links
    natural_gas_links:
        tech_groups:
            ng_transmission:
                exists: true
        techs:
            ng_onshore_transmission:
                exists: true
            ng_offshore_transmission:
                exists: true
        links:
            BEL,DEU.techs:
                ng_onshore_transmission:
                    exists: true
            BEL,GBR.techs:
                ng_offshore_transmission:
                    exists: true
            BEL,LUX.techs:
                ng_onshore_transmission:
                    exists: true
            BEL,NLD.techs:
                ng_onshore_transmission:
                    exists: true
            BEL,NOR.techs:
                ng_offshore_transmission:
                    exists: true
            DEU,DNK.techs:
                ng_onshore_transmission:
                    exists: true
            DEU,FRA.techs:
                ng_onshore_transmission:
                    exists: true
            DEU,LUX.techs:
```

```yaml
            ng_onshore_transmission:
                exists: true
        DNK,SWE.techs:
            ng_offshore_transmission:
                exists: true
        FRA,BEL.techs:
            ng_onshore_transmission:
                exists: true
        GBR,IRL.techs:
            ng_offshore_transmission:
                exists: true
        NLD,DEU.techs:
            ng_onshore_transmission:
                exists: true
        NLD,DNK.techs:
            ng_offshore_transmission:
                exists: true
        NLD,GBR.techs:
            ng_offshore_transmission:
                exists: true
        NLD,NOR.techs:
            ng_offshore_transmission:
                exists: true
        NOR,DEU.techs:
            ng_offshore_transmission:
                exists: true
        NOR,FRA.techs:
            ng_offshore_transmission:
                exists: true
        NOR,GBR.techs:
            ng_offshore_transmission:
                exists: true
# Activating the above defined blending technologies and links
    blend:
        tech_groups:
            blend_transmission:
                exists: true
        techs:
            blend_onshore_transmission:
                exists: true
            blend_offshore_transmission:
                exists: true
            ng_h2_blender:
                exists: true
            ng_h2_deblender:
                exists: true
        links:
            BEL,DEU.techs:
                blend_onshore_transmission:
                    exists: true
            BEL,GBR.techs:
                blend_offshore_transmission:
                    exists: true
            BEL,LUX.techs:
                blend_onshore_transmission:
                    exists: true
            BEL,NLD.techs:
                blend_onshore_transmission:
                    exists: true
            BEL,NOR.techs:
                blend_offshore_transmission:
                    exists: true
            DEU,DNK.techs:
                blend_onshore_transmission:
```

```yaml
            exists: true
    DEU,FRA.techs:
        blend_onshore_transmission:
            exists: true
    DEU,LUX.techs:
        blend_onshore_transmission:
            exists: true
    DNK,SWE.techs:
        blend_offshore_transmission:
            exists: true
    FRA,BEL.techs:
        blend_onshore_transmission:
            exists: true
    GBR,IRL.techs:
        blend_offshore_transmission:
            exists: true
    NLD,DEU.techs:
        blend_onshore_transmission:
            exists: true
    NLD,DNK.techs:
        blend_offshore_transmission:
            exists: true
    NLD,GBR.techs:
        blend_offshore_transmission:
            exists: true
    NLD,NOR.techs:
        blend_offshore_transmission:
            exists: true
    NOR,DEU.techs:
        blend_offshore_transmission:
            exists: true
    NOR,FRA.techs:
        blend_offshore_transmission:
            exists: true
    NOR,GBR.techs:
        blend_offshore_transmission:
            exists: true
locations:
    BEL:
      techs:
        ng_h2_blender.exists: true
        ng_h2_deblender.exists: true
    DEU:
      techs:
        ng_h2_blender.exists: true
        ng_h2_deblender.exists: true
    DNK:
      techs:
        ng_h2_blender.exists: true
        ng_h2_deblender.exists: true
    FRA:
      techs:
        ng_h2_blender.exists: true
        ng_h2_deblender.exists: true
    LUX:
      techs:
        ng_h2_blender.exists: true
        ng_h2_deblender.exists: true
    NLD:
      techs:
        ng_h2_blender.exists: true
        ng_h2_deblender.exists: true
    GBR:
      techs:
```

```yaml
                ng_h2_blender.exists: true
                ng_h2_deblender.exists: true
            IRL:
              techs:
                ng_h2_blender.exists: true
                ng_h2_deblender.exists: true
            SWE:
              techs:
                ng_h2_blender.exists: true
                ng_h2_deblender.exists: true
            NOR:
              techs:
                ng_h2_blender.exists: true
                ng_h2_deblender.exists: true
# Activating the above defined hydrogen consumption technologies
    h2_consumption:
        techs:
            hydrogen_boiler:
                exists: true
        locations:
            BEL.techs.hydrogen_boiler.exists: true
            DEU.techs.hydrogen_boiler.exists: true
            DNK.techs.hydrogen_boiler.exists: true
            FRA.techs.hydrogen_boiler.exists: true
            LUX.techs.hydrogen_boiler.exists: true
            NLD.techs.hydrogen_boiler.exists: true
            GBR.techs.hydrogen_boiler.exists: true
            IRL.techs.hydrogen_boiler.exists: true
            SWE.techs.hydrogen_boiler.exists: true
            NOR.techs.hydrogen_boiler.exists: true
# Activating the above defined hydrogen transmission technologies and links
    h2_links:
        tech_groups:
            h2_transmission:
                exists: true
        techs:
            h2_onshore_transmission:
                exists: true
            h2_offshore_transmission:
                exists: true
        links:
            BEL,DEU.techs:
                h2_onshore_transmission:
                    exists: true
            BEL,GBR.techs:
                h2_offshore_transmission:
                    exists: true
            BEL,LUX.techs:
                h2_onshore_transmission:
                    exists: true
            BEL,NLD.techs:
                h2_onshore_transmission:
                    exists: true
            BEL,NOR.techs:
                h2_offshore_transmission:
                    exists: true
            DEU,DNK.techs:
                h2_onshore_transmission:
                    exists: true
            DEU,FRA.techs:
                h2_onshore_transmission:
                    exists: true
            DEU,LUX.techs:
                h2_onshore_transmission:
```

```yaml
                exists: true
        DNK,SWE.techs:
            h2_offshore_transmission:
                exists: true
        FRA,BEL.techs:
            h2_onshore_transmission:
                exists: true
        GBR,IRL.techs:
            h2_offshore_transmission:
                exists: true
        NLD,DEU.techs:
            h2_onshore_transmission:
                exists: true
        NLD,DNK.techs:
            h2_offshore_transmission:
                exists: true
        NLD,GBR.techs:
            h2_offshore_transmission:
                exists: true
        NLD,NOR.techs:
            h2_offshore_transmission:
                exists: true
        NOR,DEU.techs:
            h2_offshore_transmission:
                exists: true
        NOR,FRA.techs:
            h2_offshore_transmission:
                exists: true
        NOR,GBR.techs:
            h2_offshore_transmission:
                exists: true
# Activating newly-built hydrogen technologies and links
    h2p_links:
        tech_groups:
            h2_transmission:
                exists: true
        techs:
            h2p_onshore_transmission:
                exists: true
            h2p_offshore_transmission:
                exists: true
        links:
            BEL,DEU.techs:
                h2p_onshore_transmission:
                    exists: true
            BEL,GBR.techs:
                h2p_offshore_transmission:
                    exists: true
            BEL,LUX.techs:
                h2p_onshore_transmission:
                    exists: true
            BEL,NLD.techs:
                h2p_onshore_transmission:
                    exists: true
            BEL,NOR.techs:
                h2p_offshore_transmission:
                    exists: true
            DEU,DNK.techs:
                h2p_onshore_transmission:
                    exists: true
            DEU,FRA.techs:
                h2p_onshore_transmission:
                    exists: true
            DEU,LUX.techs:
```

```
                h2p_onshore_transmission:
                    exists: true
            DNK,SWE.techs:
                h2p_offshore_transmission:
                    exists: true
            FRA,BEL.techs:
                h2p_onshore_transmission:
                    exists: true
            GBR,IRL.techs:
                h2p_offshore_transmission:
                    exists: true
            NLD,DEU.techs:
                h2p_onshore_transmission:
                    exists: true
            NLD,DNK.techs:
                h2p_offshore_transmission:
                    exists: true
            NLD,GBR.techs:
                h2p_offshore_transmission:
                    exists: true
            NLD,NOR.techs:
                h2p_offshore_transmission:
                    exists: true
            NOR,DEU.techs:
                h2p_offshore_transmission:
                    exists: true
            NOR,FRA.techs:
                h2p_offshore_transmission:
                    exists: true
            NOR,GBR.techs:
                h2p_offshore_transmission:
                    exists: true
# Definition of the future hydrogen penetration scenarios
# By the year 2030
    h2_penetration_goal50:
      group_constraints:
        hydrogen_min:
          techs: [electrolysis]
          carrier_prod_min.hydrogen: 1750
    h2_penetration_goal100:
      group_constraints:
        hydrogen_min:
          techs: [electrolysis]
          carrier_prod_min.hydrogen: 3500
# By the year 2050
    h2_penetration_150:
      group_constraints:
        hydrogen_min:
          techs: [electrolysis]
          carrier_prod_min.hydrogen: 26250
    h2_penetration_90:
      group_constraints:
        hydrogen_min:
          techs: [electrolysis]
          carrier_prod_max.hydrogen: 16000
```

Appendix C Model framework extension

The original model framework (Euro-Calliope v0.6.8) pre-processing core was extended in its *utils.py* file with a function to extract the transmission balance duals. The script written in PYTHON can be found below:

```
def process_transmission_balance_duals(transmission_balance_duals):
    column=transmission_balance_duals[0]

    info = column.str.split("[(::)]")
    info = pd.DataFrame(info.tolist(), index= info.index)
    info.drop([0,2,5],axis=1,inplace=True)

    tech_and_time = info[4].str.split(",")
    info[['tech','time']] = pd.DataFrame(tech_and_time.tolist(), index= info.index)
    info.drop([4,6],axis=1,inplace=True)
    info.columns = ['region1','tech','region2','timestep']
    info.region1 = pd.DataFrame(info.region1.str.split("[']").to_list(),
index=info.index)[1]
    info.region2 = pd.DataFrame(info.region2.str.split("[']").to_list(),
index=info.index)[0]
    info.tech = pd.DataFrame(info.tech.str.split("[']").to_list(), index=info.index)[0]
    info.timestep = pd.DataFrame(info.timestep.str.split("[']").to_list(),
index=info.index)[1]
    info.timestep = info.timestep + ':00:00'
    info.timestep = pd.to_datetime(info.timestep)
    info['dual-value'] = transmission_balance_duals[1]

    return (info)
```