Politecnico di Milano

SCHOOL OF INDUSTRIAL AND INFORMATION ENGINEERING

Master of Science – Energy Engineering

Effects of Allowing Natural Gas Reformers with Carbon Capture into a European Renewable Network

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Academic Year 2020-2021

Acknowledgements

First and foremost, the author would like to thank Forschungzentrum of Julich and the IEK-3 group for providing the opportunity to research the topic of European Hydrogen Networks particularly during the 2020 pandemic. Next the author would like to extend his gratitude to Dr. Colbertaldo and Professor Campanari from Politecnico Di Milano for their guidance.

Last but not least, the author would like to thank his friends: Tommy Confalonieri, Brenda Muffy, Rebecca Muffy, Michail Kovalkov, Klaus Streng and their families; his family: father Ilya Traskunov, mother Anna Dukhovny, sister Alisa Grace Traskunov; and girlfriend: Ana Luz Russek Martinez, whose support throughout this master thesis has been crucial without which graduation might not have been possible.

Abstract

Over the past several years, hydrogen's popularity as a potential energy vector in the pursuit of a renewable future grew. Its role as an alternative fuel source or as an intermediary method of energy storage allows it to be applied in sectors like electricity, heat generation, and transportation. The two main ways to generate it are through electrolysis or through natural gas reforming. Both technologies have benefits and downsides when used to satisfy electrical and hydrogen demands for a large-scale energy system the size of a continent. While there has been plenty of research done for 100% renewable networks and their associated cost, a mix of renewable and reforming (with carbon capture) may be an effective lower-cost alternative that deserves attention.

Reforming natural gas into hydrogen is one of the most popular ways of making hydrogen today. The advantages of this technology's availability and its low cost make it an interesting candidate for inclusion into a large energy network. Many countries, especially those in the European Union, are currently investigating, some even already implementing, possible pathways to help start their hydrogen futures. Some countries in the European continent have access to large amounts of renewable energy, but even with this, the continent is a net energy importer, especially for natural gas, coming from Norway and Russia which accounts for over 60% of the total demand. Natural gas from these two countries serves as the source for reformed hydrogen that is used in this thesis' European energy network.

When combining natural gas reforming with renewable energy sources, this thesis shows how varied costs of reforming technology impact the energy network. The results answer two main questions: what the changes in each case's installed technology/costs are and how a range of costs for carbon capture and carbon tax affect the final overall network costs and its competitiveness compared to a 100% renewable case used as a reference. By varying the specific cost steam reformer from 810 €/GW to 1620 €/GW, 11 different cases are compared to determine if there is a cost value at which the mixed system with steam reforming can compete with a renewable system. A portion of the emissions from the reforming process is captured while the remainder is accounted for through carbon taxes in accordance with the current and future range found in Europe.

The data used in this thesis is run through a python-based optimizer, which gives the lowest-cost network for each of the 11 cases. Looking at the final energy networks, it can be said that any inclusion of natural gas reforming lowers the total annual cost of the European energy network and there exist cases that have a range of CO_2 transportation and storage costs and of carbon taxes, whose final additional cost, when added to the total network's annual costs, makes them less than or equal to the reference renewable network.

Sommario

Negli ultimi anni è cresciuta la populairtà dell'idrogeno come potenziale vettore energetico nella ricerca di un futuro basato sulle fonti rinnovabili. Il suo ruolo di carburante alternativo o di metodo intermedio di accumulo di energia gli permette di essere impiegato in settori come la produzione elettrica e termica e i trasporti. Le due modalità principali di generare idrogeno sono l'elettrolisi e lo steam reforming del gas naturale. Entrambe le tecnologie portano sia benefici sia svantaggi se usati per soddisfare il fabbisogno di energia e di idrogeno su ampia scala a livello continentale. Mentre sono state effettuate molte ricerche per reti 100% rinnovabili e per il loro costo, raramente è stato preso in considerazione un sistema misto che sfrutti fonti rinnovabili e reforming di gas naturale (con cattura della CO_2 generata), il quale potrebbe essere un'efficace alternativa a basso costo meritevole di attenzione.

Attualmente il reforming del gas naturale in idrogeno è uno dei metodi più diffusi di produzione dell'idrogeno. I vantaggi dai dalla disponibilità tecnologica e dal suo basso prezzo la rendono un candidato interessante da includere nei sistemi energetici su larga scala. Molti Paesi, specialmente quelli dell'UE, stanno attualmente indagando, altri addirittura hanno già implementato, possibili strade per dare avvio a un futuro in cui l'idrogeno è protagonista. Alcuni Paesi in Europa hanno accesso a grandi quantità di risorse rinnovabili, ma, nonostante questo, il continente è un importatore netto di energia, soprattutto gas naturale proveniente dalla Norvegia e dalla Russia, che insieme rappresentano oltre il 60% della domanda totale. Il gas naturale proveniente da questi due Paesi rappresenta la fonte per la produzione di idrogeno tramite reforming utilizzato nella rete energetica europea studiata in questa tesi.

Questa tesi mostra l'impatto della variabilità del costo della tecnologia dello steam reforming sulla rete energetica. I risultati rispondono a due domande cardine: (i) quali sono i cambiamenti in ciascun caso in termini di tecnologie installate e costi e (ii) come una gamma di costi per la cattura dell'anidride carbonica e di carbon tax sull'emissione residua di anidride carbonica impatteranno il bilancio finale dei costi e la loro competitività rispetto a un caso 100% rinnovabile, preso come riferimento. Variando il costo specifico dello steam reforming da 810 €/GW a 1620 €/GW, 11 casi diversi vengono messi a confronto per determinare se esiste un costo che possa permettere al sistema con steam reforming di competere con un sistema totalmente rinnovabile. Si ipotizza che una porzione delle emissioni del processo di reforming viene catturata, mentre il resto è contabilizzata utilizzando un range di carbon tax in conformità con l'attuale e futuro intervallo riscontrato in Europa.

I dati utilizzati in questa tesi sono gestiti da un ottimizzatore basato sul sistema Python, che fornisce come risultato la configurazione di rete a minimo costo per ognuno degli 11 casi. Analizzando le configurazioni di sistema finali, si può concludere che la presenza di steam reforming del gas naturale è sempre in grado di ridurre il costo totale annuo del sistema europeo. Inoltre, esistono casi che hanno un range di costi per il trasporto e stoccaggio dell'anidride carbonica catturata e di carbon tax per la quota residuale emessa, il cui costo annuale aggiuntivo, sommato ai costi totali annuali, rende tali configurazioni ugualmente o meno costose del corrispondente sistema interamente rinnovabile.

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Introduction

To hold the increase of the global average temperature well below 2 degrees Celsius, several countries united and set emission standards for sectors like power generation and transportation. Agreements such as the Paris Climate Agreement [1] have set guidelines to limit greenhouse gas emissions and dependence on conventional fossil fuels. These guidelines encourage countries to cooperate and work towards a unified solution rather than an island approach that only impacts one country. The European Networks of Transmission System Operators (ENTSO-E and ENTSO-G, for Electric and Gas grids, respectively) have set additional guidelines and recommendations to help the European Union (EU) [2], [3].

On top of the recommendations set by individual governments, both ENTSO-E and ENTSO-G have recommended power to gas (defined by the European Commission in 2018 [4]) on top of other power to power (fully electrical path) as a method to couple the electric and gas networks as well as help lower carbon emissions across the electrical and gas networks. Power to gas diverts excess electrical energy to any gas formation process; the byproducts of this can be stored for later usage or later converted back to electricity when necessary. One such method, called electrolysis, involves using the excess electricity generated from renewable sources to obtain hydrogen gas that can be directly used or transported and stored for future energy generation.

ENTSO-E has recommended to increase the generation of electrical energy with renewable sources however due to the mismatch of generation and demand creating energy excesses (positive or negative) in many regions of the EU, the balancing of this mismatch is becoming an increasing issue. To resolve this issue, it is suggested that new investments in electrical or hydrogen gas transmission should be made to reach set goals [2]. ENTSO-G set three possible directions that can lead to the achievement of the decarbonization goals set for 2050 [3]. These directions involve the substitution of coal, lignite, and oil with methane, a mixture of methane/hydrogen, or hydrogen. As said in both organizations’ guidelines, the hydrogen can be produced using the defined power to gas method. ENTSO-G further elaborates on the usage of the hydrogen gas and points to its ability to work as an energy carrier across the EU and as a fuel for fuel cell electric vehicles.

Hydrogen, as determined by the International Energy Agency (IEA) in a 2019 report [5], is a very versatile fuel which can be produced, stored, and used in a wide variety of ways. On top of this, it is mentioned that it has the potential to help with the variability of renewable energy sources because it is a leading means of storing electricity over long periods of time which can then be transported over long distances. At the same time, the same report mentions that there are several challenges facing the widespread deployment of hydrogen. The first being its high cost from a 100% renewable energy source. Secondly, the lack and slow growth of hydrogen infrastructure limits the amounts that can be delivered.

Currently, most of the hydrogen is produced from fossil fuel sources; the transition from mostly fossil fuel to a mixture of electrolysis and methane reforming can help lower costs and speed up hydrogen implementation. Even with carbon capture utilization and storage requirements (on technologies like reforming), the IEA showed that costs per kilogram of hydrogen fuel can be very low (between 2.5 and 1.5 USD depending on region).

The inclusion of steam methane reforming in a Pan-European hydrogen network, is investigated in this thesis to observe if it will lower network costs and help push hydrogen to the competitive edge while storing the emitted CO_2 to keep emissions as close to a 100% renewable case as possible.

This thesis builds on a renewable network by adding already proven and utilized steam methane reformers and seeing the impact reformers haven on the overall network cost and technology composition.

Motivation

In the literature review for this thesis, 4 categories were identified as being areas of influence as to how a cross European hydrogen network should be set up. The categories are: available technologies, hydrogen potential market, hydrogen network transmission, and main influences of hydrogen production to demand pathways. These categories will be briefly described in further detail in Chapter 1. All the categories combined help in the creation of the model presented in this thesis.

In some of these studies, a renewable-based hydrogen gas generation network or a mix between green (renewable) and blue (fossil fuel based) hydrogen was able to meet most of the predicted hydrogen demand [6],and [7]. Incorporating both green and blue hydrogen on a country scale has also be done to compare such systems to a renewable one. Each network had its own set of generation, transmission and storage technologies employed to satisfy either electrical, hydrogen, or each commodity demands.

Looking into all these networks, technologies such as large-scale cavern storage in countries like Germany, France, and Romania [8],[9],[10] have shown that with increased system storage capacity, the individual network's ability to address local demand helped reduce hydrogen fuel costs. The methods of transmission from small scale regions within a country to the scale of a full country have also pointed to a preferred method such as pipeline transport due to reduction in transmission costs with increased demand and distance [11],[12]. Common generation technologies considered were: on-/off-shore wind [13], geothermal, solar, and hydro-electric plants, and in some cases nuclear [14].

Using the transportation industry as a consumer of hydrogen, the inclusion of fuel cell electric vehicles along with battery electric vehicle, gave hydrogen more paths to be implemented [9],[15], and [16]. Some studies have included multiple paths of generation and consumption of hydrogen to further expand its usage flexibility ([13],[16],[17], [18]). While showing hydrogen's potential on a region or country scale, these networks never look at systems (that have both green and blue hydrogen sources) at larger scales such as the European Union.

The novelty of this thesis is that it will build on the research done in studies with the size like in Caglayan [17] and optimize a cross European network that incorporates blue and green hydrogen generation using European electrical grid expansion research found in the E-highway study [19] while keeping overall costs low and accounting for blue hydrogen emissions.

Research question

With the aim of contributing to the progress of an international hydrogen network in Europe, this thesis creates a network that satisfies the electrical and hydrogen demand (predicted for the year 2050) by using a mix of renewable technologies and natural gas imports from Europe's neighboring states. The hydrogen demand was considering if the 75% (market penetration) of the vehicle fleet in Europe is powered by fuel cells (as of the year 2050). A range of reformer installation costs (from 810 to 1620 €/kW) will be used in addition to a range of carbon tax and CO_2 transmission and storage costs (from 25 to 200 €/t of CO_2 and 25 to 100 €/t of CO_2, respectively). The analysis of the thesis results will look at the optimized network's distribution of production, conversion, storage, and transmission technologies while at the same time commenting on the effects that blue hydrogen inclusion had when comparing the mixed network to a renewable network at a European scale.

The main questions that will be answered in this thesis are:

- What is the change in the networks' generation, conversion, storage, and transmission technologies when varying natural gas reformer costs?
- Will natural gas reforming still be a viable solution as greenhouse emission penalties increase (CO_2 transmission and storage and carbon tax costs go up)?

Structure

This thesis report starts with a review of the base literature that built the foundation for the research and the core structure of the base optimizer that was used to produce the results. This will be followed by the collection of additional data and its modification, and additions to the base optimizer to facilitate comparison between new and reference case networks.

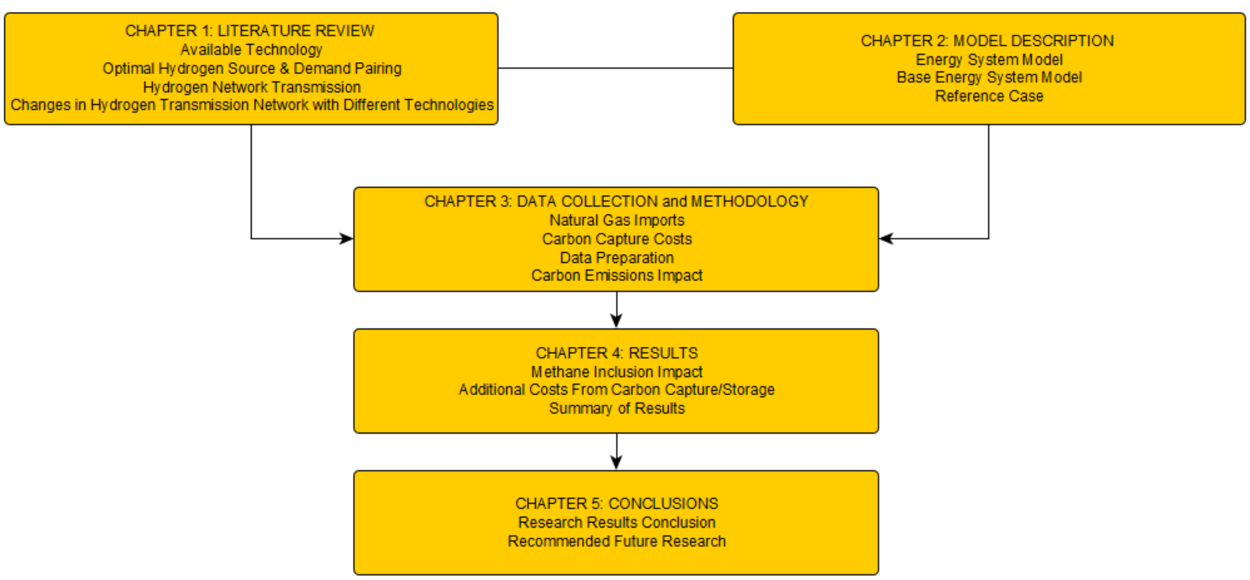


Figure 1.1 Thesis Report Structure

Chapter 1. Literature Review

An international hydrogen gas network can build on the knowledge from already constructed gaseous networks existing around the world. Just like the European natural gas market which needs a well-maintained system that satisfies the energy demand of continental Europe, so does the future European hydrogen network also need a similar system to satisfy its future demand. To justify a large-scale transmission network, an equally large demand needs to be present to recover the investment costs; one potential demand for a hydrogen network can be transportation which is an industry that connects us all, however its biggest downside is its dependence on fossil fuels. Decreasing this dependence is a key focus of several European energy policies ([1], [4]).

When building a balanced and cost-effective hydrogen network on an European scale, the available generation (energy sources and conversion), storage, transmission and potential usage has to be understood [1]–[3]. This information will help understand the technical benchmarks that need to be considered when designing and monitoring the energy flow of such a large system. A brief description of all reference material will be presented in this chapter that helped shape the research presented in this thesis.

This chapter is broken down into multiple sections discussing topics that will give the reader an understanding of the background information needed to model a cross-European hydrogen network. The literature review starts with the description of technologies that are available for a gaseous transmission network. This is followed by the overview of the hydrogen demand market and its key players. Next the idea of how to transmit the demanded hydrogen from one region to the next will be explained. The last section will describe the connections between demand and production balancing and how the selection of hydrogen production technology can influence the final transmission network.

1.1. Available Technologies for a Hydrogen Gas Network

With hydrogen not being common in nature in pure form, it needs to be synthetically generated with electrolysis and/or steam methane reforming technologies. Electrolysis is a popular method for the generation of hydrogen gas using electricity in many industries ([2],[3]). Using electricity to later generate gas, is called power to gas (P2G). The energy sources for electrolysis (such as wind, solar, and hydro) and how to combine them, is a topic that needs to be clearly understood to build a network such as one proposed by this thesis while balancing predicted demand and available energy generation. In addition to this, this chapter explores the combination of hydrogen produced from methane and hydrogen from renewable sources.

In a study done by Vo et al. [6], the excess power from Ireland's wind turbines is used to generate hydrogen that will later be combined with CO_2 to form methane. Vo et al. suggests that hydrogen that is converted back to power or combined with CO_2 to make a more sustainable gas makes an energy vector that can help couple many industries and sectors together. The island approach used in Vo et al. study while interesting, is limited in scale and misses the opportunity of further expansion into the EU to make a more robust system. The ways that P2G can integrate hydrogen into existing electrical and gas grids and how it can change the resulting network will be further explained in Section 1.4. On top of P2G technologies, the storage of generated hydrogen to address the demands of multiple countries, is encouraged by ENTSO-E/G 2050 plans. Another category of technological additions to a continental energy system is that of gaseous fuel storage.

Promising results have been seen in long term seasonal storage of hydrogen in existing geological formations to help balance future variability of renewable energy sources (RES). Research done by Iordache et al. [8], showed how hydrogen has the potential to be stored in salt caverns found in Romania; this has an added benefit of being a RES balancing service. Romania's salt cavern exploration experience and availability of spent and unusable salt caverns are a great source for short to long term hydrogen gas storage. Using the knowledge gained from Iordache et al., the usage of salt caverns across the EU was considered both for hydrogen generated from renewable and low carbon steam methane reformers; these methods from now on will be referred to as green and blue hydrogen, respectively. While looking at small-scale energy system studies can eventually help gain a near complete understanding of what can be done, a shift towards more continental or global scale study is needed since this thesis addresses the hydrogen transmission network on an EU scale.

Other in-depth studies like the Energy Watch Group "Global Energy System based on 100% Renewable Energy" [20], look at the global scale when trying to address the goals set by international agreements [1]. When presenting the findings for the EU, the continent's energy sources was varied with PV being the major contributor followed by wind, hydro, and a mixed technology category. Another statement made by the Energy Watch Group was that the complete elimination of fuels for aviation and shipping sector is not possible and the inclusion of synthetic fuels made from hydrogen and methane are a viable alternative for the near future leading up to 2040. When comparing the Energy Watch Group study to this thesis, the novelty of this thesis is that it considered methane derived hydrogen gas as an additional source for all transportation and electrical demands. The Renewable Energy study [20] showed that a renewable network on the scale of a continent and beyond is possible however there is no investigation as to where the network (transmission pipelines) for hydrogen gas transmission would be built even though the study says it will be a crucial part of the transport industry demand satisfaction.

With the EU setting ambitious goals to transition its energy sector to a mostly renewable one by 2050, there needs to be a capacity estimate that can show how much energy can be generated using the available land found on the European Continent. Investigations such as those done by Caglayan [17] show how combining renewable energy as a primary generation technology can satisfy large portions of total hydrogen demand. The technologies used by the Caglayan study were broken down into several categories: source, storage, conversion, and transmission. These technologies were taken from Welder et al. study [21]. This main category breakdown was also used in this thesis to add methane reformers and importing points into the energy model.

Transmission technologies were the last category considered. For electrical transmission, HVAC/HVDC were selected using the combination of existing lines and future planned connection from the "Ten Year Network Development Plan" [22] (TYNDP). For hydrogen, the transmission via pipeline was considered because pipeline transmission was found by multiple studies that will be discussed in Section 1.3, to be the cheapest option of transport over long distances and with large quantities.

Since methane steam reforming is included in this thesis, the capture of its CO_2 needs to be considered to maintain lower greenhouse gas emissions. An interesting technology that has been shown on industrial scale to be great for CO_2 capture involves the Allam Cycle [23]. A study done by Allam et al [24], shows that the CO_2 generated by this natural gas system can be completely captured and sent to an industrial user or geological storage facilities. This system is already in place at a Shell Oil Company facility in Alberta Canada since 2015 and captures 1 million [t] of CO_2 per year [25]. While one of these facilities is surely not enough for a European scale energy system (like that investigated in this thesis), its implementation in real life only costs around $25 per [t] of CO_2 [26] ; while the Allam cycle is not used in this thesis, the cost of transporting and storing CO_2 after its generation points to a lower limit that can be used for the capture and storage of CO_2 produced by the steam methane reforming plants found in this thesis. Recently, another plant similar to that in Alberta Canada started construction in New Zealand with the promise to have near complete carbon capture and clean hydrogen production([27] , [28]). This also shows that a near 100% capture limit is a realistic upper limit that can be used in this thesis. Carbon Capture and Storage (CCS) has been used in the industry for decades and has a range of price points depending on technology used (1000$ if capturing from air to 100$ if capturing from coal fire plants) [26]. While guaranteeing a low price of 25$ per [t] is not certain, investigating the impact of multiple price points can show at what point it would be less preferred to have a blue/green hydrogen network rather than a green one.

With governments and large energy producers creating policies to help CCS become more commercially available ([29]–[31]), the addition of this technology as a post processing step, will help offset the CO_2 emissions of steam methane reformers and level the energy mix found in this thesis with those of a 100% renewable composition. In addition to this, it has been shown that there is potential to store the sequestered CO_2 and that according to current trends of emission, will not be an issue even if using conservative estimates of 10 to 20 trillion [t] of CO_2 storage capacity available globally [26].

After getting a general understanding of what technologies should be implemented in this thesis, the next step of the literature review was to gain an understanding of how all the different aspects of a potential gaseous network can be combined to help satisfy the demands of industries like the transportation sector.

1.2. Optimal Hydrogen Source & Demand Pairing

After understanding what technologies are used in continental scale energy systems, the placement of each generation source or potential integration in existing markets is necessary. Studies in this section have investigated possible compositions of hydrogen generating technology to better exploit excess electricity generation and increase hydrogen gas production for transport uses or other energy sinks. Focus has been guided more to the transport sector as a starting consumer for the hydrogen market both in this section and others since research shows it as an optimal initial consumer ([7], [9], [16], [32], [33]).

Schoenung et al. [9] stress in their study that in a future renewable hydrogen market, only battery and fuel cell electric vehicles (BEV & FCEV) qualify as zero emission vehicles (ZEV); this fact being especially important to states in the United States of America such as California which is aggressively building infrastructure to enable FCEV deployment. This pursuit comes from the Californian legislation [34] that has made a requirement to have 50% of hydrogen by 2050 come from renewable sources. In addition, solar and wind energy are growing in capacity in this state but there are times of excess supply which need to be mitigated if the state wants to add more capacity in the future. Schoenung et al. mention that electrolysis stands as a very promising solution to renewable overproduction.

Political organizations also stress the importance of FCEVs as a crucial consumer for the hydrogen market. The California Air Resources Board and the California Fuel Cell Partnership [35] along with auto companies, base their future FCEVs on many factors, but almost all lead to the availability of fueling infrastructure. This is important because future demand not only needs access to this fuel, but it also need to have hydrogen at a low enough cost. During mid-day in spring, California historically consumes less electricity than during the morning or afternoon forming a "duck curve" (valley) and this can be detrimental to solar and wind production since there is excess production during this low demand period (especially for the former energy source). With over generation projected to grow soon, there will be more opportunities to increase hydrogen production to both reduce curtailment and to have additional demand source to avoid buildup.

Scamman et al. [14] focus on the underutilization of France’s largest power source, its nuclear plants, as a potential energy source for meeting future hydrogen demand with excess energy conversion to hydrogen. This study analyses the usage of electrolysis to fill in the 'valley' of nuclear production so that the plant can have a more stable production curve. Due to increase of variable renewable energy penetration, there is an increase in the temporal mismatch between demand and production which will need mitigation ([36], [37]). As the magnitude of this mismatch increases, simply exporting the energy to Power-to-Power (P2P) options (which heavily depend on market prices) like pumped hydro, will not be enough. With France aiming to transition to only nuclear and renewable by 2050, Scamman et al. expect the country to depend heavily on balancing functions in the next years. Rapid response electrolyzers can sell balancing services to the grid operator and reduce utilized energy in France, especially since it is the highest exporter of energy in Europe. It is shown that hydrogen can be a great source of 'energy valley filling' allowing for higher utilization of existing nuclear energy, smoother generation dynamics, and a wide usage across multiple sectors.

Scamman et al. mention that the three markets that can benefit from hydrogen production are mobility, power-to-gas, and power generation. The excess nuclear power in France far exceeds the needed amount (in converted hydrogen) for the next decade and even to the year 2050. In addition, hydrogen can be mixed in small amounts into the natural gas grid. Utilizing existing infrastructure is a great benefit and can convey and store large amount of hydrogen. France also has a good number of underground caverns that can be used for large scale hydrogen storage. Aquifers are an additional option only where existing aquifers are used for natural gas storage. While nuclear plants are not investigated in this thesis, hydrogen's ability to pair with a wide range of generation technologies to correct the mismatch between demand and production, reinforces the aim of this thesis to pair it with steam methane reformers and renewable technologies to satisfy electrical and hydrogen demands.

Countries like Italy who have shut off its nuclear program also see a spike in the mismatch between variable renewable energy and demand of electrical network. To meet future demands, understanding how the excess energy in Italy can be transferred across the country via electrical power or hydrogen will further the importance of what role specific hydrogen generating technologies can play in a hydrogen network.

Colbertaldo et al. [16] investigated how storage in the Italian electrical grid system, combined with FCEV and BEV can help Italy meet its ambitious energy goals of 2030. As mentioned in the study, plug-in electric vehicles (PEV) and FCEVs are a very promising technology that can help achieve the set guidelines. The former presents an electrical load on the system while the latter needs hydrogen produced. With power and mobility expected to intertwine more and more, energy storage is becoming a crucial technology that can help address fluctuation in production and demand on very large scales.

Looking at the results of Colbertaldo et al. study, in the technical maximum scenario, the renewable generation percentage was higher than that of conventional plants. Contribution of electric-to-electric storage was small, partially due to the limits of intra-zonal use that limited the exchange of energy (since the transmission lines are already almost fully exploited). This limited the excess renewable energy that is largely available in the South, to be sent to the North. When looking at only Italian electrical grid, Colbertaldo et al. pointed that a 100% coverage of hydrogen fuel for FCEV could be achieved within a scenario which had an aggressive implementation of RES growth coupled with a FCEV presence around 50% of the passenger car stock. The consideration of large-scale systems connecting countries, as considered in this thesis, is necessary to be able to catch even limited time windows in Italy while taking in energy from neighboring countries. While there is no guarantee that a European hydrogen grid will act in a similar fashion as the individual country's cases presented thus far, it is important to include the technologies (both production and demand) described in these studies into this thesis in addition to the novel addition of natural gas reformers exclusively for hydrogen production.

As seen in this section, hydrogen has the ability to fill in the 'energy valley' during times of mismatch when paired with multiple generation sources ([9],[14],[16]). While hydrogen is surely a good addition to energy networks (whether purely electrical, hydrogen or both), without effective transmission, its benefits will not be realized.

1.3. Hydrogen Network Transmission

Once it is understood how hydrogen generation technologies can be integrated into an energy network to effectively address demand, the transmission of this fuel is the next point of interest. The design and optimization of the transmission and distribution network is a critical contributor when addressing the final cost of hydrogen fuel [12]. The small delivery methods of hydrogen are a large reason for the final cost of the hydrogen fuel being high [38]. Noting this, it is important to optimize the delivery of the fuel from the source of production to the point of usage. Yang et al. [12] focus on optimizing this path of delivery by considering the delivery mode, (gas pipe, liquid fuel or gas trucks) and the delivery location (rural, suburban, or city).

With hydrogen's appeal being its drastically reduce well-to-wheel emissions, its spread is much needed in the current environmental field, but its lack of infrastructure limits its opportunities. For the Yang et al. study, transmission costs were determined based on the transmission distance and flow rate. When looking at the point-to-point consideration, Yang et al. controlled two variables: hydrogen flow and transmission distance. Variation in CO_2 emission noticeably affected only gas trucking, while liquid transportation did see some small increase as distances increased (gas pipeline was barely affected). This thesis uses steam methane reformers to generate extra hydrogen from methane, but the optimization of the CO_2 emission (when calculating the overall system cost) was not look at during the main optimization but rather as a post processing step to see what pairs of carbon tax and CO_2 transmission and storage costs would make the mix system not economically appealing.

After varying flows and delivery distance, Yang et al. found that lowest hydrogen transport costs were seen for high flows and high distances, while low flows and short distances were characterized by higher costs. For higher flow and longer distances it was evident that only gas pipelines would yield the lowest cost. With higher capacities, gas tank delivery was completely overruled, and the comparison was left to liquid and gas pipeline (still in many cases pipeline proved to be a more cost-effective option). Using the finding from this study and others in this section, it was decided early on that the method of transporting hydrogen gas in this thesis would be done with pipelines since transmission in this thesis was done over large distances and not within a small distribution network.

On top of the conclusion made by Yang et al. [12], Demir et al. [39] observes three different delivery and transportation methods of hydrogen gas under different temperatures and pressures. The methods of transportation included liquid cryogenic tanks, pressurized gas tanks, and gas pipelines. Demir et al. also mention that prices for the fuel are strongly linked to demand, transportation, and distribution costs. The hydrogen infrastructure cost, and the relative initial investment cost, were also related to hydrogen demand.

To have optimal hydrogen distribution, a good geographical and market conditions such as population, fuel cell vehicle penetration, number of fueling stations and city radiuses are needed. It was also noted that the contribution of other research [12], when it comes to finding transportation costs, impacted possible emissions and energy usage of a hydrogen gas network.

It was shown by Demir et al. [39] that the scenario with pipeline delivery (rather than truck delivery with or without geological storage) was the most environmentally friendly option since it does not use any trucks or special conversion technology. Looking at the levelized hydrogen cost for each scenario, because of the sheer amount that can be delivered, pipeline transmission had the lowest cost ~ 3 [$/kg H2]. Liquified hydrogen trucking was not cost effective due to the extremely high cost of liquification resulting in 8 [$/kg h2]; this is true also for small production volumes in this fuel state.

To further improve the benefits of a hydrogen transmission network, Welder et al. [10] use storage to increase the flexibility of the hydrogen network to allow for more hydrogen gas to be located in the transmission system and ready to be consumed. The objective function was set up to minimize the Total Annual Cost (TAC) while satisfying the systems energy balance (at all time steps) with power generation, conversion technology, storage, and transmission constraints. The scope of the application of these objective functions was the onshore wind capability of Germany and the hydrogen demand for hydrogen mobility. Power production was distributed based on land eligibility which was determined based on a set or constraints like that of Samsatli et al. [13] . Hydrogen demand was modeled using predictions based on future speculation for the year of 2050 while the mobility sector demand in Germany was determined by the potential usage of FCEV whose estimation was done in accordance to the research done by Robinius et al. [32] (combined with potential industrial demand). Electrolyzers were considered as the only conversion technology and the converted hydrogen could be stored in large scale storage facilities such as medium or large-scale storage tanks or large-scale underground storage. Transmission is considered through pipelines since many referenced studies pointed to them being the most cost effective.

In Welder et al. [10] results, the model-built transmission networks connected regions that did not have salt cavern storage to regions with such technology. These caverns are filled from winter to the middle of spring after which they are emptied, and then the process starts over. The resulting network's TAC was composed 66% of wind turbines while electrolyzers took 22% and salt caverns and hydrogen pipelines occupied 12%. Adding off-shore wind turbine like in Robinius et al. ([32], [40]) will drastically change the storage requirements since the amount generated will greatly exceed that of only on-shore. From the Welder et al. study, it was understood that the transmission network would not be the biggest contributor to the overall network TAC but still play a crucial role in moving the large generation from commodity generation sources (hydrogen from electrolyzers and reformers) to areas with lower renewable and reformer installed capacities. What this thesis did differently, when compared to Welder et al., was the addition of methane reformers while considering a large scope like that in Caglayan ([41], [17]).

Starting on a country scale can be effective when considering the near future, but with the EU pushing for a united approach to energy, a cross European network needs to be analyzed [1]–[3]. Caglayan [17] presents a study that aims to design and optimize a hydrogen network with a 100% renewable energy goal for a European energy system by 2050. Optimization is done by minimizing the TAC using an open-source optimization program called Framework for Integrated Energy System Assessment (FINE) that includes different temporal and spatial resolutions of a network. The technology involved were onshore and offshore wind energy, open field photovoltaics (PV), rooftop PV, as well as biomass plants, and hydro-electrical plants. In the Caglayan study, the generated energy is transmitted over the electrical transmission network or converted to hydrogen which is then transmitted via pipelines. For storage of hydrogen, vessels and salt caverns are considered. This stored hydrogen can later be converted to power or used in fuel cell electric vehicles (FCEV) through re-electrification using Open-Cycle or Closed-Cycle gas turbines. The production aim was to match demand profiles while observing maximum capacity constraints. In the end it was determined that a 100% renewable network (Biomass CHP plants emissions were not considered neutral) is feasible and can achieve the electricity and hydrogen demand goals of Europe for 2050.

The estimations for electrical and hydrogen demand were taken from other studies to help understand the behavior of future drivers and help the model cater to driving patterns. This included information for generation technologies, weather, and electrical demand data from the E-highway study [19], projected to the year 2050, and was used to maintain consistency among renewable sources.

In the results, Caglayan [17] saw that the optimizer has chosen not to install roof top and open field PV with tracking. This is because of the high investment costs of such technologies when compared to open field PV without tracking (especially in southern Europe). The first noticeable output of the optimizer used by Caglayan was the cheap electricity generation regions like Ireland and the United Kingdom, which provided large amounts of hydrogen for continental Europe. Next, countries with salt cavern storage had large capacity pipelines connected to them thanks to the availability of low-cost storage. Since this thesis was at a similar scale and technological mix, the Caglayan study was chosen to be the reference study when comparing the results of this thesis.

1.4. Changes in Hydrogen Transmission Network with Different Technology

While electrolysis and methane reforming are the two main hydrogen production methods used in this thesis, the commodity path (generation, potential conversion, and transmission) needed for these processes is worth investigating. As described in this section, the addition of multiple pathways for hydrogen, can help hydrogen fuel become a more flexible energy vector when coupling multiple industries and markets with one of the methods being utilizing excess energy.

Colbertaldo et al. [33] state that the exploitation of excess electrical energy by hydrogen production makes it a very flexible fuel that can help store unused wind and solar energy and at the same time help with the European goal of decarbonization. The extent of hydrogen's energy vector capabilities can be expressed in the term Power-to-X (P2X). This term's definition encompasses the various direction the converted hydrogen can take after being created from excess electrical power. These directions include direct use of hydrogen as a fuel for FCEV, re-electrification, and to further products for industry and transport. Colbertaldo et al. focus on three of these pathways: re-electrification via fuel-cells (Power-to-Power, P2P), injection of H2 into natural gas grids (Power-to-Natural Gas, P2NG), and fueling FCEVs (Power-to-mobility, P2M).

Colbertaldo et al. concluded that energy system storage will be a crucial element in future energy networks. Hydrogen can help address this need and act as a sector coupling energy vector for further reduction of CO_2 Emissions. It was noted that the highest reduction was seen when hydrogen was used directly as a fuel in P2M scenarios. The results also showed that in the case of Italy, single directions of P2X yielded better results than the combined cases. It is also noted that this may be due to the economics of the solution and the implemented policies rather than the technical or environmental benefits. This does not eliminate the possibility of multiple P2X pathways to be a potential solution to network optimization such as hydrogen originating from natural gas reforming and how the resulting emissions compare to the current emissions in the EU. The addition of natural gas reforming (and the comparison of its resulting emissions) is therefore a crucial investigation of this thesis.

In Guandalini et al. [18] study, hydrogen's P2G integration into countries like Italy with already existing and growing RES capacity, has been found to improve a hydrogen network's reliability in mitigating RES variation. Evidence from this study suggest that the implementation of P2G in Italy can have a visible impact of the substitution of natural gas utilization when used for hydrogen gas consumed by transportation vehicles. Even with the increase of renewable energy sources in the country replacing some thermal plants, a substantial portion of energy is satisfied by imports. The increase of renewable sources can come with a large mismatch between energy production and load. It is concluded that higher penetration of wind, in particular offshore wind, are more favorable towards wider deployment of P2G. Ruling out natural gas reforming on a country scale can be understood if the country has a large renewable energy potential; when connecting this country to others, the path that hydrogen will take (while minimizing costs) can be different. The effects of adding cheaper hydrogen from natural gas reforming, are not investigated in this study. Investigating this can show if there are changes in the installed technology capacity composition (such as wind or solar) and/or the transmission path hydrogen takes when connecting to Italy.

Samsatli et al. [13], optimized a country wide energy model across the United Kingdom by modeling the different ways excess wind energy can be transmitted with the help of hydrogen. The goal of the objective function was to minimize the total cost of the designed network, while satisfying the demands of 100% penetration for domestic transport sector on an hourly basis. The United Kingdom was divided into several uniform property zones that had the ability to connect to all their neighbors. If there was excess electricity generation from the wind turbine, Samsatli et al. model could decide if this excess was transported as electricity, hydrogen gas (from electrolysis), or if the turbine was to be disengaged.

Both above and below ground hydrogen storage were possibilities in the Samsatli et al. study. The hydrogen demands were approximated using petroleum consumption data for each 1km section for each of the national sections. The hydrogen produced from excess wind energy could be stored or transported to local or neighboring regions for consumption via underground pipelines.

The study concluded that by using only onshore wind, the United Kingdom can satisfy its hydrogen mobility demand. Combining the network with large underground storage and existing wind turbines can further reduce the cost of the network compared to a limited case with only electrical lines. Effects of large storage have been shown to help in better capturing excess energy and converting it to hydrogen; however, further understanding of the hydrogen's utilization, specifically its market penetration of FCEV, also has potential to influence final network results. The setup of this study is like that of this thesis, but it overlooks the changes that could occur when the UK is connected to the rest of Europe and how its large availability of wind energy and salt caverns would be affected with the availability of natural gas reformed to hydrogen.

When optimizing networks on a country or a continental scale, certain constraints need to be placed on the optimization model to not only help in the computation of the problem but to also help better understand the impacts of certain transmission or technological decisions. Storage has been consistently proven to help in improving flows between nodes of the network [33]. In addition to this, selection of technology that is both common in industry and has high production potential in a specific area can help not only in the demand of surrounded nodes optimization but also in adjacent or far node demand satisfaction ([33],[18], and [13]). When looking at one country, the combination power to gas (P2G), large capacity renewable source, and large-scale hydrogen storage can be the one solution to addressing its hydrogen demand; however, when connecting all of Europe, even if countries have all these properties, the resulting network may be different with or without natural gas reforming added. Therefore, the investigation done in this thesis can use a similar technology mix as in previously mentioned studies, but the resulting network may have different results due to the large scale of the network and the addition of natural gas reformers.

Chapter 2. Model Description

This chapter presents the basic structure of the model used to simulate the energy system, which balances hydrogen and electricity demands by means of a chosen mix of technologies, involving a variety of primary sources and intermediate energy vectors. The model was developed at Forschungszentrum Jujulichlich in Germany and uses a python-based framework, called Framework for Integrated Energy Systems Assessment (FINE) [42], in combination with Gurobi solver [43] to minimize the total annual cost of the cross-European energy system by selecting the most appropriate technologies and redistribute energy flows on a spatially refined representation of the system. Following this, the search and selection of additional data is described. The last section of the chapter talks about the reference case selected as the main comparison point for the results of the thesis.

2.1. Energy System Model

In this section, an in-depth description of the base energy system model, used to satisfy hourly electricity and hydrogen gas flows of each node is described. FINE's main purpose is to provide a framework to model, optimize, and assess given energy systems. The framework can be given multiple regions, commodities, and time series data and will return the optimized network in terms of installed capacities of the various energy generation (source technology), conversion, storage technologies, and time-resolved energy flows throughout the year, while minimizing the total annual cost (objective function). The parameters that are needed to define the network's geographical boundaries and its exchanged resources are: regions, commodities, and commodity units. These parameters are the base for defining the system in which the framework will balance. After defining the regions and commodities that will be exchanged in the system, time series parameters need to be defined. These include number of time steps and hours per time step (default is year-long calculation over 8,760 hours and 1-hour-long time steps). Locations represent the names of each modeled region, while commodities are the energy vectors that are exchanged within the model (with the units being their energy quantity measurements). Once these parameters are set, the next point of interest are the energy systems main components or the modeled technologies.

To complete an energy system model with FINE, five basis technology characterizations are needed. The characterizations are referred to as 'modeling classes'. Each modeling class represents a different part of an energy network such as the energy sources, the energy sinks (consumption), the methods of conversion (from one energy vector to another), storage, and finally, the methods of energy transmission. Technologies and their associated data need to be added individually to each class.

A simple representation of the model is presented Figure 2.1. The sources of energy or commodity are modeled in the same class as the sinks or points of demand (but with opposite signs). While commodities can only go in one direction from points of source to sinks, the other modeling classes can exchange commodities indefinitely as the model sees fit until the optimal conditions and demands are met. The interactions between each modeling class found are depicted in Figure 2.1.

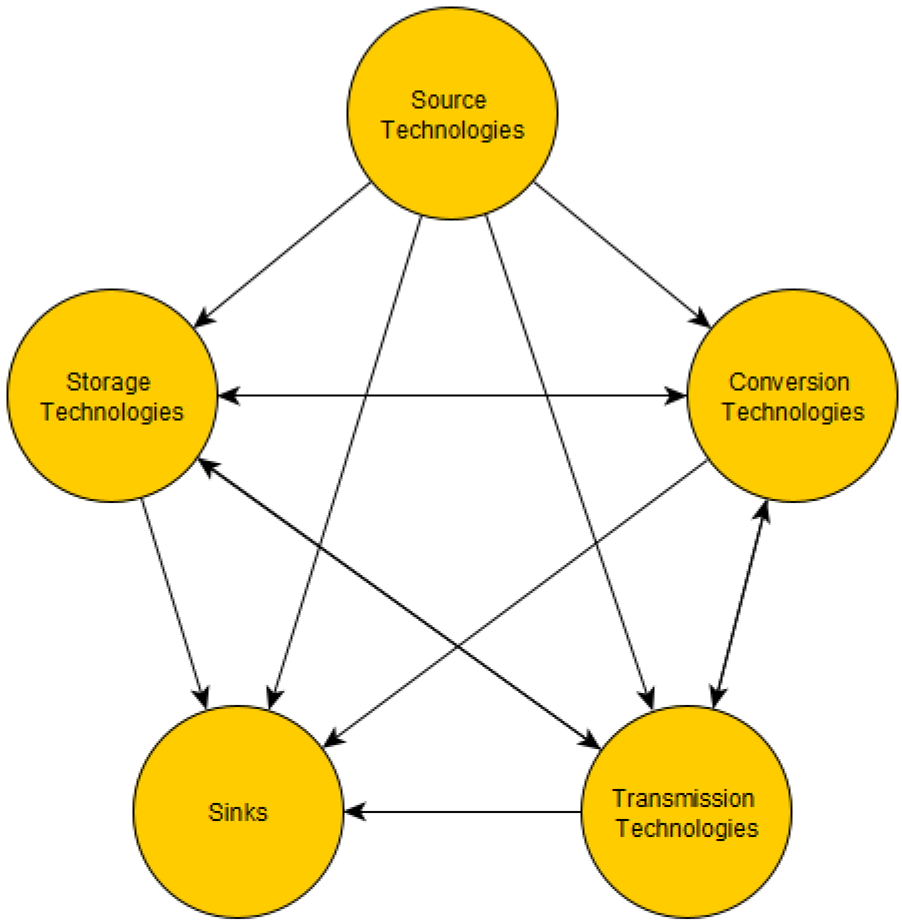


Figure 2.1 Schematic of the Simplified Energy System as modelled in FINE

The last major set of parameters that can be set for the energy system model is the number of typical periods. This parameter is strictly a positive integer and sets the time period clustering of all energy system components in the model. The clustering is done by using the Time Series Aggregation Module (TSAM) package developed by Hoffmann et al. [44]. To run the model, the FINE optimization function is used whose parameters depend on the available threads in the computational unit and on the chosen solver. While it is possible to solve this optimization problem on a personal computer, it is recommended to use a high-performance computer to get reasonable computational times. The solver of choice for this problem is Gurobi [43].

The following section describes the specific composition of each modeling class used in reference energy system.

2.2. Base Energy System Model

To set up the base of the energy system model in FINE, as mentioned earlier, there are 3 required parameters that need to be defined: regions, commodities, and commodity dictionary. The regions considered in this thesis involved continental Europe, with regions broken down the same way as in the E-highway study [19] and Caglayan [17]. There were 97 regions in total and each had an hourly profile for hydrogen gas and for electricity demand (as predicted for the year 2050), a renewable energy technology capacity, and in some specific regions, a natural gas import possibility (which had a region-specific maximum). Natural gas was not present in the reference case; this was an additional technology that was added in this thesis.

In each modeling class, the incorporated technologies can have individual maximum capacities or have a shared capacity limit with another technology. If a group of technologies must share a certain amount of allowable capacity, FINE has a feature called ‘Shared Potential ID’ that keeps the selected technologies total installed capacity within the set maximum. For example, in the reference case and in this thesis, this feature was used for fixed and tracking photovoltaic technologies due to the space limitations each region has. This was done because a location that is ideal for photovoltaics cannot be occupied by both at the same time; the breakdown in each region is decided based on the objective function of the model which was to minimize the overall network total annual cost (TAC).

The commodities hourly flows (commodity unit dictionary contained both the commodity lists and their corresponding energy unit) that were considered in this thesis were: electricity [$GW_{electric}$], hydrogen [$GW\ LHV_{H2}$], methane [$GW\ LHV_{CH4}$], biomass [$GW\ LHV_{biomass}$], and water [$GW_{electric}$]. The addition of natural gas data will be described in detail in Chapter 3. The specific hourly rates for renewable technology came from Caglayan [17]. This dataset also contained hourly generation profiles for all renewable technology broken down by each region. The water commodity was used by run-of-river, pump-hydro-storage, and reservoir (hydro dam) plants whose potential hourly flow was measured by equivalent GW of electricity produced by each technology. The parameters not mentioned specifically in this section used the default values already set in FINE.

For each installed GW of power, a technology had unique economic parameters that gives its final TAC. Wind turbines (both onshore and offshore) have additional costs that are based on both available capacity and the region’s unique cost per GW taken from Caglayan [17]. Costs of the system came from the model installing a technology or utilizing a fuel source like biomass or methane. Biomass availability was widespread across all regions and had a fixed cost per GW while natural gas was limited to regions of import and had to be converted in the same region. Renewable energy sources and water are free but with a cost for capacity installation. Combining each technologies investment and OPEX (operation expenses per GW of installed capacity) cost resulted in the model’s TAC.

The countries that were included in this thesis are pictured in Figure 2.2 (with each region’s corresponding number). While demands are not homogenous in each region, the hourly electricity and hydrogen demands are clumped together for each region and represented as one point of the transmission network. These points can be connected to each other through electrical transmission lines and/or with hydrogen pipelines. The connection points are each region’s centroids which lumped all technologies in a region together. Offshore wind turbines installations (installation regions seen in A.2.1, are combined with the other technologies; it is assumed that there are no loses within the region (for both electricity and hydrogen gas) losses only occur in transmission between regions. The same approach, as for energy generation, was used for conversion and storage technology. The availability of each technology (source-generation, conversion, and storage) was already determined by Caglayan [17], the model only had to simulate the energy balance for which significantly reduced the computational load. Not all points are connected with both DC and AC lines (these connections come from existing and future plans of the TYNDP [22]) , while all points had the potential to be connected with hydrogen pipelines. Since electrical line connections (AC/DC) were fixed, the model only had to balance the flows going in and out of each node. Hydrogen pipeline connections were made following two conditions which were: energy balance and TAC minimization. The potential connections capacities, losses, and distances for AC lines, DC lines, and hydrogen lines are shown in the Appendix figures A.2.7 to A.2.11.

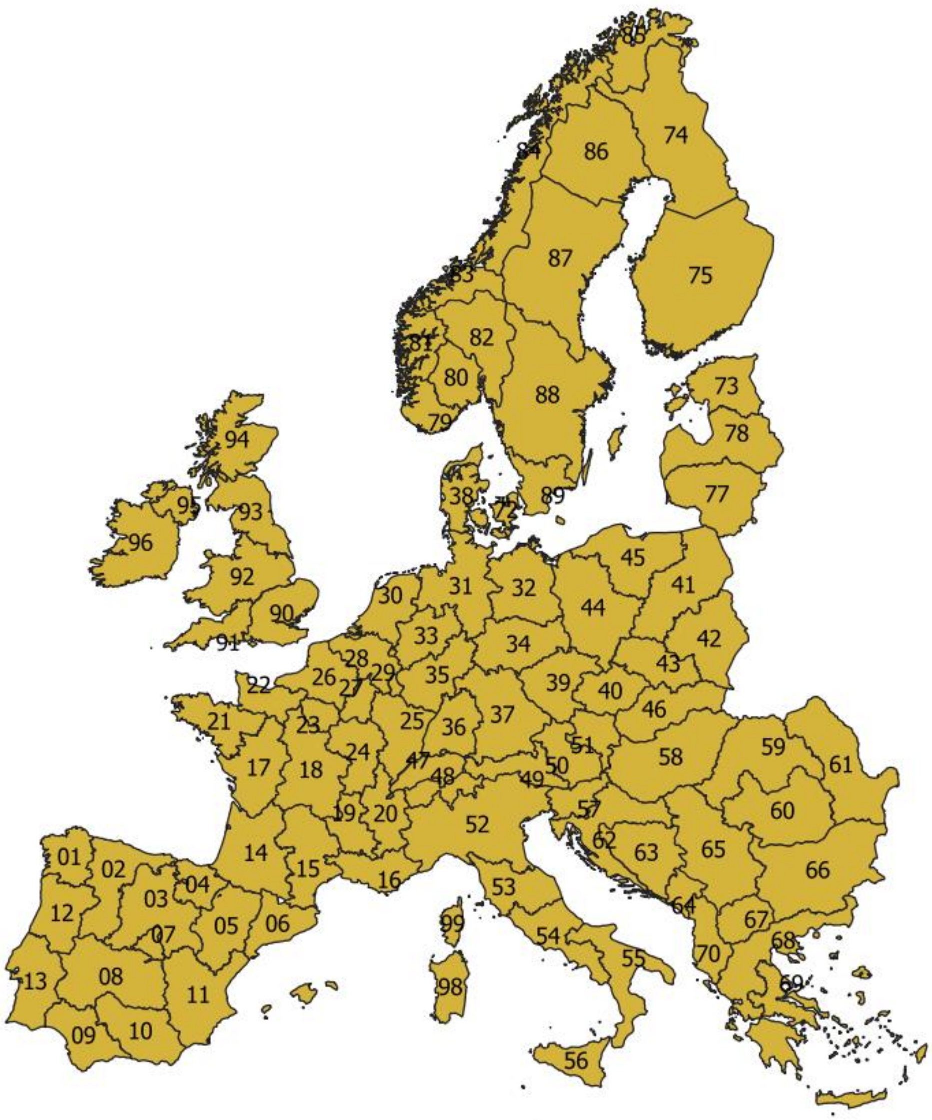


Figure 2.2 - Regions included in the thesis work, with region numbering.

2.2.1. Source/Sink Technologies

The technologies considered in this thesis were clumped into the centroids of each European region. Starting with the production technologies, each region had offshore wind (if possible), onshore wind, open field photovoltaics with or without tracking, rooftop photovoltaics, run-of-the-river plants, hydro-dam plants, pumped-hydro storage plants, biomass plants, and natural gas imports (natural gas was limited to a few nodes). Limiting the usage of natural gas to a few importing nodes avoided the need to develop a natural gas network which was outside the scope of this thesis. These importing nodes were adjacent to Europe’s two major natural gas exporters (Russia and Norway) which make up around 65% of natural gas imports [45]. Limiting the sources of natural gas to these two countries, was done because their entry points were well known (existing pipeline connections) while other exporting nations’ entry points were not given by Eurostat; giving them an approximate entry point could affect the validity of the results and therefore was avoided.

All wind and photovoltaic (except rooftop) technologies had 60 sets ‘groups’; each single group (within a specific source technology) was classified by equal division of percentiles of the technologies levelized cost of electricity (LCOE). This breakdown into 60 groups was shown in Caglayan [17] to be the optimal amount of grouping to improve the spatial resolution of each regions renewable modeling to be able to capture a wider range of weather conditions while keeping computational times low. Each of the renewable technologies had a certain maximum available energy at each hour of the year based on weather data which was taken from the National Aeronautics Space Agency’s (NASA) Modern-Era Retrospective Analysis for Research and Applications (MERRA) dataset, version-2 [46].

Run-of-the-river plants had an hourly maximum capacity in each region based on available river flow. Hydro-dams and pumped-hydro storage plants also had hourly maximum capacities based on flow rates however, pumped-hydro storage plants had the ability to convert running water into electricity or electricity into water; both commodities could also be stored in the region, with only electricity having the ability to be transported to another point. Each region’s technology maximum installable capacities are found in appendix tables A.1.1 through A.1.4. As mentioned earlier, the fixed and tracking solar PV technology had a shared maximum capacity in each region.

Each nodes sink, or demand profile, are included in the source technology modeling class but with a reverse sign to denote the usage of the commodity. These components have no cost associated with them but serve as an endpoint for the energy systems produced electricity and hydrogen. Each node has an electricity demand (which includes electrified heat demand and electric vehicle demand) time series data estimated by Syranidis [47] following the methodologies described in the E-Highway study [19]. Hydrogen demand is taken from Caglayan [17] which used the approach suggested by Robinius et al. [40]. The resulting values are the hourly demand profiles. The overall yearly demand of electricity and hydrogen can be found in the appendix (with each regions location) in tables A.1.14 through A.1.17. These values are fixed for all cases and must be satisfied by the solver. Techno-economic parameters used for source technology in the source/sink modeling class are reproduced in A.1.7.

If there was no fixed value for a technology’s economic parameter, ‘Region Dependent’ (R.D.) was written. Sources for the fixed economic values were taken from a mixture of sources; the sources were Carlsson et al. [48], Ryberg et al. [49], and Caglayan ([50] and [17]). The second and last fuel source was Biomass and unlike natural gas was not limited by the availability of the fuel but rather was limited by each region’s given maximum combined heating and power plant capacities determined by Caglayan [17]. Wind turbine technology had an additional variation in the price per installed capacity. This parameter was region dependent and was unique to offshore (if possible, for the region) or onshore. Since wind speeds are not uniform across Europe, this variation was necessary to ensure the model accurately create a wind generation network to contribute to electrical generation. The costs per region can be seen in the appendix in tables A.1.12 and A.1.13

2.2.2. Storage Technologies

Storing hydrogen and/or electricity can be done on the site of production, import, or export. This thesis considered salt caverns and gas vessels for hydrogen, while for electrical energy there are lithium-ion batteries, pumped-hydro storage plants, and related water reservoirs (hydro dams with water storage that will be later converted to electricity). Reservoirs and pumped-hydro storage plants have fixed capacities, while salt caverns have maximum capacities assumed based on their location geographical parameters. There are no imposed capacity limits for hydrogen gas vessels and lithium-ion batteries, so the installed capacity is an output of the model depending on system needs and technology costs. The maximum capacity for each regions storage technologies, taken from the Caglayan [17], can be seen in the appendix tables A.1.5 and A.1.6.

By making salt caverns have a maximum capacity rather than a fixed one, the FINE energy model was able to vary the used storage of the nodes containing a salt cavern; batteries in theory had no limit but had a set charge and discharge efficiency. While batteries can either be fully discharged or fully charged, salt caverns need to have a minimum ‘charge’ or amount of gas, so called cushion gas [51] to ensure stable extraction and filling and to stay above the minimum cavern pressure. The water capacity used in pumped hydro is different from that of reservoirs. The availability of pumped-hydro storage and hydro reservoirs was based on existing installations, while lithium-ion batteries and vessels could be built anywhere. Salt cavern estimated capacities found in tables A.1.5 and A.1.6.

In the appendix table A.1.8, which includes storage modeling class FINE parameters used in this thesis, is broken down by the storage technologies and by commodity. Just like the source technology, each storage type has a specific parameter that varied depending on region was noted with ‘R.D.’.

2.2.3. Conversion Technologies

The considered conversion technologies (except for reformers of methane to hydrogen) were the same as in Caglayan [17]. Conversion technologies can produce either electricity, hydrogen or - in the case of pumped-hydro storage - water for later electrification. As mentioned earlier, the amount of water stored in this technology was expressed in GW of electricity available for each hourly time step rather than the volume of water. Pumped-hydro storage technology and hydro dams had a maximum conversion capacity from water to electricity (pumped-hydro storage also had the reverse path maximum conversion) which is found in the appendix tables A.1.10 and A.1.11.

The transformation of one commodity to another involves a conversion ratio of the original energy source to the commodity and a conversion efficiency. In addition to this, economic variables such as investment cost, operational cost, and economic life specific to each technology can be added to the FINE framework. If not available, these values can be left blank and are not included in the objective function calculation. Appendix table A.1.9 contains all the economic parameters and conversion parameters used in the model. There is no preference set for which method or paths of conversion the model may choose hence, the hydrogen produced from steam methane reforming could be used for future electrical production through fuel cells or gas turbines as well as directly satisfying hydrogen demand of any node.

Within conversion technologies, reformers are the main addition of this thesis to the existing analyses. Reformer technologies can be modeled the same way as any other conversion technology. Reformers have a conversion efficiency that takes a certain amount of GW of methane and converts it to a set amount of GW of hydrogen gas. Economic parameters related to conversion of methane can also be added, such as cost of installation per GW, OPEX related to operation and installed capacity, interest rates and economic life. The specific values for natural gas reformers were not present in the reference case of this thesis and will be discussed in more detail in Chapter 3.

2.2.4. Transmission Technologies

There were only two commodities that are transmitted across the regions considered in this thesis: hydrogen and electricity. As pointed out in Section 1.3 of this report, pipelines are the most optimal method of transporting hydrogen fuel across great distances and in large quantities (therefore it is the sole method used), while electricity can be transported through high voltage alternating or direct current lines (HVAC and HVDC, respectively). Potential paths for hydrogen pipelines are taken from research done by Caglayan [17] while electrical line capacities connecting points in the EU were taken from the ‘Ten Year Network Development Plan’ (TYNDP) [22] for expansions up to the year 2050. The HVAC/HVDC connections and capacities proposed by TYNDP were set as exogeneous variables and were not allowed to be changed. The only transmission lines whose capacity could be changed were those for hydrogen gas transmission.

Costs for both the electrical lines and the hydrogen pipelines were modeled in the same linear way as in Caglayan [17] in order to be able to better compare this thesis results to that study (chosen as the main reference case). The locations and capacities (and reactants for the AC lines) for both DC and AC lines are seen in appendix figures A.2.7 through A.2.11.

2.3. Reference Case

To evaluate what the impact of reformer inclusion is on the energy system, a similar point of reference has been selected. For this thesis, the results of a renewable European energy system with no NG import were taken from Caglayan [17]. In particular, the results using the weather data for the year 2015 were considered to not bring in any inconsistencies.

The results from Caglayan [17], from now on will be referred to as the reference case. The network composition found in the reference case is renewable and is set up in a similar way as the network presented in this thesis without the availability of hydrogen converted from natural gas. The resulting optimized network of the reference case had a final TAC of around 220-billion-euros.

Since the objective function is the minimization of the total annual cost, if no arrangement of natural gas reforming has a lower costing network than the reference case, the solution found by this work will be identical to the reference case and there will be no changes in the hydrogen pipeline networks (connections and capacities), each modeling classes’ composition, and the overall network TAC. To ensure compatibility of the comparison, as described earlier in this chapter, each technologies’ economic and technical specifications are kept the same and the time series aggregation is set at 30 days. This value for the time series aggregation has been shown to yield similar results (when compared to highest values or even no time series aggregation) while keeping computational times reasonable [41].

In the next chapter, the additions made to the reference case are described in detail. This new data will be the core of the new model proposed by this report, with its optimization results being directly compared to those of the reference case.

Chapter 3. Data Collection and Methodology

The uniqueness of the analysis that is performed here is the addition of natural gas reformers as a source of hydrogen. While Europe has an extensive natural gas network, determining where the natural gas used in each node came from and how it traveled is not a simple task and can involve a lot of assumptions. To simplify this, natural gas reforming is modeled at the entry point of the system. This also allows to minimize the natural gas leaks along the pipelines, which would have a strong GHG effect, while carbon capture can be concentrated in a limited number of reformers at entry points and only hydrogen is transmitted within Europe. Only natural gas import via pipelines is considered, and natural gas transported over ships (liquified or in gas form) is not looked at since their points of entry and origin also require assumptions that can have significant influences on the results.

According to the International Energy Agency (IEA), most of the hydrogen produced in the world today is done through natural gas reforming [5]. The IEA also shows that with natural gas reforming, even if including carbon capture and storage, prices can range between 1 to 3 dollars per kg; omitting this technology from the deployment of a Pan-European hydrogen network can prevent the initial utilization of cheap hydrogen by sectors like transport. Looking at European countries today, it is evident that the continent is a net energy importer and most of its natural gas (~65%) comes from two countries: Norway and Russia ([45], [52]). While other countries export natural gas into Europe, it was not as clear cut to determine those points of import as it was for Norway and Russia so only these two countries were considered as natural gas exporters [53]. Since the energy network optimized in this thesis will be compared to a renewable network at the same scale (with biomass combined heating and power plants CHP), it is important to also keep CO_2 emissions as low as possible. To do this, carbon capture and storage technology (CCS) was incorporated into the model (as a post-processing step) to account for the captured and emitted CO_2 that the model has from the addition of steam methane reformers.

The main source for natural gas import data for the EU was Eurostat, the statistical organization that collects data on the EU and its internal and external interactions. At the time of writing this report, the United Kingdom had already begun its separation from the EU, but due to public data availability being before 2018, it was considered part of the thesis’ scope. Russia’s main purpose in this study was as an exporter of natural gas that would later be turned into blue hydrogen. This, along with the other hydrogen fuel sources of Europe, would be used to balance the entire European continent’s hydrogen and electrical demand as closely as possible.

The efficiency with which the emissions from the steam methane reformers is captured remains fixed at 95%; this value is within range of what industry standard CCS systems can do. While 100% is possible, the industry examples that have natural gas plants with such capture mention in multiple sources that it is nearly 100%, therefore a value slightly lower (95%) was chosen ([23], [27], [54]). It was assumed that all the steam methane reforming plants have some sort of carbon capture and storage facility, and the additional cost induced onto the network with methane reforming were the cost for transporting/storing the CO_2 that is captured and the carbon tax on the remaining CO_2 emitted into the atmosphere. The range of costs for transporting/storing CO_2 was from 25 to 100 € while the carbon tax ranged from 0 to 200 € (both per [t] of CO_2). These ranges included the current costs for carbon capture from natural gas plants, current and potential future carbon tax prices ([26],[55]).

3.1. Natural Gas Imports

When moving on to natural gas imports, not only was it possible to find the amount of natural gas that enters the EU but also the sources of this gas [52]. This data, compiled the amount and origin of all imported natural gas into the EU from other partnering nations such as neighboring Norway and Russia to a few African and North/South American countries [45]. In 2018, most imports into the EU were from Russia followed closely by Norway. The issue with the countries in North and South America such as the United States, especially countries designated as 'other' in Table 3.1, is that there is no way to exactly pin-point their points of entry, while for the other countries listed in Table 3.1, the points of entry can be assumed with relative confidence thanks to existing natural gas pipelines connecting them with the main European continent.

Table 3.1 EU Natural Gas Origin Country Percentage Breakdown [52]

Exporting Country	**Percentage (As of 2017)**
Russia	38.7%
Norway	25.3%
Algeria	10.6%
Qatar	5.2%
Nigeria	2.5%
Libya	1.1%
Peru	0.9%
United States	0.4%
Trinidad and Tobago	0.3%
Others	15.0%

Europe, as a whole, is still heavily dependent on imported energy; roughly 55% of its energy needs are met with import ; for a few countries, import percentage is above 70% [52] . Even with the plans to go towards 100% renewable, it is too extreme to cast out primary energy sources as possible production of hydrogen gas. The two biggest exporters of natural gas into the European continent (Norway and Russia) were the focus of natural gas data for two reasons: the amount of imported gas dwarfs any other exporting country and the points of entry can be easily determined. For Norway, the reforming was done in the lower portion of the country (regions 79, 81, and 83) because these are the main areas where natural gas is extracted and shipped (through pipe or shipping vessels) to other points in the EU [56]. Since Russia was not modeled in this thesis, the nodes where the gas is imported into, are modeled as those in Norway (as if they had their own deposits of natural gas). While the percentage imports change year to year, when comparing the amounts of natural gas imported from previous years to the most current on record (2019), Russia and Norway are consistently on top with 2019 having Norway export more than Russia. To stay up to date with natural gas exporting trends, data from 2019 for both Norwegian petroleum Company Norsk Petroleum and Eurostat were used.

Gas imports are not stable between each year and especially between each month. This variation can be seen in Figure 3.1 which shows monthly natural gas exports into the EU from Russia (as reported by Eurostat [45]) and from Norway (as reported by Norsk Petroleum [57]) respectively. The monthly values would be divided into each importing region based on the existing pipeline connections; while for Norwegian natural gas, it was divided among the three main exporting nodes. While Norsk Petroleum exports both gas and liquid methane to Europe (in addition to other fossil fuels), only gas exports were accounted for since the reformers considered in this thesis do not have liquid storage and expansion to gas costs included in their economic parameters.

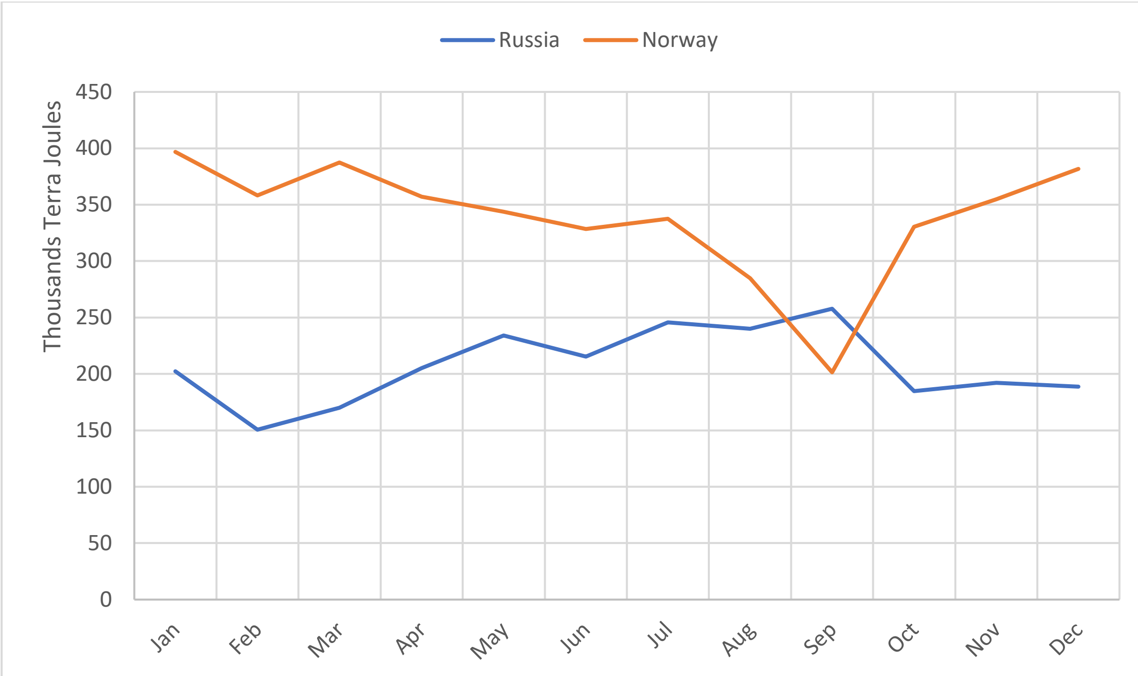


Figure 3.1 Russian Natural Gas Exports into EU 28 (TJ of natural gas) as of 2019

Looking at the figures for natural gas exports from both Russia and Norway, although the top contributors in the year 2019 (except for the month of September), the two imports seem to respond to each other; as Norwegian natural gas exports go down, Russian exports adjust slightly and contribute more. One common trend noticed in both is the decrease in around 1.5 billion kg of natural gas across the months of January and February. This can impact the production of hydrogen from methane reforming in the first quarter (or even the second half of the year) since Norwegian natural gas continues to go down.

The initial units reported by each source were different with Norsk Petroleum using standard oil equivalent (S.O.E) and Eurostat using 100 kg. To ensure that the energy contents of each exporter were in the same range, Norsk petroleum values were converted to kg using the gas density at standard conditions and 15 degrees Celsius (the values at which Norsk petroleum stated its measurements are in [58]). The conversion used a value from Air-Liquide's online Gas Encyclopedia which was 1.4173 kg/m^3 [59].

The conversion efficiency used for steam methane reforming was taken from Robinius et al. [60]. This value was 85% and meant that for every GW of natural gas, the corresponding product would be 0.85 GW of hydrogen. The range of specific investment costs per GW of reformer installed capacity is 810 M€/GW to 1620 M€/GW, which encompasses small to large scale reformers, also taken from Robinius et al [60].

The cost of natural gas, 0.0256 [€/kWh], was approximated for the whole year according to estimates done by Robinius et al. [60]. Techno-economic parameters used for source technology in the source/sink modeling class are reproduced in appendix table A.1.7. As mentioned earlier, 95% of the carbon emission from the reforming process were captured with the remainder being charged with a range of carbon tax price points that are currently found in the EU. This range included more stringent taxes (up to 200 € per [t_{CO2}]).

3.2. Carbon Capture Costs

Capturing emissions from a network with natural gas reformers, is a necessary step when comparing it to one that is renewable. While the reference case did have biomass CHP plants, their size was small compared to other technologies, and their emissions were not considered since it is carbon neutral. There are carbon capture systems for power generation plants, such as those developed for a natural gas-based cycle which features complete CO_2 capture ([54], [24]), but the exact specification of those systems are not public. While there are a few pilot and industry scale plants using this cycle (named Allam cycle), their exact configuration and full integration with steam methane reformers can potentially lead to the capture of all steam methane reforming emissions ([25], [27], [29]). For this thesis, a value of 95% was picked since the plants with 100% CO_2 capture, while proven in research, are currently being built and plants with capture efficiencies around 90% are already in operation; a middle ground between 90 and 100 was therefore a safe assumption value to use ([61], [29]).

Carbon tax prices in Europe, range from 9 to 131 US$/t$CO_2$ emitted (with most being in the lower part of the mentioned range) [55]. This range is certainly not fixed in time and countries are always adjusting this value to curb emission. To account for this range and additional growth of the maximum tax, a range from 0 to 200 €/tCO_2 emitted is used in this thesis to account for potential growth of the tax in the years leading up to 2050 (year used for demand predictions). Only 1 country in Europe has a carbon tax as high as 131 US$/t$CO_2$ emitted and it is Sweden. A value of 200 US$/t$CO_2$ will certainly capture the future growth of this country's tax which is expected to grow around the world; but even with lower carbon taxes, some countries like the United States and China have been able to flatten or even reduce their greenhouse gas emissions [62]. It is also noted that draconian carbon taxes like those in Sweden will not be seen everywhere in the world and will have modest to small impact in the future than expected, as discussed by economist Robert P. Murphy from the Institute of Energy Research which commented on the International Monetary Fund's analysis on GDP growth compared to decreases in emissions and carbon taxes [63].

As for the carbon transportation and storage values, the minimum value of 20 €/tCO_2 was picked with a maximum of 100 €/tCO_2. The Global Institute for Carbon Capture and Storage, highlighted in its recent study that Europe has an estimated 300 Gt of CO_2 storage capacity with the North Sea having an additional 200 Gt [28]. Where to store emissions from processes like steam methane reforming is not an issue of where but rather an issue of cost. In addition to this, the Global Carbon Capture and Storage Institute, has stressed that hydrogen methods using CCS and steam methane reformers, can cut costs of producing 1-kilogram hydrogen fuel down by a third when compared to electrolysis processes [28]. Today's costs for CCS fall within a wide range whose extremes come from processes such as ammonia plants 25$ per tCO_2 to 120$ per tCO_2 when capturing from an industry standard natural gas plant ([26], [61]).

The CO_2 that does end up being emitted to the atmosphere needs to be compared with current emissions of the European continent. Using data from the European Commission's EDGAR center [64], current databases such as the CO_2RE data base from the Global CCS Institute show the main European countries, emitting a total of 3.2 Gt of CO_2 for the year of 2019 [65]. The breakdown per country considered in this thesis can be seen in Table 3.2.

Table 3.2 Individual Country Emissions [64]

Individual European Country Emissions as of 2019					
Country	Emissions [Mt CO2 / a]	Country	Emissions [Mt CO2 / a]	Country	Emissions [Mt CO2 / a]
Albania	5.03	Latvia	8.04	Greece	72.15
Austria	72.24	Lithuania	15.31	Hungary	50.85
Belgium	104.22	Luxembourg	9.54	Italy	358.13
Bosnia and Herzegovina	N.A.	Montenegro	N.A.	Switzerland	39.74
Bulgaria	49.57	Netherlands	174.77	United Kingdom	379.15
Croatia	17.46	North Macedonia	8.89	Germany	796.52
Czech Republic	109.76	Norway	46.95	Sweden	50.87
Denmark	33.58	Poland	319.03	Total	3243.74
Estonia	17.9	Romania	81.13		
Finland	46.85	Serbia	N.A.		
France	338.21	Slovakia	37.85		

To include the natural gas import data into the energy model, certain conversions had to made for the data to fit. Since the natural gas was given at a monthly rate, it must be converted to GW available per hour. In addition to this, the capacity of each node (methane import) needed to be defined so that the percent capacity operation could be set. Once this was done, the method to analyze the reformers' sensitivity to a carbon tax range and a transmission and storage price range needed definition.

3.3. Data Preparation

Before combining the data of a renewable energy system from Caglayan with the natural gas import data set collected from Eurostat [45] and Norsk-Petroleum ([66],[57]), a few modifications to the natural gas data sets needed to be made in order to not only match with the hourly renewable systems data format but also with the required format of the model.

The yearly production data provided by Norsk-Petroleum was on a monthly basis with the most recent complete data from year 2019. On their website, Norsk-Petroleum mentioned that most of the natural gas it produced was exported to the EU [57], but there was a difference between what was produced and exported to the listed locations in the EU. The measurements were made in standard oil equivalent (S.O.E.); the amount of natural gas that was produced was 115.2 S.O.E. and was exported to 8 points in northern EU was 107.9 S.O.E. [57]: one in France, United Kingdom, Belgium and Denmark and 3 points in Germany. Liquified natural gas was not looked at since the technology needed to store and process it was not investigated in this thesis; in addition to this, the exact location where liquified natural gas was imported was not mentioned and due to this uncertainty, was not included.

To have the monthly gas export to the 7 locations mentioned above, the difference between yearly production and export to EU in 2019 was evenly subtracted from Norsk Petroleum's production data [66]; the final values are represented in Table 3.3 (the adjusted values are found in the corrected column). The values were then converted to cubic meters [59], further divided into hourly timesteps and converted to GJ/hr using Norsk-Petroleum's approximation for the lower heating values of methane at standard conditions [58]. Once the hourly production in each month was found, it was easier to determine the maximum operating capacities. The month with the maximum capacity was used as a point of 100% operation; dividing the rest of the months by that maximum value, gave the operation of each month relative to the maximum.

Table 3.3 Hourly Norwegian Natural Gas Export into EU

Month	S.O.E [1e6]	Corrected S.O.E [1e6]	Sm^3/month [1e9]	m^3/hour [1e7]	GJ/hour [1e5]
2019.01	11.1	10.5	10.5	1.42	5.33
2019.02	10.1	9.51	9.51	1.42	5.33
2019.03	10.9	10.3	10.3	1.38	5.21
2019.04	10.1	9.48	9.48	1.32	4.96
2019.05	9.7	9.13	9.13	1.23	4.62
2019.06	9.34	8.72	8.72	1.21	4.56
2019.07	9.58	8.97	8.97	1.21	4.54
2019.08	8.18	7.57	7.57	1.02	3.83
2019.09	5.96	5.35	5.35	.743	2.80
2019.10	9.39	8.77	8.77	1.18	4.44
2019.11	10.0	9.42	9.42	1.31	4.93
2019.12	10.8	10.1	10.1	1.36	5.13

The above natural gas is produced and exported mainly from three regions in Norway ([56]). Since the mapping and operation of natural gas pipes is not done in this thesis, the reforming of methane into hydrogen was done in those three regions ('79_no,' '81_no,' and '83_no'). The operation of each node relative to their maximum capacity is represented in Figure 3.2.

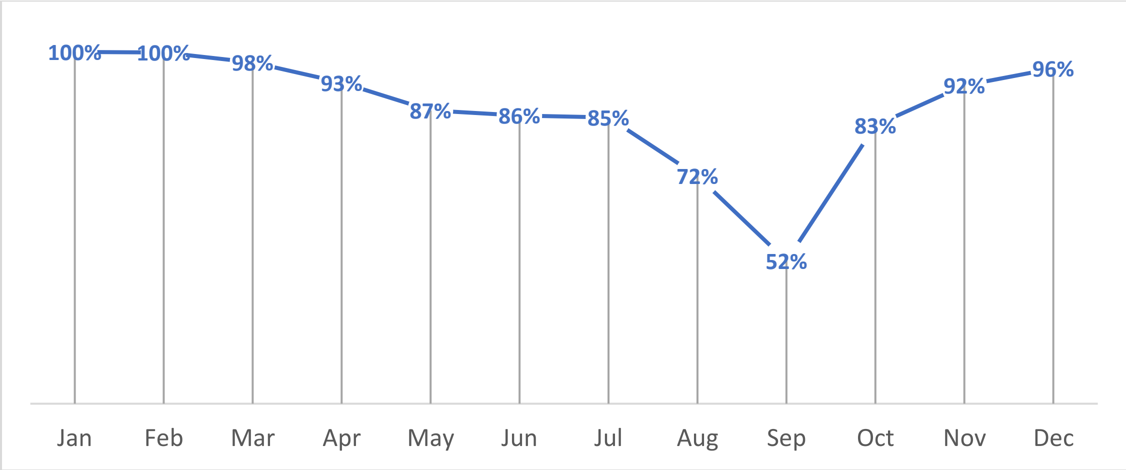


Figure 3.2 Norwegian Monthly Methane Reformer Capacity

While Russia is not modeled in this thesis, its natural gas pipeline connections into the EU are known and its hourly exports (monthly export data from Eurostat divided by hours in each month of 2019 [67]) were calculated and subdivided into 13 regions: '32_de,' '41_pl,' '42_pl,' '46_sk,' '58_hu,' '59_ro,' '61_ro,' '66_bg,' '68_gr,' '73_ee,' '75_fi,' '77_lt,' and '78_lv'. Each of these regions would have the opportunity to reform this methane into hydrogen [53]. The name of each region considered in this thesis and its hydrogen and electrical demands, can be found in appendix tables A.1.14 through A.1.17.

Table 3.4 Hourly Russian Natural Gas Imports into EU (2019)

Month	kg/month [1e9]	Sm^3/month [1e9]	GJ/hour [1e5]
Jan	3.65	5.37	2.72
Feb	2.72	4.00	2.24
March	3.07	4.52	2.29
April	3.70	5.45	2.85
May	4.22	6.22	3.15
June	3.89	5.72	2.99
July	4.44	6.53	3.30
August	4.33	6.38	3.23
September	4.65	6.85	3.58
October	3.33	4.90	2.48
November	3.47	5.10	2.67
December	3.41	5.01	2.54

The hourly capacity for the nodes importing Russian Natural gas were found with the same method as the nodes for the Norwegian natural gas. The maximum capacity (per region) values for Norwegian and Russian exports were 178 and 27.5 TJ/h, respectively. In Figure 3.3, the change in Russian importing node's hourly capacity for each month can be seen.

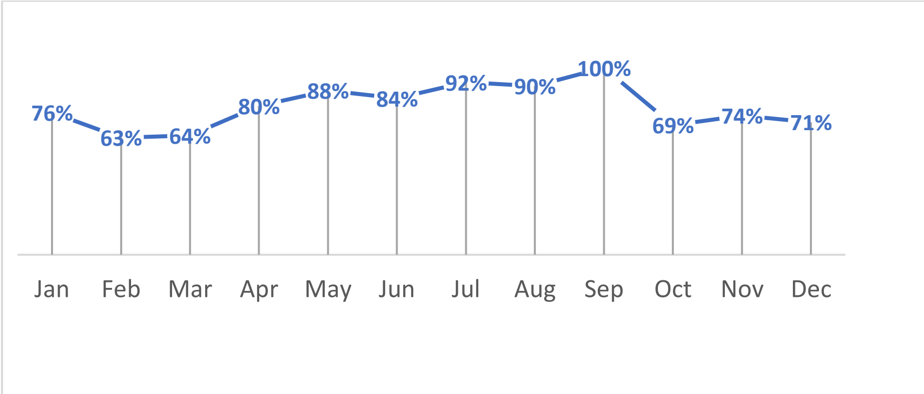


Figure 3.3 Russian Monthly Methane Reformer Capacity

3.4. Carbon Emission Impact

Unlike biomass conversion, steam methane reformers are not considered a renewable technology and thus its emissions cannot be omitted. One way to investigate the financial impact of this technology's emissions is through carbon capture and storage considerations. While carbon capture is not included in the model, its costs are incorporated after the optimal system results are calculated. The first reformer variable that was looked at in this thesis was a range of reformer prices from 810 M€ to 1620 M€ per GW of installed capacity. Eleven different price points are used from the reformer cost range; each individual price is a unique optimization model run. The specific costs that used were: 810, 891, 972, 1053, 1134, 1215, 1296, 1377, 1458, 1539, and 1620 M€/GW. This price range includes the cost for a large scale to small scale reformers with carbon capture and utilization. While it was obvious that with increased reformer specific cost, the system would choose the technology less and less, these costs do not consider the costs associated with all the emissions and the impact of the additional cost for carbon transportation and storage needs to be considered separately. Using the price range for carbon taxes and carbon transport and storage, a double sensitivity analysis was done to see the additional costs the system would experience if the CCS units with 95% capture efficiency would be less than or equal to the TAC of the reference case.

Once the emission of each reformer case is found, the cost of carbon transportation and storage is added to the overall TAC to offset the CO_2 emissions observed. These emissions are also compared to the emissions each nodes country has as recorded by the European Commission ([64], [65]). If the network costs were above the reference case TAC, the carbon tax and transmission/storage price is out of range for the case and the preference would be given to the renewable reference case.

Chapter 4. Results

In this chapter, the results of each reformer specific cost case are collected and compared to the reference case. The key results that are looked at are the cost differences and the capacity differences the overall network had with the inclusion of natural gas reforming. These results will answer the main questions of this thesis which asked about the changes each modeling class would see with natural gas reformer inclusion and the viability of these networks if there were additional costs from carbon capture and emission (non-captured CO_2).The results of each of the reformer case are compared to the reference network presented by Caglayan [17] which featured a renewable network with biomass CHP plants that acted as the foundation for the energy network in this thesis.

As described in the previous chapters, some assumptions needed to be made based on data availability. The first being the 11 specific costs of methane reformers; these values were between the 810 and 1620 M€/GW which covers the range of large to small scale reformer specific installation costs, respectively. Next, only specific nodes in the energy network presented in this thesis had the ability to reform natural gas (assumed to be mostly methane) because natural gas network repurposing or modeling was out of scope for the thesis. The natural gas used as the commodity source for the reformers was from two dominant exporters (Norway and Russia) due to the availability and trackability of the import locations of this gas. The remainder of the European imported gas was not included since its entry points were not clearly understood. Out of the total produced emission (from methane reforming), 95% was assumed to be captured since this value is in between from already existing and pilot plant values.

When breaking down the results in this chapter, the first few sections look at all the modeling classes found in the FINE framework and the technology composition within them. This is followed by a section that comments on the shift of hydrogen's role as a product of electricity to an additional source of electricity demand satisfaction through its re-electrification followed by the cost comparison between hydrogen and electricity production. At the end of the chapter, using matplotlib and excel visuals , the last research question of this thesis will be answered by comparing the emitted amounts of CO_2 to annual country wide emissions to the final system TAC with the additional costs of capture [68].

After running the optimization model on all the specific reformer cost cases, it was shown that the inclusion of steam methane reforming had visible changes on the overall system TAC and the installed capacity on a region and country basis for all technologies. In addition to this, the feasibility of these mixed networks for a certain range of carbon transportation/storage and emission taxes was proven with some cases having a TAC below the reference case.

4.1. Impact on Costs and Capacities

The first research question of this thesis asks if the inclusion of natural gas reformers (in selected few regions of the European system) has an impact on the source, conversion, storage, or transmission technologies. Looking at the result of the FINE framework's objective function of calculating the minimum cost system, is an important first step in seeing if any of the reformer cost cases help lower the system TAC and how much lower the value is compared to the reference case. Even a small change in the system TAC can have widespread effects across the whole continent. Therefore, the first section starts with this comparison and further elaborates by looking at each individual modeling class. The decrease in overall system TAC is shown in Figure 4.1.

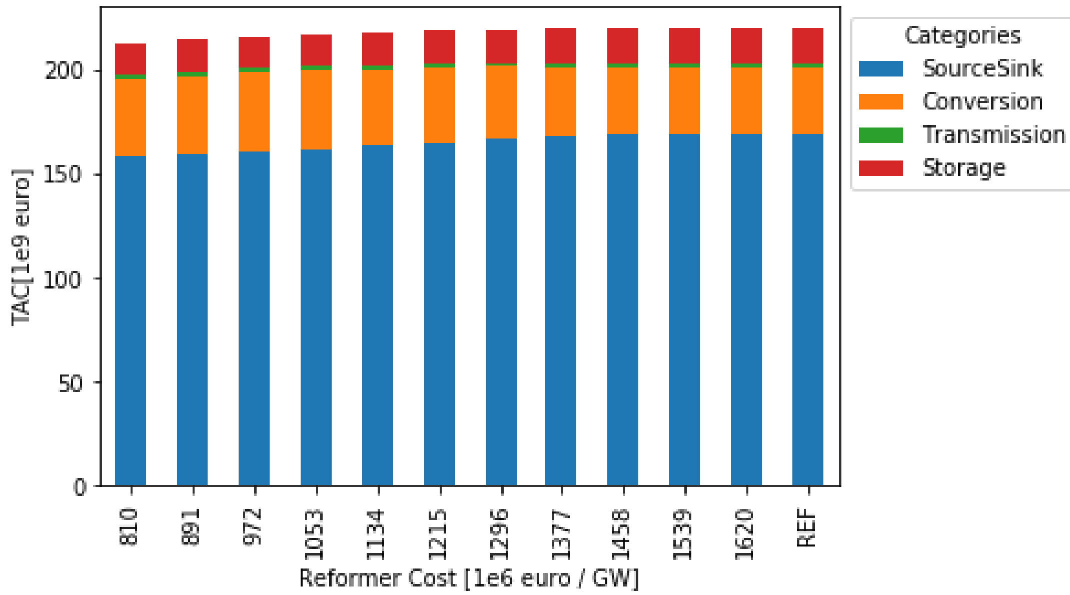


Figure 4.1 TAC Comparison Between Reformer Costs

One of the most noticeable changes in the energy system when adding steam methane reformers was the overall system TAC. As seen in Figure 4.1, as the reformer cost decreased, the overall system TAC decreased. In the lowest-cost case, the difference is around 7-billion-euros, corresponding to a 3.1% reduction when compared to the reference case. Even with the most expensive reformer case, there is a reduction of 171-million-euros. Exact values can be found in the appendix table A.1.18. While source technology saw a decrease in TAC for all-natural gas reforming cases, conversion saw a rise in both capacity and cost. This is an expected result since reformers were modeled as a conversion technology and only commodity purchase (natural gas) was modeled in the source class. An interesting result was the increase of storage and transmission TAC. Together, these changes pointed to an increase in hydrogen present in the system since electrical transmission lines had a fixed capacity while having a decrease in electrical storage (lithium-ion batteries) installed capacity and cost.

These results begin to answer the first research question, but a closer look into each modeling class is needed to understand what natural gas reformers displaced as the specific cost went down. The capacity of natural gas reformers was modeled as a conversion technology rather than a source technology therefore, its installed capacity is not reflected in the source modeling class. The source of this technology's commodity is the purchase of hourly fuel and this is reflected in the source modeling class TAC. Consequently, when looking at capacity differences for the source modeling class over all cases, the significant drop in capacity of around 300 GW (shown in A.2.2) does not tell the full story for the source technology. Instead, it makes it seem that conversion technologies replaced source technologies which is impossible since conversion technologies still need a source of commodity to run.

4.1.1. Source Technology

As mentioned earlier, the class with the most noticeable impact was source technology. Natural gas imports, while increasing the conversion modeling class TAC, in all cases, have a much larger impact on the source class than any other class. Unless specified, 3 cases will be used to show the changes that arise with various reformer costs, these being 810 M€/GW, 1215 M€/GW, and the reference case. Using these three cases will help see how the optimization framework changed the system composition going from a cheap reformer case to that with no natural gas reforming.

Looking at the layout of natural gas importing region's TAC, which shows the amount spent on natural gas imports (seen in Figure 4.2 and Figure 4.3) it is seen that certain regions are always the dominant importers of natural gas (a pattern seen in all cases). All regions, except for those in southern Norway, imported natural gas from Russia. While Norway can export more natural gas to the European continent, Russian natural gas has a bigger impact because of its large, shared border with Europe giving it more opportunities to enter the system as hydrogen, as well as the North Sea pipeline that sends natural gas to region 32 (northern Germany). After the case of 1215 M€/GW (cost per capacity of reformer) the amount of natural gas imports started sharply decreasing. The preference for certain regions over others (even though each region that imported from Russia had access to equal amounts of hourly imports), can be explained by their proximity to regions with larger demands. There were still regions that had spent over 1-billion-euros on natural gas (such as Hungary and Poland) whose pipelines connections went along the southern areas of Europe and connected to the higher capacity northern pipeline segments. This is discussed in more detail in section 4.1.5.

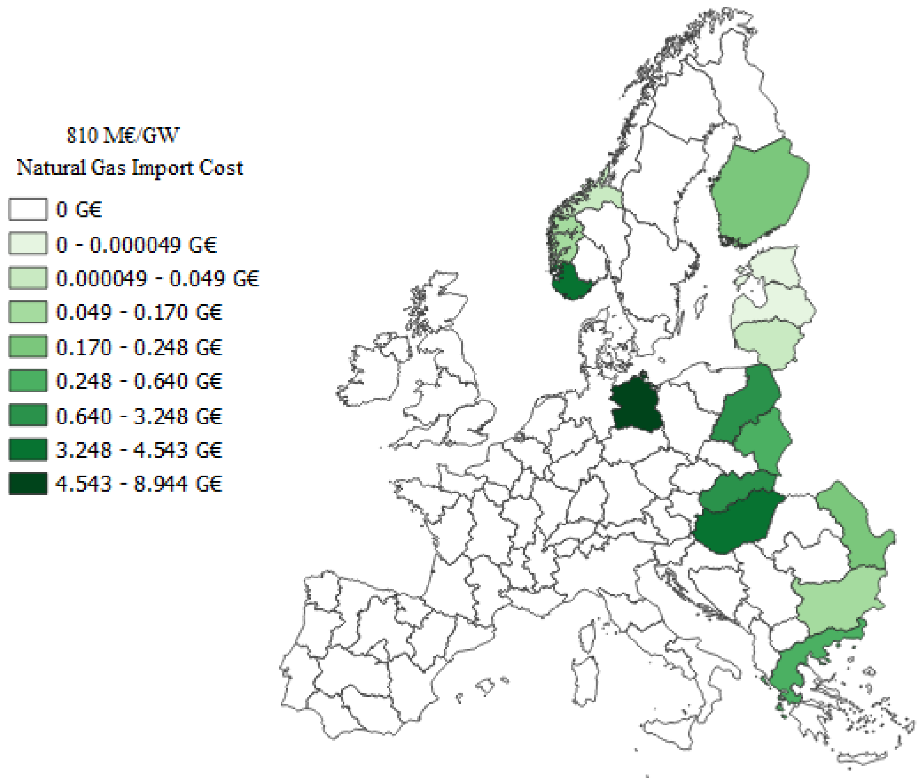


Figure 4.2 Natural Gas Importing Costs for 810 M€/GW Case

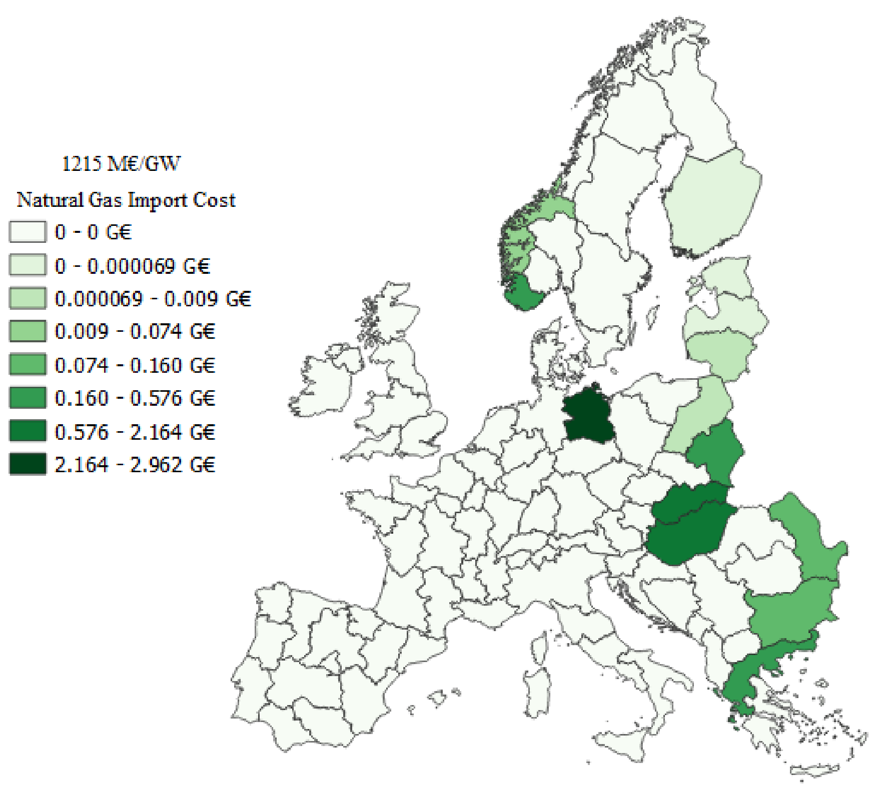


Figure 4.3 Natural Gas Importing Costs for 1215 M€/GW Case

Looking deeper into the source modeling class, with demands staying the same throughout all cases, it is understandable that reformers replace more costlier and more variable renewable sources such as wind and solar. As mentioned in Chapter 2 in the description of the base model, the hourly demands for the electricity and hydrogen commodity for each node are fixed forcing the solver to completely satisfy these demands while minimizing the objective function (overall system TAC). Looking at the overall network, the technology that is displaced the most by the inclusion of steam methane reformers is onshore wind turbines. With a TAC reduction of around 20-billion-euros, the model favored natural gas over onshore wind which in every case and the reference case was the biggest portion of source technology explained by that technologies' TAC reduction.

Looking at the per region TAC composition and total TAC change (from the selected three reformer cost cases) it is seen that in importing regions in countries such as Hungary, Slovakia, Poland, Germany, and Norway, the majority of source technology investment is spent on natural gas especially for the cheapest reformer case (Figure 4.5). This does not imply that natural gas will always replace most of the source technology spending (as seen in Greece and Bulgaria), but it will to a large extent, compete with onshore wind which in every case is preferred across almost all regions. Looking at the reference case region TAC compositions and comparing it to 1215 M€/GW reformer specific cost case affirms the hypothesis that each region's natural gas competes mostly with onshore wind as a result of the increase in onshore wind percentage in areas of natural gas import. This can be observed in Figure 4.4.

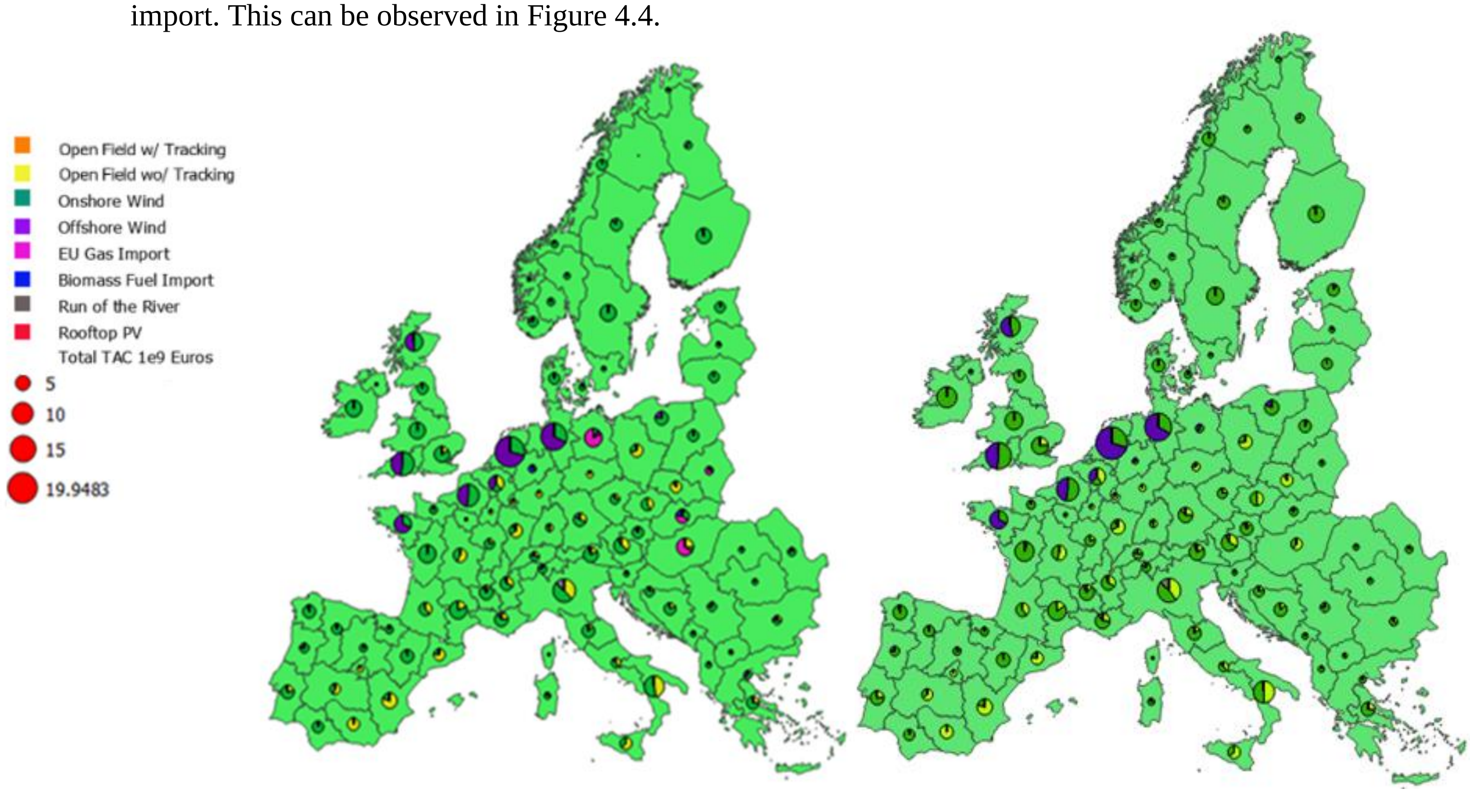


Figure 4.4 (Left) 1215 M€/GW Case per Source TAC Composition per Region; (Right) Reference Case Source TAC Composition

Looking at these same figures, it can also be noticed that offshore is slightly reduced, especially along the shores of Northern France, Germany, Netherlands, and southern UK, as natural gas imports increase. At the lowest costing reformer case, the areas with the highest TAC source technology contribution are usually the ones with natural gas imports as seen in Figure 4.5. Noting this, it can also be added that with increase access to natural gas imports, a region's source technology TAC will increase, while areas in proximity, including areas within some distance from import regions, can experience a reduction in source TAC. This reduction in areas without natural gas imports is one of the reasons the overall system TAC is reduced even with import region TAC increasing – compared to the reference case. Combining this with the overall system TAC (Figure 4.1) and the source modeling class TAC changes (Figure 4.6), shows that natural gas is in direct competition with wind energy even at higher specific cost cases.

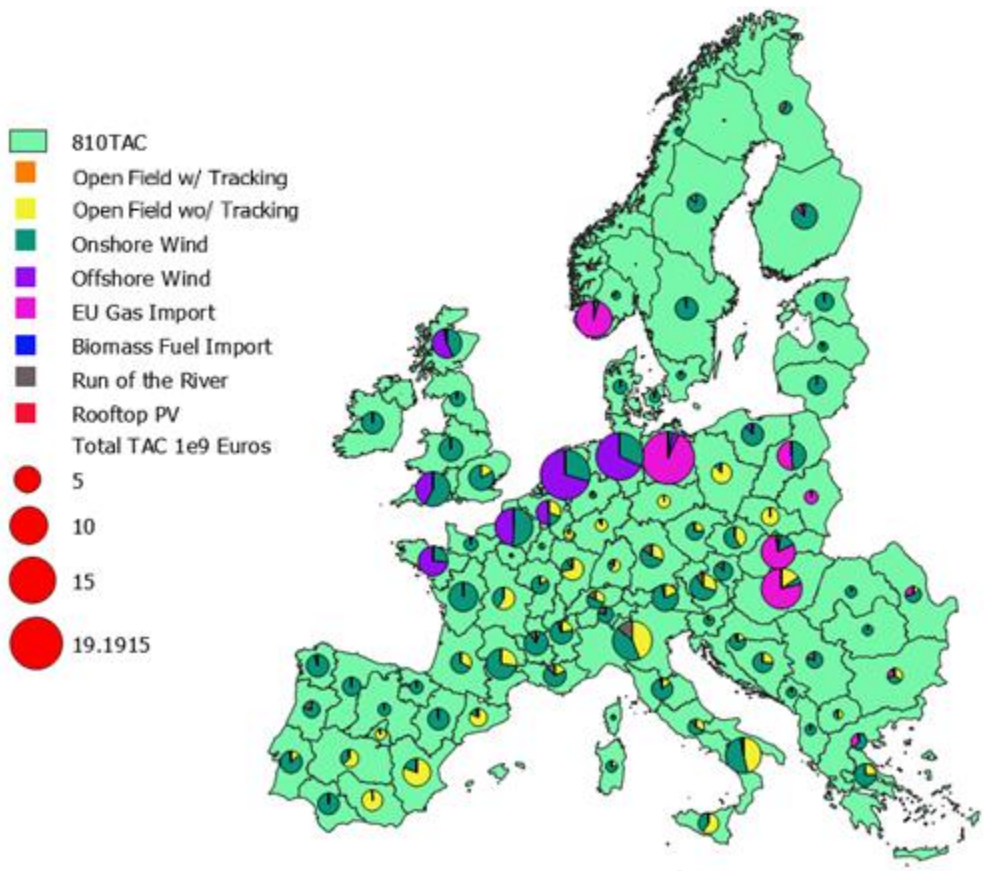


Figure 4.5 810 M€/GW Case TAC Composition and Amount Per Region

Going back to the overall system, a closer look at Figure 4.6 shows that the addition of methane reformers also reduced open-field PV without tracking which is denoted by PVfix while PVsat is with tracking. In this figure, it is easier to see how the overall system cost composition evolves with changing natural gas reformer specific costs. Apart from the already mentioned technologies, other technologies change as well but their quantity is so small that the role that they play in the overall system's commodity generation is miniscule. Biomass fuel (Biomass CHP) and run-of-the-river plants also have modest capacities in the MW range. Biomass CHP plant sudden and temporary increase in the mid-range cost cases is related to the gradual decrease of natural gas reforming and the replacement of this capacity with the major contributors (on- and off-shore wind and open field PV without tracking). This highlights an interesting point: considering all costs and efficiencies of fuel-based source technology, the optimizer - at least in countries with natural gas reformers, prefers to supply demand of the region with natural gas or biomass source technology before completely relying on other renewable technologies without considering additional costs associated with CO_2 emissions (as done in the reference case). This growth and decline behavior as the reformers' specific cost increase, can be seen in table A.1.19 in the appendix.

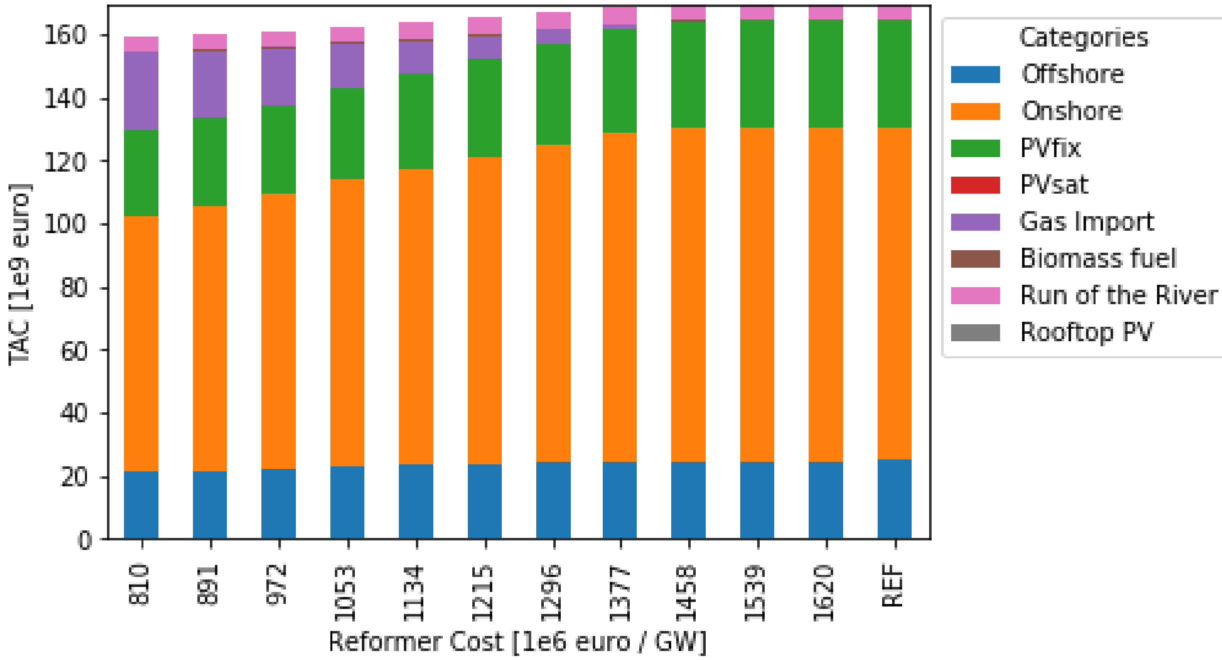


Figure 4.6 Source Technology TAC Breakdown Between Reformer Cases

Further investigation into the country-wide installed source technology capacity for every case revealed that the impact of steam methane reformers was felt much further than the import areas where imports were done in mostly eastern and northern parts of Europe. Countries like France and Spain had reductions in the order of tens of GW of both open field PV with and without tracking. Looking at Figure 4.7 and Figure 4.8, it is seen that the with countries whose capacity was most impacted by steam methane reformers (France, Spain, UK, Norway and Germany), most did not have any natural gas imports (as defined in the model) but still had their installed source technology capacities decreased. The gas shown in these figures represents the purchased gas, not the reformer capacity. Exact values for the figures Figure 4.7 and Figure 4.8 can be seen in the appendix in tables A.1.20 to A.1.23.

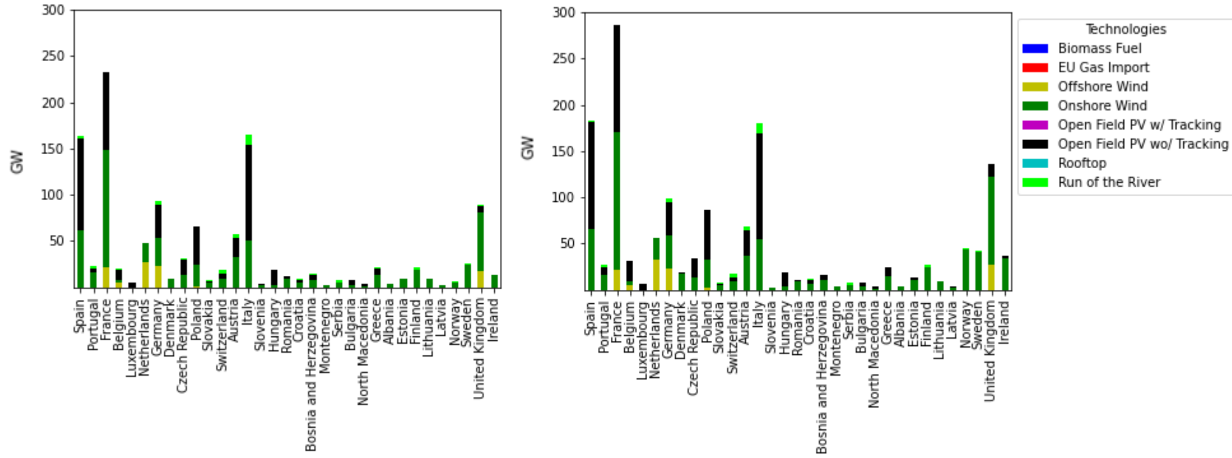


Figure 4.7 Source Technology Capacity for: 810 Case (left) and Reference Case (right).

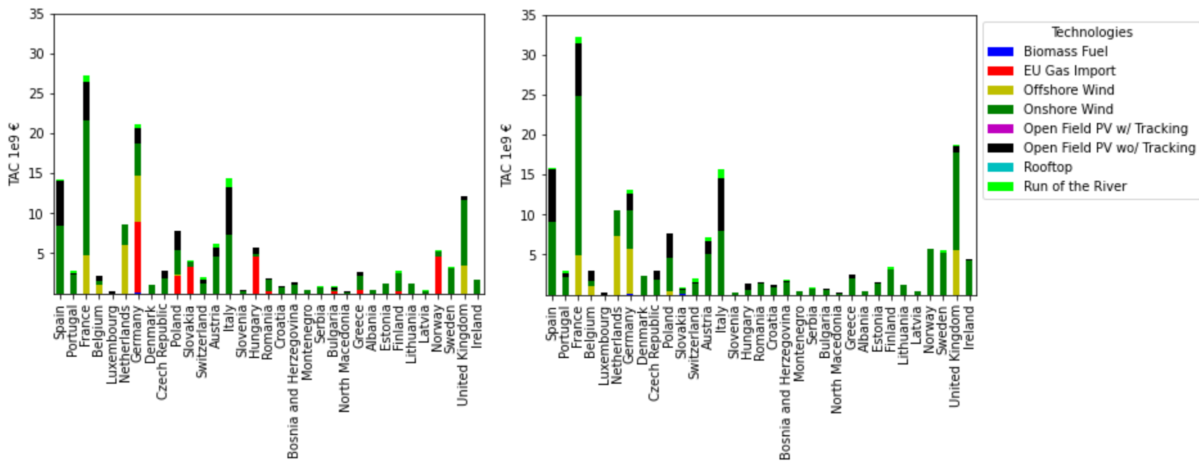


Figure 4.8 Source Technology TAC for: 810 Case (left) Reference Case (right).

4.1.2. Conversion Technology

Looking at the usual 3 specific cases (810 M€/GW, 1215 M€/GW, and reference case), the transformation of the energy system from one with relatively high methane reforming to one without can be further investigated in terms of conversion technology variations (Figure 4.9). The optimizer chooses the reformer in almost all countries where natural gas imports are possible. The capacity for just this technology dwarfed every other conversion method and was only followed by H_2 OCGT and CCGT, which can be explained by the higher production of hydrogen which will then be used for the satisfaction of both hydrogen and electricity demands. It is also important to point out that as the natural gas usage went down with increased specific costs of the reformers, the total capacity of conversion technology went down for the countries with methane reformers and up for those without them. This change with increasing reformer specific costs, suggests that steam methane reformers inclusion make the optimizer favor countries with natural gas than other countries that have a big source of other forms of hydrogen generation. This, combined with the changes seen in source technologies, continues to add understanding to methane reformer technology's role in the system: not only does methane reforming impact source technology capacities and its investment costs, but it also replaces electrolyzers across the EU with hydrogen consuming (electricity generating) technologies such as fuel cells and hydrogen gas turbine cycles.

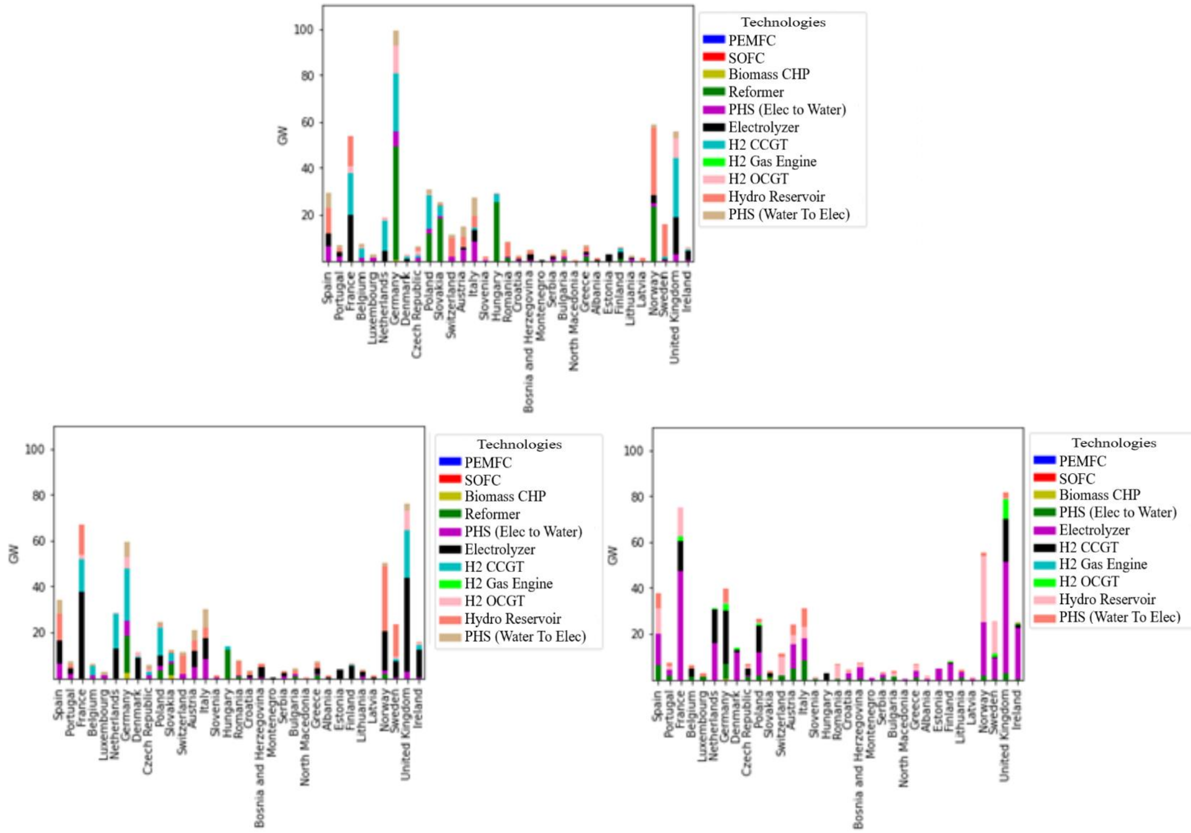


Figure 4.9 Conversion Technology Capacity by Country (top: 810 case ; bottom: 1215 (left) and Reference (right) case)

When looking at the installed capacity of conversion technologies and TAC (whose trends mimics capacity), it is seen that at lower reformer costs, apart from the increase in reformers and decrease of electrolyzers as the main source of hydrogen, there is a decrease in overall capacity. This can be explained by the already installed reformer capacity being sufficient along with some electrolyzer capacity to satisfy hydrogen demand and even some electrical demand of the whole system with re-electrification of hydrogen. The substitution of conversion technology with natural gas reformers, also suggests that regions with natural gas reforming have a greater impact on the overall system not only because this technology can produce enough hydrogen for the reforming regions and others, but also that this technology produces significantly cheaper hydrogen even with abundant renewable generation potential. The impact of reformer inclusion on electrolyzer capacity can be seen in Figure 4.10, with the lowest cost reformer case more than halving the reference case electrolyzer capacity.

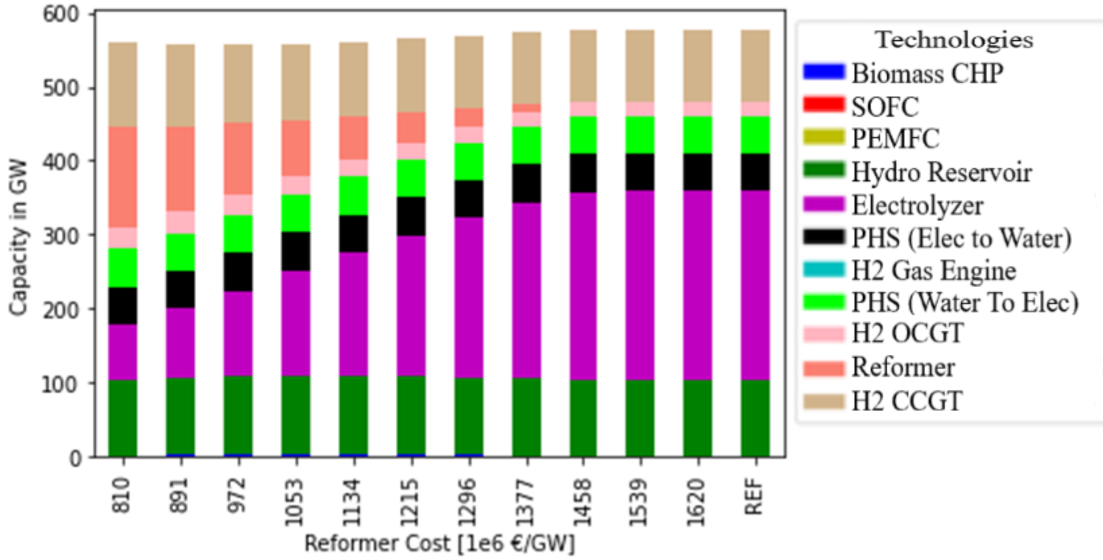


Figure 4.10 Conversion Technology Capacity per Reformer Cost Case

Looking at the overall TAC for conversion technologies (Figure 4.11), just like overall capacity case, where at lower costs there was an increase of capacity and at higher costs there was a decrease of capacity, at lower reformer cost cases, the system wide conversion technology TAC was higher. Higher capacity helped the conversion technology address demands of both close and far regions. In addition to this, the reformers also played a partial role as electrical commodity sources confirmed by the increase of the TAC of the OCGT and CCGT plants. Looking at Figure 4.11, the additional TAC that was added because of reformers was ~4-billion-euros for the 810 M€/GW case when compared to the reference case. This is less than the same case's source technology TAC reduction (~10-billion-euros cheaper than the reference case) as shown in Figure 4.6. The remaining ~6-billion-euro difference, which is part of the cheapest case's roughly 7-billion-euro reduction (as compared to the reference case) shows that having a fuel-based source rather than a weather dependent source can help a hydrogen network achieve lower costs.

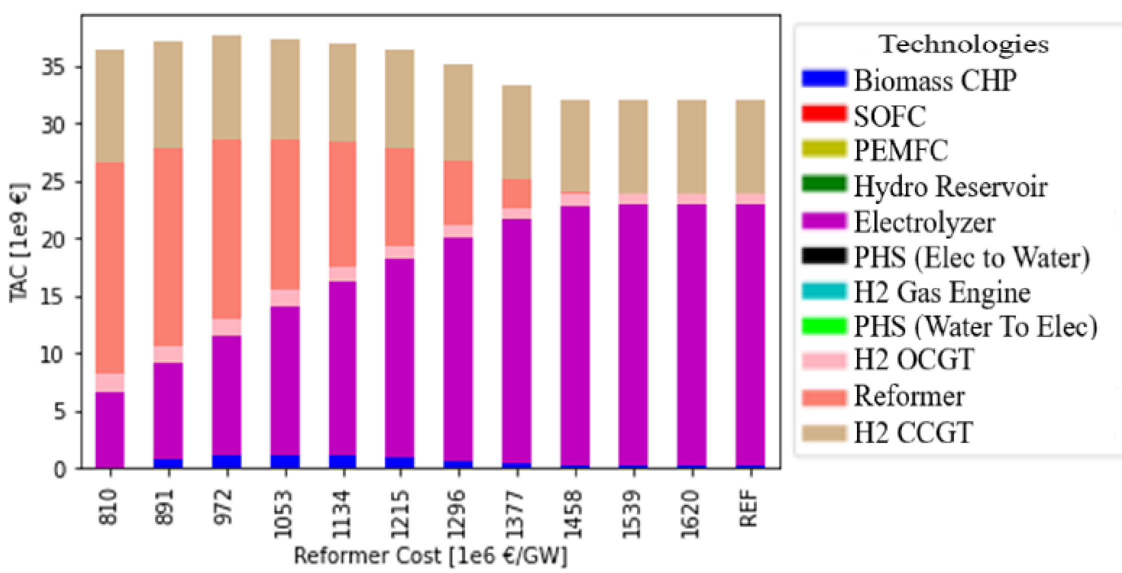


Figure 4.11 Conversion Technology Overall System TAC per Reformer Cost Case

As seen in Figure 4.6 and in Figure 4.11, the short-lived biomass CHP presence calls for further investigation into the conversion modeling class. While it is not visible in Figure 4.9, its presence in three specific countries (Germany, Slovakia, and for a bit Hungary - Figure 4.12) shows that there is a slight delay in source technology providing enough electricity and the optimizers preference to reformers even at higher costing cases. As the cost of reforming goes up, more renewable based source technology is installed up until the 1377 M€/GW (end of noticeable Biomass contribution) reformers exist in the system at a relevant capacity (Figure 4.13). The increase of hydrogen in the system, proven with higher reformer installed capacity and higher pipeline capacities found in section 4.1.5, and the increase in OCGT and CCGT plant capacity, shows that the hydrogen in the system becomes an important temporary storage for electricity.

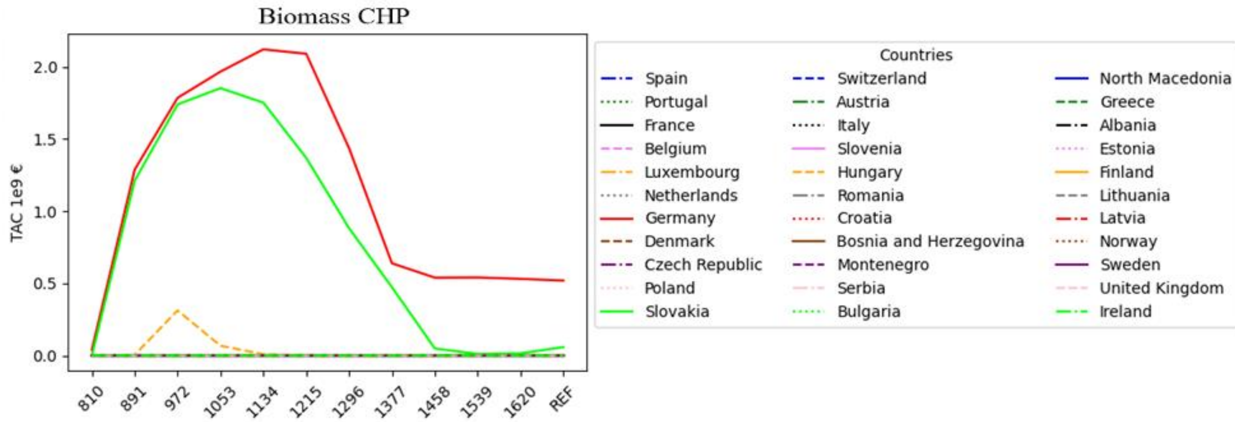


Figure 4.12 Country-Wide Biomass CHP TAC Installations per Case

After this, electrolyzers rule out the large usage of reformers and some biomass CHP to satisfy some of the hydrogen and electrical demands. In this thesis, just like in the reference study, biomass CHP plants are used to generate electricity. Electrified heat is included in the electrical demand. Just as the reformers addressed both demands during the lower cost reformer cases, electrolyzers started producing hydrogen for both at higher reformer cost case as seen in the top 4 expensive reformer cases having mostly electrolyzers and H2 CCGT/OCGT technology (Figure 4.11).

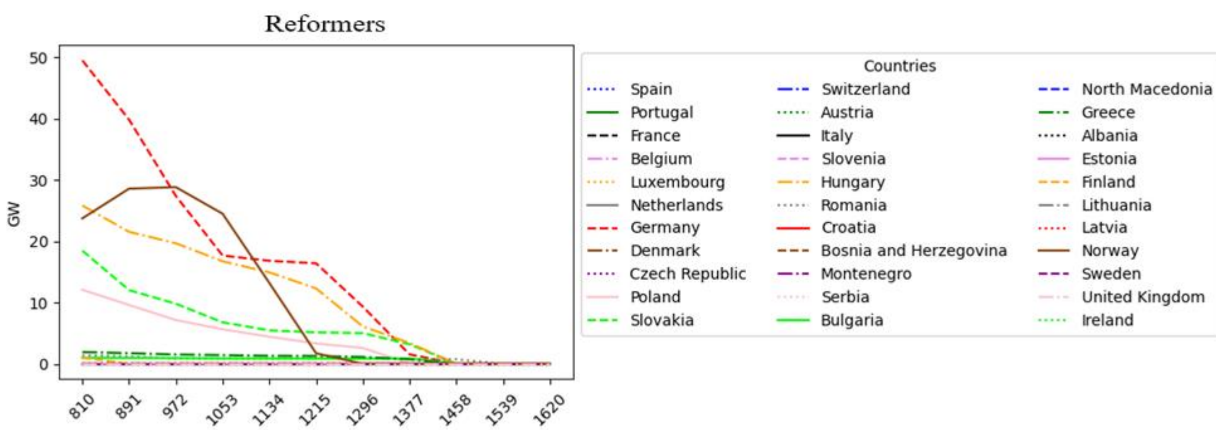


Figure 4.13 Country-Wide Reformer Installed Capacity For Each Reformer Case

As mentioned earlier, the bump of biomass CHP from 891 to 1377 M€/GW mostly comes from 3 regions found in three different countries. While the solver does not see the results of other cases (each case is an individual run), the German biomass plants are in an area that does not have natural gas reformers, the presence of biomass CHPs can be explained by this technology having a balancing role to reformers (up to a certain reformer installed capacity) until a certain cost threshold (1377 M€/GW) is met. After the 1458 M€/GW case, natural gas reformers are drastically reduced and while they are still present in very small amounts even in the most expensive case (1620 M€/GW), it is evident that they are not as cost effective as electrolyzers in satisfying the system's hydrogen needs as seen in Figure 4.13. The values for each case in Biomass CHP plants capacity can be seen in appendix figures A.2.16 to A.2.18. While this transition is happening, the optimizer selected is used to satisfy some regions electrical needs with biomass. This caused the noticeable increase in biomass CHP investment that eventually came to an equilibrium after 1458 M€/GW cost case (Figure 4.12). The biomass CHP plants in every other country follow the same trend as SOFC and PEMFC do (discussed later in this section); this can be seen in appendix figures A.2.12 and A.2.13.

Electrolyzers are not completely replaced in the cheapest reformer case, with France and the United Kingdom having around 20 GW, and still play a role in a mixed European energy system as seen in Figure 4.14. The large presence of electrolyzers in both France and the United Kingdom, even in the cheapest case of the reformers, can be linked to both countries having the biggest amount of wind energy available and thus having an opportunity to convert that electricity to hydrogen (Figure 4.7 and Figure 4.8). When looking at the 810 M€/GW case, just the top two countries with reformers, Germany and Hungary, dwarf the combined installed capacity of electrolyzers (Figure 4.13 and Figure 4.14). After the first case, reformers see a steady decline in installed capacity with Germany seeing a drastic drop between 810-1053 and 1215 and 1377 M€/GW cases. As seen in Figure 4.13, the reformers in the Netherlands (the country is represented by one region) start to increase their capacity as the rest go down but after the case of 972 M€/GW, experience a sharp drop due to the cost of reformers not being justified by the optimizer as the most minimal cost solution. It is also important to point out that effects from northern and eastern Europe reformers impacted electrolyzers as far west as Portugal.

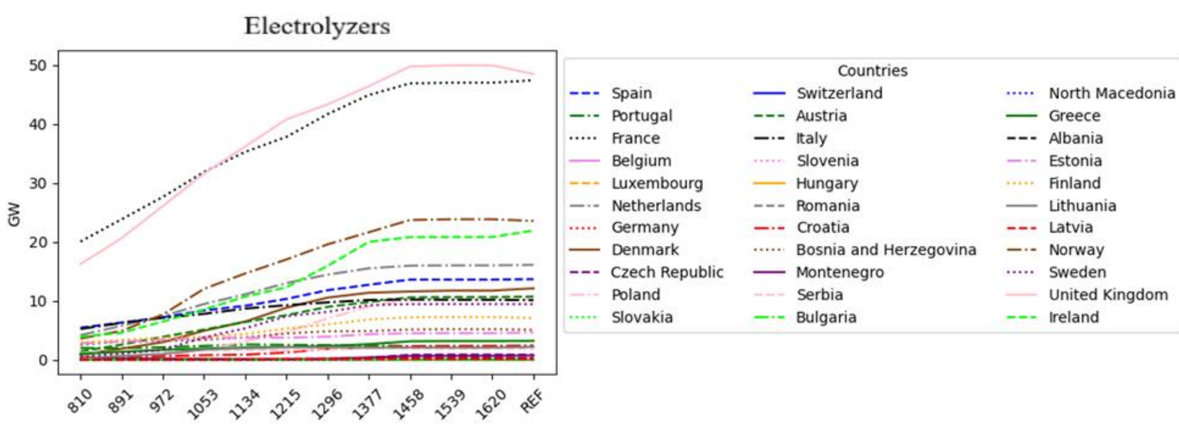


Figure 4.14 Country-Wide Electrolyzer Installed Capacity for Each Reformer Case

The two technologies that seemed to have no major preference between a system with mixed reformers and a renewable system were H_2 OCGT and CCGT. As shown in Figure 4.15, the OCGT plants in Germany did see a drastic drop while other countries with OCGT and CCGT plants saw minor changes in their installed capacities. This drastic drop in OCGT installed capacity, specifically in Germany, could be explained by the fact that in the reference case, Germany did not have such a large amount of natural gas reformers as it did in the 810 M€/GW case. As the extra hydrogen produced from reformer diminished, so did the less effective OCGT capacity (in preference to a more efficient CCGT cycle - Figure 4.16) proven by the higher TAC investment in the technology and in the installed capacity charts in the appendix figures A.2.14 and A.2.15. It is important to note that the trends of OCGT and CCGT capacities were the same as their TAC trends and therefore the same assumptions can be made by looking at one or the other. Countries surrounding northern Germany (where natural gas reforming occurred) such as Denmark and Netherlands, saw a brief increase in OCGT capacity as the Germany capacity decreased, since the hydrogen production from reformers was briefly present in large capacity until the 1215 M€/GW.

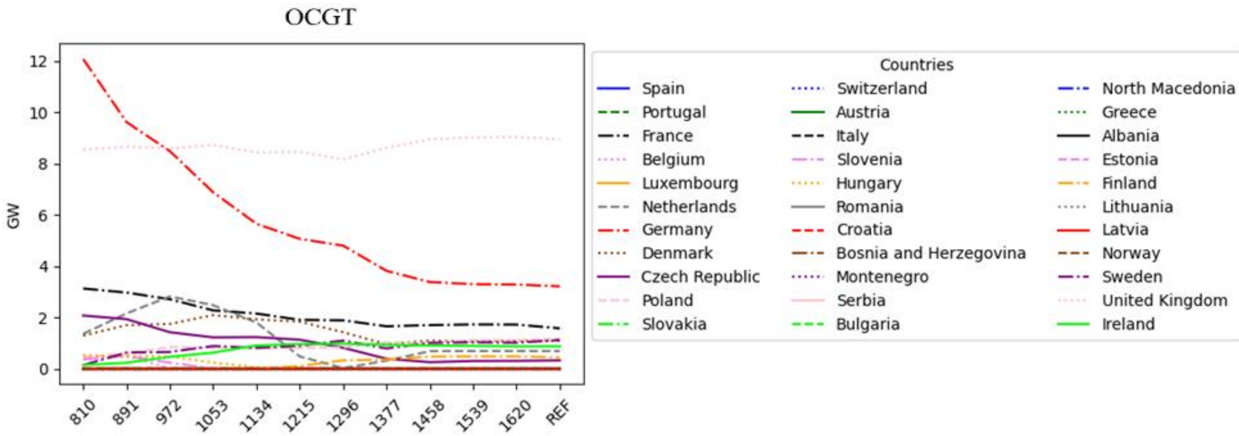


Figure 4.15 OCGT Installed Capacities in the Different Simulated Cases, by Country

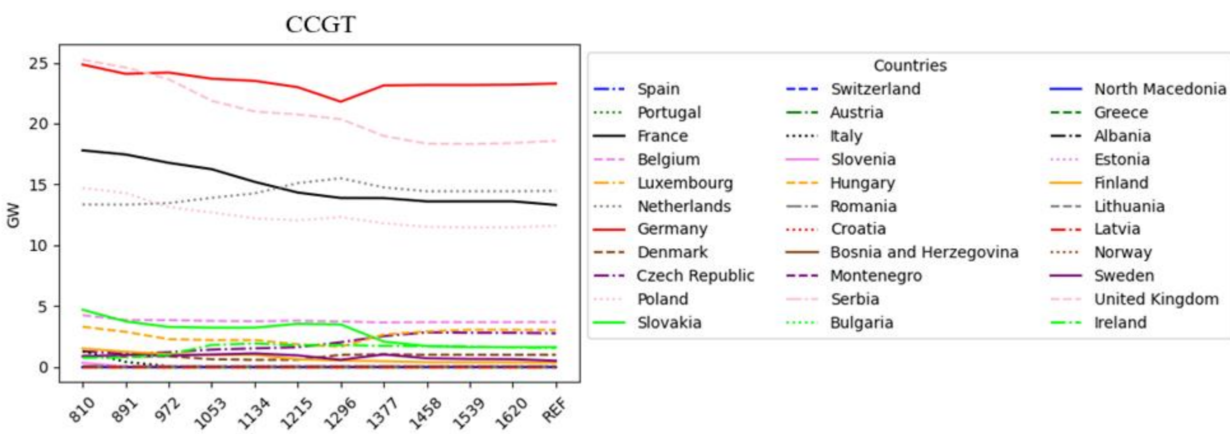


Figure 4.16 H_2 CCGT Country-Wide Capacities in the Different Simulated Cases, by Country

Technologies like SOFC, PEMFC, H_2 Gas Engines (internal combustion), while having very small capacities compared to other main conversion contributors, the zig-zag behavior (Figure 4.17) could be explained by the capacity values being within the tolerance of the solver. This leads to the conclusion that these technologies are insignificant to the system. TAC trends and capacity trends for SOFC, PEMFC, and H_2 Gas Engines were identical allowing the same assumptions to be made from looking at one or the other. While the evolution of each country's H_2 gas engine capacity seems chaotic (with some having near 0 capacity), a very small trend of diminishing capacity is seen. Since H_2 gas engines are very inefficient, their extremely small capacity (when compared to other conversion technologies) is not an unexpected result. In addition to this, the variation on a country scale in the order of a few kWs (if not Watts, for some countries) is insignificant and only serves as an extremely fine-tuning addition, hence the sporadic changes. Even with this, the diminishing capacity of natural gas reformers affects this technology. The other not shown conversion contributors (SOFC and PEMFC), had much lower capacities but the exact same trend as H_2 Gas engines. This is due to their high costs when compared to the main electrical generation from hydrogen) conversion technologies such as OCGT and CCGT, shown in the appendix figures A.2.14 and A.2.15.

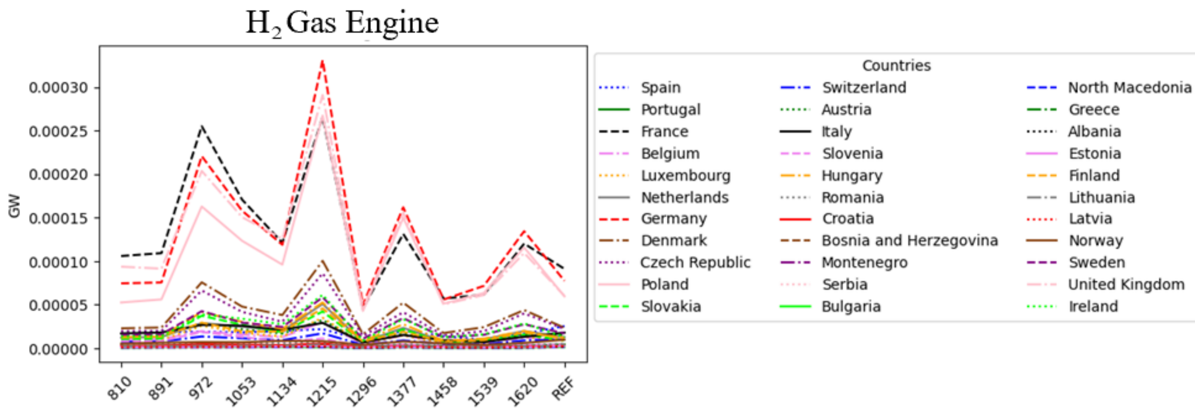


Figure 4.17 H2 Gas Engine Country-Wide Capacities

4.1.3. Hydrogen Storage Technology

With more hydrogen produced from the increased reformer presence in lower cost cases, the increase of large-scale hydrogen storage to accommodate this was an expected result. When looking at the 810 M€/GW case, keeping the capacities of each natural gas importing regions in mind (see appendix figure A.2.3), it is evident that when comparing the capacities of salt caverns in this case to the reference case (appendix figures A.2.4 and A.2.5, respectively) that there was a significant impact. Regions in Poland and Germany that had imports of Russian natural gas increased their capacity by thousands of GWh (Table 4.1). The UK also had a large increase but what caused this was the already large amount of wind source technology and electrolyzer capacity that the optimizer deemed necessary which held onto the hydrogen produced and stored in the UK. France also had an increase in many of its region's salt cavern used capacity. Just like the UK, France was a country that had a significant amount of onshore wind installed in the reference case along with electrolyzers whose hydrogen was replaced by reformer produced hydrogen in the cheapest reformer case.

Table 4.1 Salt Cavern Capacity Comparison [GWh][1]

Region	810 M€/GW	Reference	Region	810 M€/GW	Reference	Region	810 M€/GW	Reference
02 es	420	142	25 fr	2370	2280	44 pl	692	477
03 es	797	771	30 nl	12203	16065	45 pl	1434	1019
04 es	1557	192	31 de	4461	3975	59 ro	507	1365
05 es	424	170	32 de	11473	375	60 ro	574	237
06 es	1235	1292	33 de	11661	12602	63 ba	1100	1618
10 es	605	201	34 de	5036	1482	68 gr	485	420
11 es	1166	554	35 de	1009	632	70 al	142	67
12 pt	675	24	36 de	323	323	72 dk	3117	5341
13 pt	362	165	37 de	2086	2028	91 uk	8096	10699
16 fr	3653	1839	38 dk	1089	2926	92 uk	21932	8412
19 fr	1893	3502	41 pl	6282	5949	93 uk	3153	7593
20 fr	2604	1148	42 pl	2865	3921	95 uk	4203	4414
24 fr	9264	10120	43 pl	2996	4782			

While there were some regions whose salt cavern storage did slightly rise going from the low cost to reference case, overall salt cavern capacity went down by 13.83 TWh when comparing the reference case to the cheapest reformer specific cost case. This drop is directly related to the decrease of hydrogen production from reforming which was replaced with a costlier hydrogen that first needs to have electricity produced then converted with electrolyzers. The biggest decrease of salt cavern storage happened in Germany which was followed by a large drop in the OCGT installed capacity in Germany, Netherlands, and Denmark (Figure 4.15). With the increase of hydrogen converting technologies (specifically reformers) the increase in produced hydrogen in the system causes the additional capacity of salt caverns (Figure 4.18) that rule out investment in other smaller scale storage (for both electricity and hydrogen – appendix table A.1.24).

[1] For region location refer to Figure 2.2.

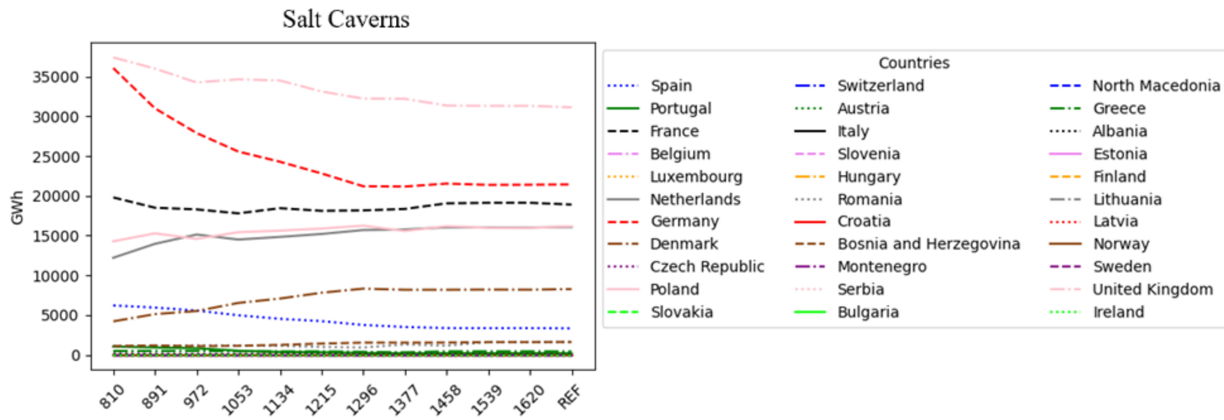


Figure 4.18 Country-Wide Salt Cavern Capacity

Out of the 16 regions that had natural gas imports, only 5 have salt caverns. The other regions with salt cavern capacities (including those as far west as Spain) also felt the impact of the diminishing reformer capacities. Countries such as the UK, France, and Spain, see a decrease in their salt cavern usage (capacity is based on geological availability) because the increase hydrogen availability, due to reformers, is no longer available. This happens even with these countries having large renewable capacities; most of their hydrogen is sent abroad and not stored for later use in the reference case as seen in the pipeline connections made in the cheapest reformer case verses the reference case (discussed in detail in section 4.1.5). The regions that did experience capacity growth for higher costing reformer cases were in countries like Denmark and Netherlands, which have a large amount of offshore wind turbines that are removed when cheaper reformers are installed. As natural gas reforming capacity diminished, the drop in salt cavern storage allowed for vessel storage to grow in importance (Figure 4.19) since more variable renewable source technology was added. While the total capacity of vessel storage is much lower than salt cavern, its growth can be explained by the increasing need to balance nodes further from salt caverns. Some of the large increases in vessel storage happen in countries with significant salt cavern storage (France, Spain, UK, and Germany) as shown in Figure 4.19. The overspill in UK's vessel storage above its 50 GWh equilibrium in the costlier cases, can be attributed to the still substantial presence of natural gas in Germany along with other eastern countries that still prevailed in the system until they dropped at the 1377 M€/GW case (seen in Figure 4.13). Similar growth in vessel storage was seen in countries like Finland and Italy which have no salt cavern storage and therefore rely on vessels to help store the hydrogen for later use. As natural gas becomes a more relevant source for hydrogen in the system combined with the cheaper large-scale hydrogen storage option like salt caverns (even when the storage location is in other countries), the optimizer required less vessel storage to ensure smooth supply of hydrogen gas to every region in both countries. Both Finland and Italy have reduced vessel capacities due to the large addition of reformer hydrogen given to those countries from reformers (Norway to Finland and Hungary to Italy). Also, there is an interwoven effect with electricity storage, which will be discussed in detail in the next section.

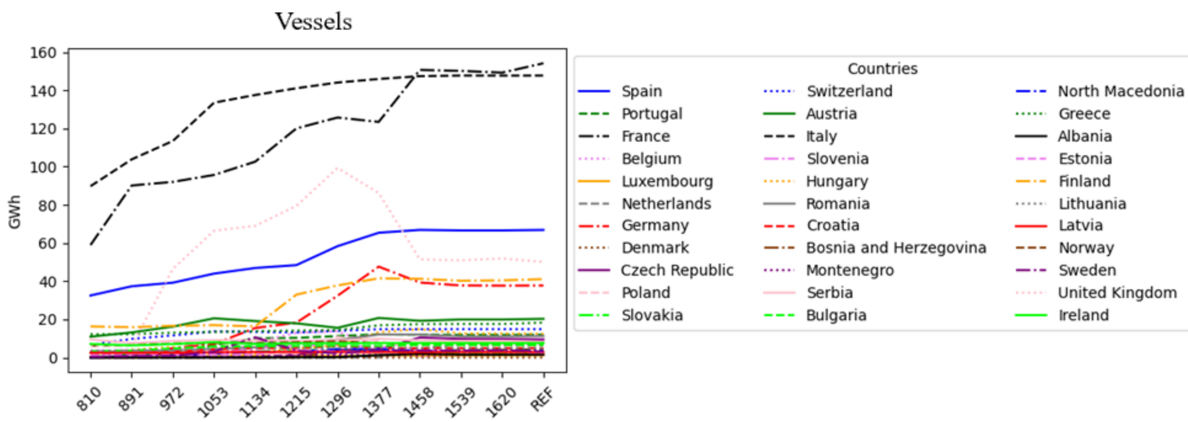


Figure 4.19 Country-Wide Hydrogen Vessel Capacity

4.1.4. Electrical Storage Technology

Hydro Reservoirs (hydro dams) and Pumped Hydro Storage capacities did not change between cases since their capacities are already installed. However, their operation was affected, as seen in their TAC in Figure 4.20 and Figure 4.21. Since these technologies' TACs were dependent on whether they converted their available water to electricity, an increase or decrease in their usage points to the country or the specific region having an imbalance because of diminishing or increasing reformer presence in the European system. The slight change seen in the pumped hydro storage TAC, in terms of the whole European system, is miniscule and can be considered relatively constant; this is especially true for when every case, 99.4% of the systems storage capacity was made up of just salt caverns and hydro reservoir technology found in appendix figure A.2.6.

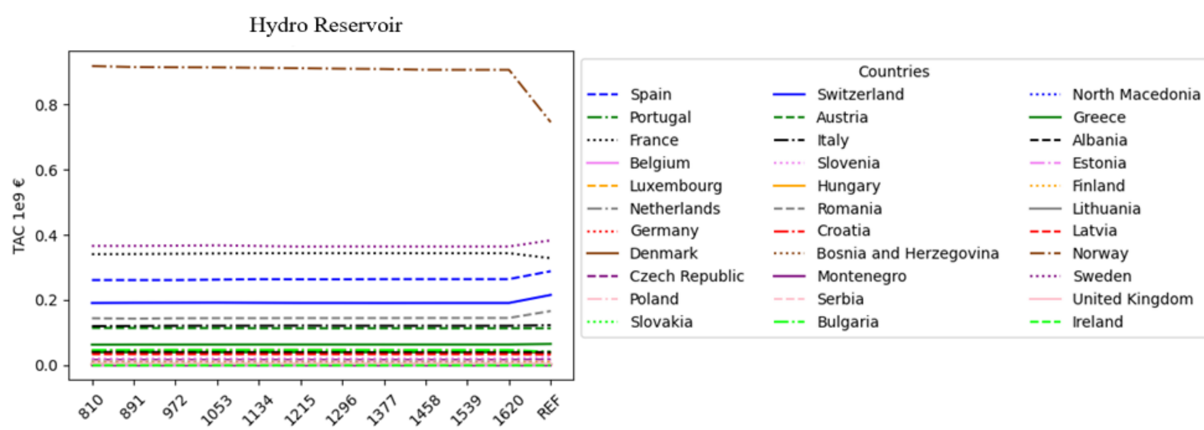


Figure 4.20 Hydro Reservoir Case by Case TAC Comparison

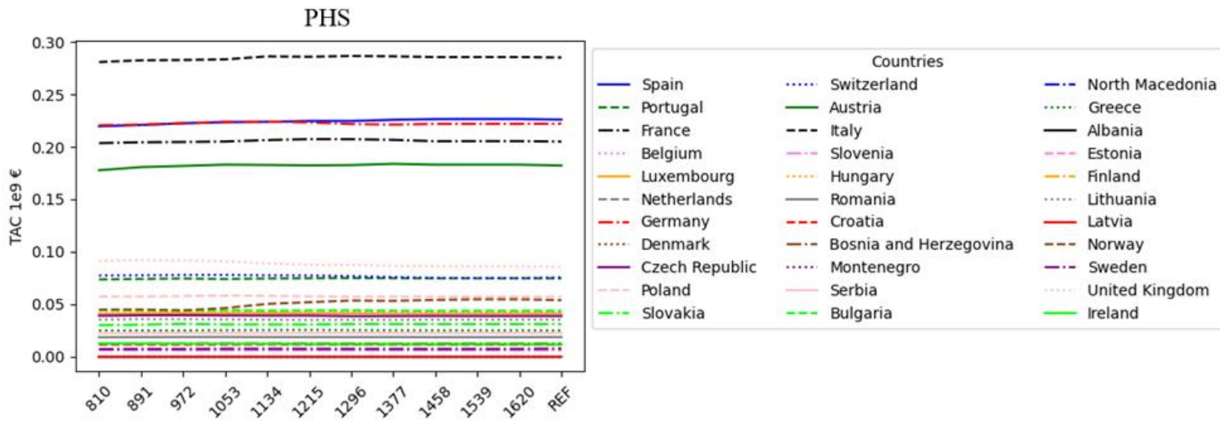


Figure 4.21 Pumped Hydro Storage Case by Case TAC Comparison

The sudden change in Hydro Reservoir TAC, when going from the most expensive reformer case to the reference case, shows how even a little presence of natural gas in the system can shift its operation. There is some natural gas present even at the most expensive reformer specific cost case, despite the capacity being 434 KW compared to 134 GW at the cheapest reformer cost case - the small presence of reformers still affects reservoir operation. The sudden change only happens after the last amount of natural gas leaves every importing region. This can be explained by the last remaining natural gas derived hydrogen being used as a substitute for the electrical energy generated by the hydro reservoir and pumped hydro technology that would later be converted to hydrogen and other technologies. Pump hydro storage, while located almost everywhere in the energy system, has most of its capacity in the north of the Europe (Figure 4.23), while salt caverns which have been shown in Figure 4.18 to have increased in usage with more reformer presence are located closer to higher demand region and reformer locations. Pumped hydro storage along with reservoir storage is better used to satisfy electrical demands of Europe, therefore since the solver used some hydrogen to address electrical demand through re-electrification, a slight change in pumped hydro storage and reservoir usage is seen (Figure 4.20 and Figure 4.21). This led to both pumped hydro and reservoir storage - most of which was in Norway and Sweden - to slightly change their operation since the solver preferred to use the hydrogen from salt caverns to address both hydrogen and some electrical needs explained by the increase used salt cavern capacity.

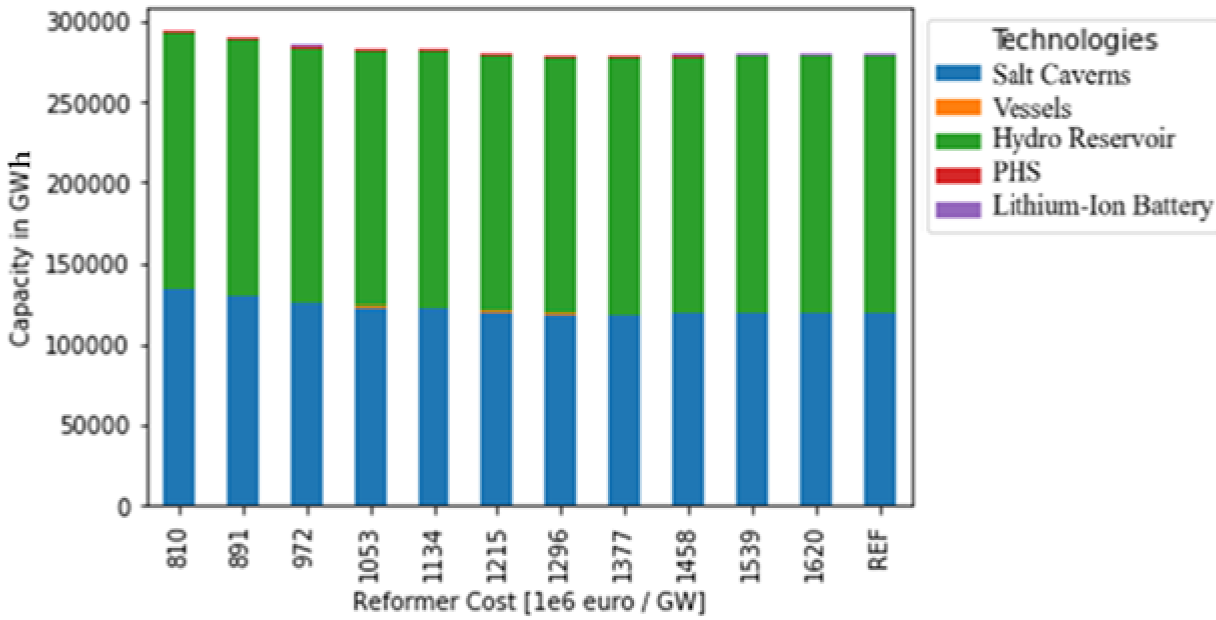


Figure 4.22 Overall Storage Composition Per Case

Looking at Figure 4.22 and Figure 4.23, it is seen how salt cavern usage went down as reformer installed capacity decreased with higher specific costs. The proximity of reformers to the two highest storage technologies for the energy system (reservoirs and salt caverns) also explain how increase hydrogen generation from reforming impacts them. The presence for smaller scale storage technologies such as lithium-ion batteries and vessels while always present, is very miniscule and therefore is barely visible in Figure 4.22. Exact values for each storage technology across all cases can be seen in the appendix A.1.25.

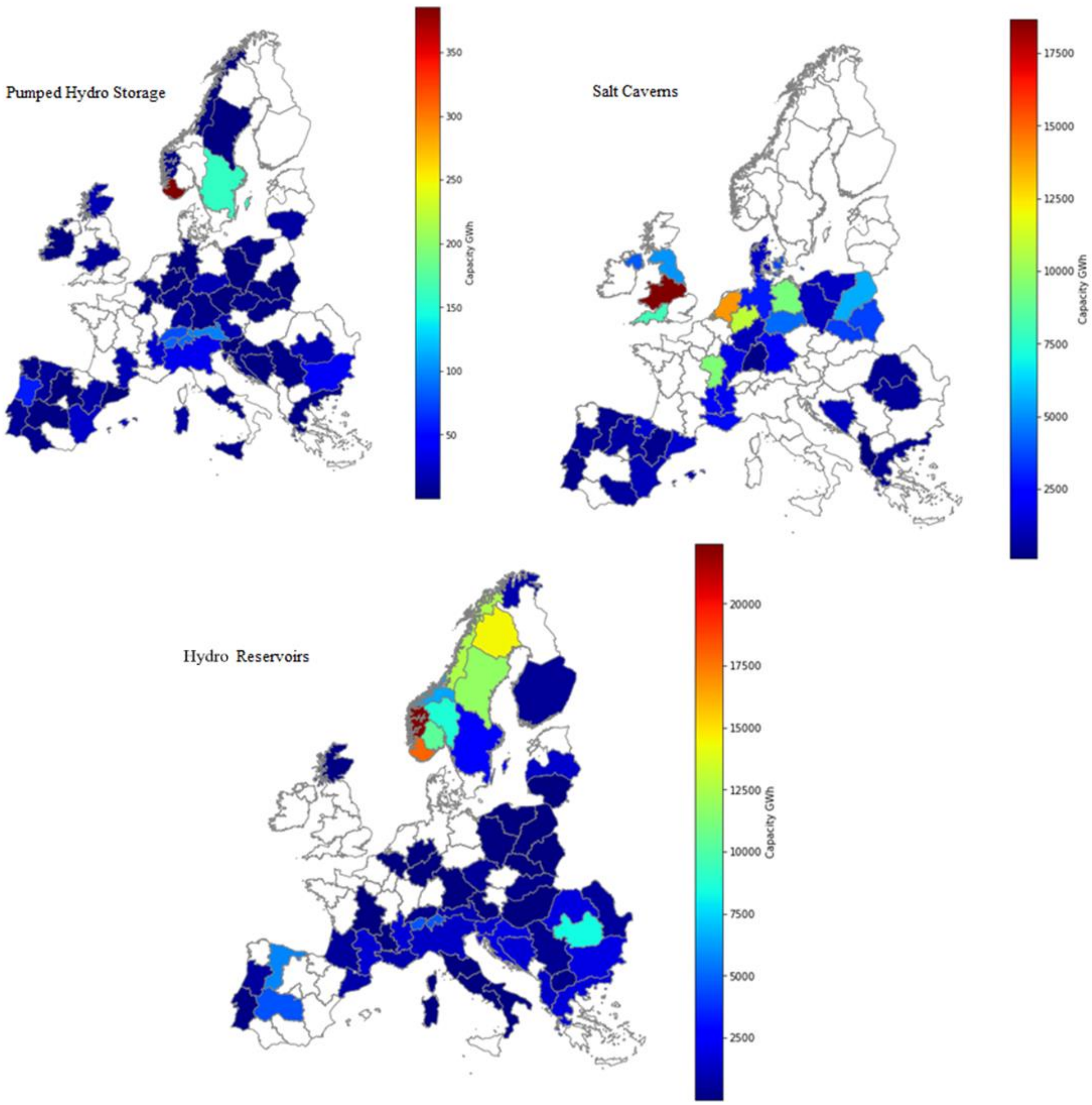


Figure 4.23 Individual Region Storage Capacity

With the increased presence of natural gas reformers in the European energy system, as mentioned earlier, the installed capacity of vessels and lithium-ion batteries went down, as shown in the storage class TAC variation per case (Figure 4.24). Batteries played an important role in regions with high amount of wind/solar source technology installations. For the cheaper reformer cases, the solver determined that the most optimal networks had increased salt cavern and reservoir storage; the former for hydrogen re-electrification and the latter for water storage which would be later converted to electricity both technologies reduced the costlier lithium-ion battery technology installed capacity. Figure 4.9 shows how, in addtion to the source technolgies from the previously mentioned countries going down, electrolyzer capacity, especially in the UK and France, dropped drastically as natural gas usage increased. The drop in these two classes are directly linked to the changes in both lithium battery and vessel storage.

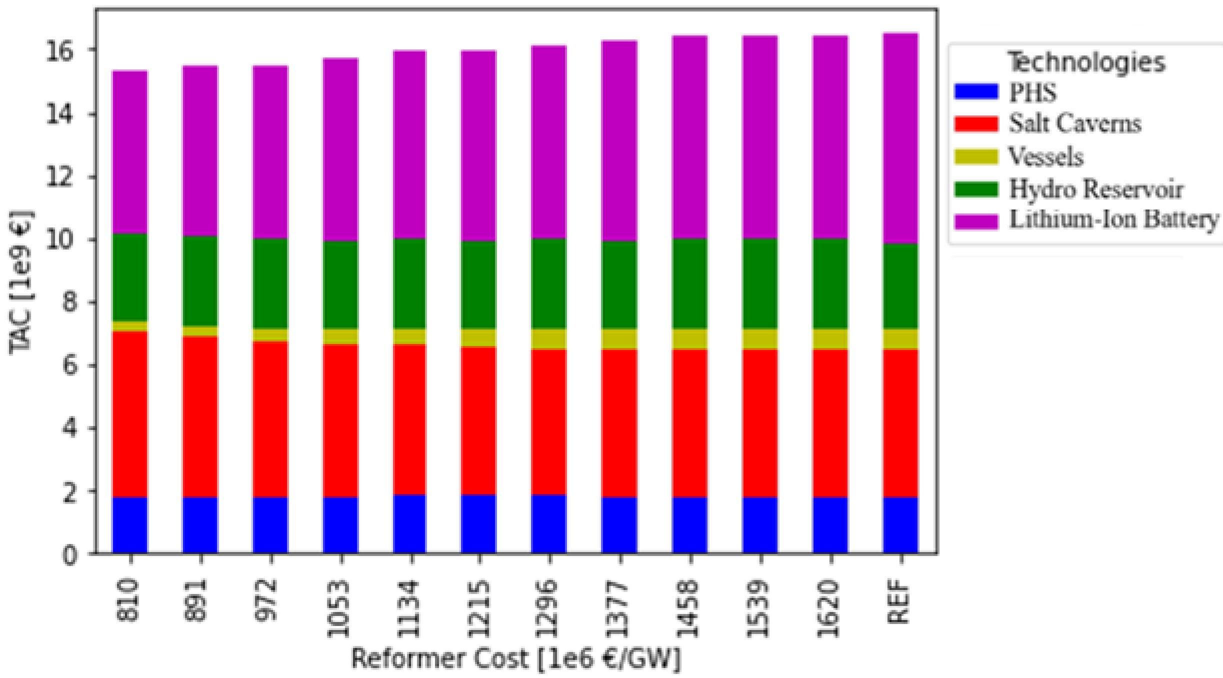


Figure 4.24 Storage Modeling Class TAC Case by Case Comparison

For both lithium-ion battery and vessel storage, the biggest changes happen in four countries: the UK, Spain, France, and Italy. These countries, while not having natural gas reforming, saw a drop in their lithium-ion storage because of higher hydrogen presence in the system which was later converted to electricity using OCGT and CCGT plants (seen in Figure 4.25). The reduction in electrolyzers for the cheaper reformer case, was another change that contributed to the reduction of lithium-ion battery storage. There were 32 fewer GWs of electrolyzers in the cheapest reformer case than in the reference case. The biggest reason for reduced lithium-ion storage was the decrease in on-shore wind turbines, which are the biggest renewable electrical commodity source. With fewer electrical source technologies installed, a drop in lithium-ion storage, especially in countries with large on-shore reductions (shown in Figure 4.7) is expected. Countries like Italy and Spain naturally have more favorable conditions for solar generation and while Italy saw a decrease in lithium-ion storage capacity, Spain saw an increase. Spain's increase can be explained in the same way as UK's salt cavern increase: even in the cheapest reformer case, the country had large amount of installed renewable capacity that was more cost effective to store generated commodity (electricity) for later use instead of transmitting it. While these four countries had changes in different technologies, the primary commodity they generate (electricity) was replaced with cheap reformer-derived hydrogen which would later be converted to electricity.

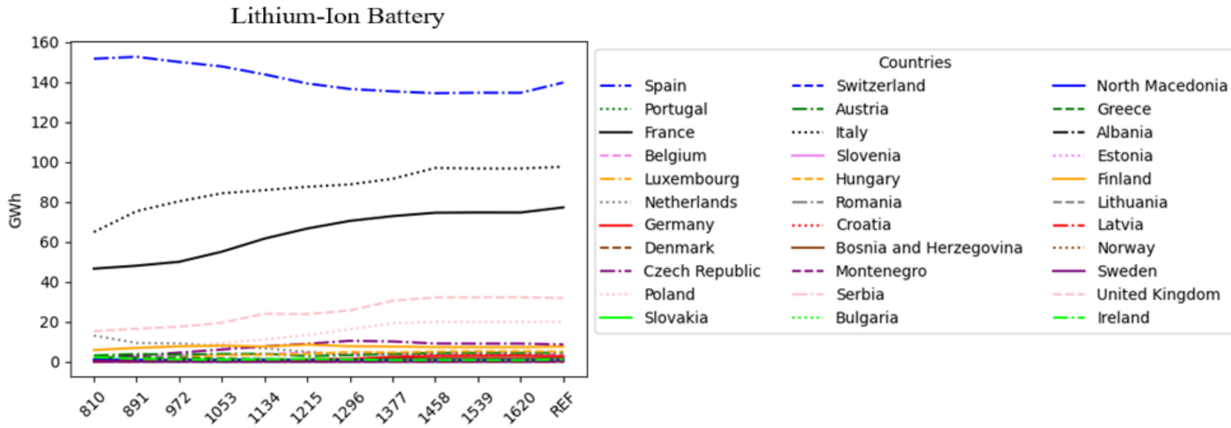


Figure 4.25 Lithium-Ion Battery Capacity Case by Case Comparison

4.1.5. Transmission of Commodities

From the previous sections, the effects of natural gas inclusion on three of the four modeling classes have been shown to be widespread and cost-diminishing. One class that has seen a cost increase, however, was the transmission class which involves the exchange of electricity and hydrogen (A.1.18). The electrical lines (their connection and capacity), as mentioned earlier in this report, have been kept constant throughout all the cases (shown in Figure 4.26). Instead, the hydrogen pipeline connections, of which there were 190 possible ones, were left up to the optimizer to satisfy demands across the whole continent while maintaining the overall TAC of all modeling classes minimal.

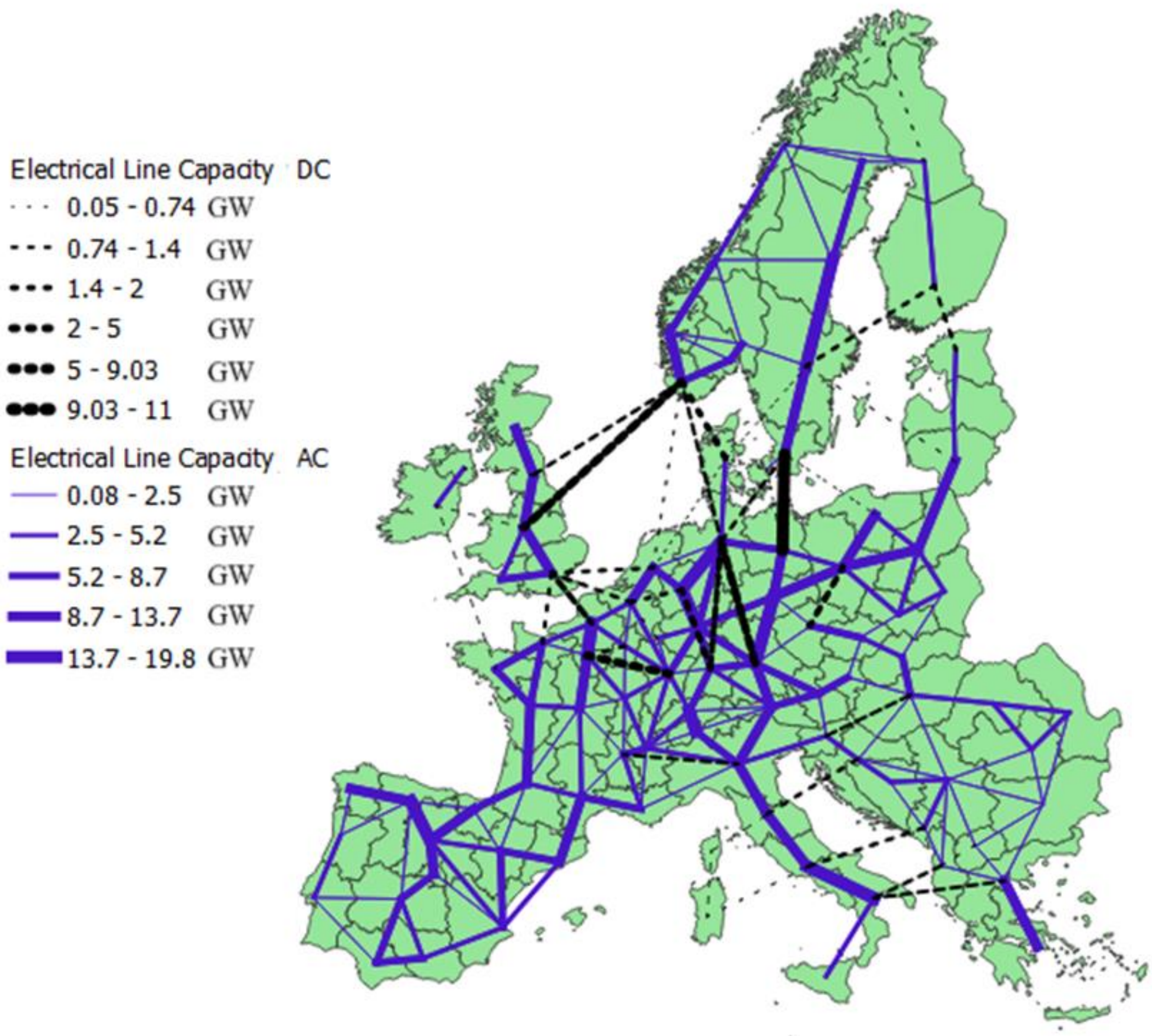


Figure 4.26 Electrical Line Layout (lines' width are proportional to capacity)

The increase in TAC of transmission technology is explained by the changes in the hydrogen pipeline network. The optimizer did not have any other methods of transmitting hydrogen other than pipelines and, as a result, some lines had capacities under 1 GW. While such small capacities are better served with other means of transmission, the pipeline method was still maintained to have comparable results with the reference case, which also only used pipeline transport. While demand is always a big incentive or transmission capacities, since it remains the same for all cases, the changes in the network can be attributed to the inclusion of reformer technology.

In Figure 4.27, we see that the hydrogen pipeline network, especially high-capacity lines, were connected to regions of high reformer and electrolyzer installations. Comparing this to the layout of the reference case (appendix figure A.2.19), it can be concluded that the presence of natural gas reformers not only satisfies the demand of the region they are in but also the demand of other regions. This is shown by the creation of larger capacity pipelines in Figure 4.27 as compared to A.2.19.

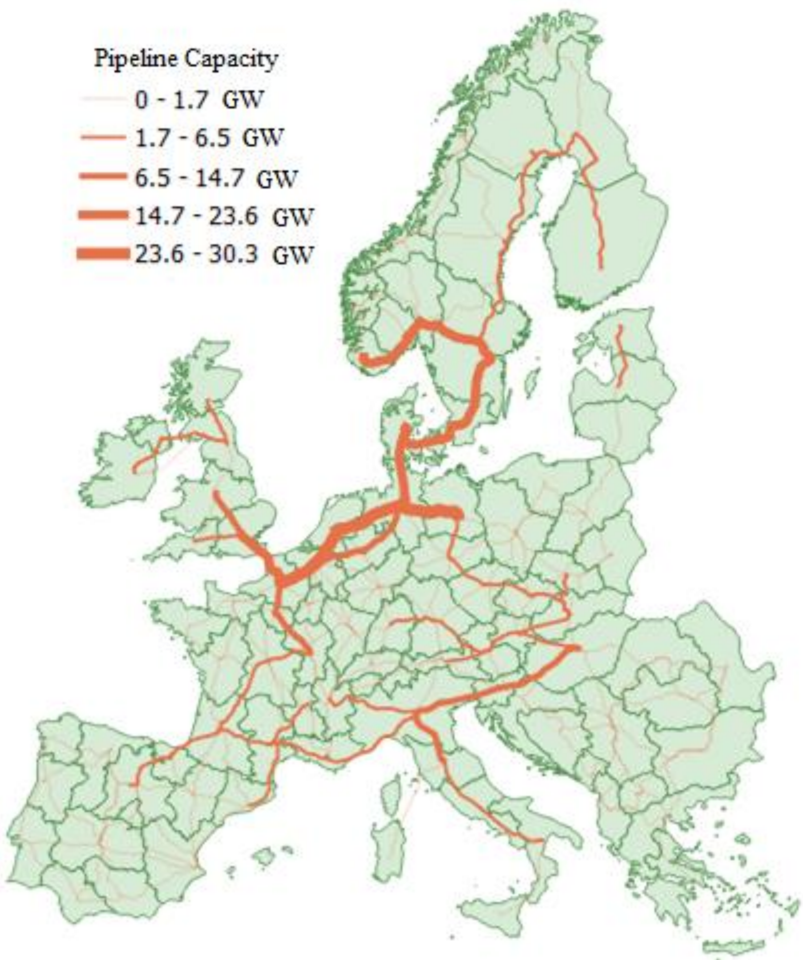


Figure 4.27 H_2 Pipeline for the 810 M€/GW Case

In addition to larger pipeline capacities, when adding the cheapest reformers to the system, the contribution from the UK, while still as big as it was in the reference case (for UK's southern regions) is still diminished as the pipelines in the north of the country are shrunk by the optimizer. The cut of large capacity pipelines in the middle of the UK, also explains the increase in salt cavern capacity shown in section 4.1.3. With a smaller pipeline connecting northern and southern region of the UK, salt caverns needed to store more hydrogen to be able to address future demand and account for renewable energy variability. Connection to Scandinavia is still present, but with Norway being added as a large contributor instead of just Sweden (reference case connections shown later in Figure 4.28). The very significant increase of pipeline capacity in the northern border of France, Belgium, Netherlands, and Germany, just like the increase in Norwegian lines, can be attributed to the presence of large capacity reformers in Germany, Netherlands, and Norway. Another area of increased pipeline capacity comes from Slovakia and Hungary, who have connections to the northern corridor and to Northern Italy, all of which were not present in the reference case. Poland, for which half of the cases had the smallest reformer capacity among the major reforming countries (shown in Figure 4.9), causes a shrinkage in pipeline capacity to its northern border while Hungary reduces the size of pipeline coming from western Romania where its salt caverns are located. Other countries like Greece, Bulgaria, Estonia, Latvia, Lithuania, and Romania all had some natural gas imports but not significant enough to affect international pipeline connections.

The additional large-scale pipelines connected to Northern Italy (region 52) allowed for more hydrogen to be sent to Italy; this can be said since the country did not have reformers and little installed electrolyzers in any of its regions, so the hydrogen used in this country was mostly imported. The increase of cheaper hydrogen to the country with high-capacity pipelines reduced the need for hydrogen storage such as vessels.

While the technologies that were replaced by reformers grew as reformer cost went up, the H_2 pipeline layout shifted to a more linear design with some detached routes. Four cases summarize the different layouts the optimizer selected as the system went from one extreme to the next. These four cases are: 810 M€/GW, 1215 M€/GW, 1377 M€/GW, and the reference case. As seen earlier, the first case had a looped layout that connected almost all the reforming regions and had significant capacity increase near the northern shores of Germany/Netherlands and the northern border of Italy while at the same time, there were decreased capacities in most UK regions as shown in Figure 4.27. The next point of comparison was case 1215 M€/GW. For this case, the layout and contributions from Hungary, Slovakia and Germany were still present but caused fragmentation of the hydrogen transmission network. The segment that connected Italy was mostly fed by Hungary, while Scandinavian countries and the UK fed western Europe and northern regions of continental Europe. All but 2 regions in Germany were connected to region 32 (Germany natural gas importing node) and this network was isolated from the rest, even though there are small connections of < 0.9 GW everywhere.

At the 1539 M€/GW case, the continental pipeline layout was very similar to the reference case, except for northern Italy which has 3 significant pipeline paths connected to its most northern region. Separated paths existed from northern Poland to Estonia, western Romania to Austria, and from Bosnia Herzegovina to Slovenia. In the reference case and the cases leading up to it, there was the increase of many connections, signifying the export of hydrogen from the country's large reserves of electrolyzers powered by significant wind electricity generation. A simplified figure of the pipeline's evolution when moving from cheapest reformer to the reference case is shown in Figure 4.28.

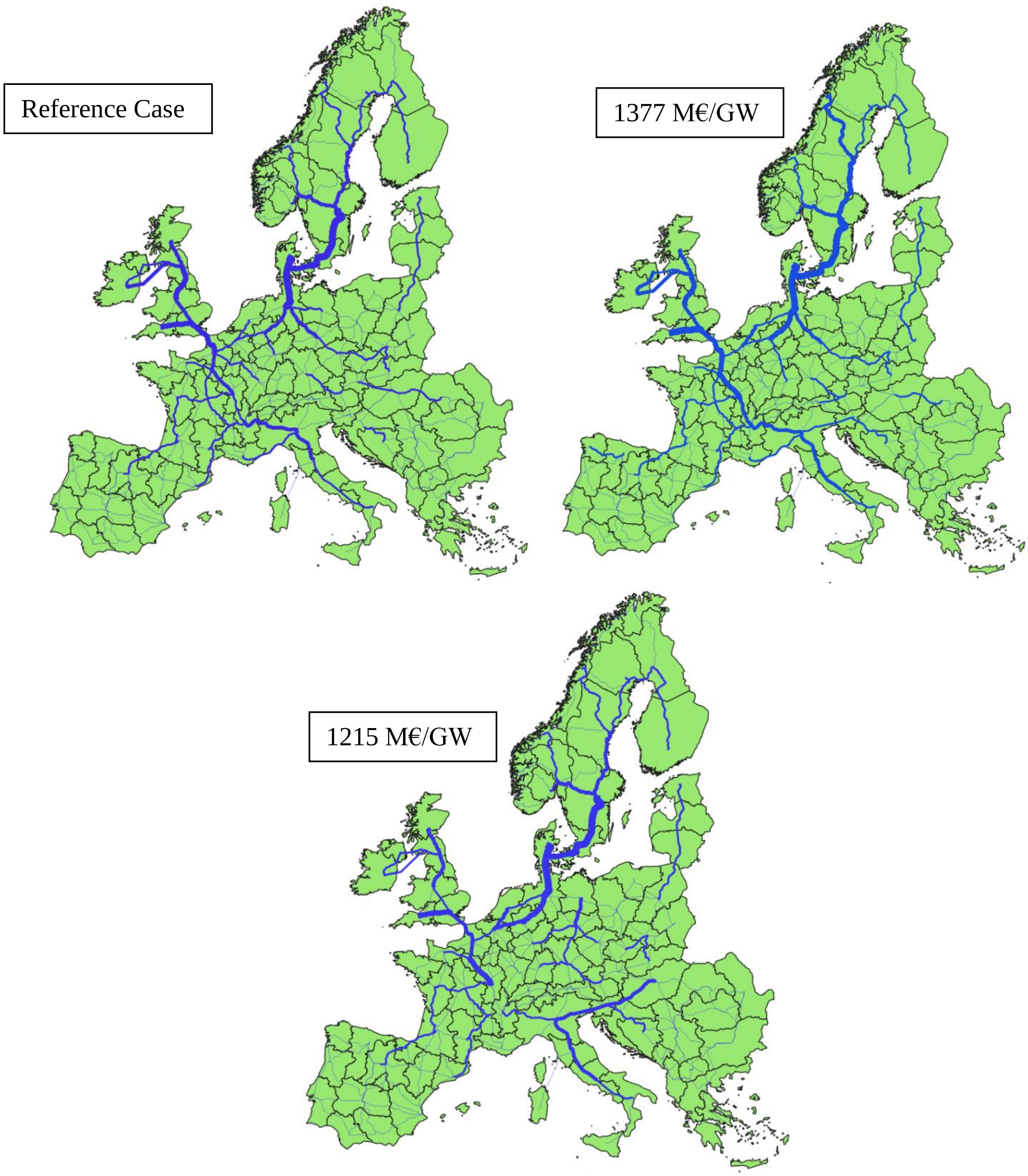


Figure 4.28 Change of hydrogen pipeline network in different simulated cases

While demand surely drove how the optimizer selected the pipeline's route and each segments capacity, it is worth noting that as reformer presence grew, the influence of regions with electrolyzers diminished. Going back to the first case (the cheapest reformer case), looking at the composition of hydrogen generating technology in each region, shows how connected the pipeline layout was to the reformer placement (Figure 4.29).

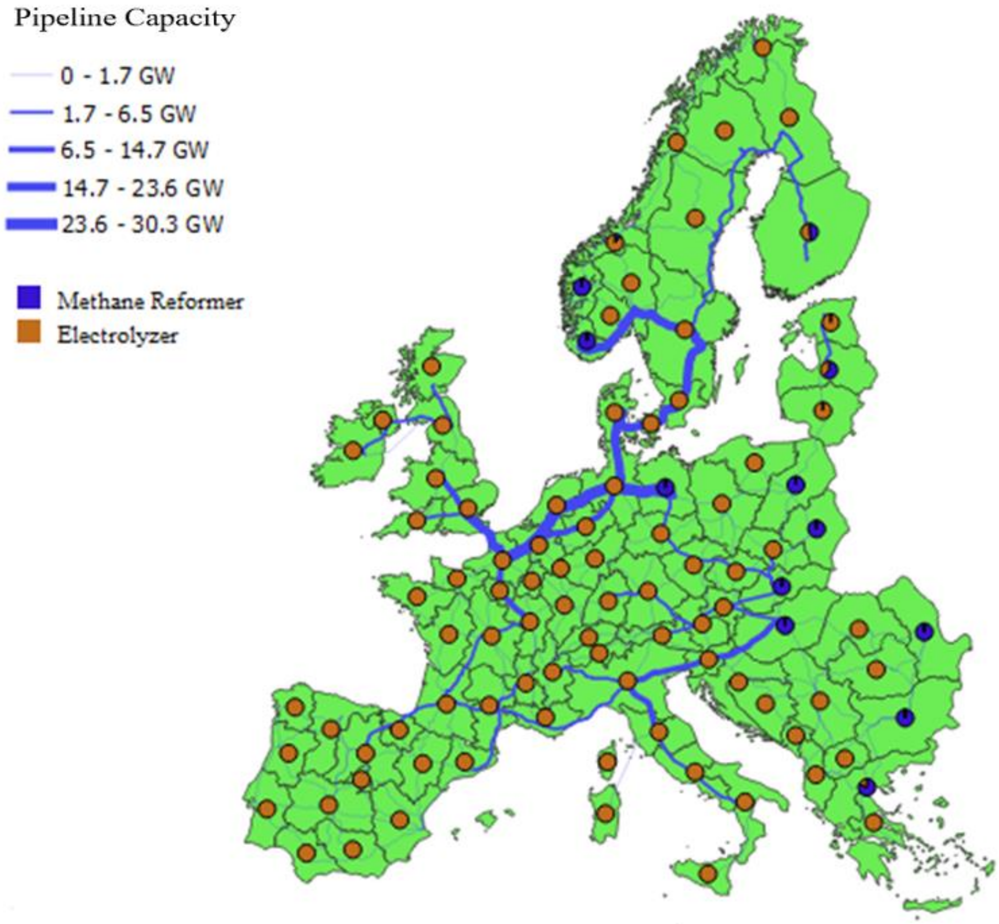


Figure 4.29 Case 810 M€/GW H_2 pipeline with each Region's Electrolyzer and Reformer Comparison

Table 4.1 Pipeline Capacity Distribution Statistics

	810	891	972	1053	1134	1215	1296	1377	1458	1539	1620	Ref
Min [kW]	28	35	35	38	46	46	20	39	30	21	34	49
Max [GW]	30.35	28.65	31.49	32.56	26.28	20.47	22.34	25.24	26.65	26.86	26.87	26.79
Range [GW]	1.87	1.88	2.15	2.13	2.15	2.20	2.28	2.13	2.27	2.39	2.40	2.37
Median [GW]	0.44	0.53	0.50	0.50	0.51	0.48	0.48	0.61	0.64	0.62	0.61	0.65
IQR [GW]	1.87	1.88	2.15	2.13	2.15	2.20	2.28	2.13	2.27	2.39	2.40	2.37

In all cases, including the reference case, the solver used all the hydrogen pipeline connections (all 190 of which most were below 2 GW) and there were no limits on minimum pipeline capacity. This caused a significant distribution skewness (the positive right direction). Looking at Table 4.1, we see that with increased reformer presence due to lower specific costs, there were higher maximums. The maximum pipeline capacity fluctuation starting at specific cost case 1053 and ending at 1377 M€/GW can be attributed to the reformers answering more local demand and therefore not needing higher capacities pipelines combined with the increased production from countries with high renewable generated hydrogen, as seen in the 1215 pipeline map in Figure 4.28.

4.1.6. Changes in the Amount of Hydrogen to Electricity Conversion

While the primary purpose of hydrogen produced from reforming or electrolysis was to satisfy each region's hydrogen demand, the increase in pipeline capacity and increase in conversion technologies capacity, specifically hydrogen to electricity path, suggests that with increased reformer presence, more hydrogen has been produced to further contribute to electrical demand. While this conversion was present in the reference case, looking at the installed capacities of CCGT, OCGT, PEMFC, SOFC, and H_2 Gas Engines (hydrogen gas combustion engines), the increase in some regions' installations (in cheaper reformer cases) for these technologies verifies hydrogen's re-electrifications increased in importance. Compared to OCGT and CCGT plants, the capacities of PEMFC, SOFC, and H_2 Gas Engine are in the order of kW, but the higher availability of hydrogen in the system caused these technologies to grow in their installed capacity and therefore this shows that there is a positive trend in electricity production from hydrogen rather than directly from renewable sources.

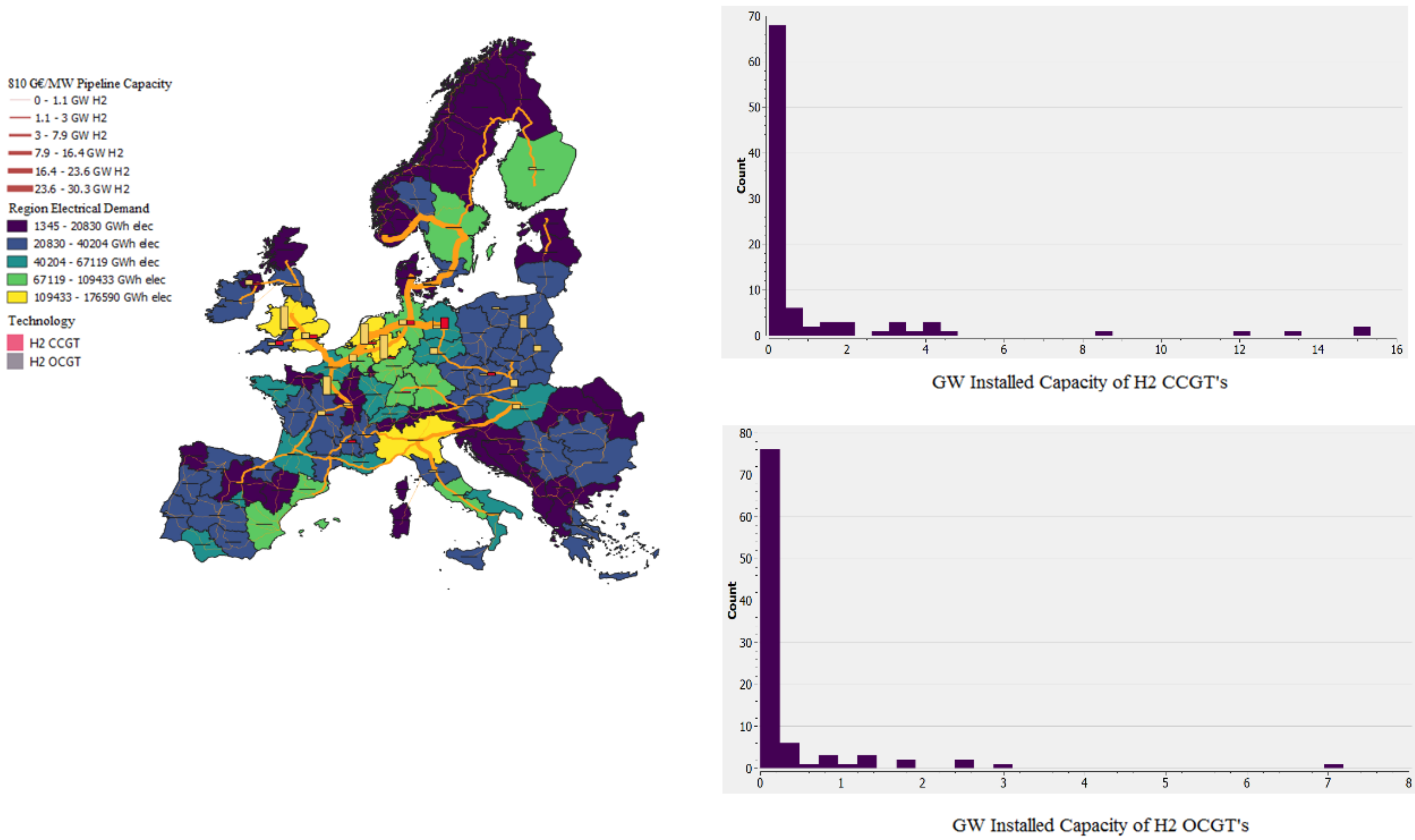


Figure 4.30 CCGT and OCGT Installations for 810 M€/GW Case with Capacity Value Count[2]

[2] Plant capacities with no visible marker are non existent in the network.

Looking at Figure 4.30 and Figure 4.31 , the installed capacities and their locations for both CCGT and OCGT plants is seen. While conversion of hydrogen to electricity is not the most direct way to satisfy electrical demand, with the increased availability of more hydrogen in the network as a result of the inclusion of reformers into the energy system paired with the increase in hydrogen to electricity conversion technologies, hydrogen in a mixed network becomes a more important intermediary commodity.

From the same two figures, it is seen that the higher capacity OCGT and CCGT plants, were installed in eastern countries like Finland, Poland, Slovakia, and Hungary in cheaper reformer cases like 891 M€/GW and especially in regions such as Netherlands and Germany which benefited from higher capacity hydrogen pipelines due to reformer presence. This shows an unexpected benefit of adding reformers into an energy network such as the one presented in this thesis, which is that hydrogen role as an intermediary energy storage source will become more relevant with decreased reformer cost.

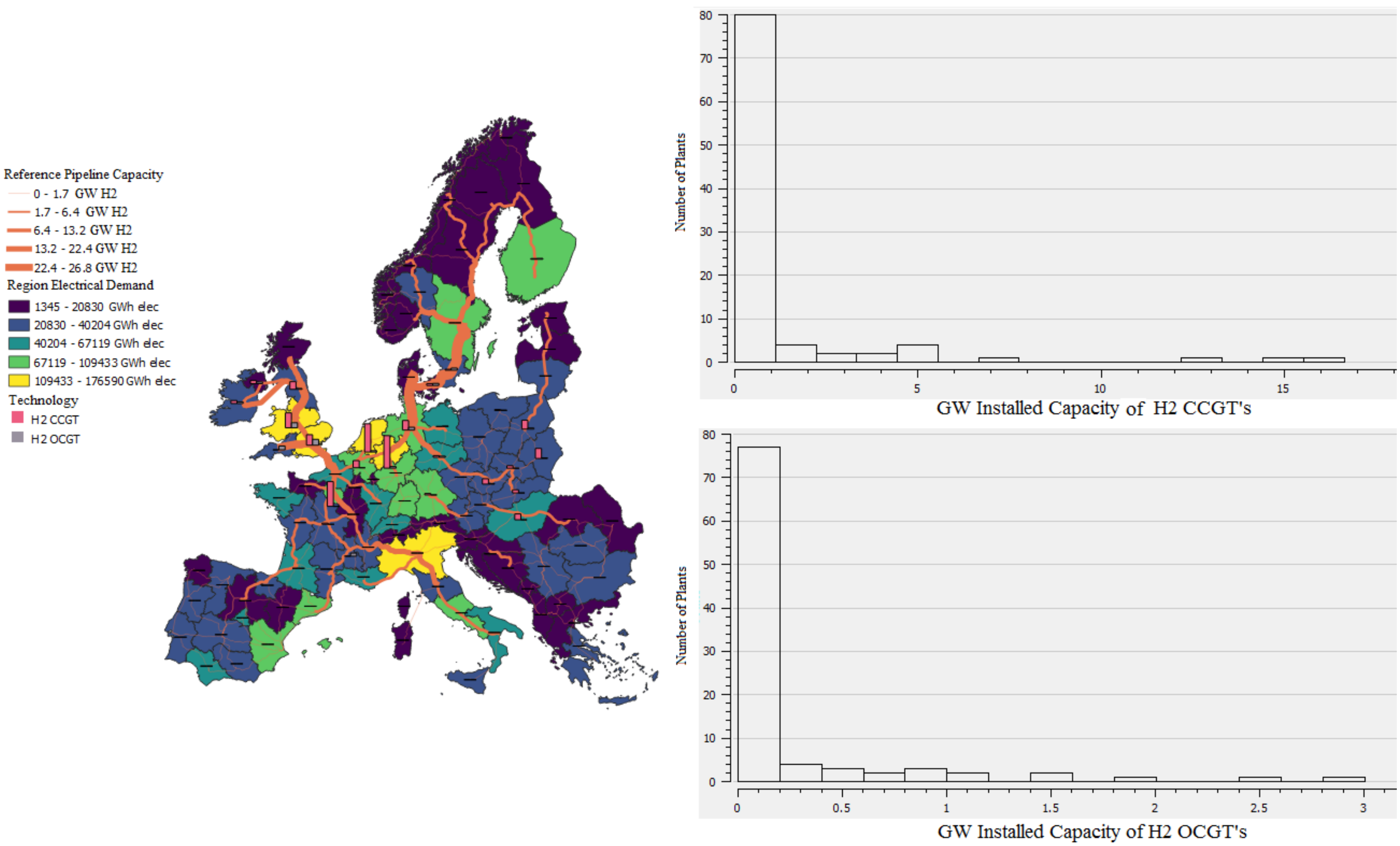


Figure 4.31 CCGT and OCGT Installations for Reference Case with Capacity Value Count

4.1.7. Cost of Hydrogen and Electricity

Since each case simulated in this thesis had the same electrical and hydrogen demand, a rough average cost per kWh of electricity and kg of hydrogen could be found. A starting point could be a Sankey diagram (Figure 4.32) which shows how energy was subdivided when going from source technology to sink (individual nodes). Figure 4.32 does not show how energy could be sent back and forth between the transmission, conversion, and storage classes as done by the solver (shown in Figure 2.2), instead it helps visualize how the energy could be split when going straight from source to sink; the Sankey Diagram also helps visualize the equations used to calculate cost (equations (4.1) to (4.5)) discussed later in this section.

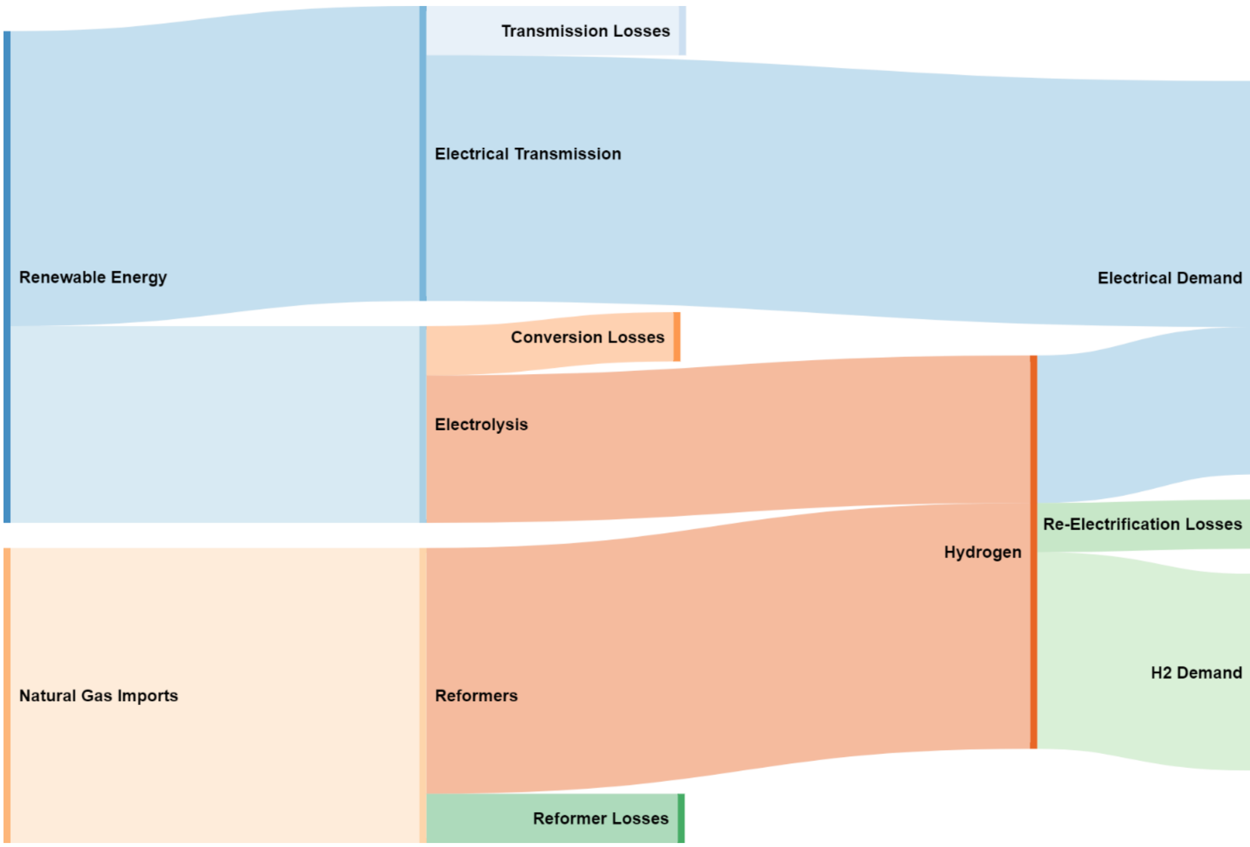


Figure 4.32 Simplified Sankey Diagram for Thesis Energy Flows [3]

From Figure 4.32, it can be determined that three parameters are used to calculate the average electricity and hydrogen cost for each case compared in this thesis. The first parameter 'K_i' shows the percentage of electricity generated by renewable sources that is sent to the electrolyzers for case 'i' (represented by equation (4.1)).

$$K_i = \frac{Total\ Electricity\ Sent\ to\ Electrolyzers\ [GWh\ elec]}{Total\ Electricity\ Generated\ by\ Renewable\ Source\ [GWh\ elec]} \tag{4.1}$$

[3] The diagram was made using open-source software called SankeyMatic Beta [75]

A similar approach is done to find the share of hydrogen that is used to satisfy electrical demands (as highlighted in section 4.1.6). Equation (4.2) shows the formula used to find this parameter 'T_i' for each case 'i.'

$$T_i = \frac{Total\ Hydrogen\ Demand\ [GWh\ H_2]}{Total\ Hydrogen\ Production\ by\ Reformers\ and\ Electrolyzers\ [GWh\ H_2]} \tag{4.2}$$

The parameter 'F' looks at the total cost related to hydrogen production. Since some of the hydrogen was produced via electrolysis, the total TAC of all renewable energy sources is multiplied by the parameter K. In addition to this, parameter 'F' includes the cost of electrolyzers, reformers, natural gas purchase, hydrogen storage and hydrogen transmission. This is shown in equation (4.3):

$$F_i = TAC\ of\ RES * K_i + TAC\ Electrolyzers + TAC\ Reformers + TAC\ Natural\ Gas + TAC\ H_2\ Storage + TAC\ H_2\ Transmission \tag{4.3}$$

With these 3 parameters, the average cost of producing hydrogen and electricity for the end user for each case 'i', could be found since the total system TAC, hydrogen and electricity demands are known. The equation used to find these values ((4.4) and (4.5)) are shown below.

$$Average\ Cost\ of\ H_{2_i} = \frac{F_i}{Total\ Annual\ Hydrogen\ Produced} \tag{4.4}$$

$$Average\ Cost\ of\ Electricity_i = \frac{Total\ TAC - F_i * T_i}{Total\ Annual\ Electrical\ Demand} \tag{4.5}$$

In Figure 4.33, each specific reformer cost cases' (including the reference case) F, T, and K parameters are shown. The decrease in all three parameters as the specific reformer cost per GW installed capacity decreased, shows how the addition of reformers not only help reduce the cost of overall hydrogen production, but also increases the hydrogen used as an intermediary commodity storage before being converted and sent to satisfy electrical demand. As a result of this, there is a decrease in electricity sent to the electrolyzers whose only function is to produce hydrogen. The decrease of 2% seen for parameter T (~14 TWh H_2) in the cheapest reformer case along with a 24% decrease in parameter K (~1300 TWh electric) shows that the additional hydrogen from reformers can significantly decrease not only the cost of the overall system (~7 billion **€**), but also the associated cost of hydrogen production 'F' by around ~20 billion **€**.

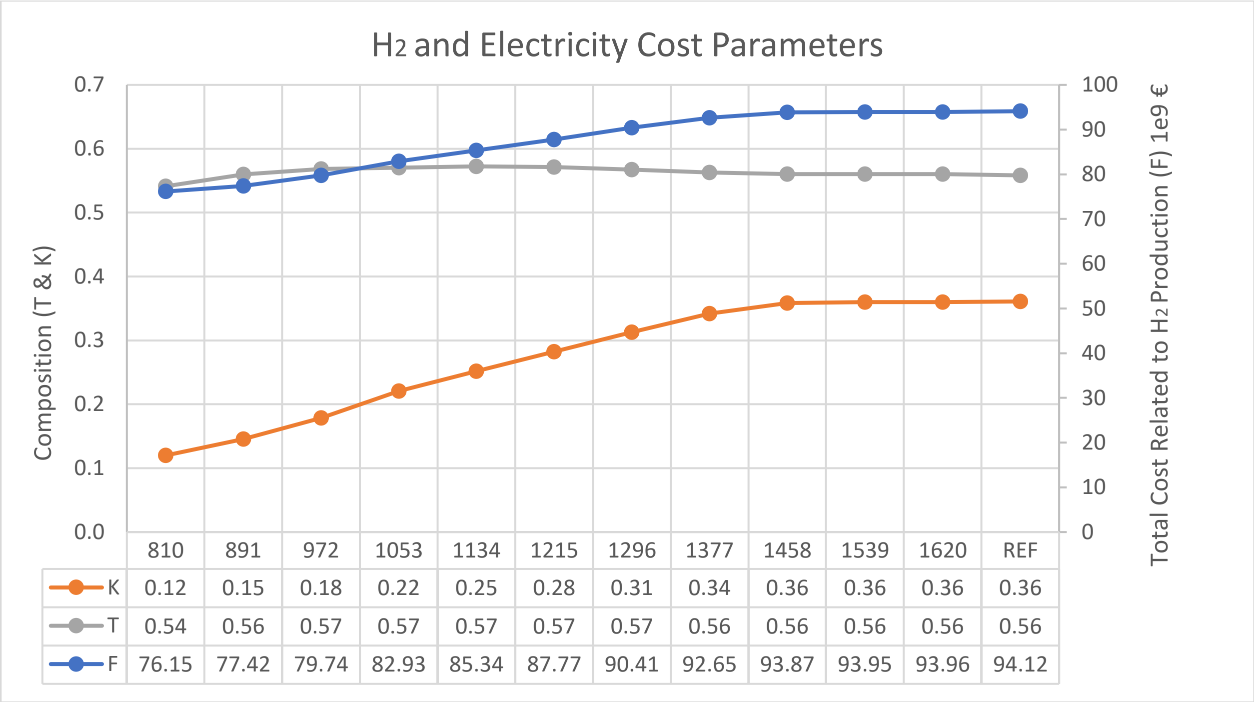


Figure 4.33 Main Commodity Average Cost for All Thesis Cases

With the reduction of the total associated hydrogen production cost, the average cost hydrogen for the end user follows a similar trend. While this is not the final market price of the commodity, a 21.5% reduction for each kg of hydrogen is a positive result. While electrical costs were higher for lower specific reformer costs, the increase of 0.12 €$_{ct}$ is miniscule. Figure 4.34 shows the costs for both commodities for all cases considered in this thesis.

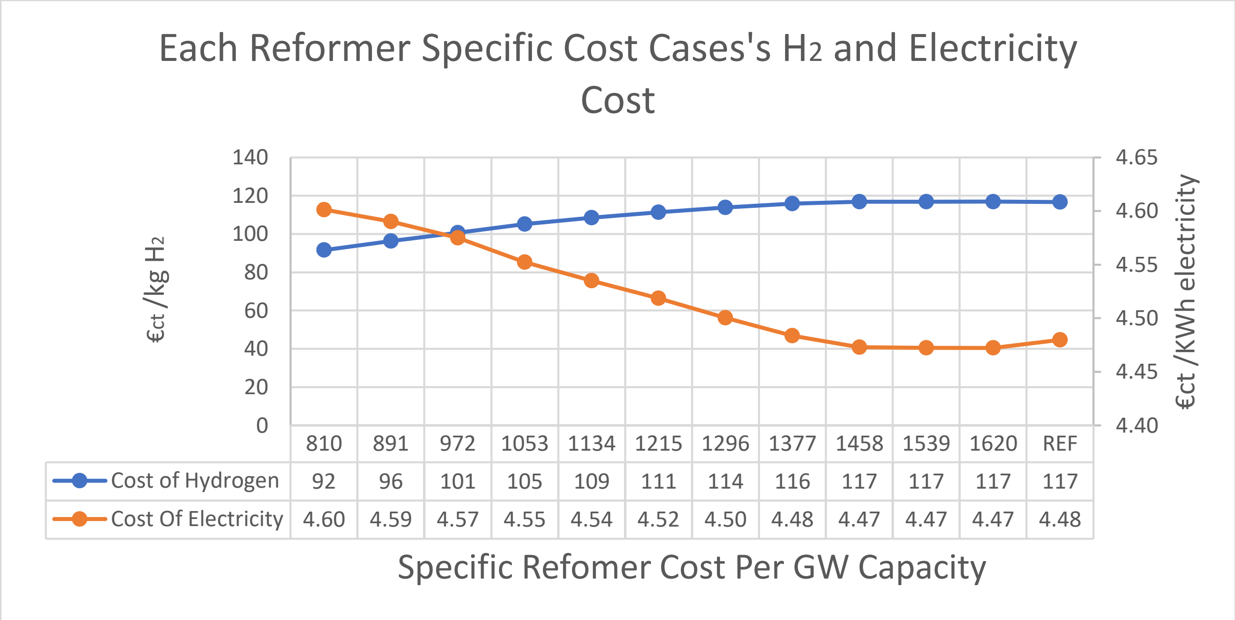


Figure 4.34 Average Cost for Hydrogen and Electricity for All Thesis Cases

The increase in electricity cost can be explained going back to equation (4.5) since as the reformer specific cost went down, the value of F*T decreased while the other equation parameters stayed the same. The slight decrease in electricity's role to satisfy both electrical demand and hydrogen production caused its production to grow in cost.

The positive trends seen with the addition of reformers to the overall European energy network modeled in this thesis warrant the additional investigation of how such inclusion would be impacted once the costs of CO_2 capture and emissions are included as a post processing step.

4.2. Additional Costs From Carbon Capture/Storage and Emission

In the performed simulations with methane reformers, two technologies had the potential to emit greenhouse gases into the atmosphere: biomass CHP and natural gas reformers. Emissions from biomass plants are a tiny part of each country or even region's CO_2. In addition to this, they can be considered renewable and thus neutral so that they are not constrained. The emissions from biomass plants are not considered in the reference case and therefore will not be considered here in the emission calculations. On the other hand, the addition of large reformers required the need to monitor and control as much as possible of emitted CO_2. The first thing to look at is the emission from the reformers on a case-by-case basis. Although the precise properties of the natural gas imported from Norway and Russia vary in time, good approximations can be made based on the available average data and assumptions. The calculations for each reforming region are described in the next section, followed by the descriptions of the results.

4.2.1. Calculations of Region Equivalent Emissions

Using each region's imported natural gas for the whole year, it is possible to find the amount of natural gas used and therefore, the equivalent CO_2 emissions that each specific cost case had. As mentioned earlier, the reference case does not have any natural gas imports and the CO_2 emissions from its biomass-fed CHP plants was considered neutral. Natural gas, according to Eurostat definitions [69], is mostly made up of methane. A constant average value of 55.4 MJ/kg (the higher heating value) at standard conditions [70] was used for the calorific value (pure methane) of natural gas in the system since the exact values of both Norwegian and Russian natural gas were not readily available. Taking the yearly amount of natural gas imported (GWh), converting it back to MJ and then to kg allows to directly find the amount of natural gas imported. Assuming stoichiometric conversion of methane (i.e., for every molecule of methane, one molecule of CO_2 is produced), the simple molar weight ratio between CO_2 (44 kg/kmol) and methane CH_4 (16 kg/kmol) will result in the mass of CO_2 emitted.

Given the assumption of using CCS-equipped reformers, a percentage of the produced CO_2 will be captured while the remainder will be emitted and compared to yearly emissions of the country in which each reforming region is in. The percentage of captured and emitted CO_2 is 95% and 5% respectively based on assumption discussed in section 3.2 of this thesis. The considered costs for each t_{CO2} captured and emitted encompass a range of values based on existing industry practices (also discussed in section 3.2).

4.2.2. Emission Results and Costs

An important trend seen in Figure 4.35, is that as the system increases, the cost of the reformer and the emissions scale down. Five countries have the biggest contributions out of all the importing regions: Germany (DE), Norway (NO), Hungary (HU), Slovakia (SK), and Poland (PL). Other countries do contribute however, their contribution to reformer-generated hydrogen and thus emission is extremely small even in the lower reformer specific cost cases.

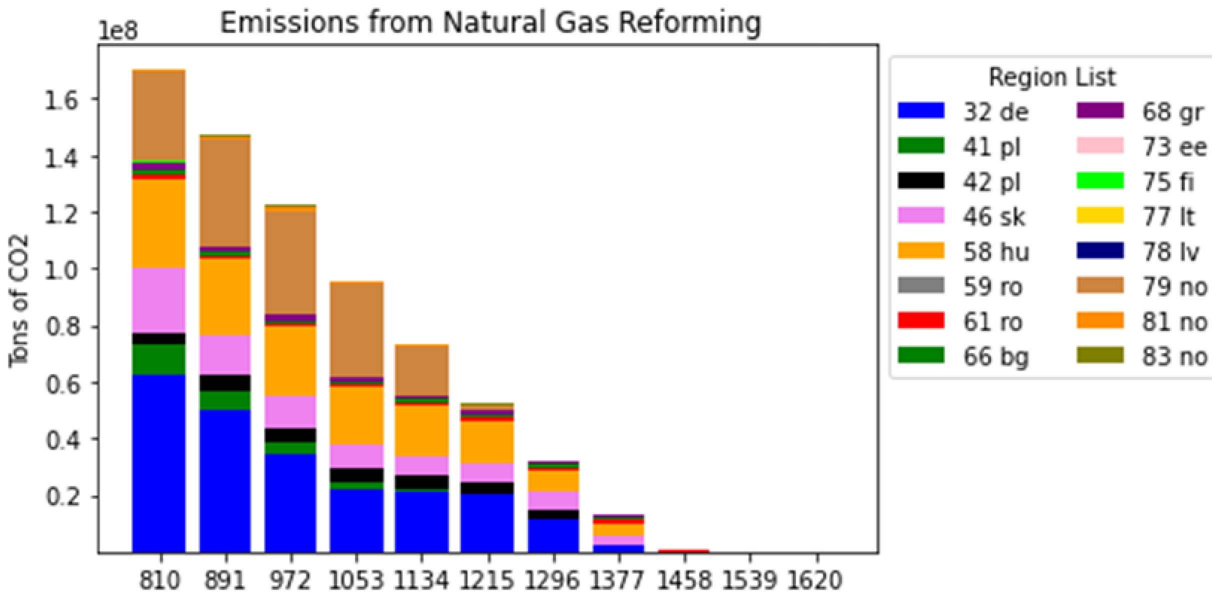


Figure 4.35 Each Reformer Cost Case Region CO_2 Emission

It is important to note that these values are showing the total amount of CO_2 produced. Even when comparing these values to the yearly emissions that each of the reforming countries had in 2019, it is shown that even in the case where the highest number of reformers was installed, each country's emission (shown in Table 4.2) did not exceed its value (recorded emissions as of 2019) as seen in Table 3.2. When comparing this to the total emissions of the European continent, (the 2019 total of 32.43 billion t), the results are far away from this limit. Considering that the demand which was addressed in this thesis was calculated by considering 75% of transportation industry (market penetration) being powered by hydrogen fuel cells for the year 2050 and the electrical demand (which included electrified heating and BEV vehicles) of the European continent, it can be concluded that even with reformers, this system can help reduce emissions.

As already mentioned, not all this produced CO_2 is emitted into the atmosphere. In Chapter 3 of this report, a value of 95% is used to account the amount of CO_2 that is captured with state-of-the-art carbon capture technologies applied on fuel gases and/or on combustion systems. The aim of this section is to compute the remaining amount of CO_2 that is emitted into the atmosphere and then calculate the additional cost (in terms of TAC) that would be added to the overall system for both management of captured CO_2 and the emission tax on released CO_2. With carbon capture technology improving from year to year, the cost range of 25 to 100 €/t of captured CO_2 was used while the cost for each emitted metric ton of CO_2 had the cost range from 0 to 200 €/t.

Table 4.2 Reforming Nodes Total Emisions of CO_2 [t]

Reformer Specific Cost Case	**32_de**	**41_pl**	**42_pl**	**46_sk**	**58_hu**	**59_ro**	**61_ro**	**66_bg**
810	62436822	10364069	4471592	22676371	31713475	0	1735693	1192168
891	50219691	6737217	5056359	14757853	26447043	0	1487787	1170197
972	34529127	3696005	5074050	12049559	24151122	0	1087912	1145350
1053	22278131	1934585	4988593	8317266	20544929	0	1045164	1085053
1134	21203011	626435	4806747	6702136	18322970	0	1014632	1083131
1215	20680733	65020	4024310	6301085	15110716	0	1120800	1064080
1296	11755975	493	3173737	6154815	7487266	0	1140182	1055149
1377	1943526	587	10310	3917929	4169564	0	939331	1073673
1458	74	43	120	185	167	0	909113	4552
1539	18	14	17	20	22	0	41	31
1620	29	28	35	48	45	0	32	32

Reformer Specific Cost Case	**68_gr**	**73_ee**	**75_fi**	**77_lt**	**78_lv**	**79_no**	**81_no**	**83_no**	Total
810	2359850	339	1238093	1386	325	31166333	780523	345831	170482870
891	2140655	568	4596	1942	340	37503861	981403	407199	146916711
972	1864942	2002	2797	9037	3551	36704730	1270227	1253638	122844048
1053	1747848	351	279	788	282	32377699	643287	298794	95263049
1134	1602127	378	222	1326	334	16748913	880728	313324	73306414
1215	1572132	426	269	966	479	1557601	520792	261996	52281406
1296	1364674	23	21	58	45	611	610	4006	32137663
1377	904120	83	53	169	128	475	585	3372	12963905
1458	967	15	8	23	19	27	28	90	915431
1539	29	8	5	11	10	12	12	12	262
1620	28	11	15	15	14	29	33	57	449

Table 4.2 shows each reforming regions' emission related data. While it is straightforward that as the specific cost for each GW of reformer capacity increased the emissions went down, different nodes dropped their emissions (linked directly to natural gas import) at a different rate. This is most likely related to nearby availability of cheaper hydrogen from renewable sources which are more favorable when reformer costs are high. Going back to Figure 4.1, it can be extracted how much TAC of each reformer cost case must increase to be equal to the TAC of the reference case. The three highest-cost reformer cases (1458 to 1620 M€/GW) were able to handle almost the whole range of carbon capture costs and CO_2 emissions costs assessed (as expected since their emissions were extremely small). The three lowest-cost reformer cases (810 to 972 M€/GW) were still able to be cheaper or as expensive as the reference case in a very limited range of prices per t of CO_2. The remainder of the other cases were not able to compete at the same costs as the reference case when including carbon capture and carbon taxes. While emissions follow a linear decrease as specific reformer costs increase, this does not mean that they decrease at the same rate as the TAC differences between each reformer case and the reference case. While optimizing the energy system, the solver did not consider emissions. Since emissions is not a tracked variable, the additional costs from capturing 95% and emitting 5% of CO_2 and the additional cost from the post-processing set of carbon capture can add up differently to each case. Therefore, while the three lowest-cost cases had a specific range of acceptable costs per t_{CO2} captured and emitted, it was only

the three highest-cost cases which had reformers in the kW installed capacity range, that could handle any additional costs simply due to their extremely low usage (as shown in Table 4.2). The cases in-between, had no possibility to have carbon capture because the savings they had when compared to the reference case, were smaller than even the lowest costing carbon capture cost pair considered in this thesis. Figure 4.36 shows that the cheapest reformer case can handle nearly all carbon tax prices on its emitted carbon however, when the cost per t of captured CO_2 nears 40€, the TAC starts to surpass that of the reference case. The values for the points found within the black border in Figure 4.36 are displayed in

Table 4.3. The same range for carbon tax, captured carbon transportation, and storage costs per ton of CO_2 for the other specific reformer cost cases are found in the appendix tables A.1.26 and A.1.1. While the possible price range is very limited, it is evident that this case and the next two reformer cost cases, even with very harsh cost on the CO_2, can still compete with and cost less than the reference case. The cost maps for all other cases are found in the appendix (A.2.20 to A.2.29).

The bold line in Table 3.4 shows the limit of the costs considered per ton of CO_2 in this thesis. While this is the lower limit of most industrial configurations, costs below this value could be achieved in the future especially if subsidies were to be given to companies that invest in such technologies. As the specific reformer costs go up, the pairs of prices that the system can handle without being more expensive than the reference case decrease until the 1377 M€/GW specific reformer cost whose possible cost combinations were all under 20€ per t_{CO2} transmitted and stored. After that reformer specific cost, the emissions are extremely low and the effects of the additional costs are not felt (almost all possible cost combinations are possible) even with a small difference in TAC when compared to the reference case.

Table 4.3 Specific Range of Potential Emission Related Costs for the Cheapest Reformer Case [1e9 €]

Carbon Transport and Storage additional cost per t CO_2 (€/t CO_2)	Carbon Emission Tax Per tCO_2 (€/t CO_2) →	0	25	50	75	100	125	150	175	200
	0	0.00	0.21	0.43	0.64	0.85	1.07	1.28	1.49	1.70
	5	0.81	1.02	1.24	1.45	1.66	1.88	2.09	2.30	2.51
	10	1.62	1.83	2.05	2.26	2.47	2.69	2.90	3.11	3.32
	15	2.43	2.64	2.86	3.07	3.28	3.49	3.71	3.92	4.13
	20	3.24	3.45	3.67	3.88	4.09	4.30	4.52	4.73	4.94
	25	4.05	4.26	4.48	4.69	4.90	5.11	5.33	5.54	5.75
	30	4.86	5.07	5.28	5.50	5.71	5.92	6.14	6.35	6.56
	35	5.67	5.88	6.09	6.31	6.52	6.73	6.95	7.16	7.37
	40	6.48	6.69	6.90	7.12	7.33	7.54	7.76	7.97	8.18
	45	7.29	7.50	7.71	7.93	8.14	8.35	8.57	8.78	8.99

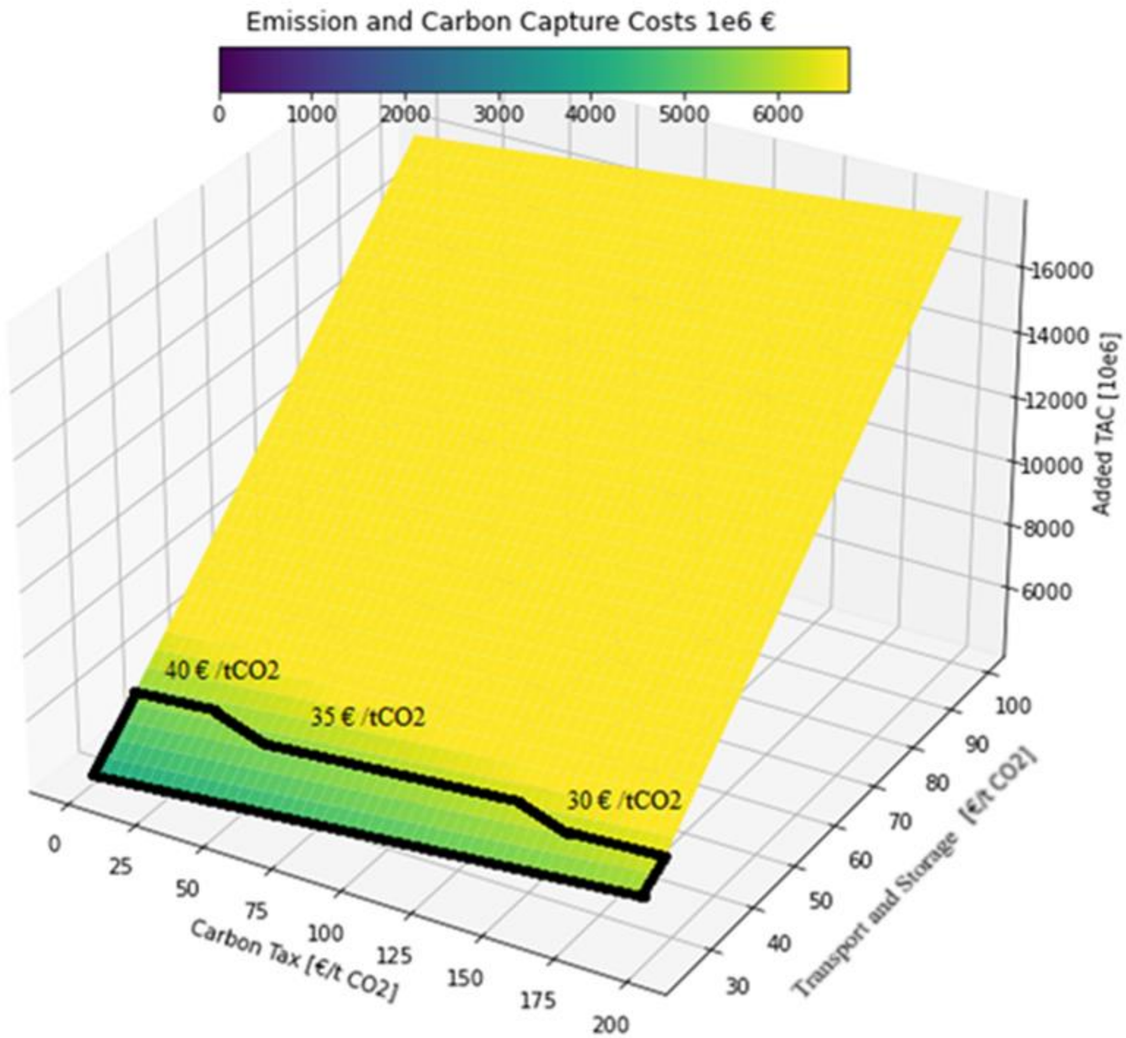


Figure 4.36 810 M€/GW Cases Additional Cost Surface Map

At this point, it can be said with confidence that combining natural gas reformers with renewable energy sources on a European scale, can help reduce the costs of the overall network and lower the costs of hydrogen production while at the same time being able to handle a reasonable range of carbon transportation and carbon emission taxes.

4.3. Summary of Results

Overall, adding natural gas reforming to the European energy system has positive results on the system's total TAC. Every section of the energy system was affected, and some technologies had a large change in the amount of installation as well as/including the role they played in the system.

One of the biggest impacts was the large substitution of variable renewable source technology - specifically onshore wind and photovoltaic without tracking - in areas with and even areas without reformers. With renewable capacities going down, a large reduction of source technology TAC followed (~10 billion €). Even with the increase natural gas usage, the cost of additional natural gas (purchase of fuel and installation of plants) was not equal to the difference between any reformer case and the reference case. The biggest difference was for the cheapest case which had a 7-billion-euro reduction when compared to the reference case. For many regions with natural gas reforming, the region's technology composition was switched to mostly natural gas as seen in Germany's natural gas importing region (32 DE). Regions with small natural gas imports were not connected with large pipelines but still served the regions' hydrogen needs with the help of CCGT and OCGT plants (as seen in Poland's eastern regions 41 and 42).

When looking over conversion technology, it is seen that as the cost of reforming went down, the optimizer selected natural gas reforming more, with the cheapest case having 134 GW capacity vs 360 kW in the most expensive reforming case. For the cheapest reformer case, the installed capacity of reformers was significantly higher than electrolyzers (seen in Figure 4.10) which was the dominant hydrogen source for more expensive and especially the reference case energy system. Between the two sources of the natural gas, while Norway had a higher amount of usable natural gas per month (as discussed in section 3.1), Russian natural gas was used the most by countries which were connected to it by having larger reformer installations especially for the cheapest reformer case shown in Figure 4.13. This is confirmed by the largest reformer installation being in Germany (region 32), Poland's regions (41 and 42), Slovakia, and Hungary, all of which had natural gas imported from Russia. In addition to this, countries like Hungary and Slovakia were part of the high-capacity hydrogen network due to the addition of reformers. The hydrogen transmission pipes coming from these countries extended to Italy and a little bit into central European countries like Switzerland, France and as far as Spain. While high-capacity pipelines to these countries did exist in the reference case, their two main sources were from the UK and Sweden while the cheaper reformer cases had a more connected hydrogen transmission system that stemmed from multiple countries (seen in Figure 4.27). Higher capacity connections meant that the system with the cheapest reformers (810 M€/GW) produced enough hydrogen to satisfy local/far hydrogen demands. In addition to this, it is confirmed that some of the produced hydrogen was used as a temporary energy storage medium since a slight increase in OCGT and CCGT capacity was seen especially in regions with very high natural gas usage when compared to the reference case.

As the cost of installing reformers went up, apart from the decrease in reformer installed capacity and increase in electrolyzer capacity, there was a temporary increase and then decrease of biomass CHP plants especially in countries where reformers were present (Germany, Slovakia, and Hungary). This 'transmission phase' occurred as the optimizer began to replace reformers with electrolyzers and balanced out small differences with biomass CHP as a conversion source for electricity. This re-affirms the role of reformers as not only hydrogen sources but also as electricity sources with hydrogen as an intermediary. While the solver did not see the results of each case, the biomass CHP pattern emerges with every increase in reformer specific cost.

With the changes seen in both hydrogen and electrical storage, it was further confirmed that seeing that hydrogen produced from reformers had a role in satisfying electrical demand. As the installed capacity of natural gas reformers grew, an overall increase in salt cavern used capacity was seen (~13.83 TWh increase in the cheapest reformer case). In countries like Germany, Netherlands, Poland, Romania and Greece, salt cavern growth was directly related to the presence of nearby reformers, while salt caverns in Spain, France, and the UK grew due to their still large installations of electrolyzers as a cause of high amount of variable renewable sources needed as a storage medium for their hydrogen. When looking at small scale hydrogen storage technology (vessels), countries with large capacities (in the reference case) saw a decrease due to the more steadily available hydrogen from reforming countries stored in salt cavern (seen in Figure 4.19). This is most evident in Italy whose vessel storage saw a significant drop (~50 GWh) due to increased high-capacity pipeline connections from Slovakia and Hungary.

Electrical storage was only available with lithium-ion batteries and saw a drop in system wide capacity with the increased presence of natural gas reformers (~90 GWh decrease for the cheapest reformer case). Pumped hydro storage was also able to address electrical storage needs but when compared to other sources of storage, even when combined with lithium-ion batteries and vessels storing hydrogen for later electrical conversion, all these technologies made up 0.6% of the total storage technology capacity. Reservoirs (hydro dams) and salt caverns were the dominating methods of energy storage (in the form of water and hydrogen gas respectively) which made up 99.4% of the European system's storage capacity. One peculiar result was the sudden change in reservoir behavior when going from the most expensive reformer case 1620 M€/GW to the reference case (seen in Figure 4.20); this shift was explained by the presence of natural gas, even at the very small amount, that changed the usage of reservoir storage. It is important to note that reservoir and pumped hydro storage capacities could not be changed, rather the amount of energy generated from them could be modified. This was reflected in the TAC changes for the technology which responded to changes in operation (capacity was fixed) in case-by-case comparison. In countries that had source technology reduction because of reformer inclusion, reservoir usage went up while the opposite happened in countries that had reformers such as in Norway. France also had reservoir usage go down, but this was linked to it having more renewables installed in the reference case and not because of reformer installation losses. Pumped hydro storage would be used more as reformer presence went down, but its contribution is relatively small while being visibly sensitive to natural gas presence.

When it comes to transmission, there was an increase of higher capacity pipelines moving hydrogen across the system with the increase of cheaper available hydrogen from cheaper reformers (Figure 4.34). As discussed earlier, the large installed capacity of reformers created a large influx of hydrogen into the systems storage, requiring adequate transmission. Large capacity connections were shared between areas with electrolyzer installations and reformer installations with the latter clearly being the biggest influencer (seen in Figure 4.29). Among the countries that reformed natural gas, Germany, Slovakia, and Hungary all created large new capacity paths creating a more interconnected Europe rather than a more western favored branch found in the reference case (Figure 4.28). The first sign that showed that the transmission network grew in capacity was the increasing transmission class TAC when going from the reference case to the cheapest reformer case (~0.2 billion €). This increase was related to hydrogen pipeline transmission because electrical lines (AC and DC) had fixed capacities for all connections; the only expansion that could happen, which is increasing connection capacities, was for the hydrogen pipeline. Areas that saw substantial additions to their pipeline segments were found in Northern Continental Europe (Netherlands, Denmark, and Germany) and the border of Italy and eastern regions of continental Europe (connections between Hungary, Slovakia, and Northern Italy). When going from a cheaper reformer case to the reference case layout, it was visible that as the reformers were slowly replaced, there was fragmentation of the loop-like network that was seen at the cheapest reformer as the network moved to the western leaning multi-branched network (seen in Figure 4.28). With all this in mind, it can be said with certainty that reformers, as their installed capacity increases, take the role of influencing the connections and pipeline capacities away from electrolyzers and make the latter an additional technology that helps in supplying regions far downstream from the reformer.

A look at how the cost of hydrogen and electricity changed with each reformer specific cost, also shows how with cheaper reformers, the overall cost of making hydrogen and using it as an intermediary commodity to satisfy electrical demand improves. The overall cost for hydrogen dropped by 30 $€_{ct}$/kg when comparing the cheapest reformer case with the most expensive (including the reference case). The availability of cheaper hydrogen (reduction of ~18-billion-euros) as seen in the drop for its overall cost, allowed for the solver to not only build more higher capacity pipelines and replace other expensive source technologies, but also increase the present of hydrogen used to satisfy electrical demands as seen with the ~2% increase found in the cheapest case compared to the reference case. This helped the OCGT and CCGT plants to produce electricity from re-electrification of hydrogen. While the cost of electricity went up by 0.18$€_{ct}$/kWh at the cheapest reformer case, the overall TAC of the system for the cheapest reformer still had a 7-billion-euro reduction when compared to the reference case, allowing for CCS cost to be implemented.

One thing that cannot be avoided when dealing with natural gas reforming are the emissions that arise from the process. Even at the most emitting case of this thesis with 8.5 Mt of CO_2 annually, the total emissions of the whole system presented in this thesis were below current recorded emission values in the EU of 3.2 Gt annually. The amount of released CO_2 was 5% of the total produced with the remainder being captured. Looking at existing ranges of carbon taxes and carbon capture technologies, the most-emitting case, which also had the highest TAC reduction, was able to handle nearly the whole range of carbon taxes but with a limited window of carbon capture prices as seen in Figure 4.36.

In the end, as presented in the reference case, based on the TAC reduction when compared to the reference case and its ability to handle a wide range of carbon taxes and carbon capture prices, the cheapest reformer case (810 M€/GW) was shown to be the most viable alternative to a mostly renewable system while still being cheaper for a reasonable range of CO_2 transportation and storage costs as well as CO_2 emission prices.

Chapter 5. Conclusions

This chapter sums up the thesis work and is broken down according to the two main research questions discussed in the Introduction Chapter. The first being what is the impact of natural gas reforming on each of the system's modeling classes capacity and Total Annual Cost, and the second being what is the effect (sensitivity analysis) of carbon capture and storage on the competitiveness of a mixed system. This is then followed by suggestions on how to further build on this thesis.

5.1. Research Result Conclusions

While only being present in 15 out of the 96 regions considered in this thesis, natural gas reforming at the cheapest case (810 M€ per GW of reformer capacity) had large impacts on all modeling class categories, capacities, and costs. Effects were seen in all cases but with increasing costs per GW of reformer capacity, the system's configuration increasingly resembled the renewable reference case as time/research went on. While both natural gas exporting countries (Russia and Norway) were used as sources for natural gas, the regions connect with Russia having ~108 GW reformer installed capacity had far more impact on the entire system than Norway-linked regions with ~25 GW reformer installed capacity.

The modeling class (group of technologies) that saw the biggest capacity and cost reduction as natural gas reforming capacity increases was the source technology class of ~10 G€. Without natural gas reformers, this category was dominated by wind and solar PV plants in both installed capacity and costs. Countries far from the natural gas reforming regions (Spain, UK, and France), which used to dominate in energy generation, saw drastic drops in installed capacity (around 30, 50, and 50 GW, respectively). This shows that natural gas, even with its additional cost of fuel, benefits the system by reducing the installation costs and can be a crucial energy sources only surpassed by wind turbines as leader resource due to the technology's widespread installation.

The changes seen in conversion technologies also help show the impact of natural gas inclusion. In the reference case with no natural gas reforming, countries that had large installed capacities of onshore wind technology (France and UK) had a combined electrolyzer installation of ~105 GW, suggesting that these countries produced enough power to supply electrical and hydrogen demands. This changed drastically as natural gas reforming capacity grew due to cheaper reformer costs. Some regions in Hungary, Slovakia, Norway, and Germany saw almost complete replacement of their electrolyzers with reformers, and the same regions became the main producers of hydrogen. While countries that had large electrolyzer capacities still had significant electrolyzer capacities even in the cheapest reformer case, it was certain that reforming was preferred by the solver. This is confirmed with the cheapest reformer case having a third of the capacity of electrolyzers when compared to the reference case. While reformers do increase the cost of the conversion technology class within the energy system, their increased presence displaces electrolyzers as the main source of hydrogen while keeping overall costs lower than that of the reference case.

With more reformers added as their specific cost went down, it was not surprising to see an increase in both hydrogen storage and transmission installations. Regions with and without reformers saw an increase in salt cavern stored capacity (~14 TWh increase for the whole network). This showed that reformers produced more hydrogen in areas that had both reformers and salt caverns while regions with only salt caverns saw increases due to the remaining electrolyzer produced hydrogen. Certainly, electrolyzers also contributed to the increase however, the drastic increase in salt cavern storage can be attributed to reformer inclusion. This adds to the first research question's answer that reformer inclusion increases the amount of hydrogen available to the system with a visible effect of higher large salt cavern usage. Since there was an increase of large hydrogen storage across the system, smaller storage technologies such as vessels and lithium-ion batteries saw a decline in capacity (~400 and 88 GWh, respectively).

While the increase in transmission Total Annual Cost of ~200 M€ was an expected result due to the increase in available hydrogen (electrical lines remained at a fixed capacity in all case), the drop in both lithium-ion batteries and hydrogen vessels across the system and especially in Italy was not. What helped explain this was the increase in hydrogen pipeline capacity from Eastern regions (such as Hungary, northern Germany, and Slovakia) going to Italy and further west to Spain. These reforming regions added significant capacity to eastern pipeline connections, making a new network that had elements of the reference case (large pipelines from northern Europe going down to the south-western regions) and a whole new eastern European pipeline which went from northern Germany through other eastern countries down to Italy and connecting to Spain through France. This additional stream of hydrogen was the reason behind the drop in Italian small-scale electrical and hydrogen storage. It is important to note that many regions had pipeline connections that were much lower than 1 GW. While for the system, the only method of transporting hydrogen was through pipelines, smaller capacities are usually better served with other means of transmission however, such fine tuning is outside the scope of this work. With all this said, the complete answer to the first research question is as follows: the addition of natural gas reforming to a renewable system will not only reduce the overall cost of the network by replacing variable renewable technologies, but also by increasing the usage of large-scale hydrogen storage and of more large capacity pipeline connections by making additional hydrogen available to the system.

The next question this thesis aimed to answer was the impact that carbon capture and emission costs had on the validity of a mixed energy network. Going back to the main objective of the optimization framework used, keeping costs below or equal to the reference network was selected as the primary success measurement. The three most expensive reformer cost cases were able to handle nearly 100% of the cost range due to their extremely low emissions, but what was unexpected was the range of costs for the three cheapest reformer cases that allowed the network configuration for those cases to be cheaper or at the same cost as the reference case. The cheapest reformer case was able to handle the full range of carbon emission taxes from 0 to 200 €/t_{CO2} and a carbon transmission and storage cost range of 20 to 40 €/t_{CO2}. Seeing this was reassuring since capture costs are going down every year and new methods of capture-transmission-storage are being discovered that help reduce costs. At some cost pairs (for emission and transmission/storage), the cheapest reformer case still had a lower TAC than that of the reference case.

Without looking at captured carbon utilization and government subsidies, the results of this thesis demonstrate that: a mixed network has cost-reducing effects on the overall European network, extends the reach of high-capacity hydrogen transmission/storage, and in some cases, can be equal to or even below the cost of a renewable network. It can be said with confidence that a mixed European energy network containing both renewable and natural gas reforming plants combined with carbon capture, can help Europe achieve its future emission reductions and keep costs low.

5.2. Recommended Future Research

With the conclusion of this thesis, the only thing remaining is to suggest what can be further researched to better understand the impacts of a mixed system. Future research can continue with the expansion of the natural gas reforming network or investigate how the utilization of existing natural gas pipelines can be used to instead spread hydrogen gas from regions with reformers.

The changes seen thanks to reformer inclusion on the whole system, even with 15 out of 96 regions having reformers, brings up the question of what will happen if more regions have access to reformers to generate hydrogen. If this path is chosen, there needs to be extra care when controlling the emissions. This is further supported because the costs for CO_2 capture are decreasing with every year thanks to consistent capture improvements. This can further help the cost reduction of systems like those presented in this thesis. In addition to this, governments are starting to create policies that reward energy plant operators that implement cutting edge carbon reducing technologies. A specific case of such can be found in the US with its 45Q program [30]. Such things can further drive the cost of carbon capture and storage technologies down. As seen in this report, these costs are more limiting to natural gas reforming growth than a large carbon tax.

Combing the findings in this report with the idea of natural gas pipeline re-assignment can also help in reducing the cost of the system presented in this report even though the transmission costs are only ~1% of the overall network cost. Certainly, a test to make sure that the current state of these steel pipelines is ready to handle a very different gas needs to be done, but research has already shown that such changes are possible with some modifications needed to ensure stable operation [71]. Varying the mixture of hydrogen and natural gas is also a very interesting concept to add to a mix network such as the one found in this report [72]. Even if placement is limited, this will help the hydrogen produced by the reformers to not only reach further points but also offset emissions of certain technologies that can handle such gas mixtures [73]. Some research has even shown that current natural gas devices can handle a small amount of hydrogen mixed with methane gas. Adding this to the research of this thesis can potentially increase the usage of reformers and help in further reducing emissions of more industries [74].

The possibilities of additions are truly endless. The future of a mixed-gas or even pure hydrogen gas network satisfying a large portion of a network’s energy demands is becoming a reality and natural gas reformers can and should play a big role in them.

Appendixes

Data tables

A.1.1 Technology Maximum Capacities for Each Region Part 1 [GW]

	Rooftop PV	Biomass	Onshore Wind	Offshore Wind	Open-Field Tracking and Fixed	Natural Gas[4]
01_es	4.43	0.75	122.796	43.77	370.939	0
02_es	3.67	1.75	172.582	14.39	366.826	0
03_es	2.44	2.75	248.136	0	282.576	0
04_es	3.37	1.25	65.837	12.33	40.272	0
05_es	1.68	2.00	170.826	0	299.819	0
06_es	7.40	1.25	67.819	25.27	58.495	0
07_es	5.39	0.25	13.229	0	34.081	0
08_es	3.37	1.50	223.870	0	661.314	0
09_es	5.99	1.75	121.412	32.25	151.856	0
10_es	3.91	2.00	115.094	24.71	163.451	0
11_es	9.19	2.00	215.197	96.32	443.979	0
12_pt	7.69	1.25	120.176	38.51	430.538	0
13_pt	6.25	1.50	162.869	74.73	486.824	0
14_fr	8.46	3.50	236.401	52.99	415.475	0
15_fr	5.29	2.00	147.115	11.89	296.108	0
16_fr	7.63	1.50	52.5328	17.92	113.306	0
17_fr	7.92	3.25	191.602	68.13	251.896	0
18_fr	6.50	4.00	226.364	0	186.933	0
19_fr	4.95	1.00	70.845	0	102.207	0
20_fr	5.74	1.00	50.359	0	65.9870	0
21_fr	8.25	0.75	155.334	303.86	349.242	0
22_fr	3.82	0.50	81.422	18.36	56.2706	0
23_fr	10.21	1.50	21.171	0	8.76308	0
24_fr	3.51	2.50	133.960	0	68.3438	0

[4] These values are the GWh of methane available to nodes at full capacity.

A.1.2 Technology Maximum Capacities for Each Region Part 2 [GW]

	Rooftop PV	Biomass	Onshore Wind	Offshore Wind	Open-Field Tracking and Fixed	Natural Gas[5]
25_fr	8.04	2.00	106.913	0	90.196	0
26_fr	10.68	3.25	110.700	17.76	35.437	0
27_fr	1.50	1.25	47.651	0	18.033	0
28_be	16.27	4.75	19.343	4.72	93.517	0
29_lu	0.83	0.00	2.530	0	6.235	0
30_nl	22.41	4.00	78.322	149.68	201.556	0
31_de	18.33	3.75	149.466	76.45	9.149	0
32_de	9.49	5.00	114.201	5.74	8.123	27543.75
33_de	22.01	3.00	25.500	0	2.433	0
34_de	12.45	4.50	79.286	0	9.900	0
35_de	15.62	3.75	56.305	0	8.785	0
36_de	14.22	3.00	52.721	0	5.818	0
37_de	18.49	4.75	140.339	0	10.393	0
38_dk	5.14	2.50	121.095	218.28	18.732	0
39_cz	8.60	2.75	114.15	0	72.978	0
40_cz	6.76	2.25	85.598	0	53.594	0
41_pl	11.63	2.50	201.990	0	209.140	27543.75
42_pl	9.50	2.75	120.295	0	140.749	27543.75
43_pl	12.67	2.00	58.938	0	63.199	0
44_pl	11.69	4.00	194.399	1.99	89.185	0
45_pl	7.51	3.00	168.926	88.72	74.605	0
46_sk	8.23	2.75	85.150	0	81.513	27543.75
47_ch	9.04	1.00	37.912	0	8.131	0
48_ch	1.91	0.25	15.534	0	0.842	0

[5] These values are the GWh of methane available to nodes at full capacity.

A.1.3 Technology Maximum Capacities for Each Region Part 3 [GW]

	Rooftop PV	Biomass	Onshore Wind	Offshore Wind	Open-Field Tracking and Fixed	Natural Gas[6]
49_at	3.35	0.75	37.260	0	8.770	0
50_at	4.86	1.25	74.414	0	74.838	0
51_at	4.81	1.50	52.303	0	42.387	0
52_it	37.15	6.75	110.909	19.31	260.692	0
53_it	8.58	2.75	106.213	42.49	107.161	0
54_it	15.30	1.00	68.448	83.28	173.302	0
55_it	9.49	2.50	144.499	142.59	188.458	0
56_it	5.91	1.25	82.919	144.14	75.225	0
57_si	3.53	0.75	30.059	0	60.089	0
58_hu	13.77	7.25	267.481	0	200.595	27543.75
59_ro	8.73	2.50	168.890	0	167.331	27543.75
60_ro	9.53	3.25	167.590	0	111.572	0
61_ro	10.09	3.50	226.923	96.33	81.557	27543.75
62_hr	6.20	0.00	132.501	109.12	588.853	0
63_ba	4.69	0.25	207.112	0	476.261	0
64_me	0.81	0.00	55.887	17.98	103.412	0
65_rs	11.70	1.00	296.984	0	671.380	0
66_bg	9.48	4.75	229.863	40.83	262.336	27543.75
67_mk	2.58	0.00	55.542	0	133.882	0
68_gr	5.07	2.00	123.003	51.23	254.097	27543.75
69_gr	7.96	1.75	157.123	271.16	323.967	0
70_al	3.54	0.00	57.442	33.47	102.428	0
72_dk	3.22	1.25	29.7116	45.41	2.467	0
73_ee	1.66	1.00	178.362	86.1	206.504	27543.75

[6] These values are the GWh of methane available to nodes capacity.

A.1.4 Technology Maximum Capacities for Each Region Part 4 [GW]

	Rooftop PV	Biomass	Onshore Wind	Offshore Wind	Open-Field Tracking and Fixed	Natural Gas[7]
74_fi	0.70	0.75	307.138	18.07	0	0
75_fi	6.23	3.00	768.545	175.99	0.500	27543.75
77_lt	3.38	1.75	263.126	18.16	451.447	27543.75
78_lv	2.21	1.75	236.270	97.01	408.535	27543.75
79_no	0.96	0.25	89.852	451.62	21.313	177795.3
80_no	1.05	0.25	126.353	4.65	31.155	0
81_no	1.20	0.00	53.867	319.2	3.024	177795.3
82_no	2.24	0.00	195.213	0	114.567	0
83_no	0.89	0.00	82.534	274.91	0	177795.3
84_no	0.78	0.00	171.315	586.97	0	0
85_no	0.08	0.00	46.123	321.83	0	0
86_se	0.37	0.75	209.699	16.88	0	0
87_se	1.18	3.00	586.522	107.25	0	0
88_se	8.18	1.25	623.096	235.25	118.534	0
89_se	2.82	0.50	123.395	34.76	38.455	0
90_uk	24.62	4.75	97.504	82.72	18.763	0
91_uk	6.69	0.50	60.550	282.52	6.192	0
92_uk	26.13	4.00	174.846	104.44	44.766	0
93_uk	7.50	1.75	156.137	276.53	94.583	0
94_uk	4.06	1.50	143.153	1212.44	69.270	0
95_uk	2.78	0.00	54.217	15.36	21.142	0
96_ie	7.15	0.25	317.061	1138.89	124.699	0
98_it	2.23	0.50	88.011	70.43	193.995	0
99_fr	0.52	0.25	10.035	0	29.081	0

[7] These values are the GWh of methane available to nodes capacity.

A.1.5 Storage Technlogy Maximum Capcities [GWh] per Region Part 1

	Salt Cavern	Vessel	Lithium-Ion Batteries	PHS	Hydro Reservoir		Salt Cavern	Vessel	Lithium-Ion Batteries	PHS	Hydro Reservoir
01_es	0	500	100	3.524	0	25_fr	24079	500	100	0	0
02_es	105233	500	100	10.042	5760.039	26_fr	0	500	100	0	0
03_es	73403	500	100	1.413	0	27_fr	0	500	100	3.6	0
04_es	51750	500	100	0	0	28_be	0	500	100	6.179	13.823
05_es	346024	500	100	14.463	0	29_lu	0	500	100	5.041	0
06_es	318177	500	100	1.539	807.389	30_nl	425868	500	100	0	0
07_es	0	500	100	0	0	31_de	5387785	500	100	1.517	0
08_es	0	500	100	1.92	4580.691	32_de	3544422	500	100	0	0
09_es	0	500	100	5.437	0	33_de	137863	500	100	1.397	0.406
10_es	134248	500	100	0	0	34_de	646460	500	100	17.467	0
11_es	228221	500	100	24.724	0	35_de	179298	500	100	3.146	0.537
12_pt	204186	500	100	58.661	581.81	36_de	323	500	100	11.686	0
13_pt	172790	500	100	8.012	105.008	37_de	2086	500	100	4.053	4.519
14_fr	0	500	100	0	552.91	38_dk	609529	500	100	0	0
15_fr	0	500	100	19.318	1605.617	39_cz	0	500	100	0.23	441.855
16_fr	45941	500	100	0	906.764	40_cz	0	500	100	5.759	0
17_fr	0	500	100	0	0	41_pl	1451254	500	100	0	8.161
18_fr	0	500	100	0	70.27	42_pl	69190	500	100	0.847	3.234
19_fr	242728	500	100	0	140.623	43_pl	22314	500	100	3.128	27.333
20_fr	173665	500	100	27.233	1720.794	44_pl	3584364	500	100	0.252	2.887
21_fr	0	500	100	0	0	45_pl	2109328	500	100	4.091	77.533
22_fr	0	500	100	0	0	46_sk	0	500	100	3.935	277.619
23_fr	0	500	100	0	0	47_ch	0	500	100	77.43	349.776
24_fr	24542	500	100	0	0	48_ch	0	500	100	86.383	4681.382

A.1.6 Storage Technlogy Maximum Capcities [GWh] per Region Part 2

	Salt Cavern	Vessel	Lithium-Ion Batteries	PHS	Hydro Reservoir		Salt Cavern	Vessel	Lithium-Ion Batteries	PHS	Hydro Reservoir
49_at	0	500	100	96.604	1017.979	74_fi	0	500	100	0	0
50_at	0	500	100	17.542	35.508	75_fi	0	500	100	0	518.988
51_at	0	500	100	0	0	77_lt	0	500	100	11.061	23.463
52_it	0	500	100	36.837	1328.295	78_lv	0	500	100	0	1472.022
53_it	0	500	100	0	71.072	79_no	0	500	100	385.524	17956.318
54_it	0	500	100	8.26	75.673	80_no	0	500	100	0	10383.694
55_it	0	500	100	0	172.186	81_no	0	500	100	6.104	22397.403
56_it	0	500	100	3.678	0	82_no	0	500	100	0	8710.98
57_si	0	500	100	0.537	1491.618	83_no	0	500	100	0	6491.531
58_hu	0	500	100	0	48.333	84_no	0	500	100	0.301	12520.2
59_ro	1083944	500	100	0	1921.047	85_no	0	500	100	0	961.007
60_ro	37078	500	100	18.553	8387.517	86_se	0	500	100	0	14440.866
61_ro	0	500	100	0	604.827	87_se	0	500	100	0.086	11893.973
62_hr	0	500	100	5.686	1955.8	88_se	0	500	100	158.595	2701.468
63_ba	817397	500	100	1.606	1692.834	89_se	0	500	100	0	0
64_me	0	500	100	0	0	90_uk	0	500	100	0	0
65_rs	0	500	100	4.315	424.602	91_uk	77056	500	100	0	0
66_bg	0	500	100	40.592	1964.217	92_uk	218466	500	100	9.733	0
67_mk	0	500	100	0	265.536	93_uk	814618	500	100	0	0
68_gr	112162	500	100	4.643	1753.395	94_uk	0	500	100	16.909	143.74
69_gr	0	500	100	0	0	95_uk	97024	500	100	0	0
70_al	51317	500	100	0	1470.553	96_ie	0	500	100	2.543	0
72_dk	72320	500	100	0	0	98_it	0	500	100	13.009	46.148
73_ee	0	500	100	0	0	99_fr	0	500	100	0	74.662

A.1.7 : Source Component Model Economic Parameters

Source Technology	Commodity	Maximum Capacity [GW]	Investment per Capacity [€ GW^{-1}]	OPEX per Capacity [€ GW^{-1}]	Interest rate [%]	Economic Life [a]	Source
Onshore Wind Turbine	Electricity	R.D.	R.D.	R.D.	0.080	20	[17],[49]
Offshore Wind Turbine	Electricity	R.D.	R.D.	R.D.	0.080	25	[17],[50]
Open-Field PV without Tracking	Electricity	R.D.	0.520	R.D.	0.080	25	[17],[48]
Open-Field PV with Tracking	Electricity	R.D.	0.710	R.D.	0.080	25	[17],[48]
Rooftop PV	Electricity	R.D.	0.880	0.0176	0.080	25	[48]
Run-of-river[8]	Water	R.D.	0 (5.62)[9]	0.0843	0	60	[17],[48]
Fuel Sources							
Source Technology	Commodity	Maximum Capacity [GW]	Commodity Cost [€ kWh^{-1}]	OPEX per Capacity [€ GW^{-1}]	Interest rate [%]	Economic Life [a]	Source
Biomass Imports	Biomass	R.D.	0.020	N.A.	N.A.	N.A.	[17]
Natural Gas Imports	Natural Gas	R.D.	0.0256	N.A.	N.A.	N.A.	[57], [58], [66], [67]

[8] Run-of-the-river had additional operation expenditures per GW of operation which were 5e-6 [€ GW^{-1}].
[9] Using the same assumption as in Caglayan [17], run-of-river capacity as of 2015 was used, therefore investment for this technology was not defined. However, they were considered in the operation per capacity costs.

A.1.8 Storage Technology Economic Parameters reproduced from Cagalyan [17]

<table>
<tr><td colspan="9">Electrical Storage</td></tr>
<tr><td></td><td>Charge/Discharge Efficiency</td><td>Charge/Discharge Rate</td><td>Self-Discharge Rate</td><td colspan="2">Invest Per Capacity</td><td colspan="2">OPEX Per Capacity [€ 10^{-3} GWh]</td><td>Economic Life</td></tr>
<tr><td>Lithium-Ion Battery</td><td>0.95</td><td>1</td><td>$4.23 * 10^{-5}$</td><td colspan="2">0.151</td><td colspan="2">0.151*0.01</td><td>22</td></tr>
<tr><td colspan="9">Hydrogen Storage</td></tr>
<tr><td></td><td>Charge/Discharge Efficiency</td><td>Charge/Discharge Rate</td><td>Min. Charge</td><td>Max. Charge</td><td>Max Capacity</td><td>Invest Per Capacity [€ 10^{-3} GWh]</td><td>OPEX Per Capacity [€ 10^{-3} GWh]</td><td>Economic life</td></tr>
<tr><td>Salt Caverns</td><td>1</td><td>$\frac{1}{604.76}$ & $\frac{1}{470.37}$</td><td>0.33</td><td>1</td><td>R.D.</td><td>0.362</td><td>0.362*0.02</td><td>30</td></tr>
<tr><td>Vessels</td><td>$\frac{1}{12}$</td><td>N.A.</td><td>0.1</td><td>1</td><td>N.A.</td><td>7.5</td><td>7.5*0.02</td><td>20</td></tr>
<tr><td colspan="9">Water Storage</td></tr>
<tr><td></td><td>Charge/Discharge Rate</td><td>Capacity</td><td colspan="2">OPEX per Charge [€ 10^{-6} GWh]</td><td colspan="2">OPEX per Discharge [€ 10^{-3} GWh]</td><td colspan="2">OPEX per Capacity [€ 10^{-3} GWh]</td></tr>
<tr><td>Pumped Hydro Storage (PHS)</td><td>1</td><td>R.D.</td><td colspan="2">3</td><td colspan="2">3</td><td colspan="2">$0.022 * \left(\frac{PH\ capacity}{PH + RES\ Capacity}\right)$</td></tr>
<tr><td>Hydro Reservoir (RES)</td><td>1</td><td>R.D.</td><td colspan="2">0</td><td colspan="2">3</td><td colspan="2">$0.02 * \left(\frac{RES\ capacity}{PH + RES\ Capacity}\right)$</td></tr>
</table>

A.1.9 Conversion Technology Parameters[10]

Technology	Used Commodities	Conversion ratio [GW:GW]	Investment Per Capacity [M€/GW]	OPEX Per Operation [M€/GW] 1e-6	OPEX per Capacity [M€/GW] 1e-3	Interest rate [%]	Economic Life [a]	Source
OCGT	Hydrogen to Electricity	2.5:1	0.5	7.5	5	8	25	[17] ,[21]
CCGT	Hydrogen to Electricity	$\frac{1}{0.4}:1$	0.76	2.4	11	8	25	[17] ,[21]
Gas Engine	Hydrogen to Electricity	$\frac{1}{0.485}:1$	0.715	7	4	8	20	[17] ,[21]
Electrolyzer	Electricity to Hydrogen	1:0.7	0.5	0.015	N.A.	8	10	[17] ,[21]
PEMFC	Hydrogen to Electricity	$\frac{1}{0.52}:1$	0.923	7.5	N.A.	8	10	[17] ,[21]
SOFC	Hydrogen to Electricity	$\frac{1}{0.7}:1$	1.5	2	N.A.	8	10	[17] ,[21]
PHS[11]	Water to/from electricity	1:1	N.A.	N.A.	N.A.	8	N.A.	[17] ,[21]
Reservoir[12]	Water to Electricity	1:1	N.A.	N.A.	N.A.	8	N.A.	[17] ,[21]
Steam Methane Reformer[13]	Natural gas to Hydrogen	1:0.85	0.810-1.620	N.A.	0.405	8	15	[60]
Biomass conversion	Biomass to Electricity	$\frac{1}{0.38}:1$	2.6	N.A.	0.065	8	30	[17],[19]

[10] OCGT: Hydrogen Open Cycle Gas Turbine, CCGT: Hydrogen Closed Cycle Gas Turbine, PEMFC: Polymer Electrolyte Membrane Fuel Cell, SOFC: Solid Oxide Fuel Cell.
[11] Economic parameters of Pumped Hydro storage technology was already considered in the source technology definition. Only the convertion of comodities was included for pumped hydro storage.
[12] Water used for pump hydro storage and resevoirs (hydro electric dams were not from the same source).
[13] Range of steam methane reformer price per GW of installed capacity was from 810 to 1620 mega euros per GW.

A.1.10 Pumped Hydro and Hydro Reservoir Maximum Conversion Capacity from water to electricity [GW to GW]

	Pumped Hydro	Hydro Reservoir		Pumped Hydro	Hydro Reservoir		Pumped Hydro	Hydro Reservoir		Pumped Hydro	Hydro Reservoir
01_es	0.93	0	25_fr	0	0	49_at	4.51	4.16	74_fi	0	0
02_es	1.79	5.81	26_fr	0	0	50_at	0.08	0.15	75_fi	0	0.3
03_es	0.21	0	27_fr	0.72	0	51_at	0	0	77_lt	0.92	0.1
04_es	0	0	28_be	1.33	0.01	52_it	5.52	3.68	78_lv	0	1.29
05_es	0.3	0	29_lu	1.33	0	53_it	0	0.2	79_no	1.05	6.49
06_es	0.55	0.81	30_nl	0	0	54_it	1.77	0.21	80_no	0	3.75
07_es	0	0	31_de	0.33	0	55_it	0	0.48	81_no	0.45	8.1
08_es	0.53	4.62	32_de	0	0	56_it	0.61	0	82_no	0	3.15
09_es	0.6	0	33_de	0.29	0.02	57_si	0.2	0.85	83_no	0	2.35
10_es	0	0	34_de	2.67	0	58_hu	0	0.03	84_no	0.07	4.53
11_es	1.49	0	35_de	0.56	0.02	59_ro	0	1.04	85_no	0	0.35
12_pt	1.14	1.28	36_de	1.95	0	60_ro	0.44	4.54	86_se	0	7.01
13_pt	0.64	0.23	37_de	0.56	0.17	61_ro	0	0.33	87_se	0.05	5.77
14_fr	0	1.43	38_dk	0	0	62_hr	0.28	1.4	88_se	0.16	1.31
15_fr	1.46	4.16	39_cz	0.05	0.65	63_ba	0.39	1.39	89_se	0	0
16_fr	0	2.35	40_cz	1.12	0	64_me	0	0	90_uk	0	0
17_fr	0	0	41_pl	0	0.01	65_rs	0.62	0.4	91_uk	0	0
18_fr	0	0.18	42_pl	0.2	0	66_bg	1.05	1.54	92_uk	2.19	0
19_fr	0	0.36	43_pl	0.6	0.04	67_mk	0	0.25	93_uk	0	0
20_fr	3.33	4.45	44_pl	0.09	0	68_gr	0.7	2.47	94_uk	0.74	0.14
21_fr	0	0	45_pl	0.88	0.11	69_gr	0	0	95_uk	0	0
22_fr	0	0	46_sk	0.98	0.32	70_al	0	1.4	96_ie	0.41	0
23_fr	0	0	47_ch	0.49	0.55	72_dk	0	0	98_it	0.25	0.13
24_fr	0	0	48_ch	1.35	7.41	73_ee	0	0	99_fr	0	0.19

A.1.11 Pumped Hydro Conversion Coefficients from Electricity to Stored Water

01_es	0.264	25_fr	0	49_at	0.047	74_fi	0
02_es	0.179	26_fr	0	50_at	0.005	75_fi	0
03_es	0.149	27_fr	0.2	51_at	0	77_lt	0.083
04_es	0	28_be	0.215	52_it	0.15	78_lv	0
05_es	0.021	29_lu	0.263	53_it	0	79_no	0.003
06_es	0.355	30_nl	0	54_it	0.215	80_no	0
07_es	0	31_de	0.216	55_it	0	81_no	0.073
08_es	0.275	32_de	0	56_it	0.167	82_no	0
09_es	0.11	33_de	0.209	57_si	0.37	83_no	0
10_es	0	34_de	0.153	58_hu	0	84_no	0.248
11_es	0.06	35_de	0.177	59_ro	0	85_no	0
12_pt	0.019	36_de	0.166	60_ro	0.024	86_se	0
13_pt	0.08	37_de	0.138	61_ro	0	87_se	0.527
14_fr	0	38_dk	0	62_hr	0.049	88_se	0.001
15_fr	0.076	39_cz	0.205	63_ba	0.244	89_se	0
16_fr	0	40_cz	0.195	64_me	0	90_uk	0
17_fr	0	41_pl	0	65_rs	0.144	91_uk	0
18_fr	0	42_pl	0.238	66_bg	0.026	92_uk	0.225
19_fr	0	43_pl	0.191	67_mk	0	93_uk	0
20_fr	0.122	44_pl	0.366	68_gr	0.151	94_uk	0.043
21_fr	0	45_pl	0.215	69_gr	0	95_uk	0
22_fr	0	46_sk	0.248	70_al	0	96_ie	0.162
23_fr	0	47_ch	0.006	72_dk	0	98_it	0.019
24_fr	0	48_ch	0.016	73_ee	0	99_fr	0

A.1.12 Wind Cost 10^9 € Per GW Installed Capacity Offshore

01_es	2.31	17_fr	3.05	33_de	0.00	49_at	0.00	65_rs	0.00	83_no	3.06
02_es	2.43	18_fr	0.00	34_de	0.00	50_at	0.00	66_bg	2.57	84_no	3.01
03_es	0.00	19_fr	0.00	35_de	0.00	51_at	0.00	67_mk	0.00	85_no	2.63
04_es	2.59	20_fr	0.00	36_de	0.00	52_it	2.14	68_gr	2.46	86_se	2.42
05_es	0.00	21_fr	2.87	37_de	0.00	53_it	2.50	69_gr	2.53	87_se	2.38
06_es	2.39	22_fr	1.99	38_dk	2.69	54_it	2.53	70_al	2.55	88_se	2.36
07_es	0.00	23_fr	0.00	39_cz	0.00	55_it	2.51	72_dk	2.30	89_se	2.05
08_es	0.00	24_fr	0.00	40_cz	0.00	56_it	2.90	73_ee	2.12	90_uk	2.36
09_es	2.50	25_fr	0.00	41_pl	0.00	57_si	0.00	74_fi	2.25	91_uk	2.82
10_es	2.63	26_fr	2.11	42_pl	0.00	58_hu	0.00	75_fi	2.35	92_uk	2.08
11_es	3.23	27_fr	0.00	43_pl	0.00	59_ro	0.00	77_lt	2.34	93_uk	2.79
12_pt	2.46	28_be	2.00	44_pl	2.08	60_ro	0.00	78_lv	2.24	94_uk	3.18
13_pt	2.48	29_lu	0.00	45_pl	2.33	61_ro	2.77	79_no	2.94	95_uk	1.95
14_fr	2.62	30_nl	2.80	46_sk	0.00	62_hr	2.54	80_no	2.36	96_ie	2.95
15_fr	2.06	31_de	2.87	47_ch	0.00	63_ba	0.00	81_no	2.80	98_it	2.42
16_fr	2.15	32_de	1.99	48_ch	0.00	64_me	2.52	82_no	0.00	99_fr	0.00

A.1.13 Wind Cost 109 € Per GW Installed Capacity Onshore

01_es	1.14	17_fr	1.10	33_de	1.14	49_at	1.21	65_rs	1.21	83_no	1.09
02_es	1.15	18_fr	1.12	34_de	1.16	50_at	1.18	66_bg	1.20	84_no	1.09
03_es	1.13	19_fr	1.11	35_de	1.20	51_at	1.12	67_mk	1.23	85_no	1.06
04_es	1.15	20_fr	1.17	36_de	1.21	52_it	1.28	68_gr	1.20	86_se	1.17
05_es	1.12	21_fr	1.09	37_de	1.19	53_it	1.22	69_gr	1.17	87_se	1.14
06_es	1.17	22_fr	1.09	38_dk	1.07	54_it	1.21	70_al	1.21	88_se	1.13
07_es	1.18	23_fr	1.12	39_cz	1.15	55_it	1.16	72_dk	1.07	89_se	1.12
08_es	1.18	24_fr	1.13	40_cz	1.12	56_it	1.16	73_ee	1.11	90_uk	1.08
09_es	1.16	25_fr	1.17	41_pl	1.11	57_si	1.24	74_fi	1.13	91_uk	1.06
10_es	1.19	26_fr	1.10	42_pl	1.12	58_hu	1.17	75_fi	1.12	92_uk	1.07
11_es	1.15	27_fr	1.13	43_pl	1.14	59_ro	1.24	77_lt	1.11	93_uk	1.07
12_pt	1.18	28_be	1.12	44_pl	1.12	60_ro	1.22	78_lv	1.11	94_uk	1.08
13_pt	1.15	29_lu	1.17	45_pl	1.10	61_ro	1.16	79_no	1.09	95_uk	1.05
14_fr	1.16	30_nl	1.09	46_sk	1.19	62_hr	1.18	80_no	1.13	96_ie	1.05
15_fr	1.11	31_de	1.12	47_ch	1.21	63_ba	1.18	81_no	1.10	98_it	1.15
16_fr	1.14	32_de	1.13	48_ch	1.19	64_me	1.17	82_no	1.14	99_fr	1.24

A.1.14 Node Location and Demands Part 1

Country	Region	Electrical Demand [GWh el / a]	Hydrogen Demand [GWh h2 / a]
Spain	01_es	11943	3558
Spain	02_es	35282	3518
Spain	03_es	19406	2389
Spain	04_es	29344	4195
Spain	05_es	12945	1843
Spain	06_es	74764	10456
Spain	07_es	63669	8947
Spain	08_es	22930	3216
Spain	09_es	53177	7293
Spain	10_es	31073	4195
Spain	11_es	86486	11577
Portugal	12_pt	32703	5191
Portugal	13_pt	31343	5071
France	14_fr	50076	9254
France	15_fr	29993	5489
France	16_fr	51226	9282
France	17_fr	40204	7395
France	18_fr	32763	6062
France	19_fr	32696	5979
France	20_fr	31340	5856
France	21_fr	44788	8098
France	22_fr	18214	3452
France	23_fr	109433	19971
France	24_fr	16639	3170
France	25_fr	45344	8536

A.1.15 Node locations and Demands Part 2

Country	Region	Electrical demand [GWh el / a]	Hydrogen Demand [GWh h2 / a]
France	26_fr	63316	11774
France	27_fr	7218	1384
Belgium	28_be	109328	20241
Luxembourg	29_lu	6460	1080
Netherlands	30_nl	146833	21284
Germany	31_de	97518	14574
Germany	32_de	55243	8677
Germany	33_de	126921	19710
Germany	34_de	55050	8954
Germany	35_de	71685	12322
Germany	36_de	77189	11862
Germany	37_de	92120	14094
Denmark	38_dk	10858	4492
Czech Republic	39_cz	36694	6460
Czech Republic	40_cz	27993	4915
Poland	41_pl	33336	6471
Poland	42_pl	23429	4552
Poland	43_pl	34393	6608
Poland	44_pl	32496	6580
Poland	45_pl	23534	4448
Slovakia	46_sk	24573	3501
Slovakia	47_ch	67119	9873
Slovakia	48_ch	4514	1712
Austria	49_at	18177	3311
Austria	50_at	24236	4532

A.1.16 Node locations and Demands Part 3

Country	Region	Electrical demand [GWh el / a]	Hydrogen Demand [GWh h2 / a]
Austria	51_at	33324	6044
Italy	52_it	176590	43819
Italy	53_it	38389	9749
Italy	54_it	80617	19984
Italy	55_it	42228	10741
Italy	56_it	30711	7763
Switzerland	57_si	12948	2936
Hungary	58_hu	55399	5680
Romania	59_ro	13073	3251
Romania	60_ro	28704	4430
Romania	61_ro	14439	4258
Croatia	62_hr	19937	5108
Bosnia and Herzegovina	63_ba	11719	1446
Montenegro	64_me	3220	360
Serbia	65_rs	26487	5468
Bulgaria	66_bg	27861	4279
North Macedonia	67_mk	7383	1463
Greece	68_gr	20830	4193
Greece	69_gr	39030	7584
Albania	70_al	13151	664
Denmark	72_dk	9152	3792
Estonia	73_ee	11528	1146
Finland	74_fi	3970	830
Finland	75_fi	72568	8204
Lithuania	77_lt	25643	3824

A.1.17 Node locations and Demands Part 4

Country	Region	Electrical demand [GWh el / a]	Hydrogen Demand [GWh h2 / a]
Latvia	78_lv	19366	2113
Norway	79_no	14306	877
Norway	80_no	12844	859
Norway	81_no	11353	717
Norway	82_no	35727	2305
Norway	83_no	10622	645
Norway	84_no	9818	630
Norway	85_no	1345	88
Sweden	86_se	3552	37
Sweden	87_se	10656	136
Sweden	88_se	80513	1047
Sweden	89_se	23680	299
United Kingdom	90_uk	131946	47790
United Kingdom	91_uk	32095	10735
United Kingdom	92_uk	128380	46394
United Kingdom	93_uk	35661	12552
United Kingdom	94_uk	17830	6857
United Kingdom	95_uk	10698	3702
Ireland	96_ie	36819	7203
Italy (Sardinia)	98_it	11517	2617
France (Corsica)	99_fr	3034	546

A.1.18 TAC Breakdown Per Category For Each Reformer Cost [10^9 €]

	SourceSink	Conversion	Transmission	Storage	TAC
810	159.137	36.419	2.343	15.352	213.251
891	159.939	37.209	2.310	15.479	214.937
972	160.980	37.626	2.253	15.509	216.369
1053	162.325	37.329	2.152	15.705	217.512
1134	163.578	36.994	1.907	15.925	218.404
1215	165.062	36.327	1.724	15.972	219.084
1296	166.591	35.063	1.803	16.082	219.539
1377	168.179	33.343	1.975	16.285	219.782
1458	169.119	32.121	2.141	16.459	219.840
1539	169.199	32.013	2.160	16.469	219.841
1620	169.203	32.010	2.160	16.470	219.843
REF	169.327	32.041	2.153	16.494	220.014

A.1.19 Source Technology TAC For Each Reformer Case [10^9 €]

	Offshore	Onshore	PVfix	PVsat	Gas Import	Biomass fuel	Run of the River	Rooftop PV
810	21.205	80.940	27.690	0.004	24.423	0.011	4.864	0.0
891	21.471	83.690	28.160	0.004	21.047	0.692	4.874	0.0
972	21.985	86.968	28.522	0.008	17.598	1.019	4.880	0.0
1053	22.896	90.658	29.230	0.006	13.647	0.998	4.890	0.0
1134	23.261	93.989	29.962	0.006	10.502	0.963	4.895	0.0
1215	23.640	97.655	30.515	0.013	7.490	0.850	4.900	0.0
1296	24.011	101.078	31.433	0.002	4.604	0.561	4.903	0.0
1377	24.528	104.101	32.510	0.007	1.857	0.270	4.905	0.0
1458	24.565	105.958	33.417	0.003	0.131	0.136	4.908	0.0
1539	24.574	106.086	33.501	0.003	0.000	0.127	4.908	0.0
1620	24.574	106.086	33.503	0.006	0.000	0.126	4.908	0.0
REF	24.905	105.757	33.622	0.002	0.000	0.133	4.908	0.0

A.1.20 810 Case Source Technology Capacity per Country

	Offshore Wind	Onshore Wind	Open Field PV w/ Tracking	Open Field PV wo/ Tracking	Rooftop	Run-of-the-River
Spain	3.0E-04	6.1E+01	1.7E-02	1.0E+02	9.9E-06	2.3E+00
Portugal	1.3E-04	1.6E+01	2.1E-03	4.2E+00	1.8E-06	2.7E+00
France	2.1E+01	1.3E+02	6.6E-03	8.4E+01	1.3E-05	0.0E+00
Belgium	4.7E+00	3.1E+00	2.4E-04	1.2E+01	8.6E-07	8.4E-02
Luxembourg	0.0E+00	4.2E-02	3.8E-04	5.2E+00	9.0E-07	0.0E+00
Netherlands	2.7E+01	2.0E+01	1.1E-04	5.0E-04	7.9E-07	0.0E+00
Germany	2.3E+01	3.0E+01	3.0E-03	3.6E+01	6.7E-06	4.2E+00
Denmark	2.5E-04	8.6E+00	2.6E-04	8.5E-04	1.4E-06	0.0E+00
Czech Republic	0.0E+00	1.3E+01	8.1E-04	1.7E+01	1.8E-06	4.1E-01
Poland	9.1E-01	2.3E+01	1.7E-03	4.1E+01	4.4E-06	4.0E-01
Slovakia	0.0E+00	4.4E+00	4.3E-04	1.6E+00	8.8E-07	1.1E+00
Switzerland	0.0E+00	8.9E+00	1.1E-03	6.3E+00	1.9E-06	3.7E+00
Austria	0.0E+00	3.2E+01	1.7E-03	2.1E+01	2.6E-06	4.6E+00
Italy	2.1E-04	5.1E+01	6.9E-03	1.0E+02	5.9E-06	1.0E+01
Slovenia	0.0E+00	2.2E+00	2.7E-04	9.8E-01	8.3E-07	1.9E-01
Hungary	0.0E+00	2.4E+00	6.5E-04	1.6E+01	9.7E-07	2.8E-02
Romania	6.8E-05	9.3E+00	1.2E-03	2.8E+00	2.7E-06	0.0E+00
Croatia	2.9E-05	5.1E+00	3.6E-04	3.0E+00	8.2E-07	4.4E-01
Bulgaria	0.0E+00	7.4E+00	3.5E-04	6.4E+00	8.0E-07	2.8E-01
Montenegro	2.0E-05	2.8E+00	4.5E-04	7.8E-03	8.9E-07	0.0E+00
Serbia	0.0E+00	5.1E+00	2.3E-04	1.6E-03	8.8E-07	2.0E+00
Bosnia Herzegovina	3.9E-05	2.1E+00	5.4E-04	4.9E+00	9.0E-07	6.1E-01
North Macedonia	0.0E+00	9.6E-01	6.0E-04	2.7E+00	9.0E-07	2.9E-01
Greece	9.2E-05	1.3E+01	1.6E-03	7.4E+00	1.8E-06	2.2E-01
Albania	2.2E-05	3.1E+00	5.5E-04	3.0E-03	9.0E-07	3.2E-02
Estonia	2.4E-04	9.1E+00	1.9E-04	1.4E-03	7.8E-07	0.0E+00
Finland	1.4E-04	1.8E+01	0.0E+00	0.0E+00	0.0E+00	3.0E+00
Lithuania	2.0E-04	9.1E+00	1.4E-04	4.1E-04	7.6E-07	0.0E+00
Latvia	1.8E-04	2.4E+00	2.0E-04	1.2E-03	8.0E-07	2.6E-01
Norway	1.7E-04	5.2E+00	4.7E-05	8.3E-05	5.2E-07	7.3E-01
Sweden	2.4E-04	2.4E+01	1.6E-04	3.5E-04	1.3E-06	1.9E+00
United Kingdom	1.7E+01	6.4E+01	8.7E-04	6.6E+00	4.7E-06	1.2E+00
Ireland	1.1E-04	1.3E+01	1.1E-04	5.0E-04	7.5E-07	1.2E-01

A.1.21 810 Case Source Technology TAC per Country

	Biomass Fuel	EU Gas Import	Offshore Wind	Onshore Wind	Open Field PV w/ Tracking	Open Field PV wo/ Tracking	Rooftop	Run-of-the-River
Spain	2.7E-06	0.0E+00	8.3E-05	8.4E+00	1.3E-03	5.7E+00	9.9E-07	2.2E-01
Portugal	3.6E-07	0.0E+00	3.6E-05	2.3E+00	1.6E-04	2.4E-01	1.8E-07	2.5E-01
France	1.5E-05	0.0E+00	4.7E+00	1.7E+01	5.1E-04	4.8E+00	1.3E-06	7.1E-01
Belgium	2.3E-06	0.0E+00	1.1E+00	4.1E-01	1.9E-05	6.6E-01	8.7E-08	8.3E-03
Luxembourg	0.0E+00	0.0E+00	0.0E+00	5.9E-03	2.9E-05	3.0E-01	9.0E-08	0.0E+00
Netherlands	1.1E-06	0.0E+00	6.1E+00	2.6E+00	8.6E-06	2.9E-05	7.9E-08	0.0E+00
Germany	1.1E-02	8.9E+00	5.7E+00	4.0E+00	2.3E-04	2.1E+00	6.7E-07	4.4E-01
Denmark	8.6E-07	0.0E+00	5.8E-05	1.1E+00	2.0E-05	4.9E-05	1.4E-07	0.0E+00
Czech Republic	2.8E-05	0.0E+00	0.0E+00	1.8E+00	6.3E-05	9.8E-01	1.8E-07	3.9E-02
Poland	3.7E-05	2.1E+00	1.9E-01	3.1E+00	1.3E-04	2.4E+00	4.4E-07	3.9E-02
Slovakia	2.9E-04	3.2E+00	0.0E+00	6.2E-01	3.3E-05	9.5E-02	8.8E-08	1.1E-01
Switzerland	4.4E-06	0.0E+00	0.0E+00	1.3E+00	8.6E-05	3.6E-01	1.9E-07	3.8E-01
Austria	2.9E-06	0.0E+00	0.0E+00	4.5E+00	1.3E-04	1.2E+00	2.6E-07	4.8E-01
Italy	9.5E-06	0.0E+00	5.9E-05	7.4E+00	5.3E-04	6.0E+00	5.9E-07	1.0E+00
Slovenia	1.6E-06	0.0E+00	0.0E+00	3.3E-01	2.1E-05	5.6E-02	8.3E-08	2.0E-02
Hungary	6.4E-05	4.5E+00	0.0E+00	3.3E-01	5.1E-05	9.0E-01	9.7E-08	2.9E-03
Romania	1.5E-06	2.5E-01	1.9E-05	1.4E+00	9.6E-05	1.6E-01	2.7E-07	0.0E+00
Croatia	0.0E+00	0.0E+00	8.2E-06	7.2E-01	2.8E-05	1.7E-01	8.2E-08	4.3E-02
Bulgaria	1.7E-07	0.0E+00	0.0E+00	1.0E+00	2.7E-05	3.7E-01	8.0E-08	2.9E-02
Montenegro	0.0E+00	0.0E+00	5.7E-06	3.9E-01	3.5E-05	4.5E-04	8.9E-08	0.0E+00
Serbia	1.6E-07	0.0E+00	0.0E+00	7.3E-01	1.8E-05	9.0E-05	8.8E-08	2.0E-01
Bosnia Herzegovina	2.2E-07	1.7E-01	1.1E-05	3.1E-01	4.1E-05	2.8E-01	9.0E-08	5.9E-02
North Macedonia	0.0E+00	0.0E+00	0.0E+00	1.4E-01	4.6E-05	1.6E-01	9.0E-08	2.8E-02
Greece	3.1E-07	3.4E-01	2.6E-05	1.8E+00	1.3E-04	4.3E-01	1.8E-07	2.1E-02
Albania	0.0E+00	0.0E+00	6.4E-06	4.3E-01	4.2E-05	1.7E-04	9.0E-08	3.6E-03
Estonia	1.9E-07	4.9E-05	5.2E-05	1.2E+00	1.4E-05	7.9E-05	7.8E-08	0.0E+00
Finland	2.9E-07	1.8E-01	3.7E-05	2.4E+00	0.0E+00	0.0E+00	0.0E+00	3.1E-01
Lithuania	6.8E-07	2.0E-04	5.0E-05	1.2E+00	1.0E-05	2.4E-05	7.6E-08	0.0E+00
Latvia	3.2E-07	4.7E-05	4.1E-05	3.2E-01	1.5E-05	6.7E-05	8.0E-08	2.4E-02
Norway	9.2E-08	4.6E+00	5.3E-05	6.8E-01	3.7E-06	4.8E-06	5.2E-08	8.9E-02
Sweden	8.1E-07	0.0E+00	5.9E-05	3.1E+00	1.2E-05	2.0E-05	1.3E-07	2.2E-01
United Kingdom	1.5E-06	0.0E+00	3.4E+00	8.3E+00	6.7E-05	3.8E-01	4.7E-07	1.2E-01
Ireland	2.5E-07	0.0E+00	2.9E-05	1.7E+00	8.7E-06	2.9E-05	7.5E-08	1.3E-02

A.1.22 Reference Case Source Technology Capacity per Country

	Offshore Wind	Onshore Wind	Open Field PV w/ Tracking	Open Field PV wo/ Tracking	Rooftop	Run-of-the-River
Spain	1.9E-04	6.6E+01	6.3E-03	1.1E+02	1.2E-05	2.3E+00
Portugal	9.1E-05	1.6E+01	1.3E-03	8.6E+00	2.5E-06	2.7E+00
France	2.2E+01	1.5E+02	3.9E-03	1.1E+02	1.5E-05	0
Belgium	4.7E+00	4.8E+00	1.8E-04	2.1E+01	8.1E-07	8.4E-02
Luxembourg	0.0E+00	4.2E-02	2.0E-04	5.6E+00	7.0E-07	0
Netherlands	3.3E+01	2.4E+01	1.4E-04	8.4E-04	7.8E-07	0
Germany	2.2E+01	3.6E+01	1.6E-03	3.7E+01	7.0E-06	4.2E+00
Denmark	2.9E-04	1.8E+01	2.4E-04	1.4E-01	1.3E-06	0
Czech Republic	0.0E+00	1.3E+01	4.0E-04	2.0E+01	2.0E-06	4.1E-01
Poland	2.0E+00	3.1E+01	1.1E-03	5.3E+01	4.6E-06	4.0E-01
Slovakia	0.0E+00	4.4E+00	2.3E-04	1.6E+00	1.0E-06	1.1E+00
Switzerland	0.0E+00	9.3E+00	5.1E-04	4.2E+00	2.1E-06	3.7E+00
Austria	0.0E+00	3.6E+01	8.0E-04	2.8E+01	2.9E-06	4.6E+00
Italy	1.7E-04	5.5E+01	3.3E-03	1.1E+02	7.2E-06	1.0E+01
Slovenia	0.0E+00	2.0E+00	1.4E-04	4.8E-04	8.1E-07	1.9E-01
Hungary	0.0E+00	3.9E+00	3.9E-04	1.5E+01	1.1E-06	2.8E-02
Romania	4.5E-05	9.3E+00	8.1E-04	1.8E+00	3.2E-06	0.0E+00
Croatia	2.3E-05	6.6E+00	3.4E-04	4.3E+00	9.3E-07	4.4E-01
Bulgaria	0.0E+00	1.1E+01	3.3E-04	4.3E+00	8.5E-07	2.8E-01
Montenegro	1.2E-05	2.9E+00	2.9E-04	1.1E+00	7.0E-07	0
Serbia	0.0E+00	5.1E+00	2.8E-04	9.8E-04	9.8E-07	2.0E+00
Bosnia Herzegovina	2.5E-05	3.4E+00	3.4E-04	4.2E+00	1.1E-06	6.1E-01
North Macedonia	0.0E+00	9.6E-01	4.2E-04	2.1E+00	9.0E-07	2.9E-01
Greece	7.7E-05	1.4E+01	7.2E-04	9.4E+00	2.3E-06	2.2E-01
Albania	1.4E-05	3.1E+00	3.7E-04	1.5E-03	1.0E-06	3.2E-02
Estonia	2.4E-04	1.0E+01	2.0E-04	2.9E+00	6.2E-07	0
Finland	1.1E-04	2.4E+01	0.0E+00	0.0E+00	0.0E+00	3.0E+00
Lithuania	8.7E-05	9.4E+00	1.6E-04	4.9E-04	6.6E-07	0
Latvia	1.4E-04	2.6E+00	2.8E-04	2.7E-01	6.6E-07	2.6E-01
Norway	2.5E-04	4.4E+01	5.3E-05	1.2E-04	4.3E-07	7.3E-01
Sweden	2.5E-04	4.0E+01	1.5E-04	3.8E-04	1.2E-06	1.9E+00
United Kingdom	2.7E+01	9.5E+01	6.0E-04	1.3E+01	4.4E-06	1.2E+00
Ireland	8.8E-05	3.3E+01	1.2E-04	2.6E+00	7.8E-07	1.2E-01

A.1.23 Reference Case Source Technology TAC per Country

	Biomass Fuel	Offshore Wind	Onshore Wind	Open Field PV w/ Tracking	Open Field PV wo/ Tracking	Rooftop	Run-of-the-River
Spain	1.4E-06	5.2E-05	9.1E+00	4.9E-04	6.6E+00	1.2E-06	2.2E-01
Portugal	2.1E-07	2.5E-05	2.2E+00	9.9E-05	5.0E-01	2.5E-07	2.5E-01
France	4.4E-06	4.9E+00	2.0E+01	3.0E-04	6.6E+00	1.5E-06	7.2E-01
Belgium	6.4E-07	1.1E+00	6.4E-01	1.4E-05	1.2E+00	8.1E-08	8.3E-03
Luxembourg	0.0E+00	0.0E+00	5.9E-03	1.5E-05	3.2E-01	7.0E-08	0.0E+00
Netherlands	3.8E-07	7.4E+00	3.1E+00	1.1E-05	4.8E-05	7.8E-08	0.0E+00
Germany	1.2E-01	5.5E+00	4.9E+00	1.2E-04	2.1E+00	7.0E-07	4.4E-01
Denmark	4.5E-07	6.7E-05	2.3E+00	1.8E-05	8.1E-03	1.3E-07	0.0E+00
Czech Republic	5.6E-06	0.0E+00	1.8E+00	3.1E-05	1.2E+00	2.0E-07	3.9E-02
Poland	8.6E-06	4.3E-01	4.1E+00	8.1E-05	3.0E+00	4.6E-07	3.9E-02
Slovakia	1.5E-02	0.0E+00	6.2E-01	1.7E-05	9.4E-02	1.0E-07	1.1E-01
Switzerland	6.6E-07	0.0E+00	1.3E+00	3.9E-05	2.4E-01	2.1E-07	3.9E-01
Austria	8.6E-07	0.0E+00	5.1E+00	6.2E-05	1.6E+00	2.9E-07	4.9E-01
Italy	1.9E-06	4.8E-05	8.0E+00	2.6E-04	6.6E+00	7.2E-07	1.0E+00
Slovenia	2.3E-07	0.0E+00	3.0E-01	1.1E-05	2.7E-05	8.1E-08	2.0E-02
Hungary	9.2E-06	0.0E+00	5.3E-01	3.0E-05	8.6E-01	1.1E-07	3.0E-03
Romania	6.7E-07	1.3E-05	1.4E+00	6.2E-05	1.0E-01	3.2E-07	0.0E+00
Croatia	0.0E+00	6.6E-06	9.3E-01	2.6E-05	2.5E-01	9.3E-08	4.3E-02
Bulgaria	7.9E-08	0.0E+00	1.5E+00	2.5E-05	2.5E-01	8.5E-08	3.0E-02
Montenegro	0.0E+00	3.4E-06	4.0E-01	2.2E-05	6.4E-02	7.0E-08	0.0E+00
Serbia	8.5E-08	0.0E+00	7.3E-01	2.2E-05	5.6E-05	9.8E-08	2.0E-01
Bosnia and Herzegovina	1.1E-07	7.2E-06	5.0E-01	2.6E-05	2.4E-01	1.1E-07	5.9E-02
North Macedonia	0.0E+00	0.0E+00	1.4E-01	3.2E-05	1.2E-01	9.0E-08	2.8E-02
Greece	1.8E-07	2.2E-05	2.0E+00	5.5E-05	5.4E-01	2.3E-07	2.2E-02
Albania	0.0E+00	4.1E-06	4.3E-01	2.9E-05	8.4E-05	1.0E-07	3.7E-03
Estonia	1.1E-07	5.3E-05	1.3E+00	1.6E-05	1.7E-01	6.2E-08	0.0E+00
Finland	1.8E-07	2.8E-05	3.2E+00	0.0E+00	0.0E+00	0.0E+00	3.1E-01
Lithuania	3.1E-07	2.2E-05	1.2E+00	1.3E-05	2.8E-05	6.6E-08	0.0E+00
Latvia	1.7E-07	3.4E-05	3.4E-01	2.2E-05	1.6E-02	6.6E-08	2.4E-02
Norway	8.0E-08	7.6E-05	5.7E+00	4.1E-06	6.9E-06	4.3E-08	8.7E-02
Sweden	4.2E-07	6.2E-05	5.3E+00	1.2E-05	2.2E-05	1.2E-07	2.2E-01
United Kingdom	8.7E-07	5.6E+00	1.2E+01	4.6E-05	7.5E-01	4.4E-07	1.2E-01
Ireland	1.1E-07	2.4E-05	4.3E+00	9.5E-06	1.5E-01	7.8E-08	1.3E-02

A.1.24 Storage Technology TAC Case by Case Comparison

	Hydrogen Vessel	Hydro Reservoir	Salt Cavern	Lithium Ion Battery	PHS
810	0.252	2.842	5.277	5.193	1.788
891	0.310	2.840	5.105	5.424	1.800
972	0.376	2.843	4.919	5.565	1.806
1053	0.437	2.847	4.835	5.774	1.812
1134	0.482	2.845	4.824	5.956	1.817
1215	0.540	2.842	4.740	6.034	1.816
1296	0.611	2.840	4.676	6.139	1.816
1377	0.631	2.839	4.650	6.351	1.814
1458	0.616	2.835	4.689	6.507	1.812
1539	0.612	2.835	4.695	6.514	1.812
1620	0.613	2.835	4.695	6.515	1.812
REF	0.615	2.739	4.693	6.636	1.811

A.1.25 Overall Storage Capacities GWh for every Case

	Hydro Reservoir	Hydrogen Vessel	Lithium-Ion Battery	Salt Cavern	PHS
810	158138.435	275.265	318.332	133945.431	1255.145
891	158138.435	338.927	332.485	129581.108	1255.145
972	158138.435	411.377	341.136	124871.804	1255.145
1053	158138.435	478.517	353.950	122728.385	1255.145
1134	158138.435	527.600	365.135	122445.343	1255.145
1215	158138.435	591.330	369.879	120307.544	1255.145
1296	158138.435	668.240	376.325	118681.507	1255.145
1377	158138.435	690.178	389.310	118038.759	1255.145
1458	158138.435	673.696	398.911	119020.997	1255.145
1539	158138.435	669.663	399.331	119178.546	1255.145
1620	158138.435	670.226	399.349	119170.206	1255.145
REF	158138.435	672.687	406.799	119123.040	1255.145

A.1.26 Additional Costs for Specific Cost Pairs Related to CO_2 Emission [G€] Part 1

		891 M€/GW Case								
		Carbon Emission Tax Per tCO_2								
		0	25	50	75	100	125	150	175	200
Carbon Transport and Storage additional cost per t CO_2	0	0.00	0.18	0.37	0.55	0.73	0.92	1.10	1.29	1.47
	5	0.70	0.88	1.07	1.25	1.43	1.62	1.80	1.98	2.17
	10	1.40	1.58	1.76	1.95	2.13	2.31	2.50	2.68	2.86
	15	2.09	2.28	2.46	2.64	2.83	3.01	3.20	3.38	3.56
	20	2.79	2.98	3.16	3.34	3.53	3.71	3.89	4.08	4.26
	25	3.49	3.67	3.86	4.04	4.22	4.41	4.59	4.77	4.96
	30	4.19	4.37	4.55	4.74	4.92	5.11	5.29	5.47	5.66
	35	4.88	5.07	5.25	5.44	5.62	5.80	5.99	6.17	6.35
	40	5.58	5.77	5.95	6.13	6.32	6.50	6.68	6.87	7.05
	45	6.28	6.46	6.65	6.83	7.02	7.20	7.38	7.57	7.75

		972 M€/GW Case								
		Carbon Emission Tax Per tCO_2								
		0	25	50	75	100	125	150	175	200
Carbon Transport and Storage additional cost per t CO_2	0	0.00	0.15	0.31	0.46	0.61	0.77	0.92	1.07	1.23
	5	0.58	0.74	0.89	1.04	1.20	1.35	1.50	1.66	1.81
	10	1.17	1.32	1.47	1.63	1.78	1.93	2.09	2.24	2.40
	15	1.75	1.90	2.06	2.21	2.36	2.52	2.67	2.83	2.98
	20	2.33	2.49	2.64	2.79	2.95	3.10	3.26	3.41	3.56
	25	2.92	3.07	3.22	3.38	3.53	3.69	3.84	3.99	4.15
	30	3.50	3.65	3.81	3.96	4.12	4.27	4.42	4.58	4.73
	35	4.08	4.24	4.39	4.55	4.70	4.85	5.01	5.16	5.31
	40	4.67	4.82	4.98	5.13	5.28	5.44	5.59	5.74	5.90
	45	5.25	5.41	5.56	5.71	5.87	6.02	6.17	6.33	6.48

		1053 M€/GW Case								
		Carbon Emission Tax Per tCO_2								
		0	25	50	75	100	125	150	175	200
Carbon Transport and Storage additional cost per t CO_2	0	0.00	0.12	0.24	0.36	0.48	0.60	0.71	0.83	0.95
	5	0.45	0.57	0.69	0.81	0.93	1.05	1.17	1.29	1.41
	10	0.90	1.02	1.14	1.26	1.38	1.50	1.62	1.74	1.86
	15	1.36	1.48	1.60	1.71	1.83	1.95	2.07	2.19	2.31
	20	1.81	1.93	2.05	2.17	2.29	2.41	2.52	2.64	2.76
	25	2.26	2.38	2.50	2.62	2.74	2.86	2.98	3.10	3.22
	30	2.71	2.83	2.95	3.07	3.19	3.31	3.43	3.55	3.67
	35	3.17	3.29	3.41	3.52	3.64	3.76	3.88	4.00	4.12
	40	3.62	3.74	3.86	3.98	4.10	4.22	4.33	4.45	4.57
	45	4.07	4.19	4.31	4.43	4.55	4.67	4.79	4.91	5.03

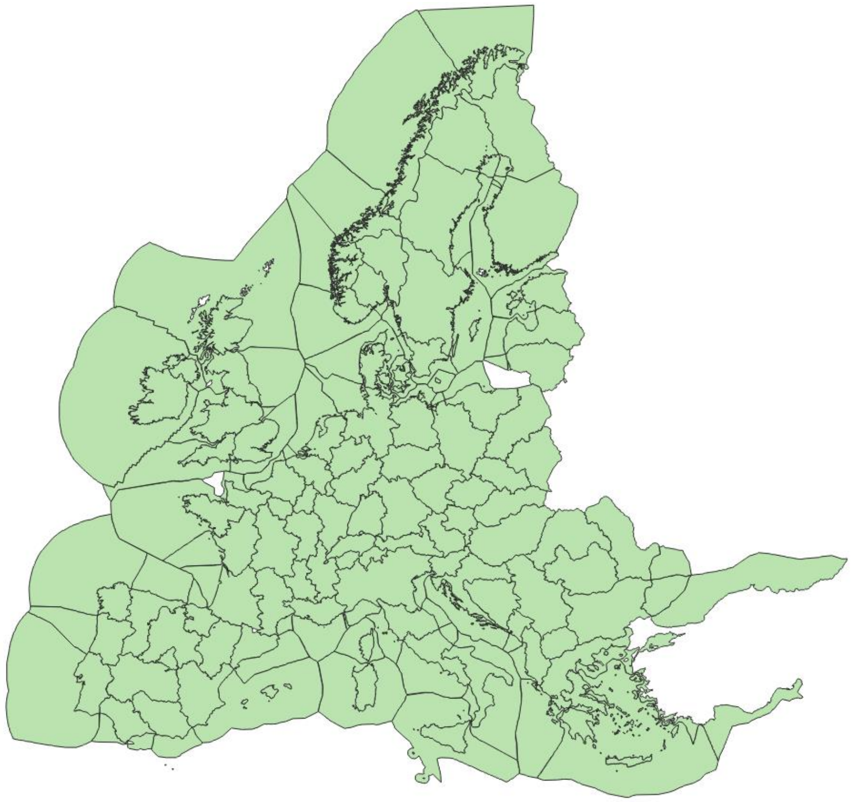
A.1.27 Additional Costs for Specific Cost Pairs Related to CO_2 Emission [G€] Part 2

		1134 M€/GW Case								
		Carbon Emission Tax Per tCO_2								
		0	25	50	75	100	125	150	175	200
Carbon Transport and Storage additional cost per t CO_2	0	0.00	0.09	0.18	0.27	0.37	0.46	0.55	0.64	0.73
	5	0.35	0.44	0.53	0.62	0.71	0.81	0.90	0.99	1.08
	10	0.70	0.79	0.88	0.97	1.06	1.15	1.25	1.34	1.43
	15	1.04	1.14	1.23	1.32	1.41	1.50	1.59	1.69	1.78
	20	1.39	1.48	1.58	1.67	1.76	1.85	1.94	2.03	2.13
	25	1.74	1.83	1.92	2.02	2.11	2.20	2.29	2.38	2.47
	30	2.09	2.18	2.27	2.36	2.46	2.55	2.64	2.73	2.82
	35	2.44	2.53	2.62	2.71	2.80	2.90	2.99	3.08	3.17
	40	2.79	2.88	2.97	3.06	3.15	3.24	3.34	3.43	3.52
	45	3.13	3.23	3.32	3.41	3.50	3.59	3.68	3.78	3.87

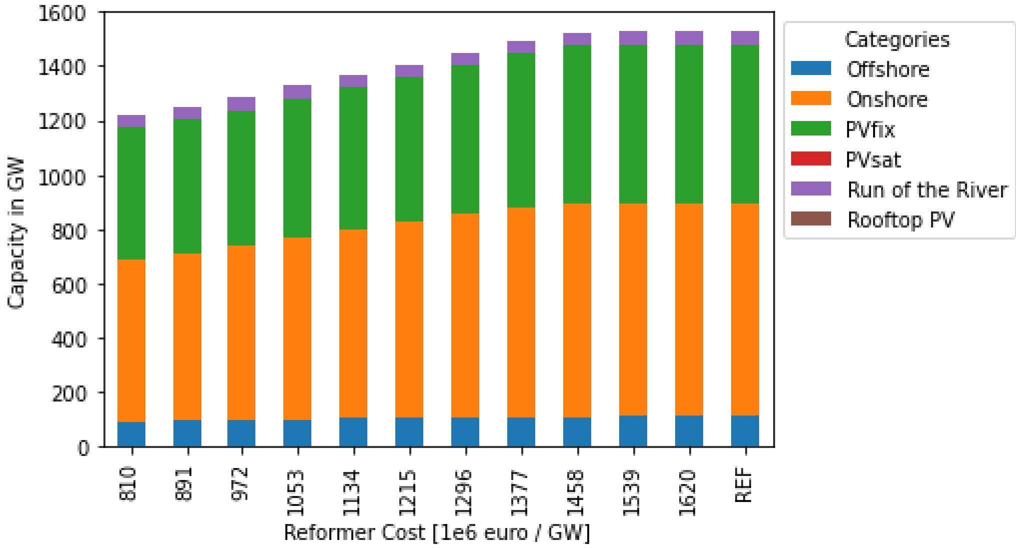
		1215 M€/GW Case								
		Carbon Emission Tax Per tCO_2								
		0	25	50	75	100	125	150	175	200
Carbon Transport and Storage additional cost per t CO_2	0	0.00	0.07	0.13	0.20	0.26	0.33	0.39	0.46	0.52
	5	0.25	0.31	0.38	0.44	0.51	0.58	0.64	0.71	0.77
	10	0.50	0.56	0.63	0.69	0.76	0.82	0.89	0.95	1.02
	15	0.75	0.81	0.88	0.94	1.01	1.07	1.14	1.20	1.27
	20	0.99	1.06	1.12	1.19	1.25	1.32	1.39	1.45	1.52
	25	1.24	1.31	1.37	1.44	1.50	1.57	1.63	1.70	1.76
	30	1.49	1.56	1.62	1.69	1.75	1.82	1.88	1.95	2.01
	35	1.74	1.80	1.87	1.93	2.00	2.07	2.13	2.20	2.26
	40	1.99	2.05	2.12	2.18	2.25	2.31	2.38	2.44	2.51
	45	2.24	2.30	2.37	2.43	2.50	2.56	2.63	2.69	2.76

		1296 M€/GW Case								
		Carbon Emission Tax Per tCO_2								
		0	25	50	75	100	125	150	175	200
Carbon Transport and Storage additional cost per t CO_2	0	0.00	0.04	0.08	0.12	0.16	0.20	0.24	0.28	0.32
	5	0.15	0.19	0.23	0.27	0.31	0.35	0.39	0.43	0.47
	10	0.31	0.35	0.39	0.43	0.47	0.51	0.55	0.59	0.63
	15	0.46	0.50	0.54	0.58	0.62	0.66	0.70	0.74	0.78
	20	0.61	0.65	0.69	0.73	0.77	0.81	0.85	0.89	0.93
	25	0.76	0.80	0.84	0.88	0.92	0.96	1.00	1.04	1.08
	30	0.92	0.96	1.00	1.04	1.08	1.12	1.16	1.20	1.24
	35	1.07	1.11	1.15	1.19	1.23	1.27	1.31	1.35	1.39
	40	1.22	1.26	1.30	1.34	1.38	1.42	1.46	1.50	1.54
	45	1.37	1.41	1.45	1.49	1.53	1.57	1.61	1.66	1.70

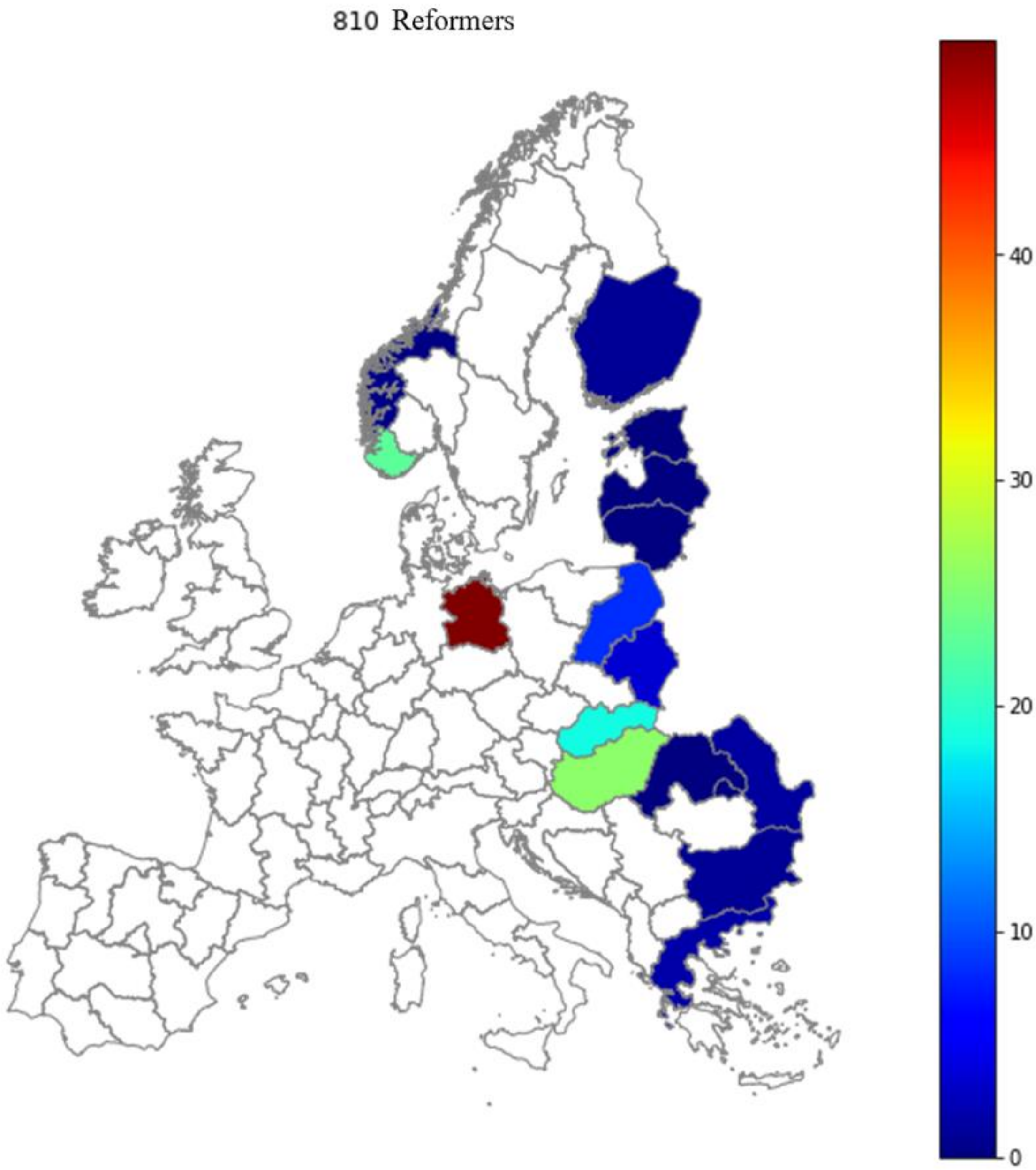
Figures



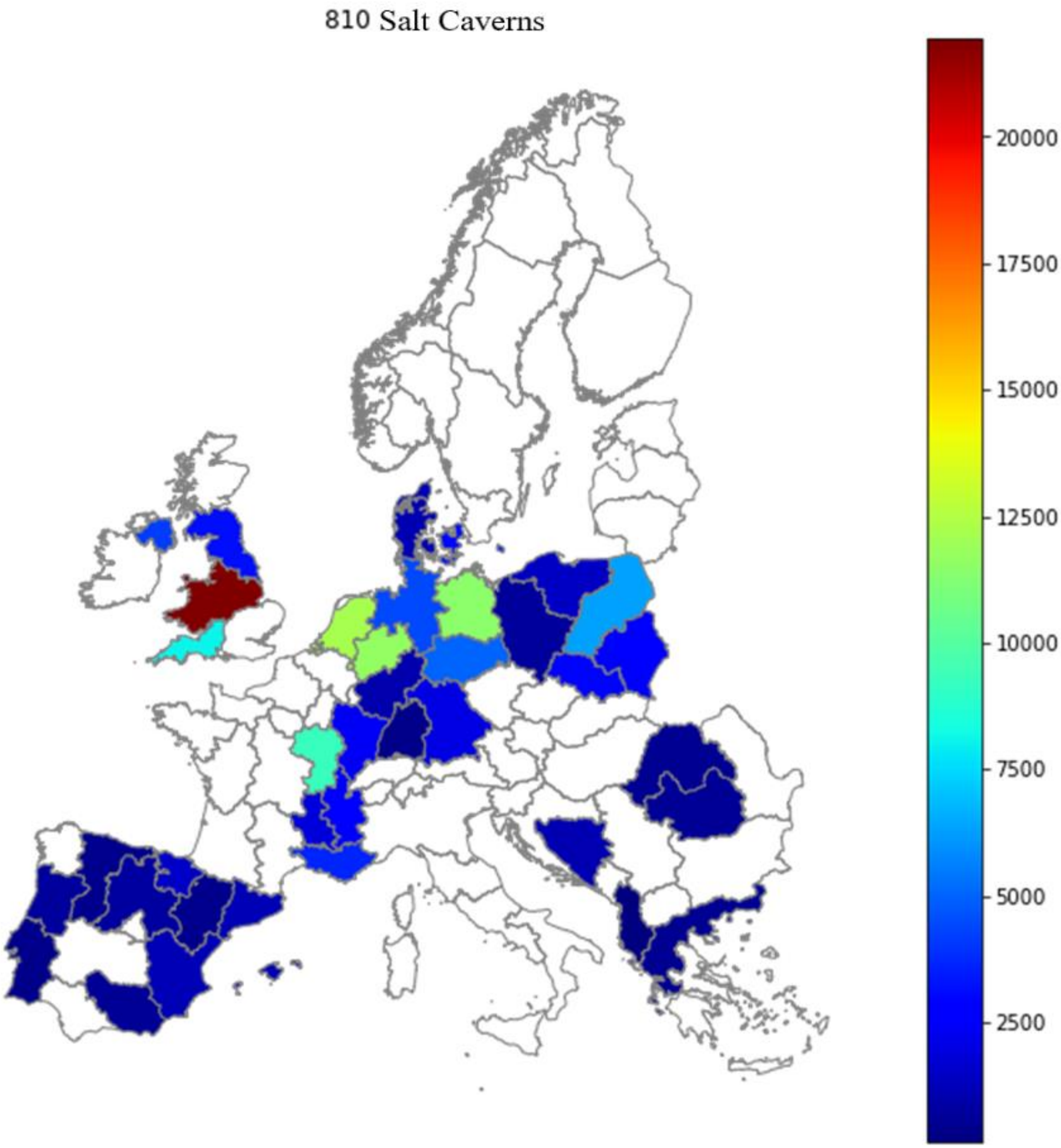
A.2.1 All Thesis Regions (Onshore and Offshore)



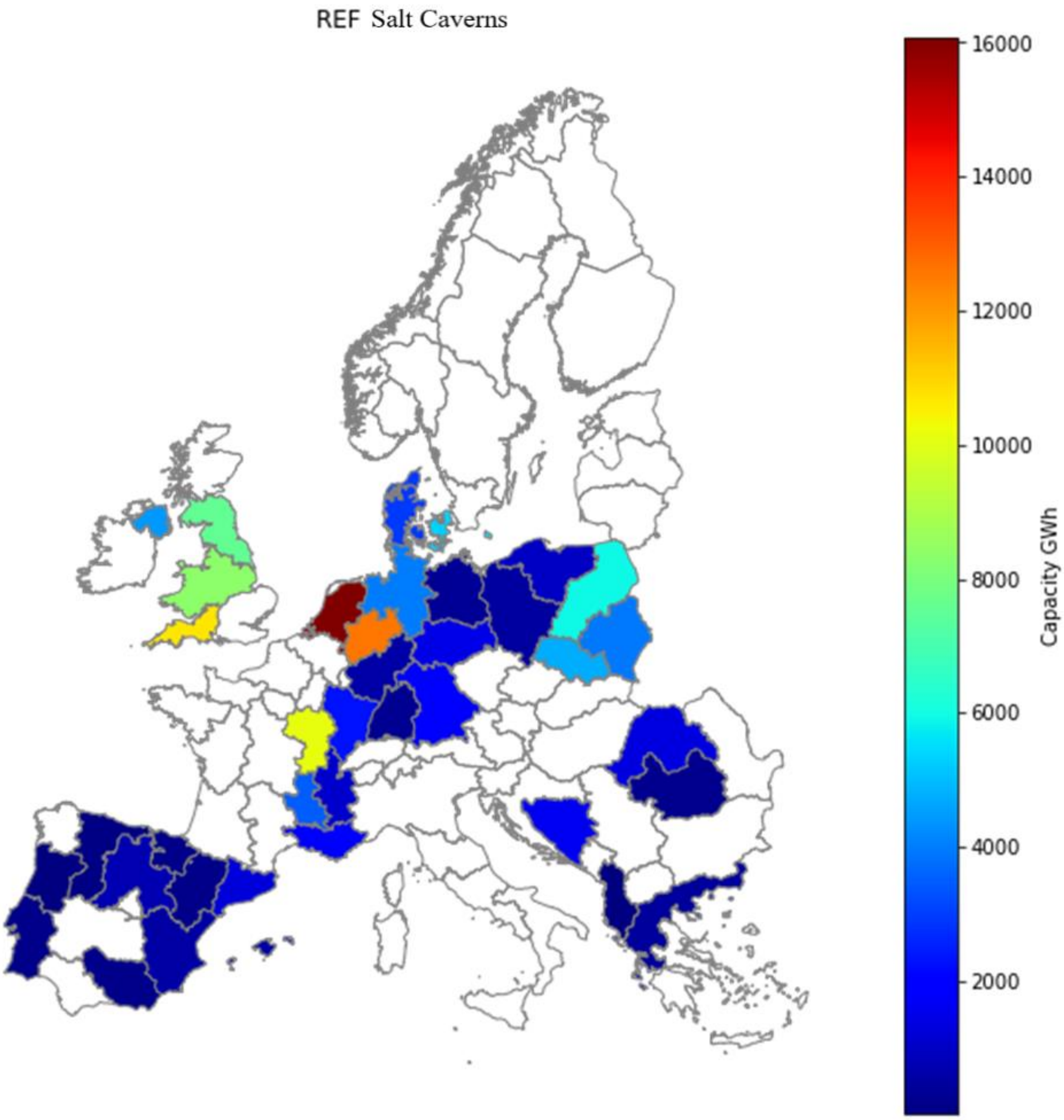
A.2.2 Source Modeling Class Capacity Comparison between Cases



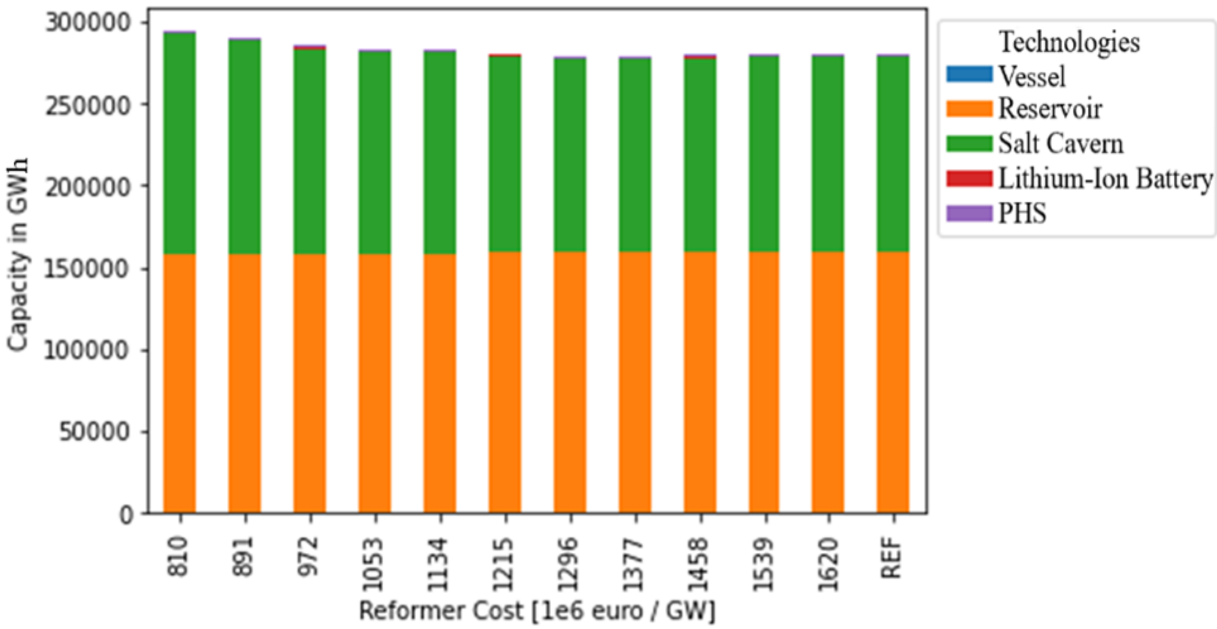
A.2.3 810 M€/GW Case Natural Gas Reformer Capacity



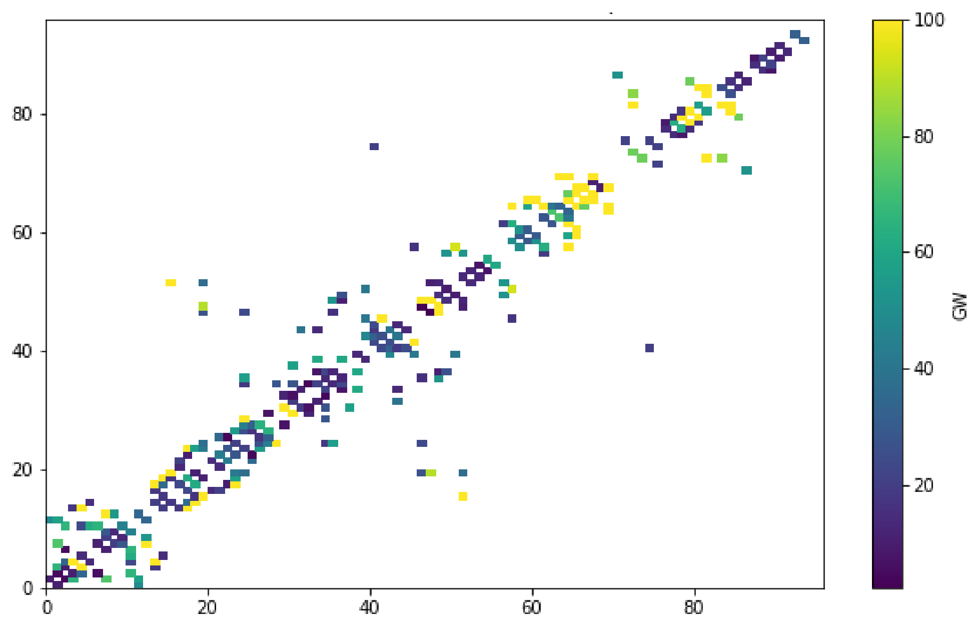
A.2.4 810 M€/GW Case Salt Cavern Capacity



A.2.5 Reference Case Salt Cavern Capacity

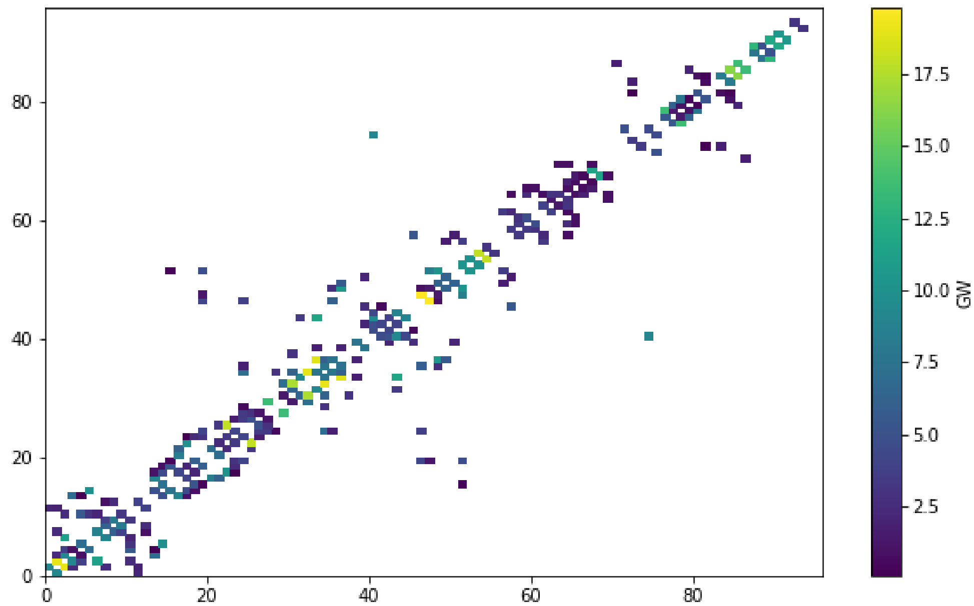


A.2.6 Storage Modeling Class Capacity Case by Case Comparison

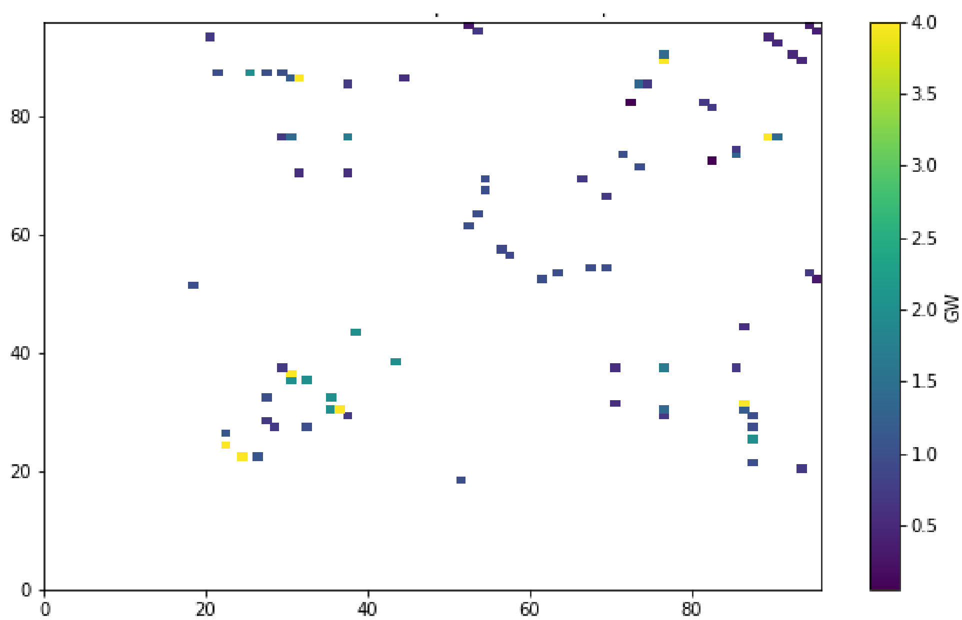


A.2.7 Color Map For AC Connection Reactants[14]

[14] Points with values equal to or greater than 100 are all the same color in order for the figure to be more legible.

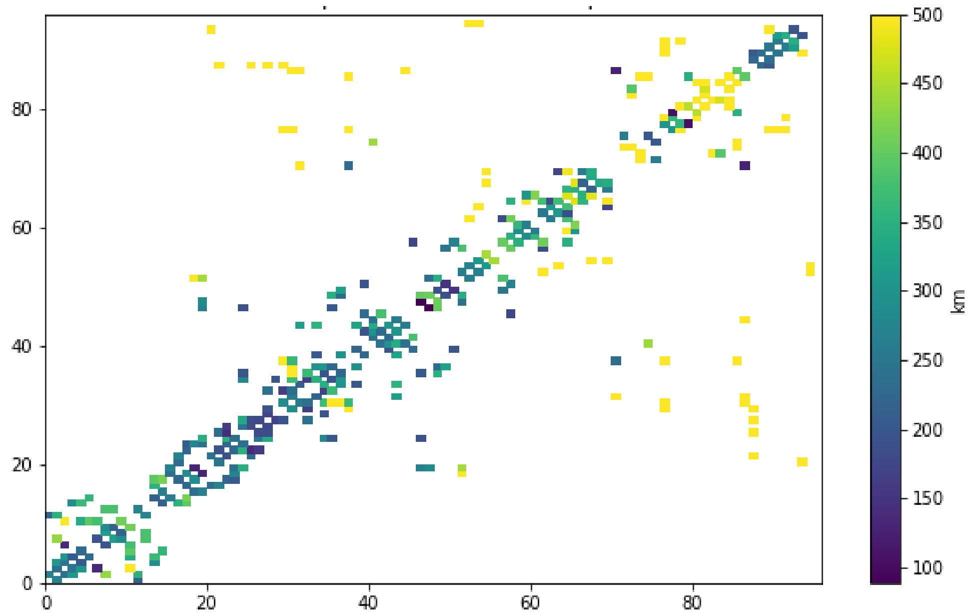


A.2.8 Color Map for all Possible AC lines (Axies are centroid names)

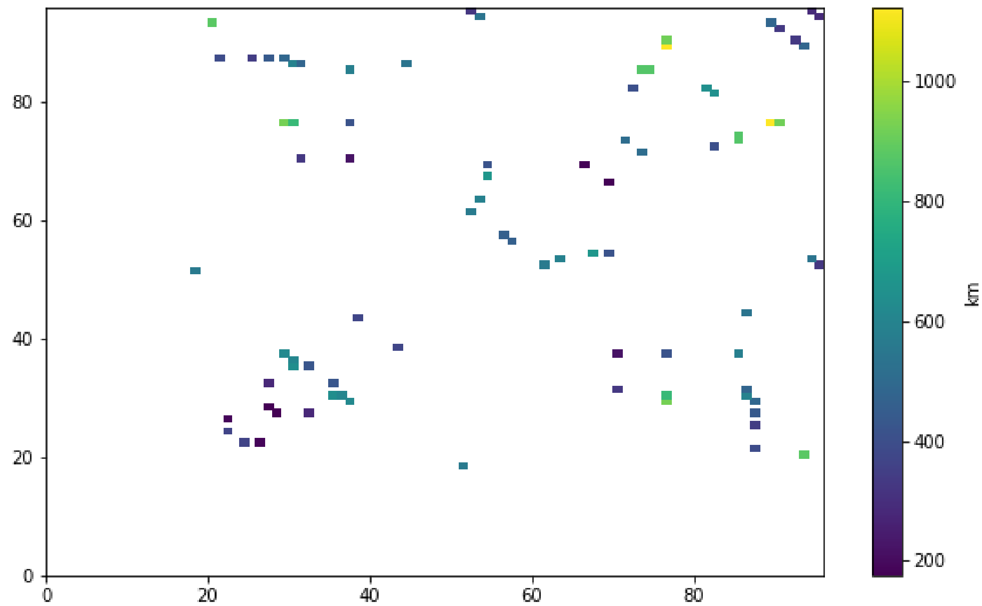


A.2.9 Color Map For All Possible DC lines (Axies are centroid names)[15]

[15] Points with values equal to or greater than 4 are all the same color in order for the figure to be more legible.

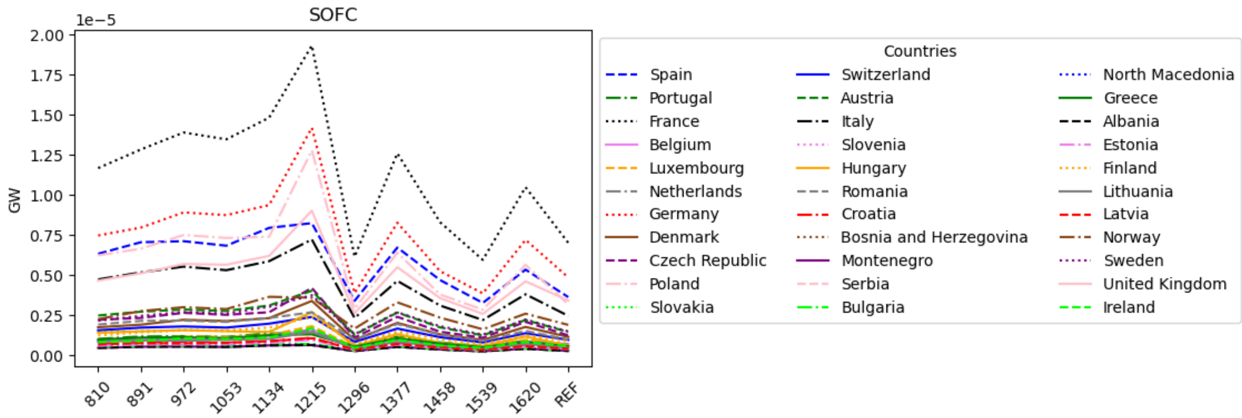


A.2.10 Color Map For All Possible H2 Pipelines (Axies are centroid names)[16]

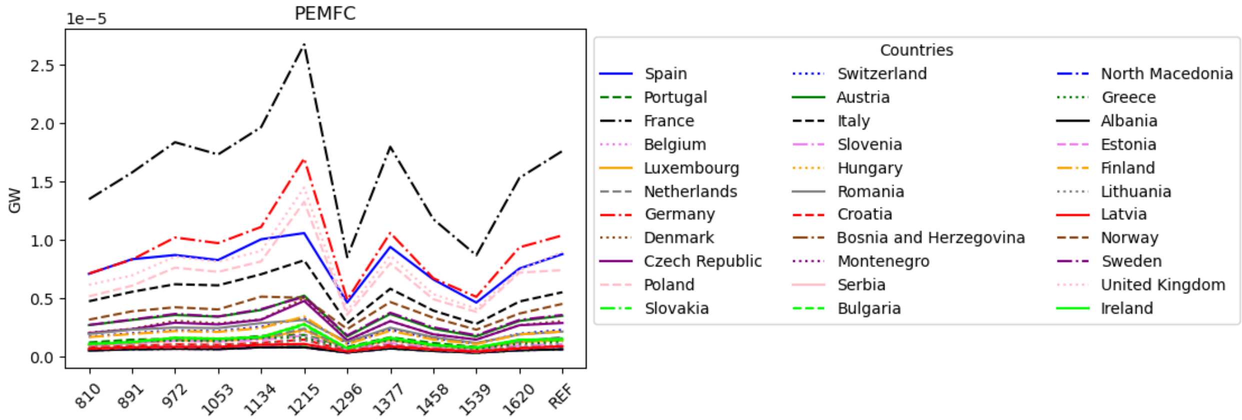


A.2.11 DC Line Distances (Axies are centroid names)

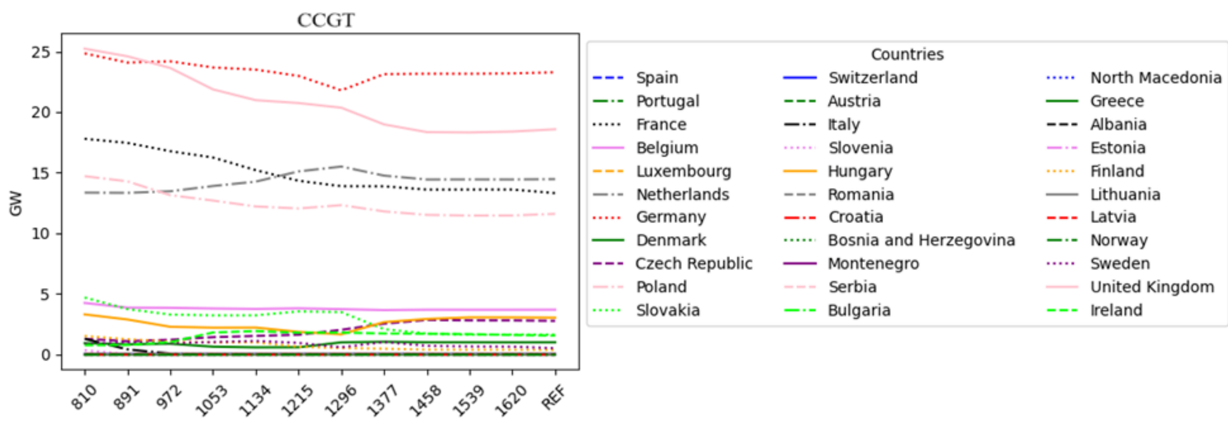
[16] Points with values equal to or greater than 500 are all the same color in order for the figure to be more legible.



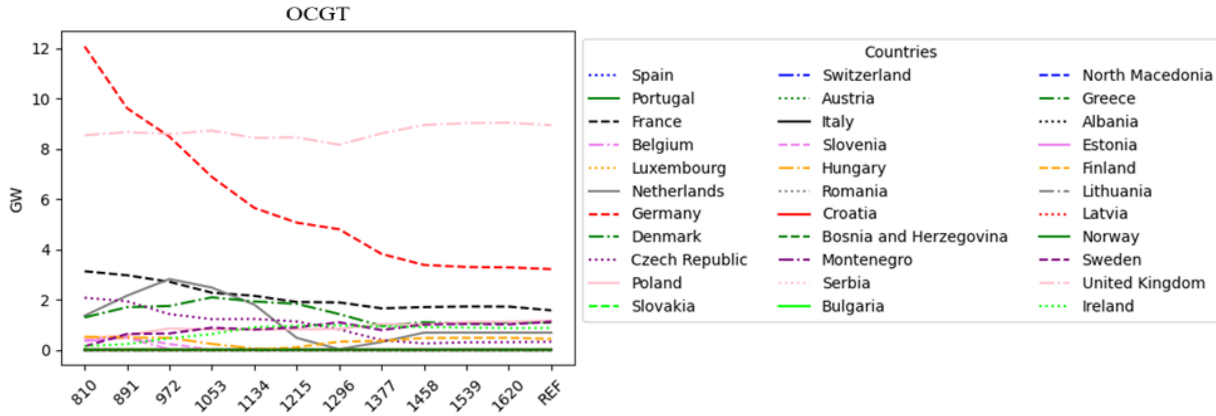
A.2.12 Country-Wide SOFC Installed Capacity Per Case



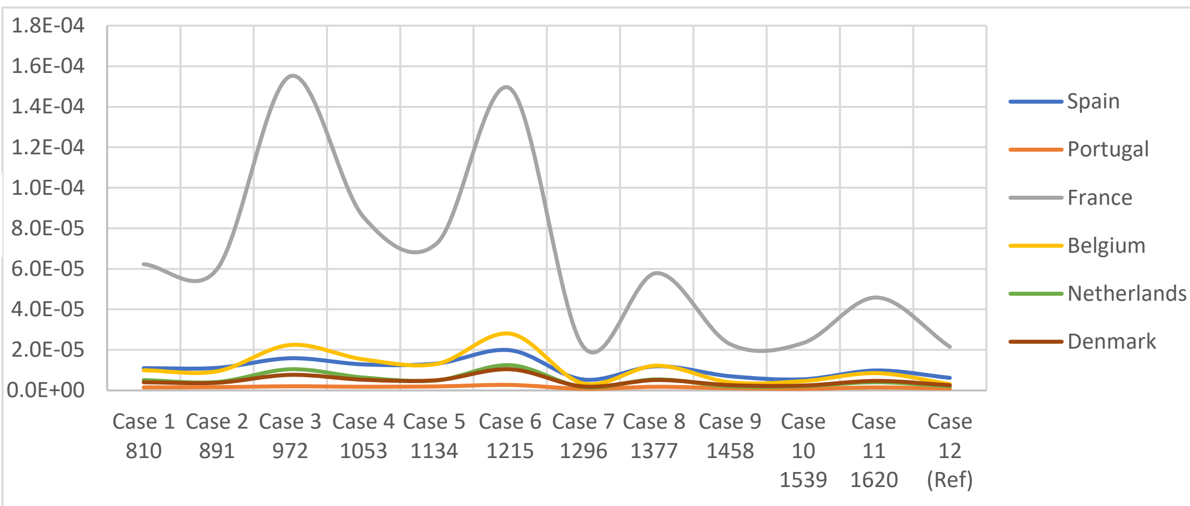
A.2.13 Country-Wide PEMFC Installed Capacity Per Case



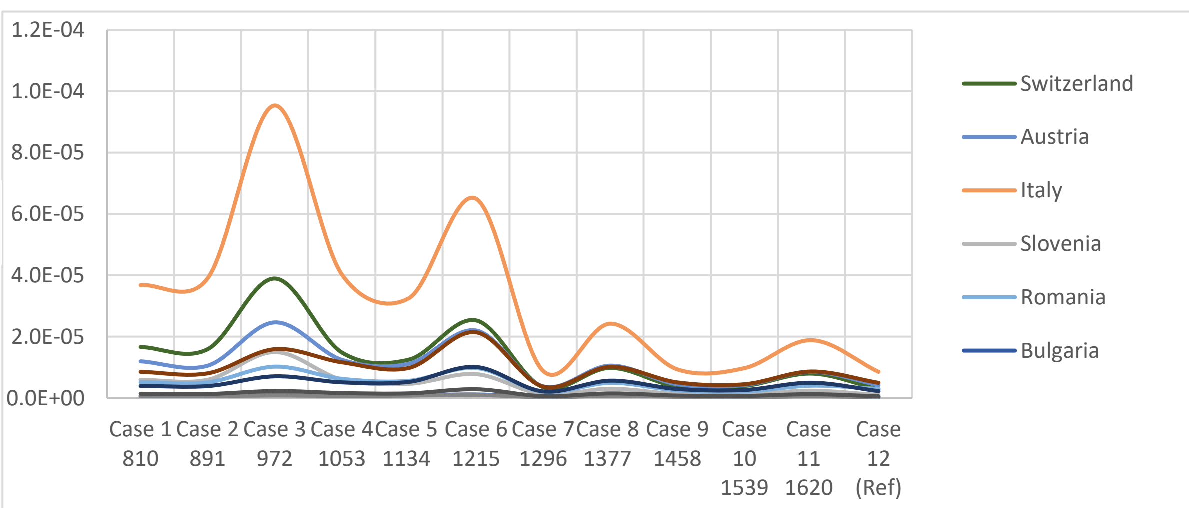
A.2.14 Country-Wide CCGT Installed Capacity Per Case



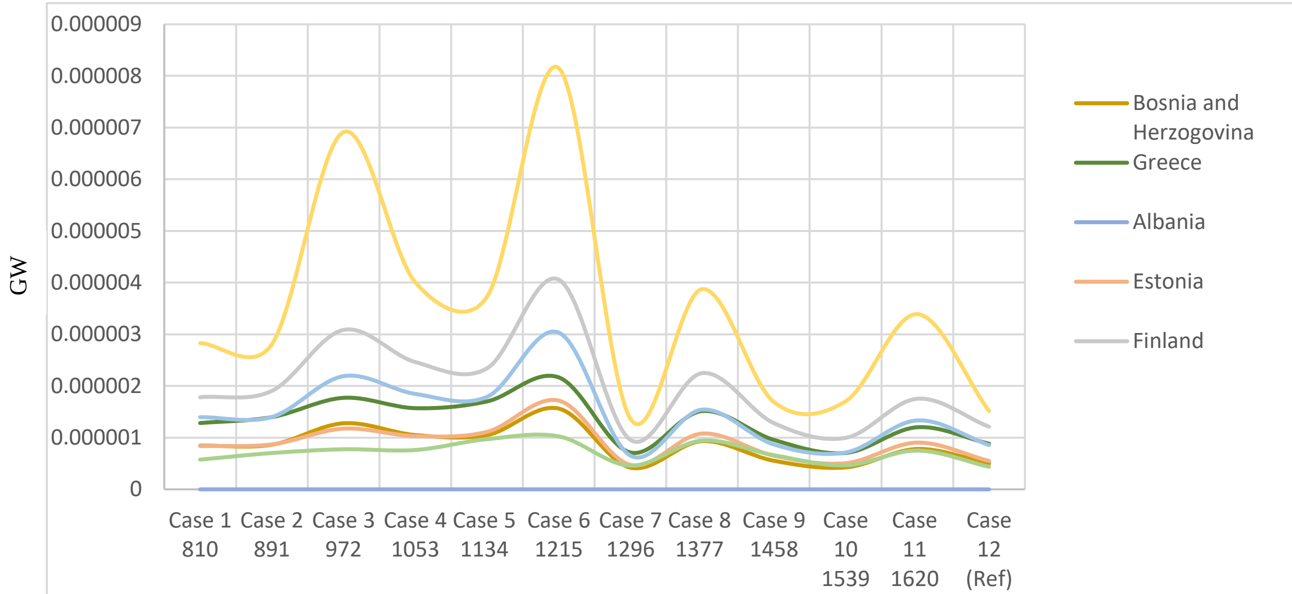
A.2.15 Country-Wide OCGT Installed Capacity Per Case



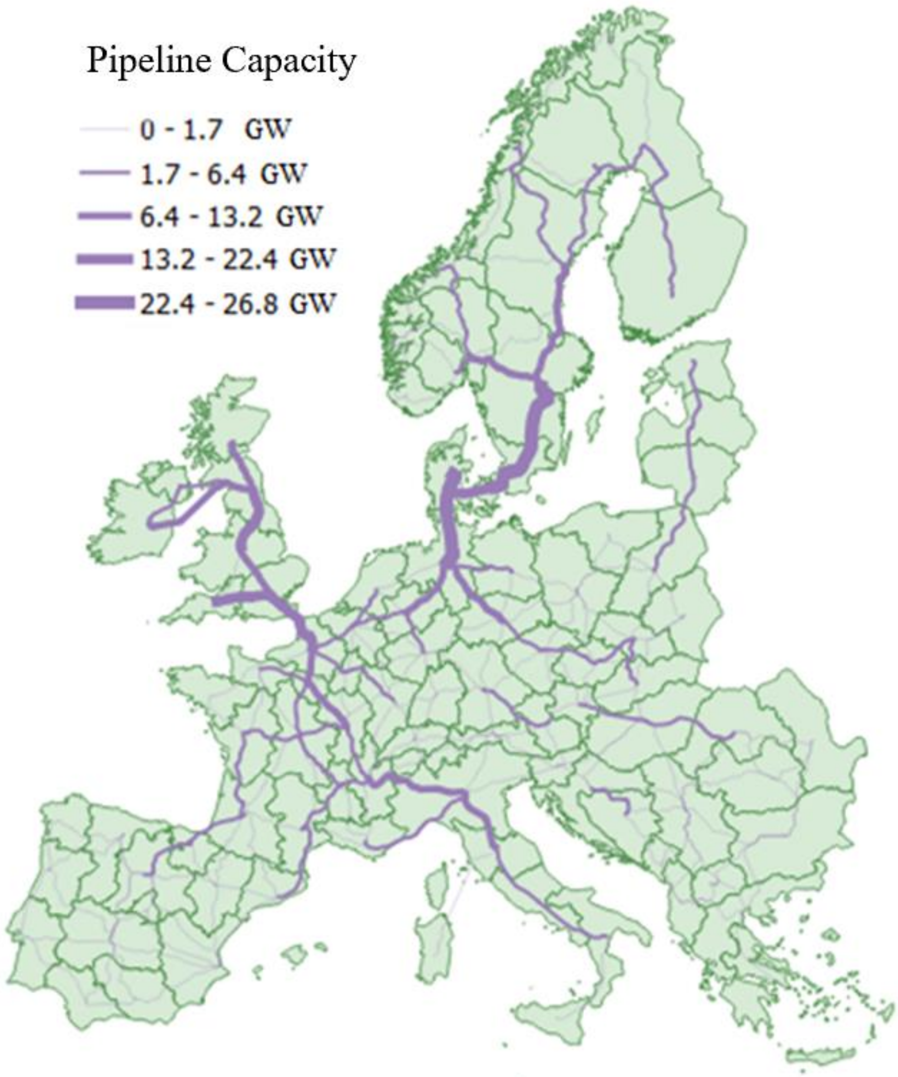
A.2.16 Country-Wide Biomass CHP Capacity Part 1 (units are GW)



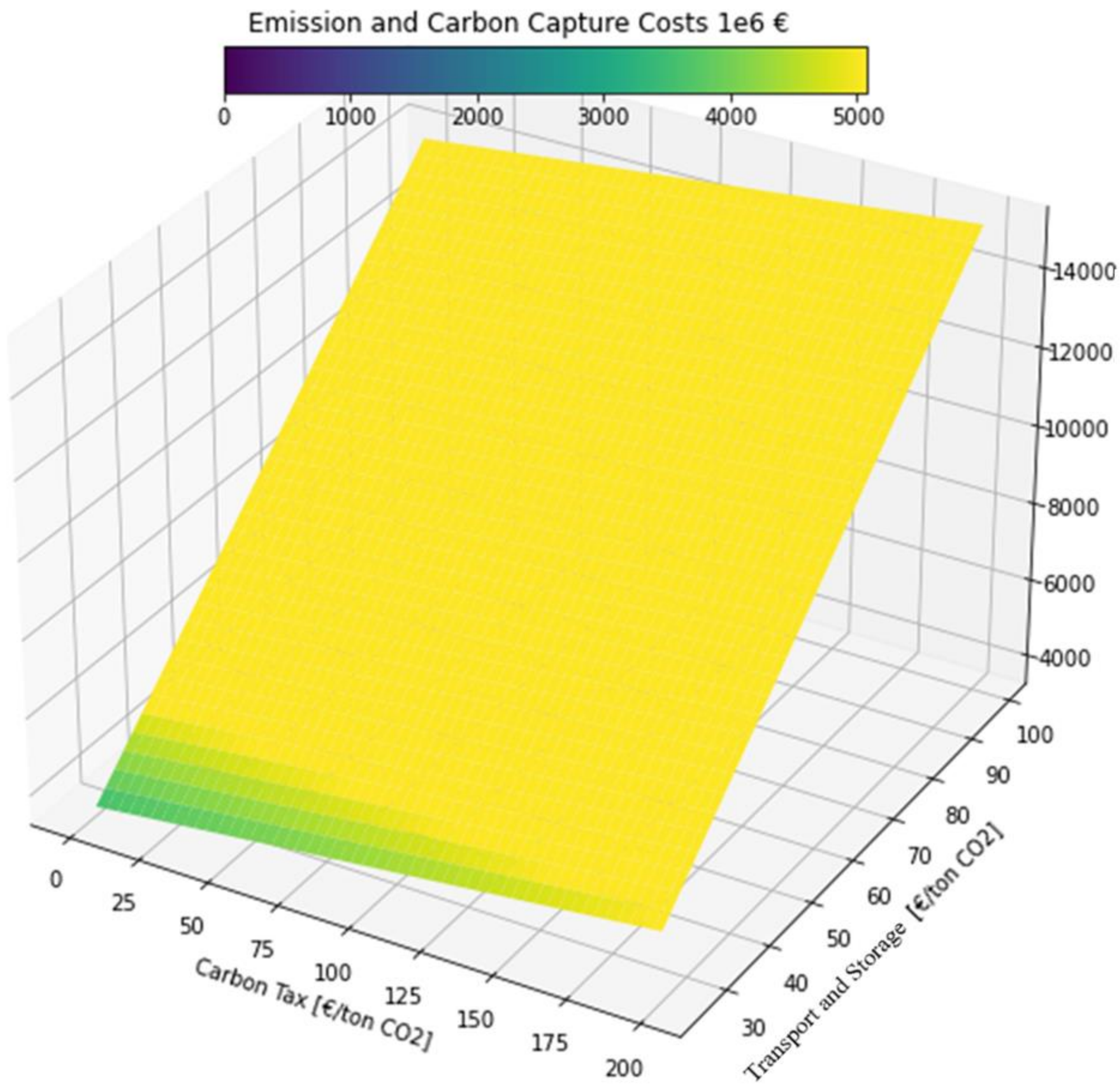
A.2.17 Country-Wide Biomass CHP Capacity Part 2 (untis are GW)



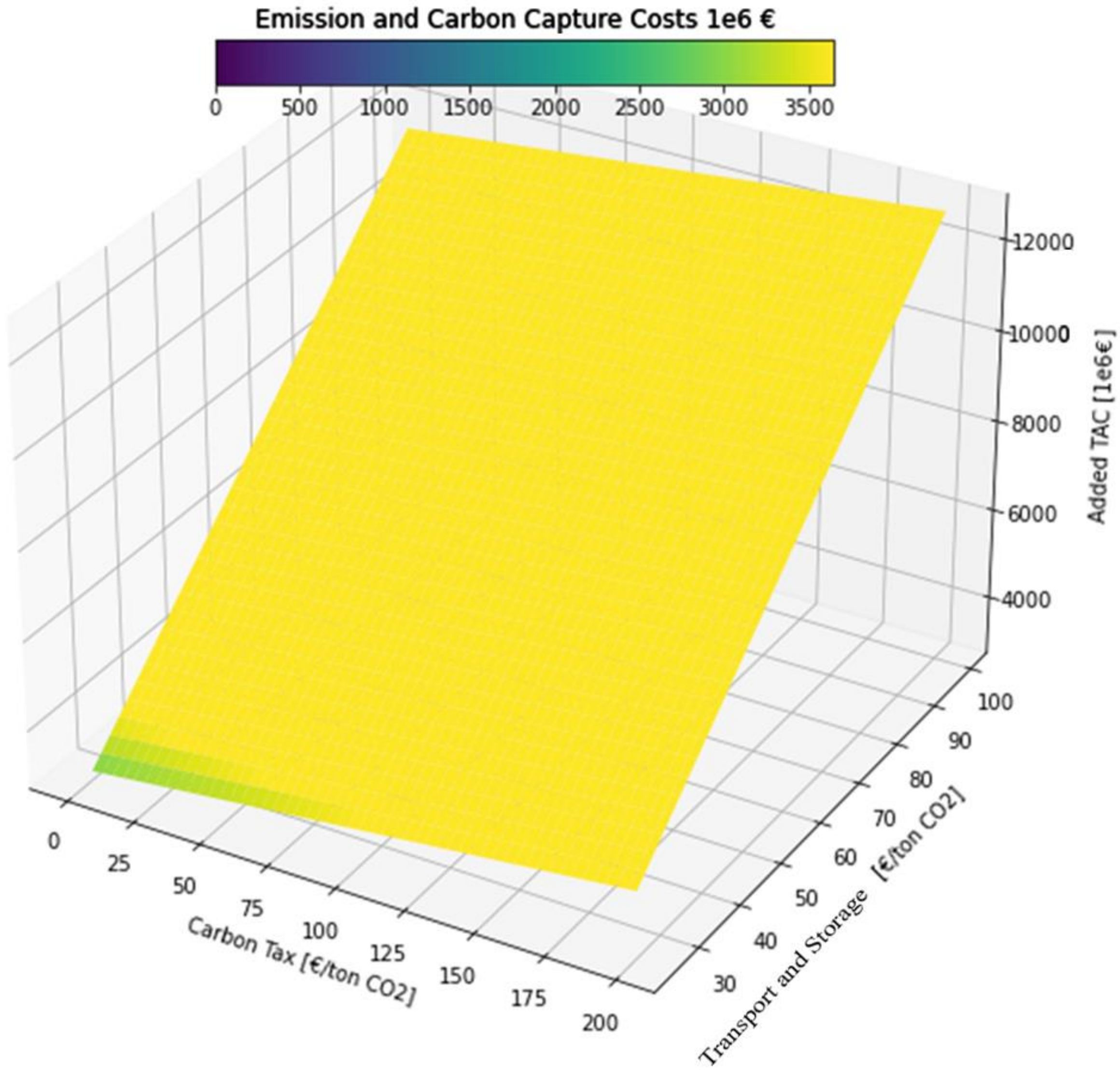
A.2.18 Country-Wide Biomass CHP Capacity Part 3 (units are GW)



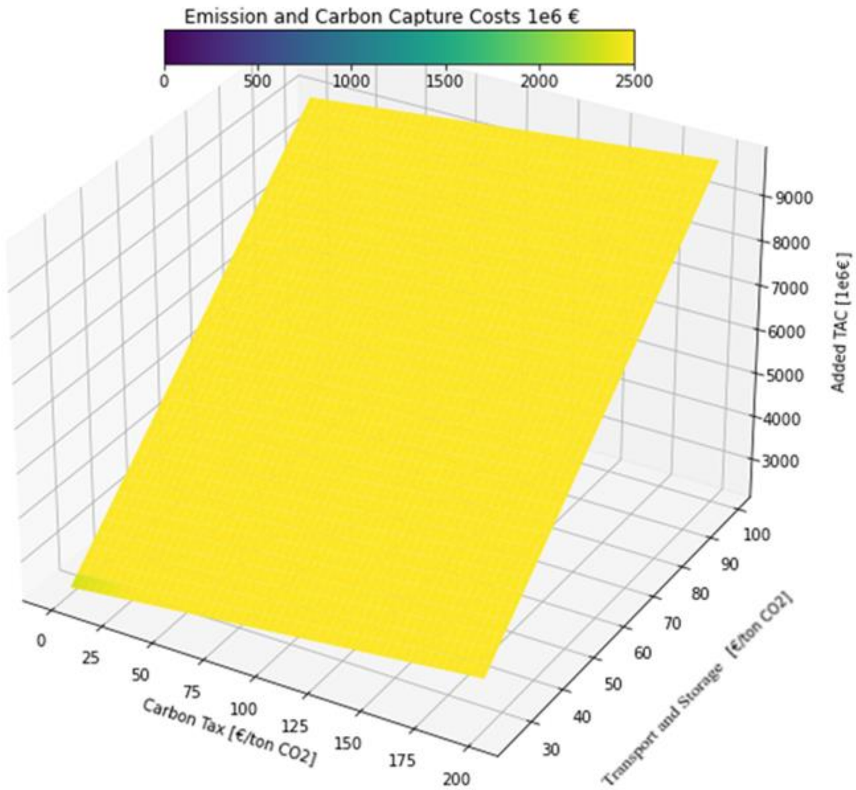
A.2.19 Reference Case H2 Pipeline Layout



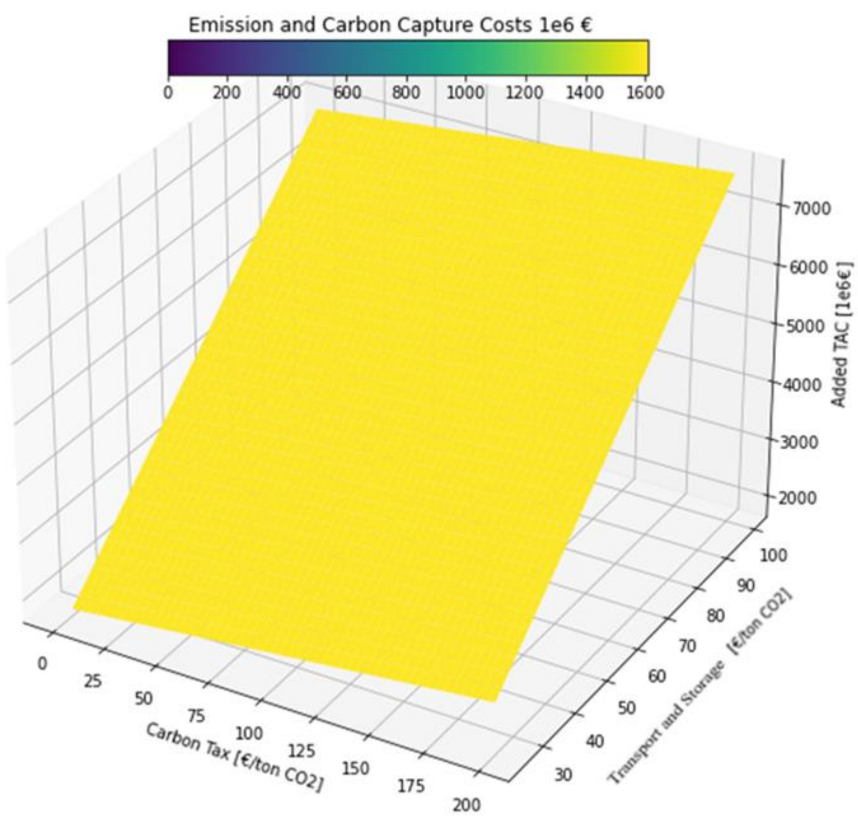
A.2.20 - 891 M€/GW Case Additional Cost Surface Map



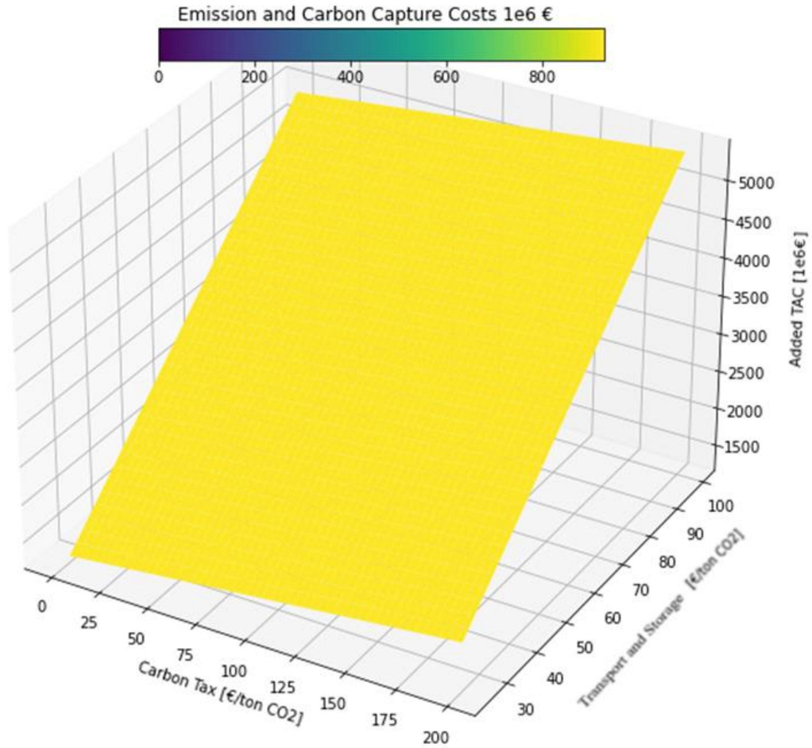
A.2.21 - 972 M€/GW Case Additional Cost Surface Map



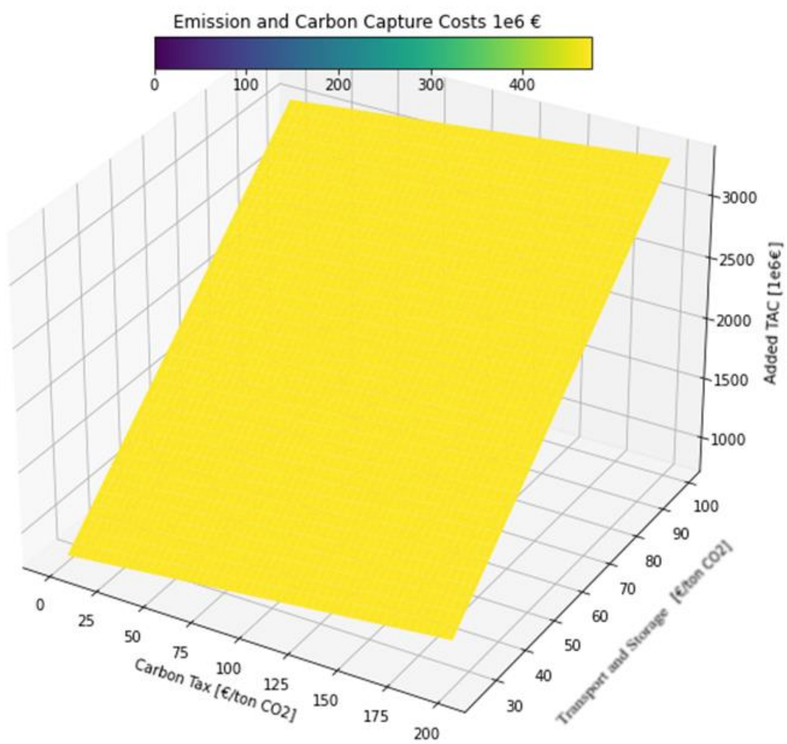
A.2.22 - 1053 M€/GW Case Additional Cost Surface Map



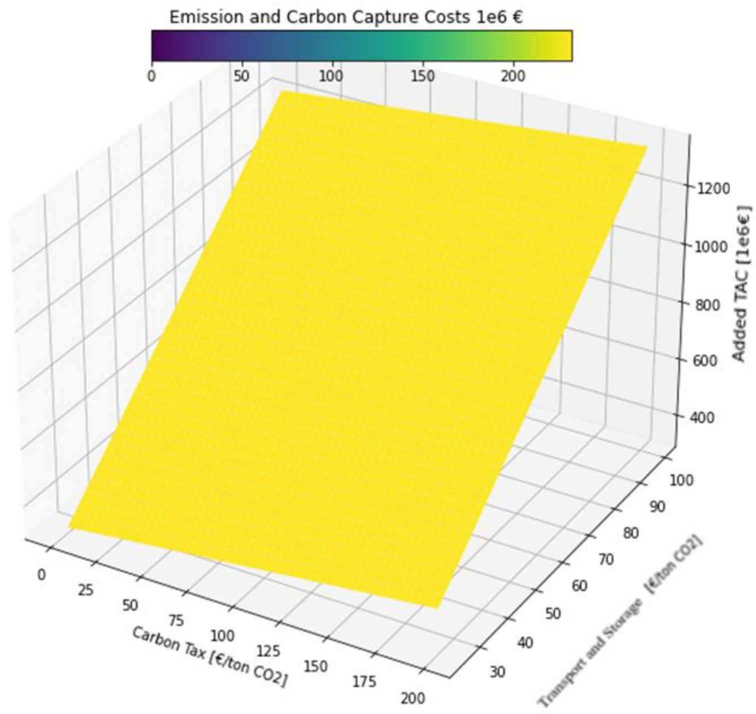
A.2.23 - 1134 M€/GW Case Additional Cost Surface Map



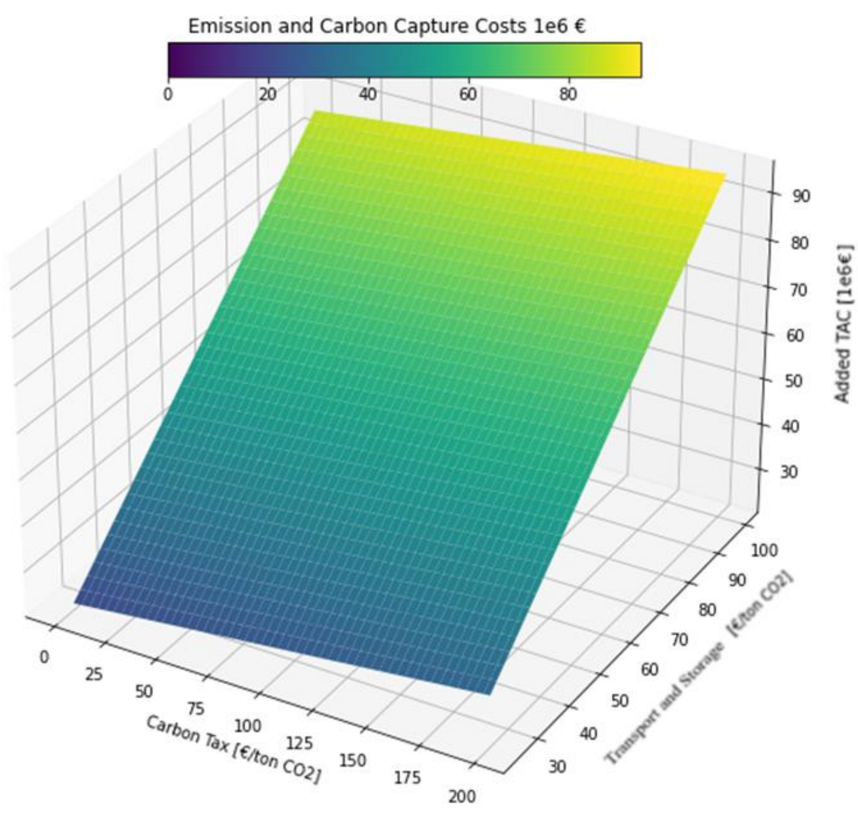
A.2.24 - 1215 M€/GW Case Additional Cost Surface Map



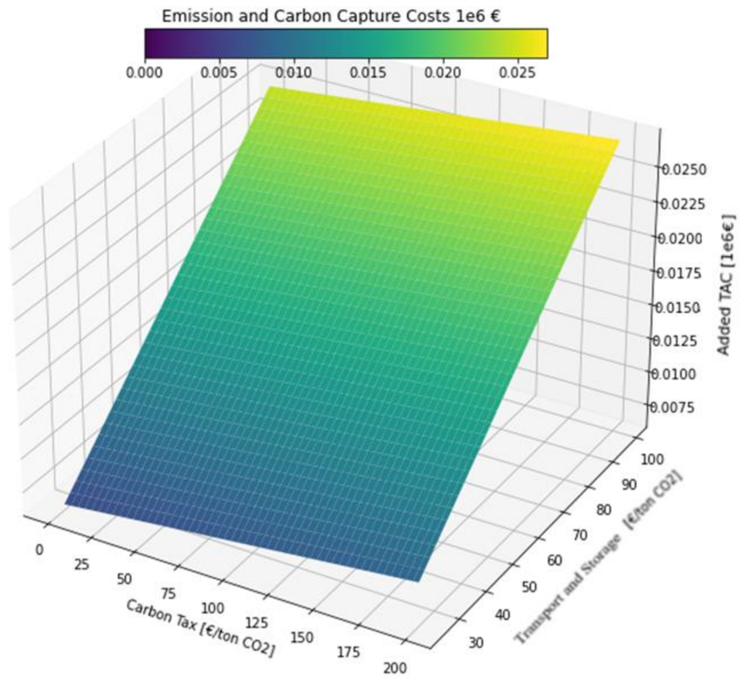
A.2.25 - 1296 M€/GW Case Additional Cost Surface Map



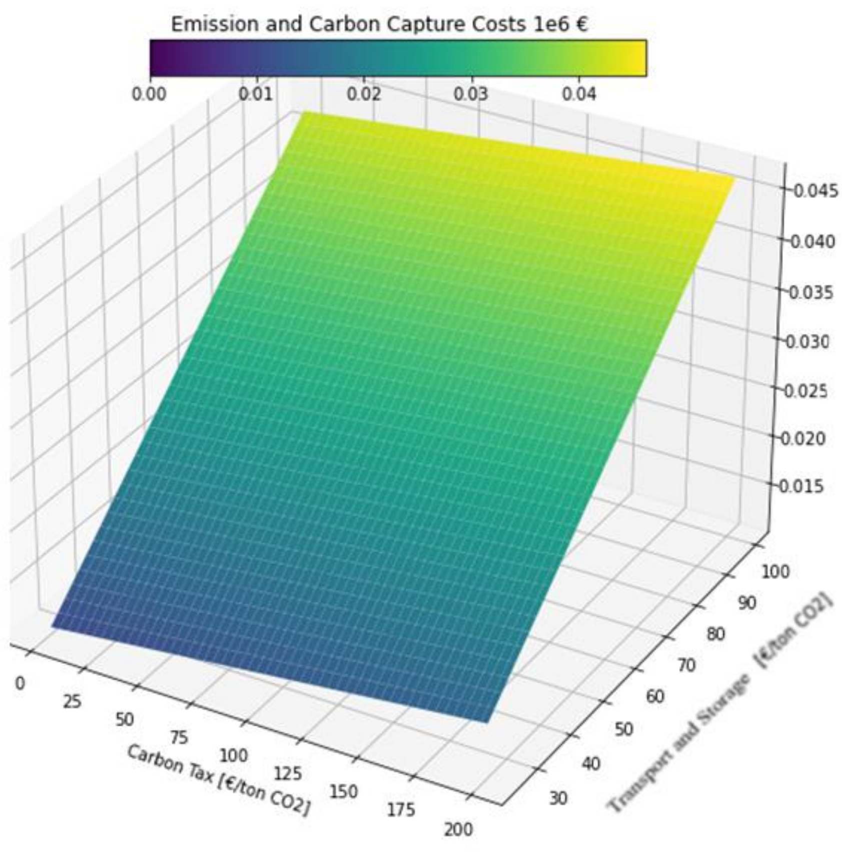
A.2.26 - 1377 M€/GW Case Additional Cost Surface Map



A.2.27 - 1458 M€/GW Case Additional Cost Surface Map



A.2.28 - 1539 M€/GW Case Additional Cost Surface Map



A.2.29 - 1620 M€/GW Case Additional Cost Surface Map

Nomenclature and Acronyms

BEV – Battery Electric Vehicle

CCS – Carbon Capture and Storage

CCGT – Combined Cycle Gas Turbine

CHP – Combined Heating and Power

ENTSO-E – European Network of Transmission System Operators (Electrical)

EU – European Union

FCEV – Fuel Cell Electric Vehicle

FINE – Framework for Integrated Energy System Analyses

GDP – Gross Domestic Product

GHG – Green House Gases

HVAC – High Voltage Alternating Current

HVDC – High Voltage Direct Current

IEA- International Energy Agency

LCOE – Levelized Cost of Electricity

MERRA – Modern-Era Retrospective Analysis for Research and Applications datasets

OCGT – Open Cycle Gas Turbine

OPEX – Operating Expenses

PEMFC – Polymer Electrolyte Membrane Fuel-Cell

PV – Photo Voltaic

P2G – Power-to-Gas

P2P – Power-to-Power

P2NG – Power-to-Natural-Gas

P2X – Power-to-X (x being any result)

RES – Renewable Energy source

R.D. – Region Dependent

SMR – Steam Methane Reforming

S.O.E – Standard Oil Equivalent

SOFC – Solid Oxide Fuel Cell

TAC – Total Annual Cost

TWh – Tera Watt Hour

TYNDP – Ten Year Network Development Plan

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