The role of gas transmission networks in future scenarios for the European energy system

Master's Thesis of

Kilian Plett Palomar

at the Department of Informatics
Institute for Automation and Applied Informatics (IAI)

Reviewer:	Prof. Dr. Veit Hagenmeyer
Second reviewer:	Prof. Dr. Ralf Mikut
Advisor:	Dr. Thomas William Brown
Second advisor:	M.Sc. Elisabeth Zeyen

February – October 2020

Karlsruher Institut für Technologie
Fakultät für Informatik
Postfach 6980
76128 Karlsruhe

at the Department of Energy System Modelling Institute of Applied Informatics

I declare that I have developed and written the enclosed thesis completely by myself, and have not used sources or means without declaration in the text.

Karlsruhe, 17-October-2020

. . . .

(Kilian Plett Palomar)

Abstract

To achieve the challenging and ambitious carbon dioxide (CO_2) emissions reduction that the European Union (EU) has agreed to, strong transformations on the whole European energy system will need to be carried out in the coming years. The aim of this work is to integrate and validate the latest available data on the current European natural gas-network (cross-border capacities and methane-demand and -supply) to the sector-coupled system and analyse its effects on three selected scenarios with net-zero emissions: A greenfield scenario without any previous methane-grid, in which a newly hydrogen-grid between 33 European countries is built; a second scenario where the current existing methane-grid operates parallel to a newly hydrogen-grid; and a third scenario in which existing the methane-grid capacities can be converted to hydrogen, if needed to, to satisfy the system demands. In all three scenarios in addition to the convertion of the natural gas network, new hydrogen pipelines can be built with higher investment costs. The present work builds on the open-source software *PyPSA-Eur-Sec* a continent-wide integrated model of the European energy system. Results show that the methane-grid is transporting methane to levels up to 10 times lower than today's pipeline capacities depending on each cross-border capacity. However the natural gas grid is still needed and serves to transport the additional 47% (352 TWh) of the share that bio-gas represents of the total methane demand, 740 TWh. Foremost, Hydrogen is generated through electrolysis in high quantity, similar to today's EU inner extraction of methane from Norway and other major European countries with as much as 3189 TWh per year. The optimized scenario solutions show little or no differences between them, as the dominant generation of renewable energy coming from wind power happens in just four countries around the North Sea and the Atlantic ocean. The routes for transporting hydrogen are not the same as for methane nowadays, therefore retrofitting pipelines plays an important role to reduce costs. However, new hydrogen-pipelines still need to be built, as retrofitted ones alone are not enough to transport and cover demands in Europe. Although the scenarios do not influence the overall optimized technologies between them, costs of 2 billion Euros per year can be saved by partially converting the existing methane grid to hydrogen. The operation of the methane and hydrogen grids does not show the same seasonal operation as nowadays, but rather a more congested operation of the gas grids; this can perfectly be cause of the optimization, but it shows that the operation of the retrofitted hydrogen pipelines can be operate almost stationary, which is a requisite of the retrofitting method selected in this work in order to extend the live operation of the pipelines. Technologies of the power-to-gas, Sabatier and HELMETH proceses, and SMR have insignificant installed capacities in the studied scenarios.

Resumen

Para lograr la desafiante y ambiciosa reducción de emisiones de dióxido de carbono (CO_2) que ha acordado la Unión Europea (UE), será necesario llevar a cabo fuertes transformaciones en todo el sistema energético europeo en los próximos años. El objetivo de este trabajo es integrar y validar los últimos datos disponibles sobre la actual red europea de gas natural (capacidades transfronterizas, demanda y suministro de metano) en el sistema acoplado por sectores (sector coupling), así como analizar sus efectos en tres escenarios seleccionados con cero emisiones netas de CO_2: un primer escenario totalmente nuevo sin ninguna red de gas previa, en el que se construye una nueva red de hidrógeno entre 33 países europeos; un segundo escenario donde la red de metano existente opera en paralelo a una nueva red de hidrógeno; y un tercer escenario en el que las capacidades existentes de la red de metano se pueden reconvertir para transporte de hidrógeno, si es necesario, para satisfacer las demandas del sistema. En los tres escenarios, además de la conversión de la red de gas natural, se pueden construir nuevas tuberías de hidrógeno con mayores costos de inversión. El presente trabajo está basado en el software de código abierto (open software) *PyPSA-Eur-Sec*, un modelo integrado a nivel continental del sistema energético europeo.

Los resultados muestran que la red de metano está transportando metano a niveles hasta 10 veces inferiores a las capacidades actuales de las tuberías, dependiendo de cada capacidad transfronteriza. A pesar de esta reducción global en el transporte y consumo de metano, la red de transporte sigue siendo necesaria y sirve para transportar adicionalmente el biogás que se prevee en estos escenarios, concretamente un 47 % (352 TWh) de la demanda total de metano, 740 TWh. Las grandes cantidades de hidrógeno generado mediante electrólisis en estos futuros escenarios, son cantidades similares al mentano extraido en Noruega y otros países europeos hoy en día, con hasta 3189 TWh por año.

Las soluciones optimizadas comparadas entre los escenarios, muestran poca o ninguna diferencia entre ellas. Esto se debe a que los excedentes de generación de energía renovable proveniente predominantemente de energía eólica generada predominantemente en sólo cuatro países alrededor del Mar del Norte y el Océano Atlántico. Las rutas para transportar hidrógeno no son las mismas que las actuales para metano, por lo que la reconversión de las tuberías juega un papel importante para reducir los costos. Junto a la reconversión de tuberías de metano, todavía es necesario construir nuevas tuberías de hidrógeno, ya que las renovadas por sí solas no son suficientes para transportar y cubrir las demandas energéticas en Europa. Aunque los escenarios no influyen significativamente en la configuración de las distintas tecnologías, se pueden ahorrar costos de 2 mil millones de euros por año al convertir parcialmente la red de metano existente en hidrógeno. El funcionamiento de las redes de metano e hidrógeno no presenta el mismo funcionamiento estacional que en la actualidad, sino un funcionamiento más congestionado en ambas redes de H_2 y CH_4; esto es causa inherente a la optimización del problema, pero muestra que la operación de

las tuberías de hidrógeno reconvertidas pueden ser operadas de manera estacionaria, lo cual es un requisito del método de reconversión seleccionado en este trabajo. El propósito de este método de operación es el de extender la vida útil de las tuberías de transporte. Por otro lado, las tecnologías de los procesos power-to-gas, Sabatier y HELMETH, y SMR tienen capacidades instaladas no significativas en los escenarios estudiados.

Contents

List of Figures

List of Tables

List of Abbreviations

Abbreviations

Abbreviation	Meaning
BEV	Battery for Electric Vehicle
CCS	Carbon capture and storage
CCU	Carbon capture Utilization
CH_4	Methane
CHP	Combined Heat and Power plant
CO_2	Carbon Dioxide
DAC	Direct Air Capture
GDP	Gross Domestic Product
H_2	Hydrogen
HELMETH	High-temperature Electrolysis and Methanation
KKT	Karush-Kuhn-Tucker
LH_2	Liquid Hydrogen
LNG	Liquified Natural Gas
LOPF	Linear Optimal Power Flow
OCGT	Open Cycle Gas Turbine
PSH	Pumped Hydropower Storage
PV	Solar Photovoltaic
PWM	Pipeline without modification
SMR	Steam Methane Reforming
TSO	Transport System Operator
TES	Thermal Energy Storage
EU	Europe
p.u.	per unit
PyPSA	Python for Power System Analysis

1. Introduction

1.1. Motivation and aim for the thesis

Europe's commitment to reach carbon neutrality by 2050 and the global effort to achieve the objectives fixed in the Paris Agreement [22] towards reducing greenhouse gas emissions makes hydrogen an essential asset to contribute to this purpose. Its implementation in all energetic sectors opens in one way or another new technological opportunities and challenges, all with the common denominator of stopping climate change.

In the electric sector this changes towards decarbonisation have already begun, where a significant amount of electricity is already being generated by renewable energies. Despite the fluctuations in delivery that renewable energies carry along, its adoption is growing every year and there have been already sporadic times in which renewable energies have had surpluses of generation which nowadays are traded between country-neighbour Transport System Operators (TSO) or destined to Pumped-hydropower-storage (PHS). As the growth in installed renewables increases the energy system expects to have increasing surpluses, and so balancing the electric grid by other means such as production of hydrogen by electrolysis, PHS, batteries for electric vehicles (BEV) or in households, or even seasonal balancing with thermal energy storage (TES) seem to achieving CO2 neutrality.

Electrolysis can help balancing the grid by producing and then storing hydrogen for a later transformation and use, as part of the power-to-X. Similar actions will be implemented in the sectors of transport, heating and industry which today strongly depend on different hydrocarbons. In all these sectors exist chances for hydrogen to influence the future decision-making in this energetic transition together with the interconnection between all these sectors, or so called sector coupling.

In this project using PyPSA-Eur-Sec the objective is to compare data on the European gas network between member states from different sources and to model energy flows in a future energy system without CO2 emissions. For the design of future energy systems, the capacity investments and operation of generation, transmission and storage options need to be considered and interconnected.

According to "A hydrogen strategy for a climate-neutral Europe" [5] from the European Commission and its German first adopted version [23] an important factor to introducing H2 in the future will be the retrofitting of the current CH4 pipelines, more than blending H2 with CH4 (as this depreciates the value of the produced hydrogen). In [4] a study of different pipeline retrofitting methods and its associated operational problems is performed and among several conversion methods the so called pipelines without modification (PWM) and pipeline operated with gas inhibitors are the most advantageous. At the same time several gas TSO's have released their study "Backbone Hydrogen Strategy" [11] with detailed routes and time horizons in the deployment of a hydrogen network, considering retrofitting actual grids from several of the countries with highest natural gas demands in Europe (Germany, France, the Netherlands, Spain and Italy) among others. This makes relevant to implement the gas network in PyPSA and study the effects of retrofitting in a sector coupled system. Also until now some of the energy loads and resources where assigned to an European node connected to all countries where the transport of some feedstocks was immediately available to all countries and now bio-gas can be transported together with natural gas after an upgrading process. The natural gas supplies inside Europe should be included to see their influences in the system. As well, industry demand of natural gas are assigned to every country and H2 future industry demands are assigned to countries. The purpose is also that other processes like steam methane reforming (SMR), and methanation processes: Sabatier, HELMETH, and Hydrogen storage per country have a role in the sector coupling and to study the outcome of several scenarios. it is important to see if there arise differences in the solution of the linear optimization power flow (LOPF) caused by implementing the gas grid and its retrofitting to H2. The model will be considered as autarchic considering that imports of hydrogen are not realistic yet and costs cannot be undefined applied, and a perfect year foresight is expected.

1.2. Research questions

This thesis builds up on several research questions for future scenarios in which the natural gas grid is the focus of it. This is because the existing methane gas-network can be retrofitted for hydrogen gas, as mentioned in [4], [11], [23], [5], and could contribute to a more competitive price of the hydrogen grid and the cost hydrogen transport. However, some considerations about the operation of the pipelines must then be met and are detailed in [4]. Therefore the purpose of reconverting the natural gas pipelines arises research questions which are intended to be answered and have lead this study. These questions are:

- What is the cost of transporting hydrogen in a retrofitted scenario compared to other scenarios?
- Which differences arise between scenarios? And are the technologies installed to achieve the objectives different between scenarios?
- How are the energy balances between demand and supply covered for CH_4 and H_2 per country and technology type?
- how much are the natural gas and hydrogen pipelines used? and how many pipes are converted?
- What compromises the pipeline retrofitting? And which routes of transport are taken by the optimization?
- Does the extraction-origin of natural gas compromise the pipeline routes and its retrofitting into hydrogen?

- How much CH_4 is supplied from the producing countries inside European borders, bearing in mind that in the models Europe counts with Norway (NO), Netherlands (NL) and Great Britain (GB) as major suppliers in an autarkic system which is disconected from any kind of LNG-imports, nor from imports from Russia, Livia and Algeria?
- how much generation capacity of HELMETH- and Sabatier-process technologies is installed, and how much methane do they provide in comparison to self extracted natural gas?
- How much of open cycle gas turbine technology (OCGT) and combined heat and power (CHP) is installed in the 3 scenarios in order to balance the electric grid?
- Is off-shore wind-energy surplus used to generate hydrogen by electrolysis in the north of Europe? and solar photovoltaic (PV) in the south of Europe? or are there other technologies implicated?

1.3. Structure of the thesis

This work is divided into 5 chapters . Chapter 2 introduces the energy system model PyPSA-Eur-Sec, including the optimization model and the constraints, input data, energy flows, and model outputs. Chapter 3 presents the model implementation of three different relevant scenarios, namely the Greenfield scenario, the Gas-grid scenario, and the Retrofitted scenario. In chapter 5 the different results are exposed and analyzed. In the last chapter summarizes and gives an outlook to the whole study.

2. System model

There exist several modeling tools to investigate energy systems, Ringkjøb, Haugan, and Solbrekke in [18] present more than 70 different modelling tools which can be used for different aims and implement different approaches.

This work has been carried out with PyPSA-Eur-Sec, which is based and relies on PyPSA and PyPSA-Eur. PyPSA is the achronim of "python for power system analysis" and is an open optimization model software which is intended for solving LOPF systems. PyPSA-Eur is in turn based on the latter and expanded with data from the Europan electric grid and is based on the ENTSO-E area. Following this conceptual line, PyPSA-Eur-Sec is based on the two latter and adds sector coupled information of various sources and types. In study meaningful data is taken from ENTSO-G to validate the gas grid and to build the several scenarios with a one node per country.

The following chapter presents two different model options. Fist a summarized description of a model applying hydraulic equations is described, its advantages and disadvantages of implementation jointly with an energy flow model is assessed in section 2.1. Then, the energy flow model is presented in a general manner through the implementation of PyPSA-Eur-Sec in section 2.2. Next, a short description of the applied energy model and its constituent parts is given in subsection 2.2.1. Then the countries that configure the system are stated in subsection 2.2.2. In subsection 2.2.3, input data for the different energy sectors (electricity, heating, transport and industry) is described: energy demands, energy supply and energy storage. Finally, in subsection 2.2.4 and subsection 2.2.5 in the energy data flow and the model output are described.

2.1. Gas flow model: hydraulic equations

A question that rouse interest was how would the methane gas-network be modeled and the accuracy that its modeling could reach. At the time the natural gas network data was available, several options were considered. First it was discussed the possibility to implement a realistic hydraulic modelling of the pipelines, for which an analysis on the quality of the pipeline's data would be necessary. Secondly to evaluate the feasibility of implementing this type of physically detailed model, bearing in mind that the electric model implemented in PyPSA has a high degree of detail.

Simulating real gas flow consumes computational resources due to an increased number of equations and the non-linearity of the problem, even with high degree of simplifications. Reuß et al. in [17], about the modeling of hydrogen pipes, mention that despite not recommending the integration of non-linearities into energy system optimization models due to their high computational burden, it is highly recommended to use the non-linear model for post-processing in order to prove feasibility of the results and strengthen their credibility, while retaining the computational performance of linear modeling. in the study [17] it is also mentioned that applying simplified linear models can heavily influence the total pipeline investment costs.

Gas flow in pipelines is mainly described by the Poiseouille flow equations. The main withdraw to overcome are the frictional losses of the flow against the pipe-containing walls. This is the cause to install compression units along the pipelines that transport gasses for long distances. For a modeling based on the flow of gas, data on average working pressure of the pipe would be needed, as well as discharge pressures at delivery points and friction coefficient. According to the latter, a detailed explanation is given by Schmidt, Steinbach, and Willert in [20] about the mechanical fluid partial differential equations (PDE) that govern the system. Summarized, a *hyperbolic system of PDEs* of the Euler equations for compressible flows comprehend the mass conservation, the momentum and the energy equations, which after considering the following simplifictions:

- isothermal approximaiton,
- 1-D flow in the direction of the flow,
- certain mean temperture T_m and pressures P_m along the pipelines,
- no significant change in height,
- and a stationary state,

end up in:

$$p_i^2 - p_j^2 = \Lambda(q)\, q\, |q| \tag{2.1}$$

where all terms are scalars, and the mass flow is $q = A\rho v$. The specific gas constant is $R_s = R/m$ with R the gas universal constant. The mean temperature:

$$T_m = \frac{1}{2}(T_a^- + T_a^+) \tag{2.2}$$

And the term affected by the friction in the pipeline is:

$$\Lambda(q) = \frac{L}{A^2 D} z_m\, T_m\, R_s\, \lambda(q) \tag{2.3}$$

with all terms being scalars, z_m being the compressibility factor and $\lambda(q)$ has to be modeled by design coefficients showed in [20] in page 144. Schwele et al. in [21] also present the same result rearranging Equation 2.1.

Concluding, even if at the moment of writing this work, the data available from the pipelines does not allow to implement the checking of the solution in post-processing, in the near future it would make sense to adopt and implement them in bigger systems for the sake of the feasibility of the system model.

2.2. Energy system model

This chapter introduces the system model finally used for this study, a system fully based on energy flows, already conceived in PyPSA and without the hydraulic equations proposed in the last section following the recomendations in [17] and for keeping the scope of the study concentrated in its main objectives.

In the following subsections a general description of the energy flow model in the system is explained. In section Model description a general view of the model is given, with subsections: Objective function; Power balance constraints; Generator constraints; Storage operation; Transmission constraints; CO_2 emission constraints; where the elements and different summarized equations to the LOPF problem are presented; and in subsection Price assignment of CH_4, new H_2 and retrofitted H_2 pipelines, the costs assignment of the different pipelines is clarified.

Then a next section in which the nodes for country areas is clarified in Countries and network, followed by the section Input for sector demand and supply, where all the loads and supplies for the sectors: electricity, transport, heating and industry is broken down. Then a global view of the whole energy flow in Energy flow and storage in the energy system model is explained and maid very representative in 2.5. Finally a section dedicated to the solving process of LOPF problem in PyPSA-Eur-Sec is presented in Model output.

For in-depth description of the PyPSA developing open-software branches, thorough information can be found in [16], [15], and the papers [2], [3], [10] .

2.2.1. Model description

In this work the gas network is represented by the overall cross-border capacities between the EU-countries. To the best of the authors' knowledge at the time of this writing there are already more detailed topological data on the EU gas system which could soon lead to a more detailed calculation of the European gas grid, both in number of pipes and by implementing hydraulic equations to prove feasibility of the system for the gas trades and grid operation.

For a better comprehension of the model, a general description of the model including the objective function and its boundary constraints are presented here. PyPSA-Eur-Sec is conceived for the coupling of different sectors, namely the electric system with different sectors of heating, industry, transport (aviation and shipping included), and biomass.

To build a general system in PyPSA-Eur-Sec the software first builds on PyPSA-Eur the electric system including the technology data in the electricity sector, which countries are included in the network, the weather data, population and land use (e.g. exclusion of protected natural areas), and electricity demand. The system is also defined by a time step specifying the number of hours, for example: 3H, 5H, 120H, and by how much the system allows the electric lines volumes (AC and DC) to be expanded or optimized. Next, PyPSA-Eur-Sec builds on this output the Technology database for the selected sectors (space and water heating, industry, transport and Biogas) and adds the corresponding specified demands. In this step also the allowed resulting CO_2 limit for the model is specified. Then the cost-optimized energy supply is calculated with the base model PyPSA and PyPSA-Eur-Sec then compiles these results and is capable of yielding several output

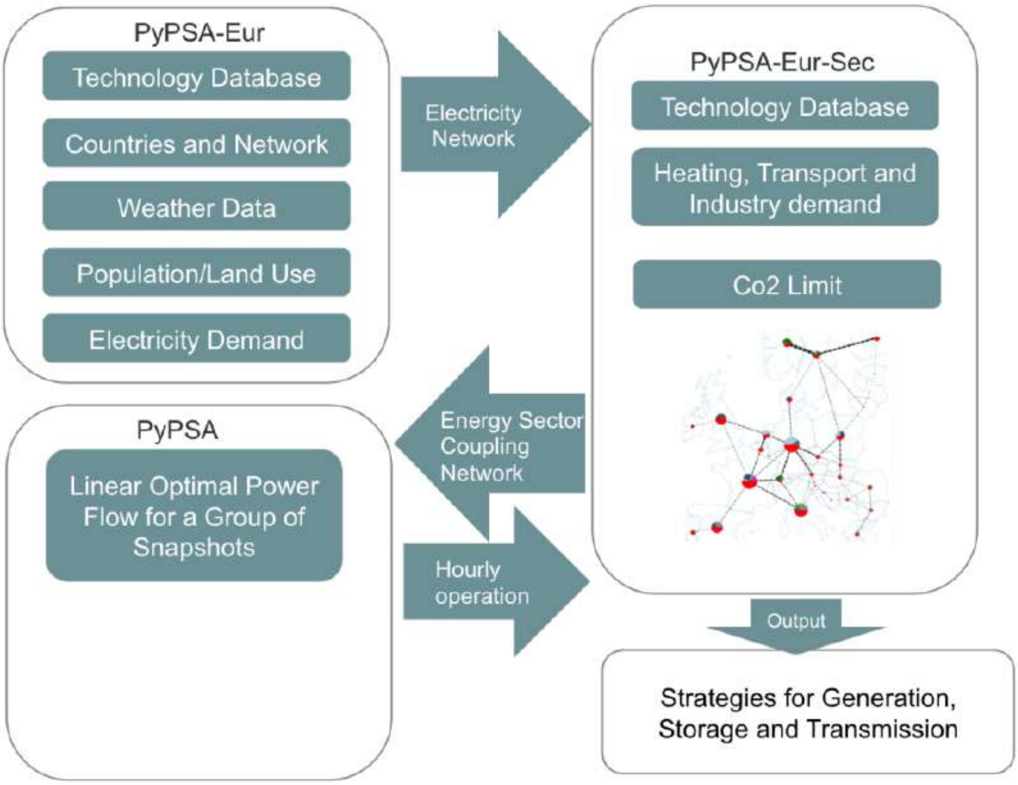

Figure 2.1.: Data handling between PyPSA-Eur, PyPSA-Eur-Sec and PyPSA, from Yang in [24]

data from the solved network (maps, tables and graphs). In Figure 2.2 a schema of system building is depicted.

Objective function

Linear optimization and perfect foresight are used in PyPSA to minimize total investments and operational costs. In [3] the linear objective function is explained and is formulated as:

$$\min_{G_{n,s},E_{n,s},F_l,g_{n,s,t},f_{l,t}} \left(\sum_{n,s} c_{n,s} \cdot G_{n,s} + \sum_{l} c_l \cdot F_l + \sum_{n,s} \hat{c}_{n,s} \cdot E_{n,s} + \sum_{n,s,t} o_{n,s,t} \cdot g_{n,s,t} \right) \tag{2.4}$$

The total system costs comprehend the following costs: the fixed annualized costs $c_{n,s}$ for storage and generation capacity $G_{n,s}$; the fixed annualized costs c_l for transmission capacity F_L; fixed annualized costs $\hat{c}_{n,s}$ for storage energy capacity $E_{n,s}$; and variable costs $o_{n,s,t}$ for generation and storage dispatch $g_{n,s,t}$. Where n poits to a country in node, s indicates the generation and storage technologies at the nodes, t the umpteenth time span, and l connector between nodes.

Several constraints and need to be met by The LOPF in (2.4), which are hereafter in the next subsections unfolded: the power balances constraint, the generator constraint, the storage operation, the transmission constraint and the CO_2 emission constraint.

Nomenclature			
n	nodes (countries)	$h_{s,\max}$	(dis-)charge time at max. power
t	hours of the year	$f_{l,t}$	power flow
s	generation and storage technologeies	F_l	transmission capacity
l	inter-connectors	K_{nl}	incidence matrix
$c_{n,s}$	fixed annualized generation & storage costs	L_l	length of transmission line
c_l	fixed annualized line costs	LV	line volume
$o_{n,s}$	variable generation costs	f_{n-1}	n-1 security factor
$\lambda_{n,t}$	locational marginal price	c_{CP}	capital cost of AC-DC converter
μ_{LV/CO_2}	KKT multipliers/shadow prices	η_*	storage effciencies
$d_{n,t}$	Demand (inelastic)	$g_{n,s,t}$	generation and storage dispatch
$G_{n,s}$	Generator installable potentials	$\bar{g}_{n,s,t}$	the capacity factor

Table 2.1.: Nomenclature for PyPSA modeling framework

Power balance constraints

Power balance is the equilibrium of all supplied energy with the overall demand, or load. If more supply is given or available than the load then this energy can be stored if an adequate storage for that type of energy is available. As shown in equation (2.5), the inelastic demand $d_{n,t}$ at node n and time t has to be satisfied by the generation or the stored energy resources $g_{n,s}$ or by supplied energy transported from connector l and a compliant energy flow $f_{l,t}$.

$$\sum_s g_{n,s,t} + \sum_l \alpha_{l,n,t} f_{l,t} = d_{n,t} \leftrightarrow \lambda_{n,t} \quad ,\forall n, t \tag{2.5}$$

If l begins at node n, then $\alpha_{l,n,t} = -1$. If l ends at node n, then $\alpha_{l,n,t} = \lambda_{n,t}$. Where $\lambda_{n,t}$ is a factor for the efficiency of the energy flow in the transmission l. The market price of the energy carrier at a node and time is represented by the Karush-Kuhn-Tucker (KKT) multiplier $\lambda_{n,t}$. The use of the KKT in electricity markets can be learned in-depth in [8] and [6]. In figure 2.2 an schema of a possible configuration is shown.

Generator constraints

Each generator and storage can supply $g_{n,s,t}$ energy up their limit technological capacity factor $\overline{g}_{n,s,t}$ or $\mathrm{g}_{n,s,t}$ in each time t.

$$\mathrm{g}_{n,s,t} \cdot G_{n,S} \leq g_{n,s,t} \leq \overline{g}_{n,s,t} \cdot G_{n,S} \quad ,\forall n, s, t \tag{2.6}$$

For flexible conventional generators the capacity factor are constant $\mathrm{g}_{n,s,t} = 0$ as the minimum to generate, and $\overline{g}_{n,s,t}$. The maximum available renewable energy generation per

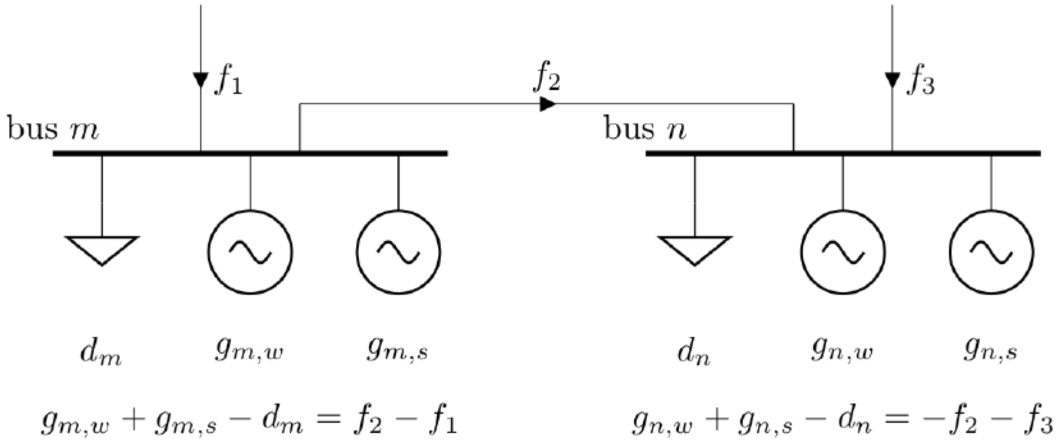

Figure 2.2.: Schema of a PyPSA energy network connection.

hour depend on the givenweather conditionsat node and time n and t, and is calculated by the capacity factor $\overline{g}_{n,s,t} \cdot G_{n,S}$. It is assumed that the excess renewable generation can always be curtailed, $\mathrm{g}_{n,s,t} = 0$. And for storages, e.g. hydrogen storage or BEV then $\mathrm{g}_{n,s,t} = -1$, and $\overline{g}_{n,s,t} = 1$.

Furthermore, geographical environment imposes maximum available capacity for renewable energy. The installed capacity is narrowed to a maximum limit $G_{n,s^{\max}}$ imposed by the geographical potential:

$$0 \leq G_{n,s} \leq G_{n,s}^{max} \quad , \forall n, s \tag{2.7}$$

Storage operation

The state of charge as its name indicates is the level at which the storages are, $e_{n,s,t}$, of each storage element for a node n at time t and can also be constrained by time series $\underline{e}_{n,s,t}$ and $\bar{e}_{n,s,t}$:

$$e_{n,s,t} = \eta_0 \cdot e_{n,s,t} + \eta_1 g_{n,s,t,\text{charge}} - \frac{1}{\eta_2} g_{n,s,t,\text{discharge}} + g_{n,s,t,\text{inflow}} - g_{n,s,t,\text{spillage}} \tag{2.8}$$

$$\forall n, s, t: \quad \underline{e}_{n,s,t} E_{n,S} \leq_{n,s,t} \leq \bar{e}_{n,s,t} E_{n,S} \tag{2.9}$$

The energy level $e_{n,s,t}$ of all storages is the result of all in- and outflows to the previous state of charge in time, and less than the limit of the total storage capacity. The storage of a dam can be charged by natural inflow of water, and has to be spilled if the reservoir is full. A standing leakage loss of the storage units is represented by λ_0. The losses during charging and discharging are represented by the efficiencies η_1 and η_2.

$$\forall n, s, t: \quad 0 \leq \mathrm{soc}_{n,s,t} \leq h_{s,\max} G_{n,s} \tag{2.10}$$

The energy capacity, $h_{s,\max} G_{n,s}$ constraints the energy level. $h_{s,\max}$ is a factor by which the storage can be charged or discharged at maximum capacity. A characteristic of the storages is that for the overall time-span these can be set to have a cyclic behaviour by which the initial charge has to be equal to the final charge, that is for $t = 0$ and $t = T$, $e_{n,s,0} = e_{n,s,T}$.

Transmission constraints

In general, for the transport of electricity as well as for the gas transport the lines and links capacities, F_l constrain the maximum energy flow to be transported between nodes.

$$|f_{l,t}| \leq F_l \quad \forall l, t \tag{2.11}$$

In this study the electric AC and DC lines F_l are not expanded in the model. The sum of transmission line capacities is then:

$$\sum_l l_l F_l = \mathrm{CAP}_{lv} \leftrightarrow \mu_{LV} \tag{2.12}$$

Whereas for the gas grids, in the study of the three scenarios investigated in this work, the original capacities, F_l, of the pipelines are allowed to expand or shrink depending on the scenario and the type of pipeline.

In the case of the newly built H_2-pipelines the capacity can only increase, because initially these are zero and by solving the LOPF hydrogen energy flows are optimized to be transported through the grid.

On the other hand, for a retrofitted methane grid, the resulting methane pipeline capacities $F_l^{CH_4}$ and the capacity of retrofitted H_2 pipelines $F_l^{H_2}$ are constraint by (2.13). Where $\delta_e = 3.01$ is the energy volumetric ratio between H_2 and CH_4, with lower-heating-values $LHV_{H_2} = 33.3kWh/kg$ and $LHV_{CH_4} = 13.9kWh/kg$:

$$F_l^{CH_4} + \delta_e \cdot F_l^{H_2} \leq F_l \tag{2.13}$$

$$\delta_e = \frac{LHV_{H_2} \cdot \rho_{H_2}}{LHV_{CH_4} \cdot \rho_{CH_4}} = 3.01 \tag{2.14}$$

CO_2 emission constraints

As part of the CO_2 reduction compromises mentioned in chapter 1, the net CO_2 emissions to the atmosphere are constrict by a cap CAP_{CO2} implemented using the specific emission e_s in tonnes of CO_2 per MWh of the generator type s, link l or storage s of CO_2 by CCS.

$$\sum_{n,s,t} \frac{1}{\eta_s} g_{n,s,t}\, e_s + \sum_{l,t} f_{l,t}\, e_l \leq \ 0 \tag{2.15}$$

Price assignment of CH_4, new H_2 and retrofitted H_2 pipelines

In this section the cost assignment to the gas-pipes representing the cross-border pipelines capacities is explained. Assigning a cost to the pipelines in the model is important for later being able to obtain a cost of transport of a gas, hydrogen or methane. In other words, to obtain the cost of energy transport.

Following the advice in [4] this thesis takes the lowest cost of the options that exist for retrofitting pipelines. this retrofitting option is called pipelines without modification (PWM), and although it is the less expensive option, some operation requirements have to be fulfilled. PWM allow to not do significant modifications to the pipes as long as a strict control of the pipelines is conducted and the pipelines are operated at pressures as constant as possible. This is because hydrogen embrittles ferric materials like gas-pipes. A gas-pipe operated with methane allows to bring up and down the pressure without problems, and just routine crack-length checks have to be done to the pipelines. However, for hydrogen, adding the inherent embrittlement issue that hydrogen carries along, in order to diminish the crack-lengths it is advised to operate the pipelines at a pressure as constant as possible to be able to to extend the live of the pipelines as much as possible. If operation at rather constant pressure where not possible, other retrofitting options could be adopted, e.g. using gas inhibitors of embrittlement. However, an in-depth study and descriptions are given in [4].

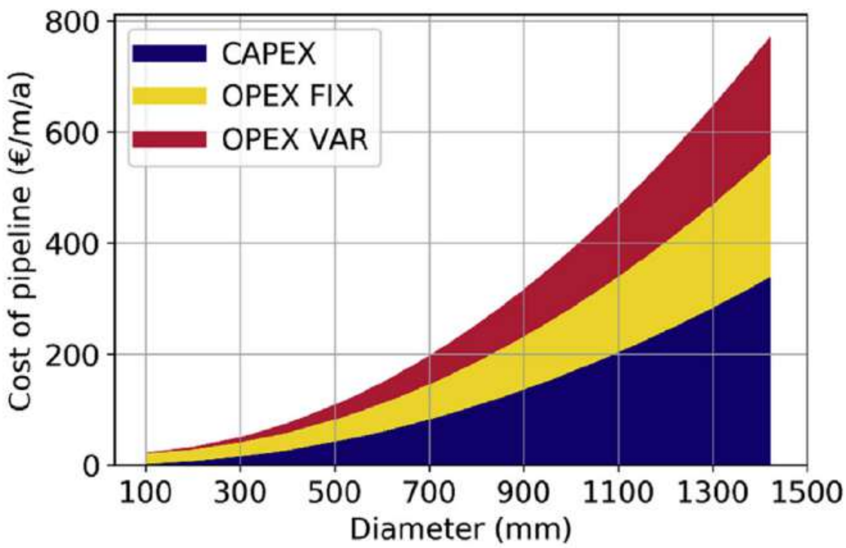

Figure 2.3.: Retrofitting cost of PWM cost structure with crack length impact on OPEX, from [4].

In PyPSA-Eur-Sec the cost of new H_2 pipelines is taken from reference [9] and it is proportional to the length of the pipe. The length of the pipelines was taken from the electric grid HVAC and HVDC lines. This is an approach to possible pipeline connections which takes the lengths of the clustered electric grid. On the other hand, in [4], the cost of retrofitting pipelines by different methods are compared to H_2 new pipelines and CH_4 pipelines, which means a relative cost can be also obtained. Hence, the scale of the cost of retrofitted pipelines and the cost of CH_4 pipelines has a certain proportion relative to H_2 newly built pipelines.

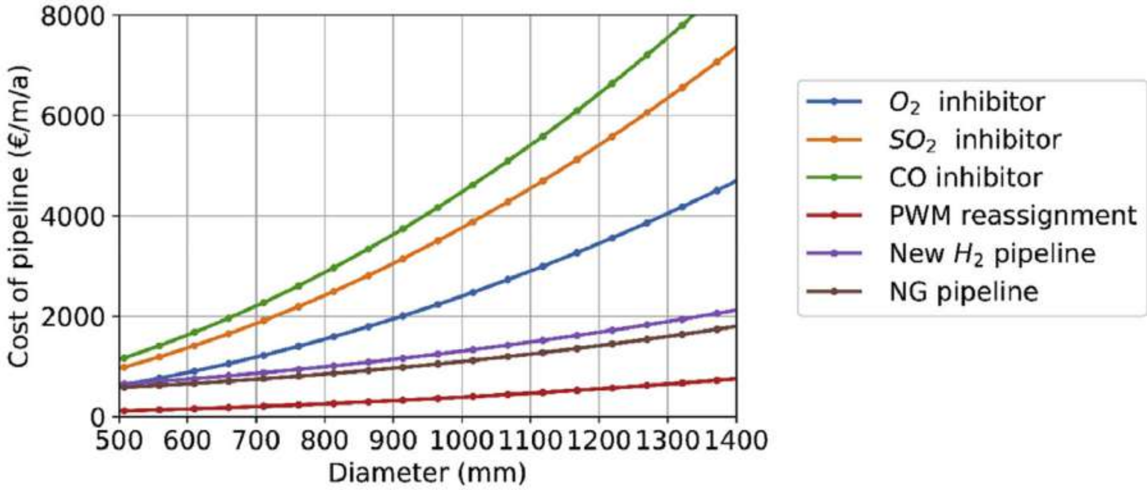

Figure 2.4.: Cost comparison of the pipeline retrofitting alternatives and new H_2 pipelines, from [4].

Last, we simply apply these proportions to the cost assigned in PyPSA-Eur-Sec, e.g. the cost of H_2 retrofitted is 35% of that of a newly built H_2 gas-pipe. For a new methane pipeline it is 85% the cost of a newly built H_2 gas-pipeline, however in this study it has been considered that existing methane gas pipelines in a future scenario are all paid off so just a 5% cost is assigned to these pipelines.

The fix-cost of operational and maintenance (FOM) can be calculated too, but it was not assigned to the model as considering that a further and more profound study should be done. The cost breakdown from [4] can be seen in Figure 2.3.

The fact that the costs are given by length and the capacity or diameter of the pipe is not taken in account is somewhat inaccurate, but we do not have a good correlation from capacities to diameters from [14] at the time of writing this thesis. We will value how acceptable can this approach be in section 4.1. Assuming only one pipeline connection between countries carries uncertainties with it, and first approaches to research questions are also needed to adjust further modelling.

2.2.2. Countries and network

In this study a total of 33 countries in Europe have been considered, except Cyprus, Turkey, Ukraine, Belarus, San Marino, Monaco, Andorra, Malta and Iceland. So, besides the excluded ones, this study includes the European Union members, Great Britain, from the European free trade association (EFTA) Norway and Switzerland, and EU Balkan countries, all countries whose TSO's are in the European Network of Transmission System Operators for Gas (ENTSO-G). At the time of writing this work the PyPSA-Eur-Sec contains 83 cross-border pipelines between countries, data which has been extracted from the ENTSO-G transparency site and website [7]. One node per country has been considered except for the islands of Sardegna, Mallorca, Northern Ireland and Zealand. This accounts for 37 nodes.

2.2.3. Input for sector demand and supply

In this section the supplies and demands of the most relevant energy sectors of electricity, heating, transport and Industry are taken a closer look.

In [3] we have input data for various technologies used for an example future scenario, where one can appreciate different technology investments that the energy model uses. Overnight costs [€] are the costs of one-time investment in one technology. The fixed costs of operation and maintainment FOM[%/a]. Similarly this study has the equivalent data available in PyPSA-Eur-Sec.

Based on the model description and model constraints from the previous sections, the energy model has also fixed variable and optimization variables in the objective function as indicated in tabel 2.1: energy demands $d_{n,t}$, availability $g_{n,s,t}$ for wind and solar energies, installable potentials $G_{n,s}$ of energy generators like onshore wind, offshore wind and solar PV, storage efficiencies η_*, capital costs of generators $c_{n,s}$, generator marginal costs $o_{n,s}$ and line costs c_l. All these inputs data presented in this section.

2.2.3.1. Electricity demand and Supply

The electric demand, supply and storage descriptions are documented in [19] for a thorough explanation. This section is a brief summary of the applied technologies.

The demand of electricity distinguishes from dedicated electricity demands of electric devices (e.g. electric motors or lighting) that do not cover other sector demands, like heating or transport, and the set of technologies that consume electricity due to the sector coupling, e.g. resistive heaters, BEVs, or hydrogen production. As shown in the resulting electric balance in Figure 4.2, the dedicated electric demand can also be observed in the figure. Also the demand of other sectors and transformed to other energy vectors, like for hydrogen, can be compared between the scenarios. The time resolution of dedicated electric demand are implemented in PyPSA-Eur after [13] with a 3 hour time resolution. Industrial demand of electricity is also assigned per country.

The supply of electricity can be covered thanks to renewable energies or to conventional fuel dependent sources. The same principle as for the demand applies here, so dedicated sources to generate electricity that do not involve other sectors are mainly renewable energies like solar photo-voltaic, off- and on-shore wind and hydroelectric. Non dedicated electricity generators are those which need another energy vector, like gas or biomass, to produce electricity, and among this set there are technologies such as OCGT, CHP from gas and biomass or fuel cell technology.

2.2.3.2. Transport demand and supply

The transport demand in divided into three categories and each of them is covered by a different energy vector. The first demand of this group is just called Transport and is covered by BEV, so by vehicles running on electricity. The second type of transport demand is H_2 for shipping, here the model assigns specific demands of H_2 that are fully destined to be covered by hydrogen. And third, the Kerosene for aviation, which in the model, the full demand of this demand is covered by Fischer-Tropsch process transforming H_2 into kerosene (and naphtha, but for industrial process). With this three types of demands is the whole transport demand modeled.

2.2.3.3. Heating demand and supply

The heating demand in this work is distributed as follows. On the demand side there are three main demands, some of which sub-classified in other branches. The three main groups of demand are households, services, and Industry. household subdivide in urban, residential and rural, and services subdivide in urban and rural. And some of the last also subdivide in centralized and decentralized.

On the supply side there are main feedstock sources, the only fully renewables of which are: solar thermal, electricity(due to the high electrification of the system due to renewable energy), bio-gas, biomass, and H_2 heat coming from Fischer-Tropsch and fuel cell recovered process heat. The non-renewable sources is natural gas (methane).

On the side of the technologies capable of covering the heat demand there are solar collectors; micro-CHP and CHP from gas, biomass; gas boilers (and with and without CCS); stored water tanks; resistive heaters and air and ground heat pumps; and thermal energy storages (TES).

Table 2.2 offers descriptive information on the assumptions and calculation premises for heating supply considered in PyPSA-Eur-Sec, as can be found in [3].

Low-density heat demand	High-density heat demand	
Individual	Individual	Central (district heating)
Gas boiler Resistive heater Ground-sourced heat pump Solar thermal Short-term TES	Gas boiler Resistive heater Air-sourced heat pump Solar thermal Short-term TES	Gas boiler Resistive heater Air-sourced heat pump Solar thermal Long-term TES Combined heat and power

Table 2.2.: Heating technologies in different density areas [3]

2.2.3.4. Industry demand and supply

Industrial demands and supplies are break down in this section. The industry demands by sector for the whole European union is based on the JRC-IDEES database [12]. The industry demand and supply is categorised by specific industrial sectors: Electric arc in furnaces, integrated steelworks, basic chemicals and other chemicals, pharmaceutical products, cement production, ceramics, Glass, pulp, paper, printing and media reproduction, Food and beverages and tobacco, Alumina, Aluminum primary route, and secondary route, and other non-ferrous metals. These production sectors have already assigned energy sources with which to carry their industrial activities and are: electricity, biomass, methane, hydrogen, heat and naphtha. The industry demand is added as flat linear along the year due to lack of data on time-series of this demand.

The supply of the basic feedstock are covered with technologies from the upper sections. Electricity supply is explained in Electricity demand and Supply, biomass is also assigned to each country depending on its biomass potentials, methane is supplied from well-extraction and bio-gas upgraded to methane, hydrogen is extensively generated from electrolysis with surplus electricity from renewable energies, heat has been comented in Heating demand and supply, and naphtha is produced through Fischer-Tropsh process take in turn hydrogen as primary source.

2.2.4. Energy flow and storage in the energy system model

In the previous section 2.2.3 the different demands and supplies in sectors have been described. In the present section now an interaction between these is exposed in figure 2.5. The graph shows a general depiction how the different energy flows are connected in the energy system model. Despite the fact that not all the technologies are present in the graph the graph is explanatory and demonstrative.

At the left of figure 2.5 we can observe the four sectors that we have just described and on the center we can appreciate the grids and storages of the energy vectors. In this thesis we have implemented the methane grid in a one node per country grid and have investigated how part of this grid can be retrofitted to transport hydrogen. Also the storages of each country have been implemented. In the figure it seems that from the hydrogen and methane grids not all the sectors can be supplied. For hydrogen however, while generating electricity through fuel cells, or by feeding naphtha and kerosene through Fischer-Tropsh, excess heat from these processes is generated and can be restored to cover heat demands. Important to mention is that in the graph one can see that there is no natural sources (from the right column in the figure) feeding the hydrogen source, becaue it is not found free in the nature and it has to be fabricated by electrolysis.

On the other hand, electricity flows through transmission lines of high-voltage alternate current (HVAC) and high-voltage direct current (HVDC) to all four sectors to cover the explained demands from Electricity demand and Supply. Storages in this grid are Batteries in households as well as BEV batteries which later, or overnight can dispatch energy back to the grid.

To balance the electric grid and the surpluses in electricity the system has the option to use storages of several types. We can distinguish between short-term, mid-term storage and long-term storage. The first one has typically low losses caused by energy conversion but its price is high. On the other hand hydrogen storage has higher losses but its storage cost can be one order of magnitude lower. Examples of this three types of storages and its classification are exemplified in table **??**

Methane is another energy source, in this case fed in figure 2.5 from bio-gas and fossil gas (extracted from underground wells). Methane can serve to generate electricity and recover exhaust gasses for heating purposes, or directly for gas boilers, as well as for several industrial processes as feedstock.

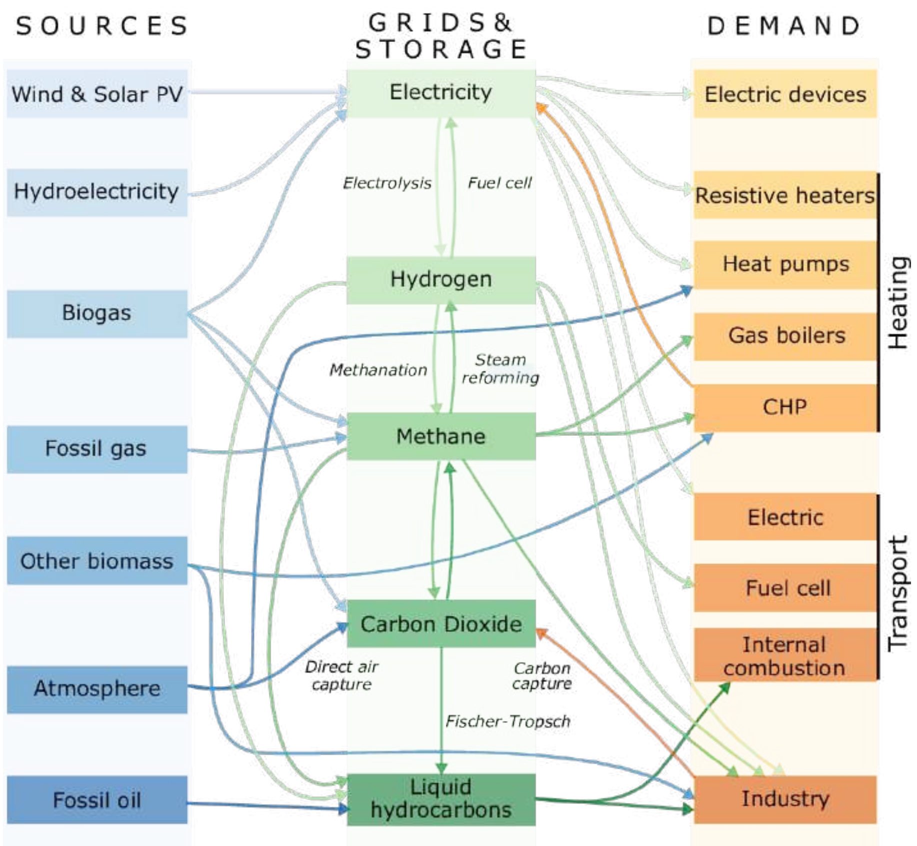

Figure 2.5.: Schematic energy flows between sources, grids, storages and demand in PyPSA-Eur-Sec.

CO_2 is another energy vector, although not used in the same way as the others, it does not have a grid associated and probably we do not expect to have one, although we do expect to have carbon capture sequestration (CCS) and CO_2-storages. The model has a net zero CO_2 constraint which implies that balancing of CO_2 can happen. As one can see in the figure, CO_2 does not supply to any of the demands and the only link out is towards the generation of methane by methanation processes like high-temperature electrolysis and methanation (HELMETH) or Sabatier.

The last energy vector are liquid hydrocarbons. However the model does not have a detailed grid for this resource. Hydrocarbons are modeled with a generator with a high price to just be used in moments of severe necesity, which should not occur as the model disposes of Fischer-Tropsch process and high proction of hydrogen is expected.

2.2.5. Model output

The optimization of the objective function stated in Equation 2.4 yields the model output. The results expres the minimum system costs, which consist of the fixed annualized investment in the capacities of generation, storage, transition lines and links, and the variable costs from supply of generated or stored energy. Solving the LOPF requires to determine the optimized generators and storages annual capacities for each node. Biomass,

Short-term storage	Medium-term storage	Long-term storage
Battery	Hydrogen	Hydrogen
Pumped-hydro	Methane	Methane
small thermal	Thermal energy storage (TES)	Thermal energy storage (TES)
	Hydro reservoir	Hydro reservoir

Table 2.3.: Short-, mid-term and long-term storage types

biogas and hydro capacities are assigned the first ones to the system. The rest of the generators and storage capacities are then optimized by the model. For renewable energies this is to determines the capacities to install of wind-power and solar for example. Then the supply of energy is balaced for every node and time instant.

Finally, the transported energy flows through transmission lines and links is calculated. For the study that concerns us the electric lines and links are left constant. Nevertheless, the pipeline capacity of the natural gas grid is in some of the studied scenarios extensible in order to accommodate retrofitted pipelines. In the third scenario we see that if retrofitted pipelines are not enough to transport hydrogen energy flows, then new H_2-pipelines are built to satisfy the dispatching of H_2.

3. Models implementation in PyPSA-Eur-Sec

In this section the implementation of three different models ready to solve their LOPF is explained. The results after solving the LOPF are in the next chapter 4. In the present thesis three scenarios have been selected for their characteristics, because differences should arise between them when introducing modifications to two of its gas-grids (methane and hydrogen). Along this thesis the interest of retrofitting current methane gas-pipelines for its operation with hydrogen has been presented and now the different models which later are assessed are described here.

The three scenarios are regarded as autarkic and build as such. This means that there exist no imports of the energy vectors descrived in section 2.2.4, namely: electricity, hydrogen, methane and CO_2. Liquid hydrocarbon fuels have a import allowed as an expensive generator for model security reasons, but in practice it does not produce any fuel, so indeed the system is autarkic. The countries inside this European countries have no imports of external methane

3.1. Greenfield scenario

The first scenario to be described is the greenfield scenario. It is built without any previous CH_4-grid, in which a newly H_2-grid between 37 European countries is built. These new H_2-grid takes the paths or routes from the clustered electric grid with HVAC and HVDC lines and sets its new H_2-grid with extendable capacities, so once set the LOPF system for solving the optimization gives the optimized values for each of the pipeline capacities.

Additionally, this scenario counts with a CH_4 generator and storage, both of extendable capacity in a node called "EU gas" which can dispatch CH_4 to any country-node that requires it. This dispatch in done through a link without length or cost. So it is like a wildcard-node for the system, capable of supplying methane to any country-node requiring it. So all technologies like OCGTs and CHP will take methane from it, and technologies like Sabatier, HELMETH give methane to the node due to their methanation processes.

Similarly happens for bio-gas and biomass, a wildcard node called "EU biogas" and "EU biomass" with an storage with all the aggregated bio-gas and biomass potentials of all countries is capable of supplying both feedstocks to all countries. These two assets can be used for example in CHPs for generating heat and electricity, cover the demand of industry, or, like in the case of bio-gas to be upgraded to CH_4.

For Fischer-Tropsch process the same applies. Namely a node common to all other country-nodes which can take H_2 from all of them if required, in order to cover the demands of naphtha and kerosene which are represented by two flat loads in the node for Fischer-Tropsch.

3.2. Gas-grid scenario

For the second scenario the current existing methane gas-grid is integrated in the system. Therefore this scenario has the current CH_4 gas-grid built in it, and a newly H_2-grid between 37 European countries is built. These new H_2-grid takes the same paths as in the previously greenfield scenario from the electric HVAC and HVDC lines with extensible capacity ready to optimize the LOPF problem.

In this scenario the current CH_4 gas-grid represents the exchange of gas between countries by means of its cross-border capacities, which act as pipelines. These cross-border capacities do not specifically represent one pipe, but the whole transmission capacity that two countries have with each other independetly of the real number of pipes, so the sum of all capacities in one direction are summed in one total capacity, and the same happens in the oposite direction if it exists a transmission in the contrary sense of flow. No storage in the pipelines is considered in this model or energy losses due to friction. The cross-border capacities are available from the ENTSOG data map [7]. The assigned costs for the cross-border capacities are described in section 2.2.1.

In this scenario storages are considered in the model for country nodes. Storages are also aggregated in the total sum of capacity that a country possesses as a one clustered storage resource per country. The country storage capacities are available from the GIE storage database [1].

There are a group of commissioned pipelines which are currently under construction and have been included in this study for considering that they are soon going to be finished and in a future scenario they will be fully operational and paid off. These are 13 pipelines, some of them allow flow of gas in both directions, others in only one, due to arrangement of compressors along the cross-border pipelines.

Generators: The countries inside this scenario have no imports of external methane and only count with its own supply resources coming from its inside borders (main supply capacities exist in Norway, the Netherlands, Great Britain and in a minor ones in Romania, Germany, Austria, Italy, Poland, Hungary and Croatia). The supply of CH_4 is modeled as generator capacities and are available from the ENTSOG data map in [7].

All technologies like OCGTs and CHP will take methane from the CH_4 gas-grid in every country that requires it, and technologies like Sabatier, HELMETH give methane to the gas-grid in each country-node due to their methanation processes.

Similarly happens for bio-gas and biomass, now these to feedstocks are disaggregated per country potentials build as storages in each country. These two assets can be use for example in CHPs for generating heat and electricity, cover the demand of industry, or, like in the case of bio-gas to be upgraded to CH_4.

In this scenario Fischer-Tropsch process is disaggregated by country. Although the demands of kerosene and naphtha are aggregated in a general global node representing the demand for all the countries in the study.

3.3. Retrofitted scenario

In this third scenario the current existing methane gas-grid is integrated in the system in the same way as in the Gas-grid scenario. However, in the Retrofitted scenario the CH_4 gas-grid can be retrofitted into H_2 in an optimized way. This means that the pipelines from the CH_4 gas-grid can must fulfill equation 2.13 described in section 2.2.1. This scenario can additionally build new pipelines in the same way that occurs in the Gas-grid scenario for the purpose of transporting all the H_2 energy flow needed to cover its demand in other country nodes.

For the rest, this scenario is identical to the Gas-grid scenario.

Following the advise from the authors in [4], for the sake of clarity: what this scenario does not consider are other H_2-technologies like LH_2-imports by ships, LH_2-tanks or the transport of H_2 by trailers in pressurized or liquefied forms.

4. Results and Interpretations

In this chapter the results of the greenfield scenario, the scenario with the actual methane-grid and a retrofitted grid scenario, all three described in previous chapter 3 are presented. The results are analyzed and conclusions are drawn to answer the research questions in section 1.2. In the following sections the results are split in three subsection: first an overall comparison between scenarios where we see if there are differences between them and what the gas grids represent for the whole system in terms of energy transported, cost of the gas grids and cost of transport of energy for the gas grids. Secondly, an analysis of methane grid by consuming technologies and sources of supply is assessed, and closer look to its grid is taken. Follows an evaluation of the solution for the hydrogen-grid where also demands and supplies of hydrogen are assessed and a finer view to its grid is taken and an analysis about the usage of the overall grid and its pipelines is displayed.

4.1. Global comparison between scenarios

In chapter 3 the implementation of the three scenarios is described and here, according to the questions in section 1.2, we want to know if there are significant differences between the three scenarios in terms of investment costs and if the technologies installed to achieve the constraint of a CO_2-neutral Europe are different between the assumed scenarios.

Overall scenario comparison

When looking at the overall costs in Figure 4.1 one sees there is no substantial difference in the total investment and marginal costs between the three scenarios and all seem to implement a similar solution of technologies in the same proportion. One can state that the different constraint implementation for the gas transport grids in the three scenarios does not lead to significant differences for each of the scenario solutions. The costs of the three scenarios is identical, €761 billion. About the solutions implemented we can see that all technologies have a strong relation to renewable energies and alone gas boilers or Fischer Tropsch have directly or indirectly CO_2 associated emissions. Alone wind-energy (on- and off-shore AC, and DC) accounts for €381 billion, or 50% of the total cost of investment and operation per year. Bearing in mind the availability time of wind in front of solar-PV technology and the substantially higher efficiencies that wind yield, we get a sense where the main source of energy is for these decarbonized scenarios. Additionally the costs of hydrogen storage and electrolyzer and pipeline-grid sum up €65 billion, representing a significant 8,5% of the total investment cost in this novel technology.

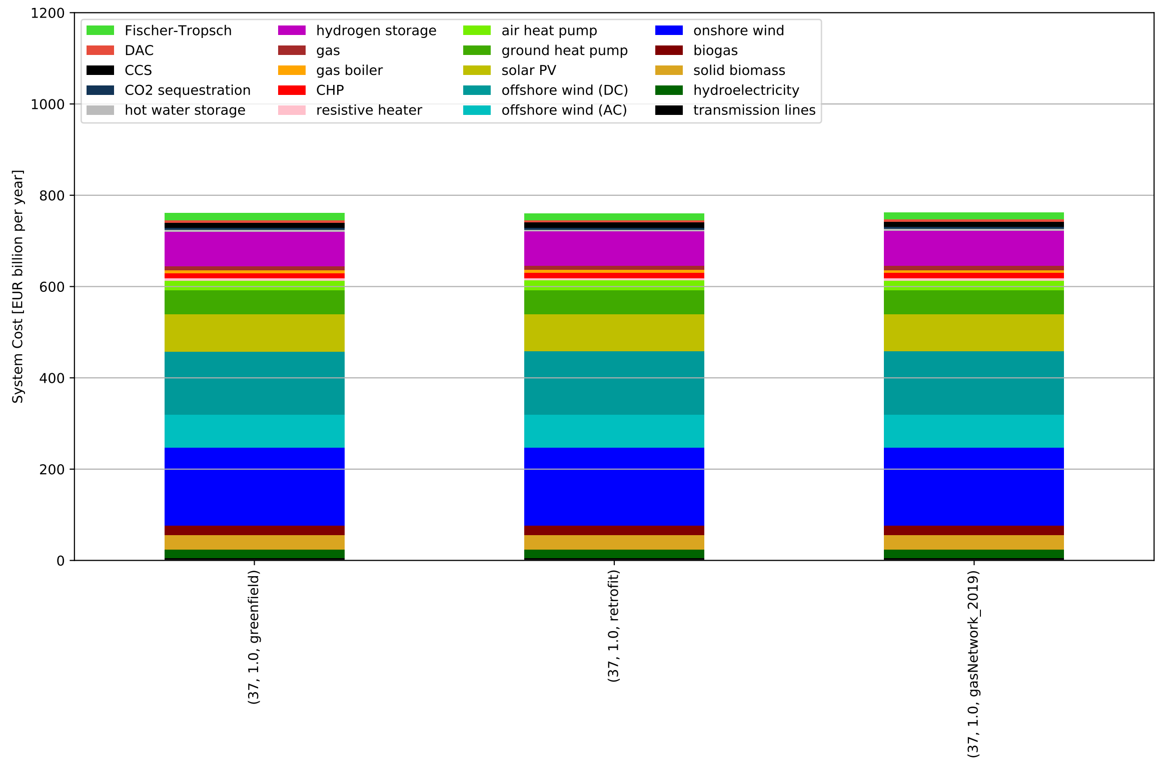

Figure 4.1.: Bar plot with total system costs for the three scenarios showing no significant difference in their cost per technology.

If we observe the energy balances of methane, hydrogen, heat, or any of the comparing balances available from PyPSA we cannot see significant differences between the three scenarios. To further exemplify this, the methane energy-balance of the three scenarios in shown in Figure A.2. In the figure one can see the supplies of methane in natural gas (extracted inside European borders), the bio-gas available (from the countrywide bio-gas potentials) and its demands split in gas for industry and the demand consumed by gas boilers. As mentioned, the differences are so small that no apparent or significant distinction can be made.

Another explanatory graph is the energy balance for electricity, depicted in Figure 4.2. It is interesting that 62% of all electricity production is destined to other demands of different energy vectors such as heat, transport or hydrogen. 35% of all electricity generated is destined to hydrogen storage (implicit is the electrolysis generation), 12% to BEV (again another type of storage, to cover transport demand). A relative 15% is dedicated to cover heat demand with several technologies: ground and air heat pumps, and resistive heaters. The rest, 38%, is dedicated to direct electricity demand and dedicated industry electricity consumption.

Another two exemplifying bar plots confirming the three scenarios have a very similar and imperceptible difference in their technology arrangement to meet net-zero carbon at the lowest cost are attached in the Appendix A. For example the hydrogen-to-Fischer-Tropsch balance, Figure A.3; and the methane energy balance in Figure A.2.

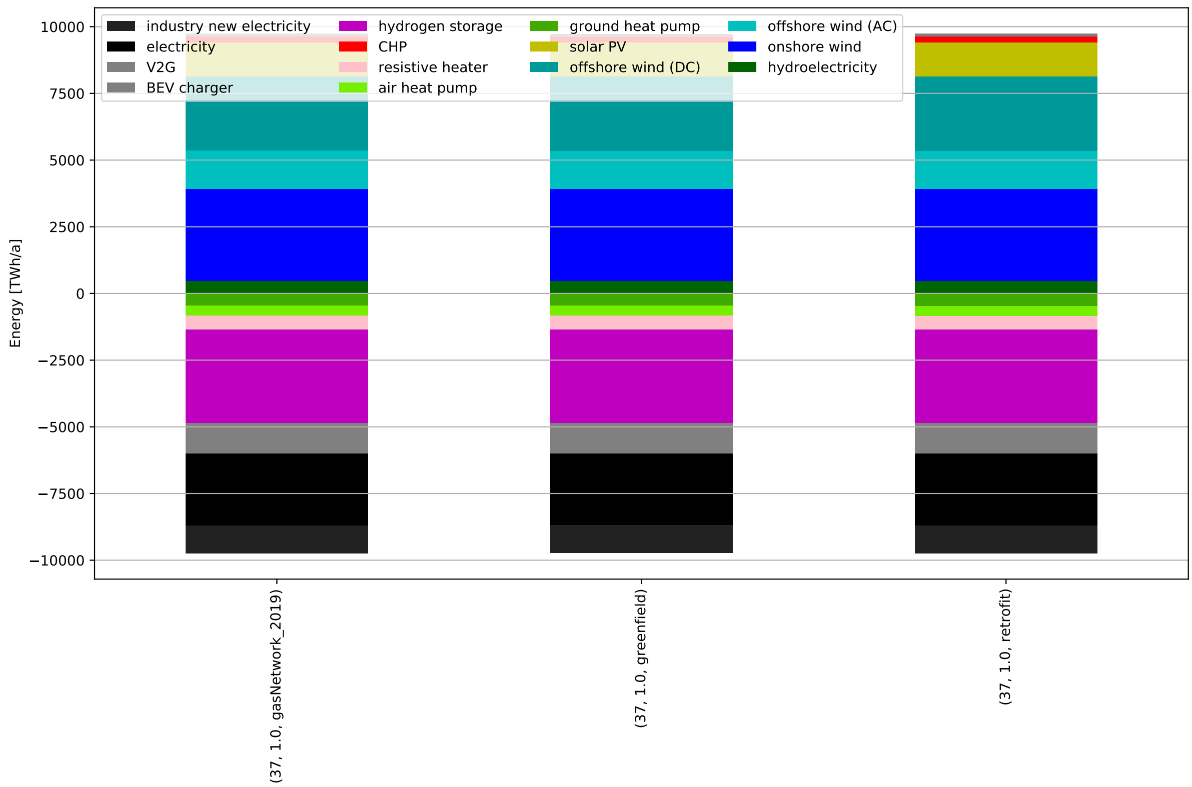

Figure 4.2.: Bar plot of the total system electric energy balance for the three scenarios.

Conversion of cross-border capacity-pipelines

Once we know the three systems have an almost equal arrangement of technological solutions to reach to the objectives and optimize the cost of the system, we want to see in-depth information about the scenarios. To give an insight to the next sections, and answer further research question, it is relevant to see how many cross-border pipelines are being converted or retrofitted from methane to hydrogen. Of course, by definition, this can only occur in the retrofitted scenario, and not in the greenfield- and the current-gas-network-scenarios (described in chapter 3). Now, if the technological solutions obtained after the optimization are almost identical, and greenfield- and current-gas-network-scenarios do not allow retrofitting as described in chapter 3, then these two scenarios which build all its H_2 transport network with new pipelines should reach a higher total grid cost. Building H_2 new pipelines has a higher cost due to their need of civil engineering construction items. So even if the overall costs of the scenarios is the same, there are differences in the specific costs of the scenario gas-grids and these will be shown hereafter.

The conversion of cross-border pipeline capacities for the retrofitted scenario is depicted in Figure 4.3. For this scenario we see a smooth conversion in the number of pipes and a wide range of pipelines still allow to have a split operation with both gases (as pipelines are clustered, for example a 66% conversion would be arranged in 3 discrete pipes: two for H_2 and one CH_4, for example). Additionally, depending on the conditions of the model, this diagram can change dramatically, e.g. Figure A.1, in Appendix A, where bio-gas was placed in a common node for EU and not transported through the natural gas grid. There, the conversion occurs in a steeper way, as less methane flows through the pipelines.

In Figure 4.6 the remaining natural gas cross-border capacities are represented (39 dedicated to CH_4 and 23 partially retrofitted to H_2, from a total of 83). In a future scenario these cross-border capacities are still used to trade CH_4 between countries. There are a number of 23 pipelines that can supplying partially CH_4 and H_2 and are relevant for the supply of CH_4 in a decarbonized scenario, as bio-gas is an energy source with zero-net contribution to CO_2 emissions. On the other hand, the fully retrofitted cross-border capacities are 21 in total, and 23 are not fully converted for hydrogen.

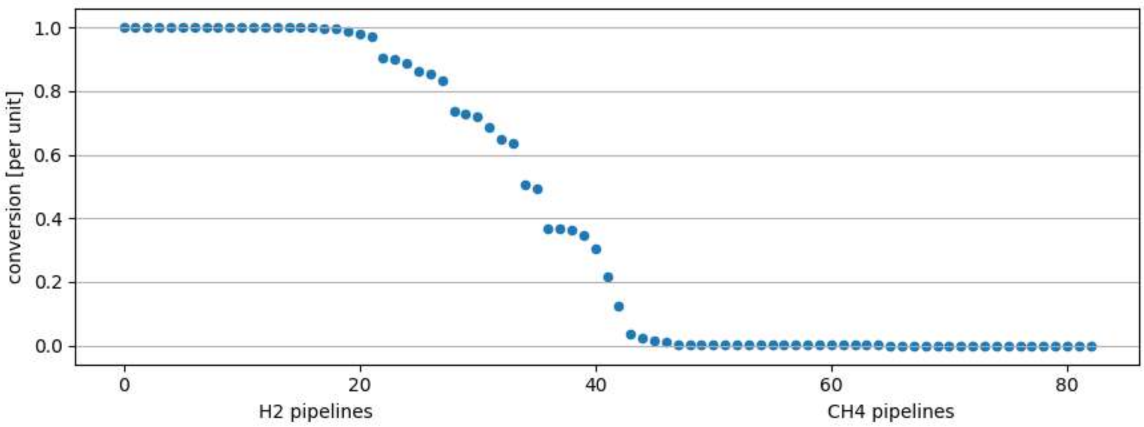

Figure 4.3.: Conversion diagram of normalized cross-border capacity retrofitting from methane into hydrogen. Fully H_2-retrofitted 21 connections; 39 remain unchanged for CH_4, and 23 are mixed with a retrofittig not lower than 2.5%.

Network costs and cost of energy transport

As described in the previous section the conversion of cross-border pipeline capacities from CH_4 into H_2 can only occur in the retrofitted-scenario, and in the other two scenarios all H_2 pipelines are only newly built. In this section we respond to the research questions that deal with the overall usage of the pipelines, mainly for the retrofitted-scenario, and take an approach to give a reference cost of the energy transport calculated by means of the cost that the H_2 and CH_4 grids have over all the annually energy transported.

However, despite the initially unknown deployment of the technologies by the optimization, there is one pipeline capacity which should be retrofitted and not newly built in the solution. This occurs between Ireland (IE) and Great Britain (GB), where the original CH_4 cross-border capacity has the sense from GB to IE and not in the other direction. This issue does not affect the general results shown here and is not significant or affecting the results for the explanatory purposes of this section.

In Figure 4.4 we can see the overall grid costs by scenario. Compared with Figure 4.1 in which no substantial differences are observed, in the figure now presented, relevant differences arise, although of course, the cost level barley affects the overall system costs for the three scenarios, as these costs only represent approximately 1 %. The greenfield scenario with its simplifications achieves the lowest cost, but as mentioned in section 3.1 this scenario counts with several simplifications for the purpose of having a reference to compare with but are not as realistic as in the other two scenarios. However one can see that the retrofitted scenario and the current gas network scenario keep a cost that does not deviate orders of magnitude one from the other, and the figures seem to correspond with the expected, namely that the retrofitted-scenario supposes a reduction in cost for the H_2-grid deployment. The overall cost of the retrofitted scenario is 7.62 billion euro annually. Split in billion euros by type of pipelines this is: 4.93 for the total new pipelines, 2.14 for the retrofitted ones and 0.54 for only the still in used the methane pipelines. The current gas network scenario is more expensive in overall, and even the costs from maintaining the natural gas grid are slightly higher than the costs of the retrofitted scenario. In this second case the costs of the newly built H_2-grid is of 8.15 billion per year, and for the natural gas grid of 0.68 billion euro a year, and in total 8.83 billion euro. So the retrofitted scenario allows for a saving in costs of 13.7% per year in front of a non-retrofitted scenario.

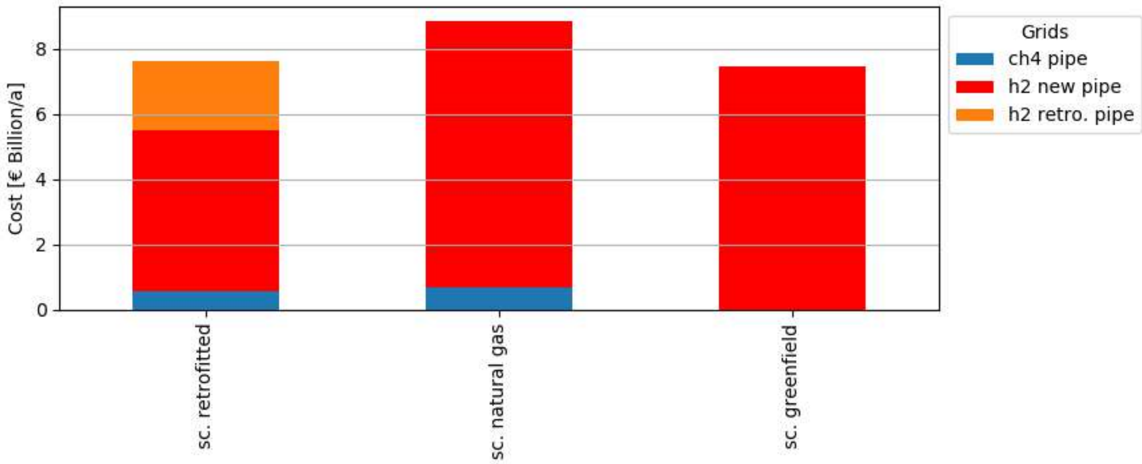

Figure 4.4.: Bar plot of total annual grid costs per scenario.

As mentioned already in this chapter we can see that the greenfield-scenario seems to have any transport of methane, but the explanation for that are virtual European nodes containing bio-gas and natural gas and connect directly with the country nodes, therefore this methane is cost-free transported through links that have no physical meaning, however we do see consumption of methane in the greenfield scenario in Figure A.2, and this is the reason for that unseen transport of methane in that scenario.

In absolute therms we can observe in Table 4.1, the use and transport of CH_4 compared to H_2 is much lower and is latter commented.

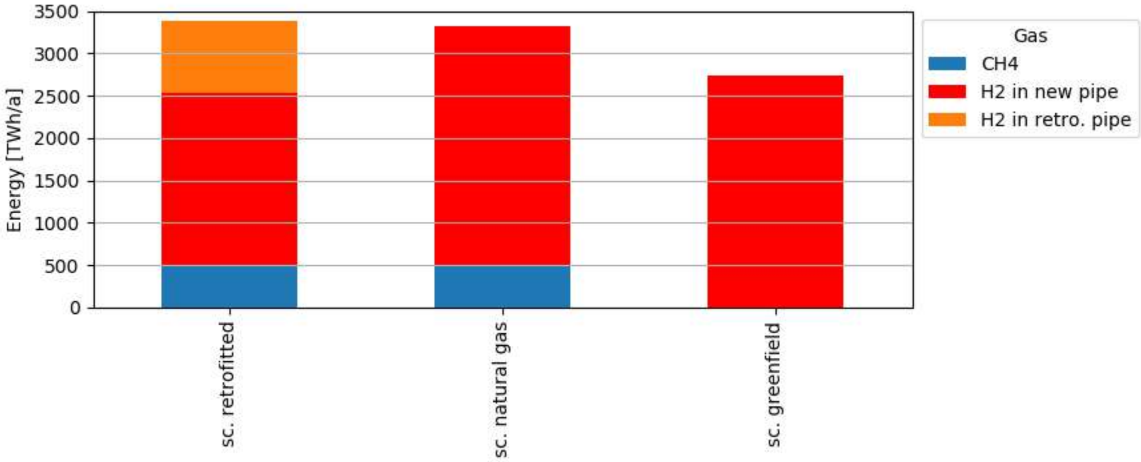

Figure 4.5.: Bar plot of annual transported energy flow by gas type and pipeline per scenario.

With the complete data from energy transport in Figure 4.5 and the corresponding costs of Figure 4.4 the associate cost of energy transport is deducted for the three scenarios in table Table 4.1. The approach to the calculating this cost is:

$$\frac{\text{total cost per network } + \text{ total energy flown} \cdot \text{VOM}}{\text{total energy flown through the pipe}}$$

However, as the operation and maintenance cost is dropped of the modelling for not having enough certainty over it the previous expression is reduced to:

$$\frac{\text{total cost per network}}{\text{total energy flown through the pipe}}$$

The cost of transport is inside margins of today's actual market prices despite the number of assumptions and the detail of the data available for this study, which is to some extend restricted. Assuming only one pipeline connection between countries carries uncertainties with it, and first approaches to research questions are also needed to adjust further modelling.

Scenario	Oveall H_2	New H_2 pipes	retro.H_2 pipes	Natural gas pipes
Greenfield	2.71€/MWh	2.71€/MWh	-	-
Current gas network	2.88€/MWh	2.88€/MWh	-	1.41€/MWh
Retrofitted	2.40€/MWh	2.40€/MWh	2.54€/MWh	1.14€/MWh

Table 4.1.: Costs of transport of energy by gas and grid.

4.2. Scenario results of the natural gas grid

This chapter provides and overview to the role that natural gas grid has in a future scenario of neutral CO_2 emissions. In the previous section we have seen that there is a demand for natural gas and so the methane grid still provides an important function for the energy balance in Europe. Here natural gas and country potentials of bio-gas are taken into account and cover a still important part of the energy demanded in a net zero emission Europe. Part of the questions that we want to address in this segment is how does a decarbonized scenario affect the current methane supplies and if there is any of the actual main sources of natural gas that is depleted. We as well want to see if the supplies accommodate to the seasonal associated heat demand that we observe nowadays. Another important matter is how does the supply of methane occur between the different European countries and which gas-grid routes does the model take as favorable to cover the different demands.

In Figure 4.6 the cross-border pipeline capacities remaining available for natural gas are observable, and the retrofitted pipelines which still do transport methane (in green). Additionally also the original capacities of the methane producing countries (extraction of methane) inside European borders is observable (cyan) and the mean supplied extracted methane coming from EU own resources.

Comparing the natural gas extraction capacities inside European borders (which matches the real capacities of the countries with this resource) against the mean supply of energy there is no doubt that in this future scenarios the underground extraction of methane will be very limited. For the case of Norway, which today supplies 40% of all European demands in a non-autarkic market, This would mean to reduce its actual methane supplies to the EU to just a 5% of its potential. But for the supplies of extracted methane the case is even worst for Ireland, Great Britain and the Netherlands, which supplied extracted methane appears depleted as we observe no mean supplied natural gas from underground extraction.

However, bio-gas seems to take the lead for the above mentioned countries and in many others as shown in Figure 4.9 (though the information displayed is different). These indicates that a change towards strongly developing the production of bio-gas should be taken in such CO_2-free scenarios.

Another important observation is that the country-nodes supplying natural gas seem to be more equally spread on the map and the origin of the gas is less concentrated in Norway, Great Britain and the Netherlands. This makes today's minor suppliers like Italy, Germany, Romania, Poland, Hungary and Austria to have a relative equal important supply of underground extracted natural gas, and for these last countries to supply underground natural gas almost or at full capacity. This can be observed in Figure 4.7.

About the cross-border capacity pipelines, comparing the actual capacities in Figure 4.6 and the mean supplied energy in the pipes in Figure 4.9 we see a reduction of about an order of magnitude between the available and the used CH_4 pipeline capacities (note the scale in the legends).

It is also the intention of the author to remark, that, even if some cross-border pipelines are small or the energy carried is low, the analysis takes also those country demands seriously as, in proportion, for the populations in those countries, the supplies of any kind of energy can be critical. So not because a demand is small or a pipe supplies low total energy the pipeline is taken as less important. With that being said, the partially converted pipelines and also smaller pipelines help interconnect the grid in to all its countries.

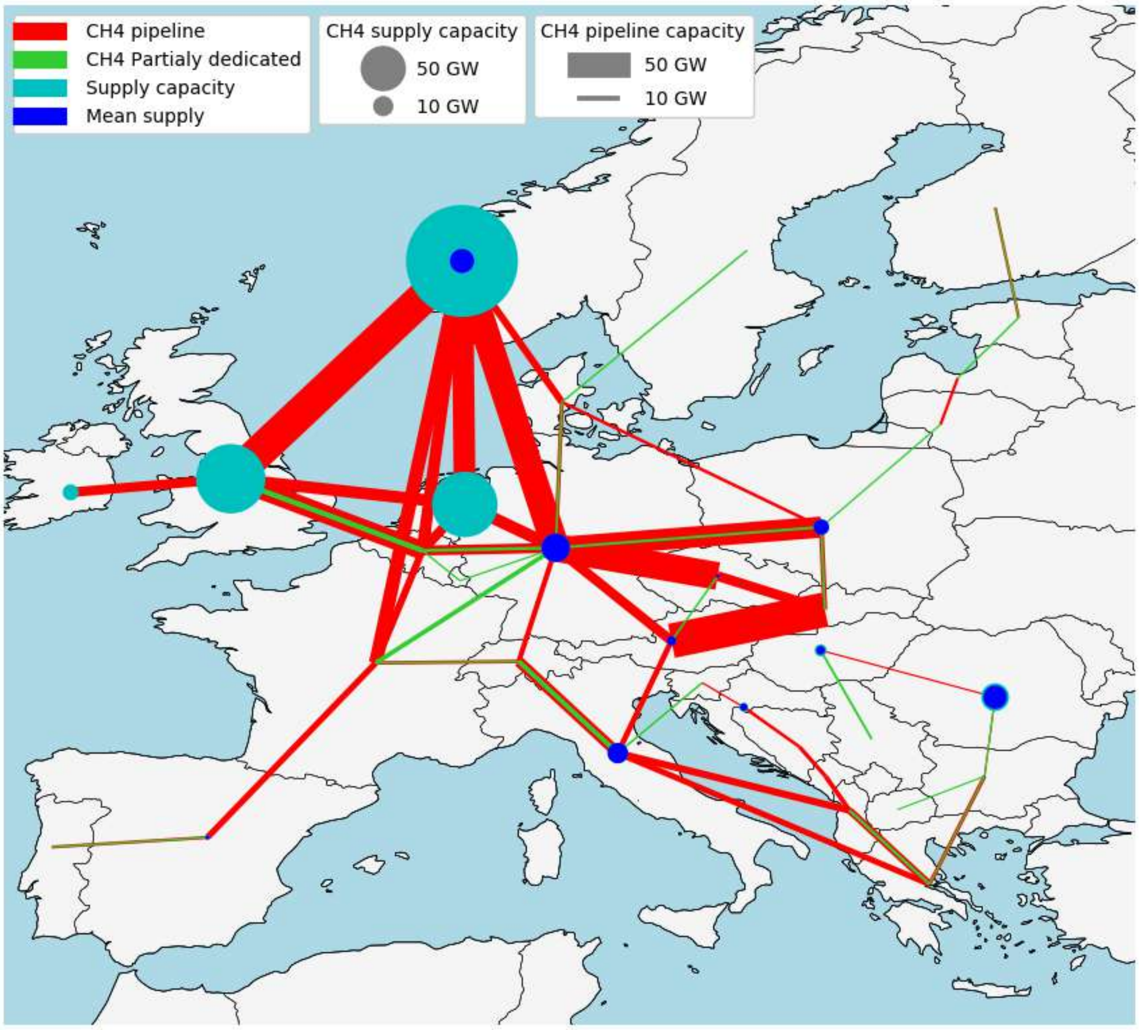

Figure 4.6.: Geographical methane capacities both for of natural gas grid and generation.

In Figure 4.7 we can see how the supply of extracted methane by country takes place along a year. It is observable that besides for Romania and Croatia no apparent seasonality in the supply in observable.

In order to understand how the demands of methane are distributed in Europe we can observe in Figure 4.8 which countries have the highest demands in the system. These countries are: Italy, Germany, Poland, France, Spain and account for the 70% of all natural gas demand. Gas boilers represent 610TWh/a, while the industry demands 129TWh/a. Outstanding are the individual demands from Italy and Germany in comparison to all other countries.

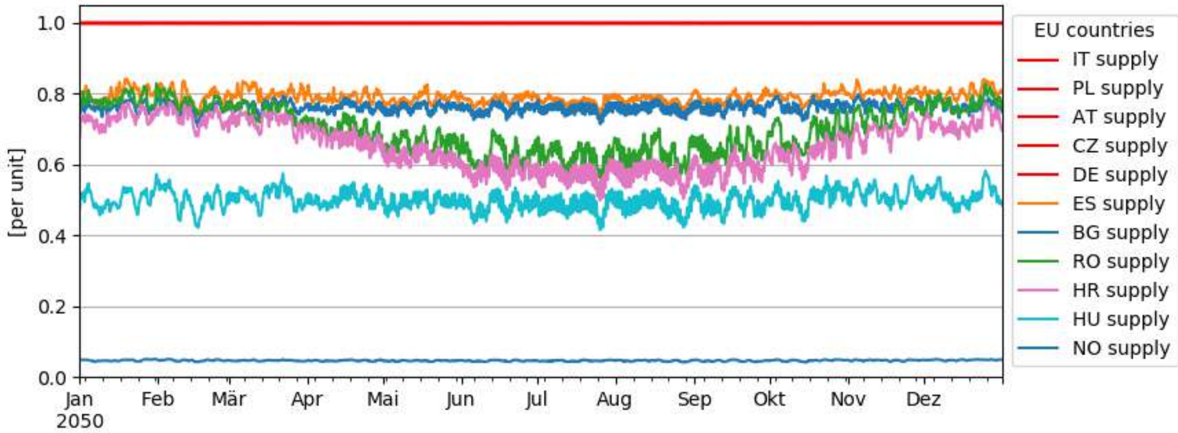

Figure 4.7.: Temporal normed supply of underground extracted natural gas of EU-countries with methane resources.

On the other hand, the supplies of natural gas count with underground extraction sources and with bio-gas potentials in each country. The two sources of natural gas are very similar, accounting 388TWh/a the extracted natural gas, and 352TWh/a for bio-gas, meaning that both sources now share a relative similar level of overall supply. The order of the countries in the figure indicated which countries are net exporter, at the left, and net consumers, in the right side. All in all, the total energy balance for methane is 740TWh, either summing supply or demand.

The research questions also contemplates how much installed capacities of OCGT's and CHP's are installed in the model. So, even if in Figure 4.1 we see a slight sign of CHP's being installed their footprint in the energy demand of methane is insignificant. The sign seen in Figure 4.1 is due to its high cost, but the energy demand that that this type of technology takes from the system is negligible to any level by several orders or magnitude. Following this explanation, OCGT's installation is nonexistent. Summarizing, the following technologies have a marginal role in any of the three future decarbonized scenarios, not even in combination with CCS: micro gas CHP, CHP's, OCGT, SMR.

A complete picture of the natural gas grid can be observed in Figure 4.9. Here all the countries can be assessed in relation to their neighbour countries and see their dependencies. Some countries are net exporters only thanks to their natural gas extraction capacities, such as Norway or Romania, but others are also only due to their bio-gas potential, such as Great Britain, France, Portugal. On the demands side, Germany and Italy have the biggest demands but specially the latter appears as a potential stress to the system. Also the connection of the Baltic countries and Finland, where all are net importers, is of great importance as it is not connected to other grids (at least in these scenarios).

A minimum offset is displayed in order to represent the smallest pipelines in order for them to be seen in Figure 4.9. A binary multiplying factor is set for all pipes that transport gas averaged over time at least at 1% of their capacity. The effect of this offset is clear in

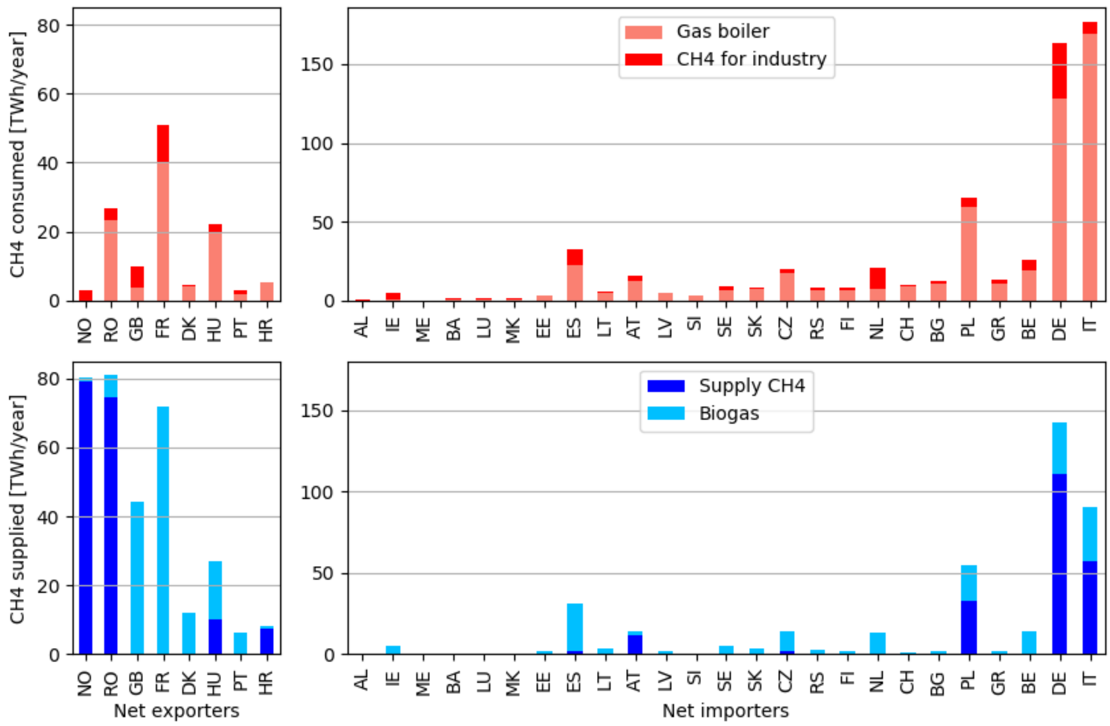

Figure 4.8.: Ordered energy net country exporter or importer bar plot of methane technology consumption and supply sources.

the connections between Austria, Czech Republic and Slovakia; or in the connections of the Balkan countries. Otherwise this pipelines cannot be perceptible.

As final analysis of this section in Figure 4.10 are shown the methane energy flows of the the 10 most representative and dominant pipelines shown in the geographical map in Figure 4.9. In the figure we can observe that the 7 pipelines work at constant level, and 5 of these work fully congested (these share the same legend color). Besides the congestion of these pipelines, which is quite unrealistic, the whole system is not showing the same behaviour of seasonality that we are used to see nowadays. Only 3 pipelines show some sort of fluctuation and two of them discharge in Italy. This fluctuations suggest that Italy discharges its methane storages during the cold winter months and as soon as possible it begins to refill the storages during the warm or mild moths, in order to meet the condition of cyclic level in the stores. Other pipelines also work seasonally, e.g. from Croatia to Slovenia, but this seasonality is not observed in the same way as we see it nowadays as shown in Figure 4.11. Other pipelines, e.g. Croatia to Slovenia show a nice seasonal curve. As a recap, the utilization of the pipelines does not follow a generalized seasonal pattern.

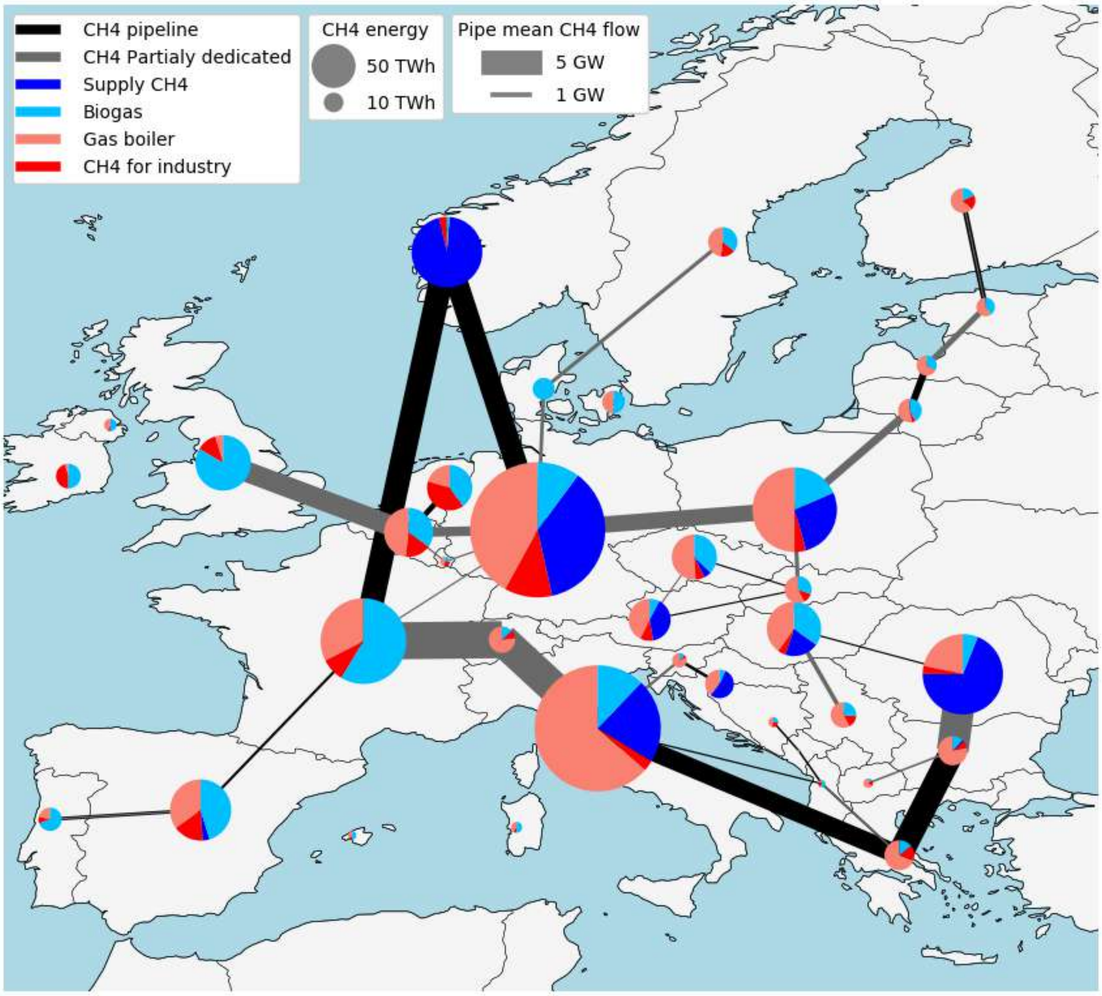

Figure 4.9.: Geographical map with countrywide methane energy balance per country and pipeline annual mean energy flow.

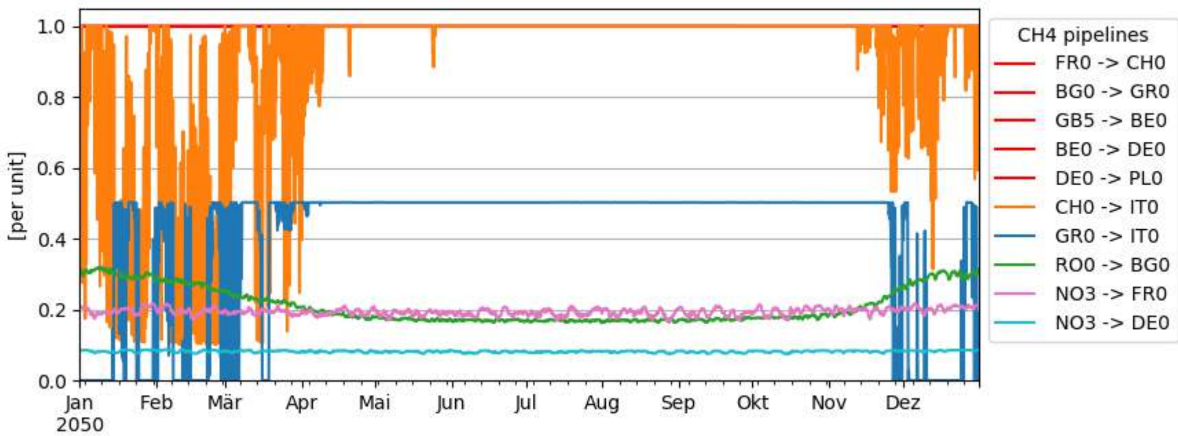

Figure 4.10.: Temporal normed methane energy flow of the pipelines with higher transported energy.

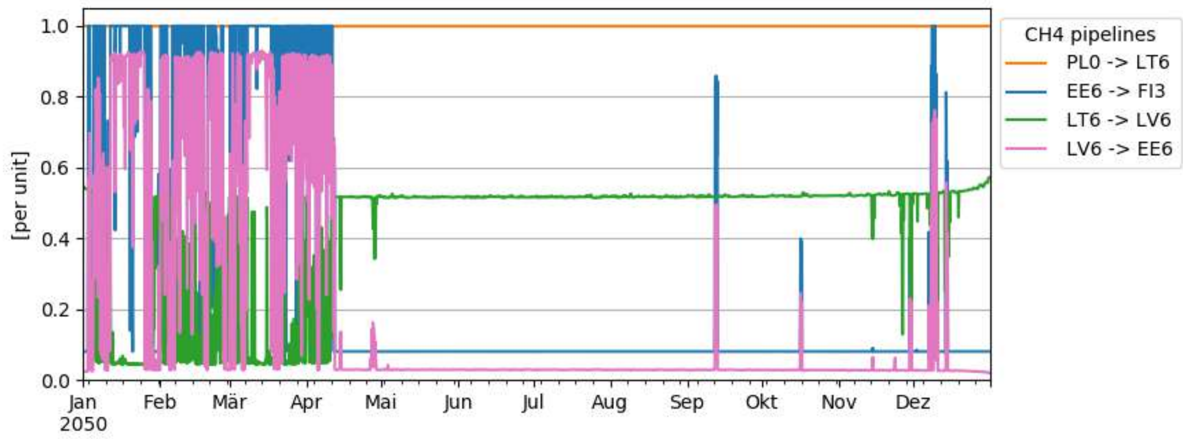

Figure 4.11.: Temporal normed methane energy flow of the pipelines supplying the Baltic countries and Findland.

In summary, besides the strong differences in energy-flow transported between the methane and the hydrogen grids, the energy demand of natural gas is still a valuable asset in the three scenarios that maintain the natural gas grids. For the case of the greenfield scenario, the natural gas and the bio-gas is still used by the system (and shows the same total quantities as the other two scenarios), but distributed via a virtual European node linked to all countries (so it is actually bypassing any grid). In these scenarios, for countries with big underground extraction capacities most of the natural gas extraction is not existent, but despite lower global methane demand they still play an important role thanks to their surplus in bio-gas potentials. In general, bio-gas does play a very important role in all the scenarios as without it, it would be even more costly to achieve the reductions of greenhouse gas emissions. The natural gas cross-border pipelines draw highlighted connections between the net exporting and the demanding countries, however the whole of Europe is still interconnected to a high extend.

4.3. Scenario results of the hydrogen grid

In the present section we review the function of hydrogen in the proposed three scenarios. The supply and consumption technologies are assessed, as well as its transport in the grid. The final hydrogen energy demand is 4,3 times bigger than that of methane (accounting 3.189TWh/a and 740TWh/a respectively). If we look at the energy transported by each of the grids the difference is almost 6 times bigger (5,95), transporting 2.995TWh/a and 486TWh/a respectively for hydrogen and methane grids. In such a future scenarios the energy demand of H_2 predominates over methane transport through the gas grids, even if the transport of hydrogen requires the construction of more cross-border capacities between countries. The H_2 grid overtakes the principal role that methane has nowadays generally in Europe. The questions whether every country can produce hydrogen with renewable energies is addressed; to which direction is hydrogen flowing in Europe's grid?; if all countries produce hydrogen in the same proportion. Also questions about the technologies that take hydrogen as an input to generate electricity or heat are explained and made clear, as well as the assigned demands to cover industry and transport (shipping) in all three future scenarios. These questions find an answer in this section.

To have a first glance of how the retrofitting of pipelines influences the system in Figure 4.12 we can observe, for the retrofitted scenario, a classification of the pipelines in three types: whether newly built, partially retrofitted or fully retrofitted pipelines. There are 21 pipelines fully converted to H_2, 23 are partially converted, and there are 33 newly build H_2 cross-border capacities from a total available of 65 (available pipelines match the electric paths). We can observe the geographical distribution of producing and consuming technologies by capacity (not the country assigned demands, e.g. industry or transport for shipping). The whole hydrogen supply is generated by electrolysis with surplus electricity coming from renewable energies. As shown in Figure 4.2 for the overall electricity energy balance the generation of hydrogen accounts for a third of all the electric production in the three scenarios. taking a look at the figure, Figure 4.12, one can already have an intuition of the energy flows in the system knowing that the system solution is optimized in PyPSA. This means that solving the optimization problem enhances the usability of the technologies that we see as predominant in this graphic. Following this idea, we see no substantial placement of SMR technology and it does not have any influence on the system, therefore no CH_4 is destined to producing H_2 in any of the three scenarios. About the greenfield scenario and the current-gas-network scenarios just mention that all the pipelines are newly built taking as possible paths the ones that link the electric grid.

Supporting the statement that hydrogen takes the main role that methane has nowadays we can compare the capacity sizes of methane supply (extracted) in Figure 4.6, and the capacities of the electrolizers in Figure 4.12. We have to be aware that the efficiency of electrolizers is of 0.8, but still the idea is valid. In a future scenarios the installed electrolyzer technology should reach capacities as big as today's inner-European methane extraction, which means an enormous economic and technological effort compared to today's situation in order to achieve neutral CO_2 emissions in Europe.

In Figure 4.13 we can see the countries ordered by net energy balance of hydrogen (exporters or importers). The net hydrogen exports are solely attributed to four countries: Denmark, the Netherlands, Great Britain and Ireland. These countries have enough production capacity to supply Europe with hydrogen due to their surplus of harvested energy, coming from wind-power, both on- and off-shore. Other northern countries like Norway, Sweden, Finland, Latvia, Estonia and Poland are also producing hydrogen but they are net consumers and do not reach enough surpluses to export in meaningful quantities (see scales). Other countries with hydrogen production capacity in the south or Europe are France, Spain, Greece and Italy, where the installation of solar-PV technology predominates. However, due to availability-hours and efficiency of solar-PV, this technology, compared to wind-power, does not allow these countries to export hydrogen. It is interesting to observe that apart of electrolysis, no other technology is installed in any country for the production of hydrogen, so SMR technology, both with- and without CCS, have no representation in the overall energy system. Therefore all the hydrogen produced is green-hydrogen and no grey- or blue-hydrogen (technologies to generate turquoise-hydrogen by pirolysis are not considered in the model).

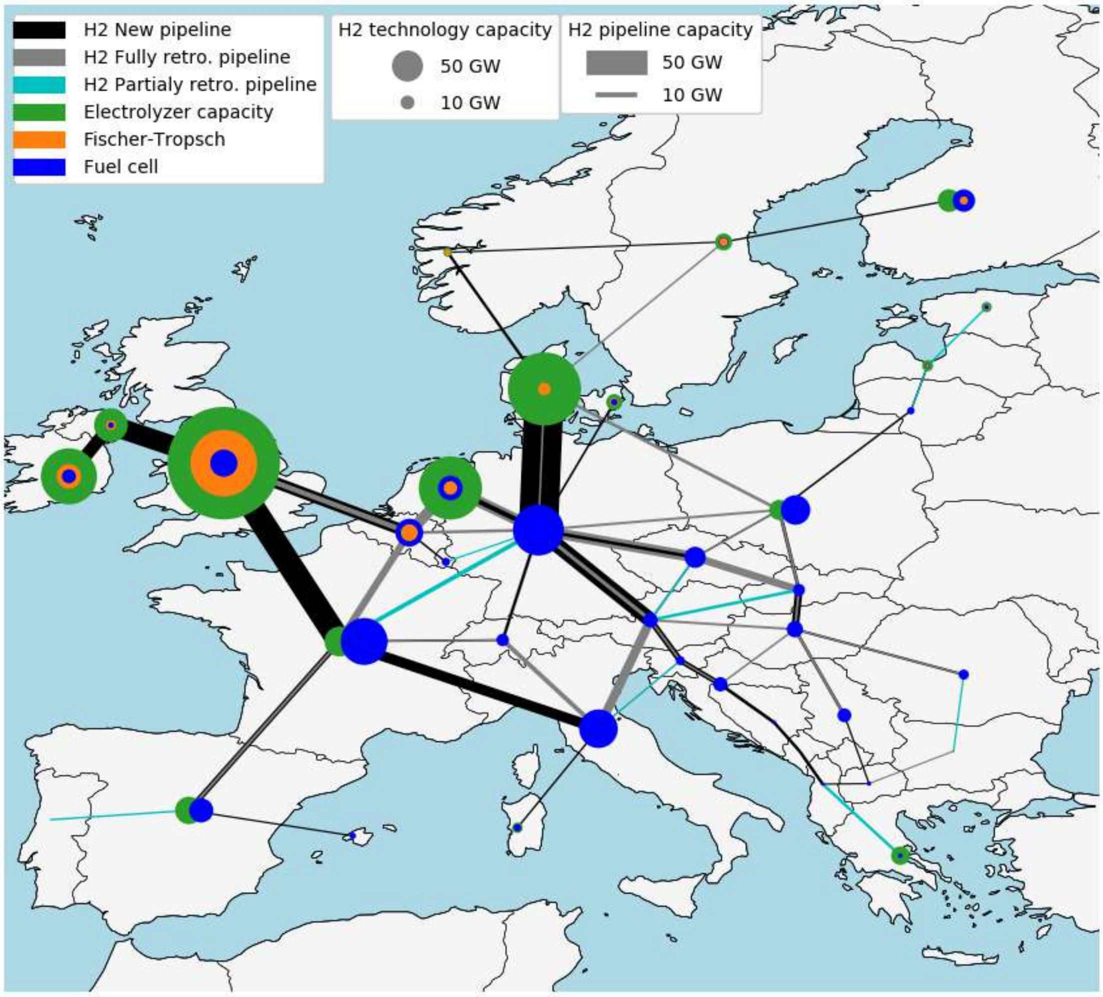

Figure 4.12.: Geographic representation of installed hydrogen-related technology capacities.

The fact that this model assumes an autarkic energy system for Europe reveals that all the transported hydrogen comes from the North-west of Europe (Denmark, the Netherlands, Great Britain and Ireland) and almost has only a one sided entry for hydrogen in Europe. Another interesting fact is that Germany, Austria or Hungary act as distributors of hydrogen to many subsequent-countries in the chain-of-transport merely due to their geographical location and the fact that the origin of production happens in the north-western countries.

On the other hand, the consumption of hydrogen, also depicted in the bar-plot in Figure 4.13, shows that the majority of the countries, and mainly smaller countries (in size and population), are net consumers of this feedstock. In countries which can export H_2 these tend to install more Fischer-Tropsch-process technology but in general in all the consuming countries fuel cells tends to be installed. Another not negligible proportion of hydrogen is designated for industry and the transport (or shipping) in general. As

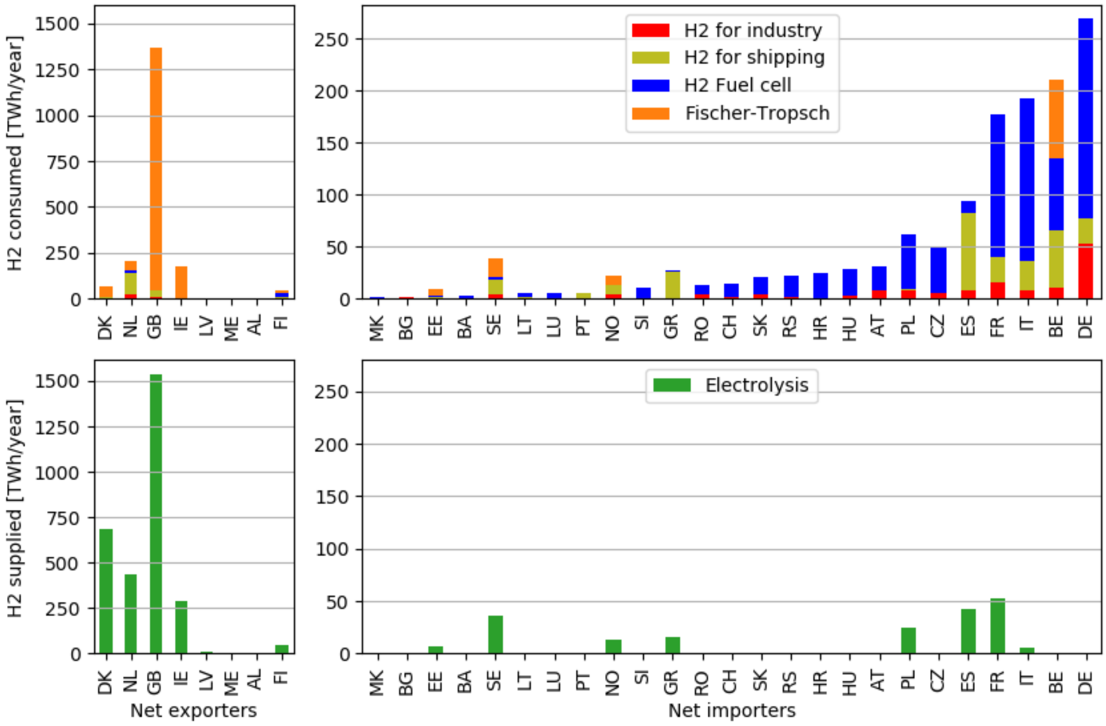

Figure 4.13.: Bar plot diagram comparing ordered net suppliers and consumers of hydrogen by technology and country in a year.

seen before, the main 6 or 7 countries that account for about 75% to 80% of Europe's consumption of methane keep also being at the head of consumption of hydrogen in all its forms, namely: Great Britain, Germany, Italy, France, Spain, the Netherlands and Belgium (all the highest GDP's in Europe).

The next depiction to analyse, Figure 4.14, shows an energy-balance for each country and averaged energy transported by the pipelines cross-border capacities. In the map one can rapidly observe the placing of the small demands, with almost no generation of hydrogen, in the East of Europe (both North and South) mainly represented by fuel cell technology (in blue). Great Britain has the highest H_2 demand of all countries as observable, with dominant installation of Fischer-Tropsch processes thanks to its high surplus of renewable energy. Indeed, all the exporting countries have Fischer-Tropsch installed and linked together to heat production, and even in southern countries Fischer-Tropsch linked with heat production is always the choice. Belgium is the only country with high installation of Fischer-Tropsch which has no exports of this asset. Fischer-Tropsch is convenient where surplus of renewable energy is present, due to its combined outputs to heat and liquid fuels: naphtha and kerosene, needed for example for industrial processes and in the aviation industry. The fact that there is so much of Fischer-Tropsch technology placed in the exporting countries relies on how the scenarios are built at the time of analysing this data. Fischer-Tropsch is a common node linked to all the countries and its outputs serve to cover the naphtha and kerosene demands, however the model optimizes this use of Fischer-Tropsch by adding heat recuperation to the process to extract more energy from a single process instead of generating demand though other processes, so it is taking the efficiency, 0.15, and recuperating it to balance part of the heat demand. If the demands of naphtha and kerosene were distributed to each country then the generation of these liquid fuels would be distributed among the countries in Europe and Fischer-Tropsch would not be so relevant in Great Britain and the mentioned north-western countries. This helps explain the fact that in Belgium appears to be Fischer-Tropsch even if there is no electrolysis installed, and it is because, as we can see, in Great Britain and Ireland all the demands are totally covered, and Belgium is taking the extra surplus of hydrogen to generate naphtha and kerosene. This explanation concerns all three scenarios. The assigned demands of H_2 for industry and shipping are also displayed per country. About the installation of technology using Sabatier processes it is fully insignificant in all three scenarios.

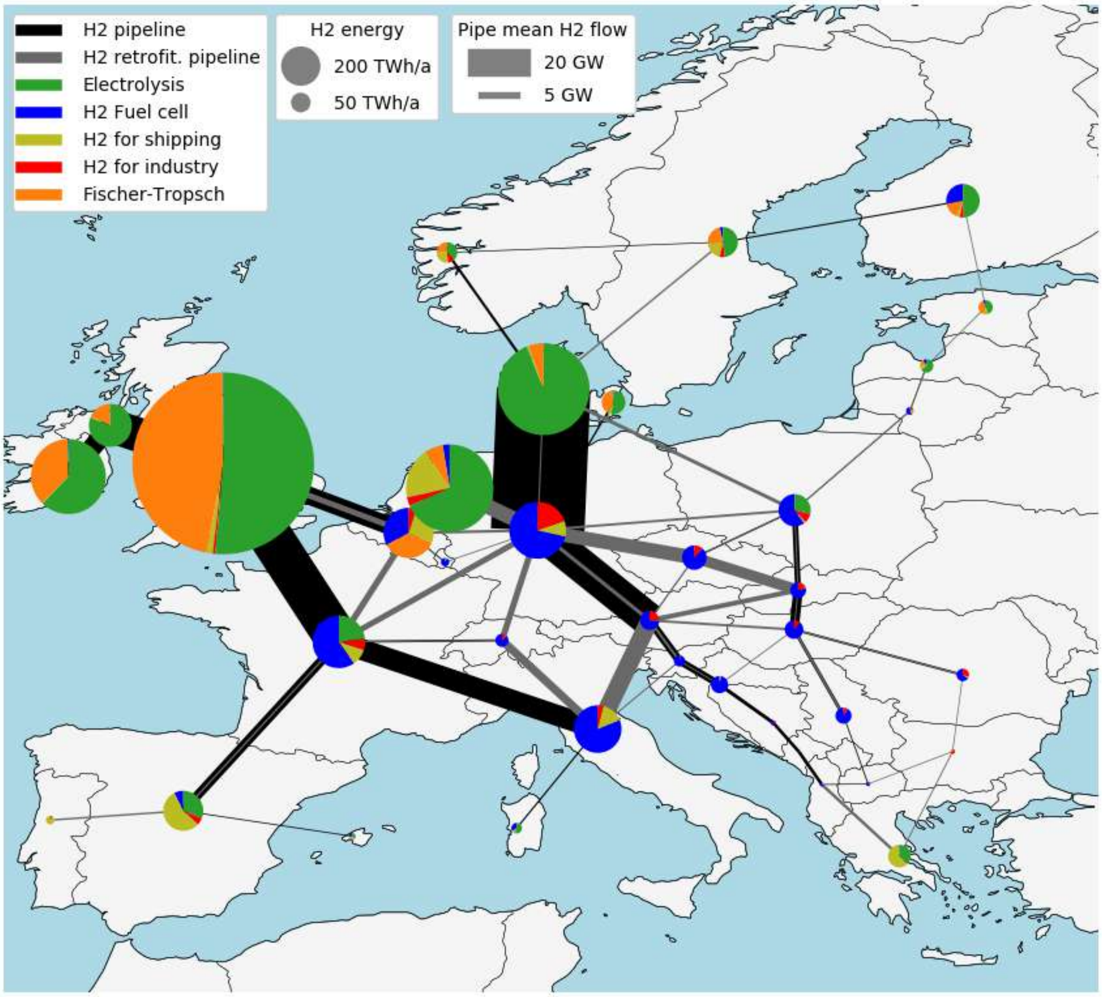

Figure 4.14.: Geographical map with countrywide hydrogen energy balance per country and pipeline annual mean energy flow.

4.4. Usage of the cross-border capacity pipelines

In this section an answer is devoted to the question about the usage of the pipes in the whole system. The questions that we want to answer are mainly about the usage of the H_2 and CH_4 pipelines depending on their conversion classification, and what is decisive and limiting when retrofitting a cross-border capacity pipeline. For the purpose of answering these questions a set of scatter plots with several magnitudes and categories are presented. Scatter plots are chosen for the advantage of plotting several axes of information and categorical information by color for our case.

To anser this questions the pipelines have been categorized in the following gropus: 1) the fully into H_2 retrofitted cross-border capacities are 21 in total, 2) pipelines partially converted for hydrogen usage are 23, 3) there are 33 newly built H_2 pipelines, and, as previously mentioned in section 4.2, 4) there are 39 pipelines dedicated to, or free to, be used for natural gas transport, and 5) the same 23 already mentioned partially retrofitted pipelines which still can transport CH_4. the last category 6) of pipelines are depleted pipelines which have not been converted and do not carry CH_4. For the individual pipelines their usage is calculated by averaging their annual energy flow and normalizing it over each pipeline capacity; for the grouped category the overall sum of the energy flow is divided over the total sum of capacities. Finally, a fourth magnitude represented by the surface of the circles is the cost of each pipeline.

The first graphic to be presented in this section is Figure 4.15 where the grouped information for the retrofitted scenario is displayed. The first remark are the depleted CH_4 pipelines, appearing to be the group with highest capacity, meaning that a lot of capacity from the natural gas grid cannot be used. This has to do with the fact that the cross-border capacities have two sense of flow, so if the pipe is only flowing in one direction, then on the other direction this capacity appears as depleted. So it is a figure that indicates that the model can still be improved to cancel a pipe if it is being used in the opposite direction already.

We can observe how the newly built pipelines is the group of pipelines with the highest installed dedicated capacity for the transport of energy, followed by the fully retrofitted to H_2 pipelines, then the fully CH_4 dedicated pipelines, then diminished CH_4 pipelines and finally the partially retrofitted H_2 pipelines.

In global, the newly built pipelines have the highest usage in the system, which makes sense if we consider their higher investment cost. Solving the optimization problem allows to enhance the usage resources as we would expected (in this case the resource is the assigned capacities to each pipeline).

Then the two groups of H_2 retrofitted pipelines have a similar usage value. Again, generally, by solving the LOPF the system tries to optimize the capacity for a maximum flow of H_2 in front of CH_4 because the capacity to be retrofitted is optimized when solving the LOPF.

On the other hand, the two groups of pipes of CH_4 show a lower usage (the "CH_4 original" and the "CH_4 diminished" pipelines in the graph). For the CH_4 original pipelines this is due to the low energy flows being transported in its pipes as previously shown in section 4.2 in Figure 4.10 for the pipelines with most transport of CH_4.

Finally, about the analysis per groups, lets focus on the partially retrofitted pipelines, both for H_2 and CH_4 (so, indeed the same pipeline and direction but with different gas). In the scatter plot we can observe that the usage of H_2 is optimized in front of CH_4.

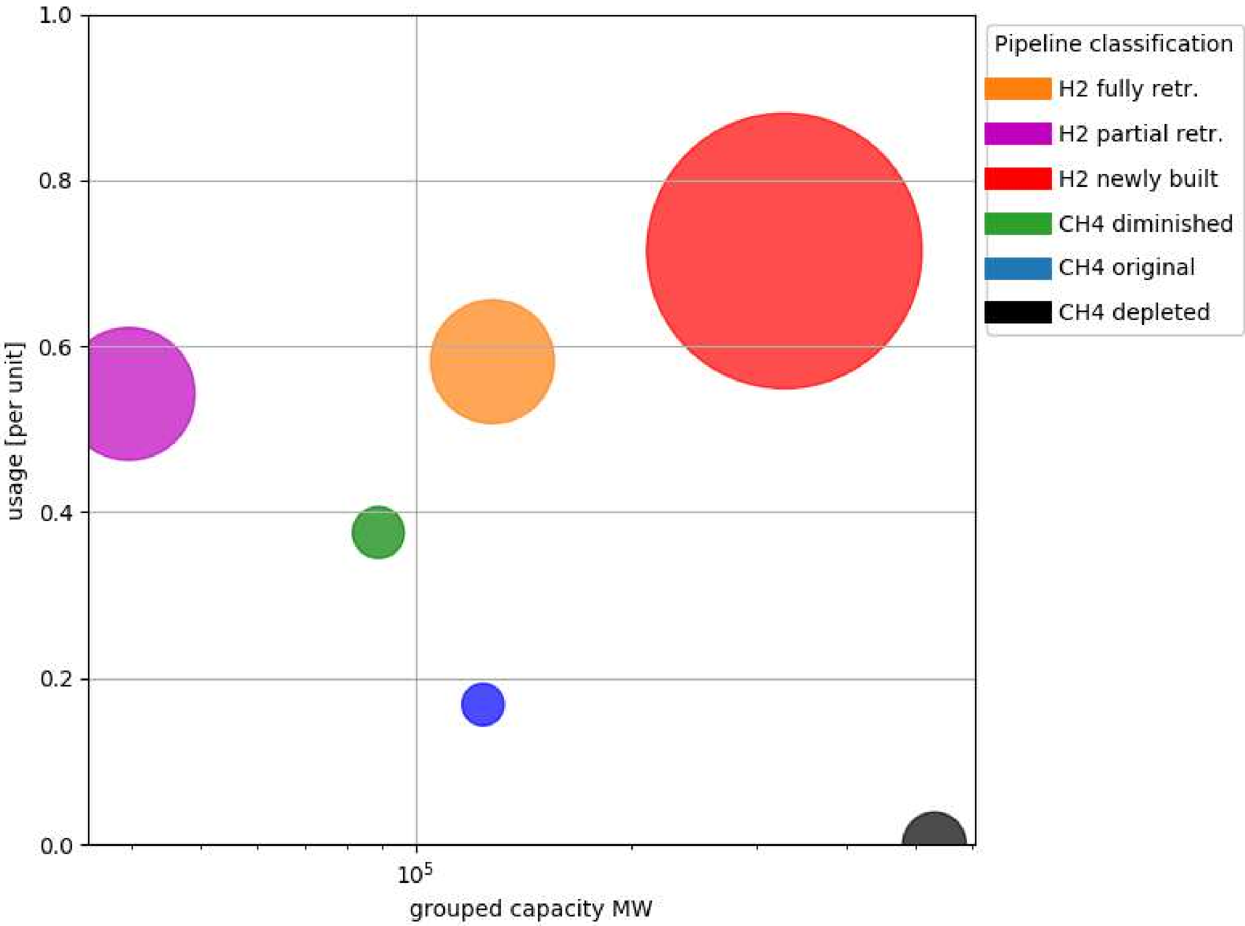

Figure 4.15.: Scatter plot with mean annual usage of the pipelines' cross-border capacities over its accumulated capacity by category groups of pipelines.

As we have seen throughout the last sections of results the greenfield scenario and the current gas-network scenario only have new H_2 pipelines, and for the latter also the natural-gas network. So for these two scenarios the the usage of the newly built H_2 pipelines is also high as we observe for the retrofitted scenario. We know that the optimized solution is carried out under the same conditions as for the retrofitted scenario. The only difference is that the cost of the overall system increases, as no low prices (like for the retrofitted pipelines) is assigned to any pipes. Basically the usage is the same compared with figure 4.15. The grouped capacity is slightly lower, as many of the potentially retrofitted pipes which we see in figure 4.14 have lower energy flow than the highest newly built pipelines, and the cost is higher as already displayed in section 4.1.

In the second graphic, in figure 4.16 we see in the scatter plot how are all the individual pipelines distributed according to usage, capacity, cost and category. In this figure it is interesting to see that 8 partially retrofitted pipelines carrying CH_4 (green circles) are in fact limiting the retrofitting of pipelines, whereas only 2 partially retrofitted pipelines carrying H_2 are limiting the conversion of pipelines. We see that these are limiting the conversion because they have a unitary usage of 1.0, meaning that that these pipelines transport gas in a congested manner continuously the whole year. However, at the same time we see that also the CH_4 partially retrofitted pipelines together with the fully dedicated CH_4 pipelines can also reach very low levels or usage.

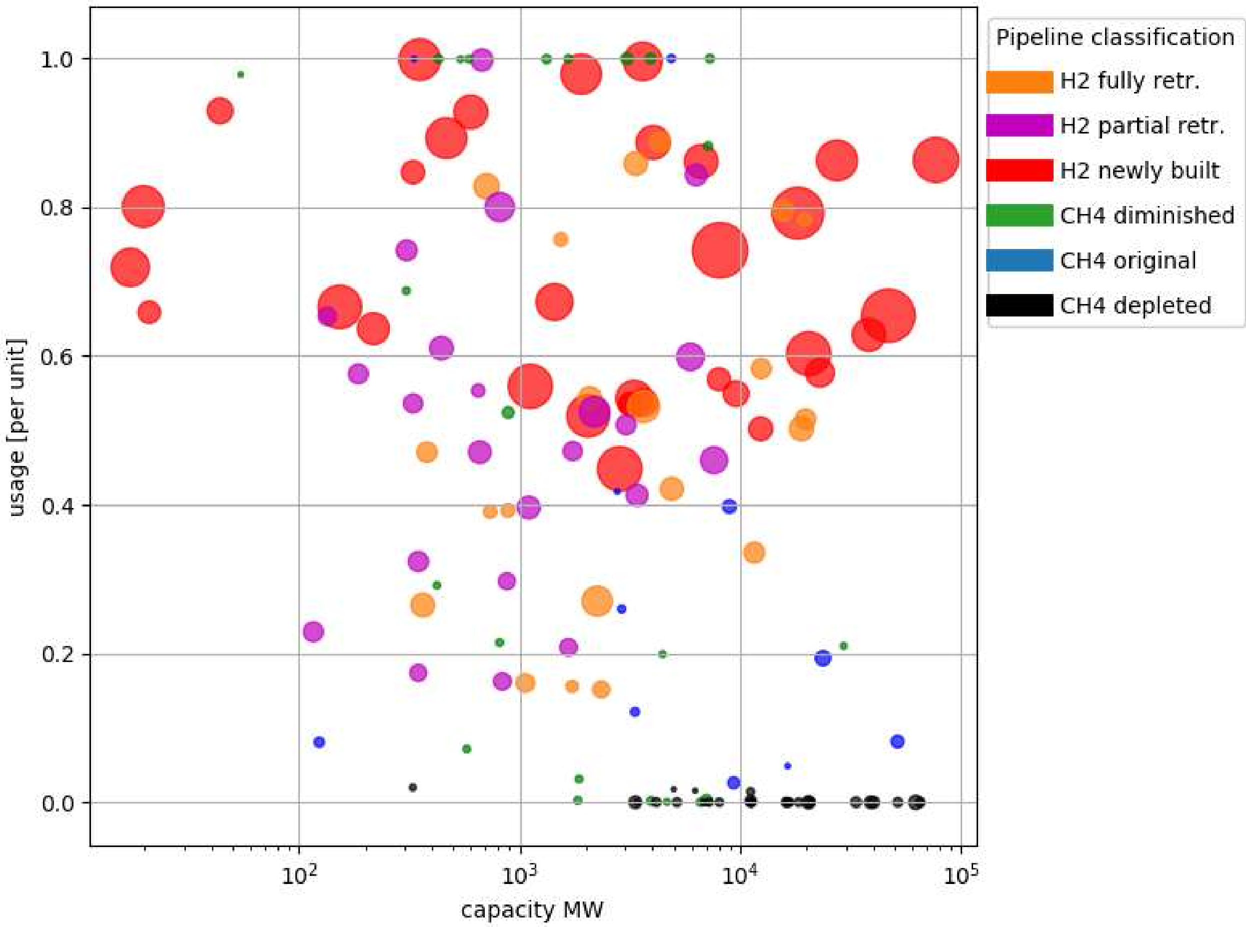

Figure 4.16.: Scatter plot with mean annual usage of the pipelines' cross-border capacities over its capacity for each individual categorized pipeline.

Finally, to complement the ideas exposed above a diagram with several duration curves of the newly built pipelines, with higher energy flow is shown in Figure 4.17 . In it we observe that, effectively, a lot of hours this pipelines are congested or use almost all the capacity available for the cross-border pipeline.

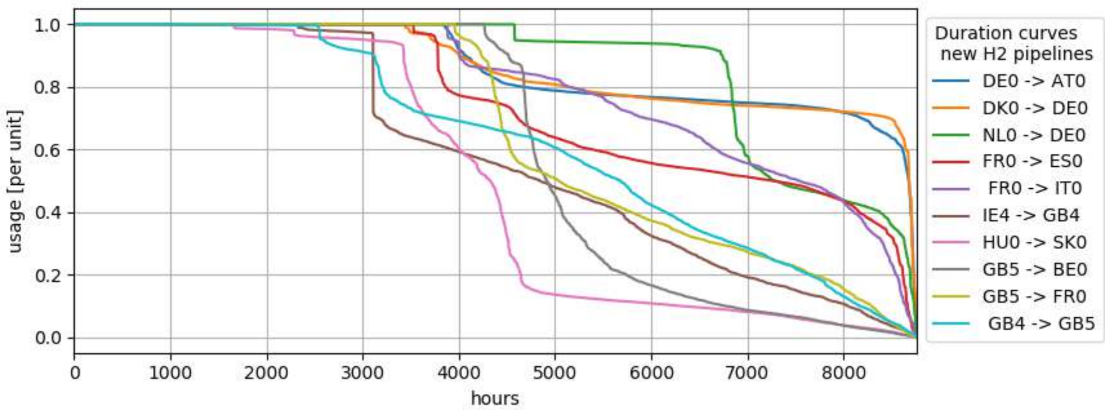

Figure 4.17.: Duration curves for newly built hydrogen pipelines transporting the highest energy flows in the retrofitted scenario.

5. Summary and outlook

In this thesis, the role of gas transmission networks for a CO_2 neutral Europe was investigated with an implementation based on the energy system model PyPSA-Eur-Sec. The implementation of the three scenarios was supported by a validation study of the gas demand in Europe in whifch several data of the current natural-gas-grid was assessed to be integrated in the system. The aim of the project has been to study and compare three future scenarios with the coupling of energy sectors. These scenarios are: a greenfield scenario where all the technologies are disposed in each country to cover the required loads of the different energetic sectors considering Europe as a greenfield of technologies where demands need to be covered; a second scenario where the current gas network was implemented in the system to work with natural and the same demands need to be covered; and third scenario where the gas network can be gradually retrofitted to hydrogen in the most appropriate way to cover the same demands. The model is run with a one year of perfect foresight of weather and demands.

By studying and combining information from references and PyPSA-Eur-Sec it has been possible to calculate a realistic cost for the transport of the energy. The costs range between 1.14 and 1.41€/MWh for methane, which is inside margins of current transport prices, and between 2.40 and 2.88€/MWh for hydrogen, for which we still do not have good references to compare with.

Concerning the natural gas demands it has been shown that methane is still operative in a future scenario with total supplies of natural gas of 388TWh and 352TWh for bio-gas that cover the demands of gas boilers and assigned to industry. However the use of methane to generate electricity by means of OCGT's of any kind of CHP's ran by gas is nonexistent. The generation of gas is more equally spread in Europe compared to today where the inner supply represents a small fraction of the whole demand. Countries which today account for a big part of the inner underground extraction rely entirely on their bio-gas production and have depleted natural gas reserves or do not have to use them in a neutral CO_2 future scenario, this are the cases of Great Britain, Ireland or the Netherlands.

Natural gas cross-border capacities do not tend to show a strong seasonal outline but rather a more stationary transport of energy and work congested for long periods of time during the year or even during the whole year. underground supplies also show little seasonality and work rather at full load or seemingly stationary with little fluctuation along the year.

The other main demand that concerns this work is that of hydrogen. All the supply of hydrogen comes from electrolyzer technology mainly located in the four countries with highest surplus of wind energy in any of its kinds. Alone Denmark, the Netherlands, Great Britain and Ireland account for almost all of the hydrogen supplied in Europe. There is a strong correlation between the installation of electrolyzers and the installation of Fische-Tropsch technology. This is due to the fact that Fischer-Tropsch is built in the system as a node with storage, linked to all countries in the model and therefore where there are high surplus of electricity as energy vector it falls into generating the main two fuel liquids which are produced by Fischer-Tropsch, namely naphtha and kerosene, used in industry processes and in aviation. Apart of the country assignments of hydrogen for industry and for shipping, the installation of fuel cells is broadly extended in Europe except in the four exporting countries with surplus of renewable electric energy from wind power. Another remarkable result is the installed capacities of electrolyzers in Europe is just half of today's for natural gas. This alone gives an idea of the huge investment that electrolyzers suppose for the overall system and what an enormous investment should be achieved to turn into a CO_2-neutral-emissions Europe in a future scenario.

About the pipelines it can be stated that newly built H_2 pipelines being the most expensive type of pipelines have the highest optimized usage among all types of pipelines at about 75%, and also account for the highest installed capacities in the three scenarios in total 320GW. Then, the H_2 retrofitted pipelines account for a high usage as well at about 55%. And the lowest usage is for the CH_4 pipelines representing a 40% of usage for the partially retrofitted pipelines and 18% for the still fully dedicated to CH_4. Nevertheless, these values are mean values of a group of pipes, so not every pipeline has exactly these averaged values.

About the limiting factors for retrofitting the pipelines, the CH_4 partially retrofitted pipelines show the highest number of pipelines that work congested during the year: 8. But also show that many of them can still carry CH_4, but the optimization awards them no energy flow, meaning that they do carry H_2, but no CH_4. H_2 partially or fully retrofitted pipelines that are congested during the whole year there is only one, and 5 more pipelines between 80% and congestion. And 25% of CH_4 original pipelines are essentially depleted.

Solving the scenarios has shown almost equal election of technologies for the three of them, mainly because in a decarbonized scenario all the renewable energy that can be harvested first has to be electrified through wind farms or solar panels and then converted to cover loads in electricity or other sectors. From the scenario energy balances it is clear that the three scenarios are not influencing the overall system investment costs by any of the gas grid option. The fact that the three scenarios have the possibility to build an H_2-grid taking the electric grid as a reference reduces the differentiating between scenarios to the difference that the retrofitting can contribute to. Considering the total system costs and the grid costs, the grid costs barely represent a 1% of the total system costs. The retrofitting does contribute to reduce the grid costs between the current gas scenario and the retrofitted scenario by 13.7%.

Some research questions about the heat demand or the about storages are still to be answered to give even a more complete answer about the scenarios, which maybe can be answered during the exposition of this thesis.

Finally, improvements to be taken in future implementations of gas grids and retrofitted gas grids are to distribute the Fischer-Tropsch storages in each country as well as the demands for naphtha and kerosene to simulate a more realistic scenario. Also to improve the cost calculation of building any pipes in the grid, as currently the cost is multiplied by the length of the pipeline and not by diameter or capacity, which are correlated; for that, a more realistic grid data is needed, as clustering the cross-border capacities in many cases result in such a big capacities that just one pipeline can not stand such a gas flow. Also taking the electric grid as a base to build the newly H_2 pipelines is not as representative, because civil engineering studies for the pipeline construction are already done, and most likely it would be cheaper to construct new pipelines beside existing ones. And to refine the assignment of retrofitting as for some pipelines which for natural gas only flow in one direction, for H_2 could indeed flow in the opposite direction. However, knowing that there are already better resolutions of the topology of the grid available towards the end of these work, improved simulations should soon be available. About the seasonality in the use of the pipes, it could be interesting if the optimized solution would be able to adopt maybe a security factor or operation factor to multiply the capacities of the newly built H_2 pipelines that are congested, and see also if the seasonality of the supply turns more similar to today's experience.

As a leitmotiv reflection, the most impressive result is maybe so see that the hydrogen production in these future scenarios is tremendous, and causes a sort of chain-reaction in all the scenario systems. Its production seems to invert today's capacities of supply of CH_4 by H_2, and that rises by itself further research questions about studying other ways of transporting and trading options that H_2 brings along and also about integrating imports of H_2 from other countries.

Bibliography

[1] *Aggregated Gas Storage Inventory (AGSI+ GIE)*. 2020. URL: `https://agsi.gie.eu/#/`.

[2] T. Brown, J. Hörsch, and D. Schlachtberger. "PyPSA: Python for Power System Analysis". In: *Journal of Open Research Software* 6.4 (1 2018). DOI: `10.5334/jors.188`. eprint: `1707.09913`. URL: `https://doi.org/10.5334/jors.188`.

[3] Tom Brown et al. "Synergies of sector coupling and transmission extension in a cost-optimised, highly renewable European energy system". In: *Energy* 160 (Jan. 2018). DOI: `10.1016/j.energy.2018.06.222`.

[4] Simonas Cerniauskas et al. "Options of natural gas pipeline reassignment for hydrogen: Cost assessment for a Germany case study". In: *International Journal of Hydrogen Energy* 45.21 (2020), pp. 12095–12107. ISSN: 0360-3199. DOI: `https://doi.org/10.1016/j.ijhydene.2020.02.121`. URL: `http://www.sciencedirect.com/science/article/pii/S0360319920307023`.

[5] European Comission. "A hydrogen strategy for a climate-neutral Europe". In: (2020). URL: `https://ec.europa.eu/energy/`.

[6] D.Biggar. *The economics of electricity markets*. June 2014.

[7] *ENTSO-G Transparency Platform*. 2020. URL: `https://transparency.entsog.eu/#/map`.

[8] R.D.Tabors F.C.Schweppe M.C.Camaranis and R.E.Bohn. *Spot pricing of electricity*. June 2013.

[9] Philipp-Matthias Heuser et al. "Techno-economic analysis of a potential energy trading link between Patagonia and Japan based on CO2 free hydrogen". In: *International Journal of Hydrogen Energy* 44.25 (2019). Special Issue on Selected Contributions from the European Hydrogen Energy Conference 2018. Málaga, Spain. March 14th - 16th, pp. 12733–12747. ISSN: 0360-3199. DOI: `https://doi.org/10.1016/j.ijhydene.2018.12.156`. URL: `http://www.sciencedirect.com/science/article/pii/S0360319918341582`.

[10] Jonas Hörsch et al. "PyPSA-Eur: An Open Optimisation Model of the European Transmission System". In: (June 2018).

[11] Guidehouse Inc. "European hydrogen backbone strategy". In: (2020). URL: `https://gasforclimate2050.eu/sdm_downloads/european-hydrogen-backbone/`.

[12] T. Wiesenthal M. Leonidas and N. Matei. "JRC-IDEES: Integrated Database of the European Energy System". In: *Ed. by Publications Office of the European Union* (June 2017). URL: `https://ec.europa.eu/jrc/en/publication/jrc-idees-integrated-database-european-energy-sector-methodological-note`.

[13] J. Muehlenpfordt. "Open power system data". In: (2017). URL: //data.open-power-system-data.org/time_series/2017-07-09.

[14] DLR Institute for Networked Energy Systems. *Open Source Reference Model of European Gas Transport Networks for Scientific Studies on Sector Coupling (Offenes Referenzmodell europäischer Gastransportnetze für wissenschaftliche Untersuchungen zur Sektorkopplung).* 2020. URL: https://www.gas.scigrid.de/.

[15] *Pypsa-Eur.* 2020. URL: https://pypsa-eur.readthedocs.io/en/latest/index.html.

[16] *Pypsa-Eur-Sec.* 2020. URL: https://github.com/PyPSA/pypsa-eur-sec.

[17] Markus Reuß et al. "Modeling hydrogen networks for future energy systems: A comparison of linear and nonlinear approaches". In: *International Journal of Hydrogen Energy* 44.60 (2019), pp. 32136–32150. ISSN: 0360-3199. DOI: https://doi.org/10.1016/j.ijhydene.2019.10.080. URL: http://www.sciencedirect.com/science/article/pii/S0360319919338625.

[18] Hans-Kristian Ringkjøb, Peter M. Haugan, and Ida Marie Solbrekke. "A review of modelling tools for energy and electricity systems with large shares of variable renewables". In: *Renewable and Sustainable Energy Reviews* 96 (2018), pp. 440–459. ISSN: 1364-0321. DOI: https://doi.org/10.1016/j.rser.2018.08.002. URL: http://www.sciencedirect.com/science/article/pii/S1364032118305690.

[19] D.P. Schlachtberger et al. "The benefits of cooperation in a highly renewable European electricity network". In: *Energy* 134 (2017), pp. 469–481. ISSN: 0360-5442. DOI: https://doi.org/10.1016/j.energy.2017.06.004. URL: http://www.sciencedirect.com/science/article/pii/S0360544217309969.

[20] Martin Schmidt, Marc Steinbach, and Bernhard Willert. "High detail stationary optimization models for gas networks". In: *Optimization and Engineering* 16 (Mar. 2014). DOI: 10.1007/s11081-014-9246-x.

[21] Anna Schwele et al. "Coordination of Electricity, Heat, and Natural Gas Systems Accounting for Network Flexibility". In: *Electric Power Systems Research* 189 (2020), p. 106776. ISSN: 0378-7796. DOI: https://doi.org/10.1016/j.epsr.2020.106776. URL: http://www.sciencedirect.com/science/article/pii/S0378779620305794.

[22] UN. "Adoption of the Paris Agreement". In: *Framework Convention on Climate Change. Paris: United Nations* (2015).

[23] Bundesministerium für Wirtschaft und Energie. "The National Hydrogen Strategy". In: (2020). URL: https://www.bmwi.de.

[24] Lin Yang. "Robustness of Energy System Models to Weather Years and Myopic Operation". In: ().

A. Appendix

A.1. First Appendix Section

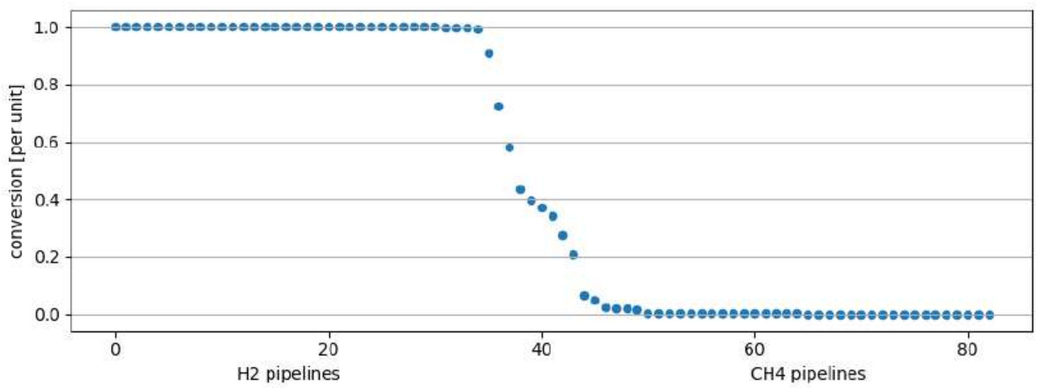

Figure A.1.: Sorted cross-border capacity retrofitting conversion for a scenario with one dedicated virtual bio-gas node for Europe, which bio-gas is not transported through the natural gas pipelines, but directly to each country.

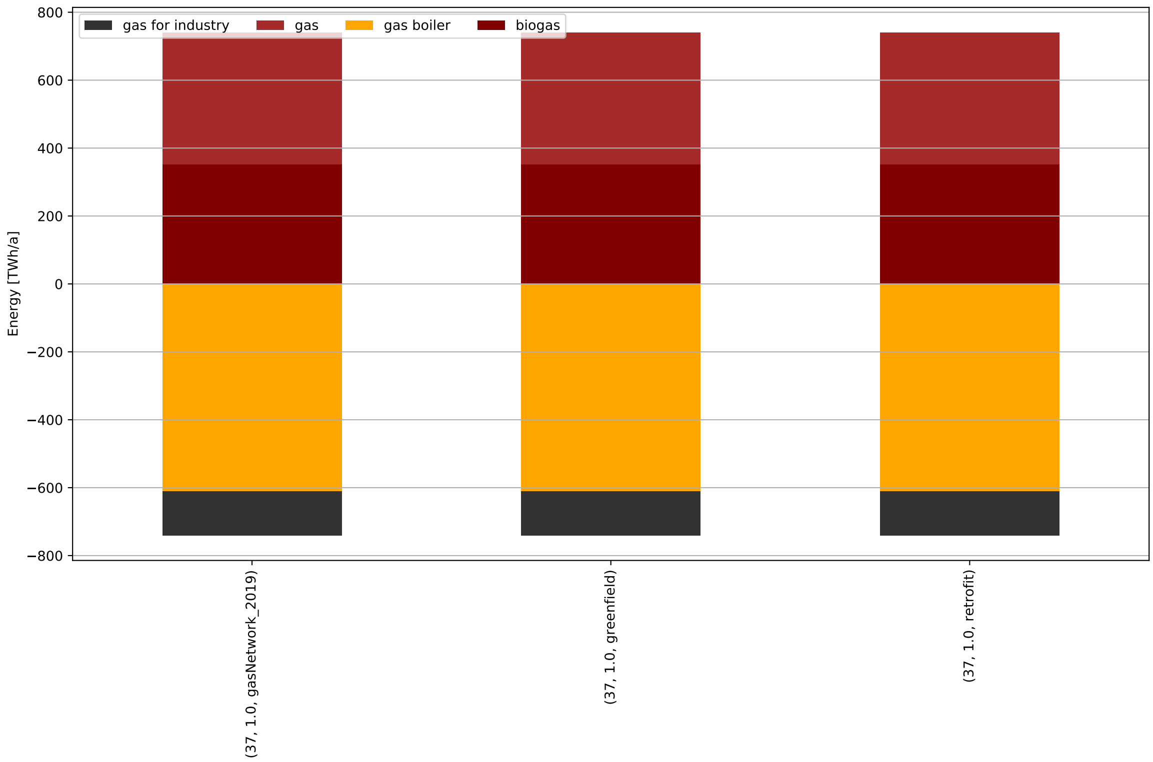

Figure A.2.: Bar plot diagram of methane energy balance. The three scenarios have highly similar balances.

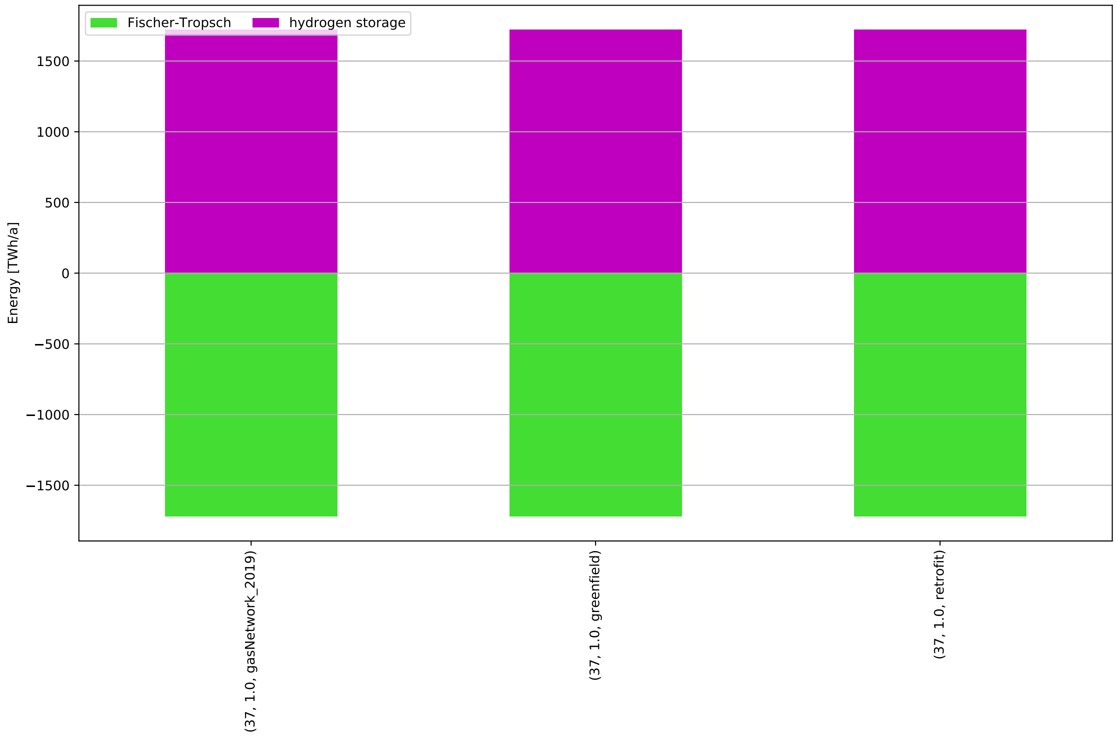

Figure A.3.: Bar plot of the hydrogen stored and supplied to Fischer-Tropsch process, for the three scenarios.

On line volume optimization:

One extra comment on the line volume change, changeing the lv1.0 (lv: electric line volume AC and DC) or lvopt leads to more significative reduction of the overall system. This is due to the mainly electrified solutions implemented with renewable energy technologies. As the model encounters numerical troubles, only an estimated approximation of the lvopt is possible and not a fully optimized one. This approximated optimal solution, set to a maximum of lv5.0, which as expected, points to a reduction of the total system cost, has a resulting lv of 4.09 in the retrofitted-scenario, accounting for a relative AC lv of 1.79 in lines, and an lv 42.03 for DC links. These changes in the electric grid affect the the solution of the overal system and a differences in the total system cost is observable between the lv1.0 and the "lv aproximated opt". In Figure A.4, we can observe a reduction of the cost of 6%.

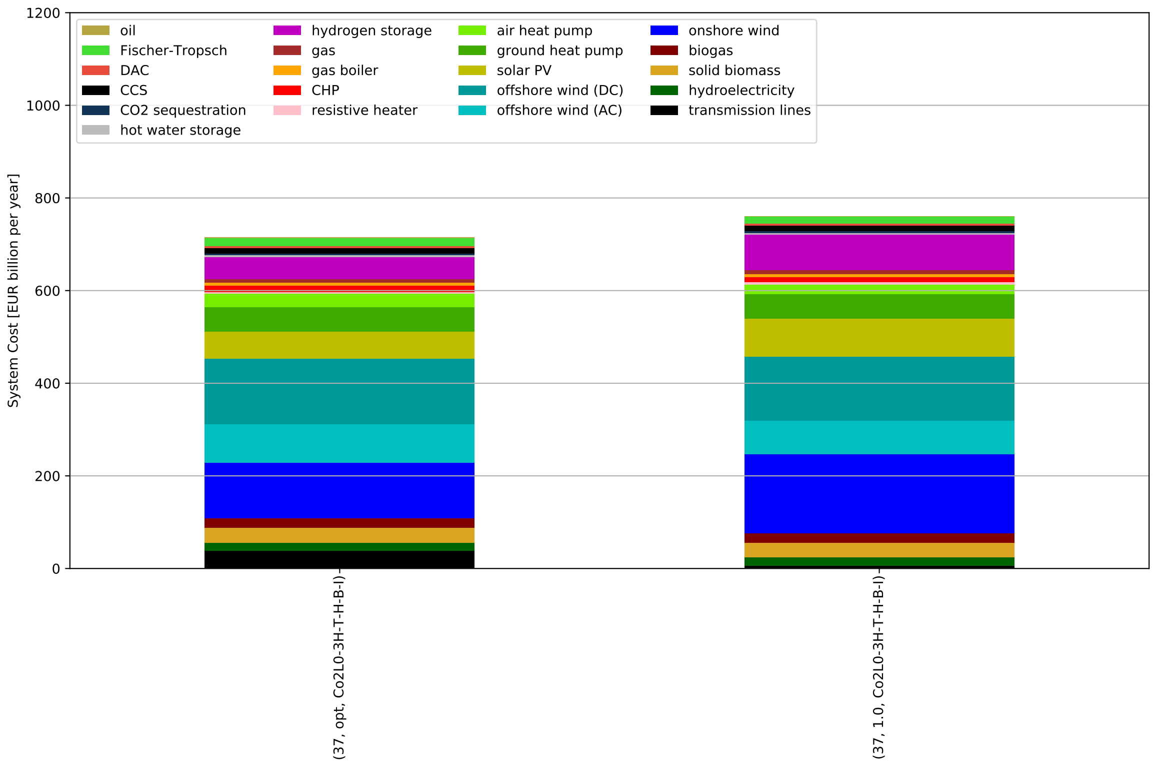

Figure A.4.: Diagram of system cost comparison between an system with lv1.0 and the smame one with resulting lv of 2.1.