Influence of CO_2 taxation und hydrogen utilization on the cost-optimal development of the German power system by 2050

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Introduction

In the recent years, a large number of countries have set targets for decarbonizing their energy systems, some through international treaties such as the Paris agreement, or, the recent EU green deal. In our study we focus on Germany, which very recently has made an amendment to its Climate Change Act, and now aims for total climate-neutrality until the year of 2045, with additional intermediate targets for years 2030 and 2040.

Two common instruments for decarbonization, are first the carbon trading schemes, which for instance have been implemented in Europe through the ETS system, where a fixed volume of carbon certificates have been allocated to the large-scale emitter entities such as power producers and industry. These certificates can be then traded between these parties (the so-called cap and trade option), so in this way it is a volume-driven approach.

Another instrument is the direct taxation of CO_2, by which every party has to pay for each amount of emissions that they cause. Thereby an extra cost is attached to the goods that have CO_2 emissions associated with them. Hence it is a price-driven approach, where the price per ton is fixed and the actual sum of emission is a reaction to this price. In Germany, a climate package had been announced in late 2019, through which a price corridor has been set up to 65 €/ton until 2026.

The aim of this study is to determine the viability of emission regulations and various generation technologies in the German electricity supply system for the year 2050. The European carbon trading scheme, which attempted to cap emissions at a specific limit, is argued by many to be an insufficient measure; opening the discussion for a taxation of CO_2 by each emitter instead. In parallel, the possible role of hydrogen–both produced and imported–in the future electricity supply by their combustion in the combined cycle gas turbines (CCGT) plants will be investigated. In the course of the study, the cost-optimal way to reduce CO_2 emissions by up to 95% (compared to 1990) is examined, assuming various projections for electricity demand of 2050.

Methods

The system costs considered in this study consist of investment costs, fixed and variable costs of plant operation, fuel costs and the costs accounting to the taxation of CO_2. Even though for the optimization of the energy system the CO_2 cost component will be included, for the later cost analysis, it is assumed that the CO_2 payments will be socially redistributed. All costs are calculated on an annual basis, i.e. the investment costs are converted to annual costs using the annuity method. The CO_2 costs include all CO_2 emissions from the natural gas-fired CCGT, which is the only allowed fossil-based generation mode in the model. The coal and oil-fired power plants are excluded from the outset for the reason that they have a higher CO_2 emission factor. In this way, the dynamics of natural gas in the supply of electricity is examined as well as possible under different assumptions. Figure 1 gives an overview of the reference energy system of the model that is considered in this study.

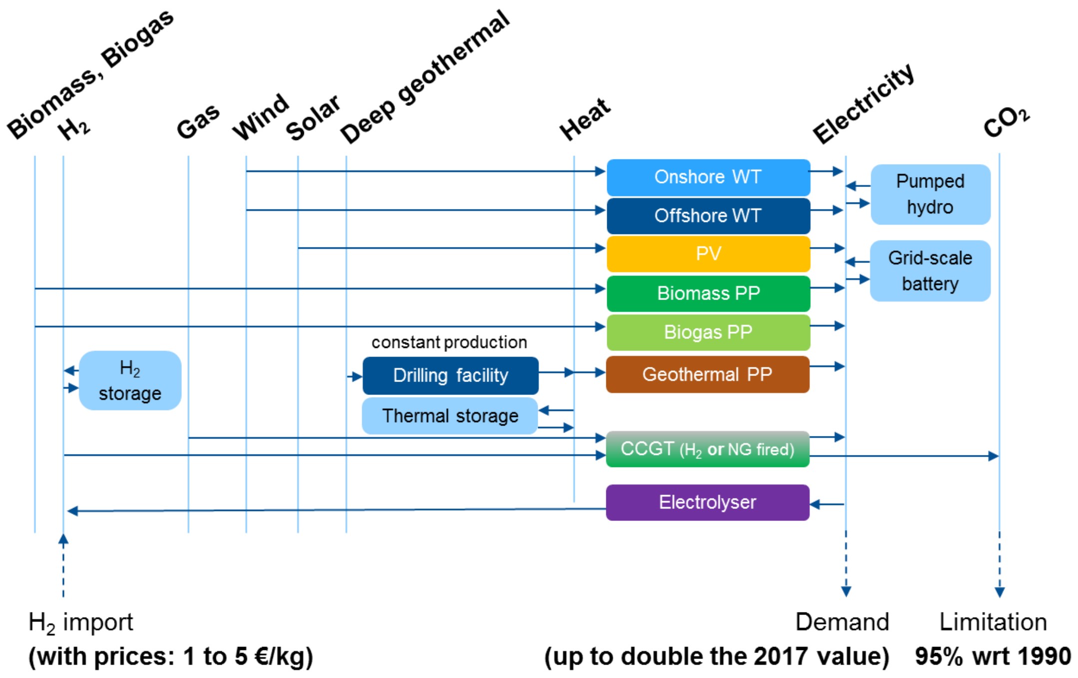

Figure 1: The reference energy system for Germany in year 2050.

For investigating the cost-optimal system evolution, the following input variations were made: 1) choice of a CO_2 tax or a defined yearly CO_2 limit and 2) a scaling of the year-round hourly time series for electricity demand. The cost-optimal development of each system variant is achieved with the linear energy system modeling framework *urbs*[1]. Here, the German energy system is modeled as a single-node (hence ignoring the grid constraints) and focuses only on the electricity sector. The work comes in two case studies: the *tax-instead-of-limit* and the *growing consumption*.

In the *tax-instead-of-limit* study, an equivalent CO_2 tax corresponding to a 95% decrease in emissions is calculated by accessing the dual variable of the CO_2 limitation constraint of the system model. The resulting tax is called the dual CO2 shadow price. Then, the constraint is removed from the model, and a CO_2 tax is introduced with a value from zero up to the 95%-reduction achieving amount. This way, the gradual effect of the tax instead of the limit, and the distribution of the system costs (between the physical costs and the tax-resultant share) is examined. Furthermore, the reduction of CO_2 emissions compared to 1990 is calculated for each step of the CO_2 tax increase, as well as the development of the system abatement costs and physical abatement costs. To calculate the system abatement costs, the difference between the total system costs (physical costs plus CO_2 payments) is divided by the corresponding reduction of CO_2 emissions after each step of the tax increase. On the other hand, the physical abatement costs are calculated by dividing only the difference in total physical costs for each step of the CO_2 tax increase by the corresponding reduction in CO_2 emissions. In addition, the progress of CO_2 reduction is determined for each leap in demand.

[1] https://github.com/tum-ens/urbs

The demand for electricity in 2017, increased by 50%, was assumed to be satisfactory assuming a high electrification rate for mobility and heating sector (1).

Growing consumption study: Studies argue that the German electricity demand by 2050 is highly uncertain as it largely depends on the electrification rate of heating and mobility. In order to compare the generation technologies that are preferred by the model in a stepwise manner, the demand is linearly varied from the 2017 values until its doubling and the cost-optimal results are obtained under a CO_2 reduction target of 95%. Moreover, the utilization mode of hydrogen as a carbon-neutral flexibility option is investigated under various import prices.

An environmentally compatible electricity system requires that a high proportion of the electricity supply comes from photovoltaic and wind power plants, so that the generation of electricity from CO_2 sources (in this case combined cycle) is limited as much as possible. In contrast to some renewable energy sources (solid biomass, biogas, geothermal energy), the generation from the volatile renewable sources such as PV and wind is fluctuating. PV and wind power plants can only provide limited guaranteed output due to their dependence on the weather. For this reason, many fluctuations between generation and consumption must be expected. The flexibility options or backup generation capacity of an electricity system help to ensure system and supply security.

Combined cycle power plants, biomass power plants, biogas power plants and geothermal power plants are the options for the backup generation capacity of the system. In addition to the generation plants, three different variants based on renewable energies necessary flexibility options are simulated:

- In the first variant, battery storage is used, which can support grid stabilization by integrating the renewable surpluses.
- Electrolyzer units represent the second variant. Here, long-term storage of the renewable surplus energy in the form of chemical energy as hydrogen is possible. Hydrogen gen then be stored it in the hydrogen storage units, and when needed, the reverse flow of the stored hydrogen into the combined cycle power plants serves to balance out fluctuations in electricity supply and demand.
- In the third variant, the electricity system has the option of importing hydrogen and and feeding it into the combined cycle power plants.

Fully flexible power generation is assumed for combined cycle and biomass power plants. This means that they supply exactly the amount of electricity that is needed at a certain model time step. On the other hand, the geothermal power plants were modeled differently. It was assumed that the supply of geothermal heat per hour remains stable. The role of the boreholes is to absorb and process the geothermal heat. The amount of heat (warm water) provided per hour also remains constant. This heat can either be fed directly into the geothermal power plants or stored in heat storage tanks so that it can be used again in times of electricity shortages.

Table 1 provides an overview of the assumed technoeconomic parameters for the technologies and fuels included in the model.

Photovoltaic systems and wind turbines			
	PV	Onshore Wind	Offshore Wind
Investment costs in €/MW	436,000 (2)	865,000 (2)	1,285,000 (2)
Fixed costs in €/MW	8,720 (2)	17,300 (2)	25,700 (2)
Variable costs in €/MWh	0 (3)	5.0 (3)	5.0 (3)
Capital interest rate in %	0.021 (3)	0.025 (3)	0.048 (3)
Amortisation period in years	25 (3)	25 (3)	25 (3)
Installed capacity in MW	42,339 (4)	50,291 (4)	5,427 (4)
Expansion potential in MW	224,403 (5)	198,000 (6)	54,000 (6)

Natural gas, solid biomass, biogas			
	CCGT plant	Biomass plant	Biogas plant
Fuel costs in €/MWh_{th}	34 (3)	28 (7)	28 (7)
Investment costs in €/MW_{el}	800,000 (2)	2,000,000 (7)	3,000,000 (7)
Fixed costs in €/MW_{el}	30,000 (2)	60,000 (7)	44,400 (7)
Variable costs in €/MWh_{el}	4.0 (3)	1.0 (7)	1.0 (7)
Capital interest rate %	0.052 (3)	0.027 (7)	0.027 (7)
Amortisation period in years	33 (8)	25 (8)	33 (8)
Installed capacity in MW	8,000 (9)	-	-
Available prim. energy in MWh_{th}	-	262,583,322 (10)	72,233,000 (5)
Efficiency (%)	64% (8)	37% (7)	37% (7)
CO2 emissions in t/GWh_{th}	201.6 (8)	0	0

Geothermal energy		
	Geothermal power plant	Drilling facility
Investment costs in €/MW_{el}	4,063,000 (11)	3,125,000
Fixed costs in €/MW_{el}	72,000 (11)	62,500 (11)
Variable costs in €/MWh_{el}	3 (11)	-
Capital interest rate %	0.07	0.07
Amortisation period in years	35 (11)	35 (11)
Available primary energy in MWh	1,926,000,000 (11)	-
Expansion potential in MW	-	218,000 (12)
Efficiency in %	14% (8)	70% (11)

Hydrogen	
	Electrolyzer
Investment costs in €/MW_{el}	400,000 (13)
Fixed costs in €/MW_{el}	16,000 (13)
Capital interest rate %	0.07
Amortisation period in years	15.5 (14)

Storage systems				
	Battery storage	Pumped hydro storage	H2 Storage	Thermal storage
Installed capacity (MW)	-	6,354 (15)	-	-
Storage capacity (MWh)	-	40,000 (15)	-	-
Investment costs €/MWh	300,000 (16)	50,000 (8)	450 (14)	25.000 (14)
Fixed costs €/MWh	3,000 (16)	600 (8)	15.75 (14)	500 (14)
Capital interest rate in %	0.07	0.07 (8)	0.07	0.07
Amortisation period in years	20 (14)	40 (8)	40 (14)	30 (14)
EP ratio	4		-	-
Insertion efficiency in %	95%	88% (8)	100%	100%
Retrieval efficiency in %	95%	89% (8)	100%	100%
Self-discharge	-	-	0.0007 (14)	-

Table 2: Technical and economic parameter of the model

Results: Case study *tax-instead-of-limit*

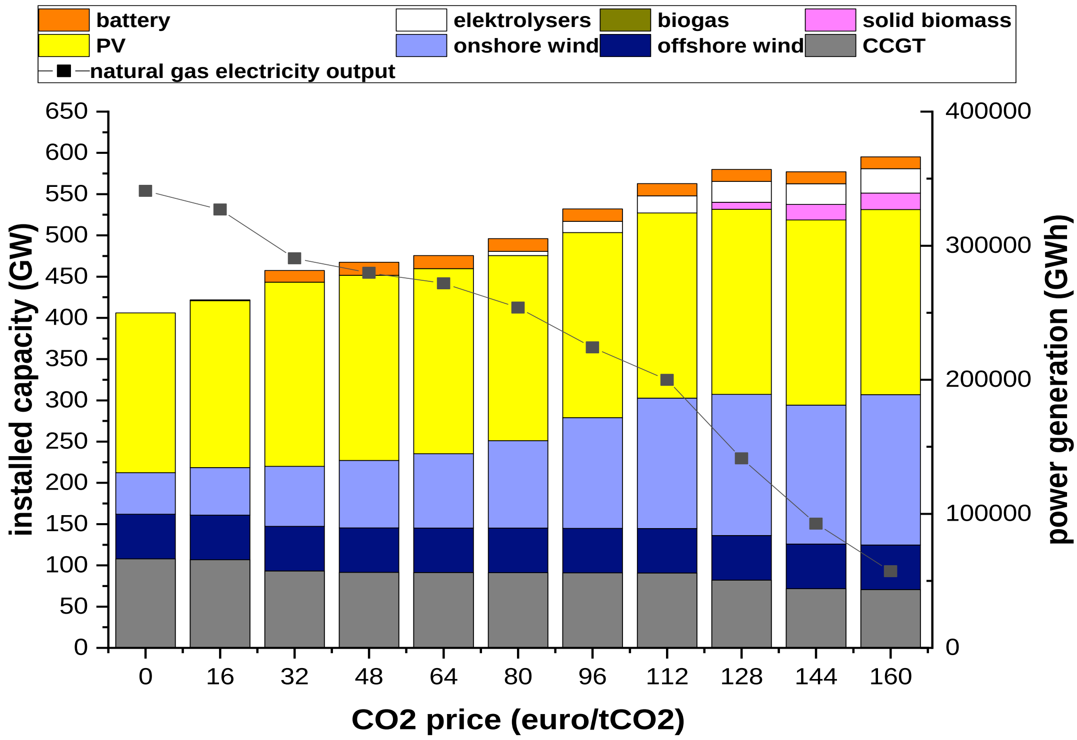

Figure 2: Case study tax-instead-of-limit, Change of the capacity mix with the CO_2 tax increase compared to natural gas based electricity generation, demand of 2017 increased by 50%, H_2 price of 60 €/MWh

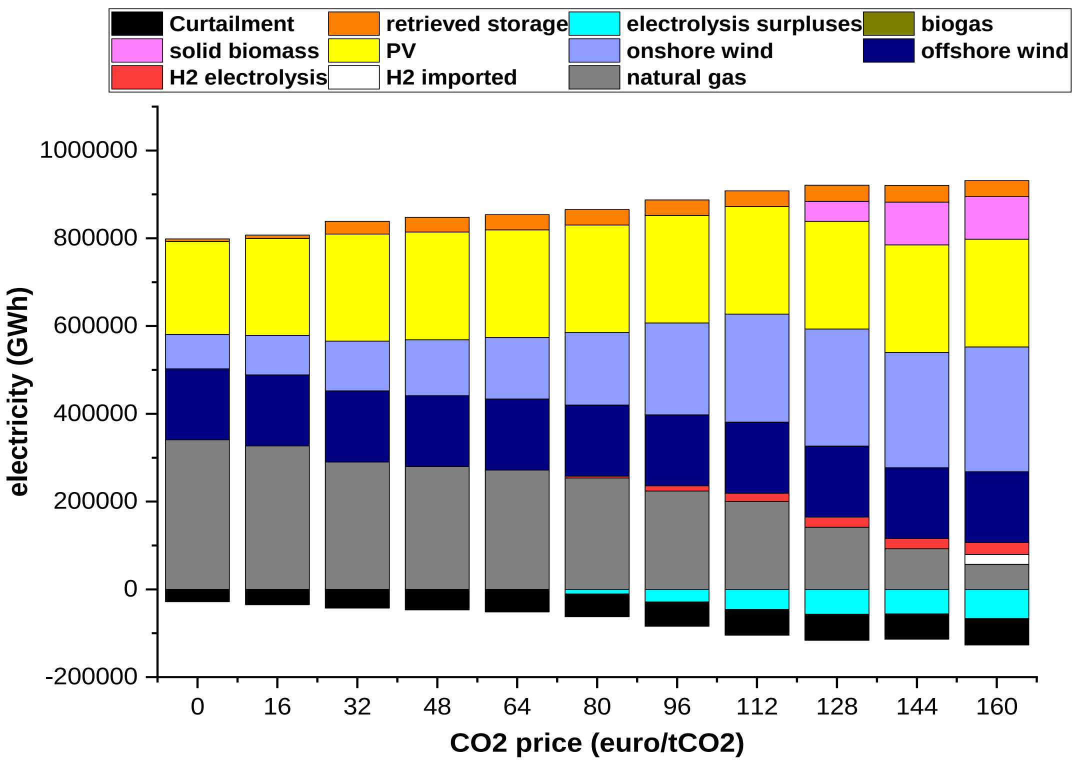

Figure 3: Case study tax-instead-of-limit, change in the electricity balance with the CO2 tax increase, demand of 2017 increased by 50%, H2 price of 60 €/MWh

If the H_2 price is set at 60 €/MWh, the CO_2 shadow price results in 160 €/tCO_2, so that CO_2 emissions are reduced by 95%. The optimization results shown in Figures 2 and 3 show how the electricity and capacity mix of the modeled system changes with the increase in the CO_2 tax from 0 to 160 €/tCO_2, if no CO_2 limitation is taken into account.

First, the system was optimized without CO_2 tax. Thereby the electricity supply from natural gas covers about 40% of the total electricity demand. Furthermore, the combined cycle power plants with 109 GW represent the only flexibility option of the system. Offshore wind turbines and PV are highly favoured even without any CO_2 tax. The PV plants have been very strongly expanded to 193 GW, while offshore wind power has already reached the assumed expansion potential. Onshore wind power remains stable at the initially set installed capacity of 52 GW, as onshore wind farms have a poorer profitability than PV and offshore wind farms. The curtailed energy of the system amounts to 28300 GWh. The integration of renewable surpluses either by means of battery storage or electrolyzer plants is not worthwhile, nor is the development of other flexibility options (biomass, biogas, geothermal energy).

The tax increase for CO_2 leads to a continuous decrease of the electricity contribution from natural gas in order to satisfy the electricity demand in a cost-optimal way. Until the CO_2 price is raised to 64 €/tCO2, the decline in electricity generation from natural gas by 70,000 GWh will be compensated exclusively by the expansion of PV and onshore wind energy (offshore wind energy already fully developed), as well as by the integration of renewable surpluses by means of battery storage.

The installed capacity of photovoltaic systems increases rapidly and reaches the potential limit of 224 GW at the CO_2 price of 48 €/tCO2, while at this point onshore wind plants are expanded to 81.7 GW. So far, the integration of surpluses participates in the flexibilization exclusively through their absorption from the battery storage. Up to this point, the battery storage facilities have been expanded to 15.7 GW and return around 33,000 GWh to the consumption grid. In between, it is more profitable for the economic efficiency of the system to use such a surplus quantity by the battery storage facilities instead of developing the PtG systems.

From the CO_2 price of 80 €/tCO_2, electrolyzer plants are gaining importance. In fact, the integration of renewable surpluses by means of electrolysis supports the flexibilization of the energy system and leads to cost advantages compared to the development of biomass, biogas or geothermal energy. Thereafter, the conversion of generated hydrogen back into electricity in the combined cycle power plants becomes more and more cost-effective with the CO_2 tax increase and as a result compensates for the reduction in electricity generation from natural gas. The use of electrolysis and the further expansion of onshore wind will substitute about 54,000 GWh from natural gas-based electricity generation up to a CO_2 price of 112 €/t CO_2.

Due to the increase of CO_2 tax to 128 €/ tCO2, the economic viability of natural gas-based electricity production will become so poor that the electricity system will push the development of biomass power plants to replace the reduced guaranteed capacity of combined cycle power plants. With the CO_2 price increased from 112 €/tCO_2 to 128 €/tCO_2, electricity generation from natural gas will drop very sharply by more than 30% from 200,000 GWh to around 141,000 GWh. This reduction is mainly covered by the provision of around 45,000 GWh from the combustion of solid biomass (the rest by growth of onshore wind and combustion of hydrogen). The biomass power plants will also be expanded to 8 GW_{el} at this point, mainly due to the reduction of the installed capacity of the combined cycle power plants by also 8 GW_{el}.

With the next jump of the CO_2 price to 144 €/tCO_2, all available primary energy from solid biomass will be used. Biomass power plants will be expanded by a further 15 GW_{el}, therefore supplementing the secured capacity of the combined cycle power plant, which has been reduced by a further 15 GW_{el}. The installed capacity of both onshore wind energy and electrolysis will be very slightly reduced, as a cost saving is achieved by the avoided costs from these technologies, if the costs for biomass increase in the resulting volume.

Once the entire biomass potential is exploited, the addition of onshore wind competes with the integration of the surplus (electrolyzer or battery storage), the import of hydrogen and the development of biogas and geothermal energy to provide a cost-optimal solution to meet the electricity demand at the CO_2 price of 160 €/tCO_2. A full integration of the surpluses by electrolyzer plants or battery storage could guarantee the security of supply, but this does not make economic sense. In addition, the expansion of geothermal power plants or biogas power plants is still an uneconomic option. Consequently, the electricity system tries to use the most cost-effective combination of onshore wind expansion together with hydrogen import and production. The installed capacity of onshore wind power plants will increase from 168 to 182 GW (16 GW under expansion potential). The power input of the electrolyzer plants increases strongly from 55,800 to 66,700 GWh. At the same time about 38,500 GWh of hydrogen are imported. Electricity production from produced hydrogen amounts to 27,000 GWh, from imported hydrogen to 22400 GWh. Due to the last mentioned changes in the electricity mix, the electricity production from natural gas drops to 57,000 GWh (at 160 €/tCO2), which means a 95% reduction of CO_2 emissions.

From the CO_2 price of 128 €/tCO2, electricity generation from biomass outweighs that from natural gas. However, the installed capacity of the combined cycle plants will always remain high, even if natural gas-based electricity generation decreases, and always dominates over the installed capacity of the biomass plants. One reason for this is the conversion of hydrogen back into electricity in the combined cycle power plants. The favorable investment and fixed costs as well as the better efficiency of combined cycle plants compared to other marketable power plants also contribute to this. Consequently, their higher capacity can compensate for the greatest fluctuations in demand. The percentage of hydrogen in electricity generation from combined cycle power plants increases from 1.7% at the CO_2 price of 57.9 €/tCO2 to 46.4% at the CO_2 price of 160 €/tCO2.

Figure 4 illustrates the cost distribution with CO_2 tax growth up to 95% cost efficient CO_2 reduction, if the H_2 price is assumed to be 60 €/MWh. Depending on the reduction of natural gas-based electricity generation, the fuel costs up to the CO_2 price of 112 €/tCO2 decrease from 18 billion € to 10.5 billion €. The combustion of solid biomass from the CO2 price of 128 €/t CO_2 increases the fuel costs of the system up to 12.2 billion € (at 144 €/t CO2). The import of hydrogen at the CO_2 price of 160 €/t CO_2 compensates for the reduced combustion of natural gas and consequently leads to a further increase in fuel costs up to 12.7 billion €.

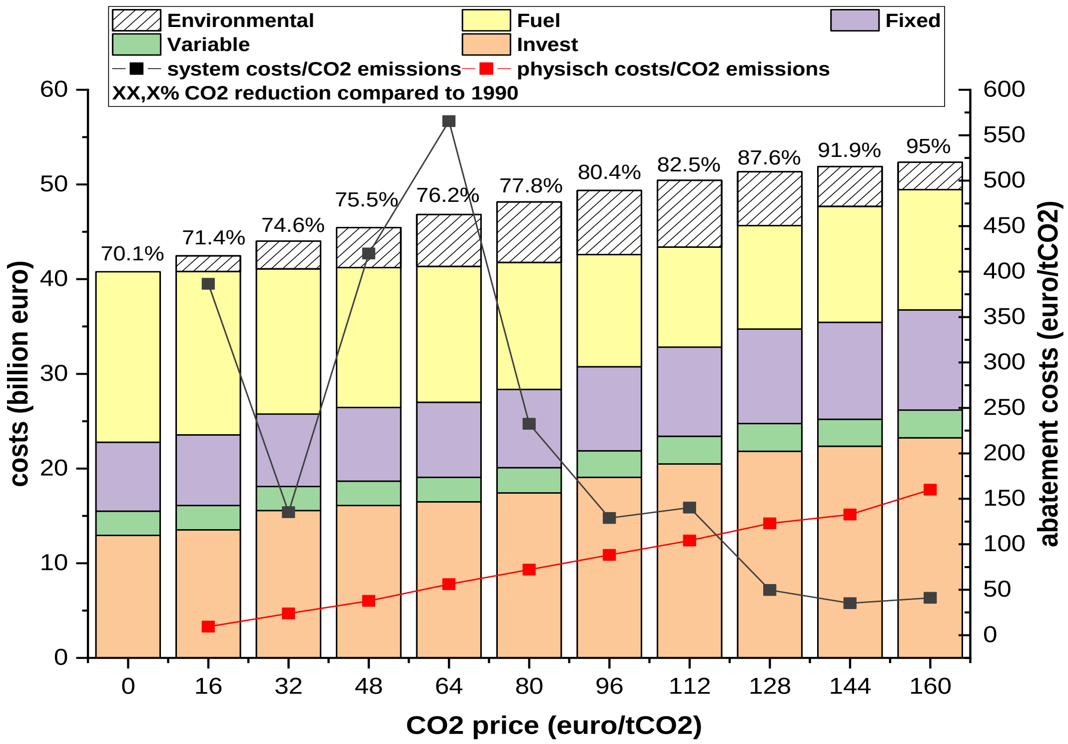

Figure 4: Case study tax-instead-of-limit, share of costs with the CO_2 tax increase, demand of 2017 increased by 50%, H_2 price of 60 €/MWh

Up to the CO_2 price of 64 €/t CO_2, the installation of PV, onshore wind and battery storage units will cause a significant increase in investment costs from 12.9 billion € to 16.4 billion €, and a very slight increase in fixed costs from 7.2 billion € to 7.9 billion €. In between, the physical system costs increase only slightly, from 40.7 billion € to 41.3 billion €, as the increase in investment costs is offset by the reduction in fuel costs.

From a CO_2 price of 80 €/t CO_2 onwards, the investment and fixed costs increase more steeply than before, as either electrolyzer plants (from 80 €/t CO_2) and biomass power plants (from 128 €/t CO_2) are expanded or onshore wind plants are more heavily built. Thus up to the last simulated CO_2 price of 160 €/t CO_2, the investment costs increase to 23.2 billion € and the fixed costs to 10.6 billion €. This results in an explosion of physical costs up to 49.4 billion €. The amount of the variable costs depends mainly on the power generation from wind power plants (5.0 €/MWh) and from combined cycle power plants (4.0 €/MWh).

The cost-optimal adjustment of the energy mix to the tax increase for CO_2 can lead to the creation of the CO_2 reduction targets mentioned above. Through the full expansion of PV and offshore wind, as well as the resulting development of batteries and onshore wind turbines, a CO_2 saving of up to 77.8% is visible. If the electrolysis occurs simultaneously with the expansion of onshore wind and the lull of the batteries, a CO2 reduction of 82.5% can be achieved cost-effectively. If the solid biomass also contributes to the counter generation of electricity and its upper limit is met, the CO_2 saving is increased by up to 91.9%. Finally, the final target of 95% is reached through the import of hydrogen.

The grey and red lines from Figure 4 illustrate the course of the abatement costs for each step of the CO_2 tax increase. The gray color represents the system abatement costs ($\Delta_{physical+CO2\_payments}$ /$\Delta_{Emissions}$), while the red color represents the physical abatement costs

($\Delta_{physical}$ /$\Delta_{Emissions}$). Assuming that the CO_2 payments are socially redistributed, the additional economic burden is negligible.

Between the CO_2 price of 32 and 64 €/tCO_2, the system abatement costs increase strongly, with a slight improvement in CO_2 reduction from 74.6% to 76.2%. This is due to the fact that in the case of electricity generation based on natural gas the reduction is only small, which leads to significantly higher system costs (due to important increase of CO_2 payments and despite almost the same physical costs) and slightly lower CO_2 emissions. Furthermore, the system abatement costs are reduced due to the more cost effective and steeper decline in power generation from natural gas, as CO_2 emissions consequently fall more steeply, while the difference in system costs remains similar. For the CO_2 prices 144 and 160 €/tCO_2, the system abatement costs remain at about the same level, as the increased total costs and the reduction of CO_2 emissions result in almost the same ratio.

The physical abatement costs are continuously increasing with an approximately constant growth rate, as the gradual increase in physical costs develops almost linearly with the progress of CO_2 reduction. Even up to a CO_2 price of 112 €/t CO_2, the abatement costs of the system are at a higher level than the physical abatement costs because the difference in the physical system costs for each step is small. From a CO_2 price of 128 €/t CO_2 onwards, the physical abatement costs are overcome compared to the system abatement costs, since the physical system costs show a greater rise than the total system costs.

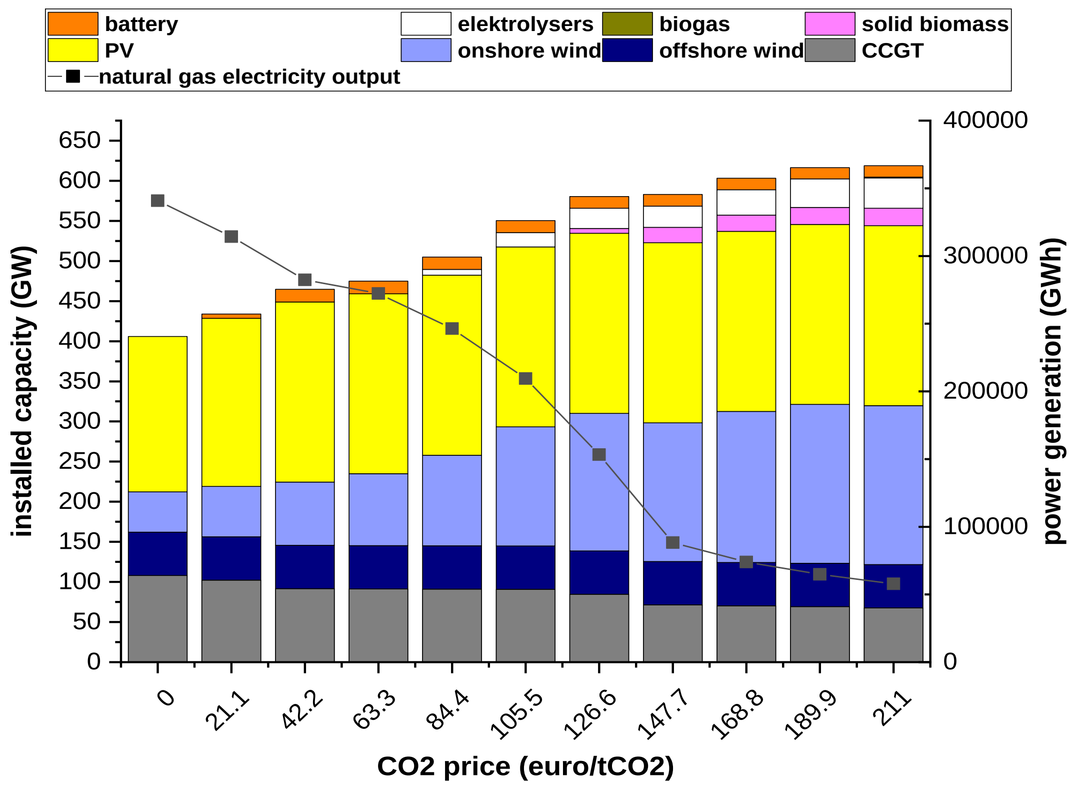

Figure 5: Case study tax-instead-of-limit, Change in the capacity mix with the CO_2 tax increase compared to natural gas based electricity generation, demand of 2017 increased by 50%, H_2 price of 90 €/MWh

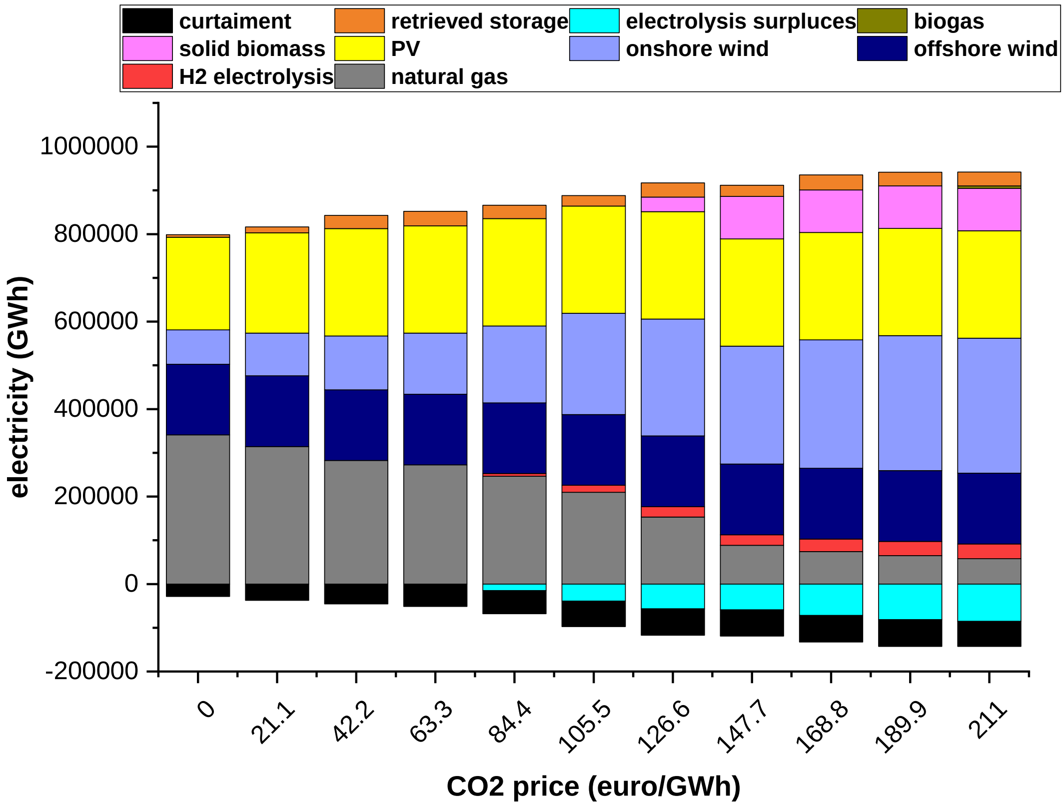

Figure 6: Case study tax-instead-of-limit, Change in the electricity balance with the CO_2 tax increase, demand of 2017 increased by 50%, H_2 price of 90 €/MWh

If the H_2 price is set at 90 €/MWh, the CO_2 shadow price will be higher compared to the case of the H_2 price of 60 €/MWh, because at the CO2 price of 160 €/tCO_2 the import of hydrogen is not cost-effective. As a consequence, a 95% reduction in CO2 emissions is not economically viable at this point. For this reason, the remaining options of the electricity system continue to compete against electricity generation from natural gas. A further extension of the tax on CO_2 up to 211 €/tCO_2 is requested until natural gas-based electricity production drops so much that a 95% reduction of CO_2 emissions is achieved. Figures 5 and 6 illustrate the conversion of the capacity and electricity mix in case of H_2 price of 90 €/MWh, if taxation is taken into account instead of limiting CO_2.

The higher CO_2 shadow price leads to a wider range of optimized CO_2 prices. For this reason, the jump for each increase of the CO_2 price is higher than in the case of the H2 price of 60€. This leads to the fact that electricity generation from natural gas increases more steeply with the tax increase for CO_2 than in the case of the H_2 price 60€. This reduction is replaced between the CO_2 prices 21.1 €/tCO2 and 105.5 €/tCO2 by the development of PV, wind power plants and battery systems.

Due to the higher CO_2 taxations, PV and onshore wind show a higher growth rate to replace the reduction of natural gas based power generation at optimal costs (compared to H_2 price 60 €/MWh). Photovoltaic plants reach their expansion potential (224 GW) at the CO_2 tax of 42.2 €/tCO2, at this point onshore wind plants are expanded up to 79 GW. Up to this CO_2 price, the electricity supply from natural gas has decreased by approx. 58,000 GWh.

At the CO_2 price 63.3 €/tCO_2 a cost-optimal combination of the decreasing electricity generation from natural gas with the expansion of onshore wind and battery storage is required. Installed capacity of battery storage remains nearly stable at 15.7 GW; more integration of surpluses is not cost-effective. The installed capacity onshore wind power has now increased from 89.5 to 112.7 GW. As a result, the natural gas-based electricity contribution has fallen by a further 10,000 GWh.

From a CO_2 price of 84.4 €/t upwards, electrolysis in combination with the further reduction of gas-based electricity could lead to cost savings. In this way, the renewable surpluses also participate in the flexibilisation by means of electrolysis. The installed capacity of the CCGT plant will remain almost the same despite its operation mode, which is gradually shifting to hydrogen firing. The installed capacity of the electrolyzer plants increases between the CO_2 prices 84.4 and 105.5 €/t CO_2 from 7.2 to 17.8 GW, the energy absorbed by electrolysis plants from 14,800 to 38,900 GWh. Onshore wind power will be significantly increased by another 36 GW. Due to these changes in the energy mix, the electricity production from natural gas at the CO_2 price 105.5 €/t CO_2 is drastically reduced to 209,000 GWh.

From a CO_2 tax of 126.6 €/t, natural gas becomes so expensive that the use of solid biomass also becomes economically viable. About 33,300 GWh of electricity is generated from the biomass, while at the same time the electricity production from natural gas is strongly reduced by another 56000 GWh. The further reduction of the secured capacity of the combined cycle gas turbine plant by 6 GW_{el} is replaced by the expansion of biomass plants to 6 GW_{el}.

With the next increase of the CO_2 price to 147.7 €/t CO_2, the biomass potential will be fully exploited, the installed capacity of the biomass power plants has grown to 19.5 GW. On the other hand, onshore wind power plants have expanded very slightly from 171.5 to 172.9 GW. This means that a strong investment in the expensive secured biomass capacity is more worthwhile at this point. Electricity generation from natural gas now amounts to 88,300 GWh.

Once the biomass potential has been fully exploited, the further development of onshore wind and electrolyzer plants is worthwhile in connection with a slight reduction in natural gas-based electricity generation compared to the previous trend. When the onshore wind turbines hit the expansion potential at the CO_2 price of 189.9 €/t CO_2, a reduction of the electricity generation from natural gas to 64800 GWh is economically created.

Almost 8000 GWh remain until the system reaches the final target of 95% CO_2 reduction. The remaining system options are: Greater integration of surpluses, import of hydrogen, development of biogas or geothermal energy. The further expansion of battery storage is not considered to be cost-effective. As a cost-optimal solution, an expansion of the electrolyzer plants from 35.4 GW (189.9 €/t CO_2) to 37.7 GW, together with a slight expansion of the biogas power plants to only 1 GW_{el}, would result. An even stronger integration of the surplus as well as the development of the geothermal power plants would not lead to a cost advantage.

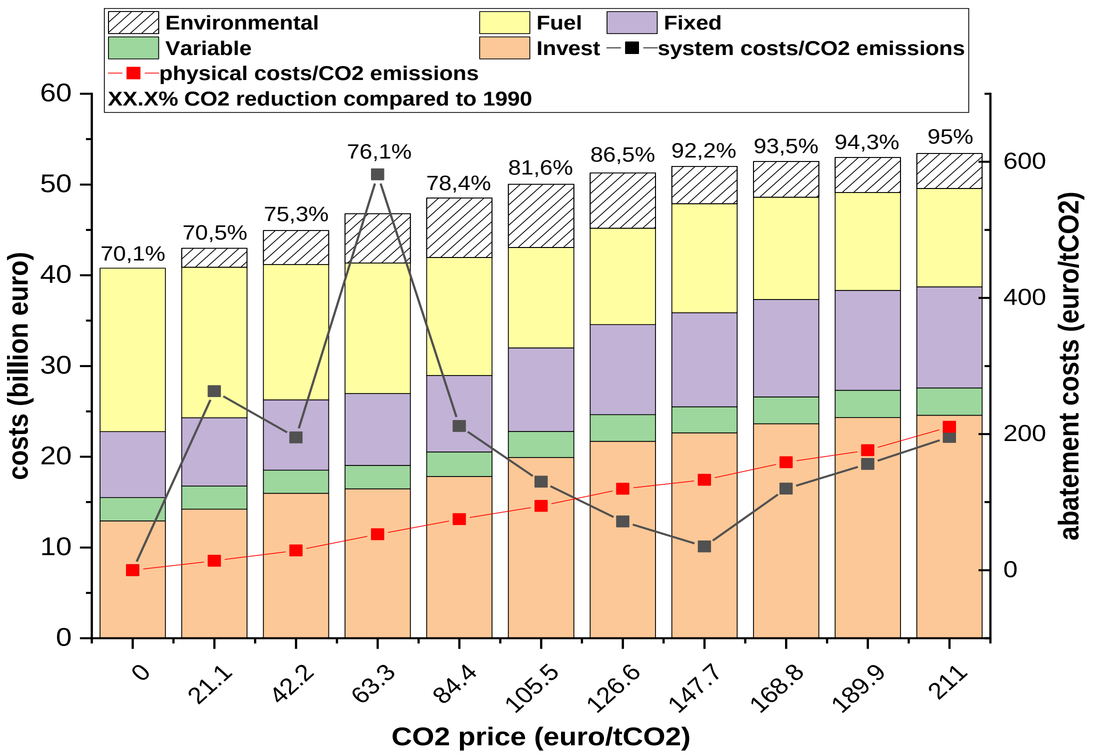

Figure 7: Case study tax-instead-of-limit, share of costs with the CO_2 tax increase, demand of 2017 increased by 50%, H2 price of 90 €/MWh

Figure 7 shows the cost distribution with CO_2 tax increase up to 95% co2 reduction, in case the H_2 price was assumed to be 90 €/MWh. Due to the falling use of natural gas, fuel costs are constantly decreasing from 18 to 10.6 billion € until the CO_2 price has reached 126.6 €/t CO_2. Thereafter, the utilization of solid biomass causes an increase in fuel costs to 12 billion € at a CO_2 price of 147.7 €/t CO2. If the CO_2 price continues to rise, the fuel costs decrease to 10.8 billion €, because the utilization of natural gas is much weaker than before. The investment and fixed costs increase from 12.9 to 16.45 billion € and from 7.2 to 7.9 billion € respectively, due to the expansion of PV, wind and battery systems, until the CO2 price rises to 63.3 €/t. Up to this point, there is only a very small increase in physical costs (total system costs minus CO2 tax payments) from €40.77 billion to 41.3 billion €, as the increase in investment is offset by the significant reduction in fuel costs.

The expansion of biomass plants and electrolyzers contributes to higher investment and fixed costs and significantly increases the physical system costs. Up to a CO_2 price of 189.9 €/t CO_2, the investment costs increase up to 24.3 billion €, the fixed costs up to 11 billion €. The slight expansion of the biogas power plants as well as the slight addition of the electrolysers during the last jump of the CO_2 price to 211 €/tCO_2 causes a small further increase of the investment and fixed costs by 0.3 and 0.1 billion € respectively. The physical costs of the system have risen to 49.5 billion € by then.

The development of variable costs is mainly influenced by generation from wind power plants (5.0 €/MWh) and combined cycle power plants (4.0 €/MWh). After the CO_2 price of 63.3 €/t CO_2, the considerable expansion of electricity generation from hydrogen (in the combined cycle power plants) and onshore wind causes a significant increase in variable costs from 2.59 billion € (63.3 €/t CO_2) to 3 billion € (211 €/t CO_2).

The absolute CO_2 tax payments will increase from 2 to 6.96 billion € up to the 105.5 €/t mark, although natural gas-based generation is declining. From this point on, these payments show a downward trend, with 211 €/t CO_2 amounting to 3.8 billion €. Assuming that the CO_2 payments are socially redistributed, the additional financial cost should be insignificant.

Figure 7 shows that a CO_2 reduction target of up to 76.1% can be achieved cost-effectively by expanding PV, wind and battery systems. A cost-optimal reduction of CO_2 emissions by 81.6% requires the use of electrolysis. If biomass power plants are also developed, a CO_2 reduction of 94.3% can be achieved in a cost-optimal manner. The final target of 95% requires a slight expansion of biogas power plants.

The grey and red lines and symbols from Figure 4 illustrate the course of the abatement costs for each step of the CO_2 tax increase. The gray color represents the system abatement costs ($\Delta_{physical+CO2\_payments}$ /$\Delta_{Emissions}$), while the red color represents the physical abatement costs ($\Delta_{physical}$ /$\Delta_{Emissions}$). Assuming that the CO_2 payments are socially redistributed, the additional economic burden is negligible. The maximum system abatement costs lie between the CO_2 prices 42.2 and 63.3 €/t CO_2, with a very slight improvement in CO_2 reduction from 75.3% to 76.5%. This is due to the fact that in the case of electricity generation based on natural gas, the reduction is only small, i.e. a small reduction in CO_2 emissions. At the same time, system costs increase noticeably despite the insignificant change in the damned physical costs, as the CO_2 payments show a considerable increase. So the quotient of the difference between the total system costs and the reduction of CO_2 emissions is much higher. Thereafter, the system abatement costs are largely reduced due to the sharp decline in electricity generation from natural gas and even up to a CO_2 price of 147.7 €/t CO_2, a CO_2 reduction of 92.2% is achieved. This means that CO_2 emissions are reduced more than the total system costs grow. Thereafter, the system abatement costs show a rising trend again, since a further reduction of electricity generation from natural gas is only slightly economically justifiable, depending on the remaining technologies, while the system costs continue to rise.

The physical abatement costs are continuously increasing with roughly constant growth rate, as the physical costs after each step increase almost linearly with the progress of CO_2 reduction. Even up to a CO2 price of 105.5 €/t CO_2, the abatement costs of the system are at a higher level than the physical abatement costs, as the physical system costs differ only slightly from each other. From a CO2 price of 126.6 €/t CO_2, the physical abatement costs are overtaken by the system abatement costs because the physical system costs show a much larger increase than the total system costs.

Results: Case study *growing consumption*

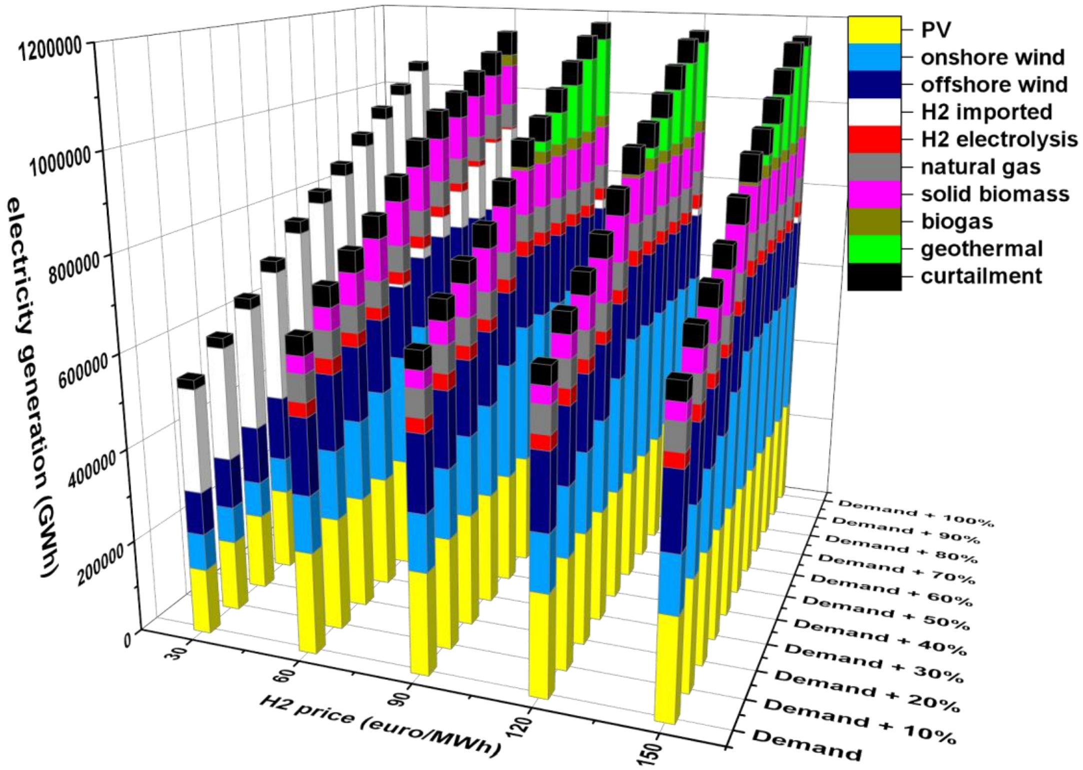

Figure 8: Case study growing consumption, change in the electricity balance with the increase in demand and H_2 price, CO_2 limit set to 95%, CO_2 tax set to zero

Figures 8 and 9 illustrate the optimization results in case both the power consumption and the H_2 price vary below 95% CO_2 limit. *The extremely favourable H2 price of 30€/MWh* leads to complete non-use of natural gas (34 €/MWh), as using H_2 instead in CCGT's for backup production becomes slightly cheaper. Thus, CO_2 emissions are always eliminated during the increase in demand. The generation of electricity from imported hydrogen is increasing in line with the rise in demand. Until the demand doubles, the electricity supply from imported hydrogen will grow from 218,000 GWh to 495,000 GWh. In this way, hydrogen will always provide a large part of the electricity demand, between 42% and 48.5%. The rest is covered cost-efficiently by expanding the fluctuating renewable energy. Due to the continuously high combustion of hydrogen, the installed capacity of combined cycle power plants is increasing more and more, from 69.5 GW_{el} to 145.7 GW_{el}.

The carbon neutrality of the system requires a strong development of photovoltaic and wind power plants. Offshore wind and PV have a higher construction speed than onshore wind due to their better economic efficiency. The expansion potential of offshore wind (54 GW) will be fully exploited as demand rises by 50%. Photovoltaic plants reach the potential limit (224 GW) in case of consumption "demand + 80%".

Installed onshore wind power remains at the initial level of 50.2 GW for many leaps in demand. The first addition of onshore wind is economically viable in the case of consumption "demand + 70%", slightly around 5 GW. With the doubling of the electricity demand, a total of about 88 GW is installed.

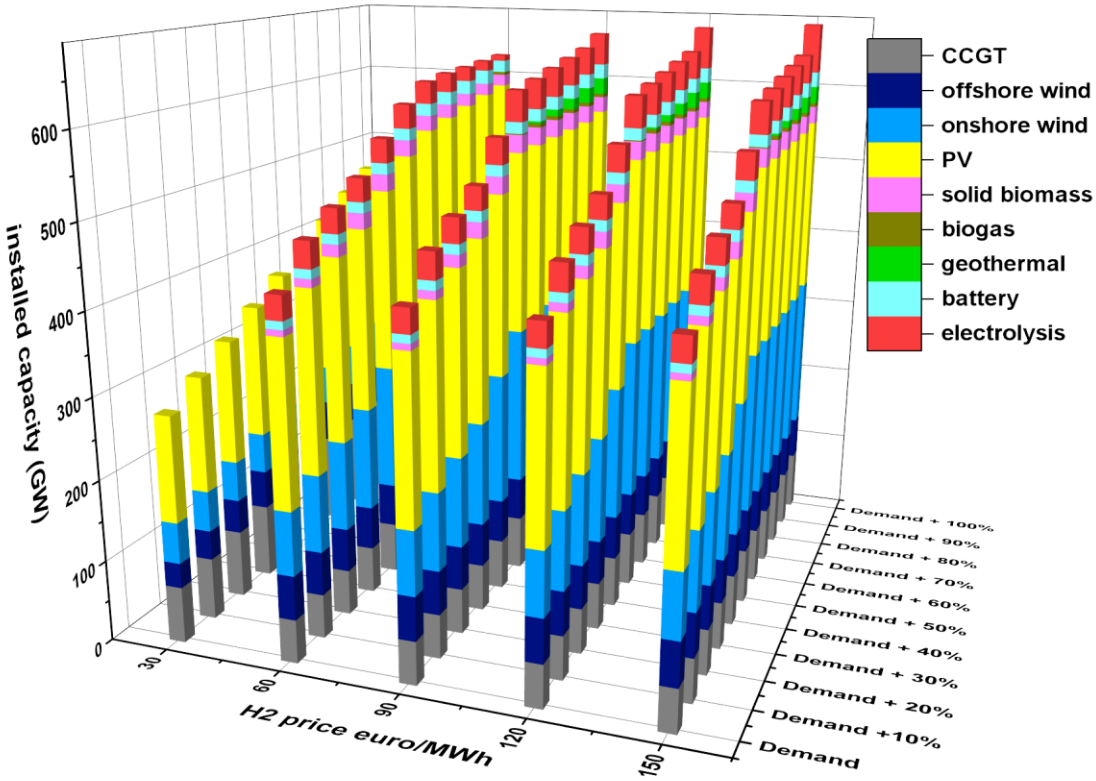

Figure 9: Case study growing consumption, change in the capacity with the increase in demand and H2 price, CO_2 limit set to 95%, CO_2 tax set to zero

The integration of the renewable surpluses either by means of electrolyzer plants or battery storage systems is never worthwhile in the light of increased demand as well as the development of biogas and geothermal energy.

Raising the price of H_2 to 60 €/MWh makes the import of hydrogen not cost-effective even up to a 30 percent increase in demand. Up to this point, the absence of electricity production from imported hydrogen will be replaced by the increased development of PV and wind power compared to the H_2 price of 30 €/MWh, as well as the use of biomass and electrolysis.

The electricity production from natural gas is at the maximum allowed electricity value of 57.000 GWh (CO_2 limit 95%) in all consumption. This should lead to the strong development of CO2-free technologies. The offshore wind potential (54 GW) will be exploited from the first case of consumption, mainly for efficiency reasons. The attractive PV systems are fully developed at "demand + 20%" (224 GW). Onshore wind power has a lower rate of expansion, with the 30% increase in demand reaching 128 GW. The biomass power plants are included in the back-up capacity of the system, while the integration of renewable surpluses either by means of battery storage or electrolysis also supports flexibility. With the 30% increase in demand, about 13 GW of battery storage and 28.3 GW of electrolysis plants are installed.

With the 40% increase in electricity demand, the electricity system starts to import hydrogen to meet the increasing demand at optimal costs. At this point the biomass potential is fully exploited, from which about 97,000 GWh are generated. The installed capacity of biomass power plants has increased from 7.6 GW_{el} to 20.5 GW_{el}. After this point, the installed capacity of biomass power plants shows a decreasing tendency down to 15.1 GW_{el} (at "Demand + 100%"). This is due to the fact that a cost saving results from the possible system costs required without this weakening of biomass plants minus the newly resulting system costs (points: reduction of biomass, development of H2 import, expansion of CCGT). For the same reason, the installed output of the electrolysis is reduced very sharply from 29.5 GW_{el} to 7.6 GW_{el} after the "demand + 50%" consumption case, because the path of the resulted strong H2 import together with this concrete weakening of the electrolysis leads to cost advantages (avoided costs from electrolysis minus additional costs from H2 import equals a cost advantage for each further jump in demand).

With the next leap in demand (at "demand + 60%") the onshore wind plants will be expanded until the end of the assumed potential (198 GW). Until the consumption of "Demand+ 90", the system aims to import hydrogen in parallel with the limitation of the expansion costs for biomass power plants and electrolysis in order to meet the increasing demand for electricity in a cost-optimised manner. In addition, there will be an increasingly easy expansion of battery storage facilities up to 18.2 GW by then. Meanwhile the electricity production from imported hydrogen increases extremely strongly up to 170,100 GWh.

With the explosion and doubling of the demand for electricity, the development of biogas power plants is a prerequisite for cost-optimal coverage. However, this requires a reduction of the installed capacity of the batteries by almost 3 GW. Biogas power plants are installed at 3.8 GW and immediately exploit the entire biogas potential, which corresponds to the production of about 26000 GWh of electricity.

On the one hand, because combined cycle power plants have attractive investment costs and good efficiency, and on the other hand, because the generation of electricity from hydrogen is developing strongly, the installed capacity of combined cycle power plants will grow from 54 GW_{el} (at "demand") to 108.3 GW_{el} (at "demand + 100%").

Now follow the comments on the optimization results *if the H2 price is above 60 €/MWh*. Until the demand for electricity has increased by 30%, the energy mix shows the same behavior as the H2 price of 60 €/MWh. In contrast to the H2 price of 60 €/MWh, the import of hydrogen is not worthwhile from a 40% increase in demand. The lack of electricity supply from imported hydrogen is mainly covered by the stronger development of onshore wind and electrolysis, even if the demand for electricity has increased by 50%. At this point onshore wind reaches the upper limit of 198 GW (60 €/MWh - 182 GW). In addition, about 37.7 GW of electrolysis plants are currently installed (60 €/MWh - 29.5 GW).

From the 60 to 90 percent increase in electricity demand, the non-use of imported hydrogen will be economically replaced both by electrolysis and by the development of biogas power plants and geothermal power plants. Approximately 35 GW of electrolysis plants have been developed with the 90 percent increase in demand (60 €/MWh - 12.6 GW). The biogas potential is already fully exploited from the 60% increase in demand, i.e. 26,700 GWh of electricity generation from geothermal energy. The geothermal potential is fully exploited with the 90% increase in demand, which corresponds to an electricity production of 188,000 GWh.

At the point of the 90% increase in demand, exactly 21.364 GWel geothermal power plants are installed, which means with the efficiency of 14% a thermal installed capacity of 152.6 GW_{th}. The drilling facilities amount to 218 GW_{th}, i.e. with the heat efficiency of 70% a constantly provided heat quantity of 152,600 GWh_{th} per hour. At the same time, the development of thermal storage facilities is not economically viable. This means that the geothermal power plants receive the entire amount of heat provided by the drilling systems every hour.

The H_2 import with prices higher than 60€/MWh occurs only in the doubling of consumption as the potential of biogas and geothermal are fully exploited. At this point: the more the H_2 price rises, the lower is the electricity supply from imported H_2 and the higher from produced H_2. Electricity generation from produced and imported hydrogen is adjusted as follows as demand doubles: At the H2 price of 90 €/MWh, this results in 22,300 TWh electricity from imported hydrogen and 30,000 GWh from produced hydrogen. At the H2 price of 120 €/MWh about 17,200 GWh from imported and 35,000 GWh from produced hydrogen are offered. At the H2 price of 150 €/MWh the amount of electricity from imported hydrogen is 14,700 GWh, while from produced hydrogen it is 37,500 GWh.

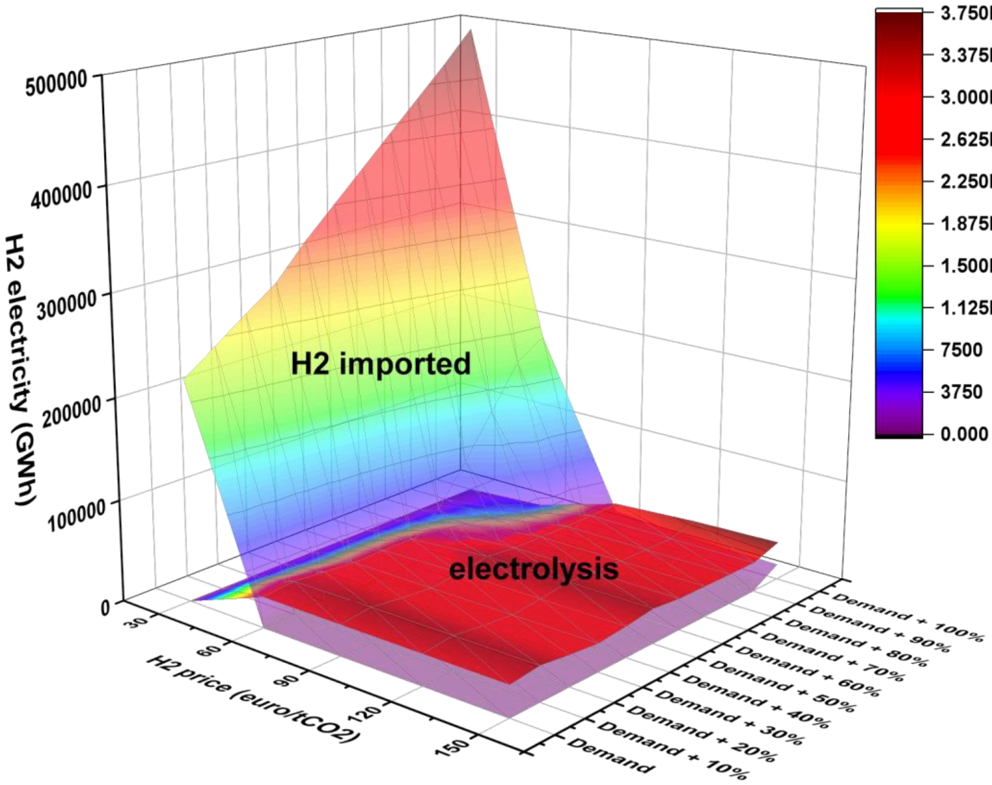

Figure 10: H2 import versus electrolysis with variation of demand and H2 price

The relation between electricity generation from produced and imported hydrogen both with the price increase for H2 and with the increase in demand is shown in Figure 10. The extremely favourable H2 price of 30 €/MWh leads to the elimination of electrolysis and alternatively to an extremely high import of H2, since the combustion of hydrogen in combined cycle power plants becomes cheaper than that of natural gas.

If the H2 price is 60 €/MWh, electrolysis occurs from the first case of consumption. With the 40 percent increase in demand, the import of hydrogen also becomes cost efficient. From the 60 percent increase in demand, the electricity contribution from imported hydrogen dominates over that from produced hydrogen.

The H2 import with prices above 60€/MWh is only possible if the consumption doubles, while electrolysis is already economical from the initial consumption. At this point, the more the price of H_2 grows, the less electricity is supplied from imported H2 and the more electricity is provided from produced H_2.

Conclusion

In this study, we an energy system modelling-based methodology has been employed in order to make analyses on a) the influence of the carbon taxation on the system costs and how they may be represented in an energy system model. There we pointed out that the system costs to the society and eventually to the consumer may be overestimated when one does a system analysis where these prices are implemented. Second, b) we observed that the comparative feasibility of the imported and locally produced hydrogen is still an open point, as we even observed some cases where both were co-present in the system.

One has to note, however, certain shortcomings of the study. In this study, a rather stylized, simplified model has been used by using e.g. a single-node model, linear representation of the model components and the simple scaling of the electricity demand for the high-electrification scenarios. In the same vein, these results hold an implicit underrepresentation of the value of hydrogen, as it offers many sector coupling potentials, such as direct use in the industry and long-range mobility. These have been ignored in this study in favor of the computational ease to generate the multiple model results presented here. The model results are thus subject to these uncertainties and the lack of mentioned level of details. The absolute values read from the model results should therefore not be taken literally and instead, the qualitative relationships between the considered scenarios should be the focus of the result analysis.

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