Designing a Smart Energy Europe from the PRIMES scenarios

Documentation report

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Identifying a baseline scenario

The first step is to identify a baseline scenario. Based on the process in replicating the PRIMES scenarios in EnergyPLAN an adjusted baseline is identified. The reason for adjusting the baseline is to ensure the modelling of the energy efficiency steps can be done coherently. Specifically, this means updating the heating and industry demands.

The first step is to increase the power plant capacity to allow for all electricity production in Europe to be handled internally. This increase means the PP capacity is moved from 310.9 GW to 575 GW.

Furthermore, the electricity storages has been updated based on the following inputs:

- Batteries have 4 hour storage capacity and a roundtrip efficiency of 0.85 (0.92 charge, and 0.92 discharge). Batteries cost 300 M€/MWh
- Hydro storage: 10 hour of storage, pump efficiency of 0.8, turbine efficiency of 0.8. Cost of 175 M€/MWh.

The goal of RE-INVEST is to find robust investment strategies for renewable energy. Thus, as part of the smart energy Europe scenario, the existing capacity of 86.82 GW of Nuclear power (with a production of 0.69 PWh of electricity) is replaced by a corresponding capacity of offshore wind.

Updating transport demand

Based on the sEEnergies research project, a new interpretation have been made of the transport demand in the PRIMES scenarios, thus the following is assumed for 2050.

PWh	Fossil	Biofuel	Electrofuel
JP	0.73	0.02	0
Diesel	1.17	0.11	0
Petrol	0.52	0.07	0
Ngas	0.16		
LPG	0		
Ammonia			0

Table 2

PWh	
H2	0.06
Electricity, dump	0.21

Electricity, smart	0.31

Updating heat demand

The heat demand is specifically for space heating. Here we have used Heat Roadmap Europe 4 to update the heating demand. This is done by scaling the current heating system defined in PRIMES BL 2050, with the heat demand identified in Heat Roadmap Europe. It is important to note that Heat Roadmap Europe accounts for 90% of the heating demand in Europe, as such everything is scaled afterwards. The table below illustrates the updated heat demands:

Scenario	BL 2050	HRE14	HRE14 scaled to 28 countries
Heat demand [PWh]	2.01	2.095	2.328

This gives a ratio of 1.16 that all heat demands are scaled within the system.

Updating industry demand

This updates the heating demand to reflect the heating for industry from sEEnergies and likewise for electricity for industry.

In terms of fuel consumption, the difference between the PRIMES baseline, and the adjusted baseline can be seen below.

Here we implement the heat demand, electricity demand and fuel demand for industry. These are as follows

Industry demand [PWh]	BL 2050 + HRE	sEEnergies Frozen
Coal in industry	0.306	0.578
Oil in industry	0.528	0.446
Gas in industry	0.872	1.211
Biomass in industry	0.512	0.365
Electricity	1.195	1.199
Heat	0.236	0.243

The main thing here is to note that the assumption for how much of the district heating demand is due to industry comes from sEEnergies. Thus the DH system changes. Based on Heat Roadmap Europe, the total district heating demand was 0.332 PWh.

From Heat Roadmap Europe, the district heating for industry can be divided into 0.041 PWh for space heating and 0.195 PWh for industrial processes. In total 0.236 PWh. sEEnergies uses 0.243 PWh for industry. We adjust, by assuming the space heating is industry is equal to Heat Roadmap Europe, but the total heat demand for industry is equal to sEEnergies. This changes the baseline as follows

PWh	BL + HRE	sEEnergies adjustment

DH for space heating in commercial and residential	0.096	0.096
DH for space heating in industry	0.041	0.041
DH for industrial process	0.195	0.202
TOTAL	0.332	0.339

The first step is to investigate the demands and identify potential system efficiencies. **TOTAL**	0.338	0.365

Reference industry demand

With implementing reference industry demand, coal is almost eliminated from the system, alongside a reduction in oil and gas demands.

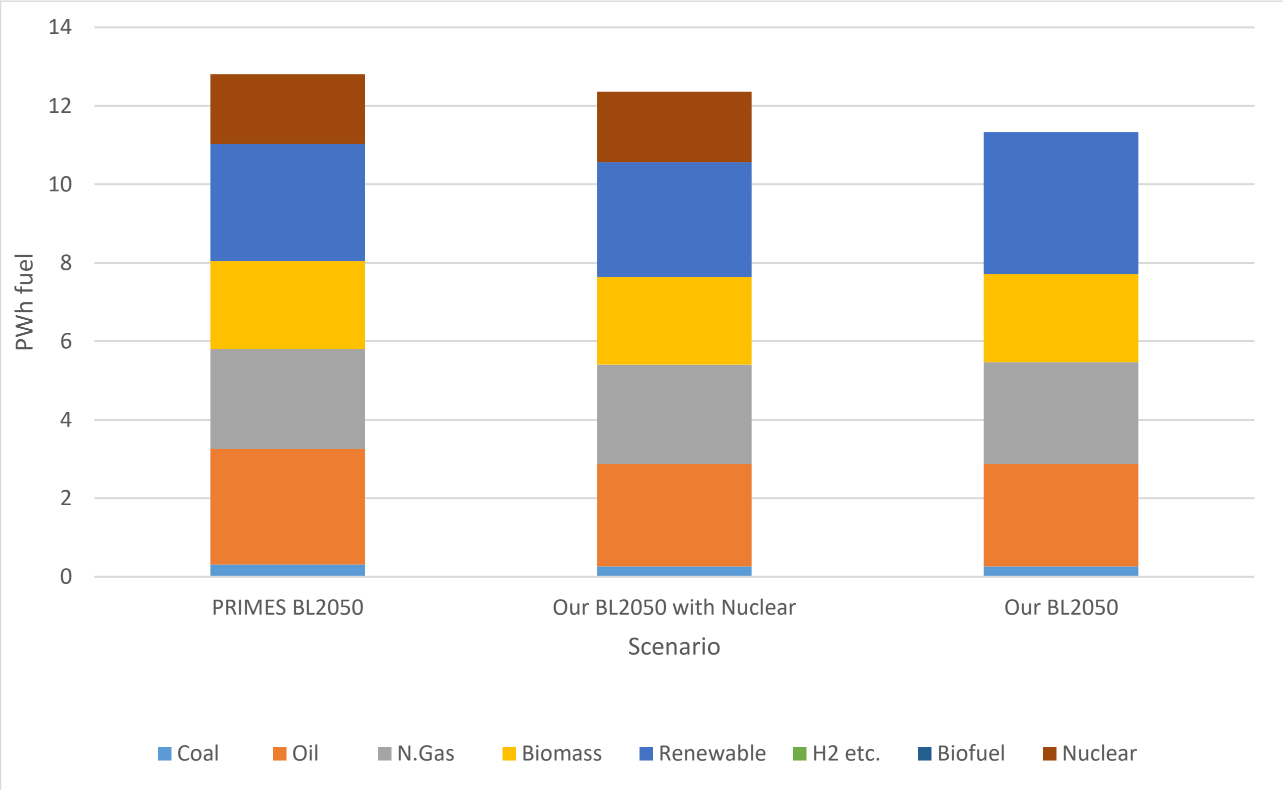
Here the "Reference" scenario for industry demand is implemented. Furthermore, the heat demand savings potential from heat roadmap Europe 4 is also implemented, as the overall heat demand in Europe. The heat savings are implemented equally in all sectors of the energy system.

Industry demand [PWh]	sEEnergies Frozen	sEEnergies Reference
Coal in industry	0.578	0.264
Oil in industry	0.446	0.179
Gas in industry	1.211	0.638
Biomass in industry	0.365	0.446
Electricity	1.199	1.145
Heat	0.243	0.270

This changes the DH system to look like this.

PWh	sEEnergies frozen	sEEnergies Reference
DH for space heating in commercial and residential	0.096	0.096
DH for space heating in industry	0.041	0.041
DH for industrial process	0.202	0.229
TOTAL	0.339	0.366

This gives the following



Finally, we also remove CCS from the process, so all systems below do not have any CCS, but might utilize CCS.

Step 1: Efficient heat demands

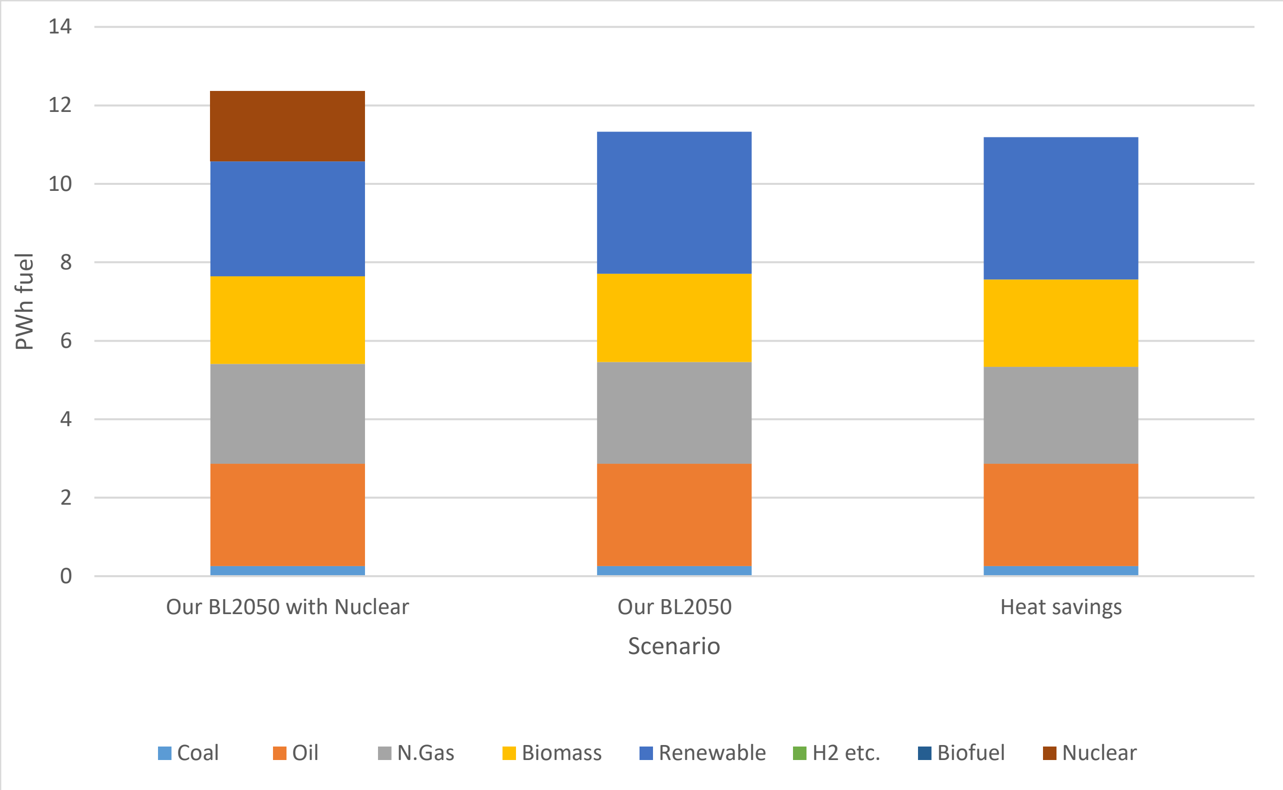
To reduce heat demands, the change in heating demand from Heat Roadmap Europe is assumed. The heat savings are conducted for space heating in both industry, residential and service buildings.

- Heating demand for residential houses and services based on heat roadmap Europe
- Space heating demand for industry based on heat roadmap Europe.
- District heating demands for industry processes are kept fixed.

This gives an overall heat saving in space heating demand of approximately 10% additional to the base step identified in HRE14.

The heat demands therefore changes to the following:

PWh	Our Baseline	Our baseline + heat savings
Indv. Oil boiler	0.01	0.01
Indv. Gas boiler	0.94	0.83
Indv. Biomass boiler	0.15	0.13
Indv. Heat pump	0.81	0.72
Indv. Electric boiler	0.08	0.07
DH	0.37	0.35



Step 2: Implementing district heating and updating heat supply

The step here is to implement district heating. Based on heat roadmap Europe 4, the amount of heating in district heating is determined. This is adjusted for district heating for industry determined by sEEnergies data. In total the district heating in Europe covers 52% of the total heating demand (1.091 PWh out of 2.11 PWh). This includes heat for industry.

The scenario therefore becomes like follows:

PWh	Individual	District heating
Indv. Oil boiler	0.007	0.004
Indv. Gas boiler	0.847	0.481
Indv. Biomass boiler	0.133	0.075
Indv. Heat pump	0.733	0.416
Indv. Electric boiler	0.075	0.042
DH	0.357	1.091

Step 2.1 Dimensioning the heating system

Based on peak district heating demand of: 298 GW, the DH boiler capacity is dimensioned to be that +20% = 358 GW

The CHP electric capacity is determined to be equal the average DH demand 144 GW. The CHP efficiency is determined to be 0.45 electric and 0.45 thermal, based on a combination of biomass CHP, single cycle and combined cycle gas turbines.

Step 2.2 Including thermal storage

The system includes a thermal storage capable of storing 8 hours of the average district heating demand.

The average heat demand is 144 GW which results in 1152 GWh ~ 1.2 TWh of thermal storage.

Step 2.2 Including industrial excess heat, geothermal and solar thermal

According to the Heat Roadmap Europe study the following amount of energy can be delivered from industrial excess heat: 0.096 PWh. This is 90% of Europe, so scaling up 0.107 PWh excess heat is implemented.

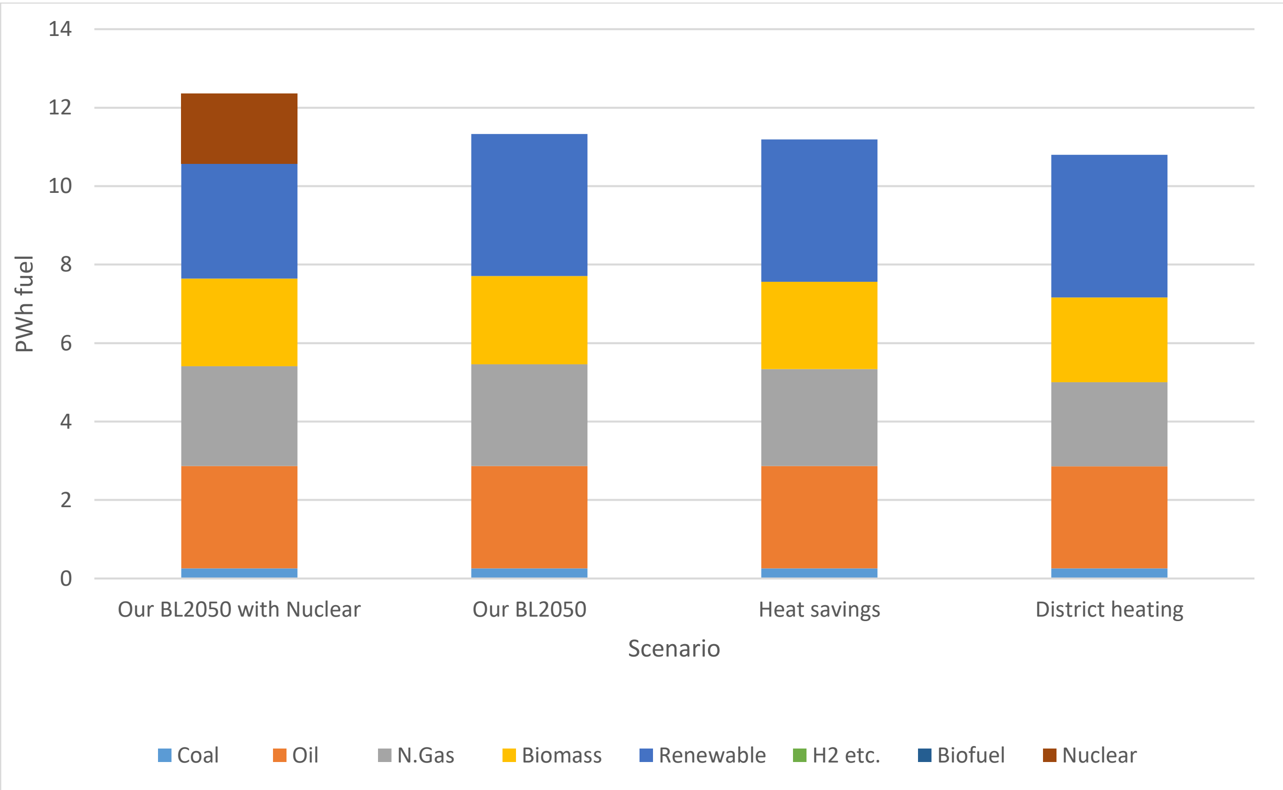
Solar thermal can deliver 0.016 PWh in HRE4, resulting in 0.018 PWh used in this study.

Heat pumps in district heating system

Heat pumps are included in the system. The technology catalogue for RE-INVEST specifies the following efficiencies:

District heating heat pumps have a COP of 4.

The first step is to implement the average heat load of 144 GW, as thermal capacity of heat pumps in the district heating grids. This gives the following result for fuel consumption



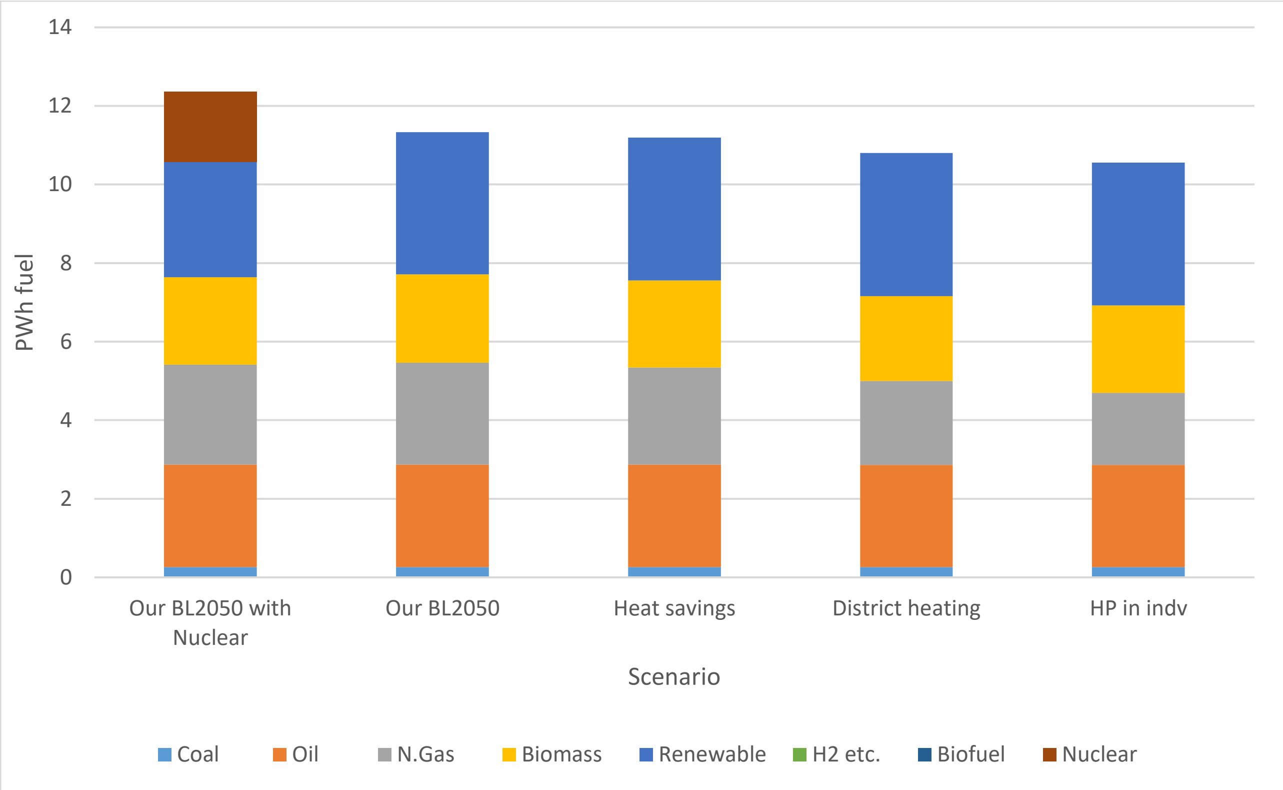
Heat pumps in the individual heating system

The next step is to change the individual gas and oil boiler to heat pumps (potentially we could also do something with biomass and electric boilers??).

The COP of the heat pumps are determined to be: 3

This means the heat pumps now cover 0.900 PWh of heating demand of the total 2.15 PWh.

This requires increased power plant capacity of 25 GW. The total is 600 GW of PP capacity.



Step 5: Demand side management and EVs

The next step is to convert the possible transport demand to electric vehicles. Based on the sEEnergies project a complete revamp of the transport sector is made. This assumes the following electrification rates. IN total this translates the system into the following demands

	Car		Light Duty		Heavy duty (based on bus)	
	Fuel to Electric	Gas to electric	Fuel to Electric	Gas to electric	Fuel to Electric	Gas to electric
Converted to electricity	100%	100%	50%	-	20%	0%

Car and light duty vehicles are assumed to smart charge vehicles with heavy duty is dump charge. Adding these values to the existing electricity demand and subtracting the determined fuel and gas demands, the transport scenario looks the following:

PWh	Fossil	Biofuel	Electrofuel
JP	0.73	0.02	0
Diesel	0.63	0.11	0
Petrol	0	0	0
Ngas	0.07		
LPG	0		
Ammonia			0

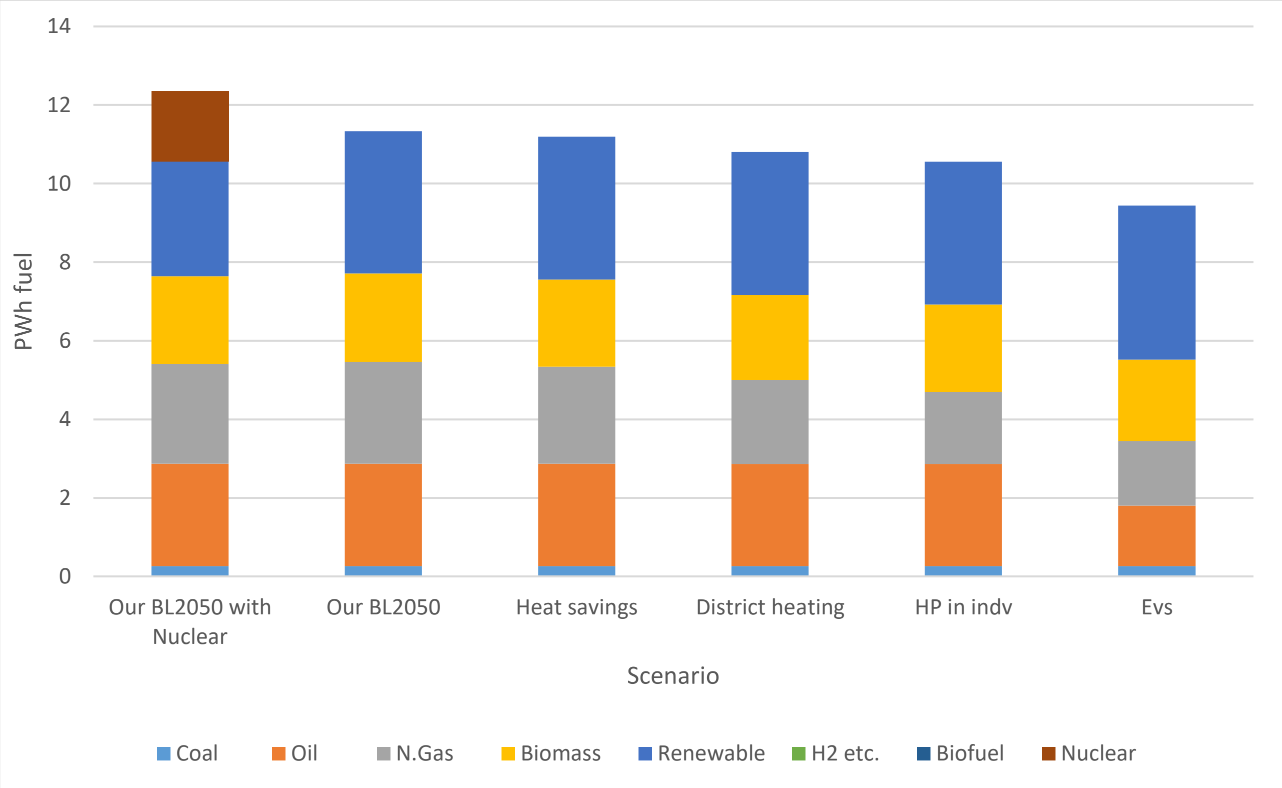
PWh	
H2	0
Electricity, dump	0.25
Electricity, smart	0.531

Based on the increase in smart charge, the capacities on cables and batteries are increased with the same ratio:

	Baseline	New
Max share	0.2	0.2
Capacity (charge) GW	1800	3301.65775
Share of parked	0.7	0.7
Charge efficiency	0.9	0.9
Storage cap TWh	3	5.50276292
Capacity (discharge	90	165
Discharge efficiency	0.9	0.9

To balance electricity with the new technology 50 GW of PP capacity is added, to a total 650 GW. Also, Offshore wind is increased to accommodate for the new demand

GW	Baseline	New
Onshore wind	441	441
Offshore wind	143	200
Photovoltaic	441	441



Step 6: Synthetic fuel for transport(DME/Methanol/JP)

This step converts all liquid fuels to e-fuels, produced on hydrogen and carbon. The gas driven vehicles will use biogas, so the production of biogas will be equal to the gas demand for vehicles.

Thus the transport scenario looks like this.

New Energy Plan scenario + Electrofuel			
	Fossil	Biofuel	Electrofuel
JP	0	0	0.75
Diesel	0	0	0.74
Petrol	0	0	0
Ngas	0.07	0	0
LPG	0	0	0
Ammonia	0	0	0
TWh electricity			
H2	0		
Electricity, dump	0.25		
Electricity, smart	0.53		

The same amount of biomass used for biofuel will not be hydrogenated that was: 0.21 PWh in the original. This results in a production of 0.27 PWh of liquid fuel from biomass hydrogenation. The remaining 1.48 PWh (before loss in e-JP of 20%), will be produced from CO2 hydrogenatoin.

The electrolysers will be dimensioned to cover 1.6 times the average demand. This results in a capacity of 440 GW. These are accompanied with a storage that can store 4 days of average load = 34 TWh.

This results in a hydrogen demand 1.93 PWh, thus the VRES production has to increase.

GW	Baseline	New
Onshore wind	441	441
Offshore wind	200	725
Photovoltaic	441	441

Step 7: Synthetic fuel power plants/backup electricity production

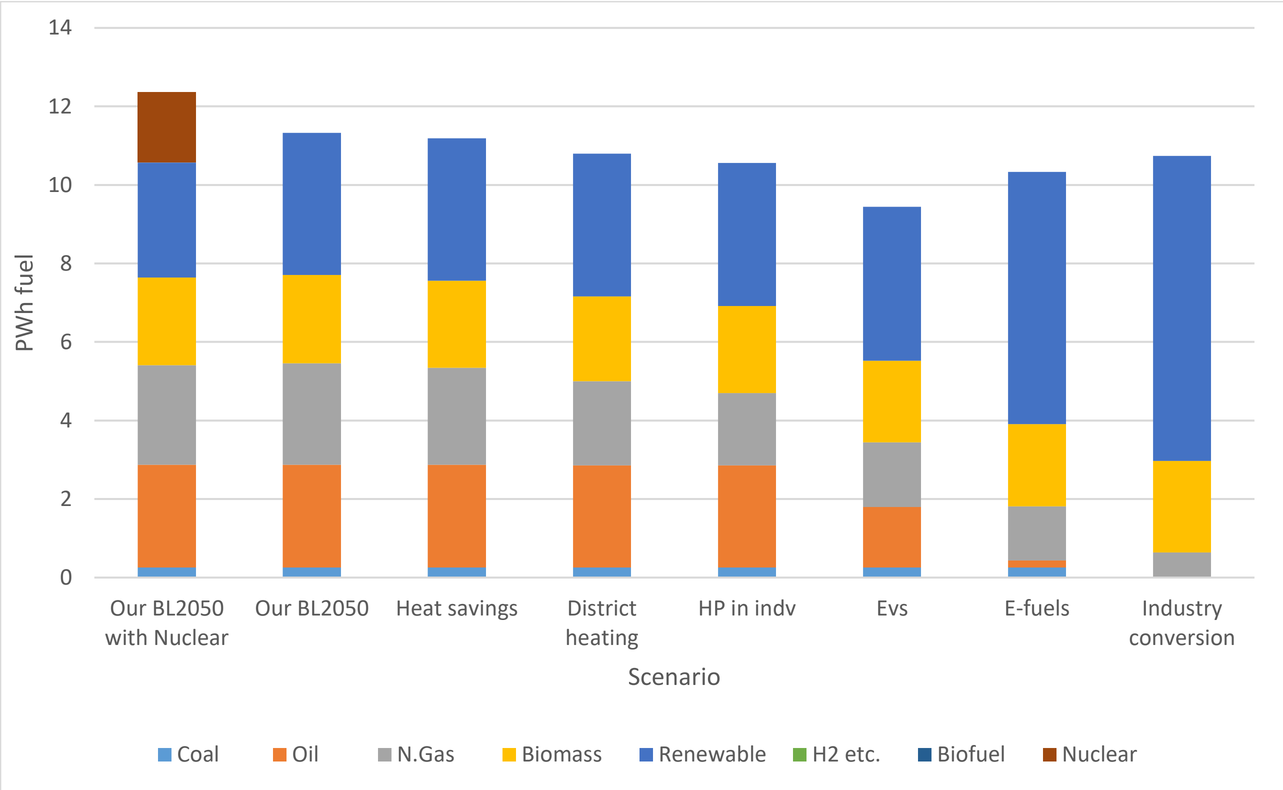
The first step here is to transform the industry to renewable energy. Here coal will be replaced with biomass and oil with gas. The gas will now be produced by e-gas from CO2 hydrogenation.

The industry will therefore change like this:

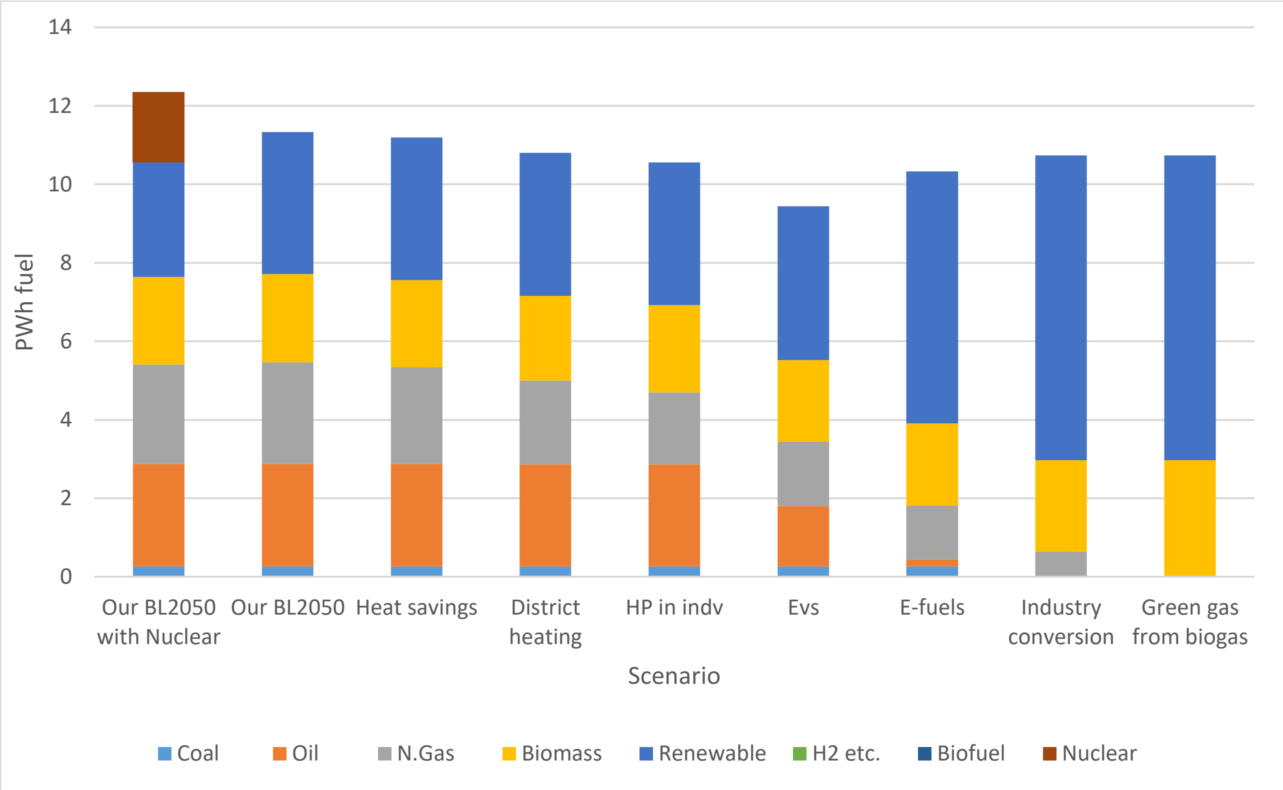
PWh	Reference	New
Coal	0.264	0
Oil	0.179	0
Ngas	0.638	0.817
Biomass	0.446	0.710

This increases the hydrogen demand to 2.92 PWh. Thus the electrolysers capacity is increased to 664 GW and the storage to 51 PWh. Thus the VRES demand increases.

GW	Baseline	New
Onshore wind	441	441
Offshore wind	725	1008
Photovoltaic	441	441



The final step comes from eliminating the last natural gas amount. This is done by increasing biogas production by 0.59 PWh. In total this brings the biogas production to 1.23 PWh.



A final step is added as an alternative to increased biogas. That is to increase CO2 hydrogenation again.

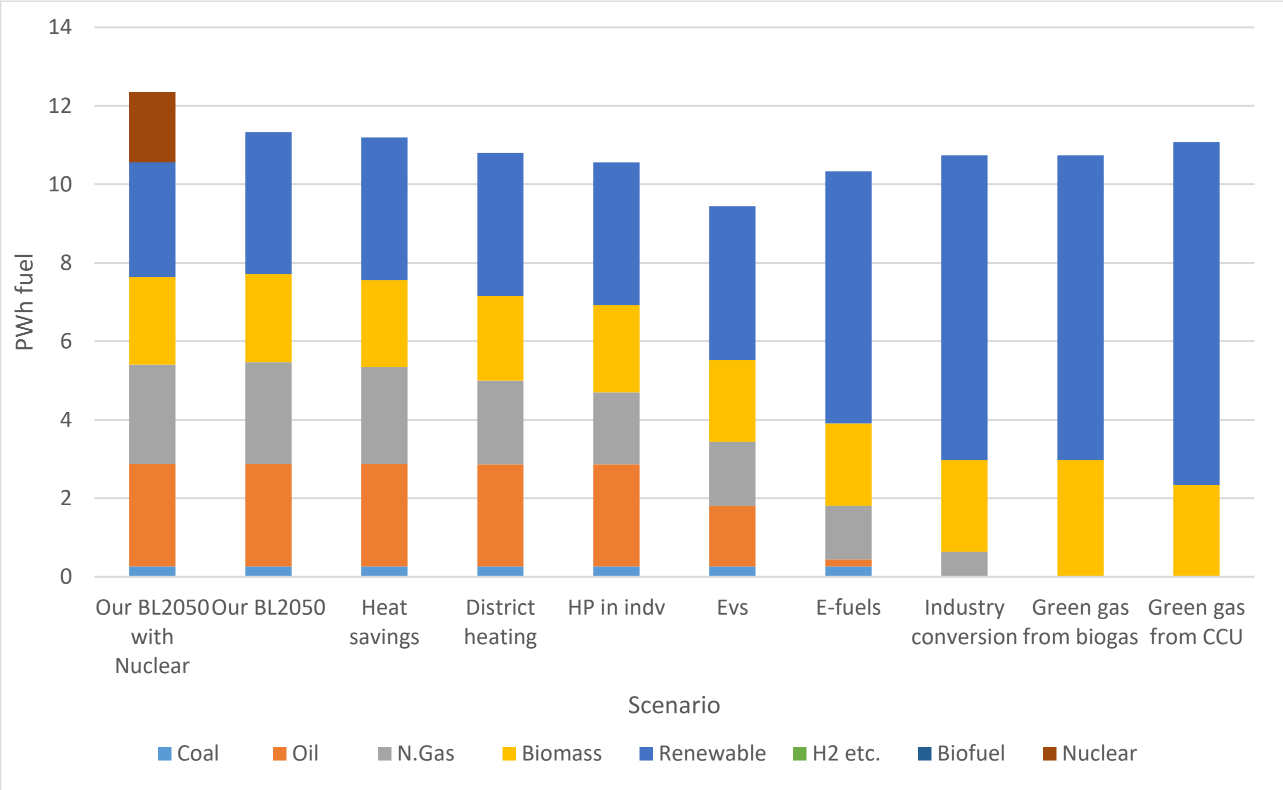
This means the output from CO2 hydrogenatoin has to be 1.457 PWh.

This increases H2 electrolyser capacity to: 838 GW and H2 storage to 64 TWh

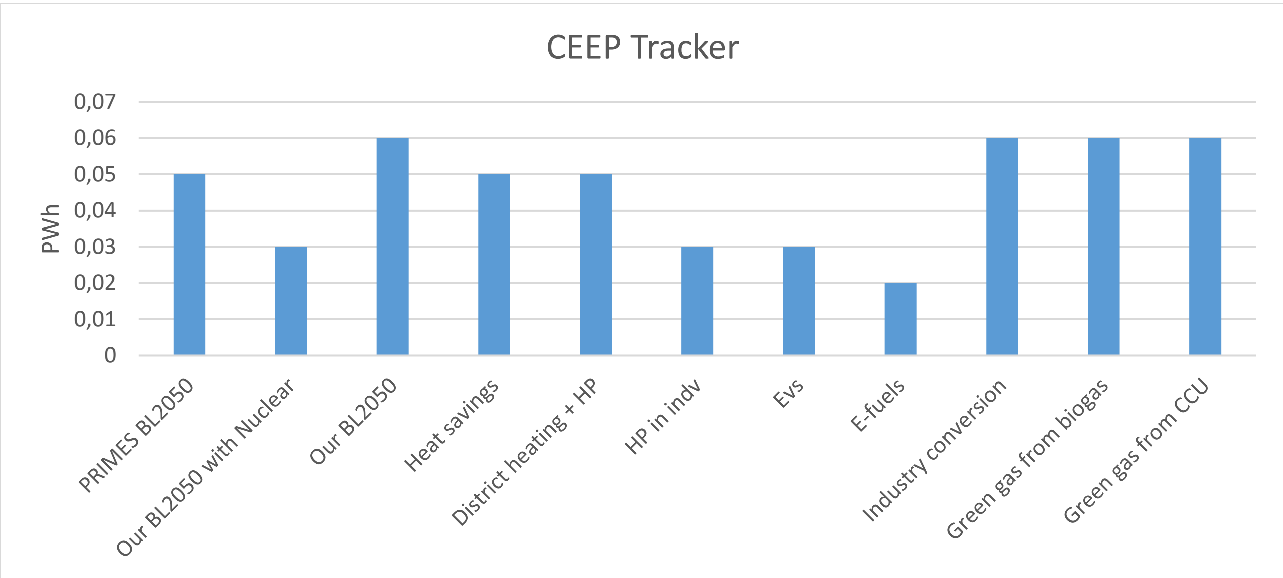
We increase renewable to become CO2 emissions of zero is an increase in VRES sources to

GW	Baseline	New
Onshore wind	441	441
Offshore wind	1008	1212
Photovoltaic	441	441

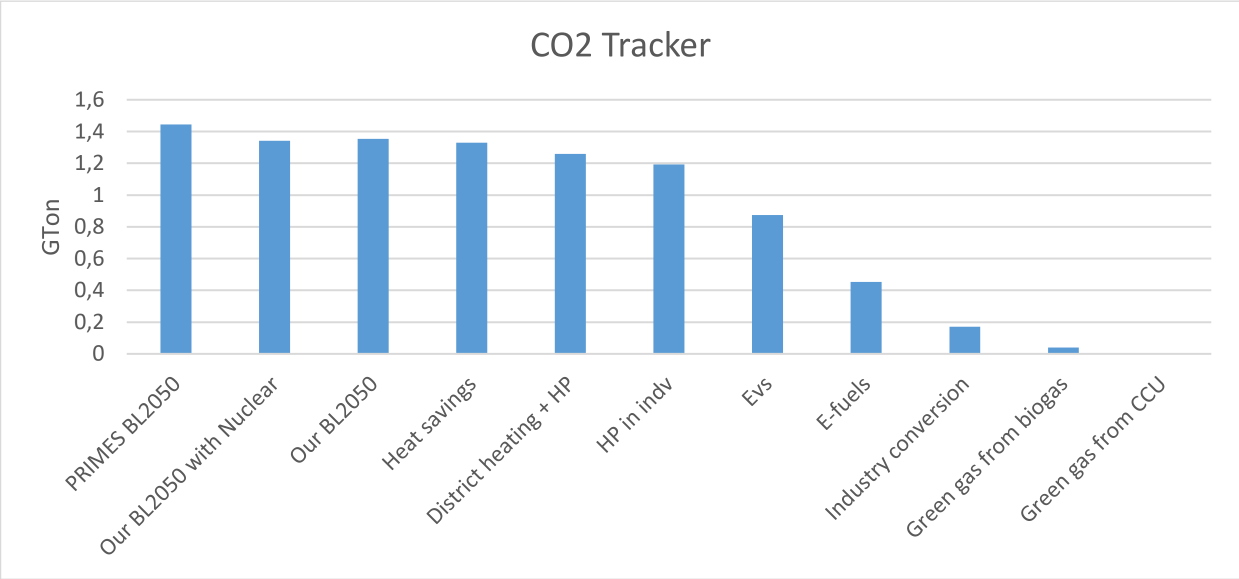
Primary energy results

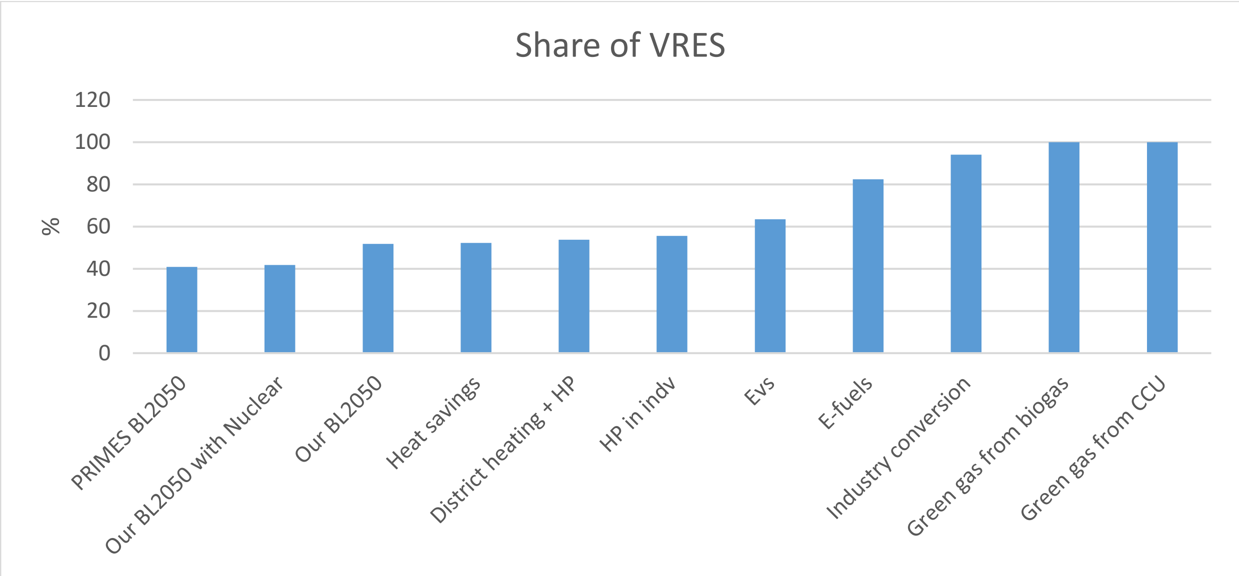


14
12
10
8
6
4
2
0
PWh fuel
Our BL2050 with Nuclear
Our BL2050
Heat savings
District heating
HP in indv
Evs
E-fuels
Industry conversion
Green gas from biogas
Green gas from CCU
Scenario
Coal
Oil
N.Gas
Biomass
Renewable
H2 etc.
Biofuel
Nuclear

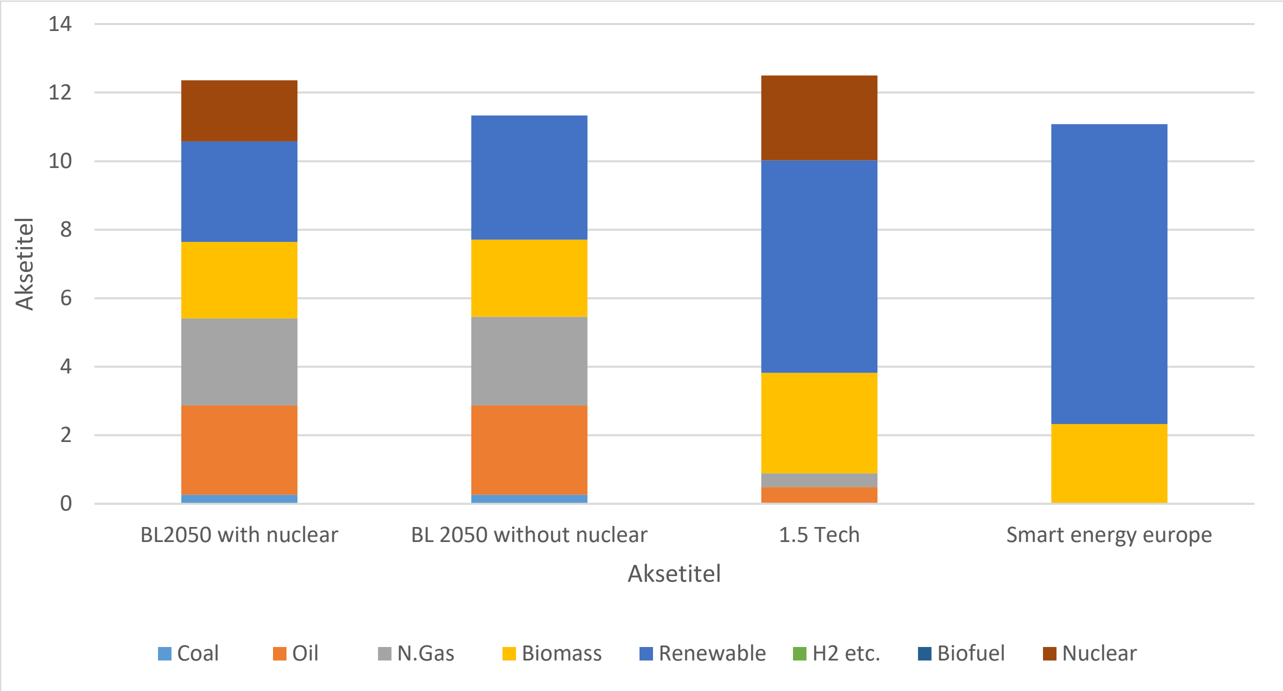


CEEP Tracker
0,07
0,06
0,05
0,04
0,03
0,02
0,01
0
PWh
PRIMES BL2050
Our BL2050 with Nuclear
Our BL2050
Heat savings
District heating + HP
HP in indv
Evs
E-fuels
Industry conversion
Green gas from biogas
Green gas from CCU

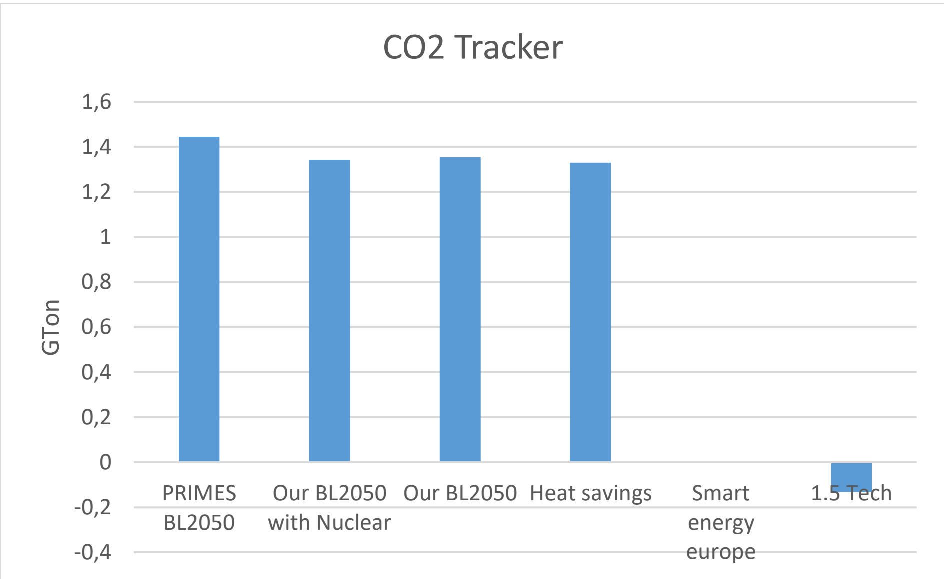




Thus, the compare, this final Smart Energy Europe system is compared to the 1.5 Tech and the Baseline scenarios in the figures below.



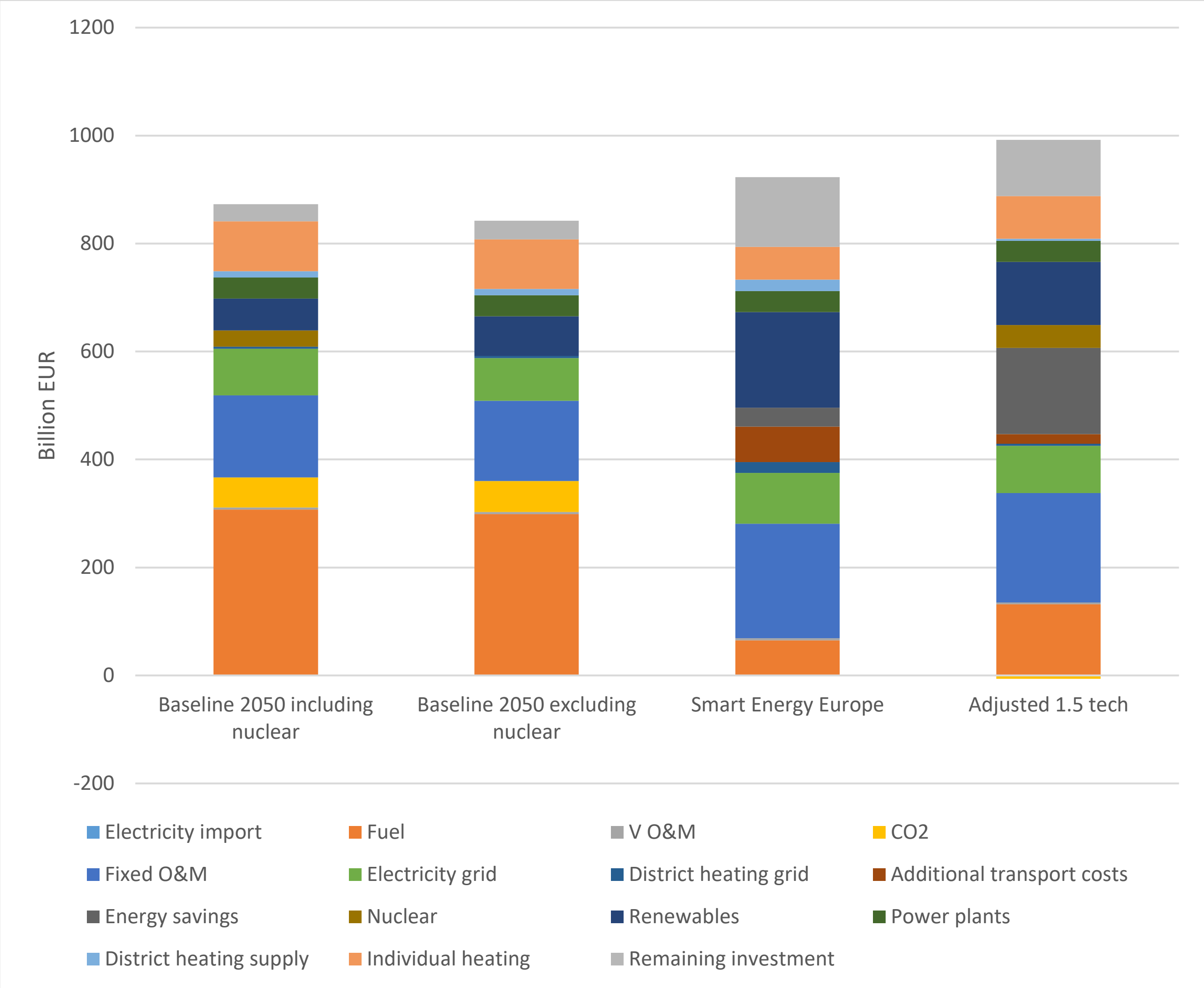
Primary energy consumption



CO2 emissions from the scenarios

Implementing costs

Cost comparison between the baseline and smart energy Europe and the 1.5 tech



Primarily the costs are taken from the RE-INVEST technology catalogue, however some are from Danish Energy Agencies cost catalogue, others from specific research in electrofuels. A full detail of costs can be found below in a number of tables. These tables also specify reference for the cost. A discount rate of 3% is assumed.

Technology	Unit	Cost	Lifetime	F O&M [%]	Note	Reference
Large CHP Units	GWe	1.35	25	3.3	Mix of steam and gas turbines	
Heat storage	TWh	3	20	0.5		
Waste incineration	PWh	201.25	25	2.3		

DH heat pumps	GWe	2.218	25	0.3		
DH boilers	GW th	0.2275	25	3.55		
Large power plants	GWe	1.35	25	3.3		
Hydrostorage	TWh	175	80	1		
Battery	TWh	300	20	0		
Onshore wind	GWe	0.963	27	1.3		
Offshore wind	GWe	1.777	27	1.9		
Solar PV	GWe	0.345	30	2.5		
Hydro power	GWe	2.76	80	1.15		
Geothermal heat	PWh	396.67	30	0.83		
Solar thermal	PWh	325	30	0		
Industrial excess heat	PWh	30	30	1		
Biogas plant	PWh	196	20	15		
Thermal gasification	GW	1.1	20	1.47		
Biogas upgrade	GW	0.25	15	2.5		
Biofuel plant	GW bio	1.45	25	6.2		
Bio jetfuel plant	GW bio	1.776	25	5.1		
Carbon recycling	GT	200	20	4.3		
Methanation	GW	0.2	25	4		
Fuel synthesis	GW	0.3	25	4		
JP synthesis	GW	0.5	25	4		
Electrolyser	GW	0.5	25	5		
Hyrdogen storage	TWh	15.06	48	1.37		Mixture of caverns and tanks
Individual boilers						
Individual biomass boilers	Mio units	5.9	20	7.42		20% in reference 25% in 1.5 tech 100% in smart energy
Individual natural gas boilers	Mio Units	2.7	20	6.74		80% in reference 75% in 1.5 tech

						0% in smart energy
Individual heat pumps	Mio units	5	18	4.78		
Indv. Electric heating	Mio units	2.5	30	0.84		

Additional costs

District heating substations and district heating grid costs

District heating substations cost and grid costs are based on the heat roadmap Europe 4 studies, with an additional 10% costs to reflect the entire European heating system.

This means that DH substations have a cost of:

Technology	Total investment [B€]	Lifetime	Fixed O&M
Susbtations – reference	53.53	25	2.47
Substations – Smart Energy Europe	117.68	25	2.47

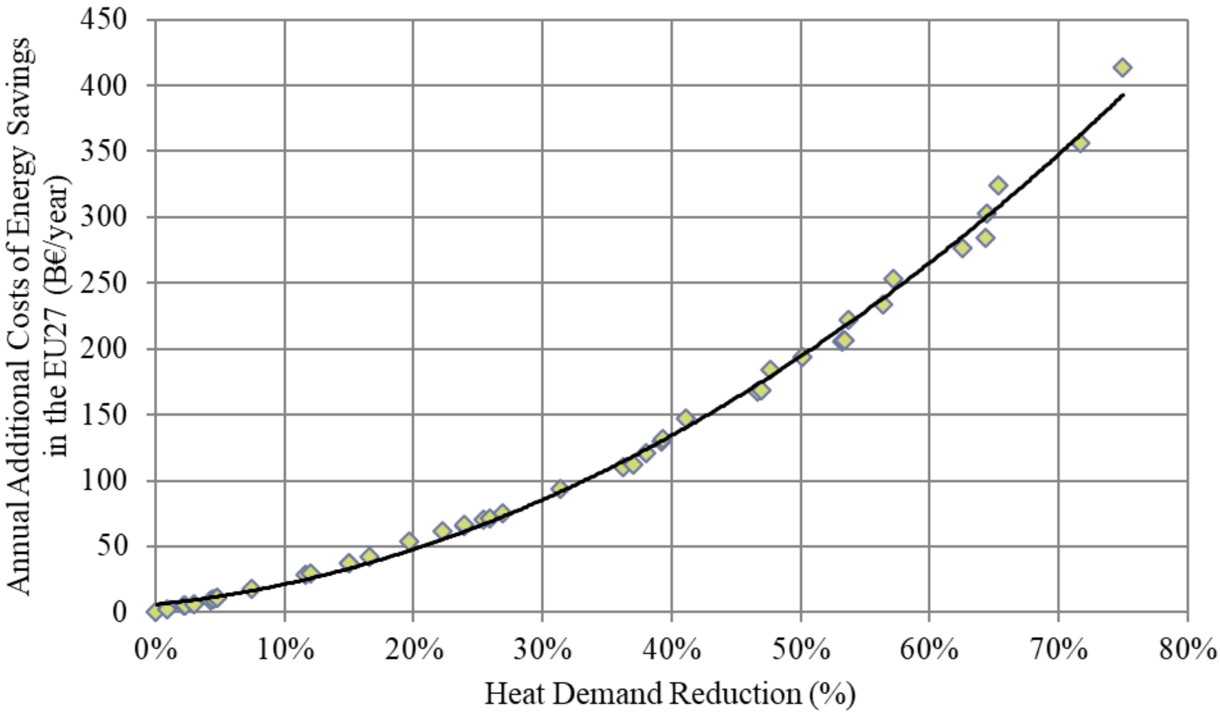
Annual costs for DH grid:

DH grid reference: 3.95 B €

DH grid smart energy Europe: 20.06 B €

Heat savings

The heat savings costs are based on the figure below, coming from the Heat Roadmap Europe 2 studies



In the baseline, it is expected that already 29% heat savings have been achieved. Thus the additional savings in the smart energy Europe and the 1.5 tech is determined as follows:

0%	3.28	PWh
29%	2.33	PWh
36%	2.11	PWh
54%	1.51	PWh

This results in the following additional costs compared to the reference:

Smart Energy Europe: 35 B€ annually

1.5 Tech scenario: 160 B€ annually

Transport costs

The annual transport costs are estimated from sEEnergies research project. Here the reference, smart energy Europe and 1.5 Tech transport have the following costs. The costs include vehicles and infrastructure:

Reference: 1228 B€ annually

Smart Energy Europe: 1294 B€ annually

1.5 Tech: 1246 B€ annually

In the graphs we only illustrate the increase in transport costs compared to the 2050 reference.

Electricity distribution grid

The distribution grid costs are identified by identifying the hourly electricity demand that is assumed distributed to invidiual users. This includes the classical electricity demand, electric vehicle demand and electric heating demand for individual households. The grids lifetime is 50 years and cost on average 3.3 B€/GW.

Reference: 2217 B€ totally

Smart Energy Europe: 2408 B€ totally

1.5 Tech: 2245 B€ totally

Carbon capture and storage

Carbon and capture and storage are divided into two costs. The carbon and capture unit is assumed to cost the same as the carbon recycling unit. Thus 200 GEUR/Gton CO_2 captured annually. The lifetime is 20 years with a fixed O&M of 4.3%. The 1.5 Tech scenario therefore has carbon capture units for a total investment of 74.8 B€.

For storage, it depends on how big the total storage should be.

The assumption here is:

I assume 15 €/tonne

Lifetime: 40 years

2 % O&M

Based on the Danish technology catalogue:

The ZEP report [14] also provides an update on storage costs:

Case			Cost range (€/tonne CO_2 stored)		
			Low	Medium	High
Onshore	Depleted oil and gas fields	Existing well	1	3	7
Onshore	Depleted oil and gas fields	New well	1	4	10
Onshore	Saline aquifer	New well	2	5	12
Offshore	Depleted oil and gas fields	Existing well	2	6	9
Offshore	Depleted oil and gas fields	New well	3	10	14
Offshore	Saline aquifer	New well	6	14	20

The assumption is that the storage should be able to store for the entire lifetime of 40 years. Thus a total of 224 B€ has to be invested in storage.

Other adjustments for costs in 1.5 Tech

Boiler costs equals 75% gas boilers and 25% biomass boilers = 5.9 x 0.25 + 2.7x0.75 = 3.5GEUR/Unit and O&M: 443 x 0.25 + 182 x 0.75 = 220 EUR/unit. The same is used for the reference costs.

Hydrogen boiler cost assumption = upper limit of gas boilers = 4000 €/unit, O&M = 218 €/Unit

Updated electricity storages to fit the operation hours described in the main text.

Changed PP capacity to be able to cover all unbalances left

- New PP capacity 530 GW (previous 266 GW)

Documentation of e-fuel costs

CCU, capture from point soure
Essentially, we are looking at 500 €/tCO2/a in 2050 with a lifetime of 25 years and 5.5% if investment for O&M.

This is based on the assumption point source capture with 8000hours of operation. For biomass plants, if flexible operation is assumed, i.e. ~4000h, then you double the costs.

Cement capture 2050		Large biomass 2050		Direct air	
160	tCO2/hour	173	tCO2/hour	125	tCO2/hour
8000	hours	8000	hours	8000	hours
1280000	tCO2	1384000	tCO2	1000000	tCO2
Cost		Cost		Cost	
1.8	mil €/tCO2/hour	1.6	mil €/tCO2/hour	4	mil €/tCO2/hour
288	mil €/plan	276.8	mil €/plan	500	mil €/plant
225	**€/tCO2**	**200**	€/tCO2	**500**	€/tCO2
O&M fixed		O&M fixed		O&M fixed	
8.64	mil €	8.304		25	
O&M variable		O&M variable		O&M variable	
3.2	mil €	3.46		2.5	
11.84		11.764		27.5	
4.1%		**4.3%**		**5.5%**	

Methanation and DAC should be split, also for EP purposes. For methanation we are looking at 0.2 M€/MW, 25 years lifetime and 4% O&M in 2050.

Liquid fuels:

0.3 M€/MW, 25 years, O&M 4%

For JP synthesis I estimated based on what I found in the literature 0.5 M€/MW, 25 years, 4% O&M.