Uloga dizalica topline velikih snaga u budućim energetskim sustavima

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UNIVERSITY OF ZAGREB
FACULTY OF MECHANICAL ENGINEERING AND NAVAL ARCHITECTURE

Master's Thesis

Dominik Franjo Dominković

Zagreb, 2015.

UNIVERSITY OF ZAGREB
FACULTY OF MECHANICAL ENGINEERING AND NAVAL ARCHITECTURE

The Role of Large Scale Heat Pumps in Future Energy Systems

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Zagreb, 2015

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"A smart man makes a mistake, learns from it and never makes that mistake again. But a wise man finds a smart man and learns from him how to avoid mistake altogether."

Roy H. Williams

I hereby declare that this thesis is entirely the result of my own work except where otherwise indicated. I have fully cited all used sources and I have only used the ones given in the list of references.

Dominik Franjo Dominković

SVEUČILIŠTE U ZAGREBU
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Središnje povjerenstvo za završne i diplomske ispite
Povjerenstvo za diplomske ispite studija strojarstva za smjerove:
procesno-energetski, konstrukcijski, brodostrojarski i inženjersko modeliranje i računalne simulacije

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Opis zadatka:

Worldwide demand for energy is increasing; as a consequence fossil fuel resources are becoming more and more expensive, in the same time making renewable energy resources more competitive. European Union has adopted 20-20-20 targets until 2020, while in the EU's 2030 framework for climate and energy policies continuing progress towards a low-carbon economy is expected. The most important objective by 2030 is to reduce the greenhouse gas emissions by 40% below the 1990 level, while increasing the renewable energy share to at least 27%. Denmark is one of the most developed countries in terms of renewable generation development and their goal is to reach 100% renewable energy system till 2050. In recent papers it was shown that large penetration of electricity produced from wind power plants have started to replace electricity produced from CHP power plants. The consequence is the increase in production of heat in electric boilers and larger amount of CO_2 released in the atmosphere. In order to tackle this problem, the large-scale heat pumps need to be integrated further into the grid in order to use excess electricity production of wind turbines, instead of electric boilers, while still allowing normal generation process of CHP power plants. Main tasks in this thesis will be:

a) To make an introduction by describing situation nowadays in terms of general overview of the current energy system, role of heat pumps nowadays with a special emphasize on Danish energy system. The latest literature findings shall be stated.

b) Analysis and comparison of the EnergyPlan model tool and MARKAL/TIMES model tool shall be done. Analysis of the pros and cons of the chosen energy planning models. MARKAL/TIMES modelling tool shall be analyzed by means of proper literature review, while EnergyPlan, besides the literature review, shall be used to develop different scenarios with thorough analysis of them.

c) Development of different scenarios with large-scale heat pumps and heat storage. One scenario has a target of minimum 50% wind energy share by 2020. Several other scenarios with different wind energy penetration shall be developed. Thorough analysis and comparison of scenarios shall be done. Furthermore, sensitivity analyses need to be carried out in terms of changing fuel prices, discount rates and technology costs.

Necessary data and literature could be obtained from the supervisors. In the thesis, it is also necessary to state used literature and received help.

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13. studenog 2014.	15. siječnja 2015.	21., 22. i 23. siječnja 2015.

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Predsjednik Povjerenstva:

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NOMENCLATURE

Symbol	Unit	Description
E_D	%	Price elasticity of the demand
Q	MWh	Quantity at equilibrium point
P	€/MWh	Price at equilibrium point
ΔP	€/MWh	Difference between the price increased for one percent and the equilibrium price
ΔQ	MWh	Difference between new quantity at higher price and the quantity at equilibrium price
$P_{1\%,i}$	€/MWh	Equilibrium price in each hour i, increased by 1%
P_i	€/MWh	Equilibrium price set in each hour
Q_0	MWh	First lower than equilibrium quantity for which the price is known
Q_1	MWh	First higher than equilibrium
P_{Q0}	€/MWh	Price that corresponds to Q_0
P_{Q1}	€/MWh	Price that corresponds to Q_1
Inv_s	€/kW$_h$	Investment per capacity
Inv	€	Total investment
P_h	kW	Heat capacity of specific technology
E_P	(kWh/kW)/year	Amount of produced heating energy per capacity per year
H	h/year	The number of equivalent full-load running hours
i	%	Interest rate
n	years	Technical lifetime
PMT	€/kW	Payment amount for a loan per capacity
$O\&M_F$	€/kW	Fixed operating and maintenance cost
$O\&M_V$	€/kWh	Variable operating and maintenance cost
F	€/kWh	Fuel (electricity) cost
PMT_E	€/kW	Payment amount for a loan per capacity of the equity
PMT_D	€/kW	Payment amount for a loan per capacity of the debt
$R_{M,PMT}$	€/kW	Payment amount for a loan per capacity of the major revision
COP	kWh$_t$/kWh$_e$	Coefficient of performance

Energy units

PJ	Petajoule	Energy
GJ	Gigajoule	Energy
TWh	Terawatt hour	Energy

MWh	Megawatt hour	Energy
GW	Gigawatt	Capacity
MW	Megawatt	Capacity
MW_e	Megawatt	Electrical capacity
MW_t	Megawatt	Thermal capacity
Mt	Mega ton	Mass
kg	kilogram	Mass

Abbreviations

BAU	Business as Usual
CEEP	Critical Excess in Electricity Production
RES	Renewable Energy Sources
DH	District heating
HP	Heat Pump
CHP	Combined Heat and Power Plant
ES	External Source
FG	Flue Gases
CS	Cold Storage
LCOH	Levelized Cost of Heating Energy
EU	European Union
IEA	International Energy Agency

Economy

EUR	Euro
€	Euro
DKK	Danish Krone
O&M	Operating and maintenance

ABSTRACT

In this thesis, several tasks were performed in order to evaluate the role of large scale heat pumps in the near term future energy systems.

Firstly, the analysis of the Danish current energy system was carried out with the special emphasize on the electricity and district heating sector. Moreover, a technical concept of the large scale heat pumps was provided.

Secondly, the analysis of EnergyPLAN and TIMES (MARKAL) modelling tools was performed in order to detect pros and cons of each of the models. EnergyPLAN was chosen as the favourable modelling tool for the assessment of the energy systems with high share of intermittent energy sources.

Thirdly, for the purpose of economic evaluation of investments in electric boilers and large scale heat pumps, a levelized cost of heating energy (LCOH) was calculated.

Furthermore, price elasticity of electricity demand on Nordpool's El-spot market was calculated in order to assess possible shift in demand due to possible increased usage of electricity by heat pumps.

Lastly, several different scenarios in EnergyPLAN were developed with different wind penetration levels, large scale heat pumps capacity and pit thermal energy storage (PTES). It was shown that for each wind penetration level, a certain amount of large scale heat pumps is optimal, which reduces the total system costs, CO_2 emissions and critical excess in electricity production (CEEP). Moreover, adding large scale seasonal thermal energy storage to the system with implemented optimal level of heat pumps capacity will decrease total system costs even more.

Key words: Danish energy system, district heat, wind energy, heat pump, EnergyPLAN, TIMES, MARKAL, levelized cost of heating energy, Nordpool, El-spot, pit thermal energy storage, seasonal thermal energy storage, CEEP

SAŽETAK

Ovaj diplomski rad predstavlja procjenu uloge dizalica topline velikih instaliranih snaga u budućem energetskom sustavu.

U uvodu je opisana analiza trenutnog danskog energetskog sustava s posebnim naglaskom na sektore električne te toplinske energije. Također je objašnjen tehnološki koncept dizalica topline velikih instaliranih snaga.

Poslije uvoda slijedi analiza dvaju modela koji se koriste za modeliranje energetskih sustava, EnergyPLAN-a i TIMES-a (MARKAL-a), kako bi se ukazalo na prednosti i nedostatke oba modela. Glavni zaključak analize je da EnergyPLAN-u ima prednost prilikom modeliranja energetskih sustava sa visokim udjelom intermitentnih izvora energije.

U sljedećem poglavlju je prikazana analiza investicije u električni kotao te dizalice topline velike instalirane snage koristeći metodu usrednjenih troškova toplinske energije (eng. levelized cost of heating energy). Također je analizirana i elastičnost potražnje za električnom energijom na Nordpool burzi električne energije. Analizom se pokušalo utvrditi hoće li povećana potražnja za električnom energijom uslijed pogona dizalica topline dovesti do porasta cijena električne energije.

Naposljetku, nekoliko različitih scenarija razvijeno je u EnergyPLAN-u s različitim instaliranim snagama vjetroelektrana, optimalnim kapacitetima dizalica topline velikih instaliranih snaga te sezonskim spremnicima topline u obliku jame (eng. pit thermal energy storage). U radu je pokazano da za svaku instaliranu snagu vjetroelektrana u energetskom sustavu postoji određena optimalna snaga dizalica topline, koja će smanjiti ukupne troškove energetskog sustava, CO_2 emisija i kritičnog viška u proizvodnji električne energije (CEEP). Dodatne uštede u troškovima energetskog sustava ostvarive su dodavanjem velikih sezonskih spremnika topline u sustav s već optimalno instaliranom snagom dizalica topline.

Ključne riječi: danski energetski sustav, područno grijanje, dizalica topline, EnergyPLAN, TIMES, MARKAL, usrednjeni troškovi toplinske energije, Nordpool, El-spot, sezonski spremnik topline

PROŠIRENI SAŽETAK (EXTENDED SUMMARY IN CROATIAN)

Naglim industrijskim te potom i tehnološkim razvojem, čovječanstvo je počelo trošiti resurse brzinom većom nego li ikada prije u poznatoj povijesti. Naglim razvojem i nedovoljnom brigom za uvjete koje ćemo ostaviti budućim generacijama, postali smo veliki teret za okoliš. U 20. stoljeću Europa je bila poprište brojnih ratova, gdje je dostupnost energije postala jedan od najbitnijih strateških elemenata. Tijekom 80-tih godina prošlog stoljeća dvije naftne krize, kao posljedica ratova na Bliskom istoku, su uzrokovale velike šokove na mnogim tržištima u Europi pa tako i u Danskoj. Osim brige za okoliš i smanjenje štetnih emisija stakleničkih plinova, sigurnost opskrbe energijom postala je jednako bitan element. Kao odgovor na naftne krize, kada su bili gotovo 100% zavisni o uvozu fosilnih goriva, Danska je odlučila krenuti u razvoj obnovljivih izvora energije. Ubrzo je i Europska komisija donijela prve konkretne prijedloge u tom smjeru, a za dodatan razvoj svijesti o važnosti obnovljivih izvora energije zaslužan je i protokol u Kyotu, kojim se reguliraju emisije stakleničkih plinova.

Trenutno je na razini Europske unije važeća strategija o postizanju 20-20-20 ciljeva do 2020. godine. Danska je otišla i korak dalje, pa je 2012. godine gotovo jednoglasno u parlamentu izglasala odluku kojom energetski sektor postaje 100% obnovljiv do 2050. godine. Kako bi se ostvario taj cilj, u prvom koraku je potrebno do 2020. godine proizvoditi 50% električne energije iz vjetroelektrana.

Spomenute količine vjetroenergije postavljaju iznimne zahtjeve na planiranje energetskog sustava, kako bi opskrba potrošača bila konzistentna i kvalitetna. Vjetroelektrane su intermitentni izvor energije što znači da nemaju konstantnu proizvodnju energije, već se ona mijenja iz trenutka u trenutak. Smatra se kako 20% do 25% električne energije proizvedene iz vjetra ne predstavlja problem u ostvarenju stabilnosti elektrenergetskog sustava, dok se u većim postocima počinju pojavljivati sati sa većom proizvodnjom električne energije od potražnje što dovodi u opasnost stabilnost sustava. Kako bi regulirala spomenute probleme, Danska je krenula putem integracije cijelog energetskog sektora, prvenstveno toplinskog, električnog i plinskog sektora. Glavna ideja ovog pristupa je korištenje jeftinijeg skladištenja toplinske energije i još jeftinijeg skladištenja tekućih goriva, umjesto skladištenja električne energije kako bi se ostvario ekonomski održiv energetski sustav.

Tehnologije koje povezuju elektroenergetski te toplinski sustav su dizalice topline te električni kotlovi jer troše jedan oblik energije kako bi proizveli drugi. U trenucima kritičnog viška u proizvodnji električne energije, ona se može koristiti u navedenim tehnologijama kako bi proizvodile toplinu te time utjecale na stabilnost sustava.

U svrhu planiranja budućeg energetskog sustava, ovaj se rad bavi procjenom uloge dizalica topline velikih instaliranih snaga u bliskoj budućnosti te analizom promjena u energetskom sustavu do kojih će dovesti integracija dizalica topline velikih instaliranih snaga.

Četiri su glavna koncepta koja su trenutno detektirana kao moguća u budućoj ulozi dizalica topline velikih instaliranih snaga.

Prvi se zasniva na korištenju vanjskog toplinskog izvora poput povratnog voda iz distribucijske mreže područnog grijanja, zemlje (geotermalni), morske vode, jezera ili solarnog sezonskog spremnika topline. Cilj je ostvariti što veću temperaturu toplinskog izvora kako bi COP (koeficijent učinka) bio što veći. Nakon što se toplina podigne na višu temperaturu, toplinska energije se može uskladištiti u spremniku ili izravno slati u distribucijsku mrežu područnog grijanja.

Drugi koncept se zasniva na istom principu kao i prethodni, samo što je integriran sa kogeneracijskim postrojenjem.

Preostala dva koncepta iskorištavaju toplinu dimnih plinova kao toplinski izvor, podižući time ukupnu efikasnost sustava. Razlika između potonjih koncepata je korištenje tzv. kocepta hladnog spremnika, koji omogućava samostalan pogon i dizalice topline i kogeneracije.
Prva dva koncepta su spremna za implementaciju, dok su druga dva još uvijek u demonstracijskoj fazi. Zadnji kocept, koji uključuje hladni spremnik, ima najveći ekonomski potencijal, dok je drugi koncept trenutno tehnički najpovoljniji koncept za integraciju veće količine OIE.

Usporedbom TIMES-a i EnergyPLANA, dvama popularnim alatima za modeliranje energetskih sustava, detektirane su prednosti i mane svakog od njih te je ocijenjena pogodnost navedenih modela za analizu sustava sa velikim udjelom intermitentnih izvora energije.

TIMES je optimizacijski generator modela koji koristi princip ponude i potražnje za različitim oblicima energije, od primarne energije do samih tehničkih sustava, kako bi bilo moguće detektirati optimalne investicijske odluke. Rezultati modela su varijable energetskih tokova te investicije u različita postrojenja.

EnergyPLAN je simulacijski alat koji se najčešće koristi za izradu scenarija sa visokim udjelom obnovljivih izvora energije. Kao ulazne varijable modelu su potrebni podaci o kapacitetima različitih postrojenja, udjelima goriva u različitim postrojenjima, podaci o individualno instaliranim uređajima za grijanje, potražnje za svim oblicima energije, distribucijske krivulje proizvodnje iz različitih izvora, itd. Rezultat EnergyPLAN-a je proizvodnja različitih oblika energije iz pojedinih postrojenja na satnoj razini. Također, ukupni trošak sustava, emisije stakleničkih plinova i potrošnja goriva sastavni su dio rezultata. Glavne prednosti i mane su pregledno razvrstane u sljedećoj tablici:

Tablica proširenog sažetka 1. Usporedba dvaju modela

TIMES	**EnergyPLAN**
Nedostatak povratnih veza	Mnoštvo povratnih veza
Nedostatak dinamike sustava	Bogata dinamika sustava
Pretpostavljena linearnost u sustavu	Nelinearni sustav modeliran
Generator modela – korisnik može izraditi model postavljajući granice sustava po želji, ali je potrebno puno vremena za izučavanje alata kao i za izradu modela ispočetka	Gotov model – jednostavno i malo vremena je potrebno za usavršavanje, ali ne može biti modificiran od strane korisnika
Bogat tehnologijama	Bogat tehnologijama
Nije modeliran sustav sa 100% OIE	Modeliran sustav sa 100% OIE
Optimira investicije, ali ne može optimirati tehnički sustav	Optimira tehnički sustav, ali investicije mogu biti optimirane samo ručnim iterativnim postupkom
Moguće uzeti u obzir starenje tehnologija	Nije moguće uzeti u obzir starenje tehnologija
Moguće različite diskontne stope za različite tehnologije	Različite diskontne stope za različite tehnologije nisu moguće

Ne može obuhvatiti vrijeme trajanja izgradnje postrojenja nakon investicije	Ne može obuhvatiti vrijeme trajanja izgradnje postrojenja nakon investicije

EnergyPLAN je odabran za korištenje prilikom modeliranja scenarija u ovom radu jer ima bolje karakteristike u pogledu modeliranja energetskih sustava sa visokim udjelom obnovljivih izvora energije poput vjetra.

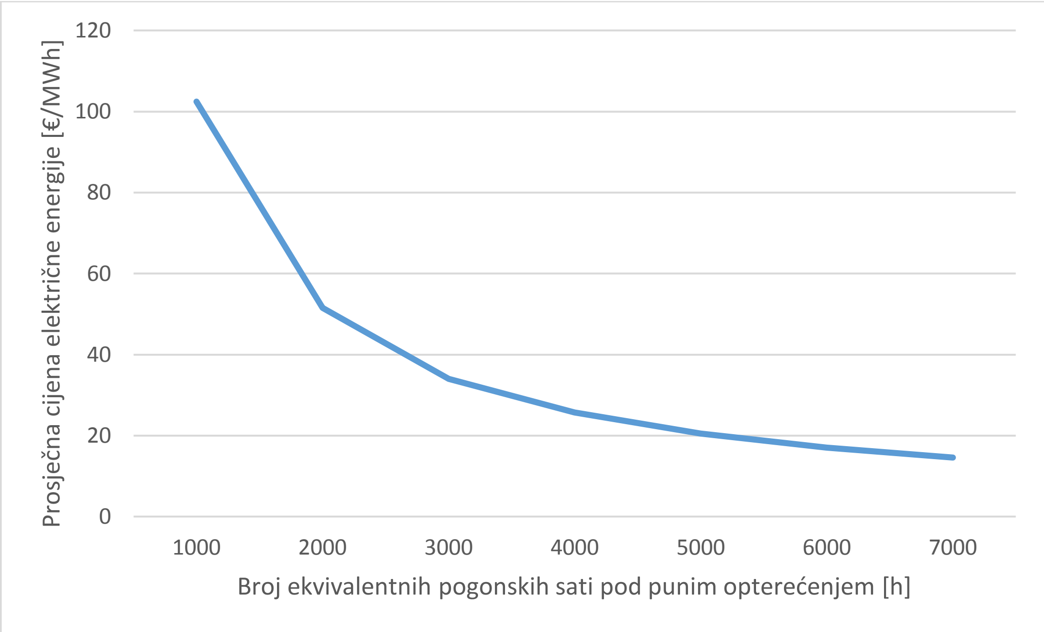
U sljedećem koraku izračunata je elastičnost potražnje za električnom energijom. Elastičnost potražnje za električnom energijom pokazuje kolika će se postotna promjena u potražnji za električnom energijom dogoditi, uslijed povećanja cijene za 1%. Elastičnost potražnje je obično negativna, pošto se uslijed povećanja cijena potražnja smanjuje. Na Nordpool El-spot burzi električne energije, ponude i potražnje za električnom energijom se predaju za svaki sat te se time krivulja ponude i potražnje konstruira za svaki sat. Podaci o ponudama i potražnjama su uz dopuštenje Nordpool-a skinuti sa servera te su izvršene kalkulacije korištenjem Matlab-a. U sljedećoj tablici mogu se vidjeti dobivene prosječne godišnje elastičnosti:

Tablica proširenog sažetka 2. Prosječne godišnje elastičnosti potražnje za električnom energijom

Godina	Prosječna elastičnost [%]
2011	0,059
2012	0,029
2013	0,028
2014	0,01

Iz rezultata se može iščitati da je potražnja za električnom energijom gotovo fiksna, tj. da se za povećanje cijene od 1% potražnja u prosjeku smanji od 0,059% do 0,01%, ovisno o promatranoj godini. Također, vidljiva je tendencija smanjenja prosječne elastičnosti na godišnjoj razini u posljednje četiri godine. Može se pritom zaključiti da se cijene električne energije neće bitnije mijenjati uslijed možebitne povećane potražnje, uslijed povećane penetracije dizalica topline velikih instaliranih snaga.

U sljedećem koraku izračunati su usrednjeni troškovi proizvodnje toplinske energije (eng. levelized cost of heating energy) dvaju različitih tehnologija, električnih kotlova te dizalica topline velikih instaliranih snaga. Pokazano je da kapitalno intenzivna investicija u dizalice topline postaje isplativija od električnog kotla nakon određenog broja radnih sati, ovisno o prosječnim cijenama električne energije. Na slici proširenog sažetka 1. može se vidjeti krivulja presjecišta dvaju tehnologija nakon koje dizalica topline postaje ekonomski isplativija od električnog kotla. Graf se treba iščitati tako da se za odabranu prosječnu (godišnju) cijenu električne energije pronađe ekvivalentan broj pogonskih sati pod punim opterećenjem nakon kojeg će dizalice topline biti isplativija investicija od investicije u električni kotao. Odaberemo li primjerice prosječnu godišnju električnu cijenu od 34 €/MWh, ekvivalentan broj pogonskih sati pod punim opterećenjem iznosi 3.000, nakon kojeg dizalica topline postaje ekonomski isplativija investicija.



Slika proširenog sažetka 1. Presjecišne točke dvaju tehnologija nakon koje dizalica topline postaje isplativija od električnog kotla.

Treba uzeti u obzir da su prosječne godišnje cijene električne energije u zadnjih 5 godina između 28 i 50 €/MWh.

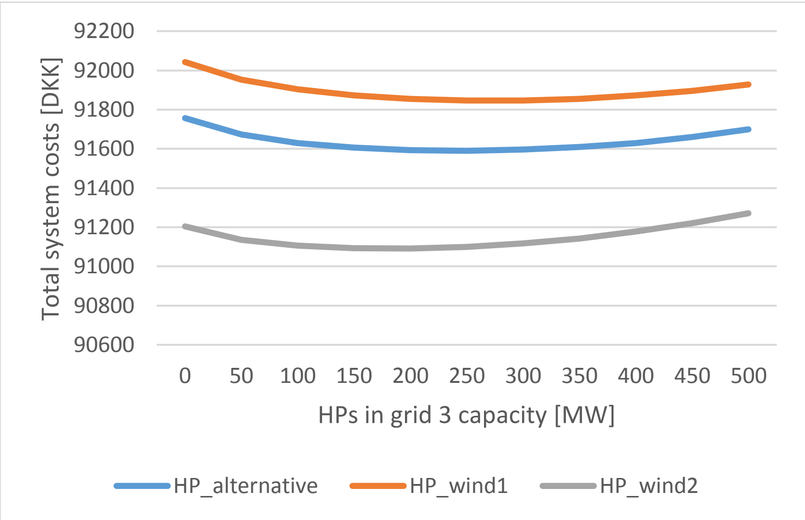
Naposljetku su napravljeni referentni model za 2013. godinu te pet alternativnih za 2020. godinu, kako bi se mogla detektirati uloga dizalica topline velikih instaliranih snaga u budućem energetskom sustavu Danske. U svim alternativnim scenarijim, snaga instaliranih kogeneracijskih postrojenja nije mijenjana i iznosi 7.830 MW_e. Pregled bitnih karakteristika za scenarije razvijene za 2020. godinu nalazi se u narednoj tablici:

Tablica proširenog sažetka 2. Glavne karakteristike različitih scenarija

2020 scenarios				
BAU	*HP_alternative*	*HP_wind1*	*HP_wind2*	*HP_storage*
Implementirana odluka da se minimalno 50% električne energije mora generirati iz vjetra	BAU + optimalni kapacitet dizalica topline velikih instaliranih snaga	HP_alternative + 4500 MW kopnenih vjetroelektrana	HP_alternative + 3700 MW kopnenih vjetroelektrana	HP_alternative + 600.000 m^3 sezonskog toplinskog spremnika u obliku jame

Ručni iterativni postupak je proveden kako bi se detektirali optimalni kapaciteti dizalica topline u scenarijima. U scenarijima *HP_alternative*, *HP_wind1* i *HP_storage* optimalni kapacitet dizalica topline ukupno iznosi 650 MW_e, dok u scenariju *HP_wind2* optimalni kapacitet iznosi 600 MW_e.

Prilikom iteracija zaključeno je kako za svaki kapacitet vjetroelektrana postoji optimalan kapacitet dizalica topline, za koji će ukupni trošak sustava biti minimalan. Prethodni zaključak može se promotriti na sljedećoj slici:



Slika proširenog sažetka 2. Optimalan kapacitet dizalica topline u *grupi 3* područnog grijanja (uz optimalan kapacitet od 400 MW_e u *grupi 2*)

Vidljivo je da je za različite kapacitete instaliranih vjetroelektrana, razina ukupnih troškova sustava različita, no krivulja dizalice topline uvijek ima oblik parabole sa jasnim minimum u jednoj točki.

Također je tijekom iteriranja zapaženo i kontinuirano opadanje emisija CO_2 te kritičnog viška proizvodnje električne enrgije, prilikom povećanjem instaliranog kapaciteta dizalica topline velikih instaliranih snaga.

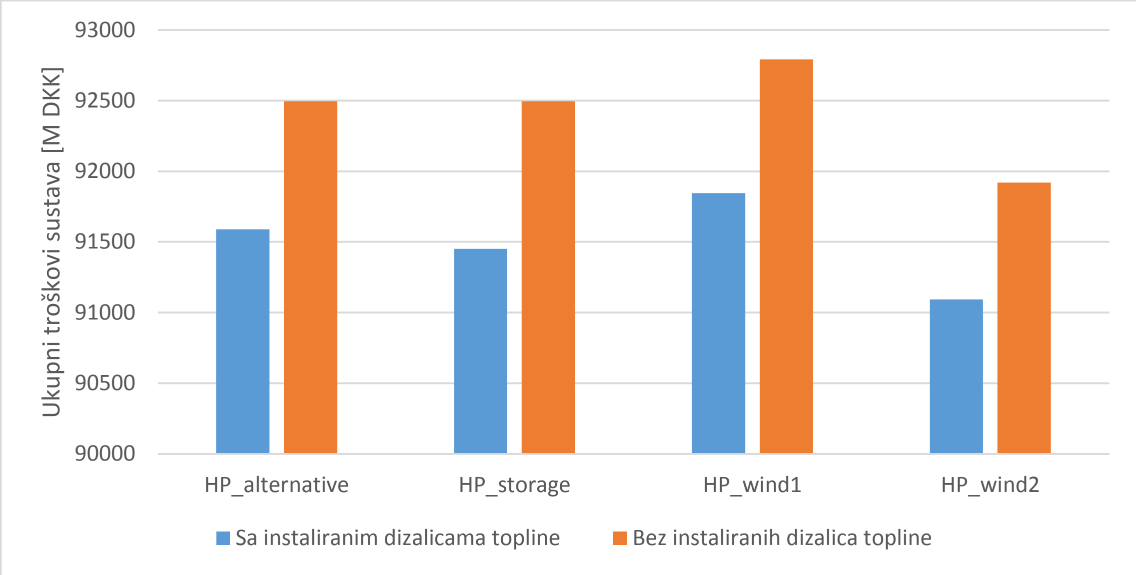
U sljedećoj tablici može se vidjeti smanjenje emisije CO_2 i kritičnog viška u proizvodnji električne energije (CEEP) uslijed instaliranog optimalnog kapaciteta dizalica topline velikih instaliranih snaga:

Tablica proširenog sažetka 3. Smanjenje emisije CO_2 te kritičnog viška u proizvodnji električne energije uslijed instalacije optimalnog kapaciteta dizalica topline te sezonskog toplinskog spremnika

	HP_alternative		***HP_wind1***		***HP_wind2***		***HP_storage***	
	CO_2 [Mt]	CEEP [TWh/year]	CO_2 [Mt]	CEEP [TWh/year]	CO_2 [Mt]	CEEP [TWh/year]	CO_2 [Mt]	CEEP [TWh/year]
Dizalice topline instalirane	35,34	3,52	35,38	3,97	35,35	2,73	35,15	3,45
Bez instaliranih dizalica topline	36,85	4,75	36,91	5,27	36,74	3,77	36,85	4,75
Smanjenje [%]	4,3%	34,9%	4,3%	32,7%	3,9%	38,1%	4,8%	37,7%

Najveće smanjenje CO_2 emisija od 4,8% ostvareno je u *HP_storage* scenariju. Kritični višak u proizvodnji električne energije je smanjen značajno, od 32,7% u *HP_wind1* scenariju do 38,1% u *HP_wind2* scenariju.

Osim smanjenja emisija te kritičnog viška u proizvodnji električne energije, pokazano je već da instaliranje dizalica topline donosi i smanjenje ukupnih troškova sustava. To se smanjenje može vidjeti na sljedećoj slici:



Slika proširenog sažetka 3. Smanjenje ukupnog troška sustava nakon instalacije optimalnog kapaciteta dizalica topline velikih instaliranih snaga.

Smanjenje ukupnih troškova sustava u različitim scenarijima nalazi se u rasponu od 0,9% do 1,14%, pri čemu je najveće smanjenje ostvareno u *HP_storage* scenariju. U apsolutnom iznosu ta ušteda iznosi 1.046 M DKK ili 140,4 milijuna eura.

Iznesenim rezultatima pokazano je kako nema razloga za odgodu implementacije dizalica topline velikih instaliranih snaga u danskom energetskom sustavu. Pokazano je naime da instalacija optimalnog kapaciteta dizalica topline donosi uštede u ukupnim troškovima sustava do 1,14%, povećava stabilnost sustava smanjujući kritični višak u proizvodnji električne energije do 38,1% te istodobno smanjuje CO_2 emisije do 4,8%. Također, niti jedan negativan utjecaj implementacije dizalica topline na sustav nije pronađen. Imajući na umu da je optimalni kapacitet dizalica topline za 2020. godinu, koji ovisno o scenariju iznosi od 600 do 650 MW_e, prilično velik, te da je trenutno instaliran beznačajan kapacitet dizalica topline, potrebno je što prije krenuti ka implementaciji dizalica topline velikih instaliranih snaga u energetski sustav, kako bi se ostvarile navedene višestruke koristi.

1. INTRODUCTION

1.1. Denmark

Denmark is located in Northern Europe, bordered to the northwest by Sweden, to the north by Norway and to the south by Germany. Its area covers 43,094 km^2 and has a population of 5.65 million [1]. The Kingdom of Denmark also has two autonomous countries, Greenland and the Faroe Islands. Danish archipelago consists of 443 named islands, out of total of 1,419 islands larger than 100 m^2 [2]. Main parts of Denmark are peninsula Jutland and large islands: Zealand and Funen. Copenhagen, the capital of Denmark, is located on Zealand. Zealand itself has nearly 2.5 million inhabitants, about 45% of the total population.

Figure 1. Three main parts of Denmark

Kingdom of Denmark unified during the 10th century and today Denmark is a unitary parliamentary constitutional monarchy. Although without a real political power, current monarch is Margarethe II, while Prime Minister is Helle Thorning-Schmidt. Official speaking language is Danish, and the official currency is Danish krone (DKK).

Administratively, Denmark is divided into five regions, while these regions are further divided into 98 municipalities. Before 2007, Denmark had 16 counties subdivided into 270 municipalities. Social services, regional development and the national health service are the most important areas of responsibility of the regions. Tax levies, including energy taxes, are entirely under the control of the government.

Denmark is a well-developed country, ranked 10th in 2013, with an index of 0.9, according to Human Development Index (HDI) [3]. According to Transparency International, Denmark is ranked first in corruption perceptions index [4]. Finally, with the nominal GDP per capita of 61,884 $ (2014 estimation) [5] Denmark is ranked 6th in the world.

As it can be seen from all of these sources, Denmark is one of the most developed countries in the world with beneficiary life conditions. It has been an EU member since the 1st of January 1973. As a part of their economic development, energy policy had an important role since the first (1973) and the second world oil crisis (1979). Moreover, Denmark is one of the leading world countries in environmental protection. Since 1971 they have a Ministry of Environment and in 1973 they implemented environmental law which was the first of its kind in the world [6]. Moreover, in March 2012 a new Energy Agreement was reached in Denmark, which brings Denmark to a pathway of 100% renewable energy system by 2050. Part of the agreement is also a 50% of electricity generated by wind in 2020.

1.2. Danish energy system

1.2.1. Primary and final energy production and consumption

Danish Energy Agency (Dan. *Energistyrelsen*) publishes every year energy statistics for the previous year as well as the historical development of technologies and fuels. In the time of writing this thesis, the last available publication is Energy Statistics 2012 [7], published in February 2014. All the exact figures about the consumption of certain fuels or technology penetrations in this outlook will be extracted from that publication, unless otherwise is stated.

In the Figure 1., the development of the primary energy consumption for the period 1990-2012 can be seen. In the 2012, primary energy consumption was lower than in 1990.

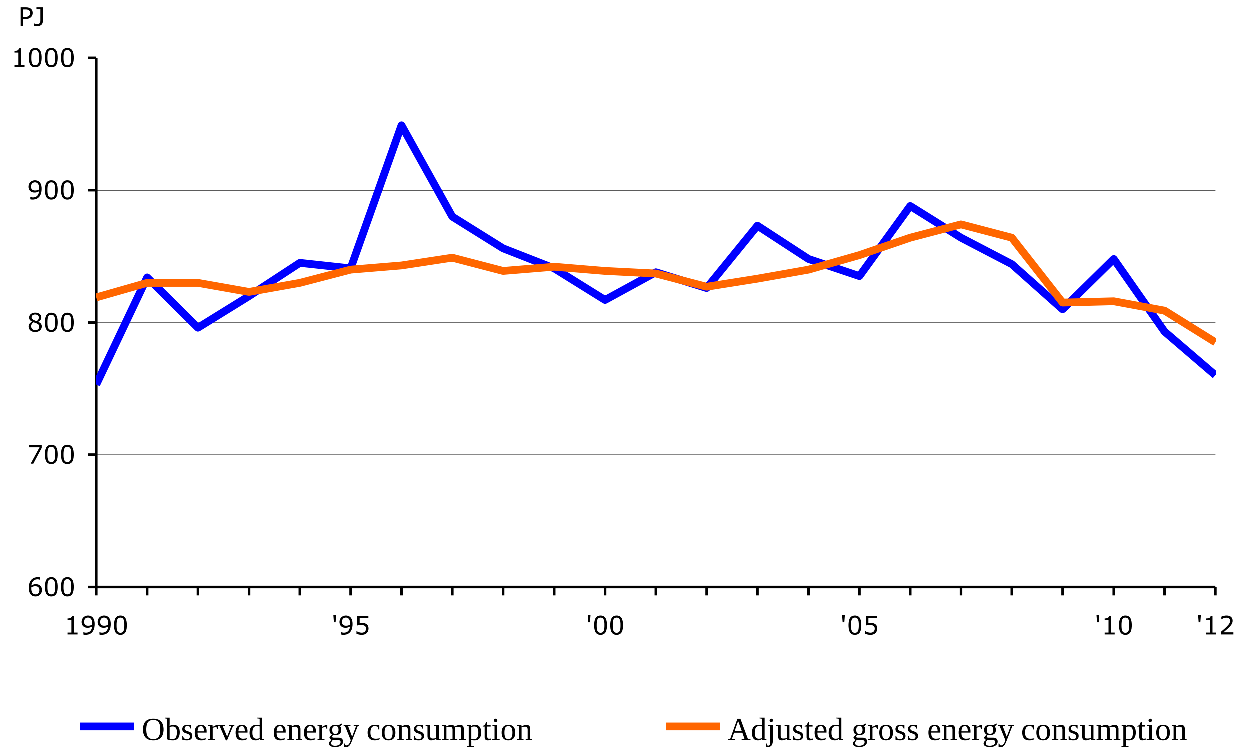


Figure 2. Observed and adjusted primary energy consumption 1990-2012 [7]

Adjusted gross (with included losses of transmission and distribution and self-consumption of energy producers) primary energy consumption in the Figure 2. is derived by adjusting primary (on the other hand, observed means unadjasted) energy consumption in a given year for climate variations to a normal weather year and to the fuel consumption linked to foreign trade in electricity.

After the oil crisis during the 1970s, Denmark decided to become self-sufficient in order to be less dependent on the future shortages in energy supply. Today, Denmark has almost 150% of self-sufficiency when talking about the oil. Moreover, in total primary energy self-sufficiency, Denmark was slightly above the 100% in 2012. Thus, Denmark was self-sufficient in terms of primary energy production. However, it is expected that in the future years, following the curve pattern that can be seen in Figure 3., degree of self-sufficiency will be less than 100%.

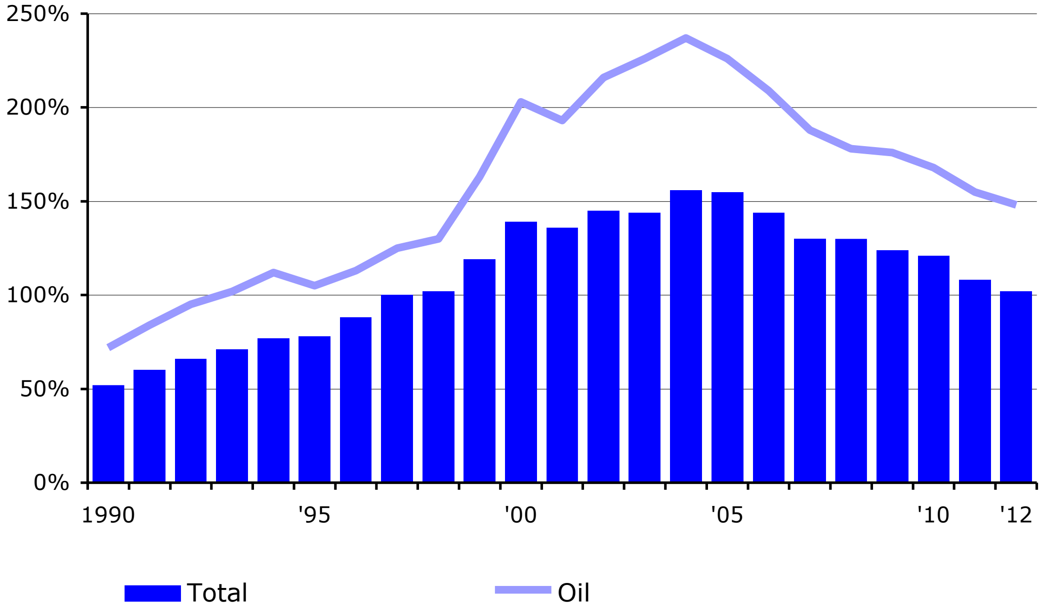


Figure 3 . Degree of self-sufficiency [7]

The highest degree of self-sufficiency Denmark had back in 2004, amounting to 156%. As it can be seen from the Figure 3., Denmark is a net exporter of the oil.

Primary energy production in 2012 was 801 PJ. Comparing to 2011, the primary energy production fell for 7.9%. Danish Energy Agency considers all the renewable energy sources as a single one in the primary energy production outlook. Thus, primary energy production consists of crude oil, natural gas and the renewable energy, including waste.

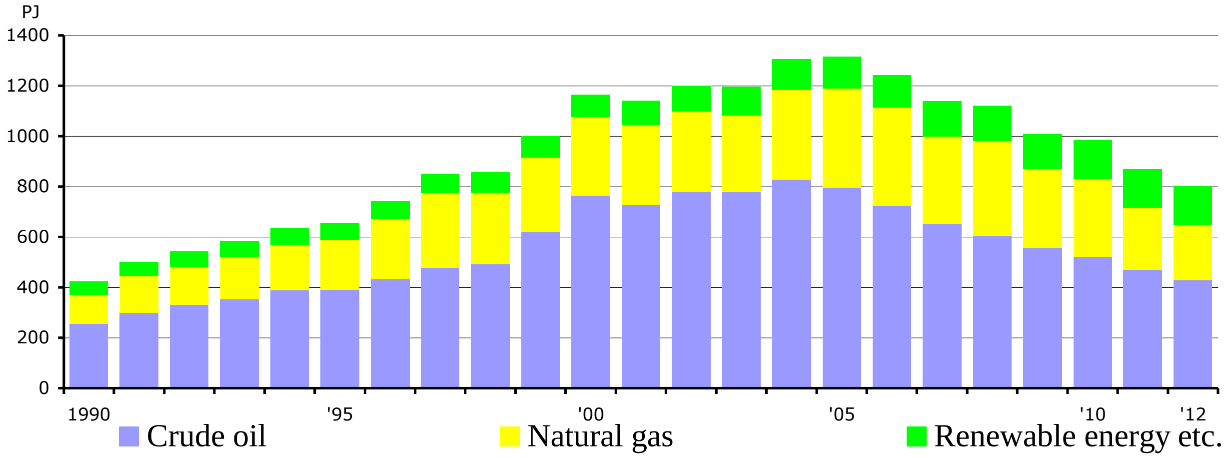


Figure 4 . Primary energy production [7]

Comparing to 2011, crude oil production fell by 8.8%, natural gas by 11.9%, while in the same time renewable energy production rose by 1.3%.

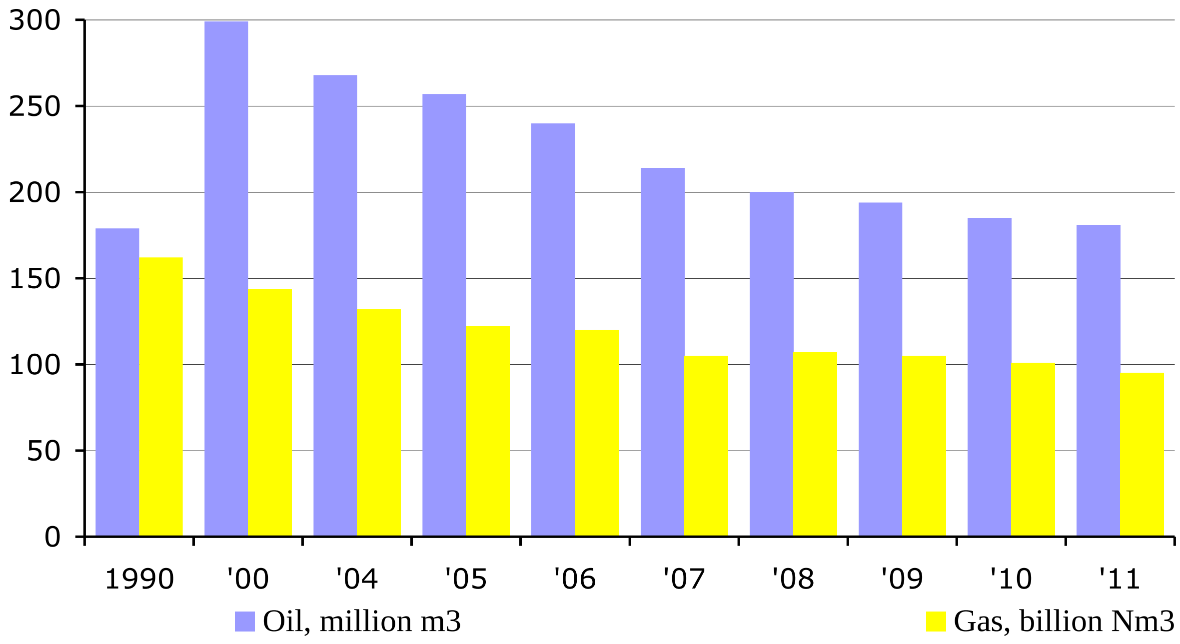


Figure 5 . Oil and gas reserves [7]

At the end of 2011, oil and gas reserves in Denmark were sufficient for the 15 years of gas production and the 14 years of oil production for the 2011 consumption level. In absolute terms, the sum of reserves and contingent resources were 181 million m^3 of oil and 95 billion Nm^3 of gas [7].

Talking about renewable energy production, a continual increase can be seen from 1990-2010, while in the last three years renewable energy production is at about the same level, i.e. in the year 2012 it amounted to 137.7 PJ. Average yearly rise of renewable energy production for period 1990-2012 equals 9.14%. Wind power generation in 2012 was 37 PJ, a rise from 35.1 PJ in 2011. Wood holds the largest share in renewable energy production, amounting to 43.9 PJ in 2012. Other significant renewable energy sources are renewable waste, with the production of 20.6 PJ, and straw with the production of 17.5 PJ. These shares can be seen in the Figure 6.

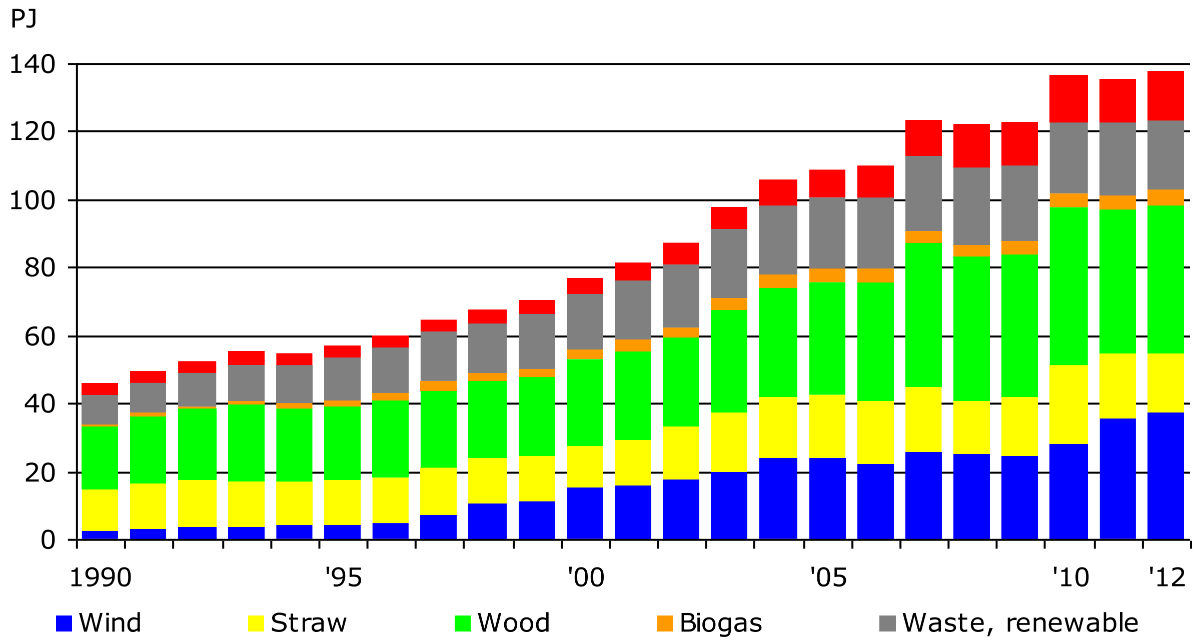


Figure 6 . Production of renewable energy by energy product [7]

According to Eurostat, share of renewables in gross final energy consumption in 2012 in Denmark was 30% [8]. In the last ten years, share of the renewable energy in gross final energy consumption more than doubled, from 14.5% in 2003 to 30% in 2012.

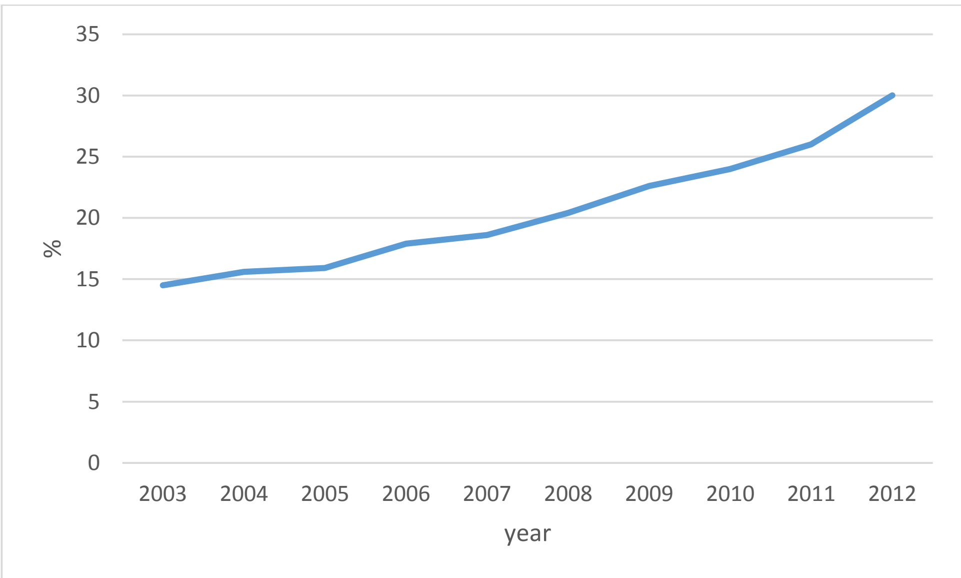


Figure 7. Share of renewables in gross final energy consumption [8]

Gross primary energy consumption by use gives an overview of energy consumption in different sectors. Danish energy agency divides overall consumption to six different sectors: households, commercial and public services, agriculture and industry, transport, non-energy use and energy sector.

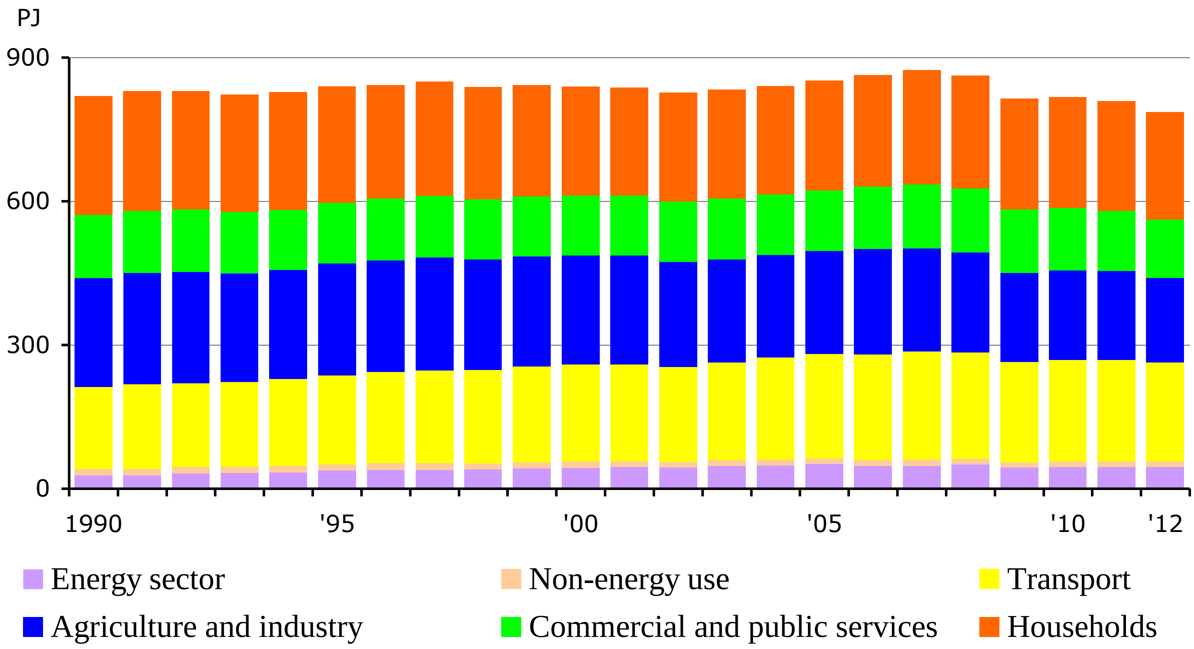


Figure 8 . Gross primary energy consumption by use [7]

Although the total gross final energy consumption differs only slightly in different years from 1990-2012, differences in sectors are larger. Comparing to 1990 level of consumption, gross energy consumption in the agriculture and industry fell by 22.4%, in the commercial and public services sector fell by 6.8% and in households sector fell by 10.2%. On the other side, gross energy consumption for transportation sector increased by significant 20.4%. However, consumption of transportation sector reduced by 2.5% since 2011.

Gross final energy consumption by energy product gives us a great insight about the energy consumption after the transformation from primary energy resources.

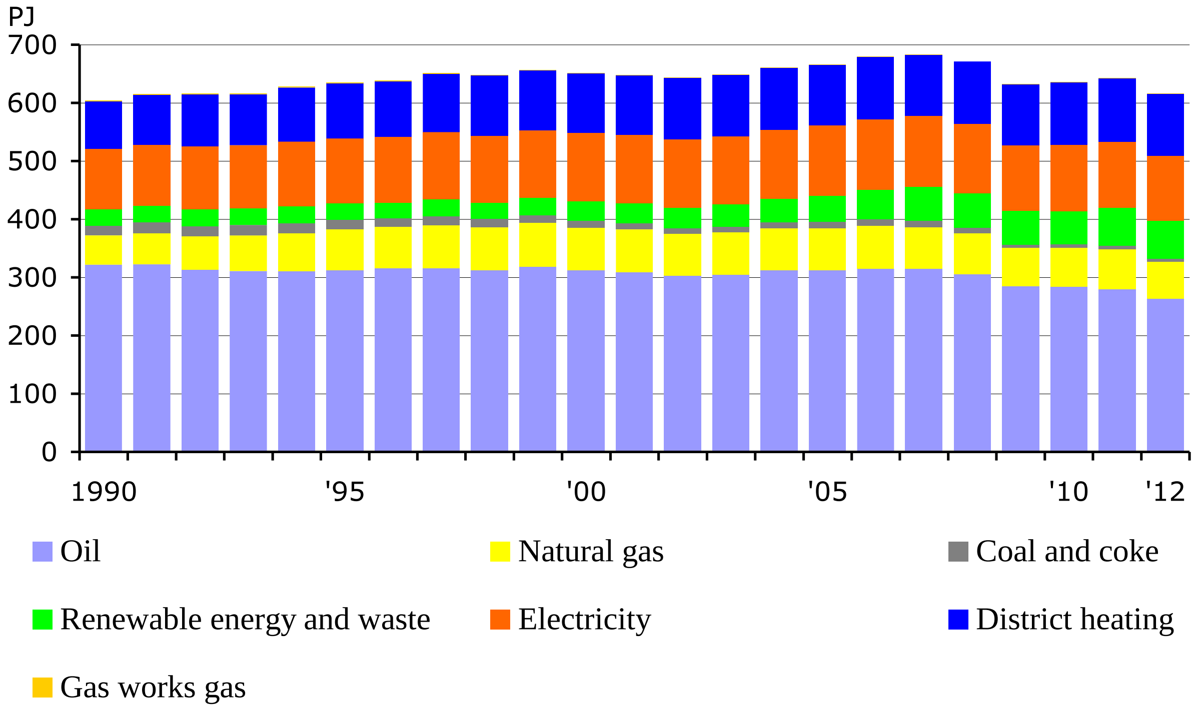


Figure 9 . Final energy consumption by energy product [7]

As it can be observed in Figure 9., oil is still a dominant energy product, although its value is lowering in recent years.

1.2.2. Electricity sector

Due to large penetration of wind energy, as well as increased generation efficiencies, fuel consumption for production of electricity fell for 35.33 PJ from values in 1990. In the same time, fuel consumption for the district heating rose for 10.8 PJ since the 1990. However, significant increase in generation efficiency can be observed here, too, as the district heating production raised by 47.2% in the period 1990-2012.

Gross final electricity consumption in 2012 was around 112 PJ, which is a 2% reduction from the 2011 level, as it can be seen in Figure 10. Final electricity consumption has been falling continually from 2005, as a result of increased energy efficiency of appliances, reduction in use of electricity as a heat source and a better insulation of dwellings.

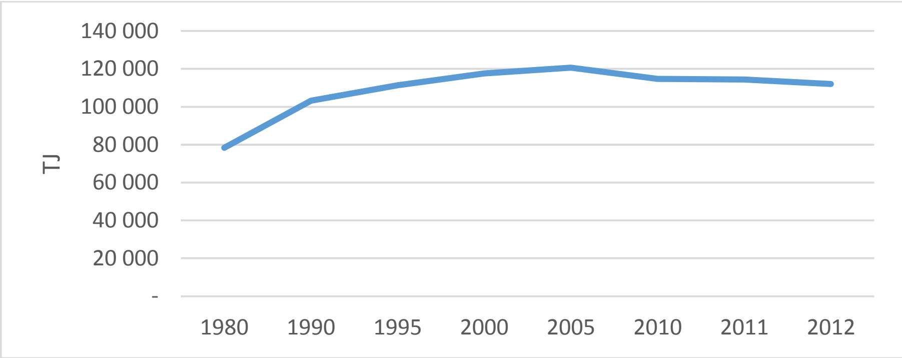


Figure 10 . Gross final electricity consumption

Electricity production mix has changed dramatically in the last few years. Large-scale units dominated electricity production from 1990, changed to CHP and wind energy dominated generation in 2012, as it can be seen in Figure 11.

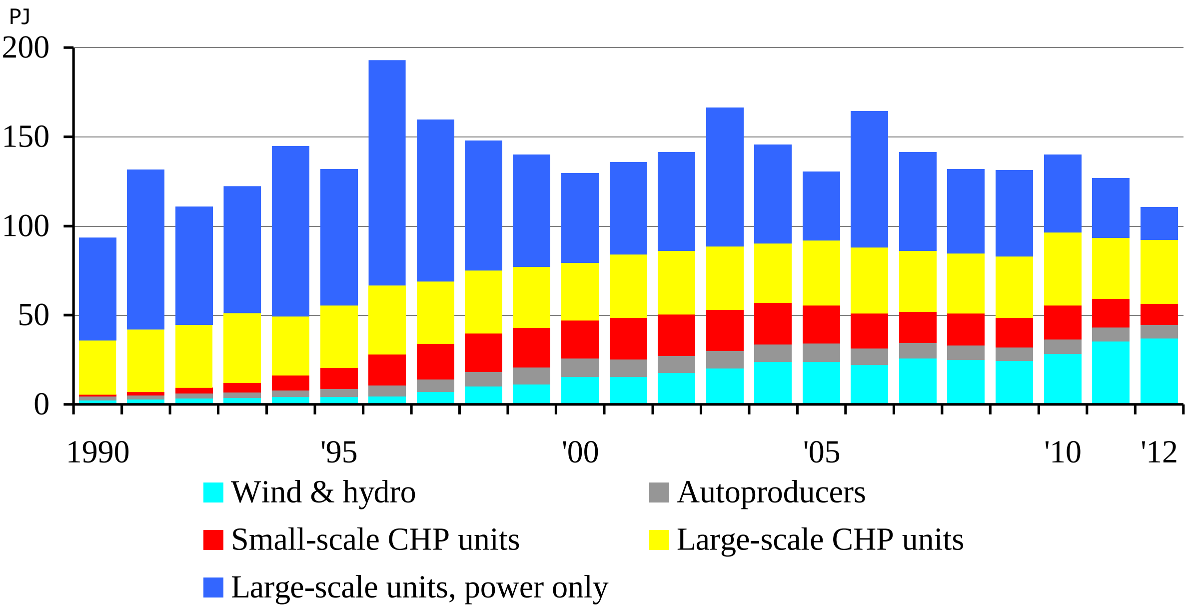


Figure 11 . Electricity production by type of producer [7]

Electricity production from large-scale power units decreased in the period of 1990-2012 for incredible 97.5%, helping to curb the CO_2 emissions.

Wind energy production share is increasing significantly from 1980, when the first turbines started generating electricity for the system.

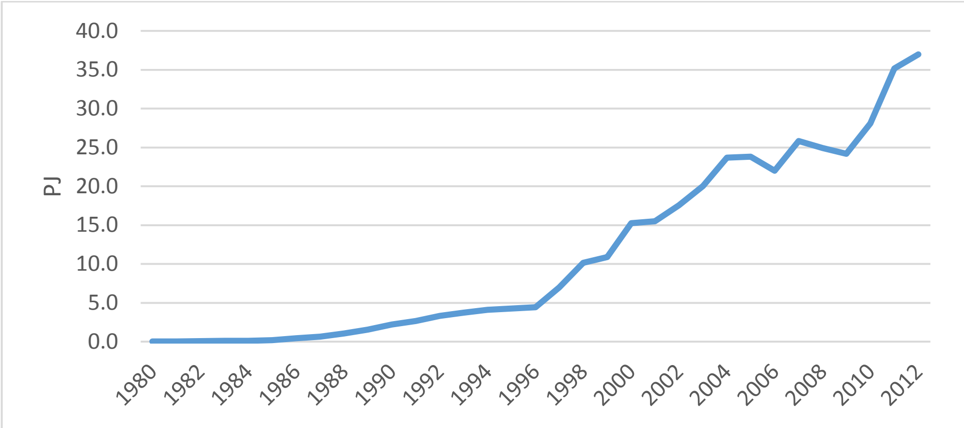


Figure 12 . Wind energy production [9]

Denmark is a well-known country for its wind energy production. Wind energy share is increasing continually and in 2012 Denmark produced 36.97 PJ of wind energy [9], approximately 29.8% of the total electricity supply for the 2012.

Wind power capacity was 4,163 MW in 2012 [7], which is a 5.3% rise from the previous year. Offshore capacity in 2012 was 921.9 MW, which is a 5.8% rise from the year before.

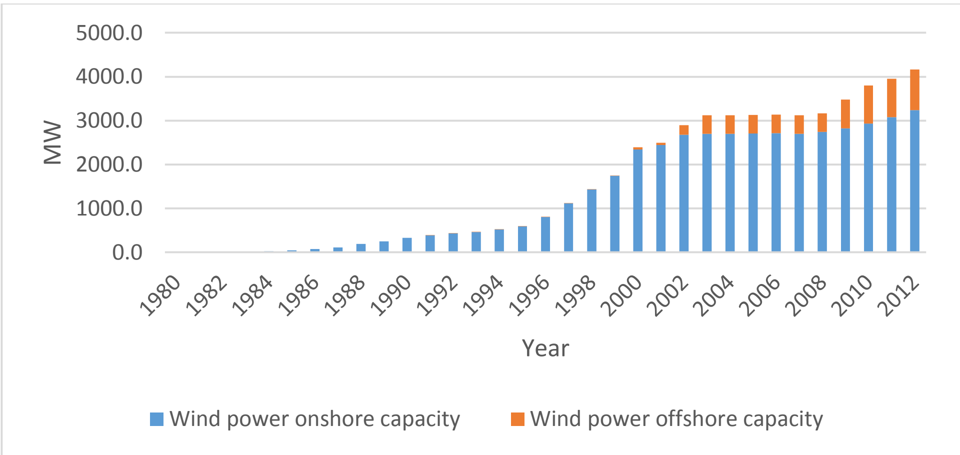


Figure 13 . Wind power capaciaties (onshore and offshore) [7]

Rapid penetration of onshore wind turbines started in the beginning of 90s and slowed down at the end of the 90s. Soon after, the offshore wind turbines started penetrating significantly. Majority of wind turbines are located on peninsula Jutland, especially in the western part.

It is interesting that the number of wind turbines decreased by 19.8% in the period from 2000-2012, while in the same time power output increased by 74.18%. While turbines with output of more than 2 MW back in 2000 were almost non-existing in the system, in 2012 these turbines had almost the same total output capacity as the turbines in the capacity range of 500-999 kW. Moreover, the turbines with sizes of more than 2 MW produced more than 53% of the total energy from wind in 2012 [7].

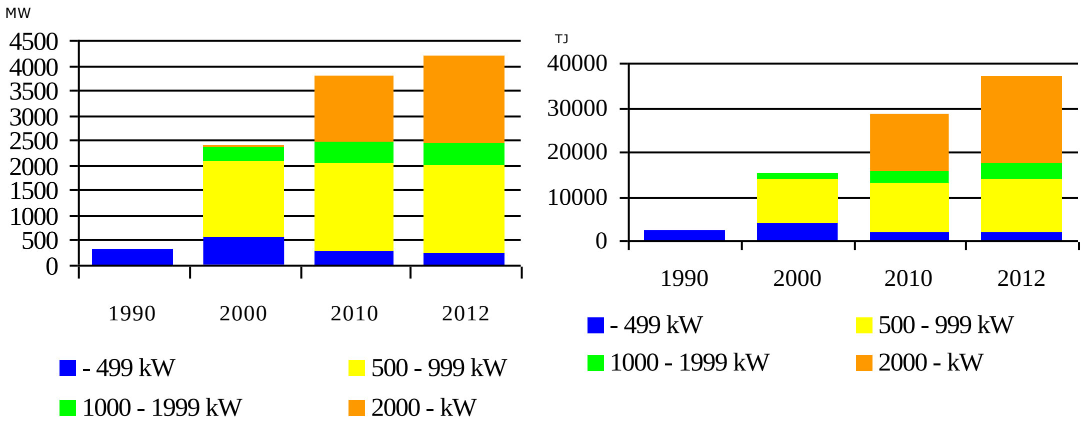


Figure 14 . Wind power capacities by turbine sizes (left) and wind power production by turbine sizes (right) [7]

Offshore wind turbines are usually of larger capacities and number of full load hours than the onshore counterparts [10]. Thus, the difference in the higher production rates of these turbines are expected.

1.2.3. Heating sector

In 2012, around 60% of heat demand for space heating and hot water consumption in Denmark was covered from district heating [7].

Heating energy in district heating is mainly produced by large-scale CHP units. Moreover, in the production of district heating energy, coal driven power plants still play an important role with the share of 23.7%.

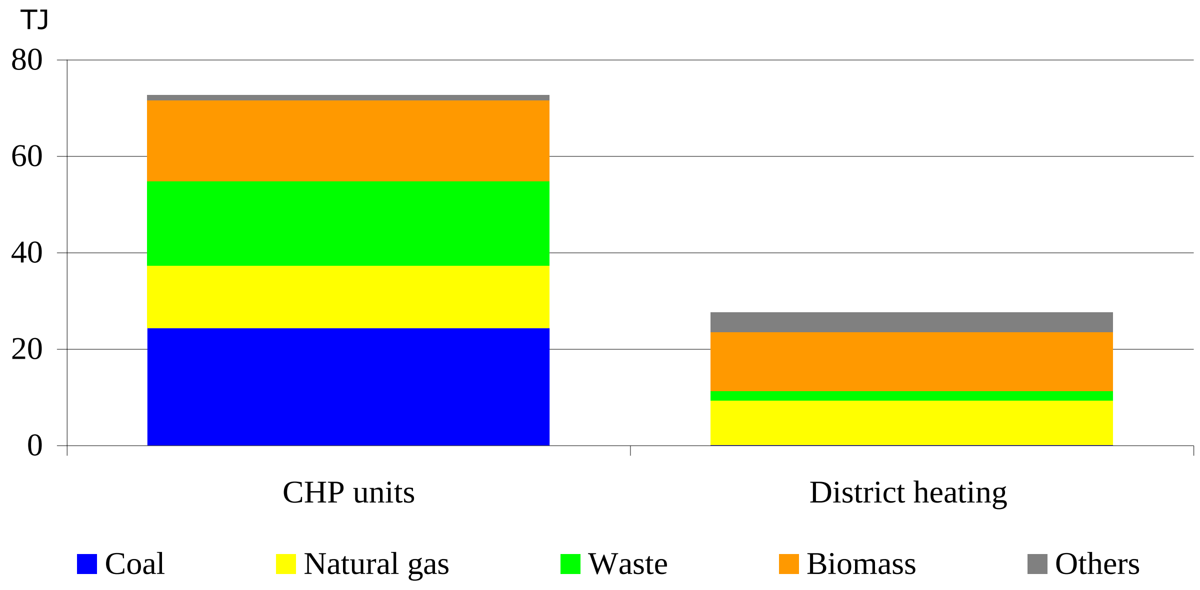


Figure 15 . District heat supply by type of fuel (2012) [7]

Although the share of coal in the large-scale units energy production is still around the one fifth, its share in fuel consumption for district heating reduced from 44.2% in 1990 to 18.3% in 2012 [7]. Meanwhile, the renewable energy sources rose from 22.6% to 43.7% in the same period [7]. Lately, large-scale heat pumps and electric boilers have started penetrating into the energy system, but their share at the end of 2012 was still insignificant, i.e. it was 0.8% [7].

Thus, it can be seen that renewable energy sources started to develop significantly in the Danish energy system following the oil crises. Especially the wind energy is the technology with a high penetration, already producing around 30% of the yearly electricity consumption. Nevertheless, a strong influence of CHPs can also be observed, as this technology is highly promoted in Denmark due to fuel efficiency, as well as good integration possibilities with the electricity sector.

Heat production from heat pumps and electric boilers in district heating system can be seen in the following figure:

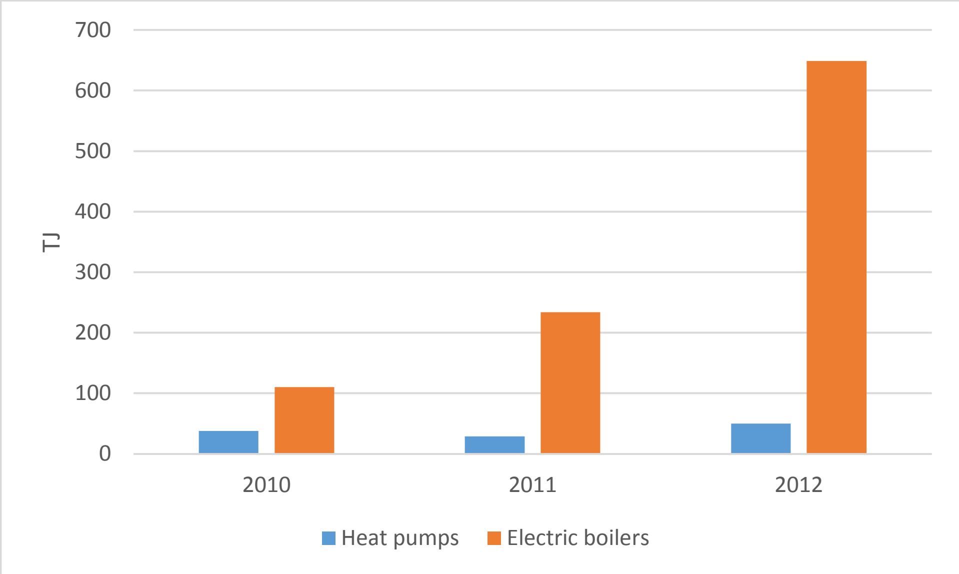


Figure 16. Heating energy production for DH by boilers and heat pumps [7]

As it can be seen, the amount of heating energy production by heat pumps is rather low, while the heating energy production by electric boilers for district heating is increasing constantly. One example of the heat pump used to provide heating energy in the district heat system is a 4 MW_t heat pump at Skjern paper mill that delivers heat to the DH at 70 ^oC [11]. The number of running hours is approximately 8,000 per year and simple pay-back period is 2.5 years [11]. The heat pump recovers the heat from moist drying air, which was previously thrown in the environment, and elevates temperature from 37 ^oC to 68 ^oC [11].

The estimated number of individual heat pumps in Danish households in 2010 was 71,305 if all types are included. Geothermal heat pumps and air to water heat pumps amounted to 27,352 units, while other were air-to-air heat pumps [12]. Average SCOP of ground and air-to-water heat pumps was 2.98. Heat provided equals to 399,630 MWh, for which the 134,327 MWh of electricity was consumed. For the air-to-air heat pumps no detailed data is provided [12]. The capacity of the heat pumps was 62,024 kW_e in 2010.

1.3. Heat pumps – a technology, application and potential use

A compression heat pump is a device that provides heat to energy sink at higher temperature than those of heat source by using additional work, most often by a compressor. The main types of heat pumps are absorption and compression heat pumps, but only the compressor heat pumps that uses electricity are efficient in terms of integrating more intermittent renewable energy in the energy system [13]. The schematic representation of general refrigeration cycle can be seen in the following figure:

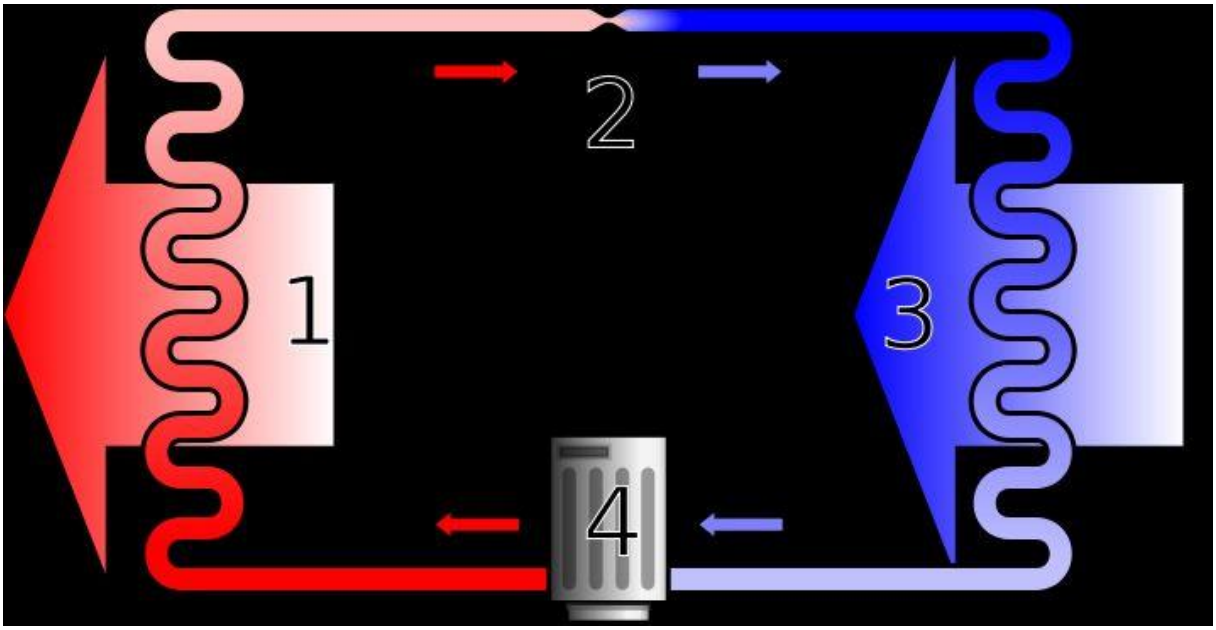


Figure 17. Representation of refrigeration cycle: 1) condenser, 2) expansion valve, 3) evaporator, 4) compressor [14]

Refrigeration cycle can also be turned around to cool the space down, instead of heating it up.

The usual way of evaluating the performance of heat pump is a coefficient of performance (COP) which is a ratio of heating or cooling energy provided to electrical energy consumed. Unlike the thermal efficiency ratio, this ratio can have values larger than one. Most often, in the large scale heat pumps, COP varies between 3 and 4 [11].

The basic concepts of large-scale heat pumps can be observed in the Figure 18. In the HP-ES (heat pump-external source) a heat source can be: ground source, waste water, ground water, sea water, solar seasonal storage, geothermal heat or cooling supply. Moreover, it can be integrated with an existing CHP plant (CHP_HP_ES) [15]. These concepts are already possible to utilize in district heating.

Other concepts such as CHP-HP-FG and CHP-HP-FG-CS are still in the demonstration phase and are expected to be on the market in the near term [15]. In the CHP-HP-FG concept heat pump uses flue gases of existing CHP plant or boiler as the heat source. Furthermore, if a cold storage (CS) is added, non-concurrent operation of HP unit and CHP/boiler unit is possible [15].

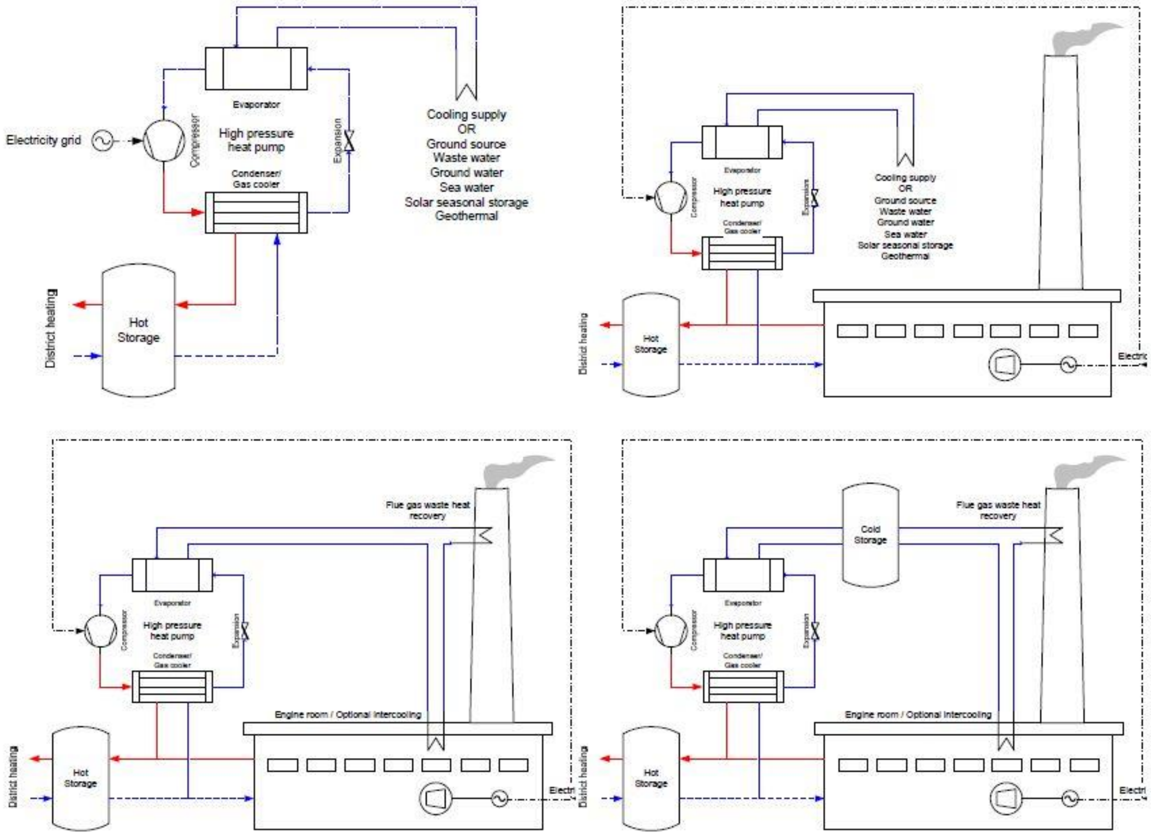


Figure 18. Large-scale heat pumps basic concepts: HP-ES (top left), HP-ES with CHP (top right), HP-FG with CHP (bottom left) and HP_FG_CS with CHP [15][16][17]

Furthermore, the CHP-HP-ES concept can be adopted by installing the heat pump on the district heating grid at any place, using the return line of the grid as a heat source [15]. Consequently, a lower return temperature at the plant allows further cooling down of the flue gasses which will increase system efficiency. Research has detected that the CHP-HP-ES is the technically most viable solution for integrating intermittent renewable energy sources into the grid, while CHP-HP-FG-CS could be the most economic feasible solution [18]. In any case, a delivery temperature at around 70 ^{o}C or more is needed before the low-temperature 4th generation district heating systems will be implemented.

2. METHODOLOGY

Firstly, analysis and comparison of the EnergyPLAN model and MARKAL/TIMES model generators is carried out in order to detect suitable model for the analysis of the heat pumps in the near future energy systems.

Secondly, the price elasticity of the electricity demand is assessed in order to detect possible influence of the increase in electricity demand, due to installation of large-scale heat pumps, on the electricity price on the Nordpool's El-spot market.

Thirdly, levelized cost of heating energy (LCOH) is calculated for two technologies; large-scale heat pumps and electric boilers. This was done in order to assess the capital intensity of investment in both technologies and to detect the number of equivalent full-load running hours when the heat pump will be more economic feasible investment than the electric boiler, as these two technologies are competing in the same area of the energy system.

Lastly, several scenarios were developed in EnergyPLAN in order to assess feasibility of the large-scale heat pumps. A model for the reference year 2013 and 5 scenarios for the year 2020 were developed. A business as usual (BAU) scenario, where only the implementation of the decision to produce at least 50% of electricity by wind will be implemented, three scenarios with different levels of wind capacities and optimal heat pump capacities, and one scenario with the large-scale thermal energy storage added together with the optimal large-scale heat pump capacity.

2.1. EnergyPLAN vs. TIMES/MARKAL analysis

Firstly, the general background of models, as well as the features and abilities are described.

Furthermore, the analysis is carried out by means of studies or reports being already published. Similar studies performed in both models were detected in order to be possible to compare results up to a certain point. Three studies are chosen, one for the case of EU, one for the case of Denmark and one emphasizing the CHP and district heating generation in general. After the detection of the suitable studies carried out in both models, a scenarios developed and results obtained are reported. This comparison and data review is provided in detail in Appendix III.

Finally, a discussion is carried out, in which the pros and cons of each of the models are reported and a major differences between them are detected and discussed.

2.2. Price elasticity of the electricity demand

Elasticity measures the sensitivity of one variable to another. A resulting number shows the percentage change that occurs in one variable in response to a one percent increase in another variable [19]. The most often elasticity being assessed is a demand elasticity and it is defined as follows [19]:

$$E_D = \frac{\frac{\Delta Q}{Q}}{\frac{\Delta P}{P}} = \frac{P\Delta Q}{Q\Delta P} \tag{1}$$

Where E_D is a price elasticity of demand, Q and P are quantity and price at equilibrium point, ΔP is the difference between the price increased for one percent and the equilibrium price, while ΔQ is the difference between quantity wanted at increased price and quantity at equilibrium price. Price elasticity is visualized in the following figure:

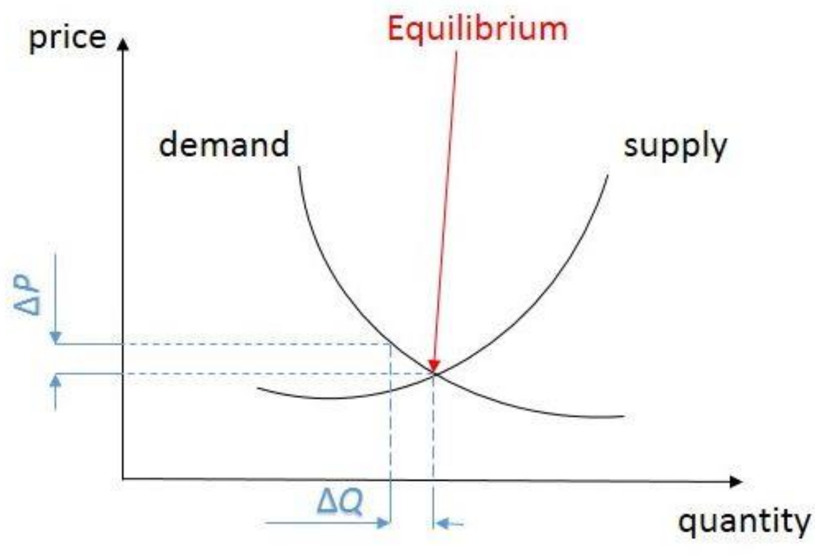


Figure 19. The price elasticity of the demand

The price elasticity of the demand is the most often a negative number, as the demand falls when the price rises. Demand is a price elastic if the elasticity measured is greater than one (in absolute terms), because the decline in quantity demanded is greater in percentage than the increase in price. Thus, if price elasticity of the demand is less than one, demand is price inelastic [19].

It is also possible to measure price elasticity of the supply side in the same way as for the demand side. However, the price elasticity of the supply side is usually a positive number, as the quantity supplied will be higher if the price rises.

Income elasticity and cross price elasticity are also important factors when considering price elasticity of demand and should not be avoided in a detailed analysis. Income elasticity of the demand is the percentage change in the quantity demanded as a result of one percent increase in income [19]. It is usually a positive number as the demand usually rises if the income rises, too. Cross price elasticity shows how the demand for some goods is affected by the prices of other goods [19]. The most suitable example of the cross elasticity is the one concerning the prices of crude oil and natural gas. When the price of crude oil rises, the demand for natural gas also rises, since it can replace crude oil in many situations. Thus, the cross price elasticity is a measure of the rise in the demand for one good as a result of the one percent increase in price of the other good.

However, in this thesis only the price elasticity of the demand on the Nordpool's el-spot is assessed, as this is the most important factor for answering the following question: *"Will the increased demand for electricity, due to consumption of it by the large-scale heat pumps, cause the increase in price of electricity and if it will, how much will the increase measure?"*. Thus, the purpose of this calculation will be to assess the possible effects on the supply side and not carrying out the research about the demand side of the electricity markets and potential human psychological behavior.

In order to calculate elasticity, the data for building up the demand curve in every hour is needed in order to assess decrease in demand due to one percent increase in price of the electricity. Moreover, quantities traded and price set in each hour are also needed data for carrying out the analysis. Price elasticity of the demand for electricity is calculated for the years 2011, 2012, 2013 and 2014 on hourly resolution because the electricity price and the quantity sold are set for each hour. Thus, one demand and one supply curve is provided in each hour. Calculations were performed in Matlab© tool. Matlab is a well-known software that is used in many areas.

It strongly encourages the usage of matrices in computations due to fast calculations that is able to perform by using it. The usage of matrices is suitable for this kind of problem, where extremely large amount of data will be needed to handle with.

Equation *(1)* is used for calculating the price elasticity of the demand. Quantity Q and the price P in each hour are downloaded from the Nordpool website [20]. For the ΔP, a price increased for one percent needs to be known. Thus, the simple calculation needs to be carried out for the increased price in each hour:

$$P_{1\%,i} = P_i * 1{,}01 \tag{2}$$

Where $P_{1\%,i}$ is the equilibrium price in each hour i, increased by 1% and P_i is the equilibrium price set in each hour.

For the calculation of change in demand ΔQ, the procedure is somewhat more complicated. In order to detect quantity that would be traded, if the price set would be a one percent larger, the data about all the increments on the demand curve are needed. This data is available on the official Nordpool website only for the last few months, but for the purpose of this student thesis, the free access to the Nordpool data on the servers was approved [20]. A large amount of bids and offers are provided in each hour and consequently, increments for demand quantities on the demand curve are rather small. Example of one of the demand-supply curves that is built from the supply and demand offers can be seen in the following figure:

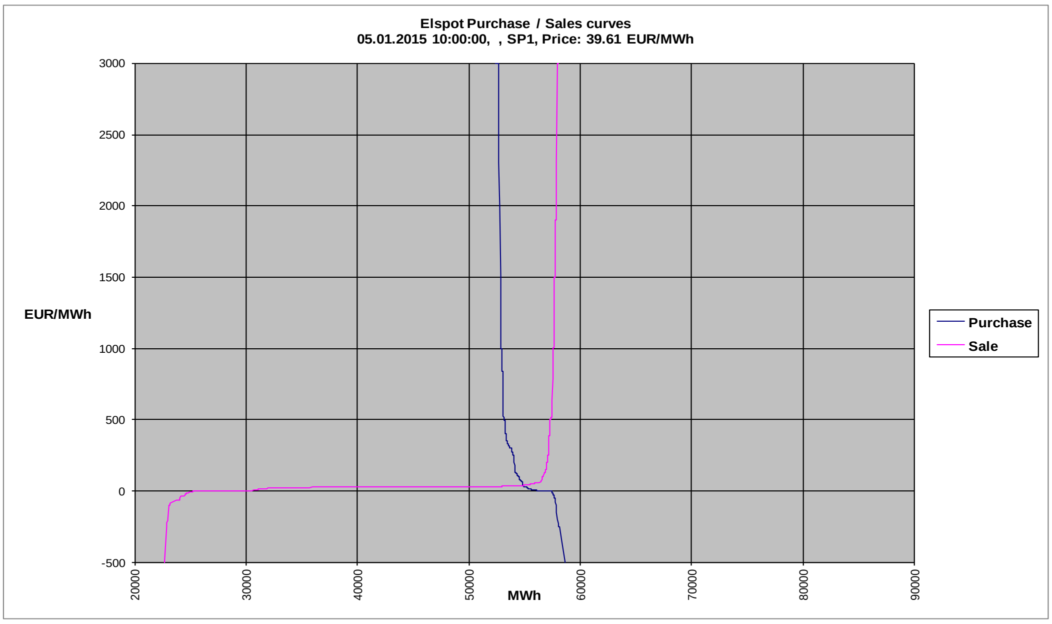


Figure 20. The Elspot purchase-sale curve on the 05th of January 2015, at 10 AM [21]

The equilibrium point is the point where the purchase and sale curve meet. In order to calculate ΔQ, the point where the sale curve shifted up for one percent would intersect purchase curve needs to be known. If the exact demand did not match the price increased for one percent in the purchase-sale data provided, a linear interpolation was used in order to calculate the matching volume demanded:

$$P = P_{Q0} + (P_{Q1} - P_{Q0}) \cdot \frac{Q - Q_0}{Q_1 - Q_0} \tag{3}$$

Where Q_0 and Q_1 are the first lower and higher quantities for which the price is known and the P_{Q0} and P_{Q1} are corresponding (known) prices.

Elasticity is calculated on hourly resolution and averages of every year and every season are provided in the results, too.

2.3. Levelized cost of heating energy (LCOH)

Levelized cost of heating energy (LCOH) is used in order to compare potential investments in large-scale heat pumps and electrical boilers. LCOH is a similar method as the levelized cost of electricity (LCOE) is, with the difference between the types of energy product being assessed. These methods are used to calculate the generation costs per unit of energy and not capacity. Moreover, all the costs up to the connection to the grid are included here, such as investment costs, fixed and variable O&M and fuel costs. It is especially suited for electricity calculation, because of the possibility to compare intermittent sources such as wind with the thermal power plants with steady generation rates, such as nuclear energy. The same procedure was adopted to calculation of heating energy costs from different sources. The method is also well suited here, because of the comparison of two rather different technologies in economic terms. Large scale heat pumps are *capital intensive* technologies, where the running costs are rather low due to high efficiency. On the other hand, electric boilers are *asset-light* technologies, where the fuel costs contribute significantly to the overall costs. Thus, the LCOH is a suitable methodology for calculating costs of these two technologies.

Following methodology is used in this thesis for calculating LCOH:

$$Inv_s = \frac{Inv}{P_h}$$

(4)

Where Inv_s is a specific investment in a certain technology [€/kW$_h$], *Inv* is a total investment [€] in the technology and P_h is the heat capacity [kW] of the technology being considered.

The amount of produced heating energy E_P [(kWh/kW)/year] is directly proportional to the number of running hours:

$$E_P = P_h \cdot H$$

(5)

Where *H* is the number of equivalent full-load working hours of specific technology [h/year].

In order to calculate a constant annuity to the present value of investment, as well as the major revision, the capital recovery factor (*CRF*) is used:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

(6)

Where *i* presents the interest rate [%] and *n* [years] the technical lifetime (as well as the loan length of time).

The payment amount for a loan (*PMT*) per capacity, taking into account the interest rate and the constant payment schedule, is calculated as follows:

$$PMT = CRF \cdot Inv_s$$

(7)

And has the [€/kW] unit.

Total annual expense (AE) [€] is calculated in the following way:

$$AE = O\&M_F + O\&M_V \cdot E_P + \frac{F}{COP} \cdot E_P + PMT_E + PMT_D + R_{M,PMT}$$

(8)

Where $O\&M_F$ is the fixed operating and maintenance cost [(€/kW)/year], $O\&M_V$ is the variable operating and maintenance cost [€/kWh], F is a fuel (electricity) cost [€/kWh], PMT_E and PMT_D are the payment amounts of loan per capacity of the equity and the debt, accordingly, and the $R_{M,PMT}$ is the payment amount per capacity for a loan for the major revision. The calculation procedure for all three latter factors are the same and equations *(6)* and *(7)* are valid, just the different values are used.

Finally, the LCOH [€/kWh] equation used is:

$$LCOH = \frac{AE}{E_S}$$

(9)

Where E_S is the heating energy supplied to the district heating network [(kWh/kW)/year]. Due to simplification, the equation $E_s = E_p$ can be used, as loses from the heat pump or electric boiler to the grid can be neglected, if the equipment is properly installed.

The same set of equations is valid for assessment of both electric boilers and large scale heat pumps.

3. MARKAL/TIMES MODEL DESCRIPTION

3.1. MARKAL

MARKAL is a model developed by International Energy Agency (IEA) in order to facilitate energy and environmental policy analysis. MARKAL is a basic, standard optimization model that has the objective function set to find the least-cost solution, i.e. the model selects *that* combination of technologies that minimizes total system cost. Mostly, the model is used for the representation of the evolution over a period of 40 to 50 years of a specific energy system at the national, regional, state or province, or community level. Moreover, in the ETSAP-TIAM (Times Integrated Assessment Model) the time horizon from the year 2000 to the year 2100 was used. The model is a result of more than two decades of work by the Energy Technology Systems Analysis Programme (ETSAP) [22]. Nowadays, it is used by 77 institutions in 37 different countries [22].

MARKAL is a bottom-up, linear programming model, although some of the variants includes non-linear algorithms and coupling with top-down economic models [22]. The solution of the MARKAL model is the optimum set of technologies that will meet the projected energy demands, subjected to the constraints introduced. The perfect foresight of the energy demand is assumed in all MARKAL models.

Unlike some of “bottom-up” techno-economic models, MARKAL doesn’t require or permit an a priori ranking of greenhouse gas abatement measures, instead, it chooses the preferred technologies and provides the ranking as a result. The model requires as inputs projections of energy service demands (e.g. room space to be heated or vehicle-miles to be travelled) and projected resource costs [22].

Some of potential uses of MARKAL [22]:

- ✓ To identify least-cost energy systems
- ✓ To identify cost-effective responses to restrictions on emissions
- ✓ To perform prospective analysis of long-term energy balances under different scenarios
- ✓ To evaluate new technologies and priorities for R&D

- ✓ To evaluate the effects of regulations, taxes and subsidies
- ✓ To project inventories of GHG emissions
- ✓ To estimate the value of regional cooperation

From the winter 2008 TIMES model is promoted for the new users and MARKAL won't be developing anymore.

3.2. TIMES

TIMES or Integral MARKAL EFOM System is the advanced successor of MARKAL. It has been developing continually from 2000 and has a relatively often update releases [23]. TIMES is a result of the continual development of the ETSAP tools. During the many years of usage of MARKAL modelling tool, strengths, weaknesses and the projected future usage has been addressed and a new model generator has been developed. Today, it is used in 70 countries by 250 institutions. It is also technology rich bottom-up model as its predecessor, used for integration of economic, environmental and technical innovation aspects in order to build alternative development scenarios, which can be used for evaluation of the impact of technical options and policies [24]. The main advantage of this model is the strength of usage of the techno-economic partial equilibrium paradigm and ease-of-use interfaces.

Moreover, improvements over MARKAL are following [24]:

- ✓ TIMES has been designed as a multi-regional model from the beginning, allowing the examination of the trade issues, assessing of the carbon leakage from one country to another, and the implementation of the Clean Development Mechanism (CDM). It also facilitates evaluation of the infrastructure needs for electrical grid and gas transportation facilities.
- ✓ Technologies are vintaged, which allows representing the changing nature of attributes of different technologies over time, e.g. decrease in efficiency of the solar panels over time.
- ✓ Time-slices can be represented to any level of detail, even down to the hour of the day. With this feature implemented, TIMES can model some of the effects of time-of-use electrical rates load curves.

The model outputs are energy flows, energy commodity prices, GHG emissions, capacities of technologies, energy costs and marginal emissions abatement costs.

The largest drawback of the model is the training which takes some months [25]. Moreover, building up the reference model usually also takes some months, because of the complexity of the bottom-up approach in such a detailed model.

3.3. Overview of ETSAP tools

In order to completely understand the model, it is necessary to understand all of the parts of the model.

MARKAL and TIMES model generators are the source codes, which process data entered into model and create economic equilibrium of the energy system. They also post-process the results of the optimization and prepare them for the representation in “shells”. The source code is available free of charge after signing a Letter of Agreement with ETSAP.

A “shell” is a user interface which manages input of data, running of the model generator and examining the results [24]. It facilitates and makes more practical usage of robust models, while simple models could be handled by ASCII file editors. There are two different “shells” systems; ANSWER developed by ABARE (property of Noble-Soft Systems Pty Ltd.) and VEDA, developed by KanORS Consulting Inc. Both ANSWER and VEDA “shells” support MARKAL and TIMES. Both of these interfaces have to be paid in order to obtain a license.

GAMS or the General Algebraic Modeling System is the computer programming language which was used to write the MARKAL and TIMES models. A solver that solves the mathematical programming problem generated by the model generators (TIMES or MARKAL) is integrated with GAMS. The license for the GAMS also needs to be paid for.

Lastly, the Model is a set of data, e.g. different spreadsheets, databases, etc., which are used to completely describe the system and its underlying problems, in a format that is compatible with the model generators used (MARKAL or TIMES).

Although the model generators can be obtained for free, after licensing of GAMS and the ANSWER or VEDA interfaces with incorporated solvers, the total cost is between USD 1,780 and USD 4,420 for the educational license and between USD 13,700 and USD 21,200 for a commercial license [25].

3.4. Model structure

All the steps in transformation from primary resources through the different processes to the final supply of the energy are implemented into the model [26]. Energy supply side consists of fuel mining, primary and secondary production, as well as exogenous import and export. Energy is then delivered to the demand side passing via the energy carriers. Demand side is structured into residential, commercial, agricultural, transport and industrial sectors.

Technologies, Commodities and Commodity flows are the basic entities which construct the TIMES models [26].

Technologies (processes) present physical devices that transform commodities into other commodities. It encompasses different processes from the primary sources of commodities, such as mining processes, the transformation activities, such as conversion in thermal power plants, and the end-use demand devices such as vehicles.

Commodities consist of energy carriers (fuels), energy services, materials, monetary flows and emissions; a commodity has to be produced or consumed by some technology.

Commodity flows are the links between processes and commodities. A flow is of the same nature as commodity, but is connected with the particular process.

These three entities are used to build an energy system that characterizes the country or region being modelled. The first step of the modelling is building a reference model, which is extremely time consuming part of modelling and can take up to several months [22]. After the reference model has been constructed, building up scenarios can begin. Scenarios are being built by introducing different constraints, e.g. GHG emissions cap or minimum share of RES, which then impact the optimization result. It is worth mentioning again that the objective function of the optimization is always to find a least cost solution.

3.5. The MARKAL/TIMES key features [24]

Technology and commodity explicit

As already mentioned, technologies transform commodities from one form into another. A number of parameters describe each technology in TIMES: technical life, availability factor, amount of inputs and outputs per unit of activity, efficiency, investment costs, decommissioning costs, fixed O&M cost, variable O&M cost, initial year available, etc.

Each of technology is described in terms of potential and supply curves. If we add also energy service demand curve, we have created input for determining final energy supply and demand in equilibrium state. Thus, the final energy is endogenous to MARKAL/TIMES model.

Multi-regional

Some of the models developed in MARKAL/TIMES include energy systems of the whole regions, or the whole world. For example, ETSAP-TIAM model covers energy systems of the 15 different regions which together form the energy system of the World.

Transformation from regional models to a single multi-regional model is performed by trade variables. They take into account the possible effects that one region can cause to another. The important part of the multi-regional models is the property of the model that the trade of each energy form between regions is determined endogenously, responding to different fuel prices. Moreover, besides the trade of fuels such as coal, natural gas, crude oil, etc., a trade of materials can also be defined (steel, paper, …).

Economic equilibrium

The most important and advanced part of the model is the computation of economic equilibrium for energy markets. The model calculates prices of both energy and flows, and compares them with the amount that the consumers are willing to buy. When the equilibrium is reached, the suppliers will produce exactly the amount that the consumers are willing to buy. This is present throughout the whole system: primary energy forms, secondary energy forms and energy services [24]. Moreover, the following properties are valid [24]:

- ✓ Technology outputs are linear functions of inputs

- ✓ Energy markets are competitive, with perfect foresight
- ✓ The market price equals marginal value in the overall system
- ✓ Each economic agent maximizes its own profit or utility

The latter two properties are very important and will be discussed further. In MARKAL/TIMES the equilibrium is calculated by maximization of total surplus, of both consumers and suppliers.

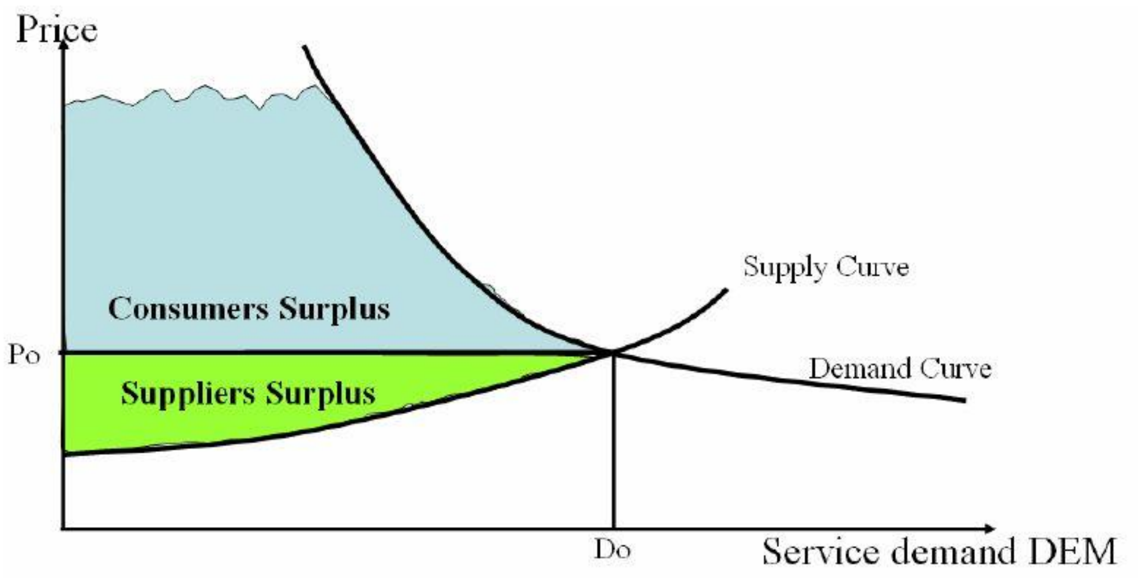


Figure 21. The equilibrium calculated in MARKAL/TIMES model [24]

As it can be seen, the equilibrium is reached at the point where supply and demand intersect. It means that the equilibrium price is equal to marginal value of the system for various commodities. This fact is very important property of the competitive markets.

The other valuable property is the assumption of competitiveness between suppliers, where the producer wants to maximize its profit. This is also a very important property of the competitive markets. However, it needs to be emphasized that this property is valid only while the equilibrium price is equal to marginal value of the system. On the other hand, if the property of marginal value pricing wouldn't be valid, the market wouldn't be a competitive one.

Finally, there are several equilibrium levels, based on simplifications of the model being used, that can be calculated within the model [24]:

I) Supply side technological optimum is achieved: the total energy sector cost is minimized

II) Supply plus demand side technological optimum is achieved-the total system cost is minimized

III) Energy service demand are in equilibrium: the total surplus is maximized (Figure 21.)

IV) General economic equilibrium occurs: the consumer utility is maximized

In the next figure it is shown how the economic equilibrium is reached in the equilibrium option I:

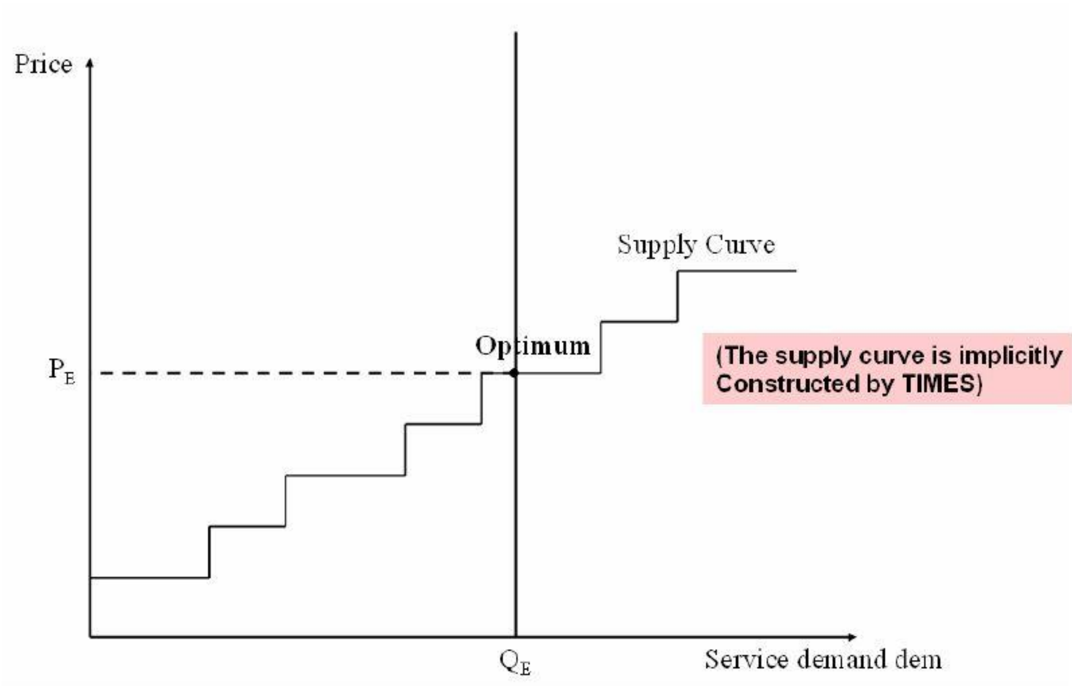


Figure 22. Representation of the equilibrium being constructed by TIMES in the program I. [24]

As it can be seen, the demand is a constant, exogenously provided by the user, and the intersection of the demand and the supply is the equilibrium point. However, in the program II, the demand side isn't fixed as in the program I, it is rather dependent on the supply side prices and vice versa. However, the demand curve is still explicitly provided by the user.

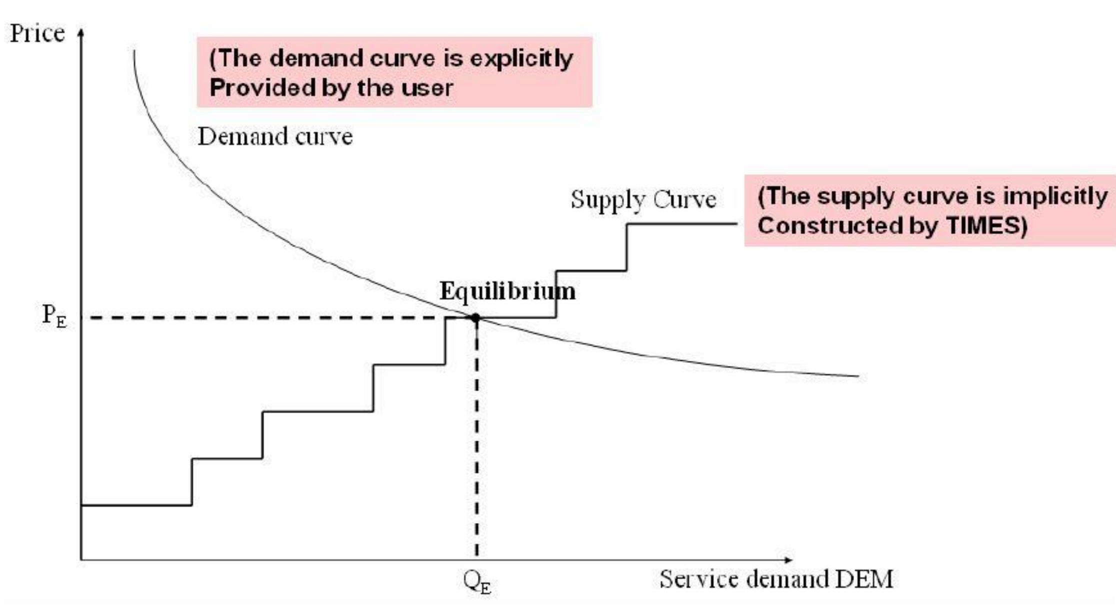


Figure 23. Representation of the equilibrium being constructed by TIMES in the program II. [24]

In the latter case, changes in demand can be assessed if the general price levels go up or down. Equilibrium is reached at the point where the demand and the supply curves meet.

3.6. Models developed in MARKAL/TIMES

Today, the MARKAL/TIMES family tools are used by more than 150 teams in 50 different countries. As a result, a number of models has been developed [22]. A short overview of the most important models developed will be presented here. The most important results, and the models itself, are discussed in ETSAP publishing, Final Report of Annex X [24] and Annex XI [27], while the Annex XII is expected to be published during the January 2015 [22].

3.6.1. International Studies using Global Models

The most important projects are The IEA Energy Technology Perspective (ETP) and the ETSAP TIMES integrated Assessment Model (TIAM).

In the *IEA ETP model*, fuel and technology analyses were carried out. The model encompasses the whole World represented in 15 different regions. The ETP model seeks for the least-cost pathways that meets the policy goals such as CO_2 emissions reduction. Moreover, the model also proposes measures to overcome technical and policy barriers. The model is being developed continually, and the main conclusion is that although the achievement of technology revolution in the short term carries substantial costs, over the long term the benefits will offset the costs. Several scenarios were developed and the most ambitious one assess the possibility of reducing CO_2 emissions to 50% below the current level until 2050. In the same time as the reducing GHG emissions effects are being implemented, increasing security of supply is achieved. As a result, supply and demand side financing needs for technology deployment and commercial investments are elaborated in detail, too. Finally, roadmaps for all important technologies were made [27].

In the *ETSAP TIAM* model, a robust transition policies towards climate sustainable systems towards the year 2100, in seven different periods of varying lengths, were assessed. It is a detailed, technology-rich global TIMES model, where a multi-region partial equilibrium model of the energy systems was used in order to describe the entire World in 15 different regions. It is a bottom-up model combined with a key-linkages to the macro economy. This is an extensive model where many uncertainties about the future development of the energy systems have been assessed. The ultimate goal of the model is to assess policies which allow a maximum of 2 ^{o}C average temperature increase in the long term. In the model, the possibility of describing penetration of intermittent renewable energy sources on a large-scale was also assessed. Moreover, carbon capture and storage (CCS) technology was thoroughly assessed within the model [27].

3.6.2. Regional models

There are several multi-regional models. Among the other studies, a special emphasize was put on the *Pan-European TIMES model*, as well as the *EU30 TIMES-Electricity and Gas supply model*. These two projects are thoroughly assessed as a part of comparison between TIMES/MARKAL modelling tools and the EnergyPLAN model and results are reported in Appendix III. Many other regional models were developed, too, such as studies exploring EU-wide “Tradable White Certificate” scheme, assessment of the European energy conversion sector under climate change scenarios, different studies for Asia assessing energy security, development of clean technologies, effects of cross-border power trade, studies for North America assessing energy and climate policies and climate and air quality planning [27].

The most often models that are being developed in MARKAL/TIMES family modelling tools are national models. Until the Annex XI [27] has been published, 32 different countries were modelled within the model generator: Bangladesh, Belgium, China, Colombia, Cuba, Finland, France, Germany, India, Ireland, Italy, Japan, Malaysia, Moldova, Nepal, Norway, Portugal, Russia, Slovenia, South Africa, South Korea, Spain, Sweden, Switzerland, Taiwan, The Netherlands, Thailand, Turkey, Ukraine, United Kingdom, United States and Vietnam. Denmark has joined only recently so their detailed model will be published in 2015 as a part of Annex XII [22]. However, they have published the first results of the model [28], which is used and thoroughly assessed in order to compare the abovementioned tools.

The Pan-European TIMES model is a result of several smaller models that were being developed over the years, i.e. the NEEDS-TIMES Pan European Model, the RES2020 Pan European model, the REACCESS Pan European TIMES model and the REALISEGRID Pan European TIMES model.

The NEEDS-TIMES Pan European Model is a model of EU27, Iceland, Norway and Switzerland. Energy system models of all 30 countries are modelled independently and in great detail. The model was a starting point for the RES2020 Pan European model, as well as REACCESS and REALISEGRID models [27].

The RES2020 Pan European TIMES model focused on the renewable energy targets of EU27 countries. Four alternative scenarios for achieving 20-20-20 targets were developed. A special emphasize and detailed analysis considering wind energy potentials and availability factors was conducted. Moreover, further enhancements of biomass and biofuels representation were made. The REACCESS project studied the effects of the competition between EU and the rest of the World for scarce resources on the energy systems. This extremely large model encompasses 45 different regions and was being modelled in great detail. Moreover, political risks were assessed in order to evaluate the security of supply of scarce fossil fuel resources.

EU30 TIMES-Electricity and Gas supply model illustrates in detail the electricity supply side of the EU27 member states and Iceland, Norway and Switzerland for the period between 2000 and 2030. Important part of the model was the assessment of the role of combined heat and power and district heat in Europe. Effects of liberalization of the European energy market were analyzed, as well as the potential ageing of the nuclear power plants. Potential of further CHP integration has been investigated, as well as district heating expansion in general. Three scenarios were developed, a reference one and two dealing with GHG emissions reduction [24].

3.6.3. Case Study of Denmark in TIMES model generator

Denmark has joined in the IEA-ETSAP programme and will be a part of Annex XII which will be published in January 2015 [22]. Currently, the Danish model in TIMES is developed and maintained by the research group at the Danish Technical University (DTU) [28]. As detected by the modelers, modelling an energy system with a significant contribution of wind power has become a key task for modelling the electricity system task in Denmark [28]. The wind share in production of electricity was around 30% in year 2012 [9]. Furthermore, as investments are endogenous in TIMES model, it is especially important to have a well modelled wind energy in order not to have overinvestment or underinvestment in the wind energy as a result. Moreover, modelling of wind energy was important part of RES2020 model on the European level. The main part of available results of the Danish model in TIMES is dealing with Utsira Storage and the costs of capture and storage of CO_2.

4. ENERGYPLAN

4.1. About the model

EnergyPLAN or Advanced Energy Systems Analysis Computer Model is a tool that has been developed continually from the year 1999. Prof. Henrik Lund initially started with a development of the tool, after which it has gone through the several major updates, connected mostly with expansion of the model with a number of new technologies. The model is programmed in Delphi Pascal and the next major update release, version 12, is expected during the January 2015. The current newest available version is 11.4.

Energy systems analyses are carried out on the hourly basis and a single analysis last for one year. EnergyPLAN is a simulation tool used for simulation of the behavior of the different technologies on the Energy market. Within the model different regulation, as well as market-economic and technical optimization strategies are available [29]. It is important to keep in mind that although named as different optimization strategies, the model is still in both cases simulation and not the optimization tool. Market-economic strategy identifies the least-cost solution of the system, assuming in the same time that all plant operators seek to optimize their business-economic profit. Technical optimization strategy seeks for the system with the lowest possible fuel consumption. Thus, implicitly the system with the lowest CO_2 emissions is sought for. The different strategies are realized by means of different behavior of decision variables.

In the market-economic strategy, the model identifies the equilibrium price at each hour by means of different variable costs of different power plants. The power plant utilities behaves in a way of maximizing their profits. On the other hand, the technical optimization strategy minimizes the import/export of electricity and the fuel consumption. The power plants mix with the least consumption of the fuel, which in the same time meet the demand, will be chosen to run.

The model can be applied from the municipality levels to the European level. The model especially well describes the interaction between the CHP plants and the renewable energy sources, especially the wind energy, in the same time allowing the interplay between the heating energy and electricity systems. Moreover, through the different means, interplay between gas grids and the heating and electricity systems is well modelled [29].

The complete system interactions of the model can be seen in the following figure:

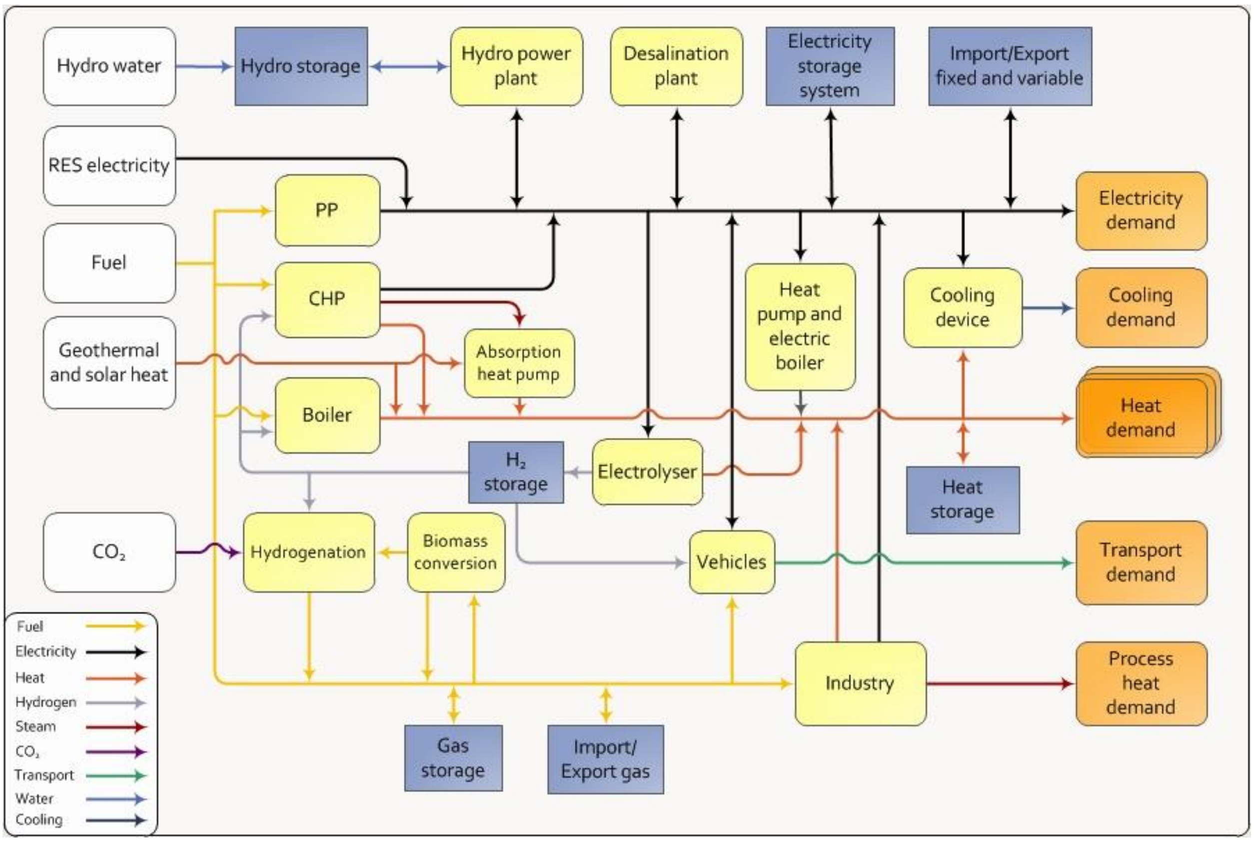


Figure 24. The EnergyPLAN model in version 11.4 [30]

The EnergyPLAN model is a detailed input/output model. Inputs that need to be set are energy demands in general, renewable energy sources, energy conversion units such as electrolysers, energy plant capacities, costs and a regulation strategy. Outputs are energy balances and resulting annual productions, fuel consumption, import/export and total costs including income from the export of electricity [29].

Depending on analysis strategy, some additional data may be needed, i.e. for market-economic analysis further inputs are necessary, such as different costs, in order to determine marginal production costs of the individual electricity production units [29].

EnergyPLAN uses holistic approach in modelling. Furthermore, it is a deterministic top-down model. It is a holistic model in terms of regulation strategies that are used within the model. Challenges of integrating fluctuating power from renewable energy sources into the electricity grid is not looked upon as an isolated issue, it is rather looked upon as one of various means and challenges of approaching sustainable energy systems in general [29]. By the term deterministic, as opposite to the stochastic models, it is described that the model generates always the same output, for the given set of inputs. It is a fast, forward model that is completely determined in every step-hour. As the model is built by analytical programming, it doesn't use iterations or advanced mathematical tools, which allows extremely fast calculations even for the most complicated systems, without any need for advanced computer systems [30].

Moreover, as the model simulates energy system behavior during one year in hourly resolution (8784 steps), it is an excellent tool for analyses of intermittent renewable energy sources, as well as the hourly, daily and seasonal fluctuations in energy demand. It is important to emphasize that the model simulates operation of the system rather than investments in the system. However, using the manual iterative approach, investments in the system can be optimized. If the energy system is well developed, the possible investments can be intuitive up to a certain point and thus, the manual iterative procedure can be rather easy. However, in the case of non-developed energy system, with a number of major alternative options possible, manual iterative procedure can become increasingly complicated and time consuming.

The calculation procedure of the model is shown in the following flow chart:

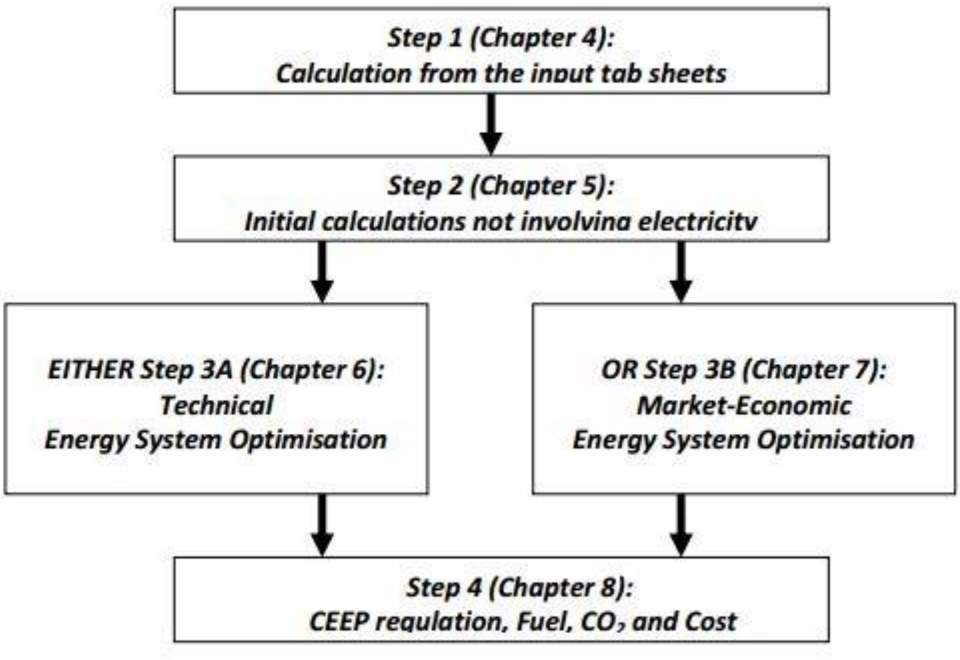


Figure 25. Flow chart of the calculation steps in EnergyPLAN [29]

During the phase of entering inputs, EnergyPLAN already makes some simple calculations, such as fixed import/export, different energy demands and other simple calculations not involving electricity balancing. In the second step further calculations are carried out in the way that different demands and supplies are calculated, however, without involving electricity in these calculations. In the following step, EnergyPLAN proceeds with the calculations according to the strategy chosen, either technical energy system strategy, or market-economic energy system strategy. After the market equilibrium price has been determined and the production rates from each power plant have been calculated, the model starts the critical excess in electricity production (CEEP) regulation.

There are seven different options of dealing with CEEP [29]:

1) Reducing renewable energy production from the largest RES sources
2) Reducing small-scale CHP production (replacing with boilers)
3) Reducing central condensing CHP production (replacing with boilers)
4) Replacing boiler production with electric heating in group 2 (*group 2* has smaller regulation ability)
5) Replacing boiler production with electric heating in group 3 (*group 3* has higher regulation ability)
6) Reducing renewable energy production from RES with lower capacities
7) Reducing power plant production in combination with all RES

All these strategies can be combined and treated together. Moreover, it is possible to use all seven different options in the same time.

4.2. Comparison of power plants behavior in technical and market-economic regulation

It is of great importance to understand differences in power plant production schedule for different regulation strategies chosen, in order to understand comparison and differences between TIMES/MARKAL model generators and the EnergyPLAN model, that will be presented in the future chapters. Complete overview is available in ref. [29], while here only a few power plants and their different production schedules are presented, which will hopefully be enough to understand the different decisions that the simulation model makes when running in different strategies.

Table 1. Comparison of different power plants' behavior in different strategies in EnergyPLAN model [29]

Component	Input	Technical regulation	Market-economic regulation
Wind power **Offshore wind** **Photovoltaic** **Wave power** **River Hydro**	Electric capacity and Hourly distribution	Are given priority in the electricity production	Are given priority in the electricity production. Marginal production costs are defined as zero.
Hydro power	Electric capacity Efficiency Storage capacity Annual Water supply Hourly distribution of water Variable operational costs	Firstly, best possible utilization of all water input given limitations on capacities is calculated and used as input. Secondly, Hydro power is relocated in the best possible way to avoid excess electricity production.	Identify highest possible production given water input and distribution, turbine capacity and water storage capacity. Sell such maximum production at the highest possible market prices to achieve the highest possible income.
Reversible Hydro Power	**Same input as Hydro plus** Pump Capacity Pump Efficiency Pump variable operational costs	**Same as Hydropower plus** In the end, the Pump is used in order to avoid excess electricity production and the Turbine to avoid production	**Same as Hydro power plus** The hydro power pump and turbine are used to optimize the profit of the plant based on marginal costs and losses in the energy conversion
Geothermal Power	Electric capacity Efficiency Hourly distribution Variable operational costs	Is given priority in the electricity production.	Produce whenever the electricity price is higher than the variable operational costs.
Solar thermal in district heating system	For each three DH groups: Annual production Hourly distribution Heat storage capacity Losses in heat storage	Is given priority in the district heating supply.	Is given priority in the heat production. Marginal production costs are defined as zero.
Solar thermal in individual houses	For each nine groups: Annual production Hourly distribution Heat storage capacity	Is given priority in the heat supply.	Is given priority in the heat production. Marginal production costs are defined as zero.
Nuclear Power	Electric capacity Efficiency Hourly distribution Variable operational costs	Is given priority in the electricity production.	Produce whenever the electricity price is higher than the variable operational costs.
Boilers	For each three DH groups: Thermal capacity Thermal efficiency	Are given last priority. If district heating can not be supplied from any other unit (Solar	The marginal operational cost, including fuel costs and taxes, is compared to relevant options (such

	Variable operational costs Fuel specification	thermal, industrial waste heat, CHP, heat pump or heat storage) then the boiler is used.	as CHP, heat pump and heat storage) and the business economically least cost solution is selected.
Heat pumps	For DH groups 2 and 3: Electric capacity COP (Coefficient of performance) Variable operational costs	Technical regulations 1 (and 4) Are given priority after CHP units to cover the heat demand. Technical regulations 2 (and 3) Are used in combination with CHP units to cover the heat demand and balance electricity supply and demand.	The marginal operational cost, including fuel costs and taxes, is compared to relevant options (such as boiler, CHP, electrolysers and heat storage) and the business economically least-cost solution is selected.
Heat storage	For DH groups 2 and 3: Heat storage capacity	Identify and implement changes in the use of CHP and heat pumps which can decrease excess electricity production and production on condensing power plants, and decrease heat production on boilers.	The heat storage is used in order to implement changes in CHP, heat pump and boilers, which will lead to better business-economic profits.
Electric boiler	No inputs	Only used as part of Critical Excess Electricity regulation if specified in the regulations strategy	Only used as part of Critical Excess Electricity regulation if specified in the regulations strategy
Power plants	Electric capacity Efficiency (electric) Variable operational costs Minimum capacity Fuel specification	Are given priority after all other electricity production units if the demand is still higher than the supply. (Or if production is requested for reasons of grid stability).	Produce whenever the electricity price is higher than the variable operational costs.

As it can be seen from the table above, the market-economic regulation strategy sorts the power plants according to marginal costs of production. Thus, it simulates the behavior of the real actors on the market. On the other side, if the technical regulation strategy is chosen, decision variables are set in that way, that the set of power plants with the lowest possible fuel consumption is chosen to produce the electricity.

4.3. Case studies done in EnergyPLAN

Numerous case studies have been done in EnergyPLAN and in the next table it will be shown which countries and which technologies were assessed in the model.

Table 2. Technologies assessed and locations of case studies carried out in EnergyPLAN

Technologies assessed	**Locations**
100% Renewable Energy	Croatia
CHP and Thermal Storage	Denmark
Cooling	European Union
District Heating	Grecce
Electric Grid	Hong Kong
Electric Vehicles	Ireland
Electricity Storage	Italy
Heat Pumps	Latvia
Hydrogen	Local Energy Plan
Photovoltaic	Macedonia
Synthetic Fuel	Mexico
Waste incineration	Portugal
Wave or Tidal Power	Romania
Wind Power	Switzerland
	The Netherlands
	USA

It is important to emphasize that several case studies were done for the case of 100% renewable energy system, i.e. the case studies of the following countries: Portugal [31], Macedonia [32], the Netherlands [33], Latvia [34], Ireland [35], Croatia [36] and Denmark [37]. Furthermore, the model was used for the assessment of the 100% renewable EU28 [8], the city of Aalborg [38] and the island of Mljet [40]. It can be concluded from this large number of studies that EnergyPLAN presents a favorable model towards modelling of 100% renewable energy systems on municipal, national and regional levels.

EnergyPLAN is distributed free of charge and currently is being used by more than 1,000 active users [25] [30].

5. ENERGYPLAN SCENARIOS

5.1. Reference scenario

Year 2013 was set as the reference year, as that was the last year for which the most of the data is already available. The Danish Energy Agency's preliminary statistics for 2013, published on their website in several documents [41], was the main source of the data for building the reference model up. The official Annual energy statistics for the year 2013, by the time of writing this thesis, was still not available in the complete form. Data not published in preliminary statistics was adopted from the annual report for the year 2012 and calibrated for the year 2013 following the historical changes.

Danish Energy Agency divides energy balance according to several criteria. In the statistics, energy demand sector is divided into four main parts: transport, agriculture and industry, commercial and public service and households.

Furthermore, price levels of fuels, energy prices, CO_2 emissions and other greenhouse gas emissions are provided, too. Detailed analysis of the current Danish energy system, mainly based on the Danish Energy Agency's report [7] was provided in chapter 1, as a part of intoduction.

5.1.1. Demand side in the reference model

Although the EnergyPLAN has a similar division of demand sectors, there are however small differences. EnergyPLAN models all the electricity demand, except in transportation, fuel conversion processes and cooling sector with the one demand curve. Moreover, heating energy demand is divided into individual and district heating demand, instead into different sectors. Only the transportation sector is modelled separately from the other sectors, as well as primary energy consumption of industry.

The total yearly demand of electricity for 2013 is set to 33.65 TWh, while total heating demand of 50.49 TWh is divided into individual heating demand of 20.21 TWh and the district heating consumption amounting to 30.28 TWh. The following figure is one example of the distribution curves used in EnergyPLAN:

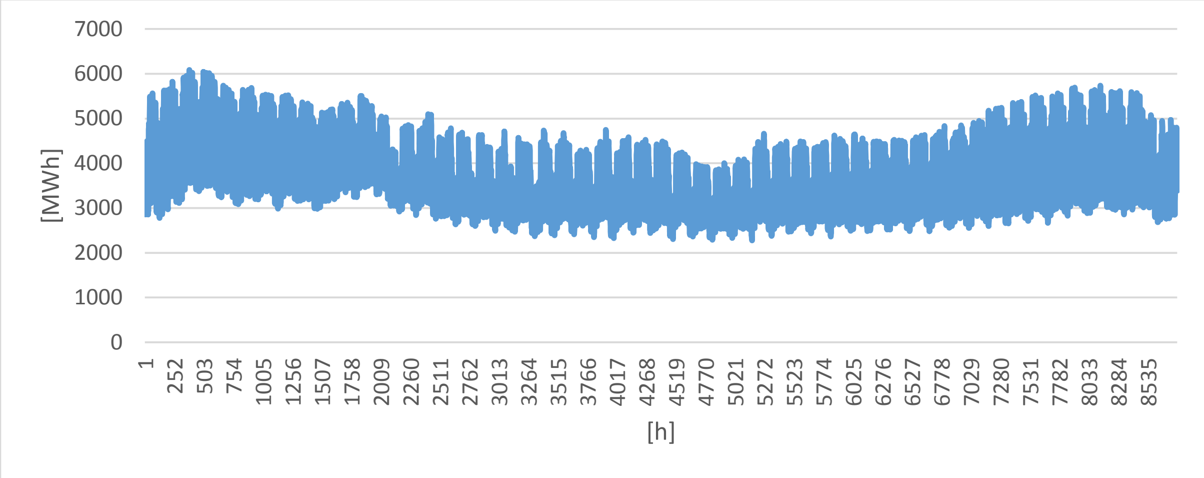
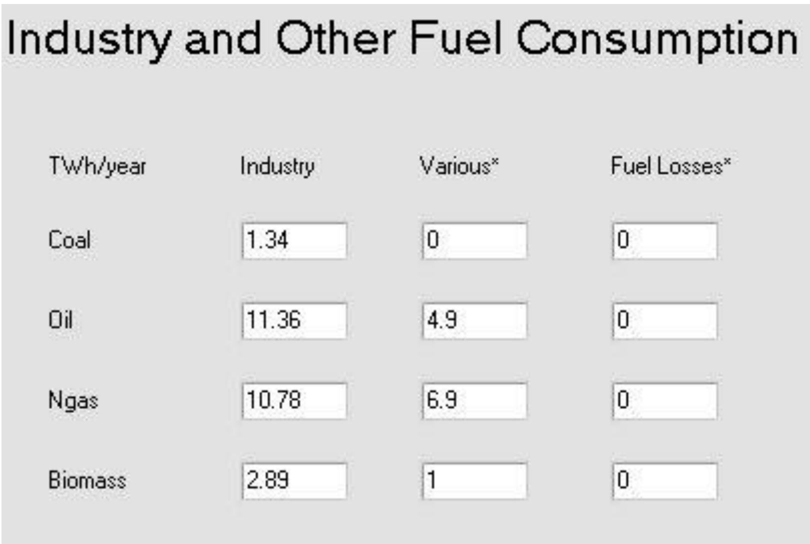


Figure 26. Electricity distribution curve named DK 2013 Electricity demand used in EnergyPLAN [30]

Curves *DK 2006 Individual heating demand.txt* and *DK 2006 District heating demand.txt*, already provided within the model, were used for distribution profiles of heating demand.

Oil and natural gas are fuels, which the industry has the largest demand for, while coal and biomass constitute only 10.8% of the total energy demand in industry.

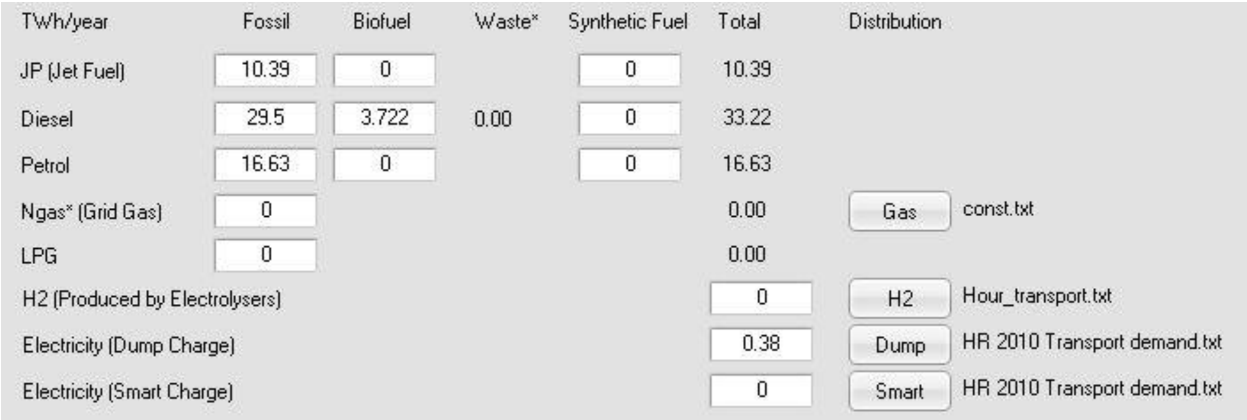


Industry and Other Fuel Consumption

TWh/year	Industry	Various*	Fuel Losses*
Coal	1.34	0	0
Oil	11.36	4.9	0
Ngas	10.78	6.9	0
Biomass	2.89	1	0

Figure 27. Industry fuel consumption [TWh/year] in the reference scenario

The transport sector's consumption can be seen in the Figure 28. By far, the largest share in consumption has the diesel fuel, while major demand also exists for petrol and jet fuel in aviation. Electric vehicles have only a minor share in the total energy demand for the transportation sector.



TWh/year	Fossil	Biofuel	Waste*	Synthetic Fuel	Total	Distribution	
JP (Jet Fuel)	10.39	0		0	10.39		
Diesel	29.5	3.722	0.00	0	33.22		
Petrol	16.63	0		0	16.63		
Ngas* (Grid Gas)	0				0.00	Gas	const.txt
LPG	0				0.00		
H2 (Produced by Electrolysers)					0	H2	Hour_transport.txt
Electricity (Dump Charge)					0.38	Dump	HR 2010 Transport demand.txt
Electricity (Smart Charge)					0	Smart	HR 2010 Transport demand.txt

Figure 28. Transportation fuel consumption [TWh/year], with included distribution curves in the reference scenario

Nevertheless, it can be noted that the biofuel has a certain share in total transportation energy demand, with a total consumption of 3.72 TWh per year.

5.1.2. Supply side in the reference model

Production side of the energy system in EnergyPLAN is divided into four main types of producers. Heat and electricity part, where power plants that combine production of electricity and heat are modelled, electricity only, where the power plants that produce only electricity are set, heat only, where power plants which produce only heating energy are modelled and waste power plants that can produce heat, electricity or biofuels. Moreover, three different groups within the system exist. Group 1 represents district heating systems with no CHP, group 2 represents district heating systems based on small CHP plants and group 3 represents district heating systems based on large CHP extraction plants.

CHP condensing power plants have a total capacity of 6,335 MW_e within the system, with the average electric efficiency of 39%. CHP back pressure power plants have a total capacity of 7,830 MW_e with the average electric efficiency around 35%. There is also some amount of industrial CHPs, yearly producing 0.26 TWh of electricity and 1.29 TWh of heating energy. Moreover, there is also a significant amount of central condensing power plants driven by oil, with the total capacity of 840 MW_e. There are no nuclear power plants, nor dammed hydro power in the current Danish energy system.

Intermittent Renewable Electricity

Renewable Energy Source	Capacity: MW	Stabilisation share	Distribution profile		Estimated Production TWh/year	Correction factor	Estimated Post Correction production
Wind	3531	0	Change	DK 2013 Wind or	7.71	-0.277	6.71
Offshore Wind	1271	0	Change	DK 2013 Wind of	2.52	0.618	4.35
Photo Voltaic	478.3	0	Change	DK Solar thermal.	0.33	0.35	0.41
River Hydro	9.9	0	Change	Croatia Run-of-riv	0.04	-0.99	0.02
Tidal	0	0	Change	hour_tidal_power	0.00	0	0.00
Wave Power	0	0	Change	Hour_wave_200	0.00	0	0.00
CSP Solar Power	0	0	Change	Hour_solar_prod1	0.00	0	0.00

Figure 29. RES capacity with the distribution curves used in the reference scenario [MW]

Out of renewable energy sources, the most significant share has wind energy, with the 3,531 MW of onshore and 1,271 MW of offshore capacity. Photovoltaics have also a significant share with the capacity of 478.3 MW. River hydro has only a minor share, while the other intermittent renewable energy sources are not represented in the current energy system.

Out of heat only producers, solar thermal has a small share with the total yearly production of 0.09 TWh of heating energy and there are no large-scale heat pumps in the current system. Lastly, the waste power plants produce 5.15 TWh of heating energy and 2.28 TWh of electricity during the year.

Fuel price alternative : Basic	Coal	FuelOil	Diesel Gasoil	Petrol/JP	Ngas	LPG	Waste	Biomass	Dry Biomass	Wet Biomass	Nuclear/Uranium Incl. handling etc.
Fuel Price (world market prices) (DKK/GJ)	2.696641	8.790941	11.7074C	11.8587E	5.890194	13.21744	+ 0	5.64899:	4.69798E	0	1.75

Figure 30. Fuel prices used in reference scenario [DKK/GJ]

On the latter figure fuel prices used in the system can be seen, while on the lower figure CO_2 content used in the model can be observed.

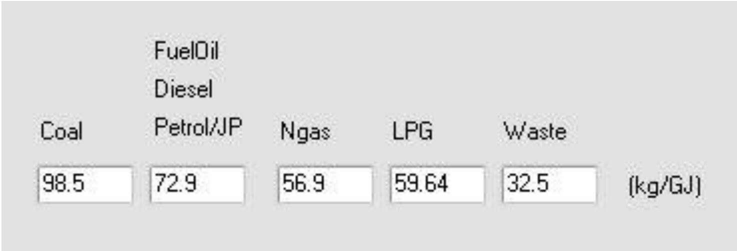


Figure 31. CO_2 content in fuels [kg/GJ]

Real discount rate used within the system is set to 3%. The reason why it is appropriate to use this low rate for investments in Danish energy system is discussed in detail in ref. [42]. The cost database used is provided and maintained by the EnergyPLAN developers and can be downloaded as a part of the software [30]. Moreover, the Danish Energy Agency updates expected changes in costs, and project future fuel costs. These projections were implemented into the cost sheet. Furthermore, all the investments, as well as the fuel costs are available in the Appendix I of this thesis.

5.2. BAU scenario

A target year in the business-as-usual scenario is 2020. The scenario was mostly developed by the data available in Danish energy outlook [43] and from Energinet's data [44].

The yearly consumption of electricity is forecasted to be 36.67 TWh [44], a raise of 8.9% compared to the year 2013. The total heating demand is 49.67 TWh, of which 29.77 TWh belongs to district heat and 19.90 TWh to individual heating. Moreover, the fuel mix of the individual heating sources changed a bit, i.e. the share of oil and natural gas fell 40% and 20%, respectively, while the share of biomass and individual HPs increased slightly. The total individual energy demand fell for 7.7% in the year 2020 compared to the base year.

In the transportation sector, increase in the number of electric vehicles occurs. In the year 2020, electricity demand for charging the electric vehicles rises to 0.59 TWh, which is a 55% increase compared to 2013. Consumption of other fuels remained the same compared to the reference year.

Nevertheless, other parts of the demand side remained at the same level as it was in the year 2013.

In the supply side of the energy system, a significant changes in penetration of renewable energy sources occurred between the years 2013 and 2020.

Intermittent Renewable Electricity

Renewable Energy Source	Capacity: MW	Stabilisation share	Distribution profile		Estimated Production TWh/year	Correction factor	Estimated Post Correction production
Wind	4231	0	Change	DK 2013 Wind or	9.23	-0.048	9.00
Offshore Wind	2671	0	Change	DK 2013 Wind of	5.29	0.7235	10.56
Photo Voltaic	1210	0	Change	DK Solar thermal.	0.84	0.35	1.04
River Hydro	9.9	0	Change	Croatia Run-of-riv	0.04	-0.99	0.02
Tidal	0	0	Change	hour_tidal_power	0.00	0	0.00
Wave Power	0	0	Change	Hour_wave_200	0.00	0	0.00
CSP Solar Power	0	0	Change	Hour_solar_prod1	0.00	0	0.00

Figure 32. RES capacity with the distribution curves used in the BAU scenario

It can be observed on the figure above, a significant increase in wind energy, both onshore and offshore, as well as photovoltaics. Onshore wind capacity increased for 700 MW, while offshore wind capacity increased for 1,400 MW, or more than 210%, comparing to the reference year. Such a significant increase is needed in order to meet the target of current legislation to generate at least 50% of the total electricity demand out of wind. Moreover, photovoltaics increased for more than 730 MW, which is equal to more than 250%.

Capacity of the large scale heat pumps in BAU scenario is set to 50 MW_e. Assumed average COP in all the scenarios will be 3.

Furthermore, minimum production by large power plants was reduced from 30% to 25% and minimum large-scale CHP plants production reduced from 550 MW to 200 MW, due to expected increase of the small CHPs power plant regulation. Thus, there will be no need for high amount of large-scale power plants regulation.

Lastly, other parts of the energy system remained the same as in reference year.

5.3. HP_alternative, HP_wind1, HP_wind2 and HP_storage scenarios

HP_alternative, as well as three other scenarios, were developed in order to assess the general total system costs levels, as well as to detect HPs optimal capacity in the systems with different wind power penetration and storage possibility. The result should present the minimum system cost for the certain heat pump level, at the given wind power penetration level.

In the *HP_alternative* scenario, wind power capacity is the same as in BAU scenario, thus 4,231 MW of onshore wind power and 2,671 MW of offshore wind capacity is installed in the system. Moreover, all the other data, except large-scale heat pumps capacity, are the same as in BAU scenario. Iterative manual procedure needs was carried out in order to detect the optimal large scale heat pumps penetration levels, where the total system cost is the lowest. Thus, the *HP_alternative* scenario has *that* heat pump capacity, for which the lowest total system costs are achieved.

HP_wind1 and *HP_wind2* scenarios are similar to the *HP_alternative* scenario with the exception of onshore wind power capacities. In the *HP_wind1* scenario the wind capacity is increased to 4,500 MW, which is a 6.5% increase compared to the levels in *HP_alternative* and BAU scenarios. On the other hand, in the *HP_wind2* scenario, the onshore wind capacity is reduced to 3,700 MW, which is a 12.5% reduction compared to the levels in *HP_alternative* and BAU scenarios. In both of these scenarios iterative procedure nedded to be carried out again, in order to detect the optimal capacities of the large-scale heat pumps. Once more, the optimal capacity of the heat pumps was chosen for the heat pump capacity in these two scenarios.

Lastly, in the *HP_storage* scenario, a large-scale pit thermal energy storage was added to the same system configuration as in *HP_alternative* scenario.

A pit thermal energy storage is a large pit in the ground, fitted with a plastic membrane and concrete walls. Water is the storage media, which is a cheap media with a high specific heat capacity value. Pit is covered with an insulated lid. The storage is rather cheap in terms of investment, as the walls are usually not insulated, except the ground that uses as an insulator, as the additional costs for insulation are higher than the energy losses. Significant economy-of-scale occurs in this kind of storages and thus, it is useful to construct large-scale storage instead of several smaller ones [45].

Storages with the total capacity of 600,000 m^3 will be added to the system. This scenario showed whether further increase in flexibility of the system can be achieved by a large-scale storage and how storages influence the total system costs.

Moreover, in the following table a short overview of the main differences between the scenarios has been provided.

Table 3. Overview of key differences between the scenarios

2020 scenarios				
BAU	*HP_alternative*	*HP_wind1*	*HP_wind2*	*HP_storage*
Implemented policy measure of minimum 50% of electricity generated by wind	BAU + optimal large scale heat pump capacity	*HP_alternative* + 4500 MW of onshore wind capacity	*HP_alternative* + 3700 MW of onshore wind capacity	*HP_alternative* + 600.000 m^3 of pit thermal energy storage

6. ENERGYPLAN VS. MARKAL/TIMES: A REVIEW

This review is based on the general description of models provided in chapters 3 and 4, as well as on detailed comparison of similar studies carried out in both models, which is provided in Appendix III.

The easiest way to understand differences of EnergyPLAN model and TIMES model generator is to distinguish the main features of each of the models. During the analyses carried out, a three main different features can be detected between the EnergyPLAN and the TIMES:

I. Simulation vs. optimization
II. Top-down vs. bottom-up
III. Model vs. model generator

Ad I.) Very important differences between EnergyPLAN model and TIMES/MARKAL model generator rise from its origin. TIMES and MARKAL are *optimization* types of models, which mean that they seek to find *the best of all alternative solutions*. Output of the optimization model are values of variables that need to be set in the resulting order of the model, in order to achieve some goal, usually maximum or minimum of the objective function. It is vitally for optimization model to have three components: the objective function that describes the target of the optimization, decision variables which need to be set in specific way in order to achieve *the best of all solutions* and constraints which embody boundaries of the values that decision variables are allowed to approach.

In TIMES model generator, flows and capacity investments present decision variables that are solution of the problem set. Thus, the model does not optimize the technological system, it rather optimizes investments in different technologies. Two options for objective function exist, to minimize total system costs, or to maximize total surplus (of both suppliers and consumers). Constrains can be set to demands, commodity balances and flow-capacities. However, it should be sought for the model with the lowest possible number of constraints, which should be used ideally only for constraining non-physical solutions.

On the other hand, EnergyPLAN is a *simulation model*. A simulation means to imitate or mimic the real system, in order to be able to study its behavior. Simulation is a usual tool to investigate how changes in certain variables will affect functioning of the system. As opposite to optimization models that are prescriptive, simulation models are descriptive, i.e. simulation models does not calculate how the certain variables should be set in order to achieve *the best of all solutions*, it only foresights what will happen in a certain situation. Furthermore, a simulation system is completely described in terms of unknown variables and number of associated equations, and thus, iteration procedures are not a part of models. However, iteration procedures can be carried out by a modeler, which can be used for optimizing the technologic system. Two main components that each simulation model needs to have are representation of the physical world relevant to the problem which needs to be assessed and decision making variables, which mimics the behavior of the different parts of the system. In the case of EnergyPLAN simulation model, the physical system that is mimicked is energy system with all of its components. Decision variables are set by equations that decide which power plant generates the energy the first, which the second and which the last. As the simulation model mimics the system, the *time* is inseparable part of the model and the system can be observed in any time step defined by the modeler during its pathway to the final time point of observing the system. Thus, in EnergyPLAN the energy system behavior can be observed in every hour, which is a valuable feature for detecting non-optimal usage of any of the technology, which allows a researcher to implement certain changes in order to optimize technologic system.

However, both simulation and optimization models have its strengths and weaknesses. Optimization is a useful technique if the problem under consideration is described in order to seek for one optimal of several well-defined alternatives. Moreover, if the term optimal is well described and the system is relatively static without feedback, optimization is a valid technique to be used [46]. On the other hand, limitations of optimization models are usually connected with definition of the objective value, unrealistic linearity, lack of feedback and lack of dynamics [46]. However, finding the objective value is seldom a problem when considering energy systems, as this is usually finding a minimum of total system costs, while unrealistic linearity, lack of feedback and lack of dynamics presents a problem for the optimization model such as TIMES.

Linearity is used often in optimization models, as this shortens computation time significantly. This is especially of importance when dealing with large models, such as one considering the whole World's energy system. Moreover, very popular optimization techniques, such as linear programming, requires that the objective function, as well as all the constraints to be linear [47]. TIMES/MARKAL modelling tools also use linear optimization technique, in order to simplify system due to the large number of system interactions taken into account. Thus, while modelling a specific system, it is important to set the proper boundaries of the problem, in order not to describe highly non-linear problems with linear functions and equations.

Lack of feedback is also often a problem in optimization models. Due to simplifications, models often ignore all or some of the feedbacks, as feedback are usually non-linear and increase computation times. It was shown how this happened in the Danish example in TIMES, where the gas power plants capacity was simply put as exogenous variable and thus, there was no more possibility to include feedback into the model. Details about this example can be seen in Appendix III. Moreover, when exogenous variables are used in the model, the model automatically ignores the feedback effects, as the exogenous variables aren't calculated by the model. Furthermore, exogenous variables should be avoided as much as possible, as they narrow the boundaries of the problem set [46]. However, as we have seen in several models developed in TIMES, especially in the case study of Denmark, exogenous variables were often set, such as constraint on gas power plants share, as well as renewable energy sources penetration. As a consequence, ignoring feedback can cause unanticipated results. Lack of feedback and dynamics is the biggest issue TIMES model has to cope with, when trying to implement renewable energy sources on a large-scale. As the system with the large share of the intermittent sources has a lot of dynamics, excluding it can cause unanticipated results.

Optimization models itself does not recognize time span of the problem considered, they rather represent an optimal solution for a particular moment in time, without considering pathways of approaching the optimal state. However, this problem tried to be diminished in MARKAL/TIMES family of models by introducing time steps (most often five year intervals), which can provide certain pathways to the optimal solution. When introducing time steps in TIMES/MARKAL, model performs several optimizations, one for each time step, instead of only one for the final point. The model optimizes the investments and energy flows, while seeking for the lowest total system cost (global optimum) in each time step and thus, every result of the optimization presents one time step. However, this kind of several optimization steps can cause certain problems, as for example the optimal solution in the fifth year can turn away the system from optimal point in some future step. The model results show the optimal energy and investment mix of each time step. However, these models are still not incorporating dynamics of the system because it cannot incorporate time delays in investments and inventions of new technologies. It only assumes that decisions are brought in each time step in order to achieve optimal solution in the future time step [46].

On the other hand, simulation models deal well with the feedback effects, non-linearities and dynamics. Moreover, simulation models are indeed often used to determine feedback effects and dynamics of the system. Taking these factors into the consideration, the EnergyPLAN is well suited for modelling systems with a lot of dynamics, such as systems with increased production of energy from intermittent renewable energy sources. Moreover, it enables 100% renewable energy systems to be modelled within the EnergyPLAN.

However, weak points of the simulation models are mainly connected with the description of the decision variables and the quantification of the “soft” variables, i.e. the variables that in nature are not quantifiable. Moreover, the choice of the boundaries of the system can provide issues in certain models.

Accuracy of the decision rules is achieved by describing the real actions of the actors of the system, which do not need to be optimal actions. In the energy systems however this is seldom a problem, as the supply side of the energy systems usually follows the business logic and usually does not provide illogical decisions. Thus, if optimal decisions can be described, the model will most probably achieve the accurate result. However, simulating the demand side of the system would be much more complicated and subjected to decisions different than optimal, if the human behavior would be taken into account.

Nevertheless, system boundaries are always a question that is raised when building up a simulation model. Should the model incorporate all the single power stations, or aggregated stations? Should the model encompass economic consequences of certain changes and imposed taxes? Demand and supply side, or only one side of the markets? These and many other questions are those that modeler have to take into account when developing the model. It is of especial importance to check the boundaries set to the system by conducting sensitivity analyses, in order to try to find a robust solution. A model which results could be radically changed by setting parameters only slightly different is not a good model, as the small changes in reality will cause unpredicted consequences. Thus, the sensitivity analyses of the model should encompass analyses of parameters uncertainty, conclusions sensitivity, as well as the sensitivity to structural assumptions and choices of the model boundary [46].

To sum up, both optimization and simulation models can be suited well for characterizing the energy systems, if and only if certain preconditions are achieved. Optimization models are a good option if several, or many alternatives are possible, each of it is well described and system can be considered as static and linear. Moreover, it can be a good solution for investment decisions, due to its nature of finding a minimum of an objective function, which is a total system cost in this case. However, describing the system, and especially treating regulation problems with a high share of renewable and intermittent energy sources is especially tough to cope with in optimization problems, as the optimization model does not recognize time in its calculations and thus, representation of intermittent sources is challenging task that can only be solved by imposing a lot of constraints. Thus, in the case of high penetration of renewable energy sources, as it is the case in Denmark, EnergyPLAN has advantageous properties compared to TIMES/MARKAL family of models, as it is able to cope with all of the problems renewable energy systems impose on the system. On the other hand, TIMES should be rather considered as a tool for investment decisions on the large-scale that takes into account many cross-sectional linkages between primary energy sources' supply and demand, technical system and demand for the energy. However, interrelations in technical system cannot be modelled in detail due to lack of possibility to describe non-linear relations and to take feedback and dynamics of the technical system into account.

Ad II.) The large number of techno-economic models can be broadly divided into *top-down* and *bottom-up* models. Bottom-up models are technologically oriented and treat energy demand as either set, or as a function of energy prices, national income and other factors [48]. Thus, it can also be said that these kind of models are partial-equilibrium models, where demand and supply equilibrium is achieved within the model. Technology of the demand side of these models is often described in great detail and changes in technologies occurs when new technologies have lower costs than the old technologies. As a consequence, technology change is explicitly described technology by technology [48].

TIMES/MARKAL family of models are representatives of the bottom-up model, as technologies considered within the model are described in great detail and partial-equilibrium state is achieved as a part of the model. However, as they encompass some of the macro economy features, such as different discount rates for different technologies, as well as vintaging of technologies, it is up to one point also a top-down model.

On the other hand, top-down models can involve the entire macro economy and describe interrelationship between labor, capital and natural resources such as energy [48]. Energy demand in top-down models is a result of previously mentioned interrelationships [48]. Top-down models do not represent technologies in a great detail, they rather use aggregated approach. As the top-down models aren't technology explicit, compared to bottom-up models, they can have erroneous conclusions about the technology development [48].

However, as the system boundaries of the EnergyPLAN model are set on technical energy-conversion system, and demand side, as well as resources depletion is not within the scope of the model, description of economic relationship is left out of the model. The model rather deals with the impacts of different technologies on the system. In that sense, EnergyPLAN has characteristics of both top-down and bottom-up model. It is a technology rich model, which is a characteristic of a bottom-up model, but it uses also aggregation of certain power plants, such as three different types (groups) of power plants in a district heating system.

It was argued in Wilson and Swisher [49] that the climate change mitigation policies indicate lower costs in the bottom-up models than in the top-down models. One explanation of this phenomena was given in Jaccard et al. [50], where it was argued that top-down models are to a large extent based on historical data of substitution the fossil-intensive technologies without willingness to change the system and as a consequence, performing technology change becomes relatively higher. On the other hand, bottom-up models include large variety of low-fossil and renewable technologies that may reduce the operating costs in the future, as well as increase its performance and thus, become competitive under future policies [48]. EnergyPLAN model does not contain almost any of the abovementioned problems as although it is a top-down model, it is still a technology rich model, with a lot of "*new*" and "*traditional*" technologies encompassed within the model. Moreover, all the economic data, such as investment costs, discount rate, fossil fuel costs, fixed and variable operating and maintenance costs etc. are exogenously entered into the model and thus, the model itself cannot provide errors in that area. The possible errors can only originate from the faulty assumptions when entering the data in the model. Moreover, demand side of the system is also exogenously set in the model and should be modelled within the scope of some other model, dealing with the demand side of the energy system. Nevertheless, the costs of climate-change mitigation policies cannot be compared in these two models, as the most of the economic results of the TIMES family of models are not published in the main ETSAP publishing [24] [27].

Ad III.) Lastly, the major difference between these two tools corresponds to the general difference between *model* and *model generator*. EnergyPLAN is a fully developed model, which is ready for entering the data after the installation. It already contains the relations, equations and different factors built and integrated into the software and thus, the user cannot change the model parts' relations in that way. The user has only an option to use or not to use certain technology incorporated within the model. However, this is seldom a problem, as the EnergyPLAN is a technology rich model. Thus, EnergyPLAN is easy to use and fast to learn, but constraints the user only to technologies included within the model. However, number of case studies developed in EnergyPLAN shows that the tool is well-suited for purposes of incorporating renewable energy sources on a large scale.

On the other hand, TIMES and MARKAL are model generators, where the model needs to be developed by modeler using the tool. Thus, the modeler needs to be somewhat proficient in use of the tool. Furthermore, the development of the detailed bottom-up model requires a great amount of time, up to the several months. That is the reason why TIMES/MARKAL models continually develops and expands with a new data and is seldom build from scratch. Thus, it gives a modeler the possibility to put the boundaries of the model around the specific point, but requires a great amount of time to learn how to model within the tool and also to build a model.

To sum up, choosing the appropriate tool for modelling of certain system is not an easy decision and needs to be carefully approached in order to achieve the best possible outcome. Whether to use EnergyPLAN model or TIMES/MARKAL modelling tool, or some other model, depends upon several factors such as the renewable energy sources penetration, importance of detailed description of certain technologies, importance of assessing cross-sectional influence, number of alternative systems, importance of demand side role in the system, etc.

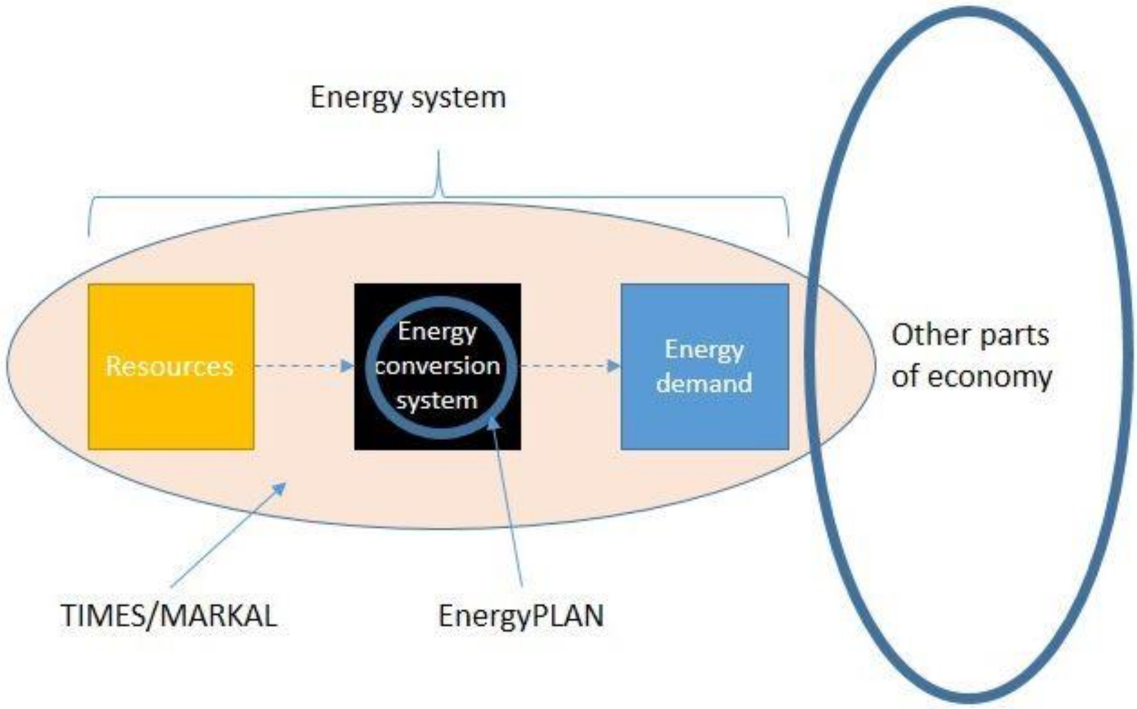


Figure 33. System boundaries of the TIMES/MARKAL and EnergyPLAN tools

EnergyPLAN is a better tool to use for fast calculations with a high penetration of renewable energy sources, where intermittency cannot be modelled properly within an optimization model. Furthermore, when a single technology behavior on the overall system needs to be evaluated, EnergyPLAN is a right choice of tool. Moreover, it is the right tool for assessing the behavior of the whole systems, with a lot of dynamics and important feedback within the system. Figure 33. shows the system boundaries of the EnergyPLAN model, from which it can be concluded that the *EnergyPLAN modelling tool is good as its assumptions about the resources, energy demand and the rest of the macro economy are*. If this exogenous data is valid and can be entered into the model safely without the false assumptions, the simulation will result in a valid result. Nevertheless, if understanding of the energy system behavior is a necessity, the simulation tool such as EnergyPLAN is the only possibility, as detailed results in every time step needed is possible to obtain from the model.

The possibilities of the EnergyPLAN model can also be seen by the type of studies it was used for. It was used for analyzing the large-scale integration of wind, for optimal combinations of renewable energy sources, management of surplus electricity, the integration of wind using V2G concept, the implementation of small-scale CHP, integration of systems and local energy markets, renewable energy strategies, the use of waste, fuel cells and electrolysers and the effect of thermal energy storage [25].

TIMES/MARKAL model generators are a good choice if complicated systems need to be represented, where a large number of technologies and investment alternatives exist and need to be assessed in the same time. Furthermore, systems with the large oscillations in performance of the same type of power plants, where aggregated data does not represent a real situation, can be properly described in this bottom-up model generator. Moreover, problems where different factors influence supply and demand side and fossil fuel depletion plays an important role can all be modelled in detail. However, the assumed linearity, lack of dynamics and feedback, and problems connected with the usage of exogenous variables need to be addressed and taken into account when developing the model. These problems are especially difficult to handle when a system with a large share of intermittent sources needs to be addressed.

TIMES/MARKAL models were used for countless studies which assess hydrogen and fuel cells, hydrogen vehicles, future role of nuclear power and nuclear fusion, and the impacts of wind power on the future use of fuels, as well as for other studies for which the general description was provided in chapter 3. However, although it was used for numerous studies, it was not used for modelling 100% renewable energy systems due to obstacles already discussed above.

Nevertheless, in order to facilitate overview of these two tools, a table with the favorable and non-favorable features has been provided:

Table 4. Overview of EnergyPLAN and TIMES tools

TIMES model generator	**EnergyPLAN**
Lack of feedback	**A lot of feedback**
Lack of dynamics	**A lot of dynamics**
Assumed linearity in the system	**Non-linear system**
A model generator – modeler able to build up a model with boundaries exactly as needed for certain purpose, but takes some time for practice and a lot of time to build a model from scratch	**A model-easy to use and fast to learn,** but cannot be modified by a modeler
Rich in technology	**Rich in technology**
Not modelled 100% renewable	**Modelled 100% renewable system**
Optimizing investments, but cannot optimize technical system	**Optimizing technical system,** but investments can only be optimized by carring out manual iterative procedure
Cannot observe the system changes during the time, only starting and end point	**Possible to observe system changes down to the hourly resolution**
Possibile to take into account vintaging of technologies	Not possibile to take into account vintaging of technologies
Possible different discount rates for different technologies	Different discount rates for different technologies not possible
Cannot incorporate delays in investments	Cannot incorporate delays in investments

7. ELASTICITY OF ELECTRICITY DEMAND

Using the methodology described in chapter 2, price elasticity of demand was calculated for the years 2011, 2012, 2013 and 2014. In order to calculate price elasticity on hourly resolution, a significant amount of data needed to be handled. In the first step, all the daily data about the construction of supply-demand curve was merged in order to gain the data for the whole year in a single matrix. In order to imagine the amount of data needed to be handled, a few facts will be provided here.

The data for a single date usually contains 24 columns with between 1,000 and 2,000 rows. Its size is most often between 1.5 and 2.5 MB. Merging all this data in one matrix results in a matrix with 24 columns and incredible 474,500 rows, sizing between 100 and 150 MB. The Matlab© code was developed in order to increase the speed of calculating the hourly price elasticity, as this significant amount of data needs to be handled several times, resulting from the fact that the hourly price elasticity needs to be calculated for four consecutive years. The Matlab code needs a 474,500 x 24 matrix consisting the data about the price and volume bids, which are used for construction of supply and demand curves in each hour. The number of 474,500 rows is obtained by multiplying 365 days with 1,300 rows that contain supply and demand bids for one hour. The 24 columns exist as one column represents bids in one hour. In order to process all the data well, the data about the bids needs to be sequenced chronologically, starting from the 1st of January and finishing with the data from the 31st of December.

Furthermore, two more matrices are needed, one containing equilibrium prices set in each hour and one containing equilibrium quantities traded in each hour. These data can be accessed free on the Nordpool website. Matrix size of both of these matrices is 365 x 24, the number obtained by multiplying a one day data on hourly resolution (1 x 24 matrix size) by 365 days. Both of these matrices need to be sequenced chronologically, too.

After these three matrices are imported in Matlab, the code performs calculations and provides the output consisting of price elasticity of demand on hourly resolution, as well as mean price elasticity during the one year. In order to make the calculation faster, loops were avoided wherever possible. As a result, the calculation of one year data lasts between 50 and 60 seconds on low to medium performance computer (2 GB of RAM, 2.2 GHz dual core processor).

In 2011 average elasticity was -0.058, which means that for a 1% increase in price, demand for electricity falls for only 0.058% in average. Thus, it can be concluded that the demand for electricity was notably inelastic. Moreover, it can be also concluded that the demand for electricity is almost fixed, no matter on changes in prices. The average yearly price was 47.05 €/MWh.

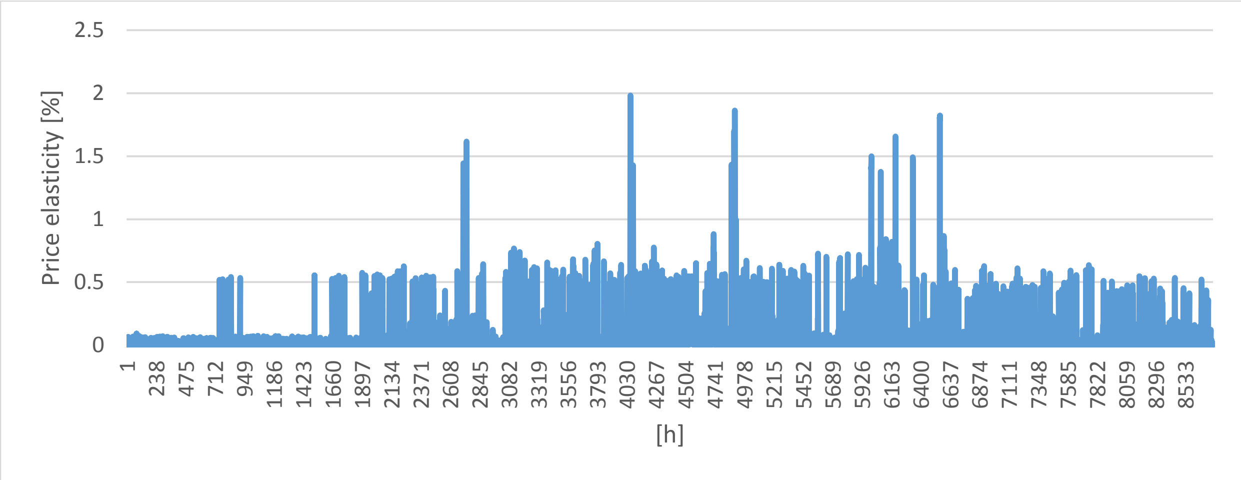


Figure 34. Absolute elasticity in 2011

On 25 occasions demand was price elastic in 2011, i.e. 25 times price elasticity of demand was larger than 1. All of these cases correspond with the very low electricity price, below 15 €/MWh. It can be observed that the price elasticity in the first 1,500 hours is very low. This corresponds with the very high electricity prices that occurred in the beginning of the year, which can be seen in the following figure:

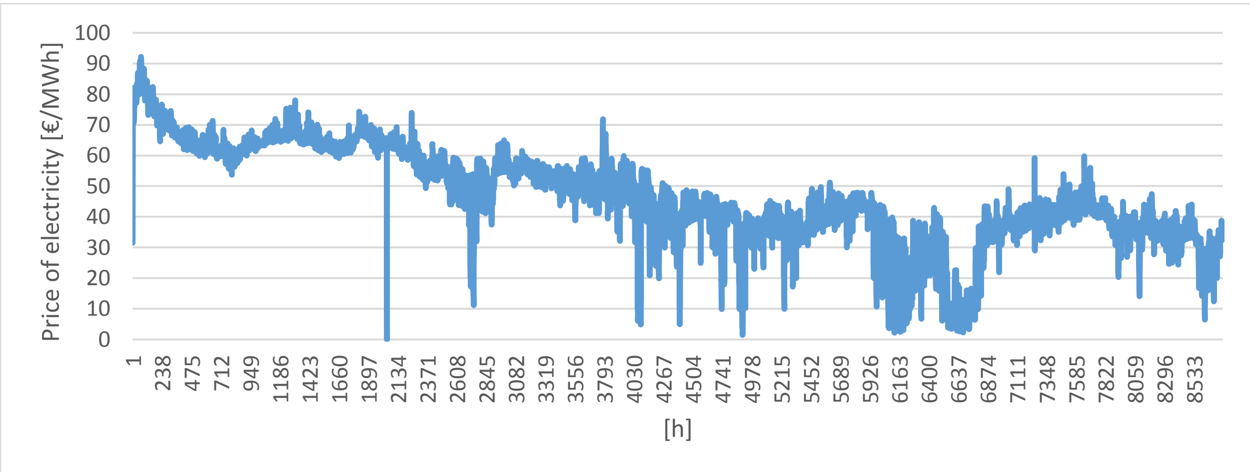


Figure 35. Horuly electricity prices for the year 2011 [20]

If comparison of the latter two figure is made, it can be also noted that a few hikes in absolute price elasticity between the 6,000th and 7,000th hour corresponds with troughs in electricity prices.

In 2012, the average elasticity dropped to -0.029, while the average electricity price was 31.19 €/MWh. This means that in 2012 demand for electricity is even more inelastic and that the demand is set for a given hour with a very little influence of prices.

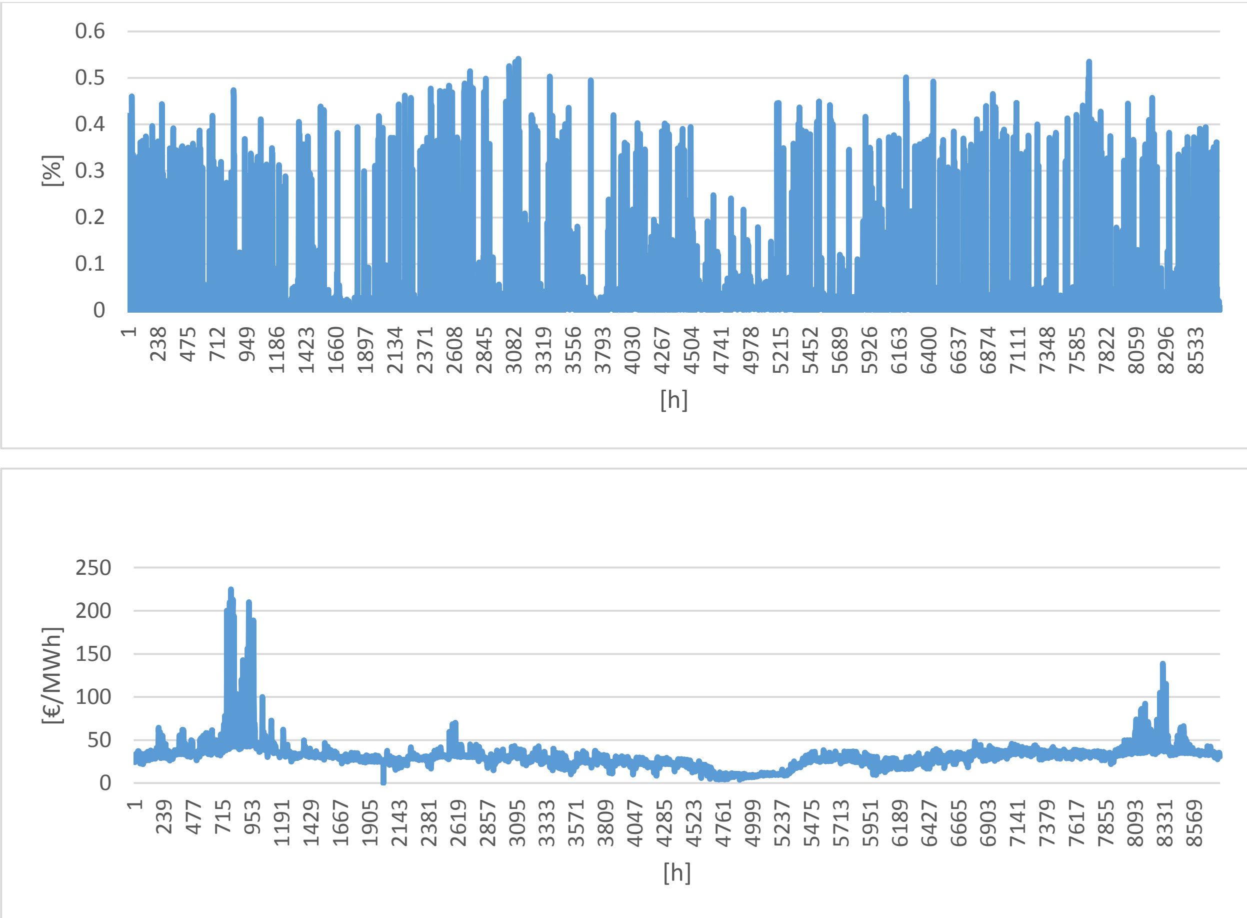
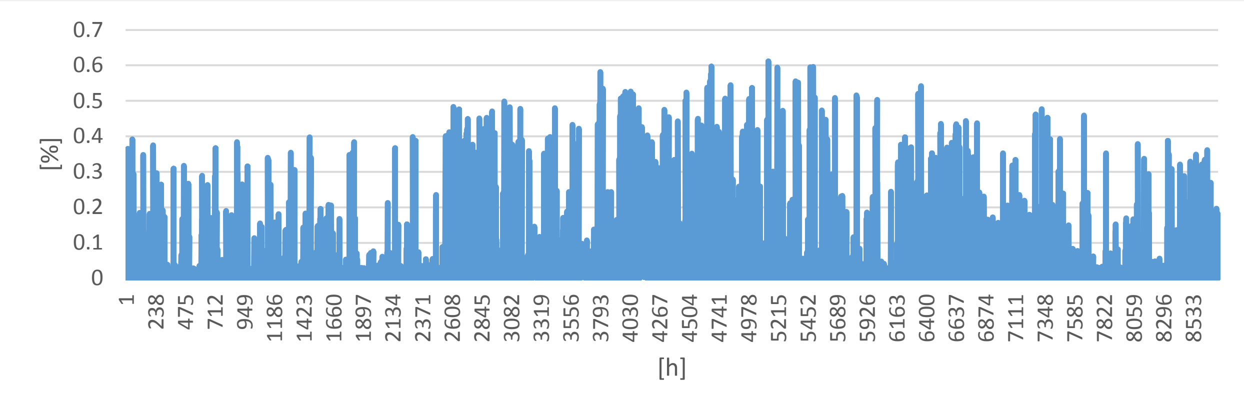


Figure 36. Absolute price elasticity of demand (up) and electricity prices (down) in 2012 [20]

In 2012 there was not a single hour where demand was price elastic, i.e. where price elasticity was larger than one. Moreover, the price elasticity never exceeded 0.6. However, it is interesting to note here that during the period of extremely high electricity prices between 770th and 943rd hour, where the prices several times peaked at more than 200 €/MWh, price elasticity was close to yearly average, i.e. average price elasticity in those hours was -0.021. Thus, it can be concluded that there is no clear linkage between the electricity prices and the price elasticity of demand.

In the year 2013, the average elasticity fell slightly more, to -0.0278, while the average electricity price in the same year was 38.16 €/kWh, 22% higher than in 2012. Thus, in 2012 the demand for electricity was price inelastic again.



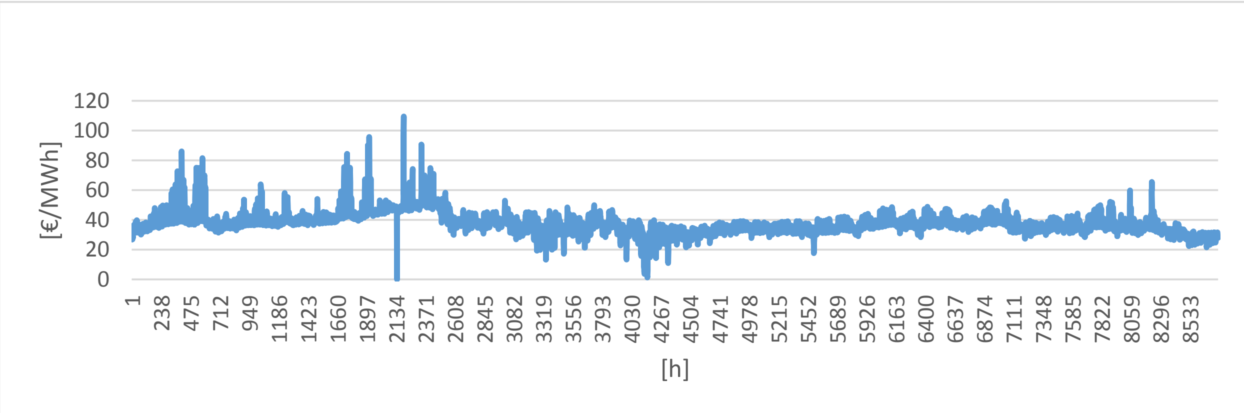
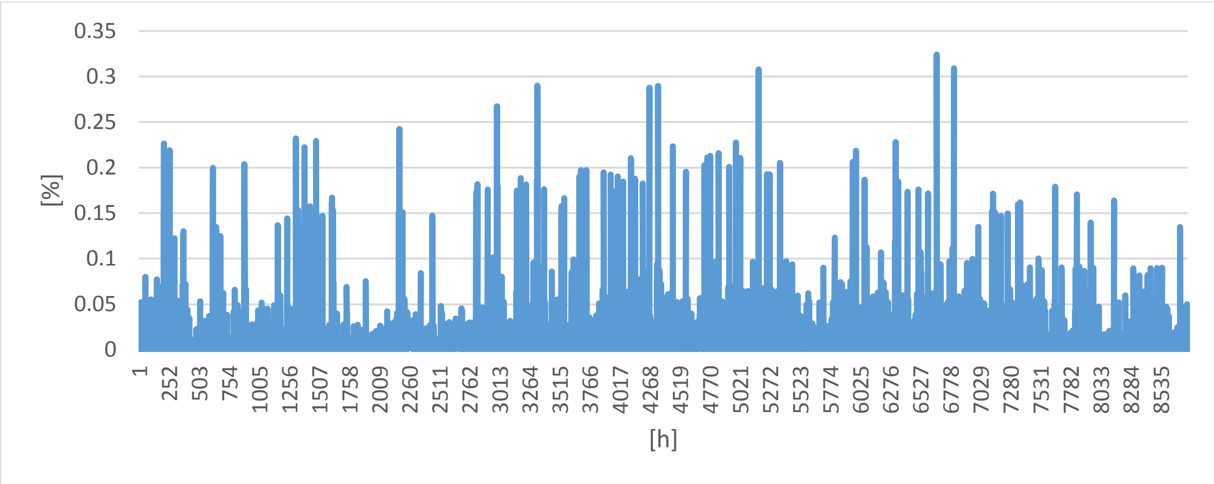


Figure 37. Absolute price elasticity of demand (up) and electricity prices (down) in 2013 [20]

It can be noticed that the price peaked in one hour slightly above the 0.6. Moreover, a minor correlation between the prices and elasticity can be noted here. In the period with peaks in electricity prices, between 1500th and 2400th hour, the elasticity went to a very low values. Furthermore, during the summer, in the middle part of the chart, when the average price of electricity is slightly lower than in other parts of the year, price elasticity often has peaks around the 0.5. However, the demand is overall still very inelastic.

Lastly, in 2014 price elasticity went even lower, to -0.010, while the average electricity price was 29.63 €/MWh during the same year. Thus, the average price level was similar to the year 2012 and 23% lower compared to 2013. If we compare years 2012 and 2014, where the average price level of electricity was almost the same, it is interesting to note that in 2014 price elasticity is 65% lower. As a consequence, the demand is almost completely inelastic in 2014, as for the increase in price for 1%, demand would lower only 0.01%.



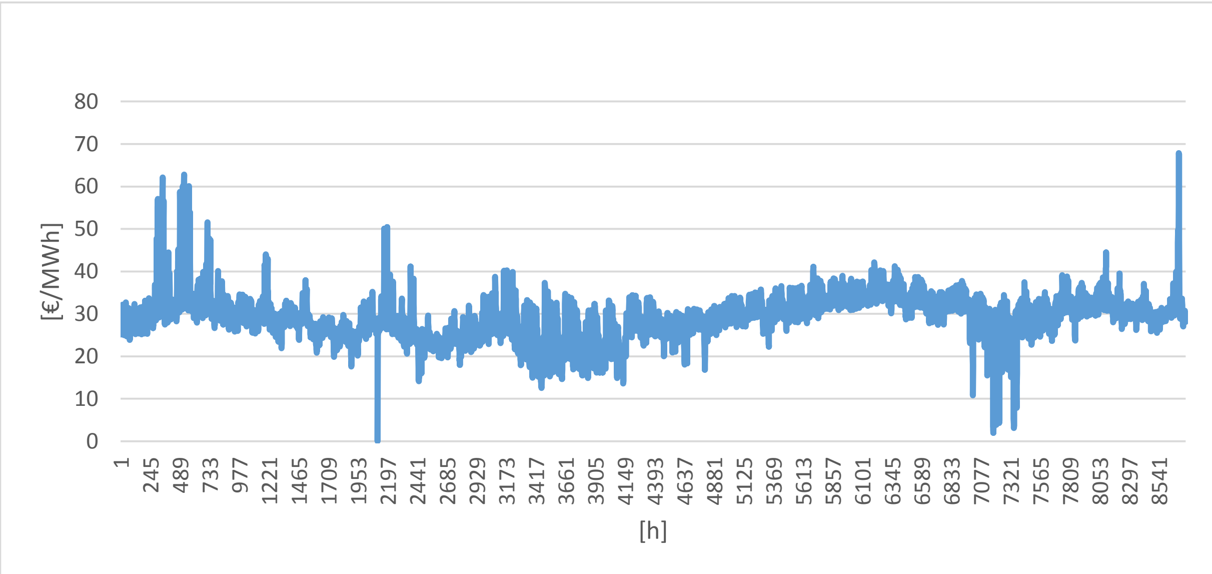


Figure 38. Absolute price elasticity of demand (up) and electricity prices (down) in 2014 [20]

In the year 2014, even the span of price elasticity is rather low, as it never peaks above the 0.35. It can be noted here that in the middle part of the year, during the summer, price elasticity peaks more often, while the electricity price is slightly lower than average for the same period.

In the following table, the data about seasonal average price elasticity, as well as electricity prices are provided.

Table 5. Seasonal mean price elasticity and electricity prices

	2011	2012	2013	2014	Average
Price elasticity					
Winter	0.024	0.028	0.022	0.008	0.020
Spring	0.066	0.033	0.034	0.011	0.036
Summer	0.086	0.031	0.035	0.012	0.041
Autumn	0.059	0.025	0.023	0.009	0.029
Average	0.059	0.029	0.028	0.010	0.032
Electricity price					
Winter	47.6	38.0	35.1	31.1	37.9
Spring	54.3	28.7	40.6	25.6	37.3
Summer	37.5	20.4	34.8	31.3	31.0
Autumn	34.2	36.8	37.0	30.9	34.7
Average	43.4	31.0	36.9	29.7	35.2

As it can be spotted in the table, the highest price elasticity occurs when the prices are the lowest, which happens during the summer. On the other hand, the lowest elasticity can be observed in winter, when the electricity price are the highest. However, vagueness in results brings up spring period when the average price levels of electricity are only a bit lower compared to winter seasons, but the elasticity is significantly larger.

Furthermore, if we take a look at the yearly trends in price elasticity, there is still ambiguity present in the results.

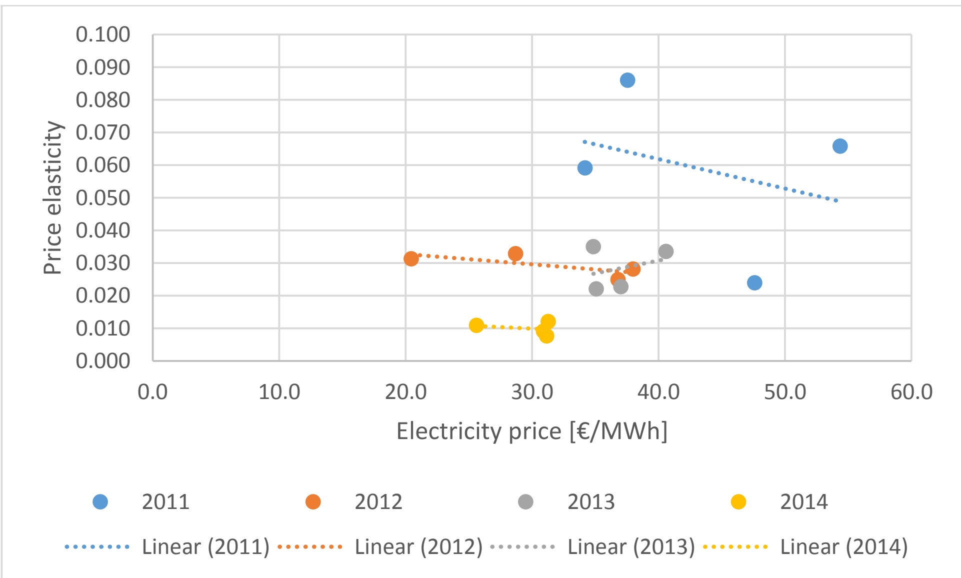


Figure 39. Trends in price elasticity in years 2011-2014

As it can be seen, the year 2013 raises questions about the results, as in that year average seasonal price elasticity rises with the higher prices, as opposite to all the other years.

Moreover, it is important to note that price elasticity of the demand is rather low in all the cases, with the average level never exceeding 0.09. This means that even in the most elastic period, demand would lower for only 0.09% for the increase in price of 1%, which is still very inelastic.

Moreover, the reason why there is no clear trendline between general price levels and the elasticity can be found in the shape of the demand curve that most often occurs. The demand is usually a curve with almost no slope in its central part and with the large slope on its edges. This results in almost the steady demand, no matter the price levels are. It can be also the consequence of the fact that the final consumers do not play a significant role on the market, because their final price per energy unit is the same in each hour, no matter what the price at the market is. Thus, there is no need for them to adjust their consumption to the prices set on market, as the spending on energy for the final consumer is the same in every case.

However, from the current point of view, it can be concluded that a raise in demand, due to usage of electricity for driving the large scale heat pumps won't cause a significant increase in average electricity price levels, as the price elasticity of the demand is very inelastic.

8. COMPARISON OF LEVELIZED COSTS OF HEATING ENERGY: HEAT PUMPS VS. ELECTRIC BOILERS

The methodology described in chapter 2 was used in order to determine the production cost per unit of energy. It is important to keep in mind that equivalent of full load running hours *H* was used, which means that the technology can run more hours, but the number of running hours needs to be scaled to the number of equivalent full load hours. Thus, in order to visualize difference in LCOH, the number of equivalent full load running hours was set as the sliding parameter in calculations, with time step of 1,000 hours. Moreover, the data used in equations provided can be seen in Table 4.

Table 6. The data used for calculating the LCOH [30] [42] [43]

	Heat Pump	Electric Boiler
Specific investment [€/kW$_t$]	840	90
Technical lifetime [years]	20	20
Equity [%]	20	20
Debt [%]	80	80
Equity discount rate [%]	10	10
Debt discount rate [%]	3	3
Major revision [% of investment]	10	10
Major revision frequency [years]	10	10
Revision interest rate [%]	10	10
Fixed O&M [(€/kW)/year]	5.5	1.1
Variable O&M [€/kWh]	0.0005	0.0005

The price of electricity is an important factor when calculating the LCOH, as it is the variable operation cost for these two technologies. Moreover, it is especially important for the electric boilers, as investment in electric boilers is asset-light technology, where the electricity cost has a significant share in total spending. Thus, three different price levels were used when evaluating the LCOH. The first two price levels were set at 39.38 €/MWh$_e$ and 29.56 €/MWh$_e$, which are the average electricity price levels in two Denmark trading regions for the years 2013 and average electricity system price on the Nordpool for the year 2012. The third price level was set at 16 €/MWh, in order to assess LCOH in the time of very low electricity price, when these two technologies will most likely be exploited.

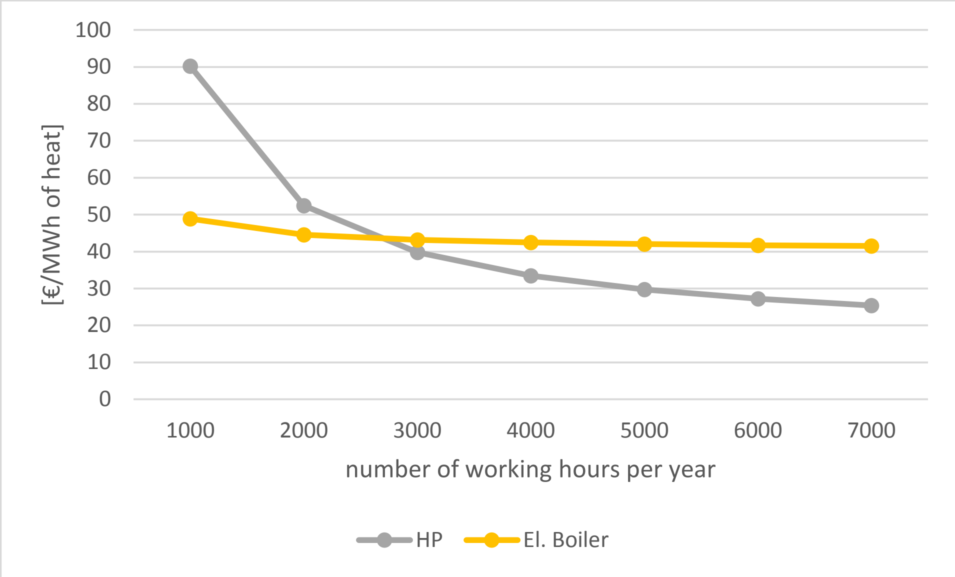


Figure 40. LCOH with the electricity price level set at 39.38 €/MWh

As it can be seen, the LCOH of heat pump sharply declines between 1,000 and 3,000 running hours. The two curves intersect in 2,610th full-load hour, after which the LCOH of heat pump becomes lower than the LCOH of electric boiler. Thus, this short business feasibility study shows that the heat pump investment would be better if the number of equivalent full-load running hours would be larger than 2,610 hours. Contrary, if the number of running hours would be lower than 2,610, investment in electric boiler would be better.

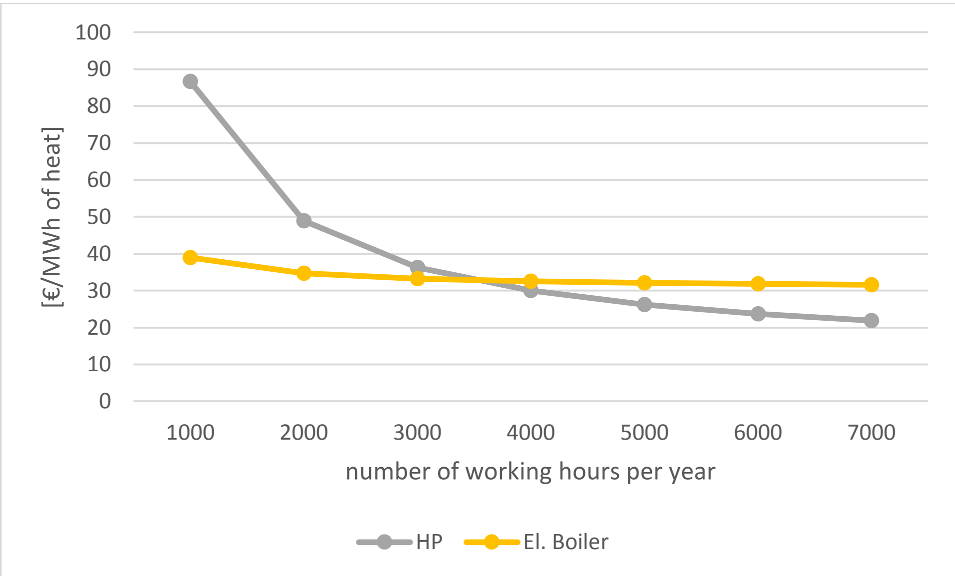


Figure 41. LCOH with the electricity price level set at 29.56 €/MWh

As it can be seen, if the electricity price is lower, the intersection point where the LCOH of heat pump becomes lower than LCOH of electric boiler shifts to the right, i.e. to the larger number of working hours. In these case, the intersection point is at 3,475th hour. Thus, the heat pump should be operating more than 40% of the year at average electricity price in order to become better investment, from the business point of view.

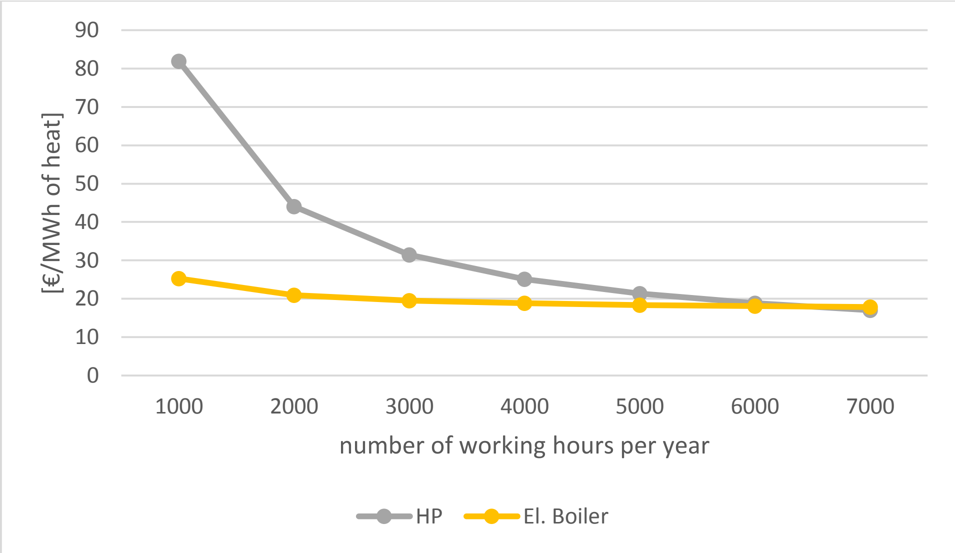


Figure 42. LCOH with the electricity price level set at 16 €/MWh

As it can be observed in the figure above, the intersection point moved far to the right and two curves intersect at 6,420th full-load hour. Thus, the number of hours with this low electricity price should be very large in order to investment in heat pump becomes economic feasible compared to the investment in electric boiler. However, this is not the case as the number of hours with the price smaller or equal to 16 €/MWh$_e$ was 583 in 2013 and 302 in 2012 on the two Danish trading regions.

If we connect all the points where two curves intersect, for different levels of electricity price, the following figure is constructed:

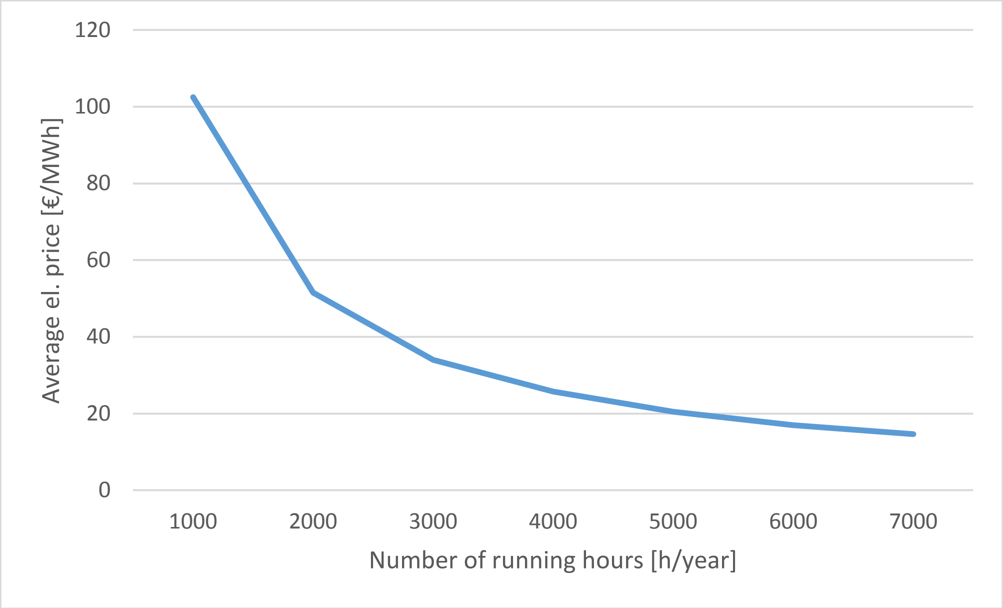


Figure 43. Heat pumps and electrical boilers' LCOH intersection points

Thus, it can be read from the curve above for how many equivalent full-load running hours the heat pump needs to be utilized, at certain level of electricity price, in order to become more economic feasible investment compared to the electric boiler.

Keeping in mind all these figures, the following findings can be noted:

- Investment in heat pumps is capital intensive, while investment in electric boiler is asset-light
- For the low number of running hours electric boilers has better economic indicators, as the investment costs are more dominating if the number of running hours is low
- LCOH curves of electric boiler and heat pump intersect at one point. Depending on the average electricity price this point can be moved to the left or right and up and down. The higher the average electricity price is, more the intersection point moves to the left and to the up. This means that the intersection point occurs at lower number of equivalent full-load running hours and at the higher average electricity price levels.

9. RESULTS OF ENERGYPLAN'S SCENARIOS

Results from all of the scenarios will be reported together in order to be easier to observe differences between the different scenarios. Year 2013 was set as the reference year for developing scenarios for the year 2020. In total five different scenarios were developed: business as usual (BAU), three scenarios with different wind capacity levels where the optimal heat pump capacities were calculated and the scenario dealing with the large-scale thermal energy storage. As a first step for the development of the *HP_alternative*, *HP_wind1* and *HP_wind2* scenarios, a manual iteration procedure needed to be carried out in order to determine optimal levels of the large-scale heat pumps.

9.1. Detecting the optimal heat pump levels

After the BAU scenario was simulated, the iteration procedure was carried out in order to calculate large scale heat pump capacities that will be used as inputs for the *HP_alternative*, *HP_wind1* and *HP_wind2* scenarios.

It is important to emphasize again that EnergyPLAN has three different types of district heating grid network represented. Group 1 represents district heating with no CHP, group 2 is based on small CHPs and group 3 is based on large CHP extraction plants with a part of capacity that always needs to be utilized. Group 2 has larger potential for integrating large-scale HPs and thus, large-scale heat pumps in this group will be optimized the first.

Table 7. Iteration steps for HPs in group 2 in HP_alternative scenario

Iteration	HP [MW_e] group 2	Total system costs [MDKK]
1	100	92,190
2	150	92,077
3	200	91,976
4	250	91,889
5	300	91,822
6	350	91,778
7	**400**	**91,757**
8	450	91,764
9	500	91,792

10	550	91,838
11	600	91,899
12	650	91,974
13	700	92,059

As it can be seen from the iteration table, for the heat pump capacity of 400 MW_e, the total system costs are the lowest. After the capacity of heat pumps in group 2 has been detected, the same procedure is applicable for the heat pumps in group 3.

Table 8. Iteration steps for HPs in group 3 for HP_alternative scenario

Iteration	HP [MWe] group 3	HP [MWe] group 2	Total system costs [MDKK]
1	0	400	91,757
2	50	400	91,674
3	100	400	91,630
4	150	400	91,606
5	200	400	91,593
6	**250**	**400**	**91,590**
7	300	400	91,596
8	350	400	91,609
9	400	400	91,630
10	450	400	91,660
11	500	400	91,699

After this iteration procedure, input data for the *HP_alternative* scenario has been detected. The optimal large-scale heat pumps capacity in *group 2* is 400 MW_e and in *group 3*, 250 MW_e.

The same procedure was carried out in order to detect optimal heat pumps capacity in the *HP_wind1* scenario, where 4,500 MW of onshore wind turbines is installed, while other parts of the energy system remained the same as in BAU scenario.

Table 9. Iteration steps for HPs in group 2 for HP_wind1 scenario

Iteration	HP [MWe] grid 2	HP [MWe] grid 3	Total system costs [MDKK]
1	150	0	92,368
2	200	0	92,265
3	250	0	92,177
4	300	0	92,109
5	350	0	92,064

6	**400**	**0**	**92,042**
7	450	0	92,046
8	500	0	92,073
9	550	0	92,118
10	600	0	92,180
11	650	0	92,254

As it can be observed from the iteration table, the lowest system costs are again in the case of 400 MW_e of heat pumps installed in group 2. The same procedure follows for the heat pumps in group 3.

Table 10. Iteration steps for HPs in group 3 for HP_wind1 scenario

Iteration	HP [MWe] grid 2	HP [MWe] grid 3	Total system costs [MDKK]
1	400	0	92,042
2	400	50	91,952
3	400	100	91,903
4	400	150	91,872
5	400	200	91,854
6	**400**	**250**	**91,846**
7	400	300	91,847
8	400	350	91,855
9	400	400	91,872
10	400	450	91,896

Heat pump capacity of 250 MW_e is optimal for the group 3, as it was the case in *HP_alternative* scenario.

Lastly, the same procedure can be applied in the HP_wind2 scenario, where installed onshore wind turbines have a capacity of 3,700 MW, which is not enough to produce 50% of electricity by wind energy. Other parts of the energy system are the same as in BAU scenario.

Table 11. Iteration steps for HPs in group 2 for HP_wind2 scenario

Iteration	HP [MWe] group 2	HP [MWe] group 3	Total system costs [MDKK]
1	150	0	91,513
2	200	0	91,415
3	250	0	91,330
4	300	0	91,265
5	350	0	91,224
6	**400**	**0**	**91,205**
7	450	0	91,214
8	500	0	91,243
9	550	0	91,291
10	600	0	91,354
11	650	0	91,430

It can be observed that the heat pumps capacity of 400 MW_e is the optimal level in the group 2, as it was the case in two previous scenarios.

Table 12. Iteration steps for HPs in group 3 for HP_wind1 scenario

Iteration	HP [MWe] group 2	HP [MWe] group 3	Total system costs [MDKK]
1	400	0	91,205
2	400	50	91,135
3	400	100	91,106
4	400	150	91,093
5	**400**	**200**	**91,092**
6	400	250	91,100
7	400	300	91,117
8	400	350	91,142
9	400	400	91,178
10	400	450	91,221

In *group 3*, 200 MW_e is the optimal capacity for the large-scale heat pumps. This is a lower amount, compared to previous two scenarios where the optimal level was 250 MW_e.

Reflecting to the iteration steps in all three scenarios, several important conclusions can be made. Firstly, for each penetration level of wind turbines, there is a certain large scale heat pump capacity level for which the total system costs are the lowest. This conclusion, concerning the heat pumps in group 2, can be easily spotted in the following figure:

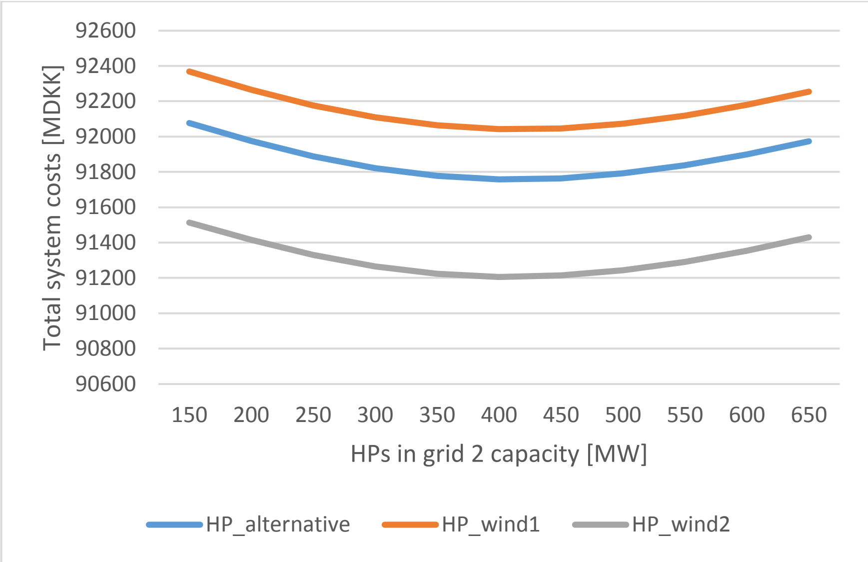


Figure 44. Optimum heat pump capacities in district heating group 2 for different wind penetration levels

It can be observed that the minimum is reached at heat pumps capacity of 400 MW_e in all three cases. Moreover, the same conclusion can be made when heat pumps are added in group 3, which can be seen in the following figure:

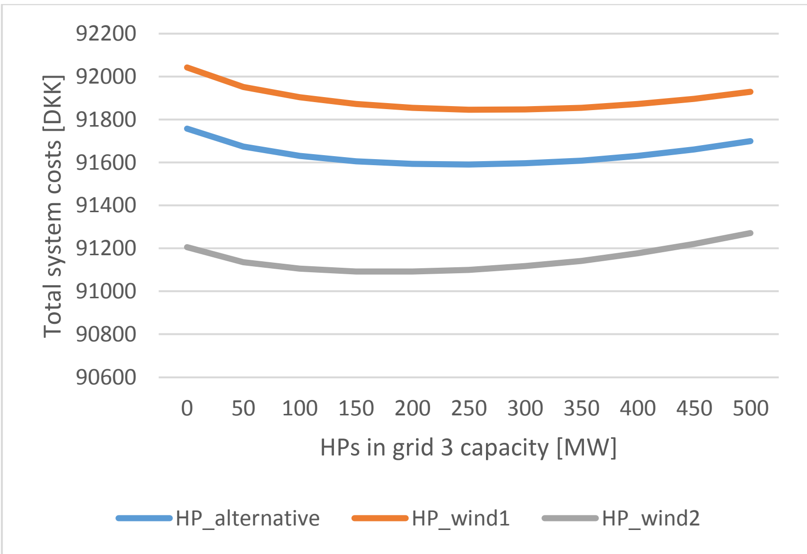


Figure 45. Optimum heat pump capacities in district heating group 3 for different wind penetration levels (group 2 HP capacity is constant at 400 MW_e in all points)

Moreover, it can be seen that for the lower wind penetration levels optimum point is shifting to the left, i.e. to the lower heat pumps capacity. However, in each case the optimum level of large scale heat pumps exists.

Furthermore, it is worth noting how the CO_2 emission levels drop with the increase in HPs capacity, which can be observed in the following figure:

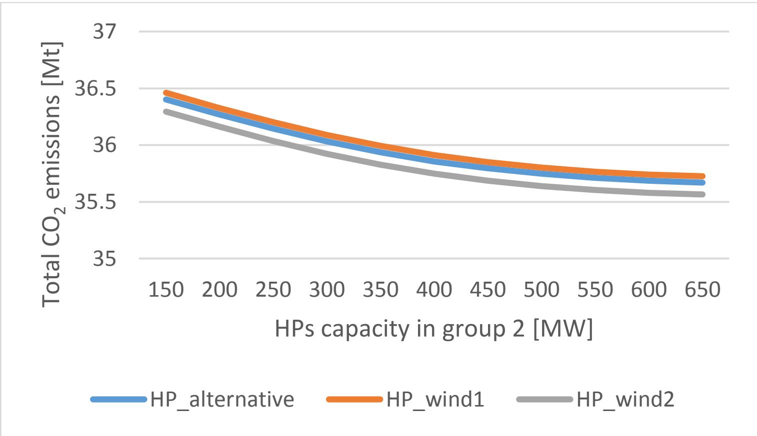


Figure 46. CO_2 emissions reduction with increase of HPs capacity in group 2

As it can be seen, CO_2 emission levels drop with the increase in HPs capacity in group 2.

It is important to note here that the emissions are declining the sharpest until the level of 400 MW_e of heat pumps, which is the optimal level of HPs in group 2 in all three scenarios. This behavior is connected with the possibility of heat pumps to replace fuel intensive heat production from boilers. When the certain amount of capacity of HPs is reached, there is no more possibility to replace more heat production from boilers and consequently to reduce CO_2 emissions by using fuel more efficiently.

Moreover, when the largest part of fuel is already replaced, increasing HPs capacity becomes less efficient, due to lower fuel savings and consequently, total system costs rise. The similar behavior can be observed in the following figure, in which the HPs capacity in group 3 was iterated:

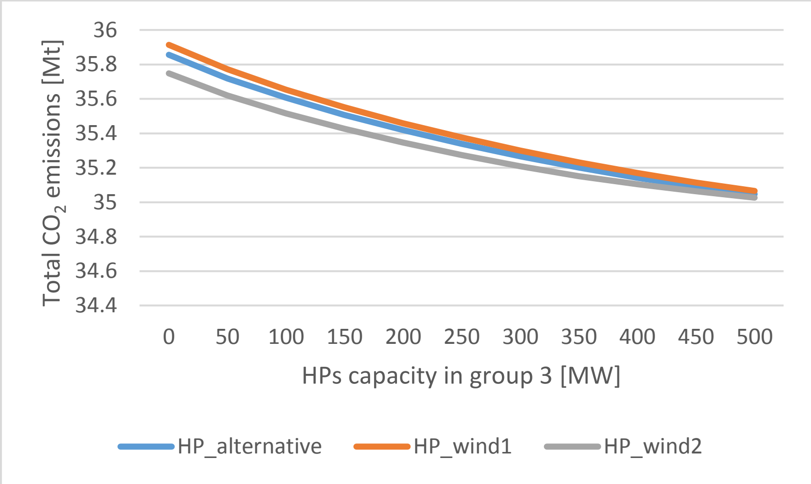


Figure 47. CO_2 emissions reduction with increase of HPs capacity in group 3

It is worth noting here the point at 500 MW_e of heat pumps capacity in group 3. After this point, CO_2 emissions are almost the same in all the cases, no matter what the wind capacity level is, as this is the maximum CO_2 reduction that HPs are able to achieve.

Nevertheless, a similar behavior can be observed in reduction of CEEP with the increase of HPs capacity level.

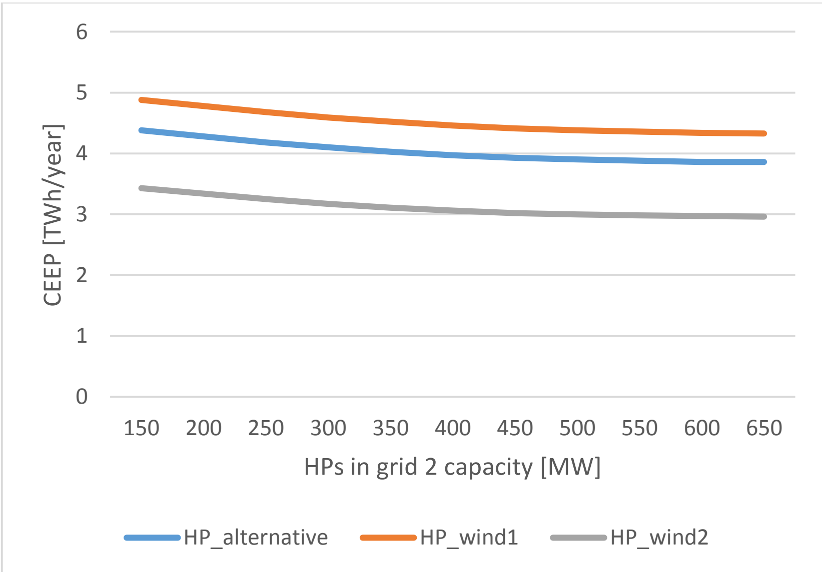


Figure 48. CEEP drop with the increase of HPs capacity in group 2

With the increase of HPs capacity, a critical excess in electricity production will decrease. However, after the capacity of 400 MW_e of HPs, decrease of CEEP is almost non-existing. This is happening because of the reasons already discussed. After the certain amount of HPs installed, there is no more space for HPs to replace the heat produced from inefficient fuel driven boilers. Consequently, this low number of running hours is also the reason why reducing CEEP by implementing large scale HPs on a larger than optimal scale will lead to an economically less viable system.

The same behavior can be observed with the increase of HPs in group 3:

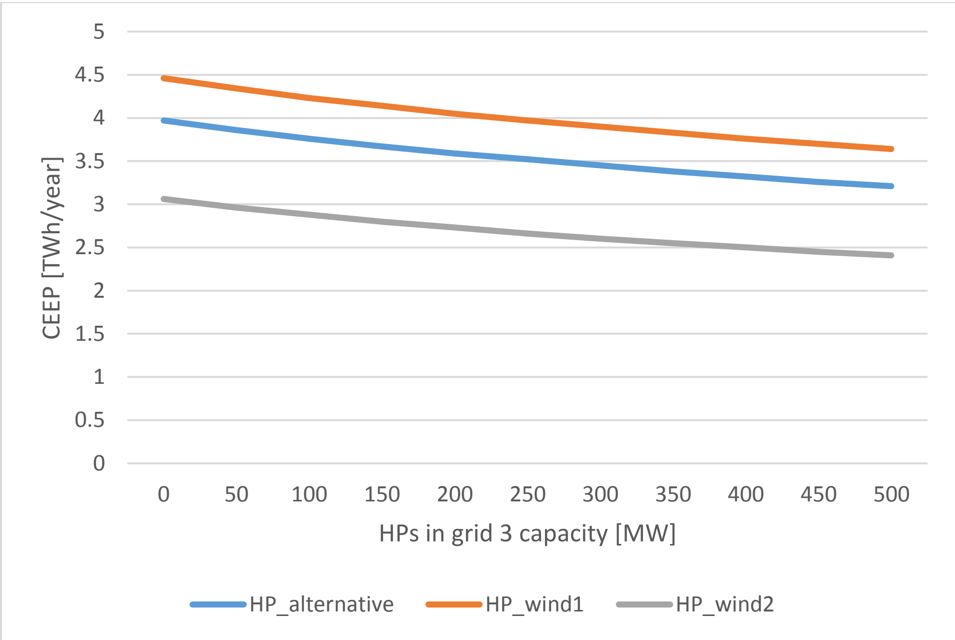


Figure 49. CEEP drop with the increase of HPs capacity in group 3

When looking at CEEP, there is space for more than 250 MW_e of HPs capacity in group 3. However, due to the target of achieving the lowest total system costs, HP capacities of 250 MW_e and 200 MW_e were chosen, respectively.

9.2. EnergyPLAN scenario results - an analysis

Electricity production from different power plants in all the scenarios can be observed in the following figure. Electricity generation is dominated by wind production, which produces more than 50% of electricity in all the cases, except the reference. CHP plants also have significant share in production of electricity, while all the other sources have lower shares in electricity production.

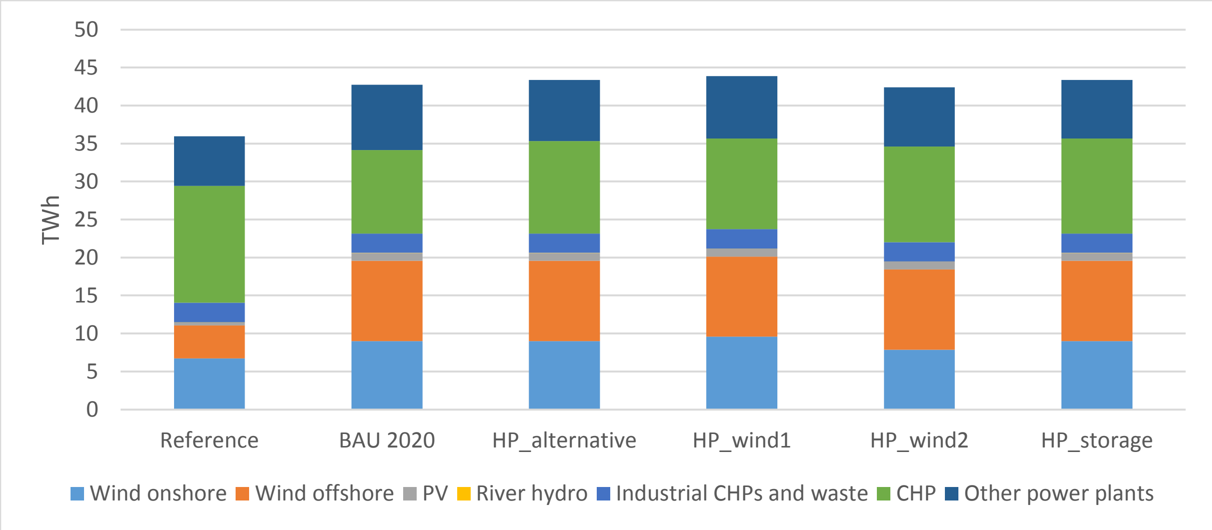


Figure 50. Electricity production from different power plants

However, it is more interesting to compare heat production sources in different scenarios in order to detect the large-scale HPs influence on the system.

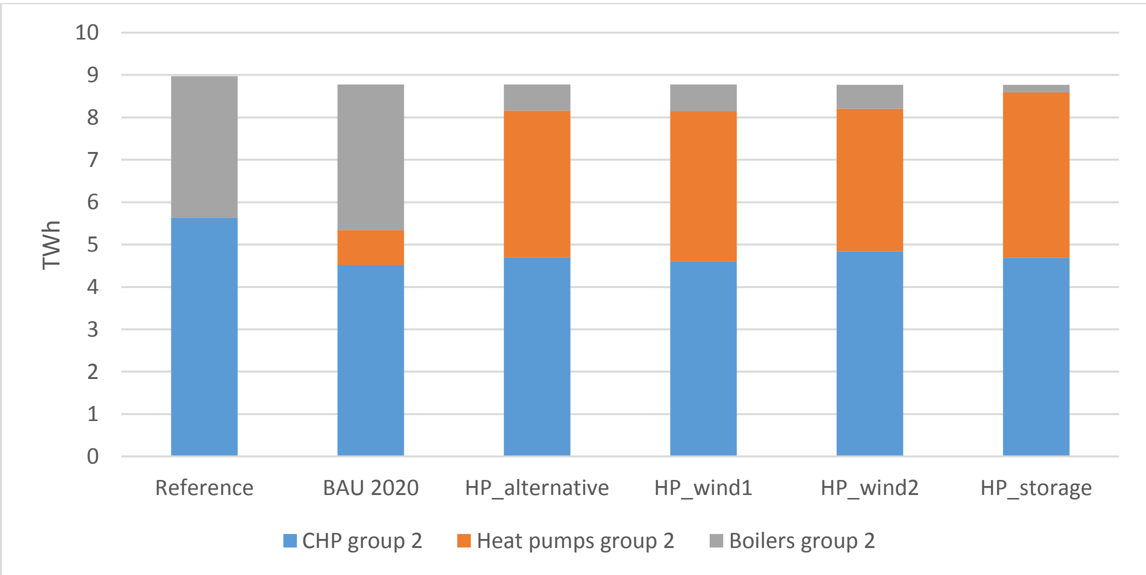


Figure 51. District heating production in DH group 2

As it can be seen, heat pumps replace the production from boilers in district heating system. Compared to BAU scenario, heat pumps replaced from 2.81 TWh of boilers production in

HP_wind1 scenario to 3.26 TWh of boilers production in *HP_storage* scenario. The reduction in the latter scenario amounts to the significant 94.8%. Two thirds of these boilers are driven by natural gas and one third by biomass. In overall, fuel savings are achieved and consequently lower CO_2 emissions are emitted. Moreover, in the scenario with the heat storage installed, even more boilers' production can be replaced by heat production from the large-scale heat pumps.

Similar situation occurs in the district heating group 3 system:

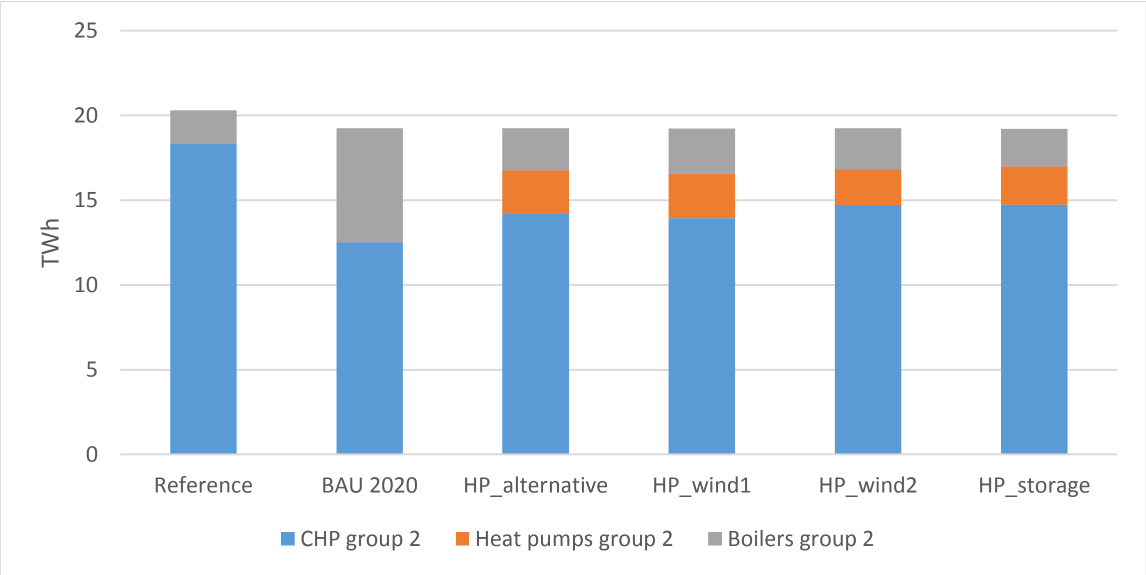


Figure 52. District heating production in DH group 2

Again, heat previously produced from boilers in district heating system is now provided from the heat pumps. Compared to the BAU scenario, reduction in boilers' production amount from 4.08 TWh in *HP_wind1* scenario to 4.53 TWh in *HP_storage* scenario. The reduction in the latter case equals to the 67% compared to the BAU scenario. Nevertheless, in *group 3*, 60% of boilers are driven by oil and 40% by natural gas and thus, the relative savings in fuel consumption and CO_2 emissions are even larger than in district heating system group 2.

Finally, it is important to compare all four alternative scenarios (without reference and BAU scenario), with the same systems, but without large-scale heat pumps installed and without the heat storage installed in the *HP_storage* scenario, in order to detect savings in CO_2 emissions, as well as total system costs after the implementation of large-scale heat pumps and the large-scale pit thermal energy storage.

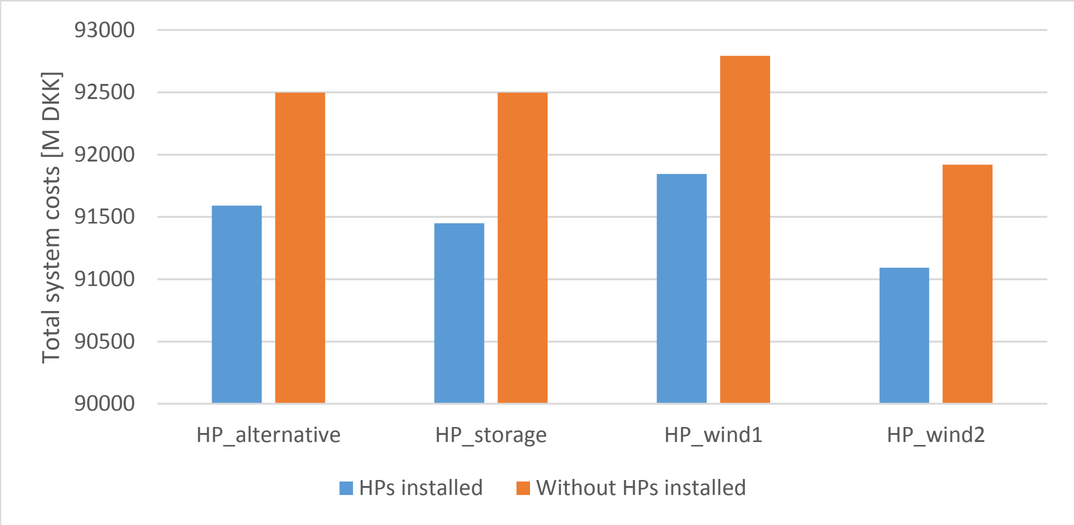


Figure 53. Difference in total system costs after implementation of HPs and thermal energy storage

As it can be seen, savings in total system costs are achieved in all the scenarios with the implementation of the optimal capacity of the heat pumps. Moreover, a further savings in total system cost can be achieved by implementing large-scale thermal energy storage, with the large-scale heat pumps already implemented. Thus, it can be concluded that savings in fuel costs by reducing production of heat from boilers are larger than the investment costs in optimal level of heat pumps. Moreover, savings in fuel costs are also larger than the investment in the large-scale thermal energy storage. Achieved savings in total system costs are between 0.9% and 1.14%, the latter in the *HP_storage* scenario. In absolute number the latter achieved savings are equal to DKK 1,046 million, or EUR 140.4 million.

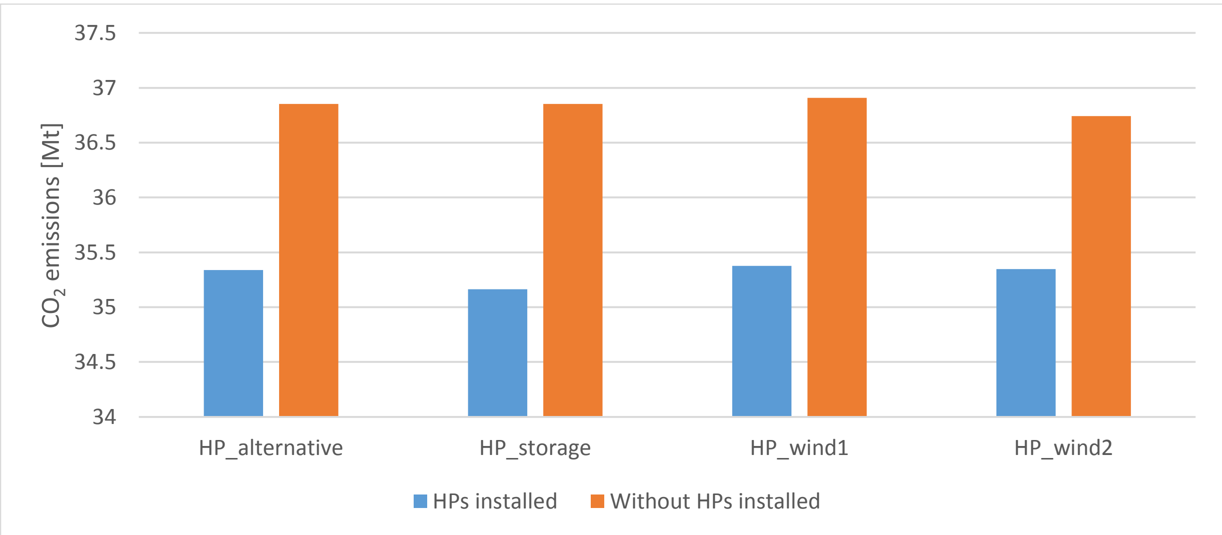


Figure 54. Reduction in CO_2 emissions after the installation of HPs and thermal energy storage

Furthermore, it can be also observed that significant savings in CO_2 emissions are achieved in all the scenarios after the implementation of large-scale heat pumps. Moreover, CO_2 savings are also achieved by implementing large-scale thermal energy storage. The achieved savings in emissions are between 3.95% and 4.8%, the latter in *HP_storage* scenario, as it can be seen in the Table 13.

In the following table, a reduction in CO_2 and CEEP in the four alternative scenarios, (without BAU) with the optimal capacity of the large scale heat pumps and without heat pumps installed, is presented:

Table 13. A reduction in CO_2 emissions and CEEP with the optimal level of HPs installed

	HP_alternative		***HP_wind1***		***HP_wind2***		***HP_storage***	
	CO_2 [Mt]	CEEP [TWh/year]	CO_2 [Mt]	CEEP [TWh/year]	CO_2 [Mt]	CEEP [TWh/year]	CO_2 [Mt]	CEEP [TWh/year]
HPs installed	35.34	3.52	35.38	3.97	35.35	2.73	35.15	3.45
No HPs installed	36.85	4.75	36.91	5.27	36.74	3.77	36.85	4.75
Reduction with HPs installed [%]	4.3%	34.9%	4.3%	32.7%	3.9%	38.1%	4.8%	37.7%

**In the HP_storage scenario in the “No HPs installed” row, it is also assumed that seasonal thermal energy storage is not installed.*

To sum up, it can be concluded that for every wind power penetration level, there is a certain capacity of large-scale heat pumps (larger than zero) at which the minimum of the total system costs will be achieved.

Moreover, larger the wind power penetration level is, the larger optimal capacity of the large-scale heat pump is.

Furthermore, as it was shown that with increase in the large-scale heat pumps level CO_2 emissions and CEEP will drop, the system will be more flexible, more fuel efficient, less polluting and cheaper all in one.

10.SENSITIVITY ANALYSIS

Fuel prices, discount rate and investment cost in large-scale heat pumps were the factors chosen for the sensitivity analysis. Moreover, sensitivity analysis was performed for two scenarios, business as usual (BAU) and *HP_alternative*, in order to assess possible different impact of these variables on the system with large-scale heat pumps installed and without installed heat pumps. Fuel prices used in original scenarios can be seen in Figure 30., original discount rate was set to 3% as described in chapter 5., while technology costs in original scenarios can be seen in Appendix I.

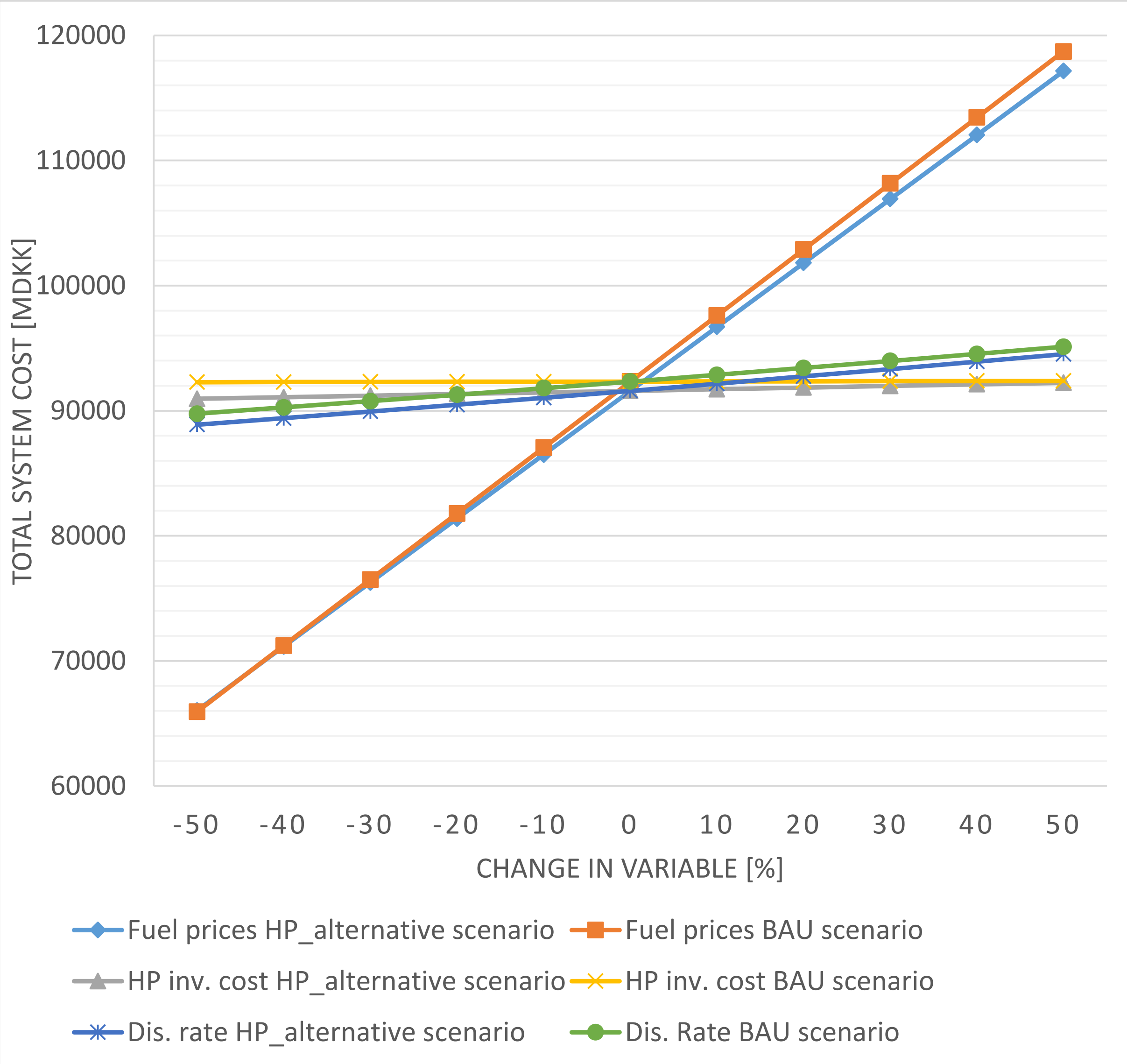


Figure 55. Result of the sensitivity analysis for BAU and *HP_alternative* scenarios

Sensitivity analysis showed that the largest impact on the total system cost is made by fuel prices. Rise in fuel prices for 50% can increase total system costs for 30%. Moreover, relative changes in both *HP_alternative* and BAU scenarios are quite similar, although the total system costs in *HP_alternative* scenario are slightly less sensitive to the rise in fuel prices.

Energy system is quite insensitive to changes in technology cost of heat pumps and discount rate in both scenarios. Between the scenarios, the system in *HP_alternative* scenario is slightly less sensitive to both discount rate and technology cost changes compared to the BAU scenario.

Thus, from the economic point of view, the energy system with the optimal capacity of large-scale heat pumps (*HP_alternative* scenario) is more feasible and robust compared to the system without large-scale heat pumps implemented on a large-scale (BAU scenario).

11. CONCLUSIONS

After all the tasks have been performed, several conclusions can be made. First of all, for modelling energy systems with a large share of intermittent energy sources, a simulation technique shall be preferred compared to an optimization technique, as dynamics of the system and feedback need to be covered in this kind of energy systems. Thus, EnergyPLAN model represents a good modelling tool for modelling energy systems with a large share of intermittent wind power, in combination with a large district heating share in total heating consumption. Consequently, modelling optimal large scale heat pump penetration level was possible by using the EnergyPLAN software.

Secondly, in the current energy market relations, there is no possibility to project serious electricity price changes and shifts in demand for electricity, as the calculated price elasticity of the electricity demand was very low and continually decreasing from the year 2011 onwards. Average yearly price elasticity was between 0.01 in 2014 to 0.059 in 2011. Thus, implementing capacity levels of heat pumps as calculated in this thesis in Denmark will provide only a marginal change in demand for electricity on the wholesale Nordpool's El-spot market.

Thirdly, levelized cost of heating energy showed that for every price level of electricity, an intersection point exists between two different types of technologies driven by electricity, electric boilers and large-scale heat pumps. The intersection point moves to the lower number of running hours when the electricity price level goes up. At the general electricity price level of 40 €/MWh, an intersection point of LCOH curves will occur at the 2,600th full load hour. Thus, the large-scale heat pump technology is not only more efficient compared to electric boiler, but also more economic feasible when running approximately more than 30% of the year.

Manual iteration procedure showed that for every level of wind penetration, a certain optimal capacity of the large-scale heat pumps exist. Moreover, it was shown that it is possible to use EnergyPLAN as a tool for manual investment optimization. The optimal capacity of the large scale heat pumps in group 2 (district heating system based on small CHP) was 400 MW_e in all the scenarios, while in group 3 (district heating system based on large CHP extraction plants) optimal capacity ranged from 200 to 250 MW_e. The former capacity in the *HP_wind2* scenario and the latter in three other alternative scenarios (without BAU). When the optimal capacity of HPs was found in each of the scenarios, the total system costs would lower. Achieved savings in total system costs are between 0.9% and 1.14%, the latter in the *HP_storage* scenario. In absolute number, achieved saving is equal to DKK 1,046 million, or EUR 140.4 million. The latter number shows that introducing seasonal thermal energy storage in the system with the optimal level of large scale heat pumps will lead to even larger reduction in total system costs, compared to the system without seasonal storage.

It was detected that introducing large scale HPs to the energy system allows more operating hours of CHPs, as well as lowers the number of running hours of boilers in district heating system. Boilers' production reduced in different scenarios from 82% to 95% in the group 2 of the district heating and from 61% to 67% in the group 3 of the district heating. In the same time, heat production in CHP plants rose from 2% in the *HP_wind1* scenario to 7% in the *HP_wind2* scenario. The difference between the CHPs' heat production and boilers' production was replaced by the large scale heat pumps production.

Moreover, during the iteration process it was shown that increase in large scale heat pumps capacity will lead to the reduction in CO_2 emissions and decrease of CEEP. Compared to the same systems as in scenarios, but without any capacity of the large scale heat pumps, nor seasonal thermal energy storage installed, reductions in CO_2 emissions were between 3.9% in *HP_wind2* scenario and 4.8% in the *HP_storage* scenario. Furthermore, CEEP decrease ranged from 32.7% in the *HP_wind1* scenario to 38.1% in the *HP_wind2* scenario.

Lastly, the sensitivity analysis showed that the heat pump technology is relatively insensitive to changes in technology cost and discount rates, while fuel price changes significantly affects the total system costs. However, in all the cases the system with the large-scale HPs implemented is less sensitive to changes compared to the system without large-scale heat pumps implemented. The most sensitive parameter showed that rise in fuel prices for 50% can increase total system costs for approximately 30%.

Thus, implementing large-scale HPs into the Danish energy system seems to be inevitable process that needs to happen in the near term future. Moreover, it is clear that the certain large-scale HPs should have already been installed in the system in order to better integrate both electricity and heating energy systems, as well as to reduce total system costs.

As it was shown that the system with the optimal level of heat pumps not only reduces the total system cost, but also reduces CO_2 level, decreases critical excess in electricity production and leads to fuel savings, there is no valuable reason not to implement large-scale heat pumps into the Danish energy system in the near future.

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APPENDIX I: INVESTMENTS AND O&M COSTS OF DIFFERENT TECHNOLOGIES

Prod. type	Investment		Period	O. and M.	Total Inv. Costs	Annual Costs (MDKK/year)	
	Unit	MDKK pr. Unit	Years	% of Inv.	MDKK	Investment	Fixed Opr. and M.
Small CHP units	1830 MW-e	8.94	25	3.75	16360	940	614
Large CHP units	6000 MW-e	6.11	25	3.66	36660	2105	1342
Heat Storage CHP	0 GWh	22.35	20	0.7	0	0	0
Waste CHP	9.97 TWh/year	1609	20	7.4	16042	1078	1187
Absorp. HP (Waste)	0 MW-th	2.98	20	4.7	0	0	0
Heat Pump gr. 2	50 MW-e	25.55	25	2	1278	73	26
Heat Pump gr. 3	0 MW-e	25.55	25	2	0	0	0
DHP Boiler group 1	1328 MW-th	0.75	35	3.7	996	46	37
Boilers gr. 2 and 3	10098 MW-th	0.75	35	3.7	7574	352	280
Electric Boiler gr2-gr3	0 MW-e	0.56	20	1.5	0	0	0
Large Power Plants	1175 MW-e	7.45	27	3	8754	478	263
Nuclear	0 MW-e	26.82	30	2.5	0	0	0
Interconnection	0 MW	0	0	0	0	0	0
Pump	0 MW-e	4.47	50	1.5	0	0	0
Turbine	0 MW-e	4.47	50	1.5	0	0	0
Pump Storage	0 GWh	55.88	50	1.5	0	0	0

Prod. type	Investment		Period	O. and M.	Total Inv. Costs	Annual Costs (MDKK/year)	
	Unit	MDKK pr. Unit	Years	% of Inv.	MDKK	Investment	Fixed Opr. and M.
Wind	4231 MW-e	9.834	20	3	41608	2797	1248
Wind offshore	2671 MW-e	17.88	20	3	47757	3210	1433
Photo Voltaic	1210 MW-e	9.685	30	2.1	11719	598	246
Wave power	0 MW-e	47.68	20	0.6	0	0	0
Tidal Power	0 MW	28.68	20	3	0	0	0
CSP Solar Power	0 MW	26.37	25	8.2	0	0	0
River of hydro	10 MW-e	24.59	50	2	243	9	5
Hydro Power	0 MW-e	24.59	50	2	0	0	0
Hydro Storage	0 GWh	55.88	50	1.5	0	0	0
Hydro Pump	0 MW-e	4.47	50	1.5	0	0	0
Geothermal	0 MW-e	20.12	20	3.5	0	0	0
Geothermal Heat	0 TWh/year	0	0	0	0	0	0
Solar thermal	0 TWh/year	2875.7	30	0.125	267	14	0
Heat Storage Solar	60 GWh	22.35	20	0.7	1341	90	9

Prod. type	Investment		Period	O. and M.	Total Inv. Costs	Annual Costs (MDKK/year)	
	Unit	MDKK pr. Unit	Years	% of Inv.	MDKK	Investment	Fixed Opr. and M.
Biogas Plant	3.00 TWh/year	1788	20	7	5364	361	375
Gasification Plant	92 MW	3.13	25	5.3	287	17	15
BioGas Upgrade	342 MW	2.24	15	15.8	765	64	121
Gasification Upgrade	92 MW	2.24	15	15.8	206	17	32
BioDiesel Plant	441 MW-bio	25.48	20	3	11246	756	337
BioPetrol Plant	0 MW-bio	5.89	20	7.7	0	0	0
BioJPPlant	0 MW-bio	5.89	20	7.7	0	0	0
CO2Hydrogenation	0 MW	6.71	20	2.5	0	0	0
Synthetic Gas Plant	0 MW	0	0	0	0	0	0
Chemical Sythesis	0 MW	4.1	20	3.5	0	0	0
Electrolyser	0 MW-e	4.25	20	2.5	0	0	0
Hydrogen Storage	0 GWh	149	30	0.5	0	0	0
Gas Storage	6360 GWh	0	0	0	0	0	0
Oil Storage	0 GWh	0	0	0	0	0	0

Prod. type	Investment		Period	O. and M.	Total Inv. Costs	Annual Costs (MDKK/year)	
	Unit	MDKK pr. Unit	Years	% of Inv.	MDKK	Investment	Fixed Opr. and M.
Biogas Plant	3.00 TWh/year	1788	20	7	5364	361	375
Gasification Plant	92 MW	3.13	25	5.3	287	17	15
BioGas Upgrade	342 MW	2.24	15	15.8	765	64	121
Gasification Upgrade	92 MW	2.24	15	15.8	206	17	32
BioDiesel Plant	441 MW-bio	25.48	20	3	11246	756	337
BioPetrol Plant	0 MW-bio	5.89	20	7.7	0	0	0
BioJPPlant	0 MW-bio	5.89	20	7.7	0	0	0
CO2Hydrogenation	0 MW	6.71	20	2.5	0	0	0
Synthetic Gas Plant	0 MW	0	0	0	0	0	0
Chemical Sythesis	0 MW	4.1	20	3.5	0	0	0
Electrolyser	0 MW-e	4.25	20	2.5	0	0	0
Hydrogen Storage	0 GWh	149	30	0.5	0	0	0
Gas Storage	6360 GWh	0	0	0	0	0	0
Oil Storage	0 GWh	0	0	0	0	0	0

Variable Operation and Maintenance Cost

District Heating and CHP systems

Boiler	1.12	DKK/MWh-th
CHP	20.12	DKK/MWh-e
Heat Pump	2.01	DKK/MWh-e
Electric heating	10.06	DKK/MWh-e

Power Plants

Hydro Power	8.87	DKK/MWh-e
Condensing	19.77	DKK/MWh-e
Geothermal	111.75	DKK/MWh-e
GTL M1	13.41	DKK/MWh-fuel-input
GTL M2	7.51	DKK/MWh-fuel-input

Storage

Electrolyser	0	DKK/MWh-e
Pump	8.87	DKK/MWh-e
Turbine	8.87	DKK/MWh-e
V2G Discharge *)	0	DKK/MWh-e
Hydro Power Pump	8.87	DKK/MWh-e

APPENDIX II: RESULTS OF SCENARIOS

Input BAU.txt

The EnergyPLAN model 12.0

Electricity demand (TWh/year):			
Fixed demand	36.68	Flexible demand	0.00
Electric heating + HP	0.59	Fixed imp/exp.	0.00
Electric cooling	0.00	Transportation	0.59
		Total	37.86

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	3.46	10.72	23.03	37.21
Solar Thermal	0.02	0.07	0.00	0.09
Industrial CHP (CSHP)	0.17	0.17	0.95	1.29
Demand after solar and CSHP	3.27	10.48	22.08	35.83

Wind	4231 MW	9.00 TWh/year	0.00	Grid
Offshore Wind	2671 MW	10.56 TWh/year	0.00	stabili-
Photo Voltaic	1210 MW	1.04 TWh/year	0.00	sation
River Hydro	10 MW	0.02 TWh/year	0.00	share
Hydro Power	0 MW	0 TWh/year		
Geothermal/Nuclear	0 MW	0 TWh/year		

	Capacities MW-e	Capacities MJ/s	Efficiencies elec.	Efficiencies Ther	COP
Group 2:					
CHP	1830	2420	0.36	0.48	
Heat Pump	50	150			3.00
Boiler		4176		0.95	
Group 3:					
CHP	6000	9882	0.34	0.56	
Heat Pump	0	0			3.00
Boiler		5922		0.90	
Condensing	6335		0.39		

Heatstorage: gr.2: 0 GWh gr.3: 0 GWh
Fixed Boiler: gr.2: 2.5 Per cent gr.3: 1.0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0.07	0.03
Gr.2:	0.12	0.51
Gr.3:	0.07	1.74

Regulation Strategy:	Technical regulation no. 3	
KEOL regulation	23450000	
Minimum Stabilisation share	0.25	
Stabilisation share of CHP	0.00	
Minimum CHP gr 3 load	200	MW
Minimum PP	0	MW
Heat Pump maximum share	1.00	
Maximum import/export	0	MW

Distr. NameDK 2013 Electricty price.txt

Addition factor	0.00	DKK/MWh
Multiplication factor	1.02	
Dependency factor	0.04	DKK/MWh pr. MW
Average Market Price	298	DKK/MWh
Gas Storage	6360	GWh
Syngas capacity	92	MW
Biogas max to grid	342	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Efficiencies Ther.
Hydro Pump:	0	0	0.40	
Hydro Turbine:	0		0.40	
Electrol. Gr.2:	0	0	0.40	0.50
Electrol. Gr.3:	0	0	0.40	0.50
Electrol. trans.:	0	0	0.00	
Ely. MicroCHP:	0	0	0.80	
CAES fuel ratio:		0.000		

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0.00	56.52	0.00	0.00
Household	0.00	3.33	5.93	12.10
Industry	1.34	11.36	10.78	2.89
Various	0.00	4.90	6.90	1.00

Output WARNING!!: (1) Critical Excess;

	District Heating: Demand Distr. heating MW	Production Solar MW	Waste+ CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Balance MW
January	6817	1	745	534	3404	113	0	2020	0	0
February	6974	5	745	548	4034	111	0	1532	0	0
March	5942	6	745	451	2640	115	0	1984	0	0
April	4761	16	745	339	2352	101	0	1208	0	0
May	3736	18	745	244	1945	91	0	694	0	0
June	1694	24	745	52	637	70	0	166	0	0
July	1695	19	745	53	739	46	0	91	0	0
August	1694	18	745	54	672	62	0	144	0	0
September	2599	12	745	139	1300	65	0	339	0	0
October	3871	6	745	259	1564	108	0	1189	0	0
November	5078	2	745	372	2399	109	0	1452	0	0
December	6064	1	745	464	1656	133	0	3065	0	0
Average	4237	11	745	292	1937	94	0	1159	0	0
Maximum	11905	134	745	1007	8426	150	0	8631	0	0
Minimum	1483	0	745	30	329	31	0	26	0	0
TWh/year	37.21	0.09	6.54	2.56	17.01	0.82	0.00	10.18	0.00	0.00

	Electricity Consumption: Elec. demand MW	Flex.& Transp. MW	HP MW	Elec-trolyser MW	EH MW	Hydro Pump MW	Production: Turbine MW	RES MW	Hydro MW	Geo-thermal MW	Waste+ CSHP MW	CHP MW	PP MW
January	4872	66	155	0	0	0	0	2283	0	0	290	2210	643
February	4738	68	157	0	0	0	0	1763	0	0	290	2624	378
March	4535	68	137	0	0	0	0	2686	0	0	290	1710	728
April	4093	65	111	0	0	0	0	2315	0	0	290	1524	687
May	3778	68	89	0	0	0	0	1964	0	0	290	1258	711
June	3769	68	40	0	0	0	0	2367	0	0	290	406	1484
July	3591	66	32	0	0	0	0	1600	0	0	290	476	1569
August	3770	68	38	0	0	0	0	2130	0	0	290	430	1505
September	3932	67	55	0	0	0	0	1913	0	0	290	840	1375
October	4154	67	96	0	0	0	0	2877	0	0	290	1004	862
November	4423	68	120	0	0	0	0	2625	0	0	290	1554	776
December	4475	66	147	0	0	0	0	3602	0	0	290	1063	974
Average	4176	67	98	0	0	0	0	2347	0	0	290	1253	976
Maximum	6632	204	268	0	0	0	0	6570	0	0	290	5459	3997
Minimum	2483	0	10	0	0	0	0	8	0	0	290	200	0
TWh/year	36.68	0.59	0.86	0.00	0.00	0.00	0.00	20.62	0.00	0.00	2.54	11.00	8.58

	Balance: Stab-Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Exchange Payment Imp Million DKK	Exp Million DKK
January	158	0	333	333	0	0	26
February	168	0	91	91	0	0	9
March	145	0	674	674	0	0	39
April	149	0	546	546	0	0	44
May	152	0	286	286	0	0	26
June	166	0	669	669	0	0	38
July	200	0	246	246	0	0	21
August	172	0	478	478	0	0	42
September	181	0	364	364	0	0	32
October	129	0	716	716	0	0	54
November	143	0	634	634	0	0	34
December	121	0	1240	1240	0	0	51
Average	157	0	525	525	0	Average price	
Maximum	358	0	4979	4979	0	(DKK/MWh)	
Minimum	100	0	0	0	0	348	90
TWh/year		0.00	4.61	4.61	0.00	0	417

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon-version	Synthetic Fuel	Wind	Offsh.	PV	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Netto	CO2 emission (Mt): Total	Netto
Coal	-	0.35	7.31	-	-	11.09	-	-	-	-	-	-	-	-	-	-	-	-	-	1.34	20.08	-5.96	14.12	7.12	5.01
Oil	-	-	0.20	-	4.49	0.89	-	-	-	-	-	-	-	-	-	-	-	56.52	3.33	16.26	81.70	-0.48	81.21	21.44	21.31
N.Gas	0.25	6.68	0.99	2.41	3.00	0.89	-	-	-	-	-3.81	-	-	-	-	-	-	-	5.93	17.68	34.02	-0.48	33.54	6.97	6.87
Biomass	2.45	2.46	13.82	1.21	-	9.12	-	-	9.97	-	4.88	-	-	-	-	-	-	-	11.46	3.89	59.25	-4.90	54.35	1.17	1.17
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	9.00	10.56	1.04	0.02	0.61	-	-	-	21.23	0.00	21.23	0.00	0.00
H2 etc.	-	0.00	0.00	0.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Biofuel	-	-	-	-	-	-	-	-	-	-	-3.72	-	-	-	-	-	-	3.72	-	-	0.00	0.00	0.00	0.00	0.00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Total	2.70	9.49	22.31	3.62	7.49	21.99	-	-	9.97	-	-2.65	-	9.00	10.56	1.04	0.02	0.61	60.24	20.72	39.17	216.28	-11.83	204.45	36.70	34.36

12-January-2015 [15:23]

Output specifications BAU.txt The EnergyPLAN model 12.0

District Heating Production

	Gr.1 District heating MW	Gr.1 Solar MW	Gr.1 CSHP MW	Gr.1 DHP MW	Gr.2 District heating MW	Gr.2 Solar MW	Gr.2 CSHP MW	Gr.2 CHP MW	Gr.2 HP MW	Gr.2 ELT MW	Gr.2 Boiler MW	Gr.2 EH MW	Gr.2 Stor-age MW	Gr.2 Ba-lance MW
January	634	0	100	534	1964	1	213	957	113	0	681	0	0	0
February	648	1	100	548	2009	4	213	1169	111	0	513	0	0	0
March	553	1	100	451	1712	5	213	721	115	0	658	0	0	0
April	443	3	100	339	1372	13	213	642	101	0	403	0	0	0
May	347	4	100	244	1076	14	213	516	91	0	243	0	0	0
June	157	5	100	52	488	18	213	129	70	0	58	0	0	0
July	157	4	100	53	488	15	213	181	46	0	33	0	0	0
August	157	4	100	54	488	14	213	147	62	0	52	0	0	0
September	242	2	100	139	749	9	213	343	65	0	119	0	0	0
October	360	1	100	259	1115	5	213	367	108	0	423	0	0	0
November	472	0	100	372	1463	1	213	653	109	0	488	0	0	0
December	564	0	100	464	1747	1	213	383	133	0	1017	0	0	0
Average	394	2	100	292	1220	8	213	514	94	0	391	0	0	0
Maximum	1107	29	100	1007	3430	105	213	2420	150	0	2824	0	0	0
Minimum	138	0	100	30	427	0	213	0	31	0	0	0	0	0
Total for the whole year TWh/year	3.46	0.02	0.88	2.56	10.72	0.07	1.87	4.52	0.82	0.00	3.44	0.00		0.00

	Gr.3 District heating MW	Gr.3 Solar MW	Gr.3 CSHP MW	Gr.3 CHP MW	Gr.3 HP MW	Gr.3 ELT MW	Gr.3 Boiler MW	Gr.3 EH MW	Gr.3 Stor-age MW	Gr.3 Ba-lance MW
January	4219	0	432	2448	0	0	1339	0	0	0
February	4316	0	432	2865	0	0	1019	0	0	0
March	3677	0	432	1920	0	0	1326	0	0	0
April	2947	0	432	1710	0	0	805	0	0	0
May	2312	0	432	1429	0	0	451	0	0	0
June	1049	0	432	508	0	0	108	0	0	0
July	1049	0	432	559	0	0	58	0	0	0
August	1049	0	432	525	0	0	92	0	0	0
September	1609	0	432	957	0	0	219	0	0	0
October	2396	0	432	1198	0	0	766	0	0	0
November	3143	0	432	1747	0	0	964	0	0	0
December	3753	0	432	1273	0	0	2047	0	0	0
Average	2622	0	432	1422	0	0	767	0	0	0
Maximum	7368	0	432	6129	0	0	5846	0	0	0
Minimum	918	0	432	329	0	0	26	0	0	0
Total for the whole year TWh/year	23.03	0.00	3.80	12.50	0.00	0.00	6.74	0.00		0.00

RES specification

	RES1 Wind MW	RES2 Offshoi MW	RES3 Photo \ MW	RES 4-7 ic MW	Total MW
January	1092	1177	11	3	2283
February	700	1007	53	3	1763
March	1363	1248	73	3	2686
April	1107	1032	174	4	2315
May	753	1010	197	3	1964
June	929	1181	255	2	2367
July	562	825	212	1	1600
August	799	1127	203	1	2130
September	703	1074	134	2	1913
October	1224	1580	70	3	2877
November	1134	1465	23	4	2625
December	1897	1687	14	5	3602
Average	1024	1202	118	3	2347
Maximum	4231	2671	1210	5	6570
Minimum	2	0	0	1	8
Total for the whole year TWh/year	9.00	10.56	1.04	0.02	20.62

Own use of heat from industrial CHP: 0.00 TWh/year

ANNUAL COSTS (Million DKK)		
Total Fuel ex Ngas exchange =		53549
Uranium =	0	
Coal =	1677	
FuelOil =	8177	
Gasoil/Diesel=	16937	
Petrol/JP =	13768	
Gas handling =	1660	
Biomass =	11330	
Food income =	0	
Waste =	0	
Total Ngas Exchange costs =		7605
Marginal operation costs =		406
Total Electricity exchange =		0
Import =	0	
Export =	-417	
Bottleneck =	417	
Fixed imp/ex=	0	
Total CO2 emission costs =		4156
Total variable costs =		65716
Fixed operation costs =		8775
Annual Investment costs =		17838
TOTAL ANNUAL COSTS =		92329

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Indi-vidual MW	Trans port MW	Indu. Var. MW	Demand Sum MW	Bio-gas MW	Syn-gas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Stor-age MW	Sum MW	Im-port MW	Ex-port MW
January	1124	1608	67	1189	0	2013	6001	342	92	0	0	0	1695	3873	3873	0
February	865	1955	39	1221	0	2013	6092	342	92	0	0	0	1786	3873	3873	0
March	1094	1217	76	1015	0	2013	5415	342	92	0	0	0	1109	3873	3873	0
April	673	1085	72	780	0	2013	4622	342	92	0	0	0	316	3873	3873	0
May	394	876	74	575	0	2013	3932	342	92	0	0	0	-374	3873	3873	0
June	94	230	155	168	0	2013	2660	342	92	0	0	0	-1646	3873	3873	0
July	54	311	164	168	0	2013	2710	342	92	0	0	0	-1596	3873	3873	0
August	82	259	157	168	0	2013	2679	342	92	0	0	0	-1627	3873	3873	0
September	195	582	143	349	0	2013	3282	342	92	0	0	0	-1024	3873	3873	0
October	662	637	90	602	0	2013	4004	342	92	0	0	0	-302	3873	3873	0
November	806	1103	81	843	0	2013	4845	342	92	0	0	0	539	3873	3873	0
December	1668	667	101	1039	0	2013	5489	342	92	0	0	0	1182	3873	3873	0
Average	644	873	102	675	0	2013	4306	342	92	0	0	0	0	3873	3873	0
Maximum	4651	4021	417	2203	0	2013	9169	342	92	0	0	0	4863	3873	3873	0
Minimum	15	26	0	127	0	2013	2312	342	92	0	0	0	-1995	3873	3873	0
Total for the whole year TWh/year	5.65	7.67	0.89	5.93	0.00	17.68	37.83	3.00	0.81	0.00	0.00	0.00	0.00	34.02	34.02	0.00

RES Share: 37.2 Percent of Primary Energy 85.8 Percent of Electricity 32.0 TWh electricity from RES 12-January-2015 [15:24]

Input HP_alternative.txt

The EnergyPLAN model 12.0

Electricity demand (TWh/year):		Flexible demand	0.00
Fixed demand	36.68	Fixed imp/exp.	0.00
Electric heating + HP	0.59	Transportation	0.59
Electric cooling	0.00	Total	37.86

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	3.46	10.72	23.03	37.21
Solar Thermal	0.02	0.07	0.00	0.09
Industrial CHP (CSHP)	0.17	0.17	0.95	1.29
Demand after solar and CSHP	3.27	10.48	22.08	35.83

Wind	4231 MW	9.00	TWh/year	0.00	Grid
Offshore Wind	2671 MW	10.56	TWh/year	0.00	stabili-
Photo Voltaic	1210 MW	1.04	TWh/year	0.00	sation
River Hydro	10 MW	0.02	TWh/year	0.00	share
Hydro Power	0 MW	0	TWh/year		
Geothermal/Nuclear	0 MW	0	TWh/year		

	Capacities		Efficiencies		
Group 2:	MW-e	MJ/s	elec.	Ther	COP
CHP	1830	2420	0.36	0.48	
Heat Pump	400	1200			3.00
Boiler		4176		0.95	
Group 3:					
CHP	6000	9882	0.34	0.56	
Heat Pump	250	750			3.00
Boiler		5922		0.90	
Condensing	6335		0.39		

Heatstorage: gr.2: 0 GWh gr.3: 0 GWh
Fixed Boiler: gr.2: 2.5 Per cent gr.3: 1.0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0.07	0.03
Gr.2:	0.12	0.51
Gr.3:	0.07	1.74

Regulation Strategy:	Technical regulation no. 3	
KEOL regulation	23450000	
Minimum Stabilisation share	0.25	
Stabilisation share of CHP	0.00	
Minimum CHP gr 3 load	200	MW
Minimum PP	0	MW
Heat Pump maximum share	1.00	
Maximum import/export	0	MW
Distr. Name	DK 2013 Electricty price.txt	
Addition factor	0.00	DKK/MWh
Multiplication factor	1.02	
Dependency factor	0.04	DKK/MWh pr. MW
Average Market Price	298	DKK/MWh
Gas Storage	6360	GWh
Syngas capacity	92	MW
Biogas max to grid	342	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Ther.
Hydro Pump:	0	0	0.40	
Hydro Turbine:	0		0.40	
Electrol. Gr.2:	0	0	0.40	0.50
Electrol. Gr.3:	0	0	0.40	0.50
Electrol. trans.:	0	0	0.00	
Ely. MicroCHP:	0	0	0.80	
CAES fuel ratio:		0.000		

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0.00	56.52	0.00	0.00
Household	0.00	3.33	5.93	12.10
Industry	1.34	11.36	10.78	2.89
Various	0.00	4.90	6.90	1.00

Output WARNING!!: (1) Critical Excess;

	District Heating										Electricity																			Exchange	
	Demand	Production									Consumption						Production							Balance						Payment	
	Distr. heating MW	Solar MW	Waste+ CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Ba-lance MW	Elec. demand MW	Flex.& Transp. MW	HP MW	Elec-trolyser MW	EH MW	Hydro Pump MW	Tur-bine MW	RES MW	Hy-dro MW	Geo-thermal MW	Waste+ CSHP MW	CHP MW	PP MW	Stab-Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Imp Million DKK	Exp
January	6817	1	745	534	3866	1052	0	618	0	0	4872	66	468	0	0	0	0	2283	0	0	290	2495	541	166	0	203	203	0	0	17
February	6974	5	745	548	4470	900	0	307	0	0	4738	68	419	0	0	0	0	1763	0	0	290	2891	323	178	0	42	42	0	0	4
March	5942	6	745	451	2959	1022	0	758	0	0	4535	68	440	0	0	0	0	2686	0	0	290	1909	640	149	0	481	481	0	0	34
April	4761	16	745	339	2601	799	0	261	0	0	4093	65	344	0	0	0	0	2315	0	0	290	1679	595	151	0	377	377	0	0	34
May	3736	18	745	244	2102	513	0	114	0	0	3778	68	230	0	0	0	0	1964	0	0	290	1358	654	153	0	189	189	0	0	18
June	1694	24	745	52	634	199	0	40	0	0	3769	68	82	0	0	0	0	2367	0	0	290	404	1491	166	0	632	632	0	0	38
July	1695	19	745	53	738	109	0	30	0	0	3591	66	53	0	0	0	0	1600	0	0	290	475	1578	201	0	232	232	0	0	21
August	1694	18	745	54	670	169	0	39	0	0	3770	68	73	0	0	0	0	2130	0	0	290	429	1513	173	0	449	449	0	0	42
September	2599	12	745	139	1325	298	0	80	0	0	3932	67	134	0	0	0	0	1913	0	0	290	856	1371	181	0	298	298	0	0	29
October	3871	6	745	259	1754	815	0	292	0	0	4154	67	331	0	0	0	0	2877	0	0	290	1124	785	130	0	522	522	0	0	44
November	5078	2	745	372	2691	906	0	362	0	0	4423	68	386	0	0	0	0	2625	0	0	290	1736	684	146	0	458	458	0	0	28
December	6064	1	745	464	2085	1460	0	1309	0	0	4475	66	589	0	0	0	0	3602	0	0	290	1329	812	124	0	902	902	0	0	42
Average	4237	11	745	292	2149	687	0	353	0	0	4176	67	296	0	0	0	0	2347	0	0	290	1385	917	160	0	400	400	0	Average price	
Maximum	11905	134	745	1007	8711	1950	0	6413	0	0	6632	204	868	0	0	0	0	6570	0	0	290	5640	4006	358	0	4398	4398	0	(DKK/MWh)	
Minimum	1483	0	745	30	329	57	0	0	0	0	2483	0	19	0	0	0	0	8	0	0	290	200	0	100	0	0	0	0	320	100
TWh/year	37.21	0.09	6.54	2.56	18.88	6.04	0.00	3.10	0.00	0.00	36.68	0.59	2.60	0.00	0.00	0.00	0.00	20.62	0.00	0.00	2.54	12.16	8.06		0.00	3.52	3.52	0.00	0	353

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon-version	Synthetic Fuel	Wind	Offsh.	PV	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Netto	CO2 emission (Mt): Total	Netto
Coal	-	0.37	8.29	-	-	10.42	-	-	-	-	-	-	-	-	-	-	-	-	-	1.34	20.41	-4.54	15.87	7.24	5.63
Oil	-	-	0.22	-	1.66	0.84	-	-	-	-	-	-	-	-	-	-	-	56.52	3.33	16.26	78.83	-0.37	78.46	20.69	20.59
N.Gas	0.25	6.95	1.12	0.43	1.10	0.84	-	-	-	-	-3.81	-	-	-	-	-	-	-	5.93	17.68	30.50	-0.37	30.13	6.25	6.17
Biomass	2.45	2.56	15.68	0.22	-	8.57	-	-	9.97	-	4.88	-	-	-	-	-	-	-	11.46	3.89	59.67	-3.74	55.93	1.17	1.17
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	9.00	10.56	1.04	0.02	0.61	-	-	-	21.23	0.00	21.23	0.00	0.00
H2 etc.	-	0.00	0.00	0.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Biofuel	-	-	0.00	-	-	-	-	-	-	-	-3.72	-	-	-	-	-	-	3.72	-	-	0.00	0.00	0.00	0.00	0.00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Total	2.70	9.88	25.31	0.65	2.76	20.66	-	-	9.97	-	-2.65	-	9.00	10.56	1.04	0.02	0.61	60.24	20.72	39.17	210.64	-9.02	201.62	35.34	33.56

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Output specifications HP_alternative.txt The EnergyPLAN model 12.0

District Heating Production

	Gr.1 District heating MW	Gr.1 Solar MW	Gr.1 CSHP MW	Gr.1 DHP MW	Gr.2 District heating MW	Gr.2 Solar MW	Gr.2 CSHP MW	Gr.2 CHP MW	Gr.2 HP MW	Gr.2 ELT MW	Gr.2 Boiler MW	Gr.2 EH MW	Gr.2 Stor-age MW	Gr.2 Ba-lance MW
January	634	0	100	534	1964	1	213	989	631	0	130	0	0	0
February	648	1	100	548	2009	4	213	1189	534	0	70	0	0	0
March	553	1	100	451	1712	5	213	756	610	0	128	0	0	0
April	443	3	100	339	1372	13	213	672	456	0	18	0	0	0
May	347	4	100	244	1076	14	213	545	268	0	37	0	0	0
June	157	5	100	52	488	18	213	129	96	0	31	0	0	0
July	157	4	100	53	488	15	213	181	55	0	24	0	0	0
August	157	4	100	54	488	14	213	147	83	0	30	0	0	0
September	242	2	100	139	749	9	213	345	141	0	40	0	0	0
October	360	1	100	259	1115	5	213	394	437	0	67	0	0	0
November	472	0	100	372	1463	1	213	687	526	0	35	0	0	0
December	564	0	100	464	1747	1	213	421	886	0	227	0	0	0
Average	394	2	100	292	1220	8	213	535	394	0	70	0	0	0
Maximum	1107	29	100	1007	3430	105	213	2420	1200	0	1774	0	0	0
Minimum	138	0	100	30	427	0	213	0	31	0	0	0	0	0
Total for the whole year TWh/year	3.46	0.02	0.88	2.56	10.72	0.07	1.87	4.70	3.46	0.00	0.62	0.00		0.00

	Gr.3 District heating MW	Gr.3 Solar MW	Gr.3 CSHP MW	Gr.3 CHP MW	Gr.3 HP MW	Gr.3 ELT MW	Gr.3 Boiler MW	Gr.3 EH MW	Gr.3 Stor-age MW	Gr.3 Ba-lance MW	RES specification RES1 Wind MW	RES2 Offshoı MW	RES3 Photo \ MW	RES 4-7 ic MW	Total MW
January	4219	0	432	2877	421	0	489	0	0	0	1092	1177	11	3	2283
February	4316	0	432	3281	366	0	237	0	0	0	700	1007	53	3	1763
March	3677	0	432	2203	412	0	631	0	0	0	1363	1248	73	3	2686
April	2947	0	432	1928	343	0	243	0	0	0	1107	1032	174	4	2315
May	2312	0	432	1558	245	0	77	0	0	0	753	1010	197	3	1964
June	1049	0	432	505	102	0	9	0	0	0	929	1181	255	2	2367
July	1049	0	432	557	54	0	7	0	0	0	562	825	212	1	1600
August	1049	0	432	523	86	0	9	0	0	0	799	1127	203	1	2130
September	1609	0	432	980	156	0	40	0	0	0	703	1074	134	2	1913
October	2396	0	432	1360	378	0	225	0	0	0	1224	1580	70	3	2877
November	3143	0	432	2004	380	0	327	0	0	0	1134	1465	23	4	2625
December	3753	0	432	1664	574	0	1082	0	0	0	1897	1687	14	5	3602
Average	2622	0	432	1614	293	0	283	0	0	0	1024	1202	118	3	2347
Maximum	7368	0	432	6359	750	0	4750	0	0	0	4231	2671	1210	5	6570
Minimum	918	0	432	329	26	0	0	0	0	0	2	0	0	1	8
Total for the whole year TWh/year	23.03	0.00	3.80	14.18	2.58	0.00	2.48	0.00		0.00	9.00	10.56	1.04	0.02	20.62

Own use of heat from industrial CHP: 0.00 TWh/year

ANNUAL COSTS (Million DKK)

Total Fuel ex Ngas exchange =		52556
Uranium =	0	
Coal =	1705	
FuelOil =	7166	
Gasoil/Diesel=	16937	
Petrol/JP =	13768	
Gas handling =	1546	
Biomass =	11435	
Food income =	0	
Waste =	0	
Total Ngas Exchange costs =		6818
Marginal operation costs =		414
Total Electricity exchange =		0
Import =	0	
Export =	-353	
Bottleneck =	353	
Fixed imp/ex=	0	
Total CO2 emission costs =		4002
Total variable costs =		63790
Fixed operation costs =		9082
Annual Investment costs =		18718
TOTAL ANNUAL COSTS =		91590

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Indi-vidual MW	Trans port MW	Indu. Var. MW	Demand Sum MW	Bio-gas MW	Syn-gas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Stor-age MW	Sum MW	Im-port MW	Ex-port MW
January	359	1690	56	1189	0	2013	5308	342	92	0	0	0	1402	3472	3472	0
February	207	2018	34	1221	0	2013	5491	342	92	0	0	0	1586	3472	3472	0
March	413	1292	67	1015	0	2013	4800	342	92	0	0	0	894	3472	3472	0
April	153	1146	62	780	0	2013	4154	342	92	0	0	0	249	3472	3472	0
May	84	928	68	575	0	2013	3668	342	92	0	0	0	-237	3472	3472	0
June	31	231	155	168	0	2013	2598	342	92	0	0	0	-1307	3472	3472	0
July	25	311	164	168	0	2013	2682	342	92	0	0	0	-1224	3472	3472	0
August	30	259	158	168	0	2013	2628	342	92	0	0	0	-1277	3472	3472	0
September	59	588	143	349	0	2013	3152	342	92	0	0	0	-754	3472	3472	0
October	172	689	82	602	0	2013	3558	342	92	0	0	0	-347	3472	3472	0
November	206	1174	71	843	0	2013	4307	342	92	0	0	0	402	3472	3472	0
December	685	754	85	1039	0	2013	4575	342	92	0	0	0	669	3472	3472	0
Average	203	919	96	675	0	2013	3905	342	92	0	0	0	0	3472	3472	0
Maximum	3363	4055	418	2203	0	2013	8135	342	92	0	0	0	4229	3472	3472	0
Minimum	3	26	0	127	0	2013	2249	342	92	0	0	0	-1656	3472	3472	0
Total for the whole year TWh/year	1.78	8.07	0.84	5.93	0.00	17.68	34.30	3.00	0.81	0.00	0.00	0.00	0.00	30.50	30.50	0.00

RES Share: 38.4 Percent of Primary Energy 82.7 Percent of Electricity 32.5 TWh electricity from RES 12-January-2015 [15:24]

Input HP_storage.txt

The EnergyPLAN model 12.0

Electricity demand (TWh/year):		Flexible demand	0.00
Fixed demand	36.68	Fixed imp/exp.	0.00
Electric heating + HP	0.59	Transportation	0.59
Electric cooling	0.00	Total	37.86

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	3.46	10.72	23.03	37.21
Solar Thermal	0.02	0.07	0.00	0.09
Industrial CHP (CSHP)	0.17	0.17	0.95	1.29
Demand after solar and CSHP	3.27	10.48	22.08	35.83

Wind	4231 MW	9.00	TWh/year	0.00	Grid
Offshore Wind	2671 MW	10.56	TWh/year	0.00	stabili-
Photo Voltaic	1210 MW	1.04	TWh/year	0.00	sation
River Hydro	10 MW	0.02	TWh/year	0.00	share
Hydro Power	0 MW	0	TWh/year		
Geothermal/Nuclear	0 MW	0	TWh/year		

	Capacities		Efficiencies		
Group 2:	MW-e	MJ/s	elec.	Ther	COP
CHP	1830	2420	0.36	0.48	
Heat Pump	400	1200			3.00
Boiler		4176		0.95	
Group 3:					
CHP	6000	9882	0.34	0.56	
Heat Pump	250	750			3.00
Boiler		5922		0.90	
Condensing	6335		0.39		

Heatstorage: gr.2: 14 GWh gr.3: 14 GWh
Fixed Boiler: gr.2: 2.5 Per cent gr.3: 1.0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0.07	0.03
Gr.2:	0.12	0.51
Gr.3:	0.07	1.74

Regulation Strategy:	Technical regulation no. 3	
KEOL regulation	23450000	
Minimum Stabilisation share	0.25	
Stabilisation share of CHP	0.00	
Minimum CHP gr 3 load	200	MW
Minimum PP	0	MW
Heat Pump maximum share	1.00	
Maximum import/export	0	MW
Distr. Name	DK 2013 Electricty price.txt	
Addition factor	0.00	DKK/MWh
Multiplication factor	1.02	
Dependency factor	0.04	DKK/MWh pr. MW
Average Market Price	298	DKK/MWh
Gas Storage	6360	GWh
Syngas capacity	92	MW
Biogas max to grid	342	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Ther.
Hydro Pump:	0	0	0.40	
Hydro Turbine:	0		0.40	
Electrol. Gr.2:	0	0	0.40	0.50
Electrol. Gr.3:	0	0	0.40	0.50
Electrol. trans.:	0	0	0.00	
Ely. MicroCHP:	0	0	0.80	
CAES fuel ratio:		0.000		

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0.00	56.52	0.00	0.00
Household	0.00	3.33	5.93	12.10
Industry	1.34	11.36	10.78	2.89
Various	0.00	4.90	6.90	1.00

Output WARNING!!: (1) Critical Excess;

	District Heating										Electricity																			Exchange	
	Demand	Production									Consumption						Production								Balance						
	Distr. heating MW	Solar MW	Waste+ CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Ba- lance MW	Elec. demand MW	Flex.& Transp. MW	HP MW	Elec- trolyser MW	EH MW	Hydro Pump MW	Tur- bine MW	RES MW	Hy- dro MW	Geo- thermal MW	Waste+ CSHP MW	CHP MW	PP MW	Stab- Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Payment Imp Million DKK	Exp
January	6817	1	745	534	3966	1053	0	498	0	20	4872	66	469	0	0	0	0	2283	0	0	290	2562	474	163	0	203	203	0	0	17
February	6974	5	745	548	4545	901	0	231	0	0	4738	68	420	0	0	0	0	1763	0	0	290	2942	272	176	0	41	41	0	0	4
March	5942	6	745	451	3051	1031	0	664	0	-7	4535	68	443	0	0	0	0	2686	0	0	290	1972	580	147	0	480	480	0	0	33
April	4761	16	745	339	2678	821	0	167	0	-5	4093	65	351	0	0	0	0	2315	0	0	290	1726	549	151	0	371	371	0	0	34
May	3736	18	745	244	2167	560	0	7	0	-5	3778	68	246	0	0	0	0	1964	0	0	290	1398	622	153	0	181	181	0	0	17
June	1694	24	745	52	643	238	0	0	0	-8	3769	68	95	0	0	0	0	2367	0	0	290	409	1484	166	0	618	618	0	0	37
July	1695	19	745	53	744	133	0	0	0	1	3591	66	61	0	0	0	0	1600	0	0	290	478	1573	201	0	224	224	0	0	20
August	1694	18	745	54	678	205	0	0	0	-5	3770	68	85	0	0	0	0	2130	0	0	290	434	1507	173	0	436	436	0	0	41
September	2599	12	745	139	1347	348	0	3	0	6	3932	67	150	0	0	0	0	1913	0	0	290	869	1362	182	0	285	285	0	0	28
October	3871	6	745	259	1808	918	0	118	0	17	4154	67	366	0	0	0	0	2877	0	0	290	1158	766	130	0	504	504	0	0	42
November	5078	2	745	372	2759	938	0	266	0	-3	4423	68	396	0	0	0	0	2625	0	0	290	1778	644	146	0	450	450	0	0	28
December	6064	1	745	464	2157	1482	0	1211	0	5	4475	66	597	0	0	0	0	3602	0	0	290	1376	768	123	0	899	899	0	0	42
Average	4237	11	745	292	2203	719	0	266	0	1	4176	67	307	0	0	0	0	2347	0	0	290	1420	885	159	0	392	392	0	Average price	
Maximum	11905	134	745	1007	8711	1950	0	6245	0	3813	6632	204	868	0	0	0	0	6570	0	0	290	5640	4006	358	0	4379	4379	0	(DKK/MWh)	
Minimum	1483	0	745	30	329	57	0	0	0	-1939	2483	0	19	0	0	0	0	8	0	0	290	200	0	100	0	0	0	0	333	100
TWh/year	37.21	0.09	6.54	2.56	19.35	6.32	0.00	2.33	0.00	0.01	36.68	0.59	2.69	0.00	0.00	0.00	0.00	20.62	0.00	0.00	2.54	12.47	7.78		0.00	3.45	3.45	0.00	0	344

FUEL BALANCE (TWh/year):	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon- version	Synthetic Fuel	Wind	Offsh.	PV	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Netto	CO2 emission (Mt): Total	Netto
Coal	-	0.38	8.49	-	-	10.05	-	-	-	-	-	-	-	-	-	-	-	-	-	1.34	20.26	-4.46	15.81	7.18	5.60
Oil	-	-	0.23	-	1.36	0.81	-	-	-	-	-	-	-	-	-	-	-	56.52	3.33	16.26	78.51	-0.36	78.15	20.60	20.51
N.Gas	0.25	7.14	1.15	0.20	0.91	0.81	-	-	-	-	-3.81	-	-	-	-	-	-	-	5.93	17.68	30.25	-0.36	29.89	6.20	6.12
Biomass	2.45	2.63	16.07	0.10	-	8.27	-	-	9.97	-	4.88	-	-	-	-	-	-	-	11.46	3.89	59.71	-3.66	56.05	1.17	1.17
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	9.00	10.56	1.04	0.02	0.61	-	-	-	21.23	0.00	21.23	0.00	0.00
H2 etc.	-	0.00	0.00	0.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Biofuel	-	-	0.00	-	-	-	-	-	-	-	-3.72	-	-	-	-	-	-	3.72	-	-	0.00	0.00	0.00	0.00	0.00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Total	2.70	10.14	25.94	0.31	2.27	19.94	-	-	9.97	-	-2.65	-	9.00	10.56	1.04	0.02	0.61	60.24	20.72	39.17	209.97	-8.84	201.13	35.15	33.41

12-January-2015 [15:53]

Output specifications HP_storage.txt The EnergyPLAN model 12.0

District Heating Production

	Gr.1				Gr.2									
	District heating MW	Solar MW	CSHP MW	DHP MW	District heating MW	Solar MW	CSHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Storage MW	Balance MW
January	634	0	100	534	1964	1	213	1030	631	0	82	0	7713	6
February	648	1	100	548	2009	4	213	1225	535	0	33	0	7295	0
March	553	1	100	451	1712	5	213	799	615	0	81	0	3826	0
April	443	3	100	339	1372	13	213	674	471	0	6	0	1300	-4
May	347	4	100	244	1076	14	213	550	294	0	2	0	1785	4
June	157	5	100	52	488	18	213	128	134	0	0	0	3635	-6
July	157	4	100	53	488	15	213	180	79	0	0	0	3905	1
August	157	4	100	54	488	14	213	147	119	0	0	0	4432	-5
September	242	2	100	139	749	9	213	348	174	0	0	0	4905	6
October	360	1	100	259	1115	5	213	405	492	0	1	0	4454	0
November	472	0	100	372	1463	1	213	692	552	0	9	0	5665	-4
December	564	0	100	464	1747	1	213	448	902	0	178	0	8415	5
Average	394	2	100	292	1220	8	213	549	417	0	33	0	4774	0
Maximum	1107	29	100	1007	3430	105	213	2420	1200	0	1774	0	13900	1390
Minimum	138	0	100	30	427	0	213	0	31	0	0	0	0	-1198
Total for the whole year TWh/year	3.46	0.02	0.88	2.56	10.72	0.07	1.87	4.83	3.66	0.00	0.29	0.00		0.00

	Gr.3										RES specification				
	District heating MW	Solar MW	CSHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Storage MW	Balance MW	RES1 Wind MW	RES2 Offshoı MW	RES3 Photo \ MW	RES 4-7 ic MW	Total MW
January	4219	0	432	2936	422	0	416	0	4684	13	1092	1177	11	3	2283
February	4316	0	432	3320	366	0	197	0	6004	0	700	1007	53	3	1763
March	3677	0	432	2253	416	0	583	0	3402	-7	1363	1248	73	3	2686
April	2947	0	432	2004	350	0	161	0	6272	-1	1107	1032	174	4	2315
May	2312	0	432	1618	267	0	5	0	11531	-9	753	1010	197	3	1964
June	1049	0	432	514	104	0	0	0	13899	-2	929	1181	255	2	2367
July	1049	0	432	563	54	0	0	0	13900	0	562	825	212	1	1600
August	1049	0	432	531	86	0	0	0	13900	0	799	1127	203	1	2130
September	1609	0	432	999	174	0	3	0	13126	0	703	1074	134	2	1913
October	2396	0	432	1403	426	0	117	0	8390	18	1224	1580	70	3	2877
November	3143	0	432	2067	386	0	256	0	4641	1	1134	1465	23	4	2625
December	3753	0	432	1709	580	0	1032	0	2716	0	1897	1687	14	5	3602
Average	2622	0	432	1654	303	0	233	0	8542	1	1024	1202	118	3	2347
Maximum	7368	0	432	6359	750	0	4711	0	13900	2979	4231	2671	1210	5	6570
Minimum	918	0	432	329	26	0	0	0	0	-1153	2	0	0	1	8
Total for the whole year TWh/year	23.03	0.00	3.80	14.53	2.66	0.00	2.04	0.00		0.01	9.00	10.56	1.04	0.02	20.62

Own use of heat from industrial CHP: 0.00 TWh/year

ANNUAL COSTS (Million DKK)

Total Fuel ex Ngas exchange =		52437
Uranium =	0	
Coal =	1692	
FuelOil =	7054	
Gasoil/Diesel=	16937	
Petrol/JP =	13768	
Gas handling =	1542	
Biomass =	11445	
Food income =	0	
Waste =	0	
Total Ngas Exchange costs =		6764
Marginal operation costs =		414
Total Electricity exchange =		0
Import =	0	
Export =	-344	
Bottleneck =	344	
Fixed imp/ex=	0	
Total CO2 emission costs =		3981
Total variable costs =		63595
Fixed operation costs =		9086
Annual Investment costs =		18760
TOTAL ANNUAL COSTS =		91441

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Individual MW	Transport MW	Indu. Var. MW	Demand Sum MW	Biogas MW	Syngas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Storage MW	Sum MW	Import MW	Export MW
January	294	1755	49	1189	0	2013	5300	342	92	0	0	0	1422	3444	3444	0
February	164	2073	28	1221	0	2013	5498	342	92	0	0	0	1621	3444	3444	0
March	359	1359	60	1015	0	2013	4806	342	92	0	0	0	928	3444	3444	0
April	108	1154	57	780	0	2013	4112	342	92	0	0	0	235	3444	3444	0
May	27	940	65	575	0	2013	3620	342	92	0	0	0	-257	3444	3444	0
June	5	230	155	168	0	2013	2571	342	92	0	0	0	-1306	3444	3444	0
July	5	311	164	168	0	2013	2662	342	92	0	0	0	-1216	3444	3444	0
August	5	259	157	168	0	2013	2603	342	92	0	0	0	-1275	3444	3444	0
September	15	593	142	349	0	2013	3111	342	92	0	0	0	-766	3444	3444	0
October	77	709	80	602	0	2013	3481	342	92	0	0	0	-396	3444	3444	0
November	156	1187	67	843	0	2013	4265	342	92	0	0	0	388	3444	3444	0
December	628	798	80	1039	0	2013	4558	342	92	0	0	0	680	3444	3444	0
Average	154	943	92	675	0	2013	3878	342	92	0	0	0	0	3444	3444	0
Maximum	3287	4055	418	2203	0	2013	8135	342	92	0	0	0	4257	3444	3444	0
Minimum	3	26	0	127	0	2013	2232	342	92	0	0	0	-1645	3444	3444	0
Total for the whole year TWh/year	1.36	8.28	0.81	5.93	0.00	17.68	34.06	3.00	0.81	0.00	0.00	0.00	0.00	30.25	30.25	0.00

RES Share: 38.5 Percent of Primary Energy 82.6 Percent of Electricity 32.5 TWh electricity from RES 12-January-2015 [15:53]

Input HP_wind1.txt

The EnergyPLAN model 12.0

Electricity demand (TWh/year):		Flexible demand	0.00
Fixed demand	36.68	Fixed imp/exp.	0.00
Electric heating + HP	0.59	Transportation	0.59
Electric cooling	0.00	Total	37.86

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	3.46	10.72	23.03	37.21
Solar Thermal	0.02	0.07	0.00	0.09
Industrial CHP (CSHP)	0.17	0.17	0.95	1.29
Demand after solar and CSHP	3.27	10.48	22.08	35.83

Wind	4500 MW	9.57 TWh/year	0.00	Grid
Offshore Wind	2671 MW	10.56 TWh/year	0.00	stabili-
Photo Voltaic	1210 MW	1.04 TWh/year	0.00	sation
River Hydro	10 MW	0.02 TWh/year	0.00	share
Hydro Power	0 MW	0 TWh/year		
Geothermal/Nuclear	0 MW	0 TWh/year		

	Capacities		Efficiencies		
Group 2:	MW-e	MJ/s	elec.	Ther	COP
CHP	1830	2420	0.36	0.48	
Heat Pump	400	1200			3.00
Boiler		4176		0.95	
Group 3:					
CHP	6000	9882	0.34	0.56	
Heat Pump	250	750			3.00
Boiler		5922		0.90	
Condensing	6335		0.39		

Heatstorage: gr.2: 0 GWh gr.3: 0 GWh
Fixed Boiler: gr.2: 2.5 Per cent gr.3: 1.0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0.07	0.03
Gr.2:	0.12	0.51
Gr.3:	0.07	1.74

Regulation Strategy:	Technical regulation no. 3	
KEOL regulation	23450000	
Minimum Stabilisation share	0.25	
Stabilisation share of CHP	0.00	
Minimum CHP gr 3 load	200	MW
Minimum PP	0	MW
Heat Pump maximum share	1.00	
Maximum import/export	0	MW
Distr. NameDK 2013 Electricty price.txt		
Addition factor	0.00	DKK/MWh
Multiplication factor	1.02	
Dependency factor	0.04	DKK/MWh pr. MW
Average Market Price	298	DKK/MWh
Gas Storage	6360	GWh
Syngas capacity	92	MW
Biogas max to grid	342	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Ther.
Hydro Pump:	0	0	0.40	
Hydro Turbine:	0		0.40	
Electrol. Gr.2:	0	0	0.40	0.50
Electrol. Gr.3:	0	0	0.40	0.50
Electrol. trans.:	0	0	0.00	
Ely. MicroCHP:	0	0	0.80	
CAES fuel ratio:		0.000		

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0.00	56.52	0.00	0.00
Household	0.00	3.33	5.93	12.10
Industry	1.34	11.36	10.78	2.89
Various	0.00	4.90	6.90	1.00

Output WARNING!!: (1) Critical Excess;

District Heating

	Demand: Distr. heating MW	Production: Solar MW	Waste+ CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Ba-lance MW
January	6817	1	745	534	3794	1069	0	674	0	0
February	6974	5	745	548	4422	917	0	338	0	0
March	5942	6	745	451	2899	1041	0	799	0	0
April	4761	16	745	339	2554	819	0	288	0	0
May	3736	18	745	244	2071	534	0	125	0	0
June	1694	24	745	52	629	206	0	38	0	0
July	1695	19	745	53	733	113	0	31	0	0
August	1694	18	745	54	665	175	0	38	0	0
September	2599	12	745	139	1313	309	0	82	0	0
October	3871	6	745	259	1712	841	0	309	0	0
November	5078	2	745	372	2647	926	0	387	0	0
December	6064	1	745	464	2009	1480	0	1365	0	0
Average	4237	11	745	292	2112	703	0	375	0	0
Maximum	11905	134	745	1007	8709	1950	0	6588	0	0
Minimum	1483	0	745	30	329	57	0	0	0	0
TWh/year	37.21	0.09	6.54	2.56	18.55	6.17	0.00	3.29	0.00	0.00

Electricity

	Consumption: Elec. demand MW	Flex.& Transp. MW	HP MW	Elec-trolyser MW	EH MW	Hydro Pump MW	Production: Tur-bine MW	RES MW	Hy-dro MW	Geo-thermal MW	Waste+ CSHP MW	CHP MW	PP MW	Balance: Stab-Load %	Imp MW	Exp MW	CEEP MW	EEP MW
January	4872	66	474	0	0	0	0	2353	0	0	290	2448	567	164	0	246	246	0
February	4738	68	425	0	0	0	0	1807	0	0	290	2860	328	176	0	54	54	0
March	4535	68	447	0	0	0	0	2773	0	0	290	1870	672	148	0	554	554	0
April	4093	65	350	0	0	0	0	2386	0	0	290	1650	619	150	0	435	435	0
May	3778	68	237	0	0	0	0	2012	0	0	290	1337	663	152	0	217	217	0
June	3769	68	85	0	0	0	0	2426	0	0	290	401	1495	165	0	690	690	0
July	3591	66	55	0	0	0	0	1636	0	0	290	472	1572	199	0	258	258	0
August	3770	68	75	0	0	0	0	2180	0	0	290	426	1511	171	0	493	493	0
September	3932	67	137	0	0	0	0	1958	0	0	290	848	1372	180	0	331	331	0
October	4154	67	340	0	0	0	0	2954	0	0	290	1096	809	129	0	588	588	0
November	4423	68	392	0	0	0	0	2698	0	0	290	1708	707	145	0	518	518	0
December	4475	66	596	0	0	0	0	3723	0	0	290	1280	867	123	0	1022	1022	0
Average	4176	67	301	0	0	0	0	2413	0	0	290	1360	934	158	0	452	452	0
Maximum	6632	204	868	0	0	0	0	6818	0	0	290	5639	4003	358	0	4719	4719	0
Minimum	2483	0	19	0	0	0	0	8	0	0	290	200	0	100	0	0	0	0
TWh/year	36.68	0.59	2.64	0.00	0.00	0.00	0.00	21.19	0.00	0.00	2.54	11.95	8.20		0.00	3.97	3.97	0.00

Exchange

	Payment Imp (Million DKK)	Exp (Million DKK)
January	0	20
February	0	6
March	0	35
April	0	36
May	0	20
June	0	39
July	0	22
August	0	44
September	0	31
October	0	47
November	0	29
December	0	43
Average price (DKK/MWh)	319	94
TWh/year	0	372

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon-version	Synthetic Fuel	Wind	Offsh.	PV	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Netto	CO2 emission (Mt): Total	Netto
Coal	-	0.36	8.15	-	-	10.60	-	-	-	-	-	-	-	-	-	-	-	-	-	1.34	20.45	-5.13	15.32	7.25	5.43
Oil	-	-	0.22	-	1.77	0.85	-	-	-	-	-	-	-	-	-	-	-	56.52	3.33	16.26	78.96	-0.41	78.54	20.72	20.61
N.Gas	0.25	6.81	1.10	0.45	1.18	0.85	-	-	-	-	-3.81	-	-	-	-	-	-	-	5.93	17.68	30.44	-0.41	30.03	6.24	6.15
Biomass	2.45	2.51	15.42	0.22	-	8.72	-	-	9.97	-	4.88	-	-	-	-	-	-	-	11.46	3.89	59.52	-4.22	55.30	1.17	1.17
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	9.57	10.56	1.04	0.02	0.61	-	-	-	21.80	0.00	21.80	0.00	0.00
H2 etc.	-	0.00	0.00	0.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Biofuel	-	-	-	-	-	-	-	-	-	-	-3.72	-	-	-	-	-	-	3.72	-	-	0.00	0.00	0.00	0.00	0.00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Total	2.70	9.68	24.90	0.67	2.95	21.03	-	-	9.97	-	-2.65	-	9.57	10.56	1.04	0.02	0.61	60.24	20.72	39.17	211.17	-10.18	200.99	35.38	33.36

12-January-2015 [15:28]

Output specifications HP_wind1.txt The EnergyPLAN model 12.0

District Heating Production

	Gr.1 District heating MW	Gr.1 Solar MW	Gr.1 CSHP MW	Gr.1 DHP MW	Gr.2 District heating MW	Gr.2 Solar MW	Gr.2 CSHP MW	Gr.2 CHP MW	Gr.2 HP MW	Gr.2 ELT MW	Gr.2 Boiler MW	Gr.2 EH MW	Gr.2 Storage MW	Gr.2 Balance MW
January	634	0	100	534	1964	1	213	969	642	0	139	0	0	0
February	648	1	100	548	2009	4	213	1174	545	0	74	0	0	0
March	553	1	100	451	1712	5	213	738	622	0	134	0	0	0
April	443	3	100	339	1372	13	213	661	467	0	18	0	0	0
May	347	4	100	244	1076	14	213	533	279	0	38	0	0	0
June	157	5	100	52	488	18	213	127	100	0	29	0	0	0
July	157	4	100	53	488	15	213	179	57	0	24	0	0	0
August	157	4	100	54	488	14	213	146	86	0	29	0	0	0
September	242	2	100	139	749	9	213	341	146	0	40	0	0	0
October	360	1	100	259	1115	5	213	379	451	0	67	0	0	0
November	472	0	100	372	1463	1	213	675	538	0	36	0	0	0
December	564	0	100	464	1747	1	213	403	898	0	232	0	0	0
Average	394	2	100	292	1220	8	213	524	403	0	72	0	0	0
Maximum	1107	29	100	1007	3430	105	213	2420	1200	0	1774	0	0	0
Minimum	138	0	100	30	427	0	213	0	31	0	0	0	0	0
Total for the whole year TWh/year	3.46	0.02	0.88	2.56	10.72	0.07	1.87	4.61	3.54	0.00	0.63	0.00		0.00

	Gr.3 District heating MW	Gr.3 Solar MW	Gr.3 CSHP MW	Gr.3 CHP MW	Gr.3 HP MW	Gr.3 ELT MW	Gr.3 Boiler MW	Gr.3 EH MW	Gr.3 Storage MW	Gr.3 Balance MW	RES1 Wind MW	RES2 Offshoı MW	RES3 Photo \ MW	RES 4-7 ic MW	Total MW
January	4219	0	432	2824	427	0	535	0	0	0	1162	1177	11	3	2353
February	4316	0	432	3248	372	0	264	0	0	0	744	1007	53	3	1807
March	3677	0	432	2161	419	0	665	0	0	0	1449	1248	73	3	2773
April	2947	0	432	1894	352	0	269	0	0	0	1177	1032	174	4	2386
May	2312	0	432	1538	255	0	87	0	0	0	801	1010	197	3	2012
June	1049	0	432	502	106	0	8	0	0	0	988	1181	255	2	2426
July	1049	0	432	555	56	0	7	0	0	0	598	825	212	1	1636
August	1049	0	432	520	89	0	8	0	0	0	849	1127	203	1	2180
September	1609	0	432	972	162	0	42	0	0	0	748	1074	134	2	1958
October	2396	0	432	1332	390	0	242	0	0	0	1302	1580	70	3	2954
November	3143	0	432	1972	387	0	351	0	0	0	1206	1465	23	4	2698
December	3753	0	432	1607	581	0	1133	0	0	0	2018	1687	14	5	3723
Average	2622	0	432	1587	300	0	303	0	0	0	1089	1202	118	3	2413
Maximum	7368	0	432	6358	750	0	4925	0	0	0	4500	2671	1210	5	6818
Minimum	918	0	432	329	26	0	0	0	0	0	2	0	0	1	8
Total for the whole year TWh/year	23.03	0.00	3.80	13.94	2.63	0.00	2.66	0.00		0.00	9.57	10.56	1.04	0.02	21.19

Own use of heat from industrial CHP: 0.00 TWh/year

ANNUAL COSTS (Million DKK)

Total Fuel ex Ngas exchange = 52564
- Uranium = 0
- Coal = 1708
- FuelOil = 7211
- Gasoil/Diesel= 16937
- Petrol/JP = 13768
- Gas handling = 1540
- Biomass = 11401
- Food income = 0
- Waste = 0

Total Ngas Exchange costs = 6805

Marginal operation costs = 413

Total Electricity exchange = 0
- Import = 0
- Export = -372
- Bottleneck = 372
- Fixed imp/ex= 0

Total CO2 emission costs = 4006

Total variable costs = 63789

Fixed operation costs = 9161

Annual Investment costs = 18896

TOTAL ANNUAL COSTS = 91846

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Individual MW	Transport MW	Indu. Var. MW	Demand Sum MW	Biogas MW	Syngas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Storage MW	Sum MW	Import MW	Export MW
January	386	1656	59	1189	0	2013	5304	342	92	0	0	0	1405	3465	3465	0
February	222	1992	34	1221	0	2013	5482	342	92	0	0	0	1583	3465	3465	0
March	433	1262	70	1015	0	2013	4792	342	92	0	0	0	894	3465	3465	0
April	165	1127	64	780	0	2013	4149	342	92	0	0	0	250	3465	3465	0
May	89	909	69	575	0	2013	3655	342	92	0	0	0	-244	3465	3465	0
June	29	227	156	168	0	2013	2594	342	92	0	0	0	-1305	3465	3465	0
July	25	308	164	168	0	2013	2678	342	92	0	0	0	-1221	3465	3465	0
August	29	256	157	168	0	2013	2624	342	92	0	0	0	-1274	3465	3465	0
September	60	580	143	349	0	2013	3145	342	92	0	0	0	-754	3465	3465	0
October	179	666	84	602	0	2013	3545	342	92	0	0	0	-354	3465	3465	0
November	217	1154	74	843	0	2013	4299	342	92	0	0	0	401	3465	3465	0
December	711	722	90	1039	0	2013	4575	342	92	0	0	0	676	3465	3465	0
Average	213	901	97	675	0	2013	3899	342	92	0	0	0	0	3465	3465	0
Maximum	3441	4055	417	2203	0	2013	8133	342	92	0	0	0	4235	3465	3465	0
Minimum	3	26	0	127	0	2013	2249	342	92	0	0	0	-1650	3465	3465	0
Total for the whole year TWh/year	1.87	7.91	0.85	5.93	0.00	17.68	34.25	3.00	0.81	0.00	0.00	0.00	0.00	30.44	30.44	0.00

RES Share: 38.5 Percent of Primary Energy 84.0 Percent of Electricity 33.0 TWh electricity from RES 12-January-2015 [15:28]

Input HP_wind2.txt **The EnergyPLAN model 12.0**

Electricity demand (TWh/year):		Flexible demand	0.00
Fixed demand	36.68	Fixed imp/exp.	0.00
Electric heating + HP	0.59	Transportation	0.59
Electric cooling	0.00	Total	37.86

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	3.46	10.72	23.03	37.21
Solar Thermal	0.02	0.07	0.00	0.09
Industrial CHP (CSHP)	0.17	0.17	0.95	1.29
Demand after solar and CSHP	3.27	10.48	22.08	35.83

Wind	3700 MW	7.87	TWh/year	0.00	Grid
Offshore Wind	2671 MW	10.56	TWh/year	0.00	stabili-
Photo Voltaic	1210 MW	1.04	TWh/year	0.00	sation
River Hydro	10 MW	0.02	TWh/year	0.00	share
Hydro Power	0 MW	0	TWh/year		
Geothermal/Nuclear	0 MW	0	TWh/year		

	Capacities		Efficiencies		
Group 2:	MW-e	MJ/s	elec.	Ther	COP
CHP	1830	2420	0.36	0.48	
Heat Pump	400	1200			3.00
Boiler		4176		0.95	
Group 3:					
CHP	6000	9882	0.34	0.56	
Heat Pump	200	600			3.00
Boiler		5922		0.90	
Condensing	6335		0.39		

Heatstorage: gr.2: 0 GWh gr.3: 0 GWh
Fixed Boiler: gr.2: 2.5 Per cent gr.3: 1.0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0.07	0.03
Gr.2:	0.12	0.51
Gr.3:	0.07	1.74

Regulation Strategy:	Technical regulation no. 3	
KEOL regulation	23450000	
Minimum Stabilisation share	0.25	
Stabilisation share of CHP	0.00	
Minimum CHP gr 3 load	200	MW
Minimum PP	0	MW
Heat Pump maximum share	1.00	
Maximum import/export	0	MW

Distr. Name	DK 2013 Electricty price.txt	
Addition factor	0.00	DKK/MWh
Multiplication factor	1.02	
Dependency factor	0.04	DKK/MWh pr. MW
Average Market Price	298	DKK/MWh
Gas Storage	6360	GWh
Syngas capacity	92	MW
Biogas max to grid	342	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Ther.
Hydro Pump:	0	0	0.40	
Hydro Turbine:	0		0.40	
Electrol. Gr.2:	0	0	0.40	0.50
Electrol. Gr.3:	0	0	0.40	0.50
Electrol. trans.:	0	0	0.00	
Ely. MicroCHP:	0	0	0.80	
CAES fuel ratio:		0.000		

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0.00	56.52	0.00	0.00
Household	0.00	3.33	5.93	12.10
Industry	1.34	11.36	10.78	2.89
Various	0.00	4.90	6.90	1.00

Output WARNING!!: (1) Critical Excess;

	District Heating: Demand	Production									Electricity: Consumption						Production							Balance					Exchange	
	Distr. heating MW	Solar MW	Waste+ CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Ba- lance MW	Elec. demand MW	Flex.& Transp. MW	HP MW	Elec- trolyser MW	EH MW	Hydro Pump MW	Tur- bine MW	RES MW	Hy- dro MW	Geo- thermal MW	Waste+ CSHP MW	CHP MW	PP MW	Stab- Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Payment Imp Million DKK	Exp
January	6817	1	745	534	3996	964	0	578	0	0	4872	66	439	0	0	0	0	2146	0	0	290	2576	497	169	0	133	133	0	0	10
February	6974	5	745	548	4554	828	0	295	0	0	4738	68	395	0	0	0	0	1675	0	0	290	2944	316	181	0	24	24	0	0	2
March	5942	6	745	451	3082	929	0	728	0	0	4535	68	410	0	0	0	0	2515	0	0	290	1987	577	153	0	356	356	0	0	28
April	4761	16	745	339	2697	717	0	247	0	0	4093	65	316	0	0	0	0	2176	0	0	290	1740	547	154	0	279	279	0	0	28
May	3736	18	745	244	2173	452	0	105	0	0	3778	68	209	0	0	0	0	1869	0	0	290	1404	636	156	0	143	143	0	0	15
June	1694	24	745	52	648	181	0	44	0	0	3769	68	76	0	0	0	0	2250	0	0	290	413	1484	169	0	523	523	0	0	36
July	1695	19	745	53	746	101	0	30	0	0	3591	66	50	0	0	0	0	1530	0	0	290	481	1592	204	0	185	185	0	0	18
August	1694	18	745	54	681	156	0	40	0	0	3770	68	69	0	0	0	0	2029	0	0	290	436	1519	176	0	366	366	0	0	38
September	2599	12	745	139	1357	261	0	85	0	0	3932	67	121	0	0	0	0	1825	0	0	290	877	1367	184	0	239	239	0	0	26
October	3871	6	745	259	1855	719	0	287	0	0	4154	67	299	0	0	0	0	2723	0	0	290	1190	730	132	0	412	412	0	0	38
November	5078	2	745	372	2778	820	0	361	0	0	4423	68	357	0	0	0	0	2483	0	0	290	1792	642	149	0	358	358	0	0	25
December	6064	1	745	464	2241	1330	0	1283	0	0	4475	66	546	0	0	0	0	3364	0	0	290	1427	703	127	0	697	697	0	0	38
Average	4237	11	745	292	2225	622	0	342	0	0	4176	67	274	0	0	0	0	2219	0	0	290	1433	886	163	0	311	311	0	Average price	
Maximum	11905	134	745	1007	8715	1800	0	6262	0	0	6632	204	818	0	0	0	0	6080	0	0	290	5642	4013	359	0	3911	3911	0	(DKK/MWh)	
Minimum	1483	0	745	30	329	57	0	0	0	0	2483	0	19	0	0	0	0	8	0	0	290	200	0	100	0	0	0	0	317	112
TWh/year	37.21	0.09	6.54	2.56	19.55	5.46	0.00	3.01	0.00	0.00	36.68	0.59	2.41	0.00	0.00	0.00	0.00	19.49	0.00	0.00	2.54	12.59	7.78		0.00	2.73	2.73	0.00	0	305

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon- version	Synthetic Fuel	Wind	Offsh.	PV	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Netto	CO2 emission (Mt): Total	Netto
Coal	-	0.38	8.60	-	-	10.06	-	-	-	-	-	-	-	-	-	-	-	-	-	1.34	20.37	-3.53	16.85	7.22	5.97
Oil	-	-	0.23	-	1.62	0.81	-	-	-	-	-	-	-	-	-	-	-	56.52	3.33	16.26	78.77	-0.28	78.49	20.67	20.60
N.Gas	0.25	7.16	1.16	0.40	1.08	0.81	-	-	-	-	-3.81	-	-	-	-	-	-	-	5.93	17.68	30.66	-0.28	30.38	6.28	6.22
Biomass	2.45	2.64	16.27	0.20	-	8.27	-	-	9.97	-	4.88	-	-	-	-	-	-	-	11.46	3.89	60.03	-2.90	57.12	1.17	1.17
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	7.87	10.56	1.04	0.02	0.61	-	-	-	20.10	0.00	20.10	0.00	0.00
H2 etc.	-	0.00	0.00	0.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Biofuel	-	-	0.00	-	-	-	-	-	-	-	-3.72	-	-	-	-	-	-	3.72	-	-	0.00	0.00	0.00	0.00	0.00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Total	2.70	10.17	26.26	0.61	2.70	19.95	-	-	9.97	-	-2.65	-	7.87	10.56	1.04	0.02	0.61	60.24	20.72	39.17	209.94	-7.00	202.94	35.35	33.96

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Output specifications HP_wind2.txt — The EnergyPLAN model 12.0

District Heating Production

	Gr.1 District heating MW	Gr.1 Solar MW	Gr.1 CSHP MW	Gr.1 DHP MW	Gr.2 District heating MW	Gr.2 Solar MW	Gr.2 CSHP MW	Gr.2 CHP MW	Gr.2 HP MW	Gr.2 ELT MW	Gr.2 Boiler MW	Gr.2 EH MW	Gr.2 Stor-age MW	Gr.2 Ba-lance MW
January	634	0	100	534	1964	1	213	1009	621	0	120	0	0	0
February	648	1	100	548	2009	4	213	1200	527	0	66	0	0	0
March	553	1	100	451	1712	5	213	779	596	0	119	0	0	0
April	443	3	100	339	1372	13	213	690	441	0	15	0	0	0
May	347	4	100	244	1076	14	213	569	254	0	27	0	0	0
June	157	5	100	52	488	18	213	134	88	0	35	0	0	0
July	157	4	100	53	488	15	213	185	51	0	24	0	0	0
August	157	4	100	54	488	14	213	152	77	0	32	0	0	0
September	242	2	100	139	749	9	213	355	132	0	39	0	0	0
October	360	1	100	259	1115	5	213	423	418	0	57	0	0	0
November	472	0	100	372	1463	1	213	703	513	0	34	0	0	0
December	564	0	100	464	1747	1	213	449	871	0	214	0	0	0
Average	394	2	100	292	1220	8	213	551	383	0	65	0	0	0
Maximum	1107	29	100	1007	3430	105	213	2420	1200	0	1774	0	0	0
Minimum	138	0	100	30	427	0	213	0	31	0	0	0	0	0
Total for the whole year TWh/year	3.46	0.02	0.88	2.56	10.72	0.07	1.87	4.84	3.36	0.00	0.57	0.00		0.00

	Gr.3 District heating MW	Gr.3 Solar MW	Gr.3 CSHP MW	Gr.3 CHP MW	Gr.3 HP MW	Gr.3 ELT MW	Gr.3 Boiler MW	Gr.3 EH MW	Gr.3 Stor-age MW	Gr.3 Ba-lance MW	RES1 Wind MW	RES2 Offshoı MW	RES3 Photo \ MW	RES 4-7 ic MW	Total MW
January	4219	0	432	2986	342	0	458	0	0	0	955	1177	11	3	2146
February	4316	0	432	3355	301	0	228	0	0	0	612	1007	53	3	1675
March	3677	0	432	2303	333	0	609	0	0	0	1192	1248	73	3	2515
April	2947	0	432	2007	275	0	232	0	0	0	968	1032	174	4	2176
May	2312	0	432	1604	198	0	77	0	0	0	659	1010	197	3	1869
June	1049	0	432	514	93	0	10	0	0	0	812	1181	255	2	2250
July	1049	0	432	561	49	0	6	0	0	0	492	825	212	1	1530
August	1049	0	432	529	79	0	9	0	0	0	698	1127	203	1	2029
September	1609	0	432	1002	129	0	46	0	0	0	615	1074	134	2	1825
October	2396	0	432	1432	301	0	230	0	0	0	1070	1580	70	3	2723
November	3143	0	432	2076	307	0	328	0	0	0	992	1465	23	4	2483
December	3753	0	432	1792	459	0	1069	0	0	0	1659	1687	14	5	3364
Average	2622	0	432	1674	239	0	277	0	0	0	896	1202	118	3	2219
Maximum	7368	0	432	6361	600	0	4694	0	0	0	3700	2671	1210	5	6080
Minimum	918	0	432	329	26	0	0	0	0	0	2	0	0	1	8
Total for the whole year TWh/year	23.03	0.00	3.80	14.71	2.10	0.00	2.43	0.00		0.00	7.87	10.56	1.04	0.02	19.49

Own use of heat from industrial CHP: 0.00 TWh/year

ANNUAL COSTS (Million DKK)

Total Fuel ex Ngas exchange =		52623
Uranium =	0	
Coal =	1702	
FuelOil =	7146	
Gasoil/Diesel=	16937	
Petrol/JP =	13768	
Gas handling =	1556	
Biomass =	11515	
Food income =	0	
Waste =	0	
Total Ngas Exchange costs =		6855
Marginal operation costs =		417
Total Electricity exchange =		0
Import =	0	
Export =	-305	
Bottleneck =	305	
Fixed imp/ex=	0	
Total CO2 emission costs =		4003
Total variable costs =		63898
Fixed operation costs =		8900
Annual Investment costs =		18294
TOTAL ANNUAL COSTS =		91092

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Indi-vidual MW	Trans port MW	Indu. Var. MW	Demand Sum MW	Bio-gas MW	Syn-gas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Stor-age MW	Sum MW	Im-port MW	Ex-port MW
January	339	1728	52	1189	0	2013	5320	342	92	0	0	0	1396	3491	3491	0
February	200	2038	33	1221	0	2013	5505	342	92	0	0	0	1581	3491	3491	0
March	397	1333	60	1015	0	2013	4819	342	92	0	0	0	894	3491	3491	0
April	146	1178	57	780	0	2013	4174	342	92	0	0	0	250	3491	3491	0
May	77	968	66	575	0	2013	3699	342	92	0	0	0	-225	3491	3491	0
June	34	239	155	168	0	2013	2608	342	92	0	0	0	-1316	3491	3491	0
July	24	318	166	168	0	2013	2690	342	92	0	0	0	-1235	3491	3491	0
August	31	267	158	168	0	2013	2637	342	92	0	0	0	-1287	3491	3491	0
September	61	605	142	349	0	2013	3170	342	92	0	0	0	-754	3491	3491	0
October	167	739	76	602	0	2013	3597	342	92	0	0	0	-328	3491	3491	0
November	205	1203	67	843	0	2013	4330	342	92	0	0	0	406	3491	3491	0
December	670	805	73	1039	0	2013	4600	342	92	0	0	0	675	3491	3491	0
Average	197	947	92	675	0	2013	3924	342	92	0	0	0	0	3491	3491	0
Maximum	3296	4055	418	2203	0	2013	8137	342	92	0	0	0	4213	3491	3491	0
Minimum	3	26	0	127	0	2013	2246	342	92	0	0	0	-1678	3491	3491	0
Total for the whole year TWh/year	1.73	8.32	0.81	5.93	0.00	17.68	34.47	3.00	0.81	0.00	0.00	0.00	0.00	30.66	30.66	0.00

RES Share: 38.2 Percent of Primary Energy 80.5 Percent of Electricity 31.5 TWh electricity from RES

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Input Reference scenario.txt

The EnergyPLAN model 12.0

Electricity demand (TWh/year):		Flexible demand	0.00
Fixed demand	33.66	Fixed imp/exp.	0.00
Electric heating + HP	0.65	Transportation	0.38
Electric cooling	0.00	Total	34.69

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	3.52	10.91	23.42	37.85
Solar Thermal	0.02	0.07	0.00	0.09
Industrial CHP (CSHP)	0.17	0.17	0.95	1.29
Demand after solar and CSHP	3.33	10.67	22.47	36.47

Wind	3531 MW	6.71 TWh/year	0.00	Grid
Offshore Wind	1271 MW	4.35 TWh/year	0.00	stabili-
Photo Voltaic	478 MW	0.41 TWh/year	0.00	sation
River Hydro	10 MW	0.02 TWh/year	0.00	share
Hydro Power	0 MW	0 TWh/year		
Geothermal/Nuclear	0 MW	0 TWh/year		

	Capacities		Efficiencies		
Group 2:	MW-e	MJ/s	elec.	Ther	COP
CHP	1830	2420	0.36	0.48	
Heat Pump	0	0			3.00
Boiler		4176		0.95	
Group 3:					
CHP	6000	9882	0.34	0.56	
Heat Pump	0	0			3.00
Boiler		5922		0.90	
Condensing	6335		0.39		

Heatstorage: gr.2: 0 GWh gr.3: 0 GWh
Fixed Boiler: gr.2: 2.5 Per cent gr.3: 1.0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0.07	0.03
Gr.2:	0.12	0.51
Gr.3:	0.07	1.74

Regulation Strategy:	Technical regulation no. 2	
KEOL regulation	23450000	
Minimum Stabilisation share	0.30	
Stabilisation share of CHP	0.00	
Minimum CHP gr 3 load	550	MW
Minimum PP	0	MW
Heat Pump maximum share	0.50	
Maximum import/export	0	MW
Distr. NameDK 2013 Electricty price.txt		
Addition factor	0.00	DKK/MWh
Multiplication factor	0.00	
Dependency factor	0.02	DKK/MWh pr. MW
Average Market Price	0	DKK/MWh
Gas Storage	6360	GWh
Syngas capacity	92	MW
Biogas max to grid	0	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Ther.
Hydro Pump:	0	0	0.40	
Hydro Turbine:	0		0.40	
Electrol. Gr.2:	0	0	0.40	0.50
Electrol. Gr.3:	0	0	0.40	0.50
Electrol. trans.:	0	0	0.00	
Ely. MicroCHP:	0	0	0.80	
CAES fuel ratio:		0.000		

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0.00	56.52	0.00	0.00
Household	0.00	3.70	7.57	9.90
Industry	1.34	11.36	10.78	2.89
Various	0.00	4.90	6.90	1.00

Output WARNING!!: (1) Critical Excess;

	District Heating Demand	District Heating Production									Electricity Consumption						Electricity Production								Electricity Balance					Exchange	
	Distr. heating MW	Solar MW	Waste+ CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Ba-lance MW	Elec. demand MW	Flex.& Transp. MW	HP MW	Elec-trolyser MW	EH MW	Hydro Pump MW	Tur-bine MW	RES MW	Hy-dro MW	Geo-thermal MW	Waste+ CSHP MW	CHP MW	PP MW	Stab-Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Payment Imp Million DKK	Exp
January	6934	1	745	545	4367	0	0	1276	0	0	4470	42	130	0	0	0	0	1306	0	0	290	2813	322	162	0	88	88	0	0	0
February	7094	5	745	559	4728	0	0	1058	0	0	4348	44	132	0	0	0	0	936	0	0	290	3064	240	170	0	6	6	0	0	0
March	6044	6	745	461	3778	0	0	1054	0	0	4162	44	111	0	0	0	0	1586	0	0	290	2422	260	150	0	241	241	0	0	0
April	4843	16	745	347	3226	0	0	509	0	0	3756	42	85	0	0	0	0	1319	0	0	290	2076	334	152	0	136	136	0	0	0
May	3800	18	745	250	2561	0	0	227	0	0	3467	44	64	0	0	0	0	1032	0	0	290	1659	639	163	0	44	44	0	0	0
June	1723	24	745	55	1094	0	0	103	0	-298	3459	44	20	0	0	0	0	1273	0	0	290	693	1432	180	0	165	165	0	0	0
July	1724	19	745	56	1128	0	0	74	0	-298	3295	42	17	0	0	0	0	818	0	0	290	718	1575	209	0	45	45	0	0	0
August	1723	18	745	56	1110	0	0	92	0	-298	3460	44	21	0	0	0	0	1122	0	0	290	705	1490	187	0	81	81	0	0	0
September	2644	12	745	143	1640	0	0	134	0	-30	3608	43	36	0	0	0	0	1007	0	0	290	1061	1398	188	0	68	68	0	0	0
October	3937	6	745	265	2509	0	0	413	0	0	3812	43	68	0	0	0	0	1607	0	0	290	1610	570	142	0	154	154	0	0	0
November	5166	2	745	380	3381	0	0	657	0	0	4059	44	93	0	0	0	0	1476	0	0	290	2175	458	153	0	202	202	0	0	0
December	6168	1	745	473	3301	0	0	1647	0	0	4107	42	114	0	0	0	0	2193	0	0	290	2084	178	132	0	482	482	0	0	0
Average	4309	11	745	298	2729	0	0	604	0	-77	3832	43	74	0	0	0	0	1309	0	0	290	1752	742	166	0	143	143	0	Average price	
Maximum	12109	134	745	1026	7877	0	0	6644	0	0	6086	132	241	0	0	0	0	4487	0	0	290	5090	3352	296	0	3222	3222	0	(DKK/MWh)	
Minimum	1508	0	745	33	906	0	0	58	0	-432	2279	0	0	0	0	0	0	5	0	0	290	550	0	100	0	0	0	0	0	0
TWh/year	37.85	0.09	6.54	2.62	23.97	0.00	0.00	5.31	0.00	-0.68	33.66	0.38	0.65	0.00	0.00	0.00	0.00	11.50	0.00	0.00	2.54	15.39	6.52		0.00	1.26	1.26	0.00	0	0

FUEL BALANCE (TWh/year):	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon-version	Synthetic Fuel	Wind	Offsh.	PV	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Netto	CO2 emission (Mt): Total	Netto
Coal	-	0.44	27.12	0.00	-	13.73	-	-	-	-	-	-	-	-	-	-	-	-	-	1.34	42.62	-2.65	39.97	15.11	14.17
Oil	-	-	0.27	0.00	1.31	0.68	-	-	-	-	-	-	-	-	-	-	-	56.52	3.70	16.26	78.74	-0.13	78.60	20.66	20.63
N.Gas	0.25	8.32	1.34	2.35	0.87	0.68	-	-	-	-	-0.81	-	-	-	-	-	-	-	7.57	17.68	38.25	-0.13	38.12	7.84	7.81
Biomass	2.51	3.06	4.03	1.17	-	1.63	-	-	9.97	-	4.88	-	-	-	-	-	-	-	9.29	3.89	40.43	-0.32	40.12	1.17	1.17
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	6.71	4.35	0.41	0.02	0.58	-	-	-	12.08	0.00	12.08	0.00	0.00
H2 etc.	-	0.00	0.00	0.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Biofuel	-	-	0.00	-	-	-	-	-	-	-	-3.72	-	-	-	-	-	-	3.72	-	-	0.00	0.00	0.00	0.00	0.00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Total	2.76	11.82	32.76	3.52	2.18	16.72	-	-	9.97	-	0.35	-	6.71	4.35	0.41	0.02	0.58	60.24	20.56	39.17	212.12	-3.23	208.89	44.78	43.78

12-January-2015 [15:21]

Output specifications Reference scenario.txt The EnergyPLAN model 12.0

District Heating Production

	Gr.1 District heating MW	Gr.1 Solar MW	Gr.1 CSHP MW	Gr.1 DHP MW	Gr.2 District heating MW	Gr.2 Solar MW	Gr.2 CSHP MW	Gr.2 CHP MW	Gr.2 HP MW	Gr.2 ELT MW	Gr.2 Boiler MW	Gr.2 EH MW	Gr.2 Stor-age MW	Gr.2 Ba-lance MW
January	645	0	100	545	1999	1	213	1087	0	0	698	0	0	0
February	660	1	100	559	2045	4	213	1298	0	0	531	0	0	0
March	562	1	100	461	1742	5	213	864	0	0	661	0	0	0
April	450	3	100	347	1396	13	213	789	0	0	382	0	0	0
May	353	4	100	250	1095	14	213	697	0	0	171	0	0	0
June	160	5	100	55	496	18	213	189	0	0	77	0	0	0
July	160	4	100	56	496	15	213	222	0	0	47	0	0	0
August	160	4	100	56	496	14	213	204	0	0	65	0	0	0
September	246	2	100	143	762	9	213	435	0	0	105	0	0	0
October	366	1	100	265	1135	5	213	582	0	0	335	0	0	0
November	480	0	100	380	1489	1	213	817	0	0	458	0	0	0
December	574	0	100	473	1778	1	213	533	0	0	1031	0	0	0
Average	401	2	100	298	1242	8	213	640	0	0	381	0	0	0
Maximum	1126	29	100	1026	3490	105	213	2390	0	0	3031	0	0	0
Minimum	140	0	100	33	435	0	213	0	0	0	31	0	0	0
Total for the whole year TWh/year	3.52	0.02	0.88	2.62	10.91	0.07	1.87	5.63	0.00	0.00	3.34	0.00		0.00

	Gr.3 District heating MW	Gr.3 Solar MW	Gr.3 CSHP MW	Gr.3 CHP MW	Gr.3 HP MW	Gr.3 ELT MW	Gr.3 Boiler MW	Gr.3 EH MW	Gr.3 Stor-age MW	Gr.3 Ba-lance MW	RES specification RES1 Wind MW	RES2 Offshoı MW	RES3 Photo \ MW	RES 4-7 ic MW	Total MW
January	4290	0	432	3280	0	0	578	0	0	0	819	479	4	3	1306
February	4389	0	432	3430	0	0	527	0	0	0	508	404	21	3	936
March	3740	0	432	2914	0	0	393	0	0	0	1040	514	29	3	1586
April	2997	0	432	2437	0	0	128	0	0	0	829	417	69	4	1319
May	2351	0	432	1863	0	0	56	0	0	0	548	403	78	3	1032
June	1067	0	432	906	0	0	27	0	0	-298	685	486	101	2	1273
July	1067	0	432	906	0	0	27	0	0	-298	406	327	84	1	818
August	1067	0	432	906	0	0	27	0	0	-298	581	460	80	1	1122
September	1636	0	432	1205	0	0	29	0	0	-30	513	439	53	2	1007
October	2436	0	432	1927	0	0	77	0	0	0	907	669	28	3	1607
November	3196	0	432	2565	0	0	199	0	0	0	851	613	9	4	1476
December	3816	0	432	2768	0	0	616	0	0	0	1463	721	5	5	2193
Average	2667	0	432	2088	0	0	223	0	0	-77	764	495	47	3	1309
Maximum	7493	0	432	5816	0	0	3727	0	0	0	3531	1271	478	5	4487
Minimum	933	0	432	906	0	0	27	0	0	-432	1	0	0	1	5
Total for the whole year TWh/year	23.42	0.00	3.80	18.34	0.00	0.00	1.96	0.00		-0.68	6.71	4.35	0.41	0.02	11.50

Own use of heat from industrial CHP: 0.00 TWh/year

ANNUAL COSTS (Million DKK)

Total Fuel ex Ngas exchange =		50252
Uranium =	0	
Coal =	3560	
FuelOil =	7002	
Gasoil/Diesel=	17125	
Petrol/JP =	13768	
Gas handling =	1863	
Biomass =	6934	
Food income =	0	
Waste =	0	
Total Ngas Exchange costs =		8551
Marginal operation costs =		447
Total Electricity exchange =		0
Import =	0	
Export =	0	
Bottleneck =	0	
Fixed imp/ex=	0	
Total CO2 emission costs =		5071
Total variable costs =		64321
Fixed operation costs =		7167
Annual Investment costs =		14945
TOTAL ANNUAL COSTS =		86433

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Indi-vidual MW	Trans port MW	Indu. Var. MW	Demand Sum MW	Bio-gas MW	Syn-gas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Stor-age MW	Sum MW	Im-port MW	Ex-port MW
January	799	1847	34	1518	0	2013	6210	0	92	0	0	0	1764	4355	4355	0
February	660	2169	25	1558	0	2013	6426	0	92	0	0	0	1979	4355	4355	0
March	683	1490	27	1296	0	2013	5508	0	92	0	0	0	1062	4355	4355	0
April	358	1345	35	995	0	2013	4746	0	92	0	0	0	299	4355	4355	0
May	169	1167	67	735	0	2013	4150	0	92	0	0	0	-296	4355	4355	0
June	71	345	149	215	0	2013	2793	0	92	0	0	0	-1653	4355	4355	0
July	50	394	164	215	0	2013	2836	0	92	0	0	0	-1610	4355	4355	0
August	63	369	155	215	0	2013	2814	0	92	0	0	0	-1632	4355	4355	0
September	100	731	146	445	0	2013	3435	0	92	0	0	0	-1011	4355	4355	0
October	295	1002	59	769	0	2013	4138	0	92	0	0	0	-309	4355	4355	0
November	446	1395	48	1076	0	2013	4978	0	92	0	0	0	532	4355	4355	0
December	1043	991	19	1327	0	2013	5391	0	92	0	0	0	945	4355	4355	0
Average	395	1100	77	862	0	2013	4446	0	92	0	0	0	0	4355	4355	0
Maximum	3791	3913	349	2812	0	2013	9503	0	92	0	0	0	5056	4355	4355	0
Minimum	37	66	0	162	0	2013	2449	0	92	0	0	0	-1997	4355	4355	0
Total for the whole year TWh/year	3.47	9.66	0.68	7.57	0.00	17.68	39.06	0.00	0.81	0.00	0.00	0.00	0.00	38.25	38.25	0.00

RES Share: 24.8 Percent of Primary Energy 49.6 Percent of Electricity 16.9 TWh electricity from RES 12-January-2015 [15:21]

APPENDIX III: MARKAL/TIMES VS. ENERGYPLAN SCENARIOS COMPARISON

List of figures in Appendix III:

III.I. Modelling of CHP and DH in Europe

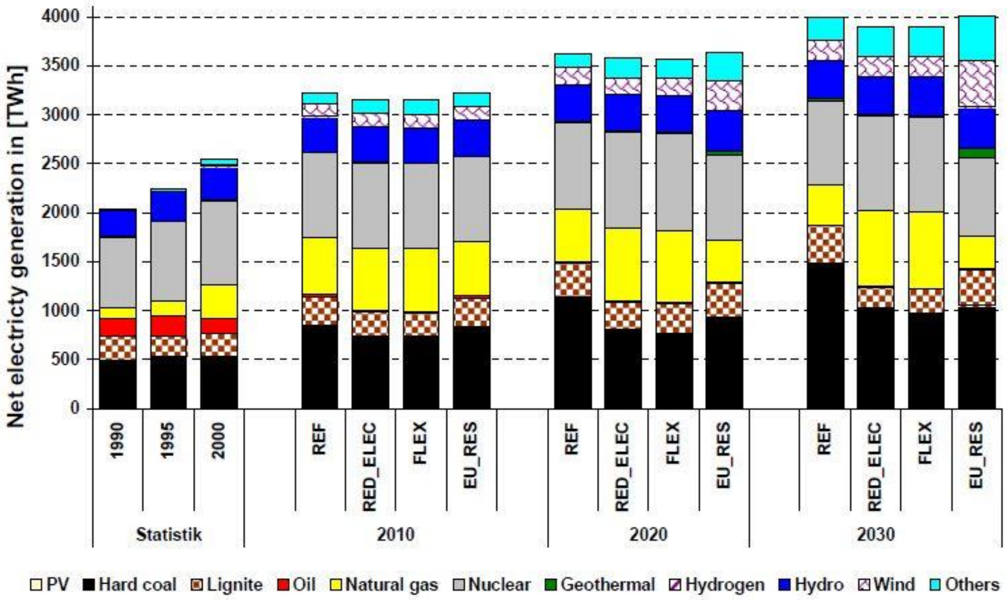
III.I.I. CHP model as a part of TIMES-EG model [24]

As a part of TIMES – EG model, Combined Heat and Power and District Heat in Europe were assessed in four different scenarios. In the reference scenario, where the continuation of the current national policies is expected in the future, doing business-as-usual was assumed and no further policy measures are assumed.

Two CO_2 reduction scenarios are named RED_ELEC and FLEX. Within them it is assumed that Kyoto target burden is shared in electricity and heat production sector in the same ratio as in the whole energy system. Moreover, until 2030 it is assumed that an additional 9% of CO_2 savings, compared to Kyoto targets, will be achieved in the EU25 (without Bulgaria, Romania and Croatia). In the RED_ELEC scenario, this target has to be achieved without the contribution of residential sector, while in the FLEX scenario CO_2 emission reductions are achieved with active participation of the residential sector.

EU_RES is a renewable energy scenario where the EU25 targets are set by the sum of the national targets. For the purpose of making projection of renewable energy sources in 2030, the same growth rate as in period 1995-2010 has been used. Moreover, green certificates are assumed to be adopted in the whole Europe. Total amount of incentives in this scenario, such as for feed-in tariffs, feed-in premiums, tenders, etc., is of same level as in reference scenario. The additional penetration of renewables is expected to be achieved by well-functioning green certificates market.

Results of the scenario shows that the electricity consumption grows for 26.8% in the year 2010 and for 56.8% in the year 2013, compared to the year 2000, in the reference scenario. There is a huge share of electricity generated from coal, i.e. the share amounts to 47% for the year 2030. In the two scenarios with CO_2 reduction targets, share of coal reduces to 31%.

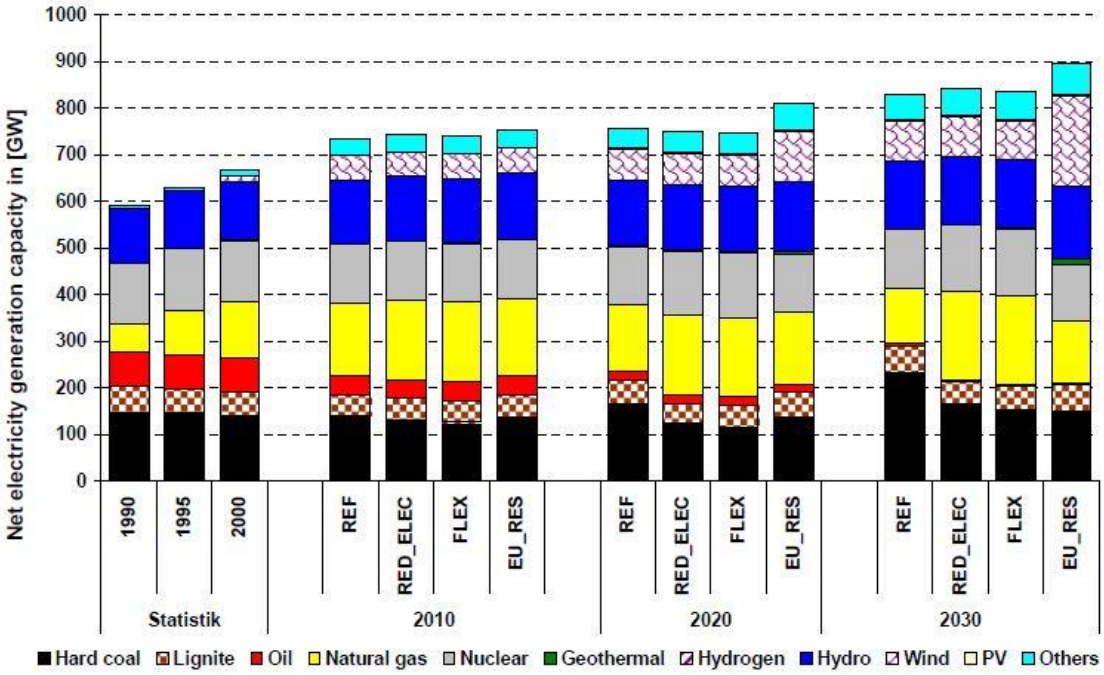


Appendix Figure 1. Net electricity generation in EU25 [24]

The electricity generated from coal in the two CO_2 reduction scenarios is mostly replaced by the electricity generated from natural gas. The share of natural gas reaches around 20% in these two cases, while in the reference scenario its share equals 10%.

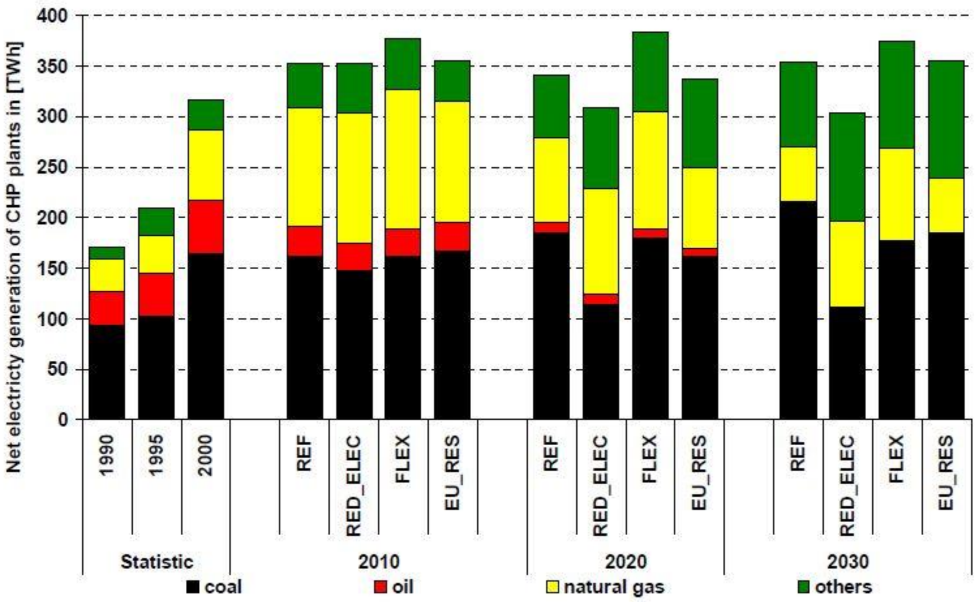
In the reference scenario, the renewable energy sources' share in total electricity generation equals 22.6% in 2030, which is a way below the EU targets for 2030. In other scenarios renewable energy target of 27% of renewable energy sources by 2030 is reached. It is important to emphasize here that the expected green certificate price in every period is 48 €/MWh. In the EU_RES scenario wind capacity installed amounts to 21 GW in 2030, while the photovoltaics amounts to 21.5 GW in 2030. This data has been implemented exogenously and thus, the investment in renewables isn't a part of the market simulated decisions.

CHP production increases from 316 TWh in 2010 to 365 TWh in 2020 and remains constant until the 2030 in the REF scenario. Newly built CHP plants during that time are gas-fired or biomass ones. Existing old condensing CHP plants are planned to be refurbished with better turbines, having larger overall power-to-heat ratio. In scenarios dealing with CO_2 reduction, due to lower emissions from natural gas CHP plants compared to coal fired CHP plants, the electricity generated out of gas increases, reducing in the same time electricity generated by coal.



Appendix Figure 2. Installed net capacity in the EU25 [24]

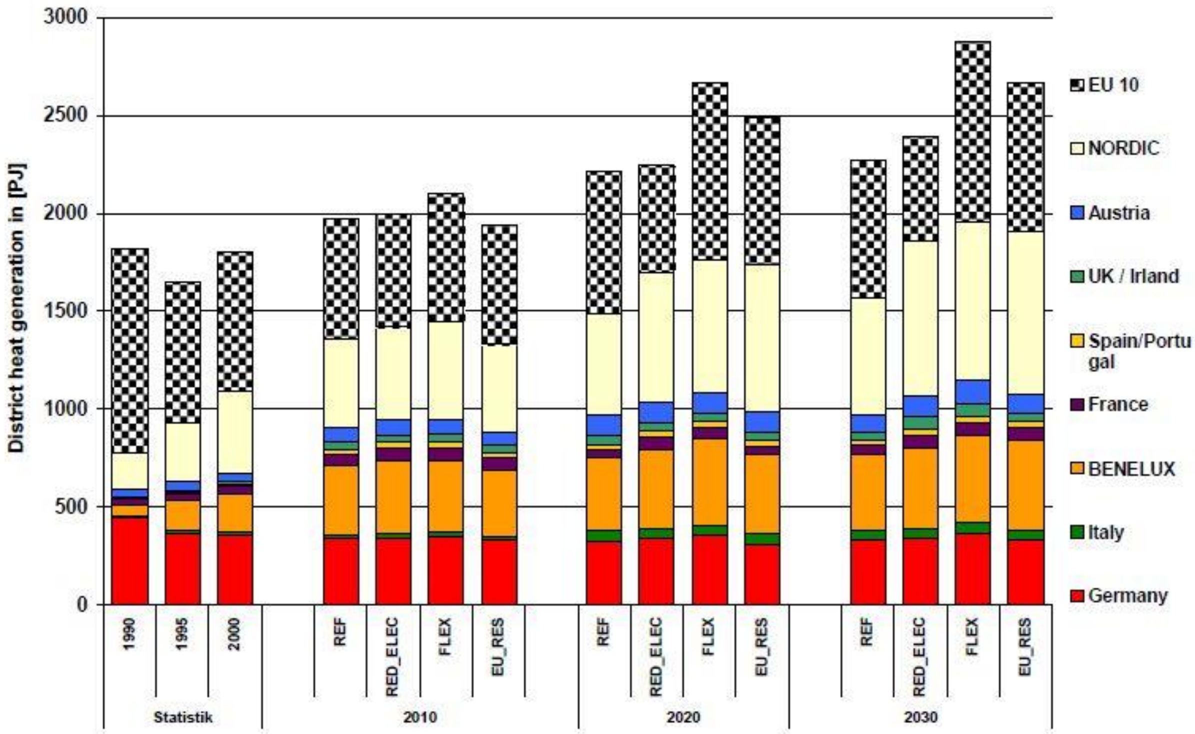
The increase in capacity in the scenarios with CO_2 reduction and the EU_RES scenario is the consequence of their intermittency. Thus, the overall capacity has to be larger in order to remain the same electricity generation.



Appendix Figure 3. Net electricity generation from CHP plants in EU25 [24]

In the EU_RES scenario electricity generated from CHP is relatively constant and remains the same in the year 2030 compared to the year 2010.

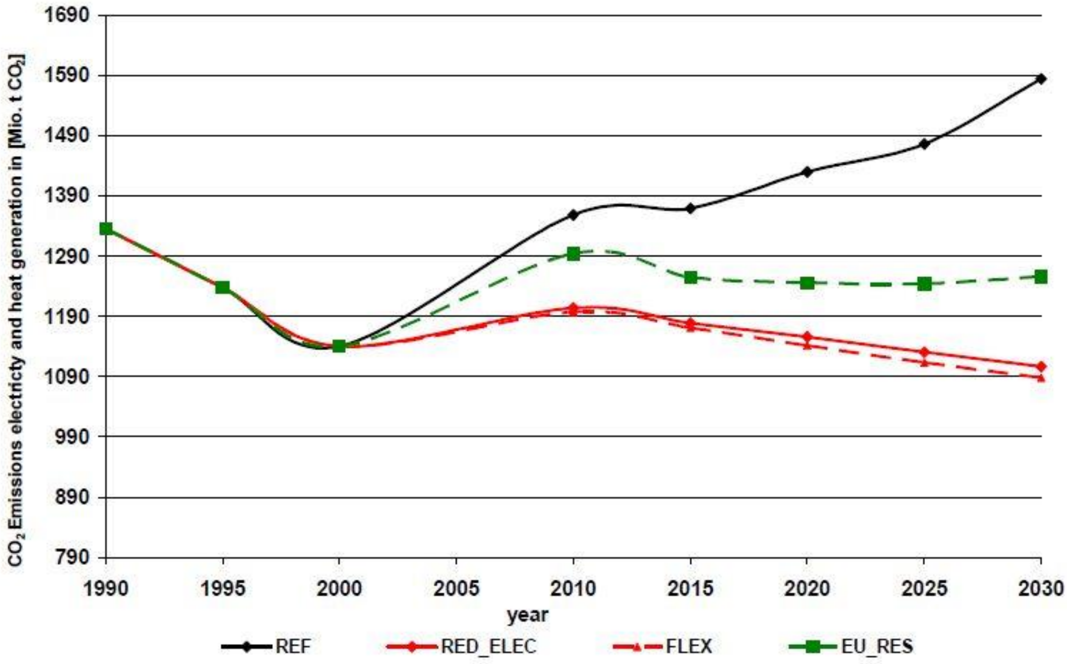
District heating production increases from 2,010 PJ in 2000 to 2,270 PJ in the year 2030 in the RED scenario. The higher district heat generation in scenarios with CO_2 reduction targets is mainly the consequence of higher heat-to-power ratio in biomass CHP plants compared to natural gas and coal CHPs. In the FLEX scenario, where residential sector is active participant of the CO_2 emission reduction targets, a significant expansion of the district heating network occurs and the district heat generation in 2030 is 500 PJ larger than in the reference case.



Appendix Figure 4. District heat production in EU25 [24]

NORDIC countries, BENELUX countries, Austria and the UK are the countries with the highest expansion of district heat by 2030.

In the reference scenario CO_2 emissions are 2.3% higher than in the year 1990 and the emissions reduction target isn't achieved. On the other hand, in the RED_ELEC and the FLEX scenarios the Kyoto target are achieved, as those was set by the boundary conditions. The marginal price of CO_2 abatement equals 22 €/tCO_2 in the year 2010 and the 30 €/tCO_2 in the year 2030.



Appendix Figure 5. CO_2 emission from Electricity and Heat Generation in EU25 [24]

In the EU_RES scenario, CO_2 emissions stay lower by approximately 65 million tons in the year 2010. However, in the year 2030 emissions will be in the range of 80-115 million tons of CO_2 above the Kyoto target.

To sum up, in TIMES generated models, district heating shows significant potential for reduction of CO_2 emissions in the future. The new CHP plants will be mainly gas and biomass driven. It is detected that the EU emission trading scheme (ETS) could face the problem because some of the sectors, like residential buildings, aren't included within the scheme. Thus, improvements in system efficiency and the energy savings in these sectors need to be carefully monitored. Lastly, the expansion of current district heat system will be economic feasible only if the costs of extension of networks and the starting losses reduces significantly.

III.I.II. The role of CHP and DH in Heat Roadmap [38]

Heat Roadmap Europe 2050 is roadmap made for Euroheat & Power by Aalborg University, Halmstad University, Ecofys Germany GmbH and PlanEnergi. It was made as a response to the Energy Roadmap 2050, published by European Commission, where lower overall system costs were sought for. The Heat Roadmap modelling part was performed in EnergyPLAN and thus, the results can be compared with the similar study made in TIMES in order to assess differences, pros and cons of each of the models.

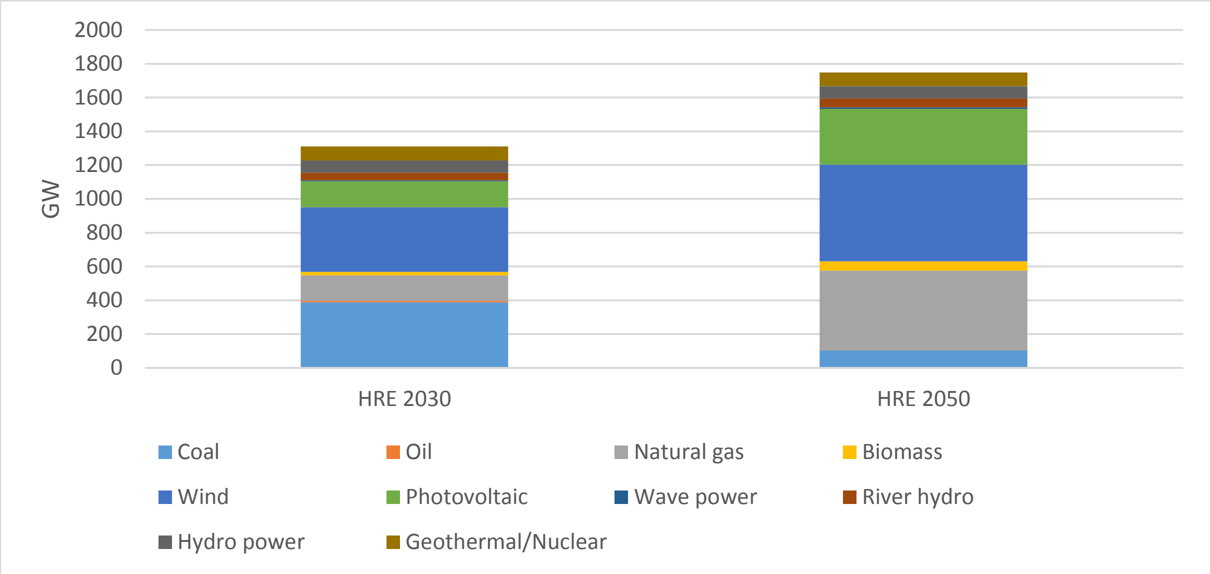
As the roadmap was an answer on Energy Roadmap 2050 issued by European Commission, the first part of the modelling was to make a reference scenario, which was one of the decarbonisation scenarios in Energy Roadmap 2050, called EU-EE. Large energy savings were assumed, which consequently lead to a decrease of 41% in energy demand by 2050 as compared to the years 2005-2006. In the next step, the Heat Roadmap Europe's scenarios were developed for the years 2030 and 2050 by implementing several technological changes with the aim of more utilization of the district heat across the EU in order to achieve cheaper solution than proposed in EU-EE scenarios.

Three pillars that the Heat Roadmap Europe is based on are [38]:

- ✓ Cheaper comfort – by reducing total system costs compared to the official EU roadmap, where the total annual savings, with the measures proposed in Heat Roadmap Europe being implemented, amounts to at least EUR 100 billion per year
- ✓ Faster decarbonisation – by implementing more renewable energy technologies and solving issues connected with integration of large amounts of wind and photovoltaic energy by integrating heating, electricity and gas systems
- ✓ Better energy – by means of more diverse energy supply compared to EU-EE scenarios, resulting with higher security of supply and consequently creating more jobs, as the local renewable resources are being used instead of large-scale imports of fossil fuels

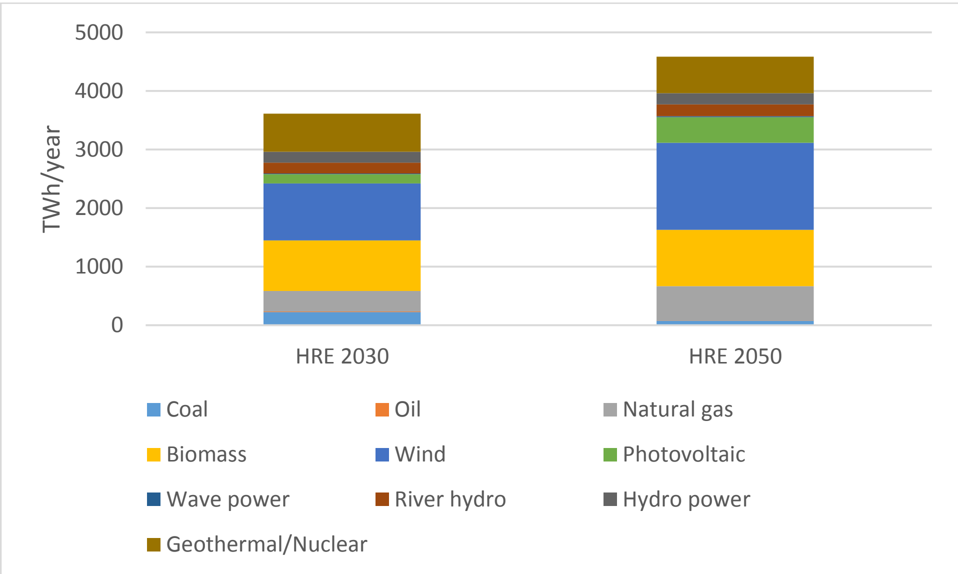
The future energy system was modelled and evaluated in EnergyPLAN, which is ideal opportunity to analyze results and compare it with similar study carried out in TIMES model generator.

Although the study put the emphasize on the heating energy system and costs connected with the overall energy system, results important for comparison with the TIMES-EG model were extracted, and will be presented here, in order to facilitate the comparison of the results of energy systems modelled in different tools.



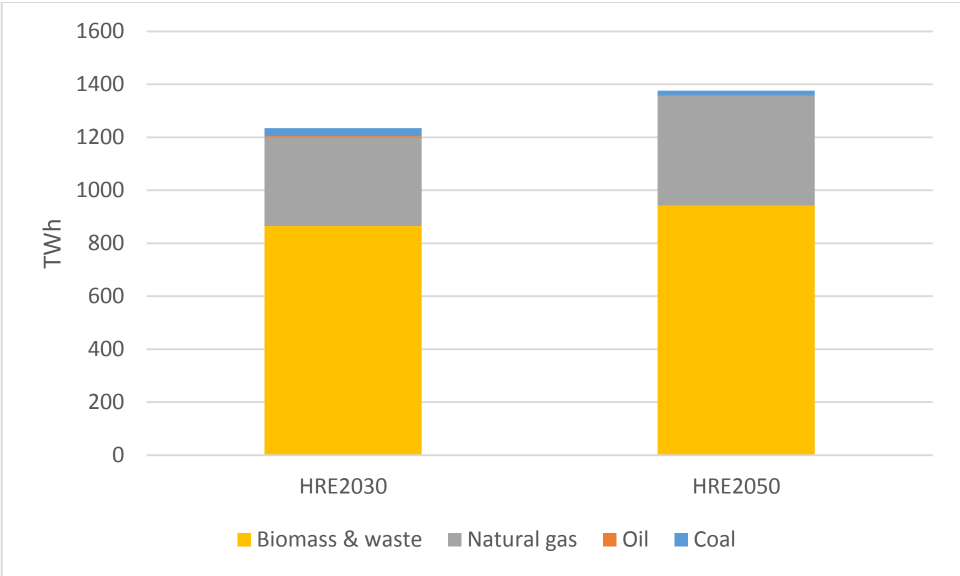
Appendix Figure 6. Installed net capacity by energy carriers in the EU27 [38]

It can be noticed from the Figure 6. that the significant share of wind capacity in 2030 increases even more till the year 2050, where its share rises to 33%. Moreover, photovoltaics capacity more than doubles from the year 2030 till the year 2050 and achieves the share of 19% in the year 2050. Nevertheless, the share of the coal driven power plants decreases sharply from the year 2030 till the year 2050, while on the other hand, gas driven power plants increases its capacity by more than three times, having the share of 27% in the year 2050.



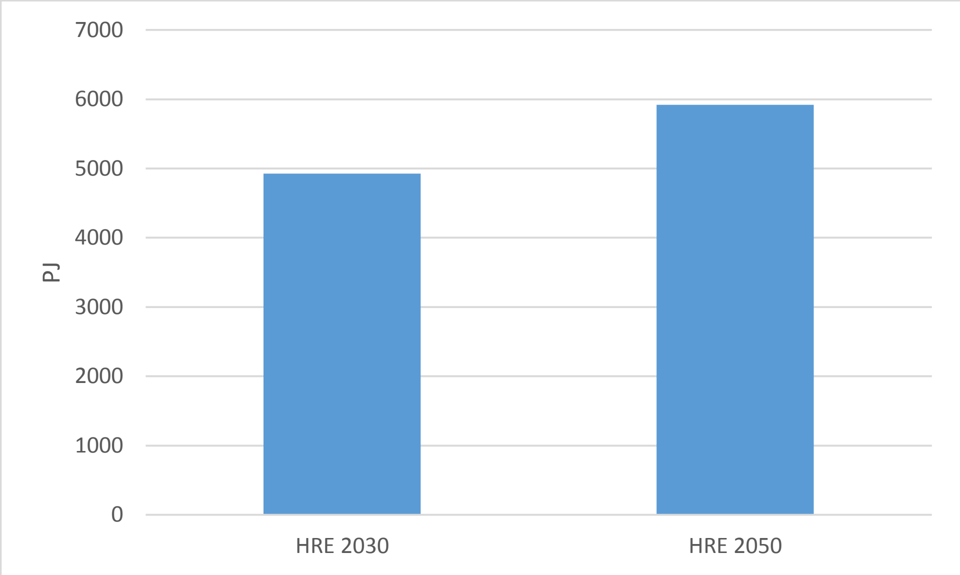
Appendix Figure 7. Net electricity generation in the EU27 [38]

It can be observed from the Figure 7. that the wind, biomass & waste, natural gas, photovoltaics and geothermal energy are the energy sources contributing the most to the electricity generation. It is especially interesting to observe the amount of electricity generated from coal power plants, amounting to only 6.14% in 2030, although the coal power plants’ share in total capacity is 29.6%. The generation from coal power plants is even lower in 2050, producing only 1.6% of the total electricity generated. This occurs because of simulation of the electricity market, where the coal power plants with variable costs higher than those of renewable energy sources run only a small fraction of the year.



Appendix Figure 8. Net electricity generation from CHP plants in EU27 [38]

Electricity from CHP plants, both in 2030 and 2050, is mostly generated from the biomass & waste and natural gas power plants, while the oil and coal driven CHP plants have insignificant share in both 2030 and 2050.



Appendix Figure 9. District heat production in EU27 [38]

Lastly, district heating production is assumed to have a significant share in the EU27 in 2030, as well as in 2050. The district heating production rises by more than 20% in the year 2050 from its already high value in the year 2030, covering a total of 5,920 PJ of heating energy demand across the EU.

III.I.III. Comparison of models' results

Target year in this comparison will be 2030, as this is the year for which the results of both studies are provided. When looking at net electricity generation, in the TIMES model, net electricity generation of approximately 4,000 TWh is projected. On the other hand, in EnergyPLAN model this projection amounts to 3,611 TWh in the year 2030. Moreover, electricity supply power plants mix is considerably different in the two models. In the TIMES model, coal and lignite fired power plants generate approximately 1,200 TWh of electricity, with slight differences between the different scenarios. Nuclear power plants produce approximately 1,000 TWh, followed by natural gas with 800 TWh, Hydro with 400 TWh and other sources, including wind energy, which constitute the last 600 TWh of generated electricity. On the other hand, mix of electricity suppliers in EnergyPLAN model in the year 2030 is dominated by wind power (973 TWh), biomass (866 TWh) and geothermal and nuclear energy with 651 TWh. These sources together accounts for 69% of the total electricity production. Thus, the share of renewable energy sources in the EnergyPLAN model is considerably larger than in the TIMES model. Other sources sorted by the amount of generation are: natural gas, coal, river hydro, hydro power, photovoltaics and wave power.

Installed net capacity mix differs in similar fashion like the generation mix, which can be observed from Figure 2. Nevertheless, the net electricity capacity in TIMES model equals approximately 850 GW with slight differences among the different scenarios, while the net electricity capacity in EnergyPLAN study amounts to 1,311 GW, which is a significantly larger capacity compared to the TIMES model.

Net electricity generation from CHPs amounts to approximately 350 TWh in TIMES model, with coal fired power plants contributing to the total amount by producing between 120 and 175 TWh of electricity according to different scenarios, followed by natural gas with approximately 80 TWh of generated electricity and other energy sources accounting to the total of 100 TWh of generated electricity. Opposite to that, in the Heat Roadmap Europe CHPs generate 1,235 TWh of electricity in the year 2030, which is more than three and a half times larger amount of generated electricity compared to TIMES model's results. Furthermore, energy supply mix is also significantly different; biomass & waste contributes to the total amount of generated electricity from CHPs with 865 TWh, followed by natural gas with 333 TWh, and coal and oil contributing with a small fraction of the total generation of electricity. Thus, only natural gas is the energy carrier that plays important role in both models.

Lastly, district heat generation amounts to approximately 2,500 PJ in TIMES-EG model, while in Heat Roadmap Europe district heat generation equals 4,927 PJ in the year 2030, which is almost two times larger amount compared to the TIMES-EG study.

To sum up, district heat generation, CHPs electricity generation and net electricity capacity are much larger in Heat Roadmap Europe compared to the TIMES-EG model. On the other hand, electricity generation and projected demand are approximately 10% larger in the TIMES-EG model. Furthermore, energy mix shows that the penetration of renewable energy, such as wind energy and biomass, is much faster in the Heat Roadmap Europe scenario, as well as decommissioning of coal fired power plants. This shows that the optimization model developed in TIMES propagates coal and lignite technology, i.e. the levelized cost of electricity of those technologies is lower compared to other technologies within the model. Nevertheless, as the cost data aren't available for the TIMES-EG scenarios, total socio-economic costs cannot be compared within the two models.

III.II. Modelling of Denmark

III.II.I. Denmark model in TIMES [28]

III.II.I.I. Scenario description-Denmark in the Pan-European model

The first Danish reference case was done for the Pan-European model. It was developed by the Danish Technology University (DTU) and published as a part of Annex XI, 2008-2010 [27]. A special emphasize has been put on the Storage Utsira project on CCS. The model was developed until the year 2050 and it was developed through the several stages in this bottom-up model.

Electricity and heat supply has taken into account the fluctuations in international electricity trade and the differences in import/export that occurs on dry and wet years. Usually, during the wet years there is a large import from Sweden and Norway, while on the dry years there is a large export from Denmark. CHPs generation is heat driven and thus, the electricity generation follows the heat production. The special emphasize was put on modern extraction (condensing) power plants, as these are the most suitable candidates for the CCS technology. Moreover, from the 1980s onwards, almost all the new capacity of CHPs were the medium condensing units. Furthermore, in the base case, it is assumed that 27% of the electricity will be produced from wind in the year 2025, which is an underestimated value. Thus, the wind capacity installed in 2010 is set to 3,550 MW, of which 800 MW is offshore. In the rest of the Business As Usual (BAU) scenario this is the minimum value of wind energy, while the maximum capacity is set to 8,000 MW, out of which 4,000 MW is offshore wind energy. Nevertheless, at an annual basis the Danish demand is covered by wind and CHP electricity production and Denmark is considered as net exporter of electricity throughout the whole period. However, due to intermittency of the wind energy source, this assumption is not completely correct, so the modelling has to be done with appropriate choice of constraints. In this starting version of the Danish energy system model, wind power capacity was exogenous parameter [28].

Currently among the wind energy, biomass energy is the only significant renewable energy source in Denmark. Biomass consumption has increased from 1980 onwards as a part of the national energy policy, contributing with 100 PJ in the primary energy supply compared to 70

PJ in the year 2000. Although both wind energy and the biomass are renewable energy sources, biomass is much easier to model in the TIMES model generator, as it is not the intermittent source. Most often it is used in the form of pellets, chips etc. in the heating sector. Straw is a common type of biomass used in CHPs, while the development of the biogas is much weaker comparing to the previous forms of biomass.

District heating and gas grids couldn’t be modelled and the investment couldn’t be optimized due to complicated representation of the geography within the model. As a consequence, gas and district heating grid development are exogenous variables.

Although the Danish model in TIMES was developed mainly to assess the possibility of the usage of Storage Utsira, the CCS potential of that storage won’t be presented here as it is not possible to compare it with the EnergyPLAN where the CCS technology is not modelled. However, as the Denmark policy set the target of 50% electricity generated from wind energy by 2020, CCS technology possibilities became highly constrained for the case of Denmark, due to lowering of the classic base load generation from the large power plants.

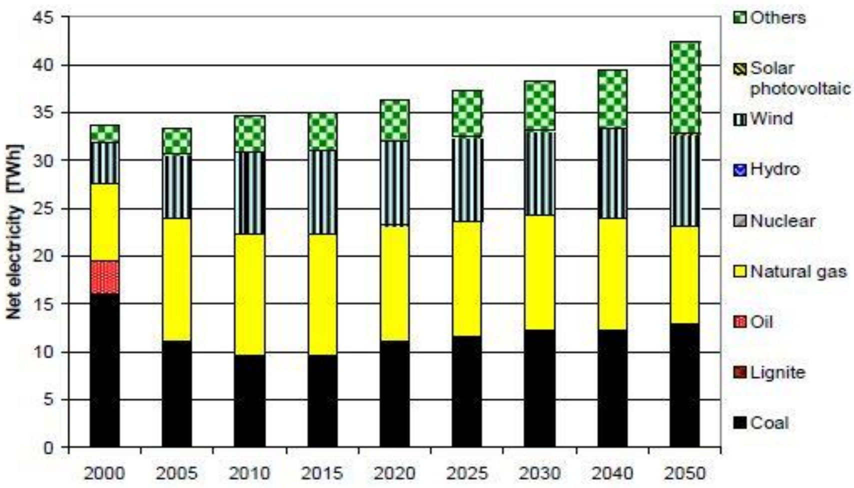
III.II.I.II. Scenario description-Denmark in the EU RES2020 project [27]

As previously mentioned, the EU RES2020 project encompasses EU27 plus Norway, Switzerland and Iceland. Thus, Denmark is one of the countries involved in this model. Three different policy scenarios were developed for the purpose of Danish energy system assessment, a RES reference scenario for the 2020, with the 2020 policies implemented, RES-T scenario with a virtual trade mechanism in RES production rights and RES-30% where GHG emission reduction is set to 30% instead of 20% that is set by the current policy.

The share of renewable energy sources was 9% in Denmark in 2000 and increases to 24% in the BAU scenario in the year 2020 and 27% in other two scenarios. The biggest difference between the scenarios is wind energy penetration levels, while the increase in bioenergy is similar in all three scenarios. Furthermore, in the RES and RES-T scenarios CO_2 emissions cap has been introduced and set to 21.2 Mt for all the sectors that don’t fall under the European Emissions Trading Scheme (ETS).

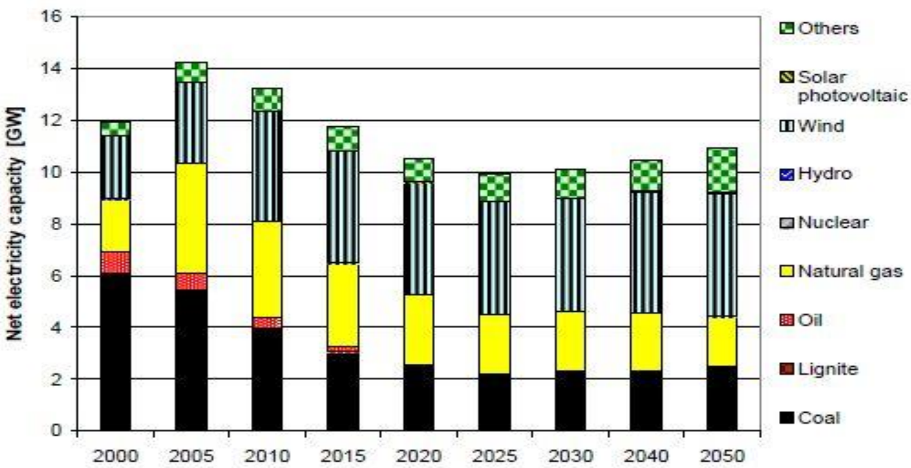
III.II.I.III Results of scenarios – Denmark in the Pan-European model [27]

So far, BAU is the scenario with the most detailed published results. The scenario was developed till the year 2050 with the time steps of five and ten years, accordingly. It is important to mention here that no CO_2 restrictions were imposed in this scenario.



Appendix Figure 10. Electricity generation in BAU scenario for Pan-European model [28]

It is important to keep in mind that the increase in wind energy is the exogenous part of this model and not the result of the optimization. Until the year 2015, the share of coal in electricity generation reduces and is being replaced by natural gas and wind energy. As there are no emission restrictions in BAU scenario, after the year 2015, share of coal power plants are rising again, due to lower levelized cost of electricity compared to the other options. A sudden phase out of oil between the years 2000 and 2005 is maybe a sign of lack of technology constraints as the oil is usually used for starting up the power plants [28].

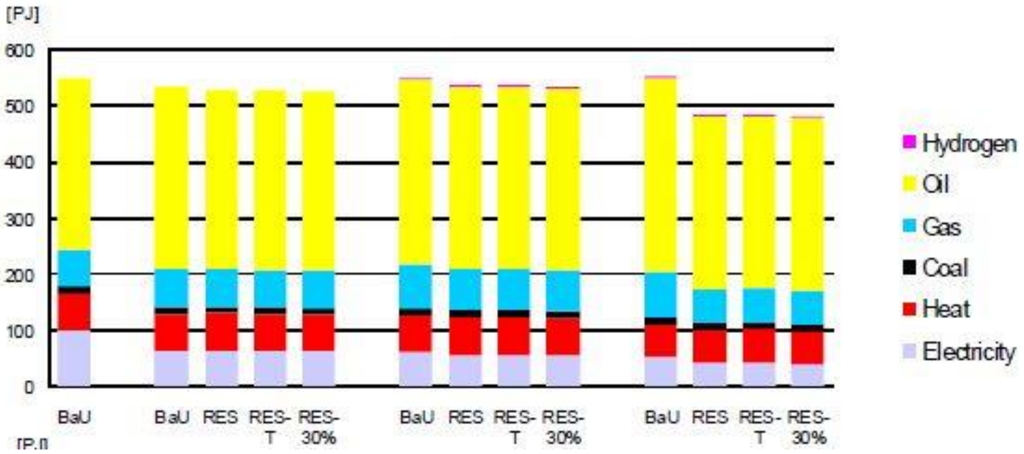


Appendix Figure 11. Electricity generation in BAU scenario for Pan-European model [28]

As it can be seen power plants capacities are, after the starting increase, decreasing until the year 2025 and then increasing at the steady rate again. In the same time electricity generation increases continually from the year 2005. As this is a result of optimization, it can be concluded that there is a significant overcapacity in the current power system.

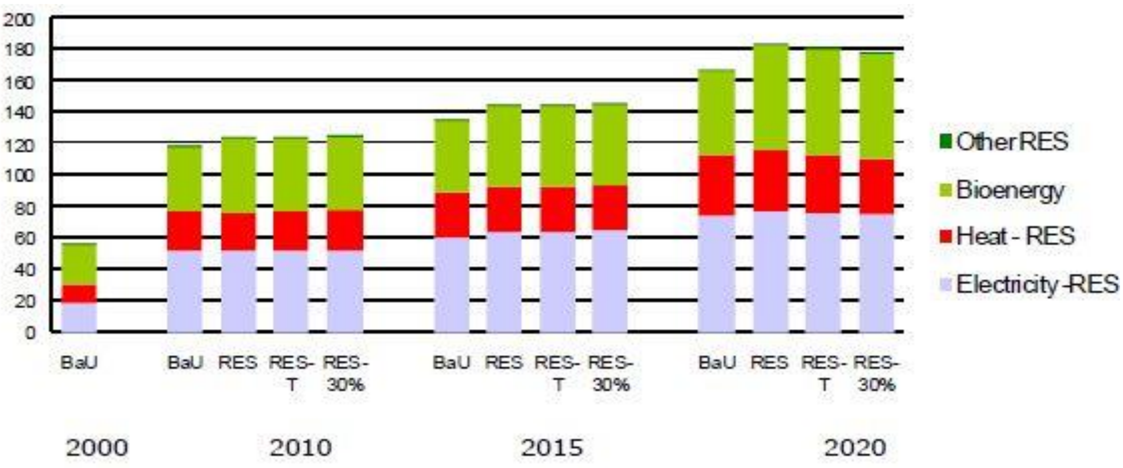
III.II.I.IV. Results of scenarios – Denmark in the EU RES2020 project [27]

As it can be seen, in all the scenarios final energy use of non-renewable sources is lower compared to the BAU scenario. The level of final energy use in all three scenarios are approximately the same.



Appendix Figure 12. Final energy use of non-renewable energy sources [28]

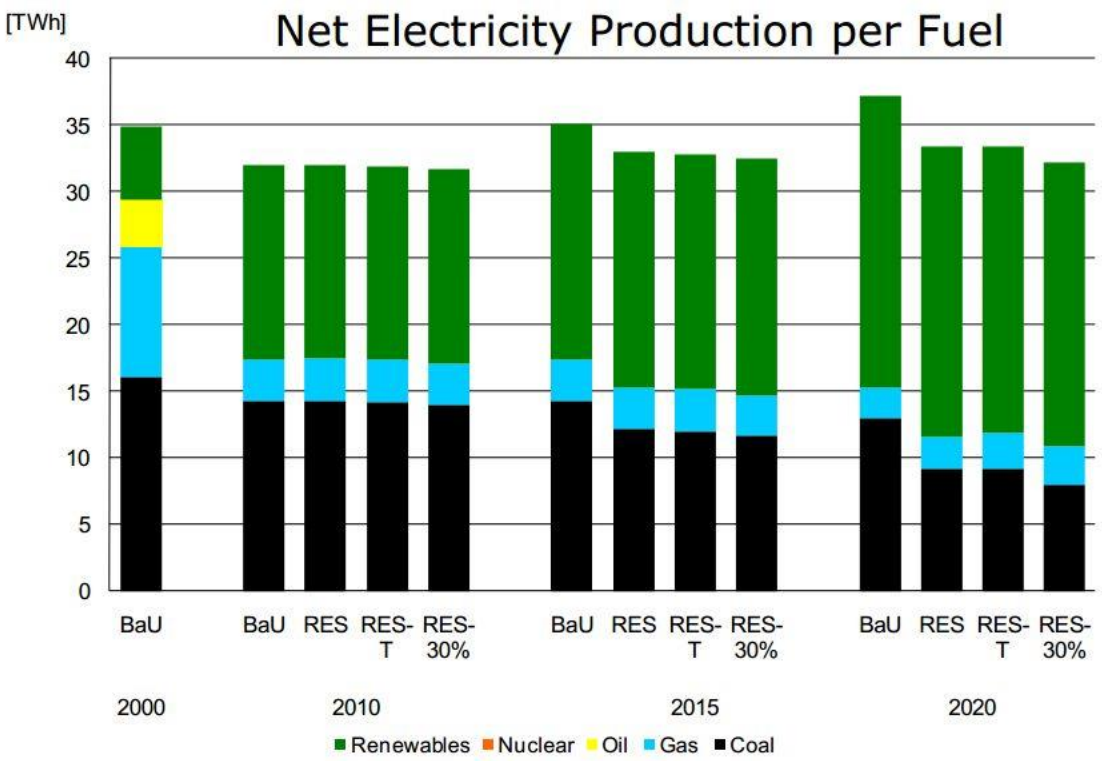
In all three scenarios, the final energy use of non-renewable energy sources is larger compared to BAU scenario. Moreover, in the 2020, final energy use is slightly larger in the RES scenario compared to the other two alternative scenarios.



Appendix Figure 13. Final energy use of non-renewable energy sources [28]

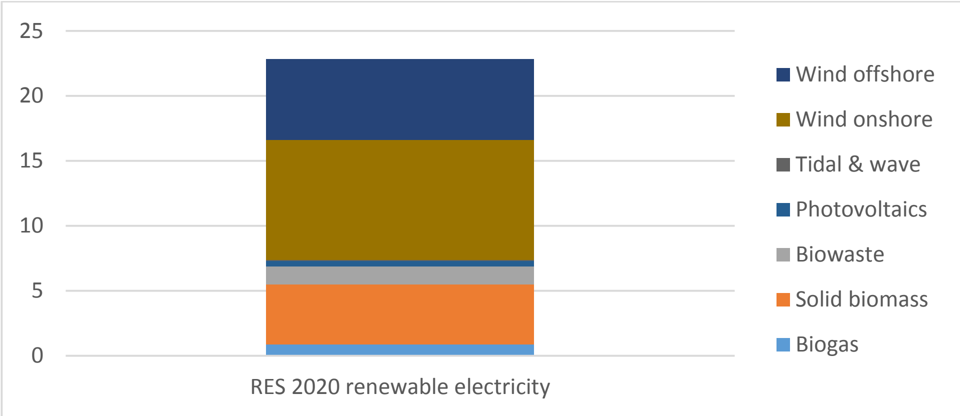
Biomass (wood) based CHP is the dominant renewable energy source shows sectorial analysis. In agriculture, straw is a dominant renewable energy source and biogas on a lower scale. The industry sector's results are shown as uncertain and are not discussed in detail in the preliminary edition of Danish report and thus, conclusion concerning the industry sector cannot be made.

All the densely populated regions are heated by district heating, while natural gas is a source for less suitable dwellings for district heating. Electric resistance heating is being phased out, while heat pumps and biomass based technologies are encouraged in the areas without access to the district heating. It is detected that the district heating systems need to be expanded in order to be possible to regulate large amounts of wind power, with the aid of heat storages [28].



Appendix Figure 14. The net electricity generation by fuel [28]

Furthermore, electricity breakdown from the renewable energy sources can be seen in detail in the following figure:



Appendix Figure 15. The RES electricity generation from different sources [28]

It can be observed on the chart that the total wind energy production amounts to 15.4 TWh in 2020, with the share of approximately 45% in the total electricity generation in the RES scenario. Electricity production from CHPs (solid biomass and bio waste) amounts to approximately 18% of the total electricity generation.

It can be concluded that due to short time horizon assessed and already high penetration levels of renewables in the BAU scenario, alternative scenarios don't differ significantly [28]. This conclusion can be observed rather easily in the last figure, where it can be spotted that penetration levels of different fuels are similar in all the alternative scenarios. Some differences can be observed in the year 2020. However, such a large similarities in all the alternative scenarios can also be a result of too strictly constrained optimization model, which doesn't allow the model itself to have significant endogenous decisions.

III.II.II. Denmark model in EnergyPLAN

III.II.II.I. The IDA Climate Plan 2050 – scenario description [42]

The IDA Climate Plan 2050 has been chosen as a study which will be assessed in order to evaluate EnergyPLAN model, as this was the tool used for carrying out the analysis [42]. The analysis has been carried out until the year 2050, with the two time steps in the years 2015 and 2030, having the task set to implement the Danish government decision of meeting the 100% renewable energy system in the year 2050. The IDA's climate plan proposes significant reduction of primary energy consumption by implementing energy efficiency measures, and in the same time promotes the large penetration of wind turbines, photovoltaics, solar thermal, wave energy and biomass.

The reference case, used for comparison with the IDA's scenarios, were developed by the Danish Energy Authority [42] until the year 2030 and forecasted until the year 2050, based on energy consumption forecast.

The IDA Climate Plan 2050 attached detailed assumptions in their scenarios, and all the data is easily accessible. Nevertheless, it is worth mentioning that the oil price of USD 122 per barrel was assumed in the socio-economic analysis, as was the International Energy Agency's recommendation by the time the study was written. Two other price levels were also assessed, with prices of USD 132 per barrel and USD 60 per barrel, accordingly. Furthermore, for socio-economic analysis expected long term electricity price is set to 497 DKK/MWh and a CO_2 price of 229 DKK per ton. A price of 447 DKK/MWh was used in the electricity market exchange analyses in 2015, as that was the expectation of Danish Energy Authority. However, the electricity price level for 2015 seems exaggerated, as the current price levels in 2014 are approximately half the expected 2015 price levels. Real interest rate of 3% was used in the model and the assumed inflation is 2% yearly. Moreover, employment possibilities were assessed as a part of this study.

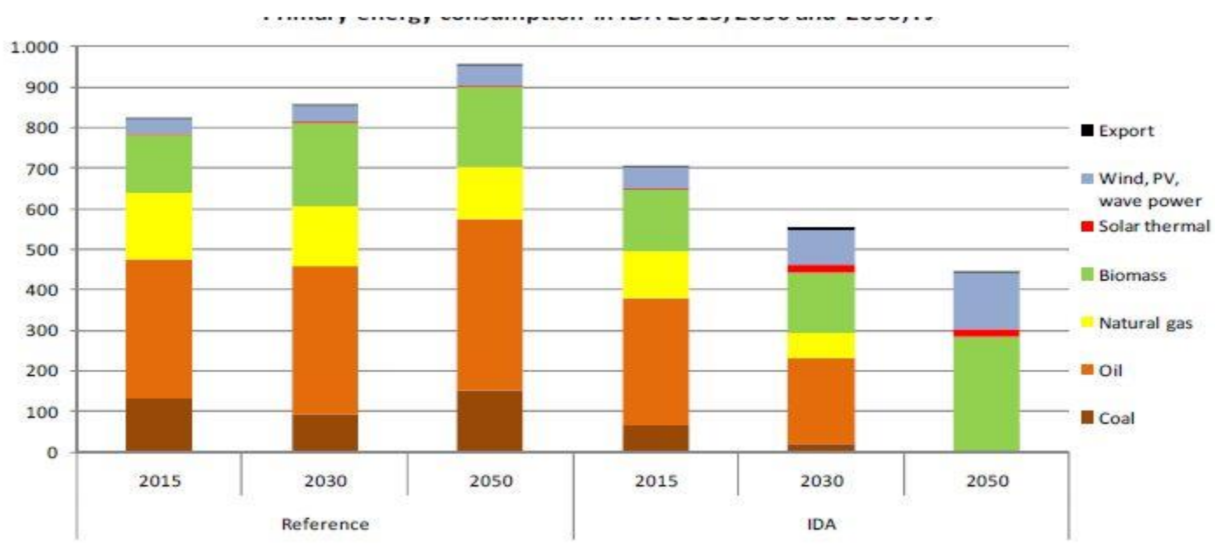
Wind power plays a major role in the future energy systems in IDA scenarios. The targeted value of wind energy generation is set to 67% of the total electricity demand in 2030, which will be achieved with 4,454 MW of onshore wind turbines and 2,600 MW of offshore wind turbines. Even with the energy efficiency measures being taken into account, demand for electricity grows continually during the entire period. It is planned to install 680 MW of photovoltaics by the 2030, producing 0.9 TWh and covering approximately 2% of the total electricity consumption. Furthermore, 5% of the electricity consumption is covered by wave power by 2050 and 3% by 2030. Waste incineration plants produce continually 9.53 TWh of heating energy and 3.29 TWh of electricity in the period between the years 2030 and 2050. Other sources used for covering the energy demand are geothermal energy, fuel cells, heat pumps etc.

Electricity consumption in houses reduces significantly, i.e. in IDA 2030 electricity consumption is reduced by 47% in the year 2030 comparing to the year 2008. New standard for newly built houses is also taken into account. The main goal is to reduce energy consumption by 75% compared to the 2008 levels from the year 2020 onwards. Thus, the energy consumption shall be decreased to the 21 kWh/m^2. District heating will cover between 63% and 70% of the Danish net heat demand by the year 2030. Outside the district heating networks, heat pumps, solar thermal and biomass boilers will be installed. Moreover, district cooling has been introduced and will generate a total of 1.65 TWh of cooling energy in the year 2030. In industry sector a continual increase in energy efficiency is expected, as well as the expansion of CHP production and conversion to biomass and electricity consumption. Electric vehicles, biofuels, expansion of the railway system, increased efficiency in aviation and shipping are the "tools" for switching the transport sector to the renewable energy consumption.

III.II.II.II. IDA Climate Plan 2050 – scenario results [42]

Although the main goal in the IDA report was to analyze the switch towards 100% renewable energy systems in 2050, in this thesis emphasize will be put on the 2015 and 2030 results in order to be able to compare it with the corresponding results of the similar study made in TIMES model generator.

The IDA 2015 energy system was simulated in several different configurations, dealing with excess electricity utilization. Due to large wind power penetration, a large part of excess electricity production needs to be dealt with. In different configuration CHPs production was being reduced, electric boilers and heat pumps were introduced in order to utilize excess electricity production and in the last stage, wind power generation was reduced.

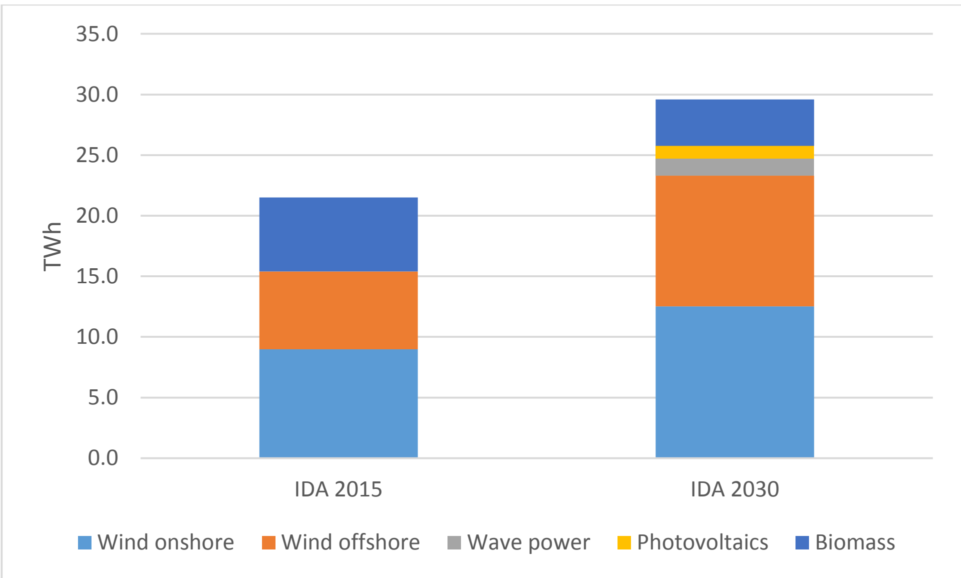


Appendix Figure 16. Primary energy consumption in IDA scenarios [42]

With the implemented measures of increased energy efficiency as discussed in the scenario description, expansion of the district heating grids and the abovementioned regulation strategies, primary energy consumption reduced to the 707 PJ in IDA 2015, down by 54.4 PJ from the reference scenario 2015. Nevertheless, CO_2 emissions reduced in IDA 2015 scenario from 47 million tons to 36 million tons compared to reference scenario. Out of total electricity consumption of 30.7 TWh, 15.4 TWh, or more than 50% is generated by the wind turbines.

In IDA 2030 further increase in heat pumps capacity is achieved, from 250 MWe in 2015 to 450 MWe in 2030. Due to large imbalances in the network, a further measures has been taken into account, such as flexible electricity consumption share in the households, industry and services, a smart charging of electrical vehicles technique, where the charging time corresponds to the periods of a high electricity generation from wind power plants.

The primary energy consumption in the 2030, with the implemented measures as described above, is reduced 554.5 PJ and the excess electricity production amounts to 1.8 TWh. Moreover, CO_2 emissions are reduced to 21 million tons, which is a 52.3% reduction comparing to the reference scenario for the same year.

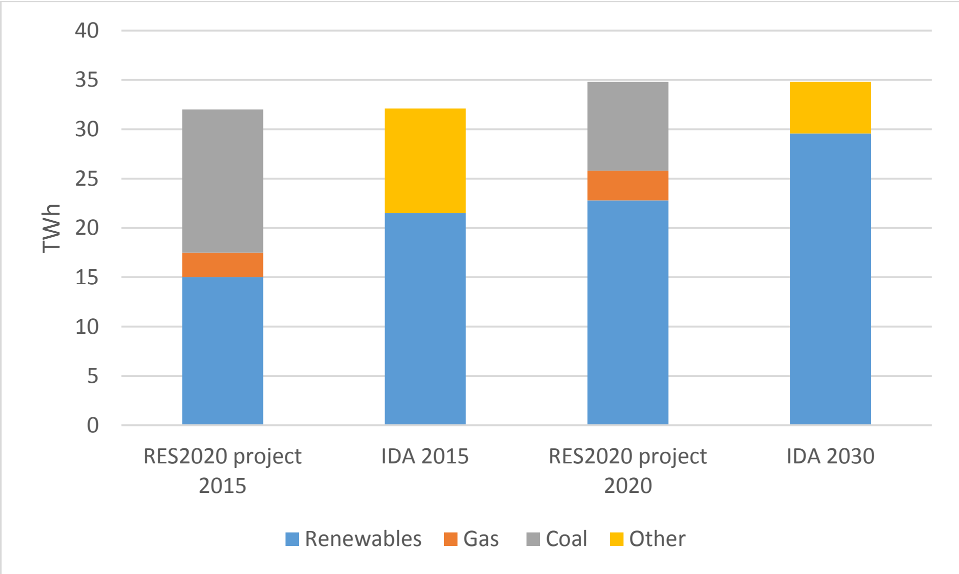


Appendix Figure 17. Renewable electricity production in the IDA 2015 and IDA 2030 scenarios [42]

As it can be seen, onshore and offshore wind generates the largest part of the renewable electricity, with a share of 48% of the total electricity production in 2015 and 67% in the year 2030. Renewable energy sources produce 67% of electricity in the year 2015 and 85% in the year 2030.

III.II.III. Comparison of models' results

Significant obstacle in the comparison presents the different results studies provided, i.e. models of Denmark in TIMES have put the emphasize on the electricity sector, while IDA project put the emphasize on the whole system and thus, primary energy consumption of the whole system prior to the electricity consumption.



Appendix Figure 18. Comparison of the electricity generation results in different models for different years [28][42]

As it can be seen from the Figure 18., the total electricity generation is approximately the same in both models for the year 2015. However, the energy mix is somewhat different. Renewables have a share of 46% in the RES 2020 project in the year 2015, while in the IDA project share of renewables amounts to 67% for the year 2015. The difference is covered in the RES 2020 project mainly by coal power plants production, which is a result of optimization as the coal has the lowest relative prices in the current model in TIMES. Moreover, it is important to notice that modelers reported that gas power plants needed to be constrained in order to avoid phasing out of gas, due to relatively high marginal prices [28].

Furthermore, it is important to notice that the optimization model developed in TIMES has a problem of representation of large amount of wind energy. The authors of the report [28] of the Danish model in TIMES reported:

"Modelling an energy system with a significant contribution by wind power has become a key task for modelling the electricity system task in Denmark…" and also "…This issue have been considered within the TIMES model for the RES2020 project, but no satisfactory solution have yet been found."

As it can be seen, wind modelling is one of the key tasks in the optimization model due to its intermittency nature. To face this issues, current models have set wind penetration levels exogenously, thus avoiding problem of possible oversupply or undersupply in installation of wind turbines. New ETSAP Annex will be published in the beginning of the 2015 where it will be reported whether appropriate methodology has been found in order to cope with this issue.
The reported problem of phasing out of gas if the model would make the decisions endogenously is also a problem which isn't discussed properly in the published report [28]. Such a serious difference in marginal costs could be a sign of lack of proper data in the technology sheet.

It is important to mention that EnergyPLAN, in which IDA project was modelled, receives all the investments exogenously, as the EnergyPLAN model is developed to simulate the system operation and not the investments. As it is obvious from the compared results that the coal power plants are the cheapest investment in the optimization RES2020 model, it would be interesting to compare the socio-economic costs in both studies, in order to have a valid comparison of the possible benefits of using the optimization tool for making decisions about investments. However, in the RES2020 report for the case of Denmark neither socio-economic costs, nor technology data sheet is provided so it is not possible to make this comparison.

There is no reference year later on as the final year in RES2020 project was 2020 and in IDA project only years 2015, 2030 and 2050 were assessed. However, it can be noted that in IDA report projected penetration of renewables has a larger pace than in the RES2020 project. Nevertheless, it is worth noting that all the alternative scenarios in RES2020 project for the year

2020 came near the same results, which is a consequence of the firmly constrained problem. As renewable energy sources are exogenously entered into model, there was only a small possibility of having different alternatives, as it is the coal that is the alternative with the lowest economic cost in a TIMES model, according to the results and the data provided. However, both models showed that renewable energy sources will play a key role in the near-term future electricity generation systems of Denmark.

III.III. Modelling of European Union

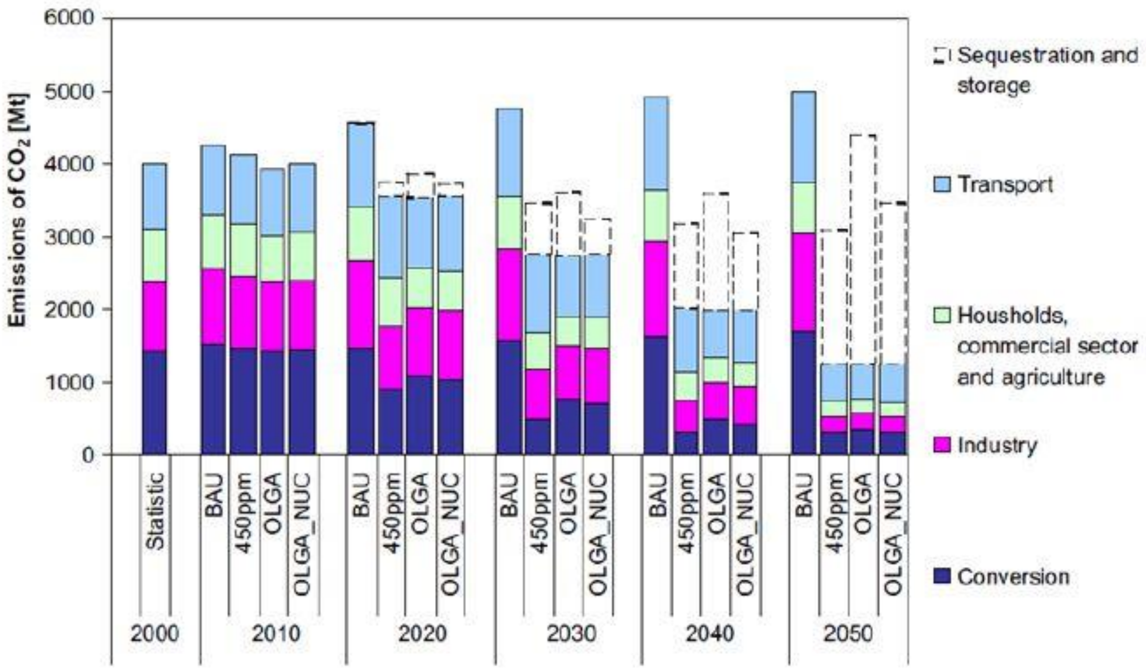
III.III.I. EU model in TIMES – The Pan-European model [27]

Pan-European TIMES model is the model that used as a starting point for the most of the EU models. The Pan-European study assessed possibilities of stabilizing the CO_2 concentration at a level of 450 ppm and thus, keeping the global temperature increase to 2 °C compared to the preindustrial levels [27]. The study assessed different technologies and their abilities with the geographical system boundaries set to EU27 countries. Moreover, energy efficiency measures and fuel switching actions were also considered within the scope of the study. The results are reported in the Annex XI of the IEA's ETSAP publishing [27].

Five different scenarios were developed as a part of this study [27]:

- *BAU scenario* with no limits on the CO_2 emissions
- *450 ppm Climate protection* with 71% CO_2 reduction compared to the 1990 levels and nuclear phase-out
- *OLGA_NUC Climate protection plus security of supply* with the same objectives as the previous scenario plus increased security of supply target by reducing oil and gas imports
- *OLGA_NUC Climate protection plus security of supply and enhanced nuclear energy* with the same targets as the previous scenario, but with the option of enhanced utilization of the nuclear energy
- *450 ppm_100 Climate protection plus high oil price scenario* with the targets of 71% of CO_2 emissions reduction, nuclear phase out and the continual price of USD 100 per barrel of oil and the corresponding gas price adoption

Results showed that the given target of 1,310 Mt CO_2 is reached by 2050 in all the climate protection scenarios. The reduction of emissions takes place firstly in the conversion sector, then in households, commercial and the industrial sector.



Appendix Figure 19. CO_2 emissions by sector in different scenarios [27]

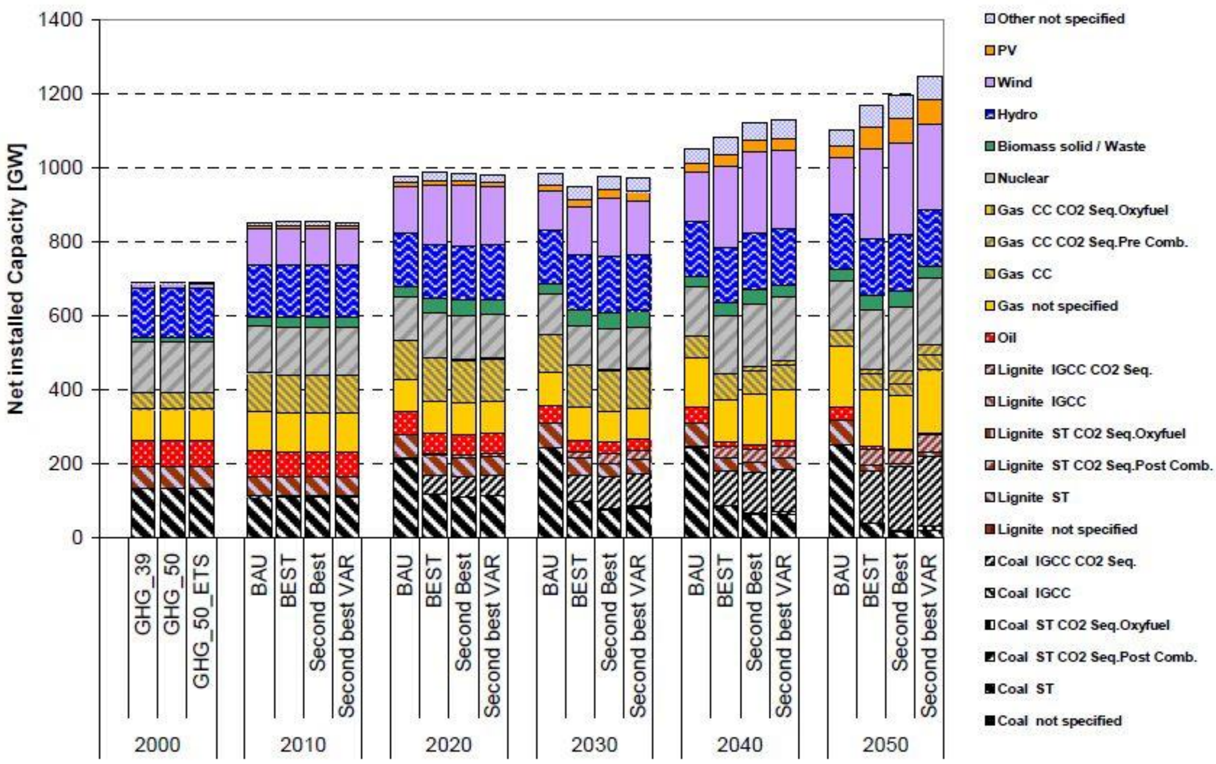
In the 450ppm scenario, fuel switching and the CCS technology are the mainly responsible technologies for the emissions reduction. The increased security of supply in the OLGA scenarios is achieved by reducing oil and gas imports and switching to coal with incorporated CCS technology. Thus, in OLGA scenarios the share of CCS based coal technologies increases significantly and becomes the major reason for reduction of CCS emissions. Renewables contribute to the emissions reduction similarly in all the scenarios. Efficiency improvements are increasingly important in the case of increased security of supply target. Lastly, it is reported that the extended nuclear power plants commissioning would lead to the cost effectiveness in achieving the targets, although the exact economic results aren't reported [27].

CO_2 prices differ quite substantially in the different scenarios, in the range of 53 €/t CO_2 in the nuclear scenario to the 94 €/t CO_2 in the 450ppm scenario for the year 2030. When the reduction target becomes more then 60% compared to 1990s levels, the prices soar above the level of 100 €/t CO_2.

One of the studies that followed from the Pan-European model is the *EU 20-20 policy implications on the EU energy system*, which assess and evaluates the EU Energy and Climate Package. Four scenarios were developed as a part of this study [27]:

- *Baseline scenario (REF)* with no emission reduction measures and minimum RES
- *BEST climate policy on global trade* with EU 20-20 target and emissions reduction by 50% till 2050
- *Second Best* with the EU 20-20 target and the emissions reduction by 50% till 2050
- *Second Best VAR* with the same goals as in the previous scenario plus limited ETS part in order to increase the non-ETS sector role in emissions reduction

Results show that economic development, requested demand, technology development and availability all have important influence on the future energy system. Moreover, results showed that with the nuclear phase out, CCS technology will play a very important role in the future energy systems [27]. Furthermore, it is expected that over 90% of the fossil fuels in the EU27 will be imported in the 2050 and the import dependency will grow to more than 70% [27].

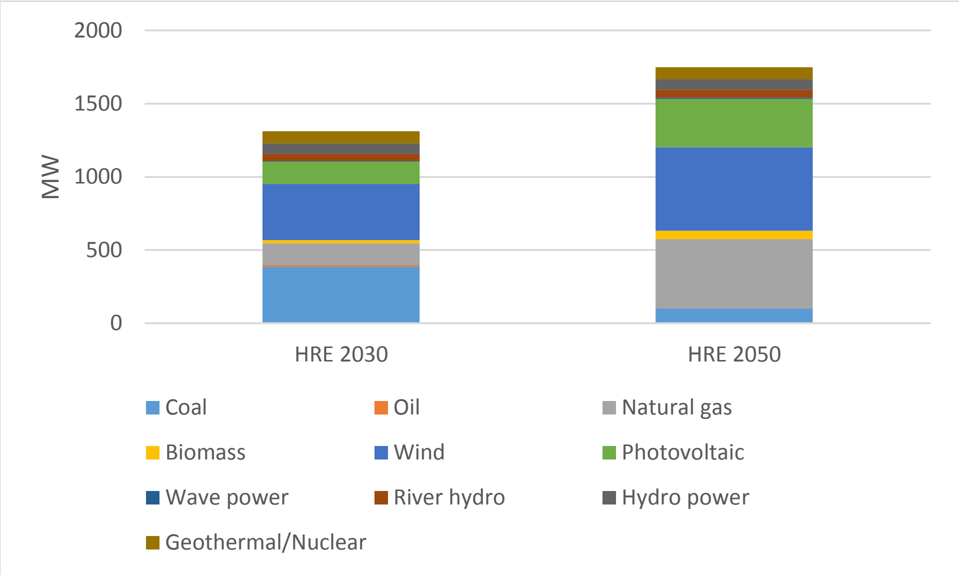


Appendix Figure 20. Net electricity installed capacity [27]

Out of renewable energy sources, wind, as well as hydro energy, present the most important sources, followed by photovoltaics and biomass.

III.III.II. EU model in EnergyPLAN – The Heat Roadmap Europe [38]

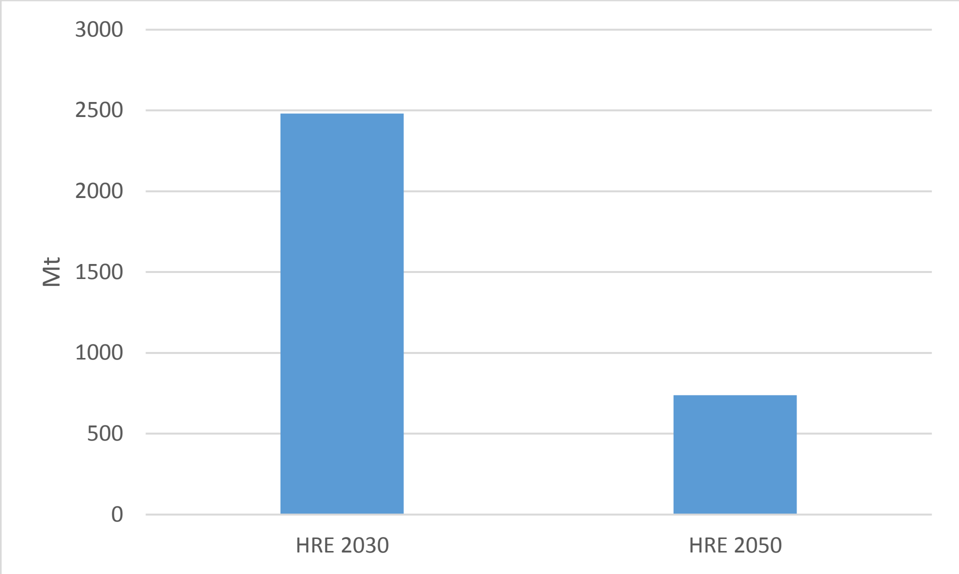
Background and the general introduction about the Heat Roadmap Europe were already presented in the previous chapters. In order to make a valid comparison of the different models, only the results needed for comparison with the similar model developed in TIMES will be presented here.



Appendix Figure 21. Net electricity capacity by energy carrier [38]

Although the Heat Roadmap Europe put the emphasize on the heating sector in order to reduce socio-economic costs of the future energy system, the whole electricity system was modelled as well, in order to detect the best alternative to the current business as usual scenario. Thus, the net electricity installed capacity by energy carriers, as well as the CO_2 emissions, was extracted from the appendices of the Heat Roadmap Europe in order to make a proper comparison with the available results of the similar study carried out in TIMES modelling tool. Results of net installed capacity in the years 2030 and 2050 show a significant share of renewable energy sources, mainly the wind energy and the photovoltaics. Wind capacity went up for 50% in year 2050 compared to 2030, increasing its share from 29% to 32.7%. Moreover, significant increase in installed capacity occurs in the year 2050 compared to the year 2030. Nevertheless, natural gas increases its share significantly in the year 2050, up to 27% from

11.4% in 2030. Meanwhile, coal has reduced its share significantly, from 29.6% in the year 2030 to 5.9% in the year 2050.



Appendix Figure 22. CO_2 emissions in different years [38]

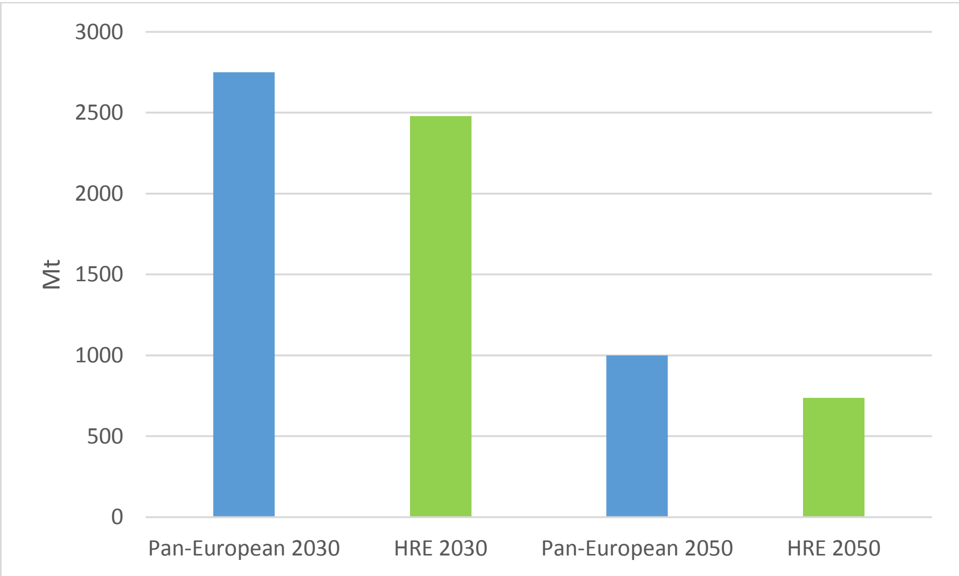
As it can be seen, CO_2 emissions reduced significantly in the year 2050, compared to the year 2030, although the electricity demand increased for 500 TWh per year. This reduction amounts to more than 70%.

III.III.III. Comparison of models' results

Interesting comparison can be provided in terms of net electricity capacity installed, as well as the CO_2 emissions, in different scenarios developed in TIMES model generator and the EnergyPLAN model. As it can be observed from Figure 16. and Figure 17., the net installed electricity capacity is much larger in the HRE scenarios, developed in EnergyPLAN, both in years 2030 and 2050. This difference is more than 32% in the year 2030 and more than 40% in the year 2050.

Power plants' mix is also significantly different in the two models. Firstly, wind capacity in the Pan-European model is less than 200 GW in all the scenarios in the year 2030 and less than 250 GW in all the scenarios in the year 2050. On the other hand, Wind capacities in HRE scenarios are 381 GW in the year 2030 and 572 GW in the year 2050, respectively. Secondly, in all the scenarios within the Pan-European model different coal technologies have more than 200 GW of installed capacity still in 2050. Most of it, however, have incorporated CCS technology. Similar situation is with natural gas power plants, contributing with more than 200 GW to overall net installed capacity in all the scenarios. In the year 2050, installed coal power plants capacity amounts to 104 GW, while natural gas power plants contribute to the total installed capacity with more than 470 GW in the HRE scenario. Thus, coal technologies are represented with twice lower amount, while gas fired power plants are represented with more than twice higher amount in the HRE scenario, compared to the scenarios in the Pan-European model. Lastly, a significant difference in photovoltaics penetration occurs, as its share in Pan-European model's scenarios is no more than 50 GW, while in the same time equals to 330 GW in the HRE scenario, in the year 2050.

As a result of all these differences, CO_2 emissions differ significantly in the two compared models.



Appendix Figure 23. CO_2 emissions in different scenarios and years [27] [38]

It can be observed on the chart that CO_2 emissions are lower in HRE scenarios in both 2030 and 2050. In the year 2050 CO_2 emissions are lower more than 25% in HRE scenario compared to the Pan-European scenarios. It can be concluded that the energy mix simulated in HRE scenarios are favorable in terms of CO_2 emissions compared to energy mix in the Pan-European scenarios. Lastly, as the socio-economic cost data are not available for the Pan-European study, it is not possible to compare system costs of different configurations.