CRUCIAL ENERGY CHOICES IN BELGIUM - AN INVESTIGATION OF THE OPTIONS

OUR ENERGY FUTURE

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1 INTRODUCTION & OBJECTIVES

1.1 CONTEXT

Belgium is at a critical turning point in its energy history. Our country is indeed facing several challenges that are creating issues of security of supply, sustainability, costs and risks. With the nuclear safety issue and the phase-out plan, and with the anticipated decreasing generation adequacy margin, it is now time to make some crucial energy choices.

Greenpeace, BBL and WWF want to make sure that these choices are future-oriented. They therefore commissioned 3E to analyse possible energy scenarios for the future with a special focus on the electricity sector and energy efficiency, and see what is needed to develop a safe, secure, affordable and sustainable energy future. This study is also meant to initiate the important discussion on Belgium's energy choices for the future.

This report presents the work on the electricity sector. The other parts will be published in a later phase.

1.2 WHAT THIS STUDY ADDS TO THE DEBATE

3E has developed a detailed model of the Belgian electricity sector. Starting point is the investor's point of view. For each technology - renewable as well as conventional technologies - a business model has been worked out that incorporates a broad spectrum of technical, financial and economic parameters (see Chapter 2 for a detailed description of the model). As a consequence this model is very flexible when it comes to impact assessment and sensitivity analysis of one or more parameters.

One of the important outputs of the 3E model is an estimation of the Levelised Cost of Electricity (LCOE) for the different generating technologies. Since the electricity price is also explicitly integrated in the model, it furthermore allows for assessing the volume of subsidies that is required to realise these investments. Moreover the model also takes into account the distribution cost of solar PV systems.

Combining all these elements together enables policy makers to assess the impact of different parameters on the required subsidy levels. Examples of what this means are given in the next section.

Furthermore the model has included some important checks to make sure that the outcomes of the model make sense. The two most obvious examples are in what extent the energy system is able to meet the peak demand and the annual energy demand (also taking into account the comparison between the required electricity imports and the available interconnection capacity at transmission level).

To summarize the 3E model will provide consistent outcomes both at micro as well as at macro-level. There are of course other models available and some studies have been published in recent years (eg. "Prospectieve studie" from FOD Economy & Planbureau[1], Climact/Vito[2] and work from Itinera[3]). These

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[1] Studie over de perspectieven van elektriciteitsbevoorrading tegen 2030, FOD Economy & Planbureau, August 2013, Available online http://economie.fgov.be/nl/ondernemingen/energie/elektriciteit/Prospectieve_studie_elektriciteit/#.U6l2cv5j3Eg

models all address specific aspects of the Belgian electricity system but none incorporates all functionalities that are described above. Compared to more sophisticated models like e.g. TIMES and PRIMES, the 3E model allows for direct assessments of specific measures whereas for these cost optimizing models it is not always clear how to evaluate the outcome of these models. Where possible and relevant, assumptions and other inputs have been based on these studies to ensure maximum coherence and allow for comparisons.

Finally, the 3E model is as up to date as possible, including for example the outages of Doel 3 and Tihange 2.

1.3 TARGET QUESTIONS TO BE ANSWERED

As mentioned above, the flexibility of the model allows for multiple sensitivity analyses, in order to come up with robust recommendations. With this model, Greenpeace, BBL, WWF and others can track concrete realisations over the next years and can quickly react to market changes or upcoming policy questions.

The model is built to help answering the following type of questions:

- What impact will higher fuel or CO_2 prices have on the total required subsidies for renewables?
- In how far can a stable policy and supporting framework (i.e. lower WACC for a certain technology) reduce the total costs for the consumer?
- How will renewable energy in Belgium reduce the dependency on fossil fuels and the risk of fuel price increases?
- What are the most cost-efficient technologies, and how does the LCOE of the different technologies relate to each other?
- How do the LCOE values change over time?
- Is it more interesting to delay large-scale investments in some technologies with a few years until they are cheaper?
- What is the impact of net metering for PV systems ('terugdraaiende teller') on investment decisions and required subsidies?
- How much biomass can be used in the electricity system in a sustainable way?

This final report discusses and elaborates these questions based on the modelling results. This is accompanied by some calculations where needed, in order to develop a set of sound recommendations to support the Belgian policy makers in making well-founded future-oriented decisions.

1.4 LIMITS OF THIS STUDY

The present study uses an accounting model for the electricity sector. It is not an optimisation model that arranges the available installations in the merit-order curve and calculates for each hour which

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[2] D. Devogelaer, J. Duerinck et al. Towards 100% Renewable Energy in Belgium by 2050, April 2013
M. Cornet, J. Duerinck et al., Scenarios for a Low Carbon Belgium by 2050, November 2013

[3] Johan Albrecht, 2014-2019: Diagnose en prioriteiten: Energy Security First!, Itinera Institute Verkiezingsreeks 2014, March 2014, Available online

installations need to deliver how much energy. This is on the one hand good because it is more clear what the impact of each parameter is and it is not a black box model where the results are hard to analyse and understand. On the other hand, this means that the input data is more rough (yearly resolution) and assumptions need to be made about e.g. full load hours and electricity prices. These assumptions are not directly linked to the inputs of fuel prices, as they would be in an optimization model.

In general, this is a good method for the period up to 2030 since the important things are the trends and evolutions, and furthermore the internal sanity checks of the model (see further) are adequate for analysing this time period. Moreover, the impact of the assumptions is assessed with sensitivity analysis in order to make more robust conclusions.

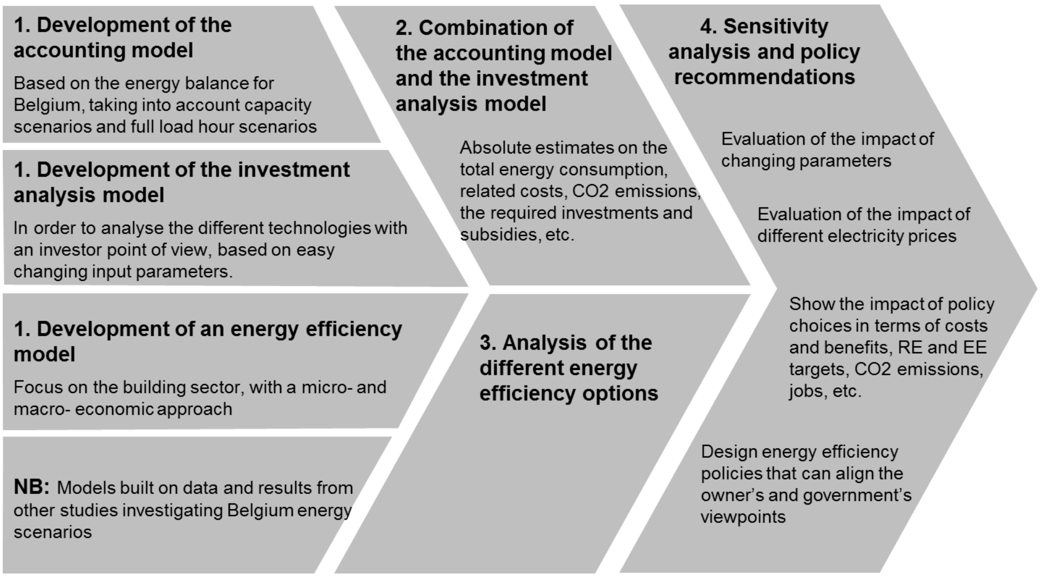
When checking possible issues in the electricity system for the next five years, this method is not sufficient. The yearly resolution and a lack of detailed public information make it impossible to accurately do this. However, even though the model was not built for that reason, it can already give some rough indications and useful insights.

2 METHODOLOGY AND ASSUMPTIONS

2.1 EXPLANATION OF THE MODELS USED

2.1.1 General methodology

For the purpose of this study, 3E developed an accounting model of the Belgian energy system coupled with an investment analysis model. An energy efficiency analysis has also been performed. The focus is on renewable energy in the electricity sector and energy efficiency in the built environment. Both a micro- and a macro-economic approach are used.



The combination of the accounting model and the investment analysis model leads to absolute estimates about the total energy consumption, the related costs, the CO_2 emissions, the required investments and subsidies, etc. In addition, and more importantly, this leads to important insights from the relative comparison of the scenarios, showing the impact of possible policy choices in terms of costs and benefits, RE and EE targets, CO_2 emissions, jobs, etc.

The above mentioned models have been developed starting from the research done by 3E in several previous studies like e.g. the assessment of the required subsidies for renewable energy in the Walloon and Flemish regions[4], and several studies on energy efficiency. Furthermore, they have been built using data and results of other studies investigating Belgium energy scenarios; in particular the Energy

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[4] Steunmechanismen voor de productie van groene stroom en WKK, analyse, aanpassingsvoorstellen en beleidsaanbevelingen, 3E for VEA, July 2011, http://www.energiesparen.be/evaluatie_steunmechanismen

Report for the Walloon Government (SPW DG04), 2013, not published yet.

Roadmap 2050 (2011)[5], the Vito/ICEDD/Federaal Planbureau study (2013)[6] , the study of the FOD Economy and the Federal Planning Bureau (2014)[7] and the Climact study (2013)[8].

The present report only covers the results of the electricity sector. The rest of the work will be published later.

2.1.2 The accounting model for the electricity sector

The accounting model is the general model used in this study for the overall energy balance (to be published later). The accounting model for the electricity sector is part of this, and simulates the evolution of the Belgian electricity system. The model uses assumptions for installed capacity, full load hour and electricity and fuel prices. Based on the installed capacity and the annual full load hour assumptions, an electricity production scenario is calculated (Figure 1). By allowing the selection of different source scenarios, analysis of the future electricity system can be performed.

The benefit of the accounting model is that it allows checking the internal coherence of the energy system, comparing the energy demand with the required import, and the installed dispatchable capacity with the residual peak demand (after flexibility is used but with reserve margin). Since it is meant primarily to investigate options for the future (period up to 2030), it works with an annual resolution.

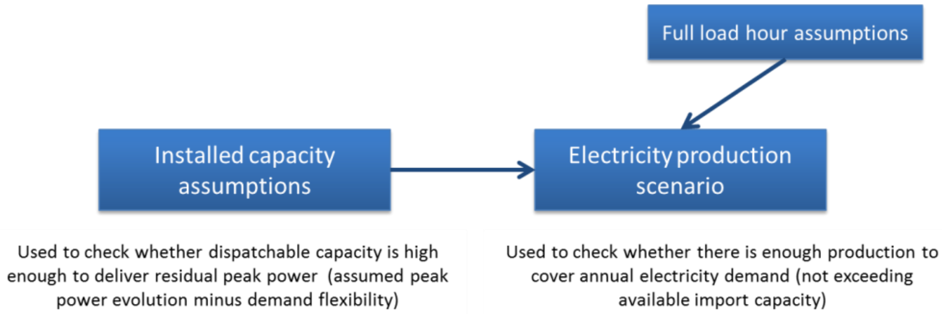

Figure 1: Key methodology of the accounting model: The electricity production scenario is developed based on assumptions of installed capacity and annual full load hours per technology. Checking peak power and total energy demand provision ensures that the results make sense.

All parameters, assumptions and scenarios in the accounting model can be changed and tested very easily, allowing for flexible and quick analysis possibilities.

2.1.3 The investment analysis model

The investment model that is used in combination with the accounting model is building on research done by 3E for the Flemish Energy Agency and the Walloon Government[9] . For all electricity production

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[5] European Commission, Energy Roadmap 2050, Impact Assessment, December 2011

[6] Vito, ICEDD, Federaal Planbureau, Towards 100% renewable energy in Belgium by 2050, April 2013.

[7] FOD Economie, Federaal Planbureau, Studie over de perspectieven van elektriciteitsbevoorrading tegen 2030, 2014

[8] Climact,Vito, Scenarios for a Low Carbon Belgium by 2050, November 2013

technologies analysed in this study, a business model is developed taking into account all relevant financial parameters (CAPEX, OPEX, WACC, tax regime, construction length etc.). Also these parameters can be adapted easily in the model to allow for quick and detailed sensitivity analysis. The exercise is done for both renewable and conventional technologies. Learning curves for CAPEX are implemented, as are efficiency improvements over the years. The model enables to determine for example how much subsidies are required in order to allow developers to get an adequate return on investment.

Parameters taken into account

For each technology, the following elements have been taken into account in the profitability analyses:

- **Investment costs** (CAPEX), in nominal terms
- **Operating revenues** composed of:
  - the grey electricity revenues coming from the auto-consumption of electricity generated on site
  - the revenues coming from the injection of residual electricity produced on the grid
  - the revenues from heat sold for the technology if applied (e.g. CHP)
- **Operating costs**:
  - O&M (operational and maintenance) costs, obtained applying a percentage of the investment costs, in nominal terms
  - Grid injection costs, in nominal terms
  - Fuel costs, in nominal terms
  - CO_2 emission costs, in nominal terms: the CO_2 emission factor considered for natural gas is of 0.202 tCO_2/MW produced.
- **EBITDA** (Earnings before Interest, Taxes, Depreciation, and Depreciation): computed as the operating revenues minus the operating costs.
- **Depreciation**: based on the linear depreciation principle, with a depreciation period equal to the operation length of the technology.
- **EBIT** (earnings before interest): calculated as the EBITDA minus the depreciation.
- **Ratio Financial expenses / revenues**: cash flows are discounted based on a discount rate that takes into account the cost of debt and cost of equity; the ratio of financial expenses/revenues is not calculated explicitly.
- **Profit before tax**: corresponds to the EBIT minus the financial expenses / revenues ratio.
- **Tax:** a tax rate of 33.99 % is considered. The tax base is calculated as the earnings before tax less the deduction for investment, less the notional interests' deduction, less the tax burden that can be carried forward in time.
- **Profit before tax**: corresponds to the EBIT minus the financial expenses / revenues.
- **Deduction for investment**: computed according to the applicable rate of deduction for investment (15.5 % of the eligible investments).

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[9] Steunmechanismen voor de productie van groene stroom en WKK, analyse, aanpassingsvoorstellen en beleidsaanbevelingen, 3E for VEA, July 2011, http://www.energiesparen.be/evaluatie_steunmechanismen

Report for the Walloon Government (SPW DG04), 2013, not published yet.

- **Notional interests' deduction**: because the notional interest deduction is not directly linked to investments in renewable energy, the financial calculation does not take it into account (only costs and revenues generated directly by the project are considered).
- **The deferred tax liabilities**: if for a given year the tax base does not cover the depreciation of the investment, the tax benefit is deferred to the following year.
- **Profit after tax**: calculated as earnings before taxes minus the taxes.
- **Operational cash flows**: computed as profit before tax plus the total depreciation (which are not cash).
- **Free cash flows**: computed as the cash flows minus the CAPEX (investment costs). The CAPEX is spread over the construction length of the technology, starting in year 0, and the operational cash flows in the years that follow (1 to n).
- **Discount rate**: equals to the WACC (in nominal terms) of each technology.
- **Discounted cash flows**: equal to the free cash flows corrected by the discount rate.

Measuring costs and required subsidies: LCOE and NPV

The profitability of each technology is in this project measured with the following two main indicators:

- **NPV** (Net Present Value): sum of the cash flows of the technology discounted on an annual basis. The net present value is the value of an investment, given the cash flows of the project:

$$NPV = \Sigma\ CFt / (1 + WACC)^{\wedge}t$$

  Where NPV is the net present value, CFt the annual cash flows, WACC the weighted average cost of capital suggested, t (from 0 to n), where n is the last year of operation of the installation. A positive NPV indicates that the technology generates added value, above the required return to compensate for the financing costs. A negative NPV means that the project requires subsidies in order to get the required return on investment.

- **LCOE** (Levelized Costs of Electricity): is a metrics calculating the cost of electricity produced by a generator, or said differently, the price at which electricity should be sold to break even over the lifetime of the technology. The following expression for the computation of the LCOE is used, given by [IEA/NEA 2010] (p.34)[10]:

$$\Sigma_t (Electricity_t{}^{*} P_{Electricity}{}^{*} (1+r)^{-t}) = \Sigma_t ((Investment_t + O\&M_t + Fuel_t + Carbon_t + Decommissioning_t)^{*}(1+r)^{-t}) \qquad (1).$$

  From (1) follows that

$$P_{Electricity} = \Sigma_t((Investment_t + O\&M_t + Fuel_t + Carbon_t + Decommissioning_t)^{*}(1+r)^{-t}) / (\Sigma_t(Electricity_t{}^{*}(1+r)^{-t})) \qquad (2),$$

  which is, of course, equivalent to

$$LCOE = P_{Electricity} = \Sigma_t((Investment_t + O\&M_t + Fuel_t + Carbon_t + Decommissioning_t)^{*}(1+r)^{-t}) / (\Sigma_t(Electricity_t{}^{*}(1+r)^{-t})) \qquad (2)'.$$

  The factors influencing the LCOE apart from the different costs are the discount rate and the load factor (which determines the amount of electricity produced per year).

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[10] IEA and OECD/NEA, Projected Costs of Generating Electricity: 2010 Edition, 2010, Paris

2.2 SCENARIOS

For this study of the Belgian electricity sector, two main scenarios have been developed. As mentioned above, the analysis of these scenarios is then complemented by several sensitivity analyses.

To be as coherent as possible with other studies, all parameters and assumptions are based as much as possible on data found in other literature.

2.2.1 The Reference scenario

A reference scenario is determined to start with. This scenario is not intended to predict the most probable or best evolution of the energy system, but to serve as a reference to evaluate different options for the future.

In order to allow for comparisons, the Reference scenario has been based on the Reference scenario Nuc-1800 in the 2014 Prospective Study[11]. The installed capacities assumed in this scenario are shown in Table 1. The full load hour assumptions used for this study have been calculated based as much as possible on the information about electricity production and installed capacity in the Prospective Study. For some technologies, the full load hours have been changed slightly in order to meet the requirements for peak power and annual energy demand and make sure the system can work in a stable way.

Table 1: Installed capacities in the Reference scenario

Electricity Demand scenario	2010	2020	2030	
Gross Final Consumption	90 400	97 510	105 180	GWh
Peak demand	13 845	14 860	15 730	MW

Capacity scenario	2010	2020	2030	
Nuclear	5 943	4 098	0	MW
Coal	1 071	0	0	MW
Peak Units	491	768	128	MW
Gas - CCGT	4 085	7 197	10 310	MW
Gas - CHP	1 848	2 557	3 265	MW
Biomass	935	1 430	1 924	MW
Wind - onshore	691	2 400	3 458	MW
Wind - offshore	195	2 200	2 860	MW
Solar PV	1 055	2 808	2 808	MW
Hydro	119	100	130	MW
Geothermal	0	0	0	MW
Pumped Hydro Storage	1 307	1 307	1 307	MW
Import	3 500	6 500	6 500	MW
Demand Flexibility	504	541	573	MW

The following details are worth mentioning about the Reference scenario:

- The earlier than expected unforeseen outages of the nuclear plants Doel 3 and Tihange 2 are not integrated in the Reference scenario based on the 2014 Prospective Study. Since the Reference scenario is mainly used to compare and analyse results on the longer-term (period up to 2030), this is thus not a big issue for the analysis meant in this study.

[11] Studie over de perspectieven van elektriciteitsbevoorrading tegen 2030, FOD Economy & Planbureau, August 2013, Available online http://economie.fgov.be/nl/ondernemingen/energie/elektriciteit/Prospectieve_studie_elektriciteit/#.U6l2cv5j3Eg

- The Prospective Study of the FOD Economy and the Federal Planning bureau was partly developed in 2010 already, before the big boom in solar PV in Belgium. The Nuc-1800 scenario on which the Reference scenario is based, assumes an installed capacity for PV of 1700 MW in 2020 and 1924 MW in 2030. Today, installed capacity of solar PV already surpassed these figures by far, amounting to a total installed capacity of about 2800 MW.
  To be in line with the Prospective Study as much as possible, the Reference scenario assumes no further growth for PV above this 2800 MW.
- The renewable energy scenarios in the Prospective Study all assume a large role for biomass. However, as will be discussed further in this study, the assumptions presented in the Prospective Study exceed the available amount of sustainable biomass, and thus don't comply with sustainability criteria.
- Electricity interconnection capacity plays a large role in any scenario for Belgium. Currently there is about 3500 MW of interconnection available to support the Belgian power system. For the future, the plans and scheduling by Elia has been followed in the scenario: 1000 MW on the Northern boundary by 2016, 1000 MW for the Nemo cable to Great Britain by 2018, and 1000 MW for the Allegro line to Germany by 2019.
  Based on discussions with Elia, it has been assumed that the full capacity of these new interconnections will be available to support the system.
- Electricity demand and peak power assumptions have been based on Synergrid and Elia data (for the historical values), and on the evolutions assumed in the Prospective Study for the future (0.76% growth of final consumption for period 2010-2030, and peak power of respectively 14 860 MW, 15 140 MW and 15 730 MW for the years 2020, 2025 and 2030).
- For the available amount of flexibility in the system, no information is given in the Prospective Study. The flexibility that is in our power system today has been estimated to be roughly 4% of peak power in Belgium, based on a survey by Febeliec, Elia and Energyville[12]. It has been assumed for the Reference scenario that demand flexibility does not further increase compared to today (stays at about 4% of the peak power).

2.2.2 The Alternative scenario

This study proposes an Alternative scenario to analyse the possibilities for the Belgium power system. Apart from giving estimations of absolute indicators such as the amount of investments and subsidies required, the Alternative scenario is mainly meant to show what is possible in Belgium, how this solution would compare to the Reference scenario, and what the benefits are of increased investments in renewables and energy efficiency to the Belgian power system.

Table 2 provides an overview of the installed capacities per technology in the Alternative scenario. The main differences with the Reference scenario are the following:

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[12] Febeliec, Elia & EnergyVille, Summary Results Demand Response Survey, 2013, Available online http://www.febeliec.be/data/1385111565Elia%20Febeliex%20EnergyVille%20Demand%20Response%20Survey%20results%20-%20public%20version.pdf

- The alternative scenario does take the outage of the two nuclear plants (Doel 3 and Tihange 2) into account. To ensure that the import capacity is not exceeded by the need for energy in Belgium, the full load hours of gas have been altered to make up partly for the loss of nuclear power.
- As shown in Table 2, the Alternative scenario assumes a more ambitious scenario for solar PV and onshore wind.
- The Alternative scenario respects sustainability criteria for biomass and has therefore a significantly lower biomass capacity than in the Reference scenario.
- A more extensive investment in energy efficiency measures is assumed, which limits the increase in energy demand significantly.
- The amount of flexibility available is increased significantly. For this assumption, a reference of the European Commission has been used[13], where they estimate flexibility to represent 10% of peak demand in 2020 and a doubling of that by 2030.
- Because of the renewable energy scenarios and the flexibility assumptions, less CHPs are needed.

The following paragraphs explain the assumptions made for renewable energy in more detail.

Table 2: Installed capacities in the Alternative scenario

Electricity Demand scenario	2010	2020	2030	
Gross Final Consumption	90 513	92 719	94 142	GWh
Peak demand	13 845	14 860	15 730	MW

Capacity scenario	2010	2020	2030	
Nuclear	5 926	3 046	0	MW
Coal	950	0	0	MW
Peak Units	491	1 500	1 500	MW
Gas - CCGT	4 761	5 061	7 000	MW
Gas - CHP	1 848	2 557	3 265	MW
Biomass	618	1 138	1 296	MW
Wind - onshore	691	3 545	7 544	MW
Wind - offshore	195	2 200	3 800	MW
Solar PV	1 055	7 431	13 431	MW
Hydro	112	157	157	MW
Geothermal	0	4	60	MW
Pumped Hydro Storage	1 307	1 307	1 307	MW
Import	3 500	6 500	6 500	MW
Demand Flexibility	504	1 486	3 146	MW

Assumptions for renewable energy in the Alternative scenario

Renewable energy is an important part of the energy future for Belgium, as it is for the world as a whole. Fossil fuels are a limited resource, make the country dependent on - mostly unstable- countries, hold risks of price volatility and price increases, and cause money leaking out of the Belgium economy. Moreover, the emissions from burning them cause climate change and damage people's health.

[13] European Commission, 'Incorporing demand side flexibility, in particular demand response, in electricity markets', Commission Staff Working Document, Accompanying the Communication on 'Delivering the internal electricity market and making the most of public intervention', Brussels, 5 November 2013, SWD(2013) 442 final, Available online http://ec.europa.eu/energy/gas_electricity/doc/com_2013_public_intervention_swd07_en.pdf on page 3 and footnote number 8.

Together with the clients and basing on existing studies and the work of ODE-EDORA, the renewable energy scenario for electricity as presented in Table 2 and more visually in Figure 2 has been put forward.

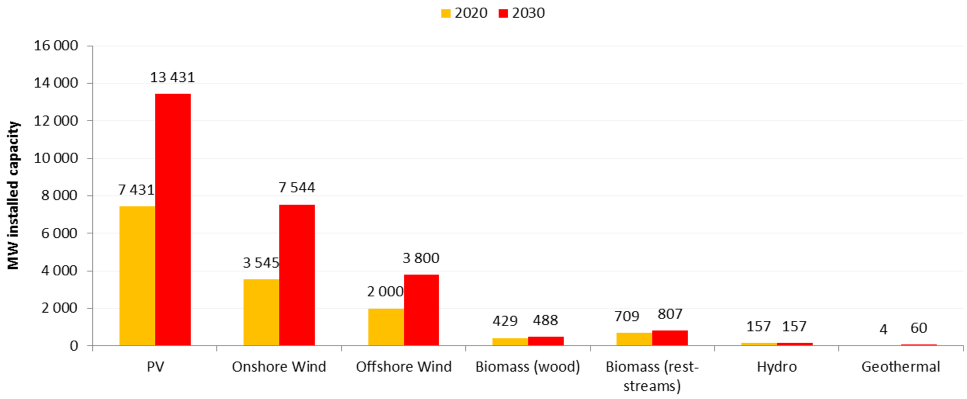

Figure 2: Installed renewable energy capacity scenario for 2020 & 2030 in the Alternative scenario

- For **PV**, this comes down to an annual installation of 600 MW, which is more than 50% less than what has been installed in the record year 2011. At this rate the installed capacity would be 7431 MW in 2020 and 13431 MW in 2030. A medium PV scenario is also developed with an installation of 5031 MW in 2020 and 8031 MW in 2030, equivalent to an installation rate of 300 MW per year. To test the impact of the learning curve of PV, some non-linear scenarios are evaluated. This study assumes furthermore that 25% of this capacity are large systems, and 75% are small systems.
- For **onshore wind** the scenario is based on a scenario by ODE-Edora in a report by Deloitte[14]. It assumes an annual installation rate of 319 MW until 2020 which increases to 400 MW until 2030. This would lead to an installed capacity of 3545 MW in 2020 and 7544 MW in 2030. A medium scenario is also developed with 2700 MW in 2020 and 5000 MW in 2030.
- For **offshore wind** most scenarios in literature[15] assume a potential of 3800 MW by 2030. This potential assumes that a second zone is developed on top of the 2000 MW in the first designated zone.
- The **hydro** scenario is based on the REPAP 2020 report[16] and on a best guess from Greenpeace, while the **geothermal** scenario uses a test phase of 4 MW by 2020 as listed in the NREAP and a development of 60 MW by 2030 based on the REPAP report.
- Today, the installed capacity for **biomass**[17] is almost as high as the capacity figures presented in the scenario in Figure 2. When taking into account sustainability criteria, the total possible

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[14] Macro-economic Impact of the Wind Energy Sector in Belgium, Deloitte, December 2012

[15] E.g. Commission Energy 2030, Belgium Energy Challenges Towards 2030, June 2007

[16] REPAP 2020 (Renewable energy policy action paving the way towards 2020) is a project supported by the European Commission under the Intelligent Energy Europe framework. One of its objectives was to ensure that the National Renewable Action Plans were ambitious enough.

capacity for electricity production from biomass in Belgium is between 1100 and 1500 MW (depending whether the biomass only comes from Belgium or whether also European import is used). The following paragraph provides more details about this calculation.

Note that the above explanations mention a base scenario and some sensitivity scenarios. In order to keep this publication focused and limit it to the essential, not all of the results of the sensitivity analysis are mentioned and discussed.

Available sustainable biomass for electricity production

Our scenarios started from the availability of sustainable wood and rest streams. Following the strict scenario in a recent study commissioned by EEB/Birdlife[18], the availability of indigenous wood in Belgium is limited to ~4 million m³. Taking into account an average energy content and density, there is about 11 TWh of indigenous wood available. The study also mentions that 25% of the available wood can be used for energy purposes. The rest can be used for industrial applications.

To maximize the useful energy production from biomass, it is best to use these 25% in CHPs since these are more energetically efficient than a separate production of electricity and heat. By assuming a CHP with an electrical efficiency of 30% and 5000 full load hours, this leads to an installed capacity of about 160 MW.

A sensitivity scenario takes European import into account and assumes that the whole European potential of sustainable wood is divided among the member states based on the electrical consumption. In this sensitivity scenario, an installed capacity of 590 MW would be possible for woody biomass CHPs in Belgium.

Next to the wood residue there are also rest streams that can be used to produce energy. Based on data from OVAM (extrapolated for Belgium assuming Flanders represents 60%) and with the same assumptions as above, an additional capacity of about 950 MW could be installed. The total capacity would thus equal about 1110 MW electrical, or about 1540 MW electrical in the European biomass scenario[19] .

The biomass scenario in Table 2 and Figure 2 assumed a medium scenario between Belgian availability and European import.

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[17] Including the Max Green plant which recently stopped operation because of uncertainty about the sustainability of its fuel and its eligibility for support.

[18] Forest biomass for energy in the EU: current trends, carbon balance and sustainable potential, IINAS, EFI & JR for Birdlife, EEB and Transport & Environment, to be published in May 2014

[19] Assuming a thermal efficiency of 50%, this represents a thermal capacity of about 1800 MW or 2500 MW in the European biomass scenario.

2.3 OTHER IMPORTANT ASSUMPTIONS

2.3.1 Energy price scenarios

Electricity price

The electricity price is a crucial factor. It has the largest influence on required subsidies. For this study, we analysed many other studies in order to find references for electricity price scenarios but with limited success. The few scenarios for electricity prices we did find, vary significantly.

Moreover, in order to be coherent, electricity price scenarios need to be linked in some way to fuel price scenarios since these fuels serve as the input for electricity production.

For these reasons, we have developed two main electricity price scenarios based on the fuel price scenarios (any other scenario can be easily modelled), starting from respectively the selected gas and coal price scenarios, the CO_2 costs, and an estimation of OPEX costs. In short, these two scenarios are calculated as follows:

- Price gas / efficiency gas plant (55% assumed) + CO_2 costs gas + OPEX gas
- Price coal / efficiency coal plant (42% assumed) + CO_2 costs coal + OPEX coal

Today, in the European context and with the currently low CO_2 prices, coal comes before gas in the merit-order and the electricity price is therefore based on the coal price (2nd scenario). However, in the future, it is expected that the European system will move more towards gas (1st scenario).

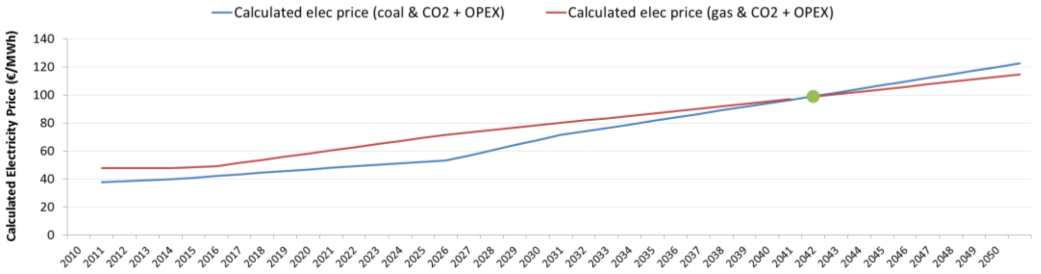

Figure 3: Comparison of the two main electricity price scenarios in €/MWh - Calculation based on fuel costs + CO_2 costs + OPEX

For several reasons[20], the 1st scenario has been used as the base assumption in what follows. This leads to a higher electricity price assumption, in particular for the first years. However, it seems to be more reasonable for the future. Moreover, it is more in line with scenarios from other studies.

The 2nd scenario is also calculated as a sensitivity analysis in this section.

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[20] A first important reason is that the earlier than expected forced shutdown of the nuclear plants Doel 3 and Tihange 2, will drive up power prices and lead to more full load hours for gas in Belgium. A second reason is the assumption that, if Europe is serious about its Climate policy, CO_2 prices will need to rise at some point in the coming years in order to bring gas before coal in the merit-order. Moreover, the future European power system with large amounts of renewables will work best with a flexible gas-based backup generation rather than with a less-flexible coal-based generation portfolio.

Please note that in the summary table (Table 3), three different scenarios for the electricity price are mentioned. As will be explained in Section 3.1.1, this is to analyse the impact of the so-called merit-order effect (i.e. lower price for variable renewables since they have zero-marginal cost).

Fuel and CO_2 Prices

The fuel price scenarios used in this study have been based on publications by others. For each vector, several scenarios have been analysed in the model in sensitivity analysis, but since not all results are discussed in this report, only the main scenarios are mentioned here.

The following bullet points explain on what the main fuel price scenarios are based for each vector. The data can be found in Table 3 below for the years 2010, 2020 and 2030).

- **Gas:** The gas price scenario is based on the assumptions from the 2014 Prospective Study (p.28), converted to €/MWh with the relevant exchange rate[21] and corrected for inflation. The resulting prices are well in line with other scenarios, such as the prices used by VITO in the 100% RE study, the Impact Assessment for the European Energy Roadmap by the European Commission[22] and the scenarios by Fraunhofer ISI[23] (which are a bit higher).
- **Oil:** As the gas price, the oil price scenario used is also based on the oil price scenario in the 2014 Prospective Study, converted with the same exchange rate and corrected for inflation. The chosen scenario is will in line with other scenarios as those from VITO and the European commission.
- **Biomass:** Since biomass is a quite diverse term with a broad scala of fuels, it is difficult to put a price on it. In this study, the price for biomass is based on the futures for industrial wood chips as published by Argus Media[24], and a price increase of 1% per year is assumed.
- **Coal:** Also the coal prices are taken from the Prospective Study, but these are merely mentioned for comparison since they are not used in any of the scenarios.
- **CO_2:** The CO_2 price scenario has been based on a scenario by the European Commission. The resulting prices are reasonable (and even on the lower end low) compared to other scenarios by PointCarbon[25] , NEP and Prognos (mentioned in the Fraunhofer ISI study),

[21] The study refers to $2008. The average exchange rate for 2008 has been used for the conversion = 0.68 dollar per euro.

[22] European Commission, Energy Roadmap 2050, Impact Assessment, December 2011, Available online http://ec.europa.eu/energy/energy2020/roadmap/doc/roadmap2050_ia_20120430_en.pdf

[23] Fraunhofer ISI, Levelised Cost of Electricity Renewable Energy Technologies, November 2013, Available online http://www.ise.fraunhofer.de/en/publications/veroeffentlichungen-pdf-dateien-en/studien-und-konzeptpapiere/study-levelized-cost-of-electricity-renewable-energies.pdf

[24] Argus media, Weekly biomass markets news and analysis, Argus Biomass Markets, Issue 14-013 page 3, Wednesday 2 April 2014, Available online http://media.argusmedia.com/~/media/Files/PDFs/Samples/Argus-Biomass.pdf

[25] http://www.pointcarbon.com/aboutus/pressroom/pressreleases/1.2584441

Summary of prices used in the Reference and the Alternative scenarios

To make the comparison relevant, the same energy price scenarios have been used for both scenarios. They are summarized in Table 3. Sensitivity analyses on these scenarios have been performed to analyse the impact of variations (see Section 3.1.1).

Table 3: Summary of energy price scenarios for the Reference and Alternative scenario

Price scenario	2010	2020	2030	
Electricity (Average)	48	60	80	€/MWh
Electricity (Av. Fluctuating sources)	48	60	80	€/MWh
Electricity (Av. Non-fluctuating sources)	48	60	80	€/MWh
Gas Price	21	27	33	€/MWh
Oil Price	37	42	50	€/MWh
Biomass Price	38	41	45	€/MWh
Coal Price	10	13	14	€/MWh
CO2 Price	5	10	35	€/tonne

2.3.2 Investment Parameters

In order to compare on an equal basis, the investment parameters used are the same for the Reference scenario and the Alternative scenario. They have been defined based on the research done by 3E in previous studies as mentioned above, complemented with updated info (e.g. CAPEX costs, OPEX costs, learning effects per technology, efficiency improvements, etc.) from recent studies (e.g. VITO[26], Fraunhofer ISI[27], IEA[28], Kema & McKinsey[29], RAP[30] & Agora Energiewende[31]).

The final assumptions made in the framework of this study are shown below:

- Table 4 explains what capacity is used per technology for the calculations in the Investment model.
- Table 5 shows the CAPEX assumptions and their evolution over the next years.
- Figure 4 shows the WACC and lifetime assumptions.

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[26] Vito, Towards 100% renewable energy in Belgium by 2050, April 2013

[27] Fraunhofer ISI, Levelised Cost of Electricity Renewable Energy Technologies, November 2013, Available online http://www.ise.fraunhofer.de/en/publications/veroeffentlichungen-pdf-dateien-en/studien-und-konzeptpapiere/study-levelized-cost-of-electricity-renewable-energies.pdf

[28] IEA and OECD/NEA, Projected Costs of Generating Electricity: 2010 Edition, 2010, Paris

[29] ECF Roadmap 2050, Available online http://www.roadmap2050.eu/project/roadmap-2050

[30] RAP, Power Perspectives 2030 – On the Road to a Decarbonised Power Sector, March 2011

[31] Marco Wunsch et al. Positive Effekte von Energieeffizienz auf den deutschen Stromsektor, Study for Agora Energiewende, March 2014

Table 4: Assumed capacity of each unit as input for the investment model in MW

Installation size used	MW
PV < 10kVA	0.01
PV > 50 kWc	0.25
Onshore wind	2.3
Offshore wind	300
CHP Gas	0.75
CHP Biomass	12.5
Hydro	0.05
Geothermal	5
Nuclear	1 008
CCGT	400

Table 5: Overview of CAPEX assumptions in €2014/MW

CAPEX scenario	2013	2020	2030	
PV < 10kVA	1 640 000	1 092 240	967 600	€/MW
PV > 50 kWc	1 300 000	865 800	767 000	€/MW
Wind P > 1 MW	1 500 000	1 438 500	1 390 500	€/MW
Offshore Wind	3 800 000	3 214 800	2 888 000	€/MW
CHP gas 500 < 1000 kW	1 000 000	1 000 000	1 000 000	€/MW
CHP Bio.sol > 5000 kW	3 900 000	3 900 000	3 900 000	€/MW
Hydro 10kW<P<100kW	6 000 000	6 000 000	6 000 000	€/MW
Geothermal	6 000 000	4 166 000	4 081 500	€/MW
Nuclear	5 800 000	5 800 000	5 800 000	€/MW
CCGT	800 000	800 000	800 000	€/MW

WACC & Lifetime scenario	WACC	Lifetime
PV < 10kVA	7%	20
PV > 50 kWc	7%	20
Onshore Wind	8%	20
Offshore Wind	13%	20
CHP gas 500 < 1000 kW	12%	20
CHP Bio.sol > 5000 kW	12%	20
Hydro 10kW<P<100kW	5%	20
Geothermal	11%	25
Nuclear	10%	40
CCGT	12%	20

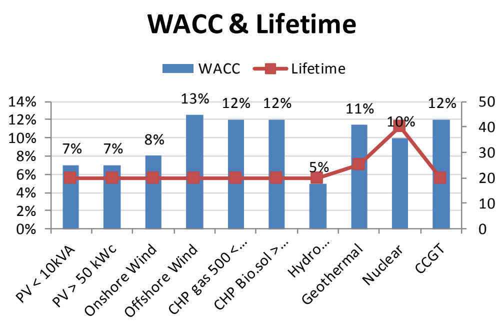

Figure 4: WACC and Lifetime Assumptions per technology for the main scenarios

3 RESULTS AND SENSITIVITY ANALYSIS

The results from the model have been structured in three key topics as shown in Figure 5.

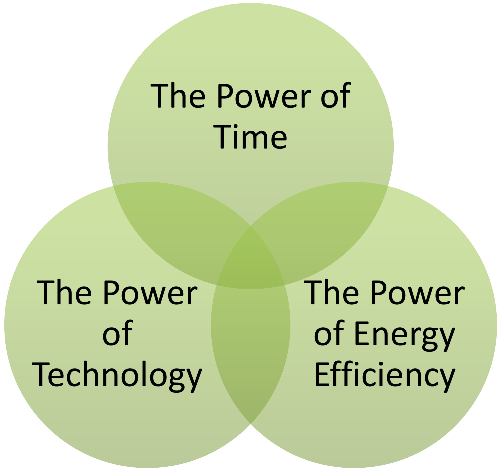

Figure 5: Three key topics of the study

These three topics comprise the key results of the study as well as the key conclusions. They can be explained as follows:

- **The Power of Time:**
  Time is crucial in the transition of an energy system. The alternative scenario developed in this study can work perfectly for the period up to 2030, meeting peak power and demand criteria while also reaching the renewable energy targets. However, short-term issues may arise due to a number of reasons, and appropriate measures need to be taken.

- **The Power of Energy Efficiency**:
  Energy efficiency is the first most important resource. The old building stock is an asset because there is still a large potential to improve efficiency. Moreover, there are ample other benefits. Energy efficiency is crucial but will not be sufficient to meet the challenges faced by the electricity sector in the next five years. Specific programs for measures with peak power reduction potential, such as relighting, need to be developed. Energy efficiency in buildings has been analysed in detail, but this work will be the subject of a later publication.

- **The Power of Technology**:
  With the current low electricity prices on the European electricity markets, no technology is cost-beneficial if the investment is included. However, renewable energies mature and a lot is expected to change in the coming years. Investment costs for renewable technologies are further decreasing, while fuel prices and electricity prices are expected to increase in the future. Wind will become the cheapest technology by 2017 and PV is expected to take over from 2019 onwards. All of this has a major influence on the optimal choices for Belgium, and will significantly impact the costs and required subsidies.

3.1 THE POWER OF TIME

As will be shown below, a first look at the results of the completed model clearly shows the importance of time. Most of the possible measures to reduce energy demand, reduce emissions and increase the use of renewable energy need time before they have an impact. However, this long time lag also means that – in order to have the desired impact – a clear vision and goals need to be defined as soon as possible.

In the electricity sector, the importance of time is also very clear. While for the period up to 2030 a lot is possible and the development of an ambitious scenario seems reasonable and realistic, in the next five years Belgium will face a more stringent challenge in terms of peak capacity and energy delivery.

Both periods pose different challenges that must be solved:

- For the period up to 2030, these concern the energy mix, the contribution of renewables, the total investment costs and the amount of subsidies required to make it happen[32]. Other important challenges are total consumption and the associated emissions.
- For the next five years, these concern how peak consumption can be delivered, what can be done to ensure enough capacity and energy, how Belgium can react to the unplanned outages of two nuclear plants, etc.

3.1.1 The period up to 2030

The main task of this project was to look at scenarios for Belgium's energy future towards 2030. As mentioned above, there is enough time between now and 2030 to reach the targets and transform the Belgian electricity system. However, in order for this to happen, it is crucial that several important steps and decisions are taken today.

This section is therefore also the main section of this report. It explains the main results of modelling for the period up to 2030. It deals with the contribution of renewable energy, gives an indication of the type of installations that will deliver the peak power and energy demand, lists which new installations would be required to make this happen and provides estimations of the total investment costs and required subsidies. Moreover, sensitivity analyses will show how sensitive these results are to the impact of e.g. electricity prices, and will also go into more detail on the impact of net metering.

Renewable Contribution

Figure 6 shows the contribution of renewable energy in the electricity sector for both scenarios. The Reference scenario only sees modest renewable energy development in the future, and results in a contribution of 23% of the electricity production in 2020 and 28% in 2030. Please note that with this scenario, it will be difficult to reach the European renewable energy target for Belgium (13% of final energy consumption in 2020) if sustainability criteria for biomass are respected.

The Alternative scenario makes it possible to reach the target and even significantly exceed it. The percentage of renewable energy in electricity production is expected to reach 32.8% in 2020 and 54%

[32] In this study, the words 'required subsidies' mean for some technologies the sum of two things: First of all, and for all technologies, it means the normal operational subsidies that are provided per produced MWh on top of the electricity value. Secondly, for some technologies (<10 kVA) it also takes into account the additional value of the net metering policy.

in 2030, despite a much lower contribution from biomass which is compensated by more wind power and solar PV.

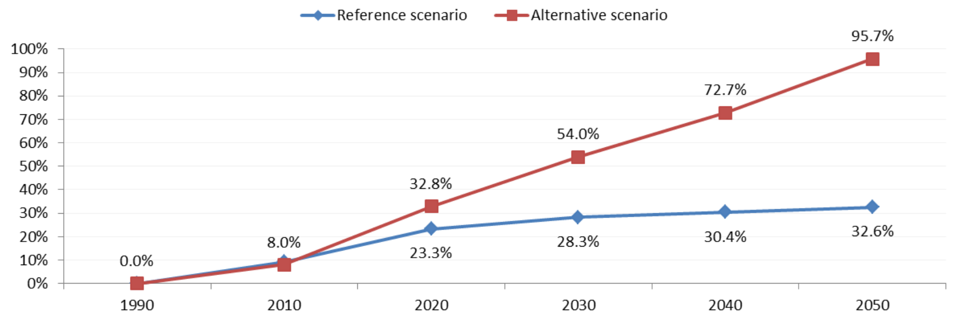

Figure 6: Contribution of renewable energy in the electricity sector for the Reference scenario and the Alternative scenario

The electricity system – peak contribution and energy provision

This section looks at how the Belgian electricity system can deliver peak power and fulfil energy demand. An overview of the Alternative scenario is provided in Figure 7 and
Figure 8. Since these figures may appear complex, the following paragraphs provide some explanation:

- **Figure 7** gives an overview of the installed capacity per technology and compares this to peak demand and the required dispatchable capacity. The objective of this graph is to quickly show whether there is enough capacity to meet peak demand in Belgium.
  - The grey line is peak demand (when there would be no additional capacity), as described in Chapter 2. It rises steadily and is based on assumptions made in the 2014 Prospective Study[33].
  - The yellow line represents the 'residual peak demand' that needs to be met by dispatchable capacity, i.e. the peak demand that is left after:
    - All available flexibility is used
    - The capacity credit[34] of variable renewable energy sources has been subtracted
    - 21% reserve margin has been added[35]

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[33] Studie over de perspectieven van elektriciteitsbevoorrading tegen 2030, FOD Economy & Planbureau, Draft, August 2013, Available online
http://economie.fgov.be/nl/ondernemingen/energie/elektriciteit/Prospectieve_studie_elektriciteit/#.U6l2cv5j3Eg

[34] The capacity credit is the amount of firm capacity that can be replaced by variable renewable energy sources. The idea is that no backup capacity is needed for this percentage of the renewable energy capacity when integrated in the grid. The capacity credit decreases with the overall penetration of renewables in the grid.
In this project, a low and conservative capacity credit of 5% is taken into account. More research is needed on the Belgian case to improve this initial assumption and detail it further.

[35] This assumption is taken from the 2014 Prospective Study in which the 'system reserve margin' is defined as the ratio between the 'guaranteed available capacity' and peak demand. The FOD assumes that a factor of at least 1.21 is needed to guarantee the reliability of the system.

- The installed capacities of all different technologies have been listed starting with the 'dispatchable capacities': Conventional technologies (i.e. nuclear, coal, gas CCGT, gas CHP and peak units), biomass, electricity import capacity and pumped hydro storage.
- The variable renewable energy technologies come on top of these.
- As long as the yellow line does not go above the grey area for pumped hydro storage, the system is assumed to be able to cope with peak demand.

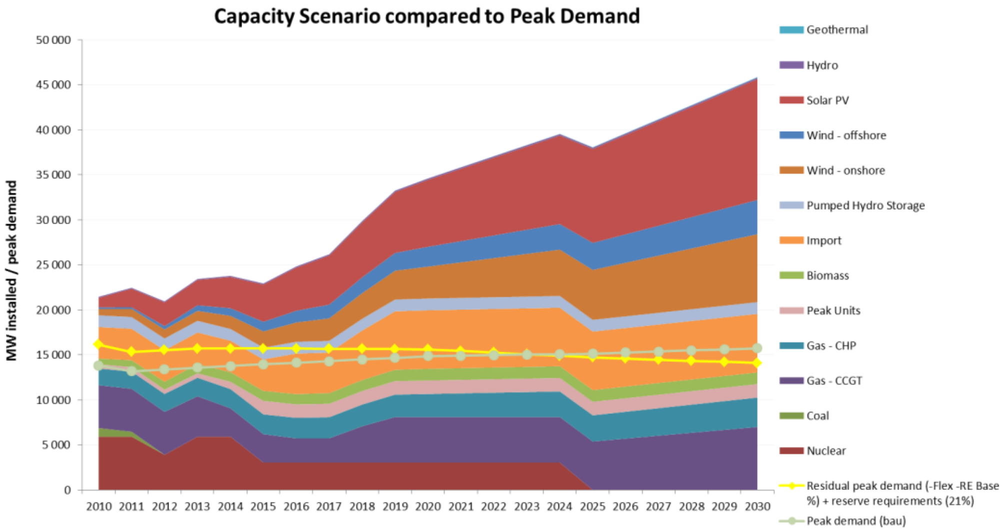

Figure 7: Capacity scenario for the Belgian energy system, compared to peak demand (without flexibility) (grey line) and required dispatchable capacity (yellow line). The areas above the grey area for pumped hydro storage show the renewable capacity from variable sources. The yellow line for required dispatchable capacity should thus stay below the top of the grey area to avoid issues with peak demand provision.

- **Figure 8** gives an overview of the energy production by each technology, along with a comparison to annual energy demand. The objective of this graph is to quickly show whether there is enough energy production in order to meet the annual total electricity demand in Belgium.
  - The yellow line represents the annual electricity demand, as described in Chapter 2.
  - The contribution in electricity production of each technology is shown with the coloured areas for the different years up to 2030.
  - The difference between the sum of electricity production of all technologies and annual demand is assumed to be covered by electricity import/export. A control formula in the model ensures that the amount of import/export stays within the boundaries of available interconnection capacity.

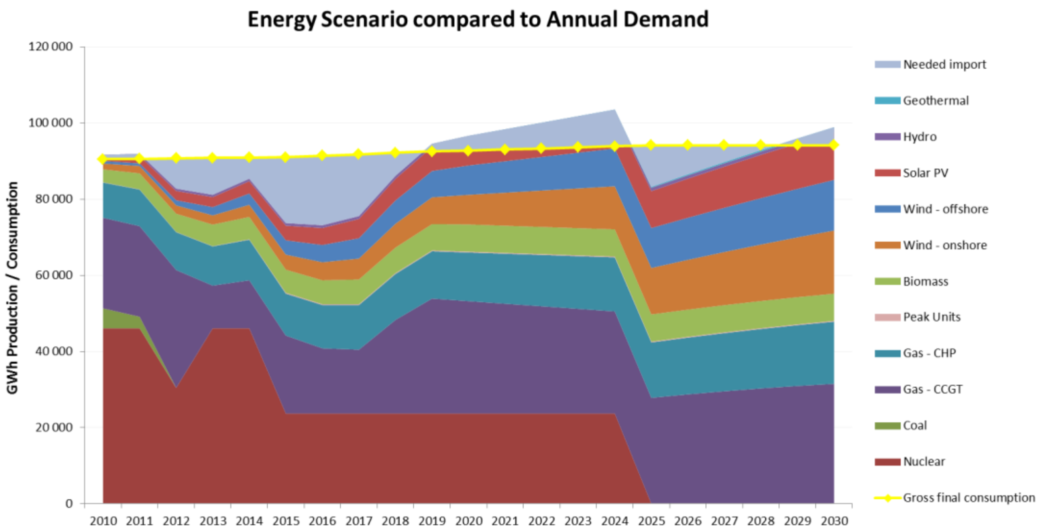

Figure 8: Energy scenario for the Belgian electricity system, compared to total annual demand (yellow line). The grey area just above or below the yellow line is the required import/export of electricity to meet annual demand.

Both Figure 7 and Figure 8 show that the Alternative scenario meets the criteria of reaching peak demand and delivering annual electricity demand provision. There is enough firm capacity (and flexibility) to meet peak demand even when wind and solar energy production are minimal, and there is enough energy production (and possibility to import if needed) to meet the total electricity demand.

As explained above, peak demand without flexibility continues to rise. Increasing flexibility in demand (assumptions based on work by the European Commission[36]) and increasing interconnection result in a significant reduction of the required backup capacity.

The figures also show that it is perfectly possible in the Alternative scenario to replace nuclear energy in Belgium during the period up to 2030. Renewable energy sources are able to add significantly to energy supply, and additional CCGT plants can help when there is too little wind and sun. Compared to the Reference scenario based on the Prospective Study (~10 GW CCGT), the Alternative scenario indicates that it should be possible to have a working system with a total capacity of about 7 GW of CCGT units instead of more than 10 GW.

The energy mix for 2020 and 2030 is shown in Figure 9. In 2020, nuclear energy still provides about 25% of total electricity produced in Belgium, even with Doel 3 and Tihange 2 closed. By 2025 nuclear energy is phased out completely and by 2030 it is replaced in particular by more wind energy, more solar energy, and more CHPs.

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[36] European Commission, 'Incorporing demand side flexibility, in particular demand response, in electricity markets', Commission Staff Working Document, Accompanying the Communication on 'Delivering the internal electricity market and making the most of public intervention', Brussels, 5 November 2013, SWD(2013) 442 final, Available online http://ec.europa.eu/energy/gas_electricity/doc/com_2013_public_intervention_swd07_en.pdf on page 3 and footnote number 8.

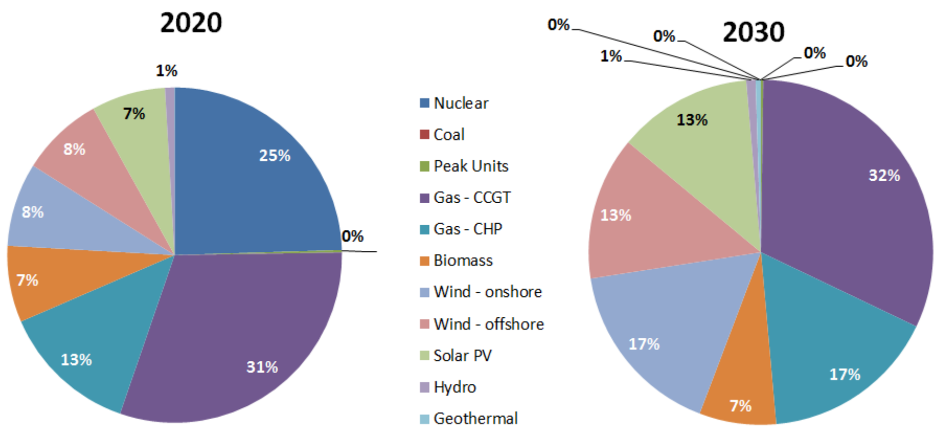

Figure 9: Installed capacity mix in the Alternative Scenario (% of installed capacity)

New installations and related costs

This section looks at the additional capacity per technology that needs to be installed in the Alternative scenario for the period up to 2030. An overview is given in Table 6.

The renewable energy scenarios have already been described in detail in Chapter 2. More details can be found in that section.

Taking into account published plans for shutdowns and mothballing in the next few years, there is an additional need for 4.3 GW from new CCGT plants and about 1.2 GW from new CHPs. Nuclear shut-down proceeds as planned and no new coal plants are built. 3 GW of new interconnection capacity is needed (based on Elia's plans and scheduling)[37].

Taking into account published plans for shutdowns of peak power plants, there will be about 500 MW of peak power plants available in 2015. In order to meet peak demand in the next few years an additional 1 GW of peak power plants has been added to the scenario[38]. More about this can be found in Section 3.1.2.

[37] Note that there are often discussions on the real available amount of import capacity vs the published maximum capacity of the planned interconnection cables. Based on discussions with Elia on this topic, it is assumed that interconnection is very important to Elia and that substantial efforts will be made to ensure maximum capacity is available at all times.

[38] Peak plants have not been modelled in the investment model and the costs are therefore not integrated in tables appearing later in the report. As will be discussed later and in Section 4.1.2, there are other possibilities for this additional 1 GW.

Table 6: Installed capacity per technology for 2030 in the Alternative scenario

	Installed capacity 2030 (MW)	To be built still (MW)	Comments
Biomass	1 296	269	Assuming Max Green is still there
Wind - onshore	7 544	6 446	
Wind - offshore	3 800	3 175	
Solar PV	13 431	10 623	
Hydro	157	45	
Geothermal	60	60	
Nuclear	0	0	
Coal	0	0	
Peak Units	1 500	1 009	Assuming shutdowns as published
Gas - CCGT	7 000	4 309	Assuming shutdowns as published
Gas - CHP	3 265	1 204	
Import	6 500	3 000	According to Elia Schedule

To develop this scenario an investment of about 43.85 bn € would be needed (Figure 10 and Figure 11). The bulk of this investment is for solar PV, offshore wind and onshore wind.

In terms of subsidies, about 12.16 bn € is needed to make the scenario happen. The largest portion of this goes to offshore wind. Note that the required subsidies for PV are relatively low, even without taking net metering into account. With net metering, small PV plants are already profitable today. This is further explored in a sensitivity analysis below. Subsidies for larger PV are only needed in the first years.

Please note that the table in Figure 10 also mentions 'subsidies' for CCGTs. With the current gas & electricity prices and the low full load hours, CCGTs are not profitable[39]. The model treats them in the same way as renewables and calculates the missing money to guarantee the required return on investment.

	Costs (M€)	
	Investment	**Subsidies**
Nuclear	0	0
Coal	0	0
Gas - CCGT	-4 098	-2 221
Gas - CHP	-1 417	0
Biomass	-1 235	-2 063
Wind - onshore	-10 915	-1 003
Wind - offshore	-11 951	-5 632
Solar PV	-13 637	-1 006
Hydro	-287	-207
Geothermal	-311	-26
Total	**-43 850**	**-12 158**

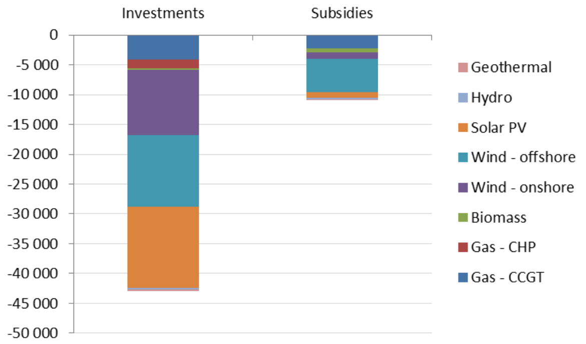

Figure 10: Calculated investment costs and subsidies for the Alternative scenario

[39] Note that it is out of the scope of this study to analyse whether this issue is to be solved and which policy measure can be used to do this (e.g. capacity mechanism, subsidies, CO_2 price increases etc.)

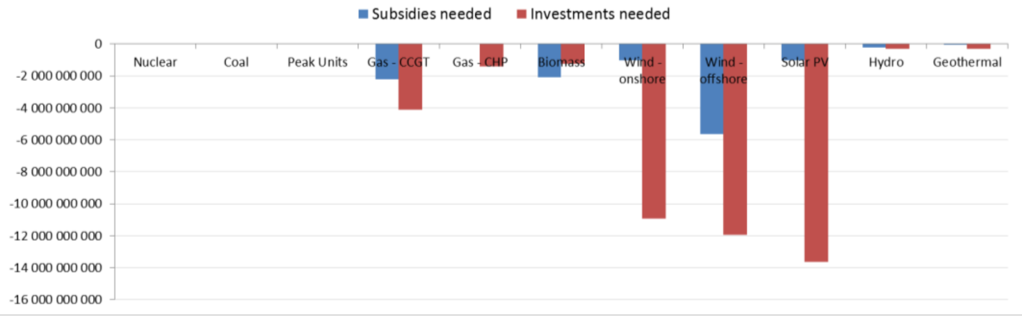

Figure 11: Overview of subsidies & investments needed in € (negative = subsidies needed)

Subsidies don't need to be provided all at once. They can be spread over several years based on the assumptions mentioned in Chapter 2. Note that this figure only shows subsidies for units installed in the period 2014-2030. The peak in subsidies for these installations is expected in the year 2027 (~0.7 bn € annually).

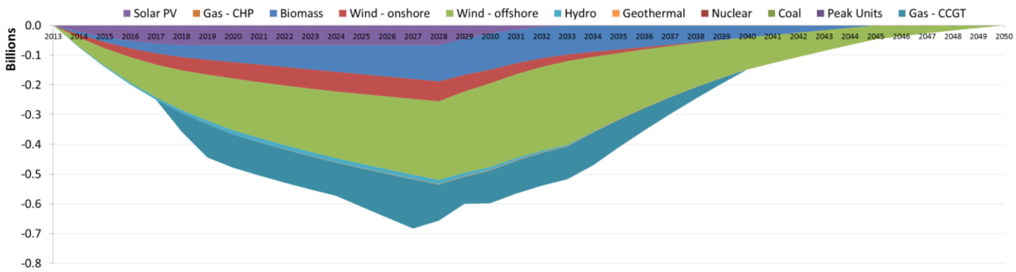

Figure 12: Total subsidies required in each year in billion €
(for electricity production units installed between 2014 and 2030)

Comparison to the Reference scenario

The results of the Alternative scenario have been compared to the results of the Reference scenario based on the scenario Nuc-1800 from the Prospectieve Studie of the FOD Economy and the Federal Planning bureau (Table 7).

The main differences between both scenarios are that the Reference scenario deals with a higher electricity demand (less reduction of demand), assumes significantly more electricity production by biomass, and assumes much more gas CCGT's in spite of renewable energy[40].

The Alternative scenario needs about double the amount of investments than the Reference scenario[41]. More important is the subsidies that are needed in order to give a fair return on investment to all installations in the second column.

[40] Note also that the nuclear capacity scenarios are different: the Reference scenario does not take into account the outages of Doel 3 and Tihange 2. Since both scenarios take the nuclear phaseout into account, this doesn't have an impact on the longer-term.

[41] These are investments that come from third parties, that might give a boost to economic activity.

Interestingly, the required subsidies in the Reference scenario are higher than in the Alternative scenario. This is mainly because of the high biomass fuel prices and the assumption made on the CAPEX (only mid-sized CHPs). The Prospective Study assumes much more biomass but without meeting sustainability criteria. Compared to the Alternative scenario, the required subsidies for biomass grow from 2 to more than 6 bn € in the Reference scenario.

Table 7 also shows the total fuel costs for the electricity production in each scenario, calculated in $€_{2014}$ based on the fuel cost assumptions and with a discount factor of 4%. Due to the more ambitious development in renewables in the Alternative scenario, the fuel costs are considerably lower than in the Reference scenario. Furthermore, as will be shown further in this report, the investment in renewables also reduces the risks of fuel price spikes and increases.

Even if the required subsidies for biomass would be left out of this comparison, the total costs for society of the alternative scenario would still be lower than the reference scenario thanks to the higher savings in fuel costs.

Table 7: Overview of Investment costs and required subsidies for the Reference scenario and the Alternative scenario

	Investment costs (M€)	Required subsidies (M€)	Total fuel costs (M€, 4% discount factor)	
			by 2030	by 2050
Reference scenario	-21 953	-14 125	-46 781	-88 597
Alternative scenario	-43 730	-12 154	-41 599	-58 887

Impact of electricity price

As mentioned in Chapter 2, the electricity price scenario is one of the most influencing parameters. In the base case, an electricity price scenario based on the gas price + CO_2 price + OPEX costs is used. In this section we analyse the required subsidies when the electricity price is significantly higher or lower. For a higher electricity price scenario, the reference case from the EC Roadmap 2050 is used[42]. For a lower electricity price scenario, both the calculated scenario based on the coal price and a scenario with inflation only are used as sensitivities.

- With higher electricity prices taken from the European Commission's 2050 roadmap (up to 102 €/MWh in 2020 and 178 €/MWh in 2030), the required subsidies drop by 75%.
- With the lower electricity price scenario based on the coal price + CO_2 price + OPEX costs, required subsidies rise by 29% compared to the base case.
- With lower electricity prices (no growth but inflation), the total required subsidies amount to 29.8 bn €, or 145% higher than in the base case.

These results are summarized in Table 8.

[42] Energy Roadmap 2050, Impact Assessment and Scenario analysis, European Commission Staff Working Paper, December 2011, Available online http://ec.europa.eu/energy/energy2020/roadmap/doc/roadmap2050_ia_20120430_en.pdf

Impact of merit-order

The above electricity price scenarios assume the same electricity price for all technologies. In reality this is not the case, and the merit-order is used. Technologies with a variable resource, e.g. wind and solar energy, will therefore see lower prices than more flexible technologies that can shift their operation to hours when prices are higher.

These effects ensure that gas plants can run in a more profitable way during the more expensive hours and that renewable energy sources will attract relatively lower electricity prices (and will thus need higher subsidies). This is what happens in real life and can be seen on the markets today. However, it is difficult to assess exactly how much exactly these prices differ. To give an idea of the impact, we take the rough assumption that the price is reduced by 10% for renewables and increased by 10% for non-variable technologies (conventional generation, hydro, geothermal and biomass). In this case, the required subsidies increase by 3.4%. When the base case is the lower price scenario calculated on the coal price, the required subsidies only increase by 1.4% (the reductions in subsidies for non-variable technologies counterbalance the increase in subsidies for renewables). The results are summarised in Table 8.

Table 8: Impact of the electricity price on the required subsidies

	Electricity price for variable generation		Required subsidies (M€)	Increase in %
	2020	2030		
Base case - Calculated gas-based	60	80	12 158	
Higher price - EC Roadmap 2050	102	179	2 994	-75%
Lower price - Calculated coal-based	48	71	15 685	29%
Lower price - No growth but inflation	40	40	29 808	145%
Impact merit-order effect - 10% assumption - starting from gas	54	72	12 566	3%
Impact merit-order effect - 10% assumption - starting from coal	43	64	15 904	1%

Impact of net metering

Under the current practice of net-metering for small-scale PV-installations, the owner receives the same tariff for injecting electricity into the grid as he pays for buying electricity from the grid. Given the sharp decline of costs of PV-systems over the last years, these installations are already today profitable without any subsidies. Under the Alternative scenario, only 78.8M€ subsidies are required for the further expansion of PV till 2030, exclusively for supporting larger PV-systems which inject electricity at a lower tariff. As those larger systems will become profitable from 2017 onwards thanks to further cost reductions of PV-systems, these subsidies are only required till 2016.

If we however include the cost for developing the distribution grid into the tariff for PV generation, the required subsidy for PV-systems would increase to 1.01 bn €. Thanks to further reductions in costs of PV-systems, even small systems will become fully competitive by 2020, even when distribution grid development costs are included.

The above assumes 20% self-consumption for small plants and 56% for larger plants on the roofs of industries & other companies. Self-consumption values the electricity at the consumption price (including grid tariffs and taxes) instead of at the wholesale market price. If this would not be allowed, an additional 1.6 bn € would be needed to support its further development until 2030.

3.1.2 The next five years

The previous section has shown that it is possible to develop an ambitious but feasible energy system in Belgium by 2030, which meets renewable energy targets, meets peak demand and can deliver annual electricity demand.

However, given recent developments in the Belgian electricity system – especially the unforeseen early closure of 2 nuclear power plants (Doel3 and Tihange2), which according the Belgian Energy Secretary of State might never re-start again – a more precise assessment of the short-term security of supply is required, even if the accounting model of 3E was not specifically designed for that purpose.

When looking at the figures of the electricity system (Figure 7 and Figure 8 on page 23), there are some important things to note for the next five years:

- With the unexpected outages of Doel 3 and Tihange 2, the margin on peak capacity (on top of the required 21% margin) will be very low during the period 2015-2017. The figure above even takes into account an additional installation of about 1000 MW of peak plants (e.g. open cycle gas) in 2015. Based on these assumptions, the margin is expected to be around 100 MW in 2015 and around 700 MW in 2016 (provided that the projected growth for all technologies in the scenario materialises).
- Also due to the outage of nuclear plants with a high capacity and high full load hours, serious imports will be needed in the next few years. The system as depicted in Figure 7 is already tight and does not offer a lot of margin. Today most CCGT plants only operate between 1000-2000 hours a year due to low electricity prices. In order to cover the loss of nuclear energy, Figure 7 already assumes that currently existing CCGT gas plants operate at a higher load factor than today. For these gas plants to be profitable, electricity prices should be higher than today on the European electricity market, otherwise import will be preferred.

In the short-term this is clearly a challenge for both peak capacity and energy provision. However, it does not mean that the lights will go out. With the right determination and proper sense of urgency, several measures can be taken to help mitigate the risks. In the scenario as shown in the figures of this report, this issue can be solved by adding short-term peak power capacity (e.g. open cycle gas units), but other measures are equally possible:

- Due to economic and strategic reasons, several perfectly working CCGT power plants are being or are scheduled to be shut-down or mothballed. This of course makes the situation worse. Some power plants (CCGT) scheduled for mothballing might need to stay open (forcibly or with new policy measures – i.e. Strategic Reserve from the Plan Wathelet). If no further plants are mothballed and the current capacity of 4761 MW of CCGT plants is fully available also in the next years, there would be no issue. There would be a margin on the peak capacity of about 760 MW in 2015 and about 2200 MW in 2016.

- Reducing electricity consumption with the focus on peak moments in such a short timeframe is challenging but not impossible. The IEA report ‘Savings in a Hurry’ is full of examples[43], as is the study 3E conducted last year for Greenpeace, BBL, IEW and WWF[44], which mentions a few interesting routes to significant savings. A special focus on re-lighting would be most effective, because the electricity demand for lighting is high during peak hours (between 18-19h). The 3E-study showed that re-lighting in the services sector has a potential to lower the peak demand by 816MW, an equivalent capacity as the nuclear power plants of Doel1 and Doel2 combined (866MW), which are scheduled to be closed in 2015.
- There is clearly a need for more flexibility in the Belgian power system. Shifting demand to times of low demand and shifting supply to times of high demand can significantly improve the situation. Measures are already being taken today, but they should be more ambitious and implemented faster.
- The currently available import capacity on the interconnection lines is not equal to the full interconnection capacity. Optimising the use of the Northern interconnection with the Netherlands could increase the total import capacity. Furthermore, by 2018, Elia's investments in interconnection capacity would increase by 3000MW (this is integrated in the scenario). To make sure no further issues arise, for part of this additional interconnection (i.e. the NEMO cable to Great Britain), the onshore grid reinforcement project STEVIN should not be delayed.

The points above fit within a general context that is shared with other EU countries[45]. It is a situation caused by a number of trends. One of the main trends is that low electricity prices are not high enough to attract any new investments, whether conventional or renewable. These low prices are mainly caused by low CO_2 prices, low coal prices and an overcapacity of electricity generation in the European electricity system. Because of low CO_2 prices and low coal prices, coal comes before gas in the merit order and gas plants are today only used for a limited period (~1000-2000 hours a year).

Higher CO_2 prices could partly solve this issue. When the merit-order is changed, gas would once again define electricity prices and there would be no need to mothball operational gas plants. Moreover, electricity in Europe would then be cleaner and it would be easier to meet ambitious CO_2 targets.

3.2 THE POWER OF ENERGY EFFICIENCY

As explained in the Introduction, this study focuses on two sectors, namely the electricity sector, and buildings. Energy efficiency in buildings has been analysed with detailed modelling, both for the residential sector and the tertiary sector.

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[43] Saving Electricity in a Hurry, Update 2011, IEA Information Paper, June 2011, Available online http://www.iea.org/publications/freepublications/publication/name-3996-en.html

[44] Reducing Energy Consumption and Peak Power in Belgium, 3E, January 2013, Available online http://www.greenpeace.org/belgium/Global/belgium/report/2013/PP_PR106150_EEStudy_Presentation_20130115.pdf

[45] E.g. Tim Webb, National Grid Switches to Europe, Business section of The Times, p.38, Wednesday June 11 2014

The results of this work have already been integrated in the explanation of the overall results (Section 3.1). However, for several reasons, it has been decided to split the publication of the study in two parts. The specific results of the work on energy efficiency in buildings will therefore be published only in the next phase. This section will just briefly touch upon the general results as an introduction to what will come later..

Energy efficiency – the Holy Grail for Belgium?

The research confirms that pursuing energy efficiency is crucial for Belgium. Compared with our neighbouring countries, Belgium has an old and thus energy intensive building stock that can be regarded as a 'resource' for reducing energy consumption. There is still a lot of potential for improvement. Moreover, there are numerous other benefits: Energy efficiency measures are relatively cheap compared to other options, improving energy efficiency supports the local economy and keeps the money largely within the country, it creates jobs and energy efficiency techniques have export potential.

Significant reductions possible over time

The study analysed the evolution of the energy consumption in the residential and the tertiary sector for the Alternative scenario, and also makes a comparison with the Reference scenario, revealing that significant savings can be achieved. Further acceleration and intensification of the renovating process should be considered as one of the key drivers to realize these energy savings.

The study also shows that energy reduction is more difficult for the tertiary sector, since this sector and its demand for energy services continues to grow, while the trend in the residential sector is moving towards smaller houses with lower energy consumption.

In both sectors, the demand for electricity does not follow trends in other vectors. It continues to grow because of, among other things, the growth of the number of households and their increasing use of electronic appliances as well as the roll out of heat pumps.

As shown in Table 9, significant reductions in both CO_2 and final energy consumption can be achieved in buildings.

Table 9: Energy and CO_2 reduction scenario in the buildings sector

CO2 reduction vs 1990 levels

	2020	2030	2050
Residential	27%	55%	89%
Tertiary	10%	25%	67%

Energy Reduction vs 2010 levels

	2020	2030	2050
Residential	26%	44%	76%
Tertiary	7%	12%	33%

Specific focus needed: energy efficiency for peak power reduction

In order to support the electricity sector and help mitigate the risks, longer-term efforts can be altered to focus on peak-reduction measures. In this context, 3E has published another study in 2013 on the potential of energy efficiency measures for peak reduction, commissioned by Greenpeace, BBL, IEW and WWF[46].

That study proves that there is large potential for peak reduction. Focusing on three major measures (electric heating in the residential sector, lighting in the tertiary sector, and electric pumps in industry), the study concludes that the three measures can:

- Reduce energy consumption by 4.13 TWh (~5% of Belgian consumption)
- Reduce the peak power demand by 1116 MW (~8.5% of Belgian winter peak load)
- Save annual operation costs by ~576 M€.

The three measures would represent an investment of about 2 bn €, with a payback time of around four years. The total profit could be more than 3.2 bn € spread over 15 years.

Short-term efficiency is therefore a win-win option, as it can both improve security of supply and reduce annual energy demand.

3.3 THE POWER OF TECHNOLOGY

This section looks at the cost of different energy technologies and aims to provide insights into the best technologies for Belgium. As this section will show, renewable energy technologies are becoming cost-competitive and required subsidies are rapidly declining.

The calculations are made using the investment model as explained in Chapter 2. Comparisons are made based on the investment costs, required subsidies, and the calculated Levelised Cost of Electricity (LCOE) values. A definition of the LCOE can be found in Chapter 2.

Comparison of LCOE values for 2014

One of the first things that can be noticed when looking at the calculated LCOE values for 2014 in Figure 13 is that none of the technologies has a LCOE value lower than 85 €/MWh. With today's wholesale market electricity prices (around 40-45 €/MWh), this means that no technology is cost-beneficial when electricity prices don't rise significantly[47].

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[46] Reducing Energy Consumption and Peak Power in Belgium, 3E for Greenpeace, BBL, IEW and WWF, 15 January 2013.

[47] These calculations thus confirm what has been discussed before and explain once again why new investments in the energy sector are not happening at the moment.

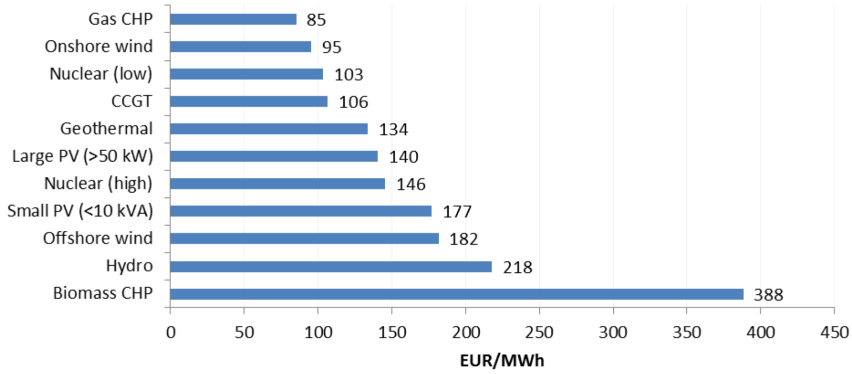

Figure 13: Calculated LCOE values for 2014 in €/MWh

When looking at the relative comparisons between the technologies, some interesting points can be noted:

- According to the calculations, gas-fuelled CHP is the cheapest technology today, followed by wind energy.
- Nuclear energy is listed with a low and a high LCOE value, since there is quite some difference in the figures found in research literature[48]. Recent developments of nuclear plants (e.g. Finland, France)[49], indicate that the high value is much more realistic.
- The LCOE value of geothermal energy looks reasonable compared to other technologies. It is calculated based on data from, amongst others, VITO[50]. However, since this technology is rather new and still in development, and since the costs of geothermal technology strongly depend on local conditions, these cost estimates should be regarded with caution.
- Large-scale PV is already cheaper than the high estimates for nuclear energy.
- From a technology point of view (and without net metering), small-scale PV and offshore wind are still quite expensive today.
- Biomass has a very high LCOE value. This is a result of certain assumptions made. The starting assumption is that biomass is too valuable to burn in inefficient plants. Therefore it is assumed that it is only used in CHPs. Since it is not realistic to find many very large heat consumers, a medium-sized CHP (12.5 MW) is used in the calculations. These have a high CAPEX cost (mainly related to pre-treatment fuels and after-treatment exhaust gases), which explains the high LCOE value. More details on the biomass assumptions can be found in Chapter 2.

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[48] William D. D'Haeseleer, Synthesis on the Economics of Nuclear Energy, Final Report for the European Commission DG Energy, November 2013, Available online http://ec.europa.eu/energy/nuclear/forum/doc/final_report_dhaeseleer/synthesis_economics_nuclear_20131127-0.pdf

[49] The latest estimates for the Finnish reactor Olkiluoto suggest that the reactor, which was expected at construction start to take four years to build and cost 3 bn € , will take at least 11 years (completion in 2016) and cost at least 8.5 bn € (Mycle Schneider, Anthony Froggatt, World Nuclear Industry Status Report 2013, Mycle Schneider Consulting, Paris, Jul 2013, Available online http://www.worldnuclearreport.org/IMG/pdf/20130716msc-worldnuclearreport2013-lr-v4.pdf

[50] Guide de la Géothermie en Belgique, VITO team Geo, December 2012

LCOE evolutions up to 2030

When comparing LCOE's for the next years and up to 2030 (see Figure 14 and Figure 15), significant changes can be noticed. There are two main reasons for this:

- Learning effects make the investment costs for renewable energy technologies cheaper
- Fuel prices are expected to rise, thereby increasing the LCOE's of fuel-based technologies.

These two effects can clearly be seen in both figures: the LCOE of CAPEX-based renewable technologies decreases over the years, while the LCOE of mainly OPEX-based (i.e. fuel-based) technologies increases.

The most drastic reduction in LCOE comes from solar PV, where the investment costs are still expected to decrease significantly. Since solar PV is a CAPEX-based technology[51], this investment costs has a very large influence on the LCOE.

Figure 15 shows again that gas-fuelled CHP is the cheapest technology today (assuming 5000 full load hours). Wind energy becomes the cheapest technology in 2017, after which larger-scale solar PV on industrial and company rooftops (assuming 4/7th of local consumption) takes over from 2019 onwards.

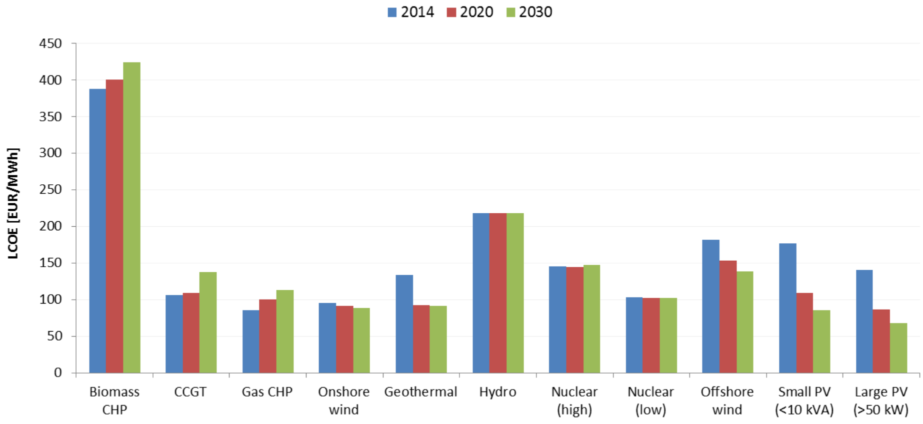

Figure 14: Comparison of the LCOE for each technology for 2014, 2020 and 2030

[51] This is important because the investment is made in the first year, when the money is most expensive, especially for higher WACCs.

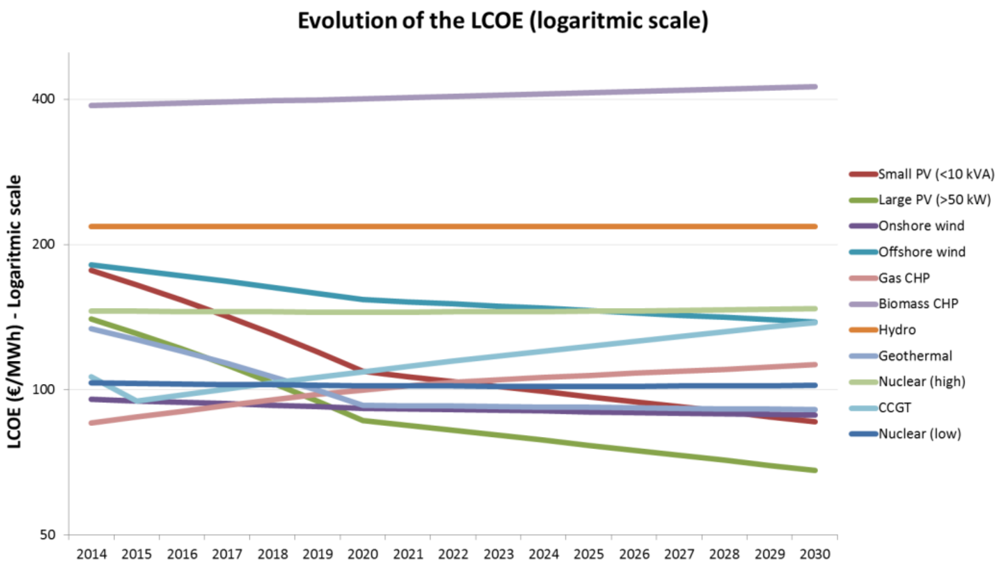

Figure 15: Evolution of LCOE up to 2030 (Logarithmic scale)

The analysis of the LCOE provides an assessment of how expensive each technology is over its lifetime, and which technology is the cheapest. Because it does not take into account the electricity price, it does not give information about the profitability of the technologies. With the investment model, it is also possible to calculate the Net Present Value and required subsidies (as used above already in Section 3.1.1). Depending on the assumed electricity prices, some technologies become profitable somewhere in the coming years. This is especially interesting to note for PV:

- When net metering is allowed (as is the case today), small PV plants are already profitable.
- When net metering is not allowed, small plants (assuming 20% self-consumption) are profitable from 2020 onwards, while larger plants (assuming 4/7th self-consumption) are profitable from 2017 onwards.

Significant impact of the electricity price and the assumptions on self-consumption

These results depend largely on electricity prices. The above has been calculated for the electricity price scenario based on gas (+ CO_2 + OPEX). When calculated for the electricity price scenario based on coal (+ CO_2 + OPEX), small plants only become profitable without net metering from 2023 onwards, and large plants from 2019 onwards.

With a lower electricity price (stable price at 40 $€_{2014}$), small PV is not profitable without subsidies and net metering before 2030, while large PV would be fully profitable from 2020 onwards. This yields an interesting insight: the most important reason why large PV is still cost-beneficial so early is the assumption that large PV is e.g. an installation of ~250 kWp on a company rooftop where 4/7 of the production is used locally (instead of 20% self-consumption for small PV plants). Because this electricity is worth more than the electricity put on the grid, the impact of lower electricity prices is not so great for larger PV installations.

A stable framework can significantly further reduce required subsidies

With a stable framework and low development risks, those investing in the development of new electricity production units demand less interest for their financing. The Weighted Average Cost of Capital (WACC) can then drop. In the long-term, this increases the value of the electricity produced for the project.

Since most renewable energy technologies are mainly CAPEX technologies, the WACC is even more important for them than for conventional technologies. A high WACC essentially reduces the value of profits at a later stage, and CAPEX costs at the beginning of the project thus become relatively more important.

To analyse the impact of the WACC assumptions, a sensitivity analysis has been performed and explained in this section with a scenario where the WACCs for each technology are only 80% of the WACCs in the normal scenario. The resulting LCOEs are shown in Table 10 and decrease significantly. The same is true for required subsidies. With the lower WACC scenario, total required subsidies amount to 10.2 bn €, which is about 1.92 bn €less (a reduction of 16%) than in the normal scenario.

Table 10: Comparison of LCOEs for the years 2014, 2020 and 2030, and analysis of the influence of the WACC assumption

	LCOE in the normal scenario			LCOE with 20% lower WACC		
	2014	2020	2030	2014	2020	2030
Biomass CHP	388.14	401.23	424.69	370.05	383.38	407.24
CCGT	106.32	108.96	137.82	103.67	107.92	135.99
Gas CHP	85.44	99.86	112.62	81.68	95.61	108.41
Onshore wind	95.48	91.57	88.51	87.49	83.90	81.10
Geothermal	133.75	92.87	90.98	115.93	80.49	78.86
Hydro	217.63	217.63	217.63	204.83	204.83	204.83
Nuclear (high)	145.66	144.89	147.46	124.57	123.89	126.95
Nuclear (low)	103.23	102.02	102.18	91.45	90.19	90.42
Offshore wind	181.72	153.74	138.11	159.22	134.70	121.00
Small PV (<10 kVA)	177.04	109.06	85.88	158.58	97.69	76.92
Large PV (>50 kW)	140.34	86.45	68.08	125.70	77.44	60.98

Small scale technologies will be able to contribute to the grid costs

Today with net metering, small PV is profitable without direct subsidies. With the expected cost reductions in the future, PV will become cheaper and large scale PV will even become the cheapest technology from 2019 onwards. This means that there will be a margin in the coming years to let small scale technologies contribute to the grid costs.

With the assumptions made in this study and the ambitious scenario for PV, this margin is calculated to be about 8.6 bn € by 2030 (or on average about 716 €/kW installed between 2014 and 2030[52]).

[52] In the first years this margin is very limited. It grows when the costs of the technology drop further towards 2030.

4 CONCLUSIONS AND RECOMMENDATIONS

This study has shown that an ambitious transition in the electricity sector is feasible and still possible by 2030. With this conclusion, this project confirms the result of other studies[53].

In addition to the results described in this report, there is now a user-friendly and flexible tool available. This tool will allow for quick analysis and reactions to events or discussions. Furthermore, it can be used to track the progress in the electricity sector in the coming years. This tool is not only modelling the electricity sector, but is capturing the whole energy balance of Belgium. Energy in buildings is also already worked out in details, and more detailed work on the other sectors might follow.

In the Belgian electricity sector, the main goals should be:

- To keep the system secure, affordable and make it sustainable
- To develop a clear vision on the future
- To make robust and well though-out choices for the most cost-efficient technologies

The present study has analysed different options and has proposed possible solutions. The following paragraphs present 5 main conclusions and recommendations.

Go for the sustainable transition of the Belgian electricity sector.

Developing an ambitious sustainable electricity sector with large amounts of renewables is possible by 2030. An investment of about 43 bn € would be needed with a subsidy of around 12 bn €. In turn, compared to a system where no more additional renewables would be installed compared to 2014 levels and only CCGT plants would be developed, around 10 bn € in fuel import costs would be avoided by 2030, and around 30 bn € by 2050.

At the same time a local economy can be created, the dependency on third countries is reduced, the risk of fuel price increases is mitigated, and the system becomes much more environmentally friendly and sustainable. Furthermore, transforming the electricity sector is a must for the transition to a low carbon system.

To make the transition work, decisions have to be taken now and a stable investment framework needs to be created with the right incentives.

Invest in RE as a hedge against fuel price spikes (CAPEX vs OPEX)

The transition towards more renewables means a transition from a merely OPEX-based to a CAPEX-based electricity sector. Once the investments are done the operational costs are limited. This means it reduces risks for the future, and can be regarded as a sort of insurance against future fuel price evolutions. This can be important: as an example the average Belpex day-ahead electricity price[54] is

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[53] EU Energy Revolution 2012,
http://www.energyblueprint.info/fileadmin/media/documents/regional/07_gpi_E_R__2012_EU27_mr_small.pdf
Greenpeace Powe[r] 2030, http://www.greenpeace.de/files/publications/201402-power-grid-report.pdf
D. Devogelaer, J. Duerinck et al. Towards 100% Renewable Energy in Belgium by 2050, April 2013
M. Cornet, J. Duerinck et al., Scenarios for a Low Carbon Belgium by 2050, November 2013

[54] The same is valid when looking at the futures prices of ENDEX. These also see an important increase, but with a lag-time: contracts made in 2008 for 2009, 2010 and 2011 were at a high price because it was expected that electricity would be expensive in the next years as well.

given in Table 11 for the years 2007 to 2013. As can be seen, the electricity price can vary very quickly. From 2007 to 2008 it increased with 70%, and the year after it again lost 45% of its value. Investments in CAPEX-technologies like wind and solar energy mitigate the risks of such events.

Table 11: Average Belpex day-ahead electricity prices for 2007-2013

2007	2008	2009	2010	2011	2012	2013
41.78	70.61	39.36	46.30	49.37	46.98	47.45

An example makes clear that this impact can be considerable: Assuming that the gas price in the year 2021 suddenly increases with 70% compared to the price in 2020 and 2022[55], leads to a drop in required subsidies of 306 M€, while the impact of the gas price increase in terms of import costs is limited with 409 M€.

Subsidise renewables but invest smartly

Looking at the technologies, Belgium should invest smartly. Onshore wind is already the cheapest technology today. Solar PV is becoming cost competitive in the coming years (especially for larger projects with self-consumption, even without net metering).

Policy makers should learn from the past and choose to support innovative technologies that have the potential to create economical added-value in Belgium.

The availability of sustainable wood residue for energy use in Belgium is limited, and this holds also for Europe as a whole. Moreover, an investment in biomass contains a certain risk since feedstock prices have continued to rise in the last years, and are expected to increase further. This increases the subsidy costs heavily and does not help to ensure the long term energy security. Biomass for energy should thus be used as efficient as possible and restrained to a sustainable level. The study shows that, even with a constrained use of biomass, significant shares of renewable electricity are possible.

As discussed before, the work on energy efficiency will be published in a separate report. However, it is clear that energy efficiency has such an economic potential for Belgium. The old building stock and the many Belgian innovative companies make that the potential is enormous. Investments in energy efficiency (and innovation in this sector) stay for a large part in Belgium and can create many jobs and technology export potential.[56] Moreover, targeted energy efficiency measures can help reducing the peak power consumption and mitigate risks of security of supply.

Take the power capacity challenge serious

Due to the unplanned early shutdown of Doel 3 and Tihange 2 and due to the mothballing of several working CCGT plants, there is a short term challenge in the electricity sector to meet the peak demand and annual demand criteria. This should be taken serious and solutions need to be created.

However, there are other solutions than providing capacity subsidies for CCGT plants. A proper CO_2 tax could potentially be part of the solution, but this is a European strategic and geopolitical issue.

[55] Since the electricity price scenario is based on the gas price, also the electricity price for 2021 is strongly increased.

[56] With the current low interest rates for Belgium, it is perhaps a good idea and maybe even possible to convince the European Commission to loosen the budget guidelines a bit, provided that the extra money lend on the markets is fully used to reduce energy consumption and the money outflow related to fuel imports.

Demand flexibility needs to be increased urgently and measures need to be created to incentivise this further. With the right measures and information campaigns, a quick reduction of peak power demand is possible, also through energy saving measures [57]. This has been proven in many countries as shown in the IEA publication 'Saving Electricity in a Hurry'[58] and was studied for Belgium[59]. Possibilities to increase the available interconnection capacity on the interconnections to the Netherlands should be discussed and analysed in detail.

Develop smart policy measures

As already mentioned above, the different governments in Belgium have several options to make the transition work. Smart policy measures that provide the right incentives are an important part in this.

Some suggestions are mentioned here:

- **Increase investor confidence**: One of the most important things when designing a support framework is to make sure that it is stable and reliable. Sudden changes are detrimental to investor confidence. This makes money more expensive and in turn significantly increases the required subsidies. If with a clear and stable framework, the WACCs could be reduced by 20%, the required subsidies for the scenario proposed would drop by 16%. This represents a huge amount of money that would otherwise only be used to finance the loans.
- **Polluter pays principle**: In order to incentivise energy efficiency in households, grid tariffs and taxation could be made more progressive, thus increasing with higher consumption[60].
- **Incentives for flexibility & peak reduction**: Similar measures can be developed to incentivise demand flexibility and peak reduction measures, e.g. by increasing the costs for larger grid connections (thereby giving an incentive to reduce the peak demand) or installing smart meters to value electricity consumption according to the hourly wholesale market prices. Other measures to reduce peak consumption have already been mentioned above (e.g. relighting campaigns, incentives to abolish electrical heating and return old electrical equipment, etc.)
- **Adapt the net metering policy**: Net metering values electricity at a much higher price which includes the grid tariffs and taxes. This makes some investments more beneficial than others, while this is not necessarily the best when seen from the viewpoint of the country as a whole.

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[57] Some possibilities are for example large relighting campaigns, group purchases of efficient electrical equipment, and incentives to return inefficient equipment. Policy should be focused on measures that have an impact on the peak. As proven in the study on energy efficiency measures by 3E for Greenpeace, BBL, WWF and IEW in 2013, relighting in the tertiary sector alone already has the potential to reduce the winter peak demand by 816 MW.

[58] Saving Electricity in a Hurry, Update 2011, IEA Information Paper, June 2011, Available online http://www.iea.org/publications/freepublications/publication/name-3996-en.html

[59] Reducing Energy Consumption and Peak Power in Belgium, 3E, January 2013, Available online http://www.greenpeace.org/belgium/Global/belgium/report/2013/PP_PR106150_EEStudy_Presentation_20130115.pdf

Potential of short-term energy efficiency and energy saving measures in Belgium, E-Ster, May 2005 http://www.greenpeace.org/belgium/Global/belgium/report/2005/6/potential-of-short-term-energy.pdf

[60] High consumption in the residential sector can be caused by a number of reasons, like e.g. poor households with cheap but inefficient electrical equipment, large households with many people, or rich people with heated swimming pools, saunas etc. Measures should be taken to limit undesirable social impacts.

The net metering policy should be brought back into the debate. The regionalisation of the competencies on grid tariffs is a good opportunity to make the system smarter. PV and other small scale technologies like heat pumps and electric vehicles can e.g. contribute to the grid tariffs based on grid use and interaction. Prioritising the installation of smart meters to the owners of these installations will lead to a better and fairer system, while giving a boost to the smart grid industry in Belgium. Moreover, this would give the necessary incentives to better match supply and demand, increasing flexibility and limiting the peak power consumption in Belgium.

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