Insights in a clean energy future for Belgium

Impact assessment of the 2030 Climate & Energy Framework

May 2018

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Federal Planning Bureau

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Abstract – In October 2017, the Federal Planning Bureau published its three-yearly energy outlook describing the Belgian energy, transport and emission projections under unchanged policy up to horizon 2050. That outlook, valuable in itself by plotting the trajectories if policies would remain unchanged compared to today, clearly demonstrates the need to speed up efforts if we want to succeed in sculpting a low-carbon society. It shows that, under unchanged policy, we are drifting away from agreed targets and international agreements made to protect future societies from hazardous levels of climate change. That is why that outlook is complemented by this report that adopts a different perspective. This publication describes and analyses three alternative policy scenarios that are compatible both with the 2030 EU Climate and Energy Framework and with the roadmap for moving to a competitive low-carbon economy in 2050. The policy scenarios discussed in this report differ in their ambition of non-ETS greenhouse gas emission reductions on the Belgian soil: they amount to 27%, 32% and 35% in 2030 compared to 2005, thereby reflecting the option to resort to flexibilities to achieve the proposed national Belgian non-ETS target in 2030 which is set at 35%.

Jel Classification – C6, O2, Q4
Keywords – Energy policy, greenhouse gas emissions, renewable energy sources, long-term energy projection

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Executive summary

In October 2017, the Federal Planning Bureau came out with the publication of its three-yearly energy outlook. That outlook documents the Belgian energy and greenhouse gas emission projections under unchanged policy up to horizon 2050. That outlook presents the development of the Belgian energy system if policies would remain unchanged compared to what is currently adopted. It shows that, under unchanged policy, we are far from meeting the targets set in the Clean Energy Package and the Paris agreement.

That is why that outlook needs to be complemented by another report that adopts a completely different perspective. That report provides and describes three alternative policy scenarios that are compatible both with the 2030 EU Climate and Energy Framework and with the 2050 greenhouse gas emission reduction target at EU level.

The Clean Energy Package – the backbone of the EU climate and energy policy beyond 2020 – includes a set of legislative proposals which are still under discussion and expected to be adopted by the end of 2018. One of these proposals is a Regulation of the European Parliament and the Council on the Governance of the Energy Union.

Integrated national energy and climate plans (NECP) are the cornerstone of the Governance regulation. Elaborated and submitted by the Member states, the plans aim to present the objectives, policies and measures and projections for each of the five dimensions of the Energy Union, namely decarbonisation, energy efficiency, energy security, internal energy market and research, innovation and competitiveness. Projections integrating planned policies and measures are thus required, including a comparison with projections based on existing policies and measures.

According to the proposed time schedule, draft NECPs are to be submitted by the end of 2018 and the final texts are due by the end of 2019. Based on the national plans, the European Commission will monitor progress towards the 2030 climate and energy objectives and assess the need for recommendations, which may trigger additional measures to be taken at national or EU level.

The Belgian NECP is being elaborated by the different entities (the three Regions and the Federal State). The main role of the Federal Planning Bureau in the process is to provide support and expertise for the analytical part of the plan (i.e. projections and impact assessment of policies and measures). In addition to this particular involvement, the present FPB’s study and the reference energy and climate scenario published in October 2017 (FPB, 2017) can provide interesting and useful results in the ongoing elaboration process and constitute a benchmark for the projections to be included in the forthcoming Belgian draft NECP.

The reference scenario (REF) provides greenhouse gas (GHG) and energy projections assuming the implementation of current policies and the achievement of the legally binding GHG and renewables (RES) targets for 2020. The policy scenarios, on the other hand, are compatible both with the 2030 EU Climate and Energy Framework and with the 2050 greenhouse gas emission reduction target at EU level. Three policy scenarios (named Alt1, Alt2 and Alt3) have been designed and assessed. They differ according to
the assumption on the GHG reductions in the Belgian non-ETS, reflecting the option to resort to flexibilities to achieve the national non-ETS target in 2030. The non-ETS reductions are respectively 27%, 32% and 35% in 2030 compared to 2005.

Several results are summarised below. They are arranged according to the five dimensions of the Energy Union and focus on the years 2030 and 2040.

**Decarbonisation**

The decarbonisation dimension of the Energy Union encompasses GHG emission reductions and the development of renewable energy sources.

As to GHG emissions, the 2030 EU Climate and Energy Framework contains a binding target to cut emissions on the EU territory by at least 40% by 2030 compared to 1990 levels. To achieve this target, EU emissions trading system (ETS) sectors have to cut emissions by 43% compared to 2005 and non-ETS sectors need to reduce emissions by 30% compared to 2005. In the long term, the low-carbon economy roadmap issued by the European Commission in 2011 suggests that, by 2050, the EU should cut its emissions to 80% below 1990 levels through domestic reductions alone. The translation of these EU objectives to Belgian GHG reductions is as follows:

GHG emission reductions range from 33% (Alt1) to almost 36% (Alt3) in 2030 compared to 1990. These reduction percentages are below the target of 40% for the EU. In REF, GHG emissions are 26% lower than the level in 1990. In 2040, GHG emission reductions from 1990 levels range from 49% to 51% against 27% in REF.

<table>
<thead>
<tr>
<th>Table</th>
<th>Greenhouse gas emissions in ETS, non-ETS and different energy sectors, REF and policy scenarios, 2005, 2030 and 2040</th>
<th>Mt CO2-eq.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2005 REF</td>
<td>Alt1</td>
</tr>
<tr>
<td>Total GHG emissions</td>
<td>148</td>
<td>111</td>
</tr>
<tr>
<td>ETS</td>
<td>70</td>
<td>47</td>
</tr>
<tr>
<td>Power generation</td>
<td>24</td>
<td>17</td>
</tr>
<tr>
<td>Non-ETS</td>
<td>78</td>
<td>64</td>
</tr>
<tr>
<td>Buildings</td>
<td>31</td>
<td>23</td>
</tr>
<tr>
<td>Transport</td>
<td>26</td>
<td>23</td>
</tr>
</tbody>
</table>

Source: PRIMES, GAINS.

ETS emissions are 32% lower in 2030 than 2005 in REF and 34% to 38% lower in the policy scenarios. The lowest policy scenario reduction is achieved in Alt3 and the highest in Alt1: more electrification in Alt3 leads to extra power generation in gas-fired power plants compared to Alt2 and Alt1. The rather small difference between REF and the policy scenarios can essentially be attributed to the narrow room for manoeuvre in the power sector where the fuel mix is already low carbon intensive in REF (approximately 60% natural gas and 40% renewables). After 2030, ETS emissions further decline in the policy scenarios (against a stabilisation in REF). ETS emissions are 42% to 46% below the 2005 level in 2040.

Non-ETS emissions are reduced by 27% in Alt1 in 2030 compared to 2005 and by respectively 32% and 35% in Alt2 and Alt3 (against 18% in REF). Extra emission reductions compared to REF can be found in the residential and tertiary sectors (buildings). In 2040, emission reductions progress and range between
49% and 56% due to the rapid expansion of electric vehicles and a more extensive use of biofuels in transport.

As to renewables, the 2030 EU Climate and Energy Framework sets a binding target at EU level to boost the share of renewables to at least 27% of EU gross final energy consumption by 2030. For Belgium, this target results in a further development of RES compared to REF. In 2030, the highest share of RES is reached in Alt3 (19.7%). Alt1 and Alt2 follow with shares of 17.9 and 18.9% respectively, compared to 15.4% in REF. In 2040, RES continue to grow and the difference between the policy scenarios reduces somewhat. The RES share can be situated between 30.5 and 31.8%, compared to 17% in REF.

<table>
<thead>
<tr>
<th>2015</th>
<th>2030</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>RES-H&amp;C</td>
<td>8.1</td>
<td>14.0</td>
</tr>
<tr>
<td>RES-E</td>
<td>15.4</td>
<td>27.8</td>
</tr>
<tr>
<td>RES-T</td>
<td>3.5</td>
<td>12.4</td>
</tr>
<tr>
<td>Overall RES share</td>
<td>8.1</td>
<td>15.4</td>
</tr>
</tbody>
</table>

Source: PRIMES.

The analysis by type of RES use shows that, in 2030, changes compared to REF are significant in the electricity and transport sectors but rather moderate for heating and cooling. The share of RES-E increases by almost 10 percentage points in the policy scenarios (38% against 28% in REF) and the share of RES-T gains 3 to 4 percentage points (15 to 17% compared to 12% in REF). By contrast, the share of RES-H&C amounts to 14 to 15% in all scenarios. In 2040, things change. Shares surge for all uses to around 24% for RES-H&C, 44% for RES-E and to more than 70% for RES-T, significantly widening the gap with REF (at 16%, 30% and 14% respectively).

Energy efficiency

The 2030 EU Climate and Energy Framework defines an indicative energy savings target at EU level of at least 27% by 2030. On 30 November 2016, the Commission proposed to revise the Energy Efficiency Directive including a new 30% energy efficiency target for 2030. In their NECPs, Member States are required to set a national energy efficiency target based on either primary or final energy consumption.

In our policy scenarios, primary energy consumption is reduced by 27 to 29% in 2030 compared to the projected (PRIMES REF2007) level of 50.1 Mtoe. Moreover, it is 29 to 30% below the consumption level in 2005 (against 22% in REF). For 2040, no figures are available in the PRIMES REF2007 scenario. However, the evolution in the policy scenarios can be translated into reductions with respect to 2005 amounting to 32 to 34% (against 22% in REF).
Final energy consumption is reduced by 21 to 24% in 2030 in the policy scenarios compared to the projected (PRIMES REF2007) level of 39.9 Mtoe in 2030. Moreover, it is 14 to 17% below the consumption level in 2005. In 2040, the corresponding percentages are 17 to 21%. In REF, final energy consumption decreases by 5% in 2030 and by 6% in 2040 compared to 2005.

**Energy security**

Energy security is a rather comprehensive concept. The present study allows quantifying some indicators reflecting the degree and evolution of a country’s energy security: the primary energy mix, the domestic production versus net imports of energy and the import dependency. These indicators are also solicited in the NECPs.

The policy scenarios show significant changes in the primary energy mix. Compared to 2015, all scenarios display a decrease in the shares of solid fuels (remaining consumption is concentrated in the iron and steel industry) and oil (mainly used in the transport sector) and an increased contribution of natural gas (for power generation), electricity (imports) and RES. The share of nuclear drops to zero due to the full decommissioning of nuclear plants in 2025.

In 2030, the role of oil and natural gas in the policy scenarios is watered down compared to REF. Fuel switching and energy savings required to fulfil the energy and climate targets lead to consumption reductions of oil and natural gas for heating purposes and of diesel and gasoline in transport at the benefit of electricity and biofuels. On the other hand, the contribution of RES intensifies; it jumps to around 20% compared to 16% in REF.

### Table

<table>
<thead>
<tr>
<th></th>
<th>Primary energy mix, REF and policy scenarios, 2015, 2030 and 2040</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015</td>
<td>REF Alt1</td>
</tr>
<tr>
<td>Solid fuels</td>
<td>7</td>
<td>4  4</td>
</tr>
<tr>
<td>Oil</td>
<td>35</td>
<td>34  32</td>
</tr>
<tr>
<td>Natural gas</td>
<td>29</td>
<td>41  38</td>
</tr>
<tr>
<td>Nuclear</td>
<td>15</td>
<td>0   0</td>
</tr>
<tr>
<td>Electricity</td>
<td>4</td>
<td>6   7</td>
</tr>
<tr>
<td>RES</td>
<td>10</td>
<td>16  19</td>
</tr>
</tbody>
</table>

Source: PRIMES.

By 2040, the changes endure and even increase for oil and RES. The strong decline in the share of oil is mainly due to further electrification and the use of biofuels in the transport sector. The significant increase in the share of RES, which occupies the second place in the primary energy mix, originates in power generation, the use of heat pumps and biofuels.

Energy produced in Belgium mainly concerns renewable energy sources (nuclear heat is also considered to be a domestic resource, but it falls to zero in 2030 and 2040 due to the nuclear phase-out). Domestic production increases by 13 to 21% in 2030 compared to REF. Extra production primarily comes from solar energy and wind. The production of biomass and waste varies only marginally among the scenarios. In 2040, the increase is more significant; it ranges from 41 to 44% compared to REF. Again, solar energy and wind production increase in all policy scenarios, as well as the production of biomass and waste.
Table | Domestic production, net imports of energy and import dependency, REF and policy scenarios, 2015, 2030 and 2040

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2030</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic production (Mtoe)</td>
<td>3.6</td>
<td>5.0</td>
<td>6.1</td>
</tr>
<tr>
<td>Net imports (Mtoe)</td>
<td>50.6</td>
<td>50.8</td>
<td>50.2</td>
</tr>
<tr>
<td>Import dependency (%)</td>
<td>84.3</td>
<td>91.0</td>
<td>90.1</td>
</tr>
<tr>
<td>Source: PRIMES.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(*) excluding nuclear heat (year 2015).</td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

While domestic production mainly concerns RES, the bulk of net imports is made up of fossil fuels, amounting to 95% in 2015. In 2030, net energy imports in the policy scenarios decrease by 9 to 11% compared to REF. The decrease is essentially caused by oil and natural gas. In 2040, the impact amplifies: net imports decrease by 16 to 18% compared to REF. Oil is first in line followed by natural gas. On the other hand, biomass and electricity net imports rise compared to REF.

In 2015, Belgium imported 84% of all the energy it consumed. Its import dependency is not projected to decrease in the policy scenarios. It declines, however, compared to REF, though marginally. That is basically because the reduction in net imports is partly overtaken by the decrease in total energy needs.

Although Belgium is heavily reliant on external supply, it banks upon a diversified portfolio of supplier countries and routes. The evolution of Belgium’s supply portfolio is out of the scope of the present study.

Internal energy market

Belgium’s natural gas and electricity transmission networks are well interconnected with other countries. Moreover, new electricity interconnectors with Great-Britain and Germany are currently under construction. They will be operational in 2019-2020.

Table | (Net) imports of natural gas and electricity, REF and policy scenarios, 2015, 2030 and 2040

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2030</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas imports (Mtoe)</td>
<td>13.9</td>
<td>15.1</td>
<td>15.0</td>
</tr>
<tr>
<td>Net electricity imports (TWh)</td>
<td>21.0</td>
<td>28.5</td>
<td>30.2</td>
</tr>
<tr>
<td>Source: PRIMES.</td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

Natural gas imports are 12 to 14% (resp. 18 to 20%) lower in the policy scenarios compared to REF in 2030 (resp. 2040). The corresponding import volumes are higher than those recorded in 2015 but lower than in 2010 (16.8 Mtoe).

Net imports of electricity reach high levels in the policy scenarios in 2030 (29 TWh vs. 26 TWh in REF), and, contrary to REF where net imports afterwards decrease and then stabilise at around 21 TWh, further increase towards 30 TWh in 2040. The divergence between the policy scenarios and REF can be understood by the integration of more renewables in the former’s power systems which poses a higher need for additional balancing. More renewables can be uptaken in these systems because of assumed market improvements and the supposed EU-wide market coupling which allows for rather low balancing costs for RES on a European scale.
Research, innovation and competitiveness

Research and innovation indicators required in the NECPs are not straightforward or even missing in our scenario analysis. However, the latter provides information on the evolution of energy costs which is often used to address competitiveness issues for industry. If the Belgian industry faces higher energy costs (increases) than its counterparts, its competitiveness may be at stake. The indicator we investigated is the unit energy cost. This indicator measures the energy input cost per unit of value added. The unit energy cost brings together two components: the energy price and the energy intensity. This could mean that an expected growth in unit energy cost compared to REF may be mitigated if decreases in energy intensity compensate for increases in energy prices, all things being equal.

Table Unit energy cost in industry, REF and policy scenarios, 2015, 2030 and 2040

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2030</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>REF</td>
<td>Alt1</td>
<td>Alt2</td>
</tr>
<tr>
<td>Industry</td>
<td>18.6</td>
<td>22.3</td>
<td>21.6</td>
</tr>
</tbody>
</table>

Source: PRIMES, FPB calculations.

The unit energy cost is projected to rise in all scenarios in 2030 compared to 2015 due to the sharp increase in energy price (by more than 40%) which is not counterbalanced by a similar decrease in energy intensity (by some 20%). However, the unit energy cost is generally lower in the policy scenarios than in REF due to additional energy efficiency improvements causing a larger decline in energy intensity. In the period 2030-2040, the unit energy cost remains roughly stable in the policy scenarios (but decreases in REF). Energy intensity continues its downwards trend and compensates for the rise in energy price resulting from an increased consumption of electricity at the expense of fossil fuels.

Although insightful, this evolution of the unit energy cost is not sufficient to assess the impact on competitiveness. Such an assessment requires a comparison with the evolution in the other Member States (and outside the EU). However, this information is not available today. It should nevertheless be presented in the NECPs according to the proposed template. Once published, comparisons can be made and lessons on competitiveness drawn.
Synthèse


C’est pourquoi ces perspectives doivent être complétées par un autre rapport adoptant un point de vue totalement différent. Ce rapport présente et décrit trois scénarios alternatifs compatibles aussi bien avec le Cadre européen Climat Énergie 2030 qu’avec l’objectif de réduction des émissions de gaz à effet de serre à l’échelle de l’Union européenne (UE) pour 2050.


Selon le calendrier proposé, les projets de PNEC doivent être soumis pour fin 2018 et les textes définitifs pour fin 2019. Sur la base des plans nationaux, la Commission européenne suivra les progrès réalisés en vue d’atteindre les objectifs en matière de climat et d’énergie pour 2030 et évaluera la nécessité de formuler des recommandations pouvant déboucher sur des mesures supplémentaires à adopter sur le plan national ou à l’échelle de l’UE.


Le scénario de référence (REF) donne des projections pour les gaz à effet de serre (GES) et l’énergie dans l’hypothèse où les politiques actuelles sont pleinement mises en œuvre et où les objectifs légalement contraignants en matière de GES et d’énergies renouvelables (SER) pour 2020 sont atteints. Quant aux

Décarbonation

La dimension ‘décarbonation’ de l’Union de l’énergie englobe les réductions d’émissions de GES et le développement des sources d’énergie renouvelables (SER).

En ce qui concerne les émissions de GES, le Cadre européen Climat/Énergie 2030 contient un objectif contraignant consistant à réduire les émissions sur le territoire de l’UE d’au moins 40 % en 2030 par rapport aux niveaux de 1990. Pour atteindre cet objectif, les secteurs du système européen d’échange de permis d’émission (ETS) et les secteurs non-ETS doivent réduire leurs émissions de respectivement 43 % et 30 % par rapport à 2005. Sur le long terme, la feuille de route vers une économie à faible intensité de carbone, qui a été publiée par la Commission européenne en 2011, suggère que, d’ici 2050, l’UE doit réduire ses émissions de 80 % par rapport aux niveaux de 1990, et ce uniquement via des réductions domestiques. Pour la Belgique, ces objectifs européens se traduisent par les réductions de GES suivantes :

Les réductions d’émissions de GES varient entre 33 % (Alt1) et près de 36 % (Alt3) en 2030 par rapport à 1990. Ces pourcentages de réduction sont inférieurs à l’objectif de 40 % fixé pour l’UE. Dans le REF, les émissions de GES sont inférieures de 26 % au niveau de 1990. En 2040, les réductions d’émissions de GES varient entre 49 % et 51 % par rapport à 1990, contre 27 % dans le REF.

| Tableau Émissions de gaz à effet de serre dans les secteurs ETS, non-ETS et différents secteurs énergétiques, REF et scénarios alternatifs, 2005, 2030 et 2040 | Mt éq. CO₂ |
|-----------------------------------------------|---------------------|---------------------|---------------------|---------------------|
| 2005                                         | REF    | Alt1   | Alt2   | Alt3   |
| Total des émissions de GES                   | 148    | 111    | 100    | 98     | 97     |
| ETS                                          | 70     | 47     | 44     | 45     | 46     |
| Production d’électricité                     | 24     | 17     | 13     | 14     | 16     |
| Non-ETS                                      | 78     | 64     | 56     | 53     | 51     |
| Bâtiments                                    | 31     | 23     | 18     | 15     | 12     |
| Transport                                    | 26     | 23     | 21     | 21     | 21     |
| Source : PRIMES, GAINS.                      |        |        |        |        |

En 2030, les émissions dans les secteurs ETS sont inférieures de 32 % à celles de 2005 dans le REF et de 34 % à 38 % dans les scénarios alternatifs. Le scénario alternatif dans lequel on enregistre la réduction la plus faible est le scénario Alt3 et celui dans lequel on relève la réduction la plus sensible est le scénario Alt1 : une plus grande électrification dans Alt3 conduit à davantage d’électricité produite par des centrales au gaz naturel par rapport à Alt2 et Alt1. L’écart relativement faible entre le REF et les scénarios alternatifs peut s’expliquer dans une large mesure par l’étroite marge de manœuvre dans le secteur.
électrique où le mix énergétique se caractérise déjà par une faible intensité en carbone dans le REF (environ 60 % de gaz naturel et 40 % d’énergies renouvelables). Après 2030, les émissions dans les secteurs ETS continuent à reculer dans les scénarios alternatifs (alors qu’il y a stabilisation dans le REF). La baisse des émissions dans les secteurs ETS en 2040 par rapport à 2005 varie entre 42 % et 46 %.

Les émissions non-ETS baissent de 27 % en 2030 par rapport à 2005 dans Alt1 et de respectivement 32 % et 35 % dans Alt2 et Alt3 (contre 18 % dans le REF). On enregistre des réductions d’émissions plus importantes par rapport au REF dans les secteurs résidentiel et tertiaire (bâtiments). En 2040, les réductions d’émissions sont plus marquées et varient entre 49 % et 56 % à la faveur de l’expansion rapide des véhicules électriques et d’une utilisation accrue des biocarburants dans le transport. Ces changements dans le secteur du transport s’ajoutent à ceux dans les bâtiments et expliquent les réductions d’émissions supplémentaires par rapport au REF.

En ce qui concerne les énergies renouvelables, le Cadre européen Climat/Energie 2030 fixe un objectif contraignant au niveau de l’UE pour accroître la part des énergies renouvelables à au moins 27 % de la consommation finale brute d’énergie d’ici 2030. Pour la Belgique, cet objectif entraîne un recours accru aux SER par rapport au REF. En 2030, c’est dans le scénario Alt3 qu’on enregistre la part de SER la plus importante (19,7 %). Alt1 et Alt2 suivent avec des parts de respectivement 17,9 % et 18,9 %, contre 15,4 % dans le REF. En 2040, la part des SER continue à s’accroître et l’écart entre les scénarios alternatifs s’atténue quelque peu. Ainsi, la part des SER fluctue entre 30,5 % et 31,8 %, contre 17 % dans le REF.

<table>
<thead>
<tr>
<th>Tableau</th>
<th>Part des SER dans la consommation finale brute d’énergie et par finalité, REF et scénarios alternatifs, 2015, 2030 et 2040</th>
<th>En %</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015</td>
<td>REF</td>
</tr>
<tr>
<td>SER-H&amp;C</td>
<td>8,1</td>
<td>14,0</td>
</tr>
<tr>
<td>SER-E</td>
<td>15,4</td>
<td>27,8</td>
</tr>
<tr>
<td>SER-T</td>
<td>3,5</td>
<td>12,4</td>
</tr>
<tr>
<td>Part globale des SER</td>
<td>8,1</td>
<td>15,4</td>
</tr>
</tbody>
</table>

Source : PRIMES.

L’analyse par type de finalité des SER montre qu’en 2030, l’écart par rapport au REF est marqué dans les secteurs de l’électricité (SER-E) et du transport (SER-T), mais plutôt modéré pour le chauffage et le refroidissement (SER-H&C). La part des SER-E augmente de près de 10 points de pourcentage dans les scénarios alternatifs (38 % contre 28 % dans le REF) et la part des SER-T s’accroît de 3 à 4 points de pourcentage (15 % à 17 % contre 12 % dans le REF). En revanche, la part des SER-H&C s’élève à 14-15 % dans tous les scénarios. Mais en 2040, les choses changent. Les parts augmentent pour toutes les finalités : elles atteignent environ 24 % pour les SER-H&C, 44 % pour les SER-E et plus de 70 % pour les SER-T. L’écart avec le REF se creuse donc de manière sensible (parts de respectivement 16 %, 30 % et 14 %).

Efficacité énergétique


**Tableau**

<table>
<thead>
<tr>
<th>Part des SER dans la consommation finale brute d’énergie et par finalité, REF et scénarios alternatifs, 2015, 2030 et 2040</th>
<th>En %</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>REF</td>
</tr>
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<td>SER-H&amp;C</td>
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<tr>
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<td>3,5</td>
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<tr>
<td>Part globale des SER</td>
<td>8,1</td>
</tr>
</tbody>
</table>

Source : PRIMES.

L’analyse par type de finalité des SER montre qu’en 2030, l’écart par rapport au REF est marqué dans les secteurs de l’électricité (SER-E) et du transport (SER-T), mais plutôt modéré pour le chauffage et le refroidissement (SER-H&C). La part des SER-E augmente de près de 10 points de pourcentage dans les scénarios alternatifs (38 % contre 28 % dans le REF) et la part des SER-T s’accroît de 3 à 4 points de pourcentage (15 % à 17 % contre 12 % dans le REF). En revanche, la part des SER-H&C s’élève à 14-15 % dans tous les scénarios. Mais en 2040, les choses changent. Les parts augmentent pour toutes les finalités : elles atteignent environ 24 % pour les SER-H&C, 44 % pour les SER-E et plus de 70 % pour les SER-T. L’écart avec le REF se creuse donc de manière sensible (parts de respectivement 16 %, 30 % et 14 %).

Efficacité énergétique

Dans nos scénarios alternatifs, la baisse de la consommation d’énergie primaire en 2030 varie entre 27 % et 29 % par rapport au niveau projeté (PRIMES REF2007) de 50,1 Mtep. La consommation d’énergie primaire est inférieure de 29 % à 30 % au niveau de 2005 (contre 22 % dans le REF). Pour 2040, nous n’avons pas de chiffres disponibles dans le scénario PRIMES REF2007. Toutefois, l’évolution dans les scénarios alternatifs peut se traduire par des réductions par rapport à 2005 variant entre 32 % et 34 % (contre 22 % dans le REF).

Tableau Consommation d’énergie primaire et finale, REF et scénarios alternatifs, 2005, 2030 et 2040

<table>
<thead>
<tr>
<th>Mtep</th>
<th>2005</th>
<th>2030</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>REF</td>
<td>Alt1</td>
<td>Alt2</td>
</tr>
<tr>
<td>Consommation d’énergie primaire</td>
<td>51,3</td>
<td>40,1</td>
<td>36,5</td>
</tr>
<tr>
<td>Consommation finale d’énergie</td>
<td>36,6</td>
<td>34,6</td>
<td>31,6</td>
</tr>
</tbody>
</table>

Source : PRIMES.

La baisse de la consommation finale d’énergie en 2030 varie entre 21 % et 24 % dans les scénarios alternatifs par rapport au niveau projeté (PRIMES REF2007) de 39,9 Mtep. Cette consommation est inférieure de 14 % à 17 % au niveau de consommation de 2005. En 2040, les pourcentages correspondants varient entre 17 % et 21 %. Dans le REF, la consommation finale d’énergie diminue de 5 % en 2030 et de 6 % en 2040 par rapport à 2005.

Sécurité énergétique

La sécurité énergétique recouvre plusieurs acceptions. La présente étude permet de quantifier plusieurs indicateurs reflétant le degré et l’évolution de la sécurité énergétique d’un pays : le mix d’énergie primaire, la production domestique par rapport aux importations nettes d’énergie et la dépendance énergétique. Ces indicateurs sont également demandés dans les PNEC.

Les scénarios alternatifs présentent des changements notables en termes de mix d’énergie primaire. Par rapport à 2015, tous les scénarios montrent une diminution de la part des combustibles solides (la consommation résiduelle se limite pour ainsi dire à la sidérurgie) et du pétrole (principalement utilisé dans le secteur du transport) et une contribution accrue du gaz naturel (pour la production d’électricité), de l’électricité (importations) et des SER. La part du nucléaire tombe à zéro en raison de la sortie du nucléaire en 2025.

En 2030, la part du pétrole et du gaz naturel dans les scénarios alternatifs est plus faible que dans le REF. La substitution des sources d’énergie et les économies d’énergie nécessaires pour atteindre les objectifs fixés en matière d’énergie et de climat conduisent à une baisse de la consommation de pétrole et de gaz naturel à des fins de chauffage et du diesel et de l’essence dans le transport au profit de l’électricité et des biocarburants. Par ailleurs, la part des SER s’accroît et passe à environ 20 % contre 16 % dans le REF.
En 2040, les changements se confirment voire s’accroissent pour le pétrole et les SER. La nette diminution de la part du pétrole s’explique principalement par la poursuite de l’électrification et par l’utilisation de biocarburants dans le secteur du transport. La progression marquée de la part des SER, qui occupent la deuxième place dans le mix d’énergie primaire, est due à la production d’électricité, à l’utilisation de pompes à chaleur et aux biocarburants.

L’énergie produite en Belgique est essentiellement le fait des sources d’énergie renouvelables (la chaleur nucléaire est également considérée comme une ressource domestique, mais elle tombe à zéro en 2030 et 2040 suite à la sortie du nucléaire). La production domestique s’accroît de 13 % à 21 % en 2030 par rapport au REF. La production supplémentaire vient essentiellement de l’énergie solaire et de la production éolienne. La production de biomasse et de déchets ne varie que de manière marginale entre les scénarios. En 2040, l’augmentation est plus sensible ; elle varie entre 41 % et 44 % par rapport au REF. De nouveau, l’énergie solaire et la production éolienne augmentent dans tous les scénarios alternatifs, de même que la production de biomasse et de déchets.

Alors que la production domestique concerne essentiellement les SER, la majeure partie des importations nettes se compose de combustibles fossiles : 95 % en 2015. En 2030, les importations nettes d’énergie dans les scénarios alternatifs diminuent de l’ordre de 9 % à 11 % par rapport au REF. Cette évolution s’observe surtout pour le pétrole et le gaz naturel. En 2040, l’impact s’amplifie : le recul des importations nettes est de 16 % à 18 % par rapport au REF. C’est principalement les importations de pétrole qui diminuent, suivies des importations de gaz naturel. Par ailleurs, les importations nettes de biomasse et d’électricité augmentent par rapport au REF.

En 2015, la Belgique a importé 84 % de toute l’énergie qu’elle a consommée. Sa dépendance énergétique ne se réduit pas dans les différents scénarios alternatifs. Elle diminue par rapport au REF, mais de manière marginale, et ce principalement parce que la diminution des importations nettes est partiellement absorbée par la baisse du total des besoins énergétiques.
Même si la Belgique dépend dans une large mesure de ses importations, elle peut compter sur un porte-feuille diversifié de pays et de routes pour son approvisionnement. L’évolution future de ce porte-feuille sort du cadre de la présente étude.

Marché intérieur de l’énergie


Tableau Importations (nettes) de gaz naturel et d’électricité, REF et scénarios alternatifs, 2015, 2030 et 2040

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2030</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Importations de gaz naturel (Mtep)</td>
<td>13,9</td>
<td>17,5</td>
<td>18,6</td>
</tr>
<tr>
<td>Importations nettes d’électricité (TWh)</td>
<td>21,0</td>
<td>25,7</td>
<td>21,0</td>
</tr>
</tbody>
</table>

Source : PRIMES.

Dans les scénarios alternatifs, les importations de gaz naturel sont inférieures de 12 % à 14 % (18 % à 20 %) à celles du REF en 2030 (2040). Les volumes d’importations correspondants sont supérieurs à ceux enregistrés en 2015 mais inférieurs à ceux de 2010 (16,8 Mtep).

Les importations nettes d’électricité atteignent des niveaux élevés dans les scénarios alternatifs en 2030 (29 TWh contre 26 TWh dans le REF), et, contrairement au REF où les importations nettes diminuent par la suite pour se stabiliser à environ 21 TWh, elles continuent à augmenter pour atteindre 30 TWh en 2040. L’évolution différente entre les scénarios alternatifs et le REF peut s’expliquer par l’intégration de davantage d’énergies renouvelables dans les systèmes électriques des scénarios alternatifs, ce qui crée un besoin d’équilibrage plus important. Davantage d’énergies renouvelables peuvent être intégrées dans les systèmes électriques en raison des améliorations supposées du marché et du couplage supposé du marché à l’échelle de l’UE qui permet d’avoir des coûts d’équilibrage relativement faibles pour les SER à l’échelle européenne.

Recherche, innovation et compétitivité

Les indicateurs de recherche et d’innovation requis dans les PNEC ne sont pas évidents ou ils sont tout simplement absents dans notre analyse de scénarios. Toutefois, cette analyse donne des informations sur l’évolution des coûts énergétiques qui sont souvent utilisées pour aborder les questions liées à la compétitivité pour l’industrie. Si l’industrie belge est confrontée à des (hausses de) coûts énergétiques plus élevé(e)s que dans les autres pays, sa compétitivité peut être compromise. L’indicateur que nous avons étudié est le coût unitaire de l’énergie. Cet indicateur mesure le coût de l’énergie consommée par unité de valeur ajoutée. Le coût unitaire de l’énergie rassemble deux éléments : le prix de l’énergie et l’intensité énergétique. Cela pourrait signifier qu’une croissance attendue du coût unitaire de l’énergie par rapport au REF peut être atténuée si les baisses de l’intensité énergétique compensent les hausses des prix énergétiques, toutes choses étant égales par ailleurs.
Le coût unitaire de l’énergie devrait augmenter dans tous les scénarios en 2030 par rapport à 2015 en raison de la croissance sensible du prix de l’énergie (de plus de 40 %) qui n’est pas compensée par une diminution similaire de l’intensité énergétique (de quelque 20 %). Toutefois, le coût unitaire de l’énergie est généralement moins élevé dans les scénarios alternatifs que dans le REF en raison des gains supplémentaires d’efficacité énergétique, ce qui entraîne une baisse plus marquée de l’intensité énergétique. Au cours de la période 2030-2040, le coût unitaire de l’énergie reste relativement stable dans les scénarios alternatifs (mais diminue dans le REF). L’intensité énergétique continue à diminuer et compense la hausse du prix de l’énergie due à une consommation accrue d’électricité au détriment des combustibles fossiles.

Bien qu’ instructive, cette évolution du coût unitaire de l’énergie n’est pas suffisante pour évaluer l’impact sur la compétitivité. Une telle évaluation requiert une comparaison avec les évolutions dans les autres États membres (et hors EU). Cette information n’est à ce jour pas disponible. Elle devrait néanmoins être rapportée dans les PNEC selon le modèle de rapportage proposé. Une fois les PNEC publiés, une telle comparaison sera rendue possible et des conclusions sur la compétitivité pourront être tirées.

Daarom moeten deze vooruitzichten worden aangevuld door een ander rapport dat een andere invalshoek aannemt. Dat rapport biedt en beschrijft drie alternatieve beleidsscenario’s die zowel verenigbaar zijn met het Europese klimaat- en energiekader 2030 als met de broeikasgasemissiereductiedoelstellingen voor 2050 op EU-niveau.

Het Pakket schone energie vormt de ruggengraat van het Europese klimaat- en energiebeleid voor de periode na 2020 en omvat een reeks wetgevingsvoorstellen die nog worden besproken en normaliter tegen eind 2018 zullen worden goedgekeurd. Een van die voorstellen is een verordening van het Europees Parlement en de Raad inzake de governance van de energie-unie.

De hoeksteen van de governanceverordening zijn de geïntegreerde nationale energie- en klimaatplannen (NEKP’s). Die plannen worden opgesteld en ingediend door de lidstaten en presenteren de doelstellingen, beleidslijnen, maatregelen en projecties voor elk van de vijf dimensies van de energie-unie: decarbonisatie, energie-efficiëntie, energiezerenheid, interne energiamarkt en onderzoek, innovatie en concurrentievermogen. Er zijn projecties vereist waarin de geplande beleidslijnen en maatregelen worden opgenomen, alsook een vergelijking met projecties die zijn gebaseerd op bestaand beleid en maatregelen.

Volgens het voorgestelde tijdschema moeten de ontwerpplannen worden ingediend tegen eind 2018 en worden de definitieve teksten verwacht tegen eind 2019. Aan de hand van de nationale plannen zal de Europese Commissie de vooruitgang naar de klimaat- en energiedoelstellingen voor 2030 opvolgen en de nood aan aanbevelingen onder de loep nemen, wat kan aanleiding geven tot bijkomende maatregelen die op nationaal of EU-niveau moeten worden genomen.

Het Belgische NEKP wordt opgesteld door de verschillende entiteiten (de drie gewesten en de federale overheid). De belangrijkste rol van het Federaal Planbureau in dit proces is ondersteuning en expertise bieden voor het analytische gedeelte van het plan (d.w.z. de projecties en impactbeoordelingen van de beleidslijnen en maatregelen). De voorliggende FPB-studie en het in oktober 2017 gepubliceerde referentiescenario inzake energie en klimaat (FPB, 2017) kunnen interessante en nuttige resultaten bieden voor het lopende ontwikkelingsproces en als maatstaf dienen voor de projecties voor het toekomstige Belgische ontwerp van NEKP.

Het referentiescenario (REF) levert projecties van de broeikasgassen (BKG) en het energiesysteem, waarbij wordt verondersteld dat de huidige beleidsmaatregelen worden uitgevoerd en dat de juridisch bindende BKG- en HEB (hernieuwbare energiebronnen)-doelstellingen voor 2020 worden bereikt.

Hieronder worden verschillende resultaten samengevat. Ze worden gerangschikt volgens de vijf dimensies van de energie-unië en zijn gericht op de jaren 2030 en 2040.

Decarbonisatie

De decarbonisatiedimensie van de energie-unië omvat de BKG-emissiereducties en de ontwikkeling van hernieuwbare energiebronnen.

Op het gebied van de BKG-emissies bevat het Europese klimaat- en energiekader 2030 een bindende doelstelling om tegen 2030 de emissies op het EU-grondgebied met minstens 40 % te verminderen ten opzichte van het niveau van 1990. Om die doelstelling te bereiken, moeten de sectoren die onder de EU-regeling voor de handel in emissierechten (ETS) vallen en de niet-ETSsectoren de emissies respectievelijk met 43 % en 30 % verminderen ten opzichte van 2005. Op lange termijn stelt de door de Europese Commissie uitgegeven Routekaart naar een koolstofarme economie dat de EU tegen 2050 haar emissies tot 80 % onder het niveau van 1990 moet terugdringen door enkel beroep te doen op interne EU reducties. Die EU-doelstellingen worden op de volgende manier vertaald naar Belgische BKG-reducties:

de BKG-emissiereducties schommelen tussen 33 % (Alt1) en bijna 36 % (Alt3) in 2030 ten opzichte van 1990. Die reductiepercentages liggen onder de 40 %-doelstelling voor de EU. In REF liggen de BKG-emissies 26 % lager dan het niveau in 1990. In 2040 schommelen de BKG-emissiereducties tussen 49 % en 51 % in vergelijking met 1990, ten opzichte van 27 % in REF.

**Tabel Broeikasgasemissies in ETS-, niet-ETS- en verschillende energiesectoren, REF en beleidsscenario’s, 2005, 2030 en 2040 Mt CO2-eq.**

<table>
<thead>
<tr>
<th></th>
<th>2005 REF</th>
<th>2005 Alt1</th>
<th>2030 Alt2</th>
<th>2030 Alt3</th>
<th>2040 Alt2</th>
<th>2040 Alt3</th>
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<tbody>
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<td>Vervoer</td>
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<td>23</td>
<td>21</td>
<td>21</td>
<td>21</td>
<td>14</td>
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</tbody>
</table>

Bron: PRIMES, GAINS.

De ETS-emissies liggen in 2030 32 % lager dan in 2005 en 34 % tot 38 % lager in de beleidsscenario’s. De laagste reductie in een beleidsscenario wordt bereikt in Alt3 en de hoogste in Alt1: meer elektrificatie in Alt3 leidt tot bijkomende elektriciteitsopwekking in gasgestookte elektriciteitscentrales ten opzichte van Alt2 en Alt1. Het relatief klein verschil tussen REF en de beleidsscenario’s kan hoofdzakelijk worden verklaard door de beperkte manoeuvrerruimte in de elektriciteitssector waar de brandstofmix al relatief koolstofarm is in REF (ongeveer 60 % aardgas en 40 % hernieuwbare energiebronnen). Na 2030
dalen de ETS-emissies verder in de beleidsscenario’s (tegenover een stabilisering in REF). De ETS-emissies liggen in 2040 42 % tot 46 % onder het niveau van 2005.

De niet-ETS-emissies dalen in 2030 met 27 % in Alt1 ten opzichte van 2005 en met respectievelijk 32 % en 35 % in Alt2 en Alt3 (tegenover 18 % in REF). Bijkomende emissiereducties ten opzichte van REF worden gerealiseerd in de residentiële en tertiaire sectoren (gebouwen). In 2040 stijgen de emissiereducties en schommelen ze tussen 49 % en 56 % als gevolg van de snelle expansie van elektrische voertuigen en een uitgebreider gebruik van biobrandstoffen in het transport.

Het Europees klimaat- en energiekader 2030 bepaalt een bindende doelstelling op EU-niveau om het aandeel hernieuwbare energiebronnen te verhogen tot minstens 27 % van het bruto finaal energieverbruik in de EU tegen 2030. Voor België leidt die doelstelling tot een verdere ontwikkeling van de HEB ten opzichte van REF. In 2030 wordt het grootste aandeel HEB bereikt in Alt3 (19,7 %), gevolgd door Alt1 en Alt2 met respectievelijk 17,9 % en 18,9 % ten opzichte van 15,4 % in REF. In 2040 blijven de HEB stijgen en verkleint het verschil tussen de beleidsscenario’s enigszins. Het HEB-aandeel schommelt tussen 30,5 % en 31,8 %, ten opzichte van 17 % in REF.

<table>
<thead>
<tr>
<th>HEB-aandeel in het bruto finaal energieverbruik en naar gebruik, REF en beleidsscenario’s, 2015, 2030 en 2040</th>
<th>2015</th>
<th>REF</th>
<th>Alt1</th>
<th>Alt2</th>
<th>Alt3</th>
<th>2030</th>
<th>REF</th>
<th>Alt1</th>
<th>Alt2</th>
<th>Alt3</th>
<th>2040</th>
<th>REF</th>
<th>Alt1</th>
<th>Alt2</th>
<th>Alt3</th>
</tr>
</thead>
<tbody>
<tr>
<td>HEB-V&amp;K</td>
<td>8,1</td>
<td>14,0</td>
<td>13,9</td>
<td>14,8</td>
<td>15,3</td>
<td>15,9</td>
<td>23,5</td>
<td>24,3</td>
<td>24,7</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HEB-E</td>
<td>15,4</td>
<td>27,8</td>
<td>37,1</td>
<td>37,1</td>
<td>37,6</td>
<td>30,2</td>
<td>44,4</td>
<td>44,1</td>
<td>43,8</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HEB-T</td>
<td>3,5</td>
<td>12,4</td>
<td>15,4</td>
<td>16,0</td>
<td>16,6</td>
<td>13,6</td>
<td>69,6</td>
<td>71,5</td>
<td>73,9</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Totale HEB-aandeel</td>
<td>8,1</td>
<td>15,4</td>
<td>17,9</td>
<td>18,9</td>
<td>19,7</td>
<td>17,0</td>
<td>30,5</td>
<td>31,3</td>
<td>31,8</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Bron: PRIMES.

Uit de analyse naar HEB-gebruik blijkt dat de wijzigingen in 2030 significant zijn in de elektriciteits- en transportsector, maar eerder bescheiden voor verwarming en koeling. Het aandeel HEB-E stijgt met bijna 10 procentpunt in de beleidsscenario’s (38 % tegenover 28 % in REF) en het aandeel RES-T stijgt met 3 tot 4 procentpunt (15 % tot 17 % ten opzichte van 12 % in REF). Daartegenover staat dat het aandeel HEB-V&K 14 % tot 15 % bedraagt in alle scenario’s. In 2040 komt daar verandering in. De aandelen voor elk gebruik stijgen aanzienlijk tot ongeveer 24 % voor HEB-V&K, tot 44 % voor HEB-E en tot meer dan 70 % voor HEB-T, waardoor de kloof met REF aanzienlijk groter wordt (respectievelijk 16 %, 30 % en 14 %).

Energie-efficiëntie

Het Europese klimaat- en energiekader 2030 bepaalt een indicatieve energiebesparingsstreefwaarde van minstens 27 % tegen 2030. Op 30 november 2016 heeft de Commissie voorgesteld om de energie-efficiëntierichtlijn te herzien en daarbij een nieuwe energie-efficiëntiedoelstelling van 30 % op te nemen voor 2030. In de NEKP’s moeten de lidstaten een nationale energie-efficiëntiedoelstelling vastleggen op basis van het primair of finaal energieverbruik.

In onze beleidsscenario’s wordt het primair energieverbruik verminderd met 27 % tot 29 % in 2030 ten opzichte van het geprojecteerde (PRIMES REF2007) niveau van 50,1 Mtoe. Het ligt bovendien 29 % tot 30 % onder het consumptieniveau in 2005 (tegenover 22 % in REF). Voor 2040 zijn er geen cijfers
beschikbaar in het PRIMES REF2007-scenario. De evolutie in de beleidsscenario’s kan worden vertaald naar reducties van 32 % tot 34 % ten opzichte van 2005 (tegenover 22 % in REF).

Het finaal energieverbruik wordt in 2030 verminderd met 21 % tot 24 % in de beleidsscenario’s ten opzichte van het geprojecteerde (PRIMES REF2007) niveau van 39,9 Mtoe in 2030. Het ligt bovendien 14 % tot 17 % onder het consumptieniveau in 2005. In 2040 schommelen de overeenstemmende percentages tussen 17 % en 21 %. In REF daalt het finaal energieverbruik met 5 % in 2030 en met 6 % in 2040 ten opzichte van 2005.

**Energiezekerheid**

Energiezekerheid is een veelomvattend concept. Deze studie maakt het mogelijk bepaalde indicatoren te kwantificeren die het niveau en de evolutie van de energiezekerheid van een land weerspiegelen: de primaire energiemix, de binnenlandse productie versus de netto-invoer van energie en de invoerafhankelijkheid. Die indicatoren komen ook aan bod in de NEKP’s.

De beleidsscenario’s vertonen aanzienlijke wijzigingen op het gebied van de primaire energiemix. Ten opzichte van 2015 vertonen alle scenario’s een daling in het aandeel vaste brandstoffen (het resterende verbruik is geconcentreerd in de ijzer- en staalindustrie) en olie (hoofdzakelijk gebruikt in de transportsector) en een toename van de bijdrage van aardgas (voor elektriciteitsopwekking), elektriciteit (invoer) en HEB. Het aandeel kernenergie daalt tot nul als gevolg van de volledige ontmanteling van de kerncentrales in 2025.

In 2030 wordt de rol van olie en aardgas in de beleidsscenario’s afgezwakt in vergelijking met REF. Fuel switching en energiebesparing die vereist zijn om de energie- en klimaatdoelstellingen te bereiken, leiden tot een verminderde consumptie van olie en aardgas voor verwarmingsdoeleinden en van diesel en benzine voor transportdoeleinden ten gunste van elektriciteit en biobrandstoffen. Anderzijds stijgt het HEB-aandeel tot ongeveer 20 % ten opzichte van 16 % in REF.

**Tabel Primaire en finaal energieverbruik, REF en beleidsscenario’s, 2005, 2030 en 2040**

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th></th>
<th>2030</th>
<th></th>
<th>2040</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mtoe</td>
<td>REF</td>
<td>Alt1</td>
<td>Alt2</td>
<td>Alt3</td>
<td>Alt1</td>
</tr>
<tr>
<td>Primair energieverbruik</td>
<td>51,3</td>
<td>40,1</td>
<td>36,5</td>
<td>35,9</td>
<td>35,7</td>
<td>40,0</td>
</tr>
<tr>
<td>Finaal energieverbruik</td>
<td>36,6</td>
<td>34,6</td>
<td>31,6</td>
<td>30,7</td>
<td>30,2</td>
<td>34,3</td>
</tr>
</tbody>
</table>

Bron: PRIMES.

Tegen 2040 zetten de wijzigingen zich voort en stijgen ze zelfs voor olie en HEB. De forse daling van het aandeel van olie is hoofdzakelijk te wijten aan de verdere elektrificatie en het gebruik van...
biobrandstoffen in de transportsector. De aanzienlijke stijging van het HEB-aandeel dat de tweede plaats inneemt in de primaire energiemix is toe te schrijven aan de elektriciteitsopwekking, het gebruik van warmtepompen en biobrandstoffen.

De energie die wordt geproduceerd in België heeft voornamelijk betrekking op hernieuwbare energiebronnen (nucleaire warmte wordt ook beschouwd als een binnenlandse energiebron, maar valt terug tot nul in 2030 en 2040 als gevolg van de kernuitstap).

De binnenlandse productie stijgt met 13 % tot 21 % in 2030 ten opzichte van REF. De bijkomende productie is vooral afkomstig van zonne-energie en wind. De productie van biomassa en afval verschilt slechts licht tussen de scenario’s onderling. In 2040 is de stijging aanzienlijk groter en schommelt die tussen 41 % en 44 % ten opzichte van REF. Zonne-energie en windproductie stijgen wederom in alle beleidsscenario’s, alsook de productie van biomassa en afval.

<table>
<thead>
<tr>
<th>Tabel</th>
<th>Binnenlandse productie, netto-invoer van energie en invoerafhankelijkheid, REF en beleidsscenario's, 2015, 2030 en 2040</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015</td>
</tr>
<tr>
<td>Binnenlandse productie (Mtoe)</td>
<td></td>
</tr>
<tr>
<td>Netto-invoer (Mtoe)</td>
<td></td>
</tr>
<tr>
<td>Invoerafhankelijkheid (%)</td>
<td></td>
</tr>
</tbody>
</table>

Bron: PRIMES.

(*) zonder nucleaire warmte (jaar 2015).

Terwijl de binnenlandse productie hoofdzakelijk betrekking heeft op HEB, bestaat het leeuwendeel van de netto-invoer uit fossiele brandstoffen: 95 % in 2015. In 2030 daalt de netto energie-invoer in de beleidsscenario’s met 9 % tot 11 % ten opzichte van REF. Die daling wordt hoofdzakelijk veroorzaakt door olie en aardgas. In 2040 wordt die impact versterkt: de netto-invoer daalt met 16 % tot 18 % ten opzichte van REF. Olie ondervindt daarbij de grootste impact, gevolgd door aardgas. Daartegenover staat dat de netto-invoer van biomassa en elektriciteit stijgt ten opzichte van REF.

In 2015 importeerde België 84 % van alle energie dat het verbruikte. De invoerafhankelijkheid van België wordt niet verondersteld te dalen in de beleidsscenario’s. Ze laat evenwel een – marginale – daling optekenen ten opzichte van REF. Dat is voornamelijk omdat de daling van de netto-invoer gedeeltelijk gecompenseerd wordt door een daling in de totale energiebehoeftte.

Hoewel België sterk afhankelijk is van buitenlandse leveranciers, kan het rekenen op een goed gediversifieerde portefeuille van leverancierslanden en -routes.

Interne energimarkt

De invoer van aardgas ligt 12 % tot 14 % (respectievelijk 18 % tot 20 %) lager in de beleidsscenario’s ten opzichte van REF in 2030 (respectievelijk 2040). De overeenkomstige invoervolumes liggen hoger dan in 2015, maar lager dan in 2010 (16,8 Mtoe).

De netto elektriciteitsinvoer bereikt een hoog niveau in de beleidsscenario’s in 2030 (29 TWh tegenover 26 TWh in REF) en – in tegenstelling tot REF waar de netto-invoer vervolgens daalt en stabiliseert rond 21 TWh – stijgt verder tot 30 TWh in 2030. De kloof tussen de beleidsscenario’s en REF kan worden verklaard door de integratie van meer hernieuwbare energiebronnen in de elektriciteitssystemen van die eerste, waardoor een hogere nood aan balancing ontstaat. Er kunnen meer hernieuwbare energiebronnen worden opgenomen in die systemen door de veronderstelde marktverbeteringen en de EU-marktkoppeling, die relatief lage balancingkosten voor HEB op Europees niveau mogelijk maakt.

Onderzoek, innovatie en concurrentievermogen

Indicatoren met betrekking tot onderzoek en innovatie die vereist zijn in de NEKP’s zijn niet makkelijk terug te vinden of ontbreken zelfs in onze scenario-analyse. Die laatste levert echter informatie over de evolutie van de energiekosten, wat vaak wordt gebruikt om het thema van het concurrentievermogen van de industrie aan te kaarten. Als de Belgische industrie te kampen heeft met hogere energiekosten (stijgingen) dan haar tegenhangers, kan het concurrentievermogen daaronder lijden. De indicator die hier wordt onderzocht, is de eenheidsenergiekost. Die indicator meet de energieinputkosten per eenheid toegevoegde waarde. De eenheidsenergiekost brengt twee componenten samen: de energieprijs en de energie-intensiteit. Dat zou kunnen betekenen dat een verwachte stijging van de eenheidsenergiekost ten opzichte van REF kan worden verzacht als een daling van de energie-intensiteit – bij gelijke omstandigheden – de stijging van de energieprijzen compenseert.

De eenheidsenergiekost wordt verondersteld te stijgen in alle scenario’s in 2030 ten opzichte van 2015 als gevolg van de forse stijging van de energieprijzen (met meer dan 40 %) die niet wordt gecompenseerd door een gelijkaardige daling van de energie-intensiteit (door ongeveer 20 %). De eenheidsenergiekost ligt doorgaans lager in de beleidsscenario’s dan in REF door de bijkomende verbeteringen van de energie-efficiëntie die tot een grotere daling van de energie-intensiteit leiden. Over de periode 2030-2040 blijft de eenheidsenergiekost vrij constant in de beleidsscenario’s (maar daalt ze in REF). De energie-intensiteit blijft dalen en compenseert de stijging van de energieprijzen die een gevolg is van een intensiever verbruik van elektriciteit ten koste van fossiele brandstoffen.
Hoewel erg instructief is de evolutie van de eenheidsenergiekost niet voldoende om de impact op het concurrentievermogen te beoordelen. Een dergelijke analyse vereist een vergelijking met de evolutie in de andere lidstaten (en buiten de EU). Deze informatie is vandaag niet beschikbaar. In het voorgestelde format van de NEKP’s moet deze info evenwel gerapporteerd worden. Eenmaal de NEKP’s dus beschikbaar zijn, kunnen vergelijkingen gemaakt en lessen over concurrentievermogen getrokken worden.
1. Introduction

In October 2017, the Federal Planning Bureau came out with the publication of its three-yearly energy outlook. That outlook documents the Belgian energy and greenhouse gas emission projections under unchanged policy up to horizon 2050. Throughout time, it has reached a wide audience of different stakeholders. That outlook, although valuable in itself by plotting the trajectories if policies would remain unchanged compared to what is currently adopted, demonstrates the need to go further if we want to succeed in sculpting a low-carbon society. It shows that, under unchanged policy, we are drifting away from agreed targets and international agreements made to protect future societies from hazardous levels of climate change.

That is why that outlook needs to be complemented by another report that adopts a completely different perspective. In the projections of that other report, targets, objectives and constraints defined on a national and/or European level are integrated. And that is what this publication is all about: providing and describing three alternative policy scenarios that are compatible both with the 2030 EU Climate and Energy Framework and with the 2050 greenhouse gas emission reduction target at EU level. The different policy scenarios differ in their ambition of non-ETS greenhouse gas emission reductions on the Belgian soil: they amount to 27%, 32% and 35% in 2030 compared to 2005, thereby reflecting the option to resort to flexibilities to achieve the proposed national Belgian non-ETS target in 2030 which is set at 35%. The policy scenarios are consistently compared with the Reference (unchanged policy) scenario. This gives a clue as to how big the gap is or what room for manoeuvre we still have to comply with the different objectives.

Moreover, this report also feeds into the discussion surrounding the Clean Energy Package. The Clean Energy Package constitutes the backbone of the EU climate and energy policy beyond 2020 and includes a set of legislative proposals which are still under discussion and expected to be adopted by the end of 2018. One of these proposals is a Regulation of the European Parliament and the Council on the Governance of the Energy Union. The cornerstone of the Governance regulation is constituted by the integrated national energy and climate plans (NECP). Elaborated and submitted by the Member states, the plans aim to present the objectives, policies and measures and projections for each of the five dimensions of the Energy Union, namely decarbonisation, energy efficiency, energy security, internal energy market and research, innovation and competitiveness. Projections integrating planned policies and measures are required, including a comparison with projections based on existing policies and measures.

The Belgian NECP is being elaborated by the different entities (the three Regions and the Federal State). The main role of the Federal Planning Bureau (FPB) in the process is to provide support and expertise for the analytical part of the plan. The present FPB’s study as well as its Reference scenario published in October 2017 can provide interesting and useful results in the ongoing elaboration process since a lot of the elements of the NECP format can be found in this publication: sometimes a bit scattered (throughout the text and supporting material), sometimes in a very straightforward way. The latter can be seen in the structure of the executive summary at the beginning of this publication: it is designed to guide you through the main results ordered per key dimension of the Energy Union.
In this publication, four chapters can be explored. After a short overview of the methodology and some key assumptions in chapter 2, chapter 3, 4 and 5 tackle the three E’s: chapter 3 describes the Environmental impact, chapter 4 the Energy system impact and finally, chapter 5 Browse some Economic impacts of the different scenarios.

Although factoring in the longer-term perspective (2050) for GHG emission reductions, the impacts on the development of the energy system and the economic impacts cover the period from 2021 to 2040. This time horizon is in line with the reporting requirements for the integrated national energy and climate plans in the proposed regulation on the Governance of the Energy Union. Moreover, going beyond 2040 is highly speculative in terms of maturity and possible technologies and behavioural changes that can allow high levels of decarbonisation.

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1 This approach was also followed, for instance, by the national TSO in a recent report (Elia, 2017) and by the European Network of Transmission System Operators for Gas and Electricity in their joint publication TYNDP2018.
2. Methodology and key assumptions

This publication aims at elaborating and analysing three policy scenarios for Belgium that are compatible both with the 2030 targets and main elements of the 2030 EU Climate and Energy Framework and with the 2050 greenhouse gas emission reduction target at EU level. The analysis includes a comparison with the REF scenario described in (FPB, 2017).

The design of the policy scenarios is inspired by the Impact Assessment issued by the European Commission on November 30, 2016 (EC, 2016) and by the Belgium target of -35% in 2030 in the proposal for an Effort Sharing Regulation 2021-2030. This target covers the sectors of the economy that fall outside the scope of the EU Emissions Trading System (EU ETS). The reduction percentage relates to the year 2005.

The chapter is split in two parts. Section 2.1 deals with the methodology and provides a description of the policy scenarios and the modelling approach. Section 2.2 summarises the key assumptions.

2.1. Methodology

2.1.1. Scenario description

The three scenarios under investigation are named Alt1, Alt2 and Alt3. The pattern of Alt1 is very similar to the EU CO30 scenario in (EC, 2016). Alt2 and Alt3 were designed to primarily address the impact of the electrification of final uses (heating and cooling, mobility) on GHG emission reductions in the non-ETS. Electrification gradually intensifies from Alt1 to Alt3 leading to augmenting the GHG reduction level in the non-ETS towards the proposed target of -35% (see Table 1).

<table>
<thead>
<tr>
<th>Table 1</th>
<th>Greenhouse gas emission reductions in the non-ETS in Belgium according to the policy scenario, year 2030</th>
<th>% compared to 2005</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Alt1</td>
<td>Alt2</td>
</tr>
<tr>
<td>GHG non-ETS</td>
<td>-27</td>
<td>-32</td>
</tr>
</tbody>
</table>

Source: PRIMES (Alt1), assumptions (Alt2 and Alt3).

The rationale behind this range of reduction levels in the non-ETS is the proposed regulation that provides flexibilities to allow for a fair and cost-efficient achievement of the national targets.

Three types of flexibilities are possible:

- Banking, borrowing, buying and selling: like under the current Effort Sharing Decision covering the period 2013-2020, in years where emissions are lower than their annual emission allocations, Member States can bank any surplus and use it in later years. In years where emissions are higher than the annual limit, they can borrow a limited amount of annual emission allocations from the following year’s allocation. Member States can also buy and sell allocations from and to other Member States.

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2 See for instance https://ec.europa.eu/clima/policies/effort/proposal_en
One-off flexibility to access allowances from the EU ETS: this allows eligible Member States to achieve their national targets by covering some emissions in the non-ETS sectors with EU ETS allowances which would normally have been auctioned. The maximum level of access from the EU ETS is set to 2% for Belgium.

Flexibility to access credits from the land use sector: in order to stimulate additional action in the land use sector, the proposal permits eligible Member States to use credits over the entire period 2021-2030 from certain land use categories to comply with their national targets. The maximum flexibility is set to 0.5% for Belgium.

Common and general assumptions on climate, renewables and energy efficiency policies that have been modelled in the policy scenarios are described in (EC, 2016; pp.69-70). They are summarised below.

The alternative scenarios are designed to meet the following 2030 targets at EU level:

- At least 40% GHG emission reduction with respect to 1990;
- 43% GHG emission reduction in ETS sectors compared to 2005;
- 30% GHG emission reduction in non-ETS sectors compared to 2005;
- At least 27% share of RES in gross final energy consumption;
- 30% reduction in primary energy consumption compared to PRIMES REF2007.

They are also coherent with an 80% EU GHG reduction target in 2050 compared to the 1990 level.

To achieve the 2030 GHG reduction target in the ETS, the linear reduction factor of the cap is increased to 2.2% per year in the period 2021-2030 (compared to 1.74% in REF). After 2030, a cap trajectory is set to achieve a 90% emission reduction in 2050 compared to 1990 in line with the Low Carbon Economy Roadmap.

The cap in the ETS translates into carbon prices in the EU ETS. They are reported in Table 2 and compared to the REF values.

<table>
<thead>
<tr>
<th>Table 2</th>
<th>Evolution of carbon prices in the ETS, REF and policy scenarios</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>EUR/t CO₂</td>
</tr>
<tr>
<td>REF</td>
<td>7.5</td>
</tr>
<tr>
<td>Policy scenarios</td>
<td>7.5</td>
</tr>
</tbody>
</table>

Source: PRIMES.

In the period 2020-2030, carbon prices are lower in the policy scenarios than in REF. This outcome results from energy efficiency and renewable policies implemented in the policy scenarios. The former leads to energy savings in EU industry (part of which belongs to the ETS) and to electricity savings in final demand sectors leading to a reduction in gas-fired power generation at EU level. Both evolutions combined with the strong development of renewables in the power sector translate into lower GHG emissions in the ETS and therefore to lower carbon prices required to stay beneath the cap. After 2030, the policies are not sufficient to compensate for the dramatic decline of the emission cap and carbon prices take off.
Energy efficiency policies in the final demand sectors include increasing the renovation rate of buildings, facilitating access to capital for energy efficiency investments, more stringent ecodesign standards for appliances and motors, more stringent CO₂ standards for cars and vans. Some concrete figures reflecting these changes are provided in chapter 4.1.

The major difference between the policy scenarios lies in the degree of electrification of selected final uses, namely heating, cooling and mobility. Electrification increases gradually from Alt1 to Alt3 leading to growing non-ETS emission reductions. This trend mainly concerns the development of heat pumps in the tertiary and residential sectors and the expansion of electric vehicles in transport. These contrasted evolutions are described in chapter 4.1.

2.1.2. Modelling approach

The evaluation of the policy scenarios is based on a quantitative modelling approach. The CO₂ emissions’ (energy-related and process-related), energy system’s and economic impacts are assessed using the PRIMES model developed by E3M-Lab/NTUA. Emission reduction constraints, the development of renewable energy sources and energy efficiency improvements influence the composition and quantity of energy needs as well as the technology choices for energy production and consumption. This model also allows computing several economic impacts. However, as PRIMES is a partial equilibrium model, the feedback effects of changes experienced in the policy scenarios compared to REF on the Belgian economy (the so-called macroeconomic impacts) are not evaluated. For example, the investments in new technologies will foster the economic activity in particular sectors and the use of economic instruments for meeting the energy and climate targets can bring about additional public revenues that could be recycled in the economy.

Non-CO₂ GHG reduction possibilities are identified through the marginal abatement cost curves calculated with the GAINS model. These cost curves are defined per type of GHG (CH₄, N₂O and F-gases) and by country.

2.2. Key assumptions

To elaborate long term energy and emission projections, it is indispensible to start with the definition of several hypotheses. The hypotheses used in this exercise relate to a number of variables, e.g. international fuel prices, economic activity and demography. They are for the most part identical to the ones described in chapter 3 of (FPB, 2017). Some nevertheless diverge: they are summarised in the so-called coordination policies post 2020 assumed in the policy scenarios. These coordination policies relate to, on the one hand, ongoing infrastructure developments that will enable a larger exploitation of energy efficiency, renewables and greenhouse gas abatement options after 2020 and, on the other hand, R&D and public acceptance that are expected to be needed to meet long-term decarbonisation objectives, having effect beyond 2030. How these policy efforts are translated into modelling material and which efforts are aimed at, is documented in (EC, 2016).
2.2.1. Economic activity, demography and energy prices

The assumptions adopted on economic activity, demography and international energy prices resort from the output of other models and are identical to the ones implemented in (FPB, 2017). They can be found in Table 3.

<table>
<thead>
<tr>
<th>Table 3 Some general indicators, 2015-2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit</td>
</tr>
<tr>
<td>GDP, billion EUR'13</td>
</tr>
<tr>
<td>Population, million</td>
</tr>
<tr>
<td>Households, million</td>
</tr>
<tr>
<td>Oil, EUR'13/MWh</td>
</tr>
<tr>
<td>Natural gas, EUR'13/MWh</td>
</tr>
<tr>
<td>Coal, EUR'13/MWh</td>
</tr>
<tr>
<td>2015</td>
</tr>
<tr>
<td>401</td>
</tr>
<tr>
<td>11.2</td>
</tr>
<tr>
<td>4.8</td>
</tr>
<tr>
<td>28.0</td>
</tr>
<tr>
<td>21.8</td>
</tr>
<tr>
<td>7.0</td>
</tr>
<tr>
<td>2030</td>
</tr>
<tr>
<td>494</td>
</tr>
<tr>
<td>12.0</td>
</tr>
<tr>
<td>5.3</td>
</tr>
<tr>
<td>52.4</td>
</tr>
<tr>
<td>31.3</td>
</tr>
<tr>
<td>14.1</td>
</tr>
<tr>
<td>2040</td>
</tr>
<tr>
<td>584</td>
</tr>
<tr>
<td>12.4</td>
</tr>
<tr>
<td>5.5</td>
</tr>
<tr>
<td>61.5</td>
</tr>
<tr>
<td>35.0</td>
</tr>
<tr>
<td>15.6</td>
</tr>
<tr>
<td>15/30((^3))</td>
</tr>
<tr>
<td>0.4</td>
</tr>
<tr>
<td>0.6</td>
</tr>
<tr>
<td>0.3</td>
</tr>
<tr>
<td>0.5</td>
</tr>
</tbody>
</table>


(*): // stands for annual average growth rate (expressed in %).

GDP continuously increases towards 2040. Between 2015 and 2030, the annual average growth rate of GDP amounts to 1.4%, between 2030 and 2040 it further accelerates to 1.7%.

Population and the number of households also tend to rise. Between 2015 and 2040, the total number of Belgian inhabitants increases by approximately 1.2 million. In 2040, this leads to a total population of 12.4 million persons living in Belgium. Combined with a decreasing average size of a Belgian household, the population increase even leads to a relatively bigger increase in the number of households. By 2040, approximately 5.5 million households reside in Belgium, compared to 4.8 million in 2015.

Oil prices are expected to reach 52.4 EUR/MWh and 61.5 EUR/MWh (expressed in 2013 prices) in 2030 and 2040 respectively. Gas prices become more and more decoupled from oil prices, mainly because of the large amount of undiscovered (conventional and unconventional) resources amongst which shale gas, while coal prices remain overall lower, although they are mounting gradually. These price assumptions have important consequences for the level of the carbon value required to meet the GHG emission reduction targets.

2.2.2. Policy context

For the exact policy context, the reader once again is referred to the (FPB, 2017) publication. It might nonetheless be useful to remind the policy adopted on the nuclear phase-out.

For nuclear energy, the legal policy framework as of 2015\(^4\) is assumed. This law modifies the phase-out calendar of nuclear power reactors Doel 1 and 2 and confirms the change in the phase-out calendar of Tihange 1: the operational lifetime of the three nuclear reactors is extended with 10 years. Hence, all Belgian nuclear power generating facilities (about 6,000 MW in total) will be shut down between 2022 and 2025.

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\(^3\) In dollar per barrel of oil, the corresponding figures are 92.2 and 107.

\(^4\) Moniteur Belge/Belgisch Staatsblad (2015), Loi modifiant la loi du 31 janvier 2003 sur la sortie progressive de l'énergie nucléaire à des fins de production industrielle d'électricité afin de garantir la sécurité d'approvisionnement sur le plan énergétique, 6 juillet 2015/Wet tot wijziging van de wet van 31 januari 2003 houdende de geleidelijke uitstap uit kernenergie voor industriële elektriciteitsproductie met het oog op het verzekeren van de bevoorradszekerheid op het gebied van energie, 6 juli 2015.
2.2.3. Some general assumptions

- The simulations are based on the last available statistics provided by Eurostat (year 2015) at the moment of modelling. This assumption also applies to the Belgian power generating units: the starting situation of the Belgian park is the one reported in 2015.

- Tax rates are kept constant in real terms. Two measures adopted by the federal government in 2015 are implemented: a VAT of 21% on electricity and the closure of the gap between excise duties on diesel and petrol by the end of 2018.

- The PRIMES model is based on individual decision making of agents demanding or supplying energy and on price-driven interactions in markets. The modelling approach is not adopting the perspective of a social planner and does not follow an overall least cost optimization of the entire energy system in the long term. Therefore, social discount rates play no role in determining model solutions. On the other hand, discount rates pertaining to individual agents play an important role in their decision making. Agents’ economic decisions are usually based on the concept of cost of capital, which is, depending on the sector, either weighted average cost of capital (for larger firms) or subjective discount rate (for individuals or smaller firms). In both cases, the rate used to discount future costs and revenues involves a risk premium which reflects business practices, various risk factors or even the perceived cost of lending. The discount rate for individuals also reflects an element of risk averseness.

The discount rates vary across sectors (see FPB, 2017). The reference figures range from 7.5% (in real terms) applicable to public transport companies or regulated investments up to 12% applicable to households.

- Degree days are assumed to slightly decline over time reflecting the decreasing trend observed since 1980. The number of degree-days in 2020 is set equal to the 2005 level (i.e. to 2669 according to the Eurostat methodology). In 2030 (resp. 2050), the number of degree-days is 2592 (resp. 2535).

- All monetary values are expressed in constant prices of 2013 (without inflation).
3. Environmental impacts

The environmental impacts of the different scenarios concentrate on greenhouse gas emissions (GHG) excluding LULUCF. The analysis covers the overall effect (3.1), the effect in the ETS sectors (3.2) and the effect in the non-ETS sectors, including a decomposition analysis of energy-related CO₂ emissions (3.3).

3.1. Total greenhouse gas emissions

Graph 1 illustrates the evolution of total GHG emissions in the different scenarios. The REF and alternative policy scenarios show divergent GHG emission paths (only) from 2020 onwards as the same drivers influence the evolution of GHG emissions to 2020 in each scenario, namely the carbon price in the EU ETS and the binding RES and GHG targets in the non-ETS in 2020. In 2020, GHG emissions are 26% below the 1990 level.

Beyond 2020, GHG emissions continue to decline in all policy scenarios whereas they stabilize at 2020 level in REF.

In 2030, GHG emission reductions range from 33% (Alt1) to almost 36% (Alt3) compared to 1990. These reduction percentages are below the target of 40% in 2030 for the EU, indicating that other EU countries diminish their GHG emissions more than the EU average.

In 2040 (resp. 2050), GHG emission reductions range from 49% to 51% (resp. from 68% to 70%) with respect to 1990.

Source: PRIMES, GAINS.
Table 4 gives more insight in the evolution of GHG emissions in the different scenarios. GHG emissions are split by type of pollutant (energy-related CO₂ emissions, non-energy-related CO₂ emissions and non-CO₂ emissions\(^5\)) and according to the sector (ETS or non-ETS).

<table>
<thead>
<tr>
<th>Year</th>
<th>Total GHG emissions</th>
<th>Energy-related CO₂</th>
<th>Other CO₂</th>
<th>Non-CO₂</th>
<th>ETS</th>
<th>Non-ETS</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>REF 148</td>
<td>Alt1 111</td>
<td>Alt2 100</td>
<td>Alt3 98</td>
<td>57</td>
<td>76</td>
</tr>
<tr>
<td>2030</td>
<td>REF 110</td>
<td>Alt1 78</td>
<td>Alt2 76</td>
<td>Alt3 73</td>
<td>47</td>
<td>40</td>
</tr>
<tr>
<td>2040</td>
<td>REF 63</td>
<td>Alt1 40</td>
<td>Alt2 38</td>
<td>Alt3 41</td>
<td>36</td>
<td>35</td>
</tr>
</tbody>
</table>

Source: PRIMES, GAINS.

Energy-related CO₂ emissions represent more than three quarters of total GHG emissions irrespective of the scenario and the time horizon.

In 2030, GHG emissions are 10% to 13% lower in the policy scenarios relative to REF. These emission reductions result from the sole decline in energy-related CO₂ emissions. This outcome is coherent with the policy assumptions in the alternative scenarios where the focus is put on energy efficiency, renewables and the revised EU ETS.

In 2040, GHG emissions are 29% to 31% lower in the policy scenarios compared to REF. The difference is mainly due to energy-related CO₂ emissions. However, non-CO₂ emissions also contribute to the decline in total GHG emissions further to dedicated policies designed for the period after 2030.

The development of GHG emissions in the ETS is driven by the EU-wide cap set on the total amount of GHG emissions emitted by installations covered by the system, and by the resulting carbon price. Over the period 2013-2020, the cap decreases each year by a linear reduction factor of 1.74%. In REF, the linear reduction factor is assumed to remain constant until 2050. In the policy scenarios, however, the cap is lowered by 2.2% per year between 2021 and 2030. After 2030, the cap trajectory is designed to achieve 90% emission reduction in 2050.

Despite the increase in the linear reduction factor in the policy scenarios, ETS emissions are not reduced much in 2030 compared to REF: from 2% in Alt3 to 6% in Alt1. After 2030, the impact becomes more significant. In 2040, ETS emissions decrease by 13% to 19% relative to REF.

The evolution of GHG emissions in the non-ETS sectors is determined by the national target of -15% in 2020 compared to 2005 specified in the Effort Sharing Decision and, after 2020, by a set of policies mainly dedicated to energy savings and energy efficiency, but also to increasing the share of renewables for heating and cooling and in transport. These policies are designed to domestically reduce non-ETS emissions in the range of 27% to 35% in 2030 compared to 2005 (27% in Alt1, 32% in Alt2 and 35% in Alt3). In the proposal for an Effort Sharing Regulation, the target for Belgium is -35% in 2030 but the regulation provides different types of flexibilities allowing for lower domestic emission reductions. The three

\(^5\) Non-CO₂ greenhouse gases encompass CH₄ (methane), N₂O (nitrous oxide) and the F-gases (fluorinated gases). Non-CO₂ GHG are emitted by a variety of sources and sectors: agriculture, fossil fuel extraction and transport, fuel combustion, waste, nitric and adipic acid production, etc.
alternative scenarios address this option. For comparison, the reduction objective in non-ETS sectors at EU level is 30% by 2030 compared to 2005.

Compared to REF, non-ETS emissions are reduced significantly by 2030: from 13% to 20%. In 2040, they decrease even further: by 37% to 44%.

The alternative scenarios were designed to primarily address the impact of the electrification of final uses (heating and cooling, mobility) on GHG emission reductions in the non-ETS. Electrification increases gradually from Alt1 to Alt3 leading to increasing non-ETS emission reductions. According to the principle of communicating vessels, and all other things being equal, this result translates into decreasing ETS emission reductions when moving from Alt1 to Alt3. Indeed, electrification means more power generation, part of which is produced in gas-fired power plants.

3.2. ETS greenhouse gas emissions

ETS covers the following sectors and gases: power and heat generation (CO₂), energy-intensive industry sectors (energy-related and process CO₂ and N₂O) and commercial aviation (CO₂). In 2015, ETS emissions were allocated among these three groups of sectors as follows: 30%, 60% and 10%. Graph 2 shows the evolution of ETS emissions in the different scenarios over the period 2005-2050.

Between 2005 and 2020, ETS emissions decline steadily and markedly by 38%. This drop combines reductions in all sectors and is the result of, among others, the closure of coal-fired power plants, coke-oven and blast furnace plants, the development of wind power and solar PV, improvements in energy efficiency and investments in N₂O reduction technologies in adipic acid production plants.

In the period 2020-2030, GHG emissions start increasing, although moderately. The growth of emissions in the power generation sector due to the nuclear phase-out is partly compensated by a continuing emission decline in industry. In 2030, ETS emissions are 32% lower than 2005 in REF and 34% to 38% lower in the policy scenarios (for comparison, ETS emissions have to be cut by 43% at EU level). The lowest reduction is achieved in Alt3 and the highest in Alt1 as more electrification in Alt3 leads to extra power generation in gas-fired power plants compared to Alt2 and Alt1. The rather small difference of impact between REF and the policy scenarios primarily results from the narrow room for manoeuvre in the power sector where the fuel mix is already low carbon intensive in REF (approximately 60% natural gas and 40% renewables).
After 2030, ETS emissions start declining in the policy scenarios (against a stabilisation in REF). ETS emissions are 42% to 46% below the 2005 level in 2040 and 72% lower in 2050. The reduction projected in 2050 is less ambitious than the EU objective of -90%.

Table 5 presents more detailed figures for the evolution of GHG emissions in the ETS to 2040.

### Table 5  ETS greenhouse gas emissions by sector, REF and policy scenarios, 2005, 2030 and 2040

<table>
<thead>
<tr>
<th>Mt CO$_2$-eq.</th>
<th>2005</th>
<th>REF</th>
<th>Alt1</th>
<th>Alt2</th>
<th>Alt3</th>
<th>2030</th>
<th>REF</th>
<th>Alt1</th>
<th>Alt2</th>
<th>Alt3</th>
<th>2040</th>
<th>REF</th>
<th>Alt1</th>
<th>Alt2</th>
<th>Alt3</th>
</tr>
</thead>
<tbody>
<tr>
<td>ETS emissions</td>
<td>70</td>
<td>47</td>
<td>44</td>
<td>45</td>
<td>46</td>
<td>47</td>
<td>38</td>
<td>39</td>
<td>41</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power &amp; heat generation</td>
<td>24</td>
<td>17</td>
<td>13</td>
<td>14</td>
<td>16</td>
<td>19</td>
<td>13</td>
<td>15</td>
<td>16</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Industry</td>
<td>42</td>
<td>26</td>
<td>26</td>
<td>26</td>
<td>26</td>
<td>23</td>
<td>20</td>
<td>20</td>
<td>20</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aviation</td>
<td>4</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>6</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

Source: PRIMES, GAINS.

Industry includes not only the final industry sectors but also transformation sectors such as refineries.

In the power sector, additional emission reductions in the alternative scenarios compared to REF come primarily from renewables. In the period 2030-2040, GHG emissions are reduced by about 45% in Alt1, 40% in Alt2 and 33% in Alt3 in comparison with 2005. GHG emissions from aviation are expected to increase or at least stabilise to 2040. Nevertheless, the strong growth in aviation’s activity is partly compensated by the introduction of more efficient aircrafts, the renewal of the fleet and the use of biokerosene after 2030. Extra GHG reductions are rather limited for industry. In the longer term (2040), they result from more electricity and renewable fuels replacing fossil fuels.

### 3.3. Non-ETS greenhouse gas emissions

Main sectors not covered by the EU ETS encompass non-energy-intensive industry, buildings, transport (excluding aviation) and non-CO$_2$ emission sources (agriculture, waste, etc.). In 2015, non-ETS emissions were allocated among these four groups of sectors as follows: 3%, 34%, 36% and 27%. Graph 3 shows the evolution of non-ETS emissions in the different scenarios over the period 2005-2050.

Between 2005 and 2020, non-ETS emissions decline by some 12% in all scenarios thanks to energy savings in buildings (residential and tertiary).

After 2020, emissions continue their declining trend in the alternative scenarios whereas they stabilise to the end of the projection period in REF.

Emission reductions in the policy scenarios compared to REF can be attributed to both energy savings (better insulation, lower CO$_2$ emission standards for cars and light duty vehicles, …) and fuel switching towards low or zero carbon energy forms (natural gas, electricity, renewables). In 2030, non-ETS emissions are reduced by 27% in Alt1.
compared to 2005 and, by construction, by respectively 32% and 35% in Alt2 and Alt3.

In 2040, emission reductions progress and range from 49% to 56% due to the rapid expansion of electric vehicles and a more extensive use of biofuel in transport.

Table 6 presents more detailed figures for the evolution of GHG emissions in the non-ETS up to 2040.

<table>
<thead>
<tr>
<th>Table 6</th>
<th>Non-ETS greenhouse gas emissions by sector, REF and policy scenarios, 2005, 2030 and 2040</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mt CO₂-eq.</td>
</tr>
<tr>
<td>Non-ETS emissions</td>
<td></td>
</tr>
<tr>
<td>Industry</td>
<td></td>
</tr>
<tr>
<td>Buildings</td>
<td></td>
</tr>
<tr>
<td>Transport (excl. aviation)</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td></td>
</tr>
</tbody>
</table>

Source: PRIMES, GAINS.

Other includes non-energy-related and non-CO₂ emissions which are not part of the ETS i.e. mainly fugitive and waste CO₂ emissions and CH₄ and N₂O emissions from agriculture and waste.

In 2030, extra emission reductions compared to REF arise essentially from the residential and tertiary sectors (buildings) and from transport. Moreover, the difference between policy scenarios mainly comes from emission reductions in buildings which increase steadily when moving from Alt1 to Alt3. Compared to 2005, the decrease in emissions ranges from 42% to 60% in buildings and from 18% to 20% in transport, while it is about 20% for industry and 17% in the other sectors.

In 2040, additional emission reductions compared to REF result from changes in buildings, transport and other sectors. As in 2030, the policy scenarios mainly differ according to the emission reductions in buildings. Compared to 2005, GHG emissions decrease by 58% to 72% in buildings, by 45% to 48% in transport, by some 29% in industry and 43% in the other sectors.

The graphs below give more insight into reductions in energy-related CO₂ emissions in buildings and transport. Yearly average emission reductions in the periods 2005-2030 and 2005-2040 are split into three effects: volume, energy intensity and carbon intensity. The decomposition analysis is provided for the tertiary sector (Graph 4), the residential sector (Graph 5), passenger transport (Graph 6) and freight transport (Graph 7).

The volume effect is measured by the value added (VA) in tertiary, by the number of households (HH) in the residential sector, by the number of passenger-kilometres (pkm) and ton-kilometres (tkm) for respectively the passenger and freight transport. The growth of economic activity and demography is identical in all scenarios whereas the growth of transport activity may vary according to the scenario; if positive, the volume effect triggers an increase in GHG emissions, all other things being equal. This trend can however be curbed or even (more than) counterbalanced by a decrease in energy intensity and/or a drop in carbon intensity. Energy intensity indicates how much energy is needed to produce one unit of VA, by one household or for a passenger or a ton of freight to travel one kilometre. Energy intensity is an indicator of energy efficiency improvements. Carbon intensity measures the CO₂ content of energy consumption. Carbon intensity gives a picture of the fuel mix. For instance, fuel switching towards less carbon intensive (e.g. natural gas) or zero carbon energy forms (electricity, renewables, etc.) translates into a decrease in carbon intensity.
In both periods, additional CO\(_2\) reductions in tertiary (Graph 4), compared to REF, result from further decreases in energy and carbon intensities which intensify from Alt1 to Alt3. Improvements in energy efficiency play a more significant role than moving to less carbon intensive energy forms in the period 2005-2030 which does not seem to be the case if we look at a longer period (2005-2040). During the last 10 years, the shares of electricity and renewables take off, leading to a sharp decrease in carbon intensity.

Between 2005 and 2040, CO\(_2\) emissions are reduced by 3.4% per year on average in Alt3. This is the net effect of an average annual growth rate of VA by 1.5% and decreases in energy and carbon intensities by 2.2% and 2.6% respectively. In REF, CO\(_2\) emissions are projected to decrease by 1.1% per year on average.

Energy and carbon intensities follow similar trends in the residential sector (Graph 5), and comparable CO\(_2\) emission reductions are to be noted in both sectors. The only differences are greater volume and energy intensity effects in tertiary than in residential.

For instance, CO\(_2\) emissions are reduced by 3.6% per year on average in Alt3 between 2005 and 2040. This is the net effect of an average annual growth rate of the number of households by 0.6% and
decreases in energy and carbon intensities by 1.7% and 2.6%, respectively. In REF, CO\textsubscript{2} emissions are projected to decrease by 0.9% per year on average.

For passenger (Graph 6) and freight (Graph 7) transport, decreases in transport demand (pkm and tkm) and carbon intensity do not contribute (much) to extra CO\textsubscript{2} emission reductions in the period 2015-2030, compared to REF. The latter results primarily from improvements in energy efficiency due to, among others, more stringent CO\textsubscript{2} emission standards for cars and light duty vehicles. Beyond 2030, transport demand is only marginally reduced but the higher penetration of electric vehicles, natural gas and bio-fuel has a strong impact on carbon intensity allowing for much higher CO\textsubscript{2} emissions reductions.

In the period 2005-2040, CO\textsubscript{2} emissions from passenger (resp. freight) transport are reduced by 3.3% (resp. 0.8%) per year on average in Alt3. This is the net effect of an average annual growth rate of the number of pkm (resp. tkm) of 0.6% (resp. 1.2%) and decreases in energy and carbon intensities by 2.1% (resp. 1%) and 1.8% (resp. 1%), respectively. In REF, CO\textsubscript{2} emissions are projected to decrease by 0.8% per year on average for passengers and to increase by 0.1% for freight.
4. Energy system impacts

The energy system impacts are scrutinized through four sets of indicators: final energy consumption (4.1), power generation (4.2), total energy needs (4.3), renewables and energy efficiency (4.4). Although factoring in the longer-term perspective (2050) for GHG emission reductions, the impacts on the development of the energy system cover the period from 2021 to 2040. This time horizon is in line with the currently proposed regulation on the Governance of the Energy Union, which defines, among others, the content of the integrated national energy and climate plans.

4.1. Final energy consumption

Graph 8 illustrates the evolution of total final energy consumption in the policy scenarios against the development in REF. Total final energy demand declines in all policy scenarios in the period 2020-2040, whereas it is almost stable in REF.

In 2030, final energy demand is reduced by 9% in Alt1, 11% in Alt2 and 13% in Alt3 with respect to REF. In absolute terms, the figures amount to 31.6 Mtoe, 30.7 Mtoe, 30.2 Mtoe respectively, against 34.6 Mtoe in REF.

In 2040, reductions in total final energy consumption intensify: 12% in Alt1, 14% in Alt2 and 16% in Alt3 with respect to REF. In absolute terms, the figures are respectively 30.3 Mtoe, 29.4 Mtoe, 28.9 Mtoe against 34.3 Mtoe in REF.

Final energy consumption can be split by sector. Hence, its evolution can be examined from a sectoral angle. Table 7 depicts the allocation of final energy consumption between the four final demand sectors.
(industry, tertiary, residential and transport) and its evolution over time according to the scenario. A more detailed analysis by sector is provided in the following sections.

Table 7  Final energy consumption by sector, REF and policy scenarios, 2015, 2030 and 2040

<table>
<thead>
<tr>
<th>Sector</th>
<th>2015</th>
<th>2030</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>REF</td>
<td>Alt1</td>
<td>Alt2</td>
</tr>
<tr>
<td>Industry</td>
<td>10.7</td>
<td>10.2</td>
<td>10.1</td>
</tr>
<tr>
<td>Residential</td>
<td>8.1</td>
<td>8.6</td>
<td>7.1</td>
</tr>
<tr>
<td>Tertiary</td>
<td>5.3</td>
<td>5.5</td>
<td>4.7</td>
</tr>
<tr>
<td>Transport</td>
<td>10.4</td>
<td>10.3</td>
<td>9.6</td>
</tr>
</tbody>
</table>

Source: PRIMES.

The energy consumption of industry is projected to decrease moderately but steadily over the projection period. The evolution is identical in all scenarios: energy consumption is reduced by 0.3% per year on average in the period 2015-2030 and by 0.5% in the period 2015-2040. Industry is and remains the biggest final energy consumer in the policy scenarios.

The residential and tertiary sectors experience, in the policy scenarios, the strongest reductions in final energy consumption over the projection period. Energy consumption declines by between 0.9% and 1.7% per year on average in the residential sector and by between 0.8% to 1.5% in tertiary in the period 2015-2030. In the period 2015-2040, the corresponding ranges are 0.5 to 0.9% and 0.4 to 0.8%. On the other hand, final energy consumption is projected to increase in both sectors in REF over the projection period.

Final energy consumption in transport evolves between the above described extreme situations. Energy consumption in the policy scenarios is reduced by around 0.6% per year on average in the periods 2015-2030 and 2015-2040. By contrast, energy consumption is projected to remain roughly stable in REF over the projection period.

4.1.1. Industry

The policy scenarios result in minor changes in energy mix compared to REF. First, there is little scope for fuel switching. The share of the most carbon intensive fuels (coal and oil) in total energy consumption is already rather insignificant in REF: 17% in 2030 and 13% in 2040. Natural gas and electricity each represent one third of total energy consumption in the period 2030-2040, the share of RES is slightly higher than 10% and derived heat closes the gap. Second, industrial production (level and structure) is assumed to evolve equally in all scenarios. For instance, steel production in integrated steelworks is identical in all scenarios so that coal and coke consumption cannot be dramatically reduced from one scenario to another.

In a nutshell, the level of energy consumption in industry is identical in all scenarios in 2030 and in 2040. The only changes compared to REF are: a slight increase in natural gas consumption at the expense of solid fuel and oil consumption in 2030, an increase in electricity and RES consumption and an equivalent drop in fossil fuel consumption in 2040.
4.1.2. Tertiary sector

The policy scenarios are not only characterised by a reduction of final energy demand compared to REF but also by changes in the fuel mix. These changes are compatible with a lower carbon intensive fuel mix and contribute to the decrease in non-ETS GHG emissions required in 2030 and beyond (see 3.3). They are shown in Graph 9.

In 2030, the main variations compared to REF are the fall in the shares of fossil fuels (oil products and natural gas, except in Alt1) at the benefit of electricity. Oil products and natural gas are mainly used for space and water heating and their decline follows the implementation of energy efficiency and energy saving measures (building insulation, more efficient boilers, etc.). Oil loses 4 to 5 percentage points and natural gas up to 7 percentage points (Alt3). Instead, electricity is used for both heating purposes (heat pumps) and appliances (lighting, PC’s, printers, etc.). Although electricity gains from 2 to 11 percentage points compared to REF, electricity consumption is lower than in REF, by between 6 (Alt3) and 13% (Alt1): the impact of energy efficiency improvements (lowering the demand) exceeds the volume effect (increasing the demand). The volume effect reflects the growth in economic activity, in the number of electric appliances per activity unit and the development of heat pumps. The decrease in electricity consumption compared to REF is lower in Alt3 than in Alt1 due to a more significant development of heat pumps in the former.

In 2040, the same trends apply but they intensify. The share of oil is divided by two compared to REF (4% vs. 8%) whilst natural gas loses from 7 to 16 percentage points. Electricity provides from 53 to 62% of the energy needs of the sector compared to 46% in REF. Moreover, the further development of heat pumps in Alt3 makes that the volume effect is bigger than the energy efficiency effect. In other words, more electricity is consumed in Alt3 than in REF. Finally, the share (and consumption) of renewables increase compared to REF (from 2 to 6%). Biomass is the main contributor to this change.
The annual renovation rate of buildings in tertiary is 0.5% in REF in the period 2015-2040 while it amounts to 1.7% in the policy scenarios.

4.1.3. Residential sector

Changes in the energy consumption pattern compared to REF (Graph 10) are very similar to those described for the tertiary sector. Due to the increased proportion of well insulated houses and additional improvements in the efficiency of boilers, the shares of oil products and natural gas drop in 2030 and 2040. In Alt3, for instance, oil and natural gas lose 8 and 11 percentage points respectively in 2030. For electricity, the gains in market share are substantial, especially in Alt3 where the development of heat pumps is the highest among the policy scenarios. Both in 2030 and 2040, a doubling of the share of electricity is to be noted in Alt3 compared to REF: from 22 to 45% in 2030, and from 24 to 51% in 2040. Nevertheless, contrary to tertiary, electricity consumption grows faster in the policy scenarios than in REF. Energy efficiency improvements of appliances do not compensate for the volume effect being made up of more inhabitants and even more households, more appliances per household and a strong development of heat pumps. The share and consumption of renewables also increase by 2040. RES gains from 3 to 7 percentage points compared to REF. Again, biomass is the principal responsible of the increase. Finally, coal almost disappears in the energy mix of the policy scenarios.

Graph 10 Final energy mix in residential, REF and policy scenarios, 2015, 2030 and 2040

The annual renovation rate in the residential sector is 0.7% in REF in the period 2015-2040 while it climbs to 1.3% in the policy scenarios.

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Renewables in the residential sector encompass biomass, geothermal and solar thermal. Solar PV, on the other hand, is accounted for in the power generation sector.
The deeper renovation package implemented in the policy scenarios translates into a better energy performance of residential buildings compared to REF. Graph 11 displays the improvements not only compared to REF, but also over time. The indicator for energy performance is the final energy consumption for heating and cooling (in kWh) per square meter. The higher the energy performance, the lower the indicator.

In 2030, the number of kWh per square meter is projected to decrease by between 19 and 29% compared to REF. It totals 134 kWh/sqm in Alt1, 123 kWh/sqm in Alt2 and 116 kWh/sqm in Alt3, against 165 kWh/sqm in REF.

In 2040, the reduction compared to REF is comparable: it ranges from 18 to 28%. The energy performance indicator drops to 116 kWh/sqm in Alt1, 108 kWh/sqm in Alt2 and 102 kWh/sqm in Alt3, against 142 kWh/sqm in REF.

Despite identical renovation rates in the policy scenarios, the energy performance improves more in Alt3 than in the other two policy scenarios because Alt3 is characterised by a more significant development of heat pumps whose conversion efficiency is much higher than that of gas boilers for instance.

Two indicators for the development of heat pumps in the residential and tertiary sectors are illustrated in Graph 12. The first indicator, called ERES, gives the amount of aerothermal, geothermal or hydrothermal energy captured by heat pumps to be considered energy from renewable sources for the purposes of the Renewable Energy Directive. The second indicator is a proxy for the number of heat pumps.

\[ \text{ERS} \]

\[ \text{proxy} \]

---


8 The number of heat pumps is an ex-post calculation from PRIMES results (it is not a variable in the model). This is an approximation because heat pumps can be of different sizes, types and uses.
The ERES indicator grows significantly in the policy scenarios. In 2030 (resp. 2040), it is 10 to 83% (resp. 48 to 112%) higher compared to REF. Despite this remarkable evolution, the contribution of heat pumps to total RES consumption for heating & cooling remains small in the policy scenarios in the period 2030-2040: from 3 to 5% in 2030 and from 4 to 6% in 2040. The bulk of RES consumption comes from biomass and renewable waste used in industry and in the residential and tertiary sectors.

The gap in number of heat pumps between REF and the policy scenarios only starts to show after 2025. In 2030, it ranges between 20 (Alt1) and 80 (Alt3) thousand units. This evolution corresponds to an average annual growth rate of 12 to 15% in the period 2015-2030. In 2040, the difference between scenarios gets wider: from 460 to 560 thousand units are projected in the policy scenarios, against 310 thousand units in REF. These trends translate into growth rates of between 9 and 12% per year on average in the period 2015-2040.

Another way to illustrate the expansion of heat pumps is to calculate the number of heat pumps that need to be installed every year (on average). In Alt3, for instance, the corresponding figures in the residential sector are around 13 thousand units in the period 2015-2030 and 24 thousand units in the period 2030-2040.

4.1.4. Transport

Transport includes road transport, railways, inland navigation and aviation (both national and international) but excludes maritime transport. Graph 13 shows that the fuel mix in the transport sector is less diversified than in the other final demand sectors. Despite a significant reduction in the share and consumption of oil (diesel, gasoline, LPG, kerosene) in the period 2015-2040, oil keeps its pole position in the policy scenarios by 2040. Starting from 96% in 2015, the oil share drops to about 86% in 2030 and 63% in 2040.
In 2030, the decrease in the share of oil is first captured by biofuels (6 to 7%), then by electricity (4% in the policy scenarios against 2% in REF) and finally by natural gas (3% in the policy scenarios compared to only 1% in REF).

In 2040, biofuel covers one fifth of the energy consumption of transport. Electricity and natural gas also see their contribution grow to respectively 8-10% and 6%.

Contrary to the trend in REF (see Table 7), energy consumption decreases steadily in the policy scenarios. This evolution mainly results from energy efficiency improvements of road vehicles and other transport means (aircrafts, barges, trains) and the electrification of the transport system\(^9\). Modal shift and decrease in transport activity play a minor role (see 3.3).

Energy consumption is reduced by 6-7% compared to REF in 2030 and by between 14 and 17% in 2040.

The two graphs below provide more insight into the contribution of energy efficiency (Graph 14) and electrification (Graph 15) to consumption reductions.

Graph 14 shows the evolution of the average CO\(_2\) emissions of private cars and vans in the different scenarios as well as the CO\(_2\) emission standards applicable to new car (95 gCO\(_2\)/km) and van (147 gCO\(_2\)/km) sales from 2021 on. Changes in average CO\(_2\) emissions can be used as an indicator of energy efficiency improvements of vehicles. However, it is worth keeping in mind that it also includes the effect of the development of electric cars.

---

\(^9\) Electric cars consume about four times less than conventional cars to drive one kilometre.
In *REF*, above emission standards are assumed to be applicable over the entire projection period. Nevertheless, the graph shows CO$_2$ emission levels in 2030 and 2040 still higher than standards. The discrepancy comes from the fact that the model computes real emissions whereas emission standards refer to lab tests based on the new European driving cycle (NEDC) standard.

The *policy scenarios* assume a tightening of CO$_2$ standards post-2021: 80 gCO$_2$/km in 2025, 70 gCO$_2$/km in 2030 and 47 gCO$_2$/km in 2040 for cars; 130 gCO$_2$/km in 2025, 110 gCO$_2$/km in 2030 and 85 gCO$_2$/km in 2040 for vans.

More stringent CO$_2$ standards lead to significant emission reductions compared to *REF*. For cars, they range from 18 to 22% in 2030 and from 53 to 64% in 2040. Although standards are identical in all *policy scenarios*, different penetration rates of electric passenger vehicles explain the variations. For vans, emissions are reduced by 10% in 2030 and by 51% in 2040.

Graph 15 presents the development of the electrical car fleet in the different scenarios with a distinction between plug-in hybrids (PHEV) and full electric cars (100% electric). The figures encompass private cars and passenger light duty vehicles. The graph also shows the evolution of the share of electric vehicles in the total fleet.

The *policy scenarios* experience a strong growth of electric vehicles compared to *REF*, particularly beyond 2030.

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The average lifetime of cars and vans is about 8 to 10 years.
In 2030, the electric fleet totals 1.2, 1.5 and 1.7 million vehicles respectively in Alt1, Alt2 and Alt3, compared to 400 thousand in REF. These absolute amounts translate into the following shares in total fleet: 17%, 21% and 23% in the policy scenarios and 5% in REF. Contrary to REF where plug-in hybrids develop more than full electric cars (70% vs. 30%), the share of both types of engines is more balanced in the policy scenarios.

In 2040, the electric fleet totals 3.5, 4.1 and 4.7 million vehicles respectively in Alt1, Alt2 and Alt3, compared to 800 thousand in REF. Accordingly, the share of electric vehicles in the total park ranges from 48 to 64% compared to a mere 10% in REF. Both types of engines increase over time but Alt3 shows a higher proportion of full electric vehicles than plug-in hybrids (55% vs. 45%).

Finally, Graph 16 presents the evolution of biofuel consumption which also contributes to the decrease in GHG emissions in the policy scenarios. Biofuel includes bioethanol, biodiesel and biokerosene, as well as first-generation biofuels (food and feed-based) and second/advanced-generation biofuels (not food-based). EU Directive 2015/1513 places a cap of 7% on the share of first-generation biofuels by 2020. This cap is assumed to be continued over the projection period. On 30 November 2016, the EC presented a proposal including decreasing targets from 7% in 2021 to 3.8% in 2030, in order to lower emissions related to indirect land-use change emissions. On 18 December 2017, the Council reached an agreement and proposed to maintain the cap at 7% beyond 2020. On 17 January 2018, the plenary resolution of the European Parliament endorsed the proposal to cap first-generation biofuels at 2017 levels, with a maximum of 7% in road and rail transport.

By 2030, biofuel consumption decreases by 10% compared to REF. This is the straight consequence of a similar diminution of diesel and gasoline consumption further to energy efficiency improvements.

11 A recast of the current Renewable Energy Directive, as part of the broader ‘Clean Energy for all Europeans’ package is currently under discussion. The main purpose of the recast RES directive is to increase the share of RES in the EU energy mix to at least 27% by 2030. Different views are shared among the European Commission, Council and Parliament as to the cap on first-generation biofuel beyond 2020. On 30 November 2016, the EC presented a proposal including decreasing targets from 7% in 2021 to 3.8% in 2030, in order to lower emissions related to indirect land-use change emissions. On 18 December 2017, the Council reached an agreement and proposed to maintain the cap at 7% beyond 2020. On 17 January 2018, the plenary resolution of the European Parliament endorsed the proposal to cap first-generation biofuels at 2017 levels, with a maximum of 7% in road and rail transport.
Moreover, the production of advanced-biofuels is still at an early stage and a ceiling is put on first-generation biofuels.

By 2040, things change. Advanced-biofuel consumption takes off not only as a (limited) proportion in diesel and gasoline used in conventional combustion engines but also through higher percentages compatible with new engines and in the form of biokerosene for aviation. Biofuel consumption is projected to represent 25% of total oil consumption in transport, compared to 7% in REF.

Besides oil products, natural gas, electricity and biofuels, there is a fifth energy form that is projected to develop in the transport sector beyond 2025: hydrogen (H₂). However, the development of H₂ is still limited compared to its alternatives by 2040: that is why it is not visible in Graph 13.
Hydrogen is often referred to as an indispensable energy carrier for the energy transition. This reputation is due to its capacity to store excess renewable production, to be used as a fuel (fuel cells) or to be transformed into electricity (electrolysis) or further into synthetic or clean gases (power-to-gas).

Hydrogen production and consumption takes off from 2025 onwards, especially in the policy scenarios. In 2030, hydrogen consumption totals 17 ktoe in the policy scenarios. In 2040, it ranges between 42 and 70 ktoe. Until 2040, \( \text{H}_2 \) is exclusively used in the transport sector (Graph 17). The power-to-gas technology is projected to be competitive only beyond that date, mainly because of rather low efficiencies.

4.2. Power system

Throughout the paper, a few results hinted towards the power system of the future. In this section, the Belgian power system will be described in more detail. A combination of methodologies is used to deepen the analysis and to provide insights in the main feedbacks and causal mechanisms.

In a first section, results from the PRIMES model are reported. PRIMES is an energy system model with a power and steam module that delivers outcomes that are fully consistent with the rest of the energy system. These results are highly valuable and add onto the previous analyses. Nonetheless, to expand our understanding of the power system of the future, a more fine-grained analysis with an extended (hourly) time resolution to deal with the variability of both demand and supply is necessary. Therefore, a second methodology is presented. In fact, it consists of a soft link created between the energy model PRIMES and Crystal Super Grid, a dedicated electricity sector dispatch model (Artelys, 2016).

In what follows, the analysis of the electricity system is split in two parts. The first part describes the electricity related outcomes from the PRIMES model that are embedded in the global energy system and hence are consistent with the sectoral analyses. The second part sketches the results from a series of sensitivity analyses ran with the dispatch model Crystal Super Grid.

4.2.1. PRIMES

a. Methodology

The PRIMES power and steam module is a component of the global PRIMES energy system model. It applies an optimisation algorithm to handle long-term simulation of power system operation, power plant dispatching, investment in new or refurbished power plants, supply/distribution, trading and pricing of electricity between countries and towards consumers. Power market simulation is
simultaneous with simulation of steam, heat market so as to capture trade-offs between cogeneration and boilers, between CHP and pure-electric plants and between self-production and distribution of steam, heat.

The PRIMES power and steam model is rich in representation of technologies, market mechanisms and policy instruments. Some examples\textsuperscript{12}:

- The fully endogenous investment and plant operation modelling covers all known generation technologies (more than 150 distinct technologies) and very detailed representation of renewable energy sources, including highly distributed resources.

- Several electricity storage technologies are endogenous, including hydro with reservoir, hydro pumping, compressed air storage and hydrogen-based storage. Several CHP technologies and their technical operation limits are also included.

- Daily and seasonal variations are captured through hourly modelling of several typical days for each year. Data for typical days include power load, wind velocity and solar irradiance. Load demand is bottom-up built from projection of energy end-uses at detailed level by the PRIMES energy demand models. Demand side management possibilities are handled at detailed level based on technical potential and costs. Highly distributed generation at consumer premises is also included and is taken into account in calculating transmission/distribution losses and costs.

b. Electricity demand

First parameter studied is the electricity demand. The demand for electricity is reflected in an indicator named called-up electrical power. This indicator represents the sum of the electricity consumption of industry, transport, residential and tertiary sectors, the energy branch as well as the losses on the transmission and distribution grids. A similar evolution in all scenarios can be noticed: between 2015 and 2040, demand grows.

All alternative scenarios display a positive growth rate towards 2030. Their annual average growth rate (AAGR) can be situated between 0.6 and 1.5%, thereby surpassing the AAGR of the Reference scenario (0.7%) in 2 out of the 3 cases. The implementation of the Energy Efficiency Directive and the rather successful application of different energy efficiency measures do not seem to be able to restrain the volume and the fuel switching element.

After 2030, a further increase in electricity demand can be observed. This surge is caused by, amongst others, a volume effect inflicted by the increasing number of households as well as the intensified

\textsuperscript{12} For more information, the reader is referred to E3MLab (2017), PRIMES Model version 6, 2016-2017: Detailed model description, http://www.e3mlab.ntua.gr/e3mlab/PRIMES%20Manual/The%20PRIMES%20MODEL%202016-7.pdf.
growth in industrial activity (see Table 3), pulling demand upwards. But what is more interesting, is that demand levels (continue to) diverge. Noteworthy is that the alternative scenarios all display (way) higher demand growth rates than REF, with AAGR’s in the 2030-2040 period reaching between 0.8% (Alt3) and 0.9% (Alt1 and Alt2) (compared to 0.4% in REF). This divergence is caused by different levels of electrification prompted by the non-ETS (and RES) target. The development of both electromobility and electrified heating options\(^\text{13}\) is way more ambitious in the policy scenarios. REF also accounts for some electric passenger transport and heat pumps, but the penetration of electric vehicles (both plug-in hybrids and pure electric vehicles) and heat pumps in the policy scenarios is considerably higher (see 4.1.4).

### Table 8 Called-up electrical power, REF and policy scenarios, 2015, 2030, 2040

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2030</th>
<th>2040</th>
<th>15//30</th>
<th>30//40</th>
<th>15//40</th>
</tr>
</thead>
<tbody>
<tr>
<td>REF</td>
<td>87.7</td>
<td>96.6</td>
<td>103.9</td>
<td>0.6%</td>
<td>0.4%</td>
<td>0.5%</td>
</tr>
<tr>
<td>Alt1</td>
<td>87.7</td>
<td>95.5</td>
<td>115.2</td>
<td>0.6%</td>
<td>0.9%</td>
<td>0.8%</td>
</tr>
<tr>
<td>Alt2</td>
<td>87.7</td>
<td>103.4</td>
<td>122.6</td>
<td>1.1%</td>
<td>0.9%</td>
<td>1.0%</td>
</tr>
<tr>
<td>Alt3</td>
<td>87.7</td>
<td>109.6</td>
<td>129.0</td>
<td>1.5%</td>
<td>0.8%</td>
<td>1.1%</td>
</tr>
</tbody>
</table>

Source: PRIMES.

Note: // stands for annual average growth rate.

In 2040, highest demand is attained in Alt3, the scenario in which the non-ETS emission reduction in 2030 for Belgium is the most ambitious: called-up electrical power almost reaches 130 TWh. Alt1 and Alt2 exhibit higher demand levels than REF at 115 and 123 TWh respectively (compared to 104 TWh in REF).

c. Net imports

As regards net electricity imports, it is essential to gain insight in how the PRIMES model goes about in calculating cross-border electricity exchanges. In fact, depending on the time period, two conceptually different methods are applied. For the period up to 2020, the Net Transfer Capacity or NTC method is employed: based on data provided by ENTSO-E, the future NTC is projected. After 2020, Flow-Based Market Coupling (FBMC) is assumed: this method supposes that the transmission of electricity within Europe will evolve in a context as if there was only one central TSO for all Member States or a framework of well-coordinated TSOs which do not apply reliability criteria from a national but from an EU-wide perspective, which is a key strategic goal for the future development of the internal electricity market within Europe.

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\(^{13}\) The use of electricity in the production of hydrogen through electrolysis of water also adds to the additional demand in the policy scenarios, although in a rather limited way: around 1 to 2 TWh in 2040.
In practical terms, the application of this method could result in electricity transmission beyond the projected NTC, eventually limited only by the installed capacity of the interconnectors between the Member States. As a result, such a system can be understood as a problem of optimizing electricity flows under the restriction of the overall capacity of the interconnectors, similarly to the problem that would be solved if the whole of Europe was a single country\textsuperscript{14}.

Graph 19 demonstrates the level of net imports in both REF and the Alt-scenarios. All scenarios show a remarkable decrease in net imports between 2015 and 2020. This can be largely explained by three elements: 1) the net import level attained in 2015 was historically high which can be attributed to a variety of factors (see Devogelaer and Laine, 2016), 2) the production of the Belgian nuclear power plants is assumed to resume by 2020, but at a slightly lower level than historically recorded, 3) the production of renewable energy sources is rapidly increasing.

In 2030, the level of net imports in the policy scenarios (REF) reaches 29 TWh (26 TWh) and, contrary to REF where net imports afterwards decrease and then stabilise at around 21 TWh, further increases towards 30 TWh in 2040. The divergence between the Alt-scenarios and REF can be understood by more renewables in the former’s power system which pose a higher need for additional balancing. More renewables can be uptaken in these systems because of assumed market improvements and the supposed EU-wide market coupling which allows for rather low balancing costs for RES on a European scale.

\subsection*{d. Power generation}

Demand can be met through net imports on the one hand (see previous part), domestically produced power on the other.

When we look into domestically produced power, we see that between 2015 and 2020, it increases due to reasons already explained above (production increase in both nuclear and renewables). Afterwards, between 2020 and 2030, it starts to display a varying evolution. In REF and Alt1, it decreases to the 2015 level, whilst in Alt2 and Alt3, it manages to keep stable at its 2020 level. Subsequently, domestic production resumes and peaks in 2040 in all scenarios (including REF).

In 2030, production levels are lower or similar to 2020 in all scenarios. This seemingly temporary dip or status quo in domestic generation can be explained by three (interrelated) factors: 1) the full nuclear phase-out, 2) the change in the mix towards a bipolar structure, being natural gas and RES, 3) an increase in imports from neighbouring countries (see Graph 19). All scenarios note depressed production levels,

\textsuperscript{14} PRIMES therefore solves a DC linear power flow optimization model which means that when determining the flows, the model respects the 1st and 2nd Kirchhoff laws.
but the lowest level is achieved in Alt1 (i.e. 67 TWh) which can be attributed to its lower called-up electrical power in the medium term.

In 2040, things change dramatically. Record production levels are noted which all exceed the REF levels: 85 (Alt1), 93 (Alt2) and 99 TWh (Alt3), compared to 83 TWh in REF. This remarkable increase in power production can be brought back to the accelerated surge in demand after 2030 and the stabilisation (decrease) of net imports in the policy scenarios (REF).

Next to the level attained in electricity production, it is also instructive to have a look at the mix. Table 9 gives an insight in the composition of net power production.

Table 9  Energy mix in Net Power Generation, REF and policy scenarios, 2015, 2030 and 2040

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2030</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>37</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Hydro</td>
<td>0</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Wind</td>
<td>8</td>
<td>22</td>
<td>28</td>
</tr>
<tr>
<td>Solar</td>
<td>5</td>
<td>6</td>
<td>14</td>
</tr>
<tr>
<td>Biomass</td>
<td>10</td>
<td>12</td>
<td>11</td>
</tr>
<tr>
<td>Coal</td>
<td>3</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Natural gas</td>
<td>33</td>
<td>60</td>
<td>47</td>
</tr>
<tr>
<td>Other</td>
<td>3</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>

Some things attract attention. First, all scenarios undergo a major transformation from a relatively diversified portfolio in 2015 with nuclear, gas(ses), biomass, coal and some (other) renewable energy sources towards a bipolar power system in 2030 and 2040, exclusively made up of gas on the one hand and (a variety of) renewable energy sources on the other.

In 2030, a marginal amount of derived gasses (accounting for some 1%) can still be spotted in the policy scenario mix, but natural gas is the dominant (fossil) energy source with a share between 45% (Alt1) and 47% (Alt2 and Alt3). Wind follows with a share between 24% (Alt3) and 28% (Alt1). In REF, the situation is quite different with a much higher share for natural gas (60%) and a lower share for wind (22%).

By 2040, the transition in the Alt-scenarios has progressed: the share of natural gas has decreased to somewhere between 38% (Alt1) and 42% (Alt3), whilst wind has been given greater weight with a share between 26 (Alt3) and 31% (Alt1). A status quo compared to 2030 can be noted for the REF shares.

Zooming in on the renewable production, Graph 21 presents an overview of the different renewable technologies in power production in the two projection years (year 2030 left, year 2040 right). This graph depicts 1) the noticeable difference between REF and the Alt-scenarios, 2) the significant increase in renewable electricity production, 3) the preponderance of wind in the Belgian power system in 2040.
In 2030, the share of renewables in the production mix can be situated between 52 and 54% in the Alt-scenarios. By 2040, this interval stretches from 58 to 61%. Meanwhile, the share of RES in REF stays constant at 39%.

Not only the shares increased, also the absolute power production based on renewables jumped to 1) levels between 36 (Alt1) and 42 TWh (Alt3) in 2030, 2) between 52 (Alt1) and 57 TWh (Alt3) in 2040. Almost 80% is being made up of variable renewable sources, i.e. wind and sun. In REF, the 2030 level reaches 28 TWh growing into 32 TWh by 2040.

When it comes to the second pillar, gas, it continues to play a non-marginal role in the power system of the future. However non-marginal, its level and contribution differ across scenarios. In Graph 22, absolute levels of natural gas-based electricity are depicted. Minimum levels are reached in 2020, the year in which the legislative Climate/Energy package introduces high amounts of renewable based electricity in the system, together with an increased use of the nuclear capital in Belgium.

Where net power generation by gas units stood at 22 TWh in 2015, it decreases to somewhere between 15 (Alt1) and 20 TWh (Alt3) in 2020 in the Alt-scenarios (compared to 16 in REF). After 2020, the natural gas-based production uniformly grows until 2035. It then levels off in the Alt-scenarios and decreases to somewhere between 33 and 42 TWh in 2040, whilst REF gas units go on producing 51 TWh.

It is instructive to note that, although demand in the Alt-scenarios is significantly higher than in REF, this additional demand is not met by an increased use of gas in the system. Increased imports and higher production of renewables compensate the surge in demand.
Box 1 Hydrogen in power generation

Hydrogen makes its appearance in the power generation system, but only after 2040. That is why it is not showing in Table 9. The option to deploy hydrogen is available in all scenarios and actually is being taken up in the final demand sectors: already as early as 2025, we notice some use of hydrogen in the transport sector (see 4.1.4). Producing power from hydrogen (as a configuration of P2X) by exploiting the round-trip cycle power-hydrogen-power is only spotted after 2040.

In fact, hydrogen is derived from a surplus production of renewable energy and therefore serves a storage purpose. This storage option is endogenous in the model and consists, next to hydrogen, of technologies like hydro-based pumped storage (HPS), air compression and even (car) batteries. Depending on the economics, storage simultaneously levels out load and accommodates the transfer of renewable energy from times when RES availability exceeds load to times when RES is insufficiently available. The model represents the possibility to produce hydrogen from electrolysis and blend it with natural gas (up to a maximum share of 30-40%). In case of high RES development, hydrogen production, assumed to take place at off peak hours, helps smoothing out the load curve, relaxing reserve power constraints and hence allowing for an even higher penetration of variable RES capacities.

e. Installed capacities

Of course, these levels of production have to be generated in different (types of) power plants. This section covers the capacity that needs to be installed in order to produce the amounts of power described above. Table 10 displays the evolution of the total installed capacity split per energy source.

Table 10 Installed power capacity, REF and policy scenarios, 2015, 2030 and 2040

<table>
<thead>
<tr>
<th>GW</th>
<th>2015</th>
<th>REF</th>
<th>Alt1</th>
<th>2030</th>
<th>Alt2</th>
<th>Alt3</th>
<th>2040</th>
<th>Alt2</th>
<th>Alt3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>5.9</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Hydro</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>Wind</td>
<td>2.2</td>
<td>5.7</td>
<td>7.1</td>
<td>7.1</td>
<td>7.4</td>
<td>6.8</td>
<td>9.1</td>
<td>9.0</td>
<td>8.9</td>
</tr>
<tr>
<td>Solar</td>
<td>3.1</td>
<td>4.0</td>
<td>8.9</td>
<td>11.5</td>
<td>13.2</td>
<td>4.0</td>
<td>13.2</td>
<td>16.1</td>
<td>18.0</td>
</tr>
<tr>
<td>Biomass &amp; Waste</td>
<td>1.2</td>
<td>1.3</td>
<td>1.3</td>
<td>1.2</td>
<td>1.2</td>
<td>1.2</td>
<td>1.8</td>
<td>1.8</td>
<td>2.1</td>
</tr>
<tr>
<td>Coal</td>
<td>0.5</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Gas</td>
<td>6.5</td>
<td>8.5</td>
<td>7.4</td>
<td>8.7</td>
<td>9.8</td>
<td>12.1</td>
<td>10.2</td>
<td>11.5</td>
<td>12.3</td>
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<tr>
<td>Other</td>
<td>0.3</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total</td>
<td>19.9</td>
<td>19.6</td>
<td>24.9</td>
<td>28.8</td>
<td>31.8</td>
<td>24.3</td>
<td>34.4</td>
<td>38.5</td>
<td>41.5</td>
</tr>
</tbody>
</table>

Source: PRIMES.
Note: “Other” stands for petroleum products.

Total installed capacity significantly increases in the Alt-scenarios. Where it stood at 20 GW in 2015, it largely exceeds this level by 2030 when it jumps to somewhere between 25 GW (Alt1) and 32 GW (Alt3). The rhythm at which total capacity expands is way higher than the rhythm at which production increases. For the period 2015-2030, the former increases at an average annual growth rate between 1.5 and 3.2% whilst the latter only grows at an annual average rate between 0 and 1.3%.

Notwithstanding this general increase in capacity, some energy forms are being phased out: nuclear loses 6 GW over the 2015-2030 period, coal 0.5 GW and oil 0.3 GW. Other energy forms then have to (more than) make up for these losses. In 2030, the installed wind capacity in the policy scenarios reaches 7 GW, solar capacity can be situated between 9 (Alt1) and 13 GW (Alt3) whilst gas hovers between 7
(Alt1) and 10 GW (Alt3). The situation is quite different from REF’s: total installed capacity in REF is similar to the level in 2015. This stabilisation in fact covers the nuclear, coal, oil and gas\textsuperscript{15} capacity losses with renewable and gas increases adding up to, in total, 6 GW of wind, 4 GW of solar and almost 9 GW of gas. All scenarios (both REF and policy) bank on an (almost) equal amount of biomass and waste (1.2 to 1.3 GW).

By 2040, capacity has continued its growth path: it now reaches levels between 34 GW (Alt1) and 42 GW (Alt3). Capacity extensions are majorly provided by RES. RES additions in the policy scenarios comprise mostly variable RES, i.e. wind and sun. In 2040, wind reaches an installed capacity of around 9 GW, whilst sun occupies between 13 (Alt1) and 18 GW (Alt3). This renewable system is complemented by gas-fired units representing between 10 (Alt1) and 12 GW (Alt3). In REF, the installed capacity also increases by 24% to reach 24 GW. The division between RES and gas in terms of capacity is 50-50 with gas units totalling 12 GW and wind, solar and biomass summing up to 12 GW.

f. Investments

In this section, we dive further into the capacity additions required to cope with 1) the increasing demand (see Graph 18), 2) the necessary replacement of end-of-technical-lifetime and decommissioned units, 3) guaranteeing the back-up for variable renewable technologies.

Graph 23 displays the height of the necessary investments in all scenarios in two (partly overlapping) periods: the first period between 2015 and 2030, the second between 2015 and 2040.

Capacity expansions solely concern RES and natural gas. Looking at the first period (2015-2030), we see that Alt1 adds around 11 GW RES and 3 GW natural gas, whilst Alt3 adds both more RES (+16 GW) and gas (+6 GW). Considerably less is joined in REF: +5 GW RES and +4 GW of gas. Differences amongst scenarios can therefore be quite substantial: the required investments in Alt3 (21 GW) are more than double what is needed in REF (9 GW). The investments in this first period can largely be attributed to the replacement of the nuclear capacity together with the RES investments necessary to honour the 2020 Climate/Energy package. The difference between REF and the policy scenarios originates in the fact that the latter integrate the 2030 Climate/Energy Framework. After 2030, it is principally the demand increase that causes the capacity expansions. Between policy scenarios, discrepancies are brought on by the degree of electrification. Since Alt3 has the highest electricity demand, more investments in its future power system are needed to safeguard its equilibrium (given that the net imports in the policy scenarios are identical).

\textsuperscript{15} Decommissioning of end-of-lifetime gas-fired units.
4.2.2. Crystal Super Grid

a. Methodology

*Crystal Super Grid* is a unit commitment optimal dispatch model for the electricity sector that can be used for one up to thirty-three European countries. It in fact minimizes total system production costs whilst aligning demand with supply. It contains an extensive library of both physical and financial assets (thermal power plants, renewable energy sources, power lines, etc.) which allows a fine-grained level of detail for analyses. The data infeed for the model mainly originates in publicly available databases. For this specific exercise, *Crystal Super Grid* is soft-linked to PRIMES, meaning that the installed capacities calculated by the capacity expansion power module from PRIMES for the EU28 are integrated in *Crystal Super Grid*. The way this is done is extensively described in Artelys\(^{16}\) (2016).

Powerful optimization solvers are used to calculate the optimal dispatch of generating facilities in the interconnected zones. Results cover e.g. imports/exports between zones (countries or regions), marginal costs of electricity generation as well as the CO\(_2\) emissions of the national and European electricity sector.

*Crystal Super Grid* uses a (rather) deterministic approach. It does not implement the Monte Carlo method but, through design, can operate in a similar manner. More specifically, when uncertainties come into play, say in future demand series or intermittent production profiles, it is possible to evaluate various annual climatological circumstances in one single scenario. This is done by simulating an elevated number of test cases per scenario and by choosing its test cases strategically in such a way that ‘extremities’ are part of the draw.

In this study, scenarios are run with three test cases each to take account of different meteorological years and hence the influence of the weather during a specific year on both demand and solar and wind production. It is important to specify that in the construction of future demand and variable renewable production profiles, a coherence between the two is taken into consideration. This is ensured by including the correlation between demand and variable renewable production observed in different climatological years. The model used to generate the different production profiles was developed by IAEW (Institut für Elektrische Anlagen und Energiewirtschaft) at the university of Aachen RWTH.

In this report, *Crystal Super Grid* with its hourly load profile, power plant ramp-up and emission trading is applied to the European electricity market to study different outsets. The European electricity market that is being considered, covers Belgium next to 32 European countries: Portugal, Spain, France, Italy, Greece, Cyprus, Macedonia, Bulgaria, Montenegro, Serbia, Romania, Bosnia, Croatia, Slovenia, Hungary, Slovakia, Austria, Czech Republic, Switzerland, Germany, Latvia, Luxembourg, Netherlands, UK, Northern Ireland, Ireland, Denmark, Poland, Lithuania, Estonia, Finland, Sweden, Norway. The commercial electricity exchanges between these different countries are modelled through inter-connections (NTC’s). The imported and exported volumes are calculated by the model for each scenario. Due to

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\(^{16}\) In this publication, the integration of PRIMES scenarios in METIS is considered. METIS is an ongoing project initiated by DG ENER for the development of an energy modelling software with the aim to further support DG ENER’s evidence-based policy making, especially in the areas of electricity and gas. The software is developed by Artelys with the support of IAEW (RWTH Aachen University), ConGas and Frontier Economics as part of Horizons 2020.
apparent differences in methodology, these volumes might differ from the ones calculated in the PRIMES model.

As regards the different power plants in this European ‘zone’, they are not modelled individually but are aggregated into production technology categories. This is done because there is an apparent lack of data concerning the power systems of the 32 other countries: taking into account very detailed plant level data for the Belgian power sector but aggregating (hence, applying mean efficiencies, mean production costs, etc) for the other countries would create significant biases in the results.

b. Sensitivity analyses

**Interconnection capacity**

<table>
<thead>
<tr>
<th>First insight</th>
</tr>
</thead>
<tbody>
<tr>
<td>Augmenting the interconnection capacity on the borders decreases system marginal costs.</td>
</tr>
</tbody>
</table>

In order to come up with this insight, two additional scenarios are constructed. These additional scenarios are based on the Alt1 scenario as previously described but differ in their maximum simultaneous import capacity. Where the Alt1 scenario banks on a maximum simultaneous import capacity of 6500 MW in 2030, the import capacity in the Alt1_interco4500 is left equal to the situation of today, meaning that the additional construction of NEMO and ALEGRO, both of whom should be finished and operational by 2020, will not influence Belgium’s maximum simultaneous import capacity. This does not mean that these two new interconnections are not taken into account nor that electricity cannot pass from one country to the other, it simply means that Belgium will not be able to import more than 4500 MW at any given time. This could be seen as a stress case or a N-1 (or N-2) of the future cross-border capacity. A second sensitivity is then taken to be the Alt1_interco8500 case, a situation in which it is assumed that, by 2030, NEMO II and ALEGRO II are part of the interconnection asset base.

First task when running the scenarios is to verify if in the different future power systems security of electricity supply is assured. Checking the extension of the Belgian cross-border capacity which is currently under construction (as simulated in Alt1), we notice that the LOLE is comfortably beneath the legally defined double criterium of security of supply as stipulated in the Belgian Electricity Act. This is not the case when we assume that the maximum import capacity stays equal to what we have today (Alt1_interco4500): the hours of LOLE increase considerably. Not only do they increase, they even breach the double criterium.
This points to the fact that keeping the cross-border capacity in Belgium constant at the current level (4500 MW) while transforming the Belgian power system to an Alt1-modus significantly deteriorates our security of electricity supply. Two options can be taken to safely return to the boundaries of the legally defined criterium: increasing the cross-border capacity or building additional gas-fired power plants in Belgium. Since the former is already looked upon in Alt1, a new scenario is constructed that augments the installed capacity of the gas-fired units. According to our calculations, 2 GW of additional gas units has to be built to secure future supply. This new scenario is called Alt1_interco4500_Gas2G.

Second task is to investigate how these different scenarios differ in system marginal cost and, derived from that, in consumer and producer surplus. The system marginal cost is in fact the equilibrium point at which supply and demand meet. Supply is determined by the merit order curve in which the different electricity production technologies are ranged in increasing order of variable production cost. Demand is sorted in decreasing order of price at which consumers are willing to buy electricity. The point where they intersect, is the system marginal cost.

The system marginal cost can hence be seen as a proxy for the “price” in an energy-only market design. Nonetheless, they are not synonyms, because:

- The system marginal cost reported in this exercise is calculated as an average over the course of a year (8760h) and over the three test cases: it therefore is not a momentary shot of the EPEX screen;
- It relates to the price of the commodity, not to the bill the end consumer receives at the end of the billing period;
- It depends on a number of assumptions as to the hypotheses relative to the price of the fuel, the price of CO₂, the conversion efficiency and the variable O&M costs.

Box 2  LOLE criterium for Belgium

In the Electricity Act of April 29, 1999 and its ulterior amendments concerning the organisation of the electricity market, a legal criterium as to generation adequacy is defined: it is expressed in LOLE. The LOLE or Loss of Load Expectation represents the number of hours per year in which, over the long-term, it can statistically be expected that supply will not meet demand (DECC, 2013). When that occurs, the national TSO needs to turn to additional means to keep the system in balance. TSOs are usually able to solve this without major impacts on the system, i.e. by using instruments such as temporary voltage reductions or the selective disconnection of large industrial users.

Because of a lack of harmonised standards on European or regional (‘zonal’) level, Belgium defined its own double LOLE criterium. It states that the LOLE cannot exceed a maximum of 3h for a statistically speaking ‘normal’ year and a maximum of 20h for a statistically ‘exceptional’ year. Interesting to know is that 3h of LOLE translates into a system security level of 99.97%, meaning that 99.97% (1-(3/8760)) of the year, there will be no expected loss of load caused by insufficient generating capacity.
Comparing the three situations (Alt1_interco4500_Gas2G, Alt1 and Alt1_interco8500), we notice that the construction of additional interconnections has a declining effect on the average system marginal cost (SMC), hence a beneficial impact on the consumer surplus will resort.

First, we compare the situation in which the maximum import capacity stays equal to today (Alt1_interco4500_Gas2G) with an increase in the cross-border capacity up to 6500 MW (Alt1). The resulting difference in SMC then amounts to 3.3 EUR/MWh. This means that proceeding with (or being able to exploit) 2 GW additional cross-border capacity that is currently under construction will be to the benefit of the Belgian consumers: they see a decrease in the average price of the commodity of 3.3 EUR per MWh consumed.18

Constructing even more interconnections (+2 GW) brings additional benefits, but of a lesser magnitude: the difference in SMC between Alt1 and Alt1_interco8500 is 0.5 EUR/MWh, meaning that Belgian consumers pay on average over a year 0.5 EUR less per MWh consumed with the extra 2 GW. Although this impact may seem rather modest, it has to be reminded that it is the result of the averaging out over three test cases and 8760 hours. The hourly impact can therefore be (very) different.

The changes in average system marginal costs are depicted in Table 11. The different values will of course reflect on the consumer surplus. The consumer surplus is defined as the difference between the maximum price the consumer is willing to pay and the actual price he does pay. Because of the higher commodity price, consumer surplus will decrease when import capacity is fixed at the current level (Alt1_interco4500_Gas2G) compared to the commercialisation of an additional 2 GW of import capacity (Alt1): 292 million EUR less consumer surplus is being created. The exploitation of 8500 MW of cross-border capacity (Alt1_interco8500), on the other hand, increases consumer surplus by 51 million EUR with respect to Alt1. The overall effect is decreasing since it is contingent on the installed production capacities of the neighbouring countries (which were fixed for this exercise).

Table 11 Sensitivity 1: Differences wrt Alt1 in average system marginal costs and CCGT production in Belgium, year 2030

<table>
<thead>
<tr>
<th></th>
<th>Alt1_interco4500_Gas2G</th>
<th>Alt1_interco8500</th>
</tr>
</thead>
<tbody>
<tr>
<td>SMC (EUR/MWh)</td>
<td>+3.3</td>
<td>-0.5</td>
</tr>
<tr>
<td>CCGT production (TWh)</td>
<td>+5.8</td>
<td>-0.3</td>
</tr>
</tbody>
</table>

Source: Crystal Super Grid.

Note: SMC stands for System Marginal Cost; CCGT stands for Combined Cycle Gas Turbine.

At the same time, production surplus is affected. The production surplus is defined as the market price multiplied by the quantity of energy produced minus the total variable cost of production. In case of an increase in cross-border capacity, the total production surplus decreases. Why? Because the average selling price for electricity is lowered. When the volume of sold electricity stays constant across the different scenarios (which is the case for wind and sun), the lower price times the same volume leads to an average decrease in producer surplus. But when electricity is being produced by burning natural gas, the volume that is sold on the market also decreases (see Table 11). This effect can be attributed to the

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17 Strictly speaking, the effect could also be caused by the increase in CCGT built to lower the LOLE (uniformly valued at 3000 EUR/MWh). This is why another simulation was run in which the installed capacity in Alt1 was augmented with an additional 2 GW of CCGT. Comparing Alt1_interco4500_Gas2G with this Alt1_Gas2G, an average SMC difference of 3.5 EUR/MWh can be observed, very similar to the number provided in Table 11.

18 The potential impact on the residential grid tariffs is not taken into account: in this part, solely the changes in the commodity price are under scrutiny.
fact that domestic production is partly being replaced by the increased access to cheaper electricity from abroad. A double effect then results: lower volume sold at a lower price, so producer surplus for natural gas fired units definitely goes down.

This is what we see when we compare Alt1_interco8500 with Alt1: the total producer surplus is negatively affected by 23 million EUR. This is not the case when we compare Alt1_interco4500_Gas2G with Alt1: the opposite reasoning holds. Higher market prices and higher CCGT production will trigger a higher producer surplus which is estimated to be at 240 million EUR\textsuperscript{19}.

Table 12 shows the differences in (net) imports and exports in the Belgian power system, year 2030 TWh.

<table>
<thead>
<tr>
<th></th>
<th>Alt1_interco4500_Gas2G</th>
<th>Alt1_interco8500</th>
</tr>
</thead>
<tbody>
<tr>
<td>Imports</td>
<td>-6.3</td>
<td>+2.5</td>
</tr>
<tr>
<td>Exports</td>
<td>-0.5</td>
<td>+2.2</td>
</tr>
<tr>
<td>Net imports</td>
<td>-5.8</td>
<td>+0.3</td>
</tr>
</tbody>
</table>

Source: Crystal Super Grid.

Table 12 depicts the different import and export levels. Since demand in all scenarios is the same, we see that the increase (decrease) in net imports equals the loss (gain) in CCGT production (Table 11). Recall that the price for CO\textsubscript{2} in the Alt1 setting is only slightly below 30 EUR/CO\textsubscript{2}, too low to trigger a switch in the merit order. Additional interconnections therefore give an opportunity to export more, but the effect is mitigated by the presence of cheap(er) coal and lignite in the European system.

This brings us to the second case: phasing out coal in Europe.

**Coal phase-out in a selection of European countries**

### Second insight

A coordinated coal phase-out throughout Europe results in a significantly lower average system marginal cost than would prevail if the carbon price rises to a level that engenders a similar level of emission reductions. Nonetheless, if the carbon price does not increase, this might have some less wanted side-effects in stalling investments in low-carbon or flexible units.

In this second part, we constructed a scenario based on Alt1 but in which the announced coal phase outs by a couple of countries were put in practice. It is called Alt1_Coal Phaseout. More specifically, the Netherlands announced in its ‘Regeerakkoord’ made public on October 10, 2017 that by 2030, it would phase out all its coal-fired units, including the most recent ones commissioned in 2015. The UK\textsuperscript{20}, France\textsuperscript{21} and

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\textsuperscript{19} Of course, the changes in consumer and producer surplus are only part of the equation: investments in transmission lines and/or in new CCGT units have to be taken into account to calculate the full social welfare.

\textsuperscript{20} The UK government unveils coal phase-out plan: https://www.theguardian.com/business/2018/jan/05/uk-coal-fired-power-plants-close-2025.

\textsuperscript{21} The French Ministry of ecological and solidarity Transition writes in its Plan Climat (July 2017): “Nous accompagnerons, dans le cadre de contrats, l’arrêt des dernières centrales électriques au charbon d’ici 2022 ou leur évolution vers des solutions moins carbonées, tout en garantissant la sécurité d’approvisionnement électrique.”
Italy\textsuperscript{22} made similar commitments. A such scenario\textsuperscript{23} generates a decrease in the European power sector CO\textsubscript{2} emissions compared to the original Alt1 scenario of 32.4 Mt\textsuperscript{24}.

In a next phase, we tried to end up with a similar amount of CO\textsubscript{2} reductions in the European power sector by modelling a higher price on carbon. This scenario was named Alt1\textsubscript{Higher carbon price}. Through trial and error, different carbon prices were integrated in the European power system until a price was found that matched the requested amount of CO\textsubscript{2} reductions. This carbon price ended up being twice as high as the original carbon price (in Alt1). Although the decrease in power sector CO\textsubscript{2} emissions is similar, other indicators are quite different. They are depicted in Table 13.

First of all, the delta in system marginal cost is dramatically different, meaning that opting for a coal phase-out instead of experiencing a rise in carbon price causes a spectacularly lower impact on the average system marginal cost, hence on the price\textsuperscript{25} of the commodity. Phasing out coal through regulatory measures hence seems to be cheaper for the customer, but there is a sting: lower carbon prices might not give the proper incentive to boost future wholesale power prices through which investments in the system of the future are remunerated. This means that specifically capital-intensive (e.g. wind or sun) and marginal (e.g. gas-fired power plants) production capacities might not be enticed to invest unless capacity remuneration mechanisms or long-term contracts are on the table.

A second observation is that the production of gas-fired units in Belgium increases more when coal is phased out in different Member States than when the carbon price rises. Two explanations can be found:

\begin{itemize}
  \item The announced coal phase-outs happen really close to us: it concerns our neighbours. Losing capacity in countries with which we are interconnected without replacing it impacts our imports (and exports), hence our own generation scheme (see Table 14).
  \item Although the carbon price is substantially higher, it still does not suffice to trigger a general switch in the merit-order between solids and gas. In other words, even with this higher carbon
\end{itemize}

\textsuperscript{22} In an announcement on October 24, 2017 by Italy’s economic development minister, he stated that his country is committed to phasing out coal and will end all use by 2025.
\textsuperscript{23} In this scenario, it is assumed that 16.6 GW of coal capacity is being decommissioned without being replaced by other reliable available capacity in the country considered. Although national LOLE’s increase, they never exceed 3h.
\textsuperscript{24} 32.4 Mt CO\textsubscript{2} is approximately the amount of CO\textsubscript{2} emitted by the Belgian transport sector in 2015.
\textsuperscript{25} Bearing in mind the nuances about the difference between price and system marginal cost explained in the previous section.
price, the CWE merit-order stays C2G: burning coal and lignite therefore still makes more economic sense than augmenting gas-based electricity production.

4.3. Total energy needs

The impact of the policy scenarios on final energy consumption and power generation translates into changes in our total energy needs and mix. In energy balances published by Eurostat and the IEA, total energy needs are (or can be) split into the following three components: maritime bunkers, non-energy consumption (i.e. energy used as feedstock, mainly in the petrochemical industry) and primary energy consumption. Total energy needs are met in two different ways: domestic production and net imports.

4.3.1. Domestic production and net imports

Energy produced in Belgium mainly concerns renewable energy sources (hydro, wind, solar, geothermal, biomass and renewable waste). Other energy forms produced domestically are non-renewable waste and nuclear heat.

Graph 24 shows the impact of the policy scenarios on domestic energy production. It focuses on the role of wind, solar and biomass & waste. Indeed, hydro and geothermal production are identical in all scenarios and nuclear heat is no longer part of our energy landscape in 2030 and 2040 according to the law on the nuclear phase-out.

In 2030, domestic production increases by 13 to 21% compared to REF. Extra production comes primarily from solar energy (0.4 Mtoe in Alt1, 0.7 Mtoe in Alt2 and 0.8 Mtoe in Alt3), followed by wind (0.3 Mtoe in all policy scenarios). The production of biomass and waste varies only marginally among the scenarios.

In 2040, the increase is more significant; it ranges from 41 to 44% compared to REF. Again, solar energy takes the lead, its production grows by 0.9 Mtoe in Alt1, 1.1 Mtoe in Alt2 and 1.3 Mtoe in Alt3. Wind production increases by 0.6 Mtoe in all policy scenarios. The production of biomass and waste rises too, by 0.8 Mtoe in Alt1, 0.6 Mtoe in Alt2 and 0.5 Mtoe in Alt3.

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26 Net imports mean imports minus exports.
Domestic energy production levels are the highest in Alt3: 6.1 Mtoe in 2030 and 7.9 Mtoe in 2040, compared to around 5 Mtoe in REF in both years. In 2015, the domestic production of RES and non-renewable waste was equal to 3.6 Mtoe.

While domestic production mainly concerns RES, the bulk of net imports is made up of fossil fuels: 95% in 2015. Among fossil fuels, oil takes the lion share with two thirds of net fossil fuel imports in 2015, followed by natural gas (29%) and solid fuels (6%). By 2040, this overall picture is not projected to change significantly in REF: fossil fuels still represent 94% of energy imports and oil remains first of the class (57%) despite a strong increase in the share of natural gas (40%).

More profound changes are expected in the policy scenarios. Graph 25 presents these changes between REF and the policy scenarios. The impact of solid fuels is not shown because the variations in net imports are very small (-0.1 Mtoe in 2030 and -0.2 Mtoe in 2040).
In 2030, net energy imports decrease by 9 to 11% compared to REF. The decrease is caused primarily by oil (2.4 to 3.2 Mtoe) and natural gas (2.1 to 2.5 Mtoe). Net imports range from 45 and 46 Mtoe in the policy scenarios compared to about 51 Mtoe in REF.

In 2040, the impact amplifies: net imports decrease by 16 to 18% compared to REF. Oil is the first concerned: about 7 Mtoe less are imported. Natural gas needs are reduced by slightly less than 4 Mtoe. On the other hand, biomass and electricity net imports rise with 1.4 and 0.8 Mtoe respectively. Net imports range between 41 and 42 Mtoe in the policy scenarios compared to 50 Mtoe in REF.

Despite these changes, fossil fuels still represent 87% of our net energy imports in 2040 (Alt3) and oil occupies more than 50% of the fossil fuel imports. These figures include oil and natural gas used as feedstock in the petrochemical industry. In the period 2030-2040, fossil fuel needs for non-energy uses are estimated to be around 9 Mtoe in all scenarios.

The evolutions described above affect another indicator: the energy import dependency. This indicator reflects the contribution of net energy imports in gross inland consumption. As Belgium does not possess indigenous fossil fuel resources, the country is used to having a rather high energy import dependency indicator of 75% and more.

In the period 2030-2040, Belgium’s energy import dependency is projected to reach even higher levels of around 90% in REF. The increase is due to the nuclear phase-out: nuclear heat is considered to be a domestic energy production which is replaced by renewables (another domestic resource) but also by imported natural gas (used in power plants) and electricity.

The policy scenarios nonetheless exhibit lower dependencies of 88% in 2030 and 84% in 2040. The decline compared to REF might seem marginal. That is basically because the reduction in net imports (the numerator) is partly overtaken by the decrease in gross inland consumption (the denominator).

4.3.2. Primary energy consumption

Primary energy consumption follows an overall decreasing trend in all policy scenarios (Graph 26) in the period 2015-2040, whereas it also declines between 2015 and 2030 in REF but then stabilises in the period 2030-2040.

In 2030, consumption reductions range from 9 to 11% compared to REF. This result converts into 36.5 Mtoe in Alt1, 35.9 Mtoe in Alt2 and 35.7 Mtoe in Alt3, against 40 Mtoe in REF.

In 2040, primary energy consumption is reduced by between 13 and 15% compared to REF. It totals 34.9 Mtoe in Alt1, 34.3 Mtoe in Alt2 and 34 Mtoe in Alt3, against 40 Mtoe in REF.

Despite different reduction targets in the non-ETS, primary energy consumption does not vary much between policy scenarios. This result is the combination of two opposite trends: the higher the reduction target in the non-ETS (Alt3), the more substantial the decrease in total final energy demand but the

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27 Gross inland consumption is the sum of primary energy consumption and non-energy uses.
higher the level of electricity demand; the latter effect leads to more power generation and therefore to higher RES and natural gas needs.

The policy scenarios exhibit significant modifications in terms of primary energy mix (see Table 15) which reflect the changes in final energy consumption and power generation (and supply) described in the previous sections.

Compared to 2015, all scenarios display a decrease in the shares of solid fuels (remaining consumption is concentrated in the iron and steel industry) and oil (mainly used in the transport sector) and an increased contribution of natural gas (for power generation), electricity (imports) and RES. The share of nuclear drops to zero due to the full decommissioning of nuclear plants in 2025.

In 2030, the role of oil and natural gas in the policy scenarios is watered down compared to REF. Fuel switching and energy savings required to fulfil the energy and climate targets lead to consumption reductions of oil and natural gas for heating purposes and of diesel and gasoline in transport at the benefit of electricity and biofuels. On the other hand, the contribution of RES intensifies; it jumps to around 20% compared to 16% in REF. This evolution comes from all RES uses: heating and cooling, electricity generation and transport (see 4.4.1).
In 2040, the changes described above continue and even increase for oil and RES. The strong decline in the share of oil (around 20% in the policy scenarios compared to 32% in REF) is mainly due to further electrification and use of biofuels in the transport sector. The significant increase in the share of RES which becomes the second energy form in the primary energy mix (31% compared to 17% in REF) comes essentially from power generation, heat pumps and biofuels.

### 4.3.3. Energy needs by sector

This section sheds an additional light on the changes in total energy needs. First, it enlarges the scope to maritime bunkers and non-energy uses; second, it provides an allocation of the resulting total energy needs between the different sectors or uses. It aims to complement the analysis provided in previous sections and therefore focuses only on a subset of energy forms, namely oil, natural gas and biomass & waste. Moreover, the comparison with REF concentrates on Alt3.

Graph 27 presents the evolution of oil requirements. The significant reductions in Alt3 compared to REF mostly come from the final demand sectors: oil consumption for heating the buildings is affected by energy savings and fuel switching to natural gas and electricity; oil consumption in the transport sector is influenced by improvements in the energy efficiency of vehicles and other transport means, and the development of electric vehicles and biofuels.

![Graph 27 Oil requirements by sector or use, REF and Alt3, 2015, 2030 and 2040](image)

Oil consumption for maritime transport is also reduced compared to REF but to a lesser extent, at the benefit of natural gas (LNG). The consequence of the above trends is the decrease in the activity of refineries (energy branch) and therefore of their oil consumption. Oil for non-energy uses is comparable between the scenarios.

By 2040, oil used as feedstock takes the pole position in Alt3 with a 39% share followed by maritime transport and other transport with slightly less than 30% each.

The sectoral changes in natural gas requirements are illustrated in Graph 28. Contrary to oil, natural gas keeps growing in Alt3 (at least to 2030) but at a much slower pace than in REF. However, similar to oil,
the most significant reductions compared to REF take place in the residential and tertiary sectors and result from building insulation, efficiency improvements of boilers and the development of electric heat pumps.

Natural gas needs for power generation are lower in Alt3 than in REF in 2030 and 2040 as more electricity is produced from renewables. By contrast, natural gas is more extensively used as maritime fuel and in the transport sector (mainly LNG).

By 2040, the power sector becomes the main user of natural gas (41% of total gas needs in Alt3) followed by industry and (residential and tertiary) buildings (20% each in Alt3).

Graph 29 presents the allocation of biomass & waste supply between the different sectors in REF and Alt3. Biomass includes solid, liquid and gaseous biomass. Waste encompasses renewable as well as non-renewable waste, namely industrial and municipal waste and waste gas.
In 2030, total biomass & waste requirements are lower in Alt3 than in REF. Reduced consumption in the final demand sectors except industry, further to energy savings and energy efficiency improvements, surpasses the increasing demand in the power generation sector. In Alt3, the latter covers half of total biomass & waste needs.

In 2040, transport’s biofuel requirements rise significantly (more than a doubling compared to REF) while additional biomass & waste is also required for power generation and in the tertiary sector. In Alt3, power generation still covers 39% of total biomass & waste needs, closely followed by the transport sector (29%).

In 2015, solid biomass & waste represented the bulk of total biomass & waste supply (80%), followed by biofuels (16%) and biogas and waste gas (5%). In 2030, the share of solid biomass & waste drops to about 70% in REF at the benefit of biofuels, pushed by the renewable target in 2020, while the share of biogas remains roughly stable. The policy scenarios lead to changes in the allocation between the different types of biomass & waste as illustrated in Graph 30.

In 2030, the demand for biomass & waste is reduced by 15 to 21% compared to REF. The reduction comes primarily from solid biomass and is the largest in Alt3. In 2040, additional biomass & waste is required compared to REF. Growth ranges from 54 to 73%. The lowest percentage increase corresponds to Alt3; this outcome can be explained by bigger energy savings and more electrification of transport.

### 4.4. Renewables and energy efficiency

This section is intended to organise or complement some results described earlier in the report so that they can easily be related to indicators required in the National Energy and Climate Plans (NECP). These indicators concern the ‘decarbonisation’ (and more specifically the ‘renewable’ part) and ‘energy efficiency’ dimensions of the plans.
4.4.1. Renewables

The indicators required in the NECP include the trajectory of gross final energy consumption of RES, the share of RES in gross final energy consumption (which corresponds to the RES target) and in the different uses (heating and cooling (RES-H&C), electricity (RES-E) and transport (RES-T)) and RES per technology.

Graph 31 shows the evolution of gross final energy consumption of RES in all scenarios in the period 2015-2040. RES consumption first increases sharply between 2015 and 2020 (from 2.9 to 4.7 Mtoe), triggered by the binding target of 13% in 2020 specified in the Renewable Energy Directive 2009/28/EC. Beyond 2020, the trend slows down in REF where RES consumption totals 5.4 Mtoe in 2030 and 6 Mtoe in 2040.

The policy scenarios present different RES evolutions: RES consumption keeps growing significantly towards 2040. It ranges between 5.8 and 6.1 Mtoe in 2030 and amounts to 9.5 Mtoe in 2040.

Compared to REF, RES consumption rises by 6 to 13% in 2030 and by 59% in 2040.

Table 16 presents the evolution of the overall RES share in gross final energy demand and splits it in the different uses. The overall RES share continues to grow after 2020 (where it is equal, by assumption, to the RES target of 13%). In 2030 and 2040, the policy scenarios are on a sustained growth path.

In 2030, the highest share of RES is reached in Alt3 (19.7%). Alt1 and Alt2 follow with shares of 17.9 and 18.9% respectively, compared to 15.4% in REF. These percentages for Belgium are consistent with the achievement of a 27% binding RES target at EU level proposed in the recast of the Renewable Energy Directive, currently under discussion.

In 2040, the difference between the policy scenarios reduces somewhat, RES share ranges between 30.5 and 31.8%, compared to 17% in REF.

Table 16 Share of RES in gross final energy demand and by use, REF and policy scenarios, 2015, 2030 and 2040

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th></th>
<th></th>
<th></th>
<th>2030</th>
<th></th>
<th></th>
<th></th>
<th>2040</th>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>REF</td>
<td>Alt1</td>
<td>Alt2</td>
<td>Alt3</td>
<td>REF</td>
<td>Alt1</td>
<td>Alt2</td>
<td>Alt3</td>
<td>REF</td>
<td>Alt1</td>
<td>Alt2</td>
</tr>
<tr>
<td>RES-H&amp;C</td>
<td>8.1</td>
<td>14.0</td>
<td>13.9</td>
<td>14.8</td>
<td>15.3</td>
<td>15.9</td>
<td>23.5</td>
<td>24.3</td>
<td>24.7</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RES-E</td>
<td>15.4</td>
<td>27.8</td>
<td>37.1</td>
<td>37.1</td>
<td>37.6</td>
<td>30.2</td>
<td>44.4</td>
<td>44.1</td>
<td>43.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RES-T</td>
<td>3.5</td>
<td>12.4</td>
<td>15.4</td>
<td>16.0</td>
<td>16.6</td>
<td>13.6</td>
<td>69.6</td>
<td>71.5</td>
<td>73.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overall RES share</td>
<td>8.1</td>
<td>15.4</td>
<td>17.9</td>
<td>18.9</td>
<td>19.7</td>
<td>17.0</td>
<td>30.5</td>
<td>31.3</td>
<td>31.8</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: PRIMES.

The analysis by type of use shows that, in 2030, changes compared to REF are significant in the electricity and transport sectors but rather moderate for heating and cooling. The share of RES-E increases by almost 10 percentage points in the policy scenarios (around 38% against 28% in REF) and the share of
RES-T gains 3 to 4 percentage points (15 to 17% compared to 12% in REF). By contrast, the share of RES-H&C amounts to 14 to 15% in all scenarios. The latter result is explained by the fact that RES consumption (numerator) and gross final energy consumption (denominator) in the policy scenarios decrease at a similar pace compared to REF trends. In other words, energy savings dominate the evolution of energy consumption and mix for heating & cooling.

In 2040, things change. Shares surge for all uses, to around 24% for RES-H&C (16% in REF), 44% for RES-E (30% in REF) and to more than 70% for RES-T (13% in REF). The evolution in heating and cooling is caused by two elements: a higher absolute amount of RES like biomass and heat pumps (numerator) and above all a lower level of final energy through energy efficiency measures (denominator). The increased RES-E share follows a higher power production from RES. Finally, the explosion of the RES-T share results from the development of electric vehicles and biofuel, energy efficiency improvements for all transport modes but also from the accounting rules (multiplicators) defined in the current Renewable Energy Directive. The multiplicators (artificially) inflate the contribution of electricity and second-generation biofuels in the numerator.

The evolution of renewables per technology is described in the previous sections (part 4.1 for heating and cooling and transport, part 4.2 for electricity).

4.4.2. Energy efficiency

According to the requirements of the Energy Efficiency Directive 2012/27/EU, Belgium notified indicative national energy efficiency targets for the year 2020. The target is 43.7 Mtoe at primary energy demand level and 32.5 Mtoe for final energy demand.

In the context of the EU 2030 Climate/Energy Framework and the Energy Union package, the Energy Efficiency Directive is being recast. Current provisions of the revised legislative text\(^\text{28}\) include a 30% binding target for reduced energy consumption by 2030, compared with projected levels calculated in 2007; this goes beyond the indicative target of at least 27% set by the European Council in October 2014; the target will be achieved by national energy efficiency contributions; as envisaged by the proposed regulation on Governance of Energy Union. Member States will notify the Commission of their contributions via 10-year integrated national energy and climate plans.

Our policy scenarios are consistent with a 30% energy efficiency target at EU level and provide corresponding evolutions of both primary (Graph 32) and final (Graph 33) energy consumption for Belgium.

Before describing the trends to 2030 and 2040, it is worth noting that current policies and binding 2020 GHG and RES targets would not allow achieving the indicative Belgian energy efficiency targets of 18% in 2020. The gap ranges between 2.6 and 3 Mtoe for the primary energy consumption and between 2.4 and 3 Mtoe for the final energy consumption.

Beyond 2020, primary and final energy demands start decreasing steadily.

In 2030, primary energy consumption is reduced by 27 to 29% in the policy scenarios compared to the projected (PRIMES REF2007) level of 50.1 Mtoe. Moreover, it is 29 to 30% below the consumption level in 2005. In absolute terms, primary energy consumption totals around 36 Mtoe (compared to 40 Mtoe in REF).

For 2040, no figures are available in the PRIMES REF2007 scenario. However, the evolution in the policy scenarios can be translated into reductions with respect to 2005: 32 to 34%. Primary energy consumption amounts to some 35 Mtoe in 2030 (compared to 40 Mtoe in REF).

In 2030, final energy consumption is reduced by 21 to 24% in the policy scenarios compared to the projected (PRIMES REF2007) level of 39.9 Mtoe in 2030. Moreover, it is 14 to 17% below the consumption level in 2005. In 2040, the corresponding percentages are 17 to 21%.

Final energy consumption ranges between 30 and 32 Mtoe (resp. 29 and 30 Mtoe) in 2030 (resp. 2040), compared to 35 Mtoe (34 Mtoe) in REF.
Graph 33  Final energy consumption and energy efficiency target, REF and policy scenarios

Source: PRIMES.
5. Some economic impacts

This chapter deals with a number of economic consequences for Belgium of implementing the EU policy Framework for Climate and Energy in 2030 and moving towards a low carbon economy by 2050. Among the large variety of impacts, the analysis focuses on the total energy system cost (5.1), the fossil fuel trade balance (5.2), energy costs in the final demand sectors (5.3) and electricity system costs (5.4).

As stressed in chapter 2, the economic impacts analysed in this report only represent a sub-set of a full cost-benefit analysis of the policy scenarios. For instance, macroeconomic, skills and social impacts are not covered in the study. From a macroeconomic perspective, the rise in costs and prices leads to changes in agent’s behaviour and demand level that are not accounted for in the present study. Also, the investments in energy efficiency equipment and in new technologies are not just costs for households and firms, they generate revenues for the sectors which produce these equipments (building, manufacturing, …). Furthermore, the additional public revenues generated by e.g. the auctioning of emission allowances can have strong impacts on the cost of labour or on investments, depending on how these revenues are used. To account for these feedback effects, macroeconomic models are needed.

5.1. Total energy system cost

Total energy system cost\(^{29}\) encompasses capital costs\(^{30}\) (related to energy producing installations, energy consuming equipment and energy infrastructure), energy purchase costs (fossil and RES fuels, electricity and heat) and direct efficiency investments costs (such as expenditures for insulation).

Graph 34 presents the evolution of total energy system cost as share of GDP in the policy scenarios as well as in REF. It concentrates on the years 2015, 2030 and 2040. The ratio of total energy system cost to GDP increases from 11% in 2015 to more than 14% in 2030 in the alternative scenarios: 14.3% in Alt1, 14.4% in Alt2 and 14.6% in Alt3. In other words, total energy system cost grows faster than GDP between 2015 and 2030. This evolution also characterises REF (13.6%) as it mainly reflects rising international fuel prices, the need to replace a significant portion of the power generation capacity and other investments required to comply with the 2020 Climate/Energy package. The cost difference between the policy scenarios and REF ranges between 0.7 and 1 percentage point.

\(^{29}\) For a more extensive definition of total energy system cost, see chapter 3.5 and annex 4.4 of (EC, 2016).

\(^{30}\) Capital costs are expressed in annuity payments.
After 2030, the ratio of total energy system cost to GDP starts decreasing, albeit slightly, to about 14% in 2040, meaning that the energy cost evolves at a slower pace than GDP in the long run. It is worth noting that, after 2030, gas import prices are projected to grow only moderately and the impact of EE and RES investments on energy purchases becomes more tangible. Nevertheless, the gap with respect to REF (12.9%) widens, ranging from 1 to 1.2 percentage points. The total energy system cost expressed in terms of GDP exceeds the 2015 figure in all scenarios.

The structure of total energy system cost changes substantially over time reflecting the increasing capital intensiveness and electrification of the energy system. This first trend was already observed in REF but intensifies in the policy scenarios. By 2030, the capital costs and direct efficiency investments (CAPEX) at final demand level\(^{31}\) represent about 36% of the total energy system cost in the policy scenarios (against 21% in 2015). In 2040, the share is even higher: 40%. The share of CAPEX in REF is projected to be 28% in 2030 and 31% in 2040.

Graph 35 decomposes the changes in total energy system cost in 2030 and 2040 into three components: capital expenditures (CAPEX), fuel purchase costs (OPEX-fuel) and purchase costs of electricity & heat\(^{32}\) (OPEX-elec).

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\(^{31}\) The split of total energy system cost into CAPEX and OPEX is made according to a final demand perspective. This means that the capital cost borne by the transformation sectors (e.g. investments in new power plants by electric utilities) is not reported in CAPEX but (implicitly) in OPEX. For instance, the electricity purchase cost which is part of OPEX is calculated from the price of electricity which in turn reflects investment costs (power plants, grid) at the power sector level.

\(^{32}\) This component also includes the purchase of hydrogen where relevant.
In 2030, the increase compared to REF result from additional capital expenditures (+6.5, +7.2 and +7.5 billion EUR in Alt1, 2 and 3 respectively) and to a lesser extent from higher purchase costs of electricity and heat (+0.6, +2.4 and +3.7 billion EUR in Alt1, 2 and 3 respectively), partly compensated by a drop in fuel purchases (-3.8, -5.5 and -6.6 billion EUR in Alt1, 2 and 3 respectively).

In 2040, the trends are identical though stronger. For instance, in Alt3, CAPEX is 10 billion EUR higher, OPEX-elec 9 billion EUR higher and OPEX-fuel 12 billion EUR lower than in REF.

These evolutions reflect, among others, the intensification of the use of electricity for heating & cooling and for passenger transport, substantial renovation of the building stock and resulting fuel savings. Subsequently, the share of fuel purchase costs in total cost collapses to less than one third in 2040 compared to about 50% in 2015.

5.2. Fossil fuels: external bill and trade balance

The reduction in fossil fuel consumption recorded in the policy scenarios compared to REF (see section 4.3) which leads to a decrease in fuel purchase costs paid by the final customers (see previous section) translates into external fuel bill effects as all fossil fuels are imported. The effects are presented in Graph 36.

In 2030, the gains in monetary terms with respect to REF range from 2.1 to 2.7 billion EUR in the policy scenarios. These gains are allocated as follows: from 1.2 to 1.7 billion EUR for oil, around 1 billion EUR for natural gas and less than 25 million EUR for coal.

By 2040, benefits increase notably. The cut in the external fuel bill compared to REF rises to 6.1, 6.4 and 6.6 billion EUR in Alt1, 2 and 3 respectively. Oil is responsible for three quarters of the cut and natural gas for one quarter; the decrease for coal is much smaller and amounts to 40 million EUR.

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33 Not visible on the graph due to the scale.
34 Ibid.
Above results obviously have an impact on the fossil fuel trade balance: reduced fuel bills improve the fuel trade balance of Belgium.

Table 17 shows the evolution of the (net) fossil fuel trade balance as % of GDP. Belgium had a fossil fuel trade deficit of 2.9% of GDP in 2015. Looking forward, the deficit increases to about 4% in REF in the period 2030-2040. By contrast, the evolution follows an upturned U curve in the policy scenarios: the fossil fuel trade deficit first rises by 2030 (to reach -3.5%) and then diminishes to return to the 2015 level by 2040 (i.e. +2.8%).

Between 2015 and 2030, the projected significant increase in oil prices\(^{35}\) is not counterbalanced by the decrease in the volume of oil imports whereas both natural gas prices and imports surge. The resulting value of imports grows at a higher pace than GDP.

Beyond 2030, the story is different. First, the price effect is softened: oil and natural gas prices are still projected to increase between 2030 and 2040 though at a slower pace than in the previous period. Second, oil consumption drops significantly in all policy scenarios (and consequently oil import) while the demand for natural gas almost stabilises. All in all, these evolutions translate into a decline of the value of imports over time and consequently into a reduction of Belgium’s fossil fuel trade deficit.

Compared to REF, the fossil fuel trade deficit as % of GDP boils down to 0.4 (resp. 1.1) percentage points in 2030 (resp. 2040).

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\(^{35}\) The evolution of oil and natural gas prices is assumed to be the same in all scenarios.
5.3. Energy costs in final demand sectors

Three cost indicators are scrutinized in the final demand sectors: (1) the energy cost and its allocation between the different cost components, (2) the unit energy cost and (3) investment expenditures. The effect of the 2030 Climate and Energy Framework and 2050 Roadmaps on these cost indicators is analysed per sector.

5.3.1. Energy cost

The energy cost encompasses four components: the capital costs of energy using equipment (e.g. boiler, oven, appliances) and building insulation expressed in annuity payments, the fuel purchase costs, the electricity and heat purchase costs, and auction payments where relevant (i.e. in the ETS sector).

a. Industry

The energy cost of industry is expected to increase by 1.9% per year on average in the policy scenarios in the period 2015-2040, compared to 1.5% in REF. Graph 37 presents the changes in the composition of the energy cost over time according to the scenarios.

Graph 37 Components of the energy cost of industry, REF and policy scenarios, 2015, 2030 and 2040

In 2030, the overall structure of the energy cost is expected to change with respect to 2015 but does not differ much between the scenarios (not even between REF and the policy scenarios). Fuel expenses represent more than 50% of the energy cost supported by industry, electricity purchases fluctuate around 31%, capital cost ranges from 13% to 15% and the share of auction payments is 2%. Compared to 2015, the major changes in 2030 concern the presence of auction payments, a higher contribution of fuel
expenses and capital costs and, on the contrary, a much lower contribution of electricity purchases in total energy cost.

In 2040, the share of energy purchases drops in the policy scenarios to 45% for fuels and to 28% for electricity at the “benefit” of capital cost (22%) and auction payments (6%). Auction payments and their contribution to the energy cost increase over time and with respect to REF reflecting higher carbon prices.

b. Tertiary sector

The same energy cost indicator is analysed for the tertiary sector. Graph 38 shows, for all scenarios, the changes in the structure of the energy cost in 2030 and 2040, compared to 2015.

The energy cost in the tertiary sector is projected to rise by some 2.1% per year on average in all policy scenarios in the period 2015-2040, compared to 1.7% in REF.

About the structure of the energy cost, significant modifications can already be noticed in 2030 contrary to what happens in industry (see supra). The share of capital cost in the policy scenarios gains 15 to 17 percentage points with respect to 2015, primarily at the expense of fuel purchases. Capital cost represents about one third of the energy cost compared to 15% in REF. The share of fuel purchases drops from 30% in REF to 16%-22% in the policy scenarios. The share of the “electricity” component decreases also but to a lesser extent; it lies in the range of 48% to 51% compared to 56% in REF. The increase in the (share of) capital cost originates in higher investments in energy efficient equipment and buildings stimulated by higher energy efficiency values and coordination policies fostering the rate and depth of

There is no auction payment in the tertiary sector, as it belongs to the non-ETS.
renovation and behavioural changes. Investments in buildings insulation influence fuel consumption more than electricity consumption. Indeed, natural gas and gasoil still dominate the fuel mix for space heating in 2030.

Beyond 2030, capital cost nearly stabilizes, fuel purchases continue to drop but the purchase cost of electricity takes off reflecting the growing electrification of the sector. These developments translate into the following shares in 2040: around 26% for the capital cost, from 13% to 18% for the fuel purchases and about 60% for electricity purchases. In REF, the percentages are respectively 17%, 29% and 55%.

c. Residential sector

The energy cost is projected to increase by 3% per year on average in the period 2015-2040, compared to 2.4% in REF. This growth rate is the highest amongst the final demand sectors.

Even though the residential sector has a different energy cost structure than the tertiary sector (see Graph 39), it shows rather similar evolutions. By 2030, the policy scenarios show a steady increase in the share of capital cost (slightly above 50% compared to 44% in REF), a share of electricity purchases ranging from 25% to 34% (24% in REF) and a significant decrease in the part taken by fuel purchases (14% to 22% against 32% in REF). By 2040, the share of capital cost stabilizes, the share of fuel purchases continues to decline (below 20%) and electricity purchases contribute even more to the energy cost (30% to 38%).

The drivers of the changes are also identical in both sectors: a progressive removal of barriers to energy efficiency in buildings, the uptake of more efficient heating equipment (such as heat pumps) and electric appliances, a speeding up of the renovation rate of buildings.
5.3.2. Unit energy cost

The unit energy cost focuses on the OPEX components of the energy cost, namely the energy purchase cost, including where relevant the auction payments. This indicator measures the energy input cost per unit of value added for industry and the tertiary sector and as share of private consumption for households. The unit energy cost brings together two components: the energy price\(^{37}\) and the energy intensity\(^{38}\). It is often used to address competitiveness issues for industry. If the Belgian industry faces higher unit energy cost (increases) than its counterparts, its competitiveness may be at stake. However, an expected growth in unit energy cost compared to REF could be managed if decreases in energy intensity compensate for increases in energy prices, all things being equal.

Table 18 shows the evolution of the unit energy cost in final demand sectors, excluding transport.

<table>
<thead>
<tr>
<th>Sector</th>
<th>2015</th>
<th>REF</th>
<th>Alt1</th>
<th>Alt2</th>
<th>Alt3</th>
<th>2030</th>
<th>REF</th>
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<th>Alt2</th>
<th>Alt3</th>
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<th>Alt1</th>
<th>Alt2</th>
<th>Alt3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industry</td>
<td>18.6</td>
<td>22.3</td>
<td>21.6</td>
<td>21.5</td>
<td>21.4</td>
<td>20.8</td>
<td>21.6</td>
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<td>21.5</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Tertiary</td>
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<td>2.1</td>
<td>1.9</td>
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<td>1.9</td>
<td>1.9</td>
<td>1.9</td>
<td>1.9</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Residential</td>
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<td>4.2</td>
<td>4.3</td>
<td>4.4</td>
<td>4.6</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: PRIMES, FPB calculations.

In 2030, the unit energy cost is projected to rise in all scenarios compared to 2015 due to the sharp increase in energy price (e.g. by more than 40% in industry) which is not counterbalanced by a similar decrease in energy intensity (e.g. by some 20% in industry). However, the unit energy cost is generally lower in the policy scenarios than in REF due to extra energy efficiency improvements causing a larger decline in energy intensity.

In the period 2030-2040, the unit energy cost remains roughly stable in all sectors in the policy scenarios (but decreases in REF). Energy intensity continues its downwards trend and compensates for the rise in energy price resulting from an increased consumption of electricity at the expense of fossil fuels and higher carbon prices.

5.3.3. Investment expenditures

While the unit energy cost deals with the variable component of the energy cost (fuel, electricity, heat and carbon price), investment expenditures zoom in on the capital cost. The changes in energy-related investment expenditures in final demand sectors (excluding transport) are presented in Graph 40. The changes are calculated with respect to REF.

\(^{37}\) The energy price is defined here as the ratio of energy purchases (fuel, electricity, etc.) to the final energy consumption.

\(^{38}\) The energy intensity is calculated by dividing the final energy consumption by the value added or the private consumption.
The largest increase is in the period 2020-2030. In the policy scenarios, investment expenditures are twice as high as in REF (100 billion EUR vs. 50 billion EUR). Extra expenditures take place principally in the residential (62%) and tertiary sectors (34%). They result from the policies giving incentives for energy efficiency investments in insulation, heating systems and appliances, and contributing to the achievement of the national and European climate and energy targets in 2030. In the policy scenarios, investment expenditures in the residential sector translate into a yearly average of 1400 EUR per household (620 EUR more than in REF). The tertiary sector would have to pay 2.2 billion EUR per year on average (compared to 0.4 billion EUR in REF). For industry the figures are 0.9 billion EUR in the policy scenarios and 0.7 billion EUR in REF.

In the period 2030-2040, investment expenditures also rise compared to REF but less significantly, namely by 30%. Moreover, additional expenditures are also noted in industry. This sector is responsible for 54% of the increase against 34% for the residential sector and 12% for the tertiary. The average annual investment expenditures total 1.9 billion EUR for industry, 0.8 billion EUR for the tertiary and around 1000 EUR per household. The respective figures in REF are 1 billion EUR, 0.5 billion EUR and 900 EUR.

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**Graph 40** Investment expenditures in demand sectors excl. transport, REF and policy scenarios, 2020-2030 and 2030-2040

Billion EUR 13

<table>
<thead>
<tr>
<th>Year</th>
<th>REF</th>
<th>Alt1</th>
<th>Alt2</th>
<th>Alt3</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020-2030</td>
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<tr>
<td>2030-2040</td>
<td></td>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

Source: PRIMES, FPB calculations.

Note: The bar on the left-hand (resp. right-hand) side of the graphs gives the value of the indicator in REF (resp. policy scenarios). The bars in between show the contribution of each element composing the indicator to the changes in the total value of the indicator in the policy scenarios compared to REF.

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39 The resulting extra investment expenditures represent approximately 0.3% of the gross fixed capital formation of the manufacturing industry in 2015.

40 The additional investment expenditures compared to REF represent approximately 1.5% of the gross fixed capital formation of the manufacturing industry in 2015.
5.4. Electricity system cost

This part mainly deals with costs related to power production, but also includes cost elements related to the grid. The cost of power generation is composed of different elements: the fixed costs, the variable costs and other costs including, for instance, the auction payments on the EU ETS market. One of these elements is the fixed costs of which the cost of capital, constituted by investments, represents a large chunk. Part 5.4.1 focuses on this cost element and describes investment expenditures in production and grid, whilst part 5.4.2 depicts the (composition of the) average cost of power production.

5.4.1. Investment expenditures

This section first translates the investments in new power capacities, estimated in section 4.2.1.f, into monetary terms. It also provides estimates of expenditures required for grid investments.

Between 2020 and 2030, investments in power generation amount to 11 billion EUR in Alt1, 14 billion EUR in Alt2 and 17 billion EUR in Alt3, compared to 5 billion EUR in REF. Between 2030 and 2040, 14 billion EUR in Alt1 and 15 billion EUR in Alt2 and Alt3 are required compared to 6 billion EUR in REF.

Extra investment expenditures in power generation are needed to (1) cover increasing load, (2) install higher RES capacities, (3) guarantee back-up for variable renewable technologies and (4) replace decommissioned units.

On average in the period 2020-2040, above figures translate into yearly investment expenditures for power generation ranging from 1.2 to 1.6 billion EUR in the policy scenarios, compared to 0.6 billion EUR in REF (i.e. more than a doubling). These annual figures are equivalent to 0.2-0.3% of GDP\textsuperscript{41}.

Extra investment expenditures in grid infrastructure (transmission and distribution networks) are also vital, notably to integrate the higher amount of RES in the power system. Between 2020 and 2030, investments in power grids are estimated to be at 14 billion EUR in Alt1, 18 billion EUR in Alt2 and 20 billion EUR in Alt3, compared to 9 billion EUR in REF. Between 2030 and 2040, 19 billion EUR in Alt1, 20 billion EUR in Alt2 and 21 billion EUR in Alt3 are necessary compared to 9 billion EUR in REF.

On average in the period 2020-2040, above figures translate into yearly investment expenditures for power grids ranging from 1.6 to 2.1 billion EUR in the policy scenarios, compared to 0.9 billion EUR in REF. These annual amounts are equivalent to around 0.3-0.4% of GDP\textsuperscript{42}.

Graph 41 decomposes the increase in total expenditures in the policy scenarios compared to REF into generation and grid components.

\textsuperscript{41} Average GDP over the period 2020-2040.
\textsuperscript{42} Ibid.
In the period 2020-2030, the increase is almost equally allocated between generation and grid but differs significantly among scenarios. Total investment expenditures boil down to 24 billion EUR in Alt1, 32 billion EUR in Alt2 and 37 billion EUR in Alt3, compared to 14 billion EUR in REF.

In the period 2030-2040, the contribution of grid expenditures to the total increase exceeds the production part. Moreover, the range of growth shrinks: the difference between Alt3 and Alt1 is 3 billion EUR while it is 13 billion EUR in the period 2020-2030. Total investment expenditures are in the range of 33 to 36 billion EUR in the policy scenarios, compared to 15 billion EUR in REF.

Graph 41 shows another interesting result. Despite much higher capacity needs in the period 2030-2040 than in the period 2020-2030 (expressed in GW), additional investment expenditures in production are lower in the last period than in the first one in at least two policy scenarios. This trend reflects the steady decreasing capital cost of RES technologies over time, which partly compensates for higher RES capacity expansions.

Investment expenditures are enormous and seem counterfactual to what we observe today in the Belgian electricity markets. What these results then convey is that the amount of investments and the ensuing capacity calculated by the model are deemed necessary to (1) be able to answer demand at all times, (2) secure electricity supply, both in terms of production and capacity, (3) achieve the nationally induced targets (set at European level) in terms of ETS GHG reductions and RES expansion, and (4) meet the national binding target in the non-ETS in 2030. These results nonetheless do not give information on how the capacity additions will be triggered or who will undertake them. In order for these investments to prevail, it is crucial to straighten out the current investment climate and to assess the market failures explaining the potential investment deficit, e.g. market interventions, market functioning, market failures in other markets, etc. These topics are out of the scope of this paper.
5.4.2. Average cost of power generation

These investments have an undeniable effect on the total costs that the power sector has to commit to in the future. In this, the choice of technology applied to cover demand is crucial since this technology not only influences the height of the equity that must be reimbursed, but also determines whether and how much fuel costs must be paid and whether and how much emission rights must be bought on the ETS market.

Table 19 presents an overview of the average cost of electricity generation for all scenarios in the years 2015, 2030 and 2040. The indicator is calculated as the ratio of total cost of power generation (in EUR) and total power generation (in MWh) in Belgium.

A steady increase can be noted in the policy scenarios in the entire projection period 2015-2040. In 2040, the average cost mounts to 112 EUR/MWh in Alt1 (+29% with respect to 2015), 114 EUR/MWh in Alt2 (+31% with respect to 2015) and 115 EUR/MWh in Alt3 (+32% with respect to 2015). For comparison, the average cost increases by a mere 5% in REF and reaches 91 EUR/MWh in 2040.

Table 19: Decomposition of average electricity generation costs, REF and policy scenarios, 2015, 2030 and 2040

<table>
<thead>
<tr>
<th>EUR’13/MWh</th>
<th>2015</th>
<th>2030</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>REF</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Alt1</td>
<td>57</td>
<td>46</td>
<td>34</td>
</tr>
<tr>
<td>Alt2</td>
<td>58</td>
<td>58</td>
<td>53</td>
</tr>
<tr>
<td>Alt3</td>
<td>58</td>
<td>53</td>
<td>54</td>
</tr>
<tr>
<td>Variable</td>
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<tr>
<td>Fixed</td>
<td>2</td>
<td>8</td>
<td>12</td>
</tr>
<tr>
<td>Variable</td>
<td>28</td>
<td>43</td>
<td>46</td>
</tr>
<tr>
<td>Other</td>
<td>58</td>
<td>58</td>
<td>53</td>
</tr>
<tr>
<td>Total</td>
<td>87</td>
<td>97</td>
<td>91</td>
</tr>
</tbody>
</table>

Source: PRIMES, FPB calculations.

Compared to REF, average cost increases by 4% in 2030 and by around 25% in 2040 in the policy scenarios.

The table also shows the decomposition in cost elements: fixed (capital costs43), variable (fuel and operational costs) and other costs (auctioning costs for the purchase of emission rights). Graph 42 illustrates the changes in average cost (total and by component) in 2030 and 2040 in the policy scenarios compared to REF.

In 2030, all policy scenarios tend to become more capital intensive compared to REF: the fixed cost part represents 58% of the total average cost, against 47% in REF. This increase is due to additional developments of capital intensive RES capacities (mainly wind and solar PV) which are not fully compensated by decreases in capital cost per MW. This evolution also explains why the (share of) variable costs drop compared to REF (36% vs. 45%). Finally, ETS allowance expenditures stay a small component of the average cost and are comparable in all scenarios.

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43 Contrary to investment expenditures described in 5.4.1, the fixed cost reported here relates to the annual capital costs. To annualise investment expenditures, a discount rate of 7.5% or 8.5% is used according to the technology.
In 2040, things change. The other costs start to gain a bigger weight. This has to do with the fact that a significant part of the power produced is still generated through the burning of natural gas (see 4.2). Burning of fossil fuels emits carbon and since carbon prices increase dramatically beyond 2030 (see Table 2), the other costs surge. In 2040, they occupy a share of 22% in the policy scenarios compared to 13% in REF.

Fixed and variable costs remain broadly stable in the policy scenarios in the period 2030-2040. However, due to the increase in average cost beyond 2030, the share of fixed costs drops to 47% in 2040 (37% in REF) and the share of variable costs goes from 36% in 2030 to 31% in 2040 (50% in REF).
6. References


