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Insights in a clean energy future for Belgium

Impact assessment of the 2030 Climate & Energy Framework

May 2018

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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 Greenhouse gas emissions in ETS, non-ETS and different energy sectors, REF and policy scenarios, 2005, 2030 and 2040
Mt CO_2-eq.

	2005	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Total GHG emissions	148	111	100	98	97	110	78	76	76
ETS	70	47	44	45	46	47	38	40	41
Power generation	24	17	13	14	16	19	13	15	16
Non-ETS	78	64	56	53	51	63	40	36	35
Buildings	31	23	18	15	12	22	13	10	9
Transport	26	23	21	21	21	23	14	14	13

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

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

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*).

Table Primary and final energy consumption, REF and policy scenarios, 2005, 2030 and 2040
Mtoe

	2005	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Primary energy consumption	51.3	40.1	36.5	35.9	35.7	40.0	34.9	34.3	34.0
Final energy consumption	36.6	34.6	31.6	30.7	30.2	34.3	30.3	29.4	28.9

Source: PRIMES.

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 Primary energy mix, REF and policy scenarios, 2015, 2030 and 2040
%

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Solid fuels	7	4	4	5	5	3	3	3	3
Oil	35	34	32	31	30	32	20	20	19
Natural gas	29	41	38	38	38	43	38	38	39
Nuclear	15	0	0	0	0	0	0	0	0
Electricity	4	6	7	7	7	5	7	8	8
RES	10	16	19	20	20	17	31	31	31

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

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Domestic production (Mtoe)(*)	3.6	5.0	5.7	5.9	6.1	5.5	7.8	7.9	7.9
Net imports (Mtoe)	50.6	50.8	46.2	45.4	45.0	50.2	42.0	41.4	41.0
Import dependency (%)	84.3	91.0	89.0	88.5	88.1	90.1	84.4	84.0	83.8

Source: PRIMES.
(*): excluding nuclear heat (year 2015).

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

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Natural gas imports (Mtoe)	13.9	17.5	15.3	15.1	15.0	18.6	15.2	14.9	14.9
Net electricity imports (TWh)	21.0	25.7	28.5	28.5	28.5	21.0	30.3	30.2	30.2

Source: PRIMES.

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
In % of VA

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Industry	18.6	22.3	21.6	21.5	21.4	20.8	21.6	21.6	21.5

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

En octobre 2017, le Bureau fédéral du Plan a publié ses perspectives énergétiques trisannuelles. Ces perspectives décrivent les projections en matière d'énergie et d'émissions de gaz à effet de serre à politique inchangée pour la Belgique à l'horizon 2050. En d'autres termes, elles présentent l'évolution du système énergétique belge si les politiques suivies actuellement sont simplement poursuivies. Elles montrent qu'à politique inchangée, les objectifs définis dans le Paquet Énergie propre et l'Accord de Paris seront loin d'être atteints.

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.

Le Paquet Énergie propre, qui constitue l'épine dorsale de la politique de l'UE en matière de climat et d'énergie au-delà de 2020, comprend un ensemble de propositions législatives qui font encore l'objet de discussions et qui devraient être adoptées d'ici fin 2018. Une de ces propositions porte sur un Règlement du Parlement européen et du Conseil sur la gouvernance de l'Union de l'énergie.

Les plans nationaux intégrés en matière d'énergie et de climat (PNEC) constituent la pierre angulaire du Règlement sur la gouvernance. Ces plans, qui sont élaborés et soumis par les États membres, visent à présenter les objectifs, les politiques et mesures et les projections pour chacune des cinq dimensions de l'Union de l'énergie, à savoir la décarbonation, l'efficacité énergétique, la sécurité énergétique, le marché intérieur de l'énergie et la recherche, l'innovation et la compétitivité. Des projections intégrant les politiques et mesures prévues sont requises, y compris une comparaison avec les projections basées sur les politiques et mesures existantes.

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 PNEC belge est élaboré par les différentes entités (les trois Régions et l'État fédéral). Le rôle principal du Bureau fédéral du Plan dans ce processus est de prodiguer son aide et son expertise pour la partie analytique du plan (c'est-à-dire les projections et l'analyse d'impact des politiques et mesures). La présente étude du BFP et le scénario de référence en matière d'énergie et de climat publié en octobre 2017 (BFP, 2017) complètent la collaboration décrite ci-avant. Ils peuvent livrer des résultats intéressants et utiles dans le processus d'élaboration en cours et constituer une référence (*benchmark* en anglais) pour les projections à réaliser dans le prochain projet de PNEC belge.

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 *scénarios alternatifs*, ils sont 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'UE pour 2050. Trois *scénarios alternatifs* (baptisés *Alt1*, *Alt2* et *Alt3*) ont été élaborés et évalués. Ils diffèrent selon l'hypothèse retenue pour les réductions de GES dans les secteurs non-ETS belges, reflétant ainsi le choix de recourir à la flexibilité afin d'atteindre l'objectif national non-ETS proposé pour l'année 2030. Les réductions non-ETS sont respectivement de 27 %, 32 % et 35 % en 2030 par rapport à 2005.

Plusieurs résultats sont résumés ci-dessous. Ils sont expliqués pour les cinq dimensions de l'Union de l'énergie et se concentrent sur les années 2030 et 2040.

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. CO_2

	2005	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Total des émissions de GES	148	111	100	98	97	110	78	76	76
ETS	70	47	44	45	46	47	38	40	41
Production d'électricité	24	17	13	14	16	19	13	15	16
Non-ETS	78	64	56	53	51	63	40	36	35
Bâtiments	31	23	18	15	12	22	13	10	9
Transport	26	23	21	21	21	23	14	14	13

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/Énergie 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'amenuise quelque peu. Ainsi, la part des SER fluctue entre 30,5 % et 31,8 %, contre 17 % dans le *REF*.

Tableau Part des SER dans la consommation finale brute d'énergie et par finalité, REF et scénarios alternatifs, 2015, 2030 et 2040
En %

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
SER-H&C	8,1	14,0	13,9	14,8	15,3	15,9	23,5	24,3	24,7
SER-E	15,4	27,8	37,1	37,1	37,6	30,2	44,4	44,1	43,8
SER-T	3,5	12,4	15,4	16,0	16,6	13,6	69,6	71,5	73,9
Part globale des SER	8,1	15,4	17,9	18,9	19,7	17,0	30,5	31,3	31,8

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

Le Cadre européen Climat/Énergie 2030 définit un objectif indicatif d'économie d'énergie au niveau de l'UE d'au moins 27 % d'ici 2030. Le 30 novembre 2016, la Commission a proposé de revoir la Directive sur l'efficacité énergétique pour y inclure un nouvel objectif de 30 % à atteindre pour 2030. Dans leurs PNEC, les États membres sont tenus de fixer un objectif national d'efficacité énergétique sur la base de leur consommation d'énergie primaire et/ou finale.

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
Mtep

	2005	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Consommation d'énergie primaire	51,3	40,1	36,5	35,9	35,7	40,0	34,9	34,3	34,0
Consommation finale d'énergie	36,6	34,6	31,6	30,7	30,2	34,3	30,3	29,4	28,9

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*.

Tableau Mix d'énergie primaire, REF et scénarios alternatifs, 2015, 2030 et 2040
En %

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Combustibles solides	7	4	4	5	5	3	3	3	3
Pétrole	35	34	32	31	30	32	20	20	19
Gaz naturel	29	41	38	38	38	43	38	38	39
Nucléaire	15	0	0	0	0	0	0	0	0
Électricité	4	6	7	7	7	5	7	8	8
SER	10	16	19	20	20	17	31	31	31

Source : PRIMES.

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.

Tableau Production domestique et importations nettes d'énergie et dépendance énergétique, REF et scénarios alternatifs, 2015, 2030 et 2040

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Production domestique (Mtep)(*)	3,6	5,0	5,7	5,9	6,1	5,5	7,8	7,9	7,9
Importations nettes (Mtep)	50,6	50,8	46,2	45,4	45,0	50,2	42,0	41,4	41,0
Dépendance énergétique (en %)	84,3	91,0	89,0	88,5	88,1	90,1	84,4	84,0	83,8

Source : PRIMES.
(*) : hors chaleur nucléaire (année 2015).

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 portefeuille diversifié de pays et de routes pour son approvisionnement. L'évolution future de ce portefeuille sort du cadre de la présente étude.

Marché intérieur de l'énergie

Les réseaux de transport de gaz naturel et d'électricité de la Belgique sont bien interconnectés avec d'autres pays. De plus, de nouvelles interconnexions électriques avec la Grande-Bretagne et l'Allemagne sont en cours de construction. Elles seront opérationnelles en 2019-2020.

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

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Importations de gaz naturel (Mtep)	13,9	17,5	15,3	15,1	15,0	18,6	15,2	14,9	14,9
Importations nettes d'électricité (TWh)	21,0	25,7	28,5	28,5	28,5	21,0	30,3	30,2	30,2

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.

Tableau Coût unitaire de l'énergie dans l'industrie, REF et scénarios alternatifs, 2015, 2030 et 2040
En % de VA

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Industrie	18,6	22,3	21,6	21,5	21,4	20,8	21,6	21,6	21,5

Source : PRIMES, calculs du BFP.

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.

Synthese

In oktober 2017 heeft het Federaal Planbureau zijn driejaarlijkse energievooruitzichten gepubliceerd. Die vooruitzichten documenteren de Belgische energie- en broeikasgasemissieprojecties bij ongewijzigd beleid tegen 2050. In die vooruitzichten wordt de evolutie van het Belgische energiesysteem voorgesteld als het beleid niet zou veranderen ten opzichte van het beleid dat is aangenomen. Ze tonen dat België – bij ongewijzigd beleid – ver verwijderd is van de doelstellingen die zijn vastgelegd in het Pakket schone energie en het Akkoord van Parijs.

Daarom moeten deze vooruitzichten worden aangevuld door een ander rapport dat een andere invalshoek aanneemt. 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, energiezekerheid, interne energiemarkt 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.

Daartegenover staat dat de *beleidsscenario's* zowel verenigbaar zijn met het Europese klimaat- en energiekader 2030 als met de broeikasgasemissiereductiedoelstellingen voor 2050 op EU-niveau. Er werden drie *beleidsscenario's* ('*Alt1*', '*Alt2*' en '*Alt3*') uitgewerkt en geanalyseerd. Ze verschillen in de hypothese rond de BKG-reducties in de Belgische niet-ETS-sector en weerspiegelen de mogelijkheid om met het gebruik van flexibiliteit de nationale niet-ETS-doelstelling in 2030 te bereiken. De niet-ETS-reducties bedragen respectievelijk 27 %, 32 % en 35 % in 2030 ten opzichte van 2005.

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

Decarbonisatie

De decarbonisatiedimensie van de energie-unie 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-ETS-sectoren 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 CO_2-eq.

	2005	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Totale BKG-emissies	148	111	100	98	97	110	78	76	76
ETS	70	47	44	45	46	47	38	40	41
Elektriciteitsopwekking	24	17	13	14	16	19	13	15	16
Niet-ETS	78	64	56	53	51	63	40	36	35
Gebouwen	31	23	18	15	12	22	13	10	9
Vervoer	26	23	21	21	21	23	14	14	13

Bron: PRIMES, GAINS.

De ETS-emissies liggen in 2030 32 % lager dan in 2005 in *REF* 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 manoeuvreerruimte 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*.

Tabel HEB-aandeel in het bruto finaal energieverbruik en naar gebruik, REF en beleidsscenario's, 2015, 2030 en 2040
%

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
HEB-V&K	8,1	14,0	13,9	14,8	15,3	15,9	23,5	24,3	24,7
HEB-E	15,4	27,8	37,1	37,1	37,6	30,2	44,4	44,1	43,8
HEB-T	3,5	12,4	15,4	16,0	16,6	13,6	69,6	71,5	73,9
Totale HEB-aandeel	8,1	15,4	17,9	18,9	19,7	17,0	30,5	31,3	31,8

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*).

Tabel Primair en finaal energieverbruik, REF en beleidsscenario's, 2005, 2030 en 2040
Mtoe

	2005	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Primair energieverbruik	51,3	40,1	36,5	35,9	35,7	40,0	34,9	34,3	34,0
Finaal energieverbruik	36,6	34,6	31,6	30,7	30,2	34,3	30,3	29,4	28,9

Bron: PRIMES.

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 energiemix, REF en beleidsscenario's, 2015, 2030 en 2040
%

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Vaste brandstoffen	7	4	4	5	5	3	3	3	3
Olie	35	34	32	31	30	32	20	20	19
Aardgas	29	41	38	38	38	43	38	38	39
Kernenergie	15	0	0	0	0	0	0	0	0
Elektriciteit	4	6	7	7	7	5	7	8	8
HEB	10	16	19	20	20	17	31	31	31

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.

Tabel Binnenlandse productie, netto-invoer van energie en invoerafhankelijkheid, REF en beleidsscenario's, 2015, 2030 en 2040

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Binnenlandse productie (Mtoe)(*)	3,6	5,0	5,7	5,9	6,1	5,5	7,8	7,9	7,9
Netto-invoer (Mtoe)	50,6	50,8	46,2	45,4	45,0	50,2	42,0	41,4	41,0
Invoerafhankelijkheid (%)	84,3	91,0	89,0	88,5	88,1	90,1	84,4	84,0	83,8

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 energiebehoefte.

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

Interne energiemarkt

De Belgische transmissienetten voor aardgas en elektriciteit zijn onderling goed verbonden met andere landen. Er zijn bovendien nieuwe elektriciteitsinterconnectoren met het Verenigd Koninkrijk en Duitsland in aanbouw. Die zullen operationeel zijn in 2019-2020.

Tabel Netto elektriciteitsinvoer, REF en beleidsscenario's, 2015, 2030 en 2040

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Invoer van aardgas (Mtoe)	13,9	17,5	15,3	15,1	15,0	18,6	15,2	14,9	14,9
Netto elektriciteitsinvoer (TWh)	21,0	25,7	28,5	28,5	28,5	21,0	30,3	30,2	30,2

Bron: PRIMES.

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 energie-inputkosten 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.

Tabel Eenheidsenergiekost, REF en beleidsscenario's, 2015, 2030 en 2040
In % van TW

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Industrie	18,6	22,3	21,6	21,5	21,4	20,8	21,6	21,6	21,5

Bron: PRIMES, berekeningen FPB.

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 browses 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[1].

[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 *EUCO30* 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 to(wards) the proposed target of -35% (see Table 1).

Table 1 Greenhouse gas emission reductions in the non-ETS in Belgium according to the policy scenario, year 2030
% compared to 2005

	Alt1	Alt2	Alt3
GHG non-ETS	-27	-32	-35

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[2]:

- 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.

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 2 Evolution of carbon prices in the ETS, REF and policy scenarios
EUR/t CO_2

	2015	2020	2030	2040	2050
REF	7.5	15.0	33.5	50.0	88.0
Policy scenarios	7.5	14.0	28.5	156.0	522.0

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 CO_2 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 CO_2 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-CO_2 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 (CH_4, N_2O and F-gases) and by country.

2.2. Key assumptions

To elaborate long term energy and emission projections, it is indispensable 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 3 Some general indicators, 2015-2040

	Unit	2015	2030	2040	15//30(*)	30//40(*)
GDP	billion EUR'13	401	494	584	1.4	1.7
Population	million	11.2	12.0	12.4	0.4	0.3
Households	million	4.8	5.3	5.5	0.6	0.5
Oil	EUR'13/MWh	28.0	52.4	61.5		
Natural gas	EUR'13/MWh	21.8	31.3	35.0		
Coal	EUR'13/MWh	7.0	14.1	15.6		

Source: FPB (2017).
(*): // 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[3] (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.

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 bevoorradingszekerheid 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).

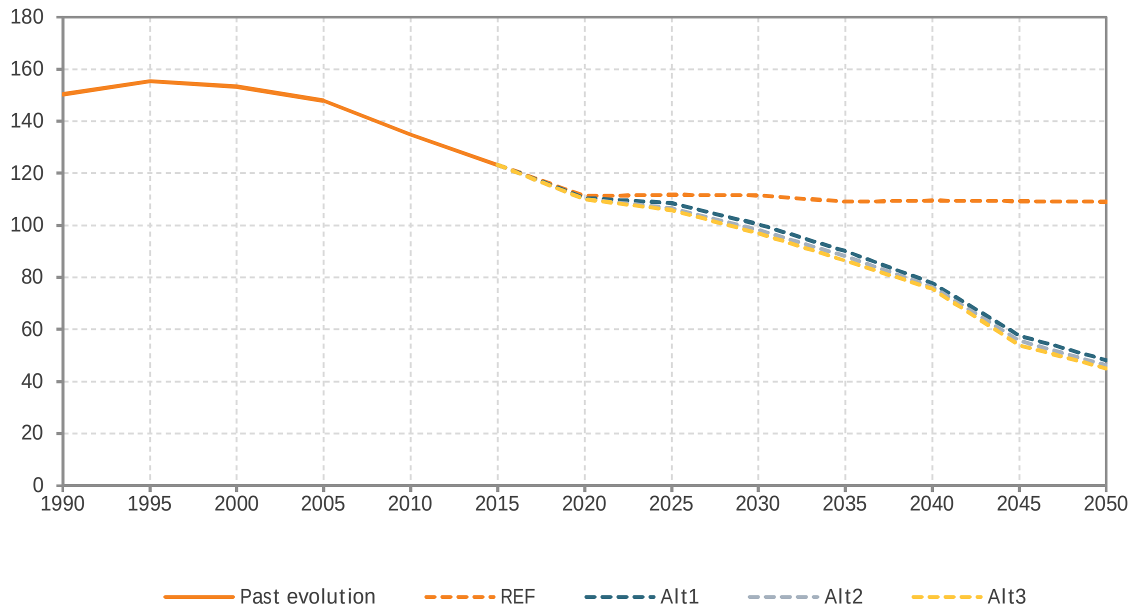
3. Environmental impacts

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 CO_2 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.

Graph 1 Total greenhouse gas emissions, REF and policy scenarios
Mt CO_2-eq.



Source: PRIMES, GAINS.

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.

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 CO_2 emissions, non-energy-related CO_2 emissions and non-CO_2 emissions[5]) and according to the sector (ETS or non-ETS).

Table 4 Greenhouse gas emissions by type of pollutant and sector, REF and policy scenarios, 2005, 2030 and 2040
Mt CO_2-eq.

	2005	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Total GHG emissions	148	111	100	98	97	110	78	76	76
Energy-related CO_2	114	87	76	73	72	86	58	57	56
Other CO_2	13	9	10	10	10	9	9	9	9
Non-CO_2	21	15	15	15	15	15	11	11	11
ETS	70	47	44	45	46	47	38	40	41
Non-ETS	78	64	56	53	51	63	40	36	35

Source: PRIMES, GAINS.

Energy-related CO_2 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 CO_2 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 CO_2 emissions. However, non-CO_2 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-CO_2 greenhouse gases encompass CH_4 (methane), N_2O (nitrous oxide) and the F-gases (fluorinated gases). Non-CO_2 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.

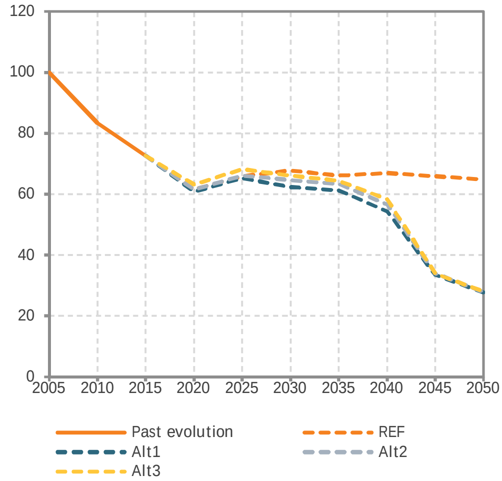
Compared to *REF*, non-ETS emissions are reduced significantly by 2030: from 13% to 20%. In 2040, they decrease even further: by 37% to 44%.

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 (CO_2), energy-intensive industry sectors (energy-related and process CO_2 and N_2O) and commercial aviation (CO_2). 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.

Graph 2 ETS greenhouse gas emissions, REF and policy scenarios
Index 100 = 2005



Source: PRIMES, GAINS.

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 N_2O 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
Mt CO_2-eq.

	2005	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
ETS emissions	70	47	44	45	46	47	38	39	41
Power & heat generation	24	17	13	14	16	19	13	15	16
Industry	42	26	26	26	26	23	20	20	20
Aviation	4	5	5	5	5	6	4	4	4

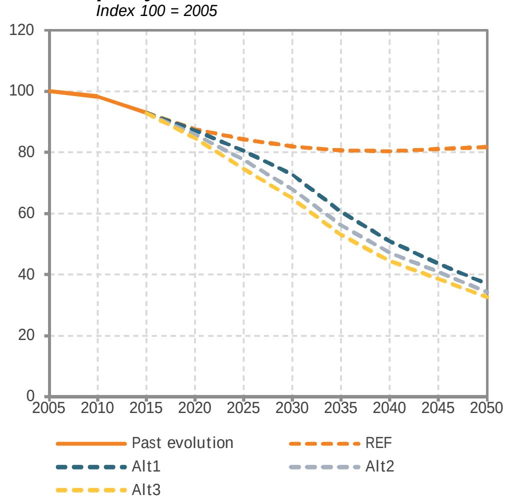
Source: PRIMES, GAINS.
Industry includes not only the final industry sectors but also transformation sectors such as refineries.

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.

Graph 3 Non-ETS greenhouse gas emissions, REF and policy scenarios
Index 100 = 2005



Source: PRIMES, GAINS.

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 stabilize 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 6 Non-ETS greenhouse gas emissions by sector, REF and policy scenarios, 2005, 2030 and 2040
Mt CO_2-eq.

	2005	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Non-ETS emissions	78	64	57	53	51	63	40	37	35
Industry	3	2	2	2	2	2	2	2	2
Buildings	31	23	18	15	12	22	13	10	9
Transport (excl. aviation)	26	23	21	21	21	23	14	14	13
Other	19	15	15	15	15	15	11	11	11

Source: PRIMES, GAINS.

Other includes non-energy-related and non-CO_2 emissions which are not part of the ETS i.e. mainly fugitive and waste CO_2 emissions and CH_4 and N_2O 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.

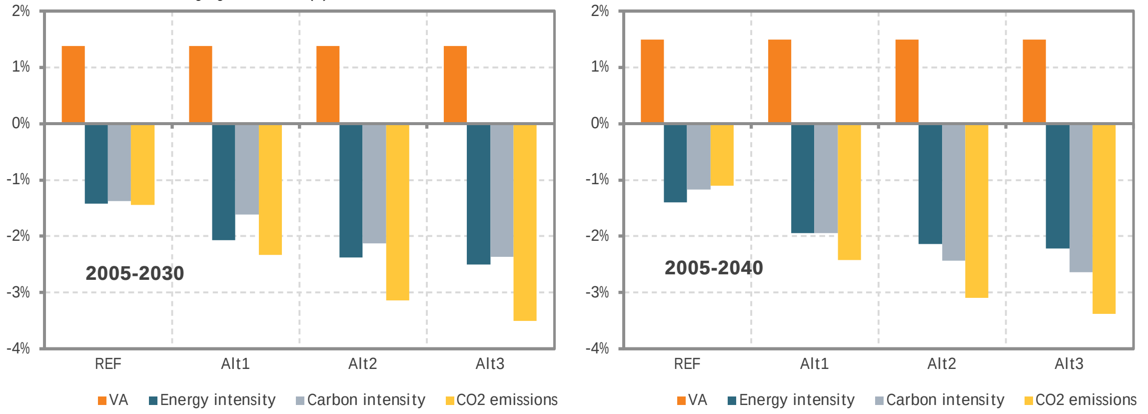
The graphs below give more insight into reductions in energy-related CO_2 emissions in buildings and transport. Yearly average emission reductions in the periods 2005-2030 and 2005-2040 are split into three effects: volume, energy intensity and carbon intensity. The decomposition analysis is provided 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 CO_2 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.

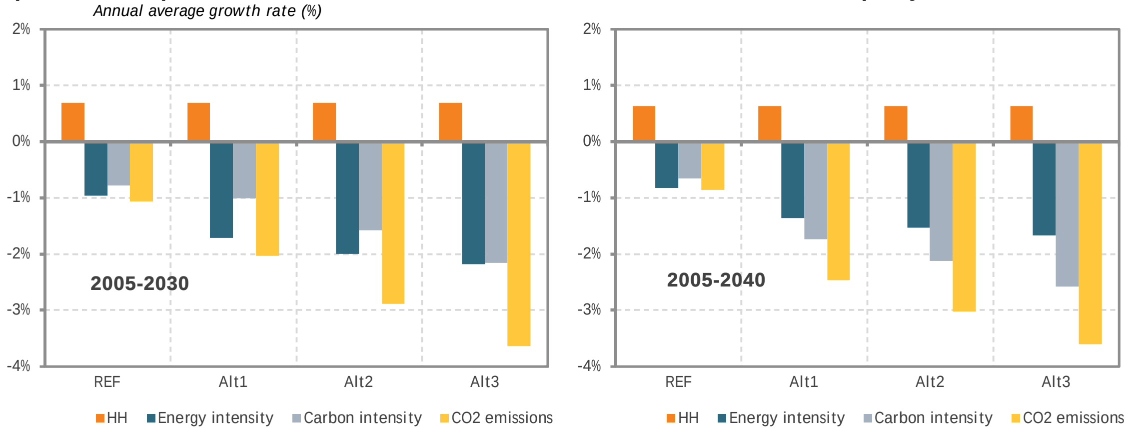
Graph 4 Decomposition of CO_2 emission reductions in tertiary, REF and policy scenarios
Annual average growth rate (%)



Source: PRIMES, FPB calculations.
VA = value added.

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.

Graph 5 Decomposition of CO_2 emission reductions in the residential sector, REF and policy scenarios
Annual average growth rate (%)



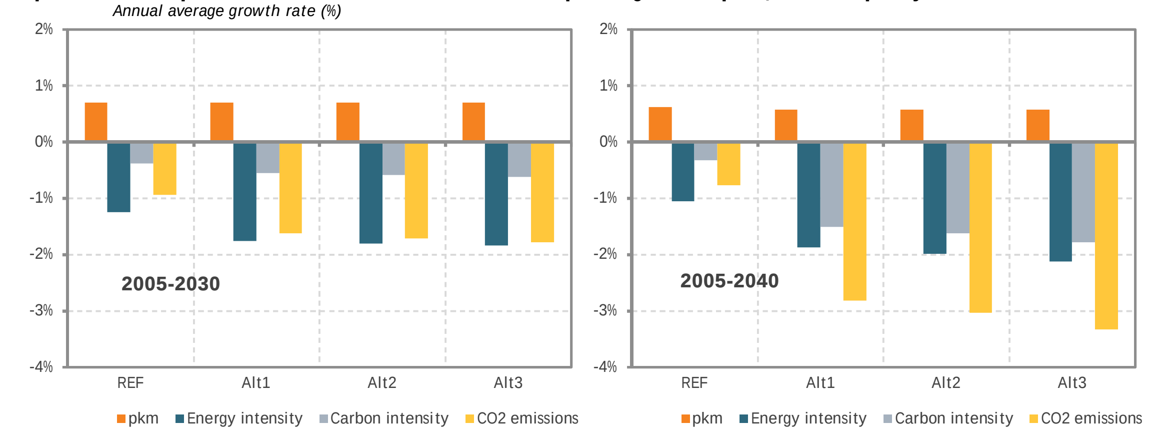
Source: PRIMES, FPB calculations.
HH = number of households.

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_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_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_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_2 emissions reductions.

Graph 6 Decomposition of CO_2 emission reductions in passenger transport, REF and policy scenarios

Annual average growth rate (%)

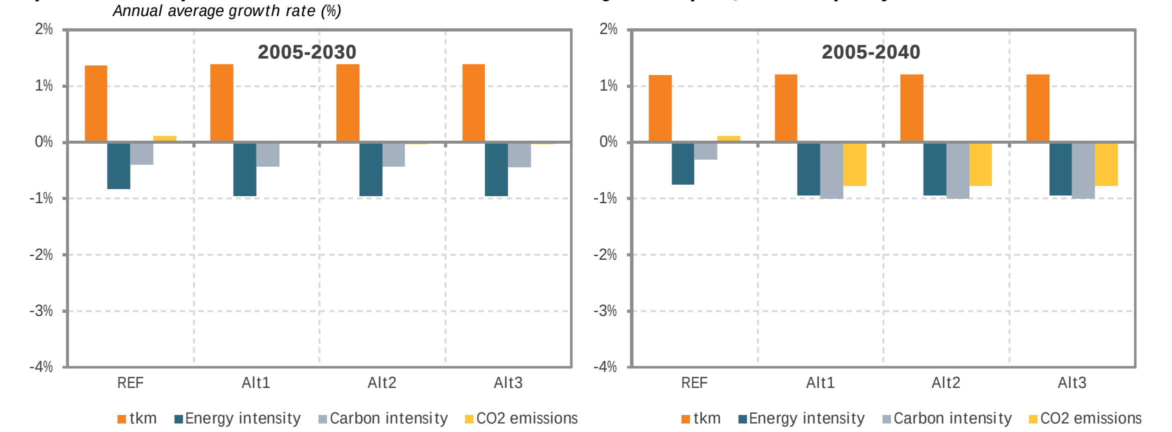


Source: PRIMES, FPB calculations.
Pkm = passenger-kilometres.

In the period 2005-2040, CO_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_2 emissions are projected to decrease by 0.8% per year on average for passengers and to increase by 0.1% for freight.

Graph 7 Decomposition of CO_2 emission reductions in freight transport, REF and policy scenarios

Annual average growth rate (%)



Source: PRIMES, FPB calculations.
Tkm = tons-kilometres.

4. Energy system impacts

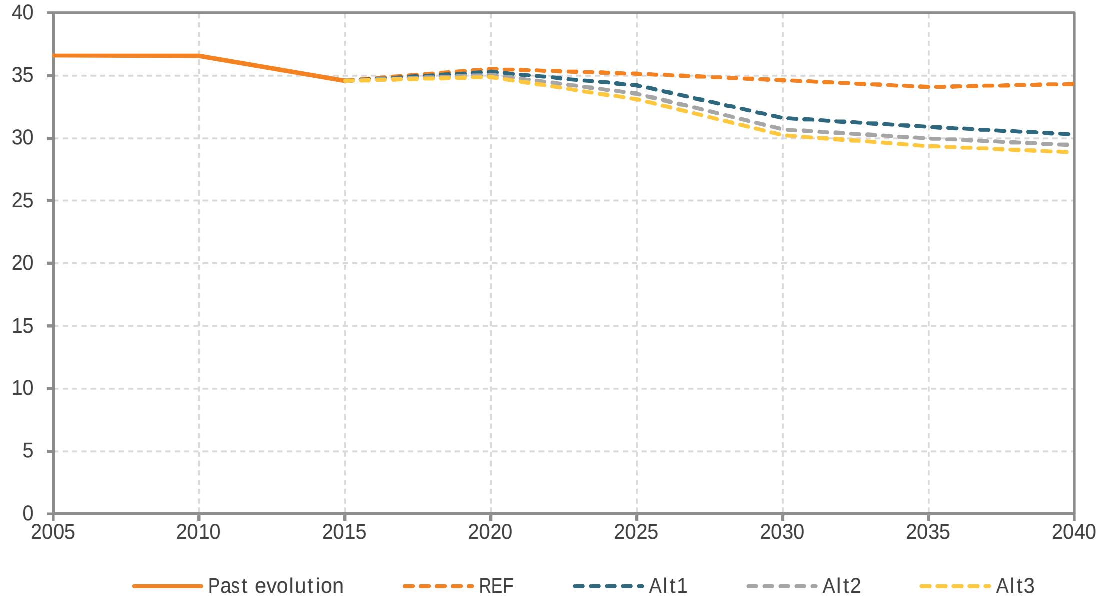
The energy system impacts are scrutinized through four sets of indicators: final energy consumption (4.1), power generation (4.2), total energy needs (4.3), renewables and energy efficiency (4.4). Although factoring in the longer-term perspective (2050) for GHG emission reductions, the impacts on the 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*.

Graph 8 Total final energy consumption, REF and policy scenarios
Mtoe



Source: PRIMES.

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
Mtoe

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Industry	10.7	10.2	10.1	10.1	10.1	9.4	9.4	9.4	9.4
Residential	8.1	8.6	7.1	6.6	6.3	8.6	7.2	6.7	6.4
Tertiary	5.3	5.5	4.7	4.3	4.2	5.8	4.8	4.4	4.3
Transport	10.4	10.3	9.6	9.6	9.5	10.5	9.0	8.9	8.8

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.

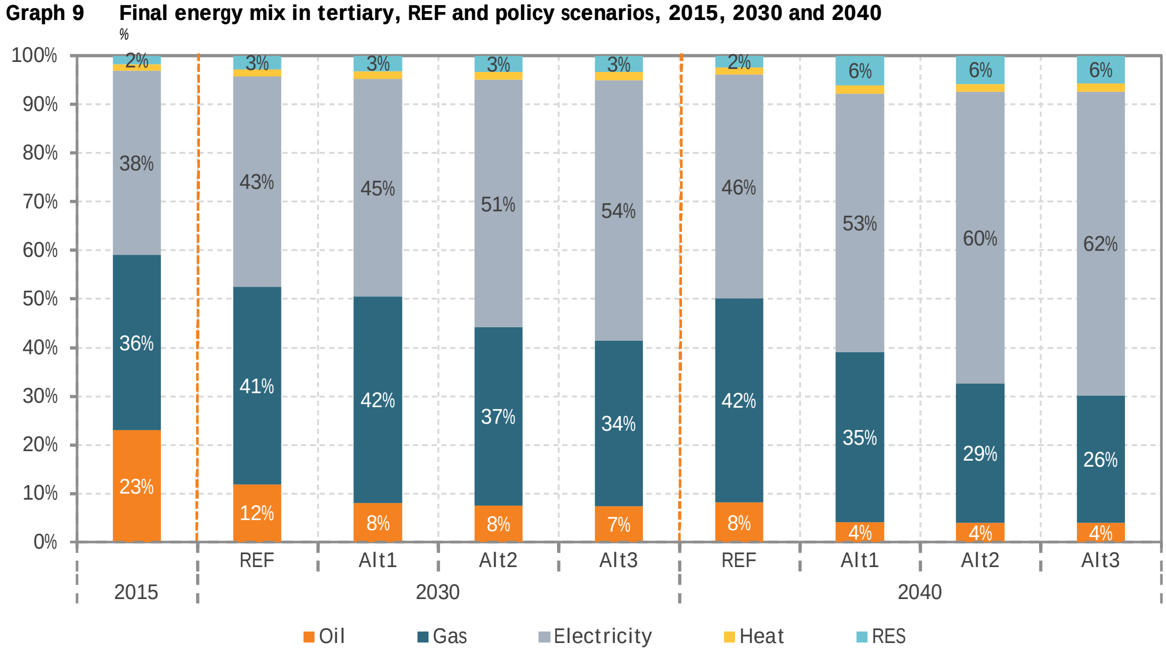
In a nutshell, the level of energy consumption in industry is identical in all scenarios in 2030 and in 2040. The only changes compared to *REF* are: a slight increase in natural gas consumption at the expense of solid fuel and oil consumption in 2030, an increase in electricity and RES consumption and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

Graph 9 Final energy mix in tertiary, REF and policy scenarios, 2015, 2030 and 2040



Source: PRIMES.

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.

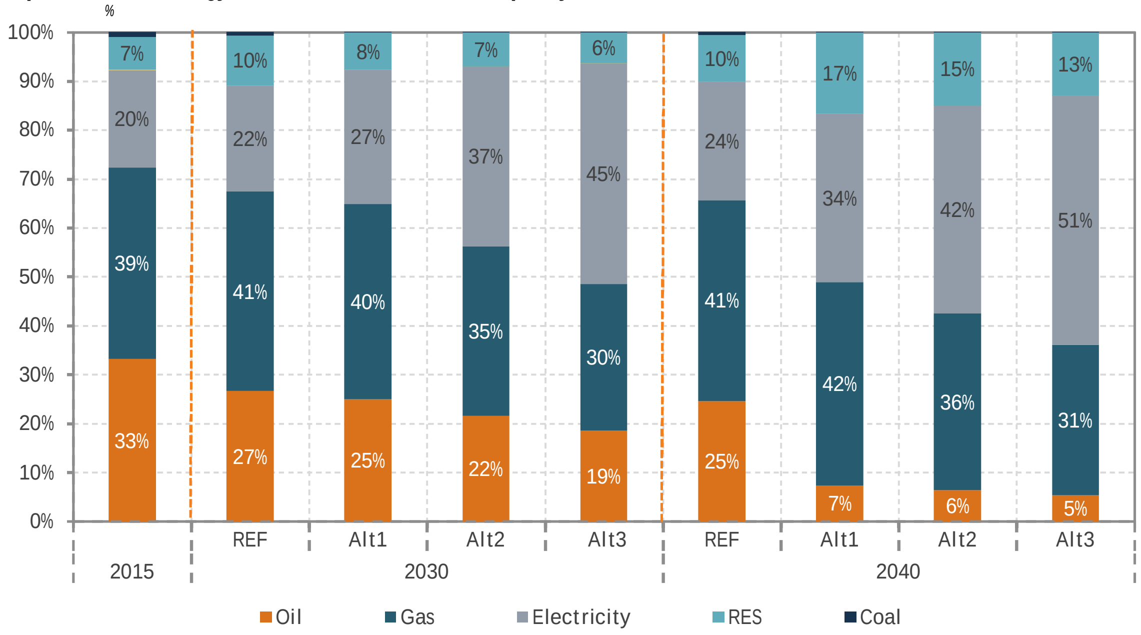
The annual renovation rate of buildings in tertiary is 0.5% in *REF* in the period 2015-2040 while it amounts to 1.7% in the *policy scenarios*.

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[6] 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

%



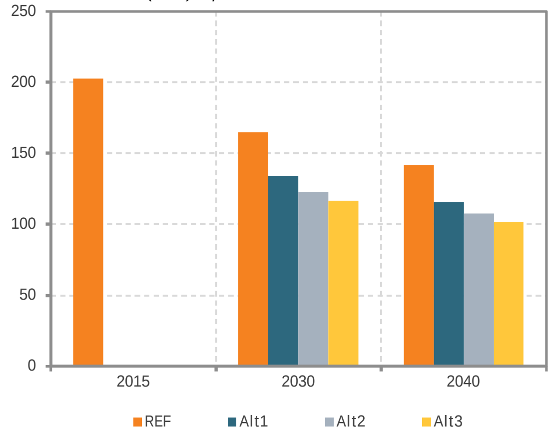
Source: PRIMES.

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*.

6 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.

Graph 11 Energy performance of residential buildings, REF and policy scenarios, 2015, 2030 and 2040

kWh (final)/sqm



Source: PRIMES, FPB calculations.
sqm = square meter.

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*.

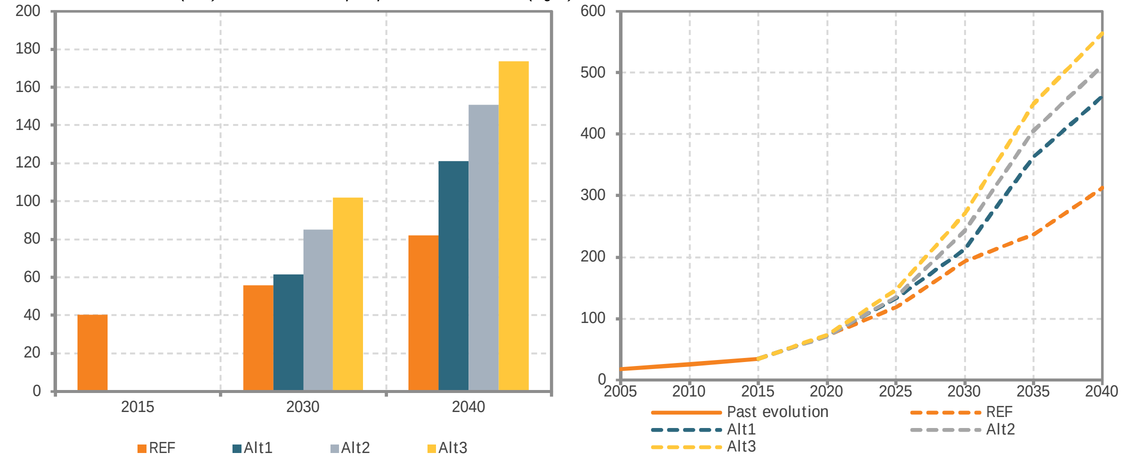
Despite identical renovation rates in the *policy scenarios*, the energy performance improves more in *Alt3* than in the other two *policy scenarios* because *Alt3* is characterised by a more significant development of heat pumps whose conversion efficiency is much higher than that of gas boilers for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

Two indicators for the development of heat pumps in the residential and tertiary sectors are illustrated in Graph 12. The first indicator, called E_{RES}, 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*[7]. The second indicator is a proxy[8] for the number of heat pumps.

7 http://sepemo.ehpa.org/uploads/media/20120529-3_Vessia_Heat_pumps.pdf

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.

Graph 12 Indicators for the development of heat pumps in residential and tertiary, REF and policy scenarios
ERES in ktoe (left); number of heat pumps in thousand units (right)



Source: PRIMES, FPB calculations.

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.

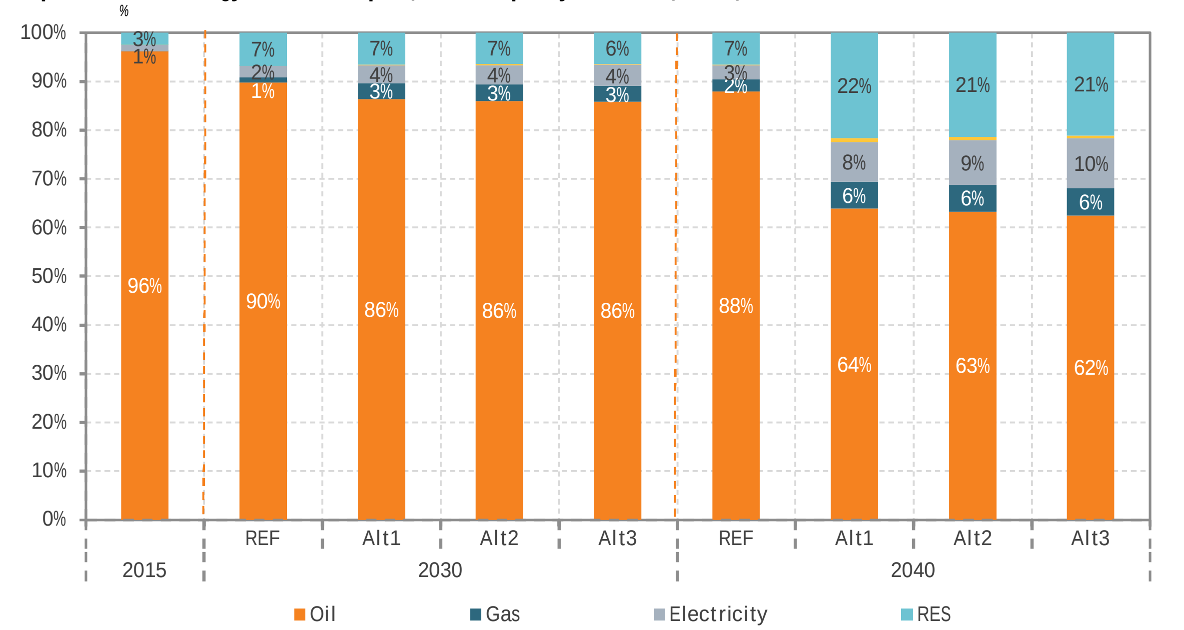
The gap in number of heat pumps between *REF* and the *policy scenarios* only starts to show after 2025. In 2030, it ranges between 20 (*Alt1*) and 80 (*Alt3*) thousand units. This evolution corresponds to an average annual growth rate of 12 to 15% in the period 2015-2030. In 2040, the difference between 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.

Graph 13 Final energy mix in transport, REF and policy scenarios, 2015, 2030 and 2040



Source: PRIMES.

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.

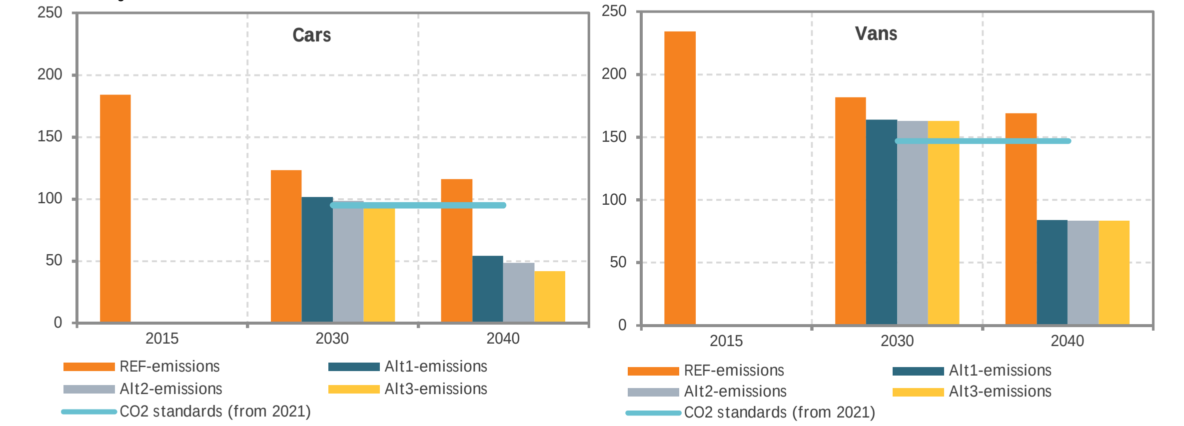
Graph 14 shows the evolution of the average CO_2 emissions of private cars and vans in the different scenarios as well as the CO_2 emission standards applicable to new car (95 gCO_2/km) and van (147 gCO_2/km) sales from 2021 on. Changes in average CO_2 emissions can be used as an indicator of energy 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[10] 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.

Graph 14 Average CO_2 emissions of private cars and vans, REF and policy scenarios, 2015, 2030 and 2040
g CO_2/km



Source: PRIMES, FPB calculations.

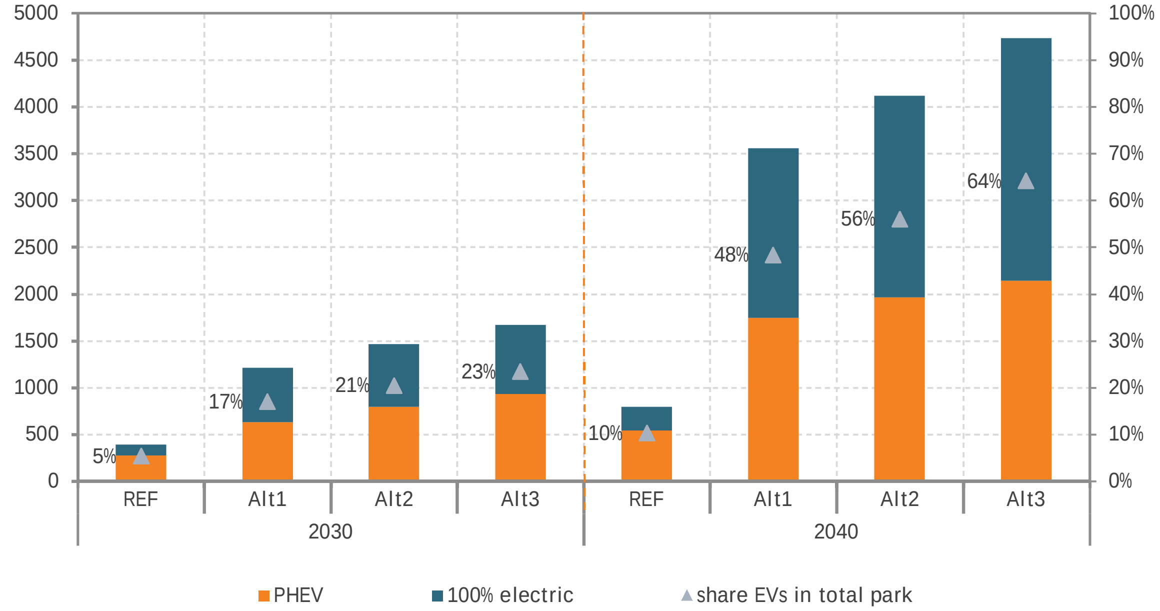
More stringent CO_2 standards lead to significant emission reductions compared to *REF*. For cars, they range from 18 to 22% in 2030 and from 53 to 64% in 2040. Although standards are identical in all *policy scenarios*, different penetration rates of electric passenger vehicles explain the variations. 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.

[10] The average lifetime of cars and vans is about 8 to 10 years.

Graph 15 Development of electric vehicles, REF and policy scenarios, 2030 and 2040
Thousand units (left axis) and % of the total fleet (right axis)



Source: PRIMES, FPB calculations.
PHEV = plug-in hybrid electric vehicle; EV = electric vehicles.

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%).

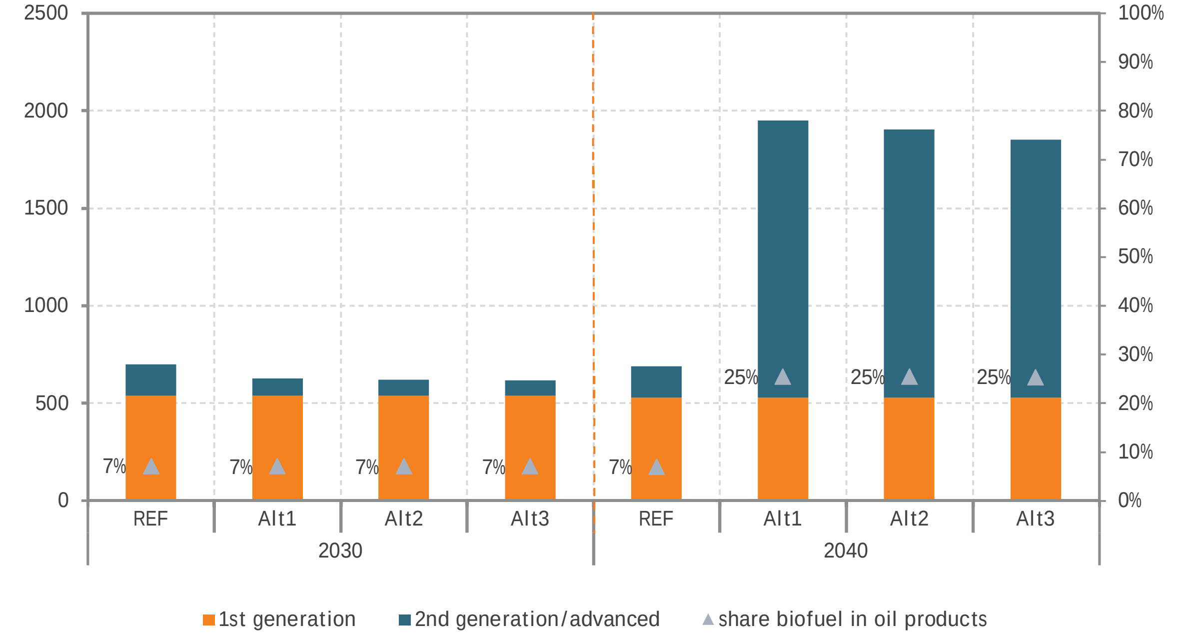
Finally, Graph 16 presents the evolution of biofuel consumption which also contributes to the decrease in GHG emissions in the *policy scenarios*. Biofuel includes bioethanol, biodiesel and biokerosene, as well as first-generation biofuels (food and feed-based) and second/advanced-generation biofuels (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[11].

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.

Graph 16 Evolution of biofuel consumption in the transport sector, REF and policy scenarios, 2030 and 2040
ktoe (left axis) and % of biofuel in oil consumption (right axis)



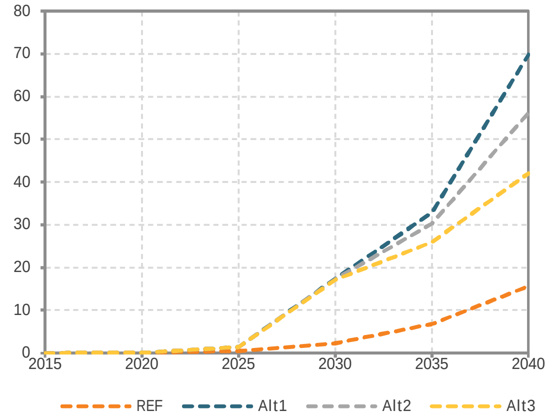
Source: PRIMES, FPB calculations.

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 (H_2). However, the development of H_2 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).

Graph 17 Hydrogen use in transport, REF and policy scenarios
ktoe



Source: PRIMES.

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, 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[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.

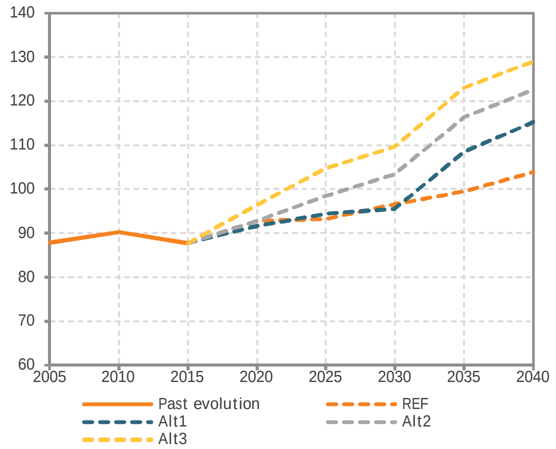
– Several electricity storage technologies are endogenous, including hydro with reservoir, hydro pumping, compressed air storage and hydrogen-based storage. Several CHP technologies and their technical operation limits are also included.

– 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.

Graph 18 Called-up electrical power, REF and policy scenarios
TWh



Source: PRIMES.

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

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[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
TWh

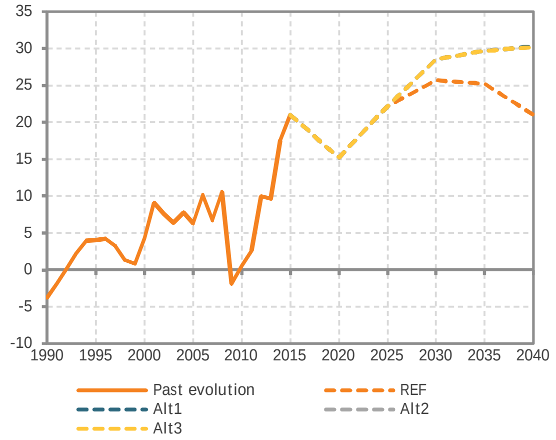
	2015	2030	2040	15//30	30//40	15//40
REF	87.7	96.6	103.9	0.6%	0.4%	0.5%
Alt1	87.7	95.5	115.2	0.6%	0.9%	0.8%
Alt2	87.7	103.4	122.6	1.1%	0.9%	1.0%
Alt3	87.7	109.6	129.0	1.5%	0.8%	1.1%

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

Graph 19 Net imports of electricity, REF and policy scenarios
TWh



Source: PRIMES.

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.

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[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.

d. Power generation

Graph 20 Net power generation, REF and policy scenarios
TWh

Source: PRIMES.

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,

[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
%

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Nuclear energy	37	0	0	0	0	0	0	0	0
Hydro	0	1	1	0	0	0	0	0	0
Wind	8	22	28	25	24	23	31	28	26
Solar	5	6	14	16	17	5	16	18	19
Biomass & waste	10	11	12	11	10	11	14	12	12
Coal	3	0	0	0	0	0	0	0	0
Natural gas	33	60	45	47	47	61	38	40	42
Other	3	1	1	1	1	1	1	1	1

Source: PRIMES.
Note: ‘Other’ stands for petroleum products and derived gasses.

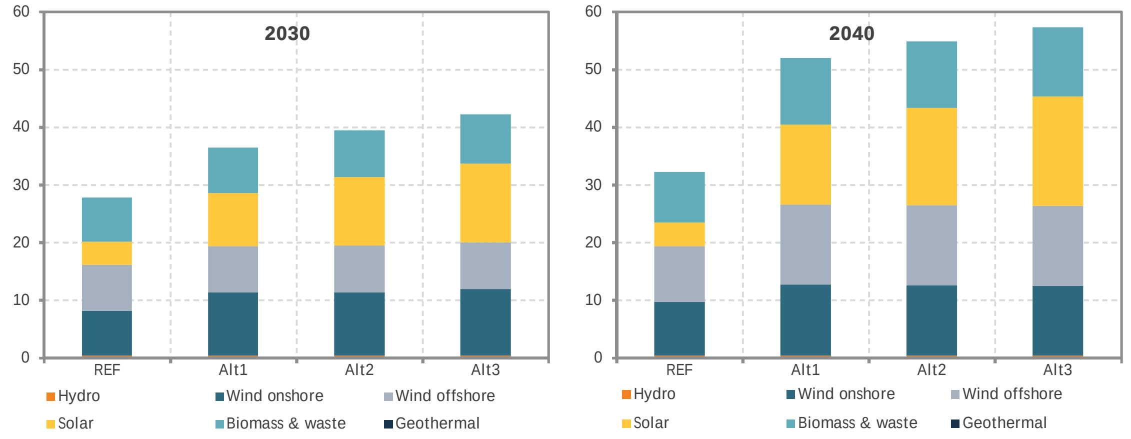
Some things attract attention. First, all scenarios undergo a major transformation from a relatively diversified portfolio in 2015 with nuclear, gas(ses), biomass, coal and some (other) renewable energy sources towards a bipolar power system in 2030 and 2040, exclusively made up of gas on the one hand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

Graph 21 Power generation by renewable energy sources, REF and policy scenarios, 2030 and 2040
TWh



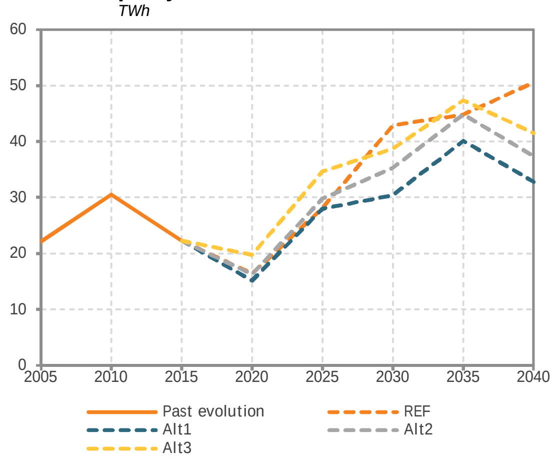
Source: PRIMES.

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.

Graph 22 Gas-based electricity production, REF and policy scenarios
TWh



Source: PRIMES.

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
GW

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

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

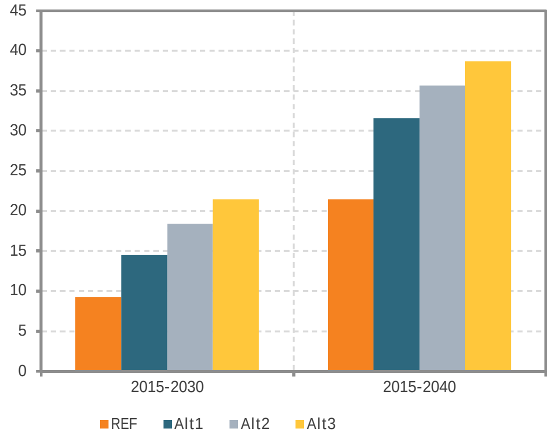
(*Alt1*) and 10 GW (*Alt3*). The situation is quite different from *REF*'s: total installed capacity in *REF* is similar to the level in 2015. This stabilisation in fact covers the nuclear, coal, oil and gas[15] capacity losses with renewable and gas increases adding up to, in total, 6 GW of wind, 4 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

Graph 23 Investments in power generation, REF and policy scenarios

GW



Source: PRIMES.

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).

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[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

First insight

Augmenting the interconnection capacity on the borders decreases system marginal costs.

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.

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.

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 CO_2, the conversion efficiency and the variable O&M costs.

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[17]. 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

	Alt1_interco4500_Gas2G	Alt1_interco8500
SMC (EUR/MWh)	+3.3	-0.5
CCGT production (TWh)	+5.8	-0.3

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

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[19].

Table 12 Sensitivity 1: Differences wrt Alt1 in (net) imports and exports in the Belgian power system, year 2030
TWh

	Alt1_interco4500_Gas2G	Alt1_interco8500
Imports	-6.3	+2.5
Exports	-0.5	+2.2
Net imports	-5.8	+0.3

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_2 in the *Alt1* setting is only slightly below 30 EUR/tCO_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[20], France[21] and

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.

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

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[22] made similar commitments. A such scenario[23] generates a decrease in the *European* power sector CO_2 emissions compared to the original *Alt1* scenario of 32.4 Mt[24].

In a next phase, we tried to end up with a similar amount of CO_2 reductions in the European power sector by modelling a higher price on carbon. This scenario was named *Alt1_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_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_2 emissions is similar, other indicators are quite different. They are depicted in Table 13.

Table 13 Sensitivity 2: Differences wrt Alt1 between scenario with the announced national coal phase-outs and scenario with substantial rise in carbon price, year 2030

	Alt1_Coal Phase-out	Alt1_Higher carbon price
EU CO_2 emissions ($MtCO_2eq.$)	-32.4	-34.5
BE SMC (EUR/MWh)	+5.8	+21.5
BE CCGT production (TWh)	+2.2	+1.4

Source: Crystal Super Grid.
Note: BE stands for Belgium; SMC stands for System Marginal Cost; CCGT stands for Combined Cycle Gas Turbine.

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[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:

– 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).

Table 14 Sensitivity 2: Differences wrt Alt1 in (net) imports and exports in the Belgian power system, year 2030
TWh

	Alt1_Coal Phase-out	Alt1_Higher carbon price
Import	-0.9	-0.1
Export	+1.3	+1.4
Net imports	-2.2	-1.4

Source: Crystal Super Grid.

– 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

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.

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.

24 32.4 Mt CO_2 is approximately the amount of CO_2 emitted by the Belgian transport sector in 2015.

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[26].

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.

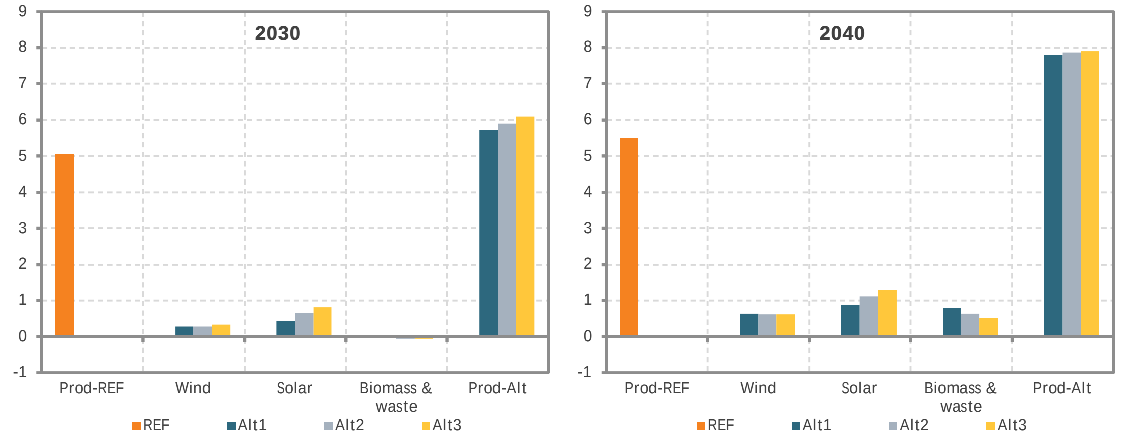
In 2030, domestic production increases by 13 to 21% compared to *REF*. Extra production comes primarily from solar energy (0.4 Mtoe in *Alt1*, 0.7 Mtoe in *Alt2* and 0.8 Mtoe in *Alt3*), followed by wind (0.3 Mtoe in all *policy scenarios*). The production of biomass and waste varies only marginally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

[26] Net imports mean imports minus exports.

Graph 24 Domestic energy production, REF and policy scenarios, 2030 and 2040

Mtoe



Source: PRIMES.
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*.

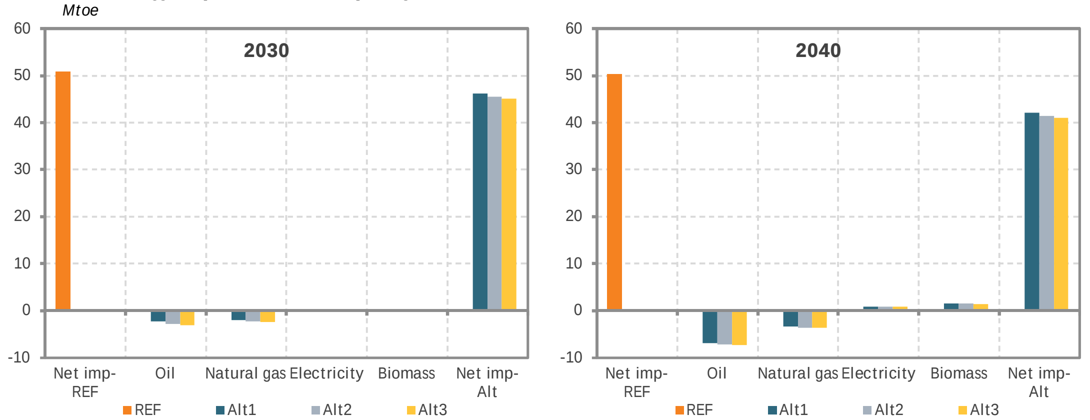
Domestic energy production levels are the highest in *Alt3*: 6.1 Mtoe in 2030 and 7.9 Mtoe in 2040, compared to around 5 Mtoe in *REF* in both years. In 2015, the domestic production of RES and non-renewable waste was equal to 3.6 Mtoe.

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).

Graph 25 Net energy imports, REF and policy scenarios, 2030 and 2040

Mtoe



Source: PRIMES.
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*.

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[27]. 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*.

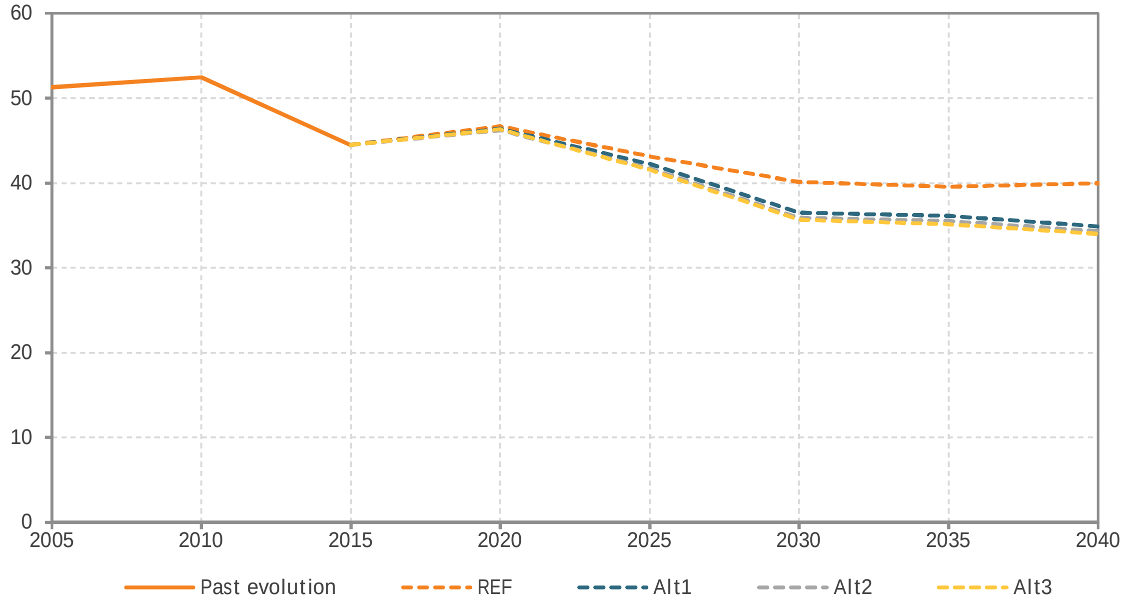
Despite different reduction targets in the non-ETS, primary energy consumption does not vary much between *policy scenarios*. This result is the combination of two opposite trends: the higher the reduction target in the non-ETS (*Alt3*), the more substantial the decrease in total final energy demand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

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.

Graph 26 Primary energy consumption, REF and policy scenarios, 2005-2040

Mtoe



Source: PRIMES.

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.

Table 15 Primary energy mix, REF and policy scenarios, 2015, 2030 and 2040

%

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Solid fuels	7	4	4	5	5	3	3	3	3
Oil	35	34	32	31	30	32	20	20	19
Natural gas	29	41	38	38	38	43	38	38	39
Nuclear	15	0	0	0	0	0	0	0	0
Electricity	4	6	7	7	7	5	7	8	8
RES	10	16	19	20	20	17	31	31	31

Source: PRIMES.

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).

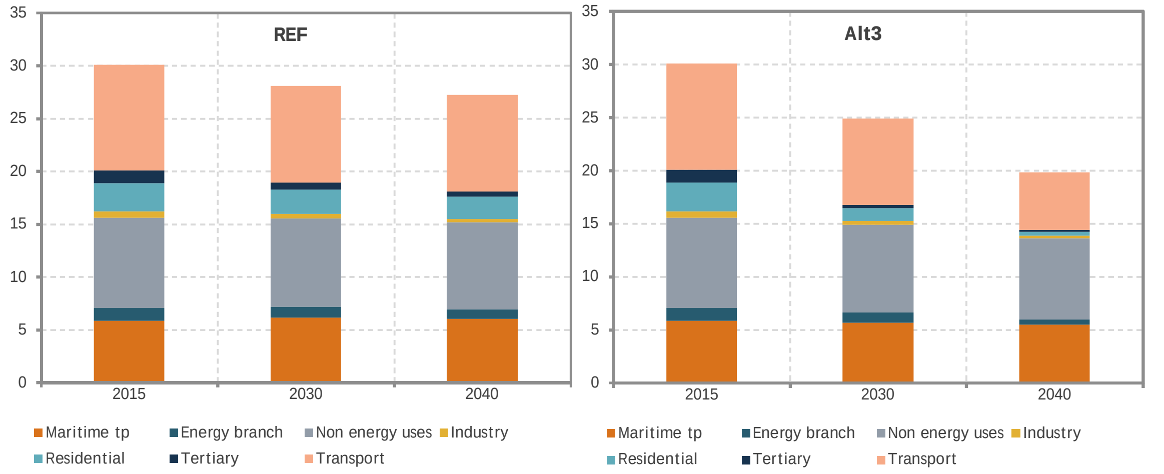
In 2040, the changes described above continue and even increase for oil and RES. The strong decline in the share of oil (around 20% in the *policy scenarios* compared to 32% in *REF*) is mainly due to further electrification and use of biofuels in the transport sector. The significant increase in the 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
Mtoe



Source: PRIMES.

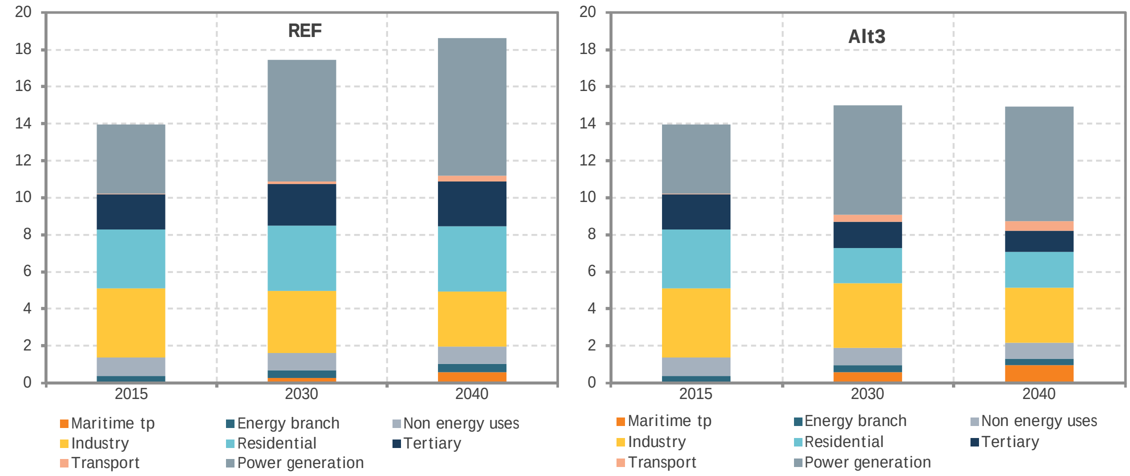
Oil consumption for maritime transport is also reduced compared to *REF* but to a lesser extent, at the benefit of natural gas (LNG). The consequence of the above trends is the decrease in the activity of refineries (energy branch) and therefore of their oil consumption. Oil for non-energy uses is comparable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

Graph 28 Natural gas requirements by sector or use, REF and Alt3, 2015, 2030 and 2040

Mtoe



Source: PRIMES.

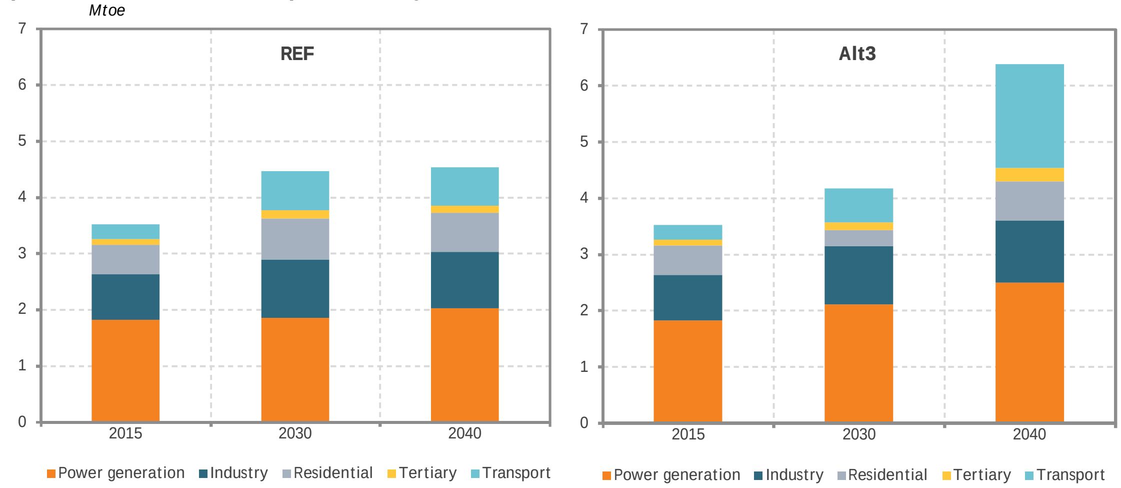
Natural gas needs for power generation are lower in *Alt3* than in *REF* in 2030 and 2040 as more electricity is produced from renewables. By contrast, natural gas is more extensively used as maritime fuel and in the transport sector (mainly LNG).

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.

Graph 29 Biomass & waste requirements by sector or use, REF and Alt3, 2015, 2030 and 2040

Mtoe



Source: PRIMES.

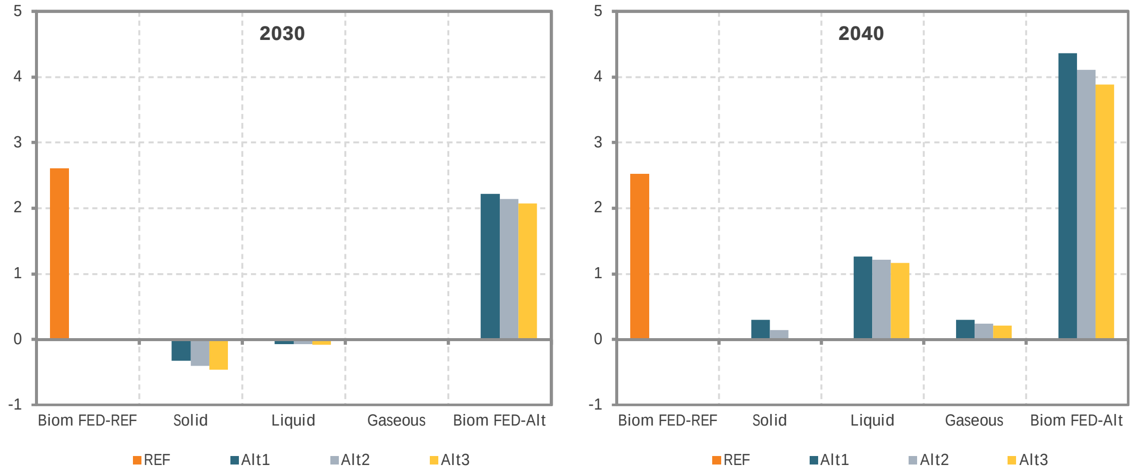
In 2030, total biomass & waste requirements are lower in *Alt3* than in *REF*. Reduced consumption in the final demand sectors except industry, further to energy savings and energy efficiency improvements, surpasses the increasing demand in the power generation sector. In *Alt3*, the latter covers half 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.

Graph 30 Biomass & waste requirements, REF and policy scenarios, 2030 and 2040
Mtoe



Source: PRIMES.
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*.

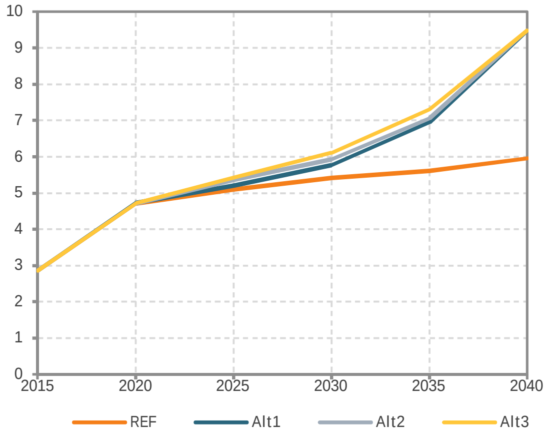
4.4. Renewables and energy efficiency

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 Gross final consumption of RES, REF and policy scenarios
Mtoe



Source: PRIMES.

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
%

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

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[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.

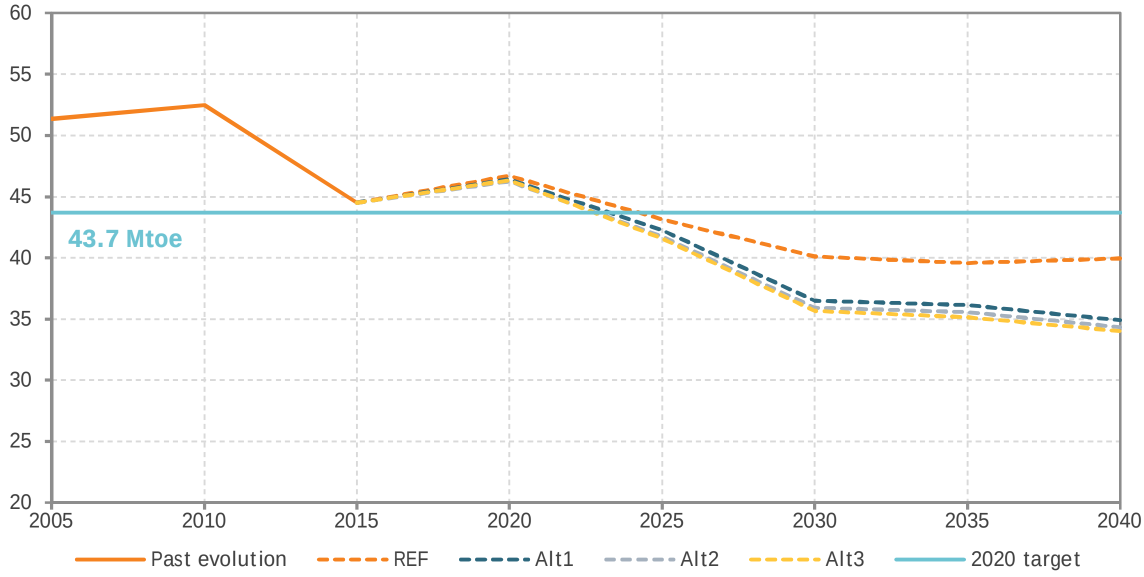
Beyond 2020, primary and final energy demands start decreasing steadily.

[28] http://www.europarl.europa.eu/legislative-train/theme-resilient-energy-union-with-a-climate-change-policy/file-energy-efficiency-directive-review

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*).

Graph 32 Primary energy consumption and energy efficiency target, REF and policy scenarios
Mtoe

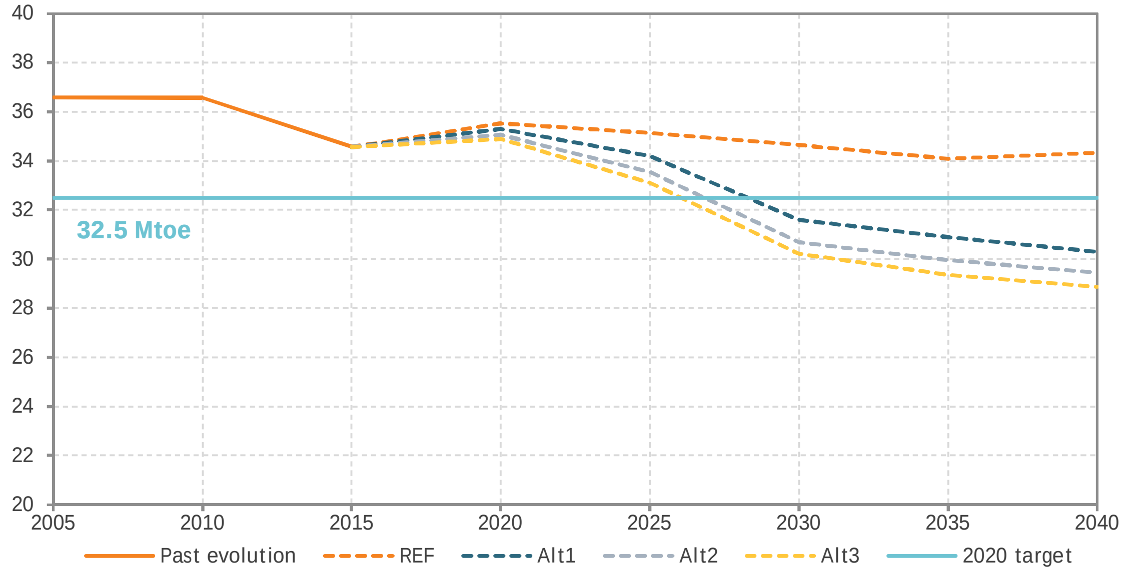


Source: PRIMES.

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
Mtoe



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.

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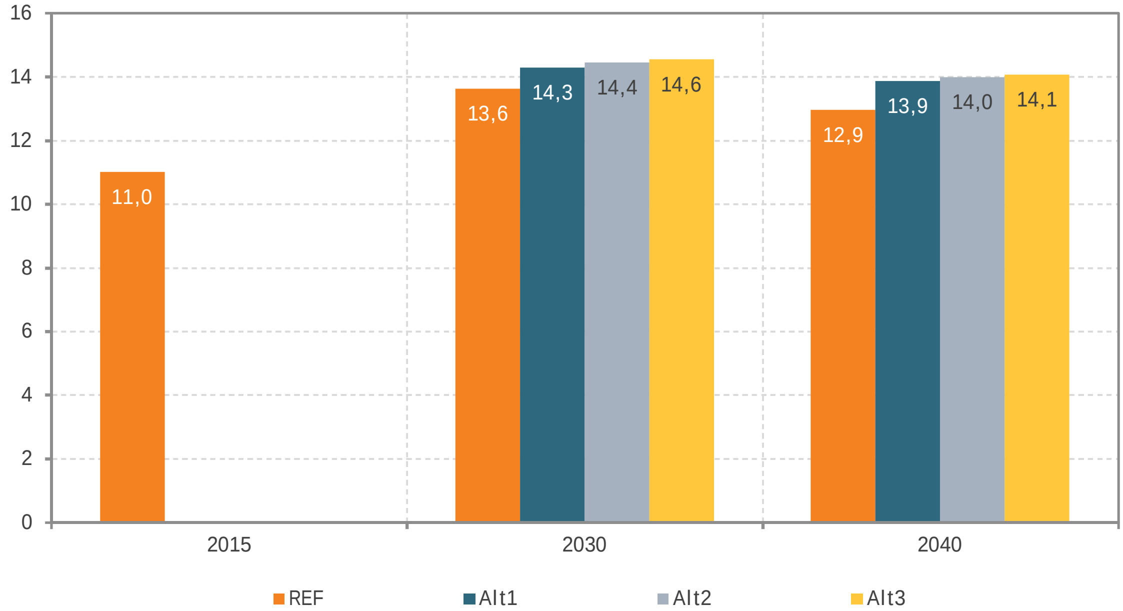
29 For a more extensive definition of total energy system cost, see chapter 3.5 and annex 4.4 of (EC, 2016).

30 Capital costs are expressed in annuity payments.

Graph 34 Total energy system cost, REF and policy scenarios, 2015, 2030 and 2040
In % of GDP



Source: PRIMES.

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.

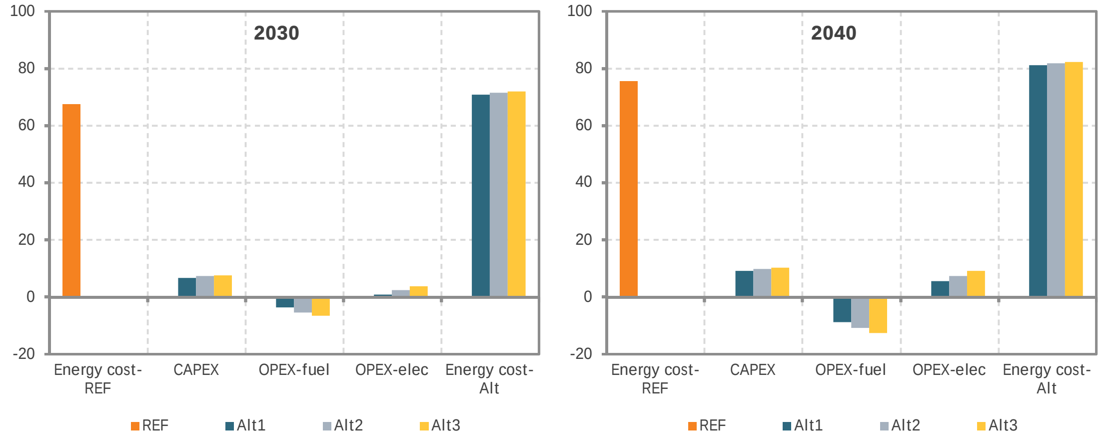
The structure of total energy system cost changes substantially over time reflecting the increasing capital intensiveness and electrification of the energy system. This first trend was already observed in *REF* but intensifies in the *policy scenarios*. By 2030, the capital costs and direct efficiency 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).

[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.

Graph 35 Total energy system cost, REF and policy scenarios, 2030 and 2040
Billion EUR'13



Source: PRIMES.
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*.

In 2030, the increases 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[33].

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[34].

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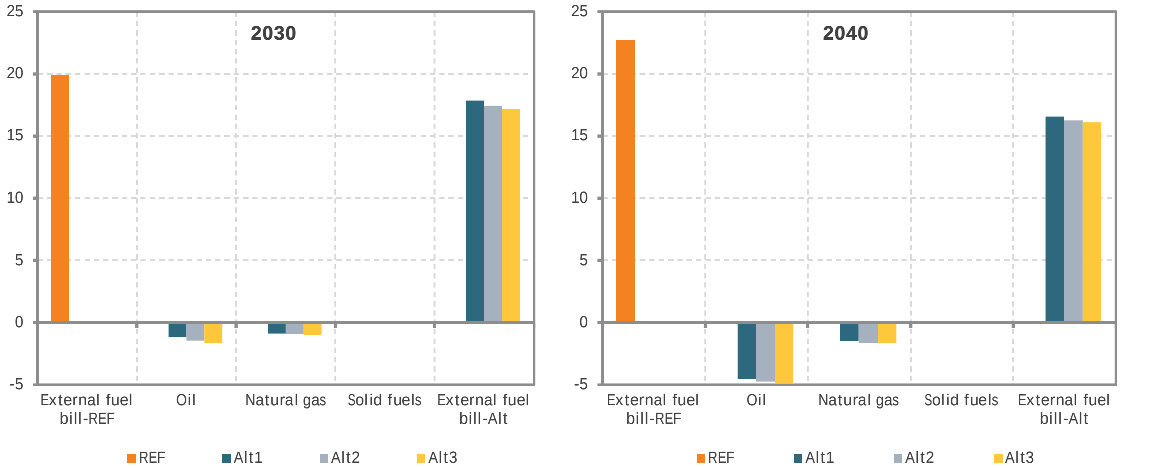
33 Not visible on the graph due to the scale.
34 Ibid.

Graph 36 External fossil fuel bill, REF and policy scenarios, 2030 and 2040
Billion EUR'13



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*.

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%).

Table 17 Fossil fuel trade balance, REF and policy scenarios, 2015, 2030 and 2040
In % of GDP

	2015	2030	2040
REF	-2.9	-4.0	-3.9
Alt1	-2.9	-3.6	-2.8
Alt2	-2.9	-3.5	-2.8
Alt3	-2.9	-3.5	-2.8

Source: PRIMES, FPB calculation.
Note: A negative trade balance means a trade deficit.

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).

[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.

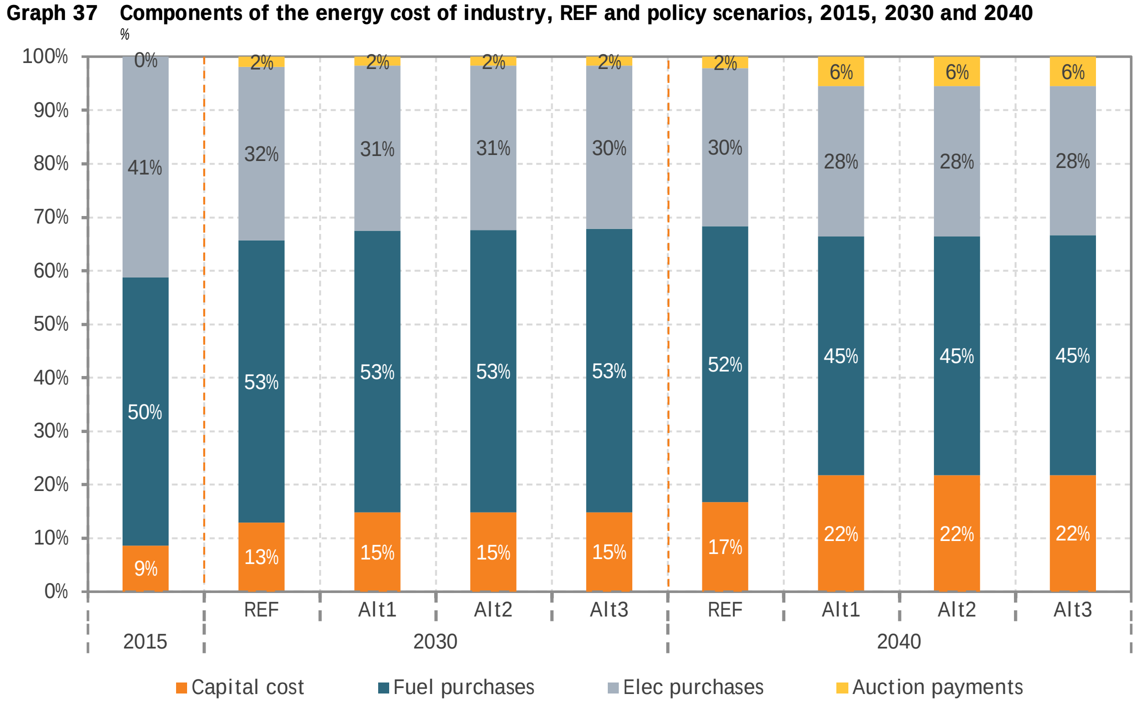
5.3.1. Energy cost

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



Source: PRIMES.
Note: The component "Elec purchases" includes electricity and heat where relevant.

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.

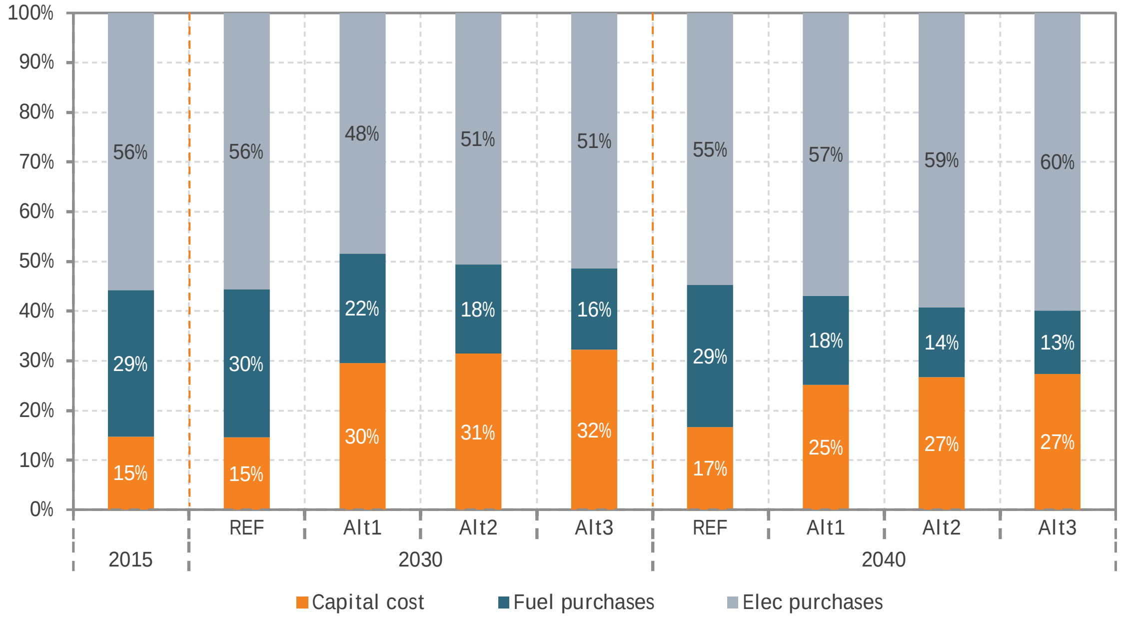
In 2040, the share of energy purchases drops in the *policy scenarios* to 45% for fuels and to 28% for electricity at the "benefit" of capital cost (22%) and auction payments (6%). Auction payments and their contribution to the energy cost increase over time and with respect to *REF* reflecting higher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

Graph 38 Components of the energy cost of the tertiary sector, REF and policy scenarios, 2015, 2030 and 2040

%



Source: PRIMES.
Note: The component "Elec purchases" includes electricity and heat where relevant.

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[36] 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

[36] 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.

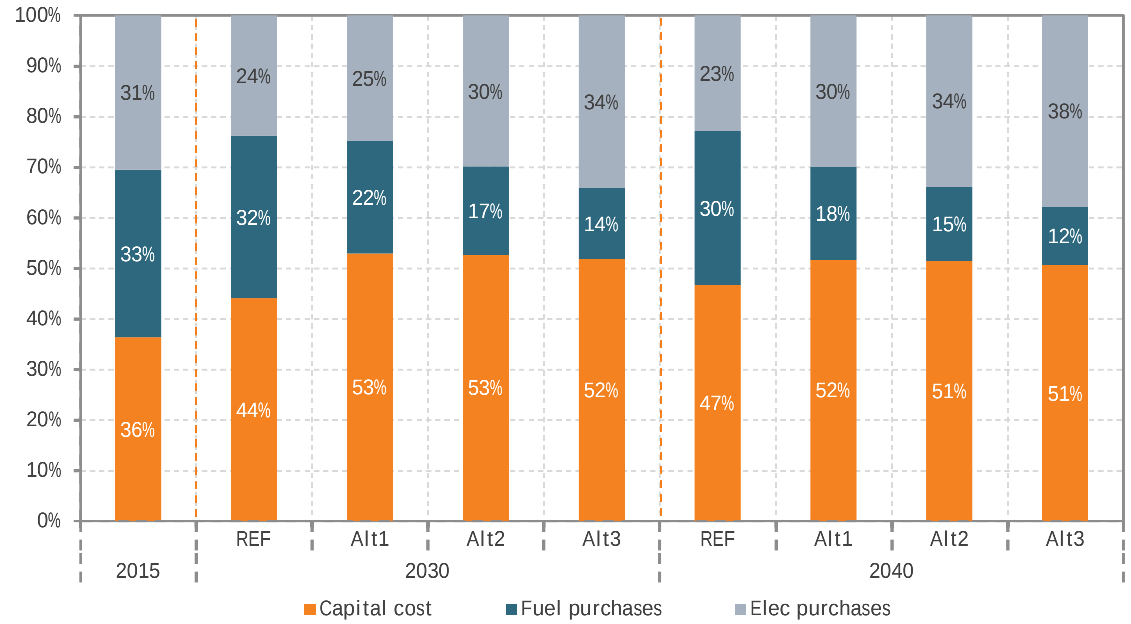
Beyond 2030, capital cost nearly stabilizes, fuel purchases continue to drop but the purchase cost of electricity takes off reflecting the growing electrification of the sector. These developments translate into the following shares in 2040: around 26% for the capital cost, from 13% to 18% for the fuel 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%).

Graph 39 Components of the energy cost of the residential sector, REF and policy scenarios, 2015, 2030 and 2040
%



Source: PRIMES.
Note: The component "Elec purchases" includes electricity and heat where relevant.

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 18 Unit energy cost in final demand sectors (excl. transport), REF and policy scenarios, 2015, 2030 and 2040
In % of VA (industry and tertiary), in % of private consumption (residential)

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Industry	18.6	22.3	21.6	21.5	21.4	20.8	21.6	21.6	21.5
Tertiary	1.9	2.1	1.9	1.9	1.8	1.9	1.9	1.9	1.9
Residential	4.3	4.7	4.3	4.5	4.7	4.2	4.3	4.4	4.6

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.

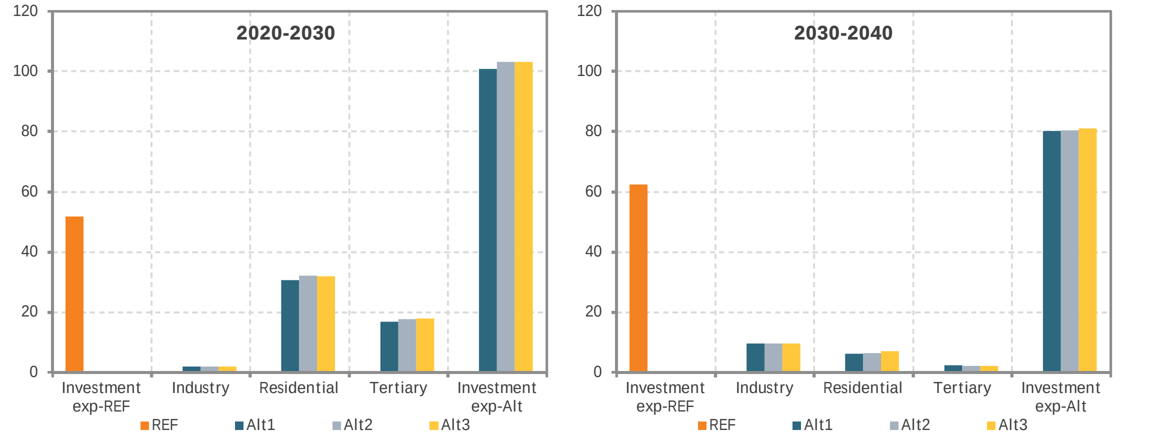
5.3.3. Investment expenditures

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.

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

Billion EUR'13



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*.

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 for energy-related investments 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*[39].

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[40], 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.

[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 de-commissioned 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[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[42].

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

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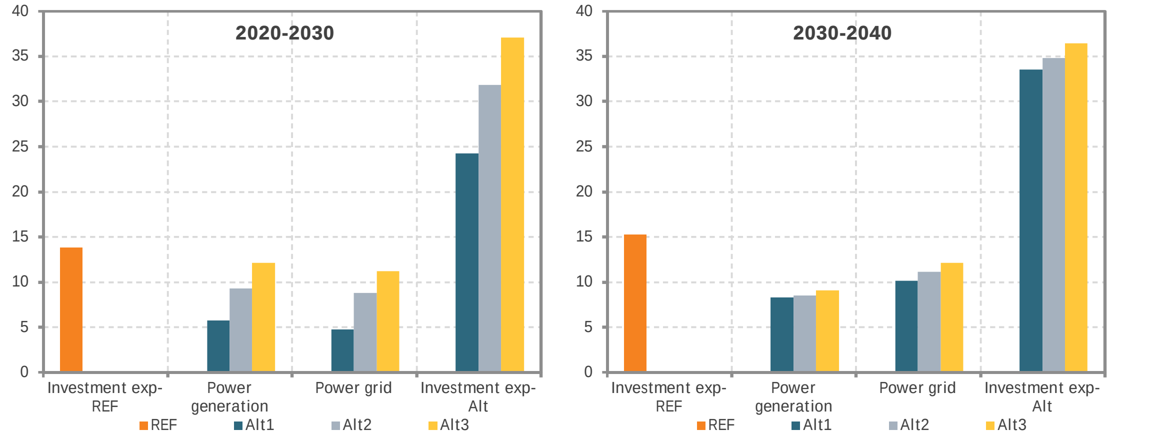
41 Average GDP over the period 2020-2040.

42 Ibid.

Graph 41 Investment expenditures for power generation and grid, REF and policy scenarios, 2020-2030 and 2030-2040
Billion EUR'13



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*.

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
EUR'13/MWh

	2015	2030				2040			
		REF	Alt1	Alt2	Alt3	REF	Alt1	Alt2	Alt3
Fixed	57	46	58	58	58	34	53	53	54
Variable	28	43	37	37	36	46	35	35	35
Other	2	8	6	6	6	12	25	25	26
Total	87	97	101	101	100	91	112	114	115

Source: PRIMES, FPB calculations.

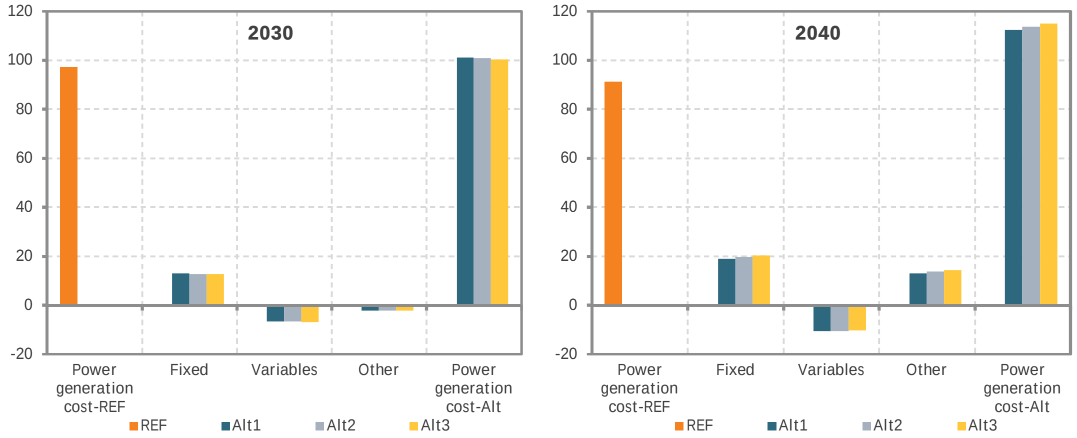
Compared to *REF*, average cost increases by 4% in 2030 and by around 25% in 2040 in the *policy scenarios*.

The table also shows the decomposition in cost elements: fixed (capital costs[43]), 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.

[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.

Graph 42 Average power generation cost, REF and policy scenarios, 2030 and 2040
EUR'13/MWh



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*.

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*).

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