SCIENTIFIC SUPPORT PLAN FOR A SUSTAINABLE DEVELOPMENT POLICY

SPSD II

MARKAL/TIMES, A MODEL TO SUPPORT GREENHOUSE GAS REDUCTION POLICIES

D. VAN REGEMORTER, W. NIJS, N. RENDERS, S. PROOST, J. DUERINCK

PART 1

SUSTAINABLE PRODUCTION AND CONSUMPTION PATTERNS

GENERAL ISSUES

AGRO-FOOD

ENERGY

TRANSPORT

.be

SCIENTIFIC SUPPORT PLAN FOR A SUSTAINABLE DEVELOPMENT POLICY
(SPSD II)

Part 1:
Sustainable production and consumption patterns

FINAL REPORT

MARKAL/TIMES, A MODEL TO SUPPORT GREENHOUSE GAS REDUCTION POLICIES

CP/22

Promotors
Stef Proost – KULeuven, Centrum voor Economische Studiën
Jan Duerinck -- VITO

Authors
Denise Van Regemorter, Wouter Nijs, Nele Renders

June 2007

D/2007/1191/44
Published in 2007 by the Belgian Science Policy
Rue de la Science 8
Wetenschapsstraat 8
B-1000 Brussels
Belgium
Tel: +32 (0)2 238 34 11 – Fax: +32 (0)2 230 59 12
http://www.belspo.be

Contact person:
Anne Fierens
Secretariat: +32 (0)2 238 36 13

Table of contents

List of tables

Introduction

1. OBJECTIVE

The main objective of this project is to support the Belgian climate change policy with the MARKAL model and its successor TIMES. Climate change is and remains a high priority research theme because an efficient and effective international and national climate policy is a necessary condition for sustainable development. A correct evaluation of the potential for emission reduction in Belgium, their allocation between economic sectors and their cost is therefore essential. More concrete, this project can contribute to the following objectives:

- Determine the GHG-emission targets, which Belgium can achieve in the long term, i.e. after Kyoto.
- Determine which sectors or technologies have to be considered in priority for GHG emission reduction
- Evaluate the interaction between climate change policy and other policies related to the energy system

2. RESEARCH STRATEGY

To achieve the goal of this project, the objective is to contribute to the further development of the MARKAL/TIMES model and to use it for the analysis of policies regarding climate change, at national and international level.

MARKAL/TIMES is a technico-economic model, which assembles in a simple but economic consistent way technological information (conversion-efficiency, investment- and variable costs, emissions, etc.) for the entire energy system. It can represent all the energy demand and supply activities and technologies for a country over a horizon of 40/80 years, with their associated emissions and the damages generated by these emissions. Compared to ad-hoc models which are more specific to a country or a sector and which use another modelling technique, it presents three important advantages:

- due to its transparency it promotes the communication between experts with different sectoral or technological background (it is the place where engineers and economists understand each other),
- it is easily verifiable: its results can be related to assumptions regarding technological data and economic parameters,
- it is comparable at an international level: as many countries use the same model, its results can be immediately compared with results from other countries.

Three main activities were covered within this project: the development of the model, the maintenance and improvement of its database and policy studies to support climate change/energy policies. Regarding the development of the model, the focus was on a contribution to the development of the new version of MARKAL, TIMES, on the extension of the capability of the Belgian model to integrate the international aspects present in any climate/energy policy and on the integration of a refinery module. The different activities are described in the next section.

MARKAL/TIMES model for Belgium

The ETSAP modelling community, including Belgium, has developed the new MARKAL, called TIMES. The objective of this undertaking is a complete re-engineering of the model to arrive at a model formulation, which is easier to understand, more flexible and allows a further enhancing of the methodology. This version is now implemented in Belgium. It covers the entire energy system with the level of detail mainly driven by the availability of data, the operationality of the model and the compatibility with the development in the EU research project NEEDS[1]. This last aspect allows integrating the Belgian model into the Pan-European model developed in NEEDS. Moreover a complete update of the technology database was realized.

In this section, a description of the adopted structure for the Reference Energy System (RES) and for the model is given. Then the technology database and its underlying assumptions are described. The complete technology database is available in access. The calibration of the model for the baseyear is given in a separate annex[2].

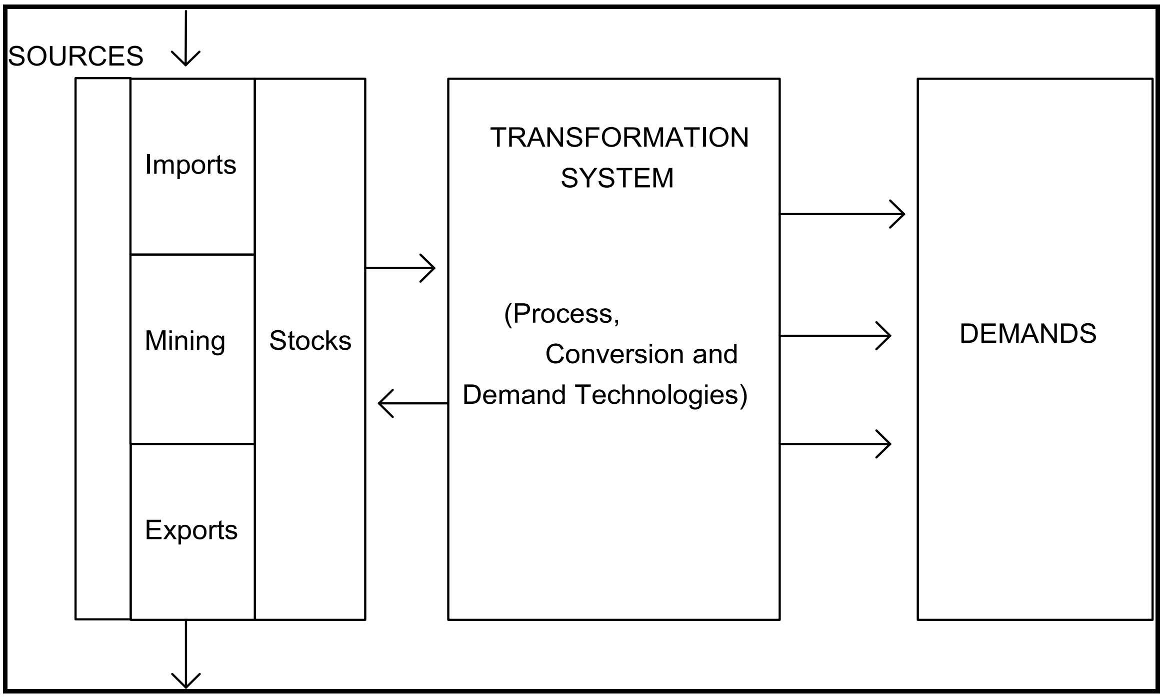
[1] http://www.isis-it.net/needs/

[2] Annex 3 Calibration of MARKAL/TIMES Belgium

3. THE REFERENCE ENERGY SYSTEM AND THE MODELLING STRUCTURE

The starting point of the modelling structure is the Reference Energy System. The Reference energy system adopted is closely related to the structure of the energy balance, with the final demand sectors and the supply sectors.

Figure 1: Modelling structure of Markal/Times



The broad demand categories, following the EUROSTAT energy balance division of the final energy demand, are industry, transport sector, residential sector, service sector and agriculture. On the supply side, there is the electricity/heat sector and the other transformation sectors (oil, biofuels …). The different sectors are described hereafter. The detailed structure of the RES is reflected in the nomenclature adopted. The nomenclature for the different sectors is constructed based on the categories and subcategories to which it belongs. A table in annex, section2 gives the complete list of the categories and their names, codes, and units. This nomenclature is important for reporting but also for emission accounting to be able to identify clearly at what step the emissions occur.

3.1. The residential sector

Because of the differences in the evolution of the demand for energy services and in the availability of technological options, the model structure distinguishes for the residential sector:

- **6 end uses**: Space heating, Space Cooling, Water heating, Cooking, Lighting, Electric appliances and others (all expressed in PJ)
- **3 dwelling categories**: Single house detached/rural, Single house in a row/urban and Multiple house/apartment, distinguishing between new and existing dwelling categories.

Space heating, space cooling and water heating have been differentiated by dwelling category whereas the others have only an average specification. The new buildings are those installed after the baseyear (2000). The distinction between existing and new building is important because of the difference in insulation between both categories and in the technological options. Cooling is not considered in the baseyear because it has still a very low penetration in Belgium.

3.2. The service sector

For the service sector a distinction is made between large and small and there is a separate demand for public lighting. This distinction is mainly driven by the technological options available. The same structure by end use as in the residential sector is adopted.

3.3. The agricultural sector

Agriculture is modelled in a very simplified manner with one generic demand without differentiating by end use.

3.4. The transport sector

The transport distinguishes the four categories of the energy balance: road, rail, navigation and air, and these are then further disaggregated by transport mode and for rail and road, between freight and passenger.

Road transport:

Passenger transport:	car travel, short and long distance bus travel, urban and intercity two wheels travel
Freight transport:	truck

Rail transport:

Passenger transport:	urban and intercity
Freight transport	

For the categories above the demand is expressed in passenger/ton km. At this stage, the occupancy rates are fixed, but if variable occupancy rates are envisaged, this can be reflected in the proper TIMES parameter which converts the technology capacity (vehicle) into an output (passenger/ton-km travelled).

Air and navigation are modelled in a very simple aggregated way, distinguishing only one category for each.

3.5. The industrial sector

The structure distinguishes between the energy intensive sectors and the other sectors. The energy intensive sectors are iron & steel, non ferro, chemical, paper and pulp and the building materials, cement, glass and lime. The others, though separated in a few sectors in the energy balance, are aggregated in one sector because they can be considered as rather similar regarding the technological options available to satisfy their demand for energy services.

For the energy intensive industries, a process-oriented structure is adopted with explicit materials and specific technologies. The demands, expressed as material demands (e.g. steel), are provided in natural units. There are also materials which are an input to a process, e.g. scrap iron. Only those materials which are important for the production processes modelled are considered[3]. The supply of these materials are either exogenous (modelled through a supply function) or produced within the model, being an intermediate output of some process considered. A list of these materials is given in annex, section 2. To try to maintain the model simple, only one main step linked to the most energy intensive process and representing the input/output structure was included. However, for some industries more

[3] The other materials are implicitly modelled in the variable cost or in the emission accounting of the processes.

than one modelling step was modelled to better take into account the substitution between processes and technological evolution.

For the aggregated sector the standard structure is more generic. It consists in a mix of five energy uses: Steam (boilers), Process heat, Machine Drive, Electrochemical, Others and Feedstock. The industrial demand consists of exogenous mixes of these six components and is expressed in PJ. For some energy intensive sectors some of their energy service demands are also modelled with this approach when it cannot be associated with a specific process because it is too aggregated.

A. The process modelled industrial sectors

Two cases are considered for those industrial sectors:

1. when the demand of material covers the whole sector production (steel and paper): there are
    - the specific processes and
    - one process aggregating in one step all the other energy consumption linked to the material and not modelled in the specific processes.
2. when the demand for material does not cover the whole sector (e.g. chemicals), another demand category is modelled covering the other energy consumption of that sector. This is then modelled by end use.

1) The steel industry

The steel industry is modelled in four steps:

- Transformation of the primary inputs
- Production of raw iron
- Production of crude steel
- Finishing process

The demand is expressed in 1000 tons of crude steel production equivalents. The three first steps cover in detail the production of crude steel and there is a finishing process which covers all possible steel finishing processes and aggregate all the energy consumption from the energy balance not included in the first three.

2) The non ferro sector

Because there is no copper refinery, neither aluminium production in Belgium, the sector is modelled by enduses.

3) The chemical sector

Within the chemical sector, ammonia and chlorine are modelled by process whereas the rest of the chemical sector is modelled by end-use. Ammonia (NH3) is an important feed-stock material for the chemical industry and namely for the fertilizer manufacturing industry. The demand is expressed in megatons (MT or 10^6 tons) of NH3, disregarding further processing of the product. As for NH3, Chlorine is regarded as being produced as feedstock material. The demand is also expressed in megatons.

4) Pulp and paper industry

For Pulp and Paper industry, only one category of paper is considered because of lack of data, though a distinction between high quality paper (magazine, etc., …) and low quality paper (paperboard, cardboard, …) could be interesting. The steps distinguish between the pulp production and the paper production.

5) Cement industry

The process modelling in the cement industry concentrates on the clinker production. The rest of the energy consumption for the production of cement is aggregated in a second step. Demand is expressed in 1000 tons of cement.

6) Glass production

Two categories of glasses are distinguished: hollow glass (bottles, …) and flat glass (windows, …) and each category has a separate demand expressed in 1000 tons of hollow/flat glass. For recycled glass a separate supply curve needs to be provided as it is not endogenized in the model.

7) Lime production

Quick lime production (CaO) is expressed by the following formula: $CaCO_3$ -> CaO + CO_2

In mass units: 1 ton $CaCO_3$ -> 560 kg CaO + 440 kg CO_2

Lime production is modelled in one step, from limestone to lime. Demand is expressed in Mt of lime.

B. The other industries

For the other industries representing the less energy intensive processes, the industrial demand is disaggregated into five components (end uses) with fix shares (a rigid process):

- Steam (boilers),
- Process heat,
- Machine drive,
- Electrochemical,
- Others

and for each enduse there are different technologies. Feedstock's are not modelled explicitly but are considered as an exogenous demand.

3.6. The electricity sector

The electricity sector is the most important supply sector. It includes also the cogeneration of electricity and heat.

The TIMES model allows great flexibility in modelling the supply of electricity. Multiple grids are considered. This distinction allows the differentiation of the delivery cost, the distinction between centralised and decentralised production with a differentiation of the sectors consuming the electricity or heat and for electricity, the identification of possibility for import/export.

It is however necessary to limit this flexibility in a well defined way. Otherwise the model will switch between different options because of small price differences which will be very difficult to justify. Therefore the following scheme was adopted for the Belgian model for electricity production:

- **Centralised production**: the power plants produce only high voltage electricity and it is delivered to the high voltage grid. There is no cogeneration at the centralised level
- **Decentralised production**: at this level only cogeneration plants are considered; their electricity production is always delivered to the grid but at a decentralised level: industry for the industry as a whole and the other sectors for the low-voltage grid. The plants are sector specific and deliver the heat to that sector. Possible sectors for the implementation of cogeneration are industry, the service sector and agriculture, the possibility of cogeneration in (apartment) buildings can be considered for the future.

For the production of heat similar assumptions have been made to limit the possible flows between supply and demand. It concerns mainly the industrial heat demand. For the residential and service sector no centrally produced heat, i.e. district heating, will be installed. When heat in the service sector is not produced by a technology specifically linked to one building, it will be through cogeneration. For the industry sector, process heat demand is always delivered by a sector specific process delivering the heat. The other heat demand (steam) can be produced by a generic boiler or through cogeneration, both technologies being attached to the specific sector. No distinction is made as this stage between high and low temperature heat because of the lack of available data.

3.7. Other supply sectors

Other energy transformation sectors are in MARKAL/TIMES, including refineries, coke oven, hydrogen production, biomass production and conversion. Some of these sectors are modelled in a very simplified way because they are very small. Hydrogen production and biomass transformation are implemented both addressing the national market.

The refinery sector is modelled with a generic refinery reproducing the refinery capacity in Belgium in 2000. The increasing demand of refinery products will be satisfied through imports. It is modelled in a very simplified manner because the mix of refinery products are decided at European level or sometimes even at higher level (*what* to produce). Therefore, it is difficult to model endogenously the relation between fuel consumption, product mix and production processes in a model considering only Belgium. A separate module for a standard refinery has been fully developed during this project and allows analysing this sector, given exogenous assumptions regarding demand. The production structure (*how* to produce) then adapts to this demand and any environmental restriction.

3.8. Energy commodities

The energy commodities distinguished in the model are based on the energy balance categories but for some demand sectors, they were aggregated to a more limited list of categories. The complete list is given in annex, section 2. Each fuel has a different name depending on the sector it is used. This naming approach allows easy reporting, immediate recognition of sector fuels, and also allows the modelling of sectoral constraints, policies, taxes, subsidies, etc.

3.9. Emissions

The emissions considered are those linked to energy consumption and contributing to air pollution. Emissions of each substance are named differently in each sector. There is also an intermediate emission for any emission that can be processed further (e.g. CO_2 that may be captured and sequestered, or SO_2 that may be neutralized, etc). The complete list is given in annex, section 2.

4. THE TECHNOLOGY DATABASE

The technology database is an essential element in a model as MARKAL/TIMES. This section gives an overview of the technologies in the database by sector. Existing technologies that have been calibrated in the base year 2000 can be found in the separate annex on calibration. The full database is available in access; when opening the database, a form appears automatically with different drop-down lists, the user can choose from the list a sector and a technology and then the information of the different parameters appears. Building a database is an always ongoing process of updating and improving when new data become available. Therefore the access database must be considered as a snapshot of the data at a certain moment in time.

In Table 1 a glossary can be found of the most important parameters that describe the technologies.

Table 1: Glossary of the parameters

Abbreviation	
EFF	Efficiency
INV	Investment costs
FIX	Fixed costs
VAR	Variable costs
IN	Input of process, this can be an energy flow or a material
OUT	Output of process, this can be an energy flow or a material
LIFE	Technical lifetime
START	Year in which the technology comes onto the market

4.1. The residential sector

The technologies are subdivided in three main groups: technologies related with space heating, technologies related with water heating and technologies related with other uses. The latter group contains mainly electric appliances and lighting. The distinction between type of dwellings (rural, urban and flat) and between existing and new dwelling is mainly important for insulation technologies and for the availability of some technologies. No differentiation in terms of cost or efficiencies is considered.

A. Space heating

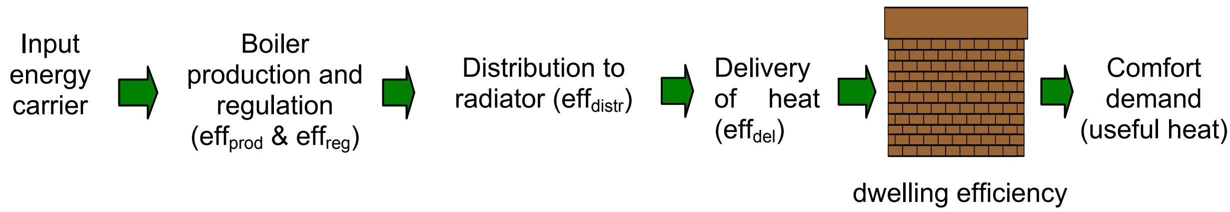
The technologies cover the heating technologies on different fuels, e.g. boilers on gas, oil, heat pump, and insulation technologies, e.g. roof insulation, double glass.

1) Heating technologies

A whole range of technologies for heating are modelled for the different subsectors. The most important parameters for the model to characterize these technologies are: efficiency (%), the investment cost (€2000/GW) and the fixed cost (€2000/GW). The numbers are coming from literature review.

There are different possibilities for the calculation of the technologies' efficiency. The overall efficiency, i.e. the quantity of energy needed to produce one unit of heat demand can be seen as the product of different factors: the boiler's efficiency, the radiator's efficiency and the overall delivery and distribution's efficiency within a building as represented in the figure below.

Figure 2: Efficiency of a dwelling



Total heat efficiency of a heating system (eff_{inst}) can thus be divided into four components: production (the boiler), regulation (the system is not 100% flexible to the demand), distribution (from boiler to heating units) and heat delivery (e.g. convectors deliver heat less efficient than radiators).

$$eff_{inst} = eff_{prod} * eff_{reg} * eff_{distr} * eff_{del}$$

where: eff_{prod} : efficiency of the boiler
eff_{reg} : efficiency of the regulation
eff_{distr} : efficiency in the heat distribution
eff_{del} : efficiency of heat delivery

They can all be integrated in a single technical efficiency but it seems better to keep the distinction because:

- the constructor's technology specifications usually do not include the distribution system's efficiency
- the delivery and distribution efficiency is independent of the technologies and can be included in the heat demand

Keeping part of the efficiency separated allows also for more transparency. The following table gives some sample values for the different efficiencies derived from Belgian data.

Table 2: Examples of efficiencies from Belgian data

		Coal	Oil	Gas	But/prop	Electricity
Local	effproduction	0.8	0.8	0.85	0.8	1
	effregulation	0.9	0.9	0.9	0.9	0.8
	effdistribution	1	1	1	1	1
	effdelivery	0.85	0.87	0.9	0.9	0.96
	effinst	**0.61**	**0.63**	**0.69**	**0.65**	**0.77**
Central	effprod (<71)		0.84	0.84	0.78	0.9
	effregulation		0.87	0.87	0.87	0.87
	effdistribution		0.9	0.9	0.9	0.9
	effdelivery		0.9	0.9	0.9	0.9
	effinst (>81)	**0.63**	**0.71**	**0.72**	**0.67**	**0.88**

For the model it was decided to include the 'distribution and delivery efficiency' in the heat demand because it is not linked to a specific technology and to add the 'regulation' efficiency to the 'production' efficiency. Therefore a correction of 0.9 was applied to the pure 'technology' efficiency. The dwelling efficiency (i.e. its insulation level) is implicitly included in the baseyear heat demand through the calibration and can be improved through insulation technologies (cf. next point)

The characteristics of the heating devices are given in Table 3.

Table 3: Heating devices characteristics

Process	EFF	FIX	INV
		€/kW	€/kW
RHMEELC101 [RSD.Space Heat.Multi.ELC.EX01.Convector]	89%	0.0	64
RHMEELC201 [RSD.Space Heat.Multi.ELC.EX01.NightAccumulator]	88%	0.0	189
RHMEELC501 [RSD.Space Heat.Multi.ELC.Ex01.Ground Heat Pump.]	298%	8.0	684
RHMEELC701 [RSD.Space Heat.Multi.OILELC.Ex01.Boiler Heat Pump.]	270%	4.4	572
RHMEELC801 [RSD.Space Heat.Multi.GASELC.Ex01.Boiler Heat Pump.]	270%	4.4	534
RHMEGAS101 [RSD.Space Heat.Multi.GAS.Ex01.Stove]	81%	4.4	26
RHMEGAS201 [RSD.Space Heat.Multi.GAS.Ex01.Boiler]	82%	3.9	195
RHMEGAS301 [RSD.Space Heat.Multi.GAS.Ex01.CondensedBoiler]	93%	5.4	272
RHMELPG101 [RSD.Space Heat.Multi.LPG.Ex01.Stove]	81%	4.4	26
RHMELPG201 [RSD.Space Heat.Multi.LPG.Ex01.Boiler]	82%	3.9	195
RHMELSD201 [RSD.Space Heat.Multi.OIL.Ex01.Boiler]	86%	4.4	220
RHMELSD301 [RSD.Space Heat.Multi.OIL.Ex01.Dual Boiler]	85%	4.4	258
RHMEPRO301 [RSD.Space Heat.Multi.LPG.Ex01.Condensed Boiler]	93%	5.4	272
RHREBIO101 [Rsd.Space Heat.Single.Rural.BIOWood.Ex01.Stove]	65%	0.0	16
RHRECOA101 [Rsd.Space Heat.Single.Rural.COA.Ex01.Stove]	65%	8.0	16
RHREELC101 [RSD.Space Heat.Rural.ELC.EX01.Convector]	89%	0.0	64
RHREELC201 [RSD.Space Heat.Rural.ELC.EX01.NightAccumulator]	88%	0.0	189
RHREELC501 [RSD.Space Heat.Rural.ELC.Ex01.Ground Heat Pump.]	298%	8.0	684
RHREELC701 [RSD.Space Heat.Rural.OILELC.Ex01.Boiler Heat Pump.]	270%	4.4	572
RHREELC801 [RSD.Space Heat.Rural.GASELC.Ex01.Boiler Heat Pump.]	270%	4.4	534
RHREGAS101 [RSD.Space Heat.Rural.GAS.Ex01.Stove]	81%	4.4	26
RHREGAS201 [RSD.Space Heat.Rural.GAS.Ex01.Boiler]	82%	3.9	195
RHREGAS301 [RSD.Space Heat.Rural.GAS.Ex01.CondensedBoiler]	93%	5.4	272
RHRELPG101 [RSD.Space Heat.Rural.LPG.Ex01.Stove]	81%	4.4	26
RHRELPG201 [RSD.Space Heat.Rural.LPG.Ex01.Boiler]	82%	3.9	195
RHRELSD201 [RSD.Space Heat.Rural.OIL.Ex01.Boiler]	86%	4.4	220
RHRELSD301 [RSD.Space Heat.Rural.OIL.Ex01.Dual Boiler]	85%	4.4	258
RHREPRO301 [RSD.Space Heat.Rural.LPG.Ex01.Condensed Boiler]	93%	5.4	272

RHRNELC101 [RSD.Space Heat.Rural.ELC.NE01.Convector]	89%	0.0	64
RHRNELC201 [RSD.Space Heat.Rural.ELC.NE01.NightAccumulator]	88%	0.0	189
RHRNELC501 [RSD.Space Heat.Rural.ELC.NE01.Ground Heat Pump.]	298%	8.0	456
RHRNELC701 [RSD.Space Heat.Rural.OILELC.NE01.Boiler Heat Pump.]	270%	4.4	381
RHRNELC801 [RSD.Space Heat.Rural.GASELC.NE01.Boiler Heat Pump.]	270%	4.4	356
RHRNGAS201 [RSD.Space Heat.Rural.GAS.NE01.Boiler]	82%	3.9	195
RHRNGAS301 [RSD.Space Heat.Rural.GAS.NE01.CondensedBoiler]	93%	5.4	272
RHRNLPG201 [RSD.Space Heat.Rural.LPG.NE01.Boiler]	82%	3.9	195
RHRNLSD201 [RSD.Space Heat.Rural.OIL.NE01.Boiler]	86%	4.4	220
RHRNLSD301 [RSD.Space Heat.Rural.OIL.NE01.Dual Boiler]	85%	4.4	258
RHRNPRO301 [RSD.Space Heat.Rural.LPG.NE01.Condensed Boiler]	93%	5.4	272
RHUEELC101 [RSD.Space Heat.Urban.ELC.EX01.Convector]	89%	0.0	64
RHUEELC201 [RSD.Space Heat.Urban.ELC.EX01.NightAccumulator]	88%	0.0	189
RHUEELC501 [RSD.Space Heat.Urban.ELC.Ex01.Ground Heat Pump.]	298%	8.0	684
RHUEELC701 [RSD.Space Heat.Urban.OILELC.Ex01.Boiler Heat Pump.]	270%	4.4	572
RHUEELC801 [RSD.Space Heat.Urban.GASELC.Ex01.Boiler Heat Pump.]	270%	4.4	534
RHUEGAS101 [RSD.Space Heat.Urban.GAS.Ex01.Stove]	81%	4.4	26
RHUEGAS201 [RSD.Space Heat.Urban.GAS.Ex01.Boiler]	82%	3.9	195
RHUEGAS301 [RSD.Space Heat.Urban.GAS.Ex01.CondensedBoiler]	93%	5.4	272
RHUELPG101 [RSD.Space Heat.Urban.LPG.Ex01.Stove]	81%	4.4	26
RHUELPG201 [RSD.Space Heat.Urban.LPG.Ex01.Boiler]	82%	3.9	195
RHUELSD201 [RSD.Space Heat.Urban.OIL.Ex01.Boiler]	86%	4.4	220
RHUELSD301 [RSD.Space Heat.Urban.OIL.Ex01.Dual Boiler]	85%	4.4	258
RHUEPRO301 [RSD.Space Heat.Urban.LPG.Ex01.Condensed Boiler]	93%	5.4	272
RHUNELC101 [RSD.Space Heat.Urban.ELC.NE01.Convector]	89%	0.0	64
RHUNELC201 [RSD.Space Heat.Urban.ELC.NE01.NightAccumulator]	88%	0.0	189
RHUNELC501 [RSD.Space Heat.Urban.ELC.NE01.Ground Heat Pump.]	298%	8.0	456
RHUNELC701 [RSD.Space Heat.Urban.OILELC.NE01.Boiler Heat Pump.]	270%	4.4	381
RHUNELC801 [RSD.Space Heat.Urban.GASELC.NE01.Boiler Heat Pump.]	270%	4.4	356
RHUNGAS201 [RSD.Space Heat.Urban.GAS.NE01.Boiler]	82%	3.9	195
RHUNGAS301 [RSD.Space Heat.Urban.GAS.NE01.CondensedBoiler]	93%	5.4	272
RHUNLPG201 [RSD.Space Heat.Urban.LPG.NE01.Boiler]	82%	3.9	195
RHUNLSD201 [RSD.Space Heat.Urban.OIL.NE01.Boiler]	86%	4.4	220
RHUNLSD301 [RSD.Space Heat.Urban.OIL.NE01.Dual Boiler]	85%	4.4	258
RHUNPRO301 [RSD.Space Heat.Urban.LPG.NE01.Condensed Boiler]	93%	5.4	272

2) Insulation on existing/new dwellings

The performance of the dwellings can be improved by means of a better insulation. There are four main categories of insulation: wall insulation, roof insulation, floor insulation and glazing. Each category can be applied in different levels, for example, one can put 4, 8 or 12 cm of wall insulation. There is a distinction between improving existing buildings and applying insulation measures on new houses. It is assumed that shell improvements are additive.

The effect of insulation depends on the type of the dwelling (rural, urban or flat) and the age (the data allows a distinction between dwellings built before or after 1970). The latter is an important parameter because of the great difference in heat demand. Dwellings older than 1970, use a lot more energy because of their lack of insulation and have therefore a greater potential for insulation.

The important parameters to characterize the different insulation technologies are investment cost and the maximal feasible savings in Belgium per type of dwelling. Both these parameters are derived from the 'savings per measure per dwelling':

- The maximum saving potential is derived from the multiplication of 'savings per measure per dwelling' and the total number of dwellings on which the insulation measure can be applied. The applicability of a measure is based on statistics from (N.I.S., 2006).
- The investment cost per PJ (M€2000/PJ) is the total investment cost divided by 'the savings per measure per dwelling' (period of 50 years). The total investment cost summarizes the installation costs and the material costs of one category of insulation measures (Isover, 1999; Royal Federation of Societies of Architecture of Belgium, 1999) . Concerning glazing, one has to mention that these costs represent the additional costs compared to the installation of the normal level of glass insulation and not the total cost

The parameter 'savings per measure per dwelling' indicates the amount of saved heat demand per year per dwelling by means of an insulation measure. The computation of this parameter is derived from a model computing the heat demand of a dwelling based on the dwelling characteristics. The heat demand is calculated as follows:

Heat demand = conduction losses + ventilation losses – gains from sun + gains from others

where

- the conduction losses are dependent on several factors, namely:
  - U-values of the walls, roof, floor, glazing and doors. An U-value gives the energy losses in [W /m^2.K]. These values are coming from the literature.
  - Difference between the indoor (17.5°C) and outdoor temperature (9.3°C), corrected for different effects such as behavioural effects. This correction is explained underneath.
  - The surface of the different shells; the average heated surface is calculated based on (N.I.S., 2001). The compactness of the houses is derived from (WTCB et al., 1997).
- Ventilation losses are dependent on:
  - Protected loss volume;
  - Air exchange rate, which is dependent on the type and age of the dwelling;
  - Difference between indoor and outdoor temperature.
- The sun gains are also dependent on the dwelling type.

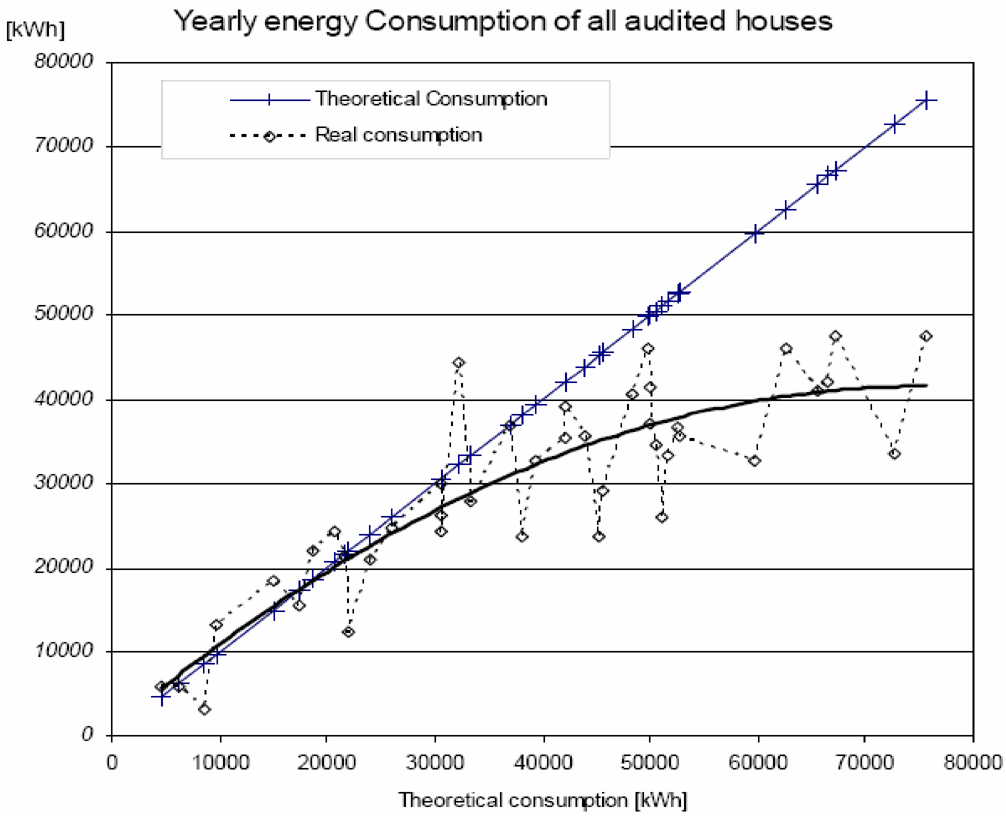
Given a value for these different parameters derived mainly from the literature and dependent on the type, the age of the dwelling and its insulation level, the heat demand per dwelling can be computed. Changing the insulation level will change the U values and therefore the heat demand.

The correction on the average difference between indoor and outdoor temperature allows taking into account different effects:

- A first effect is that the average temperature inside increases when changing the U values in different places in the house, purely caused by the insulation itself. On average, the temperature gradient increases when insulation measures are taken. In rooms where heating is requested most of the time (mostly where central heating is regulated), the temperature is requested and therefore there is no difference before or after insulation. This effect is however takes place in rooms where heating is not often requested. The effect can be compared with covering a cooking-pot: the pressure in the pot will increase the more the pot is covered. The example is only for comprehension and of course not explained by the same physical effect.
- A very important second effect is the impact of the behaviour of the inhabitants.

An audit realised in Flanders (Maes D. et al., 2006) shows the difference between the theoretical energy consumption and the measured energy consumption, as shown in Figure 3. The straight line represents the theoretical energy consumption. The smallest consumption corresponds to a small apartment, whereas the largest consumption – equivalent to 75.670 kWh per year – corresponds to a large poorly insulated house. The real consumption, however, does not follow the same line and attains only a maximum level around 41 000 kWh per year.

Figure 3: Comparison between the yearly theoretical and practical energy consumption



The difference between theory and practice can be explained by differences in behaviour: the inhabitants limit their energy consumption for different reasons when their house consumes much energy. Given such behaviour, the reduction potentials from insulation calculated from the theoretical model will be overestimated. Therefore, a correction was applied when computing the heat demand, for a good calibration in the baseyear as well as for calculating the difference before and after insulation. This behavioural effect is not the same as the price elasticity since the marginal technology does not change when a house is better insulated. The price elasticity for the heating demand is already taken into account in the same way as for the other demands.

For the construction of the TIMES database, the heat demand per dwelling was computed for

- the existing dwellings built before 1970
- the existing dwellings built after 1970
- the new dwellings built after 2000

based on the model described above and on assumptions for the insulation measures already implemented in the existing dwellings derived from (N.I.S., 2006). For new dwellings, the relative heat demand was compared to the average demand of the existing dwellings. This is done by comparing the calibrated data of 2000 with the calculated heat demand when new houses are better insulated and thus computed by the model. Standard new houses are assumed to be insulated as follows::

- 6 cm of floor insulation;
- 8 cm of roof insulation;
- double glazing;
- hollow wall insulation of 4 cm.

The comparison is given in Table 4.

Table 4: New versus existing dwellings heat demand and indicative energy level

	Rural	Urban	Flat
Heat demand new/ Heat demand existing	63 %	58 %	37 %
Indicative Energy-level (E-level) new houses	110	90	60

The insulation measures for existing dwellings are given in the tables below.

Table 5: Insulation measures for buildings build before 1970

-Process-	Potential in 2000	INV
	PJ	€/GJy (50 yrs)
RHMEINSG101 [RSD.Space Heat.Multi.INS.Ex01.Glass1]	5.5	179
RHMEINSR101 [RSD.Space Heat.Multi.INS.Ex01.Roof1]	4.4	43
RHMEINSW101 [RSD.Space Heat.Multi.INS.Ex01.Wall1]	4.7	90
RHREINSG101 [RSD.Space Heat.Rural.INS.Ex01.Glass1]	5.8	255
RHREINSR101 [RSD.Space Heat.Rural.INS.Ex01.Roof1]	13.4	61
RHREINSW101 [RSD.Space Heat.Rural.INS.Ex01.Wall1]	10.1	129
RHUEINSR101 [RSD.Space Heat.Urban.INS.Ex01.Roof1]	26.0	53
RHUEINSW101 [RSD.Space Heat.Urban.INS.Ex01.Wall1]	8.8	111

Table 6: Insulation measures for buildings build after 1970

-Process-	Potential in 2000	INV
	PJ	€/GJy (50 yrs)
RHMEINSG201 [RSD.Space Heat.Multi.INS.Ex01.Glass2]	1.1	332
RHMEINSR201 [RSD.Space Heat.Multi.INS.Ex01.Roof2]	0.4	174
RHMEINSW201 [RSD.Space Heat.Multi.INS.Ex01.Wall2]	0.4	428
RHREINSG201 [RSD.Space Heat.Rural.INS.Ex01.Glass2]	2.3	380
RHREINSR201 [RSD.Space Heat.Rural.INS.Ex01.Roof2]	2.1	199
RHREINSW201 [RSD.Space Heat.Rural.INS.Ex01.Wall2]	1.1	489
RHUEINSR201 [RSD.Space Heat.Urban.INS.Ex01.Roof2]	1.1	190
RHUEINSW201 [RSD.Space Heat.Urban.INS.Ex01.Wall2]	0.3	467

For the new dwellings, two improvements are considered: K55 and K40 houses. The insulation properties of these house types are:

- K55 houses:
    - 6 cm of floor insulation;
    - 16 cm of roof insulation;
    - double glazing;
    - wall insulation of 12 cm
- K40 houses:
    - 9 cm of floor insulation;
    - 23 cm of roof insulation;
    - double glazing filled with Argon;
    - wall insulation of 12 cm.

Table 7: Indicative energy level of new houses with extra insulation

Indicative energy level (E-level)	Rural	Urban	Flat
K55 houses	70	60	40
K40 houses	60	50	30

Table 8: Insulation measures for new buildings

-Process-	Potential in 2005	INV
	PJ	€/GJy (50 yrs)
RHRNINSK101 [RSD.Space Heat.Rural.INS.NEW.Construction.K55]	0.24	226
RHRNINSK201 [RSD.Space Heat.Rural.INS.NEW.Construction.K40]	0.37	244
RHUNINSK101 [RSD.Space Heat.Urban.INS.NEW.Construction.K55]	0.46	267
RHUNINSK201 [RSD.Space Heat.Urban.INS.NEW.Construction.K40]	0.80	262

B. Water heating

The water heating systems are the same for all dwelling types, existing or new. As they are the same, only the case of existing urban dwellings is given in Table 9.

Table 9: Water heating devices characteristics

Process	EFF	FIX	INV	LIFE
		€/kW	€/kW	y
RWUEELC101 [RSD.Water Heat.Urban.ELC.Ex01.NightWater heater.]	90%	0	459	20
RWUEELC201 [RSD.Water Heat.Urban.ELC.Ex01.Heatpump]	288%	19	1294	15
RWUEGAS101 [RSD.Water Heat.Urban.All.GAS.Ex01.Water heater.]	91%	0	34	15
RWUELPG101 [RSD.Water Heat.Urban.LPG.Ex01.Water heater.]	91%	0	34	15
RWUESOL101 [RSD.Water Heat.Urban.SOLGAS.Ex01.Water heater.]	110%	0	936	15
RWUESOL201 [RSD.Water Heat.Urban.SOLELC.Ex01.Water heater.]	120%	0	1984	15

C. Other

These technologies are related to 3 groups of end uses:

- Cooking
- Lighting
- Other electric appliances.

The investment cost (M€2000/th units) and relative efficiency are the most important parameters. The capacity for these technologies is expressed in thousand units. If the capacity is 1, this corresponds to the need for a standard quantity of light in 1000 dwellings. Table 10 summarises those parameters.

Table 10: Other appliances characteristics

Process	EFF	INV	LIFE
		M€/ th units	y
RLIGELC101 [RSD.Lighting.ELC.O1.Incandescent]	5%	0.02	1
RLIGELC201 [RSD.Lighting.ELC.O1.Fluorescent]	30%	0.15	6
	(relative)	(relative)	
ROELELC101 [RSD.Other.Electricity.ELC.O1.Appliances]	100%	80%	15
ROELELC201 [RSD.Other.Electricity.ELC.O1.Appliances imp]	110%	100%	15
RCOKELC101 [RSD.Cooking.ELC.O1]	100%	120%	15
RCOKGAS101 [RSD.Cooking.GAS.O1]	80%	110%	15
RCOKLPG101 [RSD.Cooking.LPG.O1]	80%	100%	15

4.2. The service sector

The technologies for the service sector are similar to those in the residential sector;

4.3. The agricultural sector

As the agriculture sector is modelled in a very generic way, the technologies are also generic. The possibility of cogeneration is explicitly considered (cf. section on cogeneration technologies).

4.4. The transport sector

The technologies in the database follow the subdivision in the transport sector. Each demand category can be served by a number of different technologies (e.g. the demand for car transport can be satisfied by gasoline fuelled cars, diesel fuelled cars, hydrogen fuelled cars, etc.). The technologies are characterised by the following parameters: investment cost, operating cost, fuel-type, efficiency, year of availability. Emission abatement technologies (e.g. catalysts) to comply with actual and future environmental regulations are included.

A. Transport by car

The 2000 "average" gasoline car is used as reference, considering an average yearly mobility demand of 22000 km for long distance and of 13800 km for short distance. The types of cars included are: gasoline car, diesel car and biodiesel car, LPG car, CNG car, hydrogen combustion car, hydrogen fuel cell car, electric city car, ethanol cars, inclusive the hybrid version for some types of cars.

Table 11, Table 12 and Table 13 shows the main parameters for each technology. The main sources for the data are (De Vlieger I. et al., 2005) and the hydrogen (Martens A. et al., 2006) SPSD II projects. The fixed yearly costs are assumed to be 0.7 k€ per vehicle for all vehicles, except for electric battery vehicles where the yearly fixed cost decline from 2.4 to 1.9 k€ in the period.

Table 11 : Efficiencies of car technologies (long distance, vkm/GJ)

Process	2005	2010	2020	2030	2040	2050
TCARBDL101 [Car.Biodiesel]	491	506	532	559	588	618
TCARDST101 [Car.DST.EURO4]	442	456	479	503	529	556
TCARDST201 [Car.DST.EURO4.parallelhybrid]	442	456	479	503	529	556
TCARELC101 [Car.Electric.Battery]	1296	1296	1296	1296	1296	1296
TCARETH101 [Car.Ethanol]	450	464	487	512	538	566
TCARGAS101 [Car.GAS.CNG]	450	461	485	510	536	563
TCARGAS201 [Car.GAS.CNG.parallelhybrid]	643	659	693	728	765	804
TCARGSL101 [Car.GSL.EURO4]	405	417	439	461	485	509
TCARGSL201 [Car.GSL.EURO4.parallelhybrid]	506	522	548	576	606	637
TCARHH2101 [Car.Hydrogen.Combustion]		460	460	460	460	460
TCARHH2201 [Car.Hydrogen.Hybrid.Combustion]		518	518	518	518	518
TCARHH2301 [Car.Hydrogen.FuelCell]		819	819	819	819	819
TCARHH2401 [Car.Hydrogen.Hybrid.FuelCell]		920	920	920	920	920
TCARLPG101 [Car.LPG.EURO3]	343	354	372	391	411	432

Table 12 : Efficiencies of car technologies (short distance, vkm/GJ)

Process	2005	2010	2020	2030	2040	2050
TCARBDL101 [Car.Biodiesel]	363	374	394	414	435	457
TCARDST101 [Car.DST.EURO4]	327	337	354	372	391	411
TCARDST201 [Car.DST.EURO4.parallelhybrid]	409	421	443	465	489	514
TCARELC101 [Car.Electric.Battery]	1296	1296	1296	1296	1296	1296
TCARETH101 [Car.Ethanol]	376	387	407	428	450	473
TCARGAS101 [Car.GAS.CNG]	376	385	405	426	447	470
TCARGAS201 [Car.GAS.CNG.parallelhybrid]	537	550	578	608	639	672
TCARGSL101 [Car.GSL.EURO4]	338	348	366	385	405	425
TCARGSL201 [Car.GSL.EURO4.parallelhybrid]	483	498	523	550	578	608
TCARHH2101 [Car.Hydrogen.Combustion]		384	384	384	384	384
TCARHH2201 [Car.Hydrogen.Hybrid.Combustion]		433	433	433	433	433
TCARHH2301 [Car.Hydrogen.FuelCell]		684	684	684	684	684
TCARHH2401 [Car.Hydrogen.Hybrid.FuelCell]		768	768	768	768	768
TCARLPG101 [Car.LPG.EURO3]	299	308	324	340	358	376

Table 13 : Investment cost of car technologies (k€ per vehicle)

Process	2005	2010	2020	2030	2040	2050
TCARBDL101 [Car.Biodiesel]	15.8	14.8	14.8	14.8	14.8	14.8
TCARDST101 [Car.DST.EURO4]	15.0	15.1	15.1	15.1	15.1	15.1
TCARDST201 [Car.DST.EURO4.parallelhybrid]	19.5	19.5	19.1	18.7	18.4	18.0
TCARELC101 [Car.Electric.Battery]	16.0	16.0	16.0	16.0	16.0	16.0
TCARETH101 [Car.Ethanol]	14.7	14.8	14.8	14.8	14.8	14.8
TCARGAS101 [Car.GAS.CNG]	17.6	17.6	17.6	17.6	17.6	17.6
TCARGAS201 [Car.GAS.CNG.parallelhybrid]	22.1	22.1	21.8	21.6	21.4	21.2
TCARGSL101 [Car.GSL.EURO4]	14.0	14.1	14.1	14.1	14.1	14.1
TCARGSL201 [Car.GSL.EURO4.parallelhybrid]	18.2	18.2	17.8	17.5	17.1	16.8
TCARHH2101 [Car.Hydrogen.Combustion]		18.8	18.8	16.4	16.4	15.3
TCARHH2201 [Car.Hydrogen.Hybrid.Combustion]		22.9	22.5	19.8	19.5	18.0
TCARHH2301 [Car.Hydrogen.FuelCell]		54.4	54.4	18.2	18.2	17.6
TCARHH2401 [Car.Hydrogen.Hybrid.FuelCell]		55.7	55.7	19.5	19.5	19.0
TCARLPG101 [Car.LPG.EURO3]	17.8	17.9	17.9	17.9	17.9	17.9

For well established technologies like the gasoline and the diesel cars, investment cost is projected to remain constant at its 2000 level. The same is true for cars running on new fuels, like ethanol and biodiesel, which do not require drastic changes to engine technology. Their investment cost are slightly higher than the traditional technologies because the corrosiveness of ethanol imposes the use of more costly materials for the fuel tank and fuel lines. Hydrogen combustion cars have still higher prices, because the fuel tanks have to be constructed from high cost composite materials to be able to withstand the high pressure (some 650 bar) under which the hydrogen is stored. For technologies requiring changes in the engine technology, the investment costs are expected to decrease with time. For electrically powered vehicles, with changeable battery or fixed battery, this would be mainly due to improvements in battery technology, both for the classic lead battery and for the new types of batteries ($ZnBr^-$ or NaS) which are undergoing further development and entering in the stage of mass production. The most substantial reductions in investment cost are expected in the fuel cell powered car. Fuel cell powered cars are a very novel technology and are expected to enter the market somewhere around 2005/2010, at relatively high prices. Learning effects in the production of fuel cells will reduce investment cost to a level more comparable with the other technologies towards the end of the forecasting horizon.

B. Transport by truck.

The reference technology for this category is the diesel truck. Alternative technologies are CNG-trucks, ethanol trucks.

Table 14: Characteristics of truck technologies

Process	EFF	FIX	INVCOST
	vkm/GJ	k€/veh	k€/veh
TFREBIO101 [Truck.Biodiesel]	203	1.54	47.3
TFREDST101 [Truck.DST.Euro4_5]	213	1.46	45.0
TFREETH101 [Truck.Ethanol]	203	1.54	47.3
TFREGAS101 [Truck.GAS.CNG]	178	1.59	48.9
TFREGSL101 [Truck.GSL.Euro4_5]	120	1.46	45.0

Since all the technologies considered in the truck transport category are based on a normal combustion engine, the investment costs are assumed to remain constant over the entire horizon.

C. Transport by bus

The reference technology for transport by bus is the traditional diesel bus. Alternative types considered are the diesel hybrid bus, the hydrogen fuel cell/battery bus, the LPG-bus, the electric battery bus and the electric trolley bus.

Table 15: Characteristics of bus technologies

Process	EFF	FIX	INVCOST
	vkm/GJ	k€/veh	k€/veh
TBISBIO101 [Bus.Intercity.Biodiesel]	64	5.19	221
TBISDST101 [Bus.Intercity.DST.EURO4_5]	67	5.19	210
TBISDST201 [Bus.Intercity.DST.ParallelHybrid]	79	5.19	241
TBISGAS101 [Bus.Intercity.GAS.CNG]	61	5.19	234
TBISHH2101 [Bus.Intercity.HH2.combustion]	48	5.19	1097
TBISHH2201 [Bus.Intercity.HH2.fuelcell]	192	5.19	2020
TBUSBIO101 [Bus.urban.Biodiesel]	73	5.19	221
TBUSDST101 [Bus.urban.DST.EURO4_5]	77	5.19	210
TBUSDST201 [Bus.urban.DST.parallelHybrid]	91	5.19	241
TBUSELC101 [Bus.urban.ELC.Trolley]	145	2.59	210
TBUSELC201 [Bus.urban.ELC.battery]	145	23.59	210
TBUSGAS101 [Bus.urban.GAS.CNG]	70	5.19	234
TBUSHH2101 [Bus.urban.HH2.combustion]	56	5.19	1097
TBUSHH2201 [Bus.urban.HH2.fuelcell]	220	5.19	2020

The diesel hybrid bus is subject to additional investment cost compared to the reference diesel bus for the storage system of the braking energy. The fuel cell bus is equipped with a battery for additional power during acceleration. The battery will be loaded using the braking energy. The investment cost of battery buses is modelled using the same assumptions as for the battery cars.

D. Transport by rail

Though the model distinguishes the passenger transport by rail from the freight transport by rail, the technologies are the same. Two types of trains are considered: diesel and electric train. A minimum share of diesel train is imposed because of its use is necessary to ensure this transport service.

Table 16: Characteristics of train technologies

Process	EFF	FIX	INVCOST
	vkm/GJ	k€/veh	k€/veh
TTFRDST101 [Train.Freight.diesel]	4.1	760	7600
TTFRELC101 [Train.Freight.electric]	14.9	760	7600
TTLLELC101 [Train.Passenger.light.electric]	14.9	760	7600
TTPHDST101 [Train.Passenger.diesel]	4.1	760	7600
TTPHELC101 [Train.Passenger.electric]	14.9	760	7600

E. Navigation and Aviation

These two sectors are treated in a very generic way, with one technology for satisfying the demand

4.5. The industrial sector

A. The process modelled industrial sectors

1) The steel industry

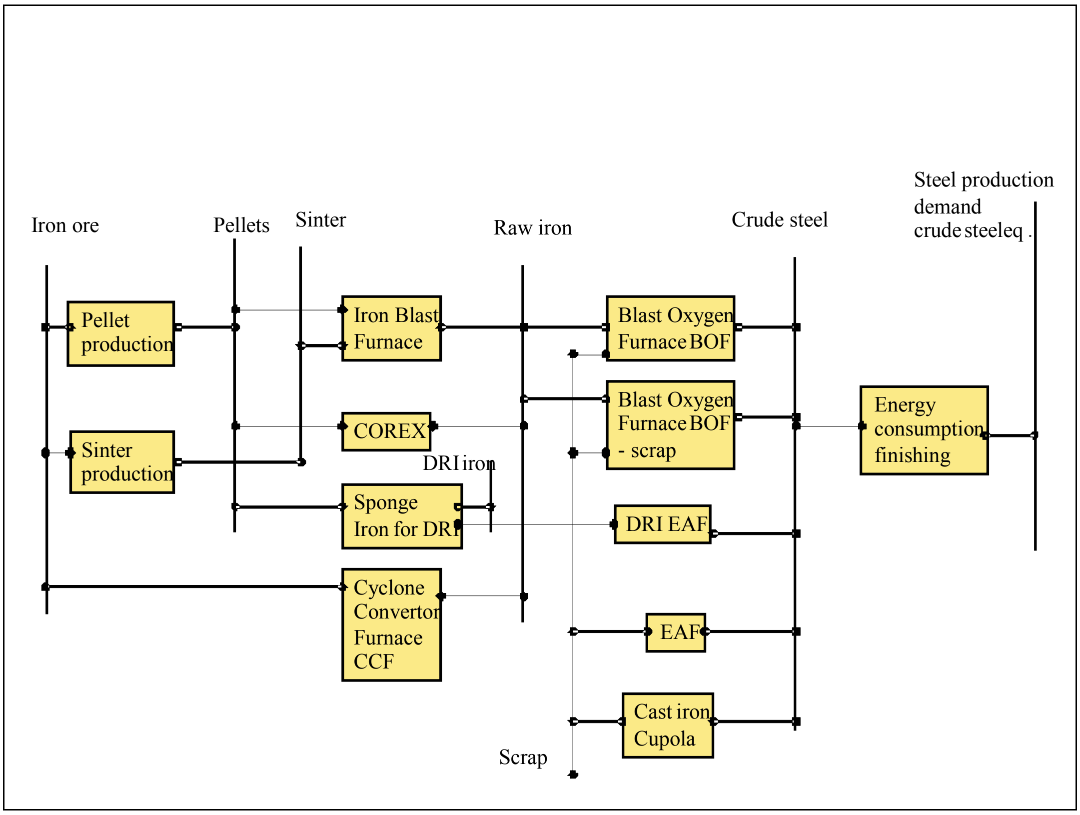
The steel industry is modelled in four steps:

- Transformation of the primary inputs
- Production of raw iron
- Production of crude steel
- Finishing process

Iron ore and scrap are considered to be primary supplies, i.e. they come with a supply curve. There is no recycling of steel scrap in the system because there is a time delay between steel going to the market and scrap returning. The demand for steel as modelled is expressed as production demand in the country and does not coincide with steel consumption and the related scrap generation.

Although steel making process consumes other materials than shown, they will not be taken up explicitly but are implicitly included in the variable cost of the process step where they are consumed.

Figure 4: Steel industry production diagram



.Table 17: Steel industry processes

	Commodity	IN	OUT	INV	FIX	VAR	LIFE	START
				€/ton	€/ton	€/ton	yrs	yr
IISAODFUR01	-			476	50	5	30	2001
[IIS.Argon Oxygen	INDBFG	1.74 PJ						
Furnace AOD Regular]	INDCOK	0.21 PJ						
	INDELC	2.30 PJ						
	INDLPG	0.50 PJ						
	MISCST		1 Mt					
	MISOXY	0.50 Mt						
	MISQLI	0.09 Mt						
	MISRFC	0.22 Mt						
	MISSCR	0.89 Mt						
IISBLAFUR01	-			150	10	2	30	2001
[IIS.Iron Blast Furnace]	INDBFG		3.25 PJ					
	INDCO2P		0.077 Mt					
	INDCOA	5.50 PJ						
	INDCOK	8.75 PJ						
	INDELC	0.17 PJ						

	MISBFS		0.25 PJ					
	MISOXY	0.05 Mt						
	MISPLT	0.04 Mt						
	MISRIR		1 Mt					
	MISSNT	1.54 Mt						
IISBLAFUR05	-			190	10	2	30	2005
[IIS.Iron Blast Furnace	INDBFG		3.25 PJ					
direct coal injection.05.]	INDCO2P		0.077 Mt					
	INDCOA	10.80 PJ						
	INDCOK	4.78 PJ						
	INDELC	0.17 PJ						
	MISBFS		0.25 PJ					
	MISOXY	0.05 Mt						
	MISPLT	0.04 Mt						
	MISRIR		1 Mt					
	MISSNT	1.54 Mt						
IISBLAFUR11	-			300	15	5	30	2010
[IIS.Iron Blast Furnace	INDBFG		3.25 PJ					
with CCS.10.]	INDCO2P		0.077 Mt					
	INDCOA	10.80 PJ						
	INDCOK	4.78 PJ						
	INDELC	0.20 PJ						
	MISBFS		0.25 PJ					
	MISOXY	0.05 Mt						
	MISPLT	0.04 Mt						
	MISRIR		1 Mt					
	MISSNT	1.54 Mt						
	SNKINDCO2		0.077 Mt					
IISBOXFUR01	-			100	4	50	30	2001
[IIS.Blast Oxygen Furnace	INDGAS	0.20 PJ						
BOF.Regular]	MISCST		1 Mt					
	MISOXY	0.15 Mt						
	MISQLI	0.05 Mt						
	MISRIR	1.75 Mt						
	MISSCR	0.43 Mt						
IISBOXSCR01	-			120	4	50	30	2001
[IIS.Blast Oxygen Furnace	MISCST		1 Mt					
BOF.Scrap]	MISOXY	0.10 Mt						
	MISQLI	0.05 Mt						
	MISRIR	0.50 Mt						
	MISSCR	0.60 Mt						
IISCOREXP01	-			200	10	2	25	2001
[IIS.COREX]	IISHTH		6.4 PJ					
	INDBFG		10.9 PJ					
	INDCO2P		0.150 Mt					
	INDCOA	29.00 PJ						
	INDELC	0.55 PJ						
	MISBFS		0.3 PJ					
	MISOXY	1.00 Mt						
	MISPLT	1.50 Mt						
	MISRIR		1 Mt					
IISCUPOLA01	-			1000	100	200	30	2001
[IIS.Cast Iron Cupola]	INDELC	4.60 PJ						
	INDGAS	11.40 PJ						

	MISCST		1 Mt					
	MISSCR	1.30 Mt						
IISCYCFUR01	-			200	10	5	25	2001
[IIS.Cyclone Convertor	IISHTH		4.3 PJ					
Furnace CCF]	INDBFG		2 PJ					
	INDCOA	12.00 PJ						
	INDELC	1.30 PJ						
	MISBFS		0.27 PJ					
	MISOXY	0.73 Mt						
	MISRIR		1 Mt					
	MISSNT	1.50 Mt						
IISDRIEAF01	-			100	4	25	20	2001
[IIS.Electric Arc Furnace	INDELC	2.25 PJ						
with DRI]	INDGAS	3.00 PJ						
	MISCST		1 Mt					
	MISDIR	1.05 Mt						
	MISOXY	0.50 Mt						
	MISSCR	0.03 Mt						
IISDRISPN01	-			100	2	1.2	30	2001
[IIS.Sponge Iron for DRI]	INDCO2P		0.077 Mt					
	INDELC	0.70 PJ						
	INDGAS	11.00 PJ						
	MISDIR		1 Mt					
	MISPLT	1.50 Mt						
IISDRISPN10	-			115	2	2	30	2010
[IIS.Iron Sponge Iron for	INDCO2P		0.077 Mt					
DRI with CCS.10.]	INDELC	0.75 PJ						
	INDGAS	11.20 PJ						
	MISDIR		1					
	MISPLT	1.50 Mt						
	SNKINDCO2		0.427					
IISELAFUR01	-			150	12	19	25	2001
[IIS.Electric Arc Furnace]	INDELC	2.00 PJ						
	INDGAS	0.50 PJ						
	MISCST		1 Mt					
	MISOXY	0.05 Mt						
	MISSCR	1.50 Mt						
IISFECRFR01 [IIS.Ferro	-			682	125	72	30	2001
Chrome Smelting Furnace]	IISHTH	0.90 PJ						
	INDBFG		7.5 PJ					
	INDCOK	15.40 PJ						
	INDELC	11.30 PJ						
	INDHFO	0.80 PJ						
	MISBFS		1.2 PJ					
	MISORE	2.30 Mt						
	MISRFC		1 Mt					
IISFINPRO01	-			200	50	10	30	2001
[IIS.Finishing	IIS		1 Mt					
Processes.new]	IISHTH	0.06 PJ						
	INDELC	1.40 PJ						
	INDGAS	2.50 PJ						
	INDHFO	0.50 PJ						
	MISCST	1.00 Mt						
IISPELLET01	-			55	3	4.3	25	2001

[IIS.Pellet Production]	INDCOK	1.01 PJ						
	INDELC	1.14 PJ						
	MISORE	1.00 Mt						
	MISPLT		1 Mt					
IISSINTER01	-			50	2.5	5.5	25	2001
[IIS.Sinter Production.01]	INDCOG	0.85 PJ						
	INDCOK	1.16 PJ						
	INDELC	0.10 PJ						
	MISORE	1.00 Mt						
	MISSNT		1 Mt					

2) The non ferro sector

Because there is no copper refinery, neither aluminium production in Belgium, the sector is modelled by enduses.

3) The chemical sector

Within the chemical sector, ammonia and chlorine are modelled by process whereas the rest of the chemical sector is modelled by end-use.

The ammonia in the model can be produced with three main processes: a standard production process and two advanced processes, one without and one with capturing the carbon dioxide.

Figure 5: RES diagram of Ammonia production

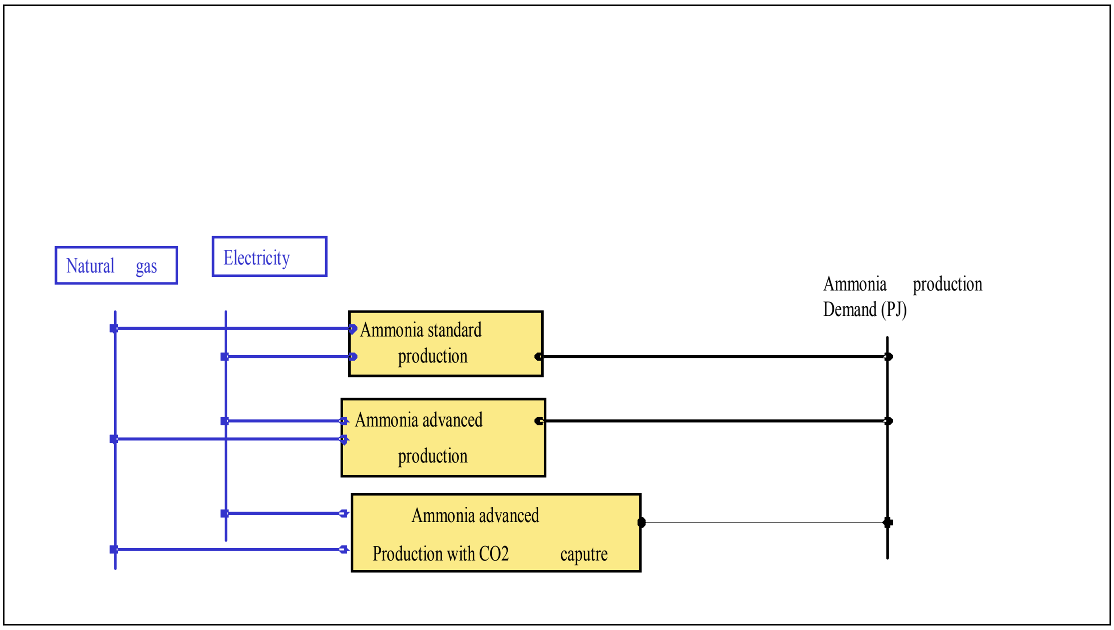


Table 18: Ammonia production processes

Process	Commodity	IN	OUT	INV	FIX	VAR	LIFE	START
		PJ	Mt	€/ton	€/ton	€/ton	yrs	yr
IAMSTDPRO01	-			275	8.2	1.2	25	2001
[IAM.Standard Production.]	IAM		1					
	INDELC	5.1						
	INDGAS	26.6						
IAMADVPRO01	-			264	8.5	1.2	25	2010
[IAM.Advanced Production.]	IAM		1					
	INDELC	7.3						
	INDGAS	23.7						
IAMADVCAP01	-			330	8.5	1.2	25	2010
[IAM.Advanced	IAM		1					
Production.CO2 Capture]	INDELC	8.0						
	INDGAS	23.7						
	SNKINDCO2		0.840					

The chlorine is modelled in a comparable way as ammonia. The production process data can be found in Table 19.

Figure 6: RES diagram of Chlorine production

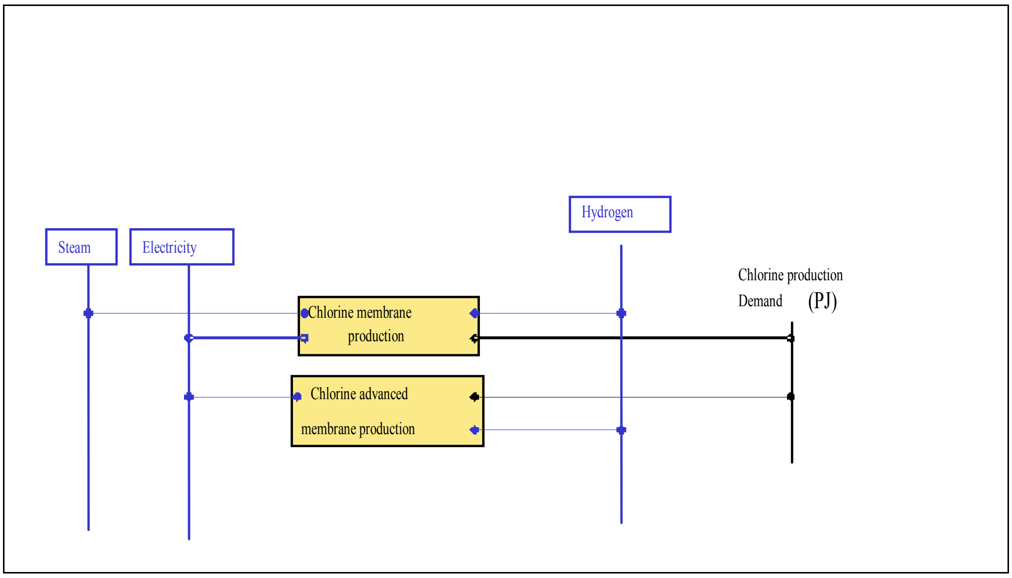


Table 19: Chlorine production processes.

Process	Commodity	IN	OUT	INV	FIX	VAR	LIFE
		PJ	Mt	€/ton	€/ton	€/ton	yrs
ICLSTDPRO01	-			750	86	90	30
[ICL.Standard Production]	ICL		1				
	INDELC	12.8					
	INDHH2		0.0034				
ICLADVPRO01	-			1100	86	90	30
[ICL.Advanced	ICL		1				
Membrane Production]	INDELC	7.5					
	INDHH2		0.0034				
ICLADVPRO05	-			1313	86	90	30
[ICL.Advanced	ICL		1.0				
Membrane Production	INDELC	6.8					
Improv.05.]	INDHH2		0.0034				

4) Pulp and paper industry

In Table 20 the different processes for producing paper and pulp are given. The steps distinguish between the pulp production and the paper production.

Figure 7: RES diagram of Pulp and Paper

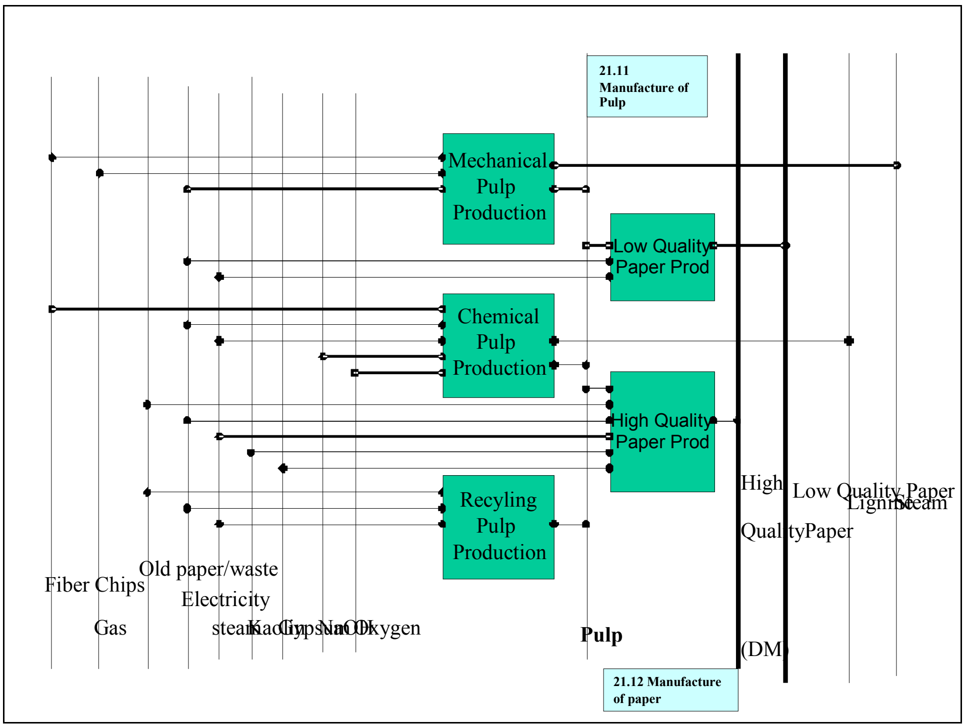


Table 20: Paper and pulp production processes

	Commodity	IN	OUT	INV	FIX	VAR	LIFE
				€/ton	€/ton	€/ton	yrs
IPPHIGQUA01	-			2500	125		25
[IPP.High Quality Paper Production]	INDBIO	2.00 PJ					
	INDELC	4.00 PJ					
	IPH		1 Mt				
	IPPHTH	5.00 PJ					
	MPPGYP	0.15 Mt					
	MPPKAO	0.07 Mt					
	MPPPUP	0.43 Mt					
	MPPRYC	0.35 Mt					
IPPHIGQUA05	-			2665	125		25
[IPP.High Quality Paper Production	INDELC	3.60 PJ					
Adv Drives.05.]	INDGAS	0.29 PJ					
	IPH		1 Mt				
	IPPHTH	5.00 PJ					
	MPPGYP	0.15 Mt					
	MPPKAO	0.07 Mt					
	MPPPUP	0.43 Mt					
	MPPRYC	0.35 Mt					
IPPLOWQUA01	-			1100	53		25
[IPP.Low Quality Paper Production]	INDELC	2.00 PJ					
	IPL		1 Mt				
	IPPHTH	8.00 PJ					
	MPPPUP	1.02 Mt					
IPPLOWQUA05	-			1210	53		25
[IPP.Low Quality Paper Production	INDELC	1.80 PJ					
Adv Drives.05.]	IPL		1 Mt				
	IPPHTH	8.00 PJ					
	MPPPUP	1.02 Mt					
IPPPUPCHE01	-			1355	40	28	25
[IPP.Chemical Pulp Production]	INDBIO		4.7 PJ				
	INDBLQ		20 PJ				
	INDELC	2.30 PJ					
	IPPHTH	4.00 PJ					
	IPPPRC	1.81 PJ					
	MPPNOH	0.04 Mt					
	MPPOXY	0.02 Mt					
	MPPPUP		1 Mt				
	MPPWOO	2.30 Mt					
IPPPUPMEC01	-			300	15		25
[IPP.Mechanical Pulp Production]	INDBIO		2.1 PJ				
	INDELC	3.00 PJ					
	IPPHTH	8.27 PJ					
	MPPPUP		1 Mt				
	MPPWOO	1.10 PJ					
IPPPUPMEC11	-			550	40		25
[IPP.Mechanical Pulp Production	INDBIO		2.1 PJ				
Airless drying.11]	INDELC	7.28 PJ					
	INDGAS	7.56 PJ					
	IPPHTH		1.8 PJ				
	MPPPUP		1 Mt				
	MPPWOO	1.10 Mt					
IPPPUPRYC01	-			642	30		25
[IPP.Recycling Pulp Production]	INDELC	1.70 PJ					
	IPPHTH	1.00 PJ					
	MPPPUP		1 Mt				
	MPPRYC	1.15 Mt					

5) Cement industry

Demand is expressed in 1000 tons of cement.

Figure 8: RES diagram of Cement Industry.

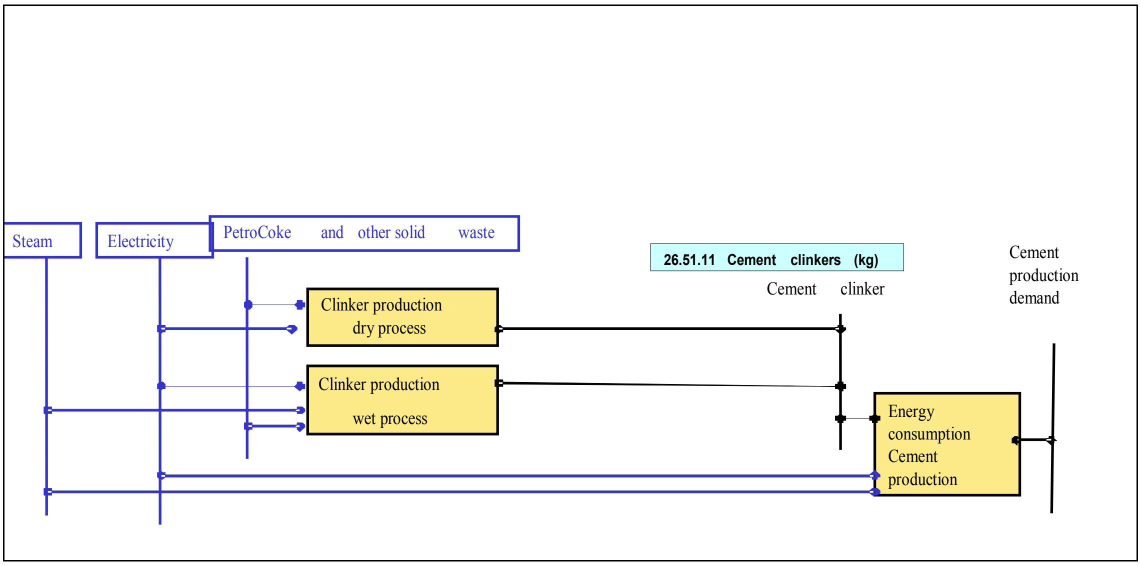


Table 21: Cement production processes

Process	Commodity	IN	OUT	INV	FIX	VAR	LIFE	START
		PJ	Mt	€/ton	€/ton	€/ton	yrs	yr
ICMDRYPRD01 [ICM.Dry Process	-			125	5	5	30	2001
Production.new]	ICMPRC	3.29						
	INDCO2P		0.510					
	INDELC	0.21						
	MCMCLK		1					
ICMDRYPRD11 [ICM.Dry Process	-			145	45	5	30	2010
Production with CO2 capture.10.]	ICMPRC	3.29						
	INDCO2P		0.510					
	INDELC	0.21						
	MCMCLK		1					
	SNKINDCO2		0.790					
ICMWETPRD01 [ICM.Wet Process	-			125	5	5	30	2001
Production.new]	ICMPRC	5.64						
	INDCO2P		0.510					
	INDELC	0.36						
	MCMCLK		1					
ICMFINPRO01 [ICM.Finishing	-			10	3	3	25	2001
Processes.new]	ICM		1					
	INDELC	0.29						
	MCMCLK	0.70						
	MISBFS	0.24						
ICMFINPRO05 [ICM.Finishing	-			17	3	3	25	2001
Processes Efficient Milling.05]	ICM		1					
	INDELC	0.20						
	MCMCLK	0.70						
	MISBFS	0.24						

6) Glass production

Two categories of glasses are distinguished: hollow glass (bottles, …) and flat glass (windows, …). Heat recovery and improved burners give the new processes a better energy efficiency as can be seen in Table 22.

Figure 9 RES diagram of Glass industry.

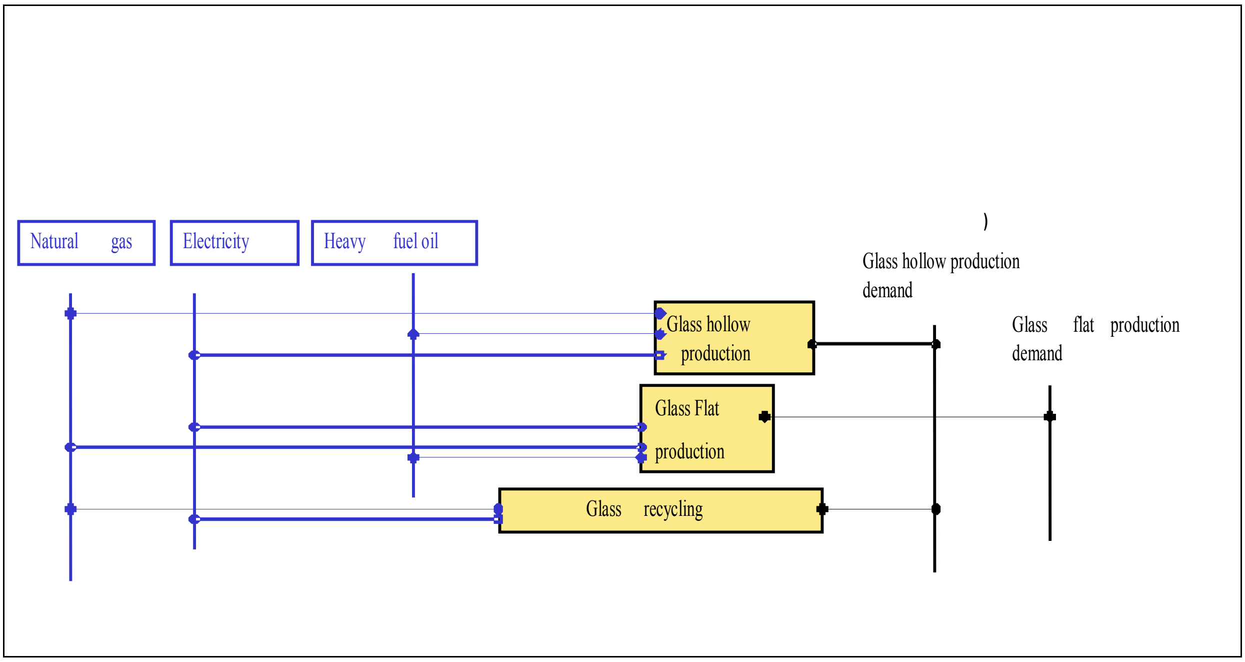


Table 22: Glass production processes

Process	Commodity	IN	OUT	INV	FIX	VAR	LIFE	START
		PJ	Mt	€/ton	€/ton	€/ton	yrs	yr
IGFFLATGL01 [IGF.Glass Flat.new]	-			150	10	50	30	2001
	IGF		1					
	INDELC	0.85						
	INDGAS	1.59						
	INDHFO	2.61						
IGFLATGL11 [IGF.Glass Flat heat	-			190	12	50	30	2010
recoveryimprov burners.10]	IGF		1					
	INDELC	0.64						
	INDGAS	1.19						
	INDHFO	1.95						
IGHHOLLOW01 [IGH.Glass	-			250	20	50	30	2001
Hollow.new]	IGH		1					
	INDELC	1.35						
	INDGAS	5.07						
IGHHOLLOW11 [IGH.Glass Hollow	-			290	22	50	30	2010
heat recoveryimprov burners.11]	IGH		1					
	INDELC	1.01						
	INDGAS	2.85						

7) Lime production

Quick lime production is modelled in one step, from limestone to lime. Demand is expressed in Mt of lime. The characteristics of the new process are given below.

Figure 10 RES diagram of Lime industry.

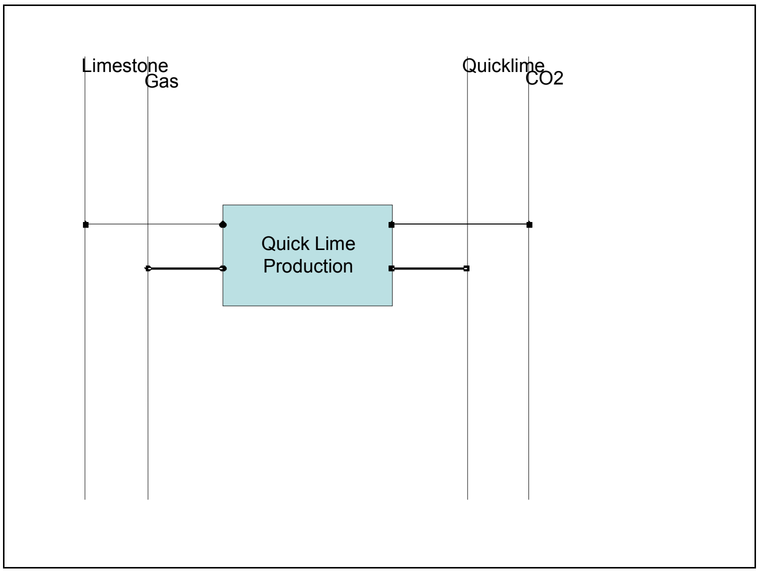


Table 23: Lime production process

	Commodity	IN	OUT	INV	FIX	VAR	LIFE	START
		PJ	Mt	€/ton	€/ton	€/ton	yrs	yr
ILMQLMPRO01	-			300	10	5	25	2001
[ILM.Quick Lime	ILM		1					
Production.new]	ILMPRC	5.23						
	INDCO2P		0.786					
	INDELC	0.40						
		Mt						
	MLMSTN	1.71						

B. The other industries

The demand is disaggregated into five components (end uses) with fix shares (a rigid process):

- Steam (boilers),
- Process heat,
- Machine drive,
- Electrochemical,
- Others

The different technologies for each enduse are given in Table 24. The technical life is always assumed to be 30 years. The energy inputs are always relative to the energy outputs, i.e. PJ input/ PJ steam.

Figure 11: RES diagram of Other Industries

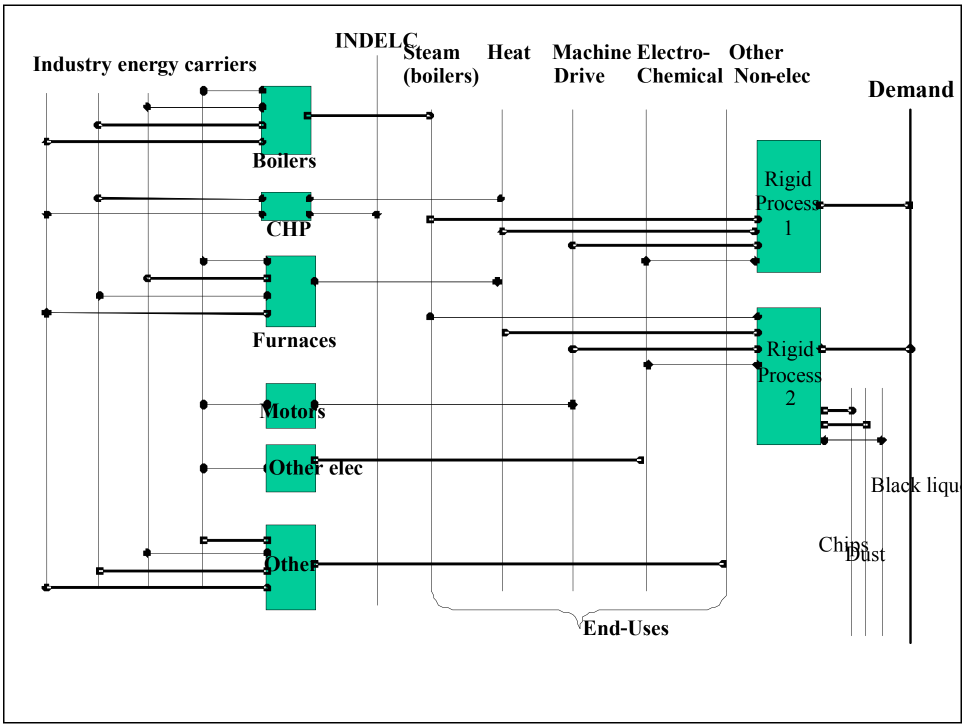


Table 24: Characteristics of endues technologies

	Commodity	IN	INV	FIX
		PJ/PJ	€/Gjy	€/Gjy
IOIELEELC01 [IOI. Other Industries.Electro-Chemical Processes.ELC.01]	INDELC	1.02	0.018	0.001
IOIMCHELC01 [IOI. Other Industries.Machine Drive.ELC.01]	INDELC	1.06	0.7	0.001
		PJ/PJ	€/kW	€/kW
IOIMCHGAS01 [IOI. Other Industries.Machine Drive.GAS.01]	INDGAS	2.86	1.78	0.2
IOIMCHLFO01 [IOI. Other Industries.Machine Drive.LFO.01]	INDLFO	2.86	2.22	0.5
IOIPRCBIO01 [IOI. Other Industries.Process heat.BIO.01]	INDBIO	1.33	728	54
IOIPRCCOA01 [IOI. Other Industries.Process heat.COA.01]	INDCOA	1.25	517	19
IOIPRCCOK01 [IOI. Other Industries.Process heat.COK.01]	INDCOK	1.30	517	19
IOIPRCELC01 [IOI. Other Industries.Process heat.ELC.01]	INDELC	1.14	473	16
IOIPRCGAS01 [IOI. Other Industries.Process heat.GAS.01]	INDGAS	1.15	208	12
IOIPRCHFO01 [IOI. Other Industries.Process heat.HFO.01]	INDHFO	1.18	378	32
IOIPRCLFO01 [IOI. Other Industries.Process heat.LFO.01]	INDLFO	1.22	315	16
IOIPRCLPG01 [IOI. Other Industries.Process heat.LPG.01]	INDLPG	1.22	315	16
IOISTMBIO01 [IOI. Other Industries.Steam.BIO.01]	INDBIO	1.25	527	54
IOISTMCOA01 [IOI. Other Industries.Steam.COA.01]	INDCOA	1.24	240	13
IOISTMCOK01 [IOI. Other Industries.Steam.COK.01]	INDCOK	1.24	240	13
IOISTMELC01 [IOI. Other Industries.Steam.ELC.01]	INDELC	1.18	826	35
IOISTMGAS01 [IOI. Other Industries.Steam.GAS.01]	INDGAS	1.09	134	13
IOISTMHFO01 [IOI. Other Industries.Steam.HFO.01]	INDHFO	1.14	197	13
IOISTMLFO01 [IOI. Other Industries.Steam.LFO.01]	INDLFO	1.11	197	13
IOISTMLPG01 [IOI. Other Industries.Steam.LPG.01]	INDLPG	1.11	197	13

4.6. The electricity sector

A. Technologies producing only electricity

The characteristics of the technologies are given in following order:

1) Nuclear power generation (1 and 2)

2) Classic central power generation

Using coal

- Conventional (3)
- Ultra Super Critical coal power plants (4 and 5)
- Fluidised bed combustion plants (6 and 7)
- Integrated Gasification Combined Cycle plants (8 and 9)

Using natural gas or kerosene

- Gas turbine (10)
- STAG (STeam And Gas) power plants (11 and 12)
- Fuel cell on gas (13)
- Supercritical on heavy fuel oil (14 and 15)

3) Renewables

- Power plants on biomass (municipal waste in the same category) (16 – 22)
- Hydro power plants (21)
- Fuel cell on hydrogen (22)
- Photovoltaic (23 and 24)
- Wind turbines (25 – 30)
  - o The offshore wind turbines differ in their distance to the coast and thus also in their investment and variable costs.
  - o The onshore wind turbines are all assumed to be the same technologies and thus the costs are equal. They differ because the different locations have different wind speeds and thus different (time sliced) availabilities.

When carbon is captured on power plants, the technologies are denoted as "CO2seq".

Table 25: Efficiency of electricity technologies

	Process	2010	2020	2050
1	EUSTNUC301 [EPLT: EPR.NUC.3th.New]	35%	35%	36%
2	EUSTNUC401 [EPLT: EPR.NUC.4th.New]	38%	38%	39%
3	EUSTCOH01 [EPLT: Steam.Turb.COH.New]	34%	35%	35%
4	EUSTCOHSC01 [EPLT: SC.Steam.Turb.COH.New]	39%	43%	44%
5	EUSTCOHSCS01 [EPLT: SC.Steam.Turb.CO2seq.COH.New]	32%	36%	38%
6	EUSTCOHFB01 [EPLT: FB.Steam.Turb.COH.New]	40%	43%	45%
7	EUSTCOHFBS01 [EPLT: FB.Steam.Turb.CO2seq.COH.New]	32%	36%	38%
8	EUIGCOH01 [EPLT: IGCC.COH.New]	40%	45%	47%
9	EUIGCOHS01 [EPLT: IGCC.CO2Seq.COH.New]	32%	37%	40%
10	EUPDGAS01 [EPLT: Turb Peak.GAS.New]	37%	41%	43%
11	EUCCGAS01 [EPLT: Comb Cyc.GAS.New]	58%	63%	66%
12	EUCCGASS01 [EPLT: Comb Cyc CO2Seq.GAS.New]	50%	58%	61%
13	EUFCGAS01 [EPLT: Fuel Cell.GAS.New]	68%	68%	69%
14	EUSCHFO01 [EPLT: SC.Steam.Turb.HFO.New]	45%	46%	46%
15	EUSCHFOS01 [EPLT: SC.Steam.Turb.CO2seq.HFO.New]	36%	41%	43%
16	EUSTWOO01 [EPLT: Steam.Turb.WOO.New]	35%	35%	36%
17	EUSTWOOHT01 [EPLT: Steam.Turb.WOO.HT.New]	38%	39%	39%
18	EUIGWOO01 [EPLT: IGCC.WOO.New]	36%	52%	57%

19	EUIGWOOS01 [EPLT: IGCC CO2Seq.WOO.New]	29%	34%	36%
20	EUSTMUN01 [EPLT: Steam.MunicipalWaste.New]	25%	25%	25%
21	EUHYDRUN01 [EPLT: Hydro.Run of River.New.]	100%	100%	100%
22	EUFCHH201 [EPLT: Fuel Cell.HH2.New]	78%	79%	80%
23	EUPVSOLP201 [EPLT: PV Plant Size.SOL.New]	100%	100%	100%
24	EUPVSOLR101 [EPLT: PV Roof panel.SOL.New]	100%	100%	100%
25	EUWINOF101 [EPLT: Wind Offshore 1.Close]	100%	100%	100%
26	EUWINOF201 [EPLT: Wind Offshore 2.Medium]	100%	100%	100%
27	EUWINOF301 [EPLT: Wind Offshore 3.Far]	100%	100%	100%
28	EUWINON101 [EPLT: Wind Onshore 1.High]	100%	100%	100%
29	EUWINON201 [EPLT: Wind Onshore 2.Medium]	100%	100%	100%
30	EUWINON301 [EPLT: Wind Onshore 3.Low]	100%	100%	100%

Table 26: Investment costs of electricity technologies (€/kW)

	Process	2005	2010	2020	2030	2050
1	EUSTNUC301 [EPLT: EPR.NUC.3th.New]	2212	2127	2019	1961	1914
2	EUSTNUC401 [EPLT: EPR.NUC.4th.New]			1734	1685	1644
3	EUSTCOH01 [EPLT: Steam.Turb.COH.New]	1262	1229	1186	1161	1138
4	EUSTCOHSC01 [EPLT: SC.Steam.Turb.COH.New]		1244	1155	1111	1078
5	EUSTCOHSCS01 [EPLT: SC.Steam.Turb.CO2seq.COH.New]		2142	1893	1783	1713
6	EUSTCOHFB01 [EPLT: FB.Steam.Turb.COH.New]		1258	1152	1101	1065
7	EUSTCOHFBS01 [EPLT: FB.Steam.Turb.CO2seq.COH.New]		2227	1968	1854	1781
8	EUIGCOH01 [EPLT: IGCC.COH.New]		1286	1168	1113	1075
9	EUIGCOHS01 [EPLT: IGCC.CO2Seq.COH.New]		2250	1960	1836	1759
10	EUPDGAS01 [EPLT: Turb Peak.GAS.New]	359	349	336	328	322
11	EUCCGAS01 [EPLT: Comb Cyc.GAS.New]	486	477	466	458	451
12	EUCCGASS01 [EPLT: Comb Cyc CO2Seq.GAS.New]		822	762	732	710
13	EUFCGAS01 [EPLT: Fuel Cell.GAS.New]		3490	1249	763	635
14	EUSCHFO01 [EPLT: SC.Steam.Turb.HFO.New]		951	917	898	881
15	EUSCHFOS01 [EPLT: SC.Steam.Turb.CO2seq.HFO.New]		1519	1342	1264	1215
16	EUSTWOO01 [EPLT: Steam.Turb.WOO.New]	1775	1590	1388	1301	1247
17	EUSTWOOHT01 [EPLT: Steam.Turb.WOO.HT.New]		1433	1194	1098	1044
18	EUIGWOO01 [EPLT: IGCC.WOO.New]		1515	1313	1227	1174
19	EUIGWOOS01 [EPLT: IGCC CO2Seq.WOO.New]		2909	2535	2374	2275
20	EUSTMUN01 [EPLT: Steam.MunicipalWaste.New]	1262	1229	1186	1161	1138
21	EUHYDRUN01 [EPLT: Hydro.Run of River.New.]	1350	1234	1103	1044	1005
22	EUFCHH201 [EPLT: Fuel Cell.HH2.New]		2685	960	587	489
23	EUPVSOLP201 [EPLT: PV Plant Size.SOL.New]	2455	1782	1187	997	917
24	EUPVSOLR101 [EPLT: PV Roof panel.SOL.New]	3148	2285	1521	1278	1175
25	EUWINOF101 [EPLT: Wind Offshore 1.Close]	1733	1682	1616	1578	1545
26	EUWINOF201 [EPLT: Wind Offshore 2.Medium]	1955	1904	1838	1800	1768
27	EUWINOF301 [EPLT: Wind Offshore 3.Far]	2844	2793	2727	2689	2656
28	EUWINON101 [EPLT: Wind Onshore 1.High]	963	934	898	877	859
29	EUWINON201 [EPLT: Wind Onshore 2.Medium]	963	934	898	877	859
30	EUWINON301 [EPLT: Wind Onshore 3.Low]	963	934	898	877	859

Table 27: Variable and fixed costs of electricity technologies

	Process	VAR	Fixed costs		
			2010	2030	2050
		€/GJ_{el}	€/kW	€/kW	€/kW
1	EUSTNUC301 [EPLT: EPR.NUC.3th.New]	0.124	53	53	53
2	EUSTNUC401 [EPLT: EPR.NUC.4th.New]	0.107	46	46	46
3	EUSTCOH01 [EPLT: Steam.Turb.COH.New]	1.150	33	33	33
4	EUSTCOHSC01 [EPLT: SC.Steam.Turb.COH.New]	2.277	27	27	27
5	EUSTCOHSCS01 [EPLT: SC.Steam.Turb.CO2seq.COH.New]	2.505	31	31	31
6	EUSTCOHFB01 [EPLT: FB.Steam.Turb.COH.New]	1.708	30	30	30
7	EUSTCOHFBS01 [EPLT: FB.Steam.Turb.CO2seq.COH.New]	1.879	35	35	35
8	EUIGCOH01 [EPLT: IGCC.COH.New]	1.139	33	33	33
9	EUIGCOHS01 [EPLT: IGCC.CO2Seq.COH.New]	1.253	39	39	39
10	EUPDGAS01 [EPLT: Turb Peak.GAS.New]	0.666	10	10	10
11	EUCCGAS01 [EPLT: Comb Cyc.GAS.New]	0.526	10	10	10
12	EUCCGASS01 [EPLT: Comb Cyc CO2Seq.GAS.New]	0.647	13	13	13
13	EUFCGAS01 [EPLT: Fuel Cell.GAS.New]	0.252	178	39	39
14	EUSCHFO01 [EPLT: SC.Steam.Turb.HFO.New]	2.192	21	21	21
15	EUSCHFOS01 [EPLT: SC.Steam.Turb.CO2seq.HFO.New]	2.411	24	24	24
16	EUSTWOO01 [EPLT: Steam.Turb.WOO.New]	0.811	64	64	64
17	EUSTWOOHT01 [EPLT: Steam.Turb.WOO.HT.New]	0.792	45	45	45
18	EUIGWOO01 [EPLT: IGCC.WOO.New]	0.755	54	54	54
19	EUIGWOOS01 [EPLT: IGCC CO2Seq.WOO.New]	1.253	63	63	63
20	EUSTMUN01 [EPLT: Steam.MunicipalWaste.New]	1.150	33	33	33
21	EUHYDRUN01 [EPLT: Hydro.Run of River.New.]	0.000	20	20	20
22	EUFCHH201 [EPLT: Fuel Cell.HH2.New]	1.258	137	30	30
23	EUPVSOLP201 [EPLT: PV Plant Size.SOL.New]	0.000	55	55	55
24	EUPVSOLR101 [EPLT: PV Roof panel.SOL.New]	0.000	48	48	48
25	EUWINOF101 [EPLT: Wind Offshore 1.Close]	0.903	80	80	80
26	EUWINOF201 [EPLT: Wind Offshore 2.Medium]	1.250	80	80	80
27	EUWINOF301 [EPLT: Wind Offshore 3.Far]	1.528	80	80	80
28	EUWINON101 [EPLT: Wind Onshore 1.High]	0.278	15	15	15
29	EUWINON201 [EPLT: Wind Onshore 2.Medium]	0.278	18	18	18
30	EUWINON301 [EPLT: Wind Onshore 3.Low]	0.278	22	22	22

Table 28: Annual availability of electricity technologies

	Process	Annual availability
1	EUSTNUC301 [EPLT: EPR.NUC.3th.New]	0.86
2	EUSTNUC401 [EPLT: EPR.NUC.4th.New]	0.86
3	EUSTCOH01 [EPLT: Steam.Turb.COH.New]	0.80
4	EUSTCOHSC01 [EPLT: SC.Steam.Turb.COH.New]	0.80
5	EUSTCOHSCS01 [EPLT: SC.Steam.Turb.CO2seq.COH.New]	0.80
6	EUSTCOHFB01 [EPLT: FB.Steam.Turb.COH.New]	0.80
7	EUSTCOHFBS01 [EPLT: FB.Steam.Turb.CO2seq.COH.New]	0.80
8	EUIGCOH01 [EPLT: IGCC.COH.New]	0.80
9	EUIGCOHS01 [EPLT: IGCC.CO2Seq.COH.New]	0.80
10	EUPDGAS01 [EPLT: Turb Peak.GAS.New]	0.80
11	EUCCGAS01 [EPLT: Comb Cyc.GAS.New]	0.80
12	EUCCGASS01 [EPLT: Comb Cyc CO2Seq.GAS.New]	0.80
13	EUFCGAS01 [EPLT: Fuel Cell.GAS.New]	0.80
14	EUSCHFO01 [EPLT: SC.Steam.Turb.HFO.New]	0.80
15	EUSCHFOS01 [EPLT: SC.Steam.Turb.CO2seq.HFO.New]	0.80
16	EUSTWOO01 [EPLT: Steam.Turb.WOO.New]	0.80
17	EUSTWOOHT01 [EPLT: Steam.Turb.WOO.HT.New]	0.80

18	EUIGWOO01 [EPLT: IGCC.WOO.New]	0.80
19	EUIGWOOS01 [EPLT: IGCC CO2Seq.WOO.New]	0.80
20	EUSTMUN01 [EPLT: Steam.MunicipalWaste.New]	0.68
21	EUHYDRUN01 [EPLT: Hydro.Run of River.New.]	0.91
22	EUFCHH201 [EPLT: Fuel Cell.HH2.New]	0.80

Table 29: Annual and time sliced availability of sun and wind technologies

		ANN	FD	FN	FP	RD	RN	RP	SD	SN	SP	WD	WN	WP
23	EUPVSOLP201	0.11	0.29	0.00	0.00	0.29	0.00	0.00	0.49	0.00	0.00	0.08	0.00	0.00
24	EUPVSOLR101	0.09	0.21	0.00	0.00	0.21	0.00	0.00	0.36	0.00	0.00	0.06	0.00	0.00
25	EUWINOF101	0.37	0.55	0.55	0.55	0.55	0.18	0.55	0.39	0.13	0.39	0.77	0.26	0.77
26	EUWINOF201	0.37	0.55	0.55	0.55	0.55	0.18	0.55	0.39	0.13	0.39	0.77	0.26	0.77
27	EUWINOF301	0.37	0.55	0.55	0.55	0.55	0.18	0.55	0.39	0.13	0.39	0.77	0.26	0.77
28	EUWINON101	0.27	0.41	0.41	0.41	0.41	0.14	0.41	0.29	0.10	0.29	0.58	0.19	0.58
29	EUWINON201	0.19	0.29	0.29	0.29	0.29	0.10	0.29	0.21	0.07	0.21	0.41	0.14	0.41
30	EUWINON301	0.10	0.15	0.15	0.15	0.15	0.05	0.15	0.11	0.04	0.11	0.22	0.07	0.22

B. Cogeneration technologies

- Gas turbines for cogeneration (high and low temperature steam)
- STAG power plants for cogeneration
- Gas engines for cogeneration
- Diesel engines for cogeneration
- Different kinds of fuel cells for cogeneration (low and high temperature).

Table 30: Cogeneration technologies

DATA ARE VALID FOR THE YEAR 2015	EFF_{el}	EFF_{th}	INV	FIX	VAR	START
Process			€/kWel	€/kWel	€/GJ_{el}	
CHPGAS101 [CHP: Comb CYC condensing S.GAS.]	33%	46%	853	50	0.43	2001
CHPGAS201 [CHP: Comb CYC condensing M.GAS.]	38%	42%	711	40	0.43	2001
CHPICBGS101 [CHP: Int Combust.BGS M.]	34%	55%	4003	115	3.47	2001
CHPICBGS201 [CHP: Int Combust.BGS L.]	39%	50%	2353	115	2.08	2001
CHPICGAS101 [CHP: Int Combust.Gas S.]	30%	55%	2503	65	3.89	2001
CHPICGAS201 [CHP: Int Combust.Gas M.]	36%	49%	1053	45	2.78	2001
CHPICGAS301 [CHP: Int Combust.Gas L.]	39%	46%	753	35	2.08	2001
CHPICOIL201 [CHP: Int Combust.OIL M.]	36%	49%	1053	45	2.78	2001
CHPICOIL301 [CHP: Int Combust.OIL L.]	42%	43%	753	35	2.08	2001
CHPISCOH15 [CHP: IGCC CO2Seq.COH.]	30%	43%	1705	70	0.99	2015
CHPMFBGS10 [CHP: Fuel Cell MEFC.BGS.]	46%	38%	5003	275	6.67	2010
CHPMFGAS01 [CHP: Fuel Cell MEFC.GAS.]	50%	34%	4503	248	3.89	2001
CHPSFBGS10 [CHP: Fuel Cell SOFC.BGS.]	44%	38%	7503	413	6.67	2010
CHPSFGAS01 [CHP: Fuel Cell SOFC.GAS.]	44%	38%	7003	385	3.89	2001
CHPSFHH201 [CHP: Fuel Cell SOFC.HH2.]	47%	43%	7003	85	0.00	2010
CHPSPCOH101 [CHP: Steam Turb condensing S.COH.]	29%	51%	1315	53	0.71	2001
CHPSPMUN01 [CHP: Steam Turb condensing.MUNSLU.]	25%	50%	1617	74	0.71	2001
CHPSPWOO01 [CHP: Steam Turb condensing.WOO.]	31%	54%	1753	72	0.00	2001

4.7. Other supply sectors

A. Hydrogen production

The data for the technologies for hydrogen production are taken from the 'Hydrogen' project of Belgian Science Policy (Martens A. et al., 2006).

Table 31: Fixed costs and investment costs of hydrogen production processes

Process	2015	2030	2050
FIXOM	€/GJa	€/GJa	€/GJa
HH2BIO101 [Hydrogen from wood (large)]	2.70	2.70	2.70
HH2COA101 [Coal gasification for H2 (large)]	0.95	0.73	0.73
HH2COA201 [IGCC Coal gasification for H2 and ELC (large)]	2.52	2.52	2.52
HH2ELC101 [Electrolyser for H2 (large)]	1.59	0.76	0.32
HH2ELC201 [Electrolyser for H2 (small)]	2.22	1.52	0.63
HH2GAS101 [Natural gas reformer for H2 (large)]	0.48	0.40	0.32
HH2GAS201 [Natural gas reformer for H2 (small)]	6.34	4.76	3.17
INVCOST	€/GJa	€/GJa	€/GJa
HH2BIO101 [Hydrogen from wood (large)]	26.95	26.95	26.95
HH2COA101 [Coal gasification for H2 (large)]	19.03	14.59	14.59
HH2COA201 [IGCC Coal gasification for H2 and ELC (large)]	50.42	50.42	50.42
HH2ELC101 [Electrolyser for H2 (large)]	31.71	15.22	6.34
HH2ELC201 [Electrolyser for H2 (small)]	44.39	30.44	12.68
HH2GAS101 [Natural gas reformer for H2 (large)]	9.51	7.93	6.34
HH2GAS201 [Natural gas reformer for H2 (small)]	63.42	47.56	31.71

Table 32: Life time and availability of hydrogen production processes

Process	Life	AF
	years	%
HH2BIO101 [Hydrogen from wood (large)]	20	0.95
HH2COA101 [Coal gasification for H2 (large)]	20	0.95
HH2COA201 [IGCC Coal gasification for H2 and ELC (large)]	20	0.95
HH2ELC101 [Electrolyser for H2 (large)]	20	0.9
HH2ELC201 [Electrolyser for H2 (small)]	20	0.7
HH2GAS101 [Natural gas reformer for H2 (large)]	30	0.95
HH2GAS201 [Natural gas reformer for H2 (small)]	20	0.7

Table 33: Inputs and outputs of hydrogen production processes

Process			2015	2030	2050
HH2BIO101 [Hydrogen from wood (large)]	IN	SUPBIO	2	2	2
	OUT	BIOHH2	1	1	1
HH2COA101 [Coal gasification for H2 (large)]	IN	SUPCOA	1.47	1.35	1.35
	OUT	ELCHIG	1	1	1
HH2COA201 [IGCC Coal gasification for H2 and ELC (large)]	IN	SUPCOA	4	4	4
	OUT	FOSHH2	1.12	1.12	1.12
HH2ELC101 [Electrolyser for H2 (large)]	IN	SUPELC	1.52	1.43	1.43
	OUT	FOSHH2	1	1	1
HH2ELC201 [Electrolyser for H2 (small)]	IN	SUPELC	1.52	1.43	1.43
	OUT	FOSHH2	1	1	1
HH2GAS101 [Natural gas reformer for H2 (large)]	IN	SUPGAS	1.33	1.28	1.28
	OUT	FOSHH2	1	1	1
HH2GAS201 [Natural gas reformer for H2 (small)]	IN	SUPGAS	1.54	1.43	1.43
	OUT	FOSHH2	1	1	1

B. Wind, Solar and Hydro

The technology data for renewables are given in the section on technologies for the sectors where they are used. An important element for this type of technologies is potential. They were taken from the report for 'Energie Commissie 2030' by J. De Ruyck (De Ruyck J., 2006).

C. Biomass conversion

The data for this sector were taken from the report by J. De Ruyck for the 'Energie Commissie 2030' (De Ruyck J., 2006) and are mainly derived from the LIBIOFuels project. Derived fuels from biomass include biodiesel (from rape seed or from wood), hydrogen (from wood), and ethanol (from wheat or sugarbeet) and cogeneration of electricity and heat. The costs associated with the conversion processes are given in Table 34.

Table 34: Biomass conversion technologies

Process	Commodity	IN	OUT	LIFE	INV	FIX	VAR
		[ ]	[ ]	years	€/GJa	€/GJa	€/GJ
BIOGASSLU101	-			20	38.05	1.52	
[Biogas from Bioresidue]	BIOGAS		1.00				
	SUPSLU	1.67					
BIOLIQFT101	-			20	86.04	3.44	0.04
[FT diesel from wood]	BIOLIQ		0.29				
	INDELC		0.14				
	SUPBIO	1.00					
	SUPRPP	0.01					
BIOLIQRPS101	-			25	12.70	0.51	0.08
[Biodiesel.Animalfeed	ANIMFD		0.44				
from rapeseed]	BIOLIQ		0.54				
	BIORPS	1.00					
	SUPELC	0.01					
	SUPGAS	0.07					
	SUPRPP	0.02					
ETHELCWOO101	-			20	68.23	2.73	0.01
[Ethanol.Electricity from	BIOETH		0.42				
wood fermentation]	ELCMED		0.15				
	SUPBIO	1.00					
	SUPGAS	0.05					
	SUPRPP	0.02					
ETHWHEAT101	-			20	17.02	0.68	
[Ethanol.Animalfd	ANIMFD		0.40				
from wheat fermentation]	BIOCRP	1.00					
	BIOETH		0.47				
	SUPELC						
	SUPGAS	0.15					
	SUPRPP	0.02					
ETHWHEAT201	-			20	12.26	0.49	
[Ethanol.Bioresidue from wheat]	BIOCRP	1.00					
	BIODRY		0.40				
	BIOETH		0.47				
	SUPGAS	0.08					
	SUPRPP	0.02					

D. Carbon removal and storage

CO_2 removal technologies can be added to some of the fossil fuel consuming energy conversion technologies, such as coal power plants, STAG and hydrogen production based on fossil fuels. The cost of the carbon removal is included in the cost of the technologies (cf. tables on the technologies in the electricity sectors). Geological disposal in deep aquifers and coal sinks is modelled for the storage of the removed CO_2. The cost for transport and storage are: 0.05 M€/kton CO_2 for short distances (20 km) and 0.17 M€/kton CO_2 for long distances (100 to 150 km). Those costs are the investment costs for a network and a storage facility assuming a lifetime of 15 years. The share of the transportation cost in the total cost increases with the distance because transportation over larger distances (in €/ton) is more expensive, although per kilometre cheaper. Carbon storage is considered with a maximum potential of 100 Mt at a distance less than 20km and 1000 Mt further. This potential is in Belgium (Laenen B. et al., 2004). The 100 Mt can be performed with high certainty in Belgium; 1000 Mt is uncertain (although, if not in Belgium, this could represent foreign sinks).

It is important to note that for the choice of the sequestration option in the electricity sector the cost per ton CO_2 capture is only one element, other factors are the efficiency and the investment cost of the power plant with carbon sequestration. The final choice will depend on the total production cost of electricity (including the penalization of CO2 and the cost of sequestration).

THE MODEL DEVELOPMENT

5. DEVELOPMENT OF THE INTERNATIONAL DIMENSION FOR THE BELGIAN MARKAL/TIMES

The international dimension has becoming increasingly important for energy and environmental policies in Belgium. The global dimension in climate change and the transboundary characteristics of more local pollution imply that every domestic policy addressing these issues must integrate these aspects. The liberalisation of the energy markets within the EU and more specifically the electricity market accentuates further the importance of the international dimension. It will clearly have an impact on the domestic market (production and consumption) and hence on the potential and the cost of GHG emission reduction in Belgium.

It is therefore important to be able to integrate this dimension within the modelling framework for policy evaluations. The work has been concentrated on the electricity market. It started with a review of the literature on the modelling of electricity markets and its impact on climate change policies. The implementation was done in the MARKAL model, as the TIMES model was not yet available when the research started. MARKAL models for the electricity sector for Belgian neighbouring countries, the Netherlands, Germany and France, have been built and integrated in a multi-country MARKAL model. This approach was preferred to the construction of a reduced form for electricity production representing supply curves for electricity from outside Belgium because of the need to represent the investment in transmission lines between countries and the possibility of compactness in modelling electricity production in the different countries.

5.1. Literature review on modelling of electricity markets

Different articles studying the opening of the electricity market both at an empirical level (European market, Nordic market) and at a more theoretical level and its impact on the cost of the electricity system and on the cost of CO2 reduction have been reviewed. They indicate that the opening of the electricity market can reduce the cost of the electricity system, but the impact on CO2 emissions depends on the technologies used for electricity production and is therefore more an empirical question. Many articles study the impact of the possible market power, especially in the short run, when opening the electricity market, but MARKAL does not allow to study this aspect because of the perfect competition paradigm implemented.

5.2. Expanding the MARKAL model

To allow for trade in electricity between different regions the modelling framework was further developed and the database was extended towards three countries, France, Germany and The Netherlands.

1. *The database*

The Belgian database covers the entire energy system (electricity sector, residential and service sector, industry sector and transport sector). For the other countries only the electricity market is modelled. The parameters for new technologies in the three added countries are taken from the Belgian database. This means that all the countries have power plants with the same characteristics, they differ in terms of demand in electricity, existing capacity of the power plants and potential for hydro and wind energy.

The demand for electricity in the countries other than Belgium is divided into two sectors: industry and residential sector. Table 35 shows the demand for France, Germany and The Netherlands in the year 2000.

Table 35: Demand for electricity in the year 2000 (TJ)

	Industry	Residential
France	532	829
Germany	964	1092
The Netherlands	130	167

The price elasticity of the industrial and residential demand is assumed -0.3 as for Belgium. The growth of the demand in the industry is assumed to be 1.2%/year and in the residential sector 1.9%/year in the reference case in the three countries.

The installed capacity in 2000 in Belgium, France, Germany and The Netherlands is listed in Table 36.

Table 36: Installed power plants capacity in 2000 (GW)

	France	Germany	The Netherlands	Belgium
Nuclear power	66.7	25.1	0.5	5.9
Coal power	11. 9	69.9	7.8	4.1
Gas power	0.1	3.4	5	1.4
Kerosene power	11.6	8.2	6.4	2.1
Hydro power	25.4	4.5	0.3	1.7
Wind power	0.1	0.5	0.2	0.1

The electricity sector in the neighbouring countries is modelled at the level of wholesale markets. Each country has its own wholesale market which is connected to the Belgian market by a transmission network. In 2000, there exists a connection between Belgium and France and between Belgium and The Netherlands. There is no connection between Belgium and Germany but investment in a transmission line is possible. The cost of investment in transmission lines was derived from the literature and different steps are considered in function of the distance. The capacities of the existing connections are presented in Table 37.

Table 37: The capacities of the existing connections (MW)

Belgium – France	2700
Belgium – The Netherlands	4870

A nuclear phase out is assumed in Belgium, Germany and The Netherlands. France can invest in new nuclear power plants. It should be mentioned that given the investment cost and efficiency assumptions for coal and nuclear power plants, the two power plants are very close in terms of annualised cost when no CO2 constraint is imposed.

2. *The modelling framework*

Within ETSAP, the model code has been expanded to allow for multiple grids and for import and export of energy and pollutants such as CO2. First, this new MARKAL version has been installed and tested and then further adapted for our needs. This has needed rather extensive contact with the model developer within ETSAP because of some problems with the existing code. Moreover, as the existing trade implementation in MARKAL did not allow for explicitly treating investment and capacity of transmission lines, we implemented in the Belgian database transmission technologies for importing from and exporting to the three new countries, imposing also that the capacity of the import and export technologies for the same country should be equal, as transmissions lines are bidirectional. The investment cost of these technologies has been adapted consequently. The trade is modelled at wholesale level.

In the actual version of MARKAL, the transmission costs are included in terms of annualised cost without explicit investment. The link technologies, representing the grid, are connecting the import or export of Belgium with the Belgian domestic market and with the export and import technologies in the neighbouring countries. As export and import have to be treated explicitly, it means that there are three import and three export technologies in Belgium. However the link import and export technology are physically the same transmission line and this is imposed through specific constraints. This extensive modelling of the different steps in import and export are needed because it is the only way to allow for investments in transmission lines.

5.3. Results of the MARKAL simulations

A. The scenarios

Two scenarios are considered. The first one investigates the impact of opening the electricity market without CO_2 emission constraints and the second one examines the implications of the liberalisation of the electricity market with CO_2 emission restrictions.

The effect of trade in electricity (without a CO2 constraint) is investigated by comparing the *baseline scenario* (a business as usual scenario without trade) with the *trade scenario* where trade between Belgium and the other countries is possible.

In the *CO_2 scenario* a CO_2 emission bound is added corresponding to the Belgian Kyoto target (a CO_2 emission reduction of 7.5% in the period 2008/2012 compared to the 1990 level). No emission constraint is imposed on the other countries in a first step. The trade in electricity in this scenario is fixed to the level of the *trade scenario*. The implications of the liberalisation of the electricity market will be studied by comparing the *CO_2 scenario* with the *CO_2 + trade scenario* where trade between Belgium and the other countries is possible. In a second step different reduction target are considered for the other countries.

B. Impact of opening the electricity market

The impact of opening the electricity market is investigated by comparing the *baseline scenario* (without trade) with the *trade scenario* (where trade in electricity between Belgium and the other countries is possible).

The *baseline scenario* is a business as usual scenario. There is no trade between Belgium and the other countries and there is no constraint on the CO_2 emissions. Table 38 shows that electricity in Belgium is mainly produced by nuclear power plants until the nuclear phase out (2020). Coal production decreases in the period 2005-2010 because the old coal plants are being closed. With the nuclear phase out coal power are again penetrating as a substitution for nuclear power: after 2010 most investments are made in new coal plants because this is the cheapest technology. No investments are made in wind power.

Table 38: Electricity production in Belgium in the baseline scenario (TJ)

	2000	2005	2010	2015	2020	2025	2030
coal	41.9	29.0	13.3	79.5	103.9	236.7	333.2
nuclear	153.2	153.2	153.2	106.3	106.3	0.0	0.0
STAG	2.6	0.0	65.2	59.3	53.8	53.3	0.0
Gasturbine	29.1	68.5	4.1	1.1	0.0	0.0	0.0
hydro	2.6	2.6	2.6	2.6	2.6	2.6	2.6
wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CHP	19.3	38.4	62.7	67.9	65.7	59.4	57.2
other	34.5	1.0	2.6	2.0	2.0	2.0	2.0
TOTAL	283.2	292.6	303.6	318.7	334.4	354.0	395.0
Export	1.4	1.5	0.0	0.0	0.0	0.0	0.0
Import	0.0	0.0	0.0	0.0	0.0	0.0	0.0

In the *trade scenario* possibility of trade in electricity is introduced. Table 39 shows the changes in electricity production in Belgium. There are no great differences compared to the *baseline scenario*.

Imports in 2010 and 2015 reduce the domestic production with STAG power plants but in the periods thereafter there is no significant trade. However electricity production increases and the shift towards coal away from gas, observed in 2030 in the baseline, is observed already in 2020.

Table 39: Electricity production in Belgium in the trade scenario (difference in TJ compared to baseline)

	2010	2015	2020	2025	2030
coal	0.0	8.9	63.7	77.1	16.5
nuclear	0.0	0.0	0.0	0.0	0.0
STAG	-44.3	-39.7	-37.7	-41.2	0.0
Gasturbine	26.5	34.1	0.0	0.0	0.0
hydro	0.0	0.0	0.0	0.0	0.0
wind	0.0	0.0	0.0	0.0	0.0
CHP	1.4	-1.7	-4.4	-9.0	-4.9
other	3.0	0.0	0.0	0.0	0.0
TOTAL	-13.4	1.6	21.6	26.8	11.7
Export	1.3	0.0	0.0	0.0	0.0
Import	15.5	2.5	0.0	0.0	0.0

It is cost effective to trade electricity in 2010 and 2015 mostly because it allows more flexibility in the investment in new capacity and around these periods installed capacities are beginning to be scrapped. However there is not sufficient difference between countries in the structure of a cost efficient energy system to induce a full shift to import/export, contrary to what was observed for the Nordic countries. No country has a cheap source of energy available. Moreover we have assumed the same cost for new technologies in all countries and the cost of nuclear and coal power plants are very close. The allocation of the demand by time slice should also be further examined, differences between countries for this allocation could be an opportunity for trade and they are not considered here.

Introducing trade decreases slightly the electricity price in Belgium, around 1% for residential use and 2% for industrial use and this increases the electricity demand. In the residential sector the increase is mainly due to an earlier shift to electric water heating (at night) which in the baseline is only cost efficient in 2030. The price decrease can be explained by the reduction in the investment cost due to a weaker peaking constraint. Allowing for trade contributes to the reserve margin needed to satisfy the peak and limits thus investment in Belgium.

In terms of environment, opening the electricity market is not beneficial: the CO_2 emissions in Belgium are increased from 2015 onwards because of the higher use of coal power plants.

Table 40: CO_2 emissions in Belgium in the trade scenario (difference in % compared to baseline)

2010	2015	2020	2025	2030
0.1%	1.8%	4.5%	4.9%	1.1%

In terms of welfare, trade in electricity causes a small increase in welfare: the discounted total surplus increased by 600 million euro compared to the *baseline scenario* which represents approx. 0.2% of the total system cost.

The overall impact remains rather small and this can be explained by two elements:

1. the MARKAL model assumes perfect competition and therefore opening the electricity market does not allow any gain from reducing the strategic behaviour of the actors on the market.
2. the assumption in the database regarding the cost of future technologies (similar in all countries) and no potential of relatively cheap energy source in one of the countries.

C. *Impact of opening the electricity market with an environmental policy*

The effect of opening the electricity market, when a CO_2 policy is in place is investigated by comparing the *CO_2 scenario* (with fix trade) with the *CO_2 + trade scenario* (where trade in electricity is possible).

In the *CO_2 scenario* trade is kept fixed (exogenously) at the level of the *trade scenario* and a bound of 7.5% compared to the 1990 level is put on the CO_2 emissions in 2010 in Belgium (the Belgian Kyoto target). No CO2 constraints are imposed on the other countries.

With the CO2 constraint and no trade, electricity demand is decreasing and there is a shift in the technologies used. The changes in electricity production in Belgium are given in Table 41. STAG plants are replacing the coal power plants. Because of the cost efficiency of the STAG when a CO2 constraint is imposed, investment in this technology already starts in 2005 instead of investment in gas turbines in the *trade scenario*. Wind power and hydro are becoming more cost efficient but their contribution remains small because of the small potential in Belgium.

Table 41: Electricity production in Belgium with climate policy and without trade (difference in TJ compared to trade scenario)

	2005	2010	2015	2020	2025	2030
coal	-0.5	0.0	-75.1	-154.3	-300.4	-336.4
nuclear	0.0	0.0	0.0	0.0	0.0	0.0
STAG	33.2	30.4	50.3	61.8	191.5	240.7
gasturbine	-36.5	-30.0	-35.2	0.0	0.0	0.0
hydro	0.0	0.7	0.7	0.7	0.7	0.7
wind	0.0	1.4	14.0	15.6	15.6	15.6
CHP	2.4	-4.3	5.2	18.3	30.3	24.2
other	0.0	-2.6	-1.0	-1.0	-1.0	-1.0
TOTAL	-1.5	-4.4	-41.1	-59.0	-63.4	-56.3

When trade is allowed, the impact depends on the CO2 policy imposed in the neighbouring countries. No specific climate policy is considered here for the other countries because the complete energy system is not modelled. Instead, to explore the impact of CO2 constraints on the results for Belgium, we consider different reductions for the CO2 emissions in the other: 0%, 5%, 10% and 15% compared to the reference (with trade). These scenarios are more exploratory than policy oriented.

When no CO2 constraint is imposed on the neighbouring countries (*CO_2 + trade scenario)*, allowing for trade is entirely beneficial for Belgium, there is nearly no change in welfare compared to the trade scenario. Comparing to the CO2 scenario without trade the welfare increases with 2997.3 million €. Instead of investing in STAG, wind energy and CHP, the imports are increasing representing respectively 15% and 40% of total electricity consumed in 2010 and 2020.

Table 42: Electricity production in Belgium with climate policy and with trade (difference in TJ compared to CO2 scenario without trade)

	2005	2010	2015	2020	2025	2030
coal	0.0	0.0	0.0	0.0	0.0	0.0
nuclear	0.0	0.0	0.0	0.0	0.0	0.0
STAG	7.5	-30.9	-28.2	-33.2	-148.8	-185.9
gasturbine	-8.5	4.4	0.6	0.0	0.0	0.0
hydro	0.0	0.0	0.0	0.0	0.0	0.0
wind	0.0	-1.4	-12.6	-14.2	-14.8	-2.2
CHP	0.0	2.5	-7.7	-23.3	-29.5	-20.5
other	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	-1.0	-25.4	-47.9	-70.7	-193.1	-208.6
Export	0.0	-1.3	0.0	0.0	0.0	0.0
Import	0.0	28.6	99.0	132.7	260.7	265.7

When tighter bounds are imposed on the other countries the benefit for Belgium is reduced. The consumer/producer surplus is reduced and the marginal abatement cost increases, though this remains limited because the CO2 reduction imposed in the other countries is limited compared to the Kyoto target imposed in Belgium. STAG and CHP are replacing the imports.

Table 43: Change in total discounted surplus (million €) and marginal abatement cost of CO_2 (€/ton) in Belgium

	Discounted surplus	CO2 marginal abatement cost				
		2010	2015	2020	2025	2030
No trade	-2997.3	48.6	76.3	88.4	161.0	191.6
With trade and 0% reduction in neighbouring countries	0	38.4	63.4	66.6	77.5	89.5
With trade and 5% reduction	-365.6	39.3	67.4	70.3	81.4	89.8
With trade and 10% reduction	-470.8	40.9	67.4	70.3	84.8	89.8
With trade and 15% reduction	-591.7	39.6	69.9	70.4	88.9	92.5

Imposing a more severe constraint on the CO2 by assuming for the other countries a stabilisation of the CO2 emissions compared to 1990 increases the loss for Belgium up to 860 million €, which is still less than when there is no trade. The availability of nuclear power plants in France explains partly this result. When a nuclear phase out is also imposed in France the loss for Belgium is increased with 25% remaining however lower than when there is no trade.

Opening the electricity market when a CO2 policy is implemented allows reducing the cost of this policy. Though trade is always beneficial with the scenario tested, the reduction is however very dependent on the CO2 policy implemented in the other countries.

5.4. Conclusion

The impact of liberalizing the electricity market in the case of no CO_2 emission constraints is small. This can be explained by the relatively similarity in the structure of the energy system in the different countries, the absence of a cheap source of energy in one country and the perfect competition assumptions of MARKAL. This is in line with the results of the studies for the Netherlands and for the Nordic countries.

Opening the electricity market in the case of emission restrictions on CO_2 in Belgium results in more imports of electricity and therefore decreases the cost of the CO2 reduction. However this gain decreases when CO2 constraints are also imposed in the other countries. It depends also partly on the possibility of having nuclear power plants in France.

At this stage no further development for a one country model are considered, because in the course of 2007, a Pan-European Times model will be available. This model is certainly more appropriate to evaluate policies with an EU wide electricity market. Special attention should be focused on the contribution of import and export to the peak equation and to the baseload equation because of the great sensitivity of the model and of the results to these aspects.

6. IMPLEMENTING REFINERIES IN MARKAL BELGIUM

Further development of the modelling framework by integrating a refinery module helps to acquire knowledge about this specific sector. As a result it is possible to examine the relation between product mix, product specifications, emissions to the air and relevant (environmental) legislation.

A separate module for a standard, but complex refinery has been fully developed during this project and allows analysing this sector, given exogenous assumptions regarding demand. The work has concentrated on working out a module where processes are endogenously modelled and linked to each other. The production processes then are adapted to this demand and any environmental restriction. The module has been developed in the software ANSWER.

A cost curve for reducing SO2 in a refinery has been derived and is given in annex, section 1. The result gives a good view on the increasing marginal reduction cost, but it is only applicable to the situation of 2000. Future work will be necessary to fine tune the model parameters. The model can now be used for examining the effect of environmental standards (bounds on SO_2 and CO_2), examine the effect of using lower sulphur fuels and evaluating BAT (Best Available Technologies) for refineries. With some additional techniques, it can compare the CO_2 in a Well-to-Wheel analysis, compare the cost of an increasing amount of biofuels and examine the possibilities of cogeneration units. The complex model will also serve as a good tool to do specific runs and as a verification of the output of a simplified version.

6.1. The refinery sector (Belgische Petroleum Federatie, 2006)

The refinery sector is the second most important sector in energy transformation. The four refineries make Belgium a net-exporter in refinery products. Figure 12 shows the primary distillation capacities of the Belgian refineries till 2002. In March 2003, Petroplus Refining Antwerp took over the refining activities of Nynas. Fina is now called "Total Raffinaderij Antwerpen".

Figure 12: Primary distillation capacities of the Belgian refineries (kton/year), Source: Belgian Petroleum Federation

Op 31 december	1973	1979	2001	2002
Belgian Refining Corporation [1]	3.500	4.600	5.500	5.550
Belgian Shell	544	544	-	-
BP Belgium	40	-	-	-
Chevron [2]	5.000	7.000	-	-
Esso Belgium	4.730	12.000	12.500	12.765
Fina Raffinaderij Antwerpen [3]	17.000	17.000	17.400	17.988
Nynas Petroleum [7]	-	-	1.200	1.200
Raffinerie Belge des Pétroles [4]	5.000	5.000	-	-
Texaco Belgium [5]	7.270	9.370	-	-
Petroplus Refining Antwerp [6] [7]	-	-	2.500	2.500
TOTAAL	**43.084**	**55.514**	**39.100**	**40.003**

Oil refining continuously evolved since it started – almost 150 years ago – and became an activity with complex conversion technologies. The input energy carriers are various types of crude oils. The main outputs are LPG, Naphta, Gasoline, Kerosene/Jet Fuel, Diesel Oil, Heavy Fuel oil and Bitumen. Naphtha is used by petrochemical industry. Bitumen is used in road construction. Other products have typical energy applications.

Figure 13: Composition of crude oils and Fuel Market in USA and Europe, Source: www.statoil.com

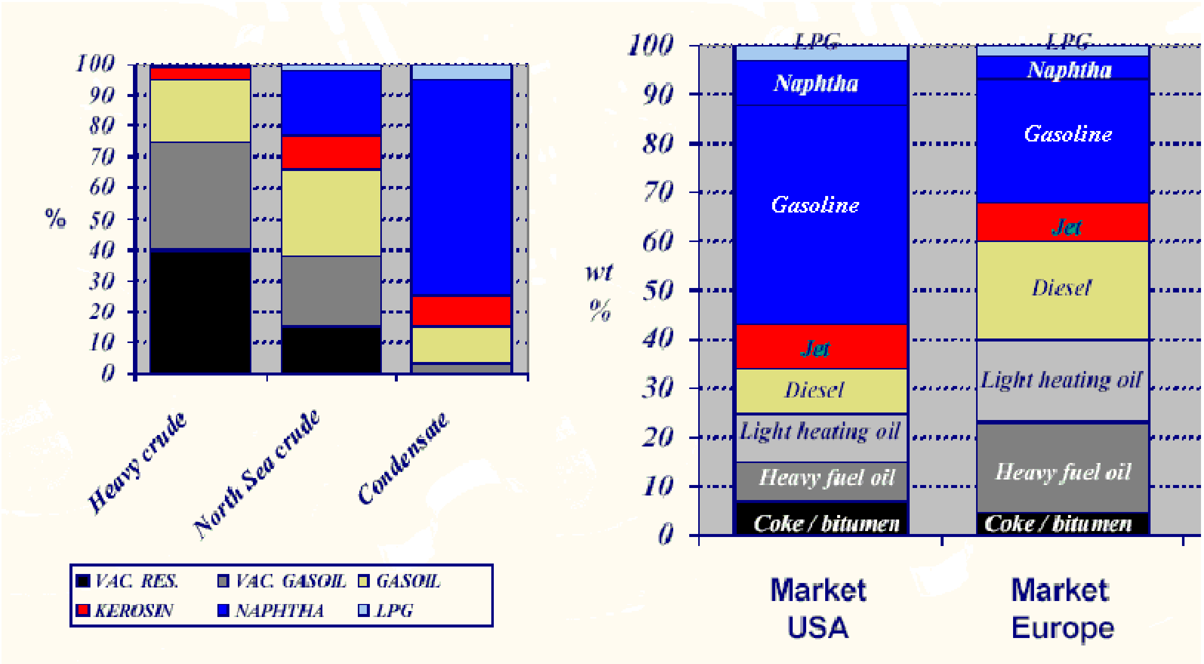
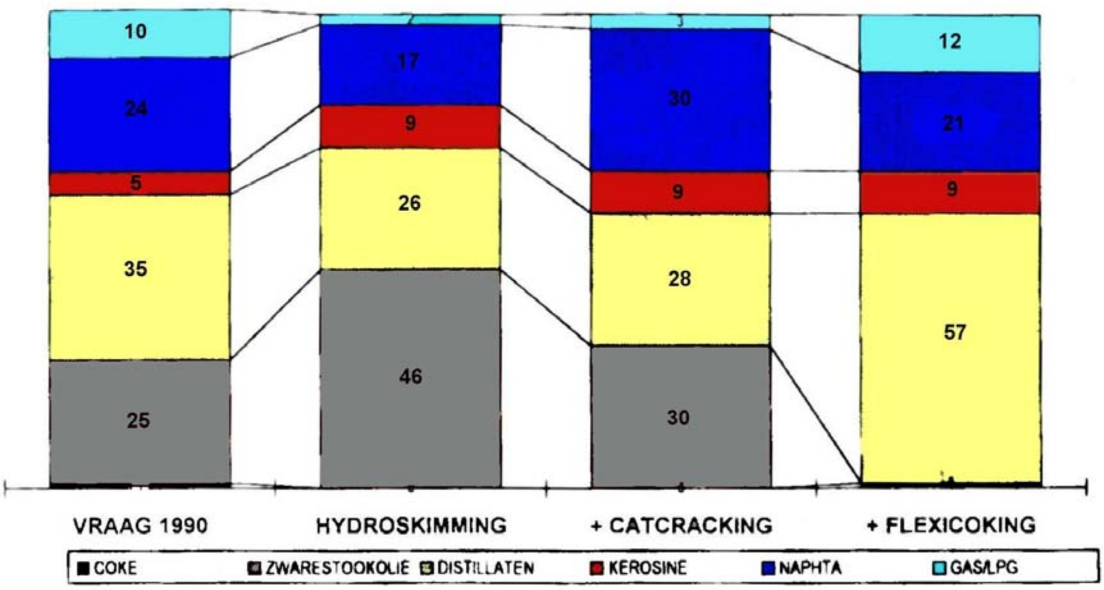


Figure 13 shows at the left hand side the composition of possible refinery feedstocks. The crudes are split up into fractions according to boiling point. On the right hand side the difference is clear between the USA market and the EU market. The most profitable products are the transportation fuels and the light heating oil. Figure 14 is essential to understand the differences between refinery configurations. A hydroskimming refinery is the simplest one and comprises a minimum of five processing units. To make more efficient use of the crude, deeper conversion units are necessary. Some large and complex refineries can comprise up to twenty different processing units or more. In Belgium, the order of complexity is in accordance with magnitude of the refineries: Petroplus, BRC, Esso and then Total.

Figure 14: Market demand (left) and output of refineries with different configurations, Source: Chemical Process Technology, Van Rompay, KULeuven



In Figure 15 the netto-production of final products in Belgium is shown. Belgium produces about 34 million tons of final products. Delivery for inland use is little more than 20 million tons. To make clear that international trade is important: about 15 million tons of final oil products are imported and about 20 million are exported (without taking into account the export of bunker fuels).

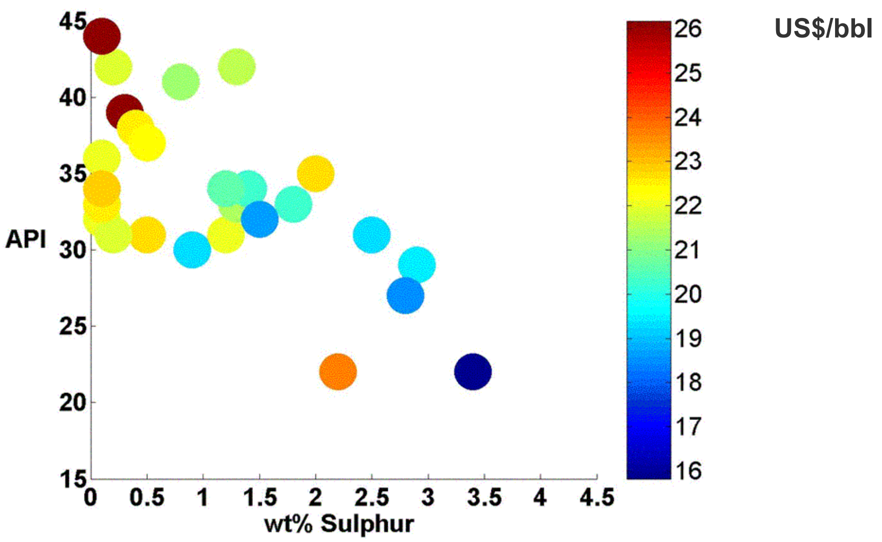
Figure 15: Nettoproduction of final products (1000 ton), Source: BPF

	kt				%		
	1973	1979	2001	2002	Variation 2002/1973	1973	2002
Autobenzines	4.768	5.088	5.494	5.775	+21,1	13,4	17,1
Vliegtuigbrandstoffen	1.111	1.515	1.913	2.067	+86,1	3,1	6,1
Gasolie	12.054	11.802	12.777	12.464	+3,4	34,0	36,9
Residuele stookolie	13.715	10.155	7.015	7.603	-44,6	38,7	22,5
Vloeibare gassen	405	499	657	656	+62,0	1,1	1,9
Bitumen	1.081	673	413	434	-59,9	3,0	1,3
Nafta	1.682	1.636	2.135	2.051	+21,9	4,7	6,1
Andere producten	694	821	2.650	2.734	+29,4	2,0	8,1
ALLE PRODUCTEN	**35.510**	**32.189**	**33.054**	**33.784**	**-4,9**	**100**	**100**

Bron: Ministerie van Economische Zaken

Although the chemical composition of crude oils are surprisingly uniform, the physical characteristics vary widely. Crude oils are evaluated by comparing properties like gravity, sulfur content, pour point, carbon residue, salt content, nitrogen content, metals content. Crude oil is commonly classified as light, medium or heavy, referring to its gravity as measured on the American Petroleum Institute (API) Scale. An increase in API gravity corresponds to a decrease in specific gravity. Most crudes fall in the 20 to 45 °API range. Together with sulfur content, the gravity has the greatest influence on the value of the crude. Figure 16 brings together this three aspects.

Figure 16: Crude oil price in function of sulphur content and API, Source: EIA, 29 december 2003



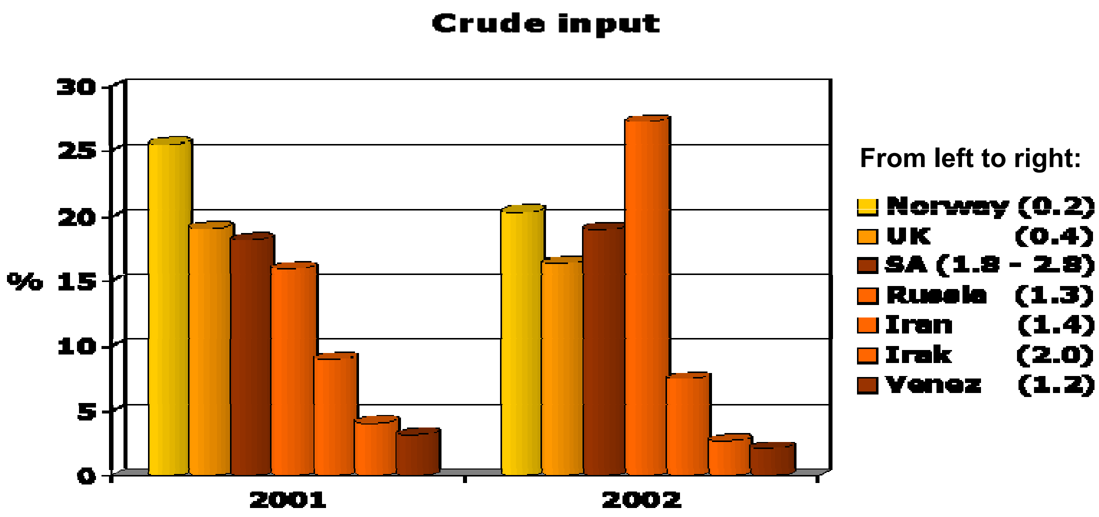
The average sulphur content of the crude oil processed in Europe is relatively low. This is due to Europe's proximity to two major sources of low sulphur crude oil production namely the North Sea and North Western Africa. In addition, these low sulphur crude oils are also relatively low in density and so produce a relatively high yield of light products. The quality of crude oils processed is expected to worsen slowly in the future with the sulfur contents and densities to increase.

The situation in Belgium is showed in Figure 17. In 2002 approximately 35% of our oil supply came from the North Sea (Norway and UK). This was 10% less than in 2001. Russia delivered about 10% more in 2002. Another 35% came from OPEC countries.

The most important factors underlying the choice of crude oil are the market for products from the refinery, the refinery configuration and location. Changing the crude slate of a given refinery will change the yields of the products produced. As a result, there is always some flexibility to change refinery product yields to meet changing market demand patterns by changing the crude slate.

The overall market structure of crude and product prices will not be affected by a change in one refinery's operation. If the overall market is changed, by a change in product specification for example, then it is possible that many refineries will see an incentive for changing their crude slate. A large change in demand for a particular type of crude can change the price of that quality of crude relative to other crudes due to the increased demand.

Figure 17: Greatest crude oil imports in Belgium, Source: BPF



6.2. The Belgian refineries and CO2.

Emission reduction from refineries is a major issue. As for the other sectors, the refinery sector must face the coming of the Kyoto protocol and the European Union Greenhouse Gas Emission Trading Scheme (EU ETS). Several EU requirements have a specific impact on the future energy management of refineries:

- the move to "greener" products as a result of EU requirements for product quality specification
- the EU-directives affecting emissions to the air from the refineries it selves.

New specifications require reductions of the sulphur content for all types of automotive fuels, lower aromatics, particularly benzene in gasoline and reduced polyaromatic hydrocarbons and a higher cetane number in diesel. The trend is that environmental quality requirements will become more stringent for all refinery products. The specifications for heavy fuel oils are regulated in council Directive 1999/32/EC relating to the reduction in the sulphur content of certain liquid fuels and amending 93/12/EC. OJ L121/13, 11 may 1999 EU B. For heating oil, the Directive entails a reduction of the sulphur content to 0.1 % in 2008 and for land trade fuel oils a limitation of the sulphur content to 1 % from 2003 onwards. For seagoing vessels the regulations of Annex VI of the MARPOL treaty, once ratified, imply that as of 2003, in so-called SO_x emission control areas, the use of fuel oils may be restricted to fuel oils with a maximum sulphur content of 1.5 %.

There is a remarkable growth of hydrogen processes due to the more severe specifications on the sulphur content of fuels. Hydrogen is needed in hydrotreating processes for desulphurization of fuels. It is also necessary for stabilization of strongly unsaturated compounds (hydrorefining) and for the conversion of heavy fractions to lighter products (hydrocracking).

The emissions to the air from the refineries it selves are among other legislation regulated by the *National Emission Ceiling Directive* (important Directive for the reduction of SO2, NOx and VOC) and by the *EC Large Combustion Plant Directive.* New units (ie units which came into existence on or after 1 July 1987) with individual furnaces greater than 50MWth or multiple heaters where aggregate thermal input is greater than 50MW, come within the scope of the EC Large Combustion Plant Directive, and must comply with its requirements. However the Directive does not cover direct refinery processes, e.g. FCCU regenerators, coking processes nor gas turbines.

The most important energy consuming processes in refineries are:

- crude oil distillation
- conversion processes
- desulphurization processes

The major sources of carbon dioxide are process furnaces, boilers, gas turbines, fluidised catalytic cracking regenerators, CO-boilers, flare systems and incinerators. All these activities are represented in the model and the sources of greenhouse gas emissions are directly linked with activities modelled.

Options for the refiner to reduce CO_2 emissions, on a kg/tonne of refinery intake basis, are:

1. Use of fuels with high hydrogen contents
2. Effective energy management:

1. Fuel choice

The composition of the refinery fuel will be adapted when CO_2 emissions have to be reduced. As well known, there will be a higher gas consumption in refinery fuel at the expense of heavy fuel oil. Such a reduction of use of liquid refinery fuels, some of them residual components, leads further to more distillation residue upgrading investments (like coking, thermo cracking or gasification). The model can simulate the amount of this reduction of greenhouse gases and predict the cost of it.

2. Energy management

Measures which improve the energy efficiency are appropriate to reduce CO_2 emissions in the refining sector. The model gives good results when the reduction of CO_2 is related to substitution of processes, or a shift to newer and cleaner energy production techniques. The model can calculate these changes quantitatively.

Reducing energy use through the integration between and within units (heat integration/recovery or steam management) is very complex. Modelling these opportunities is only feasible if further research is done by simulating the heat grid or by integrating abatement cost functions.

6.3. Methodology

Linear programming is the most widely used mathematical technique for optimization – that is, for finding the best solution (in an economic sense) to complex problems involving allocation of scarce resources across many competing activities. In refining operations, the scarce resources are the refinery's production facilities, raw materials, and process streams, and the competing activities are the refinery's manifold processing operations.

Virtually all refining companies use in-house, custom-configured LP models of their own refineries for (1) tactical and operations planning, (2) monthly and weekly scheduling, and (3) crude oil and product pricing analysis. Government agencies can use refinery LP models to estimate the effects on refining economics of proposed policies, regulations, and fuel standards. For short-term calculations, refining companies are using more and more real-time adjustments and non-linear programming.

The refinery LP model can simulate how a refinery would operate – on an average day in a specified time period – to produce a specified product slate at minimum cost. These simulations yield

- *total and marginal* refining *costs* associated with the case at hand but also
- *capital investment requirements* and *operational changes* called for;
- *marginal refining values* (or *"shadow prices"*) for all refinery streams
- *total and marginal emission levels*

Although total refining costs and total emission levels are very important factors, marginal costs and marginal emission levels can give extra information. For example, a refiner would like to investigate the effect of the production of one extra unit of ULSD (10 ppm Ultra Low Sulphur Diesel). Of course he knows at what price he can sell the ULSD. On the contrary, it is not very clear at first sight how much the total producing cost will rise and how much of each product will be sold. It is not possible to use an "average cost of producing ULSD". Average costs are derived from total costs.

After all, if the needs of the market change, the costs of production will also change. The refiner can change the severity of a process or change the imported crude to get different yields. If the demand for ULSD continues to increase, maybe an expensive new installation is required and this means that the marginal cost of that extra unit is high.

The same reasoning applies to emissions. This explains why refineries all have there own specific situation. A refinery for example has a maximum output of light distillates, unless big investments are made for deeper conversion.

Ambitious choices are made for the refinery module. Objectives were:

- a **plant-specific model** including
- **important processes** that have more then one operation mode where
- **crude properties** can be changed easily and
- **fuel specifications** are taken into account.
- **CO_2, SO_2 & NO_x** as emissions
- **bubble** for SO_2 and NO_x

From a modelling point of view, a refinery consists of a series of process units which transform materials into another. Materials may also be blended to make finished products which are subject to quality specifications. Further aspects are utilities (fuel, steam, hydrogen,…). In contrast with an elementary model, it is necessary for a complex model to represent the process streams, the most important processes and the mechanism of blending.

A. Represent all process streams with there properties

Process streams do have properties like gravity, sulphur content, octane and cetane number. All these properties determine the fuel specifications and must meet standards. In an elementary model, a flow sheet stream is always treated in the same way, no matter what crude is distilled. In reality, using a light crude doesn't only result in for example more yield of gas oil, but also in different gas oil. The properties will vary, thus the model needs to have decision variables for

- how much of each stream there is and
- what the properties of the stream are.

More about distillation: Higher efficiencies and lower costs are achieved if the crude oil separation is accomplished in two steps: first, by fractionating the total crude oil at atmospheric pressure, then by feeding the high boiling bottom fraction to a vacuum distillation.

This inevitably leads into a nonlinear model, because multiplication of the decision variables will be necessary or into a very large model, because every property of every stream is a separate variable. There is an alternative in which the model is kept linear and smaller and which is **the basis of the refinery LP model**. In this a single physical stream is represented by several distinct "grades", also called "pseudo-components". Each of these grades has a well-defined set of qualities. For each process unit, a number of distinct "modes of operation" are selected. What does this mean in the case of the crude distillation unit ? Crude distillation is the first major processing unit in the refinery. It is used to separate the crude oils into fractions according to boiling point, so that each of the following processing units will have feed stocks that meet their particular specifications. The different modes of operation are determined by choosing boiling ranges. The pseudo-components represent the pre-defined boiling point ranges or cut-point ranges on the distillation curve for the stream being characterized. The normal boiling point for each pseudo-component is defined as the weight average temperature for its cut-point range. Other properties, like sulphur content, of a pseudo-component are also averaged.

Figure 18: Sulphur content of distilled fractions of "Bryan Mount Sweet" 36°API 0.33 wt% Sulphur, Source: U.S. Department of Energy

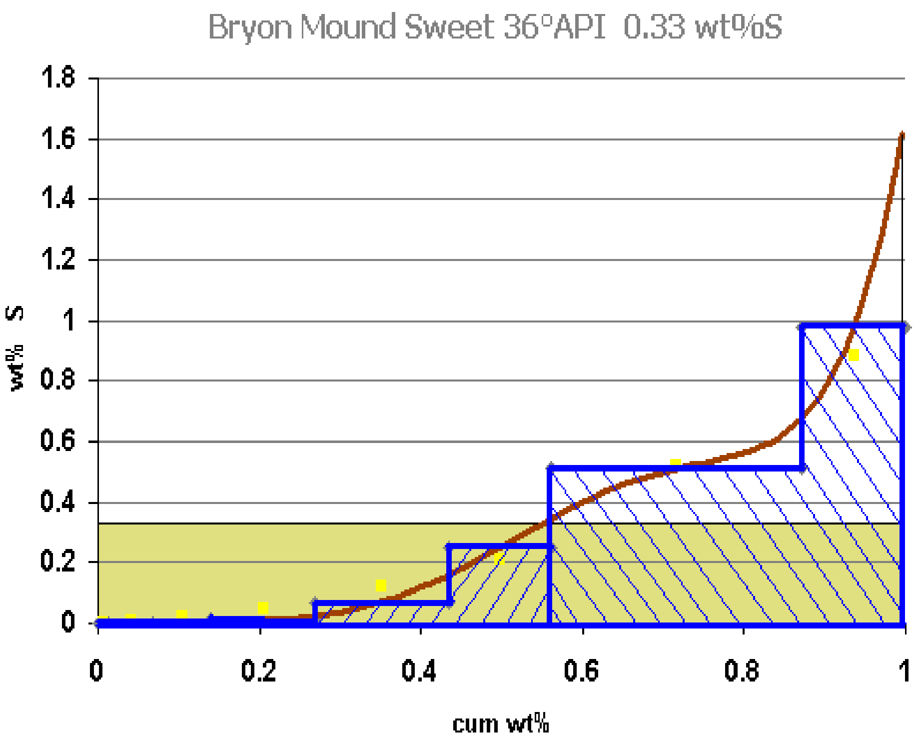
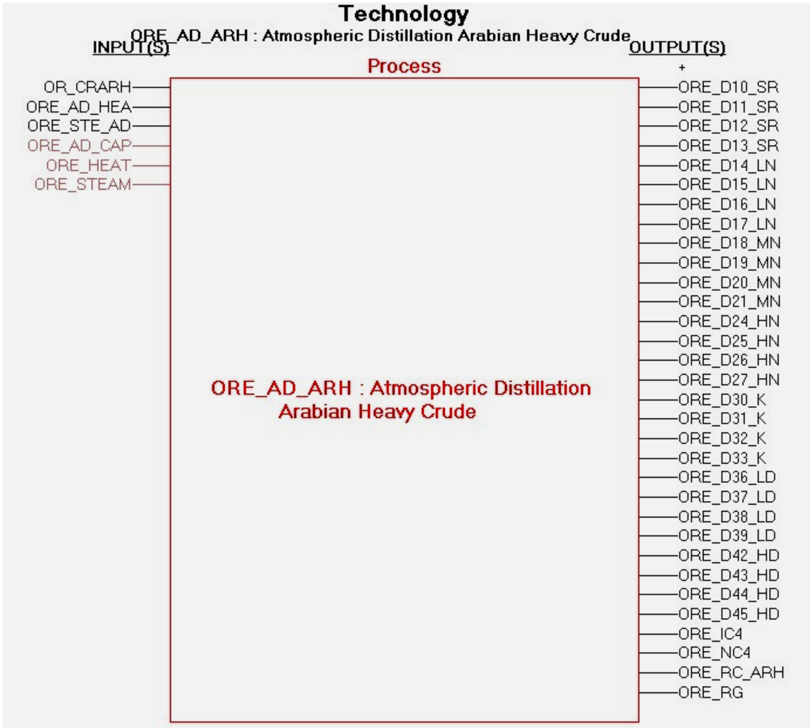


Figure 18 demonstrates that every pre-defined boiling point range (pseudo-component) has a different sulphur content. The example applies to a light crude with an average sulphur content of 0.33 weight percent. The brown line represents the sulphur content, expressed in weight %, in function of the cumulative weight percent distilled. The blue contours are different pseudo-components (the same as in Figure 13). At the left hand side, approximately 25% of the crude oil corresponds to all the lighter fractions, naphta included, containing almost no sulphur. The last two fractions are good for little more than 40% of the crude's mass. These are the atmospheric and vacuum residues and they contain 75% of total sulphur mass.

Figure 19: Atmospheric distillation in Markal



Therefore, a separate program is made in Excel that splits up a crude, resulting in a partition like in

. In MARKAL, a stream with a fixed boiling range is split up into a more paraffinic or a more naphtenic stream according to the type of hydrocarbons. On its turn, these streams are split up to make a distinction between a low-sulphur and a high-sulphur stream. Thus there are four streams for every boiling range. The excel program calculates the composition of a crude and cuts it in a manner of speaking into these pseudo-components such that the average sulphur content, the average specific gravity and the type of hydrocarbons of every boiling range is correct.

B. Represent the most important process units

Typical of chemical process technology is that materials can be converted into other materials. Refinery companies will convert heavy feedstocks to lower boiling hydrocarbon products. The market for heavy residual fuel oils has been decreasing and lower boiling products are more valuable. Fractions can be altered by combining, breaking or reshaping the molecular structure. Most of these processes and other supporting operations are showed in the scheme:

- Conversion processes
    - Cracking
        - Thermal (Visbreaking, Delayed Coker…)
        - Catalytic (Fluidized Bed Catalytic Cracker, Hydrocracker)
    - Reforming (catalytic)
    - Synthesis
        - Alkylation
        - Polymerization
- Other (Isomerization)
- HydroDeSulphurization (HDS) & Sulphur recovery unit

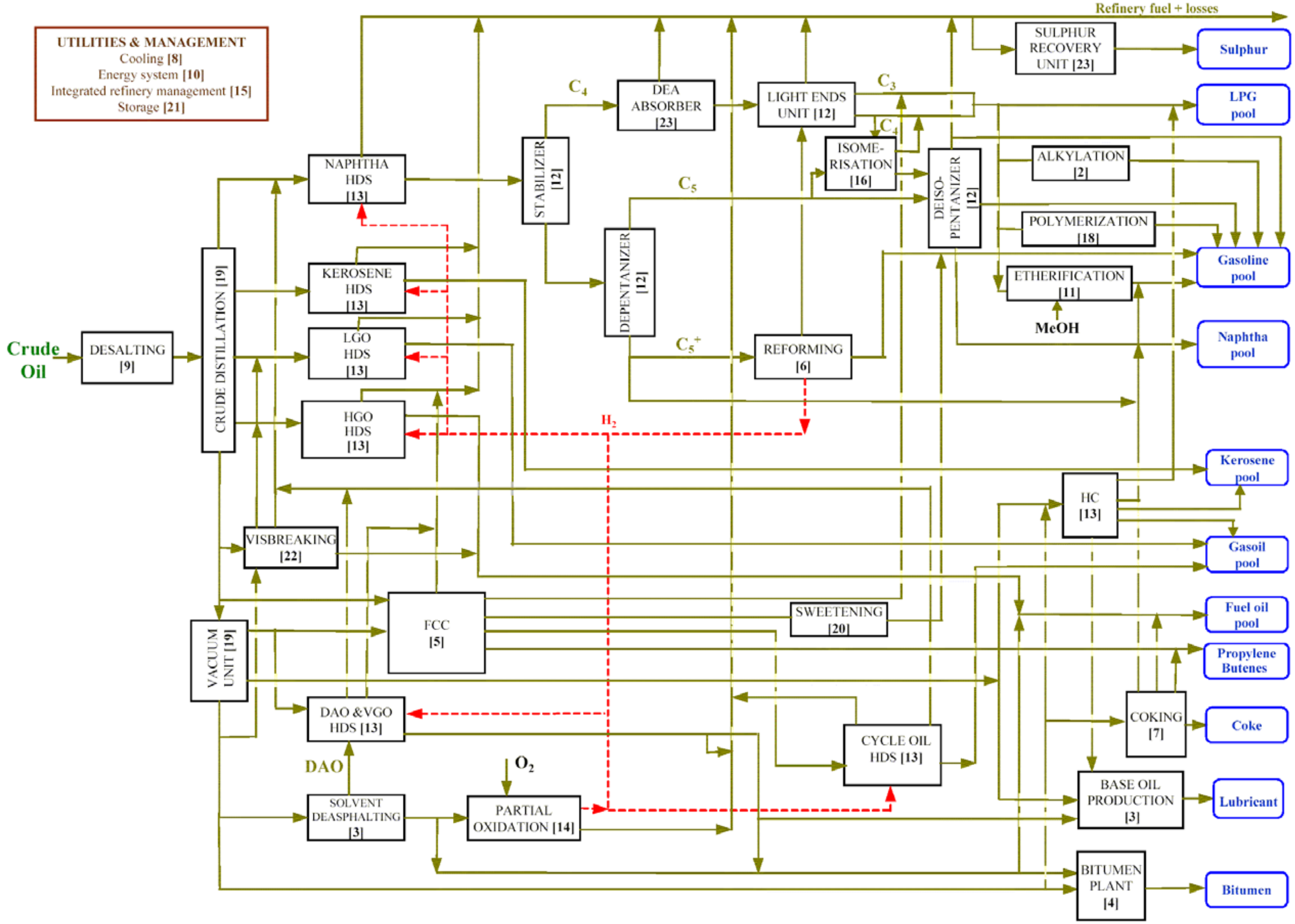
- H_2 production
- Steam reforming
- Partial oxidation
- Energy and steam management
- Blending facilities

Table 44: Scheme of processes in Belgian refineries

		Total	Esso	BRC	PRA	Nynas
9	Crude oil desalting					
19	Atmospheric distill.	(2)				
19	Vacuum distill.					
22	Visbreaking					
3	Solvent deasphalting					
13	Naphta HDS					
13	Kerosene HDS					
13	LGO HDS			Mode 1 feed = GO		
13	HGO HDS					
13	Res. hydroconversion (mild hydrocracking)	ARDS	GOFINER	Mode 2 feed = HVGO		
13	Hydrocracking					
14	Steam reforming					
	Hydrogen recup.	PSA				
5	Catalytic cracking	(2) Part. combust.				
	Naphta cracking	NC3				
	Cycle oil HDS					
6	Catalytic reforming	Continuou s	POWER-FORMER			
23	Sulfur Recovery Unit	(2) Scot				
	Aromatic plant					
2	Alkylation	HF	H2SO4			
16	Isomerisation					
11	Etherification (MTBE)					
4	Bitumen production					
3	Base oil production					
20	Merox	(2)				

Table 44should be handled with cautiousness. It illustrates a preliminary scheme of the different processes in the Belgian refineries. Petroplus (PRA) and Nynas belong together now. The numbers in the first column correspond to the numbers in Figure 20 where a general scheme of a complex refinery is given.

Figure 20: General scheme of a complex oil refinery, Source: IPPC BREF on Mineral Oil and Gas Refineries



DAO: Deasphalted oil **DEA:** Diethylamine **FCC:** fluid catalytic cracker **HC:** Hydrocracking **HDS:** Hydro desulphurisation **HGO:** Heavy gas oil **LGO:** Light gas oil **VGO:** Vacuum gas oil

C. Blend to quality specifications

Blending in oil refineries is similar to blending in other industries. In essence it is bringing together a number of components to meet a quality specification. In the model, the components are the pseudo-components. As each pseudo-component has constant qualities or properties, this gives rise to the typical quality constraints of LP models.

Some qualities, like sulphur content and specific gravity do blend linearly. A heavy fraction can be converted to a more worthy light fraction by using cracking processes. Consequently, mixing this cracked stream with the lighter fractions will raise the sulphur content of for example gasoline.

Other qualities do not blend linearly and for most of these, engineers have developed "linear blend indices" which transform the measured qualities into index values which can be constrained using ordinary linear constraints. A condition for using these indices is that the blending is on a volumetric basis. The model uses those indices for properties like octane and cetane number. Further nonlinearities can be simplified with other methods, like the "base-delta" method. In the model this is used to represent the utilities required for distillation.

Table 45 gives an example of the property restrictions of gas oil for transportation, which have been imported in the model so far. The cetane number of a fuel is related to the capacity of that fuel to self-ignite in a compression engine. The higher the number, the shorter the ignition time of the fuel.

Table 45: Property restrictions for gas oil

Specific gravity	≥ 0.820 kg/l
Specific gravity	≤ 0.845 kg/l
Sulphur content	< 50 ppm
Cetane number	> 51

6.4. Specific policy simulations

Besides that the refinery module can verify simplified modules, the refinery module can be used to answer different policy questions. Some of those evaluations need further work to make the module usable (E, F and G), other evaluations can be done with the techniques that are already in the model (A, B, C and D).

A. Examine the effect of a SO_2 bound:

What are the possibilities for the sector to reduce their SO_2 emissions at what cost ? A result is briefly discussed in annex, section 1.

B. Examine the effect of a CO2 bound:

What are the possibilities for the sector to reduce their greenhouse-gas emissions at what cost ?

C. Examine the effect of lower sulphur fuels:

Costs are being calculated for a refinery to meet the standard of minimum demand levels of for example Ultra Low Sulphur diesel (ULS).

D. Evaluating BAT for refineries:

The model can be used to evaluate the cost of implementing BAT for emissions to the air. A study has been preformed for a refinery in Haifa, Israel (confidential). The main advantage is that the model can calculate costs for meeting more than one environmental standards at a time. The methodology of the

Flemish Environmental Costing Model is used and was completed with information of the refinery module.

E. Compare the CO_2 in a Well-to-Wheel analysis:

How does the total CO_2-emissions evolves if there is a fuel shift in the demand. The discussion on differences between the use of gasoline and gas oil is at European level very important. This result might be useful for calibrating the CO_2-emission factors in a simplified refinery module.

F. Compare the cost of an increasing amount of biofuels to the reference case:

Increasing the amount of biofuels blended into final fuels does change the product balance of a refinery. What are the consequences for the costs of producing the fuels to meet the specifications with a new blending component?

G. Examine the possibilities of cogeneration units:

What are the possibilities to reduce the CO_2-emissions by extending the park of processes with cogeneration units ?

Contribution to policy analysis

7. CONSTRUCTION OF THE REFERENCE SCENARIO

Before describing the construction of the reference scenario, it is important to stress the role of this scenario for policy analysis with the TIMES model. The reference scenario has not as objective to give a forecast of the energy system. It gives a consistent path for the energy system, given the cost optimisation approach and the simplified representation of the energy users and suppliers behaviour in TIMES. It is the comparison basis for the policy scenarios, for the evaluation of the impact of policies on the technological choices in the energy system. The reference scenario can therefore deviates from the evolution of the energy system in recent years which reflects the behaviour of the economic agents in real life, their expectations and the dynamic adjustment of the energy system. It allows however a consistent treatment of the technologies in the policy evaluation.

7.1. Macroeconomic and Policy Assumptions

A. Macroeconomic assumptions

The construction of the reference scenario and the policy scenarios start with assumptions on the macroeconomic background and on the energy prices. The macroeconomic background for Belgium was derived with GEM-E3, a general equilibrium model for the EU countries. This gives the general growth assumed to be used for deriving the energy service demands in the reference scenario. These are obtained based on assumptions on the elasticity of the demand growth with the macroeconomic/sectoral evolution. The international energy prices are those used in the latest DGTREN projections[4]. After the sharp increase in 2005, the oil prices are returning to more average prices before gradually increasing after 2010, gas prices are evolving in parallel.

Table 46: Macroeconomic Assumptions for Belgium and international energy prices

	Unit	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Demographic/Economic Development											
Population	%/y		0.2%	0.2%	0.2%	0.2%	0.2%	0.1%	0.0%	-0.1%	-0.1%
GDP	%/y		2.1%	2.1%	2.1%	1.8%	1.8%	1.7%	1.5%	1.4%	1.3%
Private Consumption	%/y		1.8%	1.8%	1.8%	1.7%	1.6%	1.6%	1.5%	1.5%	1.4%
Industrial production (energy intensive)	%/y		2.4%	2.4%	2.4%	2.2%	2.3%	2.2%	2.0%	1.9%	1.6%
Other industrial production	%/y		2.0%	1.9%	1.9%	1.5%	1.4%	1.2%	1.1%	0.9%	0.7%
Transport activity	%/y		2.2%	2.1%	2.0%	1.6%	1.4%	1.2%	0.9%	0.7%	0.4%
Service sector production	%/y		2.0%	2.0%	2.1%	2.0%	1.9%	1.9%	1.9%	1.8%	1.7%
World Energy prices											
Import price crude oil	EUR_{00}/GJ	6.51	5.38	5.41	5.79	6.56	6.94	7.01	7.08	7.15	7.23
Import price natural gas	EUR_{00}/GJ	3.65	4.09	4.13	4.46	5.17	5.39	5.45	5.50	5.56	5.61
Import price coal	EUR_{00}/GJ	1.60	1.51	1.61	1.70	1.76	1.80	1.81	1.82	1.83	1.84

B. Policy and other assumptions

1) Policy assumptions

No profound changes regarding the Belgian economic, energy and environmental policies are assumed in the reference scenario. The nuclear phase-out is implemented. No climate policy is assumed. Policy

[4] http://ec.europa.eu/dgs/energy_transport/figures/trends_2030_update_2005/index_en.htm

measures like subsidies for energy efficient investment or similar measures implemented in the different regions are not explicitly accounted for. We assume that the perfect foresight/optimisation approach in TIMES already induces the impact of these measures, if they are cost-efficient. In the industry, this might not be the case because of the implementation of the EU permit system and of the impact of expectation on future climate policy. However when running the policy scenarios with carbon constraint, the impact of expectations and their cost will be taken into account if they are cost efficient because of the perfect foresight characteristic of the model.

2) Other assumptions

The discount rate is fixed to 4%, reflecting the public sector approach in the policy evaluation with TIMES.

The availabilities of the different renewables are those proposed by J. De Ruyck (2006) for the 'Commissie Energie 2030' (De Ruyck J., 2006). It is assumed that 10% of the arable land in Belgium can be used for the production of biocrops, such as wheat or rapeseed and 30% of the forest for the production of wood. Both types of biomass are also available from imports. A limit is imposed on their imports though Belgium as a small country could benefit from an infinite supply. Moreover, the supply is assumed to be available at an increasing cost by considering two steps.

For wind energy, the cost of the grid expansion needed for the implementation of the full potential of offshore is included in the cost of the power plants[5]. Data is checked with (Palmers G. et al., 2004), (Palmers G. et al., 2004) and (Devriendt N. et al., 2005).

The table hereafter summarizes the potentials assumed for the different sources.

Table 47: Potential for energy sources

		Domestic	Import
Biomass (PJ)	Woodresidue	10.8	
	Wood	22.7	25-83
	Biocrops (wheat & rapeseed)	16.5	25-83 for each crop
Wind (GW)	Onshore cat1	0.63	
	Onshore cat2	0.92	
	Onshore cat3	0.47	
	Offshore cat1	0.60	
	Offshore cat2	0.30	
	Offshore cat3	1.800	
Solar (GW, GWth)	PV	10	
	Hot water	3	

The possibility of carbon storage is also considered, with a maximum potential of 100 Mt at a distance less than 20km and 1000 Mt further. This potential is in Belgium (Laenen B. et al., 2004). The 100 Mt can be preformed with high certainty in Belgium; 1000 Mt is uncertain (although, if not in Belgium, this could represent foreign sinks).

The impact of the opening of the electricity market is also not taken into account, the model TIMES being at this stage a 'one country' model. Export and import of electricity have been fixed at their 2000 level.

7.2. Energy services demand

The macroeconomic evolution as given in the previous section is used to derive a consistent trend in the demands for energy services (tons of steel, km driven, etc..) from the different consumption

[5] As TIMES is not a mixed integer program, the cost is included as a cost per kw installed; therefore the cost computation is only correct if the full potential is installed in one time when this option is used. (rem. this is usually the case).

sectors. The sectoral activity levels and the growth in housing stock and private income (reflected in private consumption evolution) are the main determinants for the evolution in the demand for energy services in our reference scenario. The heat demand of the baseyear is corrected for temperature (2000 was a warm year) to compute the demand projections. They correspond therefore to an average temperature. The drivers' evolutions are combined with assumptions on the elasticities relating the energy service demand or the product demand to the activity of the sector or the disposable income. The trend obtained determines the shift of the demand curves for these services in MARKAL/TIMES over the horizon considered. The demands are exogenous in the reference scenario but can change in the policy scenarios in function of price changes. Table 48 summarises the main demand growth.

Table 48: Energy service demand (annual growth rate)

	2010/2005	2020/2010	2030/2020	2040/2030	2050/2040
Iron&Steel	0.7%	0.5%	0.0%	1.0%	0.8%
Ammonia	2.0%	1.7%	1.2%	0.9%	0.5%
Chlorine	2.0%	1.7%	1.2%	0.9%	0.5%
Cement	1.7%	1.6%	1.4%	1.2%	1.0%
Glass	1.8%	1.8%	1.6%	1.4%	1.1%
Lime	1.7%	1.6%	1.4%	1.2%	1.0%
Paper	1.3%	1.3%	1.1%	0.9%	0.6%
Other Industry	1.5%	1.3%	0.8%	0.5%	0.0%
Commercial heating/hotwater	1.0%	0.8%	0.5%	0.6%	0.5%
Commercial other	1.3%	1.2%	1.1%	1.1%	1.1%
Residential heating/hot water	0.2%	0.1%	0.0%	0.0%	-0.1%
Residential other	0.7%	0.6%	0.4%	0.4%	0.4%
Agriculture	1.7%	1.0%	0.4%	0.5%	0.4%
Bus transport	0.2%	0.2%	0.2%	0.0%	-0.1%
Car transport	1.8%	1.5%	1.3%	1.3%	1.2%
Train passenger	0.2%	0.2%	0.2%	0.0%	-0.1%
Road freight transport	2.1%	1.9%	1.3%	1.1%	0.7%
Train freight	2.3%	2.1%	1.5%	1.2%	0.7%
Air & water transport	2.9%	2.5%	1.6%	1.3%	0.8%

The economic sectors demands are following the evolution of the economic activity though at a lower pace. The residential sector demand and more specifically the heating and hot water demand grows less because the population evolution and the gradually disappearance of the oldest and less energy efficient dwellings.

7.3. Energy use and energy production in the reference scenario in Belgium

Given the demand for energy services computed with the trends above and the base year (2000) demand, MARKAL/TIMES optimize the choice by energy users of energy processes, energy efficiency, of fuel, as well as the choice of energy production processes by the energy sector. The choice is based on the information on the present and future availability of energy technologies, their costs and performance at the level of the energy user and at the level of the energy producer. It is clear therefore that the energy path as derived from this optimisation process, takes into account all the no-regret options and might therefore slightly underestimate the growth of energy. Other criteria besides cost minimisation are driving consumer behaviour and are not reflected in this reference. Expectations on the implementation of a carbon policy which might induce investment in less CO2 intensive technologies are also not taken into account[6].

[6] When implementing a Kyoto constraint, CO2 savings options in the industrial sector are already implemented in the first period (2000-2005) reflecting the expectations in that sectors.

The final energy demand increases around 0.5% over the time horizon. The growth is highest in the industry and the transport sector. A gradual improvement in the insulation of buildings contributes to a decrease in the demand of energy for heating. The electricity demand increases more than the fuel demand except for oil products which demand are driven by the increase in transport. The coal consumption remains rather high in the absence of any carbon constraint.

Table 49: Final Energy Consumption in the reference scenario (PJ)

	2005	2010	2020	2030	2040	2050	2050/ 2005	share in 2005	share in 2050
by fuel									
Coal	336	364	412	446	472	488	1.1%	20.5%	23.6%
Petroleum products	729	760	806	858	908	934	0.7%	44.4%	45.4%
Gas	259	257	234	231	236	249	-0.5%	15.8%	12.3%
Electricity	281	289	305	318	342	363	0.5%	17.1%	16.9%
Heat	0	0	0	0	0	0			
Bio	29	26	21	21	21	21	-1.3%	1.7%	1.1%
Waste	8	8	12	13	15	16	1.9%	0.5%	0.7%
Total	1642	1704	1790	1888	1993	2071			
by sector									
Industry	637	681	760	817	874	909	1.0%	38.8%	43.3%
Commercial	175	183	177	172	168	171	-0.1%	10.6%	9.1%
Residential	391	372	342	329	324	320	-0.7%	23.8%	17.4%
Transport	411	436	476	533	588	632	1.0%	25.0%	28.2%
Agriculture	29	32	35	37	38	40	0.9%	1.8%	1.9%
Total	1642	1704	1790	1888	1993	2071			

In terms of primary energy, the average growth follows the final energy demand growth. There is a shift to solids when coal powerplants replace the nuclear power plants. Oil products keep a relatively high share because they remain the dominant fuel in the transport sector. Renewable energy does not penetrate given the energy price assumptions.

Table 50: Primary Energy Consumption in the reference scenario (PJ)

	2005	2010	2020	2030	2040	2050
Coal	477	539	836	1159	1227	1281
Oil	1266	1331	1443	1544	1634	1681
Natural gas	390	377	267	263	267	278
Nuclear	505	505	350	0	0	0
Hydro, wind, photovoltaic	3	3	3	3	3	3
Other renewables	29	26	21	20	21	21
Waste	11	14	21	21	23	24
Total	2680	2794	2941	3010	3174	3288

After the nuclear phase-out, coal becomes the dominant fuel for electricity generation, in the absence of any carbon constraint. There is no further penetration of cogeneration in this scenario.

Table 51: Net electricity generation in the reference scenario (TWh)

	2005	2010	2020	2030	2040	2050
Coal	15.1	19.2	51.0	86.8	93.7	99.5
Oil	0.0	0.0	0.0	0.0	0.0	0.0
Gas	15.3	13.3	0.2	0.0	0.0	0.0
Nuclear	46.9	46.9	32.4	0.0	0.0	0.0
Hydro	0.7	0.7	0.7	0.7	0.7	0.7
Wind	0.0	0.0	0.0	0.0	0.0	0.0
Solar photovoltaic	0.0	0.0	0.0	0.0	0.0	0.0
Others	0.9	1.1	1.5	2.0	2.2	2.3
Total	78.9	81.1	85.8	89.5	96.6	102.5
of which CHP	2.0	1.7	1.4	2.0	2.2	2.3

The evolution in the primary energy consumption induces an increase in the CO2 emissions linked to energy. They are in 2010 24% above the level of 1990 and continue to increase thereafter, especially after 2025 when coal power plants should replace the nuclear power plants. Belgium would therefore have to reduce its CO2 emissions with 34% in 2010 compared to the reference in 2010 to reach its Kyoto target. Industry and transport remain the biggest emitters in the first periods but the electricity sector becomes an important polluter when new coal power plants are installed.

Table 52: CO2 emissions in the reference scenario (Mio.ton)

	2005	2010	2020	2030	2050	share 2005	share 2010	share 2030	share 2050
Industry	43	48	57	64	71	34%	36%	32%	32%
Hous, Com & Agr	30	29	28	27	24	24%	22%	13%	11%
Transport	29	31	33	37	44	23%	23%	19%	20%
Electricity	20	23	41	69	76	16%	17%	34%	34%
Other supply	4	5	5	5	5	3%	3%	2%	2%
Total emissions	127	135	164	201	221	100%	100%	100%	100%

8. THE POLICY SCENARIOS

8.1. The definition of the CO2 reduction scenarios

Two CO2 reduction targets were evaluated with TIMES, implying for 2030 a reduction of 15% and 30% respectively and for 2050 a reduction of 22.5% and 52.5% compared to the 1990 emissions. The Belgian Kyoto target and the nuclear phase-out are imposed in both scenarios. Only CO2 emissions are considered as the other GHG are not yet modelled and the energy system only is responsible for a small part of the other GHG.

Table 53: CO2 Targets in the scenarios (emission reduction/1990)

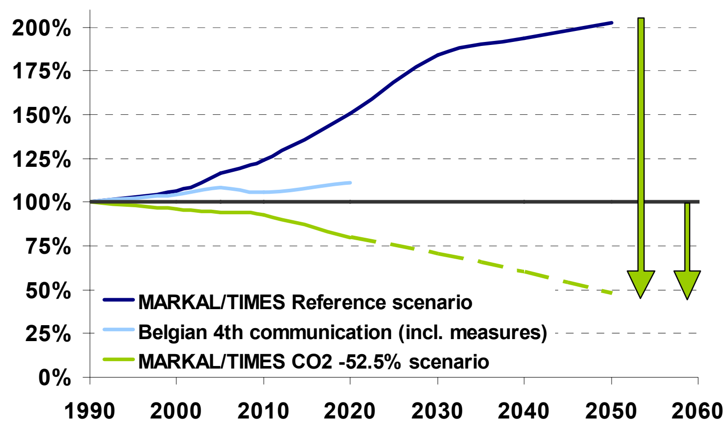
	2010	2030	2050
KYOTO+	-7.5%	-15.0%	-22.5%
KYOTO++	-7.5%	-30.0%	-52.5%

Two variants for the more stringent CO2 reduction are also considered:

- allowing a nuclear powerplant of a capacity of 1700GW
- not allowing carbon storage

These scenarios do not consider the possibility of using any of the flexibility mechanisms foreseen in the Kyoto protocol[7]. Though the second scenario imposes a very high reduction target, it is in the range of reduction targets allowing reaching a 450ppm concentration and limiting the temperature increase below 2° in the long run. The assumption that the reduction must be done in Belgium increases the stringency of the constraint.

Figure 21: Belgian CO2 emissions in MARKAL/TIMES, compared to 1990



The scenarios are:

1. CO2-be-step1: -15% in 2030 and -22.5% in 2050
2. CO2-be-step2: -30% in 2030 and -52.5% in 2050
3. CO2-be-step2withnuc: -30% in 2030, -52.5% in 2050 with nuclear
4. CO2-be-step2withoutstorag: -30% in 2030, -52.5% in 2050 without carbon storage

[7] The less stringent scenario could also represent a more stringent case but with the use of flexible mechanism, the cost of buying the permits has then to be added.

8.2. The results

A. General

The impact of the CO2 reductions is threefold:

- a decrease in the demand for energy services because of the price increase induced by the carbon constraint
- a shift towards less carbon intensive fuels, initially from coal to gas and afterwards towards more renewables and hydrogen
- a shift towards more energy efficient technologies.

The overall welfare cost increases with the stringency of the target. Allowing the nuclear option reduces the cost of the -30% target to the level of the cost of the -15% target without nuclear. Carbon storage limits the cost increase of higher target when nuclear is not available. The more stringent scenario without nuclear and without carbon storage would cost annually approx. 2.7% of GDP, while in case of a less stringent constraint, it represent only 0.8% of GDP.

This cost is the cost on the market of energy services. It does not take into account possible side benefits through the reduction of other external cost linked to energy use. Neither does it include the derived effects on other markets. This depends on the policy instrument used[8].

Table 54: Total discounted welfare cost (incl. consumer/producer surplus loss)

	%DIF	%GDP2000	Annualised %GDP2000
CO2-BE-step1-2050	2.6%	17.3%	0.77%
CO2-BE-step2-2050	4.3%	29.9%	1.34%
CO2-BE-step2withnuc-2050	3.1%	22.9%	1.03%
CO2-BE-step2withoutstor-2050	8.5%	60.2%	2.69%

This cost increase is also reflected in the marginal abatement cost of CO2, i.e. the shadow price of the CO2 constraint. The marginal cost gives the level of CO2 tax that would have to be imposed to arrive at this result, i.e. the adoption of the technological options which can satisfy the energy needs in the most cost efficient way given the carbon constraint.

Table 55: Marginal abatement cost of CO2 (€/ton)

	2010	2020	2030	2040	2050
CO2-BE-step1-2050	37	55	83	105	113
CO2-BE-step2-2050	35	85	167	214	327
CO2-BE-step2withnuc-2050	38	57	131	138	208
CO2-BE-step2withoutstor-2050	33	159	372	723	2549

B. Energy service demand

The demand function for energy services, linking the demand to the price is a short cut to represent all substitution and behavioural reactions outside the energy use and production sector. Every policy scenario that affects the energy sector will alter the marginal cost of energy services and this will affect the level of demand for energy services.

[8] Cf. double dividend literature.

The impact on the demand increases with the stringency of the carbon constraint, especially when carbon storage is excluded. The reductions are more limited where the abatement possibilities through change in technologies or fuel substitution are large. Reduction in demand remains however an important contribution to CO2 reductions. It can cover various options such as the substitution of energy by another good, a better overall organisation in the industry and the service sector or a loss in comfort, a change in life style, construction norms or urban planning. The high increase in the energy cost can make the tracking of energy savings a high priority.

Table 56: Energy service demand in 2030 and 2050 (% difference compared to reference)

	2030				**2050**			
	CO2-BE-step1-2050	CO2-BE-step2-2050	CO2-BE-step2with nuc-2050	CO2-BE-step2with outstor-2050	CO2-BE-step1-2050	CO2-BE-step2-2050	CO2-BE-step2with nuc-2050	CO2-BE-step2with outstor-2050
Iron&Steel	-0.2%	-0.2%	-0.2%	-0.2%	-24%	-26%	-26%	-26%
Ammonia	-13%	-20%	-15%	-35%	-15%	-28%	-20%	-50%
Chlorine	-3%	-5%	-3%	-12%	-2%	-5%	-2%	-27%
Cement	-3%	-7%	-3%	-25%	-14%	-19%	-16%	-44%
Glass	-5%	-10%	-8%	-20%	-10%	-19%	-15%	-44%
Lime	-27%	-37%	-33%	-47%	-35%	-50%	-45%	-50%
Paper	-5%	-8%	-8%	-15%	-7%	-15%	-10%	-37%
Other Industry	-21%	-29%	-26%	-40%	-25%	-40%	-33%	-50%
Commercial heating/hotwater	-6%	-11%	-10%	-20%	-10%	-15%	-11%	-40%
Commercial other	-1%	-1%	-1%	-5%	-1%	-2%	-1%	-11%
Residential heating/hot water	-10%	-15%	-14%	-24%	-13%	-20%	-16%	-42%
Residential other	-4%	-6%	-4%	-14%	-4%	-9%	-6%	-31%
Agriculture	-13%	-20%	-18%	-33%	-17%	-32%	-25%	-50%
Car transport	-2%	-2%	-2%	-7%	-2%	-7%	-5%	-22%
Bus transport	-3%	-3%	-3%	-7%	-3%	-6%	-4%	-22%
Train passenger	-2%	-2%	-2%	-5%	-2%	-2%	-2%	-16%
Road freight transport	-5%	-7%	-6%	-15%	-7%	-15%	-13%	-40%
Train freight	0%	0%	0%	-3%	0%	-2%	0%	-13%
Air & water transport	-10%	-17%	-15%	-27%	-15%	-30%	-25%	-50%

C. Final energy consumption

There is a shift away from coal, which is replaced by gas and in a lesser proportion by electricity and renewables. When nuclear and carbon storage is allowed the shift to electricity is far more pronounced and the reverse is true when no carbon storage is possible. Without carbon storage, other options are becoming cost efficient because the higher price of electricity. The change in the cost of electricity is driving some of the technological options chosen. At the beginning of the period the main reductions are in the industry but at the end of the horizon higher reduction are observed in the residential sector and also in the transport sector.

Table 57: Final energy consumption
(abs difference compared to reference in PJ)

	CO2-be-step1-2050			CO2-be-step2-2050			CO2-be-step2withnuc-2050			CO2-be-step2withoutstor-2050		
	2010	2030	2050	2010	2030	2050	2010	2030	2050	2010	2030	2050
by fuel												
Coal	-162	-315	-416	-161	-367	-423	-168	-362	-420	-153	-390	-471
Petroleum products	-45	-251	-327	-55	-297	-683	-45	-277	-598	-66	-547	-807
Gas	41	213	183	38	116	-20	37	143	-17	34	62	-104
Electricity	-14	2	9	-13	19	36	-14	24	88	-12	-17	-86
Renewables (wind, hydro, sol)	0	3	6	0	4	5	0	4	5	0	4	4
Bio	72	97	76	71	94	186	71	83	125	71	169	232
Waste	-1	-4	-6	1	-4	-16	0	-4	-16	0	-13	-16
Total	-109	-255	-440	-166	-436	-771	-119	-390	-691	-127	-733	-1248
by sector	0	0	0	0	0	0	0	0	0	0	0	0
Industry	-46	-139	-255	-49	-213	-352	-56	-194	-318	-53	-304	-486
Commercial	-32	-41	-42	-35	-59	-58	-32	-57	-54	-36	-72	-85
Residential	-20	-44	-69	-24	-116	-167	-19	-98	-144	-28	-159	-227
Transport	-9	-27	-68	-7	-42	-182	-9	-35	-165	-7	-194	-430
Agriculture	-2	-5	-7	-2	-7	-13	-2	-6	-10	-2	-5	-20
Total	-109	-255	-440	-118	-436	-771	-119	-390	-691	-127	-733	-1248

The chosen technological options in the different sectors are the following.

1) Residential sector

Oil still remains the dominant fuel for heating till the middle of the horizon, after that gas boiler and heat pump on electricity and gas and delivering heat and hot water, are penetrating and the shift occurs faster when the carbon constraint increases. However, when the electricity price increases more, as in the scenario without carbon storage, the penetration is slower. For hot water, gas is the dominant fuel, but solar hot water combined with gas takes a small share of the market with the high carbon constraint and no carbon storage.

The contribution of insulation is very limited in both sectors as nearly the whole potential was cost efficient in the reference. Savings lamps were also cost-efficient in the reference scenario.

2) Service sector

Heat pumps of different types (absorption heat pump on gas and electricity and ground heat pump) are penetrating fast for heating. For the rest the evolution is rather similar as the one in the residential sector.

3) Industry

There is a gradual shift to the more energy efficient technologies and towards less CO2 intensive fuels when the substitution is possible as for steam and heat production. CHP are not really penetrating except for the CHP on wood; it must be the most cost efficient application of wood for its contribution to the carbon constraint.

4) Transport

There is no shift in the transport before the highest carbon constraint (-52.5% in 2050). Then ethanol and biodiesel are penetrating from 2030 onwards as alternative fuels till the full potential of import and domestic production of biocrops is used. The possibility of mixing bio fuels with traditional fuels is implemented, but the model chooses pure bio fuels vehicles because the efficiency is higher. After 2040, when nuclear and carbon storage are available, hydrogen is penetrating produced first through natural gas reformer and at the end of the horizon through electrolyse. Hybrid cars are only penetrating in the scenario without carbon storage, when hydrogen is less cost efficient and the potential of biocrops is fully used.

The results show that bio fuels and hydrogen are two important options when high carbon constraints are imposed and they are, with the data in the model, rather close in terms of costs. It is therefore important to make sensitivity studies around their relative cost and the potential of biocrops to be able to identify the more promising technological stream. Also the assumptions for the electricity sector play an important role in their respective penetration.

D. Electricity generation

The impact of the carbon constraint is a switch to gas and an increase in electricity demand except in the scenario without carbon storage. It the last case, the increase in the price of electricity is too high to allow for this switch. When nuclear is allowed, the full allowed capacity is implemented and the demand for electricity increases. The carbon sequestration is linked to gas powerplant. Though the cost of sequestration per ton of CO2 is lower when linked to a coal powerplant, the final cost per kWh (including the penalization of CO2 and sequestration cost) remains lower with gas powerplant and this is the relevant variable for the choice of sequestration option. This result depends however on the relative cost of gas. If the gas price would increase, this relative advantage of carbon sequestration associated with gas is reduced.

The availability of nuclear and carbon storage have a clear impact on the electricity price and hence on the electricity demand. The full potential for wind energy is only used in the most extreme cases.

Table 58: Net Electricity generation
(abs. differences compared to reference in TWh)

	CO2-be-step1-2050			CO2-be-step2-2050			CO2-be-step2withnuc-2050			CO2-be-step2withoutstor-2050		
	2010	2030	2050	2010	2030	2050	2010	2030	2050	2010	2030	2050
Coal	-17.4	-86.8	-99.5	-17.3	-86.8	-99.5	-17.3	-86.8	-99.5	-17.3	-86.8	-99.5
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	5.8	77.1	91.1	6.1	80.5	115.0	5.7	25.6	121.8	6.4	50.8	48.1
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	57.9	57.9	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	1.5	3.1	3.1	1.5	5.0	15.7	1.5	3.1	5.0	1.5	15.7	13.6
Solar photovoltaic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4	7.3
Others	5.5	7.3	8.8	5.5	6.8	6.9	5.4	7.0	3.3	5.4	6.6	5.2
Total	-4.5	0.7	3.6	-4.2	5.6	38.1	-4.7	6.8	88.6	-4.0	-7.3	-25.3
of which CHP	9.0	9.1	5.1	8.1	6.2	2.3	6.9	5.9	-1.7	7.3	6.6	5.2

E. Primary energy

The different options chosen in the energy system are reflected in the impact on the primary energy consumption. The carbon constraints reduce the primary energy consumption of coal; it is replaced by natural gas or nuclear when it is allowed. Renewables are penetrating further but only to their full potential when high carbon constraint are imposed without carbon storage.

Table 59: Primary Energy
(abs. differences compared to reference in PJ)

	CO2-be-step1-2050			CO2-be-step2-2050			CO2-be-step2withnuc-2050			CO2-be-step2withoutstor-2050		
	2010	2030	2050	2010	2030	2050	2010	2030	2050	2010	2030	2050
Coal	-324	-1021	-1199	-324	-1070	-1206	-331	-1066	-1202	-316	-1078	-1263
Oil	-45	-251	-327	-53	-296	-678	-45	-277	-595	-66	-544	-802
Natural gas	58	702	805	62	641	835	67	317	762	66	467	324
Nuclear	0	0	0	0	0	0	0	590	590	0	0	0
Hydro, wind, photovoltaic	5	14	17	5	22	61	5	15	23	5	84	80
Other renewables	73	100	121	73	117	354	73	100	246	73	254	354
Waste	-3	-8	-8	-2	-8	-8	-3	-8	-8	-3	-8	-8
Total	-236	-464	-590	-238	-594	-641	-233	-329	-184	-241	-825	-1317

F. CO2 emissions

The main contributors to the CO2 emission reduction are first the power sector and the industry and then the other sectors when the constraints are becoming more stringent. The contribution of transport remains limited and becomes only significant at the end of the horizon with the -52.5% constraint. Storage of carbon penetrates after 2020 and uses its full potential in the -52.5% scenario. Nearly all emissions coming from fuel combustion in the power sector are stored. This raises the question about the very long term potential of this option.

Table 60: Yearly CO_2 emissions
(abs. in Mio.t and % difference compared to reference)

	CO2-be-step1-2050			CO2-be-step2-2050			CO2-be-step2withnuc-2050			CO2-be-step2withoutstor-2050		
absdif	2010	2030	2050	2010	2030	2050	2010	2030	2050	2010	2030	2050
Industry	-14	-32	-45	-14	-40	-51	-15	-39	-51	-14	-40	-56
Hous, Com & Agr	-4	-9	-11	-4	-16	-20	-4	-15	-19	-5	-19	-22
Transport	-1	-2	-7	-1	-4	-31	-1	-2	-26	-1	-13	-30
Electricity	-15	-65	-76	-14	-66	-76	-14	-69	-76	-14	-53	-62
Other supply	0	1	4	0	1	9	0	0	3	0	0	1
Total emissions	-33	-108	-136	-33	-124	-169	-33	-124	-169	-33	-124	-169
Storage	0	28	39	0	32	46	0	16	49	0	0	0
%dif												
Industry	-29%	-50%	-63%	-29%	-62%	-71%	-31%	-60%	-71%	-29%	-63%	-78%
Hous, Com & Agr	-12%	-35%	-46%	-14%	-60%	-82%	-12%	-55%	-76%	-16%	-70%	-90%
Transport	-2%	-5%	-16%	-2%	-9%	-70%	-2%	-7%	-58%	-2%	-35%	-68%
Electricity	-65%	-95%	-100%	-63%	-96%	-100%	-62%	-100%	-100%	-62%	-77%	-81%
Other supply	-4%	21%	77%	-5%	20%	189%	-5%	3%	51%	-5%	5%	14%
Total emissions	-25%	-53%	-61%	-25%	-62%	-76%	-25%	-62%	-76%	-25%	-62%	-76%

8.3. Renewables Scenarios

A. Definition of the Scenarios

In addition to the CO2 reduction scenario's, two renewable scenario's have been elaborated with the same database in Belgium:

1. RENELE_BE_2050 is a scenario without CO_2 constraint, but a constraint on the use of renewable energy technologies for electricity production. The model is tuned with a constraint

that fixes the share of the so called **green electricity** in the total electricity production to the share in scenario CO2_BE_STEP1.

$PROD\_ELE_{green}$ /$PROD\_ELE_{total}$ is comparable to the share in CO2_BE_STEP1.

2. RENPRIM_BE_2050 is a scenario without CO_2 constraint, but a constraint on the use of renewable energy technologies for the whole energy system. The model is tuned with a constraint that fixes the share of the **green primary energy** in the total primary energy use to the share in scenario CO2_BE_STEP1.

   $PRIM\_ENERGY_{green}$/$PRIM\_ENERGY_{total}$ is comparable to the share in CO2_BE_STEP1.

B. Results

Two main conclusions can be drawn (see Table 61). A constraint only on renewable electricity or primary energy clearly does not reduce as much CO_2 as in the CO2-reduction scenario where a 22.5% reduction is imposed. In the renewable electricity scenario, the share of green electricity production is respectively 9 % and 11.5% in 2030 and 2050. The reduction of CO_2 is 12 -16 Mton. In the renewable primary energy scenario, the share of green primary energy is respectively 4.6 and 6.0 % in 2030 and 2050. The CO2 reduction is 23 – 27 Mton.

Moreover, these renewable targets induce a choice of technologies different from the one in the CO_2 reduction scenario. The choice is maybe more efficient in terms of renewable target but not in terms of CO_2 target. The target imposed on the production of electricity or on the primary energy has only an indirect effect on the CO_2 emissions. The model replaces for example the more expensive gas power plants by the renewable electricity technologies. This is in contrast with the CO_2 scenarios where coal technologies are replaced.

Table 61: Renewables target Scenarios

	2030			2050		
Scenario	Share REN elc	Share REN prim	CO2emissions	Share REN elc	Share REN prim	CO2emissions
			Mt			Mt
Reference			202			221
CO2-BE-step1-2050	9.7%	4.5%	94	9.6%	5.1%	86
RENELE-BE-2050	9.0%	3.0%	190	11.5%	3.4%	205
RENPRIM-BE-2050	11.5%	4.6%	179	13.6%	6.0%	194

8.4. Conclusion

The scenarios analysed above show that it is possible to attain very stringent CO2 reductions in Belgium. The welfare cost remains rather limited in the case of a -22.5% reduction in 2050 compared to 1990, 0.8% of GDP on annual base but it can become rather expensive when further reductions are imposed and neither nuclear nor carbon storage are available, 2.7% of GDP on annual base. These costs are the cost within the energy system without considering any potential side benefits and assuming a CO2 tax or a permit system as policy instrument for achieving the CO2 reduction target.

The CO2 constraints do not impose major shifts in the energy system in the middle term. The use of more energy efficient technologies and a switch to gas are predominant. It should be mentioned that building insulation and saving lamps are already cost efficient in the reference scenario and because of the many barriers to their use in real life, it is important to address this issue by specific policies. Renewables such as wood and wind on shore are also penetrating rapidly.

In the long term, alternative fuels such as ethanol, biodiesel and hydrogen are penetrating in the transport sector, offering further reduction possibilities. Their relative cost seems to be rather close and therefore the choice between these different options is very sensitive to the potential of biomass production, the cost of biocrops and of electricity.

Also, in other sectors, the choice of technological options is dependant on the options in the electricity sectors and the relative price of electricity when high reduction target are imposed. This stresses the importance of evaluating reduction potentials with a model such as TIMES, which integrates the whole energy system.

A major contribution is also obtained from a reduction in the energy service demand. This reduction can cover a great number of changes outside the energy system: new production system, change in life style, in urban planning, ….

Focussing on specific renewables target can contribute to the CO2 target but the technological choices might not be optimal regarding this last target and not induce R&D in the most appropriate direction. The results from those scenarios show the importance of using a model covering the whole energy system with sector specific technologies to correctly evaluate the trade-off between the options given the overall CO2 target.

These different conclusions are clearly dependent on the cost and assumptions implemented in the model database and in the scenarios. Therefore this analysis should be complemented by sensitivity studies around the main parameters. Also, though the cost of implementing a complete infrastructure for the penetration of some option is integrated in annualised term in the cost of these options, large resources will have to be mobilised over a rather short period to invest in these infrastructure.

One should also keep in mind the characteristics and limitations inherent to a model as MARKAL/TIMES. The strongest point of the model is its consistency in treating technology related problems in the energy-environment domain. It gives good and consistent first insights for energy policy formulation and guidelines for technology policy but should be supplemented by complementary studies in both fields. A major difficulty in the direct use of the TIMES model results for specific policy formulation comes from the naive representation of energy users and suppliers in the model. It is assumed that all market participants use the same objective function (cost minimisation with imputed shadow costs for the active environmental constraints), that they have the same information and the same subjective beliefs (perfect foresight solution) and finally that the market prices equal the discounted marginal costs corrected for imputed shadow prices. The model has also limitations due to its structure: no explicit uncertainty, convex cost functions (no increasing returns to scale) and linear technologies, limited geographical scope (internal energy market), and aggregation of activities

Annexes

1. MARGINAL COST CURVE FOR SO_2 IN A REFINERY

A cost curve for reducing SO2 in a refinery has been derived with MARKAL/ANSWER. The result gives a good view on the increasing marginal reduction cost, but it is only applicable to the situation of 2000. Figure 22 is the marginal abatement cost (MAC) curve for a refinery in the year 2000. The two curves are both model results: one is by applying a bound, the other is by opposing a tax. The results are almost identical. The model chooses for changing the processes as cracking lighter fuels, changing the sulphur recovery units and also importing another crude mix. Other reduction possibilities are not chosen because they are too expensive or because they are simply not in the model. When end of pipe techniques are added into the model, the MAC would be lower. Figure 23 presents the total reduction cost of the corresponding reduction.

Figure 22: Marginal Abatement Cost curve for SO_2 in a refinery

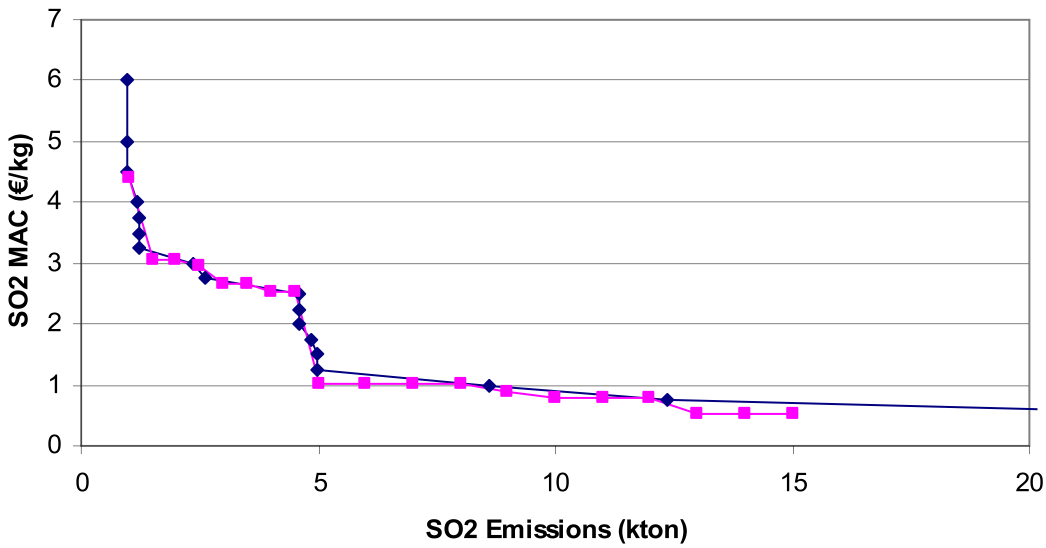
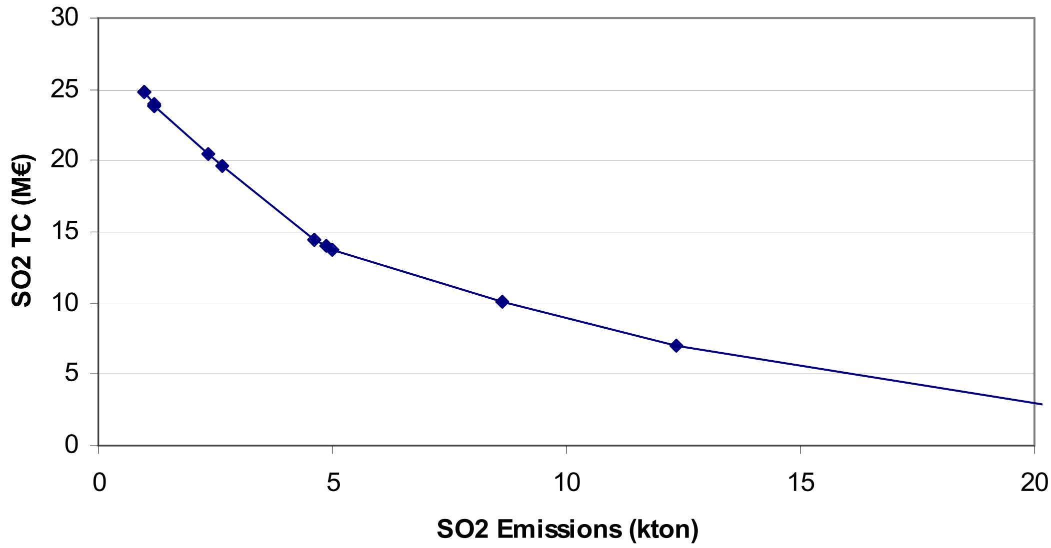


Figure 23: Total cost of reducing SO_2 in a refinery



2. THE NOMENCLATURE OF THE MODEL

This last section describes the nomenclature for the demand categories and demand materials, the fuels and the emissions. The units are given at the end of this section.

2.1. The nomenclature for the demand categories;

The codes for the energy uses in the non energy intensive industrial sector are built by adding to the code of the demand category the code of the energy enduse (S/P/M/E/O/F).

Table 62: Nomenclature for demand categories

Name	Code	Units
Industry		
Iron and steel	IIS	Mega tonnes
Non Ferrous metals: copper	ICU	Mega tonnes
Non ferrous metals: Other	INF	PJ
Chemicals: Ammonia	IAM	Mega tonnes
Chemicals: Chlorine	ICL	Mega tonnes
Chemicals: Other	ICH	PJ
Pulp and paper	IPP	Mega tonnes
Non metal minerals: Cement	ICM	Mega tonnes
Non metal minerals: Glass flat	IGF	Mega tonnes
Non metal minerals: Glass hollow	IGH	Mega tonnes
Non metal minerals: Lime	ILM	Mega tonnes
Non metal minerals: Other	INM	PJ
Other industries: Transport Equipment, Machinery, Mining and Quarrying, Food and Tobacco, Wood and Wood Products, Construction, Textile and Leather	IOI	PJ
End use category for industries modelled this way		
Steam	IOISTM	PJ
Process heat	IOIPRC	PJ
Machine drive	IOIMCH	PJ
Electro-chemical	IOIELE	PJ
Other	IOIOTH	PJ
Other segments		
Non Energy Uses in the Chemical sector	NEC	PJ
Other Non Energy Uses	NEO	PJ
Transportation sector		
Cars short distance	TCS	10E9 passenger-kms
Cars long distance	TCL	10E9 passenger-kms
Motos/other	TMO	10E9 passenger-kms
Buses, Urban	TBU	10E9 passenger-kms
Buses, Intercity	TBI	10E9 passenger-kms
Road freight	TFR	10E9 ton-kms
Aviation	TAV	PJ
Rail Freight	TRF	10E9 tonne-km
Rail Passengers Light	TRL	10E9 passenger-kms
Rail Passengers Heavy	TRH	10E9 passenger-kms
Navigation	TNA	PJ

Name	Code	Units
Residential sector		
Space heating (six building categories: existing/new x multi/singleurban/singlerural)	RHRE, RHUE, RHME, RHRN, RHUN, RHMN	PJ
Water heating (six building categories: old/new x multi/singleurban/singlerural)	RWRE, RWUE, RWME, RWRN, RWUE, RWMN	PJ
Cooking	RCOK	PJ
Electric Appliances	ROEL	PJ
Lighting	RLIG	PJ
Commercial sector		
Space heating (two building categories: large/small)	CHS, CHL,	PJ
Water heating (two building categories: large/small)	CWS, CWL,	PJ
Space Cooling (two building categories: small/large)	CCS, CCL	PJ
Cooking	CCOK	PJ
Electric Appliances	COEL	PJ
Lighting	CLIG	PJ
Public lighting	CPLI	PJ
Agriculture		
Agriculture useful energy demand	AGR	PJ

2.2. The nomenclature for the fuels

Table 63: Nomenclature for the fuels

FUEL in EUROSTAT	FUEL in TIMES	MIN/ POT	PRIM.	SEC.	ELC/ HET	SUP	TRA	AGR	RSD	COM	IND
COAL											
Coal	Hard Coal	COHRSV	COAHAR	COAHAR	ELCCOH	SUPCOA		AGRCOA	RSDCOA	COMCOA	INDCOA
Patent fuels	Hard Coal	COHRSV	COAHAR	COAHAR	ELCCOH	SUPCOA		AGRCOA	RSDCOA	COMCOA	INDCOA
Total Lignite	Black Lignite Peat	COLRSV	COALIG COAPEA		ELCCOL ELCCOP	SUPCOA		AGRCOA	RSDCOA	COMCOA	INDCOL
Brown coal briquettes	Brown Coal			COABRO	ELCCOL				RSDCOA	COMCOA	INDCOB
Coke	Coke			COACOK		SUPCOA		AGRCOA			INDCOK
OIL											
Crude oil	Crude oil	OILRSV	OILCRD			SUPCRD					
Feedstock (for refinery)	Feedstock (for refinery)			OILFDS							
Refinery gas	Refinery gas			OILRFG	ELCRFG	SUPRPG					INDRFG
LPG	Light Petroleum Gas			OILLPG		SUPRPG	TRALPG	AGRLPG	RSDLPG	COMLPG	INDLPG
Gasoline	Gasoline			OILGSL		SUPRPP	TRAGSL	AGROIL	RSDOIL	COMOIL	INDLFO
Kerosene and jetfuel	Kerosene			OILKER			TRAKER		RSDOIL	COMOIL	INDLFO
Naphtha	Naphtha			OILNAP		SUPRPP					INDNAP
Gas/Diesel oil	Diesel			OILDST	ELCDST	SUPRPP	TRADST	AGROIL	RSDOIL	COMOIL	INDLFO
Residual fuel oil	Heavy fuel oil			OILHFO	ELCHFO	SUPRPP	TRAHFO	AGROIL	RSDOIL	COMOIL	INDHFO
Other petroleum products Energy use Non energy use	Other petroleum products Energy use Non energy use			 OILOTH OILNEU	 ELCOIL	 SUPRPP SUPRPP	 TRADST	 AGROIL	 RSDOIL	 COMOIL	 INDLFO INDNEU
GAS											
Natural gas	Nat Gas	GASRSV	GASNAT		ELCGAS	SUPGAS	TRAGAS	AGRGAS	RSDGAS	COMGAS	INDGAS
Coke oven gas	Coke oven gas			GASCOG	ELCCOG	SUPCOA					INDCOG
Blast furnace gas	Blast furnace gas			GASBFG	ELCBFG	SUPCOA					INDBFG
Gasworks gas	Town Gas			GASGWG	ELCGAS	SUPGAS			RSDGAS	COMGAS	INDGAS

FUEL in EUROSTAT	FUEL in TIMES	MIN/ POT	PRIM.	SEC.	ELC/ HET	SUP	TRA	AGR	RSD	COM	IND
Renewables											
Hydro	Hydro	RENHYD	RENHYD		ELCHYD						
Wind	Wind	RENWIN	RENWIN		ELCWIN						
Solar	Solar	RENSOL	RENSOL		ELCSOL			AGRSOL	RSDSOL	COMSOL	INDSOL
Wood and Wood Products	Wood and Wood residues Pellets (separated from wood)	BIOWOO	BIOWOO	BIOWOO BIOPEL	ELCWOO ELCPEL			AGRBIO	RSDBIO	COMBIO	INDBIO
Biofuels	Energy crops Straw & residues Rapeseed (biodiesel) Miscanthus	BIOLIQ	BIOLIQ	 BIOETH BIOBDL			 TRAETH TRABDL	 AGRBDL			 INDBIO
	Black Liquor			BIOBLQ	ELCBLQ						INDBLQ
Municipal Waste	Municipal solid waste	BIOMUN		BIOMUN	ELCMUN				RSDMUN	COMMUN	INDMUN
Industrial Waste	Sludge (industrial waste?)	BIOSLU		BIOSLU	ELCSLU	SUPSLU			RSDMUN	COMMUN	INDSLU
Biogas	Biogas (Methane)	BIOGAS		BIOGAS	ELCBGS			AGRBIO	RSDBIO	COMBIO	INDBIO
Geothermal	Geothermal	RENGEO	RENGEO		ELCGEO			AGRGEO	RSDGEO	COMGEO	INDGEO
Electricity, Heat, Nuclear											
	Electricity			ELCHIG ELCMID ELCLOW	ELCELC	SUPELC	TRAELC	AGRELC	RSDELC	COMELC	INDELC
Derived heat				HETHTH HETLTH		SUPHET		AGRHTH	RSDHTH RSDLTH	COMHTH COMLTH	INDHTH
Nuclear		NUCRSV	NUCNUC		ELCNUC						
Future Fuels											
	Hydrogen			BIOHH2 FOSHH2							

2.3. The nomenclature for the non demand materials

Table 64: Nomenclature for the non demand materials

Code	Description	Exo
MISORE	Iron and Steel: Ore	Exo
MISPLT	Iron and Steel: Pellet	
MISSNT	Iron and Steel: Sinter	
MISRIR	Iron and Steel: Raw Iron	
MISDIR	Iron and Steel: DRI Iron	
MISSCR	Iron and Steel: Scrap Iron	Exo
MISBFS	Iron and Steel: Blast Furnace Slag	Exo
MISOXY	Iron and Steel: Oxygen	Exo
MISQLI	Iron and Steel: Quick Lime	Exo
MISCST	Iron and Steel: Crude Steel	
MCMCLK	Cement: Clinker	
MLMSTN	Lime: Limestone	Exo
MGLRYC	Glass: Recycled	Exo
MPPWOO	Paper: Wood	Exo
MPPRYC	Paper: Recycled	Exo
MPPNOH	Paper: Sodium Hydroxide	Exo
MPPOXY	Paper: Oxygen	Exo
MPPPUP	Paper: Pulp	
MPPKAO	Paper: Kaolin	Exo
MPPGYP	Paper: Gypsum	Exo

2.4. The emissions

Table 65: The emissions

Code	Description
CO2	Carbon Dioxide
COX	Carbon Monoxide
CH4	Methane
SO2	Sulphur dioxide
NOX	Nitrogen Oxides
N2O	Nitrous Oxide
PMA	Particulate 2.5
PMB	Particulate 10
VOC	Volatile Organic Compounds
SF6	Sulphur hexafluorides
CXF	Fluoro Carbons

2.5. Other units and constants

Units:

Monetary:	Million Euros 2000
Time:	Years
Energy:	Petajoules
Materials:	Megatonnes
Emissions:	Kilotonnes, except SF6 and CxFy (Kg)

Constants: Start year: 2000, initial period's length: 1 year. Last milestone: 2050.

References

Belgische Petroleum Federatie (2006), http://www.petrolfed.be.

De Ruyck J. (2006), "Maximum potentials for renewable energy, report for the 'Commissie Energie 2030'".

De Vlieger I., Pelkmans L., Verbeiren S., Cornelis E., Schrooten L., Int Panis L., Knockaert J. (2005), "Sustainability assessment of technologies and modes in the transport sector in Belgium (SUSATRANS CP/43)", Belgian Science Policy, SPSD II, Sustainable production and consumption patterns, VITO, ETE-CES KULeuven, 118 pp.

Devriendt N., Dooms G., Liekens J., Nijs W., Pelkmans L. (2005), "Prognoses voor hernieuwbare energie en warmtekrachtkoppeling tot 2020", i.o.v. VEA, VITO, 168 pp., http://www.emis.vito.be/index.cfm?PageID=459.

Isover (1999), "Isover, leader in thermal and accoustic insulation", http://www.isover.com.

Laenen B., Van Tongeren P.C.H., Dreesen R., Dusar M. (2004), "Carbon dioxide sequestration in the Campine Basin and the adjacent Roer Valley Graben (North Belgium): an inventory." London, 193 - 210 pp.Special publications.

Maes D., Vekemans G., Bartiaux F. (2006), "Socio-technical factors influencing Residential Energy Consumption, SEREC CP/52", Belgian Science Policy, SPSD II, Sustainable production and consumption patterns, UCL, VITO, SBI, 222 pp., http://www.belspo.be/belspo/fedra/proj.asp?l=nl&COD=CP/52.

Martens A., Pepermans G., Palmers G., Dooms G., Germain A. (2006), "Ontwikkeling van instrumenten ter evaluatie van het potentieel voor duurzame waterstof in België ", VITO, KUL, ULG, 3E, http://www.belspo.be/belspo/fedra/proj.asp?l=nl&COD=CP/55.

N.I.S. (2001), "Algemene, socio-economische enquète 2001", Brussels, FOD Economie, KMO, Middenstand en Energie, http://www.statbel.fgov.be/census/home_nl.asp.

N.I.S. (2006), "Jaarlijkse statistieken over bouwactiviteit en bouwvergunningen", http://www.statbel.fgov.be/figures/d65_nl.asp.

Palmers G., Dooms G., Shaw S., Neyens J., Scheuren C., André P., De Stexhe F., Martin J. (2004), "Renewable Energy Evolution in Belgium 1974-2025 (Solar Roadmap), CP/23", Belgian Science Policy, SPSD II, Sustainable production and consumption patterns, 3E, Imec, FUL, UCL TERM, 140 pp., http://www.belspo.be/belspo/fedra/proj.asp?l=nl&COD=CP/23.

Royal Federation of Societies of Architecture of Belgium (1999), Brussels.

WTCB, Wenk, Sint-Lucas Gent (1997), "Studie van de Energieaspecten van Nieuwbouwwoningen in Vlaanderen: Isolatie, Ventilatie, Verwarming", Vliet.