IAEA-TECDOC-1541

Analyses of Energy Supply Options and Security of Energy Supply in the Baltic States

IAEA
International Atomic Energy Agency

February 2007

IAEA-TECDOC-1541

Analyses of Energy Supply Options and Security of Energy Supply in the Baltic States

IAEA
International Atomic Energy Agency

February 2007

The originating Section of this publication in the IAEA was:

Planning and Economic Studies Section
International Atomic Energy Agency
Wagramer Strasse 5
P.O. Box 100
A-1400 Vienna, Austria

ANALYSES OF ENERGY SUPPLY OPTIONS AND SECURITY OF ENERGY SUPPLY IN THE BALTIC STATES
IAEA, VIENNA, 2007
IAEA-TECDOC-1541
ISBN 92–0–101107–5
ISSN 1011–4289

Printed by the IAEA in Austria
February 2007

FOREWORD

In its broadest meaning "energy security" is the ability of a nation to muster the energy resources needed to ensure its welfare. In a narrower meaning it refers to territorial energy autonomy. Consequently, energy supply security is a matter of both domestic policy and international relations. Perceived and real threats may be economic or logistic, politically motivated or the result of war or natural causes. They may be source, technology or transport related, specific to a facility or a function of system structure, due to sabotage or to inadequate investment or maintenance, or result from pricing or regulatory policies.

Energy security has become a growing concern in the Baltic States of Estonia, Latvia and Lithuania since regaining independence in 1991. As their national energy systems depend on essentially one single foreign supplier for most of their oil and all of their natural gas supplies, a comprehensive analysis of potential measures to improve security including alternative supply options becomes vital. Such an analysis needs to consider, for example, the availability of domestic energy reserves and resources, the vintage of existing energy infrastructures (including regional and interregional interconnections), storage facilities, as well as future technology and energy trade options. However, the Baltic States' accession to the European Union in 2004 has added further responsibilities with regard to energy security. Robust future energy development strategies, for each individual country and the region as a whole, will also require compliance with EU regulations, as well as with special stipulations formulated in the accession agreements.

Robust energy strategies need to strike a balance between the potentially conflicting dimensions of energy security, economic efficiency and environmental protection. For example, supply security is likely to incur an "insurance premium", while environmental protection may well raise the cost of providing energy services. An analysis of medium term energy demand and supply strategies that simultaneously accounts for all these dimensions is a methodologically demanding and complex task. The IAEA has developed a systematic approach, along with a set of computer based models for elaborating *national and regional energy strategies* vis-à-vis energy security, environmental impacts and costs. Under its Technical Cooperation Programme, the IAEA provides assistance to its Member States to help strengthen national capabilities for conducting energy demand and supply analyses by transferring the analytical tools, as well as providing training and expert advice.

This report is the outcome of such a technical cooperation programme and describes the results of the study on Analysis of Energy Supply Options and Security of Energy Supply in the Baltic States, conducted in cooperation with several national organizations. This study demonstrates the application of the IAEA's energy planning tools for comprehensive national analyses involving: (i) energy and electricity demand and their projections, (ii) least-cost electricity system expansion, (iii) energy resource allocation to power and non-power sectors, and (iv) environmental impacts.

For medium term energy planning the study presented in this report provides insights into the following issues:

- Identifying cost-optimal energy system development trajectories for each of the Baltic countries *individually* based on maximum national energy self-sufficiency, while complying with EU obligations (e.g. environmental protection, Directive on the promotion of electricity produced from renewable energy etc.).
- Determining and quantifying the benefits and costs of a *regional integration* of the energy systems of the three Baltic countries for different levels of energy security (e.g. sharing of infrastructures and generating capacities, access to resources and storage facilities and

utilizing interconnections, etc). Benefits and costs include the economics of energy supply, changes in the emission of atmospheric pollutants, variation in energy import dependence, etc.

- Formulating a set policy options for actions that are targeted at improving *energy security* in the Baltic region.

This study is uncharacteristic for several reasons. Firstly, similar to other East European countries the Baltic States share a process of re-organization; moving from a centrally planned economy towards market liberalisation. Secondly, the closure of Unit 1 of the Ignalina Nuclear Power Plant in 2004 and the scheduled shutdown of Unit 2 in 2009, in accordance with the EU accession agreement, raises crucial *supply security* questions not only for Lithuania but for the region as a whole. In this regard, this study provided the opportunity to analyse the economic competitiveness and energy security aspects of a wide range of energy supply options, including the construction of a new nuclear power plant. Energy planning is a continuous process. Due to the substantial changes in the energy sector of the Baltic States in recent year, it might be worth considering to start a follow-up study and perform new calculations on the basis of changing conditions.

The collaborative study was managed and carried out by a senior expert-level working group involving members from ministries, utilities, academic and research institutions of the three Baltic countries. The IAEA provided training to the members of the national teams in the use of its energy analysis and planning tools and assisted in linking the national models into an integrated regional Baltic model. A steering committee consisting of the working group and representatives from the IAEA and NATO provided overall coordination and guidance throughout the course of the study, i.e. assisted the working group in defining energy policies and measures to be analyzed, harmonizing scenario assumptions and reviewing study results. The working group was fully responsible for implementing the study, including the preparation of this report.

The IAEA officer responsible for the production of this publication was F.L. Toth of the Department of Nuclear Energy.

CONTENTS

SUMMARY

1. Background

The first North Atlantic Treaty Organisation (NATO) Advanced Research Workshop on Considerations and Options on a New Nuclear Plant at Ignalina was held in Vilnius, Lithuania, on 23–25 September 2002. It focused on the simple thesis that replacement of the Ignalina nuclear power plant (NPP) with a new NPP would resolve issues of energy supply and security that result from the shutdown of Ignalina Unit 1 at the end of 2004 and of Unit 2 at the end of 2009, as mandated by European Union (EU). Discussions held during the Workshop with participants and after the Workshop with NATO representatives, the Ministry of Economy, the Lithuanian Energy Institute and other interested parties, including the International Atomic Energy Agency (IAEA), confirmed that the issue of energy supply and security in Lithuania is not resolved by a simple replacement of the Ignalina NPP with a more modern reactor.

Issues related to the ability of Lithuania to support a new NPP financially and to integrate it smoothly in the future electricity grid were raised, as was the basic question of whether a new reactor was the least-cost alternative both to provide new electricity supply in the future and to support long term energy security goals. Also agreed was the need to consider district heating, small-unit combined heat and power generation and compliance with the relevant Directives of the European Union in any consideration of energy supply and security.

In early 2003, during final discussions on the results of the Workshop by the organisers and key participants, it was concluded that the issue of energy supply and security was best addressed on the basis of:

- The region as an integrated unit rather than as isolated states.
- A long term, least-cost investment portfolio that covers all commercially available forms of electricity generation and district heating technologies.
- An integral consideration of energy security to determine ways to obtain the most security for the lowest cost.

To pursue this objective it was decided to conduct an analysis of the short- and long term energy demand and supply options available to the Baltic countries and to identify a series of measures and policy options for the three countries and the region as a whole. Security of energy supply would be considered as an integral part of the study.

It was also agreed (a) that the study should focus on how the current low-cost energy supply systems of depreciated but aged plant and equipment could be maintained and (b) that security of supply considerations should focus on how and when to further the application of lowest cost solutions while maintaining a reasonable level of energy security. Low energy-input costs to the economy support the international competitiveness of goods and services, while minimised energy costs to domestic consumers promote a stable civil society.

A series of conditions required for the analysis were agreed in order for it to be well received by governmental policy communities, utilities and business communities:

- Participation by the three Baltic countries (Estonia, Latvia and Lithuania) should be on a joint and equal basis.
- Participation in each country should include the Ministries, academic and energy institutions and the utilities.
- The support and participation of international organisations, such as the IAEA is desirable to achieve a high level of objectivity in the proposed study and its conclusions.

- The continued use of the NATO Advanced Research Workshop process to organise and present results to a broad regional and international audience would be useful.
- The Final Report, including its methodology, underlying assumptions and conclusions, should be peer reviewed to assure unbiased analysis and recommendations.

2. Organisation of the study

Participation by Estonia, Latvia and Lithuania in the project 'Analysis of Energy Supply Options and Security of Energy Supply in the Baltic States' was established, in a joint letter of April 2003, by the Ministry of Economy of Lithuania, the Ministry of Economy of Latvia and the Ministry of Economic Affairs and Communications of Estonia. The purpose of this project was to analyse security of energy supply issues in the Baltic region and to prepare a report that assesses various options for improving energy security in the region. The three Ministries jointly requested IAEA technical support at that time, with the encouragement of NATO. The IAEA formally agreed to provide such support in June 2003 through its Technical Cooperation Programme.

A senior expert-level Working Group, composed of Ministry, utility, academic and institute experts was constituted to:

- Prepare a consistent three-country database to calibrate the methodological tools to the currently existing national energy infrastructures.
- Agree on a set of national and Baltic economic, energy demand and energy supply assumptions.
- Prepare the analyses.
- Develop an initial set of conclusions.

A Steering Committee was also formed that consisted of senior energy experts from the three countries, as well as advisors from IAEA and NATO.

3. Scope of the Study

3.1 General

It was agreed by the Working Group and the Steering Committee to analyse the period from 2005 to 2025 using a comprehensive energy system approach. Energy supply consists of all stages from resource extraction and imports through electricity generation, oil refining, district heating and gas storage, to transmission and distribution of electricity, fuels and heat. Energy demand consists of the energy needs of the industry, agriculture, transportation, household and service sectors. The electric power generation and district heating sectors were modelled and analysed with a higher degree of sophistication than the rest of the energy system. The outputs of this effort were (a) one energy demand scenario (demand by sector and fuel) for each Baltic country and (b) a variety of national and regional primary energy supply scenarios with detailed electricity and heat generation alternatives and sensitivity analyses.

The national and regional demand and supply assessments were carried out over the period 2003 to early 2005. During this period international energy prices shifted from being relatively low and stable to being considerably higher and more volatile. The upward trend has continued during the preparation of this report but declined somewhat in the second half of 2006. Therefore, several additional cases were calculated to account for the new energy price level and other new realities that now affect the Baltic region. These include:

- The Russia–Ukraine gas price dispute;
- An increase of electricity prices by some 30% in the region;
- The European Union Emission Trading Scheme (EU ETS) of 2005, which created a market for trading CO_2 emissions: emission permit prices have already soared from €8–10/tonne to €25–30/tonne – then slipped back to €12–15/tonne since April 2006;
- The scheduled completion of the Estlink cable in December 2006;
- A decision on the construction of the North European gas pipeline (underwater pipeline from Russia to Germany under the Baltic Sea) by-passing the Baltic States;
- Submission of 'Guidelines of the National Energy Program' by the Latvian Ministry of Economy to the Cabinet of Ministers (December 2005), with particular focus on the construction of a coal-fired power plant in the western part of Latvia;
- The Declaration and Communiqué signed by the Prime Ministers of Estonia, Latvia and Lithuania on cooperation to evaluate the possibility of constructing a new nuclear reactor on the site of the Ignalina NPP (February 2006) followed by a Memorandum of Understanding signed by the Chief Executive Officers of the three largest Baltic energy companies: Eesti Energia AS, AS Latvenergo and AB Lietuvos Energia (March 2006);
- The considerable attention devoted to energy supply security at the G8 meeting in St. Petersburg in 2006 and the conclusion that the rush for energy resources will continue creating price pressure and the possibility that the lowest bidder will end up with nothing. This increases the risk associated with physical limitations of pipeline capacities and over-dependency on natural gas supply. A large scale shift towards alternative energy resources like unconventional oil or orimulsion may be questionable as well due to the fast increasing demand for these sources in rapidly developing economies, such as China, and limited capacities for their production. Even the utilisation of domestic resources like oil shale may change as commodities with higher value added (e.g., gasoline) may divert them from power generation;
- The increased significance of the regional scenario (5R) with prolonged operation of Ignalina NPP Unit 2 until 2017 owing to news about the possibility of Lithuania's asking the European Commission to postpone the decommissioning of the Unit 2 until 2013.

The model analyses had in one way or another "anticipated" these new realities, some of which at the time were considered "extreme assumptions" (a CO_2 tax of 20 €/t or crude oil prices of 55 € per barrel). A general conclusion, therefore, is that the findings of the assessment have proven robust even in a rapidly changing energy world. What has changed is that the low price scenarios are less likely to serve as images of the future than scenarios characterized by high energy prices and/or high CO_2 emission costs. These new realities not only add to the urgency of a regional approach to Baltic energy security but have already prompted political responses.

The study developed two principal scenarios, i.e., the National Self Sufficiency Scenario (Scenario 1N) and the Base-Case Regional Self-Sufficiency Scenario (Scenario 1R).

3.2. National self sufficiency scenario (Scenario 1N)

The 1N scenario is composed of three separate country analyses of basic national energy requirements and supply until the year 2025. Each analysis meets each country's separate national laws and international obligations, including EU Accession and Kyoto Treaty agreements. The main features of the analyses are:

- Ignalina NPP Units1 and 2 are shut down in 2005 and 2009 respectively.
- The most probable modernisations of Estonian oil shale, Latvian combined heat and power plants and Lithuanian thermal power plant (Electrenai) are included.

- Each country's national electricity demand is 100% supplied by national power plants, starting in 2010.
- Storage requirements for oil products are set at 90 days of current supply.

These analyses include no coordination or cooperation among the countries to reduce overall investment costs, to utilise economies of scale or to increase energy security. Energy security is not considered as a requirement (apart from the oil storage requirement). This no cooperation or minimal cooperation scenario represents the status quo and a picture of the likely future if no decisions to cooperate regionally are made. To that extent the 1N scenario forms the 'no action alternative' basis for a risk-assessment study, and serves as a benchmark against which different energy supply and security strategies and their associated costs and benefits can be tested.

3.3. Base-case regional self-sufficiency scenario (Scenario 1R)

The 1R scenario is similar to 1N scenario, except for regional rather than national self-sufficiency requirements. The 1N scenario is modified to utilise existing power interchanges between the three countries, and all electricity is to be supplied from within the Baltic region after 2010. Electricity trade is permitted only within the region, and not outside the region

On the basis of the regional scenario (1R), a series of variations encompassing seven additional cooperation and coordination cases are analysed in order to establish the least-cost cases for energy supply and energy security. The cases covered include:

- New power interlinks to the Scandinavian NORDEL system (350 MW_{el}) and Poland (1 000 MW_{el}), as well as interchanges across the existing transmission links to Russia and the Commonwealth of Independent States (CIS) - Scenario 2R.
- Additional natural gas storage (120 days) from 2010 - Scenario 3R.
- Limiting the share of natural gas and orimulsion in the generation of electricity and supply of district heat to a maximum level of 25% of the total fuel supply for these purposes - Scenario 4R.
- Continued operation of Ignalina 2 until 2017 - Scenario 5R.
- Fuel diversification through either construction of Ignalina NPP Unit 3 (1 250 MW_{el}) or a coal-fired power plant (400 MW_{el}) in Western Latvia after 2010 - Scenario 6R.
- Impact of various levels (€5, €10, €20 per tonne of CO_2) of a 'carbon tax' starting in 2008. New nuclear production is constrained at not more than 3 000 MW_{el} - Scenario 7R.
- Simulation of the implementation of a quasi EU Renewables Directive assuming 3% annual growth of electricity produced from renewable energy starting in 2010 (Scenario identifier - Ea).

An additional scenario explored the impacts of increasing the share of renewables in the energy mix up to the maximum level of EU targets, on a regional basis.

A range of international energy price scenarios was used in the study. With hindsight, the original price trajectories proved too conservative and even the "extra high" price case falls short of currently observed price levels for internationally traded energy commodities.

A post-study analysis based on energy prices of March/April 2006 by the IAEA supplements the original set of model calculations. In order to avoid confusion, this summary reports the study findings for two energy price trajectories: low and high.

Low import prices (scenario suffix (Aa)) are defined here as crude oil prices around €33/barrel (€5.7/GJ). After 2005 gas prices vary between €2.7 and €4.1/GJ over the period 2005–2025, and coal prices stay at around €1.8/GJ.

High import prices correspond to the scenarios with the suffix (Ab) with prices for crude oil at €49/barrel (€8.50/GJ) after 2005, for natural gas at €150–€228 per 1 000 m^3 (€4.0/GJ to €6.1/GJ) rising steadily over the period 2005 to 2025, and for coal at around €2.70/GJ. Several test runs were performed with 20–30% higher prices than the high import case, and the conclusions from these additional model runs are included here.

4. Approach to conclusions

In developing conclusions and recommendations a number of requirements were established:

- Any conclusion – technical, commercial or policy – should be robust in its impacts on energy supply and energy security. For example, basing a conclusion on today's oil and natural gas prices in the world market would not necessarily be a robust undertaking, since it is unclear whether today's prices are representative of long term prices. A portion of today's prices represents speculation and not long term supply and demand. How much will only become clear at some time in the future.
- Any conclusion about energy supply alone should focus on the least-cost and most reliable technologies. Where an addition or change to a least-cost alternative is identified because of energy security or other policy concerns, it will be marked clearly on a separate basis.
- Options that make economic sense and also serve a useful energy security function at no extra cost should be preferred over equal-cost options that meet only least-cost requirements.
- Advantage should be taken of situations that allow a delay in investment decisions at little or no risk to economics or energy security, as these are valuable. In cases such as the decision on whether or not to add a new nuclear power plant, the completion now of low-cost steps required in any event preserves the viability of the projected start-up date and delays any immediate commitment to high-cost investments. In general, preserving options at little or no cost while the current energy cost and supply situation clarifies can save both potential economic and political embarrassment.
- In general, the energy market for each of the three Baltic countries is small – investments for larger projects are more secure and on a stronger financial and technical basis if they are shared or made on a coordinated Baltic-wide basis.
- Options that support flexibility are desirable. Thus, options that strengthen electricity and natural gas pipeline interlinks and also allow increased diversification of supply sources are exceptionally attractive. For example, adding electricity interlinks with Sweden and Poland also makes possible/profitable larger generating units because of larger markets and increased reliability of the overall system. Larger units usually have lower generating costs. This, in turn, reduces the cost of electricity as a factor input to the economy and socio-economic well being.
- The Baltic countries have made and are continuing to make important improvements in energy efficiency. Relative to some other EU countries, large gains are still to be made in reducing the kilowatt-hours required per unit of economic output. Energy efficiency is the cheapest source of heat and power and, once the investment in more efficient processes and equipment is made there is no impact from fuel costs on production costs for the avoided capacity. As fuel prices increase, agents throughout the economy can afford greater and greater improvements.

5. Summary of identified risks and proposed risk-reducing actions

5.1. Risk of over-dependency on natural gas

Baltic electricity generating capacity from diverse fuel sources will be reduced between now and 2010 by approximately 3 500 MW_{el} because of the shutdown of the two Ignalina NPP units and the loss of 500 MW_{el} to 1 000 MW_{el} of capacity from the continuing phase out of small shale oil units in Narva (Estonia) and of other old vintage units. This 3 500 MW_{el} in electricity generating capacity is to be replaced largely by the rehabilitation of existing and by new gas-fired capacity. The combination of this reduction in existing diversified capacity plus the continued and increasing installation of combined cycle gas-fired capacity increases Baltic dependency on imported gas from 14% of total fuel use for district heat and power generation in 2003 to 28% to 32% by 2010 (depending on the price scenario). It stays in that range through 2025.

An increase in natural gas usage (all of which is imported from a single source: Russia) continues - though at varying rates in all scenarios considered. The major risk of over-dependency stems from rising natural gas prices, reflecting both the adjustment of the price paid by the Baltic countries from below market levels to full market levels (an increase of some 50 percent) and the more general gas price increase as gas prices track oil prices. Uncertainties regarding gas prices in the near- to medium-term include what fraction of today's oil price includes a speculation adder, what are the expected scenarios for continued growth of the Indian and Chinese economies, and what is the likelihood of energy efficiency improvements in these two currently energy-inefficient economies. The recent competition for oil and gas reserves and attempts to take control of production capacity abroad by India and China combined with self-protection responses by the developed economies, have further added to the near-term price volatility. This competition is likely to continue for some time into the future.

5.2. Risk of Natural Gas Supply from a Single Source

Three factors argue against a heavy dependence on Russia as the single source for natural gas and oil in the Baltic countries:

- The reliable supply of natural gas can be jeopardised by politically driven interruptions, such as has already occurred in both Lithuania and (for petroleum supplies) in Latvia.
- The aging Russian gas supply infrastructure is reportedly not being maintained and refurbished on an adequate basis. This raises questions of long term reliability. Currently, two lines supply the Baltic countries, with a third line of 1950s vintage no longer in use. One line would be sufficient in an emergency as long as no common or simultaneous failures occur. Failure appears unlikely in the near term, but becomes more probable as time passes if infrastructure refurbishment continues to lag.
- The apparent willingness of the Russian authorities to use energy supply and energy security as an informal tool of foreign policy is a continuing near-term concern, especially after the gas price dispute and supply curtailments to the Ukraine. This is further heightened by the lack of transparency in the dealings of companies such as GazProm and the impasse in finalizing an agreement between the EU and the Russian Federation targeted at improving such transparency, in spite of repeated and lengthy discussions.
- The Baltic countries represent a relatively small market for oil and natural gas. In the near future, competition for these fuels from countries such as India and China as well as from the major Western European countries, potentially leave the Baltic countries as a lower priority market. This would be particularly true for situations in which supply may be complicated by a politically inharmonious situation.

- GazProm is developing alternative pipeline transit routes directly to Germany under the Baltic Sea, by-passing the Baltic Region and Poland. This could reflect a desire to avoid any mutual dependencies in the energy area with the Baltic countries and Poland, or a desire to separate pipeline fees from export revenues, or as a bargaining chip to use in price and policy negotiations with the Baltic countries. It deepens concerns in these countries about the energy security of their imports and the monopoly power of Russia over the region's gas supply.
- The bankrupt company Yukos has a controlling interest in the Mazeikiai refinery. It would be a major risk if any company that gains control of the Mazeikiai refinery were not committed to total transparency in its dealings both before and after assuming control. Mazeikiai plays a pivotal role as the sole refinery in the Baltic nations in supplying gasoline and other distillates. In addition, during a major natural gas supply interruption it would provide, in combination with crude oil supplied through the oil port at Butinge, distillates for combined cycle and electricity-generating stations that have dual fuel-firing capability. This double role of Mazeikiai makes any lack of transparency on the part of its ultimate owners double the risk to the energy security of the Baltic countries.

6. Natural gas import dependency

The use of natural gas as a fuel to generate electricity and provide district heating is both desirable and unavoidable, given its historically relatively low cost, good environmental characteristics, availability and the existing infrastructure for its supply and use. Despite its favourable characteristics, an over-dependence on gas imports from a single source represents a supply security risk. The key to the use of an attractive single-source fuel such as natural gas is not avoidance *per se*, but the management of the risks associated with its use. The main focus of such an approach is to develop a risk management strategy that first identifies and quantifies the risks and then identifies the least-cost, technically proven alternatives to reduce the risk to a socially acceptable and politically manageable level.

The practical approach is, first, to reduce the rate of increase of natural gas use through efficiency improvements and diversification, where cost-competitive, technically mature alternatives are available. The second step is to take advantage of the benefits of the use of natural gas while hedging against the negative security-of-supply aspect of the single source - Russia.

This approach is most effectively done on a least-cost basis if planned and implemented in a coordinated manner by the Baltic States rather than by each state individually. However, as Lithuania is more severely and more immediately at risk than either Latvia or Estonia, it would be common sense for Lithuania to take the lead in organising a common approach to the energy supply and energy security risks from the increasing single-source dependency on natural gas.

This joint study is a first major step in that direction, providing an initial joint analysis of the basic situation and identifying possible steps for a joint resolution.

7. Brief country profiles

For this study, energy supply security in the Baltic States is defined in terms of reducing import dependence on energy supplies that carry a risk of politically motivated price increases, surprise changes in market conditions or disruptions of physical supply. Gross Baltic energy import dependence is currently around 69%; net import dependence (adjusting for regional exports of electricity and oil products) is 45%. The region effectively depends on

Russia for the bulk of its energy needs, a situation which will be aggravated by the closure of the Ignalina NPP, the mainstay of the region's electricity supply, at the end of 2009.

Before examining the supply security benefits that result from further regional integration of the national Baltic energy systems through the sharing of resources and infrastructure, a brief review of the status quo of the national energy systems in the Baltic region is in order.

In 2003 about 75% of the primary energy supply in Estonia was domestic — mostly oil shale, wood and peat. Oil shale is a staple fuel for electricity and heat generation in Estonia and represents the largest fossil resource of the Baltic region. Imports are Russian oil, processed in the Lithuanian Mazeikiai refinery, and Russian gas, the seasonal supply of which is regulated through the Incukalns underground storage facility in Latvia.

Latvia, by contrast, in 2003 imported about 73% of its primary energy (natural gas, coal and oil products) from Russia, Lithuania and the Commonwealth of Independent States (CIS). Accounting for energy exports, the net energy import dependence[1] was about 55%. Domestic resources are biomass, peat and hydropower. Latvia also imports some 30% of its electricity from Russia, Estonia and Lithuania, although the goal is to reduce this to 10–20% by 2008. Latvia is an energy transit country for Russian crude oil, oil products, coal and natural gas. Latvia has a large underground gas storage facility and uses stored gas to even out seasonal deliveries of natural gas from Russia, for domestic use in winter and for export to neighbouring countries, including re-export to Russia.

Lithuania's gross energy import dependence[2] in 2003 was about 117%. The country depends on Russia for 100% of its natural gas, and for almost 100% of its crude oil and coal requirements. Lithuania, however, is also a sizeable energy exporter to its Baltic neighbours and beyond, and the net import dependence is about 42%. The Ignalina NPP, designed during the days of the Soviet Union as a major electricity hub in the region, continues to supply base load power to former Soviet satellite states. However, the closure of Ignalina NPP Unit 1 (Ignalina 1) at the end of 2004 caused a sharp drop in exports, and exports will cease altogether after the closure of Ignalina NPP Unit 2 (Ignalina 2) at the end of 2009. Lithuania's Mazeikiai refinery was also designed as a regional supplier of refined oil products, and it continues to export oil products to Latvia, Estonia and outside the Baltic region.

The closure of the Ignalina NPP, which before 2005 supplied some 40% of the region's electricity needs, is expected to further increase the dependence on imports, depending on the choice of replacement technologies and associated fuels. In addition, energy and electricity demand is projected to grow in the region. Given the region's limited fossil fuel energy resources — essentially limited to oil shale in Estonia — additional supplies from abroad will be required.

8. Mitigation options in the Baltic Countries

Initial analyses identified natural gas-fuelled electricity generation as the preferred replacement for the Ignalina NPP, at least before natural gas prices rose appreciably in the

---

[1] Net energy import dependence here is defined as the sum of all energy imports minus the sum of all energy exports divided by the total primary energy supply in the country or region. Although nuclear fuel is often imported (from Russia in the case of the Ignalina NPP), nuclear power is considered a domestic energy source. The small annual fuel requirements, the potential to store one or more refuelling loads on site and the inherently long refuelling cycles mean that nuclear fuels are not critically impacted by short term supply disruptions and price volatility.

[2] Gross import dependence here is defined as the sum of all energy imports divided by the total primary energy supply in the country or region.

Baltic region - first as a result of European Union (EU) accession which put an end to the preferential gas price treatment by Russia to former members of the Soviet Union, and then through the overall upward trend of international energy prices. The least-cost solution for replacing power from the closure of the Ignalina NPP increases natural gas imports from Russia.

Efforts to minimise such dependence are being made at national and regional levels, in the context of growing market liberalisation and accession by the Baltic States to the EU. Some of the measures contemplated, modelled as part of this study, include:

- Modernise the larger existing thermal power plants across the region (both to improve efficiency and to meet environmental standards);
- Construct new combined heat and power (CHP) plants;
- Maximise the use of Estonian oil shale;
- Improve air pollution controls;
- Implement the EU renewables directive;
- Construct a replacement nuclear power station or fossil-fuelled plant for the Ignalina NPP;
- Change the fuel mix and diversify imports;
- Enhance the energy supply and distribution system.

As regards fuel diversification and supply security, uranium and, to a lesser extent, coal prices account for a much lower share in electricity generating costs than do oil or gas prices (uranium prices are 2% to 5% or electricity prices, coal prices are 30% to 35% and gas prices are 60 to 70%). Hence an increasing fuel price affects nuclear- and coal-generated electricity less than electricity generation from natural gas.

Table S.1 depicts the principal energy supply technology options for the Baltic region by country. Not listed here, but included in the energy demand analyses, are efficiency improvements throughout the energy end-use systems, including transmission and distribution infrastructures. Other opportunities for common investment in measures for energy supply security that would supplement the technology options of Table ES.1 are the establishment of a Baltic wide Independent System Operator (ISO) or the interconnection of the Polish and Lithuanian gas pipeline systems.

The Baltic countries have made and are continuing to make important improvements in energy efficiency. Compared to some other EU countries, large gains are still to be made in reducing the kilowatt-hours or megajoules (MJ) required per unit of economic output. Energy efficiency is the cheapest source of heat and power, with immediate benefits for energy security, and, once the investment in more efficient buildings, processes and equipment is made, there is no impact of fuel costs on the production costs for the avoided capacity. As fuel prices increase, agents throughout the economy can afford more improvements.

As stated already, the main objective of this study was to quantify and compare the costs and benefits of an integrated regional versus a national approach to energy supply security in the Baltic region under a variety of potential future scenarios. ‘Integrated’ in this context means (a) to adopt and pursue a common regional energy policy and (b) to make energy investment decisions solely on the basis of least-cost considerations for the region — not necessarily least-cost at the national level — given common regional policy objectives.

Table S.1. Major energy supply options in the Baltic Region*

Estonia	Latvia	Lithuania
Refurbishment of oil-shale power plants	Replacement of existing CHP with new CHP (natural gas)	Modernization of Lithuania TPP including switch to
Conversion/replacement of DH boilers to/with CHP	CHPA biomass & pulp	Conversion/replacement of DH boilers to/with CHP
CFBC(oil shale)	CHP (coal)	Modernisation of existing CHPs and new CHP
CHP (imported coal)	Coal power plant	Small scale CHPs (gas & biomass)
CHP biomass/peat	CCGT	Nuclear power plant
CCGT & gas turbines	Wind	CCGT
Wind	Hydro	Wind
Mini & micro hydro	Additional gas storage	Pumped storage
Full implementation of strategic oil/oil product reserves		
Electricity links to Finland, Sweden and Poland		

* TPP, Thermal Power Plant; DH, District heating; CFBC, circulating fluidised bed combustion; CCGT, combined cycle gas turbines

9. Study Conclusions

The conclusions developed in this section are, to a large extent, based on the scenarios and model outputs described in detail in the report. There is no 'silver bullet' solution to the energy supply security of the region or a mix of measures that will best serve it. The numerous scenarios developed for and analysed in this study provide a point of departure for further analyses to identify cost-optimal measures that strengthen supply security.

Most of the scenarios consider international energy prices for the next few decades that are below current price levels. Both the interpretation of the numerical results and the conclusions here account for the changed price realities as supported by several additional model runs with energy import prices some 20–30% higher than in the original 'extra high price' cases, with the identifier (Ab). Identifier (Ab), therefore, describes the high price situation observed today and not necessarily precisely the price assumptions that underlie the scenarios reported in Chapters 5–8. The term 'high international energy prices' used in these conclusions, therefore, represents future price developments largely consistent with those represented by the scenario identifier (Ab).

> ***Conclusion I***: Solutions approached from a regional perspective are more effective than the same solutions pursued independently by each of the three countries. There are immediate economic benefits — but not necessarily improved energy supply security — from an integrated and coordinated energy approach. The energy system cost difference between the 'National Self-Sufficiency Scenario (1N)' and the 'Regional Self-Sufficiency Scenario (1R)'[3] amounts to €727 million (discounted[4]) for

[3] Unless otherwise indicated, the Ignalina NPP ceases operation as in the EU accession agreement.

[4] An 8% real discount rate was used.

the study period 2005–2025. The main difference in the regional energy supply mix is a larger share of natural gas imported from Russia and a drastically restructured trade pattern for crude oil and oil products (with additional crude imports from Russia and higher refined product exports abroad). The net result is a 4% increase in the net energy import dependence after 2010 (essentially all from Russia), which increases to 7% by 2025.

Rationale: In an environment of low international energy prices[5] and in the absence of any import restrictions to reflect energy security concerns or stringent environmental performance standards, the larger integrated regional market alone does not create sufficient economic incentives to construct a new NPP.

With low-cost natural gas and crude oil imports and no considerations of energy supply security, it is economically attractive to use Russian gas instead of imported orimulsion to generate electricity as well as increasing export revenues from refining imported crude oil and exporting oil products. Internal electricity exchange among the Baltic countries improves overall generating flexibility and thus permits additional electricity export revenues (from exports to Russia and the CIS) during the operation of the Ignalina NPP.

Conclusion II: The most efficient scenario for the development of the Baltic energy system, in terms of both economic and security of supply aspects, is the continued operation of Ignalina 2 until the end of its technical lifetime in 2017 (Scenario 5R). In principle, this option has been foreclosed by the accession agreement with the EU. The net economic benefit to the Baltic region would be on the order of €440 million (discounted) in a future with low energy prices, and some 50% higher if current international prices prevailed[6].

Rationale: The shutdown of Ignalina 1 in 2004 had a less severe impact on the region, since a part of the output was excess to Baltic demands and was sold outside the Baltic region, to Belarus, Kaliningrad and Russia. Adjustment to the shutdown was made by reducing exports. By contrast, the impact of the shutdown of Ignalina 2 can only be fully mitigated by increased imports of natural gas, orimulsion, coal and electricity or the construction of a new NPP. This is because most alternative Baltic sources of primary energy, including renewables, will either be already utilised by 2010 to meet demand growth and to compensate for the loss of Ignalina 1 supplies, or be hampered by cost considerations or long lead times, or both.

Prolonged operation of Ignalina 2 beyond the agreed closure date at the end of 2009 is warranted on purely economic terms and takes the operating license issued by the national regulator VATESI at face value. In all the scenarios in which Ignalina 2 closes by the end of 2009, the region switches from a net electricity exporter to a net importer. While import volumes vary across the scenarios, electricity imports generally correspond to about half of Ignalina 2's generation before closure.

The benefits stated above reflect energy system benefits only. The benefits of the continued operation of Ignalina 2 or the construction of a new NPP at the Ignalina NPP site would also avoid socio-economic hardships, loss of a skilled work force, relocation, reduction and re-

---

[5] Low import prices are defined here as crude oil prices around €33/barrel (€5.7/GJ). After 2005 gas prices vary between €2.7 and €4.1/GJ over the period 2005–2025 and coal prices stay at around €1.8/GJ.

[6] The benefits are the difference of discounted costs between the 5R and 2R scenarios over the period 2005 to 2025.

employment of plant and support staff, and the decline of the support and service industries and businesses in the region.

Conclusion III: Energy options that provide flexibility are desirable. Thus, options that strengthen electricity and natural gas pipeline interlinks and also allow increased diversification of supply sources are exceptionally attractive. For example, adding electricity interlinks with Sweden and Poland permits larger electricity generating facilities because of larger markets and increased reliability of the overall system. Larger units have lower unit production costs. This, in turn, reduces the cost of electricity as a factor input to the economy.

Rationale: New power interconnections with the Union for the Coordination of Transmission of Electricity (UCTE) via a 1 000 MW link between Lithuania and Poland and with NORDEL via Estlink, a 350 MW underwater connection between Estonia and Finland, as analysed in the ‘Regional scenario with cross-border power exchanges (2R)’, further improve system flexibility and overall economics by some €510 million over the period 2005–2025, compared to the 1R Scenario. On a discounted basis, grid integration adds some €44 million to costs and thereby reduces the total net benefit by this amount because the benefits from investing in these interconnections occur in the future[7]. Energy supply security, in terms of import dependence, does not really improve compared to the 1R scenario (around half a percentage point on average), but certainly improves qualitatively because of the additional electricity interconnections. Supply disruption and technical equipment failure were not modelled in this study. However, it can be safely concluded that an interconnected electricity system is better prepared to withstand disruptions and supply shocks than an isolated system.

Conclusion IV: High international energy prices[8] reduce energy import dependence and stimulate the exploitation of previously sub-marginal domestic energy resources (especially of peat, wood, biomass, wind and small hydropower), increase the use of imported coal in rehabilitated plants and in new capacities and favour the construction of a new NPP. For example, for the 2R scenario, import dependence drops by 15 percentage points in the high price situation compared with the low price benchmark.

Rationale: While imports of gas and orimulsion are greatly reduced, imports of crude oil from Russia and of electricity mainly from Russia increase considerably. Here, refining margins and higher export revenues for the oil products from the Lithuanian Mazeikiai refinery appear an attractive proposition despite the costly crude imports, although with a higher risk profile for potential supply disruptions. Electricity imports from outside the region are attractive — the higher international fuel prices do not proportionally affect electricity generating costs and may be negligible if the electricity is based on hydropower or nuclear power. As soon as electricity import prices exceed €38/MWh for extended periods of time, a new NPP with levelized generating costs[9] of €37/MWh becomes part of the cost-optimal electricity supply

---

[7] The additional discounted system costs result in savings of €82 million under high price conditions in the energy market.

[8] High import prices correspond largely to the scenarios with the identifier (Ab). The prices of crude oil are €49/barrel (€8.50/GJ) after 2005, of natural gas €150–€228 per 1000 m^3 (€4.0/GJ to €6.1/GJ) rising steadily over the period 2005 to 2025, and of coal about €2.70/GJ. Several test runs were performed with 20–30% higher international energy prices, and the conclusions also reflect these additional model runs.

[9] Including interest during construction, decommissioning cost and contribution to a waste management fund.

mix. The cost-optimal grid connection for such a plant occurs between 2015 and 2020, depending on the price assumptions for electricity imports from abroad (Russia, Finland or Poland).

Any import prices higher than in the (Ab) case simply bring forward the introduction of a replacement NPP. A test with 30% higher import prices led to the grid connection of a new nuclear plant as early as 2010[10]. However, given the lead time needed to prepare and implement a nuclear project, it is not realistic to expect a new unit to start operation much before 2015. The Lithuanian TPP fuelled by orimulsion imported from Venezuela could bridge the power supply gap until a new NPP is operational.

A detailed cost comparison of the high price scenario with 1R and 2R does not make much sense as these represent distinctly different energy futures for the region. Clearly, the supply security improvement in the 2R(Ab) scenario is significant, but so is the increase in overall energy system costs. The latter, however, are driven by energy prices and not by measures to improve energy supply security in the region.

More conclusive information about the costs associated with a higher level of energy supply security can be obtained by analyzing policy measures targeted at reducing supply security risks, namely cases 3R, 4R, 6R, 7R and the renewable energy scenario (Ea identifier). The results of these scenarios are compared below:

The comparisons were carried out using the low fossil fuel price 2R(Aa) scenario as a benchmark for three reasons:

- The scenarios with high prices for energy imports inherently improve the energy supply security situation (in terms of import dependence, but not necessarily in terms of price stability and socio-economic vulnerability);
- A low-price environment highlights the incremental costs and benefits of different policy options.
- The 2R scenario with electricity trade interlinks to neighbouring countries provides the necessary flexibility both for electricity imports and exports which is an important feature for the economic feasibility of large generating capacity additions.

However, to contrast the numerical findings of the study, reference is also made to the high-price scenario 2R(Ab).

Increasing natural gas storage in Latvia to 120 days of annual regional demand (3R). Additional gas storage capacity does not, overall, reduce dependence on Russian gas imports, but it does improve energy security (against interrupted delivery or price volatility) at a cost of €13–€26 million (discounted) per year (depending on future prices) over the period 2010–2025. These additional costs can be interpreted as ‘insurance costs’ or ‘premium’ for better energy security.

Capping the share of natural gas and orimulsion (4R). A cap (25%) on imports of natural gas and orimulsion does not really affect the level of energy import dependence. Rather, the cap leads to a different import structure in which gas is replaced by orimulsion (utilising the full 25%) supplemented by stepped up electricity and coal imports. The annual cost of diversification amounts to €9.6 million (discounted) per year over the period 2010–2025.

---

[10] This is an entirely hypothetical proposition. The model optimizes the energy supply mix of the Baltic region starting from 2000 and thus the construction of a new NPP in the model can commence in time for grid connection in 2010. From the vantage point of early 2006 this is unrealistic, and the test case was analyzed primarily to better understand the comparative economics of a new NPP.

New NPP at the Ignalina NPP site and/or a coal-fired power plant in Latvia (6R). Fuel diversification by requiring the construction of both a new NPP and a coal-fired power plant diversifies (coal imports) and lowers the region's energy import dependence by seven percentage points at an annual cost of €62 million (discounted) per year over the period 2010–2025 (or a cost of reducing import dependence of €9.2 million per percentage point). These costs may be viewed as an insurance premium for enhanced supply security. To put this 'insurance premium' into perspective, the additional cost burden of the scenario with high energy prices, 2R(Ab), amounts to €300 million (discounted) per year or about €20 million per percentage point reduction in import dependence over the period 2005–2025. (The absence of a new NPP in the 2R(Ab) scenario adds considerably to the costs.)

Carbon taxes: Tax levies on greenhouse gas (GHG) emissions inherently stimulate the use of fuels and conversion technologies that emit small amounts or no GHGs, as well as the rational use of energy and efficiency improvements throughout the energy system. Taxes on low-cost but GHG-intensive plant and equipment improve the competitive advantage of higher cost renewables, clean fossil fuel technologies and nuclear power. The effect on energy security in the Baltic region of varying taxes on carbon dioxide (CO_2) emissions is similar to that of higher fossil fuel prices — the higher the tax, the lower the overall dependence on energy imports as higher taxes induce lower overall demand and reduce demand for high-carbon fuels. A €20 tax per tonne of CO_2 – a value 25% lower than the published market value of European Union Allowances (EUA) on 3 March 2006[11] — reduces energy import dependence by five percentage points (compared with 2R) at a cost of €5 million (discounted) per year. The reduction is achieved primarily by the construction of new nuclear power capacity after the closure of Ignalina 2 and by the accelerated market penetration of domestic renewables.

The downside to carbon taxes as an import reduction tool concerns the use of Estonian oil shale. As the only sizeable hydrocarbon resource of the region, this domestic carbon-intensive fuel would also be adversely affected by any GHG tax and its use is progressively reduced with higher taxes on CO_2 emissions.

Increasing the share of renewables (Ea). The discounted costs of enforcing a 3% annual growth rate for electricity generation from renewables amounts to €709 million (discounted) for the period 2000–2025 and is one of the most costly measures for improving energy supply security. With low energy prices the obligatory use of domestic renewables appears to crowd out other domestic energy options, and renewables do not substitute for low cost imports. As a result import dependence improves only at the margin.

> ***Conclusion V***: Long term marginal costs (and prices) for energy services will increase in the region.
>
> Rationale: Rehabilitation of existing plant and equipment plus the construction of new heat and electricity generating capacities will result in higher electricity prices in the Baltic region, compared with prices reflecting only the operating costs of essentially depreciated capacity that would prevail without investment in new plant. Each closure of an Ignalina NPP unit will be followed by distinct price hikes.

With low international fuel prices, marginal electricity production costs in the Baltic market range between €31 and €36/MWh, primarily determined by generating costs of new CHPs. After 2020, the addition of new coal-fired capacities in Latvia, additional new CHPs in

[11] EUA closing value of €27.15/tonne CO_2, published by Point Carbon. http://www.pointcarbon.com/.

Estonia and the replacement of one of the Vilnius CHP units increase the marginal cost to €39–€43/MWh.

Current international fuel prices (oil marker price around US$60–US$70/barrel) inflate the generating costs by some €5–€15/MWh depending on the system response (availability of non-fossil fuel alternatives and backstop technologies).

> ***Conclusion VI:*** This study finds a strong congruence between energy supply and security measures that are less expensive and those that are regionally planned and implemented.
>
> Rationale: Especially given the small size of the individual national energy markets, investments for larger projects are more secure and on a stronger financial and technical basis if they are shared or made on a coordinated Baltic-wide basis. Some projects, such as a new NPP or additional gas storage, only make financial sense if they are supported by the combined resources and markets of all three nations.

Energy policies as well as investments can be more effective if made on a cooperative basis. Emergency measures jointly decided and authorized in advance by all three countries would ensure that the best possible use is made of available energy supplies in case of a supply disruption. Similarly, the institution of a common Baltic market for electricity supply, preferably in conjunction with the establishment of a Baltic regional independent system operator, would further add to system efficiency and supply security.

> ***Conclusion VII***: Russian energy exports will remain a mainstay of Baltic energy supply. The answer to an excessive dependence is diversification.
>
> Rationale: Natural gas from Russia can be an integral and effective part of the Baltic energy strategy, to the degree that it makes economic sense and to the extent that measures like adequate Baltic gas storage and alternative emergency measures are in place to mitigate potential market dominance by Russian suppliers. The goal is not to eliminate energy imports from Russia, but to put in place measures to mitigate the long term risks associated with such imports.

In the longer run, the most effective way to limit the potential for monopoly market abuse (in the form of supply or price disruptions) is to break the monopoly. Diversity of energy supplies and energy-system flexibility in the Baltic region are therefore the key. Hence, the following measures can be considered to enhance the security of energy supply in the Baltic region:

- Increase production of renewable and domestic energy resources; including peat, oil and oil shale;
- Extend gas storage in Latvia to 120 days or more and establish 90 days of reserves for oil and oil products;
- Enhance hydropower capacity;
- Construct or continue operation of a NPP at the Ignalina NPP site;
- Construct coal-fired power plants and coal import facilities;
- Further coordinate Baltic electricity generation;
- Further integrate the Baltic grid with other grids;
- Improve efficiency throughout the energy system.

This list of measures is by no means comprehensive and the order of the bullets does not indicate any prioritisation. However, one should not lose sight of the economic and technical supply potential for renewables in the region. Solar and geothermal energy have very low potential, transport costs for wood for biomass CHP are high, wind resources are modest and hydro resources are not expected to grow sufficiently to change their fuel mix share substantially. Renewable energy under these circumstances is costly, may require subsidies or guaranteed markets, and hence may be limited largely to meeting EU requirements.

Conclusion VIII: EU membership creates incentives and opportunities for improved energy security.

Rationale: The process of rationalising imports as well as the region's electricity system is taking place in the context of the Baltic States' accession to the EU. This accession and the requirements attached to it necessarily condition and colour the costs and benefits of the rationalisation process. Four requirements, in particular, will influence energy policy decisions and investments in the future expansion of the energy system in the Baltic States:

- Closing of the Ignalina NPP;
- Implementation of the EU Renewables Directive as well as other EU standards (ranging from environment to efficiency);
- The obligation to develop strategic oil stocks;
- Adoption of binding commitments for CO_2 reduction.

Membership in the EU provides an opportunity and a platform on which to develop an integrated Baltic energy system with common policies. It also offers the chance to expand the dialogue on grid integration and on energy supply security with other neighbouring European countries, including with Russia through the EU–Russia dialogue on energy.

With the closing of Ignalina 1 and 2 by the end of the study period, CO_2 emissions will rise, perhaps to the limits set for 2025, depending on the extent to which replacement power is generated from gas, coal or nuclear power. However, as with investments in energy supply, environmental outcomes can also be achieved more efficiently with regional approaches. For CO_2 emissions, and assuming an emission fee of €20/tonne CO_2, a regional approach to coordinated generation will permit the use of plants with the lowest emissions while long term restructuring can take place.

10. Risk response strategy

The risk of energy supply interruption can either be accepted or actions can be taken to mitigate such an impact. Mitigation strategies generally include measures to improve security of fuel supply for the Baltic electricity and district heating systems, or to improve the grid reliability, system efficiency and delivery of services to consumers. In all mitigation strategies an element of risk remains, since the cost of complete energy security at all times is unacceptably high from an economic and societal point of view.

The actions that can be taken fall into two broad categories:

- Actions can be taken to invest in supply facilities where security is an ancillary benefit, such as new generating stations, combined cycle facilities and district heating plants that must be purchased in any event to meet growth or replace old, inefficient and no longer economic facilities. The characteristics of these new facilities that do enhance supply security are incorporated into the design from the beginning at little or no additional cost to the investor or the economy. Examples are high-efficiency gas technologies, the provision of dual fuel boiler capability with natural gas and orimulsion as the fuels, diversification of fuels and fuel suppliers (e.g., orimulsion from Venezuela), or (given the current long term fossil fuel price projections) additional hydro-electric facilities and, where economically feasible, other renewables, or a new nuclear power station at the Ignalina NPP site.

- Actions that do not directly supply energy or electricity but that provide insurance against supply disruptions provide no direct return on investment except in case of supply interruptions. For the Baltic States, this is primarily natural gas and oil storage. This type of activity generally requires direct governmental support, but not necessarily financial support.

Energy investments that also improve the security of supply are those which diversify the source of fuel supplies and improve efficiency throughout the energy system, and are economically competitive and technically proven. This study shows the following supply-side investments to have these characteristics:

- A new nuclear power plant at the Ignalina NPP site in the 2015–2020 period. It is estimated that a new NPP in this time range would cost around €1 660 per kW_{el}, including all site costs, owners' costs but not interest during construction for operation in 2015[12].
- Rehabilitation and fuel switching of some or all of Lithuanian TPP to the use of imported orimulsion.
- A new 275–400 MW_{el} coal-fired power plant that meets EU environmental standards in Western Latvia in the 2015–2020 period.
- Construction of a series of high-voltage electricity interlinks with Poland in 2015 and with Sweden in 2012, and an increase in the capacity of the Estlink interlink with Finland in the near future to its maximum planned capacity of 600 MW_{el}.
- Construction of renewable energy projects that include biomass (primarily wood) and wind power projects in all three countries and small low-head hydroplants in Latvia, such that 10% of electricity and district heating is produced by these diverse indigenous energy sources by the end of 2025.
- All cases assume the continued modernisation by Estonia of the Narva oil shale units, begun in 2004, until approximately 1 400 MW_{el} of the current 2 000 MW_{el} capacity is modernised to EU standards for environmental releases. The reduction in overall capacity is the result of the retirement of several old units of approximately 100 MW_{el} each which are not worth refurbishment.
- Practical issues related to the validation (including infrastructure and logistic questions) of a new nuclear power plant need to be addressed before firmly committing to such a plant. A draft white paper enumerating these practical issues, based on international experience in purchasing nuclear units, has been prepared by a subgroup of the study Steering Committee and will be available after consideration by its members.

It is expected that these investments would generally be made by the private sector without much government involvement. In some cases, such as the new NPP, some government statutory and regulatory actions are needed to facilitate private investment. In all cases, coordinated planning and governmental agreement to encourage common investment would be most desirable.

The energy supply investments to enhance energy security considered in this study relate primarily to natural gas storage in the Baltic States and to the gas transmission infrastructure among the three States. These investments are, by their nature, primarily the responsibility of the three governments to agree on as necessary and to provide funding for construction of additional storage capacity and for filling the storage facilities.

[12] Interest during the construction is calculated by the supply model MESSAGE depending on the discount rate (here eight percent per year) and the plant's construction profile and thus is included in the least-cost decision making algorithm.

There is sufficient capacity now in the geological storage facilities in Latvia to provide 90 days of supply to the Baltic States. Estonia and Lithuania have no existing gas storage facilities. But there is no legal or commercial agreement among the three countries governing common utilisation of that storage. Indeed, the gas pipeline connection between the Lithuanian and Latvian underground gas storage facilities has been closed and is only now being re-opened. Latvia currently uses the underground storage system to balance seasonal costs by filling the storage in summer at lower summer prices and then drawing down the stored gas during the winter as needed.

Raising the capacity to a 120 days' reserve would permit the Baltic region to survive a winter-long loss of supplies. It would provide enough time for repairs and maintenance in case of a technical problem or for diplomacy if the problem is political.

The cost of raising the current storage level from 90 days to 120 days has been estimated at €13 million to €26 million (discounted) per year for the region (depending on future energy prices) over the period 2010 to 2025[13]. This includes capital, operating and maintenance costs, parts of which would already be incurred to meet the current EU requirement of maintaining a 90 days' reserve for oil (and, possibly, in future also natural gas). Given the current high dependence on gas, the investment in such storage facilities could be an affordable and cost-effective "insurance premium".

Main messages

1. Addressing energy supply and security issues on a coordinated regional basis reduces investment and operating costs, and benefits the economies of the three countries compared with individual country schemes.
2. Fuel diversification, where economically competitive and technically mature options are available (such as coal and nuclear power), addresses both near-term issues that result from a rapidly increasing dependence on natural gas from a single source, and longer term price increases caused by global competition for oil and natural gas. Use of renewable resources at about 10% of the demand range for electricity generation and district heating makes sense from a fuel diversification and economic point of view.
3. The most significant energy security issue, the rapid increase in natural gas use, can best be addressed by increasing natural gas storage to 120 days of reserve capacity. The estimated cost, while not trivial, is not huge – €13 million to €26 million (discounted) per year for the region (depending on future energy prices) over the period 2010 to 2025, shared by three countries.
4. Increasing interlinks between the Baltic countries and Sweden, Finland and Poland both supports energy security through diversification of resources in times of need and promotes longer term stability in electricity prices through access to and from more markets.
5. The Mazeikiai oil refinery is an essential part of any response to a loss of the natural gas supply. Specifically, the availability of distillates to support dual fuel-fired district heating, combined cycle and electricity generating capacity is vital in both the near- and long term future.

[13] These costs could be some 50% lower under a 30- to 40-year perspective.

6. Agreeing on a basis for jointly financing and accessing existing natural gas storage in Latvia strengthens regional energy security. No commercial or governmental agreement exists to do this.
7. Exactly how this is arranged and the timing may best be determined through a risk analysis that takes into account the probability of interruption and the societal cost of interruption. This can be done as an extension of the current analysis. A 120-day reserve would take the three countries through a winter and allow sufficient time to re-establish supplies or find alternatives.
8. The experience with 'Estlink' to arrange common projects for interlinks with Poland and Sweden could be usefully built upon.
9. There are opportunities to reshape the high-voltage network structure to take advantage of new possibilities after the construction of interlinks with Finland, Sweden and Poland.
10. Establishing an agreed basis for the creation of a common Transmission System Operator would create additional opportunities.
11. In any new ownership arrangement, it is important to maintain the transparency of ownership and operation of the Mazeikiai oil refinery that existed under Yukos.
12. Energy efficiency improvements could be pursued even more aggressively than is occurring at the present time.
13. Faster utilisation of renewable energy sources supports energy security and, to the extent renewables are economically viable and attractive, faster utilisation should be pursued as a common Baltic Energy Policy.
14. In the near-to-medium term (until approximately 2010), if Estlink is at its full 600 MW_{el} capacity, the Swedish electricity power interlink (1 000 MW_{el}) and the Polish interlink (1 000 MW_{el}) are developed and the Latvian natural gas geological storage capacity is made available to Estonia and Lithuania, with a further agreement to increase its capacity, then the Baltic countries will have created a robust and flexible fallback situation for potential gas supply disruptions. Also essential to this package is maintaining transparent ownership of the Mazeikiai oil refinery. This package will allow the Baltic States to take advantage of a continuing natural gas supply from Russia, as well as low-cost electricity from Russian excess generating capacity, thus keeping near-term electricity and district heating costs low.
15. In the medium-to-long term (2010 to approximately 2020) the possibility of a new nuclear plant at the Ignalina site (or a new coal plant in Latvia) with a 2015 start date can be kept open with relatively little initial capital by concentrating first on initial preplanning and feasibility studies, while watching the development of fuel costs for the next few years. This allows the Baltic States to still enjoy current low costs for electricity and district heating, and delays any major commitment of capital for new nuclear or coal-fired capacity until the trend of natural gas and oil prices is perhaps more clear. If all the initial analysis has been done, investment decisions about the type of new and replacement capacity can be postponed until the 2008–2010 period. This would also give time for improvements in energy efficiency to further reduce demand per unit of gross Baltic product.
16. In addressing the pursuit of energy supply on an integrated economic and technical basis as well as on a policy basis, many of the recommended approaches for adding flexibility and robustness to the overall energy supply system include some trade-offs

within the system. Continuing integrated analysis and cooperative decision-making will allow the three Baltic countries to continuously adjust and tailor their approaches to least-cost energy supply and security.

17. A joint three-country emergency plan to meet energy supply crises on a joint basis could be prepared. A mechanism to address an emergency should be in place before it is needed. The emergency could, for example be a natural disaster or a technical failure or a politically induced problem. A regional crisis-response group should be chartered as a part of this plan.
18. A mechanism to jointly analyse the continuing development of energy supply and security of energy supply now exists in the Working Group that prepared this analysis. The recommendations can only be accomplished if this is maintained.
19. To implement efficiently a common Baltic Energy Policy using the analytical output of the Working Group a coordinating body (committee) is needed. It is suggested that such a committee include representatives from governments, utilities and academe.

1. INTRODUCTION

1.1. Background

On 1 May 2004, Estonia, Latvia and Lithuania were inducted as full members into the European Union (EU). This historic date marked the end of a long and at times cumbersome and painful accession process. But membership has its privileges and opens the entire EU market to the Baltic economies with considerable opportunities for domestic economic development. Still, before the benefits can be fully reaped much restructuring of the domestic economic markets — some of which will be costly and painful — needs to be accomplished.

The national energy sectors and energy policies in the Baltic countries will have to be harmonised with EU energy policies, norms and standards, guided by the '*acquis communautaire*' — the body of common rights and obligations that ties all the Member States together. Concerning the energy sector, the prime aim of EU policy is to ensure a reliable supply of energy to all consumers at affordable prices, while respecting the environment and promoting healthy competition on the European energy market [1]. To achieve this goal, energy policies in the EU member countries are being formulated so as to:

- Ensure security of energy supply;
- Create an internal market for electricity and gas that functions efficiently;
- Promote high utilisation of renewable energy sources (RESs) in the total energy balance;
- Improve energy efficiency; and
- Integrate environmental dimensions, including climate issues, in energy strategies.

Their demographic and economic situation means the Baltic countries are among the smallest EU economies. EU integration and historical links to its Commonwealth of Independent States (CIS) neighbours mean these countries have small open economies in which trade and integration are essential for socioeconomic development.

Given the sizes of their economies, the national energy markets (electricity, gas, oil, etc.) themselves are relatively small. However, most of the current energy (and other) infrastructures date back to the era of the Soviet Union during which the Baltic countries were an integral part of, and structured for, the Soviet energy system. After the collapse of the Soviet Union and the acquirement of political independence, the inherited infrastructures were often over-developed for their individual energy markets (e.g. the Ignalina nuclear power plant (NPP) and Mazeikiai refinery in Lithuania, the Inčukalns underground gas storage (UGS) and Daugava hydro power plants in Latvia, the oil shale industry in Estonia or the electricity and gas transmission systems). Given their small open economies and existing energy infrastructures, it appears that many of the issues listed above (e.g., an internal or regional market for both electricity and gas that functions efficiently or an energy supply that is secure) can be better addressed and resolved in a regional context rather than at the respective national levels.

The following paragraphs succinctly provide the rationale for this assertion. During 2000–2002, the International Atomic Energy Agency (IAEA) provided technical assistance to the Government of Lithuania for a study on *Energy Supply Options for Lithuani*a [2]. This study assessed various scenarios for the potential power-sector developments in Lithuania, especially exploring options after the closure of Ignalina NPP's Unit-1 at the end of 2004 and Unit-2 at the end of 2009. The closure is part and parcel of Lithuania's accession obligations. Until 2005, INPP accounted not only for 80% of the country's electricity supply, but also was a mainstay of the regional electricity system. Clearly, taking out of operation an otherwise economically viable power plant of such dimensions is expected to cause discontinuity, supply problems and added costs. In essence, the results of the study show that the closure of Ignalina NPP results in:

- An increase in energy import dependence, especially with respect to natural gas, but also to electricity;
- Higher system costs and higher electricity prices compared with the continued operation of the Ignalina NPP;
- Increasing emissions of greenhouse gases and other air pollutants; and
- A new NPP of standard size that lacks competitiveness in a national-only context[14].

The insights gained from the study not only helped to formulate the Lithuanian national energy strategy [3], but also initiated discussions with Latvia and Estonia about energy supply security and the development of efficient, open regional energy markets. Building on the success of the Lithuanian project, this study (*Analysis of Energy Supply Options and Security of Energy Supply in the Baltic States*) was initiated with participation from all three Baltic countries. This regional study analyses (1) the future development options for the energy sectors in the Baltic countries from the perspectives of energy supply security, market efficiency and environmental protection, and (2) the impact of energy and electricity market integration on national approaches.

The study was supported by the IAEA under the regional technical cooperation project RER/0/19, *Sustainable Energy Options in Eastern Europe*. The IAEA provided expert services, modelling support and training of experts from the Baltic countries in model application as well as technical backup. Baltic energy supply security is an area of interest to the North Atlantic Treaty Organization (NATO), so NATO lent strong assistance to the study by organising and supporting workshops and meetings.

1.2. Objectives of the study

To meet the future energy service requirements of the Baltic countries in an efficient, secure and environmentally benign manner lies at the heart of this study. Taking into account the availability of domestic energy reserves and resources, the vintage of existing energy infrastructures (including regional and inter-regional interconnections), future technology options and future energy trade links, the study aims to identify robust energy development strategies for the region. The term ‘robust’ encapsulates the potentially conflicting dimensions of energy security, economic efficiency and environmental protection. For example, supply security is likely to incur an ‘insurance premium’ or environmental protection may well raise the costs of energy service supplies.

Specifically, the study intends:

- To identify cost-optimal energy system development trajectories for each of the Baltic countries, each based on the maximum national energy self-sufficiency while complying with EU-wide obligations (e.g., environmental protection, the Renewables Directive, etc.).
- To determine and quantify the benefits and costs of a regional integration of the energy systems of the three Baltic countries (sharing of infrastructures and generating capacities, access to resources and storage facilities and utilising interconnections, etc.) for different levels of energy import dependence. Benefits and costs include the economics of energy supply, changes in emissions, differences in energy import dependence, etc.

[14] This may no longer be the case after the steep increase in international fuel prices in 2004.

- To formulate policy recommendations for actions targeted at the improvement of energy security in the Baltic region.

1.3. Study organisation

This study is an excellent example of international cooperation between the IAEA and its Member States and between the Member States themselves. National study teams were set up in each of the countries, comprising experts from the Ministry of Economy, energy research institutes, universities and energy utilities. Senior members of each country team, together with senior IAEA staff and an expert from NATO, formed a Steering Committee, which oversaw the study execution, harmonised assumptions and inputs, checked and validated results, and provided overall guidance to the national teams. The national study teams collaborated, closely facilitated and assisted by the Study Coordinator (*Figure 1.1*).

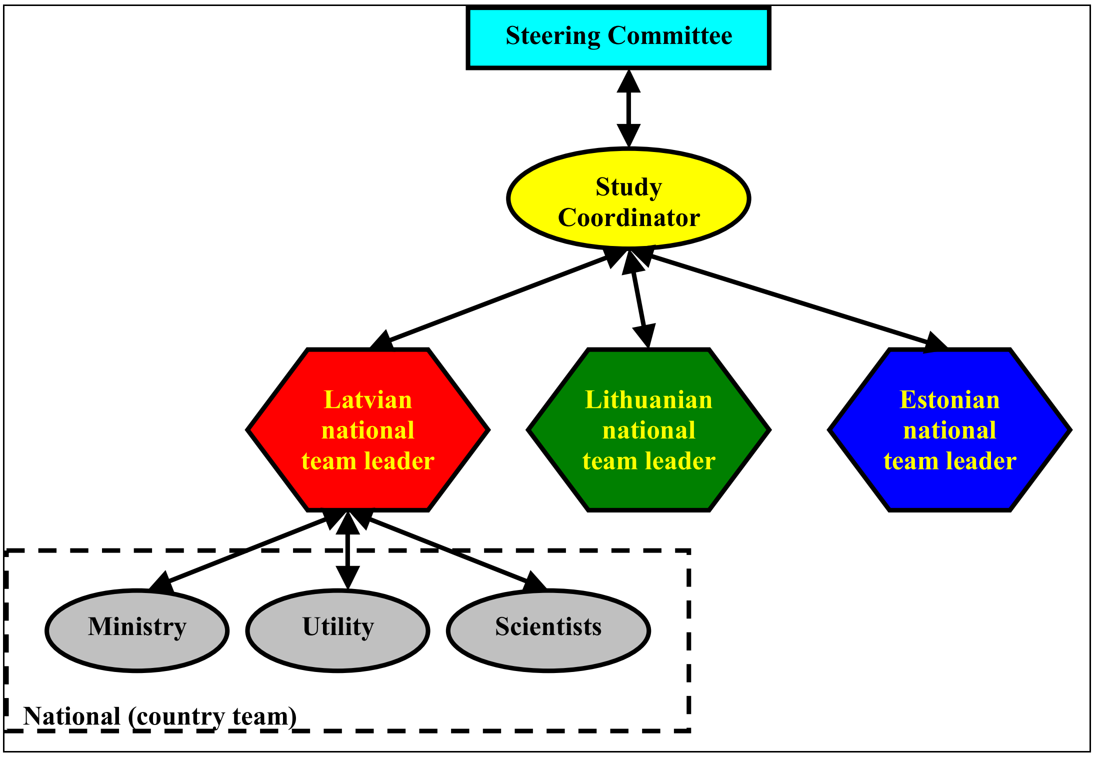


Figure 1.1. Organisation of this study.

Meetings of the study teams and the Steering Committee were held regularly to resolve outstanding difficulties, as well as to review the status of the study implementation. All parties involved contributed, to different extents, to the financing of this study. The delegation of responsibilities and financial contributions were clearly defined and agreed upon at the inception of the project (shown here in *Table 1.1* and *Table 1.2*).

Table 1.1. Delegation of responsibilities

Parties involved in this study	*Responsibility*
Ministries	— Providing information on legislation, policies and international obligations — Assistance in data acquisition by signing letters to relevant organisations — Review of results and recommendations — Contacts with policy makers — Organisation of work groups from representatives of other organisations
Utilities	— Financing (sponsorship) of study work up to the limit approved by the Management Boards — Steering Committee meeting organisation — Assisting experts in data collection, model calibration and calculations
Research Institutes	— Data collection — Calibration — Calculation — Analysis
IAEA	— Support for the Study Coordinator — Advice, consultancy — Methodology (models), training in methodology — Link to NATO and EU institutions
NATO	— Security analysis (assessment of energy supply security for the Baltic States)

Table 1.2. Division of financial responsibilities

Expenditures	*Responsible party*
Local costs, including local experts	Participating countries
Data collection	Participating countries
Costs of Study Coordinator, IAEA expert and consultants	IAEA
Expenditures for IAEA staff travel	IAEA
NATO experts	NATO
Travelling expenses for country teams	From participating countries, each party for its own costs
Hardware	Participating countries
MESSAGE model	IAEA (model is provided free-of-charge for all participating parties)
Training in MESSAGE model and Steering Committee meetings in Vienna	IAEA
Steering Committee meetings and workshop organisation in the Baltic States	Utilities
Workshops and final meeting in Brussels	NATO

1.4. Methodological description

This study is based on a scenario approach. Scenarios are neither forecasts nor predictions. Scenarios are internally consistent images of how the future might unfold depending on the underlying assumptions about future socioeconomic, technological and environmental developments.

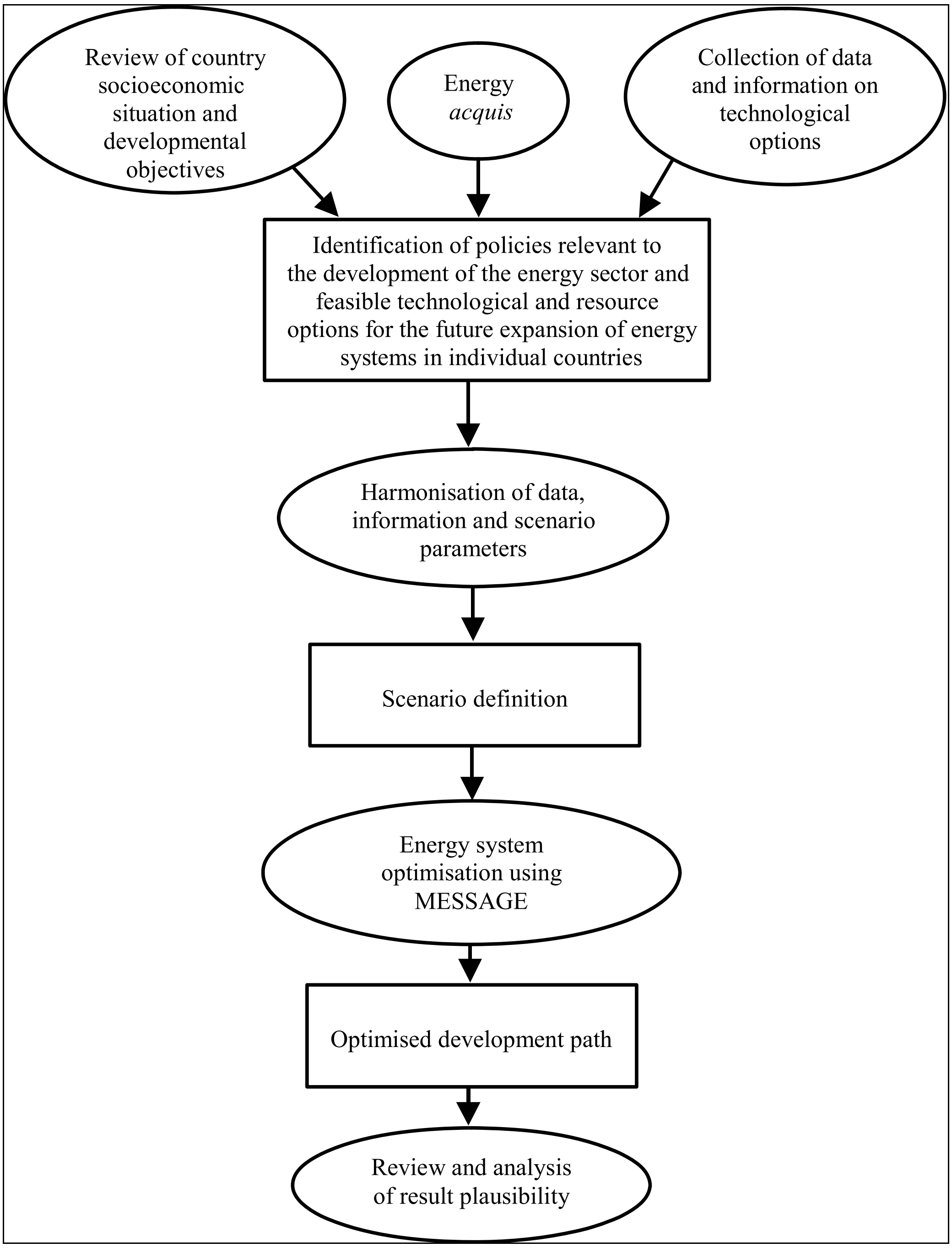


Figure 1.2. Analytical framework of this study.

Figure 1.2 shows the various steps of the study. First, a comprehensive review of each country's situation was carried out. This identified policies relevant to the future development of the national energy systems, including environmental protection measures, policies to promote the use of renewable energy, policies that target the improvement of energy efficiency and those that increase the independence of energy supply, etc. This review served as a basis to develop informed scenario assumptions about plausible future development paths. In parallel, projections of future electricity demand were derived from previous demand analyses. Second, performance data and information about current and future technology and resource options were collected.

The third step was to harmonise all scenario characteristics used by the country teams. This harmonisation dealt inclusively with scenario assumptions, compliance with EU-related obligations and all conceivable technical options for the future expansion of energy systems in the Baltic countries.

The fourth step then involved modelling and optimisation of the national energy systems as well as the integrated Baltic system for each of the predefined scenarios.

The MESSAGE (Model for Energy Supply Strategy Alternatives and their General Environmental impact) model is the main modelling platform used in this study. In MESSAGE, the entire energy supply system is represented as a network of conversion technologies, activities and links. This starts from the extraction or supply of primary energy, passes through energy conversion processes (e.g., electricity generation) to transmission and distribution to meet the demand for final energy (or energy services) in the industry, agriculture, transportation, household and service sectors. In this energy network the links represent technologies or transportation and allocation processes of energy, while the nodes represent energy forms (e.g., electricity, oil and gas). Both existing technologies and candidate technologies for future system expansion are included in the network. Technologies are represented by a set of parameters, such as specific investment costs, fixed and variable costs, fuel inputs and related costs, energy conversion efficiencies, historical capacities, availability factors, emission factors and other user-specific parameters.

The mathematical method used in the MESSAGE model is linear programming, which means that all the technical and economic relationships that describe the energy system are expressed in terms of linear functions. The optimisation criterion of the MESSAGE model is to minimise the present value of the cumulative costs of the energy system throughout the planning period. The planning period is user-defined. In this study, the calculation period covers 45 years, while analysis is mostly limited to the first 25 years.

The decision variables are energy flows and capacities of technologies. The model variables are determined subject to a system of constraints that represent structural and technological properties of the energy system, existing stocks of equipment, projected energy demands, energy policies, environmental protection policies, etc.

As a result of the optimisation given by the MESSAGE model, a least-cost inter-temporal mix of energy supply technologies can be found for each individual country in the Baltic as well as for the integrated Baltic-wide system. By analysing the results, answers to the 'what if…?' type of questions can be proposed. Thus, strategies for a future energy supply structure can be formulated, energy supply dependence can be assessed and compliances with the EU energy *acquis* can be analysed. Finally, the implications of various policy measures for the competitiveness of different technological options can be established.

1.5. Organisation of this report

Following this Introduction, Chapter 2 of the report reviews the current socioeconomic and demographic situations in the three countries. Chapter 3 details the policies and legislations that frame the energy sectors in each of the countries. This includes policies that deal specifically with energy supply security, protection of the environment and opening up of the electricity market, and also those that promote the use of renewable energies and cogeneration. Chapter 4 explains the projections of electricity demand carried out for individual countries. In Chapter 5, the evolution of energy prices is detailed, which serves as a common ground for estimating Baltic-wide energy prices in the future. Chapter 6 puts together various technological options (existing as well as new) to be considered in the individual country's energy system and also for the regional energy system in the Baltic region. Scenario definitions are given in Chapter 7, which is followed in Chapter 8 by the scenario model results, essentially the future vision of the expanded energy system that corresponds to a given scenario. Chapter 9 analyses the security indicators for the Baltic system, both individual and regional. The policy-oriented conclusions and recommendations are given in the final chapter of the report, Chapter 10.

2. COUNTRY PROFILES

2.1. Estonia

2.1.1. Geography, location and climate

Estonia, the most northerly of the Baltic States, is located on the eastern coast of the Baltic Sea. In the south, Estonia shares its border with Latvia and in the east with the Russian Federation. The western and northern overseas neighbours of Estonia are, respectively, Sweden and Finland. Estonia is one of the smallest countries in Europe, with an area of 45 200 km^2. The distance between the eastern and western borders is approximately 370 km and between the northern and southern borders approximately 240 km.

The country is relatively flat — the average elevation is about 50 m and the highest point reaches only 318 m above sea level. About 30% of the land is arable, the principal agricultural outputs being dairy products, meat and cereals. Forests cover approximately half the territory, while peatlands cover about 22% (partly coinciding with forest areas).

The climate is determined by Estonia's location in the northwestern part of the Eurasian continent in the vicinity of the North Atlantic. The Baltic Sea has a strong influence on the local climate, especially in coastal regions. The temperature ranges from an average in January of –4.0°C to +18.8°C in July; the annual mean being 6.5°C. In spite of its small size, the climate differences in Estonia are significant, especially during the colder part of the year. For example, the mean air temperature in January varies from –7.5°C in the coldest places in east Estonia up to –2.5°C on the western coast of Saaremaa Island. The annual mean air temperature in the most western point (Vilsandi Island) is 6.0°C and in the most eastern points it ranges from 4.2 to 4.6°C (*Table 2.1*). The winter snow cover lasts for about 3 months. The mean annual precipitation is quite different as well — from 500 mm on the coast to almost 700 mm in the uplands. Precipitation is heaviest at the end of summer and lowest in spring.

Table 2.1. Some climatic indicators for Estonia

	Number of days in average heating season	*Average outdoor temperature during the heating season (°C)*	*Temperature for calculation of heating demand (°C)*
Range of average values over regions	210 to 224	–1.8 to +0.7	–19 to –23
Average over regions	217	–1.2	–21

2.1.2. Demographic situation

In 2003, the population of Estonia was 1.356 million. Compared to Europe in general, the population density of Estonia is very sparse, the average density being 31.2 inhabitants/km^2. In some rural areas it is as low as 10 inhabitants/km^2. The counties, towns and rural municipalities are all relatively small. In most counties, the population is between 30 000 and 190 000 inhabitants. Most of the people (69.2%) live in urban areas. The capital Tallinn has a population of 397 000 (i.e., 29.3% of the country's total). Other major cities are Tartu (101 000), Narva (68 000), Kohtla-Järve (47 000) and Pärnu (45 000). The average population of rural municipalities is a couple of thousand people.

The population of Estonia was the highest in 1990 — 1.57 million. In 1991 its population started to decline, and by 2003 it had decreased by more than 215 000 people (i.e., by 13.7%). This reduction can be attributed both to emigration and to the decrease in the birth rate, which has been falling steadily since 1989. The annual rate of natural growth has been negative since 1991, being in the range –4.0 to –5.5%. While the total fertility rate was 2.26 in Estonia in 1988, by 2002 it had dropped to 1.37. In the meantime, the death rate increased, as the population became older. The average life expectancy among the general population is 65.2 years for men and 77.0 years for women, one of the lowest in Europe, being 7–10 years shorter than the average in European Union (EU) Member States.

2.1.3. Macroeconomic situation

After regaining independence in 1991, Estonia's transition to a market economy occurred in two phases. From 1991 to 1995 new political and economic institutions were developed, while simultaneously transforming the economic system into a market economy. Since 1995, the new institutions and market-based economy have become firmly established and new legislative and economic measures have concentrated on fine-tuning the system. The annual growth rate of gross domestic product (GDP, in constant prices), which peaked at 10.5% in 1997, has been in the range 5.1 to 7.8% during recent years. The consumer price index (CPI) has been decreasing, reaching 1.3% in 2003. The producer price index (PPI) has been even lower — 0.2% in 2003. Some key indicators are presented in *Table 2.2*.

Table 2.2. Selected indicators of economic development

	2000	*2001*	*2002*	*2003*
GDP at current prices (million €)	5926	6668	7469	8042
GDP at constant prices (million € 2000)	5926	6305	6761	7109
GDP change (% over previous year)	+7.8	+6.4	+7.2	+5.1
GDP per capita (€2000/cap)	4330	4890	5500	5920
CPI (% change over previous year)	+4.0	+5.8	+3.6	+1.3
PPI (% change over previous year)	+4.9	+4.4	+0.4	+0.2
Foreign trade turnover (% of GDP)	135.7	125.7	115.2	118.3
Export to import ratio (%)	81.4	80.8	76.4	74.3
Total external debt (% of GDP)	54.6	55.6	60.1	69.1
Current account balance (% of GDP)	–5.5	–5.6	–10.2	–13.2
Exchange rates (annual average):				
EEK/US$	16.981	17.479	16.606	13.855
EEK/EUR	15.6466	15.6466	15.6466	15.6466

Compared to EU Member States, the absolute level of the GDP of Estonia is very small — 8042 million € in 2003. The relative level is quite low as well — using the purchasing power parity (PPP) concept to compare economic indicators between EU Member States, Estonia's GDP per capita in 2002 was only 46% (49% in 2003, preliminary data) of the EU-25 average.

At the same time, economic development indicators for Estonia compared to those of the other countries of Central and Eastern Europe are average.

Economic growth in Estonia results primarily from the rapid growth of exports to industrial countries, supported by foreign investment inflow. Estonia is a country open to foreign trade. In 2002, the foreign trade volume (goods and services) amounted to 115.2% of GDP.

In 2003, the GDP structure (presented in *Table 2.3* as shares in gross value added — GVA) indicates that the service sector (*Nomenclature statistique des activités économiques dans la Communauté Européenne* (NACE –– Statistical classification of economic activities in the European Community) groups G-P) constitutes the greatest share — representing two-thirds of the GVA. Agriculture, on the other hand, is of very little importance (4.4%) nowadays.

Table 2.3. Structure of the gross value added in 2003

Sector	*Share in gross value added (%)*
Agriculture, forestry and fishing	4.4
Industry (incl. energy and water supply)	23.2
Construction	6.4
Trade, transport and communications	30.0
Business activities and financial services	19.8
Other services (incl. public services)	16.2

More detailed analysis indicates that in 2003 the greatest share of value added was generated in the trade, transport and communications sectors, which are NACE groups G–I. The largest contribution (51%) came from transport, storage and communication activities, and 44% came from wholesale and retail trade.

In industry (NACE groups C–E), 23.2% of GVA was created, of which 82.8% was created in manufacturing (NACE group D). Most of the manufacturing production is in the food industry, the metal and machinery industry and the wood, paper and furniture industry.

Since the introduction of Estonia's national currency — the kroon — Estonia has been using the Currency Board System (CBS) at a fixed exchange rate (pegged initially to the German Mark, and since 1999 to the EUR). According to the CBS, the cash circulating in the economy is completely covered by the foreign currency reserves of the central bank.

The stable monetary and fiscal policies have turned Estonia into an attractive country for foreign investors. By the end of 2003, foreign investments into Estonia totalled 10.3 billion €. The flow of foreign direct investments (FDIs) has been more than 10% of GDP per year during the past decade. The cumulative stock of FDI amounts to 5.9 billion € (as of June 2004). The main areas in which foreign-owned firms have a relatively high share, compared with domestic producers, are in the manufacturing of paper and paper products, textiles, electrical machinery and construction materials.

The high import content of the investment projects led to imports of goods increasing faster than exports, and the trade deficit has been increasing for several years, reaching 17.4% of GDP. The constant involvement of foreign resources in expanding the capital base of the Estonian economy has, besides increasing the total volume of FDIs, increased the debt burden of the Estonian economy. In 2003 the total volume of FDIs into Estonia increased to 64% of GDP and the external debt burden reached almost 70% of GDP.

In exports, traditionally the main groups of goods were machinery and equipment, timber, timber products, furniture and products of the textile industry. Imports were also dominated by machinery and equipment; followed by chemical products, transport vehicles and metal products.

During recent years the main trade partner has been the enlarged EU, whose share in the total turnover of goods amounted to 76% in 2003. Major trade partners include Finland, Sweden, Germany, Latvia and Lithuania.

The International Monetary Fund (IMF) assessed Estonia's economic performance as being among the best of the new EU countries over the past decade. After accession to the EU on 1 May 2004, at the end of June 2004 Estonia had already joined the second European Exchange Rate Mechanism (ERM II). Estonia has achieved considerable nominal convergence, with all indicators at levels better than the average of the other new EU members.

2.1.4. Energy sector

2.1.4.1. Characteristics of existing supply system

The fuel and energy sector is within the governing area of the Ministry of Economic Affairs and Communication. The Estonian market for oil products is deregulated, open and competitive. Estonia has no oil-refining capacity, and therefore all petroleum products are imported — mainly from Lithuania, Finland and Russia. Nevertheless, Estonia has long experience of processing oil shale into fuel oil — shale oil, which is the only locally produced liquid fuel. There is also considerable transit of both crude oil and petroleum products. Almost 400 companies are active as suppliers of liquid fuels.

Estonia has no indigenous natural gas, so it is fully dependent on imports of natural gas from Russia. Natural gas is imported into Estonia both directly from Russia and via the Inčukalns underground gas storage (UGS) in Latvia. A map of the major gas pipelines is given in *Figure 2.1*.

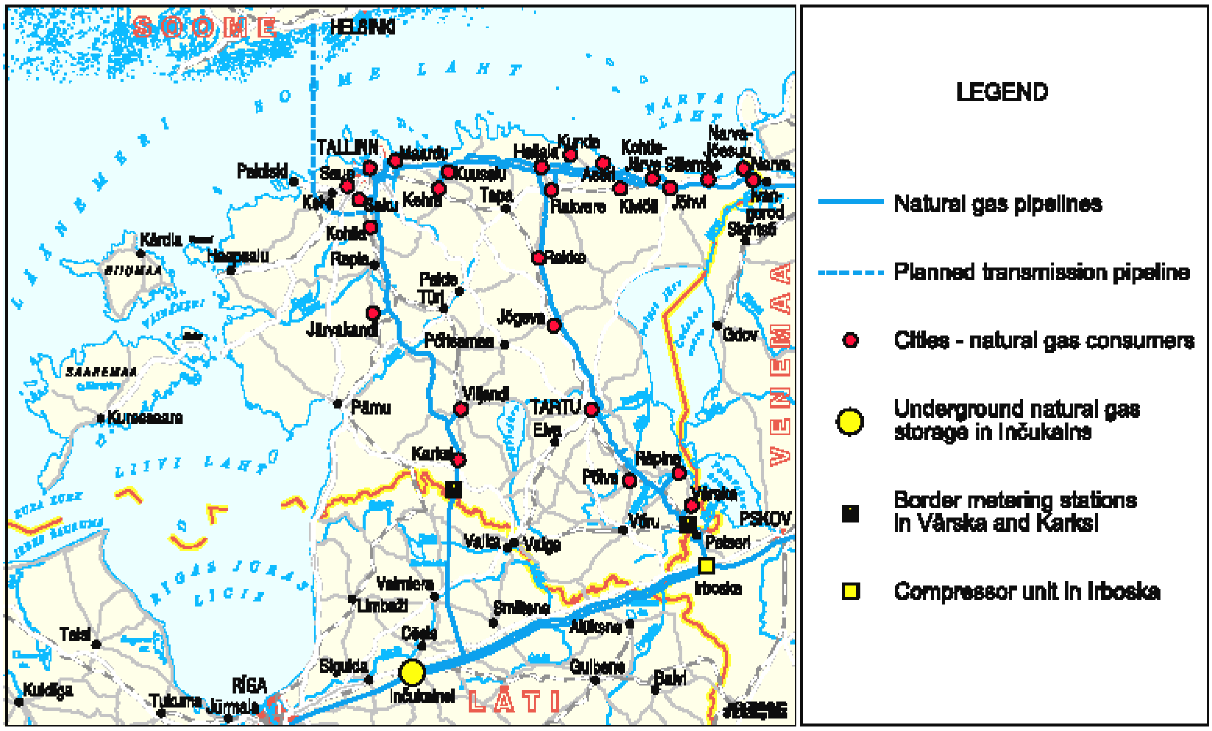


Figure 2.1. Natural gas supply network in Estonia (Source: AS Eesti Gaas).

For many years the AS Eesti Gaas (Estonian Gas Ltd) was the only gas company in Estonia engaged in the import, transportation, distribution and sales of natural gas. AS Eesti Gaas was established in 1992 on the basis of the state enterprise Eesti Gaas. Initially, the state owned 70% of the shares in the company. Privatisation started in 1993 and was completed in 1999. At present the shareholders in AS Eesti Gaas are:

- OAO Gazprom — 37.02%;
- E.ON Ruhrgas Energie AG — 33.60%;
- Fortum Oil and Gas Oy — 17.72%;
- Itera Latvia — 9.75%;
- Other shareholders — 1.91%.

The Estonian electricity sector is organised around Eesti Energia AS (Estonian Energy Ltd), which was established as an independent company in 1998 on the basis of the former state enterprise Eesti Energia and its subsidiaries. At present, the Eesti Energia Group incorporates a total of 23 companies, including enterprises that mine oil shale. Eesti Energia AS is a 100% state-owned vertically integrated public limited company, engaged in power generation, transmission, distribution and sales, as well as in other power-related services throughout almost all of the country. Nevertheless, some privately owned companies deal with generation (small-scale combined heat and power (CHP), mini hydro and wind turbines, and also some industrial CHP plants), as well as with the distribution of electricity. In total, the power plants of Eesti Energia AS generate approximately 98% of the electricity in Estonia. The data on major power plants are given in *Table 2.4.*

Table 2.4. Estonian power plants (2003)

Power plant	*Installed capacity (MW)*	*Electricity production (net; GWh)*
AS Narva Elektrijaamad	2700	8440
Iru Power Plant	190	387
AS Kohtla-Järve Soojus	67	44
Other power plants	62	230
Total in Estonia	3019	9101

The generating capacity based on renewable sources includes only 3.8 MW of hydropower and 2.5 MW of wind turbines.

According to the EU *acquis*, the unbundling of electricity-related core activities is one of the underlying conditions for the formation of an open electricity market. For the most part, other elements of the Estonian power system — transmission and distribution networks — are owned and operated by the Eesti Energia Group also. In Estonia, the legal separation of the main activities in the power sector was carried out in 2004 only. OÜ Põhivõrk (National Grid Ltd) started operations on 1 April 2004 with the task of electricity transmission, via 110–330 kV lines and substations, and technical management of the grid. The national grid consists of 136 substations and 5215 km of transmission lines. OÜ Jaotusvõrk (Distribution Network Ltd), as a separate legal entity, was started on 1 July 2004 with the task of distributing electricity to consumers at voltage levels up to 35 kV. The distribution network consists of 17 231 substations and 60 368 km of distribution lines. The share of OÜ Jaotusvõrk in the distribution and sales of electricity in Estonia is approximately 90%. Some years ago there were 80 small distribution network enterprises besides Eesti Energia AS networks. According to the new *Electricity Market Act*, in force since 1 July 2003, the requirements and responsibilities set for network operators have become significantly stricter and therefore Eesti Energia AS has acquired 30 networks and took over more than 4800 clients. At present, there are still 41 small privately owned distribution enterprises, of which the largest are Fortum Läänemaa Ltd and Narva Elektrivõrk Ltd.

As regards international connections, the Estonian electricity market is well developed — it is interconnected with the power systems of Russia, Latvia and Lithuania. There are plans for a connection to the Nordic power system (Nordel). A project for a submarine cable link to Finland is in the preliminary preparations phase. The objective is to build a 350 MW high-voltage, direct-current connection (HVDC link) via the Gulf of Finland. The project is promoted by Pohjolan Voima Oy, Helsinki Energy, Eesti Energia AS, VAS Latvenergo and AB Lietuvos Energija. The planning of the project has been ongoing since 1998, when the first feasibility studies were carried out, followed by in-depth studies into the design of the cable route and direct-current substations, studies of the land and sea routes, as well as technical studies and preliminary design.

2.1.4.2. Primary energy supply (imported and domestic resources)

Estonia is the only country in the world to use oil shale as its major primary source of energy. Oil shale is a solid fuel with a low calorific value and high ash content. Oil shale is mined in the northeastern part of Estonia. Wood is another important primary energy resource — more than half of the territory of Estonia is forested. The third important indigenous fuel is peat.

There are a number of small (mini and micro) hydroelectric power plants. The capacity of the largest plant (Linnamäe) is 1.1 MW. The installed capacity of all hydro plants is 3.8 MW and production volume was 12.8 GWh in 2003. There are some wind turbines, with a total capacity of 2.5 MW and production of 6.1 GWh (2003). In 2003 six hydro- and two wind-power plants started to produce electricity, contributing to the increase in the share of renewable electricity supply. Compared to 2002, the production of hydro energy approximately doubled.

Regarding electricity, Estonia is a net exporter: in 2003 its export (1989 GWh) exceeded its import (93 GWh) by almost 1900 GWh. In 2003, 19.6% of generated electricity was exported, mainly to Latvia, but also to Russia. The supply of Estonia's primary energy is shown in *Figure 2.2*.

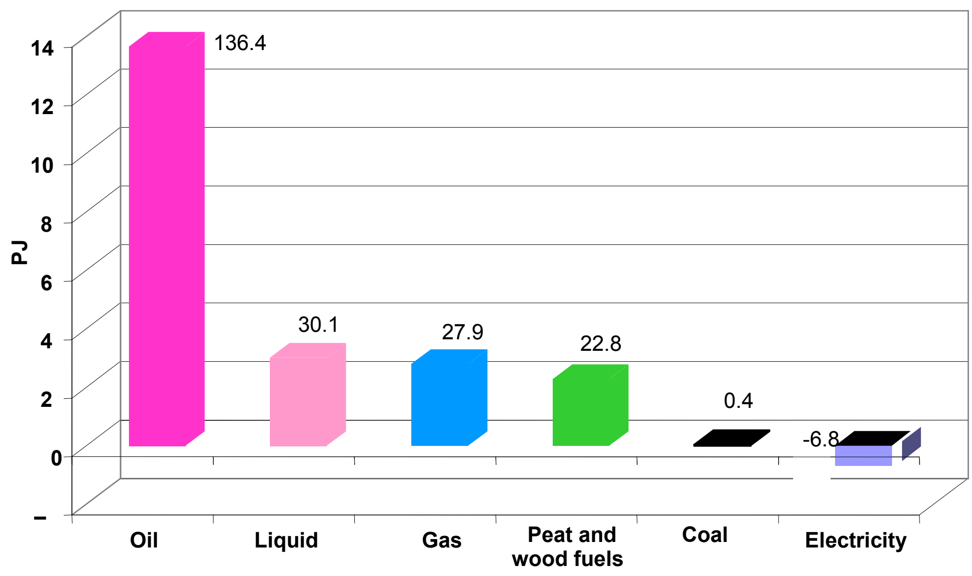


Figure 2.2. Supply of primary energy in 2003.

Estonia's dependency on imported energy sources is approximately 40%. In the total primary energy consumption, the share of fossil fuels is very high — approximately 90%. There are no indigenous oil, natural gas or coal resources in Estonia. As there are no crude-oil refineries, all petroleum products are imported. Nevertheless, a part of oil shale is processed into fuel oil — shale oil. All natural gas comes from a single source only — from Russia. In 2003, the import volume was 847 million m^3. A part of the Russian gas is imported via UGS in Latvia.

Primary energy supply has been in decline since 1991, mainly as a result of reduced industrial activity, but also because of a reduction in the production of power for export to Latvia and Russia, as well as due to efficiency improvements.

In 2003, a major part (84%) of the primary energy supply was utilised in conversion processes. Approximately half of the converted primary energy was used for electricity generation, and the rest for heat production (21%) and to manufacture secondary fuels — mainly shale oil and peat briquettes. A total of 10.7% of primary energy was utilised by the energy sector, used for non-energy purposes and lost in transmission and transportation processes, leaving 5.2% of the primary energy for direct final consumption.

2.1.4.3. Final energy consumption

The final energy consumption (FEC) in Estonia comprised 109.7 PJ. The structure of the final consumption by energy type is presented in *Figure 2.3*. Almost half of the final consumption is for heat (28.2%) and electricity (18.4%), and liquid fuels require 31.6% and solid fuels 17.3%.

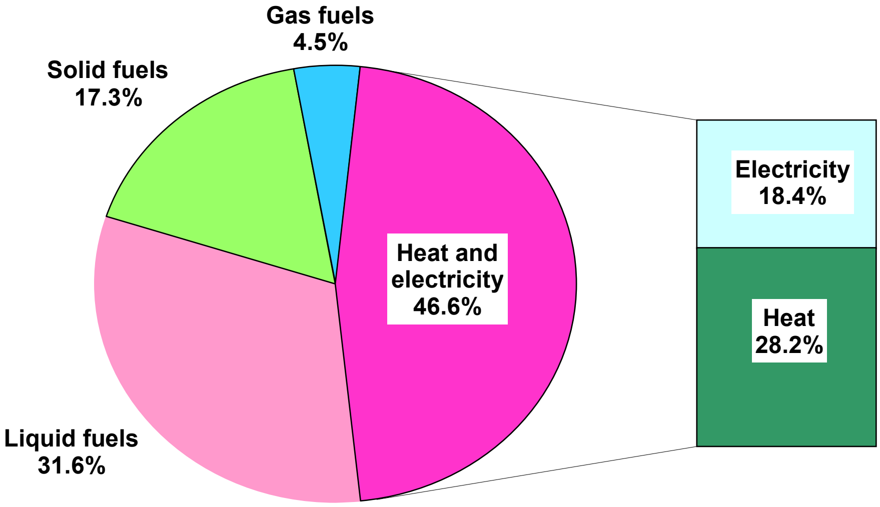


Figure 2.3. Structure of final energy use by type in 2003.

The structure of FEC by economic sectors is given in *Figure 2.4*. The total FEC by industry was 24.5 PJ in 2003, only 22.3% of the total, which reflects that Estonia is a relatively lightly industrialised country. The main branches of manufacturing are wood processing, textiles, shipbuilding, oil-shale energy, fishing and the food industry.

Approximately one-quarter of final energy is utilised in transportation (including use by households). The share of commercial services and public sector increased during recent years, reaching 12% in 2003. The use by agriculture has dropped to 4.2%.

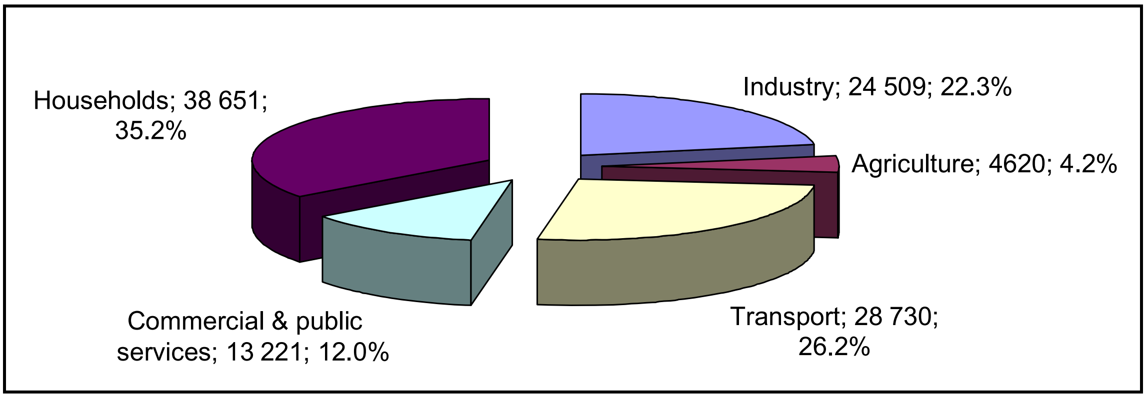


Figure 2.4. Sectoral structure of final consumption in 2003 (TJ).

The largest share (35.2%) of final energy is used in the residential sector, for which consumption was 38.7PJ in 2003, representing more than one-third of the total FEC.

2.1.4.4. Energy and fuel prices

The average prices of boiler fuels purchased by energy utilities are presented in *Table 2.5*. These prices do not include value-added tax (VAT), but excise taxes are included.

Table 2.5. Average fuel prices in energy utilities (excluding VAT)

Fuel	*Unit*	*2000*	*2001*	*2002*	*2003*	*2004 9 months*
Coal	€/t	50	54	56	56	57
Oil shale	€/t	8.8	8.8	8.8	8.1	7.9
Sod peat	€/t	15	16	18	19	20
Peat briquettes	€/t	36	39	48	52	57
Fuel wood	€/m^3s	7.0	7.7	8.9	10.4	11
Wood chips and wood waste	€/m^3s	5.7	6.3	6.9	7.5	7.6
Natural gas	€/10^3m^3	73	72	88	91	87
Heavy fuel oil	€/t	104	114	113	120	118
Shale oil	€/t	97	117	115	122	116
Light fuel oil	€/t	260	302	268	288	273

In Estonia most of the fuel prices are market based. The only exceptions are the price of oil shale and the prices of natural gas for small (non-eligible) consumers. Until 2002, natural gas prices had been equipment-based, that is, the price of natural gas depended on the purpose for its usage. Since 1 January 2002 the price per cubic metre has depended only on the quantity of consumed gas. Since 1 January 2003 all consumers have been divided into five groups, depending on their annual consumption. *Table 2.6* presents the current tariffs, which were introduced on 1 January 2003, except for the tariff for the smallest consumer group — this was enforced on 1 January 2002.

Table 2.6. Tariffs for natural gas supplied by AS Eesti Gaas (€/1000 m^3)

Annual consumption (m^3)	*Excluding VAT*	*Including VAT*
0–200	254	300
201–750	190	224
751–3000	146	173
3001–10 000	141	166
10 001–200 000	136	160

All consumers with an annual consumption over 200 000 m^3 are eligible to select suppliers and to negotiate the price of natural gas directly with the supplier.

The average prices per energy unit (€/GJ) of fuels purchased by the energy utilities are presented in *Figure 2.5* and were calculated using the average calorific values of fuels.

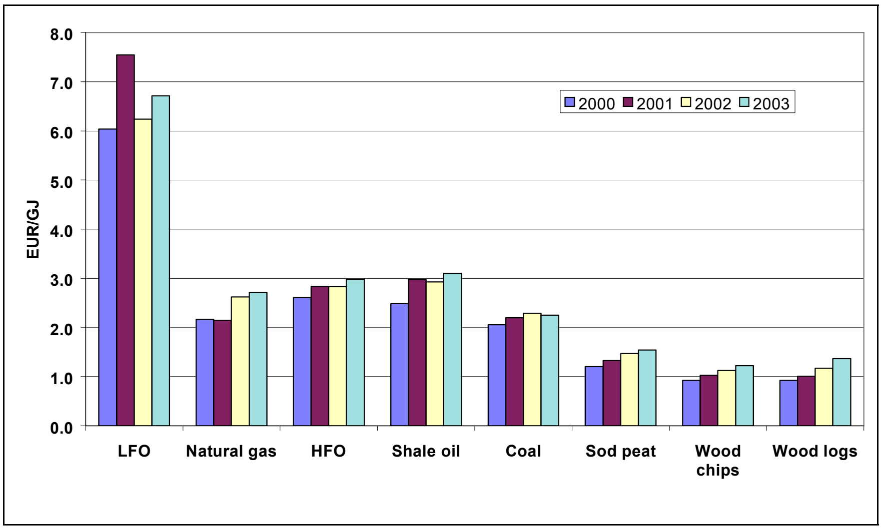


Figure 2.5. Changes in the average price of fuels used by energy utilities (excluding VAT; 2000–2003). HFO, heavy fuel oil; LFO, light fuel oil.

In Estonia, electricity prices for non-eligible consumers have to be approved by the Energy Market Inspectorate. The current tariffs were introduced on 1 April 2002. The average prices paid for electricity by non-household consumers in 2003 are presented in *Table 2.7*

Table 2.7. Average electricity price for enterprises in 2003, €/100 kWh

Consumers	*Average price*
Industry	4.51
Energy sector	4.33
Agriculture	5.14
Transport	4.96
Commercial and public services	5.08
Total average	4.79

Tables 2.8 and *2.9* present electricity prices (estimated using relevant tariffs), collected by EUROSTAT, that correspond to 1 July 2004. The prices are expressed in €s converted at PPP. This takes into account the purchasing power of the currency and enables the prices between countries to be compared on a fairer basis. Prices are also given in two ways — including and excluding taxes. In Estonia, the only tax imposed on electricity is VAT of 18%.

Table 2.8. Electricity prices for industry (as of 1 July 2004)

Consumer		*€/100 kWh*	
Group	*MWh/a*	*Excl. taxes*	*Incl. taxes*
Ia	30	5.66	6.67
Ib	50	5.34	6.31
Ic	160	5.26	6.21
Id	1250	5.02	5.92
Ie	2000	4.72	5.57
If	10 000	4.28	5.05
Ig	24 000	3.91	4.61
Ih	50 000	3.62	4.28
Ii	70 000	3.30	3.89

Table 2.9. Electricity prices for households (as of 1 July 2004)

Consumer		*€/100 kWh*	
Group	*MWh/a*	*Excl. taxes*	*Incl. taxes*
Da	0.6	7.16	8.42
Db	1.2	6.01	7.11
Dc	3.5	5.75	6.78
Dd	7.5	5.56	6.58
De	20.0	5.24	6.15

Regarding heat price, there are no national statistics on district heat prices for the producers in Estonia. The Statistical Office collects and publishes average prices of heat purchased by enterprises. In 2002, the average price was 79.38 €/GJ (excluding VAT), ranging from 77.22 for large consumers to 91.80 €/GJ for small consumers. In 2003 the average price of heat purchased by enterprises was slightly lower (78.91 €/GJ). In the price analysis the significant impact on the average price of the large heat producers in northeast Estonia (Narva, Kohtla-Järve) that fire oil shale has been taken into account. In addition to the relatively cheap fuel (oil shale), another factor enables prices to be kept at a lower level — the wide use of the cogeneration of heat and power in this region. For example, the price of heat supplied by AS Narva Elektrijaamad (the Baltic power plant that fires oil shale) to distributors is 47.88 €/GJ. The price of heat sold by the main distributor there (AS Narva Soojusvõrk) is 70.42 €/GJ. In other regions, prices of heat sold by the larger heat utilities mainly range from 91.80 to 100.80 €/GJ. For smaller heat utilities the prices are higher, often up to 115 €/GJ, but in some cases 137 €/GJ and even higher.

2.2. Latvia

2.2.1. Geography, location and climate

The Republic of Latvia, located on the south shore of the Baltic Sea, regained its independence in 1991 after the break up of the Soviet Union. Since ancient times, with its coastline exceeding 500 km and easily accessible ports (Ventspils, Riga and Liepaja), Latvia has been a significant link between the states that surround the Baltic Sea and Russia. The Baltic Sea has always been of great importance in the political, economic and cultural life of the country. The overall length of Latvia's boundaries exceeds 1800 km. Latvia is bounded by Estonia (to the north), Lithuania (to the south), Russia and Belarus (to the east).

The territory of Latvia covers 64 589 km^2, of which approximately 42% is covered by forests. The population of Latvia is 2 331 000 (1 January 2003), of which the urban population amounts to 1 580 000 (68%).

The capital city, Riga, is located in the centre of the country, is a port on the Gulf of Riga and has a population of about 740 000 constituting 32% of the total population. The largest cities are Daugavpils (112 600), Liepaja (86 985), Jelgava (65 754), Jurmala (55 156), Ventspils (44 010) and Rezekne (37 777). Latvia's currency, the lat, exchanges at approximately € 1.42 per lat, or 0.7028 lats equals 1.0 € (as at January 2005).

Latvia is not rich in important mineral resources, and among combustible resources only peat is produced in industrial amounts. There are significant reserves of raw building materials — limestone, gypsum, dolomite, clay and gravel. The climate in Latvia is determined by its location in the northwest of Eurasia in the proximity of the Atlantic Ocean and, to a large extent, influenced by flows of marine air. Frequent cyclones bring about considerable weather changes. The average annual temperature in Riga is +6°C.

In November 2002, Latvia was one of seven countries invited to join NATO, and in December 2002 Latvia was one of ten countries invited to become a member of the EU. On 1 May 2004 Latvia, together with nine other countries, became a full member of the EU. On 29 March 2004, during a ceremony in Washington, the Prime Minister of the Republic of Latvia, Indulis Emsis, handed Accession instruments for the North Atlantic Treaty to the US Secretary of State Collin Powell. This marked the completion of legal formalities for Latvia's accession process to NATO and Latvia's full membership in the North Atlantic Alliance.

2.2.2. Demographic situation

The Board for Citizenship and Migration Affairs of Latvia estimates that the resident population was 2 309 000 at the middle of 2004. The population density is currently 36.6 inhabitants per square kilometre.

The number of live births was 20 248 in 2000, which is equal to a total fertility rate of 1.23 (*Figure 2.6*). One of the reasons behind the low fertility is the declining number of women in fertile age (15–49 years), especially in the age group 20–29 years, which has the highest fertility rate. Births outside marriage are on the rise. In the past year, 40.3% of all births were outside marriage. Life expectancy at birth was 64.9 years for men and 76.0 for women.

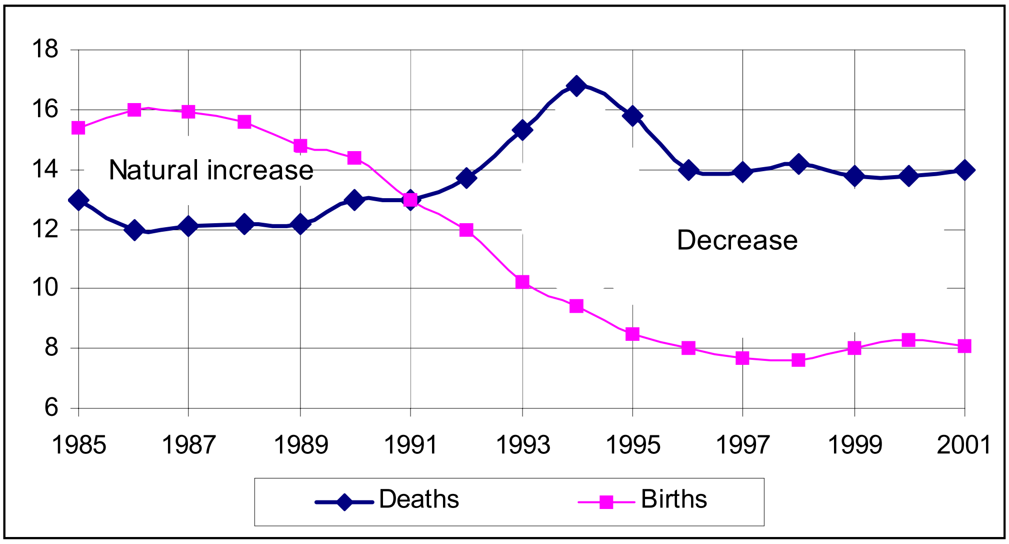


Figure 2.6. Birth, death and natural increase rates (per 1000 inhabitants).

The balance between the number of arrivals and departures of long term migrants has been negative since 1989. Emigration and repatriation reached a peak in 1992, when 53 700 people left the country (*Table 2.10*).

Table 2.10. Population change components (thousand people)

	1991	*1995*	*1996*	*1997*	*1998*	*1999*	*2000*	*2001*
Population increase/decrease	–15.2	–31.0	–24.6	–24.1	–21.6	–17.5	–17.5	–18.5
Natural increase	–0.1	–17.3	–14.5	–14.7	–15.8	–13.5	–12.0	–13.3
Net migration	–15.1	–13.7	–10.1	–9.4	–5.8	–4.0	–5.5	–5.2

2.2.3. Macroeconomic situation

Accomplished reforms in Latvia and the integration into the EU have produced a positive impact on the economic development of the country. In the period from 1996 to 2003 the Latvian GDP grew on average by 6.1% annually (*Figure 2.7*). Among the other European countries, only Ireland had higher growth rates in the same period. In 2001, Latvia's GDP went up by 8%, in 2002 by 6.4%, in 2003 by 7.5% and in 2004 by 8.5%.

High domestic demand (private consumption and investments) combined with the ability of Latvian enterprises to find new export markets were the reasons for the growth in recent years. Manufacturing, construction, trade, commercial services and transport and communications were the biggest contributors to GDP growth.

The amount of output in the manufacturing sector shows a steady growth for several years, and has reached an annual growth of 9–10% since 2001. In 2003, the highest growth rates were registered in the wood, machine building and metal product industries. Over recent years the appreciation of the EUR currency has had a favourable effect on the competitiveness of Latvian manufacturers in the EU market. Meanwhile, exports are growing not only to the countries of the EUR zone, but also to the rest of the EU Member States and Commonwealth of Independent States (CIS) countries, which proves that several industries are able to compete on the external markets even if the market conjuncture is not very favourable. It is expected that over the coming years manufacturing will remain among the sectors with the highest growth rates. Modernisation and reconstruction of production facilities, as well as use of EU funds, will promote the productivity and competitiveness of this sector.

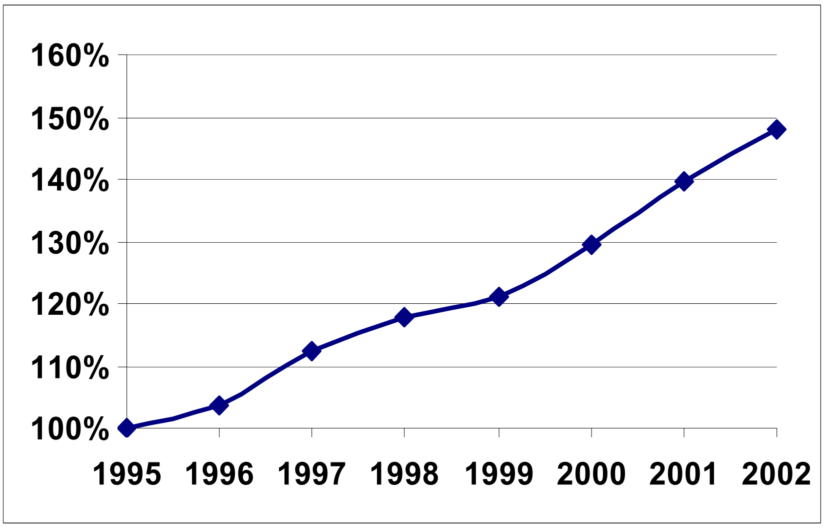


Figure 2.7. Development of GDP in Latvia, 1995–2002.

During previous years, growth had also occurred in the agricultural sector. However, low productivity and external competition have been the main obstacles to recent development of this sector. The expansion of agriculture depends on the adaptation of agricultural production units and products to EU standards and quality and to external demand. Accession to the EU provides equal competition opportunities for farmers on the internal EU market, while the support of EU funds promotes the renovation and diversification of agriculture.

High domestic demand promotes the development of services, especially those concerning wholesale and retail trade (*Figure 2.8*). In 2002 this sector grew by 12.7%, while in 2003 the growth reached 11.3%. The dynamics of domestic demand are stable and ensured by the growth of income, stability of the financial system and opening up of credit facilities.

Transit services are of great importance to the national economy of Latvia. They constitute approximately 15% of revenues from Latvian exports of goods and services, or about 5% of GDP. In 2003 the cargo turnover at Latvia's seaports grew by 5%, while the cargo turnover on rail increased by 17%, contributing to the growth of the transport and communications sector by 8.9%. Notably, two-thirds of the growth in this sector depends on domestic demand (development of communications, warehousing, parking services, tourism, etc.) and only one-third on external demand (transit). The domestic use of transport sector services is growing at a faster pace than the external use.

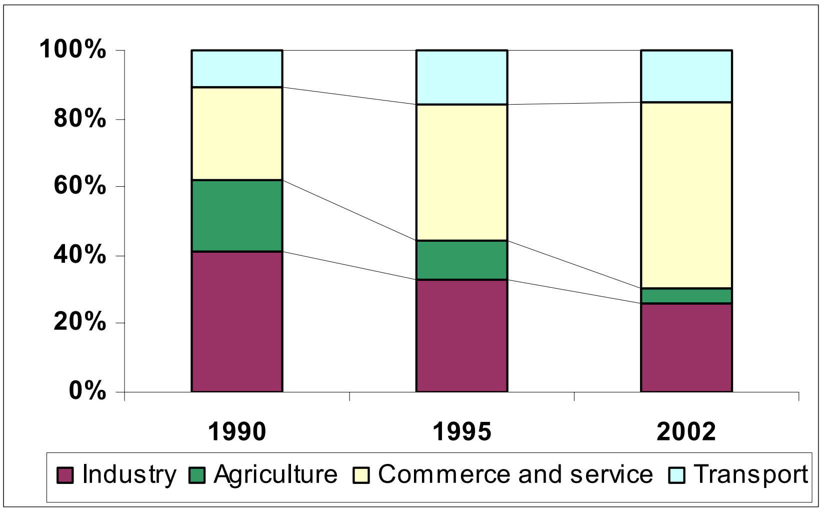


Figure 2.8. Development of GDP structure in Latvia, 1990–2002.

2.2.4. Energy sector

2.2.4.1. Characteristics of the existing supply systems

Latvia is strategically located at the crossroads of East–West energy trade. Large volumes of crude oil and refined products travel through Latvia by pipelines and rail and are exported via the port of Ventspils, Riga and Liepaja. Large volumes of natural gas from Russia are pumped into UGS in Latvia during the summer for use in the winter, and some re-exports to neighbouring countries.

2.2.4.2. Gas supply system

Latvia imports all of its natural gas supplies from Russia. The large available natural gas storage (Inčukalns UGS), with a capacity that exceeds annual domestic consumption, enables the Latvian natural gas supply system to be used for winter deliveries to the St Petersburg area and Estonia. For that the national gas supply company (Latvijas Gaze) charges appropriate storage and transit fees. According to the gas-purchasing arrangements, each year Inčukalns UGS is refilled to its maximum capacity.

Transmission

The natural gas transmission network comprises 1255 km of main gas transmission pipelines, 47 gas pressure regulation stations (GRS) with metering installations and gas odorisation units, the border gas metering station (GMS) 'Korneti' for commercial metering of gas received from and supplied back to Russia, and four automobile filling gas compressor stations (AFGCS; see *Figure 2.9*). The natural gas transmission network covers all major towns, except Ventspils. The city of Rezekne was connected to the gas supply system in October 2005 through the 47 km long gas pipeline. A decline in gas consumption in the early 1990s means that the capacity of the main pipelines, designed for an annual capacity of about 11 billion m^3, far exceeds the present consumption level.

In fact, without any notable expansion, the transmission network capacity of Latvia may accommodate any small and middle size power plants almost anywhere on the mains, except for the Southwest branch to Liepaja. At the same time, according to Latvijas Gaze, the construction of large (800 MW) gas-fired combined cycle units in the Riga CHP plant (in the city of Riga) might require an expansion of the gas transmission network from Valdai to Izborsk (in Russia). This limitation could also impact the construction of other potential gas-fired power plants in the Baltic States.

Figure 2.9. Natural gas transmission network of the Baltic States (Source: Latvijas Gaze).

Table 2.11 contains the main information on gas transmission pipelines in Latvia.

Table 2.11. Technical information on natural gas transmission pipelines

	Year of commissioning	*Diameter (mm)*	*Design pressure (bar)*
Vilnius–Riga (first line)	1962	529	46
Riga–Panevezis (second line)	1983	720	55
Iecava–Liepaja – section 1	1966	529	46
Iecava–Liepaja – section 2		377	55
Riga–Inčukalns UGS (first line)	1967	720	55
Riga–Inčukalns UGS (second line)	1985	720	55
Valdai–Pskov–Riga (first line)	1972	720	54
Izborsk–Inčukalns UGS (second line)	1985	720	55
Riga–Daugavpils	1987	533	55
Viresi–Tallinn	1994	720	55

Recently, there was an accident (explosion) in the gas transmission pipeline between Viresi and Tallinn near Valmiera, in one of the newest pipelines in the gas transmission system. This justified the necessity to pay more attention to security of gas supply.

Storage

The Inčukalns Underground Gas Storage (Inčukalns UGS) is an essential part of Latvia's natural gas supply system. The Inčukalns storage was created in the sandstone layer from the Cambrian period. The total volume of the storage is 4.44 billion m^3 and the active volume is 2.3 billion m^3. It is expected that the gas storage capacity of Inčukalns UGS will be gradually expanded to 5 billion m^3 to accommodate increased gas consumption in Latvia and also larger transit volumes.

In the winter season, Inčukalns UGS supplies gas to Latvian consumers, and also to northwest Russia, St Petersburg and Estonia. The Inčukalns UGS is connected to the Estonian transmission system by a pipeline with a diameter of 700 mm. In the future, gas may also be delivered from Inčukalns UGS to Lithuania through the existing pipeline connection. Currently, such supplies are not possible because of the lack of a gas-metering station on the Latvian and Lithuanian border. With construction of a North European gas pipeline (NEGP) from Russia to Germany on the seabed of the Baltic Sea, the importance of Inčukalns UGS might increase.

Latvijas Gaze has defined modernisation of the Inčukalns UGS facility as its investment priority for the next few years. The main objective of this modernisation is to increase the operational safety of the underground and surface equipment, as well as to ensure uninterrupted operation of the facility.

Distribution

The total length of the natural gas distribution network is over 3085 km. The average age of the network is 15 years, and the pipes are in good working condition. The gas distribution network contains 1650 gas regulation units, including 250 gas regulation points (GRPs), 576 compact gas regulation points (CGRPs) and 820 house regulators. The average age of these units is 15 years. All regulation units have been undergoing three years of modernisation according to German Deutsche Vereinigung des Gas- und Wasserfaches (DVGW) standards. By the end of 2002, 215 GRPs and CGRPs had been modernised.

2.2.4.3. Power supply system

Generation and supply

During the past 5 years central (large) power plants in Latvia supplied roughly 65% of the total annual power demand — distributed energy resources (DERs[15]) covered 3–6%, but the rest were received as import supplies from Estonia, Lithuania and Russia (*Figure 2.10*).

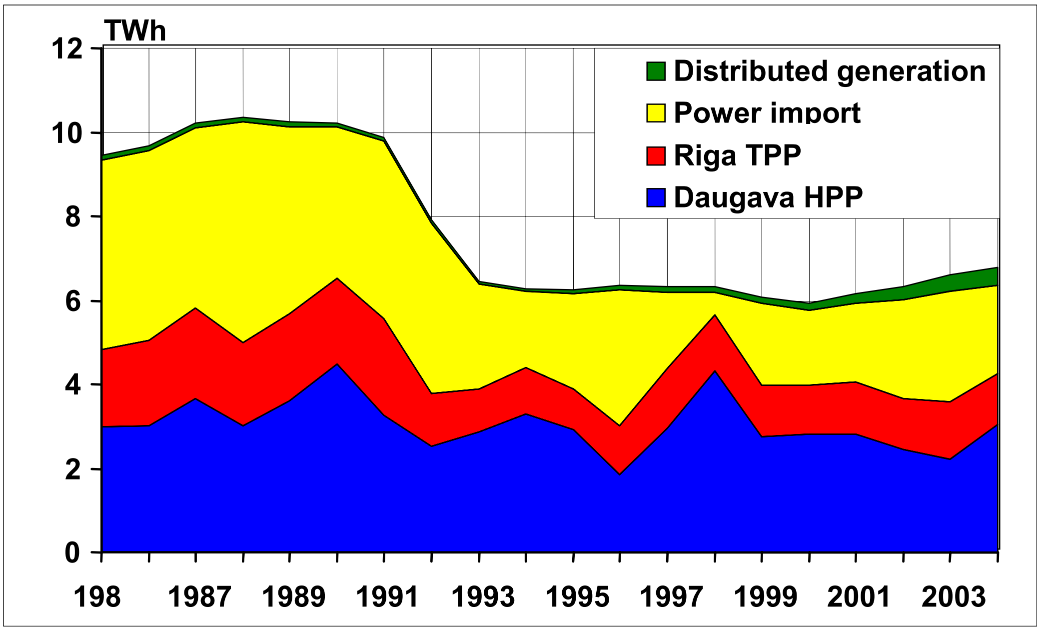


Figure 2.10. Power supply structure in Latvia.

There are three large hydro power plants (HPPs) in Latvia, which are located on the river of Daugava and form the cascade of the Daugava HPPs – Plavinas HPP 870 MW, Kegums HPP 263 MW and Riga HPP 402 MW. Daugava HPPs operate mostly during the system maximum (peak) hours of the Baltic Interconnected Power System (IPS). It is only possible to regulate power production of the cascade on a daily and part-weekly basis. The variable nature of flow in the Daugava river means the power generation of the HPPs is hard to predict in the long term. The average value of annual production is around 2.7 TWh, which is approximately 45% of the total annual demand. In 1996 the output of HPPs was only 1.8 TWh (29%), but in 1998 it was 4.3 TWh (68%). During the spring flood period, which usually lasts for 1–2 months, the cascade produces about 40% of the total annual production volume and ensures power export from Latvia (*Figure 2.11*). Technically, the Daugava HPPs are fit to operate for at least the next 20 years if the scheduled maintenance programme is implemented. Quite substantial financial resources need to be invested in dam safety.

Two large CHP plants, Riga TPP-1 with an installed electric capacity of 144 MW and Riga TPP-2 (390 MW), are located in the capital of the Latvian republic, the city of Riga. CHP

[15] DER = DG, distributed generation.

plants are the main heat-generating sources of the right bank heating networks of Riga. Power is produced mainly in cogeneration mode, according to the heat-load curve. Natural gas, peat[16] (local resource) and heavy fuel oil (HFO) are used as the main fuels. During the heating season, when there is a substantial demand for heating and hot water, Riga CHP plants produce approximately 80% of the total annual production volume, while during summer the volume of production reduces. Technically, the Riga CHP plants could also operate at full load during the summer (partly in condensing mode), but this is not reasonable from an economic point of view. The maximum power output of plants was in 1991, when 2.3 TWh were generated. In 1992 several industrial consumers (of steam) of the Riga CHP plants went bankrupt as a result of economic recession. Since 1992, the heat load at Riga has decreased for different reasons, such as an efficiency increase of the district heating system and decentralisation. In the past couple of years, heat demand in Riga has started to stabilise and some indications of a possible increase have appeared. Nowadays Riga CHP plants cover about 20% of the total annual power demand of Latvia, generating approximately 1.3 TWh.

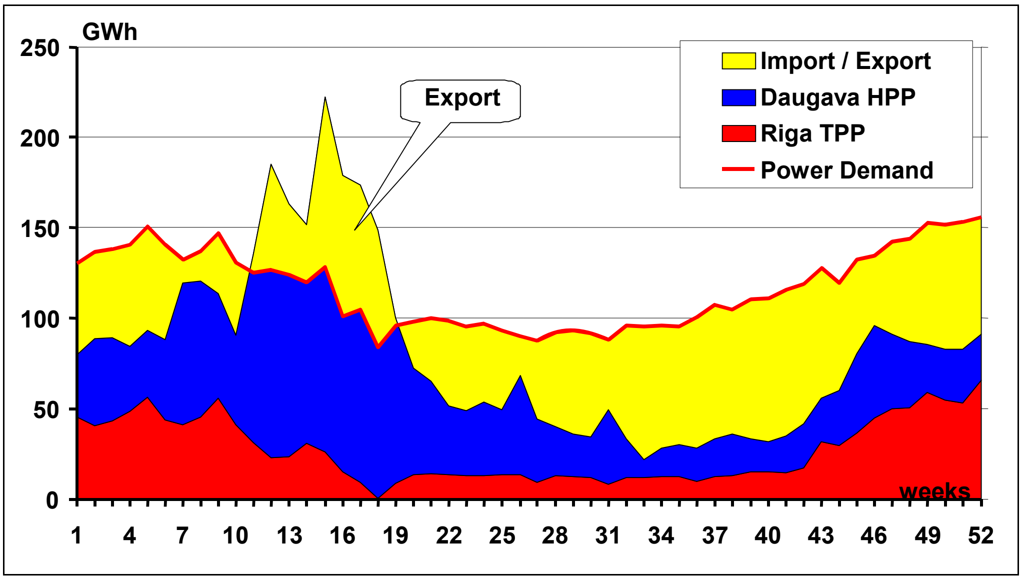


Figure 2.11. Annual fluctuations of power supply.

The development of DERs depends on legislation and promotion schemes for them. Latvian legislation is rather favourable for the wide deployment of DERs. The data on technologies and capacities of DERs in Latvia are given in *Table 2.12*.

[16] After reconstruction of Riga TPP-1 the utilisation of peat has ceased.

Table 2.12. Distributed energy resources in Latvia

	Number of plants	*Capacity (MW)*
Hydro	149	26.2
Wind	16	26.9
Landfill gas	1	5.3
Biogas	1	2
Cogeneration	28	65.6
Total	195	126.0

Transmission

The power transmission network of Latvia comprises 330 and 110 kV lines (*Figure 2.12*), and substations. 330 kV transmission lines provide electric power to the main consumption centres, as well as transit from the northern to southern parts of the Baltic States and vice versa. Latvian 330 kV lines also transmit power between eastern and western parts of Lithuania. As a rule, two and more lines connect a high voltage substation with other substations, which provides at least a double-way feed. The 110 kV network is operated in loops, typically 110 kV substations equipped with two transformers to lower the voltage level.

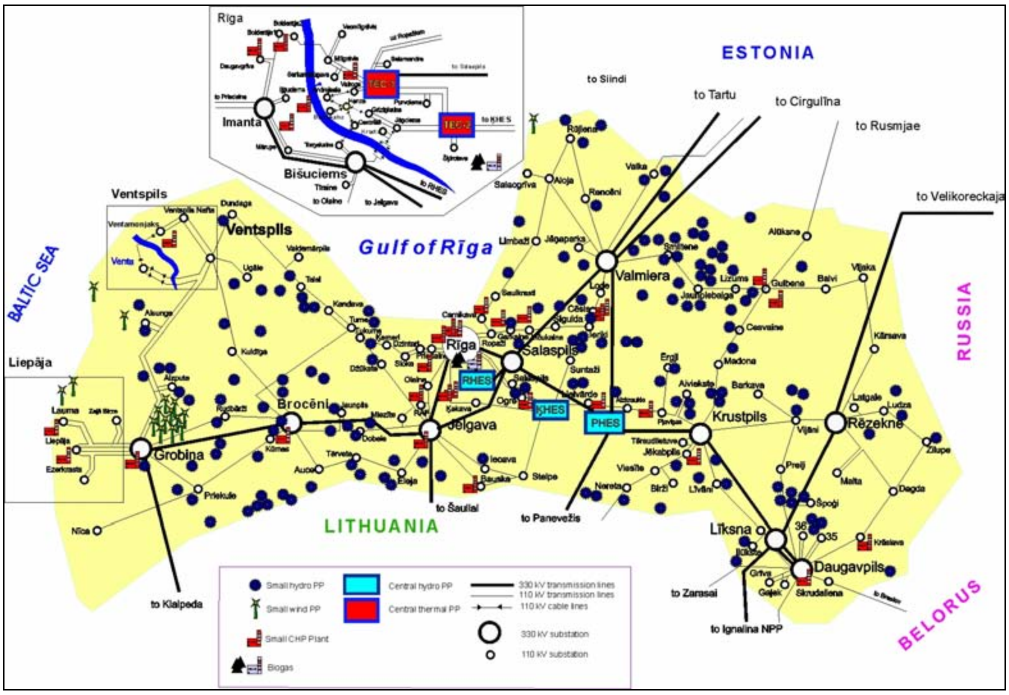


Figure 2.12. Transmission system, main power plants and DERs in Latvia.

After the restoration of independence in 1991, when most sectors of the economy, particularly industry and farming, had readapted their activities to the new market conditions, the power demand significantly decreased from over 10.4 TWh (peak load 2059 MW) in the late 1980s to 6.6 TWh (1300 MW) in 2003. The transmission network still has large reserves, despite a growing load in recent years. However, there is a reallocation of electricity consumption centres, and thus the necessity for network reinforcement in large cities. In addition, the north-western part of Latvia remains uncovered by the 330 kV network and, as it contains one of the largest industrial centres, could be considered as the most ‘sensitive’ region in Latvia. At the same time, this region potentially has favourable weather conditions for wind-farm operations. Construction of a considerable number of such power plants would require network reinforcement.

Distribution

The distribution network of Latvia is based on three middle voltage levels — 20, 10 and 6 kV — and one low voltage level — 0.4 kV. 20 kV lines comprise 29.5% of the total length of the distribution lines and mostly have overhead implementation. The 20 kV network usually provides power supply to the lower voltage grid in rural and suburban areas, and the 6–10 kV lines are used in cities and usually are of the cable type. The 0.4 kV network forms 67% of the total length of the distribution grid.

As another peculiarity of Latvia, the low density of population, especially in rural areas, is of particular interest. According to the statistical figures for 2000, 50% of the total population were concentrated in the seven largest cities. The energy-consuming units are usually located nearby. All these aspects result in long power lines, particularly at the distribution level, between energy feed-in points (generation or high-voltage substations) and the end-user. Consequently, despite the low load, power-quality problems are usual in rural areas. Furthermore, a number of remote households still remain unconnected to the electricity supply, because of the high cost of installation. In these cases, when conventional installations or reinforcements are not economically reasonable, it is possible that DERs could provide a technically suitable and economically attractive solution.

Heat supply system

Active development of the centralised district heating system in Latvia was started at the beginning of the 1950s. It was especially important in large cities, where the construction of multi-storey apartment houses was started together with the development of large industries (that consumed steam). In the city of Riga the large CHP supply plant Riga TPP-1 was constructed to satisfy growing demand. Later on, district heating systems were developed in small cities as well, and even in rural areas.

Centralised district heating systems are especially efficient in places with high density of heat demand. When planning its development, municipalities distinguish zones in which only a district heating system is possible for economic, architectural and environmental reasons.

The highest level of heat-supply centralisation is in the capital of Latvia, the city of Riga, where approximately 75–80% of the heat supply is from central plants; in other cities this percentage is lower, with an average of 57%, and in rural areas it is only 4%. The city of Riga is the largest heat-demand centre, not only in Latvia, but also in the Baltic States. It accounts for approximately 53% of the total heat market in Latvia (*Figure 2.13*). Riga’s district heating system consists of two large and several smaller heat regions. It is one of the most advanced and efficient systems in Latvia with low heat tariffs, a developed infrastructure of main (transmission) and quarter (local distribution) heating networks, individual heating points in almost every building and large cogeneration plants. A further 14 big cities in Latvia, such as Daugavpils, Liepaja, Ventspils, Jelgava, etc., occupy approximately 34% of the market, while small cities take 13%.

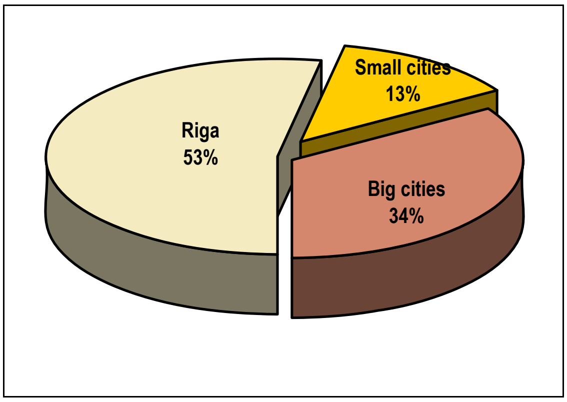


Figure 2.13. Breakdown of total heat supply by cities.

2.2.4.4. Primary energy supply (imported and domestic resources)

The rapid decline in the general economic situation after regaining independence is clearly reflected in the reduction of the total primary energy supply (TPES), which shrank by some 43% from 1990 to 1995. Since 1996 the TPES has stabilised and since 2000 there has been a small increase, because of increased economic activity (*Figure 2.14*).

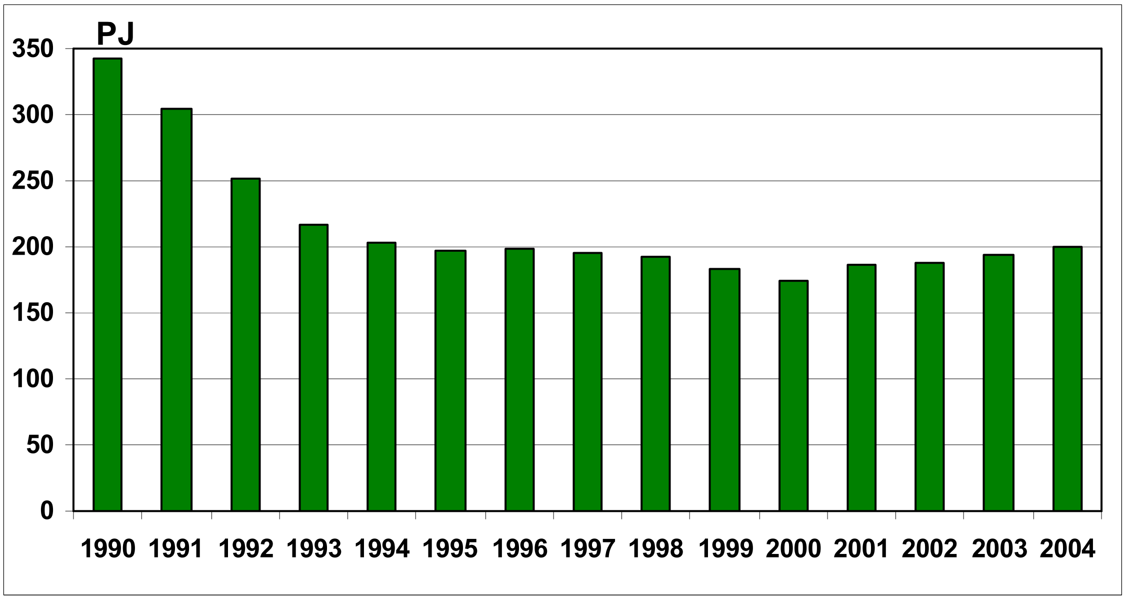


Figure 2.14. TPES development in Latvia, 1990–2004.

Historically, dependency on imports has been very high — during 1990–1995 it was around 80–90%. Positive structural changes took place in the TPES, which resulted in a reduction of import dependency to 65–70%. A significant growth in consumption of local resources, from 14% (1990) to 35% (2004), occurred mainly because of increased biomass (wood) production and consumption. The other important change in TPES structure is a significant decrease in HFO consumption. HFO has been substituted mainly by natural gas. The structure of primary energy supply in Latvia by type of fuel from 1990 to 2004 is presented in *Figure 2.15* and that of oil products in *Figure 2.16*.

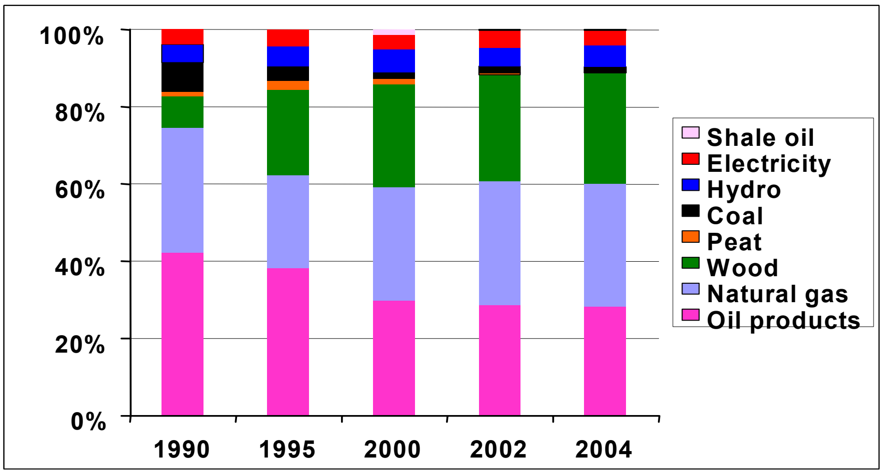


Figure 2.15 Structures of Latvian TPES 1990–2004

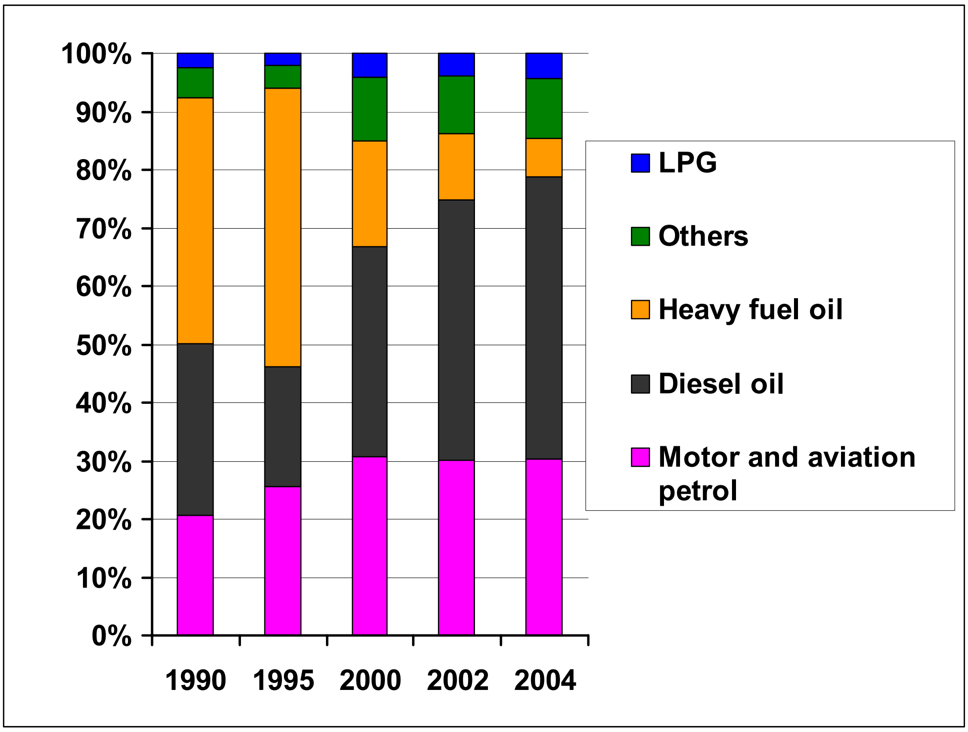


Figure 2.16. Structure of oil products in Latvia 1990–2004.

2.2.4.5. Final energy consumption

Similar to the trend in TPES, final energy demand has declined by more than 40% since independence (*Figures 2.17* and *2.18*). After a major drop in consumption during 1991–1995 (from 273 PJ to 163 PJ), it stabilised at around 161 PJ. After some decrease in 2000 (to 142 PJ), in recent years there has been a tendency for final demand to increase (168 PJ in 2004).

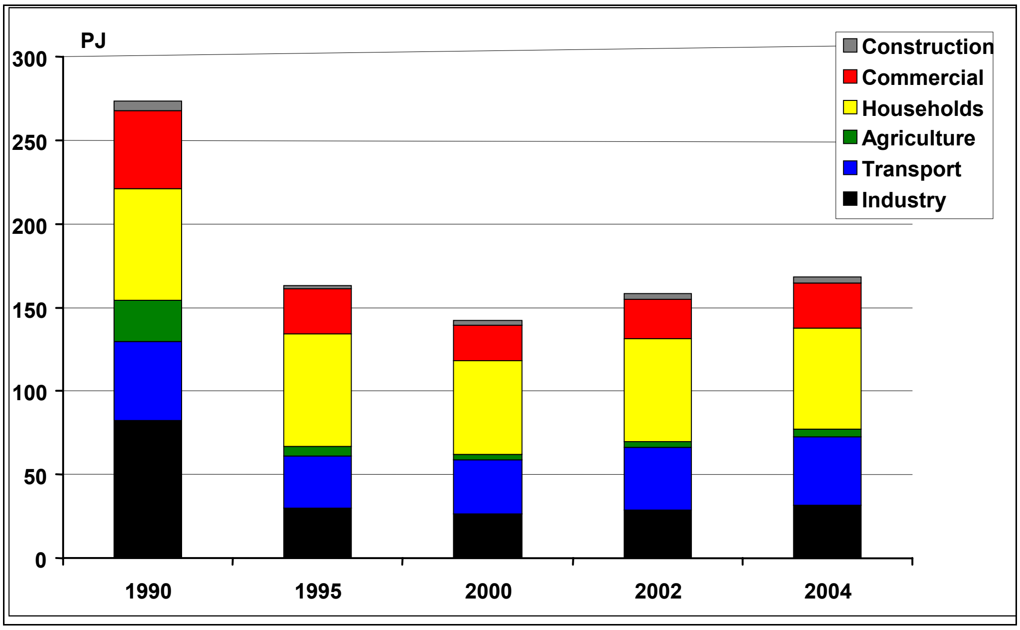


Figure 2.17. Final energy consumption by sectors in Latvia, 1990–2004.

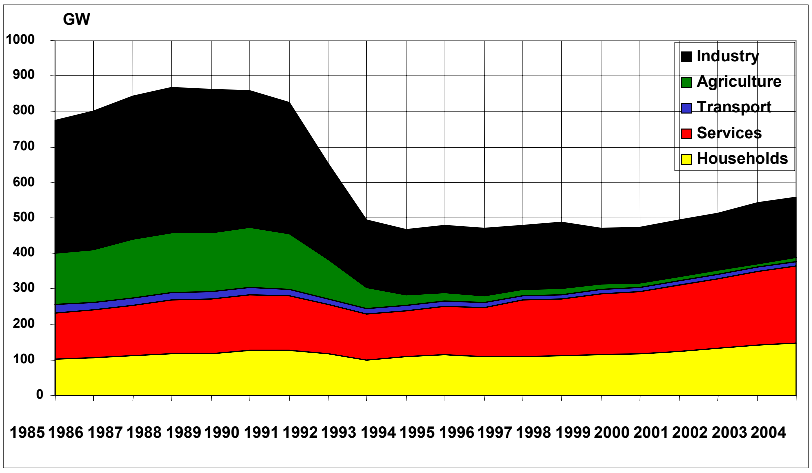


Figure 2.18. Electricity consumption by sector in Latvia, 1990–2004.

A significant part of final energy demand is heat energy (district heating), consumed mainly by the residential sector for heating. The share of district heating in the final energy demand in 2002 reached 20%. A considerable part (approximately 22%) of the rest of the final energy demand is covered by biomass (wood). Biomass is widely used in residential and service sectors.

There is a positive trend over the past 5 years concerning the energy intensity of the Latvian economy. When we analyse energy-intensity indicators (e.g., energy use per GDP unit), we can conclude that energy efficiency for 2002 had increased by approximately 30% compared with 1995.

The main reasons, besides changes in economic structures, are:

- Improvement in heat-generation technologies;
- Improvement in heat-transmission pipelines, including reinforcement of their heat insulation;
- Heat meters and controls in buildings;
- Measures to increase the energy efficiency of the demand side in all sectors.

Electricity consumption is given in *Figure 2.18*.

Indigenous fuels

Presently, indigenous fuels in Latvia mainly consist of wood fuels and peat. According to the statistical information for 2004, indigenous fuel production amounts to 78 PJ.

Prices of indigenous peat and wood fuels are determined mainly locally, and largely depend on costs of transportation and labour. As both fuels are bulk material of low calorific value, preconditions for their competitiveness are short transport distances and high efficiency in fuel production.

Wood fuels

Fuel wood is the most important indigenous energy resource in Latvia. In 2004, production was 77.9 PJ. Wood-fuel export prices exceed domestic prices, which motivates exports. Some 20% of the annual production is exported to the Nordic countries and the UK. In addition, sawdust from the mechanical forest industry is collected, pressed into pellets and exported to Sweden and Denmark.

Fuel wood accounts for 28% of the total gross energy consumption. The annual variation in fuel-wood production is quite large because of the variation in export volumes. In Latvia, wood fuel is typically used on a small- and medium-scale, with no demand for power generation so far.

Peat

Fuel peat consumption has decreased from 4.1 PJ in 1990 to 2.4 PJ in 2000, 0.9 PJ in 2002 and 0.1 PJ in 2004. Although peat is among Latvia's few indigenous fuel resources, it has until recently had limited application for energy uses. The major consumer up to 2003 was TPP-1 in Riga, which utilised almost all of the peat used in energy production. In November 2005, Latvenergo completed the reconstruction of the Riga TPP-1 plant into a combined-cycle plant fired by natural gas. This has practically ceased consumption of energy peat in the country. Also, peat demand for public heat-only boilers (HOBs) has declined from 0.1 PJ to about 0.05 PJ during the past 5 years. In addition to direct energy use, peat has been used traditionally as a raw material to manufacture peat briquettes for households, but these volumes have sharply declined (from 0.05 PJ to 0 within the past 5 years). Several studies were conducted about the utilisation of energy peat in small CHP plants, but none of them has yet been implemented.

Imported fuels

Natural gas

Latvia imports all of its natural gas supplies from Russia, which apparently will remain the only supplier in the future. Average natural gas imports from Russia were 1.3–1.6 billion m^3 during the past 5 years. Natural gas is one of the most important fuel sources in Latvia, and accounted for some 32% of the total primary energy requirement in 2004. Its share has increased notably from 20% in 1996, largely because of the increasing price of HFO.

Overall, gas consumption in Latvia depends on a few major consumers; the largest being the national power company Latvenergo, with its two CHP plants. Latvenergo accounted for 34% of total gas sales to customers. The second largest, with a 10% share, is the Riga district heating company, which operates a number of large HOB plants. The only steel mill in the Baltic (Liepajas metalurgs) consumes 9% and is the largest industrial consumer, accounting for 36% of sales to industry.

Oil products

Latvia has no domestic oil production. However, the US and Norwegian joint venture TGS Nopec has applied for oil exploration and extraction licenses. Licenses will be issued for three fields in Latvia's territorial waters in the Baltic Sea — covering 1143 km2, 765 km2 and 767 km2. Apart from the activities associated with oil-field exploration, there have been plans to construct refineries in Latvia.

Heavy fuel oil

HFO gross consumption has declined from 46 PJ to 4.5 PJ, during the past 5 years, being currently 3% of the total energy gross consumption. Reasons for the sharp decline in HFO demand are linked with competitiveness and environmental issues. Currently, the price of HFO is on the same scale as that of natural gas and three times more expensive than, for example, wood fuel.

Latvia imports HFO mainly from Russia and the CIS. The unpredictable nature and variation in HFO prices together with the technical implications of its use are its main disadvantages in competition with natural gas. However, many companies are unwilling to depend on a gas monopoly and prefer to balance gas and HFO use to maintain energy independence. Although the current regulations do not require district heating plants or industries to maintain dual fuel capabilities, most have inherited multi-fuel facilities.

High overheads mean that HFO is used efficiently only in installations that have a heat production capacity above 10 MW. For such customers, which comprise HOB district heating, CHPs and large industrial units, HFO will remain the main competitor of natural gas, at least until environment-related taxes are increased substantially. Already today, there are some serious technical and legal burdens on the utilisation of HFO. The most significant is a necessity to use HFO with low sulphur content (less than 1%).

In addition to HFO, Latvia imports limited amounts of shale oil from Estonia. Shale oil is used by public HOB plants.

Coal

Latvia imports coal mainly from Russia, Kazakhstan, Ukraine and Poland. The coal imported from Russia is of low quality, and is used in small boiler houses and households. Average coal imports were 2.7 PJ during the past 5 years, which is very little compared to the 26.3 PJ in 1990. Coal consumption has declined to 1.4% of total energy gross consumption, in comparison to 7.7 PJ in 1990.

Coal's current importance in Latvia's energy sector is very limited. Being an expensive imported fuel with high incremental transportation costs, coal is widely substituted by other fuels, particularly wood. Besides, as Latvia would in any case meet even the most stringent emission reduction obligations set according to the Kyoto process, large coal-fired power plant projects may appear to be feasible if oil and/or gas prices significantly increase, as is forecast.

2.2.4.6. Energy and fuel prices

In Latvia the majority of fuel prices are market based. The only exemption is the pricing of natural gas. The approval of prices and tariffs for natural gas and electricity is the competence of the Public Utilities Commission. Average prices (excluding VAT) by manufacturing enterprises of energy resources are provided in *Figure 2.19*, in accordance with statistical information provided by the Central Statistical Bureau of Latvia. Biomass fuel pricing is usually made on the basis of actual energy content, taking into consideration the calorific value of dry matter, moisture content and weight.

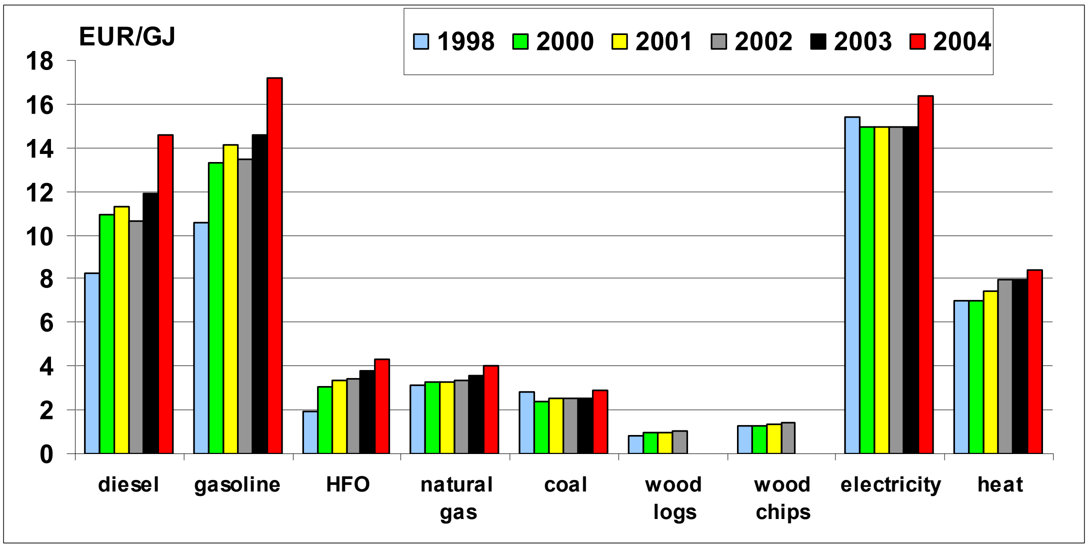


Figure 2.19. Dynamics of fuel price development in Latvia (excl. VAT).

Woody biomass of various types is currently the most competitive fuel (*Figure 2.19*), with a large price gap in comparison with coal, gas and HFO. Its ready availability and substantial potential resources mean it will maintain its already important position. Moreover, as 'industrial' biomass production and utilisation technologies adopted relatively recently develop locally, it may be assumed that biomass will also be considered one of the main options for larger (up to 50 MW) HOBs and CHPs, especially if it is combined with other solid fuels (e.g., peat).

HFO, natural gas and coal have been consumed relatively constantly in gross energy terms, although because of different usage efficiencies, gas has had a price advantage. This is, in particular, illustrated by a rapidly decreasing consumption of HFO. The very well developed gas supply system means that in the future natural gas will also be a key fuel for the larger energy-production facilities.

The price of electricity depends on the voltage from the electricity supply network. Depending on this, tariffs fall into three levels: 0.4 kV, 6–20 kV and 110 kV and greater. The price of electricity in several tariff types varies according to the corresponding time of day or night. Depending on the size of the permitted load, electricity customers fall into three groups:

- Up to 60 kW;
- From 60.1 kW to 399 kW;
- 400 kW and above.

Every electricity customer within these permitted load categories has the right to select freely a suitable tariff type that best serves his or her requirements (*Table 2.13*).

Table 2.13. Average electricity tariffs in Latvia, 2004 (excl. VAT)

Consumer group	*Rate (€/MWh)*
Residential consumers	54.26
Large consumers	38.87

Natural gas tariffs for large users depend on the annual gas consumption (*Table 2.14*). The large users group comprises industry and energy-production users, such as district heating and cogeneration. In the regulatory system, there is a fixed maximum price for all users in this group, independent of the actual costs of supply. There is a price differentiation between customers by way of regulated discounts, which increase with annual gas use.

Table 2.14. Natural gas tariffs for industrial consumers, 2004 (excl. VAT)

Annual natural gas consumption (1000 m^3)	*Tariff (€/1000 m^3)*
Up to 0.5	136
From 0.5 to 25	129
From 25 to 126	128
From 126 to 1260	126
From 1260 to 12 600	124
From 12 600 to 20 000	120
From 20 000 to 126 000	107
Above 126 000	98

2.3. Lithuania

2.3.1. Geography, location and climate

Lithuania is the largest of three Baltic States. It shares borders with the Republic of Latvia (its frontier being 610 km), the Republic of Belarus (724 km), the Republic of Poland (110 km), the Kaliningrad region of the Russian Federation (303 km) and the coastline (99 km). The total area of Lithuania is 65 300 km^2, with a population of 3.44 million.

Geographically, Lithuania is situated in the centre of Europe. The point that indicates this centre is 20 km to the north of Vilnius, the capital. However, from a geopolitical point of view the country is mostly considered as a part of Eastern Europe. The total length of its terrestrial border is approximately 1747 km. Compared to other Baltic States, Lithuania has the shortest coastline — only 99 km.

In Lithuania's coastal area a marine climate prevails, but in the west, central part and the east this gradually becomes continental. The influence of west winds renders summers moderately warm, 80% air humidity predominates and during most winters permanent snow cover is formed. The average temperature in January is –4.9°C and in July it is +17.2°C. Average annual precipitation varies from 540 to 930 mm.

2.3.2. Demographic situation

The population of Lithuania has grown from 2.8 million at the beginning of the twentieth century to 3.5 million at present. Different nationalities live in Lithuania: Lithuanians (83.5%), Russians, Poles, Belarussians Ukrainians, Tartars, Jews and people of other nationalities (*Figure 2.20*). Approximately 67% of all the population lives in urban areas and 33% live in rural areas.

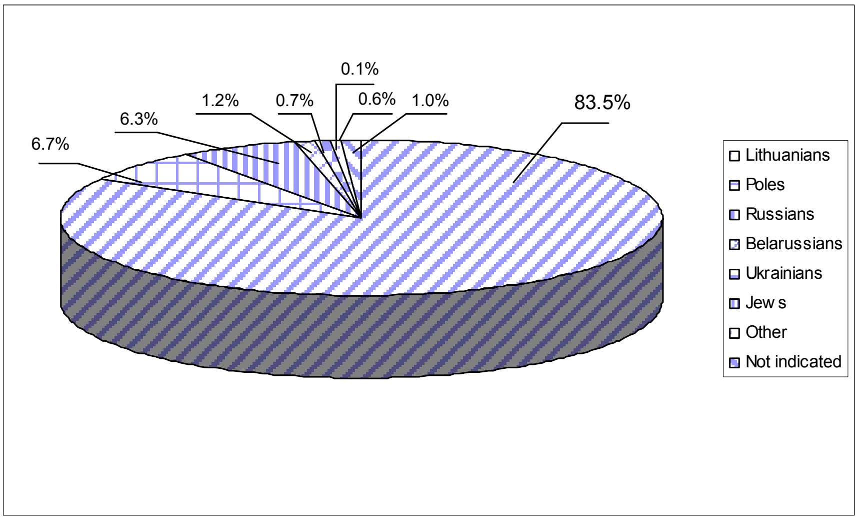


Figure 2.20. Structure of the population in Lithuania (%) [4].

According to the 2001 Census results prepared by the Lithuanian Department of Statistics, the population in Lithuania has decreased by 190 800 since the 1989 census. The natural increase was 33 700 people and the negative net migration was 224 500 during this period. This tendency still persists — in 2003 alone the negative migration was 6304. In recent years (1995–2003) the number of births was slightly lower than the number of deaths, to give an over 53 000 decrease in population.

2.3.3. Macroeconomic situation

During the five decades since 1940, the conditions of economic development in Lithuania as a small republic of the Former Soviet Union (FSU) were greatly different to the economic conditions in Western Europe. The economic structure of the 1990s was inappropriate in terms of size and access to raw materials and energy. Despite many difficulties during the transition period in Lithuania, steady progress in strengthening the performance of market-supporting institutions and undertaking the necessary reforms has enabled the possibility of a strong and long term economic recovery. This progress can be characterised by several transition indicators, such as the growing share of the private sector in total GDP, ending the privatisation process, removal of restrictions and tariff barriers on trade and foreign exchange, progress on the creation of competition policy, commercialisation and regulation of telecommunications, restructuring of energy sector, the establishment of bank solvency and liberalisation of interest rates, the emergence of non-bank financial institutions, etc.

Since February 2002, the Lithuanian currency, the Litas (LTL), has been repegged from the US dollar to the EUR (3.4528 LTL = 1 €). At the beginning of transition, however, monetary policy and a stable exchange rate between the national currency and the dollar were important ways to reduce inflation, especially because most trade was with the CIS. The share of trade with the EU and EU candidate countries has steadily increased in recent years to almost 75% (2002) of total export. Therefore, the decision of the Lithuanian Central Bank is well founded and should help to ensure macroeconomic stability.

One of the most important indicators to show the attractiveness of the Lithuanian economy and its openness to developed countries is the growth of foreign investment. In 2002, FDI reached almost 3.09 billion €. In 2003 this value reached 3.8 billion € and in 2004 almost 4 billion € [5, 6]. Since 1995 FDI has been growing very quickly — over a 6-year period it increased almost eightfold (*Figure 2.21*).

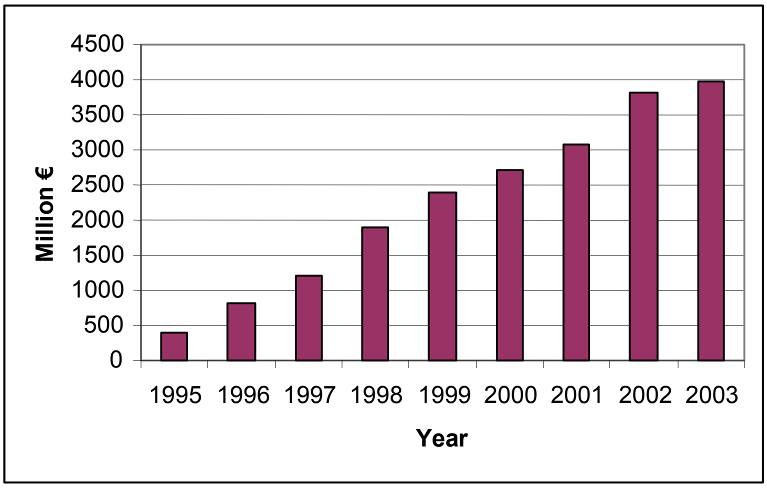


Figure 2.21. Foreign direct investment in Lithuania [5, 6].

2.3.4. *Energy sector*

2.3.4.1. Characteristic of existing supply system

Lithuania is a very dependent country in terms of energy resources. In 2000 only about 13.8% of the primary energy requirement was covered by domestic resources. The remaining primary fuel requirement is imported from neighbouring countries, mainly from Russia — all crude oil, natural gas and nuclear fuel are imported from this country. There is a concern about the political and economic consequences of this dependence. There is a good interconnection with neighbouring countries for both electrical grid and gas pipelines. The supply of crude oil is also available via pipeline from Russia and two existing oil terminals from other countries, including orimulsion from Venezuela. Coal can be supplied by railway from both Russia and Poland.

2.3.4.2. *Primary energy supply (imported and domestic resources)*

Gas is imported to Lithuania by pipeline, commissioned in 1975, from Belarus. It connects the Lithuanian gas network, with a pipeline diameter of 1200 mm, with the 'Northern Lights' pipeline that transports natural gas from Siberian gas fields. In the north of Lithuania the gas network is connected to the Latvian gas system (*Figure 2.22*). However, the pipelines that connect the two countries are closed at present. They could be re-opened in an emergency situation.

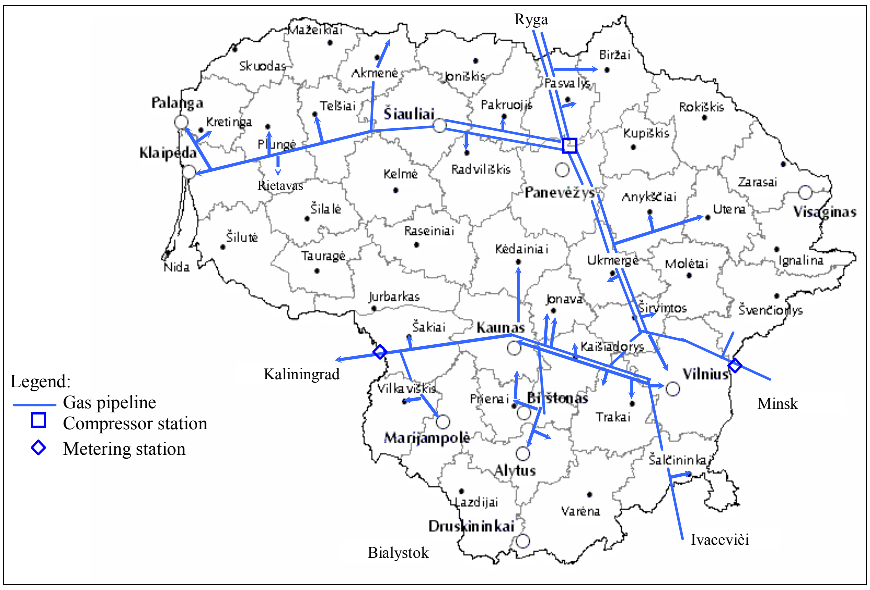


Figure 2.22. High-pressure network of Lithuanian gas supply system.

Given the existing two transmission pipelines to Latvia, there is a good opportunity to import natural gas from the Latvian gas network in the near future, via Inčukalns and Dobele underground storages, which are the largest in Eastern Europe. This could be very important during peak energy demand in the winter, as well as for energy supply security.

The share of petroleum products in the balance of the country's primary energy resources is quite significant: in 2003 the consumption of oil products by all sectors of the economy amounted to 2.26 million tons of oil equivalent (toe). This constituted about 31% of the total amount of the consumed primary energy resources in 2002. The main supplier of petroleum products in the country is the Mazeikiai Refinery 'Nafta', the only one in the Baltic States region. At present its capacity is about 8 million tons, and in 2004 almost 8.66 million tons of crude oil and other raw materials was processed. Currently, this refinery is undergoing an upgrade to produce petroleum products that are in demand in Europe.

Crude oil is imported from Russia via a line from the main Russian pipeline 'Druzba'. This crude oil comes almost entirely from the Tyumen oil fields through the double pipeline link of 720 mm diameter via Novopolotsk in Belarus to the Birzai (Lithuania) pumping station. From there one line runs to the Mazeikiai refinery, and the other to the Ventspils port in Latvia. The maximum import throughput of this pipeline is 16 million tons per year.

There are two import and export facilities in Lithuania — the Klaipeda and the Butinge oil terminals. The Klaipeda oil terminal was built in 1959 but was recently modernised. It can be used for the export and import of HFO, diesel fuel, bitumen and lubricants. The Butinge oil terminal is constructed for the export or import of crude oil. Its capacity is 8 and 6 million tons of crude oil for export and import, respectively. At present Lithuania possesses all the technological possibilities to import crude oil and petroleum products and has achieved a diversification in supply countries.

Indigenous oil resources are not very plentiful; however, domestic oil production can be continued for several decades, maintaining the annual oil extraction level of 0.3–0.5 million tons. In 2000, the extraction of domestic oil was about 1.4 times higher than that in 1999, and the trend of steady growth in its extraction – from 12 000 tons in 1990 to 382 000 tons in 2003 — is very important [7, 8]. For this reason, the oil sector and oil products will be further dependent on the import of both oil and oil products.

Coal could be supplied from various places in the Russian Federation and also from Poland. Lithuania imports coal by railway, but it does not have seaport facilities, which heavily restricts the number of supply sources. Coal is not used in power generation. Before 1990, its share was comparatively high (about 20%) in the household sector. During the transition period, the share of coal in the balance of primary energy decreased from 3.7% in 1990 to 0.9% in 2001 and started to rise slowly to 1.1% in 2003 [8]. Currently, the share of coal in the household sector is increasing slightly.

Lithuania has almost no primary energy resources. In 2001, the indigenous energy resources (wood, peat, hydro) represented about 8.5% in the primary energy balance (including the extraction of oil, this is about 13.8% indigenous energy). Their share during the period 1990–2003 increased more than four times. In recent years, energy production from wood, peat, hydro and other indigenous resources (except oil) has increased slightly. This increase happened mainly because of the introduction of support schemes and because total consumption of primary energy dropped significantly.

A rough estimate of the technically usable energy potential from indigenous and renewable resources suggests that a maximum of about 15% of the primary energy demand in Lithuania could be covered in the future by wood, peat, hydro and other local resources. Taking into account the expectations for domestic oil extraction, a figure of 15% is accessible. However, without oil this long term target is perhaps rather ambitious, given the costs and the changes that would have to take place to achieve it. The most recent expectations about the utilisation of indigenous energy resources are presented in *Table 2.15*.

Table 2.15. Forecast of utilisation of indigenous and renewable energy resources (ktoe/year; 1 ktoe = 1000 toe) [9]

	2000	*2003*	*2020*
Wood and wood waste	615.3	672.3	970
Peat	11.2	18.8	46
Straw	2.5	n.a.	15
Biogas	1.7	1.8	18
Wind energy	0.0	n.a.	40
Solar energy	0.03	n.a.	0.9
Geothermal energy	0.0	2.9	23
Biofuel	0.0	n.a.	175
Hydro power plants	29.2	27.9	40
Total	659.93	n.a.	1327.9

2.3.4.3. Final energy consumption

The total FEC in Lithuania decreased from 8.9 Mtoe (1 Mtoe = 10^6 toe) in 1990 to 4.1 Mtoe in 2003. It can be assumed that the consumption level in 2000 was the lowest in absolute value, and the expected growth of the economy in the future will stimulate a corresponding increase in energy demand. This assumption is confirmed by the slight increase of FEC in 2001 to 3.9 Mtoe, and it is still rising.

Until 2000, energy consumption in all sectors of the national economy had been decreasing (*Figure 2.23*). Analysis of the final energy demand by sectors shows a sharp decrease in the shares of agriculture, construction and industry. In 2000, the FEC in these sectors dropped to 11%, 23% and 25% of the 1990 value, respectively. At the same time the share of the trade and services sector decreased slightly. Energy demands in household and transport sectors decreased to 73% and 72% of the 1990 value, respectively. Consequently, their shares increased significantly — from 21% and 17% in 1990 to 35.3% and 29.6%, correspondingly, in 2001.

One of the legacies of central planning is the inefficient use of energy in all transition countries. At the beginning of the transition period, energy intensity in Lithuania increased because of a decline in activity in all sectors of the economy and the significant share of the household and transport sectors in the total final energy demand. However, since 1994, energy intensity in Lithuania has been decreasing, and in 2000 it was 35% lower than the 1990 level.

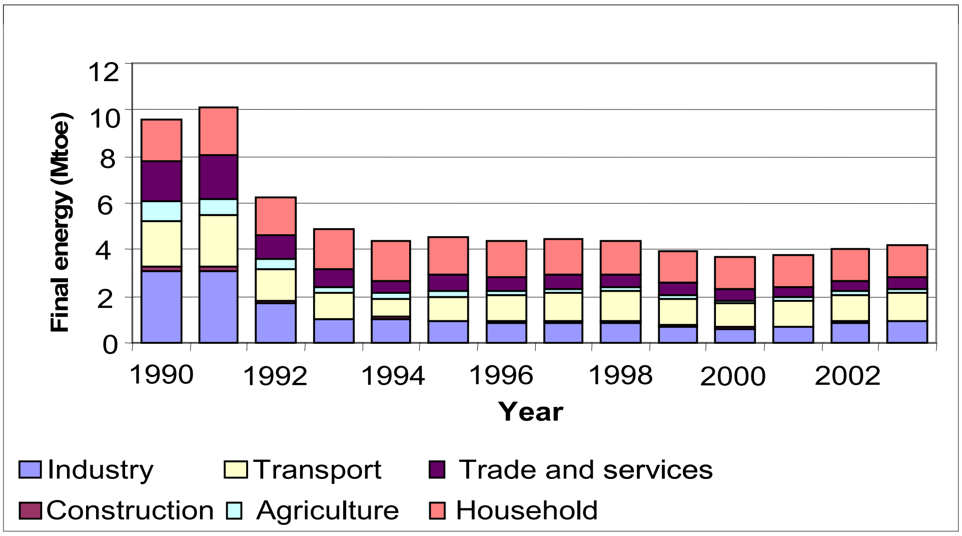


Figure 2.23. Final energy consumption in Lithuania [8].

2.3.4.4. *Energy and fuel prices*

Lithuania imports about 90% of its total primary energy requirements and exports mostly oil products and electricity. Taking into account the installed capacities of the power system, the refinery and oil terminals, energy trade flows might be much larger. However, economic decline in neighbouring countries and financial problems limit this activity.

In general, after the increase of fuel and energy prices in 1992–1993 they stayed more or less at the same level, especially during the past 4–5 years. This is illustrated by the data presented in *Figure 2.24*. Additionally, in 1997–2001 the average price ratio of Russian crude oil supplied to Lithuania to that of Brent crude oil was 0.926, lower than the crude oil price in the world market. One of the factors that led to the lower price was lower transportation cost. Russian crude oil is transported to Lithuania by pipeline. The Russian crude oil price ratio to Brent oil is taken into account when assumptions about future crude oil prices in Lithuania are made.

The price of wood (delivered to final consumers) in Lithuania ranges from 32 to 50 LTL/m3 [4], which corresponds to 1.47–2.3 €/GJ. Another source [11] indicates a price increase for wood, related to the increasing wood demand. According to the latter source [11], the average wood price in 2001–2005 is expected to be 313 LTL/toe (2.87 €/GJ) and 337 LTL/toe (2.17 €/GJ) in 2006–2010. These prices correspond well to the price range mentioned in the former source [4]. Therefore, for further analysis we assume the wood price dynamics presented in [11], keeping the same price growth after 2010. Taking into account that wood distribution cost is about 0.52 €/GJ, the average wood price before distribution (price of prepared wood) is expected to be 1.59 €/GJ in 2001–2005 and 1.65 €/GJ in 2006–2010.

The price of wood waste is in the range 6–25 LTL/m^3 [4] — 0.27–1.15 €/GJ. Taking into account the distribution cost of 0.52 €/GJ, the average price of wood waste is 0.19 €/GJ, and the same price growth rate as for wood is assumed for the analysis.

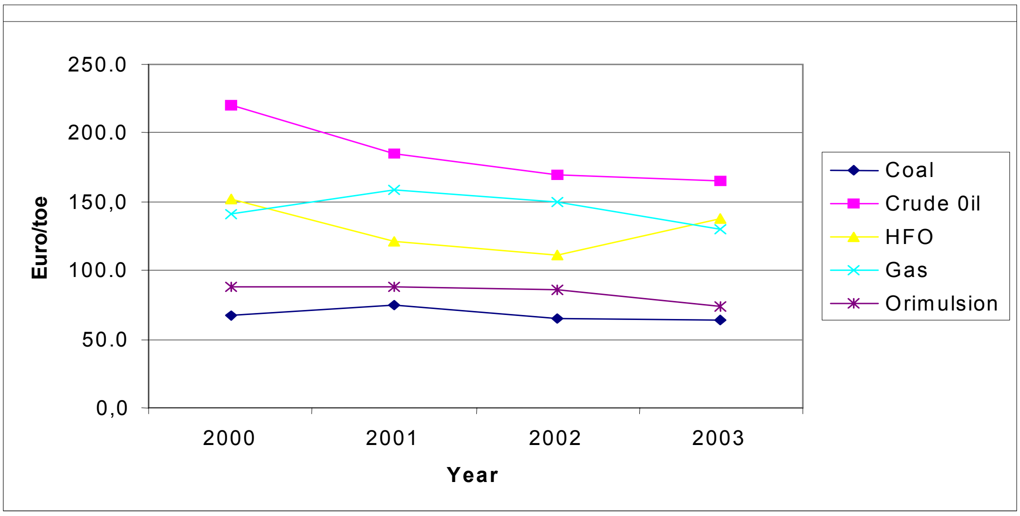


Figure 2.24. Price dynamics for selected fuel types in 2000–2004 [10].

The price of straw is in the range 35–80 LTL/t [4] — 0.69–1.58 €/GJ. Assuming a distribution cost of 0.66 €/GJ, the average price of straw will be 0.48 €/GJ. The price growth rate is assumed to be the same as that for wood because these fuels compete one with another.

The price of peat recommended for heat generation is about 130 LTL/t [4] — 3.63 €/GJ. Taking into account the assumed distribution cost of 0.79 €/GJ, the price of peat before distribution (extraction cost) will be 2.84 €/GJ. This price is rather high, but this is related to peat use in agriculture. Peat used for agricultural purposes is exported as well, and the export price is about 155 LTL/t. The limited peat resources in Lithuania and the export possibilities for non-energy needs set a rather high market price for peat.

2.4. Summary and conclusions

2.4.1. General information

Despite the slowdown in the global economy, the three Baltic States have declared an average 6.6% increase in their real GDP during recent years. With a total population of only 7.1 million people (*Table 2.16*), Estonia, Latvia and Lithuania have achieved greater presence in the international community by joining forces in a number of political and economic arenas. In 2004 Estonia, Latvia and Lithuania joined NATO as well as the EU. Membership of NATO and the EU was a stated foreign policy goal in each of the three countries once they regained independence.

Table 2.16. General information about the Baltic States

	Estonia	*Latvia*	*Lithuania*	*Total*
Territory (km^2)	45 200	64 489	65 300	174 989
Capital	Tallinn	Riga	Vilnius	
Population (thousand)	1356	2331	3440	7127
GDP/capita (€ PPP)	10 114	8370	9570	

The features of the GDP structure (*Table 2.17*) of the Baltic States could be summarised as follows:

- The share of industrial production in the GDP structure of Lithuania and Estonia is higher than that of Latvia;
- The share of agricultural sector is higher in Lithuania;
- The share of the commercial sector, which has a low energy consumption, is highest in Latvia.

Table 2.17. GDP (%) structure in the Baltic States in 2002

GDP structure	*Estonia*	*Lithuania*	*Latvia*
Industry	29.0	31.4	24.7
Agriculture	5.3	7.1	4.7
Commercial	49.8	49.0	56.1
Transport	15.9	12.5	14.5

2.4.2. Energy sector

Table 2.18 provides the main economic and energy consumption indicators of the Baltic States.

As is seen from *Table 2.18*, Estonia, in comparison with the other Baltic States, has the highest energy consumption per capita and a high primary energy intensity of the economy. This is explained by the structure of its fuel balance. In 2002, oil shale constituted the major share of the balance — almost 60%. The major part of mined oil shale is used by power plants, for which the average efficiency is low — approximately 30%.

Energy supply efficiency in Lithuania and Estonia is lower than that in Latvia. Comparatively low losses in the energy supply system of Latvia are explained by the domination of hydro energy and imported electricity in the electricity production structure. Hydro energy and imported electricity are transferred from TPES to FEC with 100% efficiency. This gives a high ratio of final energy to primary energy supply in Latvia.

All three Baltic States are strongly dependent on energy imports; especially taking into account that nuclear fuel is also imported (Estonia to a smaller extent because of its oil shale resources).

Table 2.18. Main economic and energy consumption indicators in the Baltic States, 2002

Main data	*Unit*	*Lithuania*	*Estonia*	*Latvia*
Population	Thousand inhabitants	3469	1356	2331
Primary energy supply	PJ	361	194	188
FEC	PJ	201	107	161
Gross electricity consumption (gross production + imports and exports)	TWh	11.234	7.837	6.323
Final electricity consumption	TWh	6.723	5.686	4.882
Primary energy/capita	GJ	104	143	81
Final energy/capita	GJ	58	79	69
Final electricity consumption/capita	kWh	1938	4184	2018
FEC/TPES	%	55.7	55.0	85.6
Net import share in balance	%	44	40	66

The Baltic States are net oil importers, with ~90% supplied by Russia (*Figure 2.25*). Lithuania has an oil refinery of its own (the Mazeikiai refinery), which sells its products in all three Baltic countries and is jointly owned by the Lithuanian government and Russia's Yukos oil company. Latvia owns a developed infrastructure for oil and the oil product transit business — pipeline systems, railroads and oil-reloading facilities in the port of Ventspils. The second major oil terminal is located in Butinge (Lithuania). Some oil transit is conducted by railway transport through other large Baltic ports.

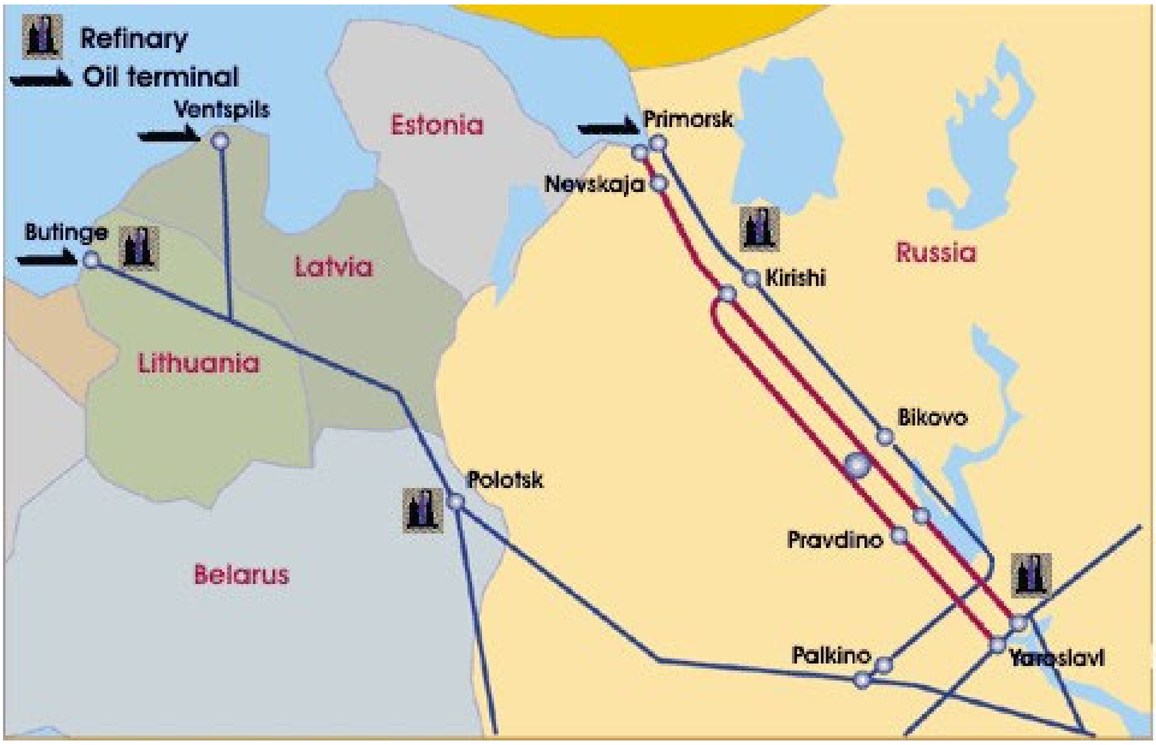


Figure 2.25. Oil network to the Baltic States

Natural gas for the needs of the Baltic States is all imported from Russia. The Russian gas giant GAZPROM has shares in gas companies of all three Baltic States (*Figure 2.26*). Currently the natural gas transmission network of the Baltic States is not connected to the network of any other EU Member States.

Figure 2.26. Location of gas reserves by Russian regions and GAZPROM's major gas fields (billion cubic metres) (Source: GAZPROM).

The TPES structure of the Baltic States is summarised in *Table 2.19*. When analysing this TPES structure, we conclude that it is very different in each. In Lithuania more than 40% of the TPES comes from its nuclear plant. In Estonia 58% of the TPES is covered by oil shale. In Latvia the TPES is represented by firewood, oil products and natural gas, about 30% each.

Table 2.19. TPES structure in the Baltic States, 2002 (%)

	Estonia	*Latvia*	*Lithuania*
Oil products	20.1	29.3	28.7
Natural gas	11.1	29.1	25.2
Coal	0.9	1.6	1.6
Peat	2.8	0.7	0.2
Oil shale	53.8	1.1	—
Biomass	10.9	29.0	7.8
Hydro	0.2	4.8	0.3
Nuclear	—	—	42.8
Net electricity import	–0.3	4.4	–6.6

Table 2.20 summarises the data on installed power capacities in the Baltic States. As of 01 January 2003, the total installed capacity in the Baltic States was 11 319.8 MW. It included different types of equipment:

- NPPs;
- HPPs;
- Condensing power plants;
- CHP plants;
- Hydro pumped storage power plant (HPSPP);
- Wind generators.

Table 2.20. Installed power production capacity, 2002 (MW)

	Lithuania	*Latvia*	*Estonia*	*Total*
Installed capacity	6155.9	2181	2982.9	11 319.8
HPSPP	800.0	0	0.0	800.0
Hydro power plant	113.1	1561.2	3.8	1678.1
Nuclear power	2600	0.0	0.0	2600.0
Thermal power	2642.8	592.9	2976.6	6212.3
Condensing	1800.0	0.0	2730.0	4530.0
CHP	842.8	592.9	246.6	1682.3
Wind	0.0	26.9	2.5	29.4

Estonia and Lithuania are net electricity exporters, and sell their surplus to neighbouring Latvia and partly to northwest Russia. In 2002, Estonia generated 8.53 TWh of electricity, mainly from its Narva power plants fired by oil shale. Lithuania generated 14.6 TWh in 2001, of which 11.4 TWh was generated by the Ignalina NPP. The first unit of the Ignalina NPP was closed on 31 December 2004. The second unit has to be closed by the end of 2009. Latvia is the only net electricity importer in the region, buying it from the other Baltic States as well as from Russia.

Interconnection of the power systems of Estonia, Latvia and Lithuania (Baltic IPS) operates in parallel (as a synchronous AC grid) with the unified power system (UPS) of Russia and the power system of Belarus via a power loop. This loop was created in the early 1960s by the interconnecting power systems of the western part of the former USSR: the Baltic States, northwest Russia, Central Russia and Belarus (*Figure 2.27*). The Russian power system provides regulation of the frequency in the system. The electrical networks of Estonia, Latvia and Lithuania, as well as the neighbouring electrical networks of Russia and Belarus, form an electric ring, which consists of 330 and 750 kV lines. The 750 kV network in the integrated power system is not closed. In practice, there are no major congestion problems in the Baltic IPS.

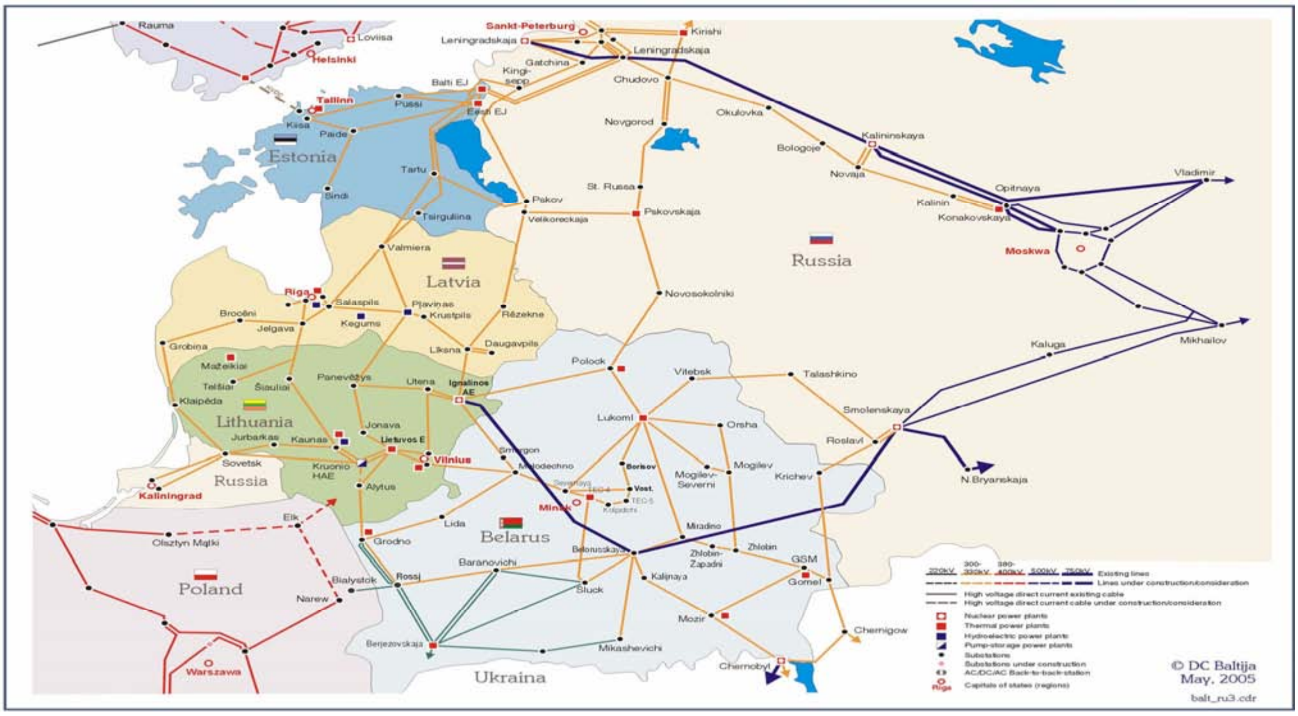


Figure 2.27. Interconnection of Baltic IPS and UPS of Russia and Belarus.

In summary, the above information on the energy sectors of the Baltic States can be briefly presented as follows:

- The Baltic States are interconnected by a well-developed power transmission network that ensures electric energy transfer — both mutual and to Russia;
- The Baltic States are also interconnected by a cross-country gas pipeline, but currently only the Latvia–Estonia connection is used;
- Latvia has an UGS that, taking into account its planned extension, is capable of supplying the neighbouring countries with the necessary seasonal gas reserves;
- All three Baltic States are highly dependent on energy imports: Lithuania 86% (44% if nuclear fuel is assumed to be domestic), Latvia 66% and Estonia has a lower share (40%) of imports because of its oil shale resources;
- Each of the Baltic countries has a different TPES structure;

- Installed power capacities in the Baltic States include electricity-generating capacities of different types — a nuclear power plant, HPPs, condensing power plants, CHP plants and a hydro pumped storage power plant;
- Today, Estonia and Lithuania are electricity exporters, whereas Latvia is an electricity importer.

3. ENERGY POLICY AND LEGISLATION

3.1. Estonia

3.1.1. General overview of legislative framework and governmental policies

According to the Constitution, Estonia is a parliamentary democracy. The 101 members of the unicameral Parliament (*Riigikogu*) are elected on the principle of proportionality. The head of state is the President, who is elected for 5 years by the Parliament. Executive powers are entrusted to the Prime Minister and to the Government. The Government consists of the Prime Minister and the heads of 12 ministries. The President may, on the recommendation of the Prime Minister, appoint up to two ministers without portfolio to office. The functions of these ministers are determined by the Prime Minister.

Local issues are resolved by local governments. There are 15 counties (*maakond*) in Estonia. Counties are national administrative units, chaired by a County Governor appointed by the central Government. The counties include 241 units of local administration — rural municipalities (*vald*) and towns (*linn*). The representative body for each municipal administrative unit is the Municipal Council (*volikogu*). Municipal councils are elected for 3 years. Local governments have their own budgets and have the right to establish local taxes to the extent provided by law.

The legal acts related to the energy sector and/or environment are initiated mainly by the Government, the Ministry of Economic Affairs and Communications, and the Ministry of the Environment. According to the Constitution, committees of the Riigikogu (Parliament) also have the right to initiate laws. The main work with the drafts (bills) of legal acts is done in the parliament committees. A committee looks through proposals for changes and amendments and is responsible for the draft law (a bill) until the Riigikogu passes the final decision about it.

The Sustainable Development Act sets the most general principles for sustainable development in Estonia and therefore forms the basis on which national and regional programmes are formulated, including plans to develop the energy sector. The first plan, The Long term National Development Plan for the Fuel and Energy Sector, was approved by Parliament in 1998 as a plan at the national level for the energy sector. In this, targets were set for the development of the fuel and energy sector up to the year 2005; some principal development trends were given for up to 2018.

In December 2004 a new long term development plan for the fuel and energy sector (up to the year 2015) was approved by the Parliament. New, stricter environmental requirements have required Estonia to reduce the share of oil shale in its electricity generation, but very large investments to renovate power plants that fire oil shale are still to be made. Nevertheless, the share of oil shale in the energy balance will gradually decrease in the near- and mid-term future. As a result, development towards a more diversified electricity energy sector is foreseen. In the new plan, several challenging targets have been set. At first, to increase the share of renewable energy resources (RESs) in electricity production, essentially from 0.2% to 5.1% of gross consumption by 2010. The second, partially related to the first, goal is to reach a 20% share of CHP in gross electricity consumption by 2020. As a very general target, it is planned to keep the consumption of primary energy to the level of 2003 up to the year 2010.

Regarding energy-related legal acts, harmonisation with the relevant European Union (EU) *acquis* was completed by the accession date — 1 May 2004. Nevertheless, transitional periods were granted for the actual implementation of some provisions. Estonia applied for derogations and transition periods mostly in the sectors that needed major investment or that were socially and politically sensitive. Transitional periods given to Estonia by the Treaty of Accession (Energy Chapter) include the following:

- To comply with the requirements to maintain minimum stocks of crude oil and/or petroleum products;
- To open the internal electricity market.

Some transitional periods are related to the energy sector in a more indirect way, such as through limits to emissions of certain pollutants to the air from large combustion plants (Environment Chapter), and through excise taxes on energy products (Taxation Chapter).

As to laws, in 2003 the former framework law Energy Act had already been repealed and replaced with a set of new laws. Since 1 July 2003 the following laws regulate the activities in the energy sector:

- Electricity Market Act;
- Natural Gas Act;
- Liquid Fuel Act;
- District Heating Act.

The Electricity Market Act regulates the generation, transmission, sale, export, import and transit of electricity and the economic and technical management of the power system. The Act prescribes the principles for the operation of the electricity market, based on the need to ensure an effective supply of electricity at reasonable prices that meets both environmental requirements and the needs of customers, and on the balanced, environmentally clean and long term use of energy sources.

The Natural Gas Act regulates activities related to the import, distribution and sale of natural gas by way of gas networks, as well as connection to gas networks.

The District Heating Act regulates activities related to the production, distribution and sale of heat by way of district heating networks, and connection to networks. As an important element of regulation, the Act stipulates the introduction of district heating regions (i.e., zones of heat supply). A district heating region is defined as an area determined by a comprehensive plan produced by the local municipality within which consumer installations are supplied with heat by way of district heating. A local government council has the right to determine district heating regions within the boundaries of its administrative territory.

3.1.2. Renewable energy sources

In Estonia the only measure that promotes the wider use of RESs is related to electricity production. A direct scheme to support the use of renewable energy for electricity generation is stipulated in the Electricity Market Act. The Act provides that every network operator is obligated to buy electricity produced from renewables within the network that the operator owns or operates. At the same time, the network operator has to pay a certain price (feed-in tariff) for renewables-based electricity — 51.77 €/MWh.

The Act provides that RESs are hydropower, solar energy, wave energy, tidal energy, geothermal energy, landfill gas, wastewater treatment gas, biogas and biomass. Biomass is defined as the biodegradable fraction of products, waste and residues from agriculture (including vegetable and animal substances), forestry and related industries, as well as the biodegradable fraction of industrial and municipal waste.

The period of validity of purchase obligation depends on the type of energy source and on the year the generating installation was commissioned. For generating installations put into operation before 1 January 2002 the purchase obligation and feed-in tariff are in force until 31

December 2008. For newer installations the relevant obligation of a network operator lasts for:

- 7 years for electricity generated using water or biomass;
- 12 years if other RESs are utilised.

In both cases no obligation will be in force after 31 December 2015.

3.1.3. Environmental protection

Estonia has signed and ratified the Kyoto Protocol of the United Nations Framework Convention on Climate Change (UNFCCC), thereby making a commitment to reduce greenhouse gas (GHG) emissions within the years 2008–2012 by 8% compared to the 1990 level. Since GHGs in Estonia were 37.174 million tons in 1990, the 8% reduction totals 2.973 million tons. Thus, the Kyoto commitment for Estonia is 34.201 million tons. The obligation to reduce GHGs established in the Kyoto Protocol has already been achieved in Estonia through significant re-organisation of its economic sectors, particularly energy production, and also of industry and agriculture (i.e., as a result of the qualitative and quantitative restructuring of the whole economy at the beginning of 1990s).

The Estonian National Environmental Strategy, approved by Parliament in 1997, is a basic document for the policy-making process in environmental fields. The Strategy provides several long term environmental targets for stationary sources (e.g., power plants), such as the reduction of sulphur oxide (SO_x) emissions to 80% of the 1980 level by 2005 and the reduction of particulate (i.e., dust and fly ash) emissions to 75% of the 1995 level by 2005. The National Environmental Action Plan (NEAP) defines concrete conceptual, legislational, organisational, educational, training and also investment measures to reach the objectives set in the National Environmental Strategy. The implementation process of NEAP, adopted by the Government, is in progress.

The continued high level of air pollution in the Ida-Virumaa region in the northeast of the country is a particularly severe environmental problem. The burning of oil shale, which generates roughly 90% of Estonia's electricity and heating, produces 88% of the country's overall emission of nitrogen and 95% of its dust (solid particles). Modernisation of large-scale power stations has already begun. About 60% of the oil shale burned is left as ash, which is stored in slag heaps. In addition, open-cast mining to extract oil shale is destroying the countryside. Transitional periods agreed upon within the framework of EU accession will expire in 2012, by which time the oil shale sector should be restructured. Along the way, major power stations are to be fitted with new technology to ensure that they meet European standards on efficiency and emissions.

A completely new Ambient Air Protection Act was introduced in September 2004. The new Act regulates activities that involve the emission of pollutants into the ambient air, damage to the ozone layer and the factors that cause climate change. The Act provides the main principles for the control of ambient air quality, sets a basis for emission standards, foresees measures to reduce air pollution, etc. The Act harmonises Estonian legislation with the relevant EU *acquis*.

Regarding energy-related emissions into the air, the Act provides that limits (ceilings) on emission have to be set for large combustion plants (i.e., for combustion installations with a rated thermal input that exceeds 50 MW). The actual values are provided by the Regulation of the Minister of Environment (MoEnv; No. 112 of 02.09.2004). For smaller combustion plants no similar limits are provided. Nevertheless, according to the Regulation of the MoEnv (No. 101 of 02.08.2004) every legal body using combustion equipment with an installed capacity of 0.3 MW has to apply for a permit to emit pollutants into ambient air (pollution permit). The permit provides the peak values (g/s) and annual volumes (t/a) of emitted pollutants. The latter quantities are taken as a basis on which to pay regular pollution charges, and if these quantities are exceeded a penalty has to be paid. To be granted a pollution permit, every enterprise has to present a document with detailed emission calculations. These must show that the emissions into ambient air will not cause pollution that exceeds the relevant limit values, alert thresholds and margins of tolerance stipulated in the Regulation of the MoEnv (No. 115 of 07.09.2004).

The National Programme for the Reduction of Greenhouse Gases Emissions for the Years 2003–2012 was approved by the Government in April 2004. The Programme gives an overview of the Kyoto commitments and analyses the implementation strategy and action measures for Estonia. Special attention is given to the strategy, structure and costs of GHG emission trading and joint implementation projects. The long term objective of the National Programme is to reduce GHGs by 21% by 2010 as compared with the 1999 emission level. This includes reduction of carbon dioxide emissions by 20%, reduction of methane emissions by 28% and an increase of nitrous oxide emissions by 9%.

3.1.4. Security of energy supply

The self-sufficiency of the energy sector in Estonia is quite high, as a major share of primary energy utilised in Estonia is of domestic origin. Imported fuels make up approximately one-third (31% in 2003) of primary energy supply. The share of domestic energy sources is high because of the leading role of oil shale. It gives important strategic independence, especially for the electricity sector — 92% of electricity production is based on oil-shale firing.

Regarding the supply security of imported fuels, the risks with liquid fuels are low as there are many import sources. The supply of natural gas originates from one country only — Russia. The national long term development plan for the energy sector emphasises the need to increase gas supply security by participating in the development of Latvian underground gas-storage facilities and procuring reserves in them. Natural gas supply risks could be reduced to some extent if another gas pipeline from Russia to Europe is constructed and a branch connection to Estonia established. It is clear that the realisation of this project does not depend on Estonia.

The declared policy of a preference to use domestic energy sources also supports supply security. This policy includes the deployment of renewables — in Estonia, mainly biomass and wind energy. For the latter, the reliability of electricity supply should also be considered.

To maintain minimum stocks of crude oil and/or petroleum products for 90 days, as provided in the EU *acquis*, would increase the supply security of liquid fuels. However, these stocks will not be established to their full extent until the end of 2009, as Estonia (together with Latvia and Lithuania) has been granted a transitional period to implement this obligation. At present, minimum stocks of liquid fuels are being established gradually, in compliance with the time schedule set out in the Minimum Stocks of Liquid Fuels Act.

3.1.5. Promotion schemes for various energy carriers or technologies

In Estonia, the leading principle of energy policy has been to orientate it towards a market-based development. Therefore, almost no direct promotion schemes have been devised or subsidies granted in the field of energy technologies. Nevertheless, some aspects of general preferences can be illustrated.

The only field in which some concrete support measures have been introduced is in the use of RESs for electricity generation. A direct scheme to support the use of renewable energy for electricity generation is stipulated in the Electricity Market Act. The scheme includes a purchase obligation for network operators and feed-in tariffs (see Section 3.1.2).

The Electricity Market Act also stipulates some indirect support for some power producers — large (with a total capacity of at least 500 MW) plants that fire oil shale, all small power plants (maximum 10 MW) and cogeneration (CHP) plants. A network operator has to purchase electricity from these producers to cover its network losses and to sell to non-eligible clients.

The introduction of the zone principle to heat supply by the District Heating Act can be treated as a district heating supporting measure. The Act stipulates the introduction of district heating regions (i.e., zones of heat supply, see Section 3.1.1). Consumer installations already connected to a network within a district heating region may be disconnected from the network and heat supply other than the district heating offered only under the conditions determined by the local government.

As a conclusion to the analysis of support strategies, it is emphasised that the development of power production based on oil shale using environmentally sound technologies has been an issue of high priority in Estonia. Here the key contribution is to replace the existing pulverised fuel boilers with circulating fluidised bed (CFB) boilers in the Narva power plants. The first two new blocks (both 215 MW) to adopt new CFB boilers were commissioned in 2004. The scope for further reconstruction of the other blocks will be determined on the basis of the experience gained from the operation of the first two.

The question of research related to oil shale was also raised on accession negotiations with the EU. Considering the unique character of oil shale, the EU agreed to Estonia's request on oil-shale research being eligible for special-purpose funding from the European Coal and Steel Community (ECSC) Research Fund for Coal and Steel (which, as of 24 July 2002, came under the European Commission's administration). As a result, the term 'oil shale' was added to the list of research that fits in with this fund's objectives (Decision 2002/234/ECSC).

3.1.6. Open electricity market

Since 1 July 1999 the Estonian electricity market has been open to eligible clients whose yearly consumption exceeds 40 GWh. Of the total Estonian consumption, the share of these users is about 10%.

New legislation to regulate the energy market came into operation on 1 July 2003, to implement the principles stipulated in the new electricity market directive. The Energy Act, which had been in force until 1 July 2003, had established a number of essential principles for the open electricity market, such as to provide access to a third party, the rights and responsibilities of the Energy Market Inspectorate, electricity energy pricing policies, etc. The new Electricity Market Act stipulates a number of measures to further restructure the Estonian electricity market. Nevertheless, because of the policy to give priority and a kind of special status to power generation from fired oil shale, Estonia has selected a very slow pace at which to liberalise the electricity market. The accession negotiations (Energy Chapter) resulted in an unprecedented agreement: Estonia became the only candidate country to be granted a transitional period to open its electricity market. By the end of 2008 at least 35% of the Estonian electricity market will be opened for competition (i.e., all consumers with an annual consumption of approximately 1 GWh will be eligible to select suppliers). In the longer term, EU Directive 2004/85/EC stipulates that Estonia has to open its electricity market gradually with the aim to complete this process by 1 January 2013.

The reasons for this very slow opening of the market are also linked to the transitional arrangements that concern environmental issues — the Treaty of Accession provides that

Estonia bring its power production facilities based on oil shale into compliance with the EU environmental requirements by the end of 2015 at the latest. The aim is to introduce environmentally sound facilities by replacing the existing pulverised fuel boilers with CFB boilers (see Section 3.1.5).

In conclusion, by accepting these long transitional periods the EU and Member States have admitted that the Estonian electricity market situation is different from that of other countries, to the extent that common solutions of electricity market regulation do not work here.

3.2. Latvia

3.2.1. General overview of legislative framework, governmental policies

In Latvia the energy policy is similar to that in the EU and other industrially developed countries, and is dominated by the following priorities:

- Security of supplies, especially considering the dependence on Russian gas supplies and integration with Russia's electricity system;
- Competitiveness, with the introduction of market mechanisms;
- Protection of the environment.

The main policy documents that deal with energy policy issues are the National Energy Programme, governmental policies in the energy sectors and the Strategy for the Sustainable Development of Latvia.

The National Energy Programme was accepted in concept by the Cabinet of Ministers on 2 September 1997. The objective of the National Energy Programme was to define a set of measures to ensure stable energy supplies at the lowest costs and lowest affordable environmental impacts that, in quantity and quality, correspond to domestic demand. This objective is to be achieved by improving energy efficiency, promoting the utilisation of domestic energy resources and decreasing the share of energy in the country's imports. It is a planning document that integrates into a single system the technical, financial and organisational measures, and it is composed of 12 sub-programmes. The Programme covers the period up to the year 2020 and is due for renewal in 2005–2006. Unfortunately, renewal of the Programme has been protracted because of other priorities in the energy sector.

The Cabinet of Ministers approved the current Government Policy for the Electricity Sector on 11 September 2001. In the current document the sector is assessed from a broader perspective and more attention is paid to the instruments of implementation. The policy aims to move towards a common Baltic electricity market, according to the commitments made by the Baltic Council of Ministers. Objectives of the policy anticipate comprehensive sector reforms and envisage competition in both the wholesale and retail of electricity. Integration of the energy supply systems of the Baltic States into those of Nordic and Central European countries should be supported.

In the future development of the energy industry, special attention shall be paid to problems related to environmental protection, taking into consideration the increasing requirements for public well-being and the international commitments of Latvia. Particular attention is paid to the domestic potential of RESs, especially wood, peat and wind, all of which have been insufficiently used in electricity generation so far. Cogeneration plants will obtain support if the annual average efficiency of primary energy use reaches 80% and heat energy is supplied mainly to district heating supply systems.

Taking into consideration the strategic importance of energy supply, the trends of the European integration process and the Transatlantic Partnership, the Ministry of Economy will, on a regular basis, establish criteria aimed at balancing the electricity demand in Latvia with domestically generated electricity and imported electricity, including imports from the electricity trade in the Baltic States. Although the policy aims 'at 80–90% self-sufficiency in electricity production by the year 2008', this statement is not based on any feasibility assessments and market analysis. In fact, after closure of the second unit at the Ignalina NPP in 2009 and oil shale units in the Narva power plants during the period 2010–2015, the situation might be even worse, when no free capacity is available in Estonia and Lithuania for export to Latvia. With the lack of interconnections to Nordel and the Union for the Co-ordination of Transmission of Electricity (UCTE), the dependency on electricity imports from Russia (as the only supplier) is not acceptable politically. This is why the new target of establishing 100% self-sufficiency should be considered.

Instruments to attain the objective of the energy policy in the electricity sector are:

- Application of *market mechanisms* to promote growth of the electricity industry and the economy;
- *Harmonisation of costs* involved in environmental protection and energy generation, transportation and utilisation;
- *Balanced sector development* in line with the overall economic growth;
- Promotion of use of renewable and domestic energy resources.

Energy legislation

The energy sector in Latvia is regulated by a legal framework of general primary and secondary legislation. Primary legislation (being dominant over general legal rules in cases of discrepancy) specific to the energy sector mainly comprises the:

- Energy Charter Treaty;
- Energy Charter Protocol on Energy Efficiency and Related Environmental Aspects;
- Energy Law;
- Law on Regulators of Public Services.

The law on the European Energy Charter Treaty was ratified by the Saeima (Parliament) on 13 September 1995 in acceptance of the European Energy Charter Treaty signed on 17 December 1994 in Lisbon. By signing the Charter, Latvia committed itself to a number of obligations, including easing the transit of energy and energy resources through its territory, eliminating any discrimination that relates to the origin of products or their destinations, and excluding any unreasonable impediments, prohibitions or dues. For Latvia these are extremely important because of large volumes of oil and gas transit.

The Energy Law passed by Parliament (the Saeima) in September 1998 and in force since 6 October 1998 incorporates the main provisions of the EU energy directives. It regulates rights and obligations of enterprises that operate as natural monopolies with the intention to protect consumer interests, promote business development within the energy sector and ensure the implementation of Government policies.

According to the Energy Law, the main task of the energy sector in Latvia is to provide a secure, environment-friendly and long term energy supply to the national economy and to the residents. This should provide the requested amount and quality at economically based and acceptable prices, to ensure efficiency and promote competitiveness in energy undertakings and in the national economy.

The Law on Regulators of Public Services was passed by Parliament (the Saeima) on 19 October 2000 and has been in force since 1 June 2001. The Law stipulates the general procedure for the regulation of public services. The terms and conditions on transparency of prices of public services are incorporated in the Law on Regulators of Public Services. A multi-sectoral regulator — the Public Utilities Commission (PUC) — took over regulation of the energy sector from 1 October 2001.

Technically, the terms and conditions for energy supply and utilisation are determined by the Government Regulations on Heat Supply and Utilisation (passed on 28 February 1995), Regulations on Electricity Supply and Utilisation (passed on 22 October 1996), and the Regulations on Gas Supply and Utilisation (passed on 20 January 1998). These were updated, in conformity with the Energy Law, by the Government on 9 March 1999.

A new Competition Law has been in force since 1 January 2002. This Law applies to all market participants and to any registered or unregistered groupings of market participants.

3.2.2. Renewable energy sources

According to Directive 2001/77/EC, Member States shall take appropriate steps to encourage greater consumption of electricity produced from RESs. The global indicative target for RES-E (RES electricity production) is 12% of gross domestic electricity consumption in the year 2010 — for the European Union the target is 22.1%. In the Treaty of Accession to the European Union (2003), Latvia verified its target to increase the share of electricity production from RES-E from 42.4% (year 1999) to 49.3% (including large hydro power plants (HPPs)) by the year 2010. However, there are many disputes concerning the reference year for gross electricity consumption[17]. If the base year is 2010, the additional volume of electricity to be produced by RES-E in Latvia is 1.4 TWh, but if the base year is 2000 this additional power volume is 0.45 TWh. For comparison, Estonia and Lithuania should increase electricity generation from RES-E only by approximately 0.4–0.6 TWh[18]. It would not be logical if Latvia, which already has a much higher share of RES-E, had greater obligations than Estonia and Lithuania. Hence in this study the reference year for gross electricity consumption is assumed to be the year 2000.On this condition, all three countries must increase RES-E by approximately similar volumes.

In Latvia many of the energy and environment policy documents recommend wider utilisation of renewable energy because it is one of the measures that decreases dependence on imported primary resources and increases security of supply. The Energy Law establishes favourable conditions in which to use local, renewable and secondary energy resources and a diversified structure of imported energy resources. The Energy Law and related government regulations promote power generation from RESs by a direct price-support scheme — feed-in tariffs.

The previous support scheme envisaged that system operators would be obligated to purchase all the power from RESs at incentive tariffs. Latvia initiated a doubled tariff that applied only to small-scale hydro and wind plants (capacity less than 2 MW) and their equipment that commenced operation prior to 1 January 2003 (hydro plants) or 1 June 2001 (wind plants). Such support was made available for the 8 years from the commencement of operation of each respective power plant. After this period the Regulator shall determine the purchase price. Also, the Regulator is to determine the purchase price for power plants that are put into operation after the date mentioned above. For small-scale power plants of capacity less than 7

---

[17] The footnote (***) for the table in the Annex of the Directive 2001/77/EC for the new member states was specified in the Treaty of Accession to the European Union. It includes the following statement: ‘For the Czech Republic, Estonia, Cyprus, Latvia, Lithuania, Hungary, Malta, Poland, Slovenia and Slovakia, gross national electricity consumption is based on 2000 data’.

[18] In case of Lithuania and Estonia this figure is practically independent of the base year for gross electricity consumption.

MW that for fuel use municipal waste or the products of its processing (biogas) and are commenced before 1 January 2008, the purchase price will correspond to the average electricity sales tariff. For any other types and capacities of power plants that use RESs different to those described above, the electricity purchase tariff will be determined by the Regulator. Currently, the average electricity tariff implemented to calculate feed-in tariffs is approximately 48.7 €/MWh.

The Electricity Market Law (passed by the Parliament on 25 May 2005) substitutes some provisions of the Energy Law. According to the Energy Law, the public wholesaler should purchase mandatory power from RESs at incentive tariffs in an amount defined by the Cabinet of Ministers. Both captive and eligible consumers are obligated to purchase (from public wholesalers) the share of RES-E proportional to its demand or (alternatively) compensate the public wholesaler's expenses. The new Electricity Market Law envisages that for new RES-E capacities a competitive bidding procedure will be implemented.

3.2.3. Environmental protection

In 1995, Latvia ratified the UNFCCC, and on 10 December 1997 signed the Kyoto Protocol, thus undertaking the commitment that GHG emissions in 2008–2012 will not exceed 92% of the 1990 level (*Figure 3.1*). In 1994, Latvia joined the Geneva Convention on Long-range Transboundary Air Pollution, which determines that the ratifying countries have to reduce air pollution within the borders of the country through the reduction of emissions. In the short term horizons for Latvia, it will not be difficult to fulfil the agreement of the Kyoto Protocol concerning CO_2 reduction because, in comparison with the 1990, the level of CO_2 emissions has decreased considerably.

The 2001/81/EC Directive to limit emissions of certain pollutants into the air from large combustion plants, which sets national ceilings for certain atmospheric pollutants, was implemented by Governmental Regulation No. 208 (9 September 2003) and the Amendments to this Regulation issued by the Government on 8 April 2004 (Regulation No 132).

The following national emissions ceilings were set for Latvia for the year 2010:

- SO_2 101 000 t;
- NO_x 61 000 t;
- VOC 136 000 t;
- NH_3 44 000 t.

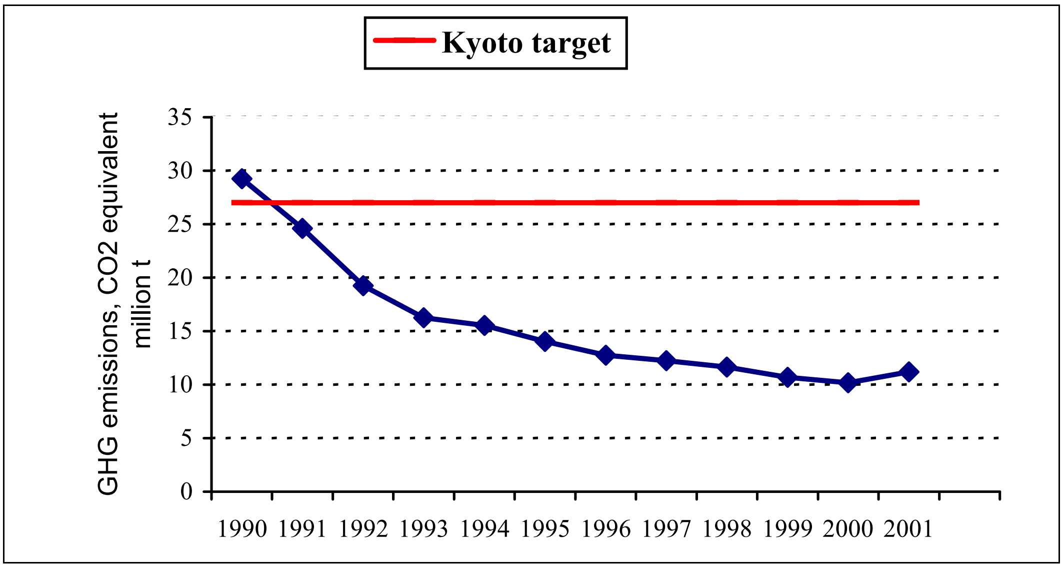


Figure 3.1. GHG emissions in Latvian and Kyoto target.

On 13 April 2004 the Government accepted the National Programme on Reduction of Air Emissions, which analyses emissions sources and evaluates the potential and measures for emissions reduction.

Forecasts related to the amount of GHG emissions up to the year 2020 show that Latvia would fulfil the obligations of the Kyoto Protocol even if no special GHG mitigation measures were implemented. Yet the government has an active position concerning environmental policy to ensure sustainable development of the economy.

The following important policy documents are relevant to climate change mitigation issues in Latvia:

- National Strategy for Sustainable Development of Latvia (2002);
- National Environmental Policy Plan for the Years 2004–2008 (2004);
- The Third Latvia National Communication under the UNFCCC (2001);
- National Plan for Allocation of Emission Allowances.

The National Strategy for Sustainable Development of Latvia (2002) aims to define the direction of the country's sustainable development. Policy objectives relevant to energy and climate change mitigation policy are to:

- Ensure the contribution of Latvia to mitigating global climate change in such a manner that does not hinder the economic development of the country;
- Promote the development of the energy industry in accordance with a balanced and sustainable economic development;
- Decrease air pollutants emanating from energy facilities;
- Decrease air pollution caused by transport;
- Increase the use of renewable (local) energy resources;
- Switch to environmentally more friendly fuels;
- Increase the use of CHP;
- Increase the security of energy supply;
- Ensure heat-energy conservation in buildings;

- Use highly efficient technologies for electricity appliances;
- Implement a system to analyse and check energy consumption.

The Latvian National Environment Policy Plan for the Years 2004–2008 was accepted by the Government in spring 2004. In its main statements, the Plan confirms and further develops the objectives and principal measures defined by the national sustainable development strategy. The Plan determines the objectives and envisages achieving significant results in terms of the rational use of energy resources and a decrease of GHG emissions. The main objectives concerning the energy sector are:

- To promote the sustainable development of energy industry;
- Through implementation of the UNFCCC and its Kyoto Protocol and the norms of EU legislation to reduce the negative impact of global climate change. The contribution of Latvia to the prevention of global climate change has to be ensured in such a manner that it does not hinder the country's economic development.

Regarding Directive 99/32/EC on reduction of the sulphur content of certain liquid fuels, Latvia has to ensure the use of liquid fuels with a sulphur content less than 1%.

The Law on Natural Resource Tax aims to restrict the wasteful use of natural resources and to encourage the introduction of new and updated technologies. The law promotes the use of renewable resources.

The Law on Environmental Protection (1991, 2000, 2002) aims to include environmental protection requirements in regulatory documents, concepts, plans and programmes that pertain to other sectors.

The Law on Pollutions (2001, 2002) aims at eliminating or, if impossible, at reducing the use of non-renewable resources and energy. The Law conforms to EU Directive 96/61/EC 'On integrated pollution prevention and control'. EU has accepted the requested transitional measure until 31 December 2010 for some energy enterprises.

The Law on Excise Tax establishes taxes for oil products.

The Law on Environmental Impact Assessment (14 October 1998) conforms to the relevant EU directives 85/337/EEC and 97/11/EC on the assessment of the effects of certain public and private projects on the environment.

3.2.4. Security of energy supply

Security of energy supply is a prime goal, in particular for countries with a high dependence on energy imports. This is true for Latvia, which imports approximately 70–80% of its total primary energy resources. In Latvia, the measures implemented to achieve energy security are:

- Diversification of fuels or fuel supply sources, such as switching the small boiler houses, especially in the countryside, from fossil fuels (coal, HFO, natural gas) to local fuels (biomass);
- Energy efficiency improvements for industry, the housing sector and transport;
- Power interconnection with European power systems (Nordel, UCTE);
- Expansion of Inčukalns UGS;
- Changing the fuel mix and use of RESs.

To maintain the minimum stocks of crude oil and/or petroleum products required for 90 days, as provided in the EU *acquis*, is one of the measures to increase security of supply. On 14

August 2001, the Cabinet of Ministers adopted the Concept on Formation of the State Oil Product Reserve.

Latvia has started to create its oil product stock. To create, store and record such a stock is a difficult process, both technically and financially. According to the Treaty of Accession to the European Union, Latvia should create oil product reserves for 30 days, which should be done by 31 December 2004. By 31 December 2009, oil product stock for 90 days should be available.

The major concern of the Latvian government in the power sector is a high share of natural gas (supplied from Russia under control of the Russian state monopoly GAZPROM) in electricity production. To avoid this increasing dependency, the government gave an order to the state power company Latvenergo to study different diversification options, including a coal-fired power plant on the west coast of Latvia or a Latvian share in Lithuania's Unit III of Ignalina NPP.

3.2.5. *Promotion schemes for various energy carriers or technologies*

The energy policy of Latvia not only supports the utilisation of renewable energy, but also the use of cogeneration technology. According to the Energy Law and Regulation of Cabinet of Ministers No 9, *Requirements for Combined Heat and Power (CHP) Plant and Procedures by which Purchase Price of Surplus Electricity Produced shall be Determined*, system operators are obligated to purchase a surplus of electricity produced in cogeneration plants at incentive tariffs (*Table 3.1*). However, such cogeneration plants must meet certain conditions:

- The fuel utilisation factor should be not less than 80%;
- 75% of heat generated by a CHP in cogeneration mode should be supplied to the district heating system;
- Electricity produced by a CHP plant in cogeneration mode is purchased according to the supporting principles specified by Regulation No 9, but power produced in condensing mode should be traded in the open market.

Table 3.1. CHP promotion scheme in Latvia

		Type of fuel	
		Fossil	*Renewable**
Installed electric capacity (MW)	<0.5	0.90 × Td† = 43.9 €/MWh	1.12 × Td = 54.6 €/MWh
	0.5–4	0.75 × Td = 36.5 €/MWh	0.95 × Td = 46.3 €/MWh
	>4	Tariff is set by the Regulator	

*Renewable energy sources are wood, biomass and biogas. They should be at least 75% of the CHP's fuel balance.

†Td — average energy tariff at distribution level, 48.7 €/MWh.

The Electricity Market Law (2005) foresees subsidies (mandatory purchase of electricity at incentive tariffs) for CHP plants and RES-E that satisfy certain criteria. In the longer perspective, we may expect that the introduction of new market-based mechanisms helps to purchase power from CHP plants and RES-E.

3.2.6. Opening up of the electricity market

The dominant role in electricity supply is played by the state joint stock company (JSC) Latvenergo, which provides more than 90% of all electricity generated in Latvia and ensures the import, transmission, distribution and supply to consumers. In addition, there are more than 100 small power plants and 10 licensed distribution and sales companies. Natural gas is supplied only by JSC Latvijas Gaze, but in the supply of liquefied gas more than 70 enterprises compete.

The energy sector legislation is approximated by implementing specific internal market requirements applicable to the energy sector in Latvia. It is executed to harmonise the overall legislation of the Energy Law and to follow this up with secondary legislation.

The Energy Law establishes a legislative and regulatory framework to liberalise the electricity and gas markets. The system operator concept is implemented both to regulate access to the transmission and distribution networks at reasonable cost, taking into account the existing capacities of transmission and distribution networks, and to expand the options for consumers to choose their energy supplier.

The creation of market conditions in the electrical energy sector is one of the priorities of the Government. For the electricity supply sector this means that the electrical energy market in Latvia must be opened gradually and work in accordance with provisions of Directive 2003/54/EC of 26 June 2003, which concerns common rules for the internal market in electricity. The most important provision, which makes this directive considerably different from the previous one, is the requirement to ensure independence of the transmission system operator (TSO). To ensure independence of the TSO and guarantee non-discriminatory access to the transmission grid, the new directive requires legal independence of the TSO, as provided by the status of a legal person, by 1 July 2004. Latvia fulfilled this obligation on 8 June 2005. According to the above directive, an independent distribution system operator (DSO) must be created by 1 July 2007. Simultaneously, the grid operator and trading functions of both the TSO and DSO must be separated.

Opening up of the market in Latvia is to be implemented in several stages, in accordance with the Regulations of the Cabinet of Ministers on Eligible Customers for Electricity (21 September 21 1999), described in *Table 3.2*.

Table 3.2. Opening up of electricity market in Latvia

Threshold for eligible consumers (share of the market)	*Year of implementation*
Market opening	2000
>100 GWh annually (5%)	2000–2001
>40 GWh annually (13%)	2002
>20 GWh annually (19%)	2003
>1 GWh annually (45%)	until 30 June 2004
All non-household consumers (75%)	2004–2007
All consumers	After 01 July 2007

The Ministry of Economy has prepared a draft policy planning document, *Guidelines for Creation of Preconditions for Electricity Market in Latvia*, which defines the:

- Basic principles for the model to open up the electricity market in Latvia;
- Necessary preconditions to open up the market;
- Market participants, and their basic functions, duties and rights;
- Principles of the prospective structure and regulation of the sector.

It also formulates the problems that currently hinder the opening up of the Latvian electricity market and the implementation of electricity users' rights of choice.

Liberalisation of the energy markets fits within the scope of the functions of the Regulator (the Energy Regulation Council from 1996 to 01 October 2001 and the Public Utility Commission (PUC) since 01 October 2001). The former Regulator (Energy Regulation Council) approved the power transmission system Grid Code on 30 May 2000. The Grid Code sets the procedures to liberalise the power supply market and states the role of power transmission and/or DSO, as well as for other market players.

The Electricity Market Law was approved on 25 May 2005. It regulates the relationships between market participants, and defines the main principles of trading and the power system auxiliary services (balancing, regulation). The target electricity market model for Latvia is presented in *Figure 3.2*.

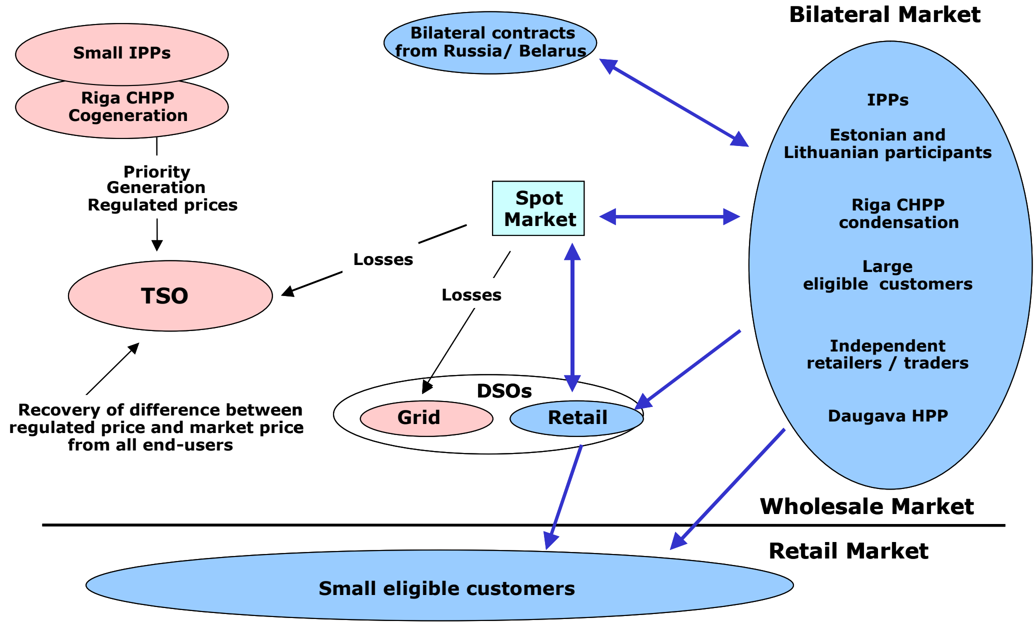


Figure 3.2. Target electricity market model in Latvia (after 1 July 2007). CHPP, combined heat and power plant; HPP, Hydro power plants; IPP, Independent Power Producer.

At present, JSC Latvijas Gaze is the only merchant in the Latvian natural gas market. This company, according to licences issued by PUC, carries out distribution, storage, supply and sales of natural gas. The Energy Law in its current wording makes no provision to liberalise the natural gas market or third party access to the infrastructure of natural gas transmission, distribution and storage. On 6 April 2004 the Cabinet of Ministers approved draft law Amendments to the Energy Law, which will set up the legal regulation to open up the natural gas market. This takes into account Directive 2003/55/EC of the European Parliament and of the Council, which is concerned with common rules for the internal market in natural gas. The draft includes issues on the operation of systems, duties and rights of market participators, and on the competition opportunities in natural gas market.

3.3. Lithuania

3.3.1. General overview of legislation framework, governmental policies

The main energy policy documents in Lithuania are the following:

- Energy Charter Treaty (ratified in June 1998);
- Energy Law (1995 and 2002);
- Law on Electricity (2000);
- Law on Heat (2003);
- National Energy Strategy (1994, 1999, 2002);
- National Energy Efficiency Programme (revised and updated version approved in September 2001);
- Strategy of National Security (approved in 2002).

The main energy policy provisions approved in the National Energy Strategy are to:

- Ensure a reliable and secure energy supply at least cost;
- Liberalise electricity and natural gas sectors in accordance with the EU directives;
- Privatise energy enterprises subject to privatisation in the energy sector;
- Develop measures that facilitate the implementation of EU directives;
- Enhance energy efficiency;
- Prepare for the decommissioning of the reactors at Ignalina NPP;
- Integrate Lithuanian energy systems into energy systems of the EU within the next 10 years;
- Strive for a share of RESs of up to 12% in the total primary energy balance by 2010;
- Ensure that 90-day stocks of oil products are available by 2010;
- Increase the share of renewables up to 7% of electricity production by 2010;Seek cooperation that provides a reserve capacity;
- Create a common Baltic electricity market and optimal utilisation of generating capacities;
- Prepare a strategy on the development of a Baltic transmission system and integration into the networks of West European and Scandinavian countries;
- Consider connecting the natural gas system to the gas pipelines of Poland and Finland.

3.3.2. Renewable energy sources

An important alteration in the Lithuanian primary energy balance is related to the striking increase (about four times during the period 1990–2002) in the contribution of indigenous energy resources (wood, peat, straw, biogas, hydro and geothermal energy) to the country's energy balance. In 2003 their share was about 8.0% (including the extraction of domestic oil, this indicator was about 12.4%). As shown in *Figure 3.3*, the main domestic energy resource is wood (including wood waste, boughs, wood chips, sawdust and waste from agriculture). At present its share in the country's energy balance is about 7.5%. The present contribution of other renewable sources is rather low. To ensure the rational use of renewables, create new jobs and improve environmental standards, efforts will be directed to increase the share of RESs in the Lithuanian primary energy balance to 12% by 2010, as well as to ensure that the share of electricity produced from RESs exceeds 7% by 2010. Conditions will be provided to develop the production of biofuels (denatured dehydrated ethyl alcohol, oils of biological origin, ethyl and ethyl ester), seeking to achieve by 2010 a biofuel share of 5.25% of the total amount of transport fuels used in Lithuania.

3.3.3. Environmental protection

Total emissions of the main pollutants (particulate matter, SO_2, NO_x, CO and non-methane volatile organic compounds) from all stationary and mobile sources of pollution in Lithuania are currently below 40% of their highest levels in 1991. This resulted mostly from the decline of industrial production and reduction of energy consumption in other sectors of economy.

In the energy sector, Lithuania will comply with the international environmental conventions it has acceded to, through the National Environmental Strategy, the Strategy for Approximation in the UNFCCC and the requirements of the EU environmental directives. Some requirements at the level of emissions from CHP and general country's obligations are presented in *Tables 3.3* and *3.4*.

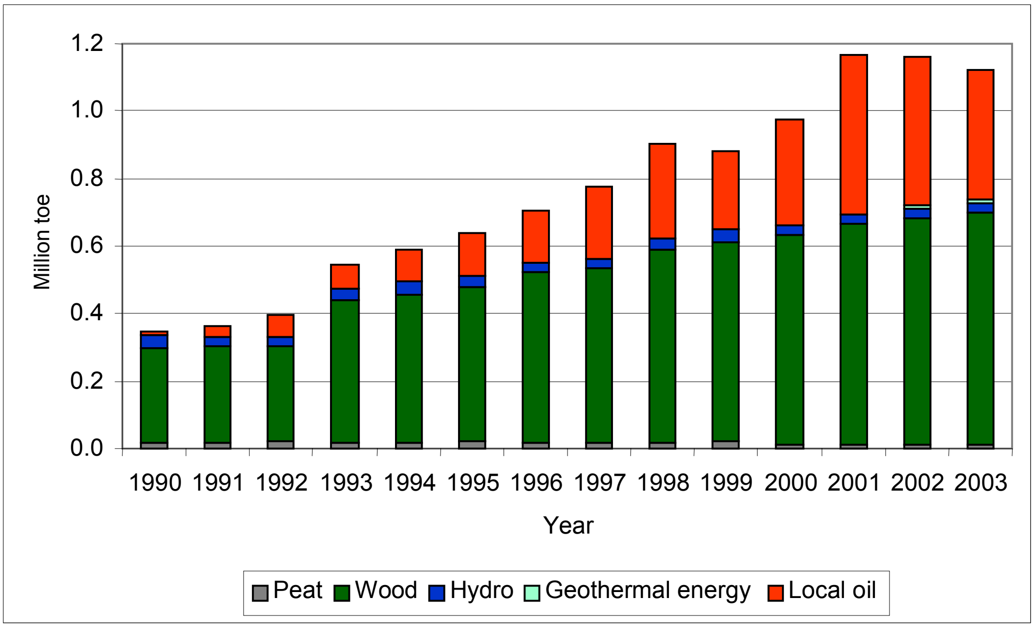


Figure 3.3. Production of renewable and other local energy resources.

Table 3.3. Ceilings of emissions from CHP (thousand tons)

Year	SO_2	NO_x
2005	28.3	4.6
2008	21.5	5.0
2010	30.5	10.5
2012	29.0	10.8

Table 3.4. General obligations of Lithuania

Emissions	*2010 (t)*	*From 1990 level (%)*
SO_2	145 000	65
NO_x	110 000	70
VOC	92 000	85
CO_2	34 300 000	92

3.3.4. Security of energy supply

Primary energy supply in Lithuania is dominated by imports from Russia — all crude oil, natural gas, coal and nuclear fuel are imported from this source. There is concern about the political and economic consequences of this dependence. However, according to the principles of international statistics, nuclear fuel is considered to be a domestic energy source independently of its supply source [12]. This principle is based on the low dependence on daily supply of this fuel and the rather large fuel inventory in the core of a nuclear power plant (NPP). Therefore, the domestic production of primary energy resources in Lithuania includes nuclear fuel, which is used for electricity generation. In fact, nuclear fuel is imported from Russian nuclear fuel enrichment facilities. However, for the above reasons, the Ignalina NPP is not sensitive to fuel supply interruptions, which substantially increases the security of energy supply. Thus, taking into account the increasing contribution of domestic energy resources and nuclear fuel to the country's energy balance the dependence of Lithuania on foreign energy supply decreased from 72% in 1991 to 43% in 2003.

After closure of the Ignalina NPP, electricity and heat generation will be based on imported fuels (oil, natural gas, orimulsion and coal), which will dominate the country's energy balance. The share of local energy sources (including local oil) and RESs will possibly reach about 18–19%. Thus, Lithuania will become much more dependent on energy imports than the neighbouring countries Latvia and Estonia. In 2010, Lithuania will become one of the EU countries most vulnerable to energy supply disruptions (*Figure 3.4*).

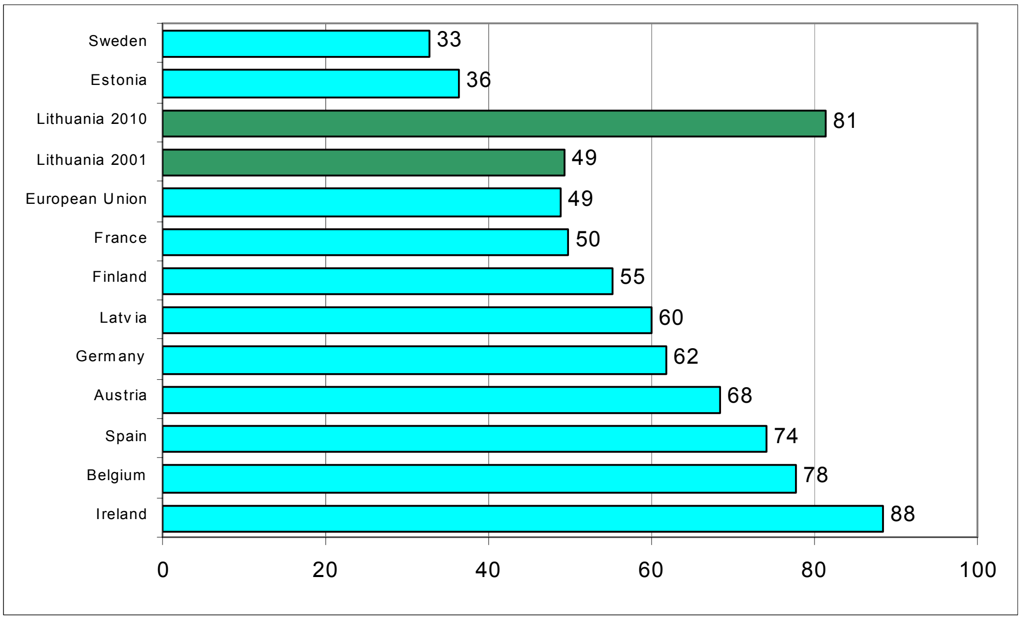


Figure 3.4. Indicator of dependence on energy imports in various countries in 2001 [12].

3.3.5. Promotion schemes for various technologies

The National Energy Strategy [13], which was adopted by Seimas on 10 October 2002, sets the main strategic priorities of the State energy policy and Lithuanian energy sector development. One of the main strategic priorities is to strive to achieve a state in which RESs account for 12% of the total primary energy balance by 2010.

The main objectives of the State in energy regulation, according to the Energy Law, which was approved on May 2002, are:

- Security of energy supply;
- Energy efficiency;
- Reduction of negative environmental impact;
- Promotion of fair competition;
- Promotion of the consumption of indigenous energy resources and RESs.

The main tasks of the State and municipal institutions that manage the energy sector and regulate and control energy sector activities are to:

- Ensure the optimum structure of the energy sector;
- Create preconditions for efficient activities in the energy sector;
- Ensure uninterrupted energy supply and stability of the established quality parameters;
- Promote energy efficiency;
- Promote the consumption of indigenous and RESs;
- Encourage enterprises to carry out energy audits.

The Energy Law establishes the relevant institutions to manage the energy sector — the Government or its authorised institutions, the Ministry of Economy, the Ministry of the Environment and the municipalities.

In July 2000 the Seimas approved the Law on Electricity. This Law establishes basic principles to regulate the generation, transmission, distribution and supply of electricity, taking into account the legal requirements of the EU. It establishes the relationships between suppliers of electricity and customers, as well as conditions for the development of competition in the electricity sector.

The main objectives of the Law on Electricity are to:

- Ensure public service obligations related to public safety, environmental protection and electricity generation using indigenous, renewable and waste energy resources;
- Establish objective, comprehensive and transparent requirements and obligations in the electricity sector;
- Promote environmentally friendly technologies in the generation, transmission and distribution of electricity.

The electricity sector is regulated by the Government or its authorised institution and the National Control Commission for Prices and Energy.

Together with a set of secondary legislation, the Law on Electricity comprises an important framework that encourages green electricity production in Lithuania. The List of Public Service Obligations for the electricity sector issued in December 2001 indicates that public and independent suppliers of electricity, as well as eligible customers engaged in electricity imports, have an obligation to purchase and sell electricity produced from renewable and waste energy resources. The rules to promote green electricity indicate that:

- The purchase of electricity produced from renewable and waste energy resources by electric installations with an installed total capacity of all generators below 10 MW shall be promoted;
- Electricity generated from renewable and waste energy resources shall be purchased at long term rates differentiated in relation to the type of renewable and waste energy sources being used, as set by the National Control Commission for Prices and Energy;
- The grid operator must ensure the transportation of electricity generated from renewable and waste energy sources primarily via electricity transmission grids (where the transmission capacity is limited);
- Payment for the reserve capacity at prices fixed by the National Control Commission for Prices and Energy shall not be applied to small power stations (with a total installed capacity of all generators below 10 MW) using renewable or waste energy resources.

According to the licensing rules for the power sector, the company that carries out the duties of electricity market operator is obligated to:

- Ensure equal and non-discriminatory conditions for all suppliers who purchase electricity produced using renewable and waste energy resources;
- Give priority to the producers who use indigenous, renewable and waste energy resources, if the same prices of electricity sale are offered at auction by several market participants.

The rules on the provision of services in accordance with public service obligations, issued by decision of the Minister of Economy in December 2001, define the general conditions, requirements and obligations for providing services in the electricity sector related to public safety, environmental protection and electricity production from renewable and waste energy resources.

The National Control Commission for Prices and Energy approved, in February 2002, the average purchase prices of electricity produced from renewable and waste energy sources (*Table 3.5*). Average purchase prices for other types of power plants that use renewable and waste energy resources will be settled by a separate decision of the Commission and could be differentiated.

Table 3.5. Average purchase prices of electricity produced from renewable energy resources [14]

Source	*Average purchase price*
Hydro power plants	5.79
Wind power plants	6.37
Power plants, using biofuel	5.79

The adopted legislation on renewable energy promotion and the quite high purchase prices of electricity produced from RESs enabled the successful development of small hydro energy plants and stimulated the high interest in wind energy.

The Government approved, in January 2004, an amendment to the order to promote green electricity. According to this order, electricity production from wind, biomass, solar energy power plants and HPP below 10 MW are encouraged. This amendment determines the order for the procurement, annual amount of green electricity procurement and capacity of new power plants (*Table* Table *3.6*) for the 2005–2009 period. The zones and total installed capacity of power plants for producers willing to install wind power plants are indicated also.

Lithuania is promoting the use of indigenous, renewable and waste energy resources by financial measures, as well as through the taxation system (fiscal measures) and financial aid or credits.

Table 3.6. Amounts of green electricity production and capacity of new power plants

Indicators	*Units*	*2005*	*2006*	*2007*	*2008*	*2009*	*Total*
Intended amount of green electricity production	GWh	522	579	659	784	932	
Intended amount of green electricity production	%	4.7	5.1	5.6	6.4	7.4	
Increase of wind power plant capacity	MW	33	33	33	25	13	157
Electricity production	GWh	84	112	140	196	278	
Increase of small hydro power plant capacity	MW	4	3	1	1	1	15
Electricity production	GWh	100	115	126	132	134	
Increase of biomass power plant capacity	MW	1.5	3	10	10	10	35
Electricity production	GWh	7.5	21	60	120	180	
Increase of solar power plant capacity	MW	-	0.2	0.8	1	2	4
Electricity production	GWh	-	0.2	1.2	3	6	

3.3.6. *Opening up of the electricity market*

Lithuania inherited the former Soviet Union energy systems, which is constructed on the principles of a centralised management of the economy. Independence in Lithuania was restored at the same time that essentially new principles of energy-sector management appeared in the economies of Western countries. Their main ideas were the unbundling of vertically integrated monopolies, the establishment of independent companies responsible for energy generation, transmission (transportation) and distribution, and the creation of free competition in the sector wherever possible. In the period after 1991 during which restoration of the economy occurred, Lithuania received major assistance from various international institutions (World Bank, European Bank for Reconstruction and Development, European Commission, etc.), as well as from individual states seeking to implement the principles of modern management in all sectors of the economy, especially in the energy sector.

At the end of 2001, after long discussions, the Government approved the Draft on Restructuring of the JSC Lietuvos energija, which was split into five juridically independent companies — two electricity generation companies (Lithuanian TPP and Mazeikiai PP), a high voltage electricity transmission grid (including the main regime controlling devices, Kruonis HPSPP and Kaunas HPP) and two distribution companies (*Figure 3.5*).

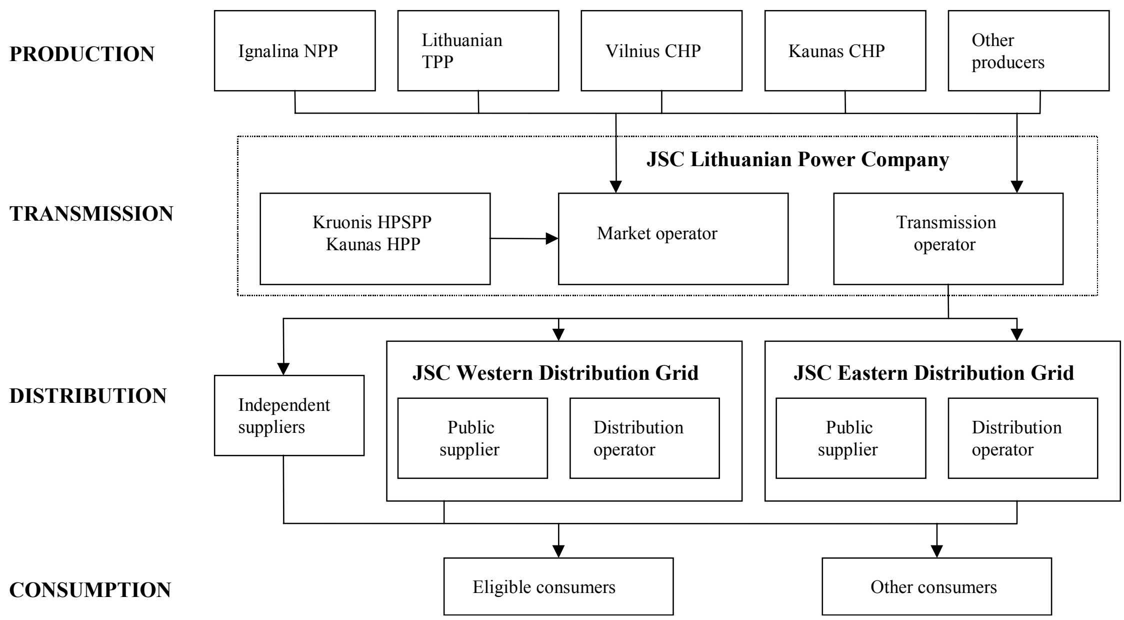


Figure 3.5. Current structure of the Lithuanian power sector.

Approval of the various rules, procedures, methodologies and other necessary legal acts (such as the Licensing Procedure, List of Public Service Obligations in the Electricity Sector, the Procedure for Promoting the Purchase of Electricity Generated by Using Renewable and Waste Energy Resources, Electricity Trading Rules, Grid Code, etc.) and restructuring of the power system provided the preconditions to further liberalise activities in the sector and to prepare for the development of an internal electricity market. According to the Law on Electricity, the prices of electricity generation, as well as of reserve capacity, have to be set by the market. However, when producers and independent suppliers form more than 25% of the market, the National Control Commission for Prices and Energy sets the procedure for regulation of their prices.

Since 1 January 2002, radical changes in the Lithuanian power system have been introduced. The Law on Electricity entered into force, new and in principle different relationships were created and these changes provided for the gradual liberalisation of the electricity sector. After 1 April 2002 the Lithuanian electricity market started to operate. The National Control Commission for Prices and Energy granted the status of eligible customers to 12 companies (consuming more than 20 GWh of electricity) with a right to choose the supplier and to purchase electricity from the selected producers. In addition, the trading of electricity at auctions was launched.

Implementation of a competitive market has begun in the sectors of electricity generation and supply, in which prices are set at auction or determined by bilateral agreement between the parties. The National Control Commission for Prices and Energy regulates the activities of the transmission network operator by setting price caps for the transmission services. The market operator organises trade in electricity according to the Electricity Trading Rules. Distribution companies perform two functions, as a distribution network operator and as a public supplier. The National Control Commission for Prices and Energy sets price caps for the distribution services for periods of 3 years. In 2003, the status of eligible customers (consuming more than 9 GWh) was granted to 25 consumers. Their share was about 26% of the total electricity sale market. Eligible consumers may freely conclude electricity contracts with any licensed producer or supplier and pay a set price for the electricity transmission and distribution. In 2003, the electricity trading balance was 70% by bilateral contracts, 12% at auction and 18% as Public Service Obligations.

From 1 January 2004, the Government set a new consumption margin (3 GWh) for eligible customers, hour-to-hour balancing was implemented for electricity export and an automatic electricity accounting system was implemented. By the beginning of 2004, the opening up of the electricity market had increased to 40%. And from 1 July 2004, all non-residential customers may be eligible. Thus, about 70% of customers (according to their share in the country's electricity balance) can choose the supplier. At present there are in Lithuania 28 important market players — JSC Lietuvos energija (which functions as a transmission network operator, market operator and exporter and/or importer of electricity), eight wholesalers, three public suppliers and 16 independent suppliers. It is expected that by 2007 the electricity market in Lithuanian will be 100% open.

3.4. Summary for the Baltic States

In Latvia and Lithuania the main legislative acts that regulate the activities in the energy sectors are the Energy Laws. In Estonia the Energy Law had been in force since 1998, but in July 2003 the framework act was replaced by four acts specific to sub-sectors — Electricity Market Act, Natural Gas Act; Liquid Fuel Act and District Heating Act. In Latvia and Lithuania special laws also regulate the electricity sector. In 2003 Lithuania introduced a special legal act for heat supply — the Heat Law.

Mid- and long term goals for energy sector development have been set by the relevant strategy documents in all the Baltic States. In Estonia the first long term development plan (1998) was replaced by a new one at the end of 2004. The Latvian National Energy Programme (up to the year 2020) was approved in 1997 and will be up-dated in 2005 or in 2006. In Lithuania the National Energy Strategy (1994) was up-dated in 1999 and in 2002. In all three states the energy sector strategies emphasise the need to improve energy efficiency and promote the utilisation of domestic (mainly renewable) energy sources. Security of energy supply and the concept of distributed energy, especially via the wider use of CHP and RESs, are also among the leading principles. The key role of the electricity sectors means that

Latvia (since 2001) and Lithuania (since 1999) have separate national strategies to develop these sectors. In Estonia, a similar national-level document has been prepared for approval.

The share of electricity produced from renewable sources in each of the Baltic States is very different: Including a large hydro input, Latvia produces 42.4% from renewables (third highest, after Austria and Sweden, among the EU-25). Estonia is among the four EU-25 Member States in which the share of RES-E is below 1%. According to indicative targets for the year 2010, fixed in Directive 2001/77/EC (amended by the 2003 Treaty of Accession to the European Union), Estonia has to increase the volume of electricity produced from RES-E by 0.5 TWh, Lithuania by 0.6 TWh and Latvia by 0.45 TWh (see *Table 3.7*).

Regarding environmental legislation, all the Baltic States signed the UNFCCC in 1992 and ratified it (1994–1995). The Kyoto Protocol was signed in 1998 and has been ratified (in 2002) also by all three countries. In accordance with the Kyoto Protocol, by the years 2008–2012 Lithuania, Latvia and Estonia have to reduce the level of anthropogenic GHG emission by 8% below the level of 1990. At present, GHG emissions in the Baltic States are significantly below the Kyoto target.

Table 3.7. Electricity production from renewable energy resources

Country	*Share of RES-E in total gross electricity consumption*			
	1999 actual		*2010 indicative target**	
	%	*TWh*	*%*	*TWh*
Estonia	0.2	0.02	5.1	0.51
Latvia**	42.4	2.76	49.3	3.21
Lithuania	3.3	0.33	7.0	0.93

* Calculated from the gross electricity consumption in 2000.

**Includes large (>10 MW) hydro input.

All the Baltic States have harmonised their environment-related legislation with the relevant acquis of the EU. Regarding environmental restrictions for the electricity sector, Estonia has been granted a transitional period to meet all the provisions of Directives 2001/80/EC and 1999/31/EC. The reason for the transitional period is the use of oil shale in power plants. To comply fully with the emission limits into ambient air (Directive 2001/80/EC), Estonia has to reduce gradually the use of oil shale in pulverised combustion processes and to stop using this type of equipment completely by the year 2016. The large amounts of hazardous waste (oil-shale ash) generated by the oil-shale power plants mean that Estonia was granted another transitional period – with regards to Directive 1999/31/EC. Estonia was required to introduce the relevant measures of handling the oil-shale ash — gradually until the end of 2009.

Lithuania, bearing in mind the expression of EU solidarity on nuclear safety, had committed to close Unit 1 of the Ignalina NPP before 2005 and Unit 2 by 31 December 2009. Unit 1 was closed at the end of 2004.

The secure supply of energy is an important element of the energy policy in all Baltic countries. At present, the level of self-sufficiency (considering primary energy supply) is highest in Estonia (60-67%). In Lithuania the level of self-sufficiency depends on whether nuclear power is counted as domestic source or not: 14% if it is counted as an imported resource and 57% if counted as domestic resource. In Latvia approximately 30-35% of primary energy supply is of domestic origin, depending on the annual production of electricity in hydro plants. All three countries are fully dependent on the supply of natural gas from Russia. Regarding the obligation to maintain 90 days of oil stocks, the same transitional arrangements (up to 31 December 2009) to implement this requirement were granted to all the Baltic States.

Summarising the promotion schemes for some power generation technologies or specific energy carriers, it has to be concluded that a common feature of all Baltic States is some support for electricity produced from renewable sources. The actual support schemes are different. In Estonia every network operator is obligated to buy electricity produced from renewables within the network it owns or operates. The price (the feed-in tariff) paid for this renewable-based electricity is fixed — 51.77 €/MWh. This obligation will be in force for:

- 7 years for electricity generated using water or biomass;
- 12 years for other RESs utilised.

In both cases no obligation shall be in force beyond 31 December 2015.

Similarly, until now in Latvia the system operators are obligated to purchase all the power from RES-E at incentive tariffs. Latvia has stated a doubled tariff for small-scale hydro and wind plants (with capacity less than 2 MW) if the operation of these plants and their equipment commenced prior to 1 January 2003 (hydro plants) or 1 June 2001 (wind plants). Such support is available for 8 years from the commencement of operation of each respective power plant. After this period the regulator will determine the purchase price. Also, the regulator determines the purchase price for power plants that came into operation after the dates above. Currently, the average electricity tariff implemented to calculate feed-in tariffs is approximately 48.7 €/MWh (without VAT).

The new Electricity Market Law envisages that for new RES capacities competitive bidding processes will be implemented.

Also, in Lithuania the suppliers of electricity as well as eligible customers engaged in electricity imports are obligated to purchase and sell electricity produced from renewable and waste energy resources. The rates of feed-in tariffs depend on the energy source (see *Table 3.8*).

Table 3.8. Average purchase prices of electricity produced from renewable energy resources (€/MWh)

Energy source	*Estonia*	*Latvia*	*Lithuania*
Hydro power	51.77	48.7-97.4	57.9
Wind power	51.77	48.7-97.4	63.7
Biomass	51.77	48.7	57.9

Also, some schemes and tools in use in all three countries promote particular technologies — electricity production from waste (Lithuania), power production in certain efficient CHP plants, etc.

In Latvia, system operators are obligated to purchase a surplus of electricity produced in cogeneration plants at incentive tariffs. However, such cogeneration plants must meet certain conditions, such as the fuel utilisation factor should be not less than 80%. Prospective electricity market models for Latvia, which are under discussion now, also envisage subsidies for CHP plants in the near future. In the longer perspective, we may also expect the introduction of new market-based mechanisms to purchase power from CHPs and RESs in Latvia.

Opening up of the electricity market is in progress in all Baltic States. Directive 2003/54/EC (replaced Directive 96/92/EC) stipulates that from 1 July 2004, at the latest, all non-household customers in all EU Member States had to be eligible. A completely open market shall be in force from 1 July 2007. Of the Baltic States, Estonia was the first to start opening up the market. On 1 July 1999, consumers with an annual consumption of at least 40 GWh were made eligible to select suppliers, which meant approximately 10% of the market had opened up. At present, the situation is the same — no more steps have been taken. Estonia has been granted a transitional period to open up its electricity market. According to Directive 2004/85/EC, Estonia has to open up the market to at least 35% (i.e., for consumers with an annual consumption of 1 GWh or more) by 1 January 2009. The further gradual opening up must result in a completely open market by 1 January 2013.

Since 1 July 2004 both Latvia and Lithuania have opened up the market to all non-residential consumers, which has resulted in an open market share of approximately 75% in Latvia and 70% in Lithuania.

4. ENERGY DEMAND PROJECTIONS

4.1. Estonia

4.1.1. Main assumption for demand forecast

4.1.1.1. Population growth

In 2004 the population of Estonia was 1.351 million people – a decrease of 13.7% (or approximately 215,000) from the peak level in 1990. This reduction can be attributed both to emigration and to the decrease in birth rate, which has been falling steadily since 1989. The annual rate of natural population growth has been negative since 1991, in the range of -4.0% to -5.5%. Similarly Estonia's total fertility rate had dropped to 1.37 in 2002 from 2.26 in 1988.

A few forecasts have been developed about the population trends in Estonia [15, 16]. According to these forecasts, population numbers will continue to fall. The projection used by the Ministry of Social Affairs and the Ministry of Finance is presented in *Figure 4.1*.

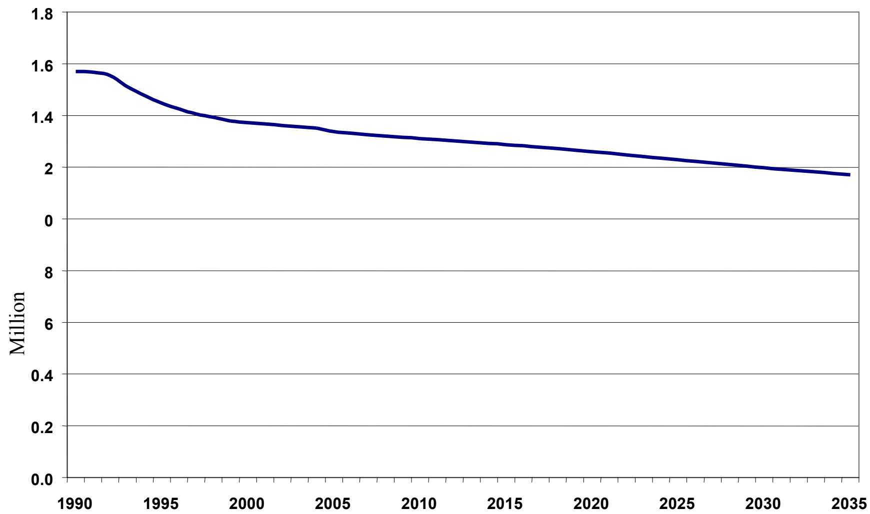


Figure 4.1. Projected dynamics of the population of Estonia.

However, some more pessimistic population projections are available. For example, the United Nations Population Division (UNPD) [17] foresees higher negative annual growth rates (–1.18% for the period 2000–2025 and –1.75% between 2025–2050) in its medium scenario. This would lead to a total population of 1.0 million in 2025 and 0.657 million in 2050. In the UNPD low scenario the population is projected to drop to 0.984 million in 2025 and 0.564 in 2050.

In the most pessimistic projections the current low fertility rate is considered to persist. Therefore, in the long term perspective, the sustainability of the Estonian population is considered questionable. It is important to develop and implement population policies to increase the birth rate and decrease the death rate, and thus stop, or at least decrease, the negative trends in population growth in the long run.

4.1.1.2. Economic growth

To project energy demand, economic development forecasts are needed for baseline calculations. At present, the only long term (up to the year 2030) forecast for the development of Estonia's national economy is that developed by the Ministry of Finance [18]. Three scenarios for economic growth have been proposed (*Figure 4.2*). All three are forcasting Estonia's economic growth to slow down gradually to EU average growth rates by the end of the study period. In the base case scenario, the average annual growth rate during the whole period is 4%. For alternative scenarios, it is 3.5% for the low-growth scenario and 4.5% for the high-growth scenario.

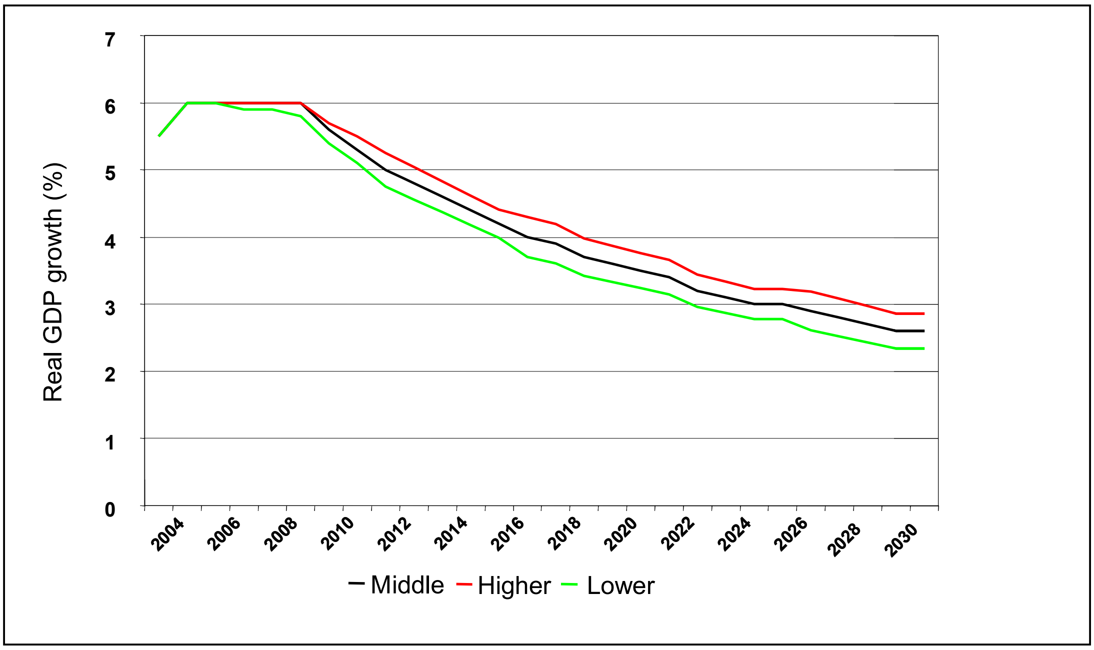


Figure 4.2. Forecast for the real growth of Estonian GDP by 2030

The above long term gross domestic product (GDP) forecast is provisional, and projects annual growth rates for GDP only. Variation in the structure of GDP determines, to a great extent, national energy consumption. The long term GDP projection of the Ministry of Finance does not contain any forecast of potential changes in the structure of GDP. In Estonia, more detailed forecasts of this type have been compiled only for the short- or medium-term (see *Table 4.1*). For the longer term, only a very general tendency can be seen — the share of industry, as a major energy-intensive sector of the national economy, can be projected to diminish gradually during the next 10–15 years.

Table 4.1. Short term GDP forecast of Estonia by the Ministry of Finance (February 2004)

	2005	*2006*	*2007*	*2008*
Main indicators				
GDP real growth (%)	5.8	5.6	5.9	5.8
GDP (€ billion)	8.9	9.7	10.6	11.5
Consumer price index (CPI; %)	3.0	2.8	2.8	2.8
Growth of value added (%)				
Agriculture	1.8	2.6	2.8	2.9
Industry	8.9	7.5	7.9	7.1
Construction	6.6	6.8	6.4	6.7
Services	4.7	4.9	5.3	5.4

4.1.1.3. Energy efficiency

In Estonia the efficiency of primary energy utilisation (the ratio of final energy consumption (FEC) to the primary energy used) is approximately 55%, which is lower than in neighbouring countries. One of the main factors is that over 90% of electrical energy in Estonia is produced in condensing power plants. The efficiency of these plants is as low as approximately 30%. Other factors, such as high losses in electricity and district heating networks, large export volumes of converted energy (electricity, shale oil and shale coke, peat briquettes, wood chips), also have an impact.

Therefore, much work has to be done in the field of energy efficiency. A national goal has been set to achieve a continuous improvement in both energy sector efficiency and energy end-use. In the year 2000, the Government of Estonia approved the second National Energy Conservation Programme. The Action Plan [19] for carrying out the measures set in the Programme for the period 2001–2005 was adopted by the Government in March 2001.

In the power sector a major effect would be achieved by the introduction of a new technology for oil shale combustion to replace the existing pulverised fuel boilers with circulating fluidised bed (CFB) boilers. This provides not only an environmentally sound solution, but also higher efficiency, approximately by 20%. The first two new blocks (both 215 MW) to adopt CFB technology were commissioned in 2004. The scope for further reconstruction will be determined during the next couple of years.

The Energy Efficiency of Equipment Act entered into force on 1 January 2004 to motivate energy end-use efficiency. The Act regulates the requirements for energy efficiency and energy labelling of certain types of household appliances, heating equipment and installations. It also provides the basis for the procedures regarding conformity assessment and attestation in order to increase the efficiency of energy consumption and of other essential resources. The preparation phase for harmonisation of the EU directive (2002/91/EC) on the energy performance of buildings is in progress to ensure energy efficiency improvements in buildings.

Many environment-related improvements in the energy sector will increase energy efficiency as well. Therefore, the Joint Implementation projects carried out in Estonia will have some positive impact on energy efficiency. Similarly, emission trading activities should lead to energy efficiency improvements.

Considering energy consumption concurrent with the development of society and economy, it is impossible to prevent future growth of primary energy consumption. Nevertheless, in the

Long term National Development Plan for the Fuel and Energy Sector in Estonia [20], the most general and ambitious target is to keep primary energy consumption in Estonia at the level of 2003 by 2010.

4.1.2. Energy demand projections

Relevant economic forecasts are needed to build-up energy demand projections. The most recent comprehensive modelling of future economic development in Estonia was carried out in the first half of 1990s using the MARKAL model, linked with a macroeconomic model called MACRO. In combination these two models generated the optimal allocation of technologies and energy on the supply side. However, albeit very significant changes in the Estonian economy since the 1990s - especially in the energy sector - no new detailed modelling has been conducted.

4.1.2.1. Electricity demand forecast

In the Development Plan [20] the GDP growth rate projection, as presented in *Figure 4.2*, was taken as a basis to compile a long term load projection for the electricity sector. The annual growth of electricity consumption is foreseen to be in the range 2.0–3.75%, resulting in final electricity consumption of 7–9 TWh in 2015 and 9–15 TWh in 2030. The basic indicators of the power system load for a lower growth scenario (2% per year) are presented in *Table 4.2*.

Final electricity consumption was also forecast in the *Development Plan for Estonia's Electricity Sector* [21] for fast, moderate and slow economic development scenarios. The slow development scenario was not used in this modelling exercise, as it does not foresee EU membership. Instead, the demand data used here is the average between the moderate and the fast scenario (see *Figure 4.3* and *Table 4.3*).

Table 4.2. Projection of power plant loads (MW) for 2005–2030 (for an annual growth rate of electricity consumption of 2%)

Loads or capacities	*Time period*	*Years*				
		2000	*2005*	*2010*	*2015*	*2030*
Net base load of power plants	Summer Winter	400 600	440 660	490 730	540 810	730 1090
Capacity required to cover half-peak part of load curve	Summer Winter	300 450	330 500	370 550	400 607	550 820
Required capacity of control plants to cover load curve peak	Summer Winter	200 250	220 280	240 310	270 340	360 460
Maximum net load of power plants	Summer Winter	900 1300	990 1440	1100 1590	1210 1757	1640 2370
Control reserve	Summer Winter	90 130	100 140	110 160	120 180	160 240
Hot contingency reserve	Always	100	100	100	100	100
Cold reserve	Always	300	300	300	300	300
Total required net capacity of power plants	Summer Winter	1400 1800	1500 2000	1600 2200	1700 2300	2200 3000
The above, plus export of 10% of electrical energy	Summer Winter	1540 1980	1650 2200	1760 2420	1870 2530	2420 3300

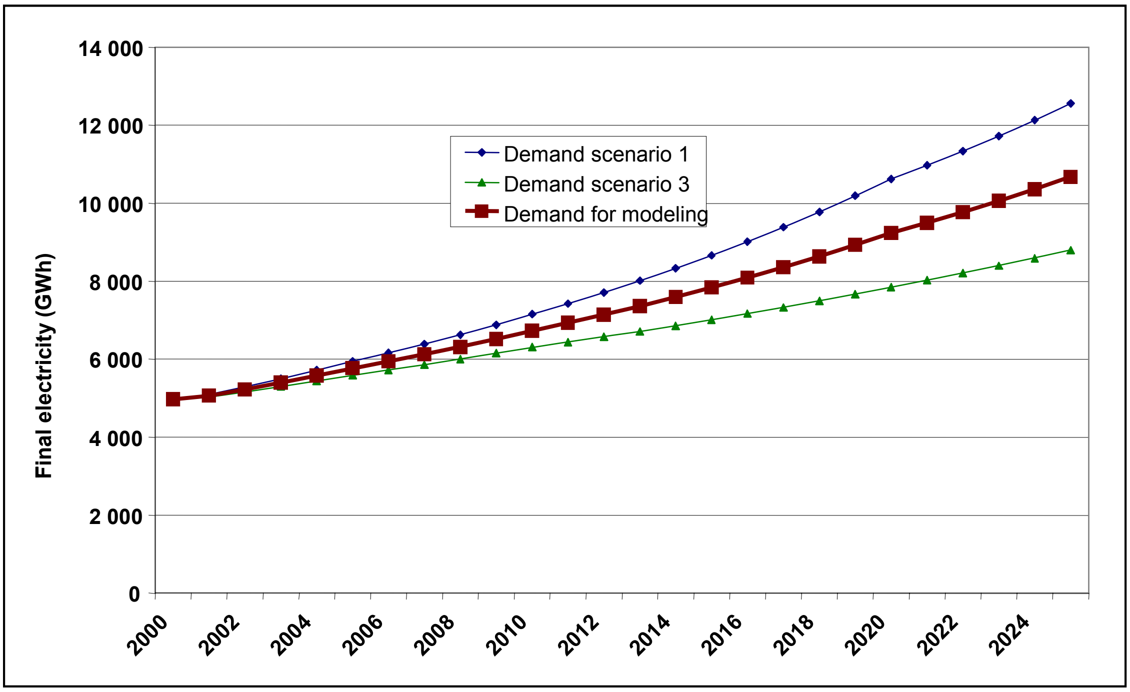


Figure 4.3. Forecast of final electricity consumption in Estonia for the period up to 2030.

Table 4.3. Demand forecasts for transport and non-transport (boiler) fuels, fuels for non-energy purposes, useful electricity and heat, by Estonian regions

	Unit	*2000*	*2005*	*2010*	*2015*	*2020*	*2025*
Electricity	TWh	4.97	5.77	6.73	7.84	9.24	10.68
Heat, including:	TWh	9.13	9.13	9.13	9.13	9.13	9.13
Viru region	*TWh*	*2.26*	*2.26*	*2.26*	*2.26*	*2.26*	*2.26*
Rest of Estonia	*TWh*	*4.05*	*4.05*	*4.05*	*4.05*	*4.05*	*4.05*
Tallinn	*TWh*	*2.82*	*2.82*	*2.82*	*2.82*	*2.82*	*2.82*
Final energy demand, including:	PJ	53.68	62.31	64.76	67.29	69.90	72.58
Transport fuels	*PJ*	*25.24*	*28.49*	*29.94*	*31.47*	*33.08*	*34.76*
Non-transport (boiler) fuels	*PJ*	*24.61*	*29.99*	*30.99*	*31.99*	*32.99*	*33.99*
Non-energy fuels	*PJ*	*3.83*	*3.83*	*3.83*	*3.83*	*3.83*	*3.83*

4.1.2.2. Forecast of heat and final energy demand

Forecasting heat and fuel demands is a problematic issue. Most scientists and politicians decline to believe that the share of local heating will slowly increase and the share of district heating will slowly decrease. The specific heat consumption per heated volume should decrease because of heat-saving measures, but at the same time the total heated volume might increase.

Based on the above assumptions, heat demand has been taken as constant in all three Estonian regions (see *Table 4.3*) and fuel demand for local heating (i.e., final consumption of non-transport or boiler fuels) to increase slightly. Consumption of fuels for non-energy purposes was assumed constant, as their share is rather small and significant changes are not foreseen.

4.2. Latvia

4.2.1. Main assumption for demand forecast

4.2.1.1. Population growth

Population increase, though comparatively low, was observed for several decades until the restoration of independence in Latvia — 1.1%/year in the 1960s, 0.7%/year in the 1970s and 0.6%/year in the 1980s. The greatest number of residents was registered in 1990, when 2.668 million people inhabited Latvia. During the period 1990–2000, the population of Latvia decreased by 10.7% (approximately by 290 000 people), through emigration and a decrease in the birth rate. In 2004 the population of Latvia was 2.319 million people.

According to a study conducted by the Latvian Institute of Economics, a decrease in the population of Latvia will continue throughout the study period [22]. Such a trend is common in all three Baltic States. Two scenarios were used for the projection — a constant decline as the minimum likely for Latvia and the probable decline as the maximum likely, as presented in *Table 4.4*. Variables for the latter were chosen taking into account the necessity to improve the population's reproduction (already experienced in recent years either in Latvia or Northern Europe) and close to those projected for Latvia in the coming period by other authors.

Table 4.4. Population growth forecast for Latvia (thousand people) [22]

	2000	*2005*	*2010*	*2015*	*2020*	*2025*
Minimum (constant) variant						
Urban	1618.7	1547.2	1468.6	1391.6	1315.4	1238.1
Rural	754.3	731.8	714.5	699.6	681.3	658.5
Total	2373.0	2279.0	2183.1	2091.2	1996.7	1896.6
Maximum (targeted) variant						
Urban	1618.7	1555.1	1501.3	1462.5	1429.8	1392.3
Rural	754.3	735.0	729.6	736.9	747.4	751.9
Total	2373.0	2290.1	2230.9	2199.4	2177.2	2144.2

4.2.1.2. Economic growth

The information presented in this chapter is based on a report by the Ministry of Economics of Latvia [23]. Reforms accomplished in Latvia and integration into the EU have resulted in a positive impact on the economic development of the country. In the period from 1996 to 2004 the Latvian GDP (calculated in Latvian Lats of the year 2000) has grown on average by 6.7% annually. Among the other European countries only Ireland had higher growth rates in the same period.

Despite the slowdown in the global economy since 2000, the Latvian economy has continued to develop at a speedy pace. In 2001, Latvia's GDP increased by 8%, in 2002 by 6.4%, in 2003 by 7.5% and in 2004 by 8.5%. According to an evaluation of the Ministry of Economics, during the first half of 2005 GDP grew by 9.3% in comparison with the first half of 2004.

The Ministry of Economics has developed two variants of the medium-term (to 2010) GDP forecast, depending on variations in external demand. The *slow variant* of development (Variant I) has limited possibilities to increase exports, and the *dynamic variant* (Variant II) has a more dynamic growth of exports, which might happen in a more favourable external environment (see *Figure 4.4*).

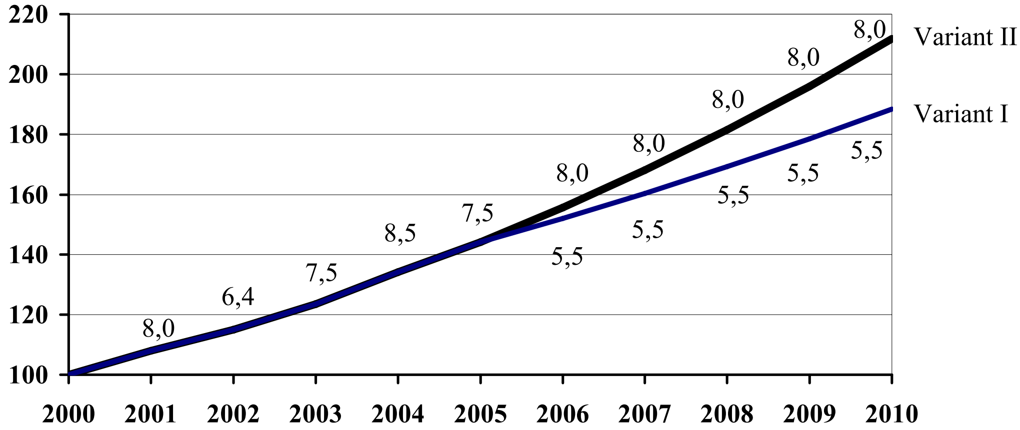


Figure 4.4 Medium-term forecast of GDP in Latvia (percentage, 2000 = 100%).

The low GDP growth scenario (Variant I) envisages an average GDP growth that will not exceed 6% throughout the period. Such dynamics of GDP growth reflect the dominant role of the service industry in the development of Latvia's economy. Since the mid 1990s investments have been mainly in trade, transport, communications and the financial sectors. To compensate for the lost markets in the Commonwealth of Independent States (CIS), a large-scale restructuring and modernisation of industry is needed, which requires investments and time.

The dynamic economic development scenario (Variant II) assumes a higher growth in the economy from 2002 (annual GDP growth of 7–8%). To achieve this, state support must be goal-oriented, directed at the promotion of export to increase the competitiveness of enterprises, and measures taken to develop small- and medium-sized enterprises. Accession to the EU results in a positive influence on the investment process in the country and improves the subsequent growth opportunities.

Longer-term economic forecasts were given in the *Long term Economic Strategy of Latvia* [24]. Two scenarios of economic development were considered — convergence and stagnation scenarios. In the convergence scenario the GDP level per capita is assumed to achieve the EU average by 2025–2030. To achieve this ambitious goal the annual average GDP growth rate should be 5–8%. *Table 4.5* presents the base-case scenario for economic development used in the final energy demand forecast. Growth rates (in percentages) in the table are given as an average annual for the period. For example, in column '2005' the annual growth rates for the period 2000–2005 are given.

Table 4.5. Long term GDP forecast for Latvia in the base-case scenario [23, 24]

	2005	*2010*	*2015*	*2020*	*2025*
Main indicators					
GDP real annual growth (%)	7.6 (3.1)*	5.5	5.5	5.0	4.5
GDP (€$_{2000}$ billion)	9.7	12.7	16.6	21.2	26.5
Private consumption growth (%)	8.0	5.8	5.5	5.0	4.5
CPI (%)	3.7	3.4	2.6	1.8	1.5
Annual growth of value added (%)					
Agriculture, forestry, fishing	4.4	2.5	3.0	3.0	2.0
Manufacturing, mining	8.7	6.8	7.0	6.5	6.2
Energy	4.3	2.0	5.0	5.0	4.0
Construction	11.9	9.2	8.0	7.0	6.0
Trading	10.4	6.0	6.0	5.0	4.5
Transport and communications	8.0	6.0	5.7	5.2	4.0
Other services	5.6	4.3	4.0	3.7	3.4

*For the period 2000–2005 real GDP growth rate calculated in Latvian Lats (LVL) was 7.6%. Fluctuation of the €/LVL exchange rate means the real GDP growth rate calculated in Euros was 3.1%. Starting from 2004 the Latvian Lat is tied to the Euro, which is why the growth rate in LVL coincides with the growth rate in Euros.

4.2.1.3. Energy efficiency

In Latvia, for the total value added in the economy, the GDP shares of the manufacturing and agriculture sectors have decreased along with an increase in the shares of the commercial and transport sectors. Final energy intensities have decreased in all sectors of the economy except the transport sectors. As the final energy intensity of the commercial sector is lower than that of industry, this has a positive impact on the final energy intensity per GDP decrease.

In the past 10 years, final energy intensity has decreased in the agriculture and commercial sectors by more than 50%, while in the manufacturing sector by approximately 25%. The rather high final energy intensity of the manufacturing sector in Latvia arises from the structure of the manufacturing branches. The main manufacturing branches are the production of wood and wood products, food, iron and steel, and textiles and leather.

The high final energy intensity in the transport sector is explained by the very fast increase in the number of cars in Latvia. By 2002 the number of passenger cars per 1000 population had increased two-fold compared with 1995. This results in an increase in fuel consumption in the transport sector.

During this period, for the EU-15 the final energy intensity of GDP declined by 7.8%. However, comparison of the current FEC/GDP levels in the EU-15 and in Latvia shows that FEC/GDP is more than twice as much in Latvia.

According to the International Energy Agency (IEA) the net primary energy consumption (total primary energy supply, TPES) required to produce a GDP value of US$1000 (TPES/GDP) in Lativa is 25.1 GJ [25]. The aim of the Latvian energy-efficiency strategy is to approach average EU efficiency levels, which requires a 25% reduction of primary energy consumption per unit of GDP by 2010.

In *Climate Change Mitigation Policy Plan for Latvia* [26], two sets of measures to mitigate climate change and increase energy efficiency were proposed, supply-side measures:

- Fuel switching to environmentally more friendly fuels;
- Improvement in energy efficiency;
- Increased use of combined heat and power;
- Increased use of biomass in the district heating sector;
- Increased use of renewable energy;

and demand-side measures:

- Heat energy conservation in buildings;
- Highly efficient technologies for electricity appliances;
- Implementation of a system to analyse and check energy consumption.

4.2.2. Energy demand projections

4.2.2.1. Final energy demand forecast

According to a decision made by the Steering Committee, one demand forecast scenario (basic growth) should be used for the MESSAGE analysis. As the Model for Analysis of Energy Demand (MAED) was not available to teams in each of the countries, it was also decided to use forecasts available from different studies and models.

For Latvia an econometric model based on MS Excel, which takes into account historical trends of energy consumption versus GDP (i.e., energy intensity and macroeconomic forecasts), was used to forecast the final energy demand. The result of this analysis is presented in *Table 4.6*.

Table 4.6. Forecast of final energy demand in Latvia (PJ)

Sectors	*2000*	*2005*	*2010*	*2015*	*2020*	*2025*
Industry	26.34	28.36	29.74	34.55	37.90	39.18
Service	9.80	12.09	14.69	17.18	19.31	20.53
Agriculture	3.31	3.05	3.25	3.51	3.94	4.12
Residents	33.02	38.49	37.80	39.45	40.00	40.34
Transport	32.04	39.00	45.60	53.10	58.70	61.50
Total	104.51	120.99	131.08	147.79	159.85	165.67

4.2.2.2. Electricity demand forecast

The maximum level of electric power consumption by end-users in Latvia was registered in 1988, when it reached 8.7 TWh. The severe economic crisis shortly after the restoration of Latvian independence decreased power consumption significantly by 40% over 2 years, while GDP dropped by 45%. Between 1994 and 2000 the end-user's power consumption fluctuated around 4.75 TWh per year – similar to consumption levels of 1975. The stagnation in electricity demand is the result of restructuring the national economy, such as:

- Reduction of both production volumes and consumption of electricity in energy-intensive industries;
- Development of industries that have low electricity demand;
- Improvement in the efficient use of electric power (wide application of energy-efficient technologies and demand-side management measures).

From 1994 to 2000 GDP grew by 24.9%, but electricity consumption only grew by 1.0%. Since 2000, power consumption by end-users has shown a stable growth of 4–6% annually with a GDP growth of 7–8% annually.

The pattern of electricity consumption changed gradually after the restoration of independence in Latvia. From 1991 to 2001 power demand reduced significantly in the industrial sector (by 60%) and in agriculture (by 90%). During the past 5 years the following tendencies have been observed among different consumers' groups — electricity consumption of the population and services is increasing, that of industry is fluctuating, and that of agriculture and transport is decreasing.

An econometric model was applied to forecast the electricity demand in different sectors of the economy. This method uses macroeconomic forecasts and calculates elasticity coefficients as the input data. Elasticity coefficients determine relationships between the consumption of electric power and several exogenous parameters — GDP by sectors, income of population, price of electricity, weather conditions and other factors. Elasticity coefficients were calculated for a statistical period of 10 years (for which data were available). GDP growth rates in accordance with the economic forecasts of the Ministry of Economy of Latvia were assumed.

In the base-case forecast, electricity consumption increases annually by 2.5–3.0%, while in the optimistic case it increases by 4.5–5.0%. For the MESSAGE analysis, the average of the base case and optimistic case was used. Two power-demand areas were modelled (East and West), as presented in the *Table 4.7*.

Table 4.7. Final power demand forecast for Latvia (TWh)

Demand areas/sectors	*2000*	*2005*	*2010*	*2015*	*2020*	*2025*
East	1.13	1.32	1.58	1.86	2.14	2.46
West	3.59	4.38	5.14	6.02	6.93	7.94
Total, including:	4.72	5.70	6.72	7.88	9.07	10.40
Industry	*1.56*	*1.83*	*2.22*	*2.66*	*3.08*	*3.58*
Agriculture	*0.12*	*0.12*	*0.12*	*0.13*	*0.14*	*0.15*
Residents	*1.19*	*1.52*	*1.77*	*2.02*	*2.33*	*2.66*
Transport	*0.12*	*0.13*	*0.14*	*0.15*	*0.16*	*0.17*
Services	*1.73*	*2.09*	*2.47*	*2.92*	*3.36*	*3.84*

4.2.2.3. Heat demand forecast

Heat demand projections took into account factors that affected both the decrease and the increase in demand for heat energy. Important factors for the decrease in demand for heat energy are:

- Increase of the actual outside temperature and changes in the length of the heating season significantly influence heat sales — an increase in average temperature by 1°C causes a heat sales reduction of 4%;
- Decentralisation, which occurs when some consumers build local or individual heat-generation sources and switch off from the centralised district heating system;
- Over recent years, losses of heat (including outage) have decreased from 28 to 20% through the liquidation of centralised heating points, reduction of the length of heat networks, and replacement of the most damaged pipelines by new industrially insulated pipelines;
- Installation of heat-energy metering devices and appointment of an energy manager in every building of Riga to regulate heat supply to apartment houses;
- Other measures for heat-energy saving, such as heat insulation of buildings, reconstruction of internal heating systems, etc.

The majority of these factors are already a *fait accompli*. Because the consumption of heat energy has already reduced substantially, further reductions in heat demand are unlikely to be dramatic.

Important factors for the increase in demand for heat energy are:

- Reduction of the actual outside temperature;
- With the increase in living standards and purchasing power the demand for comfort and heat-energy consumption per consumer will increase;
- Adjustment of natural gas prices — a greater tariff differentiation between large and small consumers will decrease the competitiveness of individual and/or local heating systems and will limit further unjustified decentralisation in areas with a high density of heat loads;
- With the development of the economy, new commercial and industrial heat consumers will connect to the centralised district heating system;
- Implementation of an aggressive marketing policy (incentive tariffs, free interconnection costs, leasing of equipment);
- Construction of new multi-story houses and intensification of the current construction activities.

As a result of the analysis, forecasts of heat demand were made for three heat demand areas — Riga (right bank heating networks), large cities and small cities (*Table 4.8*).

Table 4.8. Final heat demand forecast for Latvia (TWh)

Demand areas	*2000*	*2005*	*2010*	*2015*	*2020*	*2025*
Riga (right bank)	2.27	2.38	2.43	2.55	2.75	2.96
Big cities	3.08	3.09	3.09	3.16	3.32	3.59
Small cities	1.90	1.87	1.82	1.82	1.87	1.96
Total	7.25	7.34	7.34	7.53	7.94	8.51

4.3. Lithuania

4.3.1. Main assumption for demand forecast

After the collapse of the socialist system and restoration of Lithuanian independence, the transition to a free-market economy and common economic recession were followed by a significant reduction of the country's GDP and energy (electricity, heat and fuel) consumption (*Figure 4.5*).

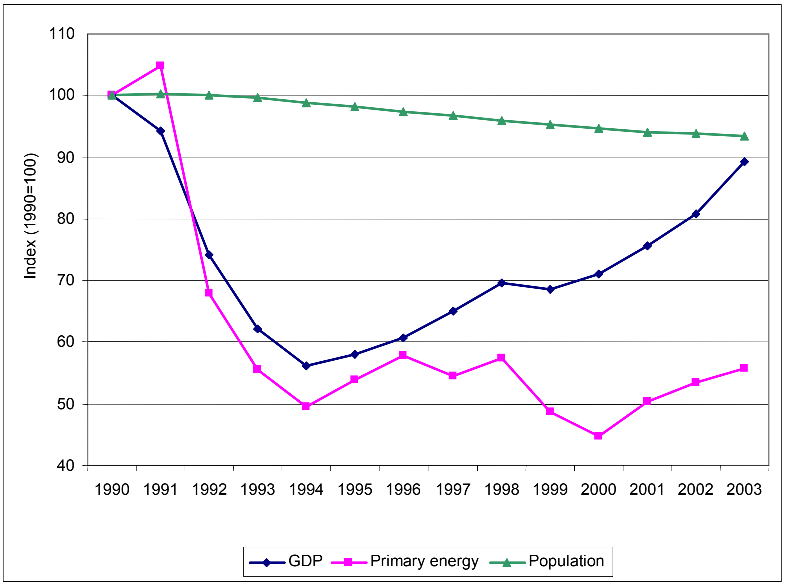


Figure 4.5. Changes of GDP, primary energy and population in Lithuania.

4.3.1.1. Population growth

Political and economic changes in Lithuania resulted in lower birth rates and increased emigration, leading to a total population reduction by almost 250 000 people during the period 1991–2003. A recent forecast prepared by experts of the Lithuanian Department of Statistics envisages a further reduction of population [27]. Although in its optimistic scenario it is predicted that population will start to increase gradually after the year 2012 (*Table 4.9*). However, the authors consider the most probable scenario to be the medium one. According to this scenario the total population will decline further and in 2025 will be about 3.2 million.

Table 4.9. Forecast of population development in Lithuania (thousands)

Scenario	*2000*	*2005*	*2010*	*2015*	*2020*	*2025*
Pessimistic scenario	3512.1	3403.9	3294.4	3193.7	3093.0	2981.2
Medium scenario (most probable)	3512.1	3406.3	3323.9	3277.4	3236.7	3184.5
Optimistic scenario	3512.1	3408.6	3353.6	3361.7	3382.1	3391.1

4.3.1.2. Economic growth

As in the Lithuanian National Energy Strategy [13], which seeks to encompass a wide range of possible long term development paths, three scenarios have been chosen — fast economic growth, basic economic growth and slow economic growth.

The fast economic growth scenario foresees rather high rates of economic growth in Lithuania until 2025 — on average 7% per year until 2010 and 3% after 2010, assuming that:

- Expansion of the Lithuanian industry will be very fast;
- Common policy of economic development will be very favourable to large investments intended to modernise the economy and the acquisition of new technologies;
- Technical and economic assistance by the EU will be generous and efficiently used.

The low average annual GDP growth rates used in the slow economic growth scenario (2% until 2010 and 3% in 2011–2025) could result from a very slow pace of economic restructuring, insufficient domestic and foreign investments, unexpected economic and political crises, slow privatisation of infrastructure enterprises, etc. This scenario was used to represent the lower bound of economic development. At present it is evident that this scenario is rather pessimistic.

The basic scenario is based on the economic development trends provided in forecasts of the macroeconomic indicators for 2002–2005 (prepared by the Ministry of Finance). These have been extended to the year 2010, and GDP growth rates of 4.7% until 2010 and 3% after 2010 assumed.

The projected GDP growth in constant 2000 prices for the basic scenario is presented in *Table 4.10*.

Table 4.10. GDP of Lithuania in the basic scenario

	2005	*2010*	*2015*	*2020*	*2025*
Main indicators					
GDP real growth (%)	4.7	4.7	3.0	3.0	3.0
GDP (€$_{2000}$ billion)	15.5	19.5	22.6	26.2	30.4
Growth of value added (%)					
Manufacturing	4.8	4.8	3.3	2.9	3.1
Construction	6.8	5.0	3.3	3.3	3.3
Agriculture	4.4	4.1	2.6	2.4	2.6
Mining	4.2	5.6	3.4	3.5	3.5
Energy	4.5	4.5	2.8	2.8	2.8
Services	4.5	4.7	3.0	3.0	3.0

4.3.2. Energy demand projections

4.3.2.1. Final energy demand forecast

MAED [28], widely applied in other countries to forecast energy demand, was used for energy demand projections in Lithuania.

In drawing up the energy demand forecast, detailed data on GDP growth and its structural changes, the development of social indicators, technological indicators of energy consumption by economic sectors (industry, construction, agriculture, transport, households, trade and service sector), changes in energy consumption and other indicators were used.

Final energy demand was forecast by estimating the energy-saving potential in particular economic sectors, in accordance with the Executive Summary of the *National Energy Efficiency Programme for Lithuania* [29]. The total increase in energy efficiency was predicted, taking into account a reduction in energy intensity (i.e. a decrease in the final energy consumed per unit of GDP). Final energy means the shares of primary natural resources (coal, natural gas, oil, etc.) and secondary energy resources (electricity, petroleum products, district heat, etc.) consumed for a particular type of industrial production, for a desired quantity of services provided by the service sector and for a desired level of living conditions. Final energy is consumed directly by the equipment used by final consumers (e.g. industrial and agricultural enterprises, enterprises in the services sector, transport, individual consumers, etc.).

A thorough analysis has shown that final energy demand in 2025 would approach 1990 demand levels only in the fast economic growth scenario. At the end of the forecast period, the total FEC in the basic scenario would be 6.7 Mtoe (million tons of oil equivalent), or about 70% of the amount in 1990 (*Table 4.11*). In this case, the energy intensity index in 2020 would constitute only 40%, as against 1990, while energy efficiency would be close to the current average level in the EU (EU-25).

Table 4.11. Final energy demand for Lithuania (PJ)

Scenario	*1990*	*1995*	*2000*	*2005*	*2010*	*2015*	*2020*	*2025*
Slow economic growth scenario	401.93	190.08	152.82	174.59	183.80	197.62	212.27	228.18
Basic scenario	401.93	190.08	152.82	195.10	219.81	238.65	259.16	280.52
Fast economic growth scenario	401.93	190.08	152.82	205.99	245.77	270.05	296.01	324.06

4.3.2.2. Electricity demand forecast

After 1991, electricity consumption in all economic sectors, especially in agriculture and industry, decreased rather rapidly for several years because of the country's economic recession. Later on, the national economy gradually recovered, but final electricity demand continued to decrease until 2000. Thus, energy efficiency continuously increased. The decrease in electricity consumption in 1990–2000 was the least compared to the consumption of other energy forms. During the past 3 years final electricity consumption in the economic sectors has increased on average by 4–5% per annum. However, Lithuania is lagging behind developed European countries and also behind new EU Member States in terms of the comparative indicator of final electricity consumption per capita (in 2003 it was equal to 2077 kWh/capita). In 2001, in Lithuania this indicator was about one third of the average in the EU and about two thirds of the acceding countries. Therefore, forecasts of electricity demand in the Lithuanian National Energy Strategy [13] and other studies were based on the assumption that modernisation of the Lithuanian economy would require a fast growth in electricity demand, and its share in the structure of final energy demand would increase for all economic sectors. For the period until 2025, final electricity demand of economic sectors *in the basic scenario* increases annually by 3.3% on average. For the *fast economic growth scenario* electricity consumption of economic sectors grows on average by 4.2% per annum. According to this scenario, final electricity demand in 2025 exceeds the 1990 level by about 1.4 times (*Table 4.12*).

Table 4.12. Final electricity demand for Lithuania (TWh)

Scenario	*1990*	*1995*	*2000*	*2005*	*2010*	*2015*	*2020*	*2025*
Slow economic growth scenario	12.01	6.93	6.20	6.94	7.65	8.65	9.77	10.98
Basic scenario	12.01	6.93	6.20	7.78	9.46	10.83	12.31	13.88
Fast economic growth scenario	12.01	6.93	6.20	8.47	11.14	13.05	15.09	17.27

The forecast electricity consumption (total consumption excluding losses) per capita in 2025 for the fast economic growth scenario reaches a level that exceeds this indicator in many acceding countries and is similar to the present average level in the EU-15.

4.3.2.3. Heat demand forecast

Heat demand forecasts were made for six demand areas: Vilnius, Klaipeda, Kaunas, Mazeikiai, Elektrenai and other cities, as presented in *Table 4.13*.

Table 4.13. Final heat demand for Lithuania (TWh)

Demand areas	*2000*	*2005*	*2010*	*2015*	*2020*	*2025*
Vilnius	2.08	2.36	2.65	2.86	3.07	3.30
Klaipeda	0.86	0.95	1.06	1.13	1.20	1.28
Kaunas	1.25	1.42	1.61	1.75	1.89	2.05
Mazeikiai	0.14	0.16	0.17	0.18	0.18	0.19
Elektrenai	0.16	0.17	0.18	0.18	0.20	0.21
Other cities	3.85	4.27	4.78	5.13	5.48	5.83
Total	8.34	9.33	10.45	11.23	12.02	12.86

4.4. Summary and conclusions

The social and economic development of society has a significant impact on primary energy consumption. Therefore, development of the main social and economic indicators — GDP and population — should be taken into account when preparing energy demand forecasts.

The operation and development of energy supply systems are directly related to changes in energy demand (e.g. electricity, heat, natural gas, oil and oil products). Changes in energy consumption, development of GDP and population growth all reflect socioeconomic progress.

These indicators are strongly interdependent. The trends of energy consumption and GDP indicators are in line with changes in population. Many other factors — national traditions, the structure of the economy and the service sector, the general level of a country’s economic development and other peculiarities — also have an impact on the trends of energy consumption and economic development.

4.4.1. Comparison of key indicators for 2002

The comparison of key energy consumption and efficiency indicators of several European countries gives a clear picture of the current state of affairs in the energy sector of the three Baltic States. It serves as a good starting point for energy demand projections. Indicators such as electricity and primary energy consumption per capita or per unit of GDP were summarised by the IEA [12]. From *Table 4.14* it can be seen that in 2002 all three Baltic States, especially Latvia and Lithuania, were far below the average European level of energy and electricity consumption per capita. This can be explained primarily by the underdeveloped state of industry, especially in energy-intensive sectors that have a high demand for energy. If such energy-intensive industries appear in the Baltic region they will have a positive impact on the indicators.

Table 4.14. Comparison of key energy consumption and efficiency indicators for 2002[12]

Country	*Electricity/Population (kWh/capita)*	*TPES/Population (GJ/capita)*	*TPES/GDP (GJ/thousand US$95)*
Romania	2027	69.5	43.1
Latvia	2280	76.2	25.1
Ukraine	2815	112.2	109.7
Lithuania	2828	103.8	35.2
Belarus	2983	104.7	49.8
Croatia	3075	77.0	14.2
Poland	3217	97.6	21.4
Hungary	3545	105.1	18.4
Bulgaria	3792	100.1	58.2
Portugal	4290	106.3	8.4
Estonia	4845	139.0	32.2
Slovak Republic	5049	144.4	31.0
Russia	5350	179.6	55.3
Italy	5447	124.8	5.9
Spain	5726	135.7	7.5
Czech Republic	5890	171.2	30.1
Ireland	6071	163.7	5.4
United Kingdom	6158	160.4	6.7
Denmark	6506	153.7	3.8
Slovenia	6526	148.2	11.7
Netherlands	6696	202.2	6.3
EU-15	6719	163.7	6.3
Germany	6742	175.8	5.4
France	7366	181.7	6.3
Austria	7453	158.3	4.6
Switzerland	7989	155.7	3.3
Belgium	8314	230.7	7.5
Luxembourg	15507	379.3	6.3
Sweden	15665	239.5	7.1
Finland	16128	286.8	8.8
Norway	24526	244.5	6.3
Iceland	27764	494.9	15.9

However, it can be concluded from *Table 4.14* that there is a great potential for improvement in the energy intensity in the Baltic countries. In fact, national energy efficiency targets envisage measures to improve efficiency to approach the EU average level.

4.4.2. Comparison of modelling assumptions and forecasts

4.4.2.1. Population growth

Planning experts of the three Baltic States have quite similar opinions about demographic trends in the region. All forecasts are comparatively pessimistic, assuming a 10–20% population decrease during the next 20 years (*Figure 4.6*). With a 20% reduction in population by 2020 in the low growth scenario - which was used for the base-case energy demand projection - Latvian specialists assume the strongest decline in population numbers. Apparently, these forecasts may underestimate migration trends — after accession of the three Baltic States into the EU, countries may have an obligation to host migrants from third countries. This side effect of EU membership is extremely unpopular in Baltic society, but it could be a reality in the near future and influence the demographics of the Baltic countries.

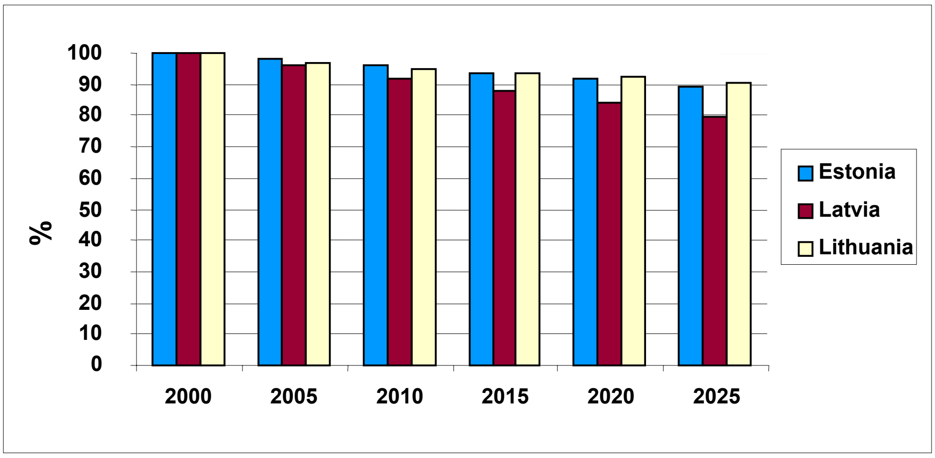


Figure 4.6. Comparison of population growth forecasts.

4.4.2.2. Economic growth

Contrary to population growth, GDP development forecasts for the three Baltic States are substantially more optimistic (*Figure 4.7*). During the 25 year period average annual growth (in the base-case scenario) is forecast to be 4.8% in Estonia, 4.7% in Latvia, and 3.7% in Lithuania. GDP growth forecasts could be overestimated through the influence of political leaders, who sometimes try to prove that the current dynamic development of economy will last for a long time. In reality, after the market has become saturated, economic development usually slows down. Nevertheless, the strategic goal of economic development in the Baltic States is to reach the average level of the EU countries.

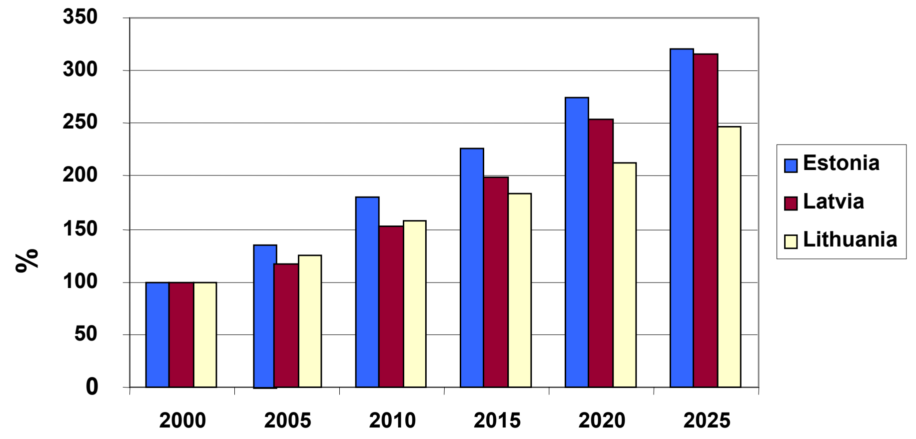


Figure 4.7. Comparison of economic growth forecasts.

4.4.2.3. Final energy demand forecast

Despite the relative pessimism of Lithuanian planning experts in forecasting GDP development, they are the most optimistic in forecasting energy demand. Estonian experts are the most pessimistic (*Figure 4.8*). During the 25 year period, the average annual growth of final energy demand forecast for Estonia is 1.2%, for Latvia 1.9%, but for Lithuania 2.5%.

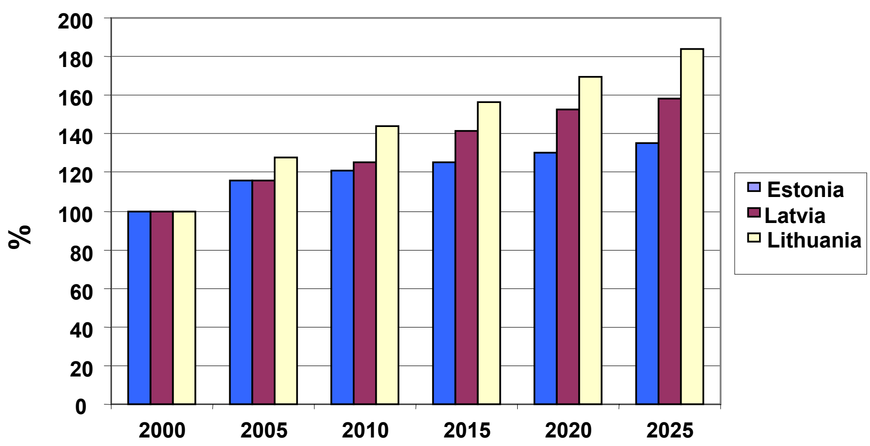


Figure 4.8. Comparison of final energy demand forecasts.

4.4.2.4. Electricity demand forecast

Electricity demand growth in each of the three Baltic States is forecast to be quite similar, approximately 3.0–3.5% per year (*Figure 4.9*).

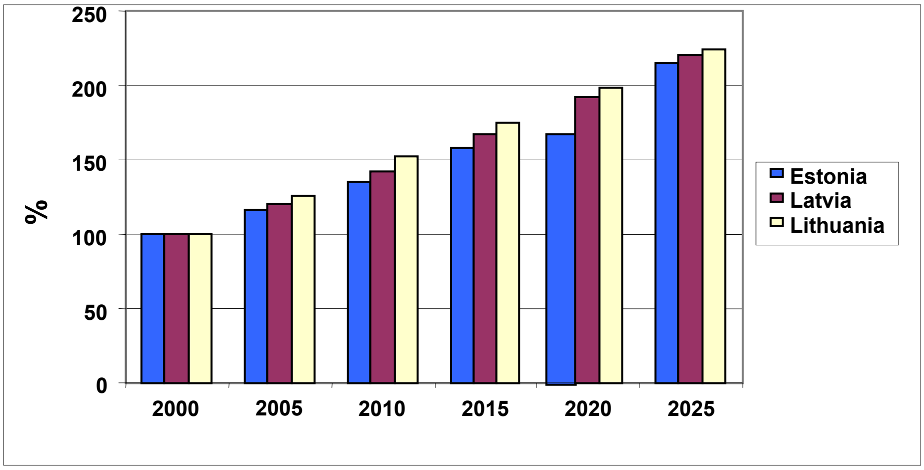


Figure 4.9. Comparison of electricity demand forecasts.

4.4.2.5. Heat demand forecast

Assumptions and visions of the future development of centralised district heating systems are very diverse among the Baltic States. Estonian experts are the most pessimistic, forecasting no increase in heat energy demand. However, during the 25 year period Lithuanian specialists foresee an approximately 55% growth in demand in district heating systems, which is approximately 1.7% per year. Latvian planners assume 'the golden mean', 17% growth in 25 years, without increase during the first years (*Figure 4.10*).

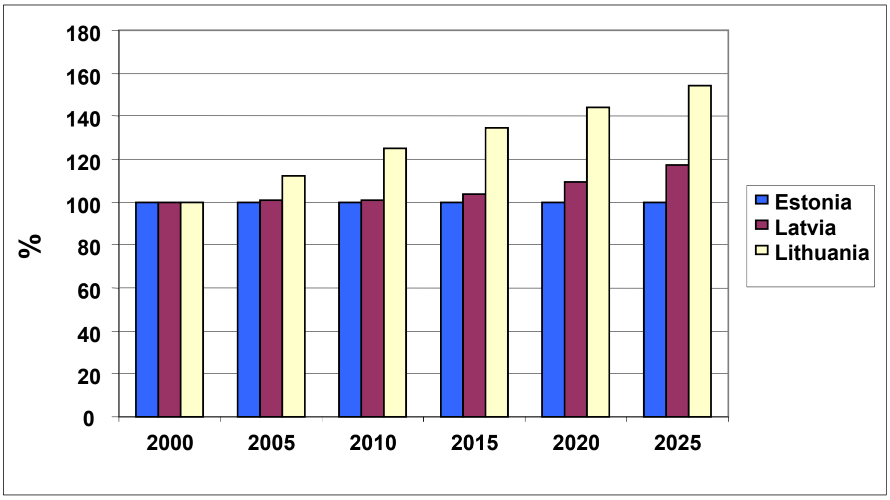


Figure 4.10. Comparison of heat demand forecasts.

4.4.2.6. Specific indicators

Table 4.15 presents electricity consumption per capita. In contrast to the IEA index (see *Table 4.14*), final electricity consumption does not include the consumption of power plants, which is why figures in these two tables differ.

Latvia has a more dynamic increase in electricity consumption per capita because of the faster decrease in population. Estonia will have the highest level of the three Baltic States.

Table 4.15. Specific electricity consumption (kWh/capita)

Country	*2000*	*2005*	*2010*	*2015*	*2020*	*2025*
Estonia	3622	4281	5114	6095	7354	8701
Latvia	1988	2498	3076	3768	4542	5482
Lithuania	1765	2284	2846	3304	3803	4359

Figure 4.11 illustrates the dynamics in energy intensity of FEC (FEC/GDP). From this figure, it is possible to conclude that Latvia and Estonia will improve their energy efficiency more rapidly than Lithuania.

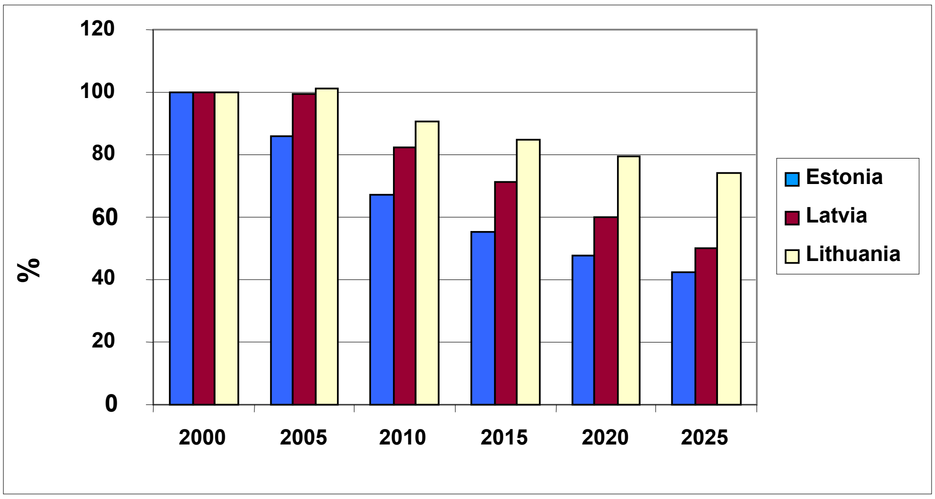


Figure 4.11. Dynamics of energy intensity development.

Main conclusions of the comparison:

- The highest energy demand growths are forecast in Lithuania and the lowest in Estonia;
- Currently and in the future Estonia has the best energy consumption and efficiency indicators amongst the three Baltic States;
- Different modelling approaches used for energy demand projections in the three Baltic States give quite different results;
- As the next step, it is recommended that one methodology be used for energy demand projections, such as the MAED model.

5. ENERGY AND FUEL PRICE FORECASTS

5.1. Estonia

5.1.1. Prices of imported fuels and electricity

Energy prices are usually important drivers of total energy demand and supply. Average end-user prices of fuels and energy are derived from fuel prices on wholesale markets. For oil fuels the world market price has to be taken into account. The level of national and/or local tax rates has to be considered as well.

The projections of prices on imported fuels are presented in *Table 5.1*. In general, the assumed trend of oil and gas prices should reflect the trend of crude oil price on the world market. The prices of oil fuels depend directly on the level of crude oil price. Prices on natural gas may remain linked to oil fuel prices. Firstly, through price indexation clauses in long term supply contracts and, secondly, through interfuel competition between gas and oil products in power plants. The sharp price increase of natural gas between 2005 and 2010 is based on the assumed Russian gas suppliers' correction of the price to that of the common European border price.

Table 5.1. Forecast of prices on imported fuels (€/GJ)

	2000	*2005*	*2010*	*2015*	*2020*	*2025*
Natural gas	2.56	2.68	3.24	3.56	3.80	4.08
HFO	2.99	3.86	3.87	4.05	4.13	4.17
Light distillates	7.38	8.28	8.61	8.94	9.22	9.39
Medium distillates	7.29	8.18	8.53	8.85	9.13	9.29
LPG	6.67	7.25	7.31	7.37	7.44	7.49
Coal	1.83	1.77	1.78	1.79	1.82	1.85
Electricity	6.14	6.34	8.53	9.41	10.39	11.48

GJ, Gigajoule; HFO, heavy fuel oil; LPG, liquefied petroleum gas.

International coal prices are assumed to remain constant or to increase very slowly. Decreases in the cost of mining and new environmental regulations that restrict the use of coal in many countries are expected to offset, to a large extent, the impact of higher oil prices on the price of coal.

In compiling the electricity price projection, the Nordic and/or Scandinavian electricity market was considered. The impact of annual climate conditions has been eliminated using the average annual supply of hydro-produced electricity.

The resulting relatively smooth price trends should not be interpreted as a prediction of annual stable prices, but rather as long term average values around which prices fluctuate. In practice, the price of gas, and especially those of oil fuels, will very probably continue to remain highly volatile.

5.1.2. Prices of exported fuels and electricity

The world market crude oil price determines to a large extent (either directly or indirectly) the prices for almost all local fuels in Estonia. For some fuels, such as biomass and peat, the impact is via the production costs, of which motor fuels and other oil products comprise a considerable share. The price projections of local fuels are given in *Table 5.2*.

Table 5.2. Forecast of prices on exported fuels (€/GJ)

	2000	*2005*	*2010*	*2015*	*2020*	*2025*
Local fuels						
Oil shale	0.91	0.92	0.94	0.95	1.00	1.05
Firewood	0.92	1.48	1.56	1.58	1.75	1.98
Milled peat	0.85	1.03	1.07	1.15	1.20	1.29
Exported fuels						
Shale oil	3.16	3.25	3.79	3.86	3.83	3.86
Wood pellets	4.86	5.14	5.37	5.71	5.94	6.32
Sod peat	2.25	2.25	2.75	2.90	2.96	3.01

The analysis of historic biomass fuel prices indicates that one factor in the relatively fast increase was the growth of motor fuel prices. Motor fuel prices, in particular that of diesel, also have an impact on future wood and peat fuel prices. Therefore, regarding the future development of fuel prices, in particular that of wood-based fuels, some factors are quite obvious. Nevertheless, no research institution in Estonia has risked publishing fuel price forecasts. In addition to international oil prices, several national and, in some cases, even local aspects have an essential impact on the price of wood fuels. In Estonia, the ready availability — in many regions the high cutting volume results in a supply considerably greater than the demand — has initiated a boom in wood-based heat production. The trend has been partially supported by environmental policy.

Principally, three fuels can be exported from Estonia. The approximate price projections for these fuels are presented in *Table 5.2*.

In Estonia, the easy availability of wood waste during the recent period resulted in the construction of several new plants for densified wood products with large production volumes, especially pellets and briquettes,. Lately, the process has resulted in a lack of raw material and several pellet plants have had to import much of their raw material. One more factor has an impact on the price of wood fuels in Estonia — the market in Scandinavian countries, in particular in Denmark, to which a large share of wood and wood fuels are exported. Therefore, in principle, Estonian users have to compete with Scandinavian ones.

5.1.3. Taxation of fuels and energy

5.1.3.1. Value added tax

As a rule of thumb, all fuel and energy types in Estonia are subject to value added tax (VAT). In Estonia the standard VAT rate is 18% of the pre-tax value (i.e., 15.3% of the end-user price). The VAT is recoverable for most enterprises.

For fuels, the only exceptions are peat, peat briquettes, coal and fuel wood sold to households, housing associations and churches, and also to enterprises financed from state and municipal budgets. For these fuels the exemption provides a VAT rate of 5% until 30 June 2007. The same provision is applied also to district heat sold to these institutions. From 1 July 2007 the standard VAT rate (18%) will be applied, which is a price increase of 12.4%.

5.1.3.2. Excise duties

During recent years, Estonia has gradually introduced excise taxes on fuels. The process began with duties on motor fuels. The first boiler fuel to be taxed with excise duty was light fuel oil (LFO). Current tax rates are presented in *Table 5.3*.

Table 5.3. Excise tax on fuels (in force from 1 January 2005)

Fuel	*Unit*	*€/unit*
Unleaded petrol	1000 l	288
Leaded petrol	1000 l	422
Kerosene	1000 l	302
Aviation spirit	1000 l	72
Gas oil (diesel fuel)	1000 l	245
Gas oil fuel for specific purposes	1000 l	44
LPG as motor fuel	t	100
Natural gas as motor fuel	t	100
Gas oil (LFO)	1000 l	44
Heavy fuel oil	t	15
Shale oil*	t	15†
Coal, coke*	GJ	0.3†

*Shale oil is exempt from the tax when used for district heating or by households; coal and coke are exempt when used by households.
†Tax was introduced on 1 May 2005.

In Estonia, natural gas used for heat generation is exempt from the European Union (EU) energy tax in accordance with Article 15 paragraph 1(g) of Directive 2003/96/EC [30]. This allows an exemption of natural gas in those Member States in which the share of natural gas in final energy consumption (FEC) was less than 15% in 2000. Exemption is for a maximum period of 10 years after entry into the force of the Directive or until the national share of natural gas in FEC reaches 25%, whichever is the sooner.

Directive 2004/74/EC [31] stipulates that Estonia may apply a total tax exemption on oil shale until 1 January 2009. Until 1 January 2013, it may furthermore apply a reduced rate of oil shale taxation, provided that this does not result in taxation below 50% of the relevant Community minimum rate as from 1 January 2011. Estonia is also eligible to apply a transitional period until 1 January 2010 to adjust its national shale oil tax to the minimum level of taxation if used for district heating purposes.

In Estonia, no specific taxes are imposed on electricity. The EU Directive 2004/74/EC (Article 1 paragraph 4) stipulates that Estonia may apply a transitional period until 1 January 2010 to convert its current input electricity taxation system into an output electricity taxation system. Although, at present, there are no direct taxes on electricity in Estonia, the power plants have to pay indirect taxes — pollution charges according to emission volumes into the environment.

5.1.3.3. Pollution charges

A kind of indirect taxation is related to the impact of fuel consumption on the environment. The Pollution Charge Act provides rates of charges (fees) to be paid for the release of pollutants or waste into the environment and the procedure to calculate and pay the charge. Charge rates for the emission of major pollutants into ambient air are given in *Table 5.4*. At present, the CO_2 charge has to be paid by all enterprises that have boilers with a total capacity of over 50 MW, excluding those that fire biofuel, peat or waste. In addition to the pollutants presented in *Table 5.4*, there are also charges for emitting mercaptans, heavy metals and compounds of heavy metals. The Act provides higher rates for some areas in Estonia (coefficients are 1.2, 1.5, 2.0 and 2.5) — densely populated, resort and/or recreation areas and areas with a heavy industrial load. The Act also provides penalties on emissions without permits and on emissions that exceed the fixed volumes in permits — the normal charges are multiplied by five for CO and solid particles, by 10 for SO_2, NO_x, volatile organic compounds (VOCs) and mercaptans, and by 100 for heavy metals.

Up to the year 2005 (inclusive) the rates of pollution charges are fixed in the Act. The Ministry of Environment has proposed to continue the increase of charge rates by 20% per year. According to the plans of the Ministry, the Pollution Charges Act will be replaced with the Environmental Charges Act, which would incorporate all provisions related to charges and fees on the utilisation of natural resources, as well as charges on pollution. The future (2006–2009) rates of pollution charges proposed in the draft bill of the Act are presented in *Table 5.4* in italics. At the time of writing this report, the draft of the Act has not yet been delivered to Parliament.

Table 5.4. Rates of pollution charge for the release of pollutants into ambient air (€/t)

Pollutant	*2005*	*2006*	*2007*	*2008*	*2009*
Sulphur dioxide (SO_2)	8.76	10.55	12.65	15.15	18.21
Carbon monoxide (CO)	1.28	1.53	1.79	2.17	2.62
Nitrogen oxides (as NO_2)	20.13	24.09	28.95	34.77	41.67
Particulates	8.76	10.55	12.65	15.15	18.21
Volatile organic compounds	20.13	24.09	28.95	34.77	41.67
Carbon dioxide (CO_2)*	0.72	0.72	0.72	0.72	0.72

*Up to 2005 (inclusive) paid if the total rated thermal input of the combustion plants of a source of pollution of an energy undertaking is greater than 50 MW, but not paid if these combustion plants use biofuel, peat or waste.

Importantly, enforcing the new act will repeal the lower limit (50 MW) of exemption for the CO_2 charge (i.e., from 1 January 2006 this charge has to be paid by all electricity and heat utilities). Exceptions will remain in force for the use of biomass[19], peat and waste.

[19] Biomass is defined as the biodegradable fraction of products, waste and residues from agriculture (including vegetal and animal substances), forestry and related industries, as well as the biodegradable fraction of industrial and municipal waste.

5.2. Latvia

5.2.1. Forecast of prices on domestic and imported fuels

Energy supply and demand patterns are sensitive to energy prices. The forecast of prices for domestic and imported fuels for this study takes into account global trends of price development and regional factors that affect prices. The forecast of fuel prices presented herein does not include any taxes or internal transportation and distribution costs.

5.2.1.1. Wood

Wood fuel is the key domestic source of energy, which at present covers a large portion of the country's energy demand. Assessment of the development of wood fuel price in general is difficult because it is of a very local nature, for which transportation distances, labour costs, regional resources and the presence and size of the woodworking industry are among the key determinants. Besides, the net energy content of wood fuels varies by a large amount according to moisture content, type of species and combustion technology. Trends over the past 3–4 years, however, indicate that wood fuel price has increased by approximately 1% per year. It can therefore be assumed that this trend will continue.

The precise mode in which gas prices are determined varies by region and the degree of competition, although gas prices are always strongly influenced by oil price. For the next 10–15 years it is envisaged that Russia will be the main supplier of natural gas to Latvia under long term contracts. Reportedly, the natural gas import price is linked to the constantly rising heavy fuel oil (HFO) price. For this reason, and because of increasing environmental concerns, it is expected that the natural gas price will increase substantially.

5.2.1.2. Heavy fuel oil

Taking into account that the world's oil prices were at unexpectedly high levels in 2000–2001, it is assumed that the HFO price will decrease in the near future. However, in the longer term it will still remain at a relatively high level domestically, particularly because of:

- Decreasing volumes of consumption;
- Increasing level of environmental taxes levied;
- Growing export custom dues and costs of transportation in Russia.

5.2.1.3. Coal

The importance of coal in Latvia's energy sector is currently very limited. Coal is imported by rail and distributed domestically by trucks. As coal is an expensive imported fuel with high incremental transport costs, it is widely substituted by other fuels, particularly wood. Notwithstanding substantial decreases in coal consumption during recent years, it may regain its position in the future, especially if considered for large power projects. Coal prices are much less volatile than those of, for example, HFO and supplies are provided by a very competitive and secure market. *Table 5.5* presents a summary of the fuel price forecast.

Table 5.5. Summary of fuel price forecast for domestic and imported fuels (€/GJ)

	2000	*2005*	*2010*	*2015*	*2020*	*2025*	*2030*
Natural gas	2.23	2.53	3.13	3.57	3.87	4.02	4.17
HFO with HSC	3.05	3.3	3.75	4.25	4.55	4.75	4.95
HFO with LSC	4.23	4.23	4.38	4.75	4.95	5.00	5.13
Coal	2.21	2.21	2.30	2.40	2.49	2.58	2.58
Medium distillates	4.93	5.34	5.75	6.16	6.84	7.53	8.21
Light distillates	6.53	7.15	8.39	9.32	10.10	10.57	11.34
Wood	1.59	1.59	1.64	1.79	1.94	2.09	2.24
Peat	1.85	1.94	2.04	2.30	2.61	2.88	3.06

HSC, high sulphur content; LSC, low sulphur content.

5.2.2. Taxation of fuels and energy

5.2.2.1. Value added tax

The following tax instruments are available in Latvia:

- VAT;
- Natural Resource Tax on Emission of Air Polluting Substances and GHGs (greenhouse gases);
- Excise duty (the law 'On Excise Duty for Oil Products').

VAT is imposed on all fuels and energy carriers, including domestic fuels, such as firewood, peat and wood chips. In Latvia the standard VAT rate is 18% of the pre-tax value. For energy carriers, the only exception was made for heat (district heating), which did not have VAT imposed until 1 July 2005.

5.2.2.2. Natural Resource Tax on Emission of Air-Polluting Substances and GHGs

The aim of the Natural Resource Tax (NRT) is to:

- Limit the non-rational use of natural resources and environmental pollution;
- Limit the production and use of certain products defined as environmentally polluting and harmful to the environment;
- Promote the penetration of new and modern technologies to reduce environmental pollution;
- Support a sustainable development strategy for economic growth;
- Create sources to finance measures of environmental protection.

The following activities relevant to the energy sector are taxed:

- Extraction of local energy resource — peat (*Table 5.6*);
- Discharge of pollutants (noxious emissions, waste) directly into the environment (*Table 5.7*);
- CO_2 emissions of fuel-combustion facilities (exemption is stated for facilities included in the National Plan for Allocation of Emission Allowances, as well as for facilities that use wood, straw and local peat as fuel);

- CO_2 emissions when the facility corresponds to the list of facilities defined by Annex 2 of the law 'On Pollution' and is included in the National Plan for Allocation of Emission Allowances, and emissions are included in the quota but the facility operator has not delivered the quota as defined by the law;
- Use of suitable properties of geological structures by pumping natural gas into storage reservoirs underground.

Table 5.6. Charges for extraction of natural resources in Latvia

Selected types of resources, relevant to the energy sector	*Unit*	*Rate (€)*
Peat, degree of decomposition up to 20% (moisture — 40%)	ton	0.195
Peat, degree of decomposition above 20% (moisture — 40%)	ton	0.105
Pumping of natural gas into geological structures	1000 m^3	0.15

Table 5.7. Charges on noxious air pollution and CO_2 emissions in Latvia

	Classification of emissions	*Unit*	*Rate (€)*	*In force from*
1	CO_2 emissions from combustion facilities	t	0.15	01 July 2005
	Exemption until 2008 from this tax is applied to: a) *Facilities that participate in the National Plan for Allocation of Emission Allowances* b) *Facilities that use renewable resources as a fuel — wood, straw, and local fuel (peat)*	t	0.45	01 July 2008
2	CO_2 emissions emitted by the facility but not included in the quota annually reported to the national authority by the facility	t	40	01 January 2005
	Note: *This particular CO_2 tax is applied from 2008 to facilities included in the National Plan for Allocation of Emission Allowances*	t	100	01 January 2008
3	Solid particulates, in case they do not contain heavy metals	t	6	Existing
4	SO_2, NO_x (sum of oxides recalculated to NO_2) Volatile organic compounds Other hydrocarbons (C_nH_m)	t	19.5 45 90	Existing 01 July 2005 01 July 2008

5.2.2.3. Excise taxes

The present law 'On Excise Duty for Oil Products' was adopted in November 1997 and was amended 13 times in the years 1998–2003. *Table 5.8* presents the current excise tax rates on oil products. Decreased tax rates for oil products with biofuels added are applied (*Table 5.9*). Pure biodiesel is exempt from excise taxes. Full harmonisation with the EU excise duty rates on diesel has to be implemented in Latvia by the year 2013, but on gasoline by the year 2010.

Table 5.8. Excise tax on fuels in Latvia from 1 June 2005

Fuel	*Unit*	*€/Unit*
Gasoline unleaded	1000 l	295
Gasoline leaded	1000 l	432
Diesel	1000 l	252
Heating oil	1000 l	22
Heavy fuel oil	t	15
Liquefied petroleum gas, gaseous hydrocarbons	t	128

Table 5.9. Present tax rates in Latvia for oil products with biofuels added from 1 January 2005

Fuel	*Unit*	*€/Unit*
Gasoline* with ethyl alcohol added	1000 l	280
Diesel† with 5–30 volume % biodiesel added	1000 l	238
Diesel with 30–99 volume % biodiesel added	1000 l	175
Biodiesel		0

*Decreased tax rate for gasoline applies if the added biofuel is produced from raw materials of agricultural origin, dehydrated (99.5 volume % of alcohol) and denaturated ethyl alcohol (6.5–7 volume %), or the ethyl alcohol derivative ethyl tertiary butyl ether (ETBE; 10–15 volume %).
†Decreased tax rate for diesel is applied if it is added biodiesel, produced from rape seeds.

Directive 2003/96/EC [30] imposes energy taxes on electricity and all types of fuels, excluding biofuels. The Directive stipulates that Latvia may apply a transition period to implement the energy tax on electricity by 1 January 2010, but that the tax rate has to reach 50% of the relevant EC minimum rate from 1 January 2007. The Directive stipulates further that Latvia may apply a transition period to implement an energy tax on coal by 1 January 2009, but that the tax rate has to reach 50% of the relevant EC minimum rate by 1 January 2007.

5.3. Lithuania

5.3.1. Prices of imported fuel and electricity

The extended experience of institutions engaged in various price projections for the energy market indicates, that retrospective analyses of energy market prices and the generalisation of factors that influence energy prices are not sufficient to make accurate projections of future energy price developments. New and important factors continually emerge that have not manifested previously. Price changes of oil, effect prices of all the other energy carriers, in one way or another.

Among the main factors that have recently had an impact on the development of oil prices are the following:

- Political instability in the major oil-exporting countries in the Middle East, where about 65% of all oil reserves are accumulated.
- The reduced surplus of oil extraction capacities has a significant impact on oil prices.
- Speculations on the Mercantile Exchange are related to uncertainties in oil markets and the expectancy that the supply of oil and oil products may encounter difficulties. Brokers are buying oil for future contracts, which also causes oil prices to rise.
- Global oil demand has increased significantly during recent years. In 2001 and 2002, the increase in oil demand was 0.7–0.8 million barrels per day. This demand growth reached 1.5 million barrels per day in 2003 and 2.58 million barrels per day in 2004.
- Changes in OPEC country quotas also have an impact on oil-price fluctuations.
- Uncertainties with Yukos assets also contribute to the increase of oil prices.

The rapid increase in oil demand and insufficient investments in oil extraction have significantly reduced the surplus of oil extraction capacities. In the near future neither significant reductions in demand growth nor the fast introduction of new capacities is expected. Consequently, the conclusion is that oil prices will remain high. With crude oil prices exceeding $20/barrel economic incentives to assimilate new oil resources, in particular heavy oil and oil sands, and to develop synthetic oil products from natural gas surely arise. However, more than 10 years will be needed for these actions to take a significant share of the market and to have an impact on oil prices. This general tendency will be punctuated by the short term fluctuations in oil prices characteristic of this energy source. Undoubtedly, in response to oil price changes, the prices of all oil products will change appropriately.

The main fuels used in the Lithuanian energy sector are uranium, natural gas, heavy oil products and coal. Oil prices have different impacts on the prices of the other primary energy supply sources. Prices of natural gas are related by a particular elasticity coefficient to oil prices. The price of the oil-processing residual HFO is influenced by its sulphur content.

For environmental reasons, in EU Member States and, according to a decision of the Lithuanian government, from 1 January 2004, the use of HFO with a sulphur content that exceeds 1% has not been recommended. High-sulphur HFO (HFO-HSC) can be used only together with cleaner fuels so that the limits set for SO_2 concentrations in flue gas are not exceeded. The changes in prices of HFO-HSC and natural gas during the recent decade are presented in *Figure 5.1*.

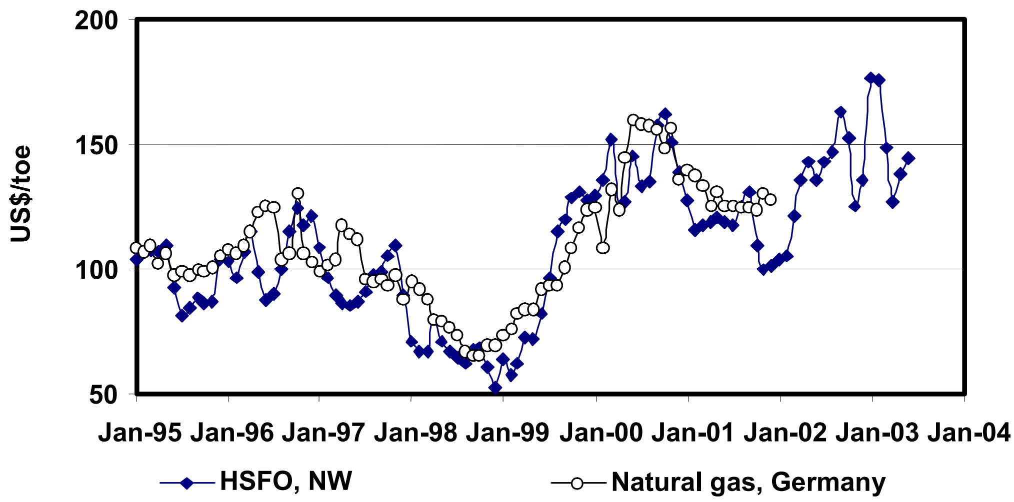


Figure 5.1. The HFO-HSC and natural gas prices in the world markets [32]. Toe, tons of oil equivalent.

The changes in HFO-HSC and coal prices in Northwest Europe (NWE) markets are presented in *Figure 5.2*. The price of coal has been significantly more stable, although it has not maintained an increase.

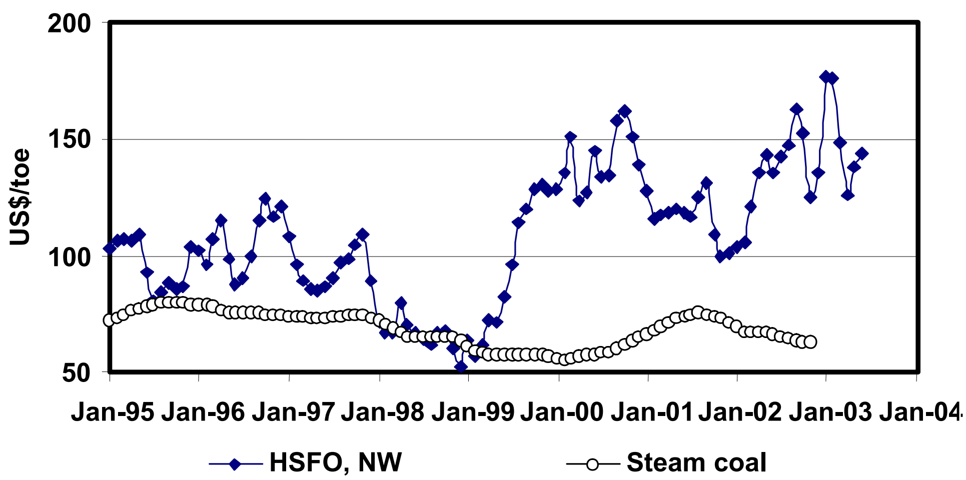


Figure 5.2. The dynamics of HFO-HSC and coal prices in the world energy markets [32].

After Lithuanian independence, the price of HFO (one of the most important primary energy sources) rapidly increased and for a short time approached the level of international prices. From 1995, Lithuanian HFO prices have been quite similar to Western European prices (*Figure 5.3*). The average difference between HFO prices in Lithuania and Western Europe during 1995–2002 was 15.3 US$/toe.

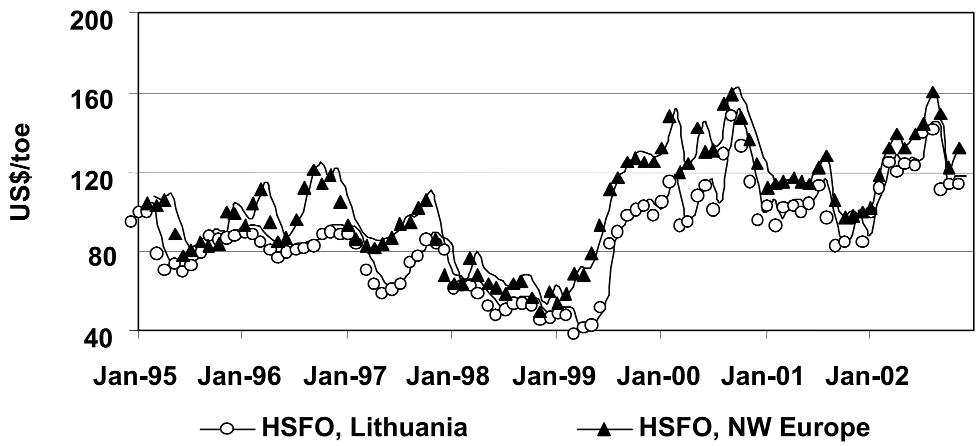


Figure 5.3. Dynamics of HFO-HSC prices in Western Europe and Lithuania [32].

The HFO-HSC and oil price in Lithuanian and Western European markets differ because of the lower transportation costs of Russian oil to the Mazeikiai refinery (*Figure 5.4*). For oil this difference is 16.9 US$/toe.

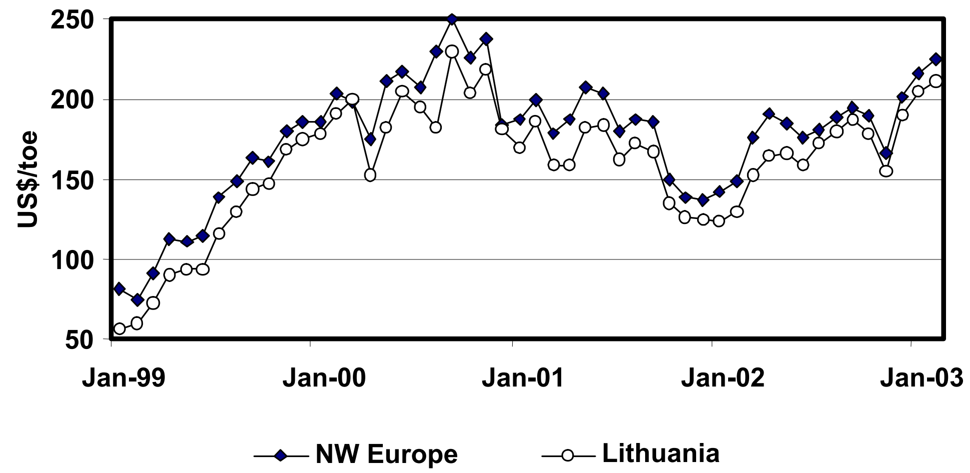


Figure 5.4. Dynamics of oil price in Western Europe and price of oil imports to Mazeikiai [32, 10].

Russian oil and HFO prices in the Lithuanian market completely match NWE prices if the oil transportation costs are removed. Therefore, by eliminating differences in transportation costs in Lithuania and NWE, oil price projections developed by the International Energy Agency (IEA) for imported Russian oil prices can be used to project oil prices in Lithuania. The question is how this can be used in this forecast.

Unlike oil product prices, the price of imported natural gas from Russia was regulated independently from oil-price developments in the world markets up to 1999. On 1 December 1999 Lithuanian Gas signed a long term 6 year purchase agreement with Russian Gazprom that recognised the relationship of natural gas prices to oil (HFO) price changes. The agreement requires that the natural gas import price shall be regulated in accordance with the average price of high sulphur content HFO (3.5% S) in the European market. This price is determined by taking into account the average HFO price of 6 months set by Reuters communication data. On 18 December 2002 an additional agreement with Gazprom was signed, which sets the conditions of natural gas supply to Lithuania from 1 January 2003. The agreement established that during the first half of 2003 Lithuanian Gas will pay a fixed price for natural gas and that from the middle of 2003 the natural gas price will depend on HFO price changes in the market.

However, on 16 January 2004, by selling 34% of JSC Lithuanian Gas stocks to Gazprom, a long term natural gas supply agreement that included a new formula to calculate the natural gas price was signed. Although Lithuanian Gas is and will remain the only importer of natural gas from Russia, a stabilisation of natural gas prices on the Lithuanian market can be expected.

Given that the export prices of Russian oil strictly match those prices on the European markets (Rotterdam) and taking into account the actual transportation costs from Russia to Lithuania, one can attempt to predict oil price developments in Lithuania if the projections developed for Western markets are reliable. In this work we attempt to approximate the oil and oil products price projections for NWE carried out by various institutions (*Table 5.10*).

Table 5.10. Approximate oil, HFO and natural gas price projections in NWE markets [33]

Scenarios	*2005*	*2010*	*2015*	*2020*	*2005*	*2010*	*2015*	*2020*
	Oil (€/GJ)				*Natural gas (€/GJ)*			
Minimum	2.97	2.97	2.97	2.97	2.27	2.27	2.27	2.27
Basic	4.08	4.23	4.39	4.55	3.12	3.23	3.35	3.48
Maximum	5.46	5.83	5.99	6.06	4.17	4.45	4.58	4.63
	High sulphur HFO (€/GJ)				*Gasoil (€/GJ)*			
Minimum	2.14	2.14	2.14	2.14	3.61	3.61	3.61	3.61
Basic	2.94	3.05	3.16	3.28	4.94	5.11	5.30	5.52
Maximum	3.93	4.19	4.32	4.37	6.59	7.05	7.26	7.33

Based on the data presented in *Table 5.10* and taking into account oil transport costs from Russia to Lithuania, prices for oil, oil products and natural gas in Lithuania are projected to lie within the ranges given in *Table 5.11* and *Table 5.12*.

Table 5.11. Projection of oil prices on the Lithuanian market (€/GJ) [33]

Projection	*2005*	*2010*	*2015*	*2020*
Minimum	2.78	2.78	2.78	2.78
Basic	3.98	4.14	4.31	4.49
Maximum	5.46	5.86	6.04	6.12

Table 5.12. Projection of HFO, natural gas and gasoil prices on the Lithuanian market [33]

Projections	*2005*	*2010*	*2015*	*2020*	*2005*	*2010*	*2015*	*2020*
	High sulphur HFO (€/GJ)				*Low sulphur HFO (€/GJ)*			
Minimum	1.91	1.91	1.91	1.91	2.08	2.08	2.08	2.08
Basic	2.78	2.90	3.02	3.16	2.94	3.06	3.18	3.31
Maximum	3.85	4.14	4.27	4.32	4.01	4.29	4.42	4.48
	Natural gas (€/GJ)				*Gasoil (€/GJ)*			
Minimum	2.04	2.04	2.04	2.04	3.24	3.24	3.24	3.24
Basic	2.95	3.08	3.21	3.35	4.69	4.89	5.09	5.31
Maximum	4.10	4.40	4.54	4.59	6.49	6.97	7.19	7.29

More than 80% of electricity in Lithuania is currently produced from nuclear fuel. The main driving force for electricity production at the Ignalina nuclear power plant (NPP) is its lower cost in comparision with fossil fuel power plants. However, world markets prices for nuclear fuel are also not stable. After a significant price decline in 1997–2002, because of the use of military uranium for electricity generation, a rapid increase in uranium prices occurred from 2003 onwards. The price of uranium between 2003 and 2004 almost doubled. Perhaps the recent volatility of fossil fuel prices will have long term consequences on the uranium price. For reasons similar to those in the oil sector, the constant shortage of investment in uranium exploration causes situations in which uranium demand exceeds uranium exploration capabilities, and quite huge reserves can suddenly be depleted. Therefore, no one can firmly forecast the levels at which uranium prices will stabilise on the markets. However, the current price of imported nuclear fuel remains quite stable and it is expected that the price of electricity produced at the Ignalina NPP will not change or will change only marginally.

During the past few years, both electricity import and export prices have tended to decrease (*Table 5.13*), but, taking into account the projected increase in almost all fuel prices, this tendency cannot persist.

Table 5.13. Electricity import and export prices in Lithuania [10]

Electricity price (€/MWh)	*2000*	*2001*	*2002*	*2003*
Import	19.1	19.65	15.36	n.a.
Export	16.9	15.0	16.3	11,5

5.3.2. Taxation of fuels and energy

All fuels, except renewables, nuclear and peat, incur excise duties as presented in *Table 5.14*. In Lithuania all goods and services incur 18% of VAT.

Table 5.14. Excise duties on fuels in Lithuania

Fuel	*Duty*
Gasoline with lead	421.2 €/1000 l
Gasoline without lead	287.04 €/1000 l
HFO*	15 €/t
LFO for transportation	292 €/1000 l
Gas*	126 €/t
Orimulsion	15 €/t
LFO for heating	25 €/t
LPG	125.2 €/t

*There is no excise tax for fuel used for electricity production in Lithuania.

Environment and/or pollution-related taxes, charges and/or fees are given in *Table 5.15*.

Table 5.15. Emission taxes in Lithuania

	CO_2 taxes (€/t CO_2)	SO_2 taxes (€/t SO_2)	NO_x taxes (€/kg NO_x)
2004–2009	–	62.8	0.1077
2010–2030*	–	62.8	0.1077

*Assumed.

5.4. Development of prices on international markets

The majority of fuels are sensitive to oil-price fluctuations, which usually do not result from purely economic factors, but arise from changes in the political situation around the world and in the market power of a few global players. During the crises of the 1980s the crude oil price increased by 900%, while the natural gas price increased by 700% and the hard coal price by 300%. A similar situation can be observed today (*Figure 5.5*).

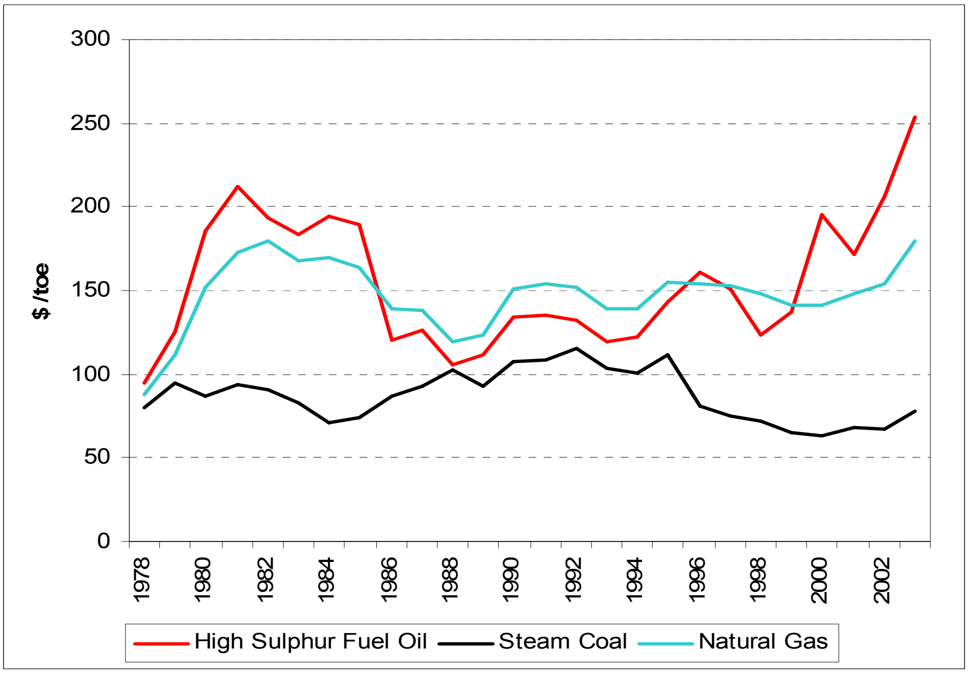


Figure 5.5. Primary energy prices.

The price of uranium is less affected by oil prices, but some growth has occurred during recent years (*Figure 5.6*).

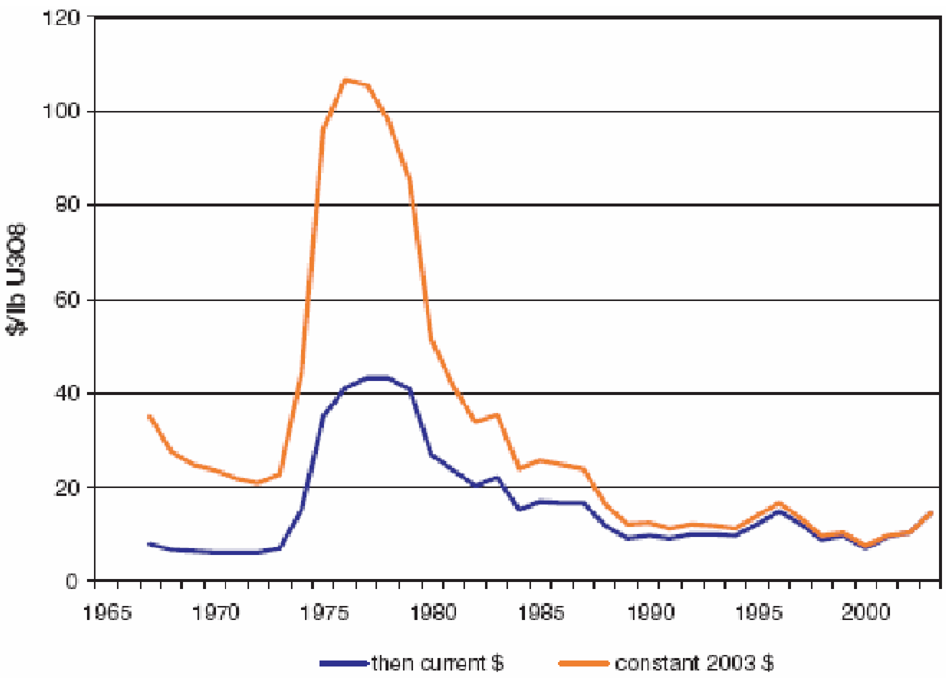


Figure 5.6. Uranium prices 1967–2003 [34].

The fluctuation of fuel prices in volatile world fuel markets discussed above are rather more short term than long term, which is why forecasts of future prices are based on more solid underlying trends that reflect long term average values.

Future relationships between internal and export prices of Russian natural gas are very important as well (*Figure 5.7*). It is obvious that the existing gap will narrow. However, to what extent is not so clear.

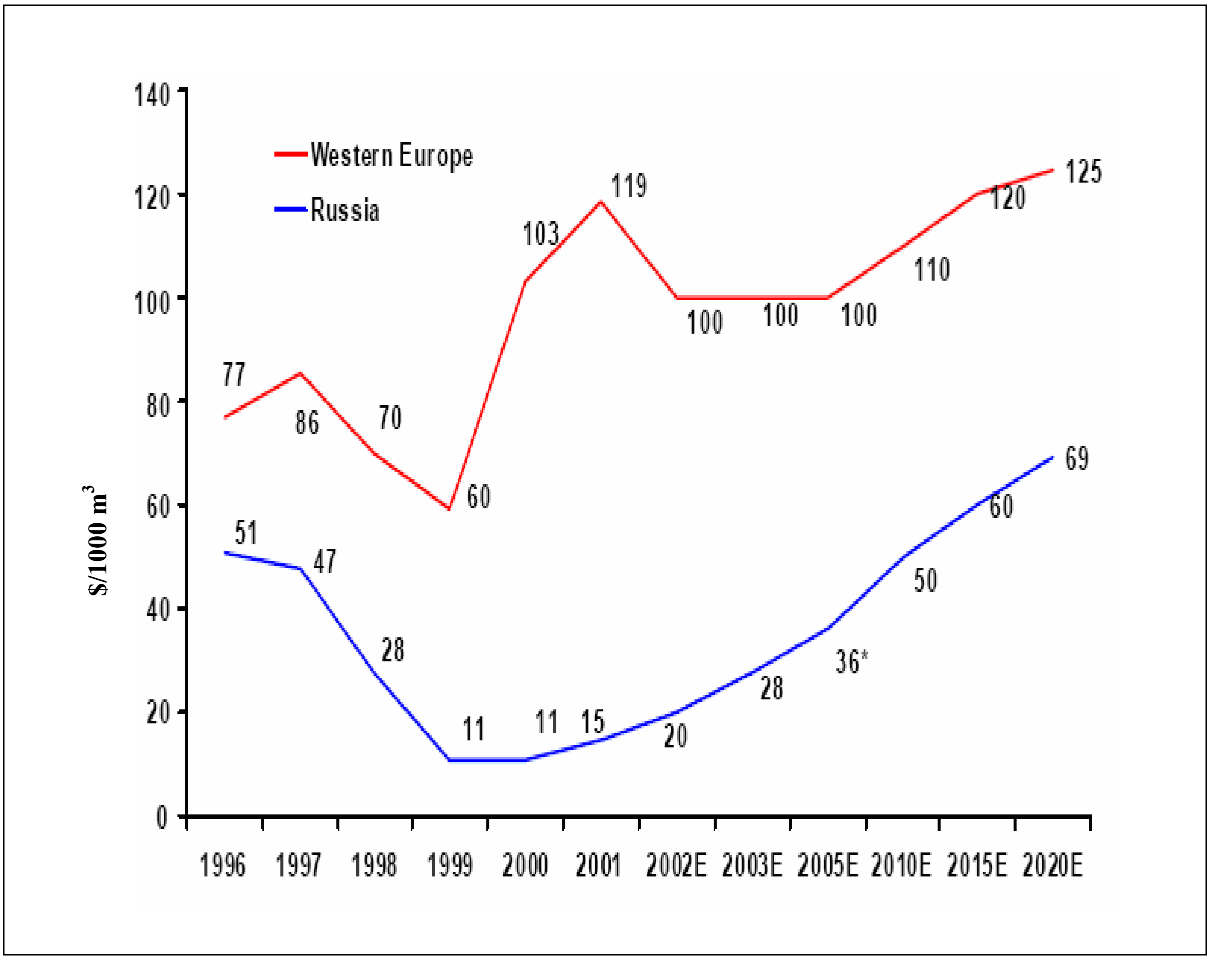


Figure 5.7. Internal and export gas prices in Russia [35], E=projection.

The forecast of electricity prices for power exports and imports is based on the analysis of prices in power exchanges of neighbouring countries. The following average day-ahead prices were observed in European power exchanges on 11 January 2005 (*Table 5.16*).

Table 5.16. Day-ahead prices in European power exchanges

Power exchange	*Country*	*Price (€/MWh)*
APX	Netherlands	32.90
EEX Phelix	Germany	31.28
Electrabel Choice	Belgium	31.60
Exaa	Austria	31.28
Ipex	Italy	93.72
Nord Pool	Scandinavia	21.91
Omel	Spain	50.35
PolPX	Poland	27.25
Powernext	France	31.16
UKPX	UK	33.64
ATS	Russia	14.42

Figure 5.8 shows the dynamics of price development in European power exchanges.

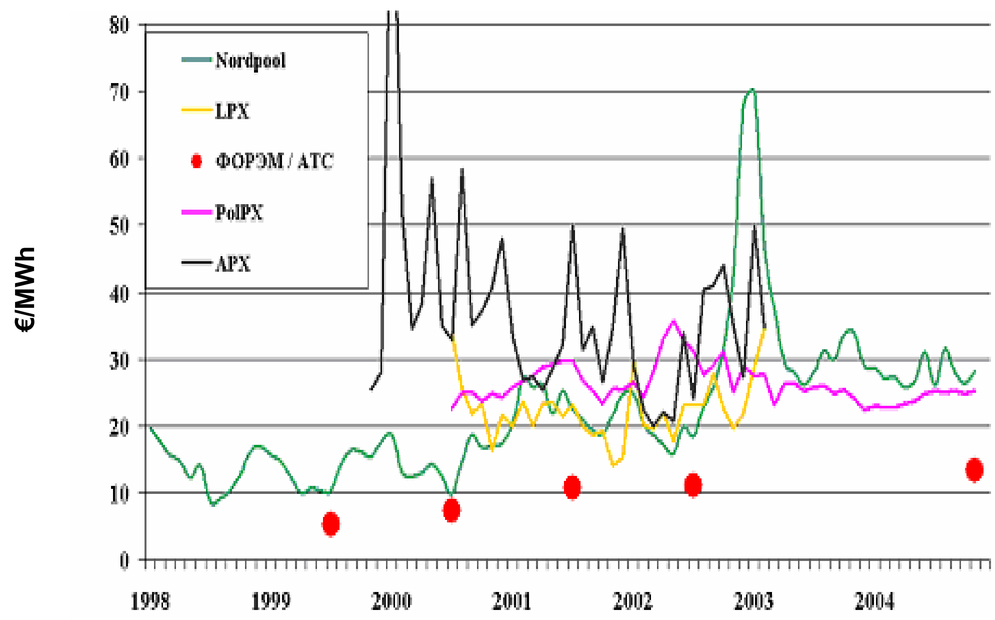


Figure 5.8. Power price development in European power exchanges.

CO_2 emission trading is a very important part of modern electricity markets. It might influence future investment decisions. The CO_2 allowance price grew from 5–8 €/tCO_2 at the beginning of 2005 to approximately 20 €/tCO_2 in the summer of 2005 (see *Figure 5.9*).

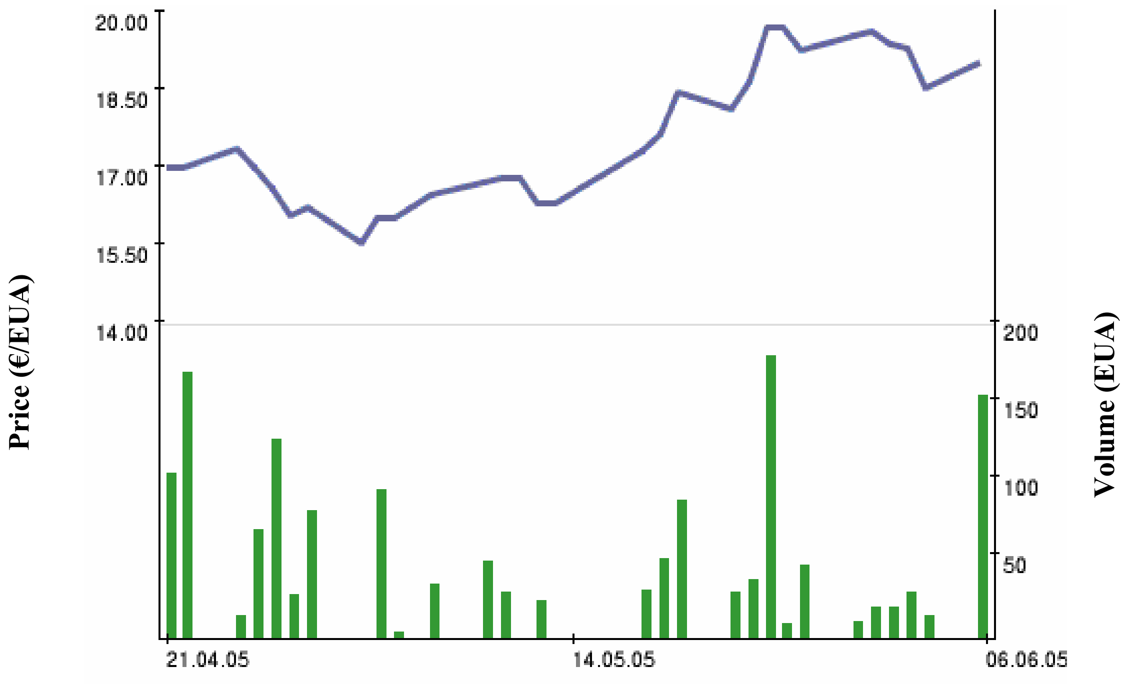


Figure 5.9. CO_2 emission trading in Nord Pool. EUA, European Union Allowance.

5.5. Price projections — summary for Baltic States

Energy prices can be considered as key drivers in the development of energy demand and supply. The situation on the world market for crude oil and oil products has an impact, either directly or indirectly, on the prices of all fuels. As to national factors, the level of taxes has an increasing role in the development of prices in every country. As all Baltic States are EU members, provisions of the relevant *acquis* have to be followed. Since 1992 the EU rules for excise duties on mineral oils have been the major energy taxation element. After many years of debate, the EU restructured the European Commission (EC) framework for the taxation of energy products and electricity with Directive 2003/96/EC, which replaced previous ones (i.e. 92/81/EEC and 92/82/EEC).

The current rates of energy taxes on fuels and electricity in the EU and the Baltic States are presented in *Table 5.17*.

The EU15 member states had to implement the provisions of Directive 2003/96/EC by introducing new tax rates from 1 January 2004. Several new Member States have applied for exemptions and transitional periods. Therefore, Council Directive 2004/74/EC (amending Directive 2003/96/EC) was issued to stipulate temporary exemptions and/or reductions in the levels of taxation. Regarding the Baltic States, Estonia and Latvia have applied for transitional periods for fuels used in the energy sector.

Table 5.17. Excise tax on fuels, in force since 1 January 2005 (€/unit)

Fuel	*Unit*	*EU minimum rate*	*Estonia*	*Latvia*	*Lithuania*
Motor fuels					
Unleaded petrol	1000 l	359	288	295	287
Leaded petrol	1000 l	421	422	432	421
Gas oil (diesel oil)	1000 l	302	245	252	292
Gas oil (for special purposes)	1000 l	21	44	21	21
LPG	t	125	100	128	125
Natural gas	€/GJ	2.6 (117 €/t)	2.2 (100 €/t)		2.8 (126 €/t)
Heating fuels and electricity					
Gas oil (LFO)	1000 l	21	44	22	25
Heavy fuel oil	t	15	15	15	15
Orimulsion	t	15	–	–	15
Shale oil*	t	15	15†	–	–
Coal, coke†	GJ	0.15/0.3	0.3†	–	–
Natural gas	GJ	0.15/ 0.3	–	–	2.8 (126 €/t)
Electricity	MWh	0.5/1.0	–	–	–

*In Estonia shale oil is exempt from tax when used for district heating purposes or by households, and coal and coke are exempt when used by households.
†Tax was introduced on 1 May 2005.

Estonia was granted the possibility to apply a total exemption from taxes on oil shale until 1 January 2009 and to use a reduced rate until 1 January 2013. Also, Estonia was given the right to apply a transitional period until 1 January 2010 to adjust its national level of taxation on shale oil used for district heating purposes to the minimum level of taxation.

Directive 2004/74/EC provides that Latvia may apply a transitional period until 1 January 2010 to adjust its national level of taxation on HFO used for district heating purposes to the minimum level of taxation. Latvia was given a similar possibility in regards to coal and coke until 1 January 2009, with the requirement that the level of tax on coal and coke shall be no less than 50% of the relevant EC minimum rates as from 1 January 2007. Latvia has reduced rates of energy tax on oil fuels that contain a biofuel component.

Regarding the taxation of electricity, the Directive allows Estonia and Latvia to apply transitional periods in which to introduce the required tax. Estonia may apply a transitional period until 1 January 2010 to convert its current input electricity taxation system into an output electricity taxation system. Latvia may apply a transitional period until 1 January 2010 to adjust its national level of taxation on electricity to the relevant minimum level of taxation.

However, the level of taxation on electricity in Latvia shall be no less than 50% of the relevant EC minimum rates as from 1 January 2007. It is important to emphasise that the fuels used for electricity production are exempt from excise duties according to the principles and practice of most EU15 countries.

In addition to excise duties, many countries have introduced environment-related direct taxes — called carbon, CO_2 or energy taxes, which have to be paid when purchasing the fuel. The Baltic States still follow a model whereby the end-user of the fuel has to pay certain charges (fees) depending on the pollution caused by combustion of the fuel. An overview of the current rates, together with mid-term projection of the charges for emitting major pollutants into ambient air, is given in *Table 5.18*.

Table 5.18. Rates of pollution charges for the release of selected pollutants into ambient air from stationary sources (€/t)

	2005	*2006*	*2007*	*2008*	*2009*
Sulphur dioxide (SO_2)					
Estonia	8.76	10.55	12.65	15.15	18.21
Latvia	19.50/45.00	45.00	45.00	45.00/90.00	90.00
Lithuania	62.80	62.80	62.80	62.80	62.80
Nitrogen oxides (as NO_2)					
Estonia	20.13	24.09	28.95	34.77	41.67
Latvia	19.50/45.00	45.00	45.00	45.00/90.00	90.00
Lithuania	107.70	107.70	107.70	107.70	107.70
Carbon dioxide (CO_2)					
Estonia	0.72	0.72	0.72	0.72	0.72
Latvia	0.15/40.00	0.15/40.00	0.15/40.00	0.45/100.00	0.45/100.00
Lithuania	–	–	–	–	–

As *Table 5.18* shows, there are some differences in the taxation of emissions into air in the Baltic States. The rates of charges are quite similar in Estonia and Latvia, while in Lithuania the rates are essentially higher. Regarding the charge on CO_2 emissions, there are many specific features, such as in Estonia the charge has to be paid only by large (>50 MW) plants, but from 2006 this charge has to be paid by all electricity and heat utilities. In Latvia the CO_2 pollution charge came into force on 1 July 2005. Both in Estonia and Latvia, all combustion plants that utilise biomass and peat (in Estonia, waste as well) are exempt from the charge.

When making fuel price projections the key factor to be taken into account is the crude oil price on the world market. The development of prices of crude oil and oil products during recent years is shown in *Figure 5.10*.

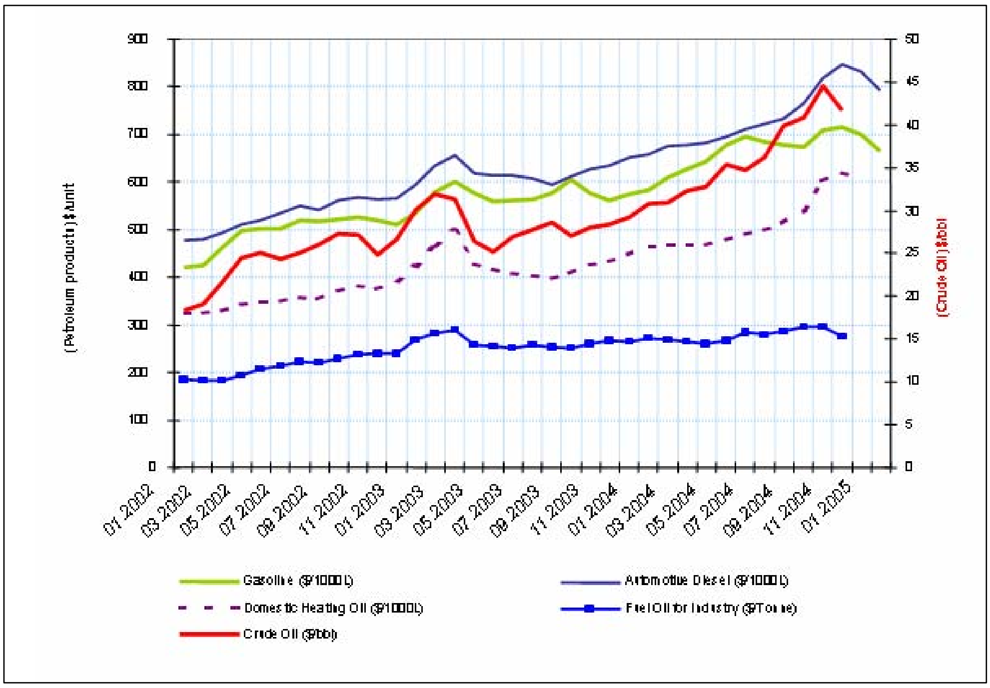


Figure 5.10. Average crude oil import cost and end-user petroleum product prices (bbl, barrels of oil).

The analysis of prices for crude oil and refined oil products over long time period indicates several sharp increases since 1999, reaching all-time highs (in nominal terms) in the second half of 2004 (e.g., 55.17 $/bbl, 26 October 2004 on NYMEX). Nevertheless, the institutions that forecast oil price development consider these as temporary fluctuations of a highly volatile crude oil price, and have not significantly changed their price projections. In *Table 5.19* a selection of oil price forecasts by several institutions is given.

Table 5.19. World oil price projections ($\$_{2002}$/barrel)

Institution	*2010*	*2015*	*2020*	*2025*
IEO2004 Reference case [36]	24	25	26	27
IEO2004 High price case	33	34	35	35
IEO2004 Low price case	17	17	17	17
Global Insight, Inc. [37]	22	23	24	25
Deutsche Bank AG [38]	18	18	18	18
National Petroleum Council [39]	18	18	18	18
SEER [40]	20	21	22	25

The Energy Information Administration of the US Department of Energy issues three scenarios for oil price development per annum. Three possible long term price paths presented in the *International Energy Outlook 2004* are given in *Table 5.19*. In the reference case, projected prices in 2002 dollars reach $27 per barrel in 2025 (in nominal dollars, the reference case price is expected to be around $51/bbl in 2025). In the low-price case, prices are projected to be $17 per barrel in 2005 and to remain at about that level out to 2025.

In the high-price case, prices are projected to reach \$34 per barrel in 2013 and to be around \$35 per barrel in 2025. It is interesting that the levelling off in the high-price case is predicted from the projected market penetration of alternative energy supplies that could become economically viable at that price (such as liquids from oil sands, natural gas, coal, biofuels and oil shale).

The IEA in its *World Energy Outlook 2002* [41] stated that 'prices are assumed to rise in a linear fashion after 2010', which is from \$21.75 per barrel in 2010 to \$30.03 per barrel in 2030. The analysis of fuel-price evolution during recent decades also indicates that gas import prices in Europe have stayed below the oil price, but broadly followed oil prices as these fuels compete for many end uses. Gas prices are influenced by two contrasting trends. Cleanliness and high end-use-efficiency cause gas prices to rise faster than oil prices; but factors such as more intensive gas-to-gas competition and greater integration of regional gas markets (e.g., with more liquefied natural gas) exert downward pressure on gas prices. So, up to now, in most projections oil and gas prices are assumed to develop in significant correlation, but in the mid-term future the correlation will probably be weaker than in the past as a result of on-going market liberalisation. Nevertheless, developments in the international oil market will continue to have a substantial impact on developments in the gas markets. *Table 5.20* presents price forecasts for oil and gas used in modelling energy demand and supply in Europe up to the year 2030 [42].

Table 5.20. Projected evolution of international fuel prices (€$_{2000}$/GJ) [42]

	2000	*2010*	*2020*	*2030*
Crude oil (\$$_{2000}$/bbl)*	28.0	20.6–36.1	24.9–42.9	29.9–50.3
Crude oil	4.78	3.51–6.16	4.25–7.32	5.10–8.58
Natural gas	2.64	2.97–5.15	3.46–6.33	3.88–7.17

*bbl, barrel.

As can be seen, the range of assumed values is quite large as a result of the pricing factors considered. As to fuel price development, the authors (affiliated with the National Technical University of Athens) have included the following options in addition to the baseline scenario:

- Gas prices in Europe grow much faster than oil prices and slightly exceed the oil price in 2030;
- A decoupling (de-linking) of the gas price from the oil price (i.e., the gas price does not follow the oil price in the long term), which results in a wider gap between oil and gas prices;
- Soaring oil and gas prices that are 80% higher than in the baseline.

Coal prices are usually assumed to remain stable and well below those of oil and gas, especially in the long run. The electricity price has a mainly regional character. The Baltic States are located close to the Nordic electricity market in Scandinavia, and therefore development projections for this market have been studied. One of the key factors in this market is the precipitation balance. A long dry period is a risk for the Nordic electricity system due to its reliance on hydro power plants. The price peaks (*Figure 5.11*) were caused mainly by supply shortages during dry years. Also, during dry years the price level of the

German market significantly affects the Nordic electricity markets. *Figure 5.11* also presents one option of price development in the Nordic electricity market.

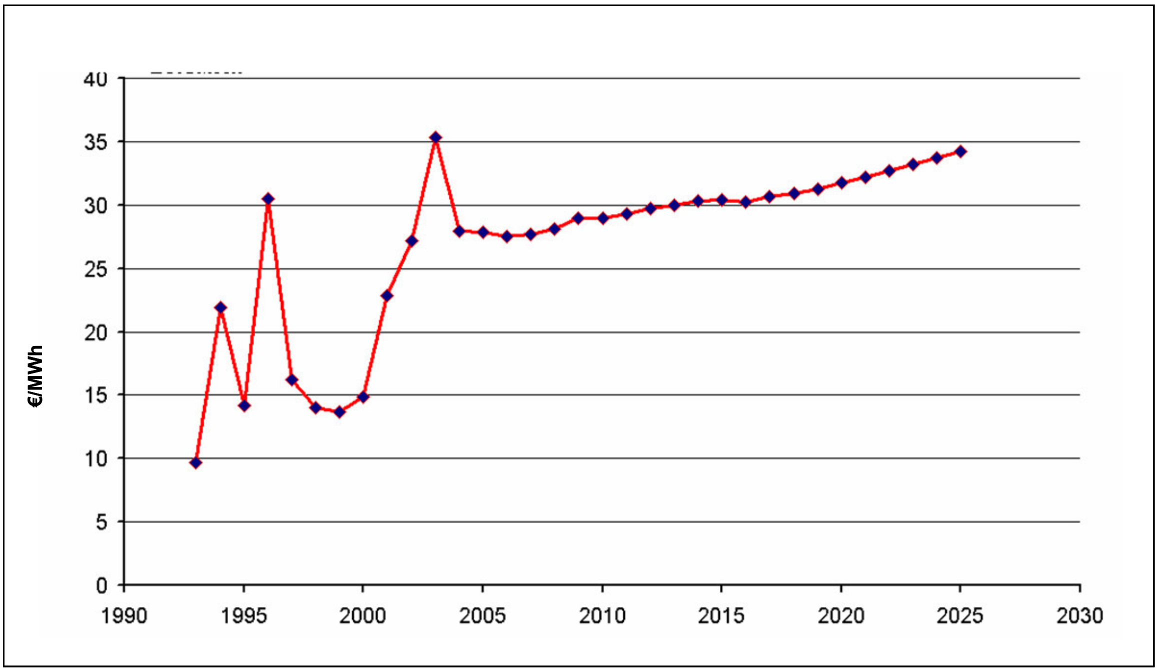
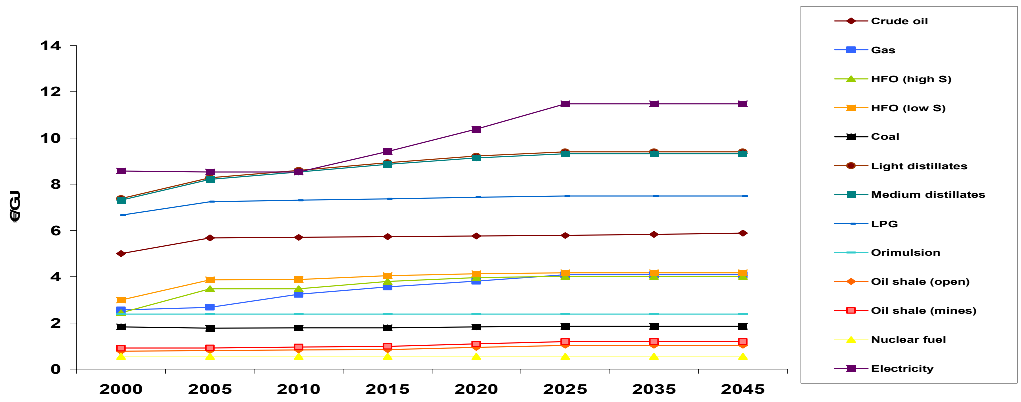


Figure 5.11. Forecast of power price in Nord Pool electricity exchange.

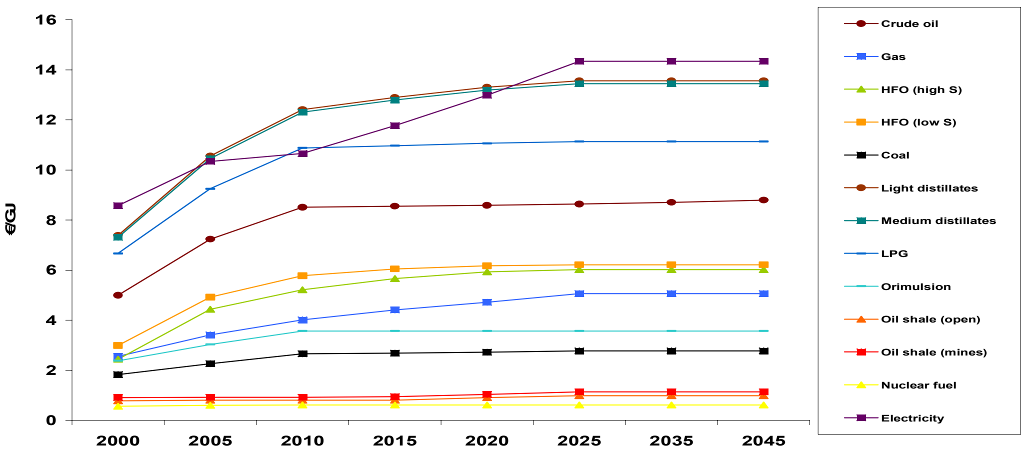
Information from different international sources and national circumstances were considered when compiling the price projections for the current modelling task. The fuel and electricity price projections used in this study are presented in *Table 5.21* and depicted in *Figure 5.12*.

Table 5.21. Price projections for selected fuels and electricity in the Baltic region (€/GJ)

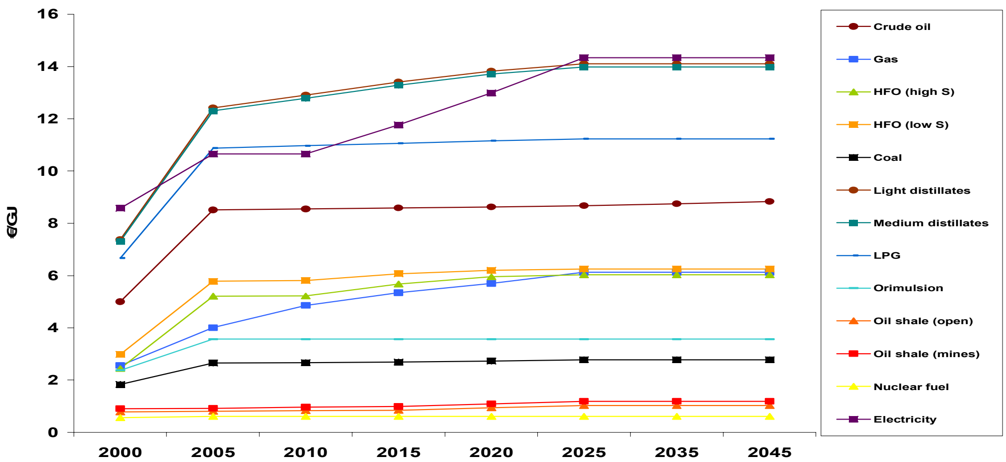
Fuel	2000	2005	2010	2015	2020	2025	2035	2045
Low fuel prices								
Crude oil	5.00	5.68	5.70	5.73	5.76	5.78	5.83	5.89
Gas	2.56	2.68	3.24	3.56	3.80	4.08	4.08	4.08
HFO (high S)	2.44	3.48	3.48	3.79	3.96	4.02	4.02	4.02
HFO (low S)	2.99	3.86	3.87	4.05	4.13	4.17	4.17	4.17
Coal	1.83	1.77	1.78	1.79	1.82	1.85	1.85	1.85
Light distillates	7.38	8.28	8.61	8.94	9.22	9.40	9.40	9.40
Medium distillates	7.31	8.21	8.53	8.86	9.14	9.32	9.32	9.32
LPG	6.67	7.25	7.31	7.37	7.44	7.49	7.49	7.49
Orimulsion	2.38	2.38	2.38	2.38	2.38	2.38	2.38	2.38
Oil shale (open)	0.78	0.80	0.83	0.85	0.94	1.03	1.03	1.03
Oil shale (mines)	0.91	0.92	0.96	0.99	1.09	1.19	1.19	1.19
Nuclear fuel	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
Electricity	8.58	8.53	8.53	9.41	10.39	11.48	11.48	11.48
High fuel prices								
Crude oil	5.00	7.24	8.51	8.56	8.59	8.64	8.71	8.80
Gas	2.56	3.41	4.01	4.41	4.71	5.06	5.06	5.06
HFO (high S)	2.44	4.43	5.21	5.67	5.93	6.02	6.02	6.02
HFO (low S)	2.99	4.92	5.78	6.05	6.17	6.22	6.22	6.22
Coal	1.83	2.26	2.66	2.68	2.72	2.77	2.77	2.77
Light distillates	7.38	10.56	12.42	12.90	13.31	13.56	13.56	13.56
Medium distillates	7.31	10.46	12.31	12.79	13.19	13.45	13.45	13.45
LPG	6.67	9.25	10.88	10.97	11.07	11.14	11.14	11.14
Orimulsion	2.38	3.03	3.57	3.57	3.57	3.57	3.57	3.57
Oil shale (open)	0.78	0.80	0.80	0.81	0.90	0.98	0.98	0.98
Oil shale (mines)	0.91	0.92	0.92	0.94	1.04	1.14	1.14	1.14
Nuclear fuel	0.56	0.60	0.61	0.61	0.61	0.61	0.61	0.61
Electricity	8.58	10.34	10.66	11.77	12.99	14.34	14.34	14.34
Extra high fuel prices								
Crude oil	5.00	8.51	8.55	8.59	8.63	8.68	8.75	8.84
Gas	2.56	4.01	4.86	5.34	5.70	6.13	6.13	6.13
HFO (high S)	2.44	5.21	5.22	5.68	5.95	6.03	6.03	6.03
HFO (low S)	2.99	5.78	5.81	6.07	6.20	6.25	6.25	6.25
Coal	1.83	2.66	2.67	2.69	2.73	2.78	2.78	2.78
Light distillates	7.38	12.42	12.91	13.41	13.83	14.10	14.10	14.10
Medium distillates	7.31	12.31	12.79	13.29	13.71	13.98	13.98	13.98
LPG	6.67	10.88	10.97	11.06	11.16	11.23	11.23	11.23
Orimulsion	2.38	3.57	3.57	3.57	3.57	3.57	3.57	3.57
Oil shale (open)	0.78	0.80	0.83	0.85	0.94	1.03	1.03	1.03
Oil shale (mines)	0.91	0.92	0.96	0.99	1.09	1.19	1.19	1.19
Nuclear fuel	0.56	0.61	0.61	0.61	0.61	0.61	0.61	0.61
Electricity	8.58	10.66	10.66	11.77	12.99	14.34	14.34	14.34



a)



b)



c)

Figure 5.12. Projections of prices for selected fuels in the Baltic region. a) Low fuel prices, b) High fuel prices, c) Extra high fuel prices.

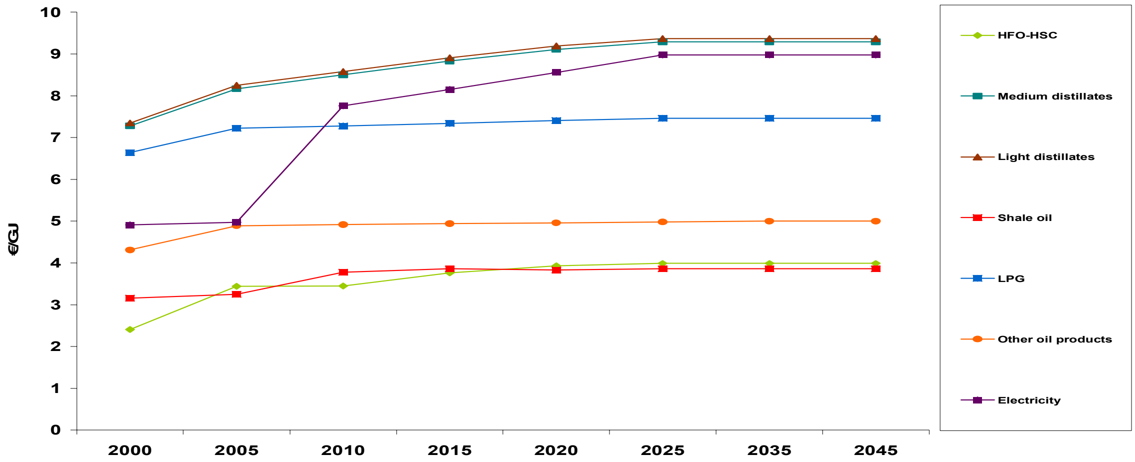
High fuel prices for imported fuels have been assumed for the study to reflect the recent price developments in world energy markets. High fuel prices, in comparison with low fuel prices, mean price increases by 27% for all imported fossil fuels and 6.3% for nuclear fuel in 2005 and, correspondingly, 50% and 7.5% increases from the low price level of 2005 in 2010. The dynamics of fuel price growth in subsequent years is the same as for low fuel prices. The 7.5% increase corresponds to a 50% increase in uranium market prices. Prices of local fuels are assumed unchanged. Prices of imported or exported electricity correspondingly increase by 21% and 25% in the case of high fuel prices.

Extra high fuel prices for imported fuels, assumed for the study, in comparison with low fuel prices represent 50% higher prices for all imported fossil fuels and 7.5% higher prices for nuclear fuel in 2005. The dynamics of fuel price growth in subsequent years is the same as for the case of low fuel prices.

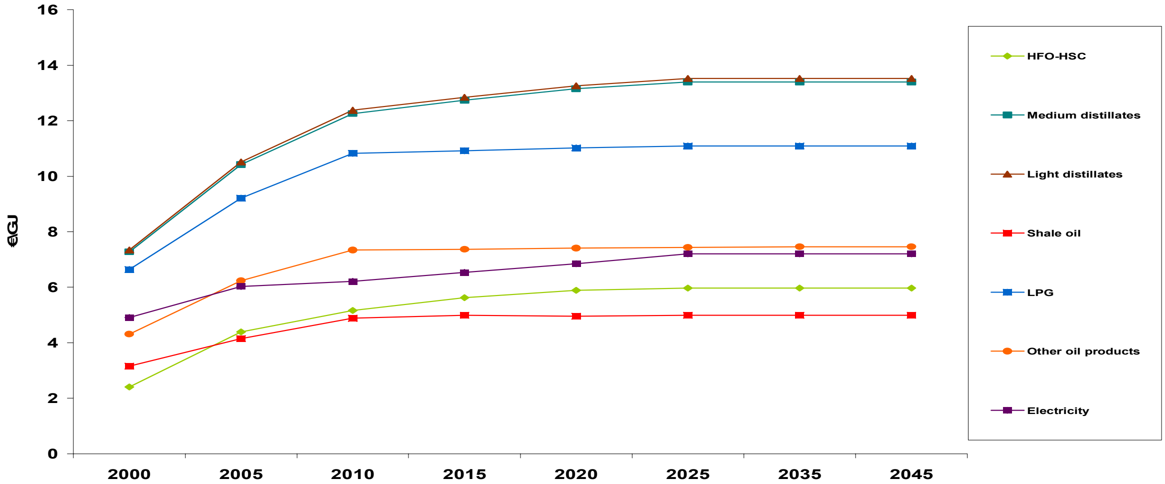
The development of export prices of fuels from the Baltic countries is given in *Table 5.22* and presented in *Figure 5.13*.

Table 5.22. Projections of prices on exported fuels and electricity in the Baltic region (€/GJ)

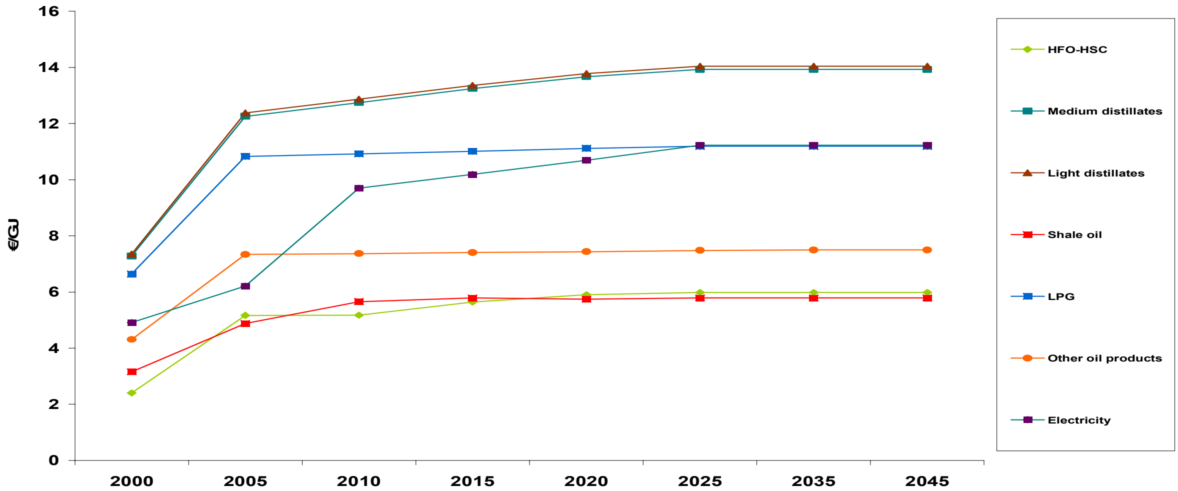
Fuel	*2000*	*2005*	*2010*	*2015*	*2020*	*2025*	*2035*	*2045*
Low fuel prices								
HFO-HSC	2.41	3.44	3.45	3.76	3.93	3.99	3.99	3.99
Medium distillates	7.28	8.17	8.50	8.83	9.11	9.29	9.29	9.29
Light distillates	7.35	8.25	8.58	8.91	9.19	9.37	9.37	9.37
Shale oil	3.16	3.25	3.78	3.86	3.83	3.86	3.86	3.86
LPG	6.64	7.22	7.28	7.34	7.41	7.46	7.46	7.46
Other oil products	4.31	4.89	4.92	4.94	4.96	4.98	5.00	5.00
Electricity	4.91	4.97	7.76	8.15	8.56	8.98	8.98	8.98
High fuel prices								
HFO-HSC	2.41	4.39	5.17	5.63	5.89	5.97	5.97	5.97
Medium distillates	7.28	10.42	12.26	12.74	13.15	13.40	13.40	13.40
Light distillates	7.35	10.52	12.38	12.85	13.26	13.52	13.52	13.52
Shale oil	3.16	4.15	4.88	4.99	4.95	4.99	4.99	4.99
LPG	6.64	9.21	10.83	10.92	11.02	11.09	11.09	11.09
Other oil products	4.31	6.24	7.34	7.37	7.41	7.44	7.46	7.46
Electricity	4.91	6.03	6.21	6.53	6.85	7.20	7.20	7.20
Extra high fuel prices								
HFO-HSC	2.41	5.17	5.18	5.64	5.90	5.98	5.98	5.98
Medium distillates	7.28	12.26	12.75	13.25	13.67	13.93	13.93	13.93
Light distillates	7.35	12.38	12.87	13.36	13.78	14.05	14.05	14.05
Shale oil	3.16	4.88	5.66	5.79	5.75	5.79	5.79	5.79
LPG	6.64	10.83	10.92	11.01	11.12	11.19	11.19	11.19
Other oil products	4.31	7.34	7.37	7.41	7.44	7.48	7.50	7.50
Electricity	4.91	6.21	9.70	10.19	10.69	11.23	11.23	11.23



a)



b)



c)

Figure 5.13. Projections of exported fuel prices in the Baltic region. a) Low fuel prices, b) High fuel prices, c) Extra high fuel prices.

6. ENERGY SUPPLY MODELLING

6.1. Structure and main features of the mathematical model used for the Baltic countries

The mathematical model 'Model for Energy Supply Strategy Alternatives and their General Environmental Impacts' (MESSAGE) can analyse the development of a country's energy system along the energy-conversion chain, including all processes, from primary energy extraction or import to the supply of final energy in different end-use sectors. The principal structures of the Estonian, Latvian and Lithuanian models are presented in *Figures 6.1* to *6.3*. The energy system models of these three countries are linked to represent a multi-regional model, which also takes into account existing and possible new links with other countries. Linking is done by modelling the exchange of various fuel and energy forms between the Baltic countries themselves and other countries. The principal structure of the multi-regional model is presented in *Figure 6.4*, while fuel and energy exchanges between the three Baltic States and other countries are shown in *Figures 6.5* and *6.6*, respectively.

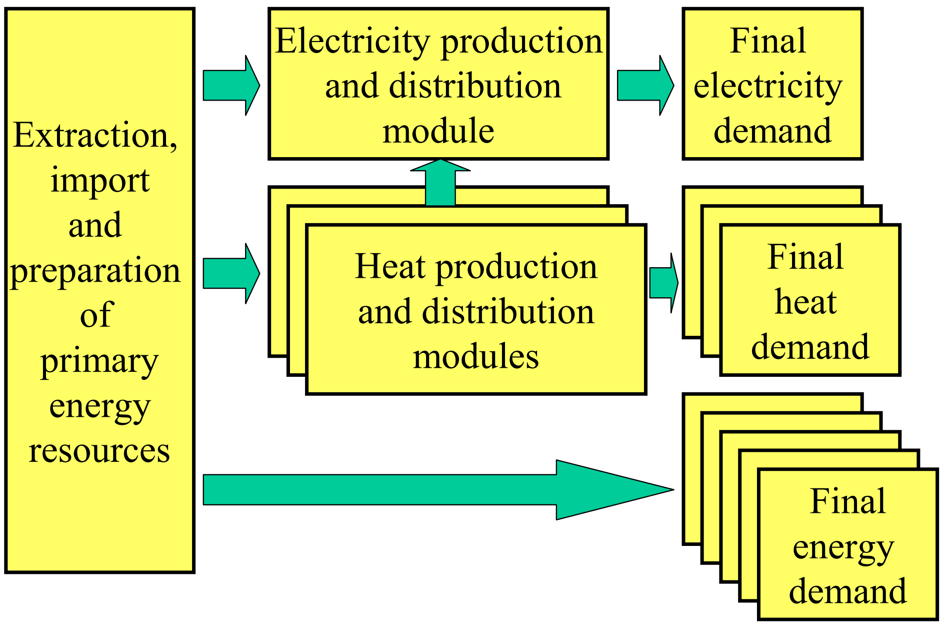


Figure 6.1. Principal structure of the Estonian energy system model.

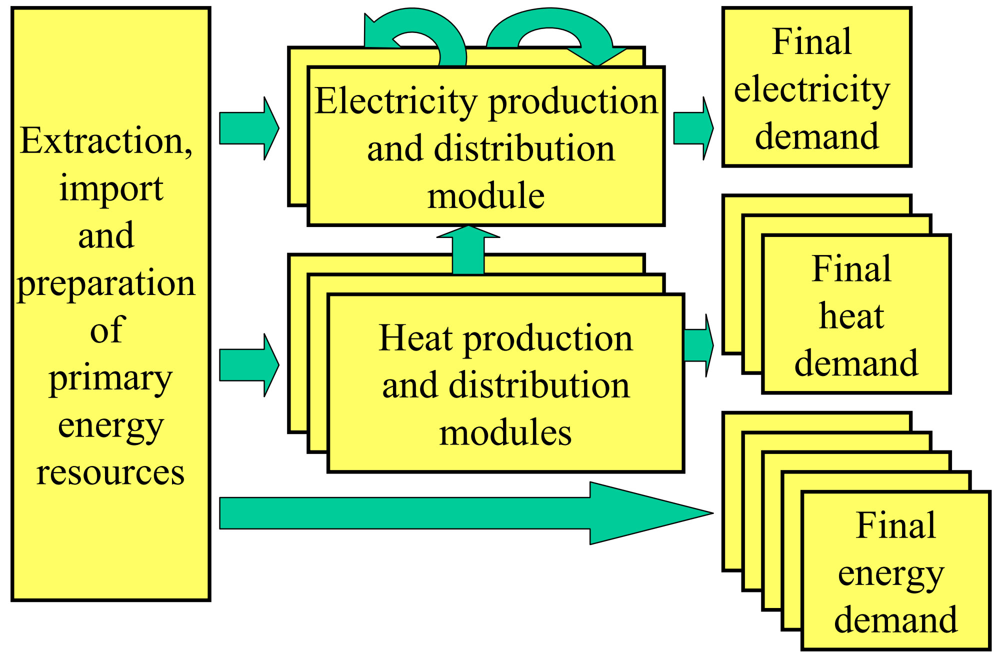


Figure 6.2. Principal structure of the Latvian energy system model.

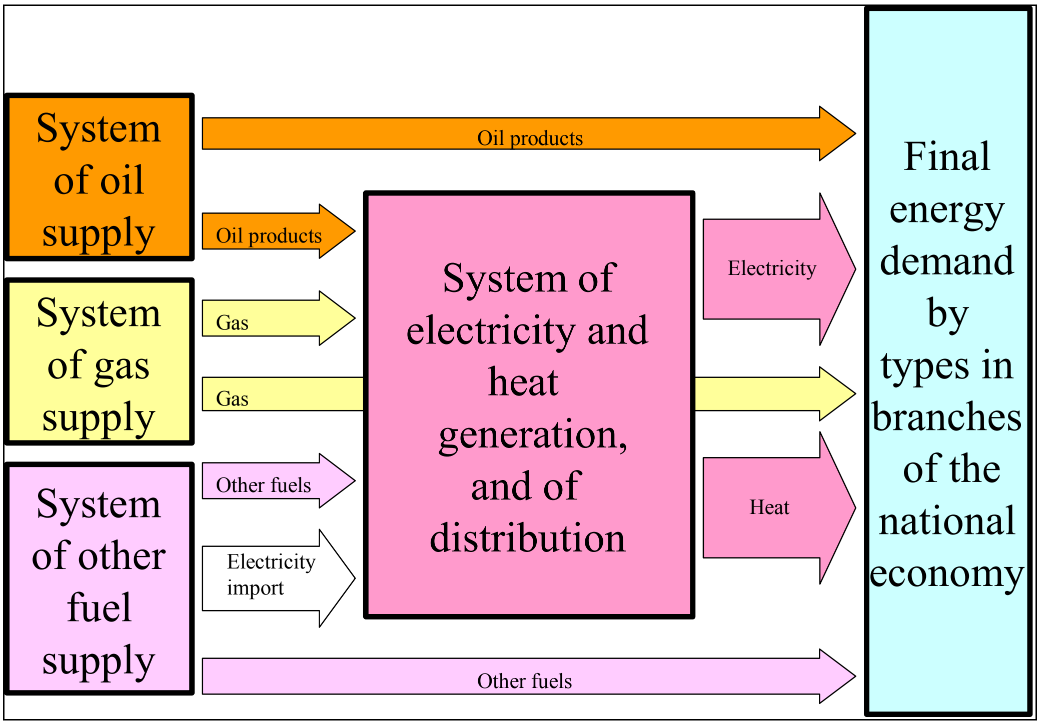


Figure 6.3. Principal structure of the Lithuanian energy system model.

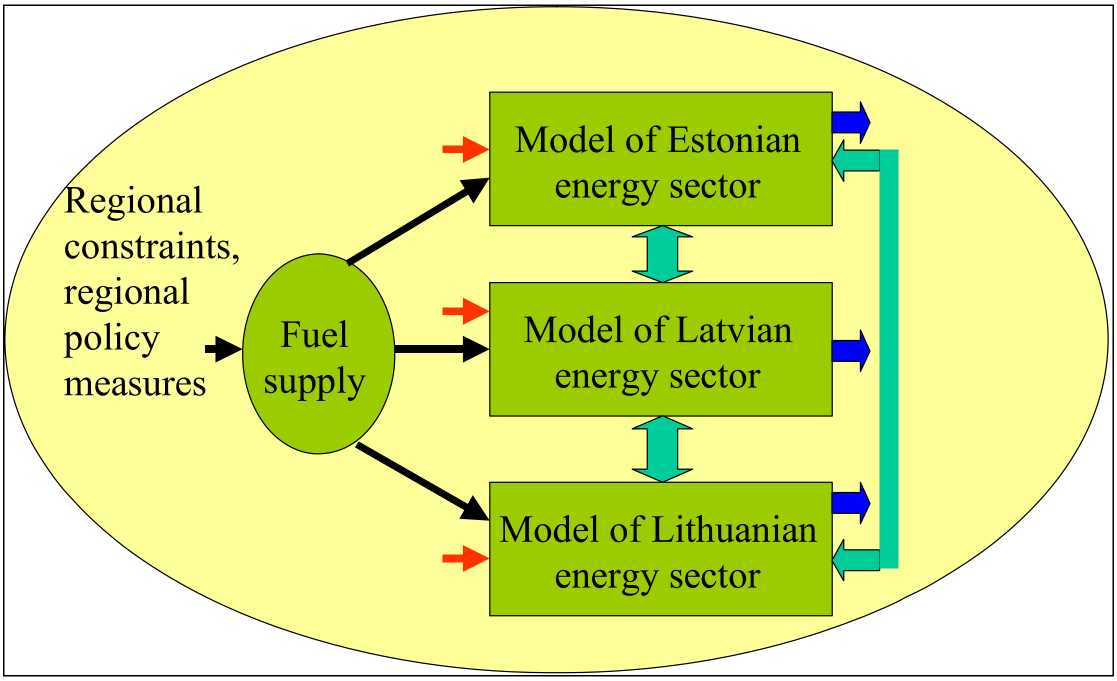


Figure 6.4. Principal structure of the multi-regional model.

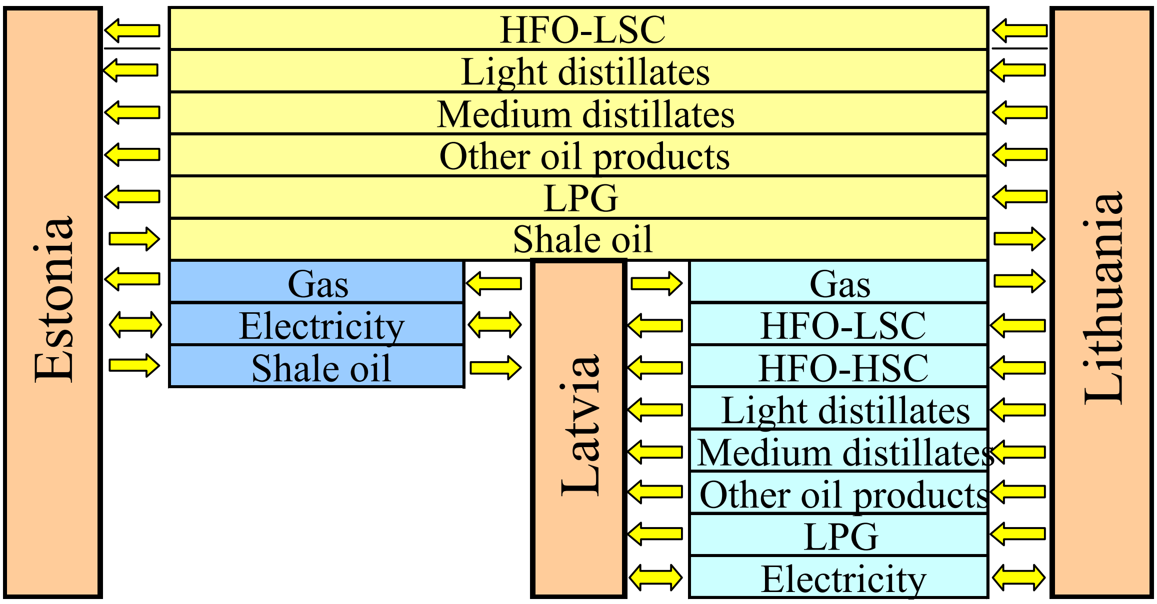


Figure 6.5. Links between Baltic countries in the multi-regional model. HFO-HSC, heavy fuel oil–high sulphur content; HFO-LSC, heavy fuel oil–low sulphur content; LPG, liquid petroleum gas.

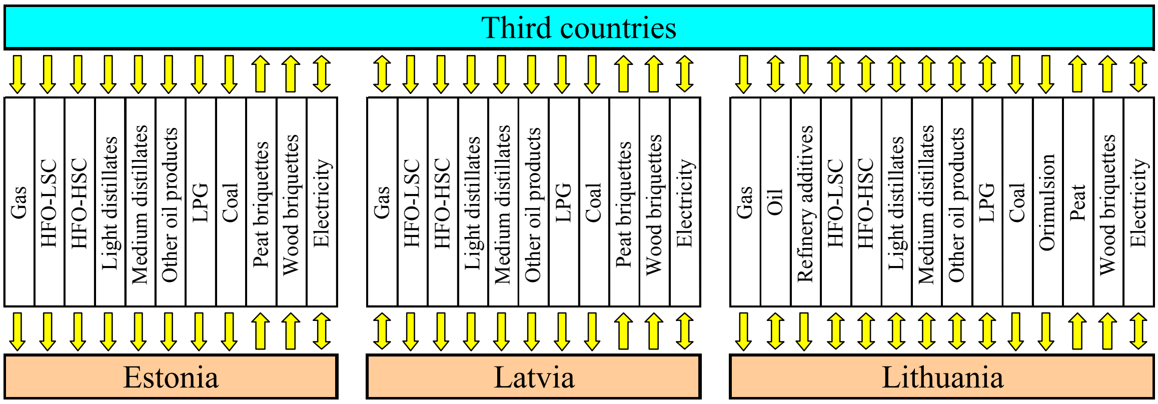


Figure 6.6. Links between Baltic and third countries in the multi-regional model.

The model is adjusted to specific country conditions to represent correctly the peculiarities of the energy systems in each country, especially those that are important for energy supply reliability and security:

- Resources of oil shale in Estonia, their extraction and conversion into other energy forms, as well as two large power plants (PPs) that run on local fuel;
- A cascade of hydropower plants (HPPs) in Latvia, underground gas storage and a large oil terminal;
- Two large terminals for oil and oil products in Lithuania, a refinery, a nuclear power plant (NPP) and the possibility of building a new one, a hydro pumped storage power plant (HPSPP) and the Lithuanian thermal power plant (TPP) that can use three types of fuel.

The mathematical model MESSAGE can be characterised by the following properties:

- It is an energy supply model that represents the energy conversion and utilisation processes of the energy system, as well as the environmental impacts for an exogenously given demand of final energy.
- It is an optimisation model that, from a set of existing and possible new technologies, selects the optimum mix (in terms of total system cost) to cover a given demand in each country for various energy forms during a selected study period.
- The mathematical method used in the model is linear programming.
- A techno-economic or engineering approach is applied. This means that the model represents the energy system by its technological structure, and aims to optimise this structure.
- It allows the development of energy strategies up to 2025, but the analysed period is up to 2045. The time horizon is limited by the technological orientation of the approach, because of the uncertainties associated with future technological development. The energy system dynamics is modelled by a multi-period approach. Milestone years for the time period are 2000, 2002, 2004, 2005, 2008, 2010, 2015, 2020, 2025, 2035, and 2045.
- It takes into account demand variations of electricity, heat and gas during days, weeks and seasons, as well as different technological and political constraints of energy supply.
- It is an energy and environmental model that enables an integrated analysis of the energy sector development and its environmental impacts.

Representation of each country's energy system in the model is based on a network concept (see *Figure 6.7*). The activities and relationships of an energy system are described as an oriented graph. This depicts the energy chain starting from the extraction or supply of primary energy, and passing through several energy conversion processes (e.g., electricity generation, transmission and distribution) to satisfy the demand for final energy in the industrial, household, transport and other economic branches. Using the notation of an oriented graph, the links of the graph represent technologies or transportation and the allocation process of energy, while the nodes represent energy forms (like electricity, oil and gas).

Each sub-system of the model contains a set of alternative technologies, both existing ones and innovations. The technologies are represented and aggregated in the model, so that the actual technological energy supply structure of the country is represented in a reasonable way. Decision variables in the model formulation are the energy flows and equipment capacities of several technologies in different time periods. They are linked by capacity-flow constraints. The model variables are subject to a system of constraints that represent the structural and technological properties of the energy system, existing stock of equipment, projected final energy demand, energy policy, restrictions, impact of the energy technologies on air pollution, emission control technologies and emission control policy restrictions.

The technologies are represented by a set of parameters in the model database, which are transformed into the model's system of equations by a matrix generator programme. Such parameters are, for example, the prices of primary energy carriers, investment, fixed and variable costs of various technologies, energy conversion efficiencies, existing capacities, availability factors, emission factors and others.

The inclusion of environmental emissions in the model is described as follows:

- Air pollution is modelled proportionally to the energy flows of each energy conversion process or fuel, respectively expressed by an emission factor or pollutant concentration in flue gases. For SO_2, emissions into the atmosphere depend on fuels used in the combustion process, while the formation of NO_x emissions depends additionally on the technology used.
- For each energy conversion technology, a set of alternative emission control technologies is provided in the model, where applicable. Diversion of energy flows in the energy conversion process through environmental technologies results in a reduction of emissions. (Methodologically, this is achieved by assigning either negative or very low emission factors to the emission control technologies to express the technology-specific removal efficiency.)
- Cost and investment, existing capacities, availability, energy consumption and other characteristics of the emission control technologies are described by a set of parameters, as in the case of energy conversion technologies.
- Emission control policies or targets are modelled by putting upper limits on either the emission flows or on emission concentrations in flue gases.
- Taxes are applied for CO_2, SO_2, NO_x and dust to analyse their impact on emission levels caused by the induced changes in the energy sector.

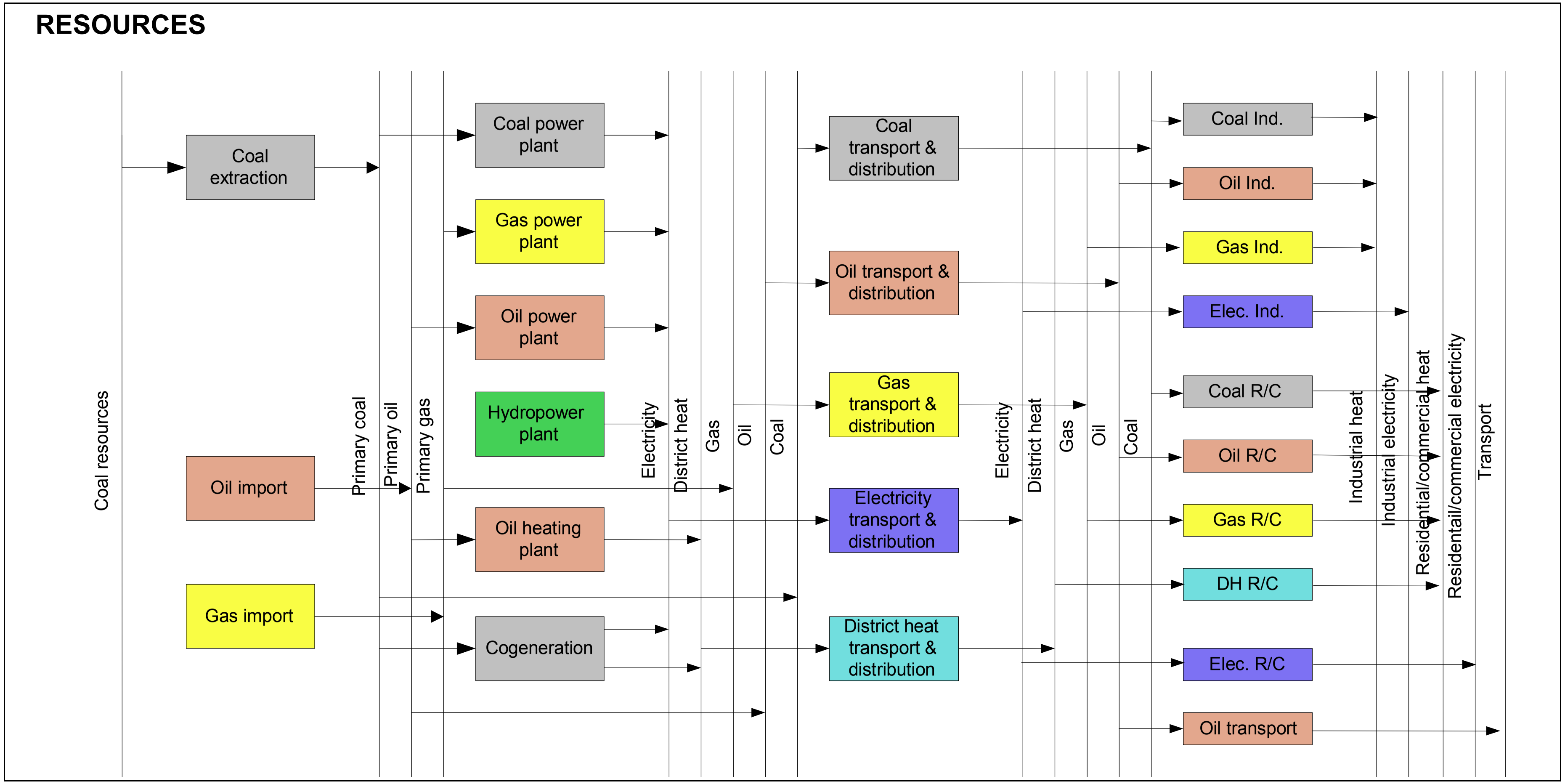


Figure 6.7. General structure of a country's energy system (Ind, industry; R/C, residential/commercial).

The model is applied by defining scenarios described in Chapter 7. Scenarios represent different hypotheses on important parameters, such as future fuel prices in the international market, market penetration of new technologies, market penetration of local and renewable energy source (RESs) and political decisions on the development of one or another type of technology, etc., to take into account uncertainties in the future.

By analysing the results, 'what if?' statements on the future energy supply structure can be made, and different strategies for the utilisation of various primary energy sources can be compared with respect to their emission reduction efficiencies and their impact on the structure and economy of the energy system.

6.2. Estonian energy system model

During the modelling of energy supply the greatest attention was paid to the following questions.

- Analyse the compatibility of power generation based on oil shale, particularly:
- Scheduling of the reconstruction of existing oil shale power plants;
- Influence of greenhouse gas taxes on competitiveness of oil shale power generation;
- Influence of Estonian–Finnish power link on Estonian oil shale power sector.
- Analyse alternatives to power generation based on oil shale, including:
- Future options in existing power and combined heat and power (CHP) plants using natural gas and other fuels;
- Options for new fossil fuel power plants;
- Options for increasing the share of renewable electricity according to European Union (EU) requirements.
- Comparison of energy prices and other parameters of the energy sector of Estonia for national and corresponding regional scenarios.
- Fuel supply, particularly:
- Sufficiency of oil shale resources and need to open new mines;
- Shale oil production using existing and new technologies;
- Dependency of fuel import (natural gas, oil products, coal) and export/import balance.

Attention was paid mainly to the district heating sector because changes in cogeneration plant capacities will influence this sector and the need for district heating boiler loads and capacity. Accordingly, Estonia was divided into three heating regions depending on CHP and fuel options.

6.2.1. Options for future energy supply systems and their characteristics

Reconstruction of Estonia's oil shale power plants has started already. The main objective is to avoid SO_2 emissions from boilers with pulverised combustion technology and to increase the efficiency of power units.

Some parameters of new power units considered as candidates in the study are given in *Table 6.1*. For oil shale combustion only one technology option was taken into account — combustion in a circulating fluidised bed (CFBC). The most advanced and promising technology, pressurised fluidised bed technology, is not yet ready for implementation as industrial large-scale units.

Both proposed new oil shale units (215 MW_{el} CHP unit for Balti PP and a condensing mode unit for Eesti PP) have the same type of CFBC boiler and reconstructed turbine. As the existing infrastructure of the plants can be used, investment costs should stay at a moderate level. As a change of turbine might be obligatory during the reconstruction of other units in Eesti PP, the investment cost includes the cost of a new turbine.

Table 6.1. Options for new electricity generation units

Fuel, energy source	*Identification of the technology*	*First year*	*Plant life/ construc-tion time (years)*	*Invest-ment cost (€/kW)*	*Comments*
Oil shale	New boiler for 215 MW_{el} CHP unit in Balti PP (CFBC technology)	2005	30/3	574	Only one unit should be built (2005), efficiency in CHP mode 31.5%
	New boiler for 215 MW_{el} condensing mode units in Eesti PP (CFBC technology)	2004	30/3	658	Efficiency 35.8%, one unit operated since 2004
Coal	CHP unit in Tallinn DH region	2012	30/4	1278	Efficiency 38%
Natural gas	CCGT unit	2010	25/3	543	Efficiency 51.4%
	New CHP units in Tallinn DH region	2008	35/3	895	Replacement of gas fired boilers
	Gas turbine CHP units	2005	25/2	480	Up to 70 MW
	Modular CHP units	2005	15/1	500	Up to 5 MW per year
HFO, natural gas	New CHP units in Tallinn DH region	2008	35/2	862	Up to 70 MW
Wood, straw	CHP units using biofuels	2005	30/2	1600	Up to 5 MW per year
Wood, peat	New CHP unit on biofuels and peat in Ahtme PP	2008	35/2	1726	Efficiency in CHP mode 18.1%
Wind energy	Wind generators	2000	30/1	1200	Upper capacity limit — 300 MW, in 2000 — 0.4 MW
Hydro energy	Mini hydropower plants	2000	30/2	1118	Upper capacity limit — 15 MW, installed in 2000 — 3.89 MW

Notes: For CHP units, the given efficiency is for electrical efficiency and the given capacity is for electrical capacity. CCGT, combined cycle gas turbine technology; CHP, combined heat and power; DH, district heating; HFO, heavy fuel.

NPPs were not taken into account in Estonia. If nuclear energy is to be a future energy supply option in the Baltic region, a new NPP might be located in the area of already existing infrastructure (Lithuania).

6.2.2. Modelling of energy supply systems

6.2.2.1. Extraction, import, preparation and export of primary energy resources

Oil shale as the most important energy source has been extracted from open pits and underground mines (see *Table 6.2*). The major part of extracted oil shale has been used in power plants and for shale oil production. A minor part of oil shale might also be used in local boilers and for non-energy purposes in the cement industry.

Table 6.2. Available oil shale resources in 2000

Name of mine	*Million tonnes*	PJ
Resources in closed underground mines (Ahtme, Kohtla, Sompa)	38.30	307.20
Resources in existing open pits (Aidu, Narva, Sirgala)	188.32	1506.56
Resources in existing underground mines (Estonia, Viru)	333.69	2669.52
Additional available resources	676.19	5409.52

Peat is also an important domestic fuel source and its available resources are shown in *Table 6.3*. Peat is produced as milled peat or sod peat. Sod peat could be used as a fuel in different boilers and stoves. Milled peat could be used as a fuel for medium- and large-scale boilers and for fuel conversion (i.e., for peat briquette production).

Table 6.3. Available peat resources in 2000

Location of the resources	*Million tonnes*	*PJ*
At peat briquette factories	337.16	3024
In other locations	1049.30	8385
Total	1386.46	11409

Coal is an imported fuel. Nowadays coal consumption is rather limited, but it might be used as a fuel in large-scale power units near seaports. As the capacity of Estonian ports has practically no limits to coal imports, coal might be an alternative to replace oil shale in the future. Just now some of Russia's coal exports are transported through Estonia (i.e., coal comes from Russia on railways and is shipped out of Estonian ports).

Natural gas is imported only from Russia. The estimated upper limit for gas imports depends on the gas pipeline capacity, which is estimated to be about 50.5 PJ per year. As the main share of natural gas imports comes through Latvia, limitation on the gas imports to Latvia will have an effect on Estonia and the whole Baltic region.

Estonia has no oil resources (shale oil is not a primary fuel) or oil refinery and, accordingly, all *transport fuels* and some types of *boiler fuel oils* are imported. Liquid fuels (fuel oils) and liquefied gas can be imported from Lithuania or from third countries (including Russia).

6.2.2.2. *Electricity generation*

The major share of electricity is generated in power plants of Eesti Energia (see *Table 6.4*). The oil shale power plants of Eesti Energia will not be fully reconstructed until 2016.

Table 6.4. Heat and/or power generation units in power plants of Eesti Energia

Name of plant and unit ID	*Number of units*	*Unit capacities in CHP mode*		*Unit capacity in condensing mode*	*Notes*
		MW_{th}	MW_{el}	MW_{el}	
Eesti Power Plant					
Units 1–7, pulverised combustion technology	7	–	–	200	Should be out of operation or replaced by CFBC units before 2016
Unit 8, CFBC technology	1	–	–	215	New unit, installed in 2004
Balti Power Plant					
Units 1–2, pulverised combustion technology	2	–	–	100	Should be out of operation after 2006
Units 3–4, pulverised combustion technology	2	280	200	100	CHP, out of operation after starting operation of one reconstructed CHP unit (Unit 11 in this table) on CFBC technology
Units 9–10, 12, pulverised combustion technology	3	-	-	200	Should be out of operation after 2015, except unit 12 with de-SO_x equipment
Unit 11, CFBC technology	1	160	215	215	CHP, started permanent operation in 2005
Reserve hot water boilers	1	250	–	–	Gas-fired boiler for heating, reserve
Iru PP					
Unit 1	1	110	90	90	CHP
Unit 2	1	203	120	120	CHP
Units 3–5	3	348	–	–	Hot water boilers
Other power plants					
Kohtla-Järve PP	1	301	39	39	
Ahtme PP	1	102	28	28	Could be reconstructed from oil shale based CHP unit into renewable- and peat-fired CHP unit

In Eesti PP one old pulverised technology boiler is already replaced and the unit reconstructed according to environmental and EU requirements. Other units should be reconstructed using the same or better technology, in terms of efficiency and environmental performance, or shut down before the year 2016. Accordingly, up to eight units might be operated at Eesti PP after reconstruction. There are no upper limits on the implementation of the proposed new oil shale combustion technology, which means that additional units might also be built at Balti PP (or even in other locations). However, the construction of new units was not examined in this study because there is no available information about such units.

Balti PP has to be operated in CHP mode to provide heat to Narva city (in the model to the Viru heating region). In addition to the already installed new 215 MW_{el} CHP unit, peak-load heating boilers should be installed as well. Other old units in Balti PP should be shut down before 2016 (old 100 MW_{el} units before 2006). If necessary, space occupied by old units might be used to build additional power units with CFBC boilers, as in the Eesti PP.

The Kohtla-Järve and Ahtme power plants should be fully reconstructed or shut down. Kohtla-Järve PP should be reconstructed into a heating boiler house or should be replaced by a medium-size CHP plant (type is not specified in the model). Ahtme PP could be reconstructed into a CHP plant that uses renewable fuels and peat. However, this reconstruction cannot be done before 2008. Of course, reconstructed or replaced Kohtla-Järve and Ahtme plants should provide heat to the Viru heating region.

6.2.2.3. Heat generation

Heat-generation options are tightly connected to local conditions. Accordingly, oil shale as a fuel should be used only near oil shale mines in the northeast (Viru) region. Tallinn, as a large city, has also specific heat-supply conditions. Therefore, it was reasonable to simulate heat-generation options by regions:

- Viru region as an oil shale mining region. In this region oil shale might be used as a fuel for CHP plants and large-scale boiler houses;
- Tallinn region — options for heating Tallinn consist of existing and new natural gas-fired boiler houses and CHP plants, a new coal-fired CHP plant and other technologies based mainly on fossil fuels;
- Other Estonia — this includes rural settlements and smaller cities, excluding cities within the Viru region.

The major share of heat in the *Viru region* (for larger cities) is generated in CHP units based on oil shale (i.e., in the Balti, Kohtla-Järve and Ahtme PPs). Sillamae City is also heated using large industrial steam boilers that use oil shale. As the share of small boilers that use other fuels in the Viru region is small and data very limited, all boilers in the region are modelled as a single virtual multi-fuel boiler. Total heating demand should be covered by this virtual boiler and new or reconstructed CHP units in the region (including the new Ahtme CHP unit based on biofuels and peat).

Heat for the *Tallinn region* is supplied by Iru CHP and by large heating boiler houses. The main fuel in Tallinn's plants is natural gas and reserve fuels are shale oil and HFOs. New alternative heat-supply options in the regions are:

- CHP units that replace heat-only boilers (HOBs) in large boiler houses and CHP units in new sites — the main fuel is natural gas, and fuel oils can be an alternative fuel;
- Coal-fired CHP plant.

Old medium-size district heating boilers might be replaced by new ones with higher efficiency.

The *Other Estonia* heating region is a virtual region that includes all large cities (excluding Tallinn), large cities in the Viru (oil shale) region, and rural settlements and small cities within district heating networks, independent of their location.

6.2.2.4. Transmission, distribution and demand of heat and electricity

Most electricity generation plants are connected to the high voltage electricity lines and only a few small- and medium-size plants are connected to the medium voltage lines. Consumers are connected using all type of electricity lines (see *Table 6.5*).

Most new power plants should be connected to the existing power grid — exceptions might be new wind power plants on islands. To connect new wind generators to the grid it might be necessary to build additional high voltage or medium voltage lines. The necessity for additional connection lines to new wind generators depends on their total installed capacity.

Table 6.5. Connection of consumers to the electricity grid

Electricity line	*Share of electricity demand from the type of line (%)*
High voltage lines	7 (eligible consumers)
Medium voltage lines	36
Low voltage (distribution) lines	57

Estonia is divided into three district heating regions and, correspondingly, there are also three virtual district heating networks. Heat losses in the network pipelines have been taken from official statistics (i.e., the share of losses was taken to be the same in all regions and networks). Technical conditions of network pipelines can be improved and, correspondingly, heat losses can be reduced. So, the model can include the reconstruction of a district heating network. Heat losses in the reconstructed district heating network were taken as 8% of heat consumption.

6.2.2.5. Modelling of energy demand

The demand forecast is described in Section 4.1.2. Both electricity and heat demands in all the heating regions have load regions. Load regions for electricity have been modelled similarly for all three countries (see Section 6.5) in tight conformity with the real electricity load curve. Variations of heating demand were assumed according to the typical distribution of outdoor temperatures. Technological heat demand and heat demand for the preparation of hot tap water are modelled to be distributed evenly during the year.

The share of fuels for energy purposes, transport and non-energy use are given in *Table 6.6*). The distribution of fuel shares was taken to be as in 2002 and was assumed unchanged during the whole modelling period.

Table 6.6. Shares of fuel demand in consumer sectors

Fuel	*Shares of fuel demand in consumer sectors (%)*
Demand of transport fuels	
Medium distillates (diesel oil)	49.445
Light distillates (gasoline)	50.555
Final demand of fuels (non-transport) for energy purpose	
Heavy fuel oil	8.060
Oil shale	5.931
Medium distillates (light fuel oil)	25.151
Natural gas	13.405
Liquid petroleum gas (LPG)	0.916
Wood (logs)	37.994
Wood waste	10.166
Sod peat	0.454
Peat briquettes	1.043
Coal	4.134
Demand of fuels for non-energy purposes	
Natural gas	42.4
Oil shale	57.6

6.3. Latvian energy system model

6.3.1. Options for future supply system and their characteristics

6.3.1.1. System of electricity supply

Riga CHP-1 reconstruction project. Riga CHP-1 was built between 1955 and 1960s and during its long term operation it was, and continues to be, one of the main heat sources in the city. The location of the plant in the city of Riga is convenient because the heat- and power-generating capacities are close to the main consumer loads and the plant site contains an elaborate infrastructure of engineering communications. Therefore, a new combined cycle (CCGT) CHP plant and new HOBs were planned for the available free area of the plant. The investment decision was supported by several pre-feasibility and feasibility studies [43-46]. The engineering, procurement and construction (EPC) turnkey contract to implement this project was placed with the Siemens industrial gas turbine business in Sweden, 'Demag Delaval Industrial Turbomachinery AB' (earlier ALSTOM Power Sweden AB) on 30 June 2003. Commissioning of the power plant was scheduled for 31 October 2005. By that time all the existing CHP units and HOBs were supposed to be decommissioned (*Table 6.7*).

Table 6.7. Riga CHP-1 before and after reconstruction

Indicators	*Units*	*Before reconstruction*	*After reconstruction*
Total electricity capacity	MW	129.5*	144
Total heat capacity, including: *CHP units* *HOBs*	MW MW MW	616 383 233	374 150 224
Power-to-heat ratio	MW_{el}/MW_{th}	0.34	0.96
Main equipment: *Steam boilers or HRSGs†* *Steam turbines* *Gas turbines* *HOBs*	 *Pieces*	 *6* *4* – *2*	 *2* *2* *2* *2*
Fuel	–	Natural gas, heavy fuel oil, peat	Natural gas, diesel fuel‡
Efficiency of fuel utilisation	%	74.8	87.7
Investments (for CHP)	€/kW_{el}	–	695
Electricity generation, gross	TWh	0.24	1.08
Heat production	TWh	0.74	1.12

*To date, the second CHP unit (27.5 MW_{el}) is out of operation.
†HRSG, heat recovery steam generator.
‡Emergency fuel for HOBs.

The capacity of the new CCGT CHP units was chosen in accordance with summer heating loads, which is why it will operate solely in cogeneration mode. The new CCGT plant will supply district heating to the right-bank heating networks of Riga. The main components of the CCGT plant are two natural gas fired (single fuel) 43 MW GTX-100 gas turbines equipped with dry, low NO_x combustion systems, two heat-recovery steam generators with supplementary gas firing and one 54 MW back pressure district heating steam turbine. In addition, two new HOBs (KVGM-100, produced in Russia), burning natural gas and diesel fuel with a total heat capacity of 232 MW_{th}, will also be installed. The total estimated investment for the EPC project is approximately €107 million, including €100 million for CCGT CHP plants and €7 million for new HOBs.

The rehabilitation of Riga CHP-1 allows the concentration and emission of harmful substances in the atmosphere to be reduced significantly in comparison to the present situation (approximately by half). Emission of sulphur oxide, vanadium oxide and solid particles are prevented completely, and the NO_x emission is significantly lower than the approved normative for Riga CHP-1. This alternative was introduced into the mathematical model as a fixed option and was not subject to optimisation.

Riga CHP-2 reconstruction project. Reconstruction of Riga CHP-2 envisages the gradual replacement of existing heat and power units by new gas-fired combined cycle CHP blocks. In the longer term, the plan is to install two new CCGT CHP units in the construction-free area of the site. The installed power capacity of each unit in the condensing mode would be approximately 403 MW, while in the cogeneration mode it would be 350 MW and a heat capacity of 270 MW (*Table 6.8*). The average efficiency of the new units would be 87.2% in cogeneration mode and 57.2% in condensing mode. It is planned that the main fuel for the gas turbines would be natural gas, with diesel fuel used as a back-up. Additionally, the project envisages the replacement of existing HFO facilities by diesel fuel facilities and the modernisation of existing HOBs. The project may also include the dismantling of existing facilities, which would be unusable after reconstruction. However, the possibilities for alternative uses of these facilities are also analysed. It is planned that during the winter heating season the new units will operate in cogeneration mode, while in the summer they will basically produce electricity in condensing mode. The reconstructed Riga CHP-2 may be used not only for the local Latvian market, but also for exports from Latvia.

Table 6.8. Riga CHP-2 before and after reconstruction

Indicators	*Units*	*Before reconstruction*	*After reconstruction*
Total electricity capacity	MW	390*	700 (806)
Total heat capacity, including:	MW	1237	1005
CHP units	*MW*	772	*540*
HOBs	*MW*	465	*465*
Power to heat ratio	MW_{el}/MW_{th}	0.50	1.30
Main equipment:			
Steam boilers or HRSGs	*Pieces*	*4*	*2*
Steam turbines	*Pieces*	*4*	*2*
Gas turbines	*Pieces*	–	*2*
HOBs	*Pieces*	*4*	*4*
Fuel		Natural gas, heavy fuel oil	Natural gas, diesel fuel
Fuel utilisation coefficient	%	80.2	87.2 (57.2)
Investments (for CHP)	€/kW_{el}	–	400–450
Electricity generation gross	TWh	0.92	5.00
Heat production	TWh	1.82	1.90

*To date, the first CHP unit (60 MW_{el}) is out of operation.

Preliminary plans envisage commission of the first new CCGT CHP unit in 2008–2009, while the second unit will be installed in 2011–2015. A new coal CHP plant in Liepaja, with a power capacity of 200–400 MW, is considered to be an alternative to the construction of the second unit.

The estimated investment for the EPC turnkey project for each unit is approximately €160–170 million. The project was justified by a number of pre-feasibility and feasibility studies [47-50]. Modernisation of Riga CHP-2 was introduced into the mathematical model as an alternative to free optimisation.

Coal power plant project in the west coast of Latvia. Many ongoing and planned power plant projects in the Baltic States are based on the use of natural gas. It was decided to consider an alternative option — the construction of a coal power plant in the west part of Latvia. There are two possible locations for the prospective power plant, the port cities Liepaja and Ventspils. Among the technologies the following are considered:

- Pulverised coal power plant on supercritical or ultra supercritical parameters (PCC);
- Atmospheric CFBC technology.

The gross power capacity of the condensing coal power plant could be around 430 MW, with an electricity self-consumption of 7–8%. The efficiency of the power plant operating in condensing mode could be 44–45%, and in cogeneration mode 55–60%. According to conditions of the district heating system in Liepaja, the heat output of the power plant could be approximately 50–60 MW, while in Ventspils it could be 40–50 MW.

The plant will be designed to burn bituminous coal imported from a diversity of worldwide sources to prevent dependence on a single supplier. Candidate sources could include:

- Russia and Ukraine, to be supplied by railway transport;
- Poland, China, Australia, USA and South Africa, to be supplied by sea transport.

CFBC technology allows the use of domestic fuels, such as peat, biomass and wastes.

The possible commissioning dates for the new power plant are betwen 2010 and 2015. It is planned that the project could be implemented on an EPC Turnkey basis. The total capital cost of a 400 MW (net capacity) unit could be around €460–520 million [51–56].

Other power plant projects. In addition to the refurbishment of existing power plants, described above, the following new technologies could be considered as candidates for Latvia:

- New combined cycle cogeneration plants: 65 MW (e.g., based on the DDIT GTX-100 gas turbine) or 125 MW (e.g., based on the General Electric MS6001FB gas turbine), with potential locations at Daugavpils and Liepaja.
- New condensing combined cycle power plants: 125 MW (e.g., based on the General Electric MS6001FB gas turbine), 190 MW (e.g., based on the General Electric MS9001E gas turbine) or 400 MW (e.g., based on the Siemens V94.3A gas turbine), with potential locations at Dobele or Broceni.
- New CFBC cogeneration units (5–20 MW), burning peat, coal or biomass, with potential locations at Ventspils (coal, 20 MW), Valmiera (peat, 10 MW) and Seda (peat, 5 MW).
- New gas engine cogeneration plants with capacities from 150 kW to 10 MW and potential locations mainly in small cities.
- New gas turbine and heat recovery boiler cogeneration plants for some industries.
- New microturbine distributed generation CHP plants.
- New fuel cell CHP plants.
- New waste incineration CHP plant (there is one project to burn municipal wastes in Riga CHP-2), with an electricity capacity from 7 to 10 MW.
- New integrated gasification combined cycle power plants. Projects to construct such power plants in a CHP configuration, burning petcoke in the cities of Liepaja and Ventspils, have been considered.
- New wind farms and/or generators (in the western part of the Baltic States).
- New small HPPs.
- New nuclear CHP plant in Riga (a very unlikely option, but could be considered).

- Construction of a pump station at Plavinas HPP to convert HPP into a hydro pump storage plant.

Most of these options were considered in the analysis.

6.3.1.2. Coal terminal

Recently, the Joint Stock Company (JSC) 'Baltic coal terminal' was created to implement a project to construct a coal terminal in the port city of Ventspils. The terminal will serve mainly as a transit coal hub to supply Russian and Ukrainian bituminous coal to western Europe. This will be a dedicated terminal to handle, sort and store coal with an annual throughput capacity of 5 million tons. Berth 26 is scheduled to be completed in 2 years. Main indicators are presented in *Table 6.9*.

Table 6.9. Key characteristics of Baltic coal terminal

Parameters	*Values*
Throughput capacity	5 million tons per year
Deep-water berth 26	Depth 16.2 m, length 350 m
Vessel types to be handled	PanaMax (DWT 75\`000) and Cape Size (DWT 120\`000) vessels
Operational area	Approximately 12 ha
Capacity of storage capacity	350 000 tons
Loading out of rail cars	15 000 tons daily
Loading into vessels	30 000 tons daily
Sorting	15 000 tons daily

The approximate cost of the new coal terminal and deepening the harbour could be €50–60 million. The coal terminal was modelled together with a new coal power plant.

6.3.1.3. Development of underground gas storage facilities

There are unique geological conditions that enable the creation of a system of natural underground gas storage facilities in Latvia, with an active volume of up to 50 billion m^3 (*Table 6.10*). Latvia could become a major seasonal regulator of natural gas for the western region of Russia and for Baltic Sea countries [57].

Table 6.10. Potential underground gas storage development in Latvia

Name	*Area (km^2)*	*Volume (billion m^3)*
Snepele	75	17.5
Aizpute	95	16.0
Dobele	47	10.0
Z-Bildene	47	9.0
Lici	65	2.5
Liepaja	39	2.5
Degole	46	3.5
Liga	40	2.5
Z-Ligatne	24	2.5
Amata	25	2.0
Valmiera	30	2.5

Recent investigations show that the capacity of Inčukalns storage could be doubled, up to 3.2 billion m^3 active gas to accommodate the increased gas consumption in Latvia and also greater transit volumes. A rough evaluation of the eventual project shows that the total investment to expand underground storage is about €50–60 million.

Other geological structures are also suitable for the development of underground gas storage in Latvia. Test wells have already been made in the structure near Dobele, located 10 km from the Iecava–Liepaja pipeline. The total capacity of this storage is estimated to be 10 billion m^3.

6.3.1.4. Development of gas transmission system

The potential directions in which the Latvian natural gas transmission system could be developed are the following:

- Preili–Rezekne in the east;
- Tukums in the centre;
- Kuldiga–Ventspils in the west of Latvia (see *Figure 2.9*).

The length of the new gas transmission pipeline to Ventspils is approximately 90 km, and the estimated investment cost is approximately €30–35 million, without the cost of the land.

6.3.1.5. Energy for the pulp and paper industry

Since the late 1980s, the presence of considerable forest resources in the country has encouraged the idea of constructing a new and modern kraft pulp mill. The first practical steps were taken in 1994, when the Forest Sector Development Master Plan proposed to develop a modern pulp industry in the country. In 1996 Jaakko Poyry Consulting AB finalised its pre-feasibility study with the overall conclusion that such an investment in Latvia could be competitive. In 1997 the Information Memorandum to invite potential investors was launched. And in 1998 the Government of Latvia decided to continue negotiations with the forest cooperatives Metsäliitto (Finnish) and Södra (Swedish). A company (A/S Baltic Pulp) was founded in 2000 to make the necessary preparations for the final investment decisions concerning the construction of a 600 000 ton bleached kraft pulp mill in Ozolsala.

Construction of a CHP plant to supply steam and electricity to the pulp mill was part of the €900 million pulp mill project. The electric capacity of the power plant, depending on the technology type, could range from 110 to 140 MW, with a steam capacity of 300 MW. Bark and black liquor could be used as the main fuels (see *Figure 6.8*). In March 2004 the Final Statement regarding the potential impact of the pulp mill on the environment was submitted to the Environmental Impact Assessment State Bureau (EIA SB). EIA SB in its statement required the use of TCF (chlorine-free) bleaching technology only, which was not acceptable to A/S Baltic Pulp. Since then the project has been postponed.

This study was initiated before the postponement of the pulp mill project. That is why the construction of the CHP plant at the pulp mill was considered as a serious alternative, which among other things could contribute to Latvia's obligations to increase the share of RESs to 49.3% by 2010. Eventually the project might be implemented, but certainly not to the time schedule planned in this study.

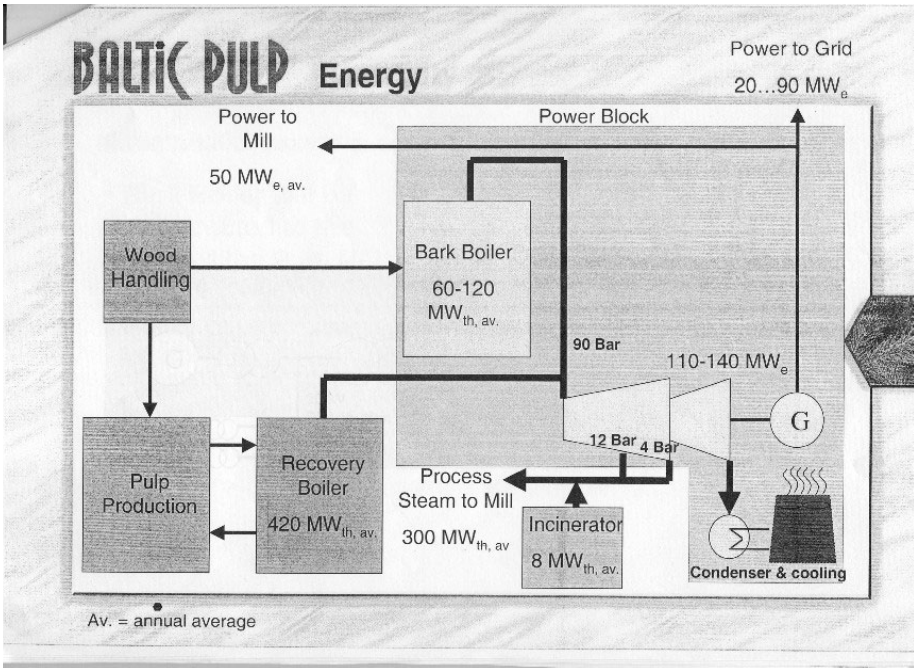


Figure 6.8. Energy flows of CHP plant in the pulp mill.

6.3.1.6. Thermal treatment of municipal wastes in Riga

In Latvia, wastes from municipal and industrial processes are mainly disposed of in several landfill sites spread across the country. Especially in the large area around Riga, the disposal and landfill of large quantities of municipal waste leads to environmental impacts. In this context and with regard to EU legislation, consideration of a modern and environmentally sound waste management system arose in Latvia. State JSC Latvenergo has ordered a study to examine the thermal treatment of municipal solid wastes (MSWs) [58] in the territory of Riga CHP-2.

A prospective waste incineration plant is designed to burn 192 000 tons of MSWs per year (which is approximately 26 tonnes/hour), with a lower heating value of 11 MJ/kg. The plant is projected to have a grate-fired furnace, a horizontal pass type boiler, and flue gas treatment with a spray absorber and fabric filter for the removal of dust, acid gases, heavy metals and dioxins. It will also have a selective non-catalytic reduction system for NO_x reduction, and a turbine with extraction and generator.

The electricity capacity of the power plant in cogeneration mode is 16.8 MW, and in condensing mode 20.8 MW. The heating capacity could be approximately 38 MW. Its overall efficiency in condensing mode is 25%, and in cogeneration mode 67%.

6.3.2. Modelling of energy supply systems in Latvia

6.3.2.1. Extraction, import, preparation and export of primary energy resources

Modelling of gas supply system. The gas supply system of Latvia is modelled in three main stages in MESSAGE: import of gas, underground gas storage and the system of gas supply networks.

The only natural gas source in Latvia is its import from Russia. The variable cost of gas import technology is equal to the gas price shown in *Table 5.1*. There are no technical limitations to gas imports from Russia because the capacity of the gas pipeline system that connects the Latvian underground storage with Russia is designed for 5 billion m^3 of annual consumption, while the current gas consumption is about 1.5 billion m^3. The capacity of all transmission pipelines is designed for an annual capacity of about 11 billion m^3, which exceeds the present consumption level by far.

The gas is supplied during summer months, from May to September, and injected into the storage aquifer. During the autumn–winter period, from October to March, no further supplies are provided, and the incoming pipelines are shut by the Russian operators. In the winter season, Inčukalns UGS supplies gas to its Latvian consumers, as well as to northwest Russia, St Petersburg and Estonia. The capacity of Inčukalns UGS is 2.1 billion m^3.

The underground gas storage is described in MESSAGE by three technologies, which present different processes: the injection of gas, storage of gas and withdrawal of gas. The variable cost of gas storage is €6.35/1000 m^3.

The system of transportation and distribution of natural gas are described in the model by three networks, one at high pressure, one at medium pressure and one at low pressure. This approach makes it possible to connect different groups of consumers to a corresponding network according to the existing gas tariff system in Latvia.

The variable costs of these technologies are based on the existing transmission and distribution tariffs approved by the Public Utilities Commission. The variable costs of gas transportation for selected networks are €13.3/1000 m^3 for the high-pressure network, €7.1/1000 m^3 for medium-pressure and €21.3/1000 m^3 for low-pressure.

The variable cost for gas transportation via medium- and low-pressure networks is calculated under the condition that the distribution expenses are included for consumers connected to the particular networks. To calculate the total cost of gas transportation for a consumer connected to a low-pressure network, all variable costs of higher pressure networks should be added to the variable costs of the low-pressure network.

The system of fuel supply. In the structure of the Latvian MESSAGE model the system of fuel supply includes local fuel (biomass, peat, waste), imported fuel (coal, oil products, LPG) and RESs (wind, biogas, straw, solar energy).

In the model, the system of local fuel supply includes fuel preparation, transportation and distribution. Biomass is divided further into wood logs, wood waste and wood chips. The wood waste can be used directly for energy production or transformed into wood briquettes, which are of higher calorific value and which can also be exported (as can wood chips). The model includes similar possibilities for the peat supply chain, since peat can be used either directly as a fuel or transformed into briquettes and then exported.

During 1995–2000 several biomass resource estimates were provided by several institutions and studies in Latvia. These estimates include the potential amount of biomass but do not include an evaluation of the economic profitability of biomass production at such amounts. Analysing and comparing these various estimates allows defining some general input data on future biomass availabilty (see *Table 6.11)* for use in this study.

Table 6.11. Forecast of bioenergy potential in Latvia, year 2020

Resources of bioenergy	*Available amount (PJ)*
Biomass from forestry	100
From forestry operations	50
Residue of wood-processing enterprises	30
From energy forests	20
Biomass and bioenergy from agriculture	3.0
Straw	2.5
Biogas from animal manure	0.5
Biogas production from treatment of food industry	0.2
Biogas production from treatment of active sludge	0.4
Energy potential of biomass content in waste	8.55

Peat is the domestic fuel in Latvia and is found in approximately 5700 bogs. The total fuel peat reserves are evaluated at approximately 7600 PJ, of which 1900 PJ (25%) are available for processing.

The total useful amount of local fuel resources is determined for all modelled periods, as well as for each year. The availability of resources during each year is limited by the capacities of fuel extraction and preparation.

The system of imported fuel supply is described in the model, including its transportation and distribution, and is characterised by the imported fuel price, by the type of delivery (rail, sea, etc.) and by the supplier's region (Russia, the Baltic, and western countries). Latvia imports HFO and other oil products (gasoline and diesel) mainly from Russia, Belarus and Lithuania and a very small share from Western Europe. Latvia imports coal mainly from Russia, Kazakhstan, Ukraine and Poland. The importance of coal in Latvia's energy sector is currently very limited, but major coal-fired power plant projects may be feasible if oil and/or gas prices increase sharply in the future.

Each of the potential sectors of fuel utilisation (energy production, industry, households and others) is characterised by its own fuel supply chain and, respectively, by its own prices. For inland fuel transportation and distribution, railways and heavy trucks are used. The expenses of transportation and distribution are based on the tariffs approved for carriage by rail and on the average expenses of carriage by truck.

6.3.2.2. *Electricity generation*

The electricity generation system of Latvia can be conditionally classified into (large) centralised power plants, which belong to the state JSC Latvenergo, and (small) distributed generation units, which are owned mainly by independent power producers. Centralised generation is connected to the high-voltage transmission grid at the 330 and 110 kV levels, while the distributed generation is connected to the average and low voltage distribution networks. The technologies that represent these power plants are connected accordingly in the network of the MESSAGE model.

Centralised generation consists of the Daugava cascade HPPs and CHP plants located in the city of Riga (*Table 6.12*). In the MESSAGE software the existing Daugava HPPs were modelled as a single technology. The storage of water resources and the river Daugava itself were introduced into the model in the form of constraints, representing water inflow into storage. Refurbishment of several hydro turbines in Plavinas, Kegums HPP-2 and Riga HPP was taken into account as an option for optimisation, but the necessary dam safety enhancement measures were taken for granted in the model because they are considered as mandatory.

Table 6.12. Centralised power plants

Power plant	*Start of operation*	*Number of units*	*Installed power capacity (MW)*	*Generation in 2004 (GWh)*
Plavinas HPP	1965–1966	10	868.5	1732.9
Kegums HPP-1	1939 (1947–1953)	4	72.1	570.9
Kegums HPP-2	1979	3	192.0	
Riga HPP	1974–1975	6	402.0	735.9
Riga CHP-1	1955–1958	4	129.5	224.5
Riga CHP-2	1975–1979	4	390.0	1000.3
Total		31	2054.1	4264.5

Riga's CHP plants consist of back-pressure units, condensing units with heat extraction and HOBs. Several units of the same type were aggregated and modelled as a single technology in the MESSAGE database. For extraction units, power production in the cogeneration and condensing modes was modelled. Heat is supplied to the district heating system of Riga. Several fuel types could be used in each single unit of power plants. The main fuel in Riga CHP plants is natural gas. Power plants could also switch to HFO. Peat use was ceased in Riga CHP-1 after the reconstruction. Diesel fuel can be used as a back-up fuel in the new HOBs of Riga CHP-1. Utilisation of other liquid fuels — HFO with low sulphur content (<1%) or shale oil — is considered in the model as a possibility for the future. To use HFO with high sulphur content (3%), an option to install flue gas desulphurisation (FGD) equipment is considered.

The reconstruction of Riga CHP-1 was modelled as an existing technology, because the investment decision about its reconstruction had already been made with the power plant commissioning in November 2005. The reconstruction project foresees a replacement of the old heat and power equipment with new combined cycle units, as well as replacement of the old HOBs with new ones. A detailed description of this reconstruction is given in Section 6.3.1.1.

In contrast, the reconstruction of Riga CHP-2 is modelled as a candidate technology (from 2008). New CCGT CHP units might replace existing units, which will be gradually removed from operation by 2019. HOBs of Riga CHP-2 are able to run until the end of the study period. Detailed information is specified in Section 6.3.1.1.

The existing power generation system of Latvia is described in greater detail in Section 2.2.4.1. *Table 2.12* lists distributed generation sources by type of power plant. Today there are approximately 195 small power plants with an overall capacity of 126 MW in Latvia.

New and existing wind power plants are modelled as one technology with a potential capacity of 500 MW (currently about 27 MW, 16 plants). The capacity utilisation factor of wind power plants is limited to 22%, which represents the real utilisation of existing wind generators in Latvia.

New and existing (~150 plants) small HPPs with capacities from 10 kW to 1.2 MW are modelled as two similar technologies. One technology represents small HPPs, which are located in the western part of Latvia, and the other is in the eastern part. The total potential capacity of the two technologies is 36 MW (today, 26 MW). The capacity utilisation factor is approximately 25%.

New HPPs on Daugava river are the Daugavpils HPP, with an installed capacity of 100 MW, and Jekabpils HPP (30 MW), and are modelled as new candidates from 2009. The capacity utilisation factor of these more efficient plants is 48%.

The new CHP plant in the pulp factory uses bark and black liquor (in the MESSAGE model the input fuel is wood) to produce steam and electricity for pulp production. Surplus electricity (about 55%) is used in the transmission system.

Existing (28 plants currently, with an overall electricity capacity of 65 MW) and new small CHP plants are divided into nine technologies that represent internal combustion engines (fuelled primarily by natural gas and secondly by HFO and light fuels) and steam cycle back-pressure units (fuelled by natural gas, HFO, peat and wood). Besides, the technology used varies by heat and power service required — electricity in the west and east and heat in large and small cities.

Gas engines using biogas or landfill gas are modelled separately. Primarily, these serve to produce electricity.

Two large condensing power plants are considered as candidates in addition to reconstruction of Riga CHP-2. They are a large condensing coal power plant in the western part of Latvia (Liepaja or Ventspils) and a natural gas-fired CCGT power plant in Broceni.

Also, as for Estonia, a new NPP is not considered to be a candidate technology for Latvia. This technology may only be considered as an option to the Ignalina NPP.

Several technologies represent new CHP plants in Latvia (*Table 6.13*) — gas-fired CCGT CHPs in Liepaja and Daugavpils, a coal-fired CFB CHP plant in Ventspils, a peat-fired CFB CHP plant in Valmiera, and new wood and gas engine CHP plants in the east and west of Latvia.

Conversion of the district heating plant Imanta into a CCGT CHP plant is considered as an existing technology, because the realisation of this project is under way.

Table 6.13. Summary of new power plant projects (not listed in Section 6.3.1.1)

Power plant	*Technology*	*Fuel*	*Capacity (MW)*		*Electricity generation (GWh)*	*Fuel utilisation factor (%)*	*Capital costs (€/kW)*
			Electrical	*Heat**			
Liepaja CHP†	Combined cycle	Natural gas	40	35	260	84	935
Broceni PP	Combined cycle	Natural gas	104	10	730	57	650
Ventspils CHP†	Circulating fluidised bed	Coal	20	40	130	88	1900
Valmiera CHP	Circulating fluidised bed	Peat, biomass, natural gas	10	30	55	80	1800
Imanta CHP	Combined cycle	Natural gas	47.9	44.7	350	86.3	740
Daugavpils CHP	Combined cycle	Natural gas	90	75	550	86	750
Jelgava CHP	Gas turbine, HRSG	Natural gas	12.9	20	85	85	810
Jekabpils HPP	Hydro	Water	30	–	120	–	2050
Daugavpils HPP	Hydro	Water	100	–	400	–	1950

*Heat capacity of cogeneration equipment in CHP.
†As an alternative to a large coal-fired power plant.

By 2010 electricity production from RESs in Latvia should be equal to or more than 3209 TWh, which is 49.3% of gross electricity consumption in 2000. This constraint was applied to all existing and new RES technologies — hydro, wind, CHP plant of pulp mill, wood CHP plants, waste incinerator and biogas plants.

Some experts, however, think that the RES electricity (RES-E) target should be calculated from gross electricity consumption of 2010. In this case, electricity production from RESs should be approximately 3970 GWh to reach the same contribution from renewables. This assumption was not considered in the study.

Emission rates for SO_2, NO_x and CO_2 were modelled for every fossil fuel power plant, both CHP and HOB, as well as for final energy use in the economic sectors. Total emissions from all emitters should not exceed the values specified in Chapter 3. These limits were included in the model.

Power plants were modelled using gross electricity and heat capacity. Their own electricity consumption of energy production was modelled as a separate technology.

To calculate a national self-sufficiency scenario, electricity imports from neighbouring countries were modelled as a generating unit with sufficiently high capacity to reflect the real transfer capacity of cross-border transmission lines. This approach assumes that an adequate generating capacity exists in the neighbouring countries. The technology is available until 2010. To calculate regional scenarios, the actual interconnections and power systems of neighbouring countries (Estonia and Lithuania) were modelled.

6.3.2.3. Heat generation

According to the available information, there are about 3000 operating boiler houses and CHP plants in Latvia, with a total installed heat capacity of approximately 8990 MW. Overall, heat production in the year 2000 was about 31.7 PJ. Today, the main fuels used in boiler houses are natural gas and biomass — HFO, coal, peat, shale oil and diesel are used as well, but in small quantities.

In the model, CHP plants and boiler houses are connected to specific district heat supply areas — RIGA, BIG and SMALL cities. The district heating system of the right bank of the river Daugava (RIGA) is supplied by Riga CHP plants, which burn natural gas (main fuel), HFO and peat (not from 2003). The total heat installed capacity of CHP plants and HOBs in the year 2000 was 2390 MW. After the decommissioning of two district heating plants, it has been reduced to 1855 MW. Existing and reconstructed CHP plants in Riga are described in Section 6.3.1.1. Large HOBs installed in Riga's CHP plants are burning natural gas and HFO and have high efficiencies (90–92%).

The heat capacities and efficiencies of boiler houses that are installed in BIG and SMALL cities are given in *Table 6.14*. The information is based on statistical data and expert evaluations.

Table 6.14. Heat capacities and efficiencies of boiler houses in large and small cities of Latvia

	Heat capacity (MW)		*Efficiencies (%)*
	Large cities	*Small cities*	
Existing gas boilers	2150	690	88–89
Existing oil boilers	1340	375	80–82
Existing coal boilers	50	125	63–68
Existing wood boilers	380	895	64–65

The technical and economic data for new boiler houses is based on internationally and nationally available data and are very similar to those used in other modelling studies. The only exception is for biomass boiler houses, which have a lower investment cost compared to international sources because, for the time being, a number of local companies that supply heat boilers operate in Latvia.

New gas boilers are subdivided into boilers that operate in district heating, local heating and individual heating systems. Investment costs for gas boilers range from €50/kW to €62/kW, while efficiency varies from 84% to 90% depending on the size of the boiler. The efficiency of new coal boilers is assumed to be approximately 70%, but investment costs range from €145/kW to €155/kW. The efficiency of wood boilers is approximately 65%, while the investment cost is about €110/kW.

6.3.2.4. Electricity transmission and distribution

Electricity transmission and distribution was modelled in aggregated form using one technology for the transmission network and one technology for the distribution of electricity. Transmission and distribution costs have been assumed to correspond to the actual tariffs. *Table 6.15* illustrates the energy flows and tariffs of the electricity transmission and distribution systems. The Latvian transmission network was divided into the western and eastern part, because it might become congested for large energy flows.

The western and eastern parts are interconnected by an 800 MW link. Interconnections of the wind parks to high- and medium-voltage levels were modelled as separate technologies. Transmission losses were assumed to be 4.3%, while distribution losses are approximately 9%.

Table 6.15. Transmission and distribution tariffs and energy flows

Voltage level (consumer classification)	*Energy flow (%)*	*Payment for load (€/kW)*	*Payment for energy (€/GJ)*
Transmission, if inside the property borders of consumer, is:			
110 kV lines	1.0	4.33	0.440
110 kV switchgears	0.7	5.77	0.517
After 110/6–20 kV transformer	98.3	6.01	0.598
(Total) Average	*(100.0)*	*5.99*	*0.596*
Distribution			
At 6–20 kV busbar of 110/6–20 kV transformers	14.3	3.08	1.264
From 6–20 switchgears to 6–20 kV lines	20.9	3.85	3.363
At 0.4 kV busbar of 6–20/0.4 kV transformers	17.1	2.00	4.585
Low voltage 0.4 kV for one-phase connection	47.7	1.15	8.632
(Total) Average	*(100.0)*	*2.14*	*5.785*

6.3.2.5. Modelling of energy demand

To describe the Latvian district heating system more comprehensively and adequately in the model, it was conditionally divided into three large heating areas named RIGA, BIG cities and SMALL cities. Riga's right-bank district heating system is included in the RIGA area; the BIG cities area embraces the district heating systems of Riga's left bank, Daugavpils, Liepaja, Rezekne, Jurmala, Jelgava and Ventspils, while the SMALL cities area encompasses the remaining Latvian district heating systems. Such a division allows each of the groups to be described in terms of their characteristic energy production and cogeneration technologies and the fuel types utilised. For example, in the RIGA heat supply area biomass and coal cannot be used.

Each of these heat supply areas is described by its characteristic heat supply network parameters (consumer density — high and low heat density areas, heat losses in the networks). The structure of the model allows for the networks to be restructured, local networks to be formed and consumers to be disconnected from the district heating system.

Heat losses in networks are:

- 19.2% for the transmission and distribution networks in Riga;
- For high density heat transmission in BIG cities 19.7%, and 27% for low density;

- 11.7% for heat distribution in BIG cities;
- For high density heat transmission in SMALL cities 17%, and 24.6% for low density;
- For heat distribution in SMALL cities 8.8%;
- For new (reconstructed) heat transmission and distribution networks, 10%.

Latvian electricity demand was represented separately for the western and eastern parts depending on voltage level. Load variation during seasons, weeks and days was represented according to the current load curve and principles described in Section 6.5.

Other energy demand in Latvia was represented according to branches of the national economy. The share of each fuel consumed was assumed constant during the study period and corresponded to the current actual status (*Table 6.16*). Load variation was not taken into account, except for that of natural gas.

Table 6.16. Structure of Latvian final energy demand according to fuel types in branches of national economy (%)

Fuel type	*Industry and construction*	*Services*	*Household*	*Agriculture*	*Transport*
Heavy fuel oil	15.43	5.90		7.49	
Other oil products	13.40				2.74
Gas	34.40	19.35	8.15	15.54	0.21
Medium distillates	5.87	10.63	0.00	50.85	45.50
Light distillates	0.17	0.92	0.40	1.35	48.84
Coal	2.68	15.13	1.56	1.75	
Peat		0.32	0.03		
Wood	28.06	47.76	86.24	23.02	
LPG			3.62		2.70

6.4. Lithuanian energy system model

6.4.1. Options for future supply system and their characteristics

6.4.1.1. System of electricity supply

Lithuanian TPP consists of four 150 MW and four 300 MW units. The oldest units (No 1 and No 2) that operate in a CHP production mode were refurbished before 1990, which extended their lifetime to 2035. The remaining operation resource of the other units ranges from 81.9 to 124.4 thousand hours. Thus, the units may be operated at full load until 2024–2026 if their operation starts in 2005 (*Figure 6.9*). The actual utilisation of these units at full load is likely to start only after the second unit of the Ignalina NPP has shut down at the end of 2009. Therefore, the actual operation time of units 5–8 of the Lithuanian TPP may be until 2029–2031. However, to prepare this power plant for reliable operation after 2010, the units should undergo minor modernisation (replacement of the control devices and instrumentation, as well as control room equipment, refurbishment of steam turbines, etc.). Such modernisation requires, in total, about €120 million (overnight investment cost). Investments for environmental protection measures will require an additional €200 million. A detailed breakdown of the expected investments is presented in *Table 6.17*.

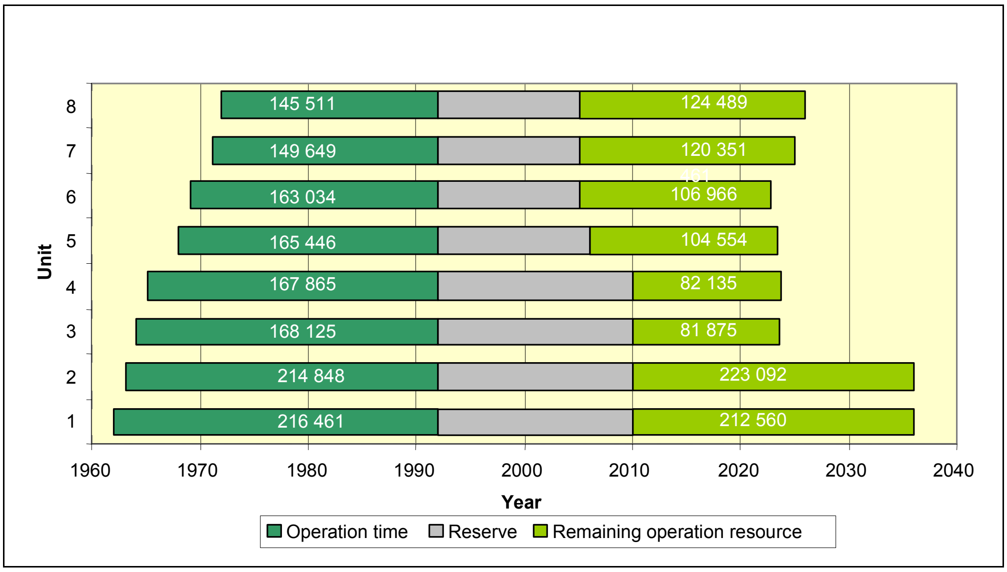


Figure 6.9. Operational history and remaining lifetime of different units at Lithuanian TPP.

Table 6.17. Investments in environmental protection measures and equipment modifications of the Lithuanian TPP (million €)

	First investment programme				*Second investment programme*				Total
	2004	*2005*	*2006*	*2007*	*2007*	*2008*	*2009*	*2010*	
Environmental investments									
FGD and electrostatic precipitators	48.60	58.36	37.35	37.72					182.03
Low NO_x burners	5.45	5.46	5.23	4.22					20.36
Total	*54.05*	*63.82*	*42.58*	*41.94*					*202.39*
Equipment modification									
Rehabilitation of regenerative air preheater	0.67	1.60	3.84	1.55					7.66
Modernisation of control systems	2.19	7.91	7.59	7.66					25.35
Total	*2.86*	*9.51*	*11.43*	*9.21*					*33.01*
Reconstruction and modifications									
300 MW turbines modernisation					26.00	26.00			52.00
G-5 modernisation							10.00		10.00
Reconstruction of 300 MW auxiliary equipment					7.50	7.50			15.00
Unit 1, 2 control system modernisation							4.00	4.00	8.00
Total					*33.50*	*33.50*	*14.00*	*4.00*	*85.00*
Annual total	56.91	73.33	54.01	51.15	33.50	33.50	14.00	4.00	320.40
Programme total	235.40				85.00				
Grand total	320.40								

Vilnius CHP-3 can fire both natural gas and HFO. The fuel type is chosen depending on fuel prices. It can also be easily converted into an orimulsion firing plant [59]. Preliminary calculations indicate conversion cost of approximately **€**1.1 million (*Table 6.18*).

Table 6.18. Investment cost of conversion of Vilnius CHP 3 to orimulsion firing (thousand €) [59]

Equipment and work description	*Unit price*	*Total*
a) Suction drum drainage pumps, two units (80 m^3/hour, 300 kPa)	8.7	17.4
b) Mains heating-system water line for circulation fuel heaters complete with instrumentation		14.5
c) Screw-type pumps, two units (160 m^3/hour, 1000 kPa) complete with motor speed regulators and fittings	23.2	46.3
d) Fuel line electric trace heating (3400 m) and thermal insulation		327.3
e) TGME-206 steam boiler fuel feed arrangement: filters (700 μm), two units; screw pumps (80 m^3/hr, 1000 kPa), two units; speed regulator, two units; water–orimulsion heat exchangers; and piping, fittings, instrumentation.	86.9	173.8
f) Steam boiler and economiser convection superheater cleaning equipment	260.7	531.3
Total		*1110.6*

Both the practical firing experience and the theoretical calculations show that the firing of orimulsion produces the following pollutant concentration in the flue gas:

- Sulphur anhydride (SO_2) 5800–6200 mg/Nm^3;
- Nitric and nitrogen oxide (NO_x) 350–450 mg/Nm^3;
- Solid particles (ash, V_2O_5) 100–150 mg/Nm^3.

Thus, to achieve the specifications set out in Directive 88/609/EEC, it appears essential to install boiler flue-gas treatment facilities, as follows:

- Ash filters, with efficiency in excess of 67%;
- Desulphurisation equipment, with efficiency in excess of 94%.

Therefore, based upon the ecological, engineering and economic considerations, the optimal flue-gas sweetening technique has been identified as that which uses an electrostatic filter coupled with the desulphurisation process, which will ensure the following [59]:

- High treatment efficiency in accordance with the EU Ecological Codes;
- Easy solution to the waste disposal problem;
- Low operating costs (approx. €87 per ton of SO_2);
- Relatively low capital outlay.

Total investment cost for the electrostatic filter and desulphurisation unit will be about €22 million [59].

To comply with the environmental standards for NO_x emissions, the installation of low NO_x burners will be required. Investment costs would be about €2.3–4.1 million [60, 61]. In addition to the above, modification of the air pre-heaters and of the control and instrumentation system and reconstruction of the electrical system to meet the requirements of the Union for the Co-ordination of Transmission of Electricity (UCTE) will require about €16.8 million additionally [61].

At the end of the technical lifetime of the existing units (after 2030) one option is to replace them with new similar units that could burn natural gas and liquid fossil fuels. This multifuel option was foreseen because of energy-supply reliability issues. The investment cost for this type of technology was assumed to be about €1000/kW, and the efficiency in combined heat and electricity production mode to be 89% and that in pure condensing electricity production mode 53%. In addition, it was assumed that from 2015 one or both units of Vilnius CHP can be replaced by new modern CCGT CHP units. The investment cost of these was assumed to be €700/kW with a total efficiency of 91% and 60% in condensing electricity production mode [62]. The power-to-heat ratio of these units is 1.9, which means that, in comparison to the existing units, the new units could produce much more electricity at the same heat output.

Kaunas CHP is similar to Vilnius CHP-3, in that modernisation will include installation of low NO_x burners for the steam boilers, electrostatic precipitators and FGD plants. Based on the cost estimation for the Lithuanian TPP [60, 62], investments for these environmental measures at Kaunas CHP can be estimated as:

- Low NO_x burners €6.1 million;
- Electrostatic precipitator (one common per power plant) €3.2 million;
- FGD (one common per power plant) €13.3 million;
- Total for environmental measures €22.6 million.

The control system of the Kaunas CHP is similar to that of Vilnius CHP-3 and its modernisation will require about €8.7 million. Reconstruction of the regenerative air pre-heater sealing system for the steam boilers of the plant will cost about €1.8 million. Improvement of the heat supply system inside the plant will require about €2.9 million.

As for the Vilnius CHP, at the end of the lifetime of existing units their replacement by similar but more efficient units that use natural gas and liquid fossil fuel was assumed. The investment cost was assumed to be €1000/kW, with efficiencies in CHP mode of 85% and in the condensing regime 37%, and a power-to-heat ratio of 1.8. From 2015 an alternative to replace the existing units by new CCGT CHP units was considered, with an investment cost of €830/kW, efficiency of 91% and power-to-heat ratio of 1.6 [62]. In addition to this, the construction of one additional CCGT unit of 80 MW capacity could be introduced as an alternative from 2008. The investment cost was assumed to be €490/kW, with an efficiency of 55% [62].

Mazeikiai CHP could be modernised at an estimated investment cost of:

- Low NO_x burners €5.4 million;
- FGD plant (one per power plant) €13.3 million;
- Total for environmental measures €18.7 million.

The main idea for modernising the Mazeikiai CHP is related to the reconstruction of the Mazeikiai refinery and conversion of this power plant to burn the refinery residue — asphaltene. Modernisation of the control system will require about €8.7 million and reconstruction of the regenerative air pre-heater sealing system on four steam boilers of the plant will cost about €2.3 million.

Both the current use of HFO and the future use of asphaltene will require the construction of flue-gas cleaning devices to remove particulates. According to data received from the power plant this will require investments of about €200/kW. The construction of a new gas pipeline and conversion of this plant into gas firing unit was analysed as an additional alternative. Conversion of Mazeikiai CHP to allow gas firing will require about €5.8 million and an additional €34.8 million for the necessary gas pipeline construction.

To burn the total asphaltene production, the construction of a new condensing unit of 210 MW was introduced as an alternative. In this case all that is necessary is the construction of the new steam turbine and generator. According to data presented by the Mazeikiai refinery, the investment cost for this new unit would be about €34.8 million.

From 2025, replacement of existing CHP units by similar new units was also considered. The investment cost was assumed to be about €900/kW, with a power-to-heat ratio of 0.5, and total efficiencies of 93% in CHP mode and 35% in condensing mode.

Kaunas HPP has been in operation since 1960. Some parts of its generation and control systems are obsolete and have to be renovated to prolong the lifetime of the plant and increase its reliability of operation. The cost for refurbishment of the power plant is estimated to be €14 million.

Kruonis hydro pumped storage plant has four 200 MW units and, additionally, four other units can be installed according to the design project of the plant. The necessary investments for each additional unit are about €43.4–57.9 million.

New CHP plants can be installed in addition to existing power plants to supply electricity and heat to the existing district heating systems in Lithuania. New CHP plants could be located in Klaipeda, Panevezys, Alytus, Marijampole, Siauliai and other Lithuanian towns. Their total capacity was not constrained and is driven by heat and electricity demand in the system. Investment costs for hypothetical CHP plants were assumed to be in the range €865–900/kW, with a total efficiency of 91% and a power-to-heat ratio of 0.6. Natural gas was assumed as a fuel for these plants, which can be based on combined cycle gas turbine technology.

In addition to the above technology, CHP plants using renewables as well as the conversion of existing boiler houses into CHP plants have been considered in the study. The investment costs for such CHP plants were assumed to be €1080/kW, with a power-to-heat ratio of 0.12.

Conversion of boiler houses into CHP plants was considered in terms of the installation of an additional gas turbine at the front of existing boilers (investment cost about €430/kW) or by adding a steam turbine behind the steam boiler (investment cost also about €430/kW).

A new CCGT plant and a new NPP can be built at the site of Ignalina, after its decommissioning, to make use of the existing site, infrastructure and qualified personnel. The investment cost in this case is lower than that of the construction of a completely new plant at a new site. In this study it was assumed that the investment cost of a new CCGT plant at the Ignalina site will be €500/kW. To avoid the concentration of large capacities in one place, the total capacity of new installations at the Ignalina NPP site should not exceed 600 MW.

In addition, a new gas-fired power plant will require the construction of a new gas pipeline, estimated to cost about €23.2 million.

Similarly, the existing space of the Lithuanian TPP site can be used to construct new CCGT units. This can be done in addition to the existing capacities or instead of modifications to the existing units. An advantage of this site in comparison to Ignalina is that the gas network extension will not be necessary. It was assumed that the investment costs for new CCGT plants are the same for both sites. The same capacity constraint of 600 MW was applied.

New CCGT plants can also be constructed at new sites in Lithuania. These, however, will require higher investment costs and extension of the gas network. The investment cost for such an installation was assumed to be €600/kW. The investment cost per capacity unit of additional pipeline was assumed to be similar to the Ignalina case.

New wind power plants are very attractive, as are any RESs, because Lithuania does not have sufficient domestic primary energy resources. An estimated investment cost of about €1135/kW was assumed for potential wind power plants in Lithuania. Taking into account the large decrease of investment cost per kW of installed capacity of wind power plants, it was assumed that the investment cost will decrease by 2 % per annum during the study period. However, the total installed capacity was constrained to 180 MW because of the limited number of available sites with sufficiently high wind speeds.

New nuclear units (one or two) were considered for the Ignalina NPP site, as were replacements of the existing reactors [63, 64]. Different technological options are considered in *Table 6.19*.

Table 6.19. Different options for the construction of new nuclear units at the Ignalina NPP site

Reactor type	*EPR-1600*	*SWR-1000*	*BWR-90*
	Pressurised water reactor (PWR)	*Boiling water reactor (BWR)*	*Boiling water reactor (BWR)*
Heat load (MW)	4300	2700	2150
Electricity load (MW)	1600	1000	800

Expert V. Jarin [65] proposed the replacement of RBMK-1500 reactors with the former ABB Atom (nowadays Westinghouse) BWR-90 reactors which, according to his evaluation, might be at least 50% cheaper than the construction of a new nuclear unit. However, international experience of replacing nuclear reactors in this way does not exist. Some specialists believe the proposed reconstruction is not possible. The investment cost for a new NPP was assumed to be similar to that for the new Finnish NPP unit, for which the overnight investment cost is about €1660/kW.

6.4.1.2. System of heat supply

Conversion of existing boiler houses into CHPs can be achieved with an additional gas turbine and generator installed in front of the existing boilers. The flue gas from the turbine would be used as hot air in a steam- or water-heating boiler, in addition to the fuel being used before modernisation. According to expert opinion, the capacity of the gas turbine in this case should be small (about 25%) in comparison to the boiler capacity, which means that a gas turbine of about 25–30 MW might be used for the PTVM-100 boiler. The investment costs for such a gas turbine would be about €380/kW and about €7.0/kW to reconstruct the boiler.

Another way to convert boilers into CHPs is to install a steam turbine with a corresponding generator. The investment cost for such a set of steam turbine generators was assumed to be €430/kW. Installation of a steam turbine can also be combined with the construction of an additional gas turbine in front of the boiler.

Conversion of existing boilers into biomass-fired boilers will be necessary as more stringent environmental standards are introduced to reduce HFO consumption, which can be substituted by natural gas or biomass. Utilisation of biomass in boiler houses can be increased in three ways:

- Construction of new biomass-fuelled boilers;
- Conversion of existing boilers to be fuelled by biomass;
- Construction of CHPs based on biomass.

The investment cost to construct a new biomass-fuelled water-heating boiler of 5–10 MW capacity is about €215/kW, while the conversion of an existing boiler to use biomass will require investment of about €150/kW [11]. The investment cost for a new biomass-fuelled CHP plant was assumed to be €1080/kW.

Conversion of existing boilers to use natural gas will be necessary to comply with stricter environmental standards in the future. This option is very realistic because a majority of the large boiler houses in Lithuania are connected to the natural gas system, so replacing HFO with natural gas will require little or no investment. Thus, the cost associated with switching from HFO to natural gas will be related to the price difference between HFO and natural gas.

When the boiler house is not already connected to the natural gas system, its conversion into a gas-fired boiler house requires an upgrade of the existing boilers. This option is more complicated because, according to Lithuanian legislation, the conversion of a boiler house from HFO to natural gas is considered as equivalent to the reconstruction of the boiler house. This requires a license from the State Energy Inspectorate, which in turn requires that the boiler operating on natural gas has a metering system, and a control and safety systems that is much more advanced compared to boilers that currently operate on HFO. A list of particular requirements is provided by the State Energy Inspectorate for each type of boiler that is to be converted to use natural gas instead of HFO.

Lithuanian boiler houses that are connected to the gas grid in the future are equipped with boilers with the marks DKVR-10/13, DKVR-6.5/13, KVGN-20 and PTVM-30M. However, experience in Lithuania of boiler house conversions from HFO to natural gas is still limited and so is the information about the associated costs. One source of information is available, namely data from the Utena boiler house. According to these data, the cost to convert a boiler house from HFO to natural gas, taking into account the requirements of the State Energy Inspectorate, is estimated to be €17.3/kW. This cost includes the necessary development of the gas supply system inside the boiler house.

According to data from the Utena boiler house, conversion of three DKVR-20/13 boilers to natural gas costs about €8.1/kW of installed capacity. Conversion of the PTVM-30 boiler to natural gas costs about €9.2/kW. These numbers do not include the cost to develop the gas supply system but account for boiler modernisation only.

In some boiler houses the conditions are such that the construction of new gas-fired boilers instead of conversion of the existing boilers could be a more economically attractive option. The investment cost for new boilers is estimated to be about €25–27/kW of installed capacity for steam boilers or about €22/kW of installed capacity for water-heating boilers. These cost estimates take into account only the investment for the new boilers to be fitted into an existing boiler house. However, they do not include the investment cost for the building and the necessary infrastructure of the boiler house.

6.4.2. Modelling of energy supply systems in Lithuania

In the sections that follow, techniques that represent various technological processes in the energy supply system, including those of the existing system and the candidates for future development, are discussed in detail. Special attention is given to the way technologies are modelled in the MESSAGE model.

6.4.2.1. System of oil supply

The Lithuanian system of oil and oil supply includes imports of crude oil from the Russian Federation and the extraction of domestic crude oil processed at the Mazeikiai refinery. The extraction of oil for export is not considered in this study because it has no impact on the remaining part of the system. The price of extracted crude oil is assumed to be equal to the export price of Lithuanian crude because the major part of it goes to export and sets the price. In principle, it is possible to consider imports by sea of medium and light crude oil. The unloading cost of light or medium crude oil at the Butinge oil terminal is €0.166/GJ.

In parallel with the import and extraction of crude oil, Lithuania can import oil products through the Klaipeda oil terminal or by rail. The variable costs of technologies that represent the import of crude oil and oil products reflect fuel prices at the border of Lithuania and are discussed in Chapter 5. The import of crude oil from the Russian Federation cannot exceed 16 Mt per year (or 2670 PJ), which corresponds to the throughput capacity of the pipeline. The import volumes of other oil products are not constrained.

The Mazeikiai refinery processes either domestic crude oil or crude oil imported from the Russian Federation. Thus, it is represented by a two-input technology — one for Russian crude oil and another for Lithuanian crude oil. Shares of product input and output to and from technology that represents the refinery have been calculated using actual data for the refinery operation in 2000. This information is presented in *Table 6.20*. The refinery output for the base year also includes refined oil products, some recovered products and inter-product transfers. This was done to obtain the actual fuel balance for the base year.

The composition of oil output products by shares is different when Lithuanian oil is refined from that when Russian crude is refined. However, the refining volumes of Lithuanian crude are very small in comparison to those of Russian crude; in addition, information about product output when Lithuanian crude is processed is officially not available. Taking this into account, the product output for Lithuanian crude in the MESSAGE model was assumed to be the same as that for Russian crude.

Table 6.20. Representation of refinery in the MESSAGE model

Input products	*Input shares*	*Output products*	*Output shares*	
			For base year	*For 2010 and later years*
Crude oil	0.8680	LPG	0.0467	0.0412
Additives (natural gas, liquids, refinery feedstocks, half-finished products, additives)	0.0580	HFO	0.1667	0
Electricity	0.0080	Medium distillates	0.2271	0.2794
Heat	0.0053	Refinery gas	0.0262	0.0364
Fuel	0.0607	Other oil products	0.0345	0.0295
		Light distillates	0.3725	0.3630
		Asphaltene	0	0.0570

The refining cost is 24US$/toe [66], which is equivalent to €11.07/GJ for the main output of the refinery (LPG). The design capacity of the oil refinery is 15 Mt of crude oil. For the existing representation of the technology in the model, oil and oil additives account for 92.6% of the total input, so with the share of the main output being only 0.0486, the capacity of the refinery related to the main output is 1045 MW.

Fuel consumption within the refinery is modelled using two technologies. The first one prepares a mix of fuel that is used in the refinery. Generally, all kinds of refinery products may be used for internal consumption. The second one relates the output of the first one to the input of the refinery.

Desulphurisation of HFO that has a high sulphur content is seen as a new option for the refinery. The investment cost for the desulphurisation unit was assumed to be €115/kW. This figure was calculated from data presented by the refinery (i.e., $340 million per 2.5 Mt of desulphurisation) [67]. The model contains specific technologies that allocate electricity and heat for the refinery's own consumption. Heat and electricity are mainly taken from the Mazeikiai CHP plant, which is why no transportation losses and costs were assumed for electricity and heat.

Trains and trucks are used to transport and distribute oil products in Lithuania. A transportation cost of €10.8/t is introduced in the model as a variable cost and, correspondingly, the following cost figures are used as inputs: €0.253/GJ for light distillates, €0.254/GJ for medium distillates, €0.269/GJ for HFO and €0.258/GJ for other oil products. No constraints on transport volumes are foreseen because there are no technical constraints to railway transportation in Lithuania.

Oil products can be first transported by train from the refinery to oil storage terminals located in different places in the country. From those terminals, oil products are distributed to consumers by truck.

The distribution cost for LPG is €0.248/GJ, for light distillates €0.253/GJ, for medium distillates €0.254/GJ and for other oil products €0.258/GJ.

Specific technologies are used to represent the allocation of HFO to power plants or the export of oil products. The variable cost of these technologies represents the prices of exported oil products, given in *Table 5.22*. To reflect the revenue from export, the prices of export fuels are given a negative value.

6.4.2.2. System of gas supply

Three alternative gas supply sources have been considered in Lithuania:

- Gas imports from the Russian Federation through the existing gas pipeline;
- Gas imports from Latvian gas storage;
- Gas imports from western European countries.

The third option requires the construction of a new pipeline, the Baltic gas ring. Construction of such a gas ring would require a lot of time and resources. So, in this study imports of gas from Western Europe are assumed possible only after 2020.

The variable costs of technologies that represent gas imports are equal to the gas prices shown in *Table 5.21*. The volume of gas imports from the Russian Federation is not limited because the Lithuanian gas network was designed for 12 billion m^3 of gas and current use is only about 2 billion m^3. However, seasonal variations in gas demand may cause constraints on the imported volume of gas because of extraction limitations that could occur in Russian gas fields.

The possible construction of a new underground gas storage in Lithuania is also represented in the model. The investment cost for underground gas storage of 1 billion m^3 capacity is €160 million, or €150/kW. The storage cost is taken to be similar to that for Latvian gas storage, €0.274/GJ.

Within the Lithuanian territory gas is supplied to consumers through networks of high, medium and low pressure. These networks are modelled individually to reflect that different consumers purchase gas from different pressure networks. In the MESSAGE model these networks are represented by individual technologies.

The transportation costs in these different pressure networks are based on existing data established by the National Control Commission for Prices and Energy. Transportation cost in the high-pressure network is €0.246/GJ and €1.045/GJ in the medium-pressure network. The latter corresponds to the gas distribution cost to consumers with an annual gas consumption from 1 to 5 billion m^3. It was assumed that these consumers are connected to the medium-pressure gas network. The gas distribution cost for small consumers using up to 800 m^3 of gas is €3.37/GJ. Assuming that the medium-pressure and low-pressure gas networks are used for this gas distribution activity, the cost of gas distribution through the low pressure network is calculated as the difference between the two distribution costs and is equal to €2.33/GJ.

Two technologies are used to model the gas supply to power plants and boiler houses. One technology models the connection of all new power plants to the existing gas network, to reflect that the construction of these new power plants does not require any work related to the extension of the gas network. If, on the other hand, construction of new power plants is related to the construction of an additional gas pipeline a separate second technology is used. This second technology models the extension of the medium-pressure gas network if a decentralised heating system is developed instead of an existing district heating system. Both technologies involve investment in a gas network extension and additional gas losses.

6.4.2.3. *System of other fuel supply*

The system of other fuel supply represents the import, preparation, transportation and distribution of coal, lignite, coke, wood, wood waste, wood chips, straw, biogas, peat, orimulsion and uranium. Imports of coal, coke and lignite are foreseen from the Russian Federation, Poland or other countries. The imports may be carried by train or ship. The second option involves an additional activity — unloading of ships and loading of trains at Klaipeda port.

The variable costs of technologies that represent the imports of various fuels include fuel prices in the world market and transportation costs to the Lithuanian border (see *Table 5.21*). The variable costs of technologies that model the import of orimulsion and uranium represent the fuel prices at the power plant, which are given in *Table 5.21*. The cost of fuel unloading and loading at Klaipeda port was assumed to be €0.43/GJ for coal, €0.64/GJ for lignite and €0.37/GJ for coke.

Coal, lignite and coke for large consumers are transported by rail. If coal is used by small consumers it is first transported to coal stores, from where it is further distributed by truck. Wood, peat, straw and similar fuels are usually distributed locally. The distribution costs for wood, wood waste, straw and peat are €0.52/GJ, €0.53/GJ, €0.66/GJ and €0.79/GJ respectively.

6.4.2.4. *System of electricity and heat generation*

This system represents existing technologies of electricity and heat production and new alternatives described in Sections 6.4.1.1 and 6.4.1.2. Existing power plants, their modernisation and their replacement by new plants at the end of their lifetime is usually represented by one technology in the model. This is done using time series for different parameters, such as investment costs, fixed and variable operational and maintenance (O&M) costs, efficiencies, lifetimes and so on. Such a representation simplifies the network of the energy system. However, for some modernisation cases, such as the possible construction of FGD, conversion of a conventional power plant into CCGT technology requires additional technologies, which represent corresponding additions to the existing equipment. Various technologies are linked with each other to represent a free choice between existing and modernised options.

Before closure of the second unit of the Ignalina NPP, it is assumed that the existing but unused capacity of the Lithuanian TPP and CHP serves as a reserve capacity. Fast reserve capacity can also be provided by the Kruonis HPSPP. To model the reserve margin after closure of the Ignalina NPP, it was assumed that the full installed capacity of the power plants could not be utilised for demand coverage. For each power plant it was assumed that the utilised capacity does not exceed 90% of the installed capacity (i.e., the installed capacity of each power plant was derated by 10%). Such a modelling approach, depending on total demand, guarantees about 300 MW of reserve capacity in the Lithuanian power system. Similarly, about 300 MW are guaranteed because of the derated capacity of power plants in Latvia and Estonia. Additional reserve capacity is available from the four unused 150 MW units at the Lithuanian TPP. The capacity of two 150 MW condensing units is not fully utilised because of low efficiency and that of two 150 MW CHP units because of insufficient heat demand in the area. Even though the reserve capacity of the unutilised 150 MW units of the Lithuanian TPP varies depending on the load in the system, it is possible to assume that 200–300 MW will be available. The above reserve capacities (including the short term Kruonis HPSPP capacity) are sufficient for the Lithuanian and Baltic power system if the Ignalina NPP is replaced by comparatively small units that run on fossil fuel.

If Ignalina NPP is to be replaced by a large nuclear unit the assumed reserve capacity in the Baltic power system will not be sufficient. Thus, for scenarios with the continued operation of large nuclear units, the Baltic power system will be obliged to cooperate with neighbouring countries for reserve capacity. In this study it was assumed that in emergency situations the Baltic countries can provide about 800 MW of reserve capacity to neighbouring countries, and receive a similar capacity from neighbouring countries in the case of an emergency shut down of the nuclear unit. Assuming this scheme of capacity exchange, an additional reserve cost was not considered in this study.

6.4.2.5. Transmission and distribution of electricity and heat

Electricity transmission and distribution networks are modelled using separate technologies. One technology represents the whole transmission network for lines of 110–330 kV. Another technology represents the distribution network (0.4–35 kV). According to data from the Lithuanian power company, electricity transmission cost is €8.1/MWh. Transmission losses are 2.5%. The high voltage electricity network has no bottlenecks because it was developed for much higher electricity flows. The cost of electricity distribution, according to data from the Lithuanian power company, is €11.9/MWh. Distribution losses are assumed to decrease from 14.6% in 2000 to 11.0% in 2025.

Heat distribution networks are modelled separately for the Vilnius, Kaunas, Klaipeda, Mazeikiai and Elektrenai district heating systems. District heating in all remaining areas has been combined into a single technology. Technologies that model heat transmission and distribution are characterised by the cost of district heat supply and distribution and by heat losses in the network. The average heat distribution cost for all heating networks is €16.2/MWh. This average cost is calculated based on official statistics, which show the total cost for heat production and distribution in Lithuania.

Heat losses differ amongst towns and it has been assumed this difference will decrease from the current level of 9.4–31.4% to 9.4–18.8% in 2024.

6.4.2.6. Representation of energy demand

Lithuanian electricity demand was represented as a total country demand, taking into account the demand variation during seasons, weeks and days. Heat demand was separated into six areas — Vilnius, Kaunas, Klaipeda, Mazeikiai, Elektrenai and the other cities of Lithuania. Individual heat demand projections were presented for these areas, also taking into account the heat demand variations during seasons, weeks and days.

Electricity and heat demand from the Mazeikiai refinery consist of two parts:

- *Constant demand*, which does not depend on the quantity of crude oil refined;
- *Variable demand*, which is directly linked to the quantity of crude oil refined.

Variable electricity and heat demand were represented as an indigenous variable, but constant demand was given exogenously, similarly to other heat and electricity demands.

Final fuel demand was represented according to branches of the national economy, with time series of shares for each fuel type during the whole study period. Shares of fuels consumed in branches of the national economy are shown in *Table 6.21*.

Fuel demand variation during the year was taken into account in this study for electricity, heat and gas, but it was not considered for other fuels.

Table 6.21. Shares of fuel consumption in branches of the Lithuanian economy

Fuel type	*Year*							
	2000	*2005*	*2010*	*2015*	*2020*	*2025*	*2035*	*2045*
Industry								
Heavy fuels	24.200	24.030	23.010	21.840	20.600	19.240	19.240	19.240
Gas	68.590	67.370	67.520	68.130	68.780	69.550	69.550	69.550
Coal	1.210	1.440	1.400	1.320	1.240	1.150	1.150	1.150
Peat	0.170	0.230	0.270	0.310	0.350	0.390	0.390	0.390
Biomass	2.680	3.580	4.020	4.360	4.740	5.140	5.140	5.140
Motor fuels	3.150	3.350	3.780	4.050	4.290	4.530	4.530	4.530
Services								
Biomass	26.730	27.420	28.160	28.930	29.700	30.550	30.550	30.550
Motor fuels	7.770	7.060	6.450	6.060	5.710	5.430	5.430	5.430
Gas	19.020	20.910	23.150	25.270	27.390	29.030	29.030	29.030
Coal	32.780	31.600	30.400	29.120	27.820	26.480	26.480	26.480
Peat	0.310	0.460	0.610	0.750	0.900	0.950	0.950	0.950
Heavy fuels	13.390	12.550	11.230	9.860	8.490	7.570	7.570	7.570
Transport								
Heavy fuels	0.010	0.008	0.006	0.005	0.004	0.004	0.004	0.004
Motor fuels	99.990	99.992	99.994	99.995	99.996	99.996	99.996	99.996
Agriculture								
Gas	35.090	31.780	31.520	31.260	31.000	30.740	30.740	30.740
Heavy fuels	3.710	3.180	2.990	2.790	2.600	2.420	2.420	2.420
Biomass	9.270	8.610	8.780	8.950	9.120	9.280	9.280	9.280
Coal	0.570	0.510	0.500	0.480	0.470	0.460	0.460	0.460
Peat	0.000	0.090	0.130	0.170	0.220	0.260	0.260	0.260
Motor fuels	51.360	55.830	56.080	56.340	56.590	56.850	56.850	56.850
Household								
Heavy fuels	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150
Gas	14.590	14.480	14.120	13.630	13.220	12.840	12.840	12.840
Motor fuels	10.660	9.110	8.740	8.390	8.100	7.830	7.830	7.830
Coal	1.910	1.820	1.790	1.730	1.700	1.650	1.650	1.650
Peat	0.930	1.090	1.280	1.420	1.560	1.660	1.660	1.660
Biomass	71.760	73.350	73.920	74.680	75.270	75.870	75.870	75.870

6.5. Representation of operation regimes of the Baltic energy system

Operation regimes of the energy system depend, first of all, on demand variation. However, the changing availability of some energy resources, like hydro, or the maintenance schedules of large power plant units can have a significant impact on the operation of energy systems. Variations in electricity, heat and gas demands and in the water resources of the Daugava river, as well as the maintenance schedule for the Ignalina NPP units (*Figure 6.10*), have a major impact on the operation of the Baltic energy system.

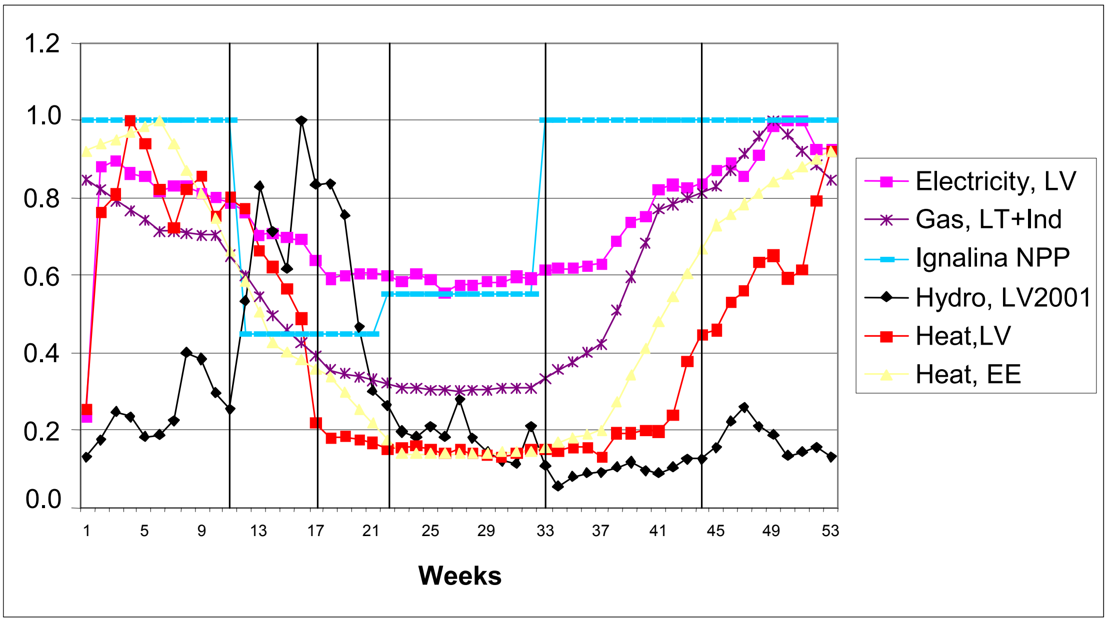


Figure 6.10. Variation of selected energy sources in the Baltic energy system (vertical lines show year division into seasons; EE, Estonia; LT, Lithuania; LV, Latvia).

To reflect correctly these variations in the MESSAGE model, the year was divided into six seasons:

Winter 1: 1 January to 12 March;

Spring 1: 13 March to 23 April;

Spring 2: 24 April to 28 May;

Summer: 29 May to 13 August;

Autumn: 14 August to 29 October;

Winter 2: 30 October to 31 December.

One typical working day and one typical day representing the weekend were selected for each of these seasons. Daily load curves for the typical days were approximated by broken lines that consist of four to six pieces. Representation of the electricity demand on typical days of the season ‘Spring 1’ is shown in *Figures 6.11* and *6.12*.

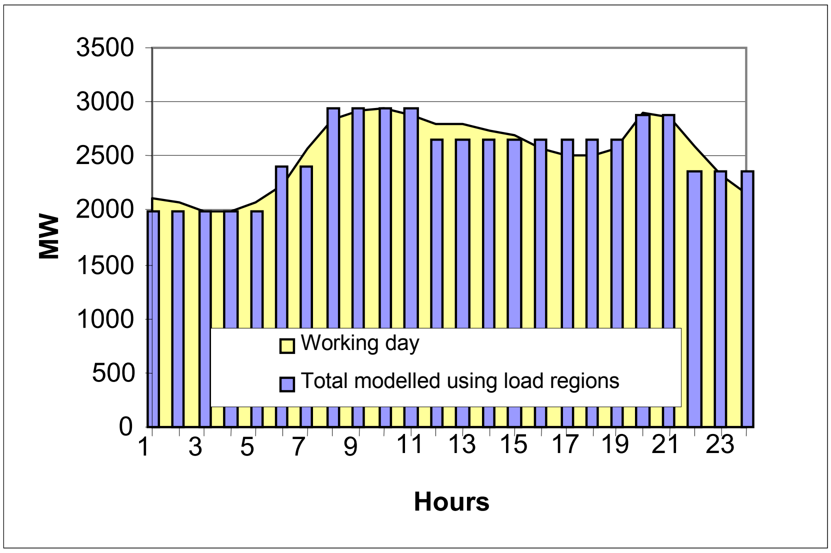


Figure 6.11. Representation of electricity demand on a typical working day in Spring 1.

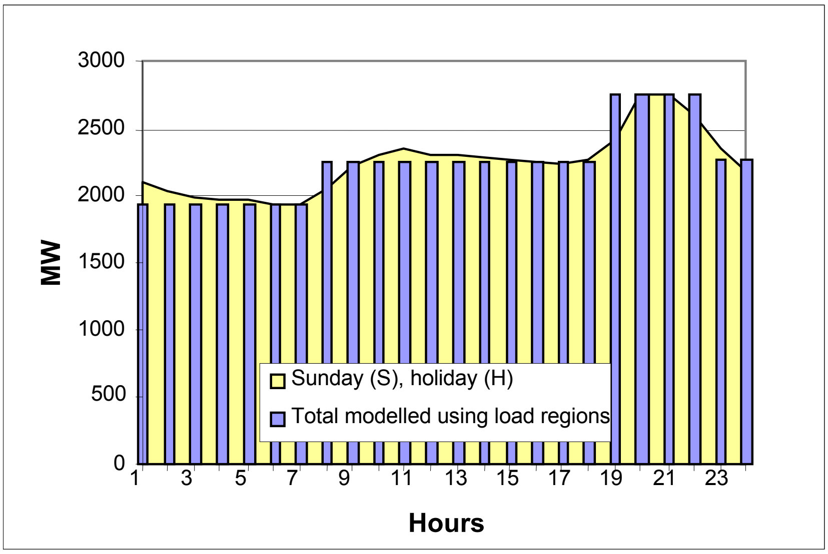


Figure 6.12. Representation of electricity demand on a typical weekend day in Spring 1.

In the study the main focus was on the electricity sector, which is why variation in electricity demand was the main concern. Typical days in a year were selected from the total demand in the Baltic countries to reflect the total maximum demand in winter and the total minimum demand in summer. The selected days, however, do not necessarily reflect the maximum and minimum demand in each country. Typical days in other seasons were selected to obtain an annual energy consumption represented by the demand on typical days as close as possible to the actual annual consumption. Actual and modelled electricity consumption for typical days are represented in *Figures 6.13* to *6.16*.

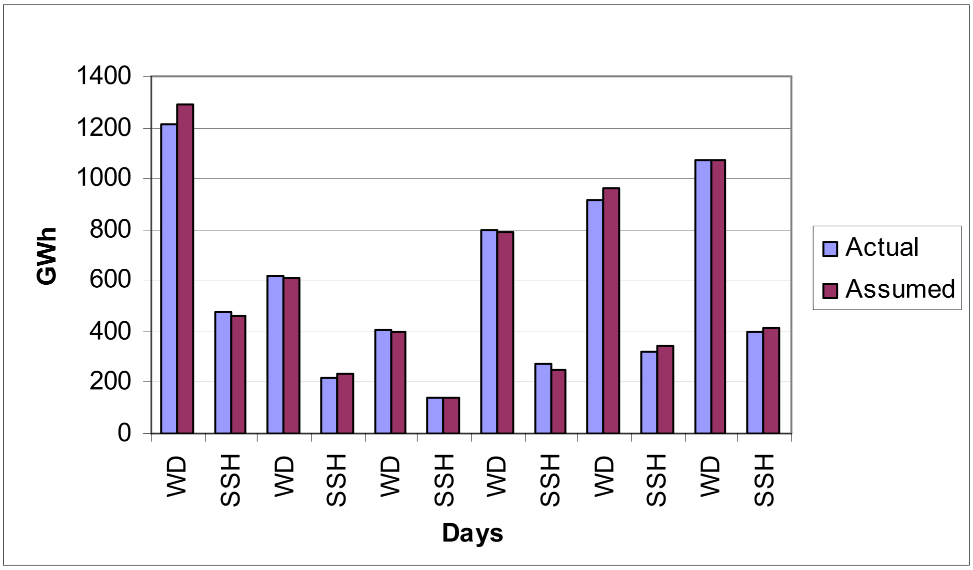


Figure 6.13. Actual and modelled electricity demand in Estonia (WD, weekday; SSH, Saturday, Sunday and holiday).

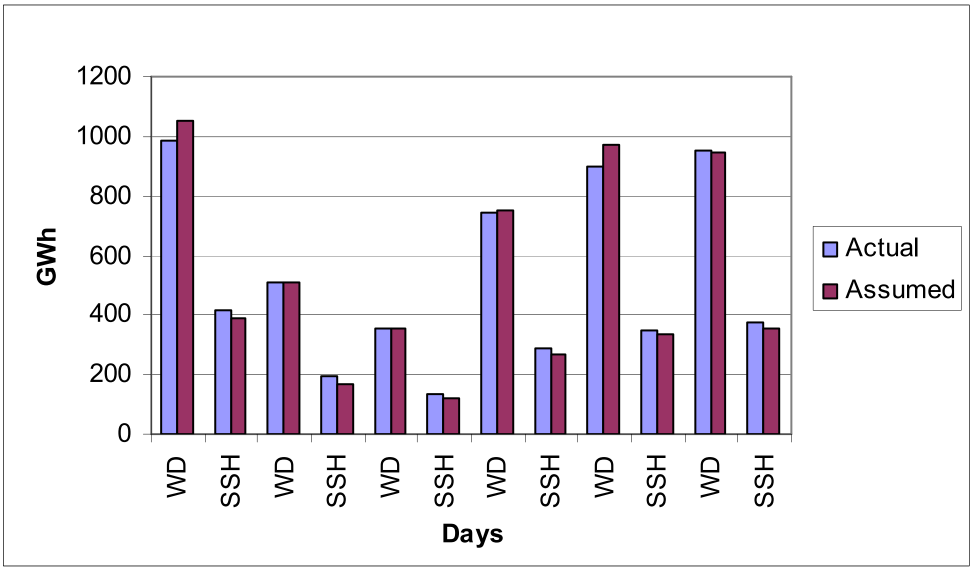


Figure 6.14. Actual and modelled electricity demand in Latvia (WD, weekday; SSH, Saturday, Sunday and holiday.

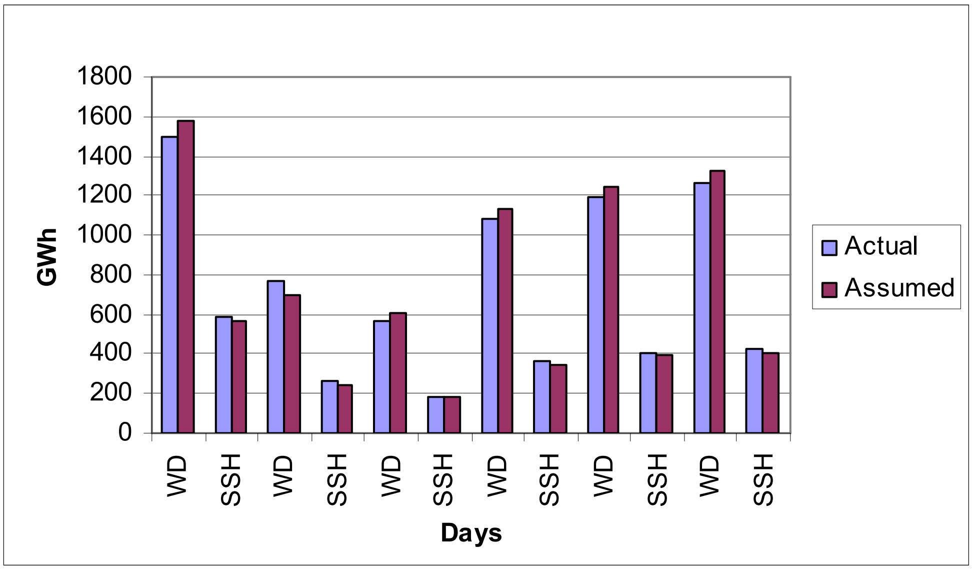


Figure 6.15. Actual and modelled electricity demand in Lithuania (WD, weekday; SSH, Saturday, Sunday and holiday.

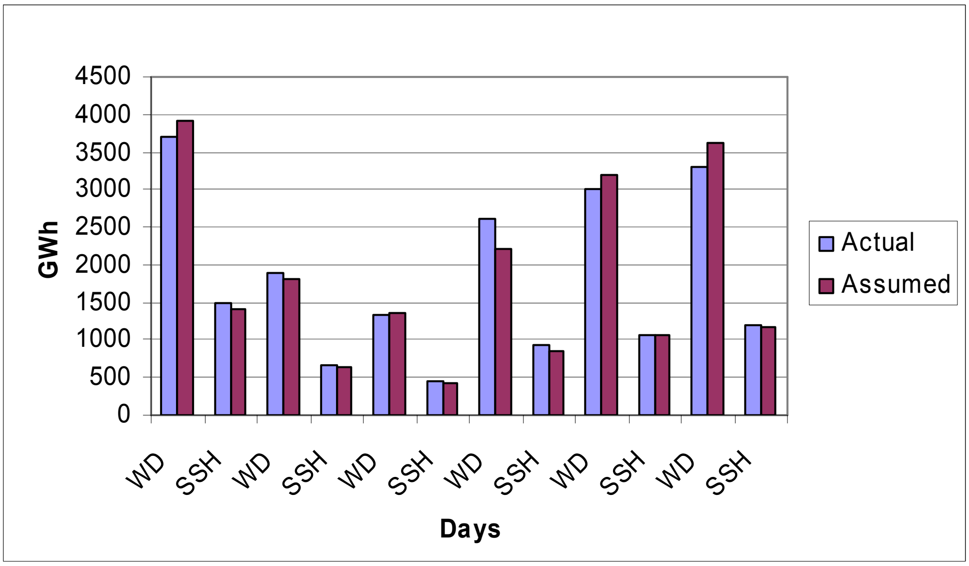


Figure 6.16. Actual and modelled electricity demand in the Baltic region (WD, weekday; SSH, Saturday, Sunday and holiday.

The difference between actual and modelled electricity demand for typical days is 1.37% in Estonia, 0.31% in Latvia, 1.42% in Lithuania and 1.03% in the whole Baltic region. Data that represent electricity demand variation in all three countries are shown in *Tables 6.22* to *6.24*.

Similar information was prepared to describe the variation in heat demand and gas demand, and the availability of water resources in the Daugava and Nemunas river.

Table 6.22. Data representing electricity demand variation in Estonia

Season	Energy (GWh)		
	Total	WD	SSH
Winter1	1805	1347	459
Spring1	840	607	233
Spring2	537	400	137
Summer	967	717	249
Autumn	1302	959	343
Winter2	1629	1212	417
	Energy fraction in seasons		
Winter1	0.2550	0.7460	0.2540
Spring1	0.1187	0.7225	0.2775
Spring2	0.0758	0.7445	0.2555
Summer	0.1365	0.7421	0.2579
Autumn	0.1840	0.7363	0.2637
Winter2	0.2301	0.7442	0.2558

Load region	Assumed energy in load regions (GWh)											
	Winter1		Spring1		Spring2		Summer		Autumn		Winter2	
	WD	SSH	WD	SSH	WD	SSH	WD	SSH	WD	SSH	WD	SSH
LR1	271	48	103	57	60	32	101	49	148	69	236	87
LR2	105	214	45	112	13	79	46	152	67	173	212	175
LR3	181	152	115	44	192	14	318	48	374	55	338	102
LR4	297	44	214	20	70	13	253	0	127	46	233	52
LR5	262	0	56	0	33	0	0	0	128	0	103	0
LR6	231	0	75	0	32	0	0	0	115	0	90	0
LR7	0	0	0	0	0	0	0	0	0	0	0	0
Load region	Assumed energy fractions in load regions											
	Winter1		Spring1		Spring2		Summer		Autumn		Winter2	
	WD	SSH	WD	SSH	WD	SSH	WD	SSH	WD	SSH	WD	SSH
LR1	0.20135	0.10507	0.16905	0.24644	0.15110	0.23384	0.14033	0.19594	0.15470	0.20219	0.19469	0.20867
LR2	0.07800	0.46773	0.07375	0.47872	0.03160	0.57257	0.06349	0.61024	0.06954	0.50336	0.17513	0.42105
LR3	0.13456	0.33105	0.18882	0.19044	0.47990	0.10168	0.44375	0.19382	0.38949	0.15952	0.27882	0.24474
LR4	0.22047	0.09615	0.35307	0.08441	0.17590	0.09190	0.35243	0.00000	0.13261	0.13492	0.19261	0.12555
LR5	0.19423	0.00000	0.09169	0.00000	0.08234	0.00000	0.00000	0.00000	0.13354	0.00000	0.08465	0.00000
LR6	0.17140	0.00000	0.12362	0.00000	0.07915	0.00000	0.00000	0.00000	0.12014	0.00000	0.07410	0.00000
LR7	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

Table 6.23. Data representing electricity demand variation in Latvia

Season	Energy (GWh)		
	Total	WD	SSH
Winter1	1625	1237	388
Spring1	678	511	167
Spring2	475	357	118
Summer	880	612	269
Autumn	1307	975	333
Winter2	1428	1074	354
	Energy fraction in seasons		
Winter1	0.2542	0.7610	0.2390
Spring1	0.1060	0.7539	0.2461
Spring2	0.0743	0.7517	0.2483
Summer	0.1377	0.6947	0.3053
Autumn	0.2045	0.7457	0.2543
Winter2	0.2233	0.7523	0.2477

Load region	Assumed energy in load regions (GWh)											
	Winter1		Spring1		Spring2		Summer		Autumn		Winter2	
	WD	SSH	WD	SSH	WD	SSH	WD	SSH	WD	SSH	WD	SSH
LR1	217	80	73	40	50	28	91	48	136	67	188	68
LR2	114	164	43	77	13	69	42	178	80	176	219	156
LR3	166	115	106	35	177	12	246	43	395	50	314	90
LR4	312	30	184	14	61	9	233	0	124	39	201	40
LR5	226	0	49	0	32	0	0	0	138	0	84	0
LR6	202	0	56	0	25	0	0	0	101	0	68	0
LR7	0	0	0	0	0	0	0	0	0	0	0	0

Load region	Assumed energy fractions in load regions											
	Winter1		Spring1		Spring2		Summer		Autumn		Winter2	
	WD	SSH	WD	SSH	WD	SSH	WD	SSH	WD	SSH	WD	SSH
LR1	0.17512	0.20493	0.14295	0.24022	0.14027	0.23776	0.14838	0.17877	0.13991	0.20007	0.17519	0.19115
LR2	0.09249	0.42107	0.08360	0.46432	0.03708	0.58470	0.06942	0.66236	0.08214	0.53020	0.20376	0.44209
LR3	0.13449	0.29669	0.20805	0.21180	0.49461	0.09775	0.40162	0.15888	0.40528	0.15104	0.29224	0.25471
LR4	0.25224	0.07732	0.35916	0.08367	0.17028	0.07979	0.38058	0.00000	0.12750	0.11869	0.18747	0.11206
LR5	0.18251	0.00000	0.09604	0.00000	0.08815	0.00000	0.00000	0.00000	0.14166	0.00000	0.07784	0.00000
LR6	0.16315	0.00000	0.11019	0.00000	0.06961	0.00000	0.00000	0.00000	0.10352	0.00000	0.06351	0.00000
LR7	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

Table 6.24. Data representing electricity demand variation in Lithuania

Season	Energy (GWh)		
	Total	WD	SSH
Winter1	2209	1646	563
Spring1	941	695	246
Spring2	788	605	183
Summer	1242	896	346
Autumn	1643	1247	395
Winter2	1734	1329	405
	Energy fraction in seasons		
Winter1	0.2581	0.7452	0.2548
Spring1	0.1099	0.7388	0.2612
Spring2	0.0921	0.7678	0.2322
Summer	0.1452	0.7213	0.2787
Autumn	0.1920	0.7593	0.2407
Winter2	0.2027	0.7663	0.2337

Load region	Assumed energy in load regions (GWh)											
	Winter1		Spring1		Spring2		Summer		Autumn		Winter2	
	WD	SSH	WD	SSH	WD	SSH	WD	SSH	WD	SSH	WD	SSH
LR1	328	121	120	62	93	44	143	67	191	82	259	86
LR2	144	225	56	109	21	102	63	208	95	195	248	163
LR3	244	171	132	54	296	20	346	71	459	69	356	106
LR4	380	45	237	21	96	16	344	0	168	50	262	50
LR5	301	0	68	0	55	0	0	0	190	0	111	0
LR6	249	0	81	0	45	0	0	0	143	0	94	0
LR7	0	0	0	0	0	0	0	0	0	0	0	0
Load region	Assumed energy fractions in load regions											
	Winter1		Spring1		Spring2		Summer		Autumn		Winter2	
	WD	SSH	WD	SSH	WD	SSH	WD	SSH	WD	SSH	WD	SSH
LR1	0.19932	0.21554	0.17337	0.25340	0.15299	0.23991	0.16014	0.19408	0.15328	0.20622	0.19489	0.21172
LR2	0.08777	0.40001	0.08066	0.44432	0.03461	0.55842	0.07053	0.59956	0.07653	0.49262	0.18673	0.40218
LR3	0.14816	0.30387	0.18960	0.21780	0.48985	0.11173	0.38586	0.20636	0.36835	0.17419	0.26767	0.26251
LR4	0.23097	0.08058	0.34140	0.08449	0.15819	0.08993	0.38347	0.00000	0.13455	0.12697	0.19686	0.12359
LR5	0.18269	0.00000	0.09834	0.00000	0.09045	0.00000	0.00000	0.00000	0.15269	0.00000	0.08347	0.00000
LR6	0.15109	0.00000	0.11663	0.00000	0.07390	0.00000	0.00000	0.00000	0.11461	0.00000	0.07038	0.00000
LR7	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

6.6. Summary and conclusions

6.6.1. Significant power generation projects and technologies

The most important power generation options are listed below:

- Reconstruction of Narva power plants (Estonia) capacity, n x 215 MW; technology, CFB; fuel, oil shale.
- Modernisation of Lithuanian TPP, adjusting it to burn three types of fuel and to UCTE requirements.
- Reconstruction of Riga CHP-2 (Latvia)
  2 x 400 MW; CCGT CHP; natural gas.
  Similar reconstructions of existing CHP plants could be realised in Tallinn and Vilnius. CCGT CHP plants with a smaller capacity and less-efficient parameters could appear in other large cities of the Baltic States.
- Coal-fired power plant in Ventspils and/or Liepaja cities (Latvia)
  400 MW; PCC or CFB CHP; coal, biomass, peat.
- Construction of units No. III and IV of Ignalina NPP or replacement of existing reactor RBMK-1500 by a modern (safe) technology (Lithuania)
  1 or 2 units x 1000–1600 MW; EPR-1600 (PWR) or SWR-1000 (BWR); nuclear fuel.
- New large HPP in Jekabpils or Daugavpils (Latvia)
  Hydro turbogenerators at Jekabpils of 30 MW, or at Daugavpils of 100 MW.
- CHP plant of pulp factory (Latvia)
  110–140 MW, indirect black liquor GCC and bark boiler, wood.
- Distributed generation, such as wind generators, small hydro, microturbines, internal combustion engines (gas, diesel, biofuel), etc.

Comparing the three types of technology (coal, natural gas and nuclear), it is possible to conclude that no technology alone is 'a clear-cut winner' [65]. *Table 6.25* illustrates this. At the same time it is possible to see that coal technology has the most uniform cost structure, while natural gas technologies directly depend on fuel cost fluctuations, but nuclear technology has quite high investment costs.

Table 6.25. Cost structure, levelised costs and specific overnight construction costs for different generating technologies

Expenses	*Pulverised coal technology*	*Combined cycle (natural gas)*	*Nuclear technology*
Investments	25–50%	15–20%	50–60%
O&M costs	20–25%	5–10%	20–35%
Fuel	25–50%	70–80%	15–20%
Total	*100%*	*100%*	*100%*
Range and average value of levelised costs of generation at 10% discount rate (€/MWh)* [65]	20–52	30–49	23–52
Specific overnight construction costs (€/kW)* [65]	560–1820	285–790	850–1950

*€1 = $1.3.

6.6.2. *Significant power transmission projects*

The most important power transmission projects are listed below and presented in *Figure 6.17*:

- Asynchronous interconnection of the Baltic transmission system with the Scandinavian NORDEL system (150 kV HVDC Light 350 MW link between Finland and Estonia) – Estlink project.
- Asynchronous interconnection of the Baltic transmission system with the Central European UCTE system (400 kV HVAC 1000 MW link with a back-to-back station between Lithuania and Poland).
- 330 kV HVAC transmission line between Latvia and Estonia.
- 700 MW HVDC (Light or Classic) link between Sweden and Lithuania, SwindLit.
- An alternative to the SwindLit project is an interconnection between Latvia and Gotland Island.

Figure 6.17. Power transmission network development in the Baltic States.

7. ANALYSED SCENARIOS

7.1. Main scenarios

The national and 12 regional cases, described below, are characterised as a set of **main scenarios**. Practically all the main scenarios are analysed for condition “Aa” — see *Table 7.1* for details — except for Scenarios 1R and 2R, which are also analysed for conditions “Ab” and “Ac”. The full code name of a scenario comprises of its name (see below) followed by the condition identifier (in brackets) as presented in *Table 7.1*.

Scenario 1N: *National self-sufficiency scenario (carried out for each country). The full code name of the scenario is 1N(Aa).* This scenario incorporates:

- All relevant laws and obligations are modeled as constraints in the national models;
- Shut down of the Ignalina nuclear power plant (NPP) in accordance with EU accession agreement;
- Most probable modernisation of Estonian oil shale power plants, Riga combined heat and power plants and Lithuanian thermal power plant (the modernisation process is already underway);
- National power plants cover 100% of the national electricity demand for all countries, starting from 2010;
- Electricity imports and/or exports are allowed only in the base regime;
- Storage requirement for oil products has to be ensured for 90 days (taken into account after optimisation calculations).

Scenario 1R: *Regional self-sufficiency scenario — base case* or *reference scenario.* The first three and last assumptions for Scenario 1N apply for regional calculations, but those remaining are changed to:

- Regional power plants supply 100% of the regional electricity demand for the complete planning period, starting 2010;
- Power exports and/or imports from the Baltic region to third countries are not allowed from 2010, but power exchanges between Baltic countries are possible;
- Power imports and/or exports before 2010 are allowed in a base regime.

Scenario 2R: *Regional scenario with cross-border power exchanges — interlinks.* The assumptions for Scenario 1R apply, plus:

- Existing cross-border power transmission infrastructure with Russia and the Commonwealth of Independent States;
- New power interconnection with the Union for the Coordination of Transmission of Electricity (UCTE; link ‘LIT-POL’, connecting Lithuania and Poland, 1000 MW) and NORDEL (link ‘Estlink’, connecting Estonia and Finland, 350 MW).

Scenario 3R: *Regional scenario with enhanced security of gas supply – gas storage.* The assumptions for Scenario 1R apply, plus:

- Gas storage within the region for 120 days of regional consumption from 2010.

Table 7.1. Conditions for scenario calculations

Aa	Unconstrained gas supply in Estonia and Lithuania, in Latvia only in the summer. Low fuel prices. Unconstrained gas supply means that there is no constraint on the quantity and regime of gas supply. Gas supply to Latvia is possible only during the summer; however, even in this case there is no constraint on quantity and supply regime. The limiting factor is only the throughput capacity of pipelines and capacity of storage, which can be enlarged if necessary, taking into account associated investment cost.
Aaa	Unconstrained gas supply in Estonia and Lithuania, in Latvia only in the summer. Gas and orimulsion are constrained for electricity and heat supply in 4R, 4Ra and 4Rc. This means that gas and orimulsion together should not exceed the shares in total fuel consumption specified for gas only. Low fuel prices.
Aab	Unconstrained gas supply in Estonia and Lithuania, in Latvia only in the summer. Low fuel prices. Forced construction of gas storage in Lithuania and extension in Latvia.
Ab	Unconstrained gas supply in Estonia and Lithuania, in Latvia only in the summer. Extra high fuel prices.
Ac	Unconstrained gas supply in Estonia and Lithuania, in Latvia only in the summer. High fuel prices.
Ea	Unconstrained gas supply in Estonia and Lithuania, in Latvia only in the summer. Low fuel prices. 3% annual growth of electricity produced from renewable energy from 2010.
Ba	Gas supply in Estonia and Lithuania is constant during the year, in Latvia only in the summer. This means that gas to Baltic countries is supplied (when it is allowed) only in the so-called base-load regime. Low fuel prices.
Baa	Gas supply in Estonia and Lithuania is constant during the year, in Latvia only in the summer. Gas and orimulsion are constrained for electricity and heat supply in 4R, 4Ra and 4Rc. Low fuel prices.
Bb	Gas supply in Estonia and Lithuania is constant during the year, in Latvia only in the summer. Extra high fuel prices.
Ca	Gas supply in Estonia and Lithuania is constant during the year, in Latvia only in the summer. Low fuel prices. No orimulsion. Modernisation of Lithuanian TPP is not obligatory. This means that the process of modernisation of Lithuanian TPP is assumed to be optional but not underway.
Da	Gas supply in Estonia and Lithuania is constant during the year, in Latvia only in the summer. Low fuel prices. Limited capacity of modernised oil shale power plants. This represents a case in which the modernisation programme of Estonian oil shale power plants will be abridged.

Scenario 4R: *Regional scenario with gas supply limitation*. The assumptions for Scenario 1R apply, plus:

- Gas supply limitation — 25% contribution of gas in the fuel balance for heat and power production in the Baltic region from 2010.

Scenario 5R: *Regional scenario with prolonged operation of Ignalina NPP Unit 2*. The assumptions for Scenario 1R apply, but:

- Operation of Ignalina NPP Unit 2 continues until 2017.

Scenario 6R: *Regional scenario with fuel diversification.* The assumptions for Scenario 1R apply, plus:

- Imposed construction of Unit 3 at Ignalina NPP and coal-fired plant in Latvia after 2010.

Scenario 7R: *Regional scenario with different environmental taxes.* The assumptions for Scenario 1R apply, plus:

- High environmental taxes for CO_2 emissions from 2008 (20 €/t).

Scenario 1R(Ac): *Regional self-sufficiency scenario with high fuel prices.* The assumptions for Scenario 1R apply, but high fuel prices are assumed — conditions (Ac):

- High fuel prices, in comparison with low fuel prices, mean price increases of 27% for all imported fossil fuels and 6.3% for nuclear fuel in 2005, and 50% and 7.5% in 2010 respectively. The dynamics of fuel price growth in subsequent years is the same as that for low fuel prices. The 7.5% increase corresponds to a 50% increase in uranium market prices. Prices of local fuels remain unchanged. Prices of imported and exported electricity are increased by 21% and 25%, respectively for the high fuel prices.

Scenario 2R(Ac): *Regional self-sufficiency scenario with high fuel prices and interlinks.* The assumptions for Scenario 2R apply, but high fuel and electricity prices are assumed.

Scenario 1R(Ab): *Regional self-sufficiency scenario with extra high fuel prices.* The assumptions for Scenario 1R apply, but extra high fuel prices are assumed:

- Price level of coal, gas, oil, oil products and other imported fuels increases in 2005 by 50% in comparison to conditions in (Aa). Prices of domestic fuels remain unchanged, as (for example) the costs of shale oil extraction in Estonia are independent of international market prices. As for nuclear, fuel costs are increased by 7.5%. (Uranium costs, which according to the assumptions also increase by 50%, contribute only about 10–15% of the total fuel costs. The rest is the cost of enrichment, fabrication, etc.) The electricity price in 2025 increases by 25% in comparison with conditions in (Aa).

Scenario 2R(Ab): *Regional self-sufficiency scenario with extra high fuel prices and interlinks.* The assumptions for Scenario 2R apply, but extra high fuel and electricity prices are assumed.

7.2. Main sensitivity cases

Eight main sensitivity cases are considered in the study, based on the scenarios discussed in Chapter 6.

Scenario 3R(Aab): *Imposed gas storage construction.* The assumptions for Scenario 3R apply, plus:

- Forced construction of gas storage in Lithuania and capacity extension of gas storage in Latvia.

Scenario 4R(Aaa): *Regional scenario with limitation on gas and orimulsion supply.* The assumptions for Scenario 4R apply, but consumption of gas and orimulsion are both constrained.

Scenario 4Ra(Aa): *Regional scenario with gas supply limitation.* The assumptions for Scenario 1R(Aa) apply plus:

- Gas supply limitation — 20% contribution of gas in the fuel balance for heat and power production in the Baltic region from 2010.

Scenario 4Rc(Aa): *Regional scenario with gas supply limitation*. The assumptions for scenario 1R apply, plus:

- Gas supply limitation — 30% contribution of gas in the fuel balance for heat and power production in the Baltic region from 2010.

Scenarios 6Ra(Aa) and 6Rb(Aa): *Fuel diversification separately for coal and nuclear.* The assumptions for Scenario 6R apply, but:

- Imposed construction of Unit 3 at Ignalina NPP (6Ra) after 2010;
- Imposed construction of coal-fired plant in Latvia (6Rb) after 2010.

Scenarios 7Ra(Aa) and 7Rb(Aa): *Different levels of environmental taxes.* The assumptions for scenario 7R apply, but:

- Environmental taxes for CO_2 emissions from 2008 — 5 €/t (7Ra);
- Environmental taxes for CO_2 emissions from 2008 — 10 €/t (7Rb).

7.3. Conditions for scenario calculations

The main scenarios (Section 7.1) and scenarios considered as sensitivity cases (Section 7.2) were calculated for various additional conditions explained in *Table 7.1*.

7.4. Summary of all analysed cases

A summary of all the analysed cases and conditions in which calculations have been performed is presented in *Table 7.2*. Cases marked in green are **main scenarios**, but those in yellow are **main sensitivity cases**. The remaining cases were calculated to check the robustness of solutions in other conditions or to check what impact different conditions have on one or another factor.

Table 7.2. Analysed cases

Scenario	*Conditions*										
	Unconstrained gas supply						*Gas supply is constant during the year*				
	Low fuel prices	*Gas and orimul-sion in 4R, 4Ra, 4Rb. Low fuel prices*	*Low fuel prices. Forced cons-truction of gas storage*	*Extra high fuel prices*	*High fuel prices*	*Low fuel prices. 3% growth of electri-city from RES from 2010*	*Low fuel prices*	*Gas and orimul-sion in 4R, 4Ra, 4Rb. Low fuel prices*	*High fuel prices*	*Low fuel prices. No orimulsion. Modernisa-tion of Lithuanian TPP is not obligatory*	*Low fuel prices. Limited capacity of modernised oil shale power plants*
	Aa	*Aaa*	*Aab*	*Ab*	*Ac*	*Ea*	*Ba*	*Baa*	*Bb*	*Ca*	*Da*
1N	+										
1R	+			+	+	+	+		+	+	+
2R	+			+	+	+	+		+	+	+
3R	+		+	+	+	+					
4R	+	+		+	+	+	+	+	+	+	+
4Ra	+	+		+			+	+	+		
4Rb	+	+		+			+	+	+		
5R	+			+		+	+		+	+	+
6R	+			+	+	+	+		+	+	+
6Ra	+			+			+		+		
6Rb	+			+			+		+		
7R	+			+	+		+		+		
7Ra	+			+			+		+		
7Rb	+			+		+	+		+	+	+

7.5. Main assumptions

The environmental factors presented in *Table 7.3* were taken into account for all calculations.

Table 7.3. Environmental assumptions

CO_2	Constraints on total annual emissions in each country were applied according to the requirements of the Kyoto Protocol; existing and forecast emission taxes were used
NO_x	Constraints on total annual emissions in each country were implemented according to the requirements of the Treaty of Accession to the EU and the Gothenburg Protocol; existing emission taxes were used
SO_2	Constraints on total annual emissions were implemented in each country according to the requirements of the Treaty of Accession to the EU and the Gothenburg Protocol; time- and fuel-dependent constraints on emission concentration in flue gases for the main power plants and boiler houses were applied in parallel; optional installation of flue gas desulphurisation technologies at main power plants was allowed; existing emission taxes were used
Dust	Existing emission taxes were used for Estonian power plants

In addition to the environmental factors, the following policy constraints were applied to all calculations:

- Required share of electricity produced from renewable energy resources in 2010 and thereafter;
- Necessary stocks for oil products.

Other assumptions taken into account during the calculations were:

- Study period until 2025, calculation period until 2045;
- Discount factor is 8%;
- No taxes on fuels;
- No fuel price variations during the year;
- Reserve capacity for power plants and boiler houses are not less than 10%;
- Costs of spent nuclear fuel management and the final disposal of radioactive waste from NPPs are taken into account.

8. RESULTS

8.1. Comparison of main cost parameters

Scenarios defined in Chapter 7 were optimised using the MESSAGE model to determine the optimal development path for the energy sector of the Baltic region over the next 25 years. Detailed results of the base case (reference case) are described in Section 8.2. The results of the main scenarios are described in Sections 8.3–8.11, and presented in Annex I. The results of a sensitivity analysis are summarised in Section 8.12 and in the conclusion.

A comparison of the cost parameters for the main scenarios is presented in *Table 8.1*, and for the main sensitivity cases in *Table 8.2*. The cost parameter 'Region subtotal' in both tables corresponds to the objective function in the MESSAGE model. The objective function represents the lowest discounted total system cost in the base year for all energy system operation and development cost over the entire study period. Specifically, the cost calculation takes into account investment costs, fixed and variable operation and maintenance (O&M) costs, fuel cost and taxes on emissions. The necessary fuel reserves were estimated after the optimisation calculations, which is why reserve costs are given in additional rows. The cost 'Region total' represents the sum of the 'Region subtotal' (or objective function) and the reserve cost.

Table 8.1. Cost comparison of the main scenarios (€ billion, discounted)

Parameter	*Scenario*											
	1N(Aa)	*1R(Aa)*	*2R(Aa)*	*3R(Aa)*	*4R(Aa)*	*5R(Aa)*	*6R(Aa)*	*7R(Aa)*	*1R(Ab)*	*2R(Ab)*	*1R(Ac)*	*2R(Ac)*
Investment cost	2.37	2.18	2.21	2.33	2.26	2.09	3.22	2.93	3.07	2.72	2.49	2.44
Fixed O&M cost	5.17	5.05	5.04	5.06	5.05	5.15	5.23	5.20	5.24	5.19	5.15	5.12
Variable O&M cost	36.76	36.31	36.40	36.37	36.25	35.86	35.61	43.16	42.31	42.80	41.58	41.45
Region subtotal	*44.30*	*43.54*	*43.65*	*43.77*	*43.56*	*43.10*	*44.06*	*51.29*	*50.62*	*50.71*	*49.22*	*49.00*
Reserve cost	0.25	0.23	0.23	0.24	0.24	0.23	0.22	0.22	0.28	0.28	0.26	0.26
Region total	*44.54*	*43.77*	*43.89*	*44.01*	*43.76*	*43.33*	*44.28*	*51.51*	*50.89*	*50.98*	*49.48*	*49.26*

Table 8.2. Cost comparison of the sensitivity cases (€ billion, discounted)

Cost parameters	*Scenario*							
	3R(Aab)	*4R(Aaa)*	*4Ra(Aa)*	*4Rc(Aa)*	*6Ra(Aa)*	*6Rb(Aa)*	*7Ra(Aa)*	*7Rb(Aa)*
Investment cost	2.41	2.58	2.28	2.19	3.09	2.27	2.23	2.33
Fixed O&M cost	5.07	5.14	5.06	5.05	5.19	5.08	5.06	5.09
Variable O&M cost[1]	36.38	36.15	36.28	36.30	35.67	36.27	38.36	40.23
Region subtotal	43.86	43.87	43.62	43.54	43.95	43.61	45.66	47.65
Reserve cost	0.24	0.24	0.25	0.23	0.23	0.23	0.23	0.23
Region total	44.10	44.11	43.87	43.77	44.18	43.85	45.89	47.88

A comparison of the total discounted system cost of the main scenarios and the sensitivity cases is given in *Figure 8.1*.

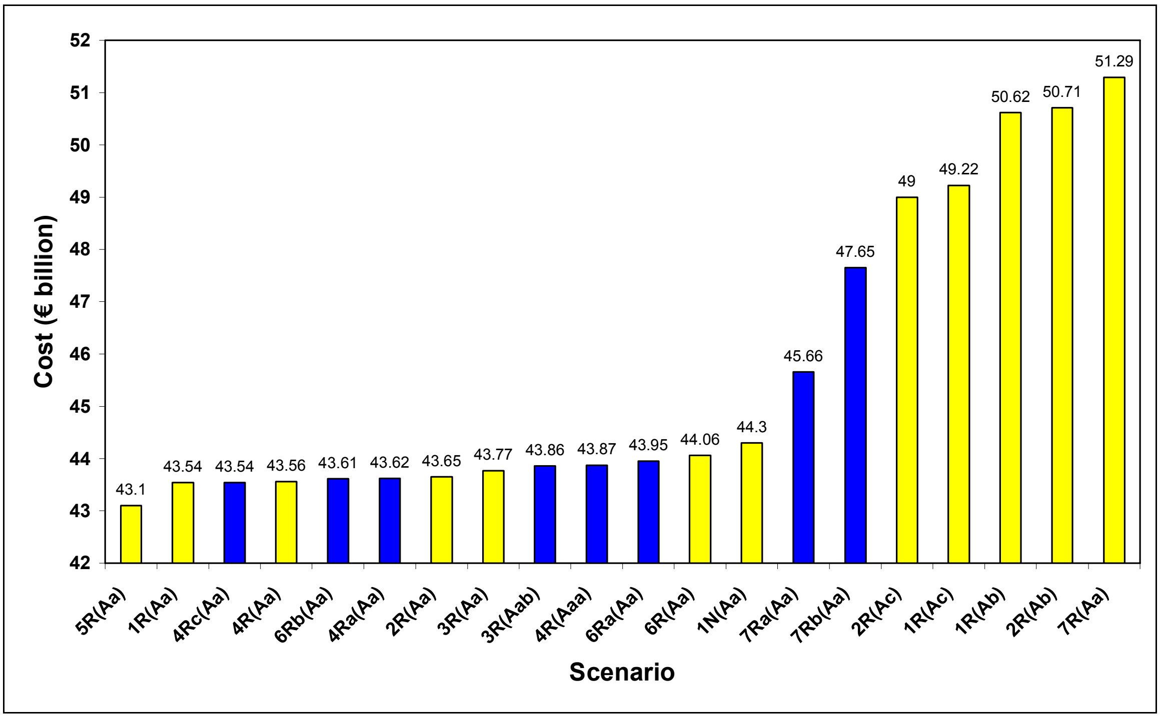


Figure 8.1. Cost comparison of the main scenarios and the sensitivity cases.

The data in *Figure 8.1* shows that the national scenario is more expensive than the regional one. The additional cost of Scenario 1N(Aa) in comparison to 1R(Aa) is more than €760 million. In other words, establishing a common Baltic electricity market can save up to €760 million. The main saving occurs at the start of the joint operation of the market or, in the terminology of this project, at the start of the analysed period and after closure of the second unit of the Ignalina nuclear power plant (NPP).

Scenario 5R(Aa) represents an extended operation time of Ignalina NPP Unit 2 and is the least cost scenario in the study. The continued operation of Unit 2 until 2017 saves €440 million, of which half (about €210 million) would be in 2006–2010 because less preparatory work is necessary for power plants otherwise needed as capacity replacement.

The construction of new nuclear and coal power plants (Scenario 6R(Aa), diversification) involves higher total discounted system costs. The impact of a new NPP (Scenario 6Ra(Aa)) is about €330 million greater than that of the coal power plant (Scenario 6Rb(Aa)). The major additional cost, in the form of investment cost, occurs in 2006–2010. However, the commissioning of a new NPP leads to lower O&M cost in comparison to other fossil fuel development scenarios, although not sufficiently to outweigh the higher up-front investment needs. Nonetheless, the use of nuclear power lowers the substantial risk of a supply shortage for natural gas and orimulsion.

Scenario 2R(Aa), with extended interlinks, is slightly more expensive compared to the reference scenario. Higher costs are linked to the first half of the study period because of the necessary infrastructure investments, although they contribute to a cost saving in the system starting from 2016.

Scenario 3R(Aa), with an increased security of gas supply, is about €230 million more expensive than the reference case because of the additional cost of gas storage. Scenario 4R(Aa), with a reduced share of natural gas used for electricity and heat generation, is €19 million more expensive than the reference scenario. Scenario 4R(Aaa) impacts greatly on Lithuanian power producers who are planning a substantial use of natural gas and orimulsion. This scenario is €329 million more expensive than the reference scenario.

Scenario 7R(Aa), with high environmental taxes, is the most expensive scenario of all the considered cases with low fuel prices. In comparison to the reference case, the additional discounted system cost of this scenario is €7.7 billion. This scenario is also characterised by a transition to environmentally less harmful technologies, such as nuclear.

High prices for imported energy resources, particularly natural gas, orimulsion, oil and oil products (Scenarios 1R(Ac) and 2R(Ac)), significantly increase the discounted cost of energy system operation and development. In comparison to the corresponding scenarios calculated for low fuel prices the total system costs are €5.4–5.7 billion higher. Assuming extra high fuel prices (Scenarios 1R(Ab) and 2R(Ab)) increases the total system cost by €7.1–7.2 billion compared to Scenario 1R(Aa). Oil shale and nuclear, which are affected less by import price fluctuations, play a greater role in the fuel balance of these scenarios.

8.2. Reference (base case) scenario

8.2.1. Electricity generation and capacity balance

The structure of electricity generation in the Baltic region for Scenario 1R(Aa) is presented in *Figure 8.2*.

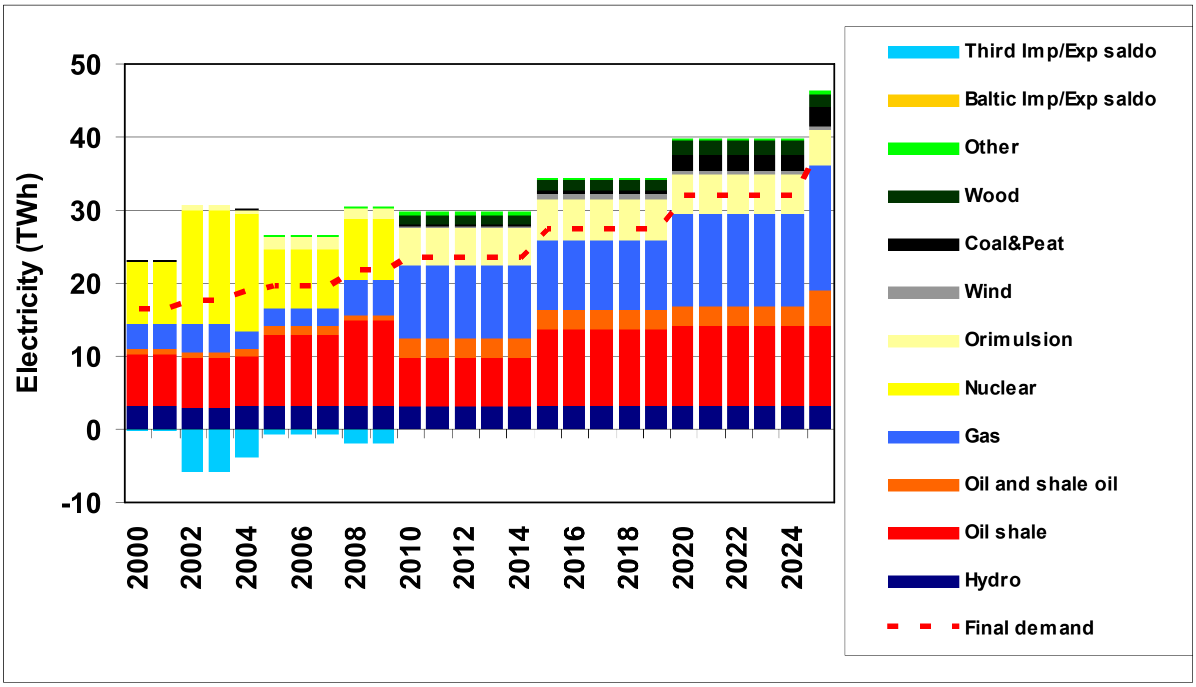


Figure 8.2. Electricity generation by fuel type in the Baltic region for Scenario 1R(Aa) (saldo means imports minus exports; third means all countries excluding Estonia, Latvia and Lithuania).

Figure 8.2 shows that after the closure of Ignalina NPP nuclear fuel is replaced by natural gas, orimulsion and oil shale. In 2009 the share of electricity produced from natural gas is about 17%, and it increases quickly to 33% by 2010, but by 2025 its share only continues to increase to 36%. Electricity generation from oil and shale oil increases from 3.0% in 2009 to 9.1% in 2010 and stays in the range 7.11–12.2% during the remaining analysed period. The significant increase in electricity generation is based on orimulsion, which is used in Lithuania. Its share in 2009 is 5.1%, but by 2010 this increases to 17.4%. From 2010, electricity generation from orimulsion remains in the range 5.0–5.7 TWh, but its share decreases to 10.9% in 2025 because of the total growth of electricity generation in the region.

Electricity generation from oil shale remains very high during the study period. Some fluctuation in electricity generation from oil shale is related to the gradual reduction of electricity generation from nuclear fuel and to the modernisation of Estonian power plants. The highest electricity generation from oil shale is after closure of the first and before closure of the second unit of the Ignalina NPP. In later years, after the modernisation of Estonian oil shale power plants, their electricity generation increases again and remains at the level of 11.5 TWh. The share of electricity generation from oil shale stays in the range of 21.9–40.1% during the analysed period.

The contribution of hydropower plants (HPPs) is the most stable in absolute terms (2.82–3.29 TWh), but its share constantly decreases from 13.8% in 2000 to 7.1% in 2025. This results from the growth in electricity generation from other fuels but relatively little investments in new hydropower capacity. Other fuels, apart from those mentioned above, play a minor role in electricity generation, but coal comes into use from 2020 onwards. Their combined share in 2025 (including peat) is 5.5%. Electricity generation by type of power plant technology in the Baltic region is shown in *Figure 8.3*.

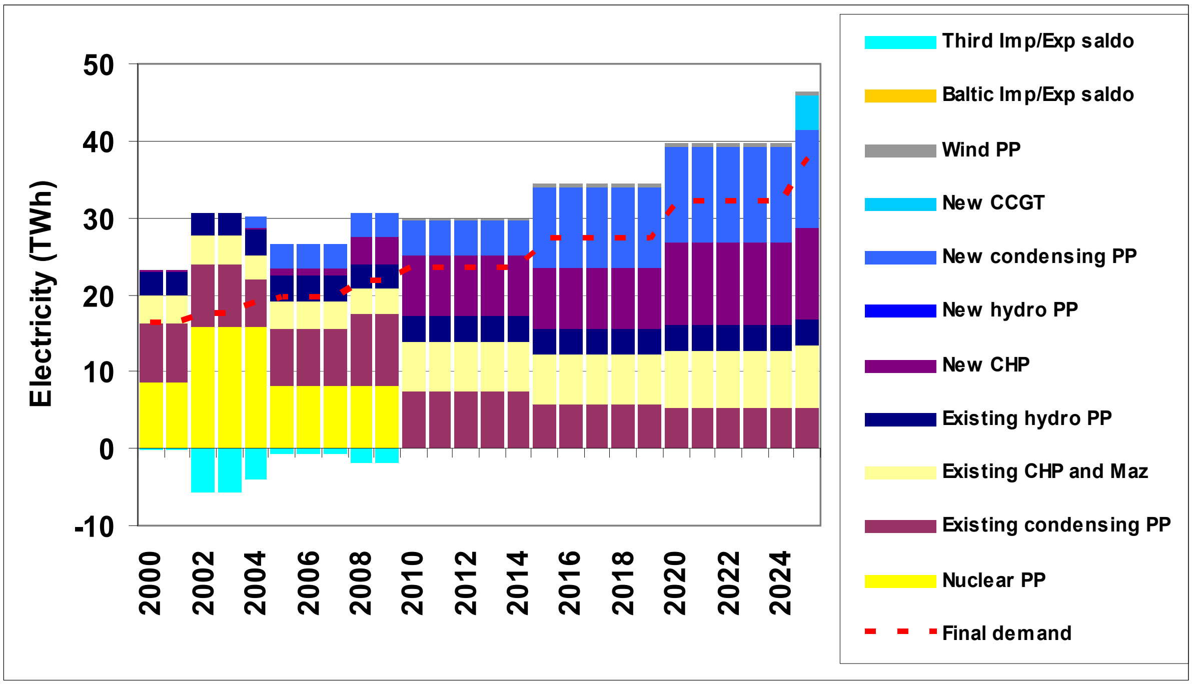


Figure 8.3. Electricity generation by type of technology in the Baltic region (CCGT, combined cycle gas turbine; CHP, combined heat and power; Maz, Mazeikiai; PP, power plant).

Ignalina NPP Unit 2 is one of the largest electricity producers in the region — just one operating unit covers 28–31% of total electricity market generation. However, after its closure conventional (condensing) fossil power plants will become the largest electricity producers. From 2010, taking into account a new condensing unit at the Mazeikiai combined heat and power (CHP) plant, they will contribute 41.6–51.5% of the total generation and produce 13.2 TWh in 2010 and 19.3 TWh in 2025. Combined heat and power generation units are only slightly yield-condensing power plants. Electricity generation from all CHP plants in 2010 is valued at 13.1 TWh, which is 43.9%, and in 2025 it reaches 18.9 TWh, or 40.7%. After closure of the Ignalina NPP Unit 2, electricity generation from CHP plants almost doubles in 2010 in comparison to 2009 - the most of all analysed technologies. CHP is the most likely technology to be used after the closure of NPPs, but its expansion is limited by heat demand.

8.2.1.1. Electricity generation in Estonia

Electricity generation in Estonia is, to a large extent, based on local fuel (i.e. oil shale), which is used at the Eesti and Balti power plants. Until 2004 only the old units at these power plants were in operation and their generation was in the range 6.96–6.98 TWh. In 2004 electricity generation from the old units decreased because one modernised unit came into operation. In subsequent years, electricity generation from the old units is to grow again because of increasing electricity demand in the region, although the majority of the increase is due to the closure of the first unit at the Ignalina NPP in Lithuania. The reduced capacity of the NPP requires increased electricity generation from dirty and inefficient but cheap (using local fuel) generating units of the Balti and Eesti power plants. From 2010, electricity generation from the old units decreases rapidly because of a renovation process that continues until the end of 2014. Electricity generation in Estonia is shown in *Figure 8.4*.

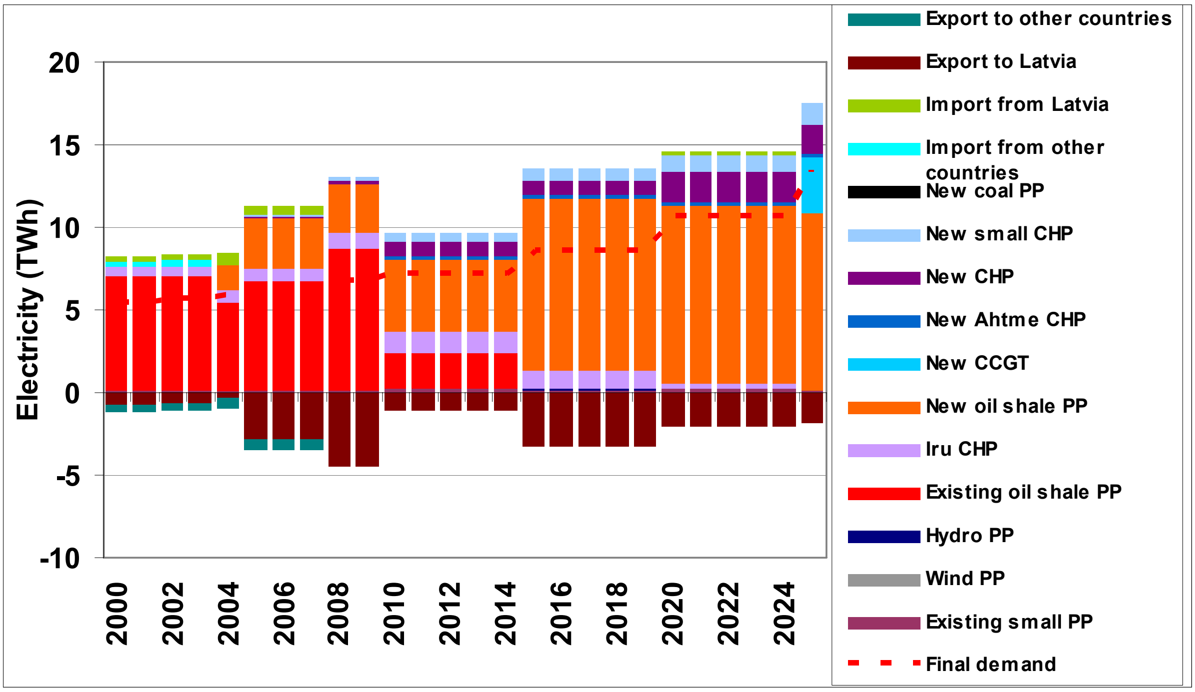


Figure 8.4. Electricity generation of power plants in Estonia.

From 2015 only the renovated units at the Balti and Eesti power plants will produce electricity in Estonia having completely replaced the old units. The calculations show that electricity generation at the renovated units increases from 1.53 TWh in 2004 to 10.43 TWh in 2015 and 10.76 TWh in 2025.

The largest input from the Iru CHP plant to electricity generation in Estonia is expected during the renovation period of the existing units at the Balti and Eesti power plants. Its contribution in the period 2005–2009 is 0.78–0.93 TWh and in 2010–2014 it is 1.3 TWh. Later this decreases to below 1.1 TWh.

New CHP plants will also contribute significantly to electricity generation in Estonia. Their output increases from 0.2 TWh in 2005 to 3.4 TWh in 2025, of which the new Ahtme CHP plant, based on oil shale and wood-waste, will contribute 0.2 TWh. Other CHP plants mainly use natural gas. In 2025, a new combined cycle gas turbine (CCGT) power plant comes on line in Estonia and its generation will be 3.3 TWh. The contribution of other power plants in Estonia is negligible.

Electricity export to Latvia, and even to Lithuania, will be significant during some periods. The largest export (2.8–4.4 TWh) to these countries will be after the first unit of the Ignalina NPP closes, but only until 2010. From 2010, until the Balti and Eesti power plants are renovated, electricity export from Estonia will be limited mainly due to environmental constraints. After renovation of the old units, atmospheric emissions will no longer be a binding factor and Estonia will again export electricity, which in 2015 reaches 3.2 TWh. In the following years, exports gradually decrease because of the growing demand in Estonia, and by 2025 it will be only 1.8 TWh. Only two fuels are significant for electricity generation in Estonia (*Figure 8.5*).

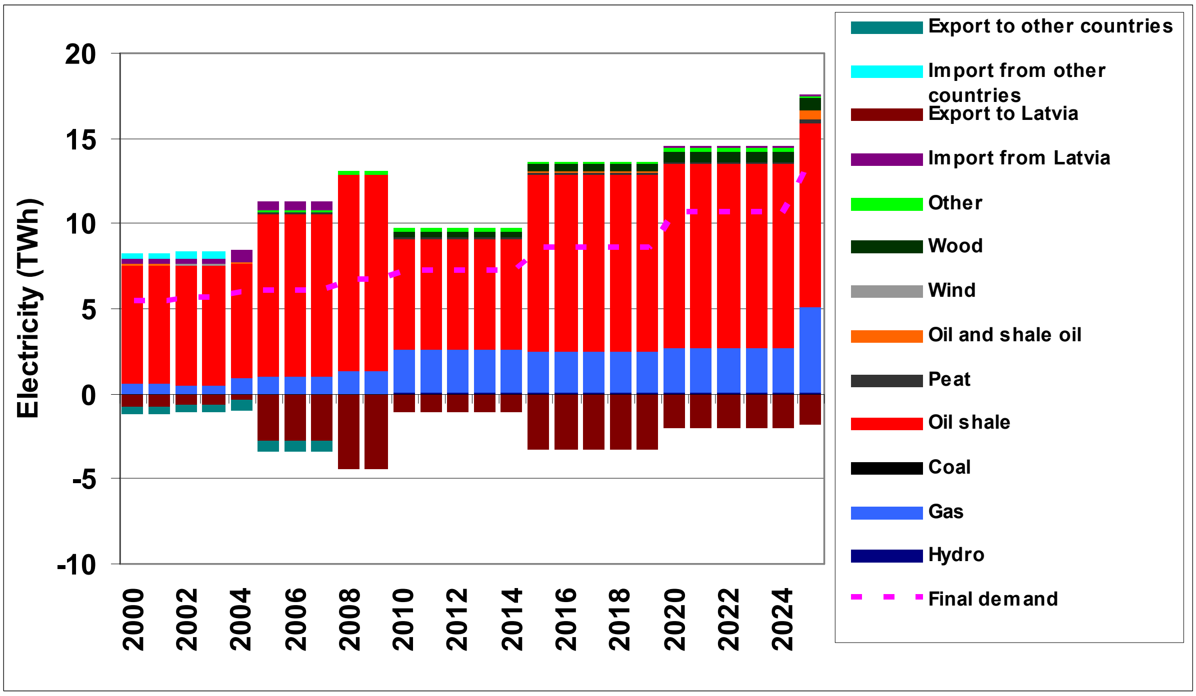


Figure 8.5. Electricity generation by fuel type in Estonia.

Oil shale is the dominant energy source during the study period The share of electricity generated from oil shale remains in the range 61.5–92%. Electricity from natural gas varies from 6.8% to 29% of the total generation in Estonia. The contribution of other fuels is very small, but electricity generation from renewable energy sources (RESs) increases from 4 GWh in 2000 to 0.9 TWh in 2025. This increase guarantees that 5.8–6.4% of total electricity generation in Estonia in the period 2010–2025 comes from RESs.

8.2.1.2.Electricity generation in Latvia

Electricity generation from power plants in Latvia is shown in *Figure 8.6*. The results show that electricity demand is largely covered by generation from HPPs and electricity imports from Lithuania and Estonia. This pattern is typical until 2008 when the new unit at Riga CHP-2 will be completed altering the supply balance. During this first period, HPPs contribute 64–78% of the total electricity generation in Latvia while CHP plants contribute 21–36%, or 1.15–1.3 TWh. Since this covers only 56–70% of the total electricity demand in the country, 30–44% of electricity is being imported.

Local electricity generation in Latvia increases significantly after 2010 when new modern CHP plants (including the Riga CHP plant) start operation. The share of CHP plants during 2010–2015 increases to 59–63% (4.2–4.9 TW) and domestic electricity generation reaches 72–91% of the gross domestic demand. At the same time, the contribution of HPPs in absolute terms remains stable, but the share decreases to 36–40%.

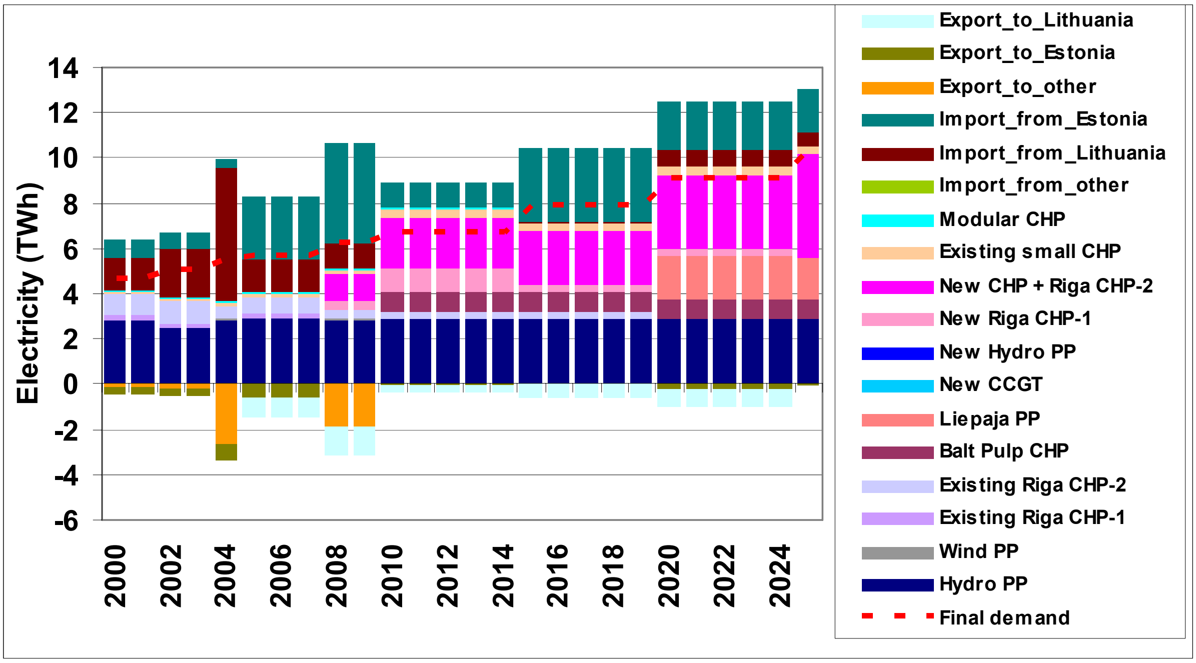


Figure 8.6. Electricity generation by types of power plants in Latvia.

For 5 years from 2015, electricity imports from the modernised Estonian oil shale power plants, based on cheap local fuel, have a significant impact on electricity generation in Latvia. In such circumstances it is not reasonable to expand the generating capacities in Latvia, but in some cases a reduction of the electricity generation at existing units may occur. For example, the annual electricity generation at CHP plants decreases by about 0.7 TWh.

However, continuous growth of electricity demand in Latvia (and in the whole Baltic region) coupled with limited capacity of modernised Estonian oil shale power plants requires capacity extension in Latvia after 2020. A new coal-fired power plant in Liepaja starts operation with an annual electricity generation of 1.8 TWh. As a result, domestic electricity generation in 2020–2025 contributes 81–84% of which HPPs generate 27–30% and CHP plants 51–55%.

Electricity generation by fuel types in Latvia is shown in *Figure 8.7*. The results show that hydropower and natural gas dominate Latvian electricity generation. Annual generation from hydro resources in Latvia is in the range 2.46–2.85 TWh. Electricity produced from natural gas after 2008 contributes 1.63–3.26 TWh. Any significant contribution from coal is limited to the Liepaja power plant, which starts operation in 2020. Total electricity generation from coal after 2020 is about 2 TWh. About 0.88 TWh of electricity can be produced from black liquor if a new paper factory is built in Latvia in 2010. Electricity generation from RESs (i.e. hydro, wind and wood) is about 2.8–3.0 TWh during 2000–2009, which is 40.2–47.5% of total electricity demand and about 4.0–4.06 TWh after 2010, or 30.3–47.4%. The decreasing trend is because of growing electricity demand. Other fuels have a rather small share of electricity generation in Latvia during the analysed period.

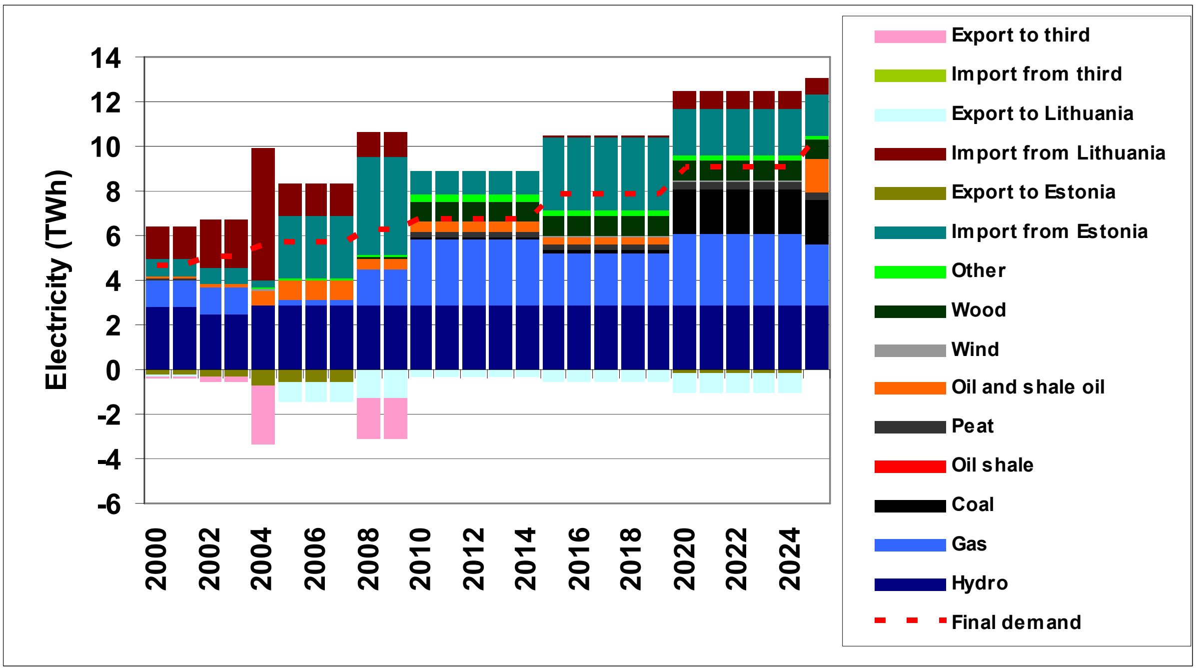


Figure 8.7. Electricity generation by fuel types in Latvia.

8.2.1.3. Electricity generation in Lithuania

Until the closure of the second unit of the Ignalina NPP, electricity generation from nuclear fuel will be dominant in Lithuania. The share of electricity produced in 2005–2010 is 64.8%-72.1 and before 2005 its production exceeded gross electricity consumption in Lithuania (*Figure 8.8*).

After 2009 electricity generation from orimulsion becomes the most economic choice in Lithuania (*Figure 8.9*). Orimulsion retains the highest share until 2020 with an annual electricity output of 5.2–5.7 TWh, or 41–33% of the total generation. Orimulsion is primarily used at the Lithuanian thermal power plant (TPP), but it is also part of the fuel balance of the Vilnius and Kaunas CHP plants. In 2020, after the replacement of one existing unit by a new CCGT CHP unit at the Vilnius CHP plant, natural gas overtakes orimulsion in electricity generation. After 2020 electricity generation from natural gas contributes more than 42% and continues to increase with the construction of new CCGT units and the replacement of the existing unit at Kaunas CHP plant by a new CCGT CHP unit in 2025. By 2035 the share of natural gas in Lithuania's electricity generation increases to 73%.

A significant share of electricity in Lithuania is generated from asphaltene at the Mazeikiai CHP plant. After completion of an additional 210 MW unit, electricity generation at this plant will be in the range of 2.08–2.18 TWh, but its share decreases from 15.3% in 2010 to 11.9% in 2025. Electricity produced from RESs is estimated to be 0.7–1.16 TWh during 2010–2025, which is equivalent to 5.7–7.1% of total electricity generation. The contribution of other fuels to electricity generation remains very small during the analysed time period.

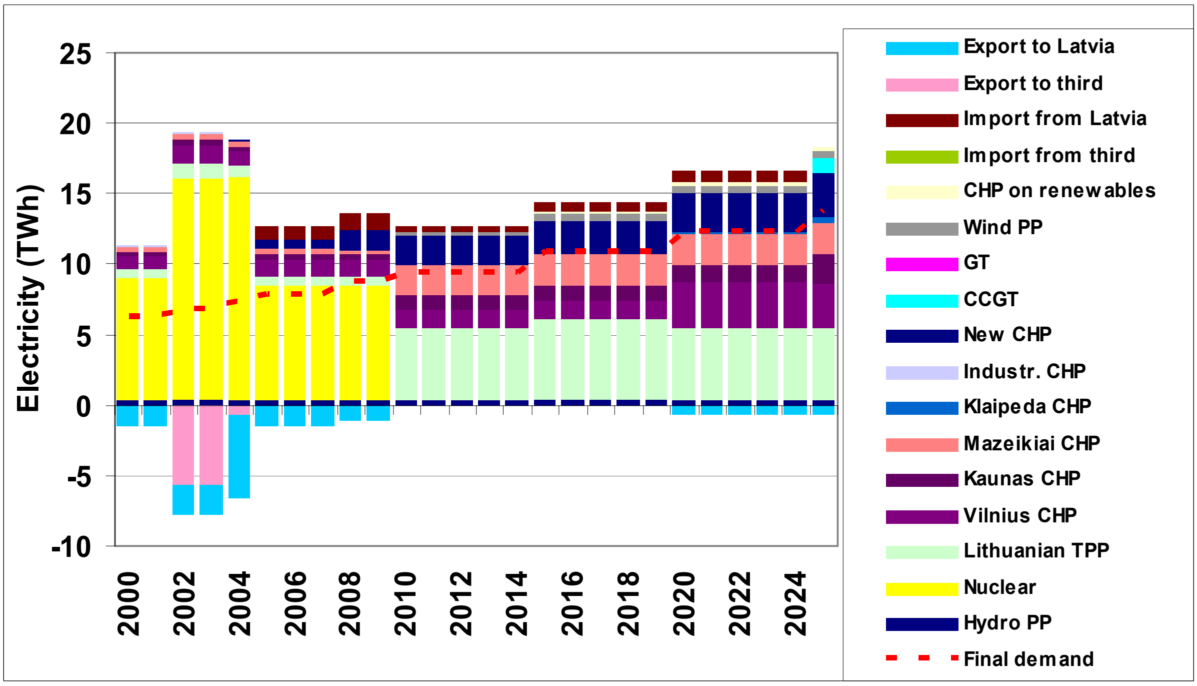


Figure 8.8. Electricity generation by type of technology in Lithuania.

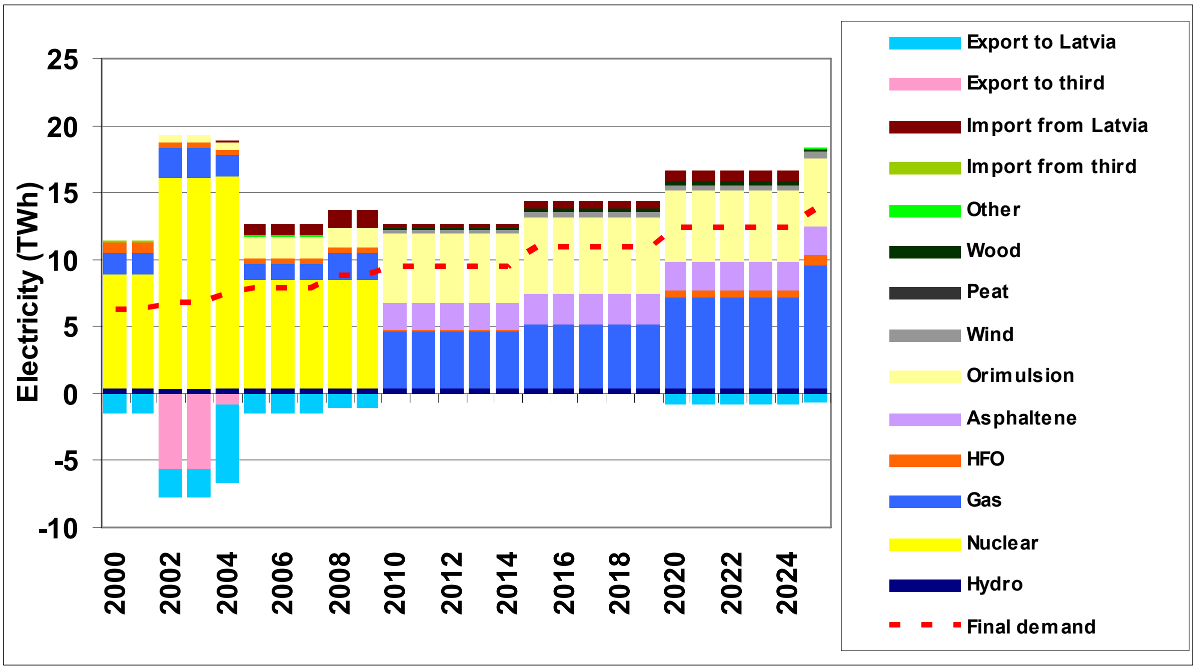


Figure 8.9. Electricity generation by type of fuels in Lithuania. (HFO, heavy fuel oil.)

8.2.1.4. Capacity balance in the Baltic region

The capacity balance in the Baltic region is shown in *Figure 8.10*. The largest electrical capacity in the Baltic region is installed in condensing power plants based on fossil fuel. In

2010 this capacity reaches 3615 MW and 3400 MW in 2015. The capacity reduction results from decommissioning of a few old units in Estonia and Lithuania.

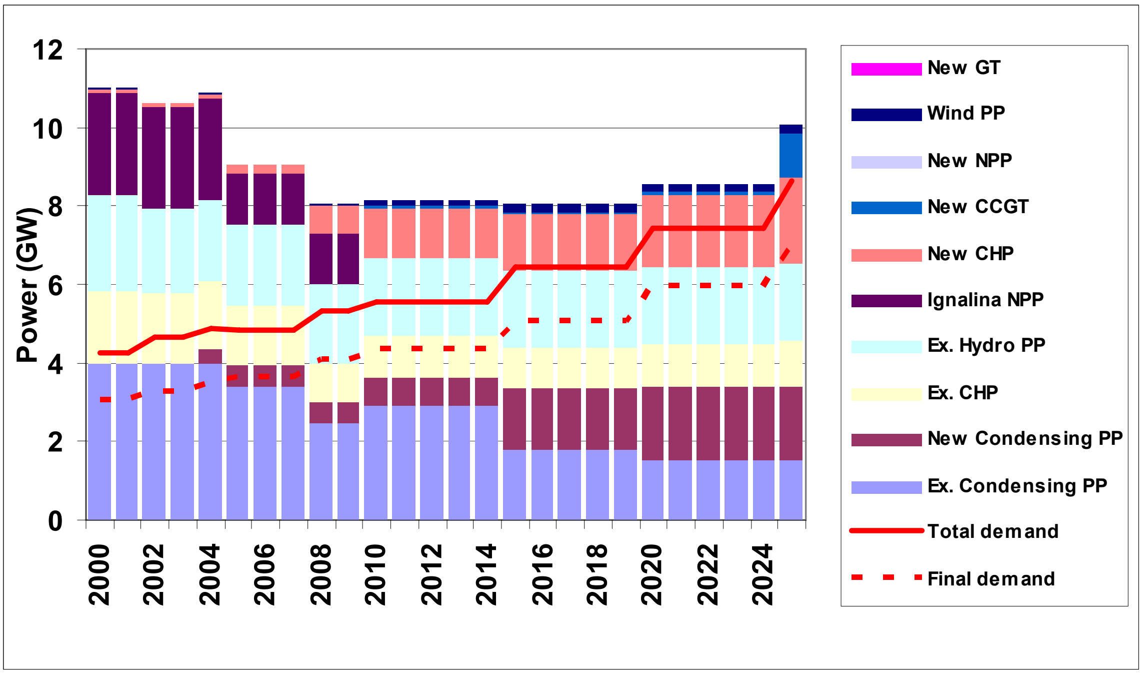


Figure 8.10. Installed capacity of power plants in the Baltic region.

CHP plants have the second highest installed capacity. If their capacity is in condensing mode this value is 2350 MW in 2010 and 3363 MW in 2025 or 29% and 33% respectively. Comparing 2010 to 2000, CHP capacity increases by 420 MW, but its share grows much faster due to the total capacity reduction in the region, mainly because of the Ignalina NPP closure. The installed capacity of HPPs, including hydro pumped storage power plants (HPSPP), decreases from 2452 MW in 2000 to 1969 MW in 2010–2014 because a few existing turbines at the Daugava cascade decommissioned. According to the model results, the renovation of these units is not economic given the remaining installed capacity and water resources in the river. In later years, the capacity of HPPs remains practically stable.

The maximum capacity of wind power plants is about 208 MW in the period 2015–2020. A new CCGT comes on line in 2010 (a new unit at Kaunas CHP plant of 80 MW), but a substantial capacity increase is perceptible only at the end of the analysed period. In 2025 its capacity is about 1120 MW.

8.2.1.5.Capacity balance in Estonia

Power plants that run on local fuel-oil shale are typical for the Estonian power system (*Figure 8.11*). Major parts of the existing older units are gradually renovated to maintain reliability and environmental standards and to build the core of the power system. Their installed capacity in the period 2000–2009 is in the range 1975-2300 MW but decreases to about 1570 MW in 2010–2014 and to 1350–1380 MW for the remainder of the study period. This capacity decrease mainly relates to the decommissioning of old 100 MW units, for which rehabilitation is not foreseen because of their technical condition.

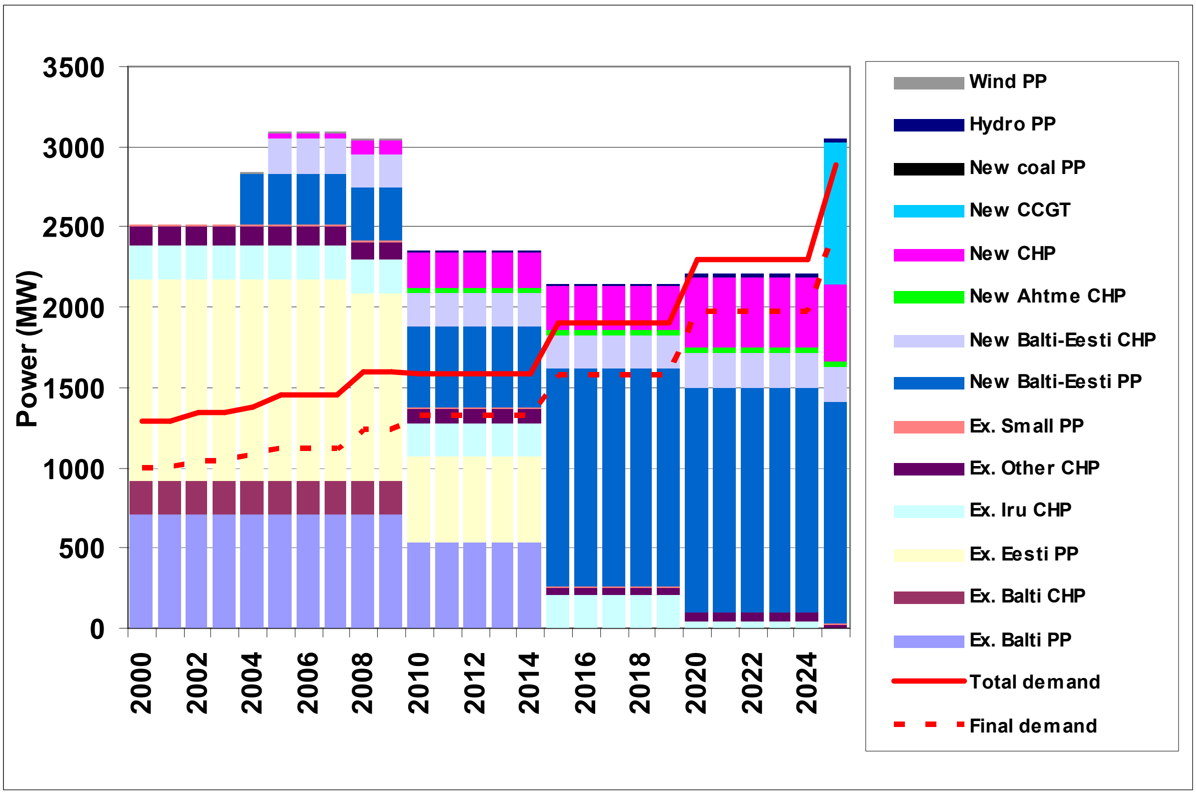


Figure 8.11. Installed capacity of power plants in Estonia. (Ex., existing.)

Given the CHP units at the Balti and Eesti power plants, CHP capacity is gradually increasing in Estonia. In 2000 it was 536 MW and in 2025 it is 755 MW. However, older units will gradually be removed from service and replaced by new ones. The new CCGT units will be ready in Estonia only at the end of the study period.

The installed capacity of Estonian power plants satisfies capacity demand only to 2020, while electricity generation is always greater than total domestic demand. This means that Estonian oil-shale power plants run in a base regime and export base load electricity, while peak load electricity is partly imported.

8.2.1.6. Capacity balance in Latvia

The installed capacity of the Latvian power system satisfies the country's demand during the analysed period, but a large part of this capacity is used for peaking purposes. Thus Latvia, despite sufficient installed capacity, imports a large amount of energy. The available capacity of hydropower plants during the winter maximum (peak) load is only 400-600 MW, which is not sufficient to cover the demand. Peaking capacity is concentrated in the Latvian HPPs. Their installed capacity is more than half of all installations up to 2020, but reduces from 1508 MW in 2000 to 1016 MW in 2010–2025.

CHP provides most of the remaining part of the installed capacity of the Latvian power system, growing from 630 MW in 2000 to 1090 MW in 2025, with some capacity reduction in 2005–2007 because the units at Riga CHP-1 are closed. A significant portion of this capacity is concentrated at the renovated Riga CHP-1 and Riga CHP-2 units. In addition, the Liepaja coal-fired power plant (275 MW capacity installed in 2020) and the existing wind power plants (26.9 MW) add to the installed capacity balance. The dynamics of the installed capacity in Latvia, as well as the country's electricity demand, are shown in *Figure 8.12*.

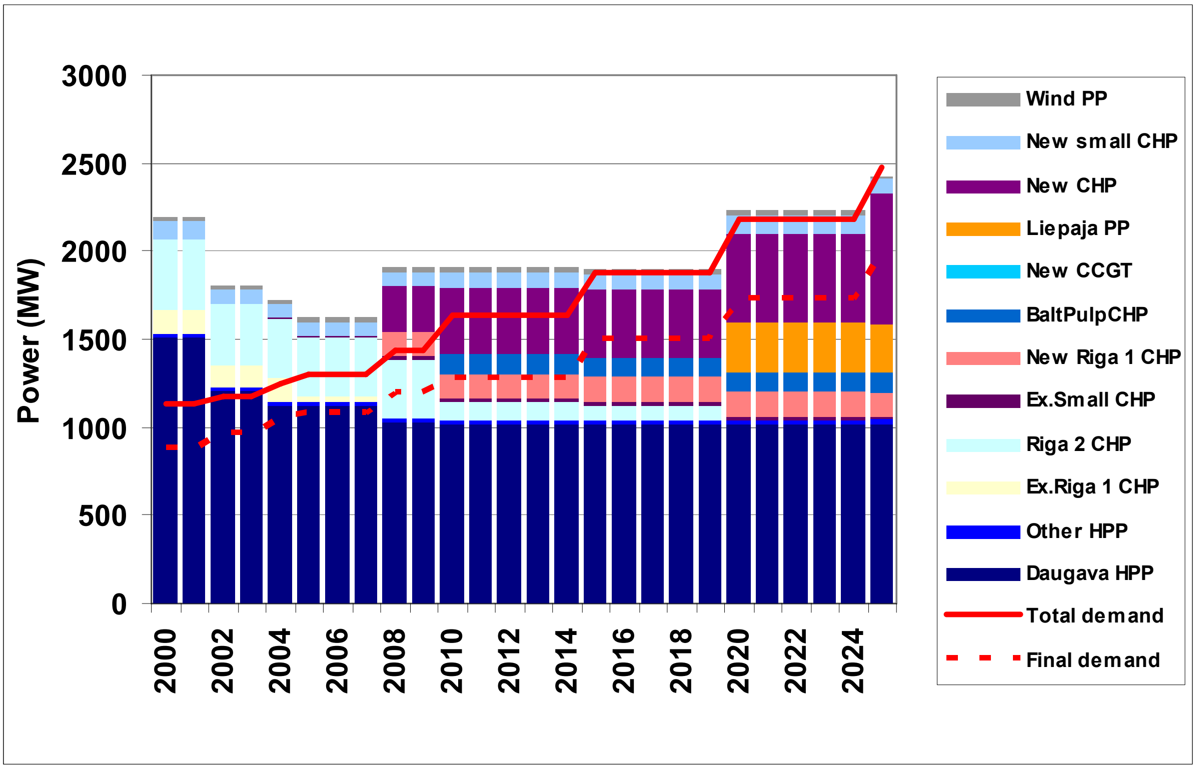


Figure 8.12. Installed capacity of power plants in Latvia.

8.2.1.7.Capacity balance in Lithuania

The capacity balance for Lithuania is shown in *Figure 8.13*. The Lithuanian system peak load, which comprises final electricity demand, electricity losses in the transmission and distribution (T&D) networks and the system's own use, increases from 1847 MW in 2000 to 3272 MW in 2025 (solid line in *Figure 8.13*). The supply capacity (columns in *Figure 8.13*) comprises the capacities of the upgraded Lithuanian TPP, both existing and new CHP plants, the HPPs, wind power plants and the new CCGT to be built by the end of the analysed period. By 2010 the total capacity of CHP plants reaches 965 MW and increases further to 1734 MW by the end of the study period. A new CCGT comes on line in 2010 at the Kaunas CHP plant, and towards the end of the study period similar units will be built at Ignalina NPP. No additional CCGT capacity is planned in Lithuania in this scenario. Most of the installed capacity of the Kruonis HPSPP is used as reserve capacity. The installed capacity of the whole system is 3870 MW in 2010 and 4586 MW in 2025.

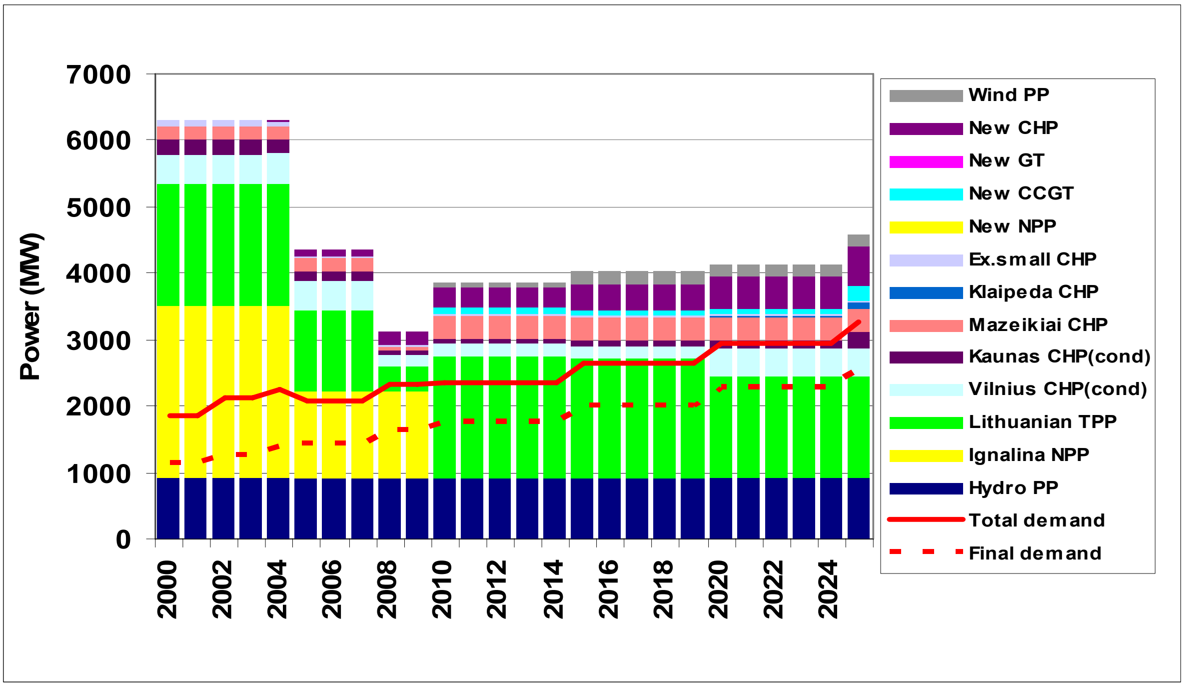


Figure 8.13. Installed capacity of power plants in Lithuania.

8.2.2. Heat production

8.2.2.1.Heat production in the Baltic region

Total final heat demand in the Baltic grows from 25.1 TWh in 2000 to 33.5 TWh in 2025. Heat production is much higher because of losses in the district heat distribution networks. Total heat output from all production sources in the same period increases from 31.7 TWh to 39.1 TWh. The dynamics of heat production by fuels are shown in *Figure 8.14* and by technologies in *Figure 8.15*.

Natural gas is the main fuel for heat production in the Baltic region, reaching 16.6–18.8 TWh or 42.4–49.7% in the study period. The second largest contribution is from wood which increases considerably in 2010 when the CHP plant at the Baltic pulp factory is built. Heat production from wood increases from 3 TWh in 2000 to 3.8 TWh in 2009, 5.2 TWh in 2010 and 6.5 TWh in 2020.

The heat contribution from coal remains relatively stable from 2004 ranging from 3.1–5.5 TWh. While the consumption of oil and shale oil for heat production slowly decreases it stays above 2.8 TWh during the study period.

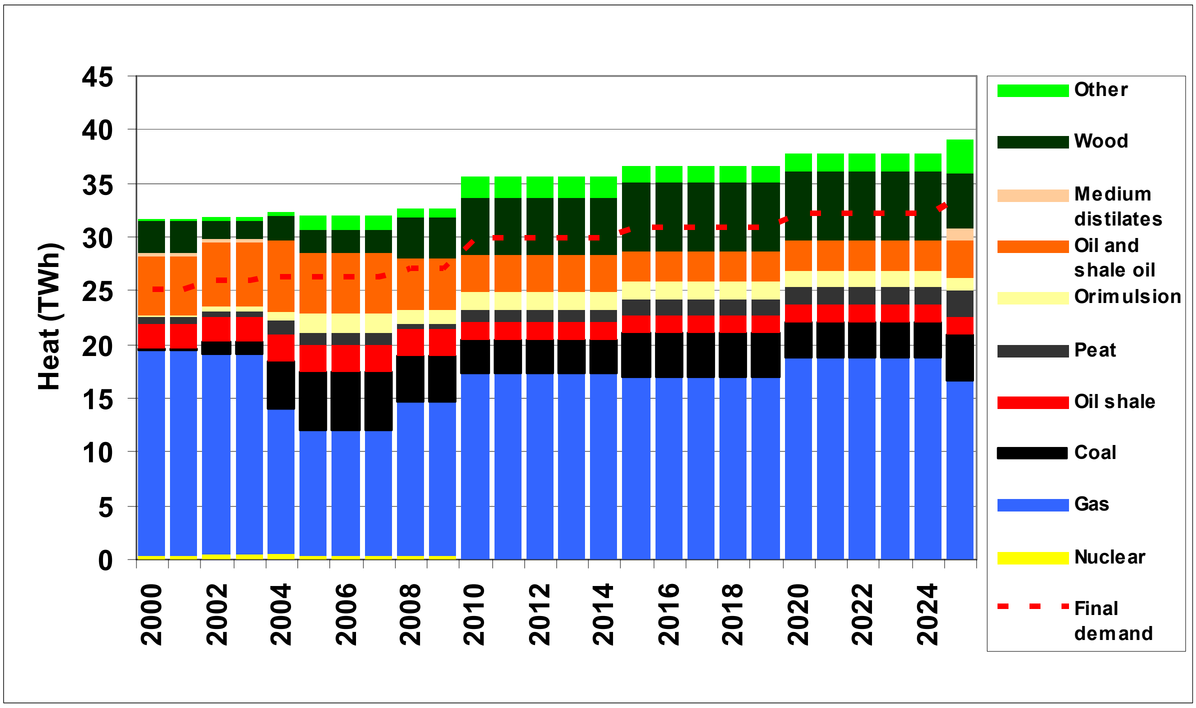


Figure 8.14. Heat production by fuels in the Baltic region.

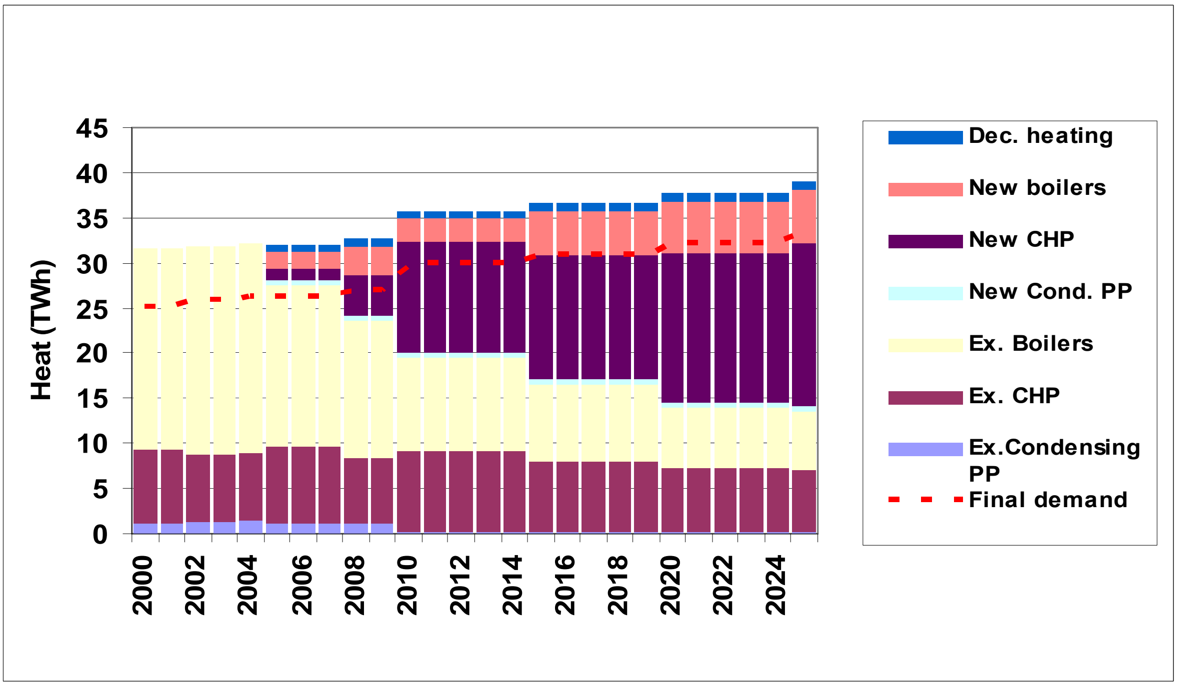


Figure 8.15. Heat production by technologies in the Baltic region.

For heat production technologies, the penetration of new CHP plants into the heat market is fast (*Figure 8.15*). New CHP plants replace existing boilers, especially evident after the closure of the second unit of the Ignalina NPP in 2009. The decommissioning of NPPs and obsolete boilers in boiler houses creates favourable conditions for the development of new CHP plants.

Heat production from new CHP plants is only 4.5 TWh in 2009, while in 2010 it reaches 12.2 TWh. In practice, this increase is likely to be slower, but the model calculations do show a clear trend. In 2025 heat production from new CHP plants reaches 17.9 TWh and, together with heat output from existing CHP plants (6.8 TWh), provides more than 63% of total heat generation (heat generation at CHP plants was only 25.7% in 2000).

8.2.2.2.Heat production in Estonia

Final heat demand and heat production in Estonia remain stable during the period analysed. However, the contribution of natural gas grows from 4.2 TWh in 2000 to 6.7 TWh in 2020 or from 40% to 62.6% respectively. In response to growing shares of natural gas, the contribution of oil shale decreases more rapidly compared to that of wood, both having similar shares in the initial years of the study period. Heat production from other fuels is relatively small during the study period. Heat output by fuel in Estonia is given in *Figure 8.16*.

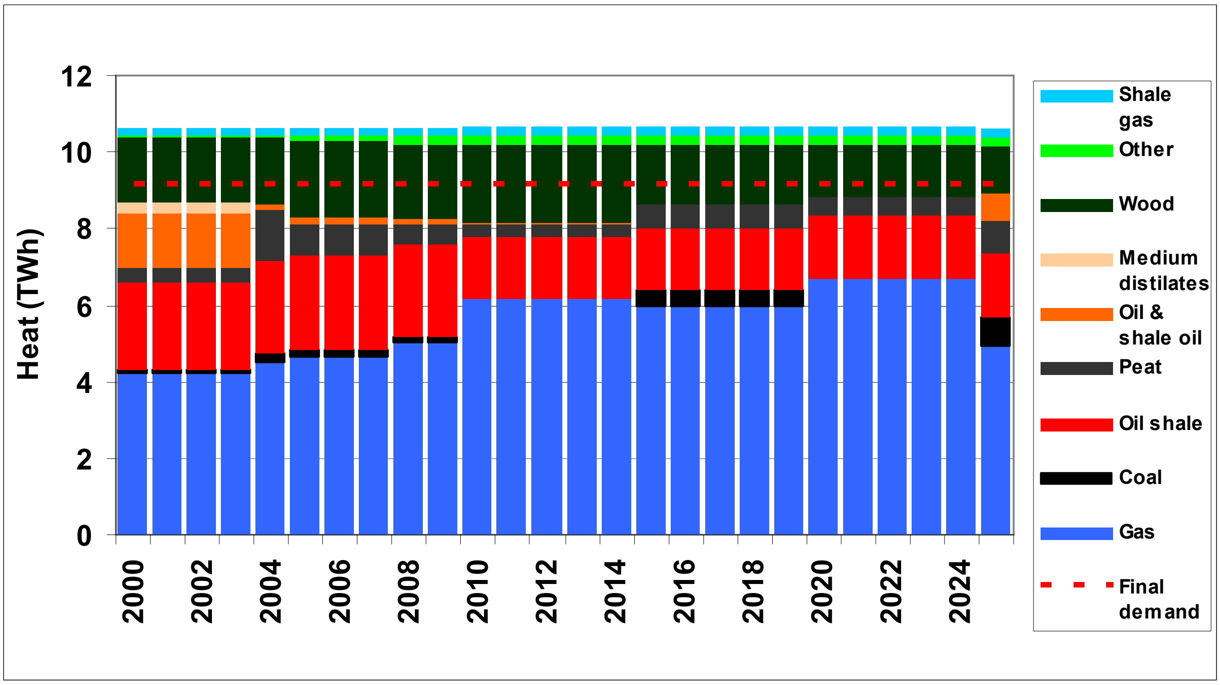


Figure 8.16. Heat production by fuels in Estonia.

The dynamics of heat production by technologies in Estonia are very similar to those of the whole region. Here, the new CHP plants also replace obsolete boilers. The contribution of CHP to heat production was 15.7% in 2000 and grows to 31.9% in 2009, to 55.6% in 2010, and to 52.6–57.4% during the remainder of the study period.

8.2.2.3.Heat production in Latvia

Final heat demand in Latvia is expected to grow mainly because of the construction of a new paper factory – Baltic pulp. This significantly increases the consumption of black liquor (fuel derived from wood, a by-product in the pulp industry) for heat production, as shown in *Figure 8.17*. In 2010 heat production from wood increases by 1.4 TWh compared to that in 2009.

The total heat production in Latvia grows from 8.9 TWh in 2000 to 11.2 TWh in 2010 and 12.5 TWh in 2025.

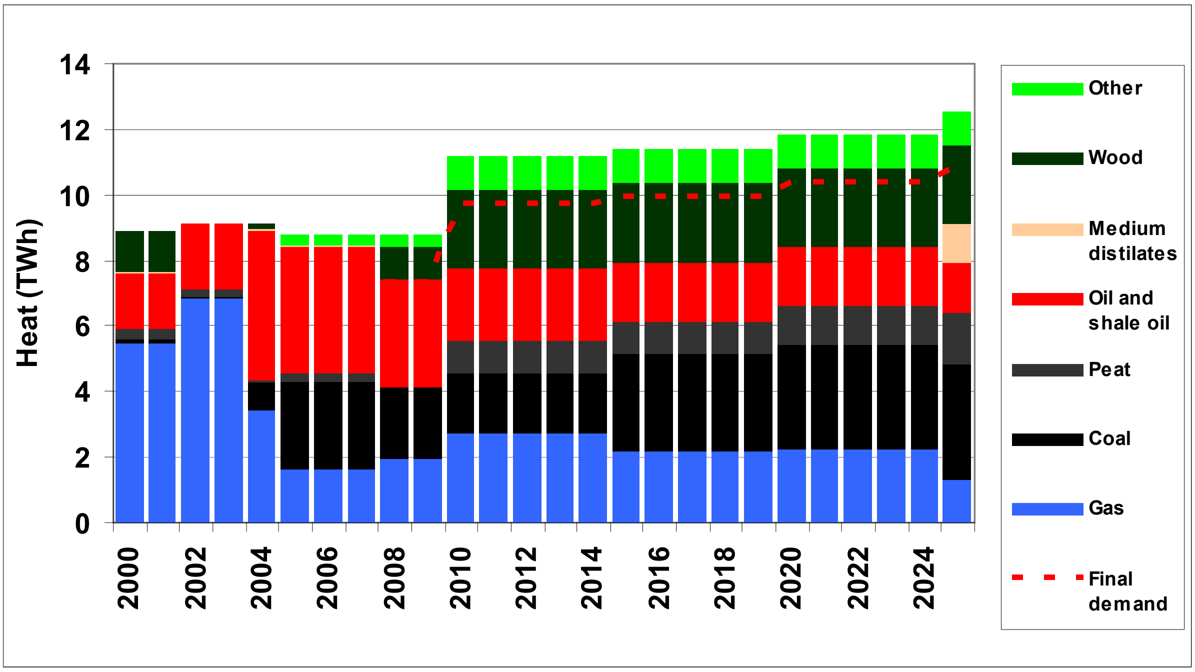


Figure 8.17. Heat production by fuels in Latvia.

Another specific feature of Latvian heat production is the rather wide diversity of fuels used. After 2010 the shares of heat produced from natural gas, coal, oil and shale oil, as well as from wood, are similar. This situation results, to a large extent, from the specific regime of gas imports to the country. According to the heat-demand pattern, the highest heat production should be in the winter period. Correspondingly, the gas demand should also be at its highest in the winter period. However, gas imports to Latvia are assumed to occur only during the summer period. This is the practice now and, according to expert opinion, will remain so in the future. Thus, seasonal gas storage increases the gas price for CHP plants and boiler houses and makes gas less competitive in comparison to other fuels.

The dynamics of heat production by technologies in Latvia are rather similar to those for the other countries and the whole region. Nevertheless, the penetration of new boilers that consume different fuels is higher than in other countries because of the special regime of gas supply to Latvia. Heat production at CHP plants in Latvia grows from 28.4–32.6% during 2000–2009 and to 56.6–67.8% during the remaining study period.

8.2.2.4.Heat production in Lithuania

Final heat demand in Lithuania grows from 8.7 TWh in 2000 to 13.5 TWh in 2025. The corresponding increase in heat production is from 12.2 TWh to 15.9 TWh. The dynamics of heat production by fuels are shown in *Figure 8.18*.

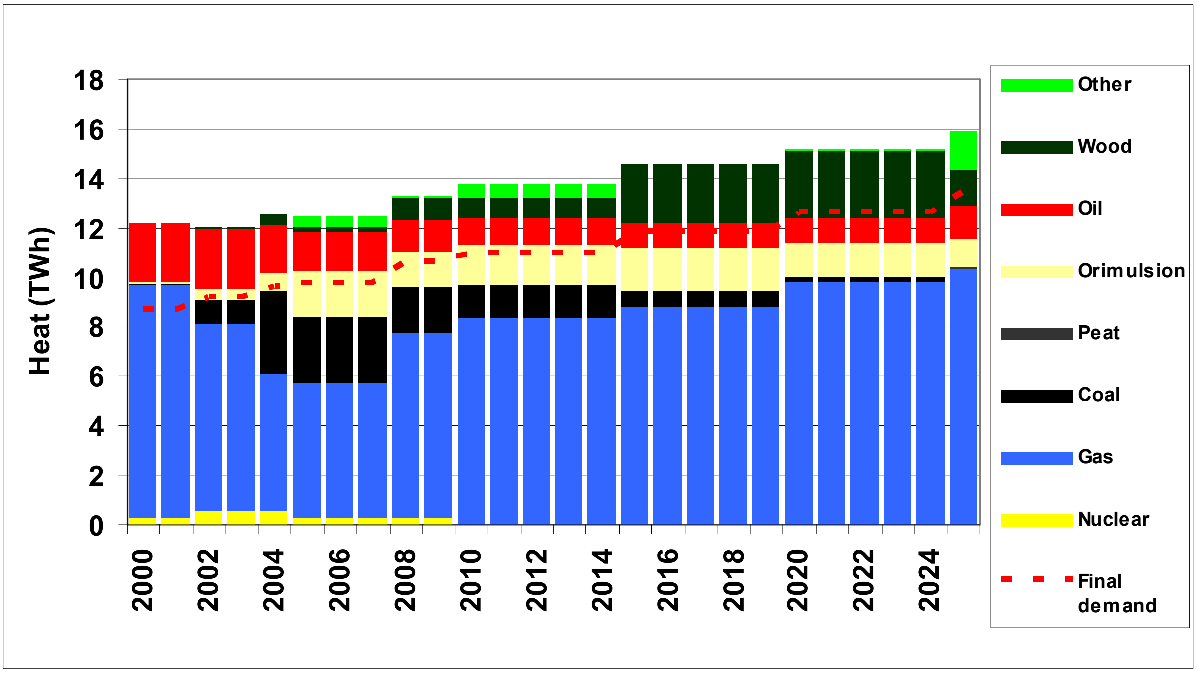


Figure 8.18. Heat production by fuels in Lithuania.

After closure of the first unit at the Ignalina NPP, the utilisation of existing CHP plants increases because they become competitive in the electricity market, operating as combined heat and power producers. This leads to a higher heat output from turbines and lower heat production from boilers that produce only heat, most of which are located at the same site as the turbines. The closure of the second unit at the Ignalina NPP has a minor impact on the heat output from existing CHP plants because these plants already operate at their maximum permissible load. This is determined by heat demand in the particular heat market and by the hydraulic regime of the heat supply network. Major changes in the structure of heat production take place in the district heating systems that do not have CHP plants. Here fast penetration of new CHP plants is possible, replacing existing boilers. The fastest growth in heat output is from new renewable CHP plants and new small CHP plants that operate on natural gas. Boiler houses converted into CHP plants, by installing steam turbines behind the steam boilers or by additional gas turbines in front of them, provide a significant contribution to total heat production.

The contribution of CHP plants, excluding the incorporated heat-only boiler (HOBs), to the total heat production in Lithuania is 25–29% in 2000–2004, 33–42% in 2005–2009 and 54–74% in subsequent years.

The Lithuanian heat supply sector is more dependent on natural gas compared to Estonia and, especially, Latvia. Heat production from natural gas contributed 77% to the total production in 2000 but decreases to reach its lowest value of 43.7% in 2007 according to the study projections. From 2008, because of stronger environmental standards and the gradual decommissioning of old boilers using other fuels, the share of heat produced from natural gas starts to grow again from 56.3% in 2008 to reach 64.8% in 2025.

According to the study results, orimulsion may become significant in heat generation if partly used at the Vilnius and Kaunas CHP plants. If this does not happen, the corresponding heat production share comes from natural gas or oil, or both. Heat production from coal can be extended temporarily at existing boiler houses, but with the decommissioning of old boilers the role of coal decreases because heat production from natural gas is economically more attractive.

8.2.3. Fuel consumption for electricity and heat production

8.2.3.1.Fuel consumption for electricity and heat production in the Baltic region

The fuel mix used for electricity and heat production in the Baltic region is shown in *Figure 8.19*.

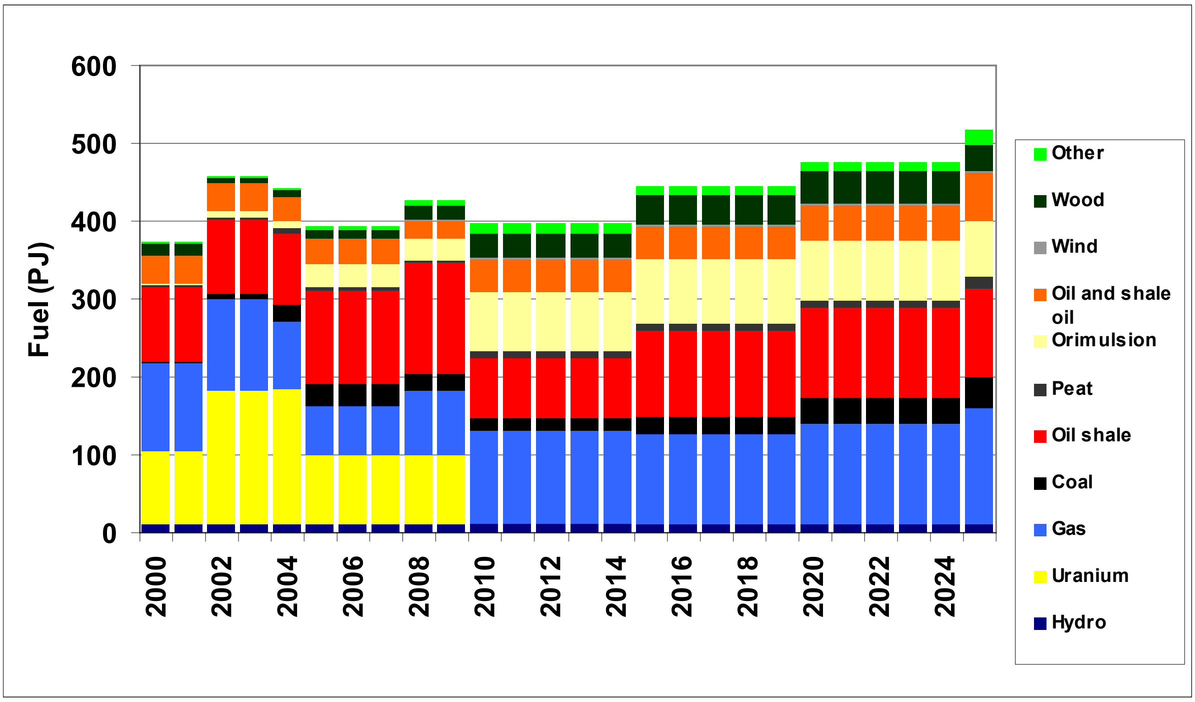


Figure 8.19. Fuel used for electricity and heat production in Baltic region.

Total fuel consumption is practically constant until half-way through the study period. The main reasons are improvements in the efficiency of heat and power generation technologies by substituting old with new equipment or by modernising older parts, as well as decreases in electricity exports to regions outside the three Baltic States. Small increases in fuel consumption during the periods 2002–2004 and 2008–2009 are linked with higher electricity exports to third countries. Fuel consumption in the first half of the study period lies between 372 PJ and 394 PJ, if electricity exports are not taken into account. From 2015 fuel consumption slowly increases because of increased electricity and heat demand, as well as the saturation of energy efficiency gains in heat and power generating technologies.

The study shows that the share of the three main groups of fuels is more or less equal for electricity and heat generation:

- Hard fuel, representing oil shale, coal and peat;
- Liquid fuel, representing orimulsion, heavy fuel oil (HFO) and oil shale;
- Natural gas.

After 2010 each of these fuels has a share of 25–33% of the total fuel consumption for electricity and heat generation, as shown in *Figure 8.20*.

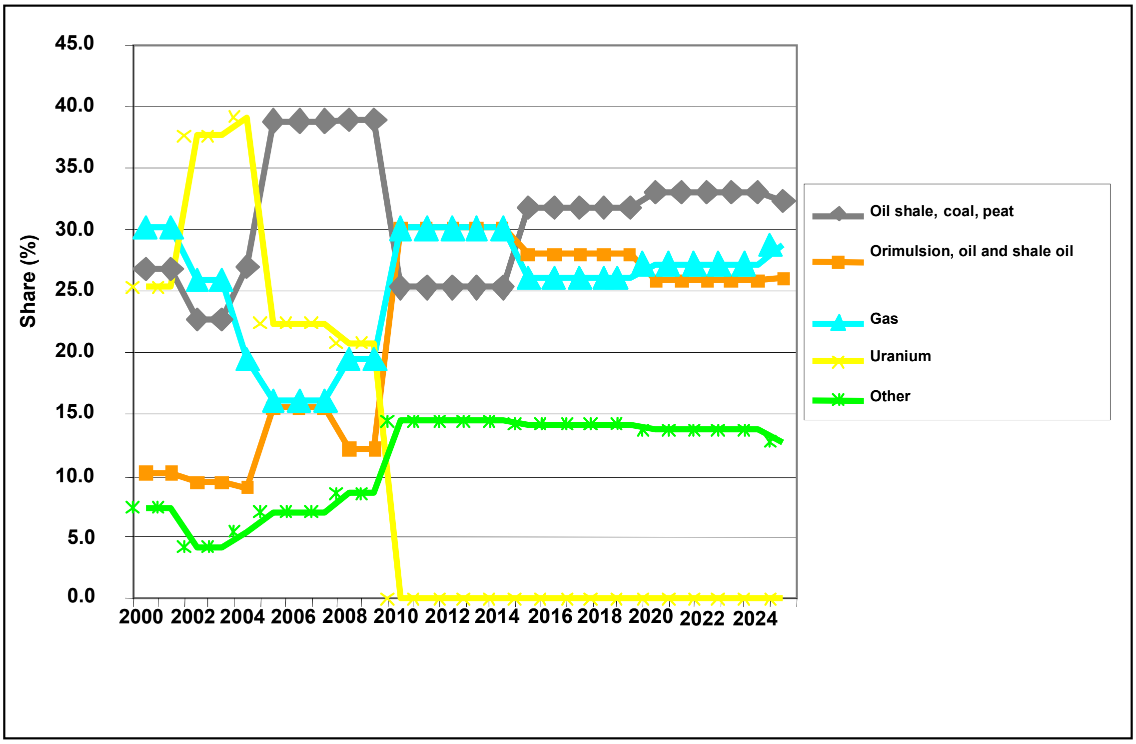


Figure 8.20. Different fuel shares in electricity and heat production in the Baltic region.

The share of other fuels remains below 15% during the study period. Nuclear fuel has a significant share only before the first unit of the Ignalina NPP closes. After 2005 nuclear fuel has a market share of no more than 22.4 % and naught after 2010 when the final unit of Ignalina is shut down.

Figure 8.20 shows that solid fossil fuels are the most important ones, not only because they are local (oil shale), but also because they have the largest share in electricity and heat production. Their use is higher than that of other fuels during most of the study period, at 90–95 PJ in 2000–2004, 120–142 PJ in 2005–2009, 77 PJ in 2010–2014 and 110–114 PJ during the remainder.

RESs contribute 23.7–35.9 PJ in 2000–2009 and 54.9–61.8 PJ in 2010–2025. The lowest share of RESs is in 2002–2003, at 5.18% of the total fuel used for electricity and heat generation, because of low water levels in the Daugava hydro cascade, while the highest share, at 14.4%, is half-way through the study period. During the second half of the study period the share of RESs remains in the range 11.1–13.0%.

8.2.3.2.Fuel consumption for electricity and heat production in Estonia

The dynamics of fuel consumption for electricity and heat generation are presented in *Figure 8.21*.

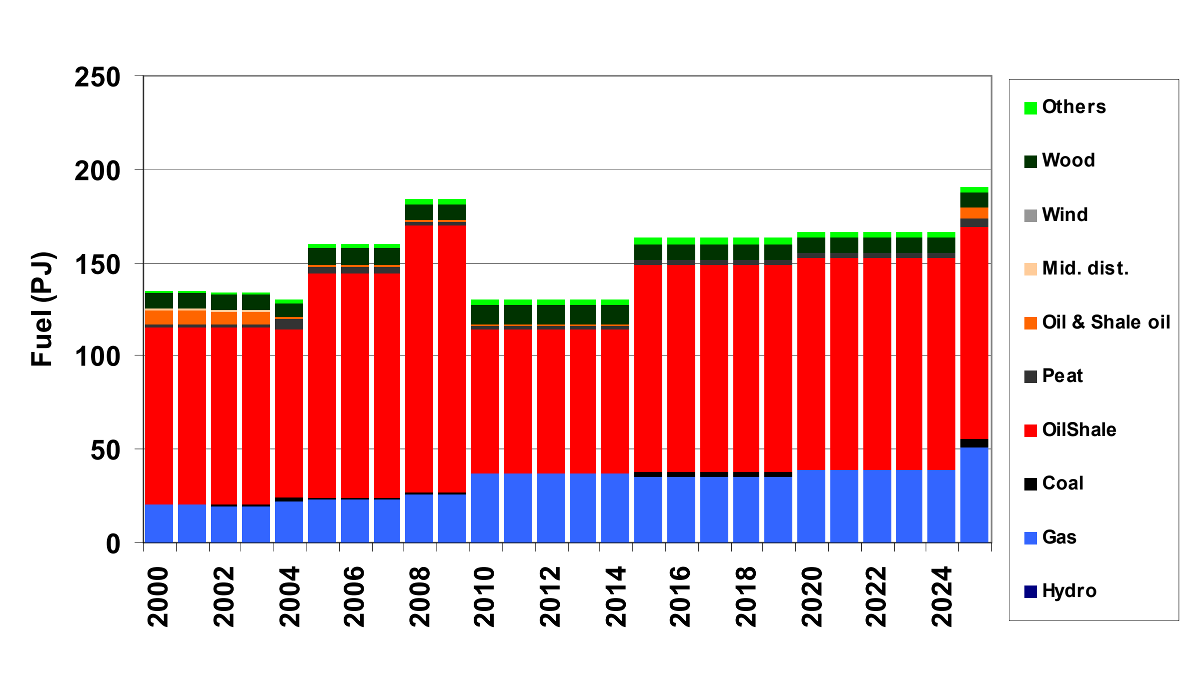


Figure 8.21. Fuel used for electricity and heat production in Estonia.

Only two fuels have a significant role for electricity and heat generation — oil shale and natural gas. The total consumption of oil shale depends on electricity exports from Estonian power plants, as well as on the modernisation schedule of the Eesti and Balti power plants. The highest consumption of oil shale is in 2005–2009. This is after Unit 1 of the Ignalina NPP has closed and while the Lithuanian TPP undergoes major modernisation since emission constraints do not significantly restrict the operation of old and un-modernised units at the Balti and Eesti power plants. Consumption of oil shale in this period reaches 120–142 PJ. The lowest consumption of oil shale is expected during 2010–2014, when the modernisation of Estonian oil shale power plants is still incomplete and a significant portion of the new CHP plants are running together with the modernised Lithuanian TPP. Annual consumption of oil shale in this period is about 77 PJ. Annual consumption of oil shale after completion of the modernisation programme at Estonian power plants reaches 110–114 PJ.

Natural gas consumption in Estonia grows continuously because of an absolute increase in CHP plant capacity, CCGT and boilers that run on gas. The annual consumption of natural gas in the Estonian electricity and heating sector is 20 PJ in 2000 and 51 PJ in 2025, or 14.8% and 26.7% respectively, while the highest share of 28.8% is during the period 2010–2014. Electricity and heat generation from RESs in Estonia is in the range of 7.8–12.1 PJ, or 5.8–9.3% respectively of the total fuel consumption for heat and electricity generation.

The efficiency of fuel conversion into electricity and heat in Estonia increases from 48.8% in 2000 to 53.1% in 2025, but the highest value of 56.4% is in 2010–2014, when condensing power plants have the lowest share of electricity generation.

8.2.3.3. Fuel consumption for electricity and heat production in Latvia

Fuel consumption for electricity and heat production in Latvia is shown in *Figure 8.22*. The results show that fuel consumption grows from 58.9 PJ in 2000 to 114.5 PJ in 2025. This growth is explained by a declining shortage of electricity generation in Latvia. The growth rate of fuel consumption in Latvia is the highest of all the countries in the region.

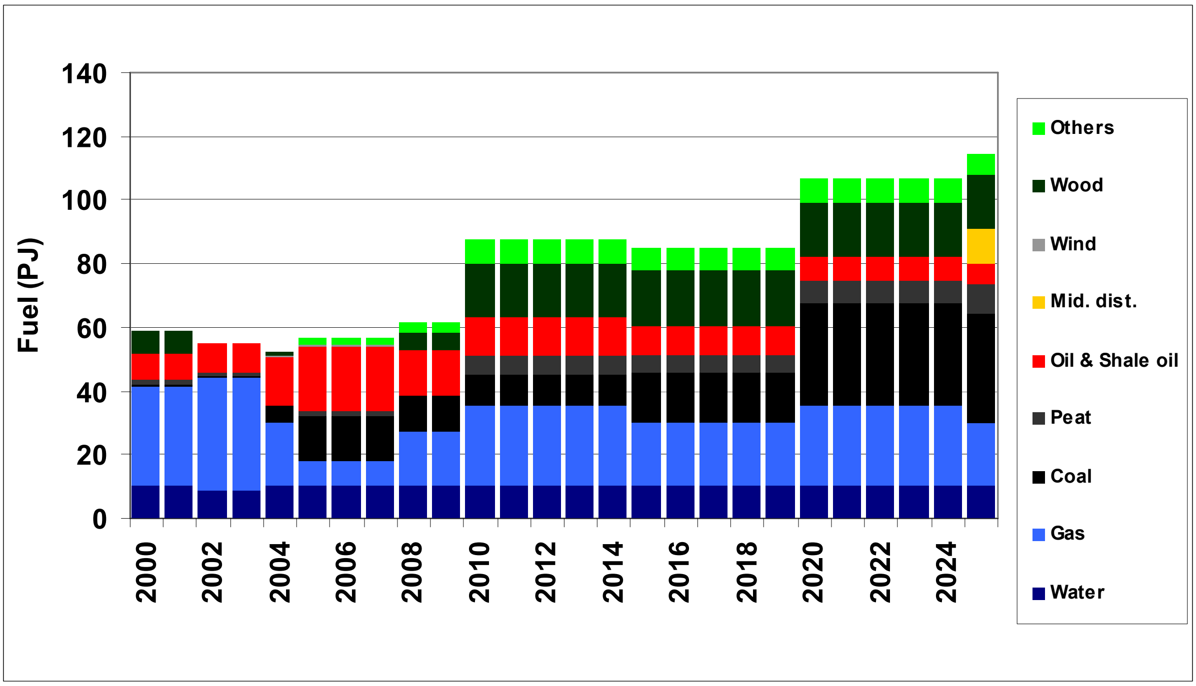


Figure 8.22. Fuel used for electricity and heat production in Latvia.

Latvia's fuel structure is also the most diverse in the region, although the fuel shares significantly change over time. For example, at the beginning of the study period natural gas was the main fuel in Latvia. However, at the end of study period coal may be the most important fuel, mainly due to the Liepaja coal-fired power plant and boiler houses. Consumption of natural gas fluctuates between 7.7 PJ and 35.1 PJ during the study period, while coal use tends to grow. Coal consumption rises from 0.5–0.6 PJ in 2000–2002 to 34.2 PJ in 2025. Wood is also a very important fuel in Latvia after the construction of the Baltic pulp factory in 2010. Wood consumption after 2010 is above 16.9 PJ and remains rather stable thereafter. Its share is highest during 2015–2019 reaching 20.1%. The share of oil and shale oil decreases in Latvia but remains above 5.4% or 6.2 PJ during the study period.

The annual hydro energy resources are about 8.9–10.3 PJ and very important in Latvia because of the high conversion efficiency into electricity. Electricity produced from hydro resources forms one of the largest shares in Latvian electricity generation. In addition, hydro energy resources are local and increase the security of energy supply.

The total annual consumption of RESs in Latvia grows from 17.3 PJ in 2000 to 33.8 PJ in 2025, which correspond to 29.3% and 29.5%, respectively. However, the largest share of RESs in Latvia occurs temporarily during 2015–2019, at 41% of total fuel consumption for electricity and heat production.

8.2.3.4. Fuel consumption for electricity and heat production in Lithuania

From an economic point of view, orimulsion becomes the main fuel for heat and electricity generation after closure of the Ignalina NPP. From 2010 the annual consumption of orimulsion may reach 72.7–82.6 PJ, or 34.2–42.1% of total fuel consumption.

Fuel consumption in Lithuania is presented in *Figure 8.23*.

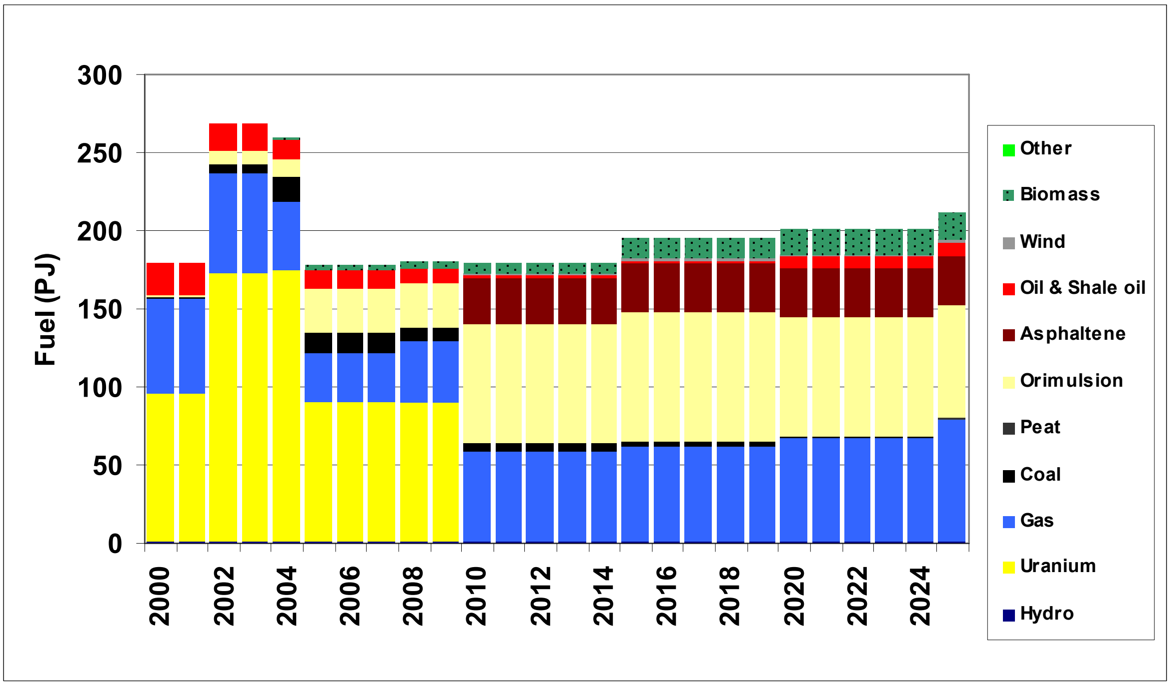


Figure 8.23. Fuel used for electricity and heat production in Lithuania.

Natural gas is the second highest energy form consumed in Lithuania. Its demand grows constantly from 57 PJ in 2010 to 78 PJ in 2025. The corresponding share of natural gas in total fuel consumption for electricity and heat generation is 31.7% and 36.9% respectively. Asphaltene is also an important fuel in Lithuania, since it can be used at the Mazeikiai CHP plant after modernisation and capacity expansion. Asphaltene is a residue produced at the modernised Mazeikiai refinery and has practically no market other than direct use at the power plant for electricity and heat generation. Consumption of RESs for heat and electricity generation in Lithuania grows from 5.6 PJ (3.1%) in 2000 to 19.7 PJ (9.3%) in 2025, but the highest share (10.6%) is in the period 2020–2024. These results correspond to the most rational utilisation of fuels from an economic point of view and takes into account constraints on CO_2, SO_2 and NO_x emissions.

If orimulsion supply becomes restricted for unexpected reasons, it can be easily replaced by natural gas or HFO. What proportion of orimulsion may be substituted by natural gas or oil depends on various circumstances and cannot be predicted. In the two boundary cases all the orimulsion would be substituted by oil or by gas. In the first case, consumption of HFO increases by 72.7–82.6 PJ to total 82–84.7 PJ. In the second case, the share of natural gas rises to 71.1–73.7%. In these boundary cases, shares of fuel consumption for electricity and heat generation in Lithuania could be as in *Table 8.3*.

Table 8.3. Boundary shares of fuel consumed in Lithuania for electricity and heat production (%)

Fuel type	*2005*	*2010*	*2015*	*2020*	*2025*
Oil and shale oil (min.)	6.3	1.3	1.1	3.9	4.4
Oil and shale oil (max.)	22.5	43.4	43.2	42.1	38.6
Gas (min.)	18.1	31.7	31.0	32.7	36.9
Gas (max.)	34.3	73.7	73.1	70.9	71.1
Orimulsion (min.)	0.0	0.0	0.0	0.0	0.0
Orimulsion (max.)	16.2	42.0	42.1	38.2	34.2

8.2.4. Total primary energy requirements and energy export

8.2.4.1.Total primary energy requirements and energy export in the Baltic region

Changes in the structure of the Baltic region's total primary energy requirements are shown in *Figure 8.24*. The total primary energy requirement in the Baltic region grows from 696 PJ in 2000 to 1013 PJ in 2025, or by 1.5% per year. In addition, *Figure 8.24* shows that the structure of primary fuels in the region is fairly stable during the study period if the removal of nuclear fuel is not taken into account.

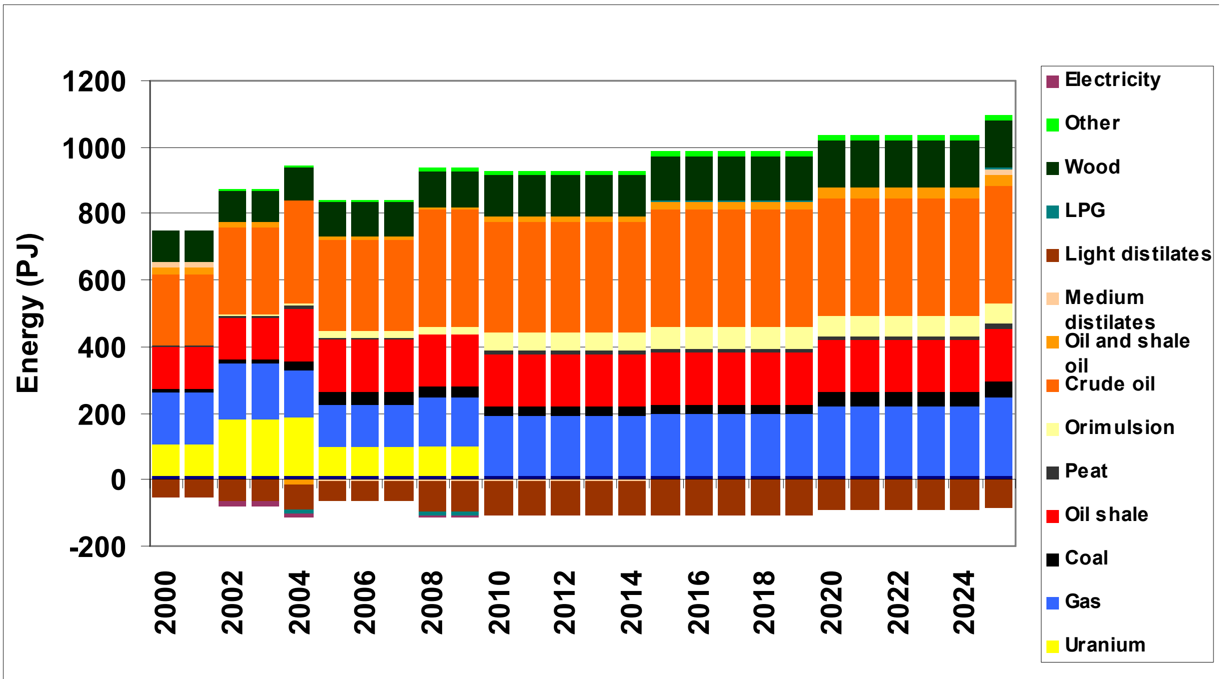


Figure 8.24. Primary energy requirement in the Baltic region.

Four fuel groups comprise the structure for primary energy:

- Natural gas;
- Oil shale, coal and peat;
- RESs, primarily wood;
- Oil products.

The largest contribution is from crude oil. Consumption of crude oil in the region is nearly 214 PJ in 2000 and about 354 PJ in 2025, although about 53 PJ and 85 PJ of oil products for the respective years are exported back from the Baltic. If all forms of oil products are taken into account, including imports and exports, the internal consumption of oil products in the region grows from 199 PJ in 2000 to 326 PJ in 2025, or from 28.6% to 32.2% respectively as a share of total primary energy demand in the region.

Annual consumption of natural gas is in the range of 125–236 PJ, about 16.2–23.3% of the total primary energy consumption. The lowest consumption of gas is in 2005–2007, when a significant part of the gas-consuming technologies undergo modernisation and are substituted in the market by technologies that utilise hard fuel — shale oil and coal. During the remaining period the gas share is more than 21%.

Annual consumption of hard fuel, which comprises oil shale, coal and peat, of which oil shale is dominant, increases from 141.5 PJ in 2000 to 224.4 PJ in 2025. The lowest consumption is during the first 4 years of the study period and the highest is after the capacities at the Liepaja coal-fired power plant are commissioned in 2020. The consumption of coal between 2005 and 2019 is fairly stable, at 15% in 2020 and 16.9% in 2025.

Generally, the structure of primary energy supply is rather diverse, which each group of fuels having a rather good market share. A negative feature is the growing import dependency of the region on Russia, as illustrated in *Figure 8.25*.

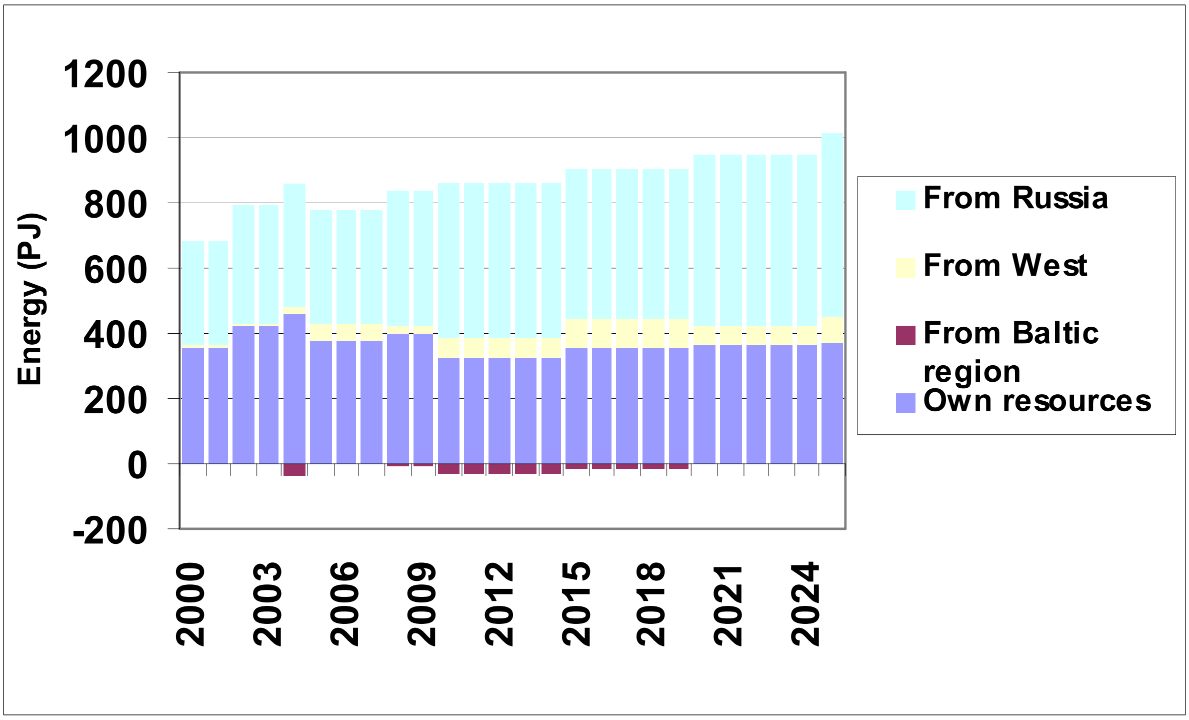


Figure 8.25. Import dependency, Baltic region.

As *Figure 8.25* shows, local energy resources total only about 327–457 PJ, while imported fuel from Russia grows from 319 PJ in 2000 to 563 PJ in 2025. This gradually increases the import dependency on Russia from 47% in 2000 to 55.6% in 2025, although the highest import dependency from Russia is expected in 2010–2015 (i.e., after closure of the Ignalina NPP and before the Estonian oil shale power plants are completely modernised).

To establish the necessary fuel reserves according to EU directives, the annual consumption of primary energy resources will be slightly higher, as shown in *Figure 8.26*. The necessary fuel reserves to be stored in each country and the region as a whole are listed in *Table 8.4*.

Table 8.4. Accumulated fuel reserves (PJ)

Product	*2005*	*2010*	*2015*	*2020*	*2025*
Estonia					
Light oil products	6.3	9.4	9.8	10.3	10.8
Heavy fuel oil and shale oil	0.2	0.2	0.1	0.1	1.3
Latvia					
Light oil products	7.7	12.7	14.7	16.2	19.7
Heavy fuel oil and shale oil	5.5	6.0	5.8	5.8	5.6
Lithuania					
Light oil products	10.3	17.0	18.8	20.7	22.6
Heavy fuel oil	4.5	4.3	4.3	5.6	6.0
Orimulsion	5.0	18.6	20.4	18.9	17.9
Baltic region					
Light oil products	24.3	39.1	43.3	47.2	53.1
Heavy fuel oil and shale oil	10.2	10.5	10.1	11.5	12.9
Orimulsion	5.0	18.6	20.4	18.9	17.9

The additional demand due to stockpiling is about 32 PJ at the beginning of the reserve formation process, and about 14 PJ in 2010, when it is necessary to substitute nuclear fuel by other fuel types. To maintain the necessary reserves requires only minor fuel additions to the reserves. Also, in reality the fuel additions in 2015, 2020 and so on will be distributed over several years. The data presented in *Figure 8.26* results from calculations with the milestone years 2015, 2020 and 2025.

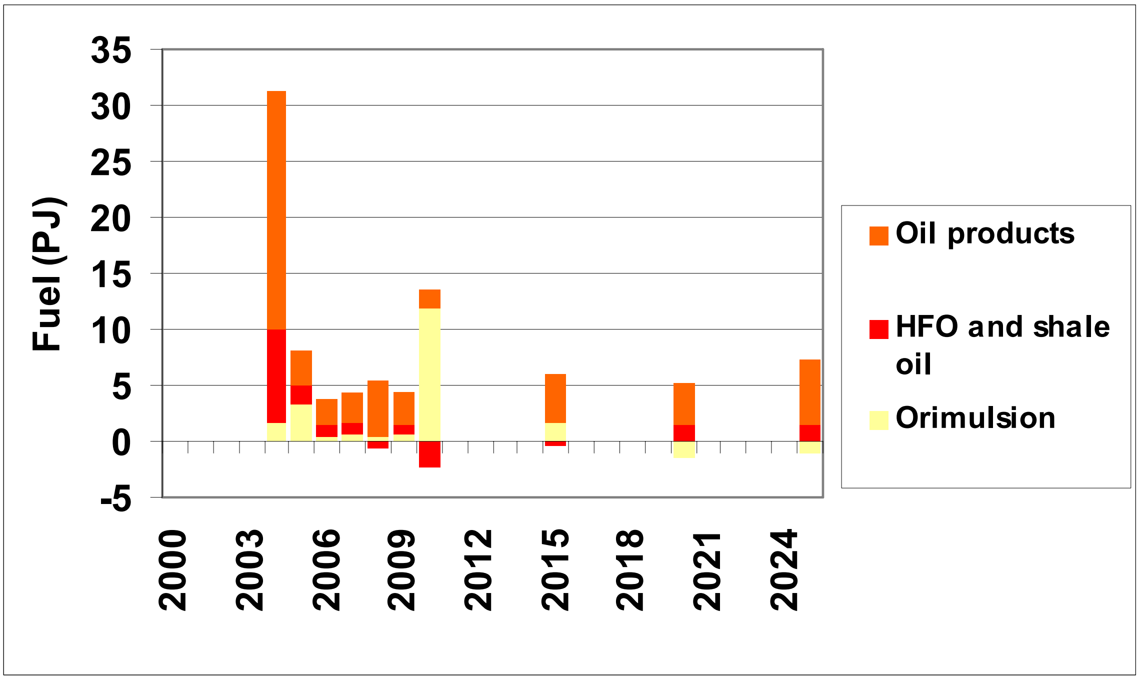


Figure 8.26. Additional fuel demand in the Baltic region necessary to form the required fuel reserves.

8.2.4.2.Total primary energy requirements and energy export in Estonia

Figure 8.27 shows the growth of total primary energy requirement in Estonia from 207.7 PJ in 2000 to 279.1 PJ in 2025.

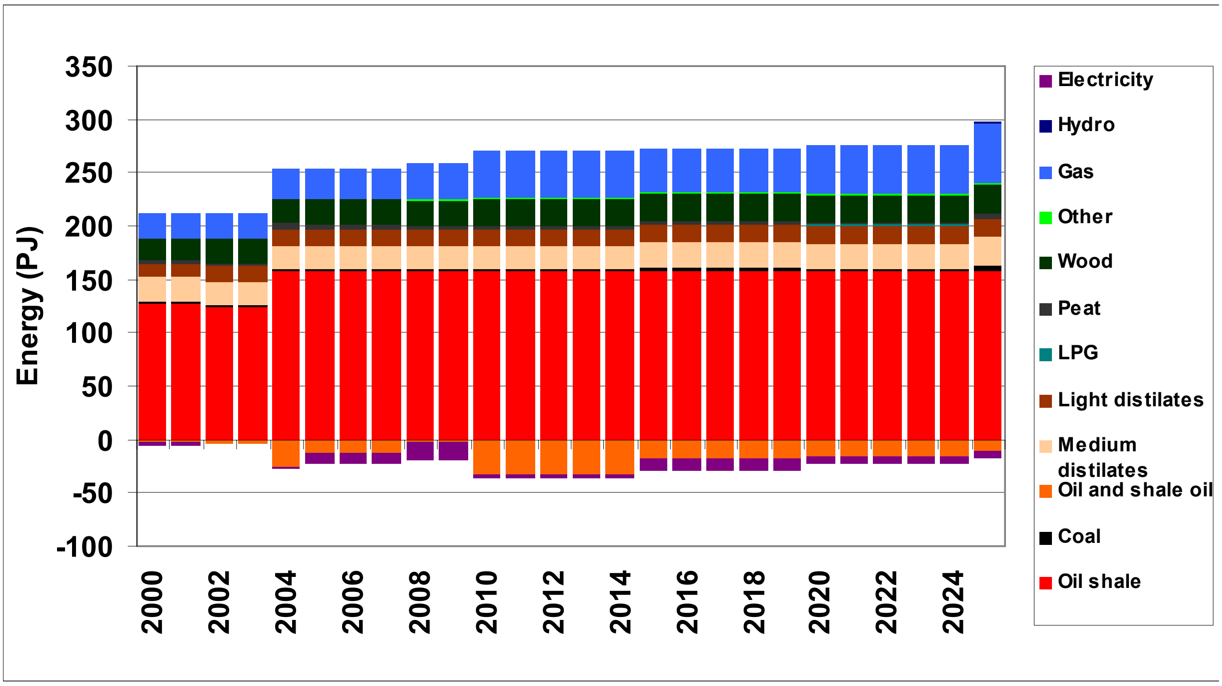


Figure 8.27. Primary energy requirement in Estonia.

Oil shale provides 56.5–69.6% of the total primary energy requirement of Estonia over the study period and is the largest local energy source in both Estonia and the whole region. Consumption of oil shale is estimated at 124–157.7 PJ/year. Oil shale is used not only at power plants for electricity and heat production, but also to produce shale oil which is used locally in boilers and exported to neighbouring countries. The export of shale oil reaches 32.6 PJ in some years, but is usually in the range 12–18 PJ. Electricity produced from oil shale is also partly exported to neighbouring countries, at about 6.8–15.7 PJ/year.

The consumption of oil products and natural gas is very similar in Estonia, in the range 35.5–43.7 PJ and 24.9–57.1 PJ, respectively. The contribution of RESs to the total primary energy requirement varies between 9.7% and 11.8%.

Estonia is the most independent country in the region in respect of fuel supply. Local energy resources provide 152.2–192.4 PJ, or 69–84%, of total primary energy requirement. The dynamics of import dependency in Estonia are shown in *Figure 8.28*.

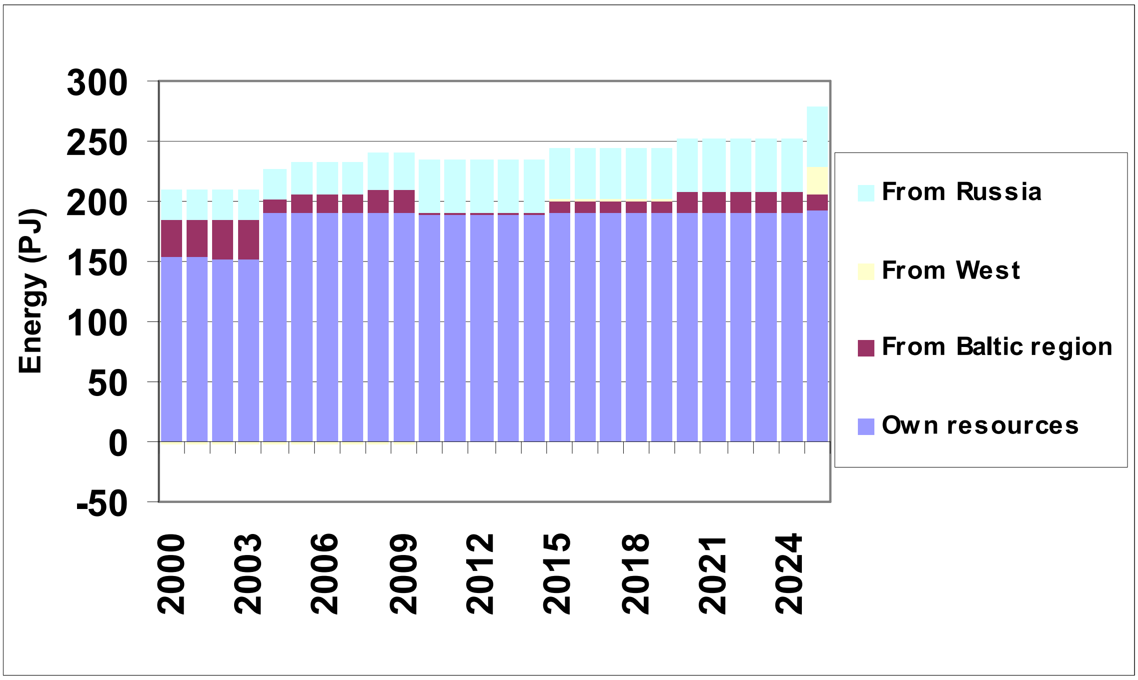


Figure 8.28. Import dependency, Estonia.

8.2.4.3.Primary energy requirement and energy export in Latvia

The dynamics of primary energy requirement in Latvia are depicted in *Figure 8.29*.

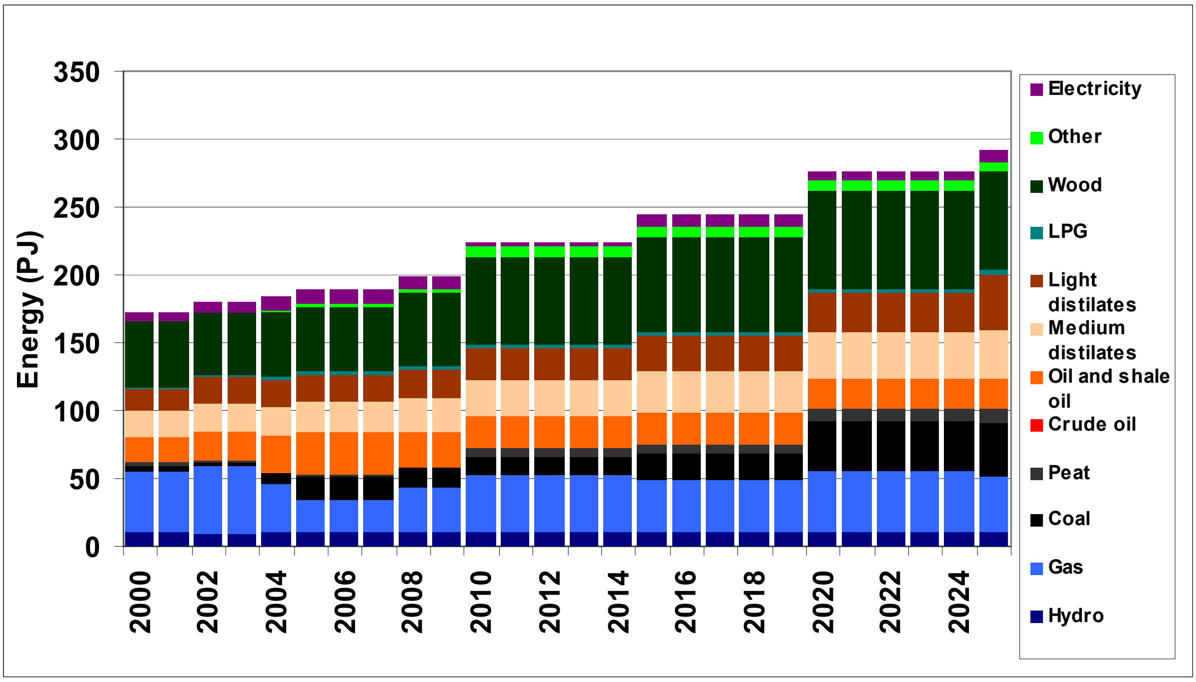


Figure 8.29. Primary energy requirement in Latvia.

In Latvia wood contributes a very large share to the total primary energy requirement, comparable with that of oil products and greater than that of gas. Consumption of oil products grows from 56.3 PJ in 2000 to 102.4 PJ in 2025, while wood demand correspondingly changes from 47.9 PJ to 73.2 PJ. Consumption of natural gas during the majority of the study period is in the range 38–50 PJ. This is because in Latvia a significant share of electricity is produced from hydro resources, as well as from coal at the end of the period. Latvian import dependency is show in *Figure 8.30*.

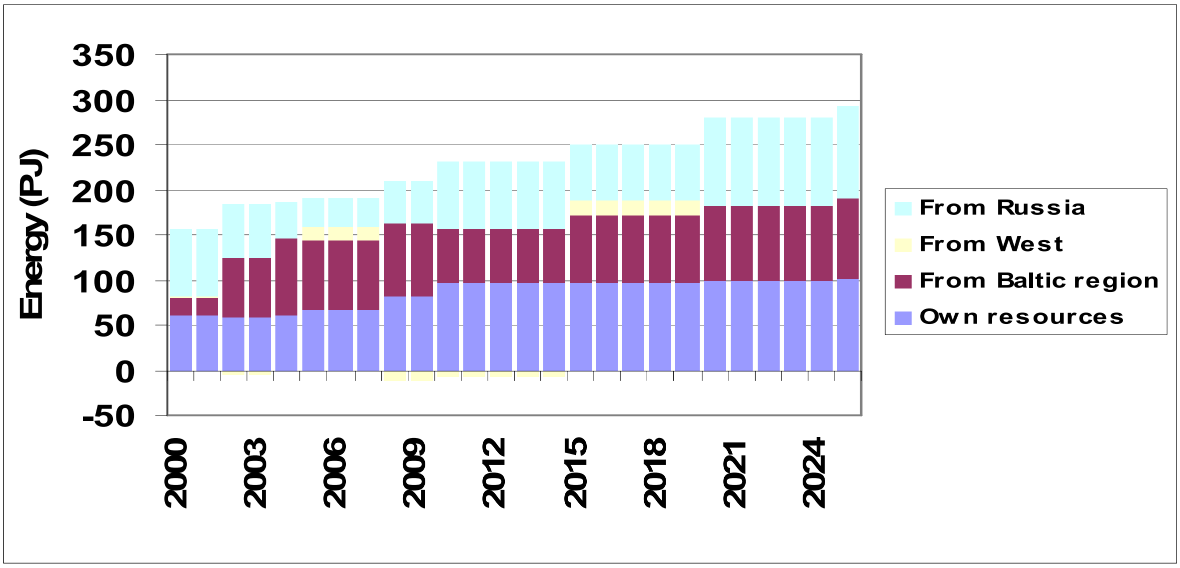


Figure 8.30. Import dependency, Latvia.

The data shows that roughly one-third of the total primary energy requirement is covered by local resources, one-third by imports from Russia and one-third by imports from neighbouring countries, mainly Lithuania.

8.2.4.4. Primary energy requirement and energy export in Lithuania

The primary energy requirement in Lithuania (*Figure 8.31*) is comparable with those in Estonia and Latvia, rising from 316 PJ in 2000 to 441 PJ in 2025. However, a significant proportion of the primary energy is converted into other forms, especially oil products, and exported to other countries,. For example, electricity exports occur during the operation of Ignalina NPP. In total, up to 200 PJ of energy resources are exported.

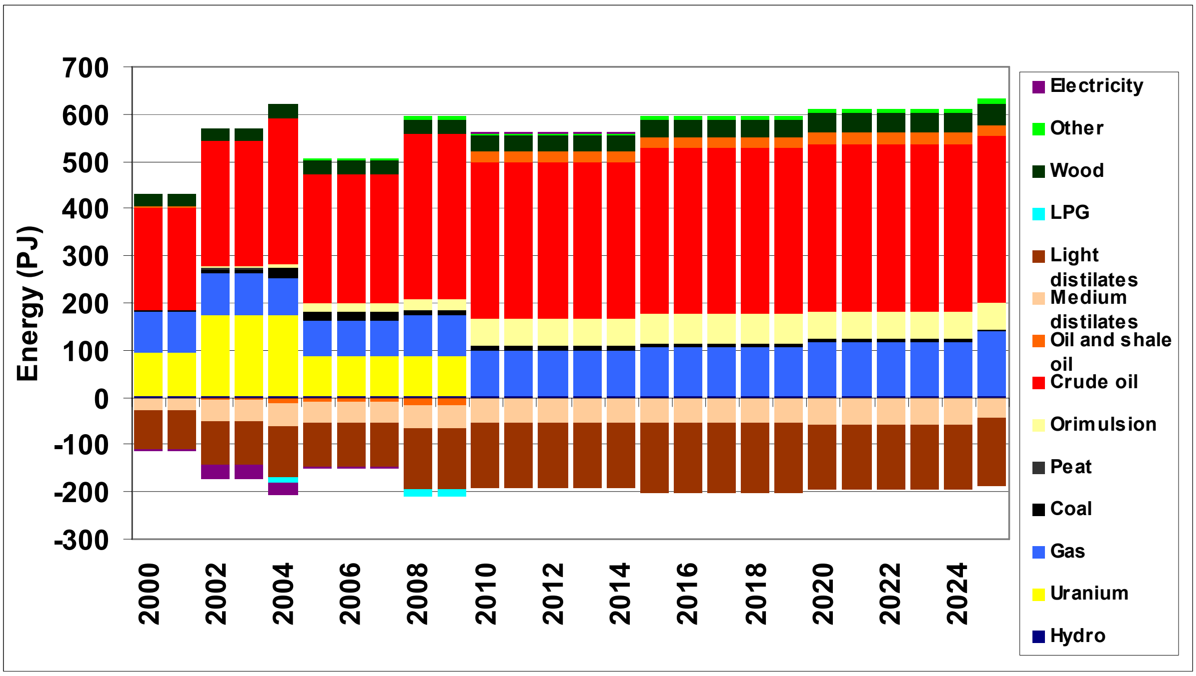


Figure 8.31. Primary energy requirement in Lithuania.

The Mazeikiai refinery is the main primary energy (crude oil) consumer in Lithuania. Its consumption grows steadily from 213 PJ in 2000 to 354 PJ in 2015 and remains practically stable until the end of the study period because the refinery reaches full capacity in 2015. Domestic demand for oil products nearly doubles during the study period (i.e., from 110 PJ in 2000 to 192 PJ in 2025).

Natural gas is the second largest primary energy source in Lithuania, and consumption during the study period increases by 60% from 86.5 PJ in 2000. However, the consumption of natural gas could be much higher if it replaces orimulsion (up to 57 PJ). As a reulst, the share of natural gas could be in the ranges 26.5–42.1% in 2010 and 31.3–43.7% in 2025.

The share of RESs in Lithuania grows from about 8.2% in 2000 to 12.2% in 2025.

Lithuania is the most energy import dependent country in the region. Nearly 89% of total primary energy resources are imported in 2010 and about 83% in 2025. Lithuania's energy import dependence is shown in *Figure 8.32*.

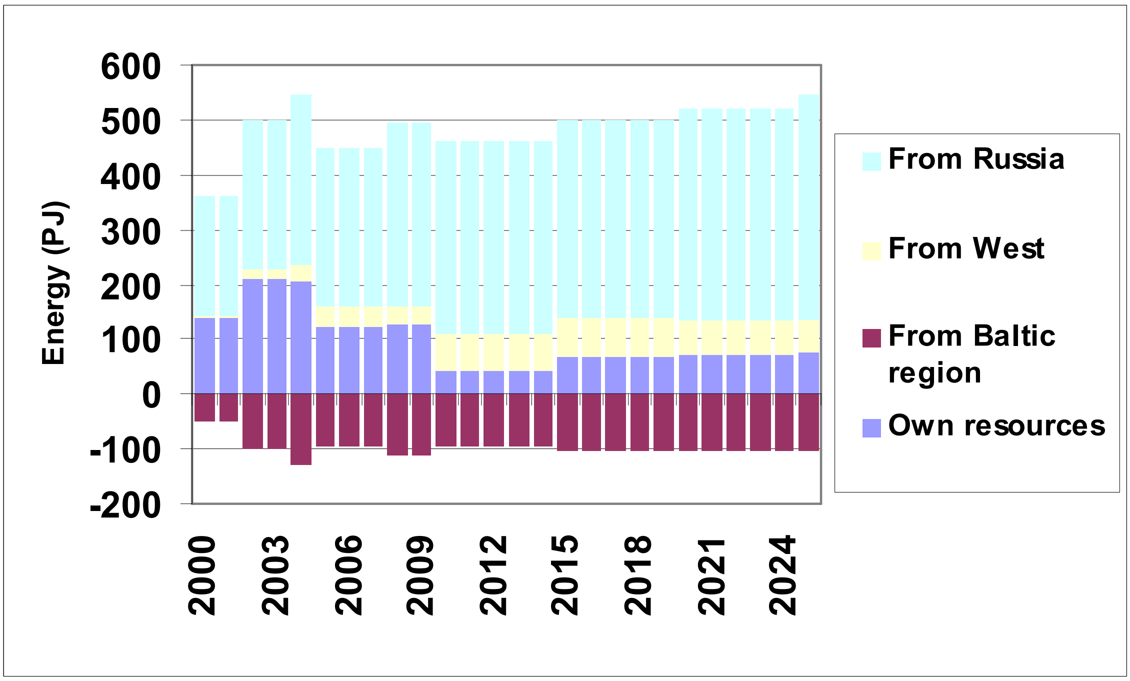


Figure 8.32. Import dependency, Lithuania.

The majority of energy is imported from Russia, a situation that may worsen if, for whatever reason, orimulsion is not being used in Lithuania any longer. Practically all energy imports will then be sourced from countries of the Former Soviet Union (FSU).

8.2.5. Environmental impact of energy sector

In this study, the energy sector in the Baltic region was optimised taking into account constraints on CO_2, SO_2 and NO_x in each country, as well as limits on the concentration of these pollutants in flue gases — the emissions in each country and in the whole region are below required limits. The dynamics of emissions in the region and each country are presented in *Figures 8.33* to *8.36*.

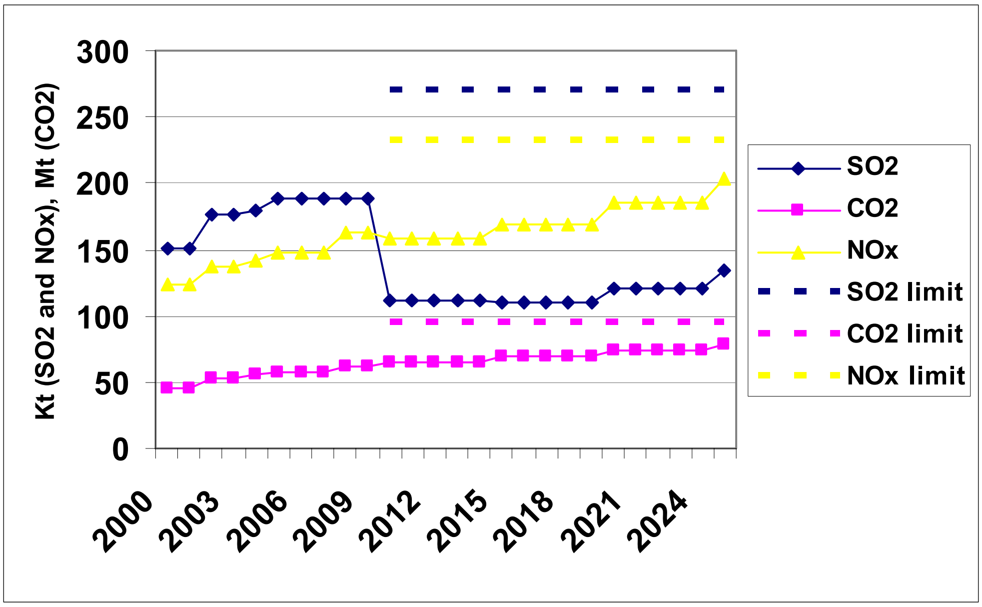


Figure 8.33. Emissions into the atmosphere, Baltic region.

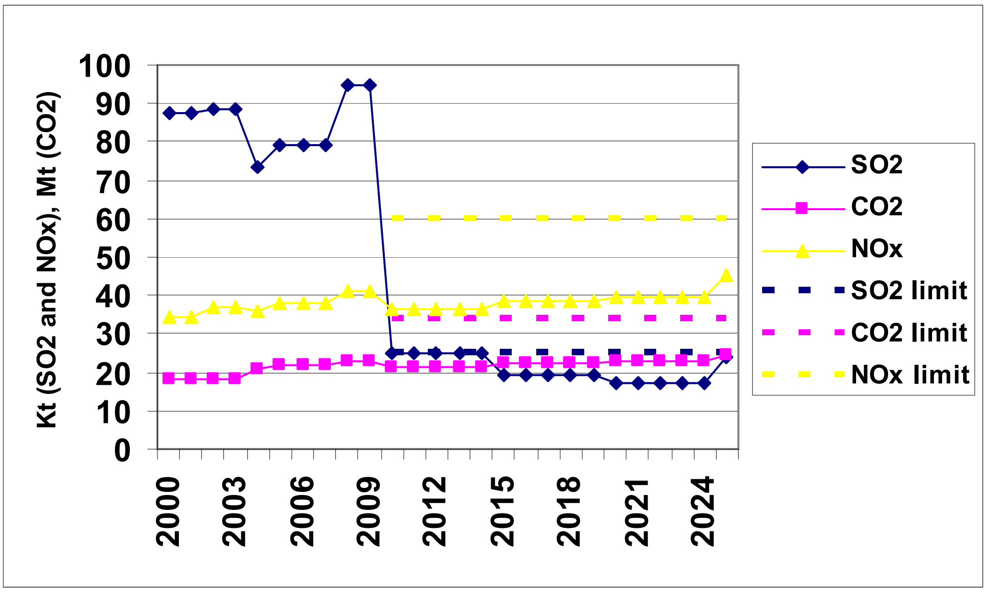


Figure 8.34. Emissions into the atmosphere, Estonia.

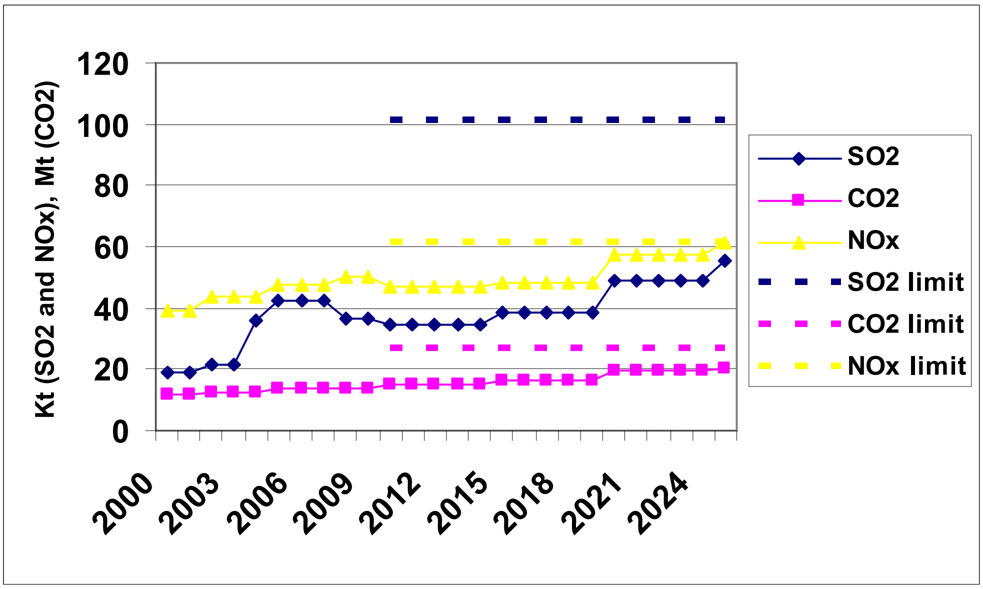


Figure 8.35. Emissions into the atmosphere, Latvia.

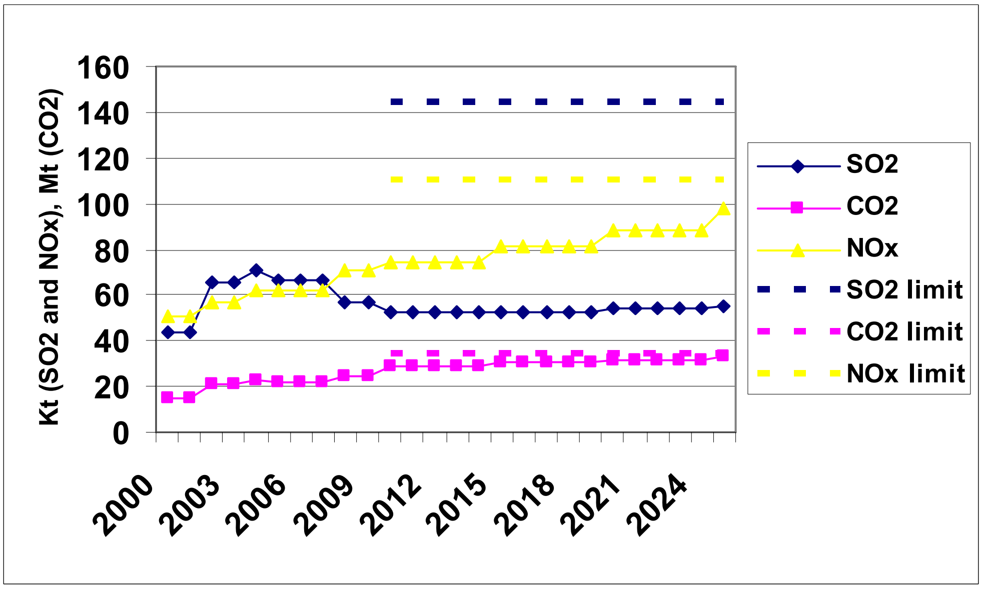


Figure 8.36. Emissions into the atmosphere, Lithuania.

The calculations show that none of the analysed pollutants reach its maximum limit in the region. The best situation in the region relates to the emission of SO_2, which has the largest gap between the allowed maximum and expected values. Emissions of other pollutants more closely reach the corresponding pollution limits. Emission profiles for each individual country are also quite good. However, in each country one pollutant is very close to the limit: SO_2 in Estonia, NO_x in Latvia and CO_2 in Lithuania.

8.2.6. Cost of electricity generation

Depending on the country, the marginal cost of electricity generation at the beginning of the study period is in the range of €17.1–21.8/MWh. The lowest cost is in Estonia because it has the cheapest fuel, and the highest in Lithuania, because the Lithuanian TPP or CHP plants in condensing mode utilise expensive fuel and form part of the marginal production cost. The cost level in Latvia is very similar to that in Lithuania because the type of CHP plant is the same in both countries. The dynamics of the marginal electricity generation costs are presented in *Figure 8.37*.

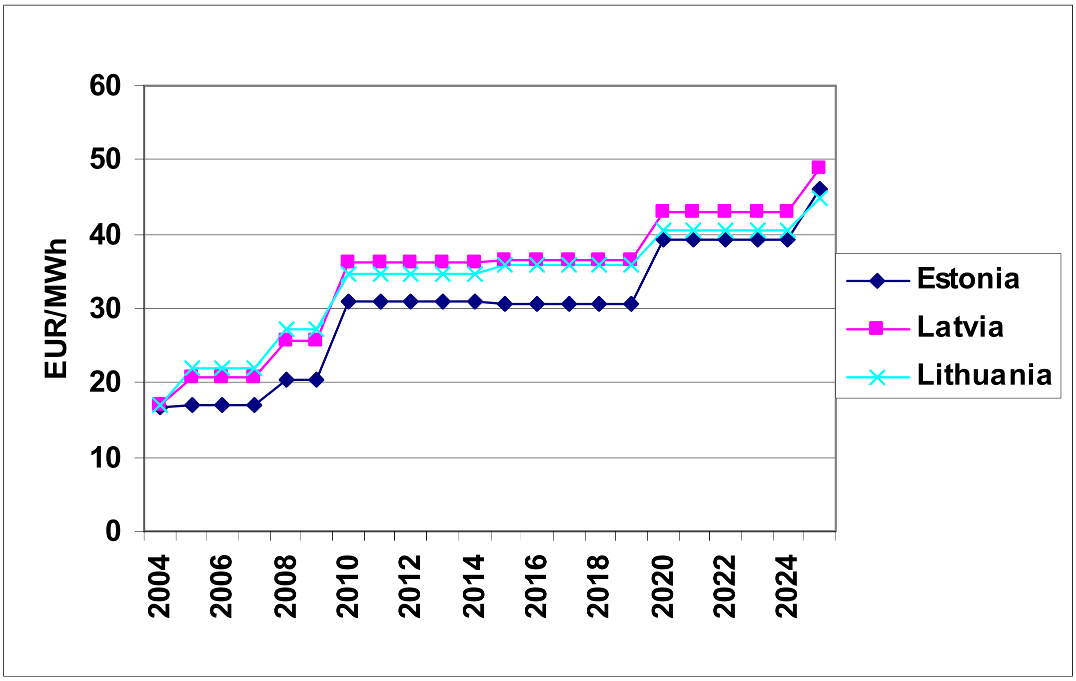


Figure 8.37. Marginal cost of electricity generation.

The marginal electricity generation cost increases to €30.9–36.4/MWh, because after the closure of Ignalina NPP new CHP capacities need to be constructed to compensate the capacity loss. This cost level remains stable until 2020 and then increases to €39.2–42.9/MWh. This increase is linked to the appearance of new condensing power plants on the market.

The costs described above represent the annual marginal electricity generation costs calculated as a weighted average of marginal costs in each period specified in the model. Marginal electricity generation costs in each period (load region) for each typical day of each typical season are different.

Costs related to the energy system operation and development for the base scenario are summarised in *Table 8.5* (discounted cost) and in Annex II.

Table 8.5. Discounted cost of energy system operation and development for the base scenario (€ million)

Cost	*2000–2005*	*2006–2010*	*2011–2015*	*2016–2020*	*2021–2025*	*2026–2035*	*2036–2045*	*Total 2000–2025*	*Total 2000–2035*	*Total 2000–2045*
Estonia										
Investment cost	232	196	205	49	96	28	0	778	807	807
Fixed O&M cost	888	503	288	122	65	73	29	1866	1939	1968
Variable O&M cost*	1628	1053	843	567	484	703	237	4576	5279	5516
Estonia subtotal	2749	1752	1336	737	645	804	266	7220	8024	8291
Reserve cost	32	12	1	1	1	0	0	48	48	48
Estonia total	2782	1765	1337	738	646	804	266	7268	8072	8338
Latvia										
Investment cost	49	320	41	94	57	79	0	561	640	640
Fixed O&M cost	830	385	238	104	59	68	29	1616	1684	1713
Variable O&M cost*	2357	1133	1211	749	562	656	245	6011	6667	6912
Latvia subtotal	3236	1838	1489	947	678	804	274	8188	8992	9266
Reserve cost	52	21	4	2	4	1	0	83	84	84
Latvia total	3288	1858	1493	950	682	804	274	8272	9076	9350
Lithuania										
Investment cost	154	343	46	19	60	91	0	622	713	713
Fixed O&M cost	878	284	157	76	45	46	21	1440	1486	1507
Variable O&M cost*	7233	4806	4231	2552	1839	2162	938	20661	22822	23760
Lithuania subtotal	8265	5433	4434	2647	1944	2299	959	22723	25021	25980
Reserve cost	66	37	5	4	1	–2	0	112	111	111
Lithuania total	8331	5470	4438	2651	1945	2297	959	22835	25132	26091
Baltic region										
Investment cost	436	859	291	162	214	198	0	1962	2160	2160
Fixed O&M cost	2597	1172	683	302	169	187	79	4922	5109	5188
Variable O&M cost*	11218	6992	6284	3869	2885	3521	1420	31248	34769	36189
Baltic region subtotal	14251	9023	7259	4332	3267	3906	1499	38131	42038	43537
Reserve cost	151	70	10	7	6	–1	0	243	243	243
Baltic region total	14401	9093	7269	4339	3273	3905	1499	38375	42280	43780

*Including fuel cost and emission taxes.

8.3. National self-sufficiency scenarios

Capacity expansion in the power sector will be required for each country in the region to become self-balancing. The necessary capacity in each individual country may be higher or lower than in the base scenario, depending on the role of the country in the regional electricity trade. The difference in installed capacity in the Baltic region between Scenario 1N(Aa) and Scenario 1R(Aa) is shown in *Figure 8.38*.

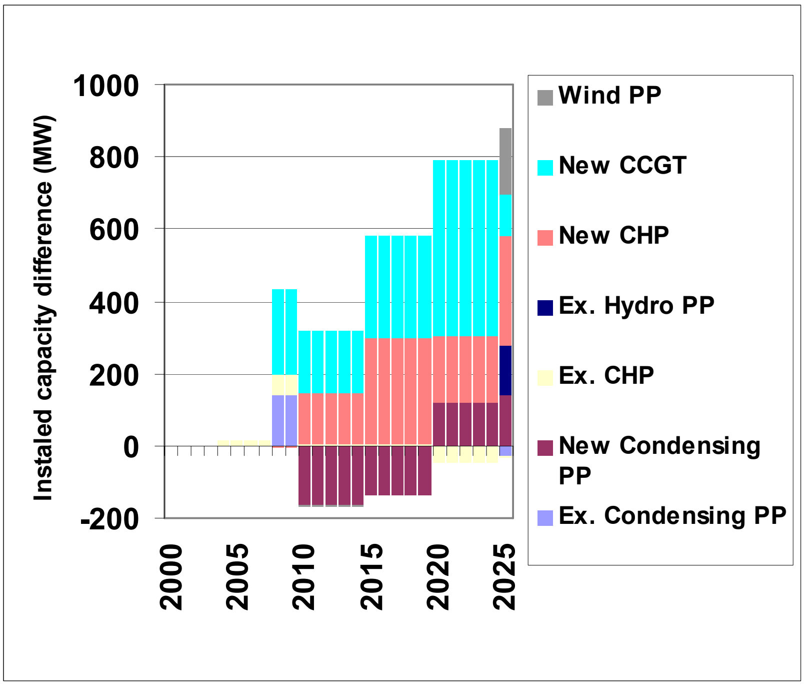


Figure 8.38. Difference in installed capacities of power plants in the Baltic region for Scenario 1N(Aa) compared to 1R(Aa).

As *Figure 8.38* shows, the country self-sufficiency scenario by the end of the analysed period requires about 800 MW extra capacities in the region. This is allocated mainly to new CCGTs (nearly 490 MW), new CHP units (about 180 MW) and new condensing power plants (about 120 MW). The capacity difference for individual countries is shown in *Figures 8.39* to *8.41*.

The self-sufficiency scenario for Estonia allows the renovation period for existing oil shale power plants to be extended. For example, during the period 2010–2014, 160 MW (about one unit) cannot be renovated. In the period 2015–2020 about two units cannot be renovated compared to the reference scenario. This lack of capacity, however, will be replaced by new CHP and CCGT units. By the end of the study period, as in the reference scenario, all the existing oil shale units will be renovated and about 300 MW additional capacity of new CCGTs will be built.

The largest capacity additions are required in Latvia because it has the biggest shortfall of electricity generation. The extra capacity needs in Latvia will be about 750 MW by 2025. Additional capacity in Latvia in different years consists of new CHP plants, the Liepaja power plant, as well as wind turbines and HPPs. The latter two will be built to the requirements of the EU directive for electricity generation from RESs and to satisfy obligations regarding NO_x emissions.

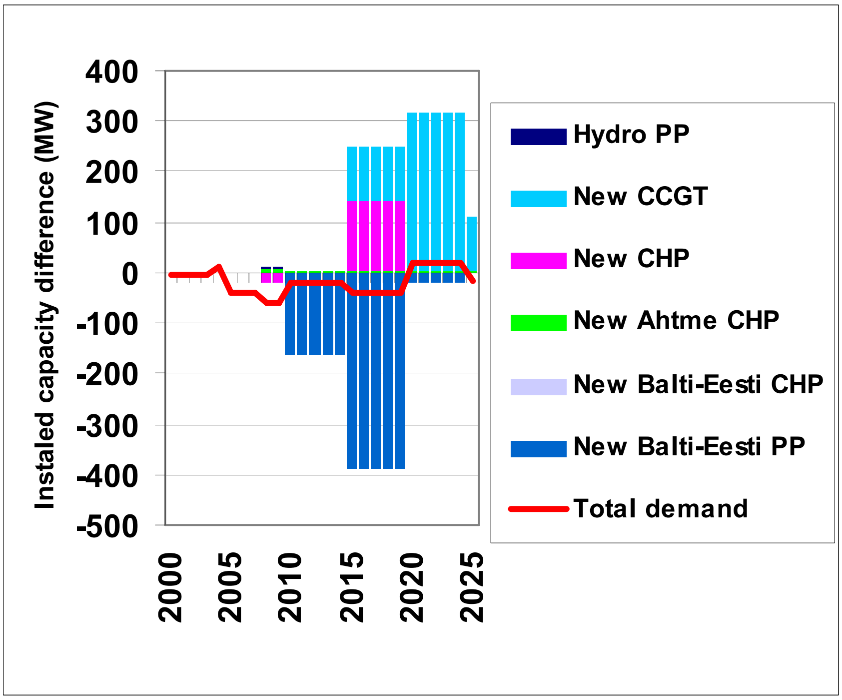


Figure 8.39. Difference in installed capacities of power plants in Estonia for Scenario 1N(Aa) compared to Scenario 1R(Aa).

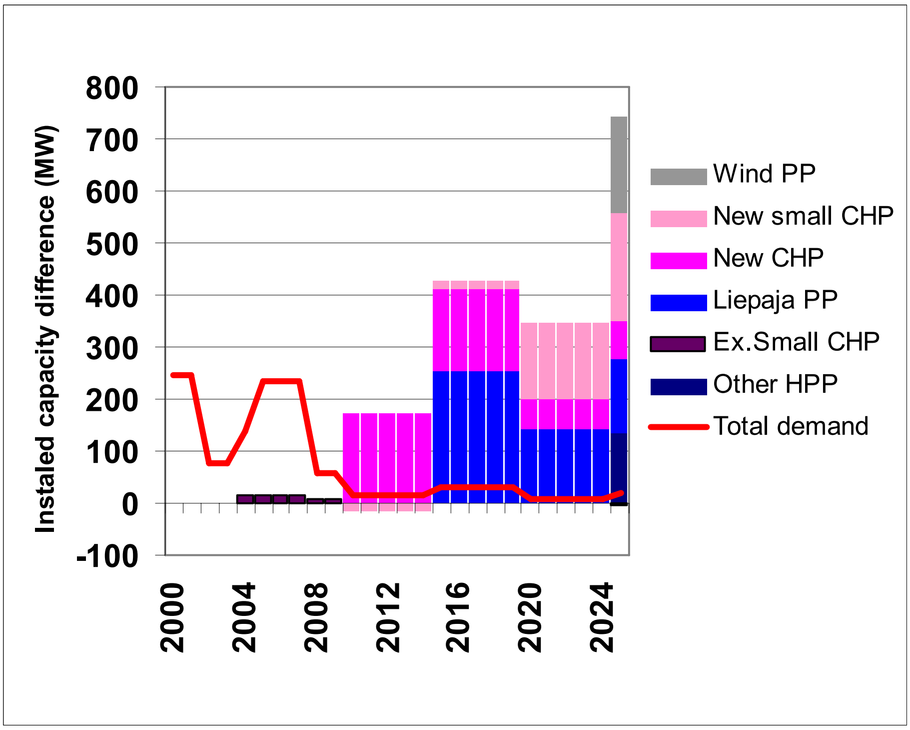


Figure 8.40. Difference in installed capacities of power plants in Latvia for Scenario 1N(Aa) compared to Scenario 1R(Aa).

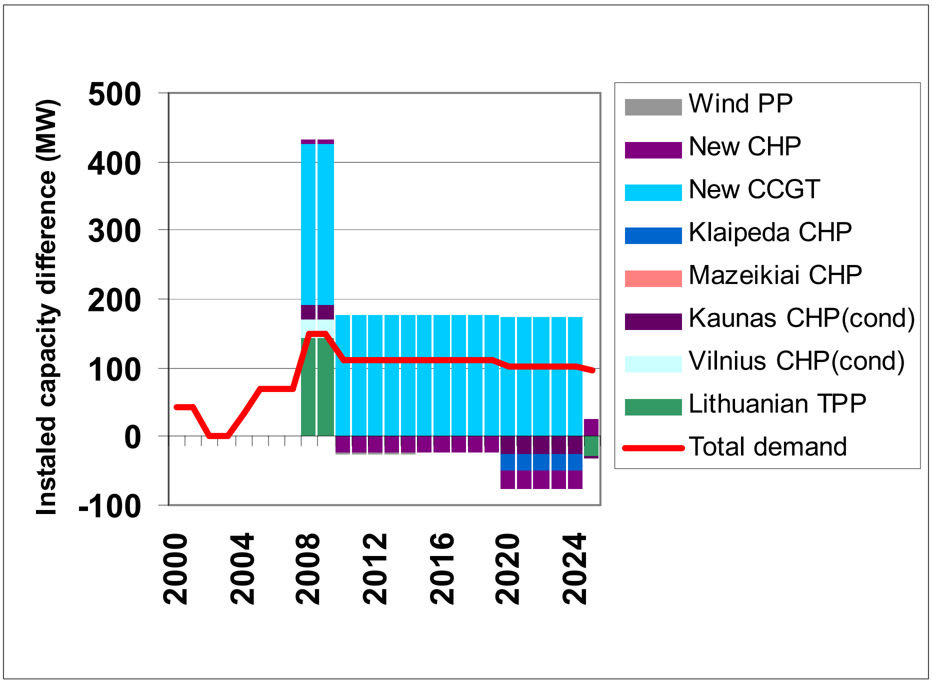


Figure 8.41. Difference in installed capacities of power plants in Lithuania for Scenario 1N(Aa) compared to Scenario 1R(Aa).

The lowest capacity additions are required for Lithuania. The self-sufficiency scenario requires an extra CCGT capacity of 174–234 MW, but this will slightly reduce the CHP capacity.

Scenario 1N(Aa), representing self-sufficiency of each individual country in terms of electricity, is more costly in comparison to the regional self-sufficiency Scenario 1R(Aa) (reference scenario) because each country has to solve its problems alone without help from neighbouring countries. The total discounted cost to operate and develop the energy system during 2000–2045 for the country self-sufficiency scenario is €44.298 billion. Taking into account the cost necessary to form and maintain the required fuel reserves, this increases to €44.553 billion. The corresponding costs for the reference scenario are €43.537 billion and €43.78 billion. The total costs do not reflect the real difference very accurately because revenues from electricity exports that go to the country in the region is not taken into account in Scenario 1R(Aa), but is in Scenario 1N(Aa). In addition, electricity export is not exactly the same in both scenarios. The most reliable cost factor is the investment cost spent on extra capacity in the region. Investment cost for the country self-sufficiency scenario is €177 million higher compared to the regional self-sufficiency scenario. Costs related to the energy system operation and development for this scenario are summarised in *Table 8.6* and Annex II.

Table 8.6. Discounted cost of energy system operation and development,* Scenario 1N(Aa) (€ million)

Cost	*2000–2005*	*2006–2010*	*2011–2015*	*2016–2020*	*2021–2025*	*2026–2035*	*2036–2045*	*Total 2000–2025*	*Total 2000–2035*	*Total 2000–2045*
					Estonia					
Investment cost	236	139	213	94	81	27	0	763	790	790
Fixed O&M cost	903	509	284	116	68	74	30	1881	1955	1985
Variable O&M cost†	2530	1393	1310	807	608	765	317	6648	7412	7729
Estonia subtotal	3670	2041	1807	1017	757	866	346	9291	10158	10504
Reserve cost	33	13	1	1	1	0	0	48	48	48
Estonia total	3703	2053	1808	1018	758	866	346	9340	10206	10552
					Latvia					
Investment cost	64	322	136	69	133	95	0	725	820	820
Fixed O&M cost	829	388	245	115	68	81	35	1645	1726	1761
Variable O&M cost†	3877	2410	2143	1370	1050	1266	526	10850	12116	12642
Latvia subtotal	4770	3120	2524	1553	1252	1442	561	13219	14662	15223
Reserve cost	52	23	4	5	4	1	0	88	90	90
Latvia total	4823	3143	2528	1558	1256	1444	561	13308	14751	15313
					Lithuania					
Investment cost	164	363	48	18	57	78	0	650	728	728
Fixed O&M cost	902	295	166	81	48	47	20	1492	1539	1559
Variable O&M cost†	5113	3238	2889	1719	1241	1484	600	14201	15684	16284
Lithuania subtotal	6179	3896	3103	1818	1346	1609	620	16342	17951	18571
Reserve cost	69	42	5	2	2	–3	0	120	117	117
Lithuania total	6248	3938	3108	1820	1349	1606	620	16462	18068	18688
					Baltic region					
Investment cost	464	824	397	180	272	200	0	2138	2337	2337
Fixed O&M cost	2634	1192	695	312	184	203	85	5017	5221	5306
Variable O&M cost†	11520	7041	6342	3896	2899	3514	1443	31698	35212	36655
Baltic region subtotal	14619	9057	7434	4388	3355	3917	1528	38853	42770	44298
Reserve cost	154	77	10	7	8	–1	0	257	255	255
Baltic region total	14773	9134	7444	4396	3362	3916	1528	39110	43025	44553

*Revenue of individual country from electricity export if it is to country in the Baltic region is taken into account and it is included into the variable O&M cost.
†Including fuel cost and emission taxes.

From an environmental viewpoint, it is better to compare the country-specific self-sufficiency scenarios with the regional self-sufficiency scenario because more new capacities are built with higher utilisation factors than those of the old ones. In other words, new equipment partly replaces existing and less efficient equipment. During the study period, the total emission reduction in the region is 135 thousand tonnes of SO_2, 162 million tonnes of CO_2, 140 million tonnes of fly ash, and 20 460 million tones of ash. Emissions of NO_x are expected to be 36 thousand tonnes higher than in Scenario 1R(Aa).

8.4. Regional scenario with cross-border power exchanges – interlinks

Interlinks between the Baltic power system and neighbouring countries under the conditions described in Chapter 6 have a moderate impact on the operation of local power plants. The main impact is for the years 2010–2014 and at the end of the study period. Energy imports from third countries substitute some power plants in the region. For example, in 2010–2014 lower electricity generation by existing condensing power plants, as well as by new CHP units, is substituted by electricity imports up to 3.7 TWh/year. At the end of the study period, new CCGTs are replaced by electricity imports, at an annual level of 4.7 TWh. These differences are shown in *Figure 8.42*.

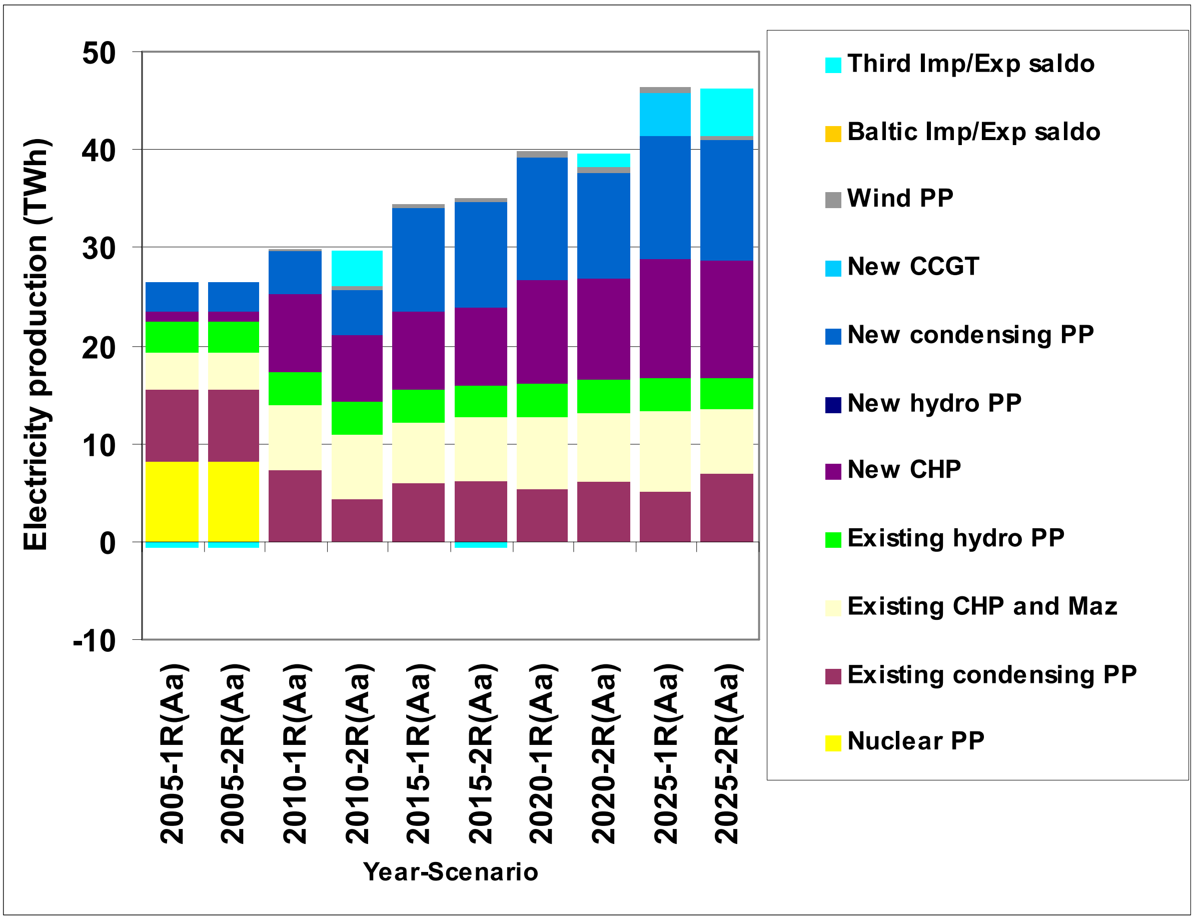


Figure 8.42. Comparison of electricity generation in the Baltic region in Scenarios 2R(Aa) and 1R(Aa).

The power system of the Baltic countries is likely to wheel electricity from Russia to Finland, as shown in *Figure 8.43*. After establishment of the S-Link, and depending on the year, the Baltic region imports 2.3–5.8 TWh from Russia and at the same time exports 1.5–3.0 TWh to Finland. However, electricity exchange based on the operating regime of power systems will also occur. From 2015 energy flows occur between the Baltic region and Finland in both directions. In addition, available interconnections with western countries will shift electricity export from the Baltic region westwards because of higher electricity prices. This tendency is depicted in *Figure 8.43,* where the transition occurs between the years 2005 and 2008. The direction of electricity export is eastwards in 2005 and westwards in 2008.

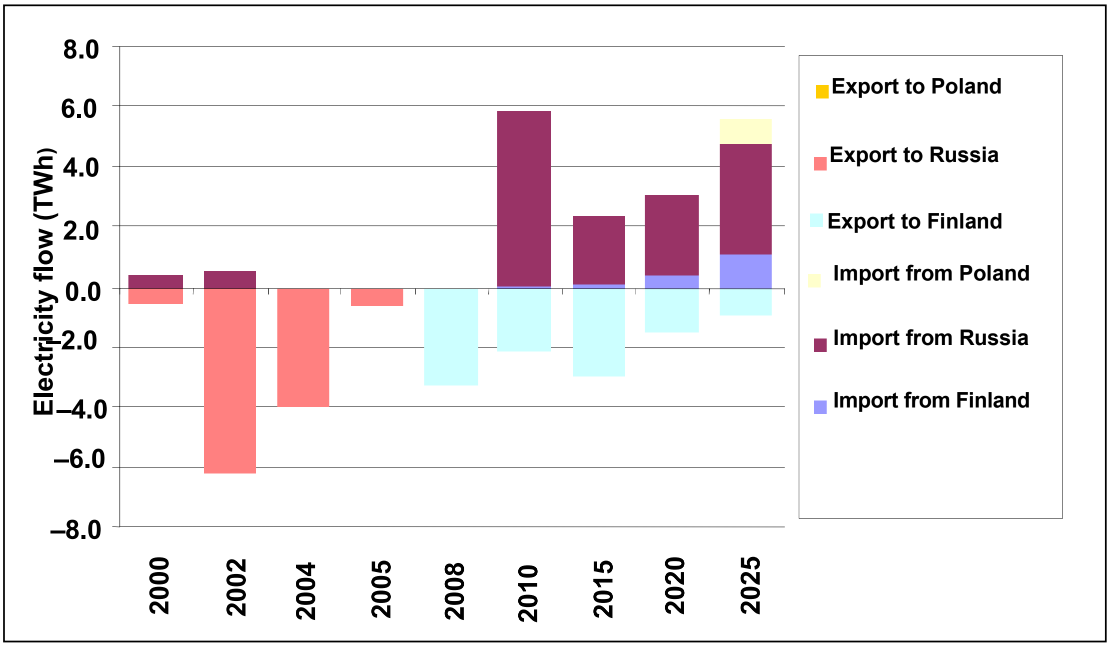


Figure 8.43. Electricity flows between the Baltic region and third countries, Scenario 2R(Aa).

Electricity imports from Russia will most likely reduce production at the Lithuanian TPP. *Figure 8.44* shows that after closure of the second unit of the Ignalina NPP Lithuania imports about 2.5 TWh of electricity from Russia. Electricity generation at the Lithuanian TPP in this case is 3 TWh lower than that in the reference scenario. In addition, available electricity imports will to some extent postpone the construction of new capacities. *Figure 8.44* shows lower electricity generation at new CHP plants compared to Scenario 1R(Aa). For example, electricity output from new CHP plants is 300 GWh lower in 2010, 200 GWh lower in 2015 and 120 GWh lower in 2025. In addition, the contribution from new CCGTs is replaced by electricity imports in 2025.

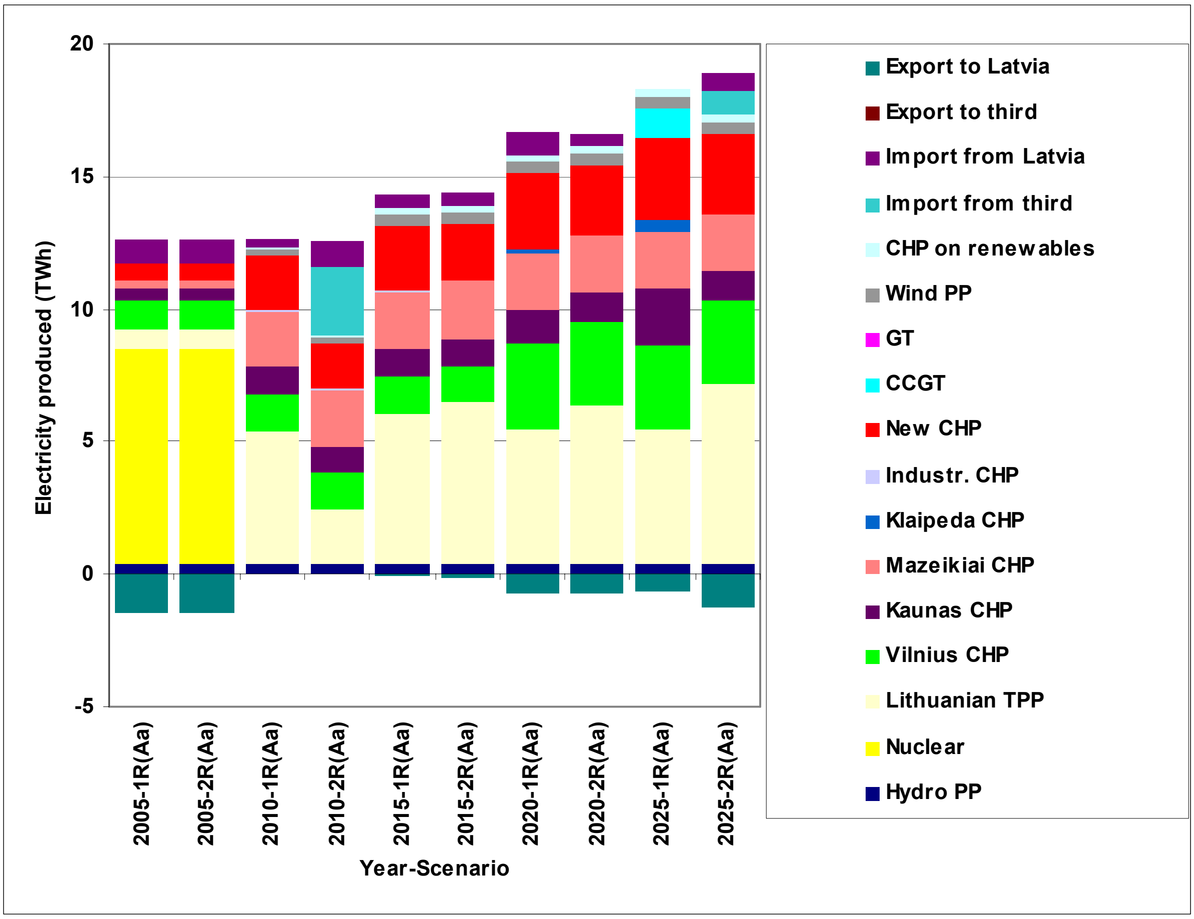


Figure 8.44. Comparison of electricity generation in Lithuania in Scenarios 2R(Aa) and 1R(Aa).

In Latvia, electricity imports from third countries reduce electricity imports from Estonia, reduce the output of new CHP plants and postpone the construction of the Liepaja coal-fired power plant. This is shown in *Figure 8.45*. Therefore, electricity generation of new CHP plants in Latvia in 2010 is 0.9 TWh lower than in Scenario 1R(Aa) and there are no electricity imports from Estonia, while in Scenario 1R(Aa) these imports are 1.08 TWh. Available electricity imports from third countries have smaller impacts on CHPs in later years. For example, CHP production in 2020 is the same in both scenarios, but the Liepaja power plant is postponed for 5 years in Scenario 2R(Aa) compared to Scenario 1R(Aa).

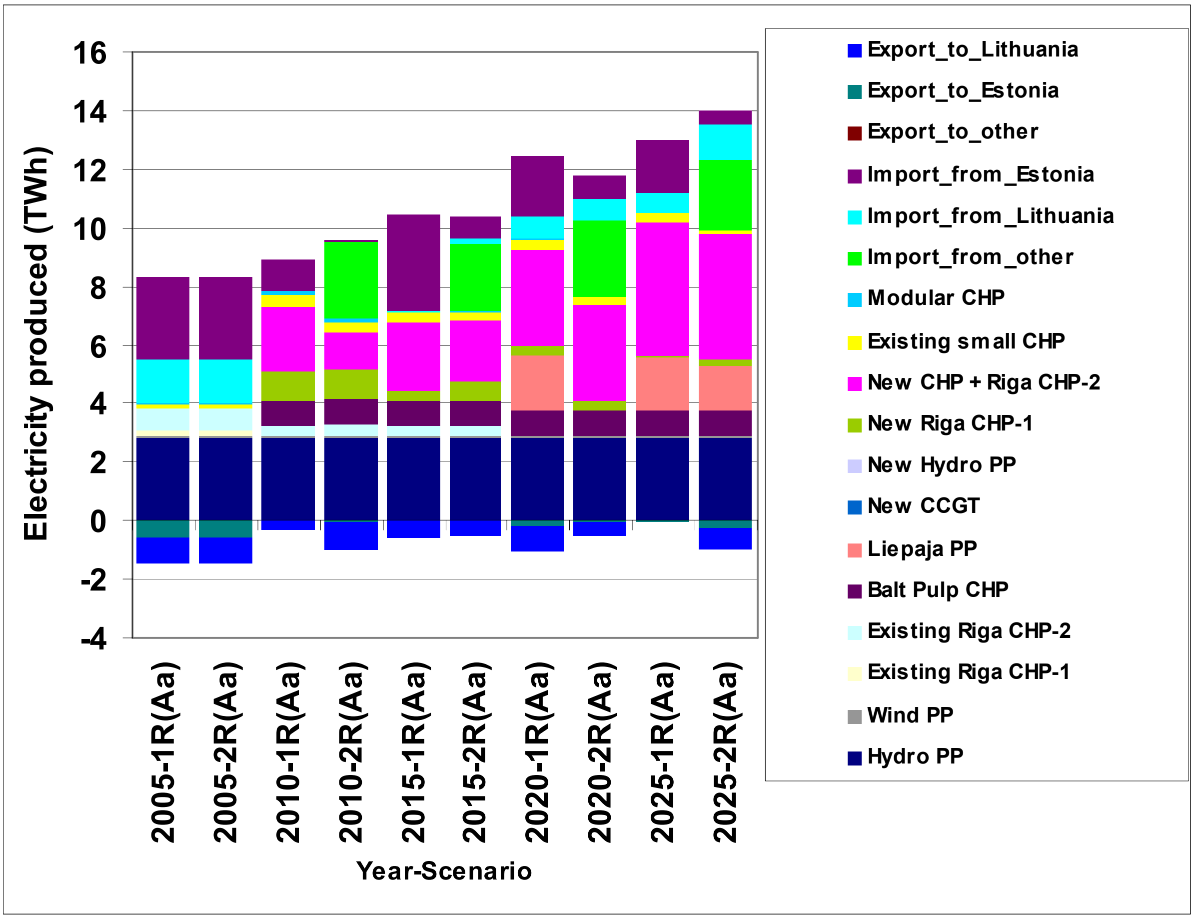


Figure 8.45. Comparison of electricity generation in Latvia in Scenarios 2R(Aa) and 1R(Aa).

The existing interconnection between Estonia and third countries has a major impact on the direction of electricity flows. Electricity trade between Estonia and Latvia is, to a large extent, replaced by Estonian trade with third countries (see *Figure 8.46*). Thus, in 2010 Estonia exports 1.06 TWh to Latvia in Scenario 1R(Aa), but in Scenario 2R(Aa) Estonia exports 1.5 TWh to Finland. A similar situation occurs in 2015 and 2020, while electricity imports in 2025, together with terminated exports, postpone the construction of a new CCGT unit. The total discounted cost in this scenario is €116 million more expensive than the reference scenario because the benefits from electricity trade do not outweigh the investment costs for the new interconnections.

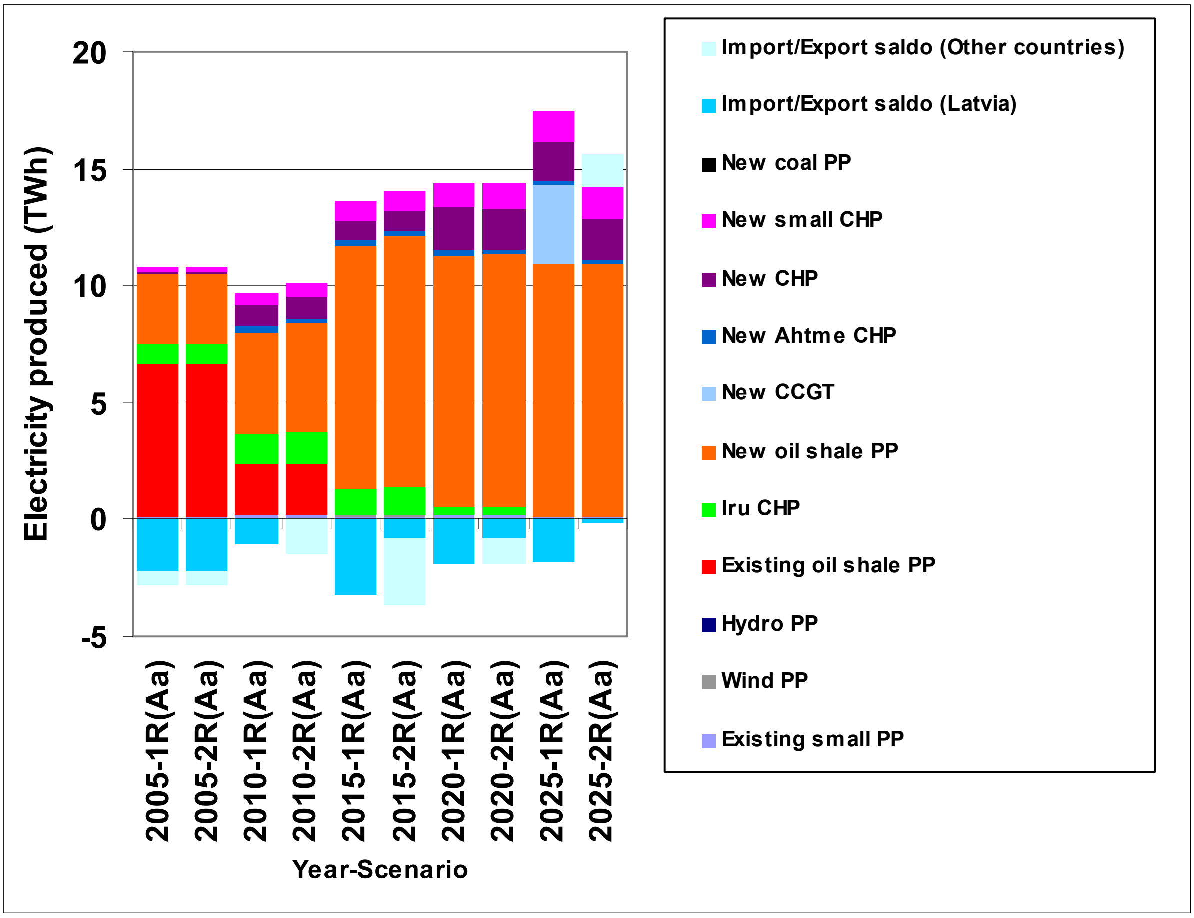


Figure 8.46. Comparison of electricity generation in Estonia in Scenarios 2R(Aa) and 1R(Aa).

8.5. Regional scenario with gas storage to cover demand for 120 days

Increased security of gas supply is the main feature of this scenario. Increased security is realised through gas storage — the amount of gas stored in each period should be greater or equal to 120/365 of the annual gas demand. This requirement is implemented for the whole region from 2010. For individual countries or before 2010 the situation can be different. The operation of gas storage in this scenario is shown in *Figure 8.47*.

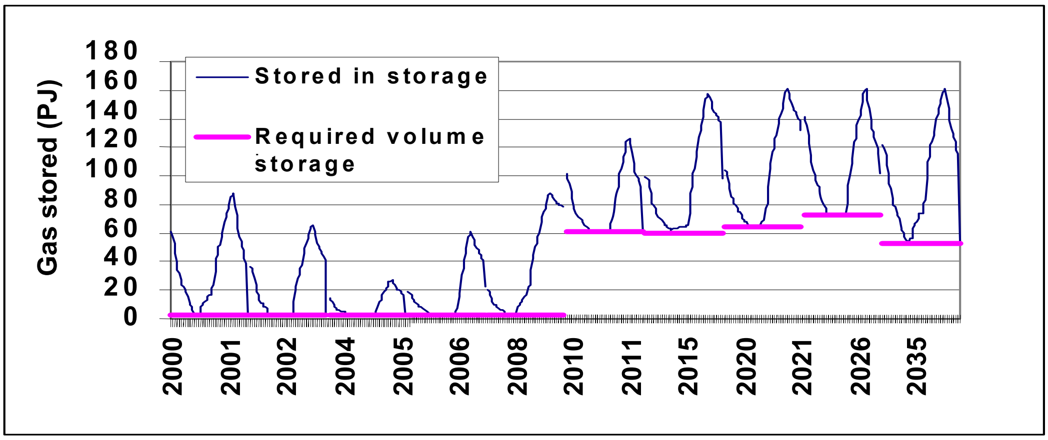


Figure 8.47. Operation of gas storage, Scenario 3R(Aa).

A higher security of gas supply results in higher costs to operate and develop the energy system. Total discounted system cost in this scenario is €230 million more than in the reference scenario. In fact, when the cost of formation and maintenance of the required fuel reserves are also considered, the cost difference between the two scenarios increases to €239 million.

The requirement for gas storage reduces the consumption of gas. The total primary gas requirement during the study period is 264 PJ less than in the reference scenario. The lower consumption of gas is compensated by an increased demand for oil and shale oil (179 PJ) and for orimulsion (95 PJ). The decrease in gas consumption for electricity and heat generation is larger than the increase in the primary gas demand and reaches nearly 308 PJ during the analysed period, which is equivalent to almost 3 years of gas consumption. The decrease in gas consumption is compensated by the use of more oil and shale oil and of orimulsion.

The structure of electricity generation in this scenario is practically the same as that in the reference scenario up to the 2025. In later years, beyond the study period, changes become significant. The requirement to keep gas in storage brings forward the construction of a new NPP. New nuclear capacities in this scenario are already commissioned in 2025 and produce 3.2 TWh of electricity annually. From 2035 the electricity generation from a new NPP is expected to be about 5.8 TWh, while in Scenario 1R(Aa) it was only 2.1 TWh. A new NPP is built instead of new CCGT units in Lithuania.

The requirement for gas storage may also reduce the contribution of highly efficient CHP plants at the end of calculation period. For electricity generation these CHP plants can be replaced by condensing power plants that run on orimulsion, and for heat production by boilers that run on coal.

The dynamics of electricity generation in Lithuania in this and the reference scenario are presented in *Figures 8.48* and *8.49*. *Figure 8.49* is similar to *Figure 8.8* with the exception that the former represents results for the whole calculation period, while the latter only for the analysed period.

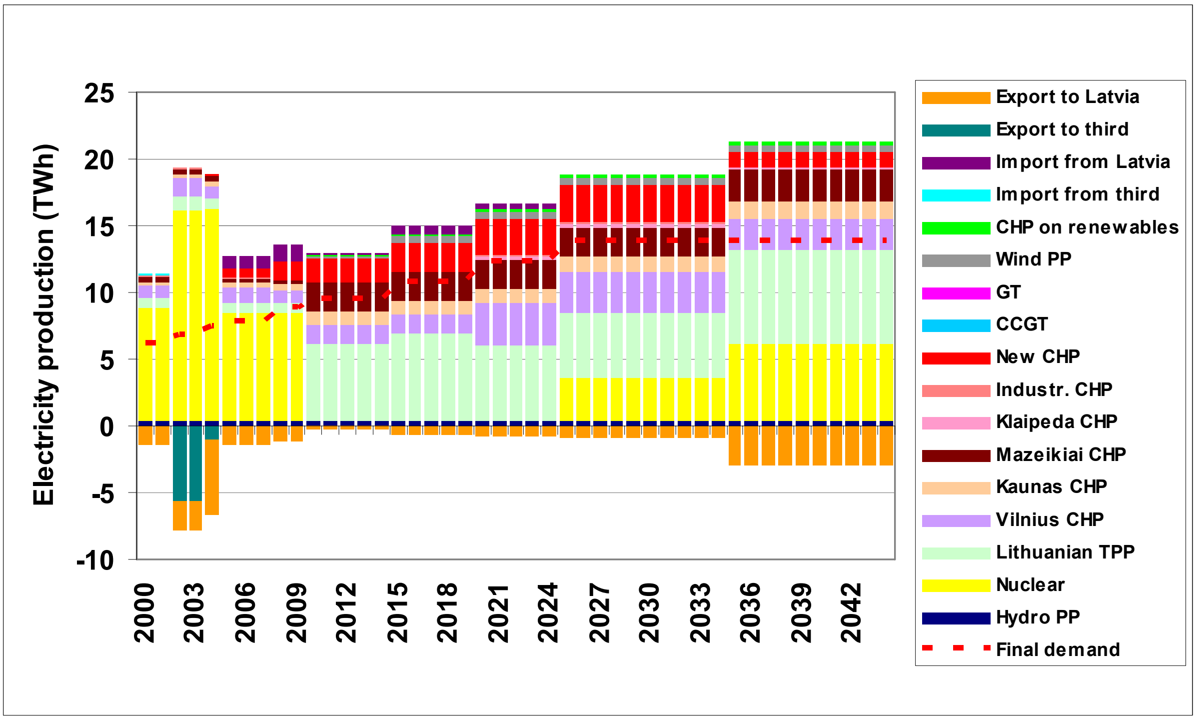


Figure 8.48. Electricity generation in Lithuania, Scenario 3R(Aa).

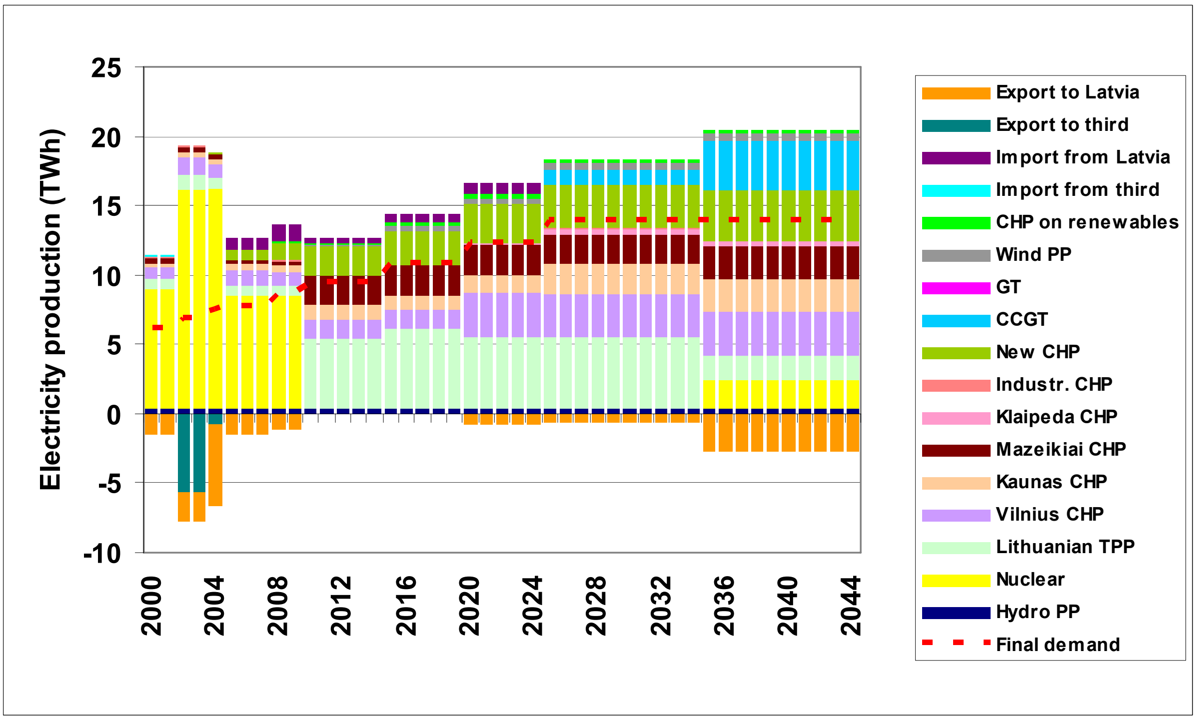


Figure 8.49. Electricity generation in Lithuania, Scenario 1R(Aa).

8.6. Regional scenario with limited gas share in the fuel mix used to generate electricity and heat

Scenario 4R(Aa) compared to Scenario 1R(Aa) has only one difference — the share of gas electricity and heat generation should not exceed 25% after 2010.

Gas consumption for electricity and heat production in Scenario 1R(Aa) is only slightly higher than 30%. Therefore, the requirement to restrict the gas share results in only minor compensatory changes in electricity and heat generation.. The differences in fuel consumption between the two scenarios are shown in *Figure 8.50*.

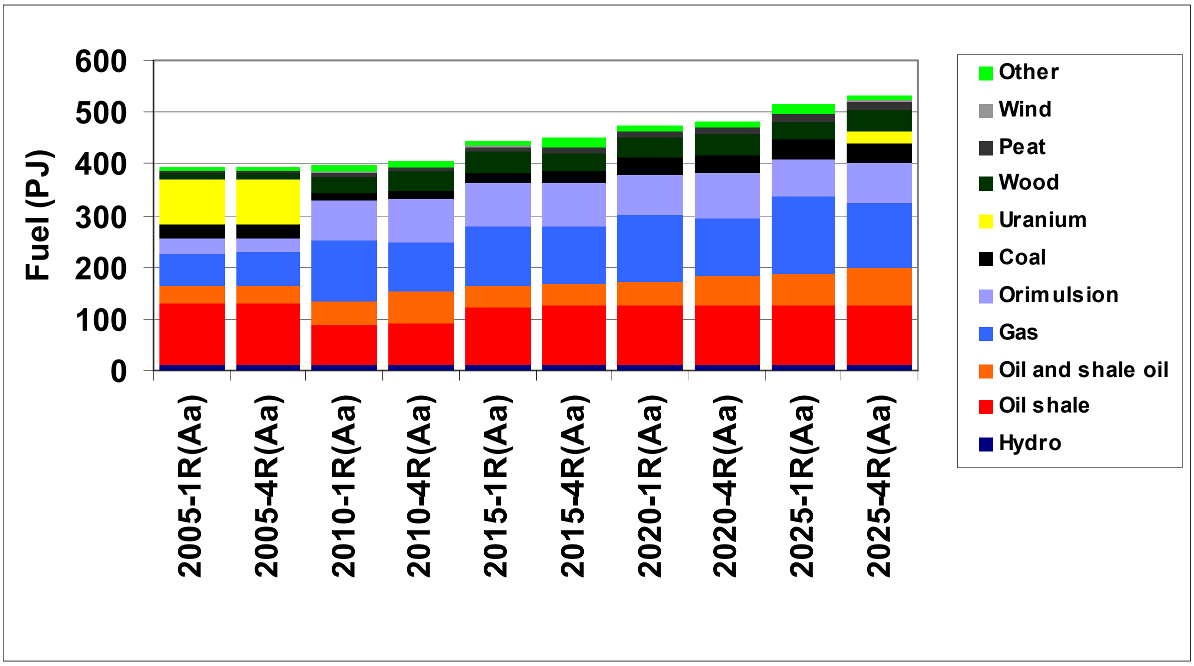


Figure 8.50. Fuel consumption to generate electricity and heat in Scenarios 1R(Aa) and 4R(Aa).

The data shows a slightly lower consumption of gas which is compensated by an increased demand for oil and shale oil for most of the study period. However, in the final study period nuclear fuel is being consumed. The structure of electricity generating capacities in the three Baltic States remains practically identical during the entire study period because many power plants in the region can burn either natural gas or HFO. In this case, switching from one fuel type to another does not require a change of technology. The only difference is that from 2025 a new NPP starts operation in Lithuania in Scenario 4R(Aa), while in Scenario 1R(Aa) its commissioning is postponed by about 10 years.

The situation is much different if the combined share of natural gas and orimulsion is constrained to 25%. The differences in fuel consumption for electricity and heat generation in Scenarios 4R(Aaa) and 1R(Aa) are presented in *Figure 8.51*.

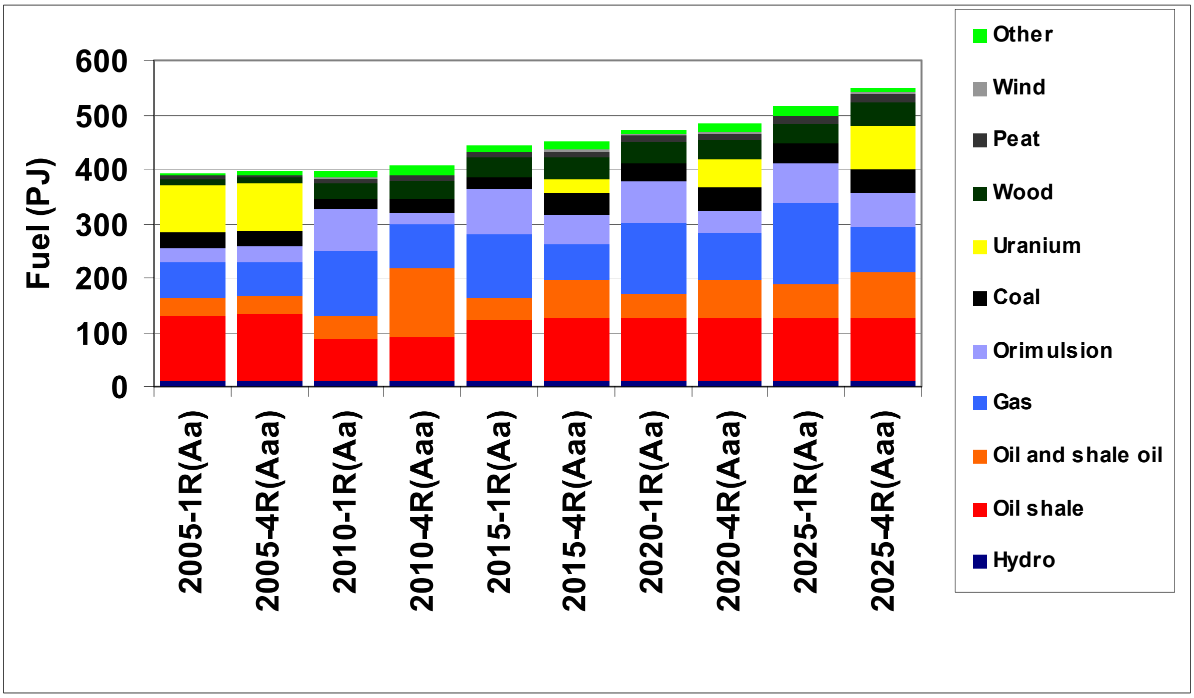


Figure 8.51. Fuel consumption for electricity and heat generation in Scenarios 1R(Aa) and 4R(Aaa).

Figure 8.51 shows that the restricted consumption of gas and orimulsion is substituted by a higher demand for oil and shale oil, as well as by nuclear fuel which is part of the fuel balance from 2015 onwards.

In Estonia the dynamics of electricity generation in Scenarios 4R(Aaa) and 1R(Aa) are very similar until 2024. However, from 2025 to 2034 a new CCGT does not come online in Scenario 4R(Aaa), and it starts operation only in 2035, while in Scenario 1R(Aa) it begins operation by 2025. These differences are presented in *Figure 8.52*.

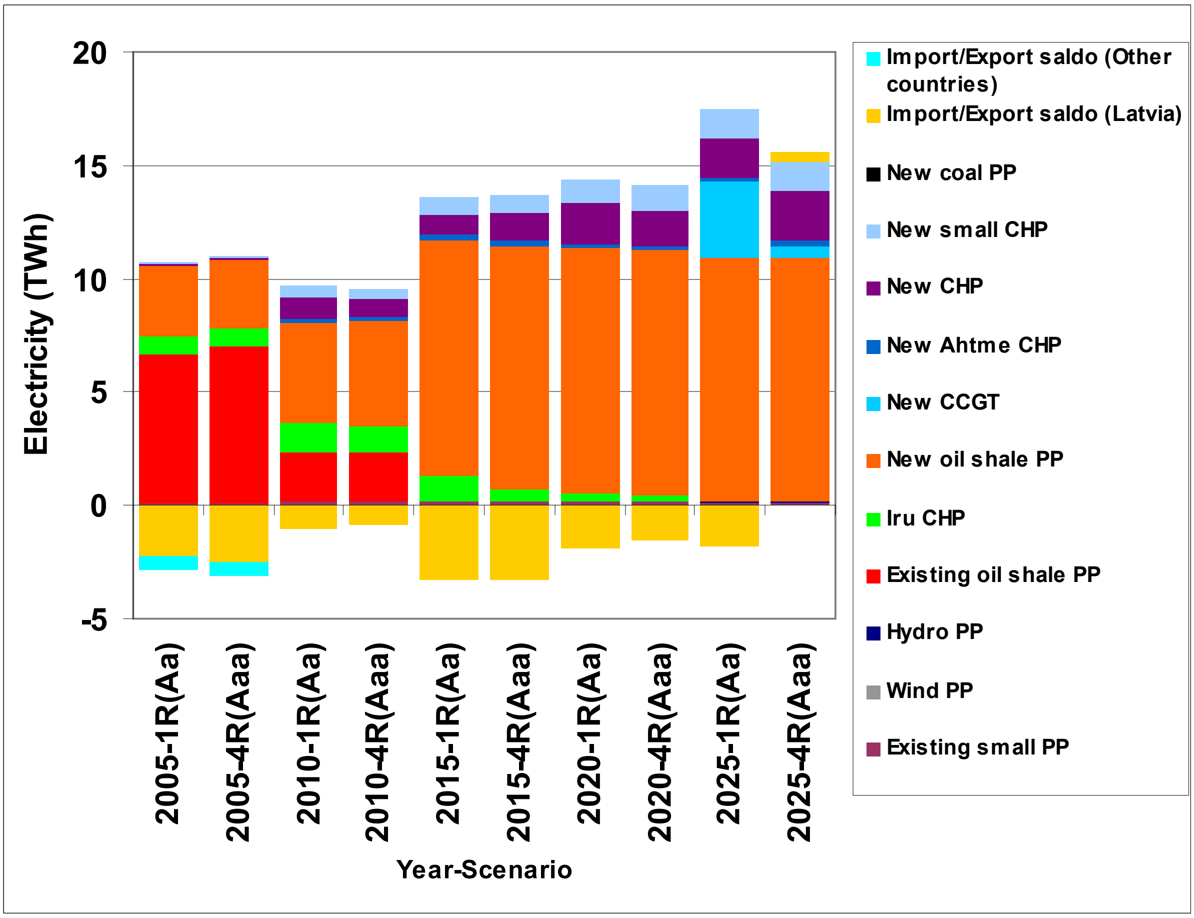


Figure 8.52. Electricity generation in Estonia in Scenarios 1R(Aa) and 4R(Aaa).

In the Latvian power system, a new coal-fired power plant in Liepaja starts to operate 10 years earlier in Scenario 4R(Aaa) than in Scenario 1R(Aa). Resultantly, this reduces the capacity and generation output of new CHP plants as well as its associated fuel - natural gas. Increased electricity imports from Lithuania after 2025 also contributes to the requirement of reduced share of natural gas and orimulsion in total fuel consumption for electricity and heat generation. The differences in electricity generation in Latvia between Scenarios 4R(Aaa) and 1R(Aa) are shown in *Figure 8.53*.

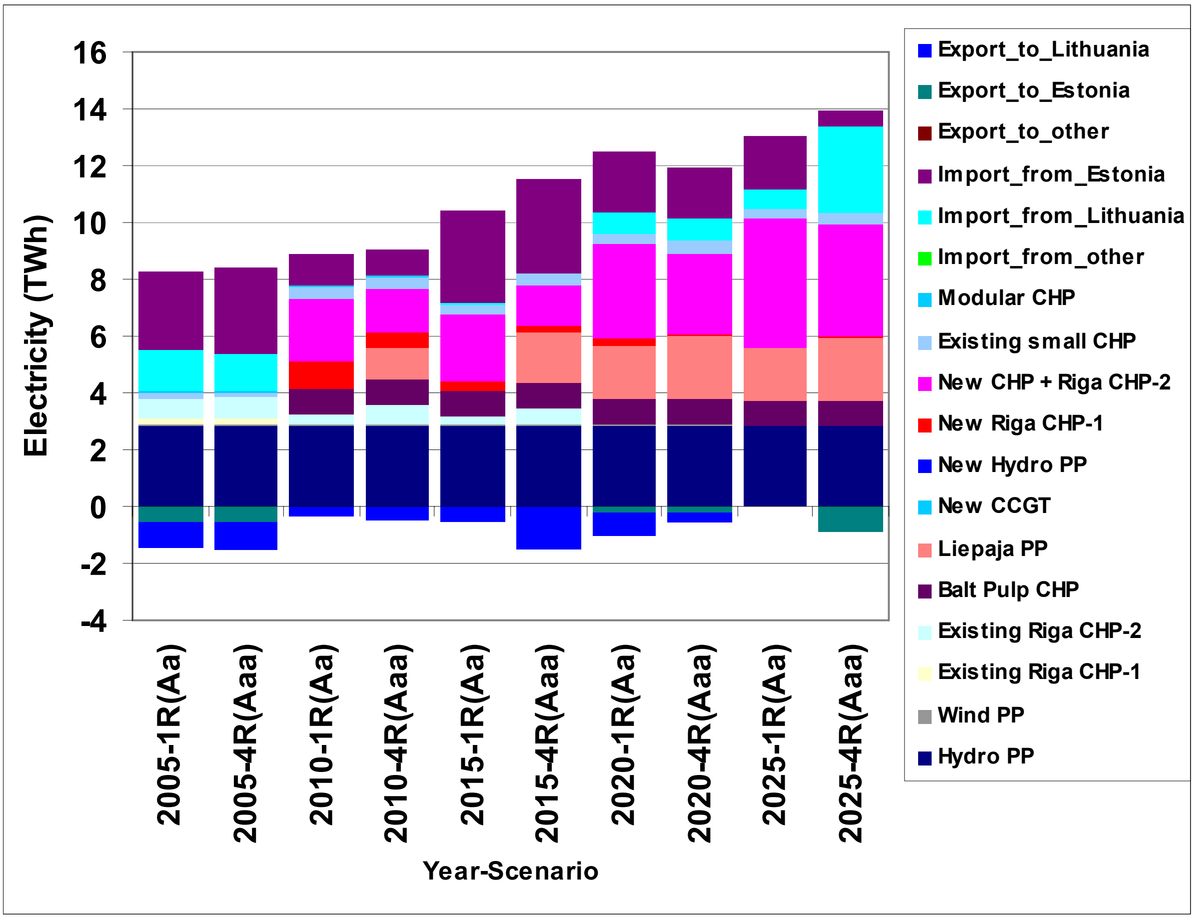


Figure 8.53. Electricity generation in Latvia in Scenarios 1R(Aa) and 4R(Aaa).

In Lithuania, the combined restriction of both natural gas and orimulsion results in the operation of a new NPP in 2015, while in the reference scenario this does not happen until 2035. The new NPP significantly reduces electricity output from the Lithuanian TPP. There is also a lower contribution from new CHP plants. A very limited contribution from the new CCGT occurs only in 2035; ten years later than in Scenario 1R(Aa). These differences are summarised in *Figure 8.54*.

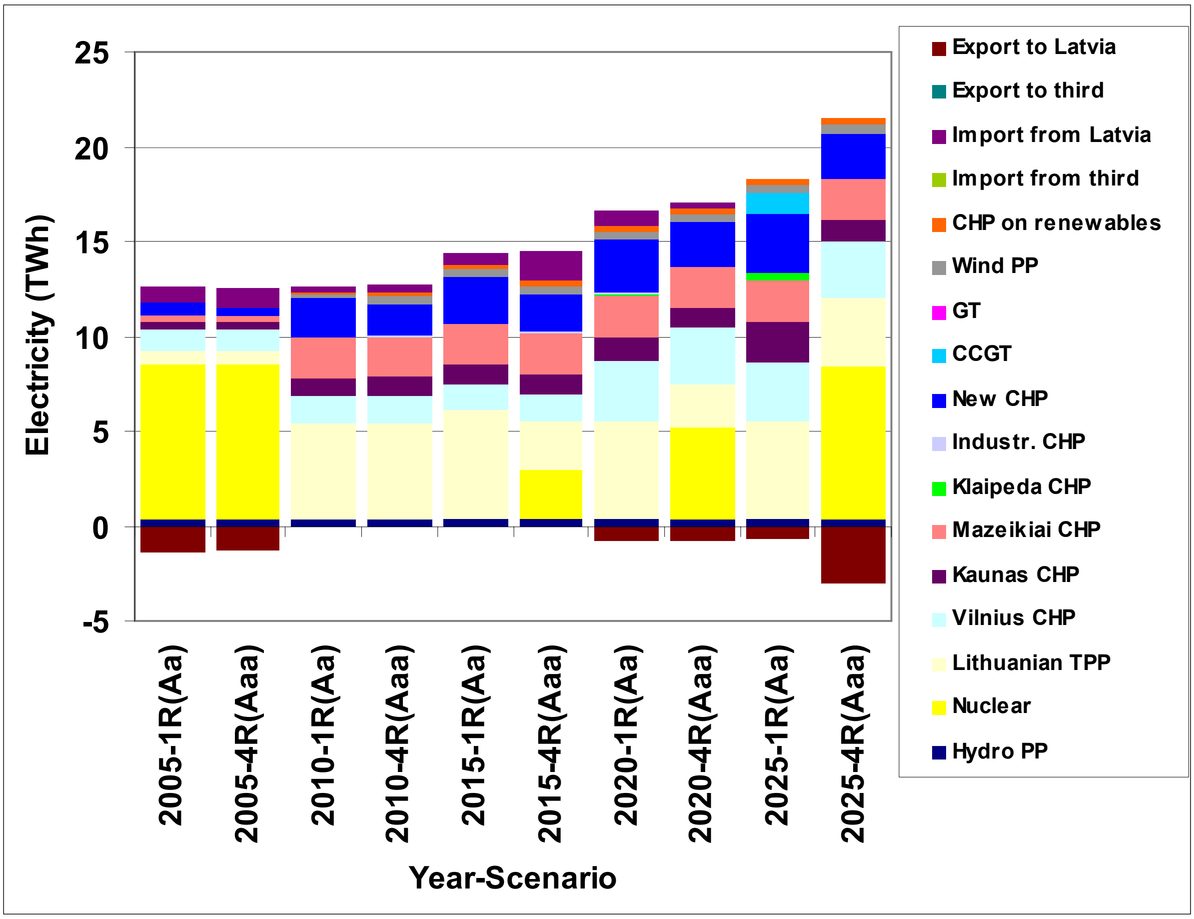


Figure 8.54. Electricity generation in Lithuania in Scenarios 1R(Aa) and 4R(Aaa).

In terms of the total discounted cost to operate and develop the energy system, Scenario 4R(Aaa) is €329 million more expensive than Scenario 1R(Aa) because the combined constraint on the share of gas and orimulsion for electricity and heat production leads to more significant changes in the system in comparison to the changes caused by a constraint on gas only.

8.7. Extended operation time of Ignalina NPP Unit 2

According to the Lithuanian National Energy Strategy, the second unit of the Ignalina NPP will close at the end of 2009 (the first unit closed at the end of 2004). However, the actual lifetime of the existing fuel channels of the second unit may be up to 2018 [68, 69]. Thus, the real lifetime of the second unit may be extended until the end of 2017. After that time fuel channels could be replaced and the unit could be in operation for an additional 15–20 years. In this study the consequences of fuel channel replacement are not analysed because there is insufficient information in Lithuania on the necessary investments for a long term safety upgrade or modernisation of the ageing unit. Nevertheless, operation of the unit until the end of 2017 does not require any special investments in modernisation or safety upgrade. This issue is a subject to investigate, especially as this would enable the estimation of the economic loss incurred to Lithuania through the early closure of the Ignalina NPP.

To evaluate the economic consequences of the early closure of the second unit of the Ignalina NPP an additional Scenario, 5R(Aa) was modelled. In this scenario it is assumed that Ignalina Unit 2 remains in operation until the end of its normal lifetime (i.e., the end of 2017). All other inputs to the model are exactly the same as in Scenario 1R(Aa). The results of this study show that the continued operation of Ignalina Unit 2 reduces the total discounted cost by about €440 million compared to Scenario 1R(Aa). If the additional costs to form and maintain the necessary fuel reserves are taken into account, the total saving will increase up to €446 million.

The total saving of undiscounted cost could reach over €1000 million. High savings are likely to occur especially in the variable O&M costs, where undiscounted costs in Scenario 5R(Aa) are €1082 million lower than in Scenario 1R(Aa). However, since fixed O&M costs are higher in Scenario 5R(Aa), although they do not outweigh the savings of variable O&M costs and investments, total savings are a little lower.

Although the discounted cost savings from the longer operation of the Ignalina NPP are highest in Lithuania, savings also occurs in Estonia and Latvia. However, a higher cost is incurred in Estonia if undiscounted costs are compared between the two scenarios. A summary of the differences in cost between Scenario 5R(Aa) and Scenario 1R(Aa) are presented in *Table 8.7*.

Table 8.7. Cost comparison between Scenarios 5R(Aa) and 1R(Aa) (€ million)

Country and cost parameter	Total undiscounted cost, 2000–2035	Total discounted cost, 2000–2035	Difference in undiscounted cost, 2000–2035	Difference in discounted cost, 2000–2035	Total undiscounted cost, 2000–2045	Total discounted cost, 2000–2045	Difference in undiscounted cost, 2000–2045	Difference in discounted cost, 2000–2045
	Scenario 5R(Aa)		*Scenario 5R(Aa) minus Scenario 1R(Aa)*		*Scenario 5R(Aa)*		*Scenario 5R(Aa) minus Scenario 1R(Aa)*	
Estonia								
Investment cost	3266.2	780.7	–72.9	–29.1	3266.2	780.7	–72.9	–29.1
Fixed O&M cost	5031.9	1875.6	–14.2	–9.3	5896.3	1909.7	–14.3	–9.4
Variable O&M cost including fuel cost and taxes	22549.9	5233.2	9.4	–49.7	30000.0	5527.6	330.3	–37.7
Estonia subtotal	30848.0	7889.6	–77.7	–88.0	39162.5	8218.1	243.1	–76.1
Reserve cost	94.7	45.7	–0.2	–0.1	94.7	45.7	–0.2	–0.1
Estonia total	**30942.7**	**7935.2**	**–77.9**	**–88.2**	**39257.3**	**8263.8**	**243.0**	**–76.2**
Latvia								
Investment cost	3606.4	631.0	–49.7	–23.0	3606.4	631.0	–49.7	–23.0
Fixed O&M cost	4380.5	1627.7	–15.3	–7.7	5251.5	1662.1	–17.4	–7.9
Variable O&M cost including fuel cost and taxes	25323.0	6590.5	–78.6	–34.8	32490.7	6873.7	–269.7	–43.0
Latvia subtotal	33309.9	8849.1	–143.6	–65.5	41348.7	9166.8	–336.8	–73.8
Reserve cost	199.7	81.1	–0.1	–0.1	199.7	81.1	–0.1	–0.1
Latvia total	**33509.7**	**8930.2**	**–143.7**	**–65.6**	**41548.4**	**9247.9**	**–336.9**	**–74.0**
Lithuania								
Investment cost	3626.9	678.2	–121.6	–42.3	3626.9	678.2	–121.6	–42.3
Fixed O&M cost	3839.6	1549.1	355.6	117.2	4481.0	1574.4	356.1	117.2
Variable O&M cost including fuel cost and taxes	85679.3	22351.8	–1033.6	–357.8	113722.9	23460.0	–1142.8	–364.6
Lithuania subtotal	93145.7	24579.1	–799.5	–282.9	121830.8	25712.6	–908.2	–289.8
Reserve cost	203.2	100.9	0.3	–5.7	203.2	100.9	0.3	–5.7
Lithuania total	**93348.9**	**24680.0**	**–799.2**	**–288.6**	**122034.0**	**25813.5**	**–907.9**	**–295.5**
Baltic region								
Investment cost	10499.5	2089.9	–244.2	–94.4	10499.5	2089.9	–244.2	–94.4
Fixed O&M cost	13252.1	5052.3	326.1	100.2	15628.9	5146.3	324.5	99.9
Variable O&M cost including fuel cost	133552.1	34175.5	–1102.8	–442.3	176213.6	35861.3	–1082.2	–445.3
Region subtotal	*157303.7*	*41317.7*	*–1020.9*	*–436.5*	*202342.0*	*43097.5*	*–1001.9*	*–439.7*
Reserve cost	497.6	227.7	0.1	–5.9	497.6	227.7	0.1	–5.9
Region total	**157801.3**	**41545.4**	**–1020.8**	**–442.4**	**202839.7**	**43325.2**	**–1001.8**	**–445.6**

8.8. Diversification of energy supply

To model the diversification of energy supply, an additional Scenario, 6R(Aa), was analysed in which a new coal-fired power plant in Latvia and a NPP in Lithuania were forced to be commissioned. In terms of total discounted cost this scenario is €511 million more expensive than Scenario 1R(Aa). A cost summary and comparison with Scenario 1R(Aa) is provided in *Table 8.8*.

However, if undiscounted cost are considered the commissioning of new nuclear and coal power plants is less expensive than the reference Scenario 1R(Aa). Thus, the discounting factor plays an important role in the cost comparison between scenarios. Preliminary calculations show that a discount factor of about 6% results in equal costs for these scenarios. (Recall that the default discount factor in this study in 8% - see Chapter 7.)

Commissioning nuclear and coal power plants significantly reduce electricity generation from modernised oil shale power plants in Estonia. The main differences arise half way through the study period. For example, in comparison with Scenario 1R(Aa) electricity generation from modernised oil shale power plants is 1.23 TWh lower in 2010 and 3.0 TWh in 2015. However, at the end of the study period generation at modernised oil shale power plants increases to the same level as in Scenario 1R(Aa). A comparison of electricity generation in Estonia between these two scenarios is presented in *Figure 8.55*.

The forced commissioning of a new coal-fired power plant in Liepaja significantly reduces electricity imports and electricity generation at new CHP plants in Latvia, and will partly replace natural gas in electricity generation. Lower capacities of new CHP plants also result in a higher heat output from new boilers. The dynamics of electricity generation by power plants in Latvia are presented in *Figure 8.56* and by fuel types in *Figure 8.57*.

The forced construction of a new nuclear plant in Lithuania effectively removes electricity generation from the Lithuanian TPP, but remains as a reserve capacity. A new nuclear plant also reduces the electricity output from new CHP plants to about one-third in 2010 and by about 15% in 2025. Nuclear fuel also significantly reduces the use of natural gas and orimulsion to produce electricity. For Scenario 6R(Aa) electricity generation from gas is 1.63 TWh in 2010 and 5.59 TWh in 2025, while for Scenario 1R(Aa) the corresponding numbers are 4.27 TWh and 9.15 TWh. For orimulsion the numbers are 1.02 TWh in 2010 and 3.44 TWh in 2025, while in the reference scenario they are 5.19 TWh and 5.04 TWh respectively. The dynamics of electricity generation in Lithuania are shown in *Figures 8.58* and *8.59*.

In Estonia an installed generating capacity that is lower than demand can also be maintained in Scenario 6R(Aa), since sufficient installed capacity in Latvia and a huge overcapacity in Lithuania allow for imports from both countries (*Figure 8.60*). This permits a relaxed modernisation schedule to be implemented for the Estonian oil shale power plants.

Table 8.8. Cost comparison between Scenarios 6R(Aa) and 1R(Aa) (€ million)

Country and cost parameter	Total undiscounted cost, 2000–2035	Total discounted cost, 2000–2035	Difference of undiscounted cost, 2000–2035	Difference of discounted cost, 2000–2035	Total undiscounted cost, 2000–2045	Total discounted cost, 2000–2045	Difference of undiscounted cost, 2000–2045	Difference of discounted cost, 2000–2045
	Scenario 6R(Aa)		*Scenario 6R(Aa) minus Scenario 1R(Aa)*		*Scenario 6R(Aa)*		*Scenario 6R(Aa) minus Scenario 1R(Aa)*	
Estonia								
Investment cost	3039.5	694.4	–299.6	–115.4	3039.5	694.4	–299.6	–115.4
Fixed O&M cost	4923.5	1859.5	–122.7	–25.3	5783.7	1893.5	–126.9	–25.6
Variable O&M cost including fuel cost and taxes	19890.5	4940.7	–2649.9	–342.3	27030.5	5223.0	–2639.3	–342.3
Estonia subtotal	27853.4	7494.6	–3072.2	–483.0	35853.6	7810.9	–3065.8	–483.3
Reserve cost	93.3	45.4	–1.6	–0.3	93.3	45.4	–1.6	–0.3
Estonia total	**27946.7**	**7540.0**	**–3073.8**	**–483.3**	**35946.9**	**7856.3**	**–3067.4**	**–483.6**
Latvia								
Investment cost	3848.3	807.5	192.2	153.5	3848.3	807.5	192.2	153.5
Fixed O&M cost	4594.4	1674.7	198.6	39.3	5488.2	1710.0	219.3	40.1
Variable O&M cost including fuel cost and taxes	25325.5	6668.1	–76.1	42.8	32373.3	6946.7	–387.1	30.0
Latvia subtotal	33768.3	9150.3	314.7	235.7	41709.9	9464.3	24.4	223.6
Reserve cost	199.7	81.0	–0.2	-0.2	199.7	81.0	–0.2	–0.2
Latvia total	**33968.0**	**9231.3**	**314.6**	**235.5**	**41909.6**	**9545.3**	**24.3**	**223.5**
Lithuania								
Investment cost	5509.8	1722.3	1761.3	1001.8	5509.8	1722.3	1761.3	1001.8
Fixed O&M cost	4339.4	1591.5	855.4	159.6	5097.1	1621.5	972.2	164.2
Variable O&M cost including fuel cost and taxes	86138.3	22345.1	–574.5	–364.5	113787.8	23438.3	–1077.9	–386.3
Lithuania subtotal	95987.5	25658.9	2042.2	796.9	124394.7	26782.1	1655.7	779.7
Reserve cost	199.8	98.2	–3.1	–8.4	199.8	98.2	–3.1	–8.4
Lithuania total	**96187.3**	**25757.1**	**2039.1**	**788.5**	**124594.5**	**26880.3**	**1652.6**	**771.3**
Baltic region								
Investment cost	12397.6	3224.2	1654.0	1039.9	12397.6	3224.2	1654.0	1039.9
Fixed O&M cost	13857.2	5125.7	931.3	173.6	16369.1	5225.0	1064.6	178.7
Variable O&M cost including fuel cost	131354.3	33953.9	–3300.6	–663.9	173191.6	35608.1	–4104.2	–698.6
Region subtotal	*157609.2*	*42303.8*	*–715.3*	*549.6*	*201958.3*	*44057.2*	*–1385.6*	*520.1*
Reserve cost	492.7	224.7	–4.8	–8.9	492.7	224.7	–4.8	–8.9
Region total	**158102.0**	**42528.5**	**–720.1**	**540.7**	**202451.0**	**44281.9**	**–1390.5**	**511.1**

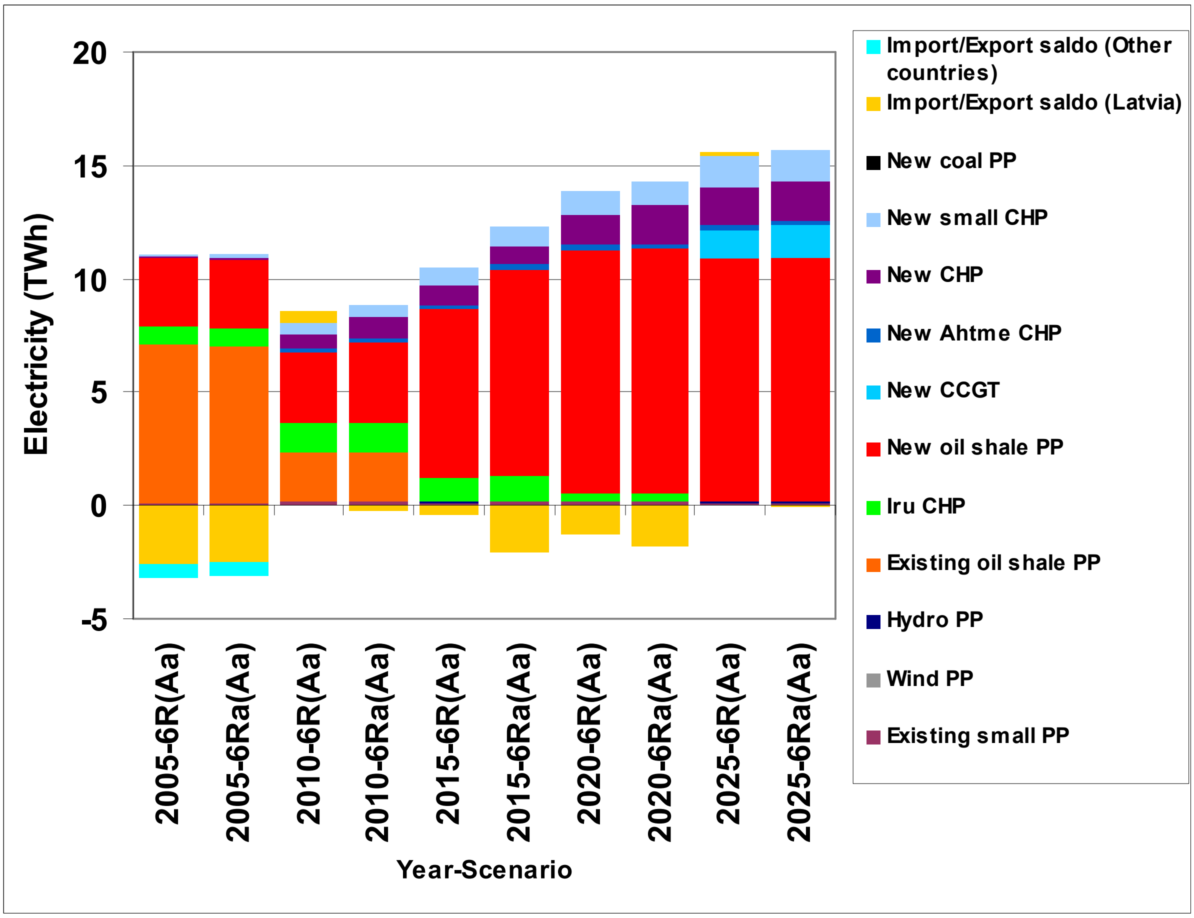


Figure 8.55. Electricity generation in Estonia in Scenarios 6R(Aa) and 1R(Aa).

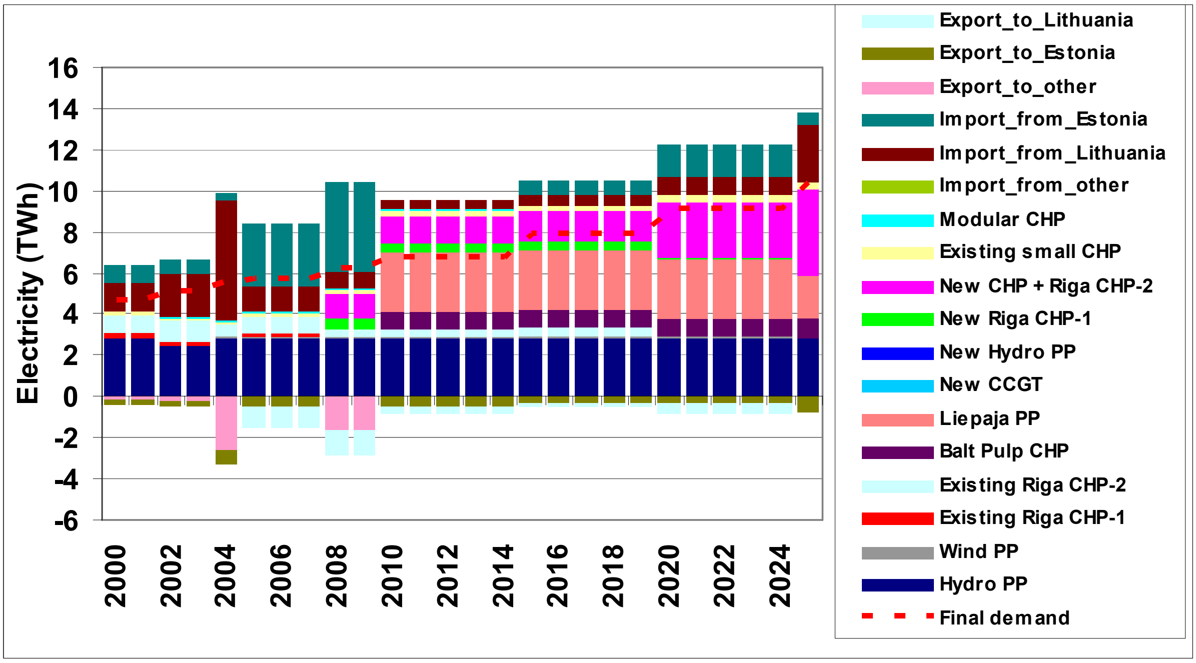


Figure 8.56. Electricity generation by technologies in Latvia in Scenario 6R(Aa).

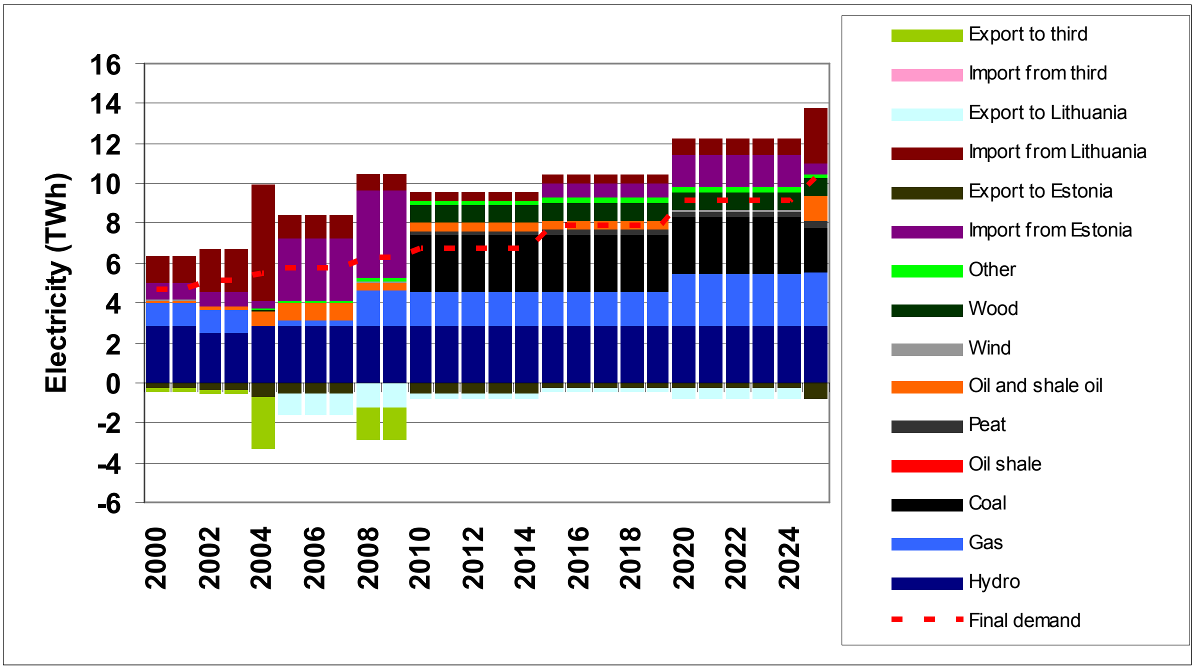


Figure 8.57. Electricity generation by fuel type in Latvia in Scenario 6R(Aa).

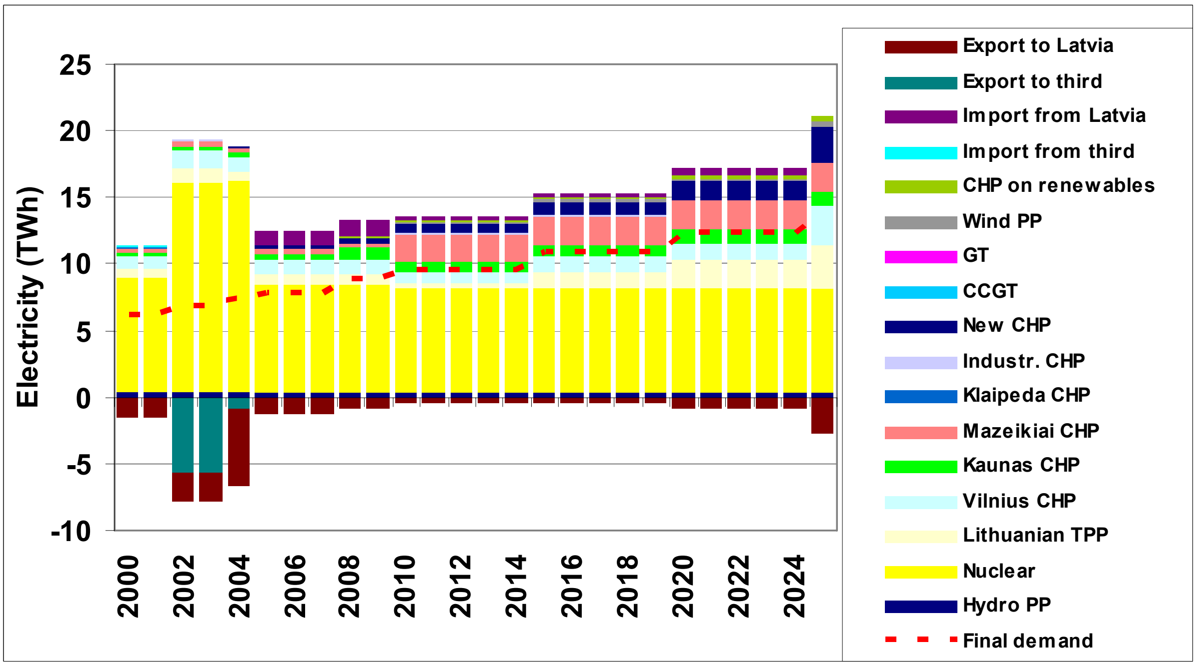


Figure 8.58. Electricity generation by technologies in Lithuania in Scenario 6R(Aa).

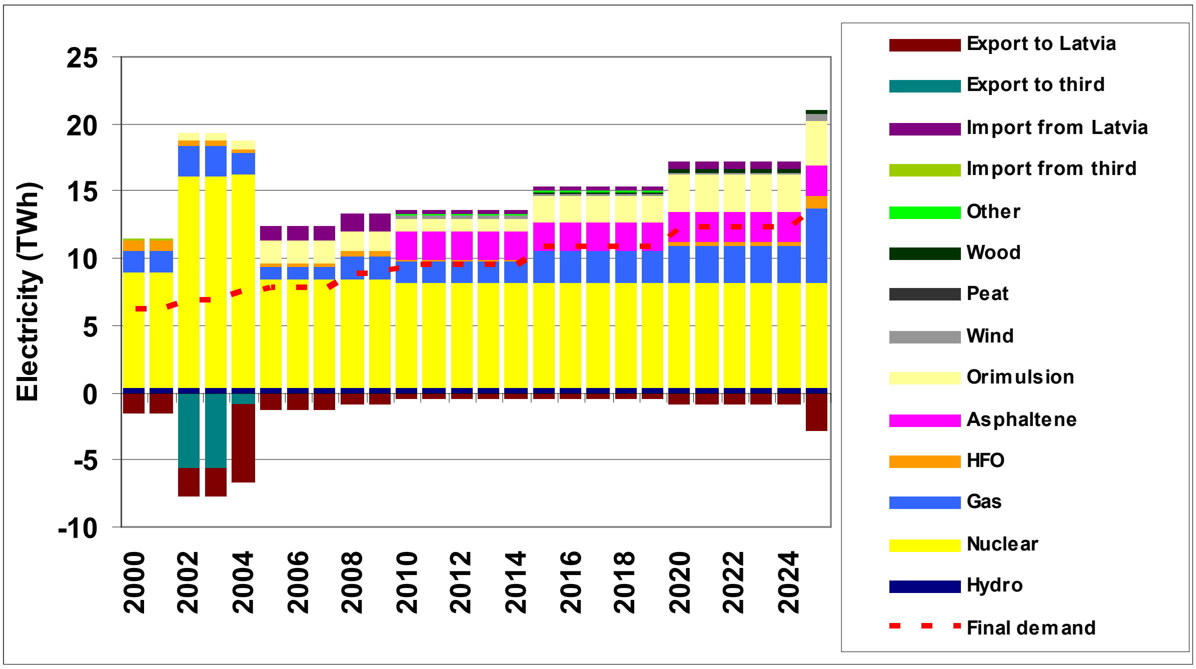


Figure 8.59. Electricity generation by fuel type in Lithuania in Scenario 6R(Aa).

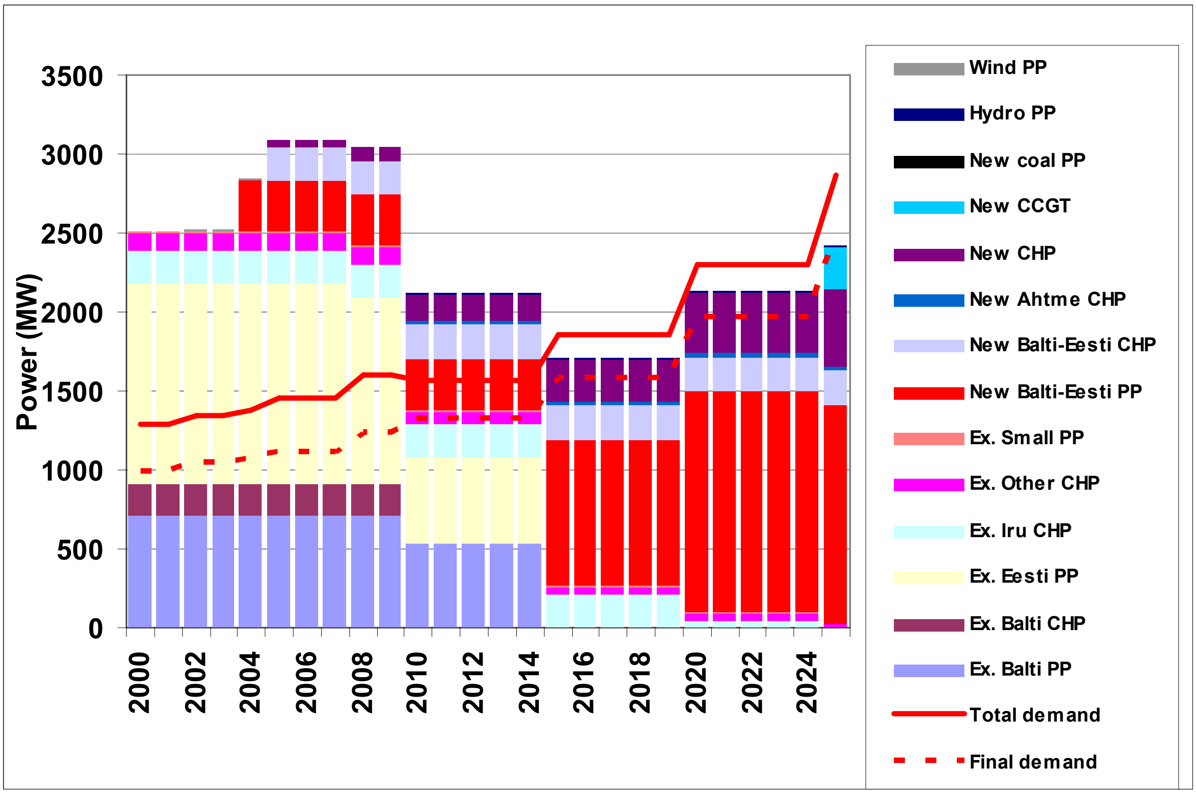


Figure 8.60. Capacity balance in Estonia in Scenario 6R(Aa).

A new nuclear and coal-fired power plant significantly reduces Latvian dependency on fuel supply from Russia. However, for Lithuania and the Baltic region as a whole, energy dependency on Russia is only slightly reduced. This is because nuclear energy not only replaces primarily orimulsion, which is imported from the West, but also reduces the efficiency of fuel utilisation. For the three Baltic States energy import dependence from Russia is 43 PJ lower in 2010 and 60 PJ lower in 2025 in comparison to the reference scenario. In Lithuania, energy imports from Russia are 337 PJ in 2010 and 405 PJ in 2025 in Scenario 6R(Aa), while in the reference case these numbers are 352 PJ and 411 PJ respectively. In addition to some quantitative reduction in energy imports nuclear fuel contributes to the security of energy supply since it can be used for a long periods of time once it is loaded into the reactor.

Since the forced commissioning of a new NPP has a much larger impact on the regional energy system than the coal power plant in Scenario 6R(Aa), one additional scenario (i.e., 6Ra(Aa)) was calculated to reflect this disparity.

In Scenario 6Ra(Aa) electricity generation in Estonia and Lithuania is very similar to that in Scenario 6R(Aa). However, in Latvia the situation is different because of the later commissioning of the Liepaja power plant in Scenario 6Ra(Aa), which starts operating not before 2025. Consequently, the contributions from new CHP plants and electricity imports are higher than in Scenario 6R(Aa). The dynamics of electricity generation in Latvia in Scenario 6Ra(Aa) compared with Scenario 6R(Aa) are shown in *Figure 8.61*.

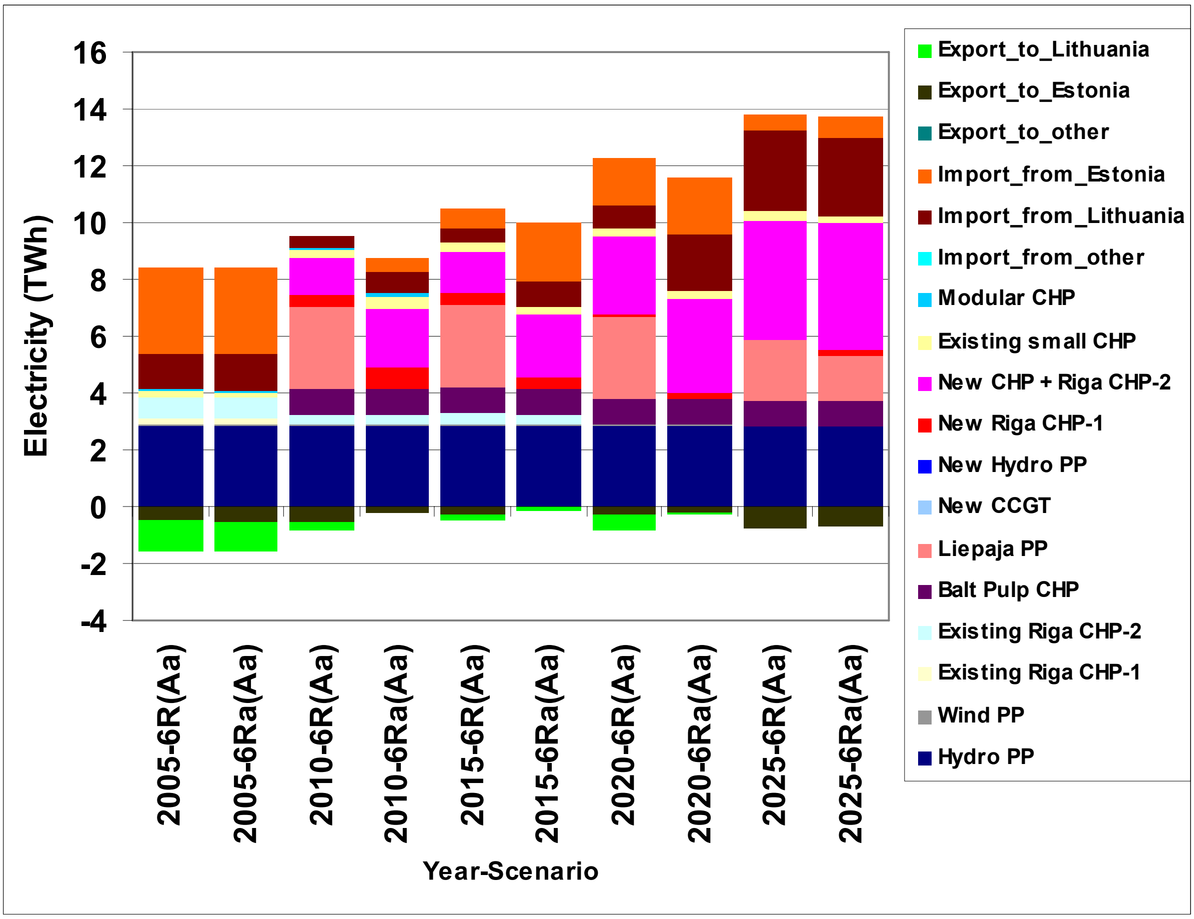


Figure 8.61. Comparison of electricity generation in Latvia in Scenarios 6R(Aa) and 6Ra(Aa).

The commissioning of a new NPP in Lithuania in 2010 increases total system cost during the whole study period by €397–404 million, depending on the cost of reserves. Undiscounted system costs are lower by €1819–1824 million. Detailed information about the cost differences between Scenarios 6Ra(Aa) and 1R(Aa) is presented in *Table 8.9* and Annex II.

Table 8.9. Difference of discounted cost between Scenarios 6Ra(Aa) and 1R(Aa) (€ million)

Parameter	*2000–2005*	*2006–2010*	*2011–2015*	*2016–2020*	*2021–2025*	*2026–2035*	*2036–2045*	*Total 2000–2035*	*Total 2000–2045*
Estonia									
Investment cost	0.0	–40.4	–13.8	22.3	–52.8	13.8	0.0	–70.9	–70.9
Fixed O&M cost	0.0	–1.0	–5.4	–3.9	–0.7	–4.6	0.0	–15.6	–15.6
Variable O&M cost*	3.4	–20.9	–64.1	–40.0	–39.6	–170.0	–6.1	–331.2	–337.3
Reserve cost	0.0	0.0	0.0	0.0	–0.3	0.1	0.0	–0.2	–0.2
Estonia total	3.4	–62.3	–83.3	–21.6	–93.4	–160.7	–6.2	–417.9	–424.0
Latvia									
Investment cost	0.6	–32.1	5.0	–52.4	47.7	0.2	0.0	–31.1	–31.1
Fixed O&M cost	0.0	–0.1	–1.7	–2.6	–5.5	0.2	–0.8	–9.6	–10.4
Variable O&M cost*	0.2	8.9	–10.5	–7.4	–27.2	–33.8	–13.2	–69.9	–83.0
Reserve cost	0.0	0.2	–0.1	–0.2	0.1	0.0	0.0	0.0	0.0
Latvia total	0.8	–23.1	–7.4	–62.6	15.2	–33.4	–14.0	–110.5	–124.5
Lithuania									
Investment cost	–34.3	1125.2	–15.4	19.4	–10.2	–56.4	0.0	1028.3	1028.3
Fixed O&M cost	–0.6	11.5	64.3	36.5	25.5	27.6	5.2	164.9	170.1
Variable O&M cost*	–0.5	–52.7	–161.4	–84.3	–17.7	88.8	–18.0	–227.7	–245.7
Reserve cost	0.1	–11.8	0.5	2.1	2.3	–0.4	0.0	–7.0	–7.0
Lithuania total	–35.3	1072.2	–111.9	–26.2	0.0	59.6	–12.8	958.5	945.7
Baltic region									
Investment cost	–33.7	1052.6	–24.2	–10.7	–15.3	–42.4	0.0	926.3	926.3
Fixed O&M cost	–0.6	10.4	57.3	30.1	19.4	23.2	4.4	139.8	144.1
Variable O&M cost*	3.1	–64.6	–236.1	–131.7	–84.5	–115.0	–37.2	–628.8	–666.0
Reserve cost	0.2	–11.6	0.5	1.9	2.1	–0.3	0.0	–7.2	–7.2
Baltic region total	–31.0	986.8	–202.6	–110.5	–78.3	–134.5	–32.9	430.1	397.2

*Including fuel cost and emission taxes.

The largest difference occurs in the investment cost in Lithuania for the period 2006–2010 and is €2.8 billion higher in Scenario 6Ra(Aa) in comparison to the base case. The corresponding discounted value is €1.12 billion. In Estonia and Latvia the investment costs during the same time period are lower by €102 million and €82 million, respectively. The corresponding discounted values are €40 and €32 million. The total investment costs during the calculation period are €1.8 billion and €0.037 billion higher in Lithuania and Latvia, respectively, while in Estonia the investment costs are €0.215 billion lower because of a lower new installed capacity in the country. The total undiscounted costs in the region are €1.82 billion lower, while they are €2.29 billion higher in Lithuania and €3.12 billion and €0.99 billion lower in Estonia and Latvia, respectively. Discounted costs are also higher in Lithuania, but lower in Estonia and Latvia.

8.9. Regional scenario with environmental taxes

High CO_2 taxes (€20/t) significantly reduce the electricity output from Estonian oil shale power plants as well as electricity exports to Latvia. The contribution of a new CCGT plant at the end of the study period is also smaller in comparison to the base case. The differences in electricity generation between the regional scenario with environmental taxes (i.e., 7R(Aa)) and the base case are highlighted in *Figure 8.62*.

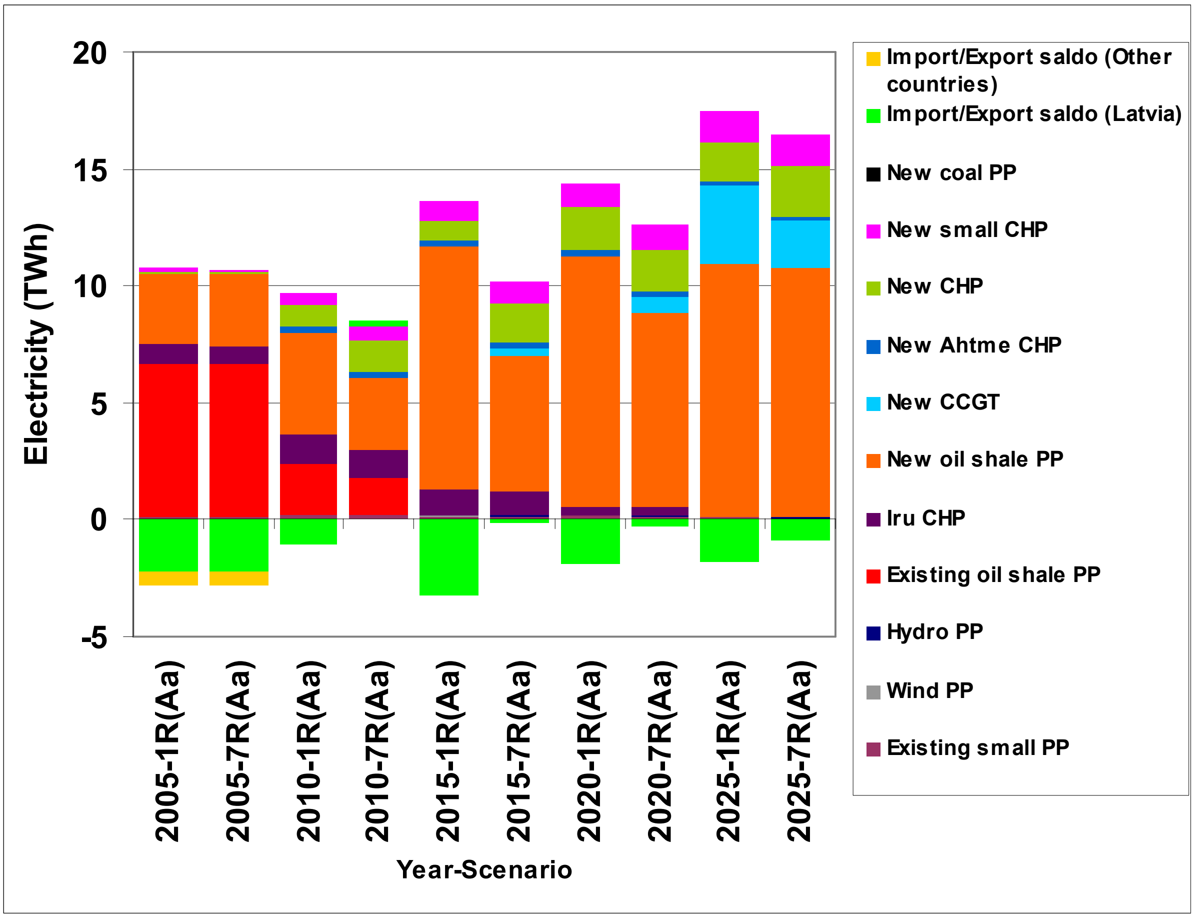


Figure 8.62. Comparison of electricity generation in Estonia in Scenarios 7R(Aa) and 1R(Aa).

With environmental taxes Latvia imports more electricity from Lithuania instead of constructing a new coal-fired power plant. An interesting feature is also the appearance of a small amount of new HPPs. However, altogether there are only minor differences in the operation of other power plants in Scenario 7R(Aa) compared to Scenario 1R(Aa) in Latvia as shown in *Figure 8.63*.

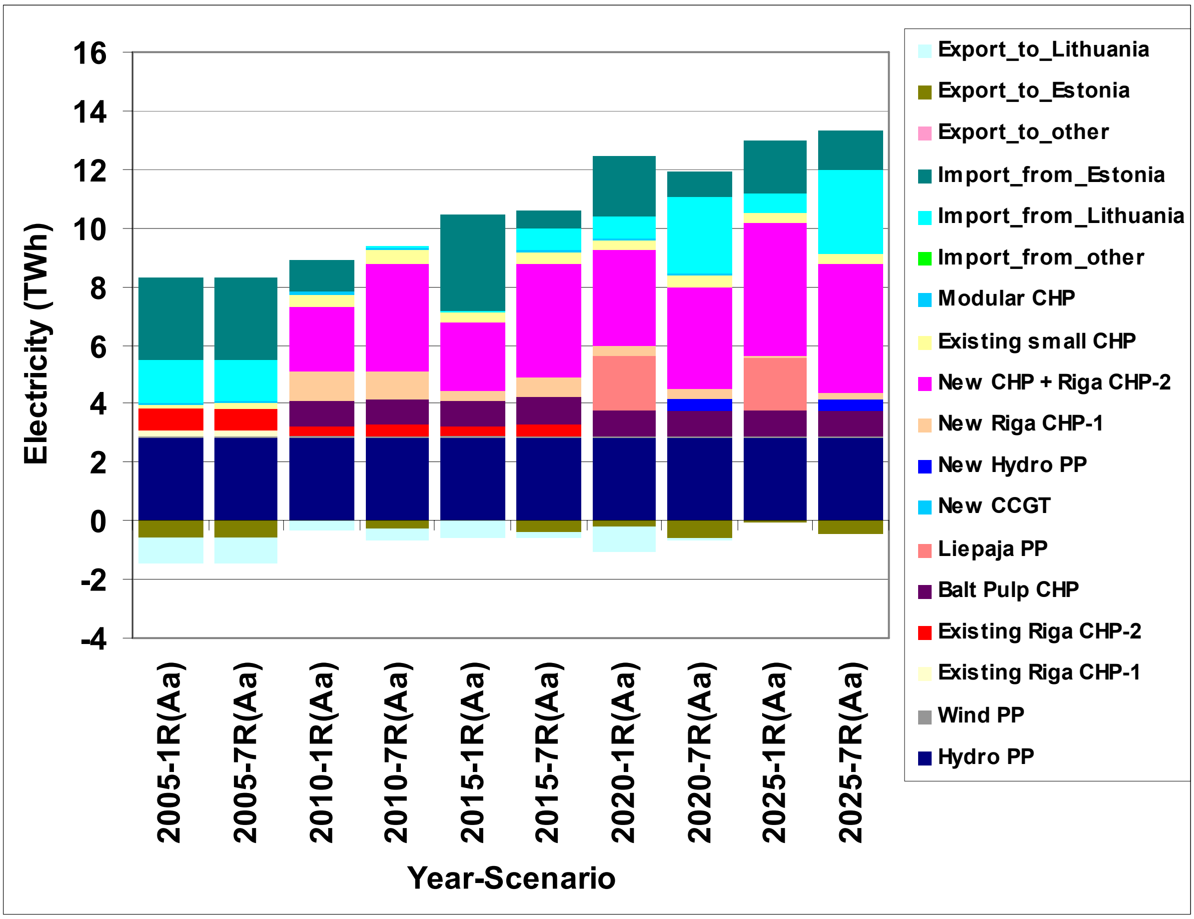


Figure 8.63. Comparison of electricity generation in Latvia in Scenarios 7R(Aa) and 1R(Aa).

In Lithuania, the main differences in the power sector due to the imposition a carbon tax is the replacement of the Lithuanian TPP by a new NPP and increased electricity exports to Latvia. Electricity generation at the Lithuanian TPP in 2010 is only 0.7 TWh, while in Scenario 1R(Aa) it is 5.02 TWh. However, generation at the Lithuanian TPP grows during the remainder of the study period because of growing demand, but in 2025 it reaches only 2.55 TWh, while in Scenario 1R(Aa) it is 5.08 TWh. The contribution of other power plants in Lithuania in both scenarios is very similar, as shown in *Figure 8.64*.

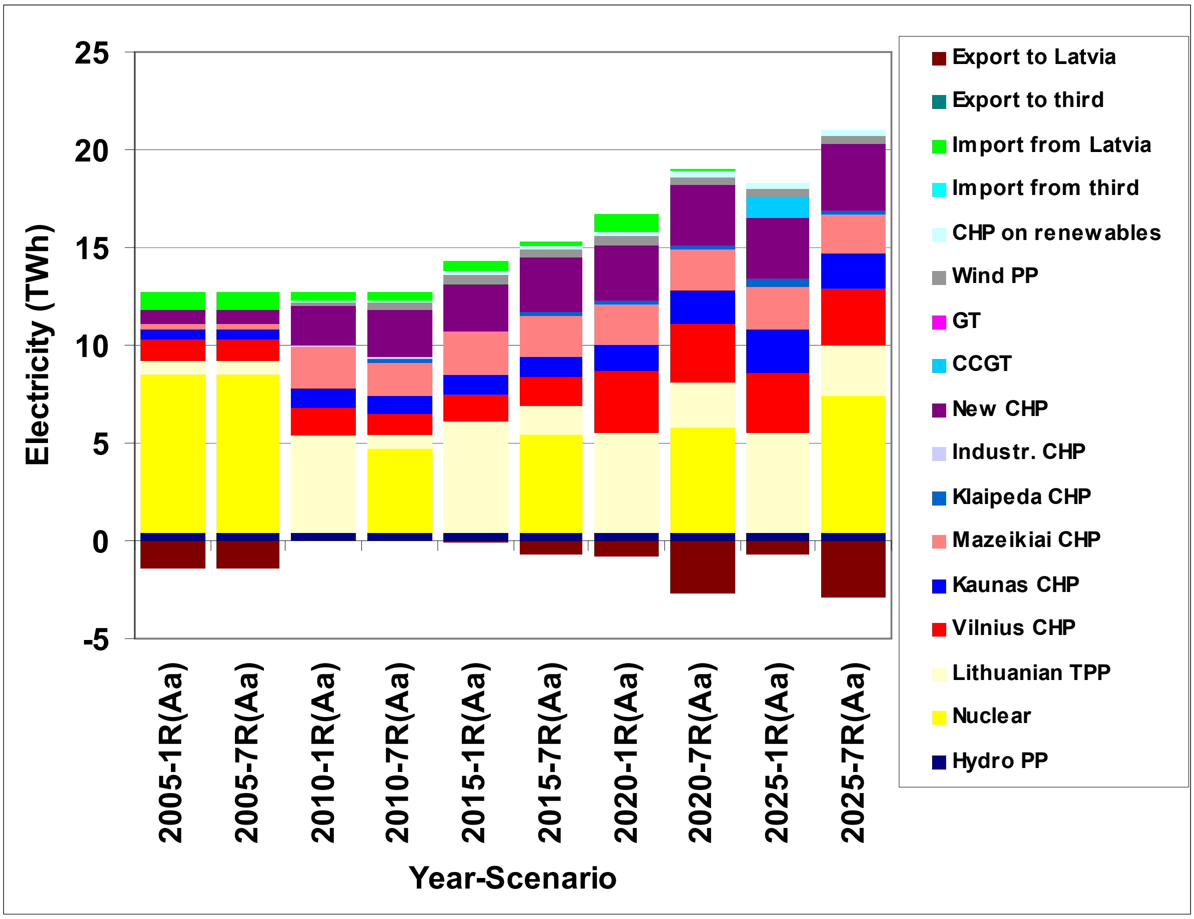


Figure 8.64. Comparison of electricity generation in Lithuania in Scenarios 7R(Aa) and 1R(Aa).

The type of change in electricity generation is similar in the case of lower CO_2 taxes (€10/t in Scenario 7Rb(Aa)), but the extent of these changes is much lower. For example, a new nuclear plant in Lithuania starts to operate not in 2010 but in 2025. The operation of the Lithuanian TPP and Liepaja coal power plant in Latvia is similar to that in the reference scenario. CO_2 taxes of €5/t do not have a visible impact on the operation of power plants in the region.

Structural changes in the energy system caused by environmental taxes determine emission reductions. During 2000–2025 emission reductions in the Baltic region reach 824 kt for SO_2, 326 Mt for CO_2, 148 kt for NO_x, 174 kt for fly ash and 37.1 Mt for ash.

8.10. Regional scenario with high fuel prices

To investigate the impact of high fuel prices on the development of the energy system in Baltic countries, Scenarios 1R(Ac) and 2R(Ac) were calculated. The resultant dynamics are explained in Section 5.5.

High fuel prices are favourable to the economic effectiveness of new CHP plants, Estonian oil shale power plants and new NPP, but reduce the economic attractiveness of the Lithuanian TPP. In the regional self-sufficiency scenario with high fuel prices (i.e.1R(Ac)) the capacity of a new NPP in Lithuania appears as early as 2020. Its capacity in 2020 is only 350 MW, but by 2025 this increases to 925 MW, which means that the new nuclear unit could be commissioned before 2025.

Figure 8.65 compares the effects of a higher fuel price, as applied in scenario 1R(Ac), on the development of electricity generation in Lithuania with the reference scenario 1R(Aa). Higher prices lead to a reduction of electricity output (by 1.54 TWh) from the Lithuanian TPP and is substituted mainly by a higher contribution from new CHP plants and higher imports of electricity from Estonia (via Latvia). For example, electricity generation in 2010–2015 from new CHP plants is 0.34 TWh higher in comparison with the reference scenario. At the same time, electricity imports from Estonia are higher by 0.66–0.94 TWh. This situation is typical in the period after the closure of the second unit of the Ignalina NPP and before the commissioning of a new nuclear unit.

After the commissioning of a new nuclear unit, electricity imports from Estonia are terminated, but the contribution of new CHP plants remains similar to that in the reference scenario. Lower electricity generation at the Lithuanian TPP is substituted by a new nuclear unit, which also produces electricity for export. The new NPP also displaces the construction of a new CCGT, which in the reference scenario starts to operate 2025.

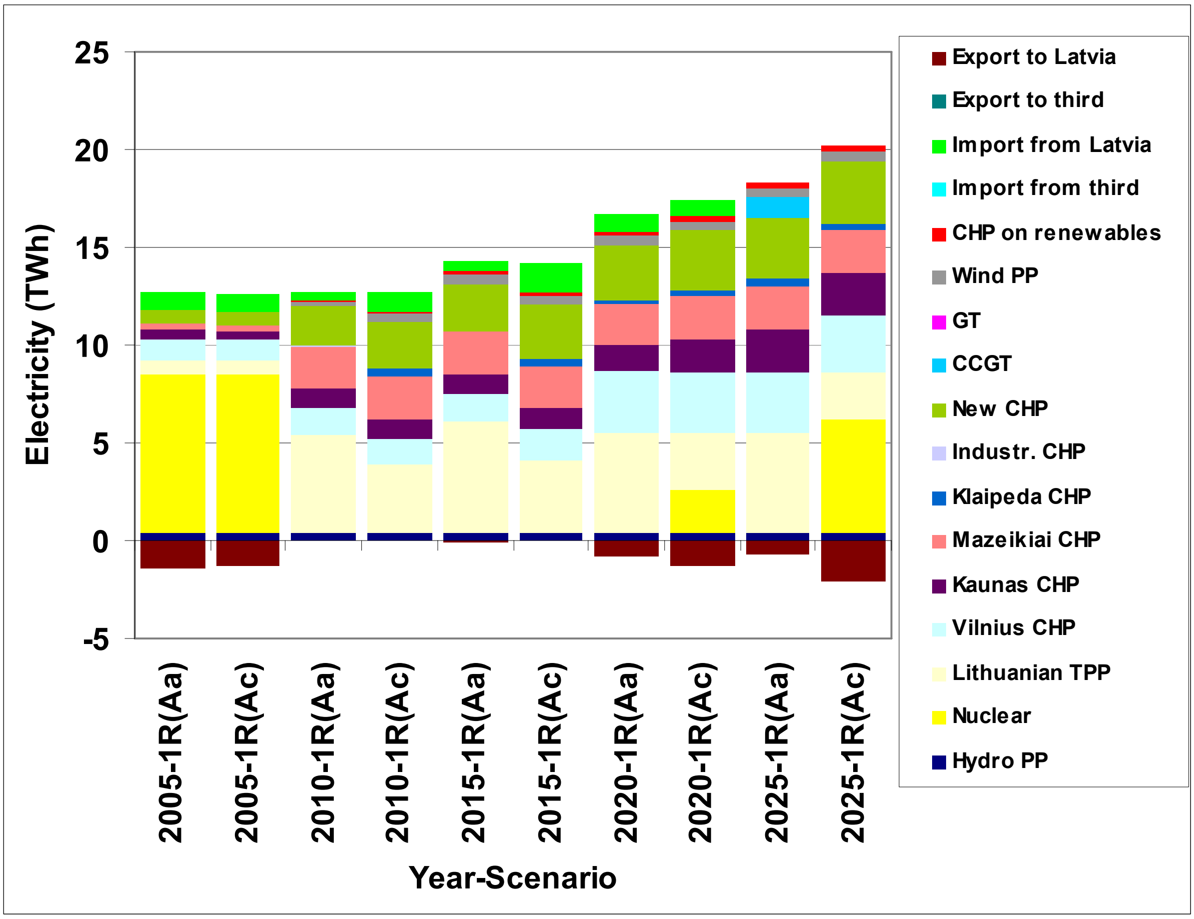


Figure 8.65. Comparison of electricity generation in Lithuania in Scenarios 1R(Ac) and 1R(Aa).

In Estonia higher fuel prices lead to an increased attractiveness of oil shale power plants. However their capacity or utilisation cannot be increased substantially because no further modernisation is possible. Half way through the study period the contribution of new CHP plants is slightly higher in Estonia, while electricity generation at new CCGTs is 1.27 TWh lower because less electricity export is required to Latvia. In Latvia higher fuel prices lead to increased electricity imports from Lithuania. Resultantly, this reduces the share of new CHP plants in Latvia at the end of the study period. In 2025 the contribution of new CHP plants to Latvian electricity generation is 0.49 TWh lower compared to Scenario 1R(Aa), while in the middle of the study period their contribution exceeds the reference scenario by 0.34–0.43 TWh. The changes in electricity generation resulting from higher fuel prices in Scenario 1R(Ac) in Estonia and Latvia are depicted in *Figures 8.66* and *8.67*.

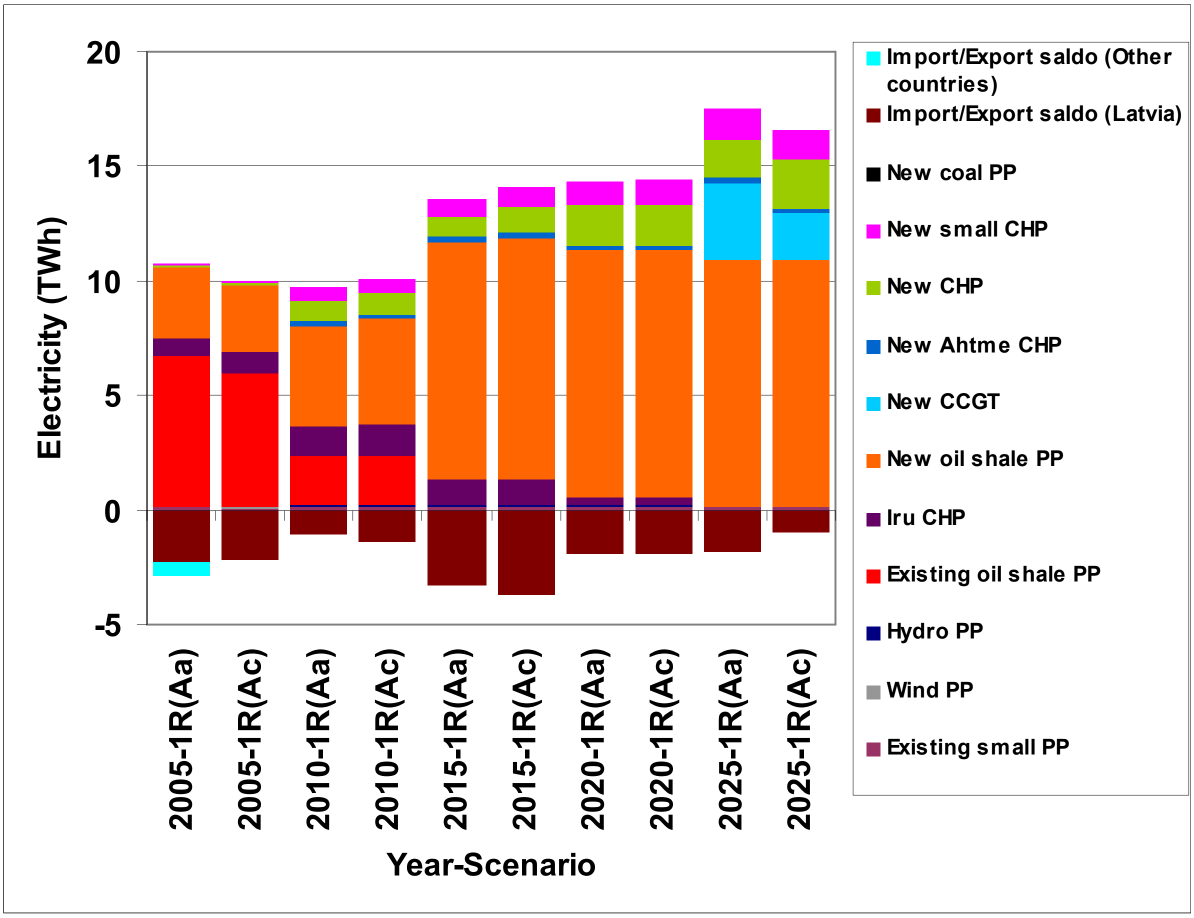


Figure 8.66. Comparison of electricity generation in Estonia in Scenarios 1R(Ac) and 1R(Aa).

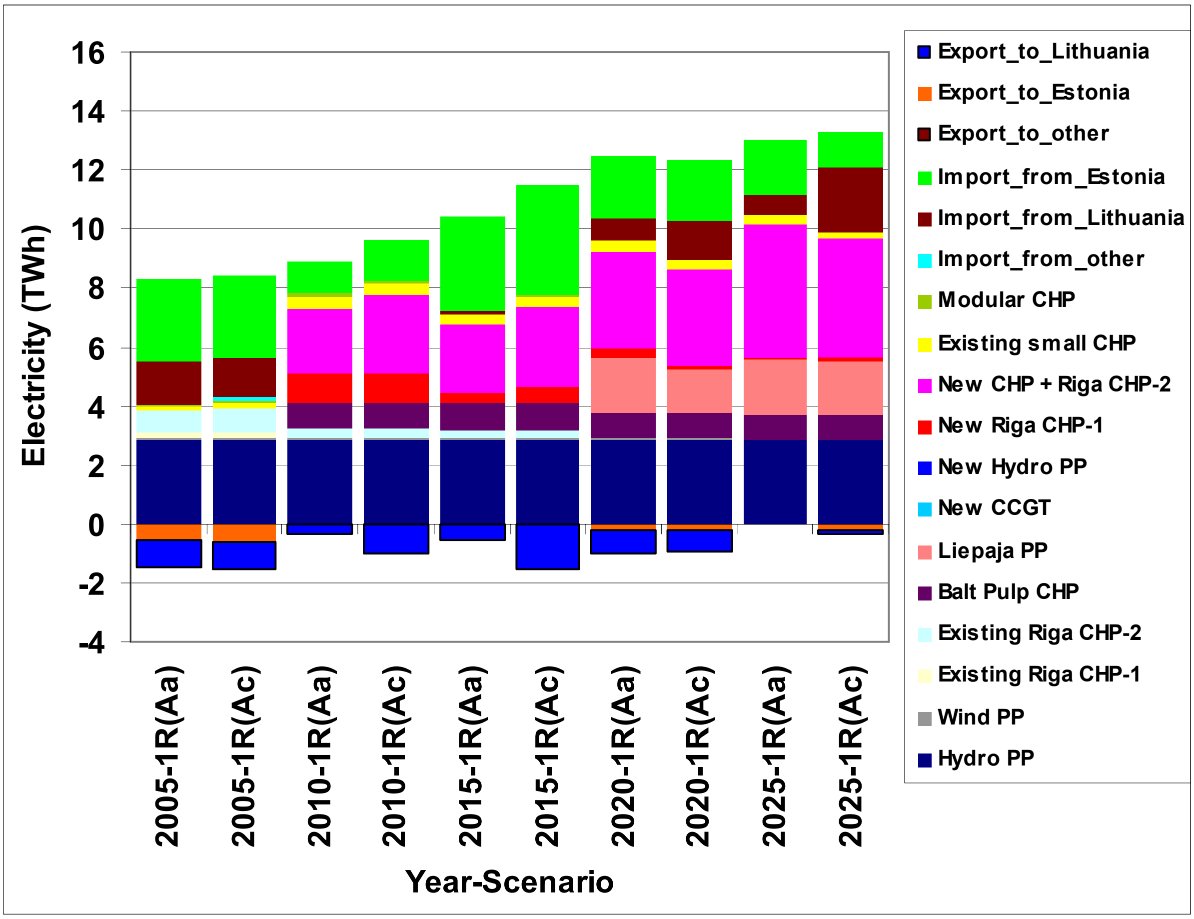


Figure 8.67. Comparison of electricity generation in Latvia in Scenarios 1R(Ac) and 1R(Aa).

For the Baltic countries together, slightly higher electricity generation occurs at the CHP plants and modernised oil shale power plants as a response to higher fuel prices. This additional generation replaces some output from existing condensing power plants, mainly from the Lithuanian TPP. At the end of the study period a new NPP also reduces the output of existing condensing power plants, as well as of the need to build new CCGT units. However, all these differences are not very significant. The changes corresponding to whole Baltic region are shown in *Figure 8.68*.

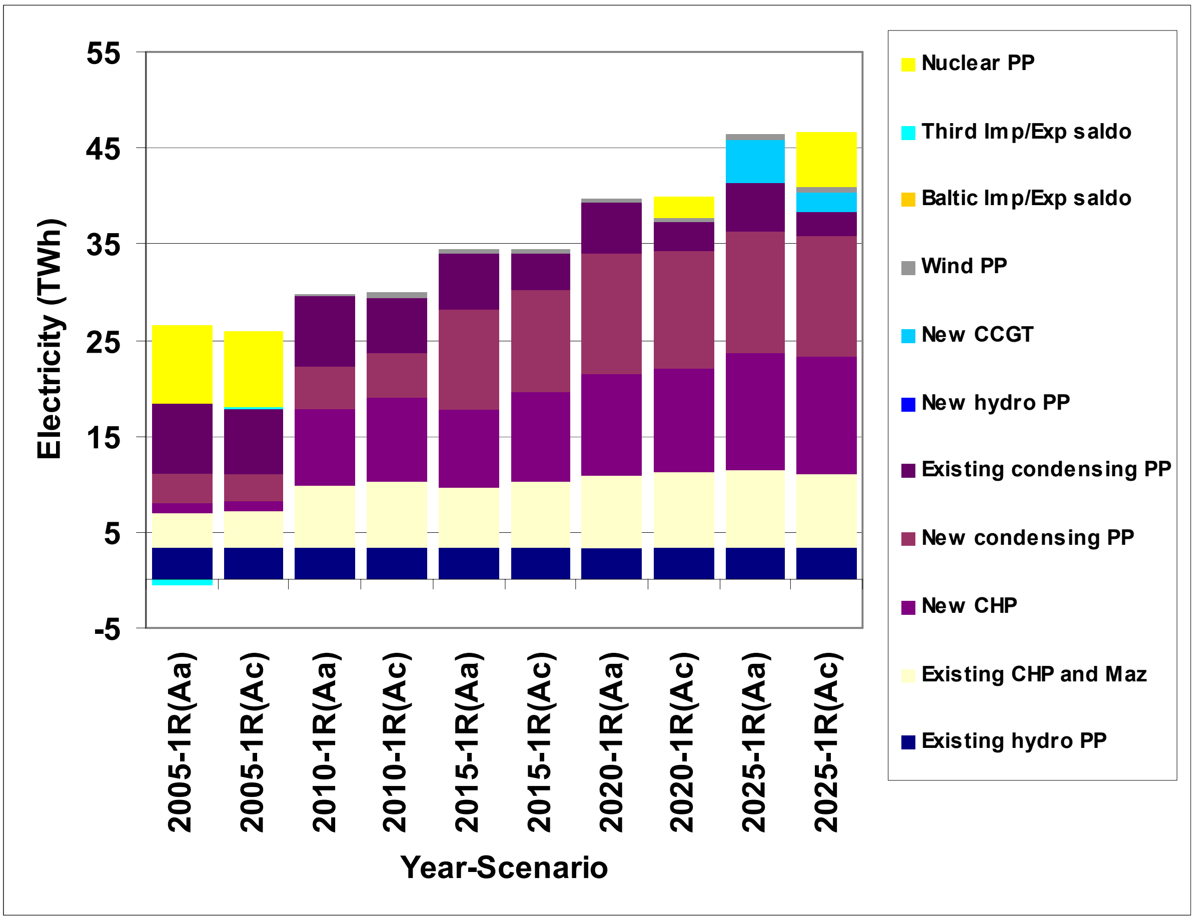


Figure 8.68. Comparison of electricity generation in Baltic region in Scenarios 1R(Ac) and 1R(Aa).

In the regional scenario with high fuel prices (Scenario 2R (Ac)), electricity imports from third countries, available at the prices specified in *Table 5.22*, also reduce electricity generation at existing condensing power plants (Lithuanian TPP). In fact, electricity imports significantly postpone the construction of a coal power plant in Latvia (to after 2035) and the modernisation of Estonian oil shale power plants. This leads to a reduction in electricity generation from Estonian power plants by 1.23–1.27 TWh during the period 2010 to 2015. In later years the contribution of these power plants is similar again to the base case (1R(Aa)). In Lithuania higher fuel prices reduce electricity generation at the Lithuanian TPP which is 1.41 TWh in 2010 or 3.6 TWh lower than in the reference scenario. Although electricity generation at the Lithuanian TPP increases to 3 TWh by 2025 it is still 2 TWh lower than in the reference case. Available electricity imports also postpone the commissioning date of a new NPP. In Scenario 2R(Ac) a new NPP starts to operate in 2025, or 5 years later than in the regional self-sufficiency scenario with high fuel prices (i.e., 1R(Ac)). Electricity imports into the Baltic region as a whole range from 6.16 TWh in 2010 to 3.69 TWh in 2020. The changes corresponding to Scenario 2R(Ac) are shown in *Figure 8.69* for the whole Baltic region.

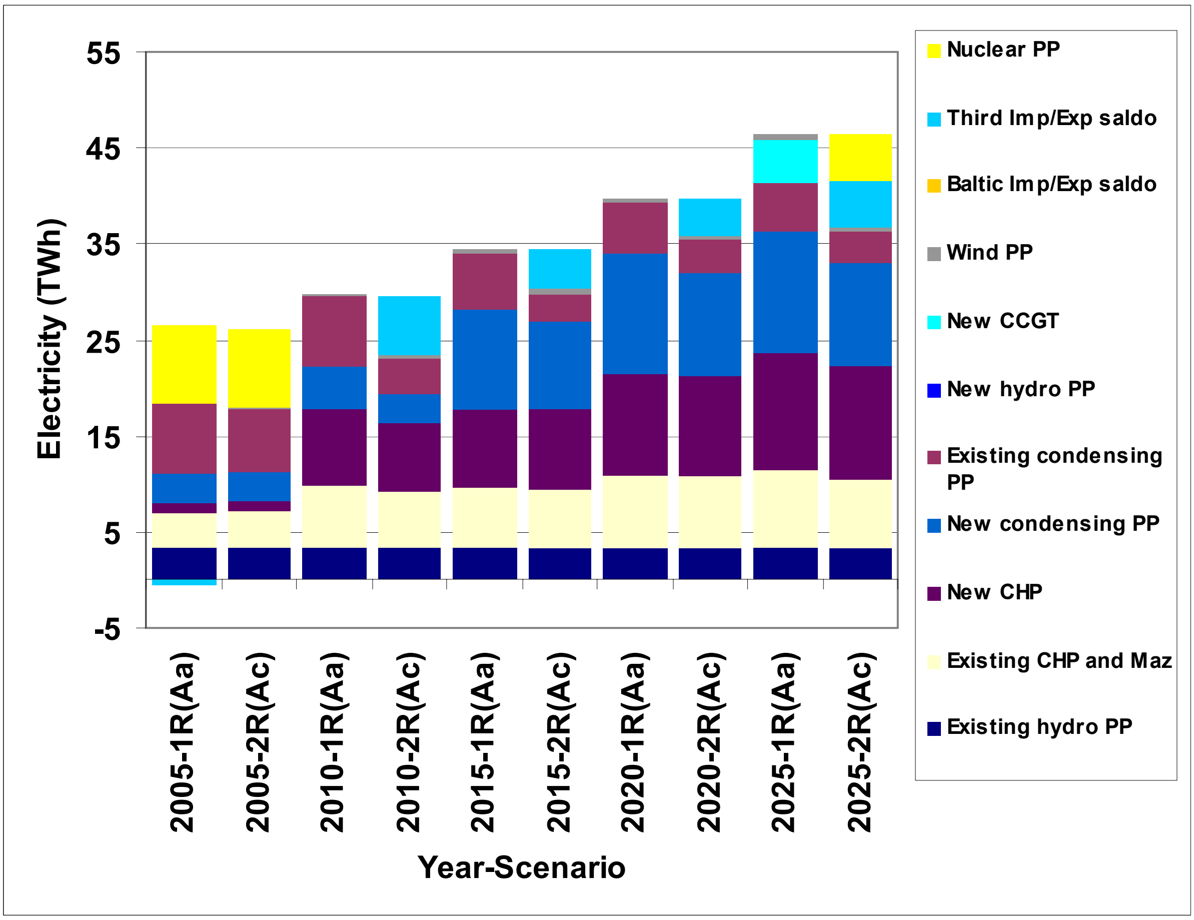


Figure 8.69. Comparison of electricity generation in the Baltic region in Scenarios 2R(Ac) and 1R(Aa).

To investigate the consequences in the energy system of a rapid fuel price growth, Scenario 1R(Ab) was calculated. The analysis was performed using extra-high fuel prices, the dynamics of which are explained in Section 5.5. The results of the calculation show that the main impact of extra-high fuel prices is that nuclear energy is utilised. In this case a new NPP should be constructed immediately after the decommissioning of Unit 2 of the Ignalina NPP or as soon as it can be implemented technically. Changes in electricity generation in Lithuania are shown in *Figure 8.70*.

The main impact of the new NPP is on the operation of the Lithuanian TPP and the construction of new CHP plants. By 2010 the Lithuanian TPP produces 1.84 TWh in this scenario, much lower than the 5.02 TWh in Scenario 1R(Aa), while the contribution of new CHPs decreases from 2.04 TWh to 1.43 TWh. Production at the new NPP in 2010 is 3.6 TWh. In subsequent years the contribution of the new NPP increases slightly and in 2020 it reaches 5.3 TWh. However, the most significant addition of electricity generation from nuclear energy appears in 2025. In comparison to 2020, its electricity generation doubles and reaches 10.4 TWh. Consequently, electricity exports to Latvia and Estonia increases from 0.66 TWh to 3.92 TWh. In 2025, Estonia changes from a country that exports electricity to one that imports electricity because the available electricity generated at Lithuanian NPPs becomes cheaper than electricity generated locally. In Scenario 1R(Aa) this electricity would have been generated to a large extend at a new CCGT.

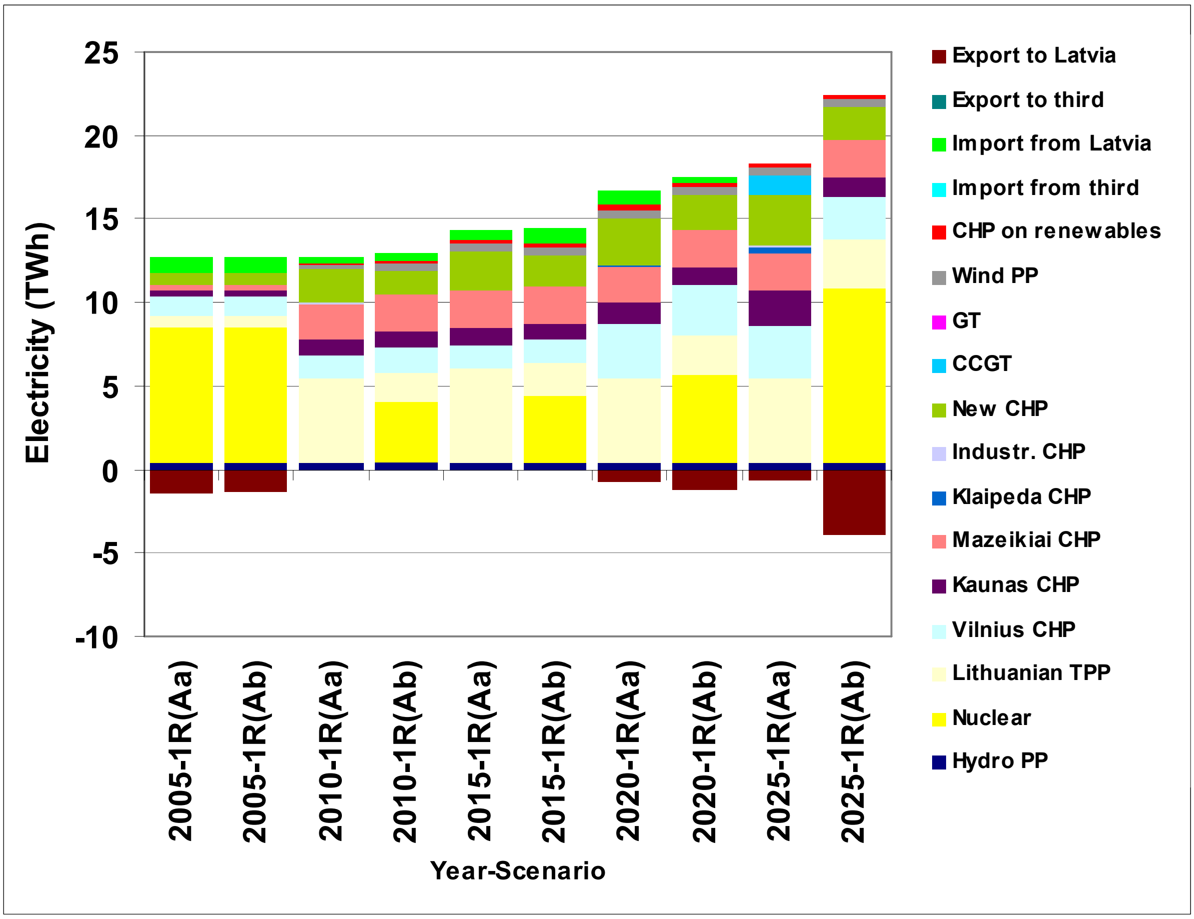


Figure 8.70. Comparison of electricity generation in Lithuania in Scenarios 1R(Ab) and 1R(Aa).

The new NPP in Lithuania also has a significant impact on electricity generation from new CHP plants in Latvia. This impact, however, is more visible in the second part of the analysed period. For example, the difference between Scenario 1R(Ab) and the reference case for electricity generation from new CHP plants in Latvia is only 0.3 TWh in 2010 and 0.18 TWh in 2015. However, in 2020 the contribution of new CHP plants decreases from 3.27 TWh in Scenario 1R(Aa) to 2.67 TWh in Scenario 1R(Ab) and from 4.55 TWh to 3.39 TWh in 2025 respectively.

The difference in the structure of electricity generation between Scenario 1R(Ab) and the base case for the Baltic region are summarised in *Figure 8.71*. After commissioning of the new NPP, nuclear fuel replaces orimulsion and natural gas. Initially mainly orimulsion is replaced, but by the end of the analysed period nuclear energy replaces mainly natural gas because the installed capacity of new CCGT units is much lower than in the base case. For example, electricity generation from orimulsion in 2010 is 2.53 TWh lower in Scenario 1R(Ab) than in Scenario 1R(Aa). The difference in electricity produced from gas is 1.42 TWh. By 2025 the difference has increased further; electricity generation from orimulsion and natural gas are now 1.75 TWh and 10.8 TWh lower.

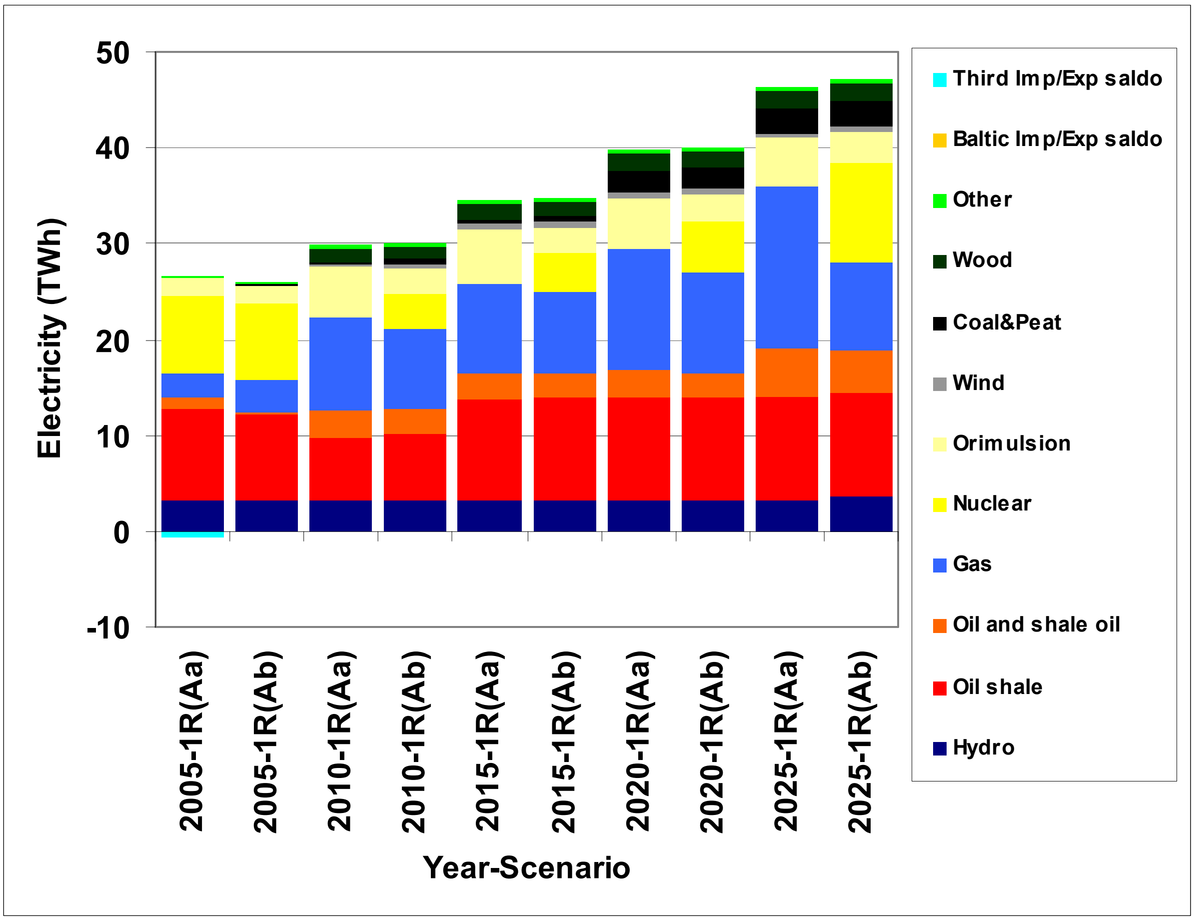


Figure 8.71. Comparison of electricity generation in the Baltic region in Scenarios 1R(Ab) and 1R(Aa).

With regard to heat production, a lower share of new CHP plants results in lower heat production from this technology, as shown in *Figure 8.72*. More specifically *Figure 8.72* shows that heat production from new CHP plants decreases from 12.16 TWh in Scenario 1R(Aa) to 11.66 TWh in Scenario 1R(Ab) in 2010. By 2025 this difference increases to 2.44 TWh from 17.91 TWh in Scenario 1R(Aa) to 15.47 TWh in Scenario 1R(Ab). Existing CHP plants also provide a smaller contribution, especially at the end of the analysed period. In 2025 heat production from existing CHP plants is lower by 1.45 TWh compared to the base case. Reduced heat production at CHP plants is compensated by higher output from boiler houses and decentralised heat supply sources.

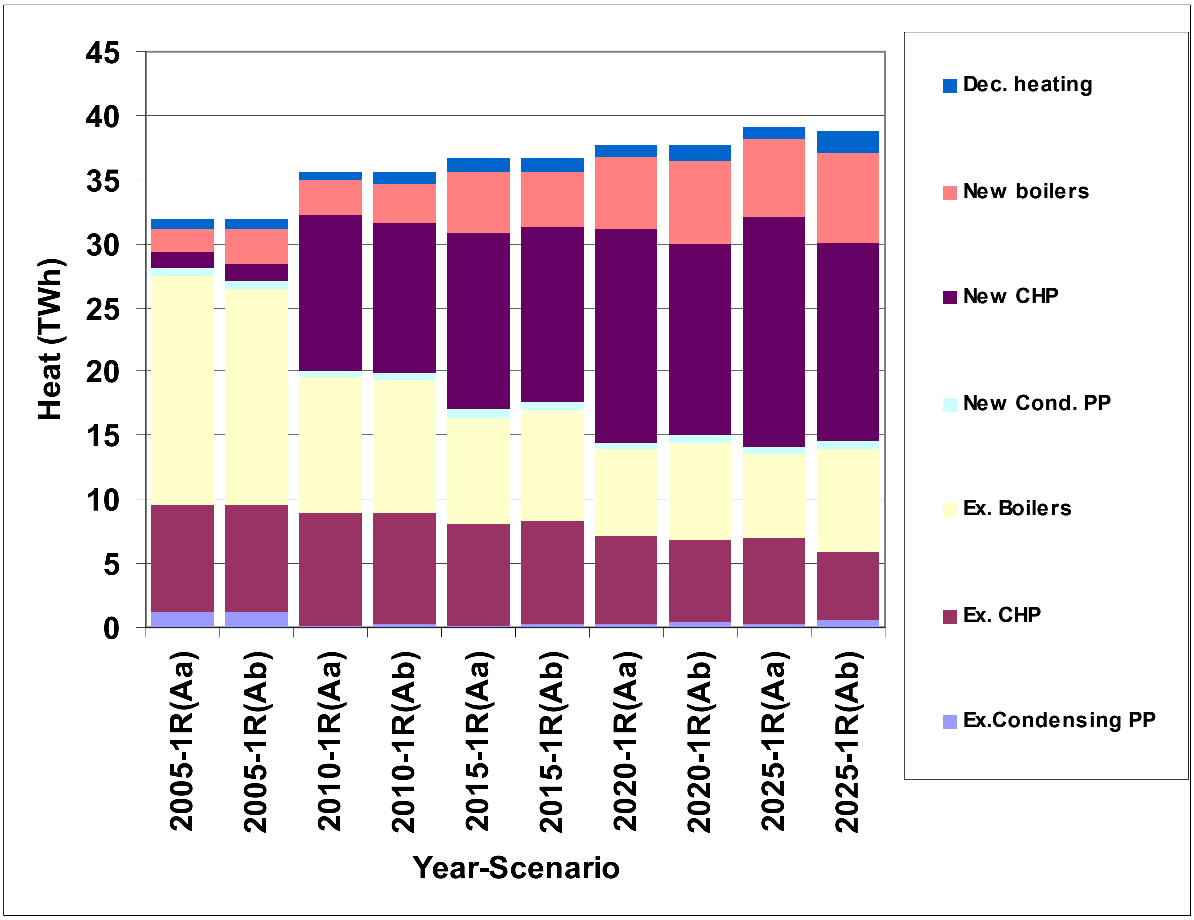


Figure 8.72. Comparison of heat production in the Baltic region in Scenarios 1R(Ab) and 1R(Aa).

As already mentioned, extra-high fuel prices force a lower use of orimulsion and gas. These fuels are substituted by nuclear fuel, coal and biomass. The differences in fuel consumption for electricity and heat production in Scenarios 1R(Ab) and 1R(Aa) are summarised in *Figure 8.73*.

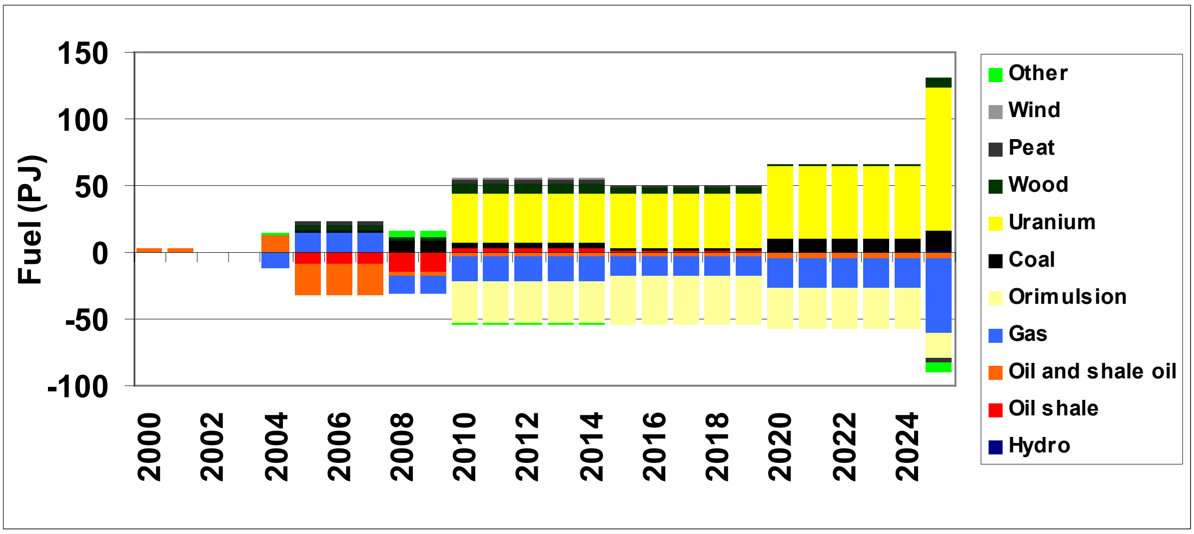


Figure 8.73. Changes in fuel consumption for electricity and heat production in the Baltic region in Scenarios 1R(Ab) and 1R(Aa).

The figure highlights that in comparison with the base case, extra high fuel prices lead to a reduction in the consumption of orimulsion by 19.5–37.6 PJ and by 14.1–55.5 PJ for natural gas from 2010. The additional requirement is mainly met by increases in nuclear fuel which ranges between 37.3–107.2 PJ during the same period. Increases in consumption are also recorded for coal (14.9 PJ) and of wood (7.6 PJ). In addition, the total fuel consumption for electricity and heat production in the extra-high fuel price scenario is higher because nuclear fuel is utilised at a lower efficiency compared to fossil fuels. The additional annual fuel demand reaches 40 PJ in 2025.

Figure 8.74 compares the energy import dependence in the Baltic region under the conditions of extra-high fuel prices (1R(Ab) with Scenario 1R(Aa). It can be noted that import dependency is lower for the high fuel price scenario. At the beginning of the study period this can be explained by the increased extraction of domestic crude oil and higher consumption of peat and wood. In subsequent years there is a lower dependency on imports because of the use of nuclear fuel, which is assumed to be domestic. At the beginning of the study period local resources provide about 58–65% of the total primary energy requirement in the Baltic region while by the end of the analysed period domestic resource use shrinks to 50–52%. Under conditions of low fuel prices the utilisation of domestic resources is somewhat lower, at 40–49% in the beginning and 36–38% towards the end of the study period.

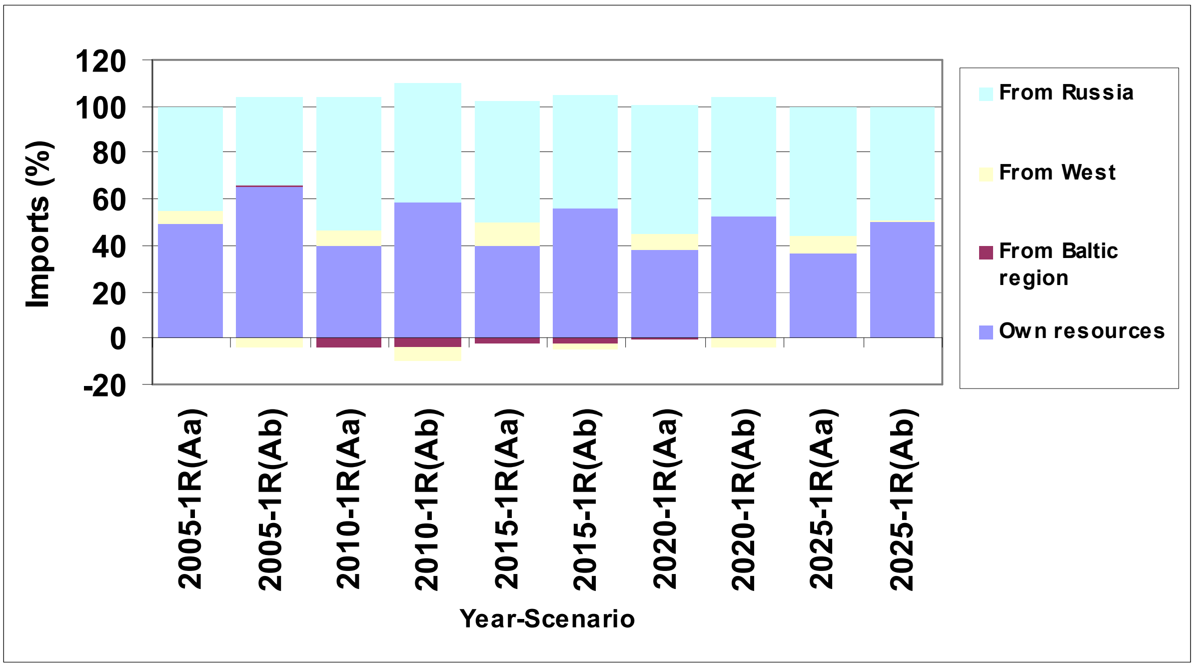


Figure 8.74. Import dependency of the Baltic region in Scenarios 1R(Ab) and 1R(Aa).

8.11. Regional scenario with extra-high fuel prices and interlinks with third countries

Scenario 2R(Ab) assumes extra-high fuel prices for electricity imports and/or exports and electricity interconnections with third countries. This leads to a lower installed capacity of power plants which is covered through electricity imports in the period 2010–2020. However, imported electricity can jeopardise the operation of the Lithuanian TPP and the modernisation of the Vilnius CHP plant, and reduce the capacity of new CHP plants and coal power plants in Latvia. Available electricity imports from third countries also postpone the construction of the new NPP until 2020. *Table 8.10* highlights the difference in the structure of electricity generation in the Baltic region for Scenario 2R(Ab) and Scenario 1R(Ab).

For example, electricity imports from third countries, depending on the time period, reduce electricity generation at the new NPP by up to 4 TWh, at existing condensing power plants by up to 0.87 TWh, and at CHP plants by up to 1.8 TWh. Increased electricity imports also lead to a lower total electricity demand in the Baltic region by up to 0.52 TWh because of reduced own consumption at domestic power plants.

Table 8.10. Electricity generation in the Baltic region in Scenario 2R(Ab) in comparison with Scenario 1R(Ab) (TWh)

Power plant	*Year*				
	2005	*2010*	*2015*	*2020*	*2025*
NPP	0.000	–3.623	–4.034	–0.015	–3.033
Existing condensing PP	0.012	–0.873	–0.387	–0.815	–0.071
Existing CHP	0.000	–0.417	–0.300	–0.046	0.307
New CHP	0.000	–1.381	–0.405	0.196	0.221
New condensing PP	–0.003	0.000	0.136	–1.038	–0.150
New CCGT	0.000	0.000	0.000	0.000	–0.628
Third imp/exp saldo	0.000	5.795	4.472	1.593	2.947
Total demand	0.010	–0.502	–0.519	–0.126	–0.407

8.12. Uncertainty factors linked to the operation of the Lithuanian TPP

A few uncertain factors should be discussed when analysing the future operation of the Lithuanian TPP. First, the supply of orimulsion. Orimulsion is supplied from one source only (Venezuela) and some interruptions of supply or price changes may occur. Second, orimulsion is a dirtier fuel than HFO. There is a risk that consumption of this fuel might be restricted or even prohibited because of tighter environmental constraints in the future. In order to take these factors into account additional calculations were made:

- With increasing orimulsion prices (assuming the same growth rate as for HFO);
- Without orimulsion imports to Lithuania from 2010.

Under these additional conditions and in the presence of low fuel prices, it is most economic to replace the Lithuanian TPP with new CCGT units at existing sites. *Figure 8.75* compares the structure of electricity generation in Lithuania under conditions of increased orimulsion prices and constant prices.

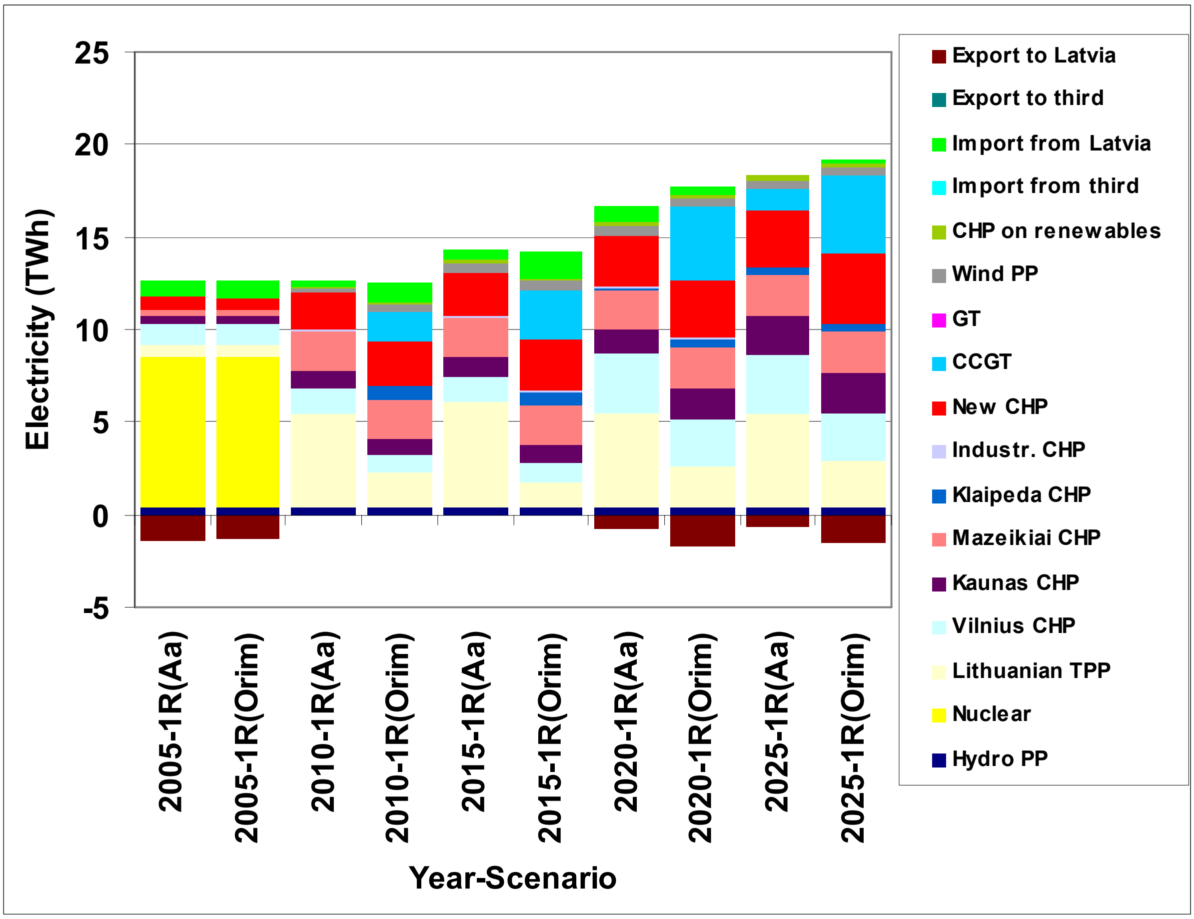


Figure 8.75. Electricity generation in Lithuania for increasing prices of orimulsion, 1R(Orim), in comparison to stable prices of orimulsion, 1R(Aa).

Higher orimulsion prices increases the consumption of gas for electricity and heat production in Lithuania to 57–63% of the total fuel consumption from 2010 onwards. The resulting additional discounted cost for the whole Baltic region is €490, and due to a mixture of both higher fuel cost and the construction of additional CCGT units. In the case of high or extra-high fuel prices a new NPP would substitute the Lithuanian TPP.

A further uncertainty is the remaining operating time of a modernised Lithuanian TPP. For example, a lifetime that is shorter than the assumed 25 years reduces its economic attractiveness. On the contrary, it not only increases the economic competitiveness of new CCGT units but also leads to an earlier commissioning date for the new NPP. Specifically, if the remaining operating time of the Lithuanian TPP is 15 years after modernisation, the commissioning date for the new NPP shifts from 2035 to 2025 in the case of low fuel prices.

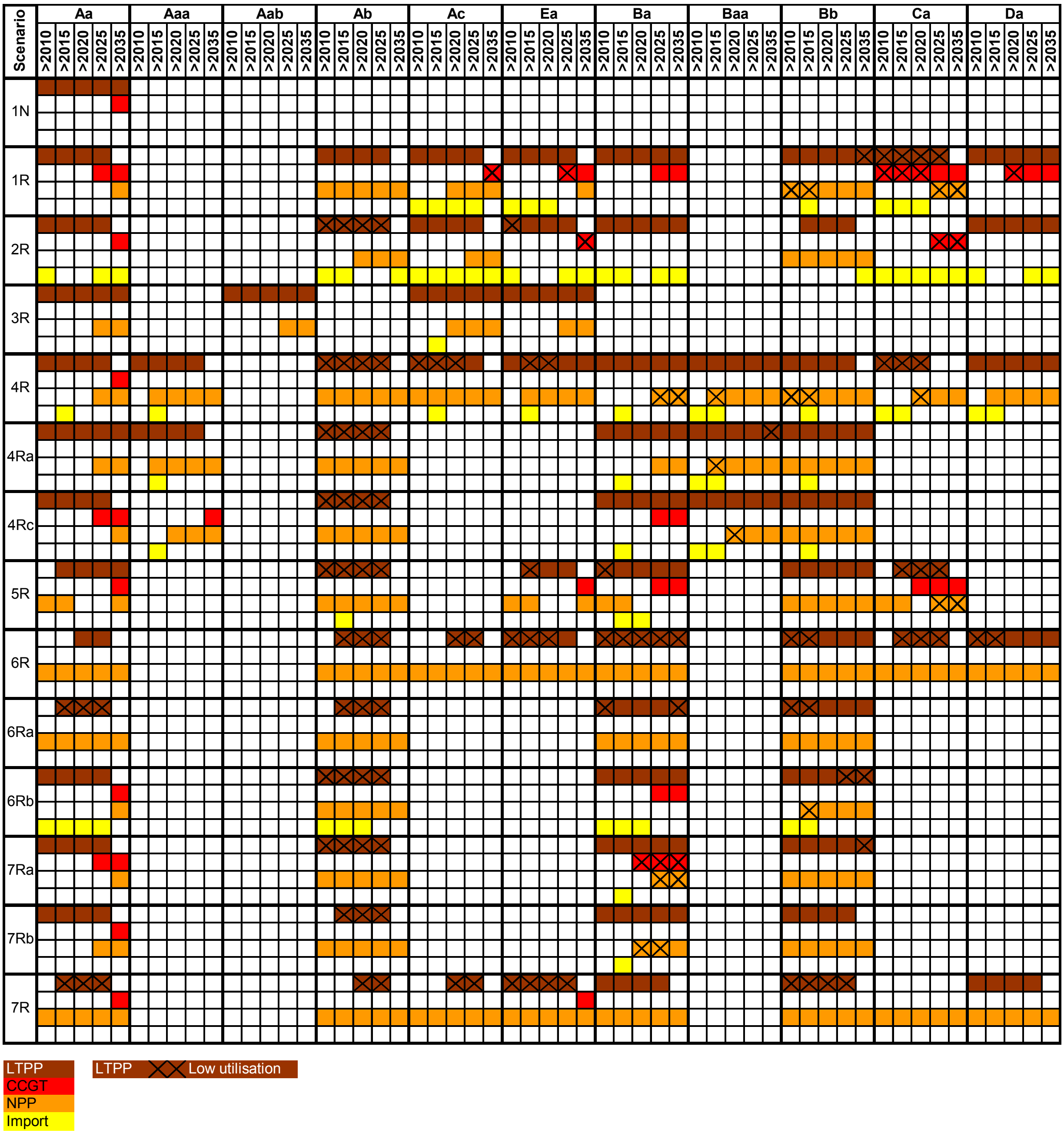
However, constructing new CCGT plants instead of modernising the Lithuanian TPP increases the Lithuanian dependency on Russian gas supply. This may result in higher gas prices in the country because the opportunity to choose fuel suppliers is reduced. Correspondingly, the Lithuanian position in negotiating gas prices is weaker. Also, the remaining lifetime of modernised units can be further extended by making additional investments in the future. Possible additional investments in the modernisation of the Lithuanian TPP, as well as the positive effect of its operation on the negotiation of gas prices, are not known and are linked to Lithuanian attempts to increase its security of energy supply and that of the whole Baltic region.

8.13. Summary of all calculated cases

To evaluate the sensitivity of the scenario results to various factors 78 different cases were calculated. The main goal of this exercise was to evaluate changes in the generating capacities in the Baltic region.

First of all, it was necessary to identify circumstances in which the fossil fuel development path is the more economically attractive, and circumstances in which NPP has an economic advantage. A qualitative representation of the results from this exercise is presented in *Tables 8.11–8.13*.

Table 8.11. Appearance of various power plants in the Lithuanian power system



Note: New CHPs are not represented in this table because their appearance is typical for all scenarios under analysed conditions.

Table 8.12. Appearance of various power plants in the Latvian power system

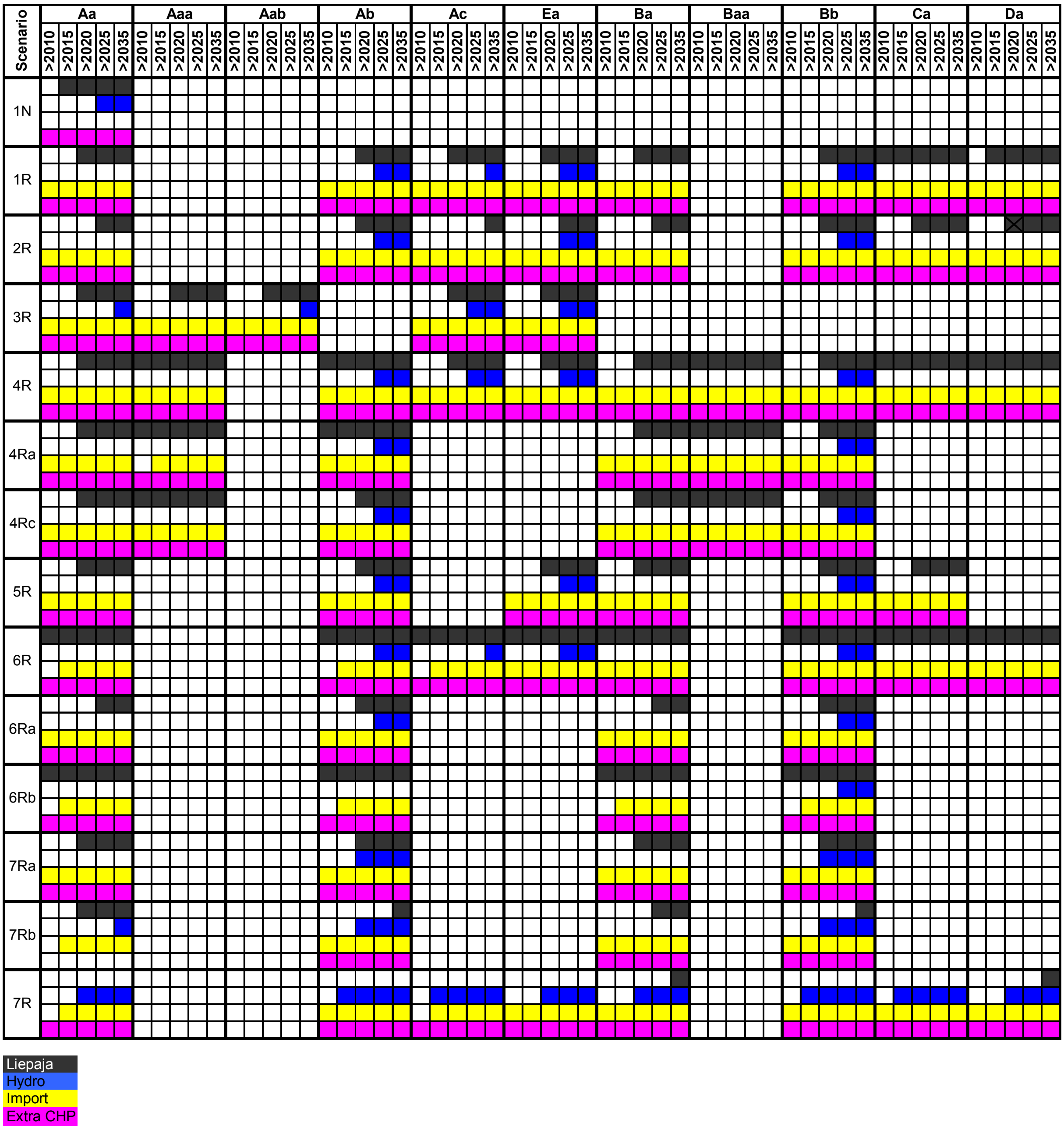
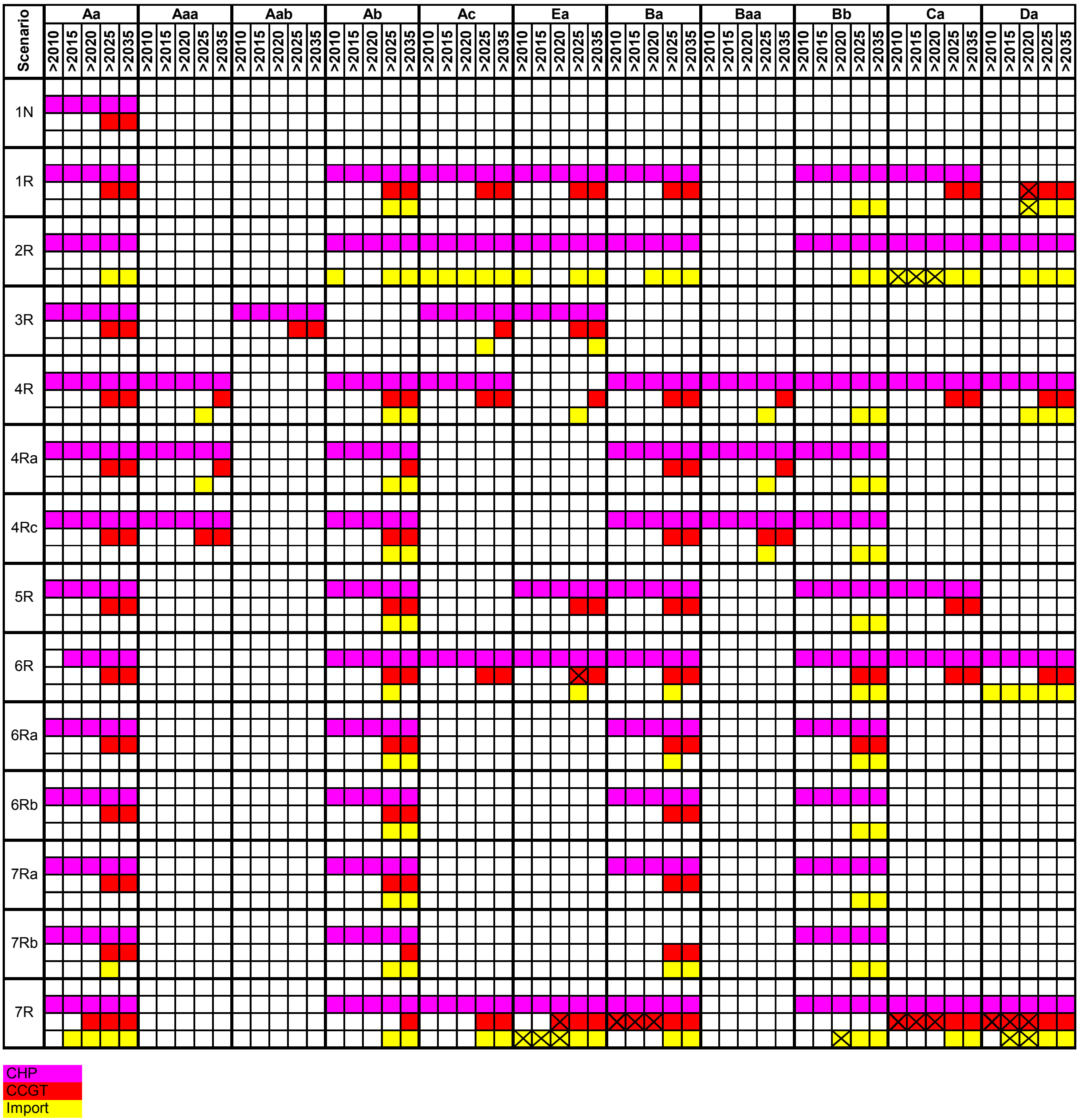


Table 8.13. Appearance of various power plants in the Estonian power system



The results presented in *Table 8.11* show that for *low fuel prices* the fossil fuel development path is economically more attractive in Lithuania and the whole Baltic region. In this case, the Lithuanian TPP as well as existing and new CHP plants provide most of the electricity generation in Lithuania. A new NPP appears only at the end of the study period. The only exception is Scenario 7R(Aa), in which high CO_2 taxes create more favourable conditions for a new NPP and discourage electricity generation from the Lithuanian TPP. Scenarios 6R and 6Ra represent the forced commissioning of a new NPP. Therefore, they do not correctly represent the economic competitiveness of a new NPP. However, moderate CO_2 taxes, constraints on the gas share in the fuel balance, as well as the requirement to keep gas in storage for 120 days, all bring forward the commissioning date of a new NPP, although no earlier than 2025. Constraints on a combined limit of gas and orimulsion as a share in the total fuel balance (conditions Aaa) requires earlier commissioning of a new NPP — in 2020 or even 2015.

The limited availability of orimulsion significantly reduces the attractiveness of a modernised Lithuanian TPP and makes new CCGTs at existing sites more economically attractive. In Estonia smaller capacities of modernised oil shale power plants increase the utilisation of the Lithuanian TPP and favour the construction of new CCGTs at existing sites in Lithuania. A constant all-year gas supply slightly reduces the attractiveness of a new NPP because as a base-load plant it still requires gas-fired plants to cover peak demand, but the prevailing gas supply regime does not match this need.

Extra-high fuel prices make a new NPP economically more attractive than the Lithuanian TPP, as well as the construction of new CCGTs, even at existing sites. Under these price assumptions the immediate commissioning of a new NPP after closure of the second unit of the Ignalina NPP is economically justified in nearly all analysed circumstances. The only exceptions are when gas is supplied to the Baltic region in the base regime (constantly during the year) and when cheap electricity imports from Russia are available. In these circumstances the commissioning of a new NPP can be postponed until 2020. Extra-high fuel prices do not economically justify the construction of a new CCGT in Lithuania. In practice, the Lithuanian TPP is a reserve capacity only. However, if gas supply to the Baltic region is constant, the Lithuanian TPP (running on other fuel types) is used to cover peak or semi-peak demand.

In the case of *high fuel prices,* the commissioning of a NPP in Lithuania can be economically justified in 2020.

Taking into account the results presented above it can be concluded that:

- In the case of low fuel prices the commissioning of a new NPP in Lithuania is economically justified in 2025 or later;
- Strong constraints (25% or less) on the *common share* of natural gas and orimulsion in the total fuel consumption for electricity and heat production bring forward the commissioning date of a new NPP. An economically justified date could be 2015–2020. Constraints on the share of gas only has practically no impact on the commissioning date of a new NPP, because orimulsion can be substituted for gas in electricity generation;
- In the case of *high fuel prices* or in the case of *extra-high fuel prices but with gas supply in the base-load regime* the commissioning of a new NPP in Lithuania is economically justified in about 2020;
- An immediate or early as possible commissioning of a new NPP in Lithuania can be economically justified in the case of *high (€20/t or more) taxes on CO_2* and in the case of *extra-high fuel prices without limitations on the gas supply regime*;
- Available cheep electricity imports from Russia postpone the commissioning date of a new NPP.

Many factors that describe the future energy system are uncertain. There is a risk that people can take decision, assuming one set of conditions, but in reality another set of conditions may occur. If so, energy companies will incur financial losses. In this study it was calculated that the early commissioning of a new NPP (in 2010) in the case of low fuel prices increases the total discounted cost to operate and develop the energy system in the Baltic region by €407 million (see Section 8.8 for details). However, if extra-high fuel prices actually occur and a new NPP is not built in Lithuania, the total discounted cost to operate and develop the energy system in the Baltic region would be higher by €120 million. These losses are lower than those in the former case. This illustrates that to construct investment-intensive projects such as a new NPP in an uncertain situation can be more risky than options that are less investment intensive.

For Latvia, the results in *Table 8.12* show that the country relies mostly on new CHP plants, electricity imports and the Liepaja coal power plant. New CHP plants and electricity imports are common in all analysed cases, while utilisation of the Liepaja power plant is less certain. Its economic attractiveness decreases with increasing CO_2taxes and at cost of €20/t and beyond it is rarely considered.

The economically most attractive year to commission the Liepaja power plant is 2020. Earlier commissioning is only reasonable with extra-high fuel prices and when the consumption of gas and orimulsion is constrained, or when the available capacity of modernised Estonian oil shale power plants is smaller. In Latvia, new HPPs are attractive in the domestic self-sufficiency scenario, when the requirement for green electricity grows, when fuel prices are extra-high or when there are high taxes on CO_2 emissions. The most likely date for their commissioning is 2025, although in the high emission tax scenarios the date can move to 2015.

The construction of a new CHP plant is an attractive option in Estonia (*Table 8.13*), and happens in all the analysed cases. Any lack of capacity (if the capacity of modernised oil shale power plants is not sufficient) in Estonia is covered by new CCGTs and electricity imports.

9. ASSESMENT OF ENERGY SUPPLY SECURITY

9.1. Introduction

First, this chapter addresses the definitions of energy supply security currently relevant to the Baltic States. Next, it addresses the proposed and possible approaches under consideration in the region to enhance supply security – policies, investments, co-ordinated regional efforts. Finally, the trade-offs among costs and impacts of various supply security scenarios are briefly discussed.

9.2. Energy supply security

There are numerous definitions of what constitutes energy supply security, depending on national or regional circumstances. They generally tend to include one or more of the following elements:

- Adequate supply to meet basic needs and development aspirations;
- Self-sufficiency;
- Protection against supply disruptions;
- Protection against price volatility;
- Physical plant and infrastructure reliability;
- Diversity of technologies and sources;
- Threats to and/or from neighbouring states;
- Energy markets that function well;
- Economic sustainability of supply (profitability);
- Environmental benignity.

The two key issues for regional and national security concerns in the Baltic region are the:

- Risk of increased import dependence on a single source for natural gas and oil in the energy supply of the Baltic economies;
- Need to rationalise regional electricity supply after the closure of the Ignalina nuclear power plant (NPP).

In energy supply security analyses, nuclear power is usually considered a form of domestic electricity generation even though the nuclear fuel is often imported or manufactured abroad. The small annual fuel requirements, the possibility to store one or more refuelling loads on site and the inherently long refuelling cycles mean that nuclear fuel is not as critically impacted by short term supply disruptions and price volatility as are fossil fuels. It is therefore assumed that there would be sufficient time to arrange fuel delivery from alternative suppliers and/or manufacturers should the necessity arise.

9.2.1. Risk of over-dependence on natural gas and imports

Over-dependence on gas imports from a single source represents a supply security risk, in terms of either actual supply disruptions or of monopolistic market control (prices and volumes). In the Baltic context, this suggests a need to limit the market power and associated security of supply aspects of single source Russian supplies.

Natural gas is entirely (100%) supplied from Russia. These supplies to the Baltic States have already been affected by supply disruptions in Lithuania, as well as by supply cut-offs or reductions through failures in equipment and pipelines along the supply chain. Moreover, the lack of alternative suppliers left Latvia with no choice but to raise regulated end-user tariffs for natural gas when Gazprom and its subsidiary Latvian gas company, Latvijas Gaze, increased natural gas prices. (Downstream investments in the country or region by an energy exporter are often viewed as a way to mitigate supply security concerns, but this is not necessarily always the case, as the Latvian case showed.)

Most Baltic oil and coal supplies also come from Russia or the Commonwealth of Independent States (CIS). The risk of oil and oil-product delivery interruption from Russia is real. Oil transit via pipeline to the port city Ventspils was virtually suspended at one point because of import pricing disputes and for political reasons, including struggles between Latvia and Russian suppliers over the privatisation of Ventspils Nafta. In either case, the Latvian response options were limited by the lack of alternative suppliers. Supply and price problems may be further exacerbated by the anticipated increased competition for petroleum and petroleum products in the global market place, especially from China and India. However, unlike natural gas, access to different oil sources (at international market prices) is much easier for crude oil and oil products.

Natural gas use continues to rise in all scenarios considered in this analysis, though the levels it reaches and the rates at which it increases vary for different scenarios. The share of natural gas use for electric and centralised heat generation in the Baltic States is expected to double from the 2003 level of 14% to 28% to 32% (depending on the scenario) in 2010 because of the closure of the Ignalina NPP.

Four factors stand against a heavy dependence on natural gas in the Baltic countries:

- The ageing Russian gas supply infrastructure is reportedly neither being adequately maintained nor refurbished, which raises questions over its long term reliability. Currently, only two out of three supply lines to the Baltic countries are in use, which could be sufficient in terms of supply security, but only if no common or simultaneous failures occur. However, failures become more probable as the infrastructure refurbishment continues to lag.
- The apparent willingness of the Russian authorities to use energy and energy supplies as an informal tool of foreign policy and their deliberate lack of transparency in commercial dealings are persistent short term concerns, especially after the gas price dispute and supply curtailments in the Ukraine.
- The Baltic countries are a relatively small market for oil and natural gas, so they may not be able to compete for Russian supplies with larger economies, such as those of China, India or Western Europe. Also, the size of the Baltic market may not be attractive enough for other gas vendors to invest in alternative gas transmission infrastructures that would allow source diversification.
- Gazprom is developing alternative pipeline transit routes directly to Germany underneath the Baltic Sea, by-passing the Baltic Region and Poland. This could reflect a desire to avoid any mutual dependencies in the energy area with the Baltic countries and Poland, or a desire to separate pipeline fees from export revenues, or as a bargaining chip to use in price and policy negotiations with the Baltic countries. It deepens concerns in these countries about the energy security of their imports and the monopoly power of Russia over the region’s gas supply.

Dependence on a single supplier also makes gas price volatility — especially price increases — a major concern. In the short term, prices will rise to adjust the currently subsidised gas prices in the Baltic countries to market levels, an increase of approximately 200%. In the longer term, there is continued vulnerability to overall increases in market prices for gas in the absence of any potential for fuel switching.

Control of the Mazeikiai refinery is linked to the issue of dependence on Russian gas imports. Mazeikiai plays a major role in the regional contingency plans for a major interruption in natural gas supply — it would supply distillates to the combined cycle and electric generating stations with dual-fuel firing capability, supplementing crude oil imports supplied through the oil port at Butinge. This double role of Mazeikiai makes its ownership and the potential for a power monopoly a serious concern for the Baltic countries in the context of energy security. Yukos has now a controlling interest in the Mazeikiai refinery. At a time when the Baltic States are being pushed to open their markets and to increase competition, monopoly control by a traditionally non-transparent foreign investor of the region's only refinery could pose serious price and supply risks.

9.2.2. Rationalisation of the electricity system — closing Ignalina

A number of adjustments will be needed in the generation and distribution of electricity in the Baltic region over the next few years, as pockets of deficiency, over-capacity, adjustments to trade and the shutdown of Ignalina NPP must all be accommodated and balanced. Although the tendency is to address these problems at the national level (e.g., by investing in national self-sufficiency), this is an expensive proposition.

From a purely economic aspect, the most rational option for security of the Baltic energy supply is the continued operation of the Ignalina NPP Unit 2 until the end of its technical lifetime with the existing fuel source and, if necessary, with its subsequent replacements. Extension of the operating life of Unit 2 of the Ignalina NPP until 2017 yields a benefit of €440–670 million, depending on the price assumptions. Additional benefits could accrue if a third unit would be built in the interim to provide replacement capacity and avoid the need for replacement power at the end of the technical life of Ignalina NPP Unit 2.

Moreover, shutdown of Ignalina NPP Units 1 and 2 has a strong negative impact on energy security in the Baltic region by increasing the demand for natural gas and electricity imports. The impact of the electricity supply loss of Unit 1 in the Baltic States is not great, since power output in excess of Baltic demand is already exported to Belarus, Kaliningrad and Russia. However, the impact of shutting down Unit 2 will require increased imports of natural gas and electricity or the construction of new NPP. Although sufficient generating capacity — on a nameplate basis — continues to exist in the region, a large portion is of old vintage, unreliable, highly inefficient and polluting and thus in dire need of rehabilitation or replacement. As a reslut, the region will turn from a net electricity exporter into an importing region (from Russia and, with the new Estlink underwater connection, from Finland).

Closure of Ignalina 2 by the end of 2009 is already incorporated in the National Energy Strategy of Lithuania and agreed with the EC during accession negotiations. And given the time needed to prepare and implement a nuclear project, it is not realistic to expect grid connection of a replacement plant much before 2015. Depending on the development of CO_2 limits and fossil fuel prices and their effect on the competitiveness of fossil fuel power plants, the construction of a new nuclear unit at Ignalina could be a sound alternative after 2015. If a third unit will be built, a thermal power plant (TPP) fuelled by orimulsion could provide power until the nuclear project is implemented.

Three issues were explored regarding the closure of Ignalina. First, whether or not a new NPP is the least-cost alternative to provide new electric energy supply as well as to support long term energy security goals (and if a new plant is not a least-cost option, assess the inferred 'insurance premium'). Second, whether Lithuania versus the region is able to support a new NPP financially and from a grid-integration aspect. Third, that the closure or replacement the Ignalina NPP cannot be assessed in a vacuum. The issues of energy supply and energy security in Lithuania are not resolved by a simple replacement of the Ignalina NPP by a more modern reactor. Issues of gas and electricity import dependence, the potential demand for district heating and compliance with relevant European Union (EU) directives on the use of renewable energy must all be factored in.

Solutions to this balancing act do not lie within the internal Baltic grid integration only. Further integration beyond the Baltic region to other parts of Europe greatly enhances market flexibility, reduces vulnerability and increases diversity. Examples of joint investments to improve the efficiency of the electricity grid include the construction of cross-border interconnections with Finland, Sweden and Poland, using their positive experience with 'Estlink' as a guide. Crucial to the success of these investments will be the reshaping of the operational structure of the high-voltage networks and learning to take advantage of new trade opportunities after the construction of interconnections.

9.3. Energy supply security enhancement measures

All mitigation strategies imply a certain degree of risk acceptance, since the cost of striving for complete energy security at all times is unacceptably high, from both an economic and a societal point of view. For that part of the risk of energy supply interruption that is considered unacceptable, actions can be taken to mitigate the potential impacts.

In well-functioning and efficient energy markets, commercial adjustments to supply disruptions tend to occur through effective price responses, maintenance and vigilance to assure asset protection of the infrastructure; and hedging mechanisms (insurance) or market flexibility to adapt to changing circumstances. When governments intervene in energy markets to try to assure stable energy supplies, they have a number of options. While the details of the individual national responses may vary, the basic policy and intervention options open to governments tend to centre around:

- Diversification of supply sources;
- Multiple fuel use capabilities;
- Inter-fuel substitution;
- Changes in regulatory or institutional mechanisms;
- Price reforms or price controls;
- Import fees;
- Restrictions on foreign investment and/or ownership;
- Subsidies and taxes;
- Expanded integration of electricity grids;
- Development of new technologies or industries;
- Changes in consumption or distribution patterns (some imposed by legislation or regulation);
- Incentives for energy efficiency and reduced consumption;
- Investing in spare or strategic capacity;
- Stockpiles.

The measures explored in this report, both at the national and regional levels, include these policy and investment measures and are now being considered among the Baltic States to reduce import dependence (particularly for gas), to increase market flexibility through diversification and efficiency improvements and to integrate and rationalise the electricity grid.

9.3.1. Regional cooperation

A major thrust of this analysis was to focus on maintaining the existing low-cost energy supply systems by applying least-cost solutions, while still maintaining a reasonable and desirable level of energy security. The main finding of this study is that addressing energy and energy security issues on a coordinated regional basis reduces the cost of investment and benefits the economies of the three countries.

Especially given the small size of the individual national energy markets, investments for larger projects are more secure and on a stronger financial and technical basis if they are shared or made on a coordinated Baltic-wide basis. Some projects, such as a new NPP, only make financial sense if they are supported by all three nations.

This study finds a strong congruence between energy supply and security measures that are less expensive and those that are regionally planned and implemented. Analysis shows that addressing energy supply and security regionally rather than on a country-by-country basis reduces investment costs by €183 million and overall system costs by €727 million between 2005 and 2050 for the Baltic countries while meeting the same energy service requirements. This constitutes clear benefits to the economies of all three countries as well as to their energy security.

Coordinated regional measures can maximise supply and security efficiencies without duplication among isolated entities within national boundaries. They can also enable the development of a long term 'least cost' investment portfolio. Cooperative regional Baltic investment is suitable for a regional gas storage facility with the capacity to withstand a 120 day supply interruption. It is also suitable for interlinks with Sweden, Finland and Poland (and thus, in the longer term, with NORDEL and/or the Union for the Coordination of Transmission of Electricity (UCTE)) to integrate the Baltic electricity and possibly gas grids with neighbouring states. These investments support energy security through import diversification in times of need and also promote longer term price stability.

The regionalisation of Baltic energy policy overall can be strengthened by pursuing energy supply on an integrated economic, technical and policy basis. This adds flexibility and robustness to the overall energy supply system, permits an equitable accommodation of trade-offs within the system, and militates in favour of least-cost energy supply and a high level of security. Integrated regional energy policy also includes a joint emergency plan to meet energy supply crises.

Using their membership of the EU, the Baltic States could actively begin a common dialogue based on integrated Baltic energy supply and energy security objectives with Russia, through the EU–Russia dialogue on energy. The EU–Russia dialogue might focus on transparency in energy pricing policies, signature of the Energy Charter Treaty, analysis of possible routes for trans-European gas transport lines. Integration of the Russian electrical grid with the West European grid could also be a subject for Baltic participation. Completion of the present report provides a basis for a Baltic–Russian dialogue.

9.3.2. General policy considerations

Policy changes and investments must go hand in hand. Investments made without regard to the overall market conditions and trade opportunities will be less than optimally efficient. The specific options for the Baltic countries to enhance supply security are discussed in detail below, but first a brief description of key policy priorities within which to frame efficient regional investment decisions is provided.

9.3.2.1. Developing Market Flexibility

A first consideration for efficient investment is to rationalise demand. In this study this translates into reducing inefficiencies in the existing energy system. This can be accomplished by encouraging efficient energy use (through pricing and technology and/or performance standards) and by improving market flexibility (through diversity of technologies and fuels and increased operational flexibility of the energy system), so as to enhance the efficiency of overall energy supply.

Improved efficiency is a least-cost approach to expanding market options. Investing in energy efficiency is the cheapest source of heat and power and once investments in more efficient structures, equipment and processes have been made, there is no impact from fuel prices on the costs of energy services and the economic production process. In short, cost-effective (on a life-cycle basis) efficiency improvements enhance energy security and reduce emissions. The present energy intensity of Lithuania's gross domestic product (GDP), for example, is still about 1.5 times higher than the average energy intensity of the EU, even though from 1994 to 2001 Lithuania reduced the value of final energy intensity by a substantial 38%. Further efficiency improvements in energy consumption are expected in all three Baltic States. For the district heating market, especially, rehabilitation investments in distribution, generation and building infrastructures are expected to reduce specific heat demand and hence the need for additional supply. As fuel prices rise, additional improvements increasingly become economically attractive.

Diversification — of suppliers and fuel mix — is a crucial element in market flexibility. It addresses both near-term issues caused by a rapidly increasing dependence on natural gas from a single source and longer term price increase issues from global competition for oil and natural gas. It provides alternatives in cases of supply interruption and for price negotiations, as well as opportunities to improve supply efficiency. Diversification can be optimised on a regional as well as national basis.

Diversification should consider all relevant fuel and technology options. In the Baltic region these include oil shale, natural gas, orimulsion, nuclear, coal, renewable and domestic energy sources, and electricity imports. Choices between these are necessarily dictated by cost and by technological appropriateness in a given market. In this context, economically competitive and technically mature options, such as coal and nuclear power, can play an important role.

In this context, for example, Latvia (particularly) is exploring the exploitation of its domestic oil and peat resources, as well as support for renewable energy resources. Estonia is exploring further development of its oil shale industry and use of oil shale in innovative circulating fluidised bed combustion (CFBC) technology. Lithuania is contemplating converting parts or all of its TPP to burn imported orimulsion. Latvia is also considering construction of a coal-fired power plant and a coal terminal. Use of CFBC technology for this plant would enable co-firing of biomass up to 10–15% of the total plant fuel input, with a consequent reduction in CO_2 and other pollutant emissions. At the regional level, the delayed shutdown of Ignalina NPP Unit 2 and the construction of a new NPP at the Ignalina NPP site would enhance the diversity of the region's electricity supply mix.

Use of renewable resources to meet about 10–15% of the Baltic electric generation mix and district heating generation makes sense in terms of fuel diversification, but not necessarily from an economic point of view. Renewables are costly and not expected to enhance significantly the security of electricity supply in the Baltic region without strong economic incentives, such as carbon taxes, subsidies, portfolio requirements or very high prices in the energy market. Wind and micro-hydro power are only intermittently available and a large share in the electricity mix may require additional investment in network upgrades, fast-response and back-up capacity. Wood or biomass supplies near heat and electricity load centres, where biomass combined heat and power (CHP) plants could be located, are limited, and transportation costs can be prohibitively high. Solar and geothermal energy have a very low potential in the Baltic States. In essence, the economic feasibility of renewables is largely determined by local factors and individual projects have to be evaluated on a case-by-case basis. By contrast, waste incineration and biogas landfill gas plants could be used in the large cities of the Baltic States.

The proposed interconnections of the Baltic grid with neighbouring grids constitute an important step to diversify the Baltic electricity markets. It is also possible for this region to import electricity from Russian producers at low prices, but the long term security implications of potential Russian domination of the market should be considered very carefully. This real market situation was not analysed in the study.

The Mazeikiai oil refinery is another essential element of a diversified Baltic supply base. Its contributions to energy supply security include compensation for a loss of natural gas supply, as well as to provide distillates to support dual fuel-fired district heating, combined cycle and electric generating capacity.

Modernising the Lithuanian TPP and conversion to orimulsion fuel input improves the diversity of fuel supply and suppliers, and thus provides greater fuel price security. Modernising the Estonian oil shale power plants also helps to enhance diversity and hence security of energy supply.

Diversification can also enhance security against price volatility, not only by assuring competition among a multiplicity of suppliers, but also by the extent to which diversification of the fuel mix introduces the use of coal or nuclear power. Coal prices have not risen to the extent or at the same rate as oil or gas prices. Uranium prices have tripled over the past 3–4 years (from a very low base that had restricted investment in exploration and mining), but their share in generation costs is small. In fact, the cost of uranium or to a lesser extent coal, accounts for a much lower share in electricity generating costs than does oil or gas (uranium 2–5%, coal 30–35% and gas 60–70%). This results in electricity generating costs that are more insulated from resource price fluctuations.

Developing storage is one way to improve market flexibility in which the Baltic States already have positive experience. Latvia already has an underground gas storage (UGS) capacity that exceeds by approximately 150% its actual annual gas consumption. UGS is widely used for seasonal gas storage to regulate gas flows for domestic use, as well as for Russia and Estonia. It also provides operational overflow during congestion in the main transit pipelines. Storage requirements are set at the demand for 90 days, though the possibility to extend this to 120 days is under consideration. Gas storage facilities are being considered in Lithuania. In addition, EU accession requires the development of 90 day reserves for oil and oil products in all Baltic countries.

9.3.3. Specific investment projects

Investments to mitigate the impact of supply security risks generally fall into two broad categories:

- Investment in supply capacity (such as new electric generating stations, combined cycle facilities and district heating plants) that must be purchased in any event to meet growth or replacement needs. Newer technologies incorporate characteristics that offer some measure of improved efficiency or security of energy supply at little or no additional cost to the investor or the economy, but their primary focus is to supply energy at a profit. Most mitigation actions available to the Baltic States fall into this category. Examples are high-efficiency gas technologies, dual fuel natural gas and orimulsion-fuelled boilers or, where economically feasible, renewables, or a new nuclear power station at Ignalina;
- Investments that provide no direct return except when there is interruption of supply. For the Baltic States this consists primarily of natural gas and oil storage. This type of activity generally requires direct governmental support.

9.3.3.1. *Supply Oriented Measures*

Energy supply investments required to improve security of supply are those that diversify fuels or technologies and are also economically competitive and technically proved. The results presented in this report show that the investments being contemplated in the Baltic region have these characteristics:

- A new 1000–1650 MW_{el} NPP at Ignalina NPP in the 2015–2020 time frame. It is estimated that a new NPP in this time range may cost in the order of €1660/kW_{el} installed, including all site costs and owners' costs, but excluding interest during construction for operation in 2015. However, the primary benefit of investment arises in providing substantial replacement capacity for Unit 2 after its shutdown, and will accrue only if the new nuclear unit starts commercial operation slightly before the shutdown of Unit 2. It requires running Unit 2 until its technical end of life in 2017 and starting the new Unit 3 by that time.
- A new 275–400 MW_{el} coal-fired power plant in Western Latvia in the 2010–2020 time frame that meets EU emission standards.
- A series of high voltage electric interlinks with Poland in about 2015, with Sweden in about 2012 and an increase in the capacity of the Estlink interlink with Finland in the near future to its maximum planned capacity of 600 MW.
- Renewable energy projects, including biomass (primarily wood) and wind power projects in all three countries and small low-head hydro in Latvia, such that 10% of electric power and district heating energy is produced by these diverse indigenous fuel sources by the end of 2025.
- Continued modernisation by Estonia of the Narva oil shale units, begun in 2004, until approximately 1400 MW_{el} of the current 2000 MW_{el} capacity is modernised to EU standards for environmental releases.

It is expected that these investments will be made mostly by the private sector, though in some cases, such as the new NPP, some government statutory and regulatory actions are needed. In all cases, coordinated planning and governmental agreement to encourage common investment would be most desirable.

9.3.3.2. *Security Oriented Measures*

The energy supply investments considered in this section, which primarily relate to energy security, are concerned mainly with the level of natural gas storage in the Baltic States and the infrastructure to transmit the stored gas between these States in time of need. Planning and funding these investments, as well as filling the storage, are primarily the responsibility of the three governments or their designated institutions.

The gas storage capacity now available in the Baltic States is in Latvia. Designed for seasonal storage, this facility could provide 90 days supply for the Baltic States. Estonia and Lithuania have no existing gas storage, nor is there any legal or commercial agreement between the three Baltic States for common usage of the Latvian facilities. Raising the storage capacity to a level of 120 days reserve for the Baltic region would provide adequate supplies to survive a winter-long supply interruption, and provides time for diplomatic or technical responses, as needed, to such a cut-off.

Reducing dependence on gas through efficiency improvements and diversification, where cost competitive, is most effectively done on a least-cost basis if planned and implemented in a coordinated manner by the Baltic States rather than by each state individually. However, as Lithuania is more severely and more immediately at risk than either Latvia or Estonia, it is common sense for Lithuania to take the lead in organising a common approach to minimise the energy supply and energy security risks from the growing single-source dependence on natural gas. Part of this plan should encompass an agreement by the three countries, firstly on a jointly basis to access (and pay for) the existing natural gas storage in Latvia in times of emergency, and secondly on the need for additional natural gas storage and a mechanism to jointly develop and pay for it.

Assuming that the necessary cooperative arrangements can be made (as in the 3R scenario), the cost of raising current storage levels from 90 days to 120 days is estimated at €13 million to €26 million (discounted) per year for the region (depending on future energy market prices) over the period 2010–2025.[20] Parts of these costs (which include capital, operating and maintenance charges) already need to be incurred to meet the current EU requirement to maintain 90 days reserve for oil and, possibly, in the future also for the supply of primary fuels, including natural gas. Given the current high dependence on gas, the investment in storage facilities is an affordable 'insurance premium'.

New power interconnections with UCTE via a 1000 MW link between Lithuania and Poland and with NORDEL via Estlink, a 350 MW underwater connection between Estonia and Finland, as analysed in the 'Regional Scenario with cross-border power exchanges (2R scenario)' add some €3 million of costs per year (discounted) over the period 2005–2025 compared with the 1R Scenario, because the benefits from investing into interconnections occur in the future. However, this insurance premium for improved system flexibility turns into an annual cash benefit of more than €5 million if energy market prices remain at the levels experienced today. However, energy supply security in terms of import dependence does not really improve compared with the 1R scenario (around half a percentage point on average), but certainly improves qualitatively through the additional electricity interconnections.

To diversify fuel and technology requires the construction of both a new NPP at Ignalina and a coal-fired power plant in Western Latvia. This lowers the region's energy import dependence by seven percentage points at an annual cost of €62 million (discounted) per year over the period 2010–2025 (or €9.2 million per percentage point reduction in import dependence). To put this 'insurance premium' into perspective, the additional cost burden of high prices in the energy market, Scenario 2R(Ab) amounts to €300 million (discounted) per year or reduction in import dependence of about €20 million per percentage point over the period 2005–2025.

9.4. Trade-offs

Different fuel and technology choices have different consequences, and all policy and investment decisions involve trade-offs among their consequences. These should be evaluated in the light of regional and national resources, policies and strategies before investment funds are committed. Consider, for example, the different effects of three possible alternatives to replace the capacity of the Ignalina NPP. The options to construct new combined cycle gas turbine (CCGT) units and to modernise the existing 300 MW units at the Lithuanian TPP have similar economics, but CCGT units significantly increase the dependence on natural gas, although they have lower levels of GHG emissions than the TPP. The second scenario to build a new NPP alters existing supply patterns as it:

[20] These costs could be some 50% lower on a 30–40 year perspective.

- Reduces the consumption of orimulsion and, to a lesser extent, of gas
- It reduces utilisation of the Lithuanian TPP and the capacity requirements for new CHP and CCGT units;
- It shifts production of decentralised heat supply from CHPs to boilers.

A third contrasting scenario to import cheap electricity from Russia reduces the utilisation of existing condensing power plants, and reduces the need for new CCGTs and, especially, for a new NPP.

10. CONCLUSIONS

The main objective of this study was to test and verify the benefits and costs of an integrated regional versus a strictly national approach to energy supply security in the Baltic region (Estonia, Latvia and Lithuania). The study identified several options for enhanced energy supply security. However, there is no 'silver bullet' solution (i.e., no single least-cost and no trade-off option — priorities and trade-offs are highlighted in the scenarios and described here.

The main, though not the only, focus of supply security is the region's high dependence on Russian oil and gas imports, which will be aggravated by the closure of the Ignalina nuclear power plant (NPP), the mainstay of the region's electricity supply, at the end of 2009. The goal is not to eliminate energy imports from Russia, but to put in place measures to mitigate the long term risks associated with such import dependence.

For this study, energy supply security in the Baltic States is defined in terms of reducing import dependence on energy supplies that carry a risk of politically motivated price increases, surprise changes in market conditions or disruptions of physical supply. Gross Baltic energy import dependence is currently around 69%; net import dependence (adjusting for regional exports of electricity and oil products) is 45%. The region effectively depends on Russia for the bulk of its energy needs, a situation which will be aggravated by the closure of the Ignalina NPP, the mainstay of the region's electricity supply, at the end of 2009.

Although the three Baltic States have quite different energy profiles, they share a common historical interdependence along with a high degree of dependence on Russian energy supplies. It is this common past, especially the legacy of large transmission and transportation, refining and electricity generating infrastructures (originally planned with a regional perspective), that results in both supply security risks and potential benefits. The regional cooperation in the Baltic countries continued after the collapse of the Soviet Union, but as ageing regional infrastructures increasingly become obsolete, there is a tendency to first seek national solutions, especially for rehabilitation or replacement investments.

The general conclusion of this study is that regionally integrated energy policies and investments are the most efficient and cost-effective approach for meeting the Baltic region's future energy needs after the forced shutdown of Ignalina NPP units 1 and 2. This presupposes, however, the balancing of each country's needs and resources within the regional context and agreement as to the sharing of the costs and benefits of regional cooperation. National differences, discussed in detail in previous chapters, form the basis of the regional cooperative strategy, and hence the rationale for the conclusions drawn from this study. It is therefore useful to review here very briefly the highlights of each country's current energy situation before examining the supply security benefits that result from further regional integration of the national Baltic energy systems through the sharing of resources and infrastructure.[21]

In 2003 about 75% of the primary energy supply in Estonia was domestic — mostly oil shale, wood and peat. Oil shale is a staple fuel for electricity and heat generation in Estonia and represents the largest fossil resource of the Baltic region. Imports are Russian oil, processed in

[21] Further details can be found in the Appendix to this chapter, including for each country the essential aspects of the current national energy markets, their optimal national future scenarios, and the gains and losses they could expect from regionalised energy policies and investments, all viewed in the additional context of their recent accession to the European Union and compliance with its requirements.

the Lithuanian Mazeikiai refinery, and Russian gas, the seasonal supply of which is regulated through the Incukalns underground storage facility in Latvia.

Latvia, by contrast, in 2003 imported about 73% of its primary energy (natural gas, coal and oil products) from Russia, Lithuania and the Commonwealth of Independent States (CIS). Accounting for energy exports, the net energy import dependence[22] was about 55%. Domestic resources are biomass, peat and hydropower. Latvia also imports some 30% of its electricity from Russia, Estonia and Lithuania, although the goal is to reduce this to 10–20% by 2008. Latvia is an energy transit country for Russian crude oil, oil products, coal and natural gas. Latvia has a large underground gas storage facility and uses stored gas to even out seasonal deliveries of natural gas from Russia, for domestic use in winter and for export to neighbouring countries, including re-export to Russia.

Lithuania's gross energy import dependence[23] in 2003 was about 117%. The country depends on Russia for 100% of its natural gas, and for almost 100% of its crude oil and coal requirements. Lithuania, however, is also a sizeable energy exporter to its Baltic neighbours and beyond, and the net import dependence is about 42%. The Ignalina NPP, designed during the days of the Soviet Union as a major electricity hub in the region, continues to supply base load power to former Soviet satellite states. However, the closure of Ignalina NPP Unit 1 (Ignalina 1) at the end of 2004 caused a sharp drop in exports, and exports will cease altogether after the closure of Ignalina NPP Unit 2 (Ignalina 2) at the end of 2009. Lithuania's Mazeikiai refinery was also designed as a regional supplier of refined oil products, and it continues to export oil products to Latvia, Estonia and outside the Baltic region.

The closure of the Ignalina NPP, which before 2005 supplied some 40% of the region's electricity needs, is expected to further increase the dependence on imports, depending on the choice of replacement technologies and associated fuels. In addition, energy and electricity demand is projected to grow in the region. Given the region's limited fossil fuel energy resources — essentially limited to oil shale in Estonia — additional supplies from abroad will be required.

Initial analyses identified natural gas-fuelled electricity generation as the preferred replacement for the Ignalina NPP, at least before natural gas prices rose appreciably in the Baltic region - first as a result of European Union (EU) accession which put an end to the preferential gas price treatment by Russia to former members of the Soviet Union, and then through the overall upward trend of international energy prices. The least-cost solution for replacing power from the closure of the Ignalina NPP increases natural gas imports from Russia.

Efforts to minimise such dependence are being made at national and regional levels, in the context of growing market liberalisation and accession by the Baltic States to the EU. Some of the measures contemplated, modelled as part of this study, include:

---

[22] Net energy import dependence here is defined as the sum of all energy imports minus the sum of all energy exports divided by the total primary energy supply in the country or region. Although nuclear fuel is often imported (from Russia in the case of the Ignalina NPP), nuclear power is considered a domestic energy source. The small annual fuel requirements, the potential to store one or more refuelling loads on site and the inherently long refuelling cycles mean that nuclear fuels are not critically impacted by short term supply disruptions and price volatility.

[23] Gross import dependence here is defined as the sum of all energy imports divided by the total primary energy supply in the country or region.

- Modernise the larger existing thermal power plants across the region (both to improve efficiency and to meet environmental standards);
- Construct new combined heat and power (CHP) plants;
- Maximise the use of Estonian oil shale;
- Improve air pollution controls;
- Implement the EU renewables directive;
- Construct a replacement nuclear power station or fossil-fuelled plant for the Ignalina NPP;
- Change the fuel mix and diversify imports;
- Enhance the energy supply and distribution system.

As regards fuel diversification and supply security, uranium and, to a lesser extent, coal prices account for a much lower share in electricity generating costs than do oil or gas prices (uranium prices are 2% to 5% or electricity prices, coal prices are 30% to 35% and gas prices are 60 to 70%). Hence an increasing fuel price affects nuclear- and coal-generated electricity less than electricity generation from natural gas.

Table 10.1 depicts the principal energy supply technology options for the Baltic region by country. Not listed here, but included in the energy demand analyses, are efficiency improvements throughout the energy end-use systems, including transmission and distribution infrastructures. Other opportunities for common investment in measures for energy supply security that would supplement the technology options of *Table 10.1* are the establishment of a Baltic wide Independent System Operator (ISO) or the interconnection of the Polish and Lithuanian gas pipeline systems.

The Baltic countries have made and are continuing to make important improvements in energy efficiency. Compared to some other EU countries, large gains are still to be made in reducing the kilowatt-hours or megajoules (MJ) required per unit of economic output. Energy efficiency is the cheapest source of heat and power, with immediate benefits for energy security, and, once the investment in more efficient buildings, processes and equipment is made, there is no impact of fuel costs on the production costs for the avoided capacity. As fuel prices increase, agents throughout the economy can afford more improvements.

As stated already, the main objective of this study was to quantify and compare the costs and benefits of an integrated regional versus a national approach to energy supply security in the Baltic region under a variety of potential future scenarios. ‘Integrated’ in this context means (a) to adopt and pursue a common regional energy policy and (b) to make energy investment decisions solely on the basis of least-cost considerations for the region — not necessarily least-cost at the national level — given common regional policy objectives.

Table 10.1. Major energy supply options in the Baltic Region*

Estonia	Latvia	Lithuania
Refurbishment of oil-shale power plants	Replacement of existing CHP with new CHP (natural gas)	Modernization of Lithuania TPP including switch to
Conversion/replacement of DH boilers to/with CHP	CHPA biomass & pulp	Conversion/replacement of DH boilers to/with CHP
CFBC(oil shale)	CHP (coal)	Modernisation of existing CHPs and new CHP
CHP (imported coal)	Coal power plant	Small scale CHPs (gas & biomass)
CHP biomass/peat	CCGT	Nuclear power plant
CCGT & gas turbines	Wind	CCGT
Wind	Hydro	Wind
Mini & micro hydro	Additional gas storage	Pumped storage
Full implementation of strategic oil/oil product reserves		
Electricity links to Finland, Sweden and Poland		

* TPP, Thermal Power Plant; DH, District heating; CFBC, circulating fluidised bed combustion; CCGT, combined cycle gas turbines

The conclusions developed in this section are, to a large extent, based on the scenarios and model outputs described in detail in the report. There is no 'silver bullet' solution to the energy supply security of the region or a mix of measures that will best serve it. The numerous scenarios developed for and analysed in this study provide a point of departure for further analyses to identify cost-optimal measures that strengthen supply security.

Most of the scenarios consider international energy prices for the next few decades that are below current price levels. Both the interpretation of the numerical results and the conclusions here account for the changed price realities as supported by several additional model runs with energy import prices some 20–30% higher than in the original 'extra high price' cases, with the identifier (Ab). Identifier (Ab), therefore, describes the high price situation observed today and not necessarily precisely the price assumptions that underlie the scenarios reported in Chapters 5–8. The term 'high international energy prices' used in these conclusions, therefore, represents future price developments largely consistent with those represented by the scenario identifier (Ab).

Conclusion I: Solutions approached from a regional perspective are more effective than the same solutions pursued independently by each of the three countries. There are immediate economic benefits — but not necessarily improved energy supply security — from an integrated and coordinated energy approach. The energy system cost difference between the 'National Self-Sufficiency Scenario (1N)' and the 'Regional Self-Sufficiency Scenario (1R)'[24] amounts to €727 million (discounted[25])

[24] Unless otherwise indicated, the Ignalina NPP ceases operation as in the EU accession agreement.

[25] An 8% real discount rate was used.

for the study period 2005–2025. The main difference in the regional energy supply mix is a larger share of natural gas imported from Russia and a drastically restructured trade pattern for crude oil and oil products (with additional crude imports from Russia and higher refined product exports abroad). The net result is a 4% increase in the net energy import dependence after 2010 (essentially all from Russia), which increases to 7% by 2025.

Rationale: In an environment of low international energy prices[26] and in the absence of any import restrictions to reflect energy security concerns or stringent environmental performance standards, the larger integrated regional market alone does not create sufficient economic incentives to construct a new NPP.

With low-cost natural gas and crude oil imports and no considerations of energy supply security, it is economically attractive to use Russian gas instead of imported orimulsion to generate electricity as well as increasing export revenues from refining imported crude oil and exporting oil products. Internal electricity exchange among the Baltic countries improves overall generating flexibility and thus permits additional electricity export revenues (from exports to Russia and the CIS) during the operation of the Ignalina NPP.

Conclusion II: The most efficient scenario for the development of the Baltic energy system, in terms of both economic and security of supply aspects, is the continued operation of Ignalina 2 until the end of its technical lifetime in 2017 (Scenario 5R). In principle, this option has been foreclosed by the accession agreement with the EU. The net economic benefit to the Baltic region would be on the order of €440 million (discounted) in a future with low energy prices, and some 50% higher if current international prices prevailed[27].

Rationale: The shutdown of Ignalina 1 in 2004 had a less severe impact on the region, since a part of the output was excess to Baltic demands and was sold outside the Baltic region, to Belarus, Kaliningrad and Russia. Adjustment to the shutdown was made by reducing exports. By contrast, the impact of the shutdown of Ignalina 2 can only be fully mitigated by increased imports of natural gas, orimulsion, coal and electricity or the construction of a new NPP. This is because most alternative Baltic sources of primary energy, including renewables, will either be already utilised by 2010 to meet demand growth and to compensate for the loss of Ignalina 1 supplies, or be hampered by cost considerations or long lead times, or both.

Prolonged operation of Ignalina 2 beyond the agreed closure date at the end of 2009 is warranted on purely economic terms and takes the operating license issued by the national regulator VATESI at face value. In all the scenarios in which Ignalina 2 closes by the end of 2009, the region switches from a net electricity exporter to a net importer. While import volumes vary across the scenarios, electricity imports generally correspond to about half of Ignalina 2's generation before closure.

The benefits stated above reflect energy system benefits only. The benefits of the continued operation of Ignalina 2 or the construction of a new NPP at the Ignalina NPP site would also avoid socio-economic hardships, loss of a skilled work force, relocation, reduction and re-

---

[26] Low import prices are defined here as crude oil prices around €33/barrel (€5.7/GJ). After 2005 gas prices vary between €2.7 and €4.1/GJ over the period 2005–2025 and coal prices stay at around €1.8/GJ.

[27] The benefits are the difference of discounted costs between the 5R and 2R scenarios over the period 2005 to 2025.

employment of plant and support staff, and the decline of the support and service industries and businesses in the region.

Conclusion III: Energy options that provide flexibility are desirable. Thus, options that strengthen electricity and natural gas pipeline interlinks and also allow increased diversification of supply sources are exceptionally attractive. For example, adding electricity interlinks with Sweden and Poland permits larger electricity generating facilities because of larger markets and increased reliability of the overall system. Larger units have lower unit production costs. This, in turn, reduces the cost of electricity as a factor input to the economy.

Rationale: New power interconnections with the Union for the Coordination of Transmission of Electricity (UCTE) via a 1000 MW link between Lithuania and Poland and with NORDEL via Estlink, a 350 MW underwater connection between Estonia and Finland, as analysed in the 'Regional scenario with cross-border power exchanges (2R)', further improve system flexibility and overall economics by some €510 million over the period 2005–2025, compared to the 1R Scenario. On a discounted basis, grid integration adds some €44 million to costs and thereby reduces the total net benefit by this amount because the benefits from investing in these interconnections occur in the future[28]. Energy supply security, in terms of import dependence, does not really improve compared to the 1R scenario (around half a percentage point on average), but certainly improves qualitatively because of the additional electricity interconnections. Supply disruption and technical equipment failure were not modelled in this study. However, it can be safely concluded that an interconnected electricity system is better prepared to withstand disruptions and supply shocks than an isolated system.

Conclusion IV: High international energy prices[29] reduce energy import dependence and stimulate the exploitation of previously sub-marginal domestic energy resources (especially of peat, wood, biomass, wind and small hydropower), increase the use of imported coal in rehabilitated plants and in new capacities and favour the construction of a new NPP. For example, for the 2R scenario, import dependence drops by 15 percentage points in the high price situation compared with the low price benchmark.

Rationale: While imports of gas and orimulsion are greatly reduced, imports of crude oil from Russia and of electricity mainly from Russia increase considerably. Here, refining margins and higher export revenues for the oil products from the Lithuanian Mazeikiai refinery appear an attractive proposition despite the costly crude imports, although with a higher risk profile for potential supply disruptions. Electricity imports from outside the region are attractive — the higher international fuel prices do not proportionally affect electricity generating costs and may be negligible if the electricity is based on hydropower or nuclear power. As soon as electricity import prices exceed €38/MWh for extended periods of time, a new NPP with levelized generating costs[30] of €37/MWh becomes part of the cost-optimal electricity supply

---

[28] The additional discounted system costs result in savings of €82 million under high price conditions in the energy market.

[29] High import prices correspond largely to the scenarios with the identifier (Ab). The prices of crude oil are €49/barrel (€8.50/GJ) after 2005, of natural gas €150–€228 per 1000 m^3 (€4.0/GJ to €6.1/GJ) rising steadily over the period 2005 to 2025, and of coal about €2.70/GJ. Several test runs were performed with 20–30% higher international energy prices, and the conclusions also reflect these additional model runs.

[30] Including interest during construction, decommissioning cost and contribution to a waste management fund.

mix. The cost-optimal grid connection for such a plant occurs between 2015 and 2020, depending on the price assumptions for electricity imports from abroad (Russia, Finland or Poland).

Any import prices higher than in the (Ab) case simply bring forward the introduction of a replacement NPP. A test with 30% higher import prices led to the grid connection of a new nuclear plant as early as 2010[31]. However, given the lead time needed to prepare and implement a nuclear project, it is not realistic to expect a new unit to start operation much before 2015. The Lithuanian TPP fuelled by orimulsion imported from Venezuela could bridge the power supply gap until a new NPP is operational.

A detailed cost comparison of the high price scenario with 1R and 2R does not make much sense as these represent distinctly different energy futures for the region. Clearly, the supply security improvement in the 2R(Ab) scenario is significant, but so is the increase in overall energy system costs. The latter, however, are driven by energy prices and not by measures to improve energy supply security in the region.

More conclusive information about the costs associated with a higher level of energy supply security can be obtained by analyzing policy measures targeted at reducing supply security risks, namely cases 3R, 4R, 6R, 7R and the renewable energy scenario (Ea identifier). The results of these scenarios are compared below:

The comparisons were carried out using the low fossil fuel price 2R(Aa) scenario as a benchmark for three reasons:

- The scenarios with high prices for energy imports inherently improve the energy supply security situation (in terms of import dependence, but not necessarily in terms of price stability and socio-economic vulnerability);
- A low-price environment highlights the incremental costs and benefits of different policy options.
- The 2R scenario with electricity trade interlinks to neighbouring countries provides the necessary flexibility both for electricity imports and exports which is an important feature for the economic feasibility of large generating capacity additions.

However, to contrast the numerical findings of the study, reference is also made to the high-price scenario 2R(Ab).

Increasing natural gas storage in Latvia to 120 days of annual regional demand (3R). Additional gas storage capacity does not, overall, reduce dependence on Russian gas imports, but it does improve energy security (against interrupted delivery or price volatility) at a cost of €13–€26 million (discounted) per year (depending on future prices) over the period 2010–2025. These additional costs can be interpreted as ‘insurance costs’ or ‘premium’ for better energy security.

Capping the share of natural gas and orimulsion (4R). A cap (25%) on imports of natural gas and orimulsion does not really affect the level of energy import dependence. Rather, the cap leads to a different import structure in which gas is replaced by orimulsion (utilising the full 25%) supplemented by stepped up electricity and coal imports. The annual cost of diversification amounts to €9.6 million (discounted) per year over the period 2010–2025.

[31] This is an entirely hypothetical proposition. The model optimizes the energy supply mix of the Baltic region starting from 2000 and thus the construction of a new NPP in the model can commence in time for grid connection in 2010. From the vantage point of early 2006 this is unrealistic, and the test case was analyzed primarily to better understand the comparative economics of a new NPP.

New NPP at the Ignalina NPP site and/or a coal-fired power plant in Latvia (6R). Fuel diversification by requiring the construction of both a new NPP and a coal-fired power plant diversifies (coal imports) and lowers the region's energy import dependence by seven percentage points at an annual cost of €62 million (discounted) per year over the period 2010–2025 (or a cost of reducing import dependence of €9.2 million per percentage point). These costs may be viewed as an insurance premium for enhanced supply security. To put this 'insurance premium' into perspective, the additional cost burden of the scenario with high energy prices, 2R(Ab), amounts to €300 million (discounted) per year or about €20 million per percentage point reduction in import dependence over the period 2005–2025. (The absence of a new NPP in the 2R(Ab) scenario adds considerably to the costs.)

Carbon taxes: Tax levies on greenhouse gas (GHG) emissions inherently stimulate the use of fuels and conversion technologies that emit small amounts or no GHGs, as well as the rational use of energy and efficiency improvements throughout the energy system. Taxes on low-cost but GHG-intensive plant and equipment improve the competitive advantage of higher cost renewables, clean fossil fuel technologies and nuclear power. The effect on energy security in the Baltic region of varying taxes on carbon dioxide (CO_2) emissions is similar to that of higher fossil fuel prices — the higher the tax, the lower the overall dependence on energy imports as higher taxes induce lower overall demand and reduce demand for high-carbon fuels. A €20 tax per tonne of CO_2 – a value 25% lower than the published market value of European Union Allowances (EUA) on 3 March 2006[32] — reduces energy import dependence by five percentage points (compared with 2R) at a cost of €5 million (discounted) per year. The reduction is achieved primarily by the construction of new nuclear power capacity after the closure of Ignalina 2 and by the accelerated market penetration of domestic renewables.

The downside to carbon taxes as an import reduction tool concerns the use of Estonian oil shale. As the only sizeable hydrocarbon resource of the region, this domestic carbon-intensive fuel would also be adversely affected by any GHG tax and its use is progressively reduced with higher taxes on CO_2 emissions.

Increasing the share of renewables (Ea). The discounted costs of enforcing a 3% annual growth rate for electricity generation from renewables amounts to €709 million (discounted) for the period 2000–2025 and is one of the most costly measures for improving energy supply security. With low energy prices the obligatory use of domestic renewables appears to crowd out other domestic energy options, and renewables do not substitute for low cost imports. As a result import dependence improves only at the margin.

> ***Conclusion V***: Long term marginal costs (and prices) for energy services will increase in the region.
>
> Rationale: Rehabilitation of existing plant and equipment plus the construction of new heat and electricity generating capacities will result in higher electricity prices in the Baltic region, compared with prices reflecting only the operating costs of essentially depreciated capacity that would prevail without investment in new plant. Each closure of an Ignalina NPP unit will be followed by distinct price hikes.

With low international fuel prices, marginal electricity production costs in the Baltic market range between €31 and €36/MWh, primarily determined by generating costs of new CHPs. After 2020, the addition of new coal-fired capacities in Latvia, additional new CHPs in

[32] EUA closing value of €27.15/tonne CO_2, published by Point Carbon. http://www.pointcarbon.com/

Estonia and the replacement of one of the Vilnius CHP units increase the marginal cost to €39–€43/MWh.

Current international fuel prices (oil marker price around US$60–US$70/barrel) inflate the generating costs by some €5–€15/MWh depending on the system response (availability of non-fossil fuel alternatives and backstop technologies).

> ***Conclusion VI:*** This study finds a strong congruence between energy supply and security measures that are less expensive and those that are regionally planned and implemented.
>
> Rationale: Especially given the small size of the individual national energy markets, investments for larger projects are more secure and on a stronger financial and technical basis if they are shared or made on a coordinated Baltic-wide basis. Some projects, such as a new NPP or additional gas storage, only make financial sense if they are supported by the combined resources and markets of all three nations.

Energy policies as well as investments can be more effective if made on a cooperative basis. Emergency measures jointly decided and authorized in advance by all three countries would ensure that the best possible use is made of available energy supplies in case of a supply disruption. Similarly, the institution of a common Baltic market for electricity supply, preferably in conjunction with the establishment of a Baltic regional independent system operator, would further add to system efficiency and supply security.

> ***Conclusion VII***: Russian energy exports will remain a mainstay of Baltic energy supply. The answer to an excessive dependence is diversification.
>
> Rationale: Natural gas from Russia can be an integral and effective part of the Baltic energy strategy, to the degree that it makes economic sense and to the extent that measures like adequate Baltic gas storage and alternative emergency measures are in place to mitigate potential market dominance by Russian suppliers. The goal is not to eliminate energy imports from Russia, but to put in place measures to mitigate the long term risks associated with such imports.

In the longer run, the most effective way to limit the potential for monopoly market abuse (in the form of supply or price disruptions) is to break the monopoly. Diversity of energy supplies and energy-system flexibility in the Baltic region are therefore the key. Hence, the following measures can be considered to enhance the security of energy supply in the Baltic region:

- Increase production of renewable and domestic energy resources; including peat, oil and oil shale;
- Extend gas storage in Latvia to 120 days or more and establish 90 days of reserves for oil and oil products;
- Enhance hydropower capacity;
- Construct or continue operation of a NPP at the Ignalina NPP site;
- Construct coal-fired power plants and coal import facilities;
- Further coordinate Baltic electricity generation;
- Further integrate the Baltic grid with other grids;
- Improve efficiency throughout the energy system.

This list of measures is by no means comprehensive and the order of the bullets does not indicate any prioritisation. However, one should not lose sight of the economic and technical supply potential for renewables in the region. Solar and geothermal energy have very low potential, transport costs for wood for biomass CHP are high, wind resources are modest and hydro resources are not expected to grow sufficiently to change their fuel mix share substantially. Renewable energy under these circumstances is costly, may require subsidies or guaranteed markets, and hence may be limited largely to meeting EU requirements.

Conclusion VIII: EU membership creates incentives and opportunities for improved energy security.

Rationale: The process of rationalising imports as well as the region's electricity system is taking place in the context of the Baltic States' accession to the EU. This accession and the requirements attached to it necessarily condition and colour the costs and benefits of the rationalisation process. Four requirements, in particular, will influence energy policy decisions and investments in the future expansion of the energy system in the Baltic States:

- Closing of the Ignalina NPP;
- Implementation of the EU Renewables Directive as well as other EU standards (ranging from environment to efficiency);
- The obligation to develop strategic oil stocks;
- Adoption of binding commitments for CO_2 reduction.

Membership in the EU provides an opportunity and a platform on which to develop an integrated Baltic energy system with common policies. It also offers the chance to expand the dialogue on grid integration and on energy supply security with other neighbouring European countries, including with Russia through the EU–Russia dialogue on energy.

With the closing of Ignalina 1 and 2 by the end of the study period, CO_2 emissions will rise, perhaps to the limits set for 2025, depending on the extent to which replacement power is generated from gas, coal or nuclear power. However, as with investments in energy supply, environmental outcomes can also be achieved more efficiently with regional approaches. For CO_2 emissions, and assuming an emission fee of €20/tonne CO_2, a regional approach to coordinated generation will permit the use of plants with the lowest emissions while long term restructuring can take place.

The national and regional demand and supply assessments were carried out over the period 2003 to early 2005. During this period international energy prices shifted from being relatively low and stable to being considerably higher and more volatile. The upward trend has continued during the preparation of this report but declined somewhat in the second half of 2006. Therefore, several additional cases were calculated to account for the new energy price level and other new realities that now affect the Baltic region. These include:

- The Russia–Ukraine gas price dispute;
- An increase of electricity prices by some 30% in the region;
- The European Union Emission Trading Scheme (EU ETS) of 2005, which created a market for trading CO_2 emissions: emission permit prices have already soared from €8–10/tonne to €25–30/tonne – then slipped back to €12–15/tonne since April 2006;
- The scheduled completion of the Estlink cable in December 2006;
- A decision on the construction of the North European gas pipeline (underwater pipeline from Russia to Germany under the Baltic Sea) by-passing the Baltic States;
- Submission of 'Guidelines of the National Energy Program' by the Latvian Ministry of Economy to the Cabinet of Ministers (December 2005), with particular focus on the construction of a coal-fired power plant in the western part of Latvia;
- The Declaration and Communiqué signed by the Prime Ministers of Estonia, Latvia and Lithuania on cooperation to evaluate the possibility of constructing a new nuclear reactor on the site of the Ignalina NPP (February 2006) followed by a Memorandum of

Understanding signed by the Chief Executive Officers of the three largest Baltic energy companies: Eesti Energia AS, AS Latvenergo and AB Lietuvos Energia (March 2006);

- The considerable attention devoted to energy supply security at the G8 meeting in St. Petersburg in 2006 and the conclusion that the rush for energy resources will continue creating price pressure and the possibility that the lowest bidder will end up with nothing. This increases the risk associated with physical limitations of pipeline capacities and over-dependency on natural gas supply. A large scale shift towards alternative energy resources like unconventional oil or orimulsion may be questionable as well due to the fast increasing demand for these sources in rapidly developing economies, such as China, and limited capacities for their production. Even the utilisation of domestic resources like oil shale may change as commodities with higher value added (e.g., gasoline) may divert them from power generation;
- The increased significance of the regional scenario (5R) with prolonged operation of Ignalina NPP Unit 2 until 2017 owing to news about the possibility of Lithuania's asking the European Commission to postpone the decommissioning of the Unit 2 until 2013.

The model analyses had in one way or another "anticipated" these new realities, some of which at the time were considered "extreme assumptions" (a CO_2 tax of 20 €/t or crude oil prices of 55 € per barrel). A general conclusion, therefore, is that the findings of the assessment have proven robust even in a rapidly changing energy world. What has changed is that the low price scenarios are less likely to serve as images of the future than scenarios characterized by high energy prices and/or high CO_2 emission costs. These new realities not only add to the urgency of a regional approach to Baltic energy security but have already prompted political responses.

APPENDIX TO CHAPTER 10: NATIONAL SUMMARIES

1. Estonia

General conclusions based on modelling results for Estonia include the following:

Regarding electricity generation which is projected to double by 2025, Estonia will maintain its national self-sufficiency (if rehabilitation of aged oil shale-fired capacities are completed on schedule) and in most conditions could still export electricity to other Baltic countries, especially Latvia. Further opportunities for export to Scandinavia are likely to result from completion of the power link between Estonia and Finland. The dominance of oil shale in the generating mix will continue but will decline. Continued oil shale generation will require the full refurbishment of these plants by 2016 and the installation of circulating fluidized bed combustion (CFBC) technologies to reduce SO_2 emissions in order to meet legislated limits (25 000 tonnes of SO_2 per year). Combined cycle natural gas turbines (CCGT) will also be attractive additions to the generating mix. Coal-fired power generation will not be able to compete with oil shale under any envisioned circumstances. The share of renewable electricity could be increased to 5.1% of gross inland supply. However, without subsidies or higher feed-in tariffs for renewable electricity, biofuel-based CHP technology is more economically attractive than wind power.

The main difference between a national and regional perspective concerns the use of domestic oil shale: In a national context oil shale would be the preferred export commodity, while in a regional context it would be used for electricity generation. However, the ability to maintain a consistent level of exports at least in the near term will depend on the ability to resolve a number of potential operational difficulties on the national power system. First, maintaining a higher generation level would require, for the period 2008–2010, continued operation or resumption of service by older oil shale plants in need of refurbishment. Big fluctuations in demand for export could put a strain on these older units, resulting in additional and unforeseen maintenance costs.

There are two factors that could alter this scenario: a steep rise in fees for CO_2 emissions, and greater regional integration.

CO_2 emission fees of 20 €/tonne or higher by 2010 would have a major impact on the generating mix and export potential for Estonian electricity. While oil shale generation will still dominate the domestic generation mix, generating costs would rise to a level that would render electricity exports uneconomic. Instead, the production and export of oil shale could become more attractive (if there is still a market for oil shale in a carbon constrained world).

In fact, a large deficit in domestic electricity generation would develop by 2010, requiring the import of more than half of Estonia's requirements for electricity. Most of the peak capacity deficit would be covered by Latvian hydro power imports. Estonia would export base load electricity to Latvia and import peak load electricity from Latvia. In the period 2010–2014, restarting old oil shale power units could ease the supply situation and by 2015, CCGT units could be in operation. It is evident form the analysis that higher CO_2 emissions fees fundamentally change the structure of Estonia's power generating sector.

Final consumer prices for electricity during the study period (2005–2025) are expected to approximately double, with slightly higher prices in the case of a high CO_2 tax, and slightly lower prices when considering regional integration.

As a final note, this current study focussed on development options in the power sector, but the modelling exercise modelled all energy related sectors. The general optimum for the Estonian energy system is not always necessarily congruent with optima generated for individual sub-sectors, like power generation. Similarly, the general regional optimum does not correspond exactly to national optima in all three countries. While full energy system modelling may not be needed for making choices in the power generation sector, modelling a general optimum is useful for governments in harmonising planning and development among energy sub-sectors.

2. Latvia

Conclusions that can be drawn from the energy supply modelling for Latvia include:

In Latvia's power generation sector, the most significant concern is the closure of Ignalina NPP Unit 2, and the need for replacement power. The bulk of electricity demand would be covered mainly by two fuels: natural gas and coal, and by imports of electricity, mostly from Estonia. Natural gas is economically and environmentally more attractive, especially with high CO_2 tax rates. Coal becomes only more attractive if natural gas supplies are limited or fuel diversification is a main energy policy goal.

Least-cost shifts in the generating mix that replaces Ignalina NPP will occur as capacity expands to meet growing demand and at the same time to satisfy EU requirements for a guaranteed share of renewables in the generating mix, EU emissions limits, and market liberalisation. By the end of the study period, Latvia will approach but not exceed EU limits for NOx and CO_2 for the anticipated generation mix. SO_2 emissions are not considered a problem. Meeting the renewables target will be accomplished largely by existing large hydro power plants (Daugava) and a new CHP plant to be built in conjunction with a pulp factory, though the future of this latter plant is questionable. However, whether or not this plant is built, the remaining shares of renewable electricity will come from new biomass CHP plants and wind parks. Given the already high share of renewables in the national electricity generation mix and most low hanging fruit already utilized, without CHP from the pulp and paper industry, the burden of EU renewables directive for Latvia is significant, and more onerous than for Estonia and Lithuania.

In terms of heat production, the share of heat produced in CHP plants would increase from 30% in 2000 to 55% in 2025. CHP has a large potential for expansion in all urban areas, and existing plants, as in Riga, are gradually being replaced by newer more efficient ones. A more diverse fuel mix is projected for heat production including wood, natural gas, coal and different types of oil products, mostly shale oil imported from Estonia. Gas will be the main fuel, though biomass, coal and especially peat might also be used. Increased use of wood for heat production would be mainly associated with construction of the CHP plant in the pulp factory. If this project is implemented, it could put a strain on the limited amount of wood resources annually available in Latvia.

With regional integration, the most efficient scenario for Baltic energy system development, from an economic and a security of supply point of view, would be continued operation of Ignalina NPP Unit 2. With this possibility precluded, all available relevant options must be considered: oil shale, natural gas, orimulsion, nuclear, coal, renewable and domestic energy sources, electricity imports. Oil shale has the supply security advantage of being a domestic fuel (in Estonia) but has the disadvantage – along with orimulsion – of having high CO_2 emissions. Given the probable rise in CO_2 emission fees, and a certain rate of resource depletion, investment in oil shale and orimulsion fuelled generating may entail economic risk.

Taking into account anticipated increases in CO_2 fees and fossil fuel prices, the construction of a new reactor unit at the Ignalina site could be a sound alternative at the earliest date possible. Converting the existing Lithuanian thermal plant to orimulsion would provide power to the region in the interim, i.e., during the next 10–15 years. By contrast, the only efficient energy option for the regional mix is combined cycle gas technology, specifically the construction of CCGT CHP plants in big cities (Riga, Tallinn, Vilnius), which can also provide potential markets for waste incineration and biogas/landfill gas plants. Wind and hydro resources will not significantly enhance the security of electricity supply in Latvia or the region as a whole. These options are costly, and require both subsidies and guaranteed market shares, and will be implemented in a least-cost case only in quantities necessary to meet EU requirements.

Electricity prices. The cheapest (and most unlikely) scenario for Latvia is prolonged operation of Ignalina NPP Unit 2, while scenarios with high emission taxes and fuel prices (though much more realistic) are the most expensive. Wholesale electricity prices in Latvia could rise significantly in 2010 with the closure of Ignalina NPP and further in 2015–2020, because of power sector restructuring.

Energy security is a major concern. From a strictly national perspective, dependence on Russia for energy imports is expected to drop slightly and will be replaced with increased dependence on the other Baltic countries. At the same time, the share of Latvia's own resources in the primary energy balance would remain essentially unchanged. Nonetheless, supply security could be enhanced by additional policy measures such as support for development of renewable and domestic resources (peat and perhaps oil), enhanced storage capabilities and diversification of the generation mix to include a coal plant and ancillary facilities in western Latvia.

In the context of regional integration, security of supply for Latvia is best assured by a different set of measures. These would include gas imports and electricity cross-border interconnections (Estlink, Swindlit, Lithuania-Poland, Latvia-Sweden (for power) and: Finland-Estonia (for gas). Fuel diversification would be accomplished on a regional basis, with support for the oil shale industry in Estonia, use of orimulsion in Lithuania, using 50% biomass in the coal plant to be constructed in western Latvia (to reduce CO_2 emissions), and construction of gas and oil storage facilities in Lithuania and Latvia or the construction of a new nuclear power plant at Ignalina. The key conclusion with respect to energy security is that, of the two main options for Latvian power system expansion - self-sufficiency and interdependence - self-sufficiency is preferable from a security of supply point of view, but would be more expensive.

Low cost imports of electricity from Russia have the potential to dominate the market in Latvia, leading to a less secure energy supply and vulnerability to future price increases. However, it is also possible that with prospective interconnections of the Baltic IPS[33] with NORDEL/UCTE, some part of these could be transited to Scandinavia and Central Europe. Such power interconnections should also even out prices across the interconnected regions.

3. Lithuania

Conclusions that can be drawn from this study for Lithuania include the following.

The closing of Ignalina NPP, and replacing that capacity most effectively, are key concerns for Lithuania. From a purely economic point of view, the most rational option for Lithuanian and for the whole Baltic energy system would be continued operation of the 2nd unit of Ignalina NPP until the end of its technical lifetime.

If Ignalina NPP Unit 2 were to be replaced by a new nuclear power plant (at an assumed investment cost 1660 €/kW), study results show different break-even points and different

[33] Baltic Power Systems Control Centre

commissioning dates depending primarily on fuel prices but also on other possible constraints. Construction of such a plant would significantly change energy system costs, operations and development, as well as their distribution among the countries in the region.

In the case of low fuel prices, no greenhouse gas emission constraints and without limitations on gas and orimulsion imports, commissioning of new NPP in Lithuania is economically viable some time after 2020. A 25% constraint on the share of both natural gas and orimulsion in the regional heat and generation mix would shift the commissioning date forward to 2015–2020. Conversely, availability of cheap electricity imports would postpone the commissioning date by some 10 years.

In the case of low fuel prices, replacement of Ignalina's capacity could be done economically through a progression of investments, starting first with using existing and new CHP (including small plants), and modernising Lithuania's thermal power plants. With concerted effort, total installed capacity of CHP could reach 965 MW in 2010, rising to 1730 MW in 2025. A major CHP generator is the Mazeikiai refinery with existing and new (210 MW) units utilizing the refinery's residue, asphaltene. A new CCGT unit at Kaunas CHP would be justified as of 2010, as would a replacement of one unit at Vilnius CHP by a new CCGT CHP unit in 2020, and in 2025 new CCGT units should come into service. In addition, a small part of electricity demand would need to be covered by imported electricity from Estonia and Russia at some times during the study period.

In the case of high fuel prices, commissioning a new nuclear plant at the Ignalina site is economically viable at the soonest point. From a logistic point of view, commissioning a new nuclear unit immediately after closing Ignalina NPP Unit 2 would be ideal but for planning and construction lead times not possible much before 2015. High fuel prices would significantly reduce output from Lithuania's thermal power plants, slow the addition of new CHP capacity and favour electricity imports if available cheaply (possibly from countries with a large share of non-fossil generation or a large domestic fossil resource base).

Security of supply. The future generation mix in Lithuania will depend not only on the relative costs of alternative expansion options and on final energy demand, but also on energy policy options to promote security of energy supply. The Lithuanian study concludes that nuclear power will tend to reduce the diversity of the fuel supply by replacing orimulsion (especially) as well as gas; will reduce utilization of Lithuania's thermal power plants, new CHP and CCGT plants; and will lead to an increase in decentralized heat supply and in the use of boilers for district heat. However, the study also concludes that the possibilities for fuel storage and the technical fuel reliability associated with nuclear power, do contribute to energy supply security.

The diversity of fuel supply in the Baltic region will remain rather high regardless of whether or not a new nuclear plant is built in Lithuania but the share of local resources in primary energy supply will fall from 55% in 2004 to 36% in 2025 without and to 38% with a new NPP. Lithuania and Latvia will be the countries in the region with the highest energy import dependence. Trade-offs among supply security options are highlighted by the choice between building new CCGT units and modernising Lithuania's existing 300 MW thermal units. Both have similar economic efficiency impacts, especially in the case of low fuel prices. However, the CCGT option significantly increases dependence on natural gas, while the modernisation option improves diversity of fuel supply and suppliers as well as fuel price stability, but increases emissions into the atmosphere. Nonetheless, emissions of CO_2, SO_2 and NO_x in the Baltic region, as well as for each country alone, remain below EU limits regardless of whether Lithuania chose the fossil or the nuclear path.

Improved interconnections with neighbouring grids will improve the possibilities for electricity trade. Connection of the Baltic and Scandinavian power systems will also probably provide a transit route for Russian electricity exports to Scandinavian countries. Electricity exports from the Baltic countries are only economic until the closure of Ignalina 2 and for a short period between the modernization of the Estonian oil shale power plants and the time when their full capacity is used for regional needs.

Electricity costs. Average regional marginal costs for electricity through 2025 would rise from some 31–36 €/MWh to 39–43 €/MWh, assuming low fuel prices. Incremental price rises during this period would reflect first the construction of new CHP (till 2020), then a new coal power plant in Latvia, new CHP's in Estonia and finally the replacement of one unit at Vilnius CHP-3. High fuel prices would raise marginal costs as high as 40 €/MWh right after shutdown, 45 €/MWh after 2015 and 46–51 €/MWh by 2020.

As soon as electricity import prices exceed 38 €/MWh for extended periods of time, a new nuclear power plant with levelized generating costs[34] of 35 €/MWh becomes part of the cost-optimal electricity supply mix. The cost-optimal grid connection for such a plant occurs between 2015 and 2020 depending on price assumptions for electricity imports from abroad (Russia, Finland or Poland).

[34] Including interest during construction, decommissioning cost and contribution to a waste management fund.

ANNEX I. MAIN COST PARAMETERS OF ALL THE CASES

Table AI.1. Main cost parameters for calculated scenarios, billion € (discounted)

Scenario	Cost parameters	Aa	Aaa	Aab	Ab	Ea	Ba	Baa	Bb	Ca	Da
1N	Investment cost	2.34									
	Fixed O&M cost	5.31									
	Variable O&M cost*	36.66									
	Region subtotal	44.30									
	Reserve cost	0.26									
	Region total	44.55									
1R	Investment cost	2.16			3.04	2.21	2.36		3.10	2.56	2.38
	Fixed O&M cost	5.19			5.39	5.19	5.47		5.63	5.49	5.45
	Variable O&M cost*	36.19			42.22	36.14	38.31		44.61	38.40	38.43
	Region subtotal	43.54			50.64	43.55	46.14		53.34	46.44	46.26
	Reserve cost	0.24			0.29	0.24	0.27		0.32	0.26	0.27
	Region total	43.78			50.93	43.79	46.41		53.66	46.70	46.53
2R	Investment cost	2.20			2.70	2.27	2.45		2.84	2.32	2.37
	Fixed O&M cost	5.19			5.35	5.19	5.46		5.70	5.42	5.43
	Variable O&M cost*	36.26			42.69	36.18	38.32		44.33	38.58	38.51
	Region subtotal	43.65			50.73	43.64	46.22		52.87	46.31	46.31
	Reserve cost	0.24			0.29	0.24	0.26		0.31	0.25	0.26
	Region total	43.89			51.02	43.88	46.49		53.18	46.56	46.57
3R	Investment cost	2.29		2.37		2.31					
	Fixed O&M cost	5.20		5.20		5.20					
	Variable O&M cost*	36.27		36.28		36.26					
	Region subtotal	43.77		43.86		43.78					
	Reserve cost	0.25		0.25		0.25					
	Region total	44.02		44.11		44.03					
4R	Investment cost	2.22	2.55		3.34	2.57	2.40	2.81	3.10	2.70	2.98
	Fixed O&M cost	5.19	5.27		5.44	5.27	5.47	5.57	5.63	5.52	5.59
	Variable O&M cost*	36.14	36.05		41.91	36.01	38.27	38.03	44.61	38.25	38.02
	Region subtotal	43.56	43.87		50.69	43.85	46.15	46.41	53.34	46.47	46.59
	Reserve cost	0.25	0.25		0.29	0.25	0.27	0.27	0.32	0.26	0.27
	Region total	43.78	44.12		50.98	44.10	46.41	46.68	53.66	46.74	46.86

Table AI.1. Main cost parameters for calculated scenarios, billion € (discounted) (Continued)

Scenario	Cost parameters	Conditions									
		Aa	Aaa	Aab	Ab	Ea	Ba	Baa	Bb	Ca	Da
4Ra	Investment cost	2.25	2.62		3.51		2.47	2.90	3.25		
	Fixed O&M cost	5.20	5.30		5.48		5.48	5.59	5.65		
	Variable O&M cost*	36.18	36.11		41.80		38.24	38.07	44.44		
	Region subtotal	43.62	44.03		50.79		46.19	46.56	53.35		
	Reserve cost	0.25	0.26		0.29		0.27	0.27	0.31		
	Region total	43.88	44.29		51.08		46.46	46.84	53.66		
4Rc	Investment cost	2.17	2.42		3.19		2.36	2.67	3.10		
	Fixed O&M cost	5.19	5.26		5.41		5.47	5.54	5.63		
	Variable O&M cost*	36.18	36.07		42.05		38.31	38.09	44.61		
	Region subtotal	43.54	43.74		50.65		46.14	46.29	53.34		
	Reserve cost	0.24	0.25		0.29		0.27	0.27	0.32		
	Region total	43.78	43.99		50.93		46.41	46.56	53.66		
5R	Investment cost	2.06			3.01	2.11	2.27		2.77	2.34	2.40
	Fixed O&M cost	5.29			5.40	5.29	5.57		5.73	5.59	5.49
	Variable O&M cost*	35.75			42.24	35.70	37.86		44.17	37.96	38.70
	Region subtotal	43.10			50.64	43.11	45.70		52.68	45.89	46.59
	Reserve cost	0.24			0.29	0.24	0.26		0.31	0.26	0.27
	Region total	43.33			50.93	43.34	45.96		52.99	46.15	46.86
6R	Investment cost	3.22			3.44	3.27	3.46		3.68	3.47	3.47
	Fixed O&M cost	5.35			5.47	5.35	5.64		5.73	5.61	5.62
	Variable O&M cost*	35.48			41.89	35.45	37.55		44.07	37.66	37.64
	Region subtotal	44.06			50.80	44.07	46.64		53.48	46.73	46.73
	Reserve cost	0.23			0.28	0.23	0.25		0.31	0.25	0.26
	Region total	44.29			51.08	44.30	46.90		53.79	46.98	46.98
6Ra	Investment cost	3.09			3.33		3.34		3.54		
	Fixed O&M cost	5.32			5.43		5.60		5.70		
	Variable O&M cost*	35.54			41.96		37.61		44.19		
	Region subtotal	43.95			50.72		46.55		53.42		
	Reserve cost	0.23			0.28		0.26		0.31		
	Region total	44.19			51.00		46.81		53.73		

Table AI.1. Main cost parameters for calculated scenarios, billion € (discounted) (Continued)

Scenario	*Cost parameters*	*Conditions*									
		Aa	**Aaa**	**Aab**	**Ab**	**Ea**	**Ba**	**Baa**	**Bb**	**Ca**	**Da**
6Rb	Investment cost	2.25			3.06		2.50		3.06		
	Fixed O&M cost	5.22			5.40		5.50		5.65		
	Variable O&M cost*	36.15			42.23		38.19		44.65		
	Region subtotal	43.61			50.69		46.19		53.36		
	Reserve cost	0.24			0.29		0.26		0.31		
	Region total	43.86			50.98		46.45		53.68		
7Ra	Investment cost	2.21			3.20		2.38		3.37		
	Fixed O&M cost	5.21			5.43		5.42		5.62		
	Variable O&M cost*	38.24			44.06		40.49		46.45		
	Region subtotal	45.66			52.69		48.30		55.44		
	Reserve cost	0.24			0.28		0.26		0.31		
	Region total	45.90			52.98		48.56		55.75		
7Rb	Investment cost	2.30			3.31		2.45		3.49		
	Fixed O&M cost	5.24			5.45		5.39		5.60		
	Variable O&M cost*	40.10			45.93		42.50		48.40		
	Region subtotal	47.65			54.70		50.34		57.49		
	Reserve cost	0.24			0.28		0.26		0.30		
	Region total	47.89			54.98		50.59		57.79		
7R	Investment cost	2.93			3.58	2.82	2.92		3.72	32.31	3.49
	Fixed O&M cost	5.37			5.52	5.17	5.39		5.57	54.52	6.34
	Variable O&M cost*	43.00			49.44	43.29	45.80		52.16	459.33	44.29
	Region subtotal	51.29			58.54	51.29	54.10		61.45	546.17	54.12
	Reserve cost	0.23			0.28	0.22	0.25		0.30	2.48	0.29
	Region total	51.52			58.82	51.51	54.35		61.74	548.65	54.42

* Including fuel cost and taxes

Table AI.2. Main cost parameters for calculated scenarios, billion € (undiscounted)

Scenario	Cost parameters	*Conditions*									
		Aa	**Aaa**	**Aab**	**Ab**	**Ea**	**Ba**	**Baa**	**Bb**	**Ca**	**Da**
1N	Investment cost	11.57									
	Fixed O&M cost	15.75									
	Variable O&M cost*	175.84									
	Region subtotal	203.16									
	Reserve cost	0.52									
	Region total	203.68									
1R	Investment cost	10.74			13.75	11.19	11.35		14.49	11.87	11.59
	Fixed O&M cost	15.30			16.38	15.38	15.56		16.58	15.64	15.44
	Variable O&M cost*	177.30			211.95	176.74	178.95		214.19	179.22	180.02
	Region subtotal	203.34			242.08	203.30	205.86		245.26	206.73	207.05
	Reserve cost	0.50			0.65	0.49	0.54		0.67	0.51	0.54
	Region total	203.84			242.73	203.80	206.40		245.92	207.24	207.59
2R	Investment cost	9.45			11.95	10.00	10.51		12.59	9.76	10.27
	Fixed O&M cost	14.86			15.78	15.00	15.16		16.23	14.78	14.89
	Variable O&M cost*	178.71			214.49	177.94	179.87		214.82	181.01	181.90
	Region subtotal	203.02			242.23	202.94	205.54		243.64	205.55	207.06
	Reserve cost	0.48			0.63	0.48	0.51		0.64	0.49	0.51
	Region total	203.50			242.86	203.43	206.05		244.28	206.04	207.57
3R	Investment cost	12.18		12.41		12.30					
	Fixed O&M cost	15.74		15.72		15.76					
	Variable O&M cost*	176.69		176.65		176.51					
	Region subtotal	204.61		204.79		204.57					
	Reserve cost	0.55		0.55		0.55					
	Region total	205.16		205.34		205.12					
4R	Investment cost	11.45	12.03		13.77	12.24	11.80	12.90	14.49	12.46	13.51
	Fixed O&M cost	15.49	16.06		16.62	16.08	15.65	16.42	16.58	15.88	16.50
	Variable O&M cost*	176.59	174.83		210.80	174.42	178.23	176.28	214.19	178.11	176.43
	Region subtotal	203.53	202.92		241.19	202.75	205.68	205.60	245.26	206.44	206.44
	Reserve cost	0.52	0.50		0.65	0.49	0.53	0.52	0.67	0.51	0.52
	Region total	203.68	203.42		241.84	203.25	206.21	206.12	245.92	206.95	206.96

Table AI.2. Main cost parameters for calculated scenarios, billion € (undiscounted) (Continued)

Scenario	Cost parameters	Conditions									
		Aa	Aaa	Aab	Ab	Ea	Ba	Baa	Bb	Ca	Da
4Ra	Investment cost	11.78	12.43		14.28		12.47	13.45	14.67		
	Fixed O&M cost	15.67	16.23		16.90		15.88	16.62	16.64		
	Variable O&M cost*	176.47	174.62		209.81		177.72	176.14	213.83		
	Region subtotal	203.93	203.27		240.99		206.08	206.21	245.14		
	Reserve cost	0.53	0.50		0.64		0.53	0.51	0.67		
	Region total	204.46	203.77		241.63		206.61	206.73	245.81		
4Rc	Investment cost	10.89	11.46		13.82		11.35	12.55	14.49		
	Fixed O&M cost	15.33	15.80		16.48		15.56	16.13	16.58		
	Variable O&M cost*	177.12	175.12		211.34		178.95	177.15	214.19		
	Region subtotal	203.34	202.38		241.63		205.86	205.83	245.26		
	Reserve cost	0.50	0.50		0.65		0.54	0.52	0.67		
	Region total	203.84	202.88		242.28		206.40	206.35	245.92		
5R	Investment cost	10.50			13.72	10.96	11.24		14.15	11.44	11.59
	Fixed O&M cost	15.63			16.40	15.70	15.87		16.84	15.96	15.44
	Variable O&M cost*	176.21			212.01	175.65	177.86		213.07	178.16	180.01
	Region subtotal	202.34			242.13	202.30	204.97		244.07	205.57	207.05
	Reserve cost	0.50			0.65	0.49	0.53		0.67	0.51	0.54
	Region total	202.84			242.78	202.80	205.50		244.74	206.08	207.59
6R	Investment cost	12.40			13.19	12.80	13.29		14.16	12.89	13.46
	Fixed O&M cost	16.37			16.70	16.43	16.63		16.88	16.33	16.50
	Variable O&M cost*	173.19			211.50	172.80	174.96		213.36	175.56	176.01
	Region subtotal	201.96			241.39	202.03	204.88		244.40	204.78	205.96
	Reserve cost	0.49			0.65	0.49	0.52		0.67	0.51	0.53
	Region total	202.45			242.04	202.53	205.40		245.07	205.29	206.49
6Ra	Investment cost	12.34			13.11		13.29		13.91		
	Fixed O&M cost	16.13			16.48		16.42		16.64		
	Variable O&M cost*	173.06			211.87		175.41		214.14		
	Region subtotal	201.52			241.47		205.13		244.69		
	Reserve cost	0.49			0.65		0.52		0.68		
	Region total	202.02			242.12		205.65		245.37		

Table AI.2. Main cost parameters for calculated scenarios, billion € (undiscounted) (Continued)

Scenario	**Cost parameters**	*Conditions*									
		Aa	**Aaa**	**Aab**	**Ab**	**Ea**	**Ba**	**Baa**	**Bb**	**Ca**	**Da**
6Rb	Investment cost	10.71			13.87		11.52		14.49		
	Fixed O&M cost	15.42			16.49		15.68		16.67		
	Variable O&M cost*	176.59			211.94		178.64		214.06		
	Region subtotal	202.72			242.30		205.84		245.22		
	Reserve cost	0.49			0.64		0.53		0.66		
	Region total	203.21			242.94		206.37		245.88		
7Ra	Investment cost	11.09			13.92		11.84		14.98		
	Fixed O&M cost	15.33			16.45		15.58		16.69		
	Variable O&M cost*	189.56			223.33		192.24		226.37		
	Region subtotal	215.98			253.71		219.66		258.05		
	Reserve cost	0.48			0.63		0.52		0.64		
	Region total	216.46			254.33		220.18		258.69		
7Rb	Investment cost	11.66			14.06		12.51		15.23		
	Fixed O&M cost	15.55			16.51		15.67		16.79		
	Variable O&M cost*	200.39			234.55		204.45		238.42		
	Region subtotal	227.60			265.12		232.63		270.44		
	Reserve cost	0.48			0.62		0.51		0.64		
	Region total	228.08			265.74		233.14		271.08		
7R	Investment cost	12.49			14.66	12.49	13.85		15.71	13.89	14.35
	Fixed O&M cost	16.03			16.87	16.03	16.14		17.13	16.31	16.20
	Variable O&M cost*	218.89			254.91	222.29	225.42		261.72	223.68	180.45
	Region subtotal	247.41			286.44	250.81	255.42		294.55	253.88	211.00
	Reserve cost	0.48			0.60	0.48	0.50		0.64	0.50	0.50
	Region total	247.89			287.04	251.29	255.91		295.19	254.38	211.50

* Including fuel cost and taxes

ANNEX II. NOT DISCOUNTED COST OF ENERGY SYSTEM

Table AII.1. Not discounted cost of energy system operation and development. Scenario 1R(Aa), M€

Cost	2000-2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2035	2036-2045	Total 2000-2025	Total 2000-2035	Total 2000-2045
Estonia										
Investment cost	373	486	784	281	844	571	0	2768	3339	3339
Fixed O&M cost	1191	1053	751	588	482	981	864	4066	5046	5911
Variable O&M cost[35]	2181	2236	2257	2786	3626	9455	7129	13086	22540	29670
Estonia subtotal	3745	3775	3791	3656	4952	11007	7994	19919	30926	38919
Reserve cost	50	26	4	4	10	2	0	93	95	95
Estonia total	3795	3800	3795	3660	4962	11008	7994	20012	31021	39014
Latvia										
Investment cost	79	767	155	547	504	1605	0	2051	3656	3656
Fixed O&M cost	1101	808	620	503	438	925	873	3471	4396	5269
Variable O&M cost[1]	3071	2427	3224	3668	4166	8847	7359	16555	25402	32760
Latvia subtotal	4250	4002	3999	4718	5107	11378	8232	22076	33454	41685
Reserve cost	81	43	17	14	32	13	0	186	200	200
Latvia total	4331	4045	4016	4732	5139	11391	8232	22263	33653	41885
Lithuania										
Investment cost	254	835	174	110	532	1843	0	1906	3748	3748
Fixed O&M cost	1156	590	412	370	330	624	641	2860	3484	4125
Variable O&M cost[1]	9820	10233	11252	12473	13631	29305	28153	57408	86713	114866
Lithuania subtotal	11230	11658	11839	12953	14493	31772	28794	62173	93945	122739
Reserve cost	102	82	18	21	10	-30	0	233	203	203
Lithuania total	11333	11740	11856	12975	14503	31742	28794	62406	94148	122942
Baltic region										
Investment cost	706	2088	1113	938	1880	4019	0	6724	10744	10744
Fixed O&M cost	3448	2452	1784	1462	1250	2530	2378	10396	12926	15304
Variable O&M cost[1]	15071	14895	16732	18927	21423	47607	42641	87048	134655	177296
Baltic region subtotal	19226	19434	19629	21327	24553	54156	45019	104168	158325	203344
Reserve cost	233	151	38	39	51	-15	0	513	498	498
Baltic region total	19459	19585	19667	21366	24604	54141	45019	104681	158822	203842

[35] Including fuel cost and emission taxes

Table AII.2. Not discounted cost of energy system operation and development. Scenario 1N(Aa), M€

Cost	2000-2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2035	2036-2045	Total 2000-2025	Total 2000-2035	Total 2000-2045
Estonia										
Investment cost	373	334	802	534	699	538	0	2742	3280	3280
Fixed O&M cost	1191	1048	726	555	496	990	880	4018	5008	5888
Variable O&M cost[36]	3320	2924	3431	3885	4446	10179	9352	18006	28185	37537
Estonia subtotal	4884	4306	4960	4974	5641	11708	10231	24766	36473	46705
Reserve cost	50	26	4	4	9	0	0	93	93	93
Estonia total	4934	4332	4963	4978	5650	11707	10231	24859	36566	46797
Latvia										
Investment cost	101	772	518	396	1169	1916	0	2955	4871	4871
Fixed O&M cost	1095	811	639	556	502	1099	1050	3603	4702	5752
Variable O&M cost[1]	5205	5105	5696	6682	7763	17065	15735	30451	47516	63251
Latvia subtotal	6401	6688	6853	7633	9434	20080	16785	37009	57089	73874
Reserve cost	81	47	15	29	38	25	0	210	235	235
Latvia total	6482	6735	6868	7662	9472	20105	16785	37219	57323	74108
Lithuania										
Investment cost	263	849	178	102	491	1534	0	1884	3418	3418
Fixed O&M cost	1156	598	424	382	341	623	587	2901	3524	4111
Variable O&M cost[1]	6680	6705	7470	8176	8963	19522	17538	37994	57516	75054
Lithuania subtotal	8100	8153	8072	8660	9795	21679	18124	42779	64458	82582
Reserve cost	104	90	18	9	20	-53	0	241	189	189
Lithuania total	8204	8243	8090	8669	9814	21626	18124	43020	64647	82771
Baltic region										
Investment cost	737	1955	1498	1032	2359	3988	0	7581	11569	11569
Fixed O&M cost	3443	2458	1789	1493	1339	2712	2516	10521	13234	15750
Variable O&M cost[1]	15206	14735	16597	18742	21172	46767	42624	86451	133217	175841
Baltic region subtotal	19385	19148	19884	21267	24870	53467	45140	104554	158020	203161
Reserve cost	235	162	37	42	67	-28	0	544	516	516
Baltic region total	19620	19310	19921	21310	24937	53439	45140	105097	158536	203676

[36] Including fuel cost and emission taxes

Table AII.3. Difference of undiscounted cost between scenarios 6Ra(Aa) and 1R(Aa), M€

Parameter	2000-2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2035	2036-2045	Total 2000-2035	Total 2000-2045
Estonia									
Investment cost	0	-102	-51	121	-422	238	0	-215	-215
Fixed O&M cost	0	-3	-14	-17	-6	-53	-1	-93	-95
Variable O&M cost[37]	6	-52	-169	-183	-298	-1962	-152	-2658	-2810
Reserve cost	0	0	0	0	-2	1	0	-1	-1
Estonia total	6	-157	-235	-78	-729	-1775	-153	-2968	-3121
Latvia									
Investment cost	1	-82	18	-285	381	4	0	37	37
Fixed O&M cost	0	0	-4	-13	-36	1	-20	-52	-72
Variable O&M cost[1]	0	19	-26	-40	-186	-401	-327	-633	-960
Reserve cost	0	1	0	-1	1	0	0	0	0
Latvia total	1	-62	-12	-339	160	-396	-347	-648	-995
Lithuania									
Investment cost	-59	2838	-57	105	-81	-973	0	1773	1773
Fixed O&M cost	-1	30	167	169	174	323	129	862	991
Variable O&M cost[1]	-1	-127	-419	-386	-95	1006	-446	-22	-469
Reserve cost	0	-30	2	11	18	-6	0	-3	-3
Lithuania total	-60	2711	-307	-100	16	349	-317	2609	2292
Baltic region									
Investment cost	-58	2654	-90	-58	-122	-731	0	1595	1595
Fixed O&M cost	-1	27	148	139	132	271	108	716	824
Variable O&M cost[1]	5	-160	-614	-608	-579	-1357	-925	-3313	-4238
Baltic region subtotal	-53	2520	-555	-527	-569	-1818	-817	-1002	-1819
Reserve cost	0	-29	2	10	17	-5	0	-5	-5
Baltic region total	-53	2491	-553	-517	-552	-1822	-817	-1007	-1824

[37] Including fuel cost and emission taxes

REFERENCES

[1] EUROPEAN COMMISSION Activities of the European Union, Summaries of Legislations, Energy: http://europa.eu.int/scadplus/leg/en/s14000.htm, European Commission, Brussels (2004).

[2] INTERNATIONAL ATOMIC ENERGY AGENCY Energy Supply Options for Lithuania. A Detailed Multi-sector Integrated Energy Demand, Supply and Environmental Analysis. IAEA-TECDOC-1408, IAEA, Vienna (2004).

[3] LITHUANIAN ENERGY INSTITUTE National Energy Strategy. Lithuanian Energy Institute, Kaunas (2002).

[4] LITHUANIAN ENERGY INSTITUTE Preparation of national energy strategy implementation, integration into West European gas network, increase of reliability of gas supply. Interim report. Lithuanian Energy Institute, Kaunas (2002).

[5] DEPARTMENT OF STATISTICS Statistical yearbook of Lithuania. Department of Statistics, Vilnius (2004).

[6] DEPARTMENT OF STATISTICS Foreign direct investment in Lithuania. Department of Statistics, Vilnius (2002).

[7] DEPARTMENT OF STATISTICS Energy balance 2001. Department of Statistics, Vilnius (2002).

[8] DEPARTMENT OF STATISTICS Energy balance in 1990–2003. Department of Statistics, Vilnius (2004).

[9] LITHUANIAN ENERGY INSTITUTE Preparation of national energy strategy. Draft report. Lithuanian Energy Institute, Kaunas (2002).

[10] JUSKA, A. AND MISKINIS, V. Energy in Lithuania 2003. Lithuanian Energy Institute, Kaunas (2004).

[11] LITHUANIAN ENERGY INSTITUTE Proposals for implementation of European council directives 88/609/EEC on the limitation of emissions of certain pollutants into the air from large combustion plants and 1999/32/EC on reduction in the sulphur content of heavy fuel oil to 1%. LEI report. Lithuanian Energy Institute, Kaunas (2002).

[12] INTERNATIONAL ENERGY AGENCY. Energy balances of OECD countries 2000-2001. International Energy Agency, Paris (2003).

[13] MINISTRY OF ECONOMY. National Energy Strategy. Ministry of Economy, Vilnius (2002).

[14] MINISTRY OF ECONOMY. Amendment of resolution on approval of legal acts necessary for implementation of the Law on Electricity. Official Gazette, No. 9-228, Vilnius (2004).

[15] STATISTICAL OFFICE OF ESTONIA Forecast of Population in Estonia. Statistical Office of Estonia, Tallinn (2001).

[16] OFFICE OF THE MINISTER OF POPULATION Forecast of Population in Estonia. Office of the Minister of Population, Tallinn (2001).

[17] UNITED NATIONS POPULATION DIVISION. World Population Prospects. 2002 Revision, New York (2002).

[18] MINISTRY OF FINANCE. Long term Forecast of Economic Development in Estonia, Tallinn (2004).

[19] GOVERNMENT OF ESTONIA. Action Plan for Energy Conservation Target Programme of Estonia. Government of Estonia, Tallinn (2001).

[20] MINISTRY OF ECONOMIC AFFAIRS AND COMMUNICATIONS Long term National Development Plan for the Fuel and Energy Sector in Estonia. Ministry of Economic Affairs and Communications, Tallin (1998).

[21] ESTONIAN INSTITUTE OF ECONOMICS AT TUT Development Plan for Estonia's Electricity Sector, TUT-EERI, Tallin (2002).

[22] EGLITE, P. (Ed.) Population of Latvia: Distribution and Change of it in the First Quarter of the XXI Century. Institute of Economics, Riga (2003).
[23] MINISTRY OF ECONOMICS. Economic development of Latvia. Ministry of Economics,Republic of Latvia, Riga. Internet site: http://www.em.gov.lv/em/2nd/?cat=137,(2004).
[24] MINISTRY OF ECONOMICS. Long term Economic Strategy of Latvia. Ministry of Economics, Republic of Latvia, Riga (2001).
[25] INTERNATIONAL ENERGY AGENCY. Energy Statistics of OECD countries 2001–2002, IEA, Paris (2004).
[26] MINISTRY OF ENVIRONMENT Climate Change Mitigation Policy Plan for Latvia. Ministry of Environment, Riga (2004).
[27] STATISTICS LITHUANIA. Population projections of Lithuania, 2005–2030. Statistics Lithuania, Vilnius (2004).
[28] INTERNATIONAL ATOMIC ENERGY AGENCY. Model for Analysis of the Energy Demand (MAED), Vienna (2002).
[29] MINISTRY OF ECONOMY. National Energy Efficiency Program for Lithuania. Ministry of Economy, Vilnius (2001).
[30] COUNCIL OF THE EUROPEAN UNION. Council Directive 2003/96/EC of 27 October 2003 restructuring the EC framework for the taxation of energy products and electricity. Official Journal of the European Union, 2003-10-31, pp 51-70.
[31] COUNCIL OF THE EUROPEAN UNION. Council Directive 2004/74/EC of 29 April 2004 amending Directive 2003/96/EC as regards the possibility for certain Member States to apply, in respect of energy products and electricity, temporary exemptions or reductions in the levels of taxation. Official Journal of the European Union, pp. 26-30 (2004).
[32] INTERNATIONAL ENERGY AGENCY. Energy Prices and Taxes. IEA, Paris (1996 … 2003).
[33] LITHUANIAN ENERGY INSTITUTE. Analysis of Lithuanian electricity market (supply and demand) taking into consideration the more local impact of all Baltic region and tendencies in demographics and demand growth. Report S1/31-579.4.4. Lithuanian Energy Institute, Kaunas (2004).
[34] MOHRBACH, L. Requirements for an EU Electricity Roadmap, A Utilities View. VGB PowerTech, EURELECTRIC, WG ‘Nuclear’, Essen (2004).
[35] GAIDAMAKA, A. Opportunities in natural gas sector for independents in Russia. Lukoil, Russian gas and power, Moscow (2002).
[36] DEPARTMENT OF ENERGY. International Energy Outlook 2004. DOE/EIA-0484(2004). Washington, D.C. (2004).
[37] GLOBAL INSIGHT INC. Global Petroleum Outlook, Winter 2003–2004. Global Insight Inc., Lexington (2004).
[38] DEUTSCHE BANK AG. World Oil Supply and Demand Estimates. Deutsche Bank AG, Frankfurt am Main (2004).
[39] NATIONAL PETROLEUM COUNCIL. Assumptions for the NPC Natural Gas Study. National Petroleum Council, Washington, D.C. (2003).
[40] STRATEGIC ENERGY & ECONOMIC RESEARCH INC. 2003 Energy Outlook. Strategic Energy & Economic Research Inc., Winchester (2003).
[41] INTERNATIONAL ENERGY AGENCY. World Energy Outlook 2002. IEA, Paris (2002).
[42] EUROPEAN COMMISSION. European Energy and Transport Scenarios on Key Drivers. European Commission Directorate-General for Energy and Transport, Brussels (2004).
[43] SILTUMELEKTROPROJEKTS. Priekšlikumi Rīgas TEC-1 esošo ģenerējošo jaudu aizvietošanai (Proposals for Replacement of Existing Generating Capacity at Rīga CHP-1), Siltumelektroprojekts, Riga (1995).

[44] SILTUMELEKTROPROJEKTS. Konceptuālie piedāvājumi Rīgas TEC-1 rehabilitācijai (Conceptual Proposals for the Rehabilitation of Rīga CHP-1), Siltumelektroprojekts, Riga (1997).
[45] SILTUMELEKTROPROJEKTS. Tehniski-ekonomiskie priekšlikumi Rīgas TEC-1 atjaunošanas un esošo ģenerējošo jaudu aizvietošanas projektam. Biznesa plāns (Technical–Economic Proposals for the Project of the Rehabilitation of Riga TPP-1 and the Replacement of the Existing Generating Capacities), Siltumelektroprojekts, Riga (2000).
[46] FVB DISTRICT ENERGY. Profitability Appraisal of Riga TPP-1 Rehabilitation and Replacement of Existing Generation Capacities, FVB District Energy, Västerås (2000).
[47] BURNS AND ROE COMPANY. TEC-2 Power Plant Rehabilitation Study, Burns and Roe Company, Oradell, NJ (1994).
[48] SILTUMELEKTROPROJEKTS. Koncepcija un pirms projekta studija Rīgas TEC-2 attīstībai (Concept and Pre-feasibility Study for the Development of Riga CHP-2), Siltumelektroprojekts, Riga (1997).
[49] SILTUMELEKTROPROJEKTS. Business Plan for Reconstruction of Riga CHP-2, Siltumelektroprojekts, Riga (2003).
[50] ENPRIMA OY. Riga TPP-2 CCGT Plant Concept Review, Enprima Oy, Stockholm (2004).
[51] WESTINGHOUSE ELECTRIC CORPORATION. Feasibility Study for the 300 MW Liepaja Thermal Power Plant by Burns and Roe Company, Westinghouse Electric Corporation, Monroeville, PA (1994).
[52] PREUSSEN ELEKTRA. Kraftwerksprojek Liepaja (Lettland), Preussen Elektra, Hannover (1994).
[53] BURNS AND ROE COMPANY. Dual Fuel Study for the Liepaja Thermal Power Plant (prepared for Latvenergo & Ministry of Economy of Latvia) by Burns and Roe Company, Oradell, NJ (1996).
[54] DEUTSCHE BABCOCK & NYKOMB SYNERGETICS BV. Construction of New 300 MW IGCC Power Plant in the City of Liepaja, Noell KRC GmbH, Deutsche Babcock & Nykomb Synergetics BV, Oberhausen (1999).
[55] SILTUMELEKTROPROJEKTS. Liepājas ogļu elektrostacijas celtniecības projekts. Būvlaukuma izvēle (Feasibility Study for the Construction of Coal Power Plant in the City of Liepaja), Siltumelektroprojekts, Riga (2004)
[56] SILTUMELEKTROPROJEKTS. Ventspils ogļu elektrostacijas būvlaukuma izvēle (Feasibility Study for the Construction of Coal Power Plant in the City of Ventspils), Siltumelektroprojekts, Riga (under development).
[57] BALTREL AND BALTIC GAS. Gas and Electricity in the Baltic Sea Region, joint study. Baltrel and Baltic Gas, Riga (2001).
[58] COLENCO. Study on the Thermal Treatment of Municipal Waste of Riga City, Colenco (ordered by Latvenergo), Baden, Switzerland (2005).
[59] EASTLINK LANKER. Firing of Orimulsion at the Vilnius Combined Heat and Power Plant, Unit 3. Feasibility Study. Eastlink Lanker, London (2001).
[60] ALSTOM COMBUSTION SERVICES LIMITED. Proposal for Electrenai Power Station, Low NOx Burners and FGD Plant. Budget proposal, Alstom Combustion Services, Derby (2002).
[61] ERM. Update of the Least Cost Plan for Lithuania, Draft final report, ERM and IPA, Edinburgh (2002).
[62] ELKRAFT SYSTEM. Technology Data for Electricity and Heat Generating Plants, Danish Energy Authority, Elkraft System, Ballerup (2004).
[63] FRAMATOME ANP. Construction of the New Nuclear Power Plant on Ignalina Site in Lithuania. Feasibility Study, Final Report, Framatome ANP, Erlangen (2004).
[64] KAUNAS UNIVERSITY OF TECHNOLOGY. Study of continuation of nuclear power in Lithuania. Report. Kaunas University of Technology, Kaunas (2004).

[65] V. JARIN. Comments to proposals of Framatome ANP. Kaunas University of Technology, Kaunas (2004).
[66] MASSERON, J. Petroleum Economics, Editions Technique, Paris, p. 519 (1990).
[67] LITHUANIAN ENERGY INSTITUTE Environmental Requirements to the Energy Sector, Report, Cowi, LEI, EPC (2002).
[68] LITHUANIAN ENERGY INSTITUTE Forecast of remaining gap between fuel channels and graphite in reactor of the first unit and forecast of gap changes in reactor of Unit 2. Final report. LEI, Kaunas (2001).
[69] LITHUANIAN ENERGY INSTITUTE Safety analysis report for Unit 2 of the Ignalina NPP. Task 2. Analysis of equipment aging and management program. Report PTOab-0345-72B1.

CONTRIBUTORS TO DRAFTING AND REVIEW

Aarna, I.[*]	Eesti Energia AS, Estonia
Andersons, J.[*]	VAS Latvenergo, Latvia
Bader, J.F.[*§]	Expert to NATO, USA
Balodis, M.[*]	VAS Latvenergo, Latvia
Bui, D.-T.	International Atomic Energy Agency
Dravnieks, D.[*§]	Ministry of Economy, Latvia
Galinis, A.[*§]	Lithuanian Energy Institute, Lithuania
Gavars, V.[*]	VAS Latvenergo, Latvia
Jankauskas, A.[*]	AB Lietuvos Energija, Lithuania
Kisel, E.[*§]	Ministry of Economic Affairs and Communications, Estonia
Kizhakkekara, J.	International Atomic Energy Agency
Klāvs, G.[*]	Institute of Physical Energetics, Latvia
Linkevičs, O.[*§]	VAS Latvenergo, Latvia
Miškinis, V.[*§]	Lithuanian Energy Institute, Lithuania
Ōim, F.[*§]	Ministry of Economic Affairs and Communications, Estonia
Piesliakas, E.[*§]	Ministry of Economy, Lithuania
Pihlak, U.[*]	Tallinn University of Technology, Estonia
Ploompuu, P.[*]	Eesti Energia AS, Estonia
Rogner, H.-H.[§]	International Atomic Energy Agency
Rudi, Ű.[*]	Tallinn University of Technology, Estonia
Soosaar, S.[*]	Tallinn University of Technology, Estonia
Strubegger, M.	International Institute for Applied Systems Analysis, Laxenburg, Austria
Stuklis, I.[*]	VAS Latvenergo, Latvia
Sulga, D.[*]	AB Lietuvos Energija, Lithuania
Tarvydas, D.[*]	Lithuanian Energy Institute, Lithuania
Toth, F.L.	International Atomic Energy Agency
Vares, V.[*§]	Tallinn University of Technology, Estonia
Vilemas, J.[*§]	Lithuanian Energy Institute, Lithuania
Weisser, D.	International Atomic Energy Agency
Zlatnansky, J.[§]	International Atomic Energy Agency

[*] Working Group member

[§] Steering Committee member