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THE BALTIC POWER SYSTEM BETWEEN EAST AND WEST INTERCONNECTIONS

FIRST RESULTS FROM A SECURITY ANALYSIS AND INSIGHTS FOR FUTURE WORK

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Abstract
Due to historical and geographical reasons, the Baltic States are strongly connected to the power (electricity) transmission grids of Russia and Belarus. Current energy security and energy independence targets in the EU trigger seeking for alternative power sources for the Baltic.

Knowing that, a power system model of the Baltic States has been developed and validated with the purpose of providing comparative options for a reliable and secure development of the Baltic electricity system. The analysis of horizon 2020 and 2030 showed that the dependency of Baltic States on the outside resources is fairly low, provided that the expansion of the electricity system goes as planned.

Title: The Baltic Power System between East and West Interconnections

- The Baltic States are strongly connected to the electricity transmission grids in Russia and Belarus
- The current policy activities are focused on secure energy supply alternatives
- To support these activities a Baltic power system model has been developed
- The power model can serve as a tool for techno-economic power system analysis
- Dependency of the Baltic States on outside resources has been found to be fairly low in 2020/30

Table of contents

Executive summary

Policy context

The energy policy of the Baltic States is integrated in the energy strategy of the European Union (EU) and aims at pursuing three major objectives: competitiveness, sustainable development and security. All the three Baltic power systems are working to fulfil the planned EU technical requirements and to adopt the European regulations, codes and standards, e.g. from the European Network of the Transmission System Operators for Electricity (ENTSO-E), and from the European Committee for Electrotechnical Standardization (CENELEC).

The integration of the Baltic States into the EU energy market has been identified as a strategic priority for all three countries. The main goal of the Baltic Energy Market Interconnection Plan (BEMIP) is to create a Baltic Sea region unified market. The current implementation of a joint wholesale electricity market for the entire Baltic States is the driving force for the energy market development in the Baltic States.

The power systems of Estonia, Latvia and Lithuania (Baltic Integrated Power System) are currently operated - as a synchronous grid - in parallel with the Integrated/Unified Power System (IPS/UPS) of Russia and Belarus. The Baltic power systems still lack adequate electricity connections, both between themselves and to other parts of the EU. However, the situation is improving: recently, the Estlink 1 and 2 connections between Estonia and Finland, the LitPol Link connection between Lithuania and Poland and the Nordbalt connection between Sweden and Lithuania have considerably raised the transfer capacity between the Baltic and the EU electricity markets.

Key conclusions

A power system model of the Baltic States has been developed with the purpose of assessing comparative options for a reliable and secure development of the region's electricity system. The model consists of buses with voltage of 110 kV and higher, mainly 110 kV, 220 kV and 330 kV. The 35 kV undersea cables connecting the Estonian mainland and the north-western islands were also included. The model has been calibrated based on the 2014 reference scenario to match the historical records from ENTSO-E.

The cross-border power flows in the Baltic model are close to the recorded ENTSO-E data in winter off-peak load and summer peak load scenarios. Two additional scenarios (winter peak load and summer off-peak load) were examined. Line loading and voltage levels within the Baltic States are within the acceptable range in all 2014 reference scenarios. The Baltic States usually exported electricity to mainland Russia but imported from Kaliningrad and Belarus. From the perspective of the Baltics, the dependence on Russia is fairly low in terms of electric power.

Lithuania’s network infrastructure is adequate and can sustain large quantity of imports. The hydro pump station is important for the shifting of generation resources, and thus plays a key role in reducing the system marginal cost.

The Latvian power system exploits considerable market advantages due to the high ratio of renewable energy - mainly hydro - in its electricity generation mix. In the reference scenario Latvia is a net exporter. However, the network seems not as adequate as that of Lithuania. Sometimes, congestion can cause the increase of the system marginal cost.

The Estonian network may occasionally experience lower voltages compared with the other two Baltic State power systems, especially when the Estlinks (interconnecting Estonia with Finland) are under heavy load conditions. Reactive compensations may be needed, particularly around the area of Tallinn. Even though the installed wind turbine capacity is the highest among the three Baltic States, this is still not enough to give Estonia the same strategic market position as Latvia.

The analysis of the horizons 2020 and 2030 showed that the dependency of the Baltic States on foreign electricity production is fairly low, provided that the expansion of generation resources goes ahead as planned.

The cross-border transmission corridors inside the Baltic States are sufficient to sustain the electricity consumption patterns assumed in the scenarios considered; however, the internal network projects should be fostered to remove congestion, especially in the northern part of Estonia and the area South-West of Riga.

Main findings

First security analyses were carried out, based upon the aforementioned input data, modelling and scenario assumptions, to identify the most critical contingencies for the Baltic power system.

The most critical contingencies for the 2030 scenario with and without the nuclear generator in Visaginas (Lithuania) are listed in the two tables below. Each table quantifies contingencies for four sub-scenarios (cases): (i) winter off-peak, (ii) winter peak, (iii) summer off-peak, and (iv) summer peak.

Additional analyses are expected to be carried out, in cooperation with the relevant stakeholders, to complement these studies and to combine the modelling efforts towards attaining an integrated overview of the Baltic power and market operation and development challenges.

Without Visaginas reactor

Cases	Contingency component	Most severe consequence	Violations	Unserved loads (MW)	Disconnected generation (MW)	Maximum overload (%)	Minimum Voltage (p.u.)
Winter off-peak	contingency 18	Disc. Gen.	0	0	13.83	-	-
	contingency 2	Num. violations	45	0	0	115	0.867
	contingency 11	Low voltage	6	0	0	-	0.799
	contingency 5	Uns. loads	0	16.07	0	-	-
	contingency 3	Overload	36	0	0	236	0.817
Winter peak	contingency 2	Num. violations	34	0	0	142.7	0.811
	contingency 9	Overload	3	0	0	161.2	-
	contingency 11	Low voltage	9	0	0	102.5	0.593
	contingency 5	Uns. Loads	0	25.61	0	-	-
	contingency 18	Disc. Gen.	0	0	23.91	-	-
Summer off-peak	contingency 14	Overload	2	0	0	150.5	-
	contingency 12	Disc. Gen.	0	0	13.33	-	-
	contingency 5	Uns. loads	0	13.72	0	-	-
Summer peak	contingency 3	Overload	37	0	0	242.7	0.808
	contingency 18	Disc. Gen.	0	0	14.29	-	-
	contingency 11	Low voltage	9	0	0	-	0.783
	contingency 5	Uns. loads	0	22.37	0	-	-
	contingency 2	Num. violations	51	0	0	118.6	0.861

With Visaginas reactor

Cases	Contingency component	Most severe consequence	Violations	Unserved loads (MW)	Disconnected generation (MW)	Maximum overload (%)	Minimum Voltage (p.u.)
Winter off-peak	contingency 16	Disc. Gen.	0	0	928.2	-	-
	contingency 2	Num. violations	45	0	0	115	0.868
	contingency 11	Low voltage	6	0	0	-	0.799
	contingency 5	Uns. loads	0	16.07	0	-	-
	contingency 3	Overload	36	0	0	236	0.817
Winter peak	contingency 2	Num. violations	35	0	0	142.9	0.811
	contingency 9	Overload	4	0	0	161.2	-
	contingency 11	Low voltage	9	0	0	102	0.59
	contingency 5	Uns. Loads	0	25.61	0	-	-
	contingency 16	Disc. Gen.	0	0	1286.22	-	-
Summer off-peak	contingency 14	Overload	2	0	0	150.5	-
	contingency 16	Disc. Gen.	1	0	928.2	115.2	-
	contingency 5	Uns. loads	0	13.72	0	-	-
Summer peak	contingency 3	Overload	37	0	0	243.8	0.808
	contingency 16	Disc. Gen.	0	0	928.2	-	-
	contingency 11	Low voltage	8	0	0	-	0.786
	contingency 5	Uns. loads	0	22.37	0	-	-
	contingency 2	Num. violations	50	0	0	119.1	0.861

Related and future JRC work

The Joint Research Centre, as European Commission's in-house science service, performs independent scientific research and support EU policy-making on transformations towards secure, smarter and interoperable electricity systems.

To this aim, we continuously develop models, methodologies and carry out experimental work to understand the evolution of the European transmission and distribution grids towards super and smart grid concepts (a complete overview is available on the website: http://ses.jrc.ec.europa.eu/).

As an example, we recently thoroughly assessed the need for investment in electricity interconnectors in Europe between 2010 and 2025, and the impact of cross-border transmission capacity on curtailment needs for RES, on hydro storage utilisation and on security of supply (in terms of energy not served). [1]

The preliminary techno-economic analyses in the current report pave the ground for more detailed market analyses, expected to be conducted with tailored market/power dispatch tools to support electricity system development policies and initiatives in the Baltic States. Different geo-political options and scenarios for higher security of energy supply and energy independence are in the process of being defined and assessed with the relevant actors, particularly in the BEMIP context.

Quick guide

One common goal of the Baltic States is greater energy supply independence through the diversification of primary energy sources. Due to the countries' limited ability to act on their own – especially on large, costly projects – joint efforts are needed.

The present report gives an insight in the ability of the Baltic States to operate their electricity systems independently of the neighbouring countries. The results show that by 2020 and 2030 the dependency of the Baltic States on the outside generation resources is fairly low, following current electricity system development trends.

1. Introduction

The interconnection of the power systems of Estonia, Latvia and Lithuania (Baltic Integrated Power System, BIPS) operates as a synchronous Alternating Current (AC) grid in parallel with the Integrated/Unified Power System (IPS/UPS) of Russia and Belarus. This is performed via a ring created in the early sixties of the last century by interconnecting the power systems of the western part of the former Soviet Union: the Baltic States (Latvia, Lithuania, and Estonia), north-western Russia, Central Russia and Belarus. The Russian power system provides primary power reserves for the frequency regulation to the whole system.

The backbone of the BIPS is formed by 330 kV high-voltage power lines. There are 58 high-voltage transmission lines with a total length of 4137 km, and 32 substations equipped with 54 autotransformers (347/242kV, 330/115kV) with a total capacity of 8665 MVA. The regional transmission network of the Baltic IPS consists primarily of 110 kV lines, with the exception of the Estonian power system, where 220 kV lines are also present.

The electricity systems of the Baltic States are tightly interconnected and integrated into the BRELL (Belarus, Russia, Estonia, Latvia, and Lithuania), that operates synchronously with the UPS/IPS zone. The transmission lines feature voltages spanning from 110 kV to 330 kV and stretch over more than 17000 km. Jointly with the neighbouring electrical networks of Russia and Belarus, the electrical networks of Estonia, Latvia and Lithuania form the "Baltic Ring", consisting of 330 and 750 kV lines. The 750 kV lines in the integrated power system are generally operated as antenna connections (open-loop).

The operation of the Baltic Ring was based on the guidelines shared by the ten power systems of north-western Soviet Union (Kola, Karelia, Leningrad, Novgorod, Pskov, Estonia, Latvia, Lithuania, Kaliningrad and Belarus), and proved effective to ensure high reliability [2]. The 330 kV lines are equipped with fast relays and single-phase auto-reclosers (providing restoration within one second in 80% of single-phase non-permanent faults). Various emergency control schemes allow for the temporary increase of the line flow limits of the ring's 330 kV lines in case of emergency. The generation reserve is provided by automatic run-up (or halt) pumping stations; predefined plans for reducing demand by curtailing/disconnecting electricity consumers are also in place. Each system in the ring represents an autonomous section, characterised by certain values for maximum power transfer capability to other sections according to the rated voltage, the number, the length and the protection schemes of the transmission lines. From the stability point of view, a characteristic feature of the closed electrical ring is that the stability break (i.e. opening of the BRELL ring without compromising electricity system stability) is possible only in two electrical sections together. Electrical sections can be mutually variable, meaning that they may feature several combinations, for example: Leningrad – Estonia and Smolensk – Belarus, or Estonia – Latvia and Smolensk – Belarus, etc. The base for combination is the place of origin of the fault with active power flow limitation, provided that, in two corresponding electrical sections, the overall power flow reaches the maximum permissible level according to the steady state stability criterion. Of course, the advantages of the electrical ring are also visible here, because the transfer capacities fulfilling the steady state and transient stability criteria for the sum of two electrical sections are always higher compared to the corresponding transfer capacity values for one electrical section taken in isolation.

Developing emergency control schemes challenge the operation principles of the electrical ring. One should therefore consider that, based on their administrative division, the power systems of the electrical ring belong to different independent sovereign countries: Estonia, Latvia, Lithuania, Belarus and the Russian Federation. The main task in this issue can be, cooperating in a global scale, to secure power system parallel operation in all cases, so that the compliance with the steady state and transient stability criteria does not require breaking the ring. Of course, when priority is given to splitting certain regional power grids from the electrical ring for isolated operation, some exceptions may well be possible.

A key fact is that the problems of the electrical ring cannot be solved locally, i.e. within the particular power systems, because such solutions are neither technically effective nor economically reasonable, and do not ensure power supply reliability. In the case of a global solution, local emergency control scheme selection principles would also undergo substantial changes.

The power generation landscape in the Baltic States changed dramatically at the beginning of 2010, when the Ignalina Nuclear Power Plant (1500 MW) in Lithuania was shut down (in 2009 it produced around 10000 GWh, almost 40% of the overall consumption of the Baltic States). A new nuclear power plant in Visaginas (1350MW) is under consideration, with an investment of about 7 G€ and a construction time of 10 years.

In 2013, generation in Estonia was mainly characterised by large thermal power plants (Eesti, Balti and Iru), with a total generation of 11892 GWh/year and renewable sources, mainly wind power, accounting for 451 GWh/year. In Latvia two main energy resources were exploited: hydro produced 2912 GWh/year (Pļaviņu, Rīgas, Ķeguma, Aiviekstes hydro power stations), and fossil fuels accounted for 2869 GWh/year (Riga Combined Heat and Power plants – CHP-1 and CHP-2). Whereas wood and wind power plants contributed with 119 GWh/year. The Lithuanian generation capacity consisted of hydropower and pumped storage power plants for 1066 GWh/year (Kaunas and Kruonis plants); gas, black fuel or oil for 2615 GWh/year (Vilnius, Mazeikiu, Kaunas and Elektrenai power plants); and wind produced 649 GWh/year.

The availability of primary energy sources for electricity production and the dependence from abroad is different for the various Baltic States. Estonia's energy independence is 90%, whereas the value is 48% for Latvia, and of 19% for Lithuania.

Besides the interconnections with Russia and Belarus, the three Baltic States are interconnected with the Western European Countries through Estlink1 and Estlink2 (Finland). For the reinforcement of the electricity infrastructure in the region several projects are under consideration, including: 1) an interconnector between Lithuania and Sweden (NordBalt, 2016, 700MW); 2) the Lithuania-Poland (LitPol) interconnection (the first 500 MW line was put in operation in 2015, whereas the second 500MW line is planned for 2020); 3) various internal Baltic interconnectors listed as projects of common interests [3].

The energy policy of the Baltic States is integrated in the energy strategy of the EU and must pursue three major objectives: competitiveness, sustainable development and security. All three Baltic power systems are working to fulfil the EU technical requirements and adopt the European regulations, codes and standards (ENTSO-E, CENELEC...).

The integration of the Baltic States into the EU energy market has been identified as a strategic priority for all three countries. The main goal is to create a unified market of the Baltic Sea region. Current implementation of a joint wholesale electricity market for the entire Baltic States has boosted energy market development in the Baltic States. So far, "energy-only" markets are established in Estonia, Latvia and Lithuania. The day-ahead (Elspot) and intraday (Elbas) electricity markets have been set up, employing implicit auctioning of cross-border transmission capacity. Baltic States have national balancing markets, which are organised by the national Transmission System Operators (TSO) in charge of balancing their areas. After the Ignalina shutdown, a generation surplus arose in the northern part of the Baltic States, while a deficit emerged in the southern part causing power transfers from Estonia to Latvia with the overloading of tie-lines. During summertime, the related congestion causes the market to split into two price-zones, with the exploitation of more expensive local capacity and import from abroad.

The Baltic States are considering how to optimise their mix of generation resources, defining priorities at the individual and common levels with one common goal: Greater energy independence. Due to their limited ability to act on their own, especially on large, costly projects, joint efforts are expected.

With this report, we provide a contribution to the assessment of electricity security in the Baltic States for both the current state, and a set of possible future scenarios, in terms of generation capacity, generation mix and network enhancement (both internally and with respect to new tie-lines). We will use a detailed steady state model of the Baltic States' power system, with a simplified representation of the interconnected networks developed in-house by the Joint Research Centre (JRC)/ the Institute for Energy and Transport (IET) in cooperation with the Institute of Physical Energetics in Riga and Politecnico di Torino.

2. Geo-political and infrastructural security

Electricity is a crucial commodity for the welfare of modern societies. The provision of electricity depends on the decisions of various players (policy decision makers, regulators and their associations, system operators and their associations, etc.) in different fields (economic, technical, strategic, etc.) at multiple scales (local, national, regional) and with reference to various time frames (from real-time to long term).

From the electricity point of view, the function of the power systems is the provision of the electricity required to meet demand at all points in time, in such a way that all customers (residential, industrial, tertiary and public service) are supplied with the needed amount of electricity at the required locations following the required power profile (with or without the possibility from the demand side to control the power profile itself) in different time frames. The provision of electricity must be reliable in the sense that the level of probability to provide the service (i.e. supply the loads) is high.

In order to be reliable, the system needs to be secure (with reference to the sources and the operation of the infrastructure) and adequate (with reference to energy conversion and electricity infrastructure). Adequacy in electricity systems signifies the ability of the electric system to supply the aggregate electrical demand satisfying all customers at all times under normal operating conditions. It further implies:

- *Generation/import adequacy*: availability of generation and import capacity to meet demand in the various timeframes. Measured by a set of different indices, such as Net Generation Capacity (NGC), Reliably Available Capacity (RAC).
- *Network adequacy*: ability of the network to transfer the needed power from sources to sinks.

Power system *security* refers to the ability of the system to continuously fulfil its function against possible adverse situations. Power system can be vulnerable to threats that, when materialised, may cause foreseeable and unforeseeable disruption. The threat against power systems can be classified into natural, accidental, malicious and systemic. Natural threats are caused by not controllable natural forces (earthquakes, tsunamis, hurricane...). Accidental threats are caused by the failure of network devices or wrong human decisions (operational fault, system equipment failure, accident due to the poor management…). Malicious threats are intentional actions to bring damages to the system (terrorist, criminal group, cyber attackers, geopolitics…). Systemic threats emerge with the evolution of the power system (the integration of renewable energy, and the interdependency between power system and other infrastructures). The possibility to withstand the materialisation of a threat into an adverse event are usually considered under *operational security* in terms of the ability to withstand perturbations reacting to external, abnormal perturbations due to natural/accidental and malicious events to keep the system's feasibility. From a strategic perspective, special consideration can be devoted to the *security of energy resources* as the ability to assure the accessibility, in the various timeframes, of primary sources to be converted in the power plants to meet the required total amount of electricity and *geopolitical security* as the ability to assure the availability of primary sources and/or electricity imports against unilateral intentional disruption by international players outside the considered region. It is obvious that geopolitical conflict is a malicious human threat.

Manifestly, the electricity security is related to different factors and the analysis of it should take all of them into account along with their inter-relations, i.e. from the origin (threats), the materialised disturbances to the source and/or to the network infrastructure (contingencies) to the end user.

Besides the above mentioned components of the system (i.e., generation and network), the demand can also play an increasing role in assuring "electricity security" by helping to provide load reductions to match with falls in supply at different time frames. The new paradigm of electricity systems, with its shift from relatively passive to active distribution systems, may provide new challenges and also new opportunities for power system security.

In current power system terminology, time frames can be articulated into several horizons serving partly different purposes:

- *Real-time*: ranging from just a few seconds to 15 minutes, this time window is employed to "instantaneously" balance demand with supply for the "on-line control" of power plants and transmission systems. Conventional sources are assumed to be available, while renewables are considered as intermittent.
- *Short-term*: usually referring to the period from a day to a few days, it is routinely employed for market based unit commitment/ dispatch and generation scheduling in the day-ahead market or in the adjustment market. The standard assumption within this timeframe, therefore, is that conventional sources may suffer disruptions.
- *Mid-term*: ranging from a month to a couple of years, it is used for yearly bilateral negotiation or contractual trades. For the security analysis in this time frame, infrastructure capacity is typically assumed to be constant.
- *Long-term*: covering the period from a year to a few decades, this is the standard horizon for energy policy planning and infrastructure reinforcement. In this time frame, then, new capacity can be built, or newly built lines can be put into service. Unlike in the previous time frames, here the non-renewable sources may be depleted.

The considered time frames for the availability of the energy sources for the Baltic States in this report are: 2014 (present situation), 2020 and 2030, respectively. The scenarios will be differentiated with reference to the evolution and characterisation of generation, such as type, availability (planned, commissioned, decommissioned, etc.), and the transmission grid expansion, such as new internal lines and cross-border interconnections. Further, for the purpose of analysing the impacts of geopolitical threats on the Baltic States' electricity security, the following elements will play a fundamental role throughout our study:

- *Electricity sources*: the place of origin of different types of sources (primary sources or direct import of electricity), such as Russia, the EU, or local.
- Capacity adequacy: the availability, capacity and flexibility of the generation units needed to match demand
- *Transmission system adequacy*: the projected network after the commissioning of new internal lines and interconnections to transfer power from sources to sinks.
- *Geopolitical security*: the way of the operation of the system: with or without synchronous connection to either Russia or Continental Europe Network, or in an island mode.
- *Technical security*: the assessment of the grid operational security (e.g. via the n-1 criterion).

3. Generation adequacy assessment

3.1 Current situation

The generation adequacy for the three Baltic States is assessed based on the best available public data from the local TSOs, along with Nord Pool Spot's and ENTSO-E's adequacy forecasting [3-8]. The key parameters for generation adequacy are summarised in the Table 1, in accordance with the standard methodology of the Union for the Co-ordination of Transmission of Electricity (UCTE) [10]. In fact, the assessment of the actual generation adequacy reflects the ability of the generating units to match demand for an indicative load reference point (peak hour of 16th January 2013). The methodology is based on a deterministic approach, to calculate the Remaining Capacity (RC) that results from the difference between the RAC and the expected peak load.

Table 1 Main metrics/variables for generation adequacy assessment

Generation adequacy key	Definition
Net Generation Capacity (NGC)	The sum of the individual NGC of all power stations connected to either the transmission grid or the distribution grid.
Adequacy Reference Margin (ARM)	Defined as the sum of a fraction of the NGC (5%) and the margin against the peak load, aimed to compensate the time synchronisation of the reference load point and the peak load.
Unavailable Capacity (UC)	The sum of the system service reserve, the outage generation, overhauls and non-useable capacity (wind, hydro, network congestion…).
Reliably Available Capacity (RAC)	The remaining NGC after deducting the unavailable capacity.
Remaining Capacity (RC)	The difference between the RAC and the reference load. A potential for export is characterised by a RC higher than the ARM while a dependence on import is characterised by a RC lower than the ARM.

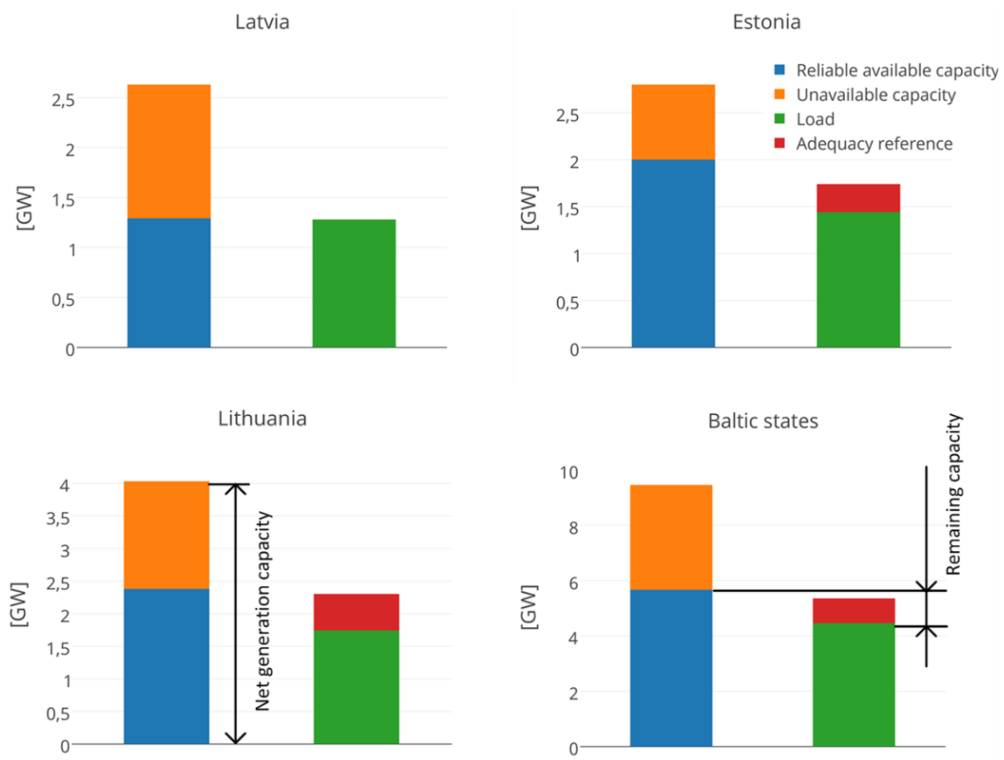

Figure 1 Generation adequacy on winter peak day

Figure 1 summarises the current generation adequacy perspective for the Baltic States. As may be seen, all countries present RCs higher than the ARM, implying adequate generation supply with a potential for electricity export to third countries. Individually, Estonia presents the highest potential for export (with 660 MW of RC), while Latvia and Lithuania did present very marginal RC.

Among the three Baltic States, Lithuania seems the most vulnerable in terms of generation adequacy as an effect of the Ignalina Nuclear Power Plant (NPP) decommissioning, with a shortage of 150~180 MW generation capacity during the 2014 winter peak, and a 130~160 MW deficit at the summer peak. Even in the case of generation sufficiency, Lithuania would still depend on imports, as 71% of the electricity consumed in 2013 is being imported (50% originated from third countries) [5][11], due to higher local generation prices. While wind generation in Lithuania can supply 15% of peak demand the volatility of renewable generation and the risk of icing during the winter peak call for further assessment of generation adequacy based on stochastic methodologies.

With a 2.6 GW Net Generation Capacity, the Estonian power system is able to cover the peak loads and also allow net exports to Latvia, Russia and Finland in case of favourable electricity prices, with 32% of the electricity generated in 2013 being exported mainly to Russia and Latvia. Despite the high NGC with respect to the annual load peak demand in Latvia and Lithuania, the RC is clearly limited due to the high share of hydro generation in both countries resulting in significant UC during peak demand. In fact, Latvia's water inflow shortage (mainly in the Daugava River [12]) imposes severe constraints during the first six weeks of the year which, as a consequence, are characterised by inadequate generation adequacy. In terms of exports, Latvia is a net exporter to Lithuania, while it still has considerable dependence on imports from Estonia and Russia, reaching 38% of load in the first semester of 2013.

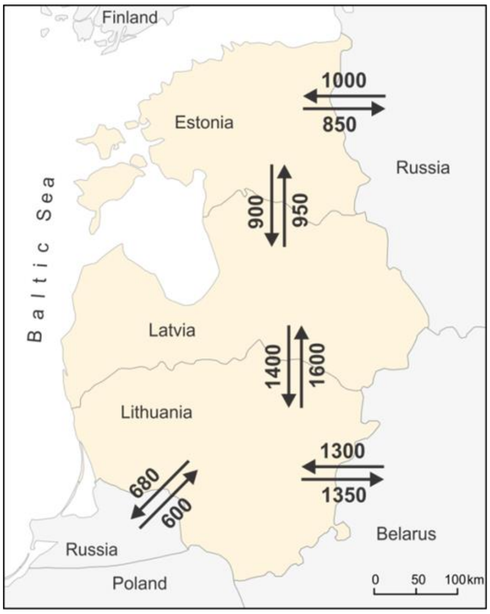

Figure 2 Maximum winter power flows (MW) between countries in the region (2013/2014)

All in all, the Baltic States are still depending on the imports from third countries (Russia, Belarus). Latvia/Russia cross-border tie-lines were loaded at 75% in 2013, with Latvia prevailing as net exporter. The Estonia-Russia interconnections, on the other hand, are the least loaded (18% in 2013) where, mainly Estonia is exporting. In absolute terms, the three Baltic States seem able to balance their energy supply and demand during a typical winter peak. This is depicted in Figure 1, where in practice only Estonia prevails as a net exporter.

In this sense, the interconnection between the three Baltic States is a key element in ensuring the overall stability of the system, where every cross-border section within the BRELL network is managed by one TSO in coordination with the relevant counterparts to agree on the maximum trading capacity between countries (Figure 2). The Baltic States TSOs (Estonia's Elering AS, Latvia's Augstsprieguma Tīkls AS, and Lithuania's Litgrid AB) initially adopted (in 2013) a common Baltic internal cross-border trading capacity calculation [5] procedure, based on transparent and non-discriminatory rules in a line with the principles of the ENTSO-E. However, following a unilateral decision of Litgrid to implement their own calculation model, a provisional bilateral new agreement between the Latvian and the Estonian TSOs was adopted in 2014. This situation reflects the difficulties in implementing a common operational framework for an integrated power system, which might have a critical impact on the security and reliability of supply within the region.

3.2 Generation adequacy assessment

The future of electricity security in the Baltic States greatly depends on the strategic choices that will be implemented both at the infrastructural and operational levels. The crucial elements to be evaluated are (i) the generation side with the development of new generation capacity, and consequently of a new energy mix; (ii) the foreseen infrastructural enhancements, both internal and cross-border; as well as (iii) the possible shift to the autonomous synchronous operation of the Baltic States or a synchronisation to the Continental Europe Network. The load's time variation should be considered as well with changes in structure, operation, and load must be set in a coherent time frame. For this purpose, the current situation is here compared with two alternative time frames: 2020 and 2030.

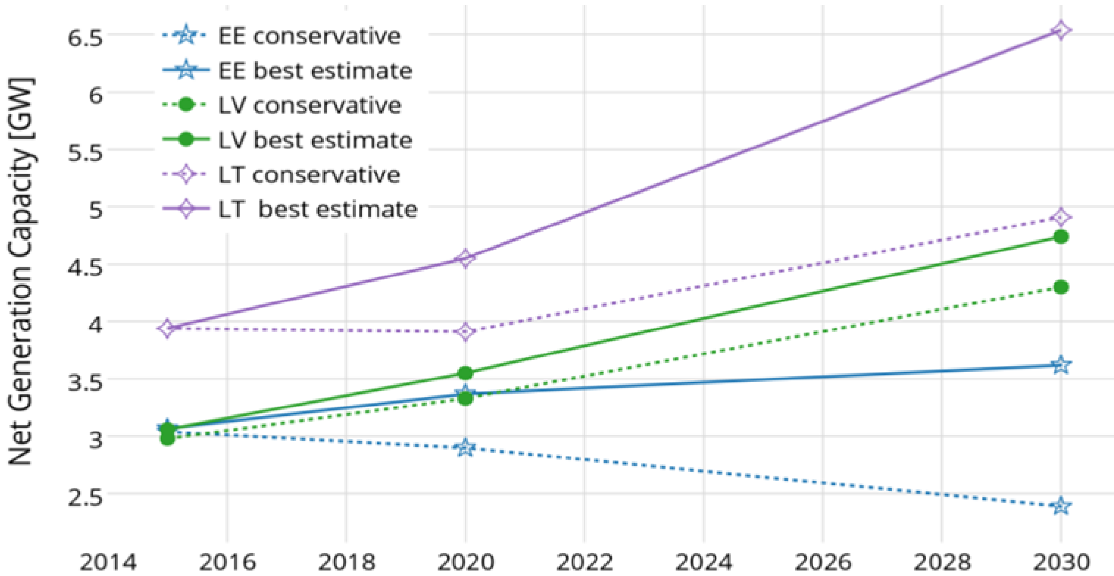

Figure 3 Net generation capacity evolution scenarios in the Baltic States

In accordance with the ENTSO-E Scenario Outlook and Adequacy Forecast [4], two main scenarios are investigated for the three Baltic States. The two scenarios are built based on a bottom-up approach consisting in a first forecasting exercise from the reference point (January 2013) until 2020, whose results are successively projected onto the 2030 horizon. The first scenario (referred to as a "conservative" one) takes into consideration only confirmed investments, while the second scenario (referred to as the "best estimate" scenario) assumes adequate market incentives and investments credibly deemed as "likely". The load forecasting for the two scenarios is assumed to be similar up to the year 2020, based on the best available national demand estimates and considering the usual climatic conditions. The two scenario projections diverge on the

2020 to 2030 horizon in terms of load forecasting, mainly due to differing the assumptions of the gross domestic product: hypothesising more favourable economic and financial conditions the best estimate scenario results in higher electricity demand and therefore increased need for generation capacity expansion and network reinforcements.

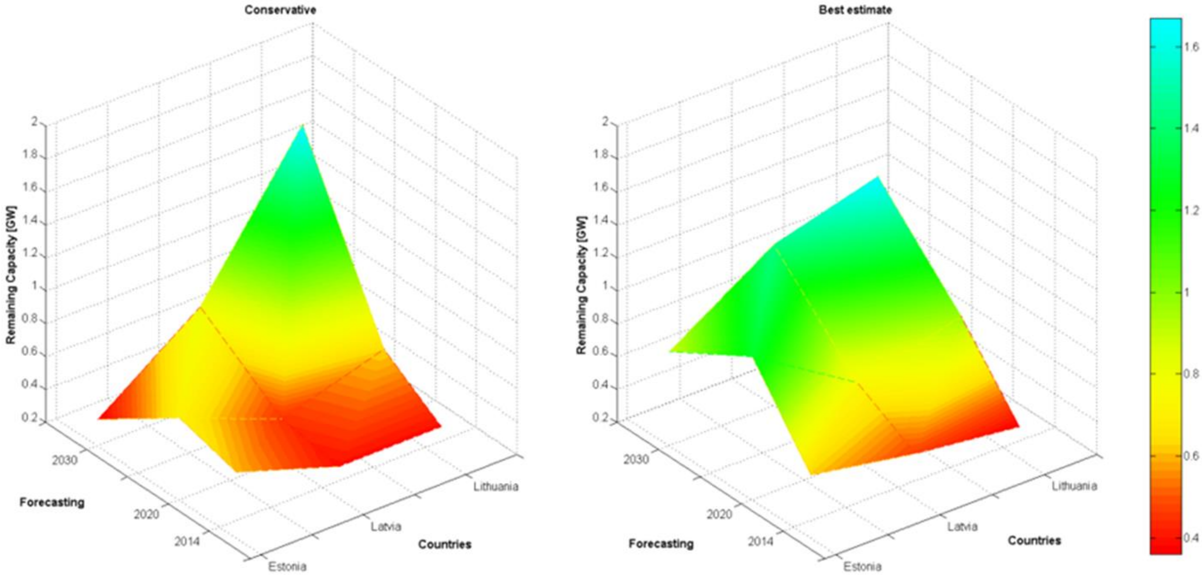

Figure 4 Reserve capacity under the two scenarios for the three Baltic states

Consistently with the present generation adequacy assessment, the mid- and long-term assessment of the developed scenarios is based on the UCTE methodology, while the data was mainly taken from the ENTSO-E Scenario Outlook and Adequacy Forecast and the forecasts of the member TSOs [4]. Table 2 lists the NGC and the RC forecasting for each Baltic country and the whole region for the years 2015, 2020 and 2030 under the "conservative" and "best estimate" scenarios. Figure 3 and Figure 4 summarises the Baltic States' generation adequacy evolution in terms of NGC and RC, for the two assessed scenarios and the three Baltic States. In both scenarios, all countries achieve adequate generation capacity, with lower predictions for Estonia under the conservative scenario in the 2030 projection. In the following sub-sections, further analyses are developed for each country under the two scenarios.

Table 2 Generation adequacy forecast for the Baltic States

Country	Capacity	Conservative scenario			Best estimate scenario		
		2015	2020	2030	2015	2020	2030
Estonia [GW]	NGC	3.04	2.94	2.39	3.07	3.37	3.62
	RC	0.60	0.70	0.36	0.58	1.07	0.77
Latvia [GW]	NGC	2.98	3.33	4.3	3.06	3.55	4.74
	RC	0.39	0.45	0.87	0.47	0.67	1.18
Lithuania [GW]	NGC	3.94	3.91	4.91	3.94	4.55	6.54
	RC	0.39	0.63	1.67	0.39	0.83	1.35
All [GW]	NGC	3.94	3.91	4.91	3.94	4.55	6.54
	RC	1.38	1.78	2.9	1.44	2.57	3.30

3.2.1 Conservative projection

The main tenet of the conservative scenario is the Estonian generation capacity decrease. In fact, Estonia's strong dependence on fossil sources will be affected starting from 2016, as seen in Figure 5 due to emission limitation directive entering into force [13]. However, it is foreseen for both scenarios that Estonia would be nevertheless capable of meeting the load by using its local generation capacity: this is due to the flexibility provided by the Industrial Emissions Directive [14] in granting exemption for power plants part of small isolated networks. Despite the prospect of keeping a few combustion power plants, Estonia is still expecting a noticeable decrease in the installed generation capacity, with 21.4% decrease between 2015 and 2030. Latvia's generation will assist to the highest increase in installed capacity, with 11.74% increase up to 2020 followed by 29.13% increase up to 2030, totalling a whopping 44.30% increase with respect to the 2015 reference year. The newly installed capacity is mainly composed of renewable energy sources, while fossil and hydro generation sources would remain similar to the reference year. For Lithuania's generation capacity, we may assist to a slight decrease by 2020 due to emission limitations, followed by a substantial increase of 25.6% up to 2030 due to the expected commissioning of the Visaginas NPP and the considerable investment in wind energy capacity.

Overall, the three Baltic States should assist to a slight increase in installed capacity by 2020 in comparison to the reference year, followed by a 16% increase of installed capacity on the 2030 horizon, mainly due to Latvia's expected generation capacity investment. For the conservative scenario, the three Baltic States can still individually meet their demand using local capacities, with positive generation RC in 2020 and 2030 (Table 2).

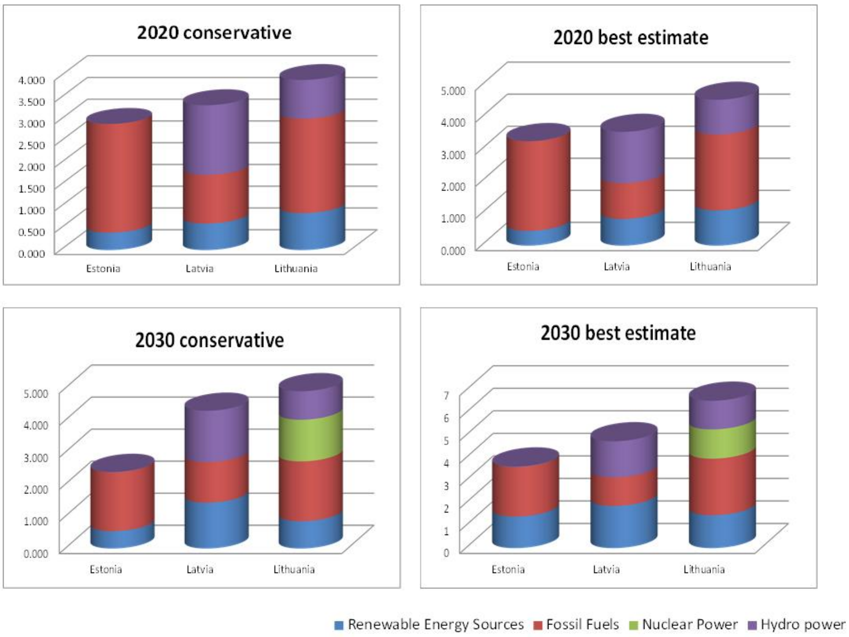

Figure 5 Electricity mix for the different scenarios

In the conservative scenario, all three Baltic States are expected to be beyond the European 2020 requirement for generation mix, and hence meet the emissions targets. Nonetheless, low penetration scenarios would still require network reinforcement and cross-border transmission investments, in order to efficiently integrate RES and reach 18% of penetration in 2020 (28% target) and 24% in 2030 for all the three Baltic States.

3.2.2 Best estimate projection

The best estimate scenario, unlike the conservative one, foresees an increase in Estonia's installed capacity. The largest expansion should take place in the share of RES with 15 percentage points (pp): the comparative figures for Latvia and Lithuania are instead 3 pp and 5 pp respectively (Figure 5). Consistently with the conservative scenario, Estonia is expected to satisfy its electricity demand relying on local generation, with positive RC throughout the 2030 horizon.

Latvia features similar patterns to Estonia, with substantially higher installed capacity and adequate RC. Furthermore, its RES share in the generation mix would remain the highest among the three Baltic States for both scenarios, with the due consequences in terms of low RAC.

Finally, Lithuania is expected to achieve a sustained improvement of generation adequacy, all the while presenting the highest load demand increase for both the conservative and the best estimate scenarios, with respectively 35% and 42% load growth in the period 2015-2030. The low share of RES in the Lithuanian electricity mix could be an obstacle in meeting the 2050 roadmap targets for power generation. The best estimate scenario presents higher hydro capacity for Lithuania, with a 42% increase compared to the conservative scenario resulting in the highest level of UC per NGC within the three Baltic States.

In general under both scenarios, all the three Baltic States are facing high demand growth forecasts, clearly above the ENTSO-E average for January 2030. While the generation adequacy assessments for all scenarios are projecting adequate RCs, further need for cross-border interconnections with ENTSO-E members is clearly expected, in preparation to the higher energy independence from the UPS/IPS. Furthermore, requirements to meet the 2050 roadmap for CO2 emissions and gradual decommissioning of fossil fuel generation power plants will result in the expected increase of offshore wind farms deployment, requiring an efficient market design and effective power balancing reserves. In this prospect, cross-border transmission capacity would specifically play a crucial role in the security of supply, by balancing the high volatility of wind power resources.

4. Steady state models of the Baltic power systems

By definition, a steady state model requires the following elements:

- a set of buses, to which transmission branches are connected; for each of these buses, at least the voltage value is required;
- the topology of the network, complete with branch parameters (i.e. lines & transformers);
- a set of calibrated generation units;
- a set of values for expected load.

Starting from a legacy dataset with 899 buses, 1216 lines, 42 generators and 310 loads, a series of validations were performed to check its consistency, including:

- reactance/resistance ratio and short circuit impedance for transformers, to identify conflicting impedances and inconsistent rated capacities;
- reactance/resistance ratio, characteristic impedance, relationship of line thermal limit for transmission lines, to discover impedance errors and inconsistent thermal limits; all the thresholds used to identify errors were compared with the Russian Standard "GOST 839-1980" for transmission lines;
- geographic information to identify topological problems, etc.

Identified errors were corrected either through iterations with experts in the Baltic States or by applying standard parameters. As a next step, a thorough list of current generation units and future foreseen investment inside the Baltic States was created with necessary information such as geographic locations, connected substations, technical limits, fuel types, technologies, etc. A quadratic cost curve was assigned to each unit (see Section 4.2). The curve was used to determine the system marginal cost in the subsequent simulation.

4.1 Reference models

The basis for assessment of future horizons is the construction of an AC power flow model calibrated and validated through reference to ENTSO-E's physical system snapshots for the current situation (2014). Four reference scenarios representing the Baltic States' electricity system in 2014 were considered:

- Winter off-peak load (15-Jan 03:00)
- Winter peak load (15-Jan 11:00)
- Summer off-peak load (16-July 03:00)
- Summer peak load (16-July 11:00)

The load flow of the network model was compared with the historical records of the physical cross-border flows reported by ENTSO-E [15].

According to the ENTSO-E consumption data inquiry for 2014 [4], the total consumption of each Baltic country was extracted for the above-mentioned scenarios (see Table 3). The load in Table 3 is "net consumption", i.e., it excludes power plants' auxiliaries but includes network losses; therefore, the maximum output of an individual generator was subtracted by its self-consumption. The load distribution among the nodes of the electricity grid was kept unchanged in proportional terms, but simply scaled up/ or down according to the assumption on the overall load for each country [4].

Table 3 Load for the reference 2014 scenarios for each Baltic country (MW)

Country	Winter off-peak	Winter peak	Summer off-peak	Summer peak
Estonia	887	1289	568	908
Latvia	678	1116	519	902
Lithuania	1001	1598	856	1396
Total	2566	4003	1943	3206

Table 4 Components of the reference model

Country	Buses	Lines	Loads	Generators
Estonia	189	256	137	30
Latvia	242	317	150	16
Lithuania	480	644	293	21
Russia	4	4	0	8
Belarus	5	5	0	10
Finland	2	2	0	4
Sweden	1	1	0	2
Poland	2	2	0	4
Kaliningrad (Russia)	1	1	0	2
Total	926	1232*	580	97

*tie-lines not included

The reference transmission system model for Baltic States consists of lines/branches with voltage of 110 kV and higher, mainly 110kV, 220kV and 330 kV. In order to connect the north-west islands of Estonia, such as Hiiumaa, the 35kV undersea cables for future connection of offshore wind farms in Estonia were also included. Table 4 reports the main features of the reference models in terms of the numbers of modelled components.

The quantity of generators and net installed capacity (excluding self-consumption) included in the power model of the Baltic States are listed in Table 5 and are classified by the primary sources.

Table 5 Power plants in the Baltic States arranged by fuel or energy source (2014 case)

Country	Coal		Oil Shale		Gas		Biomass/ Waste		Geothermal		Hydro		Wind		Total	
	-	MW	-	MW	-	MW	-	MW	-	MW	-	MW	-	MW	-	MW
Estonia	-	-	6	2180	3	190	5	74	-	-	-	-	16	320	30	2764
Latvia	1	20	-	-	5	1024	2	34	-	-	4	1550	4	41	16	2669
Lithuania	-	-	-	-	9	2865	2	40	1	35	2	1001	7	149	21	4090
Total	1	20	6	2180	17	4079	9	148	1	35	6	2551	27	510	67	9523

It should be noted that generation units belonging to the same power plant were mostly grouped as one generator. Relatively small generators connected to the distribution networks (e.g. solar power plants in Lithuania) were not modelled.

Generation capacity values in Table 5 are obtained from the Baltic TSOs: Elering [16], Litgrid [17], and AST [18]. Wind farm contribution to electricity system voltage control through reactive power injection was applied according to the ENTSO-E regulations [19]: -0.35 to 0.4 Q/P.

The equivalent areas connecting to the Baltic States were modelled by two independent generators at each outside terminal bus of a tie-line. In such a way the import/export power over a subject tie is simulated. The capacities of the two generators were set equal to the transmission capacity of the tie-line.

4.2 Generation costs

The cost curve of an electricity generator indicates its generation costs at a specific power output level. Generation cost (C_{gen}, €$_{2013}$/h) as a function of generation power (P_g, expressed in MW) is represented as a cost function in Equation 1.

$$C_{gen}(P_g) = C_{fixedO\&M} + C_{varO\&M} \times P_g + C_{fuel} \sum_{i=1}^{n} (A_i \times P_g{}^{i-1}) \qquad (1)$$

$C_{fixedO\&M}$ and $C_{varO\&M}$ represent fixed and variable Operation and Maintenance (O&M) costs for the power plant. These are respectively independent and dependent of the generation power, and are measured resp. in €$_{2013}$/h and €$_{2013}$/MWh. The cost of fuel (C_{fuel}, expressed in €$_{2013}$/MMBtu) is multiplied by the summation of n terms, where the unit of measurement, MMBtu, is one million of British thermal units. The product of the summation shapes the cost curve, so that the generator energy conversion efficiency from chemical to electrical (heat rate) at different generation power levels is taken into account. *n* determines the quantity of terms in the polynomial of the summation; e.g., if n = 3, the summation is a product of quadratic polynomial: (A_1 x $P_g{}^0$) + (A_2 x $P_g{}^1$) + (A_3 x $P_g{}^2$). The A_i 's (MMBtu/MWh) are coefficients in the polynomial. These coefficients define the changes in the heat rate of the power plant at various generation powers.

Fixed and variable O&M costs for the electricity generation technologies most commonly found in the Baltic States are obtained from a JRC report [20], and listed in Table 6 for 2013, 2020 and 2030. Variable O&M costs include neither personnel costs nor fuel and CO_2 emission costs. Transport related costs for captured CO_2 are not included in the O&M costs. O&M costs for pumped hydro storage are listed for a storage system with one natural reservoir.

Cost curves vary for different generator technologies and different fuel types. Generators powered with freely available renewable energy (i.e. hydro, wind, solar, geothermal) have linear cost curve, because the fuel cost is zero (see Eq. 1). On the other hand, nuclear fission, fossil-burning, and biomass power plants have positive fuel costs. In this case the cost curve is not linear anymore, because the heat rate varies at different generation power levels. The A_i coefficients shape the cost curve for power plants where fuel costs are applicable.

Table 6 Fixed and variable O&M costs, fuel costs, and heat rate (@ maximum electricity generation) of different conventional electricity generator technologies for 2013, 2020 and 2030 [MW and MWh units refer to electric power and energy]

Fuel/ Energy source	Technology	Fixed O&M costs, €2013/MW/h			Variable O&M costs, €2013/MWh			Fuel costs, €2013/MMBtu			Heat rate @max electricity generation, MMBtu/MWh		
		2013	2020	2030	2013	2020	2030	2013	2020	2030	2013	2020	2030
Wind, onshore	Wind turbine	4.32	3.70	3.26	0.0	0.0	0.0	N/A	N/A	N/A	N/A	N/A	N/A
Wind, offshore	Wind turbine	14.66	10.52	8.84	0.0	0.0	0.0	N/A	N/A	N/A	N/A	N/A	N/A
Geothermal	Flash steam	8.84	9.08	9.18	0.0	0.0	0.0	N/A	N/A	N/A	N/A	N/A	N/A
Hydro	Hydraulic turbine, > 100MW, with reservoir	2.51	2.51	2.51	3.0	3.0	3.0	N/A	N/A	N/A	N/A	N/A	N/A
Hydro	Pumped hydro storage	2.57	2.57	2.57	0.0	0.0	0.0	N/A	N/A	N/A	N/A	N/A	N/A
Natural gas	OCGT, conventional	0.88	N/A	N/A	13.0	N/A	N/A	8.62	N/A	N/A	8.97	N/A	N/A
Natural gas	OCGT, advanced	1.88	1.88	1.88	11.0	11.0	11.0	8.62	7.89	7.52	8.52	8.52	7.93
Natural gas	CCGT, conventional, CHP	8.54	N/A	N/A	2.4	N/A	N/A	8.62	N/A	N/A	8.12	N/A	N/A
Natural gas	CCGT, advanced, CHP	4.50	4.45	4.41	4.0	4.0	4.0	8.62	7.89	7.52	5.98	5.78	5.59
Oil shale	Steam turbine, fluidized bed	4.34	4.34	4.34	6.0	6.0	6.0	2.81	2.81	2.81	8.12	7.93	7.58
Coal	Steam turbine, pulverised, supercritical	4.57	4.57	4.57	3.6	3.6	3.6	2.59	2.38	2.24	7.58	7.41	7.10
Uranium	Steam turbine, nuclear fission, generation III	10.79	10.43	8.89	2.5	2.5	2.5	0.75	0.75	0.75	9.21	9.21	8.97
Solid biomass	Steam turbine, CHP	9.64	8.66	7.85	3.3	3.3	3.3	6.50	6.50	6.50	10.03	9.74	9.47

[Biogas and landfill gas are assumed to be burned in conventional CCGT CHP technologies]

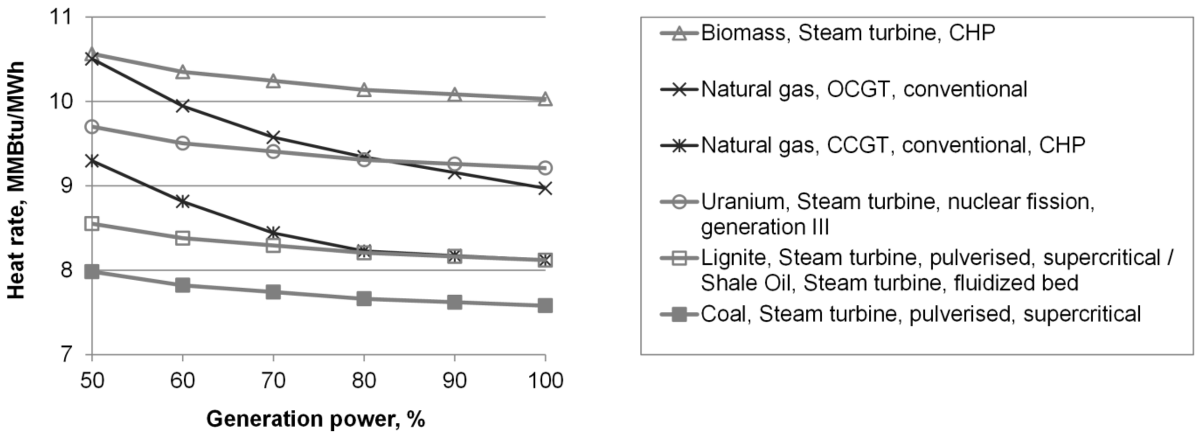

Figure 6 Adapted heat rete curves at different generation powers for conventional generator technologies

The A_i coefficients form heat rate curves and are obtained from the study of Lew et al. [21]. The heat rate curves for the relevant technologies are presented in Figure 6. It is assumed that the drop in the relative values of the heat rate (the increase in the chemical-electrical efficiency) is the same for all steam turbine generators. The shape of the heat rate curve in Figure 6 is the same for power plants fuelled with coal, lignite, uranium, and biomass; however, the absolute heat rate value differs. The shape of the heat rate curve for the Open Cycle Gas Turbine (OCGT) and for the Combined Cycle Gas Turbine (CCGT) differs from the steam turbine technology. The loss in efficiency at part-load operation is higher for OCGT and CCGT. When compared with full power generation, Conventional OCGT natural gas power plant operating at 50% power needs roughly one additional MMBtu to produce one MWh of electricity. The efficiency of the steam turbine generation technologies is less affected by a part load operation. The heat rate value for different technologies at maximum electricity generation is listed in Table 6.

4.2.1 Fuel Price

Fuel prices for fossil fuel, uranium and biomass are listed in Table 6. Fuel price for natural gas (8.62 €$_{2013}$/MMBtu) is obtained from the Eurostat database [22]. It is an average price in 2013 within EU28 for industrial consumers with annual consumption between 950,000 MMBtu and 3,790,000 MMBtu.

Coal price of 2.59 €$_{2013}$/MMBtu reflects the average steam (thermal) coal price in 2013 in North-western Europe [23], assuming coal energy density of 27.8 MMBtu/t (ton of coal equivalent). Oil shale price in 2013 (extracted in Estonia) is 2.81 €$_{2013}$/MMBtu [24] @average energy value of 9.57 MMBtu/t [25].

Long-term average price for EU28 procurements in 2013 for mined uranium (U_3O_8) is 85.19 €$_{2013}$/kg$_{uranium}$ as published by Euratom [26]. Before it is used in a rector, the mined uranium is converted, enriched, and fabricated in fuel elements. Following Kenneth D. Kok's methodology [27], the price for fuel element (including the disposal of the used fuel) is estimated at 0.75 €$_{2013}$/MMBtu (enriched UO_2 with 4.5% U-235 @burn-up of fuel of 45 MW$_{thermal}$-day/kg [28]).

Solid biomass and renewable waste (mainly wood for both) are the most common feedstock for biomass power plants in Europe, covering roughly 70% of plants capacity in 2013 [29]. Nowadays, most of biomass power generation is based on combustion technologies using steam turbines to set a power generator in motion Pellet and wood-chips prices for large-scale consumers in North-western Europe vary from 4 to 9 euros per MMBtu in 2013 @30% moisture content [30]. The average of the minimum and maximum price, 6.5 €$_{2013}$/MMBtu, is assumed as the cost for biomass in Table 6.

The gate fee paid by local authorities to energy-from-waste (post-2000) power plants in 2013/14 varies from 74 to 134 €$_{2013}$/t [31]. An average value of this range is converted in fuel cost unit listed in Table 6 and is equal to -7.43 €$_{2013}$/MMBtu @mean energy value for solid municipal waste: 14 MMBtu/t [32]. The fuel price is negative since the power plant receives money for waste treatment.

Fuel prices for the future scenarios (2020 and 2030) for natural gas and coal are updated following the Energy Technology Perspectives 2DS scenario of the International Energy Agency [33]. For oil shale, uranium and solid biomass the price is assumed constant.

4.3 Cross-border Energy Exchange

Cross-border energy exchange is limited by transmission line/cable capacity (total transfer capacity) based on which other capacity concepts may apply, such as net transfer capacity and available transfer capacity. However, since the study conducted in this report was on the assumption that all the generator output would be decided by the optimal power flow based on the cost introduced before, the net transfer capacity is assumed within the Baltic States (considering the necessary security margin for emergency reserves and technical uncertainties). At the times when imports/exports are needed for power balancing purposes, the power exchange between Baltic and neighbouring countries is applied, according to the priority list in Table 7. The priority is arranged from high to low. For example, if power imports are required in the Baltic States, firstly the power will be imported from Finland. If power imports from Finland are not sufficient for power balance, additional power imports will be asked from Russia, and so on. Higher priority in Table 7 typically indicates that the import price is likely to be lower The priority is estimated based on the generation mix in the neighbouring countries [34-37], and on the projected costs of generating electricity [38][39].

Finland likely has the lowest electricity generation price among the neighbouring countries listed in Table 7, since nearly half of its electricity is generated via a NPP (in 2015). In Russia, most of the electricity is generated from fossil fuel and uranium power plants (around 85% in 2015). Since the generation costs in the mentioned power plants in Russia are slightly lower than in other countries, the overall estimated electricity price in Russia falls between Finland and Sweden. Sweden - with 40% of electricity generation from uranium, and 42% (2015) from hydro power - follows Russia. Poland, with 86% (2015) of electricity generated in coal power plants, is listed after Sweden. Finally, Kaliningrad and Belarus close the list as the countries with the highest electricity generation costs, due to the fact that most of electricity there is generated in natural gas power plants. Belarus imports gas from Russia, and is thus located at the bottom of Table 7, after Kaliningrad.

Table 7 Electricity imports priority in the Baltic States from the neighbouring countries

Imports priority in Baltic	Exporting country
High	Finland
	Russia
	Sweden
	Poland
	Kaliningrad
Low	Belarus

In order to increase the utilisation of the generators in the Baltic States during times of power deficit, the electricity import prices from the neighbouring countries are set much higher than the highest price of the local generator. In the case of power surplus in the Baltic States, power is exported. In this case the export price for electricity (from Baltic to neighbouring countries) is set much lower than the lowest price of the local generator. The ranking in Table 7 is reversed for exports since the countries with higher power generation costs will likely offer a higher price for electricity from the neighbouring countries. For example, the first country for power export from the Baltic States is considered Belarus. If the potential for exports is higher than Belarus can absorb, the remaining power will be offered to Kaliningrad, and so on. The same exports/imports priority ranking is assumed for the future scenarios.

4.4 Technical Characteristics of Generators

Generation flexibility (as a range from minimum to maximum operation power) is presented for technologies, which participate in power balance (Table 8). The generation flexibility is expressed in percentage. 100% refers to the gross electrical capacity of the power plant. Generation flexibility applies to power plants whose output power can be fully or partly regulated. Wind farms and geothermal power plants are not considered for power curtailment. Hydro power plants with reservoir can vary their output power depending on the water inflow and the size of the reservoir. At high water inflow (in winter), these are assumed to be completely flexible (0-100%) for short term (one day) power balance; on the other hand, at lower water inflow (in summer), their flexibility is limited (from 0% to 50% of gross capacity). It should be mentioned that individual generation units in a hydro power plant have relatively low flexibility. For example, Plavinas hydro power plant (Latvia) comprises ten units of 89.4 MW. Each unit has minimum operation power of 65 MW. Lower operation power may damage turbine due to vibrations caused by cavitation. However, since generation units can be run individually, the total hydro power plant can be considered completely flexible. Historical monthly generation of hydro power plants in Latvia can be found in the records of the Central Statistical Bureau of Latvia [40]. Hydro pumped storage and OCGT power plants are fully flexible, and can be turned on and off within minutes for power balancing during peak loads [41]. Other power plants in Table 8 include steam turbine in their machinery and are thus less flexible. CCGT power plant flexibility is assumed to be in a range from 40% to 100%, whereas coal, uranium, and biomass powered plants can change their generation output from 70% to 100% [1][42] .

Table 8 Contribution to power balance expressed as generation flexibility with minimum and maximum power; self-consumption (as a percentage of gross electrical capacity); and generator availability of different conventional electricity generator technologies for all scenario years: 2013-2030

Fuel/ Energy source	Technology	Min. power, %	Max. power, % CHP off	Max. power, % CHP max	Self-consumption, %	Availability, %
Wind, onshore	Wind turbine	N/A	N/A	N/A	15	97
Wind, offshore	Wind turbine	N/A	N/A	N/A	15	96
Geothermal	Flash steam	N/A	N/A	N/A	4	95
Hydro	Hydraulic turbine, > 100MW, with reservoir	0	50-100	50-100	1	84
Hydro	Pumped hydro storage	0	100	100	20	84
Natural gas	OCGT, conventional	0	100	100	3	95
Natural gas	OCGT, advanced	0	100	100	4	95
Natural gas	CCGT, conventional, CHP	40	100	80	7	93
Natural gas	CCGT, advanced, CHP	40	100	80	7	96
Oil shale	Steam turbine, fluidized bed	70	100	100	5	85
Coal	Steam turbine, pulverised, supercritical	70	100	100	5	90
Uranium	Steam turbine, nuclear fission, generation III	70	100	100	3	90
Solid biomass	Steam turbine, CHP	70	100	80	10	90

[For the reference scenario, the minimum power of oil shale is set to 30% to match the historical records]

CHP plants, when delivering heat for heat consumers, have reduced electricity generation efficiency: in fact, their higher heat rate limits the maximum electrical power which the plant can generate. It is assumed that CHP plants, in full power operation and at maximum thermal output, can generate electricity up to 80% of their electrical capacity [20]. For example, if the electrical gross capacity of the plant is 100 MW and it operates at maximum heat output, it can develop only 80 MW in full power operation. The electricity generation in CHP plants is limited during cold seasons at high demand for district heating.

Injected power in electricity grid depends on two more technical factors of a generating system: self-consumption and availability (Table 8). Self-consumption values (as a percentage of gross generator capacity) indicate the power output fraction which is consumed onsite in plant facilities and does not reach the electricity grid [20][43-46]. For pumped hydro storage technology, self-consumption refers to losses in energy conversion: electrical – gravitational (and potential) – electrical.

Availability of a power generator in Table 8 is expressed in percentage terms, and indicates the fraction of time when the generator is able to generate electricity: for instance, an offshore wind turbine with an availability of 97% is able to operate 97 days out of 100. The data for availability in Table 8 is obtained from various sources: [20][43][47-51].

4.5 Validation of the reference models

To validate the reference models, first the power exchanges between Baltic States and the neighbouring countries are set, as indicated by the four cases selected for ENTSO-E's system snapshots [15]. Next, the power exchange results between Baltic States are compared with ENTSO-E records (see Figure 7).

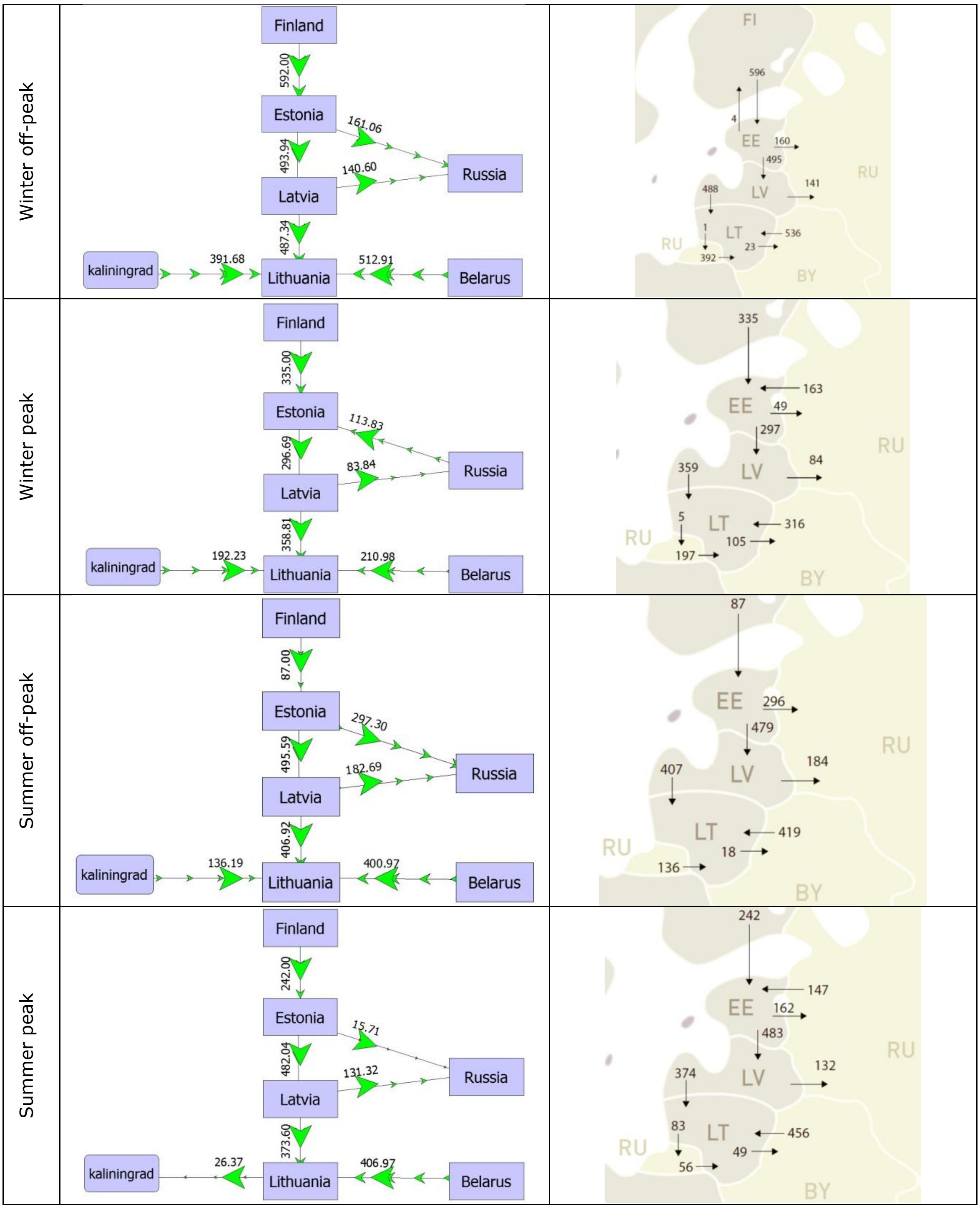

Figure 7 Validation of the reference models for selected scenarios (left column: results from reference model, right column: ENTSO-E physical flow snapshots [15])

To schedule the generation in each country, first unit commitment was performed. Due to thermal (heating) demands, cogeneration units were not allowed to switch off during the unit commitment procedure, unlike biomass/waste, coal and geothermal generators. Optimal power flow was then employed to create generation schedules in each country. The results can be used to indicate the market status of each country by locational marginal cost. As the price of the energy exchange between the neighbouring countries and the Baltic States was not a focus of this study, fictitious prices were assumed to only express the economic preferences with whom power exchanges may be schedule under different system load and generation conditions. Thus, the resulting system marginal cost can only be used to indicate the relative comparisons of market status for each country, rather than reveal the electricity costs in the Baltic States. Further, onshore wind farms were assumed to produce 30% of the rated capacity, while 40% was assumed for offshore wind farms to consider the average availability of wind generation [42].

It is manifest that by applying the method described above, we get very similar intra-Baltic-states flows for the four reference models (left column of Figure 7). The maximum difference of the cross boarder flow in the reference models, compared with ENTSO-E's system snapshots, is around 1%.

In the following sub-sections, on the top of the four reference scenarios we build the future model for the 2020 and 2030 horizons. The same methods used to validate the reference models are adopted for the analysis of the future scenarios.

4.6 Developing the models to the 2020 and 2030 horizons

After calibrating the models for the current scenarios, and validating them by the ENTSO-E snapshots, the network models, loads and generation patterns for the future horizons (i.e., 2020 and 2030.) were constructed To achieve this, the original model was modified as follows.

- Addition of network reinforcement projects
- Estimation of expected load increase patterns
- Inclusion of new generation unit

4.6.1 Network development projects

The extension of the current network into the future scenarios was performed based on the projects published in the Ten-Year Network Development Plan 2014 of ENTSO-E [52], and by BEMIP [53], as well as on the information published on the website of each TSO in the Baltic States, such as Litgrid and Elering. The projects considered for the extension of the current network are listed in Table A-1. It should be noted that the High Voltage Direct Current (HVDC) circuits are used only to connect Baltic power systems to external systems, and in our model the equivalent external systems are modelled by one single bus at the terminal of each circuit. Therefore, it makes no difference to model these circuits as HVDC lines or AC transmission lines. The flexible control advantages of the HVDC lines were then modelled by the connected equivalent generators.

Two types of transmission lines were assumed for the 330 kV circuits, i.e. 3x300 mm^2 and 3x400mm^2 [52]; whereas for the 110kV circuits, 2x240 mm^2 [54] was assumed. According to the international standards CEI 61089-1991 widely used in Europe, by assuming the average operation temperature is 5 °C [54] in Baltic States, the transmission line parameters can be derived (see Table 9).

Table 9 Technical data of the planned transmission lines

Type	Voltage [kV]	R [Ω/km]	X [Ω/km]	B [μS/km]
3x300	330	0.0289	0.289	3.569
3x400	330	0.0228	0.286	3.598
2x240	110	0.0550	0.272	3.820

4.6.2 Load growth

The construction of the future load scenarios in 2020 and 2030 was based on the data from ENTSO-E in their annual Scenario Outlook & Adequacy Forecast (SOAF) report. As the load forecast data was not available for 2030 in the latest version, i.e. SOAF 2015 [55], the data for load growth was obtained from two successive SOAF reports, i.e., the 2015 version [55] for scenario 2020 and the 2014-2030 version [4] for scenario 2030. Moreover, in order to differentiate the load increase rate in each country, Vision 1 of the

2030 scenario from the ENTSO-E report was selected, which employed data from each TSO. The load increasing rate for each Baltic state is listed in Table 10.

Table 10 Load increasing rate in the Baltic States for 2020 and 2030 (%)

Country	2020	2030
Estonia	2.26	27.82
Lithuania	1.69	5.90
Latvia	8.36	38.34
Total	3.97	22.64

The load for horizons 2020 and 2030 was scaled up according to the national increase rates listed above, while the spatial distribution and individual percentage for each load were kept unchanged as in the reference models.

4.6.3 Generation expansion projects

Modelling the expansion of generation capacity is more than just adding up the total number of additional installed generation units. It is essential to correctly locate the new commissioned/decommissioned large generation units and their connecting substations. Therefore, the BEMIP [53] and ENTSO-E's SOAF reports were used to identify projects concerning large units [55]. In contrast, to identify the location of the renewable generation units, especially wind parks, multiple resources were used (e.g. material from the Estonian wind power association [56], etc.) However, since most of the wind generation projects have not been confirmed yet, a couple of the proposed projects were selected into the model to simulate the increase in wind power in the considered time horizon. Thus, the following general assumptions were made for the projects not yet confirmed: 1) increased wind capacity in Latvia would be connected to two 330kV stations, i.e. Ventspils and Liepaja; 2) increased wind capacity in Estonia would mainly be offshore and connected to the Kanapeeksi substation in the island of Hiiumaa. It should be noted that the selected wind projects were only used to match the energy mix in the future horizons and therefore cannot be considered as liable information. The modelled generation projects are listed in the Annex (Table A-2.) Given that waste/biomass generators are usually small and mainly used locally, the generation capacity was subtracted directly from the loads with an assumed average load factor for each country [57]. The increases in other types of generation capacity were averagely shared among existing units of the same type and considered as results of improved efficiency or renovation of old units. The generation mix in 2020 and 2030 employed in the model was taken from the EU report on energy, transport and emissions trends [57].

Furthermore, the following general assumptions were made:

- The hydro pump station works as a load during the off-peak load period, but as a generator during the peak load period;
- In the summer, the maximum hydro generation will only be 50% in the peak hours to simulate the low water situation [58], while during the off-peak hours, the generation will be 0 in Latvia to simulate the fact that water is stored for peak hours.

The emergency power reserve for each Baltic country was assumed as 700MW [59], 250 MW [60] and 400 MW [42] for Lithuania, Estonia and Latvia, respectively.

The RAC, a percentage of total installed capacity which can be operated reliably (including the maintenance, scheduled outage, unavailable capacity), was also considered for different seasons in 2020 [55] and 2030 [1]. Table 11 reports the percentage of reliable available capacities in the extended models.

Table 11 Availability of generation capacity for horizon 2020 and 2030 (%)

Country	2020		2030	
	Winter	Summer	Winter	Summer
Estonia	69.57	69.22	76.15	76.15
Latvia	52.24	42.31	72.03	58.84
Lithuania	57.36	34.5	44.56	33.67

5. Reference scenarios analysis

In this section, economic and security analyses of the Baltic power systems based on the reference models are reported. The objective of the economic analyses is to understand the competitiveness of the Baltic States among themselves in the electricity markets, while capturing the impacts from the network infrastructures (such as congestions, and voltage limits) on their market merits.

Generation mix for each scenario is defined by the optimal power flow. The objective of the optimal power flow is to minimize generation cost in the electricity system based on the marginal cost of each generator, considering grid constraints such as transmission line limits and voltage range. In the following sections the marginal cost for each Baltic country is given in terms of locational marginal cost, so that possible zonal splitting due to grid congestions can be identified.

Further, contingency analysis performed on the basis of the four reference models is meant to check for the operational security of the systems, and the adequacy of resources available to the TSO in charge to handle such contingencies. The results can also be used to identify the criticalities of the system under different generation and load conditions. These are ranked by a set of metrics such as maximum overload percentage, maximum voltage violation percentage, number of violations, islanded generation and load, etc.

5.1 Economic analysis

For the simulated winter off-peak case, the simulation indicated an overall of 1.2 GW import into the Baltic States (see Figure 7); however, Estonia and Latvia were net exporting countries (mainly to Russia) with around 63 MW and 132 MW net respectively. Lithuania was the only country with a huge net import of 1392 MW, while the load of Lithuania at that time was 1001 MW; therefore, through the simulation results, we can observe that the Kruonis pump station was pumping water into the reservoir.

In the winter peak case, the overall load increased by more than 50% compared with the winter off-peak case. The power imports of the Baltic States totalled 788 MW, representing a decrease of more than one third compared with the winter off-peak case. Only Latvia kept net export of 146 MW, while Estonia and Lithuania imported 152 and 762 MW, respectively. According to our simulation, the Kruonis pump station was discharging water to satisfy its domestic loads, thus setting a comparatively low marginal cost for Lithuania.

With only 144 MW, the imported power of the Baltic States was low for the summer off-peak case. This amounted to a 90% decrease w.r.t. the winter off-peak case. Estonia and Latvia were exporting countries in this scenario, reaching 706 MW and 94 MW respectively. Lithuania was the only country with a huge net import of around 950 MW, while the load of Lithuania was only around 850 MW. The simulation results indicated that the Kruonis pump station was pumping waters into the reservoir, like in the winter off-peak case.

Compared to the summer off-peak case, the load increased by more than 50% during summer peak, but was around 20% lower than in both the winter cases. In this reference model, the total imported power of the Baltic States was 475 MW, more than three times higher than in the summer off-peak case. Only Lithuania kept net import of 754 MW while Estonia and Latvia exported 256 and 23 MW, respectively.

Figure 8 illustrates the system marginal cost in the four reference models described above. For the winter off-peak case, the marginal cost in Estonia was higher than in the other two countries, while Latvia and Lithuania had similar marginal cost. Latvia can mainly use renewables (hydro and wind) to cover the demand; yet more expensive cogeneration units based on oil/gas were running at their minimum level for district heating. Due to the large amount of import into Lithuania and the maintenance minimum operation requirements of cogeneration plants, the hydro pump storage was operating almost at its maximum. Estonia used many shale oil generators due to the lack of cheaper resources; therefore, its marginal cost was the highest among the three Baltic States.

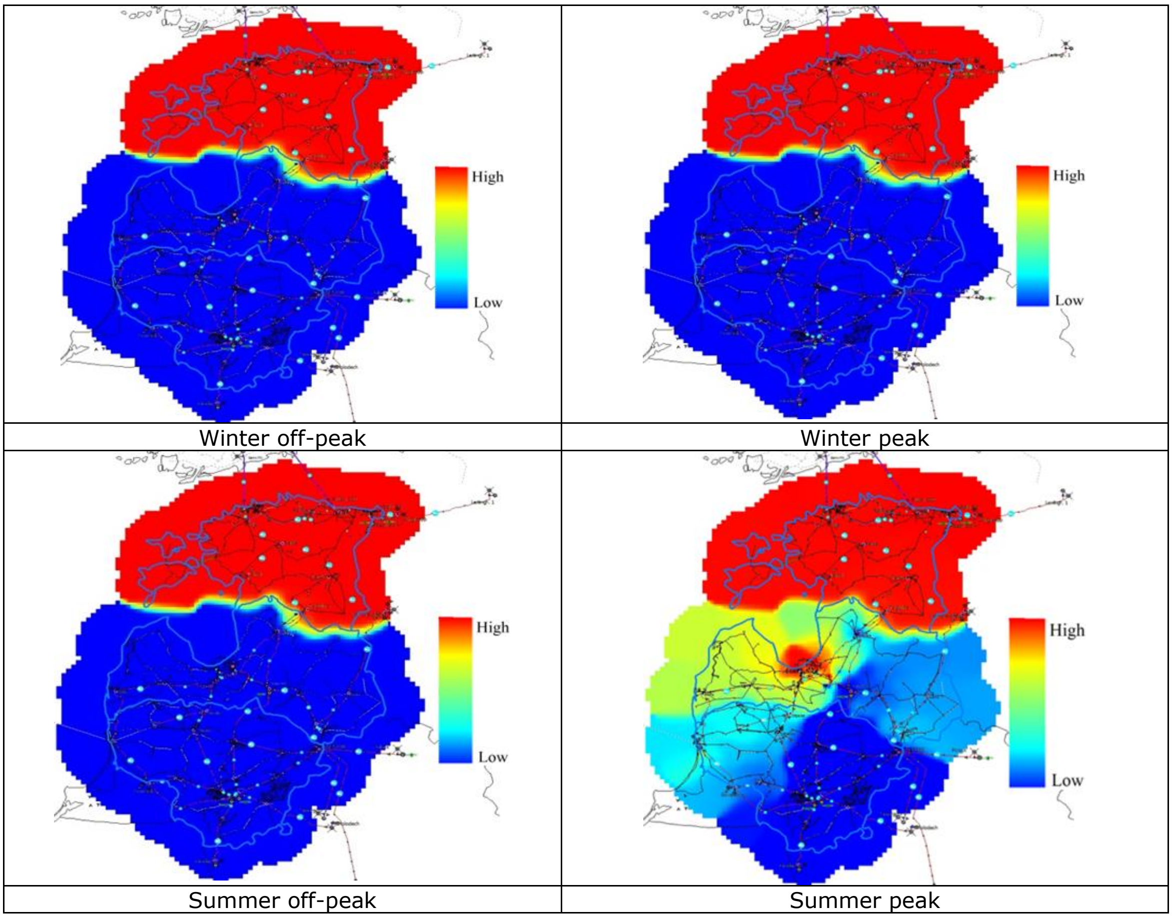

Figure 8 System marginal cost of the four reference models

For the winter peak case, the marginal cost of each state was similar to the winter off-peak case. Combining the results of both cases in winter, it is obvious that Latvia has stronger market advantage compared with the other two Baltic States due to zero marginal cost of hydro power plants. The strategy of Lithuania for using the hydro pump station to shift the generation resources from off-peak to peak loads successfully decreased its marginal cost for domestic generation.

For the summer off-peak case, with low demand the renewable resources cannot be fully exploited due to thermal power plants. For example, not all hydro power plants in Latvia reach their maximum outputs. To balance the import and generation from domestic thermal units in Lithuania, the pump station also worked at its maximum to store water into the reservoir.

For the summer peak case, the locational marginal cost varied from region to region in Latvia and Lithuania. Marginal cost in Latvia's Riga area were driven up to the same level as Estonia by frequent episodes of congestion in that region, whose effects were felt as far as in parts of Lithuania. This is mainly caused by limited maximum power of the hydro power plants in Latvia (50% of the gross electrical capacity) due to low water inflows in the River Daugava during summer season.

5.2 Steady state security analysis

Figure 9 shows the system physical features for the four reference models. They were also used as the starting operational points to perform n-1 steady state contingency analysis in the latter part of this sub-section. Under the contingency analysis the participation factors of the automatic generation control of generators in the Baltic States as a whole were set proportional to the installed capacity of the generators. Emergency power reserves for each country are activated when necessary under the contingency analysis.

In the winter off-peak case one of the Estlink cables (Estlink 1 in our simulation) was used to export a very small amount of energy to Finland, while the other one was used to import energy from Finland. As a consequence, Estlink 2 was used up to 96% of its capacity.

For the winter peak case, according to the simulation results, the Estonia's system experienced situation of comparatively low voltage, due to the lack of reactive power support under high demand. However, the voltage was still in the acceptable operational range.

For the summer off-peak case, the system voltage in Estonia was better than for the winter cases because of lower exchanges through the DC lines (Estlink 1 and 2), involving less need for reactive compensation from the system.

For the summer peak case, power flows in the area southeast of Riga reached the operational limits of the transmission lines, with congestion occurring correspondingly. Similarly to the previous cases, voltage in Estonia was affected by the exchange of power on Estlink 1.

Based on the operational points listed in Figure 9 for the four reference models, contingency sets containing each single transmission line, transformer and generator in the models were applied for the steady state security analysis lists the most severe contingencies according to each criterion in the table.

Table 12 Selected most critical contingencies according to multiple criteria for the four reference cases

Cases	Contingency component	Most severe consequence	Violations	Unserved loads (MW)	Disconnected generation (MW)	Maximum overload (%)	Minimum Voltage (p.u.)
Winter off-peak	contingency 1	System wide disturbance	-	-	-	-	-
	contingency 2	Low voltage	43	0	0	-	0.87
	contingency 3	Overload	35	0	0	165	0.84
	contingency 4	Disc. Gen.	0	0	596	-	-
	contingency 5	Uns. loads	0	10.26	0	-	-
Winter peak	contingency 6	Low voltage	114	0	135	109.7	0.792
	contingency 3	Overload	75	0	0	268	0.745
	contingency 4	Disc. Gen.	65	0	200	117.3	0.88
	contingency 5	Uns. loads	65	17	0	116.7	0.879
Summer off-peak	contingency 7	Low voltage	3	0	0	141.3	0.898
	contingency 8	Disc. Gen.	0	0	105.3	-	-
	contingency 5	Uns. loads	0	12.95	0	-	-
	contingency 9	Overload	0	0	0	165	-
Summer peak	contingency 3	Overload	36	0	0	158.7	0.865
	contingency 10	Overload	2	0	0	244.8	-
	contingency 4	Disc. Gen.	2	0	126	126.4	-
	contingency 11	Low voltage	8	0	0	132.7	0.835
	contingency 5	Uns. loads	0	21.12	0	131.3	-

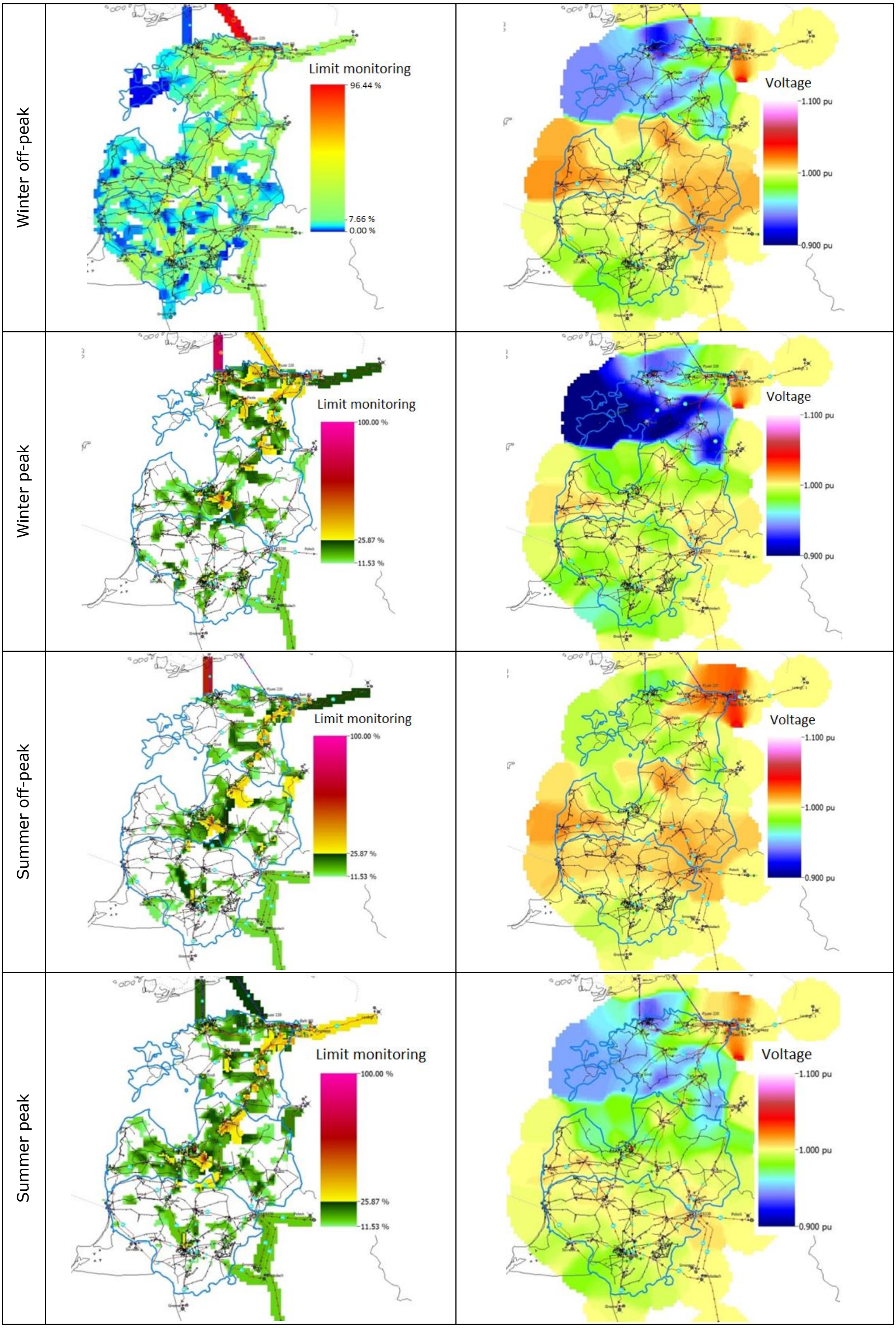

Figure 9 System performances for the four reference models under normal operation

For the winter off-peak case, the most serious contingency was the loss of a branch in contingency 1, which resulted in system-wide disturbance. The loss of component in contingency 3 created the highest overloads in the contingency set and also caused the lowest system voltage. The highest number of violations can be observed when the component in contingency 2 failed; however, the consequences were not so serious. The fault on the component in contingency 4 cut the largest import of 596 MW to the Baltic States; however, no system violations were observed.

For the winter peak case, no system-wide disturbance was witnessed. The worst contingency was to lose the component in contingency 3, which not only caused 2.7 times higher power flow than the maximum allowed flow over some lines, but also heavily lowered system voltage.

For the summer off-peak case, no system-wide disturbance occurred. The system's resilience under this reference case was the highest among all the four cases. The most severe one was the tripping of the component in contingency 7, which can bring 40% excessive flows over other lines. All other contingencies left the system largely unaffected.

For the summer peak case, no system-wide disturbance was observed. The most severe contingency was the loss of the component in contingency 10, which caused about 150% excessive current in a line, which had already been operating near the maximum limit in the normal state. Even though low bus voltage was detected, the consequences were not as serious as the winter peak case.

Obviously, the most critical components in the system were the ones in contingency 1 (which can cause system-wide disturbance in case of high demand) and contingency 3 (whose fault sets off system overload in every reference case). Other faults caused by network components not directly pertaining to our focus are not listed here.

6. Perspective models for horizon 2020

The reference models were extended into the future through the analysis of the 2020 and 2030 horizons. Based on the extended models for 2020, we will briefly discuss in this section the economic and security aspects (with special regard to the system's operational security under a specific scenario of geopolitical security concerning the IPS/UPS network) and the issues concerning energy independency of the Baltic States.

To achieve the objectives, a general scenario was assumed: zero electricity exchange between the Baltic States and IPS/UPS. In this scenario zero power flows are with both Russia and Belarus. The Baltic States remain connected with Finland, Poland and Sweden through cross-border transmission lines. Interconnections with Kaliningrad are kept unchanged.

6.1 Economic analysis

As previously described, the system models do not include a market model for the future scenarios; therefore, cross-border exchange patterns were not derived endogenously, but simply imposed by assumption of the following pecking order for electricity trading: 1) Finland, 2) Sweden, 3) Poland, and 4) Kaliningrad. The order was based on the average costs of the energy mix of each country. Furthermore, in order to study the energy independency of the Baltic States, higher prices were set for the import from outside, while export prices were set to zero.

Figure 10 gives the results of the energy exchanges between neighbouring countries in the Baltic. The results are provided for the four typical cases already seen in the previous sections. It can be noted that energy exchanges with outside countries were practically zero, which indicates that the Baltic States can satisfy their demand locally in 2020 in all four reference cases.

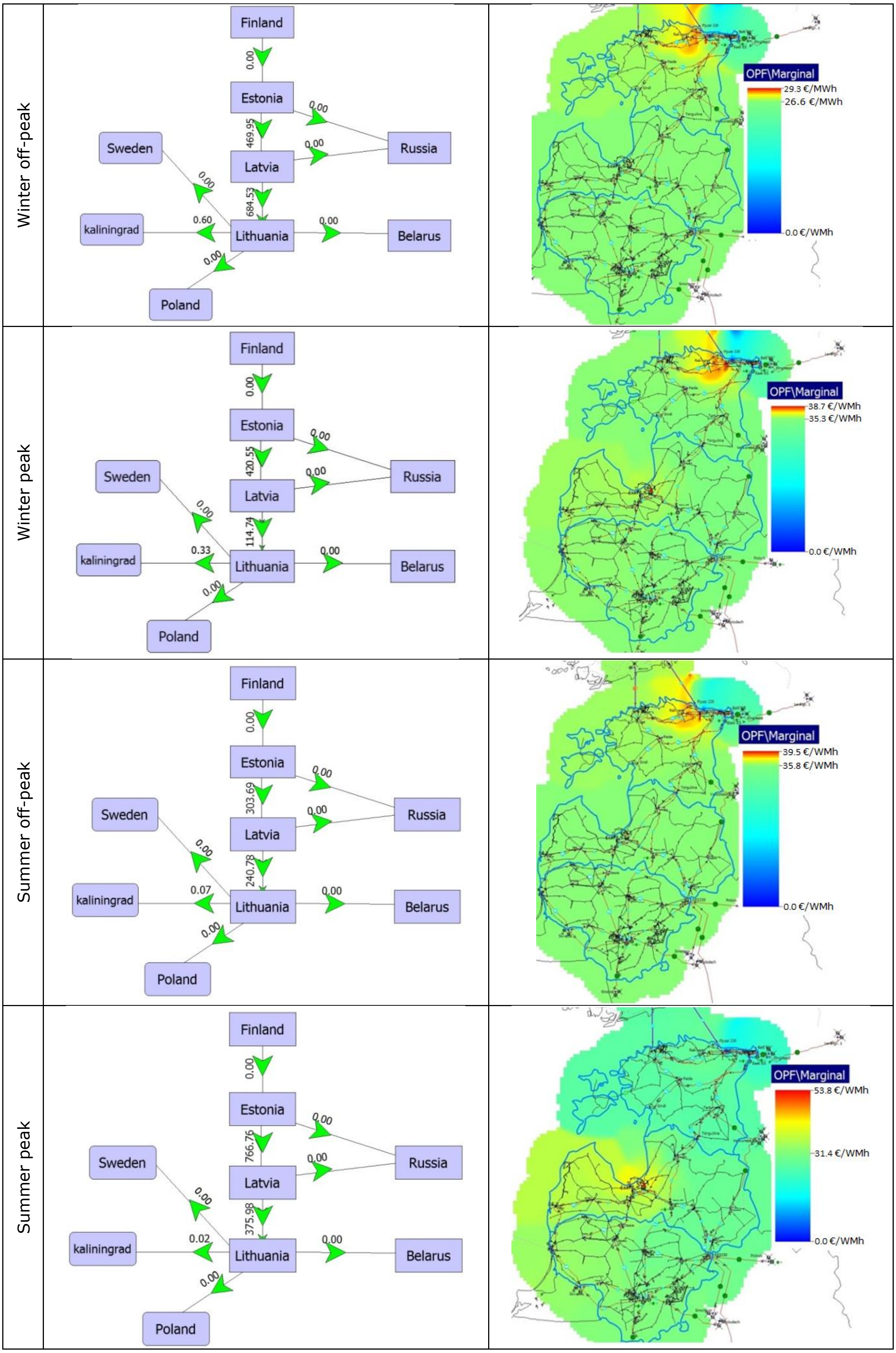

Figure 10 Energy independence levels and system marginal prices of the Baltic States

For the winter off-peak case, Estonia and Latvia provided 470 MW and 215 MW export to Lithuania as in the previous cases. Due to congestions in the north-eastern part of Estonia, the locational marginal cost varied slightly in that area. The buses' marginal cost ranged from 0 $€_{2013}$/MWh to 29.3 $€_{2013}$/MWh and the average marginal cost was 26.6 $€_{2013}$/MWh with a standard deviation of 1.7 $€_{2013}$/MWh.

For the winter peak case, Estonia exported 306 MW and 115 MW to Latvia and Lithuania, respectively. Like in the previous case, congestions can be observed in a small area near Riga and in the northeast of Estonia as well. The buses' marginal cost ranged from 0 $€_{2013}$/MWh to 38.7 $€_{2013}$/MWh, while the average marginal cost was 35.3 $€_{2013}$/MWh with a standard deviation of 2.2 $€_{2013}$/MWh. Like in the previous cases, the hydro pump station was discharging the water for generating electricity; therefore, it effectively lowered the costs for the peak hours.

For the summer off-peak case, Estonia exported 63 MW and 241 MW to Latvia and Lithuania, respectively. The buses' marginal cost ranged from 0 $€_{2013}$/MWh to 39.5 $€_{2013}$/MWh and the average marginal cost was 35.8 $€_{2013}$/MWh with a standard deviation of 2.2 $€_{2013}$/MWh. The system marginal cost were even higher than that in the winter peak case, due to the fact that the hydro units in Latvia were switched off to reserve water for the peak hours.

The summer peak case presented huge exports from Estonia (767MW) to Latvia (391MW) and Lithuania (376MW). Congestions can be detected at the southeast of Riga, while the north-eastern part of Estonia provided counter-flows to alleviate the congestion. Therefore, cost increases occurred in the western part of Latvia and Lithuania, whereas Estonia maintained comparatively low costs. The buses' marginal cost ranged from 0 $€_{2013}$/MWh to 53.8 $€_{2013}$/MWh, with an average marginal cost of 31.4 $€_{2013}$/MWh and a standard deviation of 4.4 $€_{2013}$/MWh.

6.2 Steady state security analysis

Figure 11 shows the system's physical features for the four extended models for 2020. These were also used as the starting points to perform n-1 steady state contingency analysis in the latter part of this sub-section.

Under the four simulated configurations of load and generation, network system voltages were in quite acceptable ranges during normal operation. System congestions can be mainly spotted in the northeast of Estonia and the vicinities of Riga. As in the four reference models, the voltage of Estonia was generally lower than in the other two countries.

Table 13 Most critical contingencies according to multiple criteria for the four extended models in 2020

Cases	Contingency component	Most severe consequence	Violations	Unserved loads (MW)	Disconnected generation (MW)	Maximum overload (%)	Minimum Voltage (p.u.)
Winter off-peak	contingency 12	Disc. Gen.	0	0	12.17	-	-
	contingency 11	Low voltage	5	0	0	-	0.848
	contingency 3	Overload	32	0	0	167.3	0.872
	contingency 5	Uns. loads	0	15.42	0	-	-
Winter peak	contingency 3	Num. violations	60	0	0	129	0.826
	contingency 3	Overload	13	0	0	279	0.755
	contingency 11	Low voltage	9	0	0	-	0.702
	contingency 5	Uns. loads	0	24.59	0	-	-
	contingency 13	Disc. Gen.	0	0	19.33	-	-
Summer off-peak	contingency 14	Overload	2	0	0	139	-
	contingency 15	Overload	3	0	0	132.1	-
	Line Vao-Loo2	Disc. Gen.	0	0	12.11	-	-
	contingency 5	Uns. loads	0	13.17	0	-	-
Summer peak	contingency 3	Overload	34	0	0	168.6	0.865
	contingency 13	Disc. Gen.	0	0	18.89	-	-
	contingency 11	Low voltage	6	0	0	-	0.826
	contingency 5	Uns. loads	0	21.48	0	-	-

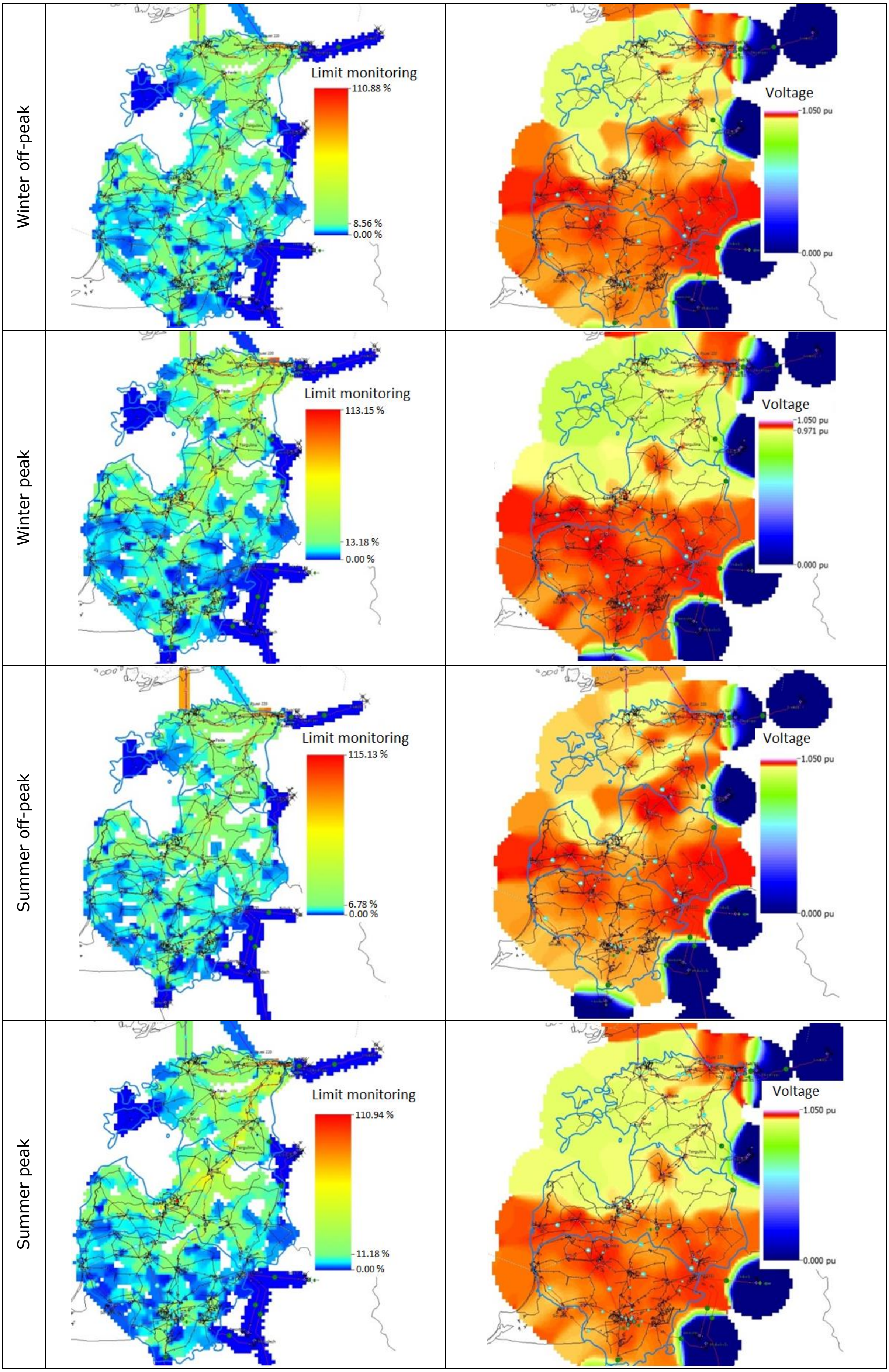

Figure 11 System performances for the four cases in 2020 under normal operation

Based on the operational points listed in Figure 11 for the four extended models of 2020, contingency sets containing each single transmission line, transformer and generator in the models were applied for steady state security analysis. Table 13 lists the most severe contingencies according to each criterion in the table.

As can be gleaned from Table 13, the system's operational security levels were not as severe as for the reference cases. No element able to cause system-wide disturbance has been detected.

For the winter off-peak case, the most serious contingency was the loss of the component in contingency 3, which created the highest number of violations and the highest overloads in the contingency set. The failure of the component in contingency 11 caused the lowest system voltage.

For the winter peak case the worst contingency was the failure of component in contingency 3, which not only caused 2.8 times higher power flows than the maximum allowed over other lines, but also heavily lowered the system voltage. The loss of the component in contingency 2 brought the largest number of violations; however, the consequences were not as serious as what followed the fault of the component in contingency 3.

For the summer off-peak case the system displayed the highest resilience among all the four cases. The most severe case was the tripping of the component in contingency 14, which is able bring about 39% of excess flows.

For the summer peak case the most severe contingency was the loss of the component in contingency 3, which caused about 69% excessive current over a line in the system.

The most critical components in the system were still the component in contingency 3 (which resulted in system overload in most cases if it had fault). Of course, there are other network components that are critical as well. For the sake of spaces, we do not list them.

7. Perspective models for horizon 2030

The models were further extended through 2030. Beside all the assumptions and methods already adopted (both in the reference and 2020 cases) we assumed that the nuclear generator in Lithuania was not a subjected to the RAC constraint. Therefore, the nuclear generator was always assumed to be available up to the maximum capacity (minus its own self-consumption).

7.1 Economic analysis

The assumption of higher importing prices and zero exporting prices of the Baltic States implied that, unless absolutely necessary to maintain the operation of the system, power exchanges with the neighbouring countries would not be observed. However, with the operation of the nuclear power plant in Lithuania, generation adequacy will be greatly increased in the Baltic States. During some off-peak cases, export to outside countries can be observed even at zero prices, simply to maintain the operation of the system. The nuclear unit would also bring about much lower system marginal cost during most of the time (uncongested/slightly congested situations). Figure 12 shows the resulting power exchange patterns and the corresponding system marginal cost.

From Figure 12, it is obvious that the cross-border power exchanges reversed their directions completely compared with the 2020 situation.

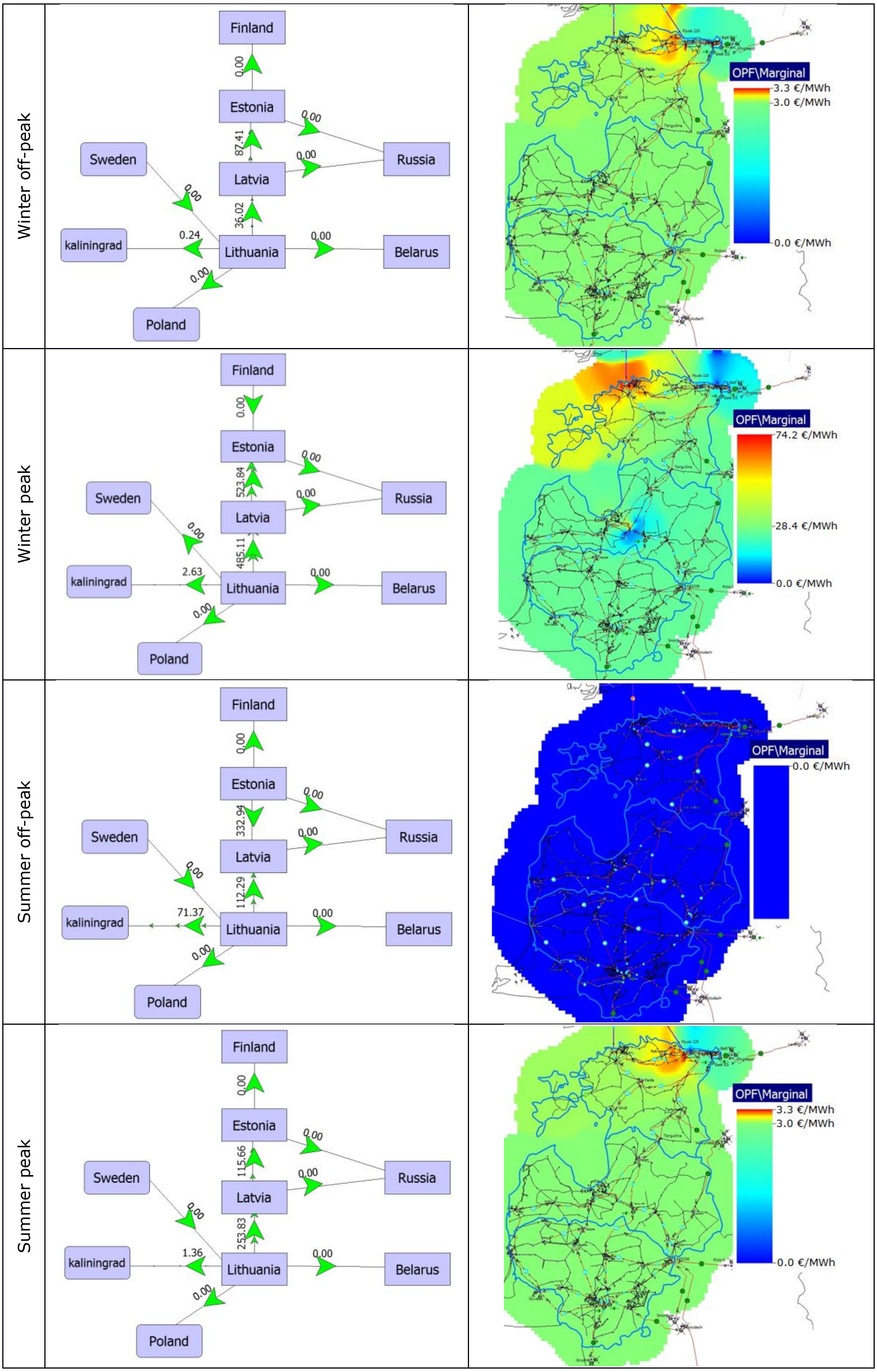

Figure 12 Energy independence levels and system marginal prices of the Baltic States

Estonia became a net importing country in the winter off-peak case, with 51 MW and 36 MW from Latvia and Lithuania respectively. Due to the congestions in the north-eastern part of Estonia, the locational marginal cost varied slightly in that area. The buses' marginal cost ranged from 0 $€_{2013}$/MWh to 3.3 $€_{2013}$/MWh and the average marginal cost was 3.0 $€_{2013}$/MWh, with a standard deviation of 0.2 $€_{2013}$/MWh.

For the winter peak case, Estonia imported 39 MW and 485 MW to Latvia and Lithuania, respectively. Congestions can be observed in a small area near Riga, as well as in the north-west of Estonia. The buses' marginal cost ranged from 0 $€_{2013}$/MWh to 74.2 $€_{2013}$/MWh and the average marginal cost was 28.4 $€_{2013}$/MWh, with a standard deviation of 10.1 $€_{2013}$/MWh. The network congestion in this case greatly affected the system's economic performance and the marginal cost of some areas.

For the summer off-peak case, Latvia imported 333 MW and 113 MW to Estonia and Lithuania, respectively. Further, due to low load in the Baltic States, export to Kaliningrad can be observed even with zero prices. The buses' marginal cost was 0 $€_{2013}$/MWh.

For the summer peak case, exports were witnessed from Lithuania (255MW) to Latvia (138MW) and Estonia (116MW). Congestions can be detected in the north-eastern part of EE. The buses' marginal cost ranged from 0 $€_{2013}$/MWh to 3.3 $€_{2013}$/MWh, while the average marginal cost was 3.0 $€_{2013}$/MWh with a standard deviation of 0.2 $€_{2013}$/MWh.

7.2 Steady state security analysis

Figure 13 shows the system's physical features of the four extended models for 2030. These were also used as the starting points to perform n-1 steady state contingency analysis in the latter part of this sub-section.

Similarly to the 2020 and reference models, the system voltages under normal operation were within the standard operational range (0.95 to 1.05 p.u.). Congestions may occur at most times in the northern part of Estonia; occasionally, the area at the southeast of Riga may also join in. Estonia had generally lower voltage than the other two countries, and during the off-peak periods, the system voltage would be higher than that prevailing at peak periods.

Table 14 Most critical contingencies according to multiple criteria for the four cases in 2030

Cases	Contingency component	Most severe consequence	Violations	Unserved loads (MW)	Disconnected generation (MW)	Maximum overload (%)	Minimum Voltage (p.u.)
Winter off-peak	contingency 16	Disc. Gen.	0	0	928.2	-	-
	contingency 2	Num. violations	45	0	0	115	0.868
	contingency 11	Low voltage	6	0	0	-	0.799
	contingency 5	Uns. loads	0	16.07	0	-	-
	contingency 3	Overload	36	0	0	236	0.817
Winter peak	contingency 2	Num. violations	35	0	0	142.9	0.811
	contingency 9	Overload	4	0	0	161.2	-
	contingency 11	Low voltage	9	0	0	102	0.59
	contingency 5	Uns. Loads	0	25.61	0	-	-
	contingency 16	Disc. Gen.	0	0	1286.22	-	-
Summer off-peak	contingency 14	Overload	2	0	0	150.5	-
	contingency 16	Disc. Gen.	1	0	928.2	115.2	-
	contingency 5	Uns. loads	0	13.72	0	-	-
Summer peak	contingency 3	Overload	37	0	0	243.8	0.808
	contingency 16	Disc. Gen.	0	0	928.2	-	-
	contingency 11	Low voltage	8	0	0	-	0.786
	contingency 5	Uns. loads	0	22.37	0	-	-
	contingency 2	Num. violations	50	0	0	119.1	0.861

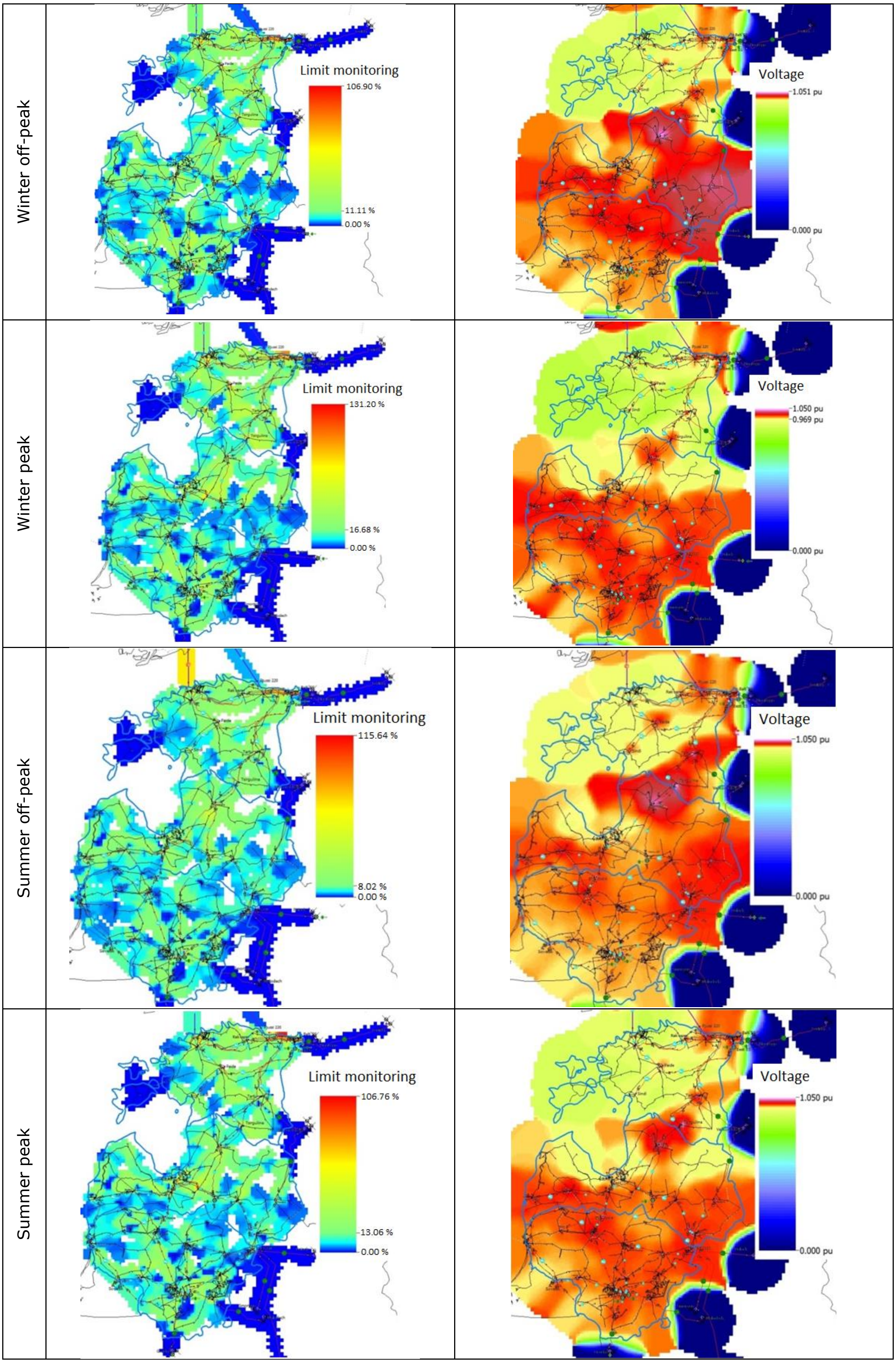

Figure 13 System performance for the four extended models for 2030 under normal operation

Based on the operational points listed in Figure 13 for the four models of 2030, contingency sets containing each single transmission line, transformer and generator in the models were applied for the steady state security analysis. Table 14 lists the most severe contingencies according to each criterion in the table. No system-wide disturbance was witnessed in the analysed cases.

For the winter off-peak case, the most serious contingency was the loss of the component in contingency 3 which created the highest overloads in the contingency set. Even though the highest number of violations can be observed when the component in contingency 2 failed, the consequences were not particularly serious.

For the winter peak case the worst overload contingency was due to the loss of the component in contingency 9, which caused power flows 60% in excess of the maximum allowed over some lines in the system. However, the most serious problem occurred with the fault of the component in contingency 11, which brought about the lowest system voltage (0.59 p.u.), at which system operation is practically unviable, causing difficulties as severe as a system wide disturbance.

For the summer off-peak case system resilience was at peak among all the four cases. The most severe problem was the tripping of the component in contingency 14, which can set off 50% excessive flows. Other contingencies did not create serious problems to the system.

For the summer peak case, like in the winter off-peak case, the most serious contingency was the loss of the component in contingency 3, which created the highest overloads in the contingency set. Failure of the component in contingency 11 determined the lowest system voltage (0.78 p.u.) in the contingency set.

Obviously, the most critical components in the system were the component in contingency 11 (which can cause un-operationally low voltage in the winter peak case) and the component in contingency 3 (which , when failing, may in some cases result in system overload). Of course, there are other network components that are critical as well, which are not listed for the sake of concision.

8. Baltic States without nuclear in 2030

The issue of the construction of the new nuclear power plant has not been entirely clarified yet. In this section, we simulate the system without the construction of the nuclear reactor in 2030. Other assumptions are still holding as before.

8.1 Economic analysis

Without nuclear reactor the power exchange with the neighbouring countries was again practically zero. The cross-border power flows and relative system marginal cost under four typical load conditions can be found in Figure 14. The system marginal cost became comparatively high again. The hydro pump stations in Lithuania were modelled as load during the off-peak hours for pumping water into the reservoir. This caused the power flow from north to the south. In contrast, during the winter peak hours, the power flow reversed.

For the winter off-peak case, Lithuania became a net importer, with 124 MW and 692 MW from Estonia and Latvia respectively. The generation in the north-eastern part of Estonia provided counter-flows to relieve system congestion, with locational marginal cost became zero at those buses. Therefore, the buses’ marginal cost ranged from 0 $€_{2013}$/MWh to 50.8 $€_{2013}$/MWh, while the average marginal cost was 25.6 $€_{2013}$/MWh with a standard deviation of 2.9 $€_{2013}$/MWh.

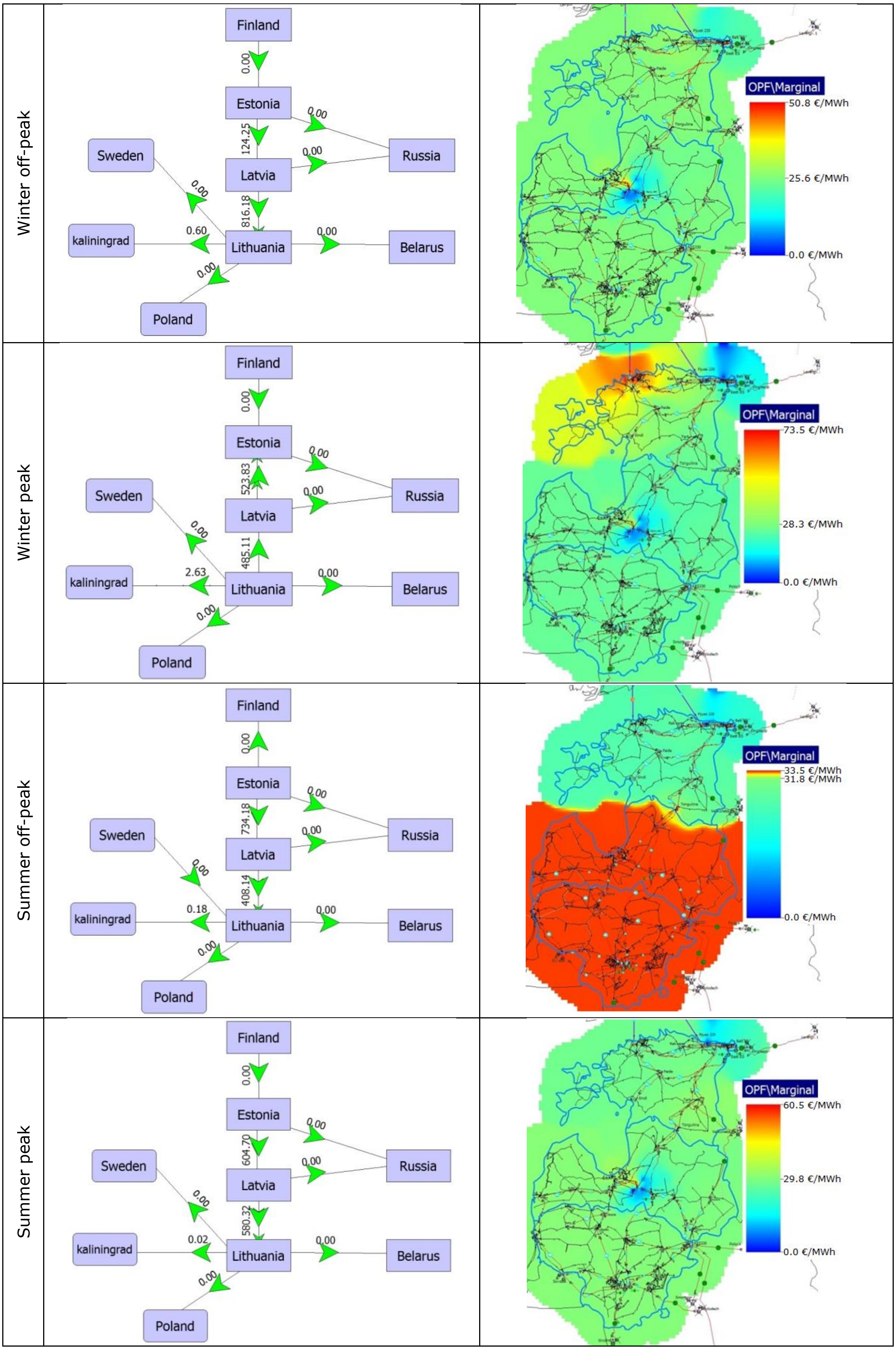

Figure 14 System performance for the four extended models for 2030 without nuclear generation

For the winter peak case, Lithuania exported 485 MW to Estonia through Latvia. Congestions can be observed in a small area near Riga and in the north-west of Estonia. The buses' marginal cost ranged from 0 $€_{2013}$/MWh to 73.5 $€_{2013}$/MWh and the average marginal cost was 28.3 $€_{2013}$/MWh with a standard deviation of 8.8 $€_{2013}$/MWh. The network congestion in this case greatly affected the system economic performances and the marginal cost of some areas.

For the summer off-peak case, huge exports from Estonia can be observed, namely 326 MW and 408 MW to Latvia and Lithuania, respectively. The buses' marginal cost ranged from 0 $€_{2013}$/MWh to 33.5 $€_{2013}$/MWh and the average marginal cost was 31.8 $€_{2013}$/MWh with a standard deviation of 3.4 $€_{2013}$/MWh. Due to the congestions at the cross-border transmission interface between Latvia and Estonia, the zonal splitting naturally occurred in this case.

For the summer peak case, export were witnessed from Estonia (605 MW) to Latvia (24 MW) and Estonia (580 MW). Congestions can be detected to the north-eastern part of Estonia and the area near Riga. The buses' marginal cost range from 0 $€_{2013}$/MWh to 60.5 $€_{2013}$/MWh and the average marginal cost was 29.8 $€_{2013}$/MWh with a standard deviation of 3.7 $€_{2013}$/MWh.

8.2 Steady state security analysis

Figure 15 shows the system physical features of the 4 extended models for 2030 without the nuclear reactor. They were also used as the starting points to perform n-1 steady state contingency analysis in the latter part of this sub-section.

Similarly to the previous cases, the system voltages under normal operation were within the standard range (0.95 to 1.05 p.u.). Congestions can occur in the northern part of Estonia at most times; they sometimes extend to the southeast of Riga. In general, Estonia had lower voltage than the other two countries, but compared with the previous cases, the system voltage in normal operation was not as high as when having the nuclear generator.

Based on the operational points listed in Figure 15 for the four models of 2030 without nuclear generation, contingency sets containing each single transmission line, transformer and generator in the models were applied for the steady state security analysis. Table 14 lists the most severe contingencies according to each criterion in the table.

Table 15 Most critical contingencies according to multiple criteria for the four cases without nuclear generator

Cases	Contingency component	Most severe consequence	Violations	Unserved loads (MW)	Disconnected generation (MW)	Maximum overload (%)	Minimum Voltage (p.u.)
Winter off-peak	contingency 18	Disc. Gen.	0	0	13.83	-	-
	contingency 2	Num. violations	45	0	0	115	0.867
	contingency 11	Low voltage	6	0	0	-	0.799
	contingency 5	Uns. loads	0	16.07	0	-	-
	contingency 3	Overload	36	0	0	236	0.817
Winter peak	contingency 2	Num. violations	34	0	0	142.7	0.811
	contingency 9	Overload	3	0	0	161.2	-
	contingency 11	Low voltage	9	0	0	102.5	0.593
	contingency 5	Uns. Loads	0	25.61	0	-	-
	contingency 18	Disc. Gen.	0	0	23.91	-	-
Summer off-peak	contingency 14	Overload	2	0	0	150.5	-
	contingency 12	Disc. Gen.	0	0	13.33	-	-
	contingency 5	Uns. loads	0	13.72	0	-	-
Summer peak	contingency 3	Overload	37	0	0	242.7	0.808
	contingency 18	Disc. Gen.	0	0	14.29	-	-
	contingency 11	Low voltage	9	0	0	-	0.783
	contingency 5	Uns. loads	0	22.37	0	-	-
	contingency 2	Num. violations	51	0	0	118.6	0.861

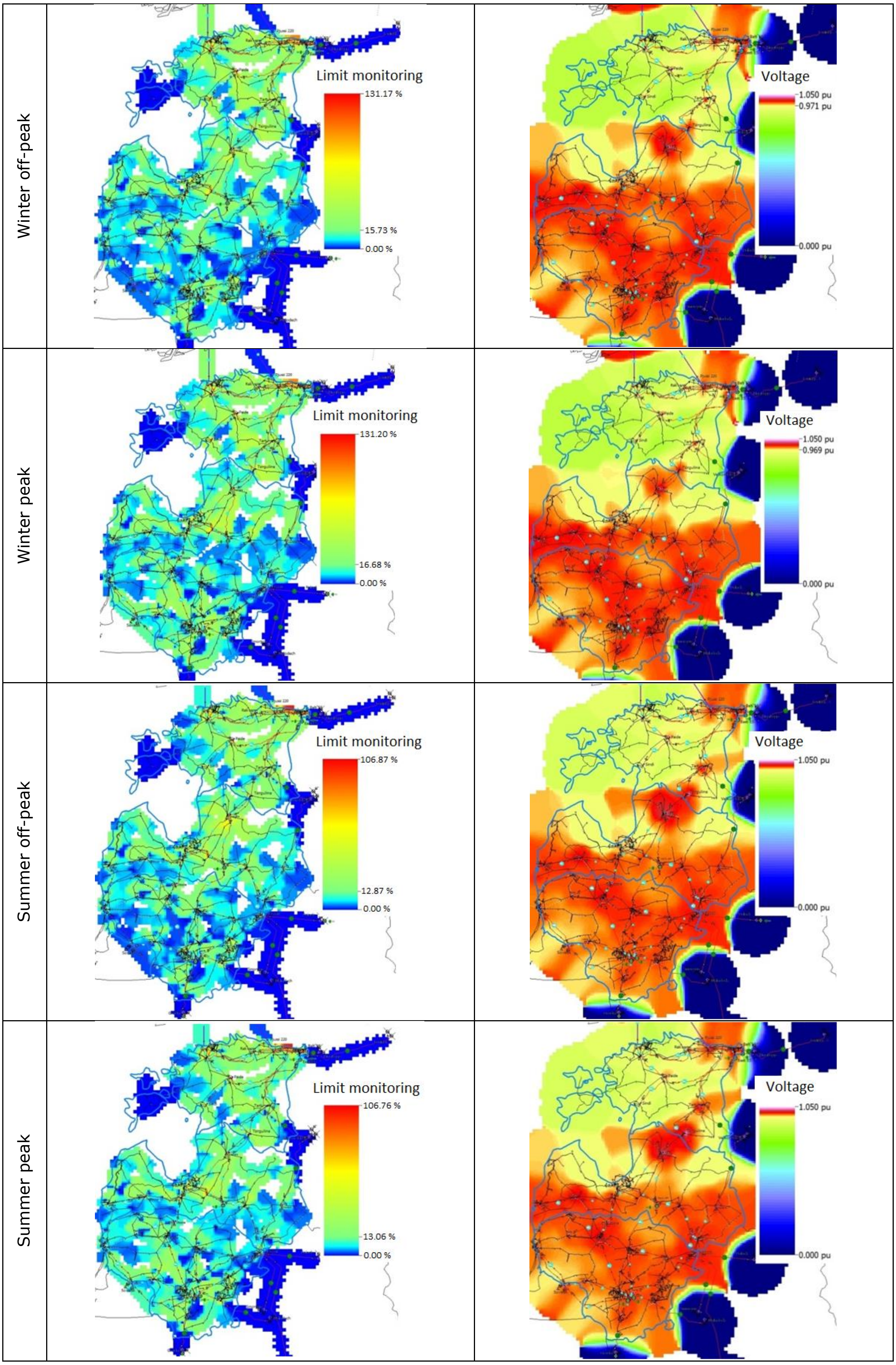

Figure 15 System performance for the four 2030 models without nuclear generator under normal operation

Compared with the case with a nuclear generator, the system security under n-1 contingency did not change much. No system-wide disturbance was witnessed in the studied cases.

For the winter off-peak case, the most serious contingency was still the loss of the component in contingency 3 which created the highest overloads in the contingency set. Even though the highest number of violations can be observed when the component in contingency 2 failed, but the consequences were not so serious.

For the winter peak case the worst overload contingency was to lose the component in contingency 9, which caused also 60% higher power flow than the maximum allowed flow over other lines. However, the most serious problem happened when the component in contingency 11 failed, which brought the lowest voltage 0.593 p.u. in the system, at which the system cannot practically operate. It is as severe as system wide disturbance.

For the summer off-peak case was most resilient among all the 4 cases. The most severe one was the tripping of the component in contingency 14, which can bring 50% excessive flows. Other contingencies did not create serious problem for the system.

For the summer peak case, like in the winter off-peak case, the most serious contingency was the loss of the component in contingency 3 which created the highest overloads in the contingency set. Also, when the component in contingency 11 fails, it brought the lowest voltage 0.783 p.u.in the system.

Obviously, the most critical components in the system were the one in contingency 11 (which can cause un-operationally low voltage in the winter peak case) and the component in contingency 3 (which, when failing, resulted in system overload in some cases). Further critical network components are not listed here for the sake of concision.

9. Conclusions

A power system model of the Baltic States has been developed with the purpose of assessing comparative options for a reliable and secure development of the region's electricity system. The model consists of buses with voltage of 110 kV and higher, mainly 110 kV, 220 kV and 330 kV. The 35 kV undersea cables connecting the Estonian mainland and the north-western islands were also included. The model has been calibrated based on the 2014 reference scenario to match the historical records from ENTSO-E.

The cross-border power flows in the Baltic model are close to the recorded ENTSO-E data in winter off-peak load and summer peak load scenarios. The two additional scenarios of winter peak load and summer off-peak load were examined. Line loading and voltage levels within the Baltic States lie within the acceptable range in all 2014 reference scenarios. As a rule, the Baltic States exported electricity to mainland Russia, but imported it from Kaliningrad and Belarus. However, from the perspective of the Baltics, the dependence on Russia is fairly low as regards electric power.

Lithuania's network infrastructure is adequate and can sustain large quantity of imports. The hydro pump station is important for the shifting of generation resources, and thus plays a key role in reducing the system marginal cost.

The Latvian power system enjoys considerable market advantages due to the high ratio of renewable energy - mainly hydro - in its electricity generation mix. In the reference scenario Latvia is a net exporter. However, the network seems not as adequate as that of Lithuania. Sometimes, congestion can cause the increase of the system marginal cost.

The Estonian network may occasionally experience lower voltages compared with the other two Baltic State power systems, especially when the Estlinks (interconnecting Estonia with Finland) are under heavy load conditions. Reactive compensations may be needed, particularly around the area of Tallinn. Even though the installed wind turbine capacity is the highest among the three Baltic States, this is still not enough to give Estonia the same strategic market position as Latvia.

The analysis of the horizons 2020 and 2030 showed that the dependency of the Baltic States on foreign electricity production is fairly low, provided that the expansion of generation resources goes ahead as planned.

The cross-border transmission corridors inside the Baltic States are sufficient to sustain the electricity consumption patterns assumed in the scenarios under the current study; however, the internal network reinforcement projects should be fostered in order to remove congestions, especially in the northern part of Estonia and in the area at the south-west of Riga.

Nuclear generation in Lithuania can greatly improve security of electricity supply in the Baltic States; even in its absence, however, the Baltic States can still count on alternatives for power generation, although with a decreased security margin.

The current report provides insight on the ability of the Baltic States to operate their electricity systems independently; furthermore, it paves the ground for more detailed market analyses, expected to be conducted with tailored market/power dispatch tools to be eventually combined/interlinked with the currently utilised power flow models.

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Annex

Table A-1 Network reinforcement projects

No.	Project name	Countries	Included in scenarios	Voltage level (kV)	Length (kM)	GTC contribution (MW)
1	Harku-Lihula-Sindi	EE	2020	330/110	140	500
2	Kilingi-Nõmme - Riga TEC II	EE-LV	2020	330/110	16	500
3	OHL between Alytus and PL-LT border	LT-PL	2020	400	51	500
4	Alytus-Kruonis	LT	2020	330	53	500
5	Klaipeda-Telsiai	LT	2020	330	85	700
6	Klaipeda-Nybro	LT-SE	2020	300	440	700
7	Grobina -Imanta	LV	2020	330	380	800
8	Tartu-Sindi	EE	2020	330/110	162	600
9	Visaginas-Kruonis	LT	2030	330	200	600
10	Vilnius-Neris	LT	2030	330	50	600
11	Panevezys -Musa	LT	2030	330	80	700
12	Sindi-Paide	EE	2030	330	75*	200
13	Tartu-Valmiera	EE	2030	330	128*	200
14	Tsirguliina-Valmiera	EE	2030	330	60*	200
15	Balti-Tartu	EE	2030	330	164*	200
16	Eesti-Tsirguliina	EE	2030	330	238*	200
17	TEC2-Salaspils	LV	2030	330	14*	600
18	TEC1-TEC2	LV	2030	330	12*	600
19	Viskali-Musa	LV-LT	2030	330	138	600
20	Aizkraukle-Panevezys	LV-LT	2030	330	123*	600

*Estimated by the authors according to the existing 110kV lines

Table A-2 Considered new power plant installations in Baltic States in 2020 and 2030

No	Country	Project	Fuel type	Installed capacity (MW)	location	Considered in Scenario	Note
1	LV	Kurzeme	Coal/Biomass	400	Ventspils	2020	Depending on Visaginas NPP project
2	LT	Visaginas NPP	Nuclear	1326	Visaginas	2030	
3	EE	Baltic Blue	Wind	420	Hiiumaa	2020	Off-shore
4	LV	Ventspils	Wind	100	Ventspils	2020	On-shore
5	LV	Baltic Wind Park	Wind	200	Liepaja	2020	Off-shore
6	EE	Baltic Blue	Wind	400	Hiiumaa	2030	Off-shore
7	LV	Ventspils	Wind	250	Ventspils	2030	Off-shore

List of abbreviations and definitions

AC	Alternating Current
ARM	Adequacy Reference Margin
ASIFI	Average System Interruption Frequency Index
BEMIP	Baltic Energy Market Interconnection Plan
BIPS	Baltic Integrated Power System
BRELL	Belarus, Russia, Estonia, Latvia, and Lithuania
CCGT	Combined Cycle Gas Turbine
CENELEC	European Committee for Electrotechnical Standardization
CHP	Combined Heat and Power
DC	Direct Current
ECOST	Expected Customer Outage Cost
ENTSO-E	Transmission System Operators for Electricity
EU	European Union
HVDC	High Voltage Direct Current
IET	Institute for Energy and Transport
IPS/UPS	Integrated Power System/ Unified Power System
JRC	Joint Research Centre
NGC	Net Generation Capacity
NPP	Nuclear Power Plant
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
RAC	Reliably Available Capacity
RC	Remaining Capacity
RES	Renewable Energy Sources
SAIFI	System Average Interruption Frequency Index
SOAF	Scenario Outlook & Adequacy Forecast
TSO	Transmission System Operator
UC	Unavailable Capacity
UCTE	Union for the Co-ordination of Transmission of Electricity

List of figures

List of tables

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