RIGA TECHNICAL UNIVERSITY
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ARTJOMS OBUŠEVS

METHODOLOGY FOR TRANSMISSION NETWORK DEVELOPMENT PLANNING CONSIDERING ELECTRICITY MARKET

THESIS
OF SCIENTIFIC DEGREE OF THE DOCTOR ENGINERING SCIENCES

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RIGA 2014

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EIROPAS SOCIĀLAIS
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EIROPAS SAVIENĪBA

This work has been supported by the European Social Fund within the project «Support for the implementation of doctoral studies at Riga Technical University».

Šis darbs izstrādāts ar Eiropas Sociālā fonda atbalstu projektā «Atbalsts RTU doktora studiju īstenošanai».

Эта работа выполнена при содействии Европейского социального фонда в рамках проекта «Поддержка развития докторантуры РТУ».

ABSTRACT

The main point of this thesis is to demonstrate the new deterministic concept with dynamic approach to transmission expansion planning in a perfect competitive electricity market based on technical and market economic regulation principals.

The main part is focused on methodology and approach elaboration to transmission development planning in the long-term. During the past years, there has been interest and investigation in the area of transmission planning. With the establishment of new regulatory framework, the necessity of reviewing the transmission planning functions has become relevant.

In power system development horizons and long-term planning tasks, decision makers and planning engineers require proper instruments that would be able assess the impacts of large-scale wind power installation. In addition, to secure optimal development solutions, a comprehensive understanding of the System and possible impacts on its operation is necessary. Moreover, understanding the electricity market, as well as the ability to calculate in advance the generation and transmission capacity requirements is needed.

The goal of the work is to introduce methodology that could be implemented for transmission adequacy planning. In addition, the methodology should bring identification of requirements for modifications of remaining technical infrastructure, of E-market design as well as interventions by the regulation of the environment, by classified actions that may be appropriate to be used during the various time horizons, such as long-time, mid-time and operational with respect of efficiency in system management.

ANOTĀCIJA

Promocijas darbā ir izstrādāta jauna deterministiska koncepcija ar dinamisku pieeju pārvades tīklu attīstības plānošanai pilnīgās konkurences liberalizētos elektroenerģijas tirgus apstākļos, pamatojoties uz tehniskiem un ekonomiskiem regulēšanas principiem.

Promocijas darbs ir veltīts pārvades tīklu ilgtermiņa attīstības plānošanas metodoloģijai. Pēdējo gadu laikā ir pieaugusi īpaša uzmanība pārvades tīklu plānošanai. Izveidojot jaunu tiesisko regulējumu, kļuva aktuāla nepieciešamība pārskatīt pārvades tīklu plānošanas kritērijus.

Energosistēmas attīstības un ilgtermiņa plānošanas uzdevumos, lēmumu pieņēmējiem un plānošanas inženieriem nepieciešams atbilstošs instruments, kas spētu novērtēt liela mēroga atjaunojamo energoresursu ietekmi. Papildus, lai nodrošinātu optimālus attīstības risinājumus, ir nepieciešama visaptveroša izpratne par Sistēmu un iespējamām ietekmēm. Turklāt, ir nepieciešama izpratne par elektroenerģijas tirgus darbību, ievērojot ražošanas un pārvades jaudas mainīgo raksturu.

Darba mērķis ir izstrādāt metodoloģiju, kuru var izmantot pārvades pietiekamības plānošanai. Tā dos iespēju noteikt un pamatot esošo un plānoto energosistēmas tehnisko infrastruktūru, to iespējamo modifikāciju nākotnē, elektroenerģijas tirgus struktūras izveidi, kā arī izmaiņas vides regulēšanā, ar klasificētiem pasākumiem, kuri var būt lietderīgi izmantoti dažādos laika horizontos: ilgtermiņā, vidējā termiņā un operatīvā vadībā.

АННОТАЦИЯ

В диссертации представлена новая детерминистическая концепция планирования динамического развития системообразующих сетей, в условиях идеального конкурентного рынка электроэнергии, учитывая технические и экономические принципы.

Основная часть диссертации посвящена методологии долгосрочного планирования развития системообразующих сетей. В течение последних лет возрос интерес к исследованиям в области планирования системообразующих сетей. В связи с созданием новой нормативной базы, возникла необходимость пересмотреть критерии планирования системообразующих сетей.

Для решения задач долгосрочного планирования, инженерам необходимо разработать надлежащий инструмент для оценки влияния возобновляемых источников энергии. Кроме того, для обеспечения оптимальных решений развития, необходимо всестороннее понимание системы с учетом факторов, влияющих на её функционирование. Также необходимо учесть влияние рынка электроэнергии на структуру генерации и межсистемных связей.

Основной целью работы является разработка методологии для решения задач динамического развития системообразующих сетей. Методология предназначена для создания и обоснования развития технической инфраструктуры, рынка электроэнергии, а также мер по регуляции окружающей среды, на основе систематических действий, которые могут быть целесообразны для использования на различных временных горизонтах, например долгосрочных, среднесрочных и оперативных, в отношении эффективности управления системой.

Theses of Dissertation

Target of Dissertation: Transmission development planning methodology with a long-term focus on technical regulation and market – economic regulation principles.

A coordinated approach including optimal power flow (OPF) implementation for capacity calculation will show the best use of the electricity transmission lines to interconnect Europe, which will open additional opportunities for development planning with social welfare estimation.

Sub-tasks:

- Transmission planning methodology development according the needs for new methods and tools for planning of the future European power system with considerable integration of RES;
- Elaboration of the transmission network analysis model, including intermitted generation and market conditions within AC model;
- Consideration of the complexity and dimension of development and optimization tasks in long-term, with appropriate method elaboration for the steepest calculation of OPF simplified by DC method;
- AC and DC OPF models compilation for development planning techniques elaboration.

The research is carried out in framework of *European Energy Research Alliance* (EERA), *Joint research Programme on Smart Grids, Transmission planning* with main target focused on R&D of next generation of smart grid technologies and systems development.

Affidavit

I certify that I have the whole dissertation prepared individually, using the literature according to a list of references. Where others sources of information have been used, they have been acknowledged.

RIGA, 25.06.14

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Acknowledgement

I would like to express my sincere gratitude to my supervisor Professor Irina Oļeiņikova from Riga Technical University for the continuous support of my *Ph. D* study and research, for her patience, motivation, enthusiasm. Her guidance helped me in all the time of research and writing of this thesis.

I am thankful to *Dr. sc. ing.* Mário Turčík, my friend and professional colleague for his help, countless number of discussions, advices, professional passion and willingness to explain and understand.

To my family for their support, encouraging and belief that was available any time I needed in studies and also in my personal life.

Contents

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List of Symbols and Abbreviations

AC – Alternating Current
ACOPF – Alternating Current Optimal Power Flow
ATC – Available Transfer Capacity
CR – Congestion Rent
DC – Direct Current
DCOPF – Direct Current Optimal Power Flow
EU – European Union
FIT – Feed-in-Tariff
ICT – Information and communications technology
IPE – Institute of Physical Energetics
IPS/UPS – Integrated Power System/Unified Power System of Russia
LMP – Locational Marginal Pricing
m. u. – Monetary Units
MC – Marginal Cost
MCC – Marginal Cost of Congestion
MCG – Marginal Cost of Generation
MCL – Marginal Cost of Losses
MCP – Market Clearing Price
MCV – Market Clearing Volume
NPP – Nuclear Power Plant
NPS – Nord Pool Spot
NTC – Net Transfer Capacity
NWE – Northwest Europe
OPF – Optimal Power Flow
PCR – Price Coupling of the Regions
PDIPM – Primal-Dual Interior Point Method
PS – Power System
RES – Renewable Energy Sources
SCOPF – Security Constrained Optimal Power Flow
SGT – Smart Grid Technologies
SRMC – Short Run Marginal Cost
SW – Social Welfare
TRM – Transmission Reliability Margin
TSO – Transmission System Operator
TTC – Total Transfer Capacity
UC – Unit Commitment
UP – Uniform Price
VOLL – Value Of Lost Load
Wind PP – Wind Power Plant
ZMP – Zonal Marginal Pricing

Introduction

Actuality of the Subject, Background and Problem Statement

To foster 2020 climate targets and estimate the technical and economic impact of renewable energy sources (RES) accommodation to transmission networks, several theories based on the social impact of the investments in competitive markets and marginal pricing are created. Electricity market and Smart Grid Technology's integration in energy sector of many countries presents completely new problems from different perspectives, such as:

- System operation and reliability issues;
- Network planning including future uncertainties;
- RES integration in different voltage levels;
- Completion of the Internal Energy Market in EU;
- Implementation of novel SGT and ICT solutions.

Many transmission expansion planning methodologies and tools have been proposed to obtain the optimal solution for the transmission expansion problem: mostly using classical optimization techniques such as linear programming, dynamic programming, nonlinear programming, mixed integer programming, optimization techniques like Benders and hierarchical decomposition etc [1, 2]. Would like to acknowledge the lifetime contributions of Latvian and Russian scientists in this direction: V. Dale, Z. Krishans, O. Paegle [3, 4] with dynamic optimisation methods, D. Arzamascev, A. Lipes, A. Mizin [5], L. Melentiev [6], V. Arion [7] and works of V. Venikov.

Methodologies for transmission network development find an optimum expansion plan by using a calculation procedure that solves a mathematical formulation of the problem. Due to the impossibility of considering all aspects of the transmission planning tasks, to obtain result in form of optimal plan, significant simplifications have to be considered, thus – it should be technically, financially, and environmentally verified, among other examinations, before the planner make a decision. In the formulation of these models, the transmission planning is posed like an optimization problem with an objective function (a criterion to measure goodness of each expansion option), subject to a set of constraints. These constraints attempt to model a great part of the technical, economic, and reliability criteria imposed on the power system expansion [1].

The great majorities of researches describe only one-time static problems investment models and do not consider additional factors that can affect the network expansion in future. The new network operation conditions create new requirements for transmission planning (chapter I), which include new methods and algorithm elaboration and implementation (chapter II). A transmission network planner's need to aggregate regional system, defined areas, or subsystems, capacity between areas, including a mixture of supply and demand. The fairly detailed and widely used created model can be implemented for various purposes including expansion planning and energy security analyses (chapter III).

The main point of this work is to demonstrate the new methodology based on the deterministic concept with a dynamic transmission expansion planning in a perfect competitive electricity market with technical and market economic regulation principals.

Research Methods and Tools

To be able to practically achieve the proposed goal, the following assumptions were accepted:

- First, this study focuses on perspective development strategies, which are elaborated by given methodology that could contribute to future electricity supply;
- Second, the given methodology does not attempt to fully and reliably analyse the power system that includes addressing sub-hourly, transient, and distribution/ transmission system requirements;
- Third, this work presents the new methodology for Modern Transmission System Planning based on common PS and electricity market characteristics required to reach 20-20-20 targets with address to SRA 2035, R&D Roadmap ENTSO-E and EC Directives;
- Lastly, a long-term development planning methodology was developed taking into account uncertainties associated with data assumptions and limitations, which can be reflected by the created methodology.

The algorithms proposed in the thesis consisted of AC/DC OPF models and were realized by the mathematical (numerical) simulation in the environment of MatLab software. The approved algorithms of development processes modelling were used in multi-step development planning tasks and further implemented in PSPlanner software.

A consideration of details in the present work is chosen with respect to the applicability of approaches, algorithms and methods: moreover, to keep the contents readable, as well as to avoid its early fall out of use. Another issue is to leave some level of adjustability or partial upgradeability, which would be beneficial in cases when progress can be made due to the new knowledge.

Practical significance of the research results

- Performed strategic bidding analysis and price formation mechanisms;
- Grid's optimal power flow distribution algorithms have been developed and tested, subject to N-1 criteria and renewable energy sources, to determine social welfare, nodal/zonal electricity prices, and to define congestions and constraints (voltage levels, active/reactive power production, etc.);
- Developed transmission network planning methodology in electricity market environment, implementation of which in practice will allow:
    - To perform long-term energy balance evaluation (security analysis for different scenarios);
    - To perform long-term perfect competition electricity price forecasting for different scenarios (price variation after introduction of new interconnection or/and power plant exploitation is started or stopped, etc.);
    - To perform long-term welfare forecasting, obtained by different agents, for different scenarios.
- The proposed simplified unit commitment algorithm allows assess influence of renewable energy sources to a power system and market formation (shifting of entire production curve due to inclusion of renewable energy sources have impact to the conventional generators);
- To address the challenges of sustainable development.

Elaboration of the thesis is based on valuable long-term experience of the Laboratory of Power System Mathematical Modelling, IPE, taking as a starting point the basic principles of development planning optimization methods and their realization experience in practice [3, 4, 8].

1. Transmission Planning Considerations

Transmission planning can be classified as static or dynamic according to the tasks that are to be solved. In the static planning tasks, the planners seek the optimal set for the single time period (for instance, single year) with a focus on the final optimal network state for the pre-defined future single period. This thesis will focus on the multiple years' consideration of optimal development strategy identification for the whole planning period, which is classified as dynamic (see Fig. 1.):

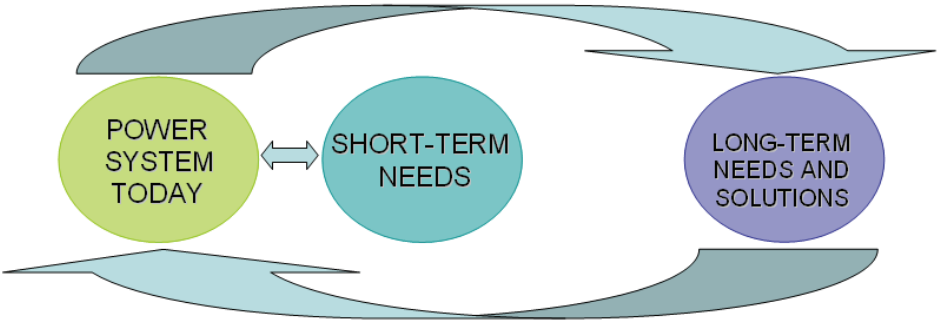


Fig. 1. Planning horizons

The optimal development strategy consideration makes it necessary to apply systems analyses and dynamic multi-step optimisation methods in order to observe reciprocal interconnections of system elements over time and space. A characteristic feature of network analysis is that for selecting an optimal solution, sophisticated systems and various variable parameters must be investigated during the development process.

The basics of the step-wise PS development approach are established from the following main factors (see Fig. 2.) [4, 8]:

- Time levels / voltage levels / loads, generation etc. modelling;
- Decision-making for advance stage (horizontal information flow) in uncertain conditions only for the nearest time period of 2–5 years;
- Estimation period shall correspond to average life-circle period, approximately within 20 to 30 years;

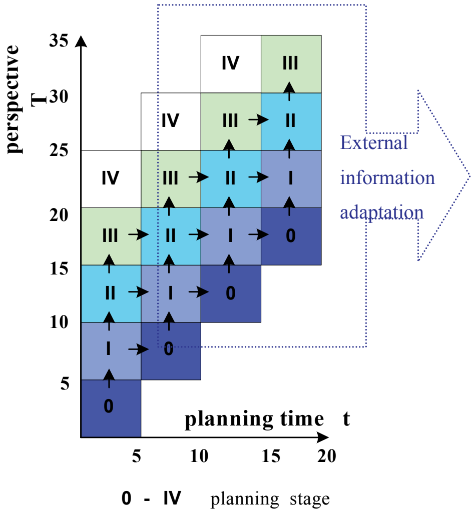


Fig. 2. Development Planning Structure

To realize this particular approach, modelling methods of the existing system development were supplemented with new technical regulation and market economic regulation criteria's and functionalities.

Fig. 3. Power System analysis modification

The modelling methods must adequately reflect real systems characteristics as much as possible, as well as include flexible generation incorporation, and perform system technical, economic and ecological criteria calculation. Moreover, effective optimization methods are required to solve optimization tasks with discrete variables [8].

Benefits that may be recognized for the sake of the availability of the well-planned transmission system are denoted to technical as well as to electricity market aspects, which is, in fact, closely connected to economical efficiency issue.

The benefits from the transmission availability can be formulated as follows:

- Connection of diverse types of loads that brings flatter system load diagram;
- Sharing of reserves among interconnected systems;
- Access to remote power generation (remote RES or due to the environmental reasons far from load);
- Sharing of power production capacities;
- Decrease of regional market concentration, thus mitigation of market power leading to more efficient market operation;
- Reduction of price volatility, as well as levelling of price differentials between areas (relative benefit);
- Decrease of system failure risk;
- Creates preconditions for further development and smoother integration of new resources (including volatile RES such as wind and solar).

Connection of all characteristics will lead to power system sustainability that is identified as the fact that up to now in designing process of electrical power systems not enough attention has been drawn to consequences of the made decisions [9]. Taking into consideration the aspects mentioned above, implementation of proposed dynamic methods and tools for system development sustainability analysis will increase the accuracy of PS development scenarios and decisions in future

1.1 Transmission Planning in Liberalized Environment

The deregulation of the electricity industry leads to global developments toward the commoditization of electric energy [10, 11]. The liberalization and privatization of the electricity sector began in Chile in 1982 and the trend spread to Latin American countries and the rest of the world in the 1990s [12]. This tendency has increased in Europe and North America, where market forces have pushed policymakers to begin removing artificial obstacles that have shielded electric utilities from competition. The electricity price is far more volatile than that of other commodities normally noted for extreme volatility [11]. Relatively small changes in load or generation can cause large changes in electricity prices in a matter of hours (with real-time dynamic prices in seconds or minutes) [13]. Unlike in other financial markets, electricity is traded every hour of the year; however, it cannot be stored efficiently. Thus, the balance between generation and consumption must be kept every hour of a year [14]. However, electricity differs from other commodity markets. Reason for the obvious difference in markets would be the variety as regards costs/expenses of electricity production. There is nearly no variable cost in hydro, solar and wind generation, however variable costs of power generation from coal, gas and another fossil fuel are considered on a wider scale. To satisfy the demand for low cost power, a great variety of generation sources is needed. Some power generation units are expensive to build; however, they can be operational all year round, continuously sustaining the generation process [15]. Other types like combined heat and power plants are used mostly to cover wintertime heating and consumers' needs during high price periods of the year. Gas powered turbines are used only for certain periods of high price and electricity demand because of their energy intensive nature [16]. Despite different deregulation processes, market concepts are relatively the same. The main tasks of a market are: to unbundle the competitive functions from the monopoly functions and to establish a free wholesale and retail electricity market.

In different jurisdictions, bulk system (or "grid") operators are termed in a different way: in Europe they are called transmission system operators (TSOs); in India – load dispatch centers; in the United States – regional transmission organizations (RTOs) or independent system operators (ISOs). Operators of the low-voltage level who reduce the voltage from the transmission lines and deliver power through the distribution lines also have different names, including distribution system operators (DSOs) in Europe and utilities in the United States. The load-serving entities (LSEs), such as utilities, competitive retailers, and the DSOs that sell electricity to retail consumers, purchase their power from the wholesale energy market.

The ultimate goal of the European process of electricity market liberalisation is the creation of a single European internal electricity market. The integration of the present 25 more or less liberalised national markets into a single European market, or even in several regional markets, is however hampered by several factors, such as the existing differences among the Member States in organisation and regulation of the electricity industry, a high degree of concentration in many national generation markets, insufficient coordination and collaboration between regulated entities and regulatory authorities, and a limited amount of available interconnection capacity between neighbouring national electricity systems [17].

The following list presents the steps of Baltic energy market integration, as one of the essential means and basis in achieving the Baltic States integration in the EU electricity market:

- April 1, 2010: via the Estlink I interconnection Estonia has joined to the Nord Pool Spot (NPS);
- June 18, 2012: Lithuania became a separate NPS price area;
- June 3, 2013: opening of the Latvian price area successfully started, which was of utmost importance for integration of the Baltic energy market into European PSs and creation of a common electricity market based on the Scandinavian model;
- February 4, 2014: the price coupling of Northwest Europe (NWE) regions was performed under common computational model EUPHEMIA [18];
- May 13, 2014: joining of South-Western Europe to the common computation model (Fig. 4.).

To improve competitive market performance and increase its liquidity and reliability, market coupling (MC) mechanisms are organized. Nowadays, grid operators and power exchanges from 14 EU Member States (Belgium, Denmark, Estonia, Finland, France, Germany, Austria, UK, Latvia, Lithuania, Luxembourg, the Netherlands, Poland and Sweden) plus Norway are implementing a pilot project for joint electricity trading, the so-called day-ahead market coupling. The NWE market coupling combines all bids and offers in a region and creates a large integrated electricity market in the area concerned, combining 75 % of today's electricity consumption in the EU. From the technical and economical point of view, such centralized architecture for many functions is indeed beneficial, since it the translates complex and complicated many-to-many relationships among participants into one-to-one relationship, thereby facilitating further enlargement of the market coupling to other market areas.

The concept of market coupling was originally developed by Nord Pool Spot and has been successfully implemented in the Nordic market over the last 20 years. In 2013, the ground was laid for the successful delivery of the key European market integration projects – Price Coupling of the Regions (PCR) and the NWE price coupling project, as the initiative of seven European Power Exchanges (APX, Belpex, EPEX SPOT, GME, NPS, OMIE and OTE). It was implemented for harmonization of the European electricity markets by developing a single-price coupling algorithm for calculation of the electricity prices across Europe with aim to reach an integrated European energy market by 2014 – the target model [19].

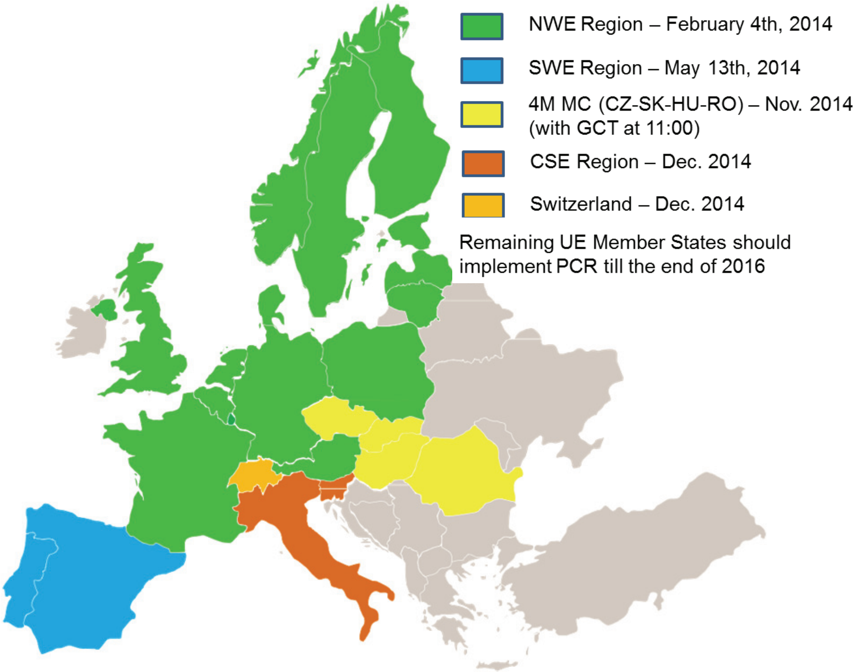


Fig. 4. Price coupling of regions implementation in Europe [20]

The PCR benefits are as follows:

- Increased liquidity, efficiency and social welfare;
- Guarantees for the overall welfare and optimal use of interconnection capacities;
- Removal of the unnecessary risks of trading separately the short-term transmission capacities and energy;
- Possibility of using cross-border capacities by all market participants;
- Promotion of liquidity, transparency and efficiency on the power markets across Europe [21].

Before liberalisation, most European electricity networks were interconnected for the purpose of mutual assistance and in some cases with a view to carrying out long term import/export contracts for electricity [22]. However, in today's liberalised electricity markets, the role of interconnections has been extended. By providing physical connection between electricity markets, interconnections form the key to the international trade. The European Commission concluded that more interconnection is needed to facilitate companies to extend their activities into other regions outside their traditional areas in order to increase competition [23].

Due to the high levels of concentration of electricity markets, strategic bidding has been deeply analyzed in the last decades by means of game theory simulation models. Current literature points out four major models in use for electricity markets: Bertrand based models, where price is the strategic variable [24–26]; Cournot-based models, where firms compete on quantities [27–29]; Stackelberg-based models, where a leader firm anticipates one or more followers moves on price or quantities [30, 31]; supply function-based models, where players bid supply curves rather than only price or quantities [32–34]. The supply function equilibrium (SFE) model applies very well to the market structure of many restructured electricity markets, such as New Zealand, Australia, Pennsylvania-New Jersey-Maryland Interconnection, California Power Exchange. In these markets, the bid format is precisely a supply function [35]. Typically, all of these models simulate the results of electricity markets with strategic suppliers exerting market power, requiring the solution of complex mathematical problems with a considerable computational time. This usually does not fit with the long term analyses for transmission expansion problem that should rely on fast and robust tools that perform market simulations over extended time horizons [36]. The typical approach applied to transmission planning is to consider a perfectly competitive market, where all suppliers bid at their marginal costs.

In Europe the high-voltage electricity transmission networks are owned and operated by TSOs. TSOs are not only charged with the task of operating and maintaining transmission networks, but also with the task of investing in new transmission capacity. TSO convinces/assure its regulatory authority that a new transmission is beneficial after which the investment costs are included in the rate base for the regulated tariff. These tariffs are separated from any charges for electricity as a commodity [22]. When interconnection capacity is limited, the available transmission capacity is allocated through market based congestion management mechanisms and Regulation [37] states that revenues resulting from the allocation of congested interconnection capacity shall be used for:

- guaranteeing the actual availability of the allocated capacity;
- network investments maintaining or increasing interconnection capacities;

- as income to be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs and/or fixing network tariffs.

Integrating transmission networks, building trans-European infrastructures, and creating a single and fully integrated energy market ask about the 218.5 bn.EUR. [The Commission estimates in 2012 that the current total investments requirements for energy networks infrastructure]. In the planning context, of a transmission system consideration of how it should be operated in future in order to achieve these targets, following scheme can be implemented [38], see Fig. 5.

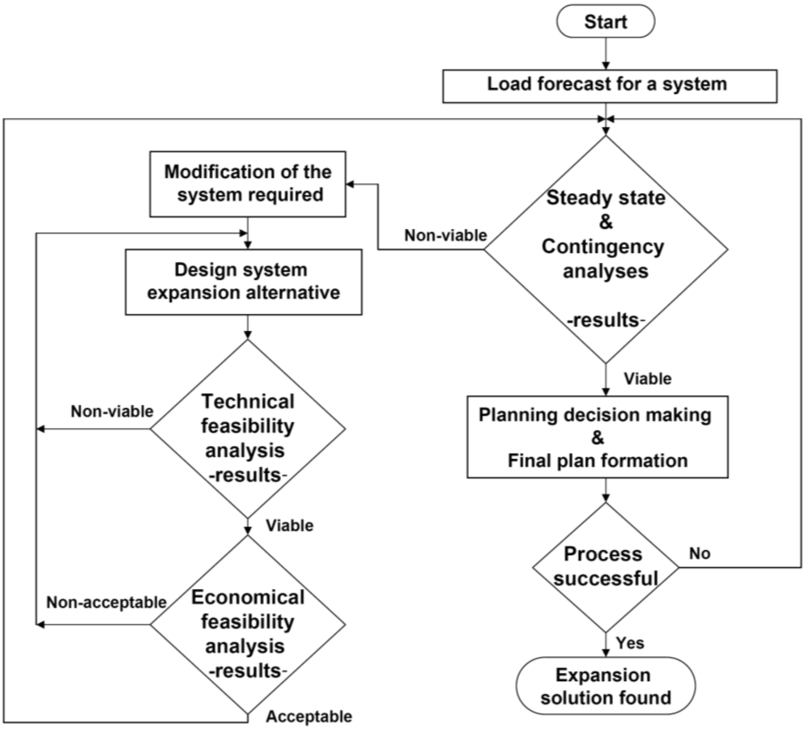


Fig. 5. Traditional Transmission System Expansion

Challenges closely related to an integration of volatile RES production, estimation of impacts both to a system and E-market associated with planning of transmission infrastructure are briefly analyzed below within the context related to:

- Volatility and balancing issues;
- System parameters and operational security issues;
- Development planning issues.

1.2 Modern Power System Expansion including Renewable Energy Sources, Europeans Targets and Developments

Current European legislation defines two different rules related to integration of the European power market [39]:

1. Electricity should flow according to price differentials through the use of market-based capacity auctions, and that cross-border capacities shall not be reduced in order to solve a country's internal congestions;
2. Priority should be given to access for renewable energy sources.

The above-mentioned rules need to be taken into account since they both are crucial for future transmission planning solution, which nowadays depended on market structure (see Fig. 6.).

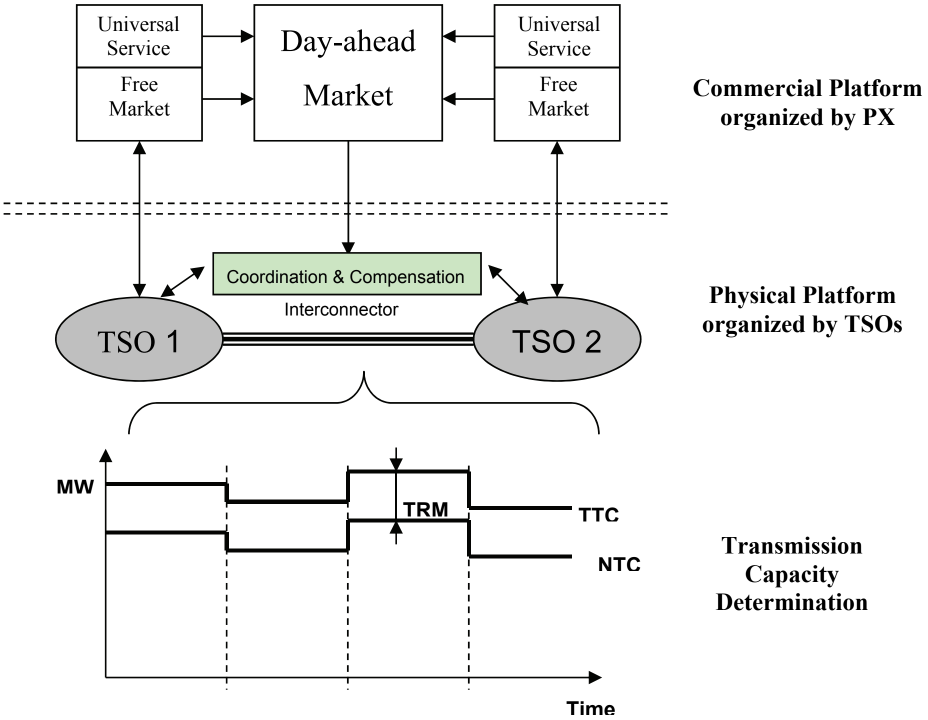


Fig. 6. E-market Environment Structure

Power system should be designed and operated in a way that the demand can be met at all times and under various conditions. Depending on the season, climate, and weather condition, the demand can fluctuate significantly over the single day, week or month. In addition to meeting the variability requirements, there is always some inherent uncertainty about future demand and the future ability of generators. Today there are various operation portfolios with hydro and thermal generation combinations to manage variability. The time scales of flexibility, from the system planning perspectives down to very short-term operation including impact of variable generation on system flexibility can be seen in Figure 7.

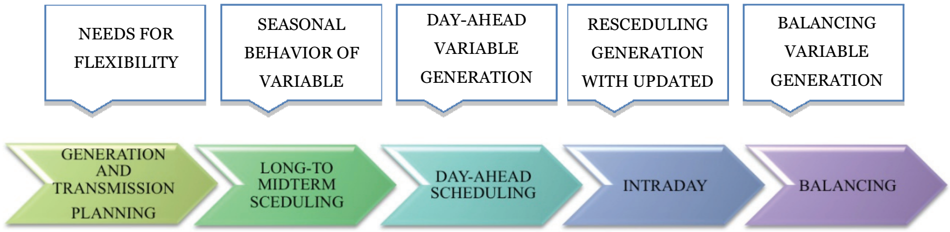


Fig. 7. Timeframes of the impact of variable generation on the system flexibility

To set the optimal expansion of the power system – transmission system in particular - under conditions of market environment, forward-looking approaches able to reflect and find balance between requirements (despite often contradictory cases) are necessary.

Market forms for different time frames of energy purchasing may be identified and distinguished in order to satisfy all types of services served by liberalized electricity market. The main time-scale categories of energy markets are long-term (weeks to years), short-term & very short-term (days-hours) energy markets, and each is characterized by manner of trading.

The relatively short time before power delivery has a significant positive impact on correct determination of available producer’s capacity as well as consumer’s level of demand. The importance of short-term and very short-term energy markets have even increased due to the difficulty in foreseeing intermittent production, such as wind or photovoltaic, and also due to the purchases of energy for its regulation (ancillary services). The organized energy markets whether as a pool or exchange usually provide more efficient additional auctions for balancing purposes called ‘balancing markets’, which are frequently used by TSOs. Modelling, simulation and analysis of the intermittent RES, such as wind, directly affects the energy markets – mostly fossil fuel markets, since those have a key role in supply of a considerable part of flexible generators, while not being the most appropriate for sub-hourly scheduling on sub-hourly markets such as the balancing market is.

2. Development process modelling

2.1 General drivers and Background to the Chapter

In this chapter the main drivers for the whole transmission grid and well market functioning is analyzed from development perspectives point of view.

According to the new requirements it is important to supplement existing transmission planning theory and tools by the following several aspects:

- The attributes to measure the goodness of a solution for each considered scenario (e. g., minimum operation costs, maximum benefits, maximum global welfare, etc.);
- Dynamic pricing;
- The introduction of flexible smart grid technologies;
- Increasing level of uncertainty.

However, this study is made on the large amount of assumptions and there are several relevant aspects that are not taken into consideration. For example aspects of appropriate market design, impact of loss factors on DC/AC interconnectors , etc.

This problem is solved from a position of a system operator, i.e. without any control on the generation planning. The different possible generation mixes and their evolutions over the time horizon are defined through scenarios. Each scenario gives technological solutions for generating units: their capacity, costs and locations (scenarios are based on the different possible energy policy choices).

2.1.1. Social Welfare

To match supply and demand curves in each market area in order to maximize consumer and producer surplus the following Social Welfare concept is used.

Social Welfare is a quantification to assess the potential implications of alternative policy options. The assessment of social welfare shall include a consideration of the additional economic benefit or cost, defined as the sum of the additional individual benefits and costs which are expected to be accrued due to the implementation of the respective policy options compared to the status quo. These benefits and costs shall be analysed independently for tariff customers (as a whole and separated based on their ability to afford the cost of electricity), Market Participants and System Operators. In undertaking this assessment, in all cases, the undertaking party shall clearly specify:

- assumptions about the redistributive effects of an increase of one of the above components for the surpluses of the other groups stated above;
- assumptions about preconditions for market functioning such as market power and liquidity;
- assumptions about implications stemming from external effects used to undertake the analysis [40].

$$\text{Social welfare} = \text{Producer surplus} + \text{Consumer surplus} \qquad (1)$$

Consumer surplus is the difference between what consumers are willing to pay for a product versus what they actually pay. In an energy market, a consumers' willingness to pay can be measured by Value of Lost Load (VOLL). This measure indicates the approximate value of avoiding involuntary energy curtailments. VoLL is the estimated amount that customers receiving electricity with firm contracts would be willing to pay to avoid a disruption in their electricity service [41, 42].

Producer surplus is the difference between what producers are willing and able to supply and the price they actually receive. Producer and Consumer surplus are calculated as presented in Fig. 8:

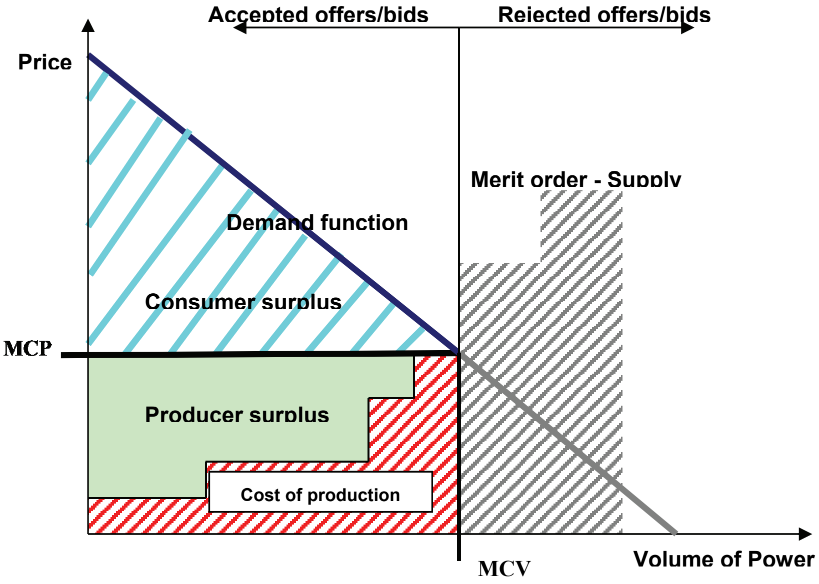


Fig. 8. General Spot Price formation principals
(MCP – market clearing price, MCV – market clearing volume)

2.1.2. Electricity pricing mechanisms

Pricing mechanisms for competitive electricity markets determine either a uniform price (UP), a set of nodal or locational marginal prices (LMP), or only a few zonal marginal prices (ZMP). Each of above mentioned mechanisms is characterized by level of complexity, ability for appropriate allocation of investments as well as rightfully allocates costs for final consumers [43].

Buyers and suppliers submit bids and offers for each hour of the next day and each hourly MCP (*or spot price*) is set in a way that it balances supply and demand. When there is no congestion, without considering transmission capacity between nodes or zones under market area and not assuming losses, entire price of system is system price and will be equal between nodes and zones MCP=LMP=ZMP; if congestion occurs, LMP and ZMP could be different.

Zonal pricing. The zonal pricing method has been introduced as reaction to solve very poor incentive ability of uniform pricing approach. According to the basic principle of zonal pricing, the whole market territory is sub-divided into several zones depending on their respective costs of congestion (Fig. 9.).

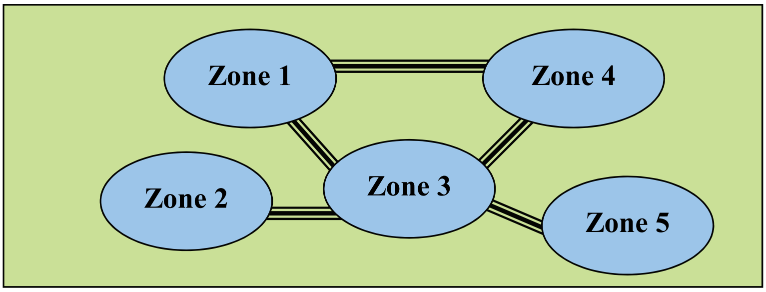


Fig. 9. Zone formation

Higher prices for electricity are paid in zones where demand exceeds transmission capability (deficit area on Fig. 10.) and vice versa. The price is uniform for entire zone. The zones are usually geographically pre-defined according to expected bottlenecks in grid, however, as in case of Nordic market (NPS PX) operation, number of zones can within the year vary according to changes in deployed generating capacities, particularly hydro resources.

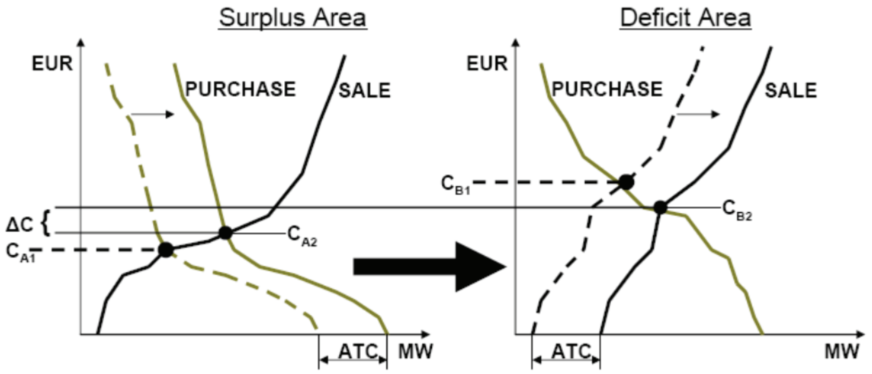


Fig. 10. Zonal price formation

where C_{A1}, C_{B1}– Prices determined as for insulated Areas (without any cross-border interconnection) [m.u./MWh]; C_{A2}, C_{B2} – Prices determined after utilization all available transmission capacity (ATC) of interconnector [m. u./MWh]; ΔC – price difference after utilization ATC (congestion) in [m.u./MWh] [44]. The European network is complex and it is operate in zonal principles.

Price differences between areas after utilization of transmission capacity between them generate an ownerless income on the spot market, trading flow from the area with a lower price to the area with a higher price. In situations when flow goes from high price area to low price area (towards low price area) due to specific operations or dispatch optimization by TSOs, generating of ownerless costs occurred.

These ownerless costs and incomes are referred as congestion rent (congestion revenue). Within the Nordic region this income is allocated to the TSOs as owners of the transmission grid. Calculation of congestion rent can be viewed in appendix 1 [45]:

$$\left(c_{B2} - c_{A2}\right) P_{A \mapsto B} = C_R, \tag{2}$$

where: $P_{A \mapsto B}$ - flow in specific hour from area A to area B [MWh]; C_R - aggregated congestion rent [m. u].

<u>Nodal pricing.</u> Method of determining market clearing prices for a number of locations on the transmission grid – nodes; Node is located in transmission system including generators and loads (substation on Fig. 12). Nodal price is equal to the cost of serving the next MW of load at a given location (node):

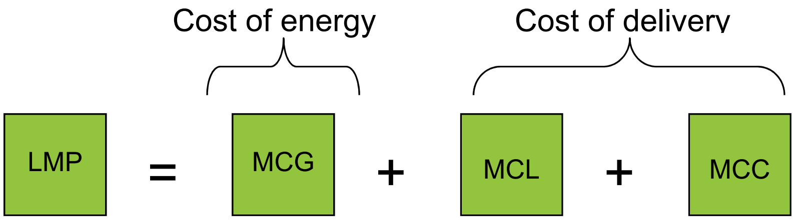


Fig. 11. Nodal price components

Nodal pricing principals:

- Required development of usual equilibrium price determination (include losses, constraints of system);
- Employed bid-based, security-constrained, economic dispatch principle;
- Higher potential for social welfare maximization than UP or ZMP.

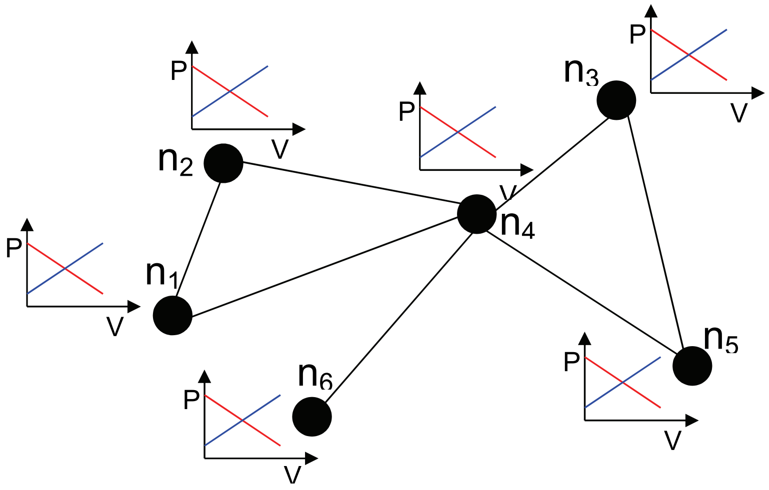


Fig. 12. Nodal Price formation principals

No congestion and losses => equal prices in all nodes

The optimization task in a case of zonal and nodal pricing models are based on social welfare maximization of consumers' and producers' surplus areas. The objective function to be maximized could be expressed:

$$\max \sum_{n} \left(\int_{0}^{d^a} D^a(x)dx - \int_{0}^{s^a} S^a(y)dy \right) \tag{3}$$

Where (a) represents an zone or node (area), d^a is demand in area (a) and D^a is the demand function in area (a), s^a is supply in area (a) and S^a is the supply function in area (a) and (n) is the number of areas.

Defenders of zonal pricing argue that system based on such principles will be well sufficient to achieve economical efficiency goals with lower complexity and therefore higher transparency to market participants. However, in heavy load periods when congestion is expected exists legitimate concern of market power abuse by market participants. Furthermore, arguable is also ability of right allocation and adequacy of incentives for new investments. Also due to that reasons the evolution of market structures worldwide introduces a nodal pricing principle as the proclaimed benchmark of congestion management, effectiveness and conformity with economic theory and physical laws.

According to aforementioned methods of price determination, the optimal prices in a transmission network are the nodal prices resulting from an optimal power flow performed by a centralized dispatcher.

The spot electricity market is actually a day-ahead market, and trading typically terminates the day before delivery. Analyzing the financial assets for most commodities the term ‘spot’ defines a market for immediate delivery and financial settlement. Such a classical spot market approach would not be possible for electricity, since the transmission system operator needs to be notified in advance in order to verify that the schedule is feasible and lies within transmission constraints. For very short time horizons before delivery the TSO operates the so-called balancing market. This is used to balance the price deviations in supply and demand from spot. The TSO needs to be able to call in extra production at very short notice, since the deviations must be corrected in a matter of minutes or even seconds to ensure physical delivery and to keep the system in balance. Spot and balancing markets serve different purposes and are complementary. Their functioning is quite different, however, and they should not be confused. For instance, in the USA the spot and balancing markets are often referred to as ‘forward’ and ‘spot’, respectively. In EU countries the convention and reserve the term ‘forward market’ for transactions with delivery exceeding that of the day-ahead market.

2.2 Long-term planning methodology under regulation and competition

Development planning is a process to determine an optimal strategy to expand the existing power system transmission network to meet the demand of the possible load growth and the proposed generators, while maintaining reliability and security performance of the power system. The general objective of the power system transmission network development planning task is to determine ‘where’, ‘how many’ and ‘when’ new element/devices must be added to a network in order to make its operation viable for a pre-defined horizon of development planning, with costs minimization and social welfare maximization for optimal expansion/development plan determination.

Main concepts of development planning are based on: Development Action (D-action); Development Step (D-step); Development Plan (D-plan). The essences of the parameters are explained on figure 13.

$$\overbrace{e(t-1)}^{Existing\ state} + \overbrace{(\dots\dots\dots)}^{\mathrm{Re}alized\ D-action(s)} = \overbrace{e(t)}^{New\ state}$$

Fig. 13. Development state formation

Development plan formation is a complicated process that requires extensive studies to determine many new network elements. Creation of the optimal development plan will ensure adequacy of the grid, generation and demand in the future.

Electricity market affects not only power system operation as whole, but also its development practices. It is determined by the condition that electricity generators are independent from transmission and distribution operators and their interests differ. This fact creates higher uncertainty conditions and time resolutions accuracy for the perspective forecasts than before and power system development planning and optimization is hampered. For network sustainable development solutions, estimation period must be assumed longer than economic life cycle period – advisable up to 30 years (see Fig. 14.). While selecting optimal development plans under uncertainty, it is necessary to formulate: information package set, representing information credibility range – prognosis, credibility estimation criteria and comparable development plans.

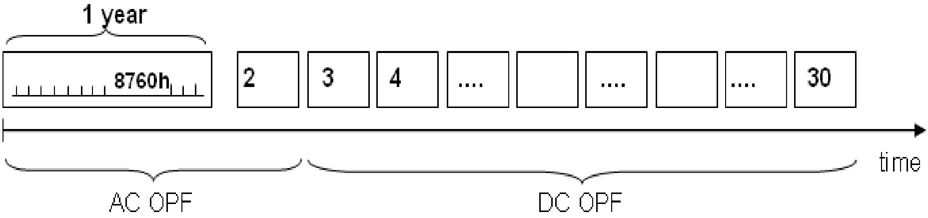


Fig. 14. Time frames within sustainable development

If the compromise between network estimation problems and development aggregated results has not been reached to match the quality of the planning results will be impaired. The following factors lead to solution to compile both the models AC and DC:

- For short-term analysis, to include intermitted generation and market conditions, of several years and subject to initial information availability can be used the full AC model;
- Considering the complexity and dimension of development and optimization tasks, as well as information uncertainty conditions, appropriate method for the steepest calculating of OPF to define criteria is simplified by DC method.

The objective function for the network development plan displays and integrates the technical and economic parameters as well as the power supply reliability (can be seen in appendix 2. [46]), ecological, etc. parameters. The objective function in (4) represents the social welfare, where the welfare is expressed as the aggregate demand utility bid function minus the aggregate generator offer function, plus aggregated congestion revenue, minus the investment cost in new lines. Objective function is a network development plan *g* quality criterion, denoted as *F*(*t*, *g*) is calculated by a formula:

$$\max F(T,g) = \max_{g\in\{G\}} \sum_{t=1}^{T} (SW(t,e(t),g) + CR(t,e(t),g) - IC(t,e(t),g)) \quad (4)$$

where: *t* – development step serial number; *T* – number of development steps in estimation period; *g* – development process; {*G*} – set of all possible development plans; *SW*(*t*, *e*(*t*), *g*) – social welfare criterion in development step *t*, development state *e*(*t*) and development process *g*; *CR*(*t*, *e*(*t*), *g*) – congestion revenue aggregated by

TSOs in development step *t*, development state *e*(*t*) and development process *g*; *IC* (*t*, *e*(*t*), *g*) – investment costs in development step t and development state *e*(*t*) and development process *g*.

According to formula (4), the objective function is the sum from $SW(t, e(t), g) + CR(t, e(t), g) - IC(t, e(t), g)$, i. e., an additive function. System graph, consumption and generation are constant values at the development step, but development actions are only realized in transition from development step *t* – 1 to step *t*. Observing these assumptions, *F*(*t*, *e*(*t*), *g*) model may look as follows:

$$F\left(t, e\left(t\right), g\right) = k\left(t\right) \cdot \tau\left(t\right) \cdot d\left(t\right), \tag{5}$$

Where: *k*(*t*) system quality criterion in the first year of the development step *t*; $\tau\left(t\right)$– number of years in development step *t*; *d*(*t*) – discount (reduction) coefficient in development step *t*.

Given that the assumed conditions are observed, *F*(*t*, *e*(*t*), *g*) is not dependent on development plan up to development state *e*(*t*). Thus, the objective function (4) allows application of dynamic programming.

To consider the impact of liberalized electricity market to technical and economic criteria each development state should be observed at an hourly base. Application of hourly calculation based on OPF allows taking into account the major trends of production and consumption during the day, taking into account consumption time shifting when considering multiple time zones, demand side management and demand response programs, distributed generation, etc [47, 48, 49].

Each development process is characterized by number of realized development actions and its realization moment, as well as by each development action realization type. Fig. 15 represent small example with 2 development actions, development step 1 year and 16 development states. The total number of development plans in this example will be 16.

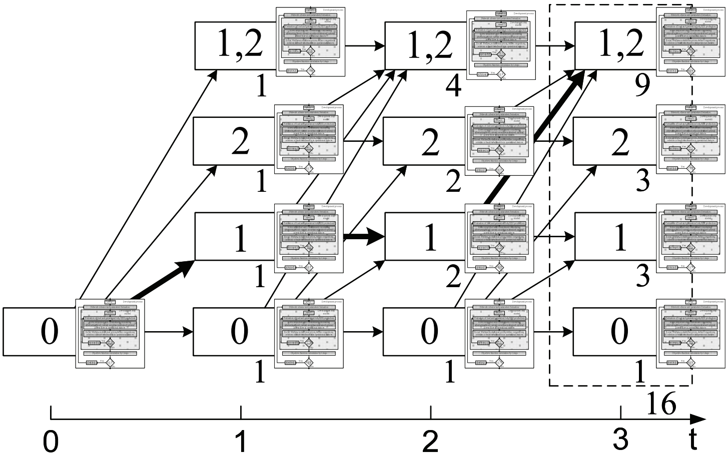


Fig. 15. Development states forming scheme example

In real tasks the number of comparable development plans attains astronomic quantity, therefore it is required to apply specialized dynamic optimization methods in power system sustainable development management process [8]. Within the frame of electric power system dynamic optimization task, power flow calculation must be performed with high-speed and certain accuracy. Due to this factor it is necessary to use specialized methods.

2.3 The AC/DC SCOPF Formulations

This chapter presents the theoretical approach of the optimal power flow method that can be used as a basis for social welfare/price calculation and modelling. OPF includes a security consideration – security constrained optimal power flow. SCOPF is used as a correct basis for transmission pricing, including security constraints by adjusting transfer capacity limits with the Transmission Reliability Margin.

The optimal power flow is a very large and difficult mathematical programming problem. The main aim of OPF is to determine the optimal steady-state operation of a power system, which simultaneously minimizes or maximizes the value of a chosen objective function and satisfies certain physical and operating constraints. To provide complex solutions for the network operation problem analysis and its consideration in development the following mathematical formulations can be implemented.

2.3.1 Formulation of OPF

OPF is a technique that has been used in the electricity industry for several decades. It was first discussed by J. Carpenter [50] and published the optimality conditions, including variable bounds, based on the Kuhn-Tucker conditions. Today OPF has been playing a very important role in power system operation and planning, which takes account of the security of the system.

The objective function of an OPF problem may take many different forms according to the different applications. The general objective is to maximize social welfare which comprises producers' and consumers' surpluses or minimize costs of production. The costs and benefits may be defined as polynomials or as piecewise-linear functions [44, 51, 52]. The problem can be formulated schematically as:

$$\max_{x} SW(x) \tag{6}$$

subject to

$$g(x) = 0 \tag{7}$$

$$h(x) \leq 0 \tag{8}$$

$$x_{\min} \leq x \leq x_{\max} \tag{9}$$

where $SW(x)$ objective function of social welfare; $g(x)$ equality constraints of active and reactive power balance; $h(x)$ inequality constraints of power flow limit of line, bus voltage limits; $x_{\min}, x_{\max}$ active and reactive power generation limits. One of the nodes is assigned a zero phase angle by setting its phase angle upper and lower limits to zero (slack bus).

2.3.2 Alternating Current OPF

The AC version of the standard OPF problem is a general non-linear constrained optimization problem, with both nonlinear costs and constraints. In a system with n_b buses, n_g generators, n_l branches and n_c consumers, the optimization variable x is defined as follows:

$$x = [\Theta; V; P_G; Q_G; P_L; Q_L] \tag{10}$$

The objective function (6) is a consumers' utility minus producers' cost (represented by function $B_L^i(P_L^i)$ and $C_G^j(P_G^j)$, respectively) shall be maximised subject to equality and inequality constraints:

$$SW(P_G, P_L) = \left\{ \sum_{i=1}^{n_c} B_L^i(P_L^i) - \sum_{j=1}^{n_g} C_G^j(P_G^j) \right\} \rightarrow \max_{\Theta, V, P_G, Q_G, P_L, Q_L} \tag{11}$$

The equality constraints (7) consist of two sets of n_b nonlinear nodal power balance equations, one for real power and one for reactive power.

$$g_P(\Theta, V, P_G, Q_G, P_L, Q_L) = 0 \tag{12}$$

$$g_Q(\Theta, V, P_G, Q_G, P_L, Q_L) = 0 \tag{13}$$

The inequality constraints (8) consist of two sets of n_l branch flow limits as non-linear functions of the bus voltage angles and magnitudes, one for the from end and one for the to end of each branch.

$$h_f(\Theta, V, P_G, Q_G, P_L, Q_L) \le 0 \tag{14}$$

$$h_t(\Theta, V, P_G, Q_G, P_L, Q_L) \le 0 \tag{15}$$

The variable limits (9) include an equality limited reference bus angle and upper and lower limits on all bus voltage magnitudes, real and reactive generator and consumption injections.

$$\theta_{ref} \le \theta_i \le \theta_{ref}, \qquad l = l_{ref} \tag{16}$$

$$v_i^{\min} \le v_i \le v_i^{\max}, \qquad l = 1 \ldots n_b \tag{17}$$

$$P_{G,\min}^j \le P_G^j \le P_{G,\max}^j, \qquad j = 1 \ldots n_g \tag{18}$$

$$Q_{G,\min}^j \le Q_G^j \le Q_{G,\max}^j, \qquad j = 1 \ldots n_g \tag{19}$$

$$0 \le P_L^i \le P_{L,\max}^i, \qquad i = 1 \ldots n_c \tag{20}$$

$$0 \le Q_L^i \le Q_{L,\max}^i, \qquad i = 1 \ldots n_c \tag{21}$$

Here l_{ref} denotes the index of the slack bus and θ_{ref} is the slack angle.

2.3.3 Direct current OPF

When using DC network modelling assumptions, the standard OPF problem above is simplified to a quadratic program, with linear constraints. In this case, the dc power flow greatly simplifies the power flow by making a number of approximations including 1) completely ignoring the reactive power balance equations, 2) assuming all voltage magnitudes are identically one per unit, 3) ignoring line losses and 4) ignoring tap dependence in the transformer reactance [44, 53, 54].

The optimization variable is:

$$x = [\Theta; P_G; P_L] \tag{17}$$

and the overall problem reduces to the following form:

$$SW(P_G, P_L) = \left\{ \sum_{i=1}^{n_c} B_L^i(P_L^i) - \sum_{j=1}^{n_g} C_G^j(P_G^j) \right\} \to \max_{\Theta, P_G, P_L} \tag{18}$$

subject to

$$g_P(\Theta, P_G, P_L) = 0 \tag{19}$$

$$h(\Theta, P_G, P_L) \leq 0 \tag{20}$$

$$\theta_{ref} \leq \theta_i \leq \theta_{ref}, \qquad l = l_{ref} \tag{21}$$

$$P_{G,\min}^j \leq P_G^j \leq P_{G,\max}^j, \qquad j = 1 \ldots n_g \tag{22}$$

$$0 \leq P_L^i \leq P_{L,\max}^i, \qquad i = 1 \ldots n_c \tag{23}$$

OPF development has been closely following the progress in numerical optimization techniques and computer technology. Many different approaches have been proposed to solve the OPF problem. These techniques include nonlinear programming, quadratic programming, linear programming, mixed programming, as well as interior point and artificial intelligence algorithms etc. [55-57]. The most successful interior point methods are based on using a primal–dual formulation and applying Newton's method to the system of equations arising from the barrier method. The theory of nonlinear primal – dual interior point methods (PDIPM) has been established based on three achievements: Fiacco and McCormick's barrier method for optimization with inequality constraints [58], Lagrange's method for optimization with equality constraints, and Newton's method for solving nonlinear equations [59]. This method has been widely used in power system optimization problems because of its favorable convergence, robustness, and insensitivity to infeasible starting points.

2.3.4 Primal-dual interior point method

The primal-dual interior point method has become the algorithms of choice for long-term development planning strategies. Given an optimization problem in the form of (6), PDIPM formulates the Lagrangian with barrier functions as:

$$L^{\gamma}(x,z,\lambda,\mu) \equiv SW(x) + \lambda^{T} \cdot g(x) + \mu^{T}(h(x)+Z) - \gamma^{k} \sum_{j=1}^{Nineq} \ln(Z_j) \tag{24}$$

where λ^T , μ^T are Langrage multipliers for the constraints of equations (12)–(15);. γ^k is the barrier parameter that is forced to decrease toward “0” as the algorithm iterates to a solution (k is the iteration counter); N_{ineq} represents the number of inequality constraints. The approach taken involves converting the N_{ineq} inequality into equality constraints using a barrier function and vector of positive slack variables Z_j.

The necessary conditions for a stationary point of the constrained optimization problem are that the partial derivatives of the Lagrangian function with respect to each variable must be zero. The Karush-Kuhn-Tucker first order conditions for the Lagrangian function shown in equation (24) are as follows [52]:

$$\begin{aligned} \nabla_x L^{\gamma} &= \nabla_x f(x) + \nabla_x g(x)\lambda + \nabla_x h(x)\mu = 0; \\ \nabla_z L^{\gamma} &= \mu - \gamma^{k}[Z]^{-1}e = 0; \\ \nabla_{\lambda} L^{\gamma} &= g(x) = 0; \\ \nabla_{\mu} L^{\gamma} &= h(x) + Z = 0 \end{aligned} \tag{25}$$

where Z, μ and γ are strictly positive. $[Z] = \begin{bmatrix} Z_1 & & \\ & Z_2 & \\ & & \ddots \end{bmatrix}$ and $e = \begin{bmatrix} 1 \\ 1 \\ \vdots \end{bmatrix}$

Hessian of the Lagrangian with respect to x is given by

$$\nabla_x^2 L^{\gamma} = \nabla_x^2 f(x) + \nabla_x^2 g(\lambda)\lambda + \nabla_x^2 h(\mu)\mu \tag{26}$$

The first order optimality conditions are solved using Newton's method. Each Newton step involves the solution of a reduced system of (25):

$$\begin{vmatrix} \nabla_x^2 L^{\gamma} & 0 & \nabla_x g(x) & \nabla_x h(x) \\ 0 & [\mu] & 0 & [Z] \\ \nabla_x g(x)^T & 0 & 0 & 0 \\ \nabla_x h(x)^T & I & 0 & 0 \end{vmatrix} \begin{vmatrix} \Delta x \\ \Delta Z \\ \Delta\lambda \\ \Delta\mu \end{vmatrix} = - \begin{bmatrix} \nabla_x f(x) + \nabla_x g(x)\lambda + \nabla_x h(x)\mu \\ \mu - \gamma^{k}[Z]^{-1}e \\ g(x) \\ h(x) + z \end{bmatrix} \tag{27}$$

where $[\mu] = \begin{bmatrix} \mu_1 & & \\ & \mu_2 & \\ & & \ddots \end{bmatrix}$ and $I = \begin{bmatrix} 1 & & \\ & 1 & \\ & & \ddots \end{bmatrix}$

The variables are updated according to:

$$
\begin{aligned}
\alpha_p &= \min(\xi \min_{\Delta z_j < 0} (-Z_j / \Delta Z_j), 1) \\
\alpha_d &= \min(\xi \min_{\Delta \mu_j < 0} (-\mu_j / \Delta \mu_j), 1) \\
x &= x + \alpha_p \Delta x; \\
z &= z + \alpha_p \Delta z; \\
\lambda &= \lambda + \alpha_d \Delta \lambda; \\
\mu &= \mu + \alpha_d \Delta \mu;
\end{aligned}
\tag{28}
$$

The parameter ξ is a constant scalar with a value slightly less than one to prevent non-negative variables from being zero and it is set to [0.995−0.99995]. During the Newton-like iterations, the perturbation parameter must converge to zero in order to satisfy the first order optimality conditions of the original problem. The barrier parameter can be evaluated by uses the following rule to update at each iteration, after updating Z and μ:

$$\gamma^k = \sigma(\mu^T Z) / Nineq \tag{29}$$

where σ is a scalar constant between [0−1] and is called center parameter, usually one can get satisfactory convergence by setting parameter around 0.1.

2.3.5 DCOPF sample

In this section, simplified 3 bus system (Fig. 16.) is studied and the simulation results are demonstrated. The 3 bus system has 3 existing lines, 1 inelastic load and 2 generators. The system parameters are listed in Tables I, II and III. Calculations were made in the MATLAB software using 1.90 GHz AMD Turion 64 x2 PC with 4096 MB of RAM.

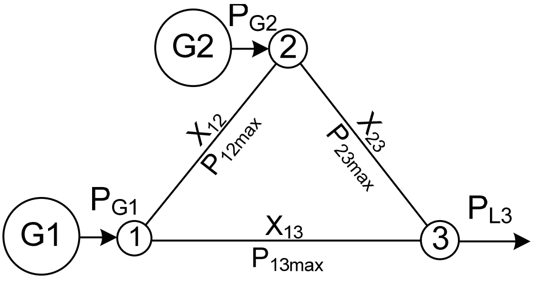


Fig. 16. Simplified 3 bus system

TABLE I. GENERATOR AND LOAD DATA FOR 3 BUS SYSTEM

Bus No.		Load parameters	Generator parameters	
		$P_{L,}$ MW	P_G^{MAX}, MW	P_G^{MIN}, MW
1	Pθ	-	50	0
2	PV	-	50	0
3	PQ	75	-	-

TABLE II. LINE DATA FOR 3 BUS SYSTEM

Branch	x_{ij}, p.u	Capacity MW
1 – 2	0.01	40
1 – 3	0.01	40
2 – 3	0.01	40

TABLE III. GENERATOR COSTS AND DEMAND BENEFITS

Node	Generators			Demand	
	Fuel source	a_j (EUR/MW^{2}h)	b_j (EUR/MWh)	c_i (EUR/MW^{2}h)	d_i (EUR/MWh)
1	Gas	0.0298	80	-	-
2	Coal	0.0149	40	-	-
3	-	-	-	0	200

The objective function:

$$SW(P_G) = \left\{ B_L^3(P_L^3) - \sum_{j=1}^{n_g} C_G^j(P_G^j) \right\} = 200 \cdot 75 - \sum_{j=1}^{n_g} C_G^j(P_G^j) \rightarrow \max_{\Theta, P_G} \tag{30}$$

The optimization variables are:

$$x = [\Theta_1; \Theta_2; \Theta_3; P_{G1}^1; P_G^2] \tag{31}$$

Equality and inequality constraints:

$$\begin{aligned} &P_G^1 + P_G^2 = P_L^3; && \frac{2}{3}P_G^2 + \frac{1}{3}P_G^1 \le P_{23\max} \\ &P_{G\min}^1 \le P_G^1 \le P_{G\max}^1; && \frac{1}{3}P_G^2 + \frac{2}{3}P_G^1 \le P_{23\max} \\ &P_{G\min}^2 \le P_G^2 \le P_{G\max}^2; && \frac{1}{3}P_G^2 + \frac{1}{3}P_G^1 \le P_{12\max} \end{aligned} \tag{32}$$

DCOPF sample demonstrates the results of uses of the primal-dual interior point method in Tables IV, V and Fig. 17, 18 representing variables, gamma and objective function value changes per iteration for 2 different cases:

- initial scheme with $P_{23\max} = 40$MW;
- scheme with reconstructed line $P_{23\max} = 45$MW.

TABLE IV. OPTIMIZATION PROCESS FOR SIMPLIFIED 3 BUS SYSTEM WITH $P_{23MAX} = 40MW$

Iterations	Θ_1, rad.	Θ_2, rad	Θ_3, rad	P_G^1, MW	P_G^2, MW	γ	$SW(P_G)$,EUR
0	0.000	0.00000	0.00000	25.00000	25.00000	1.00000E+00	11972.06250
1	0.000	0.00153	0.00017	3.95854	49.99875	2.02116E+00	12645.65187
2	0.000	0.00079	-0.00321	25.09590	48.92249	1.54104E+00	10980.99843
3	0.000	0.00031	-0.00360	32.92425	42.07575	1.66432E+00	10624.34812
4	0.000	0.00050	-0.00350	30.00015	44.99985	2.78810E-01	10743.00159
5	0.000	0.00050	-0.00350	30.00766	44.99234	2.81690E-02	10742.69761
6	0.000	0.00050	-0.00350	30.00069	44.99931	2.81694E-03	10742.97949
7	0.000	0.00050	-0.00350	30.00007	44.99993	2.81694E-04	10743.00468
8	0.000	0.00050	-0.00350	30.00001	44.99999	2.81694E-05	10743.00722
9	0.000	0.00050	-0.00350	30.00000	45.00000	2.81694E-06	10743.00747
10	**0.000**	**0.00050**	**-0.00350**	**30.00000**	**45.00000**	2.81694E-07	**10743.00750**

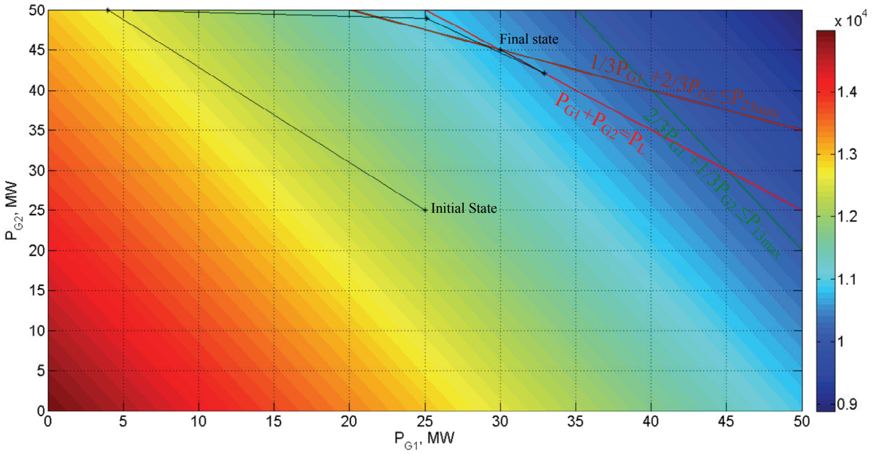


Fig. 17. Objective function for 3 bus system with $P_{23max} = 40MW$

TABLE V. OPTIMIZATION PROCESS FOR SIMPLIFIED 3 BUS SYSTEM WITH $P_{23MAX} = 45MW$

Iterations	Θ_1, rad.	Θ_2, rad	Θ_3, rad	P_G^1, MW	P_G^2, MW	γ	$SW(P_G)$,EUR
0	0.000	0.00000	0.00000	25.00000	25.00000	1.00000E+00	11972.06250
1	0.000	0.00154	0.00018	3.93320	49.99875	2.21106E+00	12647.68470
2	0.000	0.00075	-0.00337	26.23835	48.76165	1.74954E+00	10894.52257
3	0.000	0.00083	-0.00333	25.00006	49.99994	1.71345E-01	10944.12252
4	0.000	0.00083	-0.00333	25.00434	49.99566	1.71493E-02	10943.95127
5	0.000	0.00083	-0.00333	25.00043	49.99957	1.71494E-03	10944.10784
6	0.000	0.00083	-0.00333	25.00004	49.99996	1.71494E-04	10944.12328
7	0.000	0.00083	-0.00333	25.00000	50.00000	1.71494E-05	10944.12483
8	0.000	0.00083	-0.00333	25.00000	50.00000	1.71494E-06	10944.12498
9	**0.000**	**0.00083**	**-0.00333**	**25.00000**	**50.00000**	1.71494E-07	**10944.12500**

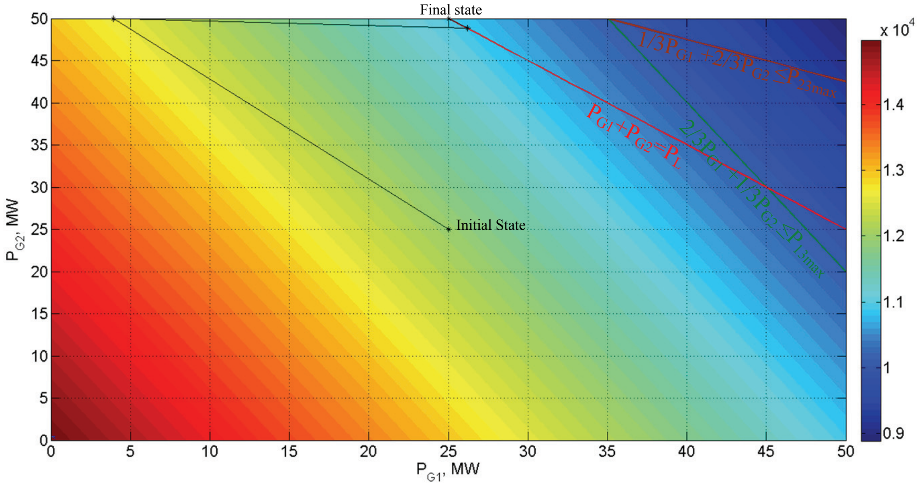


Fig. 18. Objective function for 3 bus system with P_{23max} = 45MW

The presented results show the work of the interior point method and finding the optimal power flow distribution in two different cases. In the case of investments in the power line P_{23} and increasing wires cross section, respectively increasing the capacity to 45MW, an increase of social welfare from 10743 to 10944 EUR will be achieved. However investments will reduce aggregate congestion revenues and respectively decrease first part of equation (4).

2.4 Comparison of ACOPF and DCOPF models for development planning

To compare the different methods, two approaches were applied: the hourly calculation (considered the whole year as a whole), and the typical schedules for consumption and production by months (monthly characterize trends for 24 hours). Therefore, to determine the criteria for one development state it is necessary produce 8760 calculations using the first approach, and 288 calculations using the second approach. Additionally, two 2 different systems are tested: 4 and 98 node (Baltic scheme) systems.

2.4.1 4 node system

Configuration of 4 node system contains four nodes, four generators with quadratic or piecewise cost functions, 5 branches with maximal permissible power and annual inelastic loads. Configuration and parameters of the considered system are presented in Fig. 19.

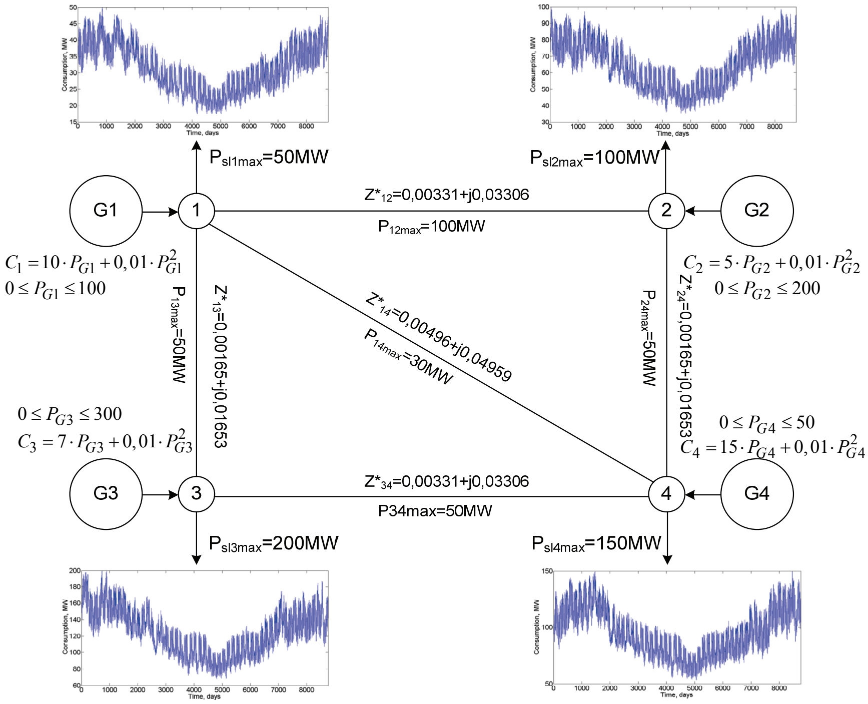


Fig. 19. 4 node system with grid parameters

The results of calculations using the above-described approaches for AC model, taking into account power system constraints, shown in Fig. 20. and Fig. 21. Application of the approach with typical schedules speeds up calculation process and preserves the main trends of the system, but smoothing of the consumption and production peaks does not give a full technical evaluation of development state.

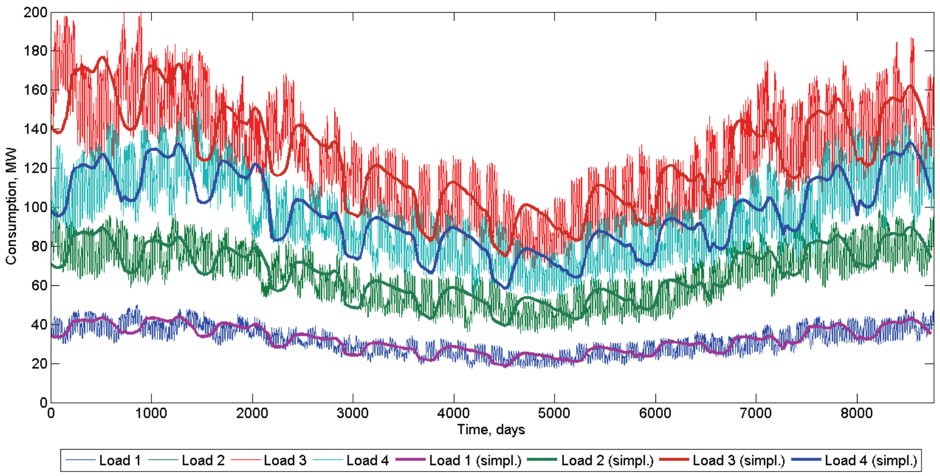


Fig. 20. 4 node system consumption profiles at full and simplified calculations

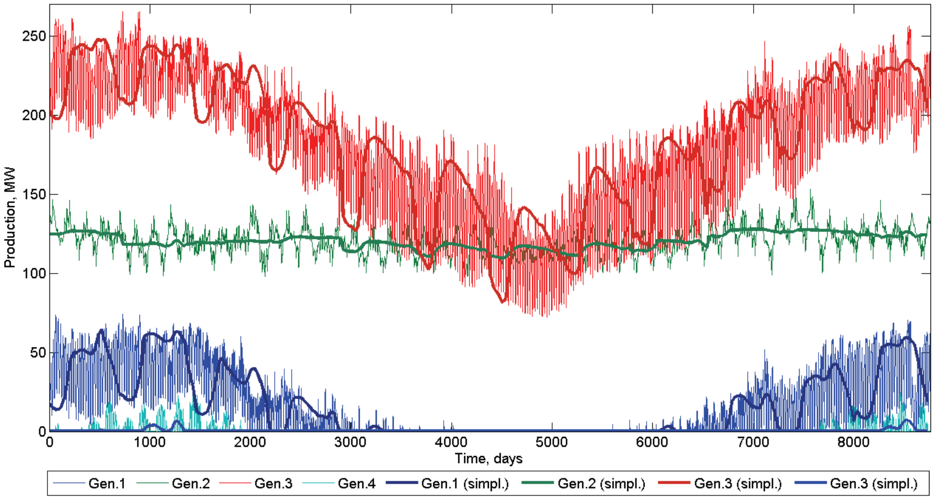


Fig. 21. 4 node system generation profiles at full and simplified calculations

Calculation results for four nodes system, comparing ACOPF and DCOPF models with different approaches, presented in Tables VI and VII. Calculations were made for different conditions of the system (with congestions and without them), using polynomials or piecewise costs functions.

TABLE VI. 4 NODE SYSTEM CASE WITHOUT SIMPLIFICATION

Name	Costs of production, €	Total production per year, MWh/year	Total consumption per year, MWh/year	Calculation time, seconds
Without Congestions				
DC without limits (polynomials)	21250166	2805405	2805405	338,06
DC without limits (Piecewise)	21265159	2805405		381,84
AC without limits (polynomials)	21262709	2806701		1066,65
AC without limits (Piecewise)	21277741	2806706		1204,02
With Congestions				
DC with limits (polynomials)	22437402	2805405	2805405	**338,61**
DC with limits (Piecewise)	22455709	2805405		385,10
AC with limits (polynomials)	22447357	2806305		1103,53
AC with limits (Piecewise)	22464853	2806371		1000,14

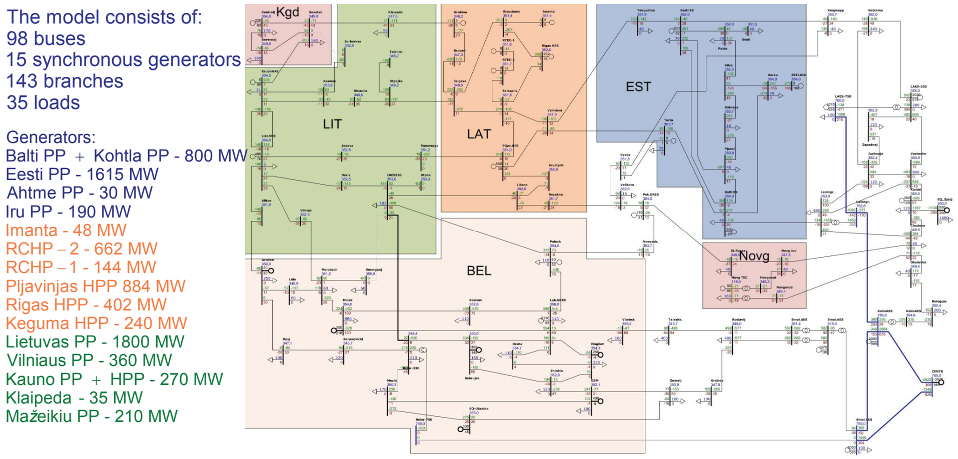
TABLE VII. 4 NODE SYSTEM CASE WITH SIMPLIFICATION

Name	Costs of production, €	Total production per year, MWh/year	Total consumption per year, MWh/year	Calculation time, seconds
Without Congestions				
DC without limits (polynomials)	21234295	2805424	2805424	11,61
DC without limits (Piecewise)	21249341	2805424		13,01
AC without limits (polynomials)	21246743	2806709		27,66
AC without limits (Piecewise)	21261863	2806716		32,81
With Congestions				
DC with limits (polynomials)	22406685	2805424	2805424	**11,70**
DC with limits (Piecewise)	22424455	2805424		13,22
AC with limits (polynomials)	22415876	2806395		29,62
AC with limits (Piecewise)	22433627	2806397		33,36

Traditionally, when optimizing the operation of a regulated power system, the objective function in (6) takes a simple smooth quadratic form. The electricity market, however, does not use quadratic cost, since it does not cognitively match the manner in which market participants want to trade in the real world [60].

2.4.2 Application to Realistic Baltic Power system

Configuration of the Baltic scheme contains 98 nodes, 15 generators (Estonian, Latvian and Lithuanian biggest power plants), 143 branches (mainly 330 and 750 kV lines) and 35 loads (Baltic states). The rest of the scheme does not include Russian and Belarus generating and consuming units due to insufficiency of information. Consideration of such scheme would be more promising, due to the fact that large generating capacity from Russia and Belarus create power flows in the Baltic networks that affect social welfare, price formation and market performance in general. This calculation is further discussed in chapter III. Configuration of the considered system is presented in Fig. 22.


The model consists of:
98 buses
15 synchronous generators
143 branches
35 loads

Generators:
Balti PP + Kohtla PP - 800 MW
Eesti PP - 1615 MW
Ahtme PP - 30 MW
Iru PP - 190 MW
Imanta - 48 MW
RCHP – 2 - 662 MW
RCHP – 1 - 144 MW
Pljavinjas HPP 884 MW
Rigas HPP - 402 MW
Keguma HPP - 240 MW
Lietuvas PP - 1800 MW
Vilniaus PP - 360 MW
Kauno PP + HPP - 270 MW
Klaipeda - 35 MW
Mažeikiu PP - 210 MW

Fig. 22. Baltic Power system scheme

Tables VIII and IX show similar calculations results for Baltic scheme. The results include annual values of total consumption and generation, costs of production, as well as the time taken for the calculation. In DC models difference between production and consumption of electric power equals zero, because losses of networks have not been taken into account.

TABLE VIII. BALTIC SCHEME WITHOUT SIMPLIFICATION

Name	Costs of production, €	Total production per year, MWh/year	Total consumption per year, MWh/year	Calculation time, seconds
Without Congestions				
DC without limits (polynomials)	205861256	26174077	26174077	584,69
DC without limits (Piecewise)	208096998	26174077		1054,69
AC without limits (polynomials)	209802978	26381625		2497,18
AC without limits (Piecewise)	212096986	26382080		**3631,15**
With Congestions				
DC with limits (polynomials)	213140547	26174077	26174077	618,85
DC with limits (Piecewise)	215763098	26174077		1056,45
AC with limits (polynomials)	215817709	26394673		2479,49
AC with limits (Piecewise)	218429201	26395308		3539,94

TABLE IX. BALTIC SCHEME WITH SIMPLIFICATION

Name	Costs of production, €	Total production per year, MWh/year	Total consumption per year, MWh/year	Calculation time, seconds
Without Congestions				
DC without limits (polynomials)	205975660	26210556	26210556	17,34
DC without limits (Piecewise)	208188513	26210556		32,76
AC without limits (polynomials)	209908095	26418094		79,62
AC without limits (Piecewise)	212166352	26418641		**116,68**
With Congestions				
DC with limits (polynomials)	213136192	26210556	26210556	17,98
DC with limits (Piecewise)	215859391	26210556		33,08
AC with limits (polynomials)	215804646	26431930		76,14
AC with limits (Piecewise)	218500249	26433685		114,98

From the above-presented results, a significant acceleration of the calculating process for one development stage using approach with the typical schedule can be seen. From Tables VI and VII, it can be concluded that DC model calculation without simplification takes 338 s (5,63 min), as opposed to calculation with simplifications taking 11,70 s (0,19 min), meaning, in 29 times faster than usual. From Tables VIII and IX, it is observable that AC calculation without simplifications takes 3631,15 s (60,52 min), calculation with simplifications takes 116,68 s (1,95 min), meaning or in 31 times faster than usual. Annual values of these calculations do not differ significantly. The proposed approach with typical schedules speeds up calculation process 30 times and preserves the main trends of the system. However, the smoothing of the consumption and production peaks does not give a full technical evaluation of development state.

2.5 Security-Constrained OPF

The SCOPF problem is an extension of the OPF problem and contains important features of reliability in the optimization model. It guarantees the stable work for the whole power system, without changing active power generation, when some predetermined contingencies occur (such as outages of transmission line) [61]. The efficient solution of SCOPF is crucial for system operators, in the context of planning, operational planning and real time operation.

Flowchart of the iterative SCOPF algorithm is provided in Fig. 23, which starts by solving an OPF with (N-0) constraints. Having solved the contingency analysis, it identifies the critical group of lines and selects lines according to these criteria:

$$K^*_{L,re} = \chi_L \cdot Ps_{L,re}, \tag{33}$$

where L transmission line ordinal number; $Ps_{L,re}$ transmission line flow in operational state; χ_L interruption probability of transmission line L;

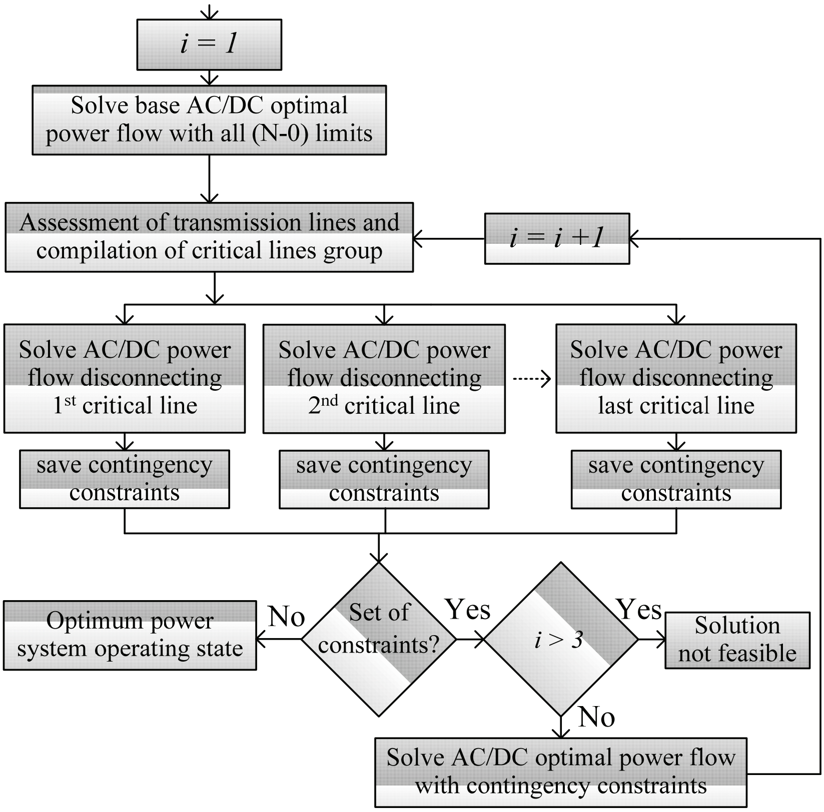


Fig. 23. Security-constrained OPF

In development planning tasks for optimal steady-state operation determination, only 10% of electric transmission lines should be taken into consideration in which transmission line flow: transmission line interruption probability and therefore criteria K* are the highest values. This criterion is necessary in order to select a critical group of lines, subsequently reducing the size of optimization problem and calculation time.

2.5.1 SCOPF sample

In this section SCOPF simplified 3 bus system (Fig. 16.) is studied and simulation results are demonstrated in Table XI and Fig. 24. Changes in system parameters are shown in Table X.

TABLE X. LINE DATA FOR 3 BUS SYSTEM

Branch	x_{ij}, p. u	Capacity MW
1 – 2	0.01	40
1 – 3	0.01	75
2 – 3	0.01	75

TABLE XI. SCOPF FOR SIMPLIFIED 3 BUS SYSTEM WITH $P_{12MAX} = 40$MW

Iterations	Θ_1, rad.	Θ_2, rad	Θ_3, rad	P_G^1, MW	P_G^2, MW	γ	$SW(P_G)$,EUR
0	0.00000	0.00000	0.00000	25.00000	25.00000	1.00000	11972.06250
1	0.00000	0.00151	0.00005	4.72488	49.99875	3.74039	12584.14600
2	0.00000	0.00104	-0.00191	17.47402	48.76274	2.91366	11607.04090
3	0.00000	0.00006	-0.00372	36.62265	38.37691	2.58197	10473.19865
4	0.00000	0.00017	-0.00367	34.99954	40.00019	0.23407	10539.68502
5	0.00000	0.00017	-0.00367	35.00578	39.99422	0.02195	10539.41877
6	0.00000	0.00017	-0.00367	35.00054	39.99946	0.00206	10539.63306
7	0.00000	0.00017	-0.00367	35.00005	39.99995	0.00019	10539.65294
8	**0.00000**	**0.00017**	**-0.00367**	**35.00000**	**40.00000**	0.00002	**10539.65481**

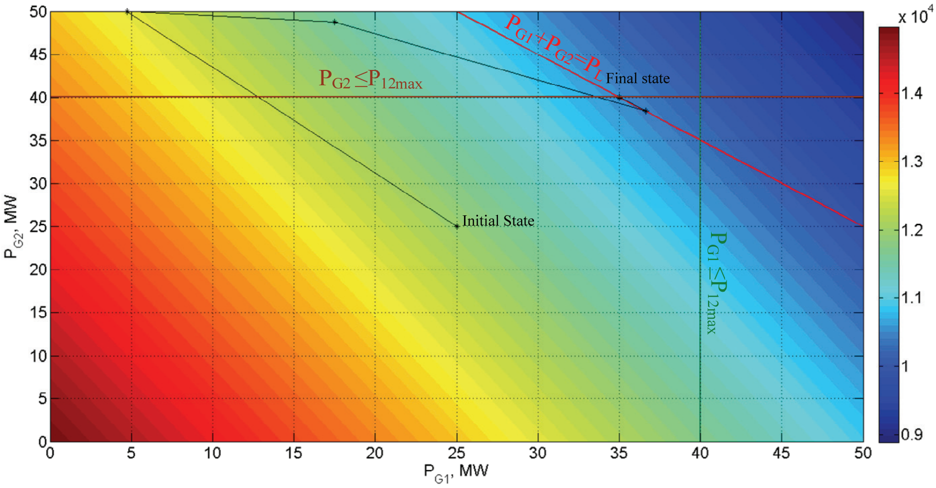


Fig. 24. Objective function for 3 bus system with $P_{12max} = 40$MW

In comparison with previous results (Tables IV and V), the SCOPF solution has a lower SW value than in OPF solution (10539 EUR ≤ 10743 EUR), however, the risk that the whole power system will lose stable work decreases. The social welfare decreases as the risk decreases. The SCOPF solution differs from the OPF solution only when a contingency transmission constraint becomes binding.

2.5.2 9 bus system with 3 zones sample

In this section, a full 9 bus system (Fig. 25.) is studied and the simulation results are demonstrated. The 9 bus system has 15 existing lines, 6 inelastic load and 6 generators. The system parameters are listed in Tables XII–XIV.

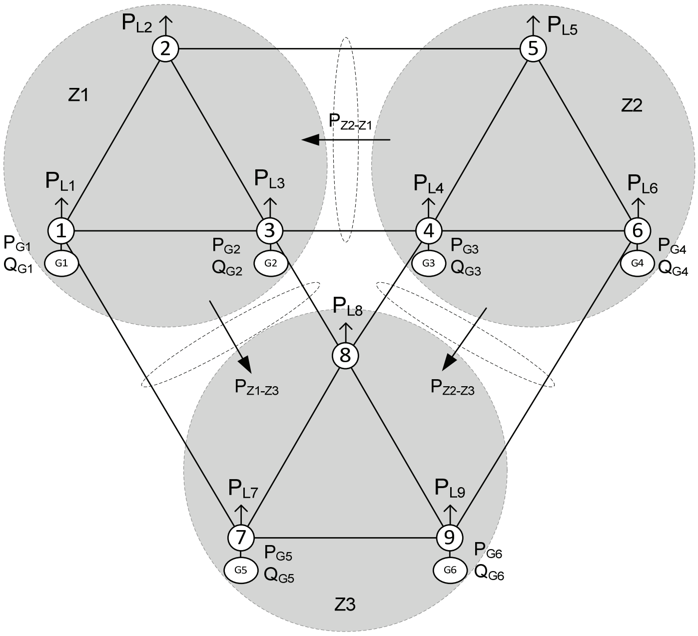


Fig. 25. Full 9 bus system

TABLE XII. GENERATOR AND LOAD DATA FOR 9 BUS SYSTEM

Bus No.		Load parameters		Generator parameters			
		P_L MW	Q_L MVAr	P_{GMAX} MW	P_{GMIN} MW	Q_{GMAX} MVAr	Q_{GMIN} MVAr
1	PV	50	20	100	0	50	-10
2	PQ	50	20	-	-	-	-
3	PV	50	20	100	0	50	-10
4	PV	50	20	150	0	75	-10
5	PQ	50	20	-	-	-	-
6	PV	50	20	150	0	75	-10
7	PV	50	20	200	0	100	-10
8	PQ	50	20	-	-	-	-
9	Pθ	50	20	200	0	100	-10

TABLE XIII. LINE DATA FOR 9 BUS SYSTEM

Branch	r_{ij}, p.u	x_{ij}, p.u	b_{ij}, p.u	Capacity	
				MW	MVA
All	0.01	0.1	0.01	45	45

TABLE XIV. GENERATOR COSTS AND DEMAND BENEFITS

Node	Generators			Demands	
	Fuel source	a_j (EUR/MW^{2}h)	b_j (EUR/MWh)	c_i (EUR/MW^{2}h)	d_i (EUR/MWh)
1	Gas	0	100	0	200
2	-	-	-	0	200
3	Coal	0	50	0	200
4	Coal	0	70	0	200
5	-	-	-	0	200
6	Coal	0	60	0	200
7	Gas	0	90	0	200
8	-	-	-	0	200
9	Gas	0	80	0	200

The objective function:

$$SW(P_G) = \left\{ \sum_{i=1}^{n_c} B_L^i(P_L^i) - \sum_{j=1}^{n_g} C_G^j(P_G^j) \right\} \to \max_{\Theta, V, P_G, Q_G} \tag{34}$$

The optimization variables are:

$$\begin{gathered} x = [\Theta_1;\Theta_2;\Theta_3;\Theta_4;\Theta_5;\Theta_6;\Theta_7;\Theta_8;\Theta_9;V_1;V_2;V_3;V_4;V_5;V_6;V_7;V_8;V_9; \\ P_{G1}^1;P_G^3;P_{G1}^4;P_G^6;P_{G1}^7;P_G^9;Q_{G1}^1;Q_G^3;Q_{G1}^4;Q_G^6;Q_{G1}^7;Q_G^9] \end{gathered} \tag{35}$$

The proposed sample demonstrates the results of uses of the primal-dual interior point method in Tables XV–XVIII and Fig 26–29 representing consumer surplus, producer surplus, TSO congestion rent and total SW values changes for 4 different cases:

- initial scheme without congestions;
- scheme with congestions;
- scheme with congestions and N-1 criteria;
- scheme with wind power plant in node 5, congestions and N-1 criteria.

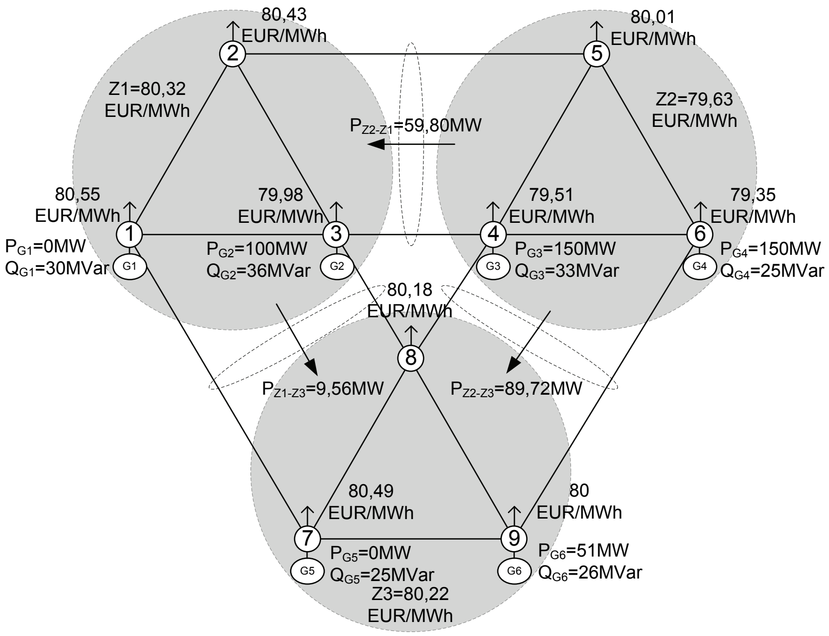


Fig. 26. Full 9 bus system without congestions (line capacity = ∞)

TABLE XV. CONSUMER AND PRODUCER SURPLUS, TSO CR IN CASE WITHOUT CONGESTIONS

Node	Nodal price, EUR/MWh	Consumer surplus, EUR	Producer surplus, EUR	TSO congestion rent, EUR	Total SW, EUR
1	80,55	5973	0,0	65,8	20950
2	80,43	5978	-		
3	79,98	6001	2998,4		
4	79,51	6024	1427,2	106,7	22386
5	80,01	5999	-		
6	79,35	6032	2902,9		
7	80,49	5976	0,0	24,8	17967
8	80,18	5991	-		
9	80,00	6000	0,0		
Total		**53974,4**	**7328,4**	**197**	**61302,8**

The calculation of this case takes 2.185 sec.

From the above-presented results, optimal active power flow distribution, nodal/zonal prices and other results can be seen. Zone 2 is the surplus area, 1 and 3 zones are the deficit areas. In this case, the results show a slight difference between the nodal (zonal) prices, which is associated with the losses in power lines. In the case of DC model, the prices were equal in all nodes and $C_R = 0$.

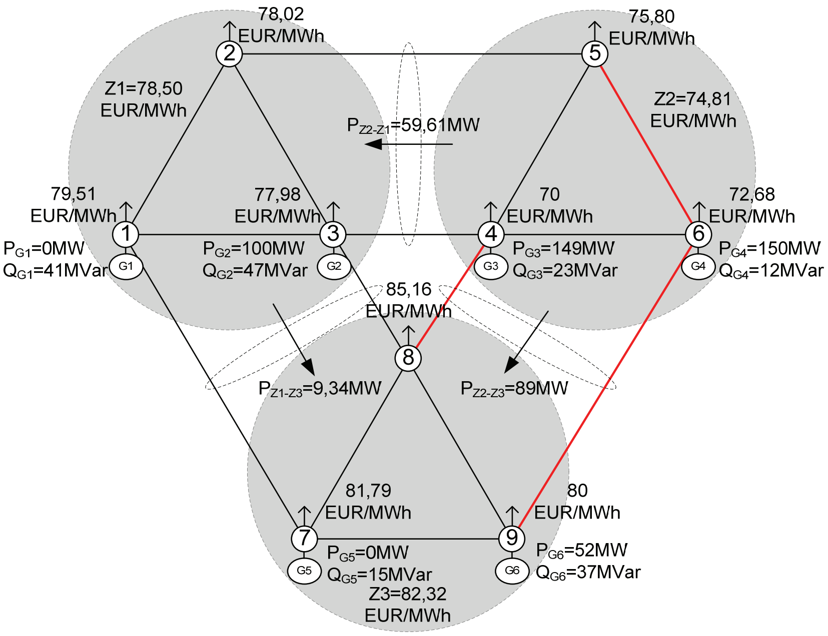


Fig. 27. Full 9 bus system with congestions

TABLE XVI. CONSUMER AND PRODUCER SURPLUS, TSO CR IN CASE WITH CONGESTIONS

Node	Nodal price, EUR/MWh	Consumer surplus, EUR	Producer surplus, EUR	TSO congestion rent, EUR	Total SW, EUR
1	79,51	6024	0,0	475,5	21022
2	78,02	6099			
3	77,98	6101	2798,5		
4	70,00	6500	0,0	1305,9	20979
5	75,80	6210			
6	72,69	6366	1903,3		
7	81,80	5910	0,0	55,6	17652
8	85,16	5742			
9	80,00	6000	0,0		
Total		**54952**	**4701,8**	**1837**	**59653**

The calculation of this case takes 2.108 sec.

In the case with congestion, zone 2 is the surplus area, 1 and 3 zones are the deficit areas. Here, the results show a significant difference between the nodal (zonal) prices, which is associated with congestions between nodes 4–8, 6–9 and 5–6. The TSOs receive congestion rent 1837 EUR and a total SW decrease from 61302,8 to 59653 EUR.

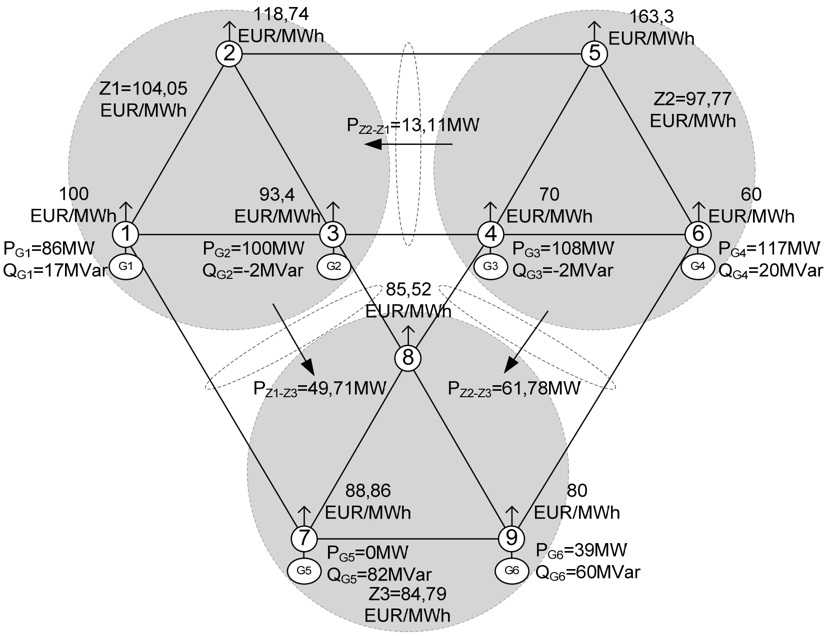


Fig. 28. Full 9 bus system with congestions and N-1 criteria

TABLE XVII. CONSUMER AND PRODUCER SURPLUS, TSO CR IN CASE WITH CONGESTIONS AND N-1 CRITERIA

Node	Nodal price, EUR/MWh	Consumer surplus, EUR	Producer surplus, EUR	TSO congestion rent, EUR	Total SW, EUR
1	100,00	5000	0,0	433,53	18733
2	118,74	4063			
3	93,40	5330	4339,8		
4	70,00	6500	0,0	6737,09	15335
5	163,30	1835			
6	60,00	7000	0,0		
7	88,86	5557	0,0	191,05	17281
8	85,52	5724			
9	80,00	6000	0,0		
Total		**47009**	**4339,8**	**7361,68**	**51348**

The calculation of this case takes 7.754 sec.

In the case with congestion and N-1 criteria, zones 1 and 2 is the surplus areas, 3 zone is the deficit area. In this case, the results show an even more significant difference between the nodal (zonal) prices than in the previous case. The difference is associated with congestions in state with N-1 element (outages of transmission line): however, in such a steady state, the power system is more reliable and the system risk subsequently decreases. The TSOs receive congestion rent 7361,68 EUR and a total SW decrease from 59653 to 51348 EUR.

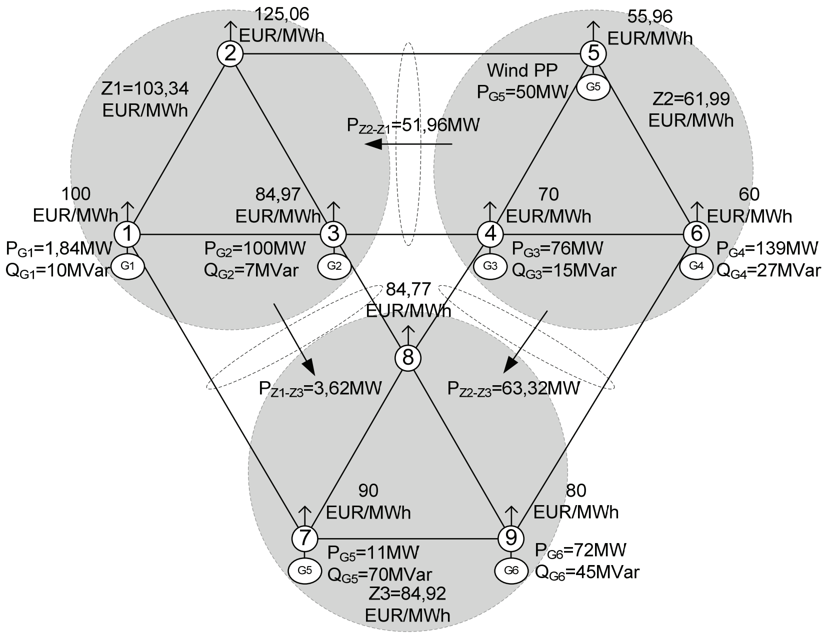


Fig. 29. Full 9 bus system with wind PP in node 5, congestions and N-1 criteria

TABLE XVIII. CONSUMER AND PRODUCER SURPLUS, TSO CR IN CASE WITH WIND PP, CONGESTIONS AND N-1 CRITERIA

Node	Nodal price, EUR/MWh	Consumer surplus, EUR	Producer surplus, EUR	TSO congestion rent, EUR	Total SW, EUR
1	100,00	5000	0,0	3966,83	17996
2	125,06	3747			
3	84,98	5751	3497,6		
4	70,00	6500	0,0	1416,70	23500
5	55,97	7202	2798,3		
6	60,00	7000	0,0		
7	90,00	5500	0,0	306,88	17261
8	84,78	5761			
9	80,00	6000	0,0		
Total		**52460,88**	**6295,92**	**5690,42**	**58756,8**

The calculation of this case takes 12.03 sec.

The integration of wind production significantly increases annual SW values and reduces the need of most expensive conventional plants, which could lead to lower average prices for electricity. However, the expansion of power production capacities with low marginal costs of production have a negative on impact to the conventional generators, mostly reducing the ability to sufficiently cover the total production costs, as a result.

2.6 Simplified Unit commitment

The unit commitment (UC) problem involves determining the start-up and shut down schedules of thermal units that are to be used to meet the forecasted demand over a future short term period [62, 63]. Due to the fact that the UC problem is a complex mathematical optimization problem and that it significantly increases the development planning tasks complexity, some assumptions have been made to simplify the problem: not to assume start-up and shut-down cost, system reserve requirements and ramp rates (each hourly base steady-state operation is independent from other hours).

Flowchart of the iterative simplified UC-SCOPF algorithm is provided in Fig. 30, which starts by solving a SCOPF without the units' low MW limits. Upon solving (SCOPF without units' low MW limits), the compilation of power plants group starts with a generation less than ε (in calculation ε assumed 10%) to identify the group of power plants, which should be switched off. Having obtained the steady-state operation, social welfare and nodal prices reflect the network real processes and thereby taken for development modeling.

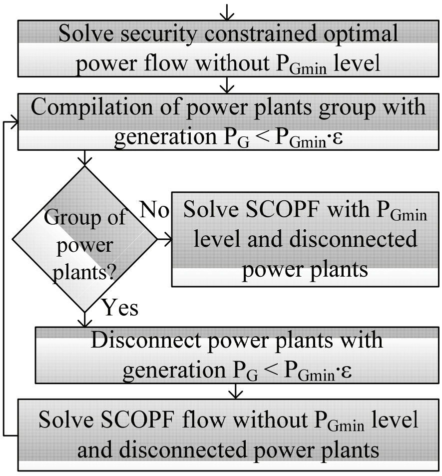


Fig. 30. Simplified Unit Commitment

A Simplified UC problem is solved for a one time step, without regard as to the intertemporal links. These links have to be taken into account when annual hourly availability of generators is formed for whole year. One week generation availability pattern example is presented in Fig. 31:

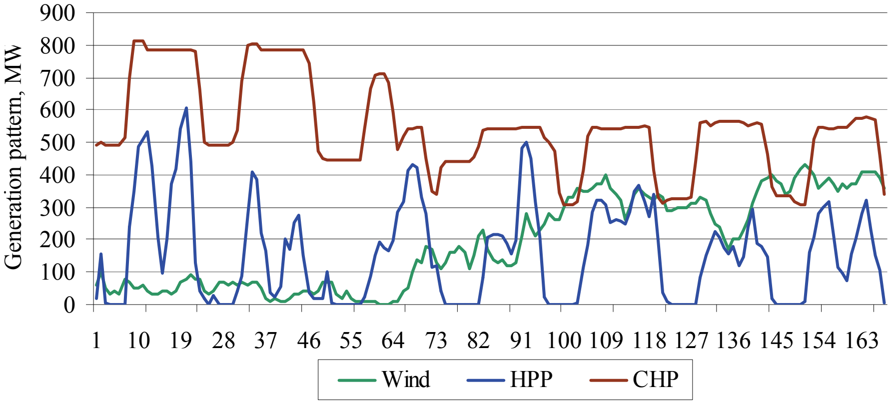


Fig. 31. Generation hourly data

The proposed simplified unit commitment algorithm allows assessing the influence of renewable energy sources as regard a power system and market formation. One of the expected influences of wind power on electricity market has been presented in the Baltic development scenario of 2020 through the merit-order effect, caused by wind production [64]. Currently, the merit-order effect characterizes influence of the electricity produced under the feed-in-tariff (FIT) law to the wholesale electricity price in way that average cost of electricity decreases. The FIT are proposed as temporary system of subsidies, however, in long-term perspectives, the direct merit-order effect that may be caused by wind production (currently covered by FIT) is expected as well. The reason for that is bidding strategies, which are used by power producers to join the short-term organized markets (e. g. Nord Pool Spot). The offer bids of the generators on those short-term markets are often placed on the level of the so-called short-run marginal costs (SRMC) of a particular producer. The SRMC of wind production are close to zero, which means that wind production belongs to the bottom of the marginal cost curve i. e. supply curve.

An example of an engagement of wind production into the estimated Baltic merit-order generation at the basis of SRMC extended with transmission capacities for winter (January) conditions in 2020 scenario are shown in Fig. 32. The level of the load in the system represents the estimated minimal, average and maximal load during January in the Baltic 2020. To better distinguish the situation, the supply curve is shifted to the maximally achieved level of wind production in 2020.

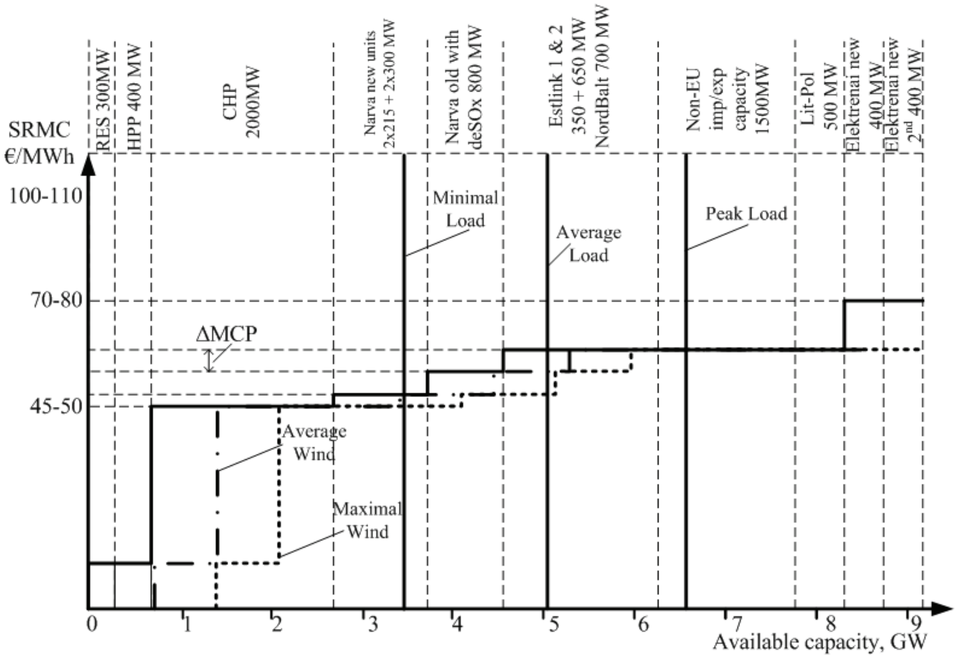


Fig. 32. System price formation in winter scenario 2020

As could be derived from presented snapshots, the integration of wind production will reduce the need of most expensive conventional plants, which can lead to lower average prices for electricity. It is quite evident that the shifting of an entire production curve due to inclusion of wind power is not constant throughout the year. The variation differs, according to the wind condition, seasonally and partially from year-to-year. The range of shifting and its duration might be clarified by duration curves of wind production. However, to the price formation process and thus on the resulting price have impact countless number of factors. In mid and long-term perspectives, such as structure, disposition and availability of power sources, the level of commercial capacities of cross-border lines and also structure and level of demand. The demand side management and demand response programs appear to have a crucial role in the future integration of wind, in order to deal with negative impacts to a power system as well as reduce the price volatility.

2.7 Firmness of the Approach

The need for transmission expansion planning techniques and model has been proposed in this chapter. A coordinated approach for capacity calculation including SCOPF implementation will show the best use of the transmission networks, as well as it will open additional opportunities for power system complex development planning.

The purpose of this paragraph is to summarize the major opportunities of the OPF and SCOPF methods and underline their implementation area, solving varying complexity development planning tasks. Nowadays, OPF has been playing a very important role in the power system operation and planning, and its extension (SCOPF) contains important features of reliability in the optimization model. It also guarantees the whole power system's stable work, without changing the active power generation. To confirm firmness of the approach, the following results were presented:

- 4 different complexity case studies were tested and analyzed;
- Presented result of uses the primal-dual interior point method on simplified scheme;
- Proposed AC/DC OPF algorithms with polynomial and piecewise cost functions were compared and tested on realistic Baltic PS;
- Proposed SCOPF algorithm was tested and compared with OPF with/without congestions on 9 bus system;
- Examined cases of RES influence to a power system and market formation;

The OPF/SCOPF/UC-SCOPF provide: deterministic convergence; accurate computation of nodal prices, full active and reactive power flow modelling of large-scale systems, quadratic and piecewise costing of active energy production, social welfare (consumer and producer surplus), TSO congestion rent and determination of congestions.

Sample studies of Chapter 2 provide results justification, and in the way - major opportunities that would be solved by the proposed SCOPF algorithm.

Obtaining the results by the presented modelling and simulation have to be repeatedly motivated in order to achieve valuable results, since the found solutions, when applied to the development planning processes, may considerably influence decisions, thus – a path of system development and its degree of optimality.

3. Modelling technique

3.1 Electrical Network Dynamic Modelling

The main point of this chapter is to demonstrate the new methodology based on the deterministic concept with a dynamic transmission expansion planning in a perfect competitive electricity market with technical and market economic regulation principals. Power system mathematical model is the system, and its development process configuration and network dynamic behaviors introduction in hardware will provide the capability to calculate and assess system criteria for decision making. To provide hardware operation on the given task, data are required and respective software comprising optimization algorithm. Taking into consideration the calculation dimension, the applicable methods must be operable with a relatively high speed and similar requirements are also applied to the data. Development modeling should include network dynamic behaviors and represent the network's real processes as much as possible. Based on the main functioning factors defined in chapter II, the following functional specifications of proposed model are considered (see Fig. 33.).

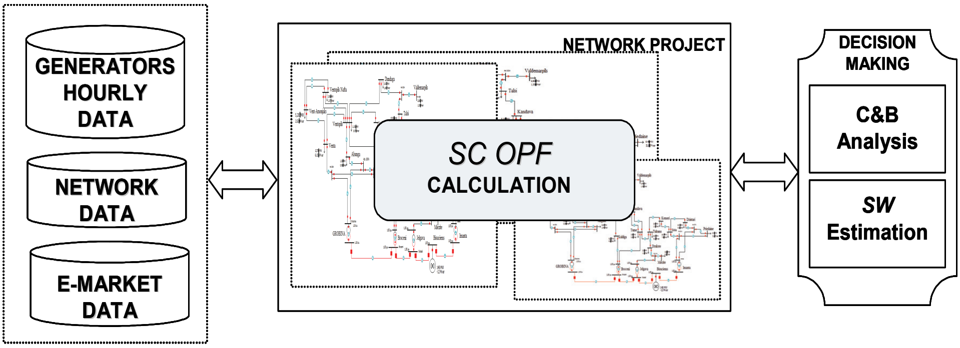


Fig. 33. Functional specification of proposed model

Development model functional specification consists the tree main blocks:

– **First block** contains the necessary input data from generators, consumers, network elements and e-market information. The input data may be classified into 4 groups:

1. group – data that within the whole calculation process is unchangeable;

Initial topology of the grid (power system graph) with the following information:

- Line data – initial and end nodes, link existence mark (α = 1 – link is in scheme, α = 0 – link is not in scheme), series resistance r_{ij}, series reactance x_{ij}, shunt charging b_{ij}, link capacity;
- Consumption nodes – node code n_c, annual hourly active and reactive consumption, linear demand function ($p_i = d_i + c_i P_i$, where p_i is the price [m. u./MWh], P_i is the consumption per hour [MWh], d_i and c_i are, respectively, the demand intercept [m. u./MWh] and demand slope [m. u./MW^{2}h] in node i.);
- Generation nodes – node code n_g, annual hourly availability of generator (in case with RES annual production curve), maximal active generation capacity P_G^{MAX} [MW], minimal stable level P_G^{MIN} [MW], reactive generation maximal Q_G^{MAX} [MVAr] and minimal Q_G^{MIN} [MVAr] stable levels, production selling price (*SRMC = Marginal Heat Rate x Fuel Price + VO&M Charge + UoS Charge + Emissions Incremental Cost*, where marginal heat rate [GJ/MWh] is the amount of additional fuel, required to make one more unit of power at the current load level and vary according to generator load level and ambient temperature, VO&M Charge [m. u./MWh] is equal to the total variable maintenance cost of some period of time (operations and maintenance, start up and shut down costs per year) divided by the expected total generation in that period, UoS (use of system) charge [m. u./MWh] is used to represent an additional charge that generators may be required to pay to the market operator for delivering rights, emissions incremental cost [m. u./MWh] is cost of the emission to the generator).

2. group – data that is specific for each development step;

   Depending on the development step, the following information must be forwarded: to consumption node: consumption and demand function prognosis; to generation node: prognosis of fuel price, cost of the emission. These data must be sent once in each development step.

3. group – data that are specific for each development state;

   The data that are specific for each development state represent information on realized development actions set.

4. group – data that are used for analysis of the results.

These are: data that provide development plan determination from the last step T in reverse direction; data required for risk analysis of information in uncertainty conditions - main data on development conditions prognosis [8].

– The **Second block** is concerned with obtaining the results for scenarios formed by the user, where SCOPF algorithm is implemented. Obtaining of the results by the presented modelling and simulation have to be always motivated by the best effort to achieve valuable results, since those, when applied to the development planning processes, may considerably influence decisions, and thus path of system development and its degree of optimality. Based on the main functioning factors defined in chapter II, the following development model was created (see Fig. 34.).

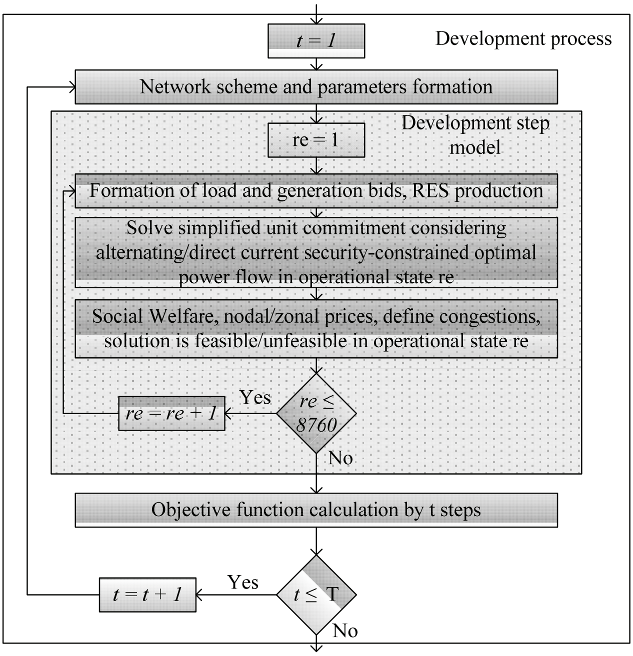


Fig. 34. Mathematical model of development process

This process allows hourly consideration of the RES impacts on the power system and market formation. In appendices 3 and 4 [64, 65], the methodology and algorithms are proposed for evaluation of the RES integration effect on the price formation and the level of system penetration.

– **Third block** could be regarded as decision making. Decision making by itself is complex procedure, and in this thesis under the decision making is assumed focus on SW and CR estimation, based on the formula (6).

Additionally, in order to analyze and compare the future investments in transmission, a set of metrics are defined that show the welfare obtained by the different agents of the market: generators, demands and additional metric that considers the effect of the new lines on the congestion revenue received by TSO [66].

$$\mu_{SW+CR}(T,g)=\sum_{t=1}^{T}\left(\frac{(SW^{*}(t,e(t),g)+CR^{*}(t,e(t),g))-(SW^{0}(t,0,g)+CR^{0}(t,0,g)}{IC(t,e(t),g)}\right)\quad(36)$$

where SW^{*} is the optimal aggregate social welfare (the first term of (4)), SW^{0} is the aggregate social welfare if transmission expansion is not considered, CR^{*} is the congestion revenue received by TSO after expansion and CR^{0} without expansion. From this definition, metric should be greater than one to justify the investment in the new lines and highest value when comparing different expansion scenarios. The ratio can be a useful metric for the entire system.

The metric available to the generators is the change in the generator surplus with respect to the investment cost in new lines. It is defined as:

$$\mu_{PS}(T,g)=\sum_{t=1}^{T}\left(\frac{PS^{*}(t,e(t),g)-PS^{0}(t,0,g)}{IC(t,e(t),g)}\right)\qquad(37)$$

This metric illustrates how the generators could benefit or detriment from the investment in the new lines. The value of μ_{PS} should be greater than the share of the cost that the generators will have to pay for, because otherwise, the generators will most likely be against the construction of those lines. Those values can be negative in systems with a high degree of congestion, because the construction of the new lines may connect inexpensive isolated generators to demand, which will cause prices to fall and, hence, generators' profits to decrease. In addition, both single-generator metrics and generating-company metrics could be calculated (zonal/nodal), taking into account only the surpluses of the relevant units, in order to compare the effect of the new lines for different generating companies.

The demands can measure the increment of their surplus with respect to the investment cost in the new lines. This metric is defined as:

$$\mu_{CS}(T,g)=\sum_{t=1}^{T}\left(\frac{CS^{*}(t,e(t),g)-CS^{0}(t,0,g)}{IC(t,e(t),g)}\right)\qquad(38)$$

This metric shows how the demands could benefit or detriment from the investment in the new lines. A single-consumer and consuming company metrics could be calculated, taking into account only the surpluses of the relevant demands to compare the effect of the new lines.

The ratio of the change in the congestion revenues with respect to the investment cost in the new lines is defined as:

$$\mu_{CS}(T,g)=\sum_{t=1}^{T}\left(\frac{CR^{*}(t,e(t),g)-CR^{0}(t,0,g)}{IC(t,e(t),g)}\right) \tag{39}$$

This metric shows how TSOs could benefit or detriment from the investment in the new lines.

3.2 Case study. Application to the modified Garver's 6-bus system

In this section, modified Garver's 6-bus (Fig. 35) transmission grid systems are studied and the simulation results are demonstrated. The basis for calculations of the modified scheme is taken from the source [67, 68].

3.2.1 Modified Garver's 6-Bus System

The modified Garver's 6-bus system has 14 existing lines, 5 loads and 4 generators. The system parameters are listed in Tables XIV, XV and XVI.

TABLE XIX. GENERATOR AND LOAD DATA FOR GARVER'S 6-BUS SYSTEM

Bus No.		Load parameters		Generator parameters			
		P_L MW	Q_L MVAr	P_G^{MAX} MW	P_G^{MIN} MW	Q_G^{MAX} MVAr	Q_G^{MIN} MVAr
1	Pθ	80	16	160	0	65	-10
2	PQ	240	48	100	0	0	0
3	PV	40	8	370	0	150	-10
4	PQ	160	32	-	-	-	-
5	PQ	240	48	-	-	-	-
6	PV	-	-	610	0	200	-10

TABLE XX. LINE DATA FOR GARVER'S 6-BUS SYSTEM

Branch	r_{ij}, p.u	x_{ij}, p.u	b_{ij}, p.u	Capacity	
				MW	MVA
1 – 2	0.04	0.4	0.04	100	120
1 – 4	0.06	0.6	0.06	80	100
1 – 5	0.02	0.2	0.02	100	120
2 – 3 x 2	0.02	0.2	0.02	100	120
2 – 4	0.04	0.4	0.04	100	120
2 – 6 x 2	0.03	0.3	0.03	100	120
3 – 5 x 3	0.02	0.2	0.02	100	120
4 – 6 x 3	0.03	0.3	0.03	100	120

TABLE XXI. GENERATOR COSTS AND DEMAND BENEFITS

Node	Generators			Demands	
	Fuel source	a_j (EUR/MW^{2}h)	b_j (EUR/MWh)	c_i (EUR/MW^{2}h)	d_i (EUR/MWh)
1	Gas	0.0298	83.9	0	200
2	Wind	0	0	0	200
3	Coal	0.0081	58	0	200
4	-	-	-	0	200
5	-	-	-	0	200
6	Coal	0.0035	69.71	-	-

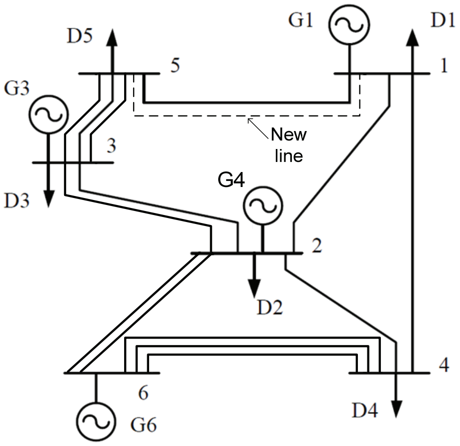


Fig. 35. Modified Garver's 6-bus system with 100MW wind PP

For the present structure of the network the following four case strategies of development are considered:

- Without wind PP and investments;
- Without wind PP and with investments for construction of a new line 1-5;
- With wind PP and without investments;
- With wind PP and investments for construction of a new line 1-5.

For development modeling calculation the following assumptions were made:

1. Consideration of a time horizon of ten years. For this time scale, we estimate the demand, the generation offers, and the demand bids. Therefore, the model represents a "Dynamic Transmission Expansion Planning" problem, for which the net social welfare is maximized;
2. Each development step is calculated in accordance with the present algorithm in Fig. 34. (AC and DC models of the network are used);

3. The generator costs were changed for all the periods of study, so that the gas price would grow each year by 1 % and coal price by 2 %. I'm considering a perfect competition strategy, generators offer at their marginal costs;
4. Each load was defined by an individual demand pattern and grew up each year by 0,5 % (see Fig. 36.);
5. Fig. 37 represents the annual wind production curve for 100MW power plant, obtained from the wind production curve simulation algorithm provided in appendices 3 and 4 [64, 65]. The production curve is fixed for each development step and does not participate in the automatic generation control.

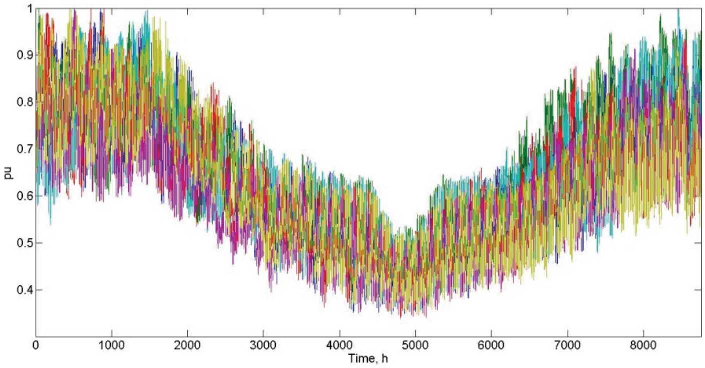


Fig. 36. Demand pattert for first development step

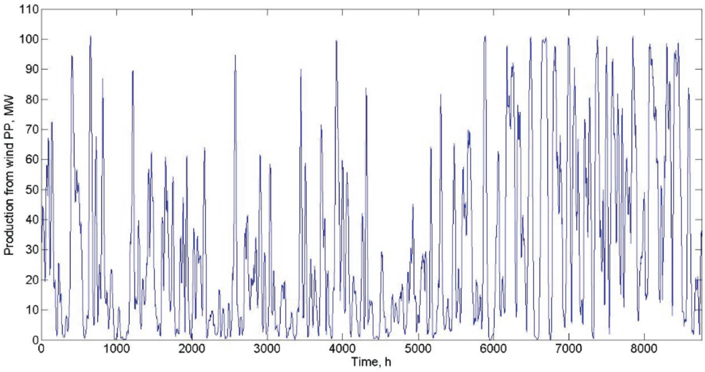


Fig. 37. Annual wind production curve for 100MW power plant

3.2.2 Analysis of results

The results of one year social welfare for the first and the last development steps without the investing are provided in Fig. 38. Tables XXII and XXIII represent the changes of the annual SW values of OPF and SCOPF problems for different development strategies:

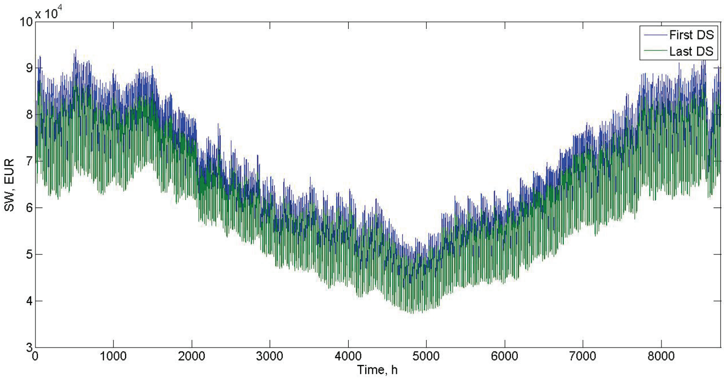


Fig. 38. First and last development step SW patterns

TABLE XXII. SW VALUES FOR THE CASE STUDY WITHOUT WIND PP

Step	Without investment		With investment	
	SW OPF, MEUR	SW SCOPF, MEUR	SW OPF, MEUR	SW SCOPF, MEUR
1	578.664	574.939	578.664	575.525
2	576.030	572.247	576.030	572.847
3	573.241	569.405	573.241	570.021
4	570.292	566.408	570.293	567.042
5	567.180	563.252	567.180	563.905
6	563.899	559.932	563.899	560.605
7	560.445	556.444	560.445	557.137
8	556.812	552.782	556.812	553.496
9	552.996	548.943	552.996	549.678
10	548.992	544.922	548.992	545.678
Total	**5648.551**	**5609.274**	**5648.553**	**5615.934**

TABLE XXIII. SW VALUES FOR THE CASE STUDY WITH WIND PP

Step	Without investment		With investment	
	SW OPF, MEUR	SW SCOPF, MEUR	SW OPF, MEUR	SW SCOPF, MEUR
1	649.103	644.525	649.175	645.317
2	646.845	642.193	646.919	643.000
3	644.440	639.715	644.514	640.538
4	641.884	637.087	641.958	637.927
5	639.171	634.303	639.247	635.162
6	636.299	631.360	636.375	632.238
7	633.261	628.252	633.338	629.151
8	630.054	624.977	630.131	625.896
9	626.672	621.528	626.750	622.469
10	623.110	617.902	623.189	618.865
Total	**6370.839**	**6321.842**	**6371.596**	**6330.563**

The presented results clearly illustrate the behavior and changes in the power system, which should be subsequently considered together with the decision making theory for the future sustainable development of transmission networks [69]. To analyze investments in transmission between nodes 1-5 it has been assumed that the total investments are 20MEUR and that the new line would be built today and would be operative for at least 25 years (discount rate and congestion rent is not assumed). In first case, without the wind PP:

$$\mu_{SW} = \sum_{t=1}^{10} \left(\frac{SW^{*}(t,e(t),g) - SW^{0}(t,0,g)}{IC(t,e(t),g) - \text{Residual value}} \right) = \frac{5615.9 - 5609.3}{20 - 20 \cdot (1 - \frac{4}{100} \cdot 10)} = 0.83$$

In second case, with the wind PP:

$$\mu_{SW\_wind} = \sum_{t=1}^{10} \left(\frac{SW\__{wind}{}^{*}(t,e(t),g) - SW\__{wind}{}^{0}(t,0,g)}{IC(t,e(t),g) - \text{Residual value}} \right) = \frac{6321.8 - 6330.6}{20 - 20 \cdot (1 - \frac{4}{100} \cdot 10)} = 1.09$$

The effect of investments in the construction of the new line is justified in the case of the integration of the renewable energy sources into generating portfolio and could be evaluated as positive, regarding the improved generation and transmission adequacy, as well as the system's reliability.

3.3 Case study. Application to the Baltic Power System

3.3.1 Baltic Power System

The extensive Baltic power simulation model, presented in Fig. 39, is initially based on the BRELL power system model data. The developed model features a full georeferencing of the buses and the transmission lines, an interconnection to Finland Estlink 1&2, and an update of the recently commissioned /decommissioned wind farms and power plants [70].

In term of components, the model's nodal representation details are illustrated in Table XXIV spanning from 110 kV to 750 kV transmission lines.

TABLE XXIV. MODEL DIMENSION OF THE DEVELOPED BALTIC MODEL

	EE	LV	LT	RU	BL	$FI_{eq.}$	$PL_{eq.}$	$UK_{eq.}$	All
Buses	182	238	479	40	22	2	1	1	955
Gen	16	14	12	11	8	0	0	1	62
Loads	141	148	291	23	20	2	0	0	625
Lines	247	323	646	56	30	2	1	2	1307
Voltage [kV]	110/220/330	110/330	110/330	110/330/550/750	330	330	330	330	110/220/330/550/750

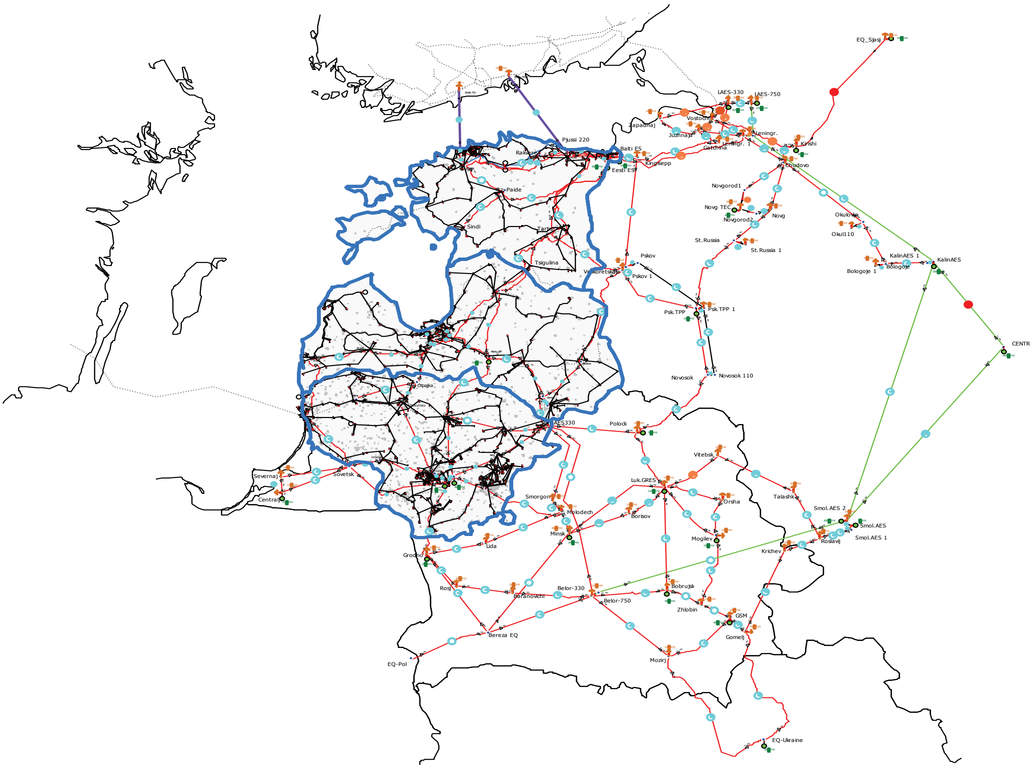


Fig. 39. BRELL power system developed simulation model

The baseline load demand data for the model is based on the peak and off-peak load profiles, registered in 2012. To ensure a continuous assessment of the model, an actual real time data retrieved from the Nord pool spot were scaled up using the initial 2012 load distribution and assuming an average power factor and a similar load distribution within the existing BRELL nodes.

The power generation mix within the Baltic States is illustrated in Table XXV, where the thermal generation shares constitute 60 % of the overall generation. It is worth mentioning that Lithuania once relying mainly on Nuclear power generation (70 %) has decommissioned its last Nuclear Power Plant (NPP) Ignalina in 2010 due to EU strong concerns over the RMBK type. This resulted in drastic power flows changes, and Lithuania, once a net exporter, is now becoming a net importer.

Although the three Baltic States are capable, in absolute terms, to balance their energy supply and demand the during typical winter peak (Table XXVI), in practice – only Estonia prevails as a net exporter.

TABLE XXV. GENERATION CAPACITY MIX IN THE BALTIC STATES

Generation capacity per type [MW]	Estonia	Latvia	Lithuania	All Baltic
Thermal	2373	930	2610	5913
Hydro PP and PSPP	7	1580	1030	2617
Nuclear	-	-	-	-
Wind and Biomass	359	150	410	919
Total	2739	2660	4050	9449

TABLE XXVI. BALTIC STATES DURING TYPICAL 2013/2014 WINTER SNAPSHOT

	Estonia	Latvia	Lithuania	Total
Total net capacity [MW]	2739	2660	4050	9449
Typical peak load [MW]	1440	1280	1740	4460
Available capacity [MW]	2070	1320	2400	5790
Export capability [MW]	630	40	660	1330

The developed model is aimed to simulate the projected transfer allocations of power flows and assess their possible impact on normal and contingency operations. The figure 40 illustrates a simulation snapshot of the cross-border power flow exchange featuring the imports of Lithuania from Belarus and Latvia, while Estonia acts in absolute terms as an exporter mainly to Latvia.

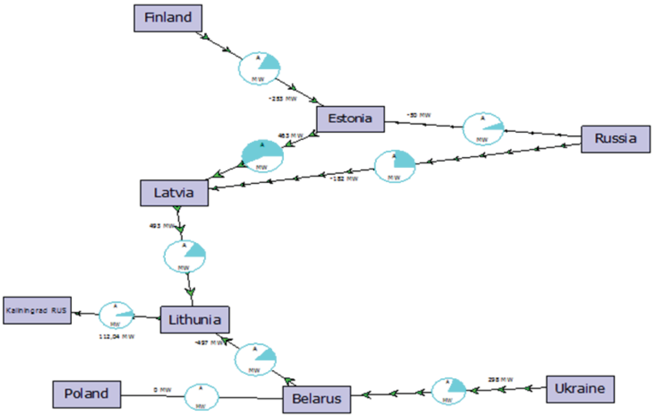


Fig. 40. Simulation snapshot of cross-borders power flow exchanges

3.3.2 Analysis of transmission system infrastructure in the Baltic region

The actual Baltic network presented in Fig. 41. characterised by countries' dependence on imports, primary control and frequency control from Russian TSO, with a significant threat resulting from the bottleneck between Russia and Belarus.

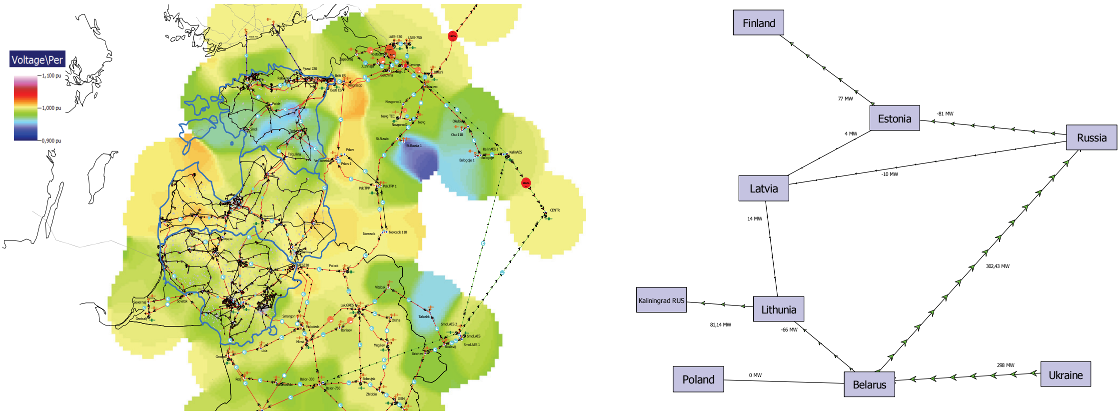


Fig. 41. Baseline scenario: per unit voltage contour and cross-border power flow winter peak (2013/2014)

The extra loading of this sensitive section is a direct result of the decommissioning of the Lithuanian Ignalina NPP. The failure of aforementioned section to result in negative consequences including equipment failure, unserved load and frequency/voltage drops.

3.3.3 Joint disconnection of Russia and Belarus

This subchapter summarizes the most critical N-1 line outages in conjuncture with a disconnection from the IPS/UPS (Russia and Belarus), as presented in Table XXVII. The reported violations within the Baltic States are characterized mainly by severe voltage drops and isolated loads. Immediate corrective measures have to be taken by either investing in redundant lines or by deployment of emergency automatic devices to isolate the affected regions from the main system in order to avoid a total blackout.

It should be noted that the outage of the Grobina-Klaipeda line has resulted in the most severe threat (49 violations in total): however, this contingency could be fully addressed in 2015 following the commissioning of the "NordBalt" interconnection with Sweden.

TABLE XXVII. CRITICAL LINES IN THE CASE OF JOINT RUSSIAN BELARUSIAN DISCONNECTIONS

Nbr	From	To	Countries affected	Min Voltage p.u	Violations
1	Grobina	Klaipeda	Latvia/Lithuania	0,692	49
2	Valmiera	Tsigulina	Latvia/Estonia	0.890	5
3	BaltiES	TartuC2	Estonia	0,888	13
4	Koigi	Paide	Estonia	0,778	9
5	Imavere	KoigiC1	Estonia	0,787	7
6	Kaunas	Jurbarkas	Lithuania		3
7	Utena	Uzpalia	Lithuania	0.882	35

The per unit voltage and the cross border power flows transfer during most serious contingency outage resulting from the loss of the line between Grobina and Klaipeda are illustrated in Fig. 42. The number of the potential violations registered and the extreme level of voltage drops suggests that if immediate actions are not taken to balance the system within the network transmission limits or to isolation the affected section, failure of the overall system is likely to happen.

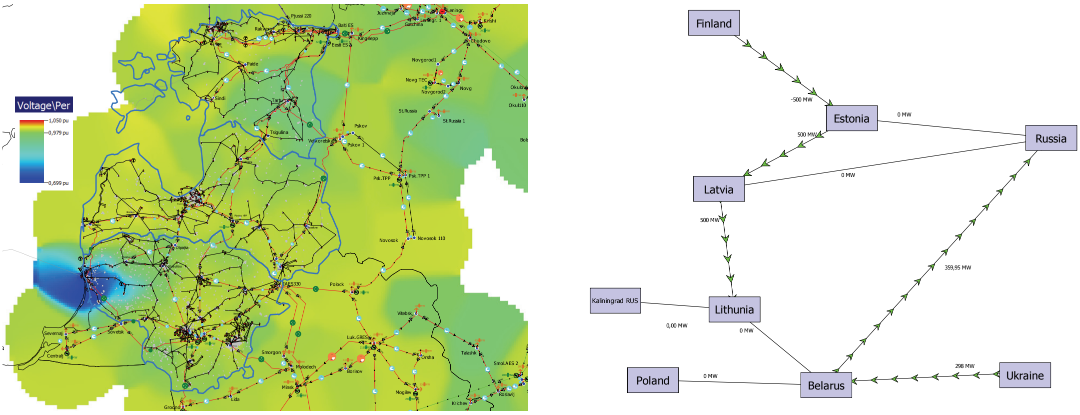


Fig. 42. Outage during joint disconnection of Russia and Belarus

3.3.4 Disconnection from the Russian network

The following subchapter summarizes the major contingency events of the Russian disconnection from the Baltic States, as presented in Table XXVIII. In comparison to the simultaneous disconnection of Belarus and Russia, the actual contingency resulted in similar failure degree, except the Utena-Uzpalia line outage that did not result in serious violations.

TABLE XXVIII. CRITICAL LINES IN THE CASE OF RUSSIAN DISCONNECTION

Nbr	From	To	Countries affected	Min Voltage p.u	Violations
1	Grobina	Klaipeda	Latvia/Lithuania	0,716	48
2	Valmiera	Tsigulina	Latvia/Estonia	0.895	4
3	BaltiES	TartuC2	Estonia	0,889	6
4	Koigi	Paide	Estonia	0,778	9
5	Imavere	KoigiC1	Estonia	0,787	7
6	Kaunas	Jurbarkas	Lithuania		3
7	Utena	Uzpalia	Lithuania		none

The per unit voltage and the cross border power flows transfer during serious contingency outage resulting from the loss of the line between Paide and Koigi are illustrated in Fig. 43. This outage would also result in a number of the potential registered violations and the extreme level of voltage drops that might lead to failure of the overall system, if no immediate actions are taken.

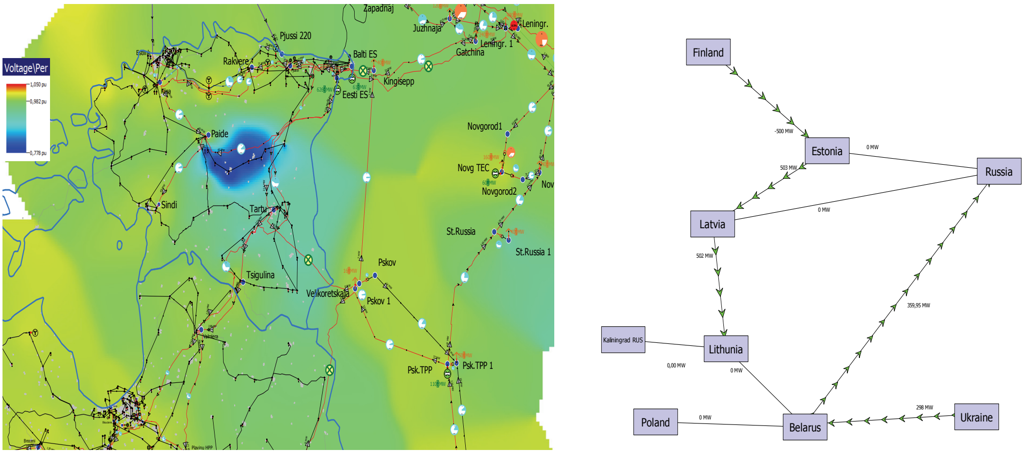


Fig. 43. Outage during Russian network disconnection

From an energy supply balance point of view, the two scenarios present no distinction as the Baltic States are likely to be able to meet the supply, relying on Estonia’s connection to Finland and potential load shedding events. However, in both cases, the loss of the Russian frequency automatic regulation is likely to put the Baltic system under a blackout threat in the event of a sustained disconnection, sudden demand change and/or N-1 contingency.

3.4 Conclusions to Chapter

The aim of the above-provided calculation was to demonstrate a methodology implementation to the real case study simulation, taking into account the development task complexity. Based on the methods and algorithms created in this thesis, the Baltic transmission system planning has become possible, and the following results estimation can be done:

- The structure of the Baltic transmission system network has significant drawbacks that reduce the reliability of certain regions’ power supply, as well as limit the further development of power system. The existing 110 kV network does not provide a sufficiently reliable power supply in regions. The main cause of power lines tripping of is wind loads (III and IV of the zone). As a result, the complete cessation of energy supply that occurred in 2005 might repeat at some point in time. With the implementation of priority projects in the Baltic region, the existing 330 kV network will be strengthened and the reliability of power supply for the consumers will increase. Simultaneously, priority projects provides the possibility of a widespread use of wind power, as well as – of increasing transit flows between the Nordic countries and Central Europe. The new transmission lines will be able to provide the currently necessary demand and the future demand of electricity in the developing regions, in the case of repairs without special restrictions.

This case study proves that a concept aimed at demonstrating an elaborated methodology's capability and application that would cover all stages – from the data input and analysis till the development scenarios estimation and decision making is indeed plausible.

Conclusion

The increasing penetration of RES and development of Internal Electricity Market in EU countries is a driver of fundamental changes in transmission planning and its operation. The variable nature of wind and solar power, the potential for offshore grids and the particularities of optimal utilisation of hydro and retained nuclear capacity reveal a need for changes to the way in which power system planning is currently conducted. However, enhanced system monitoring and online analysis of stability limits along with the potential for growth in demand side measures to address system limits suggest that, for given patterns of available generation and demand, the margins afforded by the underlying capacity of the network can be squeezed with the prospect of lower levels of network reinforcement than would otherwise have been the case. The afore-mentioned implies that attention should be given to the new ways of analysing the system (chapter I), including advanced methods, algorithms (chapter II), tools and methodologies (chapter III) to facilitate those analyses along with the new decision making processes.

The main point of this work was to demonstrate the new methodology based on the deterministic concept with a dynamic transmission expansion planning in a perfect competitive electricity market with technical and market economic regulation principals. The proposed methodology for transmission network development planning will facilitate intelligent operation and control of the modern power system, including the concrete task purposes. It will provide the possibility to incorporate smart solutions to technical (secure, stable, and good power quality), economic and environmental goals. They would also incorporate distributed generations and demand response, penetration of new renewable energy sources, forecasting of the load and price.

Contributions of Dissertation Thesis

Contribution of this work can be evaluated and summarized from scientific and practical significance:

Scientific novelty and main results

The scientific novelty includes the methodology for transmission network development planning in liberalized conditions. The new object that was investigated was a power system with an increased share of intermitted generation. The main results cover the strategic bidding analysis and price formation mechanisms, optimal power flow techniques and comparison between AC and DC models, development of optimal power flow methods and development process algorithms, which were implemented in the mentioned above methodology for the transmission network development planning in electricity market. Subsequently, the practical implementation of the planning will allow to perform the following: long-term energy balance evaluation, long-term perfect competition electricity price and welfare forecasting for different scenarios.

Practical significance of the research results

The EU energy strategy sets ambitious goals for the energy systems of the future that foresees a substantial increase in the share of renewable electricity production. The whole-sale deployment of RES connected to the network at all voltage levels will require radically new approaches for transmission system modelling that could accommodate the coordinated operation of millions of devices and various technologies, at many different scales that are dispersed across EU grid.

The developed methodology algorithms and methods can be used in power system planning practice. The potential stakeholders are the decision makers and planners who require a proper instrument for transmission development planning, as well as a comprehensive understanding of the impacts on the entire System's operation, electricity market as well as generating and transmission capacity requirements in advance, to secure optimal development solutions.

The proposed methodology is intended to be implemented into a software tool appropriate for the application in the development planning.

Contribution of this thesis are based on work approbation at international conferences (e. g. PMAPS`2012 - Istanbul, PowerEng`2013 – Istanbul, IYCE`2011 - Leiria, CYSENI'2012&2013 - Kaunas, RTU Conference - Riga etc.), they were published in scientific journals and data bases (IEEE Explore digital library, SCOPUS, EBSCO, VERSITA).

Proposal for Further Research Targets

Further research identification can be facilitated by the EU energy policy perspectives and challenges. The optimal expansion of the power system and transmission system in particular, under conditions of the liberalized market environment calls for forward-looking approaches that are able to reflect and find balance between requirements while these are often contrary.

Forward-looking research is identified in the following areas:

- Extension of existing OPF techniques with operational congestion management by coordinated control of Flexible Alternating Current Technology Systems and High Voltage Direct Current technologies;
- Implementation of Dynamic Optimal Power Flow to cover multiple time periods for network management with high penetrations of renewable generation, including energy storage and flexible demand;
- Development of multi-criteria decision-making methodology for transmission system sustainable development with preservation of the network security and reliability;
- Complex cost-benefit analysis for transmission network reinforcements based on assessments of economic levels of residual congestions;

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Appendix

Interstate DC Line Performance Assessment Methods

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Abstract--**The Article is focused on interconnection of power systems via High Voltage Direct Current (HVDC) submarine cables, its transmission capacity allocation and utilization. Sufficiency of transmission capability on market formation and operation are investigated as well as role of Power Exchange (PX) and trading principles for HVDC interconnections. Model of Nordic power system and PX data are used for technical/economic calculation and analysis based on market areas price differences and power flows through inter-state connections.**

Index Terms-- **Electricity market, HVDC technology, power flow.**

I. INTRODUCTION

Cooperation between Transmission System Operators (TSOs) of interconnected countries[1] Norway, Sweden, Finland and Denmark is covered by Nordel association. Collaboration within Nordel creates preconditions to better utilize power generation potential deployed in Countries, increase security and stability of power system as well as bring environmental and economic advantages. Recommendations of Association comprise base for technical regulations of power production, grid operation and maintain convenient market environment. Well-functioning power system under Nordel conduced in 1996 to launch first international power exchange Nord Pool for common Nordic power market purposes. Progress in market integration arise in 2000 after transformation on Nordel into organization with state objective to create conditions for an efficient and harmonized Nordic electricity market and ensure process of market development. Furthermore, Nordel provide opportunity for cooperation between TSOs in Nordic and transmission system operators out of Association what makes a contribution to a numbers of physical interconnections between the Nordel region and neighboring countries. Due to harmonization of rules and legislation in different counties associated in Nordel was formulated common code for Nordic grid – The Nordic Grid Code (NGC). The NGC consists of four main Articles: 1) Planning Code, 2) Operational Code (System Operation Agreement), 3) Connection Code 4) Data Exchange Code (Data Exchange Agreement between the Nordic transmission system operators (TSOs) The purpose of the Nordic Grid Code is to achieve coherent and coordinated Nordic operation and planning between the companies responsible for operating the transmission systems, in order to establish the best possible conditions for development of a functioning and effectively integrated Nordic power market. A further objective is to develop a shared basis for satisfactory operational reliability and quality of delivery in the coherent Nordic electric power system [1].

II. NORDIC POWER SYSTEM ANALYSIS

Diversity of power production in the Nordic leads to efforts about reinforcement on internal cross-section connection as well as about common market establishment. Common gain is increasing security and lower costs. In Norway is power generating based mostly on hydro resources. Sweden power production uses predominantly hydro and nuclear power, Finland used a mix of hydro, thermal power and nuclear. Denmark's energy supply was based almost entirely on thermal power with increasing of proportion wind. See Fig.1. Nordic grid operates at the following AC voltage levels: Denmark: 132/150/220/400 kV; Finland: 110/220/400 kV; Norway: 300/420 kV (and 132 kV northern Norway); Sweden: 220/400 kV; The HVDC links between subsystems at 285-400 kV. Cross-border interconnections also constitute numbers of lines on lower voltages.

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[1] The paper is supported by the European Social Fund Project "Scientific Group Supporting Latvian Activities of the European Strategic Energy Technology Plan", No.1DP/1.1.1.2.0/09/APIA/VIAA/027 and by Scientific Grant Agency of the Ministry of Education of the Slovak Republic and the Slovak Academy of Sciences within the project VEGA 1/0166/10.

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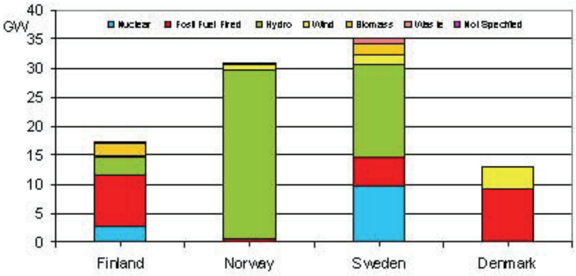

Fig. 1. Installed capacity by energy source of Nordel[1] 2010

Nordic grid comprises power systems of Norway, Sweden, Finland and eastern Denmark (Zealand) with synchronous operation. The western part of Denmark belongs to continental European synchronous area (former UCTE). Furthermore, western Denmark is asynchronously connected to Nordel (Norway and Sweden) via HVDC links. See Fig. 2.

Fig. 2. Nordic power system

Typical feature of Nordel power system is relatively weak coupling between generators due the long distances of transmission lines (high reactance of AC lines) what constraints full utilization of its capacity. Another specific feature of long transmission distances and disperse generators is that capability of interconnections transmit power depends on power flow direction which is related with power production of generators. Especially, considerable proportion of hydro power plants can cause that direction of power flows varies over the year. Further on, after calculations of technical transmission capacity with assuming safety and control margins (typically by 5-10 %) is residual transmission capacity of AC lines put as a disposal for market purposes (commercial capacity). Nominal transmission capacity for DC connections is measured on AC side of rectifier and is determined as a maximum continuous power that can be allowed at the ambient temperature that is not exceeded for more than 4 weeks per year and without affecting the nominal availability [1]. The delivery capacity of the system as a whole is higher than the sum of the individual delivery capacities of the subsystems. As a result of the expansion of transmission capacity between the subsystems, the interconnected Nordic electric power system operates increasingly as a single entity.

New interconnections planning and extension

General common rules summarized in Planning code (article of NGC) determines design of entire Nordic power system so that consumption of electricity should be met at the lowest cost. It means that the power system shall be planned, built and operated so that sufficient transmission capacity will be available for utilizing the generation capacity and meeting the needs of the consumers in a way which is economically best[2]. Planning and construction of new interconnections within Nordel or between Nordel and neighboring systems can affect not only TSOs in direct collaboration but whole Nordic power system with technical and market consequences as well. Therefore, planning of interconnections are coordinated with Nordic grid master plan [2].

III. HVDC INTERCONNECTIONS

Generally, application of DC transmission/interconnection can be mainly due to following reasons:
Requirement to transmit great power at long distance; In cases that for transmission is necessarily used cable (submarine transmission) and problems with considerable charging capacitive currents occurred; Interconnection of unequal power systems or increasing transmission capability of power system by utilization of damping control.
When only technical aspects of transmission has taken a place, comparison 3-phase AC line and bipolar DC line with grounded neutral conductor is summarized in Table 1.[3].

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[1] Nordel collaboration including also Transmission System Operator of Iceland, currently without physical interconnections to rest of Nordel.

[2] For detailed criteria and description of Nordic transmission system planning see [1].

TABLE 1
COMPARISON OF DC AND AC TRANSMISSION

Matching conditions	**Transmission capability** $\frac{P_{DC}}{P_{AC}}$	**Power losses** $\frac{\Delta P_{DC}}{\Delta P_{AC}}$	**Voltage decrease** $\frac{\Delta U_{DC}}{\Delta U_{AC}}$ $\xi = 80°$ $\cos\varphi = 0{,}95$
Equal U_{crit} of corona and cross-section of wires	1,405	$\frac{3}{8}\cos^2\varphi$	0,528
Equal U_{crit} of corona and weight of wires	2,455	$\frac{1}{6}\cos^2\varphi$	0,317
Equal level of insulation and cross-section of wires	1,65	$\frac{1}{3{,}7}\cos^2\varphi$	0,451

Total losses of direct transmission are higher due the losses in converter stations.

A. HVDC submarine cable Fenno-Skan

Submarine HVDC cable commissioned in 1989 which reinforced coupling of power systems of Finland and Sweden. Cable length is 200km. Currently owned by Fingrid (Finland) and Svenska Kraftnät (Sweden). Link is used for power exchange in both directions. Rated voltage 400 kV, presently operates as monopolar (planed bipolar extension). Transmission capacity is temperature-dependent, normally at 550 MW with short overload possibility at the 600 MW.

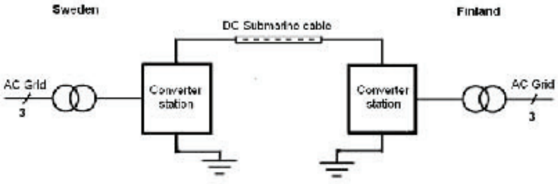

Fig. 3. Principal Fenno-Skan configuration

Main assets of interconnection are reduction of transmission distances between south-western Finland and east central Sweden, which represents areas with high concentration of consumption and generating power. Interconnection also provides possibility for power flow redistribution between 400 kV AC lines on north and Fenno-Skan (middle). Such operation brings total system losses reduction by up to 40 MW. Furthermore, Fenno-Skan has also been provided with damping control regulators and emergency power control features, which stabilize the power systems in such a way that the power transfer capability between northern and central Sweden can be increased by 250 MW and in same amount also increased capability of 400 kV northern AC lines between Sweden and Finland.

Operation and capacity redistribution

Monitoring, operation and control concerning 400 kV AC links and Fenno-Skan in Sweden is carried out by Grid Supervisor at Network Control of SvK in Racksta and in Finland from Operation Centre of Fingrid in Helsinki. Fenno-Skan regulation responsibility alternates between Finnish and Swedish side every half of calendar year. Transmission capacity of all interconnections is calculated on daily basis by Operation centres in Racksta and Helsinki. Available trading capacity is obtained as total transmission capacity minus determined margin for regulation purposes. As a starting point for trading capacity distribution between northern AC lines and Fenno-Skan is used basic distribution with rules in compliance with Nordic grid operation code. Elbas (Intraday trading of Nord Pool power exchange) and supportive power trading across the border are not handled in basic distribution. During periods when a disturbance in power system occurred loss minimization is not employed. Parties involved in cooperation do not pay any compensation for loss minimization benefit, only non-notified balance power is financially settled [1]. In period 2008-2012 is planned extension of Fenno-Skan with second pole (Fenno-Skan 2) due the increases in generation capacities, above all, integration of wind park near Gävle and uprates in nuclear power plant Forsmark 3. Changes are also concerned reinforcement 400 kV AC northern lines and modifications of substations [4].

B. HVDC submarine cable Estlink

Efforts about increasing of HVDC interconnection capacities between Nordel and rest of continental Europe are primarily based on market interests as well as better utilization of hydroelectric power generation deployed in Nordel and predominant thermal power generation in Continent. These interests are strongly powered also by European Commission with idea to establish common EU energy market. Estlink, submarine HVDC cable linked up subsystems of Finland (Espoo substation - AC 400 kV) and Estonia (Harku substation - AC 330 kV). Link with total length 210 (2 times 105) km was commissioned in 2006. Operational voltage level of bipolar construction is +/- 150 kV.

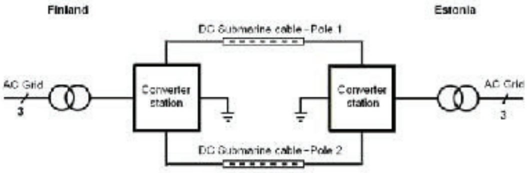

Fig. 4. Principal Estlink configuration

Maximal transmission capacity at the 350 MW with possibility to transmit energy in either direction is primary meant for market purposes (commercial operation). Besides, interconnection improved security of supply in Baltic that creates potential channel for purchasing electricity from Nordic. Construction of cable not induced any grid improvement on Finnish side. Estimated annual import 2,5 TWh from Estonia represent approximately 3% of total current Finnish consumption.

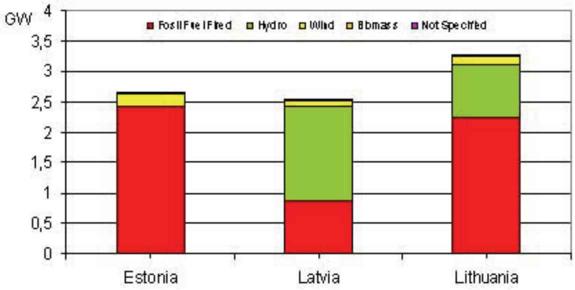

Fig. 5. Installed capacity by energy source in Baltic 2010

To evaluate new possible interconnections was launched multiregional study between Nodel, Baltso and PSE operator (Polish TSO) related to technical-economic impacts of new links [5].

IV. NORD POOL SPOT

Presently, Nord Pool Spot runs largest international electricity market on the World. Providing services for day-ahead market (Elspot) and intra-day market (Elbas) spot trading with physical electricity. As a result of matching supply and demand bids at the spot market, final spot price and trading volumes are determined. Due to potential limitations in transmission capacity spot market in Nordic was divided into Nord Pool spot bidding areas.

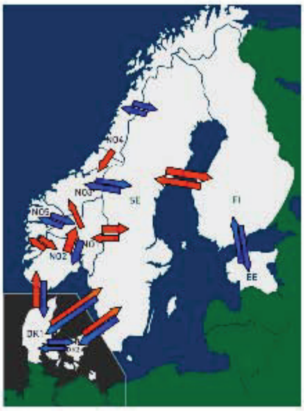

Fig. 6. Nord Pool Spot Areas

Except Denmark and Norway which are subdivided into several spot price areas, boundaries are identical with national borders.

TSOs allocate available transmission capacity on a base of production and consumption forecast. Subsequently, available capacity is allocated at Nord Pool spot market for trading purposes. Allocation of available transmission capacity is done before Nord Pool spot pricing. The available capacities for transmission are reported to Nord Pool pre bidding and are taken into account when price calculation is performed. When no congestion appeared, the prices in different areas are the same (Area price = System price). Market splitting is used if there is congestion. Solving tasks with structural congestion is related to grid investments in case that it is socio-economically feasible, otherwise market splitting is utilized, i.e. dividing the market into separate price areas. Adequate transmission capacity with effective utilization is therefore one of the basic requirements to achieve well functioning and effective electricity market.

Price differences between areas after utilization of transmission capacity between them generate an ownerless income on the spot market, trading flow from the area with a lower price to the area with a higher price. In situations when flow goes from high price area to low price area (towards low price area) due to specific operations or dispatch optimization by TSOs, generating of ownerless costs occurred [4].

These ownerless costs and incomes are referred as congestion rent. Within the Nordic region this income is allocated to the TSOs as owners of the transmission grid. Calculation of congestion rent as follows:

$$(P_B - P_A)F_{A\rightarrow B} = C_R \qquad (1)$$

P_A - Area price in area A, [m.u./MWh];

P_B - Area price in area B, [m.u./MWh];

$F_{A \to B}$ - Planned Elspot flow in specific hour from area A to area B, [MW];

C_R - Aggregated congestion rent [m.u.].

Sharing of congestion rent between TSOs is based on Sharing Agreement which provide two possible sharing options. First, calculates adequate share (participation) of all TSOs on Five prioritized projects within Nordel related to Nordic grid development. Second divide congestion rent in two equal shares only between affected TSOs[3] [1]. Incomes of TSOs are commonly used for reduction of tariffs or investments to transmission grid. New Estlink bidding area at Nord Pool Spot was launched on 1 April 2010 and connects Estonia to Nordic electricity market. The long term goal is to create a Baltic market connected to the Nordic market through Nord Pool Spot [5]. The Estlink cable is operated by company AS Nordic Energy Link (NEL). NEL was founded by Baltic and Finnish companies. These share NEL Company (transmission capacity on Estlink) as follows: Baltic companies Eesti Energia (39.9%), Latvenergo (25%) and Lietuvos Energija (25%) and Finnish companies Pohjolan Voima and Helsingin Energia (Finestlink) remaining 10.1%. Shareholders will sell before 2013 entire NEL company to TSOs Fingrid (Finland) and Elering (Estonia) [7].

Suitable environment for Estonian market establishment by Nord Pool Spot arised after Latvenergo and Eesti Energia offered their shares of Estlink capacity to the Estonian and Finnish transmission system operators Elering and Fingrid. This step ensured sufficient capacity for opening the Estlink bidding area.

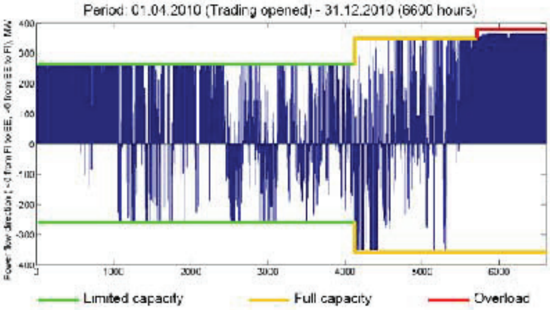

Fig. 7. Estlink power flow utilization by Elspot, 2010

Available transmission capacity allocated for the Elspot-market was 252 MW from Finland to Estonia and 262 MW from Estonia to Finland. Since September 2010 TSOs of Finland and Estonia rented full cable capacity from owners and offered for market purposes. After new agreement the available transmission capacity is 350 MW in both directions.

Increasing of transmission capacity through Estlink is very positive for the market development in the Baltic and Nordic. Adequacy capacity is one an important step in markets integration and further on, towards common European market with electricity.

V. LOSSES OPTIMIZATION MANAGEMENT

A. Fenno-Skan loss minimization and benefits sharing

Loss minimization in Finnish and Swedish grids by Fenno-Skan aggregates benefits which are divided equally between TSOs. Benefits calculation as well as distribution between parties (Fingrid & SvK) is based on following principles [1]: The overall benefit to the system in particular hour is defined as the positive difference between the calculated overall loss overheads during basic distribution and during the real reference value. As reference value minimal point is usually used. See Fig. 8.

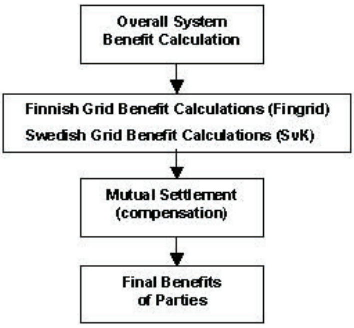

Fig. 8. Fenno-Skan benefit evaluation and distribution

B. Estlink losses calculation

Estlink power flow analysis estimates markets activity and price differences of interconnected areas. Calculations are based on physical power flow through Estlink at hourly basis from 1 April 2010 until 31 December 2010. In Fig. 9 is shown example of price differences between Estonia and Finland which caused a physical power flow through Estlink. In assumed period only flow from Estonia to Finland appeared.

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[3] For detailed description of sharing principles and changes in sharing options check: http://www.nordpoolspot.com

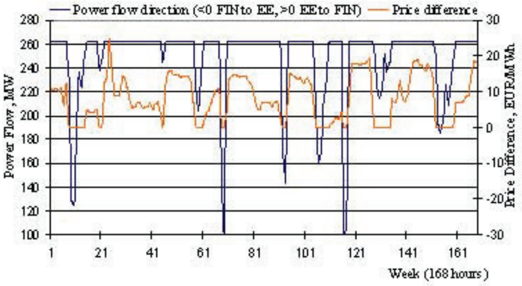

Fig. 9. Price difference & Estlink power flow

Transmitted volume in assumed period represents 1,524249 TWh of which from FI to EE is 0,243934 TWh and EE to FI is 1,280315 TWh. Calculation of Estlink losses were performed by Estlink Losses Formula. Total calculated losses caused by power flow in both directions are 75,348 GWh of which from FI to EE is 12,814 GWh and EE to FI is 62,534 GWh.
After variable transmission costs of cable were calculated, in compliance with price differences between Areas on hourly basis, costs of *ignored* transmission losses was obtained.

Figure 10 shows one week period Estlink power flow and caused (calculated) power losses.

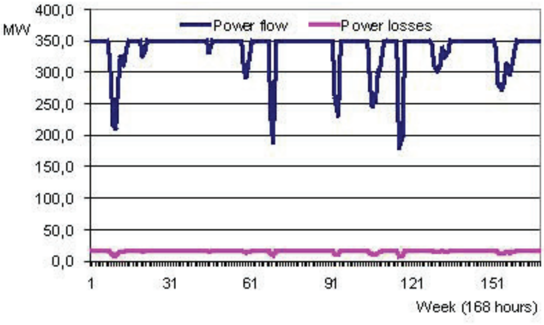

Fig. 10. Physical Estlink power flow & calculated losses

VI. MODEL OF POWER SYSTEM FOR LOSSES ESTIMATION

For the analysis of Fenno-Scan in the Nordic countries the modified Nordic32-bus test system is used. Its close resemblance to a real power system in Sweden where more generation units are in the north and heavy load centres in the south. The model consists of 33 buses, 28 synchronous generators, 51 branches, 3 DC lines and a total of 25 loads. As a starting point the simplified single diagram of the CIGRE Nordic32-bus test system [8].

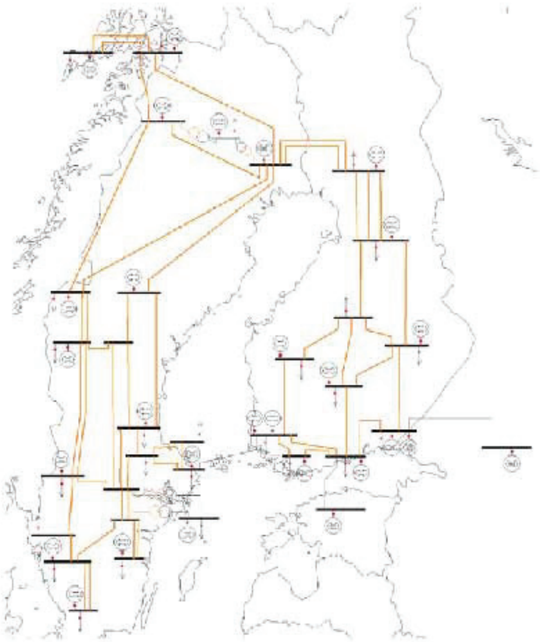

Fig. 11. Model of Nordic grid

Model of Nordic grid was created in Power World Simulator which is designed to simulate high voltage power system operation. Software contains power flow analysis and losses calculation. Simulation and parameters of grid elements takes into account current state of real power system in Nordic.

VII. CONCLUSIONS

In this paper described Interstate DC Line Performance Assessment Methods in Liberalized Market conditions. This method will be used for power flow analysis and losses calculation to estimates markets activity and price differences of interconnected areas.

It will provide facility for market participants properly organize their long-term and short-term power balance including investments into new infrastructure, in that way helping to organize power balance in the whole system and to reducing financial losses.

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IX. BIOGRAPHIES

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Appendix 2

Proceedings of PMAPS 2012, Istanbul, Turkey, June 10-14, 2012

Assessment of the Network Reliability Calculation in Transmission System Development Tasks

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Abstract— **For assessment of the network reliability calculation in transmission system development tasks, dynamic optimization model was created. In this article are given results of network reliability calculation of national project of Baltic states. The proposed model takes into account existing network structure and future development plans of power system.**

Keywords- power system, reliability, system development.

I. INTRODUCTION

The trends of power system development in Baltic are related with grid infrastructure improvement, power supply diversification, energy effectiveness, the best use of local resources and in addition considerably increasing reliability. All these projects of the base tendencies are represented in the new action plan of EU Energy Security and Solidarity. The integration of the Baltic countries into the EU power network is the main target for future stability and economic growth. This plan provides significant investments for the development of the new electricity generating capacities and the intersystem connections between Baltic, Scandinavia and continental Europe (shown on fig. 1.) [1].

Figure 1. Baltic sea power systems

A distinctive feature of electrical networks is their continuous development associated with load increasing, implementation of events to improve reliability of power supply and formation of integrated power system. Transmission system development tasks are multi-criterial, however part of these criteria are not economic. This causes serious problems and requires special techniques. Such methods are needed to account also reliability of supply for comparable development plans alternatives.

For assessment of the network reliability calculation in transmission system development tasks, dynamic optimization model has been created. In this article are given results of network reliability calculation of State national project.

II. LATVIAN ENERGY MARKET DEVELOPMENT TENDENCY

The primary function of a physical electricity market is to establish a balance between supply and demand. In a high-quality handle this task is an extremely important, because power shortages entail very substantial socio-economic costs. A well-functioning power market (fig.2.) ensures that electricity is generated wherever the cost of generation is the lowest at any time of the day.

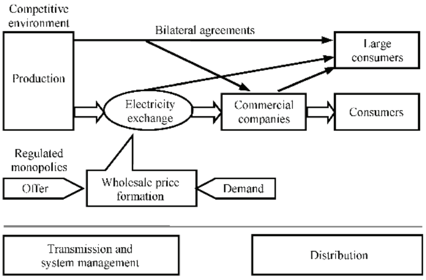


Figure 2. Baltic market organizing.

Increases in demand will be balanced by more expensive generation with higher marginal costs. This also gives the market an indication whether and when new generating capacity is required. In socio-economic terms, this provides a clear indication of the costs the society would have to bear in order to incorporate a new output in the system. Where commercial considerations are concerned, the generators will receive a good indication of where the break-even point lies for developing a new generating capacity.

The paper is supported by the European Social Fund Project "Scientific Group Supporting Latvian Activities of the European Strategic Energy Technology Plan", No.1DP/1.1.1.2.0/09/APIA/VIAA/027

The strategic objective of Baltic power systems is to integrate local power markets into the European power market area and to increase the security of supply in the whole region. By reaching these goals, with grid infrastructure improvement the entire Baltic Sea market region would become more closely integrated into the common European electricity market [2, 3].

III. RELIABILITY CALCULATION METHOD OF TRANSMISSION NETWORK

Methods for power system reliability evaluation have been developed over the past 35 years. Although research still continues in search of better models and methods but in general there is substantial body of knowledge that can be used effectively for analysis and issues related to reliability management. This knowledge can be suitably adapted to the liberalized environment in the power industry. From the observation of the past performance a set of outage models and corresponding input data are derived using appropriate outage statistics. In the calculation process of reliability criteria of transmission network interruptions or disconnections are reviewed by one and by two simultaneously. In the result of interruption:

- One or more nodes could be without electric supply;
- Overload in other power lines could occur.

Before network reliability calculation, all nodes with circuit-breakers should be marked (example is shown in figure 3. and table 1.).

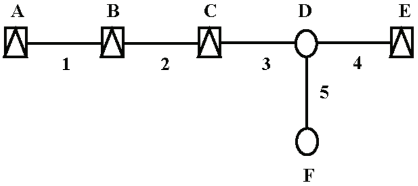


Figure 3. Network calculation scheme

Circuit breakers are in nodes A, B, C and E. Nodes D and F without.

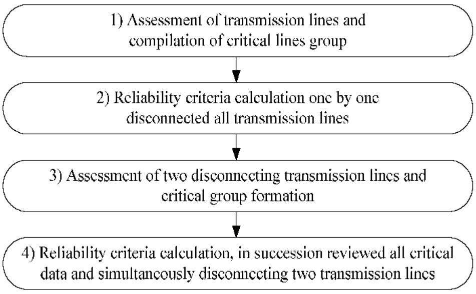
TABLE I. FAILURE ELEMENTS

Failure element	*set of links* M
1	1
2	2
3	3,4,5

All links which represent failure element are disconnected at the same time. Element time of interruption U_3 is calculated as sum of this element links:

$$U_3 = U_{CD} + U_{DE} + U_{DF} \tag{1}$$

Network reliability calculation block diagram is given on figure 4.


1) Assessment of transmission lines and compilation of critical lines group

2) Reliability criteria calculation one by one disconnected all transmission lines

3) Assessment of two disconnecting transmission lines and critical group formation

4) Reliability criteria calculation, in succession reviewed all critical data and simultaneously disconnecting two transmission lines

Figure 4. Network reliability calculation block diagram.

For the operation states calculations of transmission network consistent load duration curves are applied (fig. 5.). To assess of the network reliability in transmission system development tasks following items are calculated [4]:

- Annual interruption duration, U [hours/year];
- Non delivered energy, W [MWh/year];
- Costs of energy not supplied, C [TEUR/year]

The function of 1st block is to compose data for the estimated time limit. Power lines are selected according to these criteria:

$$K^{*}_{L,re,e,t} = \sum_{L\in M} Tre_{re=1} \cdot \chi_L \cdot Ps_{L,re=1}, \tag{2}$$

where L - transmission line ordinal number;
M - disconnected transmission line group;
e - network state;
t - development step number;
re - operational state ordinal number;
Tre_{re} - operational state (maximal loads) duration [h/year];
$Ps_{L,re}$ - transmission line L flow in operational state re [MW];
$\chi_L = \dfrac{\lambda_L \cdot DL_L \cdot r_L}{100 \cdot 8760}$ - interruption probability of transmission line L;
λ_L - specific number of failures per 100 km of lines per year;
DL_L - transmission line L length [km];
r_L - transmission line L fault prevention duration [h].

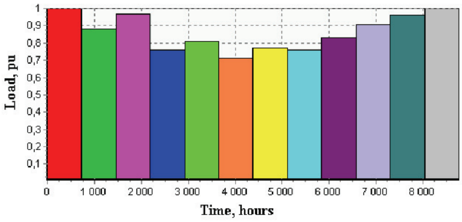


Figure 5. 12 operational states durations and load levels

This criterion is labelled as conventional load non-supplied. This corresponds to electric transmission line $L \in M$ in operational state *re* to repair duration (asymptotic unavailability parameter *U*), multiplied by flow in line. In the reliability calculation of this criterion only 20 electric transmission lines should be taken into consideration in which transmission line flow is $Ps_{L,re}$, transmission line interruption probability and therefore criteria K^* are the highest values. Such group of transmission lines is marked with value *M* and is labelled as critical group of lines. This criterion is necessary in order to select critical group of lines and thus reducing calculation time. Due to the huge scope of calculation, essential calculation problems could appear because disconnecting lines by two, sizeable combination number presented. For instance, if there are 100 elements, combination number for one operational state: $C_n = n \cdot (n-1)/2 = 4950$.

In 2nd block, disconnecting in succession all lines $L \in M$, first should be tested or checked whether load is disconnected. If load is disconnected, then amount of non delivered energy W_{L_i} is calculated as follows:

$$W_{L_i} = \sum_{re=1}^{rem} U_{re,L_i} \cdot P_{re}, \tag{3}$$

where
rem - number of operation states;
P_{re} - operation state's *re* disconnected load;
L_i - disconnected transmission line;
U_{re,L_i} - line L_i fault prevention time in operation state *re*.

$$U_{re,L_i} = \frac{\lambda_{L,i} \cdot DL_{L,i} \cdot r_{L,i} \cdot Tre_{re}}{100 \cdot 8760}. \tag{4}$$

In such case non delivered amount of energy will be equal to non delivered amount of energy in the specific line *Wund* = *WLi*. If load is not disconnected from the network, it should be tested whether overload is there or not in other lines, if there such - it defines:

$$\Delta P_L = Ps_{L,re} - P\max_L, \tag{5}$$

where $P\max_L$ - admissible load in link L.

It is assumed that to provide network normal operation overloaded lines *Li* in interruption time, load is reduced by ΔP_L. The amount of non delivered energy in line *Li* at disconnection time is calculated by the following formula:

$$W_{L_i} = \sum_{re=1}^{rem} \sum_{L \in M_{re,L_i}} \Delta P_L \cdot U_{re,L_i}, \tag{6}$$

where M_{re,L_i} - operation state *re* line *Li* at disconnection time totally overloaded electric lines.

The 2nd block algorithm scheme is shown in figure 6.

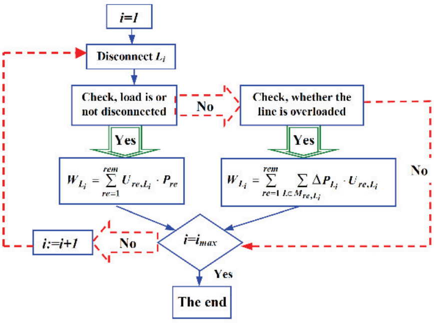


Figure 6. 2nd block algorithm scheme

For all lines non delivered energy is:

$$W_{und} = \sum_{L_i \in M_i} W_{L_i}. \tag{7}$$

Costs of energy not supplied:

$$C_{und} = c_{und} \cdot W_{und} \tag{8}$$

where c_{und} - non delivered energy specific costs [EUR/kWh]

In the 3rd block two simultaneously interrupted electric transmission lines are reviewed. It is assumed that in the reliability calculation we should observe only such electric transmission lines pairs which have highest probability values of simultaneous interruption. Selection simultaneously interrupted transmission lines according the following criteria:

$$K^*_{L\{i,j\},re,e,t} = \sum_{l \in M} Tre_{re=1} \cdot \chi_{L\{i\}} \cdot \chi_{L\{j\}} \cdot Ps_{L\{i,j\},re=1}, \tag{9}$$

where $\chi_{L\{i\}}, \chi_{L\{j\}}$ - transmission lines interruption probability.

In the reliability calculation 100 simultaneous interruption combinations should be taken into consideration. The selected set is assumed as two elements interruption critical group.

In the 4th block is continued the 3rd block initiated network reliability criteria calculation. Reliability criteria are calculated by algorithm in succession simultaneously disconnecting two transmission lines. The 4th block scheme is shown on fig. 7.

This method is applied in software LDM-TG (Latvian Dynamic Model), by which reliability analysis of transmission grid, substation and switchgear operation could be performed as well as technical and economic analysis on dynamic development process observing reliability economic ratios [5,6].

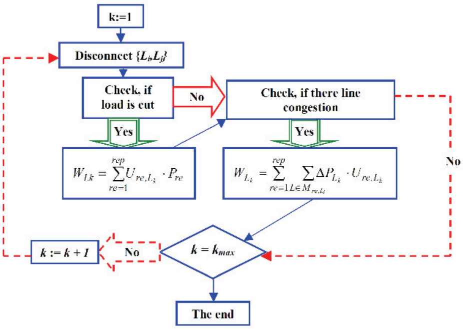


Figure 7. 4th block algorithm scheme

where L_K - simultaneously interruptible transmission lines pair k - L_i and L_j

IV. RELIABILITY CALCULATION FOR NATIONAL PROJECT OF BALTIC STATES

For assessment of the network reliability calculation in transmission system development tasks, model was created (shown in Fig. 8.), according to transmission development projects in Baltic. The model takes into account existing network structure, future development plans and load growth.

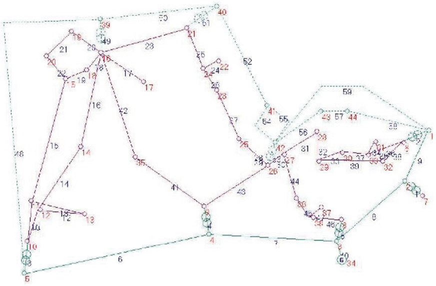


Figure 8. National project of Baltic states

For reliability calculation was used 330 and 110 kV transmission network parameters, summarized in table 2. Due to the fact that planned disconnections are strictly time dependent, probability of undelivered electricity in this case is negligible and not taken into account.

TABLE II. 330 AND 110 KV NETWORK PARAMETERS [7]

Voltage and line type	***Average frequency of stable failures per 100 km of lines per year***	***Average recovery time [h]***
Overhead line 110kV	1,3	9
Overhead line 330kV	0,6	11
Cable line 110kV	0,1	18
Cable line 330kV	0,1	22

Development steps of national project of Baltic states are shown in table 3.

TABLE III. DEVELOPMENT STEPS

Name	**Costs, TEUR**	**Length, km**	**Link**	**Operation, year**
330kV and 110kV overhead line Grobina - Ventspils	27474,29	125,7	48	2014
330/110 kV subbstation Ventspils	17142,86	-	49	2014
330kV and 110kV overhead line Ventspils-Dundaga	10731,43	49,1	50	2015
330/110 kV subbstation Dundaga	17142,86	-	51	2015
330kV and 110kV overhead line Dundaga-Kandava	13945,71	63,8	52	2017
330kV and 110kV overhead line Kandava-Abavnicki-Tume	5748,571	26,3	55	2017
330/110 kV subbstation Tume	17142,86	-	53	2017
330kV and 110kV overhead line Kandava-Pure-Tume	6032,857	27,6	54	2017
330kV and 110kV overhead line Tume-KNP	5538,571	25,3	56	2019
330kV cable line KNP	28741,71	16,6	57	2019
330kV and 110kV overhead line KNP-Imanta	7497,143	34,3	58	2019
330kV overhead line Tume-Imanta	17574,29	94	59	2019

For assessment of the network reliability calculation, five development plans was considered (presented in table 4.).

TABLE IV. DEVELOPMENT PLANS

Nr.	***Plans***	***Investments, MEUR***
1	Without network reconstruction	0
2	Grobina–Kandava–Abavnicki–Tume–KNP–Imanta	151,1
3	Grobina–Kandava–Abavnieki–Tume–Imanta	126,9
4	Grobina–Kandava–Pure–Tume–KNP–Imanta	151,4
5	Grobina–Kandava–Pure–Tume–Imanta	127,2

Additionally task is divided on commissioning steps into operation of each part of plans: 2011 – present situation, 2014– commissioning of the line Grobina-Ventspils, 2015– Ventspils-Dundaga, 2017– Dundaga-Tume, 2019– Tume-Imanta, 2045– final development step for which is performed calculation has been identify in 2045.

Tables 5 and 6 show compilations of critical groups for one and simultaneously two lines disconnection for first operational state in 2011. After determination of critical group, the calculation of reliability criteria is performed, taking into account constraints set forth in chapter III. This calculation is repeated for each year of development, taking into account load growth and new lines.

TABLE V. CRITICAL GROUP OF LINES FOR $re = 1$ IN 2011

Link	***length***	***Interruption probability***	***Transmission line L flow***	***Criteria K****
7	77,2	0,00058164	54,67	0,0318
8	44,5	0,00033527	78,1	0,0262
6	89,2	0,00067205	29,65	0,0199
43	132,1	0,00176435	8,04	0,0142
15	89,9	0,00120072	11,61	0,0139
41	54,7	0,00073058	16,98	0,0124
16	61,1	0,00081606	10,77	0,0088
45	38,7	0,00051688	15,62	0,0081
28	32,3	0,00043140	17,29	0,0075
42	55,5	0,00074127	9,62	0,0071
9	14.6	0.00011000	59,54	0,0065
11	32.2	0.00043007	13,2	0,0057
10	32.2	0.00043007	13,18	0,0057
14	32.4	0.00043274	11,73	0,0051
27	26.8	0.00035795	13,21	0,0047
31	36.7	0.00049017	9,63	0,0047
44	21.9	0.00029250	13,78	0,0040
39	19.1	0.00025510	14,16	0.0036
29	22.9	0.00030586	10,12	0.0031
38	10,5	0,00014024	20,14	0,0028

TABLE VI. PART OF TWO ELEMENTS INTERRUPTION CRITICAL GROUP

Link i	***Link j***	***Criteria K****
7	8	0,000833
7	6	0,000634
6	8	0,000522
7	43	0,000451
7	15	0.000443
7	41	0.000394
8	43	0.000371
8	15	0,000365
8	41	0,000325
6	43	0,000283
7	16	0,000279
6	15	0,000278
7	45	0,000257
6	41	0,000247
6	28	0,000237
7	42	0,000227
8	45	0,000211
7	9	0,000208
43	15	0,000198
8	28	0,000195

To compare reliability criteria with investments the costs of energy not supplied are calculated and presented in table 7 and for the specific costs of non delivered energy assumed 5,75EUR/kWh.

TABLE VII. COSTS OF ENERGY NOT SUPPLIED (TEUR/YEAR)

year	**1.plan**	**2.plan**	**3.plan**	**4.plan**	**5.plan**
2011	11382.17	11382,17	11382,17	11382,17	11382,17
2014	12065.09	11484,40	11484,40	11484,40	11484,40
2015	12406.57	12135,09	12135,09	12135,09	12135,09
2017	13089.49	11763,03	11763,03	11772,11	11772,11
2019	13772.46	12613,54	12828,46	12623,03	12838.00
2045	21057.03	19285,03	19613,77	19299,66	19628.34

The results show the change of energy not supplied in time, with introduction of new lines. 2^{nd} plan is more reliable than other plans, but more expensive. Due to the fact that developing task is a multi-criterial and each rate should be compared with investments, so, to choose the best case scenario should be taken into account all factors: reliability, investment, operating costs, energy losses, technical suitability, etc.

V. CONCLUSIONS

Further development of the Baltic electricity market is conditioned by completion of the infrastructure projects and amendments in Energy Legislation. Closer integration with the Nordic (Finland, Sweden, Denmark and Norway) electricity market will increase the reliability of supply in the Baltic; besides, it will allow the market participants to take advantages of wider common electricity market.

This research is focused on reliability improvement of transmission system of Baltic States according future network development.

Proposed Method and created model are appropriate for the solution of following tasks: 1) transmission system reliability calculation 2) transmission network structure's and configuration`s selection 3) evaluation of transmission system future development plans in liberalized market conditions.

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Appendix 3

Riga Technical University 53rd International Scientific Conference dedicated to the 150th anniversary and
The 1st Congress of World Engineers and Riga Polytechnical Institute / RTU Alumni

Assessment of Wind Production Impacts to a Power System and Market Formation in Baltic

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***Abstract* - This paper is related to an actual problem of expanding wind production integration to the power system and electricity markets. The model for simulation of wind production curves according to development of wind capacities in Baltic is proposed. In order to evaluate the effect of the wind power integration to the price formation as well as level of system penetration by wind, methodology and algorithms which taking into account development scenarios in Baltic are presented.**

Keywords – **Distributed power, Modeling, System integration, Wind energy**

I. INTRODUCTION

Numbers of wind power projects in Baltic region was proposed in last period. Integration of wind generation into power production mix has significant impact to the power system (PS) operation as well as to the electricity market.

The aim of study is assessment of wind production impacts related with considerable wind installation in future, developing of methods and algorithms enable simulations from wind conditions to final impact on a system. In a paper are proposed algorithms and methodology for estimation of those impacts including model which is capable to generate wind production curve assuming real wind conditions in a region. Results of regional wind production modeling presented in this article contains wind production and duration curves with application of different smoothing approaches, estimation of seasonal diversity of wind generation in different stages of future development of wind installations as well as comparison of annual production obtained by proposed model with expected targets in a field of wind production in Baltic. The final part of study is aimed to a estimation of power system penetration by wind generation and assessment of merit-order effect according to development scenarios of the PS in Baltic till 2020. The wind power production is based on real wind conditions in Baltic region and expected development of installed wind capacities.

II. WIND GENERATION MODELLING

Wind power and thus its modeling is significantly different from the other power technologies. Generation has specific characteristics, including variability and geographical distribution. The methodology and model presented in further part integrates specific features of large-scale wind generation deployment and regional wind conditions.

A. *Tendencies of installed wind capacities in Baltic*

The development of wind capacities in Baltic which are assumed in this study is based on planning and assumptions presented in National Renewable Energy Action Plans (NREAPs) published by three Baltic states (EE, LV, LT) related to development of wind generation capacities, both onshore and offshore by 2020 [1]. The offshore installations in Baltic are planned from 2017 mainly in Estonia and to a lesser extent in Latvia. Considering the technical availability of wind turbines which is generally at the very high level compared to other types of production sources, for further assumptions is envisaged at 97% [2]. A value of decreased available wind installed power P_{DEC} in Baltic shows table 1.

TABLE I.
TECHNICALLY AVAILABLE WIND CAPACITY

Year	**2011**	**2016**	**2020**
P_{DEC} (MW)	402	1124	1553

High level of technical availability is one of the significant advantages regarding to reliability of supply from distributed wind power installations in the power system. The requirements of maintenance or unplanned breakdown of single unit has negligible effect on overall wind production.

B. *Estimation of regional wind conditions*

Annual wind conditions applied for simulation of wind power production were measured at hourly basis in height of 10m at coastal part of Estonia in 3 localities and subsequently recalculated for wind speed conditions in height of 60m by equation 1

$$V_n = V_0\left(\frac{H}{H_0}\right)^{\alpha} ;\ \text{for } \alpha = 0{,}35 \qquad (1)$$

In further calculations, the averaged wind speed values are used. Occurrence of averaged annual wind speed shows Fig. 1.

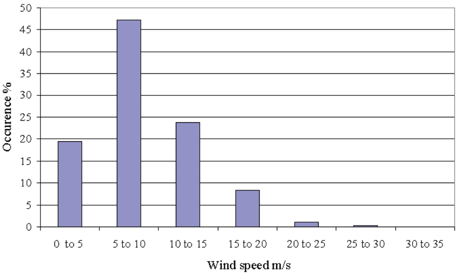

Fig. 1. Averaged wind speed occurrence.

C. Aggregated wind power characteristics modeling

To derive power output of installed wind capacity, the following model expressed by equation (2) has been introduced. This expression merges typical aggregated wind farm power curves both offshore and onshore [2]

$$\begin{aligned} f(x) = {} & a_1 \cdot e^{-((x-b_1)/c_1)^2} + a_2 \cdot e^{-((x-b_2)/c_2)^2} \\ & + a_3 \cdot e^{-((x-b_3)/c_3)^2} + a_4 \cdot e^{-((x-b_4)/c_4)^2} \\ & + a_5 \cdot e^{-((x-b_5)/c_5)^2} + a_6 \cdot e^{-((x-b_6)/c_6)^2} \\ & + a_7 \cdot e^{-((x-b_7)/c_7)^2} \end{aligned} \tag{2}$$

Variable "x" represents averaged wind speed (m/s) in every particular hour. Values of the coefficients to the formula 2 are shown in table 2.

TABLE II.
APPLIED COEFFICIENTS

a1	0,03402	**b3**	16,13	**c5**	3,818
b1	7,712	**c3**	0,5106	**a6**	0,4647
c1	2,281	**a4**	10,7	**b6**	13,16
a2	-0,1338	**b4**	21,43	**c6**	4,155
b2	19,48	**c4**	2,496	**a7**	-10,07
c2	1,606	**a5**	0,6206	**b7**	21,45
a3	0,009714	**b5**	17,15	**c7**	2,44

In order to obtain generated power according to wind speed via production curve of aggregated wind farm (Fig. 2), the difference in characteristics between onshore and offshore installations are neglected.

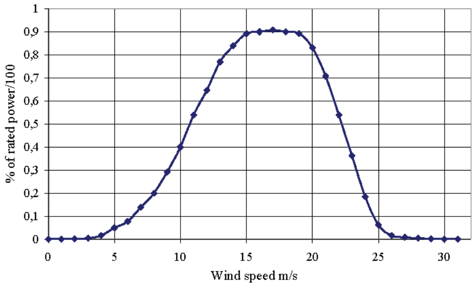

Fig. 2. Production curve of aggregated wind farm.

The resulting production curve is labeled as "raw" production curve with relatively high volatility of production. Averaging of the wind speed has partial impact to the shape of output production curve, so dynamics of variations has been decreased. However, in order to achieve characteristics observed and measured in real conditions, incorporation of so-called large-scale deployment smoothing effect (LSDSE) of wind production is performed in the next step.

D. Large-scale wind generation deployment

Large-scale wind power deployment has a significant impact to the shape of aggregated wind production curve. The more wind deployed the less dynamic fluctuations are achieved and therefore decreasing effect of aggregated wind generation in territory as production from "intermittent" energy source.

In order to incorporate this effect, the output curve of the aggregated wind farm (Fig. 2) is smoothed by the moving average method. A moving average smooths data by replacing each data point with the average of the neighboring data points defined within the span. This process is equivalent to lowpass filtering with the response of the smoothing. Smoothing algorithm applied in this task is given in figure 3 below.

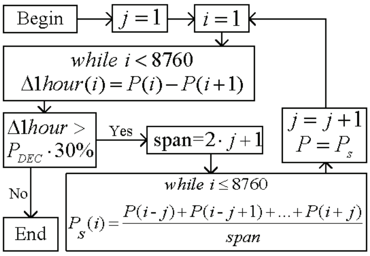

Fig. 3. Flowchart of incorporated smoothing algorithm.

Where, *P(i)* is the wind production value in hour *i*, *Ps(i)* is the smoothed value for the *i* data point, *j* is the number of neighboring data points (hours) on either side of *Ps(i)*, and *2j+1* represents the span.

The moving average smoothing method follows these rules:

- The span must be odd;
- The data point to be smoothed must be at the center of the span;
- The span is adjusted for data points that cannot accommodate the specified number of neighbors on either side;
- The end points are not smoothed because a span cannot be defined.

Takes into account experience and measurements of extreme variations of large scale regional wind installations also shown in literature [2], the following criteria for dynamics of changes in wind production was chosen. The maximally allowed positive and negative ramp rate between neighboring hours is at 30%, within 4 hours at 50% and within 12 hours at 70% of technically available installed wind capacity (P_{DEC}). In addition, the 2 approaches in smoothing of "raw" production curve are applied. The first, labeled as "sequential smoothing" involving all aforementioned criteria for dynamic changes successively, the second labeled as "direct smoothing" employs in smoothing directly only criterion about 70% maximally allowed positive or negative ramp rate within 12 hours. The results of applied smoothing are shown in figure 4.

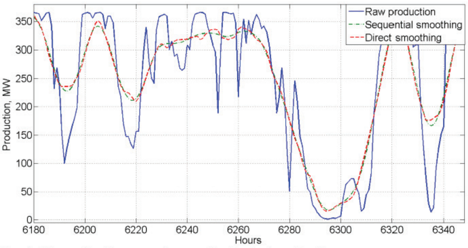

Fig. 4. Example of one week smoothed wind production.

After the smoothing of "raw" production curve has been incorporated the term 'intermittent' is for system-wide wind power substituted by the term 'variable output' and used instead in further considerations.

The procedure that was used to simulate power production by wind power plants in Baltic is summarized and presented by algorithm in figure 5. Input data to the simulation of actual wind production comprises, estimated real wind conditions (dashed box) and installed capacity decreased by technical availability. Subsequently, the curve obtained through model of aggregated wind farm is smoothed by methods in detail described in chapter D.

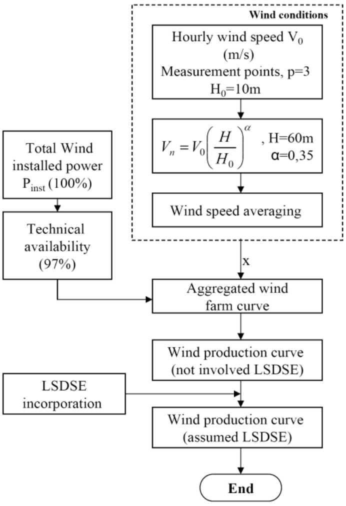

Fig. 5. Wind production curve simulation algorithm.

III. RESULTS OF REGIONAL WIND PRODUCTION MODELING

The deliverables obtained from simulation of the wind production are presented in this part of article and contains raw and smoothed production curve in Baltic 2020 scenario; monthly diversity of wind generation and duration curves with different smoothing approaches for 2011, 2016, 2020 scenarios; capacity and load factor estimation as well as comparison of the annual Baltic wind production obtained by model and expected values in NREAPs 2011-2020.

Using the algorithm shown in figure 5, according the Baltic wind development scenario 2020 has been generated smoothed wind production curve in Baltic given in figure 6 below. The smoothed production curve should be regarded without curtailment of wind production as physical production.

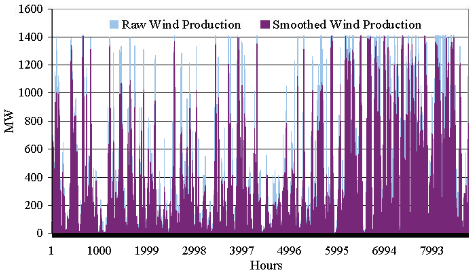

Fig. 6. Annual"raw" and smoothed Baltic wind generation in 2020.

Seasonal diversity of wind production affect proportion of wind impact to a overall PS and exposing needs for power capacity reserves. Result of average monthly generation by wind for assumed development scenarios indicates figure 7.

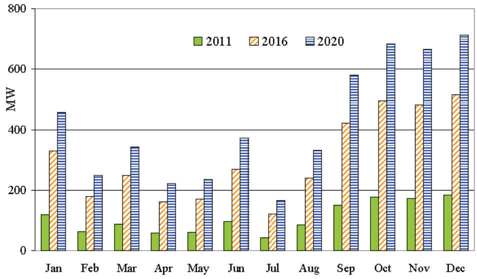

Fig. 7. Average monthly Baltic wind generation.

Within the year may be seen considerable variations in average wind generation. The lowest contribution in compliance with the figure 7 is expected during 1st (January to April) and 2nd (May to August) thirds of the year, however, during the 3rd third (September to December) a substantial contribution of wind production could be expected. Observe the seasonal and inter-annual variation of wind power production is crucial in tasks of wind power integration to a power system. The results are important in strategic power system planning as well as for estimation of long-term impacts to a electricity prices. The less importance and significance have these results to a short-term power system management and operation.

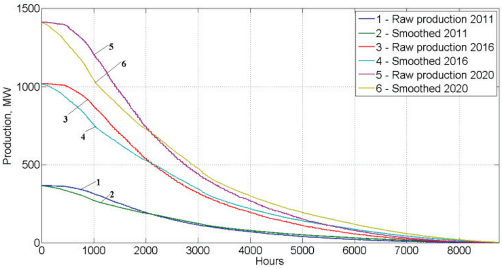

Fig. 8. Baltic wind duration curves for development scenarios 2011, 2016 and 2020.

Duration curves in figure 8 illustrate the relationship between level of wind generation and number of hours for 3 development scenarios (2011, 2016, 2020), moreover, with estimation of changes in shapes due to the incorporation of the smoothing effect. The curves are made by sorting all generation values of the 8760 hours in particular year in decreasing order. Comparing the shapes of "raw" and "smoothed" production curves is evident that improvement of flatness decreasing production in peak production hours, however, spreading this production to the remaining hours of the year. Capacity utilization rate provides important and easy comprehensible characteristics of production source. In general might be concluded, the flatter generation-duration curve, the better it is for grid operation.

The capacity factor (C_f) and load factor (L_f) of wind generation obtained from simulation and calculated by Eq. 3 and 4 reached the value 0, 26 and 0, 29 respectively.

$$C_f = \frac{\int_0^t p(t)\,dt}{P_{inst} * t}; \quad (- , \mathrm{MW}, \mathrm{MW}) \tag{3}$$

$$L_f = \frac{P_{av}}{P_{max}}; \quad (- , \mathrm{MW}, \mathrm{MW}) \tag{4}$$

Where, P_{inst} is total wind installed power; P_{av} is the average wind generation in time period t; P_{max} represents peak production of wind plants during the time period t.

Results of annual wind production simulation comparing to the targets in National Renewable Energy Action Plans (NREAPs) of the Baltic States are presented in table 2.

TABLE III. SIMULATED AND EXPECTED WIND PRODUCTION

Year	Results MWh	NREAPs MWh	Year	Results MWh	NREAPs MWh
2011	942476	901000	**2016**	2632868	2385000
2012	1399022	1095000	**2017**	2850606	2853000
2013	1640172	1579000	**2018**	2979375	3087000
2014	1914100	1843000	**2019**	3389096	3251000
2015	2061600	2133000	**2020**	3637270	3697000

IV. IMPACTS OF THE WIND DEVELOPMENT TO A POWER SYSTEM AND ELECTRICITY MARKET

Integration of wind generation into power production mix has impact to the power system operation as well as to the electricity market due to the specific technical/economic features of such type of power source. In this chapter is proposed algorithm (Fig. 9) including evaluation of the system penetration and estimation of so-called "merit-order" effect (see Ch. IV-B) according to the PS development in Baltic.

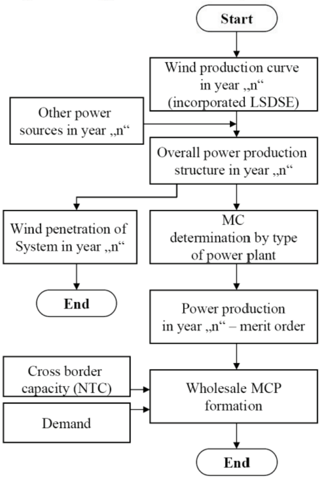

Fig. 9. Merit-order effect & wind penetration of PS – estimation algorithm.

In order to evaluate the effect of the wind power integration to the price formation and level of system penetration by wind, the development changes in power production mix and extension of cross-border transmission capacities in Baltic are based on following assumptions: Increase in overall RES production is in compliance with data published in NREAPs [1]. Capacities of other power plants in Baltic generation mix for development scenarios 2016 and 2020, only the main, confirmed projects are taken into account. Marginal costs of production for different types of power production technology are based on present and projected values published in [4]. Assumed new interconnection projects between Baltic and neighboring countries are: By 2013 Estlink II 650 MW (EE-FIN) and by 2016 NordBalt (LT-SWE) 700 MW. The LitPol contribution (LT-PL) is to be considered on 500MW in 2020. Towards non-EU countries, the constant 1500 MW transmission capacity is considered [5][6][7].

A. Wind penetration of power system

The impact of wind power to the electricity system depends mostly on the level of wind power penetration [8]. For Baltic scenarios 2011, 2016 and 2020 are calculated coefficients of wind penetration according to development of generation, transmission capacities and forecasts of system load.

Wind energy penetration is determined as the percentage of total demand $W_{A\,total}$ covered by wind energy $W_{W\,gen}$ in Baltic region estimated on an annual basis according to equation 5:

$$W_{WP} = \frac{W_{Wgen}}{W_{A\,total}} 100\,;\ (\%, \text{MWh}, \text{MWh}) \qquad (5)$$

The wind power capacity penetration shows relation of total installed wind capacity P_{DEC} to the peak load P_{Lmax} in region for the estimated time period (winter/summer) as follows:

$$C_{WP} = \frac{P_{DEC}}{P_{L\,max}} 100\,;\ (\%, \text{MW}, \text{MW}) \qquad (6)$$

The maximum share of wind power focused on power balance assessment in region is based on minimal load value P_{Lmin}, maximal wind load P_{Wmax} and available cross-border capacity P_{NTC} calculated as:

$$S_{W\,max} = \frac{P_{W\,max}}{P_{L\,min} + P_{NTC}} 100\,;\ (\%, \text{MW}, \text{MW}, \text{MW}) \qquad (7)$$

$0\% \leq S_{W\,max} \leq 100\,\%$ - Non-curtailed wind production;

$S_{W\,max} > 100\,\%$ - Required curtailment of wind production.

However, requirements for the wind production curtailment could appear due to the internal network constrains, therefore, non-curtailed wind production is assumed only in a case that capability of internal network is sufficient

The disproportions in seasonal availability mainly CHP and hydro production could significantly devalue veracity of results, thus, calculation is performed for winter and summer conditions. Results of wind penetration assessment for all scenarios are summarized in table 4.

TABLE IV. BALTIC SYSTEM PENETRATION BY WIND

Scenario/Year		**2011**	**2016**	**2020**
W_{WP}		3,4	8,4	10,4
C_{WP}	**Winter**	7,7	19,1	23,7
	Summer	11,5	28,2	34,9
S_{Wmax}	**Winter**	7,9	16,1	21,1
	Summer	5,6	11,2	14,5
S_{Wmax} (Only P_{NTC} to EU)	**Winter**	11,7	21,2	27,2
	Summer	9,7	15,8	20,1

B. Merit- order effect of the wind production

Currently, the merit-order effect characterizes influence of the electricity produced under feed-in-tariff (FIT) law to the wholesale electricity price in way that average cost of electricity decreases. The FIT are proposed as temporary system of subsidies, however, in long-term perspectives may be direct merit-order effect caused by wind production (currently covered by FIT) expected as well. The reason is bidding strategies which are used by power producers to join the short-term organized markets (e.g. Nord Pool Spot). The offer bids of generators on those short-term markets are often placed on level of so-called short-run marginal costs (SRMC) of particular producer [9]. The SRMC of wind production are close to zero, it means that wind production enters bottom of the marginal cost curve i.e. supply curve.

An example of engagement wind production into estimated Baltic merit-order generation at the basis of SRMC extended with transmission capacities for summer (July) and winter (January) conditions in 2020 scenario are shown in Fig. 10 and Fig. 11 respectively. Level of load in the system represents estimated minimal, average and maximal load during January and July in Baltic 2020. To better distinguish situation, the supply curve is shifted at maximally achieved level of wind production in 2020.

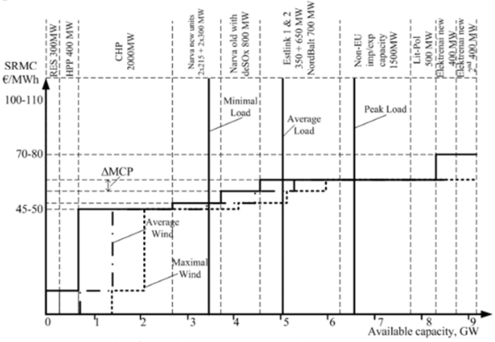

Fig. 10. System price formation in winter scenario 2020.

The most significant difference in presented snapshots is caused by CHP production, which is for summer scenario considered at 500 MWe and for winter scenario 2000 MWe.

Load of system (demand) is modeled as inflexible, determination of market clearing price (MCP) and market clearing volume is based on power pool principle, so-called one-sided auction.

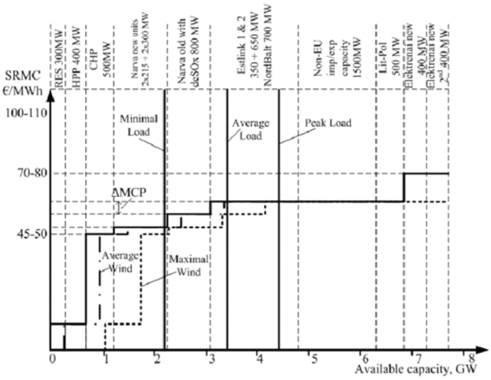

Fig. 11. System price formation in summer scenario 2020.

It is quite evident that shifting of entire production curve due to inclusion of wind power is not constant throughout the year. The variation differs according the wind condition seasonally and partially from year-to-year. The range of shifting and its duration might be clarified by duration curves of wind production. These have been on annual basis obtained by wind production modeling and presented also for 2020 scenario in figure 8. However, to the price formation process and thus on the resulting price have impact countless number of factors. In mid and long-term perspectives such as structure, disposition and availability of power sources, level of commercial capacities of cross-border lines and also structure and level of demand. The demand side management programs appear to have a crucial role in future integration of wind, to deal with negative impacts to a power system as well as reduce the price volatility.

V. CONCLUSIONS

The article proposing algorithm and manner of wind production simulation based on real wind conditions. Effect of the large-scale deployment wind generation has been considered through different approaches of wind production curve smoothing and incorporated to the proposed algorithm of wind production modeling. Subsequently, simulated wind production curves were applied in order to calculate wind penetration of Baltic power system according to forecasted state of generation, transmission and load in particular scenario and seasonal conditions with summarized results. According to deliverables and results of this study the several conclusion related to a wind penetration of power system and electricity market could be made: Results obtained by model are comparable with targets published in NERAPs, level of system penetration by wind in compliance with methodology and evaluation criteria shows that for all assumed scenarios are values within acceptable range. Though, the considerable difference of results could be observed in a case of disturbances when substantial amount of generation capacity of conventional power plants or transmission capacities is out of operation. Integration of the wind production will increase price volatility, both seasonal and short-term, however, estimate the exact effect of wind production to the electricity prices is not easy task. One of the expected influences of wind power on electricity market has been presented in Baltic development scenario 2020 through merit-order effect caused by wind production As could be derived from presented snapshots, integration of wind production will reduce need of most expensive conventional plants which can lead to lower average prices for electricity. Should be noticed that expansion of power production capacities with low marginal costs of production might have also negative impact to the conventional generators, mostly caused by decrease of their load factors, hence, reducing ability sufficiently cover total production costs.

From the long-term perspectives, effects of wind integration into generating portfolio could be evaluated as positive, regarding to improved generation and transmission adequacy as well as system reliability.

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Appendix 4

Proceedings of PMAPS 2012, Istanbul, Turkey, June 10-14, 2012

Probabilistic Method for Wind Production Forecasting and Energy Markets Trades Optimization in Power System with Large Wind Specific Gravity

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Abstract - **This article is related to an actual problem of electricity markets, particularly to the impacts caused by wind production integrated into generation portfolio. The methods and algorithms which enable modeling and simulation of wind production taking into account regional wind conditions to the final impact on electricity market price are presented and demonstrated on Baltic region in different development stages till 2020. New probabilistic method for estimation of wind generation influence to a electricity price formation is proposed in this paper as well.**

Keywords - wind generation; power system; energy market

I. INTRODUCTION

A considerable extension of wind capacities causes structural changes in European electricity markets and affecting electricity market prices. In general, incorporation of wind generation into electric power system could be evaluated as positive according to decrease of probability of system deficiency especially in a case of insulated or weakly interconnected power systems, however, in the same way probability of system surplus arises. To mitigate negative impacts in periods of system surplus due to the wind generation as well as deficiency in low wind production proper interstate transmission capability is required [1]. An appropriate market organizing by adequately liquid power exchange is needed as well in order to spread volatile wind production (bids from wind generators) to a wider area. Hence, the aim of this paper is propose the algorithms and perform calculations of wind impacts on market operation, including probabilistic method for estimation of wind production impact to the market price formation. In order that proposed methods provide applicable and valuable output, these are applied for Baltic region to obtain results. The wind power production is based on real wind conditions in Baltic region as well as on expected development of installed wind production capacities. The overall work consists of two main subsections:

1. Wind generation modeling;
2. Assessment of wind generation impacts to a power system and market formation.

The subtasks of Subsection 1 contain estimation of wind conditions in a Baltic region and its statistical evaluation. Proposal of aggregated wind power characteristics modeling and application in different development stages of installed wind capacities (2011, 2016, and 2020). The subtasks of Subsection 2 contain algorithm for wind production impact evaluation based on simulated wind production curves (from Subsection 1), calculations of wind penetration of power system, analysis of spot market participants' behavior as well as proposal for probabilistic method used in market clearing price determination with example and evaluation of results.

II. WIND GENERATION MODELLING

The simulation of actual wind production is based on estimation of real wind conditions taking into account technically available installed wind capacity. These input data are used in order to obtain "raw" power production curve, which is in the next step smoothed according to characteristics of aggregated production from large-scale deployed wind installations by so-called: large-scale deployment smoothing effect (LSDSE). The algorithm to solve this task is presented in Fig. 1.

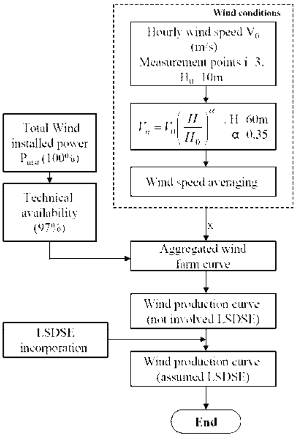

Figure 1. Wind production curve simulation algorithm.

A. Estimation of Wind conditions

Annual wind conditions applied for simulation of wind power production were measured at hourly basis in height of 10 meters at coastal part of Estonia in 3 localities and subsequently recalculated for wind speed conditions in height of 60m by (1).

$$V_n = V_0 \left(\frac{H}{H_0} \right)^{\alpha} \text{; for } \alpha = 0{,}35 \qquad (1)$$

In further calculations are used the averaged wind speed values obtained from 3 measurement points. Occurrence of averaged annual wind speed in a region is shown in Fig. 2.

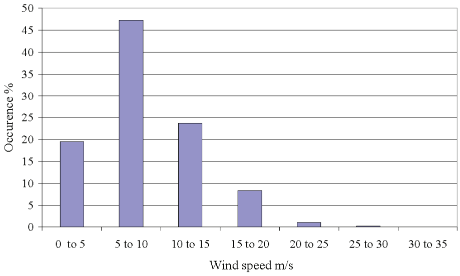

Figure 2. Averaged wind speed occurrence.

B. Tendencies of installed wind capacities in Baltic

According to a National Renewable Energy Action Plans (NREAPs) all of three Baltic states (EE, LV, LT) related to development of wind generation capacities, both onshore and offshore installations, the development by 2020 in Baltic is summarized in Fig. 3 [2]. The offshore installations in Baltic are planned from 2017 mainly in Estonia and to a lesser extent in Latvia.

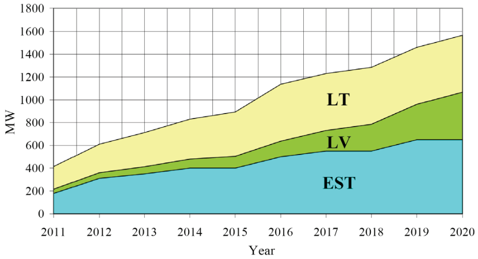

Figure 3. Baltic wind installed capacity growth.

Considering the technical availability of wind turbines which is generally at the very high level compared to other technologies, for further assumptions is envisaged at 97% [3]. Values of available wind installed power shows Tab. 1.

TABLE I. TECHNICALLY AVAILABLE WIND CAPACITY

Year	**2011**	**2016**	**2020**
P_{DEC} (MW)	402	1124	1553

Its a confirmation of one of the significant advantages regarding to reliability of supply from distributed wind power installations in the power system, that breakdown of a single unit has a negligible effect on overall availability.

C. Aggregated wind power characteristics' modeling

To derive power output of installed wind capacity, the following model expressed by formula (2) has been introduced. This expression merges typical offshore and onshore aggregated wind farm power curves [1].

$$\begin{aligned} f(x) &= a_1 \cdot e^{-((x-b_1)/c_1)^2} + a_2 \cdot e^{-((x-b_2)/c_2)^2} \\ &+ a_3 \cdot e^{-((x-b_3)/c_3)^2} + a_4 \cdot e^{-((x-b_4)/c_4)^2} \\ &+ a_5 \cdot e^{-((x-b_5)/c_5)^2} + a_6 \cdot e^{-((x-b_6)/c_6)^2} \\ &+ a_7 \cdot e^{-((x-b_7)/c_7)^2} \end{aligned} \qquad (2)$$

Variable “x” represents averaged wind speed (m/s) in every particular hour. Values of the coefficients to the formula (2) are given in Table 2 below.

TABLE II. APPLIED COEFFICIENTS

a1	0,03402	**b3**	16,13	**c5**	3,818
b1	7,712	**c3**	0,5106	**a6**	0,4647
c1	2,281	**a4**	10,7	**b6**	13,16
a2	-0,1338	**b4**	21,43	**c6**	4,155
b2	19,48	**c4**	2,496	**a7**	-10,07
c2	1,606	**a5**	0,6206	**b7**	21,45
a3	0,009714	**b5**	17,15	**c7**	2,44

In order to obtain generated wind energy according to wind speed via aggregated wind farm power curve (Fig. 3), the difference in effect between onshore and offshore installations is neglected.

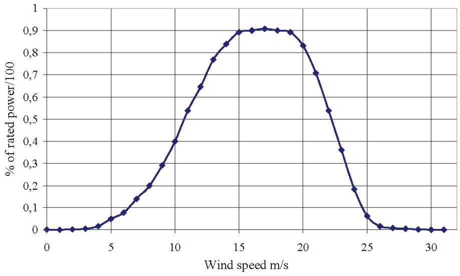

Figure 4. Production curve of aggregated wind generation capacity.

The resulting production curve is labeled as "raw" production curve with relatively high volatility, mainly due to the fact that large-scale deployment smoothing effect (LSDSE) of wind production is in this moment only partially involved via wind speed averaging.

D. Large Scale Wind Generation Implementation

Large-scale wind generation deployment has a significant impact to the shape of aggregated wind production curve. The more wind deployed the less dynamic fluctuations are achieved. Thus, the effect of aggregated wind generation in territory as production from intermittent energy source decreasing with increase of installed wind capacity. Taking into account experience and measurements of extreme variations of large-scale regional wind power as percentage of installed capacity and distribution of variations, [3] smoothing of "raw" power production curve has been involved. The conservative smoothing effect applied to the "raw" production curve considers with maximal positive and negative ramp rate of power within the time span 12 hours at 70% of technically available installed wind capacity. The result of applied smoothing effect is shown in Fig. 4.

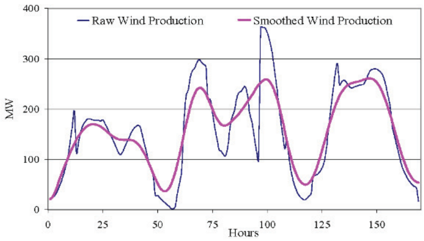

Figure 5. Example - one week wind production smoothing effect.

After smoothing of the "raw" production curve, the term "intermittent" for system-wide wind power production substituted by the term "variable" and used instead in further considerations. Applying the algorithm shown in Fig. 5 for the whole year of each of assumed development stages has been generated smoothed wind production curves in Baltic shown in Fig. 6, 7 and 8 respectively. The smoothed production curve should be regarded without curtailment of wind production as physical production i.e. as supply bids of wind generators.

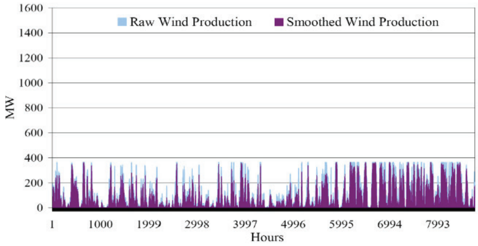

Figure 6. Annual "raw" and smoothed Baltic wind generation in 2011.

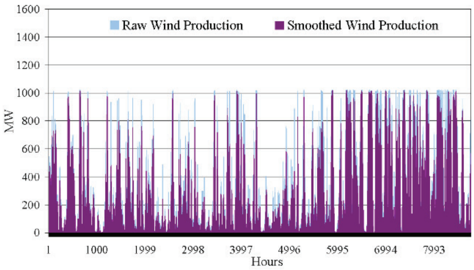

Figure 7. Annual "raw" and smoothed Baltic wind generation in 2016.

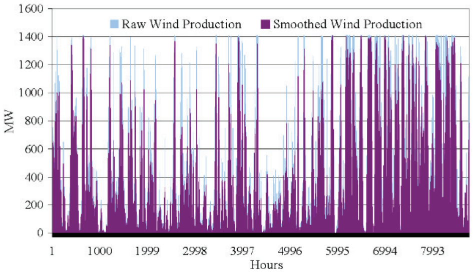

Figure 8. Annual "raw" and smoothed Baltic wind generation in 2020.

The smoothing effect is more significant on Fig. 7 and Fig. 8 rather than Fig. 6, due to the greater wind installations.

Results of annual wind production obtained by proposed model are compared with the targets published in the National Renewable Energy Action Plans (NREAPs) all of three Baltic states and presented in Table 3.

TABLE III. SIMULATED AND EXPECTED WIND PRODUCTION

Year	Results MWh	NREAPs MWh	Year	Results MWh	NREAPs MWh
2011	942476	901000	**2016**	2632868	2385000
2012	1399022	1095000	**2017**	2850606	2853000
2013	1640172	1579000	**2018**	2979375	3087000
2014	1914100	1843000	**2019**	3389096	3251000
2015	2061600	2133000	**2020**	3637270	3697000

Seasonal diversity of wind production affecting proportion of wind impact to the entire PS as well as exposing needs for power capacity reserves. Results of average monthly generation contribution by wind in all three development stages indicate Fig. 9.

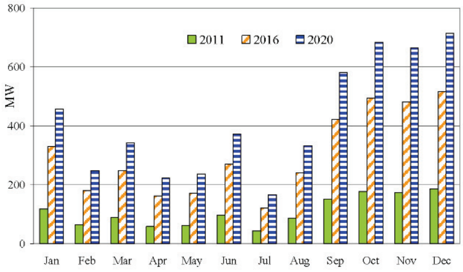

Figure 9. Average monthly Baltic wind generation.

III. ASSESSMENT OF WIND PRODUCTION IMPACTS TO A POWER SYSTEM AND MARKET FORMATION

In order to evaluate the effect of the wind power integration to the electricity market, the price formation is considered before and after the wind power deployment according the increase of load, changes in power generation mix, extension of cross-border capacities and level of wind penetration in particular development stage. The abovementioned assumptions are used to estimate these impacts on Baltic market formation in compliance with proposed algorithm presented in Fig. 10 for years 2011, 2016 and 2020.

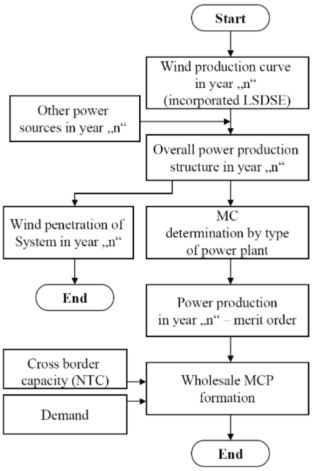

Figure 10. Wind production impacts evaluation algorithm.

To increase available generation capacity of other power plants in Baltic generation mix in 2016 and 2020 compare to the current situation, only main confirmed projects and increase of overall RES production according to NREAPs has been taken into account. Marginal costs of production for different types of power production technology are based on present and projected values in [4]. Extension of exporting capacities by new interconnection projects between Baltic and neighboring countries are assumed as follows: By 2013 Estlink II 650 MW (EE-FIN) and by 2016 NordBalt (LT-SWE) 700 MW. The LitPol (LT-PL) is not assumed till 2020 contribute to capacity expansion. Towards non-EU countries is considered with constant 1500 MW transmission capacity [5][6][7].

A. *Wind penetration of power system*

The impact of wind power to the electricity system depends mostly on the level of wind power penetration [8]. For Baltic in 2011, 2016 and 2020 are calculated coefficients of wind penetration according to forecasts of generation, load and transmission capacities.

Wind energy penetration is determined as the percentage of total demand $W_{A\ total}$ covered by wind energy $W_{W\ gen}$ in Baltic region estimated on annual basis according (3):

$$W_{WP} = \frac{W_{Wgen}}{W_{A\ total}} 100\ ;\ (\%,\ \text{MWh},\ \text{MWh}) \qquad (3)$$

The wind power capacity penetration shows relation of total installed wind capacity P_{DEC} to the peak load P_{Lmax} in region for the estimated time period (winter/summer) as follows:

$$C_{WP} = \frac{P_{DEC}}{P_{L\,max}} 100\ ;\ (\%,\ \text{MW},\ \text{MW}) \qquad (4)$$

The maximum share of wind power focused on power balance assessment in region is based on minimal load value P_{Lmin}, maximal wind load P_{Wmax} and available cross-border capacity P_{NTC} calculated as:

$$S_{W\ max} = \frac{P_{W\ max}}{P_{L\,min} + P_{NTC}} 100\ ;\ (\%,\ \text{MW},\ \text{MW},\ \text{MW}) \qquad (5)$$

$0\% \leq S_{W\ max} \leq 100\ \%$ - Non-curtailed wind production;

$S_{W\ max} > 100\ \%$ - Required curtailment of wind production.

The disproportions in seasonal availability mainly CHP and hydro production could significantly devalue veracity of results. Therefore, calculation is performed for conditions in winter and summer scenarios. Results of wind penetration assessment are summarized in Table 4.

TABLE IV. BALTIC SYSTEM PENETRATION BY WIND

Scenario/Year		**2011**	**2016**	**2020**
W_{WP}		3,4	8,4	10,4
C_{WP}	*Winter*	7,7	19,1	23,7
	Summer	11,5	28,2	34,9
S_{Wmax}	*Winter*	7,9	16,1	21,1
	Summer	5,6	11,2	14,5
S_{Wmax} (Only P_{NTC} to EU)	*Winter*	11,7	21,2	27,2
	Summer	9,7	15,8	20,1

B. *Wholesale Market Clearing Price formation*

Spot price on electricity market obtained as intersection of aggregated bids of consumers (demand curve) and producers (supply curve) is considerably dependent on shapes of those curves formed by bidding behavior of market players. To confirm simplified approach in spot price modeling as system with low demand flexibility, behavior analysis of bidding on biggest power exchange Nord Pool Spot (NPS) has been performed [9]. The Results of one-day "buy" and "sell" behavior are presented on Fig. 11 and Fig. 12 respectively.

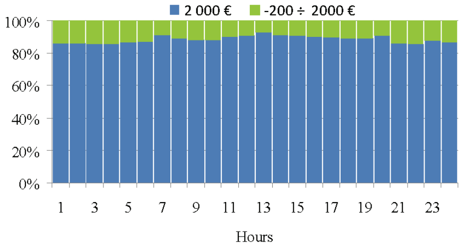

Figure 11. One day NPS PX consumers' "buy" bidding behaviour.

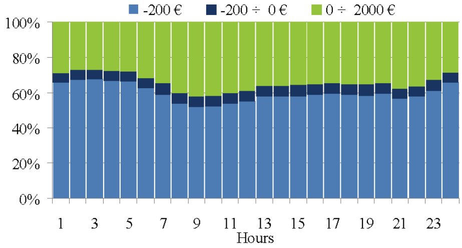

Figure 12. One day NPS PX producers' "sell" bidding behaviour.

Short-term demand and production flexibility analysis shows several important facts. Roughly 90% of consumers' bids are placed at the maximal available value of 2000€ per MWh, thus only 10% could be assumed as at least partly flexible price responsive demand. Roughly 35% of the sell-bids of generators is within the range 0 to 2000 €/MWh, about 5% - within the range 200 to 0 €/MWh and even maximal negative bids at -200 €/MWh are willing to pay by 60% of producers. Is an important to note that bids of generators are placed at the level of short-run marginal costs of production (SRMC) rather than long-run marginal costs of electricity production (LRMC).

C. *By Wind production influenced probability of MCP formation*

Increase of wind installations as production source with variable output and significant seasonal output variations affecting MCP formation according to proportion of wind installed capacity and attributes of remaining power production as well as demand. In order to estimate probability of wind production and thus its affecting of the price formation, 3 zones depicted in Fig. 13 are introduced.

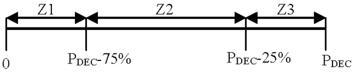

Figure 13. Wind production probability zones.

The probability that wind production will be within one of denoted zones is probability that in same way the shifting of production curve occurs (see Fig. 15 and 16). Results of wind production probability based on smoothed wind production curve in Baltic are shown in Fig. 14.

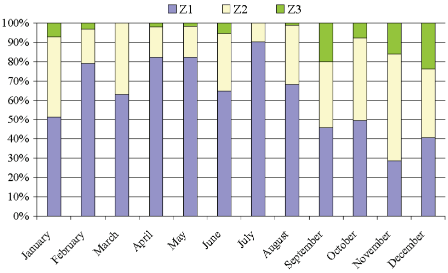

Figure 14. Monthly probability of wind productionoccurrence.

To conclude Fig. 14 the highest probability of power production occurs within the range 0 to $P_{DEC-75\%}$, during entire year in compliance with Fig. 13 denoted as zone Z1. In a lesser extent probability of production within Z2 and relatively low probability of wind power production within Z3.

The example of engagement of abovementioned wind production probability into forecasted typical Baltic merit-order generation (see Ch. III) at the basis of SRMC extended with transmission capacities for summer and winter conditions in 2016 scenario are shown in Fig. 15 and Fig. 16 respectively. To better distinguish situation, the curve is shifted at maximal achievable level of wind production.

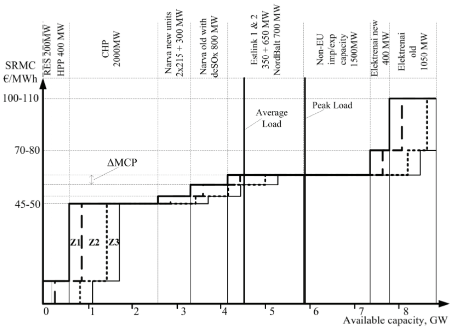

Figure 15. System price formation in winter scenario 2016.

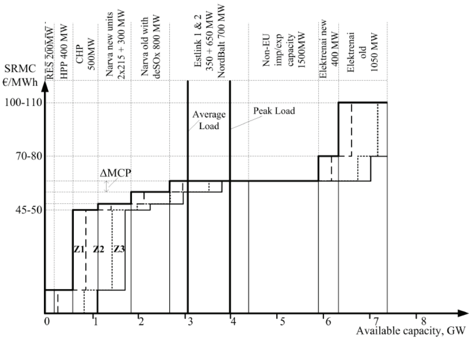

Figure 16. System price formation in summer scenario 2016.

Based on conditions modeled in winter (January) and summer (July) 2016 is possible conclude that with highest probability (Z1) in winter conditions MCP will not drops down due to the wind production in both average and peak load levels. The same highest probability (Z1) applied in summer conditions shows that MCP will not drops down due to the wind production in both average and peak load as well. However, this conclusion assumes operation of generators and interconnections according to presented snapshots in Fig. 15 and Fig. 16. Disturbances might cause MCP re-formation what could be also estimated on modeled scenarios. To achieve higher sensitivity of "production shifting" the larger number of narrower zones should be defined, however, to keep veracity of occurrence probability for every zone requires higher quality and amount of input statistical data.

IV. CONCLUSIONS

Algorithm and simulation of wind generators' biding based on real regional wind conditions and large-scale deployment of dispersed wind generation through smoothing effect algorithm of overall wind production was elaborated and implemented into Baltic development stages in 2011, 2016 and 2020. Subsequently, simulated wind production curves were applied in order to calculate wind penetration of Baltic power system according the forecasted state of generation, transmission and load in particular development stage and seasonal conditions with presented results. By analysis of bidding behavior of spot market participants was estimated price flexibility of producers and consumers. Results of analysis shows, inter alia, extremely low consumers´ response and therefore endorsed next modeling of market clearing price formation as one-sided auction.

In the last step was proposed the methodology for future value of market clearing price determination by the probabilistic way with an example applied to a Baltic development in 2016 for winter and summer conditions. Based on the results of elaborated methods and algorithms as well as results of performed analysis the following facts might be concluded:

Escalation of strain on interstate links will considerably increase also due to integrations of renewable energy sources with hardly foreseeable production, thus greater interstate cooperation will be required. Extension of generating capacities with low marginal costs of production especially in case of wind (production volatility) has negative effect to the conventional generators mostly due to the decrease of their load factors and therefore opportunity for sufficiently revenues to cover total production costs. Volatility of electricity price, whether the seasonal or short-term increases by inclusion of wind power production into generation portfolio and is highly dependent on countless number of factors in mid and long-term perspectives such as structure, disposition and availability of power sources, level of commercial capacities of cross-border lines and also structure and level of demand. The long-term effect (years) of wind integration have positive impact on reliability level of system regarding the generation and transmission adequacy, where wind power has a positive contribution to entire power system adequacy by wind capacity credit.

ACKNOWLEDGMENT

The paper is supported by the European Social Fund Project "Scientific Group Supporting Latvian Activities of the European Strategic Energy Technology Plan", No.1DP/1.1.1.2.0/09/A-PIA/VIAA/027 and by project VEGA SR No. 1/0414/12.

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