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MODERNISATION OF ELECTRIC EQUIPMENT OF COMBINED CYCLE UNITS FOR ADAPTION TO NEW ELECTRICITY MARKET REQUIREMENTS

Doctoral Thesis

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ABSTRACT

Change of market principles and European Union environmental targets leads to more cycling operations of combined cycle units, which used to operate in baseload regime. Due to generation imbalanced allocation, which mainly provoked by intermitting generation, power network becomes less stable. As a result, new requirements for generator connection in Europe were developed, challenging existing power plants to fulfill them. All this leads to higher operational costs of combined heat and power plants and solutions must be found to reduce costs and/or increase revenue.

Cycling operation negative impact on power plant thermal equipment is well studied. This Doctoral Thesis reviews the cycling operation impact on combined heat and power plant main electrical equipment and provides empirical formulas to evaluate reliability for different operation scenarios. Solutions for power plant modernisations to fulfill new requirements and provide ancillary services are analyzed. Possible costs of ancillary service provision from combined heat and power plants as well as sites connected to transmission system are evaluated, providing information for further calculations.

Detailed methodology of solar generated energy applicability for self-consumption needs was developed, which allows to choose the right power of installation to make the fastest payback time. A battery storage optimization methodology was developed to reduce self-consumption costs of power plant interacting with the solar generation or operating separately.

The methodology for combined heat and power plant operation planning enhancement was developed, which use gain from ancillary service provision to move startup's back in time or shutdowns further in future to provide highest revenue. Methodology also allows to use additional profit to grant lowest number of startup's per year. Results of both approaches are used to make incident rate calculations by developed empirical formulas, which allow to choose optimal strategy for power plant operation.

Obtained formulas can be easily used for most combined heat and power plants. Developed methodologies can be used to optimize the self-consumption of any applications. Methodology for power plant operation planning enhancement is applicable to various scenarios. All developed methodologies were tested on historical data. The results of analysis of ancillary service provision remuneration impact on combined heat and power plant main electrical equipment incident rate and possible income should lead to new researches in this area.

ANOTĀCIJA

Pārmaiņas elektroenerģijas tirgū un Eiropas Savienības izvirzītie vides aizsardzības mērķi rezultējās ar darbības cikliskuma pieaugumu kombinētā cikla elektrostacijās, kuras ierasti tika ekspluatētas bāzes režīmā. Elektroenerģijas sistēma kļūst nestabilāka, sakarā ar nesabalansētu ģenerācijas jaudu izvietojumu, ko pārsvarā provocē atjaunīgā ģenerācija. Rezultātā Eiropā tika izstrādātas jaunas prasības ģeneratoru pieslēgšanai, esošajām elektrostacijām ir sarežģīti nodrošināt atbilstību tām. Viss iepriekšminētais noved pie augstākām kombinētā cikla elektrostaciju darbības izmaksām, jāatrod risinājumi, kas ļautu samazināt izmaksas un/vai palielināt peļņu.

Cikliskai darbībai ir negatīva ietekme uz elektrostaciju ūdens-tvaika cikla iekārtām un tā ir labi izpētīta. Šajā Promocijas darbā tiek izskatīta cikliskas darbības ietekme uz termoelektrostaciju galvenajām elektriskajām iekārtām un sniegtas empīriskas formulas drošuma novērtēšanai priekš dažādiem darbības scenārijiem. Tika analizēti risinājumi priekš elektrostaciju modernizācijas, lai nodrošinātu atbilstību jaunajām prasībām un tīkla palīgpakalpojumu sniegšanu. Tika izvērtētas iespējamās palīgpakalpojumu izmaksas, sniedzot tos no kombinētā cikla elektrostacijam un ietaisēm, kas pieslēgtas pārvades sistēmai, tāda veidā nodrošinot informāciju priekš turpmākajiem aprēķiniem.

Tika izstrādāta detalizēta metodoloģija–saules ģenerētās enerģijas pielietojumam pašpatēriņa nodrošināšanai, kas ļauj izvēlēties optimālāko ietaises jaudu, lai nodrošinātu visātrāko atmaksāšanas laiku. Tika izstrādāta elektroenerģijas lieljaudas baterijas darbības optimizācijas metodoloģija, kas ļautu samazināt elektrostacijas pašpatēriņa izmaksas, darbinot bateriju izmantojot saules ģenerāciju vai bez tās.

Tika izstrādāta termoelektrostacijas darbības plānošanas uzlabošanas metodoloģija, kas izmanto papildus ienākumus no palīgpakalpojumu sniegšanas, lai pēc iespējas nobīdītu termoelektrostacijas visizdevīgāko palaišanas un/vai apturēšanas laiku, kas ļauj nodrošināt lielāku peļņu. Metodoloģija arī ļauj izmantot papildus ienākumus, lai nodrošinātu mazāku palaišanas skaitu gadā. Abu pieeju rezultāti tiek izmantoti incidentu biežuma aprēķinā ar izstrādātām empīriskām formulām, kas ļauj izvēlēties optimālu elektrostacijas ekspluatācijas stratēģiju.

Iegūtās formulas var pielietot dažādās kombinētā cikla elektrostacijās. Izstrādātās metodoloģijas var pielietot pašpatēriņa optimizācijai. Metodoloģiju priekš elektrostaciju darbības uzlabotas plānošanas var pielietot priekš dažādiem scenārijiem. Visas minētas metodoloģijas ir pārbaudītas izmantojot vēsturiskos datus. Iegūtajiem analīžu rezultātiem, par palīgpakalpojumu sniegšanas apmaksāšanas ietekmi uz kombinētā cikla elektrostaciju galveno elektroiekārtu incidentu biežumu un iespējamajiem ienākumiem, vajadzētu novest pie jauniem pētījumiem šajā jomā.

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LIST OF ABBREVIATIONS

Abbreviation	Explanation
CCGT	Combined cycle power plant
HRSG	Heat recovery steam generators
RfG	The European Commission implemented the Regulation (EU) 2016/631 of 14 April 2016, establishing a network code on requirements for grid connection of generators
TSO	Transmission system operator
BESS	Battery energy storage system
HOB	Heat only boilers
EU	European Union
EU ETS	European Union Emissions Trading System
GHG	Greenhouse gas
EEA	European Economic Area
CHP	Combined heat and power plants
NERC	North American electrical reliability corporation
BRELL	Belorussia, Russia, Estonia, Latvia, Lithuania power grid
CEN	Continental European network
WPS	Wind power station
CoBA	Baltic coordinated balancing area
mFRR	Frequency restoration reserves with manual activation
aFFR	Frequency restoration reserves with automatic activation
PV	Photovoltaic
FCR	Frequency containment reserve
OLTC	On-load tap changers
VGB	VGB PowerTech
OCGT	Open cycle gas turbines
DGA	Dissolved gas analysis
DRM	Dynamic resistance measurement
LFSM-O	Limited frequency sensitive mode — overfrequency
LFSM-U	Limited frequency sensitive mode — underfrequency
NPV	Net present value of cash flow
VAR	Volt ampere regulator
SVC	Static VAR compensator
SC	Synchronous condensers
HVAC	Heat ventilation and air conditioning system
HPP	Hydro power plant
FRR	Frequency restoration reserves
RoCoF	Rate of change of frequency
IRR	Internal rate of return of investments
PP	Power plant

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CONTENT

1. INTRODUCTION

1.1. Topicality of the Research

Combined cycle power plants (CCGT) in Latvia used to operate in the baseload regime until 2014 when Latvia joined the Nord Pool power exchange market. Change of market principles led to more cycling operations of power plants, which is typical to all open electricity markets. The European Union is in the pursuit of great improvements in energy efficiency and renewable energy use, which even more increases the number of CCGT operation cycles, due to intermitting solar and wind generation. [1], [3], [63]

Cycling operation is more damaging for power plant equipment despite many improvements that have been made to make CCGTs adopt such operation mode. Problems with the thermal fatigue of heat recovery steam generators (HRSG) and steam turbines are well known and have been studied for decades [10]–[12]. Less attention is paid to the main electrical equipment of power plants, which may suffer from cycling operation as well [13], [14].

The European Commission implemented the Regulation (EU) 2016/631 of 14 April 2016, establishing a network code on requirements for grid connection of generators (RfG), which is a good example of understanding further challenges in the electrical power grid. RfG sets high requirements for all conventional and renewable generators because the power grid becomes weaker due to the market relationships, increased share of intermitting generation, high voltage direct current interconnections and disbalance of generation in regions [9], [37], [115]

The Baltic states are going to interconnect with the Continental Europe network (CEN), which with the most probability will result in application of RfG for existing generators. In some cases additional modernization must be made demanding additional investments from generators. Synchronization with CEN, however, will lead to changes in the ancillary service provision system. Provision of frequency primary and secondary control service, voltage control service, and inertia contribution service might become market based and lead to changes in power plant operating mode [35], [114].

Renewable energy may help to optimize power plant self-consumption reducing the costs of power plant operation. Even more possibilities are brought by using battery storage systems (BESS), which could allow reducing the costs for self-consumption as well as provide ancillary services [44], [46], [59], [125].

Use of additional gains from ancillary service provision and reduction of self-consumption electricity costs can allow CCGTs to move towards more stable operating modes, which could result in lower overall costs of operation or greater income.

In this Doctoral Thesis, the following questions and challenges were studied.

- Cycling operation impact on main electrical equipment of a power plant was analyzed. Based on available main electrical system reliability statistics of combined heat and power plants (CHP) empirical formulas were obtained to evaluate the impact of different operating regimes of CCGT, also outage and unplanned unavailability caused costs were evaluated. All this can be used for risk assessment.

- Possible ways of modernization of existing power plants to fulfill RfG and provide additional ancillary services were described. Analysis of possible service provision costs from CCGT and installations connected to the transmission system operator (TSO) were made.
- Solar generation data collection from the experimental installation was made and the methodology of detailed analysis of photovoltaic (PV) system profitability in CCGT self-consumption system was developed and tested on historical data providing essential information for economic calculations.
- PV system profitability methodology was enhanced by adding BESS operation evaluation module, which optimizes BESS operation to reduce self-consumption costs and maximize use of solar energy. This module operates as a separate program and optimizes BESS operation even during the hours when PV output is neglectable or zero. The enhanced methodology was tested on historical data and could be easily used with forecast data.
- Methodology for CCGT operation planning enhancement, which considers additional income from ancillary service provision, was developed and tested using historical data. Combining results of operation planning enhancement algorithms with empirical formulas for outage rate and caused costs calculation allow choosing the best operation strategy for CCGTs – move towards income maximization or to a reduction of startup number.

Provided analysis, calculations and developed solutions allow to improve the planning of CCGT operation and make decisions about future investments in power plant upgrades. The remuneration of ancillary services might have a huge impact on the future operation of CCGT.

1.2. Hypothesis of Doctoral Thesis

Provision of ancillary service and reduction of electricity self-consumption costs allows more optimal CCGT operation, reduction of outage rate and extra costs, as well as provide additional profits. To ensure provision of ancillary services, modernization of existing CCGT electrical equipment is required.

1.3. The Aim of Doctoral Thesis

This Doctoral Thesis aims to analyze the cycling operation impact on CCGT's main electrical equipment and develop tools to evaluate this impact, as well as consider upcoming challenges and changes in legislation and in grid interconnection. It requires development of a new methodology for economic calculations of ancillary service provision for evaluation of the feasibility of proposed modernizations options. Another important target of this Thesis is the development and validation of the methodology for detailed profitability calculations of

PV generation and BESS for power plant self-consumption. The main target is the use of developed methodologies in the methodology for CCGT operation planning enhancement, which allows choosing an operation strategy.

1.4. The Task of Doctoral Thesis

To achieve the aims of the Doctoral Thesis, the following tasks were set:

- to study the degradation process in electrical equipment and reliability statistics of combined heat and power plant main electrical equipment;
- to evaluate the outage rate of main electrical equipment and caused costs;
- to overview the new requirements set up by RfG and possible technical constraints for existing power plants as well as the measures to overcome them;
- to analyze the possibilities and costs of ancillary service provision from existing CCGT;
- to develop and verify the methodology for evaluation of the feasibility of solar generation use in thermal power plant for provision of self-consumption, based on the collected data from the PV system deployed for an experiment;
- to develop and verify the methodology for evaluation of feasibility of BESS use for power plant self-consumption;
- to develop a methodology for maximization of income from provision of ancillary services and minimize CCGT number of startups/shutdowns.

1.5. Scientific Novelty

The study on incident and failure causers as well as statistics of main electrical equipment of combined heat and power plant was conducted. Within the study, new calculation methodology, which uses empirical formulas to evaluate the influence of power plant operating modes on outage rate, as well as evaluation of associated outage costs, were developed.

Methodology for technical and economic evaluation of the proposed solutions for modernization, which allow to fulfil RfG requirements of existing power plants, have been developed.

Various solutions of ancillary service provision from CCGT were analyzed and possible costs of voltage control, primary frequency control, and inertia services provision were calculated.

Methodology for evaluation of PV generation and its possible contribution to self-consumption of the thermal power plant has been developed and verified using the data from the PV system installed in Riga TEC-2 as an experiment. The methodology uses PV hourly generation and electricity self-consumption volumes for feasibility evaluation of PV system in a thermal power plant.

The developed methodology was extended to optimize the BESS operation in combination with PV generation as well as in standalone operation mode to ensure lower costs for thermal power plant electricity self-consumption. The methodology was verified using historical hourly data.

Methodology for CCGT operation planning enhancement, based on additional income from ancillary service provision, has been developed and verified on hourly historical data. Previously developed empirical expressions were applied to calculation results to evaluate the outage rate of CCGT main electrical equipment and associated unavailability costs due to shifting in operation.

1.6. Practical Significance of the Research

The obtained empirical formulas for evaluation of outage rate of CHP main electrical equipment as well as the evaluated costs of caused unavailability can be used in risk assessment management, giving a better understanding of cyclic operation consequences for combined cycle power plants.

Solutions were proposed for modernization of existing combined cycle power plants in order to fulfill new grid connection requirements and possible changes in power plant operation due to synchronization of the Baltic power system with CEN that could be implemented in 2025. The developed methodology was used to evaluate possibilities and costs of ancillary service provision from existing CCGTs after modernization and from sites connected to TSO. Costs of service provision were used to evaluate possible income for CCGT in case the ancillary services become remunerated in the future.

The developed methodology for evaluation of electricity supply from PV system to ensure self-consumption of thermal power plant could be used for different applications to estimate in detail the feasibility of such solution, as well as to allow selection of optimal power of photovoltaic system. The proposed methodology was used for evaluation of feasibility of photovoltaic systems in Riga TEC-2, which were installed during 2017−2019. The methodology for BESS operation optimization to reduce self-consumption electricity cost was developed. The interaction of both methodologies gives even more possibilities to reach ecological targets.

The methodology for CCGT operation planning enhancement based on the income from ancillary service provision was developed. It allows moving towards maximal profit from service provision or the lowest number of start-up/shut down operations. The developed empirical equation should be used to evaluate the impact of the results of both solutions on the main electrical equipment outage rate and caused costs, which will give an understanding of possible CCGT operation strategy for the planning period.

The methodologies developed in this Doctoral Thesis were mainly applied to JSC "Latvenergo" power plants, but they can be used for any other similar generation facilities. Realization and verification of the developed methodologies were made by developed C# programs, which as data source use MS Excel databases, the results are extracted as MS Excel worksheets, which makes the developed programs easy applicable for any new object of research.

1.7. Volume and structure of the Doctoral Thesis

The Doctoral Thesis is written in English. It comprises seven chapters, thirty three sections, conclusions and bibliography with 139 reference sources. It has been illustrated by 59 figures and 33 tables. The volume of the Thesis is 135 pages.

Chapter 1 provides information about topicality and hypothesis of the Thesis, formulates the aim of the research and tasks to be fulfilled. Also, scientific novelty and practical significance of the Thesis are presented. Author's scientific works are listed.

Chapter 2 provides an overview about the challenges arising from the cycling operation mode to CCGT main electrical equipment. Also new requirements for generators are briefly overviewed. Information about possible solutions for ancillary service provision and CCGT self-consumption electricity costs reduction is provided.

Chapter 3 presents a detailed overview of different stress impact on main electrical equipment of CHP. Based on statistics, empirical formulas for outage rate approximation were obtained. The costs of outage caused unavailability are estimated as well.

Chapter 4 describes the problems that arise for existing generators from new requirements, as well as calculations for possible solutions. Economic impact of power plant modernization is considered.

Chapter 5 provides a description of possible ancillary service provision from CCGT to the grid. Ancillary service provision alternatives are analyzed and service costs for Latvia are evaluated.

Chapter 6 focuses on reducing CCGT self-consumption costs as well as greenhouse gas emission footprint. A methodology developed for detailed feasibility evaluation of photovoltaic system is presented. This methodology is also enhanced by the algorithm for joint optimization of battery storage and photovoltaic system. An example of calculations using the developed methodology is provided.

Chapter 7 summarizes the results of the Doctoral Thesis and provides a methodology for CCGT operation planning enhancement based on possible income from ancillary service provision, combining the results with outage rate evaluation and possible unavailability costs.

1.8. Scientific Work

The results of the research have been presented at international scientific conferences in Latvia and abroad:

1. 2019 IEEE 7th IEEE Workshop on Advances in Information, Electronic and Electrical Engineering (AIEEE), 15−16 November 2019, Liepaja, Latvia
2. 2019 IEEE 60th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 7−9 October 2019, Riga, Latvia
3. 2018 IEEE 59th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 12−13 November 2018, Riga, Latvia.

4. 2018 IEEE International Conference on Environment and Electrical Engineering and 2018 IEEE Industrial and Commercial Power Systems Europe (EEEIC / I&CPS Europe), 12−15 June 2018, Palermo, Italy.
5. 2016 57th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 13−14 October 2016, Riga, Latvia.

During the doctoral studies, the author has participated in other international conferences, where the topical energy sector problems have been discussed:

1. 2017 IEEE 58th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 12−13 October 2017, Riga, Latvia.
2. 2015 IEEE 5th International Conference on Power Engineering, Energy and Electrical Drives (POWERENG), 11−13 May 2015, Riga, Latvia.
3. 2014 55th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 14 October 2014, Riga, Latvia.

The results of the research have been published in conference proceedings:

1. R. Oļekšijs and B. Olekshii, "Combined heat and power plant electrical equipment incident rate and unavailability empirical expression," 2019 IEEE 7th IEEE Workshop on Advances in Information, Electronic and Electrical Engineering (AIEEE), 15−16 November 2018, Liepaja, Latvia, Electronic ISBN: 978-1-7281-6730-5, doi: 10.1109/AIEEE48629.2019.8976989.
2. R. Oļekšijs and O. Linkevičs, "Possible solutions for ancillary service provision from combined heat and power plants in Latvia," 2019 IEEE 60th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 7-9 October 2019, Riga, Latvia, Electronic ISBN: 978-1-7281-3942-5, doi: 10.1109/RTUCON48111.2019.8982358.
3. R. Oļekšijs and O. Linkevičs, "Photovoltaic system application for combined heat and power plant self-consumption needs," 2019 IEEE 60th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 7−9 October 2019, Riga, Latvia. Electronic ISBN: 978-1-7281-3942-5, doi: 10.1109/RTUCON48111.2019.8982371.
4. Oļekšijs, R., Linkevičs, O. Photovoltaic system application for industry self consumption needs. In: 2018 IEEE 59th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 12−13 November 2018, Riga, Latvia. Piscataway: IEEE, 2018, Electronic ISBN: 978-1-5386-6903-7, doi: 10.1109/RTUCON.2018.8659909.
5. Makalska, T., Varfolomejeva, R., Oļekšijs, R. The Impact of Wind Generation on the Spot Market Electricity Pricing. In: 2018 IEEE International Conference on Environment and Electrical Engineering and 2018 IEEE Industrial and Commercial Power Systems Europe (EEEIC / I&CPS Europe), 12−15 June 2018, Palermo, Italy. Piscataway: IEEE, 2018, Electronic ISBN: 978-1-5386-5186-5, doi: 10.1109/EEEIC.2018.8494539.

6. Oļekšijs, R., Linkevičs, O. Failure simulation model for evaluation of CHP electrical equipment reliability. In: 57th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 13−14 October 2016, Riga, Latvia. Piscataway: IEEE, 2016, Electronic ISBN: 978-1-5090-3731-5, doi: 10.1109/RTUCON.2016.7763139.

The author's articles have also been published in conference proceedings, where different problems concerning the energy sector have been considered:

1. Krickis, O., Oļekšijs, R. Safe operation of the industrial centrifugal pump sets in parallel connection. In: 2017 IEEE 58th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 12−13 October 2017, Riga, Latvia. Piscataway: IEEE, 2017, Electronic ISBN: 978-1-5386-3846-0, doi: 10.1109/RTUCON.2017.8124774.
2. Sauhatas, A., Oļekšijs, R. Hallways and stairways lighting system cost reduction. In: 2016 57th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 13−14 October 2016, Riga, Latvia. Piscataway: IEEE, 2016, Electronic ISBN: 978-1-5090-3731-5, doi: 10.1109/RTUCON.2016.7763150.
3. Olekshii, R., Linkevičs, O., Kukļa, N. Utilization of latent heat of 330 kV autotransformer for space and water heating in substation Imanta. In: 2015 IEEE 5th International Conference on Power Engineering, Energy and Electrical Drives (POWERENG), 11−13 May 2015, Riga, Latvia. Piscataway: IEEE, 2015, Electronic ISBN: 978-1-4799-9978-1, doi: 10.1109/PowerEng.2015.7266295.
4. Olekshii, R., Linkevičs, O., Kukļa, N. Feasibility of usage of thermoelectric modules for recovering of low-potential heat from a surface of power transformers. In: 2014 55th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 14 October 2014, Riga, Latvia. Piscataway: IEEE, 2014, Electronic ISBN: 978-1-4799-7462-7, doi: 10.1109/RTUCON.2014.6998217.

2. CHALLENGES FOR CCGT ELECTRICAL EQUIPMENT

2.1. Cycling Operation Mode

Combined cycle power plants (CCGT) in Latvia used to operate in baseload regime until 2014 when Latvia joined the Nordpool power exchange market. Improvements in energy efficiency and development of small environmentally friendly district heating plants as well as cogeneration plants running on wood chop, lead to a decrease of heat energy generation by big natural gas CCGTs, which affects total cost of electricity, downgrading CCGT's chances to compete at the electric power market. Fig. 2.1 illustrates the decrease of heat generation by CCGTs and heat only boilers (HOB) running on natural as during 2014-2017 [1].

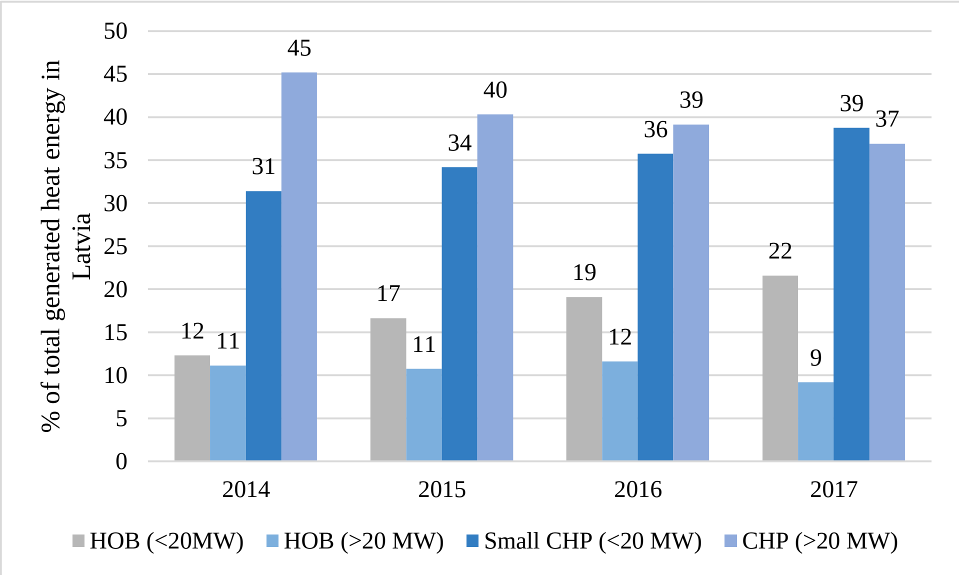

Fig. 2.1 Heat generation in Latvia by producers [1].

CCGTs are operating during the day and are forced to stop at night due to low electricity price on the market and relatively high costs of electricity production because power plants are operating in less efficient condensation mode. Prices on the electricity market in the Baltic states often are lower than CCGT electricity production costs due to various reasons, the most substantial of which is cheaper electricity export from Finland and Sweden, mostly produced by hydropower plants and nuclear power plants [2]. Even wind energy production in Denmark, which is not directly connected to the Baltic state market, has its impact on electricity prices in the region (Fig. 2.2) [3].

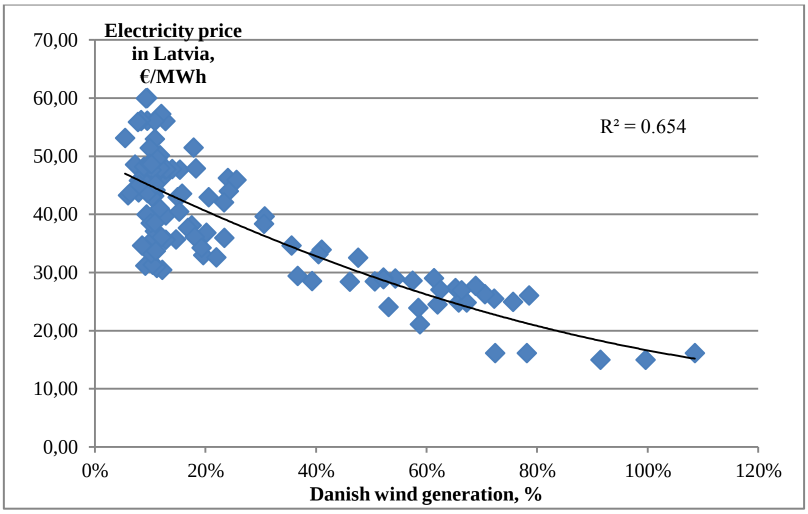

Fig. 2.2 Correlation between electricity prices in the region of Latvia and Danish wind generation [3].

Shifting from baseload operation regime, when operation of Riga CCGT’s was driven by thermal aspects to market based relations, driven by electricity market change, led to a decrease of power plant operation hours and rise of start-up number. Main changes in CCGT operation were related to the reduction of cogeneration output in baseload, shutdowns or load reduction at night and increase of factored fired hours [5].

Several European countries have established support mechanisms for certain categories of electricity producers. There are primarily two reasons for this – increasing the share of renewable generation in the national portfolio and ensuring generation adequacy. The latter is of particular importance in power systems that operate under energy-only electricity markets. Large power plants necessary for system reliability are often incapable of recouping their investments as the market price does not cover all of their marginal and fixed costs. Latest changes in Latvian legislations led to support reduction for Riga CCGTs [6].

The European Union (EU) Emissions Trading System (EU ETS) has been the cornerstone of the EU's strategy for reducing greenhouse gas (GHG) emissions from industry and the power sector since 2005. The EU ETS is a 'cap and trade system', whereby a cap (i.e. a determined quantity of emission allowances) is set on the emissions from the installations covered by the system. The cap decreases gradually in order to achieve emission reductions over time. Installations can trade emission allowances with one another, which ensures that emission reductions take place where it costs least. The EU ETS operates in the 31 countries of the European Economic Area (EEA). It limits emissions from nearly 11,000 power plants and manufacturing installations It covers around 45% of the EU's GHG emissions [7]. In 2017 average CO_2 allowance price was 5.75 EUR per ton, but in 2018 it hit 15.55 EUR/t and by the end of year even 25 EUR/t [8].

Mentioned obstacles forces combined heat and power plants to become even more efficient. Costs for power plant operation increase, as well as the price of produced electricity, which makes power plants even less competitive. Proper management of CCGT contribution in the electricity market, optimization of power plant self-consumption and contribution in ancillary service markets are main opportunities for CCGTs to improve economic indicators.

2.2. Cycling Operation Impact on Electrical Equipment

Modern CCGTs are designed for two-shift operation mode, this type of operating is more damaging for power plant equipment. It is well known, that thermal fatigue is at its most damaging when a component is operating in the creep range and is subject to a constant tensile load. This mostly affects gas turbines and heat recovery steam generators (HRSG) [10]–[12] Thus, the impact on power plant electrical equipment is not studied as much as impact on HRSG and steam turbines. Generator and switchgear can be susceptible to increased fatigue, wear, and other forms of degradation due to repeated stop-start operation [13], [14].

Most CCGTs consist of two or more synchronous generators, same number of main circuit breakers and step-up power transformers. Fault of any of mentioned equipment will lead to power plant outage. Other major electrical equipment, such as self-consumption power transformers, normally have 100% back-up and fault of one element does not lead to power plant trip, even if so, outage time is very short – usually below one hour.

Analyzing North American electrical reliability corporation (NERC) report "State of reliability 2018" shows that top outages causers as percentages of annual net MWh of potential production lost due to forced outages are problems with HRSG and its equipment forcing 12.94% loss of potential power generation in CCGT power plants. Electrical equipment problems lead to a 10.08% loss of potential power generation [15]. Data presented in Fig. 2.3 shows that power plants have many problems with generators as well as with main transformers, therefore, circuit breaker and AC conductor problems are quite rare.

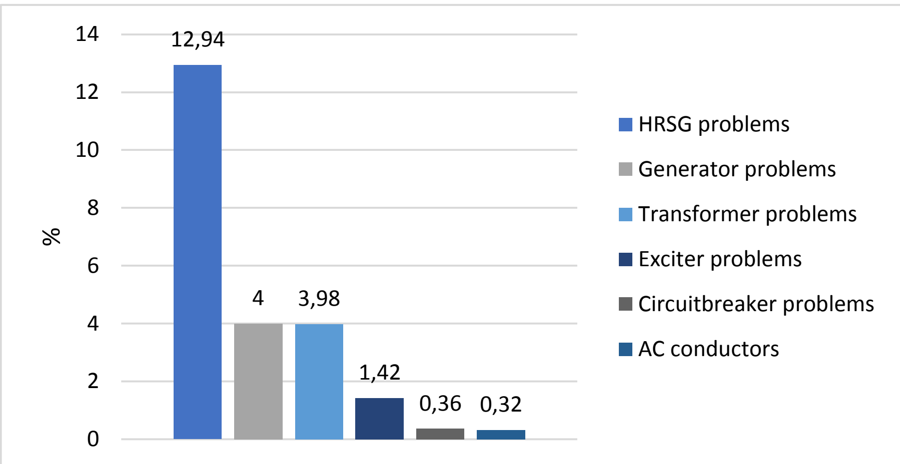

Fig. 2.3 Percentages of annual net MWh of potential production lost due to forced outages.

VGB presented its technical-scientific report "Analysis of Unavailability of Power Plants 2008-2017", this report is more relevant for Europe, also it represents specific data for combined cycle power plants. The report shows that on average there were 33.3 unplanned unavailability incidents per unit (according to VGB power plant unit, not equipment) per year during 2008-2017, causing 7,7% of unplanned energy unavailability. Table 2.1 presents data for 53 CCGTs in Europe [16]. The precise number of incidents on generators and main transformers is not reported, still, the caused unavailability time is illustrated in Fig. 2.4. Total incident count for main electrical equipment is only 1.22 incidents per unit per year, which is 3.15% of all incidents, but it causes 0,97% of energy unavailability, which is12.6% of total power plant energy unavailability.

Table 2.1

Unavailability Report for CCGT for 2008-2017

	Unavailability incidents			Energy unavailability, %		
	not postponable	postponable	total	not postponable	postponable	total
Generator system	0.53	0.09	**0.62**	0.5	0.21	**0.71**
of them generator				*0.28*	*0.13*	***0.41***
Main supply system	0.42	0.18	**0.60**	0.26		**0.26**
of them main transformer				*0.12*		***0.12***
Main electrical system total	**0.95**	**0.27**	**1.22**	**0.76**	**0.21**	**0.97**
Power plant total	33.3	5.4	38.70	6	1.7	7.7

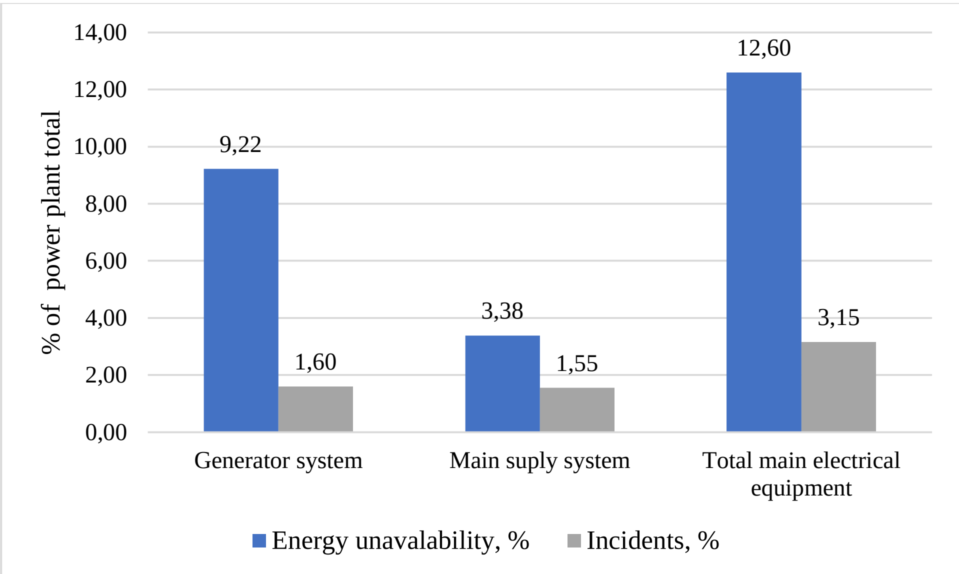

Fig. 2.4 Impact of main electrical equipment on CCGT power plant unavailability.

Generators represent 5.32% of 12.6 % unavailability time caused by the main electrical equipment. Generators operate under electrical, mechanical and thermal stress all the time. The majority of problems occur with generator insulation, although, mica insulation has great insulation capability of around 300 kV/m, the imperfections of insulation, such as cracks, voids, delamination, wrinkles or damaged mica layers lead to electrical treeing development and break down of insulation. A different state of winding insulation is shown in Fig. 2.5. [17].

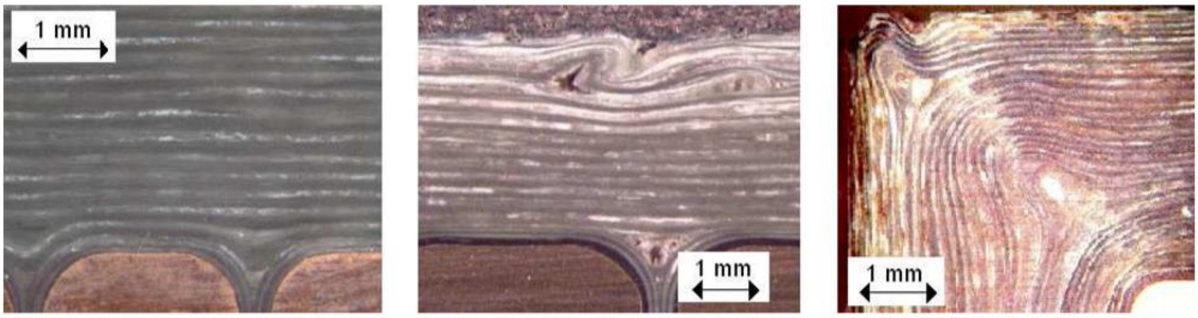

Fig. 2.5 Different mica insulation quality [17].

Perfect mica insulation (left); mica insulation with voids (center); mica insulation with wrinkled tapes (right)

According to Table 2.2, the most stresses influence generator insulation [18].

Table 2.2

Impact on Winding Life

Effect Stress	Design and manufacture	Operation
Electrical	Improper impregnation Electrical slot discharge Insufficient spacing	Electrical slot discharge Coating interface problem
Mechanical		Loose winding
Thermal		Thermal deterioration Load cycling
Ambient		Contamination

Fig. 2.6 shows increased requirements and challenges that cycling operation brings to generators, as well as impact of these challenges on generators with different cooling methods. [13] The main causes of generator failures are problems with stator windings, rotor windings and bearings, thus, no precise statistic is available [14].

Increased requirements	Physical / technical challenges	Expected strain in respect to cooling method		
		Generator components	Indirectly cooled	Directly cooled
Fast active & reactive load changes	High thermomechanical tension at windings	Main bushings of stator winding	Mid	Low
		Carbon brushes and slip rings of static excitation	Low	Low
		Stator core end zones (stepped teeth)	Mid	Low
		Stator winding, especially overhangs	High	Low
		Rotor winding, especially end-windings covered by retaining rings	High	Mid
Load ramps up to 24 % of rated MW / min	Thermal cycling	Complete stator winding	High	Low
		Complete rotor winding	High	Low
Under-excitation	High magnetic flux in end region	End teeth, press finger, press plate	High	Mid
		Stator winding in stepped core area	High	Low
Over-voltage	High magnetic flux density	Stacking beams at stator core back	High	High
		Rotor winding	High	Mid
		Stator core insulation	Low	Low

Fig. 2.6 Extended requirements on power generators [13].

The generator rotor is an excellent combination of electrical, mechanical and manufacturing skills in which the rotor coils are well insulated, supported and ventilated in a compound structure rotating at very high speed. Rotor experiences great mechanical stress and high temperatures (in some cases up to 130˚C–155˚C) while subjected to electrical voltage and current, it is expected to function in this manner for years without failure. The three design constraints that limit the size and life of generator rotors are temperature, mechanical force, and electrical insulation [19].

Directly cooled machines mostly are medium and big turbogenerators, especially hydrogen- and water-cooled machines. Such cooling systems have several advantages, the main one is the reduction of size - therefore mechanical stress due to centrifugal loads and better cooling, which, as shown previously, can impact the insulation lifetime, especially during cycling operation regimes. Indirectly cooled windings are used for small machines, this is a cheaper technology [19]. According to [13] cycling operation has higher impact on indirectly cooled generators.

Main problems with rotor are shorted turns, grounded turns and thermal sensitivity. Shorted turns appear if insulation break down occurs between two windings, usually on end windings, such state is undesirable, thus it appears on all machines and in some amount is normal causing no problems to generator performance. Increase of shorted turns will lead to generators inability to reach nameplate ratings, also it leads to local temperature rise which can end up with rotor thermal sensitivity [19].

Grounded turns appear if slot insulations break down, it is much thicker than winding insulation, but thermal and mechanical stresses can lead to insulations wear and break down as it is reported in [17]. One grounded turn will not cause immediately unavailability of generators, because excitation system is ungrounded, still, such defect should be detected and repaired, if the second turn will be grounded the current between two grounded spots will be high enough to melt down steel during several seconds and will lead to irreparable damage [19].

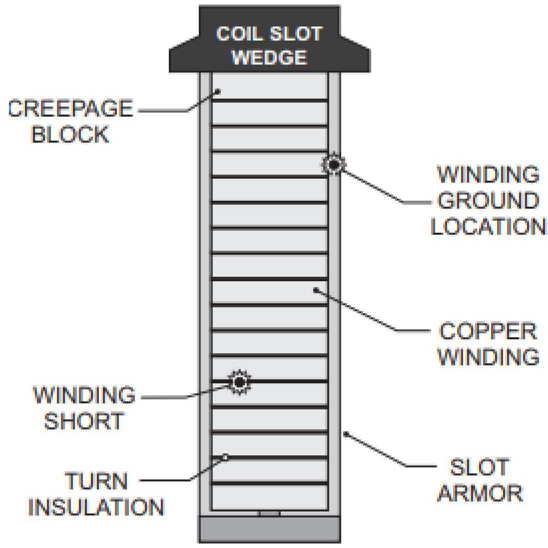

Fig. 2.7 Slot insulation breakdown [19].

Thermal sensitivity describes rotor vibration increase during the increase of field current. As copper has a greater thermal expansion coefficient than steel forging, it leads to the transmission of forces to the forging through the rotor slots, wedges, retaining ring and centering ring. The heat generated in coper is dissipated by cooling medium. If heating and proper cooling appear at the same time, there are no forces that are trying to bow the rotor. However, if a temperature difference exists across the rotor it will tend to bow, the balance of rotor will be disturbed causing additional vibrations when field current rise [19].

Almost the same problems occur to stator winding. Insulation quality greatly impacts the generator's lifetime. Small voids and cracks within the insulation is a usual thing and do not lead to fast developing defect. Insulation problems between windings mostly lead to local overheating, which can end up with damage to the mica - drying it out. The worst case is insulation problems between winding and stator core. As well as for rotor, the weakest spot is end windings, where occurs additional stress for windings and insulation. Despite the insulation enforcement in new generators, it remains the main cause of problems [20].

Usual stator defect is insulation improper impregnation (Fig. 2.5 center and right), which is manufacturing defect; thermal deterioration (Fig. 2.8 a), which usually is the result of winding short circuits and sometimes is the result of bad cooling; delamination of insulation from copper (Fig. 2.8 b) which usually is forced by cycling loading and unloading of generator, different thermal expansion coefficients of copper and mica leads to additional mechanical stress of insulation and results in crack developing and delamination. Also, ground painting problems (Fig. 2.8 c), slot vibration (Fig. 2.8 d), end winding vibration (Fig. 2.8 e), problems with corona protection, contamination, and insufficient spacing leads to the development of defects [18], [20], [21].

Fig. 2.8 Common generator stator defects [18], [21].

Bearing problems for electrical machines are quite common. Electrical machine roller bearing has fatigue in a bearing housing which causes increased vibrations and wears even if the electrical machine is properly loaded and aligned. This happens due to direct contact between bearing and rotor shaft. In addition, other factors can cause bearing degradation, such factors are improper lubrication, poor alignment or installation, contamination (water presence, small particles, sand) [22].

For large power generators, journal bearings are used, the shaft forms a stable and fixed rotating orbit lifted from the bottom position by the oil pressure, as shown in Fig. 2.9. There is no direct contact between the shaft and bearing, which makes the journal bearings more reliable than rolling-element bearings. The circulated lubricant also helps remove heat and contaminants from the bearing, provides electrical insulation between the rotor and stator, and improves mechanical stability by increasing the system damping [23].

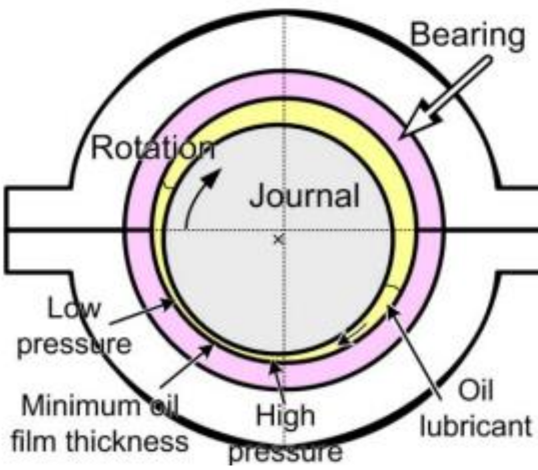

Fig. 2.9 Schematic of the oil-lubricated journal (sleeve) bearing [23].

Although journal bearings are reliable compared to rolling element bearings, but the reliable operation of journal bearings can be disrupted if the shaft load, lubrication characteristics, or in case if clearance is not proper. Lubrication system problems can cause bearing failure in a short period of time since insufficient or loss of lubrication results in extreme heating and journal or bearing surface damage. Irregular bearing clearance due to journal or bearing surface damage can be caused by contamination, frequent starts/stops, cavitation, shaft currents or corrosion [23].

To detect bearing problems, typically thermal and mechanical (acceleration and displacement) measurements are used [23]. Vibration sensors are used for acceleration and displacement measurements, these sensors are useful for the detection of a bunch of other generator defects such as stator winding faults [24], rotor short circuit faults [25] and end-winding vibrations [26].

Main power transformers represent 1.55% of 3.38 % energy unavailability time caused by the main supply system. The power transformer is the simplest electrical machine and usually does not suffer from a bunch of problems. Nevertheless, the failure of the power plant step-up power transformer can lead to big issues. Power transformer defects usually cannot be repaired within a few days and mostly leads to the replacement of the whole power transformer. Step-up transformers are expensive, and it means there are no reserves of such for power plant, whereas the grid usually has a few in reserve because operates hundreds of such [27], [28].

Dielectric failures represent the most of all power transformer failures, it is partial discharges, flashovers, and tracking. Then mechanical problems occur as bending, displacement, element breaking and vibration defects. Electrical failure modes such as open circuit, short circuit, bad contact is the third frequent transformer problem. Thermal problems like overheating and local hot spots also appear time to time. Chemical factors such as corrosion, contamination, moisture and gases lead only to 3% of total power transformer problems. Power transformer failure mode distribution by percentage is presented in Fig. 2.10 [27], [29].

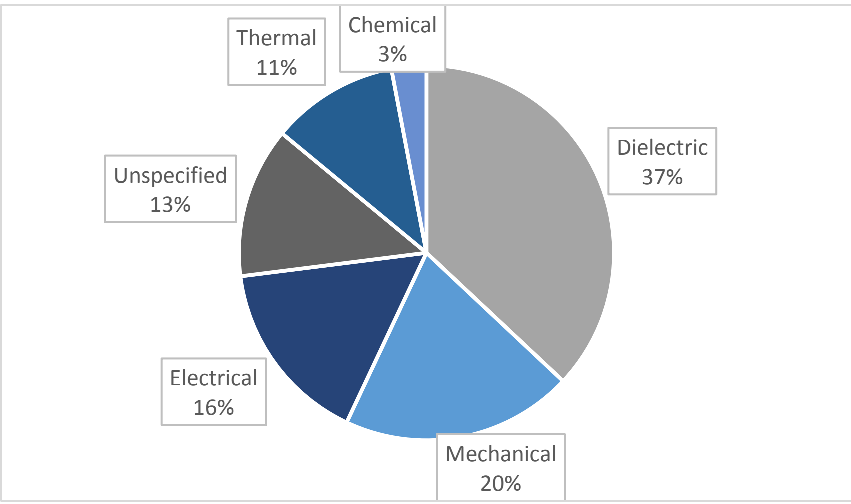

Fig. 2.10 Power transformer failure mode distribution by percentage [27].

Power transformer weakest spots or elements are represented in Fig. 2.11. Usually, problems appear with online tap changers, which are rare for step-up transformers. Problems with windings appear due to local short circuits or short circuits in the grid, as well as lightning strikes. Bushing problems also are common to all power transformers. Other problems are mostly related to the cooling system, wrong operation of relay protection or failure of self-consumption. [30] reported statistics for Latvian transmission grid power transformer failures, and in [31] failure rate for transmission grid was calculated as 0.185 per unit per year. For CHPs [32] reported failure rate is 0.094 per unit per year.

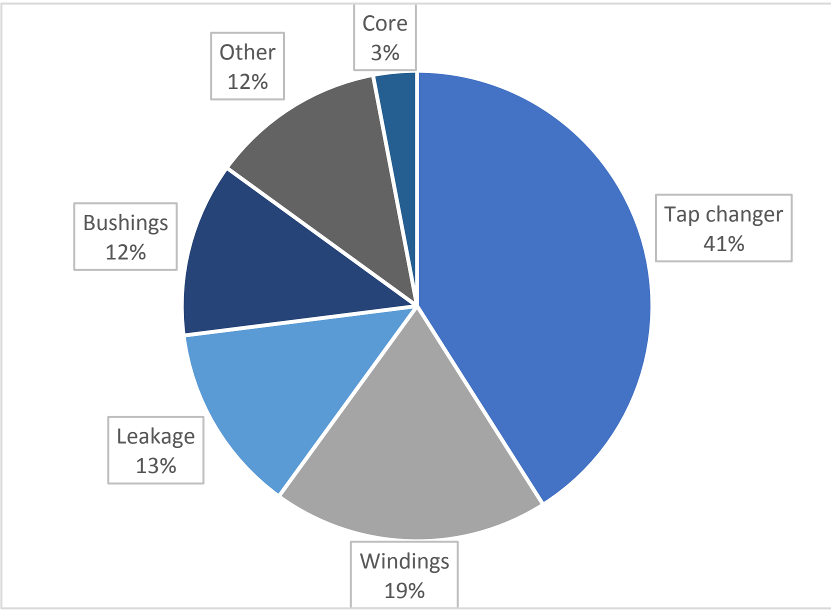

Fig. 2.11 Power transformer subcomponent failures [28].

Main circuit breakers cause very few problems for power plants, but their failure can cause long unavailability [15], [16]. Usually circuit breaker problem occurs when an operation command is performed. In some case circuit breakers locks and do not perform task operation due to failure or blocking within the circuit breaker control system, such failure mode represents 25% of failures. Electrical problems are usually related to breakdown to earth, breakdown across the pole or inability to carry flowing current. Problems with the mechanical part are not very common. Even more rare is operation without a command, in 5.4% failure case circuit breaker opens without command. High voltage circuit breaker failure modes are represented in Fig. 2.12 [27].

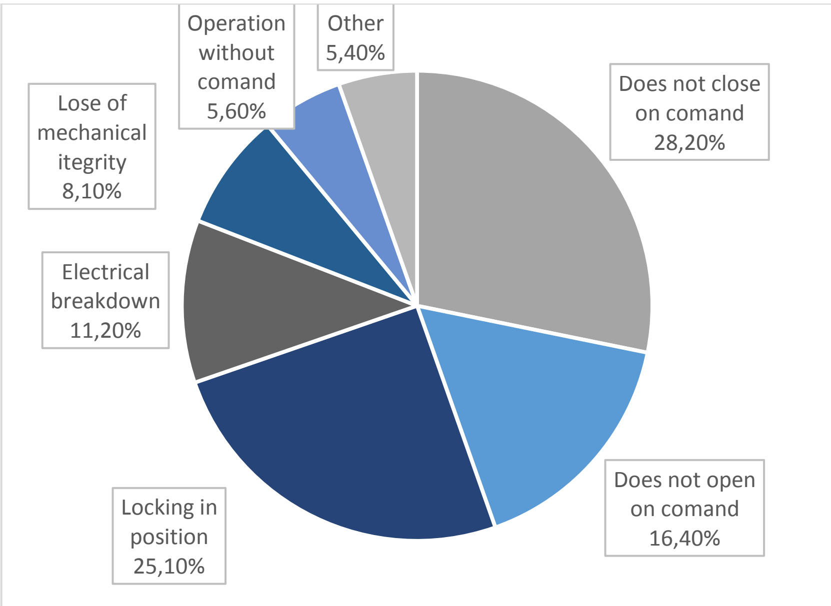

Fig. 2.12 High voltage circuit breaker major failure modes.

Minor circuit breaker failures can usually be easily fixed, they are related to SF_6 leakage - 35.8% of minor failures, operating mechanism air or oil leakage in 20.4% cases, control and auxiliary system functional characteristic change – 18.4% [27].

2.3. Transmission Grid Development and Ancillary Services

European Commission implemented the Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators (RfG), which is a good example of understanding further changes in electrical power grid. RfG sets high requirements for all conventional and renewable generators, because power grid becomes weaker due to market relationships, increased share of intermitting generation, high voltage direct current interconnections and disbalance of generation in regions [9].

RfG sets several unused rules for Baltic state power plants. Some of new requirements are stricter than those for the rest of the European Union [9]. At present Baltic states operate within the BRELL grid and are synchronized with Russia and Belarus. Until 2025 it is planned to synchronize Baltic states via Poland to the Continental European network (CEN) [34]. Connection to Poland is planed via two lines one AC – 500 MW (second circuit will be built by 2020 rising transmission capability to 1000 MW) and one DC – 700 MW (this line is still under discussion) granting 1 000 - 1 700 MW electricity exchange capacity which two times lower than possible exchange capacity between Baltic states and other BRELL participants– 12 AC lines with total capacity 3500 MW [35], [36].

As the amount of AC connections between Baltic states and neighbor countries falls, the operation regime of Latvia, Estonia, and Lithuania become more comparable to island power grids, which explains RfG stricter requirements. The interconnection map of Baltic states after

2025 is shown in Fig. 2.13. [35]. Some requirements of RfG such as requirements of frequency control are quite similar to BRELL requirements, the other are completely new. One more difference is that Baltic state power plants do not provide such services as primary frequency control and only partly participate in voltage regulation. According to RfG, all power plants should be capable of providing such services [9], [36].

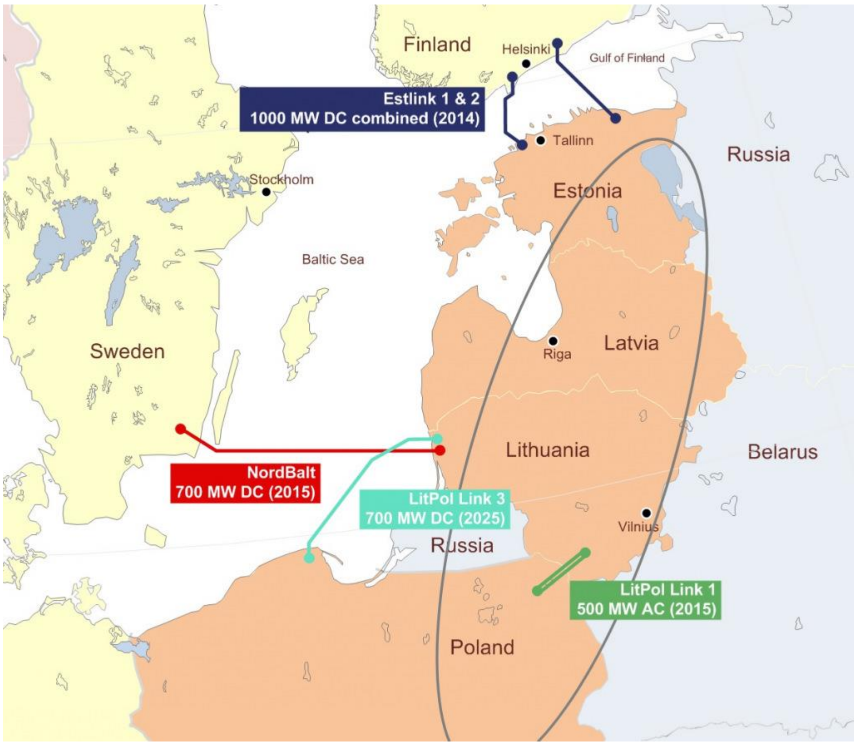

Fig. 2.13 Baltic state transmission grid connections after 2025 [35].

In [37] is stated, that in case of the successful development of the scenario of 2025 for the Latvian energy system, taking into account additional interconnection lines and increasing the share of renewable energy sources, will appear weak nodes and lines. Also, change in interconnections and increased part of the wind power station (WPS) will lead to problems with system static stability and balance of the system.

It is known, that RfG can be implemented for existing power plants, and it can become a reality for Latvian power plants after synchronization with the CEN power system in 2025. Latvian transmission system operator (TSO) Augstsprieguma tīkls published requirements for generators in Latvia. Previously existing rules did not require local power plants to stay connected a frequency below 49 and above 51 Hz, specific loading and unloading speeds, requirements for operation in undervoltage mode were not in such a wide range, admissible voltage range did not have time limited extended under/over voltage and there were no U-Q/P profiles to fulfill [35].

Synchronization with CEN will be a challenge for existing generators in the Baltic states. Thus, it also will open new markets and give more opportunities. Timetable of scheduled implementation of ancillary service markets in Europe is presented in Fig. 2.14. Baltic balancing energy market, so called CoBA is already launched providing frequency restoration reserves with manual activation (mFRR), results show a positive impact on system balance [38]. According to [137] frequency restoration reserves with automatic activation (aFFR) and frequency containment reserve (FCR) markets should be launched next.

Fig. 2.14 Frequency service implementation schedule [137].

Reactive power control is already market based in many European countries, while in the Baltic states it is contracted between generators and TSOs. Reactive power control service provision type in different EU countries is presented in Fig. 2.15. Latvian TSO has own capabilities to control voltage and contracts only hydropower plants generators operation in synchronous compensator mode, to consume excessive reactive power of 330 kV grid. Due to changes in regulations, as well as modernisation of power network, which results in the more widespread use of 110 kV and 330 kV cables known for reactive power generation, TSO might demand more reactive power compensation from generators and buy it as ancillary service. Even at present generators connected to 330 kV network are providing reactive power compensation during operation but are not remunerated [35], [137].

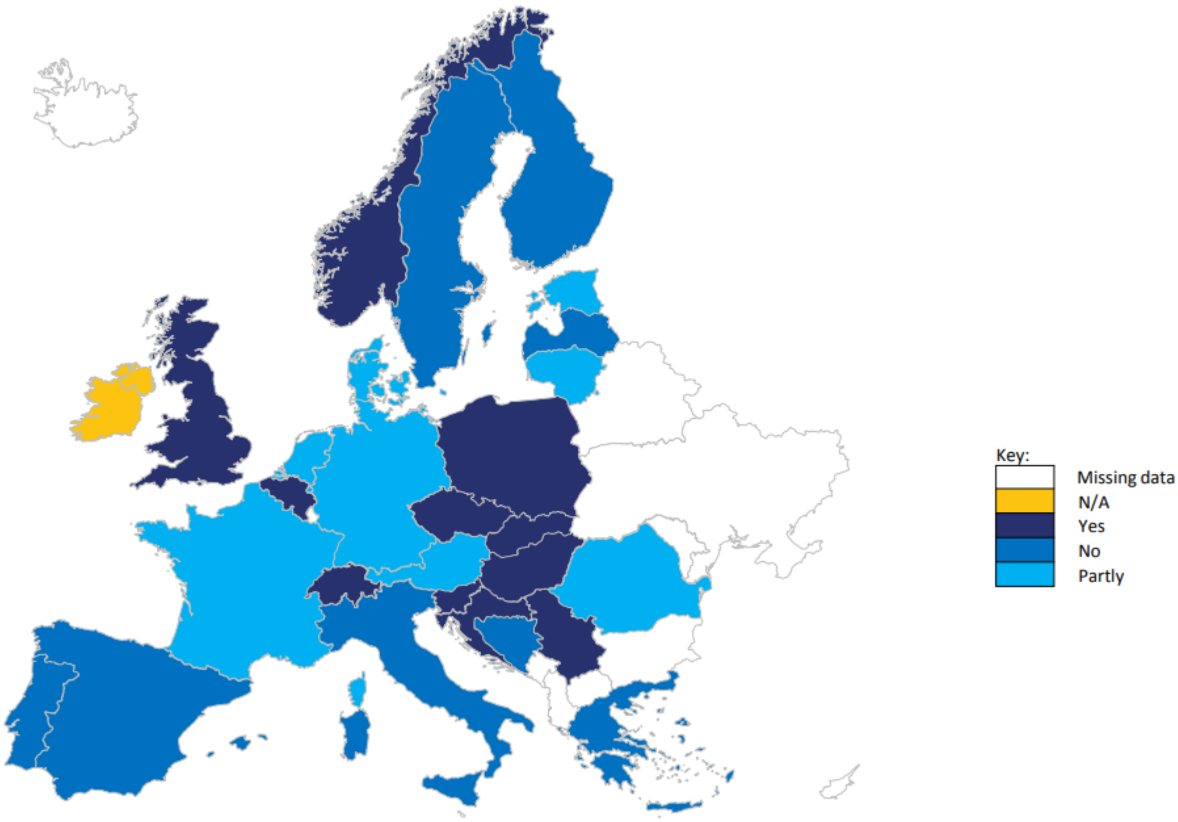

Fig. 2.15 Voltage control – is a service paid by TSO [137].

Equipment for new power plants will be provided in accordance with RfG. For existing power plants, modernisations must take place, especially in the Baltic region where, not in a very distant future, is a risk of operation in island mode. The market has numerous solutions for the voltage level contribution, like series compensators and thyristor series compensators, static VAr compensators and synchronous condenser system. The latter provides not only voltage stability, but also inertia and short circuit power [41].

Even more possibilities are provided by battery energy storage systems (BESS). Such systems are used for different applications, the technology is still developing and the costs of such systems are decreasing. The main advantages of BESS are fast response whichallows them to perform primary frequency control, operation possibility in all four energy quadrants allows them to contribute to voltage control. Also, BESS can be used for black start service. Variability of tasks BESS can perform is very wide and it allows to use them in several ways at same time, which is good for economic reasons [42, 57].

Frequency primary control service is provided by power plants from Russia, and power plants in Baltic states do not provide such services and most of the power plants are unable to do so. Voltage control service is mostly provided by TSO and hydropower plants. Before Baltic state synchronization with CEN, it is possible to operate without fulfilling RfG requirements. Resynchronization to CEN provides not only challenges for existing generators in Baltic states, but also possibilities to contribute in various ancillary service markets.

2.4. Self-Consumption Optimization

During the operation self-consumption of CCGT power plants is about 2.5-4% of total produced power. When a power plant is not in operation, it still consumes electricity from the grid. Consumption during shut down is 5-10 times lower than during operation. In Europe, according to statistics, the average operation time for CCGT units is 3486 hours per year [16]. It means in average 5274 hours per year electricity is consumed from the grid, and costs of this electricity are higher than for produced electricity because transmission fee and different taxes should be paid.

Optimization of self-consumption allows to reduce short term costs for power plants. It could be done in several ways, for example installing more efficient secondary equipment, installing frequency converters for large pumps and compressors, optimizing the logic of operation of secondary equipment. But these solutions depend on specific situations, especially when are used for modernisation or retrofitting in existing facilities [43].

European policies, global photovoltaic (PV) price reduction and CO2 market rise the interest to use solar power for self-consumption. Photovoltaic system installation is widely used for business centers and industrial facilities to reduce costs for electricity [44], [45]. Battery storage systems give even more possibilities to optimize consumption of electricity [46].

From 2008 to the second quarter of 2016, the cost of the photovoltaic module decreased by over 80% and now represents less than half of the costs of an installed PV system. Photovoltaic-generated electricity in the most competitive markets is already cheaper than residential electricity retail prices. Due to falling PV system prices and increasing electricity prices, the number of such markets is steadily increasing. Photovoltaic system installation became cheap enough and provides better than ever efficiency, due to rising prices for the end-user of electricity it becomes more and more interesting to install the photovoltaic system in households and industrial utilities [58].

BESS are well known for use in combination with an intermitting source of energy. Such combination allows to shave peaks of generation and sell energy on the market when the prices are higher [59]. Also BESS is used for off-grid solutions, to provide as much energy as possible from renewable energy sources [60]. There are two main problems, that appear operating BESS. The first is quite high installation costs, which are decreasing, the second is a limited lifetime, usually about 10 years or 4000 – 5000 full charge/discharge cycles with the reduction to 80% of capacity. Still, the lifetime may be even lower due to improper operation temperature and higher than specified number of cycles [42].

Possibilities of battery storage systems and predicted price decrease, decreasing costs of photovoltaic modules and semiconductive apparatus, as well as European energy policies and rising price of electricity for end user open new possibilities of combination of existing generating loads and new technologies to provide more energy efficient, stable, environmentally friendly and cost effective power system.

3. CHP ELECTRICAL EQUIPMENT RELIABILITY

CHP equipment degradation is studied by numerous works e.g. [47]−[50], but mostly concerns about gas turbines, heat recovery steam generators, steam turbines outages and caused cost. [49] provides information about generator failure probability distribution and caused outage, thus no dependency on the cyclic operation is presented. Some CHP outage analysis works take into account generator failures like [51] and [52] which also considered power transformer failures, thus in both works electrical equipment failure rates are estimated just to approve proposed methodology. [53] focuses on the development of generator outage model for risk-based maintenance, but generator failure rate also is estimated and has no relation to power plant operating modes. Therefore, [14], [18] and [20] discusses turbo-generator failures as a result of manufacturing, maintenance, installation or operating regimes, thus, lack of statistics does not allow to use this data for generator failure rate estimation concerning conventional power plant cyclic operating mode.

For power transformers great failure rate statistics are collected in [29] and for circuit breakers statistics and analysis is available in [27] and [33]. That is why in this Doctoral Thesis most accent is made on generator incident rate analysis. Also, economic impact of CHP's main electrical equipment incident rate is analyzed.

In this part, the main aim is to analyze generator failure process and identify main causers. Analysis of available generator incident rate statistics is provided. To estimate generator incident rate and caused unavailability depended on CHP operating mode empirical expressions were calculated. Also, power transformer and main circuit breakers failure rate were used to forecast overall CHP incident rate and caused unavailability per year. Total caused costs due to failure of CHP main electrical equipment were estimated [54].

3.1. Generator Failure Causer

Power plant main electrical equipment are generators, generators excitation, step-up transformer, self-consumption transformer, and main circuit breaker. All this equipment is designed for long-term operation under electrical stress and magnetic field flux influence, although this equipment is designed for numerous operation cycles, it still suffers additional stresses during transient regimes, especially start-ups, connection (synchronization) to the grid and disturbances in the grid. Section 2.2 illustrates the main electrical equipment failure causers, related to design, manufacturing and installation, other appears during normal operation time due to material wear and tear, transient regimes can accelerate this tear and wear effect.

Power generator biggest issues are related to stator and rotor insulation. The manufacturing process of stator epoxy-mica insulation may be described as follows. Glass fiber reinforced mica tape is wound around the copper strands to the desired thickness and numerous layers of mica tape make the insulation with a layered structure. Then the layered insulation, as well as the copper conductor, is vacuum impregnated with epoxy resin. After impregnation and cure, the mica tape layers and the epoxy resin are normally bound, and rigid and compact insulation is formed. At the manufacturing stage, the insulation is prone to produce gas filled voids. The voids often occur between layers and/or at the resin-copper interface [65].

More voids occur due to the deterioration of the adhesive strength of the epoxy resin in the insulation under operating stresses. During a long-term aging process, some of these voids are enlarged gradually. In severely aged insulation, delamination between layers, delamination of insulation from a copper strand and even cracks through layers appear. The thermal, electrical and mechanical stresses concentrate on these microscopic defects, accelerating the aging of the whole insulation material [65].

Mica insulation and copper conductor have different thermal conductivity, for mica it is 0.71 (W/mK) and for copper 385 (W/mK). During fast-cycling some spots of a generator are not properly cooled fast enough, which leads to additional thermal stress for insulation. This leads to different speed of expansion of materials, insulation is stretched by conductor, because it does not expand fast enough. When the load is rapidly decreased, insulation cannot get previous shape and voids appear between insulation layers [12], [16].

Some works analyzed generator insulation stresses separately. In [66] only thermal stress at 148-160°C was analyzed, the authors concluded that the effect on mica-epoxy insulation, which is used for modern generators, was negligible. Therefore, in thestudy, which was conducted in Switzerland, tests were performed by applying only electrical stress to mica insulation. Presented results show that mica insulation got breakdown only in case if there were defects of insulation. Test with applying 3 nominal voltages (32 kV) to insulated bars took place [17]. Fig. 3.1 shows the breakdown path in bar insulation, same was reported by [66]. It also complies with the statement that electrical breakdown does not appear in undamaged mica insulation.

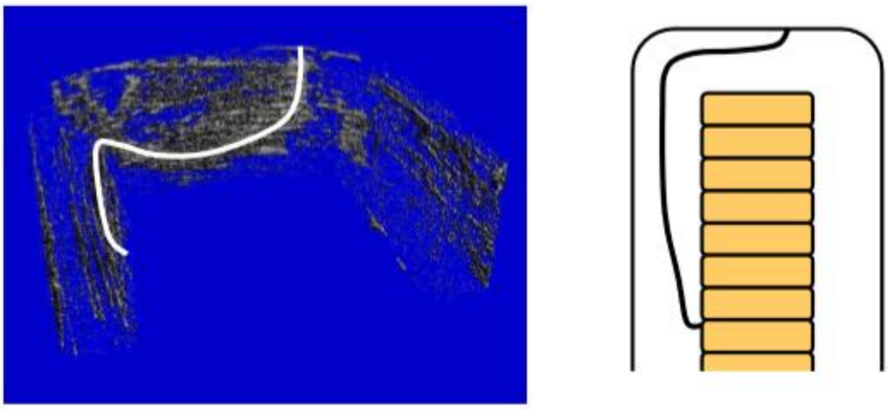

Fig. 3.1 Electrical breakdown path in a bar uncovered by Xray methods (left) and traced by burning off the binder resin and removing the layers of mica tape (right) [17].

In [67] electrical and thermal stresses were applied simultaneously. For a group of 12 stator bars with applied double nominal voltage and temperature change from 40°C to 122°C, within five hours 1500 cycles were made resulting in no breakdown. Second test was applied to the same bars with the same electrical stress, but the temperature changed from 40°C to 165°C within five hours, after 733 cycles, signs of defect appeared. It means that the combination of electrical and thermal stress took more than 11 100 testing hours before the breakdown.

An interesting finding of temperature regimes is that at operating temperature of 160°C electrical breakdown capability is better than at 20°C. This can be explained by higher flexibility of the binder resin at elevated temperature which minimizes the risk of crack formation, but also by the reduction of internal stresses coming from the curing reaction which usually takes place at temperatures around 160°C. However, further rise of temperature led to greater aging of insulation, which is shown in Fig. 3.2. Also, it is claimed, that optimal temperature for insulation is about 90°C, which is usual to rated regimes of generators [17].

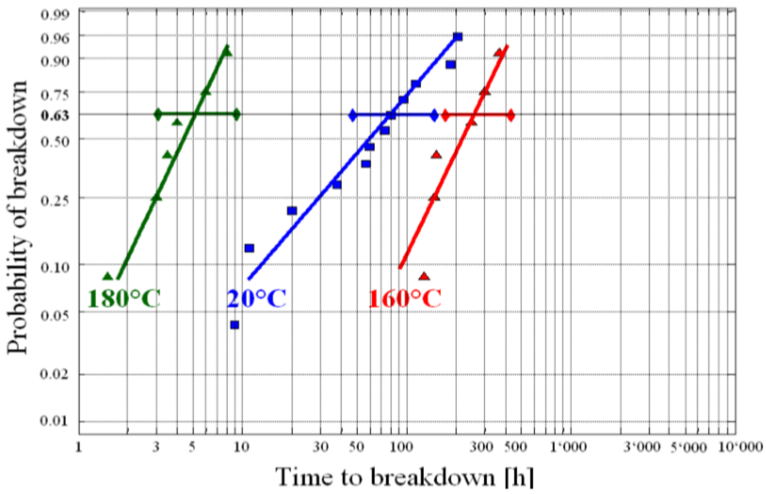

Fig. 3.2 Influence of the ageing temperature on voltage endurance [17].

Simultaneous actions of several stresses result in an aging effect that differs from that observed in case if the individual stresses were applied sequentially. Furthermore, physical aging, involving free volume relaxation, also occurs in the absence of any significant external stress, being related only to the fact that a given material might not be at thermodynamic equilibrium at a given temperature [67].

Different studies were conducted with the aim to find out how generator insulation is affected by thermal, electrical and mechanical stresses combination. In [65] under testing were species from 18 kV 300 MW generator stator bars. The electrical stress of constant value of 4.16 kV/mm and temperature stress with 130°C was applied for 126 hours. Then mechanical stress as the vibration of the magnitude of 1mm was applied for 96 hours. The last step of the test was thermal-mechanical stress, applying the same vibration and adding thermal cycling with forced cooling from 130°C to 20°C within one hour lasting for 84 hours. Total test time was up to 2100 hours. Test results showed a change of mica-epoxy insulation structure due to hydrolytic decomposition of epoxy resin, organic acid was produced. K ions will be separated from mica under the combination of organic acid and ionization under electrical stress, which will lead to the degradation of mica. This leads to change in mica interface, which results in loss of dielectric strength [65].

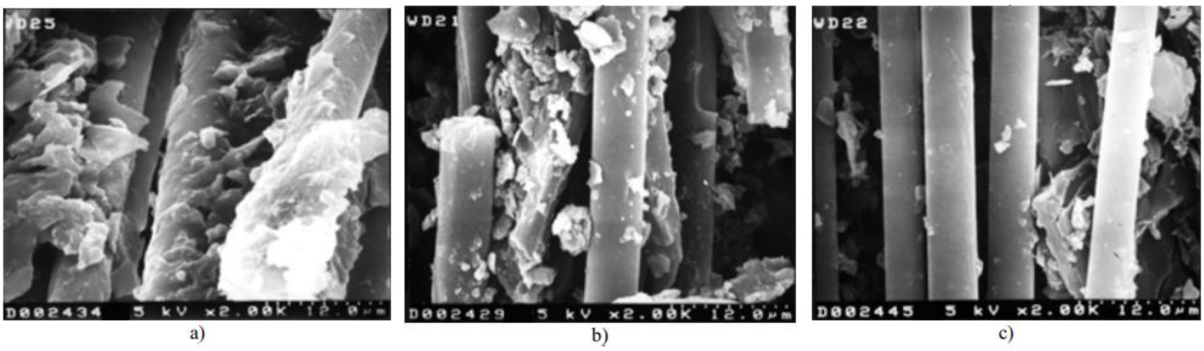

Fig. 3.3 Scanning electron microscope photographs before and after multi-stressing. a, Unstressed specimen; b, 900 h multi-stress; c; 2100 hours multi-stress [65].

In [68] experiment series were conducted at constant core temperature of 155°C, applying different electrical stress (voltage) and mechanical (vibration) stress to 11 kV rotating machine coils insulated with mica filled solvent free epoxy resin. The results show that in constant temperature and electrical stress, applying variable vibrations, failure state average appeared in 1 964 hours. Applying variable electrical stress at constant temperature and vibration level, failure state average appeared in 1 690 hours. Applying variable electrical and mechanical stress simultaneously with lower amplitudes than in first two experiments and maintaining the same operation temperature, failure state average appeared in 312 hours.

Analyzing all discussed studies, it can be concluded, that main threat for generator reliability comes from insulation degradation during operation. A combination of electrical, thermal, and mechanical stress leads to insulation ageing. Usually, insulation problems arise due to improper manufacturing and stresses above rated, which appears during generator operation and accelerates aging and defect development of insulation.

In CCGT generators are coupled with high-speed steam or gas turbines, during turbine startup they pass some critical rotating speed points, where vibration is much higher than normal. These vibrations are also applied to generator bearing leading to faster wear. The same applies in the opposite direction. Disturbances in electrical grid usually lead to electromagnetic torque change which effects the turbine mechanical torque. Generator rotor mass is almost the same as rotor mass of turbine which runs it. Moving to cyclic operation mode number of transient regime as well as caused stress rise. Theoretically, this leads to faster ageing of generator insulation, stator bar end vibrations, slot vibrations, corona protection abrasion and higher stress on bearings resulting in higher incident rate. Thus, during steady state operation thermal, electrical and mechanical stresses also are applied to generator parts, meaning that longer operation hours can lead to higher incident rate [24], [69], [70].

3.2. Power Transformer and Circuit Breakers Failure Causers

The amount of power transformers on power plants is very high, most of them have a reserve, but the main step-up transformers are present only in one piece. Any disturbance in the power transformer (even those with reserve) operation most probably will lead to trip of the power plant. In case of reserved transformers, outage will be short, but in case of step-up transformer it can last for weeks. In Fig. 2.10 and Fig. 2.11 main type of problems and equipment which causes power transformer outages is presented. Root cause investigation is presented at Fig. 3.4.

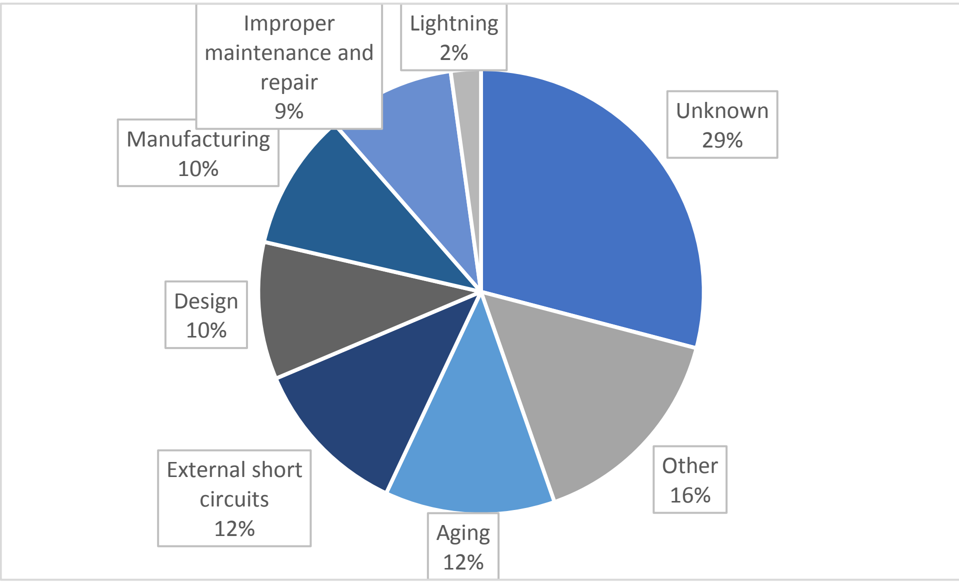

Fig. 3.4 Power transformer failure root causes [29].

Other causes mentioned in Fig. 3.4 are material quality, abnormal deterioration, lightning, quality of installation works on-site, overvoltage, loss of cooling and others. Comparing to generators transformers have lesser problems with insulation, manufacturing, and design. This can be explained by the relative simplicity of a power transformer, the absence of moving parts and oil as cooling and insulation material. But transformers are much more affected by external short circuits, they get the first shock from the grid and results in such defects such as on-load tap changers (OLTC) and high voltage bushings.

There are three main reasons for power transformer outage: improper operation or failure of OLTC, problems with windings (mainly with insulation), and high voltage bushing defects. One more big issue is a problem with power transformer tank leading to oil leakages or air penetration, and, as a result, humidity suction in oil. Such a problem causes around 13% of all power transformer outages.

OLTCs are responsible for maintaining stable voltage level under variable loading conditions. By changing a tapping on the winding, the OLTC enables the turn’s ratio of the transformer to vary and thus the level of the output voltage. OLTC has two main components; a selector switch and a diverter switch. A selection of tapping on the transformer winding is done via the selector switch. The load current is switched by a set of electric contacts of the diverter switch [71].

Power contacts of modern OLTC are placed in a separate oil tank or in a vacuum tank, which decreases tap changer failure damage to power transformer. During normal tap change, electrical arcing occurs between power contacts due to making and breaking load currents, arcing forces carbonization of oil, which leads to loss of dielectric capabilities and final breakdown [71].

For power plant, step-up transformers on-load tap changers, usually, are not used, which, according to statistics, significantly reduces the chance of transformer outage. Power transformers for self-consumption needs of power plant use OLTC, but they usually are placed in a separate tank. During the last decade, most of medium voltage power transformers of power plant have been equipped with vacuum insulated power contacts OLTC. This technology allows to significantly reduce defects in current circuit, also it prevents fire hazards [73].

As all insulation types, paper and oil combination suffers from degradation and aging. Undetected inter-turn short-circuit faults are one of the leading causes of transformer failures. An inter-turn short-circuit fault, which is mostly a result of a severe deterioration of the turn insulation, if left undetected, can propagate and lead to catastrophic phase-to-ground or phase-to-phase faults [74]. It is well known that paper and oil which are used in transformers degrade with time at rates that depend on the temperature and the amount of air and water present.

Transformer insulation tests were performed in [75], making a simultaneous test of paper and oil, degree of paper polymerization was taken as a breakdown factor. Studies show that in absence of air and water oil immersed paper would operate for 38 years at 90°C. For conditions when 2% of water and some air are present in oil and paper, time to breakdown decreases to 690 days. So, it is vitally important to keep a power transformer dry and free of air. Also, the temperature immensely impacts insulation life. Reducing the temperature from 90°C to 80°C, insulation life is prolonged by a factor of 3 [75].

Oil-paper insulation is widely used in power transformer bushings and is one of the best insulations with good electrical and heat transfer properties. However, prolonged exposure to extreme electrical (stress due to fast transients, voltage oscillations imposed by nearby lightning strikes, frequent switching and continuous high level of harmonics), thermal, mechanical and environmental stresses can deteriorate its important properties and can break the cellulose bonds of the paper. This leads to the following by-products: water, carbon monoxide, carbon dioxide, smaller values of hydrocarbons and furan [76, 77].

Power transformers are important to ensure proper operation of power plant. Similarly, as for generators, stresses due to electrical transient modes also can lead to faster ageing or power transformer parts. Thus, power transformers are operating almost all year long and all transients come from external systems (power grid or generators). Unlikely generators, for power transformers are available detailed failure statistics.

3.3. Power Plant Operating and Equipment Outage Statistics

There is a lack of statistics for power plant reliability, as well as operating hours and start-up numbers per year. Such information is very sensitive, that is why it is not publicly reported. One of the sources of such statistics in Europe is VGB PowerTech (VGB), the organization in which the biggest electricity producers in Europe are represented. VGB provides annual statistics about incidents on different types power plants. What is more, it gives statistics of energy utilization and caused energy unavailability. Still, it does not provide statistics on power plant start-up number, which is necessary, if cycling operation mode influence on power plants is analyzed [16].

The study described in [61] was made to represent further energetics development scenarios, which include start-up numbers per year for different types of power plants. During further research, which included analysis of German Bundesnetzagentur data, state organization which is in charge for energy sector, it was concluded that the number of existing CCGT (total number of units in operation reported in august 2018 - 60) is lower than number of existing lignite and coal-fired power plants (total number of units in operation reported in august 2018 - 84) [62]. Using data from [61] calculated the average number of starts for CCGT would be 10.8 per unit per year, but for coal and lignite-fired power plants 14.9.

At first glance, it is unclear why coal-fired power plants suffer more starts than CCGTs. It could be explained by two factors. The first is levelized electricity cost for coal fired power plants are higher than for CCGT. Capital investments (CAPEX) for coal fired power plants usually are 1 643 EUR/ kW, but for CCGT 803 EUR/ kW. Fixed operational costs (OPEX) for coal-fired plants – 36.8 EUR/MW, for CCGT 22.2 EUR/ MW. At the same time running marginal costs, which includes fuel and CO2 costs, for coal power plants at full load is 25EUR/ MWh and in minimum load 28 EUR/ MWh, for CCGT at full load – 31 EUR/ MWh, but at minimum load 44 EUR/ MWh. Levelized costs of operation of different types of power plants are presented in Fig. 3.5 [78] Second, the number of incidents that occur to power plants. VGB statistics show that for lignite and coal fired power plants number of not postponable incidents per year is 67.5 and for CCGT 33.3. It means more starts and stops of coal fired plants might be performed due to incidents on power plants [16].

Looking at VGB data, coal fired power plants on average operate 6360 hours per year with energy utilization of 64%, which shows that 0.88 of total operation time power plants are running at full load, or 5597 hours per year with full load. For CCGT reported average operation time is 3486 hours per year with energy utilization of 28.9% which results in 2531 hours running with full load or 73% of total operation time. Comparing this data with German average electricity market price and levelized costs, it seems like CCGT used to operate with an average 50 starts per year, which is much more than reported at [61].

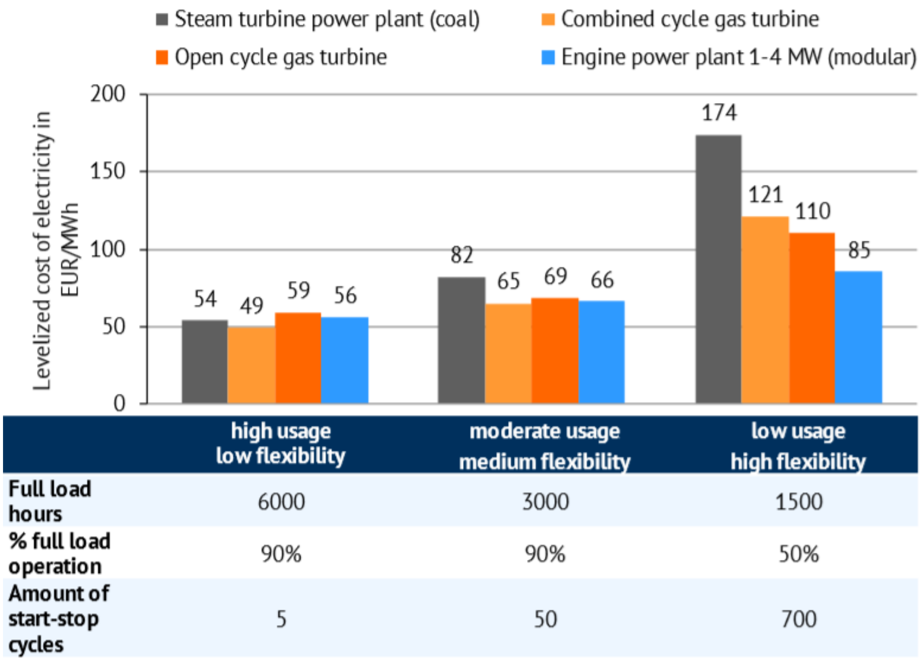

Fig. 3.5 Levelized costs of electricity in EUR/ MWh by power plant type and operating regime [78].

To make the right conclusion about operating hours and start-up number ratio, analysis of Riga CCGT's was performed for a time period of 2014-2018. Before 2014 electricity market in Latvia was not operated, but afterward number of CHP startups per year has grown significantly [63]. The results show that the cost of electricity production has the greatest impact on operation in electricity market. The real operation data for three different CCGT blocks were considered. All three have different operational costs which can be called as the lowest, medium and the highest. The difference in costs of operation results in operating hours per year and starts per year. Obtained results are present in Table 3.1. [79].

Table 3.1

Latvian CCGT Operation Data by Costs of Electricity Production

Operating costs	Average operating hours	Average number of starts	Average operated hours per start
Lowest	5521.60	20.40	310.40
Medium	3459.60	51.40	78.69
Highest	1561.33	46.67	36.42

Analyzing obtained data for Latvia and data represented in [61] and [78], it becomes clear that the power plants with lower electricity production costs operate more hours, than power plants with higher operational costs, but number of starts is not so clear. The number of starts rises due to the power plant flexibility and higher operational costs, but at some level of costs with the remaining flexibility, the number of starts decreases, due to less operated hours per year. It can be concluded that moving from baseload operating regime to cycling leads to the rise in number of startup's and lowering in operating hours, but during operation in cycling regime, lowering of operation hours does not always lead to a rise of number of startup's. Further in work star-up data from [78] and [79] will be used to analyze incident or failure ration.

For this research, real average operation hour per unit per year, incident statistics, energy unavailability percentage and other data reported by VGB is used. Data is reported for 181 fossil fired units, 53 CCGT and 42 OCGT across Europe. Incidents are calculated per unit and year. Unavailability percentage shows how big is the impact of system incidents on total power plant production, it is calculated as follows:

$$k_{un} = \frac{W_{un}}{P_N * t_y} \tag{3.1}$$

where, k_{un} – energy unavailability percent, %;

W_{un} – unavailable energy during calendar time, MWh;

P_N – power plant nominal power, MW;

t_y – hours per year, h. [16]

Generator incident rate, due to relatively high number of incidents is clearly defined in [16] and [32]. Thus, provided information about power transformers and circuit breaker is not so clear, because it is only a part of represented main supply system. The main supply system of a power plant consists of power transformers, switchboards and transmission lines. That is why data from [30] and [31] will be used for power transformers and circuit breakers failure rate estimation.

Comparing incident percentage and caused energy unavailability percentage presented in Fig. 2.4 for CCGT, Fig. 3.6 for fossil fired plants and Fig. 3.7 for OCGT. It seems that for OCGT power plants majority of the issues appear to the main electrical system. It can be explained by a lower amount of other systems where incidents can appear.

For the fossil-fired units, the majority of the incidents appear with the conventional heat generation system, high voltage transmission grid and steam, water and gas cycle system, for CCGT – steam turbine, conventional heat generation system and water and gas cycle system, which are not common for OCGT. In Table 3.2are presented operating time per year, incident rate, unavailability percentage caused by incidents for generators for different power plant capacity and type as well as the assumed number of starts per year [15], [16], [29].

The step-up transformer incident rate as for a separate part of the main electrical supply system is represented only for a few cases, and it varies in the range 0.01-0.1 incidents per unit per year, this rate is not immensely affected by the type of power plant and operating hours per year. CIGRE reported 0.0095 failures for power plant transformers, detailed statistics are presented in Table 3.3. Also, VGB reported 0.02-0.12% of unavailability caused by transformer incidents which are below 0.7% of total power plant incident caused unavailability percentage. However, NECR reported 3.98% of caused unavailability by step-up transformer failure which is almost 6 times higher.

Table 3.2

Generator Incident and Unavailability Statistics

	Coal and lignite fired units			CCGT	OCGT/Jet
	20 units	44 units	72 units	53 units	42 units
	10-100 MW	100-200 MW	200-600MW	-	-
Operating hours per year	6745.2	5851.68	6228.36	3486.48	122.64
Assumed number of starts per year [78], [79]	5	25	15	50	70
Generator system incidents per unit per year	0.12	0.49	0.63	0.53	0.3
Generator system k_{un} per unit per year, %	0.12	0.4	0.5	0.5	1.29
Postponable generator system incidents per unit per year	0	0.16	0.16	0.09	0.12
Postponable generator system k_{un} per unit per year, %	0	0.01	0.08	0.21	0.13
Total generator system incidents per unit per year	0.12	0.65	0.79	0.62	0.42
Total generator system k_{un} per unit per year, %	0.12	0.41	0.58	0.71	1.42
Total power plant k_{un}, %	9.3	7.7	6.6	7.8	6

Table 3.3

Step-up Power Transformer Failure Rate

Highest voltage, kV	< 200	200 to 300	300 to 500	500 to 700	>700
Major failures	20	43	89	9	4
Failure rate	0.0059	0.0093	0.0132	0.0049	0.0054

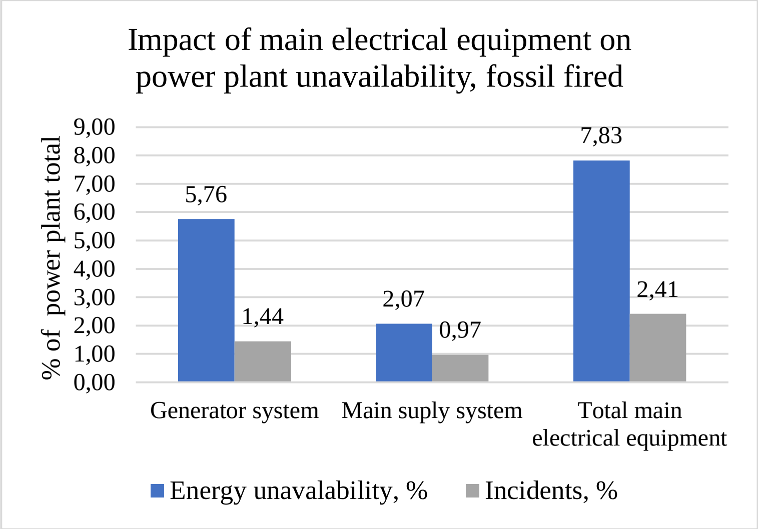

Fig. 3.6 Impact of main electrical equipment on power plant unavailability for lignite and coal fired power plants.

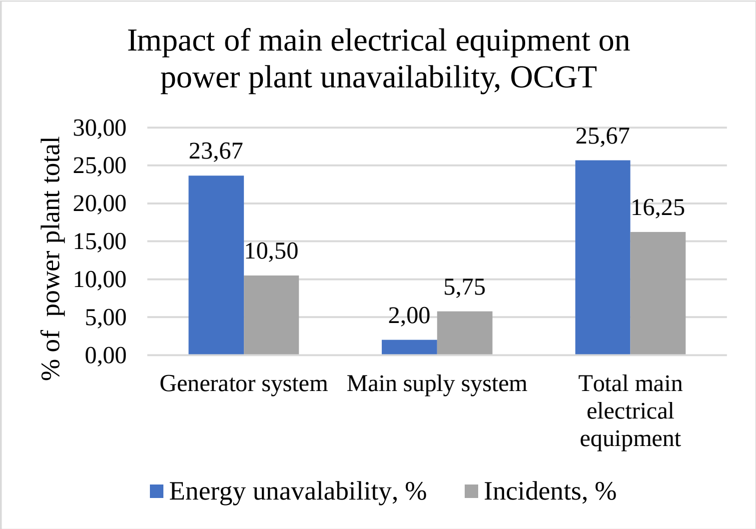

Fig. 3.7 Impact of main electrical equipment on power plant unavailability for OCGT power plants.

For circuit breakers, the failure rate is usually calculated for operation number. One start-stop operation results in one cycle of close and one open command. Generator circuit breakers can be divided into two main groups: air-blast and SF_6 technologies. SF_6 circuit breakers differ by drive type, pneumatic operating mechanism or hydro-mechanical spring operating mechanism. The statistics for circuit breaker failures depend on operating cycles. Failure rates are shown in Table 3.4. [33]. Despite the low failure rate, consequences can be critical and lead to a damage of the other main electrical equipment due to unavailability of circuit breaker to open during faults in grid or equipment [27].

Table 3.4

The Number of Major Failures per Command per GeneratorCcircuit Breaker Technology

CB type	Failure type	Λ_{cb}
Air-blast	Major failure per 10 000 close commands	0.344
	Major failure per 10 000 open commands	0.006
	Total	**0.35**
SF_6 with pneumatic-operating mechanism	Major failure per 10 000 close commands	0.032
	Major failure per 10 000 open commands	0.028
	Total	**0.06**
SF_6 with hydro-mechanical spring operating mechanism	Major failure per 10 000 close commands	0.02
	Major failure per 10 000 open commands	0.004
	Total	**0.024**

3.4. Approach of Incident Rate and Unavailability Evaluation

A failure or an incident of a generator, step-up transformer and generator circuit breaker leads to energy unavailability. For risk assessment, it is essential to know incidents appearance frequency in main electrical equipment of a power plant. In this research, two criteria are used to estimate the incident appearance, these are the power plant number of operating hours and power plant number of startup's.

Step-up transformer incidents are not affected by the number of start-ups as well as the number of operating hours, because they are connected to the transmission grid all year long, excluding the maintenance shutdowns. Only incidents reported for circuit breakers appear during operation commands, so incidents are dependent only on the number of operations. From section 3.1 it is clear, that the generator incident rate depends on various factors, which appear only during operation hours and are enforced during transient regime. Fig. 3.8 shows that the generator incident rate is not a regular function of operating hours. The same is if the generator incident rate is presented as a function of startup number. It is because of the difference of generator constructions, age and operating regimes represented in statistics, the incident rate of generators, in general, can be expressed as follows:

$$\lambda_{gen} = f(t_{op}; n_s; c; y; t_t \ldots) \tag{3.2}$$

where, λ_{gen} – generator incident rate;

t_{op} – operation time per year, h/year;

n_s – number of starts per year, 1/year;

c – cooling method (direct or indirect);

y – insulation technology;

t_t – total number of hours in operation, h; and other factors.

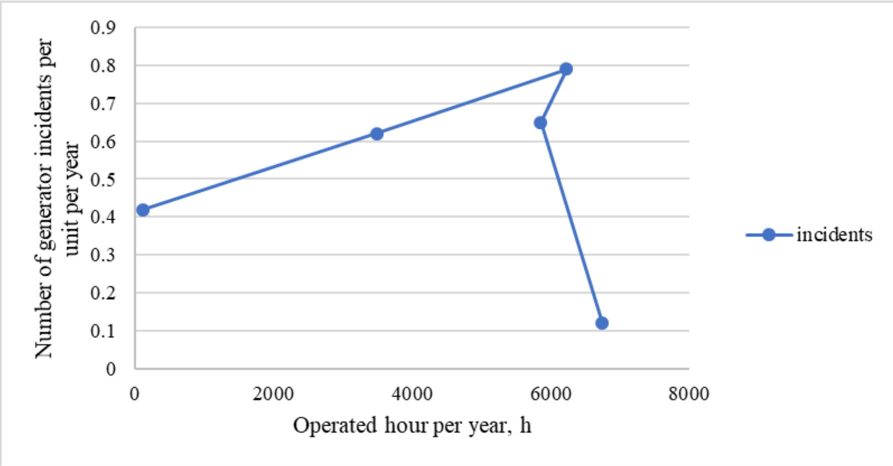

Fig. 3.8 Number of generator system incident per year per unit relation to operating hours per year.

As it is not possible to describe generator incident rate from physical model or it is too complicated to be applied in practice, the empirical model can be used to evaluate relations between different variables (startup number and operating hours) to describe incident rate probability. In this Doctoral Thesis, least square method and proposed approach are used to find out empirical formula for turbogenerator incident rate and unplanned unavailability time [80]. Using least square method incident rate would be expressed as:

$$\lambda_{gen.l} = \beta_0 + \beta_1 t_{op} + \beta_2 n_s \tag{3.3}$$

where, $\lambda_{gen.l}$ – incident rate calculated by least square method;

β – unknown parameters of empirical model.

In the proposed approach for generators, it is suggested to get rid of the number of operating hours or the number of starts, to get more clear dependency of failure rate on one of two proposed variables. Used statistics clearly defines average operated hours per year, but the number of startup's was evaluated from several sources of information (Table 3.2), so it is better to use operating hours as a base for further calculation. The hourly incident rate is:

$$\lambda_{gen.h} = \frac{\lambda_{gen}}{t_{op}} = f\left(\frac{n_s}{t_{op}}\right) \tag{3.4}$$

where $\lambda_{gen.h}$ – generator hourly incident rate.

Such expression also means that the number of starts must be expressed as number of starts per hour. This allow to get relation between failure rate per hour and startup's per hour which is presented in Fig. 3.9 and has a shape that could be described as a linear dependency. Due to much lower operation hours and high incident rate, comparing to other technologies, OCGT statistics differ a lot from other used data. For a better understanding Fig. 3.10 shows lower part of graph (marked by cloud) where fossil-fired and CCGT unit statistic appears [16].

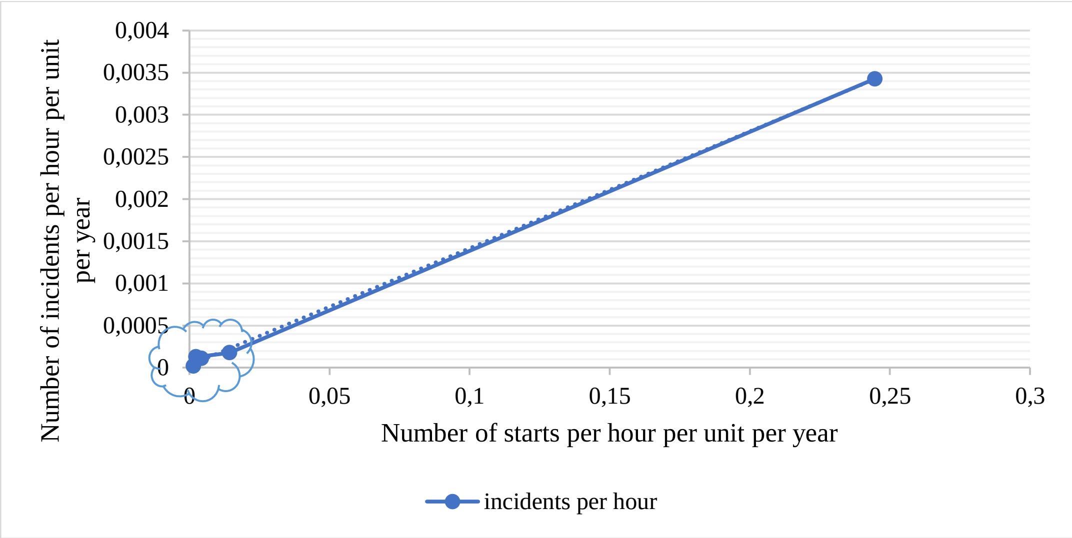

Fig. 3.9 Number of generator system incident per hour per year per unit relation to number of starts per hour per unit per year.

After excluding OCGT data, a nonlinear relation appears between the corresponding parameters and is presented in Fig. 3.10. There is a spike which appears due to the statistics of 200-600 MW generators, it may appear due to the difference of generator technology or other factors which are not time and start-up related. Excluding this data will lead to loss of information, but it also gives better options to predict the incident rate relation to the number of startup's and operated hours per year for other points on the graph. The same data exclusion is made for least square calculation. The graph with both, OCGT and 200-600 MW units, exclusions appears in Fig. 3.11 Data in this range can be calculated by logarithmic expression (3.6), for data between point of CCGT and OCGT, a linear expression can be used (3.5).

Fig. 3.10 Number of generator system incident per hour per year per unit relation to number of starts per hour per unit per year excluding OCGT data.

$$\lambda_{gen.h.u} = 0{,}0141 n_{s.h} - 0{,}00002 \tag{3.5}$$

where, $\lambda_{gen.h.u}$ – generator incident rate per hour per unit per year for the upper part of Fig. 3.9 graph;

$n_{s.h}$ – number of starts per hour per unit per year.

$$\lambda_{gen.h.log} = 0{,}00007\ln(n_{s.h}) + 0{,}0005 \tag{3.6}$$

where, $\lambda_{gen.h.log}$ – generator incident rate per hour per unit per year for Fig. 3.11 graph;

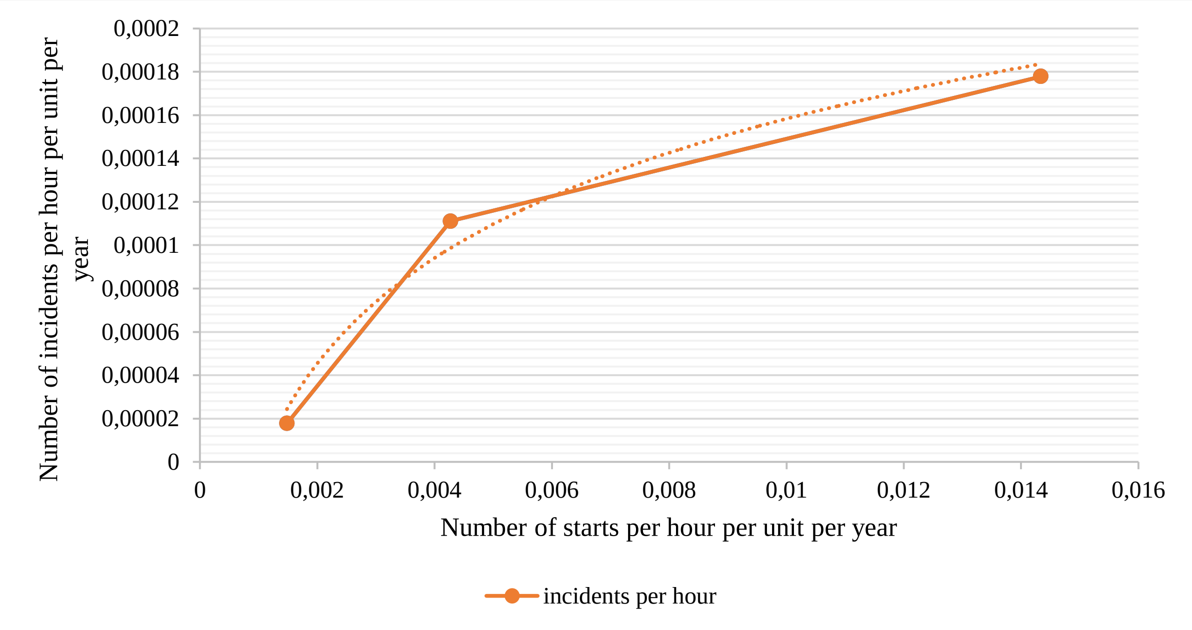

Fig. 3.11 the number of generator system incident per hour per year per unit relation to number of starts per hour per unit per year excluding OCGT and 200-600MW generator data.

Obtained (3.6) expression does not stick with the existing points of the graph, which results in a very high error coefficient, especially if a prediction of a incident rate is made for regimes with similar number of starts per hour per unit per year as presented in statistics. To avoid such situations, all data presented inFig. 3.11 are divided into parts that are expressed as linear functions and presented in Table 3.5. For incident estimation per hour per unit per year Table 3.5 must be used.

Table 3.5

Equations for Incident Rate Estimation for Generators

Number of starts per hour per unit per year	$\lambda_{gen.h}$ estimation equation	Equation number
0.000741 to 0.004272	0.0264*$n_{s.h}$ - 0.000002	1
0.004272 to 0.014341	0.0066* $n_{s.h}$ + 0.00008	2
0.014341 to 0.570776	0.0058* $n_{s.h}$ + 0.00009	3

After hourly generator incident rate is calculated for prognosed regime (3.7), it should be multiplied by forecasted operation hours per year, this will lead to generator incidents per unit per year. The calculation is made using (3.8) and equation from Table 3.5. The example result is provided in Table 3.6. It is clear, that the number of star-ups affects incident rate immensely, operating hours have much lower impact on incident rate, at low start-up number increase of operating hour results in a slight decrease of the generator incident rate. Thus, at a moderate or a high number of starts, the increase of operating hours will definitely lead to a higher incident rate of a generator.

$$\lambda_{gen.h.3} = 0{,}0058\frac{n_s}{t_{op}} - 0{,}00009 \tag{3.7}$$

where, $\lambda_{gen.h.3}$ – generator incident rate per hour per unit per year calculated by equation number 3 from Table 3.5.

$$\lambda_{gen} = \lambda_{gen.h}t_{op} \tag{3.8}$$

where, $\lambda_{gen.h}$ – generator incident rate per hour per unit per year calculated by equation from Table 3.5.

Table 3.6

Generator Incident Estimation

Prognosed operating hours per year	Prognosed starts per year	Starts per hour	Equation number	Incidents per hour	Incidents per year
2000	10	0.005	2	0.000113	0.226
2000	30	0.015	3	0.000177	0.354
2000	100	0.05	3	0.00038	0.76
3000	10	0.0033333	1	0.000086	0.258
3000	30	0.01	2	0.000146	0.438
3000	100	0.0333333	3	0.0002833	0.85
4000	10	0.0025	1	0.000064	0.256
4000	30	0.0075	2	0.0001295	0.518
4000	100	0.025	3	0.000235	0.94

In case if least square method is used expression below will be obtained:

$$\lambda_{gen.l} = -1.92807 + 0.00029t_{op} + 0.03266n_s \tag{3.9}$$

It is obvious that least square method allows to get empirical relation in much shorter time, also usage of one common formula instead of three different formulas for different occasions is much more practical. Thus, comparison of obtained results simulating different operating regimes and using proposed approach formulas from Table 3.5 and least square method (3.9) show, that, obtained incident rate for other operating regimes than used for empirical formula estimation differs a lot.

At Fig. 3.12 is presented calculated generator incident rate based on operating hours and number of startup's compared to operating hours. Both, proposed approach and least square method, fits good to real points used for calculations, but when expression obtained by least square method is applied to simulated points (not same as in Table 3.6) it gives negative results, which is not acceptable. Further in Doctoral Thesis are presented results obtained by the proposed approach of generator incident rate estimation.

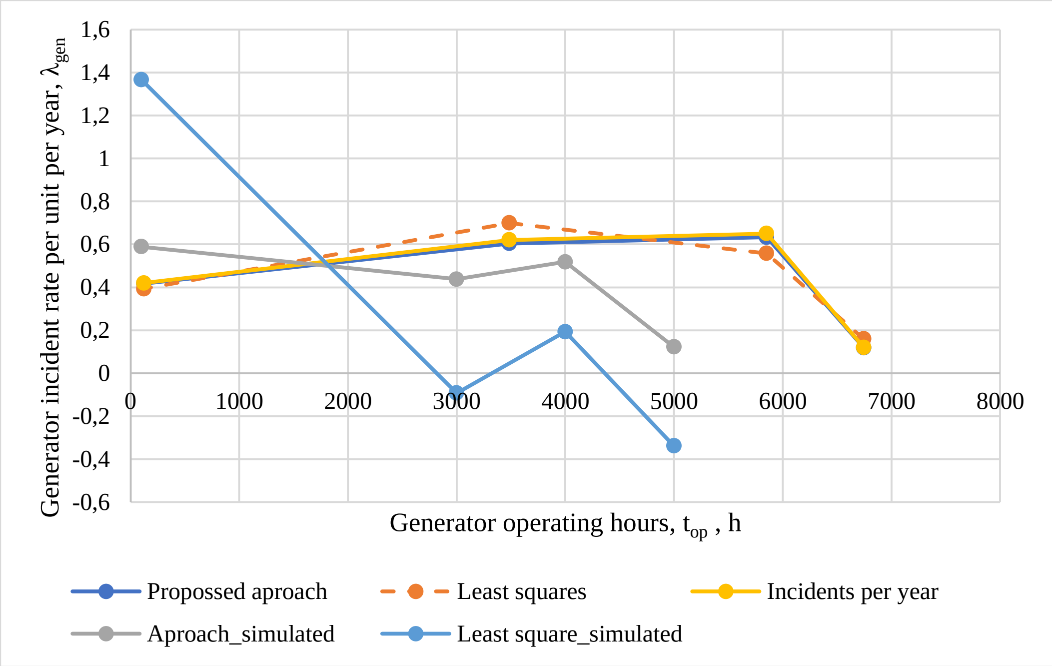

Fig. 3.12 Comparison of prosed approach results and least square results for generator incident rate estimation.

The power transformer failure rate is taken from Table 3.3, in order to calculate the number of failures per power plant unit per year. The number of step-up power transformers in one power plant unit must be observed as well as the transformer highest rated operating voltage. For circuit breakers, data from Table 3.4 will be used. To evaluate circuit breaker failure rate per unit per year a number and type of circuit breakers must be observed. Total power plant unit main electrical equipment incident rate is calculated as follows:

$$\lambda_{el.t} = \lambda_{gen} + \lambda_t + \lambda_{cb} = \lambda_{gen.h} t_{op} + \sum_1^{n_{t.v}} \lambda_{t.v} + n_s * \sum_1^{n_{cb}} \lambda_{cb.o} \qquad (3.10)$$

where, $\lambda_{el.t}$ – main electrical equipment total incident rate per unit (block) per year;

λ_{gen} – generator incident rate per unit (block) per year calculated by (3.8);

λ_t – step-up power transformer failure rate per unit (equipment) per year;

λ_{cb} – generator circuit breaker failure rate per unit (equipment) per year;

$n_{t.v}$ – total step-up transformer amount per power plant unit per voltage level;

$\lambda_{t.v}$ – step-up transformers failure rate according to voltage level of step-up transformer (Table 3.3);

n_{cb} – total generator circuit breaker amount per power plant unit;

$\lambda_{cb.o}$ – generator circuit breaker failure rate according to circuit breaker technology (Table 3.4).

Total main electrical system incident rate calculation results are shown in Table 3.7, for CCGT in Baltic states it is common to use 110 kV and 330 kV step-up transformers for one power plant unit, for circuit breaker SF6 with hydro-mechanical spring operating mechanism technology was chosen.

Table 3.7

Power Plant Unit Main Electrical Equipment Failure Estimation

Prognosed operating hours per year	Prognosed starts per year	λ_{gen}	$\lambda_{t.110}$	$\lambda_{t.330}$	λ_{cb}	$\lambda_{el.t}$
2000	10	0.226	0.0059	0.0132	0.000048	0.245105
2000	30	0.354	0.0059	0.0132	0.000144	0.373105
2000	100	0.76	0.0059	0.0132	0.00048	0.779105
3000	10	0.258	0.0059	0.0132	0.000048	0.277105
3000	30	0.438	0.0059	0.0132	0.000144	0.457105
3000	100	0.85	0.0059	0.0132	0.00048	0.869105
4000	10	0.256	0.0059	0.0132	0.000048	0.275105
4000	30	0.518	0.0059	0.0132	0.000144	0.537105
4000	100	0.94	0.0059	0.0132	0.00048	0.959105

The impact of circuit breaker failure on conventional power plant incident rate is very low, also the cost of circuit breaker overhaul or replacement is lower than for step-up transformers or generators, so this part may not be discussed in risk assessment. Step-up transformer caused power plant unit unavailability percentage is reported in a wide range even for VGB power plants, its value varies in 0.02-0.12% range of total hours per year. For generators, unavailability indicator lies in 0.12-1.42% range of total hour per year. For circuit breaker such statistics is not present, also incident rate is very low, that is why circuit breaker incident caused unavailability is not further discussed. For generator unavailability percentage estimation, the same approach is used that was used for generator incident rate estimation.

$$k_{un.h} = \frac{k_{un}}{t_{op}} = f\left(\frac{n_s}{t_{op}}\right) \tag{3.11}$$

where, $k_{un.h}$ – hourly energy unavailability percent per unit (block) per year caused by generator, %.

Obtained equations are presented in Table 3.8, equation (3.8) must be used to get from hourly unavailability percentage to yearly. The next step is calculation of unavailable or unproduced energy due to estimated failure rate, which is done using (3.14). The loss of a generator, a transformer or a circuit breaker leads to the loss of full power, so outage hours caused by incidents in the main electrical system of power plant can be calculated, the data is represented in Table 3.9. Unavailability hours are quite low, which means that failures of winding or other main parts of equipment leading to overhaul are quite rare.

Table 3.8

Equations for Unavailability Estimation for Generators

Number of starts per hour per unit per year	Unavailability % estimation equation	Equation number
0.000741 to 0.004272	0,0148* $n_{s.h}$ + 0.000007	1
0.004272 to 0.014341	0.0133* $n_{s.h}$ + 0.00001	2
0.014341 to 0.570776	0.0204* $n_{s.h}$ - 0.00009	3

Same as previously for generator incident rate expression obtained by least square method was calculated:

$$k_{un.l} = 1.35428 - 0.00018t_{op} + 0.00093n_s \qquad (3.12)$$

where $k_{un.l}$ – generator caused energy unavailability percent per unit per year calculated by least square method, %.

Unavailability percentage is much more linear dependent on operating hours than generator incident rate. It is also proven by (3.12), part of equation related with number of starts will be very low. The proposed approach expression from Table 3.8 and (3.12) were compared to statistical data, also calculation for simulated operating hours and number of startups was made. From Fig. 3.13 is clear that even with statistic data (3.12) gave very linear relation, which resulted in high difference for simulated results between the proposed approach and (3.12). To avoid this, point that represented OCGT unavailability rate was excluded and obtained least square equation presented in (3.13) and in Fig. 3.13 designated as "Least_square_simulated_v2". (3.13) unlikely the (3.9) could be used in practice to evaluate generator unavailability percentage. In Doctoral Thesis equations from Table 3.8 are used for further calculations.

$$k_{un.l\_v2} = -0.30140 + 0.00005t_{op} + 0.01674n_s \qquad (3.13)$$

where $k_{un.l\_v2}$ – generator caused energy unavailability percent per unit per year calculated by least square method from data without OCGT power plants statistic, %.

$$W_{un.e} = k_{un.e} P_N t_y \qquad (3.14)$$

where, $W_{un.e}$ – estimated unavailable energy per unit per year due to generator incidents, MWh;

$k_{un.e}$ – estimated incident caused energy unavailability percent, %;

P_N – power plant unit nominal power, MW;

t_y – hours per year, h. [16]

Literature analysis shows that the number of major incidents, leading to generator or power transformer overhaul, is negligible, thus when such incidents appear, costs and unavailability time of power plant unit become extremely significant. For further development of the proposed estimation methodology, a better statistic of generator incident rate and caused unavailability time as well as step-up transformer incident caused unavailability time should be collected. It also would allow CHP operators to make better specifications for future power plant equipment.

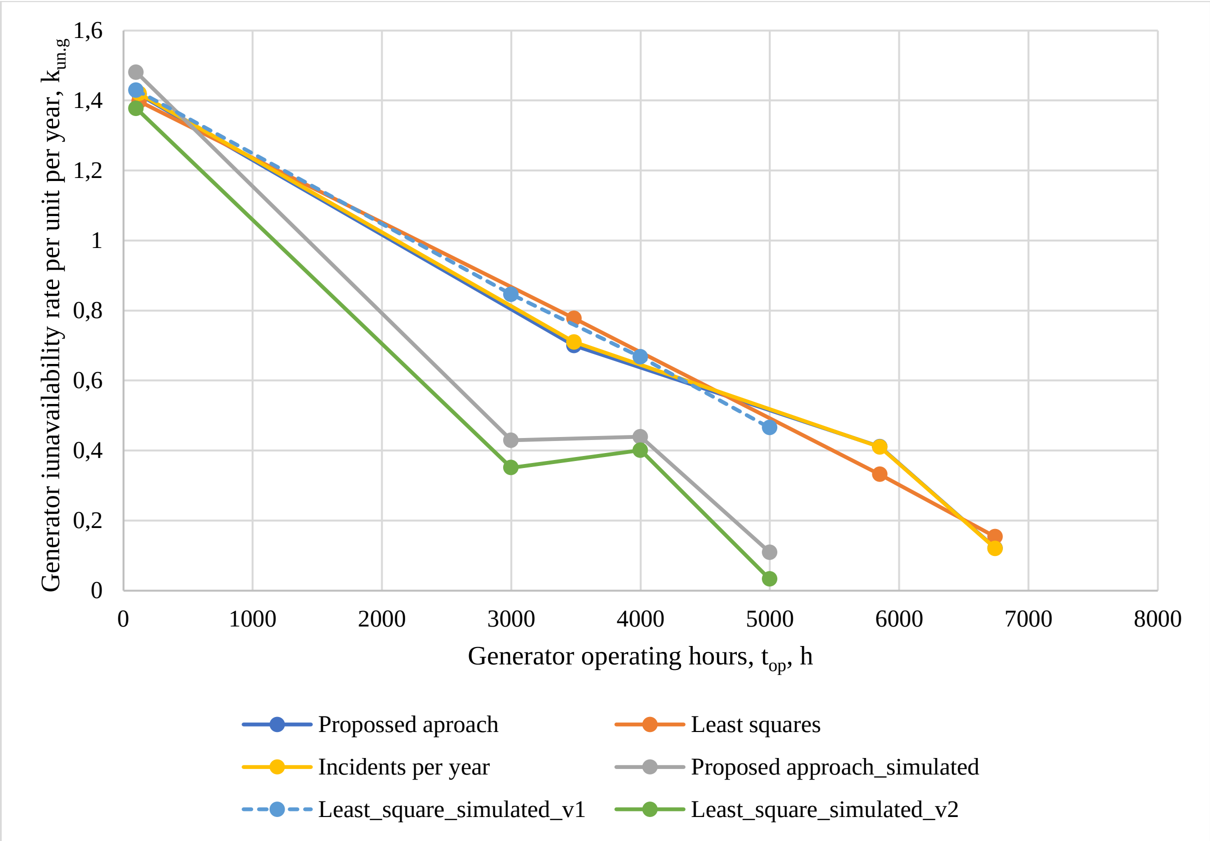

Fig. 3.13 Comparison of prosed approach results and least square results for generator unavailability estimation

Table 3.9

Power Plant Unit Main Electrical Equipment Unavailability Estimation

Prognosed operating hours per year	Prognosed starts per year	λel.t	$k_{un.g}$ generator, %	$k_{un.t}$ transformers, %	k_{un} total, %	t_{un}, unavailability hours, h
2000	10	0.245105	0.153	0.12	0.273	23.9148
2000	30	0.373105	0.432	0.12	0.552	48.3552
2000	100	0.779105	1.86	0.12	1.98	173.448
3000	10	0.277105	0.169	0.12	0.289	25.3164
3000	30	0.457105	0.429	0.12	0.549	48.0924
3000	100	0.869105	1.77	0.12	1.89	165.564
4000	10	0.275105	0.176	0.12	0.296	25.9296
4000	30	0.537105	0.439	0.12	0.559	48.9684
4000	100	0.959105	1.68	0.12	1.8	157.68

Equipment failure rate and its causers are best known for equipment producers, who tend to overcome big issues, thus some less significant issues remain, because of manufacturing technology or used additional equipment. Customers usually do not know all the details and risks when specifying equipment requirements. Despite the sensitivity of the information, customers should share more precise information about equipment incidents and failures.

Such sharing could be made on an anonymous platform, at the same time the control for data severity must be on a very high level.

For generators it is proposed to collect such data as operating hours per year, starts per year, stator insulation technology, rotor insulation technology, cooling method (direct/indirect), coolant type (air/ hydrogen/ water), rated power, average cosφ per year, rated voltage, average full load reach time per year (usual ramping rate of generator driving turbines), minor incidents mentioning system where appeared incident (outage time <24h), moderate incidents mentioning system where appeared incident (outage time >24h) and failures mentioning system where the failure appeared (all incidents leading to a generator overhaul or full replacement of a generator system element like excitation system, cooler and so on).

For power transformers CIGRE surveys provide qualitative information, but still, improvements for power plant transformer are needed. For step-up transformer, the following data must be reported: years in operation, a number of unit start-ups per year and operation hours at load (mostly are the same as for generator), rated power and voltage, cooling method, presence or absence of OLTC, bushing type (in all voltage levels) grounding mode, minor incidents mentioning system where the incident appeared (outage time <24h), moderate incidents mentioning system where appeared incident (outage time >24h) and failures mentioning system where appeared failure (all incidents leading to a power transformer overhaul or full replacement of a transformer element like bushings, OLTC, cooler and so on).

3.5. Incident and Unavailability Caused Costs

Incidents of electrical equipment and caused unavailability lead to economical loss for CCGT and impacts total operation costs. Costs of unplanned unavailability could be divided into two groups, first - additional maintenance and repair costs; second – loss of income due to incident. Previously was concluded that impact of main circuit breakers incidents is negligible and this parameter is not used in further calculation. Unavailability costs are expressed as follows:

$$C_{un} = \lambda_{gen}(C_{mr.gen}) + \lambda_{t.110}C_{mr.t110} + \lambda_{t.330}C_{mr.t330} + t_{un}P_N C_{bal} + \lambda_{el}C_s + t_{un}C_{ser} \tag{3.15}$$

where, C_{un} – unavailability costs, EUR;

$C_{mr\cdot gen}$ – maintenance and repair costs per one generator incident, EUR;

$C_{mr\cdot t}$ – maintenance and repair costs per power transformer failure, EUR;

t_{un} – unplanned unavailability hours per year, h;

C_{bal} – balancing costs, EUR/MWh;

C_s – power plant unit start-up costs, EUR;

C_{ser} – costs of loss due to undelivered ancillary services, EUR/h.

Mentioned costs can vary in wide range due to region, type of power plant, legislation and other factors. Any of mentioned costs are not often reported, because it is sensitive information for generating facilities as well as for manufacturers of generators and power transformers. In [55] generators incident costs were reported as high as 140 794 EUR. As power transformer statistics were provided for significant failures, the costs of failure are assumed as replacement costs of power transformer, costs of step-up power transformers are 15 000 EUR/ MVA [122]. So costs of power transformer failure should be calculated as follows:

$$C_{mr.t110} = S_{t.110} C_{t.110} \tag{3.16}$$

where, $S_{t.110}$ – 110 kV power transformer rated power, MVA;

$C_{.110}$ – costs of 110 kV step-up power transformer, EUR/MVA.

According to [35] average balancing price for upwards activation in Latvia in 2018 was 59.27 EUR/MWh. Basing on data from [56] incidents can lead to warm start of CCGT, for 400 MW CCGT it will result in startup costs of approximately 32 040 EUR. Using equations from Table 3.7 and Table 3.9 calculation of incident caused costs for 400 MW CCGT block with 180 MVA 110 kV power transformer and 330 MVA 330 kV power transformer were made and provided in Table 3.10. Costs of unplanned unavailability time takes most share of incident and unavailability total costs.

Table 3.10

Incident and Unavailability Overall Costs

Prognosed operating hours per year	Prognosed starts per year	λ_{gen}	$\lambda_{t.110}$	$\lambda_{t.330}$	$\lambda_{el.t}$	t_{un}, h	C_{un}, total costs per year, EUR	C_{un}, total costs per 10 years, EUR
2000	10	0.226	0.0059	0.0132	0.2451	23.9148	762 240	7 622 408
2000	30	0.354	0.0059	0.0132	0.3731	48.3552	1 402 754	14 027 549
2000	100	0.76	0.0059	0.0132	0.7791	173.448	4 562 196	45 621 966
3000	10	0.258	0.0059	0.0132	0.2771	25.3164	810 740	8 107 402
3000	30	0.438	0.0059	0.0132	0.4571	48.0924	1 436 608	14 366 089
3000	100	0.85	0.0059	0.0132	0.8691	165.564	4 418 230	44 182 304
4000	10	0.256	0.0059	0.0132	0.2751	25.9296	824 323	8 243 236
4000	30	0.518	0.0059	0.0132	0.5371	48.9684	1 495 552	14 955 528
4000	100	0.94	0.0059	0.0132	0.9591	157.68	4 274 264	42 742 641

To prevent or minimize the number of incidents in power plant generators and step-up transformers, as well as to predict and control the degradation of insulation and other elements, numerous methods are used. Generally, they can be divided into online and offline monitoring.

Generator insulation monitoring methods such as insulation resistance and polarization index can show insulation problems, thus it is mainly a pass/fail-type test that cannot be relied on to predict the condition of the insulation winding, except when the insulation has already failed [67]. Baroscopic inspection during power plant maintenance can allow to see such defects as failure of corona protection or toughness loss of end winding fastenings. Online monitoring of partial discharge can give a better look at insulation condition and changes. Thus, interpretation of such data is not easy due the huge discrepancy between laboratory gained picture and online results [81]. For failure mode detection in rotor quite effective is the vibration monitoring. But this data has to be analyzed not only as a total amplitude value but must also be present as a vibration specter with amplitudes by frequencies; also, the phase of vibration has to be considered. Usually, online vibration detectors and their software do not allow to make all mentioned measurements, so portable devices should be used. Measurements in different rotation speed and excitation regimes allow to detect the problem more precisely [82].

One of the best methods for power transformers condition control for many years has been dissolved gas analysis (DGA) [29]. During past years, many online DGA became available, prices vary from several thousand for gas and moisture control up to 50 000 EUR for systems with reference gases which actually perform DGA comparable to a laboratory test. Online monitoring of bushing becomes more and more popular, such systems cost about 25 000-35 000 EUR per one transformer and provide capacitance and dissipation factor (tg δ) measurements. Also, additional offline tests such as dielectric frequency response test can be performed for better acknowledgment of bushing conditions [77]. For OLTC, if such is present, an offline test can be used such as dynamic resistance measurement (DRM), which allows to see the change of resistance during tap change. Online measurements of OLTC are using vibration and arcing measurements to detect the defects [72].

Concluding the above mentioned, online monitoring methods must be used to analyze generators state, offline measurements also should take place. Because of periodical power plant inspection, there always is a possibility to make electrical equipment measurements. Power transformer offline measurements are good enough to detect problems. Use of additional monitoring can allow to avoid some incidents and caused costs.

3.6. Summary

To make the approach of failure rate and unavailability evaluation, numerous statistics were analyzed. Available statistics for generator system represent only incidents and caused unavailability data, thus do not provide data on major failures. For power transformers, more failure data is available, but there is almost no statistics for caused outage. Generator circuit breaker failure markers are so low, that caused unavailability was not considered.

Two approaches were used to obtained equations for generator incident rate and caused unavailability, which considers the number of operating hours per year and number of start-up per year for CCGT power plant. One approach is the use of least square method, thus, expression for generator incident rate had some errors when used for fictious operating hours and number of startup's indicating negative incident rate in some cases. For that reason, it is not recommended to use expression (3.9) obtained by least square method for generator incident rate estimation. Least square method was good for generator unavailability empirical expression, but some data exclusion was made, still (3.13) is valid for generator unavailability estimation depending on number of operated hours and startup's.

Due to lack of statistical information, a new approach was proposed. As only two variables – operating hours and number of startup's are used for generator incident rate expression in this work, it is proposed to expres generator incident rate and unavailability as function of number of startup's per hour. Due to generator incident rate irregularity and low number of available statistical points it is proposed to divide overall function into three parts each representing incident rate as linear functions of number of startup's per hour, which are presented in Table 3.5. Same approach was also applied for generator unavailability empirical expressions, presented in Table 3.8. Empirical expressions obtained by new approach were used to evaluate caused costs of incidents and unavailability of power plant main electrical equipment and are presented in Table 3.10.

Calculations of observed operating mods by proposed new approach show that the increase of number of startup's leads to the increase of incident rate and unavailability percentage. In some cases, the increase of operating hours at same startup level can lead even to lower incident rate and unavailability percentage. Proposed approach is based on available statistical data and should help in risk assessment. As a result, the best investment strategy (improved monitoring or upgrades) must be chosen based on the foreseen CCGT operation regimes.

4. NEW REQUIREMENTS FOR GENERATORS

Development of electric grid, renewable energy source wider usage as well as new interconnections lead to changes in existing electricity markets. Energy systems become more vulnerable and grid stability is challenged. In [5] are discussed reasons and consequences of changes in modern energetics, also for Latvia such researches were made and presented in [37], [115], [116].

European commission supports ENTSO-E actions in development of technical requirements for grid connected users to ensure greater security of electrical systems [84]. For existing generators compliance to some of new requirements might be problematic, especially for those which operates for longer time or did not operate in European power networks. Basing on information provide in [136] can be concluded that Baltic state reconnection to CEN will lead to a necessity to ensure higher generator security level to provide grid stability.

In this work are discussed possible challenges for mentioned generators, provided expressions for necessary calculations, as well as provided list of possible modernizations to meet new requirements.

4.1. Grid Code for Generator Connection

In section 2.3 European Commission Regulation 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators (RfG) was briefly discussed. For many European countries, connected to Continental European network (CEN) most of requirements were familiar. For Baltic states, which at present are connected to Belorussia, Russia, Estonia, Latvia, Lithuania power grid (BRELL) many of them were new. Baltic states were not obliged to provide frequency control in BRELL, voltage regulation was provided mostly by transmission system operator (TSO), for each new power plant were specified individual technical rules from TSO, that is why some existing generators are not fulfilling RfG requirements [9], [36].

In RfG stated that existing power plants not obligated to fulfill any of requirements, thus, reconnection from BRELL to CEN in 2025 will change things a lot. All Baltic states will be connected to CEN grid only by one two chain AC line of total capacity of 1000 MW and 700 MW DC link (the connection between Lithuania and Poland), which is much lower capacity than existing AC connections to BRELL. Also in operation will be DC links between Estonia and Finland as well as Lithuania and Sweden, with total capacity of 1700 MW. Average energy consumption of Baltic state is about 4 000 MW, and electricity price statistics show that all mentioned lines will operate to provide electricity to Baltic states, which means that local generation will be low, all this results in need to fulfill RfG even for existing power plants, maybe, with some exceptions. Of course, cost benefit analysis should be performed prior to demand generators to fulfill RfG requirements [9], [35].

Latvian TSO requirements developed according to RfG further in work are designated as "rules". Generators should be able to operate at frequency 49 – 51 Hz without any constrains, which also complies with IEC 60034 Rotating electrical machines requirements, which states that generators should be able to operate at 50 Hz ± 2% or 1Hz. Also, rules require to stay connected for unlimited time at 48,5 – 49 Hz and for 30 minutes at 47,5 – 48,5 Hz, as well as 30 minutes at 51 – 51,5 Hz. Below 49 Hz reduction of active power is allowed, but not more than 2% per 1 Hz. IEC 60034 foresees generator capability to operate at 47.5 - 49 Hz, but it is stated that greater deviations from nominal can appear. Same is for operation rage 51-51.5 Hz. At the same time IEC standard states, that operation in 47.5 - 49 Hz and 51-51.5 Hz range should be limited [35].

Regarding the limited frequency sensitive mode — overfrequency (LFSM-O) state, generator should react at 50.2 Hz with droop of 5%. Regarding to limited frequency sensitive mode — underfrequency (LFSM-U) state, generator should react at 49,8 Hz with droop of 5%. In both cases generators should be able to set any droop in range of 2-12%. For most generators and turbines there is no problems to fulfil such requirements, modern control logic could be easily set-up for desired value. Time of reaction for synchronous generators in case of overfrequency should be less than 8 seconds, and 30 seconds to fully activate frequency relevant load. In case of underfrequency time of reaction for synchronous generators should be below 300 seconds, and 360 seconds to fully activate frequency relevant load. Which also is not a problem for gas turbine generators and also is enough for steam turbines [9], [35].

Admissible active power reduction from maximum output with falling frequency in its control area as a rate of reduction falling within the boundaries reduction rate below 49 Hz should be 2% per 1 Hz of drop. According to generator technical documentation at range 49 – 50 Hz no change in maximum active power output should appear. For generators produced in accordance with IEC 60034 there are no problems. Thus reduction below 49 Hz usually is not specified but can be calculated using expression below. If a generator is capable to operate with rated power at 49Hz, then at 48 Hz active power will reduce by 2% which fulfills RfG [9], [35].

$$P = M2\pi f \tag{4.1}$$

where P – active power;

M – torque;

f – frequency.

The power-generating module shall be capable of providing active power frequency response in accordance with the specified parameters, active power range related to maximum capacity should be 10%, frequency response insensitivity 10 mHz, frequency response deadband in range 0 – 500 mHz. This also is acceptable for existing CCGT generators [9, 35].

In the event of a frequency step change, the power-generating module shall be capable of activating full active power frequency response, at or above the full line shown in Fig. 4.1, thus Latvian requirements ask to stick exactly to the full line. This is a problem for CCGT, because at different power levels and external conditions it might not go exactly by the line. BRELL rules has almost same requirement for power plants contributing in primary frequency control, it obliges to reach half of active power frequency response in 15 seconds and full activation within 30 seconds, which is more applicable for CCGT [9], [35], [36].

According to rules, 8% of the nominal power of the generating module should be activated according to full line in Fig. 4.1. Generating module under the scope of RfG is whole CCGT block, not each turbine, so gas turbine should be capable to increase/reduce output by 8% of total module power in 30 seconds, due to steam turbine low reaction time. To activate 8% of nominal power within 30 seconds and with reaction time 2 seconds is not a problem for heavy duty type gas turbines, thus for industrial type turbines connected to the grid this might be a problem, some power plants use such turbines. Also, rules demands to maintain fully activated frequency response active power for at least 30 minutes, which might be challenging for fully cogeneration power plants, which are not able to operate in condensation mode [35].

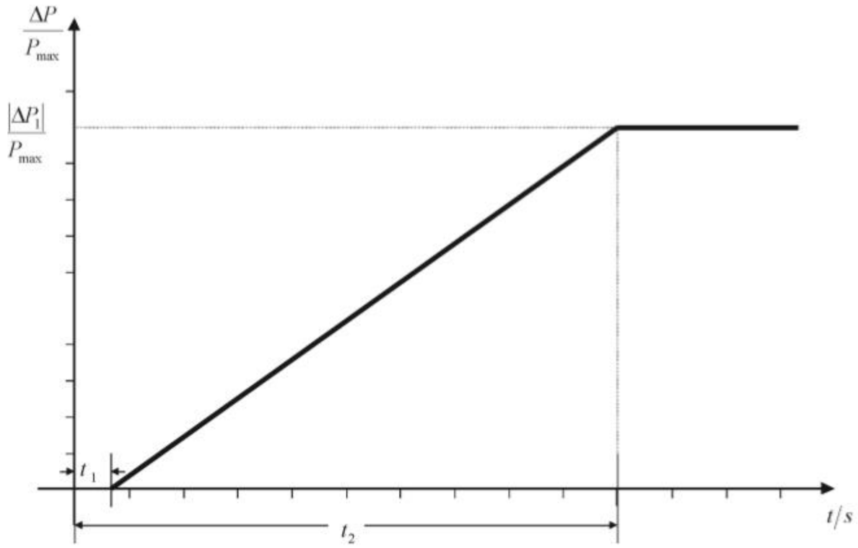

Fig. 4.1 Active power frequency response capability [35].

All CCGT should be capable to reach TSO active power task with a minimum 8% of nominal module active power per minute in range of module active power output 60 – 90% of nominal active power. It might be a problem for industrial type turbines used in existing power plants [9], [35].

Type D generators according RfG, which in Latvia are specified from 15MW rated power or all power generators connected to 110 kV or higher voltage grid, should fulfil voltage requirements shown in Table 4.1 at the connection point to the grid. Existing grid code defined normal operating voltage in range 100 – 123 kV for 110 kV grid and 300 – 362 kV range in 330 kV grid. New rules demand generators connected to 110 kV grid to stay connected at 93,5 – 99 kV for 30 minutes and at 122,98 – 126,5 kV for 20 minutes. Generators connected to 330 kV grid should be capable to operate at voltage range 290,4 – 297 kV and 362 – 379.5 kV for 20 minutes. Power-generating modules shall be capable of remaining connected to the network and operating without power reduction, as long as voltage and frequency remain within the specified limits pursuant to RfG. Exception is active power reduction at falling frequency below 49 Hz, but it should be in accordance with rules. Also, active power can be reduced due to technical and ambient limitations to synchronous generators. This requirement might be a problem in case of voltage oscillations. Especially during undervoltage, because current should be raised to maintain same power, which might be a problem for generators and transformers installed in existing power plants. Overvoltage could cause problems for generator excitation system and also it will stress equipment insulation [9], [35], [79].

Table 4.1

Voltage Requirements for Generators at the Connection Point to the Grid

Region	Voltage range	Time period of operation
Baltic 110kV grid	0,85 pu-0,90 pu	30 minutes
	0,90 pu-1,118 pu	Unlimited
	1,118 pu-1,15 pu	20 minutes
Baltic 330 kV grid	0,88 pu-0,90 pu	20 minutes
	0,90 pu-1,097 pu	Unlimited
	1,097 pu-1,15 pu	20 minutes

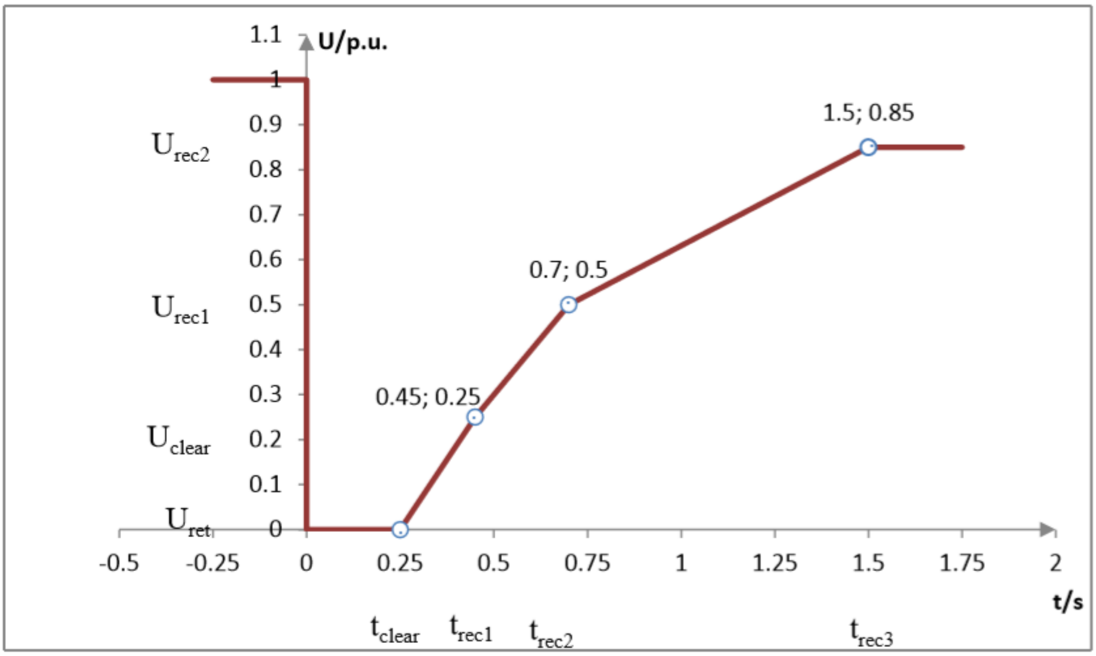

Fig. 4.2 Fault-ride-through profile of a power-generating module [35].

Uret - retained voltage at the connection point during a fault, tclear - instant when the fault has been cleared. Urec1, Urec2, trec1, trec2 and trec3 - specify certain points of lower limits of voltage recovery after fault clearance.

Fault ride through capability of type D generators also are defined in rules and represented at Fig. 4.2. Voltage requirements are stated for the connection point to the grid, excitation system usually has forcing regime, which allows to withstand such faults, but relay protection should be managed properly [9], [35].

One more technical requirement is U-Q/P_{max} profile - the reactive power provision capability requirements in the context of varying voltage. For that purpose, the relevant system operator specifies U-Q/Pmax-profile within the boundaries of which the synchronous power-generating module shall be capable of providing reactive power at its maximum active power. U-Q/Pmax-profile for Latvia is present in Fig. 4.3. This graph states tough requirements for existing generators, because nothing like this was required in the past, and some parameters were not considered during specification of generators. RfG allowed TSO to demand any shape of this profile, Latvian TSO used a rectangle. It is even more harder to fulfil because of the requirement to maintain active power at the same level during any voltage and frequency oscillations mentioned in rules [9], [35].

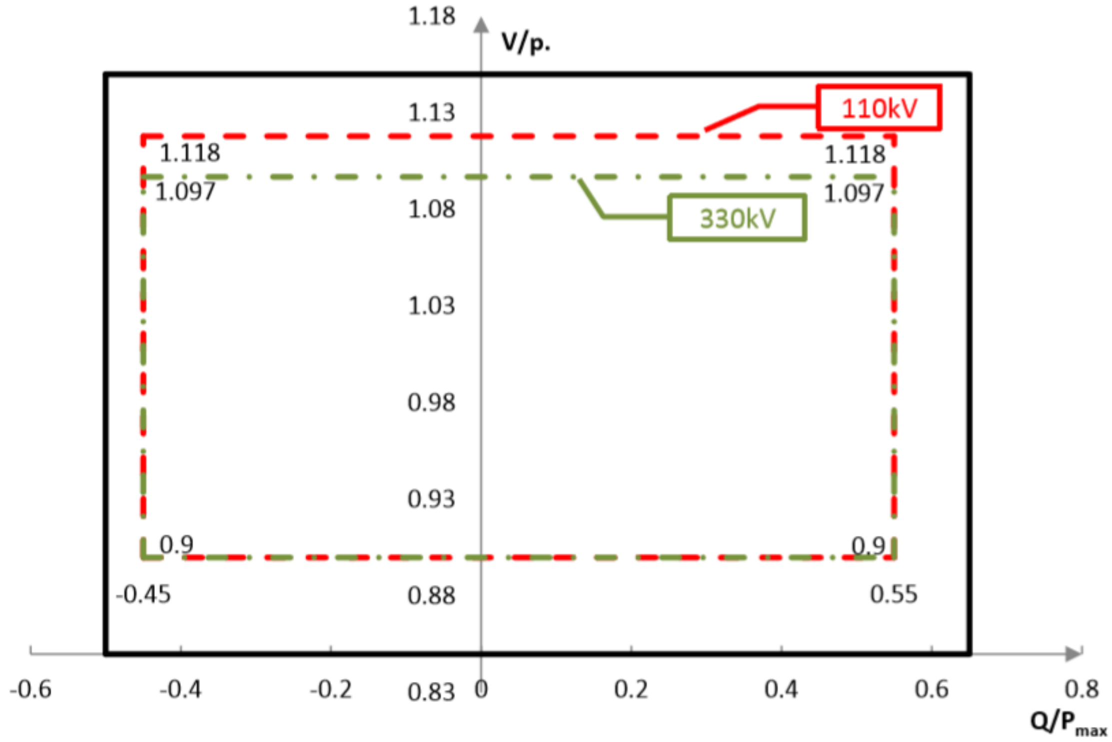

Fig. 4.3 U-Q/Pmax-profile of a synchronous power-generating module [35].

For existing CCGT plants two main concerns appear from new rules. First is load ramping speed for small industrial type turbines. This problem more address to gas and steam cycle of CCGT. Main gas turbine producers propose solutions and upgrades for existing turbines, which can greatly increase gas turbine power, efficiency and loading speed, thus heat recovery steam generator limitations should be considered. It is main reason why such upgrades do not fit all plants. Second issue is voltage ranges and reactive power provision, which is electrical problem. Many of generators also were not suggested to provide grid services, and even no requirements from TSO on operating power factor were set for them.

This leads to impropriate power matching for turbine and generator, which results in bad capabilities for reactive power production/consumption at full load [79], [85], [86].

4.2. Technical Challenges for Voltage Range and Reactive Power Capabilities

Voltage defined by RfG and presented in Table 4.1 are mentioned for the connection point. For biggest CCGTs in Latvia there are two connection voltages 110 kV and 330 kV. The grid connection point is on higher voltage side of step up transformer. It means some voltage drop will appear between the generator and transmission grid. Voltage at the connection point will be calculated as:

$$U_s = \sqrt{\left[U_g + \frac{P_g r_1 + Q_g x_1}{U_g}\right]^2 + \left[\frac{P_g r_1 - Q_g x_1}{U_g}\right]^2} \qquad (4.2)$$

where U_g – generator actual voltage, kV;

U_s – voltage at connection point to transmission grid reduced to generator voltage, kV;

P_g – generator actual active power, MW;

Q_g – generator actual reactive power, MVAr;

r_1 – resistance between generator and transmission grid, Ω;

x_1 – reactance between generator and transmission grid, Ω. [88]

In case if reactive power is consumed by the generator, the sign before reactive power in (4.2) should be changed to opposite.

Relation for turbo-generator with ignored armature resistance between internal generated voltage, stator current and grid voltage are presented at Fig. 4.4. As it was mentioned in section 4.1, generator should be capable to perform at rated output. This means, that power factor angle θ (more common designation is φ) between stator current (I_A) and grid voltage (V_φ) should remain constant according to (4.3) and (4.4). This leads to change of I_A and angle δ between grid voltage (V_φ) and internal generated voltage (E_A) which also is called torque angle [89].

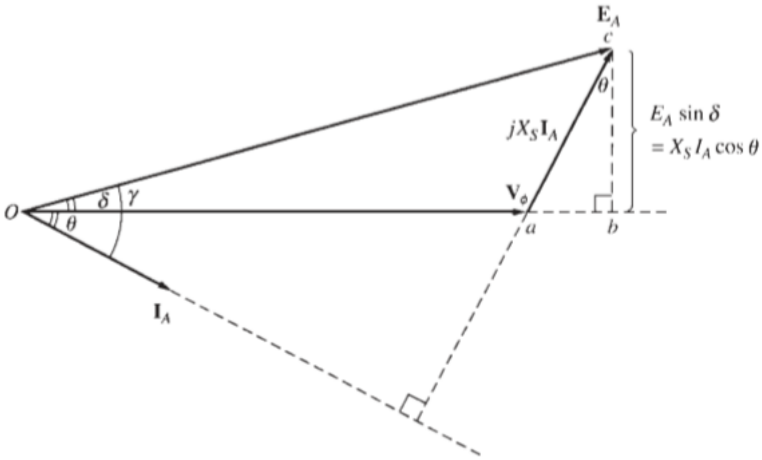

Fig. 4.4 Simplified phasor diagram with armature resistance ignored [89].

If grid voltage drops, internal generated voltage remains at same value, but torque angle becomes bigger. In case if grid voltage rise, torque angle will become smaller and internal generated voltage will grow insignificantly. For example, for generator with nominal power factor 0.8, 20% rise of grid voltage will lead to only 3.5% change of internal generated voltage. Relation between different states of grid voltage is presented at Fig. 4.5.

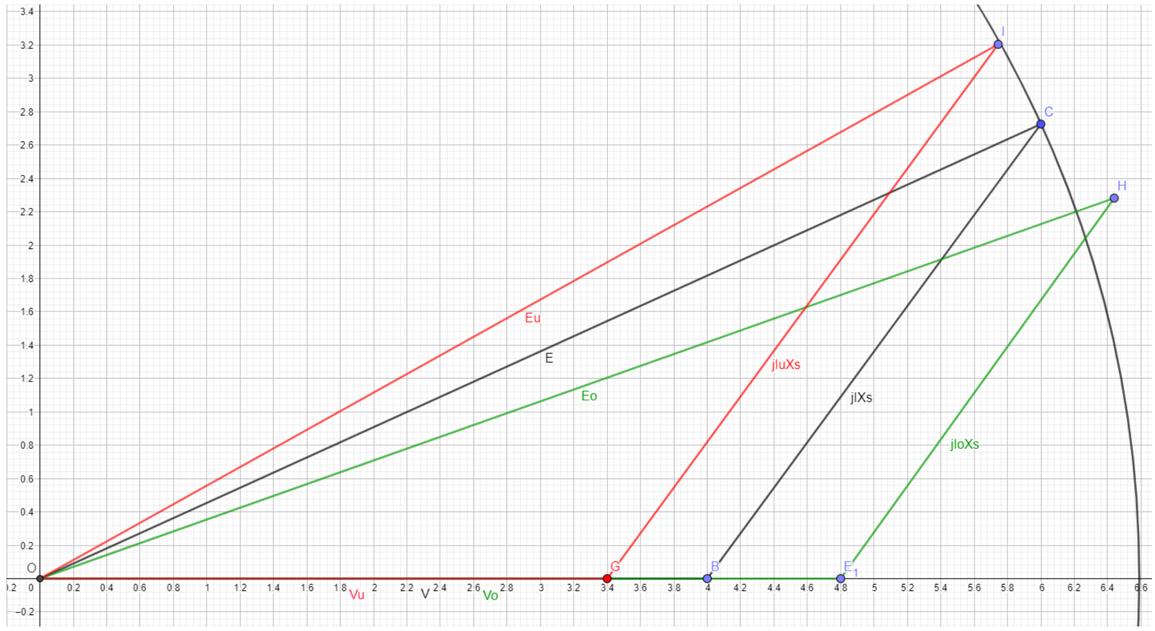

Fig. 4.5 Simplified phasor diagram for different grid voltage values at same output power.

black lines represent parameters for nominal regime with power factor 0.8; red lines represents parameters for 85% of rated grid voltage; green lines represents parameters for 120% of rated grid voltage

$$P_g = \sqrt{3} U_g I_g cos\varphi \quad (4.3)$$

$$Q_g = \sqrt{3} U_g I_g sin\varphi \quad (4.4)$$

where, I_g – generator actual current;

φ – power factor angle.

Voltage decrease at generator clamps leads to a reduction of torque, thus angle δ becomes bigger and can compensate reduction of torque due to voltage drop. In case of grid overvoltage, δ drops, but generator voltage and internal generator voltage rise, and moment should be stable. This can be proven also by the relation between angular speed and active power of generator, at constant active power output and grid frequency torque moment should remain stable. [89, 90]

$$M = \frac{\sqrt{3}U_g E_A sin\delta}{\omega X_s} \approx \frac{P}{\omega z_p} \tag{4.5}$$

where, E_A – internal generator voltage;

X_s – synchronous reactance of generator;

ω – angular speed of generator rotor 2*π*f;

z_p – number of pole pairs.

Usually generators are produced according to IEC 60034 if no special requirements stated. IEC 60034 demands generators to operate at rated power within 5% voltage oscillation, maximum difference of 8% is required to keep generator operating. For generators it is acceptable to operate with lower voltage, while current is in range and does not cause overheat, this operation range may differ from generator to generator.

Operating at overvoltage can be harmful for insulation. Generator insulation has great overvoltage capabilities, which were discussed in 3.1. Also, auxiliary equipment of generators and step-up transformers has greater insulation voltage class than rated for operation. For example, there is no such insulation level as 15.75kV and 17 kV, so for this equipment 22 kV insulation class is used. Generators and power transformers have a numerous protection systems, which in many cases will limit operation in overvoltage regimes. Manufacturers usually does not agree to change any of protection setting. Sometimes it might be done after some modernizations.

Even bigger problems could be brought by U-Q/P_{max} profile presented at Fig. 4.3. Especially it could be hard to fulfill for generators with higher nominal power factor in lagging mode. Typical generator capability is present at Fig. 4.6. Operating in reactive power consumption mode (leading) is quite hard for generators and has several limitations, such as end winding heating and voltage instability, which is caused by reduction of field current. Operation in reactive power generating mode (lagging) is preferable and has only little limitations, such as rotor heating limitations at power factor below rated power factor [90].

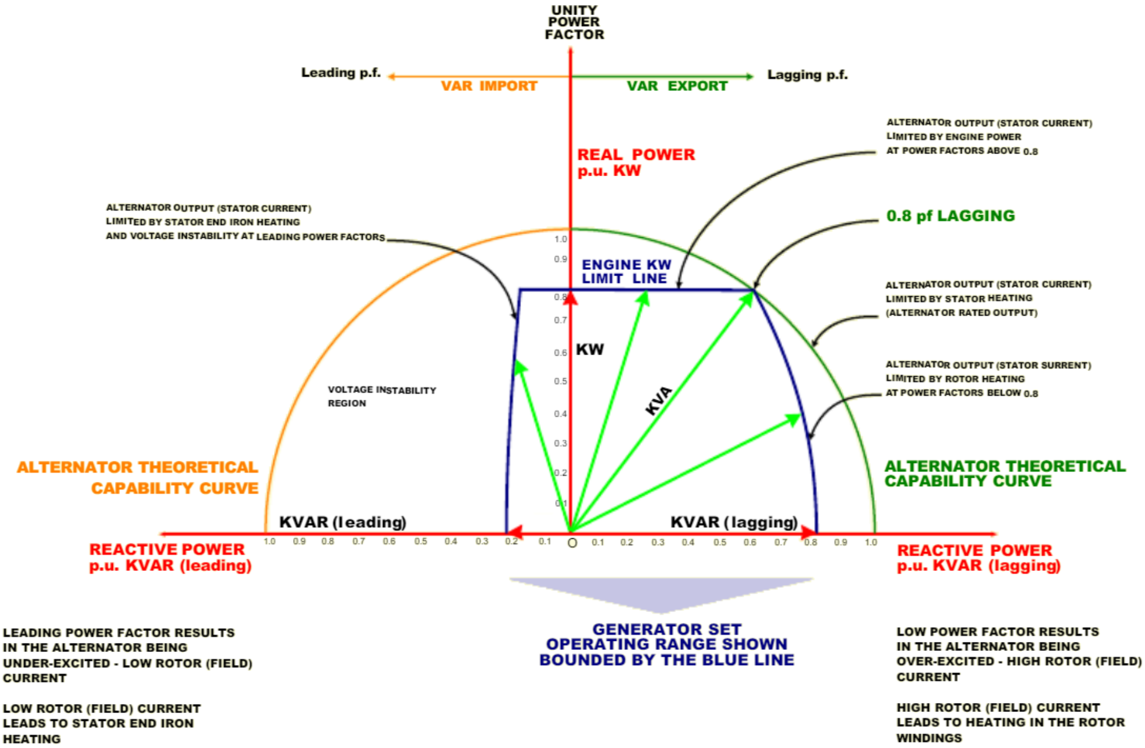

Fig. 4.6 Synchronous generator typical capability chart [92].

According to rules generators should provide reactive power equal to -0.45 P_{max} at connection point. Typically, it is not possible to provide such leading power from generator at nominal active power rating, but due to presence of step-up transformer before grid connection, which has quite high reactive power consumption, usually it is possible to provide required leading reactive power at connection point to the grid. However, for some generators with high power factor (above 0.93) in leading mode problems might appear. RfG allows to reduce active power if it is caused by technical limitations, but total output should be same, this exclusion might help in some cases, because at reduced active power below 0.7 capability curve limitations are not so strict as in area close to nominal active power. Often generators have rated power factor 0.8 – 0.85 for lagging operation mode. Still, for leading operational mode power factor usually is 0.9 – 0.95, it means that at rated active power apparent rated power of generator in leading mode is reduced.

Other U-Q/P_{max} requirement is to provide reactive power equal to +0.55 P_{max}. This is not a problem for generators with nominal power factor 0.8 and becomes a problem at nominal power factor equal to or greater than 0.84. Thus, due to step up transformer high reactive power demand, this requirement might be hard to fulfill for any generator.

4.3. Possible Solutions for Existing Equipment to Meet New Voltage Control and Reactive Power Demands

To fulfill RfG voltage and reactive power requirements three main problems need to be solved for existing generators:

1) high overvoltage up to 17%, in one hand it is not a problem for insulation, on the other hand, such overvoltage can be causer for protection operation and can lead to trip of power plant;
2) great overcurrent (5-14%) at undervoltage mode, which appears even for operating modes which should be maintained for an unlimited time period (5-8%);
3) generator inability to consume or generate enough reactive power to fulfill U-Q/P_{max} requirements.

Target is to maintain overcurrent below 5% in any operating mode, overvoltage should be within 10% of rated and reactive power consumption should be provided to fulfil U-Q/P_{max} diagram requirements from Fig. 4.3.

High overvoltage on generator terminals can be solved by choosing appropriate tap on step-up transformer. It will prevent V/Hz protection operation, which for generator usually activates at 10% deviation from normal voltage. This will lead to even more increased currents during undervoltage operating mode [93].

To reduce current of generator during voltage drop in the grid, some amount of generated power should be decreased. Thus, decreased power should be compensated. Reduction of active power to fulfill requirements is bad solution because it will cause a reduction of torque (torque angle will decrease) and can cause active power imbalance, if several generators will act in same way, which can result in frequency disturbance [67]. So, only reactive power could be decreased, but should be compensated to fulfill RfG requirement to provide full apparent power in all voltage ranges. In power network for this purpose shunt reactors and bank capacitators are used. More advanced solutions are synchronous condensers, static VAR compensators (SVC) and static synchronous compensators (STATCOMS) [94].

To keep the same active power on generator, and do not allow overcurrent more than 5% during worst voltage drop, which happens at generator clamps, next is applied:

$$I_1 > \frac{1000 S_2}{1.05 U_2 \sqrt{3}} \tag{4.6}$$

where,

I_1 –rated generator current, A;

S_2 – apparent power of generator in new regime, MVA;

U_2 – generator voltage to fulfill RfG requirements, kV;

Problem for reactive power consumption appears from U-Q/P_{max} diagram. Generator reactive power consumption capability in rated regime should be taken from generator capability curve. Thus, due to continuous undervoltage mode, which should be withstand according to U-Q/P_{max} requirements, problems could arise even with reactive power generation. Reactive power should be compensated in amount to fulfill U-Q/P_{max} requirements, step-up transformer contribution in reactive power consumption is expressed as follows:

$$Q_{grid} = Q_m - \frac{x_T(P_1^2 + Q_m^2)U_1^2}{U_2^2 S_2} \tag{4.7}$$

where Q_m – reactive power to fulfill operation mode (in case of leading operating mode sign before reactive power should be changed to the opposite), MVAr;

P_1 – generator rated active power, MW;

U_1 – generator rated voltage, kV;

Q_{grid} – reactive power at generator connection point to the grid, MVAr.;

x_T – step-up transformer reactance, Ω..

Condition should be met to comply with RfG:

$$-0.45 = \frac{Q_{grid}}{1} = \frac{Q_{m.l}}{P_1} - \frac{x_T(P_1^2 + Q_{m.l}^2)U_1^2}{U_2^2 S_2 P_1} \tag{4.8}$$

$$0.55 = \frac{Q_{grid}}{P_1} = \frac{Q_{m.lag}}{P_1} - \frac{x_T\left(P_1^2 + Q_{m.lag}^2\right)U_g^2}{U_2^2 S_1 P_1} \tag{4.9}$$

where $Q_{m.l}$ – leading reactive power to fulfill operation mode (should be taken with "-" sign), MVAr;

$Q_{m.lag}$ – lagging reactive power to fulfill operation mode (should be taken with "+" sign), MVAr;

If $Q_m \neq Q_g$, then reactive power should be compensated in amount equal to:

$$Q_{comp.PQ} = Q_m - Q_2 \tag{4.10}$$

where $Q_{comp.PQ}$ –reactive power which should be additionally provided from generator site to fulfill RfG;

Q_2 – generator reactive power to fulfill requirements in (4.6).

If Q_2 is produced by generator (lagging mode) it appears as positive reactive power, and if it is consumed by generator (leading mode), then as negative, which will lead to change of sign in equation (4.10).

Analysis of several generators was performed to clarify whether they can fulfill RfG requirements stated in Fig. 4.3, where demand for reactive power and voltage levels are presented. In Table 4.2 as an example are provided calculation data for one generator connected to 330 kV grid. Due to high reactive power losses in step-up power transformer problems with *U-Q/P_{max}* requirements arise even in overvoltage mode when reactive power should be provided to the grid. In undervoltage mode during reactive power consumption greater than allowed overcurrent appears, it could be solved only by active power reduction.

Table 4.2

Generator Main Parameters and Compensated Reactive Power to Fulfill $U\text{-}Q/P_{max}$ Requirements

U-Q/P	U_{grid}, kV	U_{grid} at generator level, kV	U_2, kV	U_2 in p.u	I_2 in p.u	$Q_{comp.PQ}$
0.55	362.01	17.35258	18.7	1.1	0.907733	20
	297	14.19566	15.878	0.934	1.048692	50
-0.45	362.01	17.23	16.66	0,98	0.92	0
	297	14.18304	13.6	0.8	1.067693	-80

Comparison between different reactive power compensation technologies and installation costs is presented in Table 4.3. [95]–[97] Amount of compensated reactive power for different generators and possible investments for different technologies that will help generators to fulfill RfG requirements are presented in Table 4.5, which includes also 10% for civil works. Synchronous compensators could not provide full rated power in leading regime, so higher rated power is chosen to fulfill requirements.

Table 4.3

Reactive Power Compensation Technology Comparison and Prices

Technology	Pros	Cons	Installation costs EUR/MVAr
Shunt reactors/ bank capacitors	• simple technology widely used in medium and high voltage; • no additional losses when disconnected.	• reaction time is up to few seconds; • MV circuit breaker should be operated to put them in operation when necessary; • installation of two separate equipment pieces and circuit breakers is necessary; • low output variation possibilities.	15 000
Synchronous condensers	• wide regulation range with fast response; • provides additional inertia to the grid; • is very robust during grid voltage changes; • compact comparing to other technologies.	• should be connected to the grid all the time, at no load regime losses are 1.5% of nominal rating; • as rotation machine needs additional maintenance work.	35 000

Continuation of Table 4.4

Static VAR compensator (SVC)	• wide regulation range with very fast response; • good performance during overvoltage (up to 130%); • operation costs lower than for synchronous condensers.	• not best performance at undervoltage state; • need filters to prevent harmonics.	65 000
STATCOM	• wide regulation range with very fast response; • good performance during undervoltage; • operation costs lower than for synchronous condensers.	• overvoltage over 120% is not admissible.	85 000

Table 4.5

Necessary Reactive Power Compensation Amount and Investments for Different Solutions

	Q comp. leading, MVAr	Q comp. lagging, MVAr	Investments, EUR			
			Capacitor bank/Reactor	SVC	STATCOM	Synchronous compensator
Industrial type turbine generator (lead cos ϕ =0,93; lag cos ϕ =0,80), 110 kV grid	0	12	198 000.00	858 000.00	1 122 000.00	462 000.00
Heavy duty turbine generator (lead cos ϕ =0,97; lag cos ϕ =0,78), 110 kV grid	-15	4	313 500.00	1 072 500.00	1 402 500.00	962 500.00
Heavy duty turbine generator (lead cos ϕ =0,91; lag cos ϕ =0,84), 330 kV grid	-80	50	2 145 000.00	7 150 000.00	9 350 000.00	5 390 000.00

Operational costs for the mentioned technologies differ. For capacitor banks and shunt reactors there are no losses and additional costs if they do not perform. For SVC technology no-load losses are about 0.3% and will appear all year long during technology availability, which is 99%. For STATCOM no-load losses are 1.5% of nominal capacity. Synchronous compensator no-load losses are 1% of rated power. At operation regimes, losses for capacitor banks and reactors should be within 2%, for SVC and STATCOM due to power electronics and inner transformer it will raise up to 5%, for synchronous condensers load losses should be below 2% [108].

Operating costs per year per reactive power provision technology are presented in Table 4.6 and are based on average generator electricity production costs and historically highest electricity market price. Calculations for reactive power compensation costs for one year by any technology may be done using expression (4.11). Interest rate and maintenance performing also are taken into account.

$$C_{QC.pp} = K_p i + K_p k_m + C_e(P_0(t_y - t_{op})k_{av}) + C_m((P_0 + P_{op})t_{op}) \qquad (4.11)$$

where, $C_{QC.pp}$ – reactive power compensation costs for power plant, EUR;

K_p – project capital investments, EUR;

i – credit interest rate, p.u.;

k_m – coefficient for maintenance costs per year;

C_e – market based self-consumption electricity costs, EUR/MWh;

P_0 – no-load losses for technology, MW;

t_y – hours per year – 8760, h;

k_{av} – availability of technology per year;

C_m – Nordpool spot market price, EUR/MWh;

P_{op} – power consumption for technology during operation, MW;

t_{op} – operating hours of generator, h.

Here and further in work self-consumption market based electricity price is calculated as follows:

$$C_e = C_m + C_g + C_{TSO} \qquad (4.12)$$

where C_g – clean energy component set as 22.68 EUR/MWh;

C_{TSO} – transmission system operator tariff set as 3.53 EUR/ MWh.

Table 4.6

Reactive Power Compensation Operation Costs per Generator per Year in EUR

	Capacitor and reactor	SVC	STATCOM	Synchronous compensator
Industrial type turbine generator (lead cos ϕ =0,93; lag cos ϕ =0,80), 110 kV grid	55 524.00	147 138.60	180 453.00	83 286.00
Heavy duty turbine generator (lead cos ϕ =0,97; lag cos ϕ =0,78), 110 kV grid	102 372.00	214 173.00	262 665.00	202 050.00
Heavy duty turbine generator (lead cos ϕ =0,97; lag cos ϕ =0,78), 330 kV grid	700 440.00	1 427 820.00	1 751 100.00	1 131 480.00

According to European Commission guide to cost-benefit analysis of investment projects presented in [107], if no revenue is prognosed and as result net present value (NPV) is below

0, then economic analysis should be performed. The main criteria is willingness to pay. For power generator operator there is no willingness to pay for increased security and reliability of supply, because most incidents occur to power plant equipment and are not a result of power system disturbance. Mentioned upgrades for reactive power control can cause some additional problems within power plant in case of malfunction. Thus, if grid would become less stable, and power plant will suffer trips from grid instability (but which is stable enough according to European Commission grid rules) resulting in undelivered energy to market and need to buy balance power in the market, generator operator might become more interested in such investments [107].

On the other hand, TSO performs payments for power plant availability, if TSO is interested in generator ability to fulfill RfG and secure power network stability, then this payment should be raised after such modernization. In case if no revenue is foreseen the criterion "do - minimum" should apply. The cheapest alternative should be chosen, according to performed calculations - use of combination of capacitor banks and shunt reactors, as example situation with heavy duty turbine generator connected to 110 kV grid is presented at Fig. 4.7.

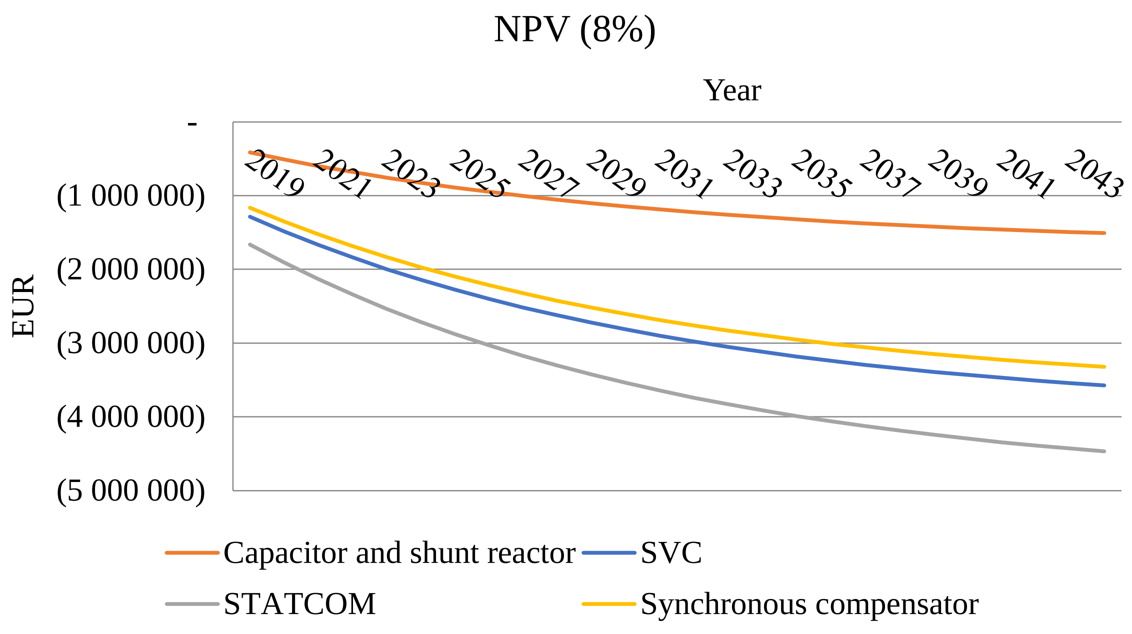

Fig. 4.7 NPV for 110 kV heavy duty turbine generator modernizations without revenue.

4.4. Frequency Ranges and Ramping Challenges for Existing Equipment and Possible Solutions

In 4.1 were mentioned two main concerns regarding operating in frequency ranges demanded by TSO and industrial gas turbine ramping capability. First problem appears for frequency ranges, because of generator manufacturing standards. IEC60034 states, that operation in range 47.5-49 Hz should be limited by time and number of occurrences, same is stated for range 51-51.5 Hz. RfG demands to operate continuously in 48.5-49 Hz and 51-51.5 Hz ranges. Usually, generator manufacturers states time limits for operation below 48.5 Hz, in many cases it is much lower than 30 minutes, also it is limited by number of occurrences per year, which is not specified in RfG. Operation in underfrequency mode leads to overheating and rise of excitation current to maintain same voltage level. To solve this problem modernisation of the generator should be performed [87], [90].

CCGT operation depends on numerous ancillary equipment which definitely will be affected by underfrequency or overfrequency. Underfrequency will lead to a lack of performance for pumps and fans, which will result in some trips due to technological process (not enough pressure or flow), which are not easily foreseen. IEC60034 states same frequency range demands for electrical motors as for generators. Power plants with high frequency converter penetration are better suited for such regimes, which after detailed study might result in only generator upgrade. In other case upgrade should be made also for power plant ancillary equipment.

All upgrades to fulfill frequency range might not be cost effective, because does not add any additional possibilities to normal operating regime, the only reason to make such upgrade might be sufficient blackout risk due to inability of an existing power plant, which should be analyzed by TSO according to RfG and guidelines on cost benefit analysis [98].

Second problem appears to CCGTs with industrial type gas turbines due to low ramping rate, which can not activate 8% of nominal power plant active power within 30 seconds, which is demanded by RfG. Also it should be done according to full line at Fig. 4.1. As steam turbine reaction time due heat recovery steam generator (HRSG) is longer than 2 second defined by TSO rules, only gas turbines of CCGT should be able to reach 8% of nominal full load in 30 seconds.

Gas turbine biggest manufacturers GE and Siemens always looks for upgrade possibilities of existing equipment, which becomes especially popular due to high penetration of renewables and more cyclic operation mode. Upgrades usually are targeted on the improvement of gas turbine lifetime, expansion of maintenance intervals, reduction of emissions, reduction of startup time and improvement of general performance – more power, flexibility and better efficiency [101], [102].

Industrial gas turbine ramp rate according to Siemens is 5% of CCGT block rated active power per minute, which is far away from 8% in 30 seconds demanded by Latvian TSO. Siemens upgrade of industrial type turbines can bring up to 10 MW of additional active power and up to 3.5% increase of gas turbine simple cycle efficiency. Thus, nothing mentioned about ramping capabilities [102].

Such upgrade might be interesting as business case due to better performance, but in case of RfG might be even harmful. First of all, increase in power within same ramping rate will result in less than 5% per minute ramping speed. Second problem will appear due to reactive power performances described in 4.2 – generator will remain at same MVA rating, thus active power output will rise and move power factor up, which might result in inability to fulfil voltage and reactive power control demands [35].

High capacity power batteries, known as battery energy storage systems (BESS), are not under the scope of RfG. Installation of them at generation site does not require changes in connection agreement, because total delivered power in connection point might be within the limits of stated rated power. at the same time, BESS could provide significant improvement in ramping speed for industrial type gas turbines as well as numerous other advantages such as reactive power control, black start capability, spinning reserve without fuel consumption, primary frequency regulation and others[91], [101], [102].

Lithium-ion technology is one of most used in power grid applications. In Table 4.7 [135] is presented comparison between different BESS technologies. Li-ion BESS are reported for 80-85% AC-AC cycle efficiency, which is not best in class, but this type of batteries have several significant advantages for grid operation, such as ability to tolerate more operating cycles, fast charge and discharge ability and very high energy density. At figure Fig. 4.8 [42] is presented lifetime of Li-ion battery depending on number of cycle and years in operation. Using Li-ion technology BESS should be oversized to prevent negative effect under discharging and overcharging, which means additional investments [132]–[135].

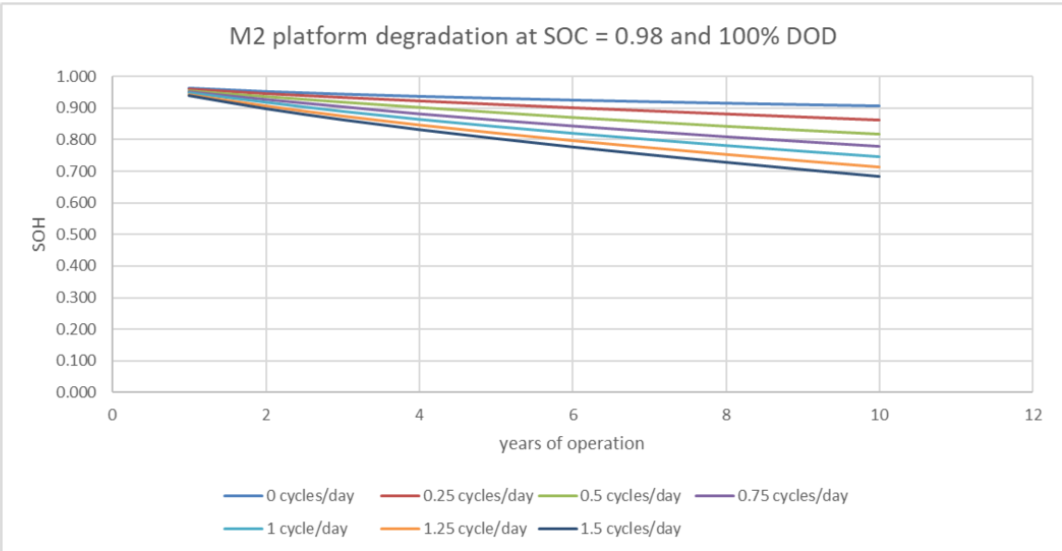

Fig. 4.8 Fluence energy battery loss of capacity depending on number of cycles and time [42].

Table 4.7

Comparison of Different Storage System Technologies

	Heating, %	Chemical losses, %	Electrical losses, %	Self-discharge, % per month	Output, %	Main disadvantage
Sodium Sulphur (NaS) Batteries	2	12	10	-	75	Potential safety issues with the molten sodium
Flow Batteries	-	23	10	-	65-75	Low energy density
Lead Acid Batteries	4	-	4	3	85-90	Hazardous. Low energy density.
Lithium ion (Li-ion) Batteries	-	4	3	8	85	Negative effects of overcharging/ over discharging.
Sodium Nickel Chloride Batteries	2	9	4	-	85	Unsuitable for short cycling.

Bloomberg survey for Li-ion battery prices, which is presented at Fig. 4.9, shows price tendency during 2010 – 2016, and prognoses price drop for Li-ion batteries to 65.5 EUR/kWh at 2030. Siemens reported 400 EUR/ kW cost for 5 MW/2.5 MWh BESS, for 10 MW/5 MWh BESS price 285 EUR/ kW and 230 EUR/kWh were presented. Drop of prices will lead to Li-ion BESS usage expansion [42], [104].

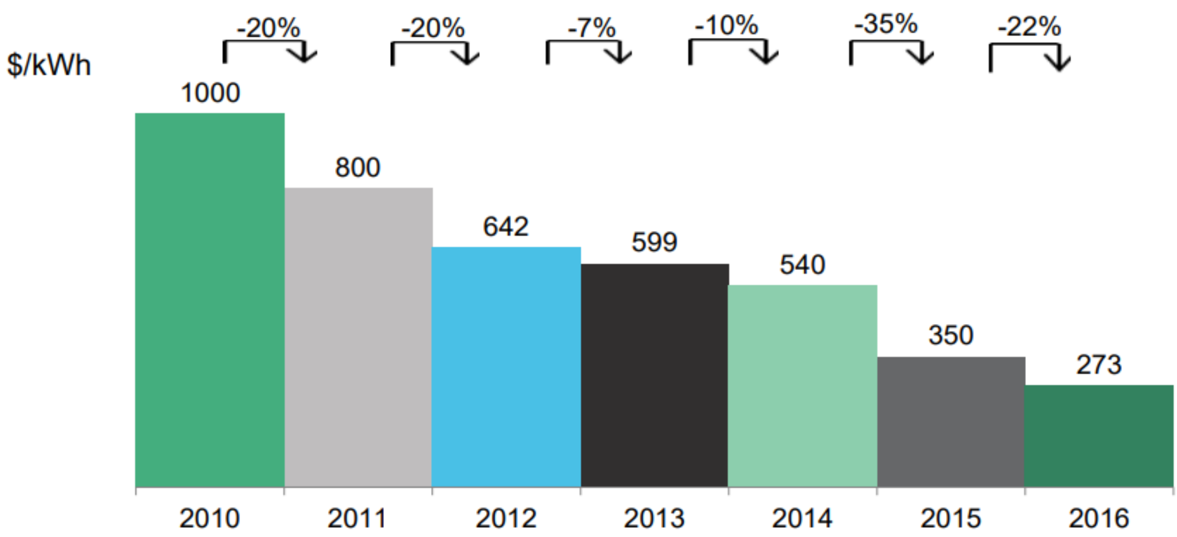

Fig. 4.9 Bloomberg Li-ion battery prices survey [104].

To choose right BESS for ramping speed improvement, several calculations should be made to understand power and capacity of installations, it will allow to estimate investments. BESS power for ensuring proper ramping rate can be calculated as follows:

$$P_{B.r} = k_p(P_{d.r} - P_{GT.r}) \tag{4.13}$$

whre, $P_{B.r}$ – power of BESS used for ramping rate improvement, MW;

k_p – coefficient to prevent lack of power, used 1.05;

$P_{d.r}$ – demanded power gain per 1 minute, MW;

$P_{GT.r}$ – GT power gain per 1 minute, MW;

Capacity of BESS should be enough to perform within period while gas turbine will reach demanded power, according to [42] Li-ion BESS should not be fully charged, usually standing 90% of charge and full discharge also should be prevented, keeping at least 20% of charge. BESS capacity for ramping rate improvement can be calculated as follows:

$$A_{B.r} = k_{ch} \sum_{t=0.0083}^{T} (t_a P_{d.r} - t P_{GT.r}) \tag{4.14}$$

where, $A_{B.r}$ – BESS capacity for ramping rate provision, MWh;

t_a – time to activate frequency demanded active power, h.

k_{ch} – coefficient to prevent overcharge and under discharge of BESS, used 1.3;

T – time to reach $P_{d.r}$ using only gas turbine ramping speed $P_{GT.r}$, h.

According to Latvian TSO CCGT should be capable to provide 8% of rated active power within 30 seconds or 0.0083 hour, but calculation is made for most stricter circumstances - 10% within 30 seconds. For industrial type gas turbine ramping rate is about 5% of total power plant active power output, within 30 seconds only 2.5% are activated. The lack of power- 7.5% should be provided by BESS. After 2 minutes gas turbine will activate all demanded power and BESS contribution is not feasible for longer period. For example, BESS power and capacity for 150 MW CCGT with 5% per minute ramping rate of gas turbine according to (4.13) and (4.14) will be 11.81 MW and 0.243 MWh, rounding up should be performed, which results in 12 MW and 0.25 MWh. So calculated power of BESS should be provided for only 1.25 minutes. According to [42] investments for such BESS will be 3 480 000 EUR.

Typical topology for utility-scale BESS is presented in Fig. 4.10 [132] It is obvious, that operation of BESS is conducted with various losses, which should be taken into account during any calculations and prognosis of BESS operation. BESS have losses for control system operation, which according to [42] is below 1%, also heat ventilation and air conditioning system (HVAC) takes about 1-3%, battery pack have inner losses and discharges during the time even without operating, for Li-ion batteries this is 5% during first 24 hours and then 2% per month. Power conversion units at nominal load can reach 97% of efficiency, thus at 0-30% load it can drop significantly, for calculations typical value of 95-96% is considered. In many studies losses of power transformer are included in system general amount of losses, in this work losses are calculated for each solution separately in accordance to size and operating mode of system [132].

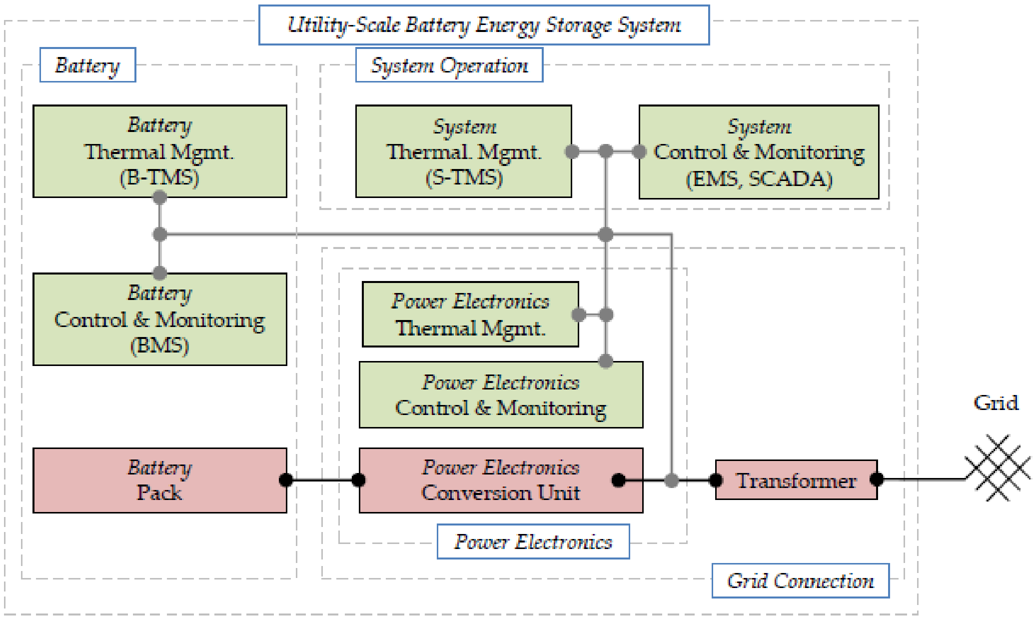

Fig. 4.10 Typical topology of BESS [132].

green - control modules, red - power modules

BESS operation costs could be divided into activation costs and upkeep costs. Here as upkeep costs are considered electricity for control system operation, HVAC of BESS, power transformer no-load loss, in case if additional power transformer is used, as well as battery pack discharges during the time even without operating. Power consumed by BESS on regular basis could be calculated as:

$$P_{bs} = P_{BESS}(k_c + k_{HVAC}) + \Delta P_{T0} \tag{4.15}$$

where P_{BESS} – BESS rated power, MW;

P_{bs} – power used for BESS upkeep, MW;

k_c – coefficient that considers self-consumption of BESS controllers, value used for calculation is 0.01;

k_{HVAC} – coefficient that considers self-consumption of BESS HVAC, value used for calculation is 0.03.

ΔP_{T0} – power transformer no-load losses, MW.

Total upkeep costs should include maintenance costs, assumed as 1%, calculation for 1 year or 12 months is:

$$C_{up} = C_{el.pp}(8760k_{av}P_{bs} + 12A_{BESS}k) + iK_p + k_mK_p \tag{4.16}$$

where C_{up} – total upkeep costs, EUR;

$C_{el.pp}$ – yearly average power plant self- consumption electricity costs, EUR/MWh;

k – coefficient that considers self-discharge in BESS, value used for calculation is 0.07.

k_{av} – availability coeficients, according to [42] equals to 0.98 for BESS;

A_{BESS} – BESS charged capacity, MWh;

K_p – total investments, EUR;

i – interest rate, %;
k_m – coefficient that considers maintenance costs of BESS.
Activation costs are calculated as:

$$C_{act} = n\frac{A_{act}}{\eta_{op}}C_{el.pp} \qquad (4.17)$$

where C_{act} – activations costs per year, EUR;
A_{act} – BESS activated capacity, MWh;
n – number of BESS activations per year;
η_{op} – inverter efficiency.

$$C_{op} = C_{up} + C_{act} \qquad (4.18)$$

where C_{op} – total operation costs of BESS per year, EUR.

For previously mentioned example upkeep costs would be 271 730.32 EUR per year, activation costs for 3 activations per year would be 16.85 EUR, such low costs for activation are due to very low capacity need for ensuring demanded ramping rate of power plant. Graph for NPV calculation is presented at Fig. 4.11. Such modernization of power plant demands significant investments and operation costs, which should be added to generated electricity price.

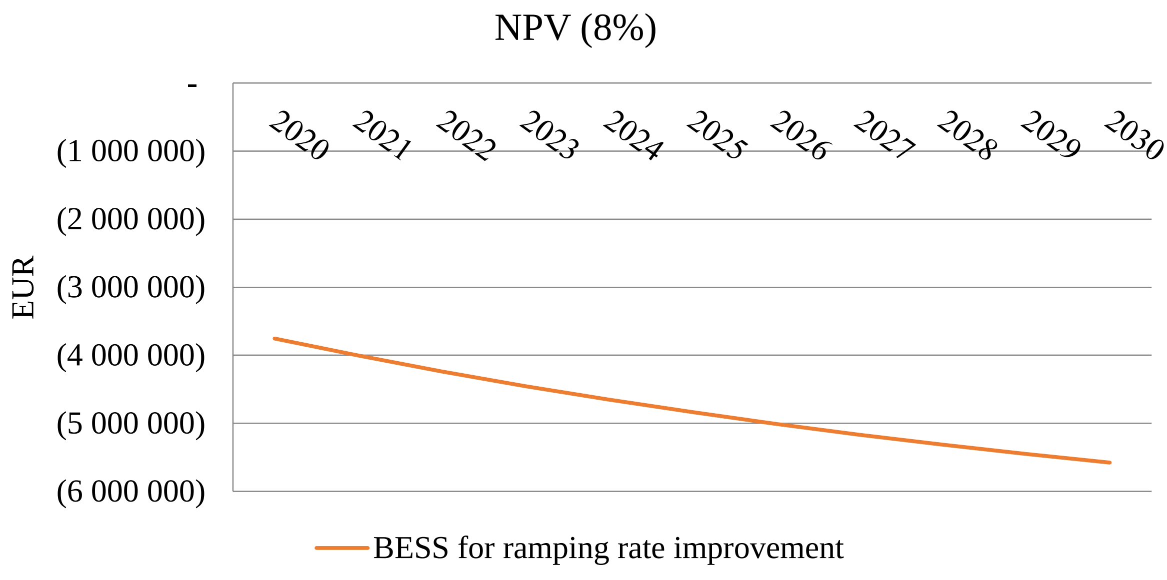

Fig. 4.11 NPV for BESS installation for improving power plant ramping rate without revenue

4.5. Summary

Analysis of new requirements for generators and the actual situation in Baltic states show, that new rules might be applied for existing generators. Theory based calculations, considering real generator technical parameters and real gas turbine capabilities, show that for existing CCGT power plants might be problematic to fulfil voltage range, U-Q/P_{max} profile and ramping rate requirements.

The good thing is, that modern technologies offer different solutions to upgrade power plant electrical equipment and solve all above mentioned challenges. Thus, significant investments (for voltage range and U-Q/P_{max} profile fulfilment from 200 000 EUR to 2 150 000 EUR for cheapest solution depending on generator; for ramping rate improvement about 3 500 000 EUR for 150 MWindustrial type CCGT unit) and operating costs (for voltage range and U-Q/P_{max} profile fulfilment from 55 000 EUR to 700 000 EUR for cheapest solution depending on generator; for ramping rate improvement about 270 000 EUR for 150 MWindustrial type CCGT unit) are foreseen.

For generating facilities, such additional investments and costs are not interesting, especially in electricity market situation, because additional investments should be compensated via electricity price, which can result in lower competitiveness. But, in case if power plant will trip due to the inability to operate at grid voltage, which according to rules are normal, then additional costs for undelivered energy and balance purchase can force generators to move towards modernizations. Prior to any modernization cost benefit analysis should be performed. TSO is responsible for power system stability, so it might support generators to perform modernizations leading to the greater security level. Also, additional services could be provided to TSO by additionally installed equipment, but they should be remunerated.

5. ANCILLARY SERVICE PROVISION

Development of electric grid, renewable energy source wider usage as well as new interconnections lead to changes in existing electricity markets. Energy systems become more vulnerable and grid stability is challenged. Possible resynchronization in 2025 can lead to even higher grid stability issues in Baltic states, which is reported in [115]. In [57], [109]–[111] are discussed ancillary services to provide greater power system stability. Ancillary services from power plants and other users, mainly energy storage systems, connected to TSO become more and more important.

A deep study of ancillary service provision situation is provided in [110], voltage control and frequency control are covered, thus, no numerical service prices are mentioned. Therefore [109] more concentrates on choosing proper ancillary service market model and presented prices for balancing and spinning reserve are just assumed as possible prices from generators. In [111] stated that BESS also can contribute to different ancillary service provision, but no service costs are mentioned as well.

R. Petrichenko, K. Baltputnis, D. Sobolevsky and A. Sauhats in [112] studied possible costs of spinning reserve provision (could provide inertia, frequency restoration reserves (FRR), frequency containment reserves (FCR) and reactive power) from biggest Latvian HPP cascade. But Only costs of HPP are considered, costs of same service provision from CCGT's or TSO connected parties are not considered. Reactive power costs provided from synchronous generators were evaluated in [113], but study presented in [99] moved further, making comparison to possible service provision from generators and capacitor banks.

This work aims to describe general methods of cost calculation for reactive power, FFR, FCR and inertia provision from generator site with or without modernizations as well as ancillary service provision from site connected to TSO. Comparison of possible service costs is made. Obtained service costs will be used in further calculations. Some results were presented in [114].

5.1. Reactive Power Control

In 4.3 and 4.4 were discussed upgrades which should be done in existing power plants to fulfill RfG requirements. Cost benefit methodology for connection network codes [98] does not provide clear guidelines on what is sufficient risks or how to calculate benefits from upgrade projects. On of possibilities to cover costs of generator upgrade is provision of ancillary services, such as reactive power control, frequency restoration reserves (FRR), frequency containment reserves (FCR) and inertia.

At present moment in Latvia reactive power provision is not a business case for CCGT generators. TSO has own capabilities to control voltage, also TSO can demand reactive power control from operating generators. TSO contracts only hydro power plant synchronous compensators, to consume excessive reactive power of 330 kV grid, which could not be done by other means. Due to changes in regulations, as well as modernization of power network, which leads to usage of more and more 110 kV and 330 kV cables known for reactive power generation, TSO might demand more reactive power compensation from generators and buy it as ancillary service [35], [95]–[97].

At normal voltage level during generator operation reactive power consumption or production may be sold to TSO. Thus, for generators production of reactive power also leads to additional costs. Generators have efficiency curves for different load factors and power factors. Maximal efficiency for any load factor is reached at power factor cosφ = 1, and it means zero production of reactive power [99], [100]. So, change of power factor will lead to decrease of generator efficiency – additional losses will appear. Calculation could be done as follows:

$$\Delta P_{g.ad} = (1-\eta)P_1 - \Delta P_{g.n} \quad (5.1)$$

where $\Delta P_{g.ad}$ – additional losses in generator, MW;

η – effieciency at demanded power factor cosφ and active power P, p.u.;

P_1 – generator rated active power, MW;

$\Delta P_{g.n}$ – losses in generator at turbine rated active power and power factor cosφ= 1, MW.

$$\Delta P_{e.ad} = (z_T + z_l)\,(I_{g.n} - I_g)^2 \quad (5.2)$$

where, $\Delta P_{e.ad}$ – additional losses in equipment before grid connection point, MW;

$I_{g \cdot n}$ –generator current at turbine rated active power and power factor cosφ= 1, A;

I_g – generator current, A;

z_T – step-up power transformer impedance, Ω;

z_l – line impedance, Ω.

$$\Delta P_{ad} = \Delta P_{g.ad} + \Delta P_{e.ad} + P_{red} \quad (5.3)$$

where, ΔP_{ad} – total additional losses for reactive power provision, MW;

P_{red} – produced active power reduction to provided demanded reactive power, MW.

Costs of reactive power provision from synchronous generator could be calculated as follows:

$$C_{Q.gen} = \frac{C_P * A_{ad}}{Q_{gen}} \quad (5.4)$$

where, $C_{Q.gen}$ – synchronous generator reactive power costs, EUR/ MVArh;

C_P – active power production costs, EUR/MWh;

A_{ad} – energy amount to cover total additional losses for reactive power provision, MWh;

Q_{gen} – total delivered to the grid reactive energy, MVArh.

Calculations for existing CCGTs show that change of power factor from 1 to the rated will lead to additional costs per MVArh, For generators connected to 110 kV grid additional costs would result in up to 0,39 EUR/MVArh in lagging mode at rated active power and power factor, in leading mode additional cost would vary in a range of 0,06 EUR/MVArh to 0,20 EUR/MVArh. For generators connected to 330 kV grid reactive power price in lagging mode from power factor 1 to rated is 0,51 EUR/MVArh and 0,17 EUR/MVArh in leading mode. Costs are given at 50 EUR/MWh costs for active power production [114].

As generator leading possibilities are quite low and in future will rise necessity of reactive power consumption, generators could compensate reactive power only by means of active power reduction. In 110 kV grid price for reactive power above nominal in leading regime will be 49.87 to 111,54 EUR/MVArh, depending on generator capabilities, and this price appears for only 15 MVAr difference from nominal. For generators connected to 330 kV grid additional reactive power consumption price will be 31.08 EUR/MVArh for 15 MVAr rise above rated. Upgrades discussed in 4.3 installed for reactive power consumption would allow to avoid active power reduction, and also allow to provide reactive power control from generator site regardless of generator operation state.

Normally TSO demands to compensate excessive reactive power in transmission lines. For the biggest CCGT's in Latvia average hourly reactive power compensation amount during 2016-2018 were 49 MVAr at 330 kV level and 15 MVAr at 110 kV level. It is a reactive power amount that could be provided to the grid 8760 hours per year. TSO for excessive injected reactive power charges 13 EUR/ MVArh from utilities and for excessive consumed reactive power from the grid price is 4 EUR/MVArh. But CCGT generators are not remuneated [35].

Reactive power market would allow power plants to sell reactive power at the connection point to the TSO. This means, that generators would be able to compensate modernization costs for compliance with RfG by selling ancillary service to the TSO. Historically TSO in Baltic states had equipment for voltage regulation and reactive power compensation. In future market-based relations would allow TSO to avoid investments for such equipment as well as operation costs. Thus, party which provides reactive power control service should ensure all year long availability of this service.

Market based service provision should ensure lowest costs and price for end-user to fulfill EU targets on electrification. Costs of reactive power provision should be calculated for site connected to TSO and for generator site. It is assumed that installed capacities are available and used 99% of time per year. Also, installation power is at least 30% higher than average yearly compensated reactive power in represented node and rounded to next highest nominal. In 4.3 was discussed generator modernization for compliance with RfG. In two cases reactive power consumption equipment should be installed, one for 110 kV grid and one for 330 kV grid. In Table 5.1 is presented case if shunt reactors and condensers are used to provide reactive power control.

Service provision costs could be obtained from NPV calculation. Two electricity price scenarios are under the scope, one with historically lowest electricity market price and second with historically highest electricity market price. As main target is to understand how high are service provision costs from each site. Exploitation time for chosen technologies should be 25 years; this also is NPV calculation period. Investments are calculated according to information in Table 4.3 and in Table 5.1 mentioned installed power.

Reactive power provision from generator site is divided in two parts, provided from generators and from additional equipment. So total operating costs per year are calculated as follows:

$$C_{Q.pp} = K_p i + K_p k_m + C_e((\Delta P_0 + \Delta P_{op})(t_y - t_{op})k_{av}) + C_{Q.gen} t_{op} Q_d \quad (5.5)$$

where, $C_{Q.pp}$ – reactive power provision costs from power plant per year, EUR;ΔP_0 – no-load losses of upgrade technology, MW;

ΔP_{op} – operation losses of upgrade technology, MW;

Q_d – reactive power average demand at power plant connection point, MVAr.

If situation remains same as now and reactive power from generators are not remunerated, then it means that site connected to TSO runs own facilities only when generators are not operating, which means lower running costs and end user price for service. Yearly costs of reactive power provision from site connected to TSO are calculated as follows:

$$C_{Q.sub} = K_p i + K_p k_m + C_e((\Delta P_0 + \Delta P_{op})(t_y - t_{op})k_{av}) \quad (5.6)$$

where, $C_{Q.sub}$ – reactive power provision costs from site connected to TSO per year, EUR.

Price for reactive power provision from site connected to TSO, if generators are not paid for reactive power provision when operating is calculated as:

$$C_{q.sub} = \frac{C_{Q.sub}}{t_y Q_d} \quad (5.7)$$

where $C_{q.sub}$ – hourly price for reactive power provision from site connected to TSO, EUR/MVArh.

Calculations presented in this part are made for capacitor bank / reactance technologies. Usually CCGT operation life is 15 years, that is why in provided calculation after 15th year costs of running reactive service from generator site are calculated by (5.6) too.

Another scenario is that generator, when operating, sells reactive power service to TSO at prices which stated in [114] for 110 and 330 kV connected generators. So, costs of reactive service provision from site connected to TSO are calculated as follows:

$$C_{Qm.sub} = K_p i + K_p k_m + C_e((\Delta P_0 + \Delta P_{op}) t_y k_{av}) \quad (5.8)$$

where, $C_{Qm.sub}$ – reactive power provision costs from site connected to TSO per year if generator reactive power control service should be remunerated, EUR.

(5.8) allow to calculate costs that appear at site connected to TSO to fully cover voltage control service needs. Price for reactive power provision from site connected to TSO, if generators are paid for reactive power provision when operating is calculated as:

$$C_{qm.sub} = \frac{C_{Qm.sub}}{t_y Q_d} \quad (5.9)$$

where $C_{qm.sub}$ – hourly price for reactive power provision from site connected to TSO site, if generator reactive power control service should be remunerated, EUR/MVArh.

Table 5.1

Comparison Between Reactive Power Price at Site Connected to TSO and Generators Site if Reactive Power Provision from Generators is not Remunerated

	Installed power, MVAr	Investments, EUR	End user electricity price, EUR/MWh	TSO price, EUR/ MVArh	Payback time
Site connected to TSO	-18	297 000	60.89	1.31	25
	-70	1 155 000		1.50	25
	-18	297 000	76.11	0.96	25
	-70	1 155 000		1.07	25
110 kV generator	-18/+5	379 500	60.89	1.31	>25
	-18/+5	379 500	76.11	0.96	>25
330 kV generator	-80/+50	2 145 000	60.89	1.50	>25
	-80/+50	2 145 000	76.11	1.07	>25

Table 5.2

Comparison Between Reactive Power Price at Site Connected to TSO and Generators Site if Reactive Power Provision from Generators Should be Remunerated

	Installed power, MVAr	Investments, EUR	End user electricity price, EUR/MWh	TSO price, EUR/ MVArh	Payback time
Site connected to TSO	-18	297 000	60.89	1.70	25
	-70	1 155 000		1.96	25
	-18	297 000	76.11	2.06	25
	-70	1 155 000		2.38	25
110 kV generator	-18/+5	379 500	60.89	1.70	7
	-18/+5	379 500	76.11	2.06	2
330 kV generator	-80/+50	2 145 000	60.89	1.96	>25
	-80/+50	2 145 000	76.11	2.38	4

From results presented in Table 5.2 it is obvious that costs of modernizations for 330 kV generator are too high to ensure competitive price of reactive power control service if electricity market price is low, thus if it is high, generators at 110 kV and 330 kV level can grant better price for reactive power control service provision. Comparing to case in Table

5.1, that is quite similar to existing situation, it is obvious that cost of service provision will rise if generators should be remunerated for reactive power provision when operating.

Prior to make decision about additional equipment installation at generator site it is necessary to calculate costs of same modernization at site connected to TSO to ensure grid security. It is assumed that generators are not remunerated for reactive power provision when operating because Table 5.2 shows that market based price will be higher than if existing practice will be used. In Table 5.3 is provided a comparison of such solution. Calculation shows that it is more economically feasible to make upgrade for system security at site connected to TSO and do not remunerate generators for reactive power provision when they are operating. Costs of service provision are lower than if reactive power provision becomes market based.

Table 5.3

Comparison Between Reactive Power Price at Site Connected TSO and Generators Site if Reactive Power Provision is not Market Based and TSO Should Ensure Grid Security

	Installed power, MVAr	Investments, EUR	End user electricity price, EUR/MWh	TSO price, EUR/ MVArh	Payback time
Site connected to TSO	-18/+5	379 500	60.89	1.37	25
	-80/+50	2 145 000		1.86	25
	-18/+5	379 500	76.11	1.01	25
	-80/+50	2 145 000		1.39	25
110 kV generator	-18/+5	379 500	60.89	1.37	>25
	-18/+5	379 500	76.11	1.01	>25
330 kV generator	-80/+50	2 145 000	60.89	1.86	>25
	-80/+50	2 145 000	76.11	1.39	>25

5.2. Inertia Provision

A study on Baltic country synchronization with Continental European Network (CEN) shows that Baltic states will be lacking 18000 MWs of inertia. It means each country should take measures to provide 6000 MWs lack of inertia. For that purpose, TSO is targeting to install synchronous compensators [35].

Inertia in a power system and the rate of change of frequency (RoCoF) are interrelated. Large amounts of inertia in the system reduce the rate of change of frequency. Power system inertia mainly derives from the kinetic energy stored in the rotors of turbine generators, which then provide kinetic energy to the grid or absorb it from the grid when the frequency changes. With high inertia, the frequency decrease is slower and the frequency containment reserves

(FCR) have more time to react and increase the frequency back towards the rated value [116], [117].

In a power system, inertia refers to the resistance of the system to change its frequency after an incident. Reserves regulate their power according to the frequency and help to keep the frequency near the nominal value. If the frequency becomes too low after a disturbance, loads are shed in progressive steps in order to boost the frequency and to keep the system operational. If load-shedding does not help and the frequency decreases too much, the generators are disconnected from the system and a blackout occurs [117].

Larger amounts of renewable energy, phasing out of nuclear units and higher imports through HVDC connections all reduce inertia and kinetic energy levels. Fig. 5.1 shows how the amount of inertia affects the frequency response after a generator trip [117].

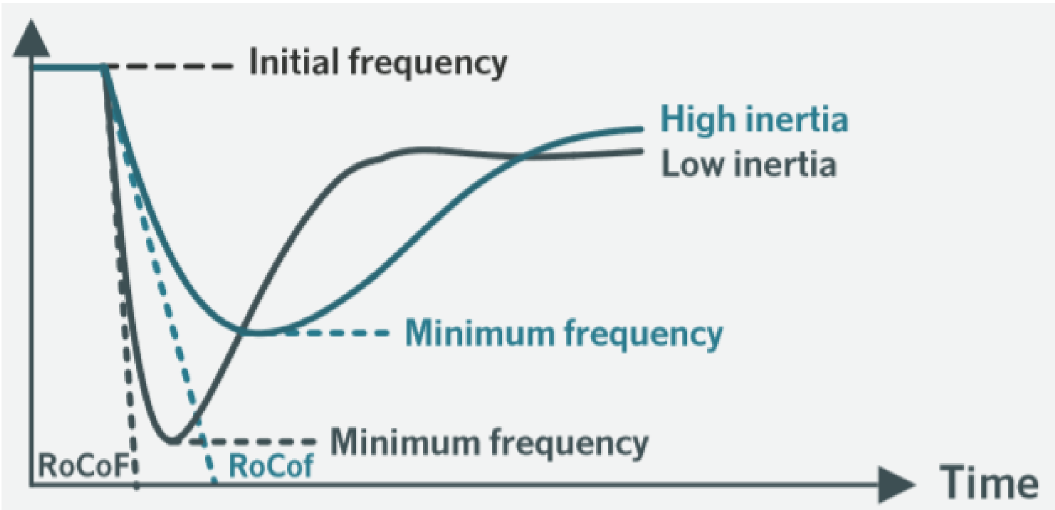

Fig. 5.1 Initial frequency and frequency responses after a generator trip with high and low inertia and the corresponding RoCoF values [117].

Generator, electrical motor or synchronous compensator kinetic energy is expressed as:

$$E = H * S \tag{5.10}$$

where, E – kinetic energy, MWs;

H – inertia constant, s;

S – apparent electrical power, MVA.

According to statistical data Latvian biggest power generation facilities with 3 hydro power plants and two CCGT's power plants can provide demanded 6000 MWs only for 20 - 23% of time per year. But about 200 hours per year biggest generators are stopped and do not provide any inertia. It means, that during the rest of time additional measures should be taken to provide inertia for system.

Inertia constant of synchronous compensators usually varies in a range of 2 – 2.5s seconds. In [118] H=2.5s is reported for 270 MVA, 15.75 kV synchronous compensator. To provide 6000 MWs at least 9 of such synchronous compensators should be installed. Greater inertia could be provided by synchronous compensators with flywheel, such technology allows to reach H=8 s for 200 MVA synchronous compensator. So, number of synchronous compensators will decrease to 4. Thus, this adds additional losses. Flywheels are known for high self-discharge, usually 1 – 1.7% per hour [119], [120] .

Main problem for site connected to TSO to run synchronous compensators are investments because additional power transformers for such large synchronous compensators should be used. In that case costs from 35 000 EUR/MVAr will rise to at least 50 000 EUR/MVAr. If synchronous compensator with flywheel is used, investments will rise for about 26% more [122], [123].

Alternatively, CCGT could be used to provide inertia, thus operating cost might be significant, because electricity should be sold in market below costs for generation, and somehow this should be compensated. Analysis of three marginal scenarios was performed to compare economic effect of installation of numerous synchronous compensators or installation of few synchronous compensators with flywheels in the grid or running CCGT generators to perform such service. Results are presented at Fig. 5.2. Two market electricity price scenarios were analyzed historically lowest of 34.68 EUR/MWh and highest of 49.9 EUR/MWh.

If any generation in Latvia is operating, then only amount of lacking synchronous compensators (SC) is started, all other are disconnected, calculation of number of started SC is made by (5.11). To run SC at site connected to TSO substations no-load losses of applicable power transformer were taken into account, if any of SC were running then declared losses of 1,5% were taken into account as well as additional losses in power transformer.

$$\mathrm{n_{SC}} = \frac{\mathrm{E_d} - E_\mathrm{p}}{E_\mathrm{SC}} \tag{5.11}$$

where n_{SC} – number of lacking synchronous compensators;

E_d – demanded of kinetic energy, for Latvia 6000 MWs;

E_p – kinetic energy provided from all generators in Latvia, MWs;

E_{SC} – one synchronous compensator provided kinetic energy, with or without flywheel, MWs.

Operating costs of synchronous compensator are calculated as follows:

$$C_{oSC} = K_p i + K_p k_m + 8760 C_e n_{SC} \Delta P_{T0} k_{av} + C_e \sum_{t=1}^{8760} [n_{SC.t} * (\Delta P_{SC} + \Delta P_T)] \tag{5.12}$$

where, C_{oSC} – yearly operation costs of synchronous compensators to provide lacking inertia, EUR;

$n_{SC.t}$ – number of running synchronous compensators in hour t to fulfill demand of inertia;

ΔP_{SC} – synchronous compensator operation losses, MW;

ΔP_T – power transformer load losses corresponding to synchronous compensator load,MW;

ΔP_{T0} – power transformer no-load losses, MW.

If synchronous compensator with flywheel is used:

$$C_{oSCa} = K_p i + K_p k_m + 8760 C_e n_{SC} \Delta P_{T0} k_{av} + C_e \sum_{t=1}^{8760} \left[n_{SCt} \left(\Delta P_{SC} + \Delta P_T + \Delta P_{fw} \right) \right] \quad (5.13)$$

where, C_{oSCa} – yearly operation costs of synchronous compensators with flywheel to provide lacking inertia, EUR

ΔP_{fw} – flywheel losses, MW;

n_{SCt} – number of lacking synchronous compensators at t hour.

Calculation of flywheel losses or consumed power from grid per hour is done by:

$$\Delta P_{fw} = \frac{E_{fw}}{3600} \quad (5.14)$$

where, E_{fw} – additional kinetic energy from flywheel, MWs;

When synchronous compensators are used only for inertia provision load losses in power transformer are negligible and could be ignored. In case if reactive power is provided from synchronous compensators ΔP_T should correspond to provided MVAr. Latvian CCGTs were divided into four products depending on lack of inertia in system. Power plants will be started and running according to Table 5.4. Minimum load of TEC – 1 is 30 MW, but for TEC – 2 blocks 200 MW. Electricity generation price of 52 EUR/ MWh was taken for calculation. Running costs were calculated as difference between historical hourly market price and generation costs.

Table 5.4

Deployment of Riga CCGTs to Cover Lack of Inertia

Started CCGTs	Covered lack of inertia, MWs	Total minimum produced energy, MWh
TEC-1	1 – 600	30
TEC-2 one block	600 – 2800	200
TEC-1 and TEC-2 one block	2800 – 3400	230
TEC-2 both blocks	3400 – 5600	400
All RigaCCGTs	> 5600	430

$$C_{oCHP} = \sum_{t=1}^{8760} \left[A_{min.t} \left(C_p - C_{m.t} \right) \right] \quad (5.15)$$

where C_{oCHP} – yearly costs to run CCGTs for coverage on inertia demand, EUR;

$A_{min.t}$ – total minimum energy produced according Table 5.4 in t hour, MW;

C_p – electricity production costs at CCGT, EUR/MWh;

$C_{m.t}$ – electricity market price in t hour, EUR/MWh.

Analysis of Latvian biggest generator operation in previous years shows that average 2654 MWs of inertia will be lacking for 6736 hours per year. As base scenario synchronous compensator with flywheel operation at high electricity market prices is chosen. Operation life of 25 years is considered. According to NPV calculation income per year were calculated to fulfill payback time of 25 years considering all operation and maintenance costs calculated by (5.12) and (5.13). Price per hour of operation was calculated as:

$$C_i = \frac{I_{av}}{E_y} E_h \tag{5.16}$$

where, C_i – lack of inertia provision price per hour, EUR/h;

I_{av} – average income per year to ensure 25 year payback time, EUR;

E_y – total provided inertia per year to cover lack of inertia, MWs;

E_h – average hourly provided inertia to cover lack of inertia, MWs/h.

Results show that one hour of lack of inertia provision will cost 1006.53 EUR in the base scenario. For all other scenarios inertia provision cost from the base scenario was taken as service price. Fig. 5.2 shows that electricity market price has huge impact on costs of inertia provided by generators, whereas for synchronous compensators and synchronous compensators with flywheel installed at site connected to TSO impact is moderate.

SC with flywheel has higher installation costs per unit, but to provided the same inertia 4 instead of 9 synchronous compensators and power transformers should be deployed, also installed power of one SC is 200 MVA instead of 250 MVA for solution without flywheel. Total losses due to flywheel rotation are lower than losses of running additional SC and no-load losses of additional power transformers.

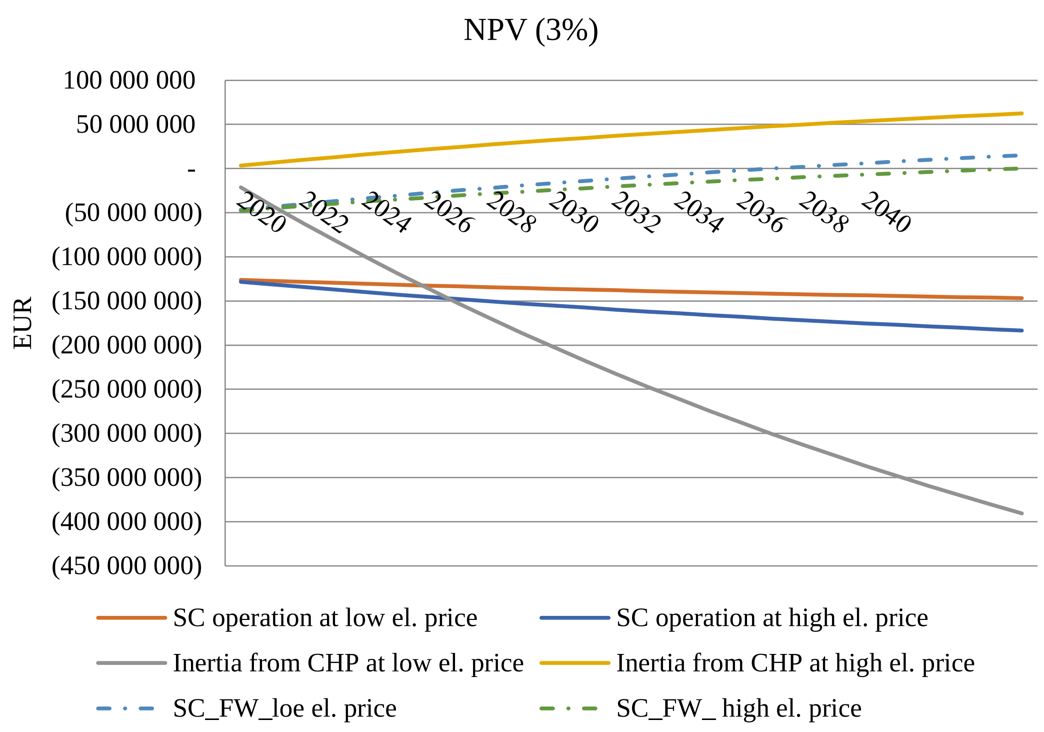

Fig. 5.2 NPV calculation for inertia provision possible solution.

To reduce cost of inertia provision complex solutions should be found, involving newest technologies, hydropower plants and synchronous compensator installation at the generator site, to reduce installation, maintenance and upkeep costs. Combined solution with forced CCGT operation and SC with flywheel can allow to reduce investments and inertia provision costs in long term. Also, synchronous compensators could be used to provide reactive power. which would allow to reduce costs of inertia service provision.

Synchronous compensators could consume about 30% of apparent power as reactive power, which is enough to fulfill demand or reactive power compensation in 330 kV grid according to 5.1. Calculation for reactive power provision is done for SC with flywheel and power plant. As the base scenario is chosen same as previously scenario: SC and flywheel at high electricity market price. Reactive power prices and amount are taken for 330 kV scenarios as were calculated in Table 5.3. Combination of reactive power provision and inertia provision allows to reduce costs for lack of inertia provision to 929.33 EUR per hour.

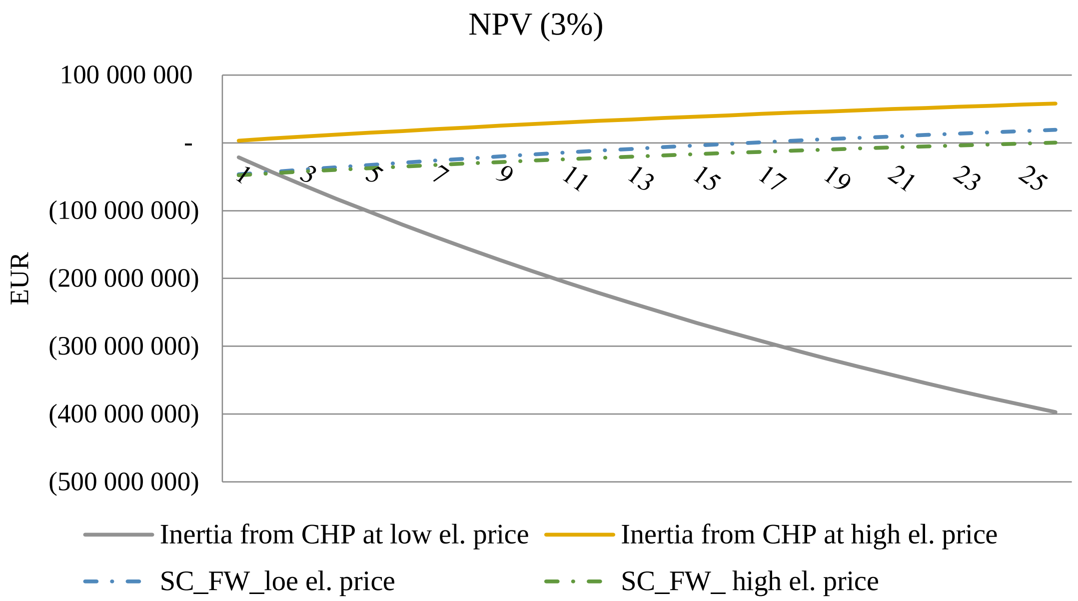

Fig. 5.3 NPV calculation for inertia provision possible solution with reactive power provision.

5.3. Frequency Contamination Reserves

Frequency related services such as frequency containment reserves (FCR) more common as primary frequency control. Full activation of FCR should be within 0-30 seconds and be available for at least 15 minutes. If the frequency deviation lasts longer than 30 seconds frequency restoration reserve (FRR) is activated, FRR can be distinguished between reserves with automatic activation (aFRR) and reserves with manual activation (mFRR). Activation time is between 30 seconds and 15 minutes and should be available for at least 15 minutes

[105]. Graphically it is presented at Fig. 5.4. According to [136] in Latvia 8 MW of FCR is needed, but according to Latvian TSO 15 MW of FCR and 15 of FRR is needed by 2025. Comparison of using BESS at generator and TSO side is performed, to determinate costs of such service.

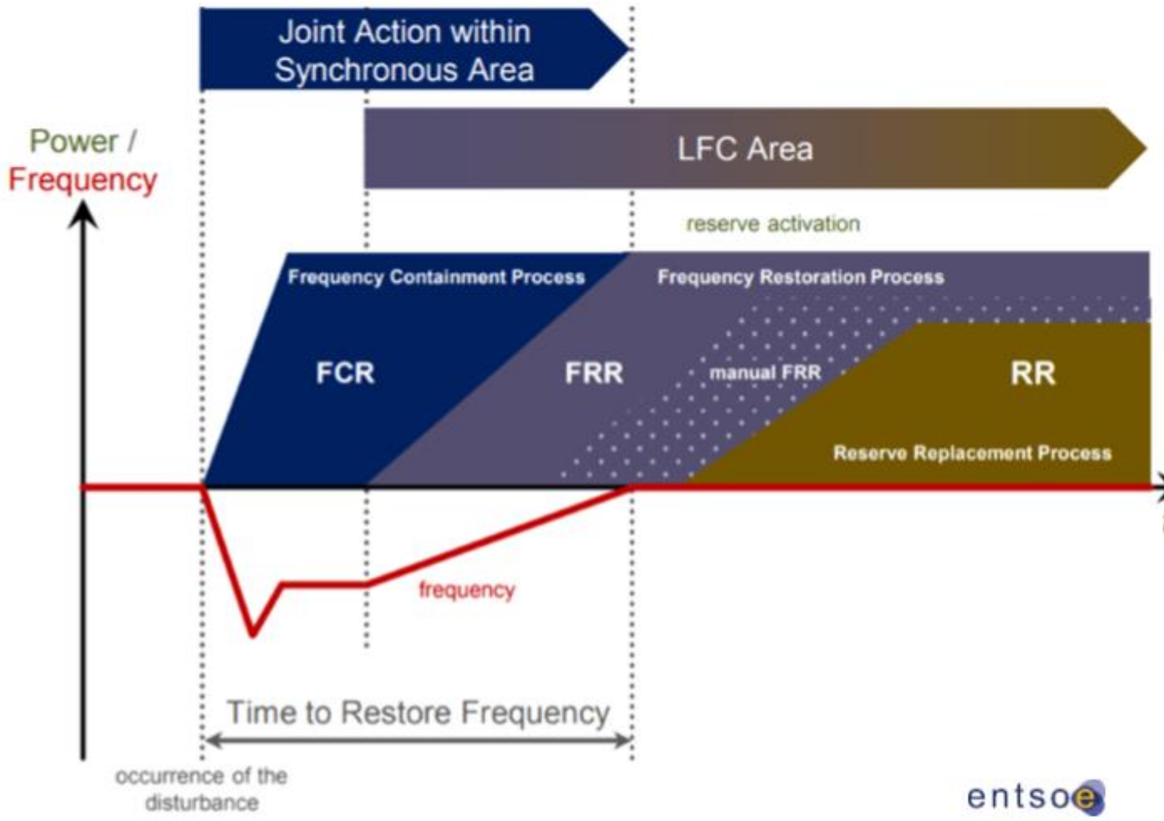

Fig. 5.4 Frequency service activation sequence [137].

At present ENTSO-E timetable both automatic and manual FRR services should be market based by end of 2021, thus, nothing mentioned about FCR [105]. Biggest hydro power plants and CCGTs in Latvia can provide FCR and FRR services for more than 6400 hours per year, rest 2360 such service could be provided by BESS. In this section will be discussed two options of FCR provision, first running BESS at power plant or site connected to TSO, and second, installation of smaller BESS at TEC-1 to provide FCR and FRR service when it is not provided by power plants operating at market, by starting up TEC-1.

First of all, power of BESS installation should be chosen:

$$P_{B.f} = k_p P_{d.f} \tag{5.17}$$

whre, $P_{B.f}$ – power of BESS used for FCR provision, MW;

$P_{d.f}$ – power demand for FCR provision, MW;

k_p – coefficient to prevent lack of power, used 1.05.

BESS usually is half loaded, because needs to have possibility to provide service in both directions. It means that BESS should be able to store at least twice of TSO demanded energy amount. Capacity of BESS should be enough to provide FCR service for 15 minutes, also lower and upper limit of state of charge should be taken into account, as it was described in subsection 4.4:

$$A_{B.f} = 2k_c t_f P_{B.f} \tag{5.18}$$

where, $A_{B.f}$ – BESS capacity for FCR provision, MWh;

t_f – time to provide FCR, h.

k_c – coefficient to prevent overcharge and under discharge of BESS, used 1.3,

BESS upkeep costs for site connected to TSO:

$$C_{up.sub} = K_p i + K_p k_m + C_e\left(8760k_{av}P_{bs} + 12A_{B.f}k\right) \tag{5.19}$$

where $C_{up.sub}$ – total upkeep costs at site connected to TSO, EUR.

Operational costs of BESS for FCR provision is hard to calculate. Problem is that BESS power as well as charging and discharging in primary control mode fluctuates in narrow window and biggest losses are related to inverter operation and no-load losses, which already are considered. According to [9] deadband of 10 mHz and droop of 2% are toughest requirements for generators, and same could be applicable for frequency primary control, according to [138]. In Continental European Network average deviation of frequency during past years is 0.016 Hz, and maximum deviation is usually within 0.1497 Hz. So average operating power is:

$$P_{f.op} = 100\frac{\Delta f}{f}\frac{P_{B.f}}{s} \tag{5.20}$$

where, $P_{f.op}$ – average operating power of BESS for FCR provision, MW;

f – power network frequency, Hz;

Δf – average yearly deviation of power network frequency, Hz;

s – droop demanded by TSO requirements;

Calculations show. that every hour when BESS operating in FCR provision mode it should activate 1.6% of installed power. Inverter losses for such low power can be quite high because efficiency reduces from 0.97 to 0.63 according to [139]. Then hourly additional energy should be purchased to ensure operation of the system:

$$A_{op.f} = \frac{\Delta P_{f.op}}{\eta_{op.l}} t_{op.f} \tag{5.21}$$

$A_{op.f}$ – energy purchased for operation in FCR mode, MWh;

$\eta_{op.l}$ – inverter efficiency operating at lower than rated power;

$t_{op.f}$ – time per year when BESS operates in FCR mode, h.

So total costs of FCR provision are:

$$C_{r.op} = C_{up.sub} + C_e A_{op.f} \tag{5.22}$$

where $C_{r \cdot op}$ – total yearly operation costs of BESS for FCR provision, EUR.

In case if BESS installed and runs at generator site, C_e in (5.19) and (5.22) should be substitute to $C_{el.pp}$. To provide FCR of 15 MW for 15 minutes, BESS with rated power of at least 15.75 MW should be installed. Capacity of battery should be 10.25 MWh. So 15.75 MW / 10.25 MWh BESS solution should fulfill FCR demand, investments for such BESS according to information presented at 4.4 should be 6 850 000 EUR.

NPV calculations are made for several electricity market price scenarios, assuming operation life of 10 years, so price of service at its minimum should grant payback time of 10 years. Due to 2% time for maintenance each year, BESS could not provide FCR all year long. Results are presented in Table 5.5.

Table 5.5

Costs of FCR if generators are not performing in service provision

Scenario	End user electricity price, EUR/MWh	Operating hour per year, h	Cost per MW per operation hour, (EUR/MW) per h
BESS at site connected to TSO. No EU foundation.	76.11	8585	10.73
	60.89	8585	9.93
BESS at generator site. No EU foundation.	76.11	8585	9.67
	60.89	8585	8.87
BESS at site connected to TSO. 75% EU foundation.	76.11	8585	6.60
	60.89	8585	5.73
BESS at generator site. 75% EU foundation.	76.11	8585	5.47
	60.89	8585	4.73
BESS at site connected to TSO. 75% EU foundation. FCR is market based. (BESS operates 2400 h)	76.11	2400	20.93
	60.89	2400	18.46
BESS at generator site. 75% EU foundation. FCR is market based. (BESS operates 2400 h)	76.11	2400	17.60
	60.89	2400	15.53

Providing FCR service from generator site is cheaper than from site connected to TSO, it is due to lower self-consumption price when generators are operating. Without EU financing costs for provision of such service is almost two times higher. If foundation is provided to only one side – site connected to TSO or generator, then other side has no chances to compete. If generators will perform in FCR service, FCR from BESS will be needed only for 2400 hours per year and price of one MW per hour provided from BESS will rise significantly.

If generators will perform in FCR and TEC-1 is upgraded by installation of BESS, it also could perform in FCR service provision. In such case hours when FCR service is not provided will decrease from 2400 hours per year to 1285 hours per year (none of generators could provide FCR). If TEC-1 will be started only for FCR provision, produced electricity will be sold on the market at price below generation costs, this difference also is covered in service provision cost calculation. Same as previously price per MW per hour is calculated for payback time of 10 years. Additional costs to run CCGT to provide FCR could be calculated as:

$$C_{f.op} = \sum_{t=1}^{8760} A_{f.t} \left(C_p - C_{m.t} \right) \tag{5.23}$$

where, $C_{f\cdot op}$ – costs for CCGT operation for FCR provision, EUR;

$A_{f.t}$ – CCGT energy production when providing FCR, MWh;

C_p – electricity production costs at CCGT, EUR/MWh;

$C_{m.t}$ – electricity market price in t hour, EUR/MWh;

As power plant runs at minimum load it can perform in FCR provision too, it allows to decrease power and capacity of BESS.

$$P_{B.fg} = k_p \left(P_{d.f} - P_{GT.30} \right) \tag{5.24}$$

whre, $P_{B.fg}$ – power of BESS coupled with gas turbine used for FCR provision. MW;

P_d – demanded power gain per 1 minute, MW;

$P_{GT.30}$ – GT power gain per 30 seconds, MW;

Capacity of BESS in such case can be calculated as follows:

$$A_{B.fg} = \ 2k_c \sum_{t=0.01667}^{T} \left[0.01667 P_{d.f} - t P_{GT.f} \right] \tag{5.25}$$

where, $A_{B.r}$ – BESS capacity for FCR provision when coupled with gas turbine, MWh;

$P_{GT.f}$ – gas turbine ramping speed, MW/min;

t_f – time to provide FCR power, h;

T – time to reach $P_{d.f}$ using only gas turbine ramping speed $P_{GT.f}$, h.

Total costs of FCR provision from all biggest generators in Latvia after TEC-1 upgrade could be calculated as:

$$C_{up.gen} = K_p i + K_p k_m + C_{e.pp} \left(8760 k_{av} 8760 P_{bs} + 12 A_{B.fg} k \right) + C_{f.op} \tag{5.26}$$

where $C_{up.gen}$ – total upkeep costs at site connected to TSO, EUR.

TEC-1 could be operated at 30 MW power during hours when no other generators can provide FCR. To provide FCR of 15 MW for 15 minutes, BESS with a rated power of at least 14 MW should be installed. Capacity of battery should be only 2 MWh, considering all constrains mentioned for previous case. 14 MW / 2 MWh solution should fulfill FCR demand, investments for such BESS according to information presented at 4.4 should be 4 450 000 EUR. Also, lower self-consumption costs will appear due to smaller size of BESS. Total investments for this project will be lower by 2 400 000 EUR than for previous case. Results are presented in Table 5.6.

Upgrading of Riga TEC-1 can lead to lower FCR price per MW per hour, which could be provided from all biggest Latvian generator sites all year long. Thus, if EU founding of 75% is given for BESS installation, generators are not performing in FCR provision and low electricity market prices are prognosed then the best solution is installation of BESS at generator site.

Table 5.6

Costs of FCR if Generators Perform in Service Provision and 100% Covers it

Scenario	End user electricity price, EUR/MWh	Additional operating costs due to CCGT operation per year, EUR	Cost per MW per operation hour, EUR/MW/h
Riga TEC-1 upgraded with BESS. No EU foundation.	76.11	100 320	7.27
	60.89	321 507	8.47
Riga TEC-1 upgraded with BESS. 75% EU foundation for BESS.	76.11	100 320	4.60
	60.89	321 507	5.80

If FCR market is open, then none of stand-alone BESS solutions can compete with Riga TEC-1 upgrade and service provision from all biggest generators. When biggest generators are in operation, they can provide FCR service almost at no costs, and only upkeep of BESS installed at TEC-1 should be covered. Thus, if none of biggest generators can provide FCR, none is operating, or all operating generators are at their minimum/maximum power, then TEC-1 should be started to perform in FCR provision.

Total costs of service provision all year long from BESS installed at site connected to TSO without fund support is 17% higher than in case of TEC-1 upgrade. In case of open market generators will provide cheaper price for most time of the year and only 2400 hours per year will be available for other players. To cover all year upkeep costs BESS operators will be forced to raise price per MW per hour significantly, it will lead to higher total cost of service per year and as result higher expenses for end user, than if TEC-1 is upgraded.

5.4. Summary

Calculations of investments and operating costs for reactive power provision show that existing model, when power plants are not remunerated for reactive power provision leads to lowest possible costs of reactive power for end-user. Assumption that existing generator should fulfill RfG requirements and install upgrades to perform in reactive power market show that costs of reactive power provision from generators will be higher than from site connected to TSO, it appears due to high investments for generator, which should install more powerful equipment to fulfill RfG than demand of reactive power is. Thus, even without investments for any upgrades, generators have additional expenses for reactive power provision which should be covered and are not covered at present. If these expenses are covered end-user price of reactive power will rise.

Inertia provision will be very actual service after 2025 which is indicated by various studies. Investments and operation costs for three different possibilities of inertia provision were analyzed – synchronous compensators, synchronous compensators with flywheel and CCGT operation during lack of inertia. Indicative costs of inertia provision are 1006.53 EUR per hour to cover average lack of inertia for 6736 hours per year. Best solution is installation of synchronous compensators with flywheel, but in case of high electricity market prices more efficient is to run CCGT's. If mentioned synchronous compensators are used for reactive power provision, priced at the reported lowest rate for 330 kV grid end-user, then costs of inertia could be reduced to 929.33 EUR per hour. Still, overall inertia provision costs are very high, complex solution should be found to provide inertia at lower rate.

Analysis of investments and operation costs for FCR provision was made for three main solutions: BESS connected to TSO; BESS deployed at generator site; small BESS coupled with CCGT generator. Lowest costs of FCR provision per MW per hour are if biggest generators in Latvia are remunerated for this service and TEC-1 is upgraded with 14 MW/ 2 MWh BESS. The next best option is deployment of 15.75 MW 10.25 MWh BESS at generator site. BESS connected to TSO will suffer higher operating costs due to more expensive self-consumption electricity. If any support from funds is provided, it should be available for all parties, otherwise it will lead to an inability to provide FCR as market based service.

6. CCGT SEFLF-CONSUMPTION MODERNIZATION

Electricity self-consumption of modern CCGT is quite low, thus changes in European policies and development of photovoltaic and BESS technologies makes to think about possibilities to use such technologies to reduce operation costs of CCGT's. Photovoltaic (PV) installation and BESS usage are reported in [45], [124] as measure to move towards zero-emission buildings, which should work for CCGT self-consumption needs too. Even more, [46] reported such solutions as cost effective, thus it was in Australia. Therefore [125] reports that Latvia has lowest PV usage in Baltic states.

At TEC-2 located in Riga small PV system was installed, results of 3 year operation and usage for CCGT self-consumption needs show possibility to reduce finances used for electricity purchase. Basing on data from installed PV system calculations for bigger systems is made in this work, to find the most economically feasible size of PV system for CCGT self-consumption needs. Calculation methodology, which considers power plant self-consumption electricity price changes depending on operation mode, as well as results of program calculation are presented. [121]

Another possibility to reduce costs of self-consumption is to use BESS for peak price shaving, such a solution is proposed in [126]. The more advanced solution could be to use BESS for PV energy storage, CCGT generated energy storage and peak price shaving, which is discussed further. Previously mentioned methodology was enhanced to optimize PV and BESS usage depending on CCGT operating regime to ensure lowest self-consumption costs. Both developed algorithms were tested on historical data of real CCGTs and real electricity market prices.

6.1. PV Generation for Self-Consumption Needs

European Union for 2030 set a target to reach at least 27 % share of renewable energy in total consumption in the EU and at least 27 % energy savings comparing to the business-as-usual scenario. From 2008 to the second quarter of 2017, photovoltaic electricity system prices fell by over 80 % in most competitive markets, and in an increasing number of markets the cost of photovoltaic-generated electricity is already cheaper than residential electricity retail prices. It is interesting to note that photovoltaic module prices also decreased by over 80 %, during the same period and now represent less than half of the costs of an installed PV system. Due to falling PV system prices and increasing electricity prices, the number of such markets is steadily increasing [127].

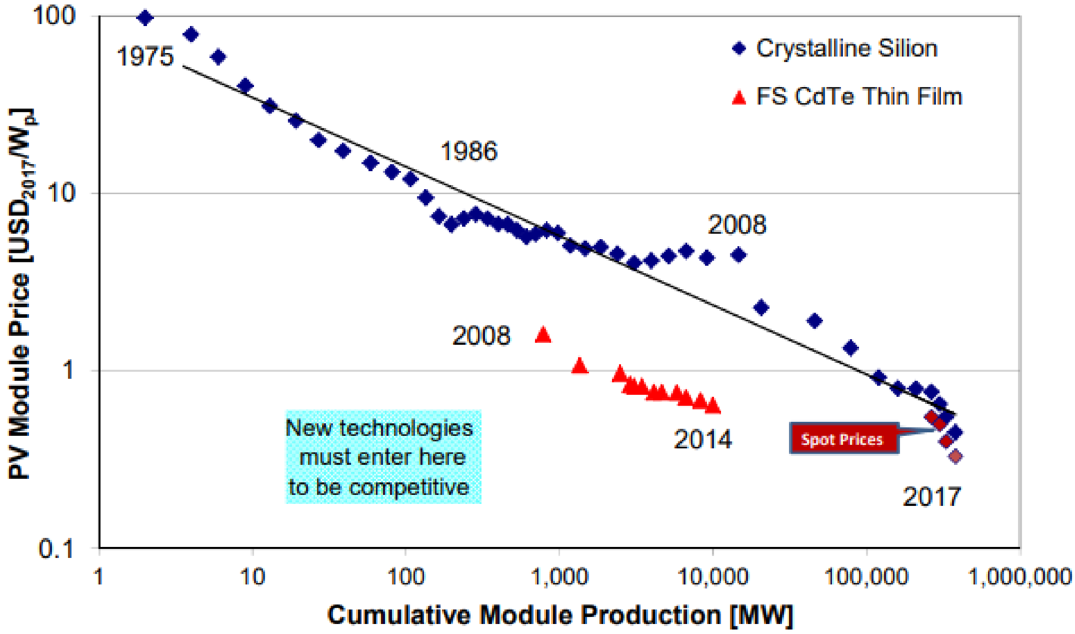

Fig. 6.1 Price-experience curve for solar modules [127].

Photovoltaic system installation became cheap enough and provides better than ever efficiency, due to rising prices for end user of electricity it becomes more and more interesting to install photovoltaic system in households and industrial utilities. At Fig. 6.1 presented decrease of photovoltaic module price which in 2017 reached mark of 0,59 EUR/Wp. Levelized cost of solar energy goes down, for utility scale PV systems it vary in range of 41 to 47 EUR/ MWh and have dropped by 86% from 2009 till 2017 [127], [128]. At such levelized costs of energy solar panels are quite competitive to CCGT with levelized energy cost of 37 to 69 EUR/ MWh. Solar generation at CCGT site could be used to cover self-consumption electricity consumption and reduce costs.

By producing clean energy from PV system CO_2 emission allowance trading is possible, or in case of overhitting the cap CCGT could avoid of buying CO_2 allowance in the market. Different prognosis provides information about CO_2 allowance price change in future, most of them prognose price of 40-50 EUR/t by 2030. Thus Refinitiv (former the financial and risk business of Thomson Reuters reported) in the end of 2018 prognosed more stable prices, prognoses are presented in Table 6.1. [8], [130], [131]

As an experimental set small PV system was installed at TEC-2 CCGT power plant in Riga for self-consumption provision and to check real capabilities of PV systems in Latvia. Data from this system were used to calculate the exact NPV and payback time of this installation, it resulted in 15-16 years for 4.6 kW system, which is good result for a system that is prognosed to operate 20 years. In addition, data from installed PV system with all known parameters allows to prognose yield amount of energy from PV system of different size after inverter – real produced energy delivered to power plant self-consumption. Usually in calculations of PV system losses in inverter are taken as an average value, for further calculations real data including inverter losses according to operation regime will be used.

Table 6.1

CO_2 Emission Allowance (EUA) Price Prognosis by Different Organizations

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Refinitiv EUA Price, EUR/t	22	24	22	22	21	20	19	19	18	18	20	21
Platts EUA Price, EUR/t	24.98	31.58	38.17	44.76	51.24	57.83	64.43	NA	NA	NA	NA	NA
EU Carbon Analysis EUA Price, EUR/t	9	8	9	10	15	20	27	32	36	39	44	49

In Fig. 6.2 is presented simulated typical solar generation and CCGT self-consumption during summer day. But for some days may appear situation presented in Fig. 6.3. If generated energy is not stored, any overproduction won't be used for self-consumption and will be delivered to the grid at market price. Higher installed power of PV system will help to cover more self-consumption by solar energy, but also additional investments might be significant, as result payback time, which should be within 20 years, will grow, but net present value will decrease. To find an optimal solution, calculation of all profits and losses as well as NPV should be done.

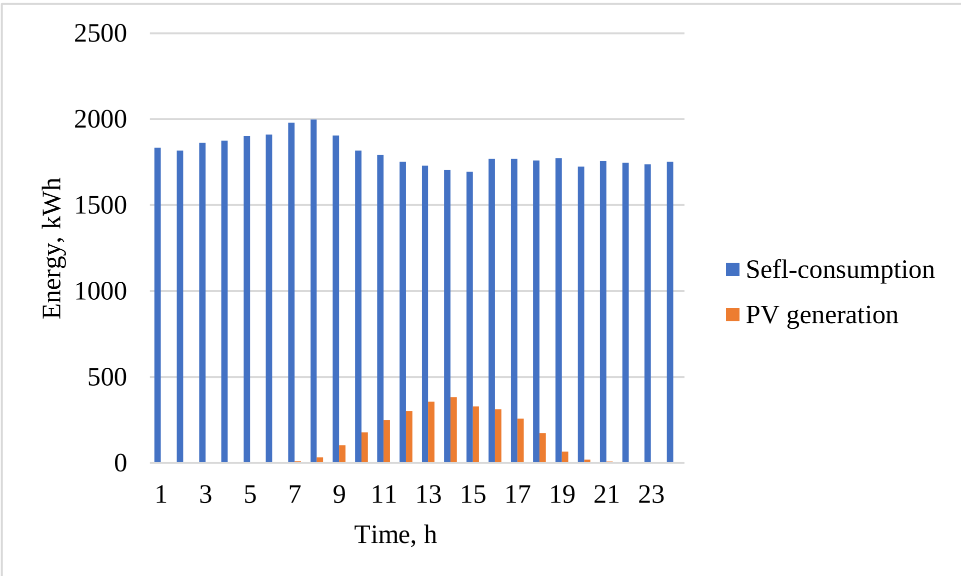

Fig. 6.2 CCGTplant self-consumption during summer day and modeled PV generation.

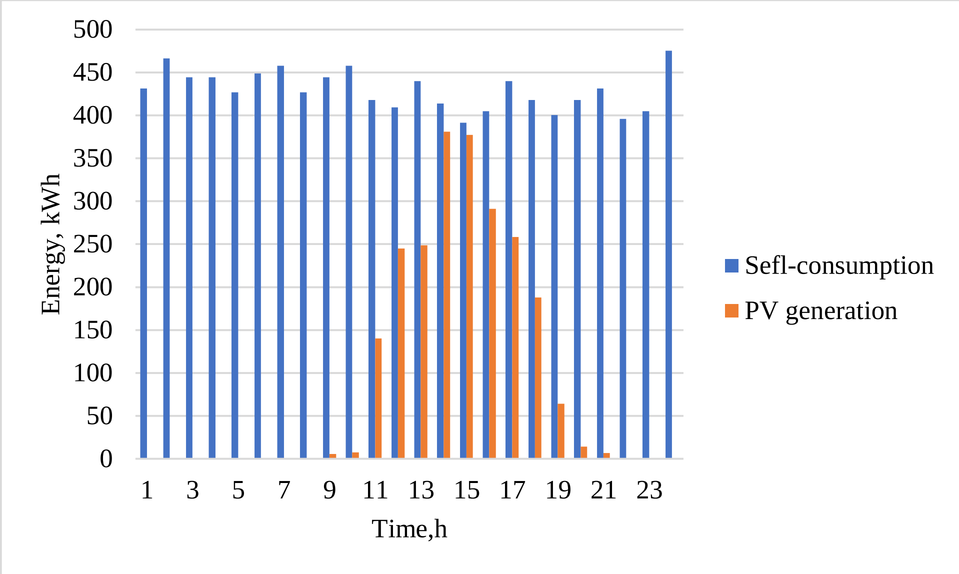

Fig. 6.3 CCGT plant self-consumption during summer with lower demand for self-consumption day and modeled PV generation.

PV system installed at TEC-2 provides data about energy generation after inverter. Basing on obtained data hourly solar irradiation, which includes losses in PV panels and inverter, was calculated. Such data allows to adopt it for any scale and type of PV panels if inverter with similar efficiency curves is used. At Fig. 6.4 and Fig. 6.5 are presented data for residential invertor used as data source and central inverter, which is used for calculation. In further calculations difference of inverter efficiency were not taken into account, because generally efficiency curves of presented inverters have same shape and for utility scale application special junction boxes are used adding 1-2% of losses, which will compensate better performance of utility scale inverter comparing to residential.

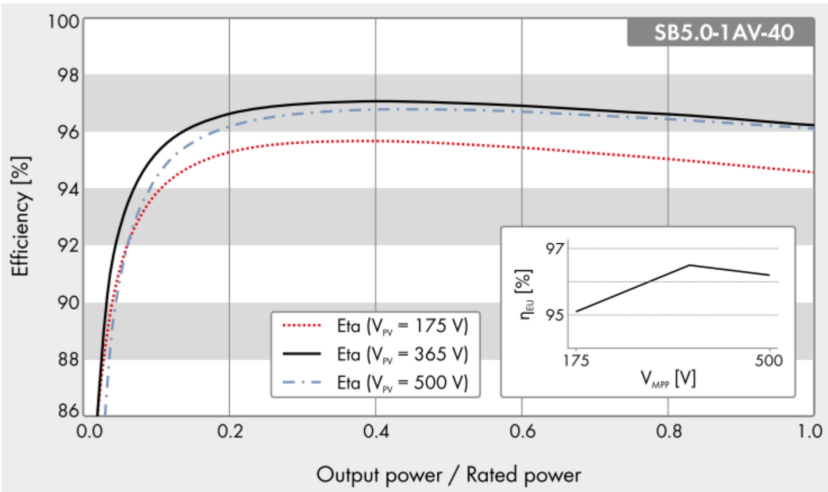

Fig. 6.4 Installed PV system inverter efficiency curve [129].

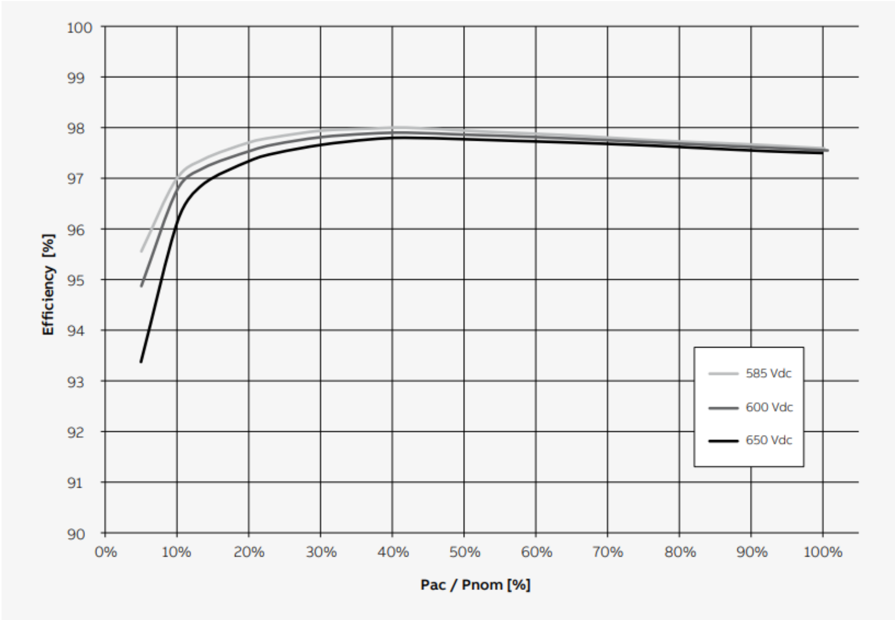

Fig. 6.5 Industrial type 400 kW solar inverter efficiency curve [41].

To calculate hourly solar irradiation that one PV panel got, obtained data were used:

$$P_{sp.t} = \frac{P_{gen.t}}{S_{inst}} \tag{6.1}$$

$$I_t = \frac{P_{sp.t}}{\eta_{inst}} \tag{6.2}$$

where, $P_{sp.t}$ – specific PV power at hour t, kW/m^2;
$P_{gen.t}$ – installed PV panel generated power after inverter at hour t, kW;
S_{inst} – total area of all installed PV panels, m^2;
I_t – solar irradiation at hour t, kW/ m^2;
η_{inst} – installed PV panel efficiency.

For any new system specific power for one panel can be calculated from hourly solar irradiation:

$$P_{sp.t} = I_t \eta_{inst} \tag{6.3}$$

Any new installation will consist of PV modules of one type and same size, calculation of area of all modules should be done, then (6.4) should be used to calculate total generation of PV system at the desired hour.

$$P_{PV.t} = P_{sp.t} S_{inst.n} \tag{6.4}$$

where, $P_{PV.t}$ – new PV installation generated power after inverter at hour t, kW;
$S_{inst.n}$ – total area of all new installed PV panels, m^2.

Additional losses will appear due to power transformer and cable line. Losses in power cable in further calculation will be limited to 2%, but losses in power transformer will be calculated according to installed power and losses defined in Commission regulation No

548/2014 requirements for tier 2 power transformers. Also, it is considered that power transformer is not operating if there is not enough solar generation. Power to run inverter control system is reported as 1% of installed power and also 2% losses in cable feeding inverter self-consumption are considered.

$$\Delta P_{inv.t} = P_{inv.n}\mathrm{k_{ic}} + (P_{inv.n}\mathrm{k_{ic}})\mathrm{k}_c \tag{6.5}$$

where, $\Delta P_{inv.t}$ – losses in inverter at hour t, kW;

$P_{inv.n}$ – PV inverter nominal power, kW.

k_{ic} – PV inverter control self-consumption, p.u.;

k_c – Losses in power cables, p.u.

Calculation for power transformer losses:

$$\Delta P_{T.t} = \Delta P_{T0} + P_{Tk}\,(\frac{P_{PV.t}}{cos\varphi * S_T})^2 \tag{6.6}$$

$\Delta P_{T.t}$ – power transformer losses at hour t, kW;

ΔP_{T0} – power transformer no-load losses, kW;

S_T – power transformer apparent power, kVA;

P_{Tk} – power transformer load losses, kW.

And losses in medium voltage cables at hour t are calculated as:

$$\Delta \mathrm{P}_{c.t} = \mathrm{k}_c(P_{PV.t} + \Delta P_{T.t}) \tag{6.7}$$

Power from PV system at hour t is calculated as:

$$\begin{cases} P_{s.t} = (P_{PV.t} - \Delta P_{inv.t} - \Delta P_{T.t} - \Delta \mathrm{P}_{c.t}) \\ P_{PV.t} - \Delta P_{inv.t} - \Delta P_{T.t} - \Delta \mathrm{P}_{c.t} < 0 \;\rightarrow\; P_{s.t} = (P_{PV.t} - \Delta P_{inv.t}) \end{cases} \tag{6.8}$$

where $P_{s.t}$ – total provided solar power at t hours, kW.

Calculation algorithm is presented at Fig. 6.6. It is used to calculate new costs for self-consumption, the difference in total spent money for self-consumption between normal self-consumption system and system with installed PV is considered as gain provided by PV system and in NPV calculation is used as revenue. As (6.8) includes all losses and consumptions of PV system, in NPV calculation module only credit interest and maintenance of PV system is added as costs:

$$NPV_y = NPV_0 + \left(I_y - C_y\right)d_y = NPV_0 + (I_y - (K_p k_m + K_p i)) \tag{6.9}$$

where, NPV_y – net present value of y year, EUR;

NPV_0 – net present value of project start year, EUR;

I_y – PV system income in y year considering all losses in PV system and degradation, EUR;

C_y – total operating and maintenance costs of PV system in y year, EUR;

d_y – discount rate of y year, %.

Optimal use of solar energy in power plant self-consumption is achieved when the function below is minimized:

$$\begin{cases} f(R) = \sum_{t=1}^{t}\left[C_{m.t}\left(A_{g.t} - A_{d.t}\right) + C_{sc.t}(A_{c.t}) - C_{s.t}(A_{s.t})\right] \\ A_{c.t} - A_{s.t} < 0 \; \rightarrow \; C_{s.t}(A_{s.t}) = C_{sc.t}(A_{c.t}) + C_{m.t}(A_{s.t} - A_{c.t}) \\ A_{c.t} = 0 \rightarrow \; C_{s.t}(A_{s.t}) = C_{m.t}(A_{s.t}) \\ A_{c.t} - A_{s.t} > 0 \; \rightarrow \; C_{s.t}(A_{s.t}) = C_{sc.t}(A_{s.t}) \end{cases} \quad (6.10)$$

where $C_{m.t}$ – Nordpool spot market price at *t* hour, EUR/MWh;

$A_{g.t}$ – power plant generated energy at *t* hour, MWh;

$A_{d.t}$ – power plant delivered to the grid energy at *t* hour, MWh;

$C_{sc.t}$ – self-consumption electricity price at *t* hour, EUR/MWh;

$A_{c.t}$ – power plant consumed from the grid energy at *t* hour, MWh;

$C_{s.t}$ – PV system generated electricity price at *t* hour, EUR/MWh;

$A_{s.t}$ – PV system generated energy at *t* hour, MWh;

Power plant hourly generated energy always is greater than energy delivered to the grid, difference of these values is self-consumption. During power plant shut-down and startup's energy is consumed from the grid and also is used for self-consumption. Produced solar energy is used to cover self-consumption needs. In case if generated solar energy is greater than self-consumption of power plant, it is sold in electricity market. When generator operates and does not consume any energy from the grid ($A_{c.t}$=0), energy provided from PV system is priced as market price, because it just allows generator to deliver more energy to market. When generator is shut down and PV generation is lower than self-consumption ($A_{s.t}$<$A_{c.t}$), PV generated energy is priced as self-consumption energy from the grid, because compensates price which could be paid. But if PV generation is higher than consumed power from the grid ($A_{s.t}$>$A_{c.t}$), part of generation is at price of self-consumption electricity,but other part is at market price. It means that function component $C_{s.t}A_{s.t}$ can change hour to hour.

It is obvious that installing more powerful PV system solar generation will rise and as result (6.10) will decrease. But increase of PV system does not always lead to better economic performance. So, results of (6.10) should be used in NPV calculation.

The special program was developed to deal with (6.10) and NPV calculation (6.9). Input data are presented in Table 6.2 but calculation algorithm in Fig. 6.6. For NPV calculation it is essential to know investments and prognosed revenue, which will be calculated in module which solves (6.10). Basing on solar generation avoided CO_2 emissions are calculated. Revenue from CO_2 certificates is calculated in NPV module.

Table 6.2

Inputs for Calculation

Designation	Units	Description
A_g	kWh	Power plant generated energy
A_d	kWh	Power plant delivered energy to the grid
A_c	kWh	Power plant consumed energy from the grid
C_m	EUR/MWh	Nordpool spot market price
C_g	EUR/MWh	Clean energy component (set as 22.68 EUR/MWh)
C_{TSO}	EUR/MWh	Transmission system operator tariff (set as 3.53 EUR/ MWh)
n	-	Amount of installed PV panels
S_{PV}	m^2	Total area of one installed PV panel
η_{inst}	p.u.	Installed PV panel efficiency
I	kW/ m^2	Solar irradiation
$P_{inv.r}$	kW	PV inverter rated power
k_{ic}	p.u.	PV inverter control self-consumption
k_c	p.u.	Losses in power cables
S_T	kVA	Power transformer apparent power
ΔP_{T0}	kW	Power transformer no-load losses
P_{Tk}	kW	Power transformer load losses
$cos\varphi$	-	Power factor for power delivered from PV inverter to consumption
m_{CO2}	t/kWh	Avoided CO_2 emissions

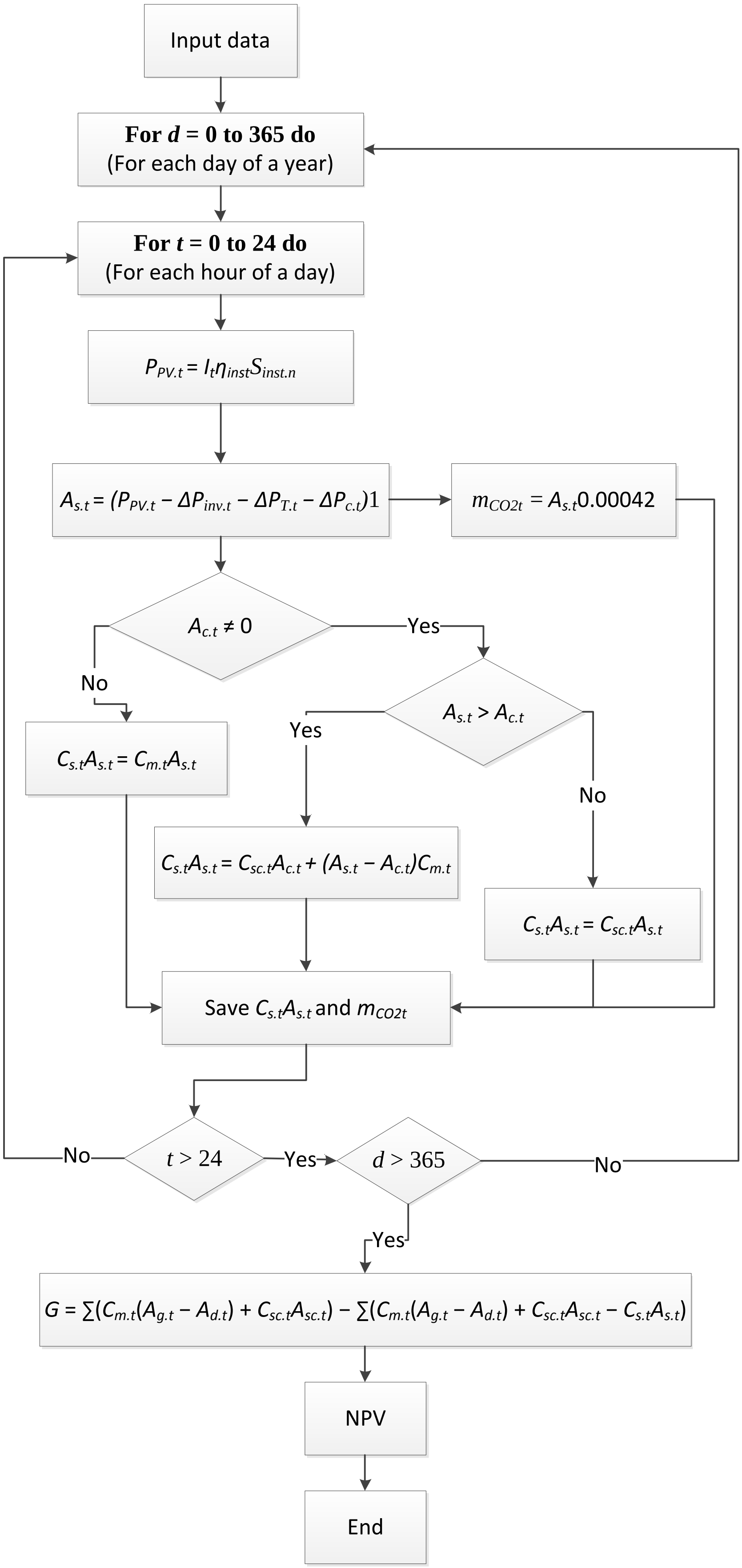

Fig. 6.6 Algorithm to calculate PV generation gain (G) for self-consumption use.

In NPV calculation PV system generation reduction of 1% per year is taken into account. Discount rate for NPV calculation is set as 3%. Average price per 1 kW of PV installation was calculated basing on known PV panel price and large inverter prices with integrated power transformer and circuit breaker, as well as using data from [127] presented at Fig. 6.7, fees/permit part of installation costs were excluded, because this work will take place within existing power plant. Total calculated costs per PV system one kW are 790,96 EUR.

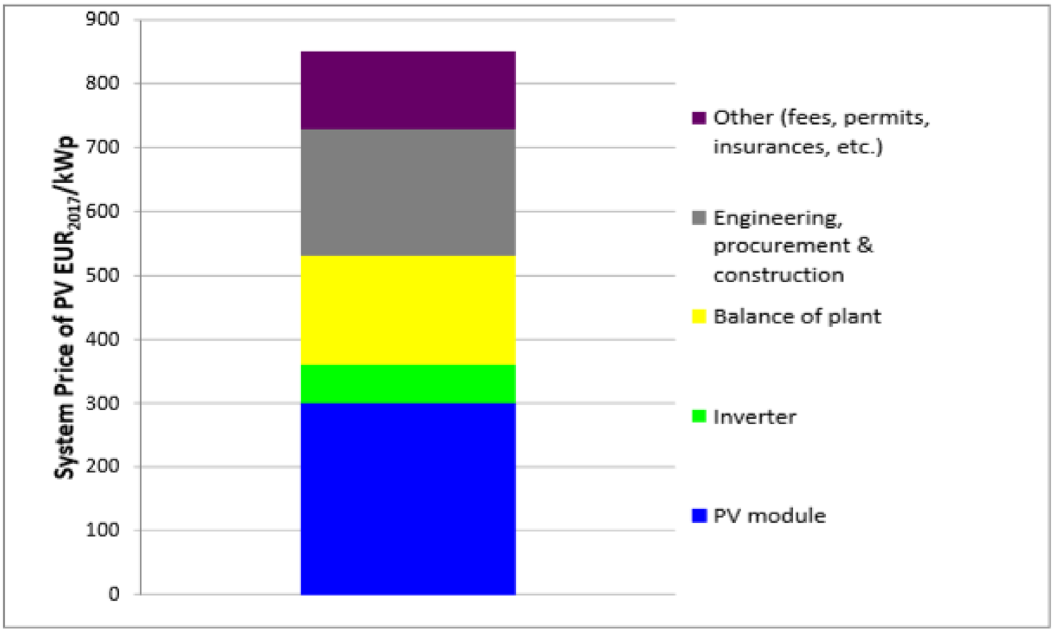

Fig. 6.7 Costs of utility-scale PV system [127].

Calculation of solar system operation for providing power plant self-consumption was performed for two power plants. One with high operating hours (3145) in summer and as result high demand of electricity, which mostly is covered by generators and a second one with low operating hours (346) during summer period as result low demand of electricity, but which mostly is supplied from the market. This analysis was performed for two different years, representing real generation and self-consumption of each power plant. These years had difference in market electricity price – 43.88%, as well as second year had more sunny days which resulted in 14.3% gain in solar generation. Two scenarios with CO_2 emission allowance price were analyzed, one with stable and relatively low price and second with fluctuating and rising price of allowance prognosed by EU carbon analysis in Table 6.1.

As European Union consistently moves towards clean energy sources it was assumed that credit with 0% interest rate could be provided, because at 3% interest rate none of discussed scenarios give payback time below 20 years. In addition, scenarios with 25% support were analyzed, it could be financing from EU or decrease of investments due to technology development. These scenarios could be used in case if investment drop by 25% for PV systems. The results of research are presented in Fig. 6.8 and Fig. 6.9.

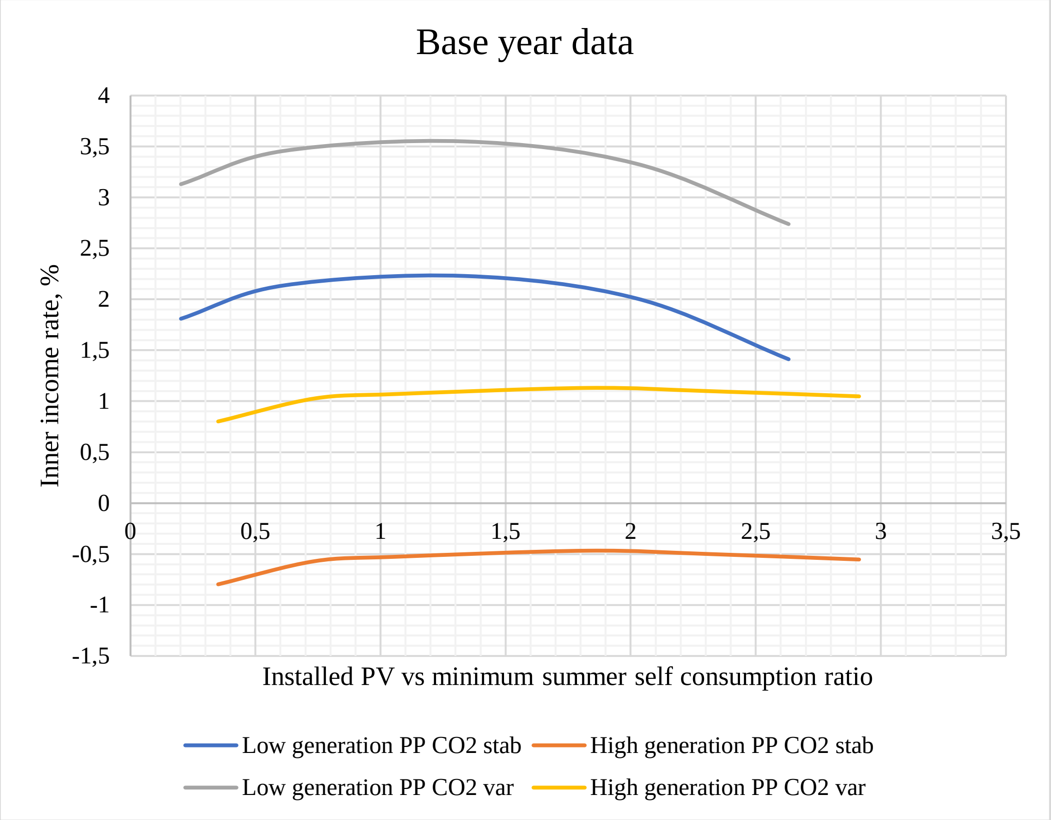

Fig. 6.8 Inner income rate (IRR) for base year scenarios with NPV (3%).

In [44] it was stated that minimum summer load is a constraint for maximum power of PV system because any overproduction will be sold on market at lower rate, that could be used for self-consumption needs and will result in lower profit of PV system. Thus, calculation result shows, that PV system optimal scale is in range 0.8 – 1.5 of minimum summer load to gain the best profitability. In some case of high CCGT operation hours during summer months even greater PV system oversizing might be applicable.

For power plant with high operating hours in summer installed PV system power has lower impact on IRR than for power plant with lower operating hour number in summer. Especially when PV system installed power ratio to minimum self-consumption load overcomes 1.5 mark. It can be explained, by much higher than minimum summer self-consumption when power plant is in generating mode. This statement is proved by second year data, where summer generation of power plant with higher operating hour number reduced by 38,76%, which led to change of IRR curve shape (Fig. 6.9). Also, more sunny year expand range of optimal size of PV panel installation, now 0.7 – 1.7 ratio to minimum self-consumption in summer is quite profitable.

Change in CO_2 emission allowance pricing mechanism gives 1.15% to 1.6% in IRR, at lower electricity price and solar generation impact of CO_2 emission allowance on IRR is higher.

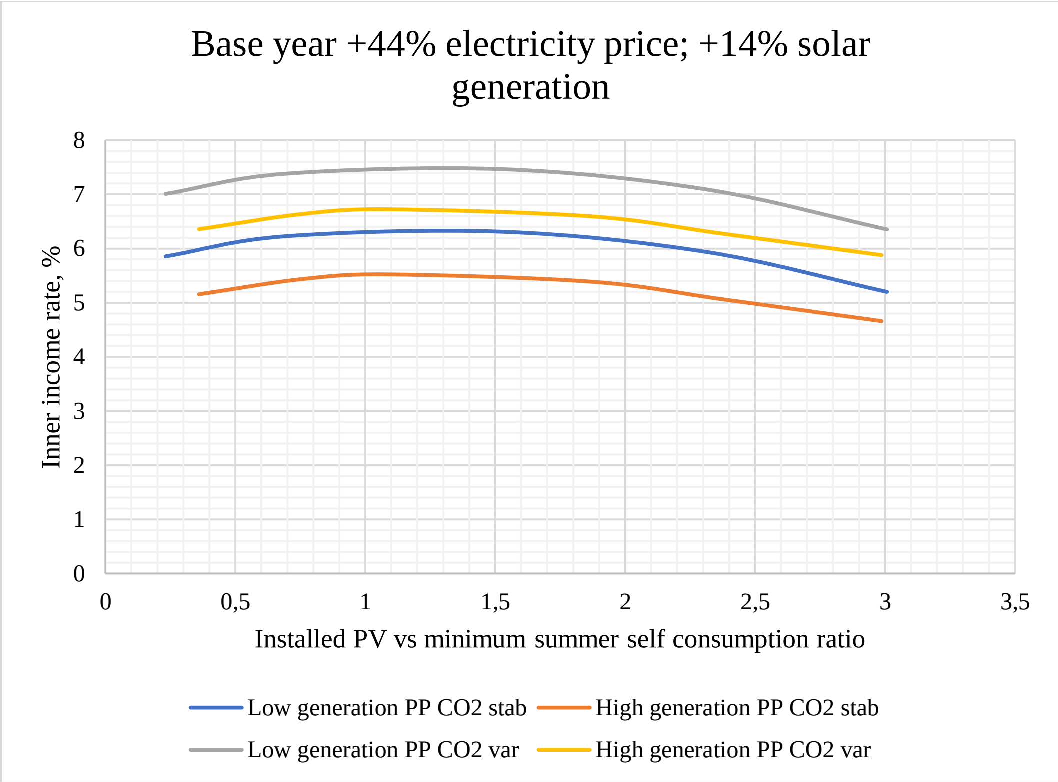

Fig. 6.9 IRR for year with 44% higher electricity price and 14% higher solar generation scenarios.

From obtained results, it could be stated that PV system installed at power should be in range of 1 to 1.5 times of minimum summer load. Still, this is not rule and should be checked individually for different self-consumption trends, which can be done using developed methodology. For example, when power plant operating hour number was high and electricity prices low, almost same economic gains could be provided by PV system 1.3 to 2 times bigger than minimum summer load (Fig. 6.8 high generation power plant (PP) scenarios). But change in operating hour number and PV system generation have moved this optimal size point towards 1 to 1.3 times, exceeding this value will lead to further decrease of income (Fig. 6.9 high generation PP scenarios). In case of power plant with low operation hour number during summer both calculations indicated optimal PV system installed power to minimum load ratio of 1 to 1.5. Analysis of different scenarios should be performed, because lack or excess of solar generation has negative impact on income rate.

Payback time for PV systems should be within 20 years, this mark was not reached according to worst case scenario, with low solar generation, low electricity price and high number of operating hours of power plant during summer. Payback time data is presented in Table 6.3. It is clear that higher CO_2 emission allowance price results in shorter payback time, thus in case of high solar generation and higher electricity prices this impact becomes less decisive. 25% support or reduction in investments for every scenario under the scope will lead to targeted payback time of 20 years. Thus more decisive impact has an interest rate, in case of 3% interest rate, even 25% support or reduction of investments would not allow to most of scenarios reach 20 year payback mark. If low market electricity prices are prognosed and no revenue for CO_2 emission allowance is paid, then installation of PV system for self-consumption needs might be inefficient.

Table 6.3

Payback Time for Different PV System Operation Scenarios

Scenario	Payback time, years	Payback time with 25% support, years
High generation hours in summer, low electricity price, stabilized CO_2 emission allowance	>25	20
High generation hours in summer, low electricity price, variable CO_2 emission allowance	>25	16
Low generation hours in summer, low electricity price, stabilized CO_2 emission allowance	23	14
Low generation hours in summer, low electricity price, variable CO_2 emission allowance	19	12
High generation hours in summer, high electricity price, higher solar generation, stabilized CO_2 emission allowance	15	10
High generation hours in summer, high electricity price, higher solar generation, variable CO_2 emission allowance	14	9
Low generation hours in summer, high electricity price, higher solar generation, stabilized CO_2 emission allowance	14	9
Low generation hours in summer, high electricity price, higher solar generation, variable CO_2 emission allowance	13	9

6.2. Battery Storage System Use for Self-Consumption Needs

In case, if it is possible (no areal constrains) to install bigger solar system – generated power can exceed consumption and should be sold in electricity market or stored. Studies for house load have proven that combination of solar generation and battery storage is good solution to maximize use of clean energy and make cost benefit. Results of different combination of PV system and battery storage is presented at Fig. 6.10., this data is provided for Australia [46].

BESS are widely used to store PV generated energy, which allows to avoid electricity provision to market at much lower rate than purchasing electricity from market. For example in EU 40% of electricity price for end-user are taxes and levies, with 73% growth from 2008. Different studies are made to optimize PV or other electricity generator operation when coupled with BESS [45], [60]. More and more BESS are used for different facility peak shaving, which allow to avoid additional electricity costs during peak hours [126]. As in Latvia is low sunny day rate, it is reasonable to use BESS not only for storing PV generated energy, but also for price peak shaving, also it is possible to charge BESS when CCGT is operating, which grants low self-consumption costs.

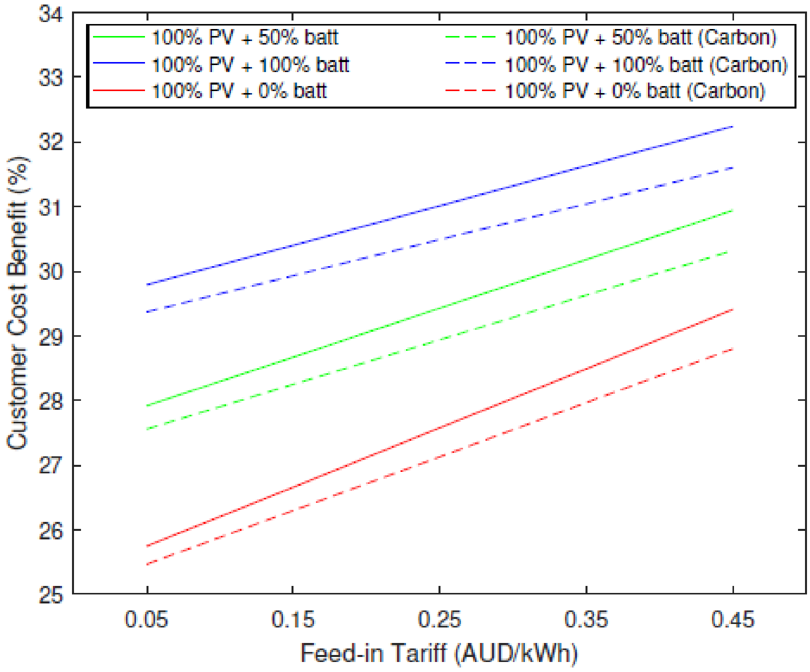

Fig. 6.10 Customer benefit depending on feed-in tariff [46].

To analyze which combination of PV and BESS is optimal solution to use for CCGT self-consumption cost reduction areal constrains were not considered. Algorithm presented in Fig. 6.6 were modernized by part presented at Fig. 6.11. Special program was developed. This program allows to use battery in various ways. In case if solar generation is available, it is priority for BESS to store excess of it (part which could not be used to cover self-consumption of CCGT) and then release solar generated energy in CCGT self-consumption grid. In case if battery could not be fully charged by solar power, algorithm will seek for possibility to charge it from grid or generators, but only in case if program foresees possibility to discharge in future, such approach allow to reduce operating cycles of BESS and losses due to BESS operation.

As only controllable variable for algorithm is BESS available capacity, algorithm uses enumeration to find best hours for BESS discharge and charge from the power grid/generators in case if PV generation is not enough. The algorithm was tested on historical data, but it is suitable for use with real day-ahead data. Main constrain for planning the future operation of BESS is PV generation and electricity market price prognosis, but it is not in the scope of this work.

For BESS application as previously for solar system is assumed that power transformer is disconnected from the grid when not performing. Target (6.10) function is changed to:

$$\begin{cases} f(R) = \sum_{t=1}^{t} \left[C_{m.t}\left(A_{g.t} - A_{d.t}\right) + C_{sc.t}(A_{c.t}) - C_{s.t}(A_{s.t}) + C_{bs.t}(A_{bs.t}) + C_{BESSc.t}(A_{bc.t}) - C_{BESSd.t}(A_{bd.t})\right] \\ A_{c.t} - A_{s.t} < 0 \;\rightarrow\; C_{s.t}(A_{s.t}) = C_{sc.t}(A_{c.t}) \\ A_{c.t} = 0; A_{g.t} - A_{d.t} - A_{s.t} < 0 \rightarrow\; C_{s.t}(A_{s.t}) = C_{m.t}(A_{s.t});\; C_{BESSc} = 0 \\ A_{c.t} = 0; A_{g.t} - A_{d.t} - A_{s.t} > 0 \rightarrow\; C_{s.t}(A_{s.t}) = C_{m.t}(A_{s.t}); C_{BESSc.t} = C_{m.t}; C_{bs.t} = C_{m.t} \\ A_{c.t} - A_{s.t} > 0 \;\rightarrow\; C_{s.t} * (A_{s.t}) = C_{sc.t} * (A_{s.t});\; C_{BESSd.t} = C_{sc.t}; A_{bd.t} \leq A_{c.t} - A_{s.t} \\ A_{c.t} > 0 \rightarrow C_{bs.t} = C_{sc.t} \\ t_{BESSc} \neq t_{BESSd} \end{cases} \tag{6.11}$$

where $C_{BESSc.t}$ – BESS charging price at hour *t*, EUR/ MWh;

$C_{BESSd.t}$ – BESS discharging price at hour *t*, EUR/ MWh;

$C_{bs.t}$ – BESS no load self-consumption price at hour *t*, EUR/ MWh

$A_{bc.t}$ – energy amount that is used for battery charging at hour *t*, MWh;

$A_{bc.t}$ – energy amount that discharged from battery at hour *t*, MWh;

$A_{bs.t}$ – energy amount used for BESS no-load losses at hour *t*, MWh;

t_{BESSc} – hour when BESS charging could be made;

t_{BESSd} – hour when BESS discharging could be made.

New target function is more complicated, because of electricity price changes of BESS during charge and discharge. Also amount of energy used for BESS charging and then discharged for self-consumption is different, developed methodology considers different losses described for BESS in 4.4 and for PV system 6.1. If no profitable charge/discharge during the day is foreseen, BESS is not operated, to reduce operating cycles energy losses. All discharges can appear only if BESS is charged. Charge and discharge power are limited by BESS rated power. BESS no-load self-consumption is set as constant value, thus, price of it changes due to operation regime of power plant. Developed program makes calculations within 24 hours and compares different charge/discharge hour and energy combinations to find optimal solution. First task of program is to find hours when battery charge could be performed from PV, for this PV generated excessive energy price is valued as 0. When all possibilities to charge BESS from PV is used, program seeks for hours when cheapest charging from the CCGT generators or grid could be performed, considering additional costs of electricity – price for charging from the grid, which is calculated using (4.12). In next step program checks whether it can discharge stored amount (considering losses in BESS, transformer and inverter) and gain some profit, if it is not possible, program reduces charging from the grid to amount that is profitable to discharge, if none – then no charging from the grid or generator is made. Discharge price also is fluctuating, in case if power plant consumes energy from the grid, price for discharged energy to cover consumption from the grid is calculated by (4.12). If there is no consumption from the grid, discharge price is equal to electricity market price. When solar generation exceeds self-consumption need and there is no more BESS capacity available, excessive energy is sold on market.

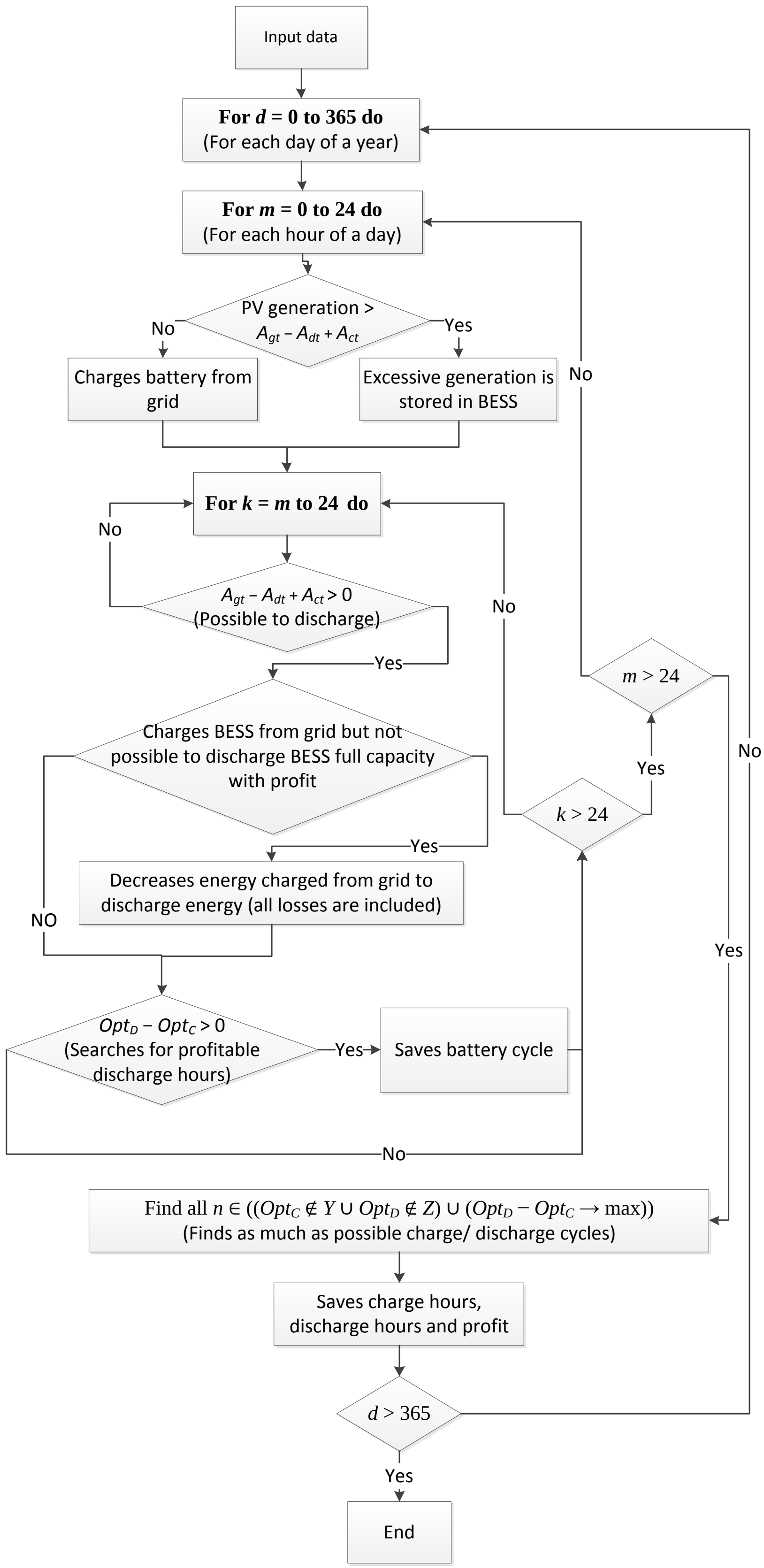

Fig. 6.11 Algorithm for BESS profit calculation for CCGT self-consumption use.

Opt – function optimum for f(R), with related hourly energy consumption; OptC – function optimum for f(PC), with related battery charging hours; OptD – function optimum for f(PD), with related battery discharging hours; Y – hours when charging not possible; Z – hours when discharging not possible.

For NPV calculation profit will be calculated from difference between normal system and system equipped with PV generation and BESS. Proposed methodology allows to make profit from BESS even when no solar generation appears. Operation of BESS is related to quite high losses which lead to a reduction of hours when BESS could operate to provide profit. Power transformer losses were chosen same as it was done for PV system in 6.1. The developed program calculates energy consumed for charging using:

$$P_{bc.t} = \frac{P_t}{\eta_{BESSinv}} + \Delta P_{T0} + P_{Tk}\left(\frac{P_t/\eta_{BESSinv}}{cos\varphi * S_T}\right)^2 \quad (6.11)$$

where $P_{bc.t}$ – power used to store in BESS power equal to P_t at hour *t*, kW;

P_t – available power for charge or discharge at hour *t*, kW;

$\eta_{BESSinv}$ – efficiency of BESS inverter, value used for calculation is 0.94.

Losses appear during discharge too:

$$P_{bd.t} = (P_t * \eta_{BESSinv} - P_t * k) - \Delta P_{T0} - \left(\frac{P_t * \eta_{BESSinv} - P_t * k}{cos\varphi * S_T}\right)^2 * P_{Tk} \quad (6.12)$$

where $P_{bd.t}$ – power used from BESS to release power equal to P_t at hour *t*, kW;

k – coefficient that considers self-discharge in BESS, value used for calculation is 0.05.

From this energy values of A_{bct} and A_{bdt} can be calculated. BESS no-load losses are calculated as stated in (4.15).

Input data from Table 6.2 must be replenished by data from Table 6.4.

Table 6.4

Inputs for BESS Calculation

Designation	Units	Description
A_{BESS}	kWh	Energy that can be operated in BESS considering under discharging and overcharging of Li-ion battery.
P_{BESS}	kW	Rated power of installed BESS
$\eta_{BESSinv}$	p.u.	Efficiency of BESS inverter
S_T	kVA	BESS power transformer apparent power
ΔP_{T0}	kW	BESS power transformer no-load losses
P_{Tk}	kW	BESS power transformer load losses
$cos\varphi$	-	Power factor for power delivered from BESS inverter to consumption
k	p.u.	coefficient that considers self-discharge in BESS
k_c	p.u.	coefficient that considers self-consumption of BESS controllers
k_{HVAC}	p.u.	coefficient that considers self-consumption of BESS HVAC

Several cases were under the scope using the same data for solar generation and self-consumption as in 6.1. Obtained results of program calculation for one winter day is presented at Fig. 6.12, but for one summer day with solar generation exceeding power plant self-consumption is presented at Fig. 6.13. In example, BESS power transformer was 3150 kVA and total usable capacity of BESS 8000 kWh.

At winter day (Fig. 6.12), when no solar generation present, price difference was used, charging BESS at cheaper hours (1, 2 and 3) and discharging during high price hours (7 and

8). To gain maximum profit from such operation, part of charged energy was discharged only at 17 hour, when revenue was higher than in any previous or upcoming hour, taking into account BESS losses.

During the day with solar generation (Fig. 6.13) main task was to store all excessive solar generation and later use for self-consumption needs. Developed algorithm correctly charged BESS during all hours when solar generation exceeded self-consumption needs. At 19 and 20 hours BESS started discharging and covered amount of energy solar generation was lacking to provide self-consumption needs. At 23rd hour price was slightly lower than at 24th hour and BESS was not discharging to make maximal profit from this day.

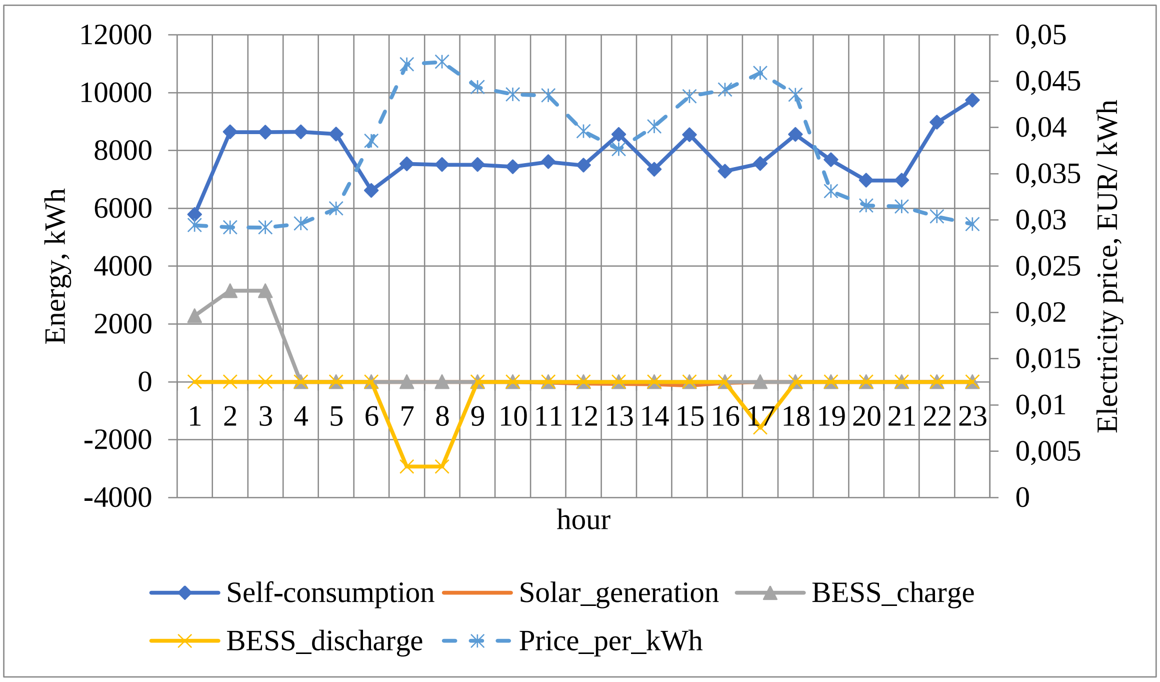

Fig. 6.12 BESS optimal charging and discharging during the day without solar generation.

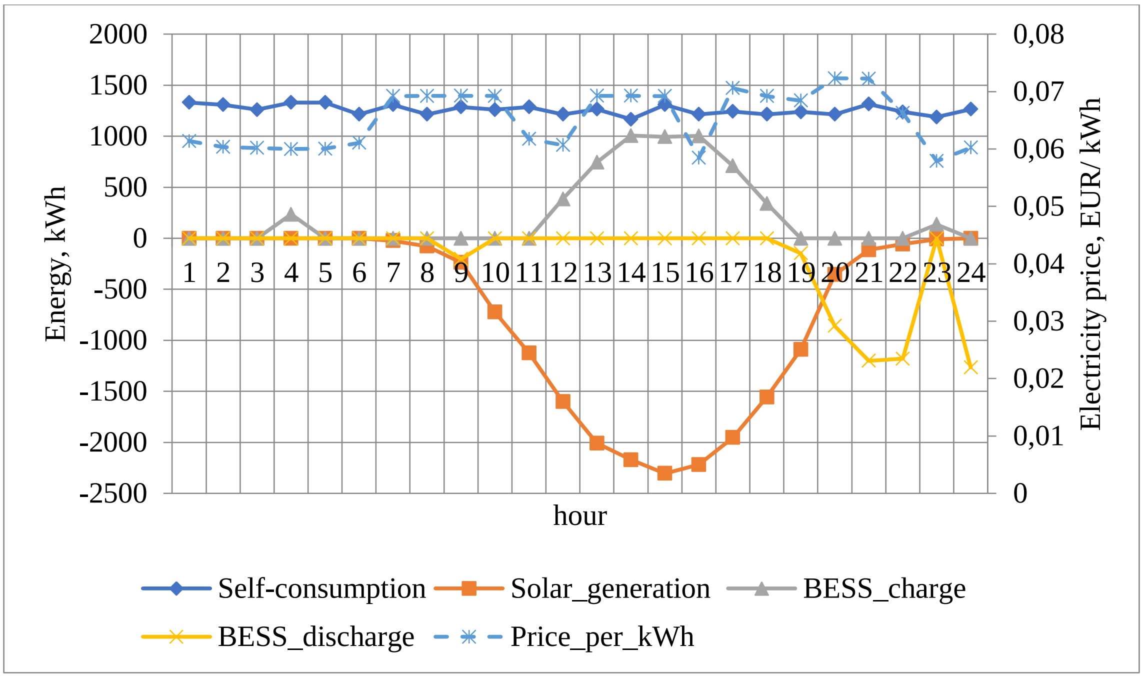

Fig. 6.13 BESS optimal charging and discharging during the day with solar generation.

Algorithm presented in 6.1 allows to choose optimal PV system size, thus than usage of BESS is possible only for optimization by charging and discharging battery according to electricity price. For that reason, oversized PV panels and different sized BESS were used to make NPV calculations for combined PV and BESS system. Some results are presented in Table 6.5. Data is represented for power plant with low generation in summer during the year with higher electricity prices and solar generation, so it is the most optimistic scenario. Revenue from stabilized CO_2 allowance price was considered.

Table 6.5

Comparison of Revenue from PV System and PV System with BESS

	Income from system operation, EUR	Maintenance and no-load self-consumption per year, EUR	Revenue per year considering operation and no-load losses, EUR	% of PV revenue
PV 1425 kW	97 940.85	11 307.12	86 633.73	100
PV 1425 kW, 1500 kWh BESS	113 318.55	58 776.70	54 541.85	62.96
PV 1425 kW, 3000 kWh BESS	123 706.18	62 226.70	61 479.49	70.96
PV 1852 kW	121 290.32	14 688.45	106 601.87	100
PV 1852 kW, 2000 kWh BESS	145 940.23	74 312.93	71 627.30	67.19
PV 1852 kW, 4000 kWh BESS	158 714.38	78 912.93	79 801.45	74.86
PV 2565 kW	151 837.10	20 324.01	131 513.09	100
PV 2565 kW, 4000 kWh BESS	205 697.16	116 187.55	89 509.60	68.06
PV 2565 kW, 8000 kWh BESS	222 321.86	125 387.56	96 934.30	73.71

Use combination of excessive solar system and BESS leads to much higher investments, BESS installation costs are significant, but even more problems arise from no-load losses of battery storage system. All year long according to presented calculation 4% of installed power is used for HVAC and control system operation. It was assumed that power transformer operates only together with BESS, it is switched on and off together with inverter power circuit. Additional income from BESS usage was much lower than costs of electricity to cover losses.

In all scenarios BESS no-load losses cost per year are higher than income from BESS operation per year. Graph obtained in Fig. 6.14 shows that use of C rate lower than 1, respectively BESS is charged or discharge for full capacity longer than in one hour, is not preferable, thus use of BESS with C rate above 1, charges/discharges faster than in one hour also does not lead to better results, because mentioned no-load losses will remain almost at the same level. Optimal solution is C rate equal to 1. Without support for installation of such system none of scenarios has payback possibility. With 75% support, best scenarios have payback time of 6 years, but worst 10 years, which equals to usable BESS lifetime.

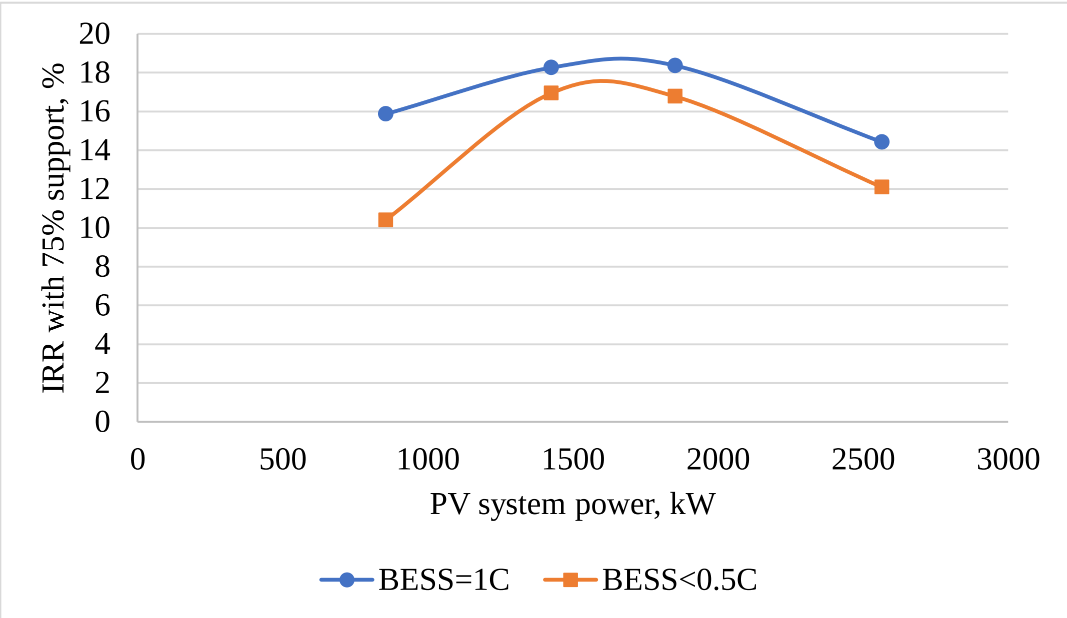

Fig. 6.14 IRR for different PV and BESS combinations with 75% support.

6.3. Summary

Photovoltaic systems can be used to cover CCGTs self-consumption needs. Results of developed methodology show that optimal size of PV system is 1-1.5 ratio to minimum summer load. Best economic performance and shortest payback time can be reached during low generation of CCGT in summer, higher electricity prices and solar generation. Best case resulted in 13 years payback time concerning all possible losses during PV system operation and stand-by, thus it was at higher CO_2 allowance prognosis. At low CO_2 allowance prices, high CCGT generation during summer, low electricity market prices and lower solar generation, payback time can be longer than 20 years, which makes PV usage economically inefficient. Thus, reported payback times are true for cases when such installations are supported at government level and credit interest rate is equal to 0%.

Oversizing PV system to combine its operation with battery storage system does not give any positive economic result, due to high investments and significant no-load and operating losses in BESS system. Only high support level can allow mentioned system to gain payback time within 10 years. Optimal charge/discharge time of BESS for such application is 1 hour. investments and no-load losses for bigger battery storages overcome possible revenue from BESS operation.

The developed program is able to maximize revenue from BESS operation using it in combination with PV system as well as stand-alone solution for days with low or zero solar generation. The developed program can be used to optimize BESS operation even for systems without PV generation; no additional changes should be done. Methodology was tested on historical data, but for real operation prognosis of solar irradiation should be performed, which was not under the scope.

7. OUTAGE AND ANCILLARY SERVICE IMPACT ON CCGT OPERATION STRATEGY

7.1. Proposed Methodology

Previously it was discussed that ancillary service provision, as well as modernisations of self- consumption system of CCGT, can lead to additional income. Additional income from ancillary service provision can allow to avoid CCGT power plant shutdowns and extend operating hours which, as discussed in chapter 3, can lead to lower incident rate and forced unavailability hours. Calculations show that income from discussed CCGT self-consumption system modernization is only enough to cover additional costs of performed modernizations and only in some scenarios can give additional profit which could be used to avoid shutdown of CCGT.

The proposed methodology is presented at Fig. 7.1. Several steps should be done before impact calculation.

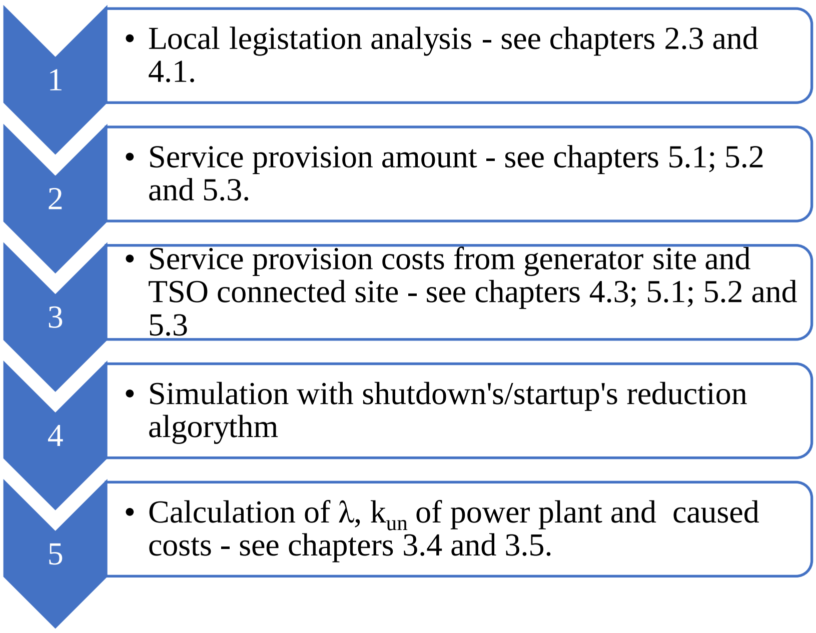

Fig. 7.1 Ancillary service provision impact analysis methodology.

First step is analytical, local legislations should be studied. This step is only indicative weather generators can or not perform in ancillary service market, in further calculations it is assumed that CCGT generators can perform in reactive power control, inertia provision and FCR service provision. Second step is related to service amount which could be sold, for biggest Latvian CCGT these amounts are shown in Table 7.1. Third step gives a look on possible price of any service which could be provided by generators, or other party (not generator) connected to TSO. If service is market based, then generators should grant better price than TSO connected party can do. Thus, in chapter 5 it was discussed that in case of upgrades for ancillary service provision generators might not ensure best price on the ancillary service market, so giving price lower than can provide other parties might result in financial loss. Prices which should be used also are presented in Table 7.1. Forth step is simulation which allow to understand whether additional income from ancillary service provision allows to reduce startup and/or shutdown number in order to reduce CCGT electrical equipment incident rate, unavailability time and caused costs. Fifth step is an analysis of simulation, in which λ, k_{un} of power plant electrical equipment and caused costs are recalculated according to simulation results and compared to results before simulation.

Table 7.1

Ancillary Service Amount and Costs

Service	Amount per hour (average per year)	Generator price for service	To TSO connected party price for service
Reactive power control	-64 MVAr	$C_{qm.sub}$ (5.9)	$C_{qm.sub}$ (5.9)
Inertia	2200 MWs	$\frac{E_{CHP}Ci\ (5.16)}{E_h}$	C_i (5.16)
FCR	15 MW/ 15 minutes	$C_{F.g} = \frac{C_{up.gen}(5.26)}{t_{op}}$	$C_{F.sub} = \frac{C_{r.op}(5.22)}{t_{op}}$

In case of reactive power provision lowest rate appears for service provision from TSO connected party, so, these costs – 1.39 EUR/ MVAr were chosen as the indicative price of CCGT provided reactive power for calculation. Inertia provision is costly and complicated to calculate. In 5.2 costs of coverage of lack of inertia were calculated. At present generators are not remunerated for inertia provision, but they should be if it becomes market based service. So hourly costs of lack of inertia coverage calculated in (5.16) were taken as an indicative price for inertia provided from CCGT, for 400 MW CGGT unit it is 2200 MWs, using proportion price is 834.35 EUR per hour. Therefore, provision of FCR is cheaper from CCGT site, but price of service was taken as calculated for BESS connected to TSO – 10.73 EUR per MW per hour, it is price which allow to compete with TSO connected BESS and ensure maximum profit.

7.2. Cycle number reduction and profit maximization algorithms

Optimization of CCGT operation e.g. increase of flexibility and reduction of operation and start-up costs is presented in various works [5], [11], [12], [49]. Provision of ancillary service could open new possibilities for flexibility improvement, due to additional income. Proposed methodology takes into account reduction of costs due to change of startup type, which is described in [56] and in addition income from ancillary service provision describe previously in this work.

For the proposed methodology power plant operation was divided into three stages, startup, operation mode and shutdown. Idea is to extend operating hours moving startup's back in time or shutdown's forward in future. The assumption is made, that such movement does not impact market electricity prices. Service provision is taken as additional income. Moving startup and shutdown hours sometimes lead to power generation in hours when market electricity prices are lower than electricity production costs. As additional income from movement is taken reduction of startup costs, so if time span between last shutdown and next startup reduces to amount which represents next better startup conditions, difference of startup costs will be assumed as additional income from startup/shutdown hour movement.

Program based on the proposed methodology is developed to solve two tasks; one is maximization of power plant profit. As moving is related to loss of income from electricity trading and program seeks to make any change only if some profit from startup costs reduction and service provision is foreseen. Second task is defined as reduction of number of startup's, for this reason proram uses all income from service provision in normal operating mode to cover losses of electricity trading when the power plant was not originally operated.

Impact of ancillary service provision on cycling operation could be estimated from historical or forecasted data, same rules will apply in both cases. Startup hours are hours when CCGT did not reach its minimum allowed load $P<P_{min}$, these hours as one set could be moved back in time. Operating hours are hours from historical data or prognosis when CCGT is operating at least with minimum allowed load $P \geq P_{min}$, these hours are static and does not move in timeline, it is assumed that they are already planned perfectly. Shutdown hours are hours that come after operating hours and apply to rule $P<P_{min}$, these hours could be moved further in future. If startup hours or shutdown hours are moving, operating hours are stable, will appear empty hours. for that reason, additional function is used to fill them with $P= P_{min}$.

Following parameters are used:

Table 7.2

Parameters for Shutdown's/Startup's Reduction Algorithm Simulation

Designation	Description
t	Time, h
t_{sp}^{n-1}	Hour of previous shutdown, h
t_{st}^{n}	Hour of actual startup, h
$P_{st.1}, P_{st.2} \dots P_{st.k}$	Active power of 1st , 2nd … kth hour of startup sequence, MW
k	Startup sequence duration
P_{min}	Generator minimum allowed active power, MW
$Q_{st.1}, Q_{st.2} \dots Q_{st.k}$	Reactive power of 1st , 2nd … kth hour of startup sequence, MVAr
Q_{avg}	Average reactive power provided from generator site, MVAr
C_t	Electricity market price at hour t, EUR/ MWh
$C_{st.1}, C_{st.2} \dots C_{st.k}$	Electricity market price of 1st , 2nd … kth hour of startup sequence, EUR/MWh
C_0	Active power generation costs, EUR/MWh
C_q	Price for generated reactive power, EUR/MVArh

Continuation of Table 7.2

C_i	Price for generator provided inertia, EUR/MWs
E_{CHP}	Generator provided inertia, MWs
$C_{F.g}$	Price of generator granted FCR of 15 MW for 15 minutes
$P_{sp.1}$, $P_{sp.2}$ … $P_{sp.m}$	Active power of 1st , 2nd … mth hour of shutdown sequence, MW
$Q_{sp.1}$, $Q_{sp.2}$ … $Q_{sp.m}$	Reactive power of 1st , 2nd … mth hour of shutdown sequence, MVAr
$C_{sp.1}$, $C_{sp.2}$ … $C_{sp.m}$	Electricity market price of 1st , 2nd … mth hour of startup sequence, EUR/MWh
m	Shutdown sequence duration
C_s	Avoided costs of startup due to change of state of startup (cold / warm / hot), EUR
$t_{sp.s}$; $t_{st.s}$	Hours of simulated shutdown and startup
n	Iteration number

Function for simulated startup hours is expressed as follows:

$$f_1 = \sum_{t={t_{st}}^{n}-1}^{t={t_{sp}}^{n-1}+1} \left[P_{st.1}(C_t - C_{st.1}) + Q_{st.1}C_q + P_{st.2}(C_{t+1} - C_{st.2}) + Q_{st.2}C_q + \cdots \right.$$
$$\left. + P_{st.k}(C_{t+k} - C_{s.k}) + Q_{st.k}C_q\right] + k\frac{E_{CHP}Ci}{E_h} \qquad (7.1)$$

Function for simulated hours between real operating hours and simulated startup hours is expressed as:

$$f_2 = \sum_{t={t_{st}}^{n}}^{t={t_{sp}}^{n-1}+k+1} \left[P_{min}(C_t - C_0) + \frac{E_{CHP}Ci}{E_h} + Q_{avg}C_q + C_{F.g}\right] \qquad (7.2)$$

Function for simulated shutdown hours is expressed as follows:

$$f_3 = \sum_{t={t_{sp}}^{n-1}+1}^{t={t_{st}}^{n}-m} \left[P_{sp.1}\big(C_t - C_{sp.1}\big) + Q_{sp.1}C_q + P_{sp.2}\big(C_{t+1} - C_{sp.2}\big) + Q_{sp.2}C_q + \cdots \right.$$
$$\left. + P_{sp.m}\big(C_{t+m-1} - C_{sp.m}\big) + Q_{sp.m}C_q\right] + m\frac{E_{CHP}Ci}{E_h} \qquad (7.3)$$

Function for simulated hours between real operating hours and simulated shutdown hours is expressed as:

$$f_4 = \sum_{t={t_{sp}}^{n-1}}^{t={t_{st}}^{n}-m-1} \left(P_{min} * (C_t - C_0) + \frac{E_{CHP} * Ci}{E_h} + Q_{avg} * C_q + C_{F.g}\right) \qquad (7.4)$$

Function of additional profit from ancillary service provision for operating hours is expressed as:

$$f_5 = \sum_{t={t_{sp}}^n}^{t={t_{st}}^n} \left[\frac{E_{CHP}Ci}{E_h} \quad + Q_{avg}C_q + C_{F.g} \right] \tag{7.5}$$

To ensure maximal profit gained from ancillary service provision following function is proposed:

$$\begin{cases} Y_{mp}^n = f_1^n + f_2^n + f_3^{n-1} + f_4^{n-1} + C_s \\ 8 < t_{st}^n - t_{sp}^{n-1} \le 72;\ t_{st.s}^n - t_{sp.s}^{n-1} \le 8\ \rightarrow C_{sh} = 16\,020 \\ 72 < t_{st}^n - t_{sp}^{n-1};\ t_{st.s}^n - t_{sp.s}^{n-1} \le 8\ \rightarrow C_s = 29\,380 \\ 72 < t_{st}^n - t_{sp}^{n-1};\ 8 < t_{st.s}^n - t_{sp.s}^{n-1} \le 72\ \rightarrow C_s = 13\,360 \\ t_{st.s}^n - t_{sp.s}^{n-1} > 72\ \rightarrow C_s = 0 \\ 0 < t_{st}^n - t_{sp}^{n-1} \le 8;\ t_{st.s}^n - t_{sp.s}^{n-1} = 0\ \rightarrow C_s = 16\,020 \end{cases} \tag{7.6}$$

To ensure least number of startup's using gain from ancillary service provision following function is proposed:

$$\begin{cases} Y_{lst}^n = f_1^n + f_2^n + f_5^n + f_3^{n-1} + f_4^{n-1} + C_s \\ 8 < t_{st}^n - t_{sp}^{n-1} < 72;\ t_{st.s}^n - t_{sp.s}^{n-1} \le 8\ \rightarrow C_{sh} = 16\,020 \\ 72 < t_{st}^n - t_{sp}^{n-1};\ t_{st.s}^n - t_{sp.s}^{n-1} \le 8\ \rightarrow C_s = 29\,380 \\ 72 < t_{st}^n - t_{sp}^{n-1};\ 8 < t_{st.s}^n - t_{sp.s}^{n-1} \le 72\ \rightarrow C_s = 13\,360 \\ t_{st.s}^n - t_{sp.s}^{n-1} > 72\ \rightarrow C_s = 0 \\ 0 < t_{st}^n - t_{sp}^{n-1} \le 8;\ t_{st.s}^n - t_{sp.s}^{n-1} = 0\ \rightarrow C_s = 16\,020 \end{cases} \tag{7.7}$$

In Fig. 7.2 is provided graphical presentation of (7.7) function. Functions (7.6) and (7.7) includes avoided costs due to better startup position, for example, moving from cold state start to hot start state will allow to avoid costs of 29 380 EUR and in Y function are included as additional profit. Prices of possible avoided costs of different startup states were calculated from data provided in [56] for similar 400 MW CCGT power plant.

When maximizing income of CCGT main objective of program is defined as:

$$\sum_{n=0}^{n} Y_{mp}^n \rightarrow max \tag{7.8}$$

When moving to reduction of number of CCGT startup's, main objective of program is defined as:

$$\begin{cases} \sum_{n=0}^{n} Y_{lst}^n > 0 \\ \sum_{n=1}^{n} t_{st.s}^n - t_{sp.s}^{n-1} \rightarrow min \end{cases} \tag{7.9}$$

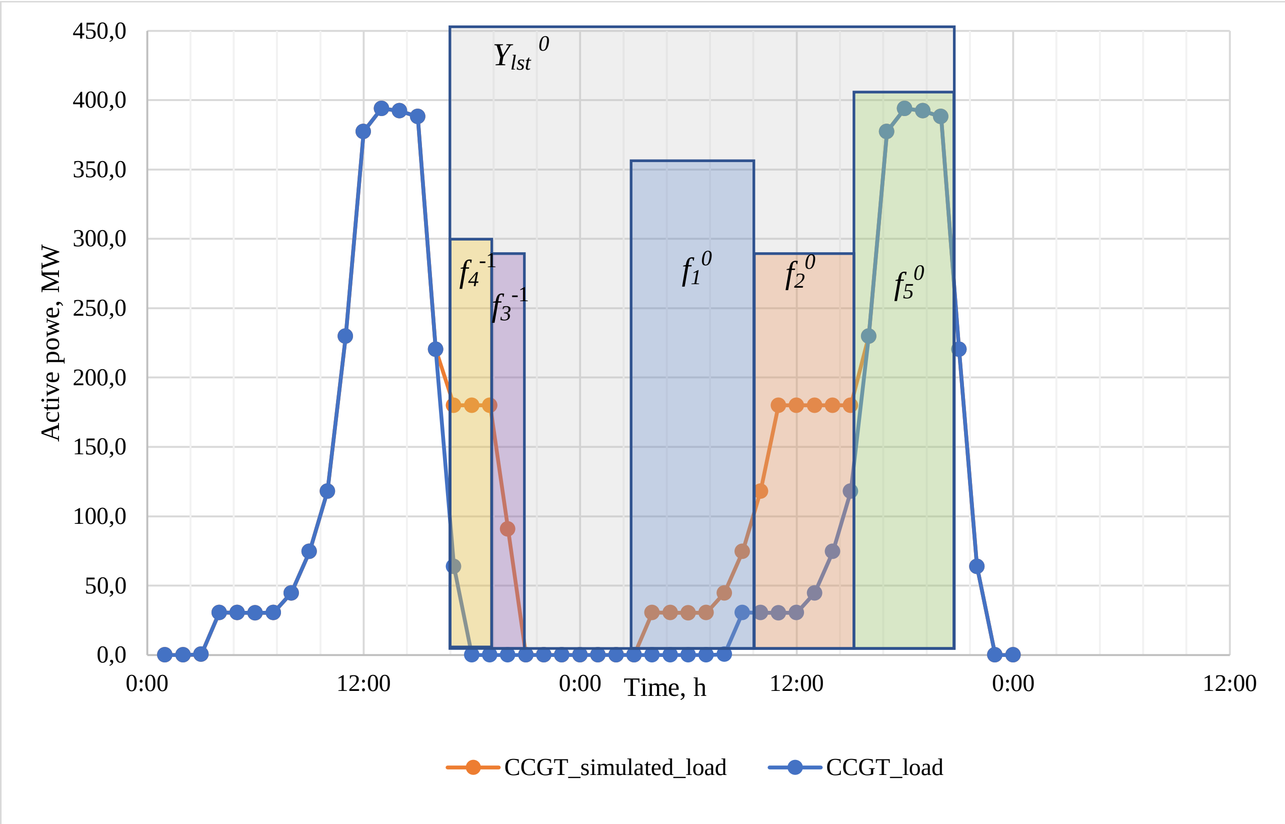

Fig. 7.2 Shutdown's/startup's number reduction algorithm visualization.

Historical data of real 400 MW CCGT as well as methodology calculation results for 400 MW CCGT running in 2017, when lowest electricity market price in Latvia was present are provided in Table 7.3; same for 2018 year when highest market electricity price was present in Latvia is provided in Table 7.4 Calculation of generator incident rate, total incident rate and caused unavailability were done as described in 3.4, costs of incidents and caused unavailability were calculated as defined in 3.5. Results show, that steering for maximum profit is better in case of low operating number (2359) of hours and high number (28) of starts, therefore in case of high operating hours (5421) and same startup number as previously, seeking for startup number reduction might lead to even better economical gain than seeking for maximal profit. The proposed methodology for power plant planning enhancement could be easily applied to various scenarios and each case should be analyzed separately, no general statement can be made from obtained results.

Table 7.3

Results of the Proposed Methodology for 400 MW CCGTfor 2017 Year

	Operati ng hours	Number of startup's			Generator incident rate	Total incident rate	Unavailability hours	Incident and unavailability caused costs, EUR	Profit from ancillary service provision, EUR	Total, EUR
		Hot	Warm	Cold						
Ancillary service provision	2358	1	8	18	0.36684	0.38594	44.03	-1 301 183	2 370 192	1 069 009
Maximum profit after planning enhancement	2479	1	12	13	0.36992	0.38902	42.98	-1 277 500	2 586 604	**1 309 104**
Least starts after planning enhancement	2773	0	5	13	0.34064	0.35974	33.91	-1 049 080	2 137 948	1 088 868

Table 7.4

Results of the Proposed Methodology for 400 MW CCGT for 2018 Year

	Operati ng hours	Number of startup's			Generator incident rate	Total incident rate	Unavailability hours	Incident and unavailability caused costs, EUR	Profit from ancillary service provision, EUR	Total, EUR
		Hot	Warm	Cold						
Ancillary service provision	5421	3	17	8	0.61848	0.63758	47.88	-1508885	565 2005	4 143 119
Maximum profit after planning enhancement	6203	2	6	5	0.35561	0.37471	31.17	-990983	7 201 747	6 210 763
Least starts after planning enhancement	6457	0	0	5	0.14491	0.16401	20.95	-651265	6 949 929	**6 298 663**

7.3. Summary

This section summarizes research and provides a look at how additional income for ancillary service provision could be used to optimize CCGT operation with target to maximize profit or reduce number of startup's. Service price calculation were based on results of calculations in 5.1, 5.2 and 5.3. Also, incident rate and unavailability calculations, as well as caused costs calculation from sections 3.4 and 3.5. are used to summarize total possible profit or losses in case of use of the proposed methodology.

Proposed methodology and developed program could be used also with other service provision prices as well as electricity prices and historical or prognosed CCGT operation data. Additional income for other than mentioned services provision could be added. CCGT has the advantage of ancillary service provision, because can ensure all kind of services all year long, except maintenance and outages periods.

Results of research show how number of startups can influence turbo generator incident rate as well as total CCGT main electrical equipment incident rate. All this results in unavailability hours and costs. Provision of ancillary service could result in extension of operation hours and reduction of number of startup's. Thus, every case should be studied individually, in some circumstances seek of maximal profit from service provision can result in better summarized situation due to reduction of unavailability costs, in other circumstances it is better to use additional income from service provision to maximally reduce number of startup's.

Adding to proposed methodology other equipment of CCGT, such as gas turbine, steam turbine and heat recovery steam generators, can lead to other results, thus, mentioned equipment was not under the scope.

In case of FCR and inertia provision CCGT almost does not have competes, wind and solar generation could not ensure fast rise of generation if no additional BESS are used, which still are costly. Hydro power plants are very dependent on water flow and in some cases it is not economically feasible or even possible to store enough water for ancillary service provision. Thus, for reactive power provision many applications could be used, and service overall price is quite low, impact of this service remuneration on CCGT operation optimization also is quite low.

CONCLUSIONS

1. Analysis of available statistics was made to obtain empirical formulas for incident and unavailability calculations for CHP main electrical equipment. Results show that the rise in number of startups leads to more incidents and unavailability of main electrical equipment, the same is with the rise of operating hours, whereas impact is much lower.
2. Costs of incident caused unavailability were evaluated to show economic impact of main electrical equipment incidents. The obtained results can be used in risk assessment and in future planning of power plant operation.
3. Additional equipment should be installed at existing generator sites to fulfill RfG. In the Doctoral Thesis calculation examples are provided to ensure proper modernization of existing generators. Some cases were analyzed, and solutions were proposed.
4. Synchronization with CEN will lead to new ancillary service markets. For that reason, calculations of costs for reactive power provision, inertia and FCR provision were made. Results show that the lowest rate of reactive power control is possible if generators are not remunerated for service provision. Provision of FCR is cheaper when provided from biggest generators. Inertia provision is the most costly ancillary service, generators should be remunerated for such service provision to reduce investments in installation of additional equipment in power network.
5. Methodology to calculate possible gains from PV system installation for CCGT self-consumption needs was developed. Results show that PV installation is especially useful for power plants with low operating hours in summer. Most optimistic results show payback time of 13 years without any support, thus 0 % interest rate was assumed. The optimal size of installed PV system should be 1 to 1.5 times of minimal summer self-consumption load. The developed program can be applied to any specific case to calculate optimal power of PV system.
6. Combination of oversized PV and BESS does not show any economic gain due to high investments, no-load losses and relatively high losses during operation. The developed methodology for BESS operation optimization for CCGT self-consumption was approved on historical data.
7. The developed methodology for CCGT operation planning enhancement was tested on historical data. It allows to seek for maximal gain from ancillary service provision or minimum startup number per year. Based on the gained results total incident rates as well as caused unavailability costs of generators and main electrical equipment were calculated. Comparing the results of both approaches allow to choose optimal operation strategy for CCGT.
8. CCGTs are capable to provide all necessary services to support grid stability. Remuneration of ancillary services will give new possibilities for CCGTs. Methodology for CCGT operation planning enhancement shows that ancillary service provision allows to move to less cycling operation mode.

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